

SB

192

(FILE 1)

<TARGET><BILL>SB 192</BILL><SUBJECT>SB 192 (FILE
1)</SUBJECT><COMM>SRES27</COMM></TARGET>

SENATE BILL NO. 192

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SEVENTH LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Introduced: 2/8/12

Referred:

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to the oil and gas production tax; and providing for an effective date."

2 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

3 * **Section 1.** AS 43.55.011(g) is amended to read:

4 (g) For each month of the calendar year for which the producer's average
5 monthly production tax value under AS 43.55.160(a)(2) for a [PER] BTU equivalent
6 barrel of the taxable oil and gas is more than \$30, the amount of tax for purposes of
7 (e)(2) of this section is [DETERMINED BY MULTIPLYING THE MONTHLY
8 PRODUCTION TAX VALUE OF THE TAXABLE OIL AND GAS PRODUCED
9 DURING THE MONTH BY THE TAX RATE CALCULATED AS FOLLOWS:

10 (1) IF THE PRODUCER'S AVERAGE MONTHLY PRODUCTION
11 TAX VALUE PER BTU EQUIVALENT BARREL OF THE TAXABLE OIL AND
12 GAS FOR THE MONTH IS NOT MORE THAN \$92.50, THE TAX RATE IS] 0.4
13 percent multiplied by the number that represents the difference between that average
14 monthly production tax value for a [PER] BTU equivalent barrel and \$30 [; OR

15 (2) IF THE PRODUCER'S AVERAGE MONTHLY PRODUCTION

1 TAX VALUE PER BTU EQUIVALENT BARREL OF THE TAXABLE OIL AND
2 GAS FOR THE MONTH IS MORE THAN \$92.50, THE TAX RATE IS THE SUM
3 OF 25 PERCENT AND THE PRODUCT OF 0.1 PERCENT MULTIPLIED BY THE
4 NUMBER THAT REPRESENTS THE DIFFERENCE BETWEEN THE AVERAGE
5 MONTHLY PRODUCTION TAX VALUE PER BTU EQUIVALENT BARREL
6 AND \$92.50, EXCEPT THAT THE SUM DETERMINED UNDER THIS
7 PARAGRAPH MAY NOT EXCEED 50 PERCENT].

8 * **Sec. 2.** This Act takes effect January 1, 2013.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

Bill Version SB 192
 Fiscal Note Number _____
 () Publish Date _____

Identifier (file name) SB192-DOR-TAX-02-09-12 Dept. Affected _____ Revenue _____
 Title Oil and Gas Production Tax Rates Appropriation Taxation and Treasury
 Allocation Tax Division
 Sponsor Senate Resources Committee
 Requester (S) RES 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				
			FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES	FY13	FY13	FY14	FY15	FY16	FY17	FY18
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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

POSITIONS							
Full-time							
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)

Initial version.

Prepared by Cherie Nienhuis, Commercial Analyst
 Division Tax Division
 Approved by Bryan Butcher, Commissioner
Department of Revenue

Phone 907-269-1019
 Date/Time 2/9/2012; 1pm
 Date 2/9/2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. SB 192

Analysis

This bill makes a change to the progressive tax rate portion of the production tax at AS 43.55.011(g) by removing the second trigger of the progressive tax rate calculation that lowers the progressive tax rate to 0.1% on production tax values of \$92.50 and greater. The bill also removes the statutory maximum tax rate of 75% under the production tax statutes. The bill retains the initial trigger of \$30 in production tax value at which point the progressive tax rate is calculated as 0.4% per dollar increase in production tax value.

Given the Fall 2011 oil price, production, and lease expenditure forecast through FY 2017, the tax rate changes from this bill are not projected to have a direct revenue impact. The Fall 2011 forecast through the time period covered by this fiscal note (FY 2017) range from \$106 per barrel to close to \$110 per barrel for Alaska North Slope crude oil. Combined with anticipated production levels and lease expenditure projections, our forecast does not anticipate production tax values meeting or exceeding \$92.50 per barrel. Therefore, based on our most recent forecast, the progressivity rate changes in this bill will not impact revenue expectations.

If oil prices were to increase, or if production were to increase with no corresponding increase in lease expenditures, production tax rates, and therefore revenue, could be increased from this bill. With current production levels, and current transport costs and lease expenditure levels, much of North Slope crude oil would be subject to a production tax increase at \$120 - \$130 per barrel (ANS WC) and above. Without a maximum production tax rate, tax rates could continue to escalate until they exceed 100%. Marginal government take exceeds 100% at approximately \$140 per barrel, when holding all other assumptions constant. This means that at \$140 per barrel, the government would take more than 100% of every dollar that the oil price increases.

The bill has an effective date of January 1, 2013.

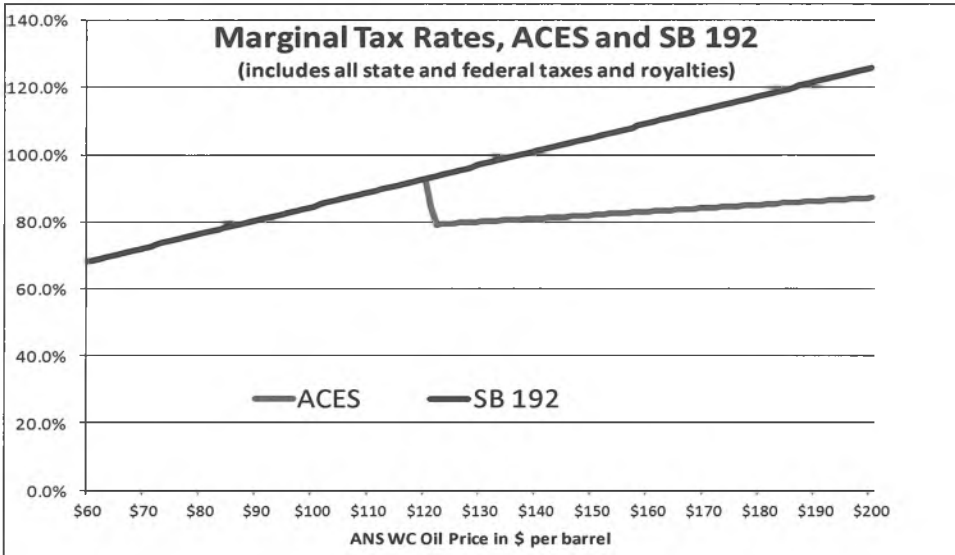
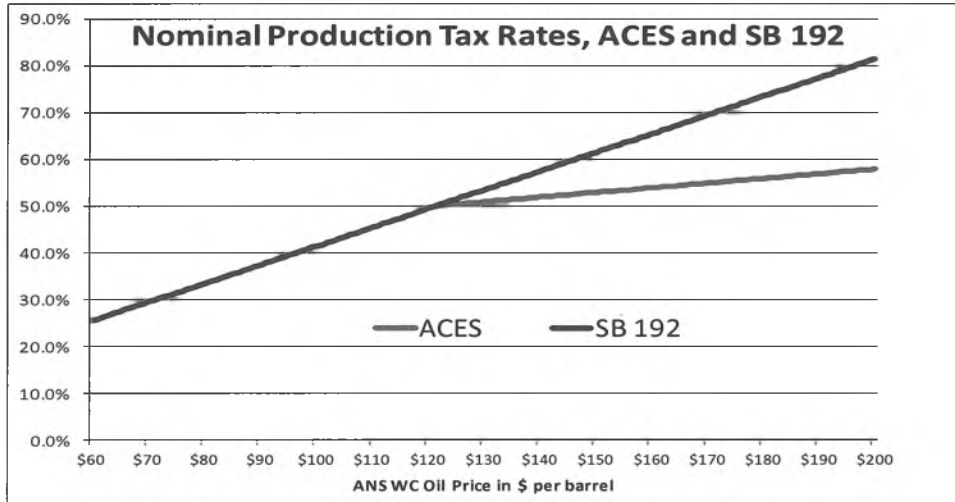
The following two graphs show nominal production tax rates and marginal tax rates at a range of oil prices given current transport and lease expenditure assumptions for ACES (current law) and SB 192. Nominal production tax rates are the ACES statutory production tax rates as calculated by taxpayers; marginal tax rates are the rates that the government collects of each additional dollar that the oil price increases. The marginal tax rate graph includes all major federal and state taxes and royalties.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. SB 192

Analysis Continued



FISCAL NOTE

STATE OF ALASKA cost # codes
 2012 LEGISLATIVE SESSION

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(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					
			FY13	FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES								
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

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
 Sponsor Senate Resources Committee Commission _____
 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
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)

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
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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



Claire Fitzpatrick

Chief Financial Officer
Alaska Strategic Performance Unit

BP Exploration (Alaska) Inc.
PO Box 196612
900 East Benson Boulevard
Anchorage, Alaska 99519-6612
Direct 907 564 5398
Main 907 564 5111
Fax 907 564 5598
Mobile 907 223 6654
fitzc3@bp.com

February 15, 2012

The Honorable Joe Paskvan
Co-Chairman, Senate Resources Committee
State Capitol Building, Room 115
Juneau, AK 99801-1182

Dear Senator Paskvan:

Thank you for the invitation to testify before the Senate Resources Committee and please accept my apologies as work commitments require me to be out of the country this week.

BP Exploration (Alaska), Inc. (BPXA), as operator of the Prudhoe Bay Unit, Northstar Unit, Milne Point Unit and Duck Island Unit (Endicott), conducts unit operations under Plans of Development (POD) approved by the State of Alaska, Department of Natural Resources (DNR). The requirements for a POD are set forth in the Alaska Administrative Code and the applicable Unit agreements. The POD is approved at or shortly after formation of each Unit, and each Participating Area (PA) within a Unit.

PODs are generally updated on an annual basis. BPXA, as Operator of the above mentioned Units, files approximately 15 POD updates annually following POD reviews with the DNR and other interested agencies (e.g. AOGCC and BOEMRE). These reviews are generally scheduled just prior to submittal of the POD and give the agencies and the unit operator a chance to review and discuss the POD. Following the submission of each PA POD, the DNR will respond stating whether the POD is deemed complete. Once the POD is deemed complete, the commissioner has 60 days to consider the POD update for approval.

The development plans submitted by BPXA on behalf of the working interest owners of the fields we operate have laid the foundation for a track record of success. As a case in point, total cumulative production from the Prudhoe Bay Unit initial participating area has already substantially exceeded the ultimate recovery that was projected when the field began operation. But that success is becoming more difficult to sustain. North Slope production is declining at an annual rate of approximately six percent. As we have indicated in the past, a revised fiscal environment will facilitate progression of more projects that will have an impact on the expected decline rate.

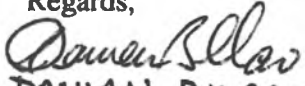
Response to Senator Paskvan's letter

February 15, 2012

Page 2

BPXA appreciates the opportunity to illustrate the POD process we follow for our operated North Slope units. We look forward to continued dialogue on the critical question of how to stem production decline and improve the investment climate on the North Slope.

Regards,


DAMIÁN BILBAO
ON BEHALF OF
Claire Fitzpatrick

ExxonMobil Production Company

P. O. Box 196601
Anchorage, Alaska 99519-6601
907 561 5331 Telephone
907 564 3677 Facsimile

Dale Pittman

Alaska Production Manager
Joint Interest U.S.

February 15, 2012

ExxonMobil
Production

The Honorable Joe Paskvan
Co-Chairman, Senate Resources Committee
State Capital Building, Room 115
Juneau, AK 99801-1182

Dear Senator Paskvan:

ExxonMobil appreciates the Resource Committee's attention to production tax reform. We understand that your committee is seeking comments on the need to reform Alaska's Clear and Equitable Share (ACES) production tax rather than on Senate Bill 192. Let me respectfully offer you ExxonMobil's views on this topic for the record and direct you to recent testimony and perspectives that we've provided.

We believe that meaningful tax reform is critical for Alaska's economic future. While I am unable to join you in person on such short notice, I do feel that the work you are undertaking is important.

ExxonMobil continues to support Governor Parnell's efforts toward substantive reform of the current production tax. It is apparent that Alaska's production tax since 2005 has had a deleterious impact on business activity and investment in the state. Simply put, the current production tax is too high to stimulate the additional investment necessary to fully develop Alaska's oil and gas resources in the decades ahead. It is essential to have a tax structure in place that encourages long-term, material development of Alaska's potential to significantly grow state revenues, secure jobs and stem the production decline.

During the 2011 legislative session, I appeared before the House Resources Committee and testified on this topic. I am attaching a copy of that testimony as well as an op-ed letter signed by Rich Kruger, ExxonMobil Production Company President, which underscores the need for production tax reform. We continue to stand by the positions stated in these two documents.

Thank you again for the opportunity to provide input and be part of the ongoing debate during the 2012 sitting of the legislature. ExxonMobil is committed to Alaska and we look forward to working with you and your colleagues during this legislative session to develop a tax regime that will allow the resources of this great state to be developed for the benefit of all stakeholders.

Sincerely,



DDP:jpc
Enclosures (2)

cc: Governor Sean Parnell
Senator Thomas Wagoner, Co-Chairman, Senate Resources Committee

TESTIMONY OF DALE PITTMAN
ON PROPOSED HB 110
TO THE ALASKA HOUSE RESOURCES COMMITTEE
February 16, 2011

INTRODUCTION

Mister Chairman, members of the committee:

Good afternoon. For the record, my name is Dale Pittman. I am the Alaska Production Manager for ExxonMobil, based in Anchorage. I want to thank the committee for the opportunity to express ExxonMobil's views regarding HB 110, the Governor's proposed amendments to Alaska's oil and gas production tax or ACES.

Let me start by saying that Alaska has been and continues to be an important component of ExxonMobil's world-wide investment portfolio. We have had a presence in Alaska for over 50 years and have been a key player in Alaska's oil industry development, investing over \$12 billion dollars to date. We are the operator of Point Thomson, hold the largest working interest at Prudhoe Bay (36.4%) and the largest lease holder of discovered Alaska gas resources. We expect to be involved in Alaska for many years to come and will continue to evaluate potential development opportunities.

At the outset, so our position is clear, let me say that ExxonMobil supports the presentation you heard today from the Alaska Oil and Gas Association. I do not intend to repeat the thorough technical comments from that testimony.

As for our specific comments, I would like to state, consistent with our prior testimony during the hearings on both the PPT and ACES, and on the proposed tax reform legislation last session, that ExxonMobil believes the changes made to Alaska's oil and gas production tax since 2005 have had a negative impact on business activity in Alaska and Alaska's overall investment climate. Alaska's current production taxes are simply too high to stimulate the additional investment required to fully develop Alaska's oil and gas resources.

It is for this reason ExxonMobil is pleased to see that the Administration recognizes the need for material change to Alaska's current oil and gas production tax system. We are encouraged by Governor Parnell's desire to see increased investments and further oil and gas development. We support his efforts to reform ACES and believe HB 110 is a good first step towards what we hope is a thorough review and revision of Alaska's production tax regime to allow the state to fully develop its vast resources.

ExxonMobil supports HB 110, and if enacted in its current form, we would expect investment activity in Alaska to increase, resulting in a corresponding benefit of more work for Alaskans. With passage of the Governor's proposed changes to ACES in its current form, we anticipate that industry will reexamine the inventory of Alaska North Slope opportunities and move forward with those projects that are made competitive by the reduced production tax burden. For example, the

proposed enhanced in-field drilling tax credits and reduction to the progressivity tax would allow us to consider additional drilling and well work activity at the Prudhoe Bay Unit. This kind of developmental drilling in the core field on the North Slope is critical to Alaska's future, particularly over the next five to ten years. Production decline must be stemmed until new developments can be discovered, progressed and brought on production.

While the enhanced in-field drilling tax credits and reduction to the progressivity tax are much needed revisions to ACES, we would urge earlier effective dates to accelerate the resulting ramp up in investment activity, Alaskan jobs and future state revenues.

However, merely providing additional tax credits while keeping the overall effective rate of the ACES tax too high is not the long term solution to improving Alaska's investment climate. While the system of tax credits under ACES does provide significant incentives for investing in capital assets to explore for, develop, and produce more oil and gas, the deduction of lease expenditures or the allowance of a tax credit is simply part of the calculation about how much tax a producer owes. The bottom line is that, between PPT and ACES, the industry's production tax obligations have more than tripled over the past five years.

ExxonMobil supports the Governor's proposal as an important first step, but additional reform of ACES is needed.

Additional reforms are needed to improve Alaska's overall investment climate over the long term. Evaluation of a further reduction in the production tax rates should also be considered. Even with the Governor's proposal, Alaska's production taxes are high in comparison to other investment alternatives, making Alaska one of the most expensive states in which the oil and gas industry does business.

As you have heard in prior testimony or may have read in recent newspaper articles, spending on the North Slope has remained relatively flat since the enactment of ACES. But what needs to be clarified is that the majority of that investment has been for maintenance or production enhancement efforts for existing operations, not for new exploration and development opportunities that would bring on new production. It is also worth noting that costs for this investment activity have gone up, so while some may argue there has been additional investment, it doesn't necessarily translate into more activity. For example costs to drill a well have increased over the years, so higher spend on drilling does not necessarily mean more wells are being drilled.

Alaska is currently producing approximately 600,000 barrels of oil per day from the North Slope. Industry currently invests more than \$1 billion per year just to

maintain current North Slope oil production decline at six to seven percent.

Without that continued investment, the annual production decline would be in the range of 12 to 15 percent annually.

The Alaska Department of Revenue is forecasting the production from Alaska's currently producing fields to decline by 60,000 barrels of oil per day this year. It goes on to predict that current field production will decline to half of its current 600,000 barrels of oil per day rate in just seven years, a decline of over 300,000 barrels of oil per day. Allow me to put the challenge of stemming that decline in perspective.

Alaska's newest development, the Nikaitchuq field, is scheduled to produce first oil early this year. The field has been more than six years in planning, development and construction and carries a total cost of over \$2 billion dollars. The field is forecasted to reach peak production of about 25,000 barrels per day four years from now. So using this as an example, it would take the startup of two to three Nikaitchuq equivalent fields every year in perpetuity just to hold North Slope production at 600,000 barrels of oil per day. Pioneer's Oooguruk field is another example. It would take three to four fields the size of Oooguruk every year to match the forecasted North Slope production decline. Clearly, the current outlook for development falls far short, and new fields are urgently needed to stem this decline.

Such development will only occur if there is an improvement in the Alaska investment climate. Alaska production tax policy is key to fostering a favorable investment climate.

Alaska's overall high production tax rates discourage investment. Companies like ExxonMobil are willing to accept the risks of long-term, capital intensive investments when there is a stable and competitive tax structure that encourages investment and ensures a corresponding opportunity for upside potential. When you take away the upside potential through a high progressivity tax you reduce the overall attractiveness of those capital intensive investments, which in turn could lead to reduced investment and resource recovery and, in the long-term, diminished state revenues. Let me reemphasize this point, while higher taxes may bring additional revenues in the short-term, it's reasonable to anticipate that any reduction in investment will decrease production and significantly reduce those revenues in the longer term.

As many of you heard me testify last year, time in the oil and gas industry is not measured in business cycles. It is measured in decades and in generations. Today's production rates are the product of government policies, technical work, and investment decisions made years ago. Increasing production rates in the decades to come will be a direct result from sound policies, decisions, and commitments that are made today. The Governor's proposed ACES changes

are clearly a significant step in the right direction towards much needed reform of Alaska's high oil and gas production tax system.

Alaska needs a long-term resource development policy that will encourage increasing investment to maximize its resource potential while receiving a fair share of the resource revenues; addressing its high level of government take is a start. The reform of ACES needs to result in a competitive, stable and predictable fiscal environment that will encourage investment, recognize that the remaining resources are economically challenged, including both new fields and resource development opportunities in existing fields. The primary driver of Alaska's long-term resource development policy should be to maximize the development of its resource base, not just maximize short-term state revenues.

Let me conclude my testimony by reiterating that while we hope to continue to pursue investment opportunities in Alaska in the future, the resource and cost structure in Alaska is becoming increasingly challenging. Governor Parnell's proposed changes to ACES are a good start to needed fiscal reform - but more is still needed.

ExxonMobil looks forward to working with the Administration, the legislators, industry and the people of Alaska in the future pursuit and development of Alaska's oil and gas resources.

Thank you again Mister Chairman for the opportunity to testify today.

UNITE FOR A BRIGHT ALASKAN FUTURE

Alaska remains full of opportunity and promise. From the very first Native Alaskans to all the citizens who live and work in the state today, Alaska's challenges have been met by those willing to look beyond the horizon.

Despite challenging environmental conditions, Alaska has achieved a remarkable and enviable position in the world by responsibly developing its natural resources – hard work that has fueled an engine of progress for the state and its people. Today, Alaska's oil and gas production accounts for more than 34,000 jobs across the state and nearly 90 percent of its general revenue.

Unfortunately, the engine is not firing on all cylinders.

Since 2007, Alaska's Clear and Equitable Share (ACES) tax regime has failed to be either clear or equitable. Under ACES, nearly every measure of progress has declined, including investments and production. And as oil volumes flowing through the TransAlaska Pipeline (TAPS) continue to decline, the engine of progress is in very real danger of stalling.

Governor Parnell has recognized the detrimental effect of ACES on Alaska's future and is leading real changes to improve the state's competitiveness. His proposals offer an important step in the right direction toward a brighter economic future for Alaska. It is our firm belief that passage of the Governor's proposed changes to ACES, in its current form, will support additional investments in Alaska that will lead to greater development and production.

Over the past several weeks there has been much discussion regarding Governor Parnell's ideas for ACES reform. Most of the talk has focused on winners and losers in the near-term. In fact, the Governor is looking beyond the horizon to long-term solutions in which everyone wins.

ExxonMobil is committed to Alaska's future. We have worked here for more than 90 years, investing more than \$12 billion to date and providing jobs for Alaskans. Currently, we are working with the state to bring the Point Thomson Project on line to produce additional oil and gas volumes in the near term. Going forward, we have joined with TransCanada to help bring a new gas pipeline to Alaska. Progressing these multi-billion dollar projects underscores ExxonMobil's continued commitment to Alaska.

Governor Parnell's proposal provides a foundation to build on the opportunity and promise of the state's vast natural resources and the indomitable spirit of its people.

Whether you are a proponent or critic of ACES reform, we all seek the same goal – a strong and prosperous Alaska. We encourage all state legislators to work together to provide industry with an investment environment that will help secure a promising future for the people of Alaska.

Rich Kruger, President
ExxonMobil Production Company



Alaska's Production Tax: Defining the Problem

*Presentation to the
Senate Resources Committee
February 10, 2012
Alaska Department of Revenue*



Facts to Begin the Conversation



1. Oil Prices began climb to all-time highs starting mid-2000's
2. TAPS throughput continues steady decline
3. Other oil producing regions enjoy production and employment booms
4. Competition is high - many other areas to invest around the world



According to the USGS, It's Not a Resource Issue



- There's no debating.....Alaska is a world-class energy basin
- Cumulative production through 2010 over 16B barrels
- Oil: Estimated to have 40B barrels of conventional oil
- Gas: Estimated to have 236 TCF of conventional natural gas
- Plus tens of billions of barrels of heavy & viscous oil as well as shale oil & gas



More Important Points

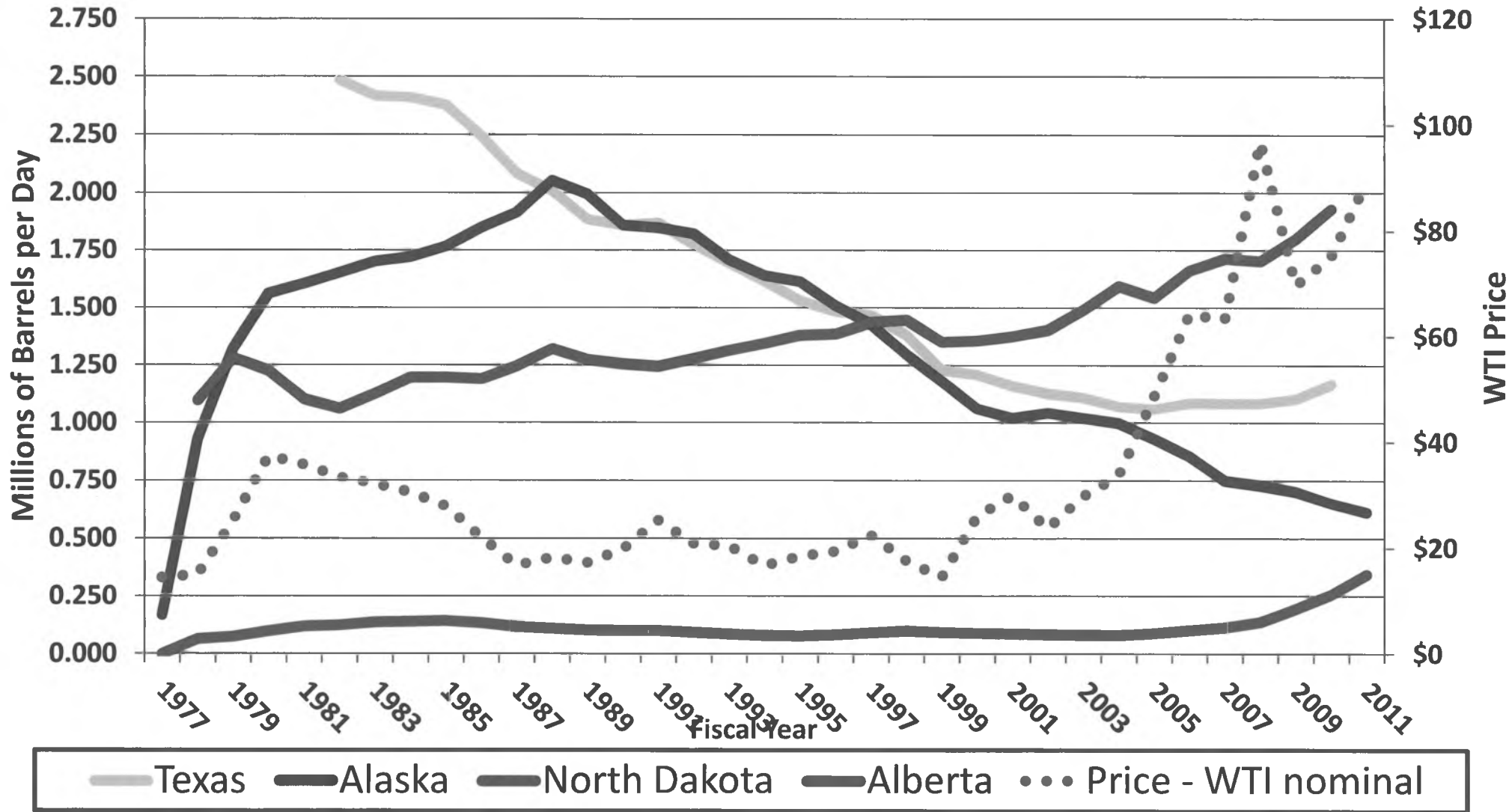


1. As a State, we are in a position we've never been in before
2. PPT/ACES Debate: "Actual" information utilized? Unfortunately No.....was not available
3. Decision makers, through no fault of their own, had to rely on modeling, forecasts, projections, theoretical assumptions
4. We now have the luxury to look back and see what actually happened over the past 5 years
5. What do we see? Record high oil prices lead to oil & employment booms in competing oil producing regions
6. And Alaska continues to decline.....



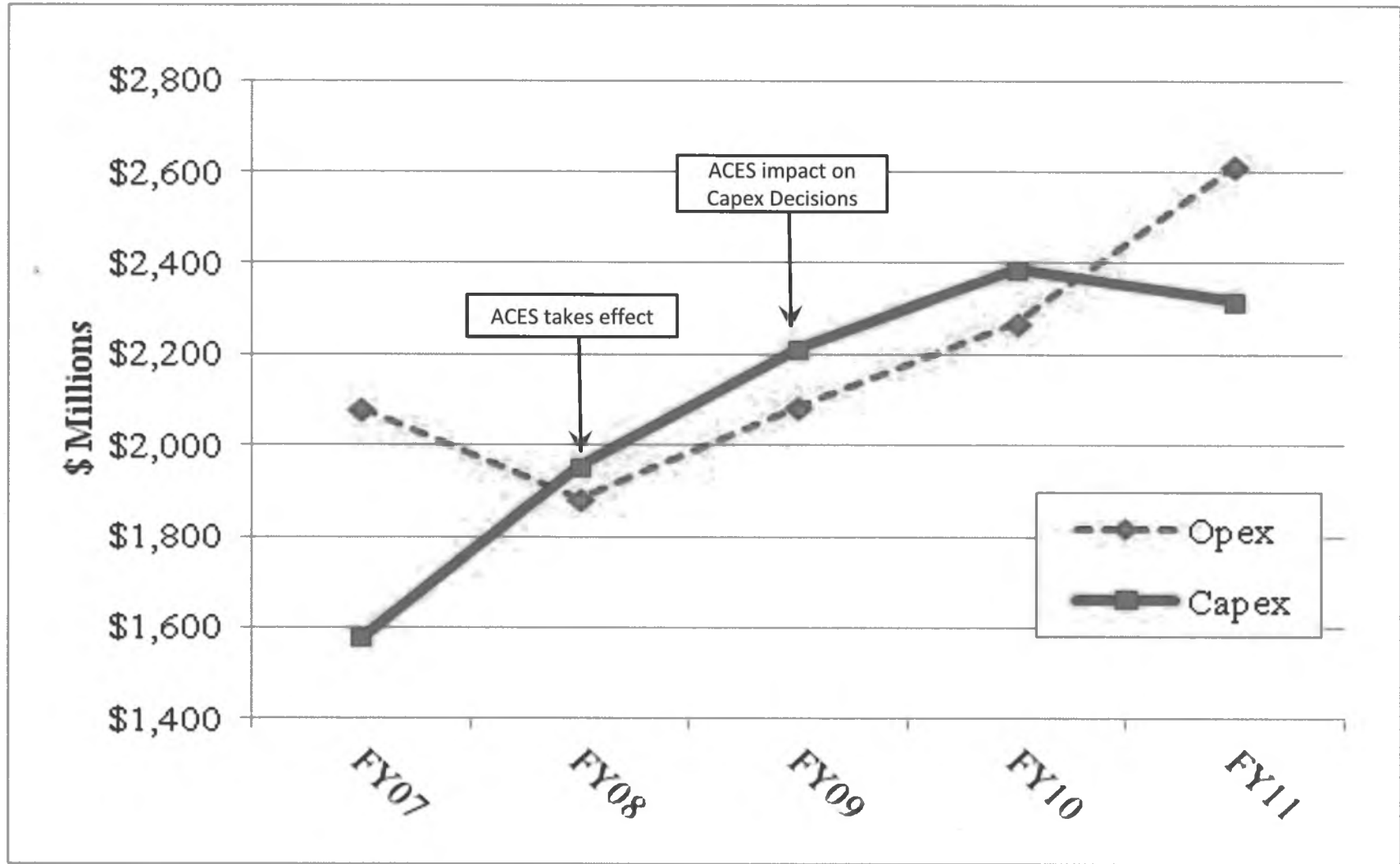
Historical Oil Production:

How Did Our Competition Fare When Prices Spiked?





Historical Actual Expenditures, FY 2007 – FY 2011

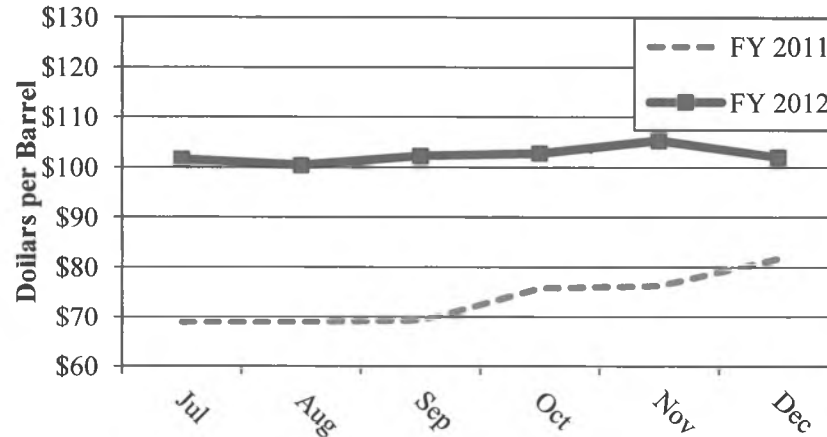




FY 2011 & FY 2012 Wellhead Values, North Slope Capex and Opex

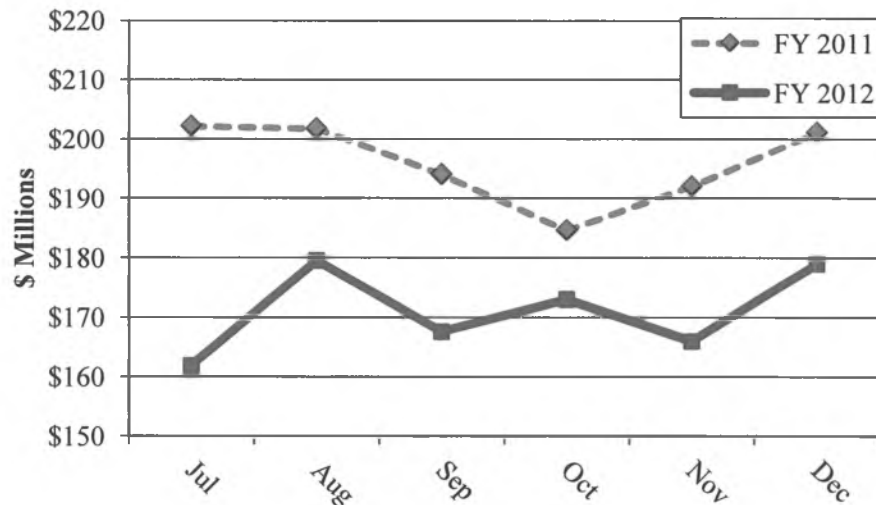


ANS Wellhead Value



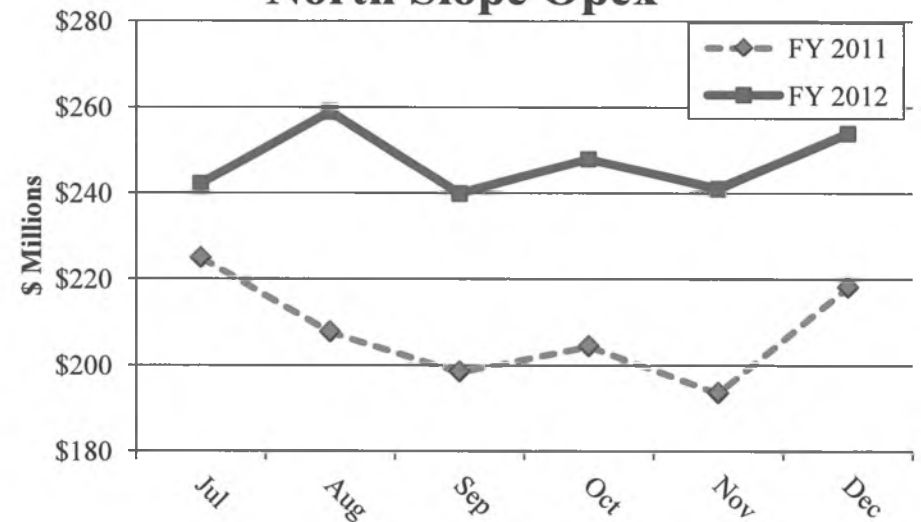
FY12 avg up 39% through 6 months

North Slope Capex



FY12 down 13% through 6 months

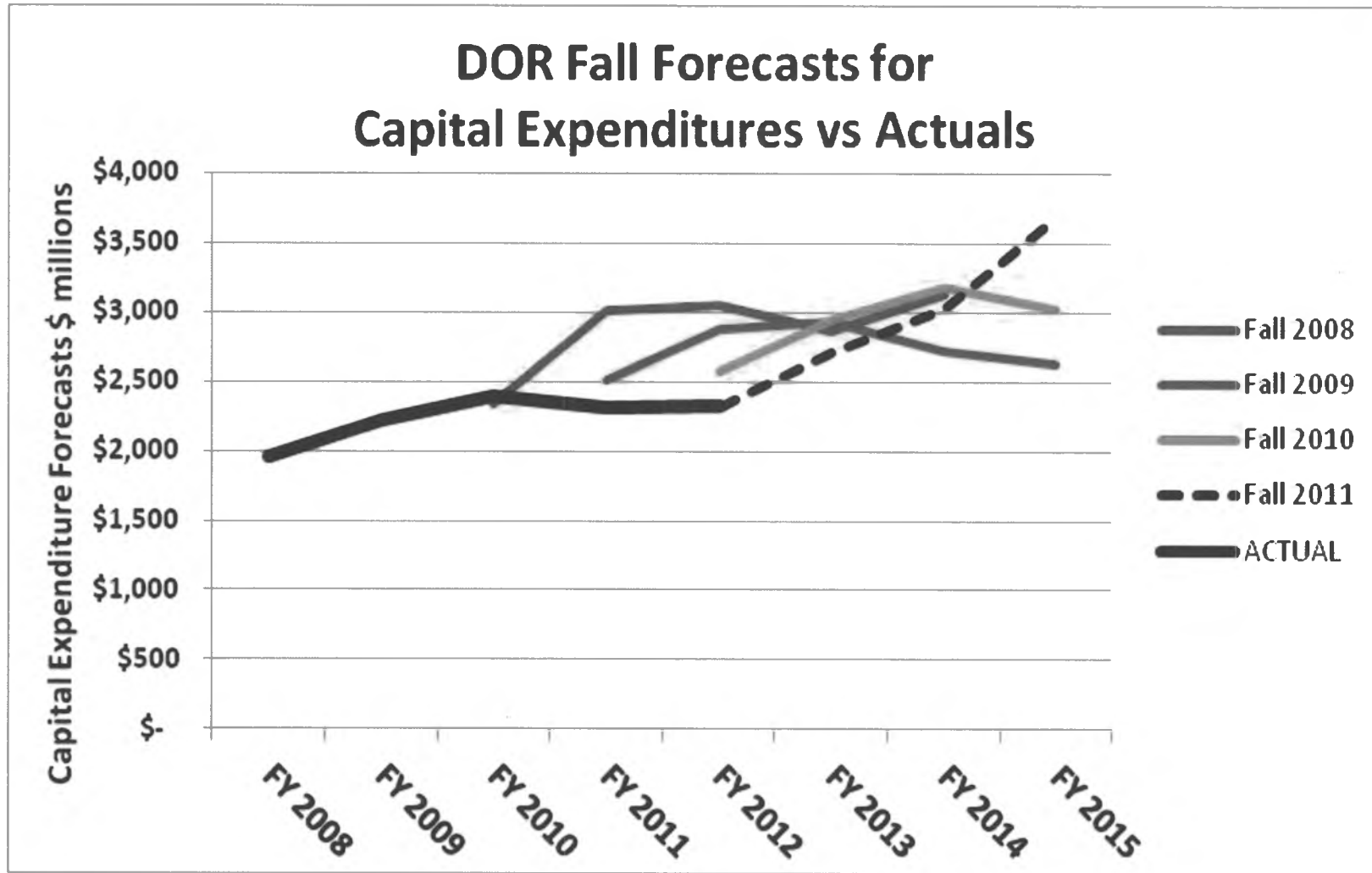
North Slope Opex



FY12 up 19% through 6 months



Capex Forecast vs Actual





Two Distinct Elements of ACES: Can't discuss one without the other



1. Tax Credits:

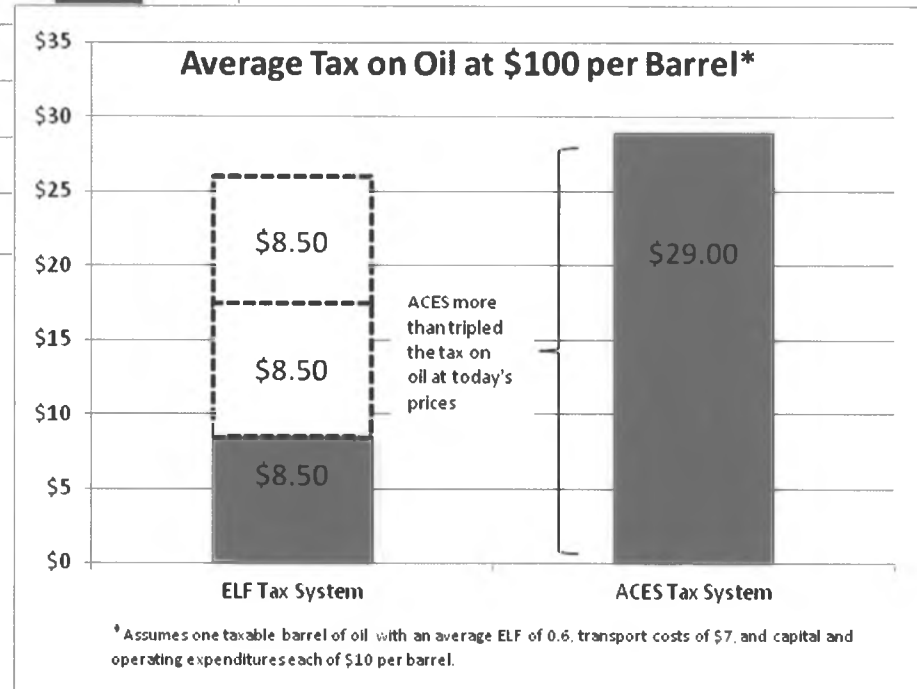
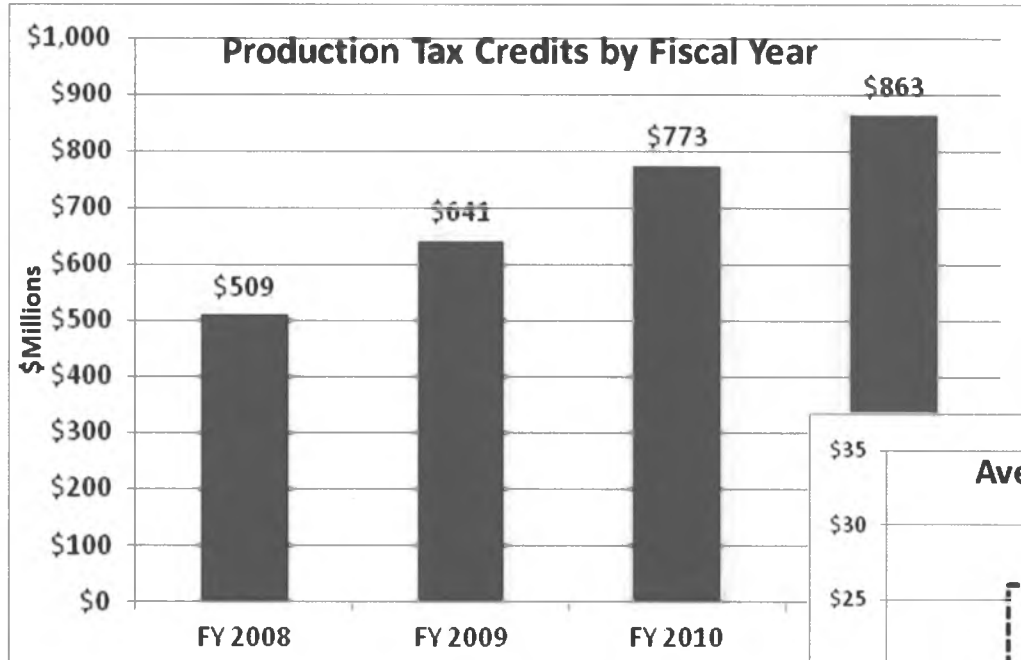
- Very generous tax credits made available over past several years help spur the anticipated exploration
- Enthusiasm of explorers encouraging but they will eventually need to become or partner with producer

2. Progressivity:

- Very progressive at high oil prices which makes AK not as attractive when compared to other world-wide options
- This “windfall tax”, while filling AK state coffers during the short term, is contributing to competitiveness issue long term



Alaska Tax Credits are up, but so are Alaska Taxes





How Do Other States Rank Alaska?



Effective Tax Rates for Oil and Natural Gas in 14 Major Oil Producing States: FY2008

	Value of Oil and Natural Gas Produced	Oil and Gas Revenue Collected	Effective Tax Rate	Maximum Statutory Rate
Alaska	\$25,741,800,390	\$6,900,000,000	26.80%	25%
California	\$21,858,237,067	\$0	0.00%	No severance tax
Colorado	\$11,834,689,515	\$139,550,829	1.18%	5%
Kansas	\$6,248,188,250	\$159,574,935	2.55%	8.00%
Louisiana	\$19,289,935,515	\$703,116,080	3.64%	12.5% oil, \$0.331 per 1,000 cu. ft. natural gas
Michigan	\$2,129,981,470	\$101,232,000	4.75%	6.6% oil, 5% natural gas
Mississippi	\$2,949,110,665	\$29,847,271	1.01%	6.00%
Montana	\$3,682,179,800	\$166,279,021	4.52%	15.06%
New Mexico	\$17,884,451,790	\$1,374,233,960	7.68%	3.75%
North Dakota	\$6,218,744,947	\$391,823,087	6.30%	11.50%
Oklahoma	\$20,650,142,263	\$493,986,142	2.39%	7.00%
South Dakota	\$161,169,059	\$5,526,990	3.43%	4.50%
Texas	\$64,669,070,628	\$4,121,526,666	6.37%	4.6% oil, 7.5% natural gas
Utah	\$4,568,953,793	\$65,510,506	1.43%	5% oil, \$1.51 per 1000 cu. ft. of natural gas
Wyoming	\$20,136,769,013	\$873,558,284	4.34%	6.00%

Source: Montana Department of Revenue, Biennial Report, http://revenue.mt.gov/content/publications/biennial_reports/2008-2010/BiennialReport-NatResTaxes.pdf

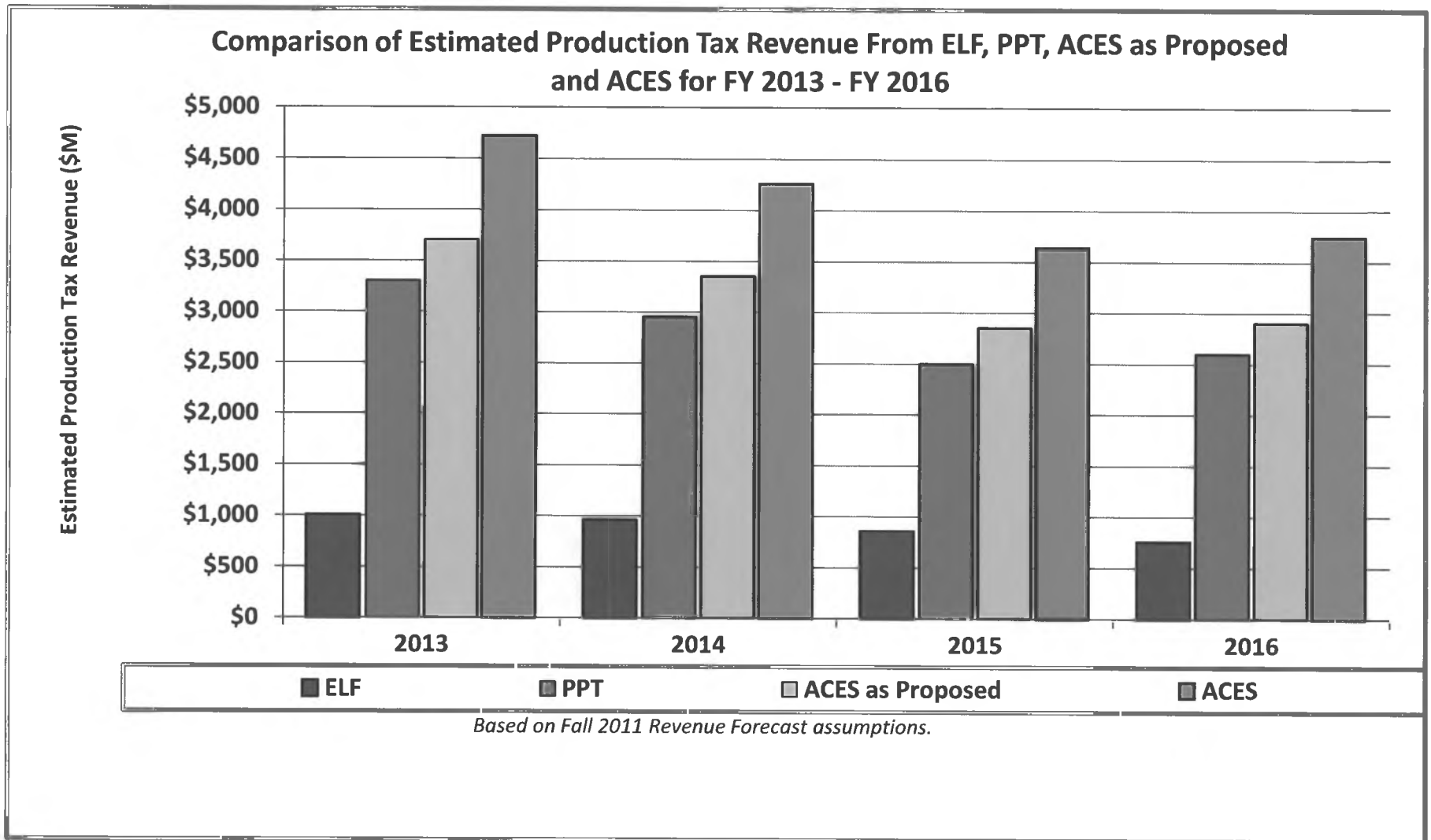
Alaska Department of Revenue



The Progressivity Problem



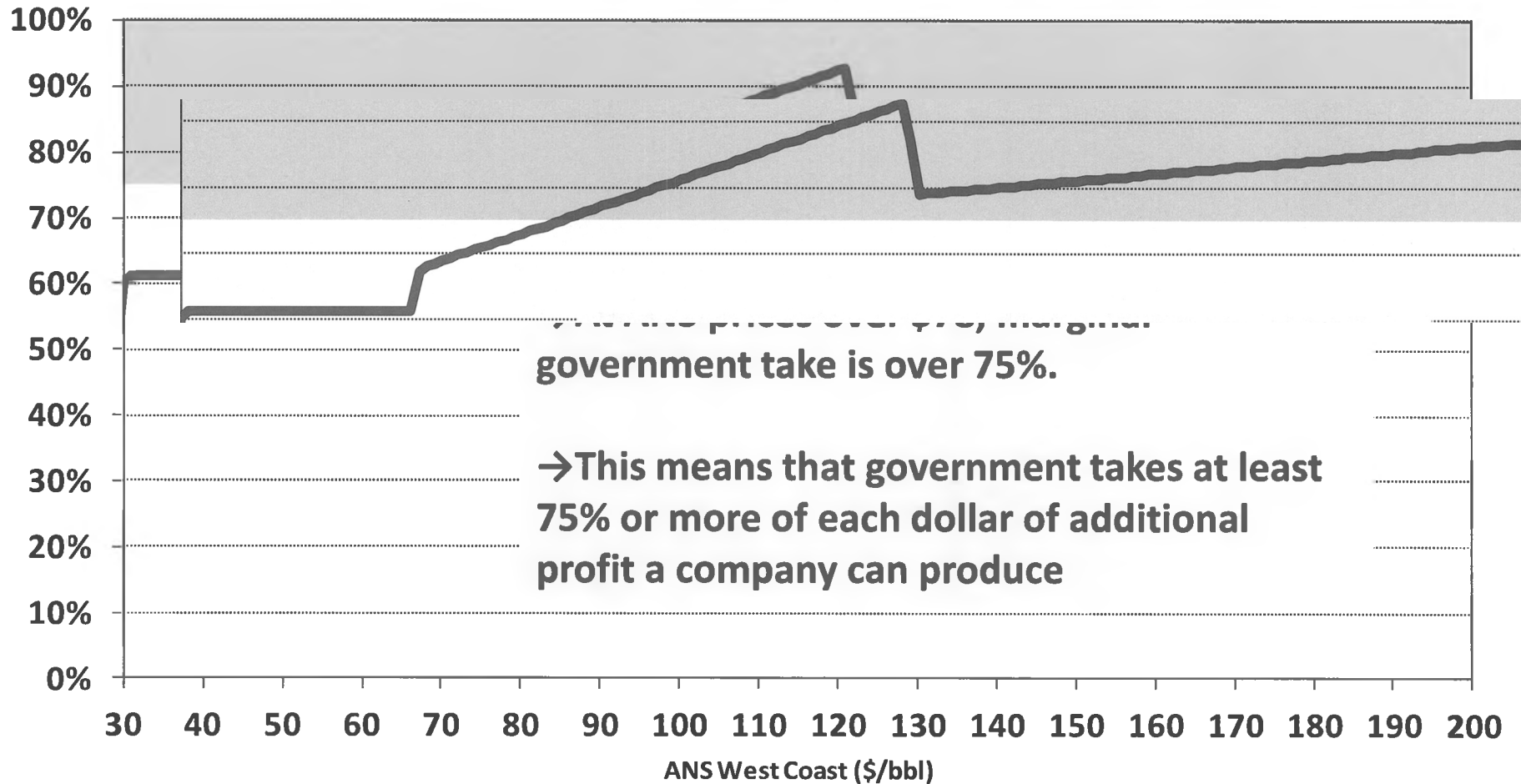
ELF, PPT, ACES as Proposed and ACES: Did The Pendulum Swing Too Far?





Marginal Government Take

Marginal Government Take



When price over \$70, marginal government take is over 75%.

