

SB

192

(FILE 3)

<TARGET><BILL>SB 192</BILL><SUBJECT>SB 192 (FILE
3)</SUBJECT><COMM>SFIN27</COMM></TARGET>

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 - Alaska Oil and Gas Conservation Commission (AOGCC)
 - Alaska Support Industry Alliance
 - Resource Development Council for Alaska (RDC)

1.

Updated Fiscal Notes

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

Bill Version CSSB192(RES)
 Fiscal Note Number _____
 () Publish Date _____

Identifier (file name) SB192CS(RES)-DNR-DOG-03-13-12 Dept. Affected Natural Resources
 Title Oil and Gas Production Tax Rate Appropriation Oil and Gas
 Allocation Oil and Gas
 Sponsor Senate Resources Committee
 Requester Senate Finance OMB Component Number 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates				
			FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES	FY13	FY13	FY14	FY15	FY16	FY17	FY18
Personal Services	743.4		743.4	743.4	441.2	441.2	441.2
Travel							
Services	139.0		139.0	99.0	47.5	47.5	47.5
Commodities	75.0						
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	957.4	0.0	882.4	842.4	488.7	488.7	488.7

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF	957.4		882.4	842.4	488.7	488.7	488.7
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		957.4	0.0	882.4	842.4	488.7	488.7	488.7

POSITIONS							
Full-time	8	0	8	8	5	5	5
Part-time							
Temporary							

CHANGE IN REVENUES	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY12) operating costs 0.0 (separate supplemental appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs 0.0 (separate capital appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

The committee substitute has added a provision to create a petroleum information management system. The Division of Oil and Gas develops, stores, and maintains much of the information identified for inclusion in the system.

Prepared by William C. Barron, Director
 Division Division of Oil and Gas
 Approved by Daniel Sullivan, Commissioner
Department of Natural Resources

Phone 907-269-8800
 Date/Time 3/13/12 4:00 PM
 Date 3/13/2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB192(RES)

Analysis

Sections 2 and 3 amend AS 31.05 by adding a new section (AS 31.05.031) which requires the Alaska Oil and Gas Conservation Commission (AOGCC) to develop and maintain an electronic petroleum information management system (PIMS) to archive state oil and gas information. The system will only include non-confidential information identified in this bill and other information AOGCC determines "necessary and relevant" to oil and gas exploration, development, and production. The Division of Oil and Gas (DOG) collects and maintains much of the information and materials listed in the proposed bill.

DOG will be a major contributor to the petroleum management system - likely designing, developing, and maintaining the system and associated materials. DOG currently houses the following information on: 1) unit and joint operating agreements, 2) state oil and gas exploration licenses and oil and gas leases, 3) exploration activities including seismic data, drilling reports, logs, geological models and maps, 4) development activities including development plans minus expenditure projections and reservoir characteristics, 5) facility maps and studies, and 6) abandonment plans and progress reports. DOG will conceivably have a role in contributing other information AOGCC deems "necessary and relevant" to oil and gas exploration, development, and production. DOG stores and maintains more than 40 years of information from Alaska's oil and gas activities. We find the directives in the proposed bill to initiate a significant undertaking by our department and others involved in supplying the requested information.

The committee substitute calls for providing information "in a form that is suitable for the commission to include in the petroleum information management system." Without sufficient knowledge of what will be construed to be "suitable" for the commission, it is assumed our information will need to re-integrated into new formats compatible with a sophisticated system easily navigated by the public. The AOGCC and DOG data collection and management systems are different in scale and scope, and synchronizing the systems will take considerable resources. In some cases, information could be linked or transferred to the PIMS site quickly; however, the information requested in the bill will demand extensive time and resources to adapt, redact, and restructure records and materials before inclusion in the PIMS.

Developing and maintaining a petroleum information management system will not likely provide any more information to the public than is currently available from our division. Non-confidential oil and gas information is currently available on DOG's website or upon request in electronic and hard copy formats. We estimate the proposed bill will initially require eight new FTEs with supporting costs and lease space expense in the division and funds necessary to hire contractors for information technology work.

The division would need five new natural resources specialists (2 NRS II and 3 NRS III) with one administrative assistant (range 12) and two analysts (range 20) for IT functions during build-out starting in FY13. In addition to staff increases, supporting costs and leased space, approximately \$75,000 in funding for software, licenses, and back-up systems is needed in FY 13. After the system build-out and population, we should be able to maintain the system with 4-5 FTEs. We project roughly \$75,000 for IT contract services in FY13 and FY 14, \$35,000 in FY15, and potentially no funds thereafter. Since we are not forecasting additional state revenue for these sections of the proposed bill, the significant costs incurred in developing and maintaining a new location for DOG information results in a negative fiscal impact to the state for years to come.

Storage for DOG seismic data (2-3 terrabytes) is too large to be stored in existing storage and therefore the division anticipates needing to contract with an electronic storage provider which could cost hundreds of thousands of dollars annually. This could happen as soon as the start of the system in FY 2013 and would be triggered by the need to segregate and store existing data within DNR. The Division has not yet formally priced this cost of data storage but DNR internal IT managers estimate a significant cost.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB192(RES)

Analysis Continued

CSSB192(RES) will also have impacts on oil production which impacts royalty revenue tracked by DO&G. Section 6 imposes a hard minimum tax (a minimum tax that cannot be reduced by credits) of 10% on production from large legacy fields (cumulative production over a billion barrels and current production over 100,000 barrels a day). Currently, the only fields that would qualify are the Prudhoe Bay and Kuparuk Units. Section 6 would substitute this tax for a minimum tax of 4% (when the West Coast ANS price exceeds \$25 per barrel) on the gross value at the point of production for the North Slope. This minimum can be reduced by credits.

The proposed hard minimum tax on production tax value at the Prudhoe Bay and Kuparuk Units will tend to discourage investment by Unit owners if those owners perceive the possibility of the minimum tax applying. If the minimum tax applies then the owners lose the tax benefits associated with the ability to deduct additional spending in both fields. All else equal, this will have an indeterminate negative impact on royalty revenue at Prudhoe Bay and Kuparuk.

Section 7 lowers the rate of increase in the production tax rate from 0.4% to 0.35% per dollar of production tax value per barrel above \$30 until the total tax rate (the base 25% plus the index based or progressive rate) equals 50%.

This bill also requires a separate production tax value per barrel calculation for gas sold outside the State. Section 14 would have the Department of Revenue issue regulations allocating costs to exported gas based on the gross value at the point of production for that gas versus that of other oil and gas production. Requiring a separate production tax value per barrel calculation for gas sold outside the State will have an indeterminate impact on royalty revenue. This impact will depend upon the anticipated relative profitability on a per unit basis of oil and gas production from the North Slope a decade or more from now.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

cost # codes

Bill Version CS SB 192 (RES)

Fiscal Note Number _____
 Publish Date _____

Identifier (file name) SB192CS(RES)-DOR-TAX-03-09-12

Dept. Affected Revenue

Title Oil and Gas Production Tax Rates

Appropriation Treasury and Taxation

Allocation Tax Division

Sponsor _____ (S) Resources

Requester _____ (S) Finance

OMB Component Number 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates					
			FY13	FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES								
Personal Services	214.8		214.8	214.8	214.8	214.8	214.8	214.8
Travel	10.0		10.0	10.0	10.0	10.0	10.0	10.0
Services	504.4		9.4	9.4	9.4	9.4	9.4	9.4
Commodities	1.0		1.0	1.0	1.0	1.0	1.0	1.0
Capital Outlay								
Grants, Benefits								
Miscellaneous								
TOTAL OPERATING	730.2		235.2	235.2	235.2	235.2	235.2	235.2

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF	730.2	235.2	235.2	235.2	235.2	235.2	235.2
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		730.2	0.0	235.2	235.2	235.2	235.2	235.2

POSITIONS							
Full-time	2.0		2	2	2	2	2
Part-time							
Temporary							

CHANGE IN REVENUES	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY12) operating costs _____ (separate supplemental appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs _____ (separate capital appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

Updated to reflect changes provided for in the CS, version E.

Prepared by Dan Stickel and Cherie Nienhuis, Economists
 Division Tax
 Approved by Bryan D. Butcher, Commissioner
Department of Revenue

Phone 907-465-3279
 Date/Time 3/9/12 4:11 PM
 Date 3/9/2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CS SB 192 (RES)

Analysis

The revenue impact of this bill is indeterminate.

This bill makes several changes to the oil and gas production tax system. Each of the major changes, along with its potential revenue impact, is discussed below.

1. Makes changes to the progressive surcharge. The "progressive surcharge" applies when the Production Tax Value (PTV) of all oil and gas produced in the state exceeds \$30 per barrel of oil equivalent (BOE). Under current law, the surcharge is 0.4% per \$1 of PTV between \$30 and \$92.50 per BOE, and it is 0.1% per \$1 of PTV between \$92.50 and \$342.50 per BOE, for a maximum surcharge rate of 50%. The surcharge rate is not bracketed: it applies to the entire PTV, not just the incremental value. Under this bill, the surcharge rate is changed to 0.35% per \$1 of PTV between \$30 and \$101.43, plus 0.1% per \$1 of PTV between \$101.43 and \$201.43, for a maximum surcharge rate of 35%. The surcharge rate continues to apply to the entire PTV, not just the incremental value. The effective date of this provision is January 1, 2013. Under Fall 2011 forecast assumptions, this change would reduce revenue by \$125 million in FY 2013, \$230 million in FY 2014, and approximately \$200 million per year in FY 2015- FY 2018.

2. Creates a \$10 per barrel allowance for production increases. This provision of the bill creates an allowance, by effectively reducing the production tax value by \$10 per barrel, for each barrel sent down the Trans Alaska Pipeline System (TAPS) by a company above their prior year level. The allowance is applicable only against the base tax rate of 25% and therefore the monetary value to the company is \$2.50 per barrel. The allowance is calculated and refunded by the Department independent of the tax and progressivity calculation and therefore does not impact the tax and progressivity rates applied. Under the Fall 2011 production forecast, several companies would receive this allowance in certain years during the time horizon of this fiscal note, but the total tax revenue impact (and therefore benefit to producers) is less than \$25 million total for all companies for all years.

3. Implements a 10% gross minimum tax for units with over 1 billion barrels cumulative production and over 100,000 barrels per day production in the most recent year. This provision of the bill creates a minimum tax of 10% of gross value for certain units, and deductions and credits cannot reduce the net tax for those units below 10% of gross value. Currently, the only units for which this provision would apply would be Prudhoe and Kuparuk. Under Fall 2011 revenue forecast assumptions, this provision would result in a tax increase for certain companies in certain years during the time horizon of this fiscal note, increasing state revenue by less than \$25 million per year. At lower oil prices, this provision would result in a significant increase in revenue to the state, amounting to over \$400 million per year increased revenue at a \$40 oil price.

As part of the minimum tax language, this bill makes changes to the calculation of the community revenue sharing fund provision at AS 29.60.850. This bill changes the calculation of the community revenue sharing fund appropriation to be the lesser of 20% of the progressivity for oil and gas for the previous year or the difference between the amount of revenue received under the minimum tax and 25% of the production tax value for oil and gas subject to the minimum tax in the previous year. The bill retains the maximum appropriation provisions. This provision, as currently written, increases the complexity of the calculation, but will likely not materially impact the amount of revenue appropriated.

4. Provides for a new petroleum information management system, to be implemented by the Alaska Oil and Gas Conservation Commission (AOGCC). This provision of the bill provides for a new information management system for publicly available oil and gas information, to be operational before January 1, 2014. The only responsibility of the Department of Revenue would be to provide certain information to AOGCC on a regular basis. These responsibilities could be implemented using existing resources.

5. "Decouples" Some Oil and Gas for Progressivity. This bill separates some oil and natural gas for purposes of calculating the progressivity portion of the production tax under AS 43.55 (also known as "decoupling"). Currently, all oil and gas are combined for purposes of calculating a single progressivity rate. Under this bill, two progressivity rates would be calculated. The first progressivity surcharge would be based on oil, Cook Inlet gas, and gas used in state. The second progressivity surcharge would be calculated based on gas other than Cook Inlet gas and gas used in state. The bill instructs the Department of Revenue, to the extent possible, to provide for the allocation of lease expenditures in proportion to the gross value at the point of production for the oil and gas produced.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CS SB 192 (RES)

Analysis Continued

For purposes of the tax calculation, exploration expenditures and development expenditures for non-producing leases or units would be allocated within geographic areas based on the gross value at the point of production of existing oil and gas production.

There would be minimal revenue impact during the time period included in this fiscal note as gas that is produced in Cook Inlet or used in state is not impacted by this bill. Small amounts of gas sales that would be decoupled prior to a major gas sale are expected to impact revenue to the state by less than \$10 million per year.

Under the current ACES system without the separate progressivity calculations, the state may receive less tax revenue with oil production and major gas sales, compared to oil production alone. This effect is due primarily to lower value gas diluting the progressivity surcharge on higher value oil under a combined tax. Under this bill, once major North Slope gas sales begin, exported gas will be subject to the separate progressivity calculation. Our modeling suggests that under this bill, and with addition of major gas sales to oil production, state revenue would be equal to or higher than revenue with oil only.

Additionally, this provision would generally increase tax revenue to the state, compared to the current tax system with a combined progressivity calculation, from major gas sales along with oil production. The amount of tax revenue increase is primarily dependent on oil and gas price and volume assumptions, along with some minor assumptions regarding expenditures and tariffs, but could be in excess of \$1 billion per year.

Costs to Implement

With the change in tax structure with decoupling, the department will need to develop comprehensive regulations. Significant regulations work would also be required to implement the other provisions of this bill, with some interrelations between the various provisions of the bill. The Department would require an additional \$495,000 for regulatory work and public participation in regulations for the package of regulations. With passage of this bill in the 2012 legislative session, the workshop and public forum process would likely begin in the summer or fall of 2012, and the majority of the regulation costs would be incurred in FY 13.

Specific costs for each major regulation project include the following:

\$75,000 for contracted professional services for regulation consulting.

\$270,000 for regulations costs including Department of Law, public notice and registry.

\$150,000 for public forums for education of taxpayers and public participation, including preparation materials and legal support, and possibly travel.

In addition to the one-time costs, the provisions of this bill will require two additional positions to handle the increased complexity of the tax law created by this legislation, in particular the increased workload associated with the gross floor, additional production allowance, and reporting requirements of this bill. The positions would be an Oil and Gas Revenue Auditor IV (Range 24) and a Tax Technician III (Range 14), at an annual cost of \$235,200.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

Bill Version CSSB192
 Fiscal Note Number _____
 () Publish Date _____

Identifier (file name) SB192CS(FIN)-DOA-AOGCC-03-8-12 Dept. Affected Administration
 Title Oil and Gas Production Tax Rates Appropriation AK Oil & Gas Conservation Commission
 Allocation Alaska Oil and Gas Conservation Commission
 Sponsor Senate Resources Committee
 Requester Senate Finance OMB Component Number 2010

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates					
			FY13	FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES								
Personal Services	1,579.0		1,579.0	1,579.0	1,579.0	1,579.0	1,579.0	1,579.0
Travel								
Services	32,520.0		5,015.0	5,015.0	5,015.0	5,015.0	5,015.0	5,015.0
Commodities	320.0		25.0	25.0	25.0	25.0	25.0	25.0
Capital Outlay								
Grants, Benefits								
Miscellaneous								
TOTAL OPERATING	34,419.0	0.0	6,619.0	6,619.0	6,619.0	6,619.0	6,619.0	6,619.0

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF	34,419.0	6,619.0	6,619.0	6,619.0	6,619.0	6,619.0	6,619.0
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		34,419.0	0.0	6,619.0	6,619.0	6,619.0	6,619.0	6,619.0

POSITIONS							
Full-time	15		15	15	15	15	15
Part-time							
Temporary							

CHANGE IN REVENUES							
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Estimated SUPPLEMENTAL (FY12) operating costs _____ (separate supplemental appropriation required;
 (discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs _____ (separate capital appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

The committee substitute has added a provision to create a petroleum information management system.

Prepared by Cathy P. Foerster, Chair, Commissioner
 Division Alaska Oil and Gas Conservation Commission
 Approved by John Cramer, Deputy Commissioner
Department of Administration

Phone 907-793-1228
 Date/Time 3/13/12 4:50 PM
 Date 3/8/2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB192

Analysis

The AOGCC, an independent quasi-judicial State agency, is the State's permitting and regulatory authority over hydrocarbon and geothermal wells. The Commission's duties include ensuring the maximum recovery of hydrocarbon and geothermal resources, preventing hydrocarbon and geothermal waste, ensuring well safety, and protecting underground sources of drinking water and correlative rights. Given the nature of the Commission's duties and responsibilities, apart from support personnel, it is staffed by expert petroleum engineers and petroleum geologists. Because its expertise is so carefully tailored to its statutory duties and responsibilities, the Commission functions well and Alaska has an unrivaled record with regard to well safety and production.

Section 3 of the committee substitute for SB 192 seeks to effectuate a substantial change in the AOGCC by requiring the Commission to establish, operate and maintain an electronic petroleum information management system comprised of available and non-confidential information. The vast majority of the information the Commission must include in the petroleum information management system has nothing to do with the Commission's mission or function – "unit and joint operating agreements," exploration licenses and leases, "work programs and budgets," "development plans," operating and capital expenditures and projections, "oil and gas sales, revenue and pricing," transportation agreements, abandonment plans and budgets, resident and non-resident hiring information, training opportunities, and other information "the commission determines necessary and relevant to the oil and gas production tax and to the exploration, development, and production of oil and gas resources." Much of this information is currently already gathered and maintained by other state agencies or is not available to any state agency.

After careful review and consideration of Section 3, the AOGCC is of the view that Section 3 radically changes the AOGCC's longstanding role as the State's petroleum technology and geology experts and jeopardizes the Commission's ability to discharge its primary duties and responsibilities in those realms. The Commission has neither the expertise nor the infrastructure to construct, maintain and operate information management systems, computer systems, and the gathering of information on other subjects not related to the safe, efficient production of hydrocarbon resources from wells. Implementation of Section 3 will create – at a substantial fiscal outlay – an additional distinct state bureaucracy within the AOGCC which duplicates functions currently performed by other state agencies.

The AOGCC's non-confidential information is already publically available on its website. Other agencies are currently working to provide similar web availability of their data. Once those agencies do so, the information will be far more readily accessible to the public on those websites and at a substantially reduced cost.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB192

Analysis Continued

Breakdown of costs:

Position **Annual Salary and Benefits**

Deputy Director	\$145.0
Petroleum Facilities Engineer	\$236.0
Petroleum Geologist II	\$145.0
Petroleum Geologist I	\$132.0
Petroleum Economist II	\$118.0
Analyst Programmer V	\$118.0
Analyst Programmer V	\$118.0
Analyst Programmer III	\$ 89.0
Statistical Technician II	\$ 73.0
Statistical Technician II	\$ 73.0
Microfilm Operator I	\$ 61.0
Microfilm Operator I	\$ 61.0
Microfilm Operator I	\$ 61.0
Executive Secretary II	\$ 75.0
Administrative Assistant I	\$ 74.0

Services

Lease Space	\$ 105.0
(Space for 15 staff plus contractors, approximately 2,500 s.f. @ \$3.50 per s.f. annually)	
Construct space for new positions	\$ 100.0
Core Services	\$ 75.0
Specialized Software	\$ 20.0
Data/Phones	\$ 20.0
Training (for current and new staff)	\$ 200.0
Building a new stand alone computer system	\$ 28,000.0
Upgrading current RBDMS system	\$ 4,000.0
(production & consulting costs begin in year 2 and out)	
Annual Maintenance and server hosting	\$ 4,700.0
Commodities	
Computers, Monitors - one time costs	\$ 45.0
Office Furniture, Chairs - one time costs	\$250.0
Supplies	\$ 25.0

2.

**CSSB 192 Oil &
Gas Production
Tax Rates
Presentation by
Senator Paskvan
March 13, 2012**

Committee Substitute for Senate Bill 192 (RES)

Oil and Gas Production Tax Rates

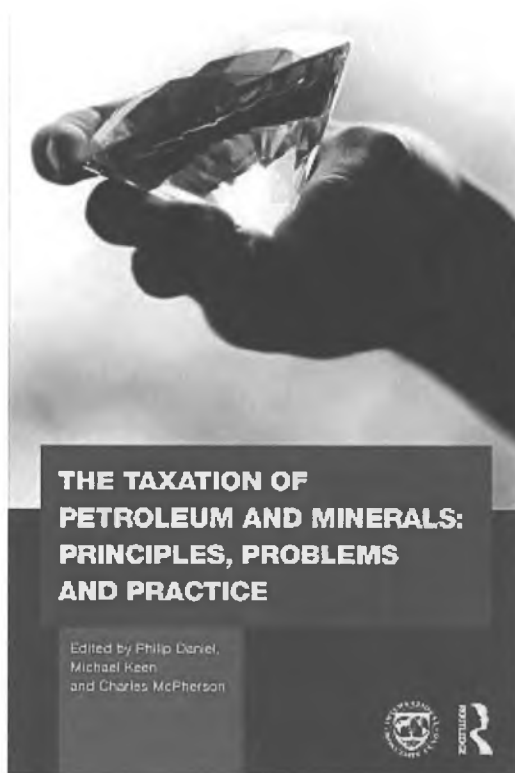


**Senate Finance Committee
Tuesday, March 13**

CSSB 192(RES) Overview

- Intro: Alaska is an Owner State
- Summary of DOR Reports
- Lessons Learned
- Basic Petroleum Economics
- DOR's "Facts To Begin the Conversation"
- CSSB 192(RES): Rationale and Overview
- Optimism for Alaska's Future

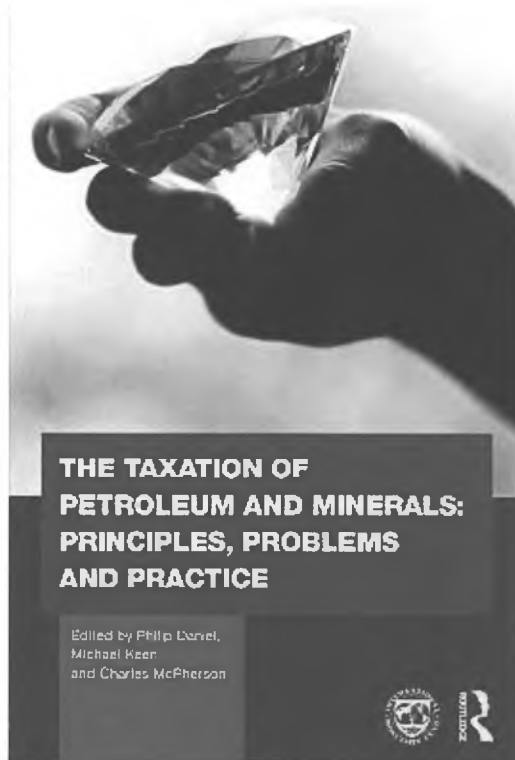
Alaska is an Owner State



“There are few areas of economic policymaking in which the returns to good decisions are so high – and the punishment of bad decisions so cruel – as in the management of natural resources wealth.”

From the Preface, page ii

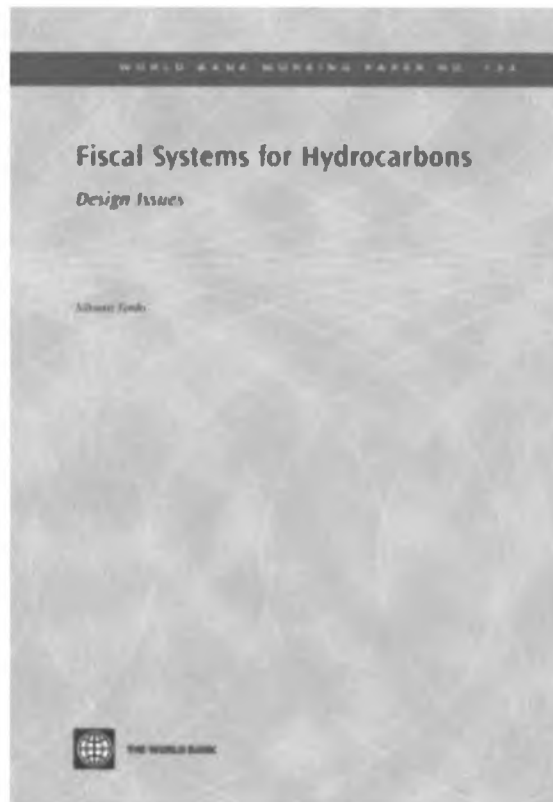
Alaska is an Owner State



“The central objective in designing petroleum fiscal regimes is easily stated. It is to acquire for the state in whose legal territory the resources in question lie, a fair share of the wealth accruing from the extraction of that resource, whilst encouraging investors to ensure optimal economic recovery of the hydrocarbon resources. How to achieve this balance is a subject of enduring controversy.”

From Chapter 4 Petroleum Fiscal Regimes: Evolution and Challenges (page 89)

Alaska is an Owner State

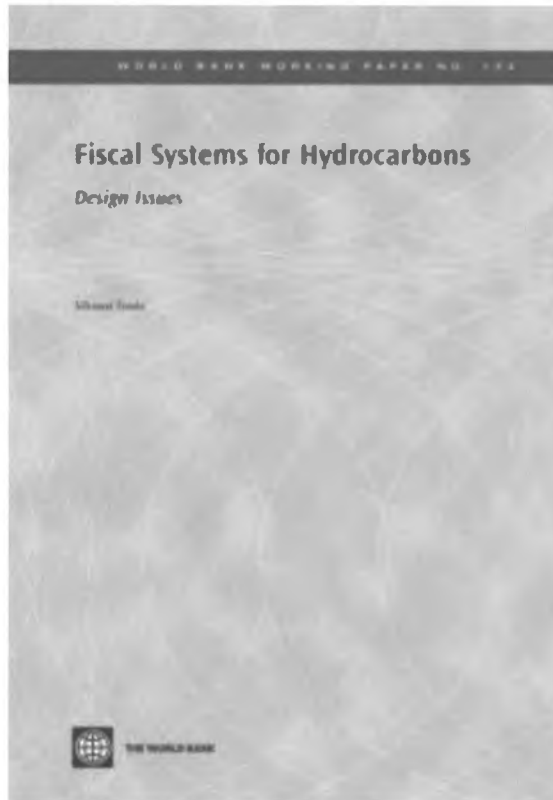


Chapter 5: Designing Efficient Fiscal Systems

Although the host government and the investor may share one common objective – the desire for the project to generate high levels of revenue – their other objectives are not entirely aligned:

Host governments aim to obtain the maximum value (not volume) for their countries over time in terms of net receipts for treasury. Their goal is to maximize the wealth from their natural resources and, at the same time, attract foreign investment. Host governments also have development and socioeconomic objectives, such as job creation, transfer of technology, and development of local infrastructure.

Alaska is an Owner State



Chapter 5: Designing Efficient Fiscal Systems (continued)

Oil companies aim to ensure that the return on capital is consistent with the risk associated with the project and with the strategic objectives of the corporation.

“Meeting the Challenge”

Bob Bartlett, Alaska Constitutional Convention



Where such vast resources potential exists one need not be clairvoyant to foresee an influx of interests wanting to develop these resources ...

This moment will be a critical one in Alaska’s future history. Development must not be confused with exploitation at this time. The financial welfare of the future state and the well-being of its present and unborn citizens depend upon the wise administration and oversight of these developmental activities.

Two very real dangers are present. The first, and most obvious, danger is that of exploitation under the thin disguise of development. The taking of Alaska’s mineral resources without leaving some reasonable return for the support of Alaska governmental services and the use of all the people of Alaska will mean a betrayal in the administration of the people’s wealth.



The second danger is that outside interests, determined to stifle any development in Alaska which might compete with their activities elsewhere, will attempt to acquire great areas of Alaska’s public lands in order NOT to develop them until such time as, in their omnipotence and the pursuance of their own interests, they see fit. If large areas of Alaska’s patrimony are turned over to such corporations the people of Alaska may be even more the losers than if the lands had been exploited. (November 8, 1955)

CSSB 192(RES) Overview

- Intro: Alaska is an Owner State
- **Summary of DOR Reports**
- Lessons Learned
- Basic Petroleum Economics
- DOR's "Facts To Begin the Conversation"
- CSSB 192(RES): Rationale and Overview
- Optimism for Alaska's Future

ACES Status Report

Alaska Department of Revenue (January 14, 2010)

Letter from DOR Commissioner Galvin to Gov Parnell:

- “The ACES Status Report evaluates whether ACES is meeting its intended goals of providing a fair share of revenue to the state while encouraging investment in new oil and gas exploration and development activities.”
- “The status report shows that ACES successfully allowed the state to share in the benefits of high oil prices while accommodating fluctuations in production costs and oil prices. ACES adjusted when oil prices tumbled and kept the oil operations in Alaska highly profitable relative to other oil provinces.”
- “Since ACES passed the legislature, overall spending on oil and gas activities on the North Slope has increased. However ... it would be premature to attribute the increased level of oil company investment to the success of ACES.”

ACES Status Report

Alaska Department of Revenue (January 14, 2010)

Letter from DOR Commissioner Galvin to Gov Parnell (cont):

“Oil taxes are clearly an important factor in industry investment decisions. However, it is misleading to isolate their influence from other key factors, such as world oil prices, geologic potential, access to land, resources and markets, costs of infrastructure and support services, and the legal and regulatory framework. As noted in the report, the true merit of Alaska’s current fiscal system can only be determined when it is evaluated in conjunction with these other variables.”

ACES Status Report

Alaska Department of Revenue (January 14, 2010)

ACES Structure and Tax Rate (page 9 – 11):

“As with any tax, ACES may be evaluated using a variety of different metrics, including ‘effective,’ ‘nominal,’ and ‘marginal’ tax rate comparisons. While each of these can be helpful under the appropriate circumstances, each is also subject to certain limitations. It is important when using these metrics to understand their relative value and how they reflect upon the objectives of the tax system ...”

“The ‘marginal tax rate’ is the rate theoretically applied to each dollar increase in oil price ... With a net based tax system, this metric shows a company the impact of making additional investment, because each dollar they invest is ‘subsidized’ by the government based on the amount of marginal tax they have avoided paying on that dollar ... For example, a marginal tax rate of up to 87% initially sounds excessive. However, at that same price level, the effective tax rate is less than 40%. The marginal rate of 87% actually represents that state’s ‘portion’ of any new investment made at such high prices.”

ACES Status Report

Alaska Department of Revenue (January 14, 2010)

Conclusion (page 15):

“Overall, the information reviewed by the department indicates that ACES is performing as expected when it was passed by the Legislature in 2007. The economic provisions are resulting in the revenue levels anticipated, and the investment incentives appear to distribute the increased tax burden in a fashion that continues to encourage reinvestment, though the experience with the credit program could be improved for new explorers. Challenges remain in the implementation by the department, but they are manageable and the department is positioned to meet those challenges.”

Production Tax Status Report to the Legislature by DOR (January 18, 2011)

From the Executive Summary (pages 1 – 2)

- **Industry Investment** – Investment in the form of capital expenditures has increased in each of the four fiscal years since implementation of the net profits tax, however, it is unclear how much of the capital expenditures were drilling or well-related and how much were maintenance or facilities-related.
- **Impact on Exploration, Development, and Production** – Exploration has generally increased from 2003, when the EIC credit was implemented, but has dropped off in 2010. Development continues in three relatively new North Slope projects, yet production continues to decline.
- **Industry Employment and New Entrants** – Industry employment rose steadily from 2006 through 2009, but dipped slightly in 2010. The number of companies filing annual tax returns doubled between 2006 and 2009, indicating interest by companies that are either new or returning to the Alaska oil and gas industry.

Production Tax Status Report to the Legislature by DOR (January 18, 2011)

From the Executive Summary (cont.)

- **Use and Expansion of Tax Credits** – The amount of credits used has increased annually since 2006 and we expect the trend to continue as new credit programs were added in the 2010 legislative session.
- **Tax Administration and Compliance** – The department continues to write regulations for the new tax system, and the first audits under the net profits tax have been completed. The department has, however, been hampered in its tax reporting and compliance efforts by the lack of a centralized database to house and manage the large volumes of oil and gas data it receives.
- **Conclusions and Recommendations** – Based on the multiple changes to the tax laws over the past few years, drawing any conclusion about their effect on Alaska's investment climate is difficult. However, what is clear is that production continues to decline. The state should continue to monitor its competitiveness with other oil and gas jurisdictions worldwide and be prepared to change its tax structure as needed.

Production Tax Status Report to the Legislature by DOR (January 18, 2011)

Conclusion and Recommendations (Pages 14 – 15):

“A government’s fiscal regime is just one element for oil and gas companies to consider when weighing options for where to invest. Many other elements, such as resource risk, political risk, environmental factors, and availability of labor and equipment, also play a part in companies’ decisions about where to invest. It is very difficult to separate these factors in order to determine the extent to which a government’s fiscal system influences investment choices.

“While it is untenable to blame a tax system for the lack of industry investment, it is equally untenable to claim that the tax system is the reason increased activity or investment occurs. The past three years have seen dramatic swings in oil prices from a high of \$134 per barrel to a low of \$38 per barrel just 6 months later. An economic recession stifled investment and business activity in the United States and much of the developed world for over a year. The economic activity of the past three years may not have been the best benchmark by which to judge the impact of a tax system ...

“... State officials should continue to monitor the state’s competitiveness in oil and gas opportunities, and be prepared to modify it as the need arises.”

HB 110 PRODUCTION TAX ON OIL AND GAS

January 18, 2011: Read the First Time – Referrals

SB 49 PRODUCTION TAX ON OIL AND GAS

January 19, 2011: Read the First Time – Referrals

CSSB 192(RES) Overview

- Intro: Alaska is an Owner State
- Summary of DOR Reports
- **Lessons Learned**
- DOR's "Facts To Begin the Conversation"
- CSSB 192(RES): Rationale and Overview
- Optimism for Alaska's Future

Comprehensive Plan and Feasibility Study by FAST Enterprises, LLC (October, 2010)

Excerpts from the Executive Summary

The Alaska Department of Revenue's Tax Division (DOR/TAX) relies on a patchwork of 17 automated systems and over 100 manual "side-systems" to administer 22 tax programs.

- DOR/TAX manages over \$3 billion in Oil and Gas Tax revenue using an eclectic mix of home-grown side-systems that include multiple databases and unsecured, unstable spreadsheets stretched well beyond their intended use. Storing sensitive taxpayer information in these databases and spreadsheets poses a high security risk.
- The 17 systems used to administer different taxes and functions have been pieced together over the past 15 years without integration or an overall architecture. The systems do not scale to meet current needs and are inflexible and difficult to maintain. Since the initial development of the systems, many tax laws have changed and the systems have not changed accordingly.

Comprehensive Plan and Feasibility Study by FAST Enterprises, LLC (October, 2010)

Excerpts from the Executive Summary (continued)

- DOR/TAX employees spend a higher proportion of their time compiling, organizing, and reconciling data than actually auditing, examining, analyzing, forecasting, or managing tax programs.
- The limitations and inflexibility of existing systems impose a burden on taxpayers. Current reporting processes are inefficient and ineffective, and create unnecessary work and cost. As one taxpayer stated, “the Tax Division’s inefficiency makes taxpayer interaction with the division inefficient.”
- DOR/TAX cannot easily produce reports required by the legislature and policy makers because the current systems prevent timely, complete, and correct extraction of data. Reports can be inaccurate and misleading due to incorrect and incomplete data and human error.

Department of Revenue

Additional Information

Single Audit of the State of Alaska (Feb 28, 2011)

- Recommendation: “DOR’s commissioner should ensure staff within its Tax Division implement controls to improve the auditing of oil and gas severance tax revenues.”
- Legislative Audit’s Current Position: “Significant control deficiencies continued over the auditing of oil and gas severance tax revenues in FY10. A loss of experienced audit staff during FY10 compounded the struggles that the audit section was already experiencing.”

Decision Following Trial De Novo: 2007, 2008, and 2009 Assessed Valuations of the Trans Alaska Pipeline System (December 30, 2011)

- “The Department’s Production Forecasts and Reserves Estimates are Unreliable” (page 170)

U.S. Energy Tax Policy (2011)

(Chapter 9) State Tax Policy and Oil Production: The Role of the Severance Tax and Credits for Drilling Expenses



Introduction

“Although most energy-producing states have levied taxes on the value of oil, natural gas, and coal production for many years, changes in these taxes have become headline news as state governments grapple with budget shortfalls brought about by the current recession. For instance, Alaska has increased the severance tax on the value of its oil production and attempted to stimulate future production by allowing a credit against this tax for expenditures on capital items, including drilling rigs, infrastructure, exploration, and facility expansion (Alaska Department of Revenue 2008).”

By Ujjayant Chakravorty, Shelby Gerking, and Andrew Leach

State Tax Policy and Oil Production:

The Role of the Severance Tax and Credits for Drilling Expenses

Questions about the effects of state energy taxes, for example:

- Do state taxes tilt the time path of energy production to the present or to the future?
- Do upstream subsidies for exploration and development work together with downstream taxes on production to influence the levels and time paths of production and tax collections?
- What are the implications of these taxes for the long-term sustainable use of nonrenewable natural resources?

State Tax Policy and Oil Production:

The Role of the Severance Tax and Credits for Drilling Expenses

Key Finding #1:

- “Oil production is closely linked to the size of the reserve base and is relatively insensitive to changes in oil prices. This outcome, which is broadly consistent with experience in the U.S. oil industry over the past 50 years, leads to the conclusion that the severance tax has little effect on production levels (p. 306).”

State Tax Policy and Oil Production:

The Role of the Severance Tax and Credits for Drilling Expenses

Key Finding #2

- “The simulations suggest that a drilling expense credit may cost more than the incremental severance tax revenue obtained, although such credits may be worthwhile concessions if a state’s objective is to generate greater support for increasing the severance tax rate (p. 307).”

Additional Research

“Effectiveness of Severance Tax Incentives in the U.S. Oil Industry” (Mitch Kunce, *International Tax and Public Finance*, 2003)

- “In general, results show that severance tax rate cuts substantially reduce state tax revenue collected, but yield moderate to little change in oil drilling and production activity. This outcome suggests that states should be wary of arguments asserting that large swings in oil field activity can be obtained from changes in severance tax rates.”

Additional Research

“State Taxation, Exploration, and Production in the U.S. Oil Industry” (Mitch Kunce et al, Nov 26, 2001)

- “Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes.”

Gas and Water Handling Constraints

“While new oil is an issue in maintaining production levels, there are also issues at existing fields, where [Dudley] Platt said facilities expansion may be needed. He said the large facilities are ‘maxed out on how much gas they can handle and they’re getting close to being maxed out on how much water they can handle. ... If they don’t expand their facilities to handle that, the oil production will continue to go down.’”

“Alaska Oil Forecast Shaky”

By Kristen Nelson, Petroleum News

Week of November 18, 2007

Gas and Water Handling Constraints

North Slope of Alaska Facility Sharing Study

Prepared for Division of Oil & Gas, Alaska Department of Natural Resources

By Petrotechnical Resources Alaska, May, 2004

“The North Slope processing facilities have specific design capacity limits, indicating the amount of oil, water and gas which can be handled by the facility. If the handling capacity of one of these streams is reached for a given facility, it limits the overall production output from that facility. While some facilities may be producing below capacity for oil, they are often limited due to capacity constraints on total water production or gas production.”

Gas and Water Handling Constraints

1989 Revenue Sources Book

Alaska Department of Revenue

“The vast majority of Alaska production will continue to come from the now declining Prudhoe Bay field ... The decline in Prudhoe Bay production is now expected to be much more rapid than assumed in our Spring forecast. This reflects a more serious gas handling constraint. As more and more gas is produced with each barrel of oil, the amount of gas which must be re-injected back into the Prudhoe Bay field has increased substantially. Since it is anticipated that there will need to be more production downtime due to field and TAPS maintenance, the gas handling constraint will limit the ability to keep average annual oil production from falling. Installation of additional gas handling equipment, GHAX1 (gas handling and expansion 1), is scheduled to start late in 1990. A second expansion is in the planning stages. Once in place, the ability to re-inject up to 5.1 bcf/day of gas production will slow the rate of decline in oil production.”

Gas and Water Handling Constraints

A Production Optimization System for Western Prudhoe Bay Field, Alaska

By D.A. Barnes, K. Humphrey, and L. Muellenberg of BPX America

Paper prepared for presentation at the 65th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in New Orleans, LA, Sept 23-26, 1990.

“For almost a decade the Prudhoe Bay field on the North Slope of Alaska has produced at a yearly average offtake rate of 1.5 million stock tank barrels of oil per day. As the reservoir depletes and field gas-oil ratios (GORs) increase, gas handling constraints make it difficult to achieve oil rate targets.”

Gas and Water Handling Constraints

Prudhoe Bay: Development History and Future Potential

By D.J. Szabo, BP Exploration (Alaska) Inc. and K.O. Meyers, ARCO Oil and Gas

Paper prepared for presentation at the SPE 1993 Western Regional Meeting, Anchorage, AK, 26-28 May 1993.

“Prudhoe Bay is seen by many as a mature oil field on an inevitable and irreversible decline ... The field’s oil production capacity dropped below 1.5 MMSTB/D in 1988 *officially* signaling the start of decline. The onset of decline was a direct result of limited gas handling capacity as opposed to limited oil production capacity.”

Gas and Water Handling Constraints

Prudhoe Bay Field: Facility Consolidations Pave the Way for an Economic Future
By K.D. Eager, BP Exploration; M.D. Briscoe, ARCO Alaska; R.A. Bolduc, Exxon

Paper prepared for presentation at the 1998 SPE Annual Technical Conference and Exhibition held in New Orleans, LA, 27-30 Sept 1998.

“The Prudhoe Bay Field on Alaska’s North Slope has produced for twenty-one years. Prudhoe’s gas and water production rates are at historic highs, but the oil production rate has declined to less than one-half of the peak rate achieved in the 1980s. As a result, significant excess oil treating capacity exists, with water and gas handling capacity constraining the current oil production rate. The owners of the Prudhoe Bay Unit developed a major facility consolidation plan in 1997 designed to rationalize this excess oil treating capacity while preserving existing gas and water handling capacity. The reconfigured facilities are expected to provide sufficient capacity at a lower cost to accommodate projected oil, water and gas production rates over the remaining life of the Prudhoe Bay Field.”

Gas and Water Handling Constraints

Prudhoe Bay Field: Facility Consolidations Pave the Way for an Economic Future
By K.D. Eager, BP Exploration; M.D. Briscoe, ARCO Alaska; R.A. Bolduc, Exxon

Paper prepared for presentation at the 1998 SPE Annual Technical Conference and Exhibition held in New Orleans, LA, 27-30 Sept 1998.

(Continued)

“Oil production rates are projected to continue to decline in the future. In developing the field development and management plans for 2000 and beyond, the PBU Working Interest Owners recognize the need to reduce lifting cost commensurate with the decline in oil production to maintain an economic asset for as long as possible. The Prudhoe Bay Facility Optimization Project will play an important role in achieving reduced lifting costs.”

Gas and Water Handling Constraints

Optimization of Production from Mature Fields

By P. Wang & K. Aziz of Stanford University and M.L. Litvak of BP, USA
17th World Petroleum Congress, September 1 - 5, 2002, Rio de Janeiro, Brazil

“Oil production in the Prudhoe Bay and Kuparuk River fields is constrained by the gas handling limits of the surface facilities.”

2003 Oil and Gas Report (for the period ending December 31, 2002)

Alaska Department of Natural Resources (Tom Irwin, Commissioner)
Division of Oil and Gas (Mark Myers, Director)

“From the beginning of Prudhoe Bay production, dissolved gas and water were separated from the crude oil and injected back into the reservoir. Over time the reservoir’s proportion of both gas-and-water to oil increased. Eventually, oil production was constrained by the rate at which the separating plants could process gas and water.”

Gas and Water Handling Constraints

Q: Does DNR agree that oil throughput at Prudhoe Bay is constrained by the ability of field operators to process and re-inject associated natural gas?

A: Yes, gas processing is a significant constraint in Prudhoe Bay. While new wells could be drilled with lower GOR's, other high GOR wells have to be shut-in because of the gas processing limitation.

Q: As of the early 1990's, does DNR agree that Prudhoe Bay was past the point where well drilling could stave off a falling oil rate?

A: Yes. The Prudhoe Bay Unit WIO had a very aggressive drilling program in 1986-1992. In addition, a major gas handling expansion (GHX-1) occurred in the late 1980s which helped stem decline. Significant delay in the production plateau would have been difficult.

(Source: Memo from DNR to Senator Paskvan re: "Responses to the 30 questions from September 22, 2011" (January 17, 2012).

Overview of the Gleason Decision

- Market Structure
- The Life of TAPS
- Access To Information

Overview of the Gleason Decision

Market Structure

Overview of the Gleason Decision

The Life of TAPS

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Access To Information

CSSB 192(RES) Overview

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Expanded Basic Petroleum Economics

Course Level: Basic

About The Course:

- Could you answer the following three questions for your next project:
 - What will it cost?
 - What is it worth?
 - Will it earn sufficient profit?
- Before undertaking any project, these questions should be answered.

Source: PetroSkills 2012 Training Guide

Example

- Estimates of drilling cost per well range from \$132,907 in Kansas, where wells tend to be shallow, to \$3,881,600 in Alaska, where the drilling experience is very different as compared to the lower 48 states.
- Marginal reserve additions from drilling range from 11,051 barrels per well in Kansas to 177,067 barrels per well in Alaska.
- Thus, while drilling a well in Alaska is markedly more expensive than in Kansas, Alaska experiences a greater payoff from these more costly exploration and development efforts.

(Source: "Effectiveness of Severance Tax Incentives in the U.S. Oil Industry," 2003, page 573 – 574)

Will it earn sufficient profit?

“Oil Industry Profitability in Alaska 1969 through 1987”

The oil industry received an estimated \$42.6 billion in profit from production and transportation activities in Alaska from 1969 through 1987 ... Alaska North Slope (ANS) production contributed \$29.1 billion to profit, with \$27.8 billion of this amount attributable to Prudhoe Bay and \$1.3 billion attributable to Kuparuk. TAPS provided \$12.4 billion. Production in Alaska other than ANS production added \$1.1 billion in profit.

Shares. The 42.6 billion in after-tax profit that accrued to the oil industry compares to \$29.3 billion in State of Alaska receipts from oil industry activities during this period. During the same period, Federal government receipts were \$25.8 billion from these activities (page I and II).

(Source: “Oil Industry Profitability in Alaska 1969 through 1987,” Prepared for the Department of Revenue, State of Alaska, by Edward Deakin, Distinguished Enterprise Professor and Director, Institute of Petroleum Accounting, University of North Texas, March 15, 1989.)

Will it earn sufficient profit?

“Oil Industry Profitability in Alaska 1969 through 1987”

Additional Benefits of ANS Oil

ANS Producers receive profits from Alaska oil outside of Alaska which provides an additional bonus beyond what it would cost if they had to purchase imported oil. An additional profit of approximately \$0.7 billion went to the producers through the operation of the U.S. Department of Energy crude oil entitlement program. Producers are believed to earn additional profit through the refining of ANS crude because, among other things, they have access to a secure source of crude oil. If they did not have the ANS crude, it would be necessary for them to acquire crude from foreign sources.

Others estimate that profits on tanker operations and the trans-Panama shipment activities added between \$.25 and \$1.00 profit per barrel of ANS crude produced. These additional profits would have been received on the nearly 6 billion barrels of ANS production. These added profits are not included on the \$42.6 billion of total oil industry profit in Alaska covered in this report (page 13).

These downstream profit issues are beyond the scope of this project. They do indicate, however, that the producer's economic benefits of Alaska oil production extend beyond the profit obtained within the boundaries of the State of Alaska (p. T-70).

(Source: “Oil Industry Profitability in Alaska 1969 through 1987,” Prepared for the Department of Revenue, State of Alaska, by Edward Deakin, Distinguished Enterprise Professor and Director, Institute of Petroleum Accounting, University of North Texas, March 15, 1989.)

Will it earn sufficient profit?

“Oil Industry Profitability in Alaska 1969 through 1987”

Hourly Profit Rate

“Looking at these profits as an hourly earning number may bring the amounts into better perspective. After-tax profits have been earned by the producers at the rate of \$463,144 per hour, twenty-four hours per day for each day of the first ten and one-half years of ANS Production (page 19).”

(Source: “Oil Industry Profitability in Alaska 1969 through 1987,” Prepared for the Department of Revenue, State of Alaska by Edward Deakin, Distinguished Enterprise Professor and Director, Institute of Petroleum Accounting, University of North Texas, March 15, 1989.)

Will it earn sufficient profit?

Lord John Browne, Chief Executive, BP
Address to shareholders (April 15, 2004)

- “In periods of high oil prices such as the one we find ourselves in today, the group generates significant ‘excess free cash flow’ after capital expenditure and dividends. Rather than using this cash to reduce debt ... we are committing to return ... 100 percent of this excess free cash flow to our investors, for as long as oil prices remain above \$20 a barrel, all other things being appropriate (*Sarah Takes on Big Oil*, page 16).”

Will it earn sufficient profit?

“Alaska’s role in BP’s portfolio is to provide a stable production base and cash flow to fuel growth elsewhere in the business while improving margins and returns.”

Sidenote:

“Over the past three years the TAPS Owners and Alyeska have studied a number of potential business efficiency opportunities ... Preliminary engineering studies have also confirmed electrifying and automating all 4 pump stations will allow Alyeska to eliminate over 285 full time positions, many of those in field locations where wage and locations premiums are very high. Currently, remote crews at these pump stations require expensive catering, transportation and other costly support services systems. Eliminating these positions translates to an annualized expense savings improvement of over \$41mm gross (+16mm net BP) by 2007 over APSC 2003 Base O&M.”

(Source: BP, Alaska Business Unit, Mid-Stream Alaska, Trans-Alaska Pipeline Pump Station Electrification, 2004, Page 13)

Will it earn sufficient profit?

Gene Therriault,
Senior Policy Advisor on In-State Energy, Parnell Administration
Email Correspondence, August 2, 2010

“Major producers like ConocoPhillips and BP have reported strong profits from their Alaskan operations under the ACES system. For example, in 2009, ConocoPhillips’ Alaska activity accounted for 12% of its worldwide production but 29% of its corporate profits. In addition, the August 1, 2010 edition of Petroleum News recently detailed ConocoPhillips current year earnings and concluded that “ConocoPhillips’ exploration and production activities continue to be more profitable in Alaska than across the Lower 48.””

Will it earn sufficient profit?

BP Prudhoe Bay Royalty Trust (BPT)

“In the past 10 years, BPT has earned a total return of 2,248%. A \$5,000 investment just 10 years ago would be worth \$117,400 right now ... To give you an idea of how strong a return that is, integrated oil giant Chevron returned 231% over the same period. That would have turned \$5,000 into \$16,550. Not bad, but nowhere near what BP Prudhoe Bay Royalty Trust did.

“And those royalties are on top of capital gains. BPT's share price gained 667% during the past 10 years thanks to rising oil prices, while Chevron's stock price went up only 137%.

“The thing is, BPT not only beat Chevron... it beat out just about every major oil company over the same period. And that's only part of the equation. Go back a few more years, and the major oil and gas companies aren't even in BPT's league.

“BPT has generated total returns of 5,089% since 1990 -- beating the "big" names in the oil and gas industry. Chevron ... Exxon ... Shell ... you name it.”

(Source: Seeking Alpha website, “BP Prudhoe Bay Royalty Trust: Why Worry About This High Yielder?,” January 25, 2012)

Will it earn sufficient profit?

BP Prudhoe Bay Royalty Trust (BPT)



(Source: Seeking Alpha website, "BP Prudhoe Bay Royalty Trust: Why Worry About This High Yielder?," January 25, 2012)

CSSB 192(RES) Overview

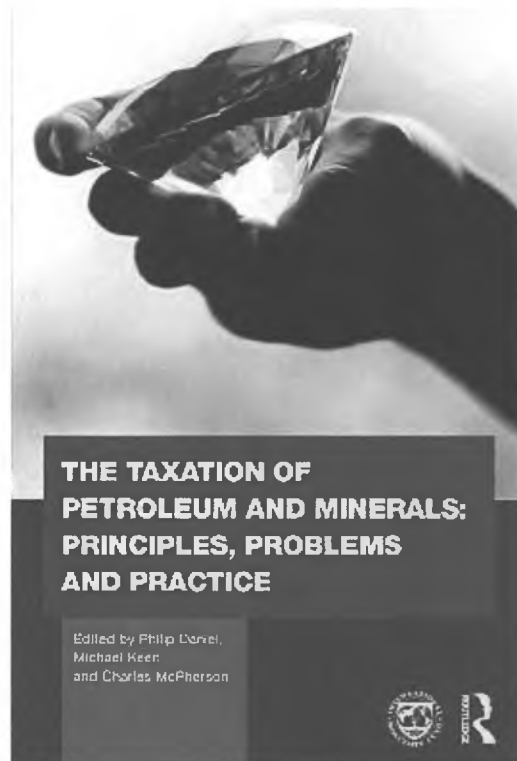
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Department Of Revenue's Facts to Begin the Conversation

- Oil Prices Began to Climb to All-Time Highs Starting Mid-2000s
- TAPS Throughput Continues Steady Decline
- Other Oil Producing Regions Enjoying Production and Employment Booms
- Competition is High – Many Other Areas To Invest Around the World

Source: Senate Resources Committee (February 10, 2012)

Oil Prices Began to Climb to All-Time Highs Starting Mid-2000s



Chapter 7: Evaluating fiscal regimes for resource projects: An example from oil development

“The unprecedented rises in the internationally traded prices of crude oil and natural gas (petroleum) between 2002 and 2008, and the sudden fall after July of 2008, have concentrated attention once again on how petroleum revenues are shared between owners of the resource in the ground (usually governments) and the companies that extract the petroleum (page 187).”

Oil Prices Began to Climb to All-Time Highs Starting Mid-2000s

Fiscal Regimes in a Volatile Oil Price Era: What Options Exist for Balancing the Interest of the Resource Country and Investor Company?

By Humphrey Onyeukwu, SPE, Centre for Energy, Petroleum, Mineral Law and Policy, University of Dundee

Paper presented at the CPS/SPE International Oil and Gas Conference, Beijing, China, June 2010

“The challenge of a fiscal policy in a volatile price oil era is ensuring a high share of value is secured for the Government. At the same time, the fiscal policy strives to encourage the exploration of these valuable resources without harming the commercial interest of the oil companies. Price volatility fundamentally alters the sharing formula; it is therefore imperative for a correct balance to be achieved between the competing state interests and the oil companies. The question becomes how equilibrium can be achieved in a petroleum fiscal system design, which guarantees a suitable government take and avoids the negative effect of instability and re-negotiation of fiscal terms.”

TAPS Throughput Continues Steady Decline

Revenue Sources Book (October, 1988)

Alaska Department of Revenue

"It is important to emphasize that the North Slope producers, while not agreeing on the exact date, have concluded that North Slope production will commence to decline in either FY 89 or FY 90."

TAPS Throughput Continues Steady Decline

Revenue Sources Book (Fall 1989)
Alaska Department of Revenue

"The fall in oil production means that the inevitable decline in the huge Prudhoe Bay field has started sooner than we predicted ... This forecast assumes that production from the Prudhoe Bay field will continue to fall steadily, and will drop to less than half its present level in less than 10 years."

"Some observers may believe that exploration will discover another Prudhoe Bay. Prudhoe Bay is the largest oil field in North America, and finding such a 'supergiant' is extremely rare."

"The State of Alaska is standing on a precipice. Only a combination of budget cuts, more efficient programs, and new revenues will keep the State from falling a long way ..."

"The decline in production from the Prudhoe Bay field is a central issue for Alaska ... The decline in Prudhoe Bay production is now expected to be much more rapid than assumed in our Spring forecast."

TAPS Throughput Continues Steady Decline

Revenue Sources Book (Spring 1992)

Alaska Department of Revenue

"The long-term revenue outlook is dominated by the depletion of petroleum reserves of the Prudhoe Bay oil field ... Despite the start of the irreversible decline at the Prudhoe Bay field this year, continued success in reservoir management in all fields will hold statewide production decline throughout fiscal year 1995 to less than 9% total (3% per year)."

TAPS Throughput Continues Steady Decline

Revenue Sources Book (Spring 1994)

Alaska Department of Revenue

"The Prudhoe Bay field, which accounts for two-thirds of Alaska statewide production, is in irreversible decline."

TAPS Throughput Continues Steady Decline

With Prudhoe Bay in Decline, What's Next for Alaska?

By James M. Davis (Senior Vice President for Exploration and Land) & Jerry R. Pollock (Manager, Prudhoe Bay Engineering) of ARCO Alaska, Inc.

Oil & Gas Journal, August 3, 1992

“By any definition, Prudhoe Bay is declining and will continue to decline...

“To accountants, Prudhoe decline began during 1988 when the field was no longer able to make its maximum allowable rate of 1.5 million b/d of oil. To engineers, the decline began long before that ...

“Unfortunately, adding more wells can't keep the oil production rate up forever. We're already past the point where drilling can stave off a falling oil rate. Oil reserves are finite. ...

“As the field matures, the production facilities reach their maximum capacities to handle produced water and gas. Wells with falling oil rates and increasing produced water or gas volumes have to be shut-in. Total field oil production drops.”

TAPS Throughput Continues Steady Decline

Hearing before the Committee on Energy and Natural Resources,
United States Senate

New Developments in Upstream Oil and Gas Technologies: Testimony by
Kevin Banks, Director, Division of Oil and Gas, Alaska Department of Natural
Resources (May 10, 2011)

“With the exception of development of heavy oil resources known to exist around the Prudhoe Bay, Kuparuk, and Milne Point fields, and potential resource plays (like the Bakken in North Dakota) that may exist on the North Slope on State controlled lands, the natural field declines cannot be replaced without access to production from Federal lands and the OCS. There are no known conventional resources on State or Native lands that are likely sufficient to replace the decline in the existing production rates.”

TAPS Throughput Continues Steady Decline

Senate Resources Committee, March 1, 2012

Testimony by Scott Jepsen, Vice President, External Affairs, ConocoPhillips Alaska

CO-CHAIR PASKVAN asked if Alaskans should expect to see 1 million barrels a day from state lands in conventional oil with the \$5 billion investment over the next 10 years.

MR. JEPSSEN said the 1 million barrels a day is a good aspirational goal, but he didn't think they could get there. It would probably take some other types of technologies than what is in the state right now. He hoped shale oil pans out and Great Bear plus some offshore help. State lands have potential, but he didn't know where they would see the upside in terms of getting to that 1 million barrels a day.

(Source: Draft Minutes, SEN RES Committee, March 1, 2012, BASIS website)

Other Oil Producing Regions Enjoying Production and Employment Booms

Resurging North American Oil Production and the Death of the Peak Oil Hypothesis

“The transfer of technology that caused the surge in natural gas production is transforming the outlook for oil production in the U.S. The unrelenting increase in oil rig count has been driven by two major forces: the sustained, high price of the commodity and the promise of improved oil production using the technology that has transformed the gas sector.

“Advances in the use of horizontal drilling and hydraulic fracturing have unlocked vast reserves of hydrocarbons originally trapped in highly dense shale rocks. The two shale oil plays that have benefited most from this transformation so far are the Bakken and Eagle Ford.”

(Source: Citi Investment Research & Analysis, 15 February 2012
https://www.citigroupgeo.com/pdf/SEUNHGJJ.pdf?source=email_rt_mc&ifp=0)

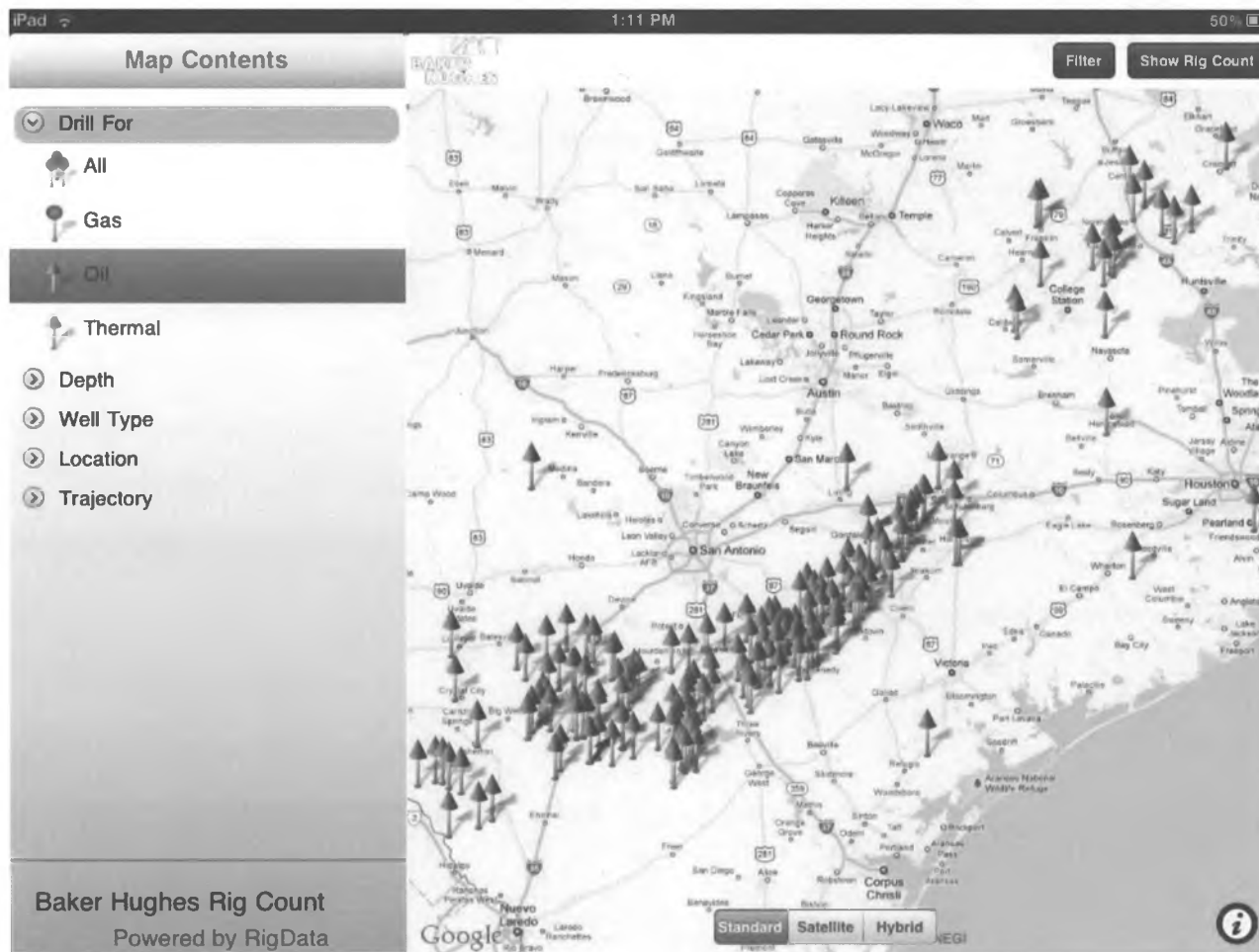
Baker Hughes Rig Count Bakken, North Dakota



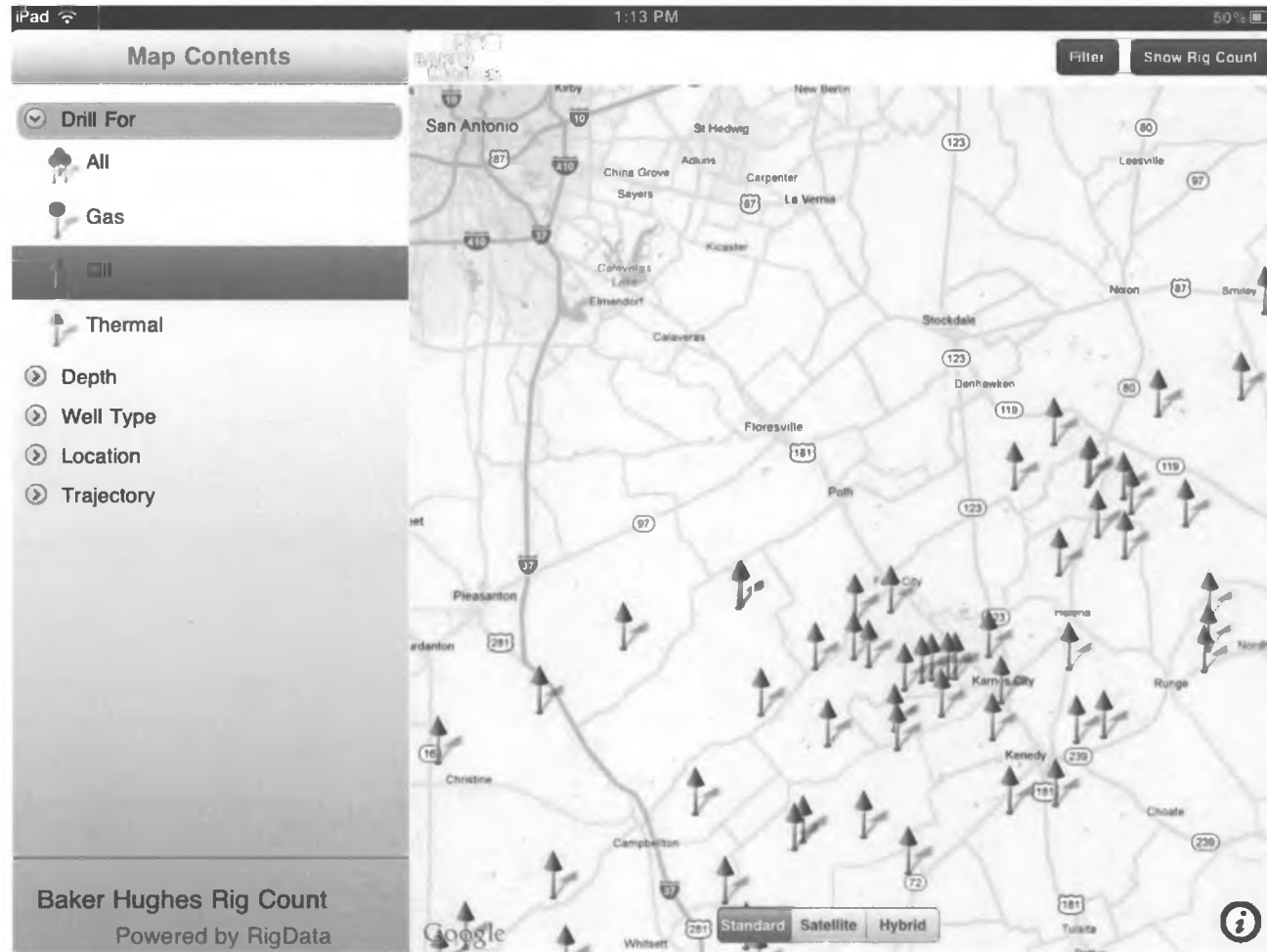
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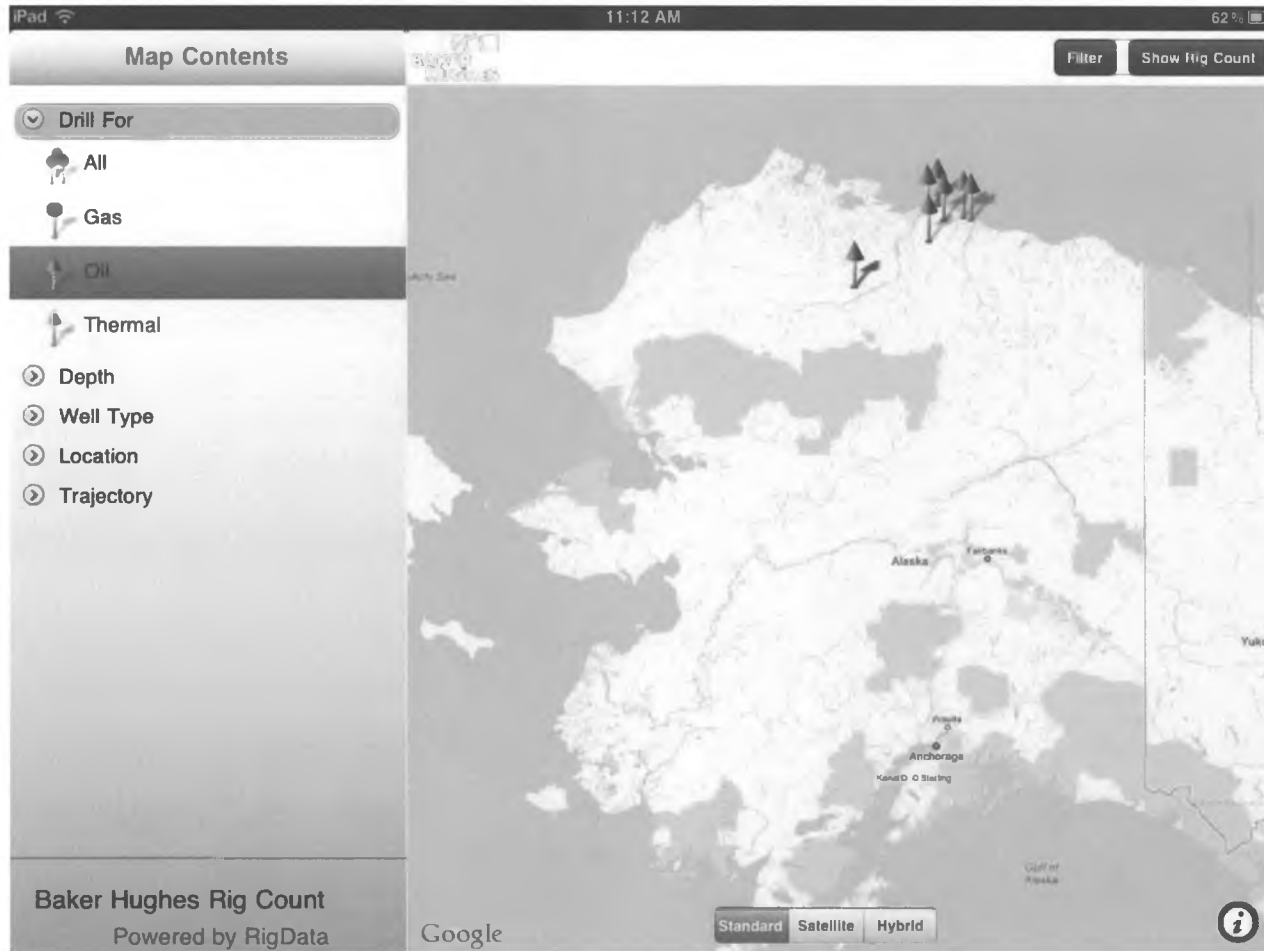
Baker Hughes Rig Count Eagle Ford, Texas



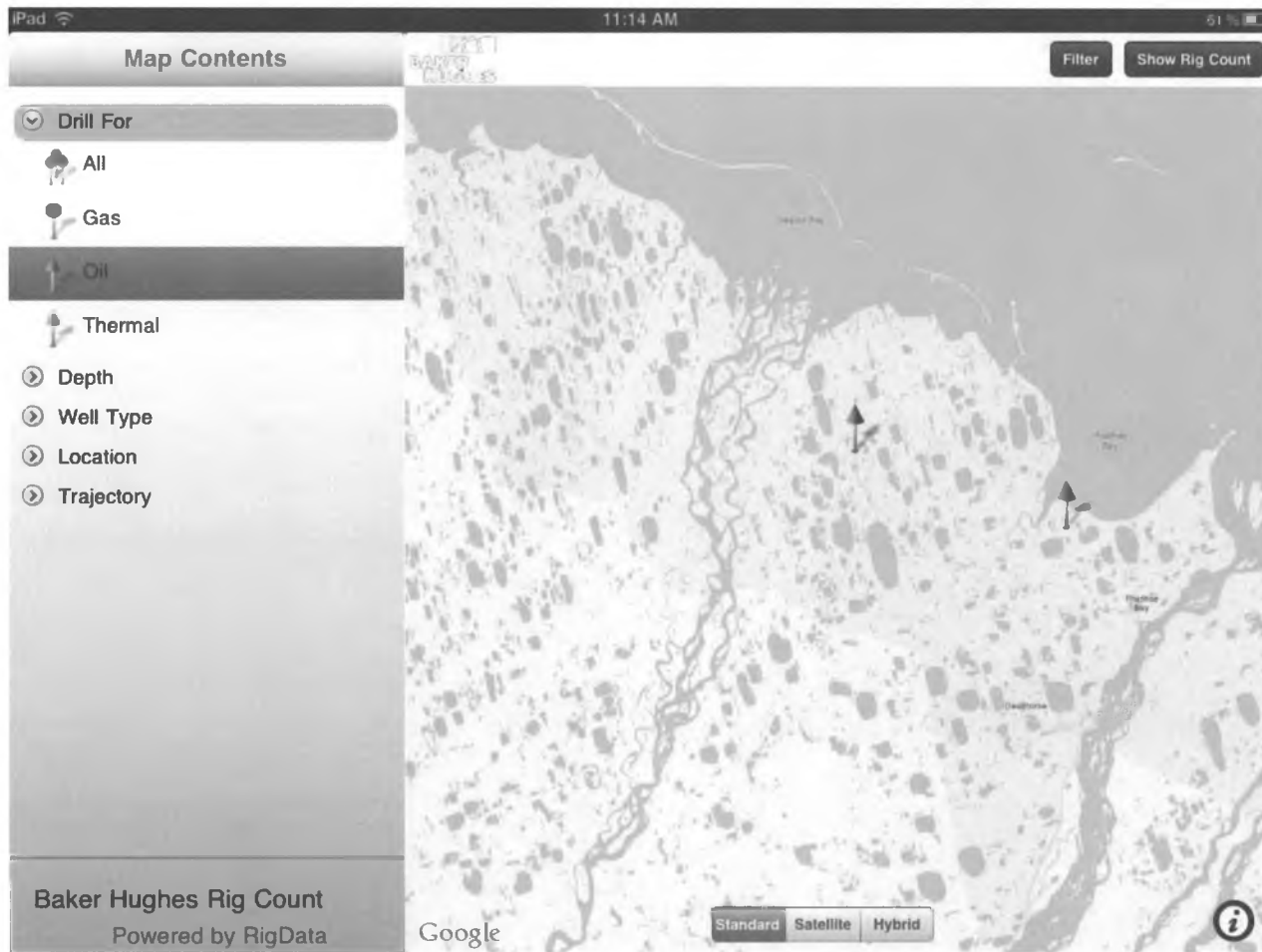
Baker Hughes Rig Count Eagle Ford, Texas



Baker Hughes Rig Count Alaska North Slope



Baker Hughes Rig Count Alaska North Slope



Other Oil Producing Regions Enjoying Production and Employment Booms

Alaska Economic Trends: Alaska's Oil Industry
September, 2008

“Dramatic improvements in technology in the last decade have had a powerful effect on employment levels.

