

**HB 110
BACKUP
MATERIALS
MARCH 23 -
29, 2011**

<TARGET><BILL>HB 110</BILL><SUBJECT>HB 110 BACKUP
MATERIALS MARCH 23 - 29,
2011</SUBJECT><COMM>HFIN27</COMM></TARGET>

Alaska State Legislature
HOUSE FINANCE COMMITTEE

Agenda
1:30 PM

Wednesday, March 23, 2011

HB 110-PRODUCTION TAX ON OIL AND GAS
Industry Testimony

3/23/11

State of Alaska
Department of Revenue

Commissioner Bryan Butcher



SEAN PARNELL, GOVERNOR

333 Willoughby Avenue, 11th Floor

P.O. Box 110400

Juneau, Alaska 99800-0400

Phone: (907) 465-2300

Fax: (907) 465-2389

The Honorable Bill Thomas, Jr
State Capitol Room 505
Juneau AK, 99801

March 21, 2011

The Honorable Bill Stoltze
State Capitol Room 515
Juneau AK, 99801

SUBJECT: Response to Questions from House Finance Meetings on March 16, 17, and 18, 2011

Dear Representatives Thomas and Stoltze:

The purpose of this document is in response to the follow-up questions from the House Finance Committee meetings on March 16, 17, and 18, 2011. The requests/questions and responses follow.

(1) What would the price of oil need to be to balance the budget in FY 2030, assuming our forecasted level of production and the expected budget growth rate?

The Department forecasts revenue through FY 2020, so producing this analysis for FY 2030 requires us to make many simplifying assumptions.

- We use the FY 2030 production forecast of approximately 334,000 barrels per day.
- We hold lease expenditures and non-petroleum revenue constant at FY 2020 levels.
- We apply a 6% annual growth rate in expenditures to the FY 2012 baseline budget estimate of \$5,466.2 million, resulting in an FY 2030 budget of \$15,602 million.

Using this set of assumptions, an ANS price of approximately \$245 per barrel would be needed to balance the budget in FY 2030. Note that this is a rough estimate and does not represent an official forecast for revenue, or spending.

(2) Has Point Thomson historically been included in the under evaluation category or did we change the classification due to litigation?

The production forecast by the Department of Revenue uses three levels of classification: currently producing, under development and under evaluation. Projects are not classified as “under development” until they are funded or awaiting project sanctioning in the very near future. Projects classified as “under development are described in the Fall 2010 Revenue Sources Book on page 40:

It includes projects that may be in the design/construction phase, as well as development drilling and enhanced oil recovery (miscible or immiscible injection), projects currently funded or underway, but not included in the “currently producing” category. It also includes incremental oil expected from the long-term gas cap water injection project at Prudhoe Bay and Endicott, which is planned for 2012. Examples of production currently under development include: the Fiord, Nanuq, and Alpine West satellites at Alpine; the Borealis and Orion satellites at Prudhoe Bay; development drilling at Tarn, Liberty, Oooguruk and Nikaitchuq.”

Using the standards listed above, production from Pt. Thomson was classified in the “under evaluation” prior to the initiation of litigation surrounding the leases at Pt. Thomson, and remains in the same category in the Fall 2010 Revenue Sources Book.

(3) Provide a chart showing our production forecast, compared to what it would be if the Department’s historic error rate over the past 20 years was applied to the production forecast.

The DOR does not forecast production using a historical error rate. Twice per year, the department performs variance analyses to determine the reasons for the change in forecast versus actual. Multiple variables like project timing, unforeseen events, forecasting methodology, etc, produce annual variances. The forecast is a collaborative effort between the DOR, DNR, the producers, and the department’s contracted petroleum engineers and are built on the best available information and set of circumstances known at the time. Narrative and analysis on the historical optimistic production forecasts and the variances may be found in the March 15, 2011 responses the House Finance Committee to questions raised on February 18, 2011.

(4) Provide a breakout of credits by type and by year, in the maximum detail possible.

Slides 7 and 10 of our March 17, 2011 presentation provide the amounts of each credit type, by year. The analysis is shown both for credits applied against tax liability, and for credit applications received from companies without a tax liability. The tables are included below and we have updated the information on credits applied for by companies without tax liability to reflect applications through March 17, 2011. While it may be possible to provide limited additional detail in regards to type of expenditures or area used, this would require a significant manual effort by the department because this information is not captured in any database.

| Production Tax Credits Applied Against Tax Liability (Fiscal Year) (\$ Millions) | | | | | | | |
|---|------------|------------|------------|------------|------------|------------|--------------|
| | 2006 | 2007 | 2008 | 2009 | 2010* | 2011* | Total |
| Capital Expenditure Credit | 65 | 227 | 219 | 280 | 349 | 391 | 1,535 |
| TIE Credits | 33 | 138 | 73 | 0 | 0 | 0 | 243 |
| Small Producer Credits | 9 | 37 | 30 | 26 | 28 | 40 | 169 |
| Exploration Credits | 1 | 47 | 55 | 28 | 34 | 20 | 185 |
| Totals | 107 | 449 | 375 | 333 | 417 | 450 | 2,131 |

* Estimated

| Production Tax Credits Under AS 43.55 Claimed by FY (\$M) | | | | | | | |
|---|--------------------|---------------------|---------------------|---------------------|---------------------|---------------------|----------------------|
| Credit Type | Pre-2007 | 2007 | 2008 | 2009 | 2010 | 2011* | Total |
| Capital Expenditure - .023(a) | | 68.2 | 91.7 | 109.6 | 168.0 | 158.2 | 595.6 |
| Net Operating Loss .023(b) | | 38.1 | 148.5 | 153.5 | 138.7 | 180.6 | 659.4 |
| Well Lease Expenditure - .023(l) | | | | | | 6.7 | 6.7 |
| Exploration -.025 | <u>48.3</u> | <u>44.9</u> | <u>85.5</u> | <u>56.6</u> | <u>99.5</u> | <u>2.4</u> | <u>337.2</u> |
| Total | <u>48.3</u> | <u>151.3</u> | <u>325.6</u> | <u>319.7</u> | <u>406.2</u> | <u>347.9</u> | <u>1598.9</u> |

* Applications received through March 17, 2011.

(5) Provide a model of a “typical” oil field, and show which credits would be received and in what amounts during exploration, development, and production.

The following table shows the tax credits relating to a hypothetical field. This is a simplified example, and is intended to be an illustration of how the tax credit system would work. The example is based on an assumption of \$80 / barrel oil and \$7 / barrel transportation costs.

The primary credits applicable to this example are:

- Exploration credit of up to 40% of eligible exploration expenditures.
- Capital credit of 20% of eligible expenditures for both development and ongoing capital.
- Net operating loss (NOL) credit of 25% of an annual loss.
- Small producer credit of \$12 million per year, limited to tax liability after other credits.

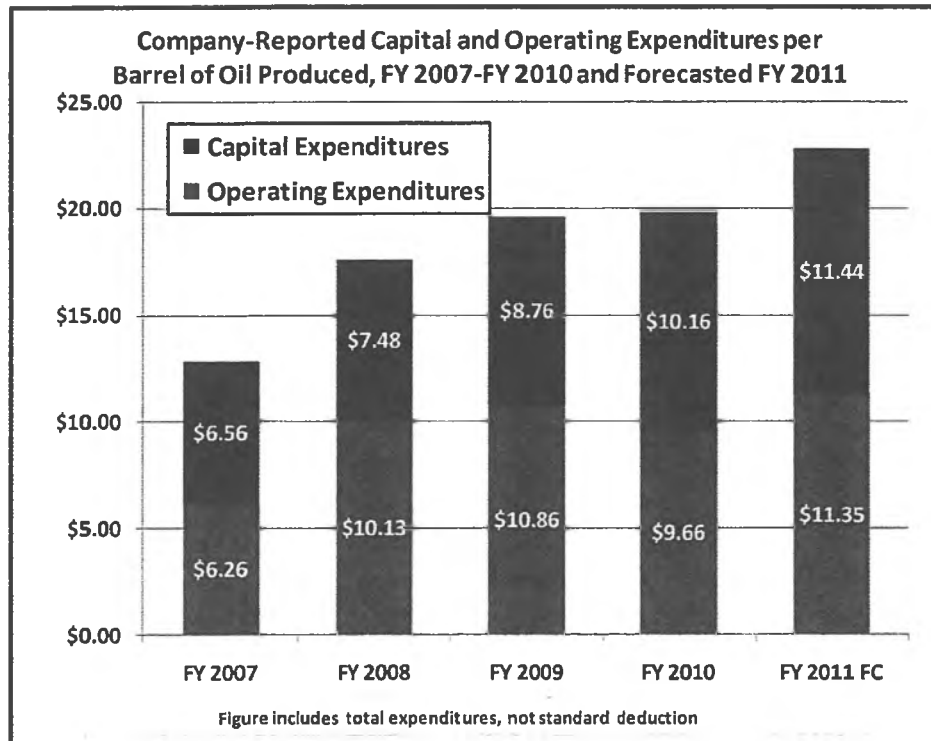
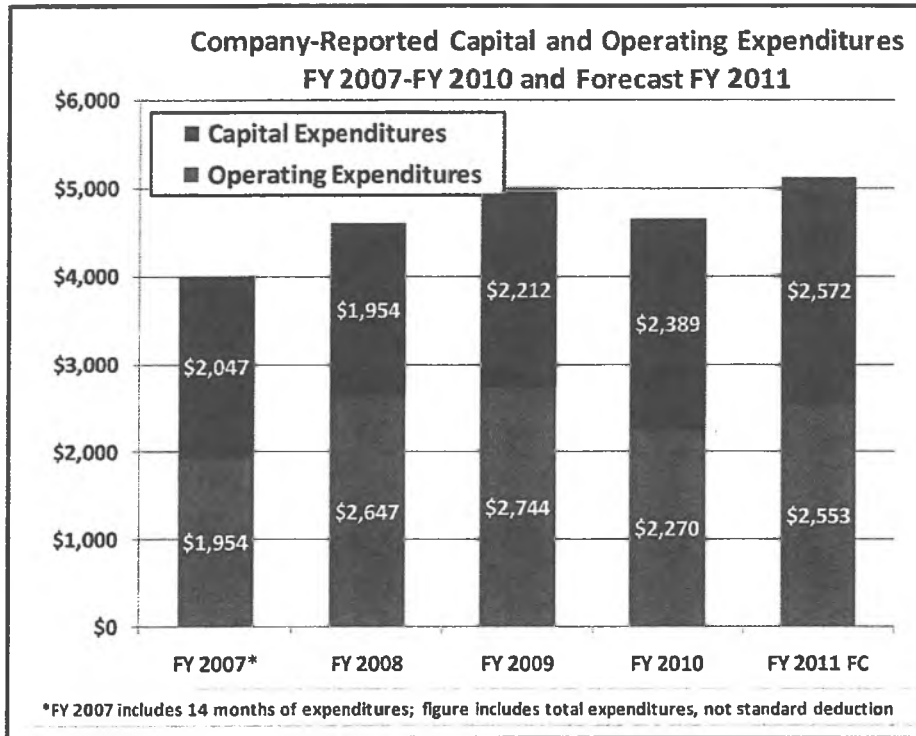
Example of a Hypothetical Oil Field from Exploration to Production

All amounts in \$ millions (except production) - assumes \$80 / barrel oil and \$7 / barrel transportation

| | EXPLORATION | | | DEVELOPMENT | | | | TOTALS Year 1- Year 8 | |
|--|----------------|----------------|----------------|----------------|----------------|-----------------|-----------------|---|---------------|
| | Year 1 | Year 2 | Year 3 | Year 4 | Year 6 | Year 7 | Year 8 | | |
| Production - barrels per day | - | - | - | - | - | - | - | | |
| Capital Spending | \$50.0 | \$50.0 | \$100.0 | \$50.0 | \$100.0 | \$300.0 | \$600.0 | Total Cost to Develop: \$1,250.0 | |
| Operating Spending | | | | | | | | | |
| Gross Value | -\$50.0 | -\$50.0 | -\$100.0 | -\$50.0 | -\$100.0 | -\$300.0 | -\$600.0 | Total State Contribution: \$602.5 | |
| Production Tax Value | -\$50.0 | -\$50.0 | -\$100.0 | -\$50.0 | -\$100.0 | -\$300.0 | -\$600.0 | | |
| Tax Before Credits - ACES | \$0.0 | \$0.0 | \$0.0 | \$0.0 | \$0.0 | \$0.0 | \$0.0 | | |
| CREDITS | | | | | | | | | |
| Exploration Credit (40% of spend) | \$20.0 | \$20.0 | \$40.0 | | | | | Net Industry Investment: \$647.5 | |
| Capital Credit (20% of capex) | | | | \$10.0 | \$20.0 | \$60.0 | \$120.0 | | |
| NOL Credit (25% of loss) | \$12.5 | \$12.5 | \$25.0 | \$12.5 | \$25.0 | \$75.0 | \$150.0 | | |
| Total Credits | \$32.5 | \$32.5 | \$65.0 | \$22.5 | \$45.0 | \$135.0 | \$270.0 | | |
| Total Paid to (Received From) State | -\$32.5 | -\$32.5 | -\$65.0 | -\$22.5 | -\$45.0 | -\$135.0 | -\$270.0 | | |
| PRODUCTION (continues into future beyond year 16) | | | | | | | | | |
| | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | |
| Production - barrels per day | 20,000 | 40,000 | 40,000 | 40,000 | 40,000 | 37,000 | 33,000 | 30,000 | |
| Royalty Paid to State | \$66.6 | \$133.2 | \$133.2 | \$133.2 | \$133.2 | \$123.2 | \$109.9 | \$99.9 | |
| Capital Spending | \$321.9 | \$243.8 | \$100.0 | \$43.8 | \$43.8 | \$40.5 | \$36.1 | \$32.9 | |
| Operating Spending | \$70.1 | \$56.9 | \$61.3 | \$67.9 | \$72.3 | \$72.9 | \$72.3 | \$70.6 | |
| Gross Value | \$466.3 | \$932.6 | \$932.6 | \$932.6 | \$932.6 | \$862.6 | \$769.4 | \$699.4 | |
| Production Tax Value | \$74.3 | \$631.8 | \$771.2 | \$820.9 | \$816.5 | \$749.2 | \$661.0 | \$596.0 | |
| PTV / bbl | \$11.6 | \$49.5 | \$60.4 | \$64.3 | \$63.9 | \$63.4 | \$62.7 | \$62.2 | |
| ACES TAX RATE | 25.0% | 32.8% | 37.1% | 38.7% | 38.6% | 38.4% | 38.1% | 37.9% | |
| Tax Before Credits - ACES | \$18.6 | \$207.1 | \$286.5 | \$317.7 | \$314.9 | \$287.4 | \$251.7 | \$225.7 | |
| CREDITS | | | | | | | | | |
| Capital Credit (20% of capex) | | \$64.4 | \$48.8 | \$20.0 | \$8.8 | \$8.8 | \$8.1 | \$7.2 | \$6.6 |
| NOL Credit (25% of loss) | | | | | | | | | |
| Small Producer Credit (Up to \$12 mm) | | | \$12.0 | \$12.0 | \$12.0 | \$12.0 | \$12.0 | \$12.0 | \$12.0 |
| Total Credits | | \$64.4 | \$60.8 | \$32.0 | \$20.8 | \$20.8 | \$20.1 | \$0.0 | \$18.6 |
| Total Prod Tax Paid to (Rec'd From) State | -\$45.8 | \$146.4 | \$254.5 | \$296.9 | \$294.1 | \$267.3 | \$251.7 | \$207.2 | |
| Total Prod Tax and Royalty Paid to State | \$20.8 | \$279.6 | \$387.7 | \$430.2 | \$427.4 | \$390.5 | \$361.6 | \$307.1 | |

(6) Provide a history and forecast of total capital and operating expenses.

The following charts show historical and forecast capital and operating expenditures. The amounts are shown both in total and as a per-barrel calculation.



(7) How many taxpayers will there be available for audit for production tax this year, compared to 2006?

The requested information was included in the "Oil and Gas Production Tax Status Report to the Legislature" released on January 18, 2011. On page 11 of that publication, we reported the following:

"In 2006, the first year that filings were made under a net profits tax, there were 19 companies filing annual returns. In 2007, the number of companies filing production tax returns totaled 26, and in 2008, 36 companies filed annual production tax returns. The filing for 2009 increased only slightly from 2008, with 39 companies filing returns."

We will know the number of companies filing annual returns for 2010 after the due date for those returns, which is March 31, 2011.

(8) Have there been any applications for credits between January 4, 2011 and March 17, 2011?

As we indicated in committee, the vast majority of applications for exploration credits occur in the first half of the fiscal year. Since January 4, there have been \$575,000 in claims for the exploration capital credit under AS 43.55.023(a)(2), and there have been no additional applications for the alternative credit for exploration under AS 43.55.025.

We have received 15 applications for credits since January 4, 2011, in the following amounts:

- AS 43.55.023(a)(1) Qualified Capital Expenditure Credits: \$84,797,000
- AS 43.55.023(a)(2) Exploration Capital Credits: \$575,000
- AS 43.55.023(b) NOL Carry Forward Credits: \$180,359,000
- AS 43.55.023(l)(1) Well Lease Expenditure Credits: \$834,000
- Total Applications for credits since January 4, 2011: \$266,567,000

(9) Provide a figure showing the amount of exploration credits claimed through January 4 of Fiscal Years 2009, 2010, and 2011.

The vast majority of applications for the alternative tax credit for exploration under AS 43.55.025 are received in the first half of the fiscal year, and no applications have been received since January 4 this year. Therefore for this particular credit, comparing the total applications in FY 2009 and FY 2010 with the applications for the first half of FY 2011 provides a valid year-over-year comparison. The amounts of credit applications from companies without a tax liability for the alternative tax credit for exploration in the three years are as follows:

- FY 2009: \$56.6 million
- FY 2010: \$99.5 million
- FY 2011: \$2.4 million (through March 17, 2011; we do not expect additional applications between March 17, 2011 and June 30, 2011)

(10) Provide a list of changes made to HB 110 in the House Resources committee, compared to the original proposal.

Following is a list of the amendments that were made to HB 110 in House Resources

House Resources meeting February 25, 2010, amendments passed:

- #1: Qualification for 15% tax rate for new fields, Section 6 of CSHB 110
- In the original bill, the 25 % base tax rate applied to oil and gas produced from a lease or property that as of December 31, 2010 was or had previously been within a unit or in commercial production. The December 2010 date was changed to December 2008. Under the CS for HB 110, the 25 % base tax rate applies to oil and gas produced from a lease or property containing land that on December 31, 2008, was within a unit or in commercial production. For other oil and gas, the base rate is 15%. Annual progressivity applies to all production.
- #2: Extends the sunset for non-transferable tax credits to 2021
- Adds two new sections 18 and 20, to amend AS 43.55.024(b) and (d) to extend the sunset date from 2016 to 2021. Change effective July 1, 2011. .
- #3: Raises small producer credit under AS 43.55.024(c).
- Adds a new section 19 to increase the maximum allowable for the small producer tax credit from \$12 million to \$15 million per calendar year.
 - Effective date is July 1, 2011, but DOR recommends changing to a future date, such as January 1, 2012, for production after December 31, 2011.
- # 4: Extends the sunset from 2016 to 2021 for AS 43.55.025
- New sections 22 and 23 amend AS 43.55.025 (b) and (k) to extend the sunset date for exploration tax credits and certain seismic expenditures from 2016 to 2021.
 - Effective July 1, 2011.
- # 5: Tax credit certificates may be used in one year, AS 43.55.023.
- Section 11 and 12 were amended to make the change to the tax credit certificate rules retroactive to January 1, 2011.
- #6: New North Slope credit of 30%
- Sections 21 and 24 amend AS 43.55.025 to add sub-section (a)(6) and a new section (n). This would add a new 30% credit for North Slope expenditures incurred outside a unit, or within a unit formed after June 30, 2008 if the expenditures are incurred before the later of the date four years after the unit is formed or the first exploration well is drilled on a lease or property within the unit.
 - Effective January 1, 2012, to expenditures incurred after December 31, 2011
- #7: Publication of tax credit information
- New section 28 amends 43.55.890 to clarify that the Department of Revenue may publish detailed aggregated information on tax credits.
 - Effective date of 12/31/2011.

House Resources meeting February 28, 2010, amendments passed:

#15: Statute of limitations stays at 6 years

- Deleted former section 19 that would have amended AS 43.55.075 to reduce the six year statute of limitations to four years.

#25: Tax credit under 43.55.023(p) for percentage of wages and compensation attributable to Alaska residents.

- Section 17 adds a new tax credit to AS 43.55.023 to allow a credit against taxes levied under AS 43.55.011(e) for the percentage of total wages and compensation attributable to Alaska residents that exceeds total wages and compensation paid by the producer.
- Effective date is January 1, 2012, applicable to expenditures after December 31, 2010.

(11) Provide the names of persons that the Department of Revenue Commissioner and Deputy Commissioner met with to discuss possible changes to the oil and gas production tax and when those meetings were held.

The Department is currently working on this response.

(12) What was the reduction in oil production and revenue from the temporary shutdown of TAPS in January 2011?

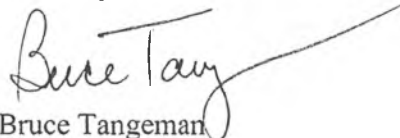
From January 1-7, average North Slope production was approximately 634,623 barrels per day. If this average rate had continued for all of January, we estimate that ANS royalties would have been \$190 million and ANS production tax would have been \$360 million, for a total of \$550 million.

The actual average North Slope production for January was approximately 471,665 barrels per day. We estimate that ANS royalties were \$150 million and ANS production tax was \$200 million, for a total of \$350 million.

The difference between these two calculations is \$200 million. This is a high level, estimated difference based on analysis using our DOR forecast model with two different assumptions for average daily production.

We hope our responses fully answer your questions.

Sincerely,



Bruce Tangeman
Deputy Commissioner

3/23/11

State of Alaska
Department of Revenue

Commissioner Bryan Butcher



SEAN PARNELL, GOVERNOR

333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Joe Paskvan
The Honorable Tom Wagoner
Co-Chairs, Senate Resources Committee
Alaska State Senate
Juneau, AK 99801

March 21, 2011

The Honorable Eric Feige
The Honorable Paul Seaton
Co-Chairs, House Resources Committee
Alaska State House
Juneau, AK 99801

The Honorable Bill Stoltze
The Honorable Bill Thomas
Co-Chairs, House Finance Committee
Alaska State House
Juneau, AK 99801

SUBJECT: Corrected Well Data from Alaska Oil & Gas Conservation Commissioner (AOGCC)

Dear State Legislators:

It has been brought to our attention that the drilling activity charts presented by the Department of Revenue on the basis of AOGCC data contained some inaccuracies. Simply put, we received different sets of data from different people within AOGCC and we realized there was a problem because the data sets didn't match. It has to do with what is and is not included as you work through the well data. Once we realized there was a problem, we worked with AOGCC to determine the correct data and it is enclosed herein. These updated slides have been based on AOGCC data and their staff have cross-checked the numbers with their internal, confidential database. What has not changed is the fact that exploration is down in 2010 and that only one exploration well is expected in 2011 by the Alaska Department of Natural Resources.

We would like to apologize for this error and provide assurance to the committees that we will be more diligent in cross checking information before providing it to any legislative body.

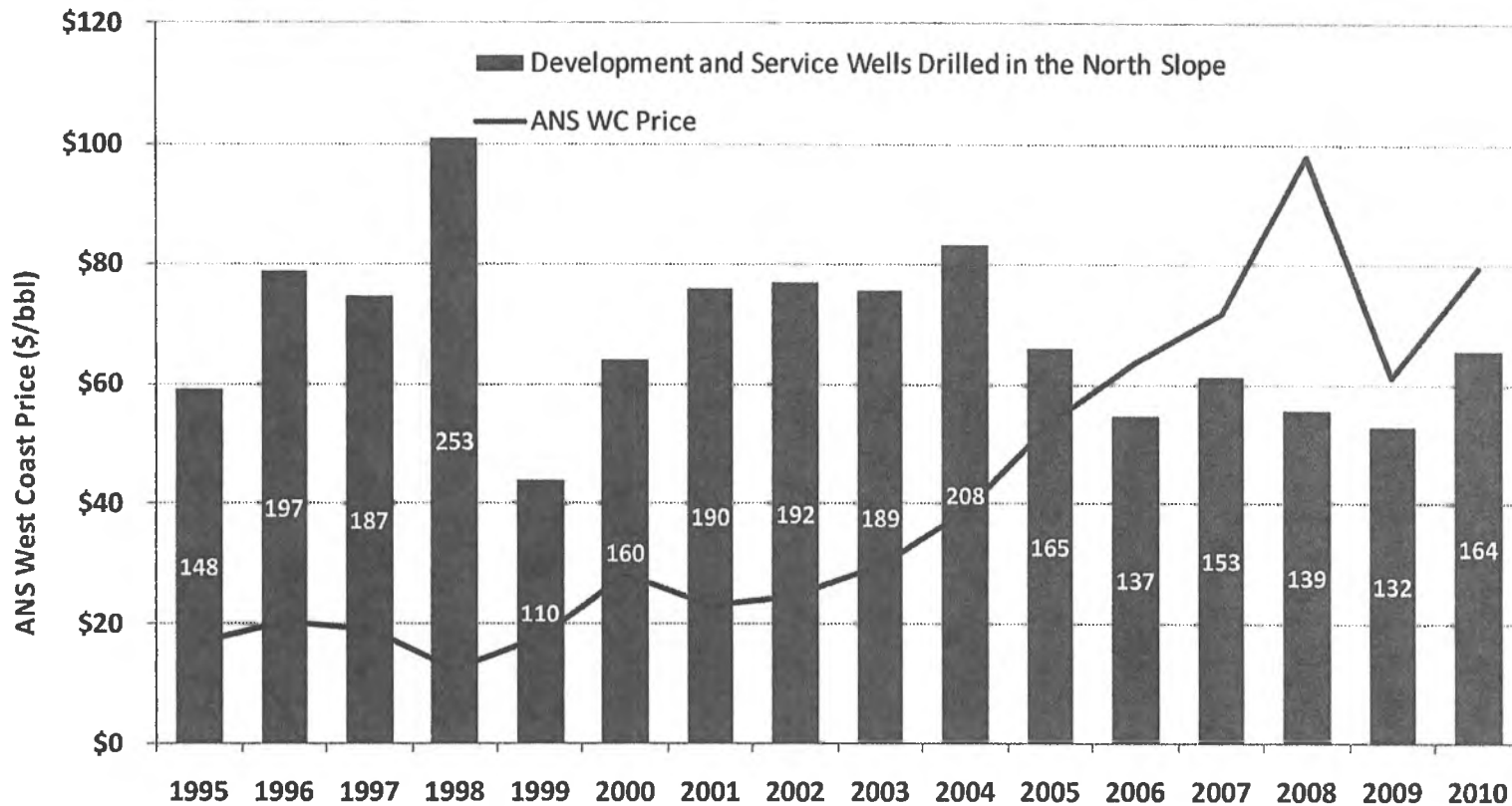
Sincerely,

Bruce Tangeman
Deputy Commissioner

Enclosure



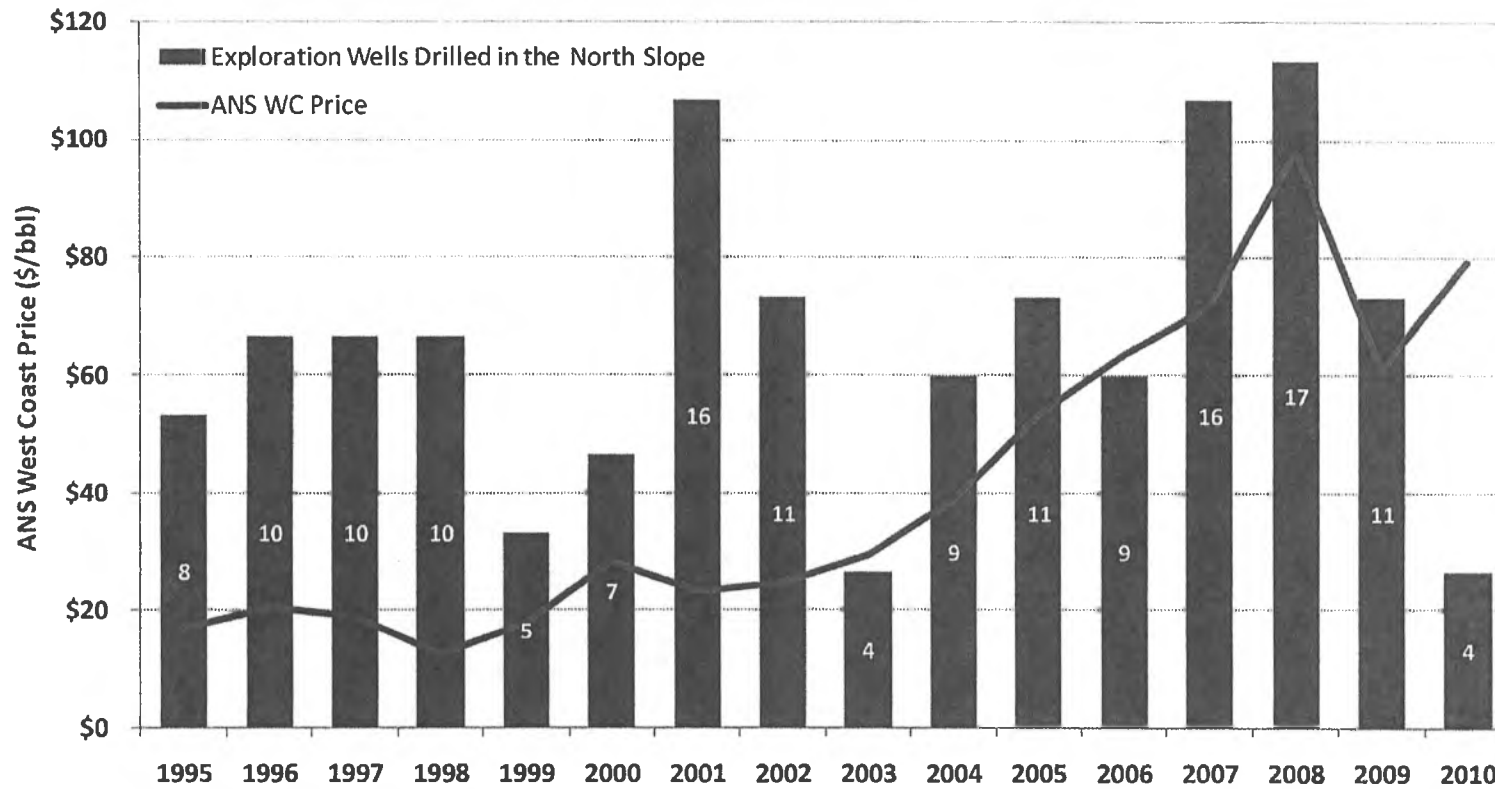
North Slope Development Drilling



Source: Alaska Oil and Gas Conservation Commission



North Slope Exploration Drilling



Source: Alaska Oil and Gas Conservation Commission

3/23/11 PM



RENAISSANCE ALASKA, LLC

House Bill No. 110

Testimony –Wednesday, March 23, 2011

Representative Stoltze, members of the committee, thank-you for the opportunity to speak with you today on House Bill 110.

Firstly, let me introduce myself and Renaissance Alaska, LLC (Renaissance). My name is Mark Landt and I am the Executive Vice President, Land and Administration for Renaissance, which is headquartered in Houston, Texas. Renaissance was formed in November 2006 and completed the initial funding of a business plan that solely focuses on growth in Alaska. The major area of focus for Renaissance is the Umiat Oil Field on the North Slope.

Since its formation, Renaissance has acquired BLM and State oil and gas leases on 19,358 acres located on the Umiat Oil Field located in the National Petroleum Reserve-Alaska ("NPRO") and the Gubik Gas Field on the North Slope, Alaska.

Since we last testified on Senate Bill 309, the State of Alaska has made significant progress in providing the incentives necessary to encourage drilling and development in the Cook Inlet, Alaska. Specifically the Special Credits for drilling the first three wells drilled to a Pre-Tertiary prospect from a Jack-up drilling rig and the repeal of the future spend requirements to monetize the tax credits provided in SB 309 and the additional 20 percent tax credit for all drilling in the Cook Inlet basin under HB 280. The combined tax credits and being exempt from production tax in ACES, makes the fiscal environment in the Cook Inlet one of the most competitive in the world.

The State of Alaska has demonstrated tremendous leadership and acted decisively to revitalize oil and gas exploration and development activities in the Cook Inlet. Similar leadership and progressive action is required to revitalize oil and gas activities on the North Slope. The giant fields have been discovered and oil through-put for TAPS continues to fall and now stands below initial estimates regarding the economic life of the line. Alaska will increasingly depend on the discovery and development of smaller fields, technically challenged resources and known reserves remote from existing infrastructure. This testimony is to address the significant challenges we see for the development of the North Slope's extensive, untapped oil and gas resources and specifically the undeveloped reserves located at the Umiat oil field.

The Umiat oil field was discovered in the late 1940s by the U.S. Navy in search of new sources of oil after World War II. It remains undeveloped to this day in spite of delineation by 12 legacy wells; the shallow depth of its consolidated, productive reservoirs; sweet, light 37 degree API gravity oil; and over 1 billion barrels of original oil in-place. To this point, remoteness (92 miles from TAPS), part of the reservoir in permafrost, and low reservoir energy have been the main development challenges. All of these challenges have been addressed through modern technological advancements such as multi-lateral horizontal drilling, electric submersible pumps, and cold gas injection for pressure maintenance to bring the Umiat development closer to fruition. Remoteness given the arctic environment is still a key challenge.

Renaissance, through Renaissance Umiat, LLC, controls the undeveloped Umiat oil field and a portion of the undeveloped Gubik gas field 12 miles to the east-northeast. Since acquiring the acreage in 2006 and 2007, Renaissance has de-risked the project through an 86 square mile 3-D seismic survey acquired in 2008 and extensive geoscience and development cost studies.

Renaissance has also focused on the plan of development and contracted third parties, including NANA WorleyParsons, Schlumberger, ASRC, Cardno (previously Entrix) and Umiat (subsidiary of UIC) on pipeline route and cost, facility layout and costs, horizontal (lateral) development techniques, and obtained an independent reserve report from Ryder Scott and Associates (one of the top oil and gas reservoir engineering firms in the world). This report has estimated 250 million barrels of recoverable oil from the shallow zones at Umiat with peak field production of approximately 50 MBOPD. In addition, the University of Alaska at Fairbanks has a DOE grant to, among other things; confirm cold gas injection as the preferred pressure maintenance mechanism.

One of the development considerations is the ability to bury the pipeline in the shoulder of the road to lower the pipeline costs and to have less of a visual impact to the environment. Since the oil is being produced cold (28-32 degrees F) and the gravity is 37 degrees, this option to move the oil exists with no risk of melting the permafrost. The oil would be heated to pipeline specs at the TAPS connection.

The Umiat oil field is unique. There is no analogy in the world of light sweet oil being produced at these shallow depths with a portion of the reservoir in permafrost. The lack of analogy and distance from infrastructure has made this project difficult to compete for investment capital given the concerns on permitting the project and the multiple winter seasons required to develop the field. Although Renaissance feels it has addressed the key technical concerns, the distance from infrastructure is still a major risk factor. Your support of "Roads to Resources" and specifically the Environmental Impact Statement being prepared by the Department of Transportation for the transportation corridor between Umiat and TAPS is going a long way to reduce this risk. Current development cost is estimated to be \$1.3 billion dollars and further technical studies are underway to finalize the Plan of Development prior to raising the funding necessary for project development. Renaissance has spent in excess of \$43MM on the Umiat project to date.

Although Renaissance is solely focused at Umiat, we must compete for capital in the international financial markets. We strongly support the proposed amendments to ACES to increase the tax credits and reduce the progressivity factor to make Alaska more competitive as an oil producing state.

Mark R. Landt
Executive Vice President
(281) 768-7652
mlandt@renaissancealaska.com

3/23/11 PM

TESTIMONY OF DALE PITTMAN
ON PROPOSED CSHB 110
TO THE ALASKA HOUSE FINANCE COMMITTEE
March 23, 2011

Mister Chairman, members of the committee:

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 the Committee Substitute to 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 CS 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 CS 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, began production 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.

3/5/11 PM



Great Bear Petroleum LLC

***Presentation to the
House Resources Committee
18th February, 2011***



Great Bear Petroleum LLC

Introducing Great Bear Petroleum



Ed Duncan

B.S., M.A., D.B.A.

President and Chief Operating Officer

- Began his career working regional exploration plays in North Alaska
- Mapped, leased and named the Kuvlum prospect in Camden Bay, planned and managed wellsite operations on the Kaktovik -1 well in the ANWR and mapped and leased the Pt McIntyre field leases
- Over 30 years of experience as a Petroleum Geoscientist and Business Development Manager involved in the evaluation of new business across many of the world's petroleum provinces
- Member of the American Association of Petroleum Geologists



Karen Bryant Duncan

BBA, J.D.

VP – Corporate, General Counsel & Secretary

- A practicing lawyer in the State of Texas since 1987
- Worked at large national law firms for most of her career, achieving partner status
- Over a decade of in-house experience working as corporate counsel for publicly traded corporations
- Karen's expertise is corporate, securities and oil and gas law

Ryan Moynagh

LLB, CFA, LIFA

VP – Finance & Chief Financial Officer

- Independent strategic and commercial advisor to oil & gas sector
- Former Investment Banker in Merrill Lynch's Energy & Power Group, based in New York, London and Singapore
- Graduated first-in class in Law and Accounting (First Class Honours), Queens University
- Wharton Business School Executive MBA graduate

Robert Rosenthal

BSc, MSc

VP – New Ventures

- Over 30 years experience in the global oil and gas industry
- Career in Alaska spans nearly 20 years
- Directly involved in discoveries of approx. 1 billion barrels of reserves as world class source rocks
- Responsible for the implementing BP's new exploration strategy in 1990
- Drilled first ever Caney/Woodford well

Mario Traviati

BSc, MSc

VP – Business Development & Investor Relations

- Former head of Energy Research Asia Pacific at Merrill Lynch
- Excellent contacts at senior levels with governments and corporates across Asia-Pacific, the Sub-Continent & the Middle East
- Formerly an Explorationist with Woodside Petroleum which discovered the vast resources of the North West Shelf



Competition for Capital

- Capital is mobile and will source out the best risk-adjusted economic returns, regardless of geography.
- Globalization has reduced sovereign risk which used to be the major impediment to investment.
- Government policies that either support or restrict investment will be an important determinant of how companies and countries fare in securing investment capital.
- Greater accessibility of technology and operating capabilities has made deepwater and unconventional resources viable competing investment opportunities
- **In the United States, the quest for capital investment has taken the appearance of State versus State competition for the oil and gas industry's attention.**

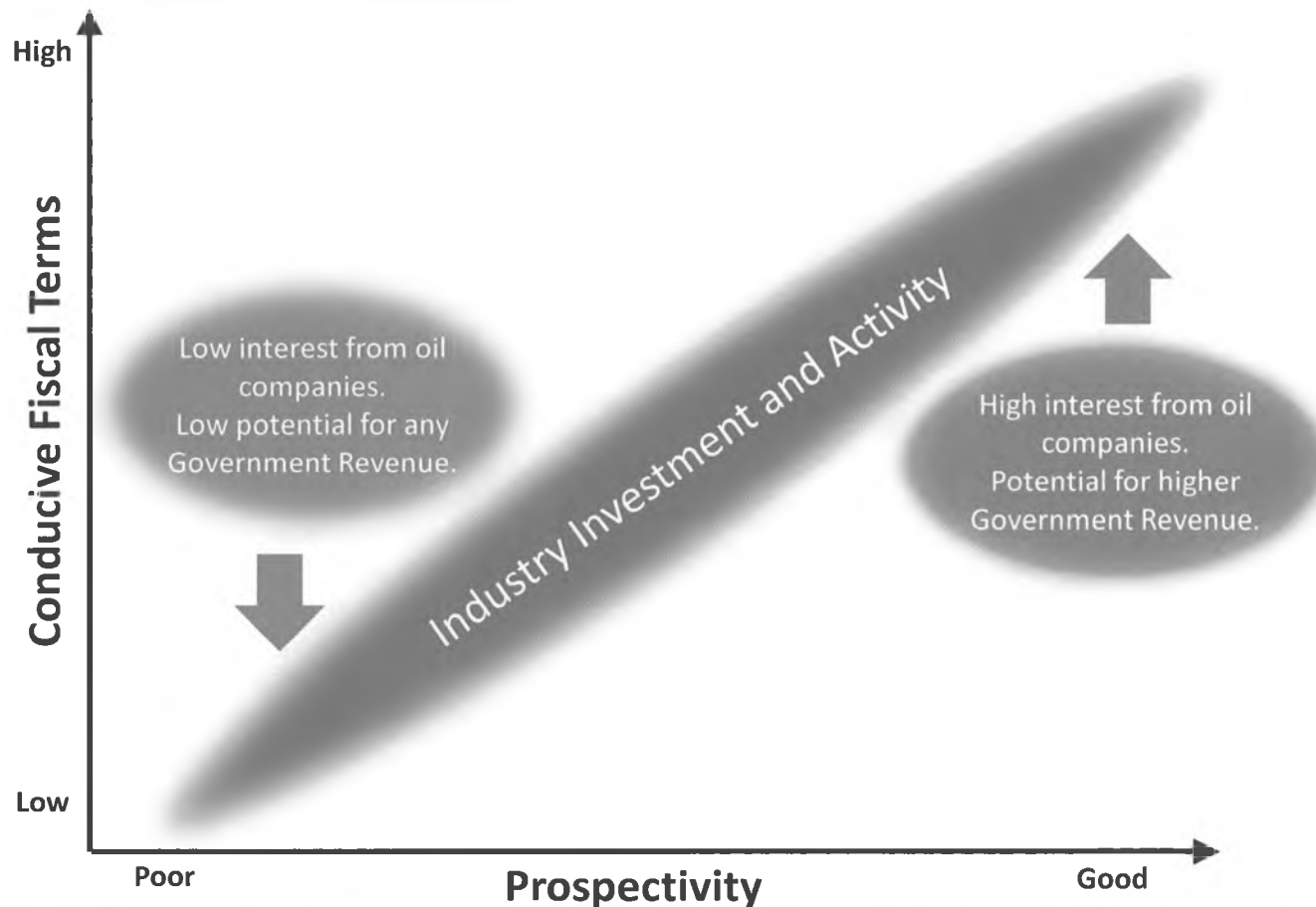
Alaska is competing both domestically and internationally for investment capital.



Great Bear Petroleum LLC

Tough Fiscal Terms Suppress Activity

- The most important factor in exploration investment is **Prospectivity**, or the likelihood of discovering oil or gas in commercial quantities. The industry will focus **where the rocks are good**.
- Effective **Conversion** from **Prospectivity** to **Commercial Production** ultimately controls the terms and the size of Government Revenue.
- Fiscal Terms will influence the **Conversion Efficiency** from Prospectivity to Commercial Production ultimately controlling Government Revenue.



Conversion from prospectivity to production can be suppressed by a non-competitive fiscal environment.



Recognition of Alaska as a Global Oil and Gas Producer has Declined

- The easy conventional oil has been found.
- Remaining large volume potential in **unconventional plays**, e.g. heavy oil, shale oil & gas, CBM.
- Costs will continue to rise on per barrel basis and economic returns will decline due to
 - Field sizes getting smaller
 - Challenging operating environment
 - Exploration for new play types becoming riskier
 - Identified plays such as “shallow heavy oil” and “oil and gas shale” are expensive
- **The ability to deliver unconventional resources to market rests primarily on commercial risk rather than technical risk factors.**
- Discovery and development of Alaska’s remaining potential would be significantly enhanced by improvements in Alaska’s fiscal terms such as those terms in **HB 110**.



HB 110: Major Impacts on Great Bear Petroleum

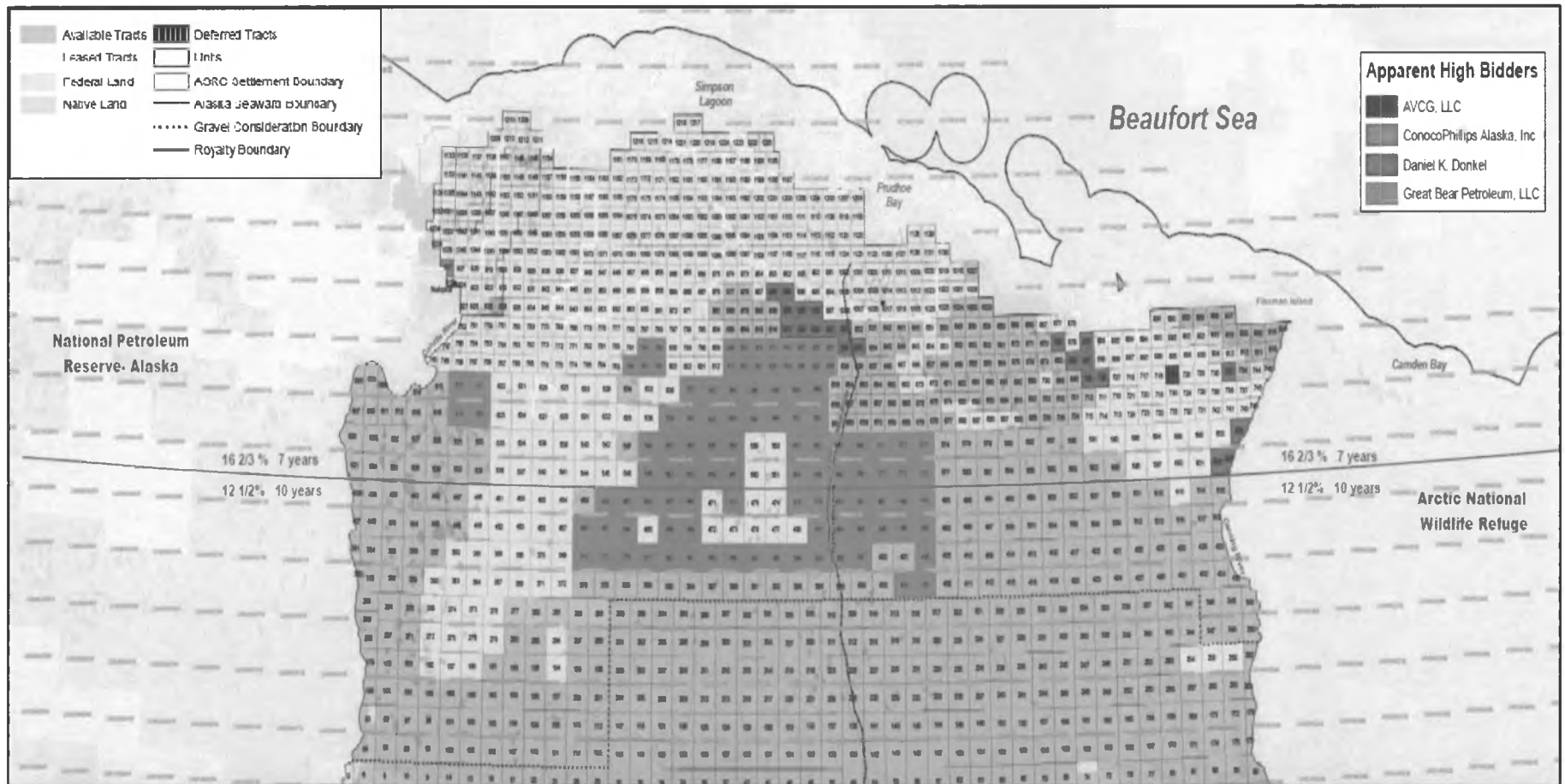
- Extension of tax credits to the North Slope
- Tax credits can be claimed in a single year versus two years
- **Reduction of production tax burden improves our commercial model reducing the risk to critically needed capital investment for full development**

Great Bear's ability to deliver on its strategy is dependent on the commercial environment within the State of Alaska.



Great Bear Petroleum LLC

High Bidder on 537,500 Acres in the 2010 North Slope Areawide Lease Sale



Great Bear's is targeting unconventional oil and gas from the source rocks beneath the North Slope providing a long term strategy for Alaska.



Great Bear's Vision

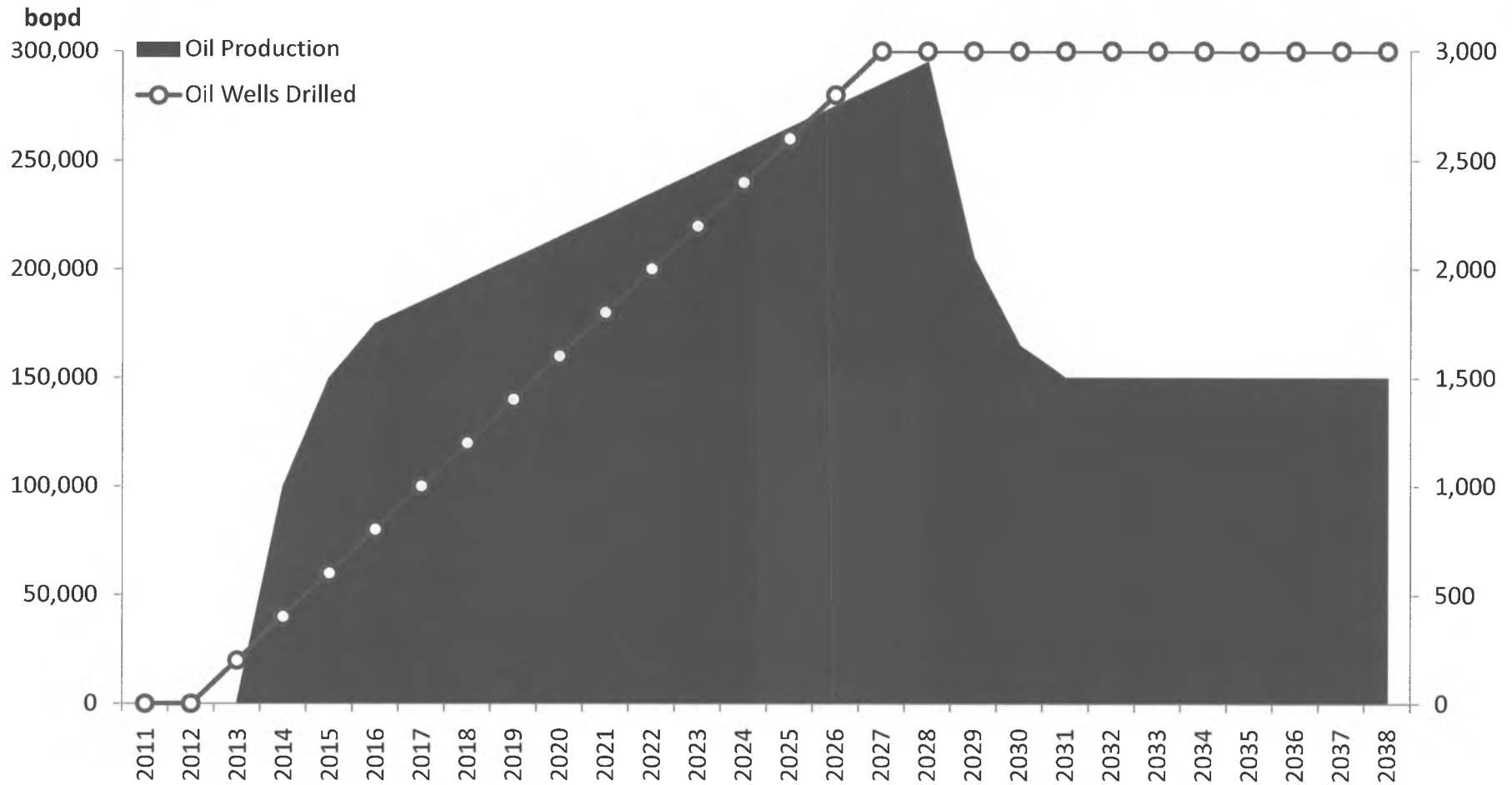
- Great Bear is leading the industry toward **development of unconventional oil and gas** resources from known, prolific source rocks on the North Slope.
- Development of this resource can secure the energy and economic future of Alaska for the next 50+ years.
- Great Bear is targeting near-term oil production delivery to TAPS.
- Longer term gas resource development will require a broader North Slope gas development strategy including LNG exportation.
- We will employ proven drilling and completion technologies developed in the Lower 48.
- We are committed to working with the State, the communities and our peers to shorten development timelines. We are singularly focused on the Alaska business development.
- We are committed to operating in a safe, environmentally responsible manner and desire to be recognized as a great corporate citizen by the State and the communities where we do business.
- We have an aggressive program that supports **250 wells per year for 20 years** starting 2013.
- We believe we can deliver **minimum steady state oil production of approximately 150,000 barrels of oil per day** with a significantly higher peak production rate. We believe we can reverse the States decline and grow production.

Great Bear's ability to deliver on its strategy is dependent on the commercial environment within the State of Alaska.



Great Bear Petroleum LLC

Great Bear Petroleum Potential Oil Production Profile



Assumptions:

200 wells per year over 15 years, commencing 2013. EUR per well 700,000 bbls.
Wells average 500 bopd for year 1, 250 bopd year 2, 125 bopd year 3 then held steady at 50 bopd for 20 years.
Year round "roads to resources" access for operations



Conclusions

- Current policy has not addressed declining production nor reinvigorated exploration activity.
- **HB 110 focuses on encouraging increased oil production immediately** and will aid Great Bear in attracting critical capital to deliver on its stated strategy.
- HB 110 encourages and supports new exploration activity. Alaska's future lies in the **discovery and development of new, long term oil production** into TAPS and **development of globally significant gas resources.**
- HB 110 and further direct investment by the State in supporting development infrastructure, such as "roads to resources", will encourage required investment of capital to support the development of these higher cost, higher risk but **long term resources.**
- **Great Bear believes that reasonable solutions can be agreed and implemented** providing much needed long-term stability to the State.

Fiscal Enhancement is necessary to improve Alaska's relative attractiveness as an investment jurisdiction.

3/23/11 PM

House Finance HB 110

ConocoPhillips Alaska
Wendy King – VP, External Affairs

March 23, 2011



Positive Impact of HB 110

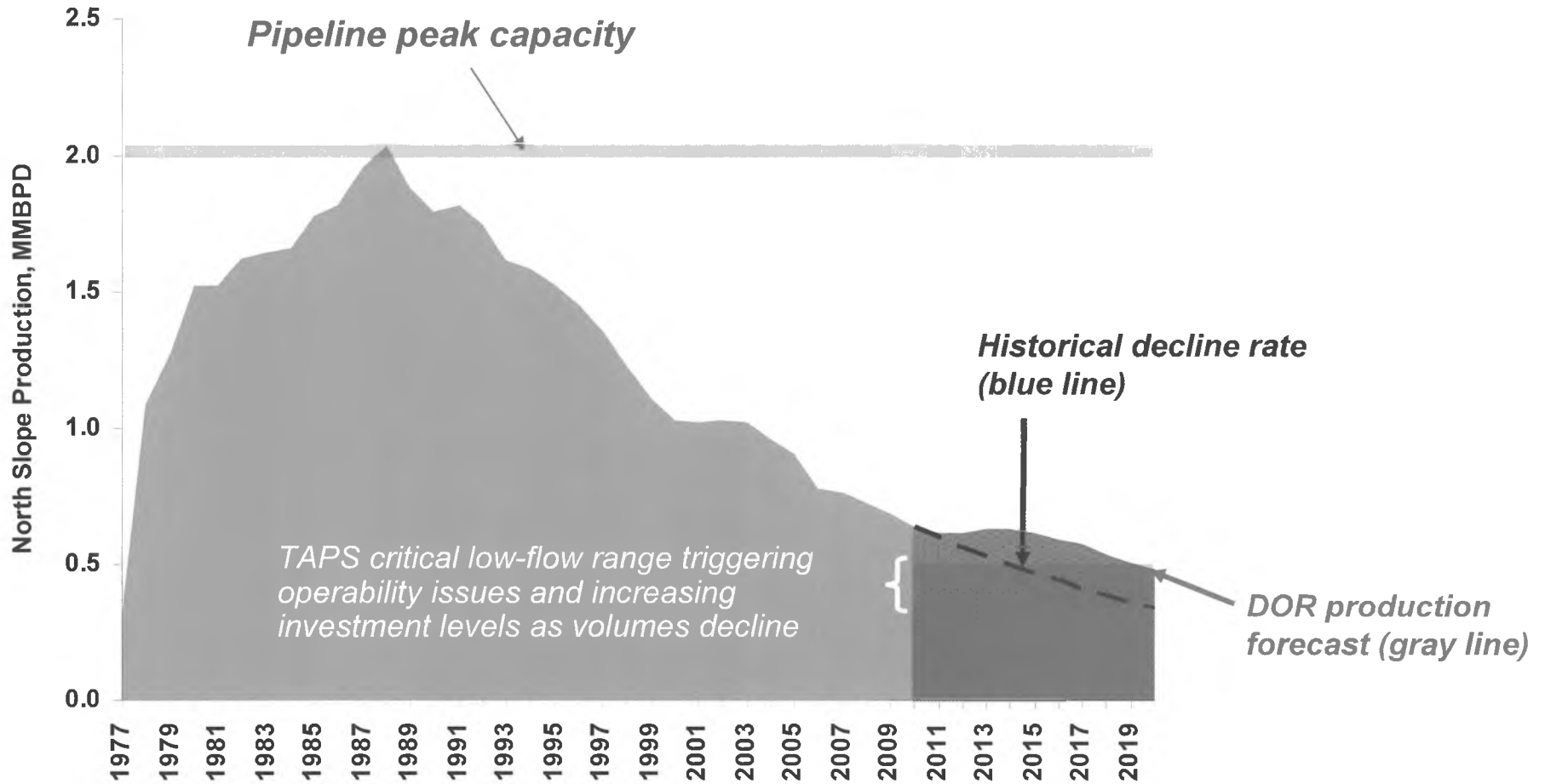
Governor's Objectives

- Be More Competitive
- Create More Jobs for Alaskans
- Increase Production

ConocoPhillips' View

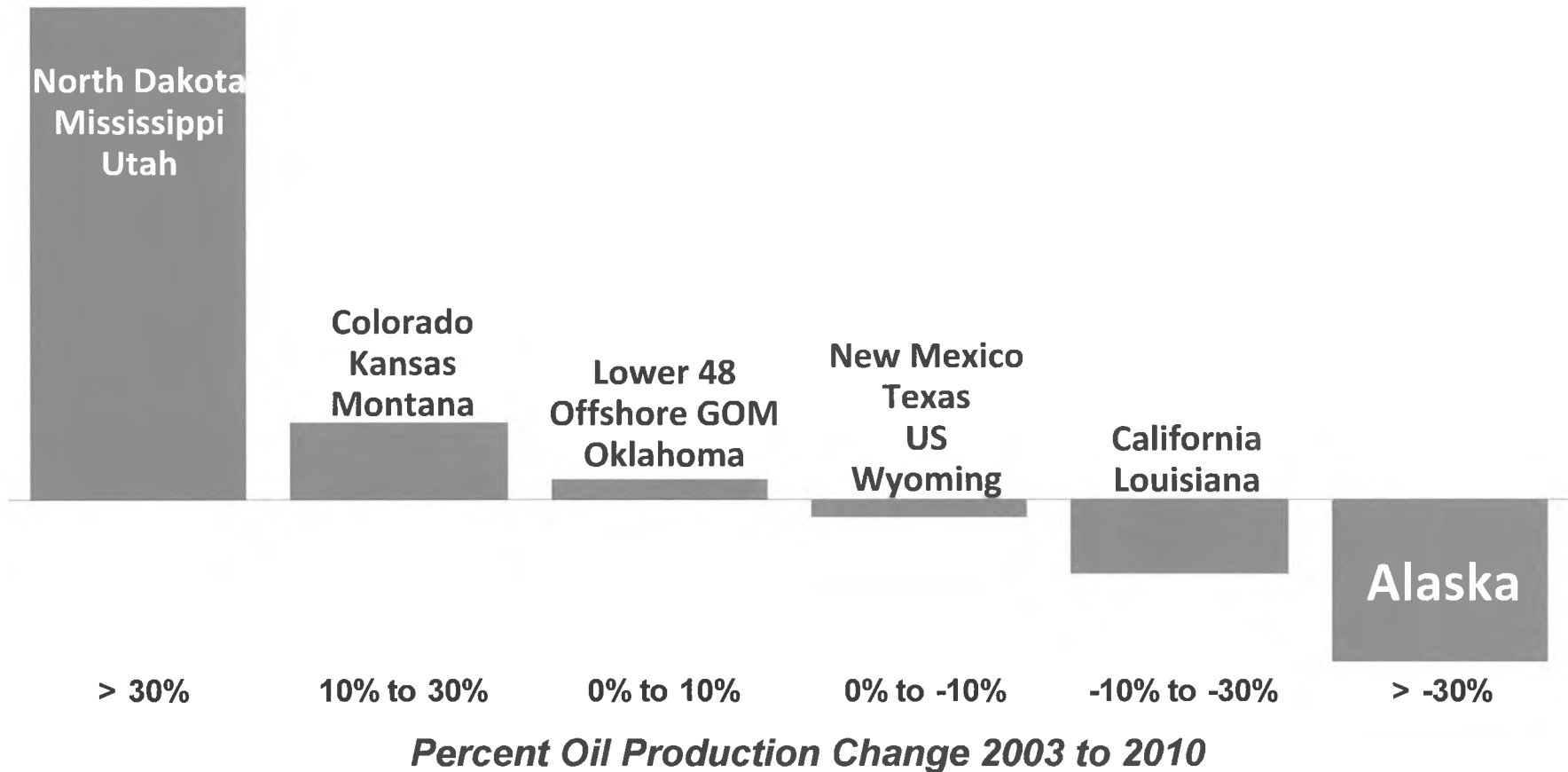


More Production Key to TAPS Future



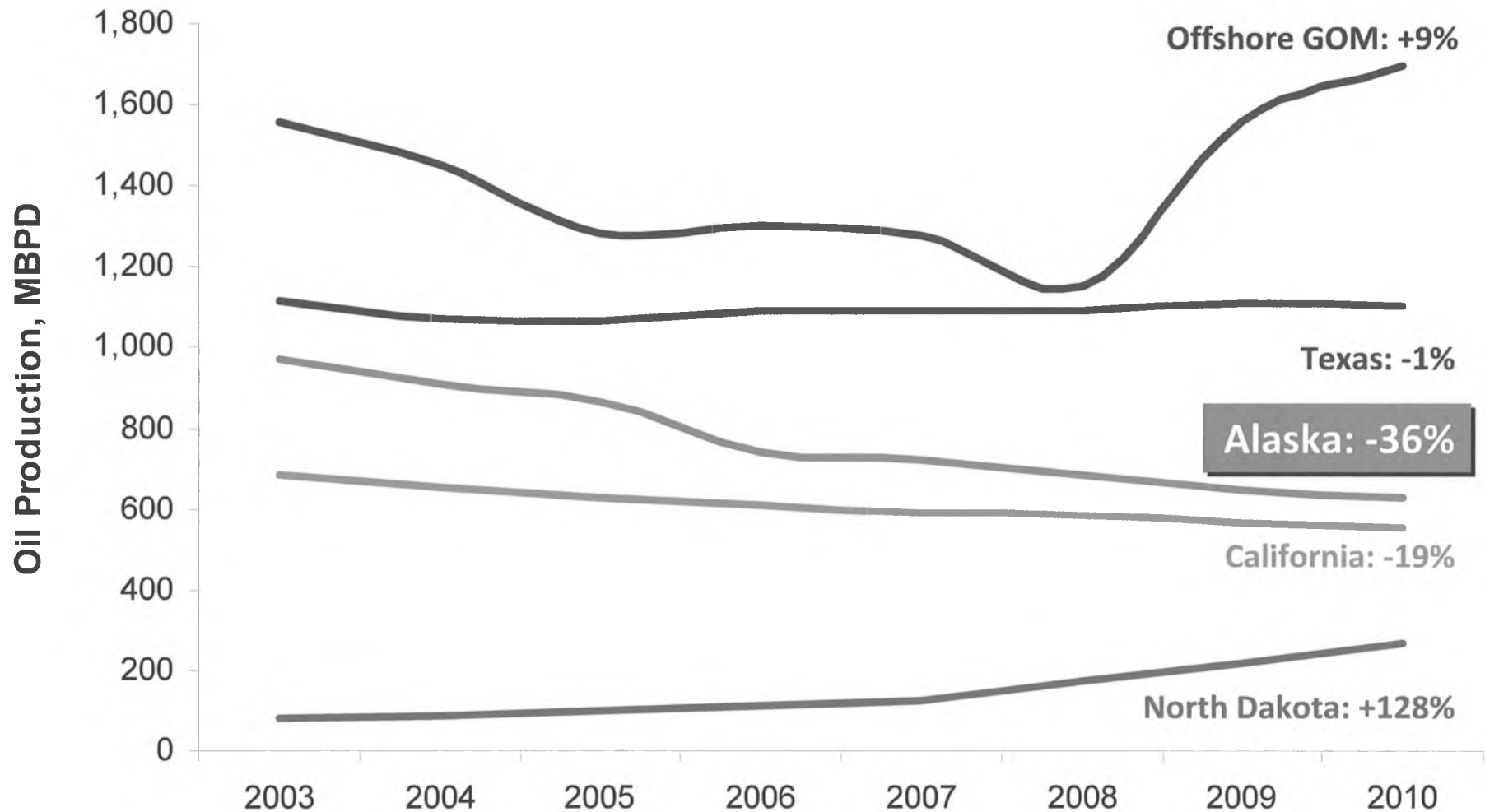
Source: Alaska Department of Natural Resources Annual Report
TAPS low flow impact study presentation, House Resources, March 9, 2010

Alaska's Decline Rate Highest in US



Source: Energy Information Administration
Regions with minimum 50,000 bopd production

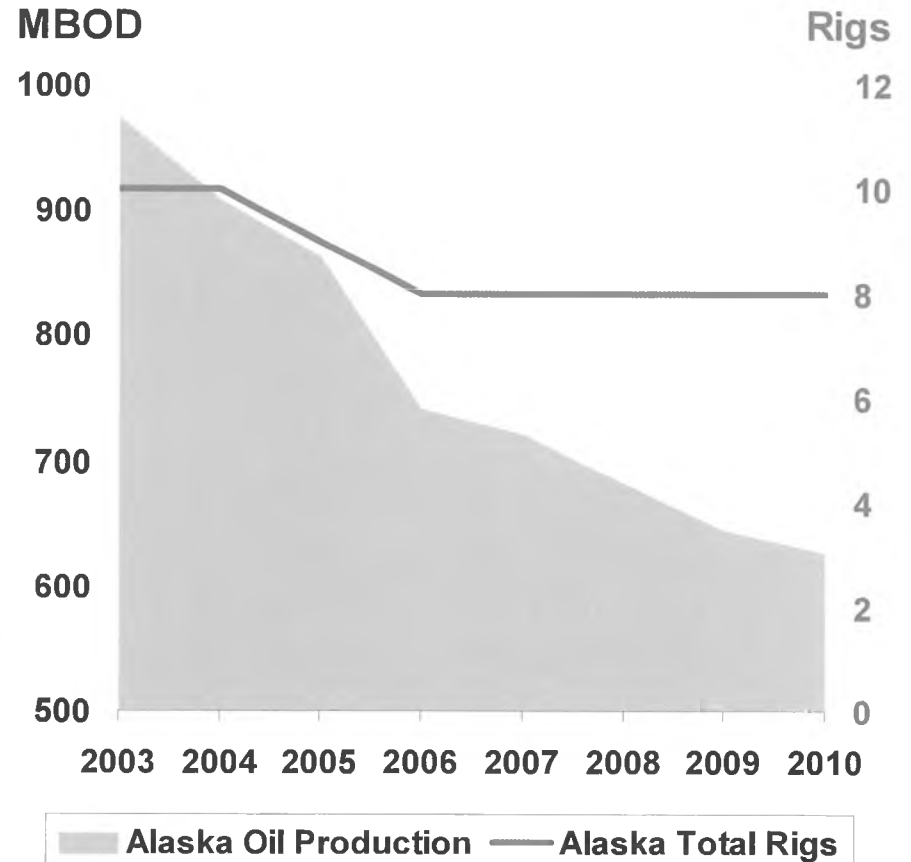
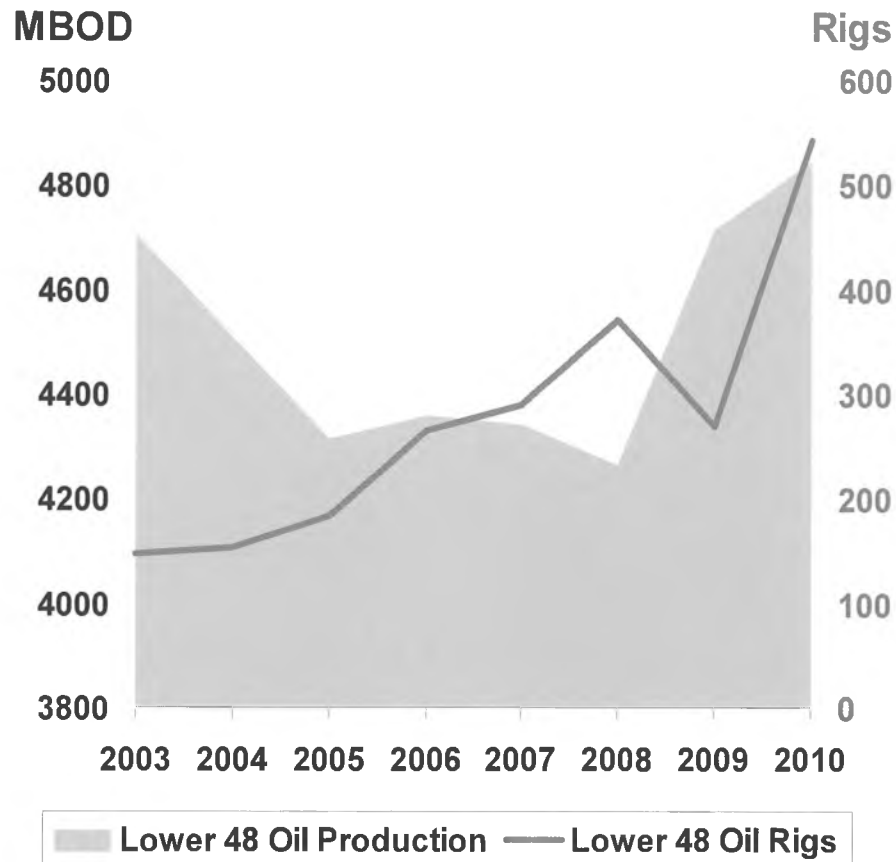
Alaska Lags Other Major Oil States



Percentage production changes are all 2010 vs. 2003

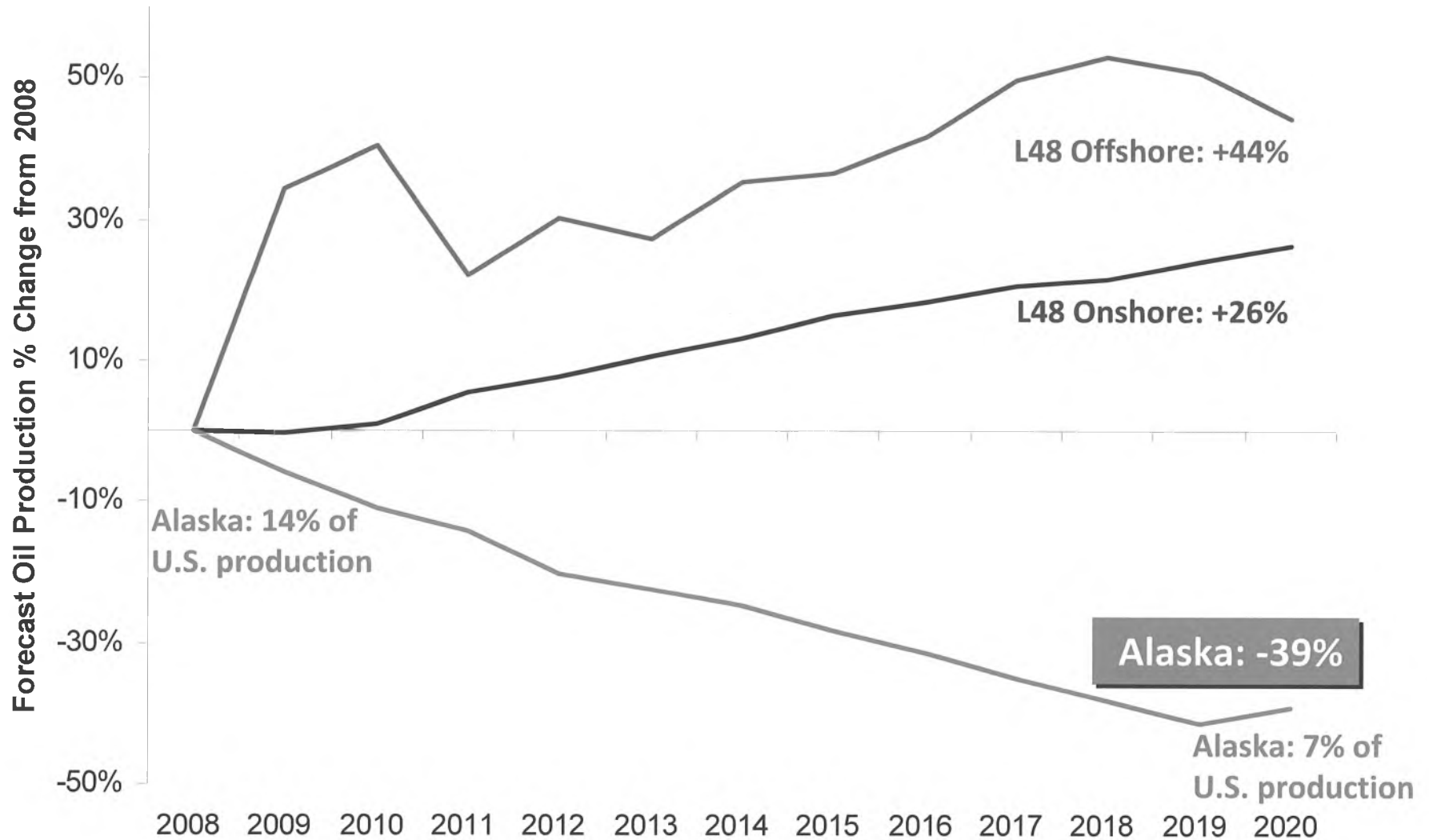
Source: Energy Information Administration

Why Isn't Alaska Booming at \$100/bbl?