→ This means that government takes at least 75% or more of each dollar of additional profit a company can produce

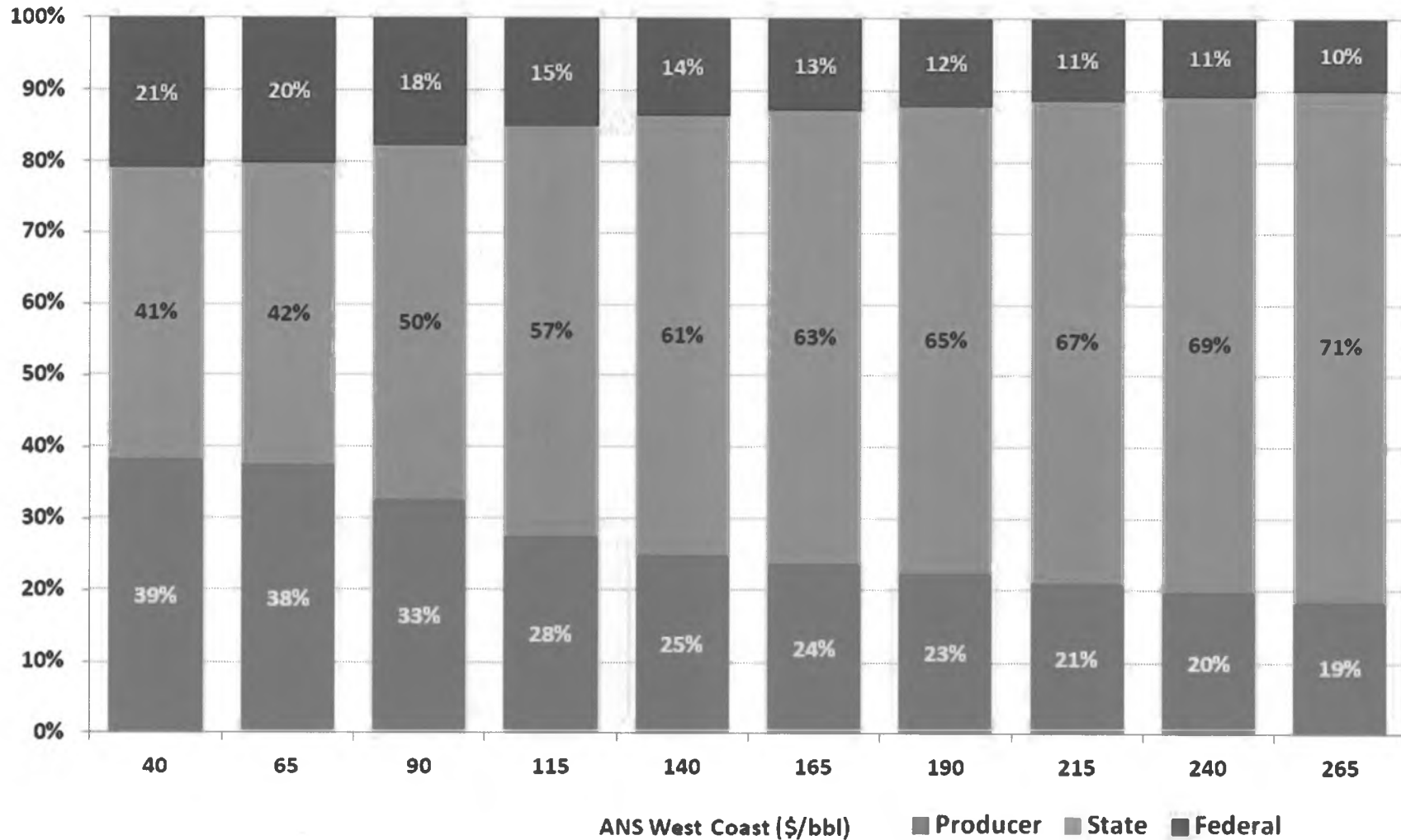
Production=600Kbbl/d, ANS Oil Price=\$100/bbl, Transportation Costs=\$6/bbl, Upstream Costs=\$20/bbl



Producer share of “profit” declines at high oil prices



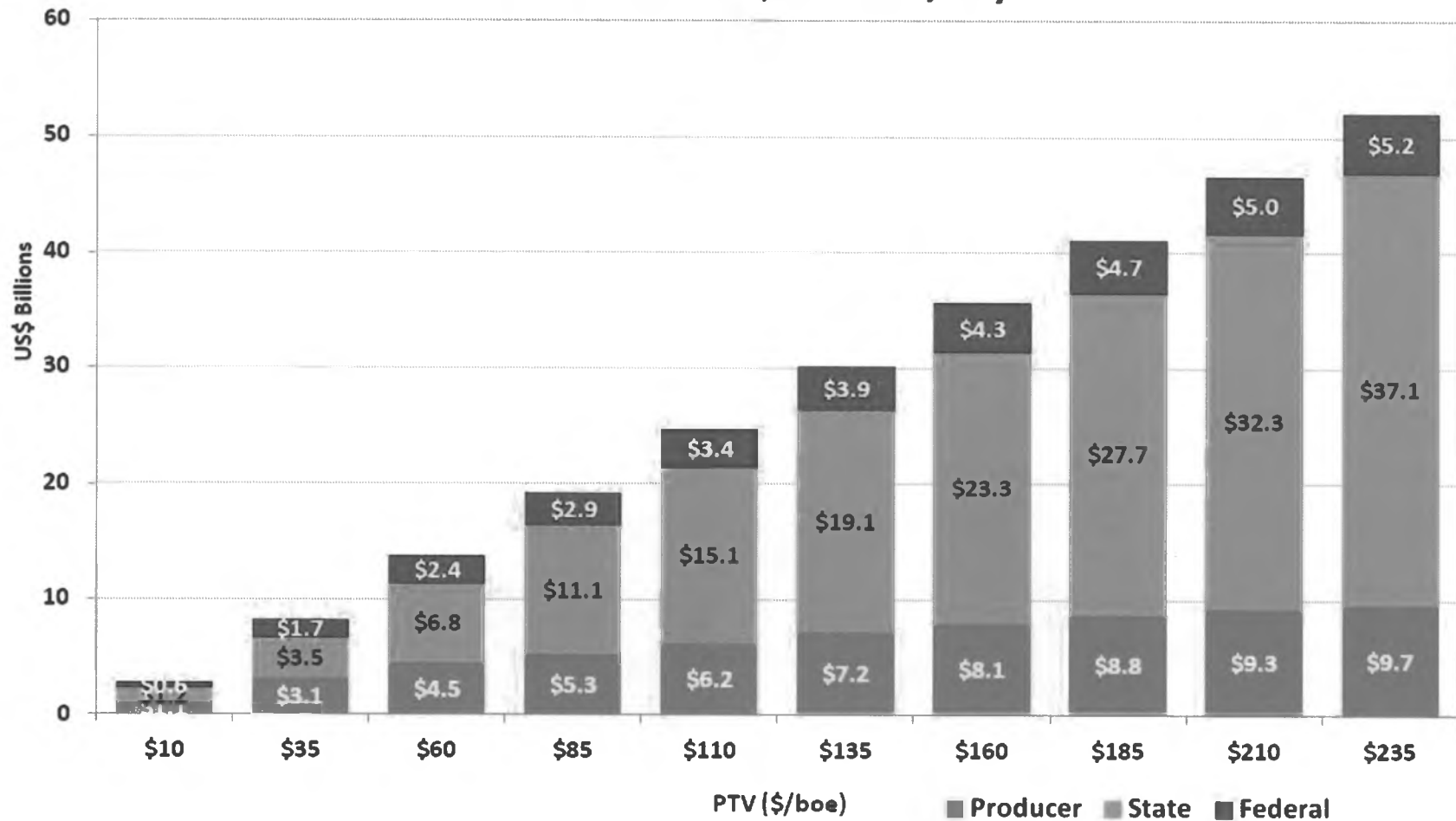
Share of Profit under Status Quo





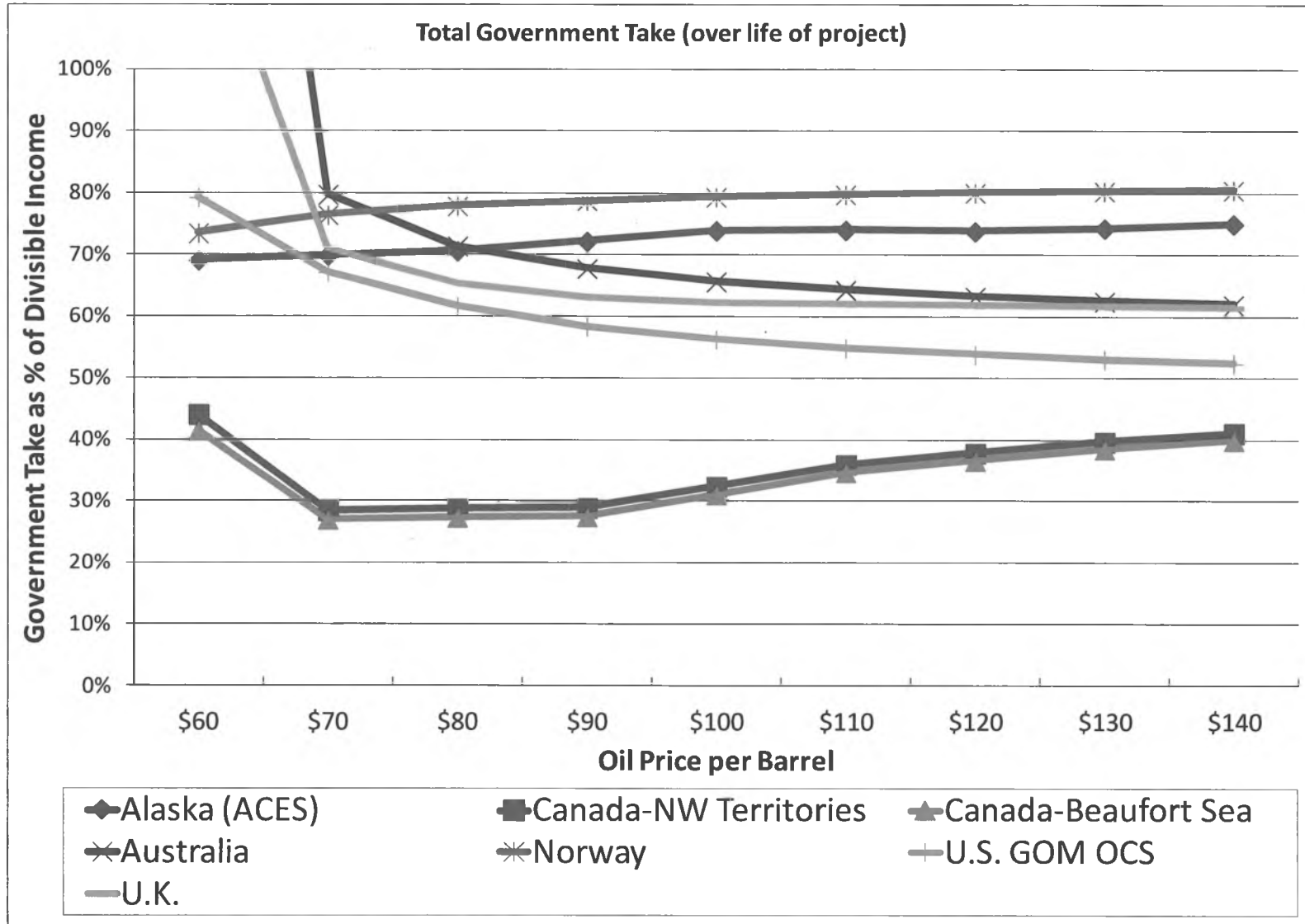
Limited upside at higher prices

Absolute Profit Split under Status Quo - One Year at 600,000 Bbls/day





Alaska Compared to International Peers in Government Take over Project Life Cycle

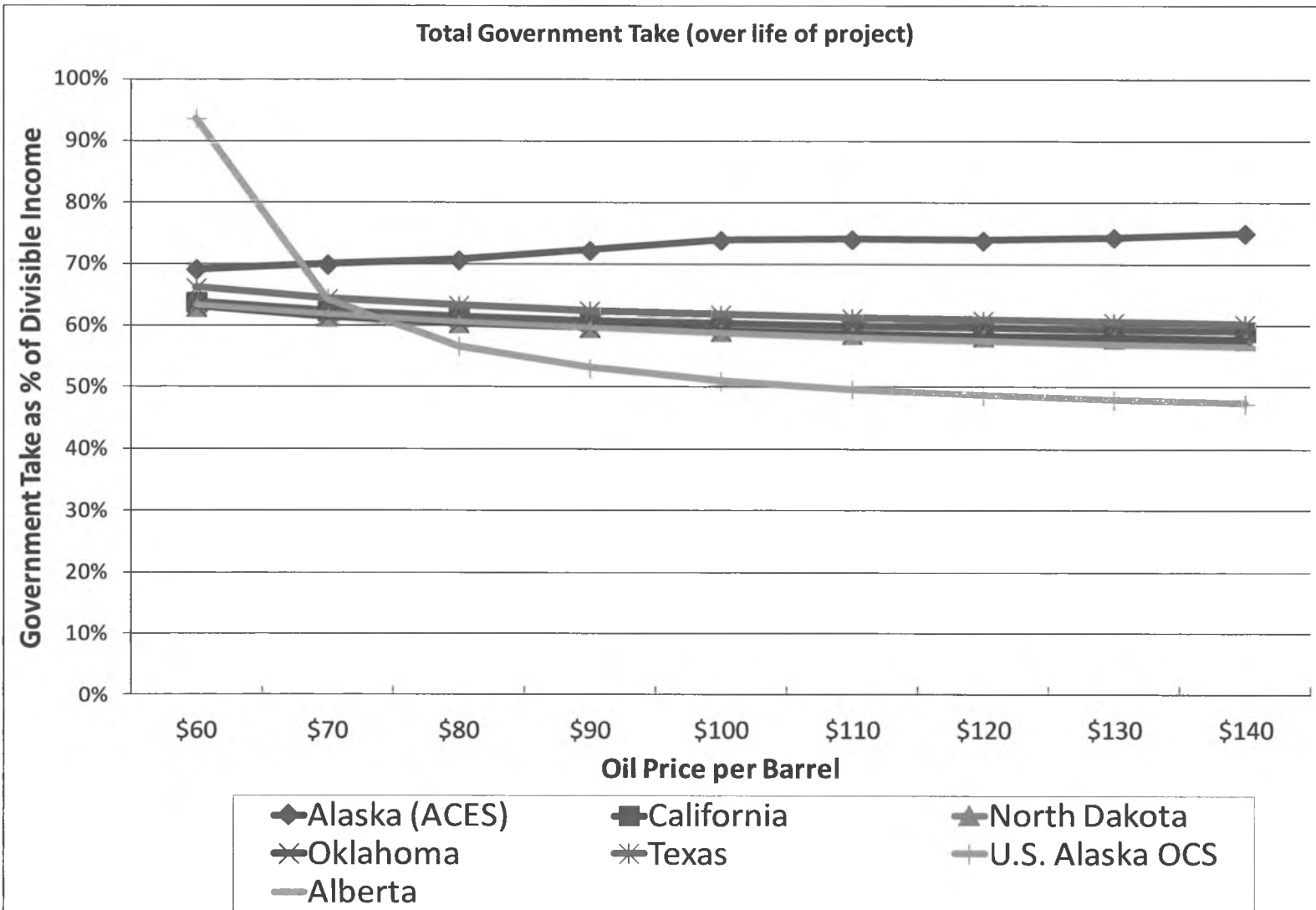


Source: Department of Revenue using Petrocash model

Alaska Department of Revenue



Alaska and North American Peers - Progressivity makes Alaska less competitive at high oil prices



Source: Department of Revenue using Petrocash model

Alaska Department of Revenue



Questions ?



5 Year Look Back

Oil Industry Capital Expenditures by Category



*Presentation to the
Senate Resources Committee
February 13, 2012
Alaska Department of Revenue*



What We'll Be Discussing.....



- Purpose of Tax Credit Provisions
- Purpose of 5 Year Look Back
- Process of 5 Year Look Back
- Capital Cost Categories
- Historical Capex Charts
- Conclusions
- Process for 2011 and Going Forward



Purpose of Tax Credit Provisions

2003 SB 185 (RES)

AS 43.55.025 became law when Alaska had a gross tax, therefore there was no need to consider upstream deductions. The original bill provided for a reduction in royalty on certain oil produced from Cook Inlet in addition to the tax credit provisions. The goals were to increase exploration and increase the State's knowledge of the natural resource base.

5/13/2003, Senate Finance Committee

- Royalty reduction provisions were to help field economics and allow producers to maximize production and continue employment
- Regarding the tax credit provision, a sponsor commented the tax credits are more applicable to exploration than discovery
- Intent was to encourage companies to drill more wells so that the possibility of both discovery and production could be "substantially" increased
- Bill was part of Governor's long range plan and ultimate goal was to increase pipeline throughput
- Drilling within an existing unit would not qualify, nor would wells under current development and exploration plans



Purpose of Tax Credit Provisions, cont'd

- The fiscal impact of the tax credits was an investment incentive that the state must offer to secure “a long-term stream of oil”
- Exploration credits *were* limited to the exploration side, and were amended to include testing but not development costs
- Clearly the focus of the legislation was to encourage exploratory work by the industry and increase the State’s understanding of resource base e.g. lease sales
- The credit was set up to encourage wildcat, high risk exploration and State shares in this risk via credit program

5/14/2003, Senate Finance Committee

- Once a well is successful, the State would stop “recovering the cost” because it is assumed that a producer would continue development.
- Wildcat exploration would qualify for a 40% credit, but the explorer must submit information about state geology and resource base during the exploration activities to DNR.



Purpose of 5 Year Look Back

- To provide informative cost information to decision makers
- To answer capital expenditure questions relating to credits
- To understand benefits and impacts of current statutes and regulation
- To create a process and reporting mechanism to collect and compile expenditure information submitted to DOR in non-standard formats
- To catch up on years of data collection
- To create standardized cost categories for reporting and data gathering to State agencies
- To establish the historical basis for future analysis and comparisons



Process of Information Gathering

- As part of the Data Assessment Project, conducted in-house discussion and review
- Conducted 4 workshops with industry
- Participation averaged 15 companies per workshop
- Industry was responsive in both active participation and written comments
- Established capital cost expenditure categories
- Developed both the 5 Year Look Back and forward-looking reporting categories



Use of Cost Expenditure Categories



- Compiled 5 Year Look back of CapEx (2006 to 2010)
- Compiling more detailed look forward of CapEx only – Effective 2011 return to be reported 3/31/12
- Look forward of CapEx & OpEx in progress – Effective 2012 return to be reported 3/31/13
- Will be submitted with annual production tax returns
- As supplemental information supporting the tax return
- Based on confidential information



Capital Expenditure Categories

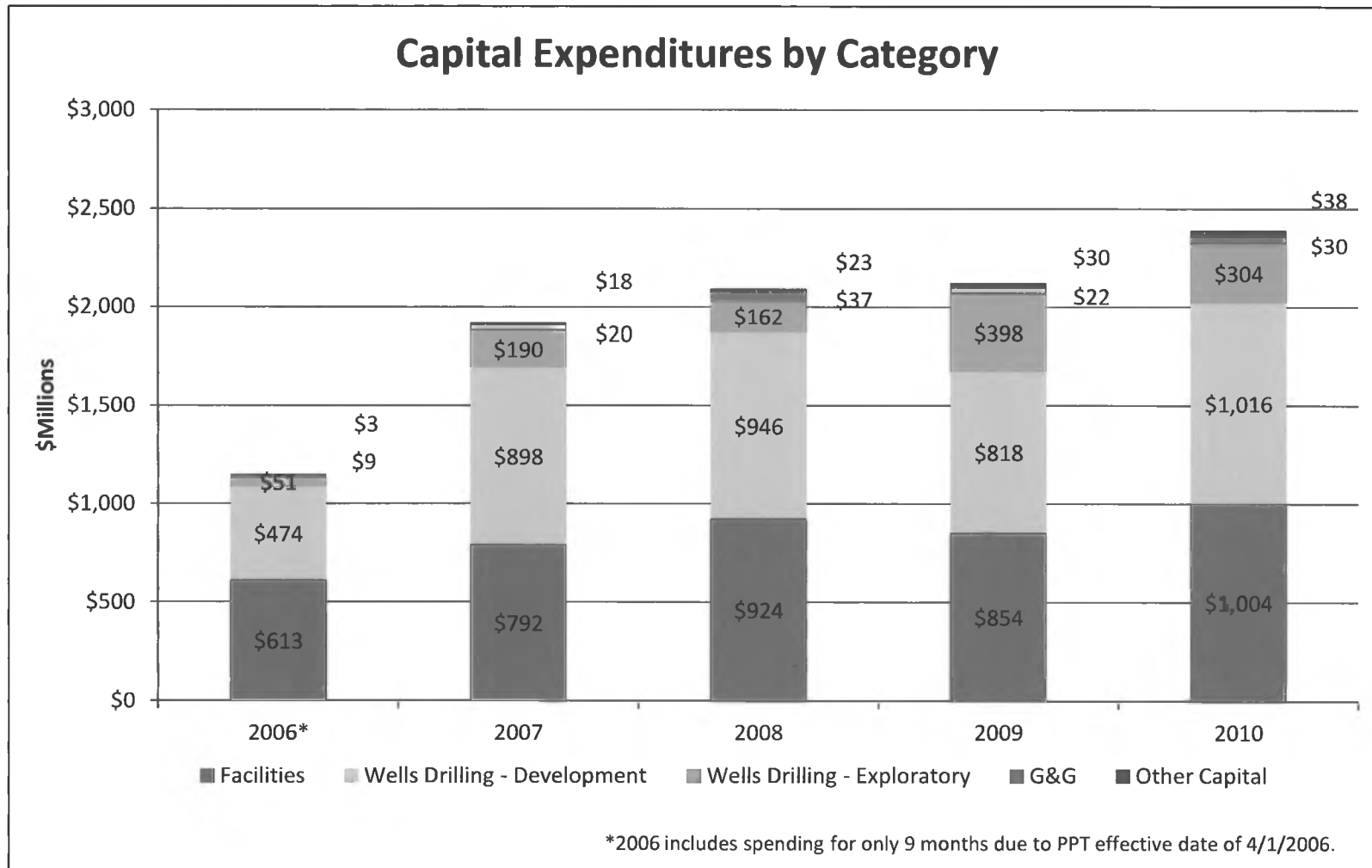
Look-back Categories For Years 2006 – 2010

- Geological & Geophysical Work (G&G)
- Exploration Drilling
- Development Drilling
- Facilities
- Other Capital

Categorized capital expenditure data represent
90% of costs related to credit applications

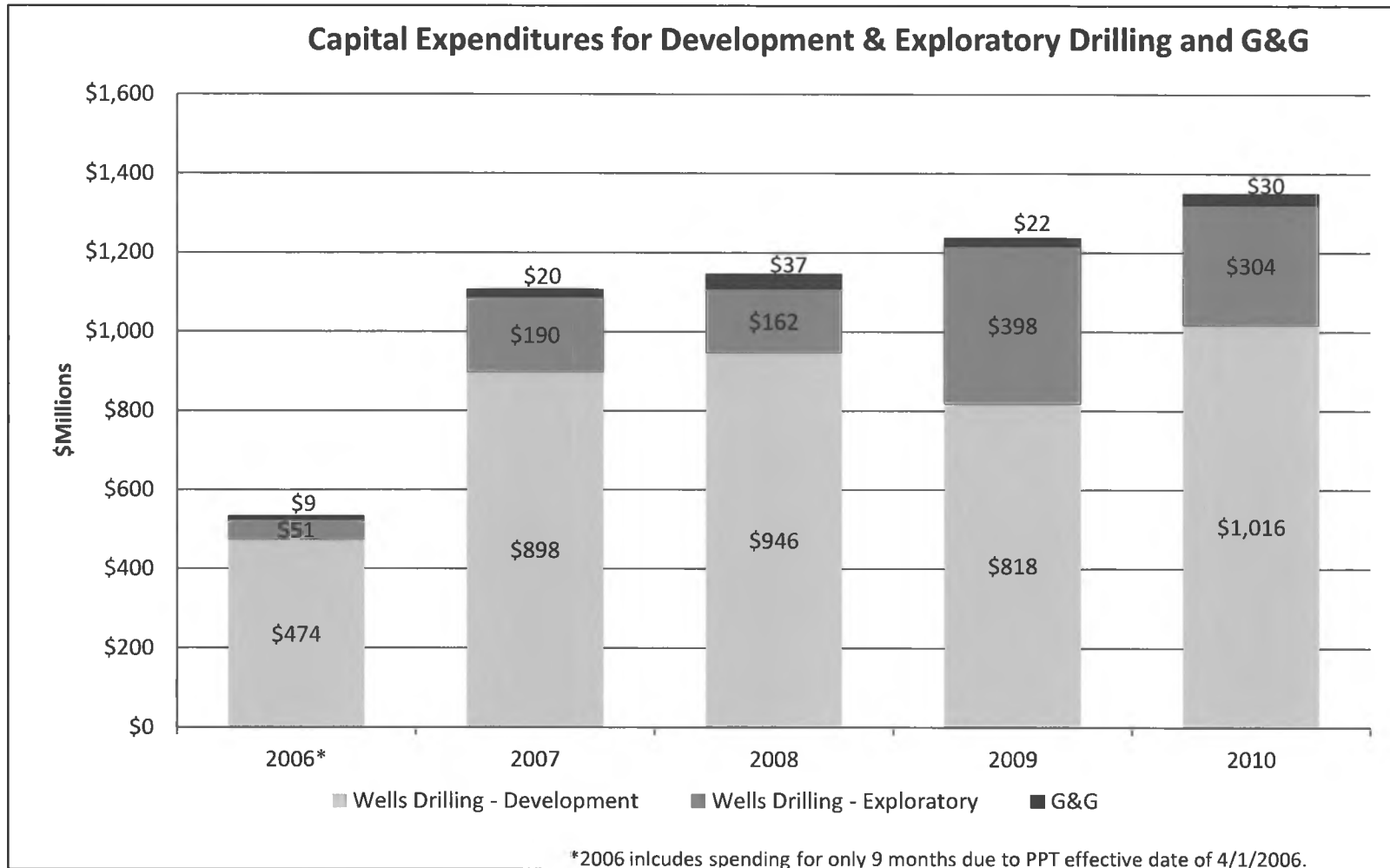


Historical CAPEX by Category (CY)



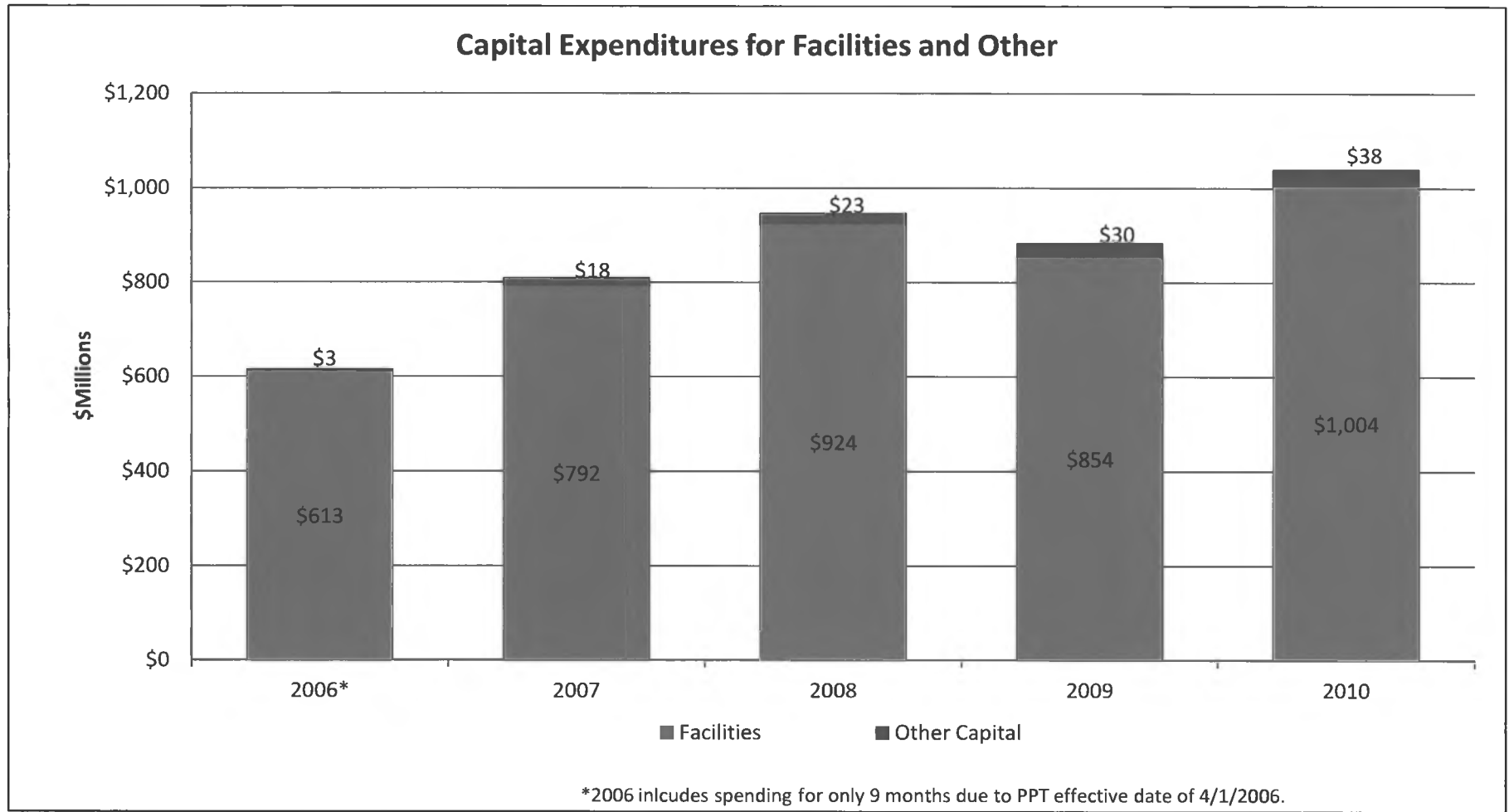


Historical CAPEX for Drilling and G&G (CY)



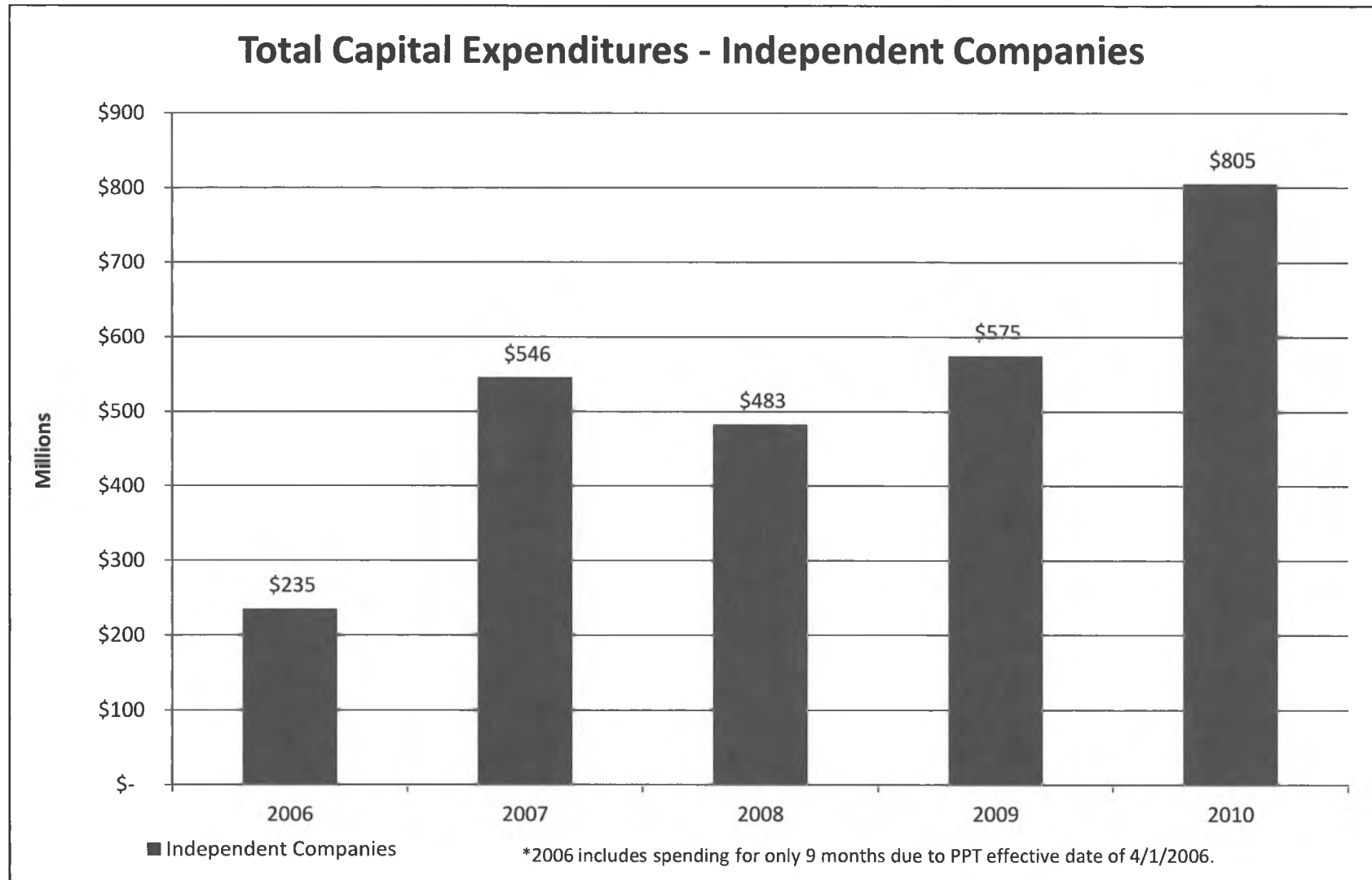


Historical CAPEX for Facilities & Other (CY)



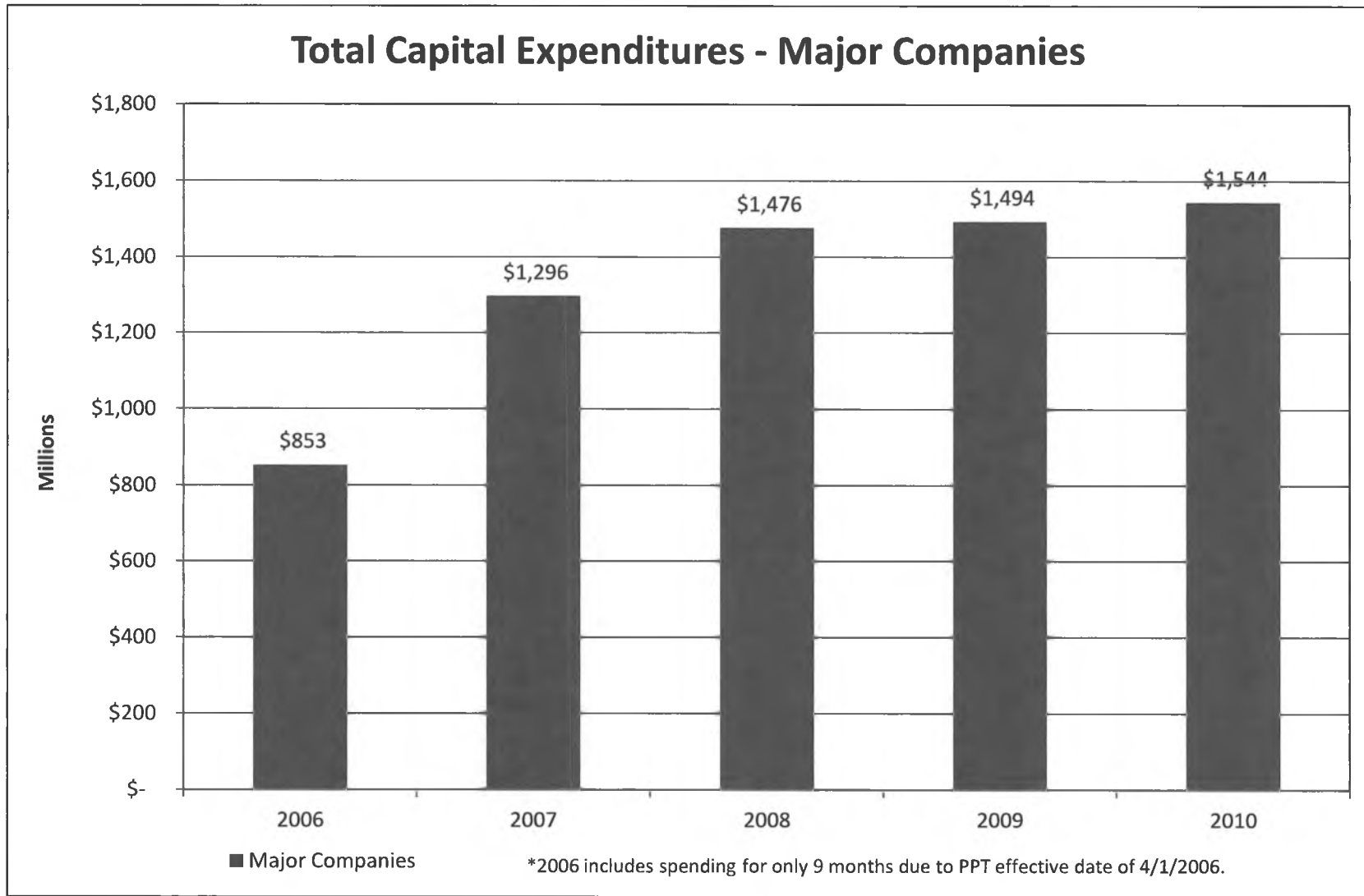


Historical CAPEX (CY)





Historical CAPEX (CY)





2006-2010 Conclusions



- We now have more actual information regarding O&G spending habits than ever before available to the State of Alaska
- More actual information in this presentation alone than available during PPT/ACES debates combined
- Capital Expenditures in 2007 - 2010 increased from ~\$2.0B to ~\$2.4B
- Explorers spent money on drilling wells and G&G
- Companies in the development stage spent money on development drilling and facilities
- Companies in transition spent money in multiple areas depending on the stage they entered a project
- Companies in mature production phase spent money on maintenance and upgrade of facilities and development wells
- Now have more players active in the field
- Two fields planned and developed prior to PPT/ACES benefited from the tax credit provisions



Prospective Cost Information Look Forward

Proposed Annual Cost Supplemental Information Report

For calendar year 2011 (reporting due March 31, 2012):

- Use Look back CAPEX categories
- Filed by producers and explorers

For calendar year 2012 (reporting due March 31, 2013):

- Use more detailed categories following additional workshops with Industry
- Filed by producers and explorers



Questions?

Policy Options for Alaska Oil and Gas

Pedro van Meurs

Monday – Tuesday, February 13-14, 2012

**Presentation
Alaska Senate Finance Committee**

**Van Meurs Corporation
Nassau, Bahamas
Tel: (242) 324-4438
e-mail: info@vanmeurs.org**

Introductory Comment

The objective of Governor Parnell is to achieve a TAPS throughput of 1 million barrels per day.

Can this objective be achieved from State of Alaska resources by 2025? Yes

How?

It will require major policy and fiscal changes as will be discussed during the seminar.

These changes need to induce an increase in investment of about \$ 7.5 billion per year over current levels.

Introductory Comment

Such major policy and fiscal changes could also induce significant exports of LNG prior to 2025.

Four Sessions

The seminar will develop in four sessions:

- 1. New policy framework required**
- 2. International competitive environment**
- 3. Proposed terms for existing and new light oil**
- 4. Proposed terms for heavy oil, shale oil and natural gas**

Session 1

New policy framework required

World Rating of Oil and Gas Terms

Much of the material to be presented during the seminar is derived from a large international study being done by Van Meurs Corporation entitled:

World Rating of Oil and Gas Terms

In this study oil and gas fiscal systems of more than 140 countries and jurisdictions, such as Alaska, are being compared and analyzed in order to determine their favorability for investors.

Information about the study is available on:

www.petrocash.com

World Rating of Oil and Gas Terms

The 2011-2012 ratings of fiscal terms will cover 6 volumes.

Four volumes have been completed:

- **North American wells and shale plays**
- **Deep water**
- **Arctic**
- **Shallow water**

Two volumes still to be completed:

- **Onshore fields and shale plays**
- **Summary**

Alaska fiscal terms

During the seminar specific new fiscal terms will be proposed for Alaska oil and gas.

The purpose of these terms is to demonstrate how a new fiscal system can be created and to indicate the order of magnitude of the amounts and rates that would need to be adopted.

Concept of Government Take

During the seminar the concept of “government take” will be used frequently. Following is an example of the calculation of the government take for a 10% royalty.

Gross Revenues	\$ 100 per barrel
Costs	\$ 20 per barrel

Divisible Income	\$ 80 per barrel
Royalty 10%	\$ 10 per barrel

Government Take: $(\$ 10 / \$ 80) \times 100\% = 12.5\%$

The Government Take in this seminar is presented on an undiscounted and real basis using an escalation and inflation rate of 2% and is based on price and cost data as contained in Volume 3 of World Rating of Oil and Gas Terms.

Policy Change required

Alaska will not be able to reverse the decline in oil production from State of Alaska leases unless Alaska encourages major investment in:

- **Heavy oil,**
- **Potentially Shale Oil, if technically and economically viable, and**
- **Maybe some GTL production**

Policy Change required

If Alaska wants to attract investment in a major way for the important new resources (heavy oil, gas and potentially shale oil), significant political change is required in Alaska.

These changes are:

- 1. Alaska has to define competitive fiscal terms for the entire range of oil and gas resources, so investors know what the terms are.**
- 2. Alaska has to offer fiscal stability on these terms for large new projects, so investors know that Alaska will honor these terms for a significant duration.**

Policy Change required

Alaska is only jurisdiction in the world without defined fiscal terms for major oil and gas resources within its jurisdiction.

Alaska has no fiscal terms designed for heavy oil.

Alaska has no fiscal terms designed for shale oil.

Alaska has no implementable fiscal terms for natural gas.

This is a major obstacle for new investment.

Alaska political climate

It will be very difficult to introduce such changes in the current somewhat unfavorable political climate in Alaska.

The unfavorable political climate in Alaska is “structural”; in other words it is unlikely to change.

It is created by two factors:

- The small size of the Alaska population creates a particular way of developing fiscal policy, and
- An dependency relationship of Alaska on three major oil companies for most of their government budget, which creates resentment among some Alaskans. “Standing up for Alaska” is politically popular.

Political climate:

Small size of population

Jurisdictions with small populations (<2 million) develop oil and gas fiscal systems differently than jurisdictions with large populations (> 2 million) .

Small jurisdictions are often “project driven”. They tend to wait for someone to propose a project before deciding on detailed terms. Often terms are complex because many local interests need to be dealt with and terms are tailored for specific conditions.

Examples with population in millions: Alaska (0.7), Newfoundland & Labrador (0.5), Trinidad and Tobago (1.3), Equatorial Guinea (0.7) and Qatar (1.7).

Political climate:

Large populations

Jurisdictions with large populations often have generic petroleum codes and tax laws which deal with all petroleum resources. Terms are identical for all investors. Terms may be adjusted for each bid round. Often petroleum fiscal terms are relatively simple.

Examples with population in millions: United States (Federal onshore and OCS) (312.1), Norway (5.0), Alberta (3.7), the United Kingdom (62.3) and Australia (22.8).

Competitive Framework for Alaska: 1997

Petroleum economic environment:

- Oil price low
- European and Asian gas prices low
- LNG trade limited
- Focus on conventional oil and gas
- Conventional oil production in US declining

Competitors of Alaska:

- Latin American, African and Asian developing countries
- Main LNG competitor: Qatar

Method of determining fiscal terms by competitors:

- Negotiations of production sharing contracts resulting typically in tough terms

Competitive Framework for Alaska: 2012

Petroleum economic environment:

- High oil prices
- High European and Asian gas prices
- Booming LNG trade
- Focus on unconventional oil and gas
- Oil production in US and Canada increasing

Competitors of Alaska:

- Lower 48 USA, Canada, Russia and Brazil
- Main LNG competitor: Australia

Method of determining fiscal terms by competitors:

- Fixed and usually attractive fiscal terms.

Alaska Political climate:

Negative experience

The fact that fiscal terms in Alaska are being defined once a project is identified has already resulted twice in the loss of a major gas export project:

- Under Governor Knowles in 1996 there were realistic opportunities for LNG exports to Asia. Yet, the process of having first to develop the “Stranded Gas Development Act” in order to enter in negotiations resulted in a situation where Asian buyers went elsewhere.
- Under Governor Murkowski in 2003 there was a significant opportunity to built a gas line to Alberta. Yet, strong opposition within government and from Alaskans delayed negotiations and resulted in a disapproval of the project.

These experiences create a negative environment for the proposal of new projects by major companies in Alaska.

Policy change required

If Alaska wants to attract major new investment in the new competitive environment of 2012 and achieve a million bopd target and LNG exports, it has to establish competitive and fixed terms for all its resources:

- Existing light oil
- New light oil
- Heavy oil
- Ultra heavy oil
- Shale oil
- New natural gas
- Associated natural gas

What Alaska needs is a “we are open for business” brochure that sets out all terms for investing in oil and gas in Alaska.

Implementation of new terms.

With respect to light oil for existing and new production it seems that no particular implementation measures need to be taken. It is likely that investors will respond positively to the new terms and make the necessary investments, unless the project involves major new investments, such as the development of Point Thomson.

With respect to heavy oil, shale oil, natural gas and GTL it is unlikely that investors will commit to large multi-billion dollar programs unless there is a degree of fiscal stability in a contractual framework.

Contractual relationship.

If investors feel that fiscal stability is required for their investments, the Government of Alaska should be authorized to sign contracts, without further legislative approval. In other words the process would be similar to the approval of an oil sands plant in Alberta.

The fiscal stability period could range from 10 – 25 years from the start of the contract, depending on the nature of the investment.

In exchange for being offered fiscal stability, the investor would have to commit to a substantive work program.

It is understood that the matter of whether or not Alaska can offer fiscal stability, is an issue to be decided by the Alaska Supreme Court.

Difficulties in achieving Alaska production increases

Increasing Alaska oil production and initiation of gas exports will face other major difficulties.

The main difficulty is that the three major oil companies are in a “harvesting mode”, which means their main objective is drawing cash out of Alaska to invest elsewhere. The reasons for this are:

- **No large and attractive projects available in Alaska under current fiscal terms for major oil companies**
- **Attractive opportunities outside Alaska.**

No attractive projects in Alaska for major oil companies

Current fiscal terms are designed for *low cost light oil*.

There is possibly about one billion barrels of new *high cost light oil* production available through:

- Discoveries as a result of new exploration
- Small discovered fields, which have not yet been brought on stream
- Infill drilling of existing fields.

Major oil companies are already infill drilling, other projects do not compare well in attractiveness with international opportunities.

As a result, the main focus of major oil companies is to draw cash out of Alaska for investment elsewhere.

Session 2

International competitive framework

Attractive terms outside Alaska

for major oil companies

In the following slides the international competitive position for Alaska will be evaluated for the following resources:

- **Existing light oil production**
- **New light oil production**
- **Heavy oil**
- **Shale oil, and**
- **Natural Gas**

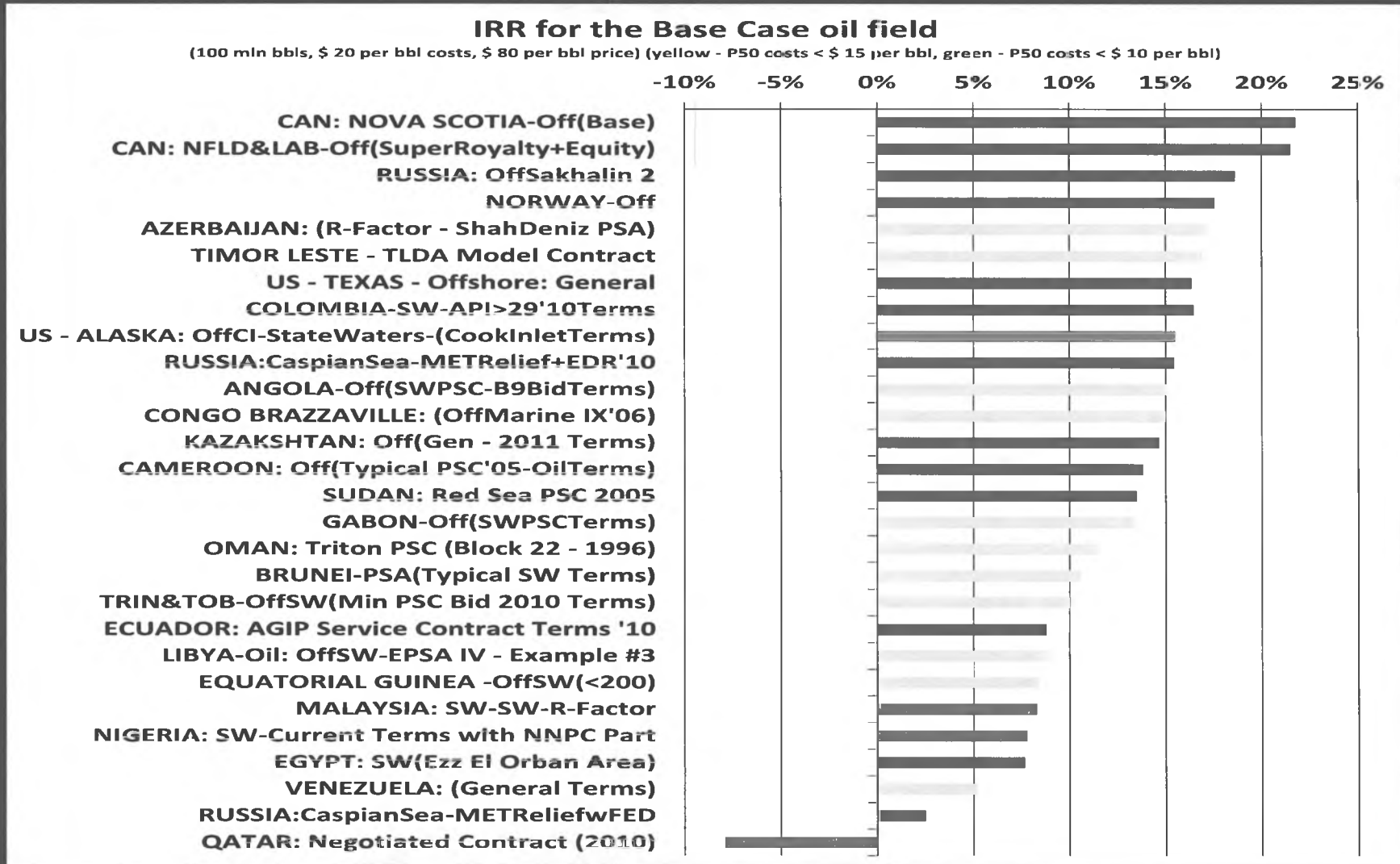
International competition: *Existing oil production*

The Shallow Water results of World Rating of Oil and Gas Terms permit a comparison with the largest “peer group”. The largest peer group for Alaska are the exporting jurisdictions. The following charts provide the results for a selection of 28 exporters of oil.

The Arctic Report permits a comparison with other Arctic jurisdictions.

Following is an overview of the results.

Shallow water exporters (Oil)

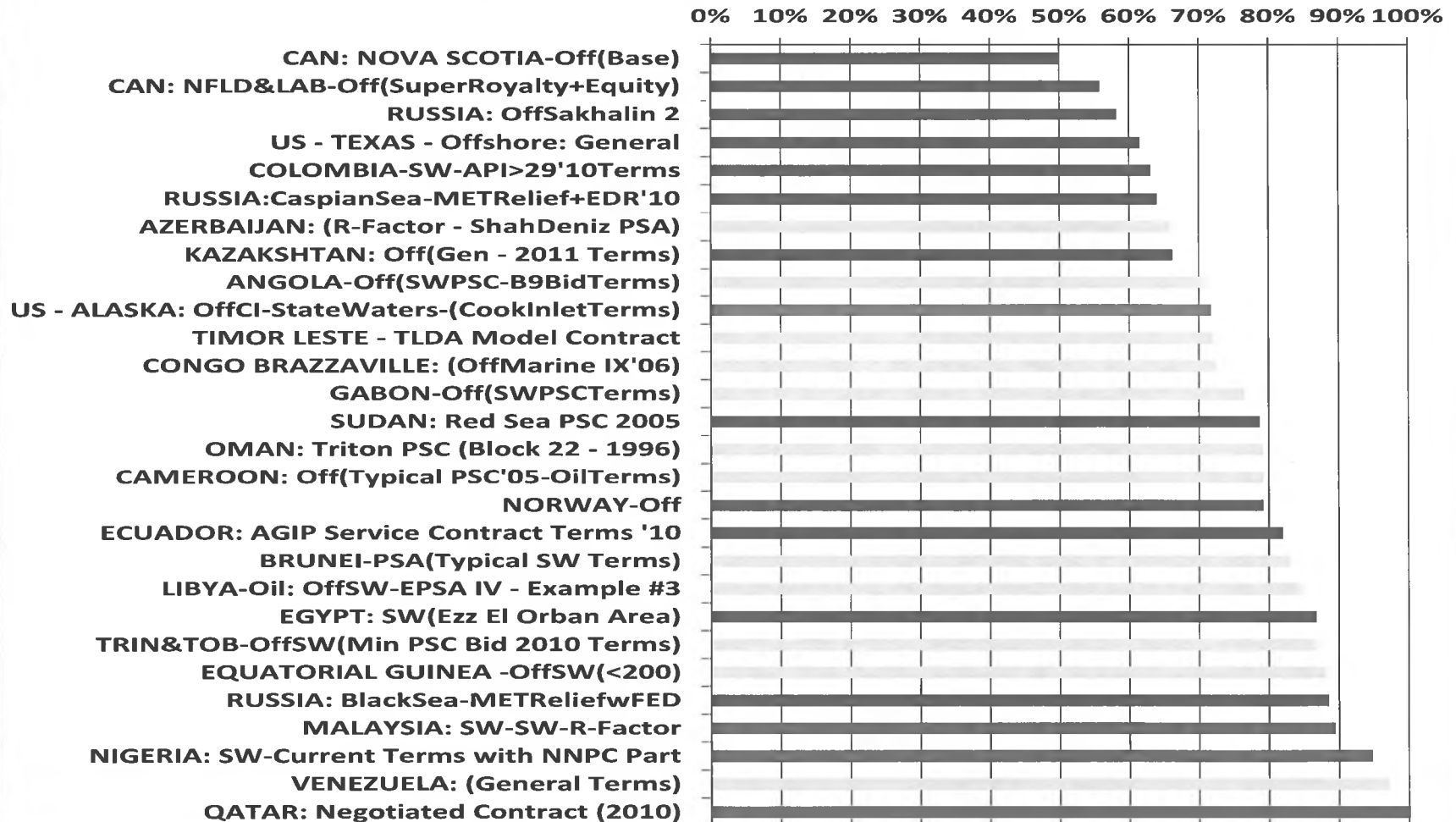


IRR: Alaska terms rate # 9 out of 28 exporters.

Shallow water exporters (Oil) - \$ 80

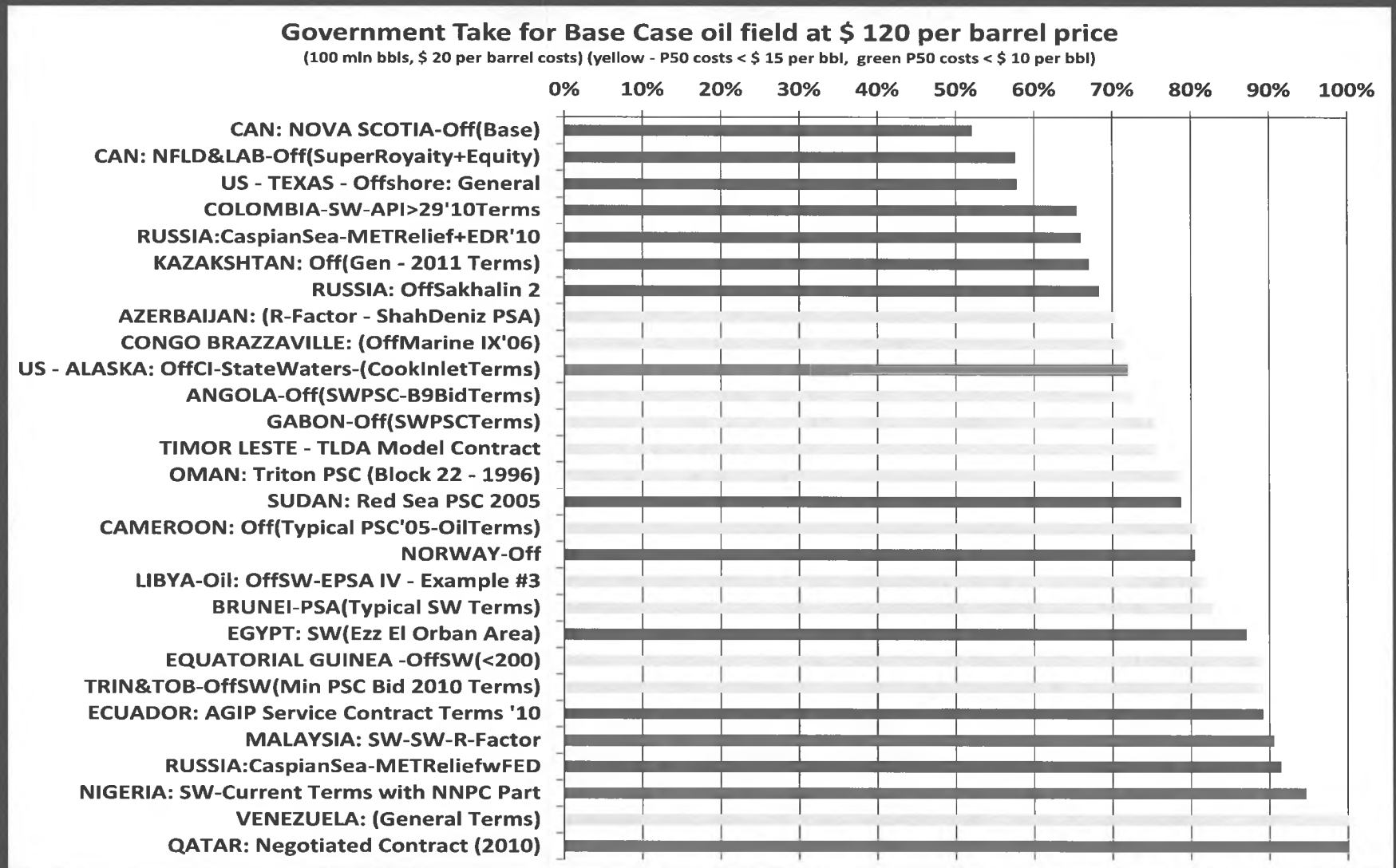
Government Take for Base Case oil field

(100 mln bbls, \$ 20 per barrel costs, \$ 80 per barrel price) (yellow - P50 costs < \$ 15 per bbl, green - P50 costs < \$10 per bbl)



Undiscounted Government Take: Alaska terms rate # 10 out of 28 exporters.

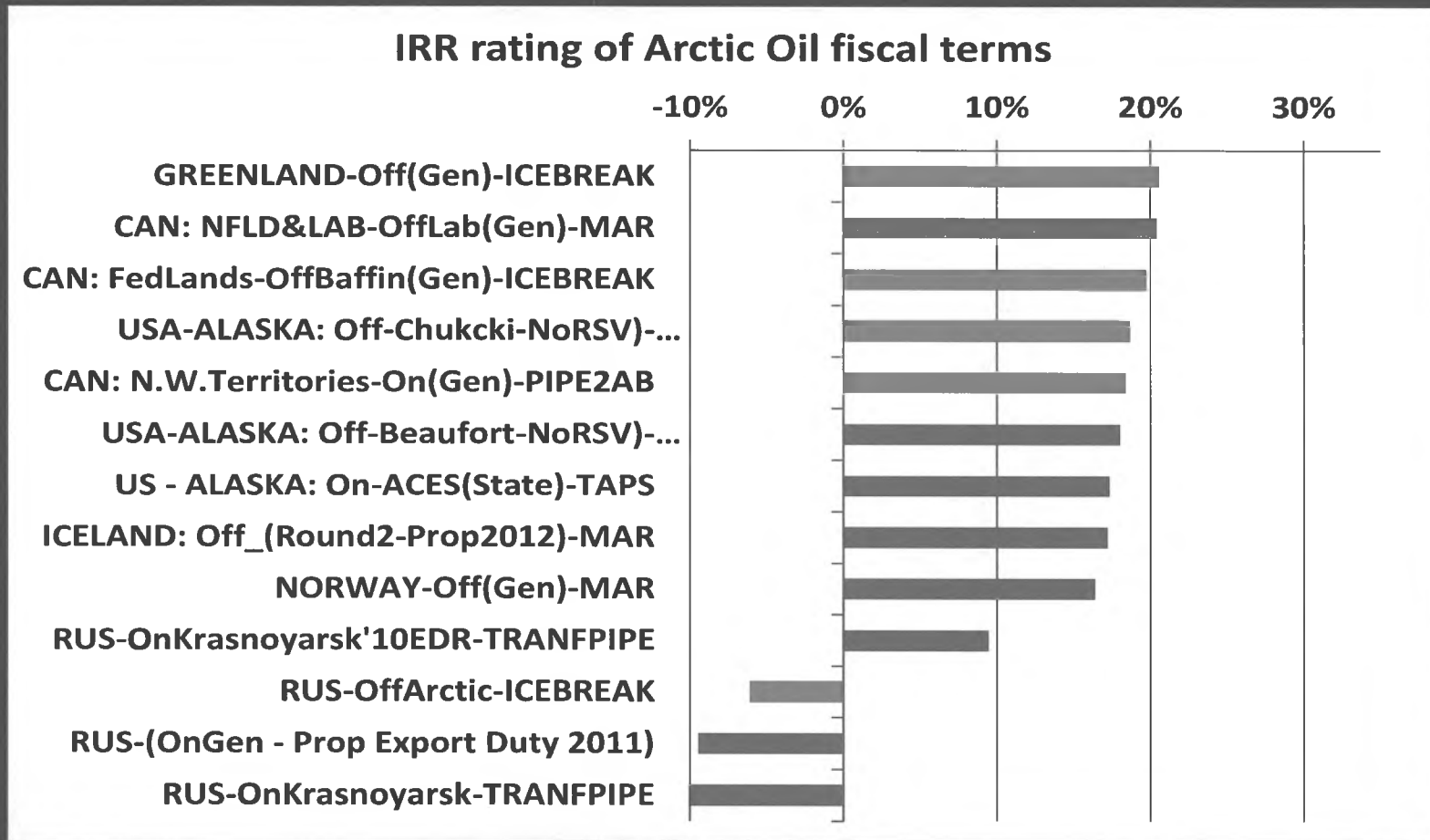
Shallow water exporters (Oil) - \$ 120



Undiscounted Government Take at \$ 120 per barrel: Alaska terms also rate # 10 out of 28 exporters.