“Examples include the widespread use of horizontal drilling, ultra extended-reach drilling, 3-D and 4-D seismic surveys, drill bit sensors and other advancements that reduced the number of wells that need to be drilled (page 6).”

Other Oil Producing Regions Enjoying Production and Employment Booms

Alaska Economic Trends: Alaska's Oil Industry
September, 2008

“According to the Federal Reserve Bank of Dallas, the national oil and gas industry was the leader in productivity gains throughout the 1990s and continues to be an above-average performer. In other words, the oil industry has been able to perform more work using fewer workers (page 6).”

Other Oil Producing Regions Enjoying Production and Employment Booms

Alaska Economic Trends: Alaska's Oil Industry September, 2008

How does Alaska compare to other oil-producing states?

“As far as the oil industry’s importance to the economies of different states, there’s little doubt Alaska ranks first. However, a person wouldn’t guess that by looking at the size of Alaska’s oil industry work force

“Alaska produced 15 percent of the nation’s domestic oil supply in 2007 but employed only 3 percent of the U.S. oil and gas work force ... (page 10).”

Other Oil Producing Regions Enjoying Production and Employment Booms

How does Alaska compare to other oil-producing states? (cont)

“There are a host of reasons that explain Alaska’s much-smaller oil industry work force, in light of its tremendous production.

“One big reason is simply that Alaska’s oil fields enjoy large economies of scale. Prudhoe Bay is the largest oil field in the nation and doesn’t need a huge work force to produce its oil ...

“In Texas, Oklahoma, Wyoming and other oil-producing states, some oil is produced from very small fields. There are 400,000 marginal fields or stripper wells operating in the U.S. and a stripper well produces 10 barrels of oil or less per day. In many of the states, there are literally thousands of families and small companies engaged in producing oil – something nearly totally absent in Alaska.”

Other Oil Producing Regions Enjoying Production and Employment Booms

Technology advances (see slide 62) lead to more drilling and more jobs in the new, unconventional (i.e., shale) oil plays in North Dakota and Texas.

At the same time, technology advances (see slides 69 and 70) lead to fewer wells and fewer jobs in the mature, conventional oil plays on Alaska's North Slope.

Competition is High – Many Other Areas To Invest Around the World

- ANS is a world class basin
- Vertical Integration of BP, ConocoPhillips, and ExxonMobile
- Transition from majors only to mid-majors and independents
- Growth of NOCs limits “areas to invest”
- Concept of immobile capital

CSSB 192(RES) Overview

- Intro: Alaska is an Owner State
- Summary of DOR Reports
- Lessons Learned
- Basic Petroleum Economics
- DOR's "Facts To Begin the Conversation"
- **CSSB 192(RES): Rationale and Overview**
- Optimism for Alaska's Future

CSSB 192(RES)

Rationale and Overview

- Preserves Industry-Friendly Components of ACES
- Reduces the Rate and Cap of Progressivity
- Rewards Increased Production
- Establishes a Gross Minimum Tax
- Separates oil and natural gas for purposes of calculating the progressivity portion of the production tax
- Creates an Oil Information System

CSSB 192(RES)

Preserves Industry-Friendly Components of ACES

- Preserves Deductions of Capital Expenditures, Operating Expenditures, and Transportation Costs (i.e., net profits tax)
- Preserves Tax Credits
- Preserves Royalty Rate
- Preserves Royalty Modification

CSSB 192(RES)

Reduces the Rate and Cap of Progressivity

- Retains the original trigger of \$30 in Production Tax Value (PTV); at which point the progressive tax rate is calculated at .35% per dollar increase in PTV up to 50% (\$101.43);
- At 50% (\$101.43), the CSSB 192 adds a second trigger on the progressive tax rate calculation that lowers the progressive tax rate to .1% on PTV up to 60% (\$201.43);
- Adds a statutory maximum tax rate of 60% under the production tax statutes.

CSSB 192(RES)

Rewards Increased Production

- Companies that increase their North Slope production levels from one year to the next will earn an allowance on the oil they produce above the prior year.
- The allowance reduces their Production Tax Value (or PTV) by \$10 for the new barrels of oil produced. This allowance should not be confused with a tax credit or a lowering of tax rates.
- It is a reduction in the PTV used to calculate production tax.

CSSB 192(RES)

Establishes a Gross Minimum Tax

- This provision of the legislation will establish a production tax floor of 10% of the gross value of oil at the point of production for legacy fields in Alaska. The floor would apply only to fields which have already produced a billion barrels of oil and are still producing 100,000 barrels a day on average.
- This provision is intended to alleviate concerns that the current floor does not adequately protect the state when oil prices are low. In fact, at prices as low as \$70, the state may take in more with a 10% gross floor than it would with ACES.
- As consultants have told us, ACES needs to be durable in a wide range of price environments. This provision helps achieve that goal and protects the state at the downside.

CSSB 192(RES)

Separates oil and natural gas for purposes of calculating the progressivity portion of the production tax

- This legislation separates oil and natural gas for purposes of calculating the progressivity portion of the production tax.
- Under current law, the tax rate is based on the combined BTU value of oil and gas. However, oil and gas can, and do, have vastly different values on a BTU basis. Currently, a BTU of oil is worth much more than a BTU of gas. Accordingly, once a major gas sale starts, overlaying the existing oil production, the BTU value of the combined oil and gas would be much lower than it was for oil alone.
- This legislation removes the dilution effect by having progressivity calculated distinctly for oil and gas. This will result in no reduction in oil taxes from a major gas sale.

CSSB 192(RES)

Creates an Oil Information System

- Concerns have been raised about oil and gas information that is not available to legislative policy-makers and the public. While much of the information is confidential under law, there is a considerable amount that is public, but it is scattered among several agencies and can, at times, be difficult to find.
- This provision in law will begin the process of making information more available to the policy-makers, public, and oil and gas companies who may be seeking to do business in Alaska's oil fields.
- Alaska Oil and Gas Commission (AOGCC) will be required to develop an electronic Petroleum Information Management System that will contain public information currently gathered by the commission, as well as the Departments of Revenue, Natural Resources and Labor & Workforce Development.
- The legislation directs the departments that have control over the various aspects of the information to provide what is not confidential to the commission in a form suitable for distribution.

CSSB 192(RES) Overview

- Intro: Alaska is an Owner State
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- **Optimism for Alaska's Future**

Optimism for Alaska's Future

- 7 – 8 billion barrels of oil (plus heavy, shale, OCS, NPR-A, ANWR)
- ANS is worth more now than it was in 1977
- Spending Forecast is Up: Above and Below Ground Infrastructure Rebuilt
- Cathy Foerster, AOGCC: ANS is Healthy
- DNR Ad: “Alaska: We’re Open for Business”
- North Slope Booms

CSSB 192(RES) Review

- Intro: Alaska is an Owner State
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Questions?



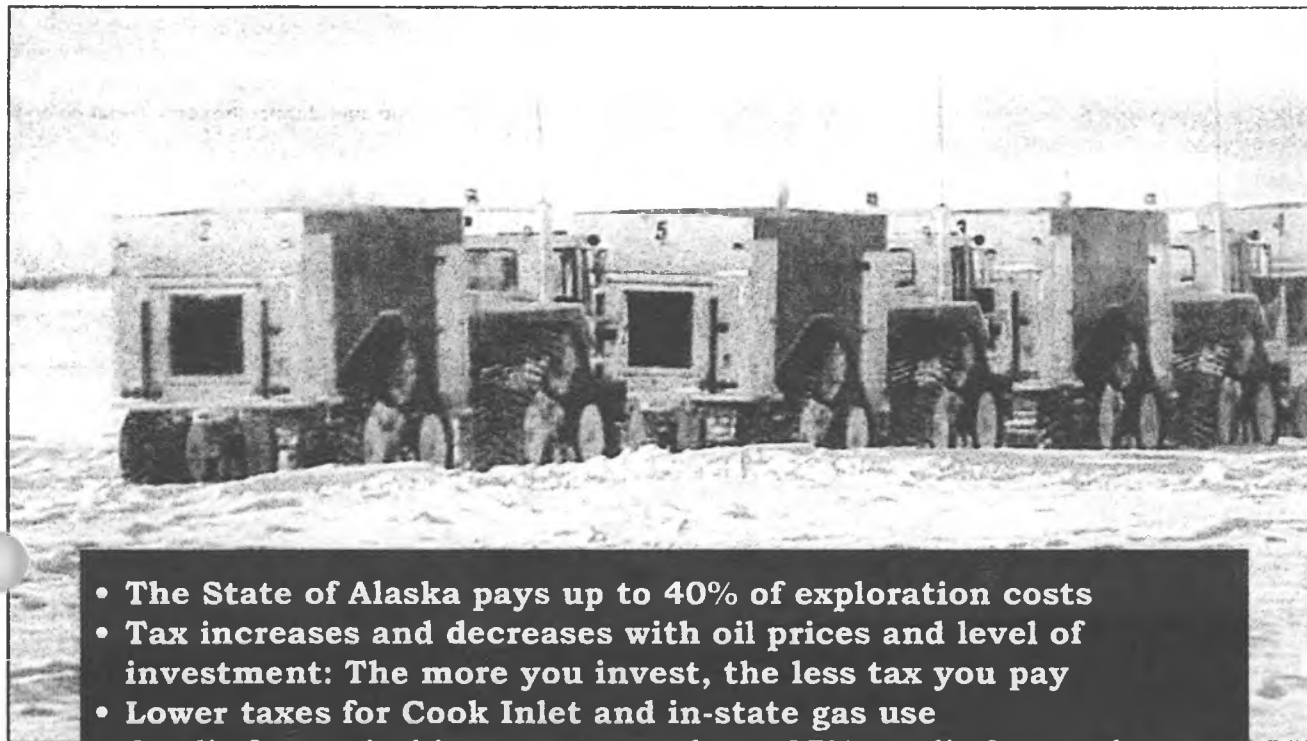
voir integrity question is pertinent to RCA certification of CINGSA's facility, in that a lack of reservoir integrity would undermine

wise defective," the commission said in a March 17 order. "Therefore, we deny the petition for consideration."

Contact Alan Bailey
at abailey@petroleumnews.com

"For someone new to the state or for a company that does not already have a large production base ... credits for capital investment and the credit for net operating losses are very advantageous."

Savant Resources, 2009



- **The State of Alaska pays up to 40% of exploration costs**
- **Tax increases and decreases with oil prices and level of investment: The more you invest, the less tax you pay**
- **Lower taxes for Cook Inlet and in-state gas use**
- **Credit for capital investments, plus a 25% credit for net losses**

Alaska is successfully encouraging investment from companies that are new to the state, with the number of petroleum companies doing business in the state almost doubling between 2006 and 2008.

Legacy producers on the North Slope are investing in their own assets, leaving room for new players, as evidenced by Pioneer's Oooguruk (production started in 2008) and ENI's Nikaitchuq (expected to start production in 2010).

The past two years of lease sales on the North Slope successfully leased a total of 1,276,207 acres, all to smaller companies.

"[T]he state has been a good partner for new explorers."

(Brooks Petroleum Corporation, 2008)

Alaska: We're Open For Business!

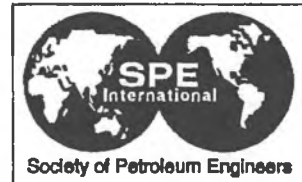


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3.

**Response to
Questions
March 13, 2012**



II
SPE 49063

Prudhoe Bay Field: Facility Consolidations Pave the Way for an Economic Future

K. D. Eager, BP Exploration, M. D. Briscoe, ARCO Alaska, Inc., R. A. Bolduc, Exxon Company, USA

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Abstract

The Prudhoe Bay Field on Alaska's North Slope has produced for twenty-one years. Prudhoe's gas and water production rates are at historic highs, but the oil production rate has declined to less than one-half of the peak rate achieved in the 1980's. As a result, significant excess oil treating capacity exists, with water and gas handling capacity constraining the current oil production rate. The owners of the Prudhoe Bay Unit ("PBU") developed a major facility consolidation plan in 1997 designed to rationalize this excess oil treating capacity while preserving existing gas and water handling capacity. The reconfigured facilities are expected to provide sufficient capacity at a lower cost to accommodate projected oil, water and gas production rates over the remaining life of the Prudhoe Bay Field.

This paper describes the Prudhoe Bay Surface Facility Optimization Project, from conceptual engineering initiatives in 1996, through preliminary engineering, economic justification, attainment of support from operations personnel and approval by the working interest owners of the Prudhoe Bay Field. Technical challenges and the challenges of projecting benefits associated with the consolidations were resolved through networking and technical discussions throughout the BPX, ARCO and Exxon world-wide organizations. The ultimate approval of the plan by the PBU Working Interest Owners is a clear example of teamwork and information sharing on a global scale.

Introduction

The Prudhoe Bay Field first produced oil in June, 1977. Daily production reached a plateau between 1979 and

1989 at 1.6 million barrels of oil and condensate. The field has since declined to a total daily production rate of 750 thousand barrels (combined oil, condensate, and natural gas liquids "NGLs"). Production to date has been approximately 9.5 billion barrels of liquid hydrocarbons with significant additional remaining reserves. During the field's development, gas production has increased to a current annual average of 7.5 BCFD with funded projects planned to increase gas offtake to about 8.3 BCFD. Gas production is expected to remain stable into the foreseeable future. Currently, produced gas is stripped of saleable components and either reinjected for gas cycling and pressure maintenance or consumed as fuel in operations on Alaska's North Slope. Daily water production is currently 1.3 million barrels and is expected to remain relatively stable for the foreseeable future.

The field was developed with six large oil separation facilities, three ARCO operated Flow Stations (Eastern Operating Area, EOA) and three BPX operated Gathering Centers (Western Operating Area, WOA). Each facility was designed with a nominal oil handling capacity of 330 to 360MBD. Current oil production rates at the facilities range from a low of 75MBD to a high of 180MBD. Oil production rates are projected to decline in the future. In developing the field development and management plans for 2000 and beyond, the PBU Working Interest Owners recognize the need to reduce lifting cost commensurate with the decline in oil production to maintain an economic asset for as long as possible. The Prudhoe Bay Facility Optimization Project will play an important role in achieving reduced lifting costs.

Opportunity for Consolidations Identified

Figure 1 highlights the forecast oil production rate with the capacity of separation facilities in the WOA. The three existing WOA facilities each have four separation trains for a total of 12 trains. Expected oil production will be less than the capacity of one separation facility within several years. The situation in the EOA is similar.

In 3Q 1996 a small team consisting of members from BP, ARCO, and Exxon was chartered with the goal of developing possible scenarios to decommission facilities no longer required to maintain projected

production rates. The team was to use as a starting point, the various ideas, studies and informal proposals circulating within the Operator's organizations. If economic scenarios were developed, the team was to complete conceptual studies and develop plans for moving the concepts into preliminary engineering. Team members were based in Alaska and the United Kingdom. Some outside contractor and operations resources were utilized for short periods during the conceptual phase.

Project Development

The team investigating facility decommissioning and consolidation opportunities rationalized the various proposals into a single preliminary engineering proposal during the second half of 1996. In late 1996, the PBU Working Interest Owners funded a preliminary engineering study focused on field wide consolidation. A combined operator, owner, and contractor team conducted the study.

The overall objective of the preliminary engineering study was to evaluate and justify economically the decommissioning of under-utilized crude oil processing equipment that is excess to current and future needs. Boundary conditions were established for the team requiring the reconfigured facilities to have the ability to handle and produce crude oil, condensate, gas, water, NGLs, and miscible injectant ("MI") at rates no lower than the existing facilities could handle and produce with projected Prudhoe Bay Field oil, gas, and water production rates. Further, the proposed facility configuration could not compromise safety, reliability, and product quality, and should maintain the ability to accommodate known potential future new developments.

Preliminary Engineering

Existing Facilities. Prudhoe Bay wells are located on centralized gravel pads and directionally drilled to reservoir targets. Local manifolds at the well pads route the flow to common flowlines. Flowlines route the flow to the six separation facilities.

As shown in Figure 2, Prudhoe Bay's installed separation facilities utilize three stages of separation in a parallel high pressure/low pressure scheme. Production from high-pressure wells is separated in two phase 1st stage separators at 650 psig (HP separators). Production from low pressure wells is separated in large three phase separators/slug catchers at 170 psig (LP separators). The oil/water outlet from the 1st stage HP separators is combined with the oil outlet from the 1st stage LP separators in two phase 2nd stage separators at 80-110 psig, where additional gas is removed. The oil outlet from the 2nd stage separators is routed into oil dehydrators where remaining water is removed via electrostatic grids at 50-60 psig. Remaining gas is

removed in the final 3rd stage separators (or stock tanks) at slightly higher than atmospheric pressure. Fluid composition and temperature leaving the facility is important because NGLs are blended into the crude oil stream downstream of the 3rd stage separators for transportation through the Trans Alaska Pipeline System and the operating procedures call for maximizing the volume of NGLs blended.

Figure 3 is a simplified process flow diagram of the produced water handling facilities at a typical Prudhoe Bay separation facility. Produced water removed in the LP separators and the oil dehydrators is combined in water skim tanks. Oil is removed from the produced water in the skim tanks via internal design and residence time, providing water quality sufficient for reservoir reinjection. Water from the skim tanks is routed to booster and injection pumps for injection into the producing intervals while excess volumes are injected into a higher non-producing formation. Several of the separation facilities were equipped with further water treatment facilities, generally gas flotation cells ("GFCs"). The GFCs proved difficult to optimize, and their use has been discontinued at all but one separation facility as better upstream separation operation and better overall optimization achieved sufficient water quality.

Figure 4 is a simplified process flow diagram of the gas compression and dehydration facilities at a typical Prudhoe Bay separation facility. The majority of gas (500-1900 MMSCFD per separation facility) is produced through high pressure wells and is separated in the 1st stage HP separators at 650psig. Gas separated at lower pressures is treated, compressed, and mixed with the high pressure gas stream. The majority of this gas is separated in the 1st stage LP separators at 170 psig (approximately 600 MMSCFD per separation facility) and compressed in the Low Pressure System 'LPS' compressors. Relatively small volumes of gas are separated in the 2nd stage separators (roughly 30 MMSCFD per separation facility) at approximately 80 psig and compressed in Intermediate Pressure 'IP' compressors. An even smaller volume of gas is separated in the 3rd stage separators (under 20 MMSCFD per facility) at slightly above atmospheric pressure and compressed in the Stock Tank Vapor 'STV' compressors that discharge into the IP compressors.

The combined high pressure gas stream is routed directly to local gas dehydration facilities within the separation centers. Once dehydrated to -40F, gas is routed to the Central Gas Facility for NGL and MI extraction. Residue gas from the Central Gas Facility is then compressed in the Central Compression Facility for reinjection into the reservoir gas cap.

Production Forecasts. The three major owner companies initially established a single consensus

production forecast for use in preliminary engineering. This was accomplished by using the higher of the three companies' production forecasts for each separation facility and pressure system. The projected production capacities then served as lower limits for acceptable facility capacity. During preliminary engineering, the project team developed capacity tables for each major equipment item in each consolidated and receiving facility. The projected capacities were compared to the production forecasts to develop pinch point tables that identified limiting equipment and feasible consolidation timing.

Development of planned consolidation scope. Initial studies aimed at eliminating under-utilized equipment recognized that the separation facilities had considerable excess oil processing capacity while operating at near design limits for water and gas handling. Further discussion and study identified that the bulk of fluids were separated in the 1st stage HP and LP separators. Thus, if water and gas could continue to be processed at each facility while transporting partially processed "fizzy oil" from the outlet of the 1st stage separators to a centralized oil processing center, large parts of some facilities could be decommissioned. This concept led the study team to conclude that four of the six separation centers could eventually be converted into partial processing facilities while maintaining two full processing facilities.

Preliminary Engineering focused on determining how to apply the partial-processing concept to the existing Prudhoe Bay separation facilities. The concept can be summarized as follows:

1. Maintain first stage separation at all six separation facilities.
2. Use existing idle or converted cross country flowlines to transport partially processed "fizzy oil" from the outlet of first stage separators at partial processing facilities to the inlet of second stage separators at full processing facilities for final processing.
3. Decommission second and third stage separators, dehydrators/treaters, and the IP and STV gas compression systems in partial processing facilities.
4. Decommission related utility systems, some water treatment facilities, and all other equipment identified as no longer necessary.

Figure 5 provides a simplified schematic of the post consolidation arrangement for one of the sending and receiving facility combinations (figure is simplified to one production train at each facility). Figure 6 depicts the overall final consolidation plan ultimately recommended by the team.

Under the proposed plan consolidations would proceed as follows:

1. The first phase in 1998 will convert Gathering Center 3 to a partial processing facility, routing its oil to Flow Station 3 for final processing.
2. The second phase, planned for 2000, will convert Flow Station 2 to a partial processing facility, routing its oil to Flow Station 1. Water from both facilities will be processed at Flow Station 2.
3. The third phase will consolidate Gathering Centers 1 and 2. The timing and direction of this consolidation could be impacted by the development of satellite reservoirs located near these processing facilities. This consolidation could occur as early as 2000, or as late as 2003. If Gathering Center 2 is used for processing most satellite fluids, then Gathering Center 1 will be converted to a partial processing facility, with its oil used to fill remaining Gathering Center 2 capacity with excess oil routed to Flow Station 3 via Gathering Center 3. If Gathering Center 1 is used for processing most satellite fluids, then Gathering Center 2 will be converted to a partial processing facility and its oil will be routed to Gathering Center 1 for final processing.
4. The fourth phase of consolidation. Planned for 2004, will convert Flow Station 3 to a partial processing facility, routing its oil and the partially processed oil from Gathering Center 3 into Flow Station 1.

5.

Preliminary Engineering Challenges. As preliminary Engineering progressed, significant bottlenecks were identified at the proposed receiving facilities in dehydrator water handling and in the IP and LP gas compressors. Design assumptions used to develop consolidation concepts originally assumed the 1st stage HP and LP separators would remove 97% of the entrained gas and the 1st stage LP separators would remove 80% of the water. These assumptions, particularly with relation to water separation, later proved to be limiting.

With 80% of the water assumed to be removed at the sending facility, the receiving facilities' oil dehydrators/treaters' capacity was determined to be insufficient under most scenarios when the facility received fizzy oil from more than one partial processing facility. This capacity limitation would delay extensive consolidation by 5 or more years. Capacity comparisons showed that reliable separation of 90% water (rather than the initial assumption of 80% separation) in the 1st stage LP separators would overcome the water handling capacity bottlenecks at the receiving facility.

The team set out to determine whether it was reasonable to assume reliable 90% water separation in the 1st stage LP separators was achievable. Field testing of the existing facilities demonstrated that water

separation was better than 95% in clean (solids free) vessels, but only 75-85% in dirty (solids filled) vessels. Considerable support was enlisted to validate the high separation efficiency assumptions. Laboratory bottle testing was completed to determine theoretical oil-water separation limits based on fluid composition and modeling was completed in the UK to determine theoretical separator capability. A world-wide survey of ongoing operations was used to determine separation efficiency at other, similar operations. Finally, ongoing testing was used for several months to validate performance of clean separators and to validate feasibility of using on line solids removal with sand jet systems to maintain clean vessels.

Based on this work, the team accepted higher water separation assumptions as the design basis for later consolidations when two partial processing facilities would be sending fizzy oil to a single full processing center. Another mitigating factor was that the intervening years between the first and second consolidation to a full processing facility allowed time to test separator performance and validate design basis assumptions. Given the importance of the water separation assumptions to the proposed consolidations, as well as the ongoing savings associated with avoiding periodic vessel cleanouts, the PBU Working Interest Owners approved installation of on-line solids removal sand jetting systems in all 1st stage LP separators not already so equipped.

Capacity constraints in the receiving facilities were also encountered in handling the gas produced off of the 3rd stage separators. The capacity of the STV gas compression systems is utilized at or near its installed capacity to keep the vapor pressure of the final oil stream as low as possible to allow the maximum possible blending of NGLs downstream of the separation facilities. Routing partially processed crude oil from sending to receiving facilities would require that all of the gas entrained in the fizzy oil be handled in the receiving facility's STV and IP gas compressors. In some cases the existing capacity of the STV and IP gas compressors were used as limits that deferred the planned facility consolidation dates. In other cases, economic solutions were developed to accelerate consolidation timing.

In the case of the first consolidation, GC-3 into FS-3, a modification was proposed to reduce the amount of entrained gas in the fizzy oil stream as much as possible. This modification would route the oil outlet of the 1st stage HP separators (flushed at 650-670 psig) through the LP 1st stage separators (flushed at 150 psig). It was also proposed to compress other very low pressure gas streams from tank sweep gas, gas dehydration stripping gas, and other small sources through a new gas compressor which would discharge into the first stage LP separators. The resulting fizzy oil

stream leaving GC-3 would have a low enough volume of entrained gas that the existing IP and STV gas compression capacity at FS-3, the receiving facility would be sufficient without modification.

Project Justification

Benefits Development. Benefits associated with the proposed consolidations were projected using the following techniques:

1. A bottoms up approach was utilized to develop projected direct and indirect cost savings. Savings in maintenance costs for each equipment item were projected based on eight years of historical data. The operations representatives on the team estimated savings associated with a reduced number of operations personnel. Indirect savings associated with reduced requirements for personnel support costs such as transportation, living quarters, meals and training, were estimated based on incremental changes in these costs. The bottoms-up approach provided the foundation for justification of the program.
2. The total direct and indirect savings were compared to the total operations and maintenance budgets as a reasonableness check. The direct savings estimates were not changed based on this comparison, but the estimated reduction in indirect costs was increased. It was assumed that the magnitude of the consolidations would allow for a larger reduction in personnel support costs than estimated on an incremental basis.
3. Benchmarking within BP's world-wide operations was utilized to further validate the estimated savings in direct costs. This approach uses a detailed comparison of equipment in service with known performance in other assets, makes adjustments for local productivity, and allows a close approximation of operations and maintenance costs of in service equipment.

Facility Reliability. Another area of analysis during project justification was projecting the future reliability of consolidated facilities. With consolidated facilities, planned or unplanned events at a receiving facility would impact production from the upstream partial processing facility, while failures of equipment removed from service at a partial processing facility would be eliminated. The team developed a detailed history of all production impacts at all Prudhoe Bay separation facilities for the previous eight years and used that as a basis for projecting future facility reliability. An analysis was completed of each production-impacting event to determine whether the proposed consolidations would eliminate, leave neutral, or increase the magnitude of a similar event in the future. The projections made using this method, with reasonable uncertainty bands, were used in analysis of the proposed consolidations.

Attention will be given to mitigating possible production impacts as the planned consolidations are engineered and implemented.

Workforce and Owner Support.

Workforce Support. Both of the operators encountered organizational and cultural challenges in estimating the benefits associated with the proposed facility consolidations. This resulted from operating cultures that had largely focused on growth and development of new reserves for some twenty years. While both operators had made significant strides to reduce field manpower and lifting costs since 1990, there had not been significant decommissioning of facilities to accompany decline.

Attaining full workforce support of the planned consolidations is an ongoing challenge and is being fostered through a broad communication and implementation plan. An important aspect of the implementation effort has been ensuring that people who are affected by changes understand what is intended and have input to the process. A small, behind the scenes team has been used extensively during the first phase implementation to foster work force support. The team has used the following tools to help develop support:

1. Workshops
2. Informal Meetings
3. Posters (A series of high level communications posters explaining what, why, how, when, etc.)
4. Newsletters and other intranet communications
5. "Townhall" meetings (presentations to large groups of staff)
6. Toolbox meetings at the start or end of workdays with operations staff
7. Assigning staff to the project design and implementation teams to foster knowledge transfer and communication.

Owner Sanction and Project Go-Ahead. Following completion of preliminary engineering in 1997, the Prudhoe Bay Working Interest Owners endorsed the facility consolidation plan as proposed. The first phase, consolidation of Gathering Center 3 into Flow Station 3, was funded and implementation is underway. The phased nature of the consolidation plan will allow validation of estimated implementation costs, estimated production impacts, estimated benefits, and operability assumptions before proceeding with additional phases. The plan is also flexible to accommodate possible satellite reservoir developments. Future consolidations will be authorized and funded to accomplish remaining portions of the plan as economic development plans for each affected facility are completed.

Several smaller projects identified during the study are also being implemented during 1998. These

projects, mostly implemented in the WOA, include the decommissioning of a single oil treating train from service at Gathering Center 1 and Gathering Center 2, the installation of on-line solids removal at Gathering Center 1 and Gathering Center 2, the decommissioning of gas flotation cells and related equipment at Gathering Center 2 and Gathering Center 3 and the elimination of other minor equipment.

Lessons Learned

1. There is benefit to 'taking the long view' when developing new oil field infrastructure. It may be possible to incorporate features into original facility designs that could lower full-life costs by allowing efficient consolidation of facility infrastructure as a field's production declines.
2. It may be possible to reduce operating costs or extend field life in mature fields by consolidating under-utilized equipment and/or utilizing idle equipment in a way it was not originally contemplated, but for which it is suitable.
3. Facility infrastructure consolidation represents significant change in how a field is operated. Organizational resistance to such change is to be expected and may require a significant culture shift to successfully capture the associated benefits. In the case of Prudhoe, the focus on development and expansion has been expanded to include consolidating and elimination of equipment where economic.
4. Communicating early, openly, and frankly about options and eventualities is essential to securing work force acceptance and support of change.
5. Approaching the development of consolidation plans, designs, and justification with an integrated owner, operator, and engineering contractor team is crucial to success. A team approach with common goals and objectives is the most effective means of developing support for a complex program.
6. Early and frequent involvement of the individuals who ultimately will sanction the project in significant decisions is instrumental in obtaining project approval in a timely manner.

Practices that Contributed to Project Success

The project team was staffed from the beginning of the preliminary engineering phase with representatives from both operator's operations, maintenance, and construction organizations. This proved to be instrumental in securing operations endorsement of design and performance assumptions, isolation and decommissioning methods, safety considerations, fire protection, and other areas. During later phases of the preliminary design effort, representatives from the previously selected construction contractor assigned staff to the project to assist in developing detailed

construction strategy, layouts, and detailed, target-costed cost estimates. As the project has progressed from preliminary design towards 3Q 1998 installation and operation, cost estimates completed during preliminary engineering have proved to be generally valid and there have been only minor disagreements with operations and maintenance organizations regarding project details, implementation, and operation.

All of the participants in the conceptual and preliminary engineering phases of the project utilized global resources to validate assumptions, solve technical challenges, and provide design assurance. ARCO, BPX, and Exxon provided technical assistance from research centers in Dallas, London, and Houston to solve challenges around multiphase flow in regimes not previously modeled, separator performance capability, chemical compatibilities, and other areas. Operations input was provided from worldwide networks at both ARCO and BP, including input from Gulf of Mexico, North Sea, and Middle East operations. Operations input was instrumental in increasing operator confidence regarding water separation performance and assumptions. Contractor staff utilized consultant resources to solve challenging multiphase flow problems. Finally, a peer assist process was used at several points in the design process to validate and improve assumptions related to project design and cost, project benefits, production impacts, cost estimates, and project schedules. That process brought worldwide experience to a single location for concentrated, facilitated reviews and problem solving sessions (generally concentrated to 1-3 days).

Summary

The Prudhoe Bay owners are now proceeding with the first phase of a new multi-year facility consolidation plan. With successful implementation of the initial phase, the planned consolidations can continue for another 5-7 years and will result in a flexible, optimized, lower cost operation that will support long term development of the field. Teamwork, communications, and willingness to change were instrumental in developing and sanctioning the consolidation program.

Acknowledgments

The authors would like to thank all those who have contributed to this paper, especially co-workers at Nana-Colt Engineering, ARCO Alaska, Inc., BP Exploration, and Exxon Company, USA.

This paper reflects the views of its authors and does not necessarily reflect the views of ARCO Alaska, Inc., and/or BP Exploration (Alaska), Inc., and/or Exxon Company, USA.

Figure 1: Western Operating Area Production Rate vs Time and Separation Facility Capacity (Peak Upside Rate Case)

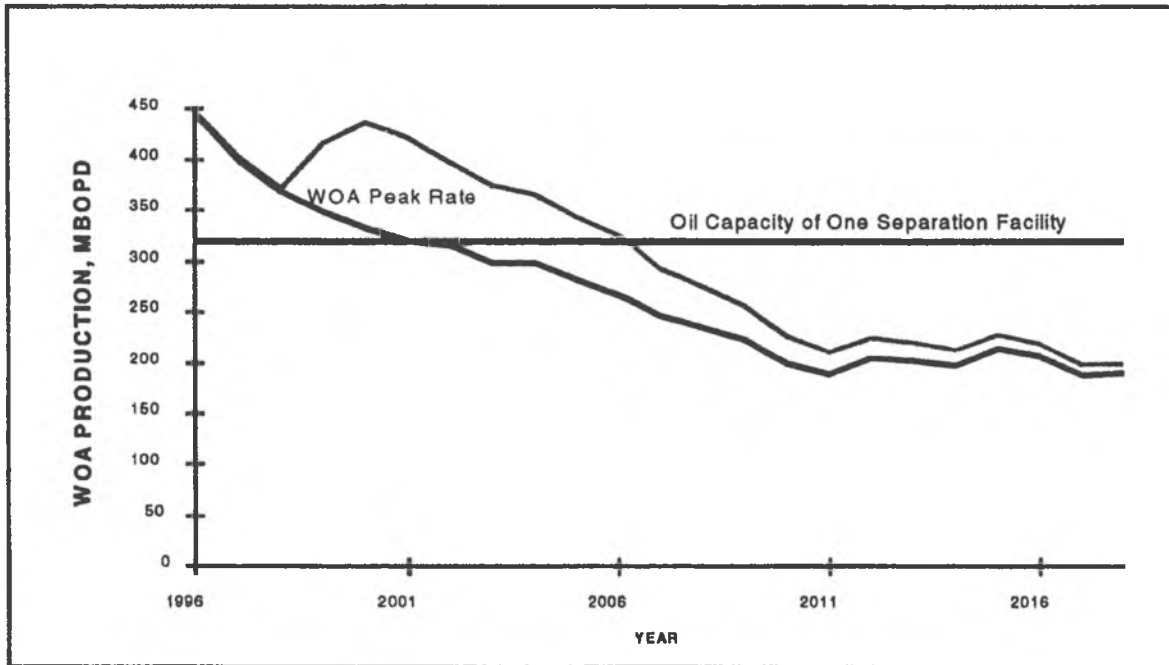


Figure 2: Simplified Separation Facility Oil Processing System

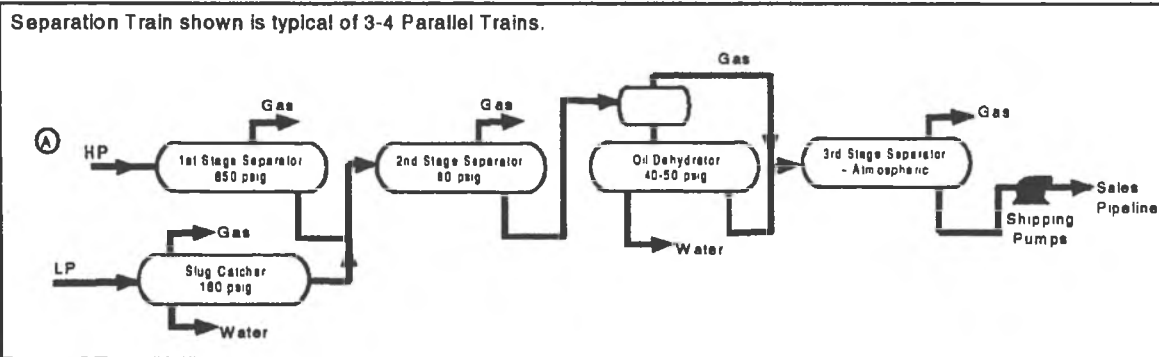


Figure 3: Separation Center Water Processing System

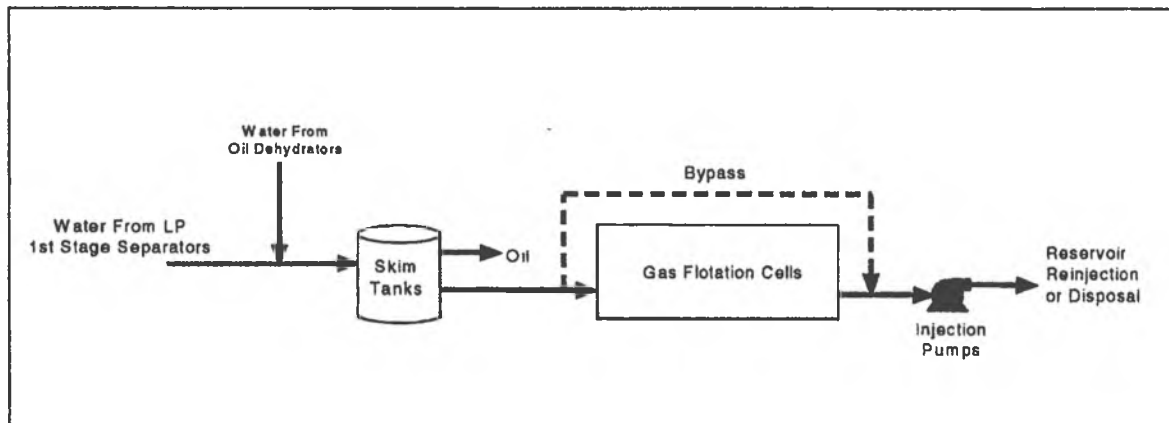


Figure 4: Separation Center Gas Processing System

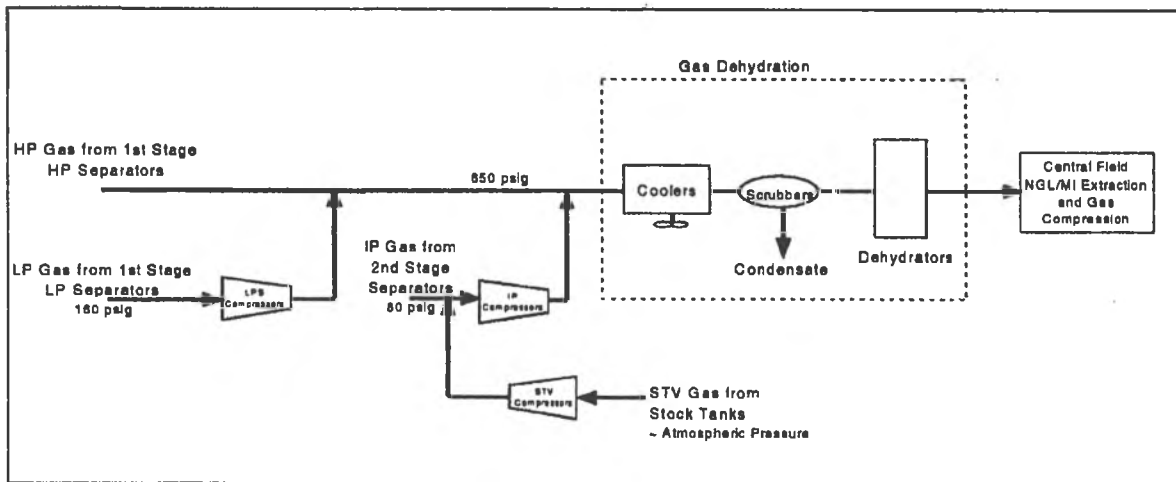


Figure 5: Simplified Facility Schematic After Consolidation (Shaded Areas are Decommissioned)

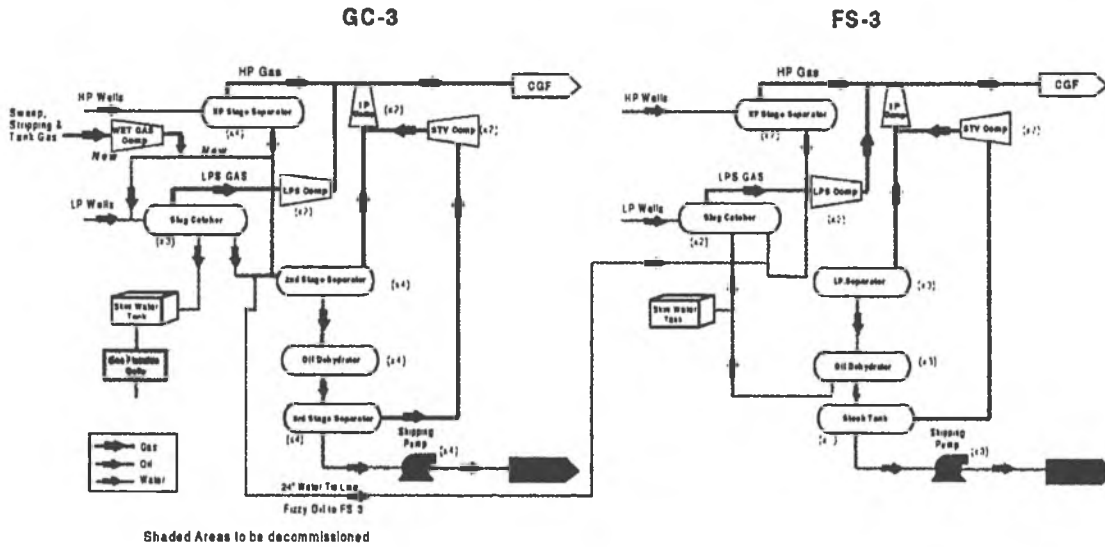
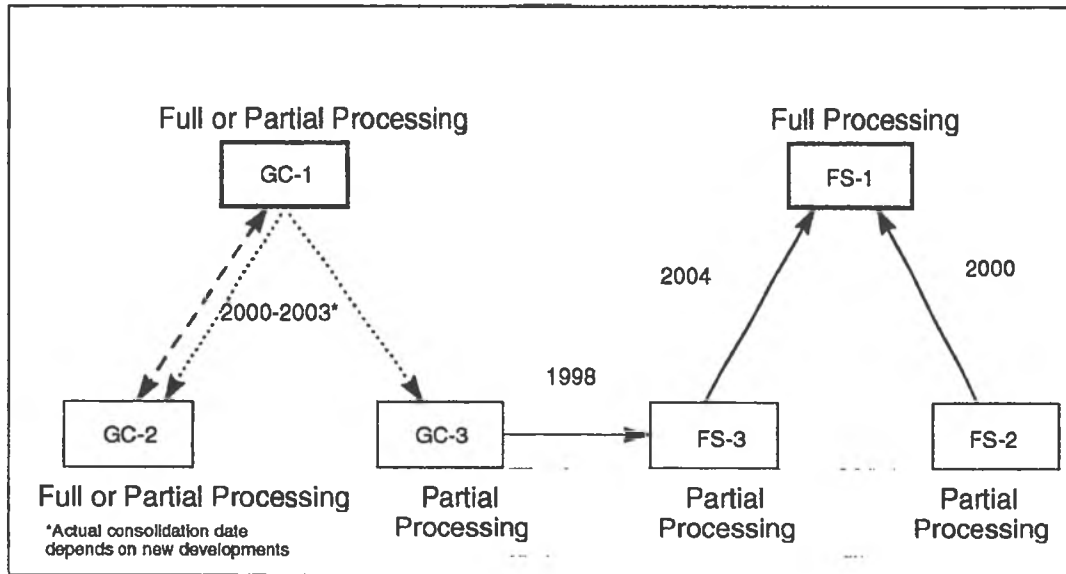


Figure 6: Prudhoe Bay Field Facility Consolidation Plan



MEMORANDUM
Department of Natural Resources

State of Alaska
Division of Oil & Gas

TO: James Clark
Chief of Staff
Office of the Governor

DATE: January, 02, 2002

FILE NO.:

PHONE NO.: 269-8800

FAX: 269-8938

THRU:

SUBJECT: Oil and Gas Briefing Paper

FROM: Mark Myers
Director

Jim,

Thank you for last week's the opportunity to provide some input to you , the Governor and the Lieutenant Governor last week. As you requested during the meeting, I am attaching a short oil and gas issues paper. Obviously, a short paper only scratches the surface of some very complex and difficult issues that are key to the Governor's goal of increasing production. We at the Division would welcome the opportunity to provide you with a longer and more detailed briefing. A more detailed briefing would take about two hours and could be accomplished on short notice, subject to your availability.

I am emailing this package, however I also send a hard-copy that includes a Gas Pipeline Supply map generated by the Division in September, 2002.

Again, thank you for the opportunity to provide suggestions to you on oil and gas policy.

Meeting the Governor's Goal
Increasing Oil & Gas Production by Three Percent Per Year

Division of Oil and Gas
January 2, 2002

Oil production from the main reservoirs in Alaska's largest producing fields is dropping by approximately 10% per year. Production from satellite fields, increased development of heavy oil resources, and the development of Pt Thomson will in the short term offset this decline, but, these alone will not be sufficient to meet the Governor's goal of increasing oil and gas production by three percent per year in 2005 and later years. To meet the Governor's goal, a significant number of new oil and gas fields will need to be discovered and brought on line. We at DNR believe that the geologic potential exists on the North Slope and Beaufort Sea for the discovery of sufficient reserves to meet the goal. However, for that to be accomplished there must be a dramatic increase in the number of exploratory wells drilled in the near future and new discoveries must be rapidly delineated and developed (See attached graph). The State can and should play an important role in stimulating this new wave of exploration.

Mergers and market concentration on the North Slope have created a non-competitive environment in which three majors have a near monopoly that gives them a large competitive advantage in exploration, development, production, and transportation. It is this uneven playing field that has raised the barrier to new entrants, from smaller independents through large integrated majors. As long as these majors invested sufficient capital for exploration and development activities, the State accepted the consequences of the oligopoly. Since the existing majors no longer are willing to invest sufficient resources on exploration or development, the State must look elsewhere. The State must look beyond the existing majors to the new wave of independents and remaining majors. This situation parallels the experience in other oil and gas basins worldwide, several of which have successfully made this transition.

Independent oil and gas companies are bullish on Alaska and prepared to explore and drill as long as certain barriers to entry can be diminished. The State can help reduce those barriers to entry. Oil and gas companies make their investment decisions based on their evaluation of the geologic potential of an area, economics, and their tolerance for risk. Independents are excited about Alaska's geologic potential. However, they are concerned about the near-monopoly on access to facilities, the high cost of TAPS pipeline transportation, the uncertainty of access to a gas pipeline, the timeliness and certainty of permitting, and access to data. The State can address these concerns and make for a more competitive environment at the same time. Accordingly, the administration may want to consider one or more of the following potential courses of action, each of which is relatively low cost:

1. Streamline permitting.
2. Provide easy and expanded access to data critical to the evaluation of oil and gas prospects.
3. Require that fees to existing underutilized facilities be just and reasonable.

4. Sell a portion of the State's royalty gas to guarantee exploration in the North Slope Foothills.
5. Assure a lower pipeline tariff for explorers by leaving a portion of the in-state oil market to those without an ownership interest in TAPS, selling only enough royalty oil to assure in-state refiners access to affordable crude.
6. Stop defending TSM-based TAPS tariffs and consider actions that may encourage those without an ownership interest in TAPS to challenge the interstate tariff.

Additionally, if the State chooses to offer financial incentives, it may want to target those financial incentives to accomplish the Governor's three percent goal. Specifically, it may want to:

1. Condition any incentives for the construction of a gas pipeline on the granting of access to that gasline on terms more typically akin to oil pipelines than gas pipelines.
2. Condition any incentives targeted at existing fields on the granting of access to facilities under cost-sharing terms deemed reasonable by the State (e.g. use utility rate-making principles).
3. Limit any program of exploration incentive credits by time and volume, and to fields a specified distance from existing areas of production.

Several of the low cost and subsidized means of providing for a more competitive environment, and hence more production, are discussed below.

1. Selling Royalty Gas to Foothills Explorers.

The Foothills area is a gas-prone region. It will not be explored by those seeking oil alone, and it will not be explored absent access to a gas pipeline in sufficient volumes to allow for commercial development. To acquire a commercially viable quantity of space in the gas pipeline, the Foothills explorers must commit to pipeline capacity in an initial "open-season" for the pipeline, which will be conducted shortly after an initial decision to build the pipeline is announced. During the open season, the Foothills explorers will be required to sign contracts obligating them to pay for pipeline space for a period as long as twenty-five years, regardless of whether they are successful in finding gas to fill that space. Companies will make this type of commitment only if they are certain they will have access to gas to ship. The State can provide that certainty by offering to sell a portion of its Prudhoe Bay and Pt. Thomson royalty gas to Foothills explorers, who could then carry the royalty gas in their pipeline capacity until such time as they have enough of their own Foothills gas to fill the pipeline capacity they must pay for.

Following competitive bidding, DNR, Anadarko, and EnCana agreed on terms for the sale of royalty gas to Anadarko and EnCana, though the contracts will not become effective unless this administration chooses to prepare a final best interest finding in favor of the sale and the legislature approves the sale this legislative session. Under the proposed contracts, Anadarko and EnCana offer to pay the State as much as it would receive for its gas if left in-value with the Prudhoe Bay and Pt. Thompson producers, plus an upfront premium of \$350,000, a premium of

\$2 million for every five years of purchases, and a per/MCF premium of \$0.02 in years 1-5, \$0.04 in years 6-10, \$0.06 in years 11-15, etc. They also commit to spend not less than \$50 million on exploration in the Foothills, and to local hire, local training, a preference for in-state gas use, and a preference for in-state gas processing. Northern Economics concluded that the State would be bettered by \$6.4 billion if the royalty sale proceeds and the explorers are successful in the Foothills; net benefits to the State would be lower in the event of exploration failure.

To capture the benefits of sale of royalty gas to Anadarko and Encana, the administration must issue a final best interest finding in favor of the sale within the next month, and must submit the proposed sale to the legislature for approval in the 2003 legislative session.

2. The TAPS Tariff – Making It Just and Reasonable

On November 27, 2002, the Regulatory Commission of Alaska issued a decision in which it concluded that the intrastate TAPS tariff exceeded just and reasonable rates by \$9.9 billion (20%) from 1977-1996, and by 57% from 1997-2000. The rationale provided by the RCA extends, logically, to interstate tariffs, which apply to 90% of Alaska's North Slope oil, though the matter has yet to be brought before FERC.

Explorers—indeed all without an ownership interest in TAPS—would be well served by a TAPS tariff limited to just and reasonable rates. If the RCA decision is projected into the future and applied to both intrastate and interstate barrels, it could improve company economics by \$1-2/bbl. This difference is substantial, and apt to be decisive for a number of potential new projects. However, the State needs to act to maximize the benefits of the RCA decision.

While there may be legal impediments that limit or prevent the State from sharing in the benefits of the RCA decision when it comes to calculating royalties and production taxes on existing production, the State should nonetheless support lower tariffs for independents, in-state refiners, and anyone willing to invest new capital in exploring remote regions of Alaska. To this end, the administration may want to consider the following:

a. *Sell royalty oil to the in-state market, but only in such volumes as to assure the availability of the in-state market to those without an ownership interest in TAPS.* Until such time as there is a successful challenge to the interstate tariff, a lower tariff will be available only to the in-state market, which totals 90,000-100,000 b/d. Companies such as Forest Oil, Murphy, Anadarko, and Chevron-Texaco currently have North Slope production, but no ownership interest in TAPS. Their production levels should be totaled, and the State should consider not competing against them for that volume of the in-state market. The State's restraint in its royalty oil sales will send the clear message that it is intent on improving the economics for new players and minority interests. And while the State's royalty income will be somewhat diminished by its failure to monopolize the higher-value, in-state market, perhaps that is appropriate given the State's historic role in creating tariffs recently adjudged too high.

b. *Stop defending the TAPS Settlement Agreement and TAPS Settlement Methodology.* While the State historically defended the TSM, it did so before a regulatory body had adjudged the consequent rates as grossly excessive. Given the RCA's decision, it is time to

stop defending the TSM. Arguably, there will be a further cost to stopping—to “losing”—due to the interstate make-up provisions of the TAPS Settlement Agreement, but that cost is no greater than 10% of the total of excess tariffs paid under the TSM. Moreover, the Carriers will appeal the RCA decision with or without State participation; hence, the State will obtain any alleged advantages of a reversal of the RCA decision regardless of whether it participates in an appeal.

c. *Examine ways to encourage a challenge to the TAPS interstate rate.*

While the terms of the TAPS Settlement Agreement may prevent the State from appearing before FERC in support of lowers tariffs, the State might be able to create an incentive for another party to undertake the task and costs of such a proceeding. For example, if legal, perhaps the State could sell a portion of its royalty oil to an interstate shipper on price terms that would share the benefits of a decrease in FERC-approved tariffs.

3. Conditioning Incentives for the Construction of a Gas Pipeline.

The State may want to consider conditioning any incentives for the construction of a gas pipeline on the granting of access to that gasline on terms more typically akin to oil pipelines than gas pipelines.

Pipeline regulation is an artifact of Lower 48 practices and the prior regulation of natural gas prices. As a consequence, different rules and practices prevail for oil and gas pipelines, though there is little pragmatic difference between a single ANS oil pipeline and a single ANS gas pipeline in the absence of pipeline regulation. Nonetheless, TAPS has been regulated as a common carrier, and consequently potential shippers can obtain pipeline space on relatively short notice and for short periods of time; in the event of excess demand for pipeline space, pipeline capacity is prorated among all. Conversely, the federal government will regulate an Alaska gas pipeline as a contract carrier. Parties wishing pipeline space sign contracts obligating them to pay for that space years before pipeline construction begins; commitments to space may extend for 15-25 years. Consequently, access may be denied for 15-25 years, or may be limited to expansion capacity, which itself is too limited in volume and too uncertain in timing as to warrant exploration risk and expense.

While the State could not normally dictate that a gas pipeline be a common carrier, or something more akin to a common carrier, it can condition the grant of pipeline incentives on improved terms for access. The national energy bill considered by Congress this year included certain terms intended to improve access; that bill may or may not become law in the next year, and if it does, the access terms may or may not remain intact. The State may want to consider conditioning any pipeline incentives—such as a property tax holiday—on access terms equal to or stronger than those included in the national energy bill.

4. Streamline Permitting

Three major permitting issues need to be resolved. Permits must be issued in a timelier manner, permit requirements must be consistent with stipulations and mitigation measures supported by science and engineering data, and the process for the permit applicant must be clear, efficient, and reliable. There are multiple different models and organizational structures that could be used to accomplish these goals, all of which have advantages and disadvantages. These alternatives

will not be discussed in this briefing paper. However, there are several key improvements that should be made independent of organizational structure.

The current permitting system does a poor job of analyzing and managing risks. Many of the issues involving oil and gas permits revolve around mitigating very low risk but high impact events, such as large spills or well blowouts at a remote location. In order to properly assess and mitigate these events, the state needs a higher level of technical expertise in the permitting agencies. For example, DEC would be well-served by having an experienced drilling engineer on staff. Additionally, risk management issues often cross agency lines of responsibility but are poorly understood or communicated between agencies. It is imperative that division and department managers, directors and commissioners have the technical knowledge, policy coordination and willingness to work together to achieve the common goal of timely and environmentally responsible permitting of oil and gas projects. Given the reality of limited staffs and funding, it is also extremely important that managers are constantly prioritizing work and deadlines based on the larger best interest of the state. Finally, the state should be aggressive in pursuing and encouraging the use of newly developed technology that can both decrease risk and environmental footprint. This support must be institutionalized within the regulatory regime. Anadarko's Arctic Platform and well-capping are two such examples of this new technology.

One of the significant inefficiencies in the permitting process is overlap and redundancy of standards and agency requirements. For example, past delays in oil and gas project permitting has been caused by the inefficient interaction between ACMP and ADEC's air quality permitting and contingency spill plan approval processes. A possible solution for this and other redundancies is to reinterpret the regulatory requirements to avoid separate agency determinations under the same standard.

From a Division of Oil and Gas perspective, our greatest historical problems with permitting have come from delays caused by internal agency elevations on lease sales or exploration licenses. Many of these delays are the result of conflict between the Southcentral Region of the Division of Habitat and Restoration of the Department of Fish and Game and DNR. These internal elevations have in some cases delayed the issuance of leases or licenses for more than a year. From the Division's perspective, the Division of Habitat and Restoration has often used the process as a negotiating tool to gain concessions and to extend their authority beyond that justified by current statutes and regulations. These politically-motivated elevations must be eliminated. Elevations should only occur when the elevating agency can support their concerns with solid scientific and other factual data. The elevation process should not be used as a standard interagency negotiating tool with the associated effect of creating long delays in projects and leasing.

5. Access to Data

Independent oil and gas companies and newly involved major oil companies lack data crucial to their evaluation of the North Slope and other basins. This data includes seismic, well log and core data. The State should do all it can to assist in making this data readily available. In addition the State—possibly in conjunction with USGS--should expand and focus geological research and publication-in order to provide baseline non-confidential information to industry. Specifically, the State should require that seismic data be made public 10 -15 years after it is

acquired or require that it be made available for purchase at low cost through a brokerage system. The State should continue its effort to create a WEB-based system for downloading publicly available well log data. The State should require that a 1/3 section of each core be given to the State, instead of the current core chips every foot. This standard is used in Canada with great success. This data would become public information on the same schedule as currently used for well data. Furthermore, the State's current core facility is entirely inadequate. The State should build or lease a new facility, which would also contain the publicly available well and seismic database. This facility could be built in conjunction with the United States Geologic Survey, United States Department of Energy, Bureau of Land Management, Minerals Management Service and/or the University of Alaska. I am pursuing your suggestion that we investigate the seafood processing facility to determine its feasibility as a core facility.

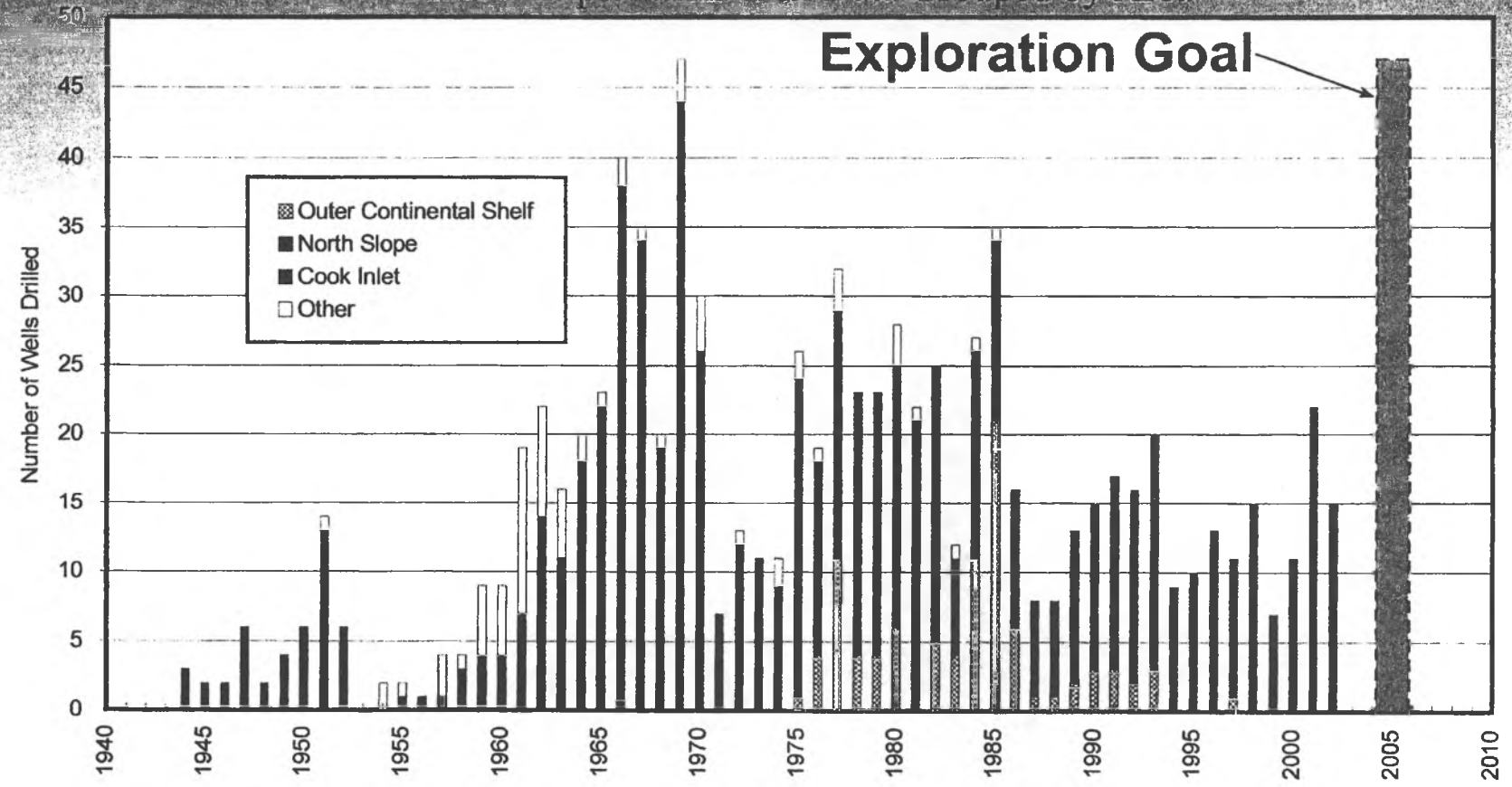
6. Access to Remote Areas For Oil and Gas Exploration and Development

As exploration and development activities move away from established core areas that can be reached through the existing infrastructure or with relatively short length ice roads, different methods will need to be used for physical access. Given significant variations in terrain, climate, biological and cultural environment, and the geology of these remote exploration sites, no single method will be used for access.

The State can improve access by encouraging the development of new lighter weight drilling rigs that are more readily transportable by air or rolligon, eliminating the need for some ice roads. Other technologies that should be encouraged are the use of removable mats for temporary roads and Anadarko's elevated arctic platform. Finally, the State should evaluate the need for new and improved roads to remote areas, new airstrips, and remote exploration and equipment storage pads (insulated ice, mat, or gravel). Any decision on roads and airstrips should target the areas of highest oil and gas potential and should consider the needs of local communities. The State will need to address complaints that new roads may increase cumulative environmental impacts and will face strong opposition from environmental organizations and others opposed to oil and gas exploration in ANWR and other remote areas.

In Order to Increase Alaskan Oil Production the Number of Exploration Wells Drilled per Year Must Dramatically Increase.