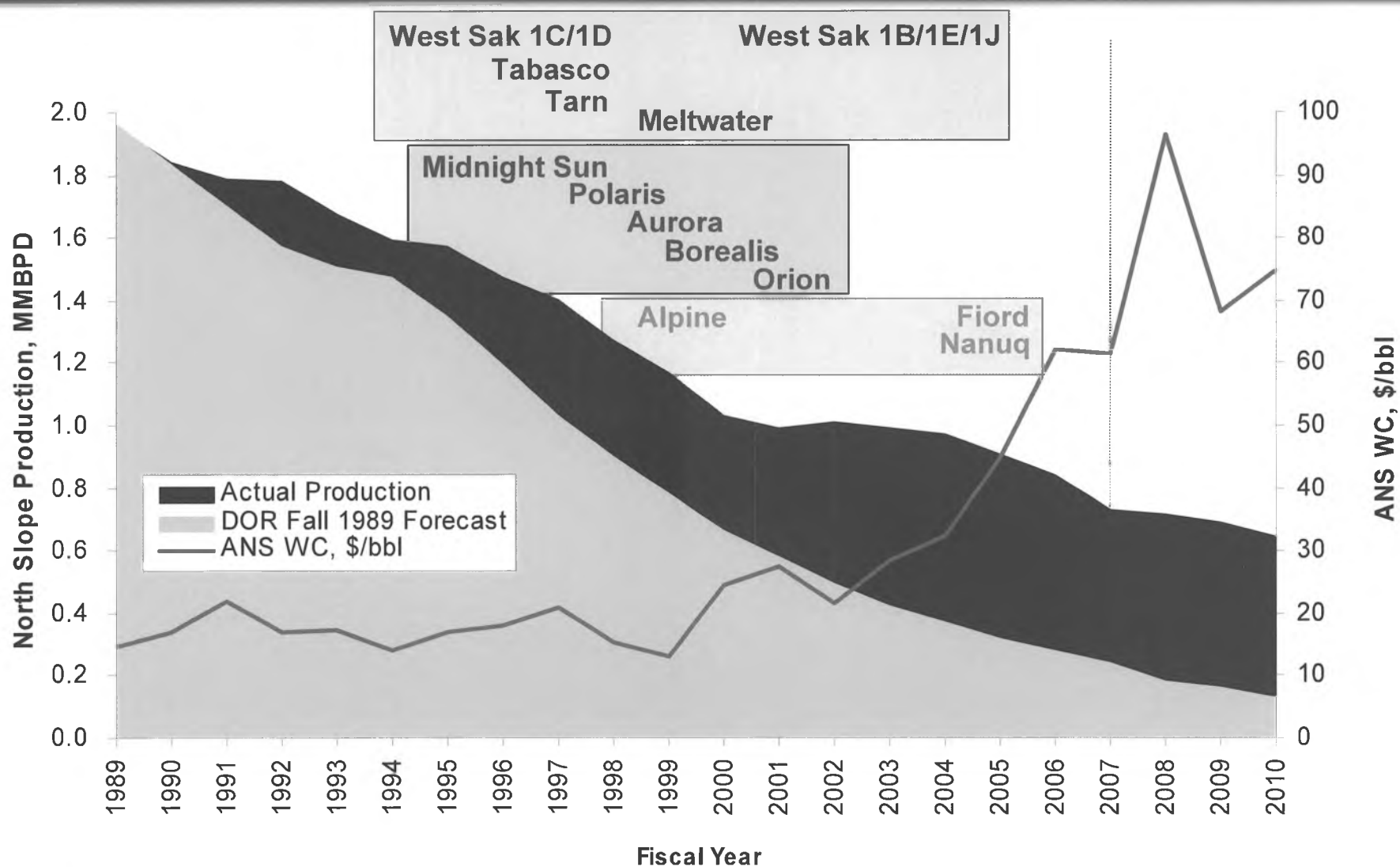
Is This the Future We Want for Alaska?

Alaska Forecasted to Fall Further Behind



Source: Energy Information Administration, AEO2011 Reference Case

ELF Generated Significant Incremental Production



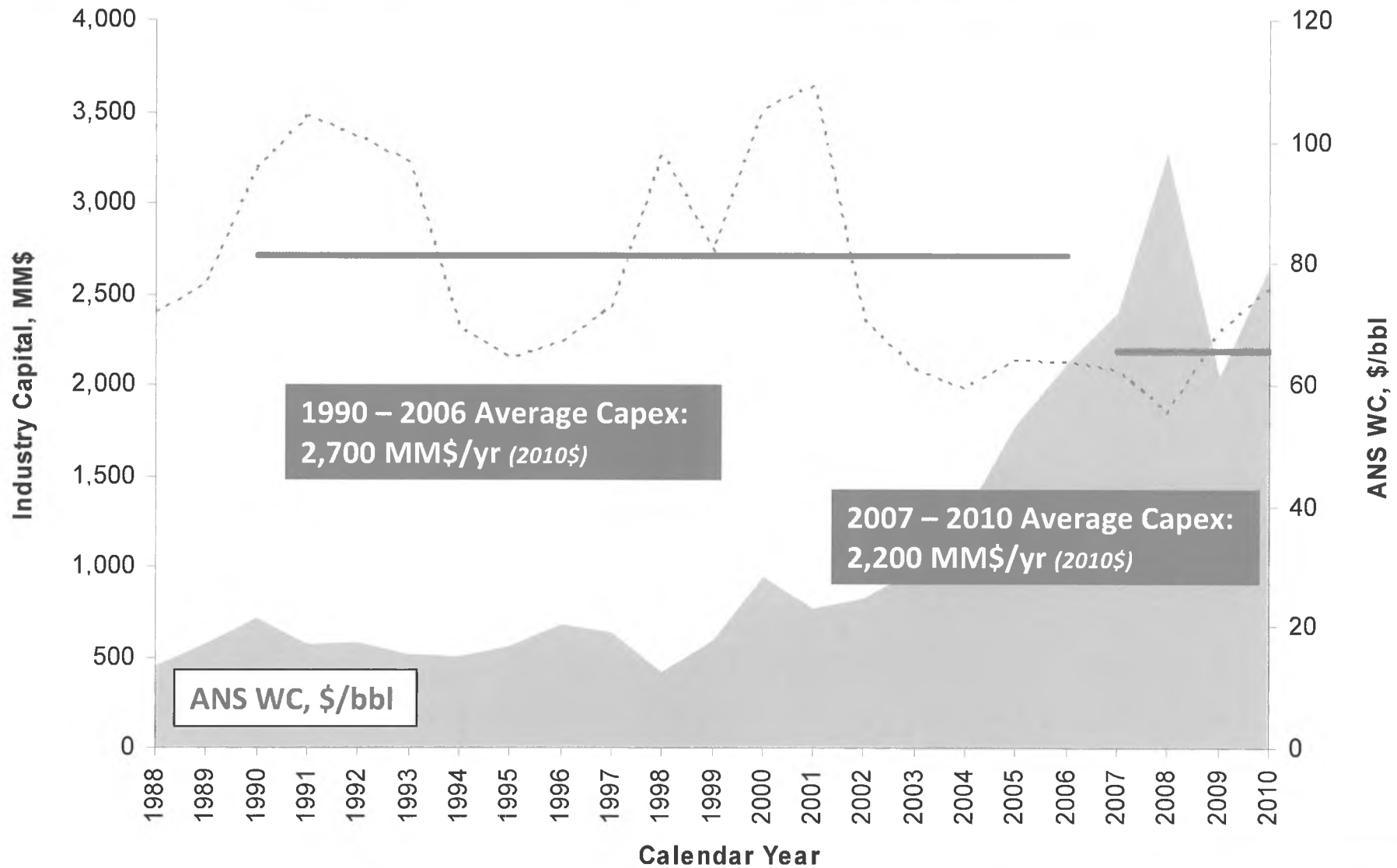
Source: Production forecast: DOR Fall 1989 Revenue Sources Book

Actual production: DOR website, <http://www.tax.state.ak.us/sourcesbook/AlaskaProduction.pdf>

ANS WC pricing: DOR website, <http://www.tax.alaska.gov/programs/oil/oilprices/ansyearly.aspx>

Satellites timing: ConocoPhillips Internal

North Slope Investment Under ELF



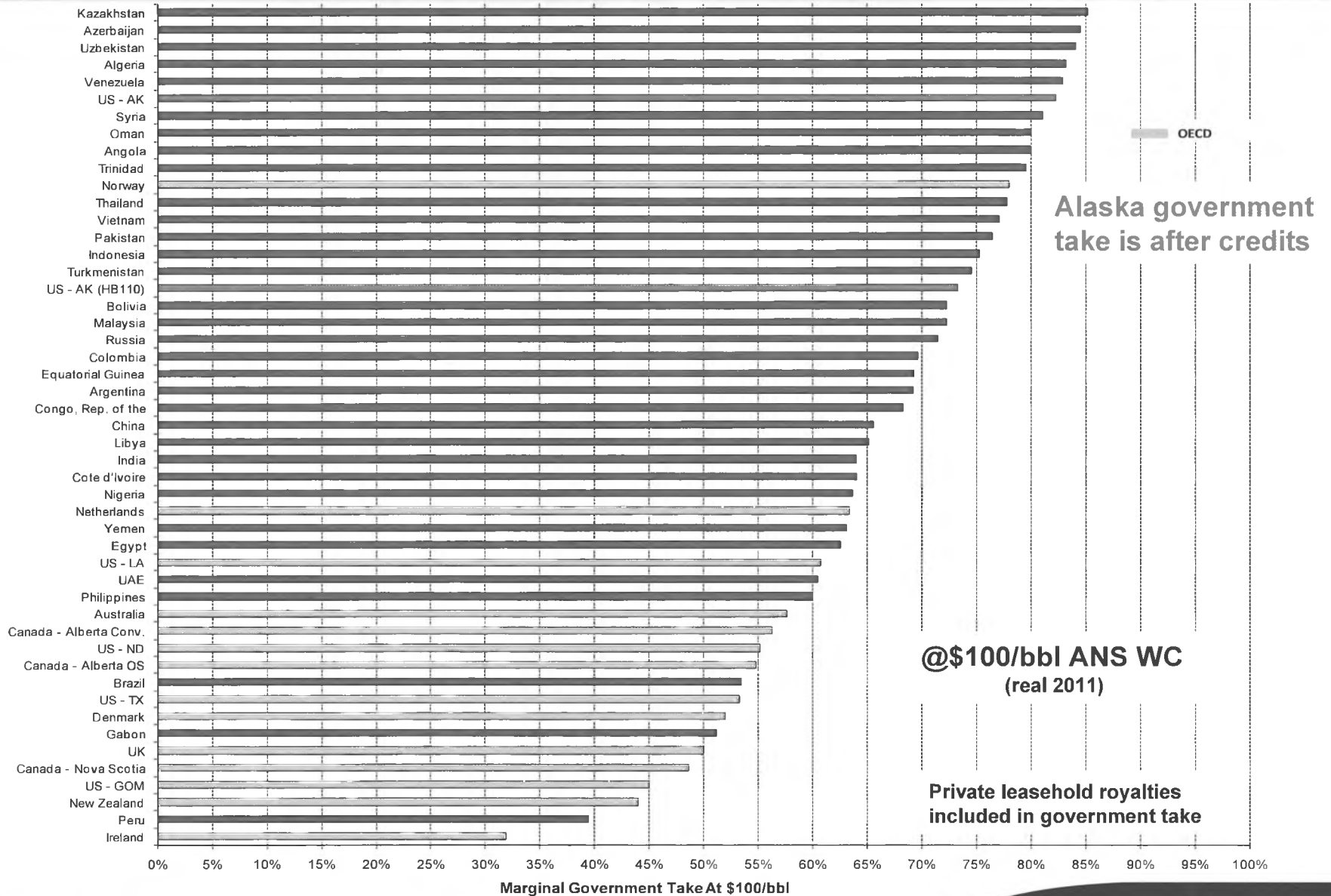
Sources: DOR February 23, 2011 "Response to Questions regarding House Bill 110 on February 11, 2011" letter to House Resources Co-Chairs Feige and Seaton

DOR October 24, 2007 "Capital Spending on North Slope Wells, Field Facilities and Exploration" letter to Legislature

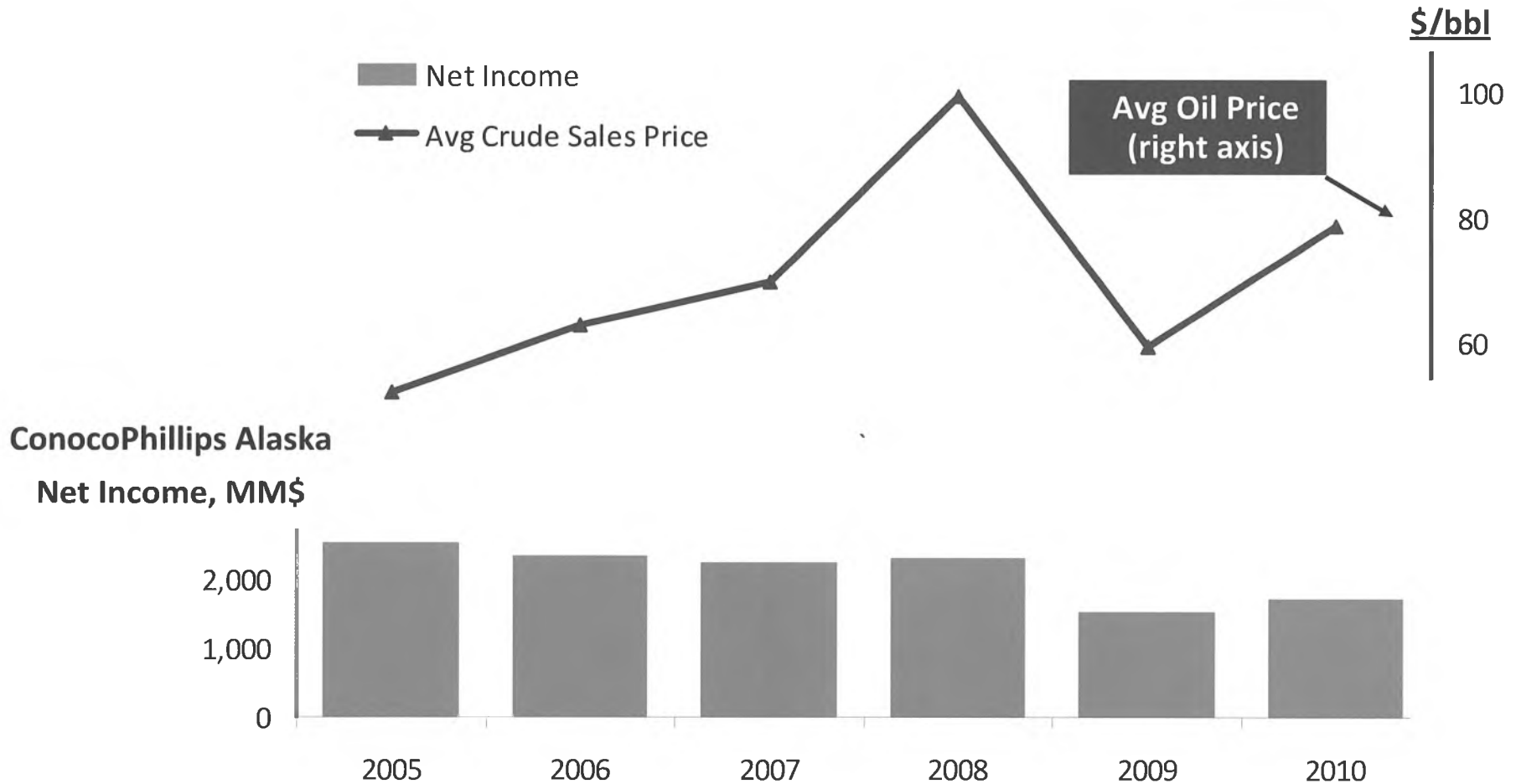
CERA and BLS oil and gas industry cost indexes

Alaska Not Competitive

Marginal Government Take

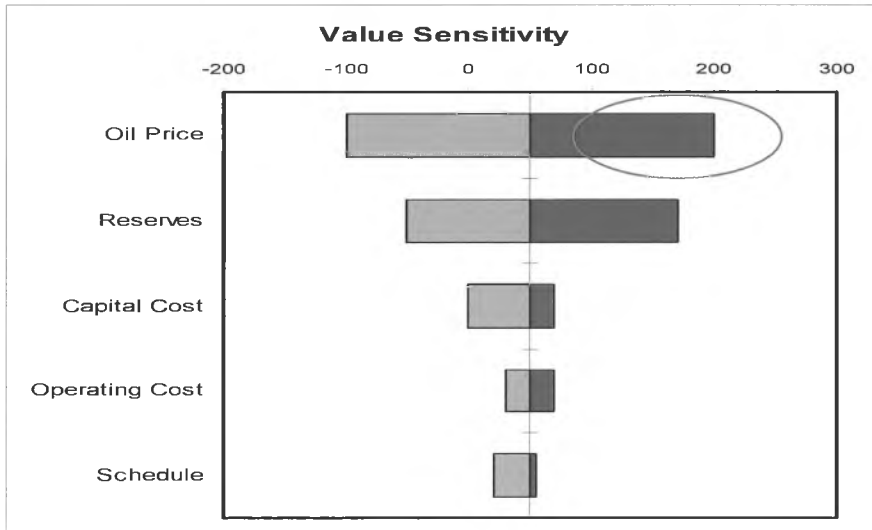


Progressivity Removes Upside

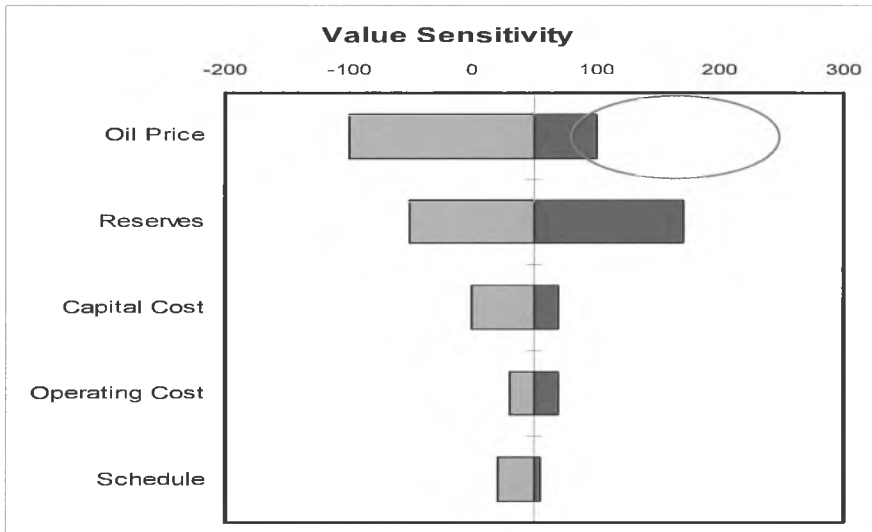


Risk-Based Decision Making

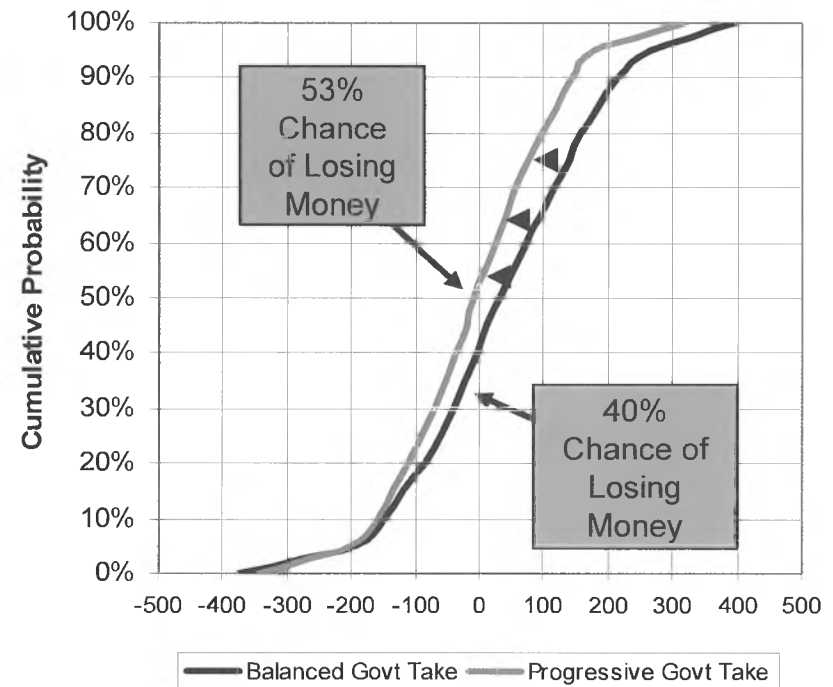
Balanced System



Progressive System

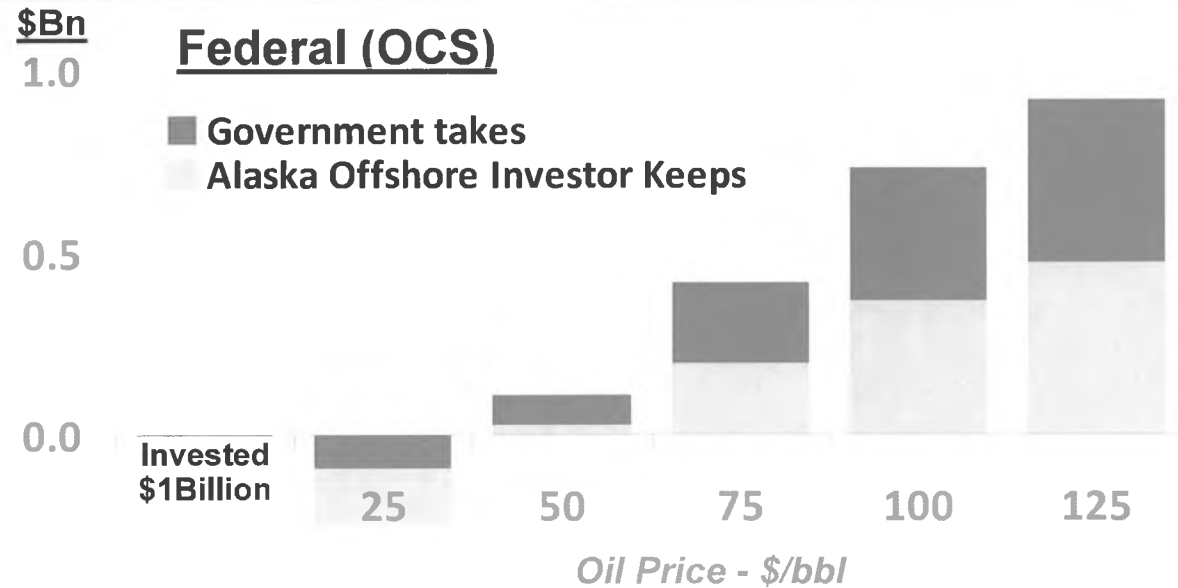


Value Uncertainty

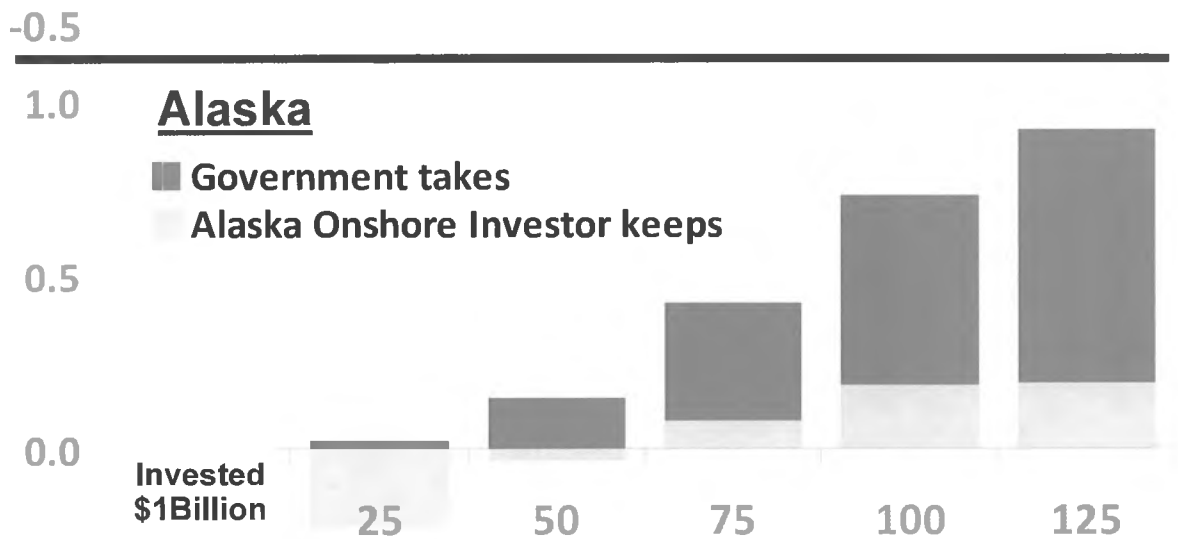


Progressivity Breaks Risk / Reward Balance

Example – \$1Billion capital investment



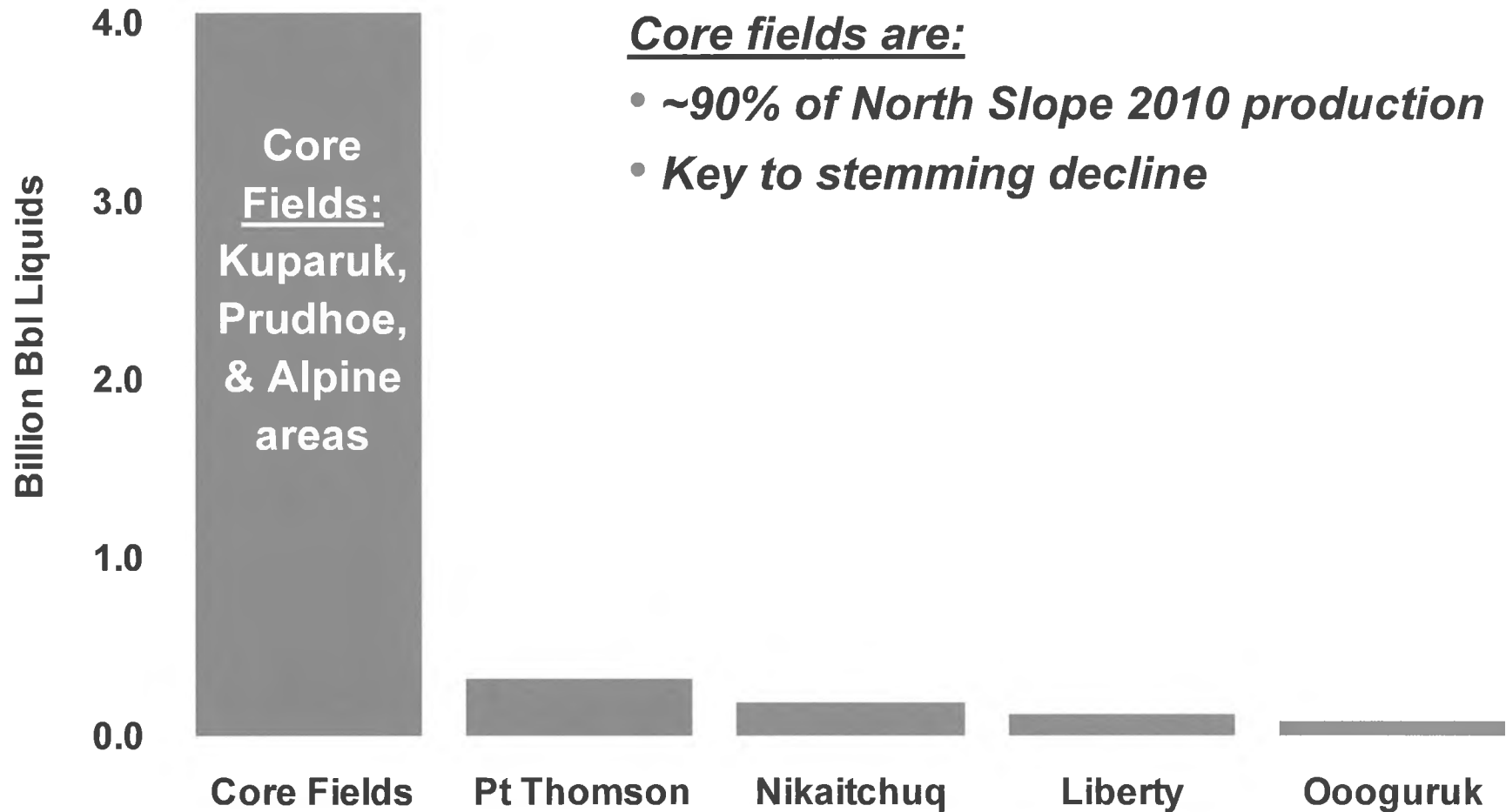
- Adequate returns in success case justify upfront investment risk



- Alaska onshore fiscal terms: Risk / reward is out of balance

*Discounted cash flow
Government take is after Alaska credits*

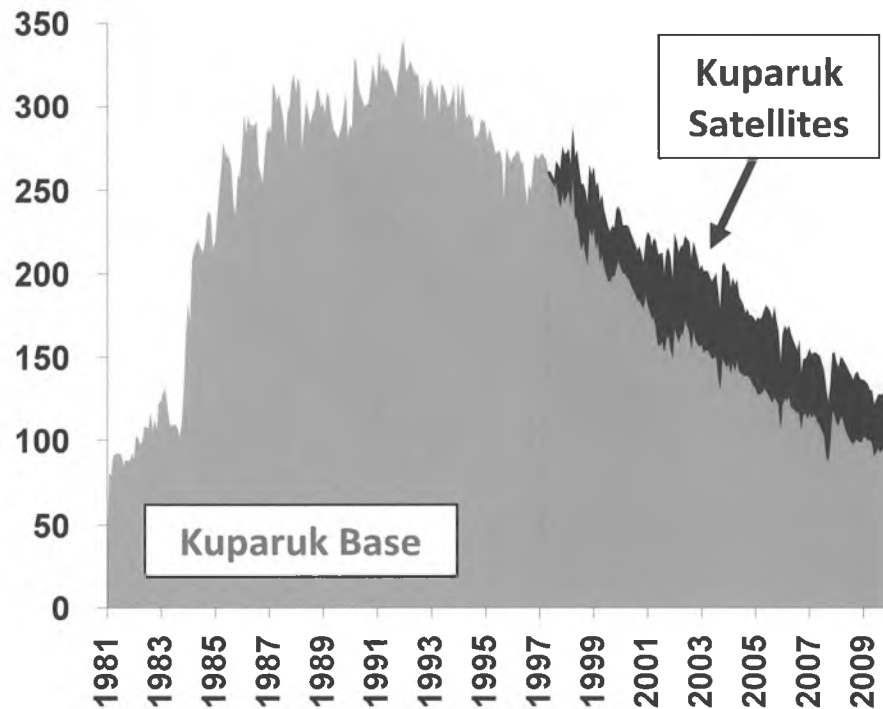
Core Fields are Key to State Production



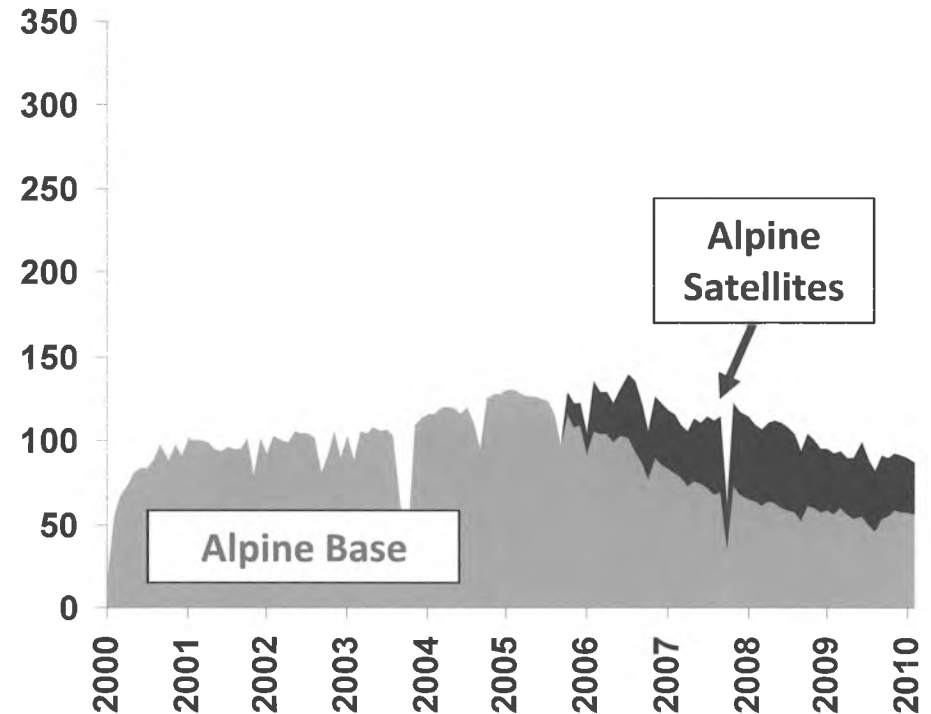
Source: DOR 2009 production forecast 2010 – 2050 volumes

Investment Reduces Production Decline

Kuparuk Production - MBD



Alpine Production - MBD



HB 110 Improves Alaska Investment Climate

▪ Existing Units

- Bracketing Progressivity is critical component
- Moves Alaska toward a more balanced risk/reward environment
- Incentivizes investment in core fields and existing units
- Supports longer term projects / longer term investment

▪ Improved Well Credits

- Incentivizes well related activity
- Increased drilling/workovers provide additional short-term jobs
- Support language being clarified to include workovers

▪ Administrative Improvements

- Audit period to 4 years – provides improved tax payment predictability
- Interest – eliminates punitive rate for good faith tax filings
- Monthly vs. annual progressivity – improves alignment on cost and revenue calculations

▪ Effective Date

- COP believes effective dates should be accelerated by 1 year

ConocoPhillips Supports HB 110

Alaska's Oil Future is At Risk

| | <u>Lower 48</u> | <u>Alaska</u> |
|-----------------------------------|-----------------|---------------|
| Oil Price | Up | Up |
| Active Rigs | Up | Flat |
| Actual Production | Up | Down |
| Expected Future Production | Up | Down |

HB 110 Important to Changing this Picture

3/23/11

Wendy D. King
Vice President, External Affairs
700 G Street, ATO (99501)
P. O. Box 100360
Anchorage, AK 99510-0360
Phone (907) 265-6026
Fax (918) 662-8060


ConocoPhillips
Alaska, Inc.

March 25, 2011

The Honorable Bill Stoltze
Co-Chairman, House Finance Committee
Alaska State Legislature
Alaska State Capitol, Room 515
Juneau, AK 99801-1182

The Honorable Bill Thomas
Co-Chairman, House Finance Committee
Alaska State Legislature
Alaska State Capitol, Room 505
Juneau, AK 99801-1182

Dear Co-Chairmen Stoltze and Thomas:

Thank you for the opportunity to present to the House Finance Committee on March 23, 2011, regarding the State of Alaska's oil tax structure and our support for HB 110 as a positive step towards improving the investment climate in Alaska.

Questions raised during the committee discussion are addressed below with additional details provided in the attachments.

Question #1: Can you provide the fiscal comparison analysis performed by PFC Energy on an average government take basis at \$100/bbl and \$82.50/bbl?

Response: Attachment 1 is the PFC fiscal comparison on a marginal basis at \$100/bbl, Attachment 2 is the PFC fiscal comparison on an average basis at \$100/bbl, and Attachment 3 is the PFC fiscal comparison on an average basis at \$82.50/bbl. In all three cases Alaska under ACES is identified by the red bar, Alaska under HB 110 is identified by the green bar, and other states and OECD countries are identified by yellow bars. The Alaska values are government take after credits have been applied. On an average basis at these prices, government take for Alaska ranges between 73 percent and 76 percent, while on a marginal basis at \$100/bbl government

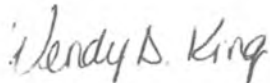
take for Alaska exceeds 82 percent. The government take for Alaska is significantly higher than for any other state, where oil activity is booming in the current high price environment.

Question #2: Can you illustrate where HB 110 would fall on the chart comparing industry/government take in Alaska vs. Federal (OCS) for an example \$1 billion capital investment?

Response: Attachment 4 is the chart shown during testimony, with the addition of the impact on industry take under HB 110.

Please do not hesitate to contact me if the Committee has further questions or requires additional information.

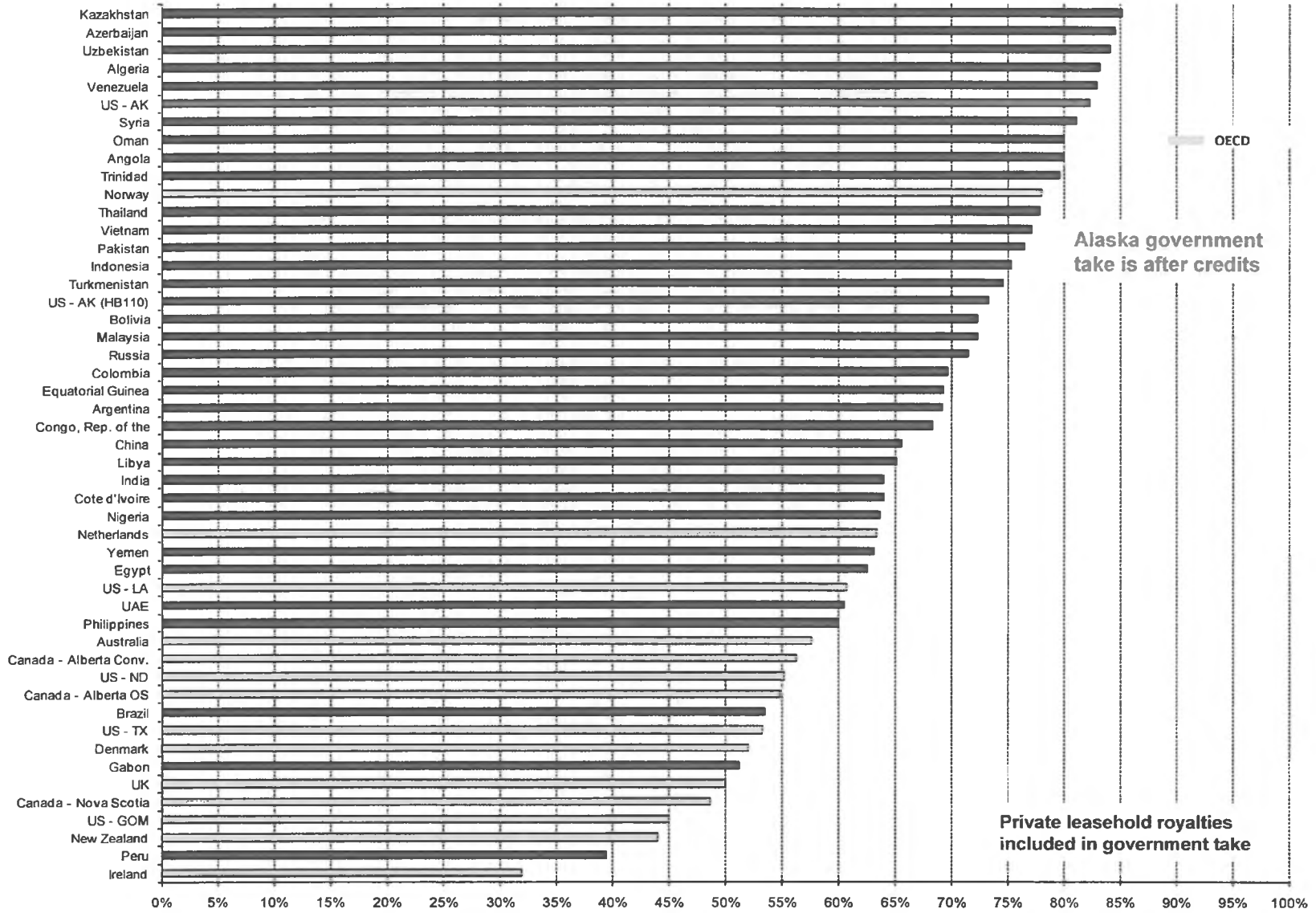
Respectfully,



Wendy D. King

Attachments

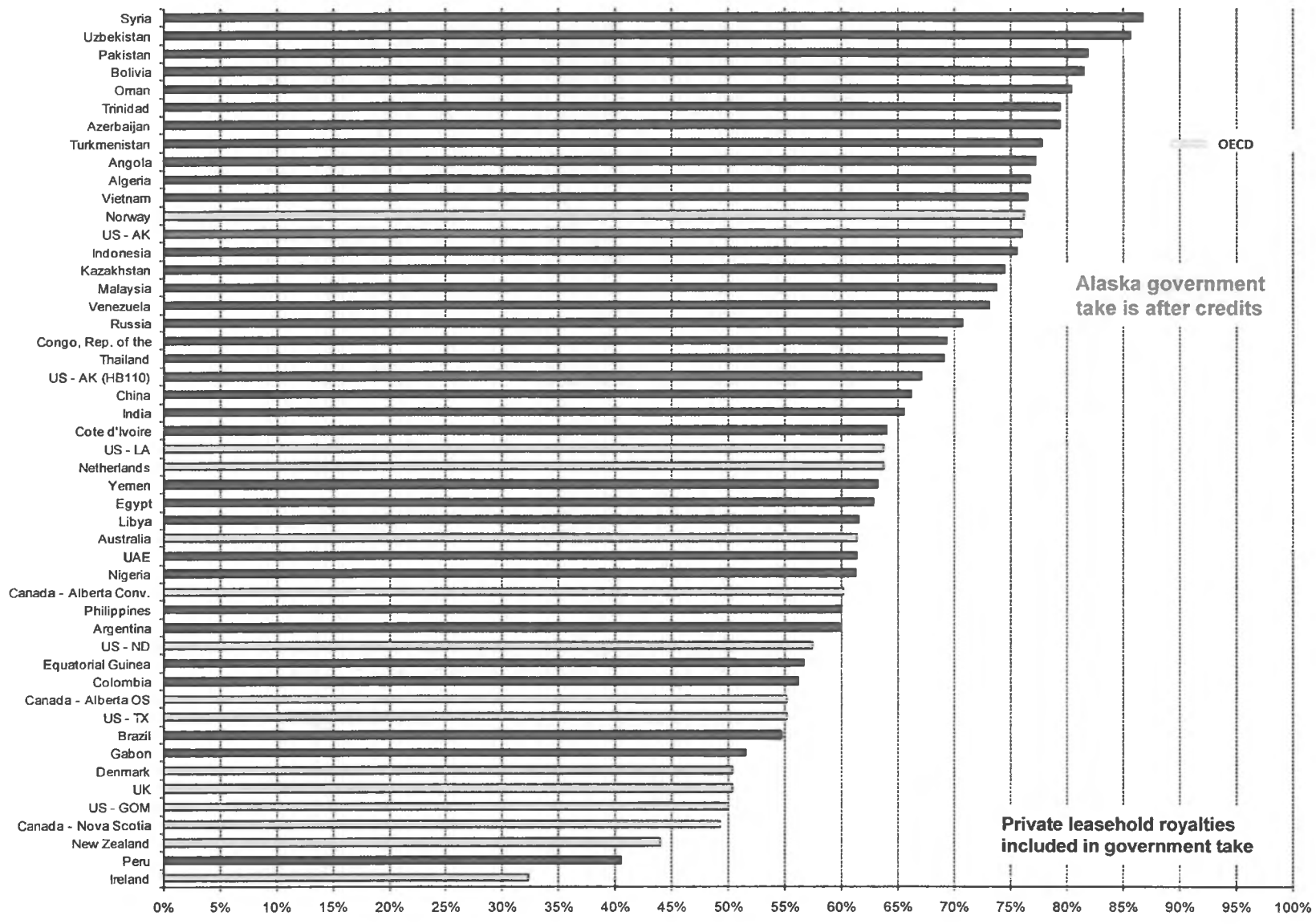
Marginal Government Take @ \$100/bbl ANS WC



Attachment 1

Source: PFC Energy

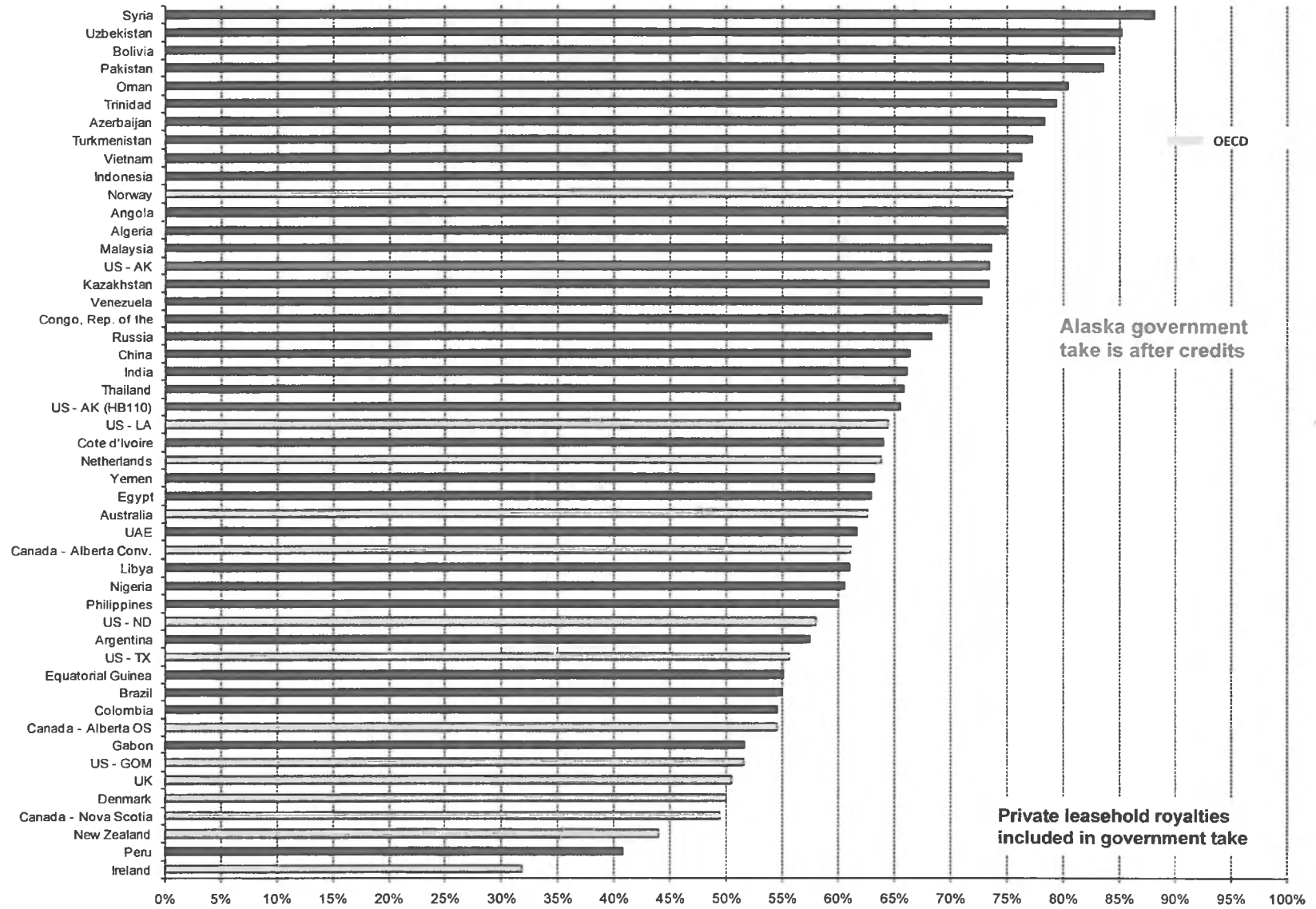
Average Government Take @ \$100/bbl ANS WC



Attachment 2

Source: PFC Energy

Average Government Take @ \$82.50/bbl ANS WC

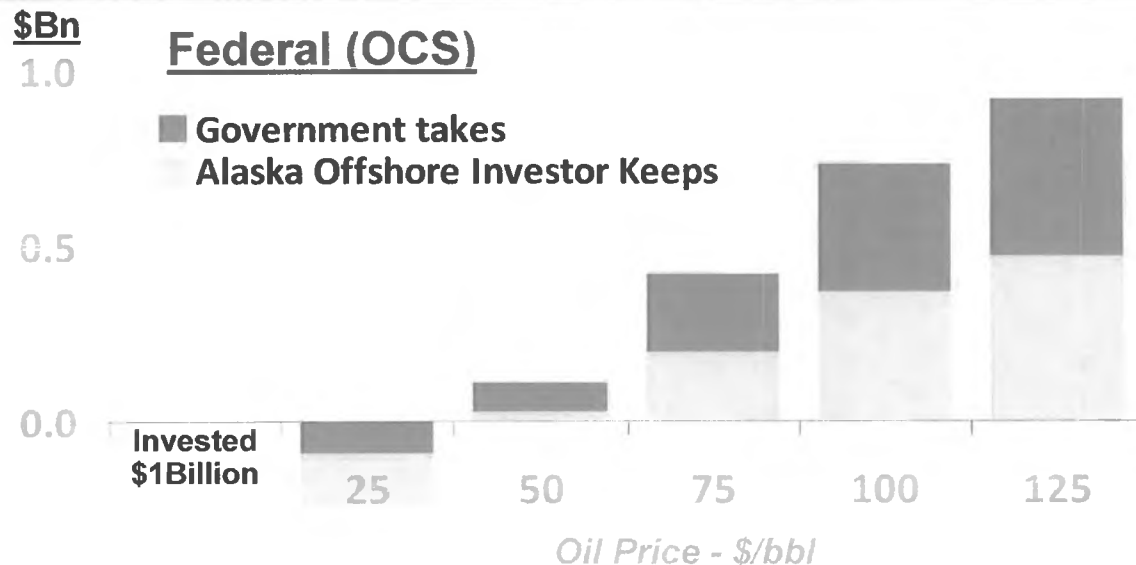


Attachment 3

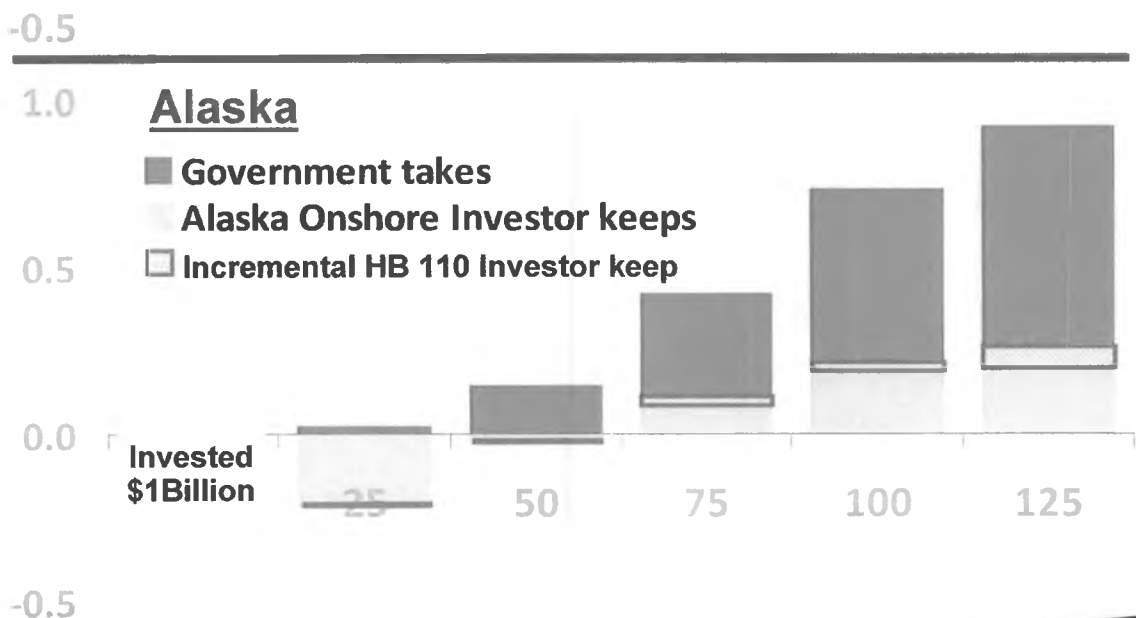
Source: PFC Energy

HB 110 Improves ACES

Example – \$1Billion capital investment



- Adequate returns in success case justify up front investment risk



- Alaska onshore fiscal terms: Risk / reward is out of balance

*Discounted cash flow
Government take is after Alaska credits*

3/23/11

PIONEER

NATURAL RESOURCES

**House Resources Committee
Testimony re: CSHB110(RES)
March 23, 2011**

NYSE: PXD
www.pxd.com

Forward Looking Statements

Except for historical information contained herein, the statements, charts and graphs in this presentation are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, international operations and associated international political and economic instability, litigation, the costs and results of drilling and operations, availability of equipment, services and personnel required to complete the Company's operating activities, access to and availability of transportation, processing and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility and derivative contracts and the purchasers of Pioneer's oil, NGL and gas production, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, and acts of war or terrorism. These and other risks are described in Pioneer's 10-K and 10-Q Reports and other filings with the Securities and Exchange Commission. In addition, Pioneer may be subject to currently unforeseen risks that may have a materially adverse impact on it. Pioneer undertakes no duty to publicly update these statements except as required by law.

Pioneer Alaska Profile

PIONEER
NATURAL RESOURCES

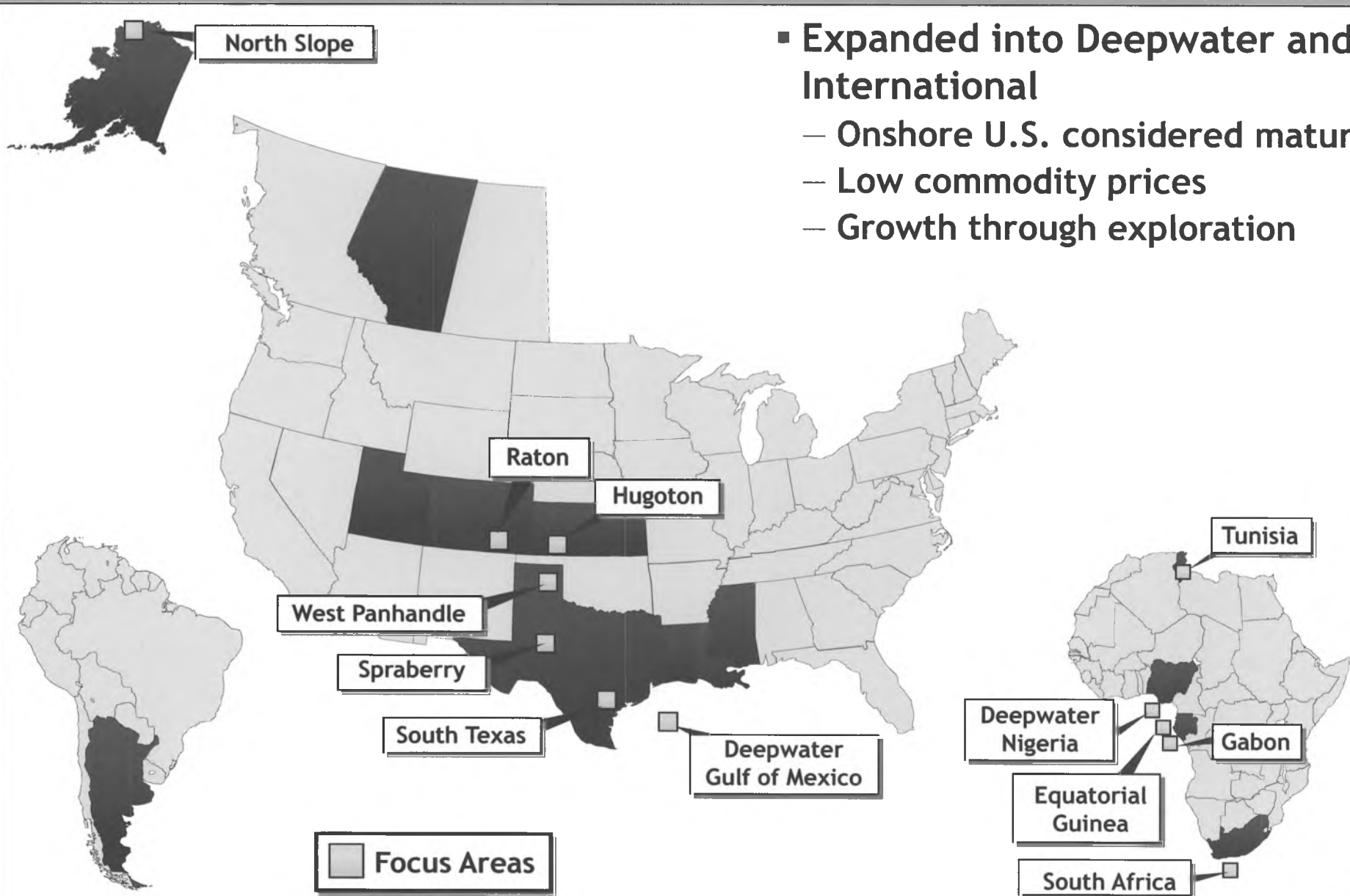
- Anchorage headquarters
- 60+ full-time AK employees
- ~120 AK contract workers
- World class Ooguruk project
- 1st independent operator on NS
- ~\$1B capital investment
- 120-150MMBO resource potential (net)
- 2010 Production ~10MBOPD (gross)
- State and NS producer support



Pioneer: 1997 - 2005 Deepwater / International Focus

PIONEER
NATURAL RESOURCES

- Expanded into Deepwater and International
 - Onshore U.S. considered mature
 - Low commodity prices
 - Growth through exploration



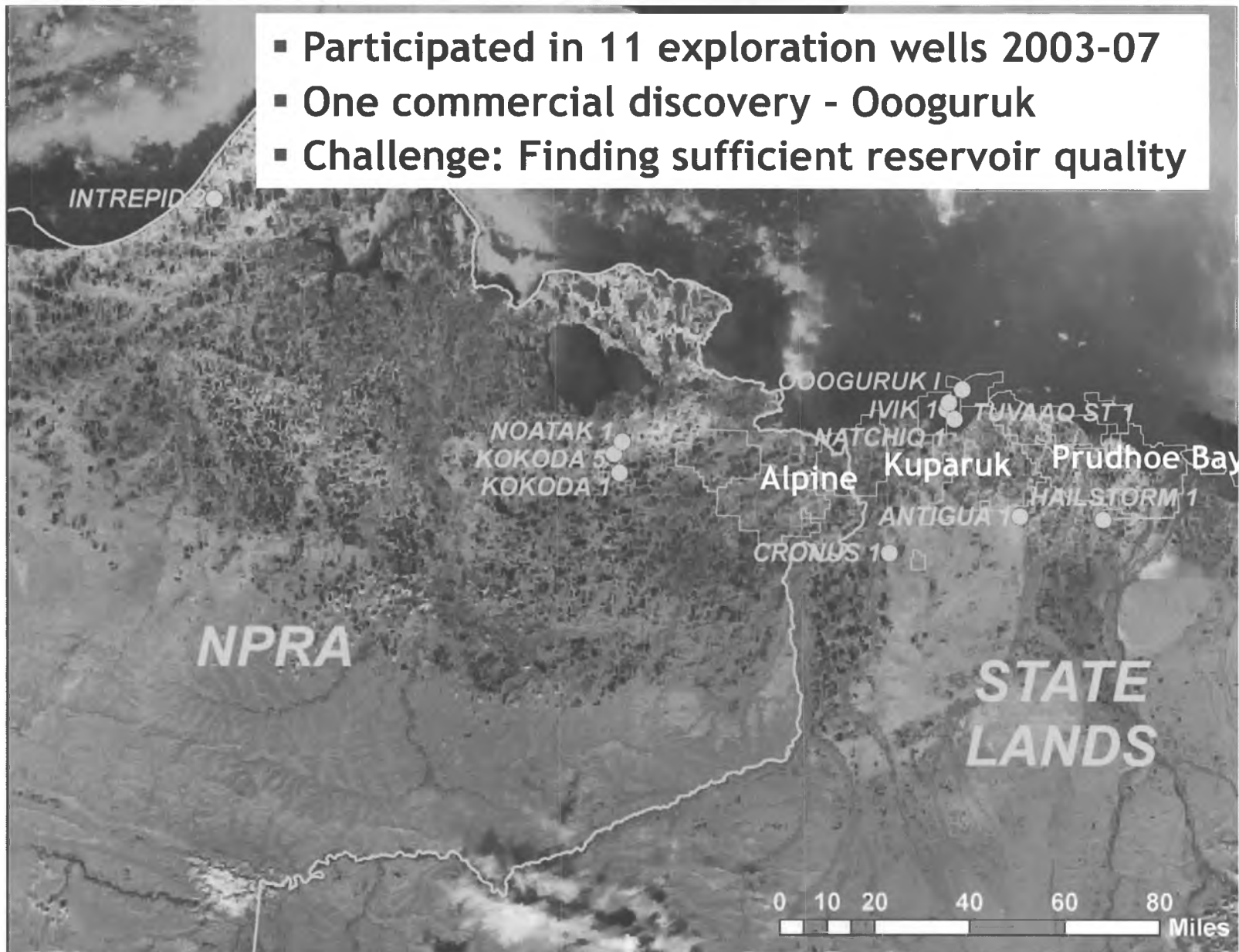
Why Alaska in 2002?