Arctic (Oil)

(red – no transport system available)

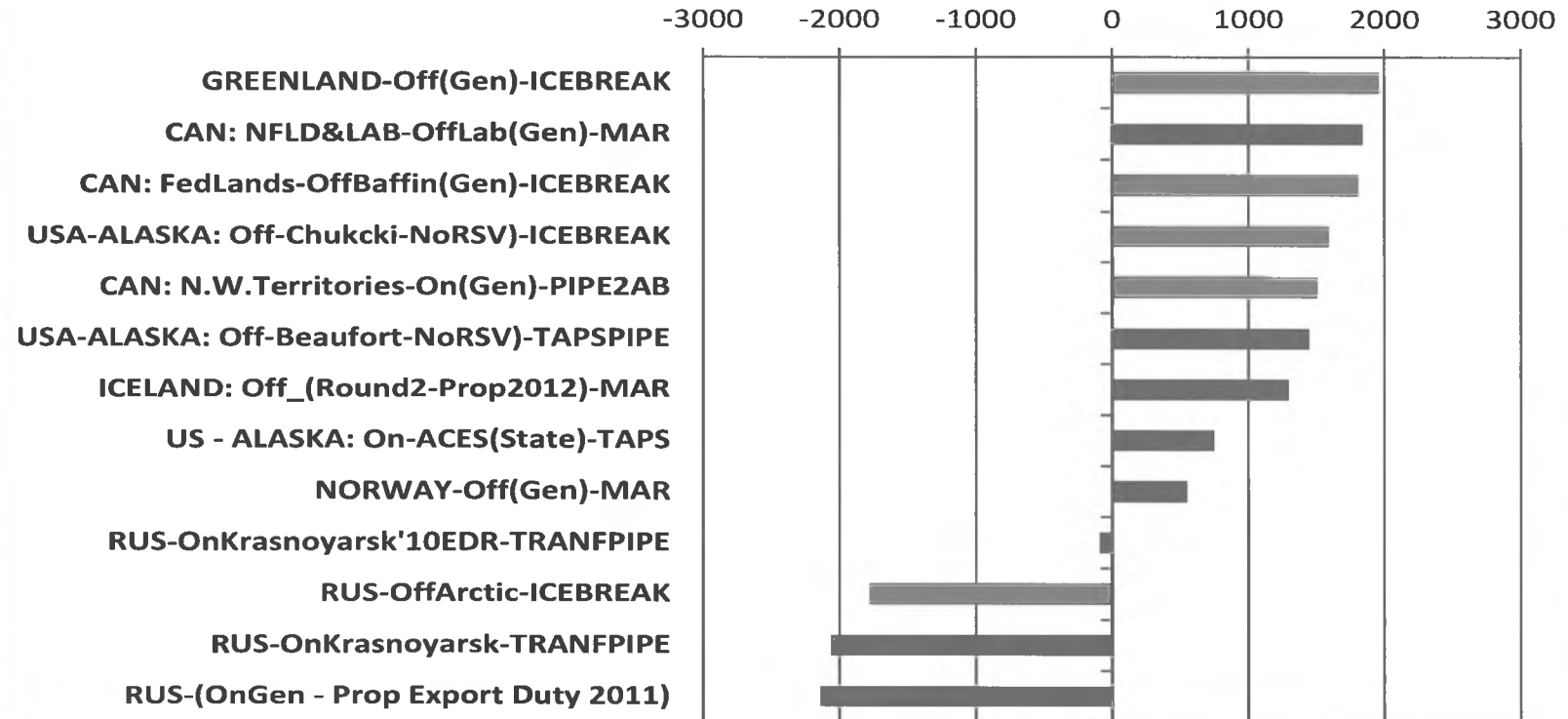


Alaska ACES IRR compares favorably with other Arctic jurisdictions. Russia still very tough under high cost and slow development conditions. Russian terms are rather attractive under lower cost conditions.

Arctic (Oil)

(red – no transport system available)

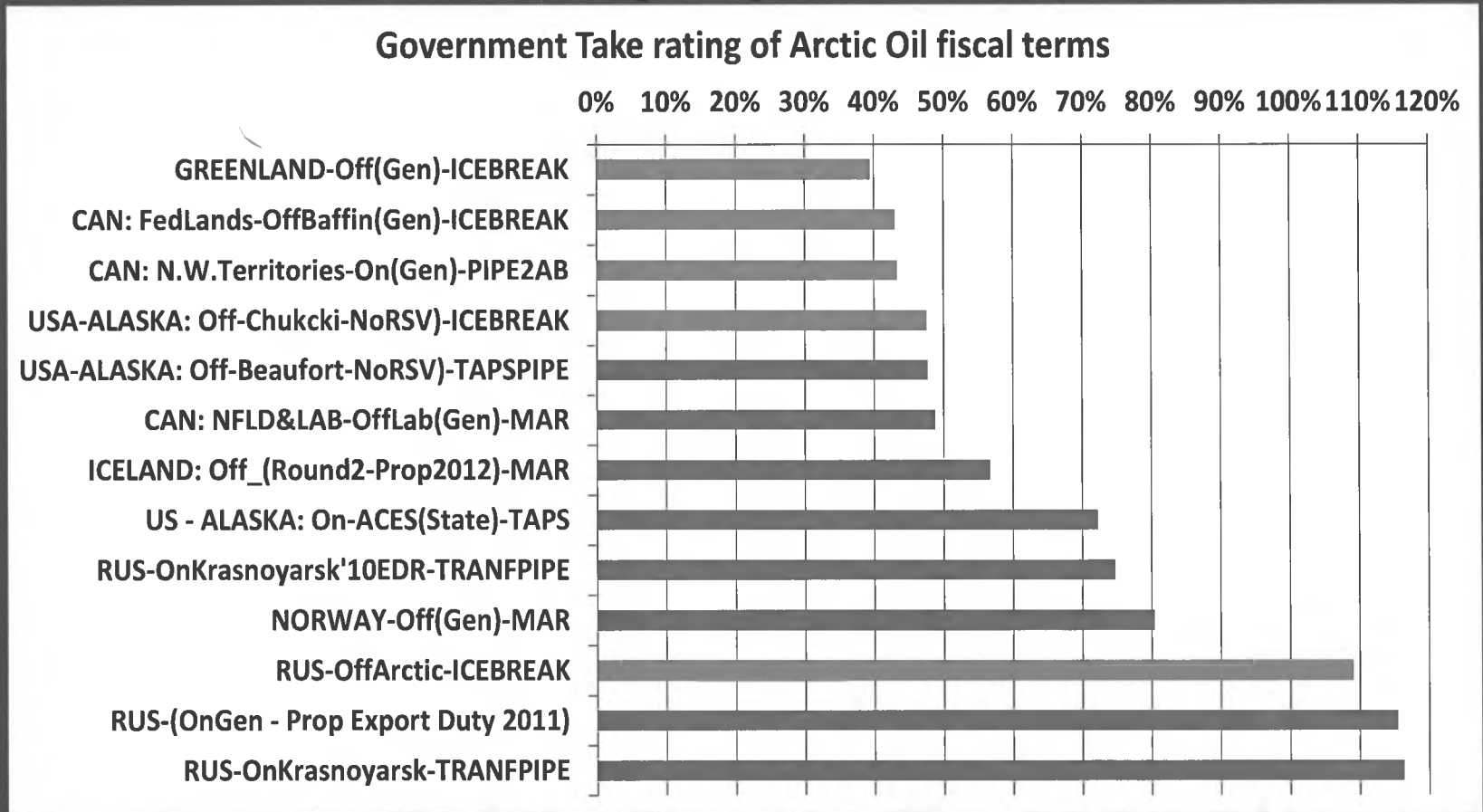
NPV10 rating of Arctic fiscal terms (\$ million)



Alaska ACES NPV10 seems OK compared to other jurisdictions, but is somewhat meager. Note how Federal Beaufort and Chukchi acreage is attractive. Russia still very tough.

Arctic (Oil)

(red – no transport system available)

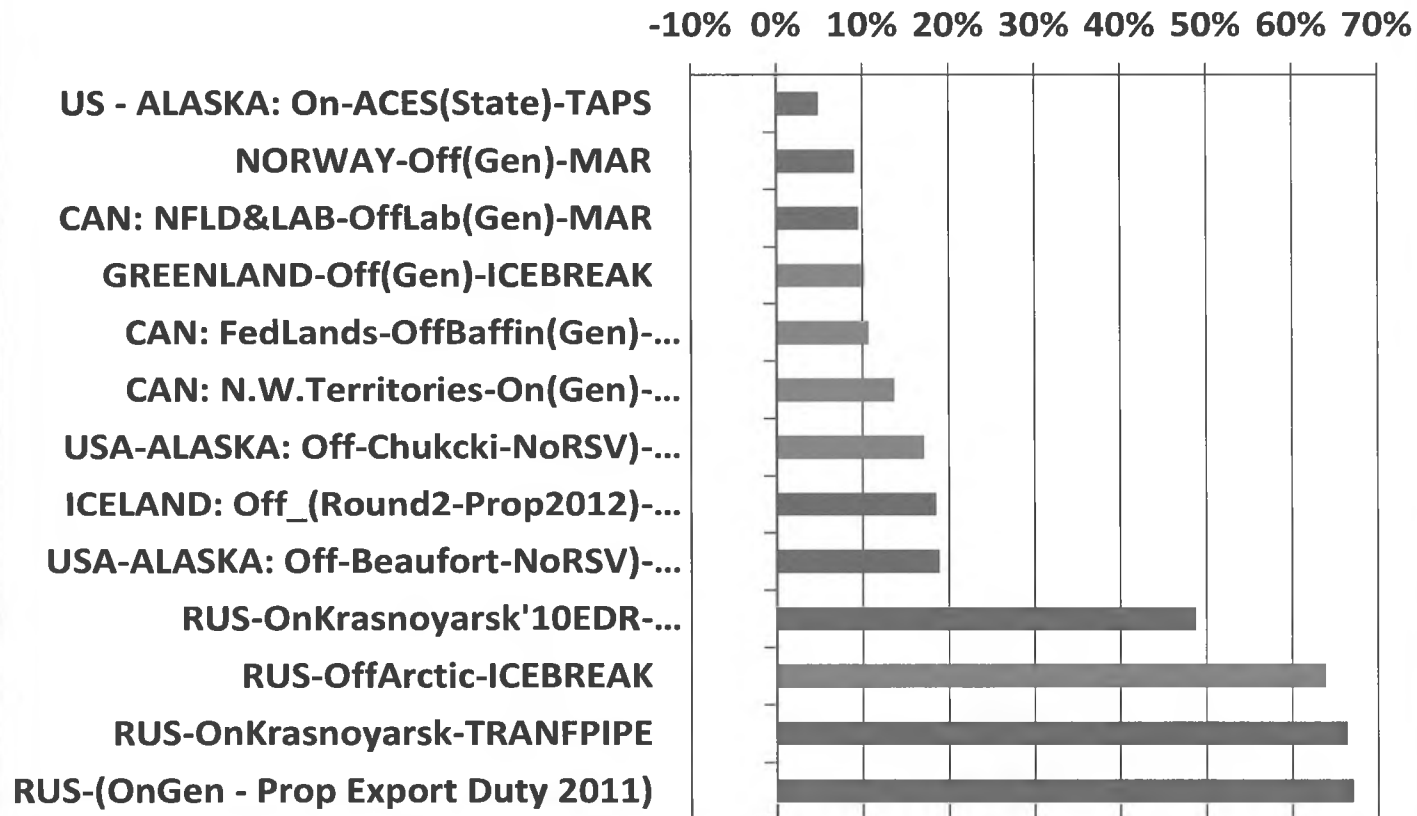


Alaska ACES government take is attractive from a government point of view and approximately at the right level for existing operations for investors. Interestingly new Russian terms compare with Alaska and Norway government take.

Arctic (Oil)

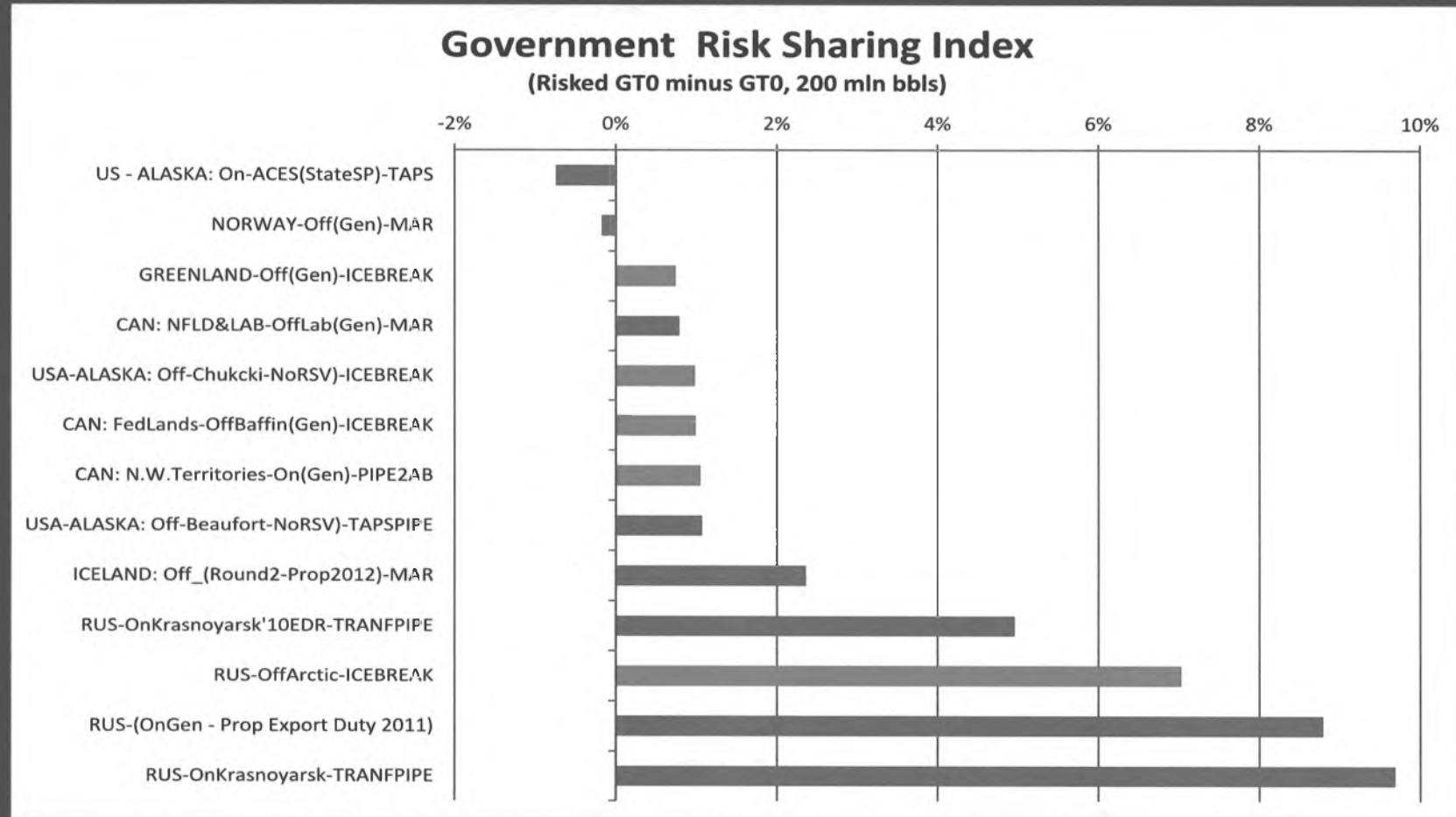
Comparative Front End Loading Index

(GT10 minus GT0, 200 mln bbls)



Alaska ACES government take is relatively well balanced compared to other Arctic jurisdictions in terms of the time distribution of the government take.

Arctic (Oil)



Under Alaska ACES the Alaska government is one of the few governments which shares disproportionately in the geological risk, indicating very strong support for exploration. In fact, with South Africa, Alaska rates the highest in the world in this respect.

International competition

Existing Production

The government take of about 70%-75% for Alaska is reasonable compared to the other exporters for existing operations. It is maybe slightly on the high side.

Alaska also offers a favorable time distribution of the government take and very favorable sharing of geological risk.

International competition

Existing Production

Both House Bill proposals lower the government take below 65% for existing as well as for new operations.

Although some improvements could be made in the existing terms, the results of the reports indicate that a significant lowering of government take (below the 70 – 75% range) for existing operations is not necessary.

SB 192 retains significant revenues on existing production in the 74 – 76% government take range.

International competition

New Production

The Alaska light oil production is rapidly declining at about 5% per year.

As stated earlier, there may be about one billion barrels of possible new production under more favorable fiscal terms. The production costs of this new oil is likely high on a per barrel basis.

The World Rating for Oil and Gas Terms provides information as to a reasonable government take for new production from the Deep Water report and the North American report.

Deep Water results

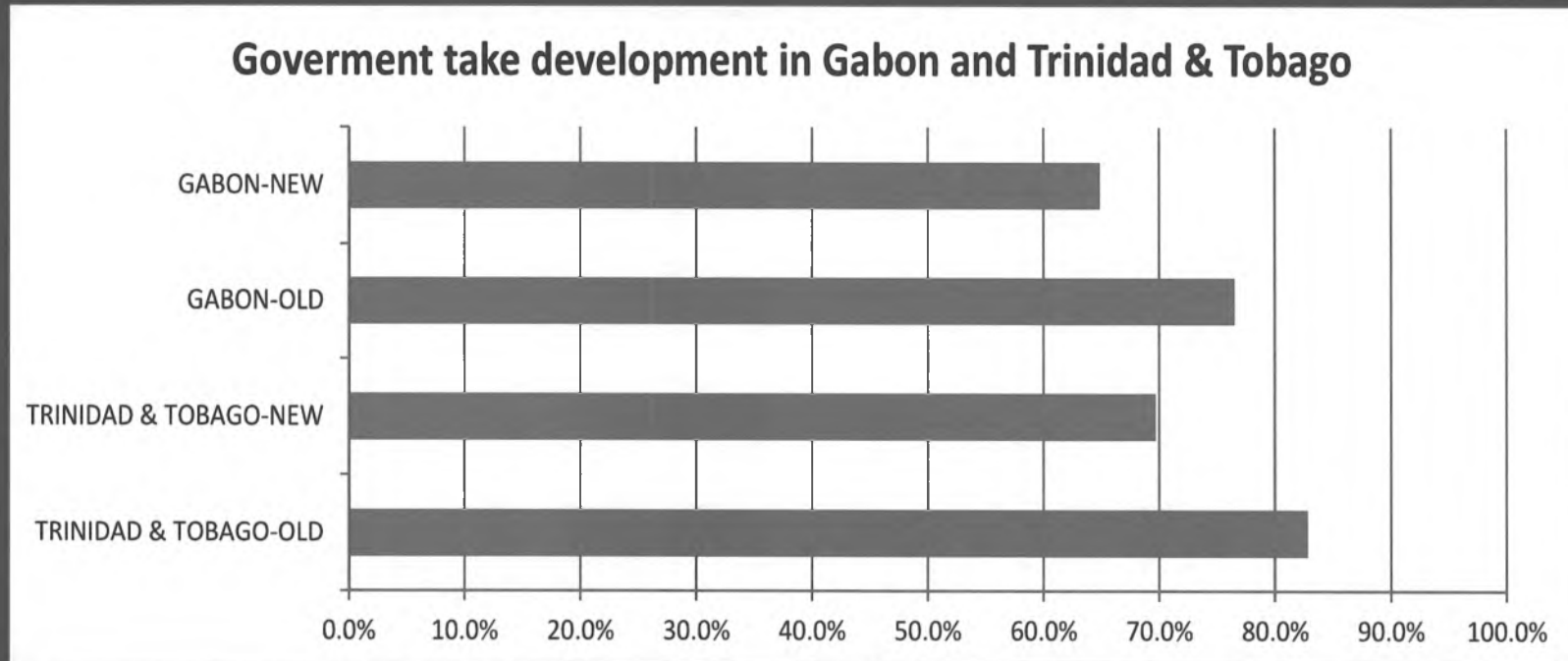
An important “peer group” for Alaska would be exporting jurisdictions with a declining conventional oil production.

There are not many jurisdictions in this group, but examples are Alberta, Gabon, Trinidad & Tobago, Malaysia.

Both Gabon and Trinidad applied about a 12 percent drop in order to attract new investment in an effort to offset declining production.

Both in Gabon and Trinidad this only applies to new blocks. Terms and conditions on old blocs remain unchanged.

Deep Water results



Gabon and Trinidad and Tobago are exporters with a declining oil production and have recently reduced their terms by about 12 percentage points.

North American Wells

Fiscal terms

Another way of competing with a fiscal system is to design the system for a wide range of economic conditions.

In Canada the fiscal systems consist of:

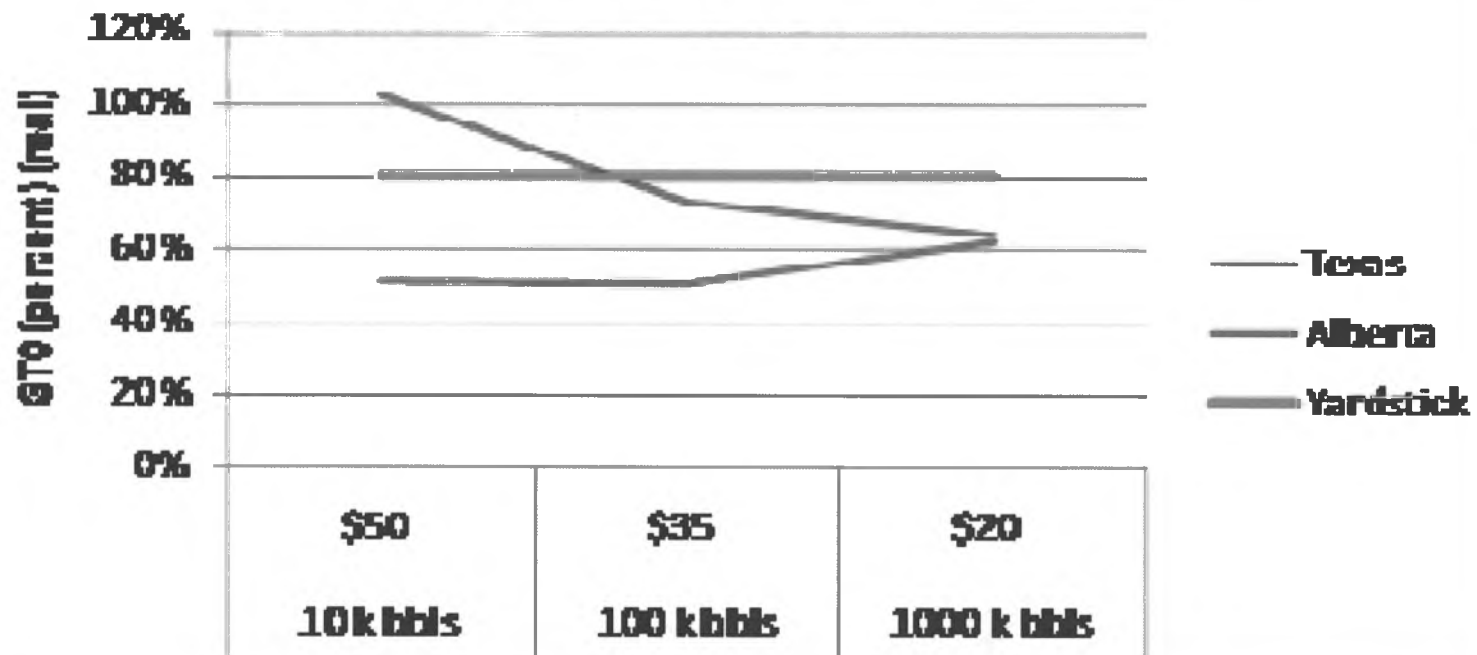
- **Royalties, based usually on formulas**
- **Federal and provincial corporate income tax**

In the United States the fiscal systems consist of:

- **Royalties, usually a fixed percentage**
- **Federal and often state corporate income tax**
- **Severance (production) taxes**
- **Property taxes**

North American Wells (Oil)

Chart 3.1.3.1-2 GTO for Texas and Alberta for varying well sizes with different costs



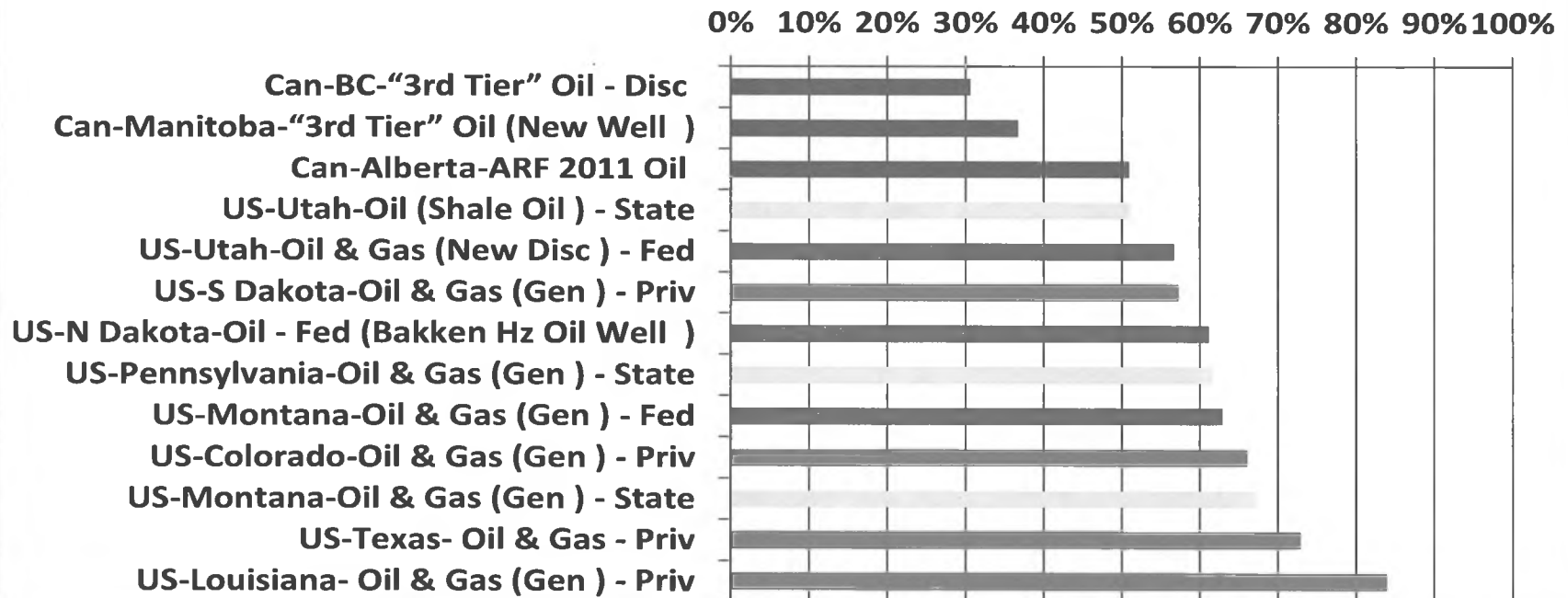
In Canada the government take usually goes up and in the United States the government take goes down with higher level of production per well or with higher prices (or both).

North America Wells (Oil)

Typical Well: 100,000 barrels, \$ 35 costs, \$ 80 price

Government Take on Oil Wells in North America

Government take (%)(real)



The government take on oil wells varies between 30% and 83% in North America and depends very much on the resource owner: Canadian provinces (blue), US Federal lands (green), US State lands (yellow) and US private lands (red)

North American Wells

Fiscal terms

Since 1997 Canada has lowered government take considerably, while the government take in the United States stayed the same.

The combined federal- provincial tax rate in Canada declined from about 45% to 25%.

Due to declining conventional oil production, the major Canadian oil producing provinces promote strongly new activity with more attractive royalties formulas which compete over a wider cost range.

International competition

New Production

International examples indicate that dropping the government take by about 10% for new production is reasonable once the jurisdiction faces a declining production.

The experience of Alberta, which faces a declining conventional oil production, indicates that designing lower fiscal terms in the 50 to 65% range of government take for higher cost resources is a viable strategy to increase investment.

International competition

New Production

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.

SB 192 terms are too tough to encourage costly new production.

International competition

Heavy Oil

Heavy Oil can be separated in two groups:

- **Heavy Oil: 15 – 22 degrees API.** This oil can typically be produced with conventional production methods, since oil flows to the wells. The oil can also be transported by pipeline and in marine tankers
- **Ultra Heavy Oil or Bitumen: 8 – 15 degrees API.** This oil which needs to be produced with special production methods. The oil cannot be transported by pipeline or marine tanker. It needs to be mixed with condensate or it needs to be converted in an upgrader to synthetic crude oil.

Heavy Oil

Alaska has significant heavy oil potential, probably in excess of 5 billion barrels. Alaska heavy oils range from 10 to 22 degrees API.

The most important deposits are:

- **Heavy Oil - 15 – 22 degrees API – West Sak, Schrader Bluff, Orion, Polaris, Nikaitchuq.**
- **Ultra Heavy Oil – 10 – 15 degrees API – Ugnu**

Separate fiscal terms are required for these two groups.

Alberta Oil Sands

The most important competitor for heavy oils in North America is Alberta with the oil sand deposits which may well contain in excess of 500 billion barrels of recoverable oil.

For Alberta oil sands, at 10 degrees API, government takes are in the range of 43% - 55% depending on the oil price.

In order to compete the government take for ultra heavy oil in Alaska may have to be similar to Alberta.

For heavy oil the terms could be between ultra heavy oil and new light oil production.

International competition

Heavy Oil

In order to be competitive Alaska would have to offer the following government takes for heavy oil:

- Heavy oil: 55 – 60%
- Ultra heavy Oil: 45 – 55%

International Competition

Shale Oil

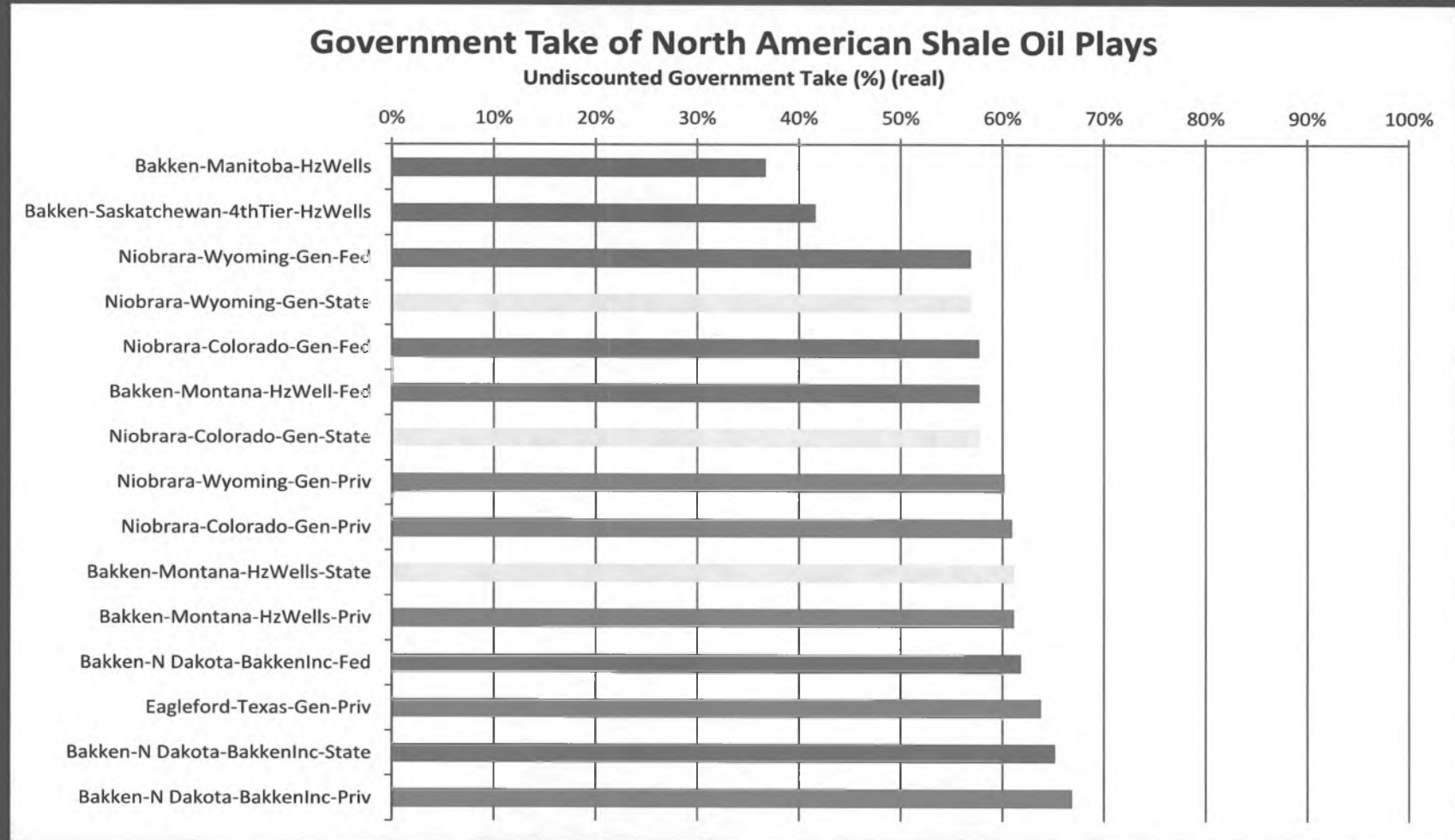
At this time it is not known whether shale oil production will be possible in Alaska. Pilot projects will be required to identify whether reservoir characteristics are of a nature that would permit fracking and would result in a sufficient flow of oil to make shale oil economic.

If shale oil would be economic, the resources may be quite considerable, for instance, in excess of several billion barrels. It is therefore very important for Alaska to identify whether shale oil is economic or not.

New shale oil developments will likely require major new infrastructure. The Federal permitting of this infrastructure and related environmental concerns could be a major stumbling block.

North American Wells (Shale Oil)

Government Take



Shale Oil plays in the United States are typically subject to a government take of about 60% and in Canada 40%.

International competition

Shale Oil

Alaska may have significant shale oil potential.

However, given the fact that the formations are relatively deep, operating conditions are severe and infrastructure is lacking, the costs per barrel would very likely be higher than in Canada and the Lower 48 States.

It is unlikely that large capital investments can be attracted unless the government take is in the 45 – 55% range.

International competition

Natural Gas

The Pacific market is very competitive

Current major *new* LNG suppliers in the Pacific LNG market are Australia and Papua New Guinea. Government take is less than 50% for dry gas.

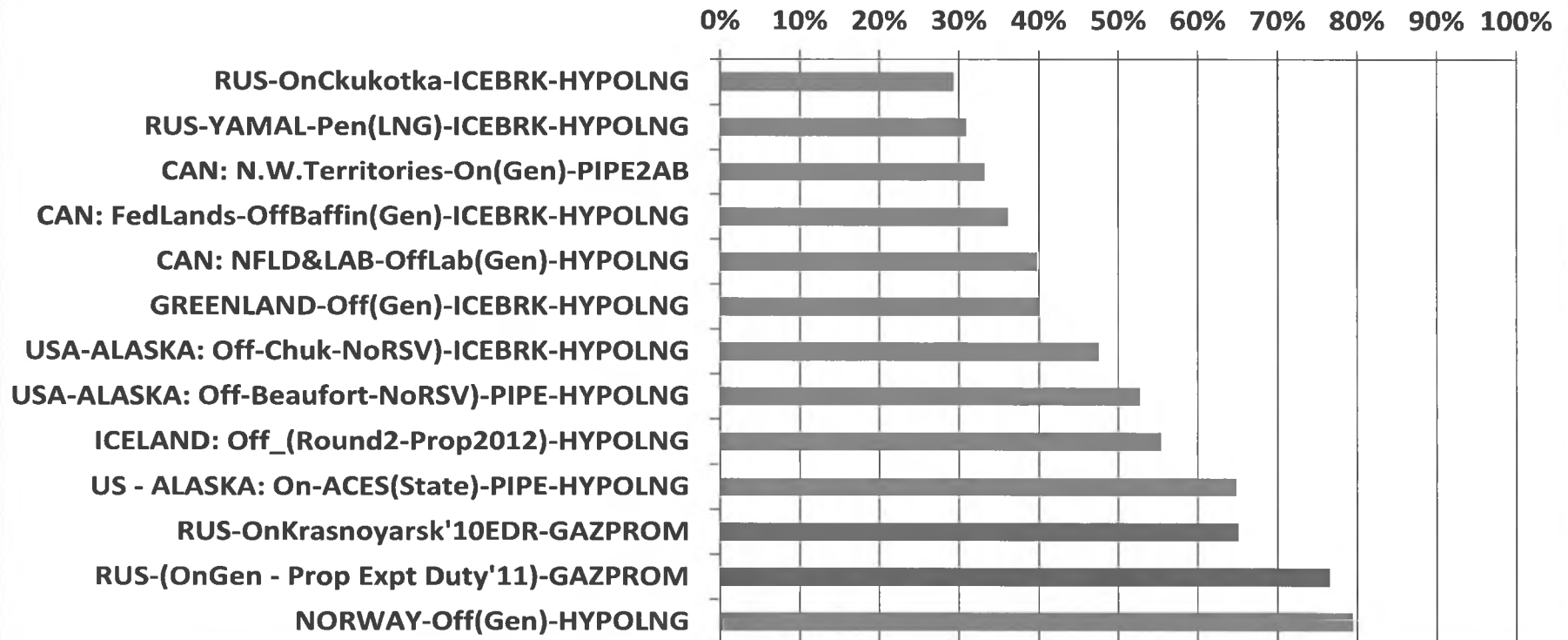
Offshore and onshore conventional gas production in China is also significant. Chinese owned companies often benefit from a system where China does not participate on a carried basis, resulting in a government take of 42% for dry gas.

In addition to the conventional gas resources, China has in situ 1300 Tcf of coal bed methane gas and 1100 Tcf of shale gas.

Arctic (Gas)

Government Take of new gas field projects (not including transport)

(10 Tcf, 500 mln bbbls)



Alaska government take for gas aimed at Pacific LNG markets is about 25% to 30% too high compared to strong Russian competition.

International competition

Natural Gas

Given the strong challenges of Russia, Australia, PNG and Chinese producers themselves, Alaska would have to offer a government take in the range of 45-55% in order to be competitive for the production of gas from new gas fields such as Point Thomson.

For gas from Prudhoe Bay, whereby most of the production costs have already been absorbed by oil production, a government take in the range of 55 – 60% may be appropriate.

International competition

Summary

In order to be competitive, Alaska needs to develop a fiscal system that offers the following government takes for the various resources:

- Existing light oil production: 70 – 75%
- New light oil production: 60 – 65%
- Heavy Oil: 55 – 60%
- Ultra Heavy Oil: 45 – 55%
- Shale Oil: 45 – 55%
- Natural Gas – new gas fields: 45 – 55%
- Natural Gas – Prudhoe Bay: 55 – 60%

Session 3

**Proposed terms for existing and new
light oil**

Overall framework for a new PPT

A new PPT should preferably structured in such a manner that it deals with the following important issues:

1. The current ACES system has serious deficiencies. A new PPT should remove these problems.
2. A new “architecture” for the PPT needs to be created to permit a greater variety of terms for the different oil and gas resources.
3. The system should be made simpler.

Complexity

An important other issue is complexity.

The production tax is far too complex - The current complexity of the production tax is a strong disincentive for investment.

It can be strongly recommended to review the tax to see what changes can be made to reduce complexity.

Deficiencies in the current ACES system

The current ACES system has five main deficiencies:

- 1. PPT tax rates up to 75% in addition to 41% corporate income tax are too high to stimulate efficiency in operations.**
- 2. The price based sliding scales and result in a situation where under high prices the producer is actually better off with a lower price.**
- 3. The excessive tax credits result in a situation where Alaska may pay all of the costs of a well.**
- 4. The BOE concept results in a situation where new gas production could lead to massive losses of oil based revenues.**
- 5. Under marginal circumstances the ACES system actually creates a negative PPT, in other words the government will loose PPT on certain fields.**

Deficiencies

Excessive Tax rates

The combination of the maximum ACES rate of 75% and the normal corporate income tax rate (state and federal) of 41% creates a combined tax rate of 85.25% under high prices.

Such an excessive tax rate reduces significantly the incentive for companies to be efficient because they can only keep \$ 0.1475 of every dollar saved. This means the cost savings index is only 14.75%.

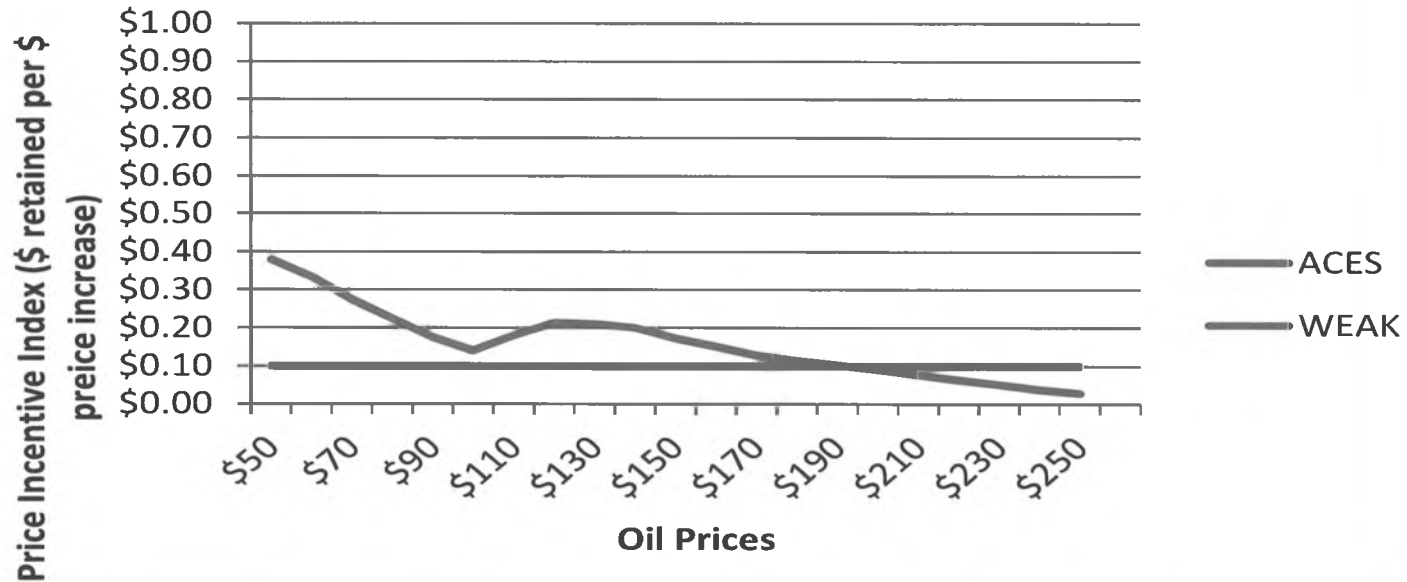
This is well below the cost savings index of most countries. Usually, it is recommended to have a cost savings index well over 20%.

It should be noted that the combined tax rate of 85.25% is in addition to the regular royalties.

Deficiencies

Excessive price progressivity

Chart 3.2.4.3-2 Price Incentive Index for Alaska - ACES
Base Case (500 mln, \$ 25 costs)

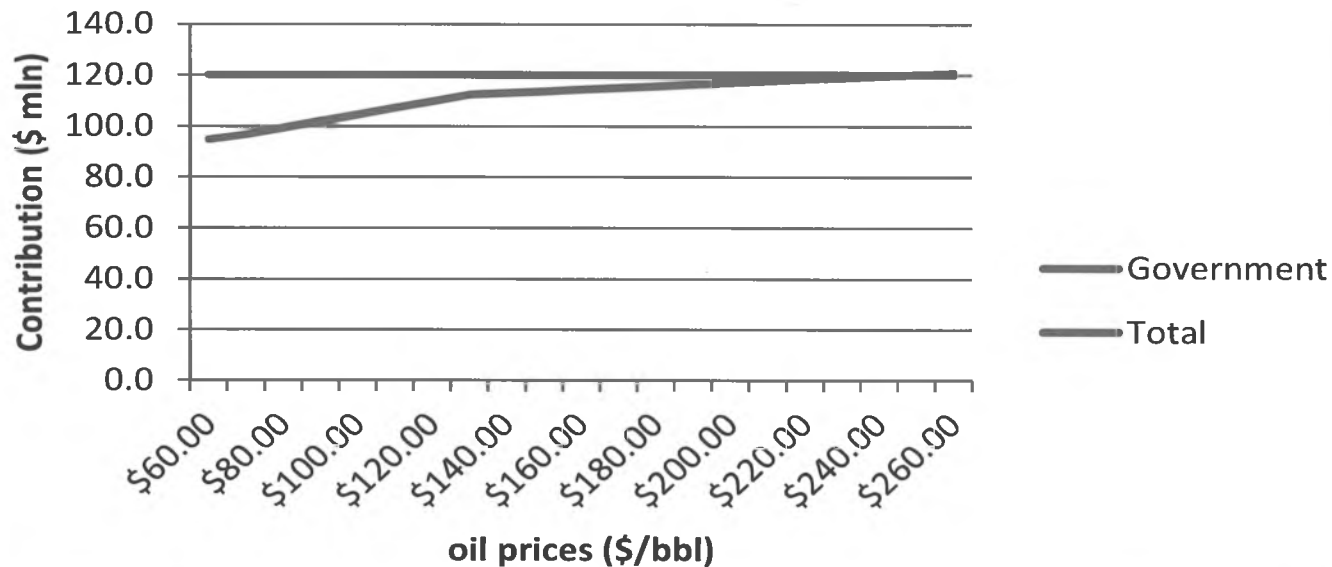


For ACES, at high prices, the combined tax rate becomes so high that there is the price incentive performance becomes very weak by international standards. This leads to lack of interest in achieving the highest prices on an arms length basis and strong incentives to try to “transfer price”.

Deficiencies

Excessive exploration support

Chart 5.1.3.1-1 Government contribution to a \$ 120 million exploration program



Existing producers under ACES are entitled to the 40% tax credit as well as all normal deductions of the exploration expenditures. This means that at \$ 111 per barrel, the Alaska contributes 90% of the exploration costs. At \$ 245 per barrel Alaska contributes 100%.

Deficiencies

Nonsensical cross subsidization of gas

**Table 5.1.3.1-1 Incremental Gas Economics for ACES in Alaska
(Country Incremental, Real)**

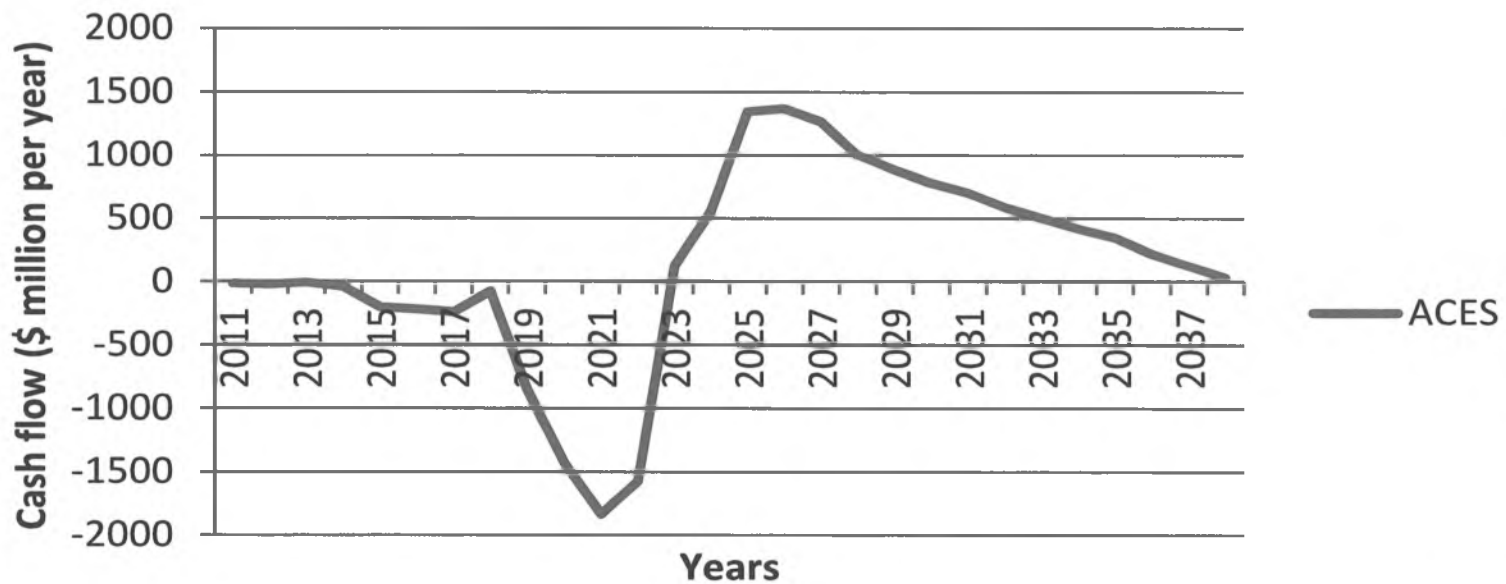
	Oil only	Oil + Gas	Incremental
Oil production (mln bbls)	500	500	0
Gas production (Bcf)	0	10000	10000
Oil price (\$/bbl) North Slope	100	100	100
Gas Price (\$/MMBtu) North Slope		1.0	1.0
Gross Revenues (\$ mln)	50000	60000	10000
Total Production (Mln BOE)	500	2167	1667
Capital Expenditures (\$ mln)	7500	11000	3500
Operating Expenditures (\$ mln)	5000	7500	2500
Divisible Income (\$ mln)	37500	41500	4000
Royalties (\$ mln)	6250	7500	1250
Property Tax, other	852	1504	652
Production Tax Value	30398	32496	2098
Production Tax Value per BOE	60.80	15.00	-46
PPT (\$ mln)	15186	6900	-8286
Corp Income Tax (State) (\$ mln)	1466	2474	1008
Total State Revenues (\$ mln)	23754	18378	-5376
Corporate Income Tax (Fed) (\$ mln)	4942	8340	3398
Total Government Revenues (\$ mln)	28696	26719	-1977
Undiscounted Government Take	76.50%	64.40%	-49.3%
IRR	21.10%	19.30%	17.3%

The BOE concept would result in massive government revenue losses on oil production if incrementally also gas would be developed. This does not make any sense. It is clear that Alaska would not accept such unnecessary losses. This in turn impedes gas project development.

Deficiencies

Negative PPT

Chart 4.1.2.1-1 ACES cash flow to Alaska for Base Case for Gas-Condensate (stand alone)



By definition, for a marginal project the total negative ACES cash flow to government as a result of tax credits and tax deductions becomes (almost) identical to the positive cash flow. In other words the net government receipts are low or even negative.

Deficiencies

Negative PPT

With the existence of a tax credit, there are always economic conditions under which the government may lose more in credits and deductions than it receives in income.

However, this effect should be minimized in the fiscal design. This is not done under ACES.

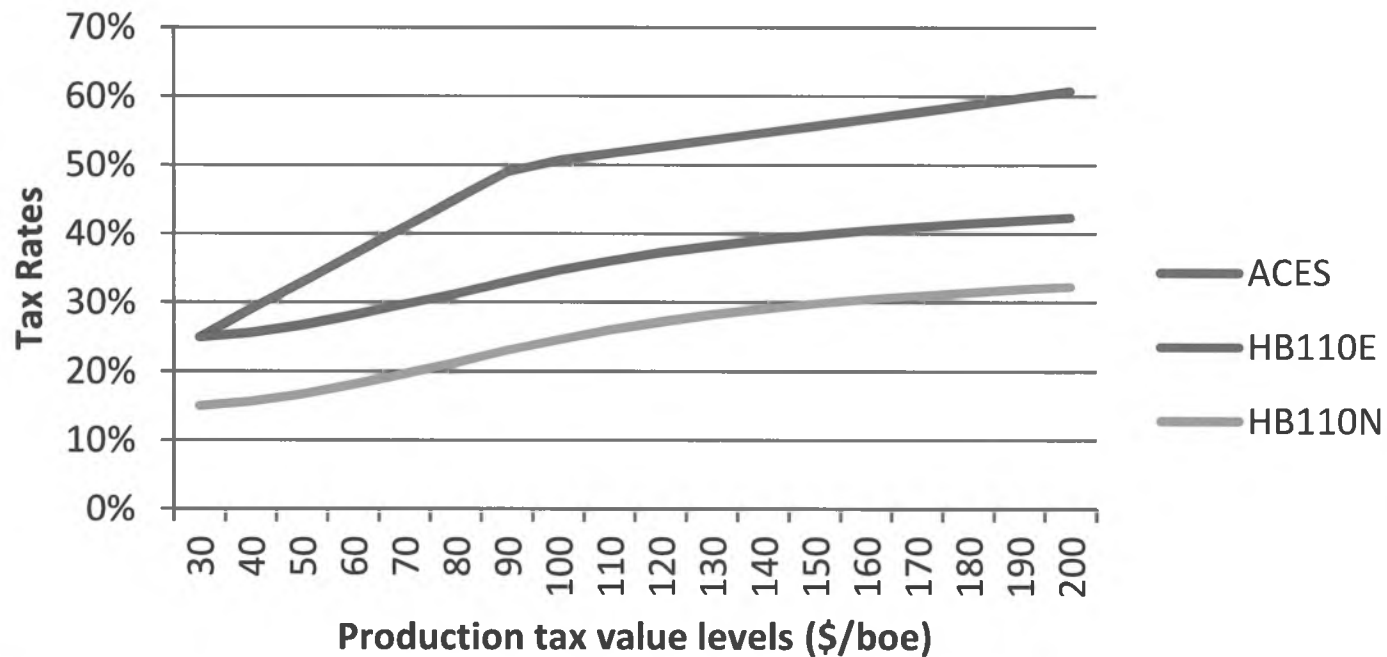
Proposals for light oil

Proposals for light oil production will be discussed first, based on this discussion the variation for other resources can be introduced

HB 110 has been introduced modify ACES.

Proposals for light oil: HB110 Analysis: PPT rates

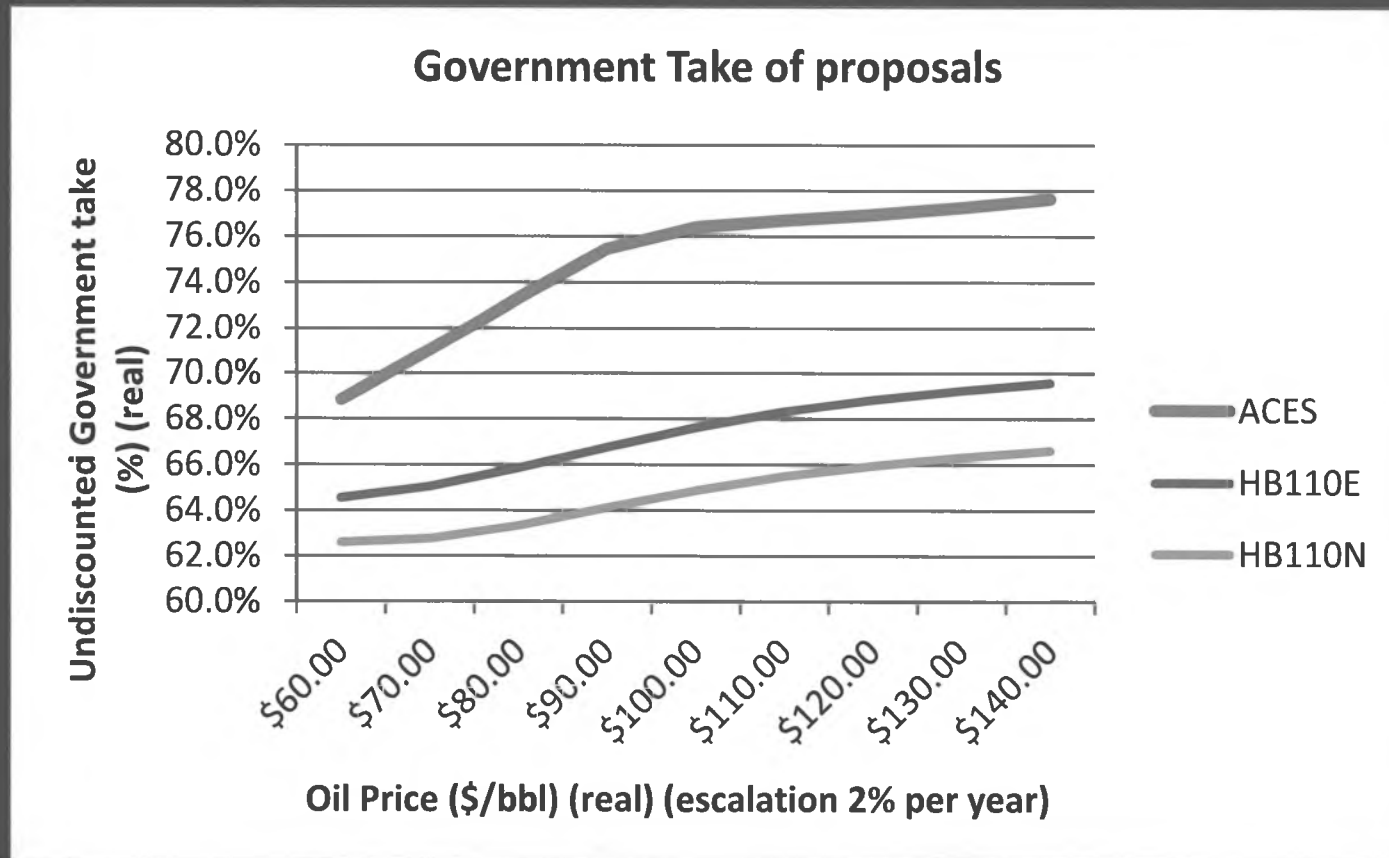
Various average tax rates for different production tax value levels per boe



The bracketing procedure creates a significant lowering of the average PPT rates. The HB 110 N rates apply only for 7 years from the start of production for new production.

Proposals for light oil: HB110

Analysis: Government take



At \$ 100 per barrel, the government take of ACES would be 76.4%, HB 110 (Existing) 67.6% and HB 110 (New) 64.9%

HB 110: Existing Production

The HB 110 proposal is relatively complex. It is based on so-called “bracketing”. Following is the scale:

< \$ 30.00	25.0%
< \$ 42.50	27.5%
< \$ 55.00	32.5%
< \$ 67.50	37.5%
< \$ 80.00	42.5%
< \$ 92.50	47.5%
> \$ 92.50	50%

Bracketing means that the final average rate is based on the weighted average of all the brackets. This means the rate will never be 50%.

HB 110: New production

For new production the rates will be lowered by 10% for the first 7 years of production.

This means that new production has to be “ring fenced”. All production and all revenues and costs will have to be allocated to “existing” and to “new” production.

This is complex from an administrative point of view.