Alaska Exploration Well Data Grouped by Area



Number of Alaskan Exploration Wells Drilled per Year

Oil and Gas Consolidation

Two options: Create a Department of Oil and Gas/Department of Energy: or strengthen the DNR Division of Oil and Gas (DO&G)

Department of Oil and Gas or Department of Energy Approach

Positives:

- Direct access to Governor, and Cabinet.
- Some efficiency gains if the Alaska Oil and Gas Conservation Commission (AOGCC), most permitting functions, some of Department of Law's (DOL), Department of Community and Economic Development's and DO&G's functions are consolidated.
- Department would have higher public visibility and potentially a more unified approach when dealing with industry and the federal government on oil and gas issues than do the various divisions.
- A new and separate department may have the ability to create an exempt workforce at near industry salaries that would allow the state to recruit and retain highly-skilled experts throughout the Department

Negatives:

- Will require substantial legislation with new regulations and long period of reorganization
- A substantial part of the efficiency gain would come from combining the AOGCC and the DO&G. This will be opposed by industry, which prefers an independent AOGCC
- Will place in separate Departments the surface ownership responsibilities that are currently under the Division of Mining, Land and Water (DMLW) and the subsurface responsibilities under DOG
- Substantial consolidation of oil and gas permitting into a single Department will require duplication of permitting staff for non-oil and gas permitting (mining, timber, infrastructure, fishing, manufacturing etc), which would presumably need to remain in the current agencies.

Recommendations to Strengthen the Existing Oil and Gas Structure Within DNR

- Permitting: Expanded use of large mine coordinator model with respect to oil and gas exploration and development permitting
- Move Habitat Division of the Department of Fish and Game and the Division of Governmental Coordination into DNR.
- Return royalty audit authority to the Division of Oil and Gas and recruit a very experienced and highly motivated auditor with an industry background to lead the audit group.
- Create a research section within the Division of Oil and Gas to include focused geoscience and engineering research, and commercial studies.
- State Geologist position should be in Anchorage. To the extent that Division of Geological and Geophysical Surveys (DGGS) Energy Section stays independent of DO&G, its research effort should place a higher-emphasis on applied basin analysis in support of exploration and development. Under this option, DGGS should have at least one position in Anchorage filled with an experienced petroleum geoscientist.
- Increase joint research efforts with the United States Geological Survey, Department of Energy and University of Alaska on projects that have significant impact to commercial oil and gas development
- In order to accelerate the process of bringing new production on line, increase DOG staffing in unitization, leasing and permitting.
- Full funding of DO&G to fill existing vacant positions (reservoir engineer, permitter/inspector and accounting technician
- Rebuild the Royalty Accounting system so that it integrates better with other key state systems and can be used more efficiently and effectively for commercial analysis in advance of audits and royalty reopeners.
- Build or lease a modern core facility to replace the inadequate facility at Eagle River. The facility should contain an oil and gas well log library. This facility will create a one-stop data center for independents. Advocate for funding support from DOE, USGS, MMS, NSF, universities, and industry.

- Increase funding for outside experts with respect to commercial issues including facilities access, gasoline and royalty reopeners.
- Increase very focused promotional efforts toward attracting new companies to Alaska beyond AAPG and NAPE.
- Create a more positive attorney-client relationship with the Department of Law, particularly with respect to policy decisions and direction.

INCREASING PRODUCTION AND REVENUE – DIVISION OF OIL AND GAS							
No.	Category	Item	Action	Impact Timing/ Duration			
				Short	Medium	Long	
1.	Increase Exploration Access & Activity	Seismic Data	Released to public after reasonable time		X	-	
			Fed/ State seismic data sharing		X	-	
		Well Data	Limit confidential Period		X	-	
			Fed/ State well data sharing		X	-	
		Basic Research	More emphasis on basic Oil & Gas basic geologic & geophysical research		X	-	
			Increased federal funding		X		
			Acquire specific expertise		X		
			Reprioritization of DGGGS effort		X		
			Public access to basic research - Locate effort in Anchorage to facilitate industry-government relationship;		X		
			DOE grant for digital Log, Mapping, & Lease Sale data	X	-	X	
			Modern core data public repository		X		
			Better coordination with USGS, MMS, DOE, and BLM	X	-	-	
			Increase outreach to Independents.	Engage in technical discussions; provide information, data, advice	X	-	-
			Facilities	Study cost & cost-sharing; Report findings	X	-	-
		Facilitate reasonable published commercial facility access fees; Regulate if necessary	X	X			

No.	Category	Item	Action	Short	Medium	Long
			Study ways to pool equipment (rigs, spill prevention & cleanup)		X	
			Use Unitization Authority proactively to protect correlative rights, state's interests, and enhance competition.	X		
		Pipelines & Other Transportation	Assure reasonable access to contract carrier & other transportation. (See also Pipeline in section 4, above)	X	X	
2.	Incentives	Federal Incentives	EOR / Heavy Oil Tax Credit; OCS Royalty Reduction		X	
			Section-29 Credits for Coal Bed Methane		X	
			Gasline price floor credit (state royalty share included)		X	
			Oil/Gas exploration tax credit for Foothills / Interior Basins.		X	
		State Incentive	EIC credits for exploration; make it focused & discretionary [Caution: impact of state credits are dampened by federal tax deductibility]	X		
			EOR credit external to unit if in state's interest; revise royalty reduction statutes	X		
			Increase chargeable acreage cap in specific areas with specified conditions	X		
			EIC to be non-transferable and used only in field of exploration	X		

No.	Category	Item	Action	Short	Medium	Long	
3.	Permitting	Process/Administration	Streamline; quicker; coordinated; better risk management;	X			
			Education & awareness	X			
			Progressive leadership	X			
			High technical expertise		X		
			Scientific management		X		
			Better state-fed-local coordination	X			
			Extend tundra travel and winter drilling seasons	X			
			Emphasis on creative efficient solutions – not problems	X			
			Assure timely permits and reasonable Permit Terms (E.g., PTU \$150 million per year revenue gain)	X			
			Stipulation & Mitigation Measures	Stop Authority Creep; Limit Elevation	X		
				Justify stipulation with data/evidence (where's the beef?)		X	
	Federal Acreage	Encourage development of known, undeveloped fields – Liberty, Hammerhead, Kuuvlum.		X			
4.	Unitization	Exploration & development requirements	More aggressive; Tougher commercial & work-commitment terms upon unitization.	X			

No.	Category	Item	Action	Short	Medium	Long
5.	Leasing	Accelerate lease issuance	Eliminate current one-year delay	X		
		Work Commitments	Areas near infrastructure – short terms and/or work commitments	X		
			Areas with no infrastructure – apply work commitments	X		
		Exploration Licensing	Modify Licensing; more emphasis on Shallow Gas; more discretion to DNR commissioner	X		
		Lease Sale Policy	Higher minimum bids; use reservation prices to assert option to reject bids	X		
			More leasing coordination with Native Organizations & Fed	X		
			Increase lease rental rates			
6.	Infrastructure	State-built basic infrastructure	Roads, Transportation & Communication Systems			
7.	Federal Revenue Sharing	NPRA	Reallocate revenues to state general fund			
		ANWR	90/10 per Statehood Act v. 50/50 as proposed in legislation			
8.	State Taxes	Production Tax	Tax Rate– Modify (statute)			
		ELF	Add progressive price term			
		ELF	Modify definition of “Field” (Administrative)			
		Property Tax	Modify allocation between boroughs and state Gen Fund.			
		Tax Audit	Make audit more thorough and aggressive; increase field work			

No.	Category	Item	Action	Short	Medium	Long
9.	State Royalty	Audit Authority	Change from DOR to DNR	X		
		NPSL's	Examine cost allocation methodologies to be certain they are appropriate and equitable		X	
		Process & Admin	Make more thorough & timely	X		
			Increase skill level		X	
			Accelerate Electronic Reporting	X		
		Re-openers	Capture Full Value; pro-active monitoring of markets & costs		X	
			Increase analysis of data		X	
			Increase support from legal and outside experts	X		
			Increase in-house training	X		
			Fund Legal support through DNR budget	X		
			Redistribute royalty revenue away from Perm Fund (Repeal Chp.13 to pre-1979 status)		X	
10.	General Commercial	Conflict of interest	Enforce standards w/ outgoing employees	X		
		RIK Oil and Gas	Maximize	X		
		Pipeline Tariffs	Limited to actual and reasonable		X	
			TAPS – Revisit Settlement; conduct comprehensive review		X	
			New Pipelines – Re-evaluate need for settlements		X	
			Support non-PL owners before FERC – (Interpret duty to defend clause correctly – Initial hearing; not ongoing.)		X	
			Gasline deductions – actual and reasonable		X	



Society of Petroleum Engineers

SPE 26053

Prudhoe Bay: Development History and Future Potential

by D. J. Szabo, BP Exploration (Alaska), Inc. and K. O. Meyers, ARCO Oil and Gas

SPE Members

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ABSTRACT

Prudhoe Bay Field is the largest producing field in North America. Prudhoe Bay is currently expected to yield at least 25% more reserves than estimated at field start up. This paper briefly describes the history of the field and some of the key developments that have taken place which have contributed to improved recovery efficiency. These incremental developments have resulted from a process of continuous surveillance, interpretation of field performance, management of multiple reservoir mechanisms, efficient utilization of the gas resource, and exploitation of the existing field infrastructure.

There are four dominant recovery processes currently at work in Prudhoe Bay; Gas Cap Expansion/Gravity Drainage, Waterflood, Miscible Flood, and Gas Cycling. Continuous management of these processes and analysis of field performance leads to identification of attractive targets for further development. Major components of the current field development plan are described in this paper.

Prudhoe Bay is seen by many as a mature oil field on an inevitable and irreversible decline. The major Owners in Prudhoe Bay continue to pursue incremental developments to mitigate decline and supplement proved reserves. Unit technical studies are typically done in multi-company, multi-disciplinary work teams. The pooling of resources in this manner has enabled efficiency gains and has promoted the sharing of ideas and best practices. The current view of potential future development targets and some of the opportunities under consideration for development of these targets are discussed.

INTRODUCTION

Prudhoe Bay field was discovered in early 1968 by ARCO and Exxon with the drilling of the Prudhoe Bay State #1 well. A confirmation well was drilled by BP Exploration in 1969. The next 8 years saw frenetic activity as ARCO, BP, Exxon and other companies with lease holdings in the vicinity worked to delineate the reservoir, resolve equity participation, put together an initial plan of development, and design and construct the initial infrastructure.

Prudhoe Bay came on stream in June of 1977, rapidly ramping up production until the field's maximum allowable rate was reached in 1979 at 1.5 MMSTB/D. This plateau rate was maintained until 1988. The current production rate from the field is approximately 1.15 MMSTB/D.

In late 1992 the 8 billionth barrel of liquids was produced from Prudhoe Bay. Pertinent Prudhoe Bay facts are listed in Table 1.

GEOLOGICAL SETTING

The Prudhoe Bay Field is a combination structural and stratigraphic trap. A regional cross section representative of the Alaskan North Slope is shown in Figure 1. (Ref 1). The Unitized intervals are of Triassic age and include the Sag River Formation, Shublik Formation, and the Sadlerochit Group. The most important interval is the Ivishak Sandstone of the Sadlerochit Group which contained more than 95% of

the unitized original liquids in place and accounts for the vast majority of proven and potential reserves. The Geological setting has been described in detail (Ref. 1, 2, 3).

RESERVOIR CHARACTERIZATION

Reservoir character plays an important role in the selection of reservoir processes to be applied for efficient depletion of the reservoir and interpretation of field performance for management and optimization.

The Owners' understanding of reservoir character and its influence on reservoir performance has evolved through time. (Ref 4) For example, in early 1992 after fully two thirds of the expected recoverable reserves had already been produced from Prudhoe Bay, the Owners embarked on an ambitious two year study to better describe the lower most and poorest quality section of the reservoir. This effort is in support of ongoing performance analysis and depletion studies aimed at identifying effective means to improve ultimate recovery from the interval. (Ref. 5) Stochastic modeling techniques have been successfully applied to advance our ability to interpret field performance and predict future behavior. (Ref. 6) Today the reservoir description toolbox contains methods for developing a lithology based deterministic sand/shale description, stochastic methods for generating multiple realizations of interwell reservoir character that honor observed well data, and a wide range of field surveillance data with which to condition the various plausible reservoir descriptions developed. Reservoir descriptions are routinely generated for input to reservoir simulation models using these tools. We have learned that close interaction between reservoir describers and reservoir modellers is necessary to ensure the description is fit for purpose. (Ref. 7)

Reservoir description is also critical for characterization of the remaining targets enabling definition of incremental development potential.

FLUID DISTRIBUTION

The Prudhoe Bay reservoir was saturated at discovery and had a large gas cap in direct communication with the oil rim. This fan-shaped reservoir dips at 1 to 2 degrees from Northeast to Southwest. There is a very large associated aquifer. The gas cap directly overlies approximately two thirds of the oil rim.

A variable thickness but areally extensive zone of relatively low API gravity crude is found at the oil/water contact. This zone is termed the Heavy Oil Tar (HOT). The HOT plays an important role in reser-

voir performance acting as a partial barrier to water influx.

In addition to the oil target in the oil rim, there are significant liquid resources in place in the original gas cap. The condensate yield of gas cap gas at original conditions was approximately 30 STB/MMCF. The gas cap also contains a significant amount of "relict" oil. This oil exists in the liquid phase at very low saturations and is a remnant of the saturation and geological history of the reservoir.

An approximate distribution of original liquids in place is given in Figure 2.

A schematic cross-section illustrating the initial fluid distribution is shown in Figure 3.

DEVELOPMENT OVERVIEW

The initial development plan for Prudhoe Bay envisioned 500 or more wells on nominal 160 acre spacing. The area under the initial gas cap would be depleted by gravity drainage, while the peripheral areas downdip from the GOC would be subject to a water-flood due to anticipated inefficient pressure support from the gas cap.

The initial development plan also anticipated gas sales starting up within 5 years of first oil production. Gas sales for other than local fuel have not materialized to date and as a result field development planning has been modified accordingly. Gas sales prospects are discussed briefly later in this paper.

Maximum allowable oil offtake rate was set at 1.5 MMSTB/D for the field. Condensate and Natural Gas Liquids could be produced in addition to the "black oil". The maximum allowable offtake rate was specified by the Alaska State Oil and Gas Conservation Commission (AOGCC) based on testimony by the Owners and consultants contracted by the AOGCC.

The oil column was in excess of 400 feet thick in the heart of the reservoir. Early development wells were completed with a minimum of 100 feet of standoff to the Gas Oil Contact (GOC) and 50 feet of standoff to the Water Oil Contact (WOC). Initial well capacities were often in excess of 20 MB/D.

At field start up in June 1977, 63 wells were available for production. Development drilling has continued unabated since then. The total number of development wells drilled to date is greater than 1100. Drilling is a key component of many incremental reservoir development projects. Virtually all of the reservoir is developed on nominal 80-acre spacing today. There are plans to drill up to 300 more wells by the end of the

decade associated with various improved recovery projects.

Aside from drilling, two major projects dominate the development history of Prudhoe Bay; waterflood and produced gas handling capacity expansions.

A brief description of each of these major projects gives insight to the range of development studies that have been undertaken since field start up.

Waterflood Development

Development optimization studies have continued from before startup through present day. In the early stages of field depletion a major effort was undertaken to define the appropriate scope and timing for the planned waterflood. Early in field life reservoir performance data was gathered providing insight into the effectiveness of primary depletion in various parts of the reservoir. The operators used this early performance data to optimize the scope of the waterflood project. Ultimately it was agreed among the PBU Owners that the waterflood would cover the majority of downdip areas beyond the extent of the original gas cap and the Eastern "Flow Station 2" area of the field.

Key parameters in defining waterflood scope were reservoir character, aquifer strength, production performance, the timing of gas sales, and water sources.

Key components of the installed waterflood infrastructure include a sea water treatment plant with a design capacity of 2 MMBW/D of water, two water injection plants (one on each side of the field to boost injection pressure) and several miles of seawater distribution lines with diameters ranging from 6 to 40 inches. By mid 1984, the water distribution network and sea water treatment plant were installed and commissioned. The seawater treatment plant was commissioned with a daily capacity of 1.5 MMBW/D.

Seawater injection commenced in the fall of 1984 into the North West Fault Block (NWFB), Eastern Peripheral Wedge Zone (EPWZ), and the Flow Station 2 (FS-2) areas of the field. The Western Peripheral Wedge Zone (WPWZ) came on line in mid-1985. The major waterflood areas are shown in plan view in Figure 4.

Since waterflood start-up, a considerable amount of attention has been applied to the management of the floods and interpretation of performance results. (Ref. 8, 9) Many unexpected challenges have arisen and been dealt with. Reservoir character has been a dominant factor in waterflood performance as expected. The challenges varied in the different areas of the waterflood. High permeability contrast in "single zone" targets, poor injectivity/productivity, and verti-

cal barriers providing effective isolation have all been encountered. In spite of the challenges, waterflood performance has exceeded all expectations. Ultimate recovery by waterflood is expected to be in excess of 50% in all the major flood areas. Supplementing the strong waterflood performance is an ongoing Miscible Gas flood which will ultimately affect the entire waterflood area.

The applicability of EOR techniques was under study even before the waterfloods started up. At Prudhoe Bay, the Owners found themselves in the position of having to process a large stream of produced gas with no commercial market. The gas was reinjected into the gas cap to provide pressure support, but it was recognized early on that there was a captive source for a hydrocarbon miscible injectant. Recognition of this resource provided incentive for the Owners to develop a comprehensive EOR program. Unit studies led to a pilot Miscible Injection project with start up in 1982, the Flow Station 3 Injection Project (FS3IP). The large scale Prudhoe Bay Miscible Gas Project (PBMGP) started up in 1987. Further expansions to the PBMGP were certified in 1992. Details of the process selection and initial design have been described in detail. (Ref. 10, 11, 12)

The latest certification covers the entire waterflood area including prospective waterflood expansion targets adjacent to the current floods. Ultimately more than 130 injectors may be converted to water-alternating-gas (WAG) injectors. The volume of MI available for the PBMGP is expected to peak near 700 MMSCF/D upon completion of the Gas Handling Expansion Phase 2 project in 1994. A map of the current extent of the PBMGP and future expansion areas is shown in Figure 5.

Manufacture of MI for the PBMGP is part of a comprehensive project that also enables extraction of NGL's from separator off gas. The Central Gas Facility (CGF) is the key facility component of this project. It was installed in 1986 and was expected to process 3 BCF/D of separator off-gas to produce up to 50 MB/D of NGL for blending with the crude stream into the Trans Alaska Pipeline System (TAPS) as well as 250 MMCF/D of Miscible Injectant (MI) for the PBMGP. CGF modifications made since the plant started up allow 5.5 BCF/D of gas to be processed, yielding approximately 70 MB/D of NGL and 400 MMCF/D of miscible injectant.

Gas Handling Capacity/Gas Cycling

The initial plan of development called for installed gas handling capacity of more than 2 BCF/D. This design was predicated on a larger waterflood than was ultimately implemented and the expectation of an early gas sale.

As the reservoir matured and the prospect of gas sales in the near future dimmed, it became apparent that the gas handling capacity of the field would become a limiting factor in field production. Free gas production became more and more difficult to avoid in the Gravity Drainage area. (Ref. 13)

Through a series of incremental steps involving facility debottlenecking, compressor upgrades, pipeline upgrades, and installation of the CGF the gas handling capacity of the field was increased from 2.4 BCF/D in 1986 to approximately 3.9 BCF/D by 1988.

Installation of the CGF and associated increases in Field Gas Offtake (FGO) offered the Operators increased flexibility to further optimize the recovery of gas cap condensate, gas cap relict oil, and residual oil from behind the encroaching gas front in the gravity drainage area by managing the distribution of field gas offtake.

The success of historical gas offtake increments in boosting field production and reserves led to further optimization efforts. A significant increment in facilities would be required to increase gas handling capacity further. The prospect of large capital expenditures required a detailed assessment of the reservoir benefits that would flow from increases in gas handling. The reservoir benefits of a gas handling expansion have been characterized as "Black Oil" or separator liquid recovered as a result of being able to produce wells at higher Gas - Oil Ratios (GOR's), "Vapor Phase" or additional separator liquids recovered as a result of cycling additional gas through the reservoir which displaces condensate laden rich gas and vaporizes residual oil, relict oil, and retrograde condensate, "NGL" which is liquids recovered at the CGF by processing a greater volume of separator off-gas, and "EOR" which is oil recovered as a result of manufacture and application of a larger volume of miscible injectant in the miscible floods. After developing a more thorough understanding of the nature of the reservoir benefits, and a considerable amount of facilities engineering study and optimization, the Unit agreed to the funding and implementation of the Gas Handling Expansion 1 project (GHX-1) in 1987. This project was implemented in late 1990 increasing the field gas offtake from an annual average of 3.9 BCF/D to 5.5 BCF/D. In 1990, the Owners agreed to a second GHX project (GHX-2) which will be implemented in two stages beginning in 1993 with an increase in peak FGO capacity of 1.3 BCF/D in the Western Operating Area (WOA) of the field. The second phase for installation in 1994 will increase peak FGO capacity by a similar amount in the Eastern Operating Area (EOA). Upon completion of GHX-2 total field gas offtake capacity will be 7.5 BCF/D annual average.

Understanding the reservoir benefits of gas handling expansions has led to more emphasis on the management of the gas cycling process and awareness of the "compositional" nature of the reservoir. Estimates of remaining reserves suggest that the expected future production from Prudhoe Bay can be attributed in approximately equal thirds to continued black oil production from the gravity drainage area of the field, continued production from the waterflood/ EOR areas, and vapor borne liquids - condensate, NGL, and vaporized relict and residual oil recovered as separator liquids primarily from gravity drainage area wells.

THE INTEGRATED SYSTEM

Prudhoe Bay has evolved through time to an extensive facility infrastructure fully integrated with the reservoir processes to optimize recovery. This "System" is depicted schematically in Figure 6. Bottlenecks in the system dictate the field's production capacity.

Many of the projects implemented in Prudhoe Bay represent the largest of their kind in the world. Integration between projects is extremely important and adds another dimension to the complexity of developing incremental opportunities. Any perturbation in the integrated facility/reservoir system needs to be fully understood and its impacts on the existing developments, both competitive and synergistic, need to be quantified and accounted for.

Learning to identify what and who needs to be involved in assessment of a development opportunity has been one of the significant advances in being able to maximize the value captured from the Prudhoe Bay resource.

HISTORICAL PERFORMANCE

Prudhoe Bay cumulative production had exceeded 8 billion barrels of liquids by the end of 1992. Historical production performance is shown in Figure 7.

The field's oil production capacity dropped below 1.5 MMSTB/D in 1988 "officially" signaling the start of decline. The onset of decline was a direct result of limited gas handling capacity as opposed to limited oil production capacity. GOR's have continued to rise in the field as the reservoir and in particular the gravity drainage process has matured. Aggressive well workover and stimulation programs and ongoing field development programs have been able to mitigate the overall rate of production decline, holding it to an average of approximately 5% per year over the last 5 years. The field's underlying "base" decline rate is difficult to ascertain given the pace of wellwork and in-

cremental development activity. Individual well declines vary widely, but on a regional basis tend to average in the 15% to 25% per year range.

RESERVES GROWTH

The success of the ongoing field development program has translated into reserves growth of more than 25% since field start up. Prior to field start up, the Operators' estimate of recoverable reserves was 9.6 BSTB. Today recoverable hydrocarbon liquid reserves are expected to approach or even exceed 12 BSTB.

Estimated ultimate recovery of liquids from Prudhoe Bay is approaching 50% of estimated original in place liquid volumes. Projected recovery factors in this range may suggest limited upside associated with incremental development. A closer look at reservoir performance on a regional basis reveals some very attractive development opportunities. In some sections of the reservoir, projected recovery factors are in excess of 60% while in others, projected recovery factors are significantly below average. Analysis of the relative maturity or success of reservoir processes helps define the most attractive targets for incremental development.

CAPTURING INCREMENTAL VALUE

Reservoir Surveillance

An extensive surveillance program was implemented during the early stages of development which is still maintained. This program includes open and cased hole logs, core acquisition, production and injection logs, repeat formation tester (RFT), pressure, chemical and radioactive tracer, and detailed production data. This data has proved critical to the interpretation of field performance, management of the reservoir for optimum depletion, and as a basis for defining incremental developments.

Reservoir surveillance methods have evolved through time driven mainly by demands of the complex data set we are working with and facilitated by advances in technology for managing and visualizing the data captured.

The key to our reservoir surveillance effort is a numeric "static" model of the reservoir. The static model is a volumetric model with a framework created from "hard" well and seismic data. All hard data recovered from specific wells is hung on this framework. The static model also contains digital versions of maps of virtually all mappable parameters which have been created from the available hard data. Mapped sur-

faces are stored on a very fine grid which can be interrogated at any point in space to get an interpretation of the reservoir and fluid character.

Base input data for all reservoir models and most other reservoir studies is derived from the static model.

The static model also allows us the flexibility to update the "tank" with observations of present day fluid contacts so that a "current" picture of the reservoir's attributes can be output or displayed for any section of the reservoir under study.

In Prudhoe Bay, the fact that multiple mechanisms can be active in any part of the reservoir complicates interpretation of surveillance data and makes predictions of future performance difficult. Throughout the life of the field, variations in offtake distribution have caused lateral fluxes to vary in direction, magnitude, and composition. Complexities like this demand that multiple tools and in most cases, a multidisciplinary team are required to interpret field performance.

Reservoir description is one of the key controls on reservoir performance, interpreting reservoir behavior, and predicting future performance. The description of the Prudhoe reservoir has evolved over the years. In the early days of field production, having a good handle on reservoir description was not critical since for the most part wells were completed in relatively homogeneous, high quality sands, and it was adequate to have a feel for the position of any large, correlatable reservoir events. Any anomalies in well performance or fluid movement could be reconciled with a relatively primitive reservoir description.

The dependence of reservoir performance on reservoir character has been amplified as the field has matured. It is not surprising that the regions of the reservoir holding the most potential for further exploitation are the more complex and/or lower quality reservoir zones.

Reservoir Management

Reservoir management is a broad topic which will be defined here as the integration of available information on reservoir performance, facility infrastructure, and predicted future performance to maximize the value of the asset.

Prudhoe Bay presents a considerable challenge in reservoir management because of the complexities of the reservoir and facility constraints.

Effective reservoir management will lead to capture of maximum value from the asset with the currently installed infrastructure and reservoir processes. It will also enable the identification of opportunities for in-

cremental developments. Day to day operations are managed by region - with the major regions being the Gravity Drainage and Waterflood/ EOR areas.

In the gravity drainage area, the primary producing constraint is gas handling capacity, therefore the basic reservoir management strategy is to maximize daily oil rate within gas handling constraints and without jeopardizing long-term reservoir performance. Producing characteristics of the gravity drainage area have been described in Ref. 13.

In the waterflood /EOR flood areas, the basic reservoir management strategy is the same, but the guidelines applied are specific to the waterflood/EOR mechanisms. The overall objective is to mature the oil recovery process as rapidly as possible with a minimum of produced water and maximum efficiency of the available miscible injectant.

The supply of miscible injectant is finite, being dictated by the CGF gas processing capacity. Efficient use of the available MI is critical for maximizing the economic value of the EOR flood. Novel methods for monitoring EOR flood response and efficiently distributing the available MI to target EOR flood patterns have been implemented. (Ref. 14, 15, 16)

Development Opportunities

A discussion of future development opportunities requires a description of the expected nature of the reservoir fluid distribution at the end of field life with the current development plan. Background on the reservoir description that is dictating where those resources will reside is also required.

An integrated understanding of reservoir character, reservoir performance, facility capacities and limitations, and reservoir management objectives allows the Owners to identify opportunities for capturing incremental value. These opportunities can involve optimization of reservoir processes, implementation of new/improved reservoir processes, facility debottlenecking and expansions or changes in reservoir management guidelines.

Large increases in facility capacity are prohibitively expensive and at this time appear unwarranted. There are expected to be opportunities for improved recovery from the reservoir through incremental developments, optimization of existing processes or improvements in reservoir management strategy.

A look at the reservoir with the approximate fluid distribution at the present time gives an indication of the character of potential development targets in Prudhoe Bay.

Targets that have been identified for future development include:

Zone 1. Zone 1 is probably the largest "conventional" development target. Development of Zone 1, the lowest reservoir interval, has lagged the other zones in the reservoir because of its relatively poor quality and consequent inability to compete hydraulically with the other zones in multi-zone completions. Until recently, development of Zone 1 as a stand-alone target wasn't competitive with other development opportunities. In the gravity drainage area of the field, the gravity drainage process is expected to be relatively inefficient in Zone 1. Poor vertical and lateral connectivity will result in a significant oil "Pad" at the base of the oil column which we will be unable to produce at competitive GOR's. Recovery from this zone may be enhanced by drilling on denser well spacing, the application of non-conventional (horizontal or very high angle wells at 85 to 95 degrees), and possibly by implementing a waterflood. Unit technical work predicts a target of up to 1.5 BSTB oil in place in Zone 1 at the end of field life if no further development occurs. This potential development target is actively being addressed from several aspects by multi-company, multi-disciplinary work teams.

The only waterflood/EOR flood area with significant oil in place in Zone 1 is the northern part of the FS-2 area. The depletion maturity of Zone 1 lags the other intervals in this flood primarily due to poor reservoir quality which impedes the ability of Zone 1 to compete hydraulically in production and injection. Dedicated Zone 1 waterflood development was begun in this area in 1991 with a successful in-fill drilling program. Further dedicated Zone 1 development is planned for 1994.

Waterflood/EOR Areas. Performance of the water and miscible floods has been outstanding in aggregate, generally exceeding all early expectations. Pattern by pattern and regional performance analysis helps identify areas that are performing relatively poorly. Anomalous performance may be due to several factors including reservoir quality, reservoir structure, pattern geometry, flood rate, etc. Kwan discussed some of the techniques used for identification of anomalous waterflood behavior in Ref. 9. Exceptional performance in parts of the waterflood/EOR flood area has raised expectations for the entire flood and has heightened the Operator's awareness of opportunities which may be available. In 1991 a Unit technical team recommended a novel program to redevelop a portion of the NWFB waterflood/EOR flood area. This project would increase the well density from nominal 80 acre to 60 acre spacing and convert the existing inverted 9-spot flood pattern to a line drive. This program, termed High Viscous to Gravity

Ratio Flooding (HVGR), was expected to improve recovery in the target area from 62% to 66% (Ref. 17)

A systematic program of Pattern Size Reduction (PSR) is ongoing in the WPWZ waterflood/EOR area to improve flood performance in an area that has lagged behind the field average. (Ref. 18)

Peripheral Development. Development of the periphery of the field, both down-dip and up-dip, has lagged behind the more productive heart of the field due to relatively thin LOC, relatively low productivity, and expectations of difficulty in competing for facility capacity due to either high water cut or high GOR. The target in the up-dip periphery is Zone 1 which has been discussed. In the down-dip periphery the target is upper Zone 4, another relatively low quality interval. The greatest challenge in this part of the reservoir is achieving a completion that will sustain flow at economic rates.

In both the up-dip and down-dip periphery, the application of high angle well technology promises to unlock more reserves. In both cases the reservoir thickness is not sufficient for successful fracturing and the productivity gains achievable with high angle wells present an opportunity to capture the reserves. In 1992, 13 wells were drilled in peripheral areas targeting less than 75 feet of oil column. Continuing advances in drilling technology are providing the opportunity for cost-effective development in the periphery.

Gravity Drainage Area. The gravity drainage process is very efficient in PBU however it is a time-dependent process. Unit studies indicate that the residual oil saturations in the depleted part of the GD area will be between 20% and 30% at the end of field life. This residual oil represents a target of 3 - 4 billion barrels of oil that is well defined in terms of location and character and is readily accessible through the more than 600 wellbores that are expected to have been drilled in the GD area by the end of field life.

Selective infill drilling may access reserves isolated structurally, or otherwise inefficiently depleted. Increasing well density to 40-acre spacing over the entire area cannot be justified at this time, but advances in drilling technology which would enable more efficient wells or less expensive wells could change this outlook.

Further increases in gas handling capacity are currently not being contemplated, but remain a possibility under more favorable economic conditions.

Enhancing the gas cycling process by managing lean gas sweep may allow some of the GD residual oil to be recovered through vaporization.

Potential Future Opportunities

The Owners are continuing to identify development opportunities in the field. The opportunities do not become a part of the Unit Field Development Plan until technical studies have been completed to assess their viability and the Owners reach consensus on the project. There are several opportunities which are currently under study. Potential projects include:

Pressure Management. This project would involve injecting a large volume of water into the gas cap area to mitigate the rate of pressure decline in the reservoir. Increased reservoir pressure over the remaining life of the field could yield incremental oil reserves through enhanced inflow performance throughout the field, improved vaporization efficiency, displacement of rich gas cap gas to producing wells, and reduced shrinkage. Risks associated with this project include potential impairment of the gravity drainage process by unfavorable water flux, potential impairment of gas recovery, and potential water handling problems.

40-acre Infill Drilling. The reservoir is currently developed on nominal 80-acre spacing. Studies are ongoing to define the potential for adding to the reserve potential by increasing the well density. The work is focused on the gravity drainage area. Attractiveness will depend on reservoir character. There is potential for more than 200 locations if the reservoir benefits can be defined with reasonable certainty and if drilling and tie-in costs can be reduced substantially.

Fieldwide HVGR. This project would extend the concept applied in the NWFB HVGR project to the rest of the waterflood/EOR areas. Success of HVGR is dependent upon reservoir character and sufficient MI availability. As many as 150 new wells may be required to address all the potential target areas. Controlling facility and drilling costs will be critical to the viability of this project.

Gas Sales. The gas resource in Prudhoe Bay is large. Recoverable dry gas for sale is expected to be in excess of 20 trillion cubic feet after accounting for estimated North Slope fuel usage.

To date, produced gas has been reinjected into the reservoir to enhance oil production in the absence of a gas sale. Gas reinjection benefits oil production by helping to maintain reservoir pressure, cycling through the reservoir and vaporizing residual oil and condensate, and by supplying the components to make the hydrocarbon miscible injectant used in the EOR flood.

Gas sales will have an impact on oil production. The most immediate effect would be an increase in the rate of reservoir pressure decline. The amount of gas cir-

culating through the reservoir will be reduced and the amount of Miscible Injectant that can be made will also be reduced. Counteracting these losses, gas sales may prolong the economic life of the oil rim resulting in incremental oil recovery. Quantification of these reservoir impacts is largely a function of the timing and rate of gas sales.

The Owners are continuing to assess the opportunity for gas sales and the potential impacts of a gas sale on ongoing development. However, reservoir management is only one challenge among many which must be addressed to realize commercialization of the gas resource.

Other Targets

Other targets include the "minor reservoirs" which were unitized along with the Ivishak, but which have been relatively unattractive compared to ongoing Ivishak development. There are plans to drill the first dedicated Sag River producing wells in the 1993 drilling program. Improved drilling and completion technology is a key to unlocking more of this resource.

At the end of field life, more than 12 Billion barrels of hydrocarbon liquids are expected to be left in the reservoir. This is oil that is unrecoverable using processes and knowledge available to us today. This target is one that attracts a great deal of attention from the Owners who are continuously investing in Research and Development to try and identify means to unlock more of the resource. Capturing only 10% of this target represents more than a billion barrels of oil - far more than any recent field discovery in the United States.

Prudhoe Bay development has provided an integrated infrastructure hub on the North Slope. There are several small discoveries in the vicinity of Prudhoe Bay which are uneconomic as stand-alone developments. It may be feasible to develop these pools if capacity in Prudhoe Bay facilities becomes available. The Prudhoe Bay Owners are investigating options for development of some of these pools.

CAPTURING DEVELOPMENT OPPORTUNITIES

Unit Process

The process for reaching consensus on future development opportunities in the Unit has evolved through time and is far more efficient today than it was just a few years ago. A large part of this improvement can be attributed to recent emphasis on development of a consensus Unit Depletion Plan.

Unit Depletion Plan. In early 1992 representatives of the Major Owners met to identify and work through barriers to a consensus Unit Depletion Plan. A prioritized list of key technical issues that would need to be addressed was agreed and Unit teams put in place to address them. All Owners recognized that further development would be impaired if Unit consensus could not be achieved on these or any other technical issues that may arise. It was agreed that the most efficient means of achieving technical consensus would be to form work teams with representation from all the major Owners and consensus work plans. Also, the Owners may need different levels of technical support on the various issues and work plans have to accommodate (within reason) the needs of all companies on each issue. Finally, and perhaps most importantly, the Owners realized an opportunity to minimize duplication of effort, to share best practices, and to build a healthier work environment through cooperation. The Depletion Plan Elements now represent the key opportunities being addressed in the Unit at this time. This will ultimately result in the capture of more value for all the Prudhoe Bay Owners.

Work Process

The entire petroleum industry has been evaluating business processes recently. Various terms have been used to describe these efforts to simplify and streamline processes, provide higher quality products, and empower employees to identify and implement improvements. "Process Evaluation Teams" and "Continuous Improvement Process Teams" typically identify significant opportunities for process efficiency improvement through improved communication. This was true in Prudhoe Bay as well. An "assembly line" process for working up development opportunities had prevailed historically whereby Geoscientists would work up the reservoir description for an area of the reservoir, the Reservoir Engineers would develop a scheme for improving recovery from the reservoir, the Facilities Engineers would design and build a facility to accommodate the new project, the commissioning team would install the project on the North Slope and then they would hand it over to the Operations people to manage. We all know that if each of these steps is carried out independently, there is a high probability that the project will be sub-optimum. Considerable animosity can also be experienced along the way as specifications are not understood or are not reasonable or appropriate.

Placing emphasis on who the customers are for the product to be delivered and who the suppliers of input to each stage of the process has helped overcome inefficiency in the work process. In practice multidisciplinary teams are set up at the outset, common

Goals and objectives are agreed, and workplans are established which accommodate continuous feedback between disciplines throughout the project.

SUMMARY

Efficient development of additional reserves has been achieved in Prudhoe Bay Field.

A thorough understanding of reservoir mechanisms and reservoir description facilitated by working in multi-disciplinary teams supported by a comprehensive surveillance program is required for development of a major oil field like Prudhoe Bay.

Effective management of a large resource like that available in Prudhoe Bay can yield attractive incremental development opportunities as the field matures.

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The observations and opinions expressed in this paper are those of the authors and are not necessarily shared by the Prudhoe Bay Unit Working Interest Owners.

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Table 1

Prudhoe Bay Facts

Operators:

Western Operating Area - BP Exploration
Eastern Operating Area - ARCO

Ownership:

	<u>Oil Rim %</u>	<u>Gas Cap %</u>
BP Exploration	50.7	13.8
ARCO	21.8	42.6
EXXON	21.8	42.6
Mobil	1.9	0.3
Phillips	1.9	0.3
Chevron	0.7	0.5
Others	1.2	0.0

Production Startup:

June 19, 1977

Cumulative Liquid Production to 12/31/92:

8.0 Billion STB

Current Production Rates (1993):

Hydrocarbon Liquids:	1.15 MMSTB/D
Gas:	5.6 BCF/D
Water:	1.3 MMB/D

Total Production and Injection Wells at 12/31/92: 1115

Figure 1

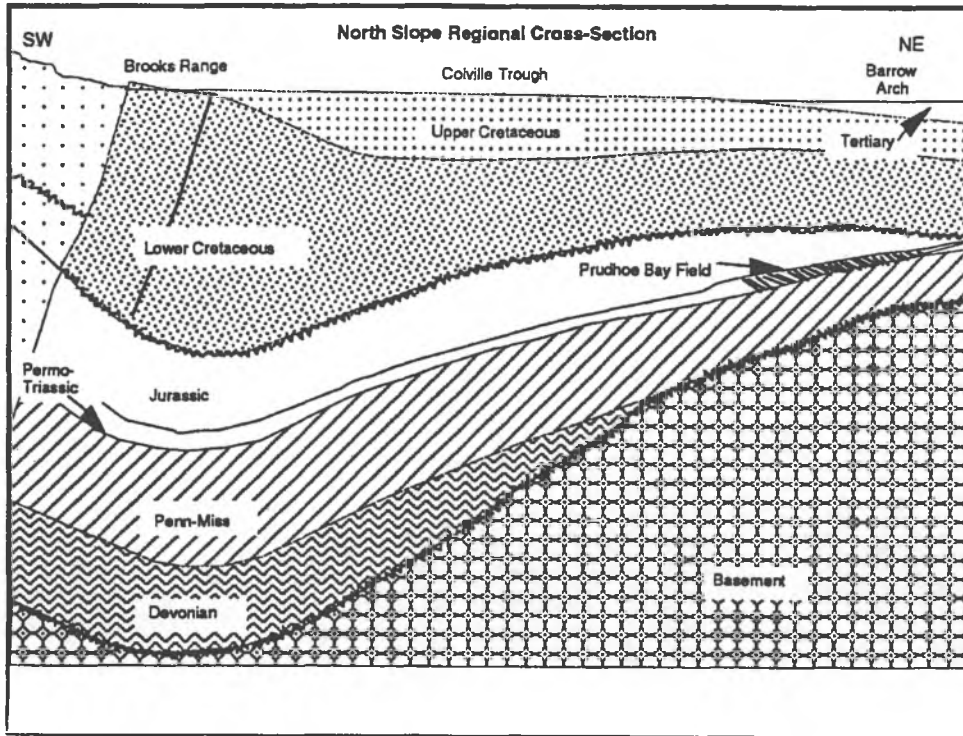


Figure 2
Prudhoe Bay Original Liquids In Place

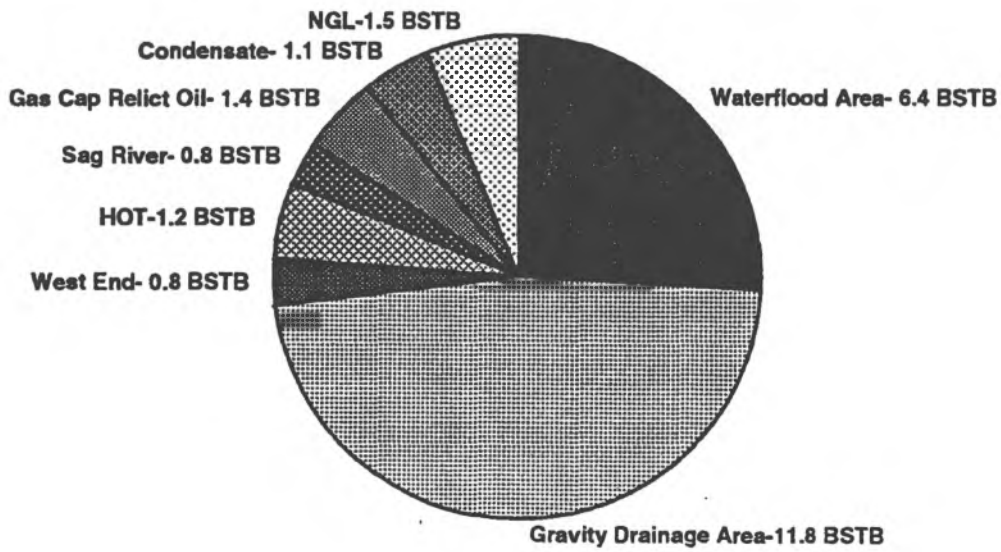


Figure 3

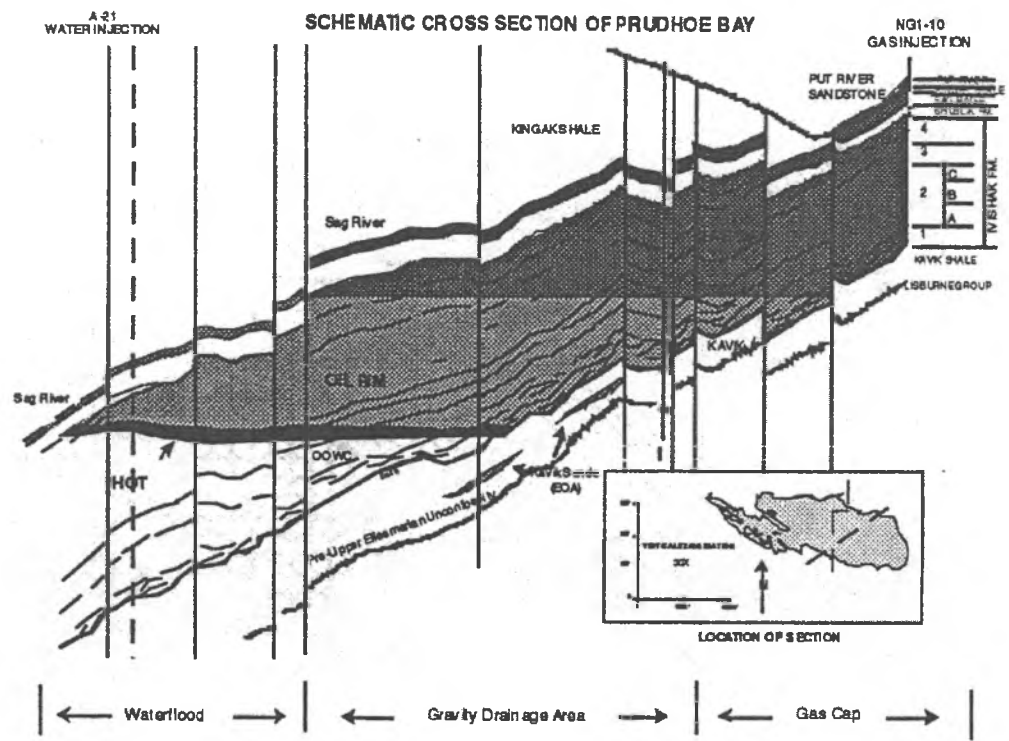


Figure 4

PBU DEVELOPMENT PROJECTS

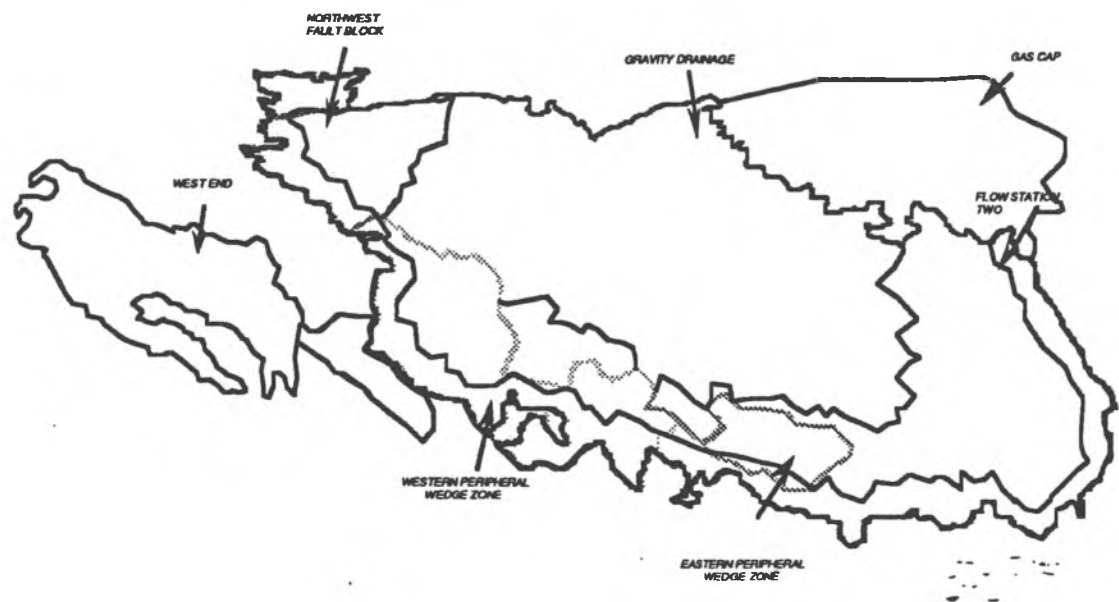
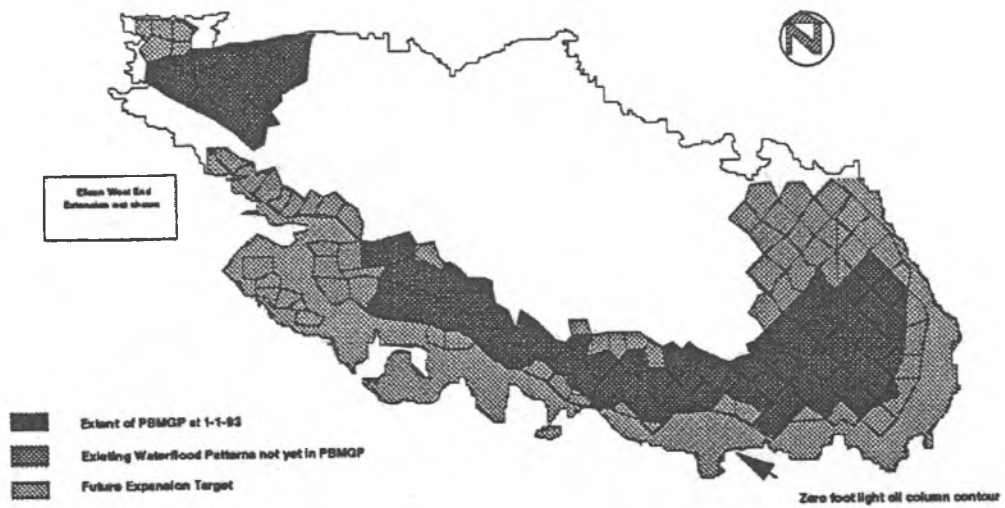


Figure 5



Delineation of PBMGP at 1-1-1993 and future expansion targets

Figure 6

PBU Facilities/Reservoir Schematic

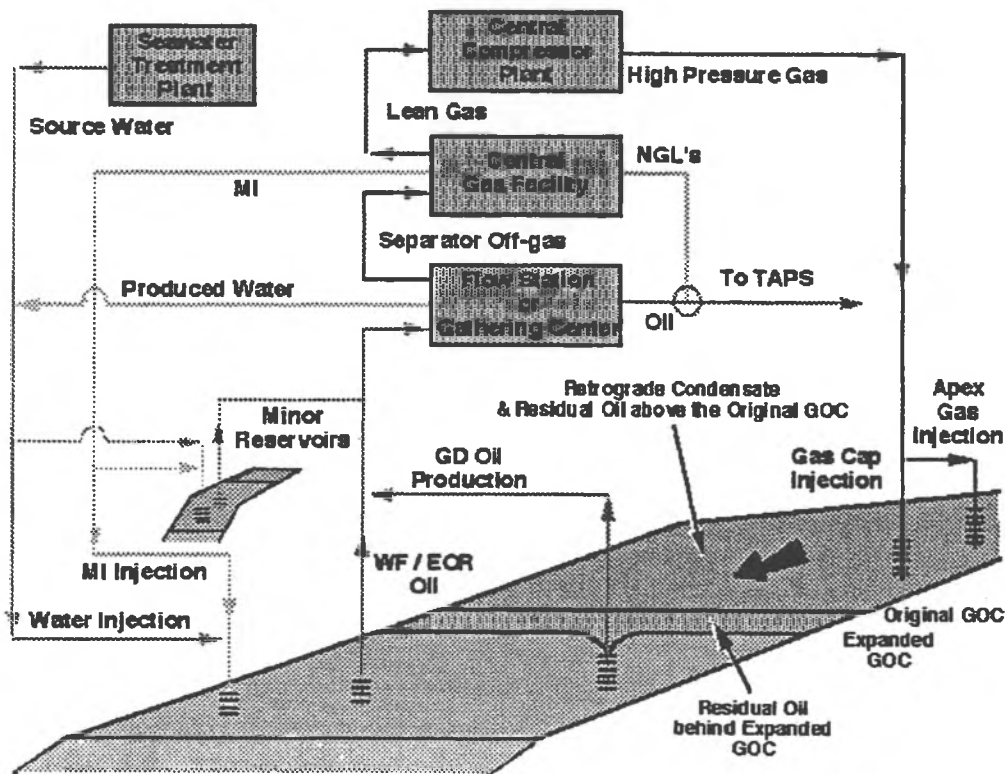
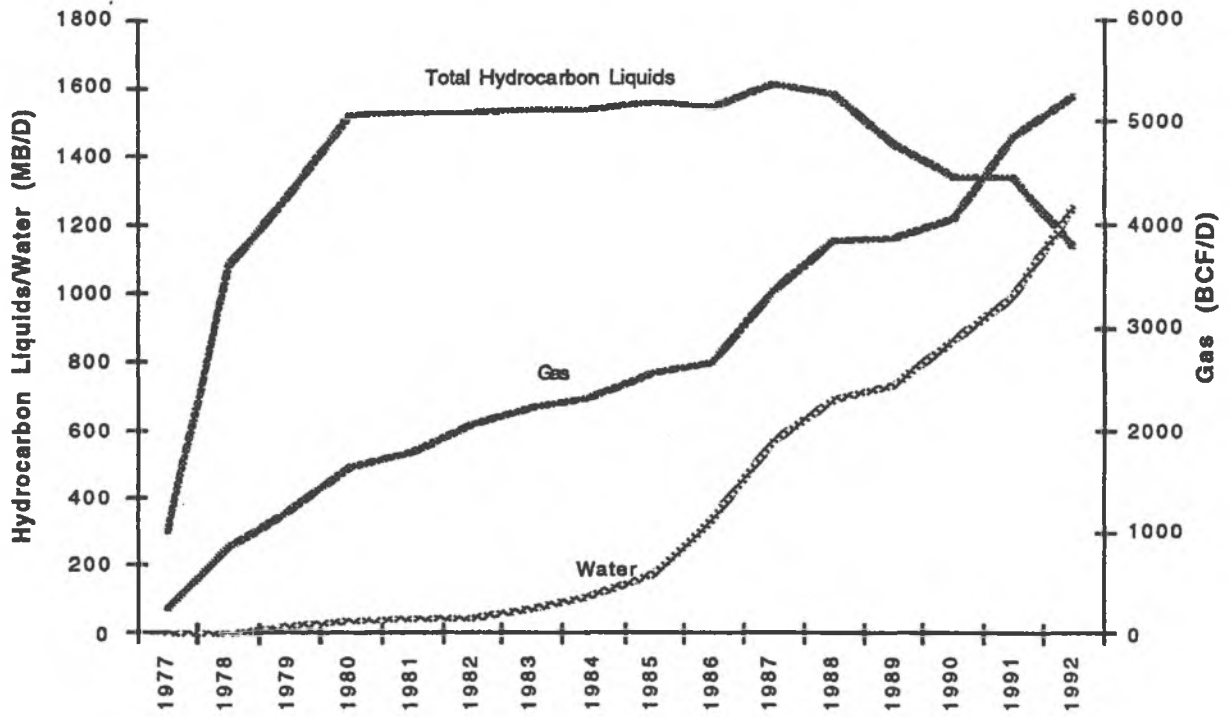


Figure 7

HISTORICAL PRODUCTION (Annual Average Rates)



OPTIMIZATION OF PRODUCTION FROM MATURE FIELDS

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Abstract

In many mature fields, the production of oil, gas, and water is facility constrained. For such fields, optimal use of existing surface facilities is the key to increasing well rates and/or reducing production costs. Here we propose solution procedures for such nonlinearly constrained production optimization problems. The objective function of the optimization problem is oil or gas production from the field. Production is subject to multiple flow rate constraints at separators, pressure constraints at specific nodes of the gathering system, total gas-lift volumes, and maximum velocity constraints for pipelines. The control variables are the well rates, gas-lift rates, and well allocations to flow lines.

The problem is formulated as a mixed integer nonlinear optimization problem and is solved by a heuristic nonlinear optimization method. The optimization algorithm is coupled with models for multiphase fluid flow in the reservoir and surface pipeline network in a commercial reservoir simulator.

The proposed procedure was tested in a Gulf of Mexico oil field and a published example, and then applied to the Prudhoe Bay field in the North Slope of Alaska. Results demonstrate the effectiveness and business value of the developed tools.

Introduction

In some mature fields, oil production is constrained by the gas and/or liquid handling capacities of surface facilities. While facility expansion may be an option to increase rates, it may not be the optimal choice. An economic alternative is to make optimal use of existing production facilities. In this study, we address the following operational decisions to enhance production:

1. How to control well rates with chokes?
2. How to distribute available lift-gas among specified wells?
3. How to route fluids by switching well connections to flow lines?

These operational decisions are constrained by multiple capacity constraints in production facilities and wells, along with velocity constraints in flow lines to avoid excessive corrosion/erosion.

Various aspects of the gas-lift optimization problem have been studied by Kanu et al.¹, Buitrago et al.², Nishikiori et al.³, and Martinez et al.⁴ using various optimization techniques, i.e., the equal-slope method, a Quasi-Newton method, and a genetic algorithm. Fang and Lo⁵ proposed a linear programming model to optimize lift-gas subject to multiple nonlinear flow rate constraints. In these studies various gas injection scenarios were evaluated using gas-lift performance curves for individual wells, ignoring interactions among wells. Dutta-Roy et al.⁶ analysed a gas-lift optimization problem with two wells sharing a common flow line. They pointed out that when flow interactions among wells are significant, nonlinear optimization tools are needed. They applied a Sequential

Quadratic Programming (SQP) method to a linearly constrained gas-lift optimization problem with 13 wells and showed the advantages of their method.

Oil production in the Prudhoe Bay and Kuparuk River fields is constrained by the gas handling limits of surface facilities. Barnes et al.⁷ presented the Western Production Optimization Model (WPOM) for the Prudhoe Bay field. This model maximizes oil production while minimizing the need for gas processing. Their model allocates the oil rate and gas rate to surface facilities and wells based on the "incremental GOR" concept, which produces the next incremental barrel with the lowest GOR. Litvak et al.⁸ built an integrated reservoir and gathering system model of the Prudhoe Bay field, and employed some heuristic methods to allocate well connections to manifolds. Gas-lift rates were allocated based on gas-lift tables of gas-liquid ratio, liquid well rate and water cut. Lo et al.⁹ developed a linear programming (LP) model that allocates well rates subject to multiple facility constraints. This LP model was then used as a screening tool to evaluate development opportunities at the Kuparuk River field. Stoisits et al.^{10,11} applied a neural network to determine optimal allocation of lift-gas to wells subject to multiple gas constraints in the same field. The neural network was trained by results obtained from nodal analysis⁺⁺ simulations. In 1997, Stoisits et al.¹² addressed the production optimization problem at Kuparuk River field using a genetic algorithm. In their study, the decision variables were production well status (shut-in or open) and incremental GOR for drill sites. A neural network model was used for the surface pipeline network.

In most commercial reservoir simulators^{13,14}, rate constraints on facilities are handled sequentially by ad hoc rules. For example, first, gas constraints are considered at the lowest predictive well management (PWM) level. Ad hoc rules based on the gas-oil ratio of production wells are applied to scale well rates and meet the gas constraint. Then, water, liquid, and oil rate constraints at the lowest PWM level are sequentially handled and the procedure is repeated for the next PWM level, etc. Furthermore, gas-lift optimization is usually considered separately from well rate optimization using, for example, the following approach. First, lift-gas rates are determined for specified wells based on their gas-lift performance curves or other information. Then, these lift-gas rates are scaled using some rules to match constraints on total amount of available gas. A number of such procedures are available in commercial reservoir simulators. In some cases, these procedures may not yield the optimal solution. Also, using such approaches, it is difficult to determine how much of the gas handling capacity should be used for gas-lift and what portion should be allocated for other purposes.

In summary, available literature does not provide robust procedures for the simultaneous optimization of well rates, lift-gas rates, and well connections. Either only a part of the problem is addressed, or ad hoc rules are used that lead to sub-optimal operations. Hence, it is necessary to design approaches that can simultaneously optimize all control variables subject to all constraints. In the approach presented here, different control variables are optimized using different algorithms, yet these algorithms can be combined together in a flexible manner to optimize all control variables simultaneously. The optimization tools are tested on a synthetic case based on an oil field in the Gulf of Mexico (GoM) and on a published example, and then successfully applied to the Prudhoe Bay oil field.

**Proposed
Methodology****Description of the Optimization Problem**

The type of constraints considered in this study include the following: minimum pressure at the bottomholes and/or tubingheads of production wells; maximum/minimum oil, gas, water, and/or liquid flow rate in production wells; minimum pressure at the inlet/outlet of flow lines; maximum oil, gas, water, and/or liquid handling capacities of surface facilities; maximum fluid velocities in pipelines to mitigate excessive erosion/corrosions; and maximum amount of gas available for gas-lift at different PWM levels. The objective is to increase the short-term oil production by allocating well rates and lift-gas rates.

In some fields, well connections to separation facilities can be switched. On such fields, the optimization algorithm should also guide the operator on when and how to switch well connections so that the production facility is fully utilized.

In summary, we wish to optimize well production rates, lift-gas rates, and connections to the separation facilities in a way that maximizes total oil/gas production subject to applicable constraints. This problem is formulated as a mixed integer optimization problem:

$$\text{maximize } \sum_i^{n_w} \sum_{p=0,g} w_{p,i} q_{p,i}(x, y), \quad (1a)$$

$$\text{subject to } c_j(x, y) \leq 0, \quad j = 1, \dots, m, \quad (1b)$$

$$y \in \Omega_{wc} \quad (1c)$$

where n_w is the number of production wells; $w_{p,i}$ is the weighting coefficient for $q_{p,i}$, the flow rate of phase p from well i ; c_j represents the j th constraint; x is the continuous decision variable, namely, the well rates and the lift-gas rates; and y is an integer variable indicating well connections; Ω_{wc} represents the domain of feasible well connections.

Overall Methodology

A commercial compositional simulator¹⁵ that can simultaneously simulate multiphase fluid flow in reservoirs, well tubing strings, and surface pipelines was used. The gathering system had a tree-like structure without loops. Flow line junctions are modeled as nodes of the tree. Each node can have any number of input connections but only one output connection. A link represents sequentially connected flow devices (pipeline, choke, etc.). Two nodes can be connected by a link or a flow device. The pressure and rate constraints are imposed on either wells or nodes. Well bottomhole and/or tubinghead pressure constraints are considered (See Litvak et al¹⁶ for details).

The optimization tools are combined with the solution procedure for modeling flow in the coupled reservoir and gathering system in the following manner (Step 1–5 define one outer iteration of the coupling procedure):

1. Start with pressure and fluid compositions in reservoir gridblocks calculated in the previous outer iteration. Use well lift-gas rates and well connections from the previous outer iteration as initial guesses.

2. For well i , perform the following operations:
 - a. Switch well i from its current output connection to a new feasible output connection.
 - b. Determine well production rates from pressure drop calculations in well tubing strings and surface pipeline network system subject to pressure constraints in wells and nodes 16. These rates are used as additional maximum well constraints in Step 2(c).
 - c. Invoke optimization tools to redefine well rates and lift-gas rates to maximize the objective function (1a) subject to flow rate and velocity constraints. (These optimization tools are described in the next section).
 - d. Repeat Step 2(a)–2(c) for all feasible output connections of well i . Define the output connection that produces the maximum objective function value as the best output connection of well i .
 - e. Decide if well i should be switched to the new connection as determined in 2(d), based on operational rules.
3. Select a new well and repeat Step 2.
4. Based on user selected criteria, repeat Steps 2 and 3 until convergence.
5. Determine active constraints in wells and nodes. Linearize multiphase fluid flow equations for well tubing strings and the surface pipeline network system (numerical derivatives are used). Add these equations to the linearized fluid flow equations for reservoir gridblocks.
6. Solve the linearized system of equations, and repeat Steps 1 to 6 until convergence of outer iteration.
7. March to the next time step.

In Step 2 to 4 only a small portion of the domain of feasible well connections is considered, this is referred to in this work as the partial enumeration method. Step 2(e) and (4) are rule based and operational policies can be enforced at these stages. In the current implementation, the user may define the maximum total number of well reconnections allowed and the flow rate threshold for well switching.

The optimization tools used in Step 2(c) for well rates and lift-gas rates allocation can be invoked without performing well connection optimization.

Optimization Tools Used for Well Rates and Lift-Gas Rates Allocation

Three methods with increasing robustness but decreasing efficiency are used for the allocation of well rates and lift-gas rates in Step 2(c) of the overall methodology: a linear programming method, a separable programming method, and a genetic algorithm. Various techniques were developed to provide flexibility in handling problems of different sizes and complexity.

Let $q_{p,i}^{\max}$, $p = o, g, w$, be the well rates for well i from step 2(b). The linear programming (LP) method scales these rates to satisfy flow rate and velocity constraint. Assume that the water cut and gas liquid ratio of each well is constant. Then any flow rate between 0 and $q_{p,i}^{\max}$ can be

expressed as $\alpha_i q_{p,i}^{\max}$, where $\alpha_i \in [0,1]$ is the rate-scaling factor of well i . Consequently, the objective function and the constraint functions in problem (1) are linear functions of α_i . Hence problem (1) with fixed well connections becomes a linear programming problem, which can be solved by either the simplex method¹⁷ or the interior point method¹⁸. In this study, we use the simplex method, because the optimal solution from the simplex method is always an extreme point of the feasible region.

The separable programming (SP) method extends the work of Fang and Lo⁵. In this method, we take the well header pressure from the previous optimization iteration as the minimum pressure constraints on that well head and perform nodal analysis to obtain a gas-lift performance curve for each well. Besides, the relationship between the oil flow rate and the formation gas or water flow rate can also be approximated by piecewise linear curves. Hence the lift-gas, formation gas, or water flow rate can be regarded as functions of a single variable (the oil flow rate of that well). And problem (1) with fixed well connections becomes a separable programming problem. An SP problem can be reformulated as a linear programming problem or a mixed integer programming problem¹⁸.

In the SP method, the gas-lift performance curves and inflow performance curves are obtained by ignoring interactions among wells. This is reasonable when the flow through well chokes is critical (reaches sonic velocity) or the pressure drop across tubing strings is dominant. However, there are cases when flow interactions cannot be ignored. In such cases, we need to evaluate gas-lift performance by rigorous simulation. Consequently a nonlinear optimization algorithm has to be employed. Currently we use a genetic algorithm for its robustness and ease of use. In the genetic algorithm, we take the lift-gas rate as the decision variable, and evaluate the performance of a lift-gas distribution scenario in the following manner. First, we perform rigorous facility simulation with the allocated lift-gas subject to the pressure constraints. Then the LP method is used to scale the well rates if certain flow rate or velocity constraints are violated, and assign the optimal function value from the LP method as the fitness of the corresponding lift-gas distribution. Other aspects of the genetic algorithm can be found in Goldberg¹⁹.

Applications

In this section, we first test the LP method and the partial enumeration method on a synthetic case based on an oil field in the Gulf of Mexico (GoM). Then we applied the SP method to a published gas-lift example. Finally we applied the developed tools to the giant Prudhoe Bay field in the North Slope of Alaska.

Gulf of Mexico Oil Field Example

An integrated reservoir and surface pipeline network model has been built for one of the Gulf of Mexico oil field. Our test example is based on this reservoir.

Five production wells, A1–A5, are tied to a 40-slot conventional fixed-leg platform. Ten production wells were drilled from a 10-slot subsea template and connected to the platform by two 22000 feet long pipelines. On the platform, a three-stage separator processes the produced fluids. Wells A1–A5 can be tied to any stage of the separator. Wells B1–B10 can be connected to either the

OPTIMIZATION OF PRODUCTION FROM MATURE FIELDS

low-pressure stage or the high-pressure stage of the separator. Figure 1 illustrates the production system.

For evaluation purposes, we impose two hypothetical constraints on the gathering system. The separator has a maximum of 30 MMSCF/D gas handling capacity and a maximum of 5000 STB/D water handling capacity. Moreover, the separator cannot receive gas from either pipeline at a rate more than 12 MMSCF/D. Our job is to maximize the oil production by selecting appropriate well rates and well connections.