- **Worldwide exploration focus**
- **Alaska - large, oil resource potential in the U.S.**
- **Limited competition for resources**
- **State actively courting independents**
 - Exploration credits, low severance tax (ELF)
 - Available acreage at a low cost
- **Independent mindset**
 - Quick decision making
 - Lower cost structure

North Slope Exploration History

PIONEER
NATURAL RESOURCES

- Participated in 11 exploration wells 2003-07
- One commercial discovery - Oooguruk
- Challenge: Finding sufficient reservoir quality

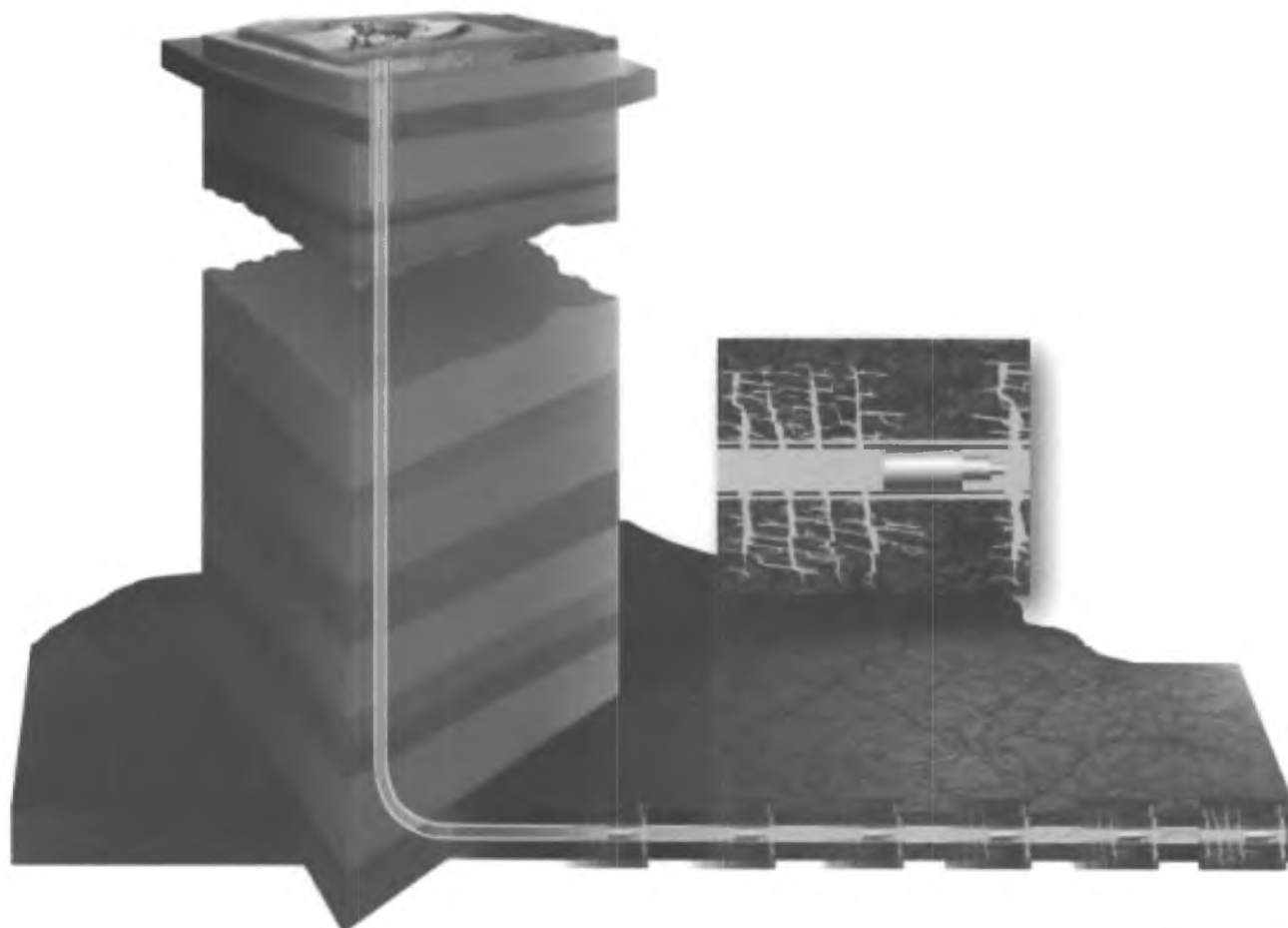


8 Years Later - What has Changed?

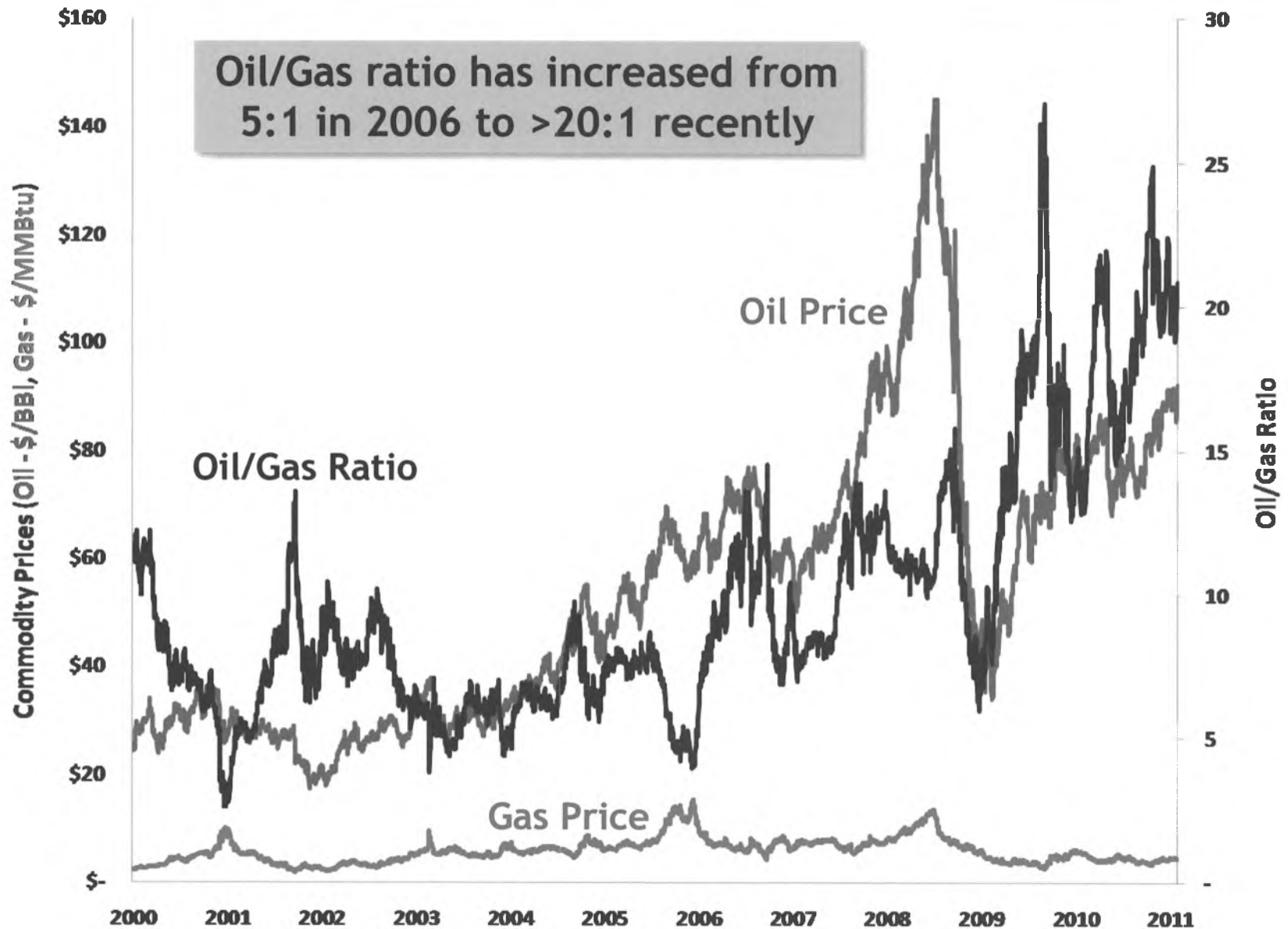
- **Technology**
- **Oil and gas prices**
- **Resource play development**
- **Alaska's severance tax system**



- Horizontal well improvements
- Fracture stimulation



Oil and Gas Price History

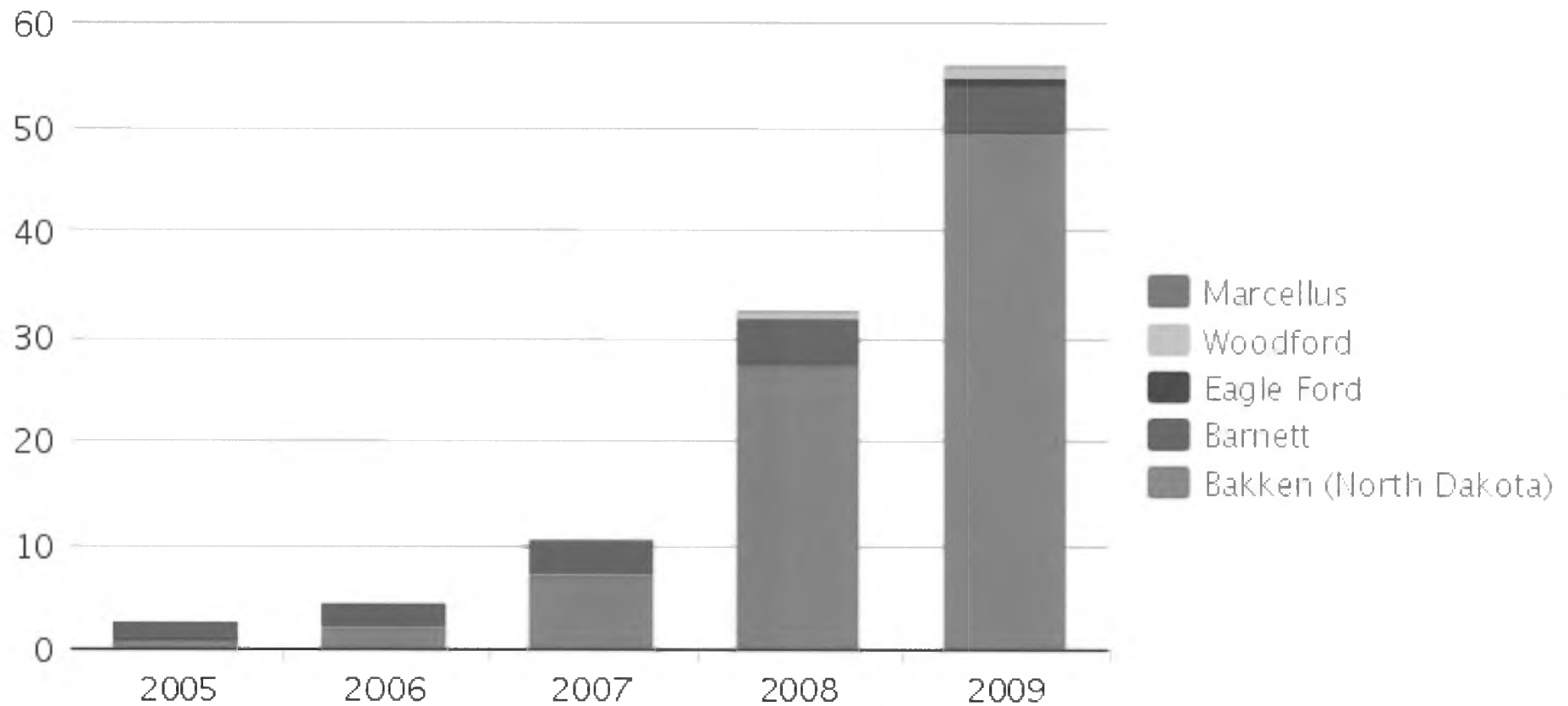


Oil/Gas ratio has increased from 5:1 in 2006 to >20:1 recently

U.S. Shale Liquids Production

PIONEER
NATURAL RESOURCES

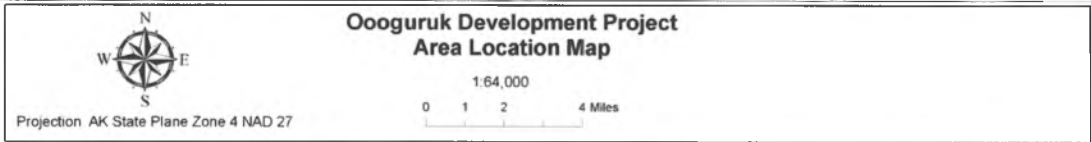
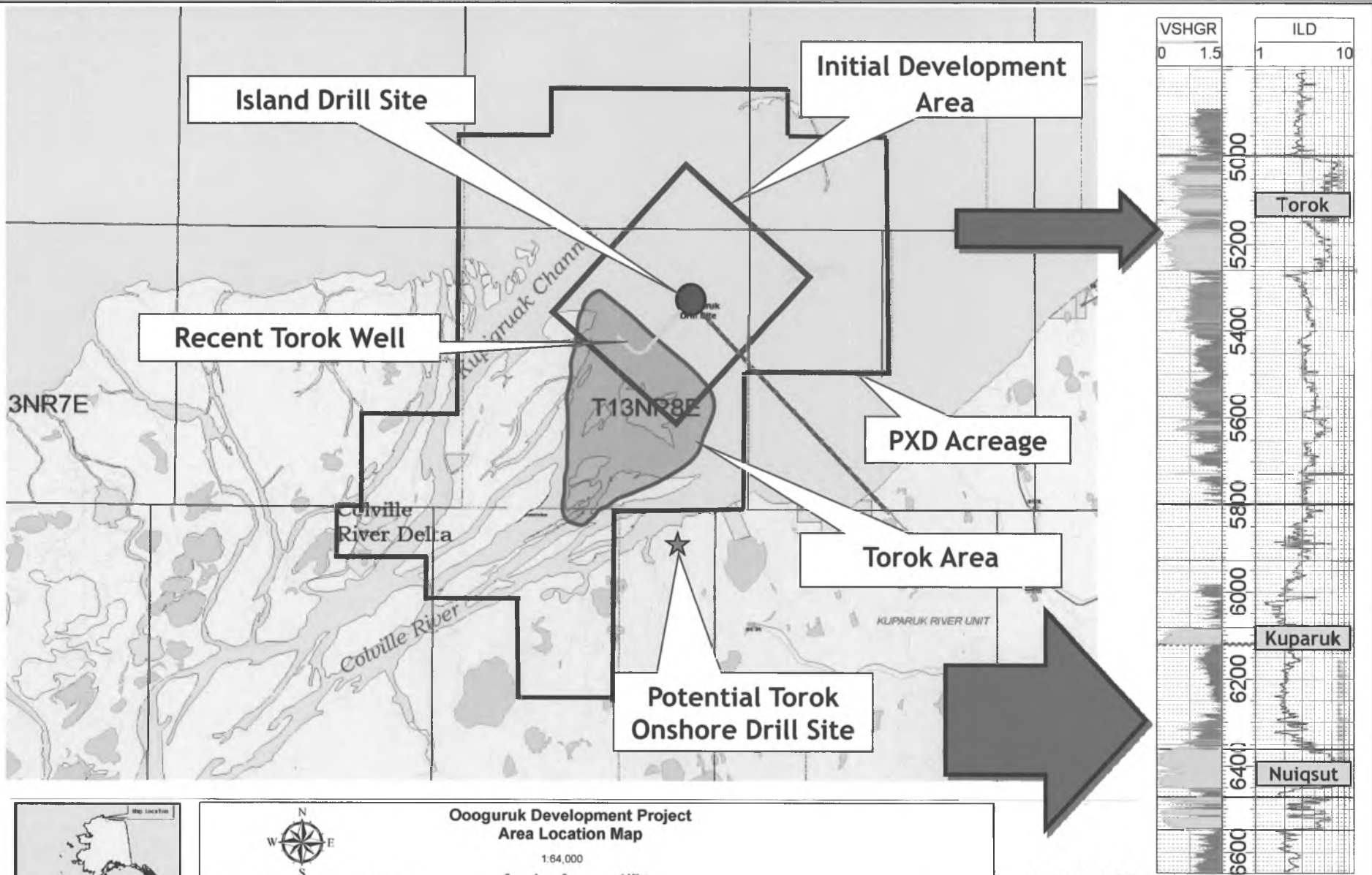
Shale liquids production
million barrels



Source: HPDI, LLC
Published by: U.S. Energy Information Administration

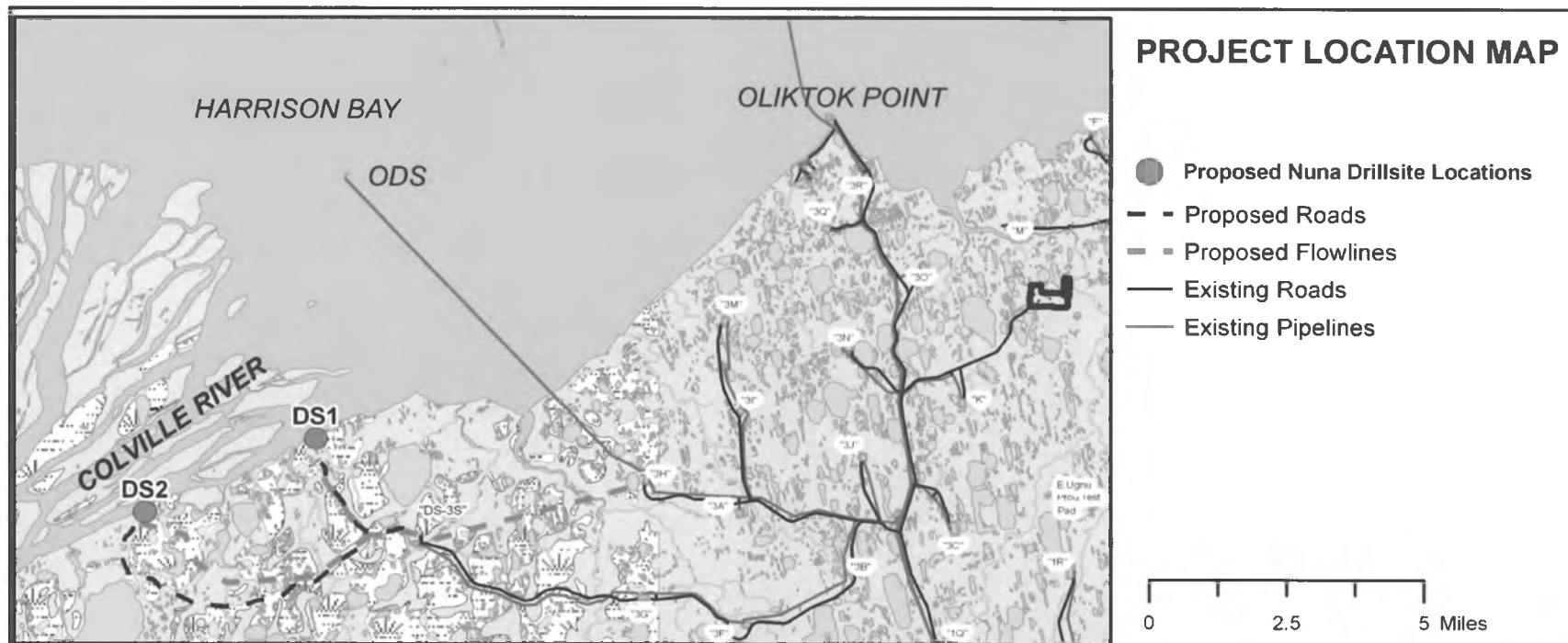
- **Pre 2007: ELF (Oooguruk project sanction)**
 - Low rate fields - no severance tax
- **2007: PPT (Oooguruk construction)**
 - 20% investment tax credit
 - 22.5% net profits tax
 - Moderate progressivity
- **2008: ACES (Oooguruk first production)**
 - 20% investment tax credit
 - 25% base tax rate
 - Aggressive progressivity (not indexed)
 - Maximum tax rate = 75%

What's Next? Oooguruk Expansion



Expansion Project Scope

- 1 or 2 onshore drillsites connected to Oooguruk tie-in pad
- ~25 development wells envisioned
- Large, but challenged oil resource
- Project contingent upon pilot waterflood success
- Must compete with low risk, high margin projects in L48



- **Pioneer resource plays in Texas**
 - Spraberry: West Texas
 - Eagle Ford shale: South Texas
 - Barnett shale: North Texas
- **Investment characteristics**
 - Low geologic and project execution risk
 - Short project cycle times and high margins
 - Year round operations and simple logistics
 - Low severance taxes - no progressivity
 - Much lower well and services costs
 - Flexibility to ramp up or ramp down activity

Pioneer: 2011 “Back to Our Roots”

PIONEER
NATURAL RESOURCES

Spraberry

Oil & Gas
900,000 Acres
~500 MMBOE Proved
1,150+ MMBOE Resource
20,000+ Drilling Locations
30 Rigs Running; Increasing to 40+

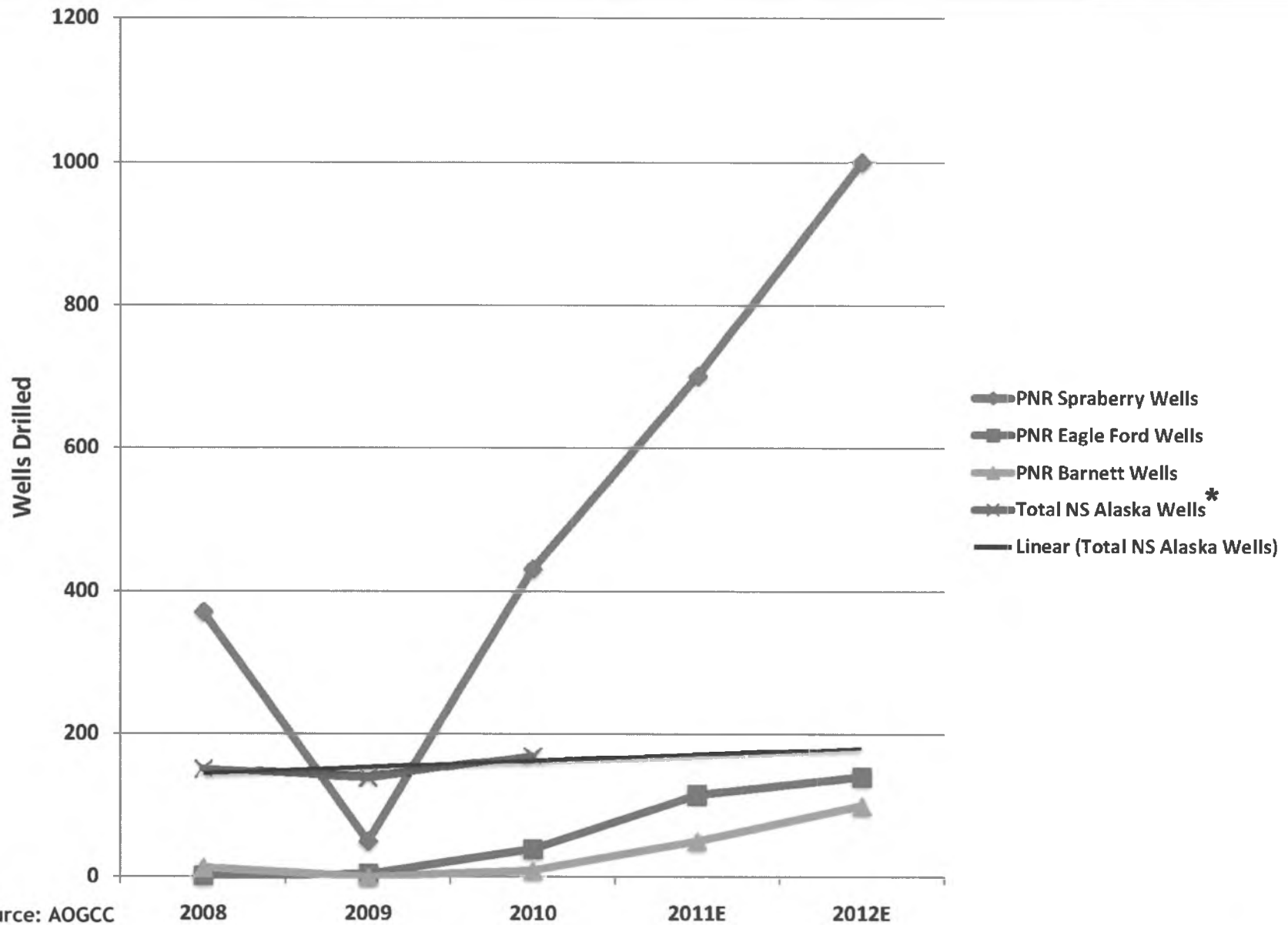
Barnett Shale Combo

Liquids & Gas
65,000 Acres
200+ MMBOE Resource
600+ Drilling Locations
2 Rigs Running; Increasing to 4

Eagle Ford Shale

Liquids & Gas
300,000 Acres
700 MMBOE Resource
2,000 Drilling Locations
7 Rigs Running; Increasing to 19

Competition for Capital



* Source: AOGCC

- **Oooguruk expansion must compete with L48 resource plays with:**
 - Large resource potential in Pioneer's back yard
 - Short project cycle times and high margins
 - Very favorable fiscal terms
 - Much lower capital cost
- **Oooguruk expansion**
 - New project - new barrels in TAPS
 - Create ~500 construction jobs
 - Create ~100 development jobs
- **HB 110 will have a positive, material impact**
 - Increased investment credits for well related costs
 - Bracketing of progressivity
 - Provide administrative certainty

3/23/11 PM



JOHN R. BEDINGFIELD

Vice President - Worldwide Exploration
and New Ventures

WWW.APACHECORP.COM

DIRECT (713)296-6416

FAX (713)296-6451

March 16, 2011

The Honorable Bill Stoltze, Co-Chair
The Honorable William Thomas, Jr., Co-Chair
House Finance Committee
Alaska State House of Representatives
State Capital
Juneau, Alaska 99801-1182

Dear Chairmen Stoltze and Thomas:

Thank you for the opportunity to submit testimony to the Alaska State House Finance Committee regarding our company and comment on the proposed oil and gas tax legislation before you. I regret I am unable to appear before you personally. I hope you find the comments we provide useful in your deliberations and would entertain any questions my testimony may generate.

Company Background

Established in 1954, Apache Corporation (Apache) has grown to become one of the world's top independent oil and gas exploration and production companies with over \$29 billion in assets. In August 2010 Apache acquired almost 200,000 acres of State oil and gas leases in Cook Inlet primarily from Daniel Donkel and Samuel Cade. Since then Apache has picked up additional acreage from the Alaska Mental Health Trust bringing our Cook Inlet acreage to approximately 300,000 acres.

Investment Decisions

In making decisions on investments there are a number of criteria Apache takes into consideration. Specifically when we looked at Alaska what made investment attractive is that it has been sparsely explored and new technology will help find new reserves that can be produced more efficiently. Another factor is the percent of profit available on a barrel of oil after taxes, royalty and costs. There are incentives available in Cook Inlet as well as the tax structure makes it attractive. Conversely, the North Slope is expensive due to the operating environment and a different tax structure.

Cook Inlet Exploration

Apache's objective in acquiring the Cook Inlet leases is to explore for oil. Permit applications were submitted in November 2010 to conduct a 2D seismic technology test using a new Nodal technology. All the necessary permits were issued in February 2011 with the seismic work to be completed in March 2011 in Cook Inlet's West Forelands. Apache has begun conversations with the stakeholder groups and regulatory agencies about the 3D seismic program to commence in the fall 2011. We will spend approximately one year doing seismic exploration on the Apache leases that stretch from Wasilla to Anchor Point. After analysis of the seismic data we will then be in a position to determine where to undertake exploratory drilling.

One of the many questions Apache has been asked is why are we interested in Cook Inlet. With the discovery of oil on the North Slope in the late 1960's the companies that were operating in Cook Inlet moved north. We believe there is significant untapped oil potential in the region and the incentives offered by the State of Alaska are attractive. Those two reasons compound with a skilled workforce and stable government make Cook Inlet attractive.

Alaska Oil and Gas Tax Structure

In addition to looking for acreage in Cook Inlet, Apache has examined opportunities to make investments on the North Slope. We have made the decision to focus our efforts in Cook Inlet for now in part due to the oil and gas tax structure embedded in the North Slope fields. Specific areas of concern include:

- High tax rate
- The progressivity surcharge
- Lack of incentives and tax credits

The base tax rate for the North Slope is 25%. House Bill 110 proposes to lower this rate to 15% for areas outside of current fields or units not in commercial production prior to December 31, 2010. This is a step in the right direction to encourage companies, like Apache, to invest.

There are a number of issues surrounding the progressivity surcharge. One, it is regressive. Once a company makes more than \$30 barrel the company is charged at the 25% tax rate PLUS they are charged for every single dollar over the \$30, a form of double taxation.

Chairmen Stoltze and Thomas
Page Three

The proposal for capping the progressivity tax at 50% rather than the current 75% provides some of the uplift needed to encourage companies to take the risk. Also proposed is moving to an annual calculation versus today's monthly calculation. An annual calculation synchronizing revenues with expenses would more accurately reflect the philosophy behind the progressivity feature.

If incentives are going to be provided then it should apply to all new oil associated with new field development and exploration. Equally it should apply to new oil arising from existing producing fields using in-field drilling, secondary recovery and tertiary recovery techniques. Apache would encourage you to include incentives for all new oil.

In May 2010 the Cook Inlet Recovery Act included tax credits to incentivize and encourage further exploration. Apache would encourage the Alaska State Legislature to apply these same credits to all regions undertaking oil and gas exploration and development in Alaska.

Again, I apologize that I am unable to attend your hearing in person. Should you have questions please feel free to contact me.

Sincerely yours,



for

John R. Bedingfield
Vice President, Worldwide Exploration and New Ventures
APACHE CORPORATION

Cook Inlet, Alaska



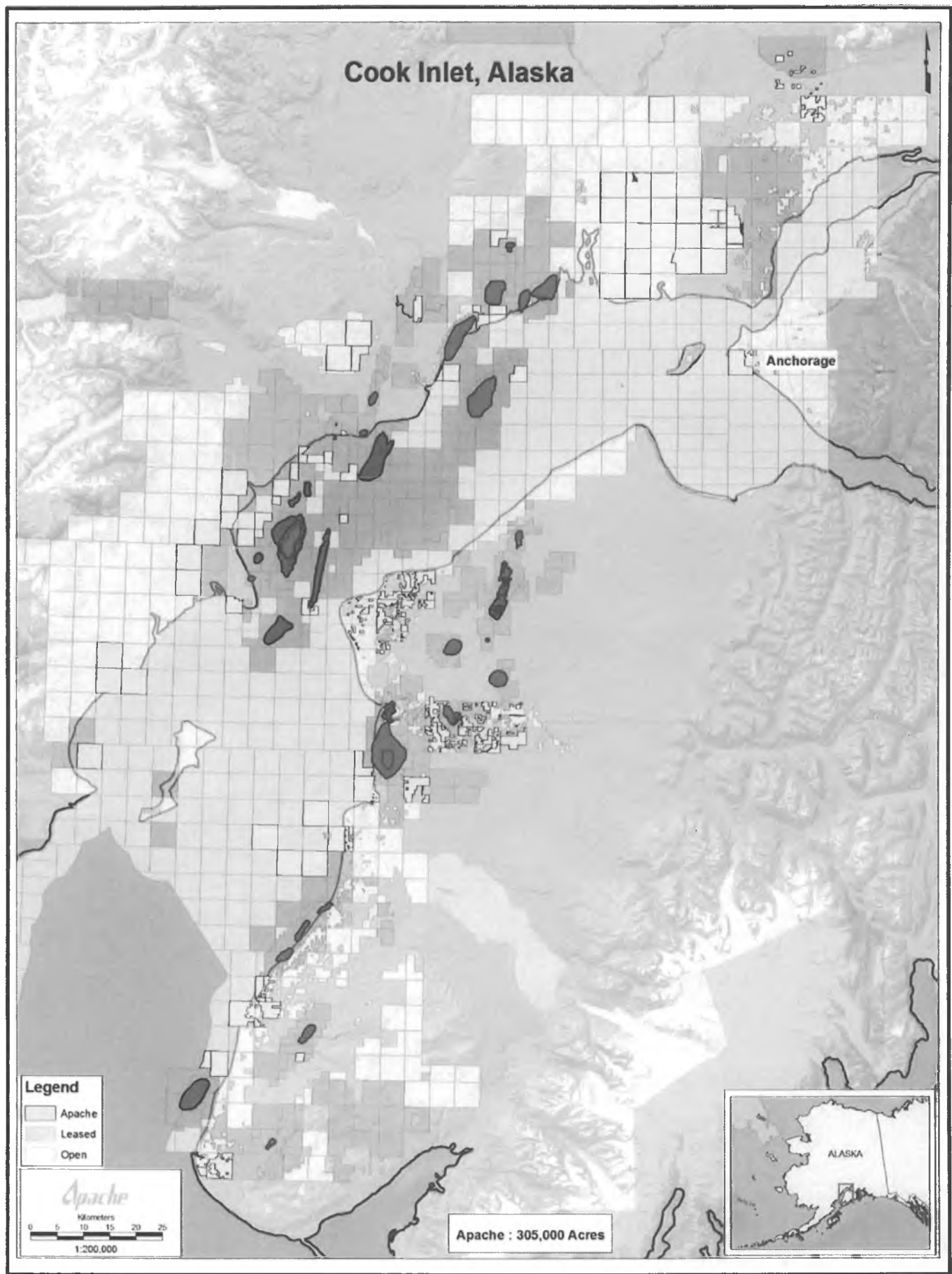
Anchorage

Legend

- Apache
- Leased
- Open

Apache
Kilometers
0 5 10 15 20 25
1:200,000

Apache : 305,000 Acres



3/23/11 PM

eni us operating

eni us operating co. inc.
1201 Louisiana, Suite 3500
Houston, TX 77002
Tel. 713-393-6100 Fax 713-393-6205



March 17, 2011

Representative Stoltze
Alaska State Capitol
Room 515
Juneau, AK 99801-1182

Representative Thomas
Alaska State Capitol
Room 505
Juneau, AK 99801-1182

Representative Feige
Alaska State Capitol
Room 126
Juneau, AK 99801-1182

Representative Seaton
Alaska State Capitol
Room 102
Juneau, AK 99801-1182

Dear Representatives:

Thank you for the invitation to testify on HB 110.

Eni Petroleum Co. Inc. is the US subsidiary of Eni SpA, a major integrated energy company, committed to growth in the activities of finding, producing, transporting, transforming and marketing oil and gas.

Eni has operations in more than 70 countries, employing more than 78,000 people, and it is recognized by the market as a leader in sustainability, focused on enhancement and safety of its employees and communities, on environmental protection, on technological innovation and research and on energy efficiency.



eni us operating

Eni has achieved a varied and growing exploration and development portfolio in Alaska since 2005, including leasehold interests in both State onshore and offshore leases, as well as in the federal OCS in the Chukchi and Beaufort Seas. Eni currently has a total of 140 leases in Alaska with 89 leases being located in the federal OCS (Chukchi Sea, Beaufort Sea) and 51 in the State of Alaska lands and waters. Eni's main producing assets in Alaska are a 30% working interest of the Ooguruk Field operated by Pioneer Natural Resources and a 100% working interest of the Nikaitchuq Field at Oliktok Point, located on the North Slope, immediately north of the Kuparuk River Unit. Eni acquired the interest and operatorship as the result of agreements with Armstrong in 2005 and with Kerr-McGee Oil and Gas Corporation in 2007. In March 2006, Eni opened an operating office in Anchorage, which employs about 70 people.

The Nikaitchuq Project foresees the drilling of 52 wells from both onshore and an offshore artificial island located 3.8 miles from Oliktok Point, yet still within the barrier islands of the Beaufort Sea. The offshore wells will then be tied back to the production facility located at Oliktok Point utilizing a state-of-the-art subsea pipeline.

Eni achieved first oil production from the onshore drillsite on January 30, 2011, 3 years from the sanction of the project. The total actual investment is approximately \$1.3 billion; an additional \$0.7 billion will be spent to reach first oil from the offshore drillsite in December 2011 and to complete the drilling campaign in 2014.

Eni decided to sanction the project in 2008 considering the improved overall economic results after the State of Alaska agreed to provide royalty reduction at low oil prices; the development incentives provided in the form of Petroleum Production Tax (PPT) credits alone would not have been sufficient to secure viable project economics.

Passage of HB 110 would contribute to Eni's business in Alaska in two ways. First, it would make Alaska projects more competitive for internal investment dollars in comparison to other opportunities around the world. Second, it could improve the economics of marginal fields and reservoirs. Each unit may contain a number of reservoirs of oil, yet only some of those reservoirs are part of a development plan because others are uneconomic under the current law. If HB 110 were to become law, economic evaluations would better support the viability of these additional reservoirs, which would encourage expansion of the projects' original development plans and ultimately lead to production of additional recoverable reserves.

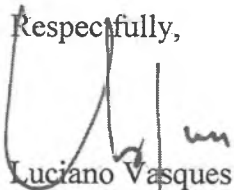
In addition, Eni believes that passage of HB 110 as currently written would provide the incentive needed to motivate oil companies to re-evaluate higher risk projects on which the future economic health of Alaska will depend. This will have a beneficial effect on the local economy of Alaska and on all professional contractors with whom Eni has collaborated on the Nikaitchuq Project.



eni us operating

Again, thank you for the opportunity to share Eni's position on HB 110.

Respectfully,



Luciano Vasques
President & CEO
Eni Petroleum Co. Inc.

3/23/11 PM

Carri A. Lockhart
Production Manager
Alaska Asset Team



P.O. Box 196168
Anchorage, AK 99519-6168
Telephone 907/565-3040
Cellular 907/382-0752
Fax 907/565-3076
E-Mail: calockhart@marathonoil.com

March 22, 2011

Representative Bill Stoltze, Co-Chairman
House Finance Committee
State Capitol Building, Room 515
Juneau, Alaska 99801

Dear Legislators,

Marathon Oil supports Governor Parnell's effort to change Alaska's tax structure through the passage of HB110 and to make Alaska a more competitive place to invest.

As you know, Marathon Oil Company has been operating in Alaska since before statehood. Our Alaskan operations are focused on natural gas production in the Cook Inlet with limited oil production.

We sell to every natural gas market available including the local utilities. Marathon has been in business in Alaska for over 56 years and we remain committed to serving the natural gas needs of SouthCentral Alaska through our various contractual commitments.

As the market environments have changed over the years in the Cook Inlet, the State of Alaska has recognized the unique challenges and opportunities and has been willing to adjust its tax structure to meet the needs of both its citizens and the industry.

The State of Alaska is now in the position to do the same for the more prolific North Slope oil and gas fields. Marathon Oil supports the Governor's efforts and encourages the Legislature to continue its efforts to attract more investment and make Alaska a more competitive place to do business.

Sincerely,

A handwritten signature in black ink, appearing to read 'Carri Lockhart', is written over a horizontal line.

Carri Lockhart

Cc: Governor Sean Parnell

3/23/11 PM



March 20, 2011

Hon. Representative Bill Thomas, Jr.
Co-Chairman, House Finance Committee
State Capitol Room 505
Juneau, AK 99801

Hon. Representative Bill Stoltze
Co-Chairman, House Finance Committee
State Capitol Room 515
Juneau, AK 99801

Re: HB 110

Thank you for the opportunity to testify on the subject bill. Unfortunately, I can't testify in person, but I will furnish my comments via this letter. Before I start, I thought I'd furnish you a brief introduction to UltraStar, which was formed in 2001 by Dale Lindsey of Seward, John Winther of Petersburg, and me. Dale was born and raised in Seward, and he and his widow, Carol, built a small fuel delivery service into the largest marine and land fuel distributor in the State. John was born in Fairbanks, raised in Juneau, and now lives in Petersburg, from where he manages a fleet of long liner vessels that fish cod and black cod in the Bering Sea and Gulf of Alaska. I was born and raised in the oilfields of Wyoming, and worked in project engineering, construction, and operations and executive management for ARCO for 30 years, 23 of which were spent working in various capacities on Prudhoe Bay, Kuparuk, Lisburne, Pt. McIntyre and West Sak. I moved my family to Anchorage in 1985. UltraStar's business plan is to acquire North Slope Leases close to existing infrastructure, develop projects on these leases, and prove up commercial reservoirs with the drill bit. To my knowledge, we are the only 100% Alaskan owned company that has drilled wells on the North Slope. We have another well and sidetrack planned for the first quarter of next year.

I am pleased to add UltraStar's name to the list of independents that support the Governor's proposed changes to ACES. We firmly support both HB 110. We support not only lower marginal tax rates, but also the elimination of the requirement that credits be paid over a two year period, which goes a long way toward "leveling the playing field" for start-up companies like ours with no current production.

As much as we like the direction these pieces of legislation are going, we feel that if ACES is going to be re-opened, one other issue should be addressed, and that is the Small Producer Credit. This is a credit of \$12 million per year for companies producing less than 50,000 barrels of oil equivalent per day, and is due to sunset in 2016. My suggestion is to recognize the lead times associated with finding, developing and producing reserves on the North Slope, and extend that sunset date. First, we must acquire leases, then seismic, then evaluate the seismic and develop drillable prospects

3111 C Street, Suite 500
Anchorage, AK 99503

(907)-258-2969

If the drilling finds commercial quantities of oil, then facility access terms and conditions need to be negotiated and established with the owners of the likely production facility where the oil, gas and water will be processed, and roads need to be built and the well(s) need to be connected to that facility. If the commercial accumulation is large enough, stand alone facilities may be a more appropriate approach to get production on line. Finally, somehow or another, production can commence, and the cash flow meter can start (hopefully) turning the other way, or at least slow down. Unfortunately, UltraStar has yet discovered commercial oil, but it has taken an average of 6 years per well to get to the point where we were able to get the drill bit into the ground.

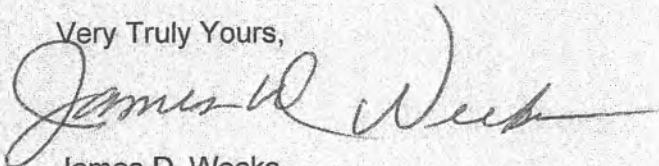
Rather than have a specific year when the Small Producer Credits expire, I recommend that it stay in place for each reservoir or unit until payout of the exploration, delineation and development costs necessary to get oil flowing. I believe this would be a much stronger incentive than a date certain year. New leases acquired last year have no chance of realizing this credit.

Not in the bill is re-consideration of the tax credits, which is good. The Qualified Capital Expenditures and the Carry Forward Loss provisions in the existing law are important, are working and should not be changed. It is safe to say that the last well drilled by UltraStar, the Dewline No. 1, would not have been drilled without the use of these credits. We simply could not have raised the money from the venture capital investors who funded the drilling and other exploration expenses without these credits. They do work for small independents like ours.

Lastly, it mystifies me why some in the Legislature want to take all the precious time in this short session having studies done to determine the competitiveness of Alaska. The major producers have had those studies done, probably by the same consultants the Legislature would use, and the answer given to the Legislature by the same consultants will be the same as the conclusions given to the major producers--Alaska is the bottom third or lower in the world. I can't speak for the major producers, but my guess that any one or all of them will be willing to share the details of the studies they commissioned with any Legislator who has an interest.

Thanks for hearing this bill and moving the process forward. The State of Alaska, the workers and citizens of Alaska, and the investors in exploration in Alaska need and appreciate your support.

Very Truly Yours,

A handwritten signature in cursive script, appearing to read "James D. Weeks". The signature is written in dark ink and is positioned above the printed name and title.

James D. Weeks
Managing Member

3/23/11 PM



21 March 2011

Representative Bill Stoltze
Representative Bill Thomas
Co-Chairs, House Finance Committee
State Capitol
Juneau, AK 99801-1182

Dear Representatives Stoltze and Thomas,

Statoil appreciates your invitation to testify before the House Finance Committee (regarding HB 110) this week. We regret that we will be unable to attend because a number of Statoil personnel, myself included, will be traveling to the Chukchi Coast villages at that time. The purpose of our trip is to give presentations to the village residents regarding our upcoming activities in the Chukchi later this summer. Although we cannot be present at the hearing in person I will include some general comments regarding the legislation in this letter.

Currently Statoil only owns leases in the Federal waters of the Chukchi Sea and thus we have no State tax obligation. Statoil is Operator of 16 leases, 14 of which are in partnership with ENI. Additionally, we have a 25% interest in the ConocoPhillips-Operated Devil's Paw prospect. Statoil has a very small (but growing) Alaska staff that is currently almost entirely dedicated to acquiring permits for our various activities on these leases. I know you are aware that this process has become quite complicated and time-consuming.

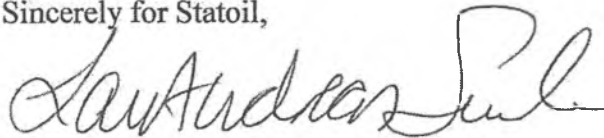
Statoil, because it has no State tax obligation, has not done any internal evaluation of the specific provisions of HB 110. As members of both AOGA and RDC, and through conversations with our Alaska colleagues and partners, we are well aware of the importance of this pending legislation to both the industry and the fiscal health of Alaska.

Statoil is supportive of any measures that the Governor and the legislature may take to improve the investment climate in Alaska. Increased investment in both exploration and in existing ("legacy") fields will ultimately lead to additional oil being delivered to TAPS. The viability of TAPS in the future is of major importance not only to us and the rest of industry, but to all Alaskans as well. Our current projects, located 100 miles offshore in the Chukchi Sea, offer no short-term solutions for keeping TAPS utilized. We must rely on the State government to create and maintain responsible and prudent fiscal policies that encourage production of new oil.

We recognize that there may be near-term financial consequences of this legislation, but we also realize that if TAPS shuts down, then a major source of Alaska's future revenue will remain forever stranded on the North Slope.

We wish you every success in your ongoing deliberations.

Sincerely for Statoil,

A handwritten signature in black ink, appearing to read "Lars Andreas Sunde". The signature is fluid and cursive, with a large, stylized initial "L" and "S".

Lars Andreas Sunde
Vice President, Exploration, Alaska Operations

**Biography for Claire Fitzpatrick
Chief Financial Officer
BP Alaska Region**

Claire Fitzpatrick is the chief financial officer for BP in Alaska. Central Business Services which falls under Fitzpatrick's responsibility includes finance, strategy and planning, commercial, control & accounting, supply chain, tax, facilities and aviation.

Fitzpatrick came to Alaska in 2007. She has worked in a variety of financial roles over her 20 year career, primarily with companies whose focus is on exploration and production or commodity trading. She joined BP in 2002. She holds a bachelor's in Biological Sciences from Edinburgh University in Scotland and is a qualified Chartered Accountant.

Fitzpatrick serves on the board of the Anchorage Economic Development Corporation.

3/23/11



House Finance Committee
BP Alaska Testimony- Claire Fitzpatrick, CFO
March 23, 2011



Balanced Fiscal System Investments

FIRST PRODUCTION 1995-2005

- Sag River (1995)
- West Sak (1997)
- Badami (1998)
- Eider (1998)
- Tabasco (1998)
- Tarn (1998)
- Midnight Sun (1998)
- Polaris (1999)
- Aurora (2000)
- Meltwater (2001)
- Northstar (2001)
- Borealis (2001)
- Orion (2002)
- Put River (2004)
- Raven (2005)

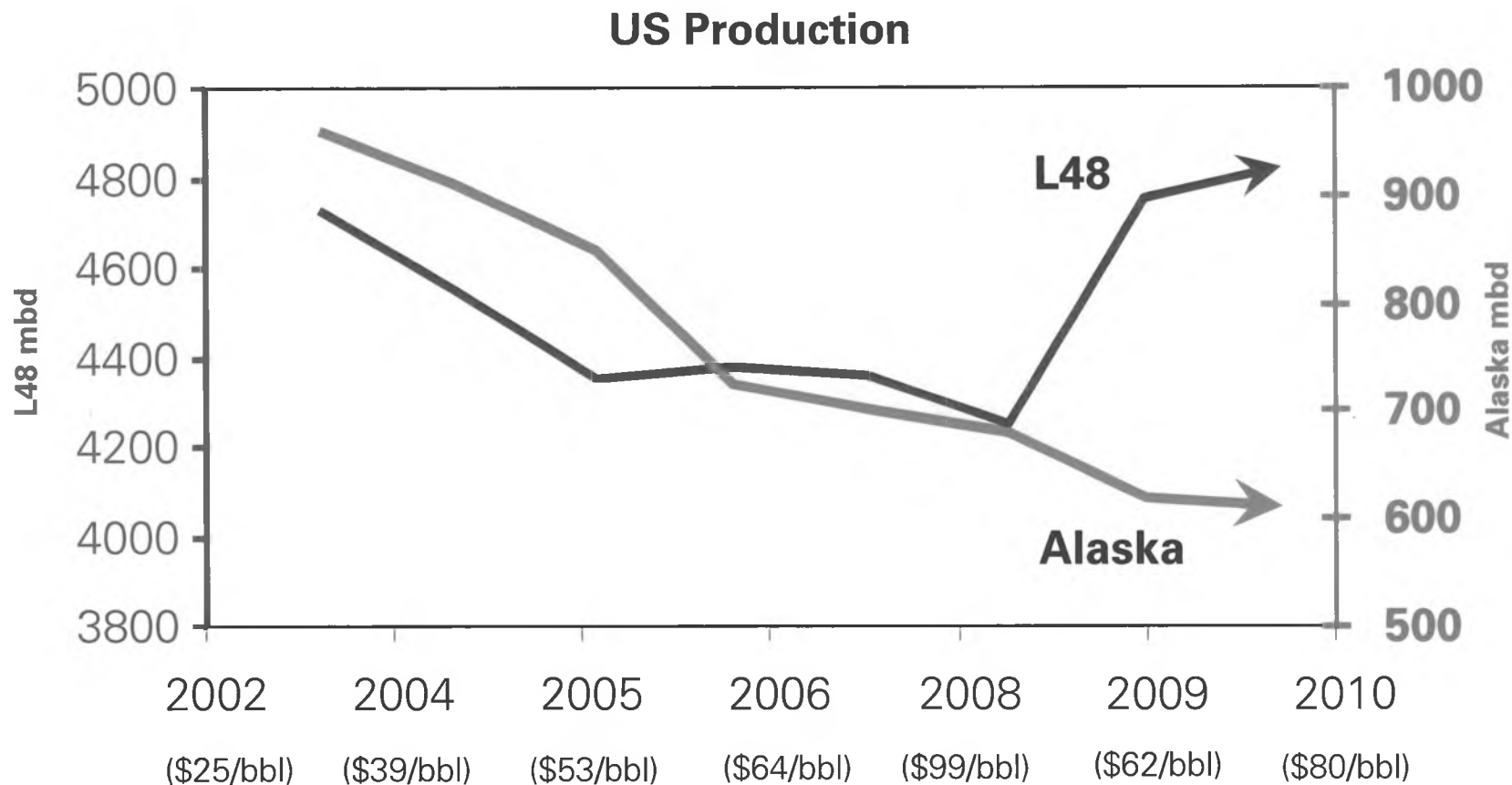
PRODUCTION SUPPORT INVESTMENT

Pipeline upgrades
~1997
~2002

Alaska Tanker Fleet
4 Tankers
~2001-2006

Source: Division of Oil and Gas Annual Report 2009

US production is growing; Alaska production isn't



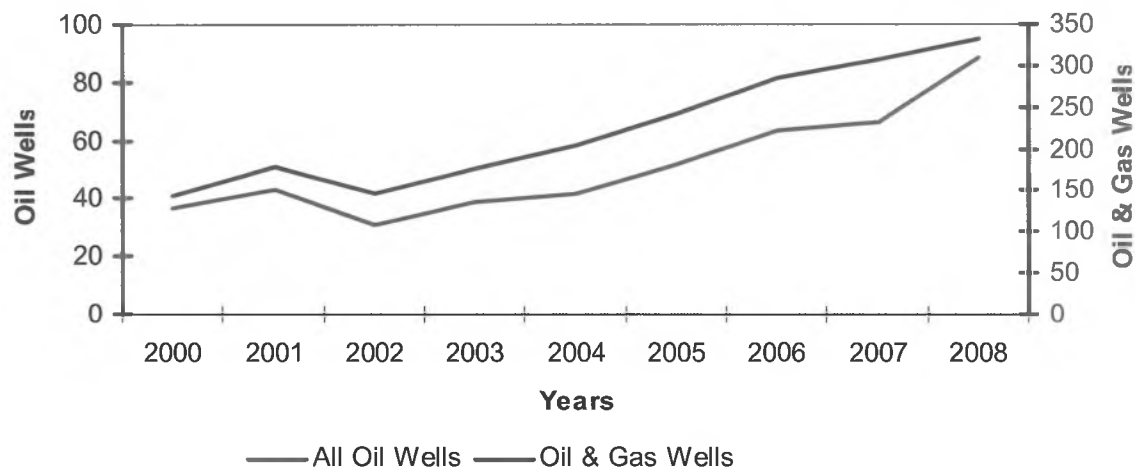
- Production in the Lower 48 has been increasing.
- Alaska production is in steady decline

Source: Energy Information Agency



Lower 48 activity is increasing; Alaska activity isn't

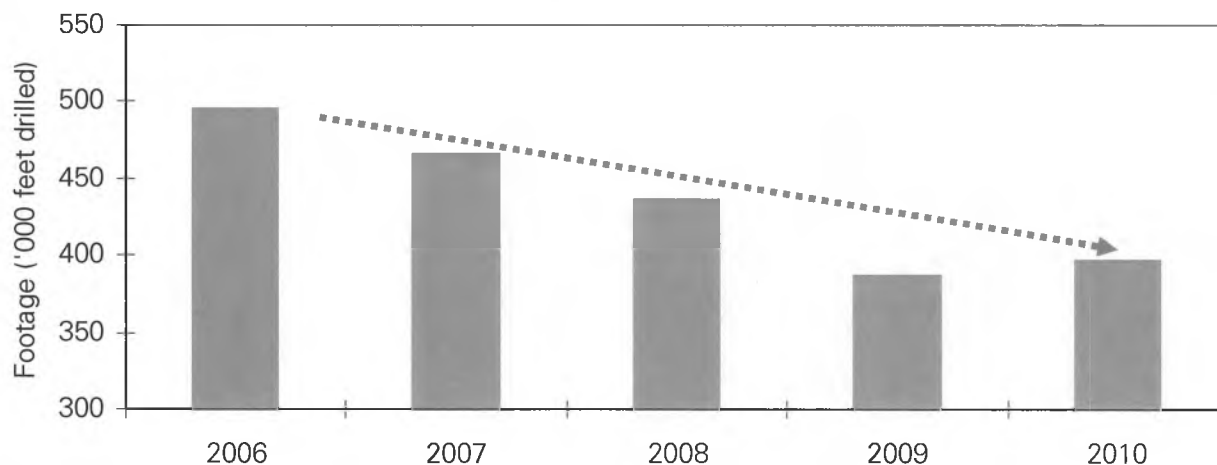
Total US wells drilled footage (million ft)



Source: Energy Information Agency

- Looking at footage Drilled, the Oil and Gas activity in the Lower 48 has been increasing over last few years.

BP Alaska operated fields - Footage Drilled

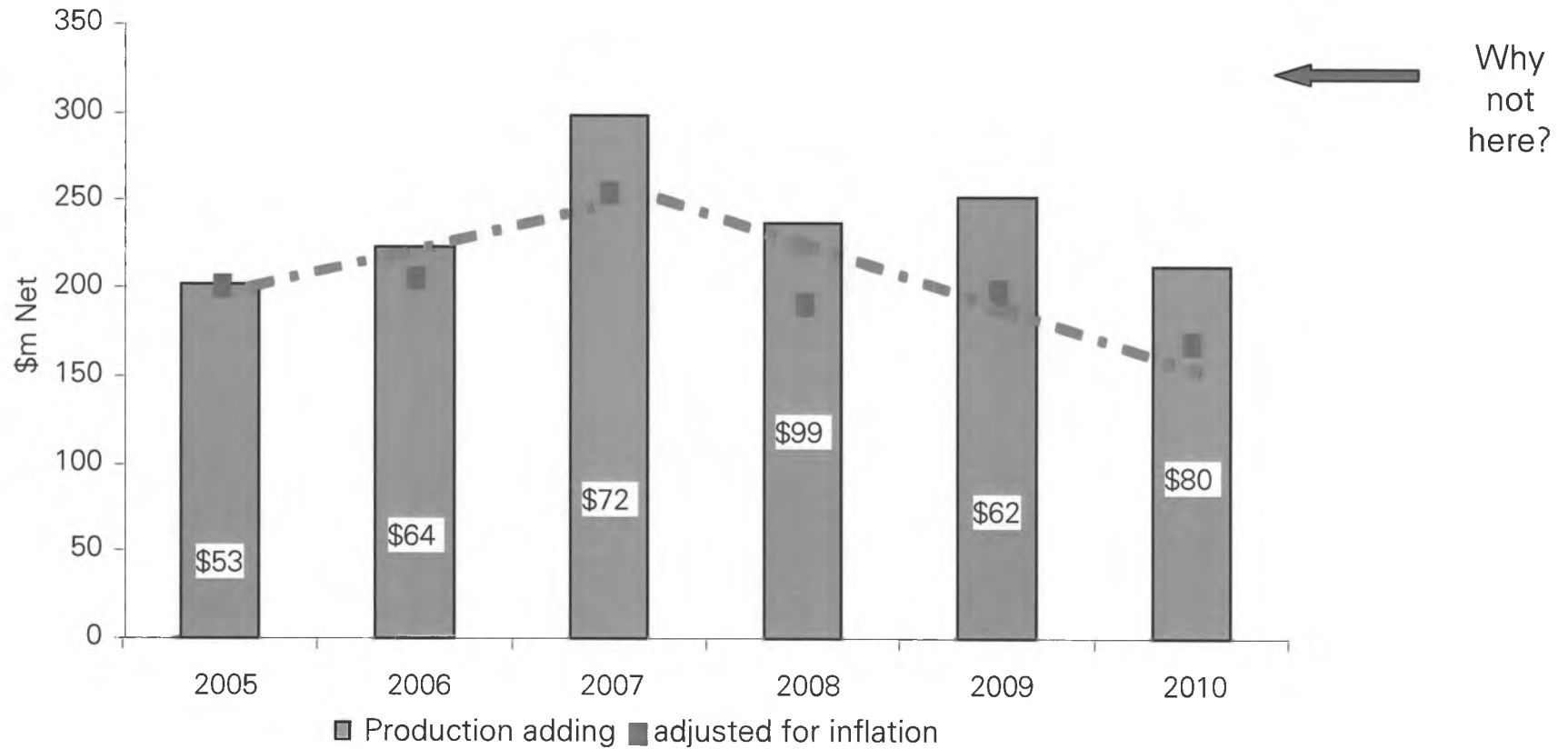


Source: BP Alaska Internal Records

- Footage Drilled by BP in its operated fields has been on a steady decline.



Less money being spent on new oil since ACES



BP Operated Fields Production adding investments, after adjusting for inflation*

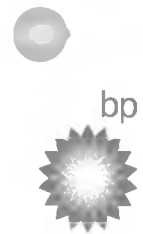
* Using Producer price inflation index for oil and gas field machinery and equipment index

Source: BP Alaska Data and US Department of Labor, ANS price



Governor's Bill (HB 110) – A step in the right direction

- BP continues to support this bill
 - Improves competitiveness and encourages investment
- What we like
 - Bracket structure for progressivity
 - ✓ Incentivizes investment
 - ✓ Rebalances risk reward
 - Additional credits for drilling investments
 - ✓ Incentivizes production adding investments
 - Reduction in statute of limitations and punitive interest rate
 - ✓ Increases certainty, removes unfair provision
 - Annual calculation of production tax rather than monthly
 - ✓ Matches costs with revenues and increases predictability



Increased investment = Alaskan jobs and production

- BP will re-evaluate the entire inventory of opportunities
 - Note: BP owns 26% of Prudhoe Bay - investments require other working interest owner approvals
- Opportunities that could become competitive if bill is passed:
 - Increased drilling, potentially adding another Rig in service
 - Increased wellwork
 - Gas Partial Processing /I - PAD
 - Evaluate 'at scale' development viscous opportunities
 - Increased R&D spending to develop heavy oil
- The sooner the bill takes affect, the sooner increased activity can happen

3/23/11

Alaska Oil and Gas Association



121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907)272-1481 Fax: (907)279-8114
Email: crockett@aoga.org
Marilyn Crockett, Executive Director

COMMENTS OF THE ALASKA OIL AND GAS ASSOCIATION
ON CSHB 110(RES)
HOUSE FINANCE COMMITTEE
MARCH 23, 2011

The Alaska Oil and Gas Association (AOGA) appreciates the opportunity to express its support for CSHB110(RES), the Governor's proposed amendments to the ACES production tax. We sincerely believe these provisions, when enacted into law, will increase the competitiveness for investment dollars in Alaska, resulting in increased job opportunities and the development necessary to stem the decline in oil production currently facing Alaska.

Today we are providing our comments on specific provisions of this legislation:

PROGRESSIVITY RATES/BRACKETING/TAX CAP

AOGA supports the provisions in CSHB110(RES) which establish bracketing of the progressivity rates and caps progressivity at 25%, for a maximum rate of 50% for progressivity and the base rate combined.

Under the current form of ACES, at \$30, the taxpayer pays at the 25% base rate. But as the taxable Production Tax Value (PTV) raises above \$30, the progressivity feature kicks in, and instead of applying the higher tax rate to just the incremental dollar, the current tax system reaches back and taxes the entire original \$30 at the higher rate. Each time the PTV per barrel increases further beyond \$30, all prior dollars are taxed at the higher rate instead of just that further increase. This approach is what creates such high marginal tax rates, and creates an imbalance in the risk-reward investment environment in Alaska. Removing the upside to the degree the progressivity feature does makes it much more difficult to compete for investment dollars with other areas that are not as fiscally challenged as investments here in Alaska.

Bracketing sets tax rates for the different levels of PTV so that each level is taxed only once and at a specific rate for that bracket, moderating the impact of ACES' high rate of tax. As you have seen, the bracketing described in CSHB110(RES) generally follows the same line of progressivity as in the current version of ACES. But by not reaching back and taxing those dollars that have already added value to the project and that have had taxes paid on them and not taxing them again, CSHB110(RES) adds much needed

stability and predictability to the tax. As companies realize higher prices and greater PTV, the State likewise continues to share in those benefits.

Bracketing of income to pay taxes is a time-tested approach. There isn't a person here that doesn't have a personal interest in the concept and how it works. Just look to your personal income taxes with the IRS. The difference between what we are currently experiencing with ACES' progressivity feature and the notion of bracketing is quite compelling. Under ACES, as you've heard already from the DOR and in a number of presentations and publications over the last year, the rate is too high.