Deficiencies in HB 110

HB 110 deals with only two of the deficiencies of ACES:

- 1. PPT tax rates up to 75% in addition to 41% corporate income tax are too high to stimulate efficiency in operations.**
- 2. The price based sliding scales and result in a situation where under high prices the producer is actually better off with a lower price.**
- 3. The excessive tax credits result in a situation where Alaska may pay all of the costs of a well.**
- 4. The BOE concept results in a situation where new gas production could lead to massive losses of oil based revenues.**
- 5. Under marginal circumstances the ACES system actually creates a negative PPT, in other words the government will loose PPT on certain fields.**

Deficiencies in HB 110

In addition HB 110 creates an entirely new problem.

Specifying different tax rates for Existing and New Production requires tax payers to submit different tax returns for these two classes of production. This is called ring fencing.

This in turn means that all revenues and costs need to be allocated to “existing” and “new”. This is complex to administer and could lead to significant revenue losses for the State. HB 110 does not specify how this process would have to take place.

HB 110 is therefore not a viable alternative to ACES.

BOE complications

An important drawback of ACES is the BOE problem.

This means that in case major oil companies would propose a new Alaska LNG export project to the Pacific, the entire fiscal system has to be revised again. This is an unnecessary obstacle to the introduction of a new gas project.

It is therefore essential that in any revision of ACES this problem is also dealt with in advance. This would permit to add gas terms to the package later (or immediately) without having to change oil terms again.

PVM Proposal: Existing and New Production

The PVM Proposal is going further than merely creating new levels of government take for existing and new production. The proposal also:

- Creates a new “architecture” to which terms for heavy oil , shale oil and natural gas can be easily added, and
- Resolves all the deficiencies associated with ACES.

PVM Proposal for New Production

At \$ 100 per barrel, the HB 110 for New Production is equal to a much simpler concept, which is:

- 25% flat PPT
- 20% tax credit, plus a
- 2.25% severance feature.

The severance tax feature is no different from the way the severance tax used to be calculated in Alaska. The severance tax is a percentage of the value of the gross production less the royalty. For instance, with a royalty of 12.5% and an oil price of \$ 100, a 2.25% severance feature would be equal to:

$$2.25\% * 87.5\% * \$ 100 = \$ 1.96875 \text{ per barrel}$$

PVM Proposal for New Production

In order to make the severance feature match the government take of HB 110 for new production, the following price sensitive sliding scale is proposed:

- The sliding scale starts at an oil price of \$ 60 per barrel,
- Between an oil price of \$ 60 and \$ 180 per barrel, the severance feature would increase with 0.05% per dollar increase, reaching a value of 6% at \$ 180 per barrel
- Thereafter, the sliding scale would increase 0.1% in order to reach a maximum of 15% at \$ 270 per barrel.

New “architecture”

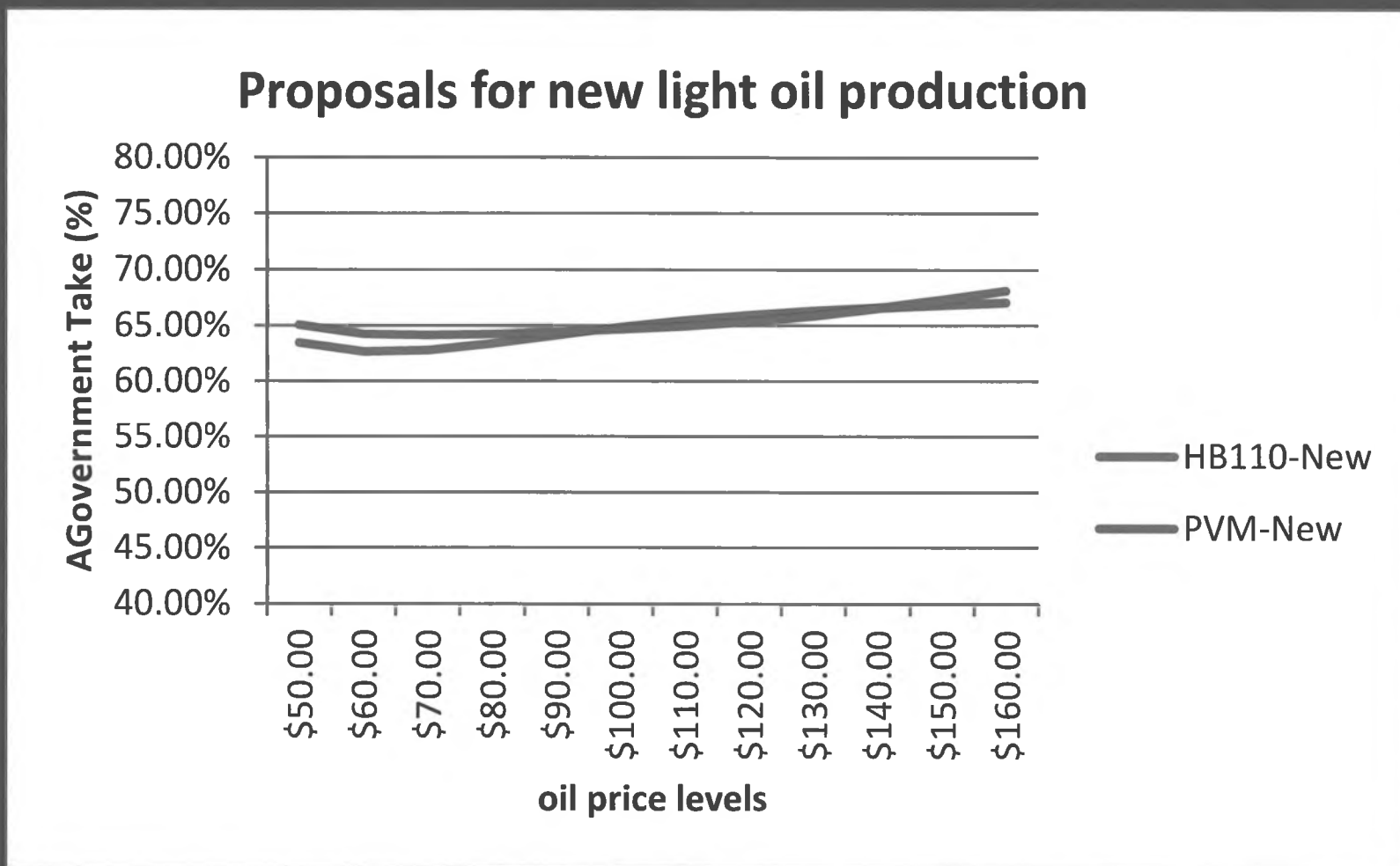
The PVM Proposal creates a new “architecture” which is not BOE based. The severance feature is simply gross revenue based for oil (after the royalty) and therefore it does not apply to gas.

As a result PPT revenues from oil remain the same if also gas is produced. This solves a major deficiency of ACES.

Also excessive exploration support is eliminated because:

- It is proposed to limit tax credits to 20% and not increase tax credits to 40% for certain exploration expenditures, and**
- By creating a maximum PPT tax rate of 25% and corporate income tax rate of 41.1%, for a total maximum of 55.75%.**

PVM Proposal for New Production



The PVM proposal results in almost exactly the same government take as HB 110 for new production for the entire price range from \$ 60 to \$ 160.

PVM Proposal for New Production

The main advantages of the PVM Proposal are:

- **Much easier to administer**
- **Can be consolidated with existing production, so no need for ring fencing**
- **An “architecture” which permits other resources to be added to the fiscal terms**
- **No excessive tax rates, in fact a combined rate of 55.75%.**
- **No excessive price progressivity**
- **No excessive exploration support**
- **No nonsensical cross subsidization of gas based on BOE values**
- **Reduced negative PPT characteristics**

Alternative Proposal for Existing Production

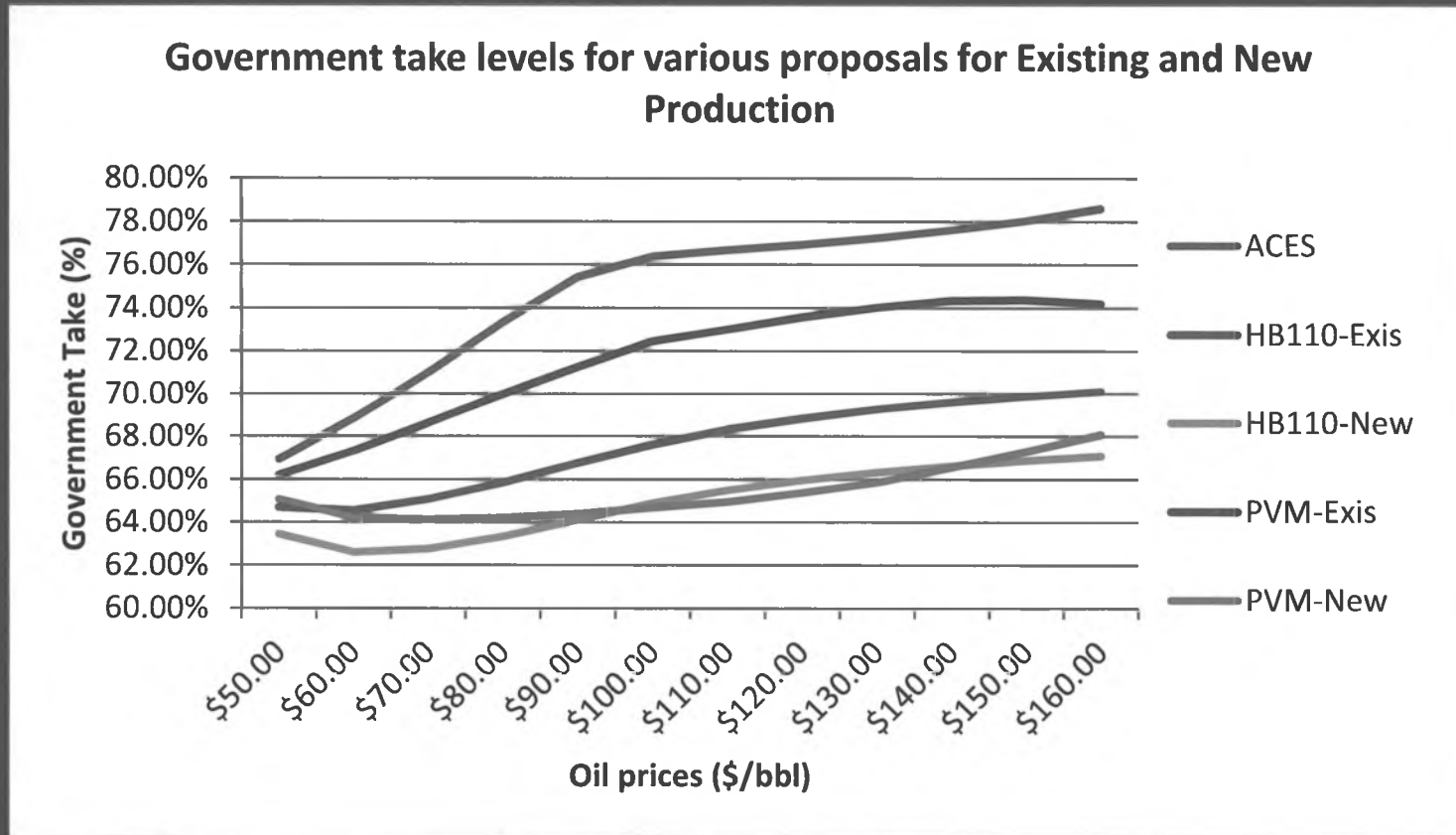
It is now easy to add a proposal for existing production.

Terms for existing production could be close to the current government take levels of ACES. It is not necessary to give up significant revenues.

Existing production terms could also be based on:

- **A flat 25% PPT**
- **20% tax credits**
- **A severance feature starting a \$ 60 with 0.2% increases per dollar increase in price up to \$ 130 per barrel and from there 0.1% up to a maximum of 20%.**

All Proposals for Existing and New Production



The PVM Proposal for existing production would result in a much higher government take than HB 110 for existing production. The PVM proposal for new production is about equal to HB 110 for new production.

Old and New Production

HB 110 does not determine how to distinguish between new oil and existing oil. It is proposed to use the following methods:

Decline curve method.

With the decline curve method Alaska would establish the average production for each company in 2011. An exponential decline curve would be established per company. For instance one could use 6% per year for all companies for light production. Any production over the decline curve per company would qualify as “new”.

The main advantage of the method is that it goes to the essence of the problem in Alaska. It also strongly stimulates investment by new companies. It is easy to administer. The main disadvantage is that existing companies may be rather differently affected. Therefore, this method needs to be complemented with other options.

Old and New Production

New non-producing lease method.

Another simple method is to consider “new” production, as production from leases which were not in production prior to December 31, 2011.

The main advantage of the method is that it is easy to administer and is a well established international practice. It would encourage new investment in new leases with fields which maybe more expensive.

New approved program method.

In principle it is possible for existing producers to make specific comprehensive proposals to the Alaska Government for new investments that will increase production from existing fields. This would relate to programs that would be in excess of ongoing investments.

Old and New Production

These programs could include:

- The drilling of new more expensive deeper or shallower reservoirs,
- Enhanced recovery projects
- Horizontal well drilling projects in thin reservoirs,
- Extensive new infill drilling beyond current rates, or
- Any application of new technology.

DNR would establish the base line production above which production would be considered “new” on a year by year basis, based on reservoir and other studies.

Old and New Production Summary

“New” light oil production (higher than 22 degrees API) would be:

- the higher off:
 - New production from programs specifically approved by the administration, and
 - New production above a pre-determined decline curve for light oil production of 6%.
- production from non-producing leases.

Based on these definitions it is easy to apply the differences in the severance features between existing and new production.

Session 4

**Proposed terms for heavy oil, shale oil
and natural gas**

Terms for Heavy Oil

General

Major heavy oil development may face significant challenges, since a mixture in the TAPS line of too much heavy oil may cause operational problems.

Major heavy oil development may have to be stimulated in conjunction with expansion of light oil projects, with possible condensate and liquid stripping projects from gas fields (such as Point Thomson) and/or a construction of GTL plant(s) (with subsequent cracking of waxy components).

Alternatively, one could build upgraders fueled by cheap natural gas on the North Slope in order to upgrade heavy crudes to lighter crudes. It is not known at this time whether construction of upgraders would be a viable possibility.

Terms for Heavy Oil

Proposed Terms

With the new “architecture” in place for light oil production it is now easy to add terms for heavy oil.

At this point in time only 40,000 bopd of heavy oil is being produced.

It is not recommended to divide heavy oil in “existing” and “new”.

Firstly, because it would be difficult to determine a fair decline curve at this time.

Secondly, the volume is too small to make unnecessary complications in the fiscal terms.

Terms for Heavy Oil

Proposed Terms

For heavy oil the fiscal system could be based on the same PPT as follows:

- PPT based on a flat rate of 25%
- 20% tax credit
- A 15% allowance based on the gross value of the heavy oil as special deduction for the determination of the PPT
- A severance feature starting at \$ 160 per barrel at 0.05% per barrel increase up to \$ 200 and thereafter 0.1% per barrel increase up to a maximum of 10%
- A floor price for the purpose of calculating PPT of \$ 55 per barrel escalated with inflation.

Terms for Ultra Heavy Oil

Proposed Terms

For heavy oil the fiscal system could be based on the same PPT as follows:

- PPT based on a flat rate of 25%
- 20% tax credit
- A 25% allowance based on the gross value of the heavy oil as special deduction for the determination of the PPT
- A severance feature starting at \$ 160 per barrel at 0.05% per barrel increase up to \$ 200 and thereafter 0.1% per barrel increase up to a maximum of 10%
- A floor price for the purpose of calculating PPT of \$ 55 per barrel escalated with inflation.

Terms for Ultra Heavy Oil

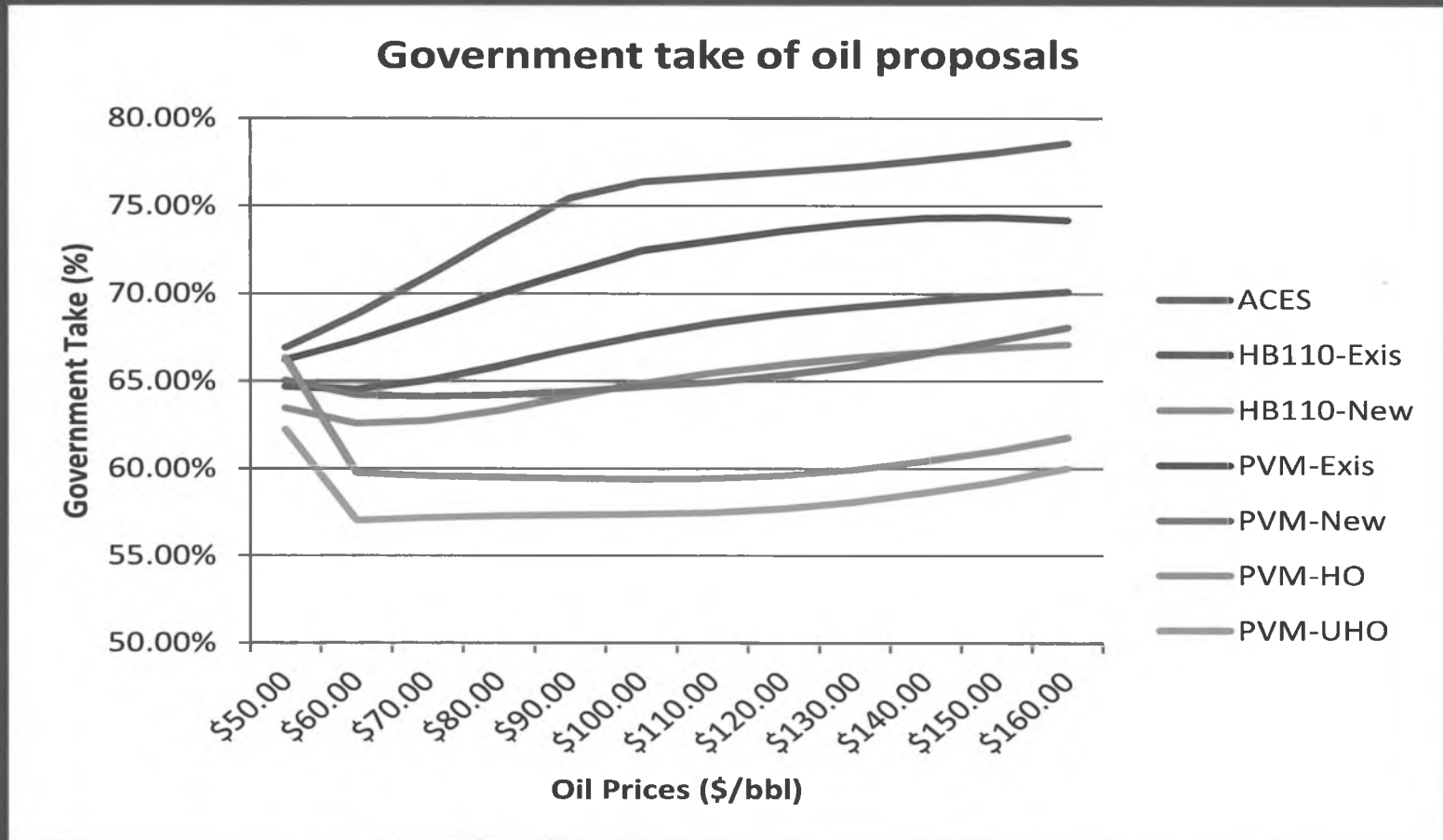
Proposed Terms

It is very important for Alaska to upgrade ultra heavy oil. This would create additional value added in the State and would make the operations of the oil line much easier.

It can therefore be suggested that producers are given the option to have a “feed price” into the upgrader for ultra-heavy oil which would be equal to 65% of the value of the synthetic oil that would be produced. The feed price would be the basis for royalties and PPT.

It would allow companies to only pay corporate income tax on the upgrader, since this is in fact a mid-stream type operation. This same concept is applied in Alberta for oil sands or refineries in Alaska.

Terms Overview



The PVM terms for existing light oil, new light oil, heavy oil and ultra heavy oil would be a simple overall scheme that would be easy to administer and implement and would not have the deficiencies of the current ACES system.

Terms for Shale Oil

The Shale Oil terms could be the same as the terms for ultra heavy oil.

However, there is a small probability that the shale oil operations may turn out to be rather profitable if fracking operations are very successful and primarily light oil is being produced.

So, it is possible to make the allowance of 20% more flexible and reduce the percentage in case shale oil production proves to be rather profitable.

This can be done with a so-called R-factor. The 20% could be reduced if the ratio between cumulative revenues and cumulative costs for a project become very profitable.

Terms for Natural Gas

New Gas Fields

Any condensates and other liquids from natural gas production could be dealt with as new light oil production.

For gas the fiscal package could be:

- Flat 25% PPT
- 20% tax credit
- 25% allowance of the gross value of the gas revenues
- Severance feature starting at \$ 8/MMBtu at 0.05% per \$1 per MMBtu, and after \$ 20/MMBtu at 0.1% (which means that on a Btu equivalent the severance feature is much stronger for gas than for oil)
- A floor net back gas price of \$ 3.00 per MMBtu for PPT purposes and a floor price for liquids and condensates of \$ 70 per barrel.

Terms for Natural Gas

Gas from fields with existing oil production

Any condensates and other liquids from natural gas production could be dealt with as new light oil production.

For gas the fiscal package could be:

- **Flat 25% PPT**
- **20% tax credit**
- **15% allowance of the gross value of the gas revenues**
- **Severance feature starting at \$ 8/MMBtu at 0.05% per \$1 per MMBtu, and after \$ 20/MMBtu at 0.1% (which means that on a Btu equivalent the severance feature is much stronger for gas than for oil)**
- **A floor net back gas price of \$ 3.00 per MMBtu for PPT purposes and a floor price for liquids and condensates of \$ 70 per barrel.**

Government Take issues

As a first step it can be recommended to bring the government take down to higher levels than indicated by international competition for:

- Ultra heavy oil
- Shale oil
- Natural gas

The reason is that international competitive levels cannot be reached unless Alaska would lower the royalties. It seems prudent to first “test the market” on the packages proposed in this seminar.

New fiscal terms

	Light-Exist	Light-New	HO	UHO	Shale Oil	Gas-Exist	Gas-New
PPT Rate	25%	25%	25%	25%	25%	25%	25%
Tax Credit Rate	20%	20%	20%	20%	20%	20%	20%
Sev Feature - Base Price	\$60	\$60	\$160	\$160	\$160	\$8	\$8
Sev Feature - Initial Increment	0.20%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
Sev Feature - Change Price	\$130	\$180	\$200	\$200	\$200	\$20	\$20
Sev Feature - Increment 2	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
Sev Feature - Max Rate	20%	15%	10%	10%	10%	15%	15%
Allowance - % gross rev	0	0	15%	25%	25%	15%	25%
Floor price - oil	no	no	\$55	\$55	\$55	\$70	\$70
Floor price - gas	no	no	no	no	no	\$3	\$3
R-factor	no	no	no	no	yes	no	no

The proposed fiscal terms would provide for a simple to administer overall system and would set terms for all possible oil and gas investments. Significant investment may occur as a result of these terms.

Failure to achieve goals

What would happen if Alaska adopts these terms and no significant new investment takes place in Alaska, while oil production continues to decline:

- 1. Alaska would not have lost anything compared to the current situation.**
- 2. A very valuable benchmark would be established as to how fiscal terms may have to be changed further in order to eventually attract the investment in these resources.**

Summary

With the appropriate fiscal and contractual framework Alaska can achieve:

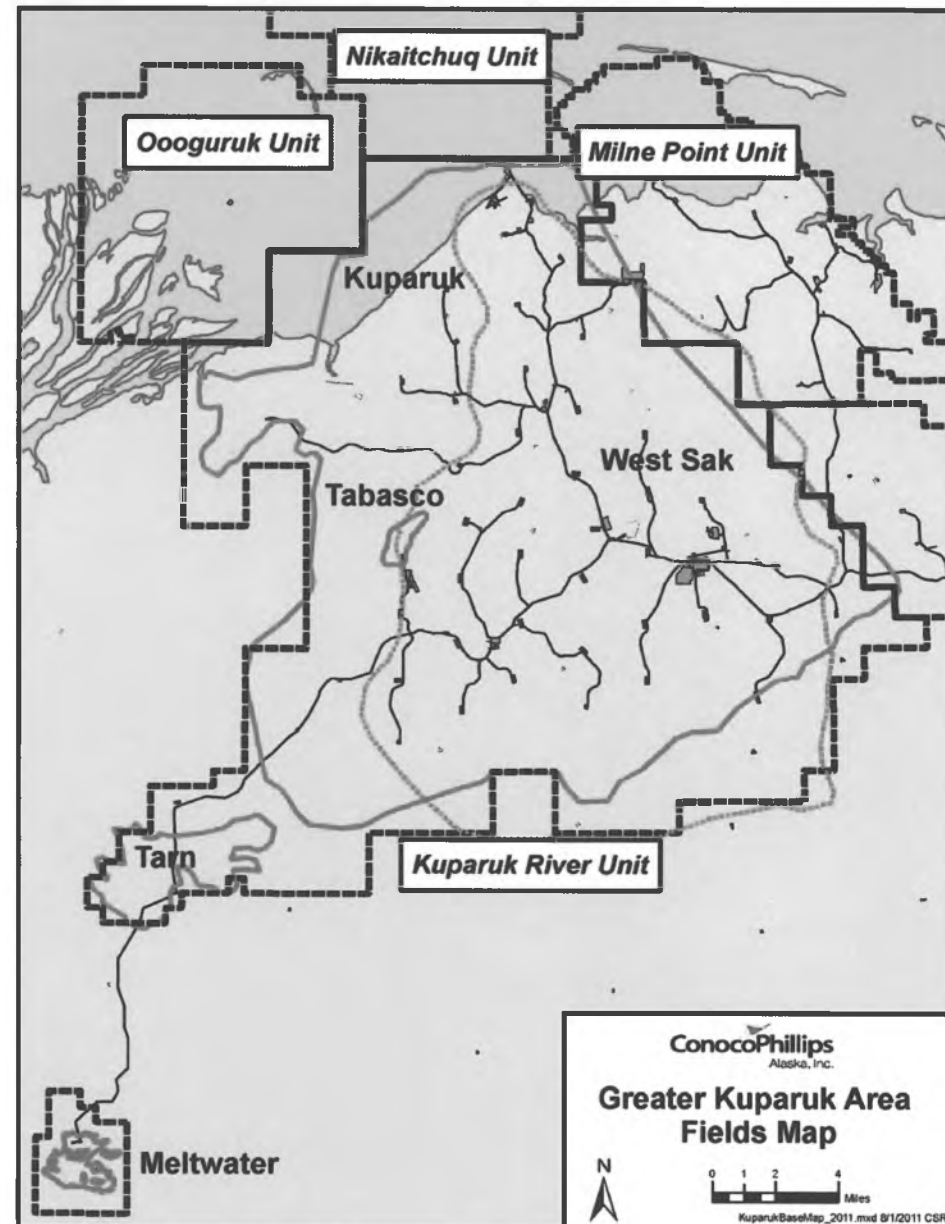
- 1 million barrel per day throughput through the TAPS line, and
- Significant LNG exports to the Pacific market

However major political and fiscal change is required.

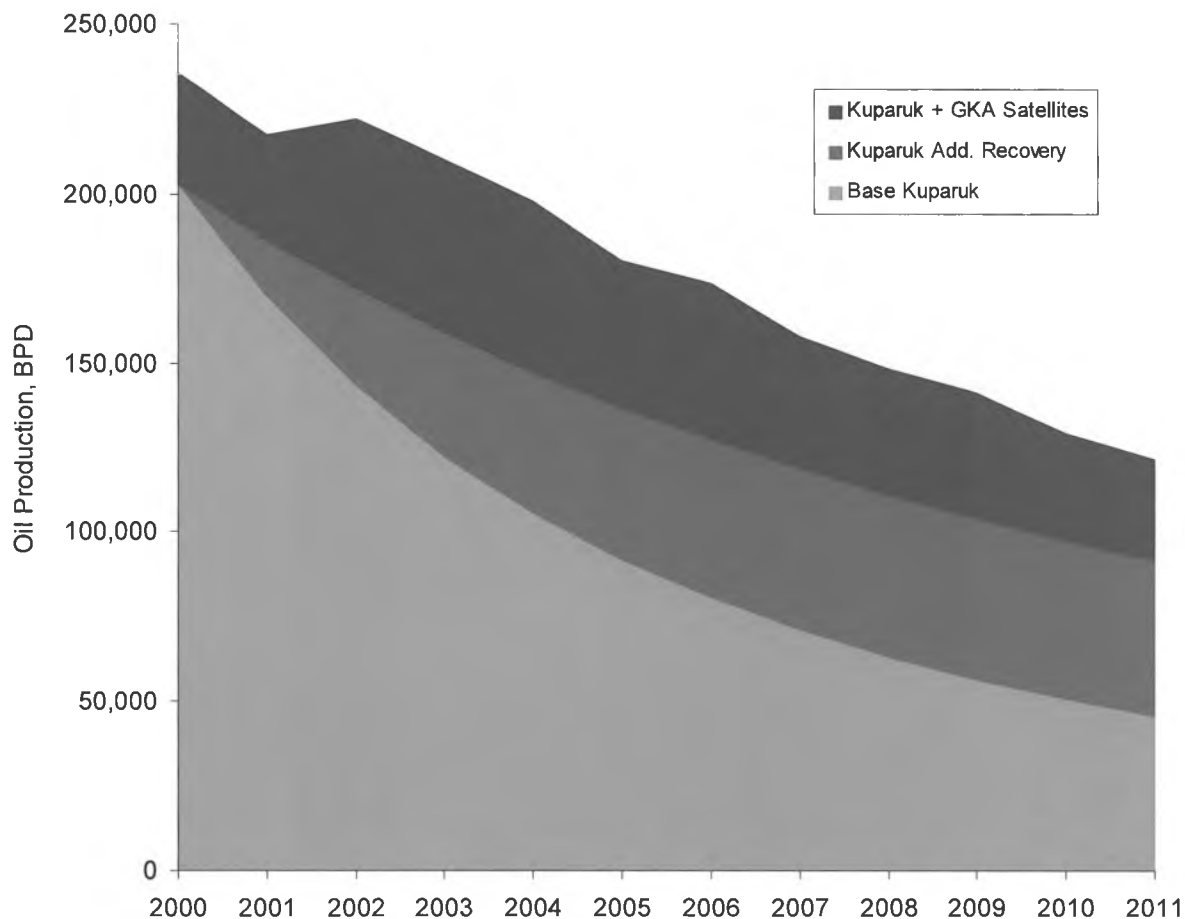
The sooner the process starts to encourage these changes the better the future of Alaska will be secured.

Greater Kuparuk Area (GKA)

- Field start-up 1981
- 5 producing fields; COP operated
 - Kuparuk (waterflood, EOR)
 - West Sak (waterflood, VRWAG pilot)
 - Tarn (waterflood, EOR)
 - Tabasco (waterflood)
 - Meltwater (waterflood, EOR)
- 3 production facilities, 47 drill sites, ~1140 wells
- >2.4 billion barrels produced to date
- 3rd party processing of Pioneer's Oooguruk Field
- Current production: ~121 MBOPD

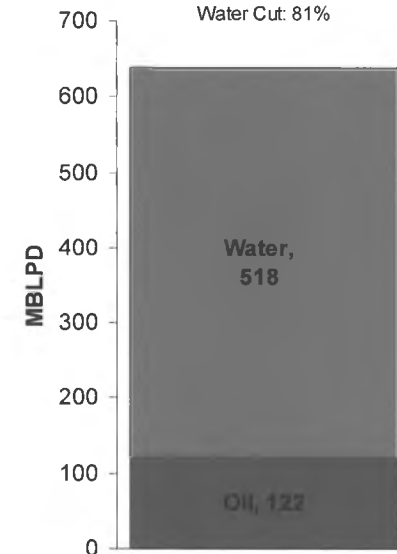


Greater Kuparuk Area Production



GKA 2011 Total Liquid Production

Oil + Water: 640 MBLPD
Water Cut: 81%



2011 Production	Oil STB/d	Water B/d	Gas Mscf/d
KRU	91,391	480,630	203,578
Meltwater	2,671	589	9,873
Tabasco	1,608	14,238	253
Tarn	10,450	17,718	13,637
West Sak	15,718	4,673	9,689
Total	121,839	517,848	237,030

Total gas handled ~600,000 Mscfd including injection gas, gas lift, and fuel

Development

- Continued coil tubing drilling (CTD) rig
- Ongoing rotary development program
- Evaluate water injection expansion at CPF1
- Shark Tooth appraisal well
- Evaluate 220 sq. miles of recently acquired seismic
- Evaluate enhanced recovery techniques

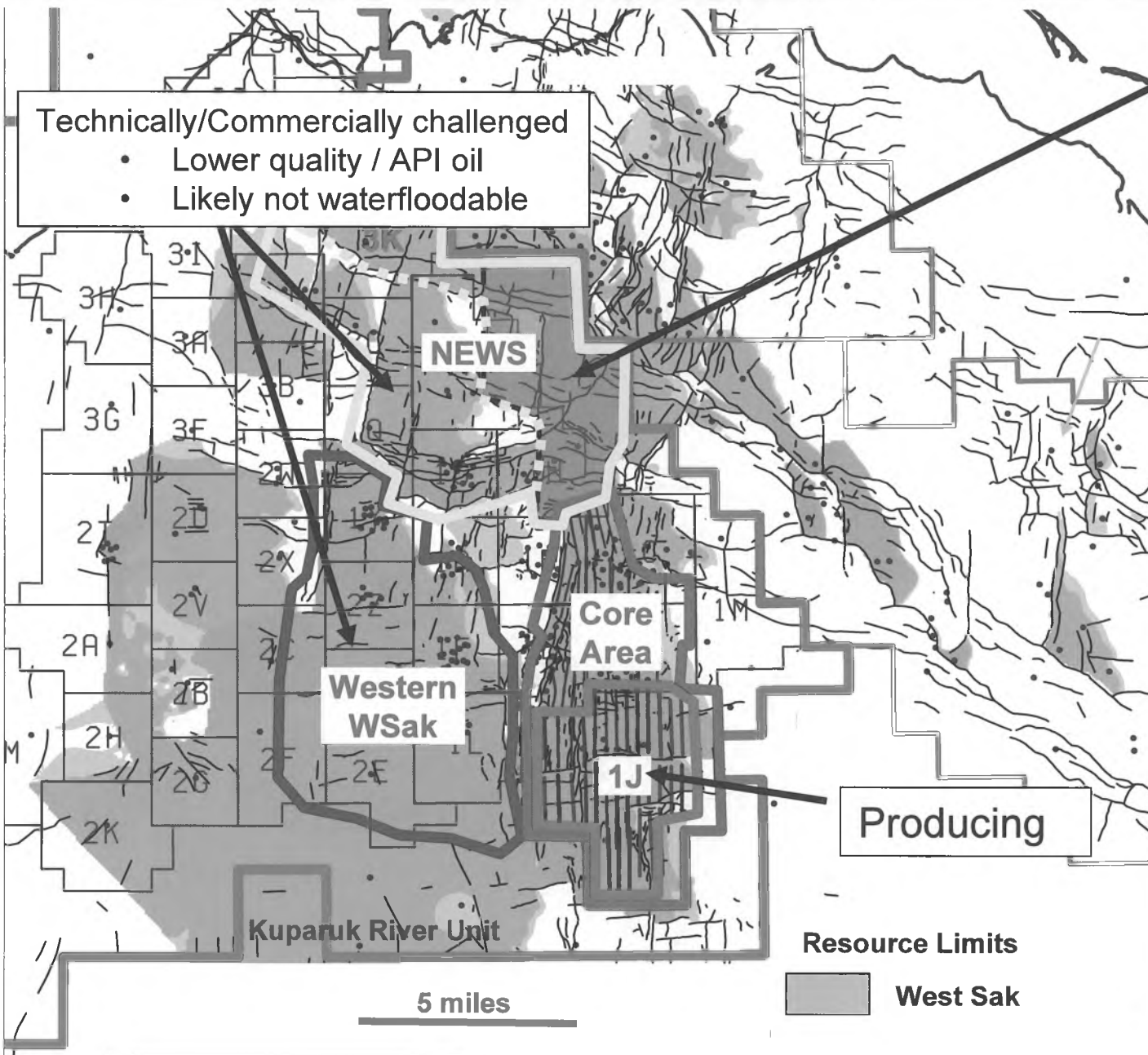


Maintenance / Renewal

- Kuparuk runway upgrade
- Smart pig program
- Well line upgrades
- 1 workover rig
- Ongoing O&M



GKA West Sak Viscous / Heavy Oil Resources



Eastern NEWS

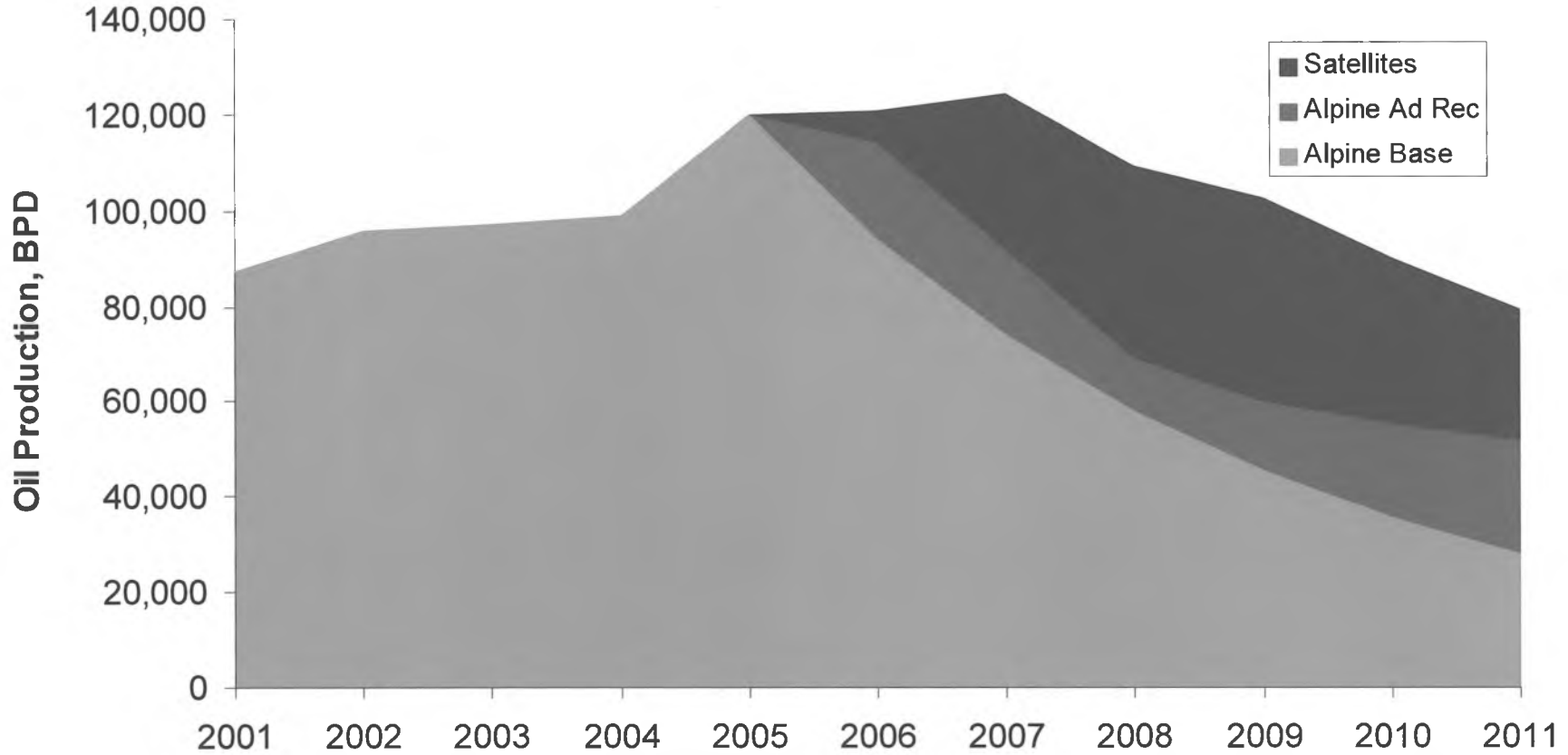
- ~\$1 - 2.5 billion potential project
- One or two new well pads
- Up to 115 new wells and 150 MMBO
- Technically challenged
 - Sand control
 - Matrix bypass events
 - Productivity
 - Ultimate recovery
 - 1J history
- Project sanction a function of technical evaluation and economics

Western North Slope (WNS) Development

- First production in 2000
- Largest US onshore discovery since 1970s
- 4 producing pools; COP operator
 - Alpine (waterflood, EOR)
 - Fiord (waterflood, EOR)
 - Nanuq (waterflood, EOR)
 - Qannik (waterflood)
- 4 drill sites & processing plant
- 172 wells
- Current production: 77 MBOPD
- 413 million barrels produced to date



Western North Slope Production



2011 Average	Oil Production STB/d	Water Production B/d	Gas Production Mscf/d
Alpine	50,812	36,848	53,259
Fiord	20,907	10,259	19,035
Nanuq	4,772	12,589	6,594
Qannik	1,955	19	1,157
CRU Tract	1,006	36	3,602
TOTAL	79,452	59,751	83,648

Total gas handled ~185,000 Mscfd
including injection gas, gas lift and fuel

Development

- Continued rotary drilling of extended-reach horizontal wells
- Ongoing stimulation program
- CD3 facility upgrade
- CD5 (Alpine West) development

Maintenance / Renewal

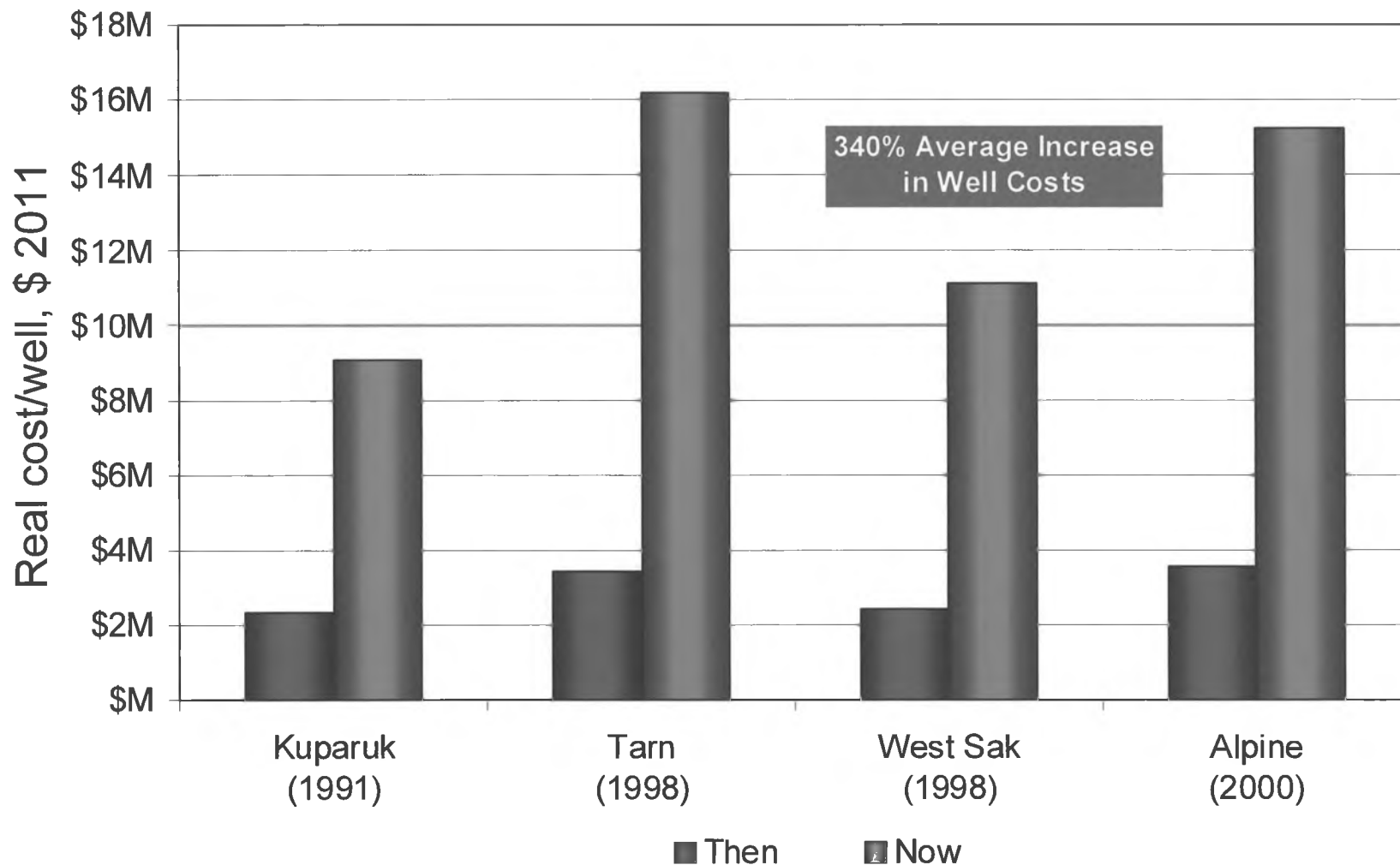
- Smart pigging program
- Pipeline upgrades
- Ongoing O&M



- Production estimate
 - 10 - 18,000 BOPD
- New drill site
 - Up to 33 well slots
 - Drillsite facilities, gravel road, pipelines and power
- Milestones
 - Project sanction 2012
 - Estimated production start-up 2015



Representative Drilling Costs, Then and Now



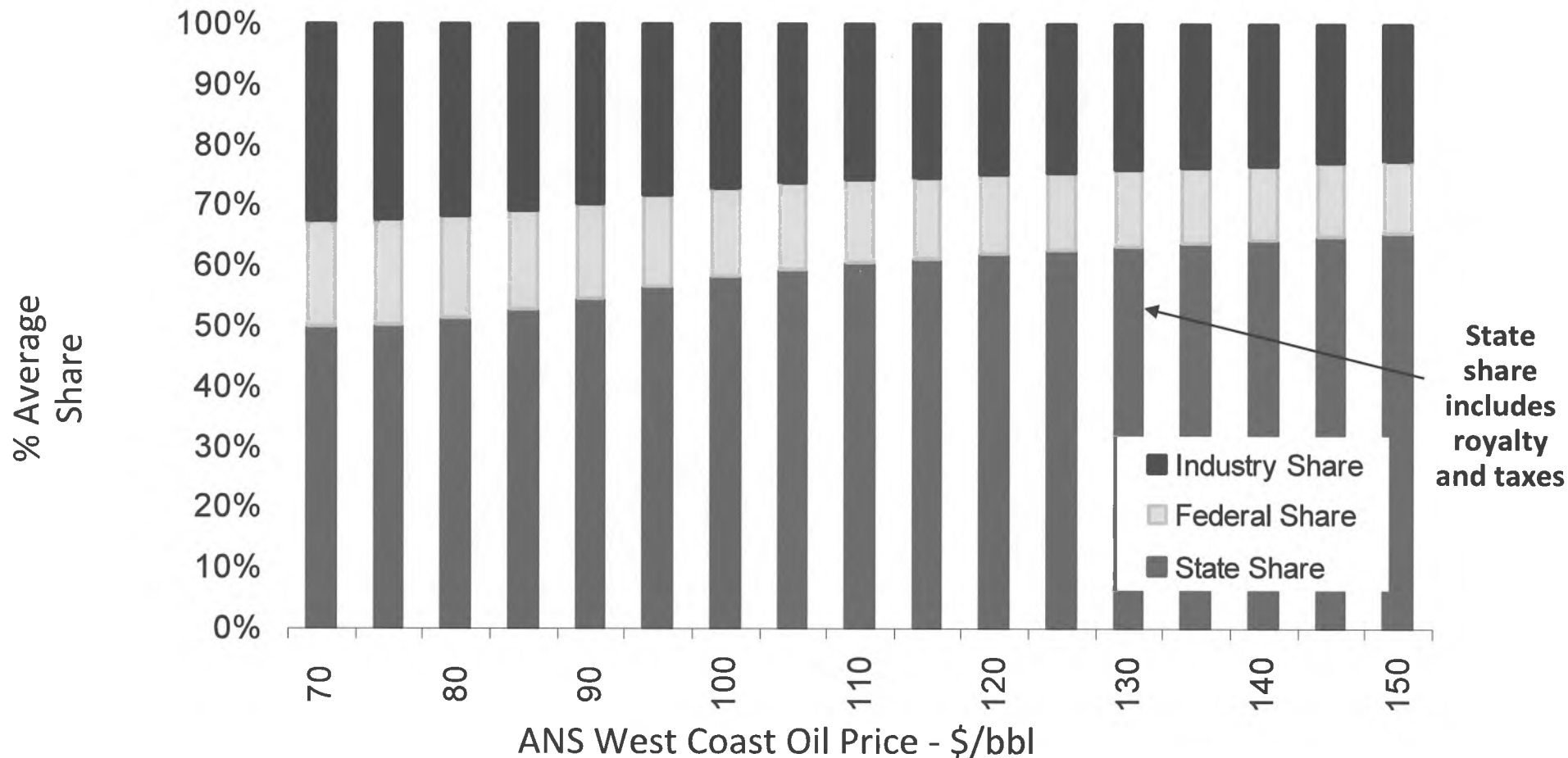
GKA and WNS Development Summary

- Near term focus on light oil
 - Technology available
 - Greater potential to add near term rate
- Viscous oil maturing
 - Have made technological advancements
 - Core area West Sak on line at 14,000 BOPD
 - Evaluating next significant investment (Eastern NEWS)
 - Challenged technically and commercially
 - More engineering needed
- Evaluating heavy oil technologies
- Exploration and satellite targets

Investment decisions include evaluation of all factors affecting economic assessment – including cost, production, technical, regulatory and fiscal risks

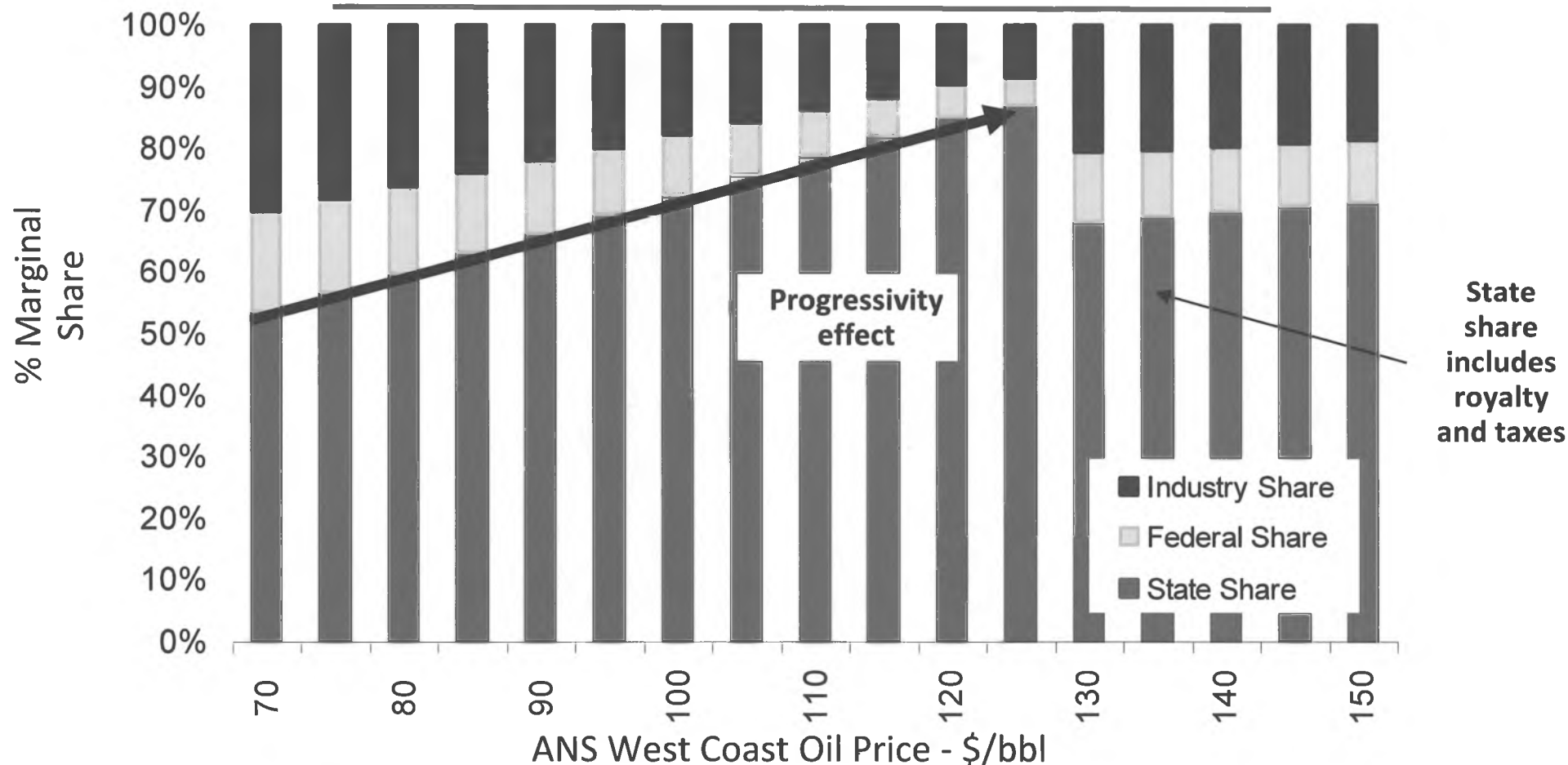
High Average Government Take in Alaska

Government and Industry Average Share in Alaska



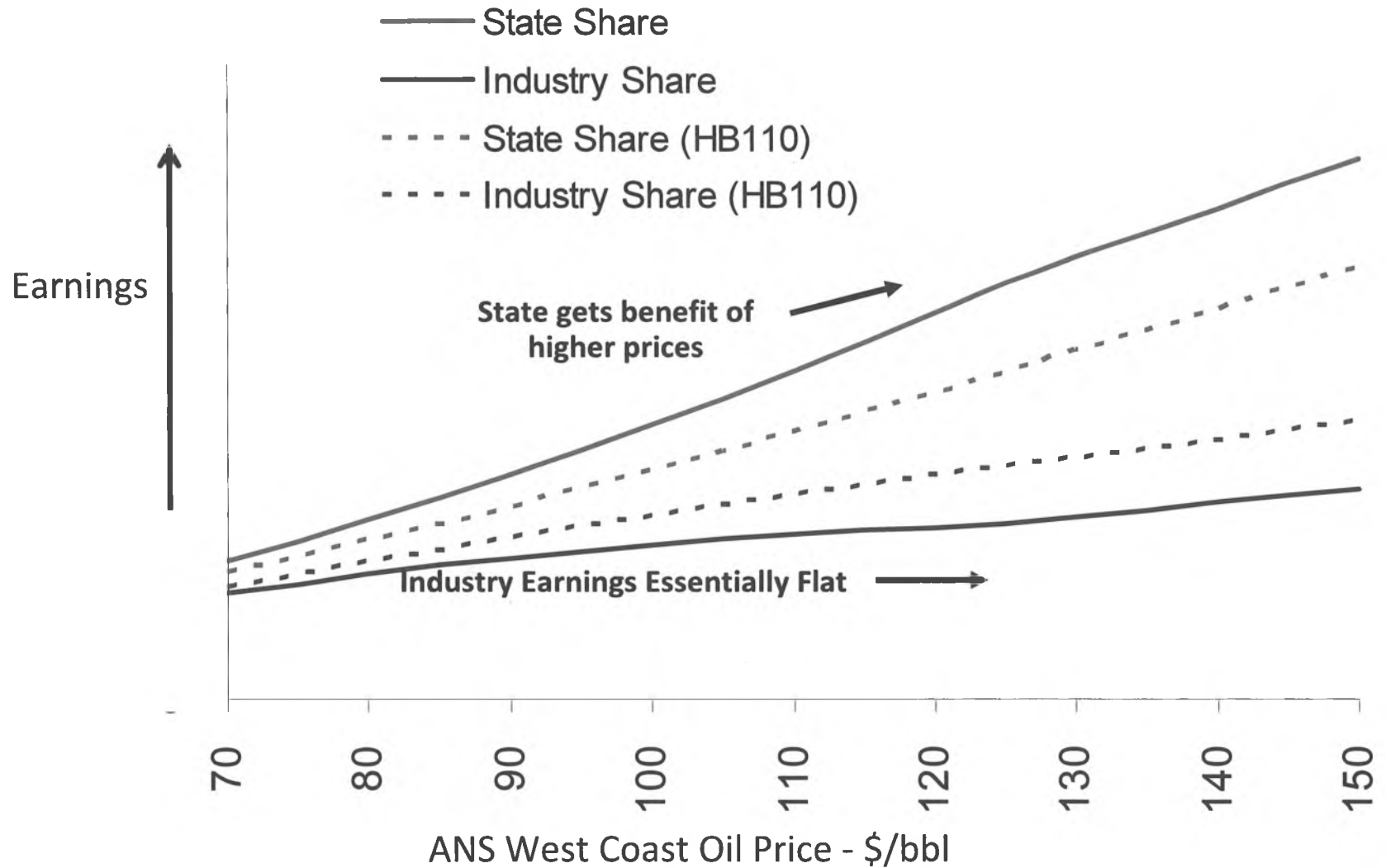
Progressivity is the Problem

Government and Industry Marginal Share in Alaska

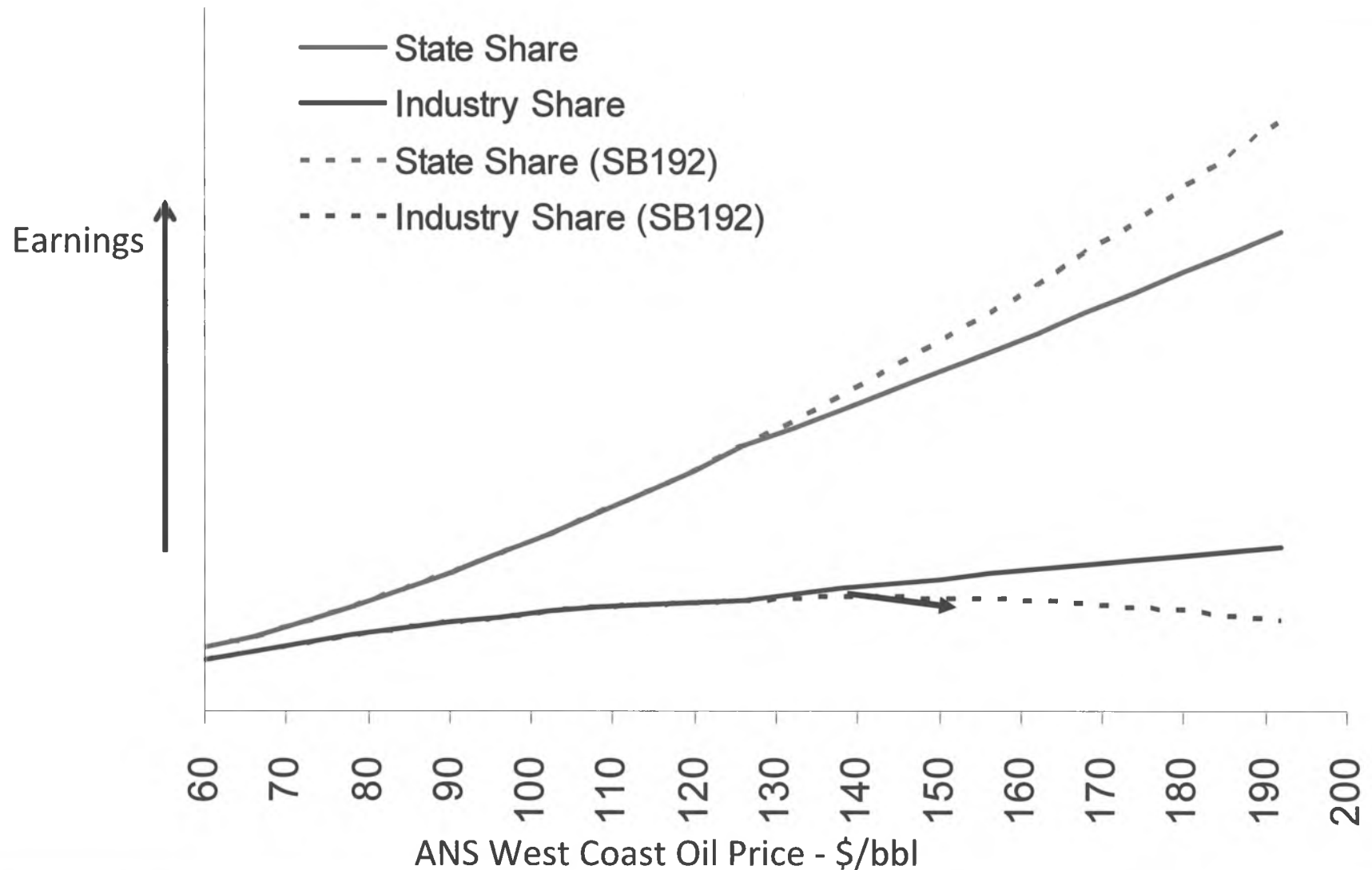


**By comparison, industry marginal share in L48
40% to 50%**

Industry Earnings Limited in Alaska

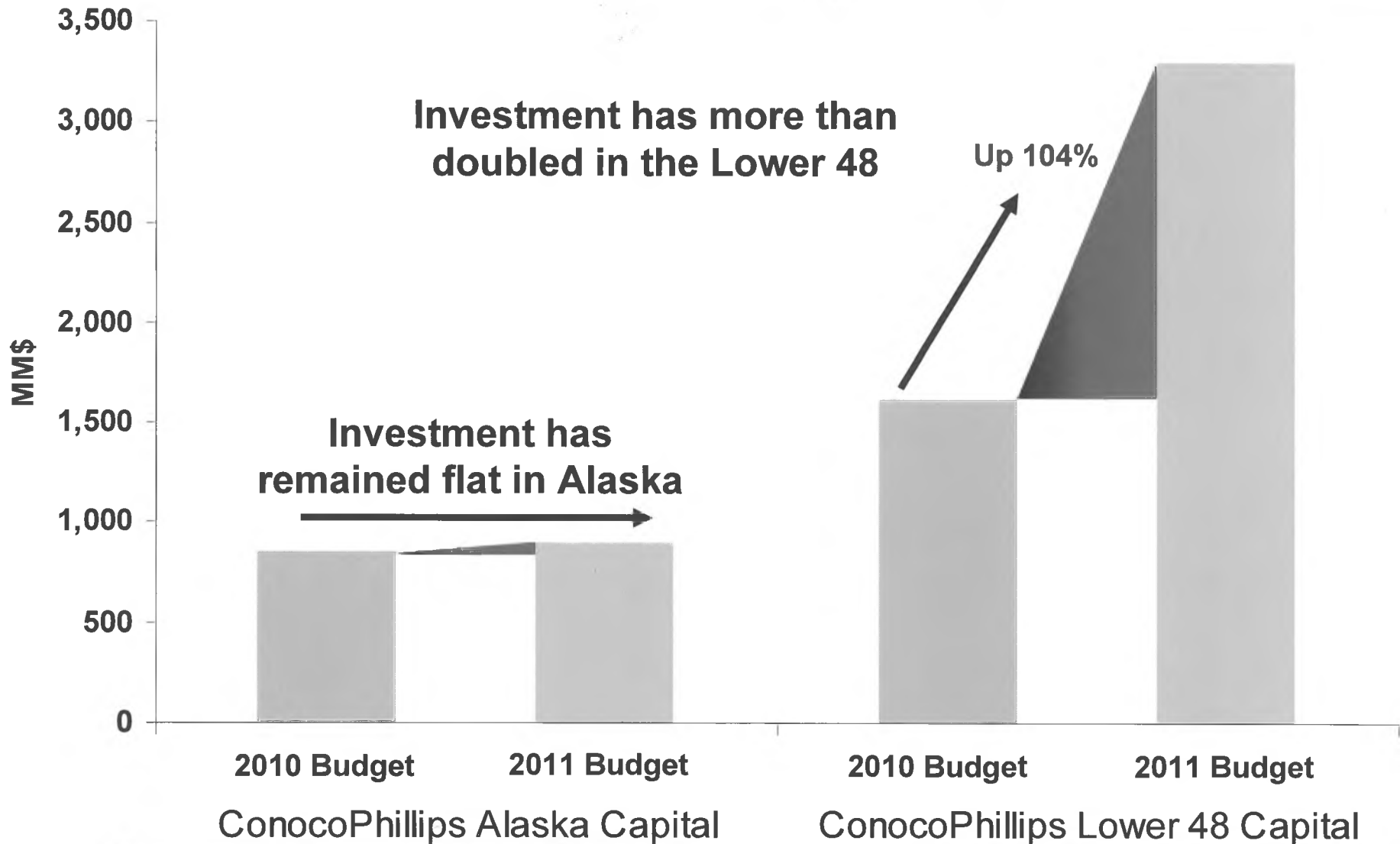


Is Marginal Take Important?