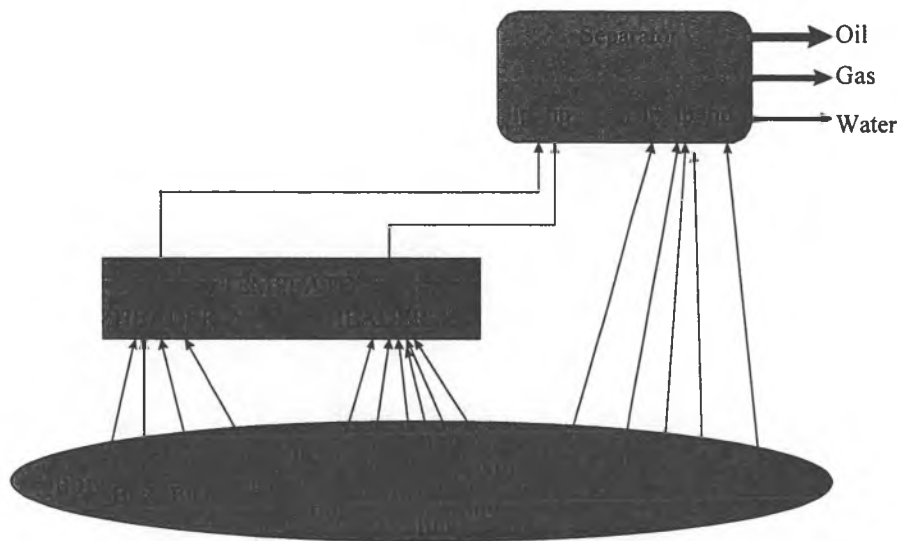
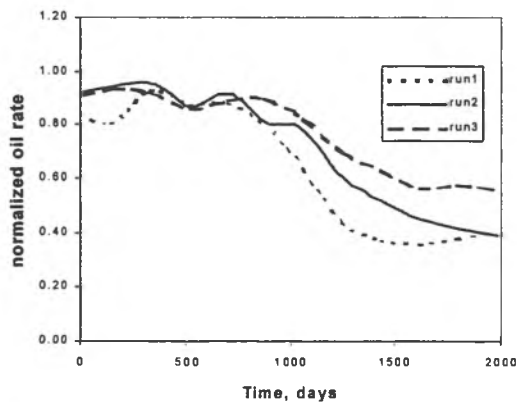


Figure 1: Gulf of Mexico oil field gathering system

We made three predictive runs using a commercial simulator. Each run predicts the oil production for about five years. In the first run, we sequentially check flow rate constraints and scale the well rates. In the second run, we apply the LP method to select the well rates. In the third run, we apply the partial enumeration method with the LP method to optimize the well rates and well connections simultaneously. The results are plotted in Figure 2-6.



run1: scale well rates sequentially.
run2: scale well rates using LP method
run3: optimize well rates and well connections

Figure 2: Normalized total oil rate

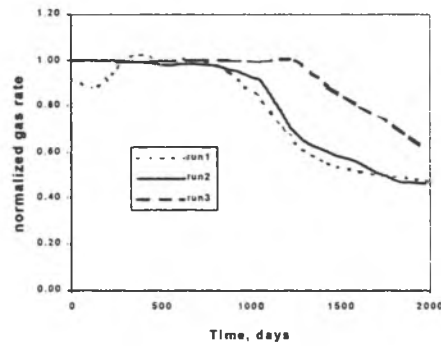


Figure 3: Normalized total gas rate

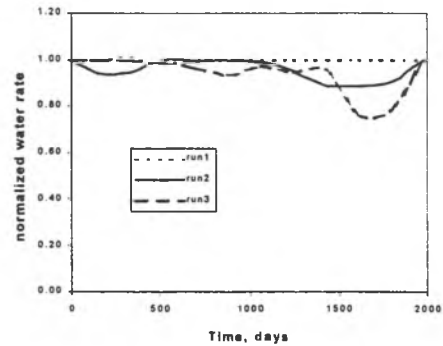


Figure 4: Normalized total water rate

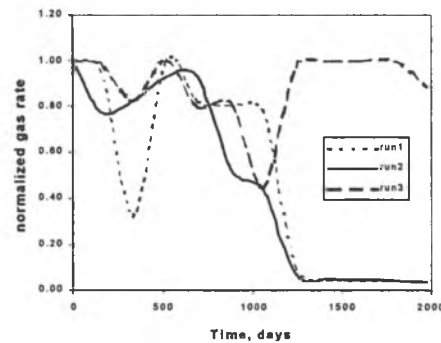


Figure 5: Normalized gas rate at HEADER_Y

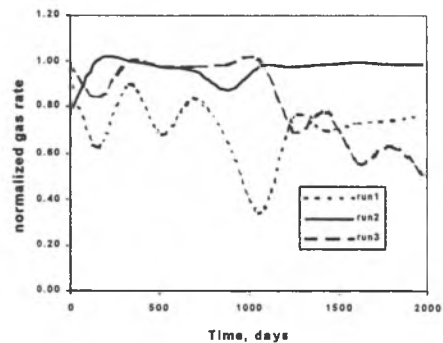


Figure 6: Normalized gas rate at HEADER_Z

The well rates are normalized by some fixed oil, gas, and water rates. Figure 2 shows that run2 can produce at a much higher rate than run1. Run3 is even better. Over five years, run1 predicts 11.2% more oil than run1, and run3 shows 18.9% more oil than run1. The excellent performance of run2 and run3 can be explained by Figure 4–6. As shown in Figure 4, the oil production in run1 is always limited by the water rate constraint. This is due to the fact that the procedure in run1 first scales the highest GOR wells to meet gas constraints, and then scale the highest water cut wells to meet water constraints. This results in a suboptimal solution. Run2 checks all constraints simultaneously; as a consequence, it scales well rates differently. This fact is demonstrated in Figure 6, where most of the time production in run2 is limited by the gas constraint on HEADER_Z, while that is not the case for run1. The fact that run3 outperforms run2 can be explained as follows. At later times, without well switching, most of the producing capacity of HEADER_Y is wasted, while HEADER_Z is constrained by gas rate. The algorithm in run3 identified this imbalance and a high GOR well was switched from HEADER_Z to HEADER_Y.

A Gas-lift Optimization Example

This example is from Buitrago et al². The problem is to optimize oil production from a set of 56 wells with 225,000 MSCF/D of available gas (Gas-lift performance data are presented in Buitrago et al²). Some of these wells can not flow without gas-lift. Buitrago et al² solved the problem by both the Equal-Slope method and the Ex-In method, a stochastic algorithm that calculates the descent direction heuristically. In this study, we solve this problem by the SP method. For wells that can not flow without gas-lift, their gas-lift performance curves are not concave. Thus we introduce an integer variable for each such well, and formulate the gas-lift optimization problem as a mixed integer problem. The problem is then solved by the branch and bound method²⁰, which reduces the mixed integer problem to a sequence of linear programming problems.

Table 1 compares the performance of the SP method with the Equal-slope method and the Ex-In method. Results for the Equal-Slop method and the Ex-In method are taken from Buitrago et al². The SP method outperformed both the Equal-Slope method and the Ex-In method for this example.

	Equal-Slope	Ex-In	Separable Programming		
			(1)	(2)	(3)
Gas-lift Volume (MSCF/D)	22,508	20,454	22,500	14,175	17,040
Oil Rate (STB/D)	21,265	21,790	22,632	21,265	21,790

Table 1: Gas-lift allocation results obtained from different methods

- (1) Allocate all available lift-gas of 22500 MSCF/D
- (2) Minimize lift-gas use for oil rate of 21265 STB/D
- (3) Minimize lift-gas for oil rate of 21790 STB/D

To demonstrate the efficiency of the SP method, we applied it to other problems created by cloning the 56-well example discussed above. For example, in the second case, we have 560 wells and 22,5000 MSCF/D injection gas available. All computations were performed on a Sun-Enterprise 5500 machine with 4GB of RAM and 2GB of swap space. The second row of Table 2 shows the computational time (wall clock time). The third row of Table 2 shows the number of LP problems solved in the process of solving the mixed integer programming problem. Clearly, the SP method is very efficient for this problem.

Number of Wells	56	560	3360
Wall Clock Time (second)	0.27	3.06	140.29
Number of LP problem solved	5	6	40

Table 2: Computational time for the SP method on various problems

Application to Prudhoe Bay Oil Field

Litvak et al⁸ has a good description of the Prudhoe Bay Field. The following short description is extracted from this paper.

"Production wells are tied to 22 well pads in the Western Operating Area (WOA) and 16 drill sites in the Eastern Operating Area (EOA). Most production wells can be switched between high and low-pressure headers at the well pad manifolds. Gas-lift is used in some production wells with high water cut. Gas-lift wells can be tied only to low-pressure headers. Well chokes are installed in well pad manifolds.

The production stream from individual well pads and drill sites is sent without any separation to three gathering centers in the WOA and to three flow stations in EOA. Well pads and drill sites are tied to separator banks through high pressure and/or low-pressure flow lines. Each gathering center and flow station has four three-stage separator banks. Separator banks can operate in high pressure or low-pressure mode with first separation stage pressure of about 670 psig and 150 psig, respectively.

Separator off-gas is routed from the gathering centers and flow stations to the central gas facility where natural gas liquids and miscible injectant are extracted. The natural gas liquids are then blended with the oil stream coming from the separators. The miscible injectant is used in the enhanced oil recovery project. The lean gas, after compression in the central compression plant, is reinjected into the gas cap for pressure maintenance."

The oil production in the Prudhoe Bay field is constrained by the gas handling capacity. To maximize oil production without expansion of existing gas handling capacity the developed optimization tools have been applied. Well connections to high pressure or low pressure flow lines as well as well production rates are selected to maximize total oil production from the field subject to the gas and water constraints in gathering centers and velocity constraints in flow lines. Integrated reservoir and surface pipeline network model has been applied. The optimization system is applied on a daily basis. The performance of the partial enumeration method is verified by two approaches by optimizing well connections and well rates in the WOA. In the first approach, we start with the partial enumeration method from six randomly generated well connection configurations. In the second approach, we use a genetic algorithm to solve the same problem. Their convergence histories are shown in Figure 7. All the partial enumeration runs converge to approximately the same oil well rate after 300 function evaluations. The genetic algorithm also converges to approximately the same oil well rate after 600 generations. Each generation takes 10 function evaluations. Hence, in this case the partial enumeration method outperforms the genetic algorithm.

To demonstrate the advantage of optimizing the well connections and well rates simultaneously, we present two optimization runs for the whole Prudhoe Bay field. In the first run, we optimize well rates only using the LP method. In the second run, we optimize well rates and well connections simultaneously by the combined use of the partial enumeration method and the LP method. All other aspects of these two runs are same. Results show that the second run improves oil production by 2.55% compared to the first run, which is significant for this large field. On an IBM RS6000 computer, a typical simultaneous optimization run takes about 850 seconds.

OPTIMIZATION OF PRODUCTION FROM MATURE FIELDS

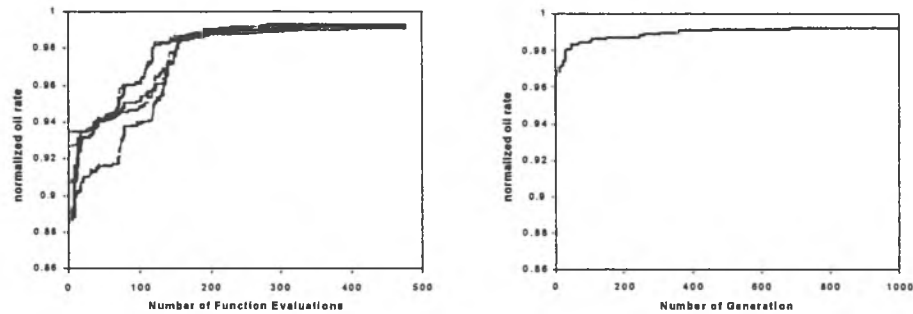


Figure 7: Convergence history of the partial enumeration method (Left); Convergence history of the genetic algorithm (Right). The oil well rate is normalized by a fixed oil rate.

Discussion

The production optimization problem addressed is nonlinearly constrained with discrete decision variables. It is difficult to design a solution procedure that is both robust and computationally feasible. We have proposed a unique approach for the efficient optimization of the entire system. This is accomplished by optimizing continuous variables and discrete variables using different optimization algorithms. For example, by the combined use of the partial enumeration method and the LP method, we can optimize well connections and well rates simultaneously, even for large production systems as in the Prudhoe Bay field.

Our approach is also flexible. According to the problem characteristics and time available for optimization, different rates allocation procedure can be used during the well connection optimization. A more rigorous but time consuming rates allocation method may be employed after the well connections are optimized.

There are some limitations of our approach. For gas-lift optimization problems, the LP and SP method is efficient, but it can not handle the interactions among wells. The genetic algorithm is robust but inefficient. It is desirable to have an efficient algorithm that can also handle flow interactions. In addition, we only optimize short-term oil production based on static reservoir conditions. We have not considered reservoir dynamics during the optimization step. We are currently investigating the impact of decisions based on this approach on long term oil recovery.

Conclusions

1. A mixed integer programming model is formulated to optimize well rates, gas-lift allocations, and well connections subject to multiple constraints. A partial enumeration method for well connection optimization and several tools for gas-lift optimization are developed.
2. The optimization tools are incorporated in a commercial code. The approach presented can be used for production control or reservoir development.
3. The optimization tools were successfully tested and applied to a mature oil field.

Acknowledgements

The financial support of members of the Stanford University Reservoir Simulation Industrial Affiliates Program (SUPRI-B) and BP Exploration Inc. is gratefully acknowledged. We thank Lynda Hutchins (BP), Roger Skinner (BP), and Katerina Papalexandri (BP) for their support and important recommendations. We also thank Bruce Darlow (Landmark) and C.H. Wang (UNI-TECH

Consulting Services, Inc.) for their help in the implementation of optimization algorithms in the VIP reservoir simulator. The linear programming problems are solved by a simplex linear programming solver²¹ developed by R. J. Hanson and K. L. Hiebert. Finally we thank the management of BP for granting permission to publish this paper.

Nomenclature

c_j	j th constraint function in the optimization problem
m	number of constraints
n_w	number of wells
$q_{p,i}$	flow rate of phase p from well i
$q_{p,i}^{\max}$	maximum flow rate of phase p from well i defined in the linear programming method
$w_{p,i}$	weighting coefficient for flow rate of phase p from well i
x	continuous decision variable, namely, well rates and lift-gas rates
y	discrete decision variable, namely, well connection indicator
Ω_{wc}	domain of feasible well connections

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+ For the work reported here the VIP simulator of Landmark Graphics Corporation was used.

++ Nodal analysis is a trade mark of Schlumberger limited.

4.

**Department of
Revenue Comments
on CSSB 192
March 14, 2012**



Comments on CSSB 192



*Presentation to the
Senate Finance Committee
Department of Revenue 3-14-12*



Presentation Organization



- DOR position on bill and individual components of bill
- Comparison to ACES and CS HB 110 (FIN)
- Suggested improvements to bill



Components of CSSB 192



- Progressive surcharge
- Allowance for production increases
- Gross minimum tax
- Petroleum information system
- Decoupling some oil and gas



CS SB 192

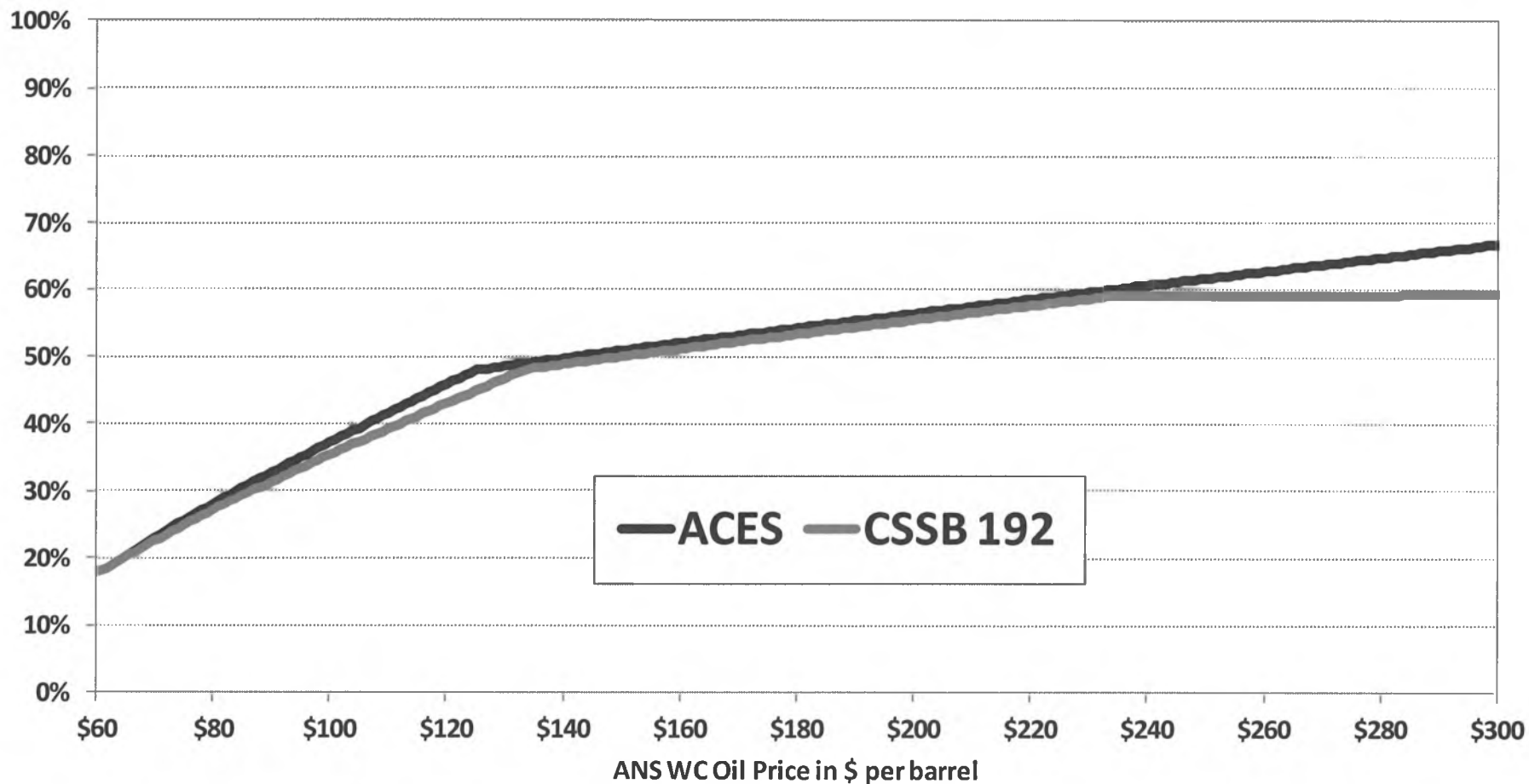
Changes to progressive surcharge



1. Changes the progressivity rate over \$30 / barrel production tax value from 0.4% to 0.35%
2. Changes the trigger point that slows the rate of progressivity to 0.1%, from \$92.50 to \$101.43 / barrel production tax value
3. Changes the maximum production tax rate from 75% to 60% (would apply over \$201.43 / barrel production tax value)
4. Based on our Fall 2011 forecast, reduces revenue by \$125 million in FY 13, \$230 million in FY 14, and \$200 million / year in FY 15.



Effective Production Tax Rates: ACES and CSSB 192 (progressivity only)



Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.

Alaska Department of Revenue



Progressive Surcharge

- Changes do not do enough to provide a meaningful change that would influence investment decisions.
- The biggest benefit from this provision comes at very high prices, from the change in maximum tax rate.
- Suggestions:
 - Keep the lower maximum tax rate; consider a 50% cap on maximum rate.
 - Consider a bracketed approach, so that higher rates apply only to additional profit and not to the first dollar of profit.
 - Or, consider further reductions in slope of progressivity to provide a meaningful change.



Allowance for production increases



- Describe allowance
- Revenue impact
- Examples
- Does not create an incentive that would alter an investment decision
- Does increase complexity for DOR and taxpayers
- Suggestion: New field incentives, or provide allowance by means of a credit



CS SB 192

Allowance for production increases



- Allowance for each additional barrel sent down TAPS, over prior year's level.
- Effectively reduces PTV by \$10 per additional barrel, only for the base rate of 25% = \$2.50 per additional barrel.
- Not part of production tax calculation; benefit is calculated and refunded by DOR.
- Based on our Fall 2011 forecast, reduces revenue by less than \$25 million total for all companies, for all years.



Allowance for production increases: Example



- Major producer with 200,000 barrels per day
- Invests \$1 billion per year to achieve modest decline rate in legacy fields
- Invests an additional \$5 billion to develop several marginal fields and in-field projects in legacy fields
- Increases production 5% to 210,000 barrels per day, and maintains that level for several years.
- First year benefit is \$9.1 million
- Benefit in following years is ZERO



Allowance for production increases



- Allowance does not provide a meaningful change that would influence investment decisions.
- A very small benefit, for only one year, with no benefit for maintaining production.
- Mechanism requires DOR to track and calculate the benefit.
- Suggestions:
 - Consider replacing this incentive with reduced tax rates for new fields or incentives for in-field development.
 - If this concept is furthered, use a credit as the mechanism as it would be easier to administer.
 - If this concept is furthered, acknowledge that maintaining production would be a significant accomplishment for some producers.



CS SB 192

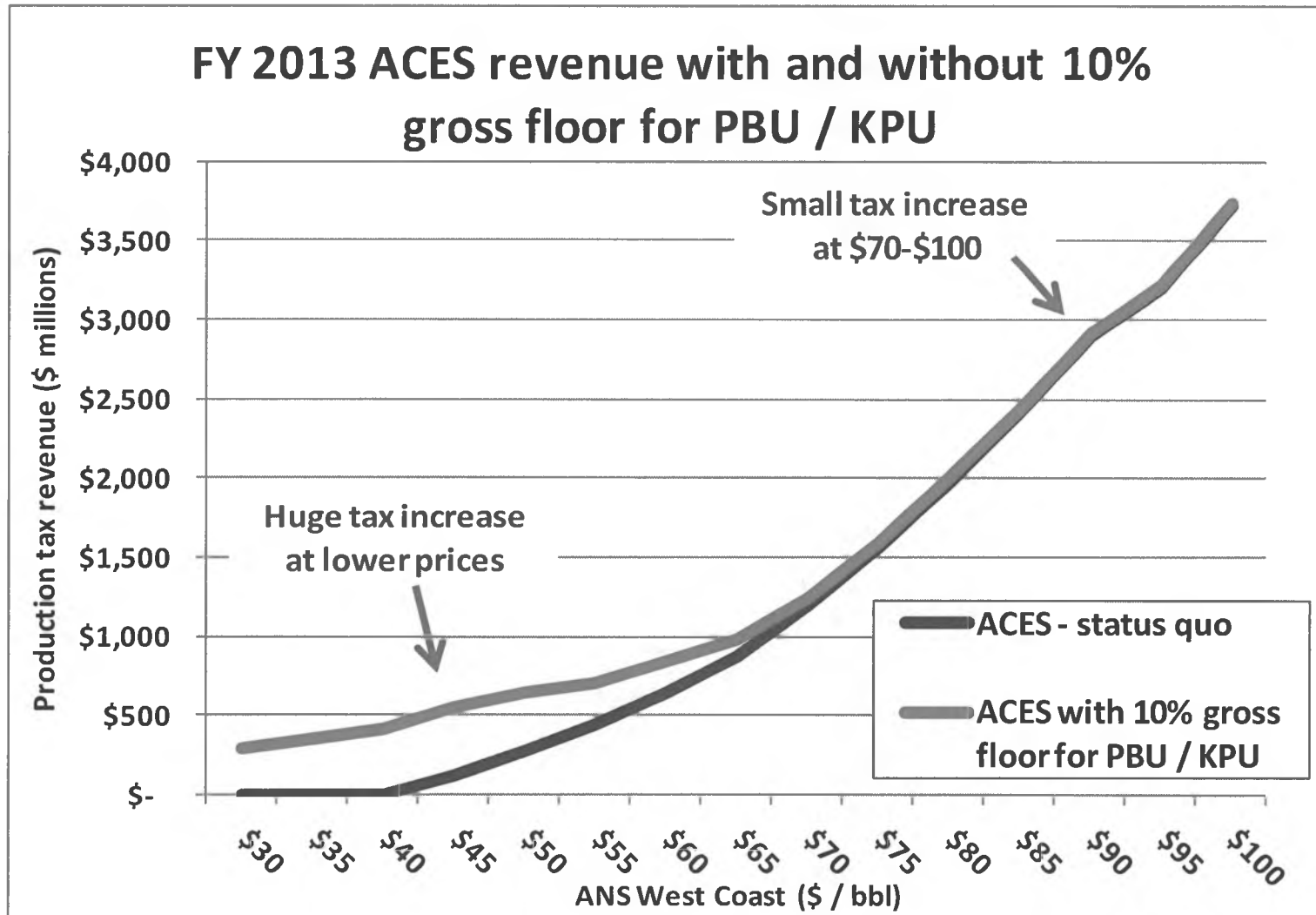
Gross Minimum Tax



- 10% gross minimum tax for certain fields
- Applies only to units with over 1 billion barrels cumulative production and over 100,000 barrels per day in most recent year
- Effectively applies only to Prudhoe and Kuparuk
- “Hard floor” – credits cannot be used to reduce tax for these fields below 10% of gross value.
- Also changes community revenue sharing provisions
- Based on our Fall 2011 forecast, increases revenue by less than \$25 million per year.
- At \$40 / barrel, increases revenue by over \$400 million per year.



Gross Minimum Tax vs. Status Quo





Community Revenue Sharing



- This bill impacts appropriations to the community revenue sharing fund
- Currently 20% of revenue from progressivity
- Would change to lesser of:
 - 20% of progressivity revenue, or
 - Difference between 25% of PTV from fields subject to 10% minimum tax, and minimum tax for those fields.
- Maintains existing limit on revenue sharing: \$60 million or the amount that brings fund balance to \$180 million.
- Increases complexity of the calculation, but not likely to materially impact the amount of revenue appropriated.
- If this change ever would make a difference it would be to the detriment of municipalities.



Gross Minimum Tax



- Provision will impact some companies at current prices.
- Provision creates a substantial tax increase at lower prices (<\$60 / barrel).
- Creates a disincentive to investment in Prudhoe and Kuparuk, Alaska's most important fields.
 - Including development drilling, expansions such as new pads and facilities, and heavy oil development
- Mechanism requires DOR to track and calculate the benefit.
- Suggestions:
 - Remove this provision as it represents a tax increase.
 - If this concept is furthered, allow credits to be applied against minimum tax so there is still some incentive to invest at lower prices.
 - If this concept is furthered, consider removing the change to community revenue sharing language.



CS SB 192



Petroleum Information System

- New information system to be implemented by AOGCC.
- Operational before January 1, 2014.
- Suggestions:
 - Consider need in context of DOR efforts to make more information available.
 - Defer to AOGCC on challenges with this provision.



CS SB 192



Decoupling Some Oil and Gas

- Identical to SB305
- Creates 2 separate progressivity calculations:
 1. Oil, Cook Inlet gas, and gas used in state
 2. Gas other than Cook Inlet and used in state
- Allocates lease expenditures based on Gross Value
- Revenue impacts:
 - Less than \$10 million / year prior to major gas sale
 - Could increase revenue by over \$1 billion / year with major gas sale



Comparison to ACES and CS HB 110 (FIN)

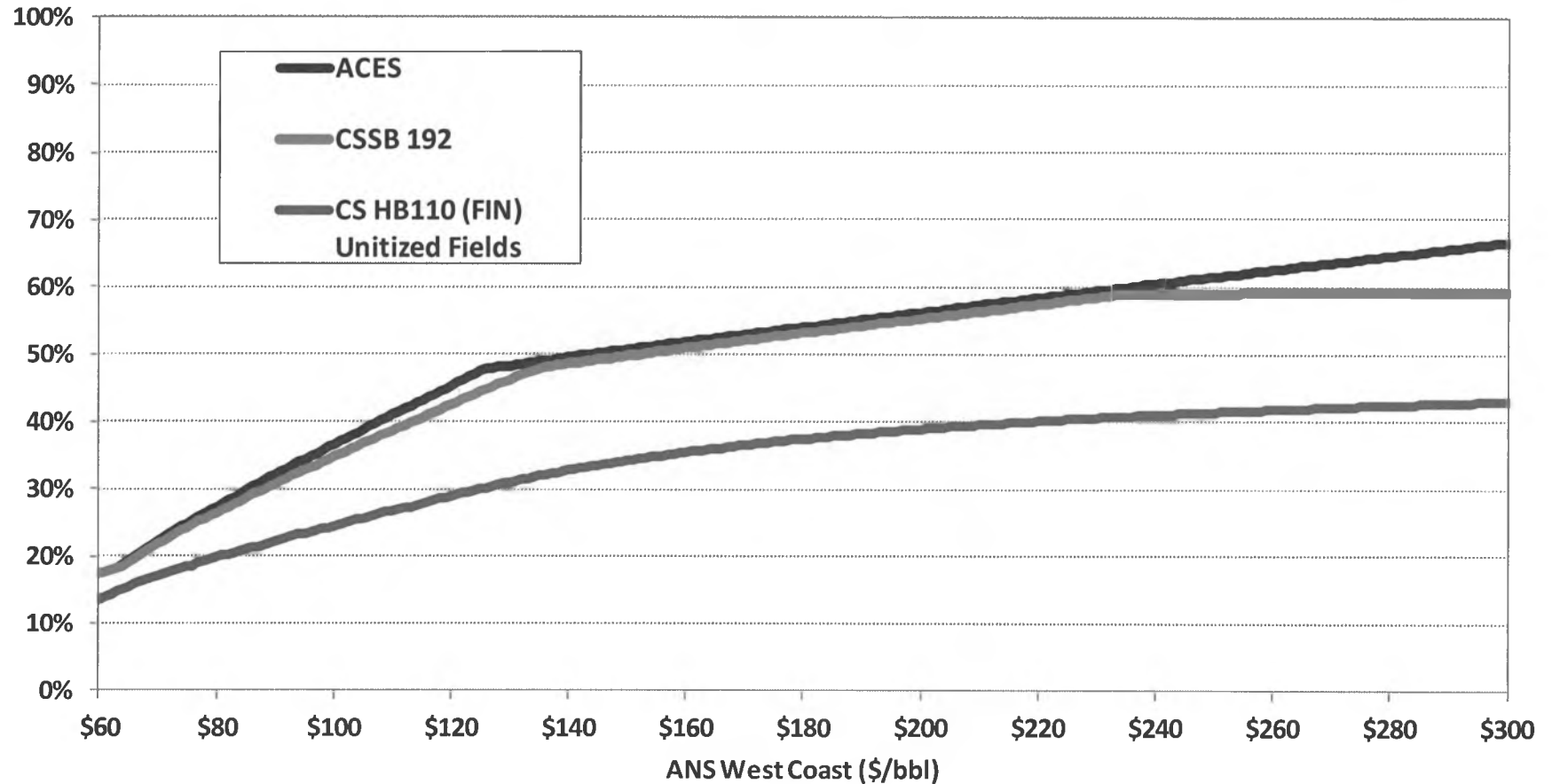


Key Revenue provisions of ACES, CSSB 192, and HB 110

	ACES	CSSB 192	CS HB 110 (FIN)
Progressivity (based on PTV per barrel)	Not bracketed, rate applies to entire PTV \$30 to \$92.50: 0.4% per \$1 \$92.50 to \$342.50: 0.1% per \$1	Modifies ACES structure. \$30 to \$101.43: 0.35% per \$1 \$101.43 to \$201.43: 0.1% per \$1	Bracketed, rate applies only to incremental value \$30 to \$42.50: 27.5% total tax rate \$42.50 to \$55: 32.5% total tax rate, etc
Maximum tax rate	75%	60%	50%
New production incentives	Existing credits	\$10 / barrel allowance for increased production	Lower tax rate for new fields, in-field drilling credits, extends sunset for small producer and exploration credits
Minimum tax	Ranges from 4% of gross for prices >\$25 to zero for prices <\$15, credits allowed.	Increases tax to 10% gross for PBU/KPU, no credits allowed.	Existing provisions



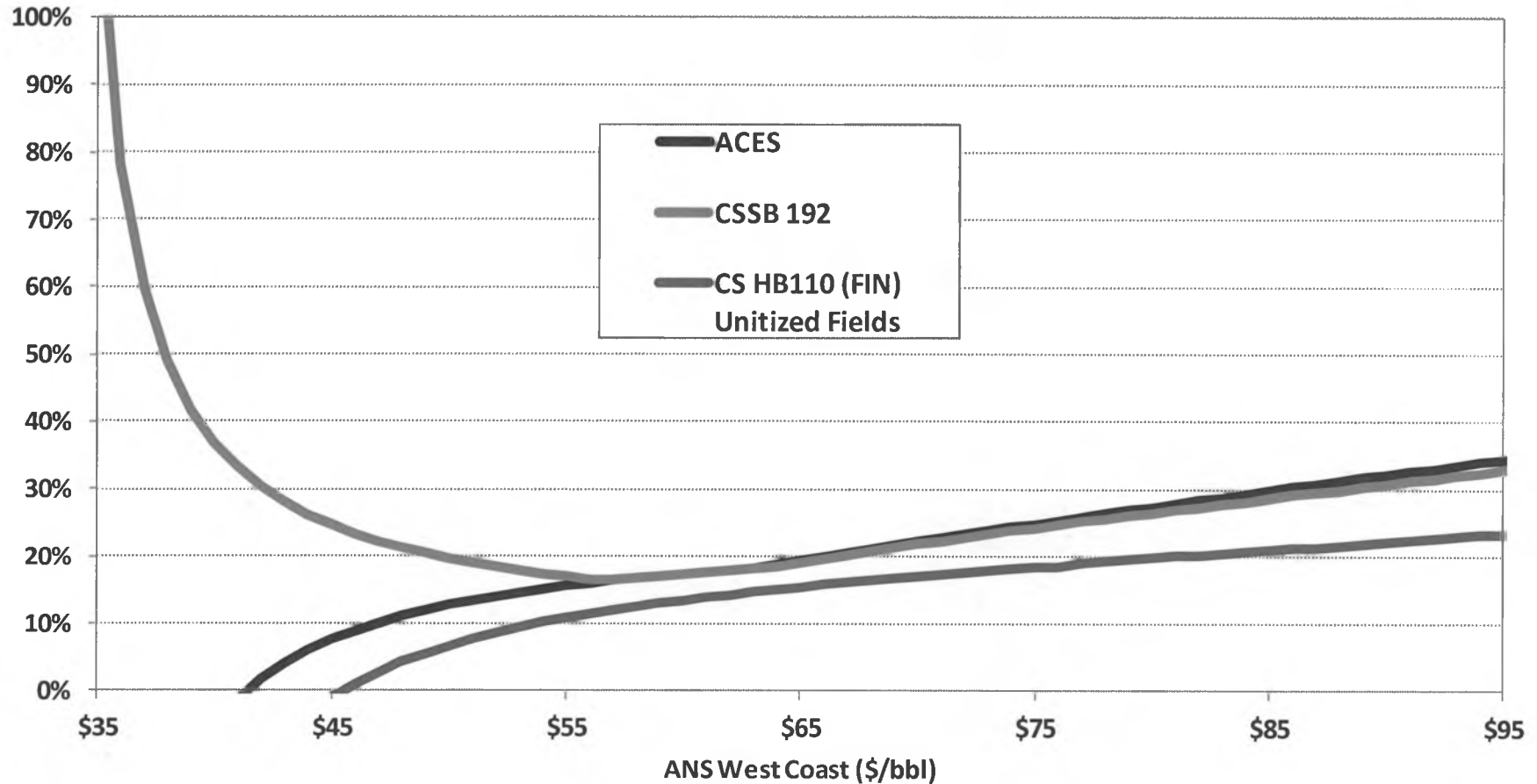
Effective Production Tax Rates: ACES, CS SB 192, CS HB 110 (FIN)



Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.



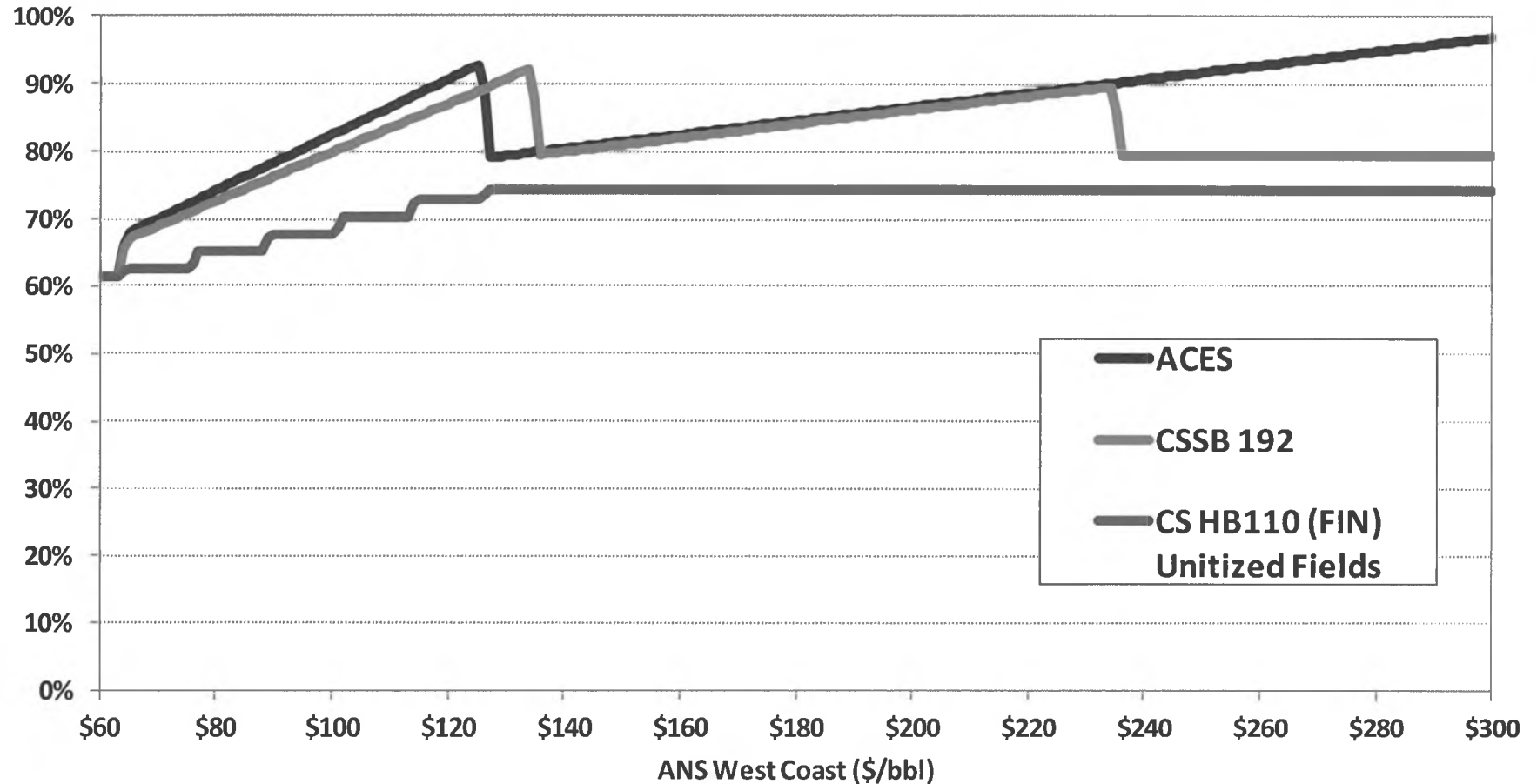
Effective Production Tax Rates: ACES, CS SB 192, CS HB 110 (FIN) Impact of 10% gross tax



Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.
Assumes that 80% of production is impacted by 10% gross minimum tax with no credits allowed against gross tax.



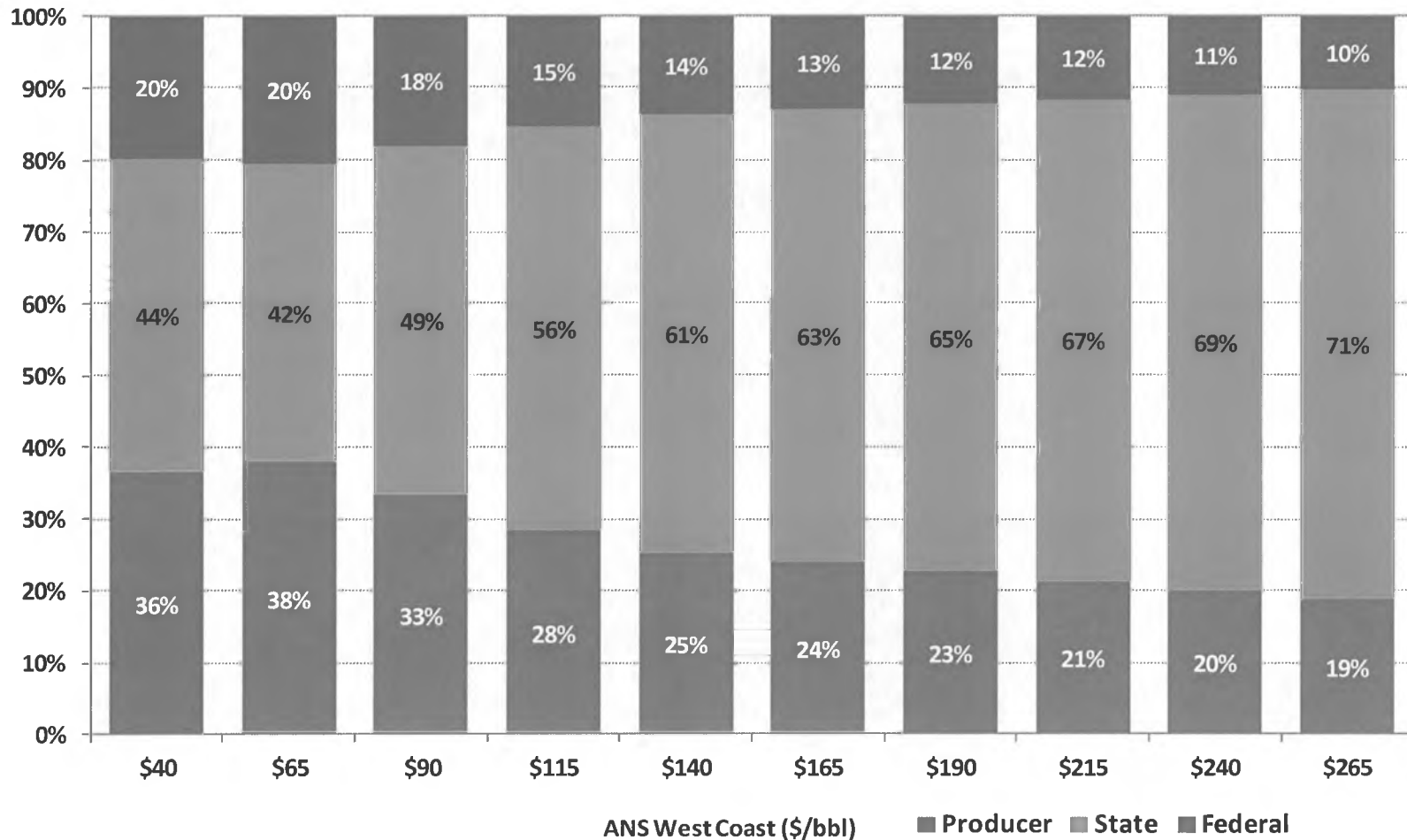
Marginal Government Take: ACES, CS SB 192, CS HB 110 (FIN)



Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.



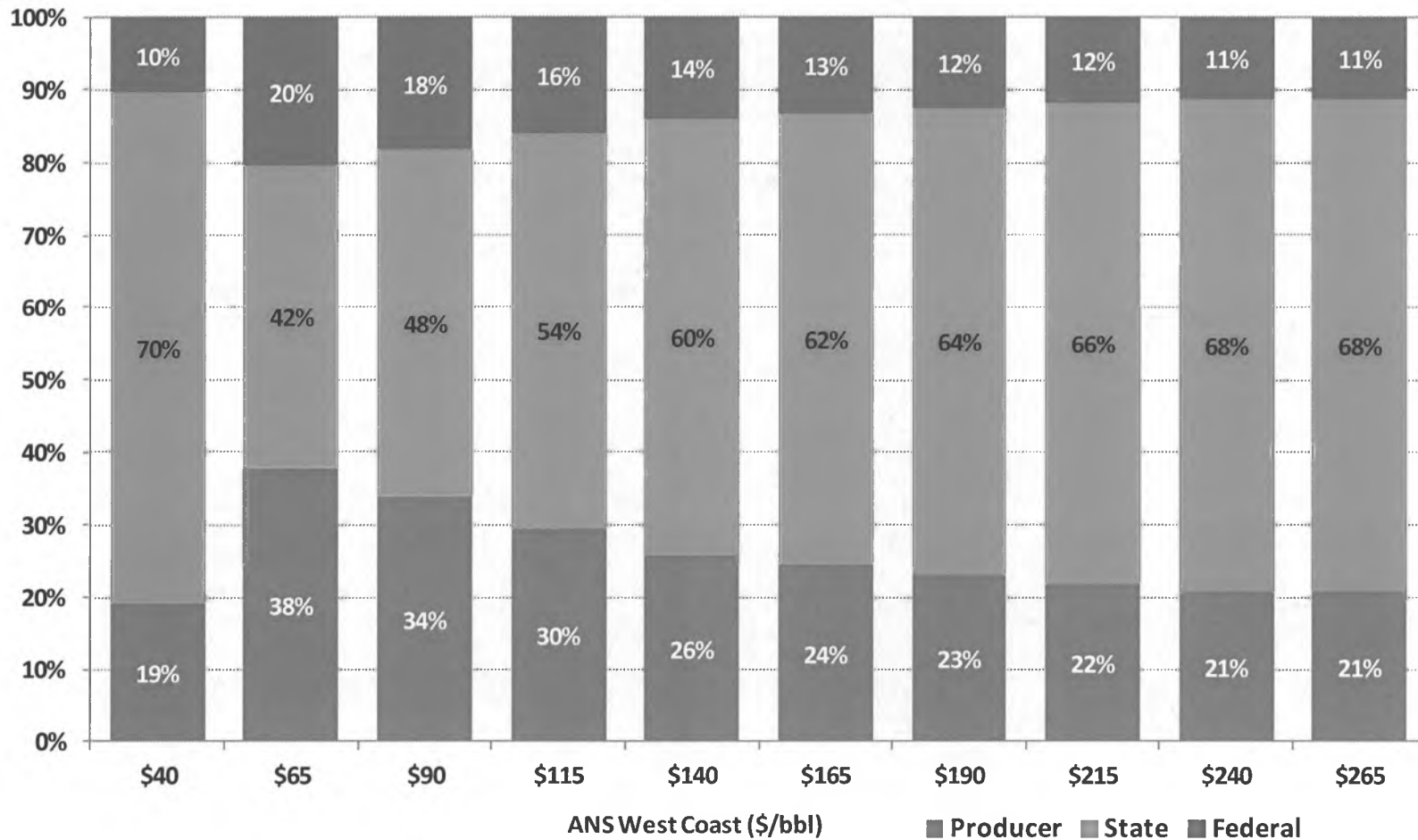
Share of Profit under ACES



Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
 Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.
 Alaska Department of Revenue



Share of Profit under CSSB 192

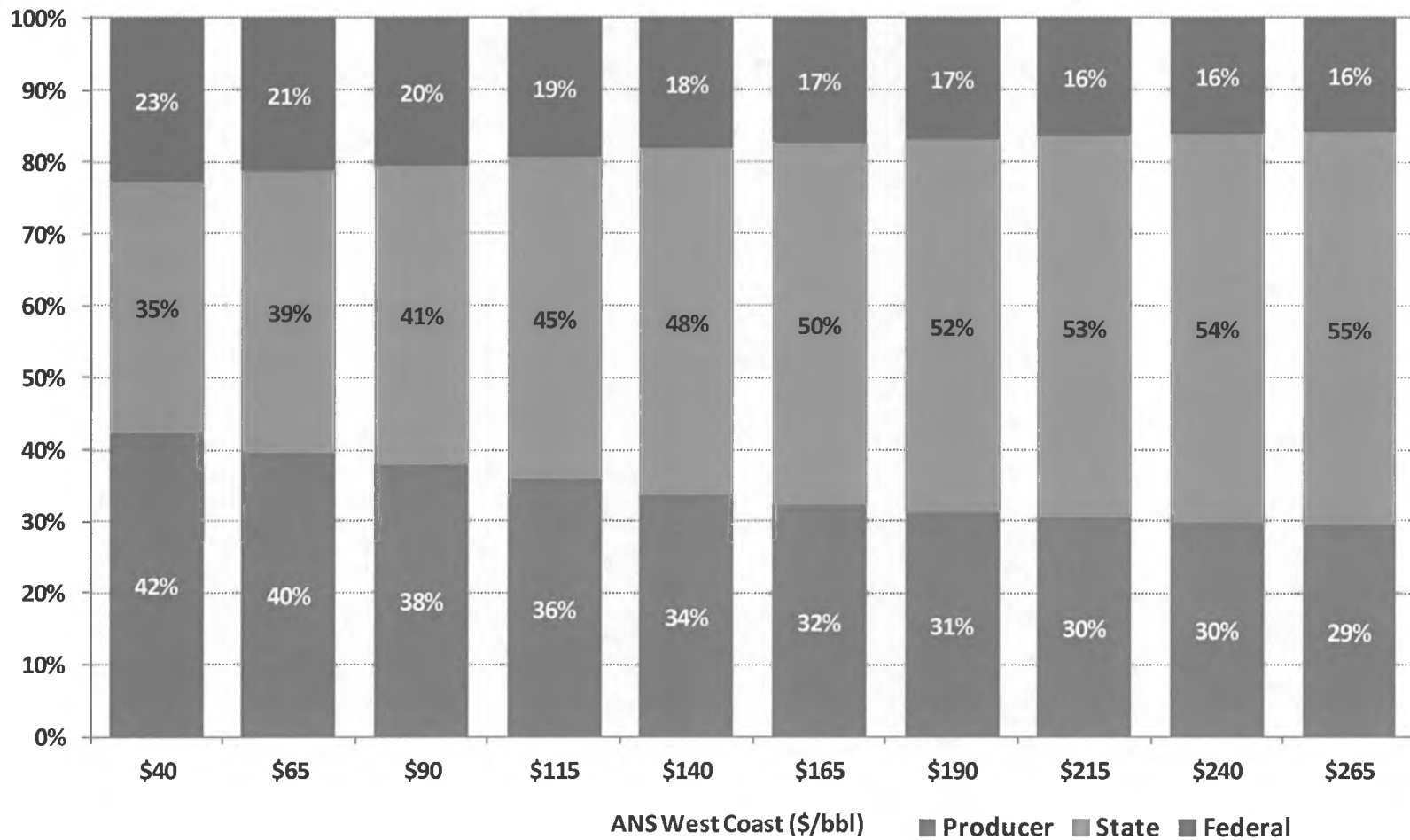


Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
 Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.
 Assumes that 80% of production is impacted by 10% gross minimum tax with no credits allowed against gross tax.

Alaska Department of Revenue



Share of Profit under CS HB 110 (FIN)



Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
 Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.
 Alaska Department of Revenue



Suggested improvements



- Bracketed progressivity
- Lower cap on progressivity
- Reduced tax for new fields
- Increased credits for in-field drilling



Bracketed progressivity

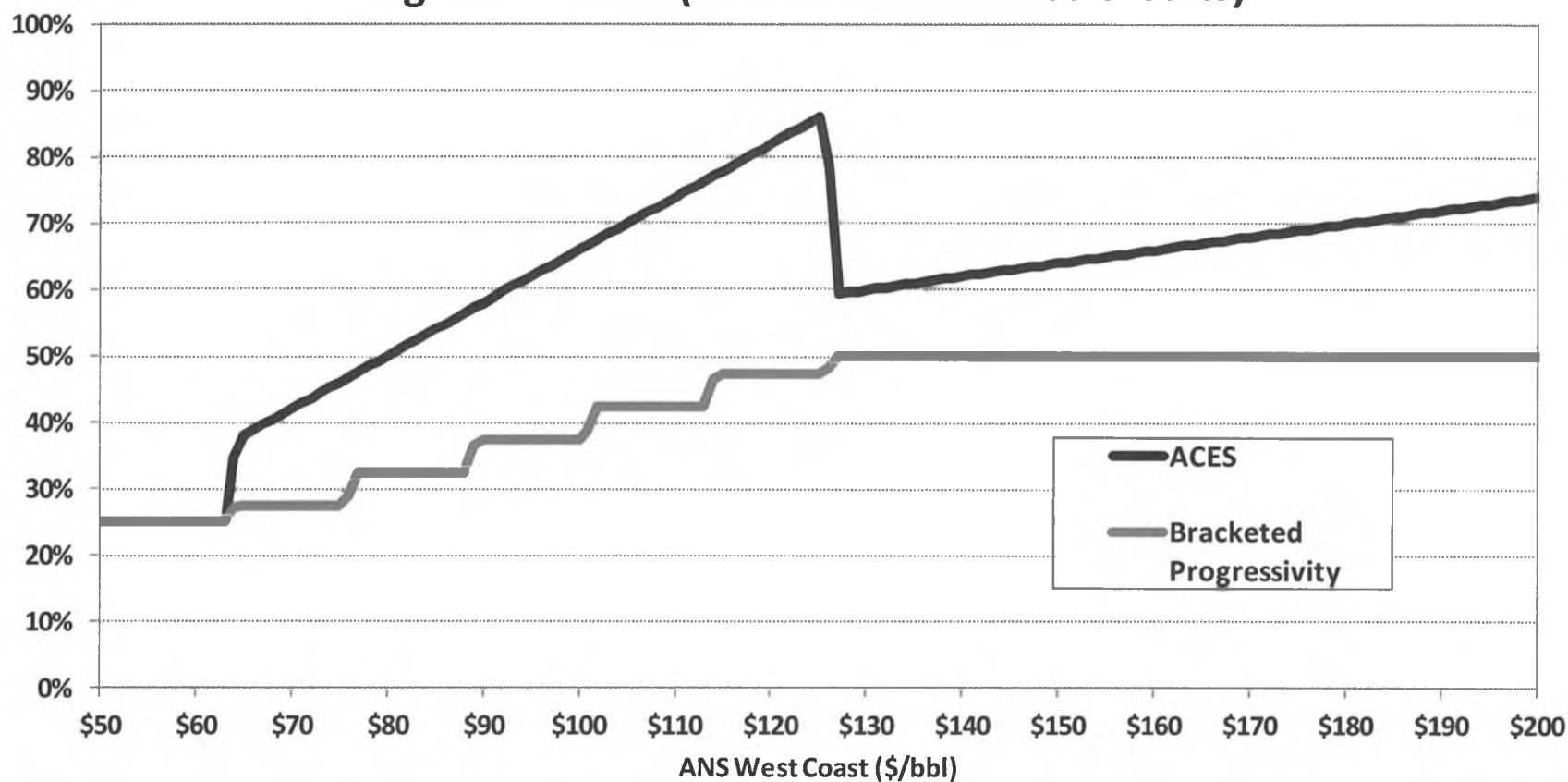


- ACES and CSSB 192 apply progressive tax rate to the entire production tax value
- Tax on the first \$1 of value can vary from 25% to 75% (ACES) or 60% (CSSB 192)
- Bracketed approach applies progressive tax only to the incremental value
 - Similar to how income tax brackets work...
- Other jurisdictions with price progressive systems use a bracketed approach
- Companies have committed \$5 billion under this tax change



Bracketed progressivity

Marginal Tax Rate (Production Tax Post-Credits)



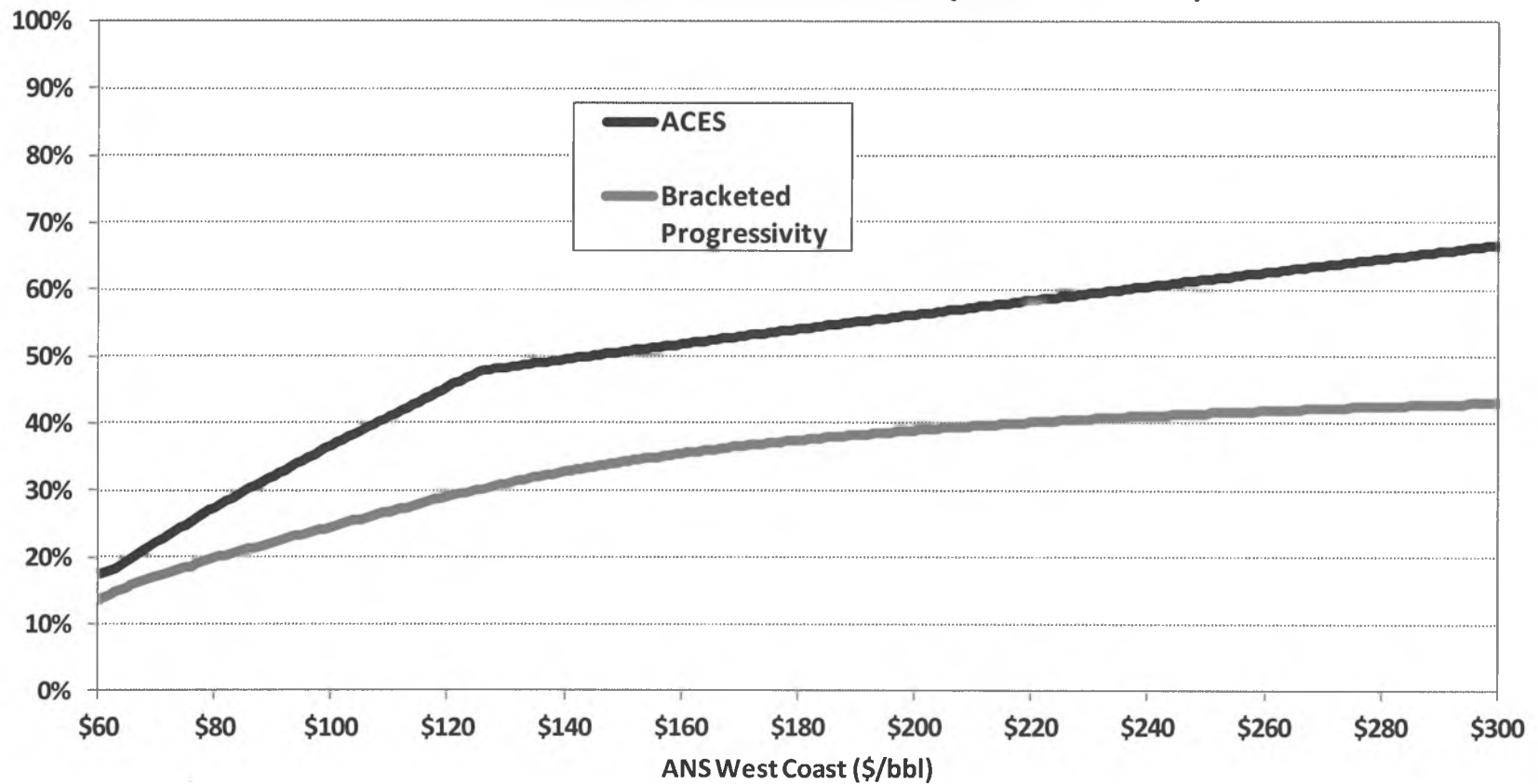
Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.



Bracketed progressivity



Effective Production Tax Rate (Post-Credits)



Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.



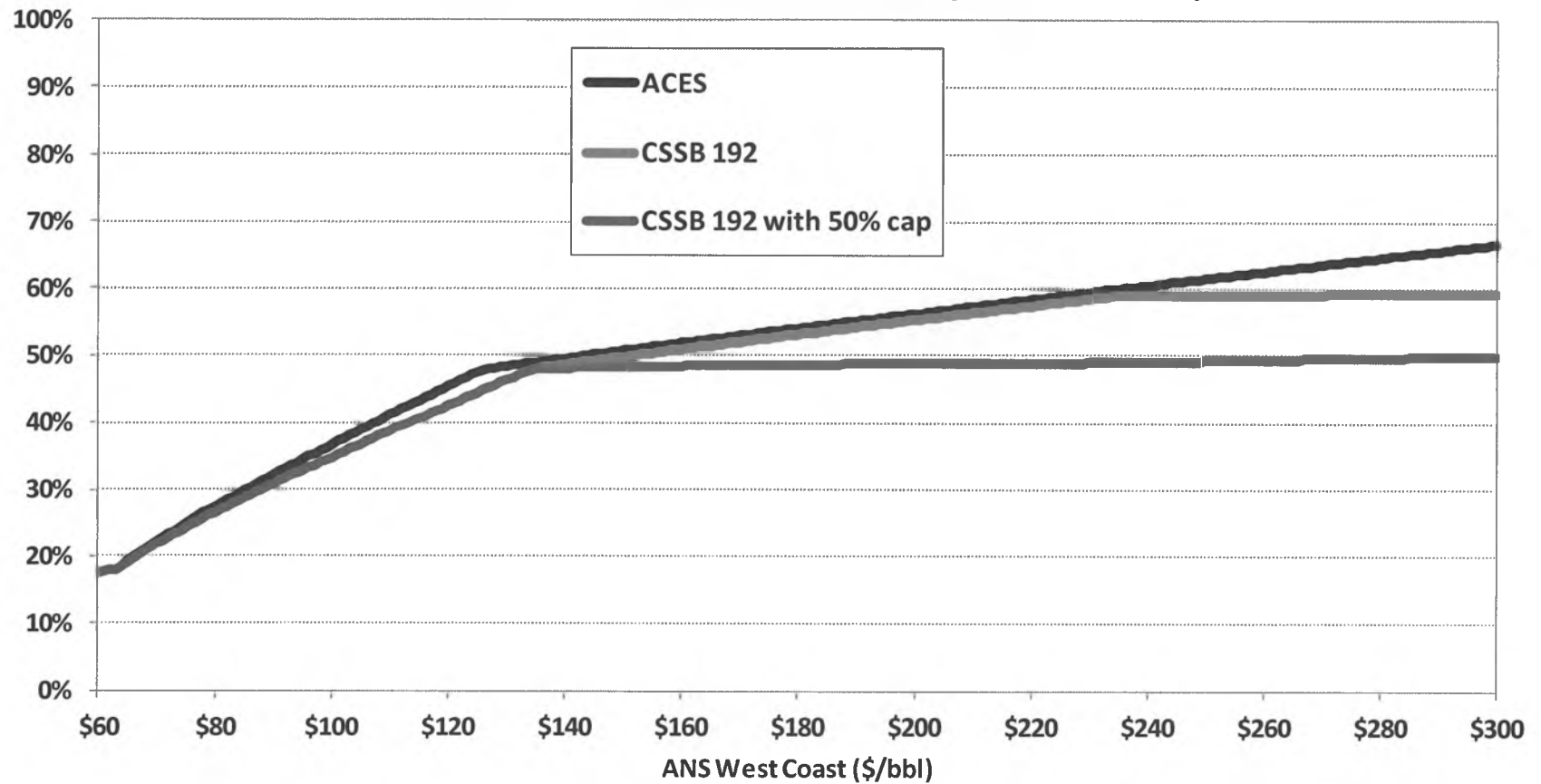
Lower cap on progressivity

- Part of a bracketed or non-bracketed approach
- Provides the “upside potential” companies need to make investments attractive at higher prices.
- 60% cap in CSSB 192 would only apply at prices over ~\$240 / barrel
- 50% cap in CSSB 192 would apply at prices over ~\$140 / barrel



Lower cap on progressivity

Effective Production Tax Rate (Post-Credits)



Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.



Reduced tax for new fields

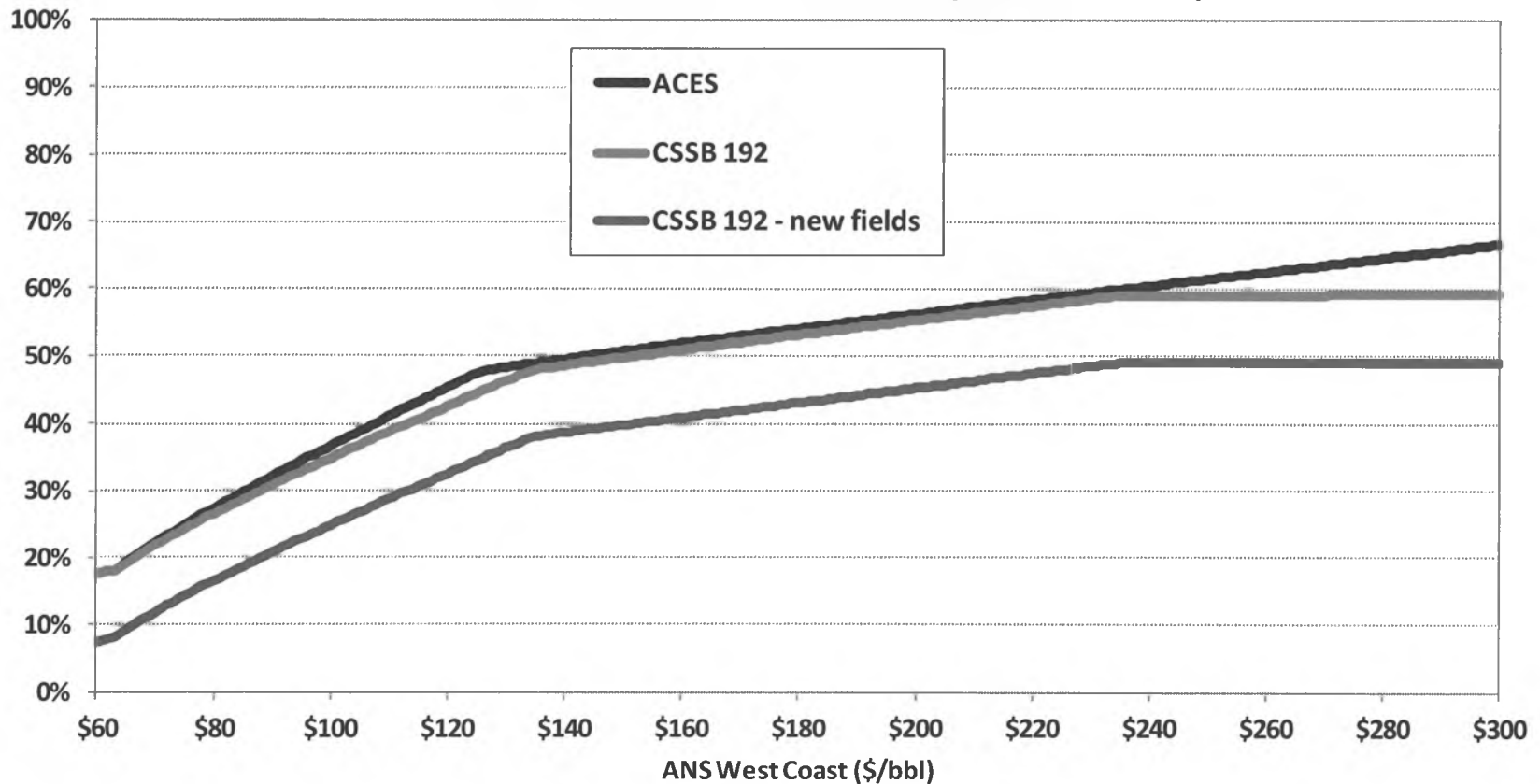


- Provide a lower tax rate to incentivize new fields over the life of the project.
- No fiscal impact for many years
- Would apply primarily to production that is not even in our current forecast – the state has “nothing to lose”



Reduced tax for new fields

Effective Production Tax Rate (Post-Credits)



Example reduces all tax rates by 10% for “new fields”

Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.