In addition, capping progressivity and the base tax at the 50% combined rate under CSHB110(RES), rather than the current 75%, also provides the impetus needed to motivate companies to undertake the high risk projects on which the future economic health of Alaska will depend. This change creates a business climate where the reward is commensurate with the risk and keeps the needs of the State and the producers in a more appropriate balance.

You will be hearing from our member companies regarding this risk/reward and the need for an adequate upside, and the challenges they face when presenting projects to their respective Boards. The competition for these dollars is real and anything to move Alaska to a more competitive position will make those arguments more palatable and possible.

ANNUAL -v- MONTHLY

Another aspect of progressivity is the monthly calculation of the progressivity rate. The inherent flaw in this and why AOGA supports moving to an annual progressivity is simple. The revenues that are used in the calculation of the progressivity are actuals, reflecting current production and current prices. They are subject to the seasonal swings in production or market pressures of price. In calculating the PTV, though, the deductible lease expenditures are the actual expenses for the whole year, with 1/12 of the annual total being allocated to each month during the year. In other words, the present version of progressivity creates a huge mismatch by using each month's *actual* gross value at the point of production (GVPP), but deducting 1/12 of the actual expenses. This result is achieved at the annual true-up on March 31st of the following year. In making estimated monthly payments, however, the mismatching is compounded because taxpayers have the actual GVPP for each month but will have to rely on a monthly figure for the *estimated* lease expenditures for the whole year, in order to calculate the PTV and the resulting progressivity rate for that month.

The monthly approach to progressivity actually taxes artificial PTV, raising the Alaska tax rates higher than reported on any graph of tax rates. None of those graphs account for mismatching in the progressivity tax on monthly PTV. The difference is solely driven by the fact that progressivity taxes the inflated, incorrect monthly PTV resulting

solely from this mismatching. We support moving from a monthly calculation of progressivity to an annual calculation to synchronize the revenues with the expenses, avoid the mismatching, and more accurately reflect the philosophy behind what a progressivity feature should look like.

TAX CREDIT INCENTIVES EXTENDED TO NORTH SLOPE

CSHB110(RES) expands the existing 40 percent *well lease expenditure* tax credit currently available only to qualifying expenditures in “Middle Earth” and the Cook Inlet Sedimentary basin,¹ so it will also be available for qualified expenditures made on leases or properties north of 68 degrees North Latitude.

The well lease expenditure concept was introduced and enacted into law in May 2010 in connection with chapter 16, 2010 Session Laws of Alaska (the Cook Inlet Recovery Act). Under AS 43.55.023(o) a well lease expenditure (WLE) is defined as:

a qualified capital expenditure and an intangible drilling and development cost authorized under 26 U.S.C. (Internal Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made under 26 U.S.C. 263(c) . . .²

A well lease expenditure is the subset of qualified capital expenditures (QCE) that currently define the scope of capital spending that qualifies for the 20% QCE credit under sub-section .023(a). Thus, within the QCE “bucket” are a set of costs that would be eligible for a full 40% tax credit instead of the usual 20% QCE credit. The definition of WLE as *intangible drilling and development cost* (IDC) has several advantages. First, IDC is a concept that is well-defined in oil and gas tax law. IDC is designated for special tax treatment under the U.S. Internal Revenue Code.³ It represents the part of

¹ i.e., South of 68 degrees North Latitude under AS 43.55.023 (l) and (n).

² The full language under subsection .023(o) reads as follows:

(o) For the purposes of (m) and (n) of this section, a well lease expenditure incurred in the state south of 68 degrees North latitude is a lease expenditure that is

- (1) directly related to an exploration well, a stratigraphic test well, a producing well, or an injection well other than a disposal well, located in the state south of 68 degrees North latitude, if the expenditure is a qualified capital expenditure and an intangible drilling and development cost authorized under 26 U.S.C. (Internal Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made under 26 U.S.C. 263(c); in this paragraph, an expenditure directly related to a well includes an expenditure for well sidetracking, well deepening, well completion or recompletion, or well workover, regardless of whether the well is or has been a producing well; or
- (2) an expense for seismic work conducted within the boundaries of a production or exploration unit.

³ Intangible well costs are distinct from tangible costs such as equipment and drill pipe and are 70-100 percent deductible against federal taxable income when incurred. (See *Petroleum Accounting: Principles, Procedures, & Issues*, 5th Ed. (University of North Texas: PriceWaterhouseCoopers), p.72.

capital expenditures that has no physical attributes or salvage value, such as fuel, labor and rig rental. Thus it is a convenient and readily accessible accounting designation.

Second, WLE is consistent with language already existing in the PPT-ACES framework. Producers will not have to wait for the DOR to write regulations that describe what is included and not included in the WLE.

Third, IDC is focused on costs associated with drilling wells and getting more production out of both existing fields and new field development. As stated in subsection .023(o)(1), well lease expenditures include "well sidetracking, well deepening, well completion or recompletion, or well workover expenditures" that would target new areas of the reservoir.

Lastly, since labor costs may be included in IDC, the 40% WLE credit indirectly supports hiring and job creation.

In sum, AOGA strongly endorses this special category of QCE that is targeted for the credit uplift because 1) this category of expenditure is tied directly to in-field drilling; 2) includes labor costs; and 3) is a convenient and readily accessible accounting designation. Also, this proposal has the advantage of an earlier effective date compared with other provisions in HB 110, thus potentially jump-starting production sorely needed to stem the production decline in the near-term.

LOWER TAX RATES FOR NEW FIELD DEVELOPMENT

CSHB110(RES) includes provisions (under Sections 6 and 8) that would lower the base tax rate from 25% to 15% for oil and gas produced from areas outside of current fields and units or not in commercial production prior to December 31, 2008.

In addition, the progressivity surcharge for oil and gas produced from areas outside of current units would be capped at 40%, or 25% above the base tax rate. And progressivity would be subject to parallel tax-bracketing treatment, where tax rates for a particular discrete tax bracket are applied only to incremental income in that bracket. Also, the progressivity tax is levied on an annual basis instead of monthly, the same as for the fields in production. This change would be effective January 1, 2013, and apply to production after December 31, 2012. The proposed base and progressive tax rates applicable to existing and new field development are summarized in Exhibit 1, below.

**Exhibit 1. Summary of Proposed Base Tax and Progressivity Surcharge
for New and Existing Fields**

| Taxable Production | Field or Unit In Production Prior to 31-Dec-2008 | Field or Unit In Production After to 31-Dec-2008 |
|---|--|--|
| Base Tax | 25% | 15% |
| Max Progressive Surcharge | 25% | 25% |
| Max Combined Tax Rate | 50% | 40% |
| Progressivity Annual instead of Monthly | Yes | Yes |
| Bracketing Applies | Yes | Yes |
| Effective Date | 1-Jan-2013 | 1-Jan-2013 |

AOGA cautiously supports this proposal for new field development, which represents a significant reduction in the implied tax burden. However, it raises several questions. First, as with other provisions in CSHB110(RES), the implied lag in the effective date is problematic. There clearly is a sense of urgency with regard to the need for investment and stemming the decline in production, and delaying the effective date of these provisions seems counter to that urgency.

Second, the DOR *Fall Revenue Sources Book* anticipates production from new developments from state and federal lands to account for a significant portion of total ANS production over the next decade. (See Exhibits 2 and 3, below.) But almost all of these areas of potential new field development overlie existing producing fields and/or units. Would new field development from these areas qualify for the lower base tax and progressivity schedules contained in Sections 6 and 8 of CSHB110(RES)? Providing an answer to this question by regulations could be a drawn-out, difficult process — assuming they could be drafted in a way that provides the answer while remaining consistent with the statute.⁴

Third, the provisions in sections 6 and 8 of CSHB110(RES) are silent on the treatment of lease expenditures for new field development. Since the proposed change in base tax and progressivity is driven by the PTV associated with new field development, some form of ring-fencing production, revenue and costs is implied. This in turn raises

⁴ AS 44.62.030: “a regulation adopted is not valid or effective unless consistent with the statute” that it is “implement[ing], interpret[ing], mak[ing] specific, or otherwise carry[ing] out.

questions about the complexities of allocating joint operating and capital costs. AOGA favors addressing the matter of cost allocation in statute rather than through regulation.

**Exhibit 2. DOR Commissioner's Presentation to the House Resources Committee,
February 7, 2011**

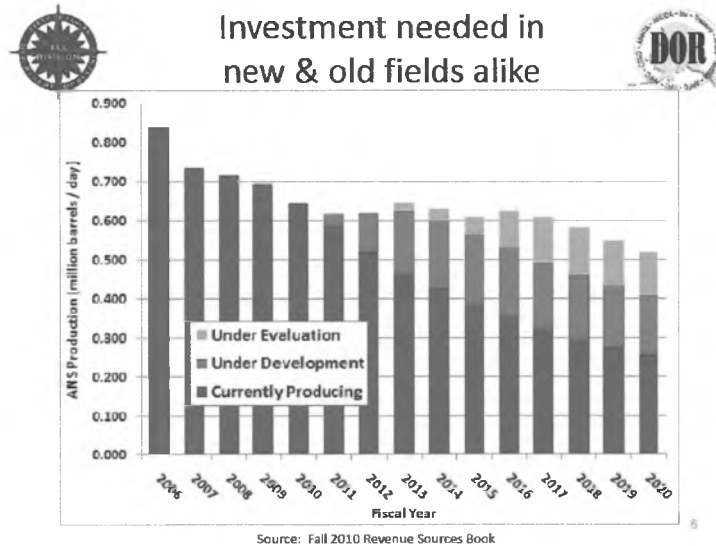


Exhibit 3. Areas of New Field Development over Next Decade

1. State lands
 - a. Expanded heavy/viscous oil development
 - i. West Sak
 - ii. Orion
 - iii. Polaris
 - iv. Schrader Bluff fields
 - b. Continued satellite development at Alpine
 - i. Fiord
 - ii. Nanuq
 - iii. Qannik fields),
 - c. New developments
 - i. Oooguruk
 - ii. Nikaitchuq
 - d. Point Thomson – startup in 2015
 - e. Badami - Restart 4Q 2010
2. Federal lands
 - a. NPR-A,
 - i. Alpine West field (start up in the 2013)
 - ii. Mooses Tooth unit
 - iii. Umiat field.
 - b. Liberty development 1Q 2012
 - c. Nikaitchuq field start-up 1Q 2011

Lastly, and most importantly, it is important to incentivize ALL new oil. This means new oil associated with new field development and from exploration, as well as new oil from existing producing fields using in-field drilling, secondary recovery, and tertiary recovery techniques. If attracting investment in the near term is the goal, then AOGA respectfully urges consideration of extending the new field incentives in sections 6 and 8 to any and all new oil development, including that arising from existing fields.

Reducing the Interest Rate on Tax Under and Over Payments and the Statute of Limitations

AOGA supports the Administration's proposed reductions to the statutory interest rate on tax under and over payments and the statute of limitations for performing tax audits. We are pleased to see the Administration and particularly the Department of Revenue recognize the need to address these two provisions and their negative impacts on Alaska's investment climate.

Unfortunately, the provision reducing the timing of the statute of limitations in the version of the bill before you now was deleted in the previous committee. We encourage you to reinstate it.

Currently the state's interest rate applicable on tax under or over payments is the greater of the federal funds rate plus five percentage points, or 11%, whichever is greater, compounded quarterly. Interest rates in other states are much lower.

The time period for which the Department can audit a taxpayer's tax return is three years from the date of the filing of the tax return for all taxes except for the production tax. With the enactment of ACES, the statute of limitations for auditing production tax returns was increased to six years. We never understood why that change was needed when the three-year audit period has worked successfully for all other taxes and can be extended and re-extended any number of times as appropriate and taxpayers were generally willing to do so.

The longer an audit is allowed to run, the greater the amount of interest there will be that accrues on any underpayment claimed in the audit. Under the current interest rate provisions, after three years, interest represents at least 38¢ for each dollar of additional tax claimed. But after six years the accrued interest grows to at least 92¢ for each dollar of additional tax claimed. The longer statute of limitations, coupled with the high interest rates, mean a greater likelihood that audit disputes will be litigated instead of settled, because the interest, which under state law cannot be compromised or abated, represents such a substantial portion of the amounts at issue even at the very beginnings of the disputes.

Reducing the interest rate provisions to the lower of the federal fund rate plus three percent or 11%, and shortening the statute of limitations from six years to four, are both clear steps in the right direction to improve Alaska's tax regime. They are long overdue. We encourage this Committee to reinstate the previous provision reducing the statute of limitations from six years to four.

Minimum Tax

A provision of CSHB110(RES) which concerns AOGA is increasing the minimum tax on North Slope production.

One element that increases the attractiveness of a tax system is the sharing of risk by the government with the investor, whether the risk turns out well or poorly. Even with the changes to the progressivity tax proposed in CSHB110(RES), Alaska would still take a greater share for itself of the upside for price risk. The minimum tax avoids or reduces the State's exposure on the downside of price risk, increasing the risk on investors, thereby making investments in Alaska less attractive.

Complicating this problem is the fact that the minimum tax is imposed on the gross value at the production of the oil and gas, without deductibility of any development or processing costs. Therefore, the minimum tax in essence is akin to a second regressive royalty payment as upstream costs of producing the oil or gas are ignored. The producer could be obligated to pay the tax even when losing money. This disproportionate shift of the investment and price risks to the producer or explorer could result in less investment and premature shut-in and thus lost production and state revenues.

Having a minimum tax along with the high level of progressivity tax has harmed Alaska's investment climate. Further increasing the minimum tax is a step backwards. It will not increase Alaska's competitiveness and is inconsistent with what the rest of CSHB110(RES) is seeking to do.

Again, thank you for the opportunity to submit these comments.

House Bill 110
House Finance Committee
Testimony by AVCG, LLC

Ken Thompson
Managing Director of AVCG, LLC
March 23, 2011

Agenda

Purpose: Present *ideas to re-incentivize investment and increase the competitiveness of Alaska relative to other oil basins with **one common State & Industry Goal** in mind:*

LEVEL ALASKA'S OIL PRODUCTION

- Introduction to Alaska Venture Capital Group (AVCG)
- AVCG's approach to working with the State
- Fundamental improvements to ACES to attract new investors for E&P
- The “**next frontiers**” for major developments on the NS
 - ✓ **Exploration with smaller fields sharing regional processing facilities**
 - ✓ **Low-permeability sands**
 - ✓ **Source rock shales**
 - NS viscous oil
 - NS natural gas
 - NS offshore oil

AVCG & BRPC: Entity Comparison

AVCG LLC

Holding company

Own all leases

Assignments

ORRI

Production Revenues

Manage overall direction, strategy

BRPC budget, plan

Staffing

Negotiation of all business deals

Attract new investors



Brooks Range Petroleum Corporation

Subsidiary of AVCG, LLC

Technical services for AVCG

JV companies as needed

Manage operations

office

staffing

misc. services

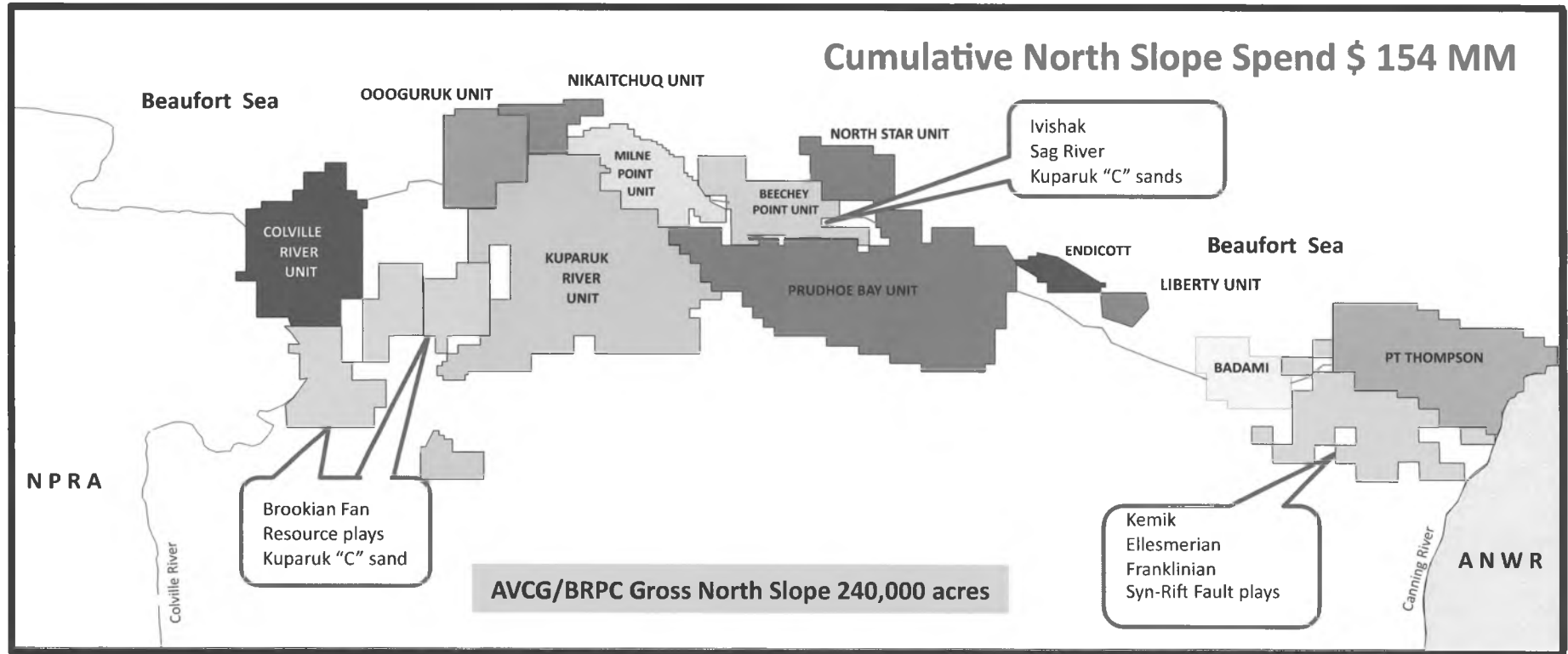
Administrative services

AVCG billings

accounting

lease administration

AVCG JV Leasehold Portfolio



Western – 94,142 acres

Central – 52,878 acres

Eastern – 89,800 acres

Activity

220 sq. mi. new 3 – D seismic
Drilled Kuparuk test & discovery

Activity

130 sq. mi. new 3 – D seismic
Drilled Ivishak, Sag River & Kuparuk tests
Ivishak & Sag River discoveries
Formed Beechey Point Unit
Acquired Pete's Wicked discovery

Activity

Purchased area 2 – D lines

Plan

Drill North Tarn Brookian/Kuparuk test
Progress 3D seismic and prospects
Exploit resource plays in area

Plan

Drill East Shore Kuparuk formation test
Progress Plan of Development of known reserves
Obtain approval of development sanctioning

Plan

Acquire 150 sq. miles of 3D seismic
Looking for partner on Shoot-to-Earn
Continue to progress 2D data
Monitor Point Thomson activities

Attracting New Investors In The Face Of Global Competition For Capital

Side note: effect upon AVCG relative to Bow Valley/Dana Petroleum, i.e. Dana Petroleum elected not to participate on North Slope because of better tax treatment and higher returns in North Sea

UK North Sea exploration/development

Substantial tax incentives enacted 2009 to encourage development

- NEW FIELDS EXEMPT FROM 20% SUPPLEMENTARY SURCHARGE IT LEVIES ON TOP OF 30% CORPORATION TAX
- EXEMPTION APPLIES TO FIRST \$1.3 BILLION OF EACH FIELD'S TAXABLE INCOME

2010 vs 2009: 1Q drilling up 29%; drilling 2Q up 133%!

Anticipate significant new production

North Dakota to Surpass Alaska in Daily Production

Suspension of severance tax for initial development, i.e. "Severance Tax Holidays"

Expedited permitting by State

650 new wells drilled in 2010 with 168 per month in December!

Reserve estimates of 5-11 billion bbls compared to Prudhoe 13 bbl

Record oil production **ON THE INCLINE** to double this decade

370,000 BOPD to increase to 700,000 BOPD and surpass Alaska

Israel : Oil tax structure

Increase government take from 30% to 52% - 62%
Maintain 30% rate until producer recovers 200% of investment

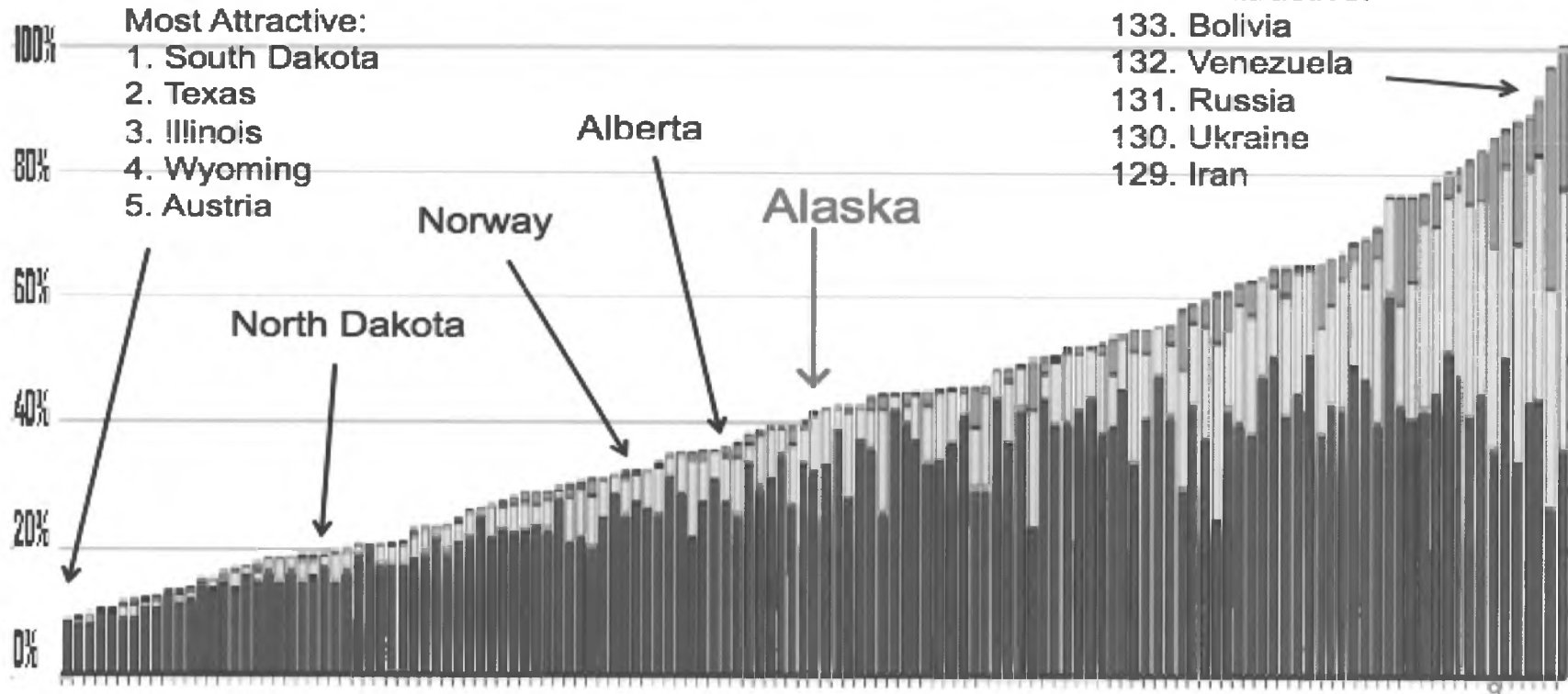
Attracting New Capital and/or New Investors To Alaska Are Keys To Increasing Activity That Will Level Production



Frasier: Alaska is #68 of 133 in terms of overall attractiveness



Frasier All-Inclusive Composite Index for 133 jurisdictions
Percentage of negative survey responses



Source: Frasier Institute 2010 Global Petroleum Survey

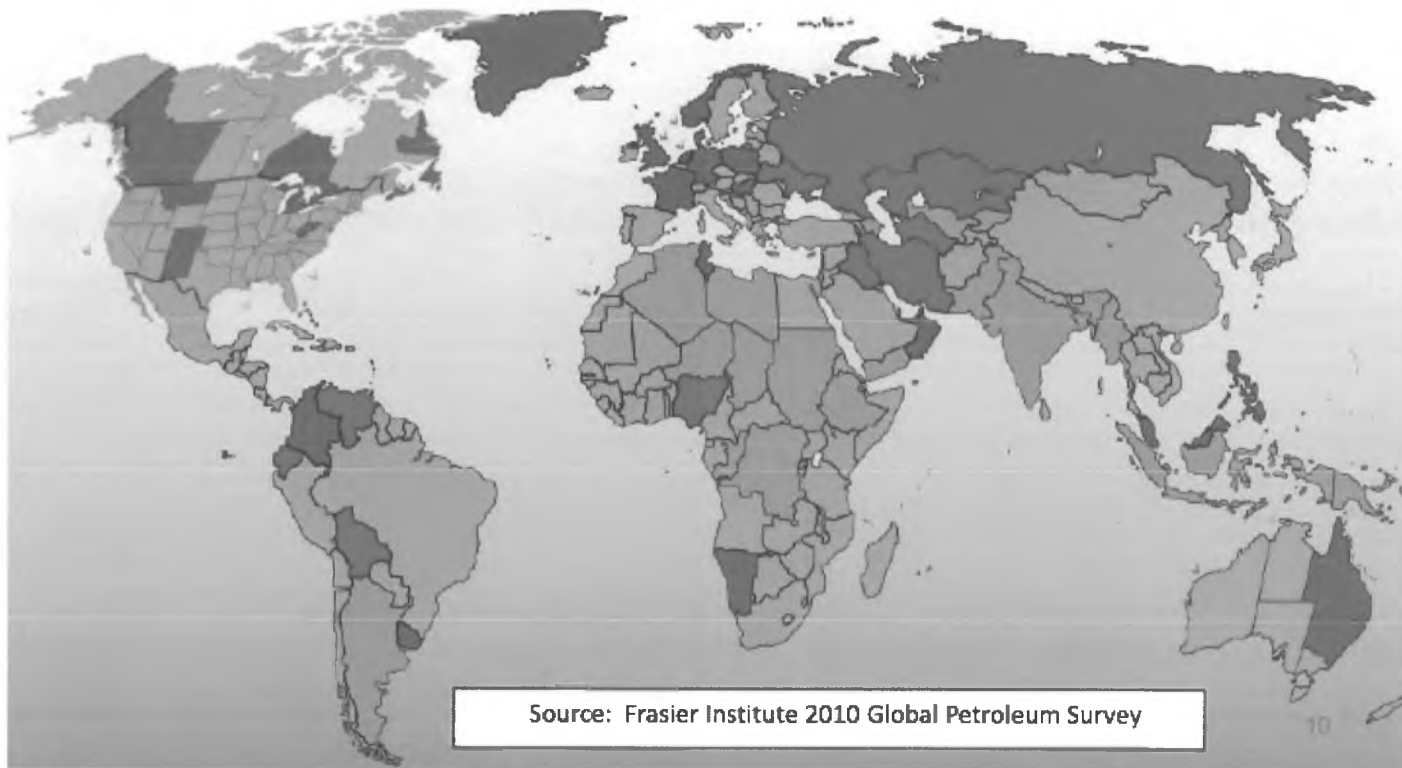
Source: HB 110 Dept of Revenue Presentation, 2/5/2011



Frasier: Alaska's investment climate is "in the middle" globally



Most attractive ■ 2nd Quintile ■ 3rd Quintile ■ 4th Quintile ■ Least attractive ■ Unmeasured ■



Source: HB 110 Dept of Revenue Presentation, 2/5/2011

AVCG's Recommendations To Assist In Achieving The Common Goal of "No Decline"**Support proposed changes in HB 110 :**

- ✓ **Revise the progressivity surcharge to the "bracketed tax structure" with calculations made annually instead of monthly**
- ✓ **Cap the total tax at 50% when oil prices top \$92.50/bbl**
- ✓ **For development of new fields outside existing production units, the base tax rate will be 15% instead of 25% and cap the total tax at 40%**

A bracketed structure with reduced base rate and cap and a reduced base tax rate for new fields with a lower cap would attract more investor partners for AVCG et al to increase small field development and establishment of the North Slope's first "open access" facility sharing processing facilities.

- ✓ **Accelerate the payment for exploration and other qualified capital investments to one year vs. two years**

The acceleration of credit recovery payments to a one year cycle would allow for AVCG and its partners to consider drilling 3 exploration wells per year instead of an average of 2 per year...a chance for more discoveries sooner

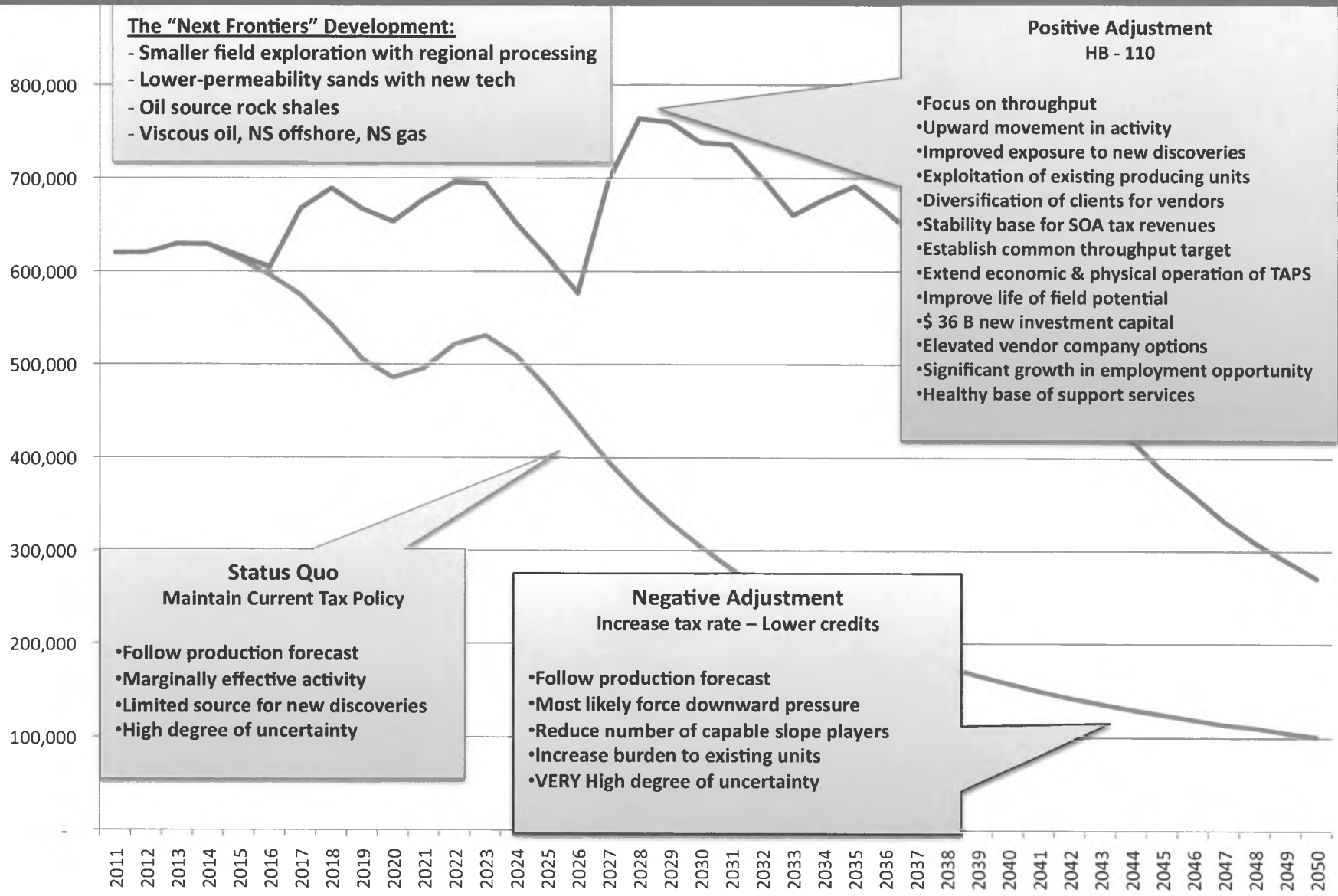
- ✓ **Increase the tax credits for "qualified capital" investments from the current 20% to 40%**

An increase in qualified capital credits to 40% would provide immediate impact to BRPC's project investment base and would extend our ability to encourage additional and continued capital investment from our current WIO's therefore providing more opportunities for successful discoveries and future development projects

- ✓ **Extend indefinitely the "Small Producer Tax Credit" of \$12MM a year from expiring on May 1, 2016 (or certainly extend another 5 years to May 1, 2021 then re-assess at that time). This is an item not currently in current bills but would be helpful in attracting new long-range development capital for BRPC and others like our company.**

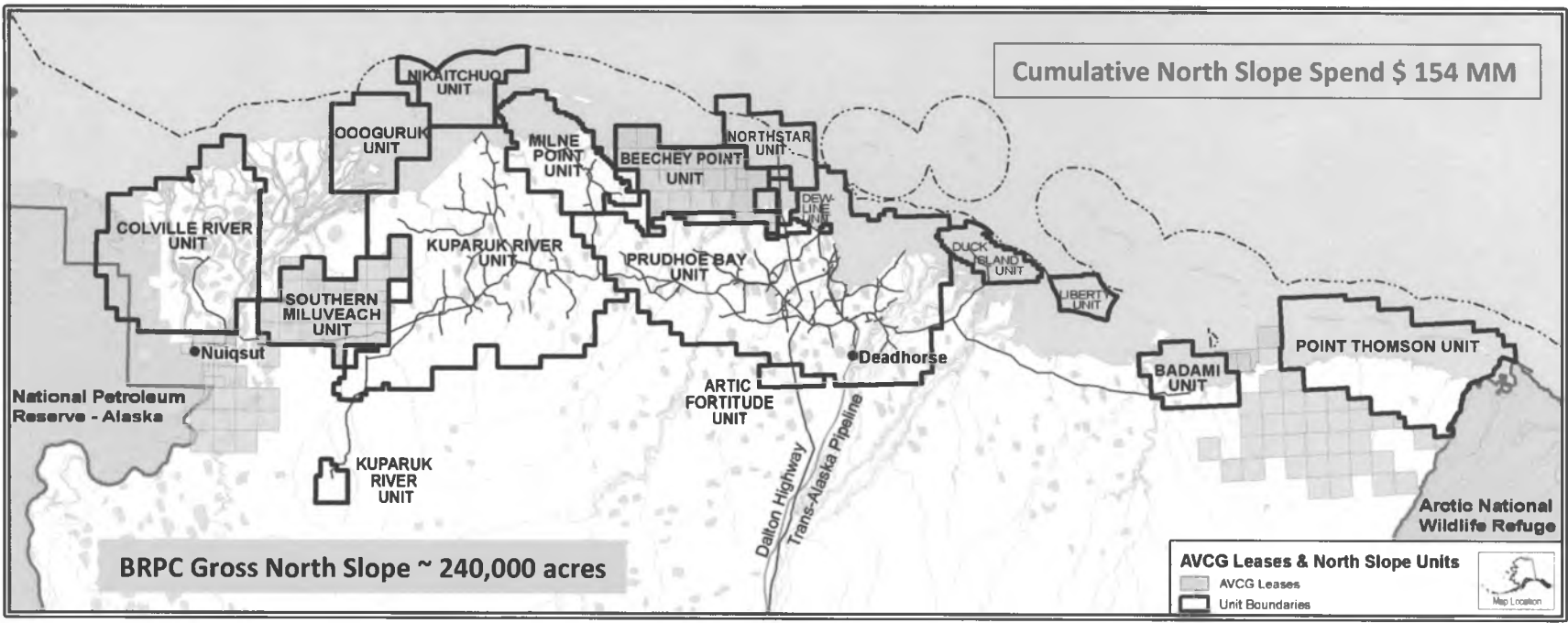
Currently, we have a sanctioning proposal in front of our WIO's that projects first oil and revenues in 2013. With the Small Producers Credit expiring in May 2016, the development would be limited to a 3 year use of this credit. We would propose an extension through 2021 to allow our first project the full credit to attract new investors.

AVCG LLC

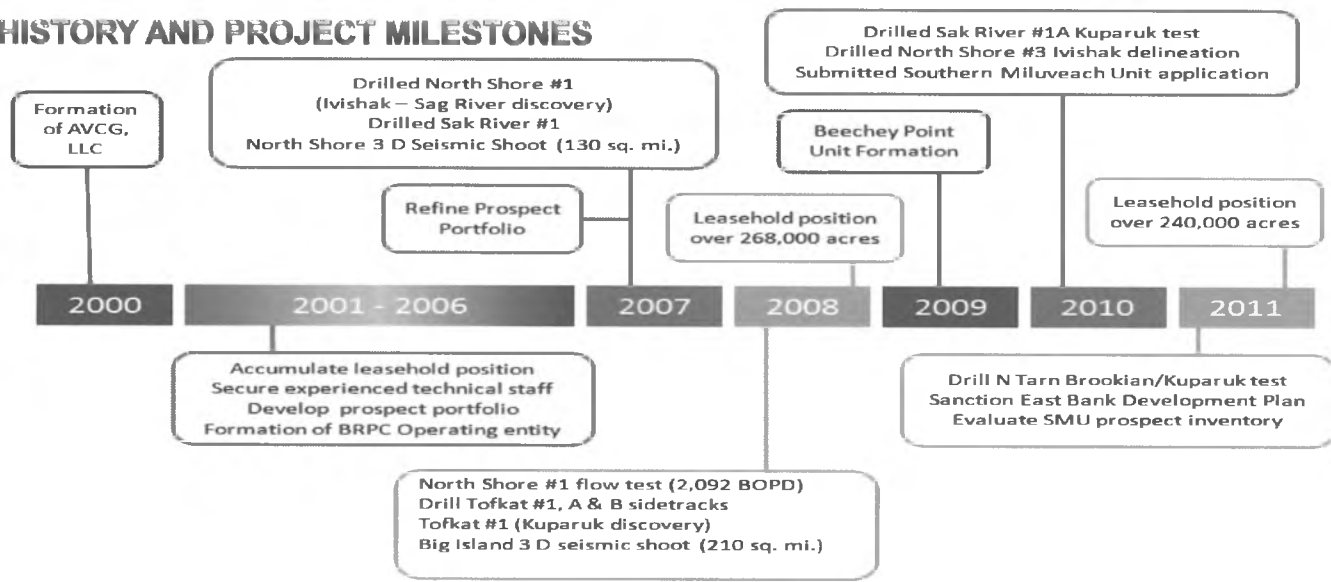


3/23/11

Brooks Range Petroleum Corporation



10 YEAR HISTORY AND PROJECT MILESTONES





- ❖ WIO's represented by BRPC are committed to Alaska and currently have a \$ 154 MM investment that needs to perform
- ❖ Current business plan approved by our investors has a timeline which reflects first oil and revenues from production in mid 2013
- ❖ Each year we delay, has an adverse effect on the investments ROI and IRR
- ❖ Current economic models used by BRPC, marginally support an acceptable IRR on smaller targeted accumulations with an assumption that reserve base would expand to include other prospect potential in the project area
- ❖ An increase in tax rate and a reduction in capital credits would have a negative reaction when applied to current models most certainly moving the project to an un-economic portfolio position and would shorten our active participation on Alaska's North Slope
- ❖ Increased capital credits, lowering of the base rate and progressivity when applied to our model would assure an attractive IRR, and would foster a more aggressive prospect portfolio and in turn, provide encouragement to our WIO's for added funding for our NS projects.
- ❖ Elevate the interest level of other players with a watchful eye on Alaska



COMMON GOAL : Slow or level the decline of oil production and throughput in Alaska

Support proposed changes in HB 110 :

- ✓ Revise the progressivity surcharge to the "bracketed tax structure" with calculations made annually instead of monthly
- ✓ Cap the total tax at 50% when oil prices top \$92.50/bbl
- ✓ For development of new fields outside existing production units, the base tax rate will be 15% instead of 25% and cap the total tax at 40%

A "bracketed structure with reduced base rate and cap" would support BRPC's ongoing activity level in Alaska by providing a more favorable economic structure and near term effect on our eventual ROI and IRR with respect to our pursuit of smaller and normally marginal accumulations.

- ✓ Accelerate the payment for exploration and other qualified capital investments to one year vs. two years

The acceleration of credit recovery payments to a one year cycle would allow for the planning and execution of an expanded work program and an increased level of activity and the associated employment base and support services required to perform relative project support

- ✓ Increase the tax credits for "qualified capital" investments from the current 20% to 40%

An increase in qualified capital credits to 40% would provide immediate impact to BRPC's project investment base and would extend our ability to encourage additional and continued capital investment from our current WIO's therefore providing more opportunities for successful discoveries and future development projects

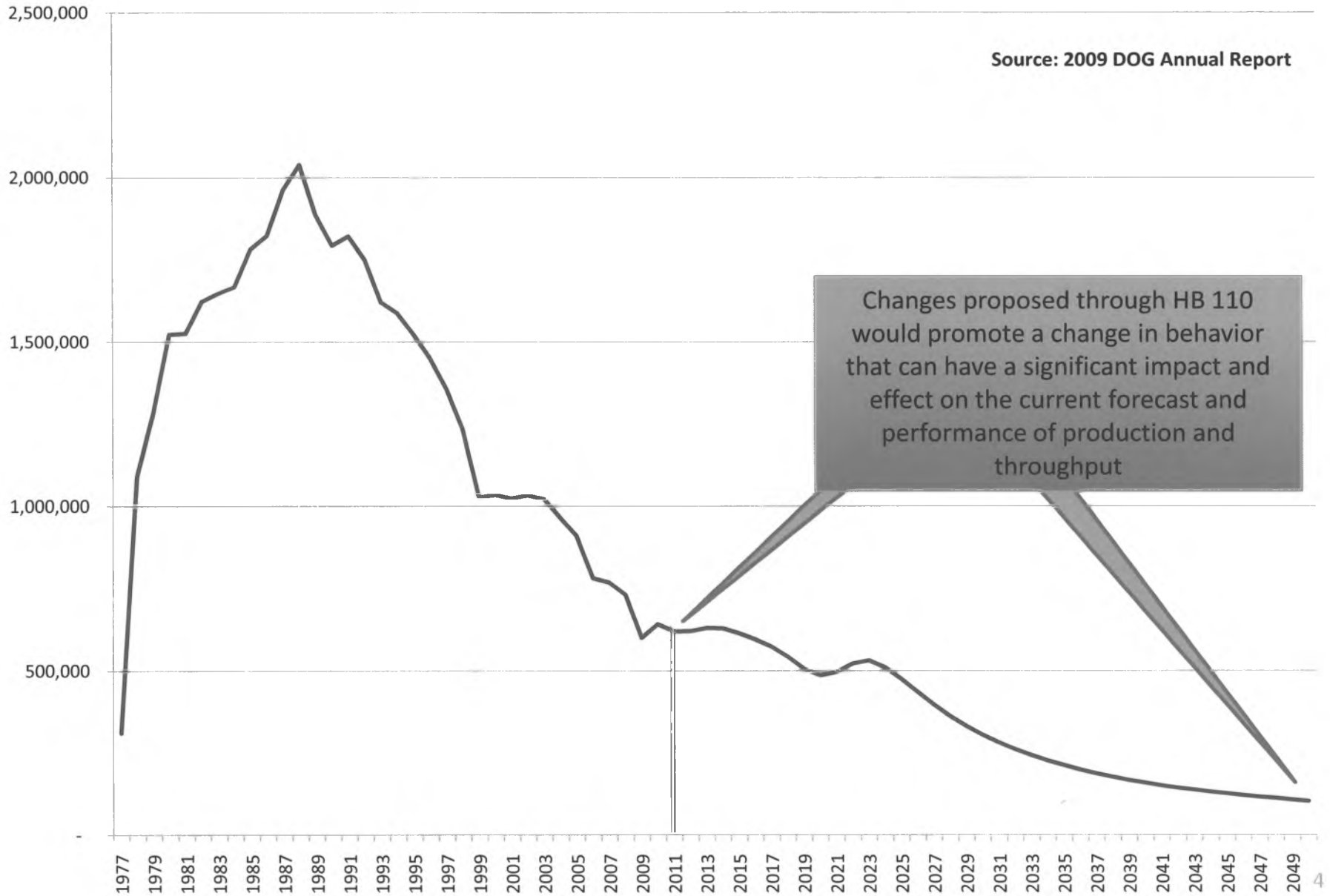
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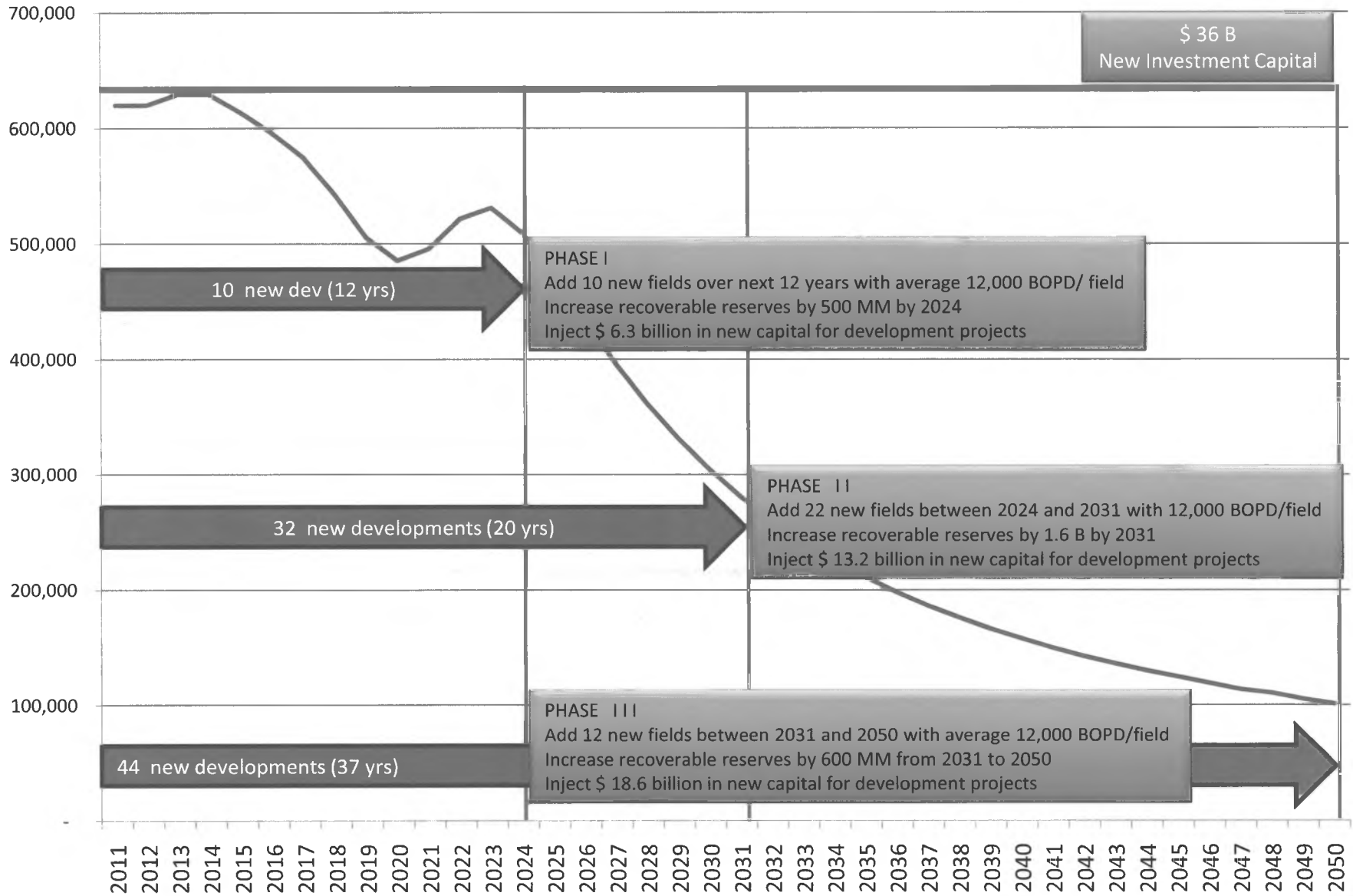
HB 110 - Opportunity to Change the Current Trend

Source: 2009 DOG Annual Report



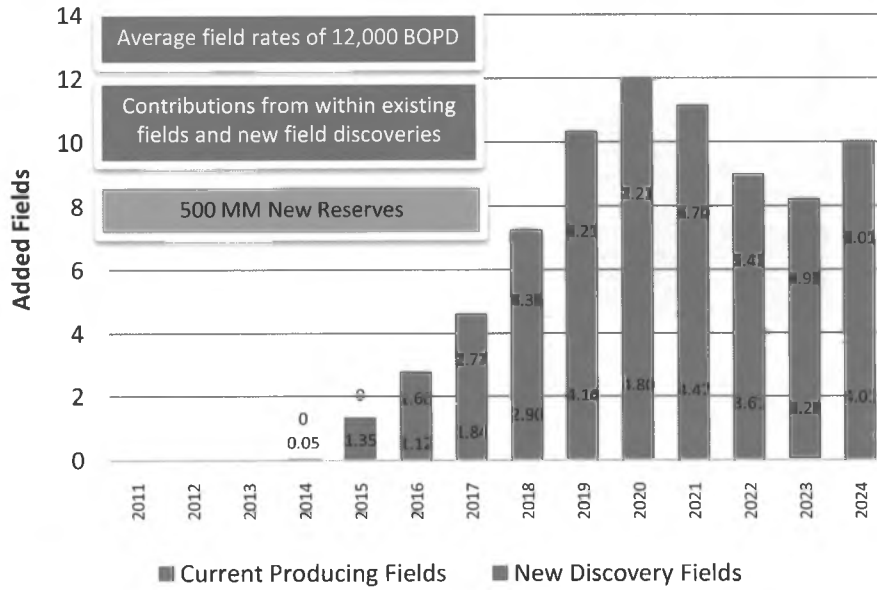


Current Forecast with Flattened Production Target

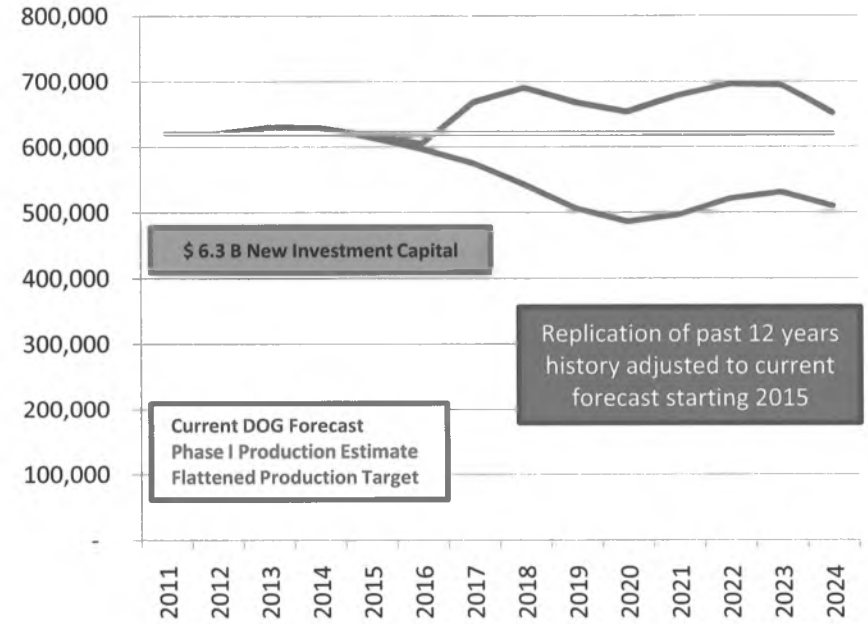




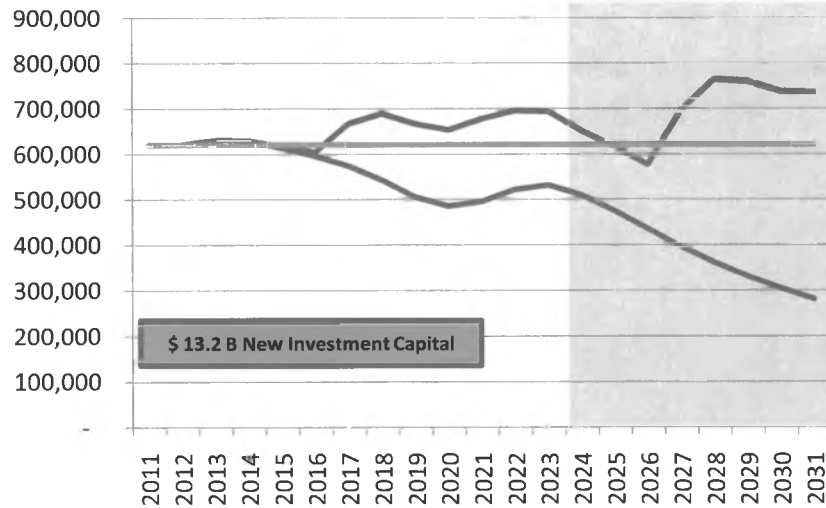
Required Field Additions to Flatten Decline



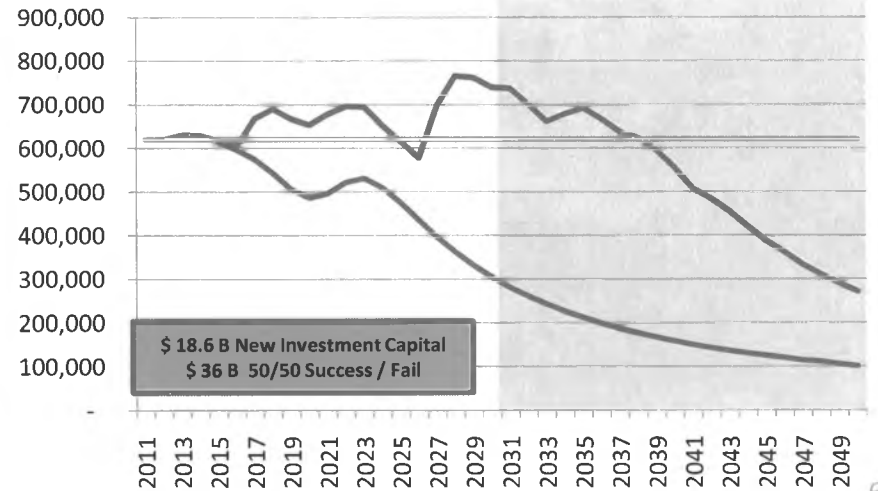
PHASE I - 10 New development projects over next 12 years

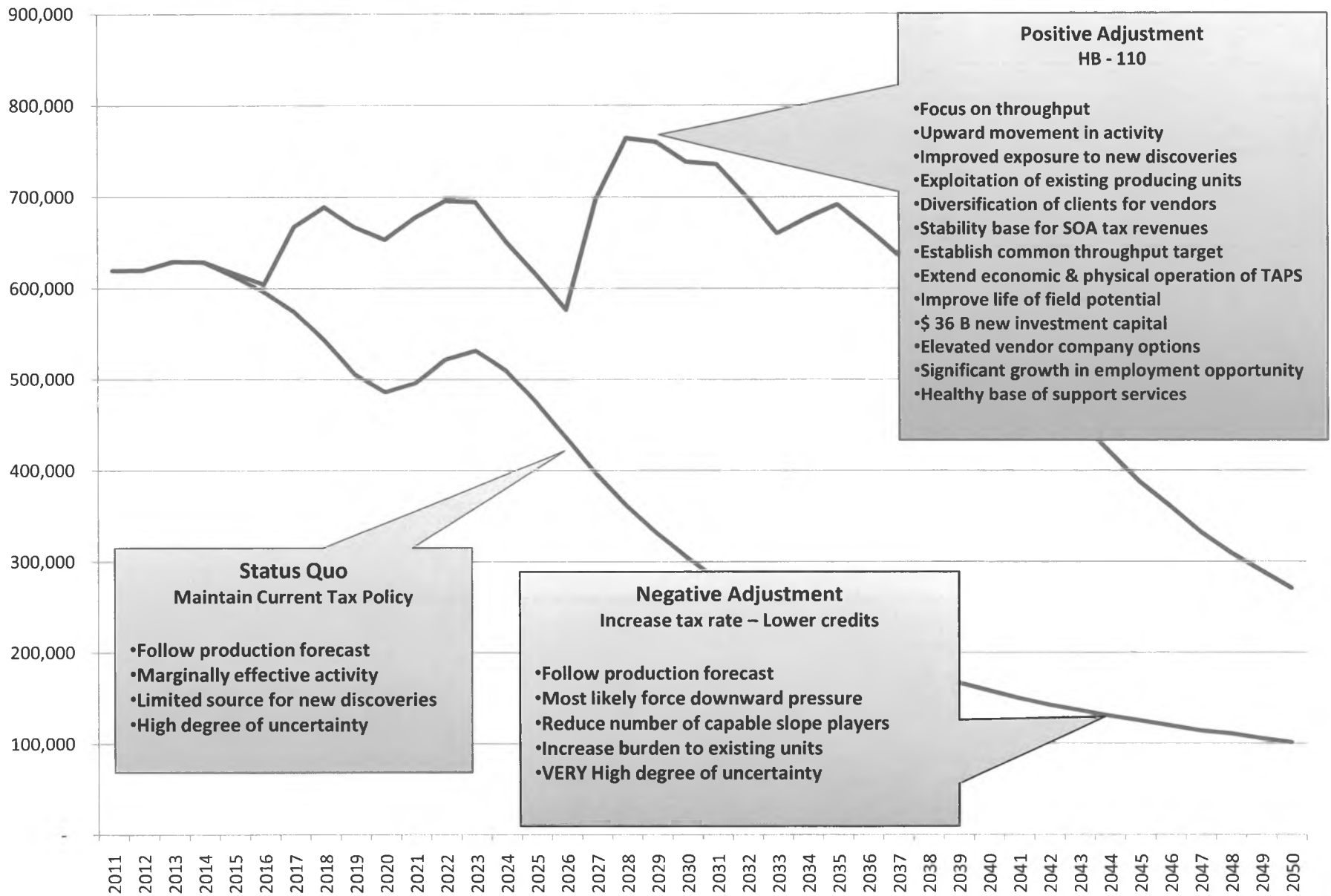


PHASE II - 22 New development projects 2024 - 2031



PHASE III - 12 New development projects 2031 - 2050





Status Quo
Maintain Current Tax Policy

- Follow production forecast
- Marginally effective activity
- Limited source for new discoveries
- High degree of uncertainty

Negative Adjustment
Increase tax rate - Lower credits

- Follow production forecast
- Most likely force downward pressure
- Reduce number of capable slope players
- Increase burden to existing units
- VERY High degree of uncertainty

Positive Adjustment
HB - 110

- Focus on throughput
- Upward movement in activity
- Improved exposure to new discoveries
- Exploitation of existing producing units
- Diversification of clients for vendors
- Stability base for SOA tax revenues
- Establish common throughput target
- Extend economic & physical operation of TAPS
- Improve life of field potential
- \$ 36 B new investment capital
- Elevated vendor company options
- Significant growth in employment opportunity
- Healthy base of support services



COMMON GOAL : Slow or level the decline of oil production and throughput in Alaska

Support proposed changes in HB 110 :

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Alaska State Legislature
HOUSE FINANCE COMMITTEE

Agenda
8:00 AM

Thursday, March 24, 2011

HB 110-PRODUCTION TAX ON OIL AND GAS
Presentation by Department of Natural Resources

✓ Dan Sullivan, Commissioner
Department of Natural Resources

✓ Bob Swenson, Director
DNR Division of Geological & Geophysical Surveys

✓ Kevin Banks, Director
DNR Division of Oil & Gas

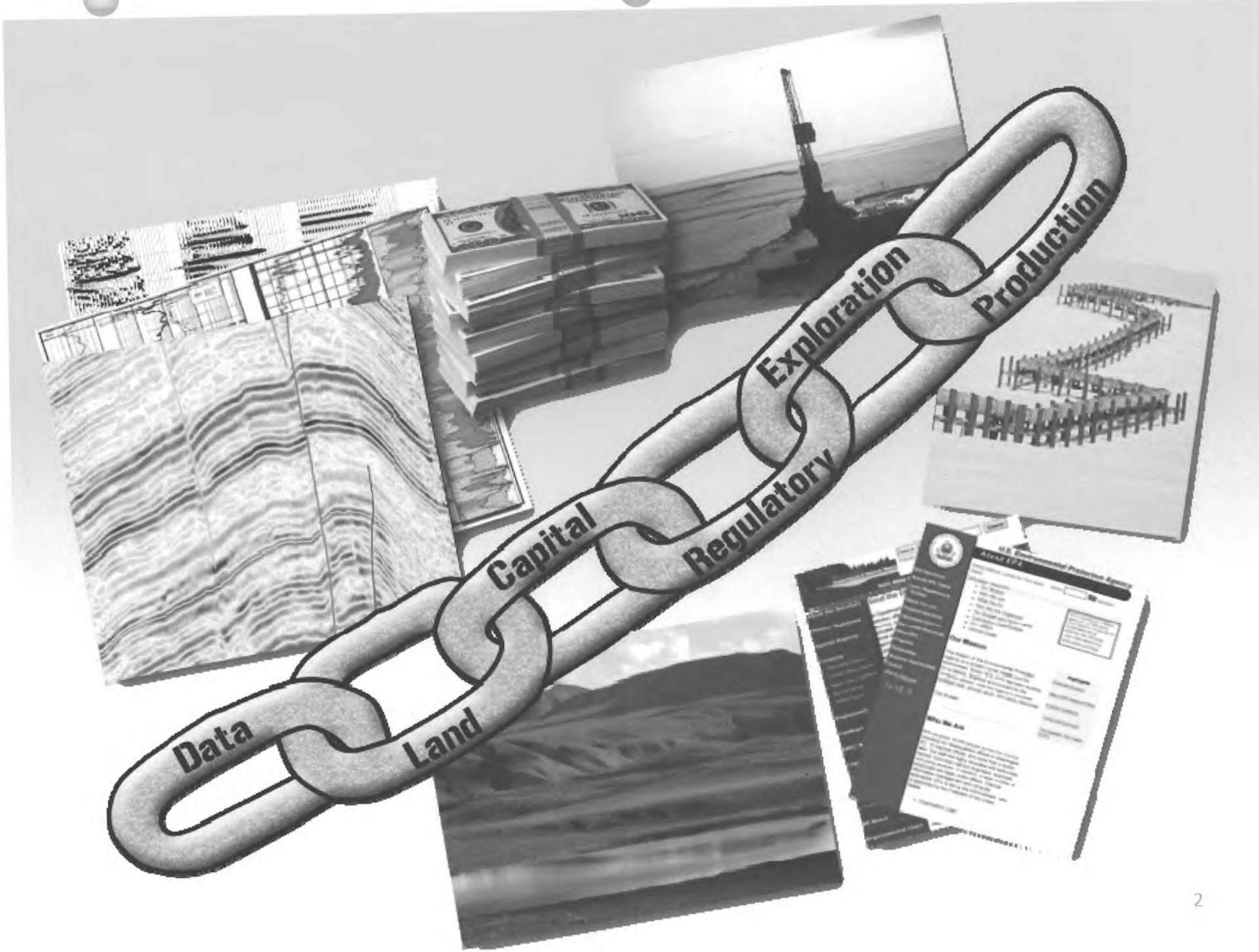
✓ Paul Decker, Manager
Resource Evaluation Section
DNR Division of Oil & Gas

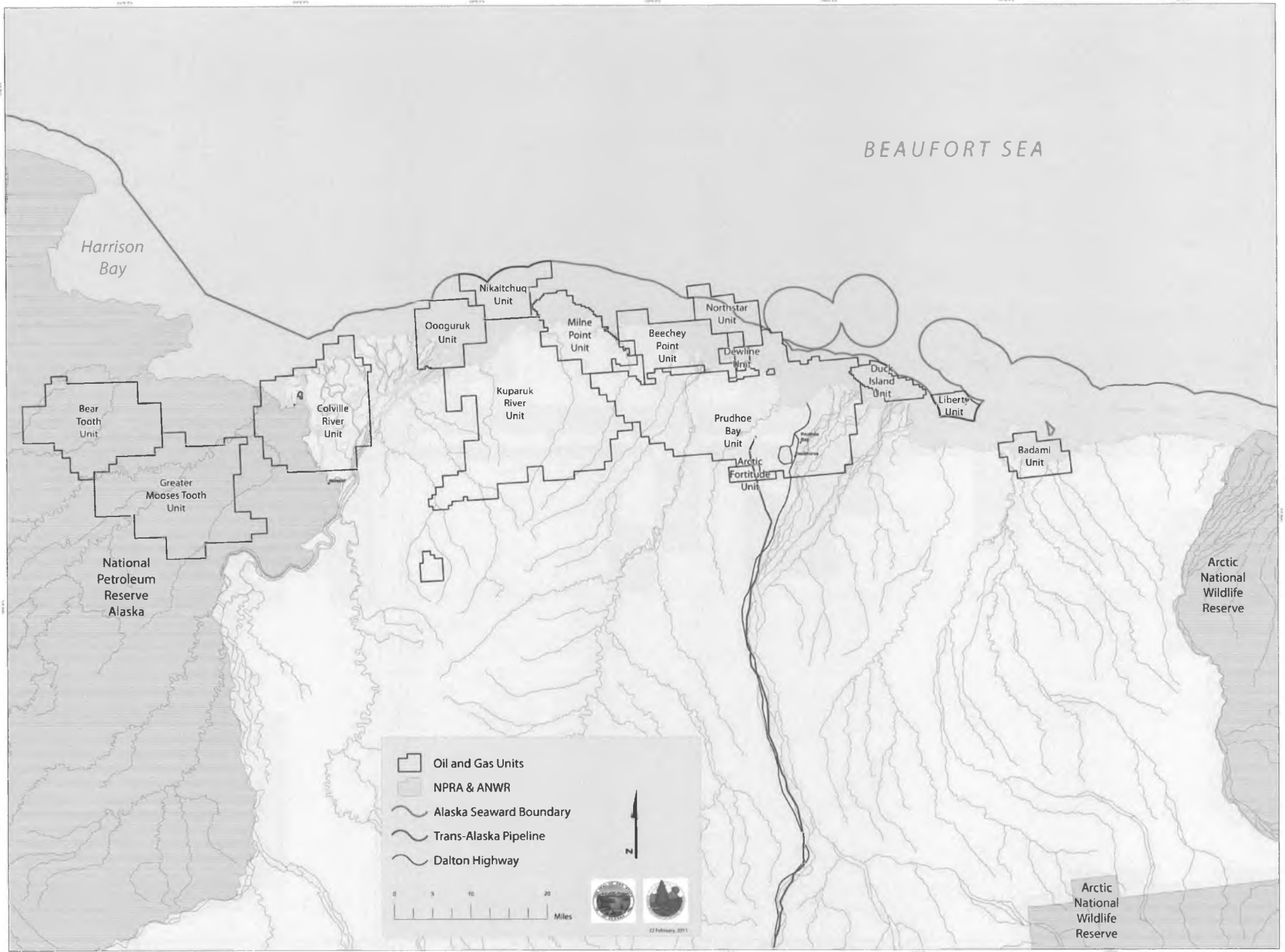
Northern Alaska and Arctic OCS Resource Estimates



Kevin Banks, Director

March 24, 2011





Oil and Gas Units
 NPRA & ANWR
 Alaska Seaward Boundary
 Trans-Alaska Pipeline
 Dalton Highway

22 February 2011

Arctic National Wildlife Reserve

North Slope “Reserves” Estimates

Developed or Delineated

| | Oil Remaining MMBO | Gas Remaining BCF |
|--------------------------|--------------------|-------------------|
| Barrow | | 34 |
| Colville River | 420 | 400 |
| Duck River | 102 | 843 |
| Kuparuk River | 990 | 600 |
| Milne Point | 210 | |
| Northstar | 64 | 450 |
| Prudhoe Bay | 2,450 | 24,500 |
| Oooguruk | 73 | |
| Nikaitchuq | 187 | |
| Liberty | 114 | |
| Point Thomson | 417 | 8,000 |
| NPRA | 140 | |
| Total North Slope | 5,166 | 34,827 |

Source: Div. of Oil and Gas, 2009 Alaska Oil & Gas Report

North Slope and Arctic OCS

Discovered Undeveloped Resource Estimates

| | Oil – Recoverable Resource MMBO | Gas – Recoverable Resource BCF |
|------------------------------|------------------------------------|-----------------------------------|
| Umiat | 70 – 300(?) | |
| Gubik | | 600(?) |
| Sivulliq (aka Hammerhead) | 100 – 200 | |
| North Tarn | 27 – 72 | |
| Kuvlum | 160 – 300 | |
| Sandpiper | 12 | |
| FEX NPRA | 300 – 400(?) | |
| Total Alaska/Beaufort | 1,299 – 1,984 | 600 |

Various sources.