SB 192: With marginal government take > 100%, a case study in why marginal rates matter

Progressivity is the Problem



Investment flows where investor has upside

Will Alaska Benefit From Reduced Oil Taxes?

Last spring ConocoPhillips made the following commitments to Alaska if the business environment is improved:

- More effort to bring challenged oil to market
 - Increased drilling activity
- Pursue more satellite developments at Alpine and Kuparuk
- Pursue major projects in existing fields

An Open Letter to All Alaskans from ConocoPhillips

Our Commitment to Moving Alaska Forward

Dear Alaskans:

The oil industry in Alaska is at a crossroads. The annual budget of the State of Alaska provides for a 10% increase in oil taxes from 2010 to 2011. This is a significant increase, and the State of Alaska is facing a budget deficit. We are committed to working with the State of Alaska to find a solution that is in the best interests of all Alaskans.

We believe that the best solution is to reduce the oil tax rate to 10% for the next five years. This would provide a significant source of revenue for the State of Alaska, and it would also help to reduce the budget deficit. We are committed to working with the State of Alaska to find a solution that is in the best interests of all Alaskans.

ConocoPhillips has invested a total of \$1.5 billion in Alaska in an effort to develop and produce oil and gas. We are committed to working with the State of Alaska to find a solution that is in the best interests of all Alaskans.

In Alaska, we work to create jobs and economic growth. We are committed to working with the State of Alaska to find a solution that is in the best interests of all Alaskans.

We will continue to work with the State of Alaska.

We are a progressive company that believes in the power of innovation and technology to create a better future for Alaska.

We will work with the State of Alaska to find a solution that is in the best interests of all Alaskans.

We will aggressively pursue new satellite developments at both Alpine and Kuparuk. We are committed to working with the State of Alaska to find a solution that is in the best interests of all Alaskans.

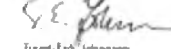
At ConocoPhillips, we believe in the potential of Alaska's oil and gas. We have demonstrated our commitment to the environment by investing in the research and development of clean energy technologies. We have a long history of working with the State of Alaska to find a solution that is in the best interests of all Alaskans.

If the Legislature provides for an effective date of 2011, ConocoPhillips will do our best to provide new energy to the State of Alaska.

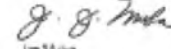
Alaska has tremendous natural resources, and we at ConocoPhillips have over 20 years of experience in working with the State of Alaska to find a solution that is in the best interests of all Alaskans.

We are committed to working with the State of Alaska to find a solution that is in the best interests of all Alaskans.

Sincerely,


Fred-Enr. Johnson

President
ConocoPhillips Alaska


Jim Miller

Chairman and Chief Executive Officer
ConocoPhillips

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Alaska's Oil & Gas Company

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February 2012

Vol. 17, No. 7

Week of February 12, 2012

ConocoPhillips joins North Slope winter explorers

Kay Cashman

Petroleum News

As it turns out, ConocoPhillips' Shark Tooth 1 well in the Kuparuk River unit is an exploration well, per the drilling permit issued by the Alaska Oil and Gas Conservation Commission.

This brings the total number of 2012 North Slope explorers to six and the total oil exploration wells to between 23 and 27. The record was 35 in 1969, following the Prudhoe Bay discovery.

The explorers and the wells they expect to drill are: ConocoPhillips 1; Pioneer Natural Resources 2; Repsol 9; Savant 1; Brooks Range Petroleum 2; Great Bear Petroleum 4-6 verticals plus 4-6 horizontals.

All exploration involves ice roads and pads except Great Bear's proof of concept program, which is in the Dalton Highway's transportation corridor, meaning the company can drill year-round from gravel roads and pads.

Doyon rig 141 is almost finished drilling ConocoPhillips' Shark Tooth 1, which is "critical" for "future development of this part of the Kuparuk reservoir," the company said in agency filings.

As of Feb. 8, Nabors rig 9ES was at Repsol's K-1 ice pad and expected to begin drilling in the next day or two. Nabors 105AC was on Repsol's Q-2 ice pad, with drilling to begin soon. Nabors 2ES was headed out to Repsol's Q-1 ice pad. Doyon's Arctic Fox has not been moved to Q-4, Repsol's ice island, because it

can't begin drilling until 9ES is finished at K-1, as the North Slope Borough is only allowing Repsol to operate three rigs at one time.

Around March 1, 9ES will travel to Badami to drill Savant's Red Wolf 2.

Nabors rig 27E is drilling the first of two Pioneer Natural Resources' wells, Nuna 1 and Sikumi 1, which target the Torok formation in the Oooguruk unit.

Brooks Range is drilling the first of two Mustang wells.

Great Bear will start drilling 8-12 wells in May.

Also part of this winter's exploration is Anadarko Petroleum's rig-less testing of its Chandler 1 gas well. The test, under way by Expro, includes hydraulic fracture stimulation by Schlumberger. (In last week's issue PN erroneously reported Schlumberger was doing the testing.)

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**Providing coverage of Alaska and northern Canada's oil and gas industry
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Week of January 29, 2012

CPAI earns \$1.9B in 2011

A 34 percent jump in oil prices helped offset a 6.5 percent decline in production

Eric Lidji

For Petroleum News

A steep rise in oil prices last year helped ConocoPhillips earn nearly \$2 billion in Alaska, an increase over 2010 earning despite falling oil and natural gas production in the state.

ConocoPhillips earned \$1.9 billion in Alaska last year, up from \$1.7 billion in 2010.

While ConocoPhillips' annual earnings in Alaska rose, its quarterly earnings fell.

The company earned \$443 million in the fourth quarter, down 11 percent from the third quarter (\$501 million) and 7 percent from the fourth quarter of 2010 (\$476 million).

ConocoPhillips earned \$1.2 billion from its Lower 48 E&P operations in 2011, up from around \$1 billion in 2010, while maintain roughly level production throughout the year.

Companywide, the company earned \$12.4 billion in 2011, up from \$11.3 billion in 2010.

Rising Lower 48 oil

While ConocoPhillips continues to earn more from its upstream operations in Alaska than from its upstream operations in the Lower 48, that balance could start

to shift this year.

The company plans to ramp up its activities in the oil-rich Eagle Ford and Bakken Shales this year to take advantage of high oil prices and, conversely, shut-in around 100 million cubic feet of North American natural gas production due to chronically depressed prices.

In Alaska, ConocoPhillips produced 215,000 barrels of oil and natural gas liquids per day in 2011, a 6.5 percent decline from the 230,000 bpd of liquids the company produced in 2010. ConocoPhillips produced 61 million cubic feet of natural gas per day in the state last year, down roughly 25 percent from the 82 mmcf per day the company produced in 2010.

In the Lower 48, ConocoPhillips produced 168,000 bpd of liquids in 2011, up slightly from 160,000 bpd in 2010, and 1.5 billion cubic feet of gas per day, down from 1.7 bcf in 2010.

Significantly higher oil prices in Alaska continue to offset gradual production declines for ConocoPhillips. The company realized an average oil price of \$105.95 per barrel for Alaska last year, up from \$78.61 in 2010. By comparison, the company realized an average price of \$74.09 per barrel for Lower 48 liquids in 2011, up from \$57.69 in 2010.

While oil jumped, natural gas prices remained relatively flat year-over-year for ConocoPhillips, from \$4.62 per thousand cubic feet in 2010 to \$4.56 per mcf in 2010. By comparison, Lower 48 gas prices fell from \$4.25 per mcf in 2011 to \$3.99 per mcf in 2010.

Liquefied natural gas sales declined considerably in 2011, as ConocoPhillips began the process of closing its nearly 45-year-old facility on the Kenai Peninsula. The company sold 26 mmcf per day in 2011, down nearly 45 percent from 47 mmcf per day in 2010.

While mentioning recent discussions about a proposal to market North Slope natural gas as LNG, ConocoPhillips' executives made no noteworthy comments about the project.

Tax debate continues

ConocoPhillips has released its year-end earnings as Alaska lawmakers are once again considering changes in the state's production tax code.

In his recent state-of-the-state address, Gov. Sean Parnell tied tax reform to his goal of increasing throughput in the trans-Alaska oil pipeline to 1 million barrels per day over the coming decade. Because it is the only major oil producer to break out financial figures for Alaska on a quarterly basis, something BP only does annually and Exxon does not do at all, ConocoPhillips' earnings often become a wedge in those debates, something Parnell seemed to anticipate by

asking, "Do we have enough will to give up short-term gains for long-term growth?"

With tax reform, the industry is willing to invest \$5 billion in legacy fields, Parnell said.

Rep. Les Gara, an Anchorage Democrat, is promoting an alternative bill designed to create incentives for companies to explore and develop new fields in the state.

ConocoPhillips doesn't release its complete annual report until late February. The filing typically includes Alaska-specific taxation, spending and budgetary information.

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**Providing coverage of Alaska and northern Canada's oil and gas industry
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Pumping Up TAPS: A change in direction for ConocoPhillips?

ConocoPhillips' participation in the State of Alaska's Dec. 7 North Slope and Beaufort Sea areawide lease sales raised eyebrows since by 2002 the newly merged ConocoPhillips, which had picked up ARCO's Alaska assets two years earlier through Phillips, had begun concentrating on finding "new" oil in its legacy units in the state, such as Prudhoe and Kuparuk. The company was still exploring, but on federal acreage, looking for big fields and dropping its state exploration acreage unless it was close to one of its producing units.

Over the next decade ConocoPhillips dropped even its Beaufort Sea federal leases and pulled back from wildcat exploration in the National Petroleum Reserve-Alaska, concentrating on its step-out development of the Colville River unit into NPR-A.

It looked to its federal leases in the Chukchi Sea for its next giant oil discovery in Alaska.

So, given its position on Alaska's current production tax, ConocoPhillips participation in the latest lease sales was a bit of a shocker.

The company bid unsuccessfully in partnership with Exxon on just one tract in the Beaufort Sea sale, but was high bidder on 35 tracts in the North Slope sale, with the bulk of the tracts in a large block south of Point Thomson and Badami on the eastern North Slope in the Slugger/Jacob's Ladder area. (In October, Alaska Venture Capital Group, or AVCG, relinquished a number of leases in the area from its proposed Greater Bullen unit, and some Anadarko leases in the area expired this year.)

Subject to economic evaluation

Although some of the bidders in the sale appear to have been consolidating

existing lease positions, ConocoPhillips was clearly establishing a new position in known, but undeveloped, areas of interest.

“That’s acreage that we have looked at in the past and when it became available we chose to bid on it,” ConocoPhillips Exploration Manager Michael Faust told Petroleum News senior reporter Alan Bailey after the lease sale.

The region is prospective for oil — to the north of ConocoPhillips’ new leases AVCG’s operating company, Brooks Range Petroleum, is hoping to develop some known oil resources between the Point Thomson and Badami oil fields.

But Faust said the acquisition of state onshore leases to the east of Prudhoe Bay does not mark some new strategic direction for ConocoPhillips — the lease purchase was simply a case of snapping up some attractive acreage that became available.

The company will now evaluate the leases, identifying drillable prospects that can be added to the company’s worldwide portfolio of exploration opportunities, Faust said.

The company already owns 3-D seismic data for the area, ConocoPhillips Land Manager David Brown told Bailey.

Faust said that funding to drill would depend on how the prospects in the leases compare with exploration opportunities elsewhere, and that the state’s ACES production tax would be a factor in that comparison — ConocoPhillips wants to see changes in the progressivity elements of ACES.

—Kay Cashman

Editor’s note: The Dec. 7 lease sale brought three new players to the North Slope, and added acreage to existing leaseholders’ portfolios. In addition to ConocoPhillips’ surprising exploration acreage grab, Shell picked up a substantial block of leases in state waters on the west side of Harrison Bay — the first state leases in recent history that Shell has owned offshore the North Slope. The tracts were previously leased by Talisman subsidiary FEX and will likely not go into production in the next decade because they are too far west of existing infrastructure. See articles and a map in the Dec. 11 edition of Petroleum News.

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Week of January 08, 2012

Pumping Up TAPS: Fastest source: legacy fields

BP, Conoco operated oil fields have 4.2 billion barrels of oil left in producing units

Kay Cashman

Petroleum News

There are approximately 4.2 billion barrels of recoverable oil in northern Alaska's legacy fields — specifically those fields that are currently producing oil and operated by BP and ConocoPhillips.

Fields operated by those two companies represent about 98 percent of all current oil production from the North Slope. (For simplicity's sake, in this article the "North Slope" includes all oil fields north of the Brooks Range in Alaska, including offshore pools.)

Heavy oil and oil from source rocks is not included in the 4.2 billion barrels, but some lighter viscous oil, already in production, is included with conventional crude.

A 4.2 billion barrel field qualifies as a super-giant by world standards, and would be the second largest field in Alaska.

The number came from remaining recoverable oil reserves based on the sum of Alaska Department Revenue forecasted production from 2010 through 2050 — based on year-end 2006 reporting, which is bound to be more accurate than forecasts from later years because it reflects very few of the cutbacks BP and ConocoPhillips have made as a result of Alaska's production tax.

It also does not include Badami, which was operated by BP in 2007 but in warm shut down. Today Badami is operated by Savant. Nor does it include any Alpine West oil from the National Petroleum Reserve-Alaska, because the State of Alaska has very little control as to when that oil can be accessed. It does include Northstar because it's in production, but excludes Liberty because it is not in production — and is in federal waters.

Because the legacy operators and their partners invested in technologies such as horizontal drilling, miscible gas injection and gas cap water injection their recovery rates at Prudhoe, Kuparuk, Alpine and others fields are between 50 and 60 percent, as compared to a 35 percent average worldwide.

With continued investments in new technology, that percentage can only rise.

But continued investment — i.e. increasing amounts of oil in the trans-Alaska oil pipeline — the two companies say, will not happen from their fields without passage of Gov. Sean Parnell's legislation to reform the state's production tax. (House Bill 110 passed the House not the Senate; SB 49 will be up for discussion when the Alaska Legislature convenes in January).

More important, enough of the 4.2 billion barrels can be quickly drilled and put in the pipeline to level out North Slope production — probably before explorers Repsol, Brooks Range Petroleum, UltraStar and ASRC Energy can get most of their fields online.

Also to be considered is the fact that not all the explorers will find fields which justify standalone production facilities: Some will need to get BP or ConocoPhillips to allow them to use existing facilities in legacy fields.

Or perhaps truckable/portable production skids, which are being considered by several companies, will work, along with new production facilities that can be shared.

Observations, arguments, promises

Let's look at some of the observations, arguments and promises BP and ConocoPhillips' executives have made in the last two years:

- Alaska's current oil tax system is the biggest impediment to getting more oil into the trans-Alaska oil pipeline — Trond-Erik Johansen, president of ConocoPhillips Alaska, and Claire Fitzpatrick, chief financial officer for the Alaska region and senior vice president of BP Exploration (Alaska).
- The "easy oil" has been drilled. The sweet spots were drilled when the fields were developed — when you put them online, they produced a lot of oil. There is a lot of light oil left on the North Slope, but it's not as easily accessible. And while early water production was low, 3 million barrels a day of water are now being produced: "We're more a water production company than an oil production

company,” and that water has to be managed. —Johansen

- In many parts of the Prudhoe Bay field liquids production is constrained by the volume of gas being produced. Gas partial processing would remove a production bottleneck so that more oil could be produced. I Pad and a gas partial processing project represent an investment of about \$2 billion; investments BP will not make without the tax breaks in HB 110. —John Minge, president of BP Exploration (Alaska) Inc.

- Some of the investments BP has held off sanctioning in its fields have had enough work done on them that they are ready for consideration when the investment climate becomes more competitive. Among those are I Pad development at Prudhoe Bay; western region development at Prudhoe; S pad expansion with low salinity water flooding; and Sag River reservoir development at Milne Point. If those projects had moved forward over the past four years, the projected 25 percent decline between 2011 and 2020 “would be essentially flat.” —Fitzpatrick

- Using inflation-adjusted figures, relative drilling costs in the early wells in Kuparuk, West Sak and Tarn cost about \$2-4 million a well and took about 10 to 15 days to drill. Today it costs four times as much and it takes four times as long, because wells are no longer vertical or near vertical, but are horizontal. And those wells produce less. —Johansen

- There will be “significant investments in infrastructure and pipeline upgrades,” but capital spending on activities that produce more oil, such as drilling and pad expansion, are “limited or on hold” without tax changes. —Fitzpatrick

- Production has dropped more than 140,000 barrels per day since ACES passed. —Fitzpatrick

- I Pad alone will result in drilling some 50 new wells to access about 80 million barrels of additional reserves. That is ... like finding another small oilfield. BP does not lack opportunities in a new fiscal environment. —Minge

- ConocoPhillips is prepared to spend \$5 billion over the next three to five years to generate 90,000 barrels per day if the governor’s tax bill becomes law. —Jim Mulva, ConocoPhillips chairman and CEO

- In the Lower 48, oil production grew 3 percent from 2003 to 2010; Alaska production declined 36 percent over the same period. —Johansen

- Oil at \$50 a barrel in 2008 doesn’t compare to similar prices in 2005 because “the fundamental cost of our business has changed.” Producing a barrel of oil in the Arctic costs between \$25-50 today (early 2010). —former ConocoPhillips Alaska President Jim Bowles

- In previous exploration activities BP identified more than 5 billion barrels of

resources. These resources can be unlocked with a competitive fiscal policy. — Minge

- BP recently approved two seismic acquisition programs, one at Milne Point and one at Point McIntyre, “in anticipation that the tax law will change.” The seismic will be shot in 2012 and 2013, cost \$100 million, and yield “at least 20 to 40 extra wells, if governor’s tax bill is passed.” —Minge

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**Providing coverage of Alaska and northern Canada's oil and gas industry
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Week of January 08, 2012

Pumping Up TAPS: Less about pumping up than stabilizing flow

Kay Cashman

Executive editor & publisher of Petroleum News

This magazine started out as an attempt to identify the potential sources of oil that could meet Gov. Sean Parnell's goal of getting 1 million barrels of North Slope oil per day in the Trans Alaska Pipeline System, or TAPS, within 10 years.

But it soon became more about whether it was possible to stem the decline from an expected average production in 2011 of 605,000 bpd to 530,000 bpd in 2020, as projected in the Alaska Department of Revenue's spring 2011 forecast.

What I learned in my research was that it might be possible to meet the governor's goal in a 10-year period, but only if production from Alaska's source rocks and offshore comes off without any major hitches or delays.

Not wanting to bet on something exciting, but completely untried on the North Slope, and with geologic, technical, economic and political challenges, I decided not to include shale oil in production numbers for the next decade.

Shell, the lead company in northern Alaska's offshore development, could conceivably have one or two Beaufort Sea fields in production in 2021, but even Shell predicts the start of its outer continental shelf Chukchi oil production is at least 10 years out IF it can drill in the open water season of 2012 and there are no more permitting, lawsuit or other delays.

That's more than a long shot, so I excluded the OCS.

Explorers such as Repsol and Brooks Range Petroleum will certainly play a part in putting new oil in the pipeline, so they were included — sort of, as it's not

clear they will develop and produce all their discoveries without a change in Alaska's production tax.

BP and ConocoPhillips, which operate the fields currently producing 98 percent of the oil going into TAPS, could step up production in their legacy fields and increase investment in heavy oil, but the opposite is actually happening — both companies are unwilling to increase their capital investment because they say Alaska's production tax, commonly known as ACES, is a disincentive. Until it is changed —until the governor's legislation, House Bill 110, has passed into law — the companies say they will not be stepping up investment.

Worse, BP predicts the decline in North Slope production will be greater than Revenue projected because 52 percent of the oil between 2011 and 2020 in the state's spring 2011 forecast was from projects not yet sanctioned, and many of those were BP or ConocoPhillips projects that are now on hold. Revenue's fall forecast was due out after all pages except the On Deadline section of this magazine had gone to press. I expected output of 474,000 bpd in 2020, which was the last year in the spring forecast, but you can find out for sure by checking page 8.

Increase in tariff would hurt investment

Less oil in TAPS means less revenue for the state and possible mechanical problems in the line.

But trying to keep production flat at 605,000 bpd is not just about protecting state revenues or avoiding unexpected flow problems; it's also about the trans-Alaska pipeline tariff for non-TAPS owners, such as Repsol, Pioneer Natural Resources, Savant, Brooks Range, Eni, Linc, UltraStar, Great Bear, Shell, Statoil, ASRC Exploration and others. The tariff will undoubtedly go up as system costs are shared among fewer and fewer barrels of oil, which is a disincentive for non-TAPS owners to produce oil on the North Slope.

And if TAPS operator Alyeska Pipeline Service Co.'s low flow impact study is correct (see story on page 23), there is a whole list of mitigation measures that Alyeska will have to implement to keep the pipeline operating as throughput drops below 600,000 barrels a day — costly mitigations that could also raise the tariff.

Subsidiaries of the North Slope's largest producers, BP, ConocoPhillips and ExxonMobil, own large chunks of TAPS, so a higher tariff is not going to necessarily sour them on Alaska. But it has driven off other operators in the past, including Conoco before it was ConocoPhillips and owned ARCO Alaska's share of TAPS — just as a drop in the tariff due to agency and court decisions helped attract new players to Alaska, starting in 2000.

So, this magazine became more about investigating whether the decline in North Slope oil production can be halted, especially without the cooperation of BP and

ConocoPhillips, than it did about achieving the governor's goal.

The first article, an analysis by me, is titled, "First, can the decline be halted? BP, Conoco operate 98 percent of northern Alaska oil production: can it be done without them?"

The next three articles deal with related subjects — oil prices, drilling rig shortages, and TAPS potential low-flow issues.

The next article is about the governor's five-point strategy to achieve his goal, followed by articles about the various sources of oil that could help stem the decline and/or reach the 1 million bpd target.

Finally, there is a group of opinion and analysis pieces that cover everything from impediments to filling TAPS by Jim Weeks, to Rep. Les Gara's position that HB 110 is a giveaway, to Dan Dickinson's five not-so easy pieces to put 1 million barrels in the pipeline, and more.

In the end, we have a photo layout about TAPS, from construction, to start-up, and snapshots of the last 34 years of operation.

I hope you enjoy this magazine, and find it helpful in understanding the incredible challenge in pumping up TAPS.

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Pumping Up TAPS: First, can the decline be halted?

BP, Conoco operate 98% of northern Alaska oil production: can it be done without them?

Analysis by Kay Cashman

Petroleum News

Before determining if it's possible to increase flow in the trans-Alaska oil pipeline from projected 2011 levels of about 605,000 barrels a day to 1 million barrels, the governor's goal, it's important to first determine if the decline in North Slope production can be halted — specifically, stabilized without increases in investment from the region's two major operators, BP and ConocoPhillips, which with ExxonMobil and their smaller partners account for almost 98 percent of the liquids in the pipeline.

Executives from BP and ConocoPhillips say they do not expect to increase their capital spending in Alaska until the state's production tax is reduced.

BP, ConocoPhillips and ExxonMobil, the largest producers in the fields BP and ConocoPhillips operate, say the state's production tax — Alaska's Clear and Equitable Share, or ACES — takes away the incentive to invest at high oil prices, which they are ably demonstrating is true by not increasing capital investment in their North Slope legacy fields.

All three producers support Gov. Sean Parnell's proposed legislation to, as they describe it, "reform" ACES. House Bill 110 reduces the tax by changing how progressivity is applied, capping it and establishing a lower base rate for new fields.

HB 110's companion bill in the Senate, SB 49, went nowhere during the first regular session of this two-year legislative term, but is expected to be the major focus of that body in January, when the Legislature convenes.

Detractors of HB 110 say ACES is working, BP and ConocoPhillips are making big profits in Alaska, and that the two largest operators are holding the state hostage with the tax bill.

It doesn't matter who's right

I say, it doesn't matter who is right.

The fact is, without added investment by the three largest producers on the North Slope, their production, at least, is going to fall.

But if there are "improvements in the fiscal regime" in Alaska, ConocoPhillips Alaska President Trond-Erik Johansen said Nov. 16, "you will see more action. ... You will see more drilling; you will see more projects. ... That's just the way capitalism works."

So, let's look at current and projected oil production for the North Slope. (For simplicity's sake, in this article the "North Slope" includes all oil fields north of the Brooks Range in Alaska, including offshore pools.)

State says 12.4%; BP says 25%

In November, North Slope production averaged 624,687 barrels per day, down 6,850 barrels from the 631,537 bpd in November 2010, which is slightly more than a 1 percent drop, month to month. Over the last year throughput in the trans-Alaska oil pipeline dropped 7-8 percent, Johansen said.

The Alaska Department of Revenue's spring 2011 forecast predicts production will drop from a daily average of 605,000 barrels a day in 2011 to 530,000 barrels a day by 2020, a decline of 12.4 percent.

But Claire Fitzpatrick, chief financial officer and senior vice president of BP Exploration (Alaska), predicts a 25 percent drop in oil production between now and 2020 for BP-operated fields on the North Slope, and a 7-8 percent decline in the next couple of years.

Fitzpatrick reminded attendees of the mid-November Resource Development Council conference that fields operated by BP account for about two-thirds of current North Slope production, meaning she's in a position to know how much oil is likely to be produced.

What's the difference?

Why the big difference between the Department of Revenue and BP's production

estimates for 2020?

According to Fitzpatrick, Revenue's estimates include some "big buts" — that 52 percent of the department's forecast for 2020 is from projects under development or evaluation, including projects in existing producing fields. (See figures 6, 7, and 9 from Revenue's spring 2011 forecast, which support what she says.)

A lot of the "under development" has not yet had final investment decisions from the owner companies, she says.

So, Fitzpatrick concludes, more than half the oil the state is banking on in 2020 comes with a big "If."

That means that more than half the production in the spring forecast — and therefore a big chunk of projected state revenues — depends on investments yet to be made.

"I don't know what the next DOR forecast is going to show in terms of decline over that timeframe. I do know what my forecast shows, and we are showing a steeper decline over that period than I was at this time last year," Fitzpatrick says.

"We've reviewed our plans and activities much more rigorously in terms of what's possible versus what's realistic in the current business climate," she says, meaning some of the projects BP talked to Revenue about prior to the spring forecast are now off the table.

On Dec. 1, Revenue officials confirmed that the latest Revenue forecast, due to be released in mid-December, will reflect a much lower production rate in 2020. (Pumping up TAPS goes to press on Dec. 9, but we're holding space in the On Deadline section near the beginning of this magazine to report on Revenue's latest forecast.)

Still, some new oil will most certainly be produced, with or without, a tax change. The ExxonMobil-operated Point Thomson field, for example, will likely be produced under a settlement agreement with the state of Alaska — that's 2,000 barrels a day in 2015 and 9,000 barrels thereafter, per Revenue's spring 2011 forecast.

And after all ConocoPhillips' work to get approval to build a bridge across the Colville River in order to start producing oil from CD5 in the National Petroleum Reserve-Alaska, where it is eligible for ACES tax credits, it's safe to assume ConocoPhillips will move forward with NPR-A exploration and development. In Revenue's spring 2011 forecast, that's 10,000 barrels a day in 2015, 65,000 barrels by 2020, including production from Linc Energy's Umiat oil field.

Even BP expects to proceed with its Liberty project in federal waters, which Revenue shows at 5,000 barrels a day in 2013, then peaking in 2014 at 39,000 barrels, and dropping to 14,000 barrels in 2020.

Still, a 25 percent drop in two-thirds of 98 percent of North Slope production by 2020 is considerable. And BP, remember, has to approve most of the investments in the ConocoPhillips-operated fields because it's a working interest owner in many of them. ("Has to approve" is not a legal mandate; but the unit owner relationship is much like a marriage. "Sure you can buy that pool table, honey, but...")

Oil BP, Revenue not including

Production from the only oil fields not operated by BP or ConocoPhillips on the North Slope — Eni's Nikaitchuq unit, Pioneer Natural Resources' Oooguruk unit and Savant's Badami unit — are included in the Department of Revenue's forecast.

Revenue's projections put Oooguruk and Nikaitchuq at a combined daily average of 19,000 barrels in 2012, up from 12,258 in November, and peaking at 38,000 barrels a day in 2014.

But Pioneer's Nuna development, which is inside the Oooguruk unit, and Savant's Red Wolf prospect, part of the Badami unit, are not in the forecast.

More important, not a drop of oil from the North Slope's active explorers — Repsol, Brooks Range Petroleum, UltraStar Exploration, ASRC Exploration and Great Bear Petroleum — is included in Revenue's forecast, per Victoria Ferguson, a petroleum economist with the department.

With the exception of ASRC, all these companies are planning to drill exploration wells this winter; although as of Dec. 1, two of the explorers will probably not be able to find drilling rigs, bumping their wells to the winter season of 2012-13.

Potential production from these seven companies' projects, some of which are unitized and have been previously drilled, do not meet Revenue's standards for inclusion in its forecasts, Ferguson says, providing a list of those standards:

- A. Reservoir delineation through new penetrations, drill stem testing and seismic.
- B. The reservoir should be fairly well defined and proved to have productive capabilities
- C. The operator should have fairly concrete development plans in place.

Great Bear production excluded

Despite the Parnell administration's enthusiasm for Great Bear's source rock exploitation plans, the company has to prove it can produce oil from the formations on the North Slope, Ferguson says.

"Since production from source rock is considered unconventional, we will wait

for some extensive, definitive production data from a pilot project before we forecast any significant production from the Great Bear properties,” she says.

Those standards make sense when you’re looking for absolutes. Even ignoring Great Bear’s very bold production estimates makes sense, although its project could potentially reverse the decline on its own, and more, within the 2015 to 2020 timeframe.

Still, Great Bear is proposing to produce oil from source rock; something that has never before been done on the North Slope. And given the difference in the cost of operating in northern Alaska versus in North Dakota’s Bakken or Texas’ Eagle Ford shale plays, Great Bear might need the tax breaks in the governor’s bill to make its Alaska project economic.

Ed Duncan, Great Bear’s president and chief operating officer, told legislators in February that competition for capital is on a global scale, and while Alaska presents an opportunity for oil and gas investment, “we also see a great opportunity for Alaska to improve its position globally” by making the tax changes proposed in HB 110.

Alaska is prospective for development because “it has some of the best rocks in one of the best petroleum provinces in the world.” But, Duncan says, “it also has some fiscal terms that are suppressing development.”

The risk in Great Bear’s source rock exploitation plans is not technical but “commercial viability in competition for capital (because it) requires capital to make this play really happen,” he says, describing the play as both capital intensive and labor intensive.

“This is an opportunity to deliver a play that has long-lived production; manageable risk; allows the state to forecast forward revenue; (and) has tremendous job growth associated with it — if we can make it happen.”

The objective of Great Bear’s exploration and evaluation program is to run short tests on at least four wells, with those tests potentially leading to the sanctioning of a pilot plant to more fully determine the production characteristics of the rocks, Duncan told Petroleum News in November.

It will be necessary to obtain at least a one-year production profile, determining parameters such as production decay characteristics, as well as assessing the economic feasibility of oil production from the rocks, before making a decision to move to full field development, which he says could occur in 2015.

A 123,000 barrel a day difference

If you’re looking to leave ACES as is, you have to know whether the other explorers, all of which have access to adequate funding and two of which are already producing oil in the region, have a chance of filling the gap between

2011's projected average of 605,000 barrels of oil flowing through the Trans-Alaska Pipeline System, or TAPS, and what will be running through it daily in 2020.

Cutting another 8 percent off 605,000 barrels a day in deference to Fitzpatrick, another 48,000 barrels are deducted from Revenue's projected 530,000 barrels, for a drop to 482,000 barrels a day between now and 2020.

That's a difference of about 123,000 barrels a day. (Maybe more, maybe less: Remember to check out the On Deadline section at the front of this magazine with Revenue's latest forecast.)

In 10 years, Alaska might see some federal outer continental shelf production from Shell, but Shell says that's only if nothing goes wrong between now and then, and it can drill in 2012. It would be foolish to count on Beaufort and Chukchi OCS oil in the next decade, but if Shell picks up Beaufort Sea leases in the Dec. 7 state sale, as rumored, then it's possible (see On Deadline).

And trying to keep production flat is not just about state revenues; it's also about the trans-Alaska pipeline tariff for non-TAPS owners, such as Repsol, Brooks Range Petroleum, Linc, Great Bear and others. The tariff will undoubtedly go up as the cost of the system is shared among fewer and fewer barrels of oil, another disincentive for non-TAPS owners to produce oil on the North Slope.

And if TAPS operator Alyeska Pipeline Service Co.'s low flow impact study is correct (see story on page 23), there is a whole list of mitigation measures that Alyeska will have to implement to keep the pipeline operating as throughput drops below 600,000 barrels a day — costly mitigations that could also raise the tariff.

BP, ConocoPhillips and ExxonMobil own the largest percentages of TAPS, so a higher tariff is not going to sour them on Alaska, as a pumped up tariff has in the past with several oil companies, including Conoco before it merged with Phillips, which in turn purchased the assets of ARCO Alaska.

Repsol hoping for 119,000 bpd

So, excluding Great Bear's potential production, let's look at possible production in the next 10 years from other explorers, starting with Repsol, which has about 20 prospects on just under 500,000 acres that were identified by minority partners Armstrong Oil & Gas's North Slope subsidiary 70 & 148 and GMT Exploration.

Oil production from Repsol's first five exploration projects is scheduled to come online between 2015 and 2018, peaking at 119,000 barrels a day in 2017 or 2018.

The company appears to be drilling its low-to-moderate risk prospects first, although one of the initial five drilling sites was switched out for another where several leases are set to expire.

If the company is only able to permit and drill four of those projects this winter, it is likely to drill the prospect it dropped next winter, along with several others, delaying one project's production by a year.

Armstrong expects changes in ACES

With at least 119,000 barrels a day in the pipe by 2018 or 2019, it appears Repsol will nearly singlehandedly save the day for Alaska.

But what wasn't said in Repsol's March 7 press release announcing its deal with Armstrong and GMT was a single word about ACES, although the company did say one of the reasons it entered into the \$768 million transaction is because the Parnell administration is looking at ways to make the state more attractive for oil and gas investment versus trying to squeeze more tax dollars from industry.

Just three weeks before the long-awaited deal closed Armstrong Vice President Ed Kerr submitted a letter to the co-chairs of the Alaska Legislature's House Resources Committee, saying that the governor's bill, "HB 110 will have a significant impact on our capital expenditures and future activities in Alaska. The improved fiscal terms as proposed by HB 110, particularly the portions of the bill that apply to activities outside of existing units, will give us the needed incentive to not only drill multiple new wildcat and delineation wells, but the motivation to drive certain projects to development."

Kerr said Armstrong has "more than a dozen ideas outside of existing producing units" on its project list, ideas it hopes to drill and test.

"In many cases we know the oil is in place. The improved fiscal terms as provided in HB 110 will greatly affect whether these projects will get developed."

Presumably the bigger finds will have the best rate of return, so they would get developed under ACES as it is today.

Pioneer's Nuna Development

Also not included in Revenue's spring 2011 forecast was Pioneer's Nuna Development within the newly expanded Oooguruk unit. Its primary target is the Torok formation (see page 41).

Original oil in place is estimated to be 340 million barrels in the Oooguruk offshore drill site area and the core area of the unit — the planned initial development area where the Oooguruk-Torok reservoir is completely filled with oil. That oil would be included in Revenue's projections.

In the prospective Nuna area, the Oooguruk-Torok reservoir appears to be only partially filled with oil; the original oil in place is estimated at 690 million barrels. Pioneer estimates that it can produce up to 25 percent of that through primary and secondary recovery methods, for a net 173 million barrels.

The Alaska Oil and Gas Commission, looking at primary recovery of 20 percent, or 138 million barrels, says the production rate for the Oooguruk-Torok oil pool over an expected 20-30 year project life is expected to average 4,000 to 9,000 bpd, with peak production of about 8,000 to 15,000 bpd, plus natural gas.

Production could conceivably start in 2017, so it would have some bearing in the next 10 years.

A lot depends on appraisal and exploration drilling into the Torok this winter and next.

And on the economic competitiveness of the project with Pioneer's oil and gas assets outside Alaska.

At a Feb. 16, 2011, House Resources Committee meeting in Juneau, Ken Sheffield, at the time president of Pioneer in Alaska, said the company supports HB 110. He said Pioneer's challenge is finding the next opportunity to grow its business. The company might have the opportunity to expand its Oooguruk project to produce the Torok accumulation, but a half a billion dollars for Torok would have to compete for funding against other opportunities in the Lower 48 in fiscal regimes where the tax burden is not so high.

So, another question mark.

If BP and ConocoPhillips elect not to increase investment and all the stars align for Repsol, the Madrid-based major stands to produce the most new oil from the North Slope in the next 10 years.

Armfield's plan 2050

But there is one other explorer whose production could make a dent in arresting the decline, and that's Brooks Range Petroleum Corp. An active explorer on the North Slope (see page 40), BRPC has drilled five wells and several sidetracks since 2007. It tends to target known, but untapped, fields between 25 million and 50 million barrels close to infrastructure.

Again if all the stars align, it might have two or three fields online in the next 10 years, producing between 5,000 and 12,000 barrels each (numbers not confirmed by BRPC).

In February testimony to House Resources in favor of HB 110, Bart Armfield, vice president of operations for BRPC, talked about his "plan 2050," which takes an incremental look at what would be required to keep the trans-Alaska oil pipeline flowing at 600,000 bpd through that time.

It's a phased approach, he said, requiring the cooperation of the state, majors and independents.

If 10 new fields averaging 12,000 bpd are brought on in the next 12 years, that would increase recoverable reserves by half a billion barrels, and require in excess of \$6.3 billion in investment.

“History demonstrates that we can” do this, Armfield said, based on what has occurred over the last 12 years with Alpine, Northstar, Oooguruk and Nikaitchuq coming online and Badami restarted.

That isn’t 10 fields, he said, “but collectively they represent the equivalent of 10, 12,000-barrel-of-oil-per-day field projects.”

To get to the next level, 20 years out, requires 22 more fields be brought online.

Armfield said unconventional resource plays and technology developments in the Lower 48 demonstrate what can happen, and said that in the very near future that may be applicable to the North Slope.

By the end of the day, in “plan 2050,” 44 new developments have occurred, requiring more than \$18 billion in new investment.

Armfield said the new fields are a combination of developments within existing units and grassroots developments. In the first 12-year phase, if existing units supported four new developments “then new players would support six grassroots developments.”

But the \$18 billion to bring on that much new development really requires \$36 billion in investment, Armfield said, because “not every project is going to be successful on the North Slope.” He said he used the 50-50 rule, with half failures and half successes, “which is probably very aggressive.”

To get \$36 billion of new investment capital coming into the state requires “the positive adjustment through HB 110,” Armfield said.

Other companies agree with BP, Conoco

The questions posed at the beginning of this article were, Can the decline be halted? And since BP and ConocoPhillips operate 98 percent of northern Alaska oil production, can it be done without them?

Maybe. If most of the companies exploring, or set to explore this winter, on the North Slope are successful, there might be enough production to halt the decline in the next 10 years, especially if I’m right about Revenue’s fall forecast, so compare the numbers on page 14 with those in the page 8 On Deadline article about Revenue’s fall forecast, which came out after all but those pages went to press.

But, the next question is, will those explorers develop their discoveries under ACES?

Not all of them have answered that question.

But they have all said they need HB 110 to make producing oil in Alaska competitive with investments elsewhere.

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Natural Gas – The Gift
Remarks by Jim Mulva
CERA Conference
March 9, 2010

I remember 20 years ago when a bright young man wrote a book about oil. He named it “The Prize” – and the rest is history. “The Prize” captured a fundamental truth, oil is a precious commodity that powers the world economy.

There was little mention of natural gas. Historically, it never matched oil in importance. But look at gas today – the world’s third-leading energy source, with room to grow.

In fact, if oil is “The Prize,” then natural gas is “The Gift.” Nature’s gift to the people of the world. For many outside our industry, it is an unexpected gift. They believe that renewable energy will quickly and easily replace hydrocarbons, and cure all that ails us.

But it is clear from the experts that carbon-based fuels, though in cleaner forms, must keep carrying the load. Renewables just can not ramp up fast enough to replace them. But where will this energy come from? Fortunately, Mother Nature, human ingenuity and technology have provided the answer. That is, if we are allowed to unwrap the gift.

Let’s consider what gas can mean for the future. The real future, not the pipe dreams of the “hydrocarbon deniers.” These are the well-intentioned people who support renewables at any cost, and oppose hydrocarbons at any consequence. They seem not to realize that platitudes are not BTUs. That it will take abundant and affordable energy to enable further human progress.

Let’s spin the clock forward 40 years, to 2050, and look at a possible future if government chooses the right policies.

By then, it will be a different world, with 9.2 billion people, 35% more than today. It will need more energy, not less, despite higher efficiency and conservation. And tomorrow’s energy must remain affordable.

The idea that all forms of energy are needed will long be accepted. So will a sense of shared responsibility for environmental stewardship. Many people will drive electric cars. Fleet vehicles, trucks, buses and trains, will use natural gas to reduce both emissions and maintenance. Housing will use active and passive solar power, and smart meters. Living “off the grid” will be popular.

In our industry, we will drill wells with, who knows, perhaps laser beams. There will be technological advances that would seem inconceivable today.

Vast arrays of wind-powered turbines will be online. So will solar and nuclear power. But they will not be the biggest electricity sources. After all, there are only so many places

where massive development is economical, and publicly acceptable. And only so much government funding to subsidize the renewable sources.

Natural gas will remain a leading base-load power generation and heating source, due to its cleanliness, abundance and reasonable cost. Through its flexible reserve capacity, when the wind dies or the skies are cloudy, gas will backstop wind and solar power.

Here in the U.S., gas production will be more national in scope. New York, Pennsylvania, Virginia and other states will join the major producers. They will gain the job creation and industrial development for which Texas is known today.

On the oceans, an expanded fleet of liquefied natural gas tankers will tie the world together. Neither remote supplies nor consumers will remain stranded.

Coal will remain essential too, through its abundance and low cost. But it will be used in more advanced ways. Among them, through oil industry technology, it will be converted into gas or liquid fuels.

Oil will continue as a transportation fuel, wherever alternatives are impractical. And it will be essential for lubricants and petrochemicals. Supply will largely come from unconventional sources, like Canada's oil sands, and shale rock in Colorado, Utah and Wyoming. To facilitate recovery, natural gas will provide clean heat and power.

And everywhere, new technologies will reduce greenhouse gas emissions, with processes in place to capture and sequester carbon.

So by 2050, natural gas will have potentially helped meet four great energy challenges:

- First, achieving both national and world energy supply security.
- Second, providing consumers with affordable energy.
- Third, driving economic prosperity and job creation.
- And finally, reducing greenhouse gas emissions.

Now, the first question the hydrocarbon deniers would ask is, "Where will all that gas come from?"

The Natural Gas Resource Base

To answer, let's consider the rebirth of a once-dying U.S. industry. Natural gas consumption here peaked nearly 40 years ago. Over the next three decades, it fell by 25%, and reserves fell by nearly half. Conflicting, changing and short-sighted government policies played a major role. As recently as 2003, the National Petroleum Council as well as others warned that imported LNG would be increasingly necessary.

But since then, the entire market has turned:

- Production capacity is rising,
- Prices are down,
- Reserves are growing, and

- We foresee a century of domestic supply.

Some people even forecast the U.S. becoming an LNG exporter. What happened? Never underestimate the power of technology to drive human progress.

There are few remaining conventional gas prospects here. At least, not in the areas where we are allowed to drill. So the industry turned to the less-desirable unconventional reservoirs. These typically have “tight” rock, which does not flow nearly as well.

To make this rock productive, over a 60-year span we developed new and sophisticated technology. Completion techniques, hydraulic fracturing, drilling and seismic imaging all advanced. As a result, unconventional gas is now a key part of U.S. reserves.

Then in the 1980s, we realized that coal formations, which often contain so-called “mine gas”, might be made productive. A new process called “cavitation” enabled the gas to flow. We also became better at finding the best sites to drill.

As a result of all these steps, unconventional gas and coalbed methane helped stop the decline in U.S. gas reserves during the 1990s. Demand began to grow. ConocoPhillips increased our North American gas exposure, and so did others.

Meanwhile, another technology came along – horizontal drilling. Today, lateral extensions up to 8 miles are possible. A single well can have several, spread like the fingers of your hand.

These techniques are expensive, and feasible only in certain situations. But again, technology opened new horizons.

Now, another truism. Never underestimate human ingenuity. It occurred to the industry to reexamine shale – a common source rock that was too tight for production. But horizontal drilling exposed more rock to the wellbore. And fracturing enabled gas to flow. This opened new drilling trends and revolutionized the industry. And rather than being expensive, shale gas is often the low-cost source, commercial at \$4 to \$7 per Mcf.

The same success now appears possible in Canada. And these technologies can be applied elsewhere. Exploration for tight gas, coalbed methane and shale gas is under way in more than a dozen other countries. More will follow.

Consider the ramifications. The world uses 107 trillion cubic feet of gas a year. Proven conventional reserves are 6,500 TCF, a 60-year supply. With undeveloped conventional resources, there is potentially more than a century of supply. Now, adding unconventional gas expands total resources to more than 38,000 TCF, or multiple centuries of supply.

But this may only be the beginning. Up to 700,000 TCF of methane hydrates lie beneath the ocean floor and the Arctic. They have never been produced commercially, but

research is getting us closer. It may even be possible to liberate the methane by pumping carbon dioxide into the formations. That would be a dual energy and carbon storage solution. ConocoPhillips is in the early stages of researching this.

The full magnitude of nature's gift is now apparent. Natural gas is more than a bridge fuel. It is part of the long-term energy solution. There is an old U.S. saying, "Don't look a gift horse in the mouth." It basically means, "Appreciate what you have been given." But we face two big obstacles in delivering the gift of natural gas. We must overcome the opposition of the hydrocarbon deniers. And government must find the political will to address long-term energy needs pragmatically.

Answering the Hydrocarbon Deniers

The idea that gas is abundant challenges beliefs that fossil fuels are running out. So the deniers raise the warning flags of price volatility, environmental impact and greenhouse gas emissions. These may sound compelling. But every energy source poses challenges.

Wind and solar power have their own problems: cost, reliability, visual impact, land and water use, bird strikes and massive power-line rights of way. Current-generation biofuels require a lot of land and water, impact food prices, can increase greenhouse gas emissions, are vulnerable to crop failure, and require subsidies. Coal is carbon-intensive. Nuclear faces waste disposal, proliferation and public acceptance issues.

So let's look realistically at the objections to natural gas. During the recent severe winter, U.S. prices hardly reacted. The rising abundance of gas reduces the risk of long-term price volatility. Short-term volatility has also moderated, due to several factors. The industry has added new storage facilities and supply pipelines. The nine LNG terminals now in service can quickly increase deliveries. Also, shale gas is developed through highly repeatable long-term drilling programs, in virtually a manufacturing-type approach. This raises efficiency and lowers costs, and thus enables low prices. And drilling can ramp up quickly in response to any change in the market.

Another advantage offered by gas is that development requires a small land-use footprint. It's only 1/20th that of equivalent wind or solar power. Gas-fired combined-cycle power plants have low water consumption, particularly compared to some renewable sources.

Yes, gas is carbon-based. But it burns cleanly, and produces practically no nitrogen oxide, sulfur dioxide or particulates. So there is less threat of acid rain and smog. In terms of climate change, gas-fired power plants produce half the carbon dioxide of coal-fired units. Their waste heat can be captured to produce steam for industrial applications. This further reduces the carbon footprint.

Also, substituting gas for other fuels is the fastest and most cost-effective way to reduce greenhouse gas emissions. Cost matters. Or at least it should.

Now, let's address the final obstacle, government vision.

Government Vision

The U.S. needs coordinated policies on energy and climate. Policies that establish certainty through the years, regardless of who is in office. And that encourage development of all energy sources. Otherwise, energy initiatives ping-pong back and forth whenever the political pendulum swings.

Currently, the U.S. government strongly supports renewable energy. Unfortunately, it also proposes higher taxes on the natural gas industry, and is tightening resource access. Perhaps it has not yet learned that if you tax something, you get less of it. Less supply security, fewer jobs and lower reinvestment.

Another concern is the mandated use of renewable energy for electricity generation. This could prove very expensive. Why not instead implement clean electricity standards. Then let renewable energy, natural gas, clean coal and nuclear power compete.

Look at China. Yes, they support renewable energy. But they are also pragmatic. They recognize that all sources are needed. They do not oppose fossil fuels. They believe in technology. They will soon begin assessing their shale gas potential. With assistance, I might add, from the same U.S. government that has ignored the shale potential here.

U.S. energy policy brings to mind a famous Winston Churchill quote, "A riddle wrapped in a mystery inside an enigma."

For example, the U.S. government holds 2.4 billion acres of mineral estate. That is larger than the land area of any of the world's countries, except Russia and Canada. Of this, 3%, yes, only 3%, has been leased for energy development.

Like our parents told us, "It's not what you say, but what you do that counts."

The shale gas revolution here occurred on private and state land, not federal land. Think of the economic development and job creation potential if more land was opened. And if less red tape tied up the acreage that is leased.

In closing, I want to emphasize that ConocoPhillips supports development of all energy sources. We recognize that in order for the world to prosper, energy must be abundant and affordable. Our core businesses are carbon-based because these are the only sources that currently meet these criteria. We also support legislative enactment of a sound, mandatory federal climate policy.

For all these reasons, we are aggressively pointing out the benefits of greater use of natural gas. It truly is nature's gift to the people.

- Gas can enhance energy supply security through its abundance. There is enough to meet industrial, residential, commercial and power generation needs.
- Gas should remain very affordable to consumers.
- Gas offers the energy base upon which to build economic development and job creation.

- And gas offers a viable and cost-efficient way to reduce greenhouse gas emissions.

Thank you.

END

Oil & Money Conference
Panel Discussion – CEO Forum: Global Upstream Challenges
The IOC Response to Turbulent Times and Challenges
Remarks by James J. Mulva
October 20, 2009 – London

Well, we in the oil industry certainly know about turbulent times.

In discussing our upstream challenges, I'll start with the obvious – the world economic downturn. It has caused the largest decline in energy demand in 25 years. Oil prices that took eight years to reach \$147 per barrel – after stagnating for two decades – lost more than two-thirds of that value in eight months. Today, they are \$70 – but may not hold.

Compounding this are government fiscal takes. A number of countries raised their takes during the boom, assuming that prices would remain high. Now, most have not lowered them. Also, reserve replacement costs are more than double their 2003 levels. They are not falling as fast as prices did.

All these factors challenge the economics of new investments. Government seems to assume that we will invest anyway. But perhaps the screws have now been tightened too much. World upstream investments are down by \$100 billion this year, or 21%, according to the IEA.

There are other challenges, like restricted access. In many resource-rich countries, the best, if not all, opportunities go to NOCs. IOCs are left out, despite their expertise and access to capital and markets.

There is also climate change legislation pending in key countries. This creates uncertainty over what the rules and costs will be. Investment flees uncertainty. We need the world to decide what it will or will not do.

And finally, we face political hostility. Fossil fuels are unpopular because of their price volatility and perceived carbon impact. So governments are promoting renewable sources. At best, they are ignoring oil and gas policy – while overlooking how natural gas could ease the transition to a low-carbon economy. Since fossil fuels must provide 80% or more of world energy even by 2030, this is like Nero fiddling while Rome burns.

These challenges and flawed policies have serious implications. They could lead to new energy price spikes once the world economy recovers.

Further, today's energy downturn is not like the 1980s. We are unlikely to have a long production surplus and weak oil prices this time. The drop in oil demand then was three times today's decline. Conventional non-OPEC crude production was rising then, thanks to the North Sea and Mexico. Now, it is falling. And unlike then, world demand now is primarily driven by the rising prosperity of the developing world's 5.6 billion people.

They outnumber the population of the OECD countries by nearly five to one, and the margin is growing.

So demand growth will inevitably resume, and renewable energy cannot meet it alone. Unless our industry is ready, and governments have the right policies, supply could fall short. This would damage the world economy and undermine living standards.

At ConocoPhillips, we are dealing with these challenges today, while also anticipating tomorrow's needs.

- We have adjusted our operating and capital programs to live within our means. The best projects continue, while others have been deferred.
- We are working with suppliers to reduce costs.
- We are maintaining balance sheet strength by managing our debt.
- We are engaging in the public debate over climate change, energy security and taxation.
- But despite these immediate steps, we are maintaining our long-term strategy. We are funding our commitments and preserving optionality. We continue spending through the cycle in our resource-play drilling programs. And we are focusing on our core businesses, while continuing renewable energy R&D, but at a measured pace.