Alaska Department of Revenue



Increased credits for in-field drilling



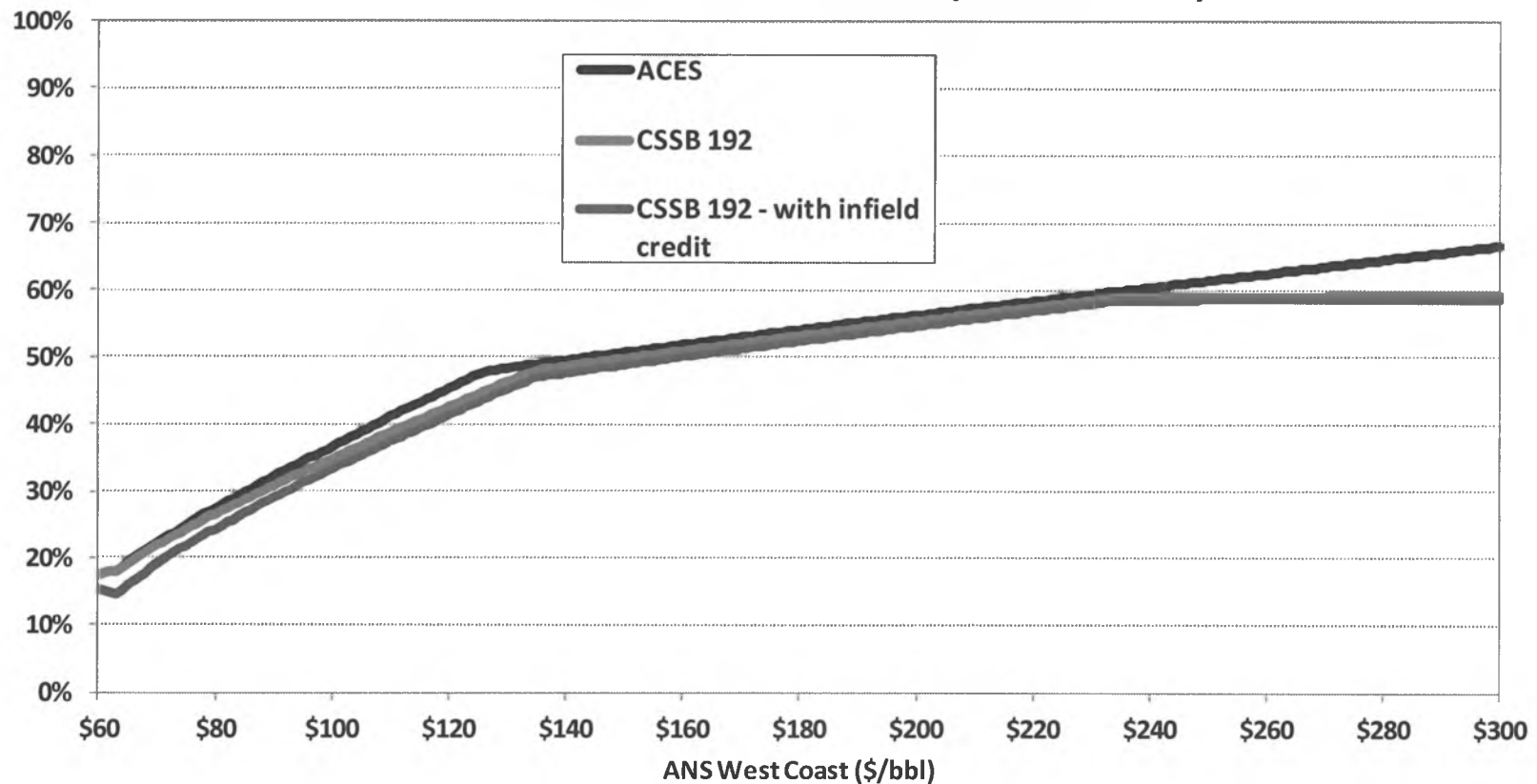
- Existing 40% credit for well-related lease expenditures outside North Slope.
- Recommend extending credit to include North Slope.
- Makes in-field development work more attractive to companies.
- Improves economics of developing new North Slope fields, and increasing production from existing fields.



Increased credits for in-field drilling



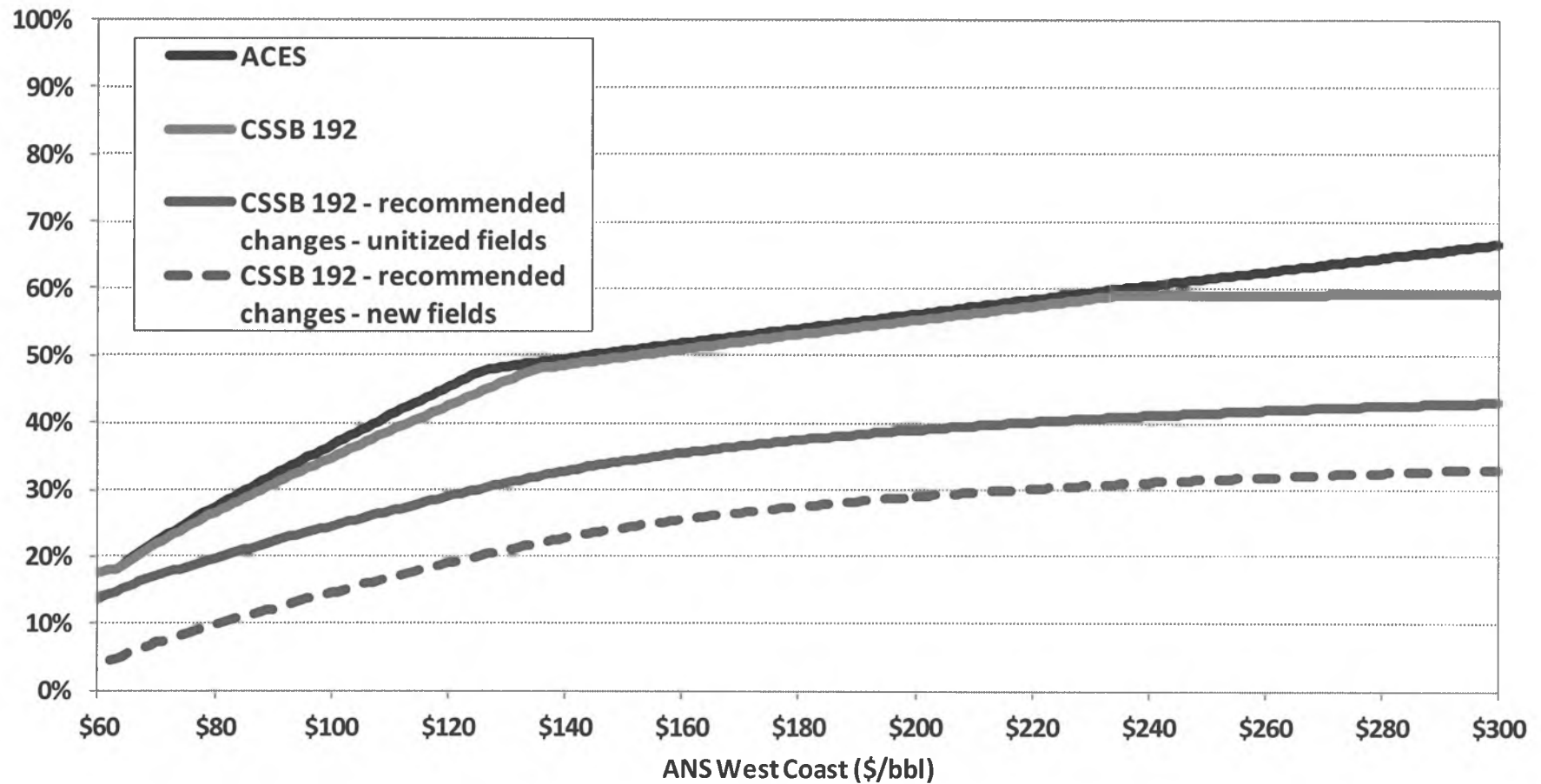
Effective Production Tax Rate (Post-Credits)



Example assumes that 50% of qualified capital expenditures qualify for higher 40% credit
Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.
Alaska Department of Revenue



Summary: Effective Production Tax Rates: ACES, CS SB 192, CS SB 192 with recommended changes



Assumes FY 2012 Transport costs of \$8.72/ bbl, Opex of \$14.03 per taxable barrel, and Capex of \$10.25 per taxable bbl.



Questions ?

5.

Discussion

Slides:

Gerald Krepes,

PFC Energy

March 15, 2012



Discussion Slides: Alaska Senate Finance Committee

March 15, 2012

Gerald Kepes

Partner and Head of Upstream & Gas

PFC Energy

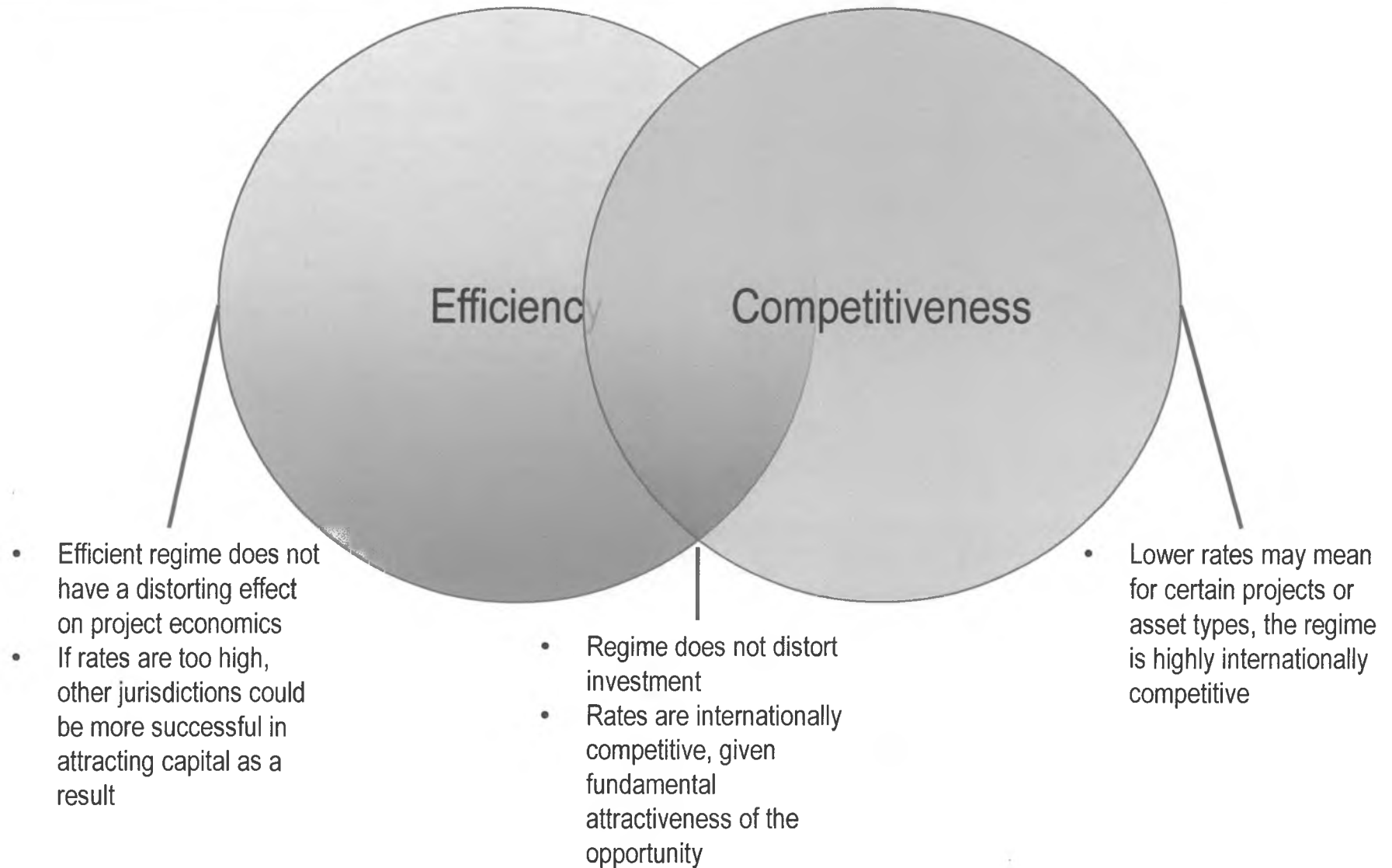


Background – Key Fiscal Terms Concepts

Fiscal Regime Design: Finding the Intersection of Efficiency and Competitiveness

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

Fiscal Regime Design: Finding the Intersection of Efficiency and Competitiveness



Relative Government Take (Definition)

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

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

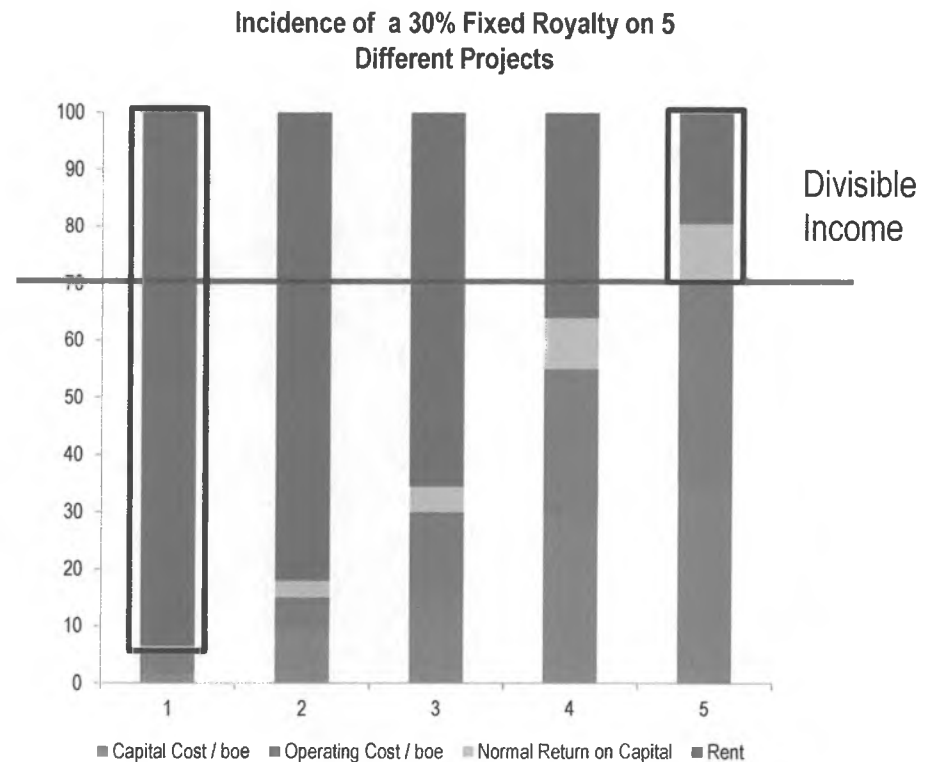
Government Take includes all payments the government mandates in its function as a sovereign:

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

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

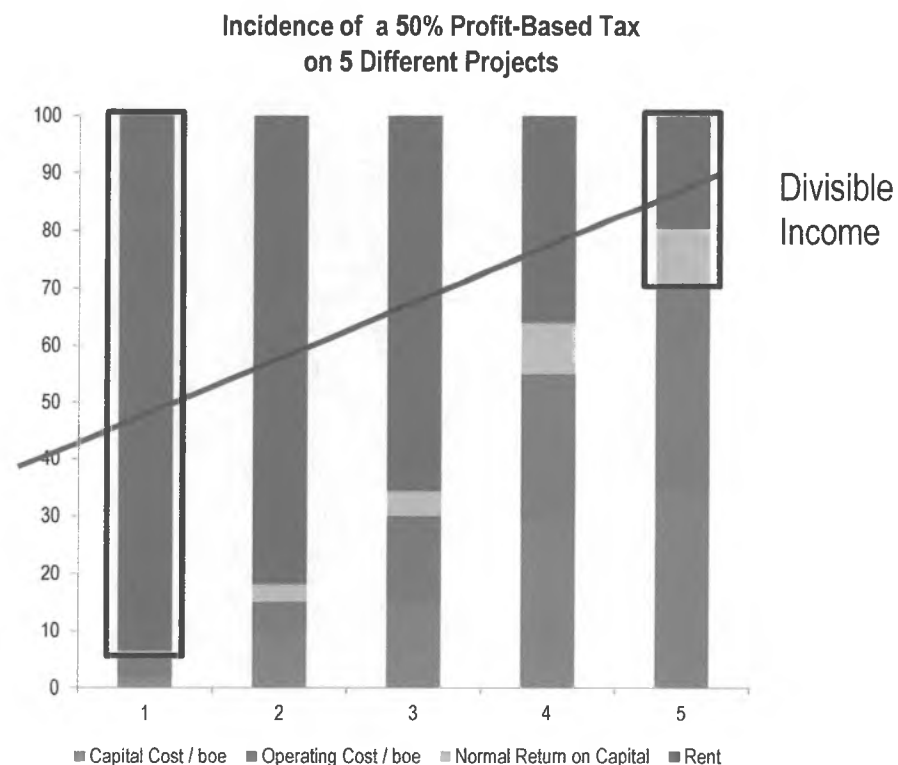
Fixed Royalty Systems: Inefficient, But Potentially Highly Competitive

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



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

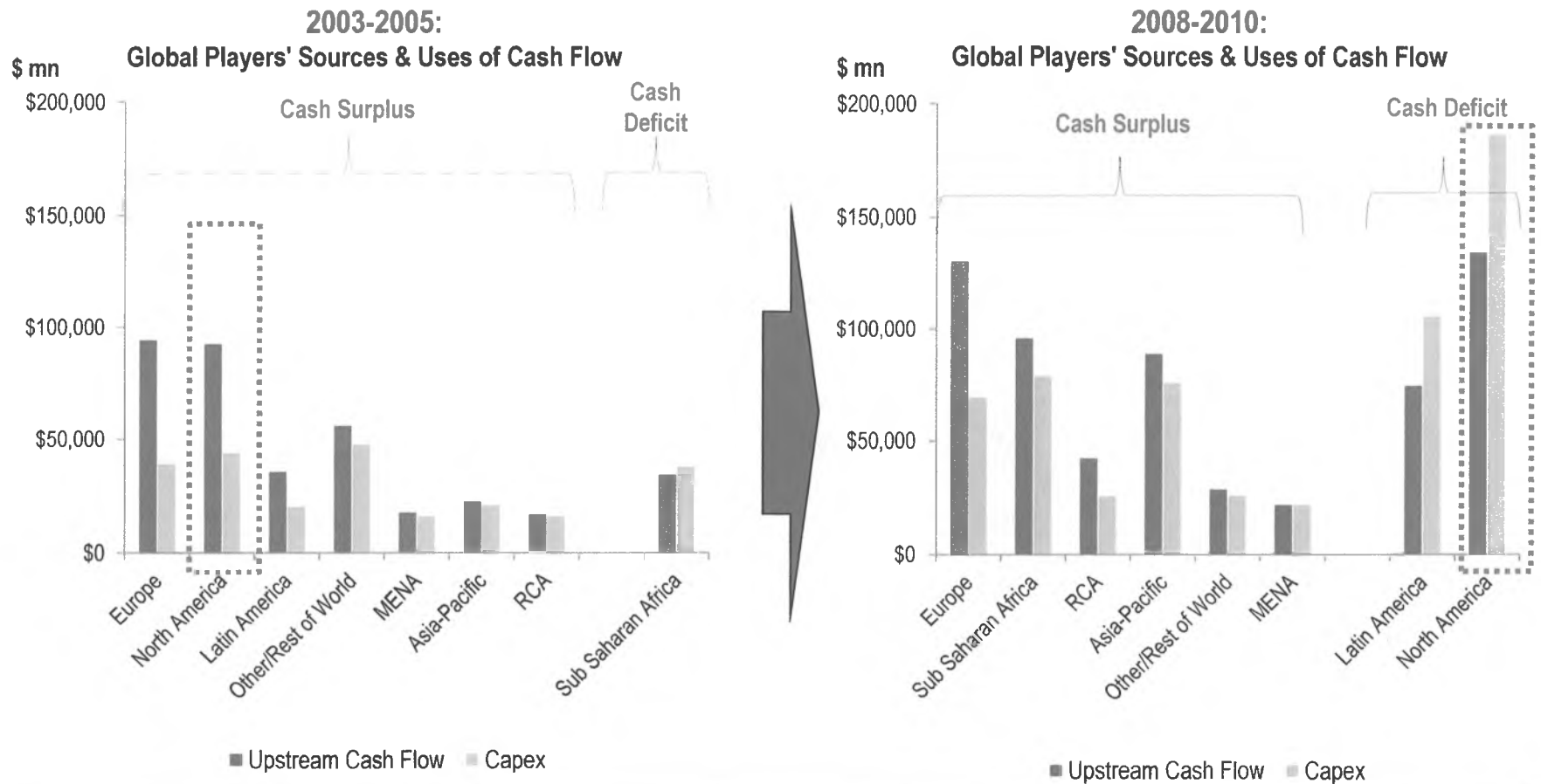
- A Profit-Based fiscal system may be
 - A contractual arrangement, such as a Production Sharing Contract
 - A tax which applies to revenues less costs
- Such systems can be capable of **raising greater revenue, while reducing inefficiency**
 - In low oil price environments, or high cost environments,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





**Alaska's Oil & Gas
Competitive Context**

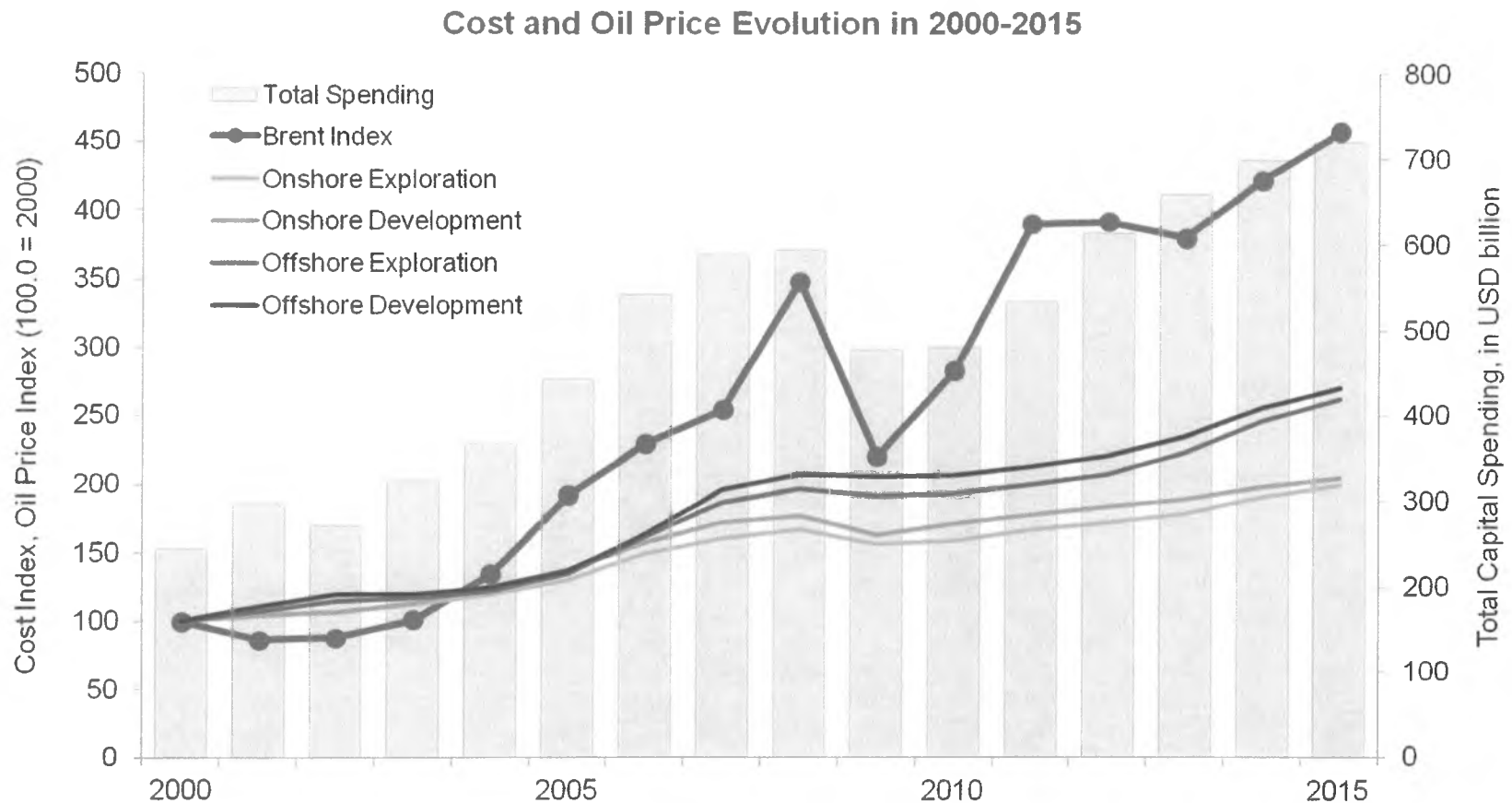
Fixed-Royalty Jurisdictions in US Lower 48 Are A Key Competitor to Alaska for Investment Dollars



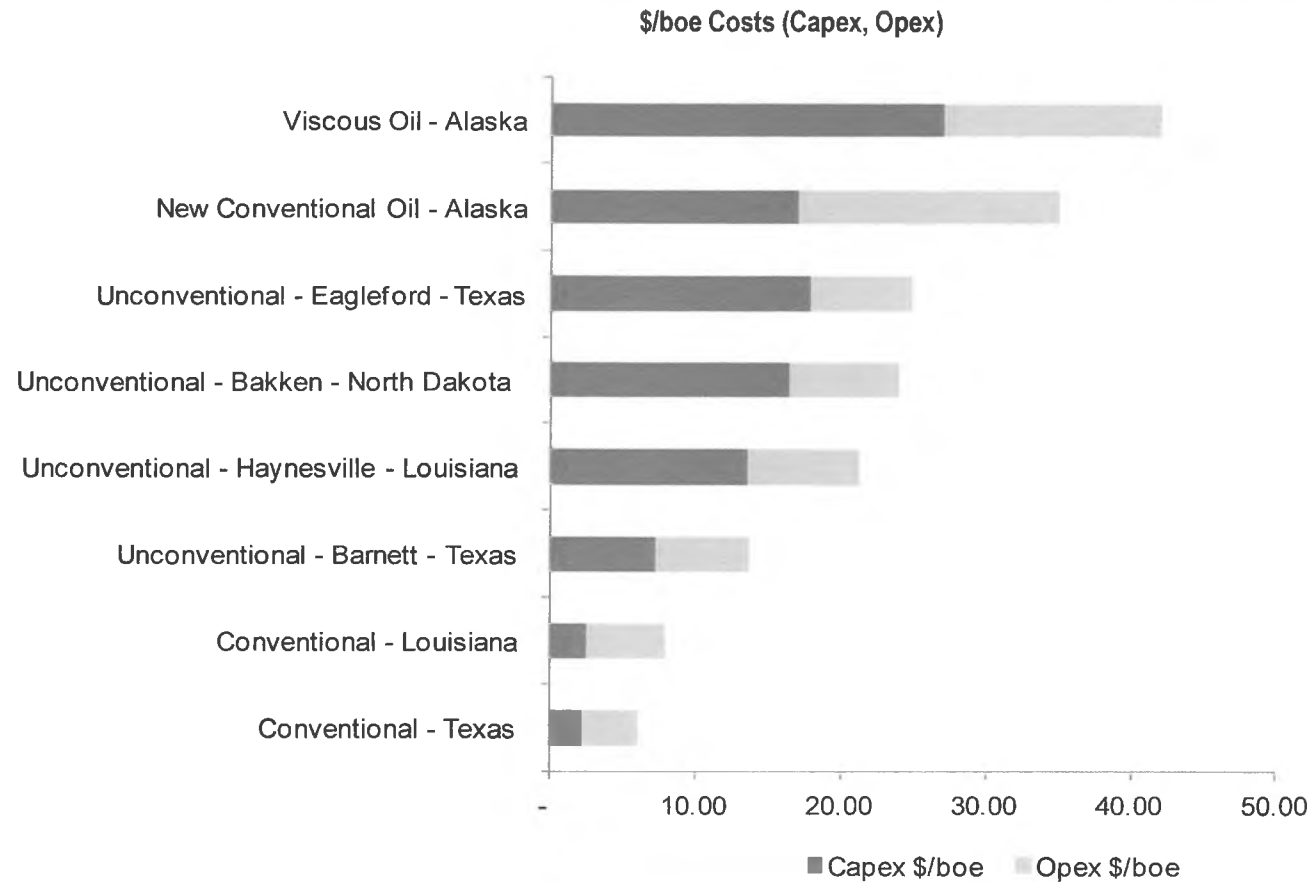
It is now an exception not to be targeting unconventional in North America as a major growth platform.

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

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



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



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

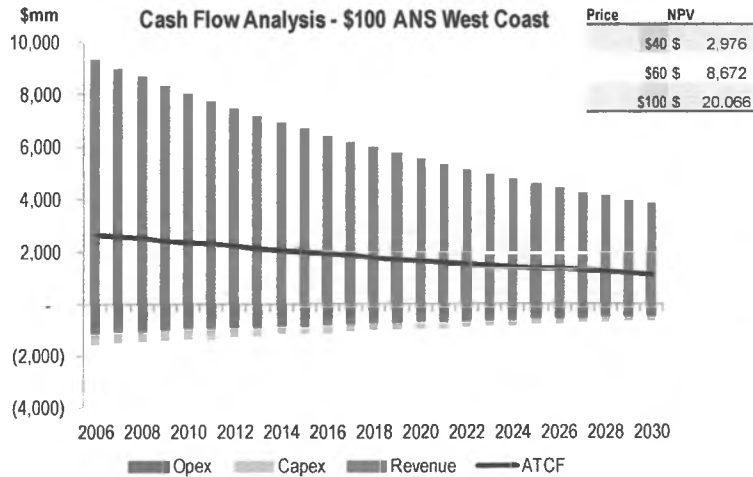


Evolution of the ACES fiscal regime

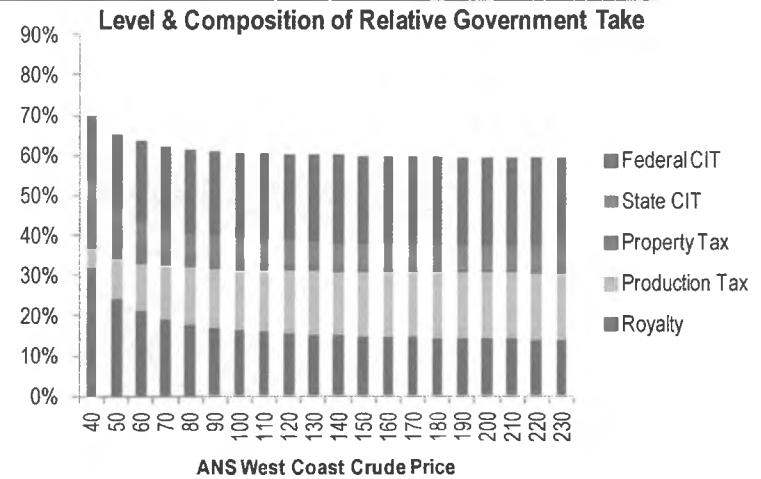
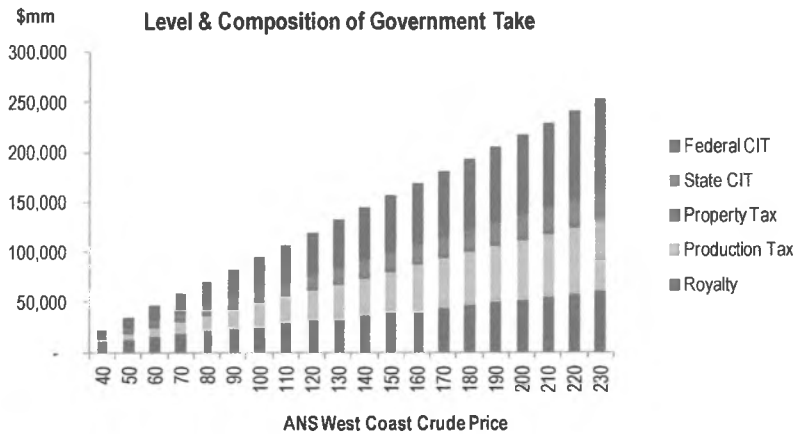
Cost Assumptions Underlying Fiscal Analysis

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

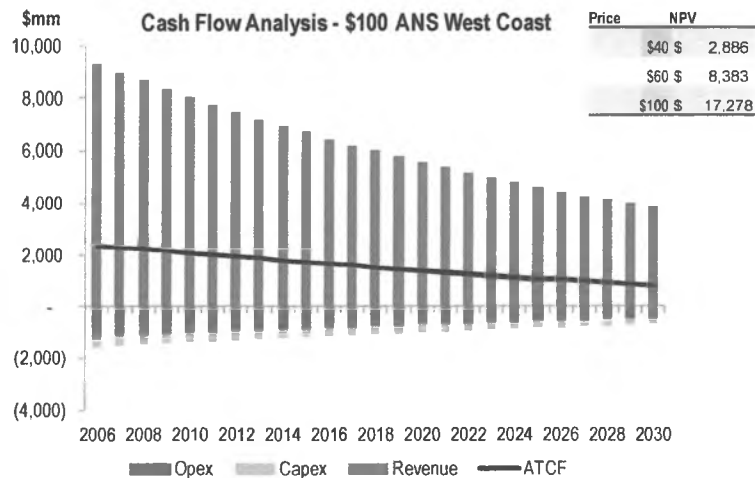
PPT As Originally Proposed (Existing Producer)



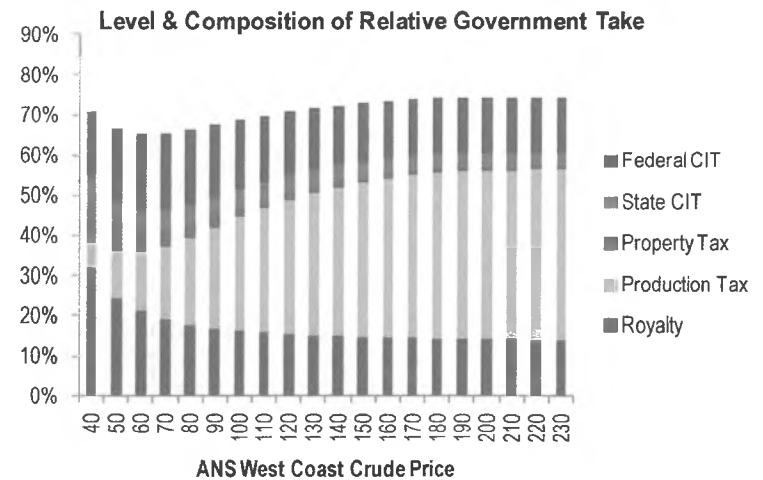
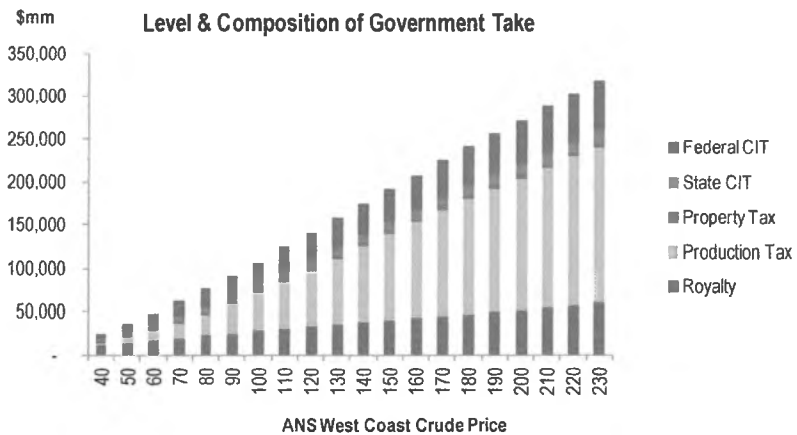
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	5%	12%	4%	53%	17%	70%
50	24%	10%	8%	5%	47%	19%	65%
60	21%	12%	5%	5%	44%	20%	63%
70	19%	13%	4%	5%	42%	20%	62%
80	18%	14%	3%	5%	41%	21%	62%
90	17%	14%	3%	6%	40%	21%	61%
100	17%	15%	3%	6%	40%	21%	61%
110	16%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



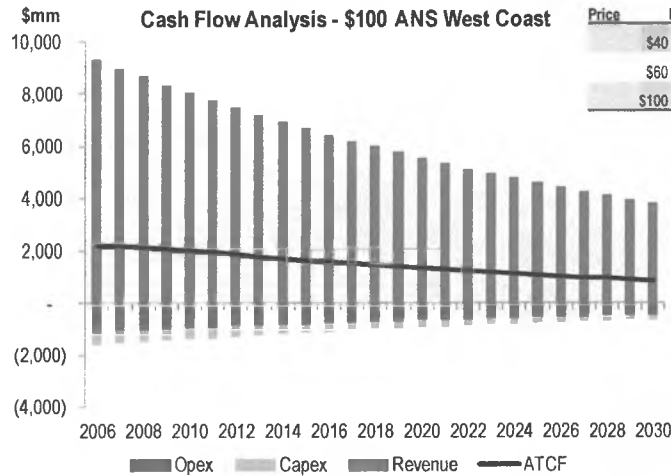
PPT As Enacted (Existing Producer)



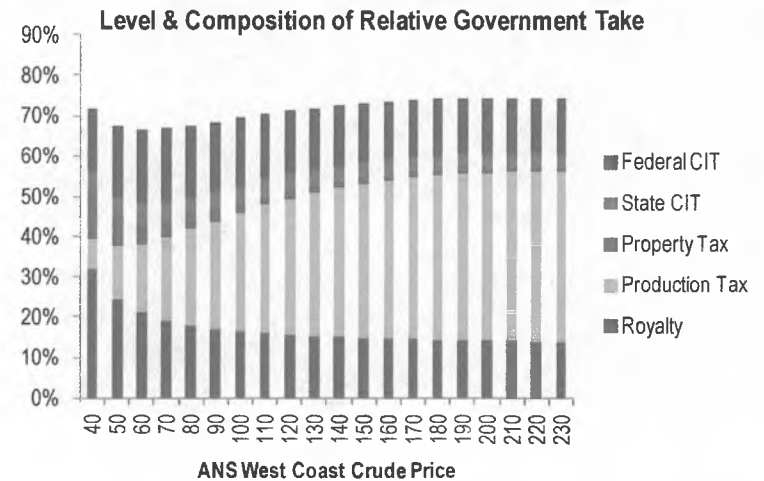
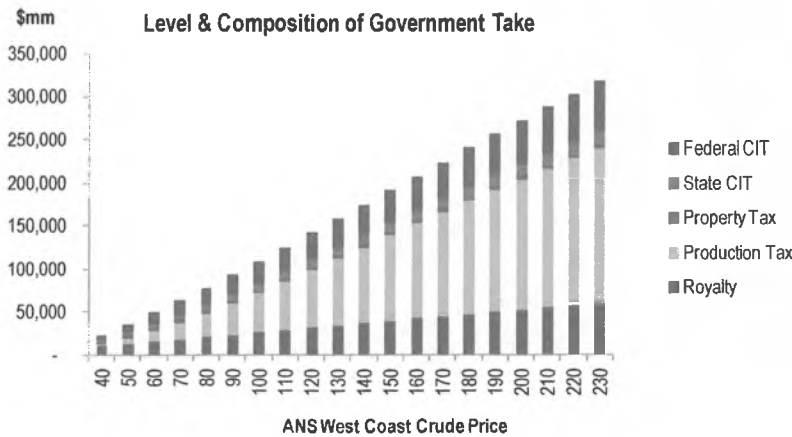
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	6%	12%	4%	55%	16%	71%
50	24%	11%	8%	5%	48%	18%	66%
60	21%	15%	5%	5%	46%	19%	65%
70	19%	18%	4%	5%	46%	19%	65%
80	18%	21%	3%	5%	48%	18%	66%
90	17%	25%	3%	5%	50%	18%	67%
100	17%	28%	3%	4%	52%	17%	69%
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120	16%	33%	2%	4%	55%	16%	71%
130	15%	35%	2%	4%	56%	15%	72%
140	15%	37%	2%	4%	57%	15%	72%
150	15%	38%	2%	4%	58%	15%	73%
160	15%	39%	1%	4%	59%	14%	74%
170	15%	40%	1%	4%	60%	14%	74%
180	14%	41%	1%	4%	60%	14%	74%
190	14%	42%	1%	4%	61%	14%	74%
200	14%	42%	1%	4%	61%	14%	74%
210	14%	42%	1%	4%	61%	14%	74%
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230	14%	42%	1%	4%	61%	14%	74%



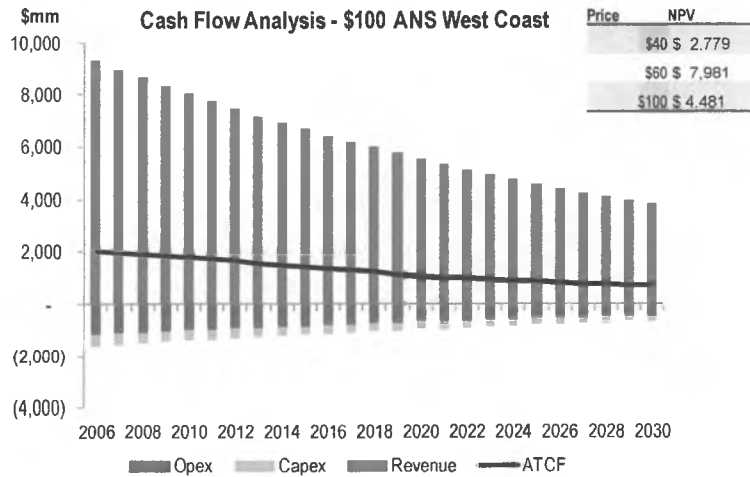
ACES As Proposed (Existing Producer)



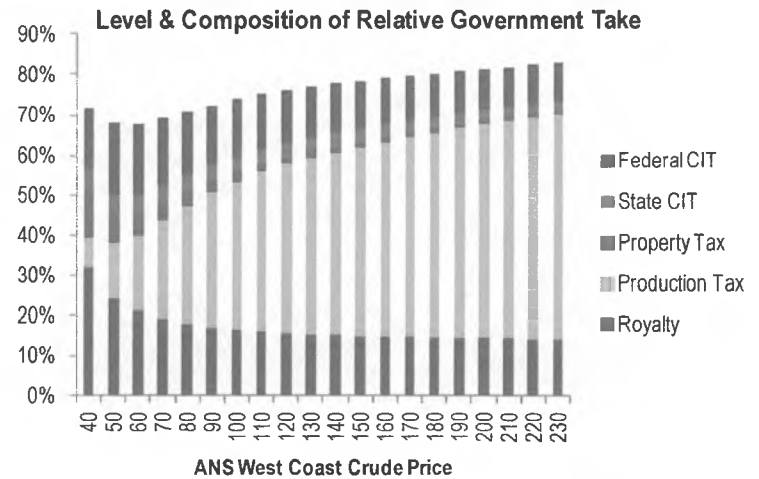
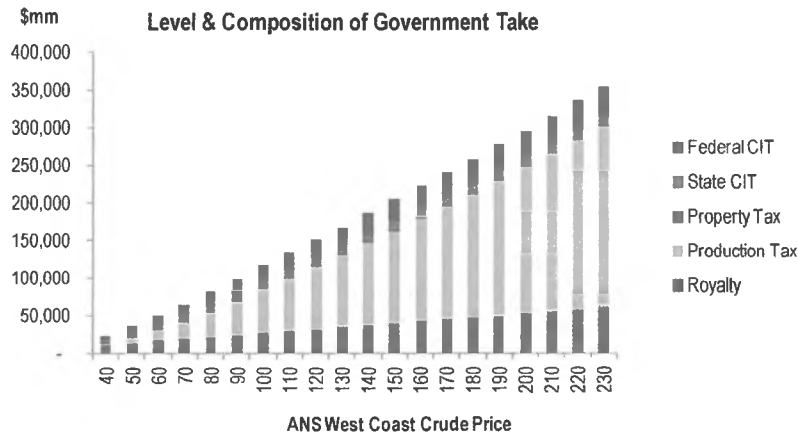
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	24%	13%	8%	5%	50%	18%	68%
60	21%	17%	5%	5%	48%	18%	67%
70	19%	21%	4%	5%	49%	18%	67%
80	18%	24%	3%	5%	50%	18%	68%
90	17%	27%	3%	4%	51%	17%	68%
100	17%	29%	3%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



ACES As Enacted (Existing Producer)

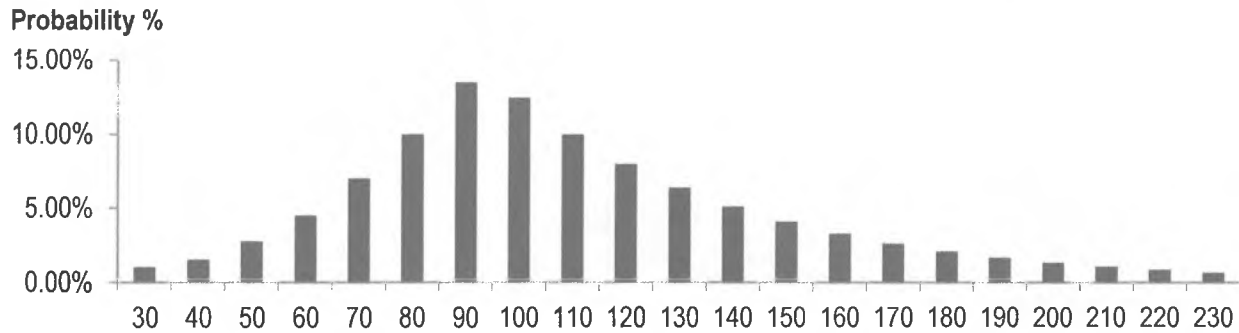
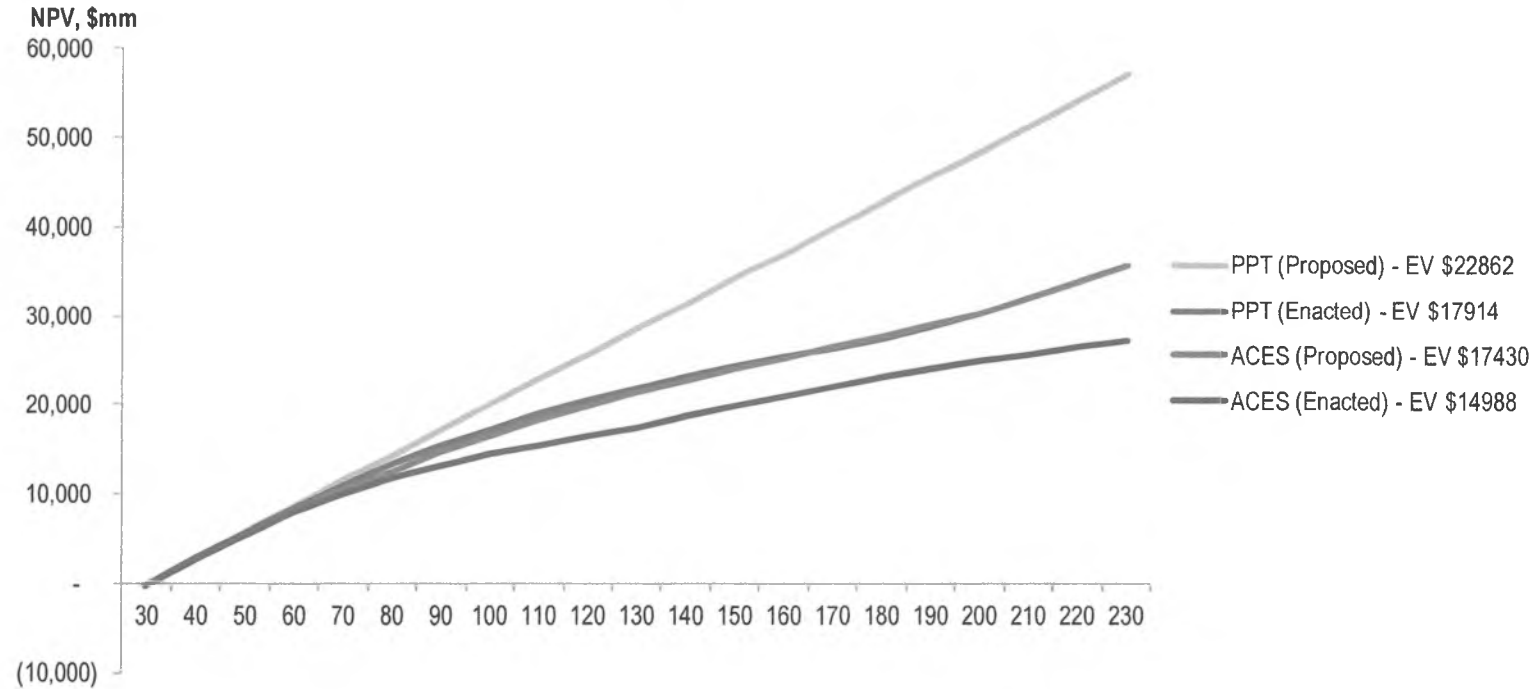


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	24%	14%	8%	5%	50%	18%	68%
60	21%	19%	5%	5%	50%	18%	68%
70	19%	24%	4%	4%	52%	17%	69%
80	18%	29%	3%	4%	55%	16%	71%
90	17%	33%	3%	4%	57%	15%	72%
100	17%	37%	3%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



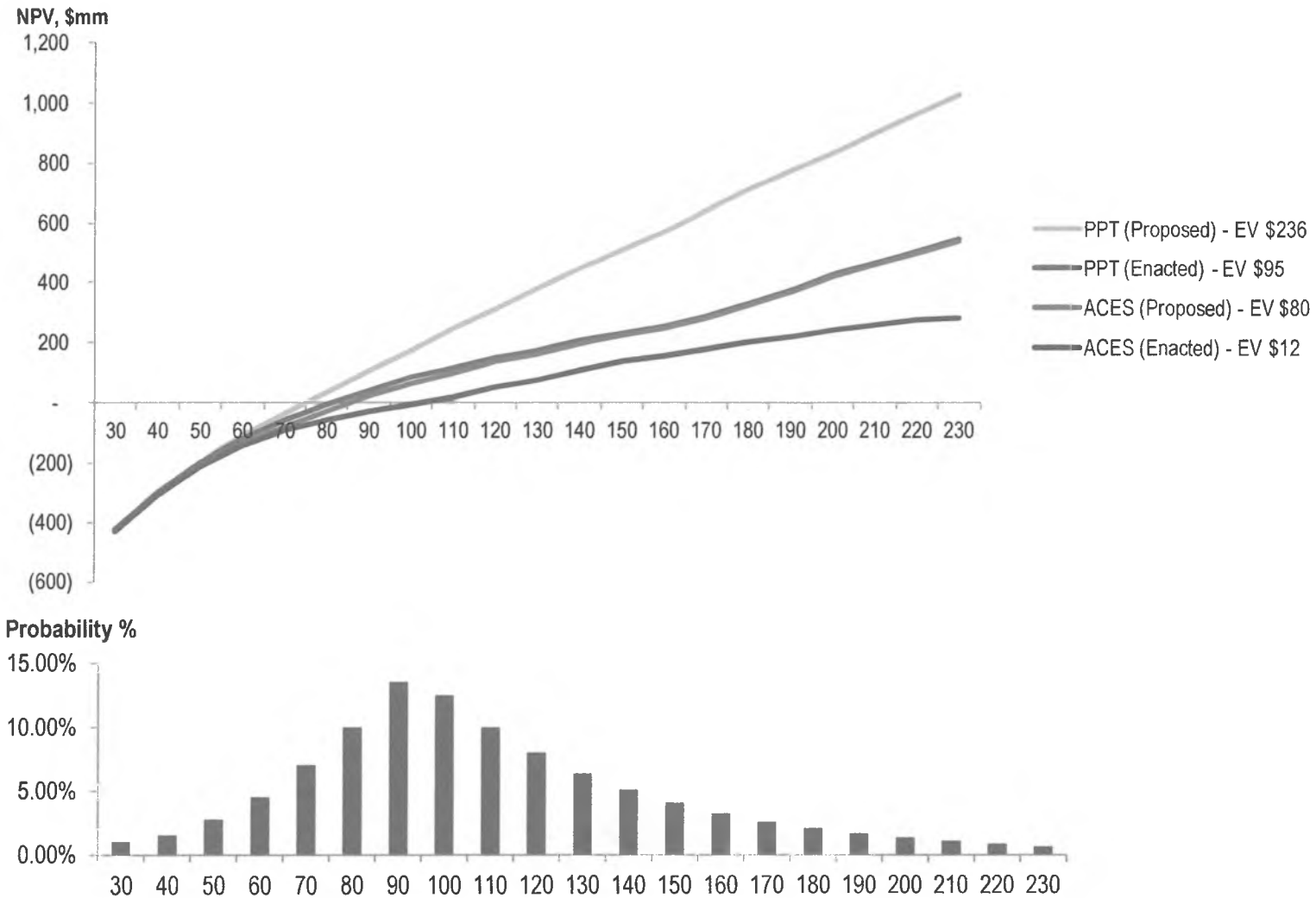
Limitations on Price Upside: A Probabilistic Approach

Existing Base Production

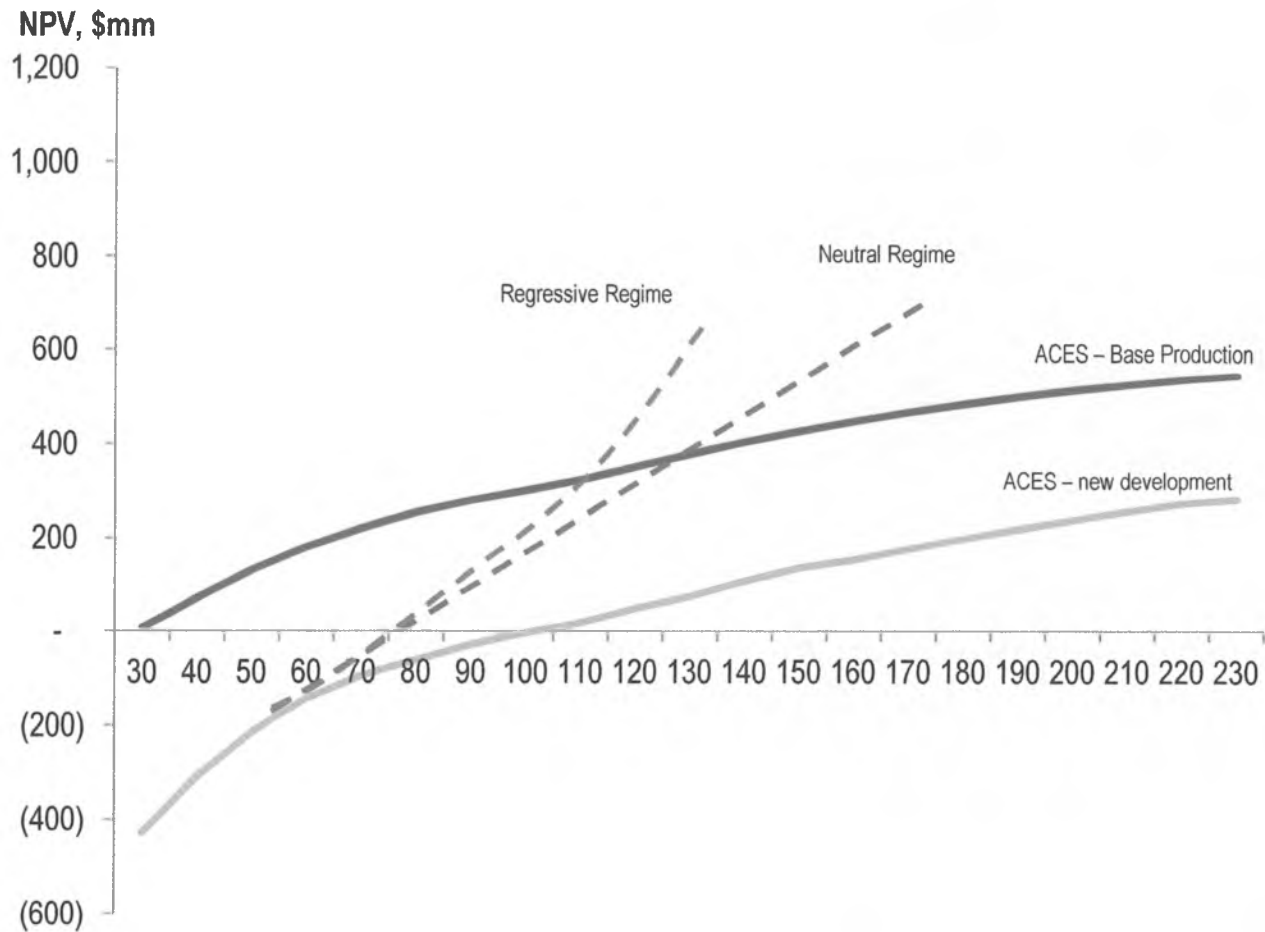


Limitations on Price Upside: A Probabilistic Approach

New Development



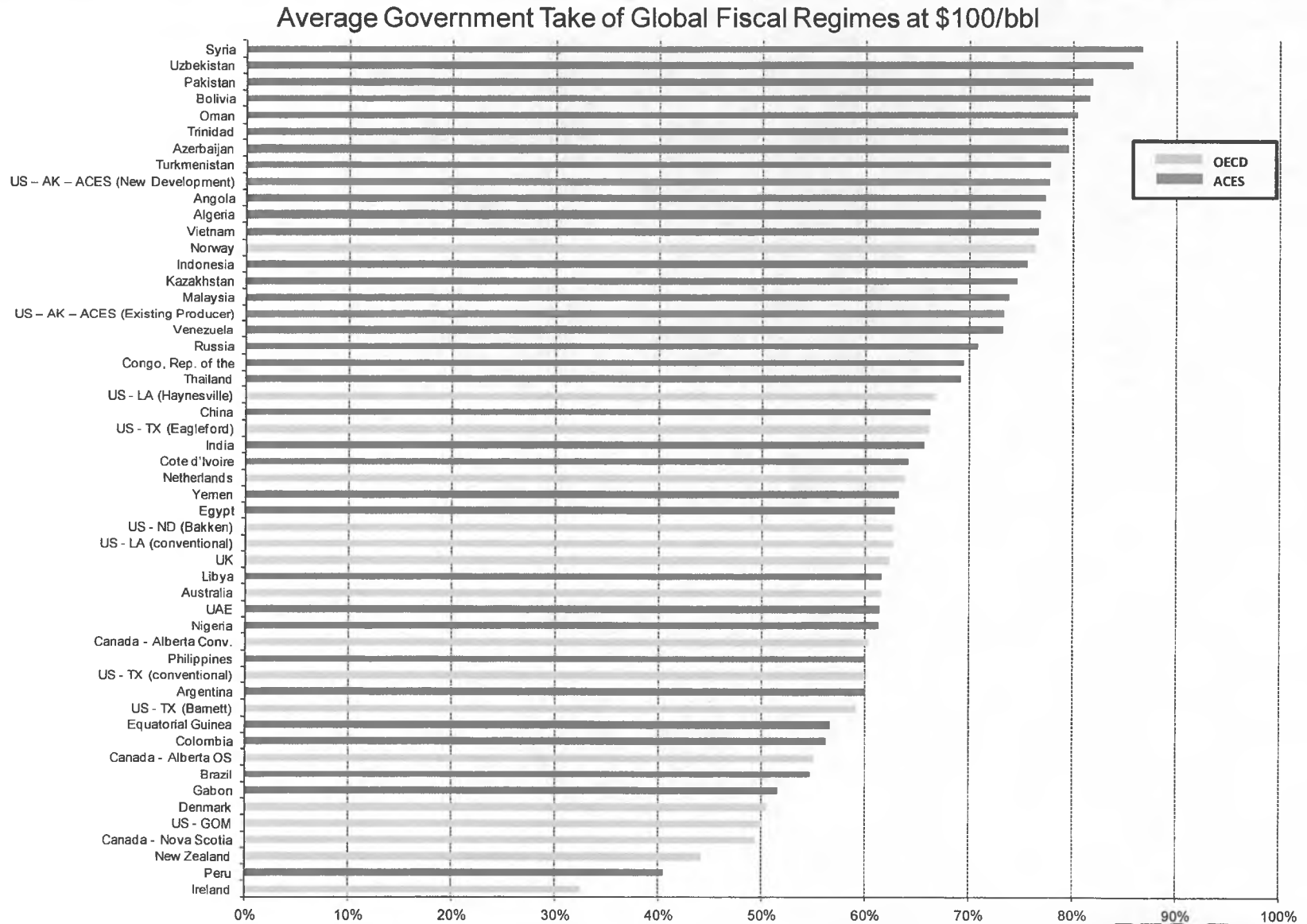
ACES Impact on Oil-Price Upside, and on High Cost Development Economics





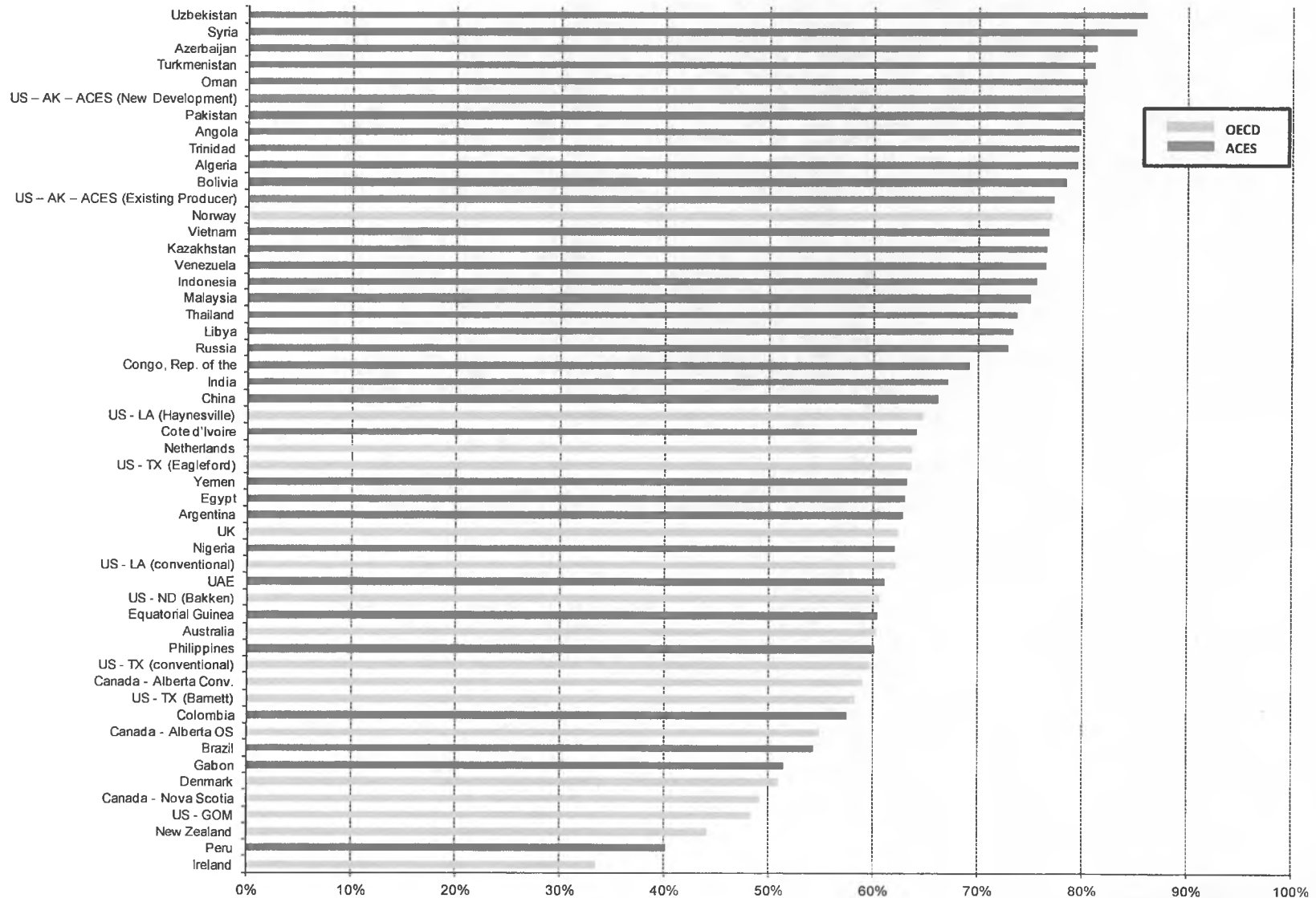
**ACES: Global
Competitiveness**

Regime Competitiveness: Average Government Take

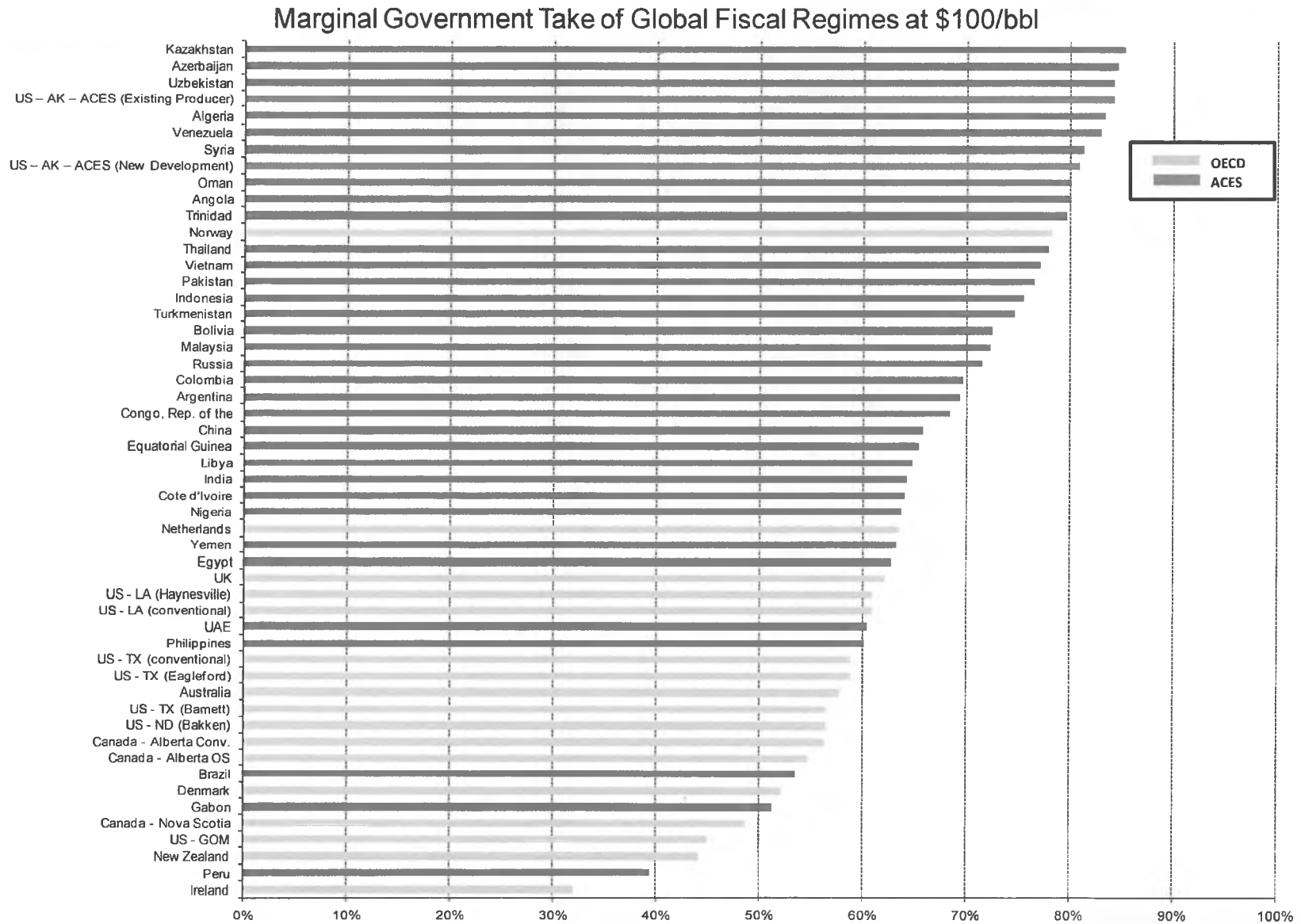


Regime Competitiveness: Average Government Take

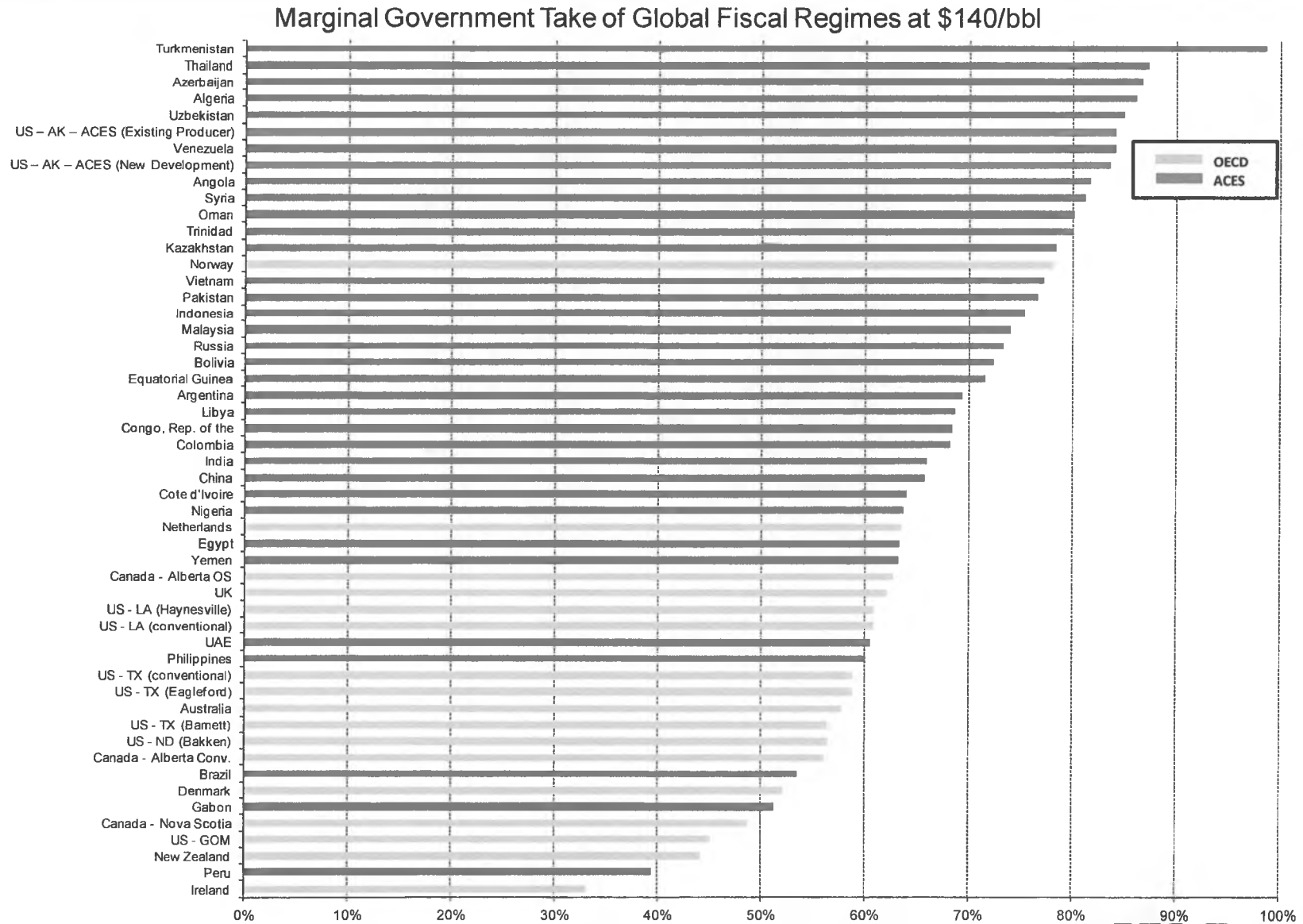
Average Government Take of Global Fiscal Regimes at \$140/bbl