Other North Slope and Arctic OCS

Undeveloped Resource Estimates

- Ugnu (Kuparuk/Milne Point area)
 - Up to 20 billion barrels of *heavy* oil in-place
 - BP conservatively estimates that roughly 10 percent may be recoverable, 2 billion barrels
- Burger (Chukchi Sea)
 - 31 million to 1.7 billion barrels of condensate in-place
 - 8 to 27 TCF natural gas in-place

North Slope Alaska and Arctic OCS Oil and Gas Potential



Dan Sullivan, Commissioner

February 2011

DNR Briefing Presentations

- **Northern Alaska and Arctic OCS Resource Estimates**
Kevin Banks, Director, Division of Oil and Gas
- **Arctic Alaska Conventional Oil & Gas Exploration Potential**
Bob Swenson, Director and State Geologist, Division of Geological and Geophysical Survey
- **Source-Reservoired Oil Resources--Alaskan North Slope**
Paul L. Decker, Petroleum Geologist, Division of Oil and Gas

GOOD NEWS

Alaska Oil and Gas Resource Potential: “World Class”

- **33 Percent of Undiscovered, Technically Recoverable Oil Resources in the Arctic.**
- **13 Percent of Undiscovered, Technically Recoverable Gas Resources in the Arctic.**
- **40 Billion Barrels of Oil; 230 Tcf of gas**
(Based on the mean estimates from ranges reported by USGS/BOEMRE.)
- **Does not Include unconventional resources.**

This resource potential lies in the Arctic “backyard” of the largest petroleum consuming market in the world.

Alaska's Challenges

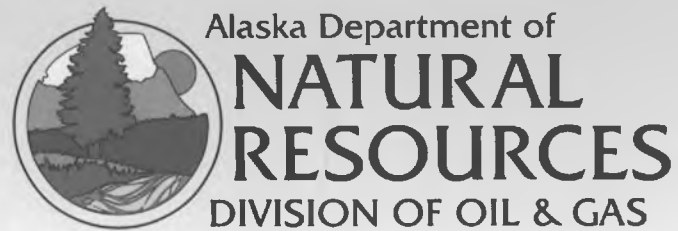
- **Biggest Challenge: TAPS Low Flow**
The best way to address this critical factor is to increase throughput.
- **Federal Government Anti-Development Posture**
The Federal government has turned from the role of environmental protection to putting up a “Off Limits” sign for resource development.
- **High Cost**
For example, exploration drilling in Alaska is between 3-8 times the cost of drilling in the North Dakota.
- **Environment**
Harsh climate, resource conflicts, seasonal limits to exploration and development activities.
- **Lack of Infrastructure**

Addressing the Challenges

We need all the policy tools to meet these challenges.

- **Fiscal Competitiveness**
- **Federal Cooperation**
- **Permitting Timeliness and efficiencies**
 - **Both State and Federal Governments**
- **Increase Infrastructure development**
- **Continued identification of the Resource**
- **Domestic and International Promotion of Alaska**
- **Accelerated Development of Unconventional Resource**
- **Encourage All Players of All Sizes**
- **Access to Markets**

Source-Reservoired Oil Resources Alaskan North Slope



Paul L. Decker, Petroleum Geologist

Alaska Department of Natural Resources, Division of Oil and Gas

March, 2011

Unconventional resources

Distinguished from conventional resources by

- **lower geologic risk...** hydrocarbons are almost certainly present everywhere within the play fairway

BUT

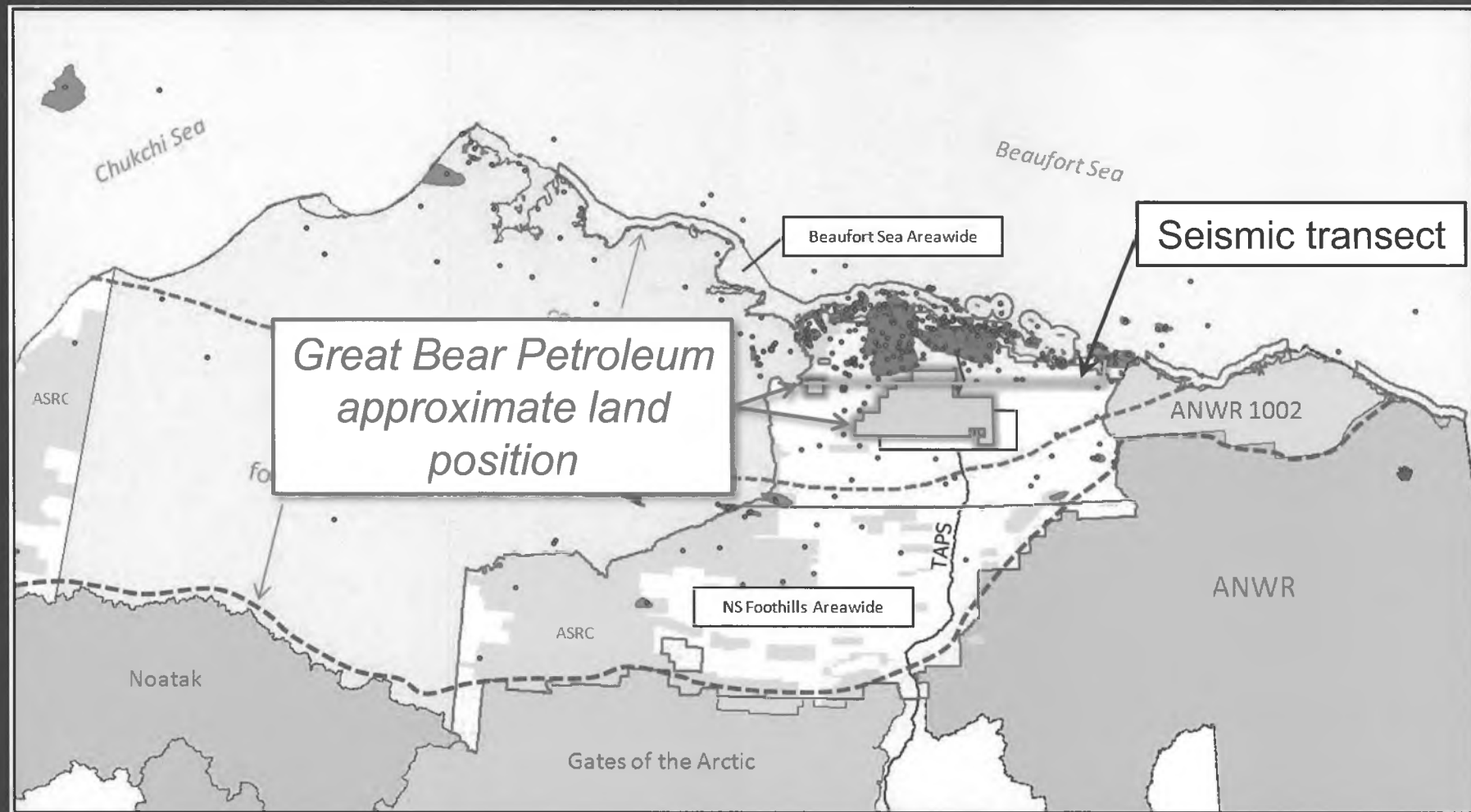
- **higher engineering risk...** not sure the resource will be recoverable everywhere (massive stimulations must succeed)

Unconventional terminology

Some terms are more specific than others

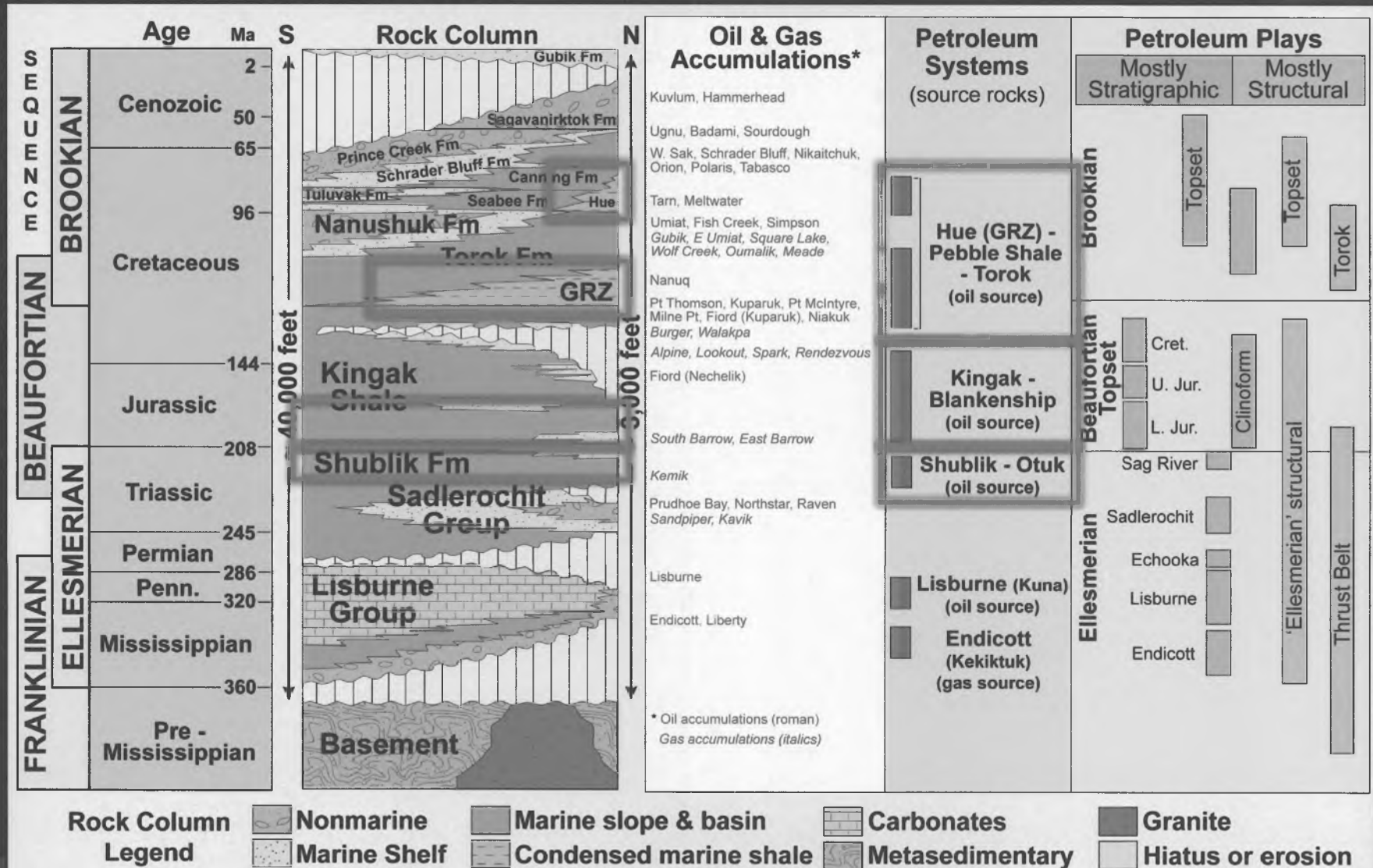
- Resource plays
- Continuous accumulations
- Basin-centered accumulations
- Technology reservoirs
- Tight oil / gas
- Shale gas / shale oil (\neq oil shale)
- Source-reservoired oil / gas
 - ✓ *Source = Reservoir = Trap*

North Slope Region



North Slope Petroleum Systems

3 prolific source rock intervals



Modified by Alaska Division of Oil and Gas staff from Ken Bird and David Houseknecht (U.S. Geological Survey), personal communication, 2002

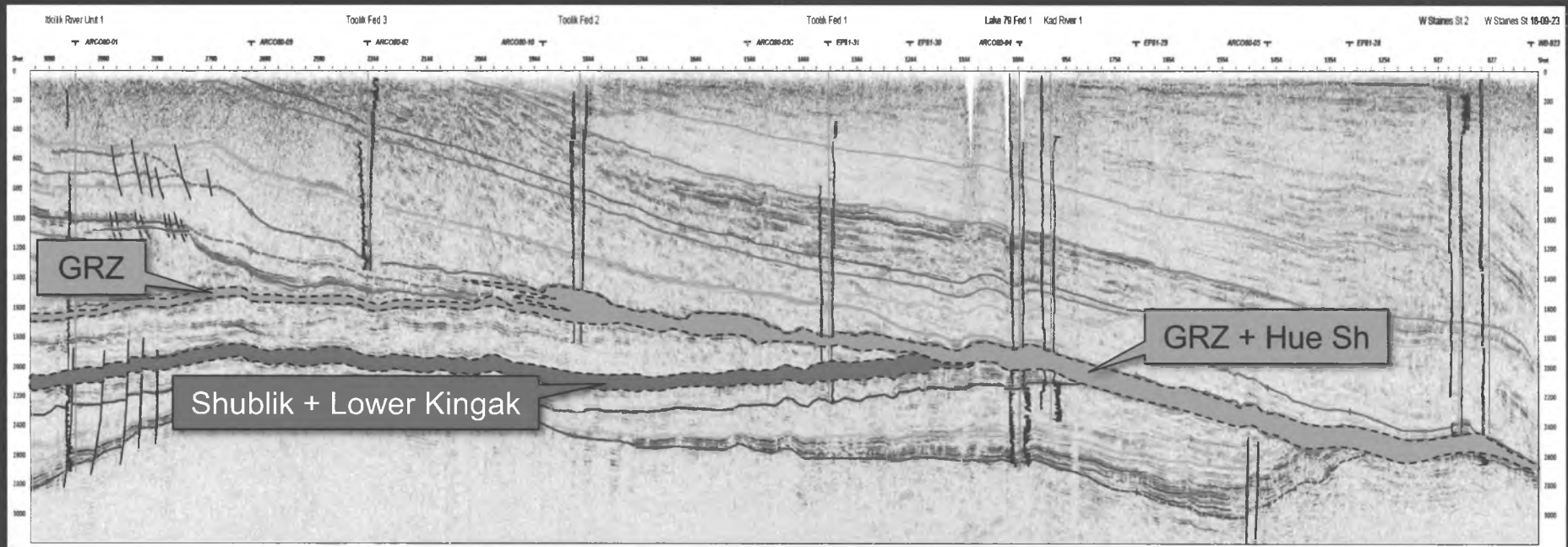
Central North Slope Seismic Transect

Public Seismic Line ARCO 80-07 & 80-06

West

Total length ~120 miles

East



- GRZ-Hue Sh at ~8,000 – 13,000 ft depth
- Shublik + Lower Kingak at ~10,000 ft depth

(Decker, unpublished data, 2010-11)

Key Geologic Factors -- Shale Resource Plays

● Organic Geochemistry

- ❑ Total Organic Carbon content (richness)
- ❑ Hydrogen Index (oil-prone, gas-prone, or inert kerogen types)
- ❑ Oil properties (gravity, in-situ viscosity, wax & asphaltene content, etc.)

● Thermal and Tectonic History

- ❑ Thermal maturity (immature → oil window → gas window → supermature)
- ❑ Stress-strain history (# of phases of natural fracturing, etc.)
- ❑ Current stress regime (determines orientation of artificial fractures and whether natural fractures are propped open)

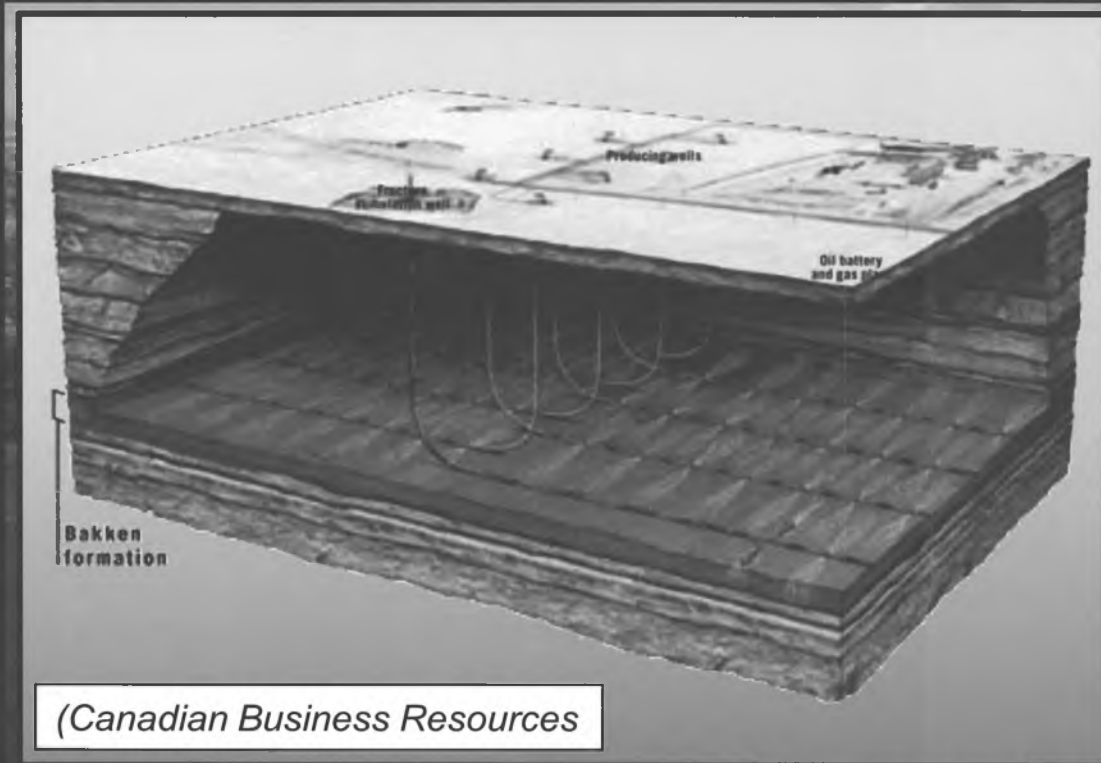
● Petrophysics

- ❑ Porosity (void space between grains, within grains, and in fractures)
- ❑ Permeability (how connected are pore spaces?)
- ❑ Relative Permeability (oil, gas, water – which flows more readily?)

● Geomechanics -- Is the rock brittle enough to create and sustain fractures?

- ❑ Cement content and types (carbonate, silica, sulfides, etc.)
- ❑ Grain content and types (silt, sand, fossil debris, etc.)
- ❑ Layering (thickness and mechanical contrast)

Close Well Spacing, Many Pads



(Canadian Business Resources)

70 acres total surface impact (14 pads, 5 acres each) → 17,920 acres of subsurface development (2 mile-long laterals on each side of road times 7 miles length times 640 acres/mi²)

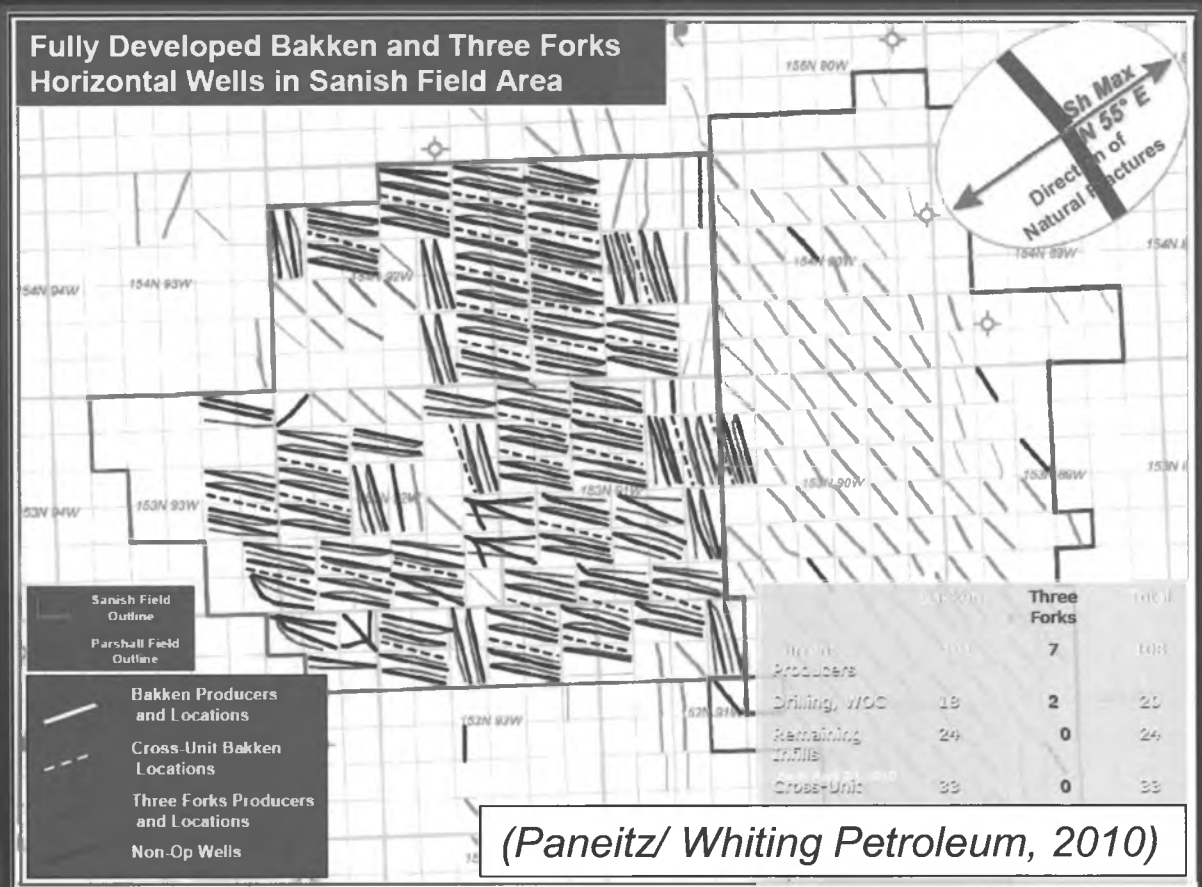


(courtesy Lynn Helms NDIC, DMR, 2011)

Close Well Spacing, Many Pads

Infrastructure-intensive development

- Bakken Shale 640 acres/well (Sanish & Parshall Fields)
- Eagle Ford Shale 125-140 acres/well (EOG plans)
- North Slope ? 120-160 acres/well (Great Bear estimates)



Frac FAQs

❖ How do they work?

Fluid (water + sand + additives for gelling and gel-breaking, etc.) is pumped into an isolated part of the borehole under increasing pressure. When the fluid pressure exceeds the rock strength, the formation fractures and the sand-rich fluid shoots out into the growing cracks. The sand props the fractures open after the frac fluid flows back into the wellbore.

❖ How much water do they use?

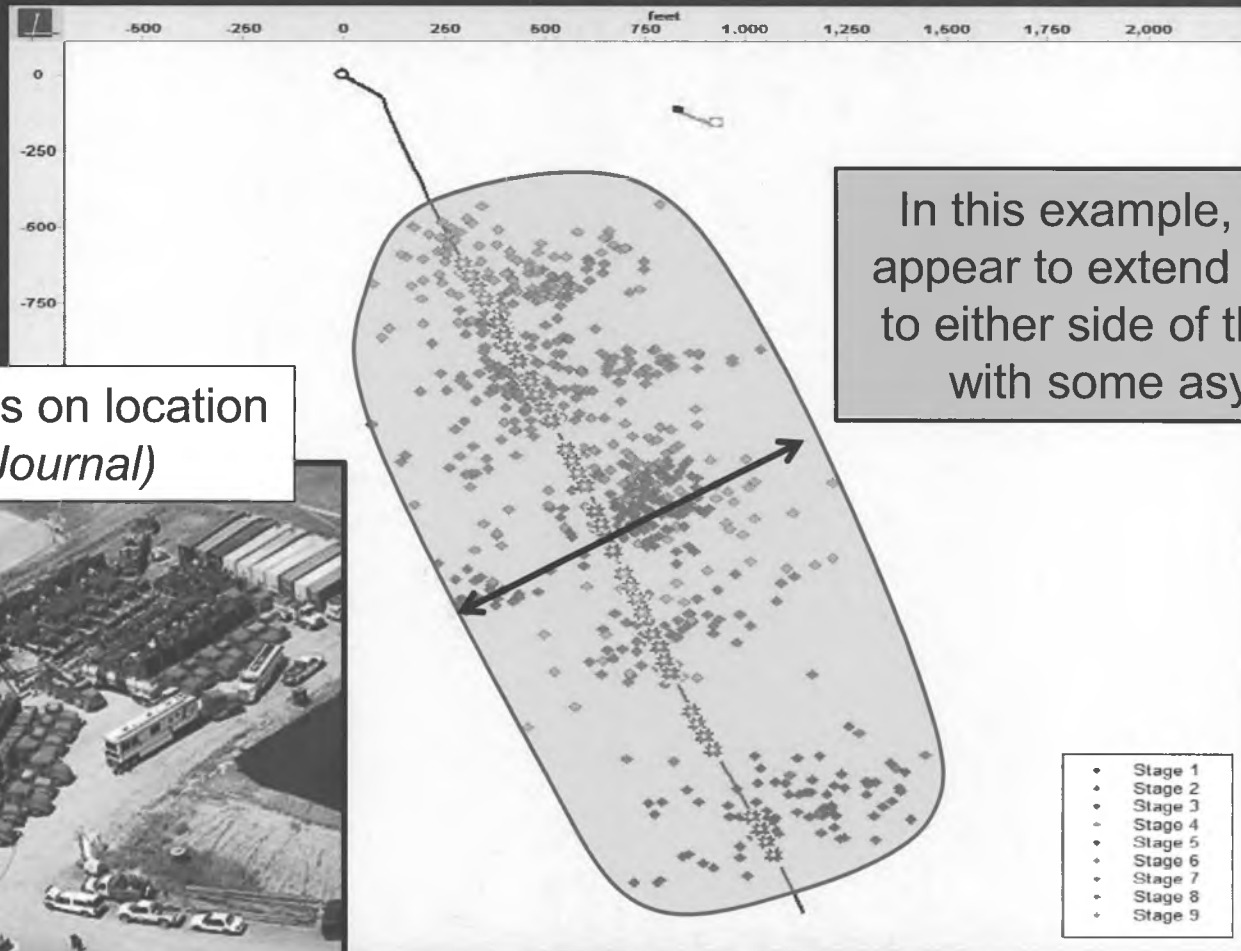
Frac jobs for horizontal producers in L48 shale plays consume 1 to 5.5 million gallons of water (and millions of pounds of sand) per well, depending on rock properties, number of stages pumped, etc.

❖ What are the environmental risks?

*Contamination of fresh water aquifers with hydrocarbons and/or frac fluids can occur where the hydrocarbon target and aquifer are not sufficiently separated. **THIS SHOULD BE AVOIDABLE!***

Frac Jobs

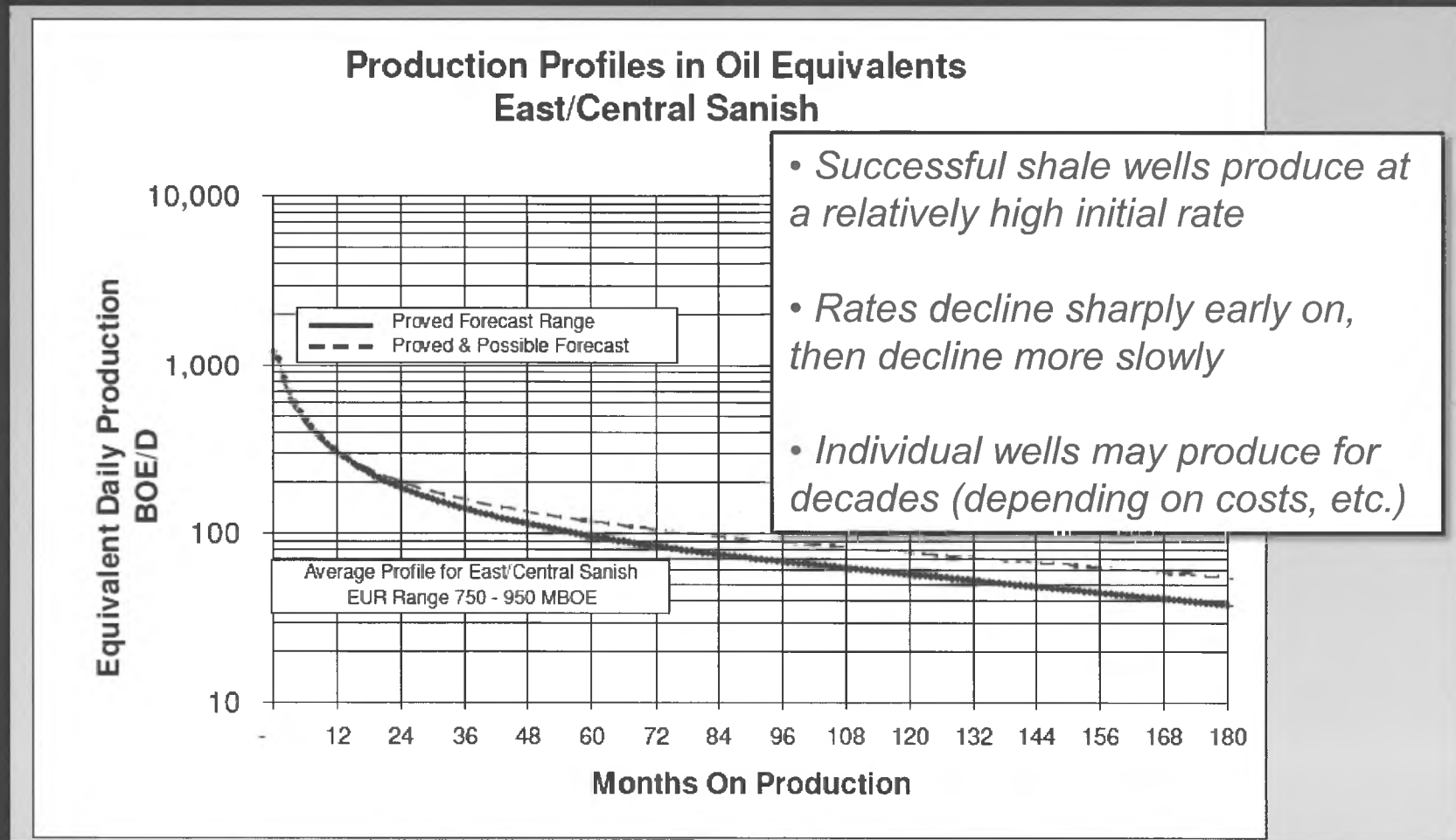
Where are the fractures and how far do they extend?



Microseismic map of 9-stage hydraulically fractured horizontal well (Bello, 2009)

Single well flow rate over time

One producer's average production profile for Bakken Formation production wells – North Dakota

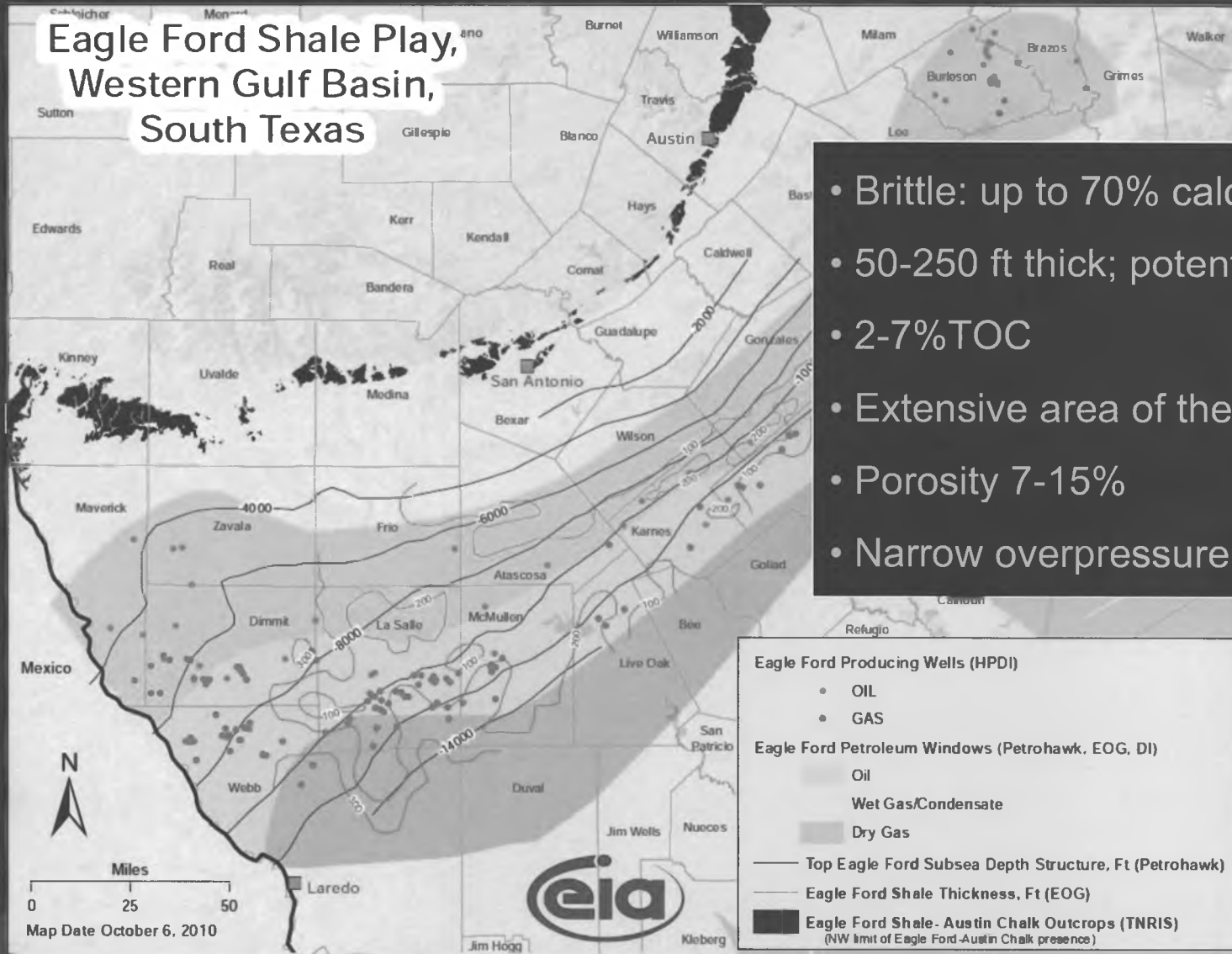


(Whiting Petroleum, 2011)

Texas Analogue (?)

Upper Cretaceous Eagle Ford Shale

Eagle Ford Shale Play,
Western Gulf Basin,
South Texas

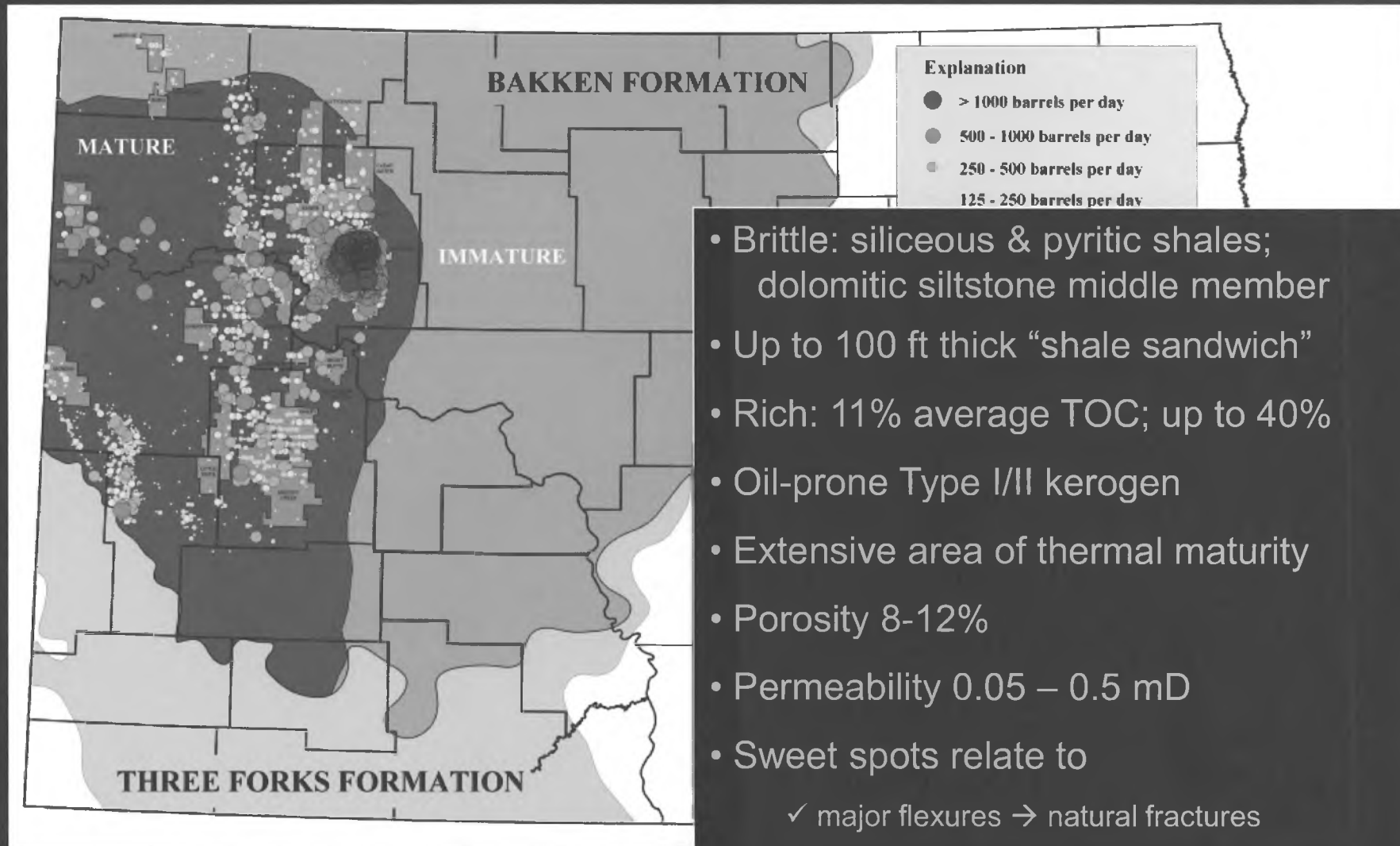


- Brittle: up to 70% calcite
- 50-250 ft thick; potentially all net pay
- 2-7% TOC
- Extensive area of thermal maturity
- Porosity 7-15%
- Narrow overpressure zone

(Energy
Information
Administration,
2010)

North Dakota Analogue (?)

Devonian-Mississippian Bakken Fm – First 60-90 day oil rates



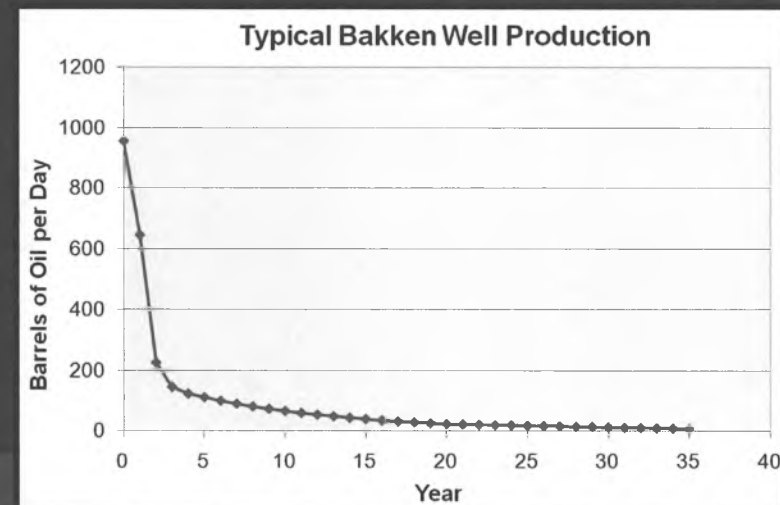
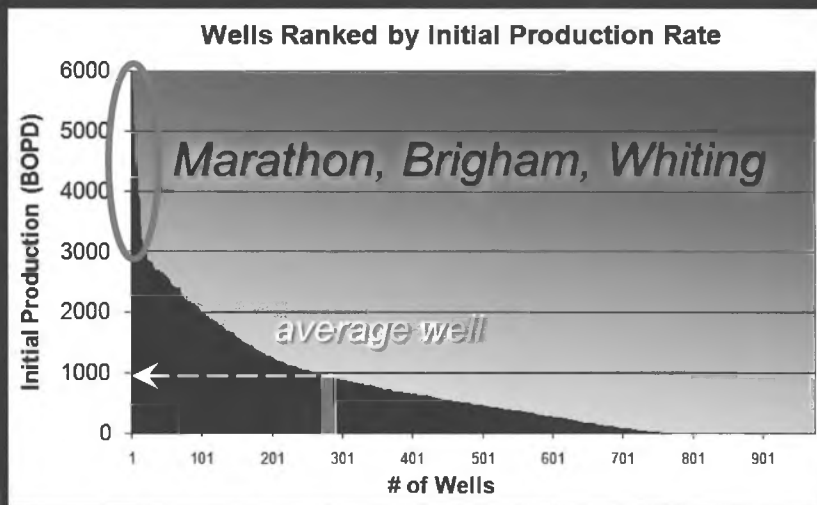
- Brittle: siliceous & pyritic shales; dolomitic siltstone middle member
- Up to 100 ft thick “shale sandwich”
- Rich: 11% average TOC; up to 40%
- Oil-prone Type I/II kerogen
- Extensive area of thermal maturity
- Porosity 8-12%
- Permeability 0.05 – 0.5 mD
- Sweet spots relate to
 - ✓ major flexures → natural fractures
 - ✓ early oil window maturity → overpressure

(Nordeng, 2010; Nordeng and others, 2010)

Bakken Well Economics and Production

North Dakota Industrial Commission, Department of Mineral Resources

- Well Cost, Horizontal Producer \$6.1 million (47 jobs)
- Operating Cost, Monthly < \$7,000 (1 job)
- Royalty Rate 16.7%
- Average Initial Production Rate 955 BOPD
- Breakeven IP Oil Rate 235 BOPD
- Breakeven Reserves per well 183,000 bbl
- Breakeven Reserves Success 83%



(courtesy Lynn Helms NDIC, DMR, 2011)

Shublik Formation

Variability in outcrop and well logs



Interbedded shale & limestone, silty-muddy, phosphatic, pyritic (up to 600 ft thick)

Shublik Fm

Zone A

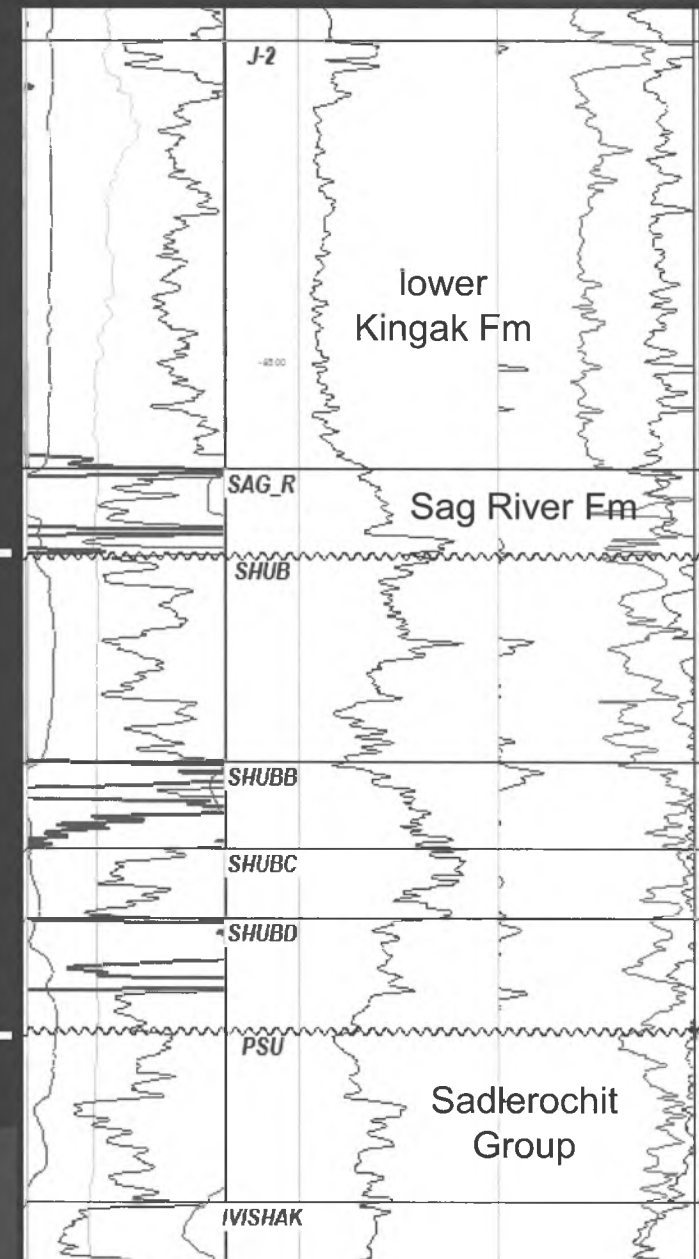
Zone B

Zone C

Zone D

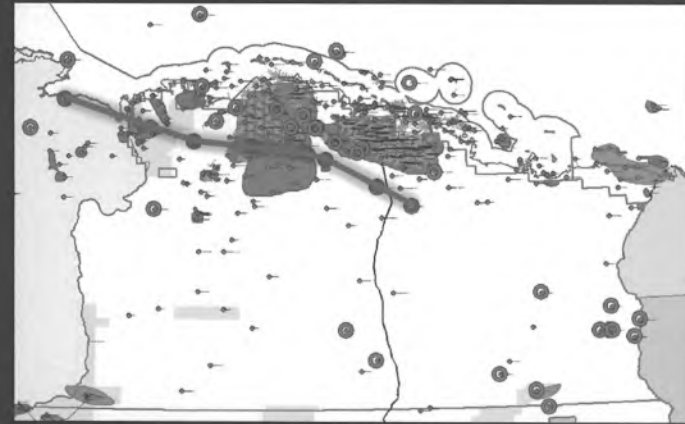


Rock Flour 1



Shublik Formation

Well logs and zonal correlations



S Harr Bay 1

Kookpuk 1

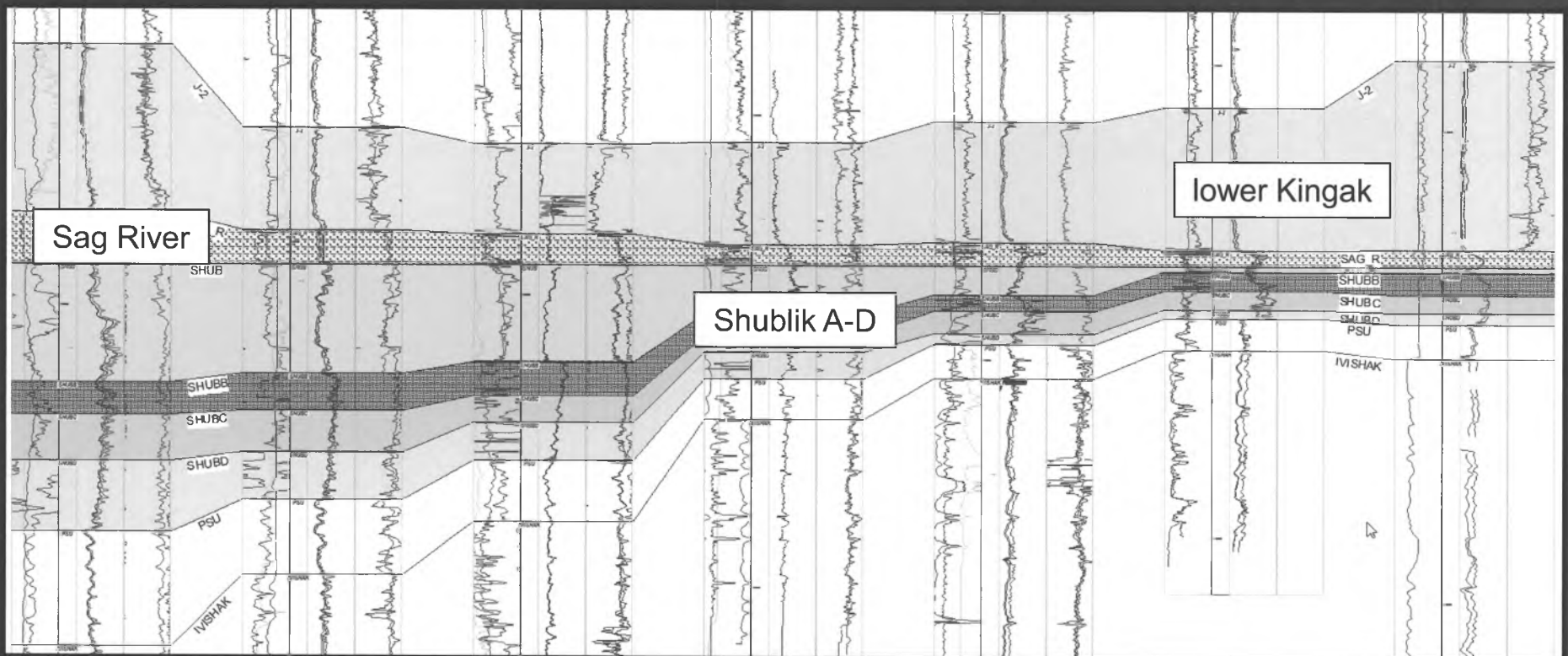
KRU 2F-20

Rock Flour 1

Hemi Spr 1

Hemi Spr 3

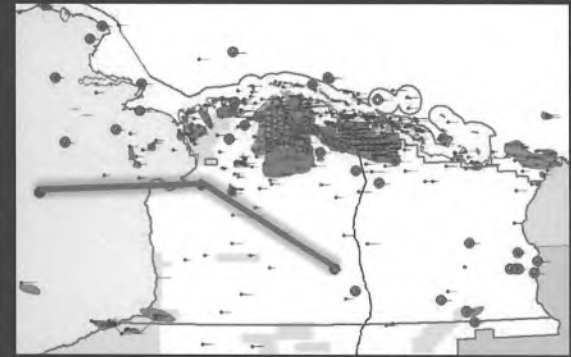
Toolik 1



(Decker, unpublished data, 2011)

Lower Kingak Formation

Δ Log R source rock screening



Inigok 1

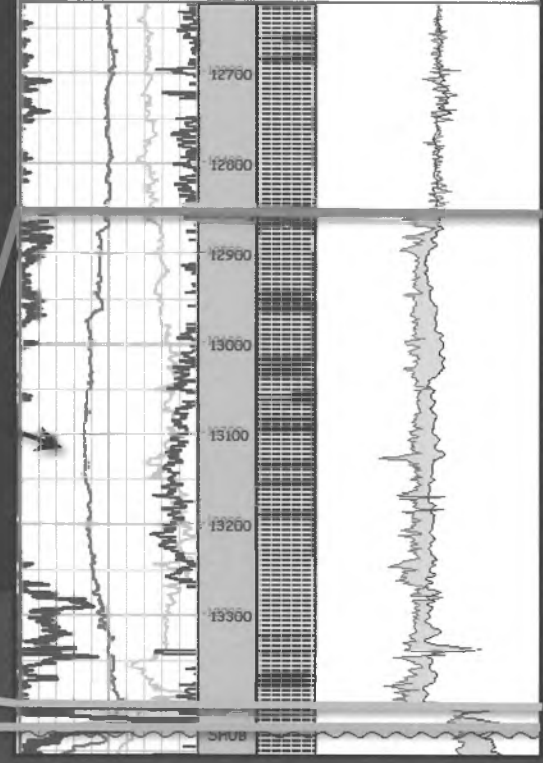
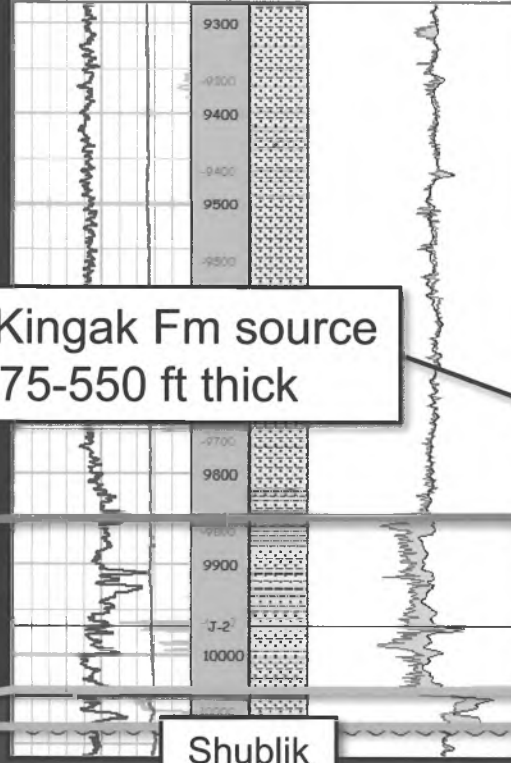
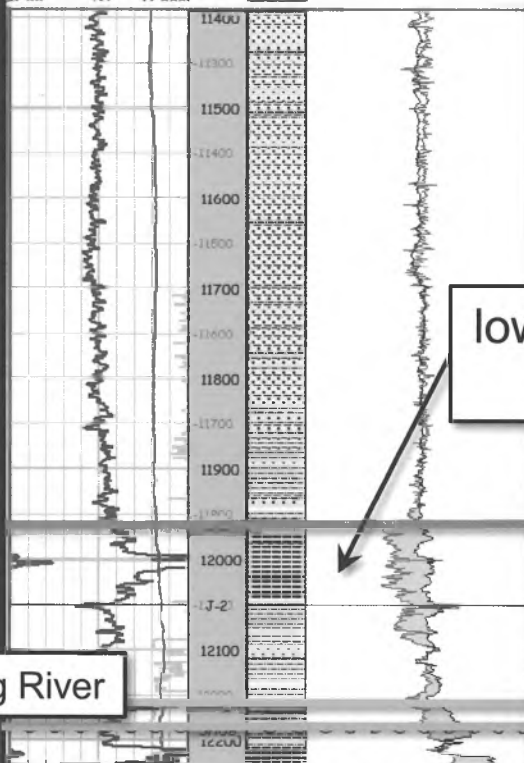
Itkillik River 1

Bush Fed 1

| Correlation | Depth | Litho | DeltaLogR |
|-------------------|-------|----------|---------------|
| GR | <MD | Dolomite | ResB(ILB) |
| 0.000 API 150.000 | | | 0.03 OHMM 300 |
| GR | TVDSS | Imestone | DT |
| 150 API 300 | | 200 | US/FT 0 |
| SP | | Imestone | DeltaLogR |
| -100 MV 70 | | | |
| CALI | | Sandston | |

| Correlation | Depth | Litho | DeltaLogR |
|--------------------|-------|----------|--------------|
| GR | <MD | Dolomite | ResB(RD) |
| 0.000 GAPI 150.000 | | | 0.02 OHMM 20 |
| GR | TVDSS | Imestone | DT |
| 150 GAPI 300 | | 200 | US/F |
| SP | | Imestone | DeltaLogR |
| -100 MV 70 | | | |
| CALI(CAL) | | Sandston | |

| Correlation | Depth | Litho | DeltaLogR |
|-------------------|-------|----------|----------------|
| GR | <MD | Dolomite | ResB(ILB) |
| 0.000 API 150.000 | | | 0.012 OHMM 120 |
| GR | TVDSS | Imestone | DT |
| 150 API 300 | | 200 | US/FT 0 |
| SP | | Imestone | DeltaLogR |
| -100 MV 70 | | | |
| CALI | | Sandston | |



lower Kingak Fm source
~175-550 ft thick

Sag River

Shublik

Hue Shale/GRZ

Correlations and log-based Total Organic Content estimates

Itkillik R 1

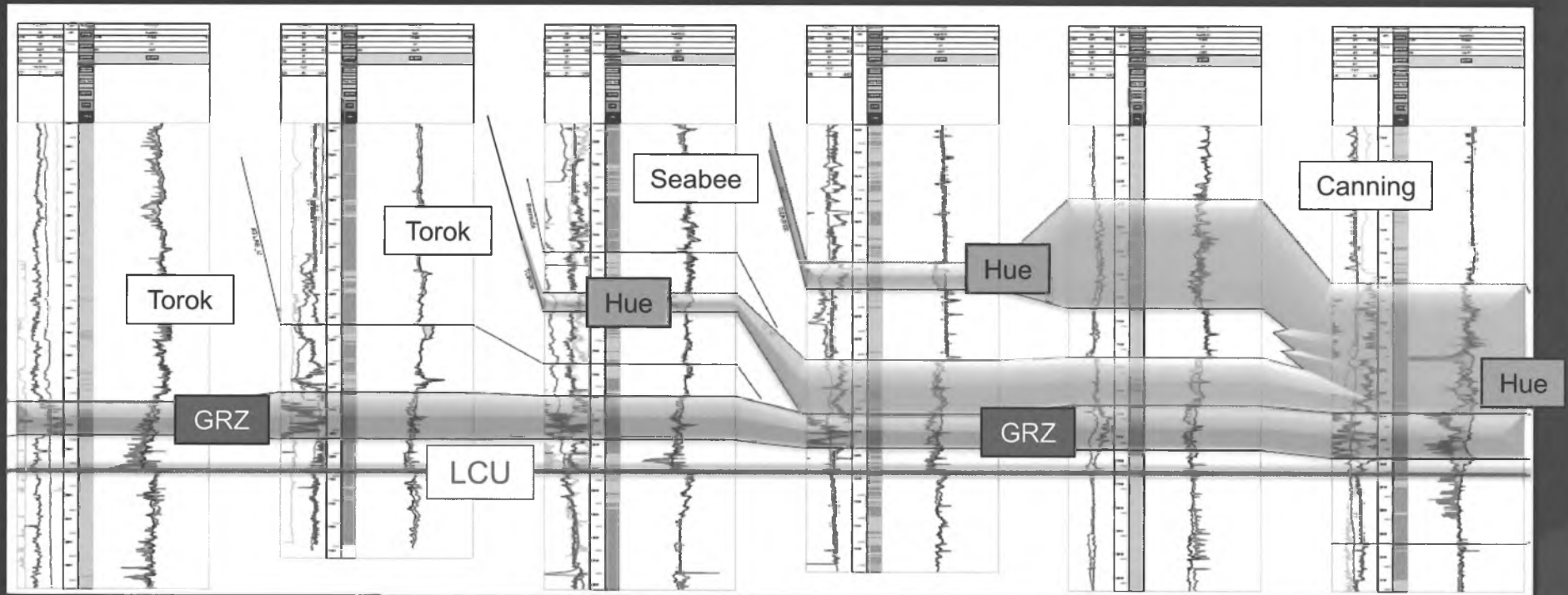
Atlas 1

Narvaq 1

W Sak 26

Toolik 2

Hemi Spr 3



Δ Log R calculated
TOC estimates

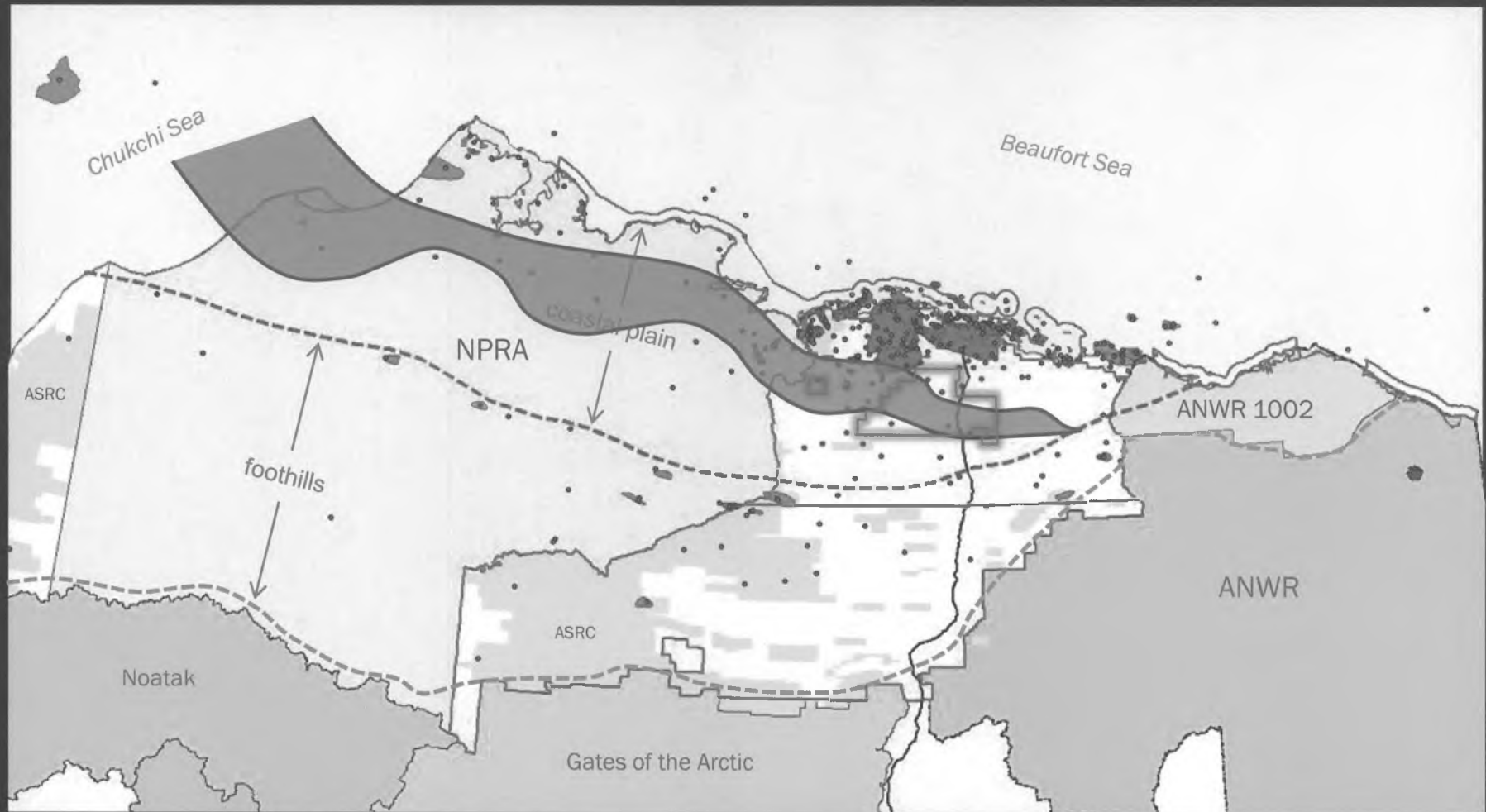
| | | | | |
|--------|------|------|------|----------|
| Hue Sh | 4.9% | 2.6% | 3.1% | 4.8% (?) |
|--------|------|------|------|----------|

| | | | | | | |
|-----|------|------|------|------|------|-----------|
| GRZ | 2.6% | 2.4% | 1.6% | 5.0% | 3.1% | 10.3% (?) |
|-----|------|------|------|------|------|-----------|

(Decker, unpublished data, 2009)