Obviously, there is much government must do.

First is improving access. The world has ample oil and gas. We can produce it efficiently while protecting the environment. We just need access.

- Second, government must stop viewing our industry as a cash cow. Some \$12 trillion in global oil and gas investment is needed by 2030 to ensure adequate supply. These investments cannot occur if our funds are taxed away. Third, government must encourage development of all energy sources, and not pick "winning" technologies. The public, through the market, can determine the best sources far more efficiently than government.
- And finally, government must coordinate its policies on energy and climate. Otherwise, policy conflicts could undermine both.

So there are solutions to our challenges, provided that we, and most importantly government, take the right steps.

Thank you.

END

The Realities of the U.S. Energy Future: A Producer Perspective
Detroit Economic Club – National Summit Energy Town Hall
Remarks by Jim Mulva
June 16, 2009

Introduction – the basic realities

I want to thank the Detroit Economic Club for putting together a challenging agenda with a diversity of views.

It was only a year and a half ago that I spoke here about the shared future of the energy and auto industries. Of course, we did not know what was ahead. The world economic upheaval. Millions of jobs lost. And severe impacts on the people of America.

The past year has proven that we all depend on each other. In that spirit, we seek common ground on some of the key issues of our times. Specifically energy and climate policy, and their role in economic prosperity.

History shows that when energy is readily available, reliable and affordable, it encourages high economic growth. But when supplies are short and prices are higher, economic growth lags. You know the saying – those who forget history are doomed to repeat it. We will need energy in the future, just as in the past – in high volumes, and at reasonable cost. But this simple statement comes with a set of hard realities.

The future energy situation

First among these is that future energy demand will grow. Why? Because world population will expand by one-third, reaching 9 billion people by 2030. Also, the developing world is catching up economically. More people are building homes, electrifying them, and buying cars and appliances. The U.S., long the world's largest energy consumer, also has a growing, energy-hungry population.

Second, modern society is inherently energy intensive. We can learn to use less energy, but there are practical limits. After all, you can't fly a 747 on Piper Cub engines.

These first two realities dictate a third – we must develop a more diverse “basket” of energy supplies. This includes alternative and renewable energy. But it also includes more fossil fuels. Fortunately for all of us, we benefit from a massive, efficient and highly successful energy infrastructure. It is based on fossil fuels. Building it required 150 years, trillions of dollars in investments, and generations of work – by untold millions of people. They drilled wells, and constructed oil and gas pipelines, fleets of tankers, coal mines and electric power plants. Their work transformed society, created affluence, and improved our quality of life. Replacing this energy foundation would take an unimaginable effort. It could not be done quickly, despite the desire to do so. There simply is not enough investment capital, skilled labor and materials available. And much of the technology needed is still being developed. So building sufficient capacity to replace fossil fuels will take – who knows, decades, perhaps even a century.

The fourth reality is that alternative energy has its own issues and detractors – just like fossil fuels. Every energy source poses unique challenges. They may be in terms of the environmental impact, the economic considerations, the regulatory requirements, or even just public acceptability. There are “not in my back yard” objections to wind turbines, just as there are to oil wells and power plants. There are hazardous chemical concerns associated with solar panels. Nuclear energy creates tremendous concern. Biofuels impact food production. And so on.

The fifth reality is that the advantages of fossil fuels are too often overlooked. They generally cost less than alternatives – which is why they are the market leaders. You will pay a lot more for “green energy” – either in utility bills, or at tax time due to the heavy subsidies it requires. Also, fossil fuels are generally more reliable. They don’t tail off when the wind dies or the sun goes down.

Altogether, these realities mean that Washington’s apparent belief – that we can choose between renewable energy and fossil fuels – is mistaken. We will need more of all energy sources. So our path forward must include five steps ...

- One, encouraging conservation,
- Two, diversifying our energy supplies by developing alternative and renewable energy,
- Three, developing our domestic oil and gas resources,
- Four, encouraging imports from secure producers,
- And last but not least, addressing climate change.

With these points, I’ve just committed blasphemy in some people’s minds. As an oil and gas producer, I’ve endorsed conservation and supply diversity. I’ve referred to the “inconvenient secret” that the U.S. still has a lot of undeveloped oil and gas. I’ve touched the third rail by suggesting that we will still need imports. And also by acknowledging that climate change is a serious issue.

Now, let’s get down to the policies needed, beginning with what our industry must do.

What industry must do

We and our peers are already investing heavily to develop new supplies – and new technologies to make our products cleaner. This must continue. We are researching ways to reduce the cost and facilitate development of alternative and renewable energy.

ConocoPhillips has already produced renewable diesel fuel, made from vegetable oil and byproduct animal fats. We are researching new biofuels made from agricultural waste and algae. We are evaluating investments in other areas, such as wind power. In the meantime, we are improving our own energy efficiency, which will help reduce our carbon intensity.

Altogether, we are investing tens of billions of dollars in our energy businesses – despite the most challenging economic environment of my lifetime. We have seen oil and gas prices fall below replacement cost at times.

Also, we are facing severe restrictions on our access to energy resources. In the U.S., drilling is banned in many areas due to environmental objections. Overseas, some of the best areas are reserved for national oil companies. These trends force us to concentrate in the mature producing basins where we do have access. But these have been picked over for years, so they are generally more expensive and offer less potential. We must do a better job of making our case to government for expanded access.

There are other financial pressures – such as higher taxes. A number of countries jumped on the tax bandwagon to get a bigger cut when prices were high. Now, they want to keep it despite today's harder times. Here too, we are working to inform these countries of the economic realities of today's energy market.

What government must do

Next, there is much that the U.S. government must do to ensure that our country remains competitive in the global race for energy. Unfortunately, we are running this race while dragging anchors behind us.

First, it must encourage greater efficiency, by setting energy performance standards throughout the economy. Its actions must be cost effective, since they would increase the cost of cars, buildings and appliances. But conservation alone is not enough.

We've said for decades that the U.S. needs an inclusive national energy policy. One that supports investment in all forms of energy, including fossil fuels. The U.S. remains the world's third-largest oil producing country. We do that with less than 4% of our 2.4 billion acres of federal acreage under lease for development. Too many unexplored areas are off limits – like the Atlantic and most of the Pacific offshore, parts of the West, and large parts of Alaska.

These resources belong to the public. But the same government that tells us to get off foreign oil is blocking development – needlessly. The industry has a good environmental record, and it can explore these areas responsibly.

Also, there is a natural gas renaissance under way. But government appears not to have noticed. Since 2005, estimated recoverable gas resources have more than doubled. This is thanks to new technology to produce from shale rock. So Lower 48 supplies are up, and prices are down. And we still have huge resources in Alaska awaiting pipeline construction.

Consider too the benefits to the environment. In power applications, gas emits half the CO₂ of coal. So we should be relying on gas as a bridging fuel while we build a low-carbon economy. Unfortunately, proposed tax increases and regulations are threatening to marginalize gas. For example, one proposal would impose standards for electricity

produced from renewable fuels. It sounds good, but it would likely force greater cutbacks in the use of gas, than coal.

Another point. Since we can not produce all the energy we need, we should encourage imports from secure and friendly sources. Like Canada. Its oil sands are one of the world's largest hydrocarbon deposits, with 8 times current U.S. oil reserves. We already process this oil here, creating U.S. jobs, income and tax revenue. It puts the Midwest at the front of the line for oil supplies.

But there is fierce opposition to importing this oil. It is based on objections to surface mining, and the oil's carbon intensity. But most new developments are not surface mines, but wells. And although the carbon intensity is slightly higher than for conventional or heavy oil, we are working to reduce the impact.

Of course, the concern over carbon intensity relates to the climate impact. We believe that government should address climate change. But it should balance its approach with the need for energy supply security. For example, climate change should not serve as an excuse to halt imports from the oil sands. That would only cause increased imports from less reliable areas – or even oil shortages.

ConocoPhillips has closely tracked the climate issue. In 2007, we joined the U.S. Climate Action Partnership. This is a group of diverse businesses and environmental NGOs that share our desire for a balanced approach. It supports legislation to set a price for carbon avoidance, linked to international agreements. This would be more efficient and less expensive than regulating carbon under existing statutes designed for other purposes. Such as the Clean Air Act, or the Endangered Species Act.

Federal legislation would hopefully preempt the current patchwork of state regulations. But it must not create new conflicts by imposing overlapping requirements. For example, current standards already mandate the greater use of renewable fuels. So a pending proposal to require the use of low-carbon fuels is redundant.

We believe too that all sectors of the economy must be treated equitably. Under current climate proposals, electricity consumers would have 83% of their carbon costs mitigated. But transportation fuel consumers would bear the full cost on day one. Meanwhile, coal-fired electricity generators would receive free allowances for half of their emissions. But cleaner-burning gas-fired generators would receive no allowances. So use of coal would be encouraged, while gas would be penalized. This is nuts.

Also, refiners would be accountable for the greenhouse gas emissions that result from use of all oil-based products. This is one-third of the U.S. total. But refiners would receive only 2% of the available allowances. So they would have to purchase credits, and then pass the costs along to consumers. This means higher gasoline prices. But competing imported fuel products would not have this cost burden. This could put domestic refiners out of business. It would also force both jobs and emissions to leak overseas. So the Administration should grant refiners allocations for any costs they can't pass on. And it

should help consumers of transportation fuel, just as it would help those in the other energy sectors.

One final area in which government can help is by encouraging innovation. It can provide incentives for technology R&D, and greater support for education. This could ease the shortage of technical personnel we see in many American industries, including energy.

What government must not do

While there is much that government can do, it should resolve first to do no harm.

It must not create unrealistic expectations for new energy sources. Neither should it attempt to pay for them at the expense of fossil fuels. After all, more fossil fuels also will be needed. The oil industry must be able to continue developing the energy needed to keep the economy going.

Further, government should not try to pick “winning” technologies. Its job is encouraging overall progress. Then, to let the market decide the best and most cost-effective sources. Consumers and investors are very good at that.

Government must also resist a fallacy. And that is that so-called “green jobs,” created by alternative energy development, will drive an economic recovery. In reality, since these sources will cost more than fossil fuels, energy prices will rise. This could actually hurt the economy and cost jobs by making the U.S. less competitive against countries with cheaper energy.

Further, government must resist the “raise taxes” mentality. Our industry already pays a U.S. income tax rate of over 40%, compared to less than 27% for all manufacturing. Last year, ConocoPhillips paid \$13 billion in income taxes, \$5 billion in other taxes, and several billion in royalties to government. The Administration’s proposed 2010 budget contains tax provisions that will reduce our ability to invest in increasing production. This would cause greater oil and gas imports, higher fuel prices, and reduced competitiveness. It could also cost many of the 6 million direct and indirect jobs supported by our industry.

We caution too against enacting unnecessary regulations. We believe that fair, balanced and well-coordinated regulatory processes are necessary and appropriate. However, the benefits of proposed regulations should equal or exceed their cost to the public in terms of making domestic energy more expensive.

Conclusion

In conclusion, the U.S. is at a crossroads. Government action is needed on energy and climate policy. And some form of legislation seems likely to pass. We hope that it is realistically based on the hard energy facts I’ve mentioned and not on politically popular hot air.

The availability of energy at reasonable cost underpins the U.S. economy. So the decisions made in the months ahead will deeply affect all of us.

We urge government to adopt wise, carefully crafted, and balanced policies. Good policies will facilitate our enduring economic health and quality of life. Bad policies will do the opposite.

None of this will be easy. We would hope that the views of energy producers are heard and considered – along with those of other constituencies.

Thank you.

END

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ConocoPhillips Added About 738 Million Barrels To Reserves In 2011

Published January 23, 2012 | Dow Jones Newswires

HOUSTON – ConocoPhillips (COP) said it added about 738 million barrels of oil equivalent to its proved reserves in 2011, allowing the oil giant to more than replace oil reserves lost from production.

Acquisitions and dispositions reduced reserves by 45 million of oil equivalent, primarily from the dilution of the company's interest in an Australia Pacific liquefied natural gas project and sale of North American natural gas assets, the company said in a press release.

Reserves and reserve-replacement ratios are considered two of the oil-and-gas company's most significant assets and are used by Wall Street analysts to measure a company's performance.

Conoco said its production for 2011 is expected to be 617 million barrel oil equivalent per day, or 1.69 million barrel of oil equivalent per day, including fuel gas. The company also expected to end 2011 with 8.4 billion barrels of oil equivalent of proved reserves.

It is positive Conoco replaced its production, but until it files its annual report with details about the mix of oil and gas of the added reserves it is early too early to read much into the company's announcement, say Alan Good, an analyst with Morningstar.

Conoco, the third-largest U.S. oil company by market value, said it expects to file its 10-K with the Securities and Exchange Commission in late February.

Houston-based Conoco said 2011 reserves were added across the portfolio, including at the company's Canadian oil sands properties at Christina Lake and Surmont.

The company said it also added reserves in liquids-rich U.S. shale areas, such as Eagle Ford and Bakken; in the North Sea, through expansion projects in the Ekofisk, Eldfisk and Clair developments; and in Malaysia, with sanctioning of the Keabangan project and ongoing development of the Gumusut Field. Reserve additions were also delivered across the company's North American conventional asset portfolio, the company said.

Conoco is in the midst of a three-year repositioning aimed at shoring up finances and making itself more attractive to investors. The plan includes the sale of \$15 billion to \$20 billion in assets, large-scale share buybacks and the spin off of its refining arm, expected to be completed this year.

The company is set to report fourth-quarter earnings Wednesday.

Shares were recently down 0.9% at \$70.50. As of Friday's close, the stock was down 5.4% over the past six months.

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A tale of two ConocoPhillips presentations with Alaska comments

by Dermot Cole/ cole@newsminer.com

02.03.12 - 11:53 pm

FAIRBANKS — The Make Alaska Competitive Coalition has a PowerPoint presentation on its website from Marianne Kah of ConocoPhillips titled “Alaska’s Role in World Energy Supplies.”

The contents are in keeping with the message the coalition repeats in its ad campaign — Alaska should cut oil taxes by billions of dollars or else.

On pages 20 to 22 of her presentation, Kah, the chief economist of the company, has slides on the general topic of “A Tale of Two States,” showing how oil production and GDP growth are climbing fast in North Dakota, but oil production is falling in Alaska and GDP growth is not as high in Alaska as North Dakota. Job growth in Alaska is not as high as North Dakota, it says.

The Jan. 6 presentation also has a slide that says, “Alaska Progressivity — Least Attractive Among OECD Countries at Current Prices,” while the next says, “And its marginal take is one of the Highest Globally.”

The tax rate is “limiting investment and production in Alaska,” Kah concludes. The state has the “highest cost structure” in the portfolio of ConocoPhillips investments.

“Alaska has the highest tax rate of any of the developed countries that ConocoPhillips might operate in. And of course that tax rate goes up substantially as the oil price goes up. So there is no upside for investment in Alaska,” the coalition quotes Kah as saying.

The one big plus mentioned in the presentation is the “Strong rule of law/political stability” and the “permitting/regulatory environment.”

The overall thrust was that these aren’t the best of times in Alaska.

But ConocoPhillips executives have been known to say that these aren't the worst of times in Alaska for the third largest energy company in the U.S.

In a third-quarter conference call last year, the company CFO referred to Alaska as one of the places with “higher than average margins.”

And on March 23, 2011, another executive of ConocoPhillips offered remarks that were anything but gloom and doom.

One slide from the March presentation to stock analysts said the “strong cash margins” in Alaska are noteworthy and that future growth will be driven by in-field drilling, Western North Slope satellite fields, unlocking the 1.7 billion barrels of heavy oil reserves the company has and doing something about natural

gas.

Granted, the presentation covered the company's diverse worldwide operations and highlighted many profitable prospects, including North Dakota and points south, but there was no mention made of Alaska tax rates stifling investment.

Greg Garland, the senior vice president of exploration and production in the Americas, said this about Alaska as part of a discussion about future growth for the company, according to the transcript:

"Talk about Alaska, we like Alaska. We've been in Alaska a long time. We're the largest producer in Alaska. Last year 240,000 BOE (barrel of oil equivalent) a day, strong cash margins in this area and we have a significant infrastructure position, we've built an extensive operating capability. We have a strong culture of safety and environmental excellence in Alaska and we think we have a strong competitive advantage here. Reserves at 1.6 billion BOE resources, 5.7 billion BOE. We'll invest \$350 million in exploitation this year, all at very good returns. We're targeting sanction of our West Alpine project which is CD-5 if we can get the permits this year. And longer term, there's other opportunities. West of Alpine, we've got the heavy oil that we've talked about. We'd like to take a look and see what's in the Chukchi Sea if we can get permits to drill. And then, longer term is North Slope gas. ..."

Garland is not an unimportant figure in the giant oil firm. He is in line to become the chairman and CEO of the new Phillips 66, the downstream company that is being spun off this year to become a stand-alone corporation.

In every walk of life, speeches and presentations are tailored to appeal to the audience that the speaker wants to reach and accomplish the goals the speaker has in mind. There is a selection process about what to leave in and what to leave out.

You have one set of goals when the idea is to build support for a local tax cut that will make Alaska operations more profitable. You have another set when you are talking to analysts who follow the company's fortunes on a global basis.

It's a normal process, one that makes it hard to unravel situations where complex tales are presented as simple truths.

...

GRAND OPENING: Hot Springs Gas, the new store on Chena Hot Springs Road, caps its grand opening today with a snowmachine drawing at about

1:30 p.m.

Retired farmer Henry Gettinger is expected to be on hand to draw the winning name.

...

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Oil company executive says Alaska offers 'strong cash margins'

by dermatocole

04.08.11 - 08:23 am

Company presentations to stock market analysts invariably stick to the sunny side of the street.

But policy makers in Alaska operating with eyes wide open instead of half-closed need to have a working knowledge of the international self-portraits offered by the oil companies to these specialized audiences.

On March 23 in New York, eight leaders of ConocoPhillips held their annual meeting and conference call with 16 Wall Street analysts, competitive critics who are hired to make informed judgments about profit and loss potential. The account makes for informative reading.

The news coverage about the meeting dealt largely with the company plan to sell \$5 billion to \$10 billion worth of "noncore assets" over the next two years, using most of the money to buy back \$10 billion in stock and invest in its business. Over the last two years, the stock of ConocoPhillips is up more than 80 percent, beating BP and ExxonMobil, the New York Times said.

While the most glowing language in the presentation was about such prospects as the Eagle Ford shale deposits in East Texas, the Permian Basin in West Texas, ("The gift that keeps on giving"), North Dakota, the Alberta tar sands, Australia and other locations, the ConocoPhillips Alaska situation was also given a positive spin.

The company said the Alpine West (CD5) project is expected to go ahead in 2013-2015 along with the Lookout (CD6) project. Alaska North Slope natural gas and the Ugnu heavy oil resources are among the projects set for 2016 or later. There was next to nothing said about onshore exploration in Alaska.

Future growth in Alaska will be driven by "in-field drilling opportunities, Western North Slope satellites, unlocking heavy oil potential and ANS (Alaska North Slope) gas commercialization," a slide shown to analysts said. The Alaska drilling program for 2011 is expected to increase somewhat over 2009 and 2010 with a cost approaching \$340 million or so, according to the slide.

Greg Garland, the senior vice president of exploration and production in the Americas, said this about Alaska:

Talk about Alaska, we like Alaska. We've been in Alaska a long time. We're the largest producer in Alaska. Last year 240,000 BOE (barrel of oil equivalent) a day, strong cash margins in this area and we have a significant infrastructure position, we've built an extensive operating capability. We have a strong culture of safety and environmental excellence in Alaska and we think we have a strong

competitive advantage here. Reserves at 1.6 billion BOE resources, 5.7 billion BOE. We'll invest \$350 million in exploitation this year, all at very good returns. We're targeting sanction of our West Alpine project which is CD-5 if we can get the permits this year. And longer term, there's other opportunities. West of Alpine, we've got the heavy oil that we've talked about. We'd like to take a look and see what's in the Chukchi Sea if we can get permits to drill. And then, longer term is North Slope gas and we have 10 Bcf gas.

Regarding the offshore potential in the Chukchi Sea, another leading ConocoPhillips executive said the company is in a better position than some of its competitors. He didn't mention Shell, but it's clear that is the company he was talking about when he said another company was "burning" cash with its Chukchi plan.

Larry Archibald, a senior vice president of exploration and business development, said the Chukchi Sea prospects face regulatory hurdles. CEO Jim Mulva said he thinks his company's premise is that nothing is going to happen there before 2013.

"Yes, 2013 at the earliest," said Archibald. "We're actually in a, I guess, enviable position. We're not burning any cash on that operation as we wait for their regulator environment to be sorted out, unlike at least one of our competitors. We're not pregnant in an Arctic drilling fleet. And we're going to wait and see what develops there. And in the meantime, we're getting tolling, extension on our leases there. So we would like to get after it, but it's not urgent. In the meantime, we're going to park things until we see regulatory certainty. "

When the subject turned to North Slope natural gas, a stock analyst asked this: "On transportation capacity and political factors, you've had this Alaskan gas for a long time and dealing with the Alaskan government has been difficult. In the past few weeks the energy picture has changed a little bit with the tragic accident in Japan. And you could make a much stronger case today that we would have thought a few years ago for LNG on the Alaskan coast and sending it to Japan. So that the case for the Alaskan pipeline might be a lot better today than it was a year ago. Can you give us any comment on how do you think the government of Alaska is going to be more helpful in developing that kind of a project?"

Mulva responded:

"Well, it's a -- I'll ask Al to comment here in a moment, his thoughts on this. But it's an indigenous resource. We know that it's been there. It's probably going to be a high cost to the market. We'd like to get it developed, we know Alaska would, but it's going to take some fiscal certainty, maybe some incentives to make this happen. We have and along with other producers up the North Slope, who have looked at certainly a pipeline down the lower 48 or connect a manifold into the Lower 48 to the Canadian system.

I think that gas long-term is a real winner but still Alaska is going to be pretty high cost. We have looked at, as the other producers, we looked ourselves at LNG export. So whether that changes and leads to the development of our Salt gas,

who knows. "

FINAL TRANSCRIPT

Thomson StreetEventsSM

COP - ConocoPhillips Analyst Meeting

Event Date/Time: Mar. 23. 2011 / 12:30PM GMT

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ConocoPhillips - Chairman, CEO

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ConocoPhillips - SVP - Finance, CFO

Ryan Lance

ConocoPhillips - SVP - Exploration & Production International

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ConocoPhillips - SVP - Exploration & Production Americas

Larry Archibald

ConocoPhillips - SVP - Exploration & Business Development

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- Analyst

Jason Gammel

Macquarie Research Equities - Analyst

Arjun Murti

Goldman Sachs - Analyst

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Maxim Group

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JP Morgan

PRESENTATION

Clayton Reasor - *ConocoPhillips - VP - Corporate Affairs*

Great. Well, good morning to everybody. We're certainly glad to be here. I welcome you to ConocoPhillips 2011 Analyst Meeting. Welcome to those of you here in the room in New York as well as those listening on the Web.

Safety is the most important thing that we do at ConocoPhillips. And this meeting is no exception, so we'd like you to please locate your nearest exit. And in case of emergency, we'll have somebody from the staff direct you to a safe location.

Of course, I need to remind you that we'll be making forward-looking statements in response to questions and also part of our prepared remarks. The actual results may differ from -- from what we're saying today. And the sources of these differences can be found in our filings with the SEC.

So, again, welcome. We think we've got a great agenda. We're going to cover some specifics this morning on -- on our operating and our financial as well as our strategic objectives. We think we've got some specifics you'll find interesting. And it's really a continuation on our approach to create value through improving returns, growing our profitable production and increasing distribution. And there's no one better to start the discussion than our Chairman and CEO, Jim Mulva. Jim?

Jim Mulva - *ConocoPhillips - Chairman, CEO*

Okay. Clayton, thank you very much and good morning. I'd like to welcome all of you here present in our analyst meeting here in New York City. It's good to see a lot of new friends, but particularly a lot of the old faces and friends that I've known for a long period of time. So I welcome you. And it's good to see you. As well as -- as Clayton said -- welcome all those who are participating in the worldwide webcast.

To get started, I think it was about 18 months ago, in the October time period or so of 2009, we assessed our company and we looked at the business environment and we looked at our portfolio and our investment opportunities, and given the environment that we saw, we said, you know, we think there's a better way for us to create value for our shareholders.

And so we announced a program that, essentially, Clayton just enumerated, which was we were going to have far more constraint with respect to how we invested our money, improve our returns in our portfolio, in which certain assets would be sold; and invest only in the best projects; and have a lot of emphasis on E&P, less on the refining side; and have a strong balance sheet, but get more aggressive on distributions to our shareholders in the form of dividends and share repurchase.

So then a year ago at this time, we had our 2010 Analyst Meeting. And in my first slide, essentially, this is what we said that as we look forward for 2010-2011, this is what we want to do. We want to improve the value of our portfolio, our returns, mostly on a financial basis and a cash basis, with the emphasis on more upstream, less downstream, invest only in the best projects. We want to have a stronger balance sheet, so some debt reduction and the emphasis on -- we have a lot of resources -- not that



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we have enough resources, but we want to take the resources that we have and let's really emphasize conversion of those resources to proven reserves and production.

And if we do this efficiently then we can replace our production at competitive finding and development costs, then we can create a lot of value for the shareholders. And the emphasis was not just on absolute volume growth, but really the metrics is on the per-share metrics -- the metrics in terms of reserves, production, income, cash per barrel of oil equivalent, whether it's upstream or downstream, again, as you see the emphasis on increasing distributions to our shareholders.

So that's what we said we were going to do last year. So what did we actually do this past year? Well, in many regards, we outlined it as a two-year program, 2010 and 2011. And, actually, a lot of the things that we said we were going to do over a two-year period of time, a great deal has been accomplished in this past year. We had a really good 2010. But, you know, that's a good year. What's most important is we got to keep going and keep this up not only in 2011, in subsequent years.

So what did we do? Well, we improved the return on capital employed. What we have found in our experiences about, whatever the improvement that comes in this metric, about two-thirds comes from commodity prices, our crack spreads. About one-third of the improvement comes from self-help in terms of how we invest, how we operate our cost structure.

Constraint on capital program, we said we were going to sell \$10 billion in assets over a three-period of time. We sold \$7 billion in 2010. It's not a -- it's not an issue with respect to completing this program this year. In fact, we're going to announce here this morning that we have aggressively new numbers of what we're going to do over the next two-year period of time.

When we came last year, we said we'd like to lighten up our investment in LUKOIL. And then we moved that up to say, well, given what we see in Russia and where we can re-deploy the funds and buy our shares in, we essentially said we're going to sell all of our interest in LUKOIL.

We essentially did most of that last year. And then we completed all of our sales in the early part of this year. And so we had good reserve replacement last year and in presentations this morning you're going to hear that we -- we intend and we have the plans to continue to do that. We started out pretty aggressive on share repurchase and the importance of increasing our dividends.

So as we assess our company today, and where we are and where we're going, we think we're pretty unique -- unique in terms of we're a little bit different, right? In other words, we look at our company in the environment and we do what we think is right for our company. Other companies can do -- have a different approach, but, for us, we think we have unique -- a unique position because we have a strong portfolio of legacy assets that are going to continue to deliver a lot of value for decades to come.

We have legacy opportunities and a -- and we're going to fund the best opportunities. And, again, the emphasis is on exploration and production. We continue to prune the portfolio, sell assets that are more mature, have more value to someone else, but do it in a way that we don't give value away from the shareholders. It's got to be tax efficient.

You'll see on the pie chart on the right-hand side of the slide, the Company was built, and we feel pretty strong on OECD presence -- OECD in terms of our cash flow, our portfolio. You'll see on the pie chart there on portfolio, the emphasis will be growing the upstream part of -- the percentage of the portfolio, less in the downstream.

And in our presentations this -- this morning, you'll hear about our pipeline of growth, the projects that we're going to be investing on -- in, and that's particularly in the E&P side of the business. Value creation comes from always operating excellence, cost constraint, but let's make sure when -- what we produce and what we run through our downstream refineries that we're improving the metrics per barrel equivalent, and the emphasis, ultimately, the bottom line is how we're going to bring value to -- for our shareholders.



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So the strategic objectives of the Company that we outlined in the past year or two continue to be the same. We really think we have the right plan for the next number of years that fit our company and fit the business environment we see. So how are we going to continue to improve the returns? You know, you don't just do this overnight. It's a journey that we're on. So to do this, it's -- how do we improve the portfolio, how do we invest our funds and shareholder distributions?

A lot of emphasis as I said on the metrics per share, and we want to always expand and improve those metrics per barrel equivalent of income and cash flow. We want to do even better. And you'll hear presentations this morning on how we can grow and develop our -- the exploration side of our -- of our company. And, again, so the emphasis is on making sure that we're pretty aggressive with respect to shareholder distribution.

So since we accomplished a great deal in 2010, we really felt that it was pertinent coming to our analyst meeting today that we look at the two-year period of time going forward. So, we said, okay, let's build on what we did in 2010. What -- indeed more granular to you -- to you, what do we -- can you expect of us at 2011 and 2012? Well, continue to discipline on our capital spending. I've got a slide here of what we have in mind for the next several years. And then in the presentations, you'll get more information on this.

Additional asset sales for the next two years of \$5 billion to \$10 billion. Now, this \$5 billion to \$10 billion is on top of the \$7 billion that we did in 2010. And it's on top of the disposition of the LUKOIL shares. So, I just want to make that very clear when we talk about \$5 billion to \$10 billion, it's on top of what we did selling LUKOIL, and what the \$7 billion we sold last year.

\$10 billion plus in share repurchase, I've got another comment or two in the subsequent slide. Really watch carefully and closely at the presentation of how we're going to replace our reserves via organic means. And we really have the resources to do that over the next five-year period of time. We always look at five years. And gets a little more gray obviously as you go beyond five years up towards ten years, and reducing our exposure on the refining side of the Company.

We -- as you know, we indicated and felt that we don't want to just part with assets and not create value that we thought that we could improve our performance in the downstream. And the downstream has had better crack spreads. But there is a better opportunity for us to lighten our position in the downstream, not in 2010, but looking more in 2011, 2012 and 2013.

So let's talk now for a moment about asset sales. Well, you could see, we announced \$10 billion. We get \$7 billion. So, no -- you add the \$5 billion to \$10 billion. So over this three-year period of time, '10, '11, and '12, our plans are somewhere between \$12 billion and \$17 billion of asset sales.

You see in the upper right-hand side of the slide, it just gives you some metrics of what we've already sold which is primarily the more mature things in the upstream side of the Company because we're going to do refining side a little bit later when we thought the market would be better to do this.

And we feel that we've created value for what we sold. And we did it in a pretty tax efficient way. The selection criteria for what we're selling does not change. We got really good values. It's got to be tax efficient. And we're not interested in selling or parting with any real strong legacy asset positions in the Company.

Take a look at our capital program. Well, you can see over the last several years what we've been spending in capital. And we have announced a \$13.5 billion program for 2011. And about 90% of that is going toward E&P, going forward somewhere in the \$14 billion to \$15 billion level.

And we're going to go see metrics that we feel that the spend at finding development cost and the mid to high teens, why, we can fund our projects and replace our -- our reserves. So, to give you an order of magnitude, \$13.5 billion this year and maybe \$14 billion to \$15 billion, maybe \$14.5 billion in 2012. So, that's our thought process and then longer period of time, \$14 billion, or \$15 billion. It's not, \$16 billion, \$17 billion, or \$18 billion. It's more in the \$14 to \$15 billion kind of level.



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Then as I said earlier slide, a lot of emphasis on the metrics per share. For our company just absolute growth in volume is not as important as the metrics per share because we're pretty aggressive in terms of our share repurchase.

So, this just shows production per share growth. Now, if we look at our company and the presentations by Greg Garland, Ryan Lance, and Larry Archibald, what you're going to hear about our production levels is before assets dispositions.

Our production level is about 1.7 million BOE a day. So then, we sell our assets. Before selling our assets, our production will decline. Somewhere in the neighborhood of 1% or 2% for '11 and '12 and then it starts to grow 2% to 3% absolute terms from 2013 to subsequent periods of time. And that comes from bringing on the large legacy investments and projects that we're doing.

Now, frankly, whether -- we're not that good to hit it within 1% or 2% because a lot depends on weather, operating excellence, how well we really run our assets, whether all of these different things. But all I want you to know is that production that is kind of flat, down 1% or 2% for two years and then it starts to up 2% or 3%. So, then to the extent that we're pretty aggressive buying our shares over the next several years, well, we really lever up. We're improving the production per share.

And then when we really add in the organic growth of absolute increases in production, you can see how it ramps up. So we really think this is the important metric is reserves, production per share and you want your production to be really valuable. And we think our -- in today's world, critical risk and everything -- OECD presence makes a lot of sense. Sometimes the cost structure is higher but the bottom line fiscal return is quite a bit better in the OECD type countries.

We're not too interested for our company in being a service provider or a contractor. We really like to have equity interest. Shareholder distributions -- changing the subject here -- annual dividend increases, well, we think it's really important, the discipline of increases in dividends, you can just see our track record from the time of the merger going back to 2002, it's around 14% a year.

When you start increasing dividends at that rate, you essentially double your dividends in the neighborhood of five years, a little bit more than five years. When we raised our dividend this past month or so by 20%, and then you can argue 12%, 14% or something like that but we can afford pretty substantial increases in dividend each year. So our -- it really is a statement when we increase the dividends 20%. It's a statement to the shareholders that we're very serious about the cash return to our shareholders.

As you can see on the slide, we certainly feel that we can afford it. So let's just in a summary way take a look then at what does the financial cash, source and use of funds look like over this next two-year period of time? It's a waterfall and the numbers that we have in this cash source and use of funds really come from First Call and some of our own numbers that we crank in. And so I'll start on the left hand side of the slide.

We ended the year, 2010, with \$10 billion of cash. Now, that comes from pretty good commodity prices, assets sales but primarily it comes from the sale, a pretty aggressive sale of LUKOIL ownership shares. Now, it does have an impact carrying that much cash. We don't want to carry that much cash because the return is not that great and we have \$10 billion in cash. It does have an impact on return on capital employed.

So we start with \$10 billion cash from operation, First Call says over this two-year period time about \$38 billion. Then we sell as we just updated you another \$5 billion or \$10 billion in asset sales so you can see the green, there's the sources of funds. The \$28 billion in solid blue means average about \$14 billion of capital spending for the two years '11 and '12.

And then our dividends, we increase each year adds up to about \$7 billion debt reduction. We think we are in a sweet spot in our balance sheet; Jeff Sheets will go through that. The reason we pay off \$2 billion is to require repayment that comes along. So we figured well, we'll just reduce anything that comes along in debt repayments. And Jeff will show you that our debt is essentially all fixed rate with very long duration.



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Share repurchase. Well, we -- before we announced the most recently the additional \$10 billion of share repurchase we did \$4 billion of a \$5 billion program by the end of 2010 so come up with \$11 billion by \$1 billion left in the old program and \$10 billion of the new program. And I think you can assume that a substantial portion of this \$11 billion is going to get done this year.

So that leaves us -- you can see on the far right hand side of the slide we're at \$5 billion to \$10 billion in cash. Now we're going to have more or less depending on commodity prices. I don't think you're going to see the capital spend move dramatically. It can be up or down \$1 billion or \$2 billion by opportunities where we can get into discovered resources or exploration acreage, things like that.

But -- so we have the opportunity to ramp up share repurchase more or fund some additional capital spending. So it gives you a feel for how we look at our sources and uses of funds and we think the application, allocation of capital fits very consistent with the strategy that we've outlined and continue to follow.

Growth in returns. Well, we feel that our approach and strategy is the right one for our company, the right one for the business environment we see. As I said earlier, the improvement about -- from 2009 to 2011, that -- about one third comes from self-help improvement, about 2/3 from the commodity prices. But then when you go from '11 to '13, a little bit more than maybe a third comes from self-help and how we change the portfolio.

So we've always been pretty competitive on cash return on capital employed but we're really working hard to close the gap with respect to our ROCE and as I said it's a journey that we're on through -- do this in the right way. I'm going to go to one of my last slides to just give you this -- the metrics associated with the investment, the strategy, the operating plan of the Company.

So the top line well, we always look over a multiple period of time but generally a five-year period of time is a -- is a good proxy however we're doing a reserve replacement, we've done pretty well if you look back over the last five years. But you're going to hear in our presentations that we see that over the next five years we're going to more than replace our reserves.

I gave you -- won't go through this again -- the metrics associated what's going to happen with production over the next several years. And then ultimately we're at 2% to 3% organic growth. You see what happens per share if you got 2% to 3% organic growth and then you do some share repurchase. Share repurchase after 2012 probably won't be as aggressive as what you've seen in 2010, '11, '12.

So that's why we rely more in the future on our portfolio of investments than just share repurchase. You're going to hear in our presentation, we think we can replace our reserves, investments we're making, we have the finding and development cost for projects, we're going to give you metrics on many of the projects, \$16 to \$18, reducing our capacity in refining and marketing, we're committed to this, particularly the smaller, less sophisticated refineries. We look at all the alternatives, I know that question will come up.

But we want to make sure that when we reduce our refining exposure that we do it in a way to create value for the shareholders. Competitive returns, we think distributions when you look at dividend and share repurchase for our company, our industry about 40% makes a lot of sense.

Debt to capital ratio improves in the later time periods because we probably aren't as aggressive on share repurchase after the next two-year period of time. And you don't pay out all of your earnings in the form of dividends. So, the last slide that I have, that pretty well covered all of this.

The strategy and approach of the Company is entirely absolutely consistent from what we said last year and 18 months ago. This is the plan over the next number of years. We think that certainly it fits the environment that we see. It fits the assets and opportunities that we have; the emphasis is on improving the returns to the shareholder. And that comes from selling the more mature things to those who want to pay more value to it than we see in our assets.



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Emphasis is going to be on the upstream, less downstream. We think we are in a sweet spot in our balance sheet. Obviously be real aggressive in operating well, safety performance, cost structure, but we are quite convinced that it's most important to keep our distributions up to our shareholders and that's in the form of share repurchase but particularly pretty significant increases in our dividends each year.

So that gives you the overview and so we're going to go through the presentations and those, the lineup making the presentations for the Company, this is – we want to showcase. This is the leadership team of our company today but it's the leadership team of our company in the future.

So hopefully, you'll see more granularity behind this overview and this plan. And then later, at the end of the morning session, I'll come up and try to respond to the questions and observations that you may have of the Company. So I think, Al, you're next up. Thank you.

Al Hirshberg - ConocoPhillips - SVP - Planning and Strategy

Thanks, Jim. Good morning, everyone. Jim talked about our strategic objectives and the benefits that they bring to our corporate results. So the next question is how are we going to go about achieving those objectives.

So that's what we want to spend the rest of the morning talk about -- talking about is the execution of the strategy that Jim just articulated. So I'm going to start out with two topics, first to provide some context to the rest of this morning's discussion, I'm going to talk for a few minutes about ConocoPhillips' view of the current business environment.

And then second, I'm going to talk about some corporate level initiatives that we've had underway that we think are good enablers to help us to execute our strategy more effectively. First, I'm sure it will come as no surprise to everyone in this room when I say that hydrocarbons are the dominant source of the world's energy supply and that we believe that that will continue to be the case for decades into the future.

We also believe that as the world's demand for oil and gas continues to grow over coming decades, that the world suppliers of oil and gas are going to be challenged to keep up. In the nearer term, we've seen that the world's economic recovery, particularly in the world's growing nations is causing an increase in demand for oil, for gas and for our refined products.

The one area around the world where we have a bit of a weak spot in the supply and demand picture, of course, is in North America natural gas. As you know, the large increases that we've had in production, unconventional gas production in the US, has left us with an oversupplied market in the US and relatively weak prices.

We also expect to see a continued tough political environment going forward, continued increases in geopolitical risk, difficulties with resource access. In fact, we see more in the past year that even in areas where we already have resource access, more difficulty getting permits to drill, to construct, for resources that we thought we already had access to, but hard to actually get the work done -- get the work done.

In addition, we also see continuing threats with increased fiscal take attempts by governments around the world and also continuing uncertainty in the regulatory environment. Overall though, we think that the strategy that Jim just got finished talking about is responsive to and will stand us in good stead in this business environment going forward.

We see over the coming decades, say 25 years from now out to 2035, about a 50% increase in the world's demand for energy. And as you could see in the plot, fossil fuels today make up about 80% of that demand and we expect that will still be the case several decades from now.



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We -- you could see from the plot that we expect the highest growth rate out of the segments we show here to be in renewables with encouragement and subsidies from governments around the world, renewables, we expect will have the highest growth rate. But still starting from the small base even with the high growth rate, the world is still going to need growth in oil and gas production in order to meet demand.

We showed you this plot last year of world oil demand on a year-over-year basis. And at that point in time the blue area was just beginning to poke above the zero line. So we had experienced 2.5 million barrels per day of demand destruction at the height of the recession. And we're just beginning to see a little bit of growth in demand.

Now, one year later, we look at this plot and we see that the growth in oil, world oil demand has more than offset the demand destruction that we had at the height of the recession. And we're now setting new highs going forward for world oil demand.

ConocoPhillips has a number of significant potential LNG projects in our resource base. And so we pay close attention to the world situation, supply and demand for LNG. The red curve shows you our projection of forward world LNG demand. And you could see that we're expecting a pretty high growth rate. I should mention that this curve was put together before the recent tragic events in Japan.

And so we're reassessing this curve now and I expect that it's going to move up as Japan uses more LNG to generate power to replace the power generation loss from the nuclear plants that are off line and that are expected to stay offline for some time to come. So we expect to see an impact there in the near and medium term on that curve.

In addition, you can see the world's governments and investors starting to reconsider some of their forward plans for nuclear power, and to the extent that those plans change, that could also increase the longer term demand for LNG versus what we show here. Then at the bottom part of the plot, we're showing you the global LNG supply from approved projects and they're organized by the year in which the project started up.

So you could see that the older projects along the bottom in this time period are starting to decline. So we show you it this way to illustrate the point that the industry not only needs to increase LNG supply to supply our projected future growth, but also to offset decline from some of the industry's older LNG projects.

These older LNG projects are declining both because they're running out of gas supply as they get toward the end of their life and also because increased domestic demand in host countries for natural gas is starving some of these plants of supply that they need to make more LNG.

If you look at what the industry has been able to do over the past five or six years, we have only approved new LNG projects at a pace of about 1 billion cubic feet per day per year of new projects approved. Going forward, if you're going to meet the gap that we show here, that will have to increase by about 2.5 times to 2.5 billion cubic feet per day of new LNG projects approved each year in order to fill that gap.

ConocoPhillips has been reducing our investment in North American natural gas over the past year or two -- when we look at this plot, we'll see the reason why. In the bottom, in green, is existing gas production in the US on about a 10% decline. The new story, of course, is in the blue, the large increases in production from unconventional gas in the US.

And as a result there's been essentially no need for LNG in the US to meet demand and so with that lack of LNG import in the US, it has left the US market disconnected from the rest of the world's natural gas markets and left us with low prices.

And we expect that situation to continue for some time into the future, assuming no new legislation in the US. Of course, new legislation in the US could have a significant impact on the supply side, the demand -- the demand side or both and change the supply demand balance in the US.



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So with all of that supply-demand data, what do we think about forward prices? We show here a summary of consensus forecasts. First, for crude oil on a WTI basis, in the near term, \$90 to a \$105 a barrel and in the longer term, a little bit wider range. Natural gas on a Henry Hub Basis, \$4 to \$5 per million BTU, although in recent weeks we've seen a lot of time in the upper threes kind of territory, and then in longer term, about \$1 more.

Gulf Coast cracks spreads on an LOS basis, \$4.50 to \$6.50 a barrel. Recently, we've also have been on the low end or below that range for LOS crack spread; longer term, about a \$1 more. So that's -- that's the range of forecast that we see a consensus around in the industry. Our view of forward pricing is in that similar kind of range.

ConocoPhillips replaced 138% of our production last year with organic reserves replacement. So the -- but the question for us next is how are we going to continue to do that going forward? And, more importantly, how are we going to do that efficiently at a competitive finding and development cost?

So what I'd like to spend a little time talking about in the next segment of this discussion is some of the corporate level improvement initiatives that we've had underway to enhance our ability to do exactly that. So I'm going to talk next a little bit about capital allocation, project execution, our efforts in procurement, and integration of new technology, and how these impact our ability to convert resources into reserves. Then a little later this morning, Larry Archibald will be up and he's going to talk about our plans in the exploration arena.

We've put into place a set of capital allocation principles in ConocoPhillips. The first one is that we -- the first is it recognizes that we operate in an industry that's got inherent risks that must be managed. And we don't want to put at risk our people, the communities that we operate in, our assets or, even potentially our company or the environment with the way we operate.

And so our first priority in setting our capital budget is to ensure that our maintenance and our asset integrity needs are taken care of first. So that's the first priority in our principles. Next is that we want to fund our high return exploitation projects. So these are the new ideas that our engineering and geoscience teams come up with each year for increasing recovery, increasing production in and around our existing assets.

So this tends to be high return stuff and, in 2011, we expect to have a significant increase in the amount of this work that we'll be investing in. In fact, if you look at the numbers, we expect that in 2011, we will invest almost twice as much money in this piece of the upstream exploitation as we will in the entire downstream segment in 2011.

I'd like to say two things about the way that we're funding major projects. First is that we're enforcing a worldwide priority list in how we look at all of our investment opportunities that are in our portfolio to ensure that we're investing in the highest return opportunities.

Second is that we're being rigorous about not investing in any projects, not going to sanction any projects until they are fully mature. And by mature, I mean from a technical standpoint with respect to the regulatory situation and, even most importantly, the commercial side of these projects.

And so a good example of this is the APLNG project. At this same meeting one year ago, we told you that we expected to take FID on the APLNG project by the end of last year. And we didn't do that. And the reason is exactly what I've just have been talking about is that we -- we could have taken it to FID, but we felt that we could improve the return on that asset by taking more time to improve our commercial position. And you've seen some of the things that we've announced since that point in time that do in fact improve our commercial situation on APLNG.

Jim talked earlier about our objective to convert 10 billion oil equivalent barrels from our resource base into proved reserves over the next ten years. So, obviously, as we do that, we also need to have a significant effort underway to reload our resource base as we go. And so we also want to consistently fund our exploration work. And you'll see in the numbers that I'll show in a minute that were increasing our budget for exploration in 2011.



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In addition to that, we're also considering targeted asset acquisitions were appropriate. And you've heard us talk about the deepwater for as an example where we would like to increase the size of our deepwater portfolio. And this is one way that we can -- can do that.

Then this last principle that I show here is just to remind us that we do recognize that we have to live within our means in setting our capital budget. So where are we going to spend our money in 2011? You can see that we expect 90% upstream, 10% downstream, no big surprise there, about half the money being spent in North America. And then on the right, you see the split of the \$13.5 billion for 2011 in refining, maintenance, exploration, the exploitation that I was talking about, and then the biggest wedge is major projects.

So this and this is where most of the growth is in our budget from 2010 to 2011 is upstream major projects and it is primarily in three categories. First is long life, long reserve projects like APLNG, the oil sands SAGD projects in Canada. The second category is increasing unconventional liquids production in the US And the biggest area there where we're going to spend money into 2011 is the Eagle Ford.

And then the third category where we're increasing our investment in 2011 on major projects is in new major projects that are high return projects in and around our existing infrastructure. Most of this increase in 2011 will be in Norway, the UK and Malaysia.

So with all of this increase in upstream project spending, how do we feel about our ability to spend that money efficiently? Well, in 2006, ConocoPhillips put into place a worldwide upstream-downstream project management function to guide our work there and to ensure that we use best practices in the way that we go about executing our projects.

At the same point in time, we also put in place a rigorous gated project management system to help our practitioners more effectively execute our projects. And the results are shown in the bar charts. If you look at all of the projects that we sanctioned since the merger of ConocoPhillips and through to the end of 2006 prior to putting this new system in place, on average, we were 21% over the budget that we had set for those projects and we took 16% longer to get to startup versus what we had expected at the time we budgeted the projects.

If you look at all the projects that we have sanctioned from 2007 on, from the time of this new system forward, we've got -- had a significant improvement. On average, we've been 5% under the budget that we set at the time of sanction, although, we have still been about 5% over on the schedule to startup versus what we had budgeted.

We've also looked at these data, comparing them to industry benchmarks, and we've seen similar progress over this period of time versus cost and schedule on an industry-wide basis. But we still have some challenges here. In particular, we're -- we're seeing some upward cost challenges in various places around the world and, particularly, in places where we have competition for resources.

We have a number of areas where we are trying to execute major projects where the industry also has a lot of activity. I think you'll hear about the Alberta Oil Sands, the Queensland coal seam gas and, also, on Curtis Island, the LNG plants that are going to be built. In addition, the Eagle Ford, the Bakken, these are all places where the industry has a lot of activity over the coming years and we're in competition for resources.

So we have some special programs in place to ensure that we capture the most effective execution resources that we can for these projects. And, of course, a key part of the Company where we do that sort of work is in our procurement organization. We've been working hard to strengthen over the last few years our procurement efforts and to expand the scope of what we're doing. And during the downturn, that allowed us to capture some significant savings.



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And then in 2010, we were able to improve the cost structure even further by broadening the scope of our procurement capabilities. You could see in the data down at the bottom that we estimate -- we saved about \$600 million on an annualized basis through these efforts last year.

The last area I'd like to talk about is new technology. This is one of my favorite areas to discuss because I started my career in research. And I've been pleased to see, since I've come across to ConocoPhillips, the strength of our technology program and the benefits that we've been getting from it. And it's really that view that's causing us to want to increase the size of our technology work. And so you could see from the bar chart that we're working right now to increase the scope and increase the benefits that we get from integrating new technology into our work.

I'll mention some examples in two particular areas where we're working in technology. First, in a broad bucket of work that we're doing that's designed to improve the profitability of our existing production or near-term projects, I'll mention an example in the oil sands. As you know, the oil sands make up a very large part of our resource base. And so it's -- it's a very large part of our R&D effort as well.

Our work so far in research on oil sands has allowed us to reduce our steam oil ratios, which, of course, saves us operating costs, reduces our energy usage, reduces our greenhouse gas emissions. We've also have been able to reduce our water usage through our research efforts. That's an important environmental criterion for the oil sands development.

We also have an integrated upstream-downstream research effort, a fully integrated team that has allowed us to fully exploit the full value chain, as that heavy oil produced in Canada makes its way south into the US and is processed in our mid-continent refineries. We have a research effort underway that's allowed us to improve our profitability from that full value chain.

Next, I'll mention a little bit about some of our research effort that's focused on more challenged resources -- resources that really aren't economic yet, aren't ready to develop, but we're working with new technology to try to get them there. A good example there is our work in the Arctic.

We have a number of new concepts that we've been working on that are at varying stages of maturity, but which have the potential to make a step change reduction in the cost to develop our Arctic resources. A good example of this is the work that we're doing on floating drilling rigs in ice-prone waters.

Right now, the industry is only able to drill from floaters in ice-prone waters for a very short season of the year that makes it difficult to do exploration or development drilling. And so we have concepts that we've advanced that will allow us to significantly extend that drilling season. You could see how that would have a big impact on our ability to develop those resources.

One of the most important jobs of our management team is to translate strategy into an effective execution plan. And so that's what I've tried to spend a little time talking about this morning is how we go about doing that. And I've discussed our improvement initiatives on capital allocation, project execution.

I also talked about our -- our efforts to expand procurement and our integration of new technology and the impact, the ability of these -- these efforts to enhance our ability to convert resources over to proved reserves. So we -- and also allow us to maximize the value of our reinvested capital. So next up to continue that discussion and talk about it on a segment level is Ryan Lance, who's going to kick off the E&P discussion.

Ryan Lance - ConocoPhillips - SVP - Exploration & Production International

Thank you, Al, and good morning. I'd like to go ahead and kick off the E&P part of the presentation as Al said. And I know we get some questions about our portfolio from many of you in the room here today. They ask is it -- is it deep enough? Does it



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have the projects that we expect to grow -- organically grow our production and reserves over time? And then we get questions about the portfolio. Does it have the cash flow? Does it generate the cash flow to be able to fund those projects over time?

So what myself and Larry and Greg would like to do today is talk through the E&P portfolio and talk about the opportunities we have for investment that we think that are going to -- the projects we're investing in will show organic growth in both our reserves and our production going forward.

Let me start with our strategy. As Jim described, it largely is unchanged, it's probably been a little bit different than maybe some of our competition over the last couple of years. We're pretty focused on trying to invest in those things that are going to improve the returns, improve the returns of the portfolio and, ultimately, the returns to the shareholders as we go forward.

And we're not just chasing growth for growth's sake. And we could do some of that. An example of that might be the North American gas market that Al described. We have a fairly large position in North America. We're blessed with a position, though, that doesn't force us to drill into the low North American gas prices that we see today, and we're just not going to do that. So we're not going to invest in that, but we believe over the longer term that prices will recover a little bit and we're prepared to invest when those prices do recover.

And we've been making some high grading decisions selectively within the portfolio to improve it through our divestiture plans that we've had over the last couple of years and that Jim announced going forward over the next couple. But we can't forget about what makes a great E&P portfolio. It is about replacing your reserves. It's about growing your production. It's about doing it safely and efficiently; and it's really about adding new opportunities through -- through exploration as well that Larry will talk about here in a little bit.

A few takeaways from today, I hope you'd leave with today. You know, we're running well. We're running safely and we're running efficiently. And we're progressing a number of very key projects. We've got a number of project sanctions coming this year that will add 500,000 barrels a day of production by 2015.

And we're also very focused on our North American shale gas plays. And you can see here that we'll be adding 170,000 barrels a day by 2013 from the Lower 48 alone. And as I mentioned, we're maintaining our optionality in North America. We do see the low North American gas prices, but we feel like they'll recover with time as demand picks up following the recession and we're prepared to invest in that when that happens. And then, again, you'll see us high grading the exploration portfolio and adding new material opportunities to the portfolio as we go forward.

Our success starts and stops with the safety and efficiency of our operations. 2010 was kind of a year to remember with the Macondo incident and the impact that an incident like that can have on a company. We're improving. We're improving, but we're not where we want to be. We'll never get there until zero, until we reach zero across all our operated upstream locations. But we are improving and we're getting better and it's showing up in our bottom lines through increased uptime and lower injuries to both our contractor and our employees.

We don't have a large deepwater Gulf of Mexico position, operated position today, but, certainly, have aspirations to grow in that particular area as Larry and Jim have talked about. But we did notice through the Macondo incident there was a capability gap in the industry. And we felt it was important to be a founding member of the Marine Well Containment Company to improve on that capability within the industry. And we announced that at the end of last year.

So let's talk a little bit about our portfolio. Today, we produce a little over 1.7 million barrels per day. It's a global, but a large OECD asset base as Jim talked about. We have a growing position in the Asia Pacific region. We're a global and diverse and growing exploration portfolio as shown by the dots on this diagram. But, more importantly, we have the size, we have the scale, we have the skills and we have the workforce to compete for unconventional and conventional resources around the world.



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That OECD position provides us with a leading cash margin relative to our peer group. We don't have a large exposure to the PSC contracts, so as commodity prices rise over time, we're able to bring that into the portfolio and capture those increases over time. Some of those maybe high cost as Jim described a little bit, but with a commodity price rises, we're able to capture that in the portfolio today.

You'll see on the right hand side, our portfolio generates a \$23-a-barrel cash margin, a pretty modest oil price as shown there on the thing -- on the chart. And our plan as we've -- as we said is the projects will show you that we'll go through in a little bit more detail, are a higher cash margin than this average portfolio. So, over time, we're going to be improving the returns in the portfolio relative to where we stand today.

Today, we enjoy a 43-billion-barrel resource space. It's 75% liquids and LNG. And it's -- those -- those LNG reserves are also tied to liquid oil price type contracts. It's unchanged despite selling 1.2 billion barrels of resources over the last couple of years. And as Jim said, and now maintain our job is to take those 10 billion barrels of resources, move them to reserves and then, ultimately, to production over the next ten years. That's the game we're in.

Our focus on organic growth is delivering results. If you look over the last five years, these are our proved reserve additions which we've enjoyed over 100% proved reserve additions over the last five years. And that's our intention going forward in the portfolio. We'll deliver that going forward over the next five years.

You can see 50% of those adds come from -- the chart on the right -- come from APLNG from the SAGD and Qatargas, but the rest of the world is contributing as well. We're seeing additions from our Lower 48 and Canadian shale gas positions, from Asia Pacific and Russia Caspian as well.

When we talk about the 100% reserve replacement, that's fueling the production growth that you see here on this slide. These projects are real. They're over on the right hand side. They're in various states of development today. And we're going to talk about these projects and show you what kind of margins that they're delivering and that they are adding to this production, organic production growth that we're showing here on this slide today.

And, of course, the absolute level of that production may vary a little bit, as Jim described, depending on the assets that we choose to divest to high grade the portfolio going forward. But the growth is there, the growth is real and the projects are real.

I'm a petroleum engineer by a degree and training. And I spent all my life fighting decline in these natural resources. And this is what really gets us excited going forward. It's these kinds of projects that show this kind of ramp up and provide this kind of growth and development for the Company.

You see that they're geographically dispersed around the world. And then you can see what kind of margins that each one of these projects provide. And remember to compare that back to the \$23 a barrel average margin in our portfolio today. So what we want to show you and talk about today is some of the projects that make up this curve. And it described where we're heading and how we're organically growing our production and, ultimately, our rate and reserves as we go forward in our portfolio.

E&P will spend \$12 billion in 2011. That's about \$2.5 billion more than we spent last year. And you can see the major increase that Al described as coming from that green wedge in the major projects. So, you see, it's pretty geographically dispersed on that right hand doughnut chart there.

The exploitation wedge in yellow is increasing as well. And that's largely driven by our North American shale gas investments in the Eagle Ford, the Bakken and the Barnett. Surprisingly, even the 100-year-old Permian Basin is generating very competitive investment opportunities for us going forward. And we're looking at investing in every one of those, all the opportunities we have even in the Permian.



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Al described the maintenance capital of \$1.5 billion at the bottom of the stacked bars. And that's important. We have to keep investing in our legacy assets. We have to improve the efficiency. We have to keep them safe, keep them reliable and keep them running for many years to come as we exploit the surrounding opportunities.

So we're investing \$12 billion. We're replacing our reserves and we're growing our production. So what are the projects that underpin that growth? Let me talk about a few of those in my part of the world and the international part of E&P.

Let me start with the Qatargas project that we got started up in November of last year. Got it to 80,000 barrels per day net to ConocoPhillips. We're now up and running at the design throughput for the facility at 7.8 million tons per annum.