Regime Competitiveness: Marginal Government Take

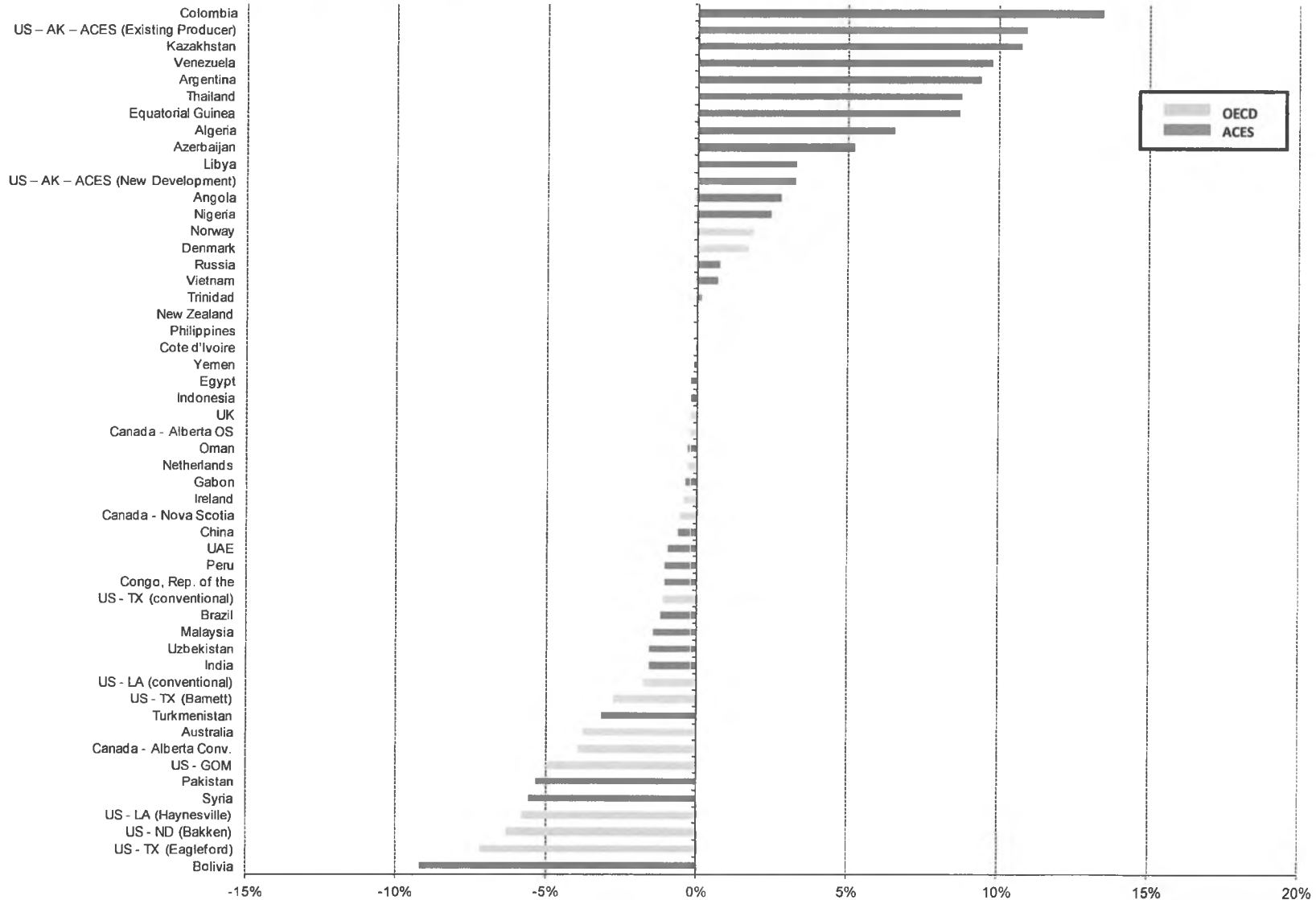


Regime Competitiveness: Marginal Government Take



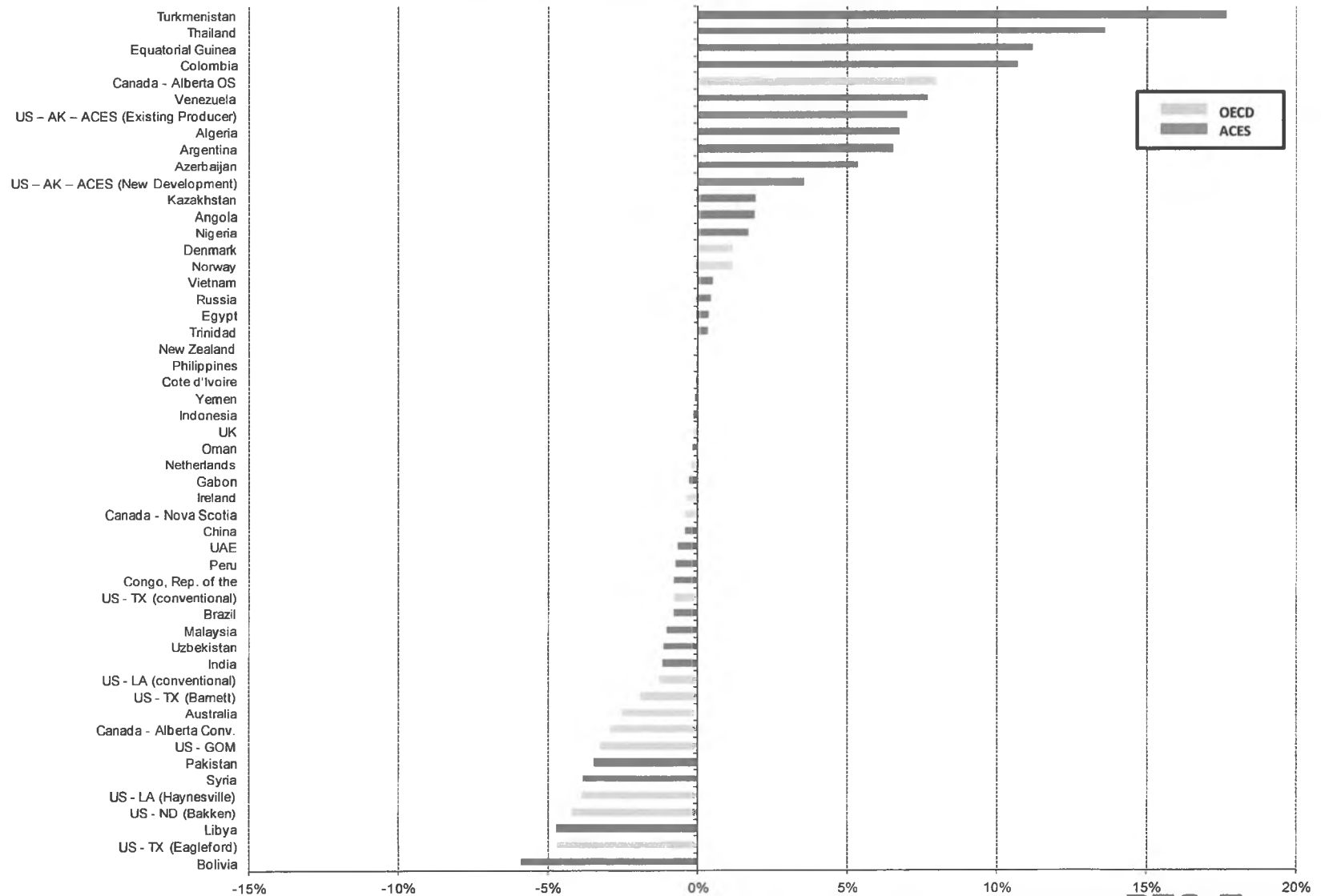
Benchmarking Progressivity for a Range of Global Regimes

Progressivity (Marginal less Average Take) of Global Fiscal Regimes at \$100/bbl



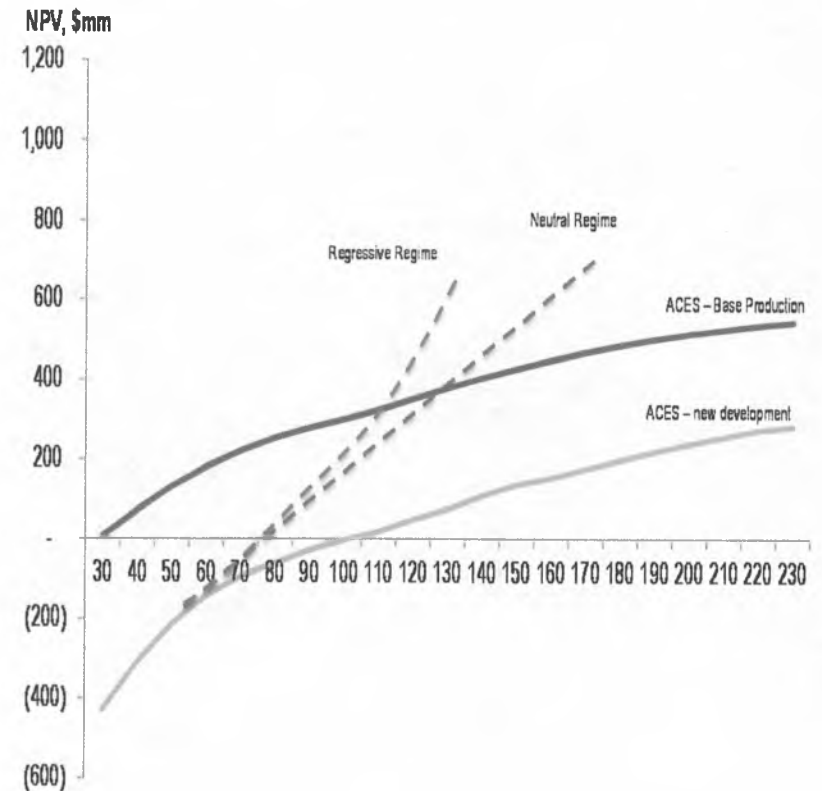
Benchmarking Progressivity for a Range of Global Regimes

Progressivity (Marginal less Average Take) of Global Fiscal Regimes at \$140/bbl



ACES – Effective as a Harvest Area Fiscal Regime

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



Options to Spur New Developments

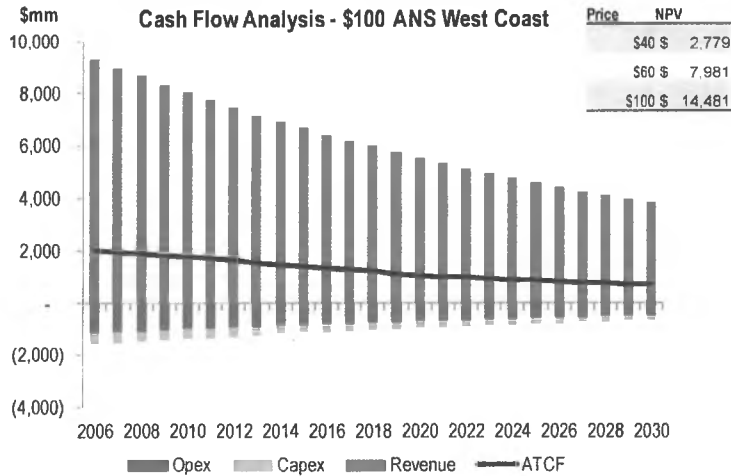
Approach	Implementation Options	Advantages	Disadvantages
Uniform lowering of Government Take	<ul style="list-style-type: none"> •Bracketing •Reduced Base Rate •Increased Progressivity Thresholds •Reduced Progressivity Rates •Progressivity Caps 	<ul style="list-style-type: none"> •Does not require increased complexity •May present opportunities for simplification 	<ul style="list-style-type: none"> •Incentivizing new high cost resources through this method alone requires giving substantial 'rent' back to producers on the mature producing assets
Differentiation between old and new production	<ul style="list-style-type: none"> •Allowance for New Oil •Switching in part away from Net Profits taxation to Gross Revenue Taxation, to enable different tax rates for different production streams without separate cost accounting and tax returns •Use of some combination of definitions for incremental production, ie base decline rate, regulator-agreed new programs, new areas 	<ul style="list-style-type: none"> •Allows significant reductions in Govt Take on new and costlier developments (including heavy oil etc) without requiring significant reductions on the mature producing assets 	<ul style="list-style-type: none"> •Administrative difficulties around definitions of 'new production'
Enhancements to cost progressivity of ACES	<ul style="list-style-type: none"> •Changes to allowable cost deduction or credits mechanism etc to provide greater 'uplift' for high capital and operating costs, while restricting negative Production Tax in marginal cases •Enhancements to royalty relief 	<ul style="list-style-type: none"> •Does not require structural change away from ACES 	<ul style="list-style-type: none"> •Increases already high complexity and opacity •May exacerbate problem of poor cost control incentives •Increases likelihood of unintended consequences •Likely less significant impact than new production differentiation

ACES v CSSB192

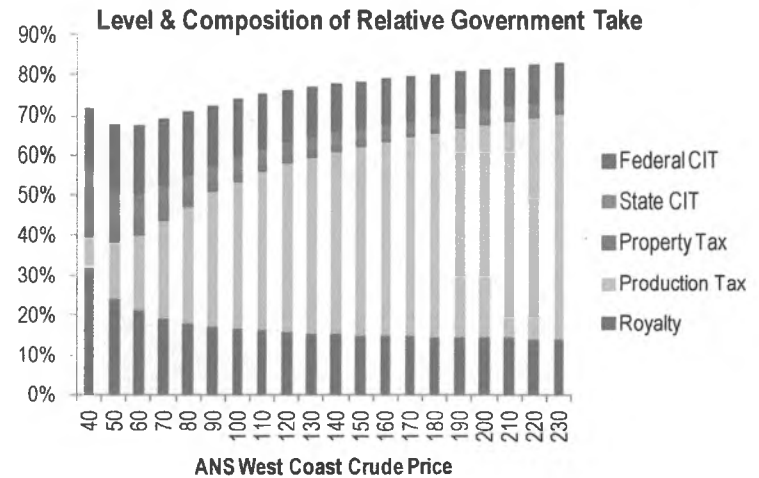
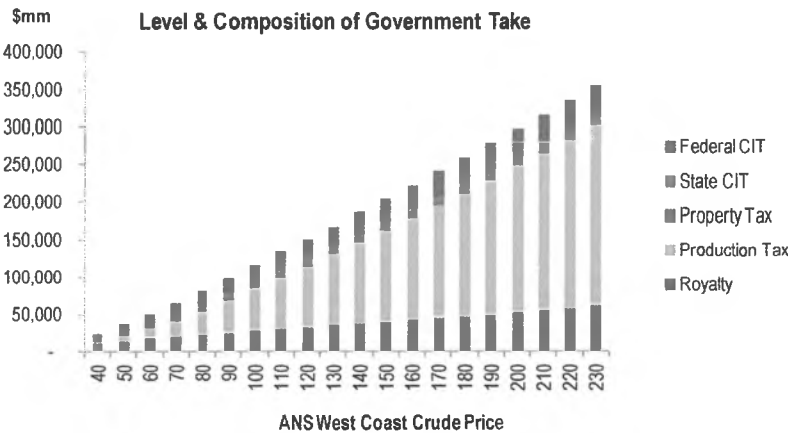
ACES			
Is Production Tax Bracketed?	No		
Are oil and gas assessed separately?	No		
Rates for non-bracketed system:			75% maximum
<= 30	\$ 30.00	PTV/BOE	25% base
> 30 but <= 92.5	\$ 92.50	PTV/BOE	0.40% progressivity
> 92.5		PTV/BOE	0.10% progressivity

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

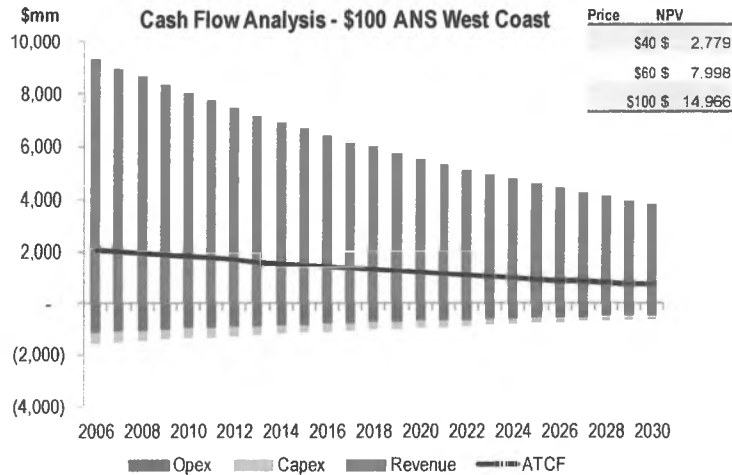
ACES (Existing Producer)



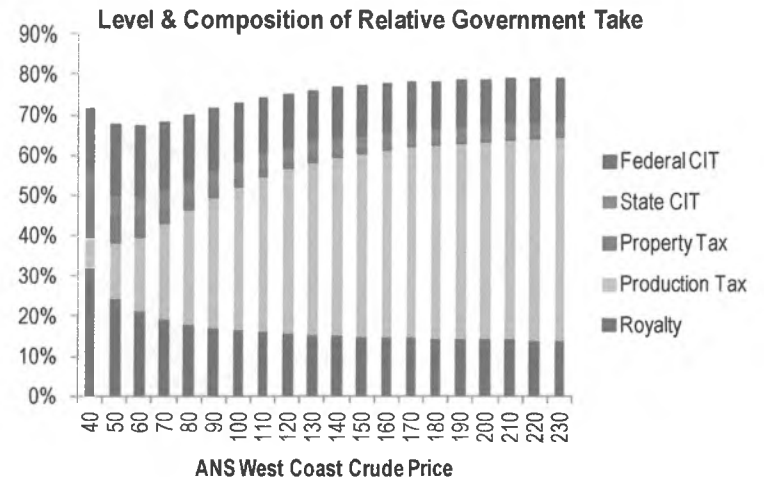
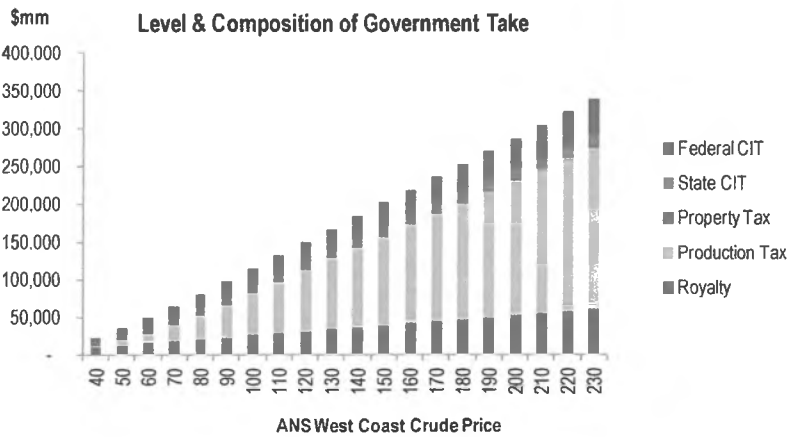
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	8%	12%	4%	56%	16%	72%
50	24%	14%	8%	5%	50%	18%	68%
60	21%	19%	5%	5%	50%	18%	68%
70	19%	24%	4%	4%	52%	17%	69%
80	18%	29%	3%	4%	55%	16%	71%
90	17%	33%	3%	4%	57%	15%	72%
100	17%	37%	3%	4%	60%	14%	74%
110	16%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



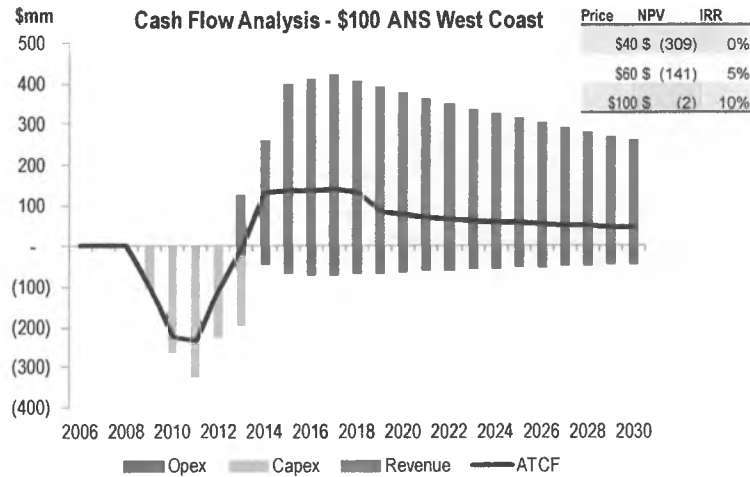
CSSB 192 (Existing Producer)



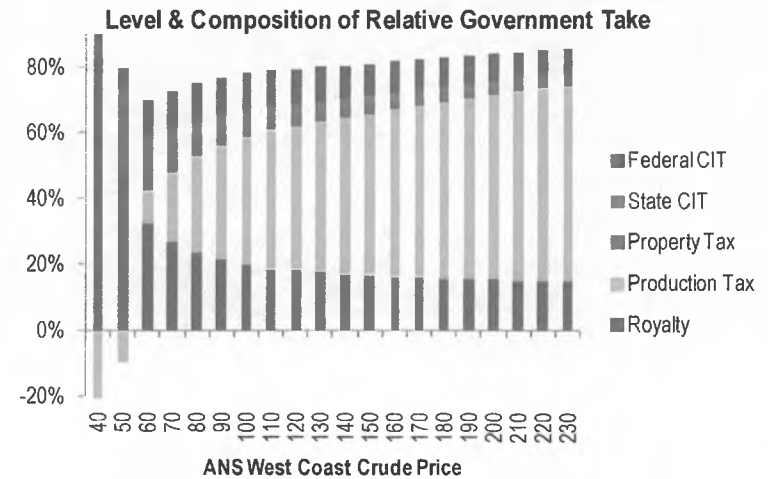
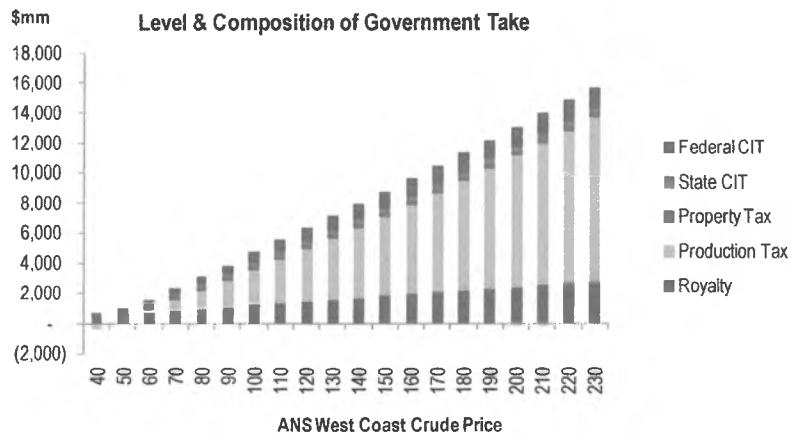
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	8%	12%	4%	56%	16%	72%
50	24%	14%	8%	5%	50%	18%	68%
60	21%	18%	5%	5%	50%	18%	67%
70	19%	24%	4%	4%	51%	17%	69%
80	18%	28%	3%	4%	54%	16%	70%
90	17%	32%	3%	4%	56%	15%	72%
100	17%	35%	3%	4%	58%	15%	73%
110	16%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



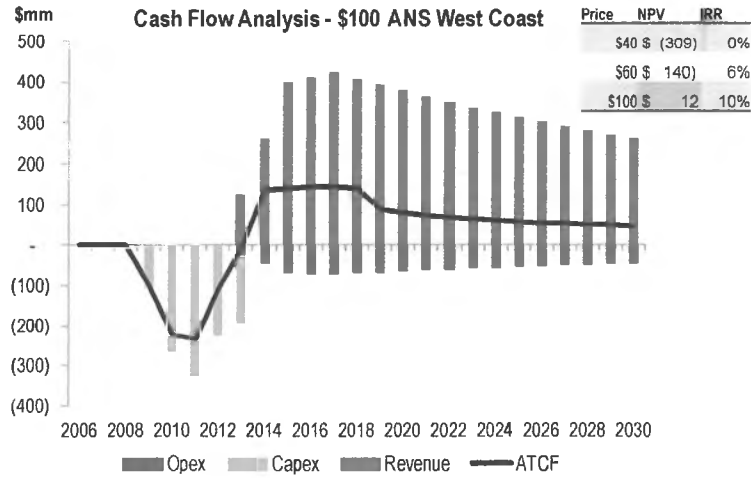
ACES (New Development)



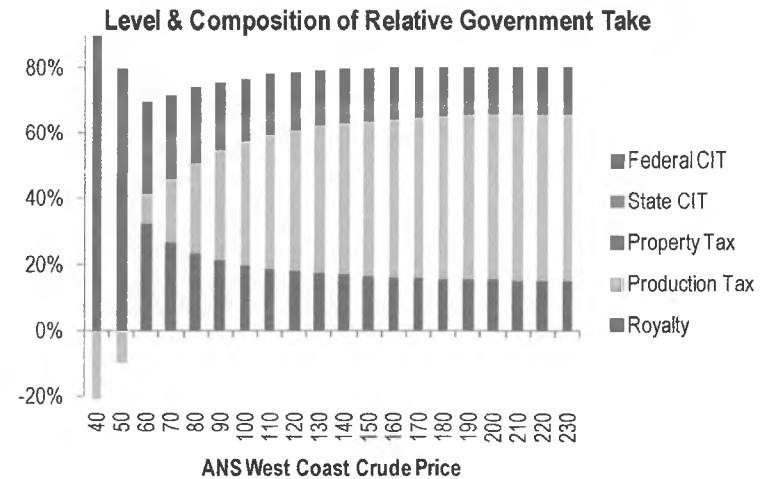
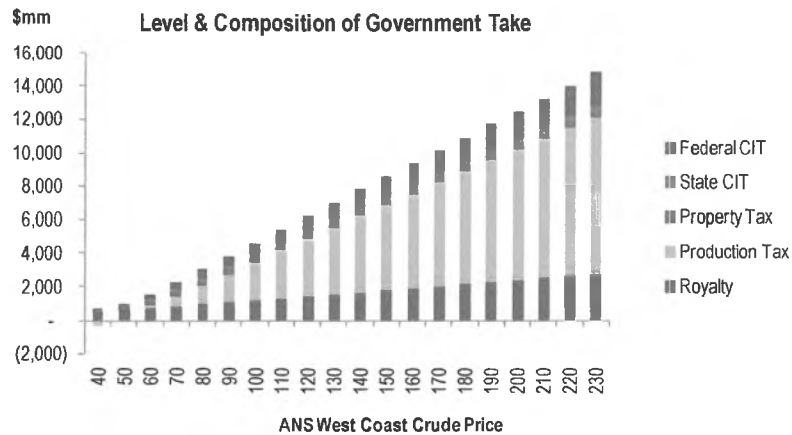
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	162%	-119%	99%	0%	142%	0%	142%
50	48%	-10%	23%	2%	63%	7%	70%
60	32%	10%	13%	3%	58%	11%	70%
70	26%	21%	9%	3%	60%	12%	73%
80	23%	29%	7%	3%	63%	12%	75%
90	21%	35%	6%	3%	65%	12%	77%
100	20%	39%	5%	3%	67%	11%	78%
110	19%	42%	4%	3%	68%	11%	79%
120	18%	44%	4%	3%	69%	11%	80%
130	17%	46%	3%	3%	69%	11%	80%
140	17%	48%	3%	3%	70%	10%	81%
150	17%	49%	3%	3%	71%	10%	81%
160	16%	51%	2%	3%	72%	10%	82%
170	16%	52%	2%	2%	73%	9%	83%
180	16%	54%	2%	2%	74%	9%	83%
190	16%	55%	2%	2%	75%	9%	84%
200	15%	56%	2%	2%	76%	8%	84%
210	15%	57%	2%	2%	76%	8%	85%
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CSSB 192 (New Development)

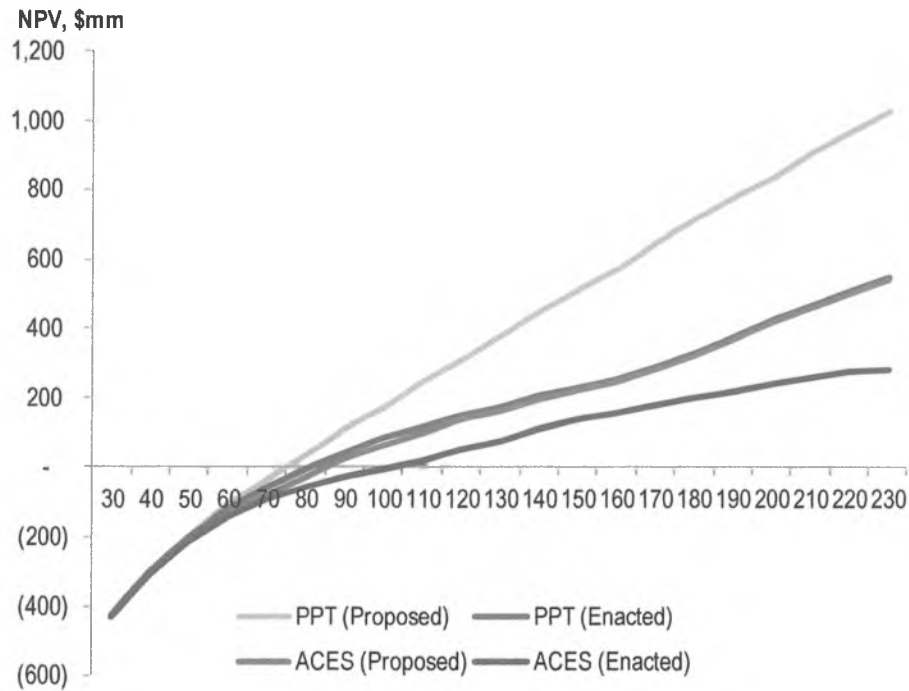


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	162%	-119%	99%	0%	142%	0%	142%
50	48%	-10%	23%	2%	63%	7%	70%
60	32%	9%	13%	3%	58%	12%	69%
70	26%	20%	9%	3%	59%	13%	72%
80	23%	28%	7%	3%	61%	13%	74%
90	21%	33%	6%	3%	63%	12%	76%
100	20%	37%	5%	3%	65%	12%	77%
110	19%	41%	4%	3%	67%	11%	78%
120	18%	43%	4%	3%	68%	11%	79%
130	17%	45%	3%	3%	68%	11%	79%
140	17%	46%	3%	3%	69%	11%	80%
150	17%	47%	3%	3%	69%	11%	80%
160	16%	48%	2%	3%	70%	11%	80%
170	16%	49%	2%	3%	70%	11%	80%
180	16%	49%	2%	3%	70%	10%	80%
190	16%	50%	2%	3%	70%	10%	80%
200	15%	50%	2%	3%	70%	10%	80%
210	15%	50%	2%	3%	70%	10%	80%
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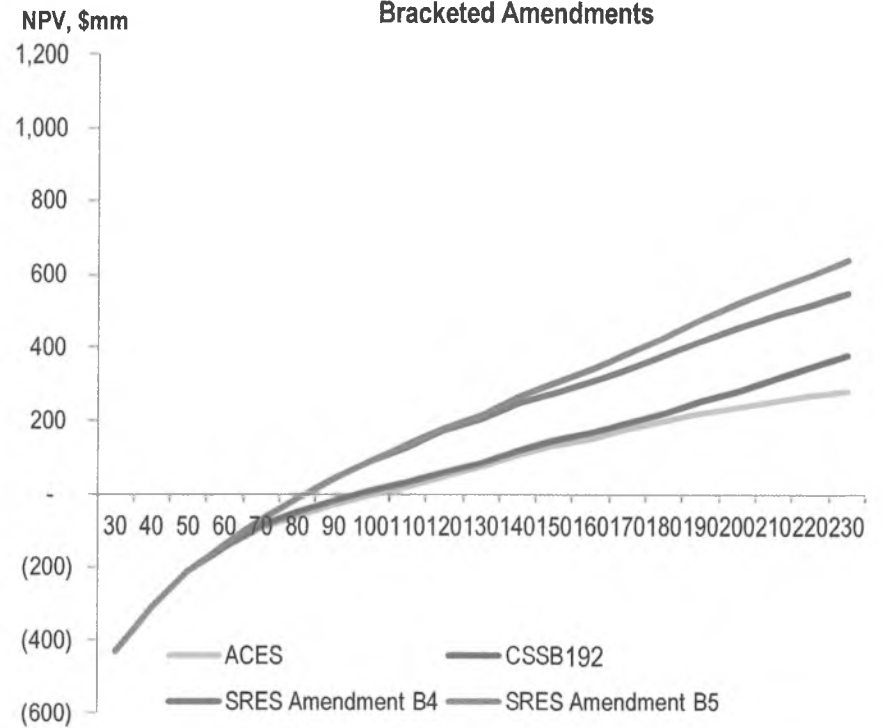


Progressivity Impact on New Development Project Economics

ACES v Predecessor Regimes (Actual & Proposed)

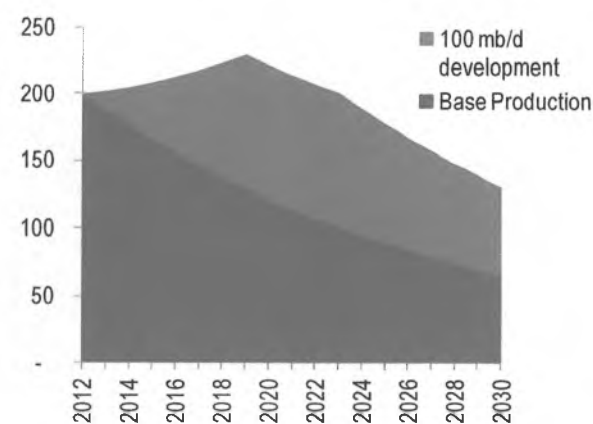
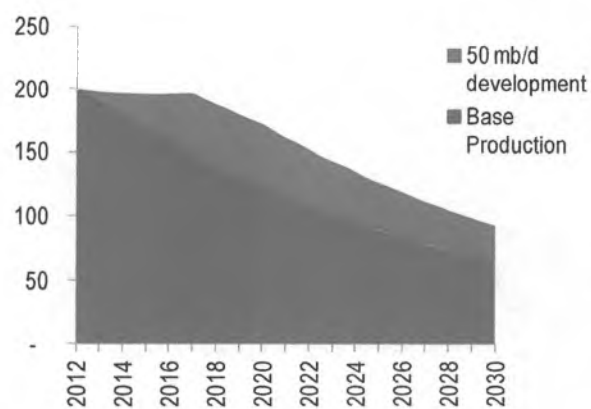
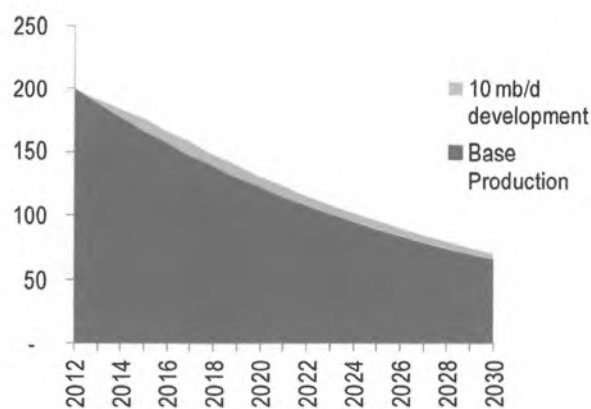


ACES & CSSB 192 v Bracketed Amendments



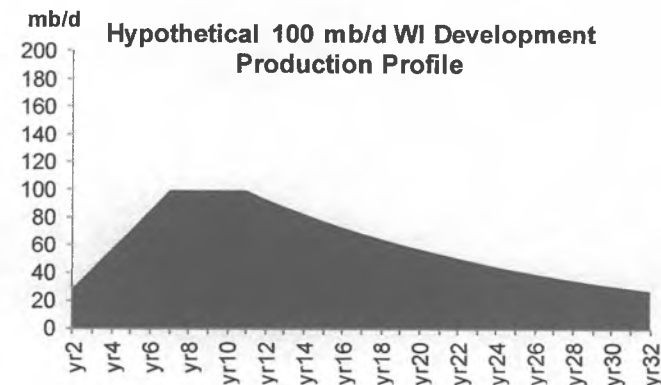
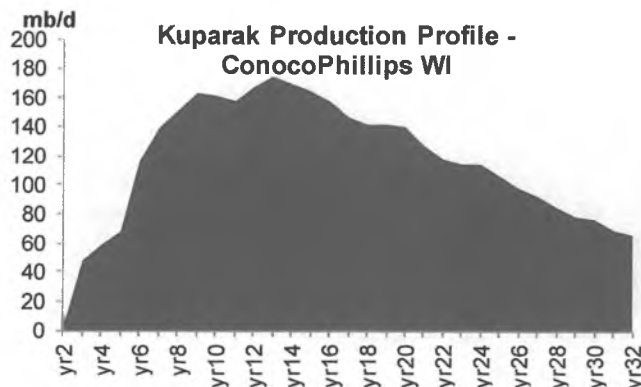
New Oil Allowance: Incremental Production on a Declining Base

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



A Hypothetical 100 mb/d (Working Interest) development

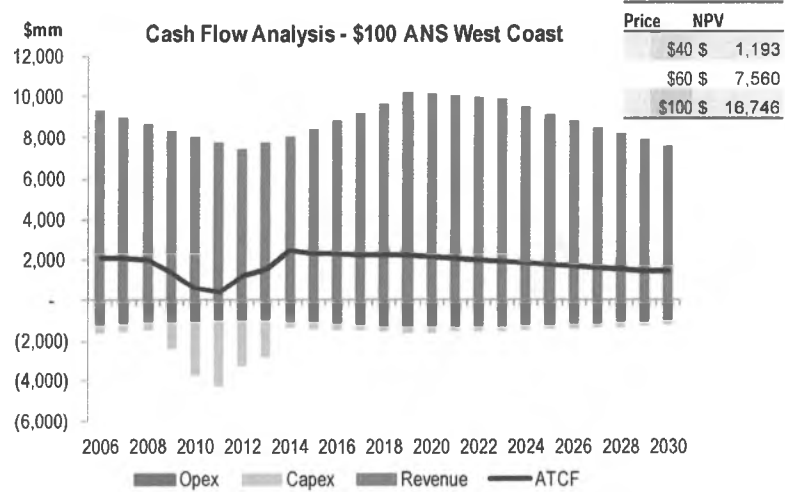
- A new source development that produced 100 mb/d at peak for a working interest partner would be a very significant new development. By way of comparison, Kuparak, the second largest field in North America, peaked at ~320 mb/d gross production
 - This represented **working interest production** to ConocoPhillips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



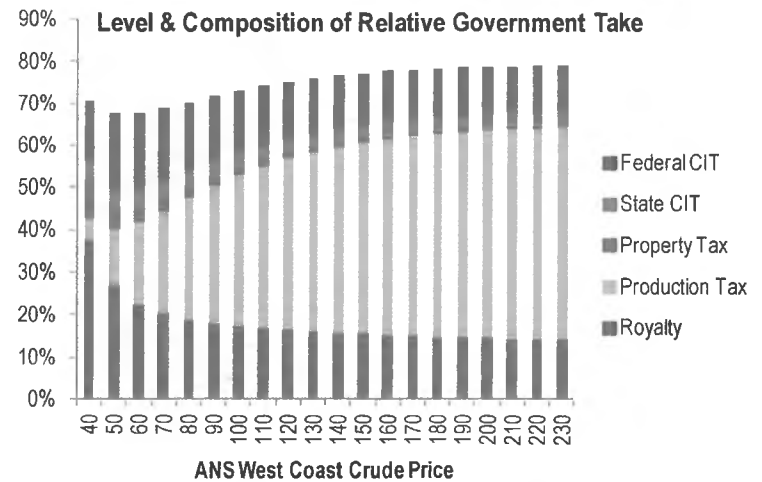
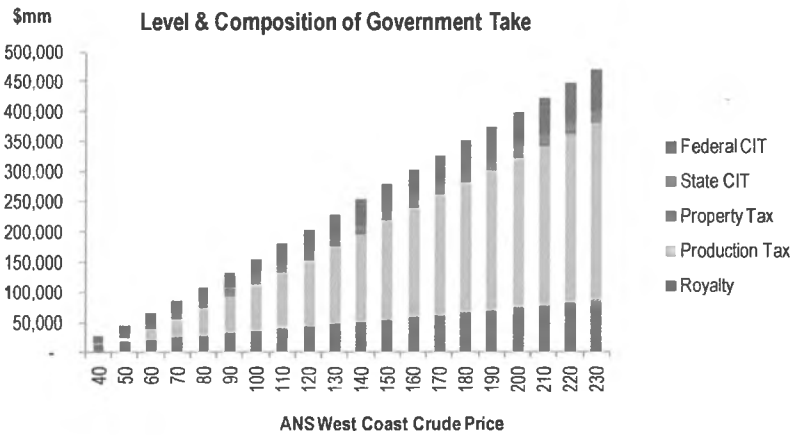
Assumptions

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

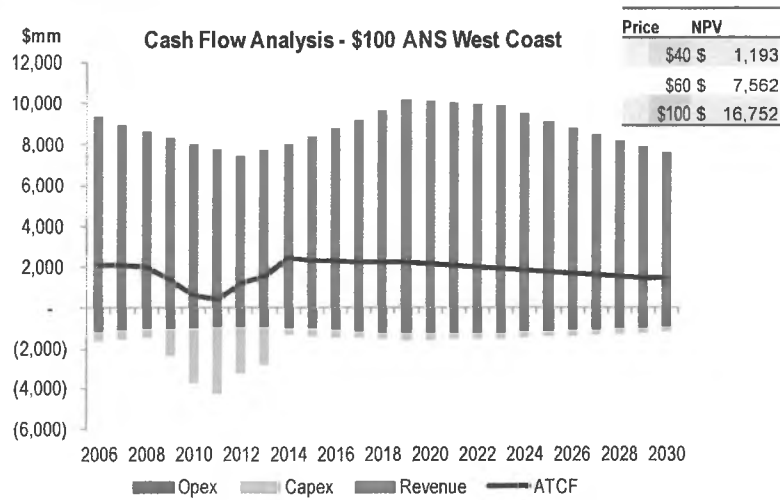
CSSB 192 Excluding New Oil Allowance (Existing Producer)



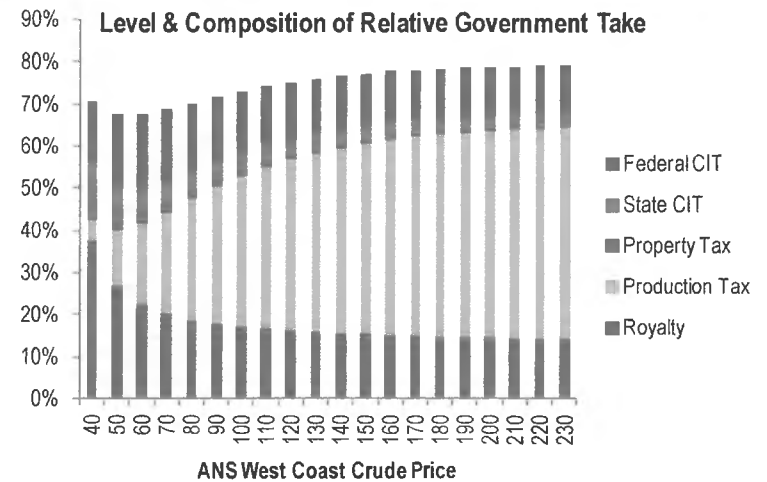
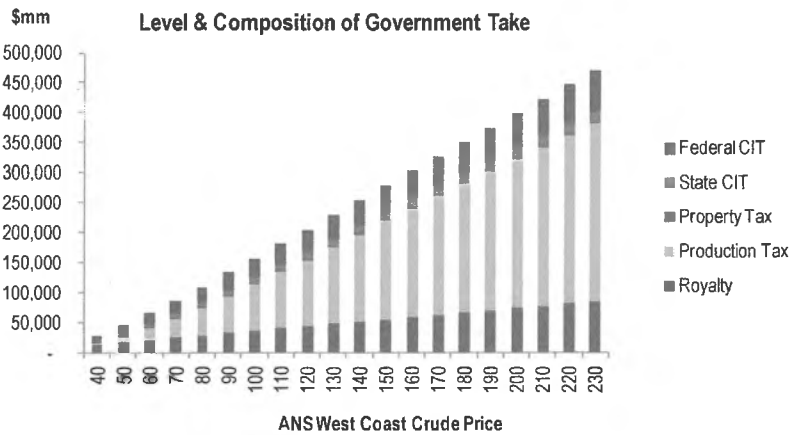
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	38%	5%	9%	4%	56%	15%	71%
50	27%	13%	5%	5%	50%	18%	68%
60	23%	19%	4%	5%	50%	18%	68%
70	20%	24%	3%	4%	52%	17%	69%
80	19%	29%	2%	4%	54%	16%	70%
90	18%	33%	2%	4%	56%	15%	72%
100	17%	36%	2%	4%	58%	15%	73%
110	17%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



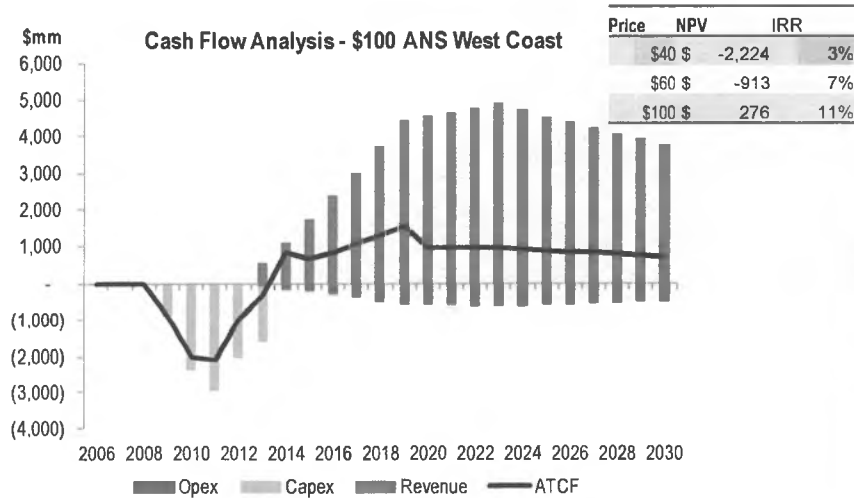
CSSB 192 Including \$10 New Oil Allowance (Existing Producer)



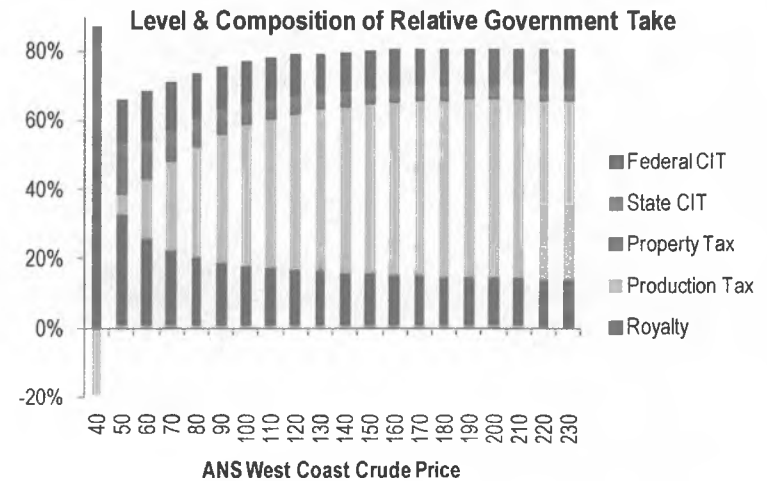
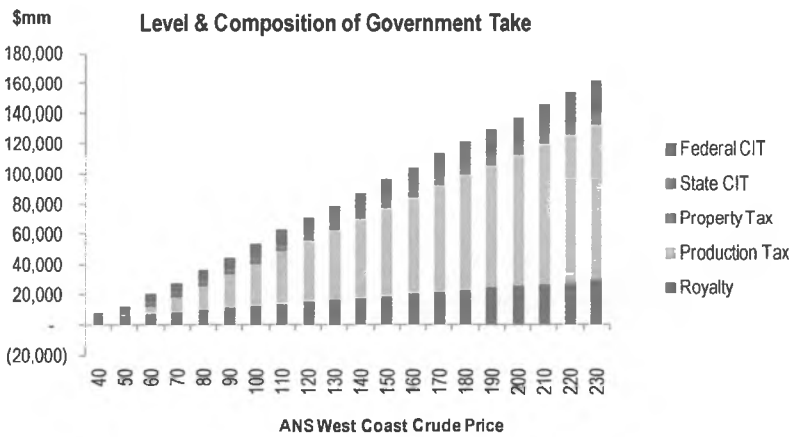
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	27%	13%	5%	5%	50%	18%	68%
60	23%	19%	4%	5%	50%	18%	68%
70	20%	24%	3%	4%	52%	17%	69%
80	19%	29%	2%	4%	54%	16%	70%
90	18%	33%	2%	4%	56%	15%	72%
100	17%	36%	2%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



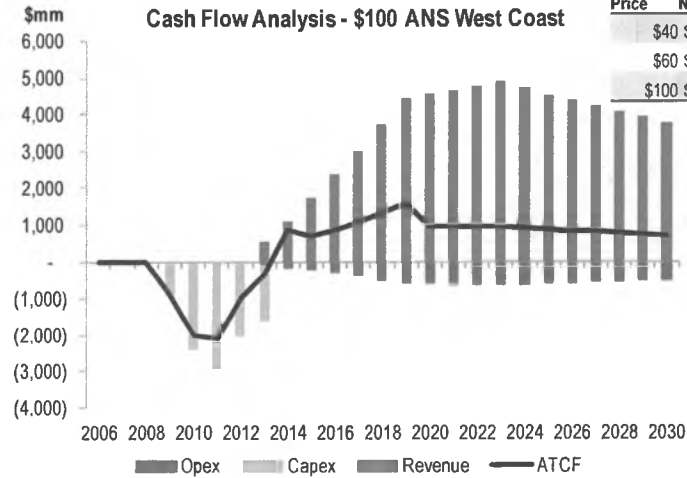
CSSB 192 Excluding New Oil Allowance (New 100 mb/d Development)



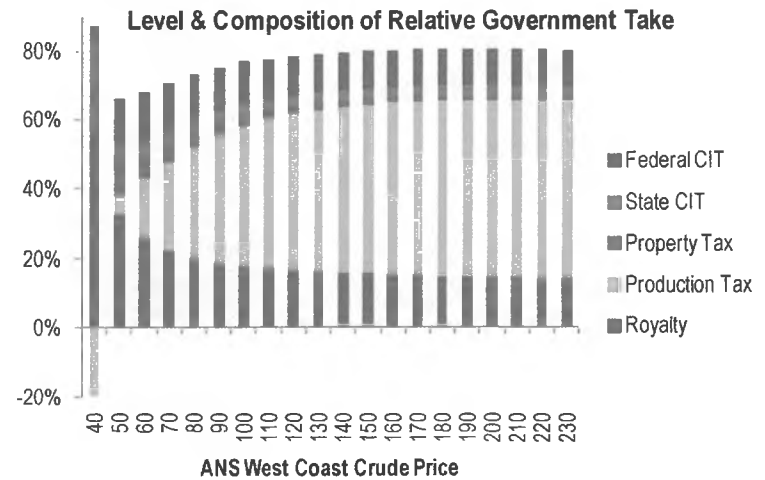
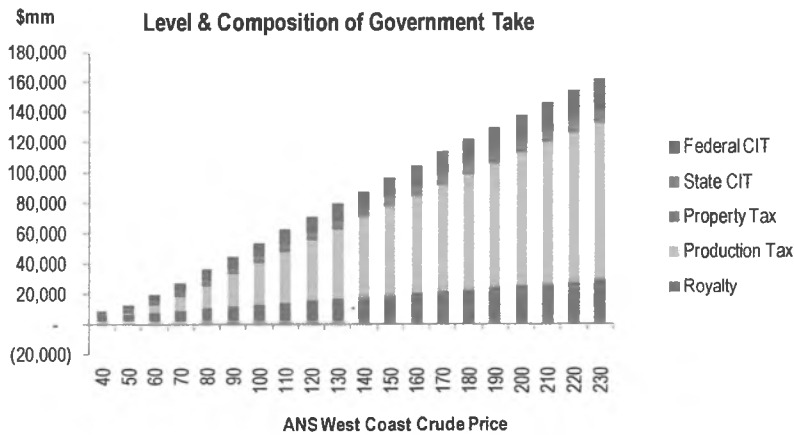
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	33%	5%	12%	3%	54%	13%	66%
60	26%	17%	8%	4%	55%	14%	69%
70	22%	25%	6%	4%	57%	14%	71%
80	20%	32%	5%	3%	60%	13%	74%
90	19%	37%	4%	3%	63%	12%	75%
100	18%	40%	3%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



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



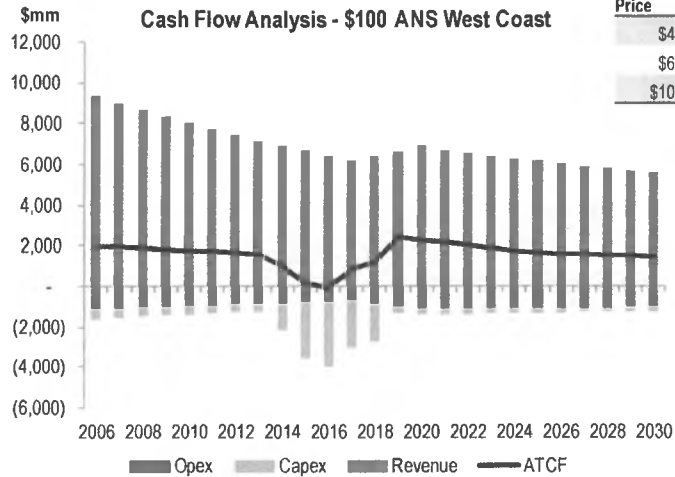
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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60	26%	17%	8%	4%	54%	14%	68%
70	22%	25%	6%	4%	57%	14%	71%
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130	16%	46%	2%	3%	68%	11%	79%
140	16%	48%	2%	3%	69%	11%	80%
150	16%	49%	2%	3%	69%	11%	80%
160	16%	49%	2%	3%	69%	11%	80%
170	15%	50%	2%	3%	70%	11%	80%
180	15%	50%	2%	3%	70%	11%	80%
190	15%	51%	1%	3%	70%	11%	80%
200	15%	51%	1%	3%	70%	11%	81%
210	15%	51%	1%	3%	70%	11%	81%
220	15%	51%	1%	3%	70%	11%	80%
230	14%	51%	1%	3%	70%	11%	80%



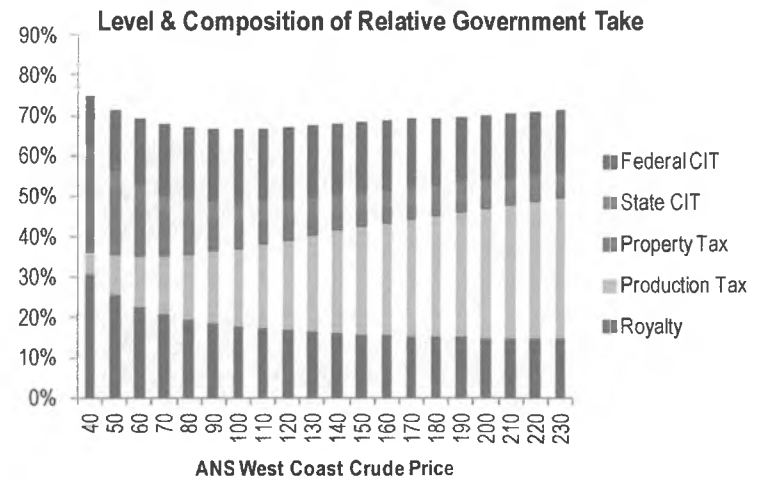
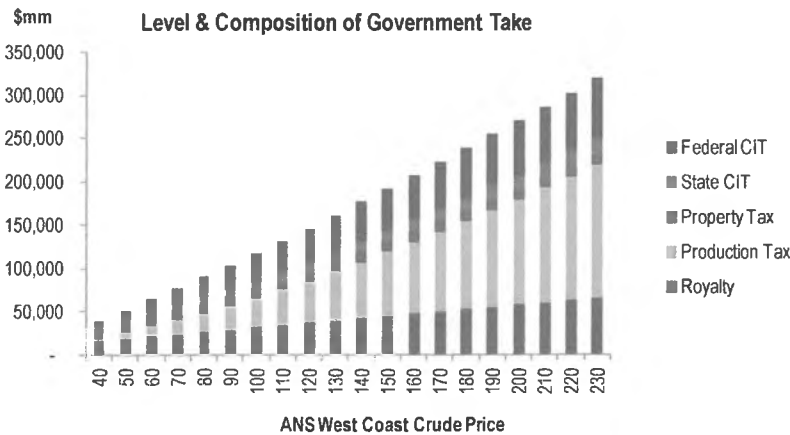
Oil / Gas Decoupling

- Under ACES, production tax value is assessed on a combined BTU-equivalent basis for both oil and gas production
 - So long as no major gas export project is under development, this has no impact
 - In the event of the development of a major gas export project, however, when gas prices are significantly lower than oil prices, this could lead to significant reductions in Government Take
- CSSB 192 includes a provision to de-couple the calculation of production tax value on North Slope gas sold out-of-state, in order to eliminate this impact of gas production
 - The impact of the decreased government take without decoupling is only pronounced with very low gas prices, and very large gas production
 - In order to illustrate the impact at the extreme, the following analysis thus assumes a \$1/mcf net-back sale price for North Slope gas, and a 2018 1bcf/d gas project. Under less extreme scenarios, the difference with and without decoupling would be significantly less

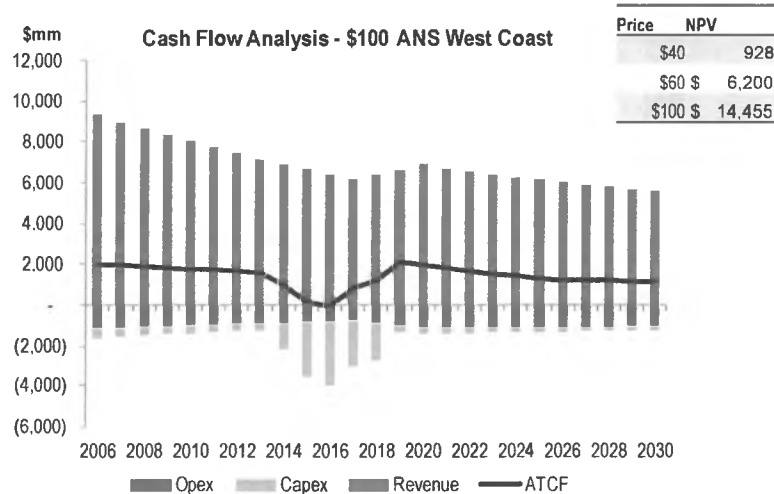
CSSB 192 – Existing Producer with 2018 Gas Project, No Decoupling



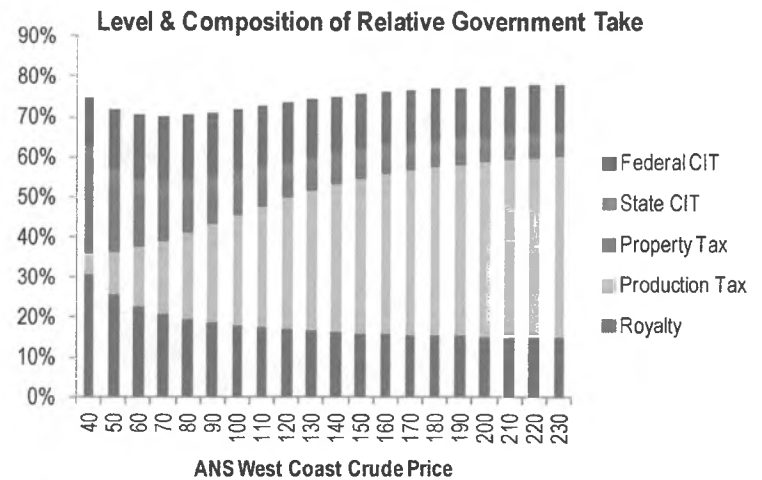
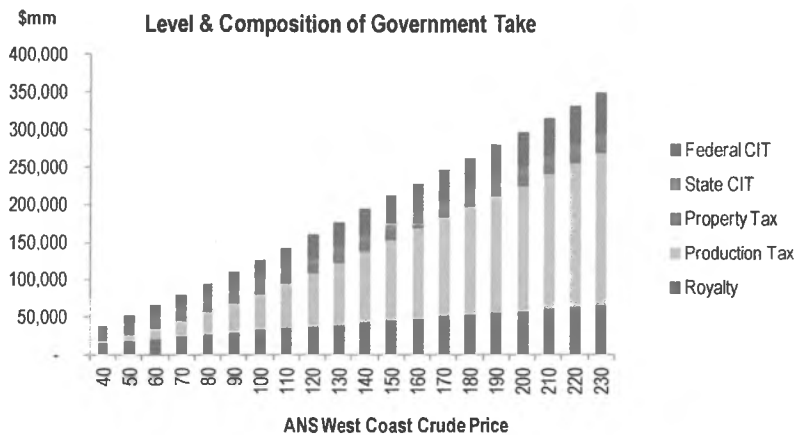
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80	19%	16%	9%	5%	49%	18%	67%
90	19%	18%	8%	5%	49%	18%	67%
100	18%	19%	7%	5%	49%	18%	67%
110	17%	21%	6%	5%	49%	18%	67%
120	17%	22%	6%	5%	49%	18%	67%
130	16%	24%	5%	5%	50%	18%	67%
140	16%	25%	5%	5%	51%	17%	68%
150	16%	26%	4%	4%	51%	17%	68%
160	16%	28%	4%	4%	52%	17%	69%
170	15%	29%	4%	4%	52%	17%	69%
180	15%	30%	4%	4%	53%	17%	69%
190	15%	31%	3%	4%	53%	16%	70%
200	15%	32%	3%	4%	54%	16%	70%
210	15%	33%	3%	4%	55%	16%	71%
220	15%	34%	3%	4%	55%	16%	71%
230	15%	35%	3%	4%	56%	15%	71%



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

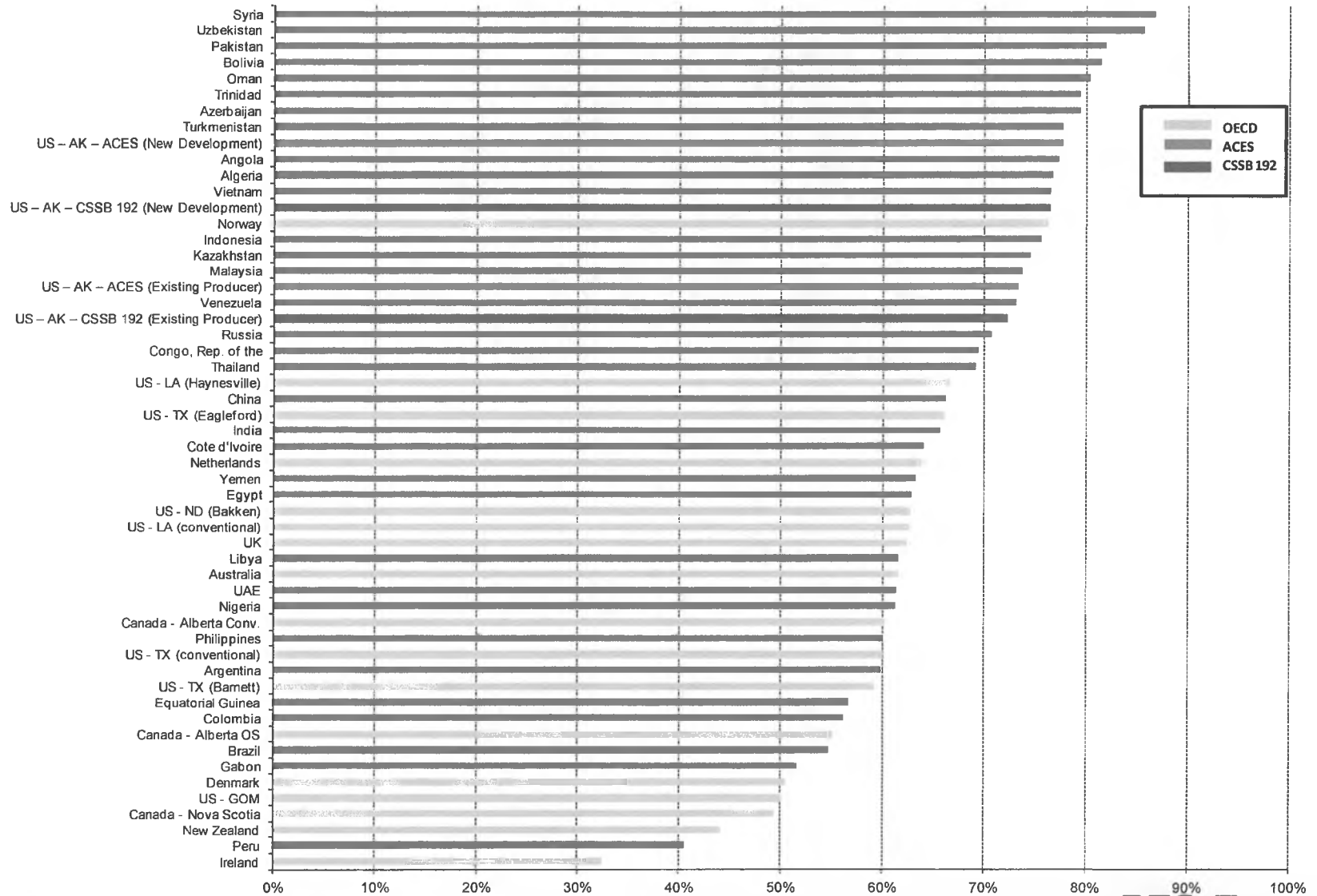


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total CIT
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190	15%	43%	3%	3%	65%	12%	77%
200	15%	44%	3%	3%	65%	12%	77%
210	15%	44%	3%	3%	65%	12%	78%
220	15%	45%	3%	3%	66%	12%	78%
230	15%	46%	3%	3%	66%	12%	78%