Shublik and Lower Kingak Formations

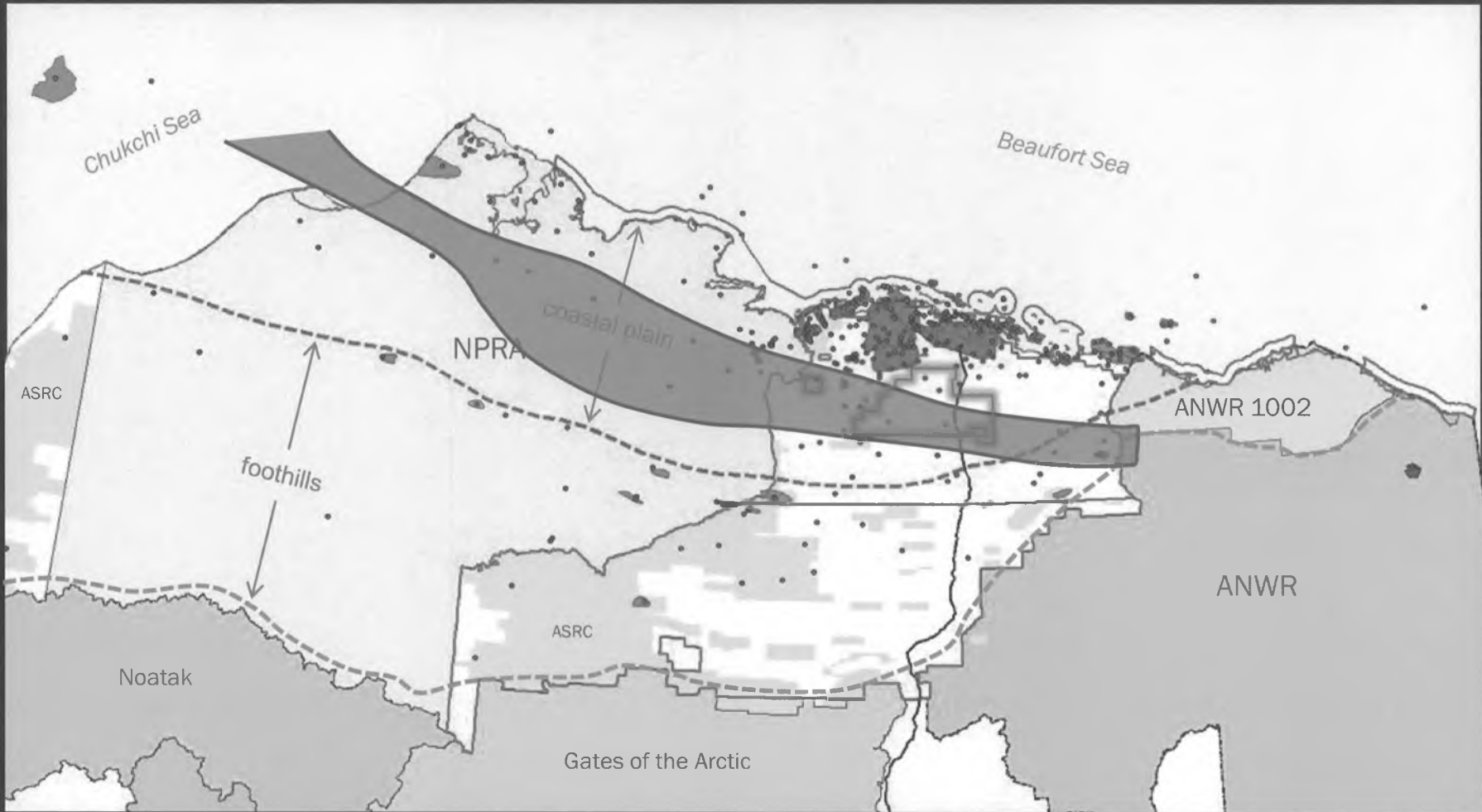
Thermal Maturity Zone



(mature area after Peters and others, 2006)

Hue Shale/GRZ

Thermal Maturity Zone



(mature area after Peters and others, 2006)

Comparison

Source rock characteristics

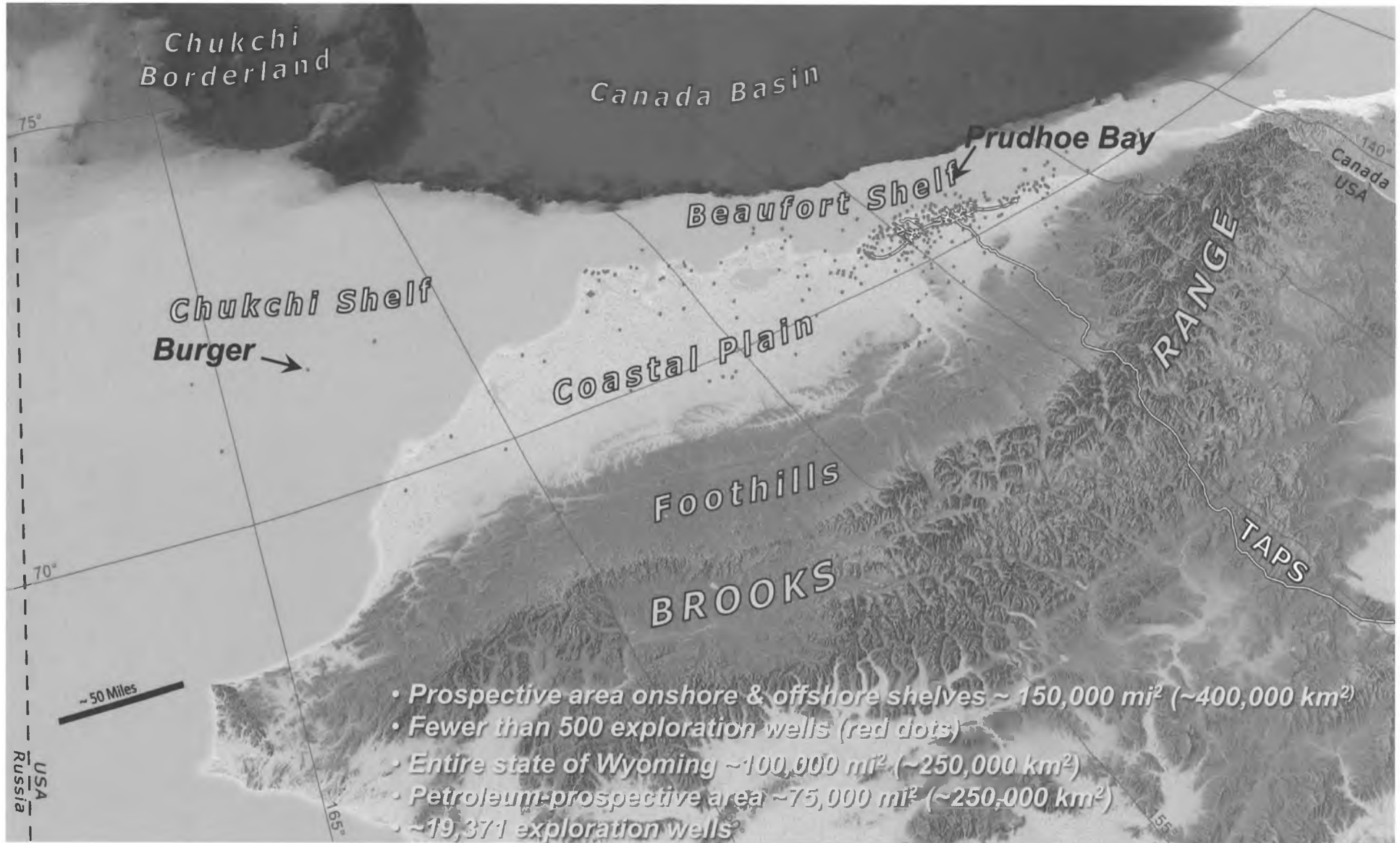
| | Bakken | Eagle Ford | Shublik | L. Kingak | Hue/GRZ |
|-------------------------|---------------------|---------------------|-----------------------|------------------|------------------|
| Total Organic Carbon | 10% avg | 2-7% | 2.4% avg | 5% avg | 3% avg |
| Main Kerogen Types | I/II (<u>oil</u>) | I/II (<u>oil</u>) | I/II-S (<u>oil</u>) | II/III (oil-gas) | II/III (oil-gas) |
| Oil Gravity, °API | 42° | 30-50° | 24° | 40° | 38° |
| Thickness | up to 100 ft | 50-250 ft | 0-600 ft | 175-550 ft | 100-800 ft |
| Thermal Maturity | Imm-Oil-Gas | Imm-Oil-Gas | Imm-Oil-Gas | Imm-Oil-Gas | Imm-Oil-Gas |
| Lithology & Variability | Sh-Slts-Sh | Sh-Slts-Ls | Sh-Slts-Ls | Shale | Sh-Tuff |
| Brittleness | Yes - Quartz | Yes - Calcite | Yes - Calcite | No ? | No ? |
| Natural Fractures | Yes | Locally | some zones | ? | ? |
| Overpressure | Yes | Locally | ? | Probably | Locally |

(compiled from various sources, Decker, 2011)

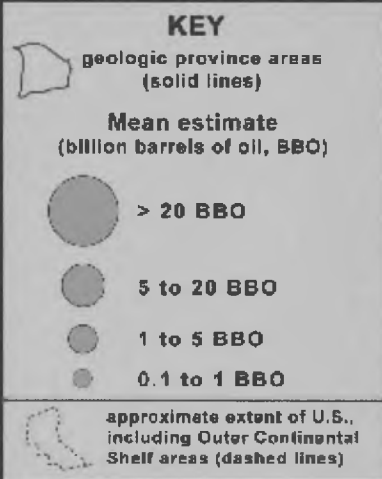
Summary

- ◎ Many variables impact productivity of source-reservoired oil and gas
 - Organic geochemistry
 - Thermal and tectonic history
 - Petrophysics
 - Geomechanics
 - Drilling and completion practices
- ◎ Development of North Slope shale oil will likely depend on
 - Successful exploration drilling, data gathering to establish geological favorability
 - Successful production pilot project(s)
 - Lowering drilling and operating costs
 - All-season roads for year-round surface access to new areas
 - More hydraulic frac crews
 - Sufficient water supplies for frac make-up fluid
 - Factual understanding and operator transparency regarding frac practices

Arctic Alaska Conventional Oil & Gas Exploration Potential



Global Conventional Oil Resources



Global Conventional Oil Resources - Undiscovered, Technically Recoverable

Data sources:

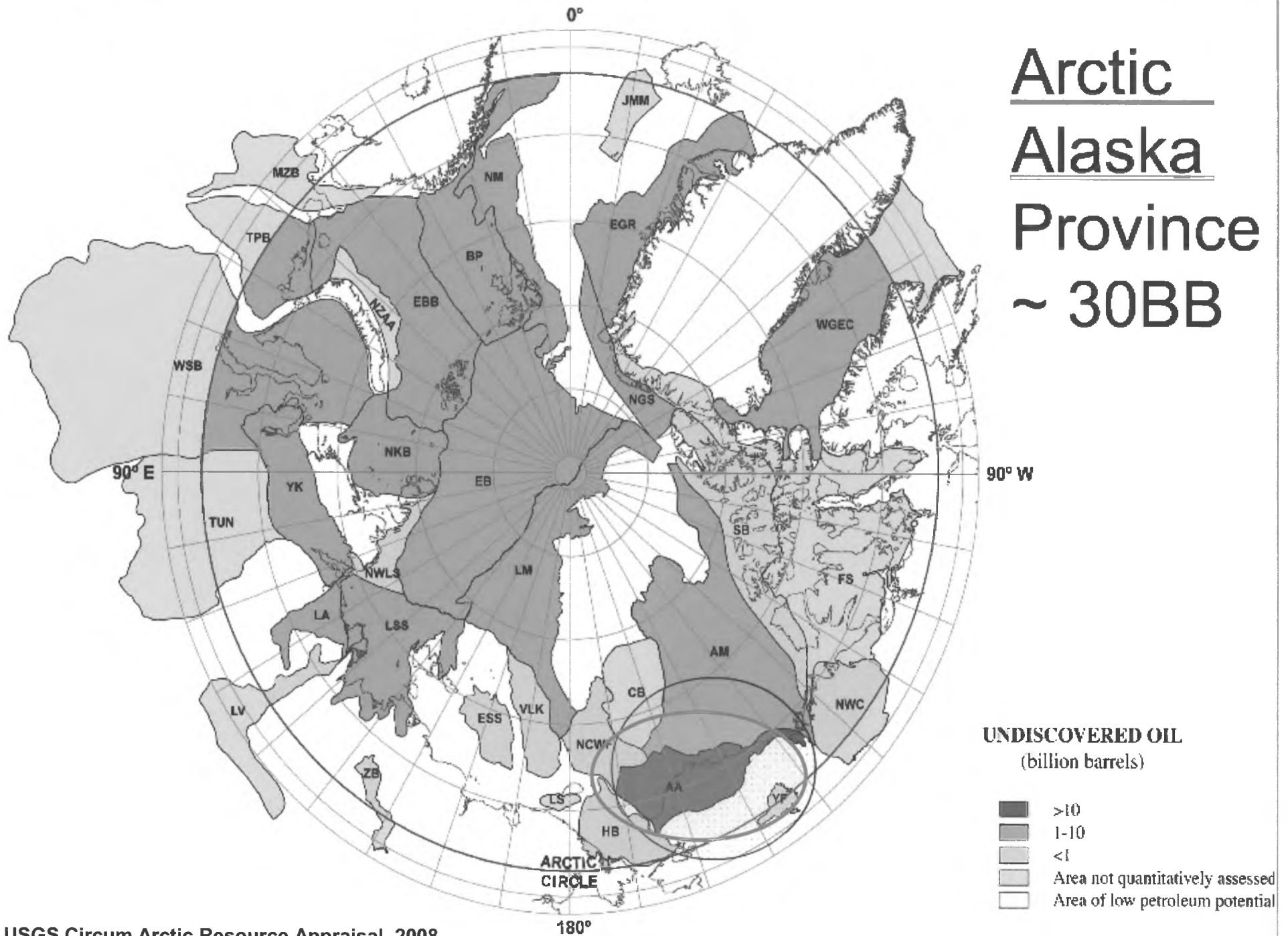
- USGS World Petroleum Assessment 2000 and updates
- USGS National Oil and Gas Assessment, 2006 update
- MMS 2006 National OCS Assessment
- Earth At Night Image courtesy of NASA/GSFC, NOAA/NGDC DMSP Digital Archive

Note: Map does not include results from USGS Circum-Arctic Resource Appraisal

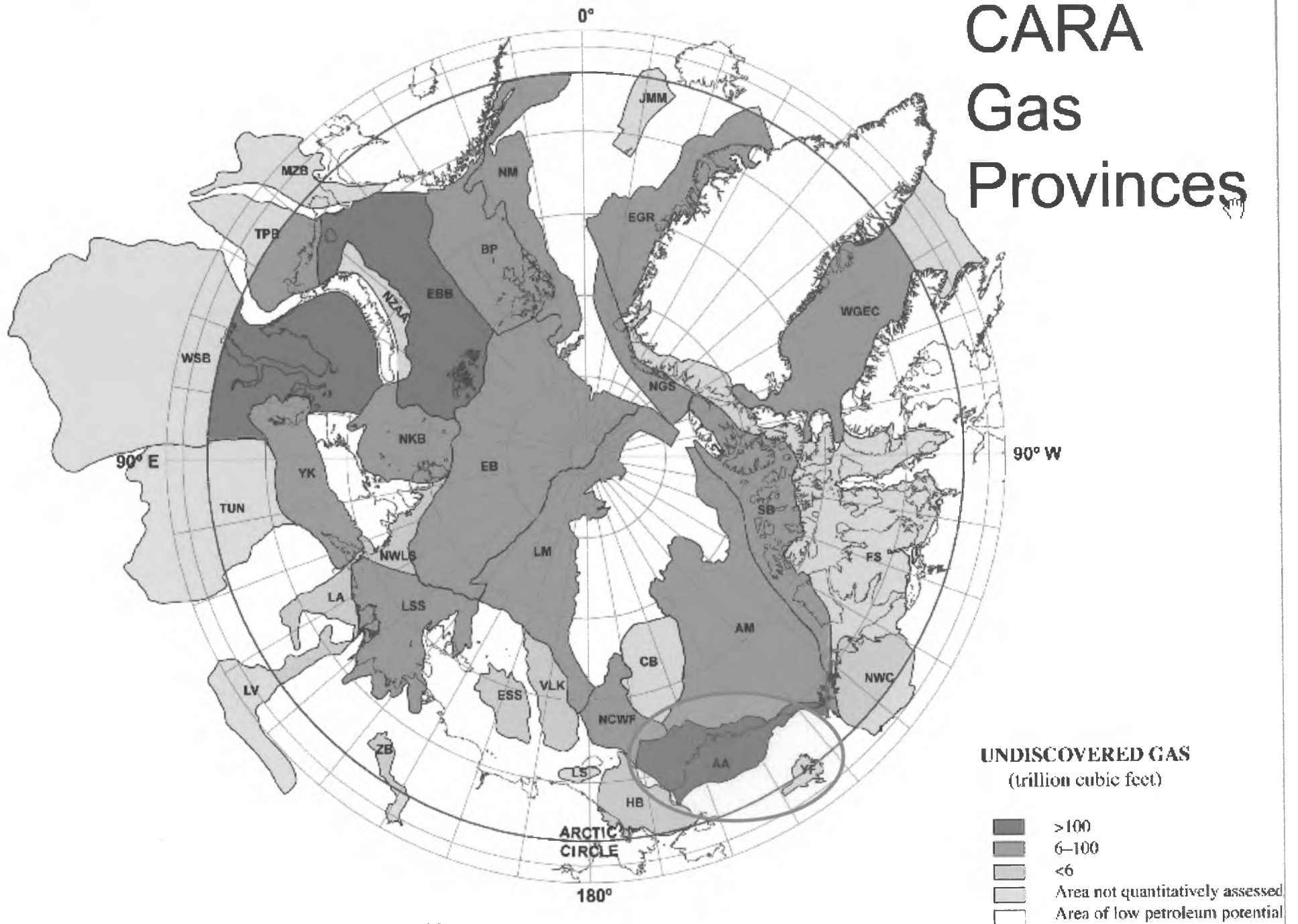


Note: Does not include results from USGS Circum-Arctic Oil and Gas Resource Appraisal study.

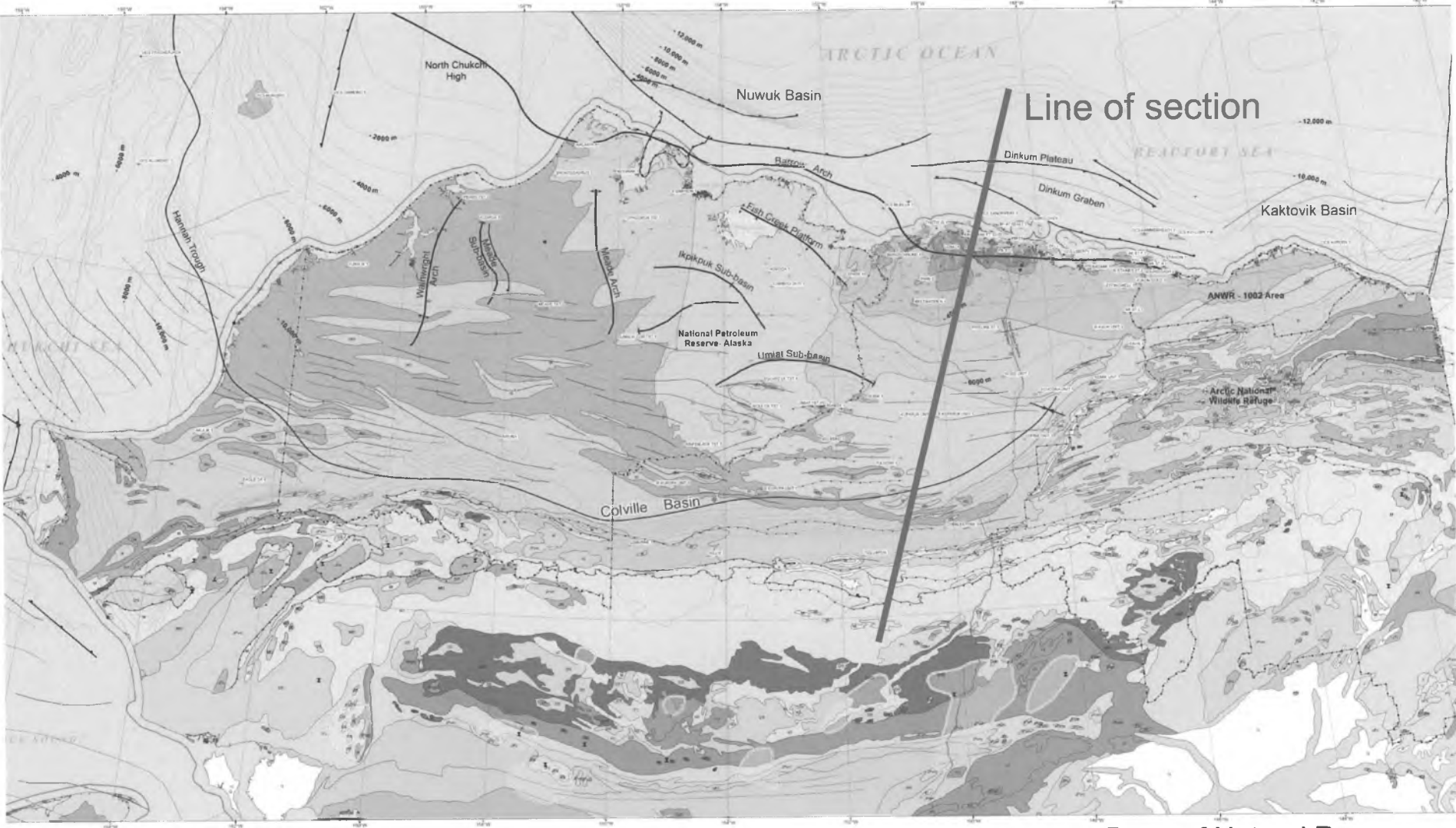
Arctic Alaska Province ~ 30BB



CARA Gas Provinces

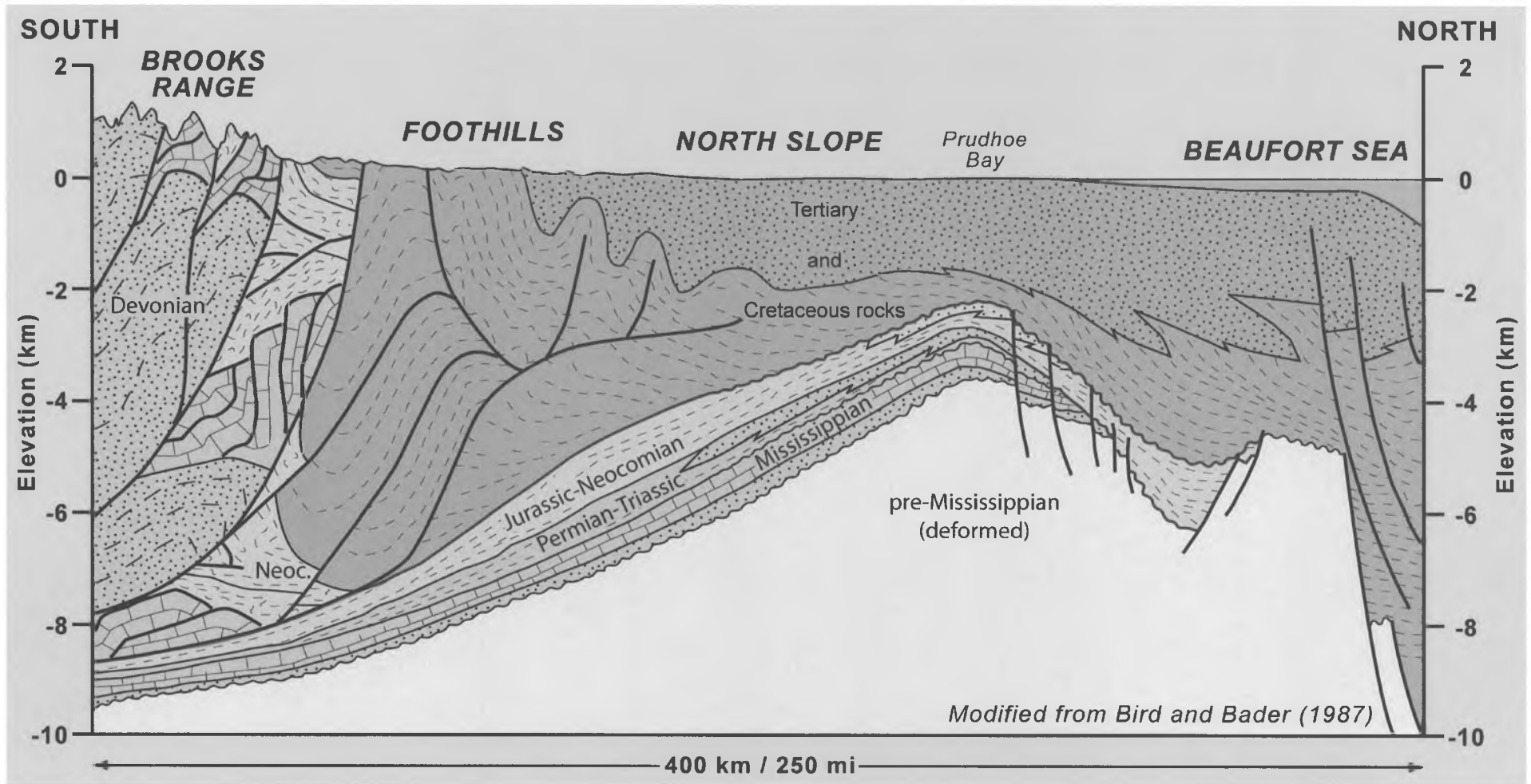


North Slope Regional Geology



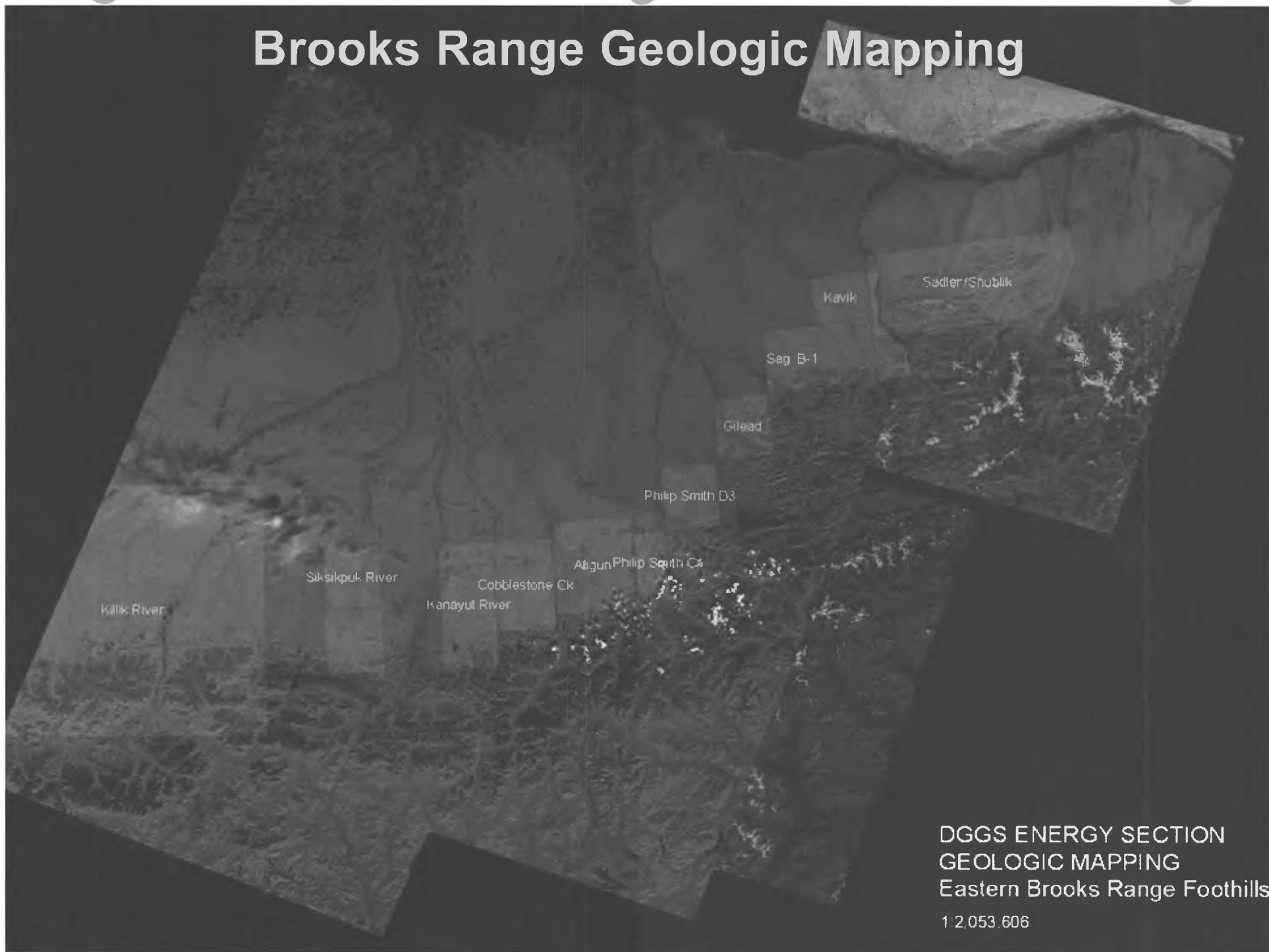
Alaska Dept. of Natural Resources
Division of Oil & Gas

Simplified and Generalized Regional Cross-section



USGS

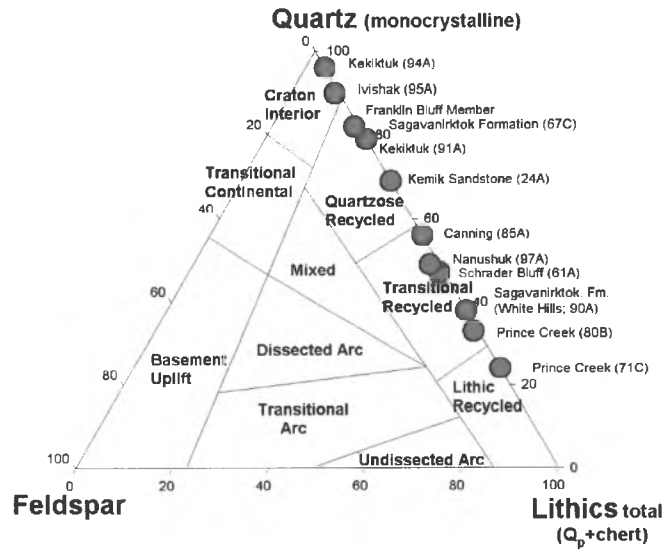
Brooks Range Geologic Mapping



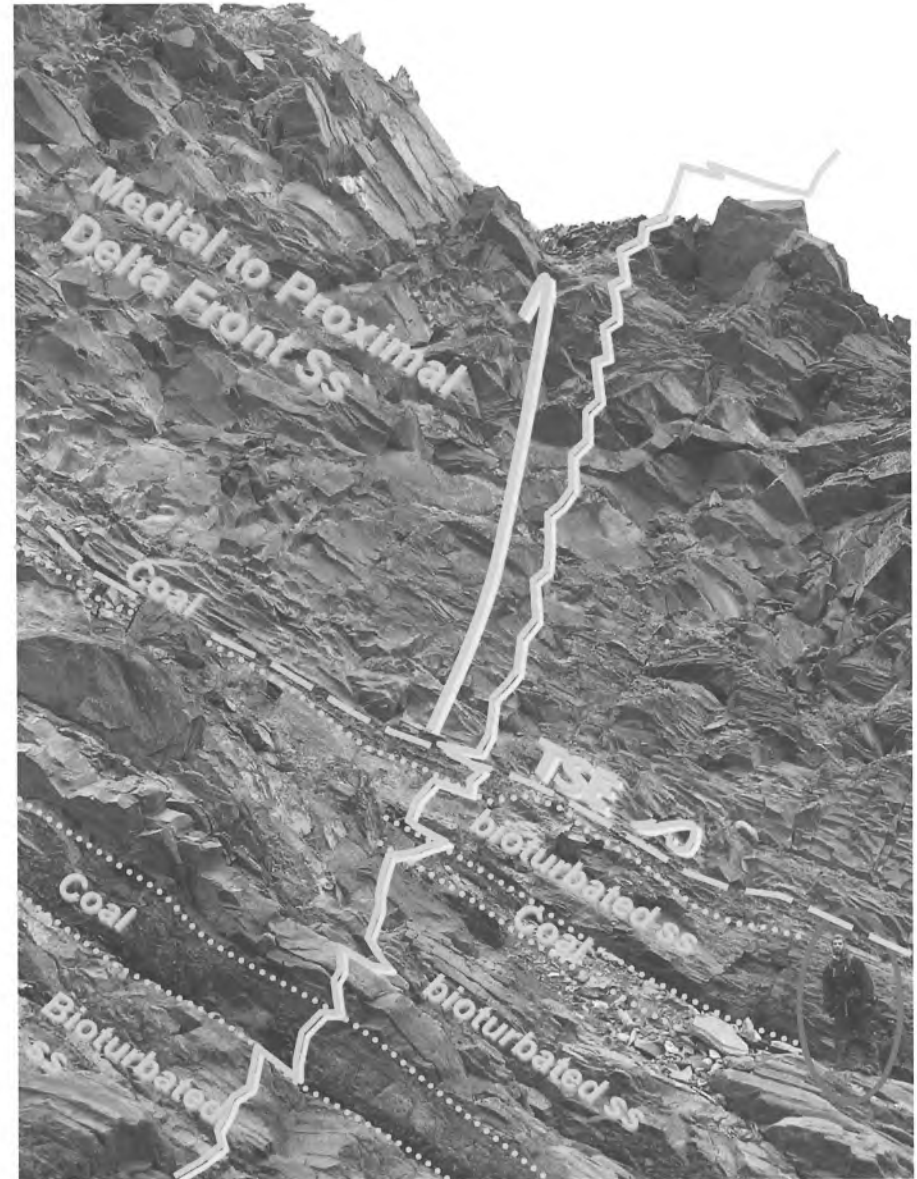
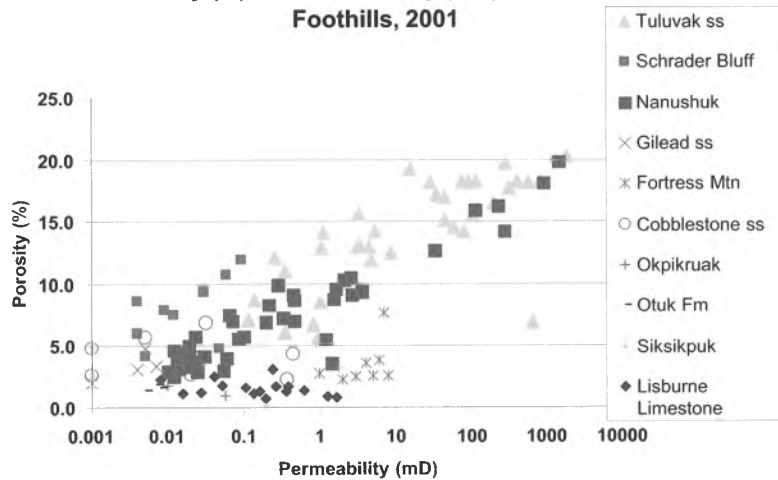
DGGS ENERGY SECTION
GEOLOGIC MAPPING
Eastern Brooks Range Foothills
1 2.053.606

Topical Petroleum-related Studies

Quartz (monocrystalline)-Feldspar-Lithics (total)

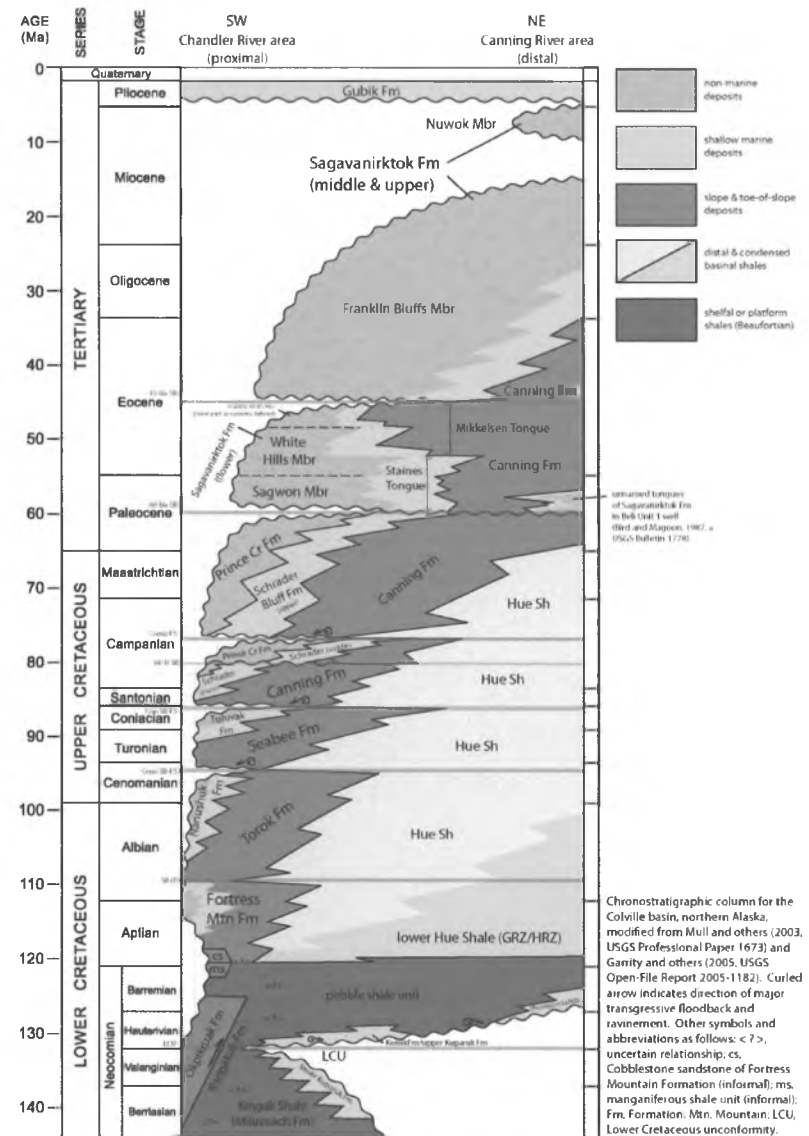
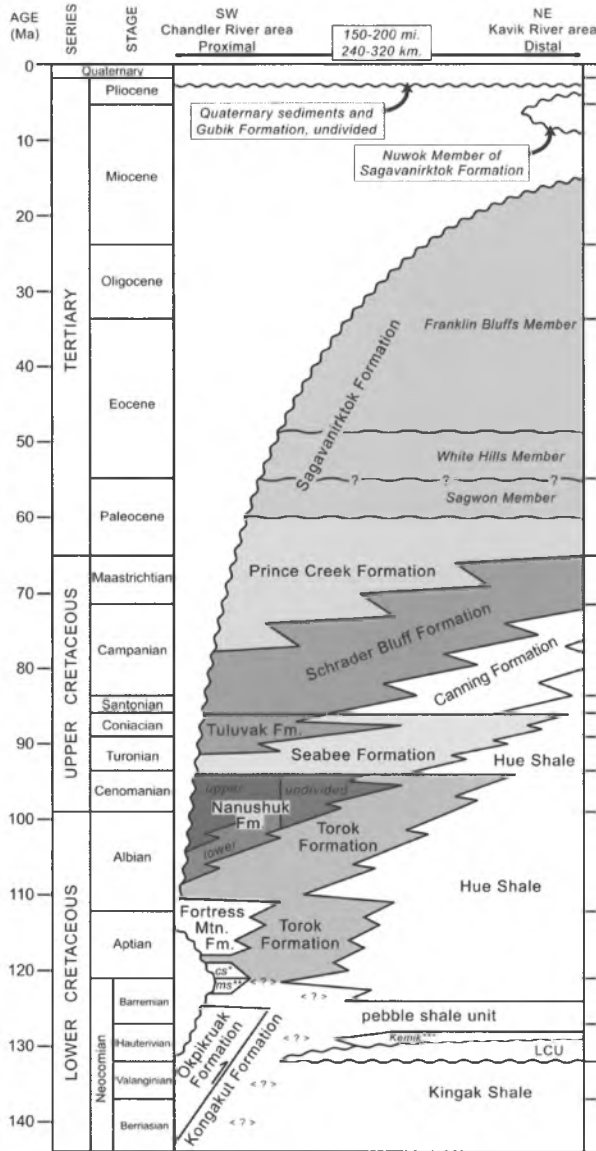


Porosity (%) vs. Permeability (mD) North Slope Foothills, 2001



Killik Bend non-marine to deltaic succession, highstand aggradational system tract

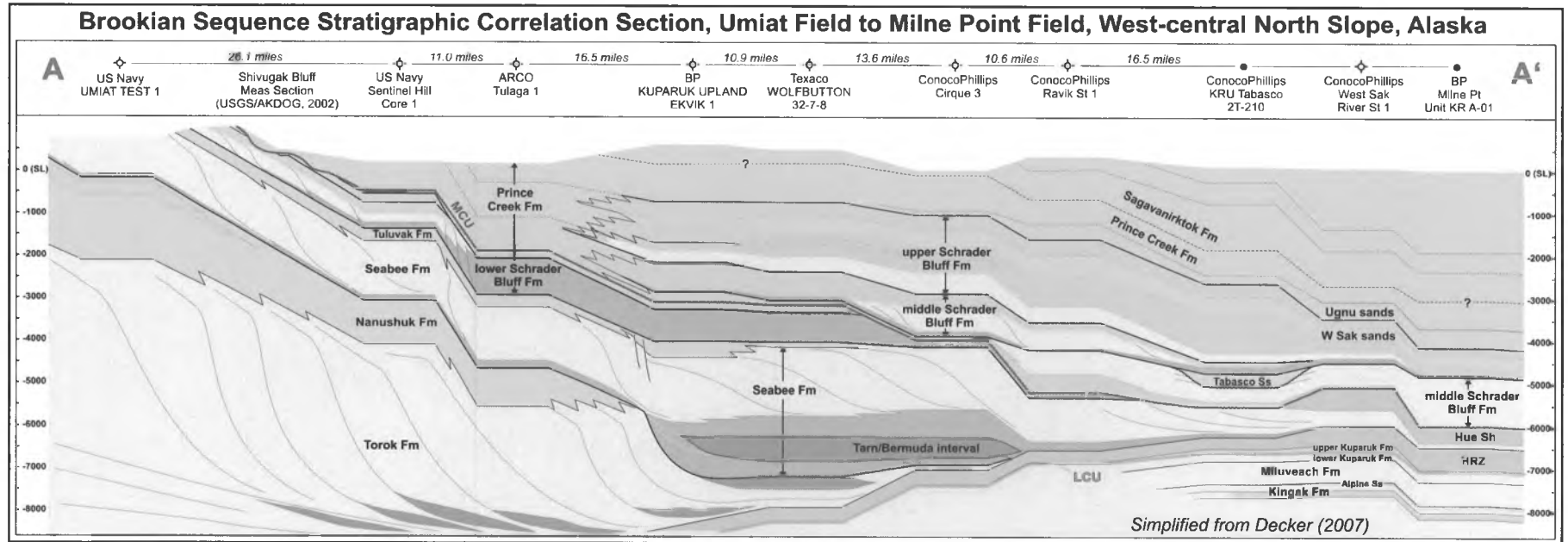
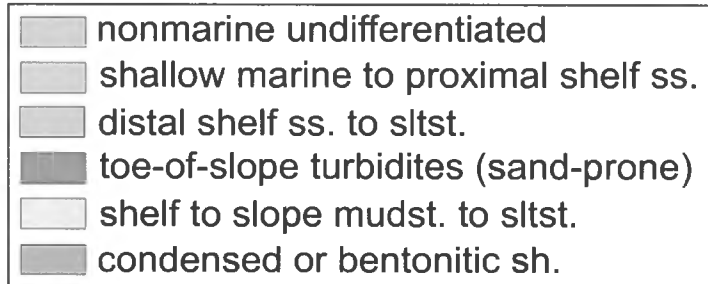
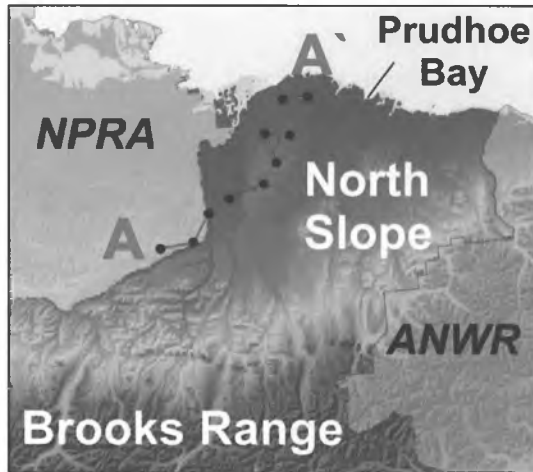
Revising and Codifying Stratigraphic Nomenclature



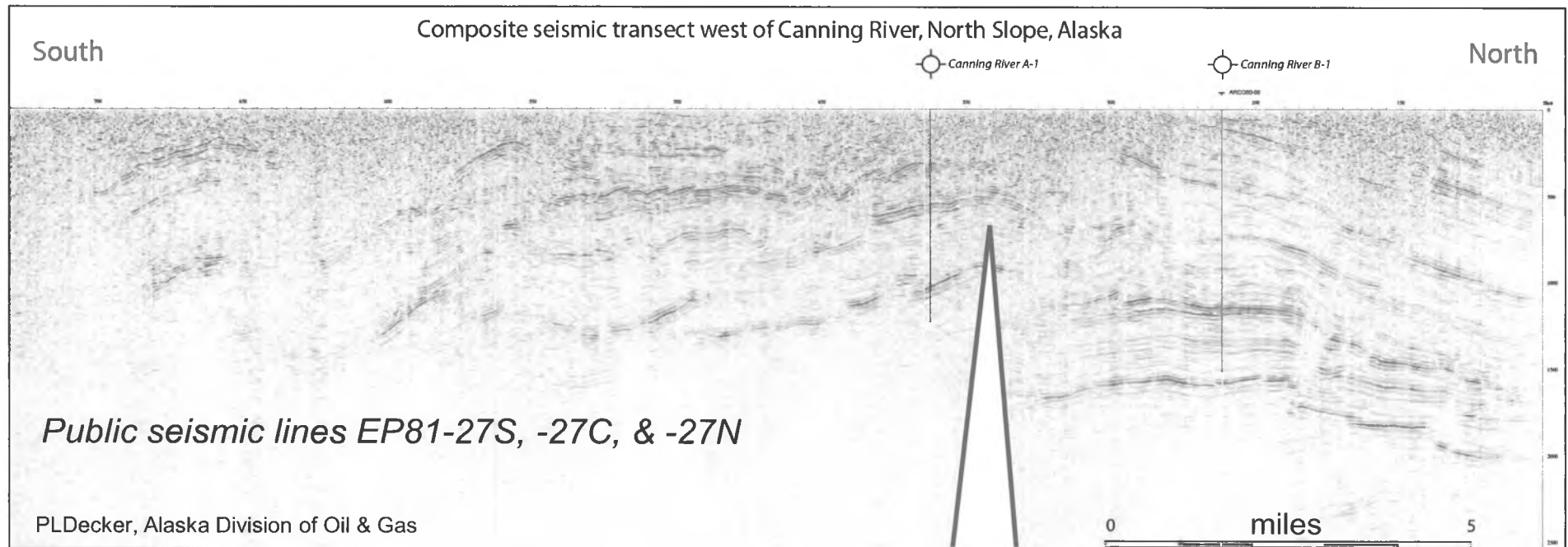
Red lines and text indicate key sequence stratigraphic surfaces, abbreviated as follows: SB, sequence boundary; FS, transgressive flooding and/or ravinement surface; Camp, Campanian; Cen., Cenomanian; MCU, mid Campanian unconformity.

Chronostratigraphic column for the Colville basin, northern Alaska, modified from Mull and others (2003, USGS Professional Paper 1673) and Garity and others (2005, USGS Open-File Report 2005-1182). Curled arrow indicates direction of major transgressive floodback and ravinement. Other symbols and abbreviations as follows: < ? >, uncertain relationship; cs, Cobblestone sandstone of Fortress Mountain Formation (informal); ms, manganese shale unit (informal); Fm, Formation; Mtn, Mountain; LCU, Lower Cretaceous unconformity.

Merging Surface and Subsurface Data

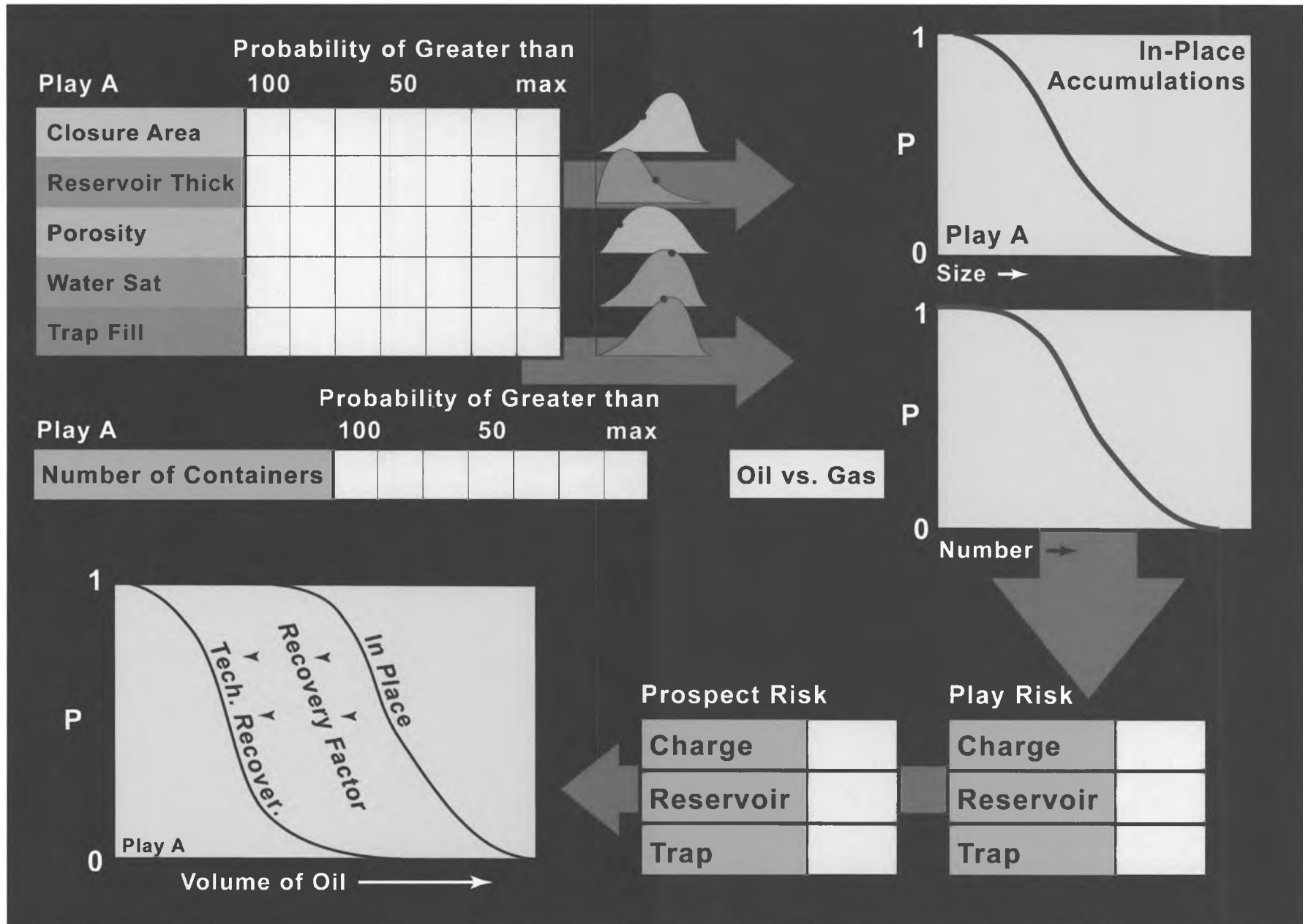


Foothills Structural Plays Seismic Interpretation



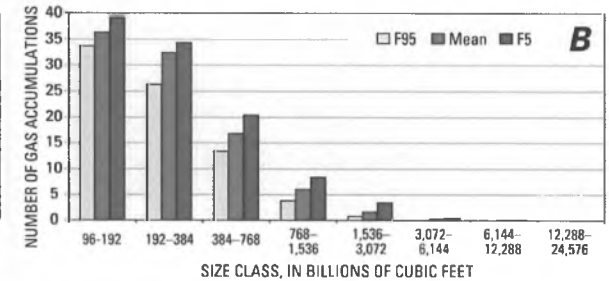
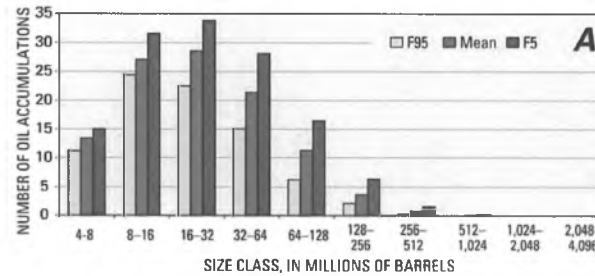
Kavik structure

USGS Assessment Methodology – Geologic Basis

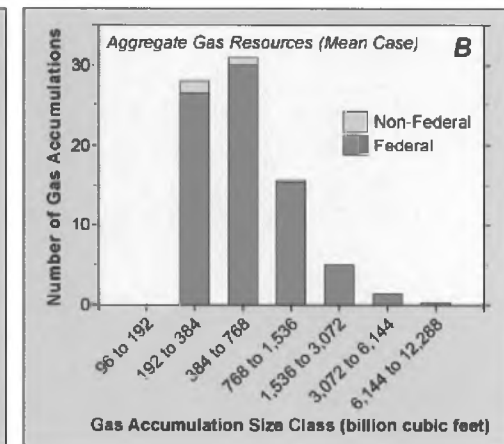
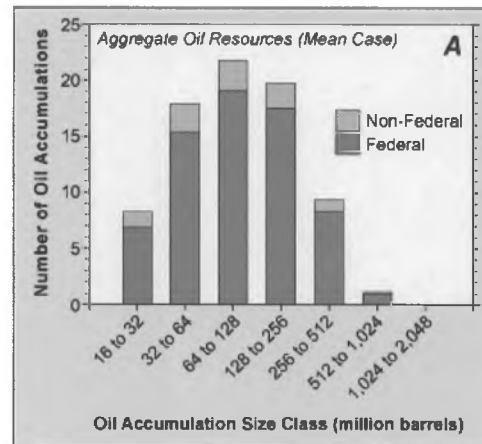


Undiscovered Mean Field Size Distributions - USGS

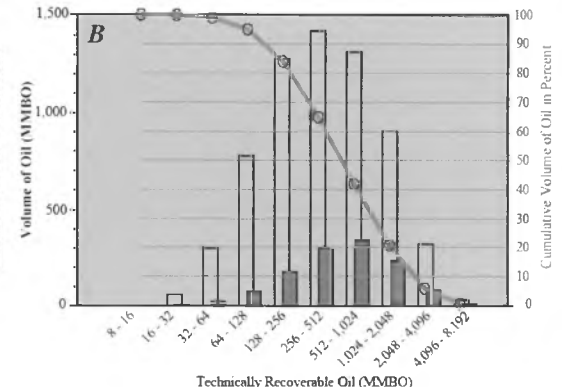
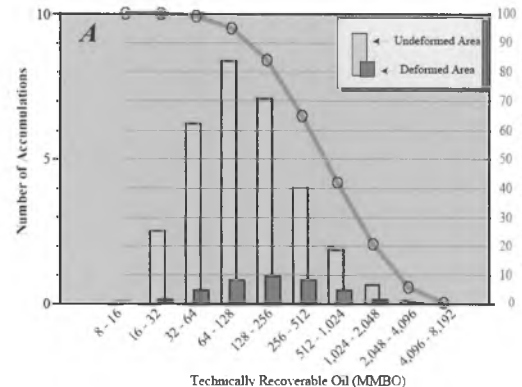
State Lands: ~1 undiscovered oil accumulation > 250 MMBO recoverable. ~ 2 undiscovered gas accumulations > 1.5 TCF recoverable.



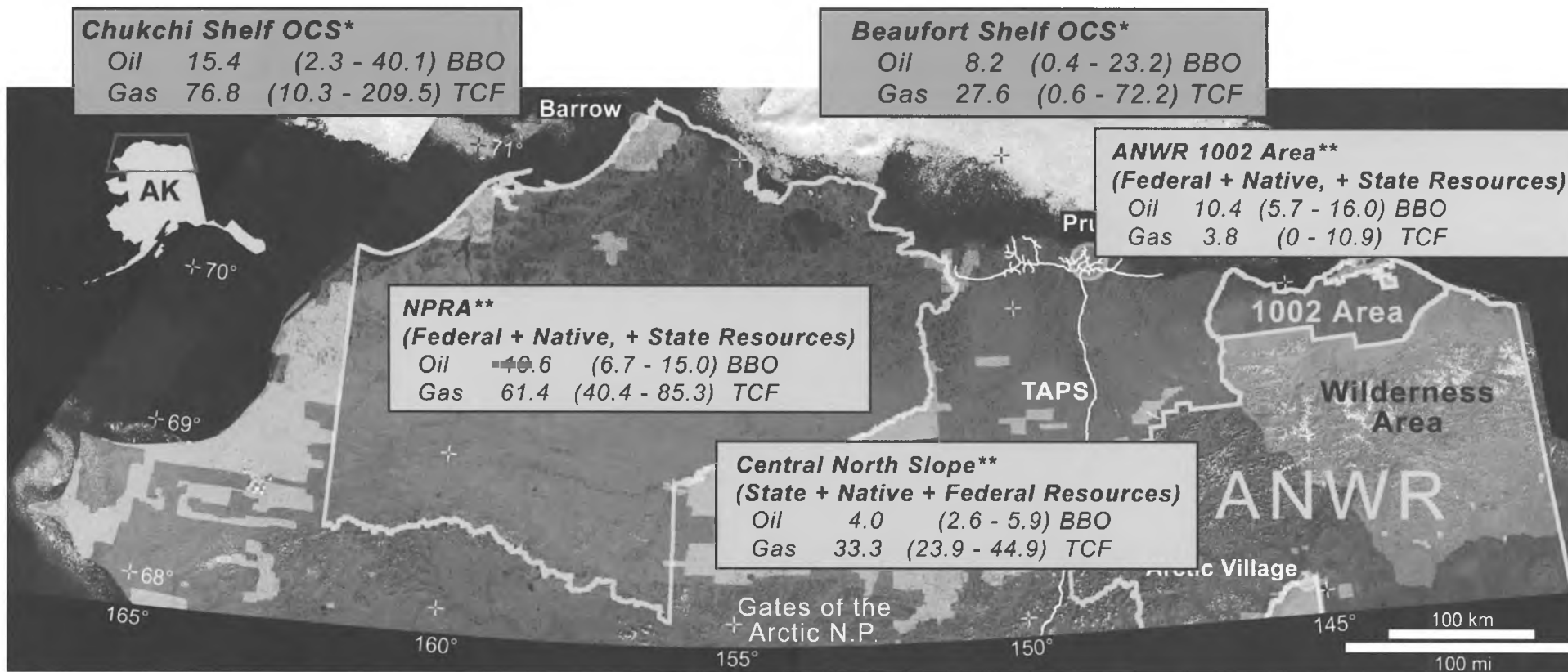
NPRA: ~11 undiscovered oil accumulations > 250 MMBO recoverable. ~7 undiscovered gas accumulations > 1.5 TCF recoverable.



ANWR 1002: ~9 undiscovered oil accumulations > 250 MMBO recoverable (~65% of estimated total recoverable oil volume); gas resource not shown.



USGS Potential for Undiscovered Petroleum in Arctic Alaska



* Oil includes crude oil + natural gas liquids
Gas includes nonassociated + associated gas

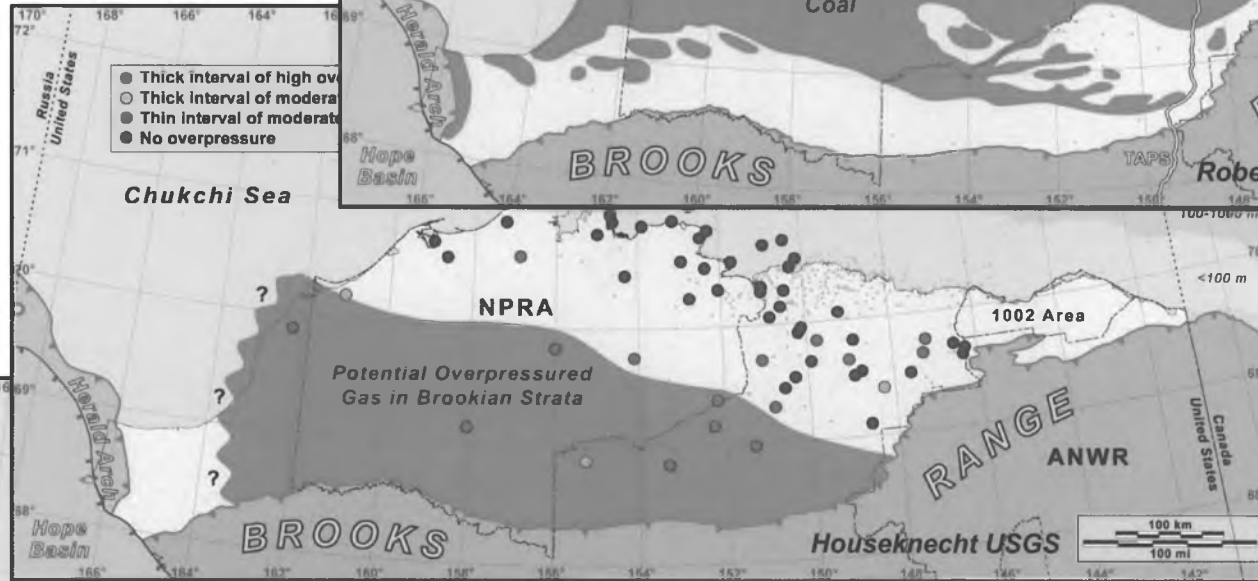
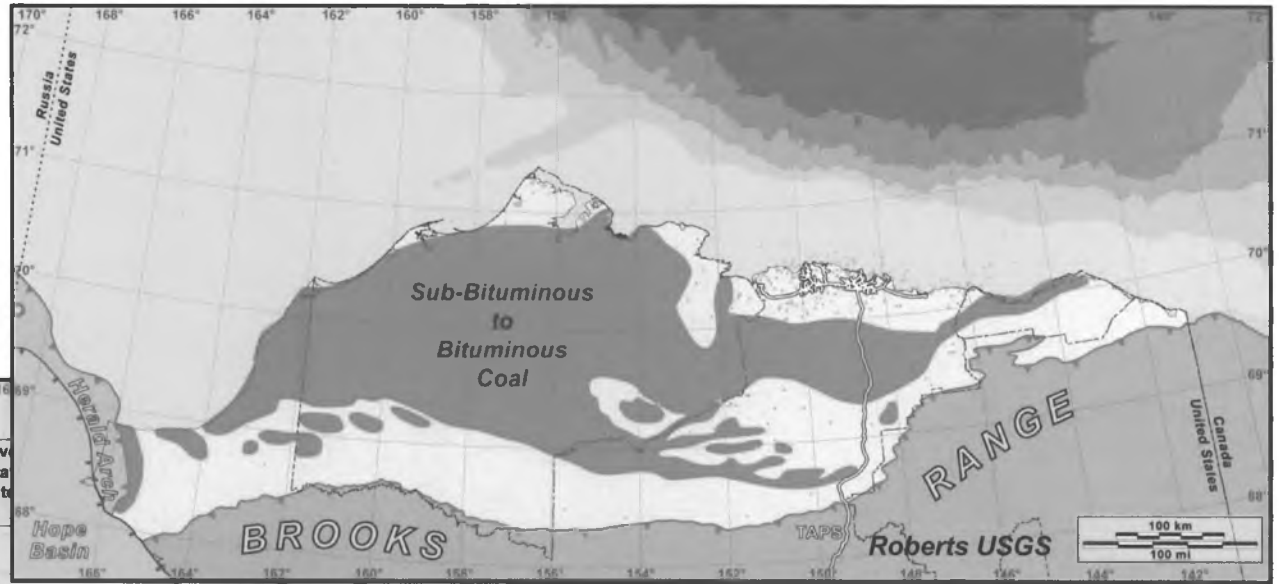
** Oil includes crude oil only
Gas includes nonassociated gas only

“Unconventional” Gas Resources (continuous resources)

Coalbed Gas

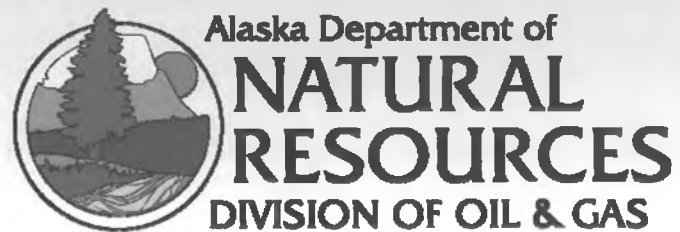
Overpressured, Basin-centered Gas

Gas Hydrates



Evaluation in Progress

Royalty Modification



Kevin Banks

Director

March 24, 2011

Royalty Modification

AS 38.05.180(j)

- Allows commissioner to modify royalty to allow for production from a field or pool that is:
 - Not yet in production
 - Field or pool must be sufficiently delineated to the satisfaction of the commissioner to conduct the analysis
 - Field that would not otherwise be economically feasible
 - Royalty shall never be lower than 5%
 - Producing (to prolong the economic life)
 - Royalty shall never be lower than 3%
 - Shut-in (to re-establish production)
 - Royalty shall never be lower than 3%

Royalty Modification

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Royalty Modification

AS 38.05.180(j)

- Commissioner may not approve unless he determines that lessee makes a clear and convincing showing that relief is in the best interest of the state
 - But for royalty modification, development would not proceed
 - Royalty modification is applied only to the point where investor is inclined to develop, nothing more
- DNR may hire an independent contractor at the applicants expense, for up to \$150,000 per application
 - Selected by lessee from contractor list provided by DNR
- Relief mechanism must adjust percentage based on price and may also adjust based on production rate, ultimate recovery, CapEx, OpEx.
- Between issuing the preliminary and the final findings, DNR must offer to appear before LB&A to explain the preliminary finding.