Most of our effort right now is focused on maximizing the value chain. So when this project was originally envisioned and sanctioned, all the volume was destined for the North American market. At that time, gas prices were \$10 million to \$12 million a BTU and it looked like the most favorable place to send the LNG. Fast forward a good five or six years, and, of course, we're seeing the shale gas renaissance and the increase in supply in North America and lower prices, so most of our effort right now is focused on diverting those volumes and sending them to the higher price markets in Europe and in Asia Pacific.

And, certainly, with the recent Japanese crisis, we're trying to satisfy our customers in that part of the world, too, with additional LNG. And, of course, these are very competitive finding and development costs and great returns to the Company. We can take many more of these kinds of opportunities.

Let me talk a little bit about Asia Pacific, a growing area in our portfolio. We maybe don't spend near enough time talking about this, but, you know, we have a leading legacy position there. We intend to invest \$2.4 billion in 2011. And you can see the pretty significant production growth that we're going to experience across this whole region and the margins that we think our investments in this particular region are providing. And this is underpinned by growth in China, in Indonesia, in Malaysia and in Australia.

And let me talk a little bit about that and start with our Asia Pacific LNG project. Al talked a little bit about this and I'll kind of follow on with a couple more slides. So we have a leading -- we've talked about this -- a leading resource in reserves position at APLNG.

So nearly 12 TCF today a proven P1 and P2 reserves which is twice what the rest of the competition in the Queensland basin coal bed methane assets have. So we have a very compelling and large resource position that is the Premier 1 in the Queensland state.

As Al talked about, we are focused on how to reduce the capital and optimize the project going forward. We're not going to rush it, but we're going to do what's right. We're looking for opportunities to cooperate with everybody in the region. And we know that there's going to be competing projects built on Curtis Island. And so we're doing everything we can to make sure that ours is moving along as fast as it can, but as efficiently as we can as well.

And as we see, the recent events in Japan have underpinned that there is a growing amount of LNG demand in Asia now probably more than there was even two weeks ago. And you see that we've announced Heads of Agreement with a customer, Sinopec, that will underpin and purchase the first full train of LNG off of our APLNG project. And we've done that in an oil linked contract and we've done that at competitive prices for what CSG is selling into Asia today so we haven't had to discount the price in order to place the LNG in to the market.

We're the largest domestic supplier of CSG gas in the Queensland state today. Why is that important? Well, we're going to build two 4.5-million-ton trains of LNG capacity on Curtis Island. And when those trains are built and ready to go, we're going to need an immediate supply of almost 600 million cubic feet of gas a day to feed those plants. You got to dewater the coals. You got to get them ready. You got to get the production ready to go and up and available for those plants.



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So the fact that we're the largest domestic producer today -- we produce 250 million cubic feet a day into the domestic market -- we're able to play with our wells a little bit and get them prepared for that ramp up. So the minute that plant is available to us, we can ramp up the gas and quickly get it up to full capacity. And that's an important economic enabler for these projects.

And then, finally, I would say that this project is not unlike other LNG or even SAGD projects that have long life reserves. They don't have as good a return as some of our exploitation investments in our portfolio, but these are important projects in the portfolio. They are going to be a steady source of long-term net income and cash flow into the portfolio over 20, 30 years. They -- they increase our RTP. They have low finding and development cost and they're a source of reserve adds for a very, very long period of time.

So in this business of very competing metrics, these are important projects in the portfolio to have. And then our job over time with the self-help that we can do and the capital reductions we can make and maybe some improvements in the commodity price markets, these are going to be very attractive and competitive projects going forward. And that's what we're trying to do on APLNG.

A little bit more on APLNG, we'll invest \$1.4 billion in 2011. These are the metrics, the finding and development costs that we see for APLNG. We're on track for a mid-year FID at this point. You'll see we had our permits approved in February. And we did some commercial realignment with our partner, Origin, and they're on track for FID this year and then first delivery of LNG in 2015.

Let me look across some of the other areas -- places in Asia Pacific. So in Malaysia, we're in the midst of execution in four projects. We have four additional projects in the queue that we're studying as well. We're on track for 80,000 barrels a day of net peak production in the next couple of years. You can see it's a very competitive finding and development cost and a very attractive investment and organic growth story for the Company and for our E&P portfolio.

Moving to the right, in Indonesia, we're executing projects offshore, Block B, and in South Sumatra. These are typically gas projects with very competitive finding and development cost, but they're also going to the high valued gas markets that we're exporting to in both Singapore and Malaysia. And, in fact, some of the domestic Indonesian gas markets are improving pretty dramatically as well. So this is a very attractive investment in exploitation and projects for our E&P portfolio.

When you look across the North Sea, 2011 will represent one of the strongest investment years that we've had in quite some time in the North Sea. So our Jasmine discovery reached sanction last year. And we're on track for a 2012 startup, and even the large Ekofisk field is still yielding some fabulous new exploitation opportunities with the EKO-South addition and the Eldfisk 2 project.

And, in fact, we see future projects going out into the -- into the future that are going to help alleviate the decline in Norway, as we show from the production plot in the lower right hand portion. So these are the bread and butter of our business. This is really what makes the difference. It's really what drives performance. It helps offset decline. It's the high margin opportunities that help fuel our other projects around the world.

So what makes a compelling E&P portfolio? Well, it's certainly a rich and a deep set of opportunities like the ones that are shown here. It begins with legacy assets and exploitation opportunities and new projects that will continue to organically grow your production and your reserve base. And, more importantly, what do these have in common? They're good rocks. They got low finding and development costs and a low cost to supply; and they're feeding markets that are in need of this demand.

So I've talked a little bit about the international projects that make up this portfolio and that are fueling this organic production and reserves growth. Now, let me turn it over to Greg Garland. He's going to talk about what we're doing in the Americas side of the business that also is helping to fuel organic production and reserves growth.



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Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

Thanks, Ryan, and good morning, everyone. Has your view on the North American E&P business changed? Is this a business that you think maybe is just old and tired or perhaps it's just a continuing story of acquiring gas assets with limited upside. Or maybe your view is like ours, that this is really a story about technology and an innovation unlocking growth, opportunity and value creation.

So here today we want to talk about our North America E&P proposition. We're going to focus on value, not volume. The fact is we complete our portfolio reset through our asset dispositions and as we preferentially fund liquids devolvement over gas, near term production is going to decline in the Americas, 1% to 2%, but growth will return post 2012 and the interim, the value uplift from the margin of liquids over gas is value creation in the portfolio.

We think we're very well positioned in the unconventional plays in North America. In fact in the past two years we've watched while major IOCs have bought their way back into the oil-sand projects. They've joint ventured and bought assets into the shale plays. But you know what? We were already there, quietly going about our business, fine tuning, honing our skills and our expertise and building and capturing value.

When you consider the unconventional resources, we're number one in North America in coalbed methane and we have some of the very best parts of the play. We have the largest acreage position in the Canadian SAGD and we're the second largest SAGD producer.

We think we have enviable positions in the liquid-rich shale plays like the Eagle Ford, the Bakken, the Barnett and then we have a strong foundation from which we can grow conventional and unconventional in that hundred-year old Permian that Ryan was talking about.

We think we have a terrific opportunity here in the Americas. We have 22 million acres, 5 billion BOE of reserves, 30 billion BOE of resources. Three quarters of our company's opportunity is right here in the Americas, so our leverage to this large, secure and attractive opportunity is going to be a significant portion of the value growth of our company over the next couple of years.

The bottom line is we think we have a portfolio that will deliver improved competitive returns and long-term growth that will offset normal fuel decline. We plan to invest \$6 billion in the Americas this year, which is about 50% more than what we spent last year.

If you look at Lower 48 and Western Canada and look at the drilling program, about \$3 billion, 75% of that is going to be focused towards conventional oil and the liquids-rich shale plays. If you rewind back to just 2008, about 80% of our spend was on gas development. So you can see a significant shift in how we're allocating capital here in the Americas.

The balance of our portfolio spend this year will go to other competitive opportunities like Western Canada and the San Juan basin. As you can see, both of these areas will have a significant part of our portfolio volumes in 2011, but we're going to show you on some subsequent slides where we're going to let volumes decline in these two large areas which are mostly gas over the next couple of years.

Here's our Lower 48 drilling plan for this year. We plan to drill 450 gross wells in the liquid rich areas, the Eagle Ford, Bakken and the North Barnett and the Permian. We're drilling another 240 gross wells in other competitive areas, 195 wells in the San Juan might surprise you a little bit but we think this is a competitive set.

We'll talk more about the San Juan. This is significantly less than what we've done in past years and we're comfortable with this level of activity. And then if we can get the permits we'd like to drill four wells in the Gulf of Mexico this year.



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Talk about the Eagle Ford, the Eagle Ford is a game-changer. It's a game changer for the industry and for our company. We expect to have a total discovered resource approaching a billion BOE in the Eagle Ford. We think we're in the very heart of the play with 220,000 acres.

Forty-five dollar a barrel cash margins last year, the Eagle Ford margins were about twice the average of the global portfolio. The \$80 oil leases are all 25% plus wells. So you can see why we really like this play.

We're planning to spend \$1.4 billion in the Eagle Ford this year and drill 144 wells. As you know, the resources in these areas are stretched thin, but we entered 2011 with 13 rigs, three dedicated frac crews. We have the resources in place today to execute our 2011 plan in the Eagle Ford.

Since January of last year, drilling costs have come down 40%, so drilling days are coming down. We're increasing our frac efficiencies. We're fine tuning our completions here in the Eagle Ford. And so we're very pleased, you can see the latest five well results. We will put this up against some of the best in the industry and what's being done in the Eagle Ford.

2011 production, 30,000 barrels a day, 75% liquids content. Another important shale play for us is the Bakken. We have an advantage position of 460,000 acres here in the Bakken, 400 million BOE of resource and over 1,700 high-value drilling opportunities. Our recent well tests here continue to confirm this is a very attractive play for our company.

We're completing our latest wells, the 10,000 foot horizontals plus 20 stages of fracs. You can see our EORs have increased significantly. Our drilling times are coming down, frac efficiency is coming up, so total cycle times are coming down in this area.

The cash margins here in the Bakken, like the Eagle Ford, are very strong and accretive to the portfolio. We expect 2011 production to be at 40% versus last year at 20,000 BOE a day.

Move and talk about the Permian and the Barnett for just a minute. We call the Permian the gift that keeps on giving. Like a 122% reserve replacements over the last four years, like the 5% increase in production in this 100-year-old asset. We have a million acres in the Permian, 700 million BOE and we have greater than 5,000 new well opportunities here, so material net cash flow generator to our company in high liquids production. We expect 2011 production levels to be 50,000 barrels a day.

You know, last year in the Permian we saw for the first time since 1972 a 5,000 barrel a day increase in our operated properties. So horizontal drilling, these advanced fracturing techniques are literally breathing new life into some of these old fields. Some of these fields like the Howard Glasscock have been on production since the 1920s and we've seen year-over-year production coming up. We're also pursuing new resource plays in the Permian like the Avalon shale and there's some others that we're interested in prosecuting this year.

Just think about the Barnett for just a minute. We exited the South Barnett last year to focus and concentrate on the North Barnett. We just like it better, higher liquids content, high working interest so we can control the pace of development in the North Barnett.

We have 65,000 acres and about 200 million BOE of resource here. We expect 2011 production to be 15,000 BOE a day. So between the Permian and the Barnett we'll invest \$400 million in these areas this year on exploitation. Good solid cash margins, accretive to the portfolio, a little lower than what we see in the Eagle Ford and the Bakken. Why is that?

Well, the Barnett, a little lower liquids content, the Permian across a lot of that production is older production, high EOR cost, lower margins but still significant margins, very attractive return projects in these areas.

So we're building a portfolio in these liquid rich areas that will move our margins, will improve our returns. We have an early mover advantage in the Eagle Ford. We got in for \$350 an acre. We've seen offers north of \$14,000 an acre and that just confirms what we already know and the rest of the industry thinks that Eagle Ford is a good place to be.



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In all these basins we have a large presence so we can leverage our expertise, our skills and we can leverage our costs. We think from a sub-surface perspective we're in some of the very best parts of these plays. We added 140,000 acres last year around these key areas and other areas that we're chasing and you'd expect us to do similar things this year.

We plan to spend \$2 billion in 2011 developing these plays and by 2013 production of up to 170,000 barrels a day. So the question is, is it material? Does it make a difference? So this will move the North American E&P ROCE at normalized prices by 1.5%. So, yes, it's material, yes, it makes a difference.

I promised you we'd talk about the San Juan just a little bit. We are the largest producer in the San Juan. We are the largest acreage holder in the San Juan and lowest cost producer in the basin.

Last year we produced 180,000 BOE a day, 27% liquids yield. This represents about 40% of the Lower 48 production and about 10% of the Global E&P production. So it's a significant source of our production.

Total discovered resource, 1.7 billion BOE and even in this low price gas environment we have greater than 3,000 economic drilling opportunities. So this would be 20% return wells for us. So we can sustain a strong and ongoing development program here. You can see from a production chart we're going to let production drift down over the next four years. We've gone from 14 rigs in 2008 to four rigs last year. We're going to run four rigs in the basin this year.

We have a cash break even in the San Juan of about \$2 an M, so positive income, positive cash and good solid returns here. We're progressing horizontal well developments in the basin, we think there's a lot of up room with 1.7 billion BOE. The message today, the critical part of our portfolio, you should expect the San Juan to continue to be a viable part of our portfolio for many years to come.

Talking about Western Canada, Western Canada is a strong cash flow generator for our company. We think we're advantaged in this area. We're the only major player in all the key fairways. We own and operate a lot of our own infrastructure which we think is a major competitive advantage. We're going to reduce our capital spend in 2011 in response to low gas prices. In fact reduce it significantly. You can see production is going to come down over the next four years.

We have some exciting things going on in the Deep Basin. We're drilling some horizontals with very encouraging results. One of the areas we're very enthusiastic about is the Cardium. We have 137,000 acres in the Cardium. We drilled eight horizontals there so far this year. What I can tell you is the initial results are encouraging, they look a lot like the North Barnett in terms of the production and the liquids content.

So 1.7 billion BOE in this area, a lot of upside running room. As Ryan talked depending on where gas prices go we have a lot of optionality of what we can do in this area.

So today we purposely peeled back the Americas for you. We stripped out the oil sands. We stripped out Alaska to give you a view directly in what we're trying to do in the Lower 48 and Western Canada. These areas have historically been focused on gas development.

We want to materially shift the portfolio into production. You can see in 2010 we were about 30% liquids yield in these two areas. By 2013 we expect to be about 40% liquids yield and about the same level of production. The Lower 48 by 2013 will be approaching 50-50 on liquids.

Another unconventional opportunity that we have with liquids is the Canadian SAGD. We have just world class position here, a million acres, 15 billion barrels of resource. We're exclusively in situ in our development and we like this better and we think over in the long term we can generate the best returns here.



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We're going to invest \$1.2 [billion](company corrected after call) in Foster Creek, Christina Lake and Surmont this year. And we're going to invest \$1 billion to \$1.5 billion a year for the foreseeable future in the oil sands. We talked about steam oil ratio, it's key metric in looking to profitability and comparing projects. So we've shown you Christina Lake, Foster Creek and Surmont. You can see they're very attractive in terms of steam oil ratio.

AI talked about our technology and trying to drive that. We plan to spend \$100 million a year driving technology improvement. So we want to reduce our environmental footprint, that's land, water, drive down greenhouse gas but it's also about improving efficiencies and recoveries, driving down CapEx, driving down OpEx.

These projects are very capital intensive but we really like these projects. They're long lived. They have a low F&D cost, low decline rates. We're going to be producing in the sands for the next 30 to 40 years. In addition to FCCL, and Surmont we have other heavy oil interests.

In Canada we have Thornbury, Clyden and Saleski, 100% working owned, we'll be delineating those opportunities over the next couple of years. Within Alaska we have 1.7 BOE of heavy oil resource.

We said we'd spend a billion dollars a year in the oil sands, here's how you do it. You have deep portfolio projects, some preparing for execution, some moving through the gates, some working in terms of their environmental projects, some in the delineation phases. But we've planned four major sanctions this year at FCCL.

You can see we plan to grow our production by 10% to 15% a year through 2020 and we'll continue to grow for the next decade. Thank you. So by 2020, 250,000 barrels a day of production and we're going to grow for another 20 years beyond that, so by 2040 we should be approaching 500,000 barrels a day.

Talk about Alaska, we like Alaska. We've been in Alaska a long time. We're the largest producer in Alaska. Last year 240,000 BOE a day, strong cash margins in this area and we have a significant infrastructure position, we've built an extensive operating capability. We have a strong culture of safety and environmental excellence in Alaska and we think we have a strong competitive advantage here. Reserves at 1.6 billion BOE resources, 5.7 billion BOE. We'll invest \$350 million in exploitation this year, all at very good returns.

We're targeting sanction of our West Alpine project which is CD-5 if we can get the permits this year. And longer term, there's other opportunities. West of Alpine, we've got the heavy oil that we've talked about. We'd like to take a look and see what's in the Chukchi Sea if we can get permits to drill. And then, longer term is North Slope gas and we have 10 Bcf gas.

So our focus on value, our portfolio reset, our shift from liquids or shift to liquids from gas is going to drive value creation in North America. We expect the cash from operations will be up 40%, 2010 to 2015.

During that same period of time, return on capital employed up 5 percentage points, 40% from anticipated price improvement, 60% for portfolio improvements. We believe that we're well-positioned in the unconventional. We think that the opportunity set is compelling. It's real. It's material. We have the technology, the expertise, human capacity to execute.

We think our focus on liquids development is clear. And importantly, we have the resource and projects to drive liquids growth. So the bottom line is we think our portfolio is capable of delivering improved, competitive returns and value growth and this is the real heart of our opportunity.

So we have to continue to reload the resource phase. We do that through Exploration and Business Development and, Larry Archibald, the Senior Vice-President of Exploration and Business Development will cover that.



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Larry Archibald - ConocoPhillips - SVP - Exploration & Business Development

Thanks, Greg. Now, let's talk about the fun stuff -- exploration. As we've been telling you for some time, we're emphasizing organic growth much more than we did the previous decade. And I'm pleased to tell you that we're seeing good results from our higher impact exploration program both on the conventional and the unconventional sides of that portfolio.

2010 was another good year. You may not know that. We don't explore via press release. But I'll tell you briefly about it. We discovered more than we produced again. We have about a 90% success rate in our exploration and appraisal program. About 108 out of 120 wells we participated in. A lot of those were successful delineation wells in our Lower 48 in Canada shale programs.

But in addition to these very successful Lower 48 and Canada shale programs, we participated in discoveries in Kazakhstan, Australia, Libya, Nigeria and China. One of the 2010 highlights had to be that Lower 48 program in the shale plays. We participated in 80 wells, a lot of them delineation wells, all of them successful in Lower 48. In fact, 41 of those were drilled to expand our footprint and test the limits of our core Eagle Ford position and results there just continue to exceed our earlier expectations.

And more importantly, for exploration in 2010 and 2011, we continue to add both and depth and quality to the exploration portfolio both in the conventional and unconventional plays. That includes plays we accessed in deepwater settings and shelf settings, in arctic environments and in various onshore environments.

So what are we spending in exploration, how are we allocating that capital? Well, in 2010, in spite of lower than anticipated spending on wildcats, as I mentioned, we discovered more than we produced and more importantly, we discovered primarily high-margin values in plays such as that liquids rich Eagle Ford play.

As you know, 2010, the exploration program in the Gulf of Mexico was delayed due to the moratorium. But although we spent less on the high-impact Gulf of Mexico wildcats, we picked up the pace of leasing on some very attractive plays in shale plays. We also picked up the pace of delineating prior year successes.

And in 2011, we're going to increase the budget substantially for exploration and appraisal. We're going to continue a heavy emphasis on improving the portfolio, accessing some quality acreage positions and delineating prior successes. But on the exploration side, we also have plans to drill some large wildcats in the Gulf of Mexico, the Caspian, Norway and Indonesia. Equally important, we plan some new shale pilot wells, several new pilots in North America, both in the US and Canada, as well as overseas in Poland.

And this next slide helps to illustrate the breadth of our activity. As you can see, we're increasingly geographically diversified. We continue to high-grade and prioritize globally. We continue to drive more of our spend into higher impact plays and I include material positions in shale as every bit high-impact as material wildcats.

We're adding good acreage in both proven and frontier basins. Proven plays like in the Gulf of Mexico, sectors of the North Sea. Proven shale plays, we're consolidating expanding positions whether it's Northern Barnett, Muskwa, Canada and others. Frontier plays, we're adding new frontier shale positions. We're also adding conventional frontier acreage in places as far north as Baffin Bay in the Arctic and the Angola subsalt.

So speaking of Angola, the deepwater Kwanza basin is one of the more interesting wildcat opportunities we're in the process of adding to our portfolio. We're currently negotiating PSCs for a 30% working interest in operatorship of two blocks, 36 and 37. These are the two blocks. The only two blocks we high-graded and targeted in the recent Angola bid round.

Some of you know, seismic and geologic studies suggest this Angolan subsalt play analogous to the Brazilians - successful Brazilians Santos Basin subsalt play on the conjugate Atlantic margin and we certainly hope it is.



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After completing PSC negotiations, we plan some extensive 3D seismic in the remainder of 2011 and 2012. We could be drilling wildcats here as early as 2013. We're among the early movers in this play and we're very pleased to be given the chance to operate both of the blocks we targeted.

This is an example of how we're doing exploration these days. We intend to be among the early birds getting the juiciest worms, metaphorically speaking, whether it's shale plays like the Eagle Ford or new deepwater provinces such as this one in the Kwanza Basin. Let's move to another world-class petroleum system. There are several sectors in the Caspian that are clearly way under-explored and we believe have some very good exploration running room.

In 2010, we drilled the Rok More discovery in Block N Kazakhstan. This well encountered both oil and gas pay zones. So we're making plans for a future appraisal drilling and testing. To inform that future appraisal drilling, we're first going to acquire a 3D survey over this large Rok More structure to better understand it.

In the meantime, our joint venture on Block N is planning a second wildcat which may spud as early as fourth quarter of this year to test the very large Nursultan structure which is due west of the Rok More discovery.

We really like the geology of the Caspian and we intend to pursue other opportunities there. For example, we're in the midst of the PSC negotiations along with our partner Mubadala for block 19 offshore Turkmenistan.

Now, let's move to a great exploration arena with good potential closer to home. We continue to focus our Gulf of Mexico studies on the emerging lower tertiary play where we see a great deal of running room. As you know, activity levels in the Gulf of Mexico were impacted by post Macondo regulation. So our ultimate 2011 and 2012 activity is going to depend on large part on the pace of permitting there.

We do hope though that we'll see the Coronado wildcat spud the second half of this year as well we had hoped to drill in 2010 already. Coronado is a large lower tertiary prospect in the vicinity of our 2009 Shenandoah discovery. And based on what we learned from Shenandoah, we believe Coronado is in the right zip code, not only for very good fluids, but good reservoir quality.

In addition, operators of our 2009 Shenandoah and Tiber discoveries are anxious to get after appraising those and we are, too. So we're hoping to start appraisal of one or both of those either in late 2011 or latest 2012.

Now, Jim stated several times, we'd like to expand our footprint in the deepwater Gulf of Mexico at the right price and at the right time and we're actively evaluating opportunities to do that.

In addition, as Ryan mentioned in his talk, we're a founding member of the Marine Well Containment Company and this helps underpin our commitment of becoming an increasingly active operator in the future in the deepwater Gulf of Mexico.

Now, we're also a very experienced operator of high pressure, high temperature wells or HPHT wells is what we call them shorthand. And we see a great deal of running room for HPHT wells in certain sectors of the North Sea.

For example, we paid a number of large Triassic HPHT discoveries in the UK's central Graben J-block. We think similar perspective of Triassic geology extends right across the border in the Norway where we've got plans for at least two more HPHT Triassic wildcats in the near term. And in fact, we're in the process of serving up a sizzling Peking Duck wildcat. It's going to spud this week. And we're making tentative plans to follow that up with an even deeper and hotter Pelican wildcat in 2012.

Let's move down under. We followed up our large 2009 Poseidon discovery in the Browse Basin of Australia with the 2010 Kronos discovery. Kronos proved up material volumes of gas in a large fault block adjacent to Poseidon. And more importantly, a DST of the Kronos well demonstrated the quality of the Jurassic Plover reservoirs here and the capability of those Jurassic Plover reservoirs to flow at commercial rates.



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We're also quite pleased with the results of a 3D survey we acquired in this area in the last year or two. The survey reveals more prospects than we've seen before. So we're finalizing plans now for a five to seven well exploration and appraisal program in this part of the Browse that we'd like to kickoff at the second part of this year if we can get permits in the timely fashion.

Now, as you just heard Greg talk about, we continue to focus on the shale plays with higher liquid yields in North America in order to generate the better returns. In fact, we continue to appraise, delineate and expand the footprint of the oil and condensate rich windows in some of these profitable Barnett, Bakken and Eagle Ford plays.

In addition to these proven plays, our new exploration access of new shale plays has been biased more heavily towards the shale oil types of plays than the shale gas types of place in North America.

In our early identification in leasing of some of these best shale plays such as the Eagle Ford has enabled low-cost access relative to our peers. And more importantly, access to some of the sweet spots in these plays. As you guys know, just about everybody claims to have an Eagle Ford position these days, but location really matters. And what with delineation drilling we've done this year, we're pretty proud of our position on that play.

So now, we've continued that early access. We continue to add acreage in a variety of new shale plays across North America for what we believe will be a fraction of the cost late entrants are paying.

Now, many of you know, we've also been leveraging that considerable North American unconventional expertise to both screen and access shale plays overseas. We can talk about this one as we've been active in this plan Poland for a while. We've got the option for a 70% working interest in operatorship on about a million acres in the Baltic Depression in Northern Poland. We've been leading the way in this emerging play and, in fact, we participated in two of the first wells targeting shale in this basin in 2010.

These first two pilot wells were vertical holes designed to collect basic rock, fluid and gas content data. Initial results were encouraging. We're going to follow that up with a more extensive pilot program starting in 2011. In fact we're going to spud the Lebian horizontal well in May and follow that up with the Damnica horizontal well later in the year. Both of these are going to be completed and tested with multi-stage fracs.

With that -- I'm going too fast. Here we go. With that, I'll finish up by reinforcing a few of our upstream messages. First of all, as I've been telling you, we are seeing success from that high-impact exploration program. We're adding large volumes of high-margin barrels both from the conventional and the unconventional plays. We got a great pipeline of projects that are going to deliver both volume and value over the next year.

In North America, we're aggressively expanding our footprint, several very profitable liquid rich plays while retaining optionality on a primarily held by production vast portfolio of gas opportunities. You've heard us talk about our dispositions. I've mentioned a few of our recent exploration acreage acquisitions. This underpins our commitment to constantly upgrade and high-grade the portfolio.

However, we think it's really important to stress, we think we already have a unique and very competitive portfolio, comprised largely of long-lived, high-margin assets in stable OECD countries.

So with that, I hope you could see why we're excited about in our upstream portfolio and our direction. We look forward to updating you throughout the year.

And now, I'd like to introduce my colleague, Senior Vice-President, refining, marketing, transportation and commercial, Willie Chiang. Willie's going to update you on performance and outlook for our downstream and commercial organizations. Willie?



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Willie Chiang - ConocoPhillips - SVP - Refining, Marketing, Transportation and Commercial

Thank you, Larry. Good morning. Well, what a difference a year has made in the downstream. Last year, I was in front of you and we were talking about coming off a very difficult 2009. We were talking about tightening our belts, controlling CapEx, and trying to shrink our downstream in order to protect our cash position.

Well, this year, the belt is still very tight. We're still controlling CapEx. You're aware we exited our Yanbu project in Saudi Arabia and we cancelled the Wilhelmshaven project in Germany. And we're continuing to strive to reduce our footprint to 15% of ConocoPhillips asset base as Jim shared earlier. The key to do that is at the right value.

Now, the big difference is the markets have been much stronger than we anticipated. And when you combine that with the self-help that we've generated ourselves, we've really been in a better position cash flow-wise and generated positive cash flow for the Company.

So today, I'm going to talk about how we are going to continue to improve our business going forward and how we intend to be smaller, stronger, have a higher return business which will allow us to generate better margins in cash flow per barrel as we go forward.

So you've seen this slide before. It's our strategy and it's very consistent. We based our business on a strong foundation of operating excellence, safe, reliable and efficient operations allow us to capture more utilization. And in the US, we've been able to capture 5% more than the average of 90% and that allows us to capture market opportunities.

We're also very proud of our safety performance, in 2010 we finished at the best year since the merger. So our real focus is how do we improve return on capital employed and also get our cash flow stronger. And you're going to see in my slide as I talk more today about how we intend to reduce our refining footprint to ultimately under 2 million barrels a day and how do we get our return on capital employed up to the mid teens.

Now, we value integration pretty strongly. There's been a lot of news lately about spinning off entire down streams and we feel that we create much more value as an integrated company both in being able to deliver higher returns and value to the corporation.

There's the obvious benefits of having economies of scale on overhead, financial strength and having a deep talent pool of people across the company. But let me give you a few examples of where upstream and downstream can help each other as we've seen in the past. It's given us some great partner opportunities. If you think about our Cenovus joint venture with the Canadian oil sands, that's allowed Cenovus to get into a great refining asset in the US, avoiding upgrade expenditures. And it's really allowed us to get into a great position and probably, the best SAGD position in Canada.

As Ryan talked about growth plans in Malaysia, our Melaka refinery allows us to avoid a 10% crude export duty as we run equity barrels into our own refinery. There's a few good examples of partner opportunities.

Technology and best practice sharing is often understated, but there's a lot of value there whether it's finding logistic solutions for Bakken or Eagle Ford, or sharing best practice on sulfur plants, gas plants, and refineries. So the value is real. And even with the smaller downstream, we think we can gain the benefits of that and still generate positive cash flow back to the corporation to grow our upstream.

So this slide shows our performance against our peers and then highlights our RM&T business in the US. And you can see, for all market cycles, we performed well. We've got a competitive model. We've got strong reliable refineries and we've got cost efficient – cost efficient in transportation and marketing channels to get our products to market. We also focus very, very heavily on value chain optimization. Since 2003, we've averaged a 14% return on capital employed for the system and we've returned \$17 billion of cash to the corporation.



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So the past is great, but we always talk about what we like to do going forward, and this slide will tell you how we improved our return on capital employed. Last year, I talked about a \$500 million bogey of self-improvement that we had. And we delivered on that in 2010. So we ended '10 with a return on capital employed of about 5%, and these were areas of improving ourselves in cost, yield and optimization. Larry Archibald talks about the juicy worms in the downstream business. You know, all those are our juicy worms.

And as you move from left to right, in 2011, we've ground in another 2% of self-help into our return on capital employed improvements. The yellow bar shows what our restructuring and further improvements will give us. That's worth 4%, and that involves taking 500,000 barrels a day refining capacity out of our system and continued real business improvements.

And then longer term, as the economy grows and the world recovers, we expect to get some benefits from market improvements. And you can see how that actually takes us to the mid teens on return on capital employed. So let's talk a little bit more about these areas. Specifically for 2011, you can see this slide highlights what we're going to do.

Obviously, we're going to continue the relentless pursuit of operating excellence which really allows us to capture market opportunities when they present themselves. I talked about our \$400 million of improvements or the 2% that we've ground into our budget this year. And this again is in the area of costs, yields and optimization.

If you look at the top right-hand side of the chart, you'll see the yield improvement of almost 1% for this year. And just to remind you, 1% of yield is a \$100 million of net income for our business a year.

We also are going to take the opportunity of better diesel and gasoline selectivity and allow us to make the higher value product when the market demands. And on the lower right, we're going to continue to work hard at maximizing our advantaged crude to our assets. Now, typically, we run about 40% of advantaged crudes, and that's comprised of heavy and sour -- which is shown in the green and the red bars.

And, today, as you know, WTI has actually become advantaged. And when you combine the WTI end, we're just over 50% of advantaged crude to our assets. Now, we joke a little bit about using planes, trains and automobiles to get -- distressed crudes to our refineries, but it's not too far from the truth. We do have barges. We've got trucks and we've got railcars moving barrels to our assets and getting it to market. And we've been able to place over 50,000 barrels a day more than our budget of being able to get some of these crudes into our assets.

So this is our operating initiatives. Let me shift to the portfolio side. We continue to try to improve our portfolio in a couple of ways. We've got asset sales and capital -- which I'll talk about on a later slide. And since the merger, we've averaged \$750 million of asset sales a year and we've totaled \$6 billion since the merger of sales.

In 2011, we planned to have a \$1 billion worth of asset sales in our systems. And these sales are all part of that \$17 billion I talked about of cash flow back to the corporation since the merger. And these have been traditionally been non-strategic or lower return assets that we've been trying to dispose of.

Now, moving forward, the big challenge is how do we reduce our refining footprint. And there are a number of ways we do that. There's obviously the sale, the outright sale, which we're going through right now with Wilhelmshaven in Germany. If the sales aren't successful, there is the conversion to the terminals. But we're pursuing a number of other options as well. And that is joint ventures with either a strategic crude partner, such as Cenovus, as we've done with Cenovus, or someone that needs product and, perhaps, having a joint venture to be able to facilitate both of those.

We also have been looking hard at multi-refinery options. And this is where you have refineries that are nearby each other and the opportunity of optimizing those two refineries, avoiding CapEx, creates a lot of potential value.



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Now, we've actually done this before. We've got a number of systems in our portfolio that are multi-site facilities. Our Los Angeles refinery is the Wilmington and Carson plants. Our San Francisco refinery is Santa Maria and the Bay Area San Francisco refinery. And you'll recall, Wood River, we bought the Hartford coker years ago and integrated that in. So it's something we're very familiar with.

So, of course, the key to do this is you got to do it the right time and you got to get the right value and it's got to be tax efficient. So let me share a bit more on the criteria on how we look at our portfolio. We do have a very disciplined methodology as we try to shed our 500,000 barrels a day. And you can see the criteria includes integration, both upstream and downstream; financial performance and competitive position in the regions that we operate in.

This chart shows our refining assets. And you can see right is good on this because it's competitive. And you can see most of our assets are pretty competitive in the regions we operate in. On the up and down axis, you can see that we do have a range of strategic value to the corporation. So the dark green dots show assets that are heavily integrated in with upstream -- perhaps, the Canadian Oil Sands -- and, as you move further down, these are assets that don't have as much specific integration to us and may have more value to others and would be more sustainable.

So we're chasing all these opportunities in gray. And it's the ways that I talked about on the previous page in many of those different ways that we're looking at trying to monetize the assets. The other way we look at this is how do we improve our return on capital employed.

And if you look at the lower right hand side of this chart, what we're really trying to do is to take the lower return tail and improve that, ultimately returning the return capital employed of the entire portfolio. And with this framework, this really allows us to get towards that 15% of the ConocoPhillips asset base and all the financial metrics that we talked about.

Al Hirshberg talked about the market outlook. And, really, the point I wanted to bring out on this slide is that we're well-positioned to capture market improvements as they occur. Long term, we feel crack spreads will follow global recovery. And as they strengthen and light heavy spreads strengthen with Canadian crude production, we benefit from that. So every dollar of light oil spread is worth \$500 million a year to us and the light heavy spreads are worth \$80 million a year.

We invest in our assets. The integrity is sound and we feel that we're very well-positioned to meet ongoing challenges and legislative and regulatory changes. And we also have a strong commercial group that allows us to respond to global events to be able to get fuel and products, to the right places in the world as well as to capitalize on potential market dislocations. Some examples of this, when we had the Canadian pipeline outages late last year, we have a space on the Keystone Pipeline and we were able to take in more Canadian crudes into our system in the mid-continent.

And we do expect more rationalization in refining, particularly around the Atlantic basin. If you look at the current capacity that's out, it's about 1.5 million barrels a day. And we think there'll be another 1.5 million barrels a day of capacity that will be rationalized going forward.

Now, shifting to capital, we remain very, very disciplined on capital. We've got \$1.2 billion in the 2011 plan for downstream. I've already talked about Wilhelmshaven and Yanbu, but just to give you the context of that, that freed up over \$5 billion of commitments that we had going forward. So you can see the significant impact of not doing those projects for us.

Most of our CapEx is focused on asset integrity, reliability, clean fuels projects, equipment replacement, infrastructure improvements. We talked about meeting our consent decree requirements as well as improving the quality of fuels -- benzene and sulfur to be specific.

Now, just because these are must-do projects, it doesn't mean that we don't get a return out of them. Every time we have an expenditure, we always look hard at how can we convert these to a payout project. And I'll give you a few examples of that.



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We have an emissions control project that we had to put in our Bayway Refinery in New York Harbor on the stack to reduce emissions. By the time that we had to make the changes on the stack and the heater, it was actually more cost-effective for us to replace the entire heater. We got energy benefits and yield improvements in the unit. And that generated over a 20% return for us.

A few other examples in some of our plants, in Alliance in Wood River, it makes more sense to meet the benzene specs. Rather than saturating the benzene, we actually extract the benzene and are able to sell it for a higher price. And we have another good, low cost, high return project at our Whitegate Refinery in Ireland. We are putting a sulfur recovery unit in there that allows us to run lower sulfur – higher sulfur crudes at lower cost which improves that facility, and that's a 25% plus return project.

So you can see our target. We want to get our capex spend below our DD&A levels. We think by doing this it really distinguishes us against the peers. And it's a very, very good disciplined approach for us. So on the subject of capex, I would be remiss if I didn't talk about our Wood River core project. This project is our project at the Wood River refinery, which is 50-50 owned with our joint venture partner Cenovus.

This is another excellent example of upstream integration with a downstream asset. The project is a \$3.7 billion project, and it's a project built around a coking complex. And, essentially, what it allows us to do is to take what used to be asphalt and upgrade it into gasoline, jet and diesel. And that improves our yield by 5%, improves the net income earnings on the refinery by \$300 million a year gross, and \$4 a barrel improvement.

By doing this, Wood River will be one of the top competitive refineries in the Pad 2 region. The project is 90% complete. And we expect full operation fourth quarter of this year. So I've shared our story on how we're really trying to be excellent at everything we do. I hope you can see the many ways that we've tried to attack this through operating excellence, maximizing our realized yields, working the value chain to capture market opportunities and finding innovative ways to reduce our refining footprint.

We look forward to keeping you abreast of our progress of this through the years. And while we're getting smaller, we're going to be a stronger downstream asset and we're going to always be a key contributor to our integrated company both strategically and financially.

So you've heard a lot of challenges from my colleagues and I about our business. And I'll tell you, this is tough stuff, but it is what we do. So, at this point, I think I'll introduce Jeff Sheets, our CFO, who will tie it all together for you.

Jeff Sheets - ConocoPhillips - SVP - Finance, CFO

Thanks, Willie. Well, the shareholders in the room would probably agree with me when I say that creating shareholder value is a matter of combining strong operational strategies like what we've been talking about this morning with the right financial strategy.

And I'm going to talk about our financial strategy. Before I do that though, I'm going to spend just a few minutes rounding up the operational side with a few words about our chemicals and our midstream business. As you're probably aware, we participate in both of these businesses through 50-50 joint ventures that we started more than a decade ago. And both of these are very strong competitors in their respective businesses.

But first, a few words about DCP Midstream, our 50-50 joint venture with Spectra Energy. DCP is a really strong competitor in the gas gathering and processing business. You can kind of -- the proof point there, the fact that it's the largest NGL producer in the United States.

It's an interesting time for DCP right now. If you think about what's going on in the Lower 48 in terms of the shale gas revolution and all the requirements for natural gas infrastructure, DCP is well-positioned to take advantage of the investment opportunities



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that are there, both by virtue of their existing footprint of assets and their financial capabilities and operational capabilities. There is a lot of interesting investment opportunities for growth for DCP going forward.

If you kind of look at what they've done for us in the past though, it's been a consistent cash contributor back to ConocoPhillips. In the last five years, distributions have averaged \$500 million a year back to ConocoPhillips. If you think about that in terms of return on capital employed, if you look at we have invested in the midstream business and the income we get back from it, the ROCE of this business is more than 30% for us.

So, likewise, we've got a very strong joint venture on the chemical side in our CPChem joint venture with Chevron. Chevron Phillips has also got very strong growth opportunities, a lot of big projects coming to the startup phase now. They started up the Q-Chem II Project in Qatar in 2010, so it's ramping up in 2011.

And in 2011, they'll start up the Saudi Polymers project, which is a large integrated chemical -- world-scale chemicals complex in Saudi. They've got that growth coming on, but they also have a very strong environment for chemicals currently. If you think the combination of high crude oil prices, low natural gas prices, for a company that's pretty much a natural gas liquids feedstock company, that has created an environment where 2010 was actually the strongest year that CPChem has had since they were formed back in 2000, nearly 500 million of income back to ConocoPhillips in 2010.

Like DCP, CPChem is a consistent cash contributor back to ConocoPhillips, averaging 300 million a year of distributions over the last five years. And, likewise, the return on capital, if you look at what we have invested, the ROCEs are quite strong, greater than 20% for this business.

So that wraps up the operational discussion. Now I want to move back and talk about financial strategy. So when we were here a year ago in this room, we talked about all the things we wanted to do to try to improve shareholder value. On the operational side, we talked about improving production per share and production levels. We talked about driving higher margins for that production. We talked about the things we're going to in the downstream side to try to improve that business.

And on the financial side, we talked about how we needed to make sure that that improved earnings and cash flow stream will be better valued in the marketplace. We had kind of three particular areas where we felt like we needed to make improvements. The first one was on strengthening our balance sheet. The second one was on showing that we could improve our returns on capital, and the third one was on the area of shareholder distributions.

So, likewise, this morning, what you've heard, you heard from Greg Garland and Ryan Lance about our E&P portfolio to show you where that production growth is going to come from. They spent quite a bit of time talking in some detail about how that production growth is coming at higher margins than what we've seen in the past. So we'll have kind of an improved profitability for BOE.

And Willie just got done talking about the things he's going to be doing on the downstream side to drive improvements there. So we hope you can visualize how that's going to mean to improved earnings and improve cash flow for us. So on the finance side, we need to make sure that that's -- that we're doing the things to make sure that those earnings and cash flow are properly valued by the marketplace. So, again, it's the same kind of emphasis going forward, making sure we maintain a strong balance sheet, higher capital efficiency and continued improvement in the shareholder distributions.

Now, a big part of our being able to make that happen is the asset sales program that we've been talking about. So Jim talked earlier this morning about the fact that we're going to take from what we said last year \$10 billion of asset sales over 2010 and 2011 and expand that to an additional 5 to 10 on top of the 7 we did last year to where we're going to be \$12 billion to \$17 billion of asset sales over a three-year time period.

Now, last year when we got up here, we were pretty specific about what was going to be in the 2010 asset sales program. You're not going to see that same level of specificity from us going forward on asset sales. It's more likely that you'll see us talk about



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transactions as they occur. But let me give you just a little bit of guidance on what would be in our 2011 and 2012 asset sales program.

You'll see us continue to do things like what we've done in the past where we look at more mature areas of our portfolio like in the North Sea and North America and take a portion of that portfolio, the more mature assets, the non-strategic parts of our portfolio and continue to make reductions there.

You heard us earlier announce that in conjunction with the sale of LNG from the APLNG project, it would be selling a 15% interest between us and our partners selling a 15% interest. So we'll go from 50% down to 42.5% in that project. As we look around the world this year and next, there are some countries that we're in which would probably determine our non-strategic; and if we can get good value for the assets we have in those countries there may be certain countries that we'll exit going forward.

Willie talked about the things we're going to be doing on the downstream side as that market is now -- it looks like it's picking up to divest the non-core assets there. And then there will be other producing and non-producing assets, that could become part of the asset sales going forward.

So what does all that mean in terms of impact? You know, we can't give you a real precise guidance, but just some general thoughts on that. It's probably 50,000 to 100,000 barrels a day in production and something like 200 million to 400 million barrels of reserves.

So with that discussion on the assets, I wanted to turn back and talk about some of the financial factors. And the first one is where do we want to be in our balance sheet? Jim talked earlier today about how we really feel like, as far as our capital structure, we're pretty much in the sweet spot currently. We took \$5 billion from our asset sales program last year and used that to reduce our debt from \$28 billion down to around \$23 billion. That brings us right into our target debt-cap range at 20% to 25%.

If you look at kind of how we stacked up compared to a lot of the peer group, it's a pretty similar capital structure to a lot of our peers as well. If you look at kind of the cost of our debt, the maturity profile of our debt, it's all very manageable. And we don't really see any compelling reason to bring our debt balance down substantially from where it is today. So it may drift down a little bit as things mature but we're pretty happy with where we are today. So we think in terms of strengthening our balance sheet, we're pretty well -- we are done with where we think we need to be on this.

So next thing I want to talk about is the question of improving returns. So lots of things that go in to improving returns and let me just highlight three of them in the -- in the few minutes. The first one is we need to always be sure we're controlling our operating cost. We need to make sure we maintain capital discipline. And we need to continue to invest in things that are -- have higher returns and move our portfolio away from things that have low returns. So there's a portfolio shift going on.

First on the controllable cost side, we've had -- we've seen quite an uptick in commodity prices lately. We think that that is probably going to bring upward cost pressure on prices going forward. But despite that upward cost pressure, we want to continue to decrease our overall controllable cost levels.

For 2011, we'd like to see our controllable costs to be a couple of percent lower than they were in 2010. You know, part of that is going to happen because of some high cost properties that will be disposed off in 2010 and things that we might do in 2011. Al talked earlier about some of the initiatives we have in the procurement side to continue to be as effective as we can at driving cost down in that area.

And then just as you've heard others talk about this morning, it's just part of our business to continually optimize our operations and drive cost down. So the overall picture on controllable cost is continued discipline in driving those costs downward despite the upward pressure we're likely to see in the marketplace.



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The second area on improving returns is continued capital discipline. If you look at our level of capital employed last year and going forward, it's basically flat capital employed. I think everybody here knows how you calculate ROCEs, that's denominator of calculations so that's basically flat. If you can grow income, you're going to have improving ROCE.

And that's where we think we're going to be going forward. It's basically flat capital employed and improving income. So, you know, how could we make that happen? A lot of it has to do with the fact we've moved from a phase of rapid growth, accumulating a lot of resource to a phase of exploiting the resource base that we have which is what you've heard our E&P folks talk about earlier today.

So we think that this is a recipe for improving returns by holding capital relatively flat and driving higher income going forward. And the last thing I want to talk about on improving returns on capital is the portfolio shift we have going on. So when we were here last year, we talked about the fact that about half of our portfolio was earning basically, you know, 1% or no return. And that being our North American natural gas business and our refining business which made up about half of our capital employed.

Now as we roll forward in time, we think that as we invest most of our money in upstream and most of our money in liquids rich parts of upstream, well that portfolio is going to shift from being for those components make up around 50% to closer to 40%. And that's going to help drive our returns as that portfolio shift happens.

But as important as the portfolio shift going on in that part of our business, it's also what you heard Greg Garland talking about on how we're driving returns higher in North America through the shift away from gas and to liquid in the higher margin plays that we have there. And you heard Willie just get done talking about the things were going downstream.

So it's not just the shift but the fact that we're going to be improving the portions of our portfolio that have lower returns. And finally on the finance side, I want to talk about the subject of shareholder distributions. I don't know -- let me wrap up a little bit on getting ahead of -- wrapped up a little bit on returns. We're going to tie this all together with everything we've done so far with the portfolio shift, improving cash margins. We think we're going to get help from the marketplace. They're all going to do these things that help drive our returns higher.

But another thing to keep in mind is that we ended 2010 with \$10 billion in cash. And as we go through 2011 and 2012, the majority of that cash is going to share repurchase. So you can think of that as something that's also going to help accelerate improvement in returns on the capital employed.

So in 2009, we had a return on capital employed at around 7%. We can see that being nearly twice that in 2013. And similarly, we think we can have very strong improvements in cash returns on capital employed. So now let me shift to talking about shareholder distribution. Jim talked earlier this morning about the fact that we've increased our dividend every year since the merger at an average compounded growth rate of 14%. And that we increased our dividend earlier this year by 20%.

If you look over time, we've also been spending a fair bit of cash on putting money back to our shareholders in terms of share repurchase. You focus on 2010 in particular, we paid out \$3 billion roughly in dividends and \$4 billion in share repurchase. You add that together and you compare that to our market cap and that's something like a 6% or 7% cash yield back to our shareholders.

Looking forward to 2011 with the 20% dividend increase that we had earlier this year, that's \$3.5 billion to \$4 billion going out to our shareholders in terms of dividends. We've talked about the increase share repurchase; let's just say that's going to be in the range of \$5 billion to \$10 billion in 2011. You combine the dividend and share repurchase for this year and you're looking at something it's more like an 8% to a 12% cash yield back to our shareholders. So we're going to be quite aggressive on shareholder distributions in 2011.

So how does that compare to what we've done in the past -- in the past and compared to what the peer group is doing, last year when you looked at the comparison -- that's what's on the left hand side of this chart -- we found that while we've been



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aggressive on increasing dividends and we had been a participant in share repurchases, compared to our peer group we are relatively not as aggressive as they were.

You contrast that to where we were in 2010 to where we distributed nearly 40% of our cash flow in either dividend or share repurchases and that puts us right at the top of the peer group. So this 40% cash flow a Jim mentioned earlier, it's kind of where we think we need to be going forward in terms of shareholder distributions.

So what do we want you to take away from the meeting today about ConocoPhillips? ConocoPhillips is well positioned to continue to create shareholder value and in some ways we're kind of uniquely positioned to do that. You think in terms of the cash flow that we generate from our assets coming from strong cash flow coming from OECD countries primarily.

Going forward, we're going to augment that strong cash flow with continued proceeds from asset dispositions. We've got a strong pipeline of projects that we can reinvest that cash flow in where we're going to continue to be disciplined about the rate at which we reinvest the shareholders' funds.

We recognize that there are parts of our portfolio where the returns aren't as good as they should be and we're taking steps to address that. So you take that disposition and that approach and we think that's going to get us going forward. You've heard us talking about continue 100% reserve replacement going forward.

Our production per share growth short term, absolute production growth longer term, that production growth is coming at higher margins than what we've seen in the past. That's going to drive higher returns. You put higher production growth together with higher margins, that's a recipe for increased earnings, increased cash flow.

And as we go forward, we want to make sure that we're sharing those earnings and our cash flow with our shareholders. That means continuing to be aggressive on shareholder distributions. So we were here a year ago and outlined the steps that we were taking to increase shareholder value. I think the general feedback we got right away was, it's a good plan but we need to see it executed. I grew up in Missouri, I kind of understand the show-me attitude for that.

And as the year goes -- went on and we demonstrated that we were doing what we said we're going to do, the market reacted very well. And we had a very good year in terms of shareholder return in 2010. Now we know you didn't come here to hear us talk about what we're going to do in -- what we did in 2010. It's all about what we're going to do going forward.

So this morning, we've outlined what steps we're going to take to build on the success that we had in 2010. And we believe that this plan is going to continue to drive higher shareholder value going forward. That wraps what we're going to talk about today. We've tried to talk to you quite a bit of detail about our plans; we realize that there may be questions that you're going to have so we're going to take about a 15-minute break and then we'll come back and take those questions so thank you for your time and attention this morning.

(BREAK)

QUESTIONS AND ANSWERS

Clayton Reasor - ConocoPhillips - VP - Corporate Affairs

If people can find their seats, we'll start the Q&A session, please. So if people could find their seats, we'll start the Q&A. Thank you. Okay, I thought the presentations went very well. And I think we gave a lot of good information out and I know that there may be some questions that have come up as a result. So I think Jim's going to come up and take your questions and then to the extent that he wants to supplement his answers, well he'll redirect to some of the presenters. So, I'll turn it over to Jim Mulva.



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Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, Clayton, thank you and so let's just start with Doug.

Doug Terreson - Analyst

Jim, You got (inaudible - microphone inaccessible) okay. Okay, [Doug Terreson], Jim you got (inaudible - microphone inaccessible) pretty considerable improvement in growth and return profile over the last couple of years. And when you think about the production per share plan that you have which is obviously dependent upon repurchase plan, that that figure is something around 5%, you know, per share annually through '15.

But at the same time, the growth rate really doesn't appear to use much free cash flow or repurchases beyond 2011 which appears pretty conservative to me. So my question is, what repurchases are included in the 5% growth rate through '15 and what are the implications for dividend policy in this longer term scenario?

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, Doug, one of the things we tried to do is makes sure that we -- to some extent I agree with what your basic premise or your question you're asking -- is maybe we're a little bit conservative. We try to under-promise and over-deliver, quite bullish myself on oil prices for all different reasons.

I like to think the long term -- long term natural gas is going to be a real winner. It's going to take a while to get there though and so if you look at our company, I think there's opportunities to really ramp up share repurchase more than maybe what you see in the slides.

So if we probably are a bit conservative in that regard in terms of our capital spending, now \$14 billion, \$15 billion, you know, can go up a little bit, down a little bit, that's pretty much ballpark. Dividends, we like to be aggressive on dividends. Double digit growth in dividends each year, we think that's really good discipline. It's quite a signal to our shareholders. So when we build in, we're not thinking 5% and 6% we're saying double digit.

So double digit what does that mean to people, well demonstrated can be 10%, 15% and 20%. But then given the strength of what we see our legacy assets and our investments and our position of adding production like production per share, we look at -- there's probably a lot more opportunity beyond what we're saying that we could allocate more money towards share repurchase.

But then the question becomes, you know, how much -- how many shares do you buy in order to find shares of \$50 or \$70 or \$80 a share certainly has impact with respect to per share growth. So we won't buy shares just at any price but on the other hand I agree with you as we look beyond this year into 2012, '13, '14 I think it's good opportunity to see growth in terms of share repurchase and metrics in terms of growth of production per share to be even better than what we've demonstrated. So there's a bit of under promise and over deliver here.

Jason Gammel - Macquarie Research Equities - Analyst

I'm Jason Gammel from Macquarie. Jim, a few specific questions about the divestiture program. First of all, are there any of the refineries that are on the market outside of Wilhemshaven? Or would you expect a billion in downstream divestitures to be made up of marketing terminals, et cetera?



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Second, is the REX pipeline still a component of the divestiture program? And third, the equity divestment in APLNG, would you expect that to be -- to a strategic off-taker? Or would you expect that to be another industry player?

Jim Mulva - ConocoPhillips - Chairman, CEO

First, APLNG, that is our partner, Sinopec. So they bought in what -- taking a full train. They want an equity participation to full chain. In terms of the divestitures on a -- on the downstream side of the Company, we are -- we are looking at selling refineries, we're looking at terminals, everything in it. Maybe, Willie, you might want to comment just what you can see and foresee.

Look, the market is a little bit better, assets are starting to move, so our premise by waiting a year or two, we think, is the right thing. But on the other hand, it's not like we're not doing anything. We sold our precision LUKOIL, a substantial sale of our asset disposition. We want to make sure that when we sell refineries or we venture them or whatever we do with them that reduce our participation that we're really creating value for the shareholders. So, Willie, do you want to comment on REX pipeline and some of the refineries?

Willie Chiang - ConocoPhillips - SVP - Refining, Marketing, Transportation and Commercial

So, Jason, right now, it is only Wilhemshaven that's up for sale. That's only one that's out there. The answer on the billion dollars, it's -- it's a mixture of all three. It's refining marketing and transportation asset -- refining and mostly transportation assets. And we will be more specific as we -- and as we kind of go through the year there.

Jim Mulva - ConocoPhillips - Chairman, CEO

But Willie said it's the only refinery that's technically on the market, we're talking to many people about everything that we have on a downstream. So you -- but a formal process where you get an investment banker and to help you sell an asset, that's really -- it's Wilhemshaven. But the discussions with strategic players that should want to own a given asset or a competitor in the business while we -- those discussions are on going. Arjun?

Arjun Murti - Goldman Sachs - Analyst

Thanks, Jim. It's Arjun Murti with Goldman Sachs. Jim, your team highlighted the large amount of unbooked resources you have in your portfolio. And I know you're focused on developing those internal options. I was wondering if you could comment at all in your latest thinking on acquisitions what role they'll play in using some of the -- the free cash load Doug had mentioned earlier. Should we expect tactical deals like the APLNG? Would you still consider larger transactions? Just run in your latest thoughts on the acquisition at what role that plays? Thank you.

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, come back on the REX pipeline. We didn't answer the question. But strategically, we would like to part with our interest in REX pipeline. We felt that the offers we were given, say, a year ago or whatever, we're not good enough, but we said we're going to revisit this at some point in the future and we will. So we haven't changed our mind in terms of what we want to do in the REX pipeline.

Arjun, on acquisitions, I could be wrong about this. But I just see the environment for buying at making substantial investment to buy another company or something like that. Consolidations may take place, but I don't see it in the next several years. So our concentration really is on organic growth and our ability -- I want ask Greg and Ryan to give their comments on what they see as opportunities for, I'll say, acquisitions.



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But it's going to be directed more into positions, discovered resources, how can we complement hundreds of millions of dollars or a billion or two, that sort of thing, but I don't see the acquisition in the M&A market over the next three to five years or whatever time period it is like we've seen in the past decade. That doesn't seem to be available of the cost, whatever, political reasons or a fit really for what we're doing with our -- with our company. So, I'll start with Ryan. Do you want to say something and try to respond to Arjun?

Ryan Lance - ConocoPhillips - SVP - Exploration & Production International

Yes, Arjun. So we're looking -- you saw Larry talk about growing the exploration portfolio, looking for new opportunities like Angola. But we still -- we call them DROs, Discovered Resource Opportunity. We are still out there looking for good opportunities in the areas that will complement our existing portfolio, and we think fit going a long term.

So Asian gas, we think it's going to be pretty strong, so some of the opportunities that present some stuff out there you'll see us looking at some of that kind of stuff. So we continue to look. It's a hard business. You got to keep reloading the inventory. Bringing more resources in.

We're going to do a lot through our own portfolio. We're going to do it through exploration. But we continue to look at discovered resource opportunities around the world as well.

Arjun Murti - Goldman Sachs - Analyst

Is shale all part of that as well?

Ryan Lance - ConocoPhillips - SVP - Exploration & Production International

Sure. I think Greg can comment on and Larry both, but we'll look for shale opportunities and nonconventionals as much as conventionals.

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

So, Arjun, I think we have said with \$1 billion, \$2 billion, \$3 billion in the Gulf for opportunities, and we'd like to continue to look at that. Anything around our core areas we're interested in adding positions there, but, you know, I know weren't looking at companies or we're looking at assets and land mostly. So, Larry, do you want to anything?