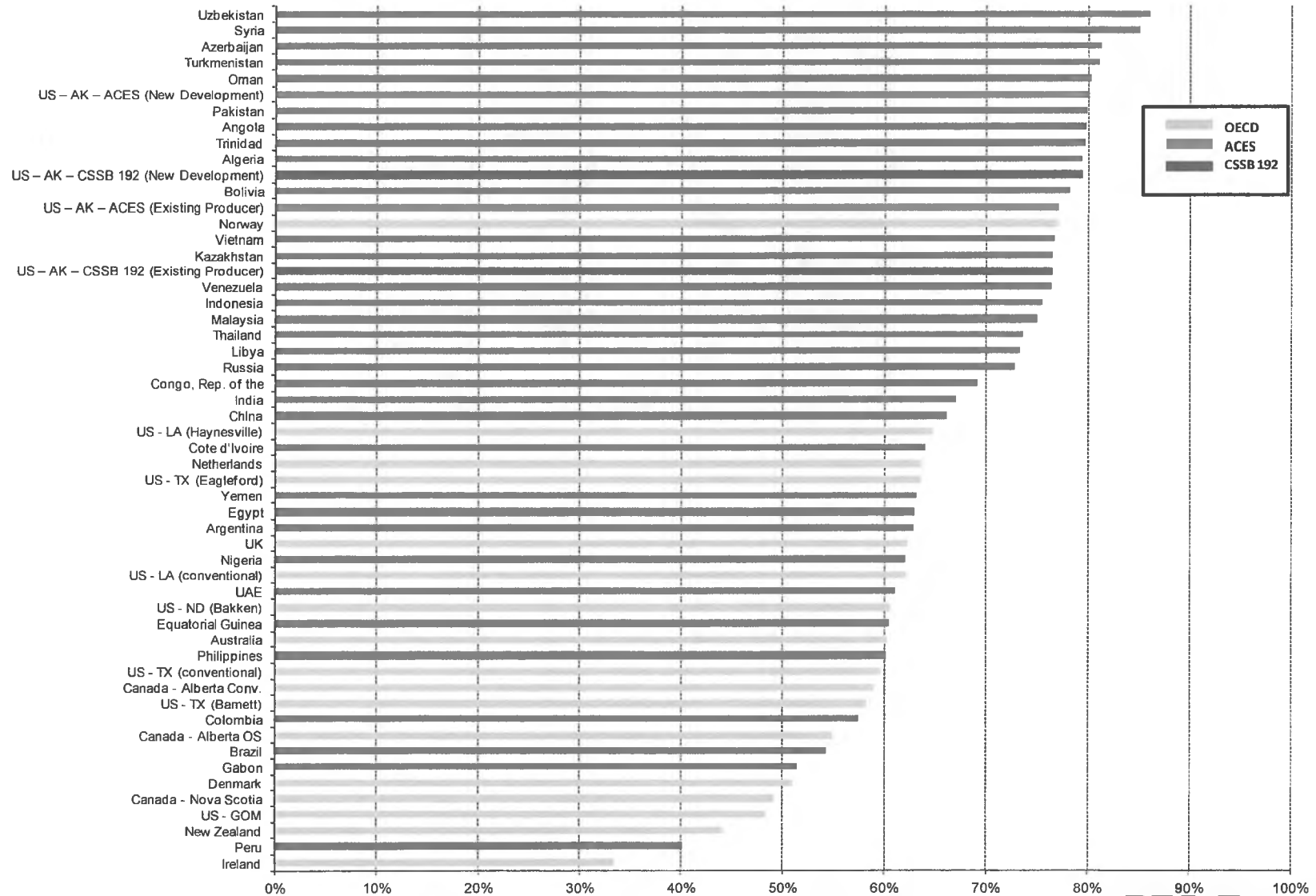
Regime Competitiveness: Relative Government Take

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



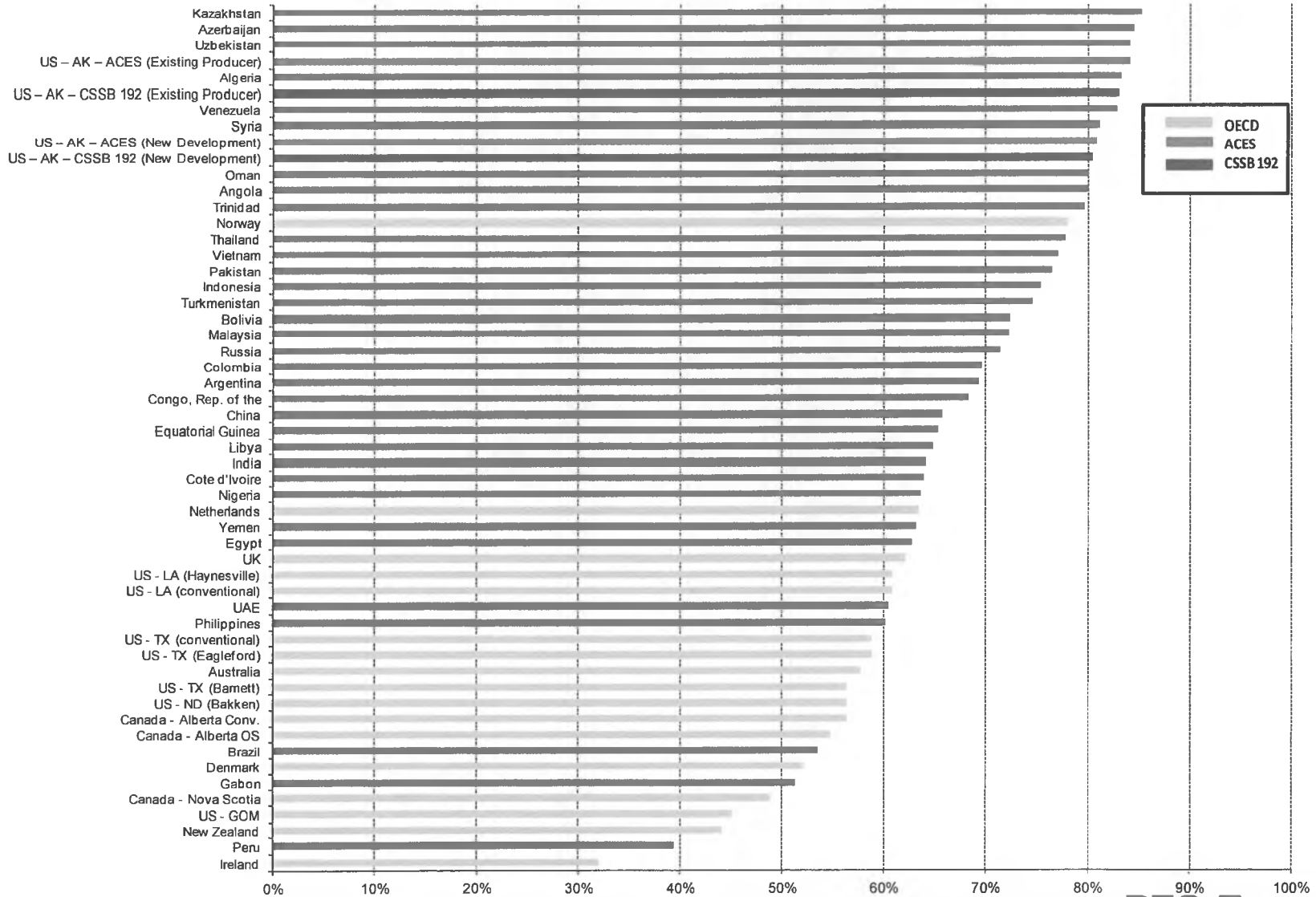
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$140/bbl



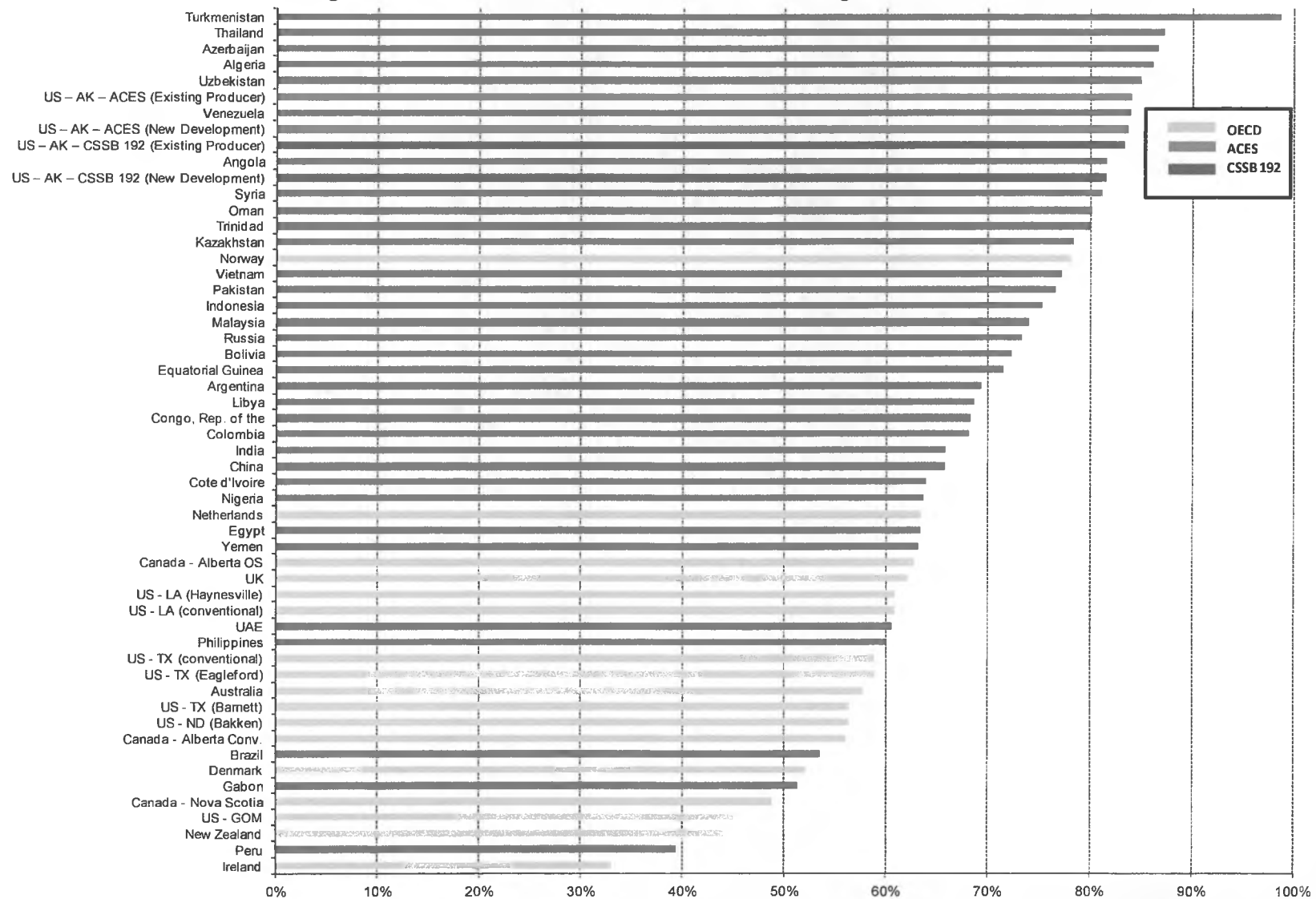
Regime Competitiveness: Relative Government Take

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



Regime Competitiveness: Relative Government Take

Marginal Government Take of Global Fiscal Regimes at \$140/bbl

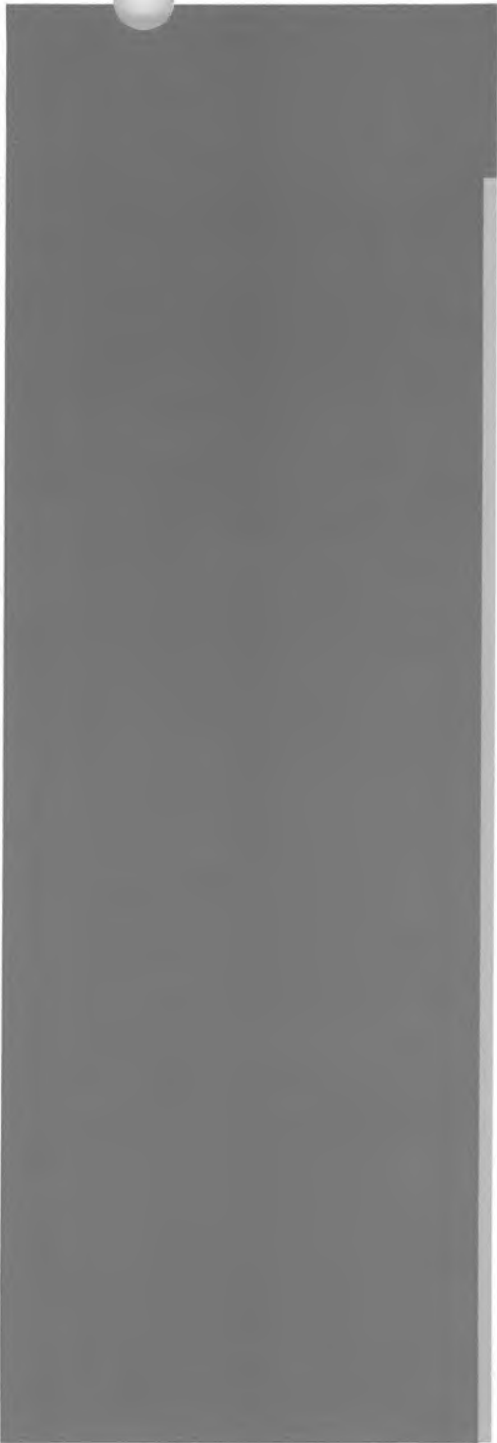


Conclusions – Changes to Progressivity, Overall Government Take, and Oil/Gas Decoupling

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

Conclusions – New Oil Allowance

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



**Global Strategy & Portfolio
Overview of Major Alaska
Producers**

BP: Company Overview

Strategic Signature

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

Company Overview

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

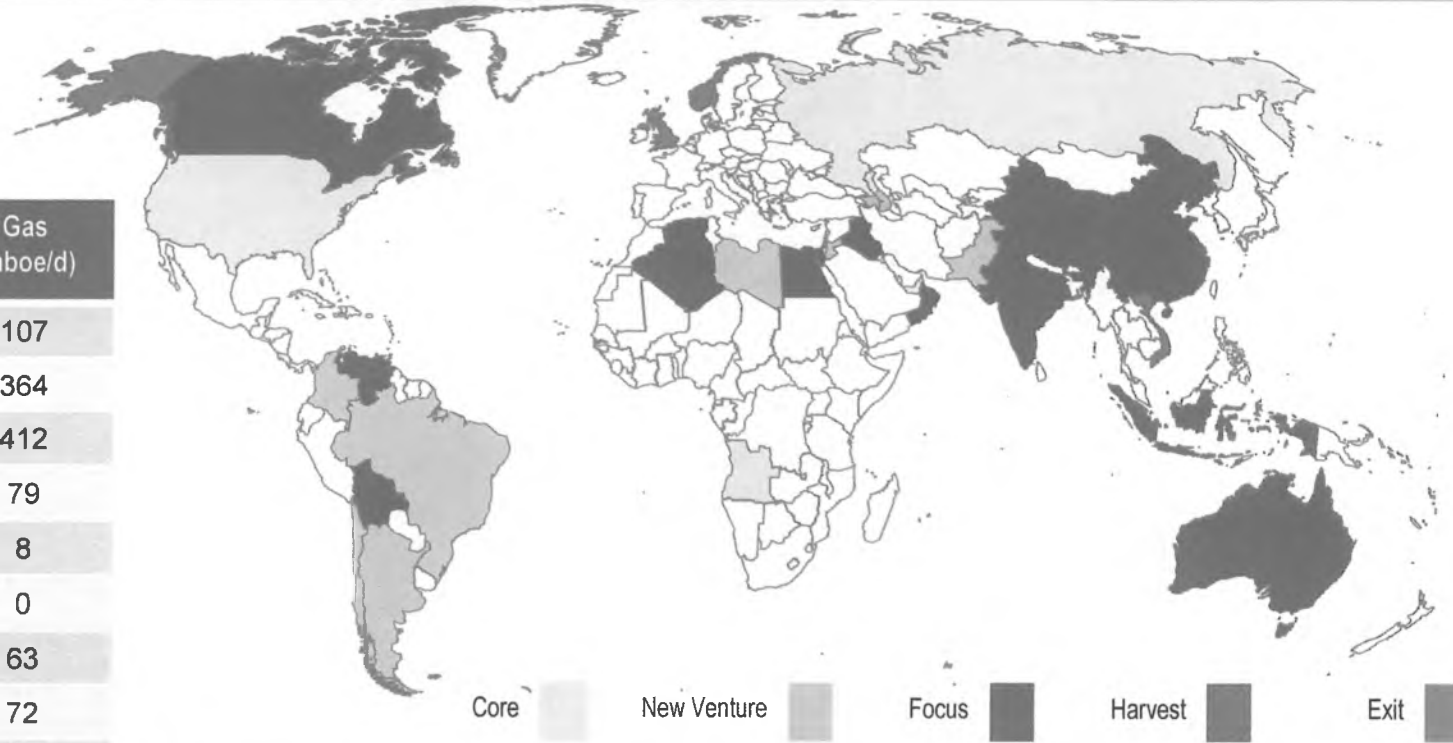
Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconventionals	Oil Sands	LNG
✓	✓	✓	✓	✓	✓

Partnership History

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

BP: Global Areas of Upstream Operations



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

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

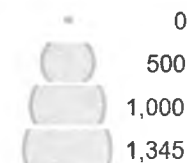
	Liquids (mboe/d)	Gas (mboe/d)
Iraq	0	0
Oman	0	0
Jordan	0	0
Libya	0	0
India	0	0

BP Global Production Portfolio - 2010

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

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

mboe/d



Asset Type

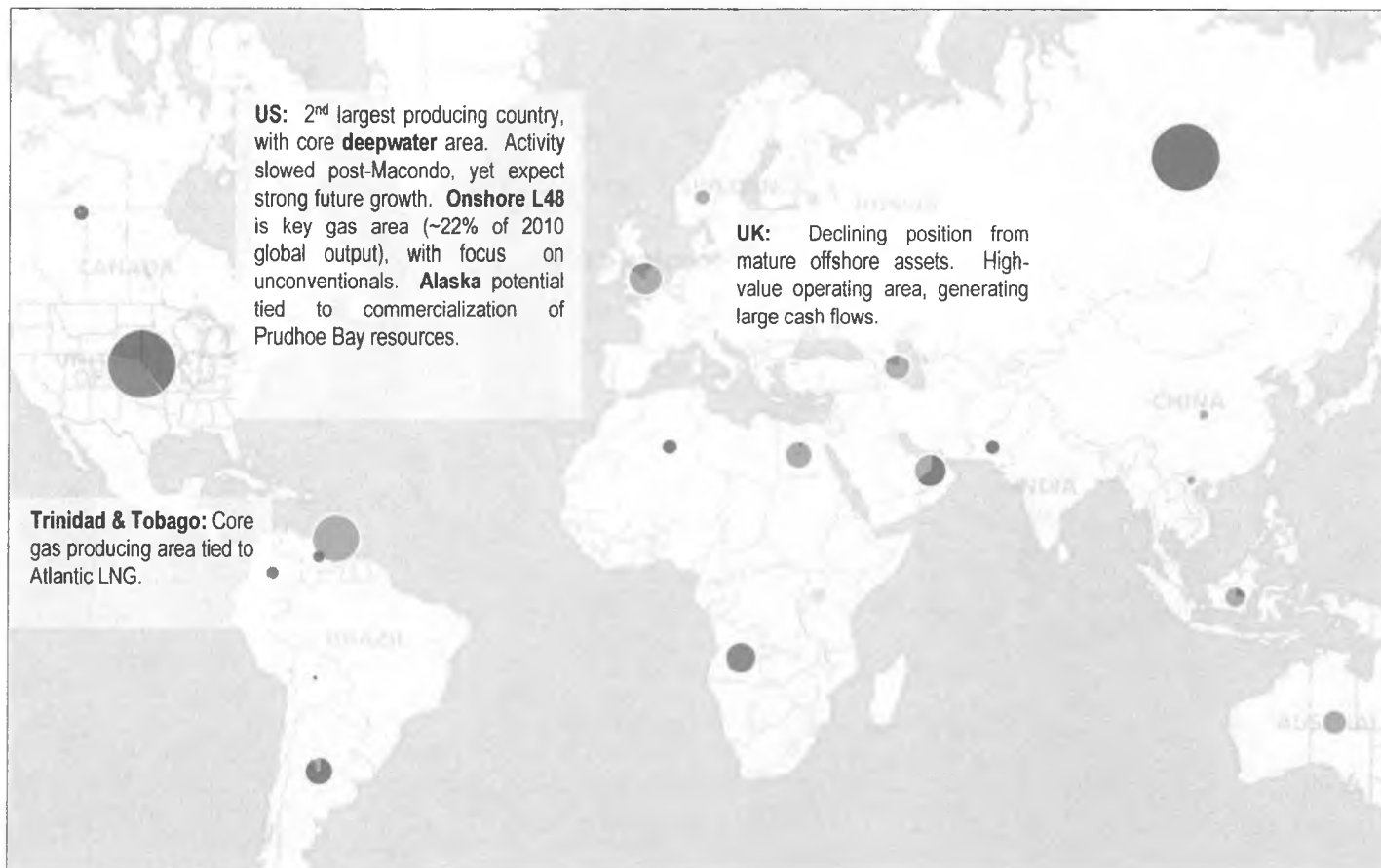


Azerbaijan: Participation in 2 large-scale projects: Azeri-Chirag-Guneshli & Shah Deniz.

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

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

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



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

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

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

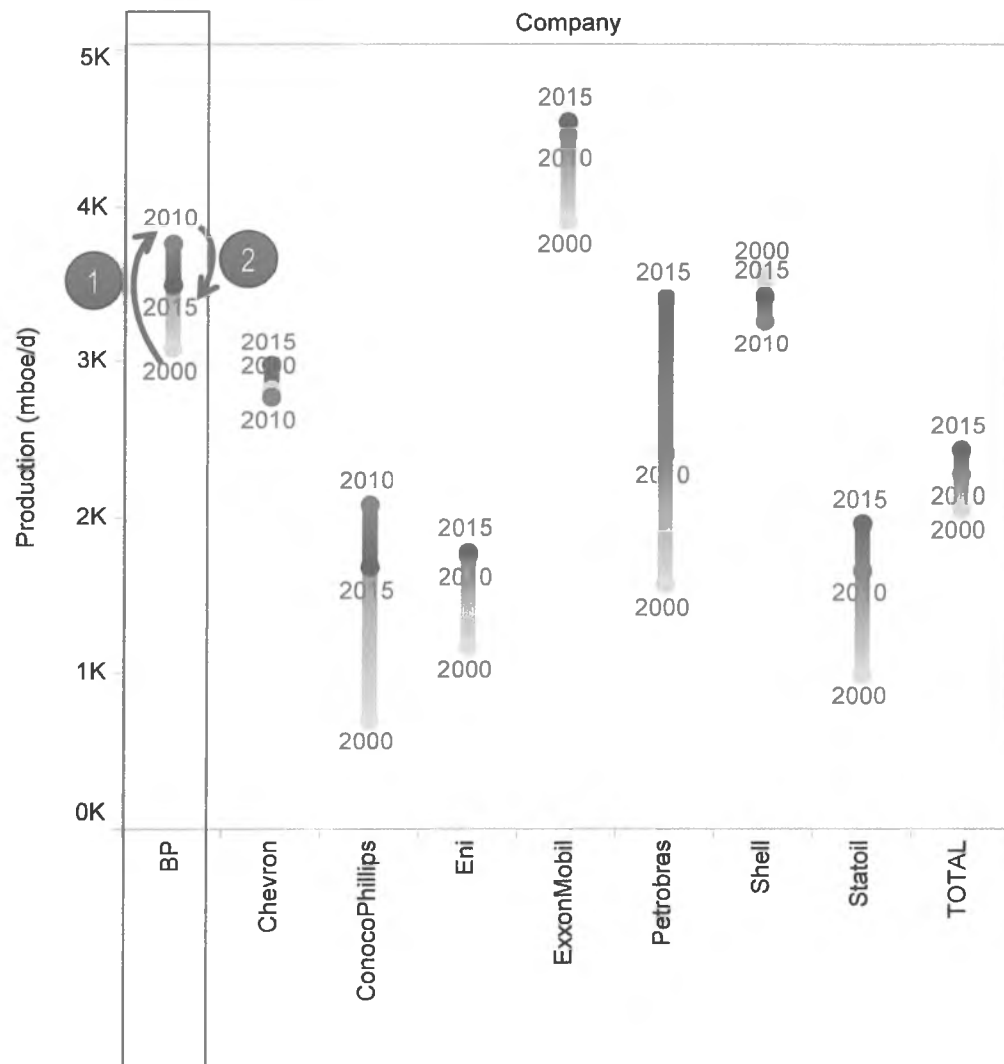
Argentina: onshore & shallow water assets (held by PAE) were to be sold to Bidas, but transaction failed in 4Q:11.

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

Iraq: Development of Rumailia oil field

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

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



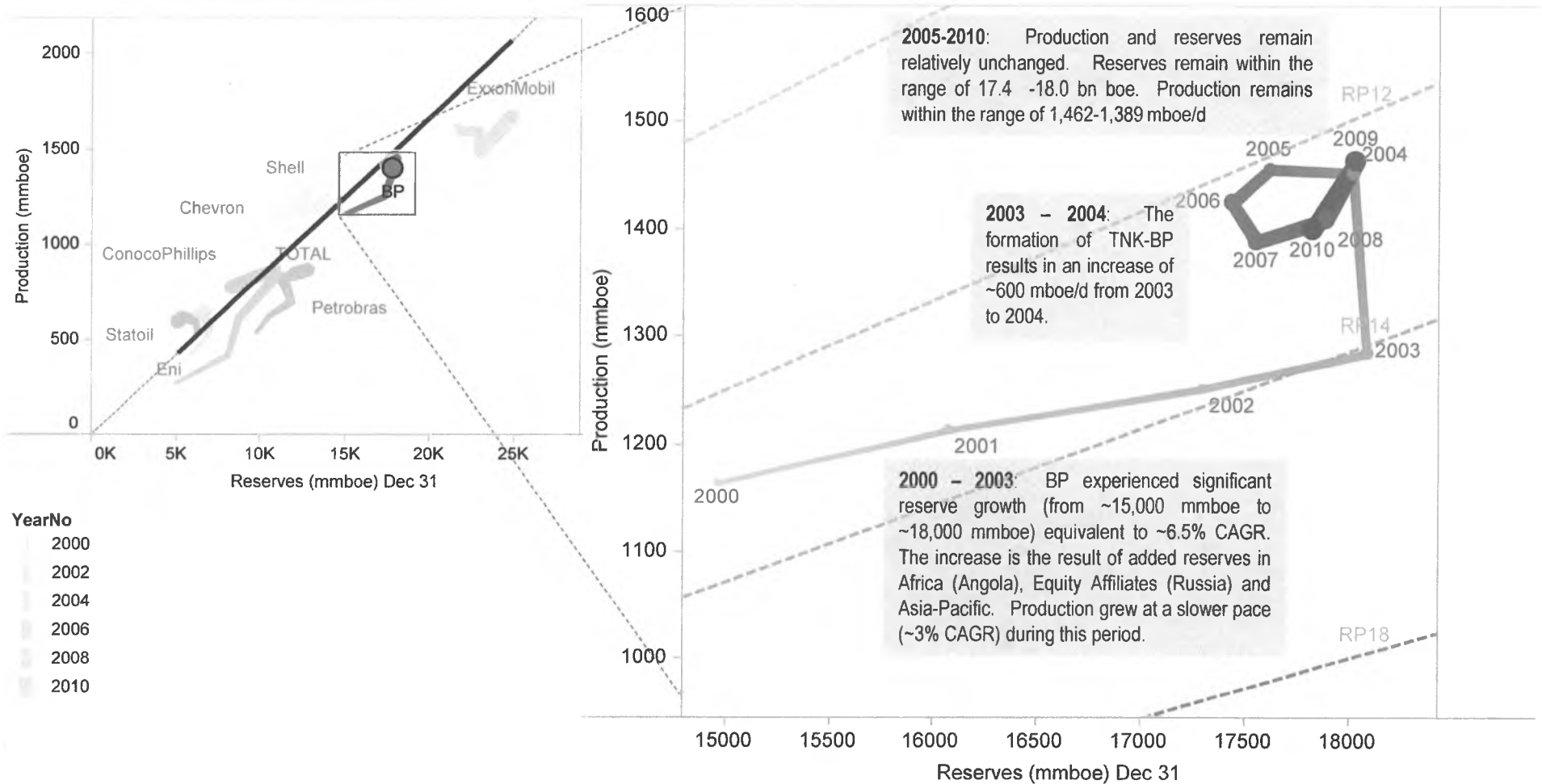
In 2010, BP was the second largest producer of the peer group. Yet, from 2010 to 2015, BP and COP are the only two companies to experience a reduction.

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

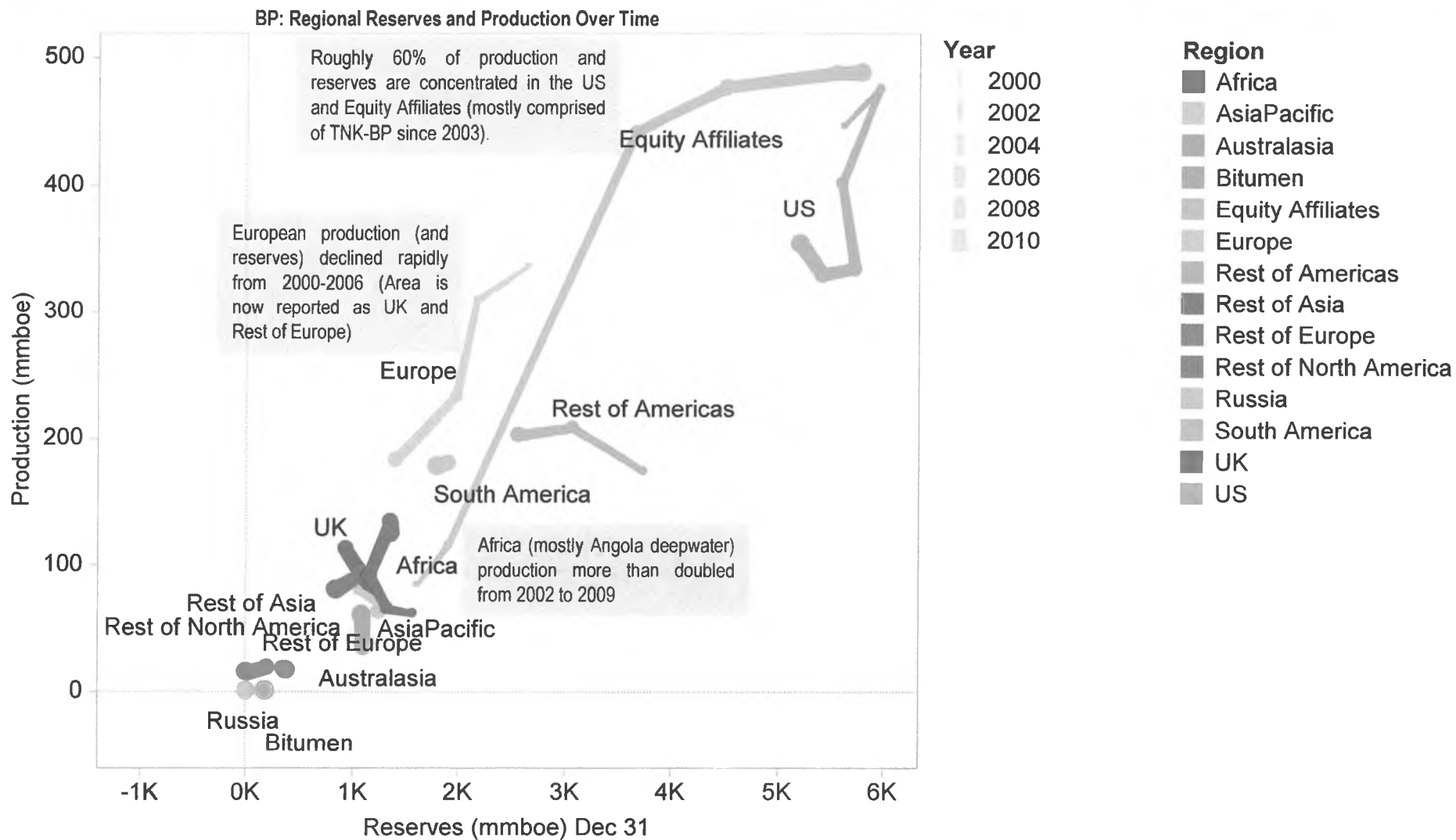
2 **2011-2015:** BP's production is expected to decline from 2000-2015, due mostly to the post-Macondo asset divestiture program, combined with curbed activity in the GOM deepwater.

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

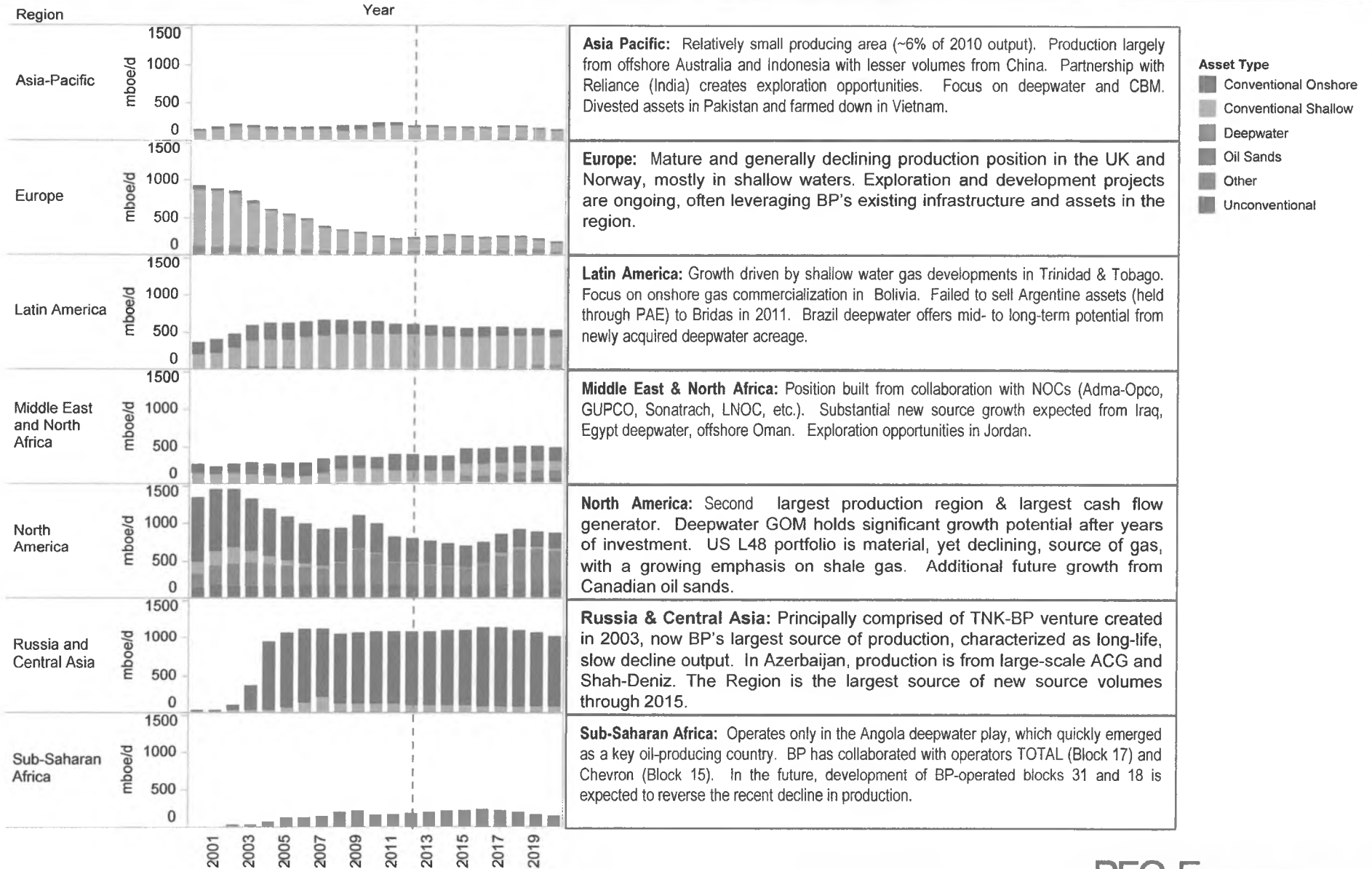
Reserves and Production (mmboe) 2000-2010: BP and Peers



Reserves and Production: BP Intra-Portfolio Performance



Global Production: Evolution of the Portfolio



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

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

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

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

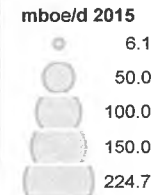
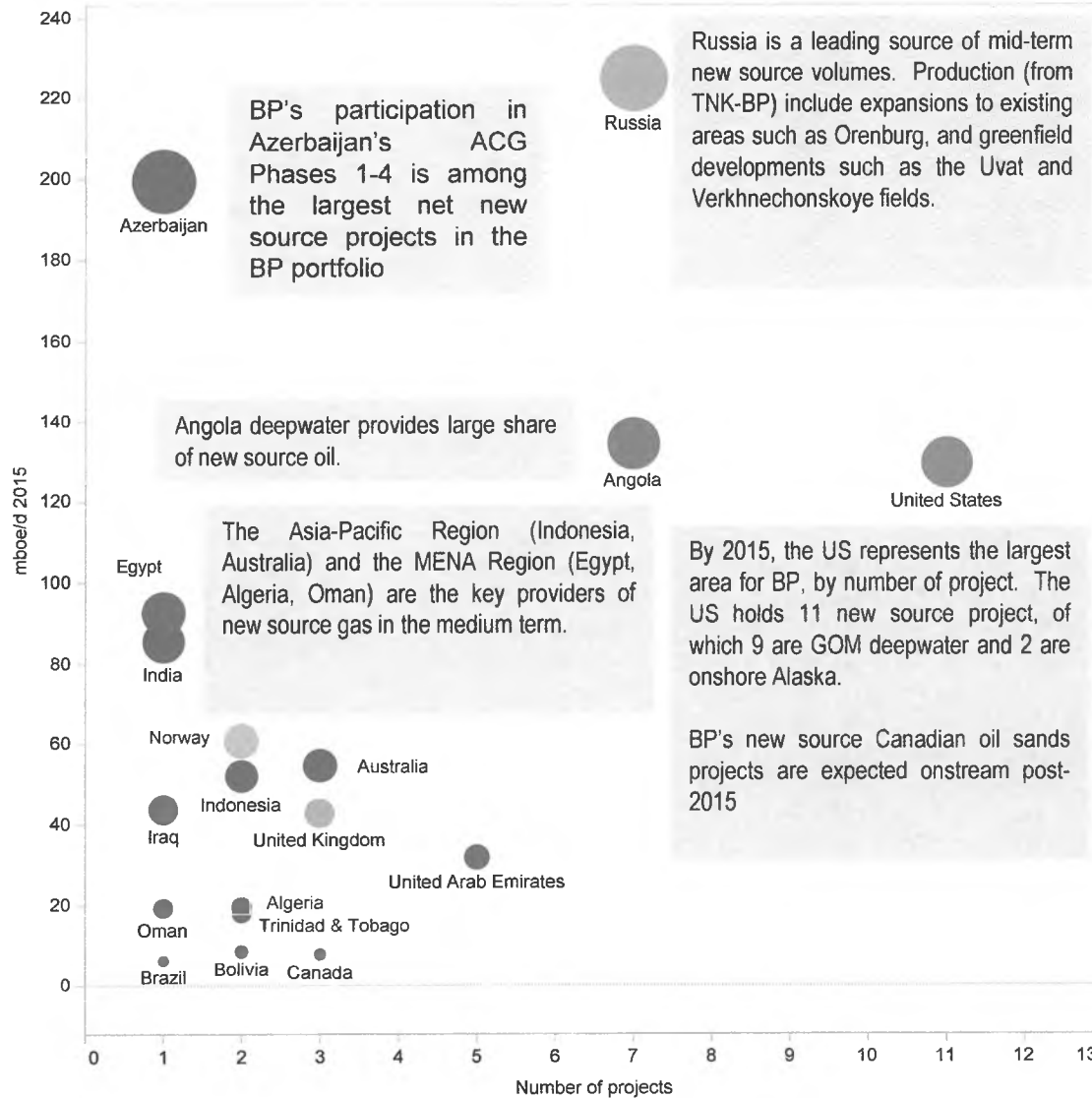
North America: Second largest production region & largest cash flow generator. Deepwater GOM holds significant growth potential after years of investment. US L48 portfolio is material, yet declining, source of gas, with a growing emphasis on shale gas. Additional future growth from Canadian oil sands.

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

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

Global Production: Country Growth Project Analysis

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



BP's participation in Azerbaijan's ACG Phases 1-4 is among the largest net new source projects in the BP portfolio

Russia is a leading source of mid-term new source volumes. Production (from TNK-BP) include expansions to existing areas such as Orenburg, and greenfield developments such as the Uvat and Verkhnechonskoye fields.

Angola deepwater provides large share of new source oil.

The Asia-Pacific Region (Indonesia, Australia) and the MENA Region (Egypt, Algeria, Oman) are the key providers of new source gas in the medium term.

By 2015, the US represents the largest area for BP, by number of project. The US holds 11 new source project, of which 9 are GOM deepwater and 2 are onshore Alaska.

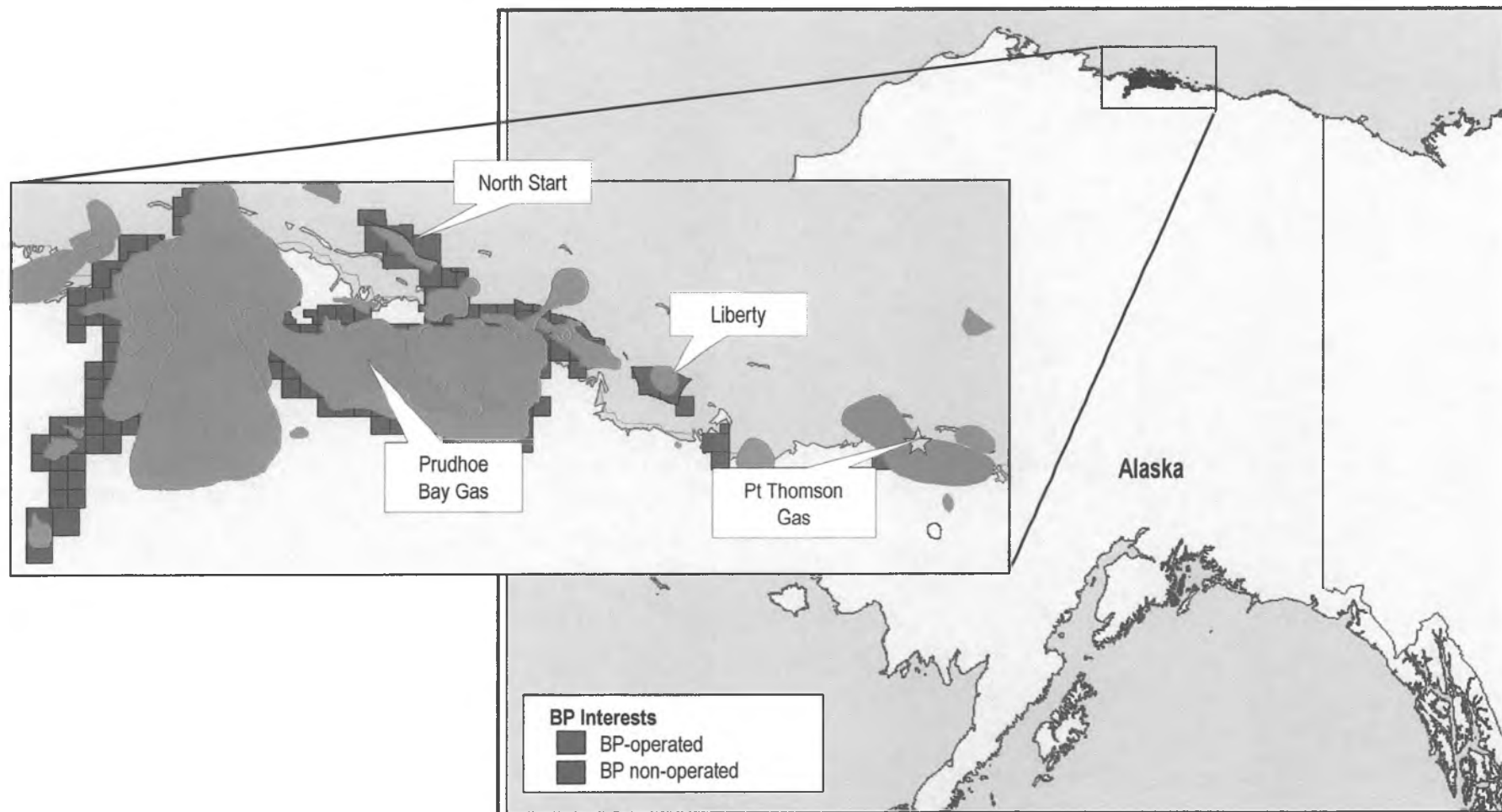
BP's new source Canadian oil sands projects are expected onstream post-2015

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

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

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

BP in Alaska



BP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
<p>Harvest Area</p>	<ul style="list-style-type: none"> • Most of BP's assets are located on the North Slope, where production volumes have generally declined because of the maturity of the asset base and/or gas infrastructure constraints. Liquid production has declined from ~224 mboe/d in 2006 to ~166 mboe/d in 2010, while gas production has fallen from ~67 mmcf/d to ~46 mmcf/d over the same period. • BP's largest source of production is the Greater Prudhoe Area (26% w.i., operated), covering ~150,000 acres with more than 1,000 active wells. Gas resources are currently stranded because of the lack of pipeline capacity to southern markets. BP and ConocoPhillips had teamed up to propose a new natural gas pipeline (Denali) to run from Prudhoe Bay through western Canada to US markets. However, in May 2011, the partners announced that plans for the pipeline had been terminated, citing the lack of long-term purchase contracts. The proposed pipeline would have accommodated 4 bcf/d of natural gas. • BP and partners are moving forward with the development of gas liquids on the ~8 tcf Point Thomson field (32% w.i., non-operator). The gas cycling project is expected to produce ~10 mb/d of liquids; first production is targeted for 2014. Full field development awaits gas transport infrastructure. • In the Beaufort Sea, BP has suspended work on the extended-reach drilling program on the Liberty oil field (100% w.i.), pending revision of project design and schedule. • BP is also seeking to develop viscous (Kuparuk) and heavy (Milne) oil resources on the North Slope. 	<p>Current production volumes are modest and declining, yet significant potential lies in the long-term commercialization of Prudhoe Bay and Point Thomson gas resources. Cancellation of the Denali gas pipeline proposal leaves BP as a potential supplier to an alternative pipeline-export option, should one be approved and developed.</p>

PFC-Identified Challenges

- Re-establish its operator profile in the global deepwater: While its competitors extend their commitments to global LNG, unconventional shale gas exploitation, and oil sands development in order to drive future portfolio growth, BP has deepened its commitment to the global deepwater play, despite the ongoing fallout from the Macondo oil spill. Expansion of its US GOM lease holdings (through the Devon portfolio acquisition), entry into the Brazil deepwater, and a material commitment to the K-G Basin deepwater play in India, together with phased field development offshore Angola and West Nile Delta in Egypt, positions BP as arguably the premier deepwater player in the Global Player peer group. BP will be under the spotlight regarding its future conduct and performance throughout the global deepwater basins.
- Resolve shareholder relationship issues within the TNK-BP JV: Accounting for ~26% of total worldwide production in 2010 (and ~36% of total worldwide oil production), the TNK-BP position is absolutely core to the BP portfolio from a volumetric perspective. However, the unsuccessful attempt to partner with Rosneft in the Russia Arctic raises concern over how much value TNK-BP can continue to create for BP. With TNK-BP now focused on international expansion, must BP settle for lower returns from what has until now been a highly lucrative position?
- Complete the portfolio rationalization process: The strength of the global asset transactions market prompted BP to expand its divestiture program from an initial \$20 bn to \$30 bn, divesting large swaths of its portfolio deemed non-Core and/or non-aligned with the company's growth focus. While the company did not plan on the depth of portfolio rationalization undertaken to date, this is a rare opportunity to high-grade asset holdings with the blessing of shareholders and analysts alike. BP is expecting to complete the divestiture process by end-2011.
- Determine a path forward in the Brazil deepwater: Having secured Brazil government approval to acquire the Devon asset portfolio, BP has established a foothold in the Brazil deepwater, with potentially the largest operated pre-salt portfolio outside Petrobras. The next step is to determine the appropriate approach to growth in the pre-salt play. With legislation now in place granting NOC Petrobras a minimum 30% w.i. and operatorship in all unlicensed pre-salt acreage, this may be another case of executing a strategic alliance (similar to that secured with Reliance in India and proposed with Rosneft in the Russia Arctic).
- Accelerate development of US Onshore unconventional gas resource: BP received a very competitive price for the Permian Basin and Western Canada conventional gas assets sold to Apache (totaling ~75 mboe/d of production and ~340 mmboc 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

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

Company Overview

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

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconventionals	Oil Sands	Other
✓	✓		✓	✓	

Partnership History

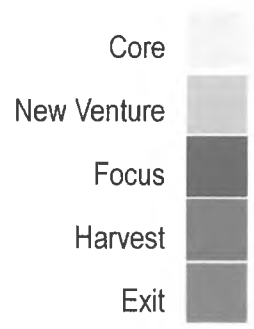
Date	Partner	Region (or Country)	Type
2003	LUKOIL	Russia	Various
2006	Cenovus	Canada	Oil Sands
2008	Origin Energy	Australia	LNG

ConocoPhillips: Global Areas of Upstream Operations



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

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



ConocoPhillips Global Production Portfolio - 2010



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

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

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

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

China: Modest offshore production from Bohai Bay.

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

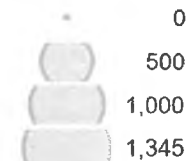
Nigeria: Interests in six onshore assets, serving as feedstock to **Nigeria LNG Trains 4-6**.

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

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

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

mboe/d



Asset Type

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

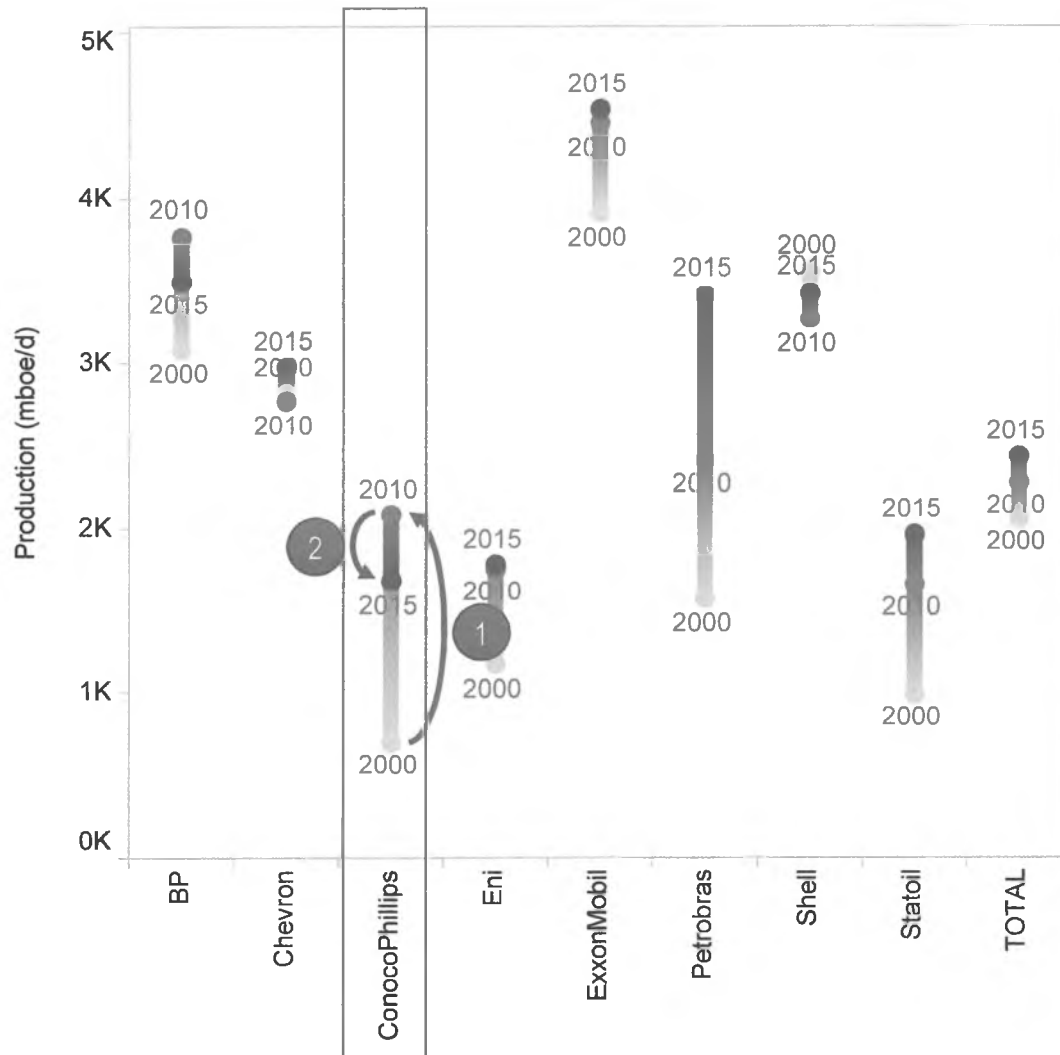
Vietnam: Continued development of mature Cuu Long Basin; **potential divestment target**.

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

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

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

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



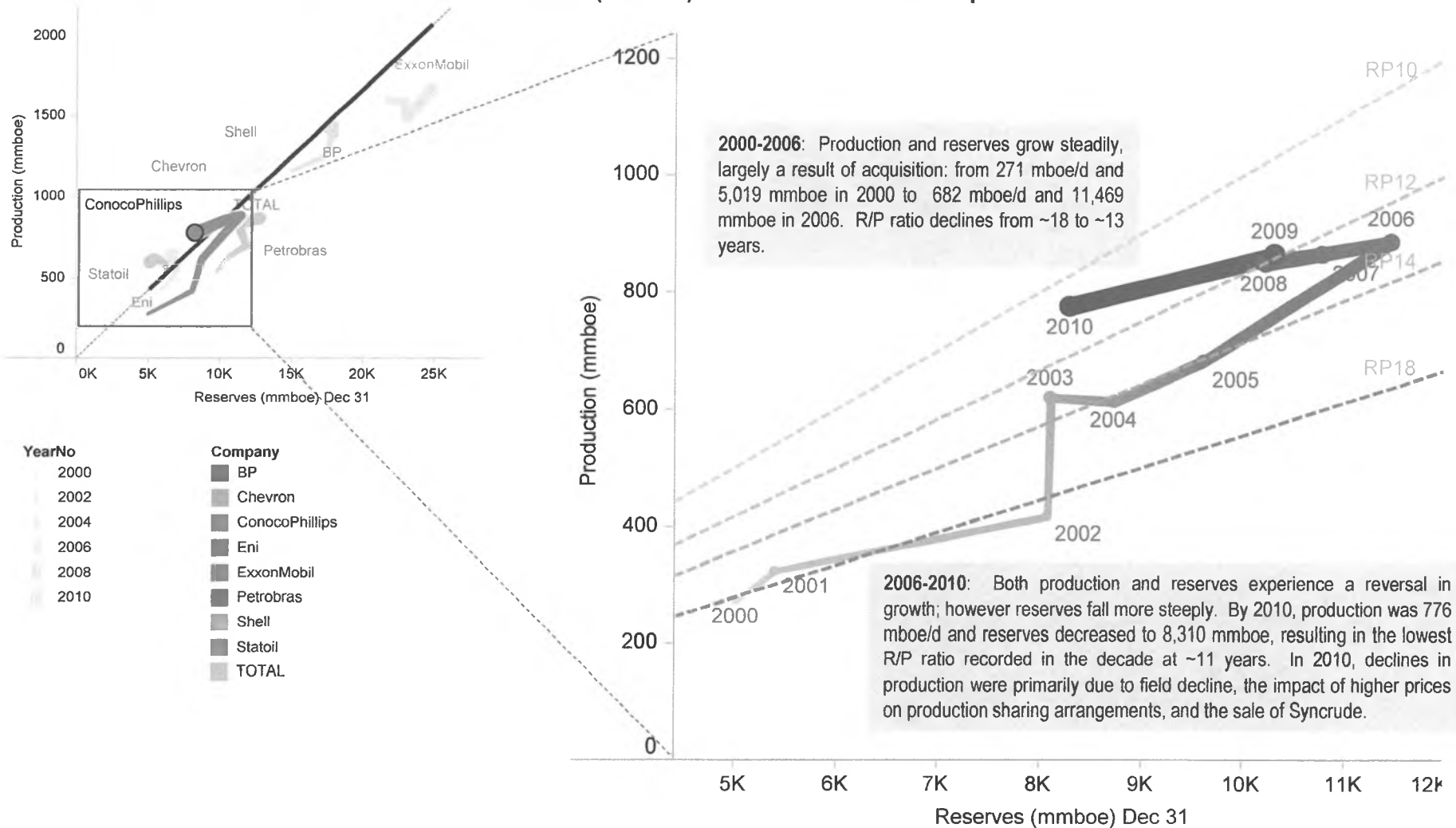
ConocoPhillips' 2010-2012 Restructuring Plan will see the company become the largest of the Independent, non-integrated international oil & gas companies, compared to its former position as the third-smallest of PFC Energy's expanded Global Player peer group.

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

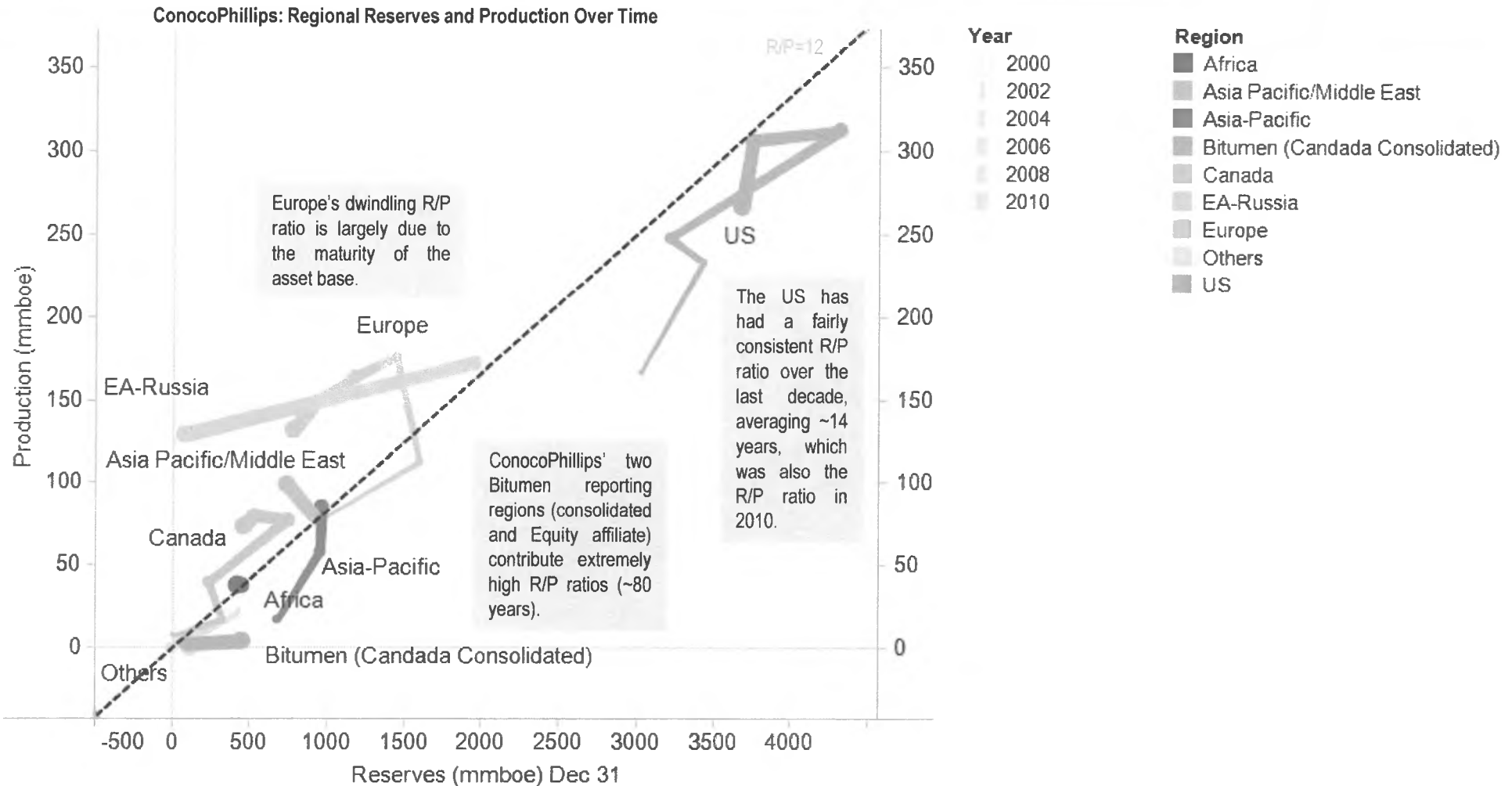
2011-2015: ConocoPhillips's production is expected to decline from 2010-2015, due to the company's intensive asset divestiture program (the initial ~\$15 bn asset and joint venture divestment program was expanded in 2011 when ConocoPhillips announced it would shed an additional \$5 bn-\$10 bn in non-Core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

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

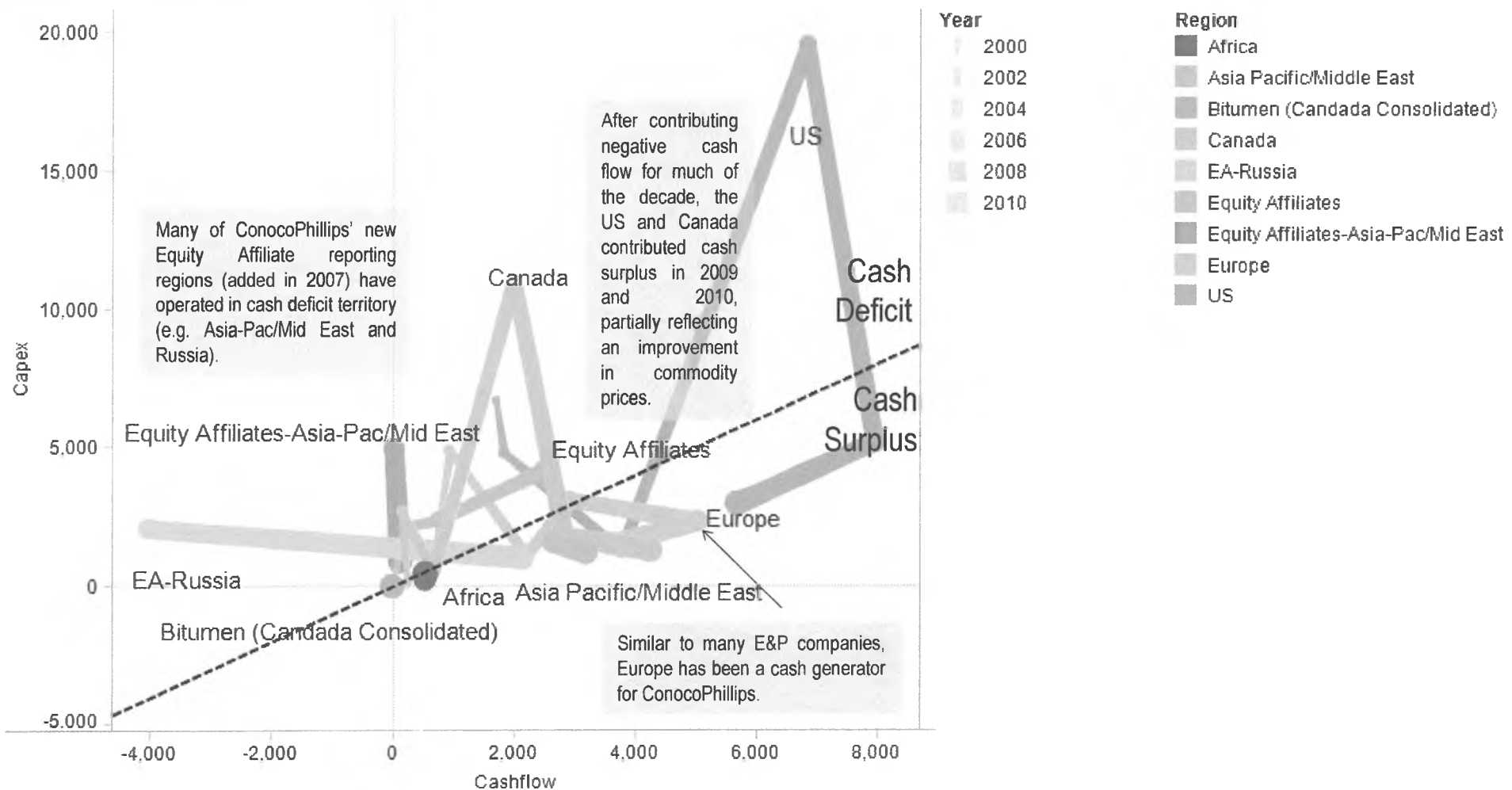
Reserves and Production (mmboe) 2000-2010: ConocoPhillips and Peers



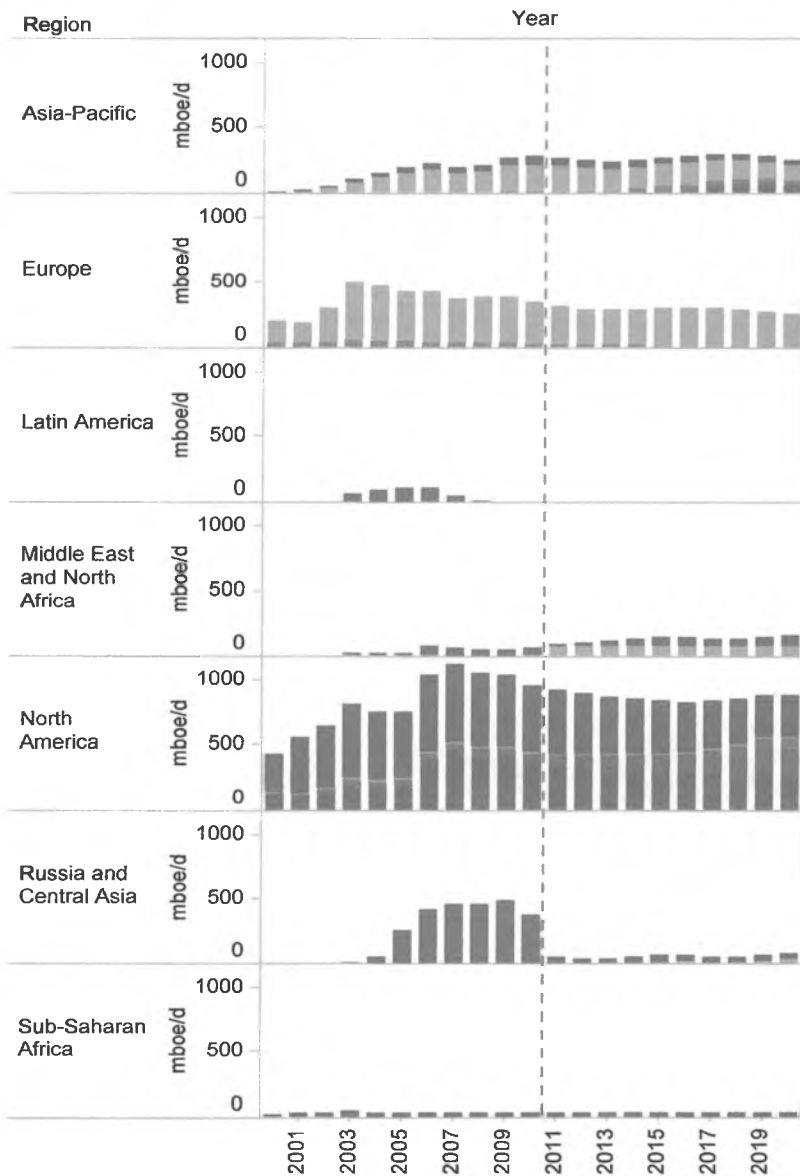
Reserves and Production: ConocoPhillips Intra-Portfolio Performance



How the Portfolio is Financed: Sources and Uses of Cash



Global Production: Evolution of the Portfolio



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

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

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

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

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

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

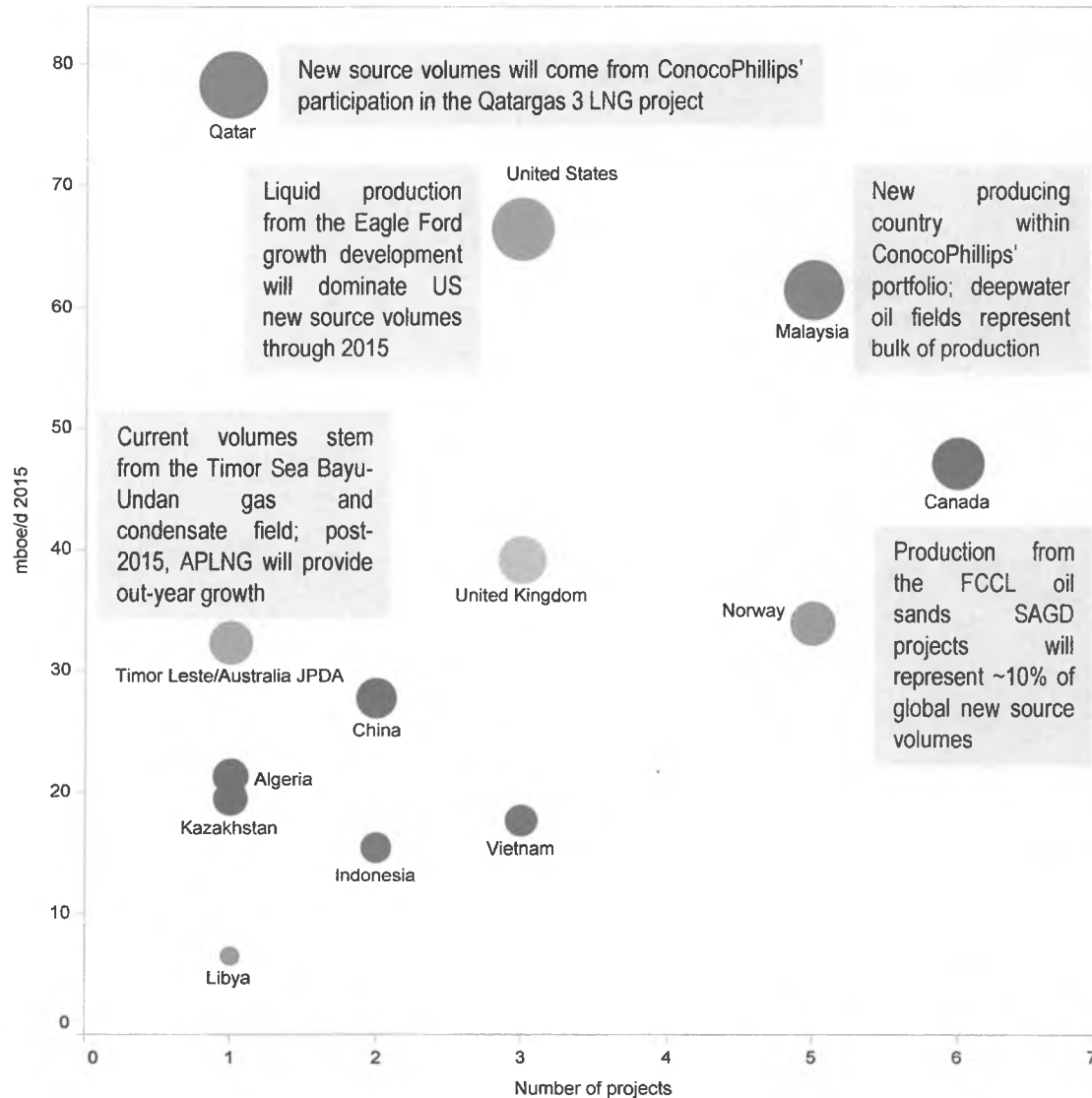
Sub-Saharan Africa: Onshore assets serve as feedstock to Nigeria LNG Trains 4-6. Longer-term upside tied to feedstock for the yet-to-be-sanctioned Brass LNG plant, while 2011 re-positioning in Angola could provide exploration opportunities critical to securing new source ventures for long-term growth.