Royalty Modification Applications

- February 1995 BP application for Milne Point
 - Application explicitly made only to comply with BP's contract with OXY
 - BP called the application "a formality, we do not intend to push it, nor should you take this seriously"
- 1997 Unocal application for 10 platforms in Cook Inlet
 - Unocal did not continue to pursue application
- 1999 Phillips application for Tyonek Deep in Cook Inlet
 - Phillips withdrew the application

Royalty Modification Applications

- 2005 Pioneer Natural Resources application for leases in and near the Ooguruk Unit
 - Approval effective February 2, 2006, with conditions
- 2006 Kerr-McGee application for leases in the Nikaitchuq and Tuvaq units
 - Denied October 31, 2006
- 2007 ENI application for leases in the Nikaitchuq Unit
 - Approval effective January 30, 2008, with conditions
- 2007 Chevron application for leases in the Ivan River and Stump Lake units
 - Chevron withdrew the application

Appendix

Oooguruk Unit

- Pioneer Natural Resources application for the existing Oooguruk Unit and adjacent leases, on behalf of itself and Eni (70/30% WIOs)
- Applied May 20, 2005, amended application filed November 1, 2005
- Approval effective February 2, 2006
 - Royalty modification mechanism is based on payout on one net profit share lease centrally located over two reservoirs delineated in the application
 - Additional terms also apply

Nikaitchuq (Kerr-McGee)

- Kerr-McGee applied for RM at Nikaitchuq and Tuvaq Units and adjacent leases, on behalf of itself and Eni (70%/30% WIOs)
- Applied January 11, 2006
- Anadarko acquires Kerr-McGee
- Economic analysis of Kerr-McGee
 - New tax regime materially improved economics for Applicant
 - Relief not needed
- Denied effective October 31, 2006

Nikaitchuq (Eni)

- Eni (now 100% owner) application for several Nikaitchuq Unit leases
- Applied October 16, 2007
- Approved effective January 30, 2008
 - New cost projections changed economics of the project
 - Low price trigger: for 25 years after first commercial production, if ANS WC inflation adjusted price falls below \$42.64, royalty is modified to 5% on production from all subject leases from the reservoirs delineated in the application
 - Low production trigger: between 18 months and 120 months after first commercial production, if production from all subject leases averages below 4,000 BOPD, royalty is modified to 5% no matter what oil prices are
 - Additional terms also apply

Ivan River/Stump Lake

- Union Oil Company of California applied for royalty modification on three leases at Ivan River and Stump Lake units (not all leases in these units)
- Applied on September 14, 2007
- The three leases were held by units
- The three leases had high royalty rates, 62% - 64%
- Application made no attempt at reservoir delineation
- Unocal withdrew their application on February 18, 2008, after conversations with DNR

House Finance Committee

HB 110 – Testimony from Industry

Wednesday, March 23

* = Testimony by phone

| | | |
|----------|--|------------------------------------|
| 8 am | Brooks Range Petroleum Corp. | Presentation submitted |
| | <i>arm</i> Bart Armfield | VP of Operations |
| *8:30 am | Alaska Venture Capital Group (AVCG) | Presentation submitted |
| | Ken Thompson | Managing Director |
| 9 am | Alaska Oil and Gas Association (AOGA) | |
| | Marilyn Crockett | Executive Director |
| *9:30 am | BP Alaska | |
| | Claire Fitzpatrick (phone from London) | Chief Financial Officer, BP Alaska |
| | Ralph Portell (in person) | Tax Manager, BP Exploration Alaska |

(Floor Session starts 10:30 am)

| | | |
|----------|----------------------------------|---|
| 1:30 pm | Pioneer Natural Resources Alaska | Presentation submitted |
| | Ken Sheffield | President, Pioneer Natural Resources Alaska |
| 2 pm | ConocoPhillips Alaska | |
| | Wendy King | VP of External Affairs |
| 2:30 pm | POSTPONED to 4:30 | |
| *3 pm | Great Bear Petroleum | Presentation submitted |
| | Ed Duncan (via phone) | President and Chief Operating Officer |
| | Ryan Moynagh (via phone) | VP Finance and Chief Financial Officer |
| *3:30 pm | Anadarko Petroleum Corp. | |

| | | |
|---------|-----------------------------------|---------------------------------|
| | Mark Hanley (via phone from D.C.) | Manager, Government Relations |
| 4 pm | Exxon Mobil Alaska | |
| | Dale Pittman | Alaska Production Manager |
| 4:30 pm | Renaissance Alaska | Presentation (letter) submitted |
| | Mark Landt | Executive Vice President |

5 pm – Adjourn

Letters

Apache Corporation - Apache Corporation is an 'independent' and a newcomer to Alaska. The company has over 300,000 acres of oil and gas leases in Cook Inlet and is actively engaged in seismic exploration at this time.

Eni – E-N-I is a National Oil Company owned in part by the Italian government. Eni recently (January 2011) started up new production at Nikaitchuq on the North Slope.

Marathon – A key Cook Inlet natural gas producer with limited oil production, Marathon is an 'independent.'

Statoil – Statoil is a National Oil Company owned in part by Norway's government. Statoil is not currently producing in Alaska, but holds significant leases in Alaska's outer continental shelf (Chukchi Sea), many of which they partner with Eni on. This is a growing presence in Alaska.

UltraStar – UltraStar is a very small company made up of three Alaskans, with decent lease positions on the North Slope. UltraStar has a well and a sidetrack planned for drilling in the first quarter of 2012.



Alaska State Legislature

Mike Doogan

Representative
District 25, Anchorage

Commissioner Designee Bryan Butcher
State of Alaska, Department of Revenue
P.O. Box 110400
333 W. Willoughby, 11th Floor SOB
Juneau, Alaska 99811-0400

March 23, 2011

Re: Response to question in House Finance Committee

Dear Commissioner Butcher:

During the morning House Finance Committee meeting on March 17, 2011, I asked you to provide a complete list of meetings and participants relating to the drafting of HB 110 (the exact wording is attached).

On March 21, your office provided to the Finance co-chairs responses to several questions asked in the committee. For the one you numbered (11) you provided the following: "Provide the names of persons that the Department of Revenue Commissioner and Deputy Commissioner met with to discuss possible changes to the oil and gas production tax and when those meetings were held." And then, "The Department is currently working on this response."

If you'll look at the attached transcript you'll see that you have mischaracterized my question. Please answer my question as I asked it. In addition, we are moving at a rapid clip on HB 110, so I would like an answer to the question in the attached transcript while the bill is still being considered in the Finance Committee.

Thank you for your attention to this issue.

Sincerely,

A handwritten signature in cursive script that reads "Mike Doogan".

Representative Mike Doogan

State Capitol
Juneau, AK 99801
907-465-4998 or 800-689-4998
Fax 907-465-4419

716 West 4th Avenue
Anchorage, AK 99501
907-269-0216
Fax 907-269-0218

Rep.Mike.Doogan@legis.state.ak.us



(10:04:18 AM)

House Finance Committee Meeting Wednesday 3/17/11, 8:05 AM

Representative Doogan stated that he "wanted a list of the meetings that were held by yourself [Commissioner Butcher], any of the people at this table, any of their predecessors, and anybody in the governor's office, on this question. I want to know when they met and who was at the meetings. I understand that somebody might offer a privileged defense to the contents of the meetings, so I'm not asking for those, but I want to know who was talking about stuff and when they were talking about it."

Commissioner Butcher reported he would relay the information to the governor's office. He asked whether Representative Doogan also wanted a list of Native Corporations, as it was a broad group, not limited to just a handful of folks that the department was eliciting opinions from.

Representative Doogan stated that he wanted "a list of everybody involved, anybody you talked to and when you talked to them."

*

House Finance Committee

Revised

HB 110 – Testimony from Industry

Wednesday, March 23

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Alaska State Legislature
HOUSE FINANCE COMMITTEE

Agenda
8:00 AM

Thursday, March 24, 2011

1:30 PM Continued from 8:00 AM

HB 110-PRODUCTION TAX ON OIL AND GAS

Presentation by Rick Harper, Energy of Business
Consulting Associates

Department of Revenue

An Independent View of HB 110

Presentation to the House Finance Committee

March 24, 2011

Rick Harper

Energy of Business Consulting Associates

Houston, TX

What I'll be discussing

1. Alignment and diversity of interests between the state and industry
2. Industry decision making criteria
3. Obligations of a lessee
4. Limitations of claims by industry
5. Production declines and resource potential
6. Specific concerns with proposed bill
7. Advantages of current tax law (ACES)
8. Alternatives

Summary of Conclusions

- ▶ The administration and industry has not made their case that a tax rollback of this scale will be offset by production gains
- ▶ Industry has steered the debate towards fiscal competitiveness and away from prospect economics
- ▶ The bill disproportionately benefits existing production
- ▶ Industry's response to this bill suggests the state's goals will not be met
- ▶ There are alternatives

Rick Harper: Highlights of Professional Experience

- ▶ Principal, Energy of Business Consulting Associates
- ▶ Senior Vice President, Northwest Natural Gas Company
- ▶ President and CEO, Canor Energy Ltd. (Calgary, AB)
- ▶ President, ARCO Gas (Atlantic Richfield Company)
- ▶ Assistant to the President, United Gas Pipeline Company

Rick Harper: Consulting Practice

- ▶ 38 Years domestic and international experience
- ▶ Lease to the burner tip
- ▶ LB&A Consultant on Stranded Gas Contract
- ▶ Advised Palin Administration on Tax and Gasline issues
- ▶ Work for industry, government, and private royalty owners

What I'll be discussing

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What is the alignment with industry?

- ▶ Royalty and taxation
- ▶ Relevance of studies and testimony
- ▶ Not just what you're hearing– what aren't you hearing?
- ▶ Informing your intuition

WORKING TOGETHER IS BETTER THAN NOT WORKING AT ALL.

If history has taught us anything, it's that higher taxes don't equal more jobs. Changes in ELF (the Economic Limit Factor) would mean higher oil taxes in a state that already has the highest oil taxes in the nation.

ELF encourages the oil industry to invest money in all fields of Alaska, large and small. That means more jobs—directly and indirectly—throughout Alaska.

The massive investments by industry, which are required to keep North Slope production as high as possible, mean more jobs now and more income for the state in the future.

All we need is cooperation in providing an investment climate that encourages oil production. Working together is a lot better than not working at all.



ARCO Alaska, Inc. ACE 5599579

Oil companies have been saying tax increases will severely limit the industry for a long time.

Source: Alaska Journal of Commerce,
February 6, 1989

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Authorizations for Expenditure

- ▶ Before they get to final decision makers, capital requests are streamlined
- ▶ Low, Expected, and High cases
 - The Expected case is given by far the most weight. In my opinion, most proposals today use an expected oil price in the \$60 – \$70 range
 - The Low case is also very important because company executives want to protect against loss
 - The High case is the least important consideration
- ▶ (ConocoPhillips calls “Expected Case” the “success case”)

What issues are considered?

- ▶ Prospectivity (resource potential) is by far the main driver
- ▶ Progressivity in Alaska is very low in the \$60–\$70 range and doesn't become a significant cost driver until \$80–\$90 and beyond
- ▶ Because of our front-loaded credits, the current system benefits producers more at the low end than it costs them at the high end

What issues are considered?

- ▶ Timing, permit, and technical issues
- ▶ Fiscal system also considered, but based on the effective tax rate
- ▶ Dale Pittman of ExxonMobil, testimony March 23: *“For us it’s the effective tax rate”* that is the primary driver.
- ▶ I will say more about “marginal” versus “effective” tax rates later in the presentation

What issues are considered?

- ▶ Projects don't have to compete against the rest of the world
- ▶ The industry is not capital limited, although individual companies may be
- ▶ Each basin stands on its own, including North Dakota, Deepwater Gulf, etc.
- ▶ This is not a zero sum game
- ▶ Energy and commodity ventures are currently a magnet for capital worldwide
- ▶ There are alternatives for development for lessees

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Obligations of a Lessee

- ▶ The reason Alaska is desirable is prospectivity. The rocks.
- ▶ Companies bid leases based on belief in these rocks
- ▶ Signing the lease is a go / no go document
- ▶ The decision to sign the lease is a commitment to develop given “reasonable expectation of profit”
- ▶ After that point Alaska is not expected to compete with the rest of the world

Prudent Operator Standard

- ▶ Alaska's leases are based on the "Reasonably Prudent Operator Standard."
- ▶ Implied covenants are: to develop, to market, and to administer the leases
- ▶ The operator must develop given a reasonable assumption of profit
- ▶ Profit.
Not meeting an international hurdle rate.
- ▶ The contractual relationship with each lessor stands on its own independent of other similar arrangements

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Alaska is Desireable

- ▶ Consistent argument that we must be competitive with other jurisdictions
- ▶ Not providing field development plans, hard economic projections, or AFEs (authorizations for expenditure)
- ▶ No evidence has been presented that the economics are upside down in Alaska
- ▶ Many factors in Alaska's tax code work in industry's favor (will be discussed later)
- ▶ What's missing here is more relevant to your decision than what's present

Contributions to cyclical decline

- ▶ Crash of late 2008 / total collapse of capital markets
- ▶ Alaska has complex logistics
- ▶ Facility capacity and access issues
- ▶ Permitting issues– both State and Federal
- ▶ Limited available labor and equipment, especially with major technology–driven boom in North Dakota and shale gas booms in the Lower 48
- ▶ Delay in project advancement due to potential tax change



How Can We Reverse the Trend

- Sample Investor Decision Criteria
 - Prospectivity
 - Geopolitical stability
 - Regulations (access to resources, development permitting, environmental constraints)
 - Operations (existing infrastructure, experienced workforce availability, costs, market proximity)
 - **Tax Regime => CS HB 110 (RES) Focus**

The Commissioner of Revenue said that many factors influence investment.

He said taxes are just the easiest one we can control.

Source: CS HB 110 (RES) Introduction, Proposed Changes to the Oil & Gas Production Tax, Presentation to House Finance, March 14 2011, Alaska Department of Revenue, p. 10.

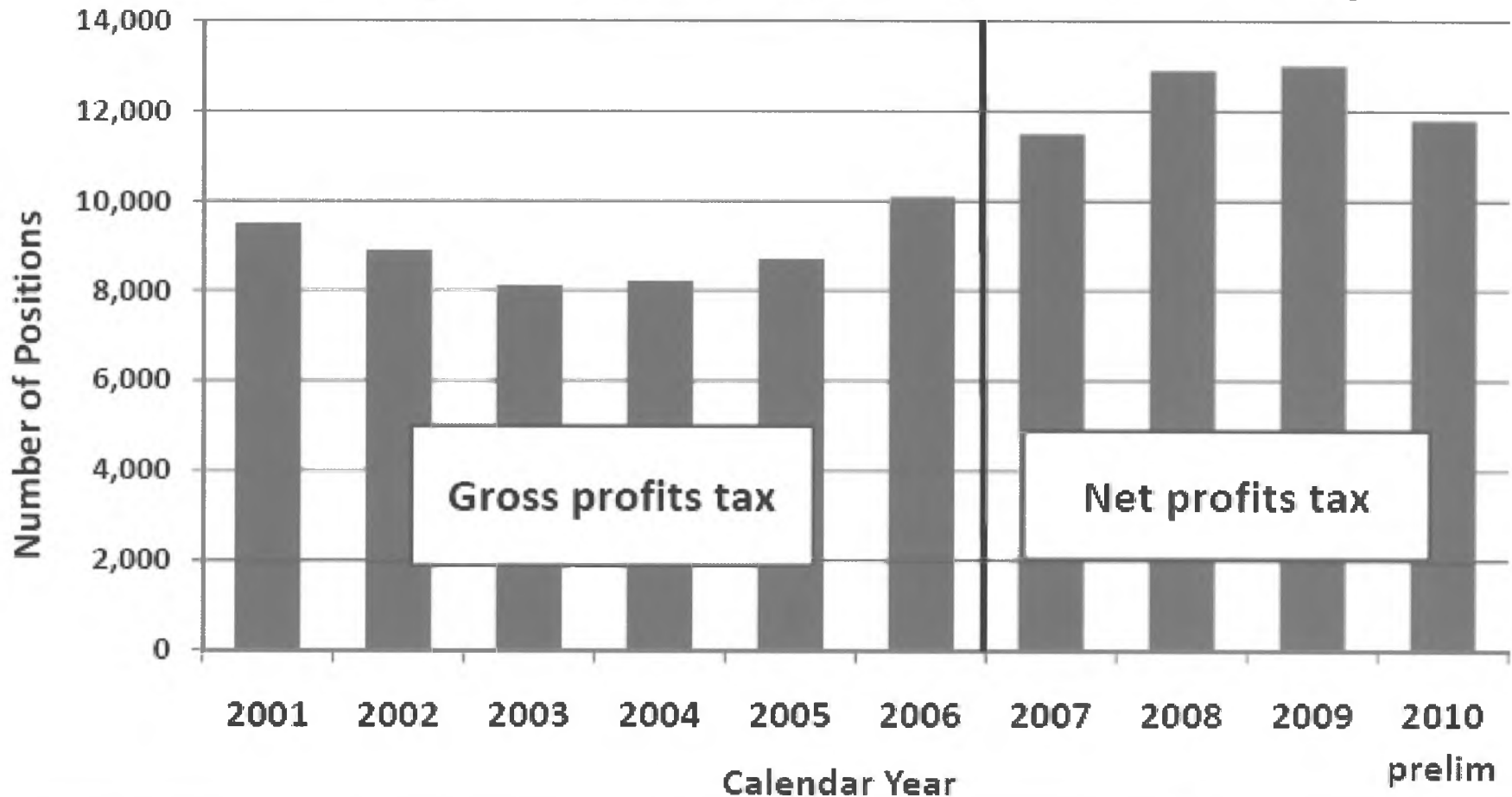
In the absence of concrete and verifiable analysis of specific prospects, a presumption should be made that no change in taxation is warranted

- ▶ Alaska offers Royalty Relief if a producer can prove the economics of a field require it.
- ▶ It's only been requested four times since 2000, and granted twice.

Lost Jobs: Correlation does not Imply Causation

Employment declined in 2010, but is still above 2007 levels and is nearly 50% higher than in 2004

Chart 8: Employment in Alaska's Oil and Gas Industry

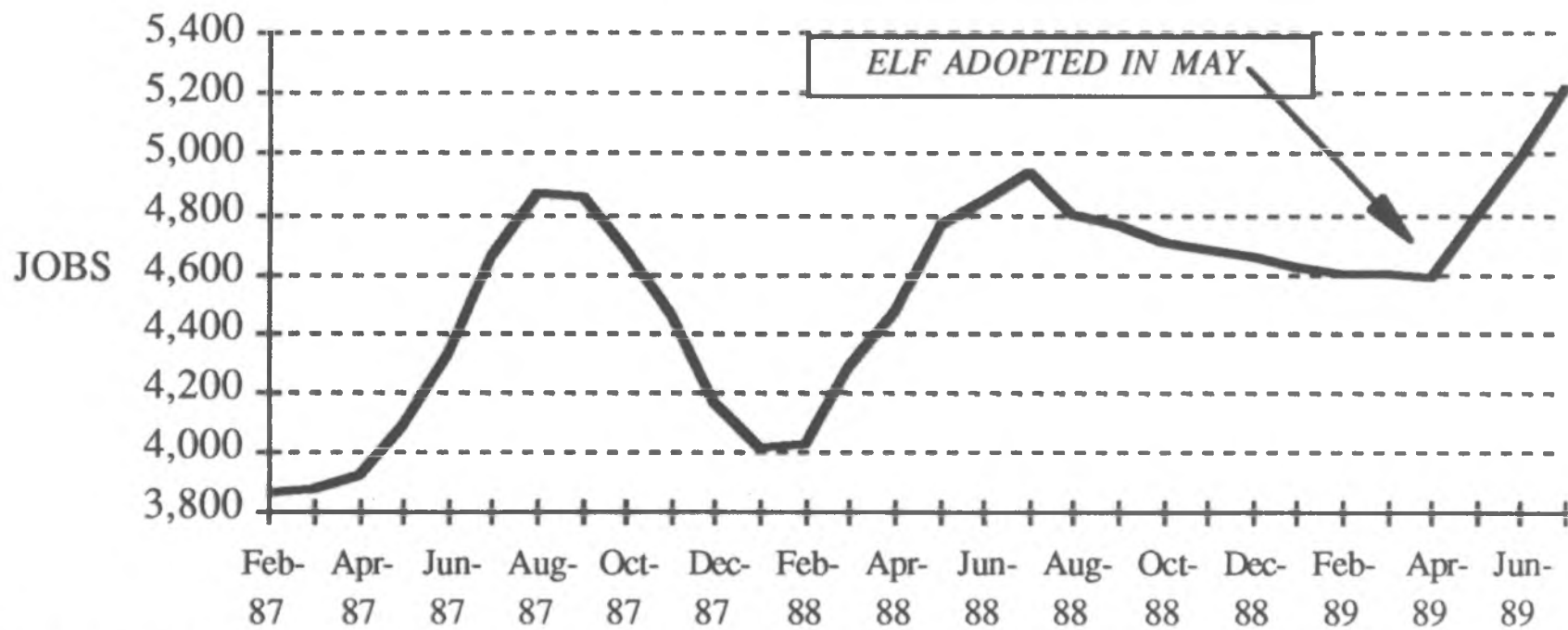


Source: Oil and Gas Production Tax Status Report to the Legislature
Alaska Department of Revenue January 18, 2011, p.11

Despite similar concerns at the time, oil field employment also increased after the ELF tax increase of 1989.

Also notable- total North Slope oil industry jobs then were less than half what they are today.

NORTHERN ALASKA OIL INDUSTRY EMPLOYMENT
(3 mo. moving average)

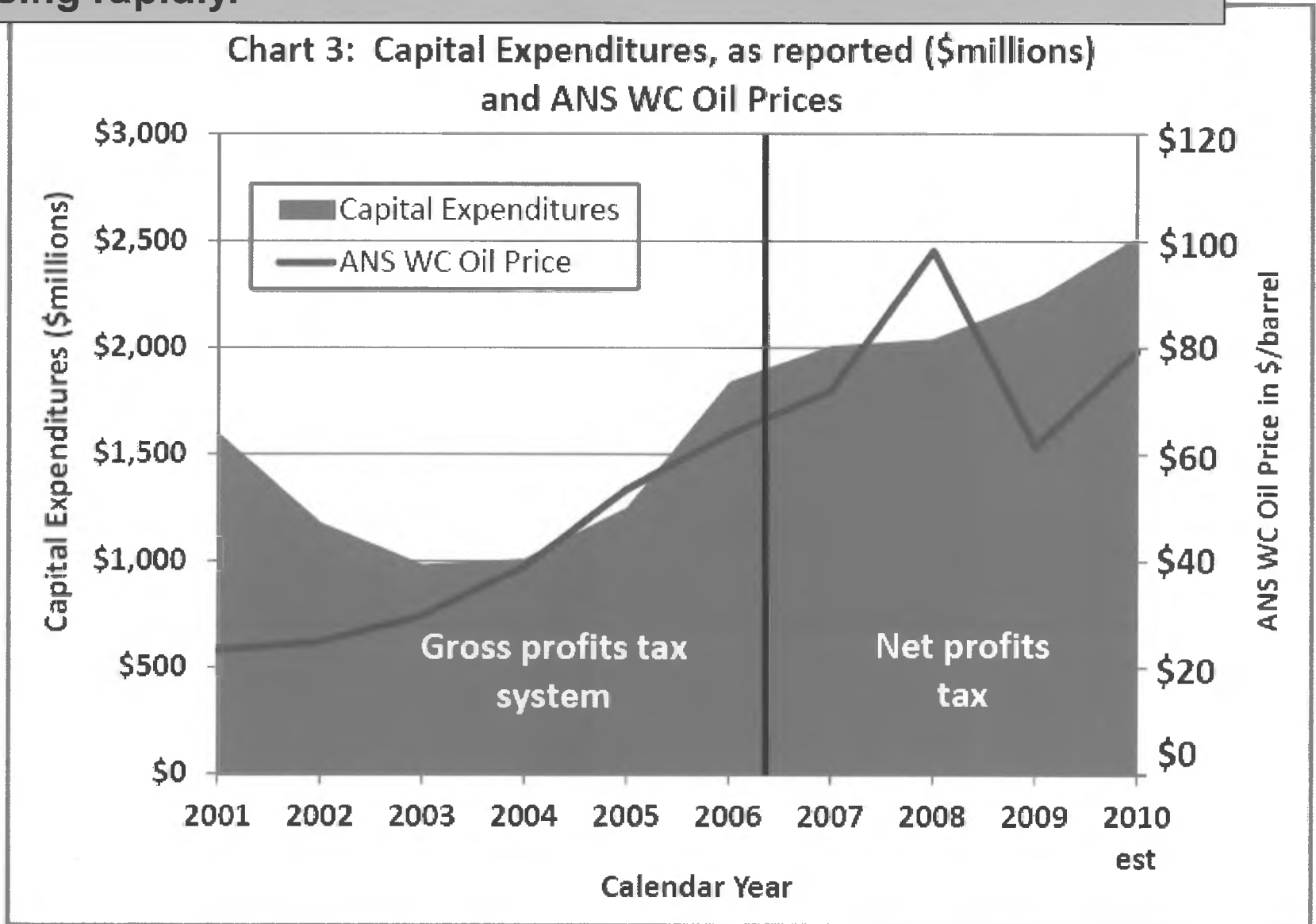


Source: Alaska Dept. of Labor

Source: Alaska Department of Labor, 1989

Declining Activity: Ain't Necessarily So

Total capital spending, as well as spending per barrel, are increasing rapidly.



Source: Oil and Gas Production Tax Status Report to the Legislature
 Alaska Department of Revenue January 18, 2011, p.6



JuneauEmpire.com

From just a few weeks before the start of this session

Oil industry boosting Alaska spending

Tuesday, November 30, 2010

Story last updated at 11/30/2010 - 10:49 am

Oil industry boosting Alaska spending
By Pat Forgey | JUNEAU EMPIRE

Alaska's oil industry is boosting its spending in the state more than expected, which may be good for future oil production and jobs, but is limiting the state's profit from rising oil prices.

The state's official oil production tax estimate for the current fiscal year is now \$2.6 billion, down about \$250 million from last year.

A combination of declining production and increased industry spending kept the state from profiting from the price rise as much as it would have otherwise, however.

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Production Declines

- ▶ No discernable evidence yet that ACES has impacted production one way or another. Not enough time has passed
- ▶ The impact of changes to ACES on production is highly speculative
- ▶ North Slope production has declined 4% to 6% per year since the peak in 1989. This is the natural trend for a maturing basin
- ▶ Production taxes on all new / small fields was less than 1% through 2005, and production declined at the same rate

Firm commitments from industry are lacking

- ▶ All companies carefully word what they say, but there is no identifiable commitment to add new oil or reduce the rate of decline
- ▶ “If its and butts were candy and nuts, my what a Christmas we’d have!”
-Dandy Don Meredith, circa 1972



Increased investment = Alaskan jobs and production

- BP will re-evaluate the entire inventory of opportunities
 - Note: BP owns 26% of Prudhoe Bay - investments require other working interest owner approvals
- Opportunities that could become competitive if bill is passed:
 - Increased drilling, potentially adding another Rig in service
 - Increased wellwork
 - Gas Partial Processing /I - PAD
 - Evaluate 'at scale' development viscous oppo
 - Increased R&D spending to develop heavy oil
- The sooner the bill takes affect, the sooner increased activity can happen

**Read carefully,
there are no
promises here**

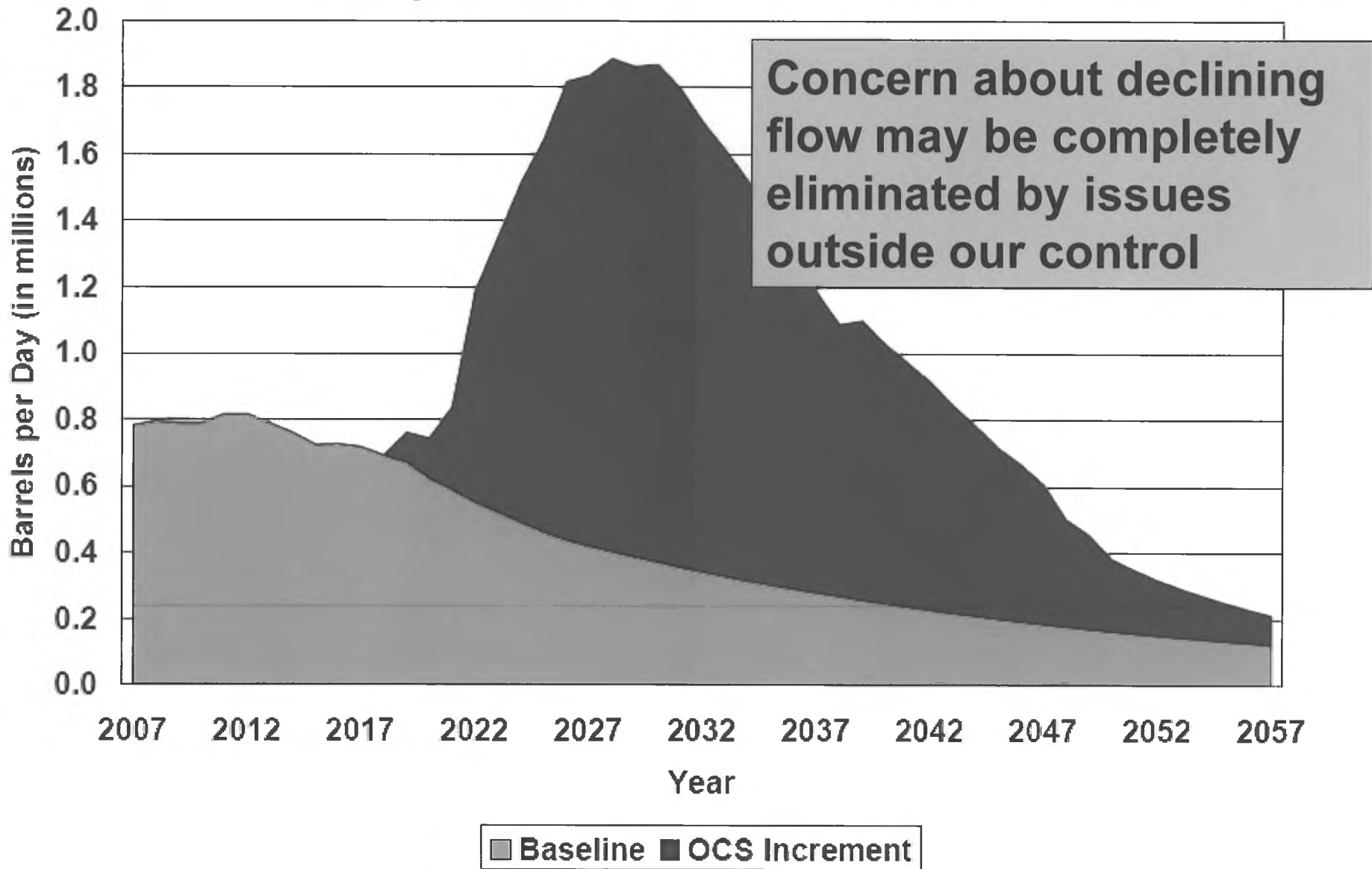
Is Industry About to Walk Away from TAPS?

- ▶ Major producers own a piece of the line. The economics of TAPS and oil production are integrated.
- ▶ 6% decline highly unlikely given current ongoing investment and updated projections.
- ▶ Natural reduction in decline rate appears to be occurring in recent years.
- ▶ No consensus on technical limits of TAPS. Many things can be done to recondition the line to work at lower flows.

Things that may dramatically increase production include

- ▶ Technology changes, such as advances in seismic capability and multi-lateral wells
- ▶ Due to higher prices and technological development, greater economic viability of traditionally challenged resources including heavy oil, tight sands, and shale oil
- ▶ Major discovery coming on line offshore or on federal land (NPRA / ANWR)
- ▶ Gasline, GTL, or LNG projects

North Slope Oil Production With OCS



Source: Alaska Oil & Gas Association Testimony to the House Resources Committee on House Bill 110, Marilyn Crockett, AOGA Executive Director February 16, 2011, p.8

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Changes to Progressivity

- ▶ This is where most of the revenue will be lost:
\$800 million to over \$2 billion / year
depending on the price of oil

FY 2013: -\$382 million

FY 2014: -\$961 million

FY 2015: -\$1,126 million

FY 2016: -\$1,341 million

FY 2017: -\$1,423 million

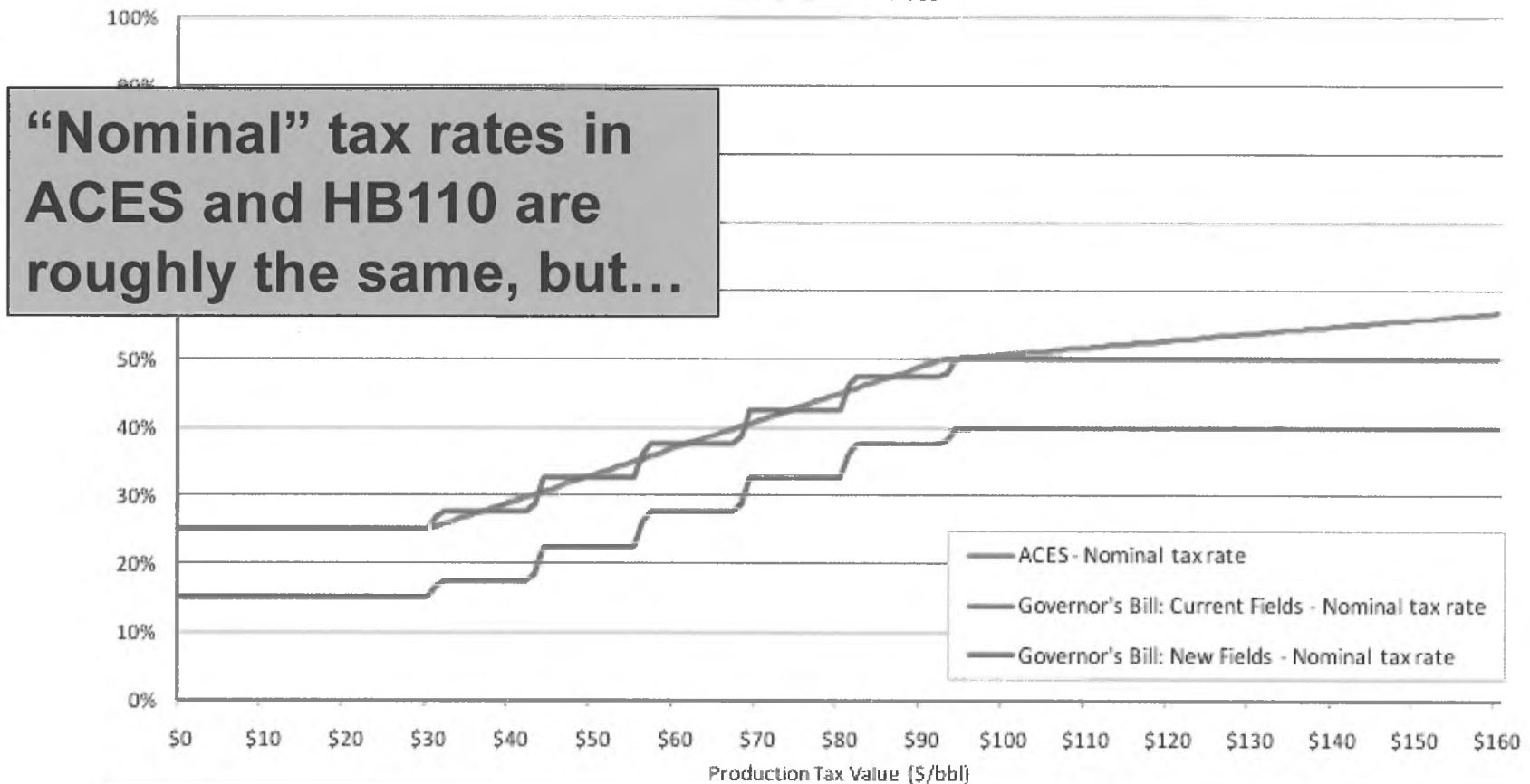
Source: HB110 Fiscal Note #1, Department of Revenue



Nominal Tax Rates Current law and HB 110



Nominal Tax Rates

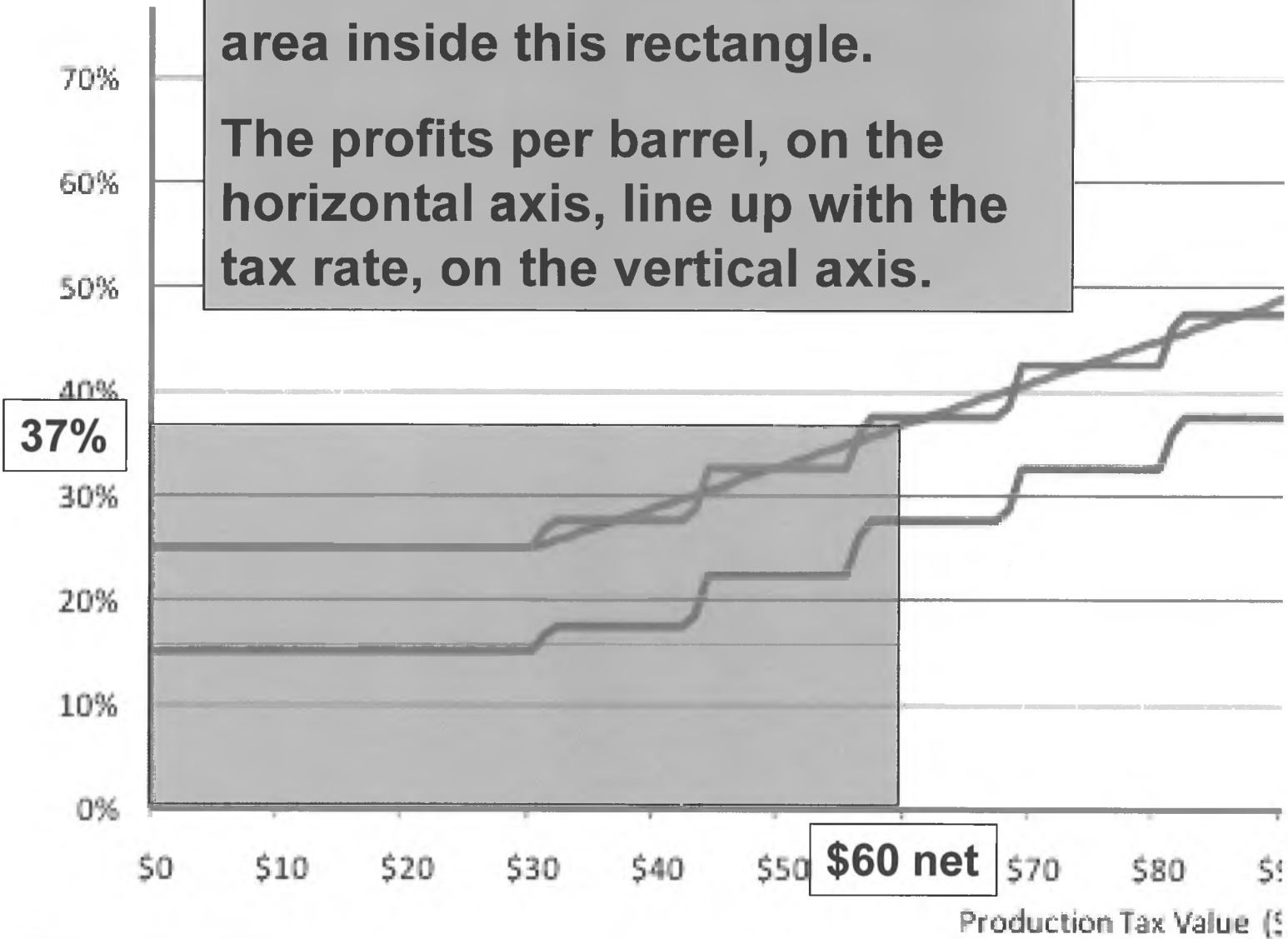


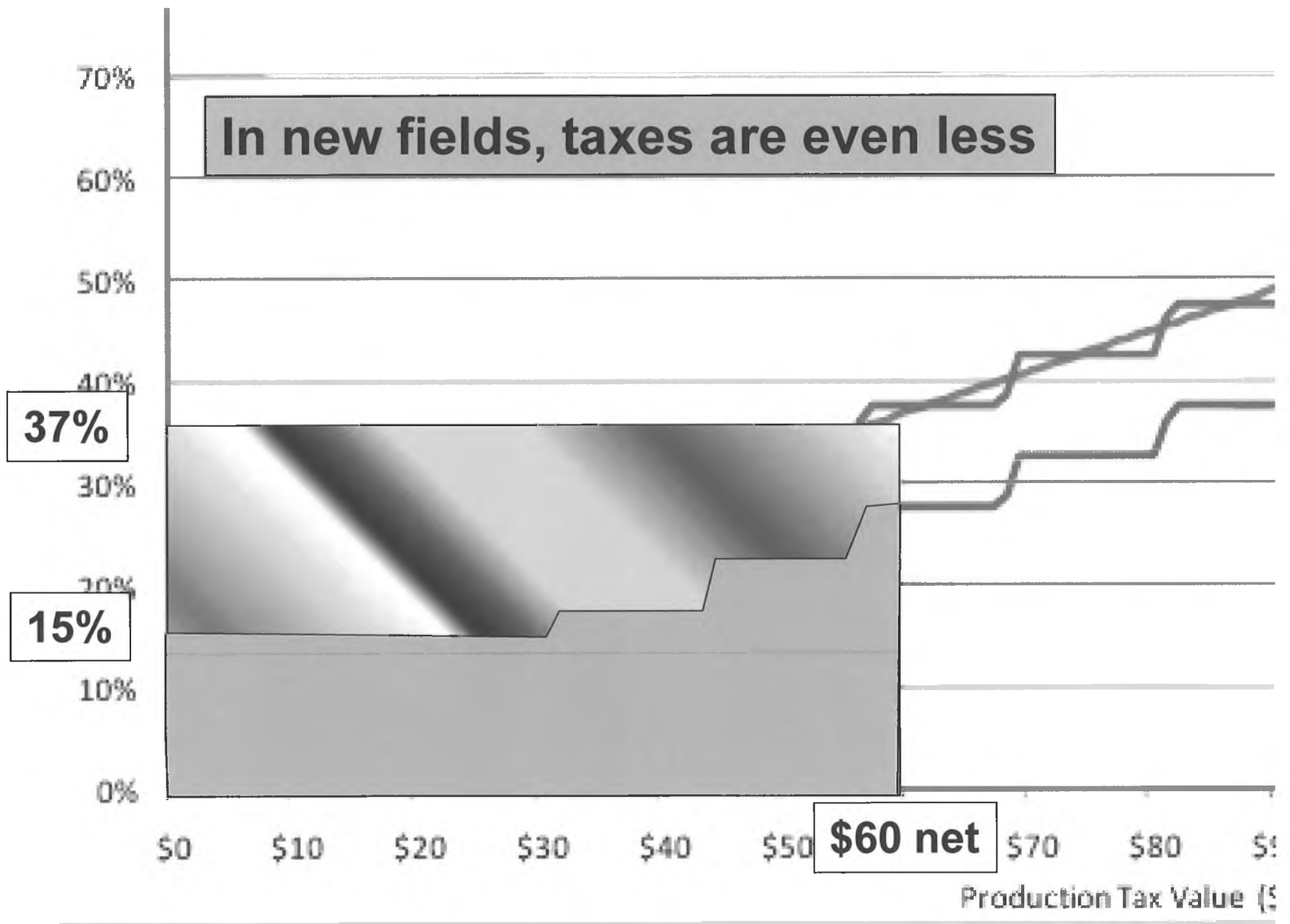
“Nominal” tax rates in ACES and HB110 are roughly the same, but...

Source: HB 110 Presentation, Primary Goals Tax Rates and Cash Flows, Bill Sectional, Presentation to the House Resources Committee, February 21, 2011, Alaska Department of Revenue, p.12

Under current law (ACES), our taxes can be envisioned as the area inside this rectangle.

The profits per barrel, on the horizontal axis, line up with the tax rate, on the vertical axis.





Changes to Progressivity

- ▶ “Brackets” are inappropriate for a net profits tax. ACES is very different than the personal income tax
- ▶ All deductions and expenses are recaptured by the producer before the first dollar of taxes is paid.
- ▶ A producer could be paying the base 25% rate on \$billions in net income.
- ▶ In current law, the \$12 million “small producer credit” effectively creates a lower tax bracket for developers of new, smaller fields

Changes to Progressivity

- ▶ Most arguments in favor of changes are based on high “marginal tax rates.”
- ▶ Very little discussion of what this really means
- ▶ Total taxes paid on the last dollar earned. Despite what is said, profits go up steadily with the price of oil
- ▶ High marginal rates were built into ACES
- ▶ The flip side = high marginal state participation in new investment
- ▶ Effective tax rates drive producer decisions, not marginal rates.

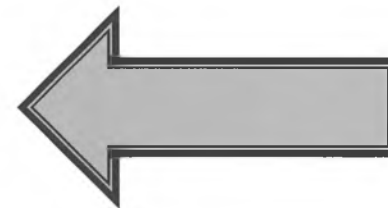
Progressivity, by its very nature, creates marginal tax rates that are higher than the effective rate.

During the ACES debates, this was discussed as a positive benefit.



Progressivity Impacts

- The use of progressivity creates a sizeable difference between the effective rate and the marginal rate of tax in relation to investment decisions
 - This is present with the existing PPT language
 - The impact provides either:
 - A good sized “carrot” to invest; or
 - A good sized “stick” to not export after tax cash flow from Alaska



Source: Gaffney Cline, Alaska’s Equitable Share, House Finance Committee, November 7, 2007, p. 15



How The Net Tax System Operates

- “Net” taxes all fields at a single rate
 - If only looking at the “headline” net tax rate, this would be the perception
 - In reality, the tax burden is different for different parts of the state, depending on the type of different reservoirs at different locations
 - Based upon their individual profitability

If a company invests, their tax burden decreases dramatically.

- **Further, it doesn’t tax operating profits, but retained cash flow after reinvestment**

Changes to Progressivity

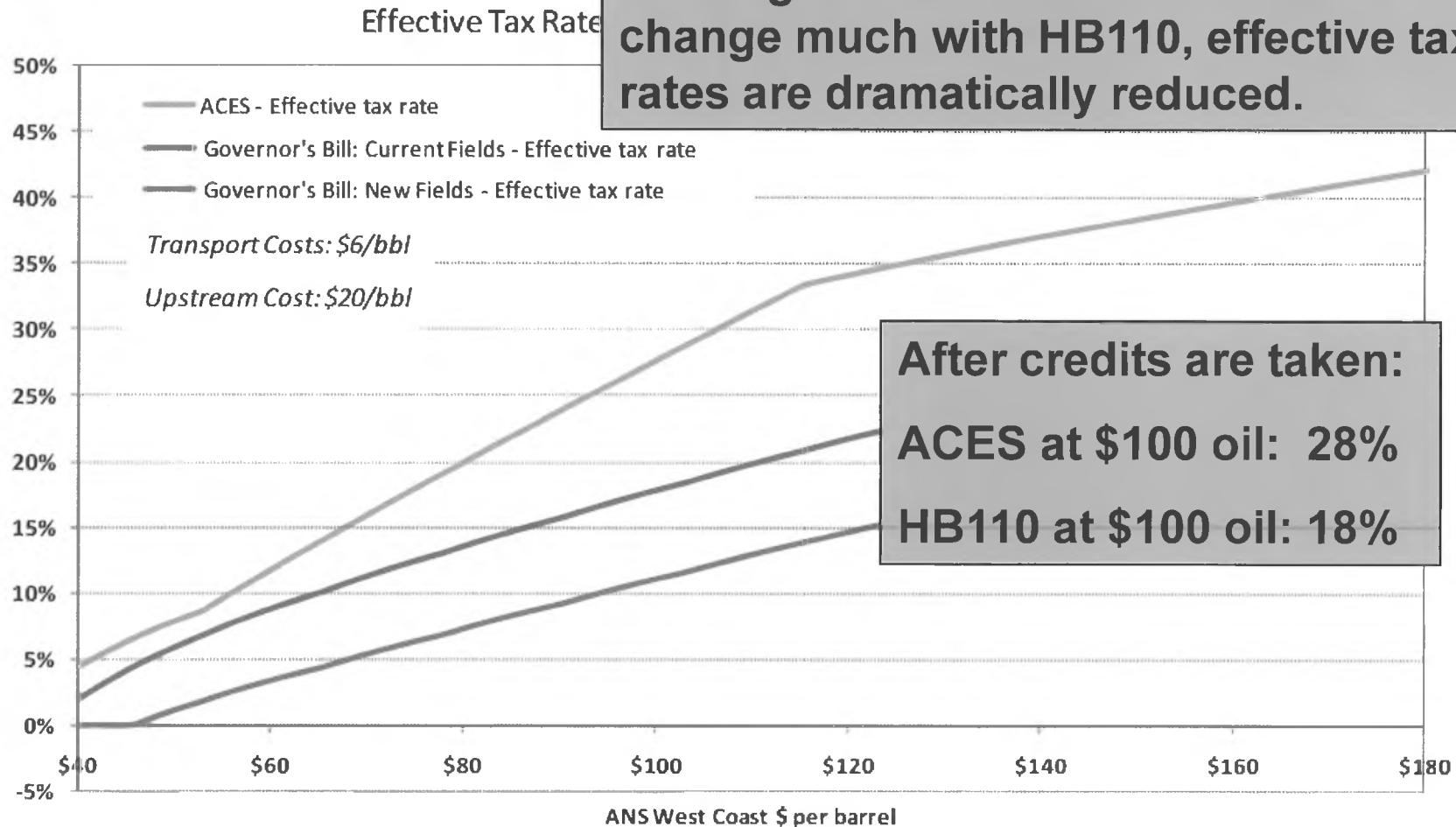
- ▶ Dale Pittman of Exxon said in testimony:
“For us it’s the effective tax rate” that drives decisions



Effective Tax Rates on Gross Current law and HB 110



Although nominal tax rates don't change much with HB110, effective tax rates are dramatically reduced.



Source: HB 110 Introduction, Proposed Changes to the Oil & Gas Production Tax, Presentation to the House Resources Committee, February 7, 2011, Alaska Department of Revenue, p.33

Reduced Base Rate for New Fields

- ▶ Under ELF, there was a lower base rate for the first five years of production: 12.25% versus 15% of the gross
- ▶ The reduced rate in HB110 lasts forever
- ▶ There is no economic reason to maintain any reduced rate for longer than it takes a producer to recapture their initial investment

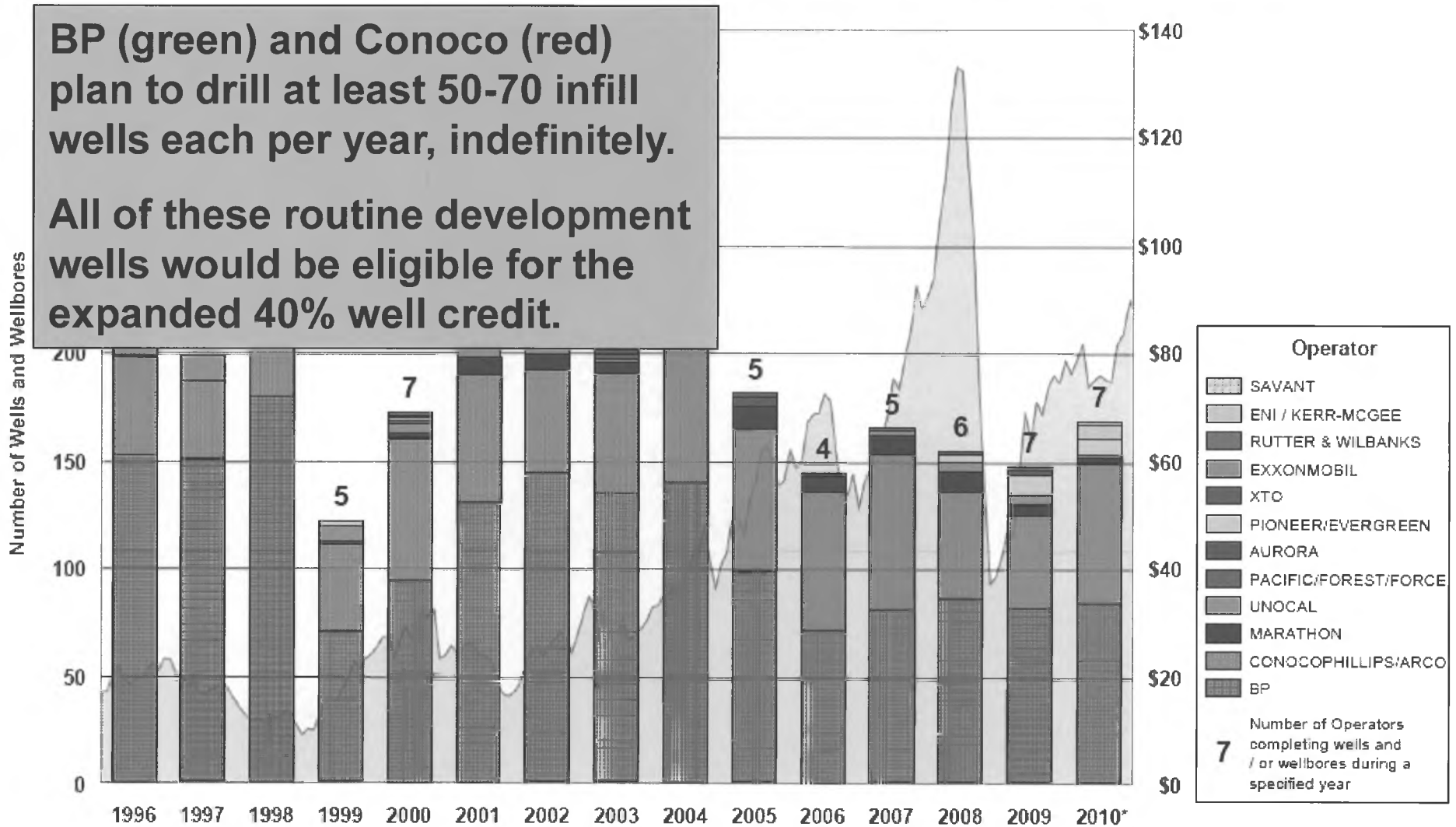
Well Credit Increase

- ▶ Department of Revenue estimates this will cost between \$200 and \$400 million / year
- ▶ This broad a range indicates a lack of knowledge from which to estimate the actual extent of these costs
- ▶ The vast majority of this credit will benefit activity that is already happening
- ▶ Industry has indicated that 80% of new oil will come from legacy fields. This sort of infill drilling has been shown to be highly profitable

DEVELOPMENT AND SERVICE WELLS / WELLBORES

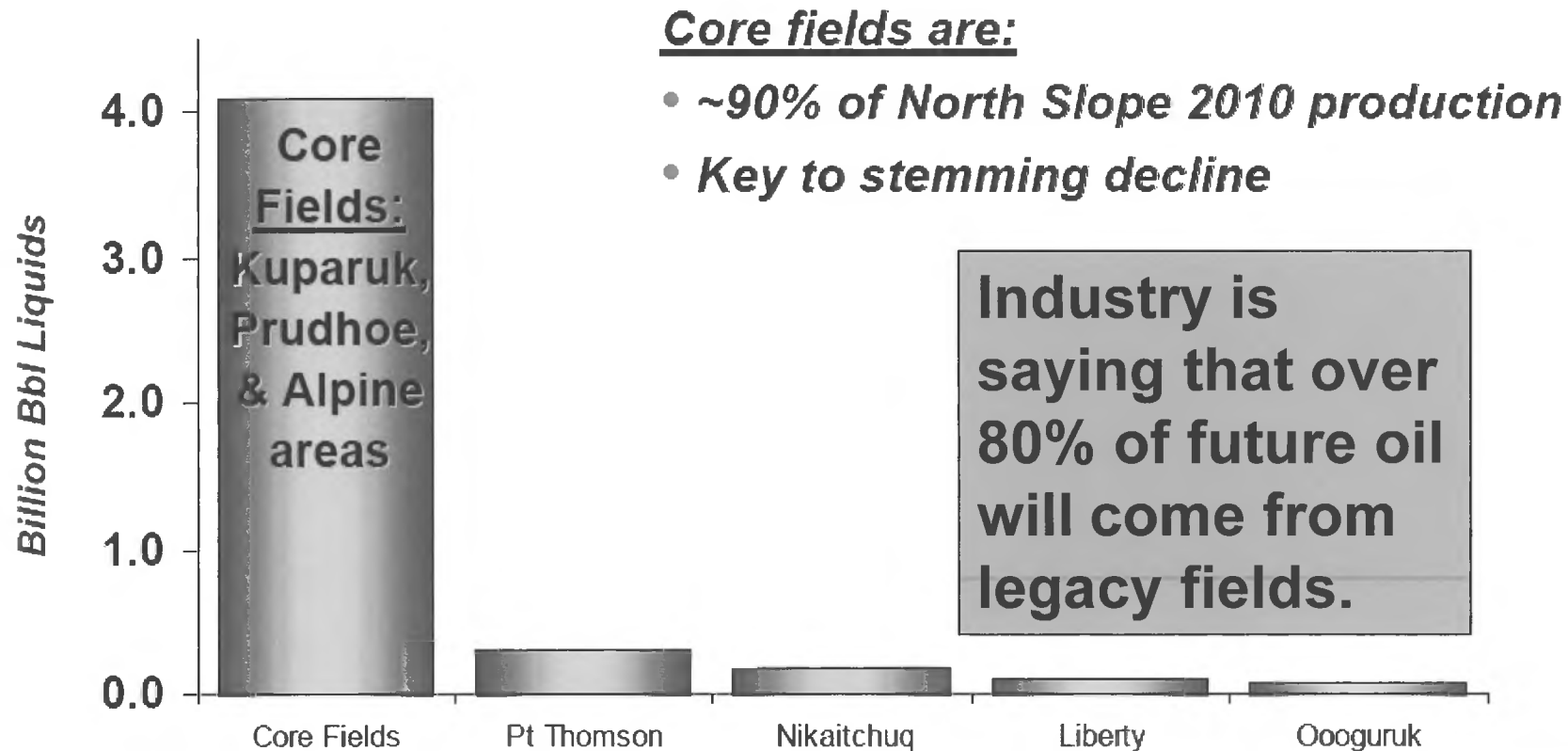
Statewide: Completed, Suspended or Abandoned (1996 - 2010)*

with West Coast Spot Price for Alaska North Slope Crude Oil (Dollars per Barrel)



Source: Alaska Oil and Gas Conservation Commission (AOGCC), Presentation to House Finance Committee from Commissioner Dan Seamount, March 17, 2011, p. 23

North Slope Remaining Barrels



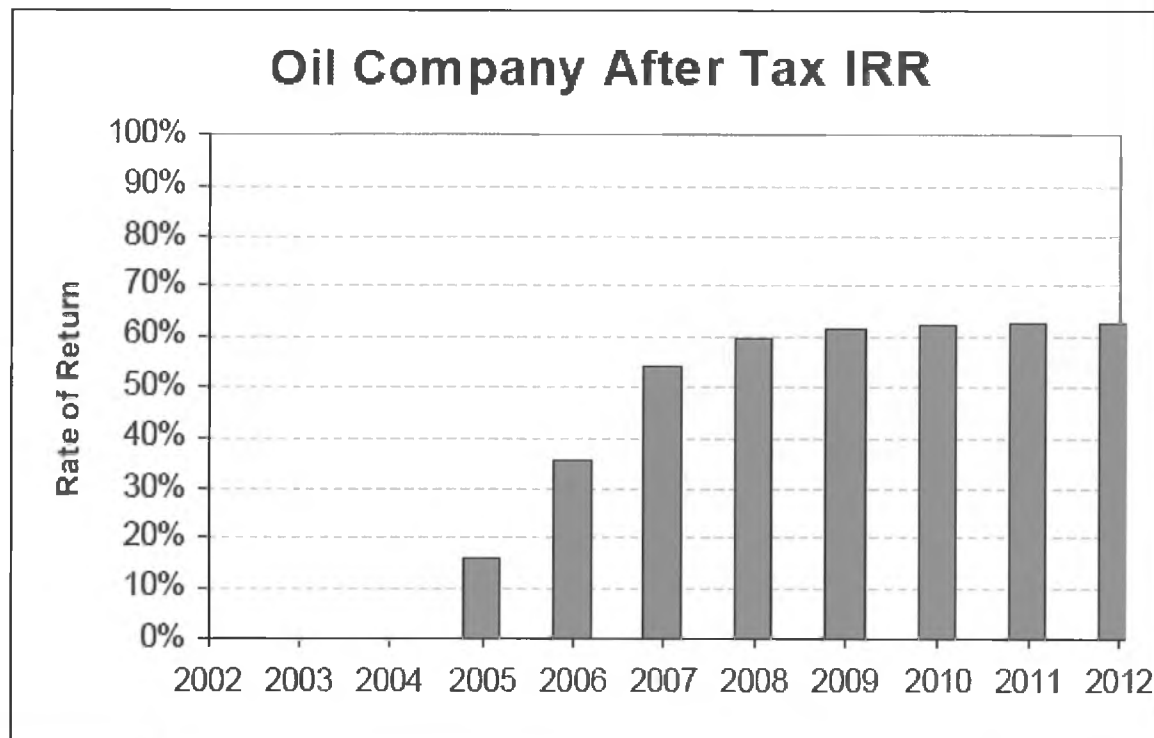
Core fields are dominant source of state production

Source: ConocoPhillips testimony to House Resources Committee on HB110, February 16, 2011, p. 10



BP Prudhoe Bay

- This is the after tax return on (300%) investment realized by the Prudhoe Bay owners



In 2007 the Administration's consultant showed that even if costs triple, the rate of return on infill drilling in Prudhoe Bay was over 60%.

They could not find a stress case where infill drilling was uneconomical.

Change from Monthly to Annual Progressivity Calculation

- ▶ Fairness: producers sell oil into price spikes that often have nothing to do with conditions in Alaska (i.e. a Middle East crisis)
- ▶ Alaska should also be able to benefit
- ▶ Alaska gets value from volatility. Revenue increases more during a price spike than it declines during a price drop.
- ▶ According to the Department of Revenue, Alaska would have lost between \$150 and \$450 million / year since 2007 with an annual instead of monthly tax calculation

**Revenue impact of price volatility:
Different scenarios with \$90 oil cost
(ACES tax system)**

Average Annual Cost of Oil = \$90

| Price for each of four quarters | | | | Revenue (\$million) | Change |
|---------------------------------|----|-----|-----|------------------------|--------|
| 90 | 90 | 90 | 90 | 3,724 | - |
| 80 | 90 | 90 | 100 | 3,764 | 40 |
| 80 | 80 | 100 | 100 | 3,807 | 83 |
| 70 | 70 | 110 | 110 | 4,049 | 325 |
| 70 | 70 | 70 | 150 | 4,186 | 462 |
| 60 | 60 | 80 | 160 | 4,355 | 631 |

**A switch to annual calculation of value is not
just about convenience.
It is a real financial hit to the state.**

General Conclusion

- ▶ HB 110 bill unfortunately results in reducing taxes significantly on current production
- ▶ The goal should be to increase exploration and exploitation may not be met and is overshadowed by massive tax cuts on legacy production
- ▶ The tax reductions in HB110 are so large that it would be almost impossible for Alaska to recapture the foregone revenue
- ▶ If the bill passes, without significant new production Alaska's non-permanent-fund savings will be depleted in 8-10 years

Required Production to Replace Lost Revenue

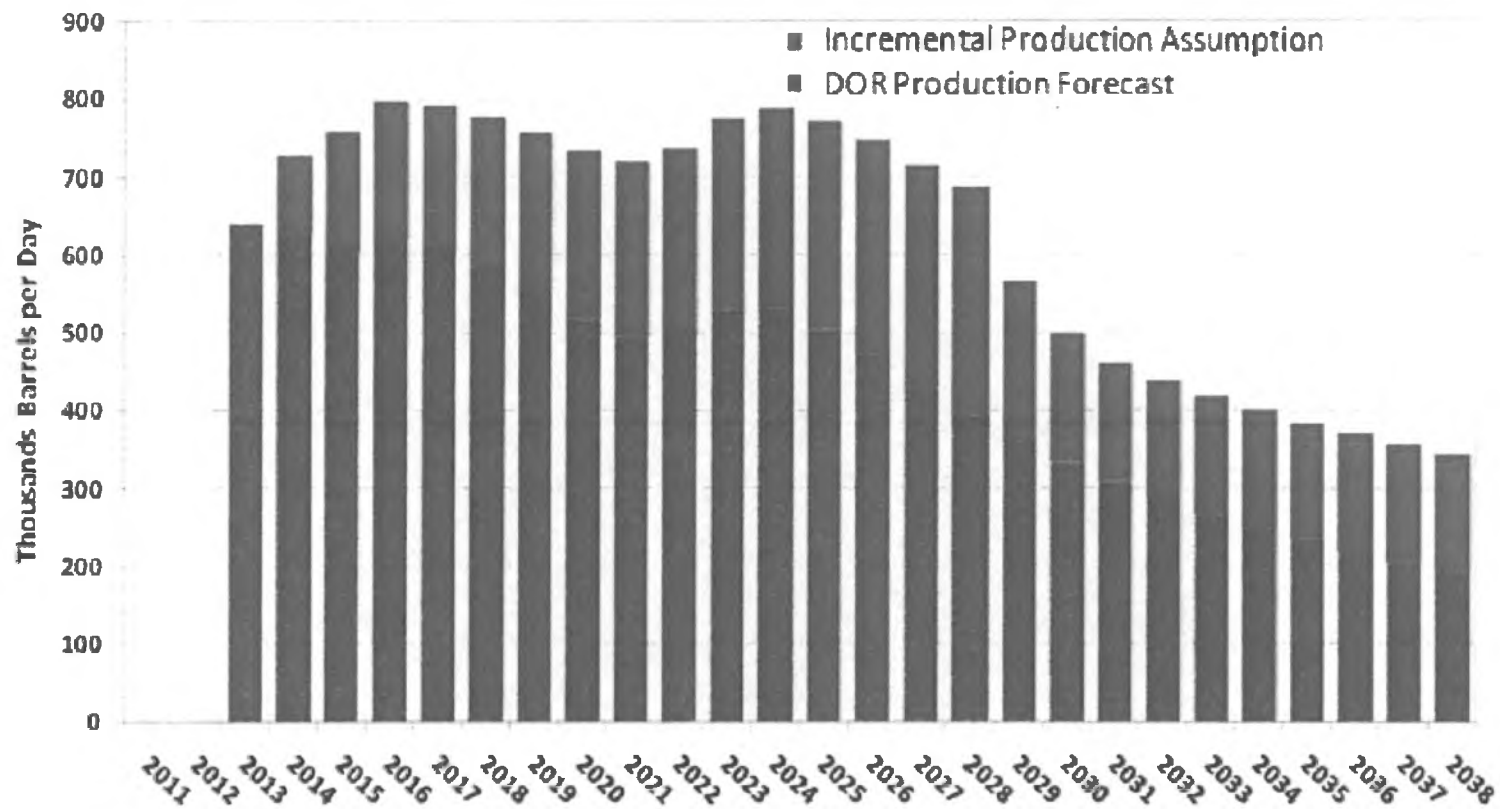
| | ACES | HB110 | HB110 |
|---|-------------|--------------|--------------|
| Barrels / day | 622,000 | 622,000 | 1,040,000 |
| Price of Oil | \$80 | \$80 | \$80 |
| Production Tax Revenue, net of credits (\$millions) | \$2,590 | \$1,580 | \$2,590 |

| | ACES | HB110 | HB110 |
|---|-------------|--------------|--------------|
| Barrels / day | 622,000 | 622,000 | 1,070,000 |
| Price of Oil | \$100 | \$100 | \$100 |
| Production Tax Revenue, net of credits (\$millions) | \$5,000 | \$3,040 | \$5,000 |

This scenario, from a DOR response to the Resources committee, is speculative.