Larry Archibald - ConocoPhillips - SVP - Exploration & Business Development

No, I think it's been pretty said. But, yes, we want balance between unconventional and the conventional, obviously, and I always prefer to grow those unconventional positions organically rather than doing the multibillion dollar late entry acquisitions and spin offs from Chesapeake and others that many of our competitors have done. But if we see exceptional value out there that's a good fit, we're going to jump on it whether it's discovered resource or exploration acreage.

Jim Mulva - ConocoPhillips - Chairman, CEO

As Larry said earlier in his presentation, we're putting the money, the financial resources, the technology in the people side to find the next Eagle Ford, and if not just in one or two areas, multiple areas in the Americas, as well as Ryan said internationally, we'd like to take what we know and what we've learned and go to other place and see the world.



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Stan Harbison - Hudson River Global Energy - Analyst

I'm [Stan Harbison] from [Hudson River Global Energy]. In terms of incremental opportunities that would seem to me sort of following from what you said would be selling not buying. When you have KNOC, Chinese companies, two of which you have strong relationships with, Reliance and whomever else, we seem to be paying a premium over the industry estimates of value. Wouldn't that be great a way to channel cash through into more share repurchase?

Jim Mulva - ConocoPhillips - Chairman, CEO

In other words, sell refining more aggressively?

Stan Harbison - Hudson River Global Energy - Analyst

No, upstream. Upstream is getting huge -- huge premiums I think.

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, obviously, we have done some of that. We talked to all of those companies. And there is an interest, but yet we also want to make sure that when we look at selling upstream assets that they're fact sufficient. You can take some of -- I'll just give you an example. You could take some of our very large positions that we have in the North Sea and you could sell an asset and you'd get an incredible price for it.

I don't know what the numbers are, but you get 50% to 60% back to the government, the shareholders, what do they get? So what really drives us, you know, we're not in love forever with everything. But we got to make sure that we -- that we say we'll sell something, we'll look at anything and everything, and we recognize and agree with what you're saying. But we got to make sure it translates into cash that's available to give ultimately the reinvestment are back to shareholder. Ed?

Ed Westlake - Credit Suisse - Analyst

Yes, maybe two upstream questions. It's Ed Westlake with Credit Suisse. Firstly, Greg, you've got strong liquids growth out to 2013. Can you talk about where in the Lower 48, specifically, how confident you are that you can continue to drive the liquids growth higher beyond that? And then a question in the Arctic, obviously, that's a contentious subject, but it's shallower water. How confident are you that we can get back to drilling, say, in Chukchi Sea and what timescale?

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

Is it on? It is on, okay. Okay, so first question, I think as we continue to build around our core areas that will deliver liquids growth beyond the 2013 timeframe Lower 48, there's no questions the SAGD is going to continue to drive liquids growth for very, very long period of time.

The second question is a lot harder to answer because I'm not sure we really know when we're going to get to start drilling again in the Arctic. You saw the comments in the commission's report about the Arctic and really forecasting that we should exercise caution before we go back into the Arctic.

So that's a question that I think is difficult to answer. We're starting to get back into the Gulf of Mexico. I think Shell just got a permit recently in the deepwater well to start prosecuting that. But I think that will come with time. But there are some -- but I think there's big challenges remain in the Arctic.



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Jim Mulva - ConocoPhillips - Chairman, CEO

Our premise says that we are scheduled on our plan, I think, Larry, is to get going in Chukchi, 2013.

Larry Archibald - ConocoPhillips - SVP - Exploration & Business Development

Yes, 2013 at the earliest. We're actually in a, I guess, enviable position. We're not burning any cash on that operation as we wait for their regulator environment to be sorted out, unlike at least one of our competitors. We're not pregnant in an Arctic drilling fleet. And we're going to wait and see what develops there. And in the meantime, we're getting tolling, extension on our leases there. So we would like to get after it, but it's not urgent. In the meantime, we're going to park things until we see regulatory certainty.

Kevin Kelly - Morgan Stanley - Analyst

Yes, Kevin Kelly from Morgan Stanley. You know, clearly, the view and the significance in North American unconventional liquids has changed for Conoco as well as the industry. How do you view your organizational limits for reinvestment? And then it's clear that -- appear to have more running room in the Bakken or some other place. How does it -- how do you balance an impact of a buyback versus an opportunity for reinvestment at high returns?

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, I thought you were leading first, and, Greg, you can comment here in a moment, that we had organizational bottlenecks or people or issues, you know, how can we have the people to do everything we want to. And I think one of the things we -- in the past year when we said no to some of the major projects like Yanbu, Shah, Wilhemshaven, this allowed us to redirect our available people and all to do the projects even better than we thought.

That was -- what Al Hirshberg was talking about. In terms of our projects where we invest, first and foremost, we look at what good opportunities do we have to invest capital on our basic business. And we do all the best projects, then after that, we look at giving it back to the shareholders, but I'll ask Greg and all of you, do you want to comment on this question?

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

I'd be happy to do that. So in terms of organizational limits, I think that we've got human capacity, subsurface drilling to execute it. There are limits in terms of the services. And one of the things we have with our size and our scale, you know, we can lever that size and scale, for instance, like in the Eagle Ford, you know, we were able to get three dedicated frac crews. They're signed up. We'll have them in place.

And so, we're not waiting on any capacity. I think that the limits that we see in the Bakken and we would like to do more for sure, they're more related to takeaway capacity. And we don't want to over drill the existing takeaway capacity. So, you know, there are pipelines being built and so as those come up, we can accelerate there, the same thing in the Eagle Ford. We don't want to over run that takeaway capacity.

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

I guess, I just might add that we -- you can see from the cash position that we showed earlier that we've got quite a bit of flexibility on our balance sheet. So to the extent that we can find attractive enough work to do, we may go spend more money



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doing it. But we -- what we don't want to do is lose our discipline, our focus on returns and chase too far down the list. And so, to the extent that those opportunities are there, then we'll invest in them.

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, the other point is we don't want to lose the optionality of that opportunity. So we can do it today, we can do it next year, but always an optionality. It's just a question of how quickly we move on. Paul?

Paul Sankey - Duetsche Bank - Analyst

Jim, you've outlined a plan through 2013, which would encompass your retirement age. Could you -- in the past you said you might continue to be on that age. I just wanted what your current feelings are on that? And secondly, to what extent would a way of bowing out for you to be to sell or merge ConocoPhillips? Thanks.

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, that's great. First of all, the inferences, I plan to be alive beyond 2013, that's the first. But in a serious way, look, in terms of secession and retirement and all of that, we -- that's a decision by our board of directors. We have a pretty robust secession plan and development of our people.

You see the -- as I said this morning that this is the leadership team of today and tomorrow. So you can -- the plans are that I will retire sometime during the year 2012. The 2013, when we have numbers up there, is convenient for driving with respect to what is an expression of what the Company, or the business line, or what the capital spending, or the balance sheet will look like just to give you a manifestation or expression what to lays ahead. It has nothing to do with respect to my time in the Company.

But the plans are to sometime in 2012, I will retire and, you know, the Company is in really good shape. We really like our strategies and our plans, and we've got the people to do it. And so, you know, it makes a lot of sense to -- at that point in time.

Now, your -- I think you're second question was, you know, some big transaction or some kind of a strategic change in the Company as a final action before I retire. And you really directed it, I think, more towards to the downstream I think. Was that right?

Paul Sankey - Duetsche Bank - Analyst

No, I think you got the whole ConocoPhillips lock, stock and barrel. But I also had the idea that you might spin out the downstream and the way that Marathon has --

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, Paul, you have two, two unique things. One, you think big. And the second is you have a way of always asking more than one question or so.

So the first is from the whole idea of, as I just said, I think as Arjun, mergers, acquisitions, consolidations, we really think we've got a great plan. I don't think this is the business environment to do things like that. I don't think we'd be creating value for our shareholder. So the Company you see in the plans that we have, that is our approach and our direction now.



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Now, but you raised an interesting thing on the second question, which is the refining side of the business. As you see in our plans and approaches, one, we're pretty good at the business. So, as Willie outlined it, we're doing things that are further going to improve, less capital employed in it, less of our portfolio but improved our pretty strong position that we have in the refining side.

I think that historically we did the right thing. We got out of the marketing side pretty much, so it's really the refining side. And we're going to be [lessening] our volumes and whatever. We looked at selling. We looked at venturing. Willie said. Maybe someone has a facility next to ours. Can we do something with cost capital investment, improve efficiencies.

Now, what you're really suggesting is do we look at or should we consider doing something like Marathon. And you know, for us, I don't think so. But on the other hand, I watch what Marathon has done and the market response has been pretty good. On the other hand, you have to ask yourselves if things are done just in the short-term. How sustainable? How much real value creation? What are you doing to the nature of the Company, because it's really not just in the short-term, it's the medium and the long-term, are you really creating value for the shareholders.

So I applaud what Marathon has done. I think for them, they've decided it seems to make sense and work for them. Whether that's something that we should do, I don't think so. But we are certainly going to take a good look at it to see whether it does or doesn't make sense for us. Okay? Sorry, I can't see the name.

Doug Leggate - Bank of America Merrill Lynch - Analyst

Thanks, Jim. It's Doug Leggate, Merrill Lynch. A couple of quick ones. As we look at the production that you've laid out today, the disposals take you to I think you said 1.65 million barrels per day. And then you talked about 2-3 percent production growth, but there's a 0.50 million barrels of new projects coming online.

Either the decline is getting a little faster or that you're being very conservative on the targets. Can you elaborate a little bit on how you see the visibility and perhaps what you think our production could look like under the current plan? Another follow-up, please.

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay. Well, it's difficult for us to try to give some bands on production because it depends on what we sell. Jeff indicated that there are mature assets like maybe in the North Sea that we part with and the Americas. And then he indicated that there's potential smaller country interest that we have. So it's kind of hard for us.

Our commitment to selling an additional 5 to 10 certainly is there. On the other hand, making it happen, we don't know for sure because we're just not going to part with something just to part with it, we got to make sure we're getting value. So that's why we gave you this little bit of gray area in that respect in terms of this is what's going to happen.

In terms of our decline rates, I'll let Ryan talk about this because Ryan, what -- I think we're about 5% after we spend money to arrest our decline. But go ahead, Ryan. Why don't you --

Ryan Lance - ConocoPhillips - SVP - Exploration & Production International

Yes, just right. We are kind of unabated decline, we run at about 11%. When we exploit the assets, we cut that in half down to about 5% decline rate. And the projects that we're adding, you saw the profile going forward, it is 500,000 barrels a day. You add that to the decline. And the uncertainty around the 2% to 3% long-term growth rate is just trying to put all that together, trying to put that decline rate together.



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The level of exploitation investment, you saw Greg talk about our North American portfolio. We're not investing in some of those. The San Juan and some of those other properties are declining because we're not going to invest against those low gas prices. We're ready to ramp up that investment, that impacts some of our decline going forward, so we draw that together and it generates the kind of perspective that you saw today.

Jim Mulva - ConocoPhillips - Chairman, CEO

But as the portfolio going forward, if we have more oil sands, more LNG projects, that natural decline would probably be less. And then the other thing is we can make that number pretty much what we want because we have available prospects. We think – I think, longer term, natural gas is a real winner. Well, we're going to be able, we don't know. We're not premising a real significant improvement to natural gas prices. But once it starts moving about \$5 an MCF on a sustained basis, we said longer term, 5 to 7. Well, we've got a lot we can do to add production and that certainly is going to have an impact on that decline rate.

Doug Leggate - Bank of America Merrill Lynch - Analyst

Thanks. But my follow-up is really just a philosophical question on the share buybacks. Clearly a terrific strategy for the Company, but buying back stock at \$60 versus buying back stock 30% higher. How do you think about in terms of shareholder return on that investment if you like versus Arjun's earlier point about the 40% to 50% returns you can get in reinvesting in the business. Thanks.

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, yes, so we get to keep our eye always first on what returns can we get to redeploy whatever cash we have back into the business. That comes first, we'll do that. The other is right with it, we want increases in dividends every year. A share repurchase. We have the cash. I think we, as per Doug's question, I think we might be on the conservative side in terms of the amount of a share repurchase. But on the other hand, you just don't buy shares irrespective of the price. So, hopefully, as the share price continues to move up like we've experienced, we have to ask ourselves, you know, is it the best use of our cash.

Historically, over the last – a long period of time, anywhere from five to ten years past, our component return to our shareholders has been share price appreciation and dividend of about 13%. So we've got to always keep figuring in the short, medium and long-term how we're going to continue to do 13%.

And if our share price gets to a point where it's not supportive of that then at some point you ask yourself how do you give it back to the shareholders, maybe more dividends or obviously be looking at can we do more than spending. So there's not at any price that we just keep aggressively buying our shares. That's really the answer.

Jim Mulva - ConocoPhillips - Chairman, CEO

Mark?

Mark Gilman - The Benchmark Company - Analyst

Jim, thanks. Mark Gilman, The Benchmark Company. Two questions, I think there was mention earlier on in the presentation of 12 anticipated upstream project sanctions in 2011. I can get to six based upon things that were said, four in FCCL, APLNG, and the West Alpine satellite project, and I was hoping that the upstream team could give me some insight as to what the other six are.



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The second question relates to, in part, the divestiture activity. You still have a meaningful Canadian liquids conventional position. Does that pass the acid tests in terms of maturity, tax efficiency even though it kind of cuts against the grain a little bit from an oil versus gas perspective? Thanks.

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay. So I'm going to let Greg. You can address the second one, the second question of Mark.

I'm not surprised at your first question, Mark. You always will count to see whether it's 12 or it's 13 or it's 11. I'm pretty sure it is 12. And maybe I'll just ask Al and there's someone after or if could come back and just go through what the 12 are and to try to go through it. Right now I'm pretty sure you've counted properly, but we've got the 12 to respond. So, Greg, do you want to try to address Mark's question?

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

I was finding Ryan his 12 projects there. So he's ready to do it. So your question is about Western Canadian Gas and is that an opportunity, all the liquids in WCG? Yes, so there are some. We talked about the Cardium today. And so when we're thinking about our focus and where we're going to drill in WCG over the next couple of years, we're going to pursue the liquids piece of that. So we're not taking our spending to zero in Canada, Western Canada. We're spending about --

Mark Gilman - The Benchmark Company - Analyst

(inaudible question - microphone inaccessible)

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

Oh, a divestment? I missed that. I'm sorry. Will we divest it? I think that any asset we have, if someone's willing to pay us more value than what we see in the asset, we'd be happy to sell it. And I think that we'll just -- everything is for sale in the portfolio.

Mark Gilman - The Benchmark Company - Analyst

(inaudible question - microphone inaccessible)

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

Yes. So you go back to this criteria for any asset sale, it's got to bring value to us. It has to be tax-efficient for us. And if it doesn't pass those criteria, we won't do it.

Jim Mulva - ConocoPhillips - Chairman, CEO

I don't know on this specific question that Mark has. I don't know if Jeff or Al has any question. Because I know you're pretty familiar with the tax side of Canada.



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Jeff Sheets - ConocoPhillips - SVP - Finance, CFO

It's really a property by property thing, and you can't think of generalizations, how things are structured, can you do things as sale of a partnership interest or sale of a company interest as opposed to sale of an asset. So it's hard to say just categorically that something is tax-efficient or something is not tax-efficient. So it's really a case by case thing, and that's the kind of thing we looking at when it comes to time to do an asset sales to try to drive that tax efficiency we've been talking about.

Jim Mulva - ConocoPhillips - Chairman, CEO

That really was our experience at Syncrude. We had a unique asset, highly desired, and we had a way that we could very efficiently sell it. Other questions? I think there's one over here.

Blake Fernandez - Howard Weil

I believe this is a question maybe for Willie. Willie, you mentioned the opportunity to barge truck and rail crude presumably away from Cushing. Can you give us an idea of the cost per barrel range on that, which you believe a kind of a more normalized spread between WTI Brent would be? And, Jim, maybe if you have any comments on reversing Seaway? Thank you.

Jim Mulva - ConocoPhillips - Chairman, CEO

Willie, you can answer the second question as well.

Willie Chiang - ConocoPhillips - SVP - Refining, Marketing, Transportation and Commercial

Your question around moving barrels out, I don't have an exact number on the barging cost. I can tell you on the trucking cost, it's about \$10 a barrel. But the constraints that we've seen really haven't been dollars, it's actually been the barge or the train or the truck, to be able to move it. And I think if you look at the spread that's between WTI, and I'll just say Brent today, at \$15, and you would think if there were available equipment, everything would move. But I think just that fact that we haven't been able to move all the barrel shows that there's a limit of logistics constraints and equipment. The question on Seaway, you know, I've gotten that, you really want me to answer that one, Jim?

Okay. Seaway, the issue there is we have a mid-continent refining center in Ponca City, and we also want crudes that allow us to make what we call "premium coke" at Ponca. So if there's a need for us to bring crudes into the mid-continent, the other piece on it, everyone talks about reversing Seaway as being a very quick solution. And I would tell you that it's not, you can't do it overnight. The timeframe could be six months, it could be a year. The dollars are not free either, it costs money to be able to reverse it.

And so we're looking at that with our partner. But conceptually, you've got to look at other ways -- you know, that you got TransCanada's pipeline that's going to come through Cushing and you have to ask yourself when will that come to fruition from Cushing to the Gulf Coast. I think TransCanada just came out and said that there may be some delays with regulatory approval and they're pushing this back to, at the earliest, probably 2013. So that pushes it back.

But you've also got additional capacity of tankage that's being built in Cushing to the tune of 20 million barrels plus. So you have to factor all those things in. And what we wouldn't want to do is to spend money to reverse seaway, impact the refining capacity and then not have it generate cash back for us for the joint venture seaway or hurt our refining production capabilities.



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Jim Mulva - ConocoPhillips - Chairman, CEO

You know, that brings up TransCanada, the pipeline, coming down where its infrastructure that's well-known, that is really required. It's a good example. You know, we talked frequently over the years, that our country does not have an energy policy. I'd go a little further, the policy is no. They just say no to everything. Because this TransCanada pipeline needs to be built and it's just a good example of its expression of no energy -- and that we don't have an energy -- that it's policy is no to everything.

Our industry feels where you have the technology and the capabilities to get going on exploring in the Gulf of Mexico, with Chuckchi Sea infrastructure, there are so many things. But to get through and getting the permits and essentially when you say we don't have energy policy, all we really have is a policy of saying no, no, and that's really not good for jobs, investment or energy security. So, you know, as a country we've got to turn this thing around. Paul?

Paul Cheng - Barclays Capital - Analyst

Thank you, Jim. Paul Cheng, Barclays Capital. Jim, since we're talking about logistics, you've been selling so much in the logistics side but you still quite a lot pipeline and terminal and all that. And while you said your stock has already gone up a lot over the last 12 months. But comparing to what some of the MLP can trade, that it's still very low. So, I mean, you just continue to sell some of the assets. Does it make sense that you look at whether making an MLP out of your logistics systems will perhaps create even better value for the shareholders.

And also that talking about logistics, do you -- adding production from Bakken from Eagle Point and knowing that is just going to just increase quite rapidly. So are you just relying on the industry that to build out the infrastructure, to allow those oil out or that you actively and what step you're taking to ensure that you get the best max (inaudible) in comparison to your competitors in those areas? Thank you.

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, I'll just talk around these two questions and then I'll ask Jeff to respond to MLP and then others who ever want to on the evacuation.

Generally, we tend -- I think it's unique by area or whatever the opportunity is, to let others build that, the evacuation capacity. If it's not, then it's really impacting just us, why we obviously would get into spending the money to doing that.

So others on the E&P side can comment on that. But, Jeff, you want to say something on MLP because we have studied MLPs for 20 years and they seem to sometimes and then sometimes not. Yet, on the other hand, we really haven't done much in this regard.

Jeff Sheets - ConocoPhillips - SVP - Finance, CFO

Yes. And then we've studied MLPs backwards and forwards the last, you know, like Jim said, 20 years. I mean, we do participate in the MLP market through DCP and midstream and that midstream company has an MLP. So we're very familiar with how the market works.

When we look at it, we think of it, what's the potential source of capital. It's somewhere between debt capital and equity capital. It's not just like issuing equity. We don't think of that. When we think about all of our sources and capitals being a particularly efficient source of capital for a company of our size, I think it makes a lot of sense for smaller companies who may have some constraints on their access to capital. And we don't really see that. And also, when we look at the types of logistics assets that remain in our portfolio, you know, all of our midstream businesses is done in DCP, so there's no midstream asset of any size to put in there.



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We have a few downstream assets, but a lot of our downstream assets which might be an MLP or things that are kind of 100% used by our proprietary systems and there are things that we have a real strategic interest in keeping longer term. So as we look at it, there's not -- we don't think there's really critical mass in our company to create a really strong MLP. So it's not likely to be something that we do going forward.

Jim Mulva - ConocoPhillips - Chairman, CEO

In terms of Bakken evacuation, you want to say something, Greg?

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

So I think we have to look at each of these areas on a case by case basis. For instance, Eagle Ford. We're going to lay some backbone infrastructure in Eagle Ford that will allow us to connect to multiple parties. One of our preferred connects will be DCC obviously, our midstream company.

In Bakken, we're taking the approach we're going to connect to multiple people but we're not going to make investment and take away capacity. We don't think it's required in this case. And so we're working with multiple parties to ensure that we can take the capacity weight.

The same thing with the oil sands. You know, take away issues from the oil sands. We're working with our partner Cenovus in developing a holistic transportation strategy. So we make sure that we can get those barrels evacuated out of that area.

Jim Mulva - ConocoPhillips - Chairman, CEO

Kurt

Kurt Wulff - McDep LLC

Thank you, Jim. On transportation capacity and political factors, you've had this Alaskan gas for a long time and dealing with the Alaskan government has been difficult. In the past few weeks the energy picture has changed a little bit with the tragic accident in Japan. And you could make a much stronger case today that we would have thought a few years ago for LNG on the Alaskan coast and sending it to Japan. So that the case for the Alaskan pipeline might be a lot better today than it was a year ago. Can you give us any comment on how do you think the government of Alaska is going to be more helpful in developing that kind of a project?

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, it's a -- I'll ask Al to comment here in a moment, his thoughts on this. But it's an indigenous resource. We know that it's been there. It's probably going to be a high cost to the market. We'd like to get it developed, we know Alaska would, but it's going to take some fiscal certainty, maybe some incentives to make this happen. We have and along with other producers up the North Slope, who have looked at certainly a pipeline down the lower 48 or connect a manifold into the lower 48 to the Canadian system.

I think that gas long-term is a real winner but still Alaska is going to be pretty high cost. We have looked at, as the other producers, we looked ourselves at LNG export. So whether that changes and leads to the development of our Salt gas, who knows? Al, you want to make a comment? Oh, I was trying to get you to talk while I'm trying --



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Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, let's go to the next question. I know, Mark, you got your head raised, but I want to get around to everyone else.

Faisal Khan - Citigroup - Analyst

As I'm looking through slide 39, it looks like liquids production is relatively flat from 2010 to 2015 and I just suspect that's because you've got a ramp-up in unconventional liquids and the decline in some of your legacy portfolio. But can you give us an idea of how the margin per barrel trends over that timeframe? Are these going to be more profitable barrels on the liquid side in 2015 or roughly the same, all else being equal?

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, I don't have the slide in front of me. But I think what you heard from us is we're really driving through not only -- or to improve the returns, meaning the income and the cash per barrel. And I'd like to -- maybe, Jeff, you can comment, or AI, that we are growing in those margins if we self-help, not just through the commodity-price expectation. So, either AI or Jeff, do you want to comment?

AI Hirshberg - ConocoPhillips - SVP - Planning and Strategy

If you go through all the other pages that are in here and all the data on cash margins the E&P guy showed you, you can piece together pretty well the answer to your question of how we expect to see -- that it's really two parts.

First, is that the volumes and the areas that we're growing, we showed you the 2010 cash margin. So without any improvement, what we've made last year from those areas and what you'll notice is all the areas where we're growing volumes, the cash margins last year were higher than the corporate average. And the areas where volumes are shrinking like US gas, for example, over the next few years, is where we have cash margins at 2010 that were lower than the corporate average. So you can do the math from there.

But in addition, we talked about all of things that we're doing so that forward margins from self-help initiatives will be better than the 2010 margins. Greg mentioned, for example, the dramatic reductions we had in drilling cost in several of the unconventional areas, those sorts of things.

So in addition to any increase in realizations that you might assume, it will obviously also improve cash margins. We've got a lot going on in the self-help arena too. So those two factors together should significantly improve our returns going forward.

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, next?

Iain Reid - Jefferies International

I've got a couple of questions about Australia. Is it possible to say on the Sinopec divestment what you realized from that and how we should think about that relative to your entry cost into APL&G?



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And secondly, on Poseidon, you saw that's commercial now. Can you give us some idea of what the resource is now, Matt, and how the Browse getting going as a project. Do you intend to try and utilize that with Browse or do you have another development scheme in mind?

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, Ryan, you want to address those questions?

Ryan Lance - ConocoPhillips - SVP - Exploration & Production International

Yes. So the first question on APL&G, we have signed the contract with Sinopec and sold a 15% equity and sell that first trade and gas. Unfortunately, we can't talk specifically about how much we sold the equity for nor the gas prices. The terms and conditions of that contract still remain confidential until we take FID later this year. So it will be some time before we can potentially talk a little bit more about it, we can't today.

On the barrels, when Larry mentioned commerciality, what he meant was that an important part of the Plover and in that part of the world is making sure that Plover can produce at commercial quantities. So we had to -- as our road test of the opportunity and the discovery there, what we learned was pretty important is that we can get commercial flow rates out of the wells.

We haven't declared commerciality in terms of meeting our minimum size. We have more exploration and appraisal to do in the area before we've met up by resource size that we think is sufficient to launch the project. So we still have some more appraisal to do on the field. So the commerciality was, with respect to the Plover, can floor commercial rates of gas.

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, next question?

Kate Lucas - JP Morgan

In looking at your long-term production growth rate of 2% to 3%, can you talk a little bit about how much of that is contingent on the resumption of activity in North America natural gas and then how much of it would be contingent on exploration success in new areas? And then to the latter, how soon would you need to see some success in your exploration program in order to be sure that you've kind of backfilled the projects late? Thanks.

Jim Mulva - ConocoPhillips - Chairman, CEO

Well, I think -- and others should get ready to comment -- but in terms of our growth rates in our production levels over the next five years, we're really not assuming anything from exploration success. That we don't already have and factored in. The others want to speak and address to the questions?

Greg Garland - ConocoPhillips - SVP - Exploration & Production Americas

2013, really, gas is going to be declining in our portfolio. As we start moving out to 2015, you can see AI talk about it, we see price expectations kind of in the \$5, \$6, \$7 range. As it starts going above \$5, then we'll start reengaging. And so you'll see gas start being a more important component in terms of the forward look. But clearly, you know, the oil sands and the shale plays for the first two or three years are going to be the big part of driving the liquids area.



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Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, two more questions. Way in the back.

Elias Palacios - Maxim Group

Thank you. This is Elias Palacios with Maxim Group. A question about LNG, what is your -- can you come under interest to expanding your footprint there in various regions whether it's in liquefaction or regasification or even participation in the spots market?

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay. Our participation, we like LNG projects and I think that was one of your questions, if we've got the right resource, a good resource, we feel that we've got the technology and the transportation capability, we can get to the market. I don't know if, Ryan, you want to say anything to that?

Ryan Lance - ConocoPhillips - SVP - Exploration & Production International

No, I think Jim is right. We enjoyed the cascade technology that we use. It's pretty efficient. It's low-cost. It's very fit for purpose for multiple different applications. That these are large projects, they do require contracts to underpin the risk associated with developing these projects. So we still like the contract, but I think Willie can comment. I think we have aspirations too to increase our exposure to the spot sales and the marketing of LNG as well. So as we grow their equity position, our supply position, that's going to lead to new opportunities for us on the commercial side as well.

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, Willie. Is that -- okay, one last question anyone? Okay, Mark, you get it.

Mark Gilman - The Benchmark Company - Analyst

Thanks, Jim. Since the DCP and CPChem joint ventures were created, the industry environment, to say the least, has changed rather dramatically from the chemical side at least for the time being anyway, creating considerable advantage as opposed to disadvantage for gas-based feed stocks.

In terms of the DCP side, as I think your colleagues alluded to with the changes in the distribution framework, if you will, within North America, there's a significant opportunity set that is now in place that was probably not in place at the time the joint ventures were created. I'm wondering how well those structures -- and I'm not just speaking about MLP -- those structures serve would you believe to be the Company's best long-term interest as we go forward?

Jim Mulva - ConocoPhillips - Chairman, CEO

Okay, let's talk about the chemical joint venture that we have with Chevron. It's -- you know, several years ago, we felt that we are very disadvantaged with a lot of our capacity in North America. There was natural gas, ethane and propane drive for the chemical business that's why we went to the Mid East. We had access to whole cross-feed stock, did not access the new low cost feedstock. Really plentiful availability in the Middle East in terms have changed at lot on the loan availability, but we got into the ground floor in chemical business in the Middle East and we've really got a great position.



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But what has turned around is, you know, the chemical business, and you might argue, to some extent the oil cross-feed stock sources in North America, so it has changed pretty dramatically. So from a chemical point of view, ourselves and Chevron, we're very supportive of our chemical company to really grow and develop it. The other aspect, if you could step back and say and look at this business and say, well, if you're a producer, you can also participate as a user of gas. So you kind of had your balance naturally to businesses, you are in, by being a producer versus you as a consumer of natural gas.

So we really like the chemical business. It doesn't represent a big part of our portfolio, but it's an incredible contributor of cash. Cash doesn't go to it, it just comes one way. And I know Chevron feels the same way. The midstream business, we're good at it. They're aggressive, they've got a great team. To try to do with anything with our midstream joint venture would be very tax inefficient. And to some extent, the chemicals, the same way, but the midstream joint venture, very tax efficient.

So what you see, our participation, we really like our joint ventures in midstream and chemicals. And we are encouraged and supporting them through our board participation to aggressively grow. So that completes our story and the messages today. And I very much appreciate everyone who has participated with us this morning here in New York as well as all those on the webcast. Our team is still here, so any questions that you may have, come up and talk with members of our team. And those who are participating by webcast can always come in by email and submit your questions or whatever. So thank you very much for being with us here this morning.

Editor

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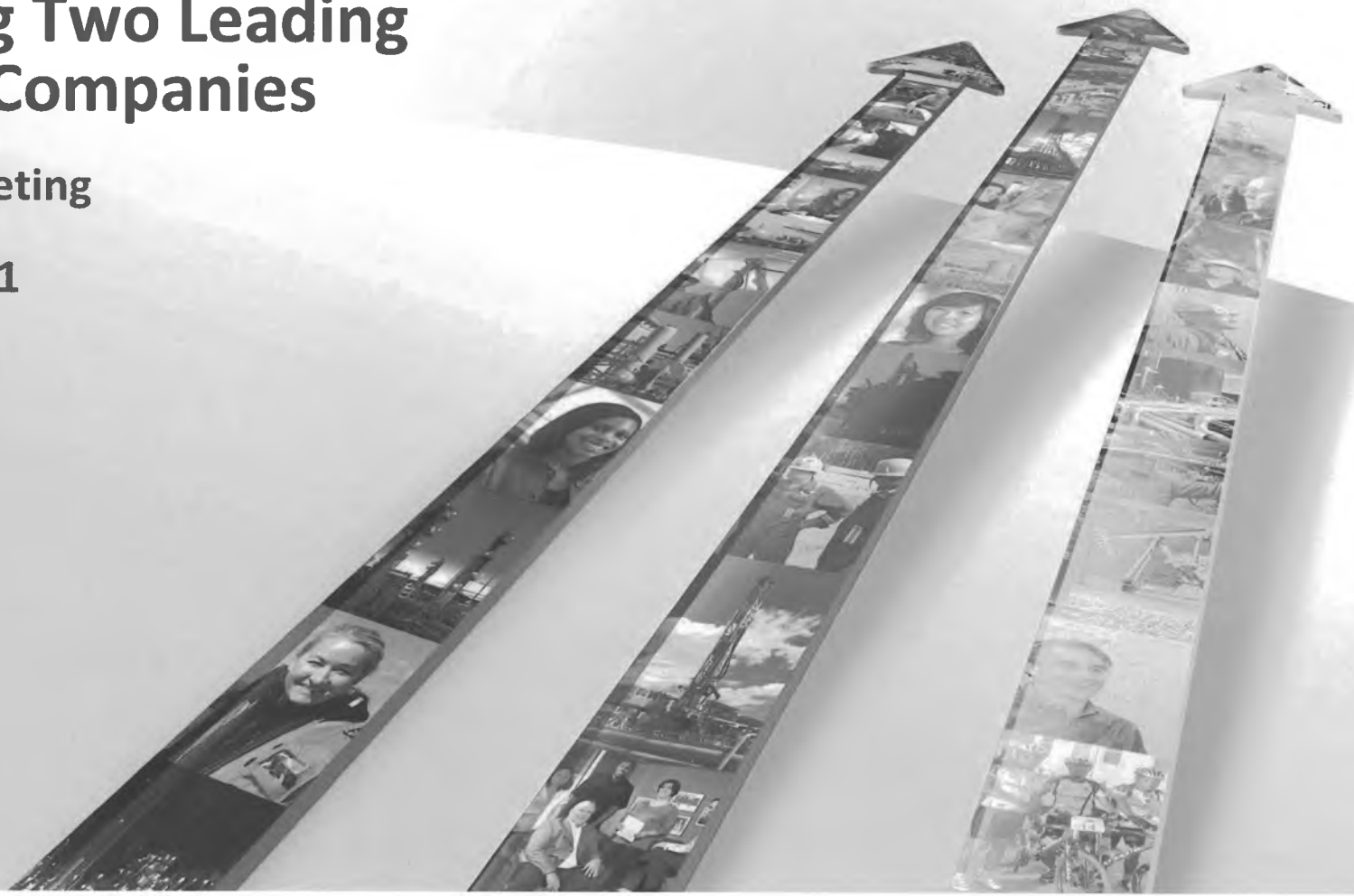




Creating Two Leading Energy Companies

Analyst Meeting

July 14, 2011



Cautionary Statement



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■ Key Premises

- Integration creates value
- Scale and scope needed to compete
- Growth in hydrocarbon demand
- Resource capture will be more difficult and expensive

■ Execution

- Positioned each business line to compete effectively
 - E&P, R&M, Midstream and Chemicals
- Quality assets – but portfolio optimization needed
- M&A integration and cost synergies captured

Led to significant value creation

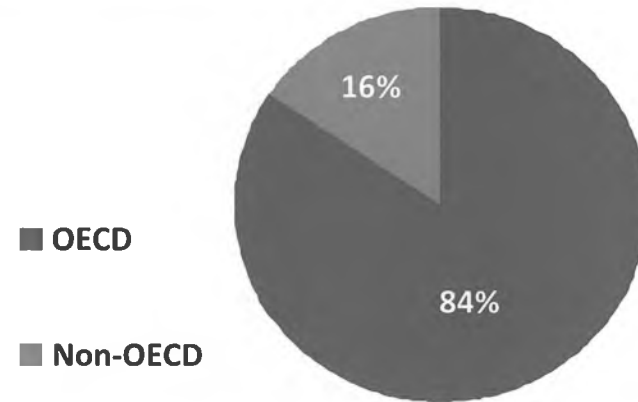
ROCE improvement

Margin enhancement

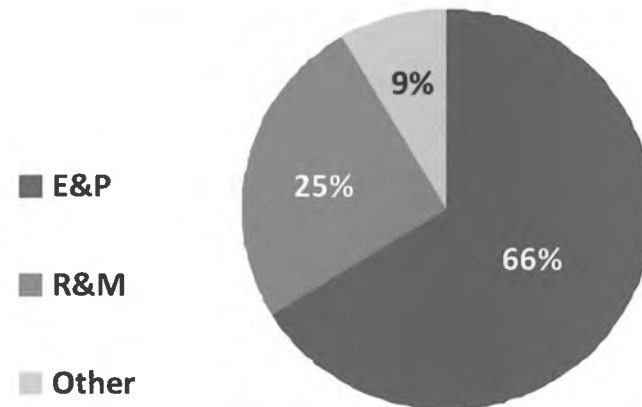
Per share growth

Shareholder distributions

Cash from Operations



\$92 B Capital Employed



Increasing shareholder value

2010 cash from operations and average capital employed. Corporate capital employed distributed across segments.

Current Strategic Objectives



- **Improve ROCE**
 - Expand margins per BOE
 - Maintain capital discipline
 - Portfolio optimization

- **Grow per share**
 - Reserves and production
 - Earnings and cash flow

- **Increase distributions**
 - Annual dividend increases
 - Share repurchases

Creating shareholder value

Key 2011 / 2012 Initiatives

- Disciplined \$28 B capital program
- Additional \$5-10 B in asset sales
- \$10+ B in share repurchases
- 100%+ reserve replacement
- Reduce refining capacity



Improve ROCE

- **Integrated Strategy has been effective**
 - Increased reserves and production
 - Generated competitive shareholder returns
- **Environment has changed**
 - Downstream capability not key to resource access
 - Resource Nationalism and NOC competition
 - Movement to “service” agreements
- **Value of IOC assets not reflected in equity value**
 - Transparency and potential of businesses not as clear as pure plays
 - Increasingly difficult to create differential value to larger Integrations
 - Emphasis on additional volumes not always value creating

Continually testing and assessing execution of strategy

- Pursuing tax free spin of Downstream business
- New independent pure-play publicly-held Downstream company
- ConocoPhillips becomes leading pure-play E&P company
- Expect transaction completion in first half 2012

Creates two strong independent companies

- **Create two profitable and independent companies**
 - E&P Strategy unchanged
 - Downstream given opportunity to add value through portfolio optimization
- **Greatest opportunity to create differential value**
 - Independent but consistent strategies
 - Both companies continue to benefit from size and scale
 - Both companies to have strong financial flexibility
 - Transparency of pure play over integrated business model
 - Management focus
 - Ability to attract and retain talent

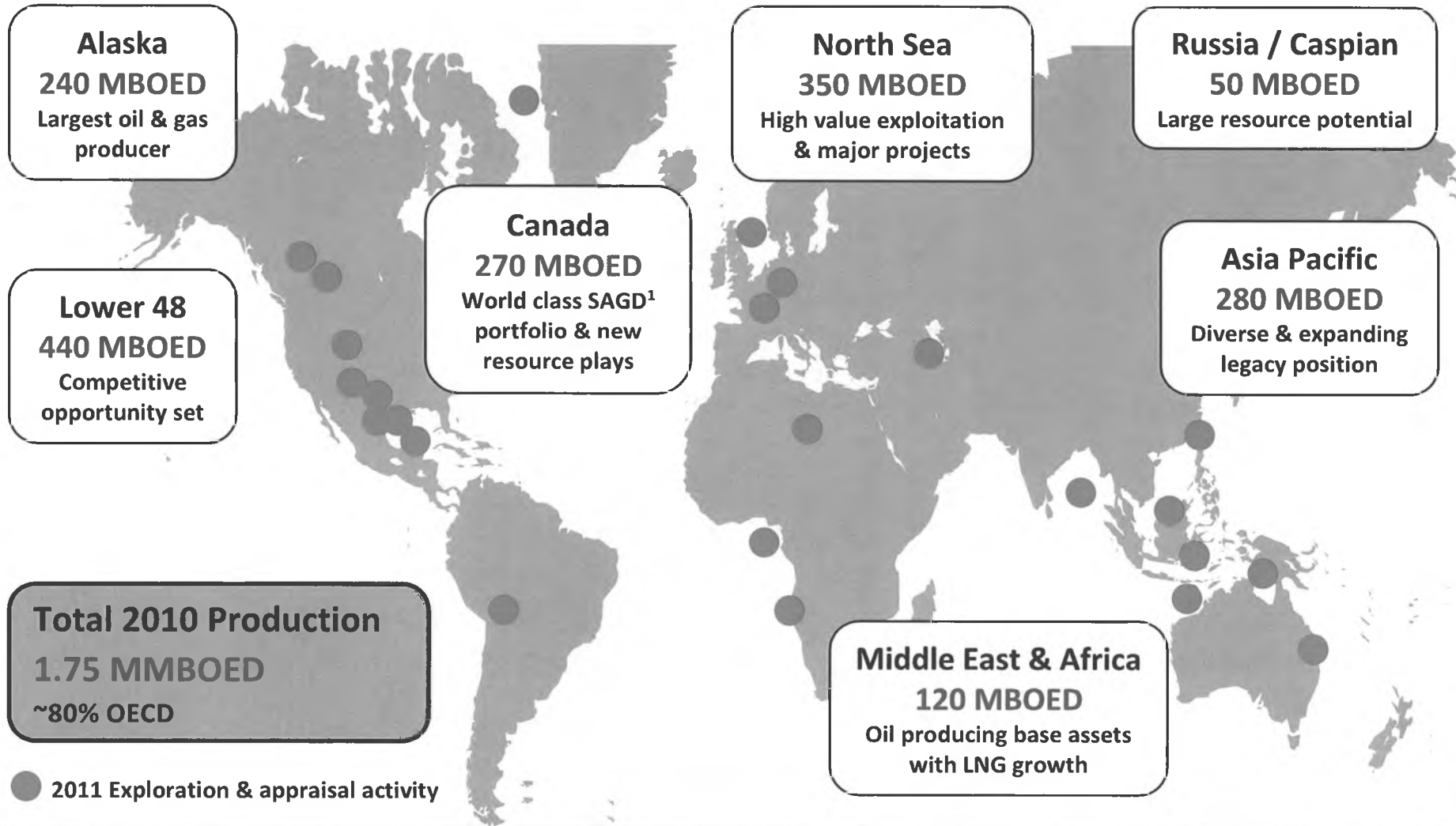
New ConocoPhillips Description

- **Largest U.S. pure-play E&P company**
 - 1.7 MM BOED 2011 production
 - 8.5 B BOE reserves / 43 B BOE captured resource
 - Strong OECD position
- **Financial and technical capability on par with larger integrated majors**
- **No change in upstream strategy**
 - Improve ROCE
 - Per share growth in production and reserves
 - Complete portfolio strengthening
 - Capital discipline
 - Competitive F&D
 - Improve margins per BOE



Asset disposition and share repurchase plans unchanged

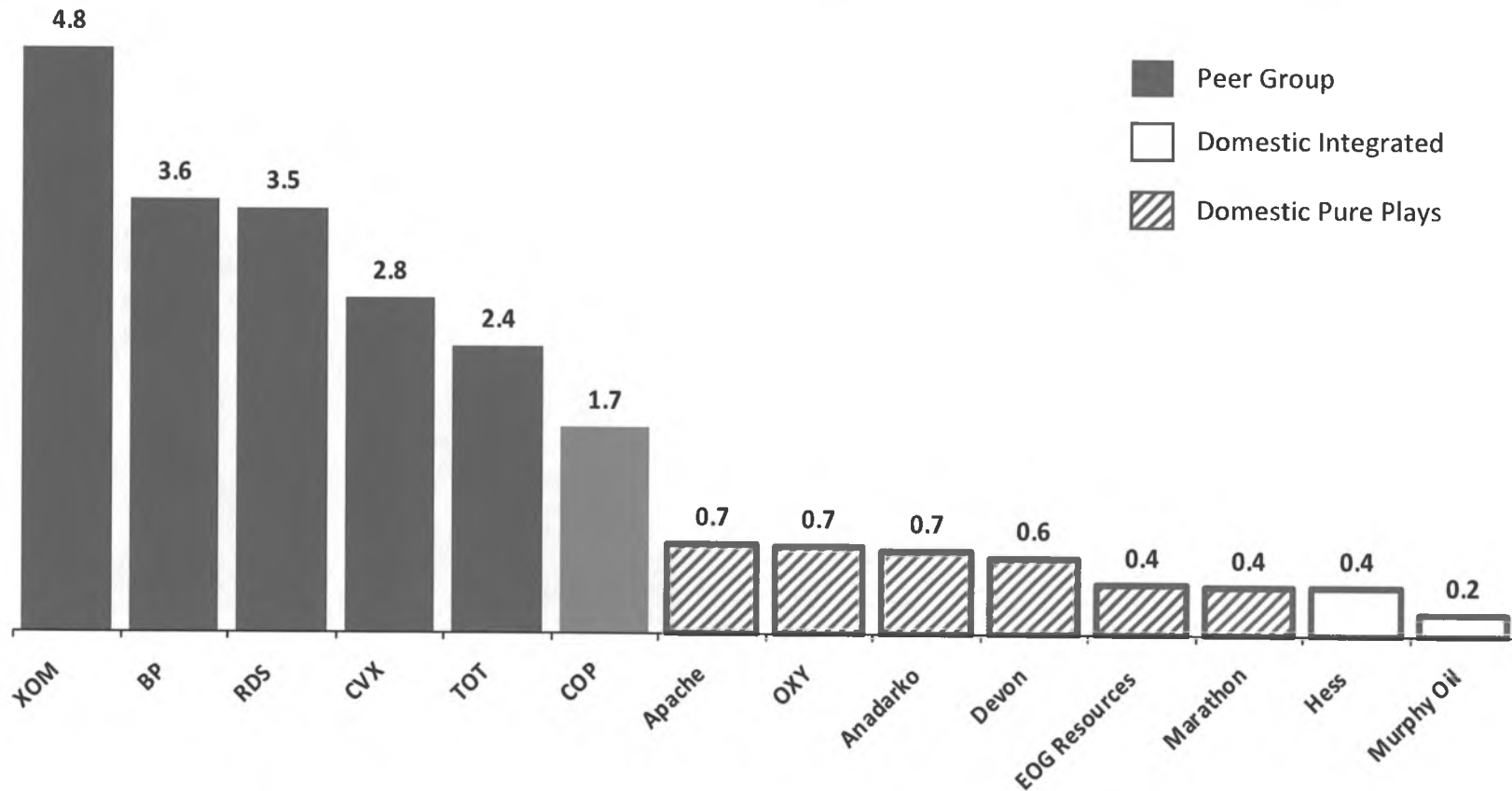
E&P Overview



International growth opportunities underpinned by OECD position

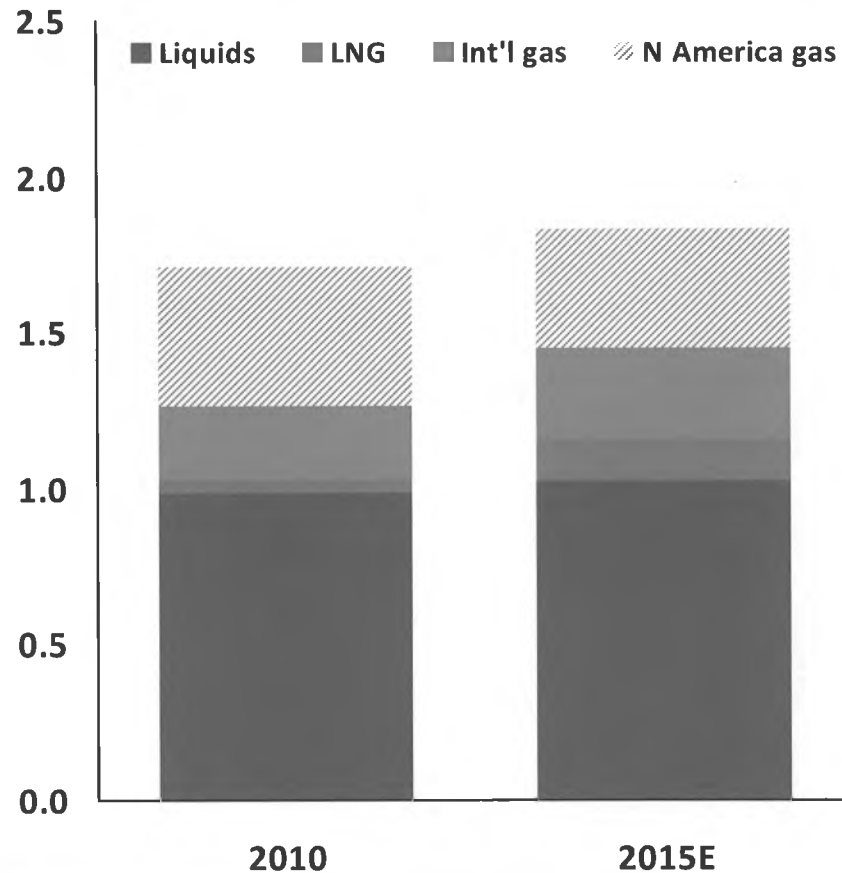
¹ Steam Assisted Gravity Drainage

Q1 2011 Worldwide Production - MMBBD



Source: Company reports

Production by Product - MMBOED



Sources of Growth

- **Asia Pacific**
 - APLNG, Malaysia, Indonesia
- **North Sea**
 - Jasmine, Clair, Ekofisk, Eldfisk
- **Caspian**
 - Kashagan
- **L48 liquids**
 - Eagle Ford, Bakken, Barnett, Permian
- **Canada SAGD**
 - FCCL, Surmont

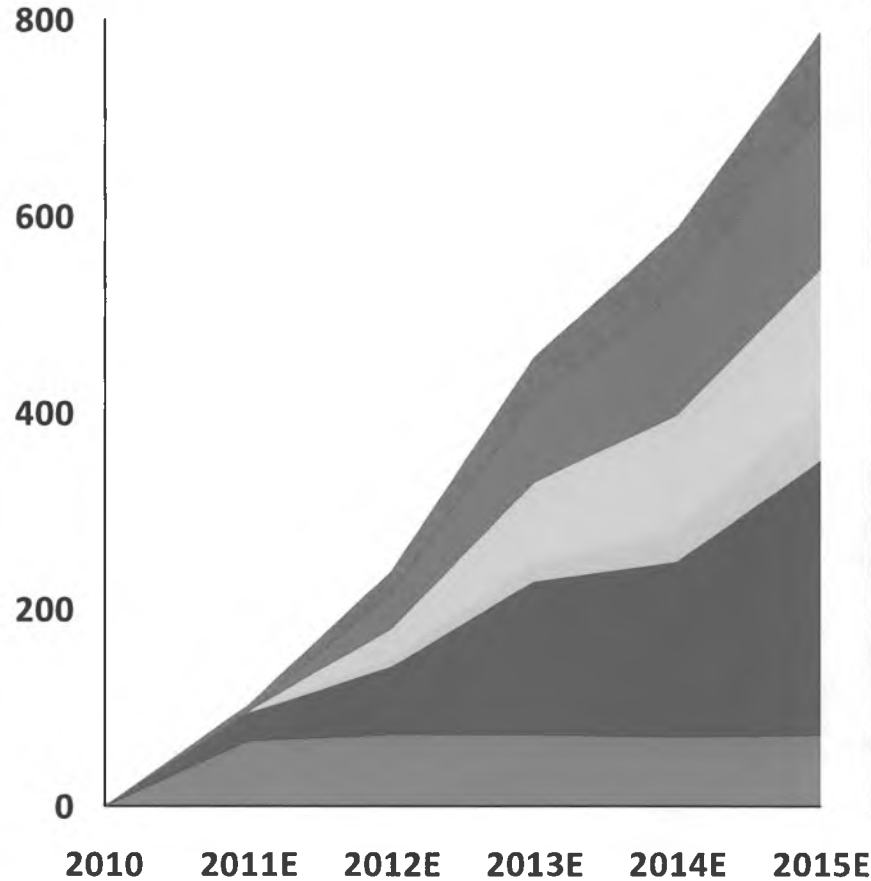
Strong portfolio of investments leads to production growth

Excludes impact of future dispositions.

2011-2015 New Production



MBOED

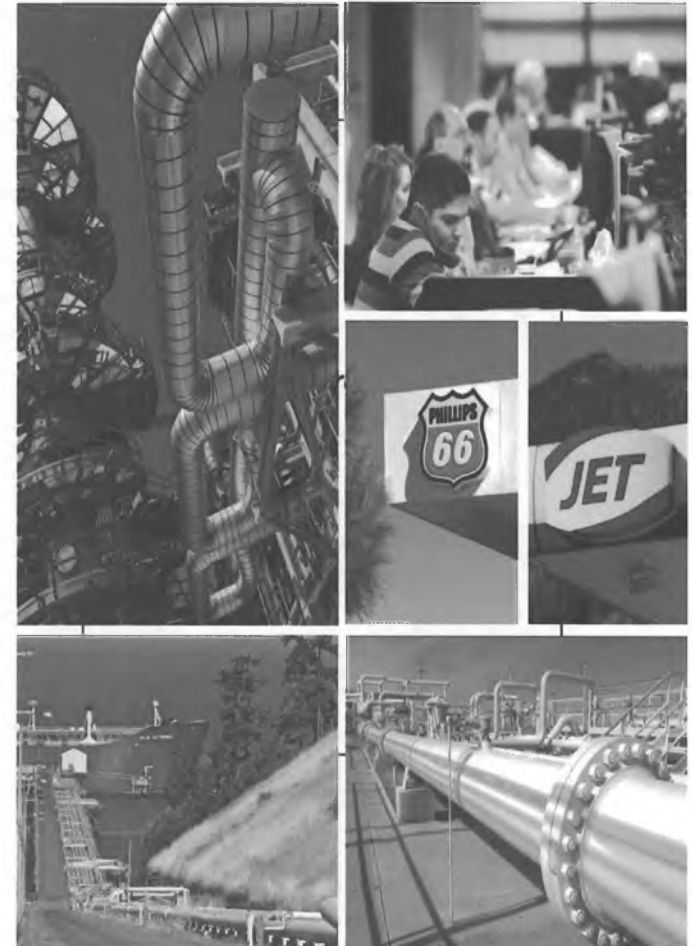


Asset / Region	2010 Cash Margins
Rest of World	Various
Other L48 & W Canada	\$14 - \$40 / BOE
North Sea	\$29 / BOE
SAGD	\$30 / BOE
L48 liquids growth	\$31 / BOE
Asia Pacific	\$35 / BOE
Qatargas 3	Attractive

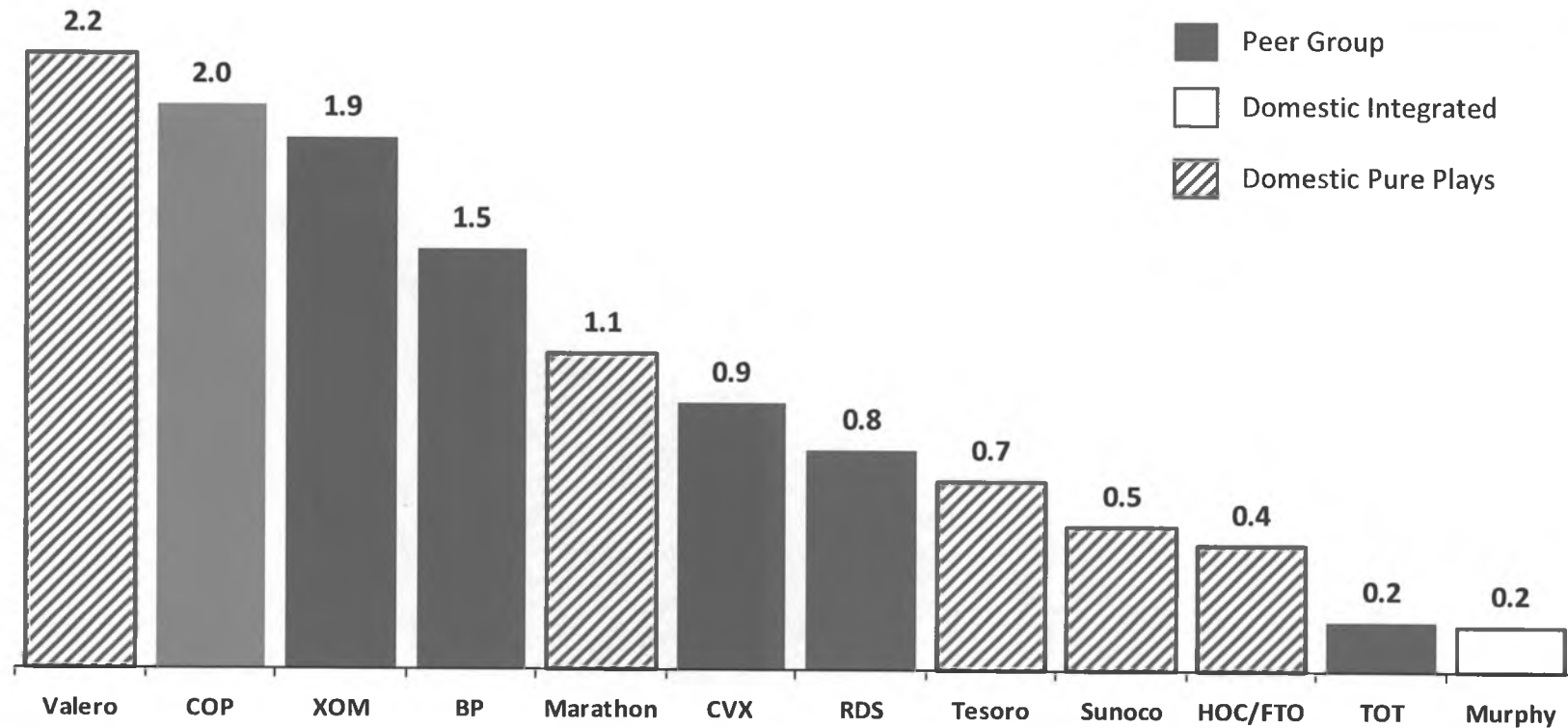
Improving margins through major projects and exploitation

New Downstream Company

- **Global Refining & Marketing leader**
 - 2.4 MM BPD worldwide refining capacity
 - Low cost, integrated Marketing and Transportation
 - 2 MM BPD domestic capacity
 - Significant position in mid-continent
 - Exposure to all PADDs
- **Strong investment grade credit with significant financial flexibility**
- **Strategy focused on value creation**
 - Improve ROCE to mid-teens
 - Sell or joint venture less competitive assets
 - Disciplined reinvestment of free cash flow
 - Competitive shareholder distributions
 - Earnings and cash flow growth potential
 - Operating excellence



Q1 2011 U.S. Refining Capacity - MMBD



Leading domestic refining company with portfolio of top quartile assets

Source: Company reports

Downstream ROCE Improvement

- **Selective asset sales**
- **Finalization of Wood River CORE project**
- **Capital discipline**
 - **Implementing selective high return projects**
- **Optimization initiatives**
 - **Increase utilization and clean product yield**
 - **Lower cost structure**
 - **Capture feedstock advantage**

Generate mid-teens returns and free cash flow

Key Milestones

- Detailed separation planning followed by IRS tax ruling request
- Announcement of new board and leadership teams
- Favorable IRS ruling
- Final COP Board approval
- Expected closing first half of 2012

Continued asset sales

Strong OECD-based cash flow

Enhanced queue of growth projects

Disciplined capital investment

Strengthened portfolio

- 100%+ reserves replacement
- Production per share growth
- Improved returns
- EPS/CFPS growth
- Increased distributions

Restructuring consistent with commitment to shareholder returns