Asset Type

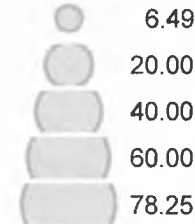
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Global Production: Country Growth Project Analysis

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



mboe/d 2015



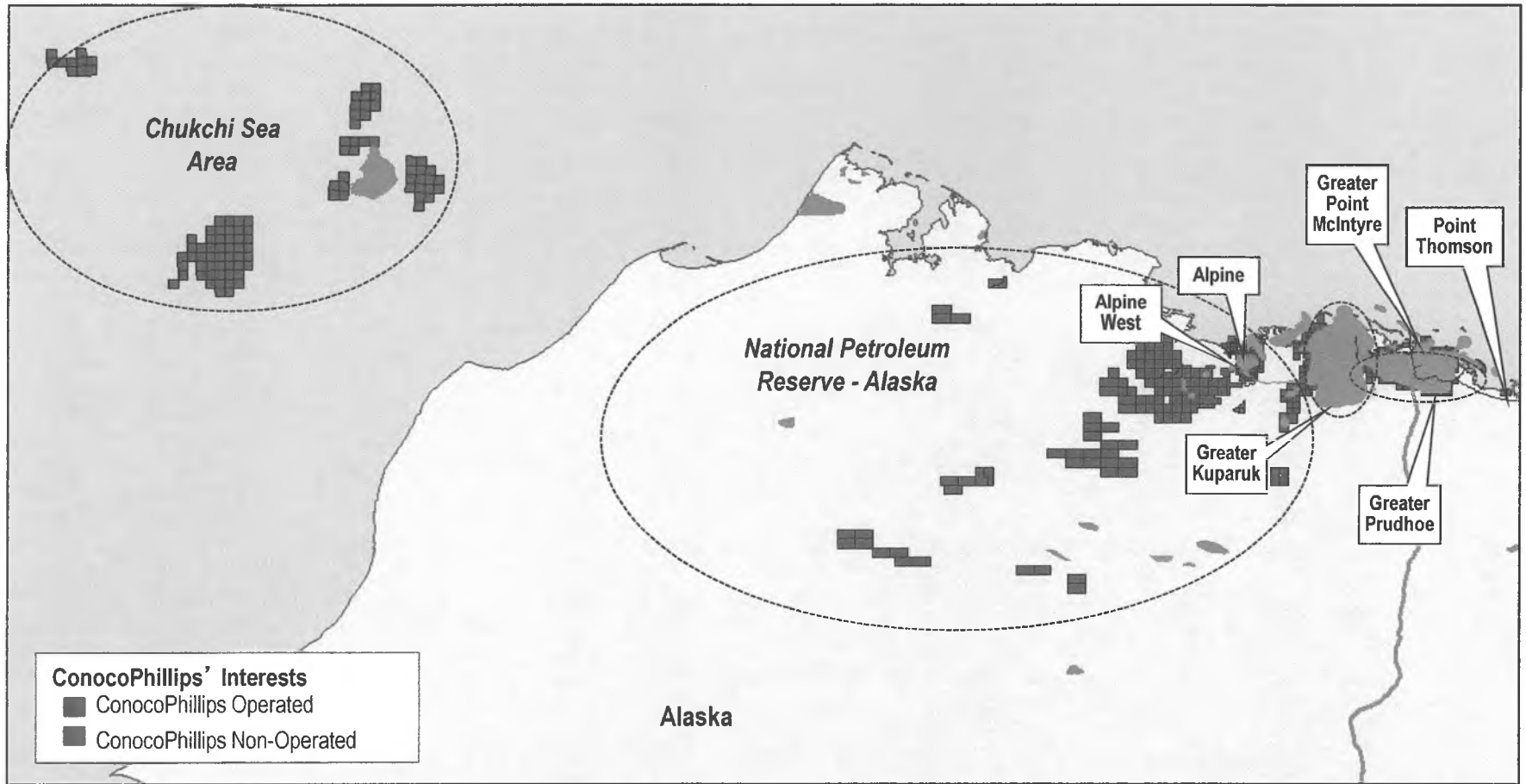
Oil %



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

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

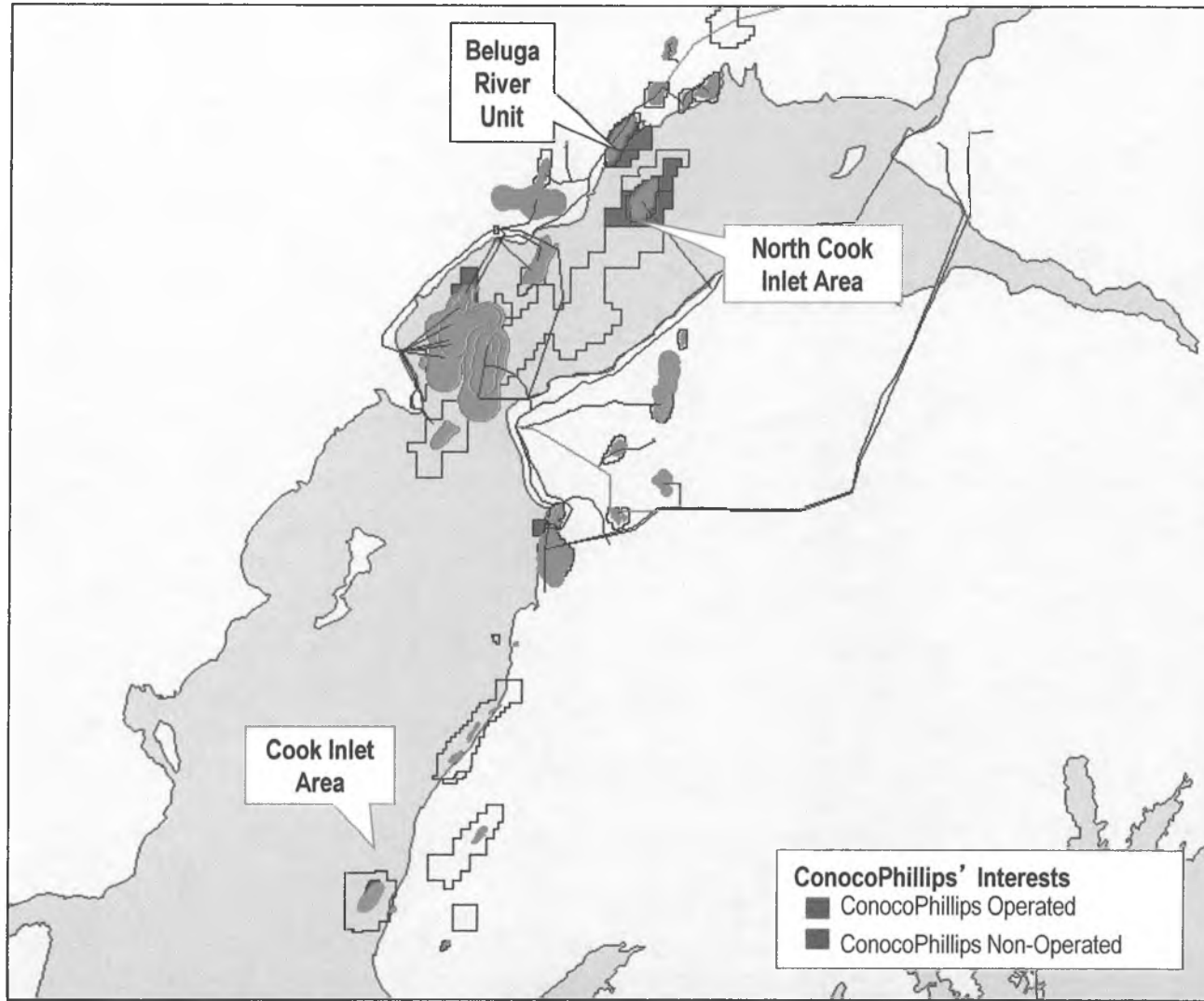
ConocoPhillips in Alaska – North Slope



Produced with PetroView®

ConocoPhillips in Alaska – Cook Inlet

ConocoPhillips' Interests in the Cook Inlet (Alaska)



Produced with PetroView®

ConocoPhillips Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
<p>Core Area</p>	<ul style="list-style-type: none"> • ConocoPhillips' assets in Alaska are legacy assets acquired from Arco Alaska in 2000 and include the Greater Prudhoe Area, Greater Prudhoe Bay Area, Greater Kuparuk Area, Western North Slope, and Cook Inlet Area. The company's largest producing area in Alaska is the Greater Prudhoe Area, a collection of mature, long-life fields. Production from the mature Alaska portfolio has been in slow decline since 2004. In 2010, net production from Alaska averaged 230 mb/d of oil and 82 mmcf/d of gas, accounting for ~21% of US production. • ConocoPhillips and BP have been joint proponents of the Alaska Gas Pipeline (or Denali Pipeline), intended to accelerate commercialization of Prudhoe Bay gas through Western Canada and into US markets. In 2010, the partners officially withdrew their support for the proposed project, in response to continued US gas price weakness and absence of buyer commitments. This places substantial uncertainty around further commercialization of ConocoPhillips' Alaska gas resources. • Activity in the ConocoPhillips-operated Greater Kuparuk Area (GKA), has recently focused on development of viscous oil resources. The GKA, located 40 miles west of Prudhoe Bay on the North Slope, includes the Kuparuk field and its satellites: West Sak, Tarn, Tabasco, Meltwater, and Palm. Heavy oil resources West Sak and Ugnu (52.2% w.i., operated) are potential projects currently in the appraisal phase. Expected gross peak production is ~23 mboe/d. 	<p>As Alaska's largest oil and gas producer, ConocoPhillips holds a leading position in the region. Although the company continues to target smaller projects within the GKA (West Sak and Ugnu) and NPR-A (Alpine West, Greater Moose's Tooth unit and Fiord West), ConocoPhillips will ultimately need expanded access to Asia gas markets in order to reverse the downward production trend in Alaska.</p>

COP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
<p>Core Area</p>	<ul style="list-style-type: none"> • In the Western North Slope, ConocoPhillips faces regulatory challenges surrounding project development in the NPR-A region. In order to offset declines at the Alpine field (78% w.i., operated) and its three satellites, Nanuq, Fiord, and Qannik, ConocoPhillips is exploring development of additional satellite fields in the adjacent NPR-A, an area that requires distinct permit approval. Alpine West (or CD-5), a proposed Alpine satellite project, has been significantly delayed due to local opposition and regulatory barriers. Most recently, in early 2010, the U.S. Army Corps of Engineers denied a permit for a bridge that would provide access to the CD-5 site, a move that will further delay the project (originally planned for 2012) and several additional developments that would depend on the infrastructure. Other possible projects on the NPR-A include the Greater Moose's Tooth unit and Fiord West, which are both in appraisal phases. • While ConocoPhillips has three primary gas fields in the Alaska region—the North Cook Inlet, Beluga River, and Point Thomson—Point Thomson (5% w.i., non-operated) remains the only potential new source development. In 2010, development activities continued with the drilling of two appraisal wells. First production of gas liquids is anticipated in 2014. Longer-term growth potential lies in commercialization of the gas reserves, which is in turn dependent on construction of a long-distance gas trunk line. • In 2010, ConocoPhillips and Statoil engaged in an asset swap wherein ConocoPhillips sold a 25% w.i. in 50 of its Chukchi Sea leases to Statoil in exchange for financial payment and a 50% w.i. interest in 16 Statoil-operated Gulf of Mexico leases, as well as Statoil's 25% w.i. in five additional GOM leases already operated by ConocoPhillips. All of the involved GOM blocks are in the emerging Lower Tertiary play. ConocoPhillips plans to begin exploratory drilling on its Chukchi acreage in 2013. 	

PFC-Identified Challenges

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

ExxonMobil: Company Overview

Strategic Signature

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

Company Overview

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

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconventionals	Oil Sands	Other
✓	✓		✓	✓	✓

Partnership History

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

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

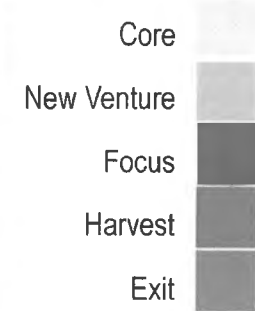
ExxonMobil: Global Areas of Upstream Operations

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

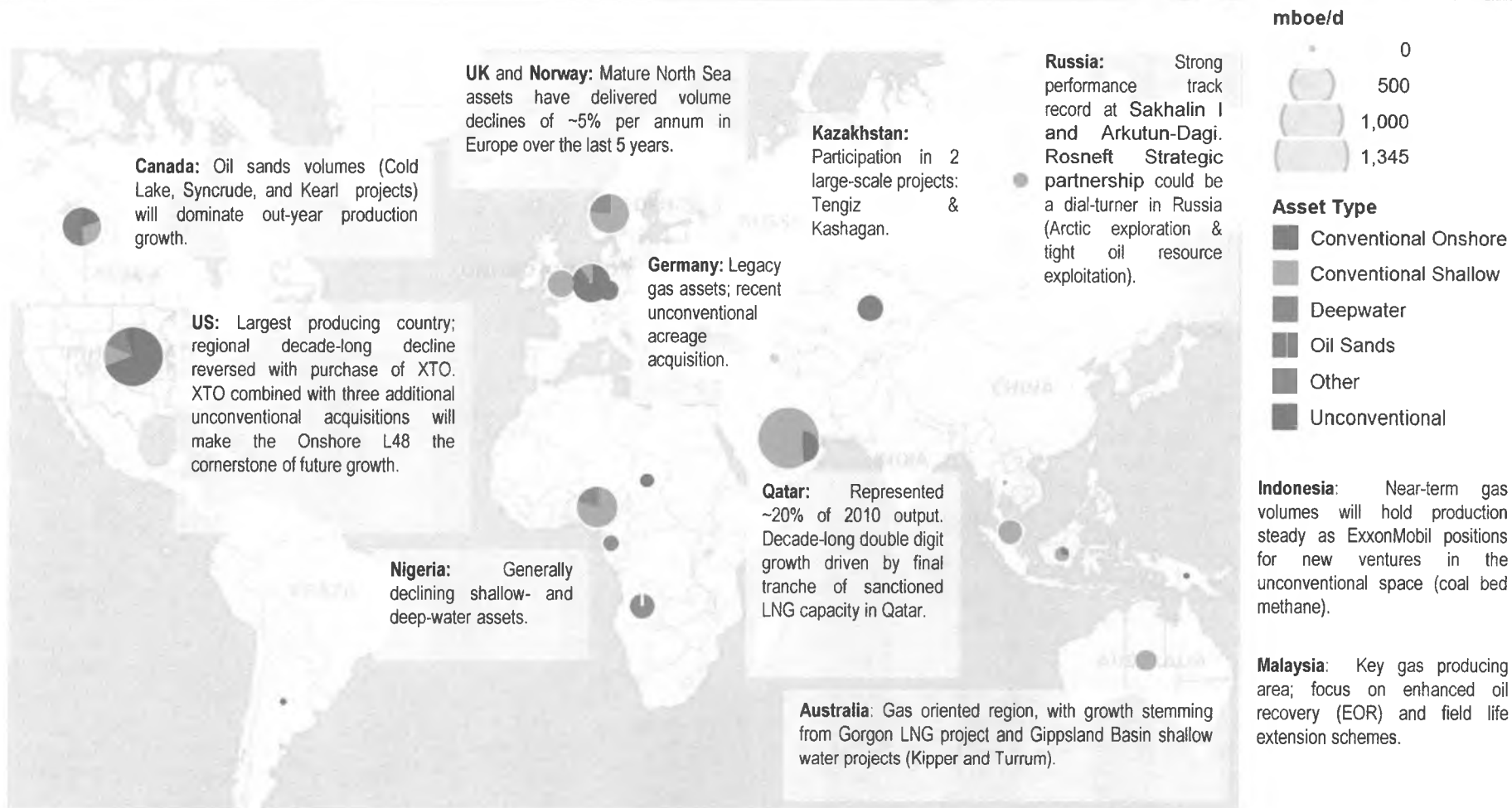


Country	Liquids (mboe/d)	Gas (mboe/d)
Brazil	0	0
Cameroon	0	0
Colombia	0	0
Congo	0	0
Greenland	0	0
Guyana	0	0
Hungary	0	0
Iraq	0	0
Ireland	0	0
Italy	0	0
Libya	0	0

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

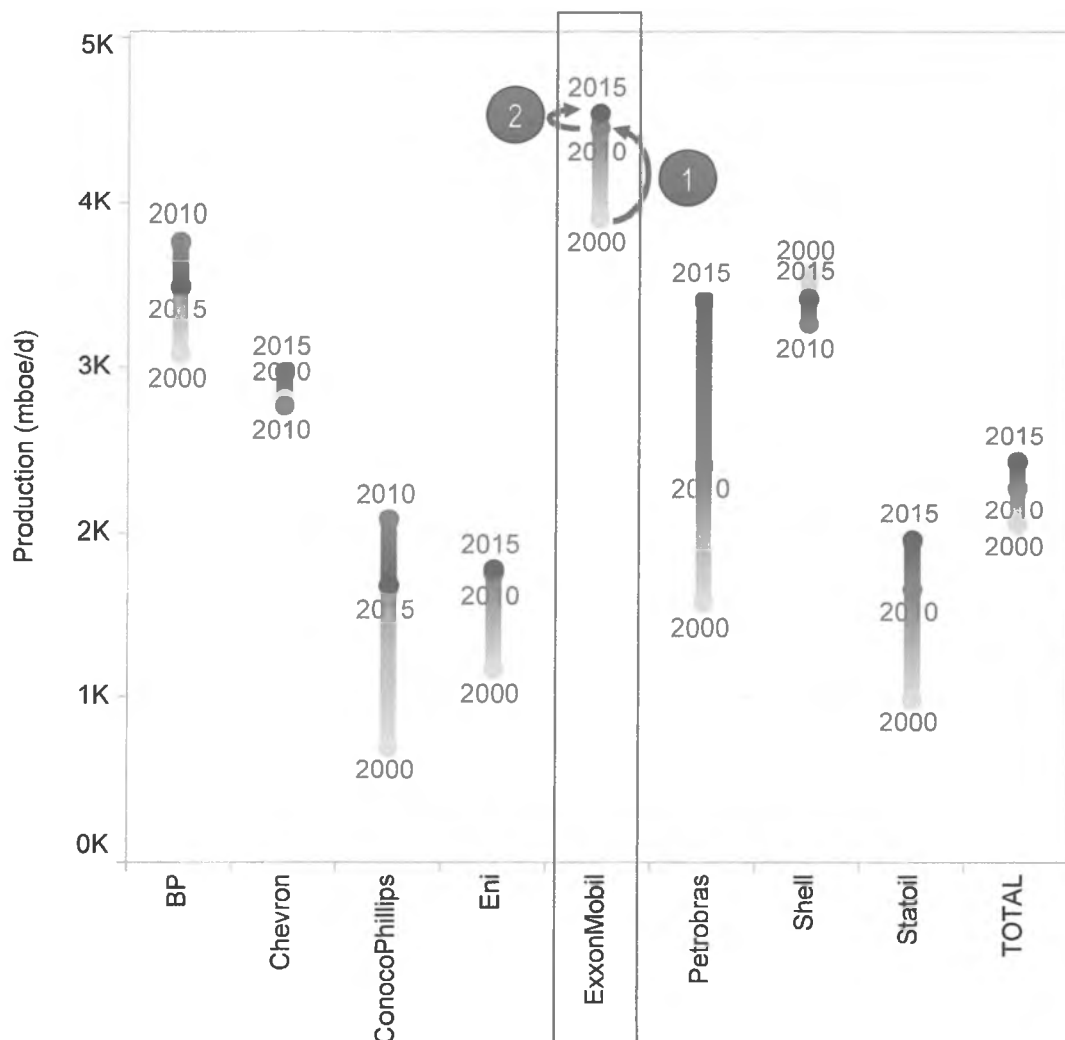


ExxonMobil Global Production Portfolio - 2010



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

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



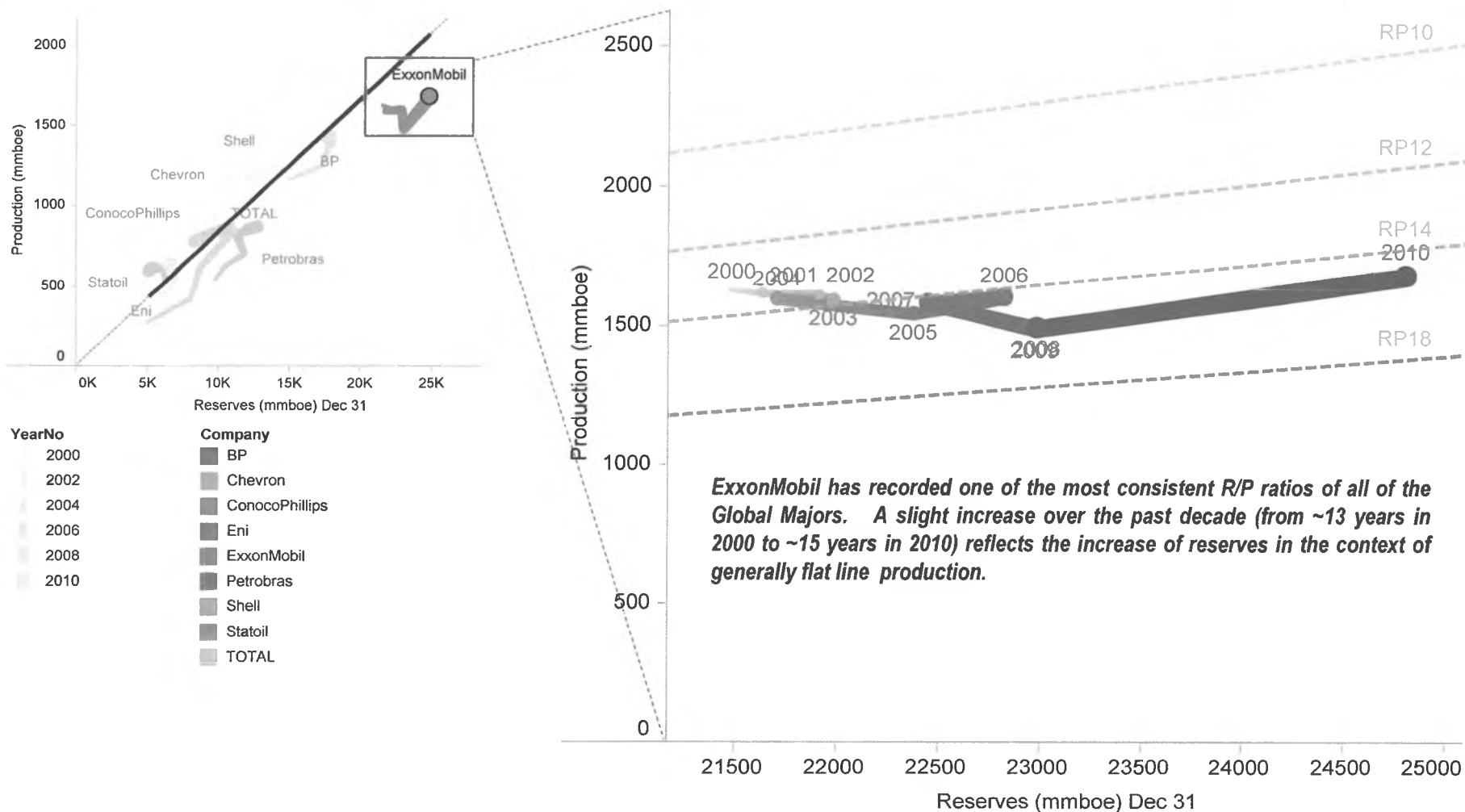
Averaging ~4.45 mmboe/d in 2010, ExxonMobil continues to lead its peer group in terms of production.

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

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

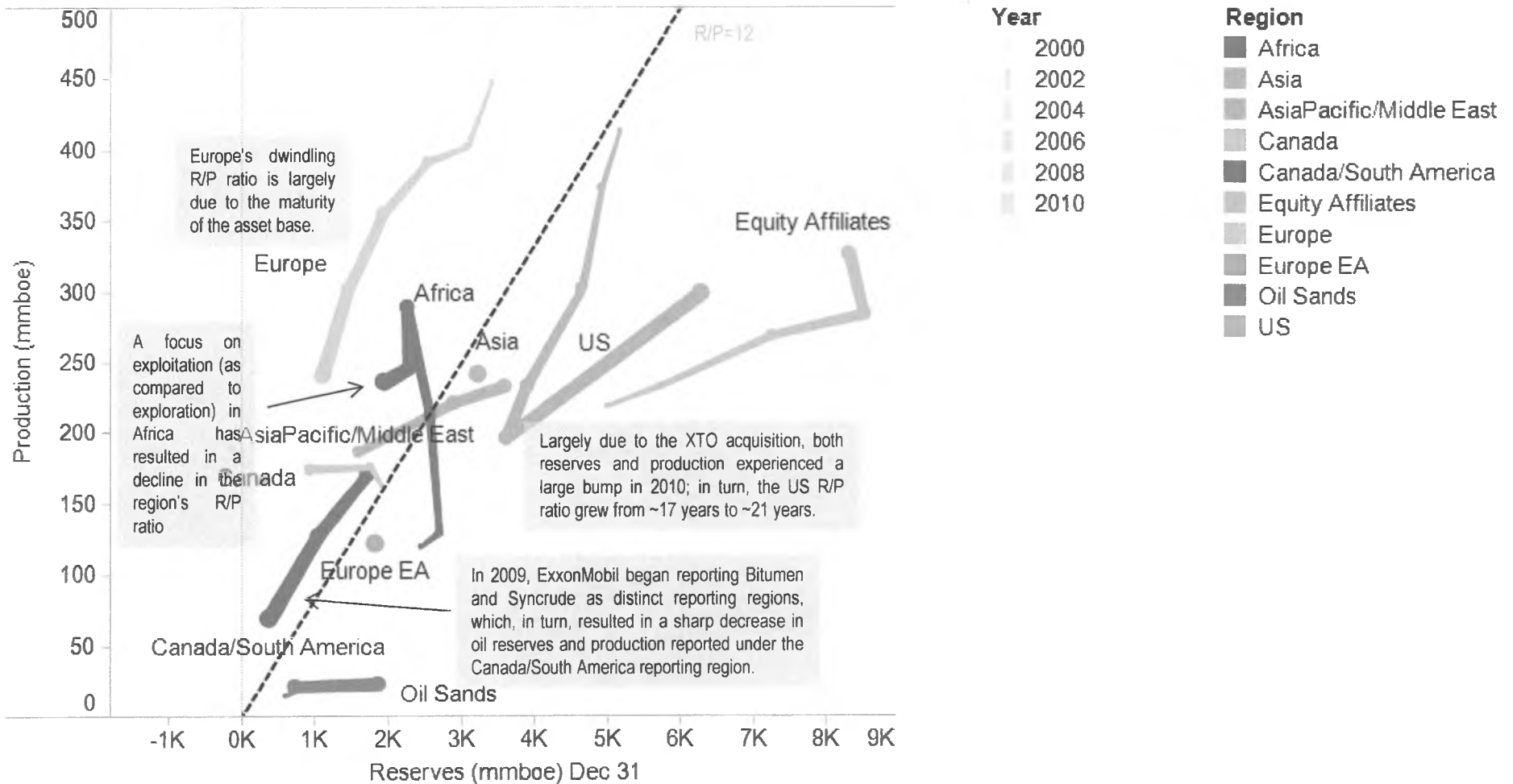
Reserves and Production: ExxonMobil vis-à-vis the Competition

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

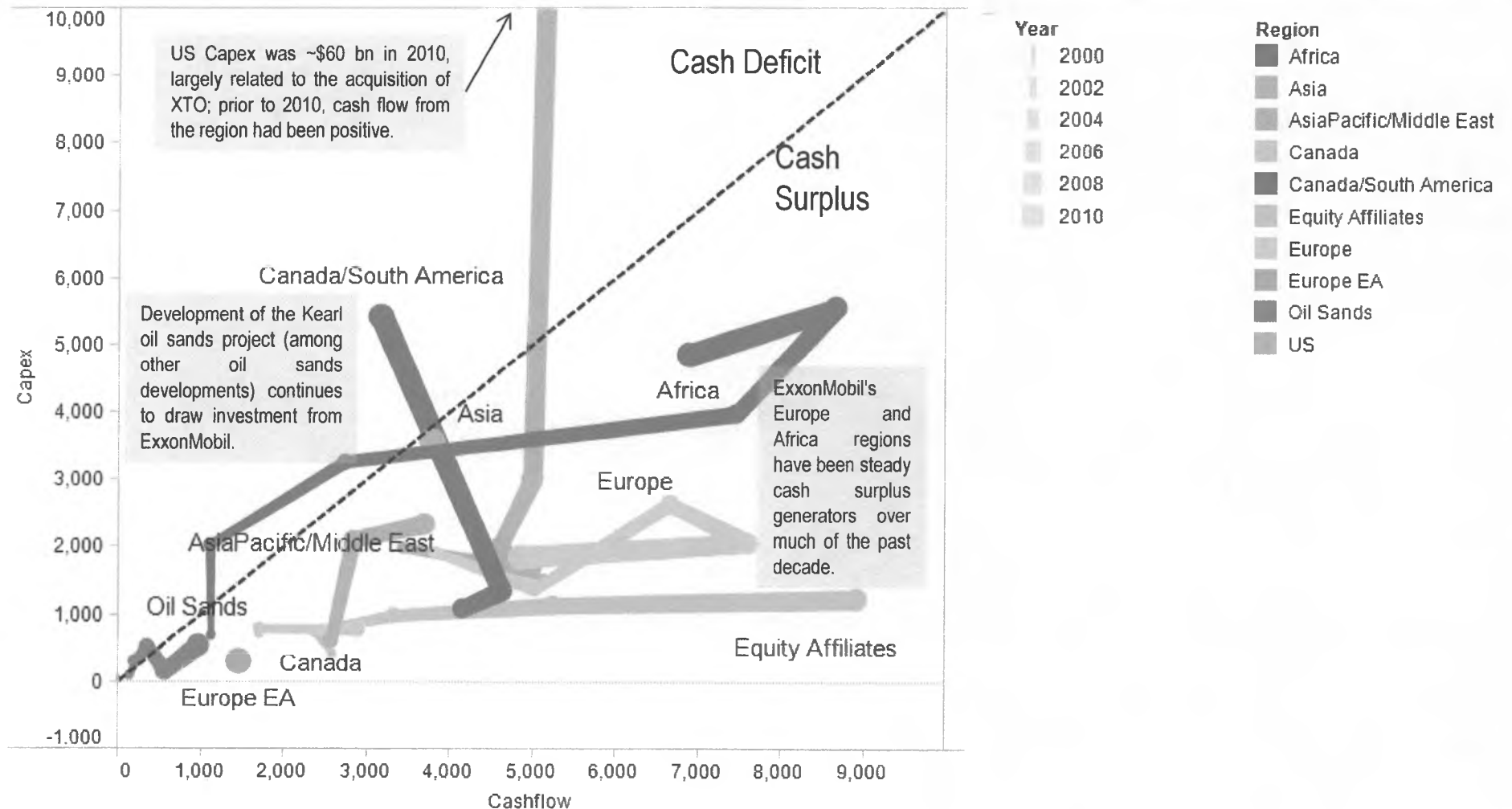


Reserves and Production: ExxonMobil Intra-Portfolio Performance

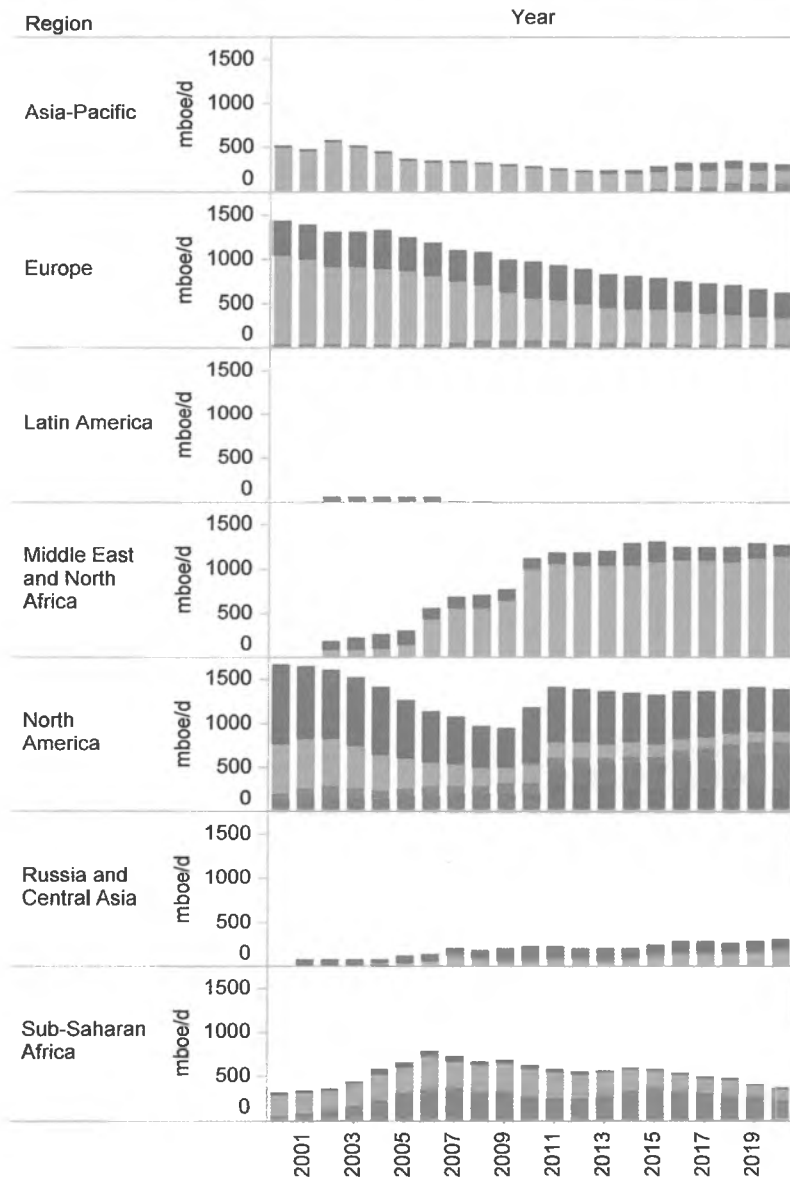
ExxonMobil: Regional Reserves and Production Over Time



How the Portfolio is Financed: Sources and Uses of Cash



Global Production: Evolution of the Portfolio



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

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

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

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

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

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

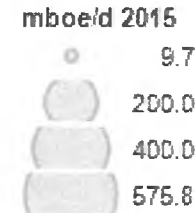
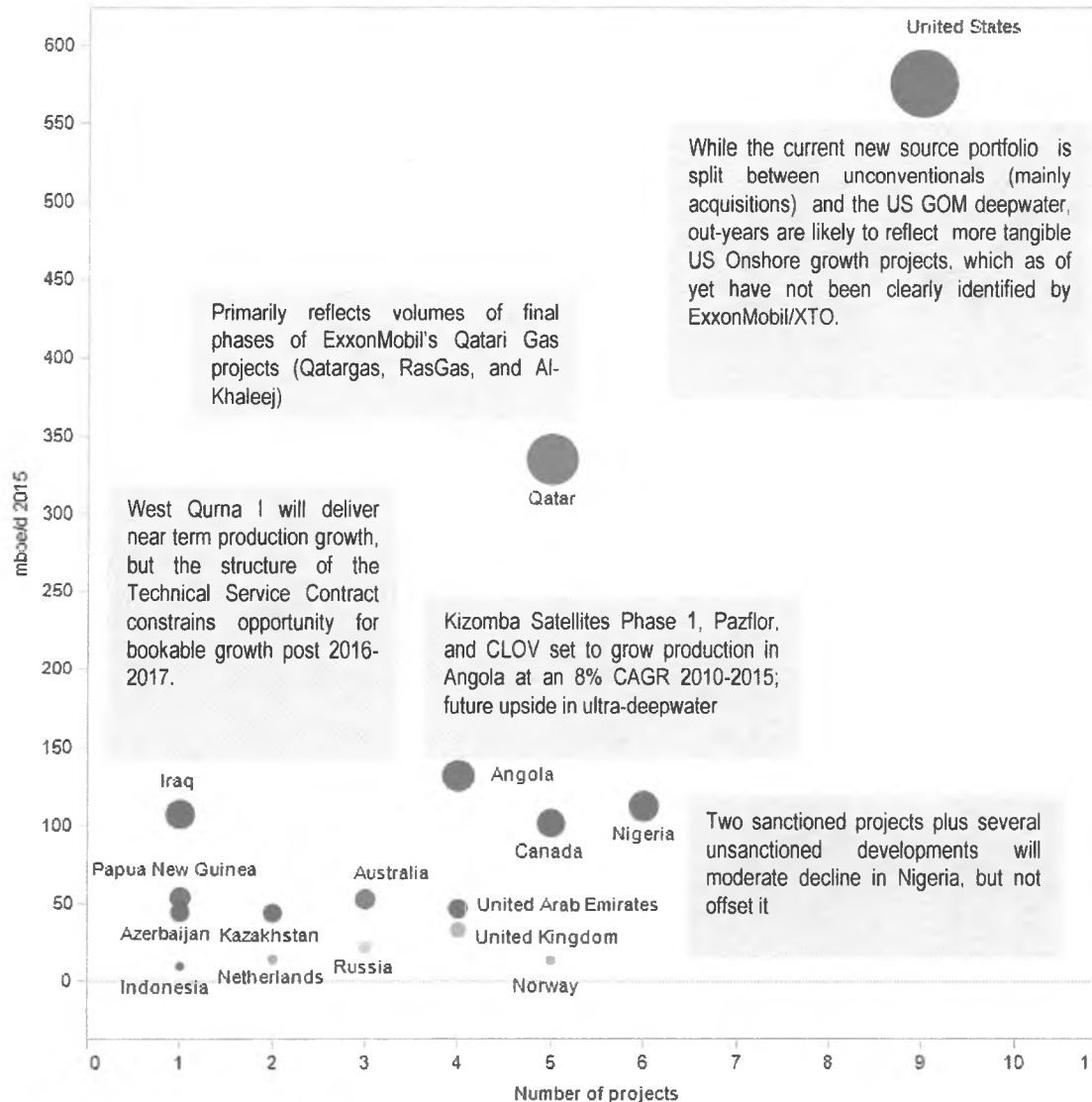
Sub-Saharan Africa: Growth in SSA has leveled off as new developments struggle to keep pace with steep deepwater decline rates. The primary bright spot in portfolio is Angola, where three new projects (Pazflor, Kizomba Satellites, and PSVM) are scheduled to come onstream over the next two years.

Asset Type

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

Global Production: Country Growth Project Analysis

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

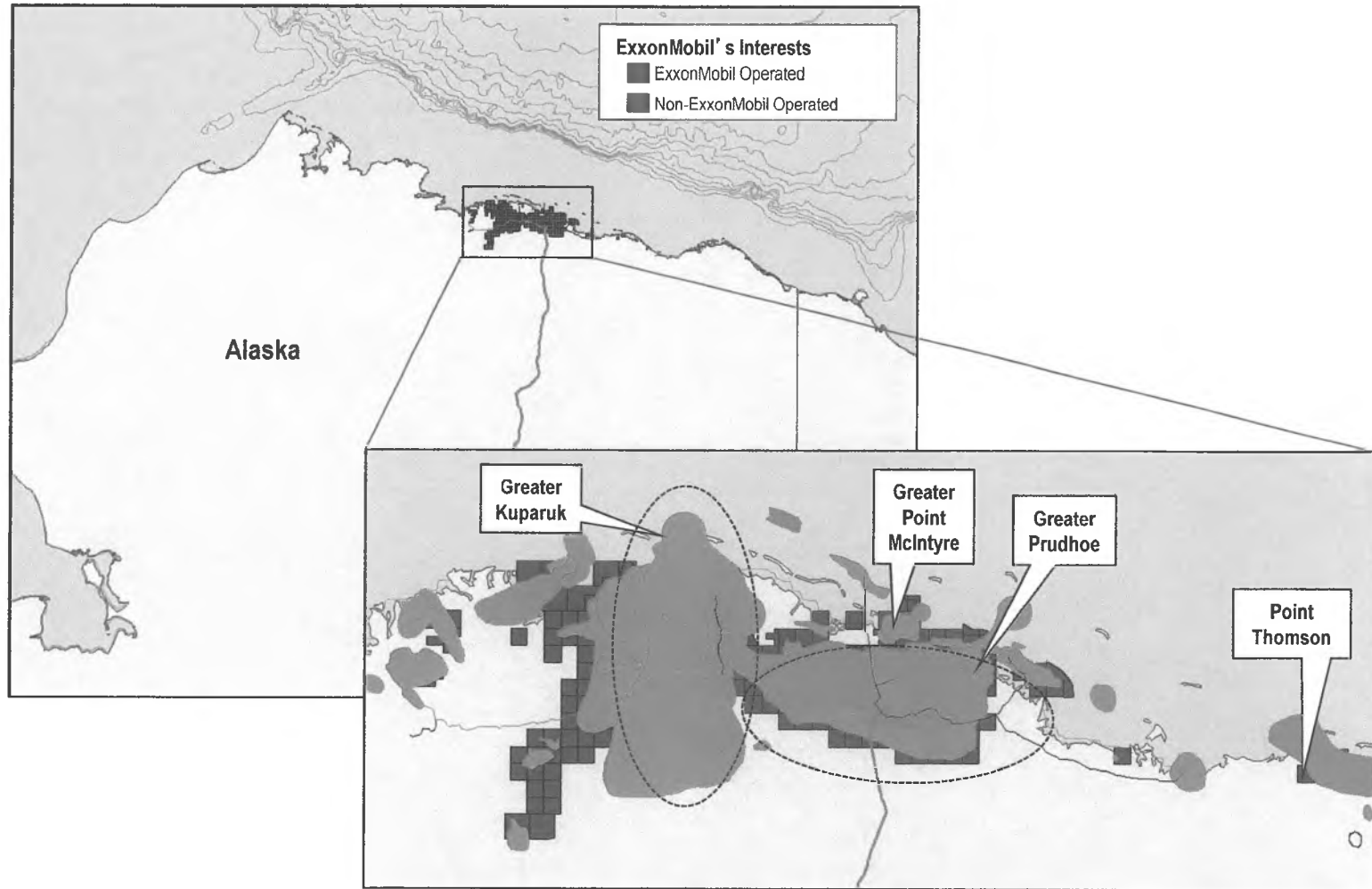


ExxonMobil's US new source portfolio will dwarf new source production from all other countries. Through 2015, the US will contribute nearly 40% of global new source incremental volumes, 99% of which will stem from the company's unconventional activities (acquisitions plus the Piceance tight gas development).

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

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

ExxonMobil in Alaska – North Slope



ExxonMobil Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	<ul style="list-style-type: none">• In Alaska, ExxonMobil holds interests in the Greater Prudhoe, Greater Point McIntyre, and Greater Kuparuk areas. The company is one of the largest North Slope producers, although production from the region is declining; 2010 net production averaged 117 mb/d of liquids.• Development activities continued at Point Thomson in 2010 (35% w.i., operated), and first production of gas liquids is anticipated in 2014. The longer-term potential lies in commercialization of the gas reserves, which is dependent on building a gas pipeline.	Material harvest position. As the largest holder of discovered gas resources on the North Slope and a co-operator of the Prudhoe Bay Western Region development, ExxonMobil holds a leading position in Alaska.

PFC-Identified Challenges

- Deliver on unconventional resource positioning: The XTO Energy acquisition and subsequent shale gas acreage transactions have made ExxonMobil a force in the North America unconventional resource play. That said, the company has provided limited guidance on pace of forward development despite continued acreage accumulation. Furthermore, given the weak US gas price environment, it is unclear how rapidly ExxonMobil's management will grow sales volumes. ExxonMobil is counting on additional long-term value arising from the XTO transaction through development of its expanding portfolio of International unconventional resource holdings.
- Execute on Asia-Pacific LNG Projects: ExxonMobil has a queue of LNG developments in Asia-Pacific, including Gorgon LNG (operated by Chevron), PNG LNG, and the potential Scarborough gas field development, all of which are poised to generate longer-term volume growth. Each of these projects comes with significant technical challenges—CO₂ capture and disposal at Gorgon LNG, remote gas field development and long distance pipeline transport in the case of PNG LNG, and the remote offshore location of the Scarborough field in the Carnarvon Basin (which may result in the field being dedicated as feedstock supply to the Pluto or Wheatstone LNG projects, rather than a greenfield LNG development). Performance will be critical to ensuring long-term regional portfolio growth.
- Maintain leadership in share buy-back and dividend performance: ExxonMobil has been a clear peer group leader in returns to shareholders, distributing ~\$19.7 bn through dividends and share buy-backs in 2010 and spending ~\$114 bn on share repurchase over the 2006-2010 period. With the increased emphasis being placed on unconventional gas resources to deliver future volume growth, shareholders will be looking for ExxonMobil to continue its leading dividend and share buy-back performance, as the core differentiator from its faster growing (in volumetric terms) peer group companies.
- Replace volume growth from Qatar North Field commercialization: With full ramp-up of the final four liquefaction trains at the RasGas and Qatargas LNG complexes, and continued imposition of a development moratorium for the North Field resource by the Qatar government, ExxonMobil will be challenged to deliver material global growth.
 - It is not clear how aggressively ExxonMobil will look to develop its US Onshore unconventional gas resources, given current and projected gas pricing in the North America market;
 - Monetization of captured frontier gas resources in North America (Alaska North Slope, Mackenzie Delta) continues to face delays in the form of regulatory hurdles (recently removed for the Mackenzie Valley gas pipeline project) and gas market supply-demand balances;
 - Development of captured oil reserves in the Caspian region have experienced significant delays and cost over-runs, and are coming under increased political risk through accelerating resource nationalism;
 - ExxonMobil was successful in securing a growth position in Iraq through the West Qurna-1 redevelopment project, but will have to share the larger Iraqi resource prize with a number of IOCs and NOCs. It is not clear that Iraq can become a Core growth area for the company.

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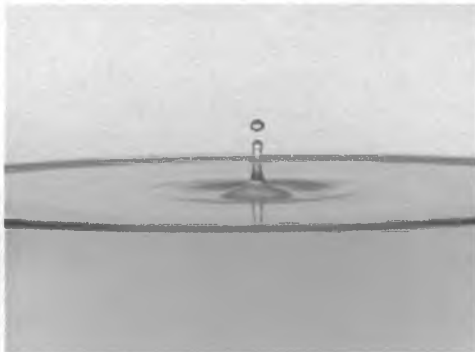
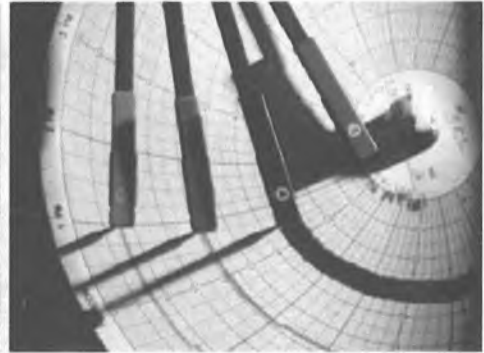
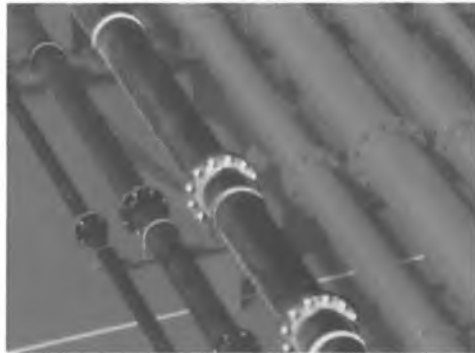
PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable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

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PFC Energy

6.

**Testimony by
Industry
March 16, 2012**

**Alaska Oil and Gas Association
Alaska Oil and Gas Conservation
Commission**

**Alaska Support Industry Alliance
Resource Development Council for
Alaska**



**OIL & GAS:
FUELING
ALASKA'S
ECONOMY**

**Senate Finance
Committee**

March 16, 2012

Kara Moriarty, Executive Director

AOGA Member Companies

PIONEER
NATURAL RESOURCES ALASKA



petroleum



Decoupling – Sections 5 & 11 of CSSB 192 (RES)

- AOGA Opposes Proposed Language
- Proposed Language results in a tax increase
- Recognize need to eventually resolve the concern that combining the value of gas with that of oil when significant gas sales occur will reduce the tax on the oil, unless they are decoupled.
- AOGA open to trigger mechanism, but reserve right to evaluate proposed language

AOGA Opposes CSSB 192 (RES) – March 16, 2012

Petroleum Information Management System Sections 2 & 3 of CSSB 192 (RES)

- New section would blur the current clear authorities & accountability of DOR (Taxation Power) & AOGCC (Police Power)
- Could lead to companies providing the same information over and over or in different formats to different agencies
- Proprietary/confidential information may not be adequately safeguarded
- Creates unrealistic expectations about public access to certain specific kinds of information
- May create federal disclosure issues

AOGA Opposes CSSB 192 (RES) – March 16, 2012

Progressivity & “base” tax rate
Sections 5, 7, and 8 of CSSB 192 (RES)

- 25% base rate is too high
- CS does not provide brackets – brackets are meaningful
- CS lowers starting slope by merely 1/8
- The new cap will not be reached until approximately \$244/barrel

AOGA Opposes CSSB 192 (RES) – March 16, 2012

New Minimum Tax – or “Floor” Section 13 of CSSB 192 (RES)

- Only applies to legacy fields (Prudhoe & Kuparuk)
- Creates a disincentive to invest in legacy fields, especially at low prices
- Requires allocation of costs among the two fields & a producer's interest in their other fields

AOGA Opposes CSSB 192 (RES) – March 16, 2012

Summary

- AOGA Opposes CS SB 192 (RES)
- Overall government take for Alaska would still be too high under this CS
- AOGA supports meaningful changes – such as progressivity brackets
- Tax Policy does affect business decisions
- CS will not improve ability to attract more investment
- CS will not lead to more production

AOGA Opposes CSSB 192 (RES) – March 16, 2012

Impact of Section 3, CS SB 192 on AOGCC

The AOGCC, an independent quasi-judicial State agency, is the State's permitting and regulatory authority over hydrocarbon and geothermal wells. The Commission's duties include ensuring the maximum recovery of hydrocarbon and geothermal resources, preventing hydrocarbon and geothermal waste, ensuring well safety, and protecting underground sources of drinking water and correlative rights. Given the nature of the Commission's duties and responsibilities, apart from support personnel, it is staffed by expert petroleum engineers and petroleum geologists. Because its expertise is so carefully tailored to its statutory duties and responsibilities, the Commission functions well and Alaska has an unrivaled record with regard to well safety and production.

Section 3 of the committee substitute for SB 192 seeks to effectuate a substantial change in the AOGCC by requiring the Commission to establish, operate and maintain an electronic petroleum information management system comprised of available and non-confidential information. The vast majority of the information the Commission must include in the petroleum information management system has nothing to do with the Commission's mission or function – "unit and joint operating agreements," exploration licenses and leases, "work programs and budgets," "development plans," operating and capital expenditures and projections, "oil and gas sales, revenue and pricing," transportation agreements, abandonment plans and budgets, resident and non-resident hiring information, training opportunities, and other information "the commission determines necessary and relevant to the oil and gas production tax and to the exploration, development, and production of oil and gas resources." Much of this information is currently already gathered and maintained by other state agencies or is not available to any state agency.

After careful review and consideration of Section 3, the AOGCC is of the view that Section 3 radically changes the AOGCC's longstanding role as the State's petroleum technology and geology experts and jeopardizes the Commission's ability to discharge its primary duties and responsibilities in those realms. The Commission has neither the expertise nor the infrastructure to construct, maintain and operate information management systems, computer systems, and the gathering of information on other subjects not related to the safe, efficient production of hydrocarbon resources from wells. Implementation of Section 3 will create – at a substantial fiscal outlay – an additional distinct state bureaucracy within the AOGCC which duplicates functions currently performed by other state agencies.

The AOGCC's non-confidential information is already publically available on its website. Other agencies are currently working to provide similar web availability of their data. Once those agencies do so, the information will be far more readily accessible to the public on those websites and at a substantially reduced cost.



THE ALLIANCE

...for responsible development of Alaska's Oil, Gas & Mineral Resources

THE ALLIANCE & C55B-192

Doug Smith
President/CEO - Little Red Services
Government Affairs Chair -
Alaska Support Industry Alliance

Presentation Organization

- ▣ Background
- ▣ Impact to Member Companies
- ▣ Observations
- ▣ Questions

Our story hasn't changed...

- ▣ Alliance members, at their own expense, have traveled to Juneau more than 10 times during the 27th Alaska Legislature
- ▣ We have consistently advocated for significant tax reform
- ▣ Members and their employees have participated in every public testimony opportunity in 2011/2012
- ▣ The McDowell Report confirmed the facts we've presented
 - Alliance companies average between 70% and 90% Alaska hire
 - Alliance companies employ non-residents who were formerly long-term Alaska residents
 - Record employment on the North Slope has not led to a reduction in the production decline

Alliance Member Composition

- ▣ The Alliance is comprised of 460 member businesses
- ▣ 35,000 employees
- ▣ Our membership is comprised of businesses in 43 different sectors from Automotive to Welding
- ▣ Our mission statement is to “promote responsible exploration, development and production of oil, gas and mineral resources for the benefit of all Alaskans”

The current investment climate impact on Alliance members

- ▣ Continued decline in projects
 - Three largest fabrication shops in the state are currently operating at a loss, with little to no work, in order to keep core employees on staff

- ▣ Alaskan companies are looking for work, resulting in many relocating or shifting resources and investment to the lower 48 (CIRI, Solsten, Fairweather, Builders Choice, Northern Industrial Training, Carlile, Lynden, Peak Oilfield Services, Cruz Construction...)

Jobs

- ▣ As indicated in the McDowell study, record high employment on the North Slope does not represent a thriving oil industry
 - 2000 - 108,000 barrels of annual production for every job
 - 2010 - 28,000 barrels of annual production for every job
- ▣ Loss of highly trained professionals to outside competition
- ▣ Reduction of jobs based in Anchorage and Fairbanks like engineers, fabrication work, etc.

My Company - Little Red Services

- ▣ Letter in your committee packet
 - Relocating an asset from production-related activity to maintenance activities that do not increase production
- ▣ Financing
 - Banks outside of Alaska are concerned about our current tax policy and its potential impact on future financial forecast of our service company

The future of Alliance members in the oil business...

Oil tax reform must address the following:

- ▣ Existing light oil production
- ▣ New light oil production
- ▣ Viscous
- ▣ Exploration
- ▣ New companies and investment in the Alaska market

Observations

- ▣ Existing production
 - Low-cost light oil (existing production)
 - ▣ “Government take of 70-75% is reasonable. It is maybe slightly on the high side.” (*PVM slide 28, presentation to Alaska Support Industry Alliance*)

Observations

▣ New production

- The allowance for production increases in CSSB 192 does not reflect the recommendation of Dr. van Meurs: “the 60-65% government take for more costly new light oil resources as proposed in HB 110 and HB 17 is a reasonable level from an international perspective.” *(PVM slide 38)*
- Dr. van Meurs includes in-field drilling of existing fields as new high-cost light oil production *(PVM slide 16)*
- Dr. van Meurs “The main reason for major companies to be in a harvest mode is that projects outside Alaska are more attractive. No large attractive projects available in Alaska under current fiscal terms for major oil companies” *(PVM slide 15)*

Observations

- ▣ New Production, continued...
 - Both Gabon and Trinidad applied an approximate 12 percent drop in order to attract new investment in an effort to offset declining production (*PVM slide 31*)
 - ▣ Marginal government take in Gabon at \$100/bbl is 52%
 - ▣ Marginal government take in Alberta is 57%
 - ▣ Marginal government take in Alaska under ACES is over 80%
(*PFC Energy, slide 49*)

Observations

- ▣ Viscous (called heavy by Dr. van Meurs)
 - Dr. van Meurs “To be competitive Alaska would have to offer government takes for heavy oil at 55-60%.” (*PVM Slide 42*)

- ▣ Exploration
 - Tax credits have stimulated significant exploration this season
 - Will this result in the required investment to bring new discoveries to production under the current ACES tax structure?

Observations

- ▣ New companies in the Alaska market
 - CSSB 192 does not simplify our tax structure for companies looking to invest in new markets and it does not make us competitive for new projects
 - ACES does not compete well when developing higher cost light oil (*PVM slide 37*)
 - “ACES inhibits the development of new projects and resources that might help stem or even reverse decline.” (*PFC slide 28*)

Observations

- ▣ There is probably a point where industry and the State share the pain of low prices
 - Industry should not have to give up total profits to taxes
 - The State treasury should not collect zero tax at low prices

- ▣ A healthy partnership should exist on both ends of the price spectrum

Observations

- ❑ Decoupling may be in the State's best interest if it is revenue-neutral to industry
- ❑ The Alliance feels this bill, in its current form, does not go far enough to encourage a significant shift in investment
- ❑ Although we have touched on several points from Dr. van Meurs on different types of production and corresponding tax rates it would be difficult to implement the approach
- ❑ The method and levers to be adjusted is the challenge before the senate but we support a magnitude of change that would place us in the middle of a comparative chart produced by PFC Energy

TESTIMONY OF RESOURCE DEVELOPMENT COUNCIL FOR ALASKA TO
SENATE FINANCE COMMITTEE,
REGARDING CSSB192(RES)
MARCH 16, 2012

Good morning Co-Chairs Stedman and Hoffman and members of the committee. My name is Rick Rogers, Executive Director of the Resource Development Council for Alaska (RDC). RDC is a statewide membership-funded non-profit trade association representing the common interest of the Forestry, Fishing, Tourism, Mining and Oil and Gas industries in Alaska. Our membership is truly a broad cross section of Alaska businesses including the aforementioned industries as well as communities, all twelve Alaska Native Regional Corporations, organized labor, utilities and support business that recognize the important role resource development plays in our economy.

RDC thanks the committee for this invited testimony. I regret being unable to be with you today in Juneau, and appreciate the LIO and staff facilitating testimony from Anchorage. I have prepared no slides for today's presentation.

RDC is appreciative of this committee's recognition of the need to improve the investment climate in Alaska's oil and gas industry to stem TAPS throughput decline. I hope to emphasize the sense of urgency and the broad base of support from RDC membership towards meaningful adjustment to the production tax to achieve a more attractive investment climate in Alaska. Some of the most vocal proponents of production tax reform among our membership are not directly involved in the oil and gas industry. The business community is fearful what continued TAPS throughput decline will do to our economy as a whole.

We are convinced that ACES in its current form is retarding investment and contributing to an accelerating production decline. Alaska is sitting on the edge of a fiscal cliff. A sobering outlook can be found in the Governor's budget, the ten-year budget projection that shows several plausible scenarios with significant budget deficits by 2014. While meaningful tax reform will result in short-term revenue decline, long term it is imperative that we sacrifice some short-term tax revenues to reinvigorate production. From the RDC perspective, this is about acting in the long-term interest of Alaskans.

The long-term discussion needs to be how to encourage more production. Taxing ourselves to prosperity is not a strategy. The CS to SB192 as currently drafted will not provide the improved business climate that results in the investment needed to increase production.

- The changes to the progressivity formula in CSSB192(RES) are insufficient to change investment behavior. RDC has heard this from both industry and the Department of Revenue.
- The allowances for new production in the bill have minimal impact, approximately \$25 million per year according to the Department of Revenue March 14 testimony to this committee.
- The gross minimum tax is a tax increase of up to \$400 million per year at \$40 oil and according to the bill's sponsor statement this is a tax increase at prices up to \$70/bbl. We cannot expect tax increases to stimulate investment.

This is a historic turning point for Alaska. Rhetoric characterizing tax reform as a "give away" that legislators must "stand up to" unfortunately mischaracterizes the objective. The Senate Finance Committee is faced with making tough choices necessary to empower the private sector to increase Alaska's productivity to the ultimate benefit of its citizens. We are looking to the Senate Finance committee to provide the leadership necessary to make meaningful reforms that will result in needed investment and resulting production.

Ironically as currently drafted the bill is a giveaway because it will not increase production, which I think we all agree is the ultimate objective. RDC is interested in meaningful results that move the needle, slowing and then reversing production decline. As currently drafted CSSB192(RES) will not move the needle. PPT and then ACES tripled production taxes since 2005, contributing to an accelerating production decline in spite of robust oil prices. DOR analysis suggests this bill makes little difference compared to ACES. Tripling up while "tweaking" down is not going to result in the investment needed to move the needle to increase investments that will lead to more production.

Some have suggested meaningful tax reform that really makes a difference to the investment climate is somehow inconsistent with Title 8 of Alaska's constitution. I do

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not recall Governors Hammond, Sheffield, Cooper, Hickel, Knowles or Murkowski being accused of failing to uphold Alaska's constitution when they had far lower oil and gas production taxes than we do today. These governors presided under more balanced fiscal regimes, and RDC encourages this legislature to return to a more balanced fiscal regime for the mutual benefit of Alaska and the industry. This is not to suggest we support going back to the economic limit factor (ELF), but clearly we need something far more substantive than CSSB192(RES) as currently drafted.

RDC supports HB110 because it will move the needle. The producers have committed \$5 billion in new investment if meaningful reform such as HB110 passes, and they have said that \$5 billion is just a start. While some have criticized the validity of those commitments, I cannot envision a rational corporate strategy that would make those types of commitments and then not follow through.

Investment decisions are made based on a multitude of variables, few of which the Alaska Legislature has any control over. Alaska is one of the highest-cost jurisdictions in the world. Alaska has immense challenges due to limited infrastructure, federal jurisdiction over wetlands, limited drilling seasons and other hurdles. Companies need to assess project economics on all these variables, and burdening production with taxes that are too high has discouraged investment. We should be in a boom of investment at \$120 oil, but we are seeing flat investment and an associated accelerating decline curve. For example, Conoco Phillips Alaska capital investment is flat in Alaska vs. a 104% increase in the Lower-48 (2010-2011).

I understand the Senate has rejected HB110 and has chosen a different path. RDC does not care which legislative vehicle gets us across the goal line. We do care that it is substantive, significant, and meets the objective of encouraging private capital to return to the North Slope. The legislature is setting the stage for Alaska's future. Will it be a future of accelerating declines or a flattening decline curve and eventually increased production? If SB192 is the vehicle of choice, it needs far more meaningful adjustments to progressivity or adjustments to other "levers" to approximate a revenue curve more in keeping with HB110.

RDC is glad that exploration credits, which are working, have not been reduced or removed in CSSB192(RES). Exploration is an important element, however exploration credits need to be part of a broader approach leading to increases in near term and long-term production. When new oil is found we need an investment climate to

encourage its production.

Geology, federal regulatory oversight, remoteness, high costs, short drilling seasons, and volatile commodity prices are all out of the State's control. The bottom line is tax policy is one of the few variables in the oil and gas business that the State can control. We are going to get what we ask for. If we continue with a policy that discourages investment and directs it elsewhere, Alaskan's better start battenning down the hatches as we are entering a very dark time for Alaska's economy that I fear it will make the 80's look like a walk in the park.

A better approach is to make substantive changes that result in compelling fiscal terms leading to robust activity to slow and reverse the production decline. This discussion is about what is best for Alaska, not what is best for the oil and gas industry. The oil and gas industry has the capacity to do great things in Alaska; we need to set the stage and turn it loose. We did not get to 16.5 billion barrels of production by being timid. It's time for some bold action to get Alaska back on track.

The producers are the ones making the investments. There are many places for the industry to invest and Alaska does have to compete. Consultants can offer helpful direction, but the companies at the end of the day are the ones making the investments. Please listen to them and take to heart the criteria that companies look at when deciding where to invest.

Thank you Chairman and members of the committee for hearing from RDC on this most important issue for Alaska's future.

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