It adds large amounts of oil in the first few years, which dramatically effects long term revenue projections.

DOR Production Forecast plus Incremental Production

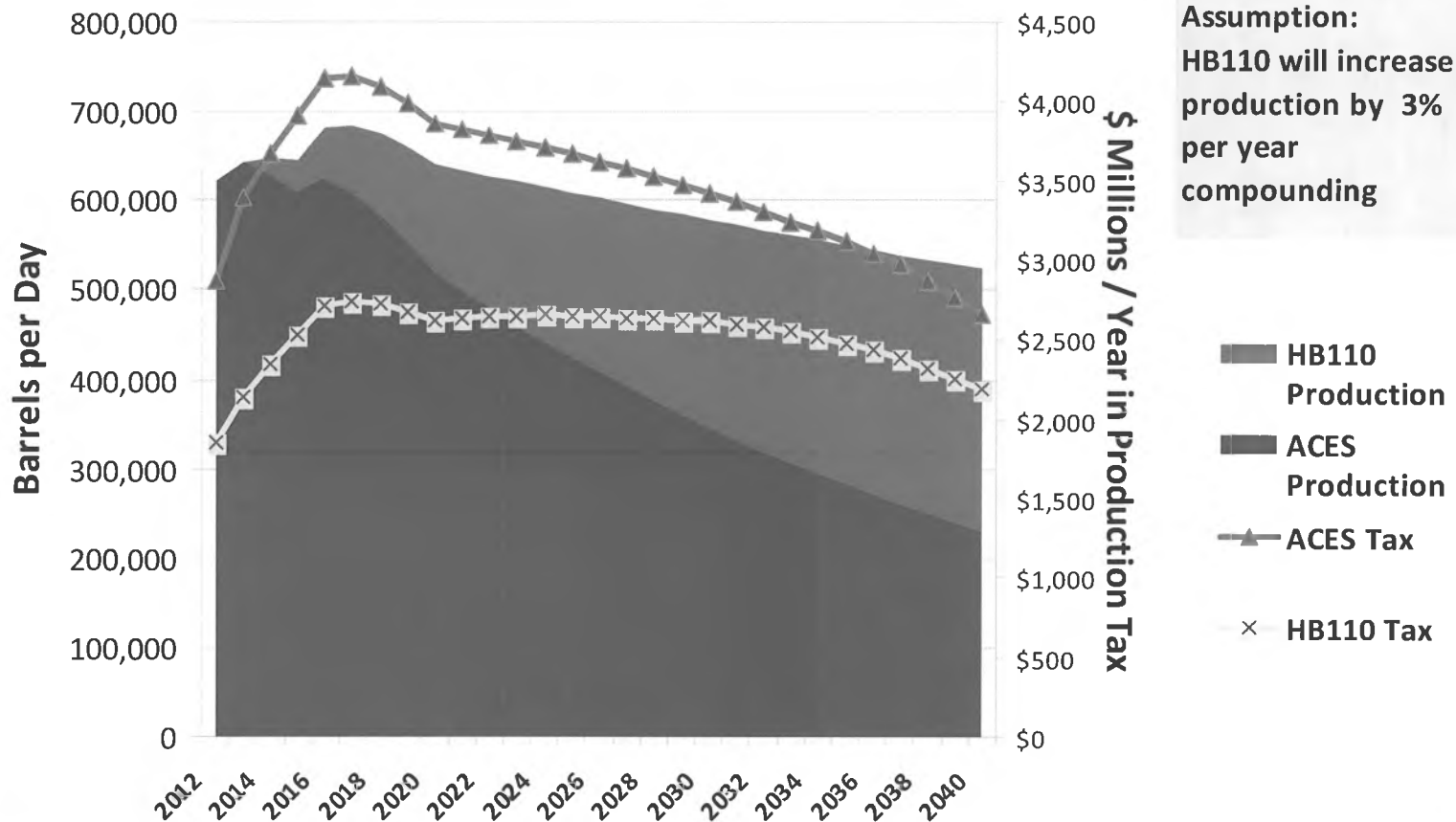


Source: DOR Production Profile; Fall 2010 Revenue Sources Book.
Incremental Production: Great Bear Petroleum; 18 February, 2011.

An alternative scenario shows gradual added production over time.

In these scenarios, it is much harder to catch up to the foregone revenue.

**Future Production and Production Tax Revenue:
ACES versus HB 110**



Source: House Minority, internal model

What I'll be discussing

1. Alignment and diversity of interests between the state and industry
2. Industry decision making criteria
3. Obligations of a lessee
4. Limitations of claims by industry
5. Production declines and resource potential
6. Specific concerns with proposed bill
7. **Advantages of current tax law (ACES)**
8. Alternatives

Advantages of ACES

- ▶ **100% Capital recapture in first year**
(no depreciation)
- ▶ **No Ring Fencing**
(new field development work can be deducted against current production)
- ▶ **Stackable credits**
(state pays 45% to 80% of development costs)
- ▶ **Pays for desired actions**
(spending reduces both taxes and tax rate)
- ▶ **Political stability**

Outsiders' View of Alaska

Many provisions of our current tax code make Alaska extremely attractive

| | Rank* | Economic Impact |
|--------------------------------------|-------------|---------------------------|
| Immediate Deduction of Capex | Top 1-3 | High |
| Investment Credits | Top ¼ | Moderate-High |
| Amount (up to 40%) | Top 10 | High |
| Credits to Cash | Top 1 or 2 | Moderate, Big, Huge Ind. |
| No ringfence (Exploration/Appraisal) | Top 10 | Huge |
| 87% Marginal Rate | Bottom 5-10 | Moderate (Huge Optically) |
| Cost per bbl | Bottom ¼ | High |
| Environmental Costs | Bottom 10 | High |

* Where Top is best Bottom is worst from Producer viewpoint

Source: Petroleum Fiscal System Design, Presentation to House Resources Committee, Rich Ruggiero, Gaffney Cline, February 11, 2011, p.12

What I'll be discussing

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5. Production declines and resource potential
6. Specific concerns with proposed bill
7. Advantages of current tax law (ACES)
8. **Alternatives**

An example of alternative approaches

- ▶ Targeted credits to improve exploration economics
- ▶ Better information requirements
- ▶ Permit streamlining and certainty
- ▶ Facility sharing / facility access
- ▶ Enforce duty to develop

3/24/11

APPENDIX A

SUMMARY PROFESSIONAL BIOGRAPHY W.R. HARPER, JR.

Energy of Business Consulting Associates

2001 - Present
Principal

Northwest Natural Gas Company

1992 - 2002
Senior Vice President (Marketing, Supply, Transportation, Trading and Storage)
Vice President (Marketing Services)
Vice President (Industrial and District Operations)
General Manager (Industrial and Commercial Business Operations)

Canor Energy Ltd. (Calgary, Alberta)

1994 - 2000
Chief Executive Officer
President and Chief Executive Officer

United Gas Pipeline Company

1992
Assistant to the President

Atlantic Richfield Company

1977 - 1992
President, ARCO Gas
Manager, Strategic Planning and Regulatory Affairs
Manager, Natural Gas (U.S.)
General Manager, B&A Pipeline Company
Supervisor, Gas Contracts
Senior Gas Contract Representative
Regional Gas Coordinator

Texas Eastern Corporation

1975 - 1977 (Texas Eastern and Transwestern Pipelines)
Gas Contract Representative
Gas Contract Administrator

Degolyer and McNaughton

1972 - 1975
Engineering Assistant

Education:

Cum Laude Graduate 1975
Cox School of Business
Finance and Economics
Southern Methodist University

Industry Associations:

Board of Directors
Northwest Gas Association 2000-2002

Advisor
Northwest Power Planning Council 2001-2002

Special Advisor to the Board
TRIMET 1998-2001

Board of Directors
Christie School 1995-2001

President
Natural Gas Society of North Texas 1989

Vice President
Natural Gas Society of North Texas 1985-1989
American Gas Association 1992-2002
Southern Gas Association 1995-1991
Natural Gas Supply Association 1988-1992
Natural Gas Society of Houston 1975-1992
Natural Gas Society of New Orleans 1975-1992
Natural Gas Society of Permian Basin 1997-1992
Natural Gas Society of Rocky Mountains 1985-1992
Natural Gas Society of North Texas 1975-2002

3/24/11

RICK HARPER

Three Allen Center
Suite 4470
Houston, Texas

503/887-4940 (cell)
713/333-0063 (Houston office)

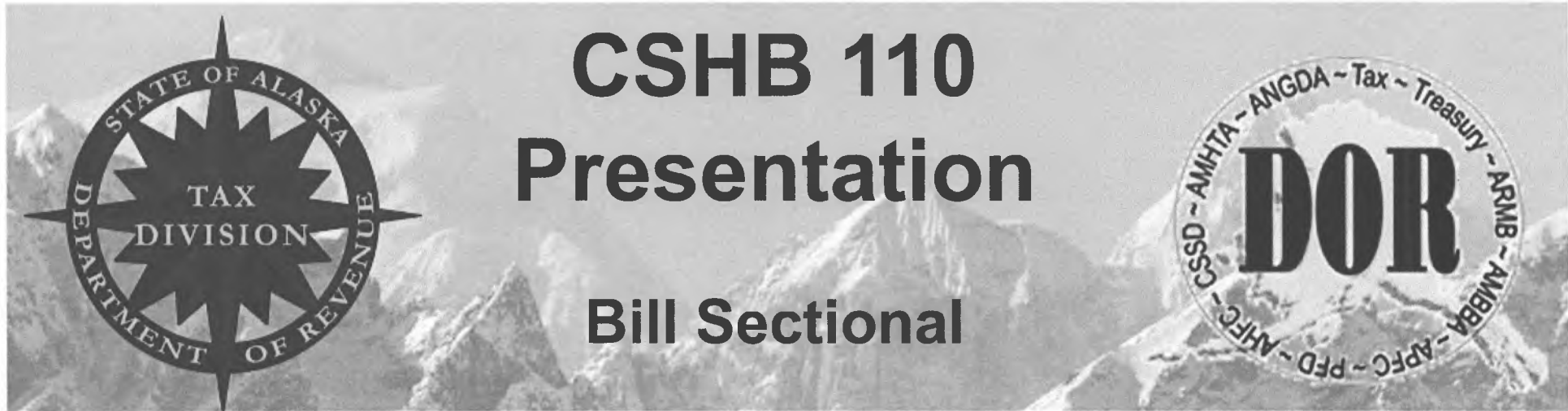
I have been involved in the energy industry both domestically and internationally for over thirty five years. I have had extensive professional, managerial, and executive experience in a number of areas including marketing, trading, supply, gathering, transportation, processing, and storage of product; product pipelines; oil and gas exploration and production; local distribution; contracting, contract negotiations, and contract administration; regulatory and governmental affairs; and strategic planning.

Among other things, I have served as President, ARCO Gas; President; Chief Executive Officer of CANOR Energy Ltd. (Canadian based fully integrated oil and gas exploration and production company); Assistant to the President of United Gas Pipeline Company; and Senior Vice President of Northwest Natural Gas Company (NYSE gas distribution, pipeline, and storage company).

I have served as an advisor and consultant in varying capacities for the past eighteen years. I have managed a full time consulting practice for over ten years. I have had clients in the oil and gas, utility, electric, high tech, and manufacturing industries both domestically and internationally. With regard to oil and gas, my consulting business operations routinely address transactions ranging from lease formation to end use including for instance lease, joint operating, Unit, AMI, joint venture, storage, supply, transportation, balancing, asset management, and division order agreements. I have extensive experience in matters related to prudent operator standard, royalty, and severance tax related issues. I have offices and staff in Three Allen Center in Houston, Texas and a satellite office in Portland, Oregon.

I have had a great deal of involvement in litigation, disputes, and arbitration over the past twenty years continuously. On numerous occasions, I have variously served as an Arbitrator, as an expert witness, as a fact witness, as an investigator, and as a litigation consultant. The majority of my business endeavors have not been related to litigation however. I have also been involved in venture capital funding, strategic planning, business development, market planning, regulatory & governmental affairs, etc. with various clients.

I directly advised Governor Sarah Palin's administration for approximately two years on all matters related to the proposed natural gas pipelines (and gathering systems) from the North Slope to the Mid-West along with various oil and gas taxation, lease development, and other issues. During that time I also provided advise and counsel to Rep. Beth Kerttula and the House Minority. I previously provided direct assistance to Governor Murkowski's administration and separately to the leadership in the House and Senate on similar matters. In addition, my royalty and tax related clients have included Judge John Duhe (Chief Justice, Fifth Circuit Court of Appeals), Senator Lloyd Bentsen (family interests), Trish Pollard (Board Chair, Texas State University System), Administration of Governor Bill Richardson, and the State of Louisiana among others. Currently, I am the sole testifying expert on behalf of the private royalty owners in Texas in a class action lawsuit against most major and independent producers in the state on matters pertaining to severance taxes and severance tax revenues. I have also advised Governor Kitzhaber of Oregon and currently serve as an ongoing advisor to the Northwest Power Planning Counsel and the Northwest Industrial Gas User's Association among others.



*Presentation to the
House Finance Committee
March 24, 2011
Alaska Department of Revenue*



Main proposed changes



| | |
|--------------------------------------|--|
| Progressivity Rates & Cap | Progressivity levied as discrete brackets, rather than as a continuous function, and applied only to incremental revenue. 2013 |
| Base Tax Rate | Base tax rate of 15%, plus progressivity for leases or properties neither unitized nor producing as of 12/31/2008. Base rate of 25% plus progressivity for currently producing fields. 2013 |
| Tax Credits | Extension of 40% well lease expenditure tax credits to North Slope. Tax credits can be claimed in a single year instead of two years. 2012 2011 |
| Tax Calculation | Yearly tax calculation based on average prices and costs, instead of monthly tax calculation impacted by short term price and cost peaks. 2013 |

- 2011** Effective 1/1/2011 for expenditures made after 12/31/2010.
- 2012** Effective 1/1/2012 for expenditures made after 12/31/2011.
- 2013** Effective 1/1/2013, applies to production after 12/31/2012.



CS HB 110 (RES)

Bill Sectional



Interest Rate Changes



Section 3: AS 43.05.225 is amended to reduce interest rates on overdue taxes and refunds to federal rate plus 3% or 11%, whichever is lower.

- Current rate – federal rate plus 5% or 11%, whichever is greater.
- Applies as of July 1, 2011.
- Conforming sections 1-2, 4, 10, 13, 29-31.



Two base rates: 25% and 15%



Section 6: Levy of Tax

43.55.011(e)(1): Tax levied on oil and gas produced from leases or properties containing land that was within a unit or in commercial production as of December 31, 2008, is 25% base + progressivity.

Tax levied on production from leases or properties not subject to 43.55.011(e)(1) is 15% base + progressivity.

Section 8: Tax rate for calendar year.



Minimum tax



Section 7: Lowers threshold prices for calculation of minimum tax on oil and gas production from the North Slope.

- 4% of gross minimum tax would apply when ANS WC price is over \$20 (currently \$25).
- Thresholds for 0% to 4% minimum tax on North Slope production lowered.



Changes to progressivity and maximum tax rate



Section 8: Incremental bracketed progressivity rates apply, if annual production tax value is over \$30, to the fraction of the production tax value that falls within the incremental rate.

Incremental rates are:

- Up to 50% for production subject to the 25% base rate.
- Up to 40% for production subject to the 15% base rate.



Conforming amendments for tax rate changes



- **Section 9:** Statute requiring monthly payments is revised to account for annual progressivity calculation and new tax rate for certain fields.
- **Section 27:** AS 43.55.160 is repealed and reenacted to account for changes in progressivity and new 15% tax rate. Annual production tax value calculations maintained per current statute.



Capital credits can be taken in the year earned



- **Section 11:** Removes requirement that tax credits for qualified capital expenditures be taken over two years.
- **Section 12:** Provides that tax credit certificates will be issued as one certificate.
- **Section 14:** Conforming amendment to reflect repeal of AS 43.55.023 (m), relating to the issuance of well lease expenditure credit certificates.
- **Section 32:** Repeals AS 43.55.023(m), since all capital credit certificates will be issued as one certificate.



40% well lease expenditure credit extended to North Slope



- **Sections 15-16:** Expands the 40% well lease expenditure credit to qualified expenditures made on the North Slope.
- **Sections 25-26:** Conforming amendments to reflect repeal of AS 43.55.023 (m).



Amendments in House Resources

CS HB 110 (RES)



Wage based tax credit



Section 17: A new section is added to AS 43.55.023 to allow a credit against production taxes for a producer that incurs more than 80% of its wages and compensation for Alaska residents.

The credit is for the percentage by which wages paid to Alaska residents exceeds 80% of all wages and compensation paid by the producer in the State.



Small Producer Credits



Sections 18 - 20:

- The sunset date for AS 43.55.024(a) and (c), non-transferable credits, is extended from 2016 to 2021.
- The small producer tax credit for a calendar year is raised from \$12 million to \$15 million. Applies if average production is less than 100,000 BTU equivalent barrels a day.



North Slope Exploration Credit



- **Sections 21 and 24:** Amends AS 43.55.025 to allow a 30% credit for exploration expenditures for qualified North Slope exploration outside a unit, or for certain expenditures within a unit formed after June 30, 2008. Effective January 1, 2012.
- **Sections 22-23:** Extends sunset date for credits under AS 43.55.025 from 2016 to 2021.



Disclosure of Credit Information



- **Section 28:** Amends AS 43.55.890 to clarify that DOR may publish detailed information related to tax credits, including the statutory type and amount of each credit taken under each statute, and whether the expenditure was for exploration, development or production.



CS HB 110 Effective Dates



Section 33: Explains when expenditures must be incurred for provisions to apply.

Sections 35-39: Effective dates:

Sections 11-12: Retroactive to January 1, 2011.

Sections 14-17, 21, 24-28, 32 and 33(b): January 1, 2012.

Sections 6-9, 27 and 33(c): January 1, 2013.

Sections 11, 12, 33(a), and 35: Effective immediately.

Except as provided in sections 36-38, this Act takes effect July 1, 2011.

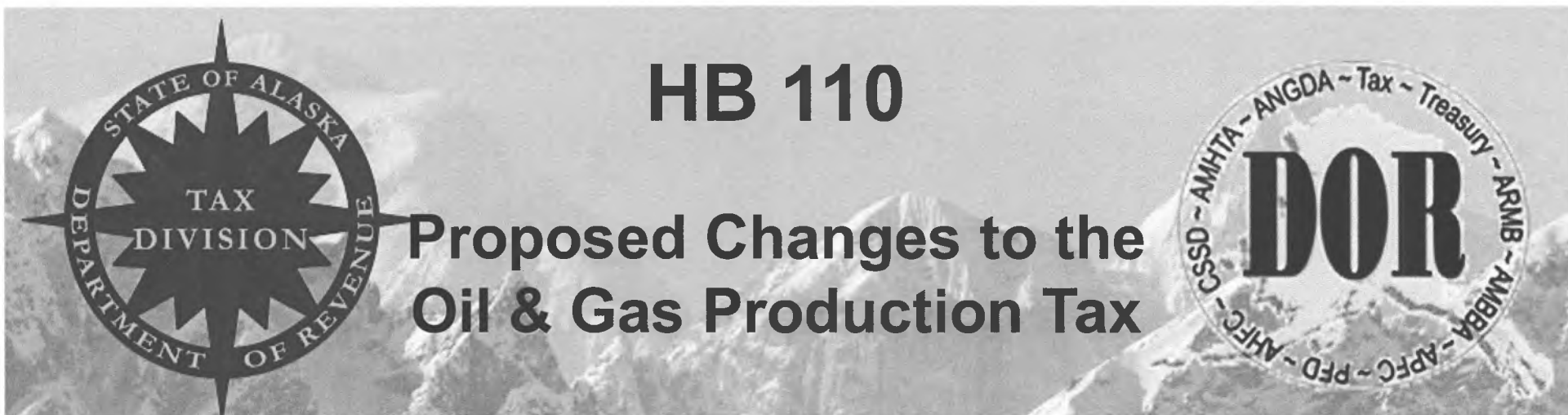
Alaska State Legislature
HOUSE FINANCE COMMITTEE

Agenda
11:00 AM

Saturday, March 26, 2011

Postponed Until 1:30 PM

HB 110-PRODUCTION TAX ON OIL AND GAS
Presentation by Department of Revenue



HB 110

Proposed Changes to the Oil & Gas Production Tax

*Presentation to the
House Finance Committee
Saturday, March 26, 2011
Alaska Department of Revenue*



HB 110 Goals



1. Improve investment climate
2. Increase production
3. Create jobs for Alaskans



The Problem



1. Oil production is declining in Alaska, faster than the rest of the U.S.
2. Higher taxes have chilled investment in Alaska
3. Alaska's economy is fueled by a robust oil patch, however the pipeline currently runs two-thirds EMPTY.
4. Low through-put levels increase maintenance costs and threaten a shutdown.



The Solution

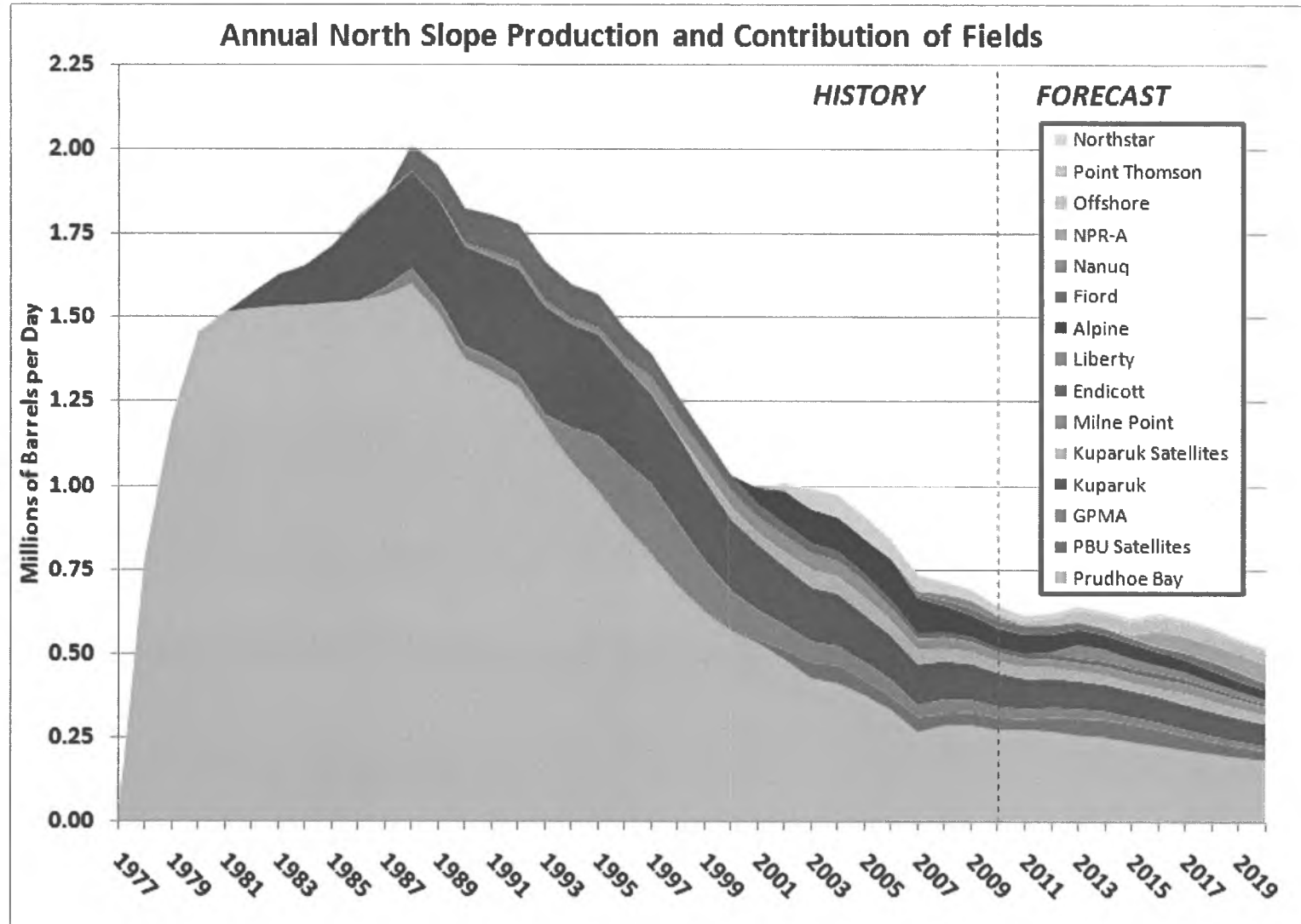


We MUST:

1. Reform our oil taxes to be globally competitive.
2. Provide tax credits for drilling in technically challenged fields.
3. Lower the tax rate for drilling new, untapped fields.
4. Cap taxes to encourage more immediate investment at higher oil prices.



North Slope Production

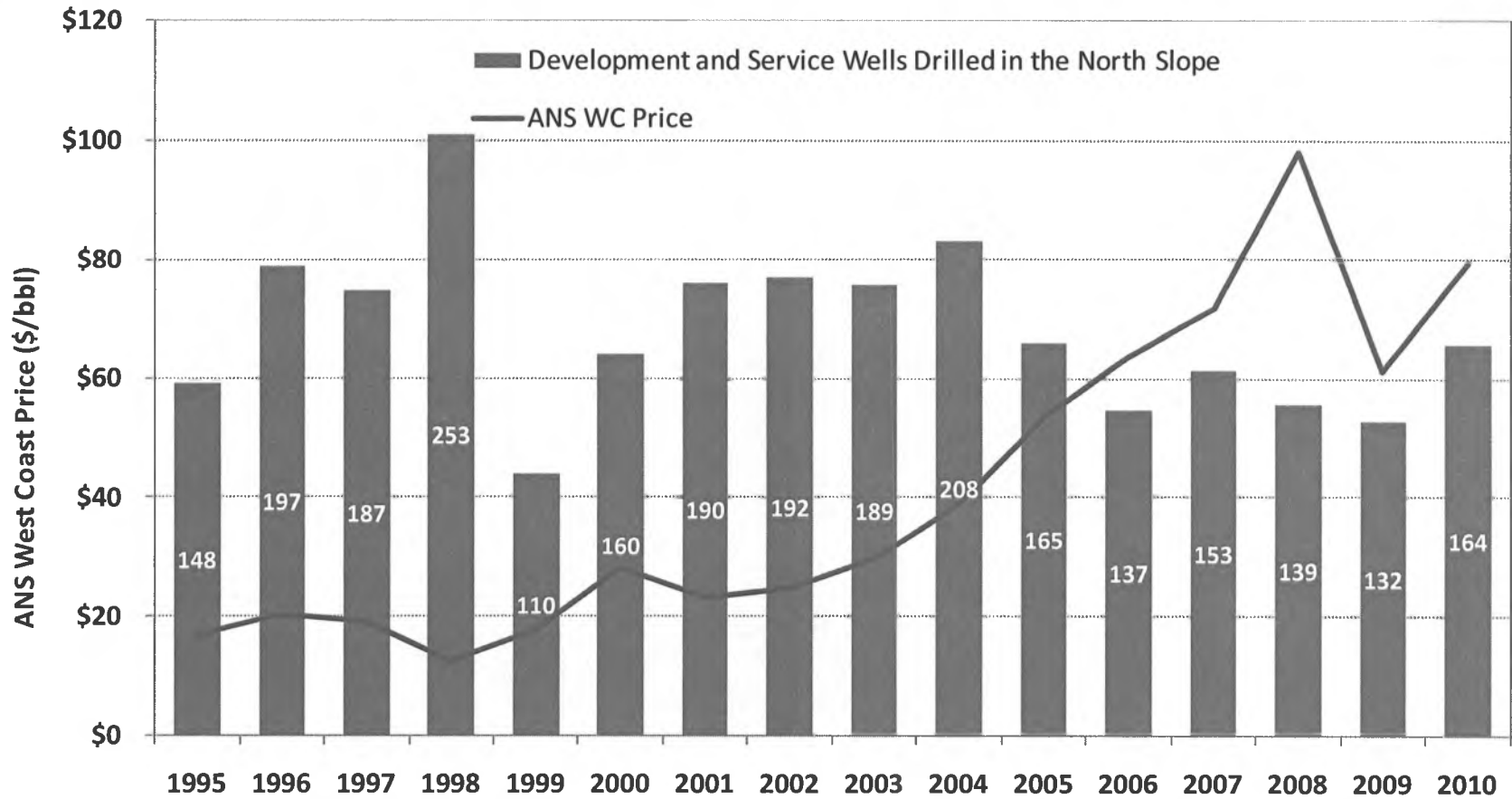


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Source: Fall 2010 Revenue Sources Book



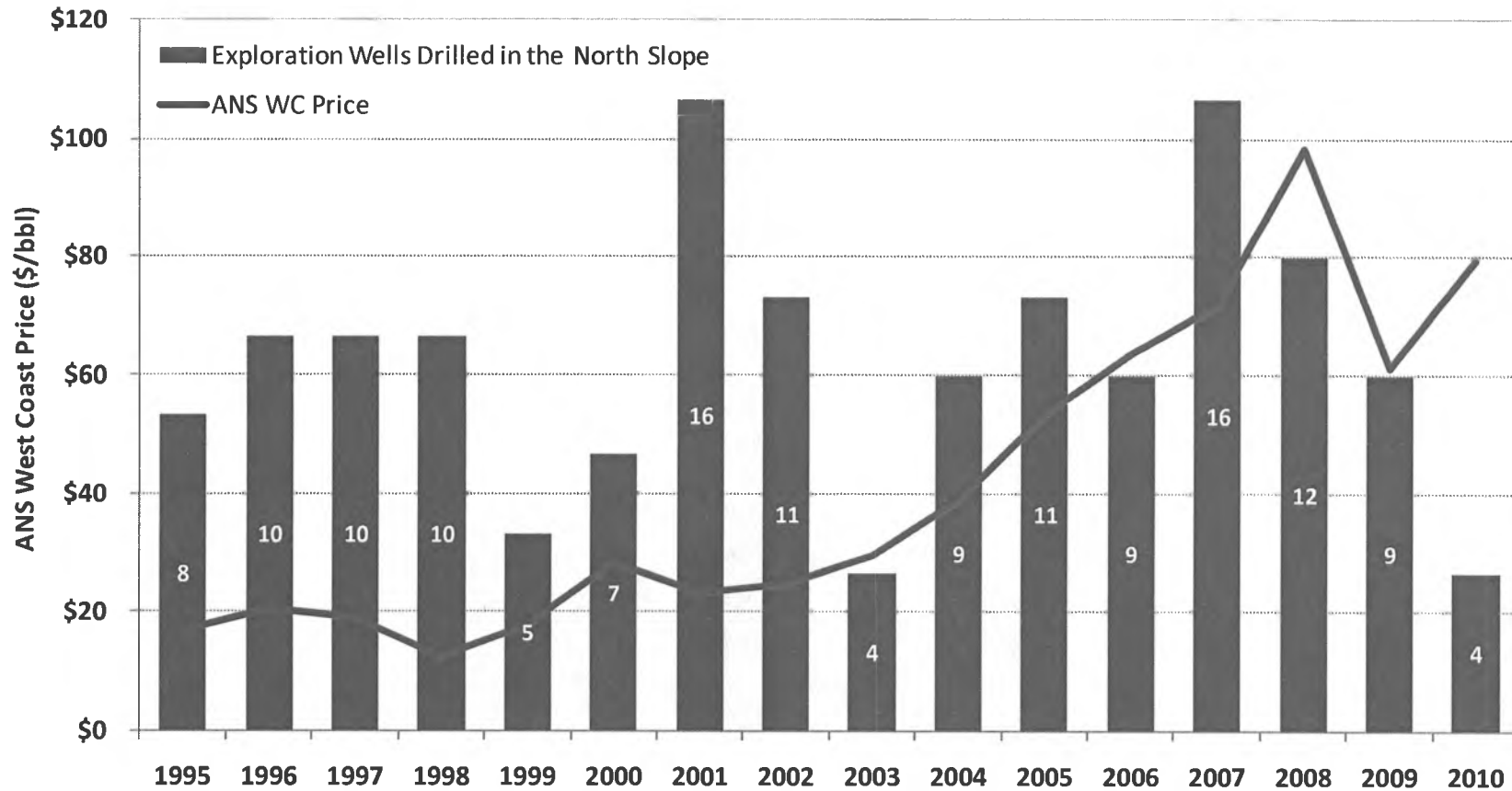
North Slope Development Drilling



Source: Alaska Oil and Gas Conservation Commission (revised)



North Slope Exploration Drilling



Source: Alaska Oil and Gas Conservation Commission (revised)



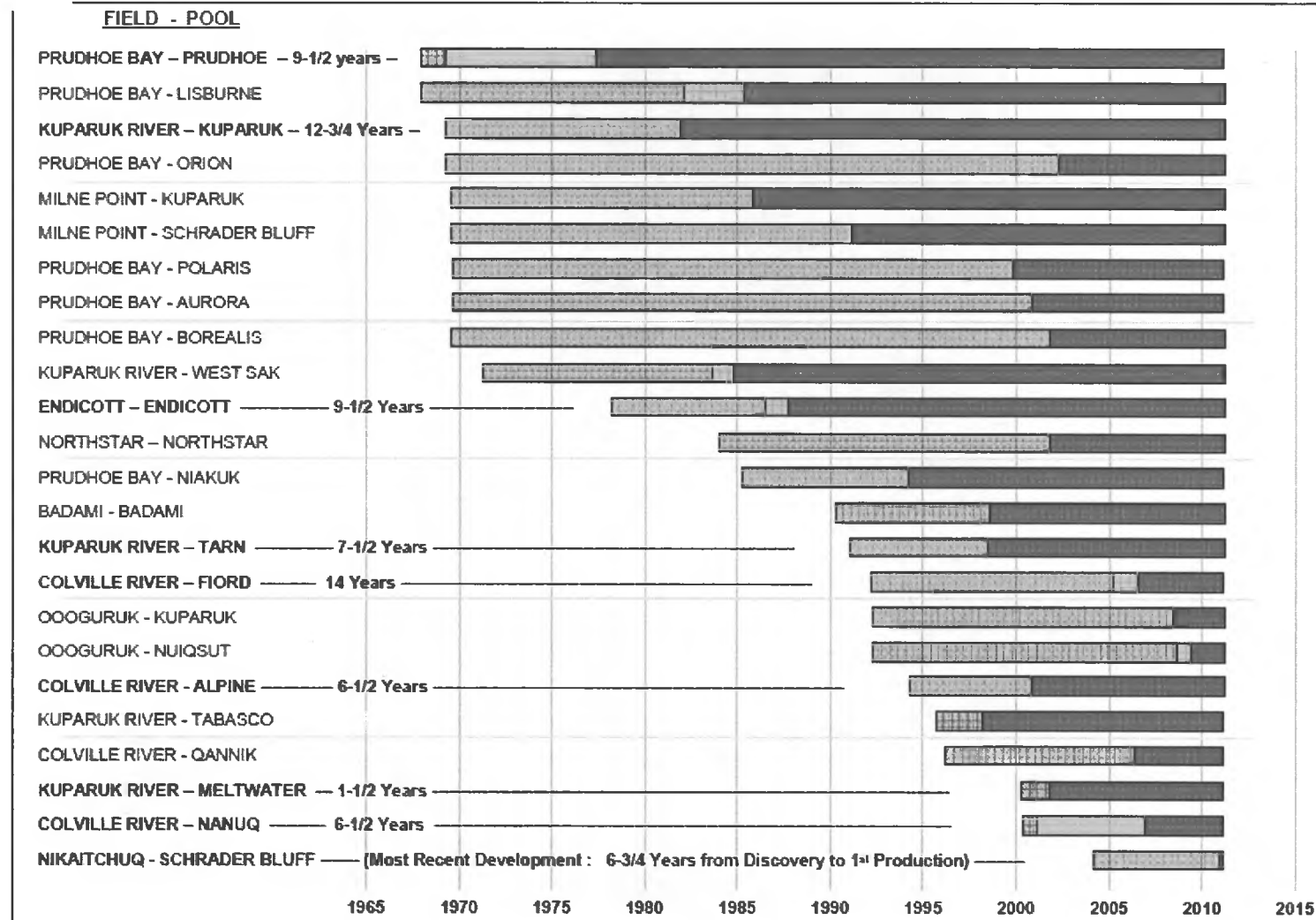
There's lots of oil left in Alaska...



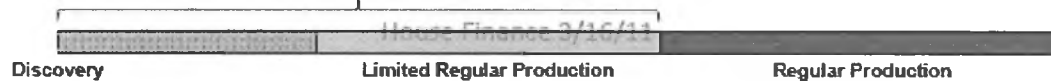
- Cumulative production through 2010 has been over 16 billion barrels
- Remaining North Slope recoverable volumes exceed 5 billion barrels
- Geology-based estimates of total oil volumes are much higher. For instance, we do not include any of the approximately 20 billion barrels in the giant Ugnu deposit, or offshore volumes from the Chukchi or Beaufort Seas, in our forecast



Development Timeline for North Slope Oil Fields



Average = 11 years (neglecting the 5 longest)





Outline for Presentation



- Goals and Rationale for SB 49
- HB110 Overview
- Outlook and Conclusion



Main proposed changes

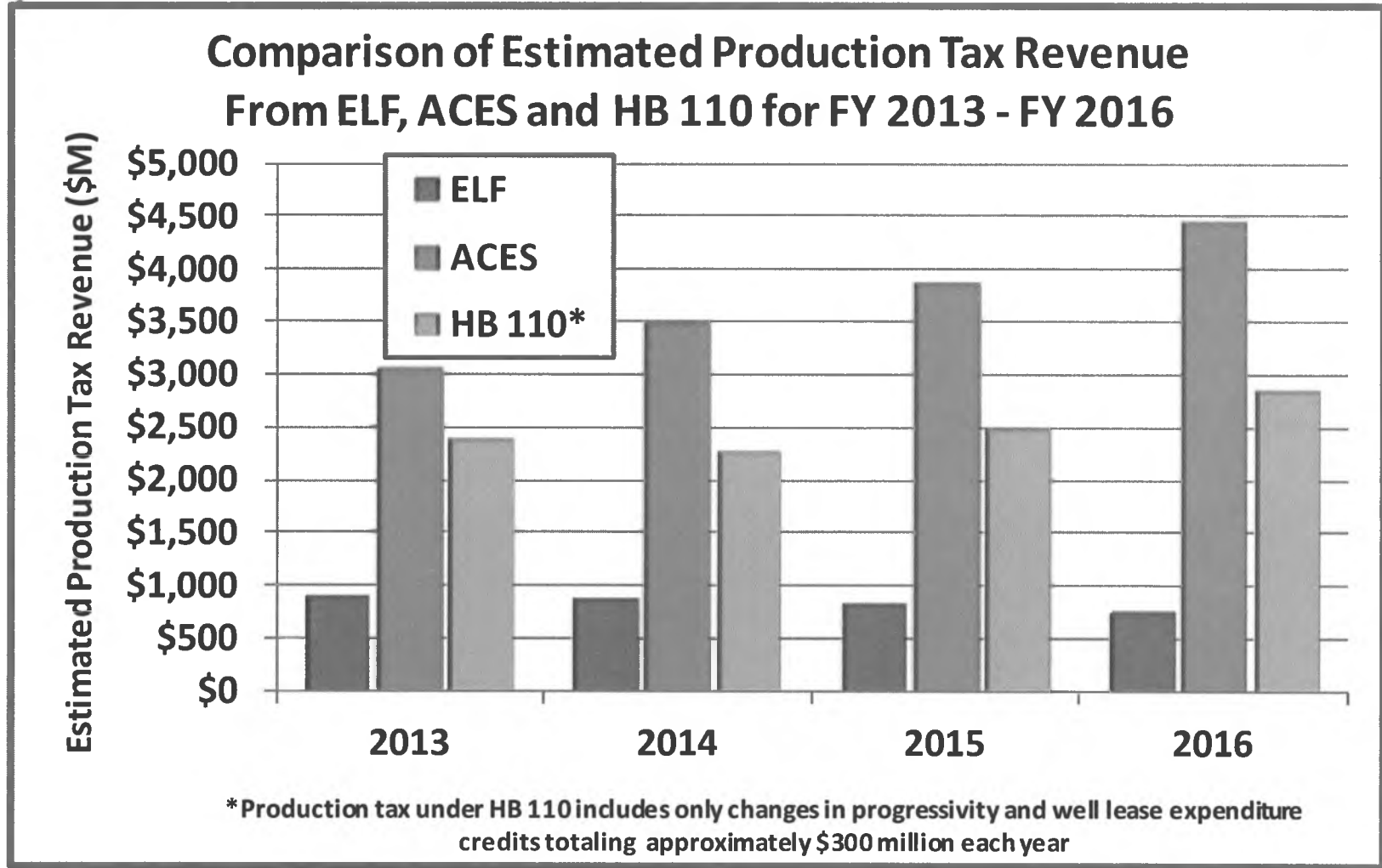


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HB 110 compared to ELF and ACES



Based on Fall 2010 Revenue Forecast assumptions. This analysis **does not include** any incremental production as a result of bill passage.



Outline for Presentation



- Goals and Rationale for SB 49
- HB110 Overview
- Outlook and Conclusion



HB 110 Fiscal Projections



- General Fund Revenue, General Fund Appropriations, and Savings Balances (CBR / SBR only).
- Based on 10-year Fiscal Model developed by DOR Tax Division, DOR Treasury, and OMB.
- Incorporates preliminary Spring 2011 revenue forecast, production forecast, and investment forecasts.
- Spending projections using Legislative Finance presentation from March 1, 2011.
- Key provisions of HB 110 / SB 49 added – tax rate change, tax calculation, well lease expenditure credit.
- Alternative production scenarios & associated costs developed to evaluate various possible outcomes



Preliminary Spring 2011 forecast compared to Fall 2010 forecast



ANS Price Forecast (nominal \$ per barrel)

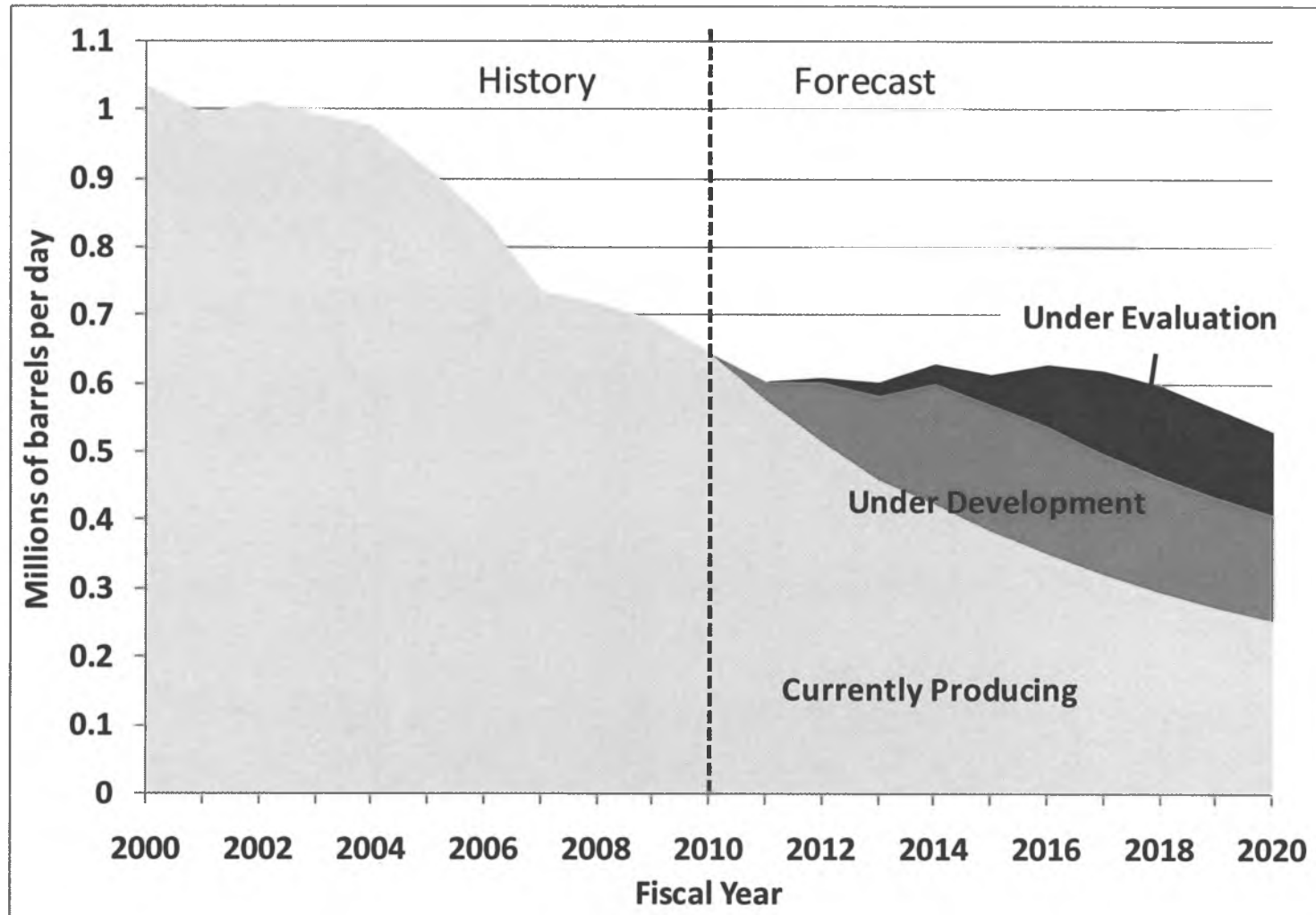
| | FY2011 | FY2012 | FY2013 | FY2014 | FY2015 | FY2016 | FY2017 | FY2018 | FY2019 | FY2020 |
|--------------------------------|----------------|----------------|----------------|----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Fall 2010 | 77.96 | 82.67 | 87.86 | 92.41 | 97.34 | 100.08 | 102.9 | 105.8 | 108.78 | 111.84 |
| Preliminary Spring 2011 | \$91.13 | \$94.70 | \$95.79 | \$96.33 | \$100.76 | \$103.60 | \$106.52 | \$109.52 | \$112.60 | \$115.76 |
| \$ change | \$13.17 | \$12.03 | \$7.93 | \$3.92 | \$3.42 | \$3.52 | \$3.62 | \$3.72 | \$3.82 | \$3.92 |
| % change | 16.9% | 14.6% | 9.0% | 4.2% | 3.5% | 3.5% | 3.5% | 3.5% | 3.5% | 3.5% |

ANS Production Forecast (million barrels per day)

| | FY2011 | FY2012 | FY2013 | FY2014 | FY2015 | FY2016 | FY2017 | FY2018 | FY2019 | FY2020 |
|--------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Fall 2010 | 0.616 | 0.622 | 0.642 | 0.629 | 0.608 | 0.623 | 0.607 | 0.582 | 0.551 | 0.520 |
| Preliminary Spring 2011 | 0.602 | 0.608 | 0.601 | 0.628 | 0.613 | 0.628 | 0.618 | 0.597 | 0.563 | 0.530 |
| Volume change | (0.014) | (0.014) | (0.041) | (0.001) | 0.005 | 0.005 | 0.011 | 0.015 | 0.012 | 0.010 |
| Percent change | -2.2% | -2.3% | -6.3% | -0.1% | 0.8% | 0.8% | 1.9% | 2.5% | 2.2% | 1.9% |



Forecasted ANS Production FY 2010 - 2020

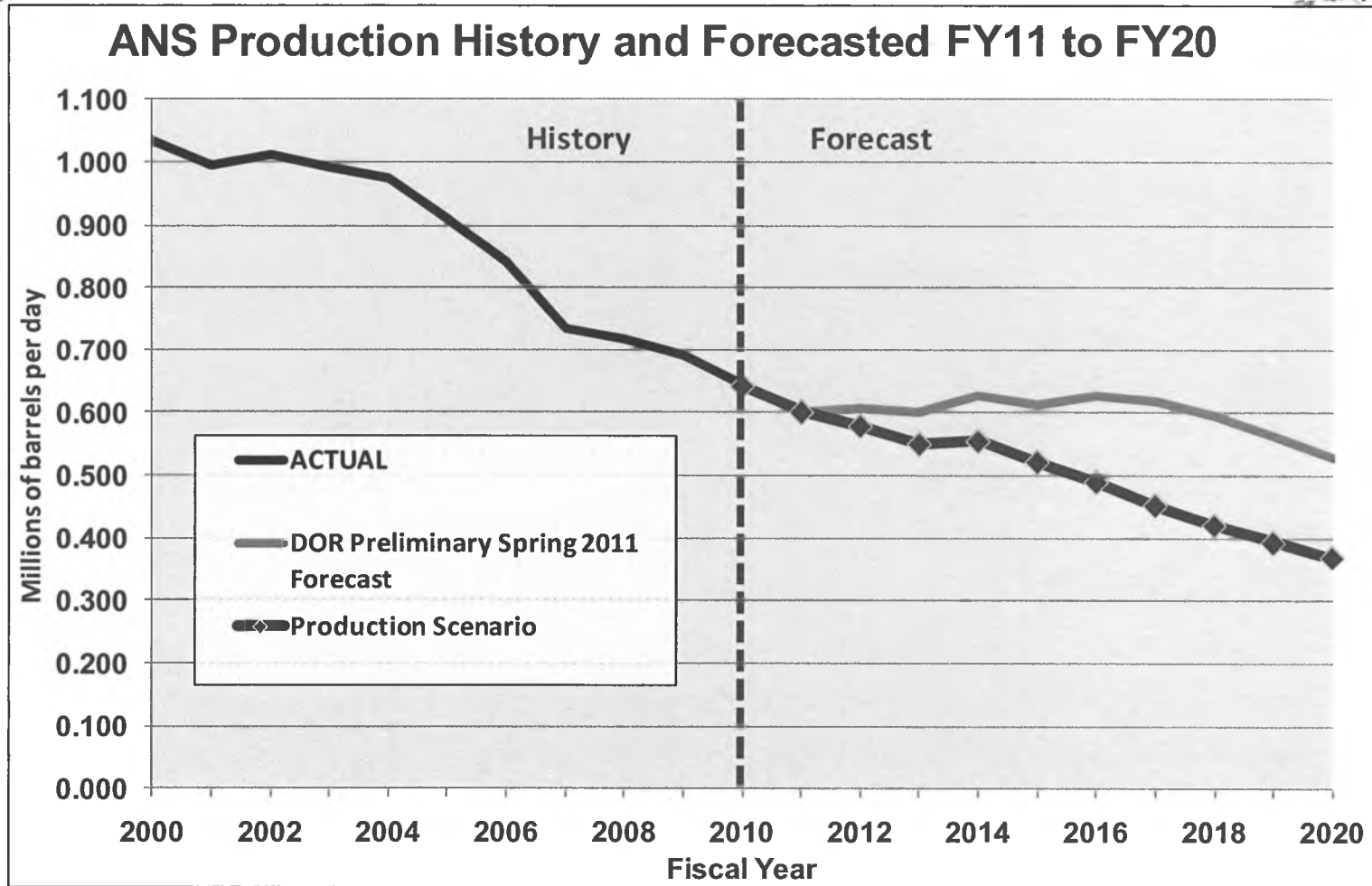


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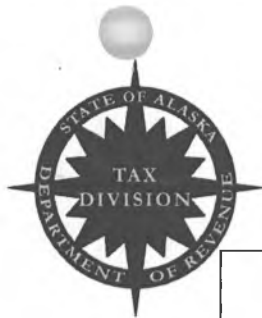
Source: Preliminary Spring 2011 Revenue Forecast



Scenario 1: ACES Tax Structure, No "Under Evaluation" and only 75% of "Under Development" Production *



*Assumes that the "Under Evaluation" component of the DOR forecast does not materialize and only 75% of "Under Development" component materializes.

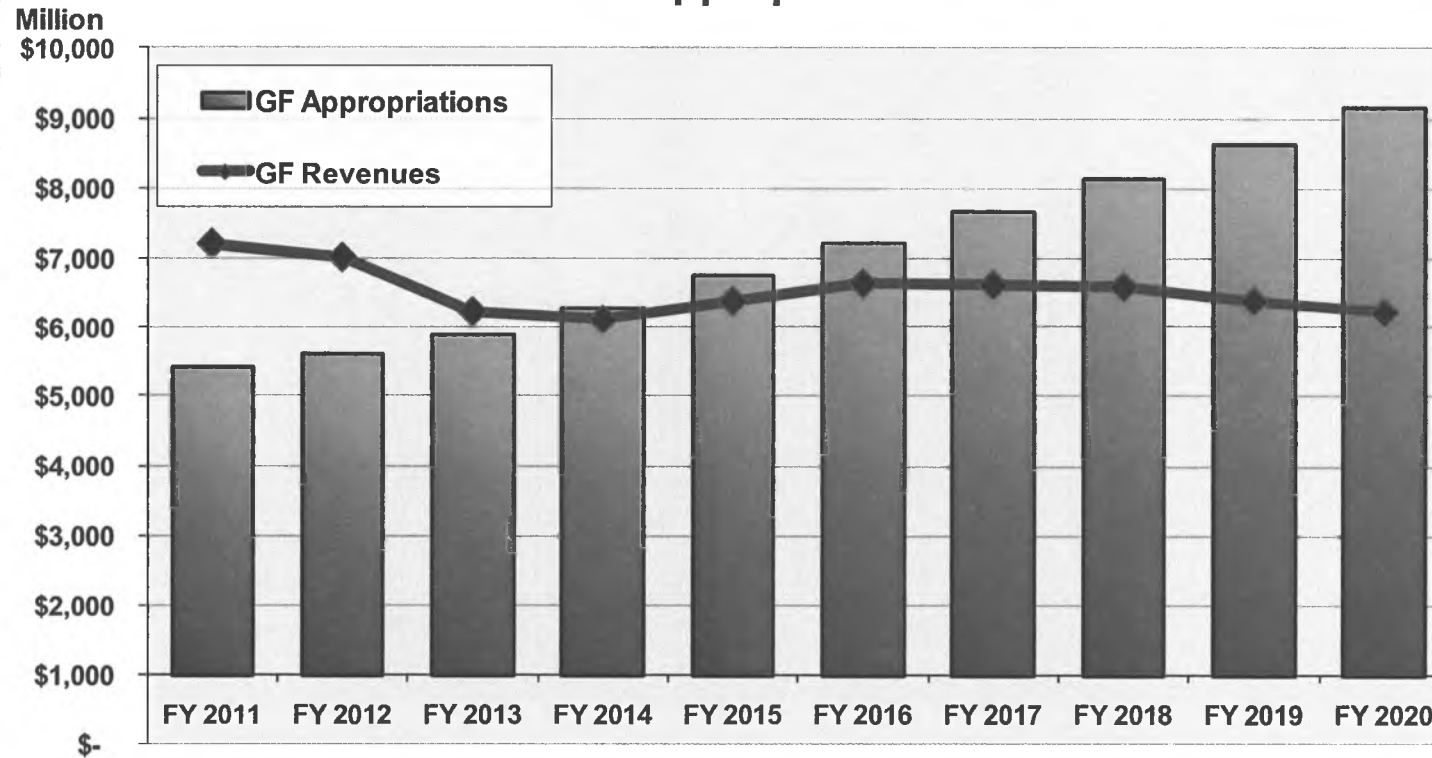


Scenario 1: ACES Tax Structure, No "Under Evaluation" and only 75% of "Under Development" Production *

Tax: ACES / Prices: Prelim Spring 2011 / Budget: LFD projection



GF Revenue versus Appropriations FY11 to FY20



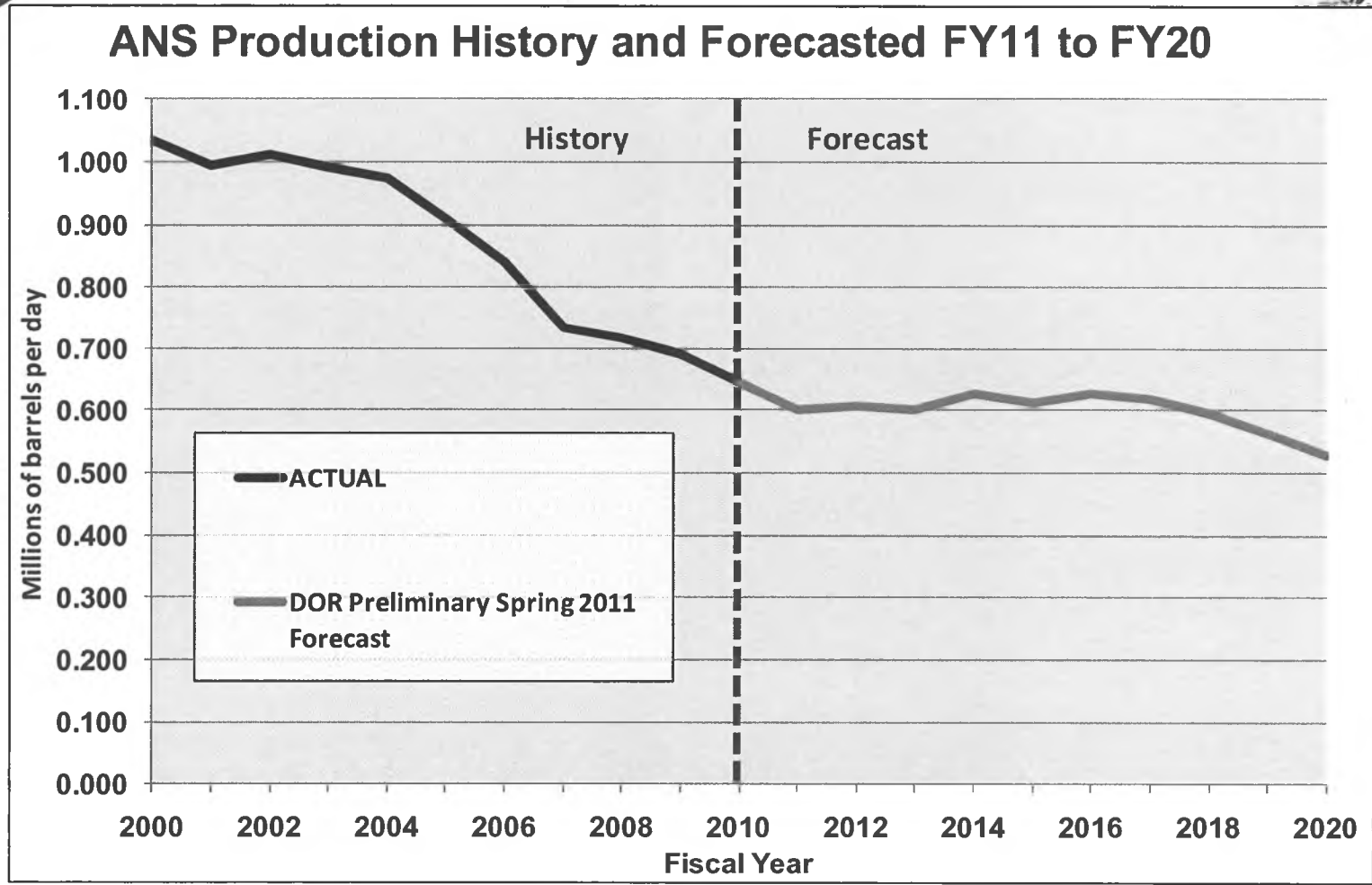
Annual appropriations exclude deposits to Public Education Fund and other special purpose appropriations such as to the Constitutional Budget Reserve or Statutory Budget Reserve.

| | FY 2011 | FY 2012 | FY 2013 | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| Forecast Oil Production (barrels / day) | 602,377 | 580,006 | 551,336 | 556,042 | 522,950 | 491,052 | 453,605 | 421,445 | 393,741 | 370,091 |
| Forecast Oil Price (ANS \$ / bbl) | \$ 91.13 | \$ 94.70 | \$ 95.79 | \$ 96.33 | \$ 100.76 | \$ 103.60 | \$ 106.52 | \$ 109.52 | \$ 112.60 | \$ 115.76 |
| <i>(Amounts below in \$ Millions)</i> | | | | | | | | | | |
| General Fund Revenues | \$ 7,207 | \$ 7,012 | \$ 6,229 | \$ 6,111 | \$ 6,383 | \$ 6,634 | \$ 6,618 | \$ 6,589 | \$ 6,382 | \$ 6,215 |
| General Fund Expenses | \$ 5,403 | \$ 5,596 | \$ 5,894 | \$ 6,286 | \$ 6,752 | \$ 7,224 | \$ 7,664 | \$ 8,132 | \$ 8,629 | \$ 9,164 |
| Budget Surplus / (Deficit) | \$ 1,804 | \$ 1,417 | \$ 335 | \$ (175) | \$ (369) | \$ (590) | \$ (1,047) | \$ (1,543) | \$ (2,247) | \$ (2,949) |
| TOTAL RESERVES (CBRF & SBR) | \$ 13,283 | \$ 15,291 | \$ 16,252 | \$ 16,741 | \$ 17,075 | \$ 17,231 | \$ 16,975 | \$ 16,272 | \$ 14,890 | \$ 12,775 |

*Assumes that the "Under Evaluation" component of the DOR forecast does not materialize and only 75% of "Under Development" component materializes.



Scenario 2: Preliminary Spring 2011 Forecast*



*Assumes the DOR Preliminary Spring 2011 production forecast

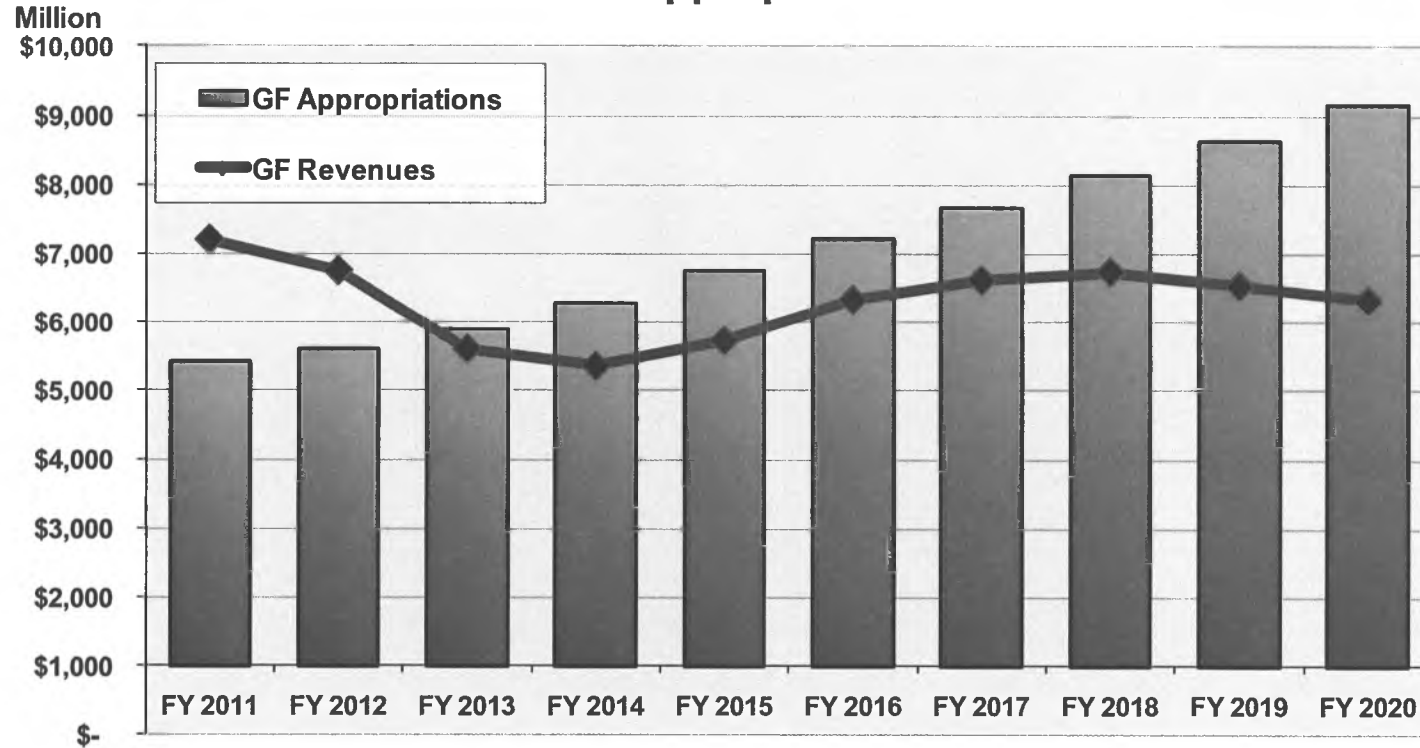


Scenario 2: Impact of HB 110 on Preliminary Spring 2011 Forecast*

Tax: HB 110 / Prices: Prelim Spring 2011 / Budget: LFD projection



GF Revenue versus Appropriations FY11 to FY20



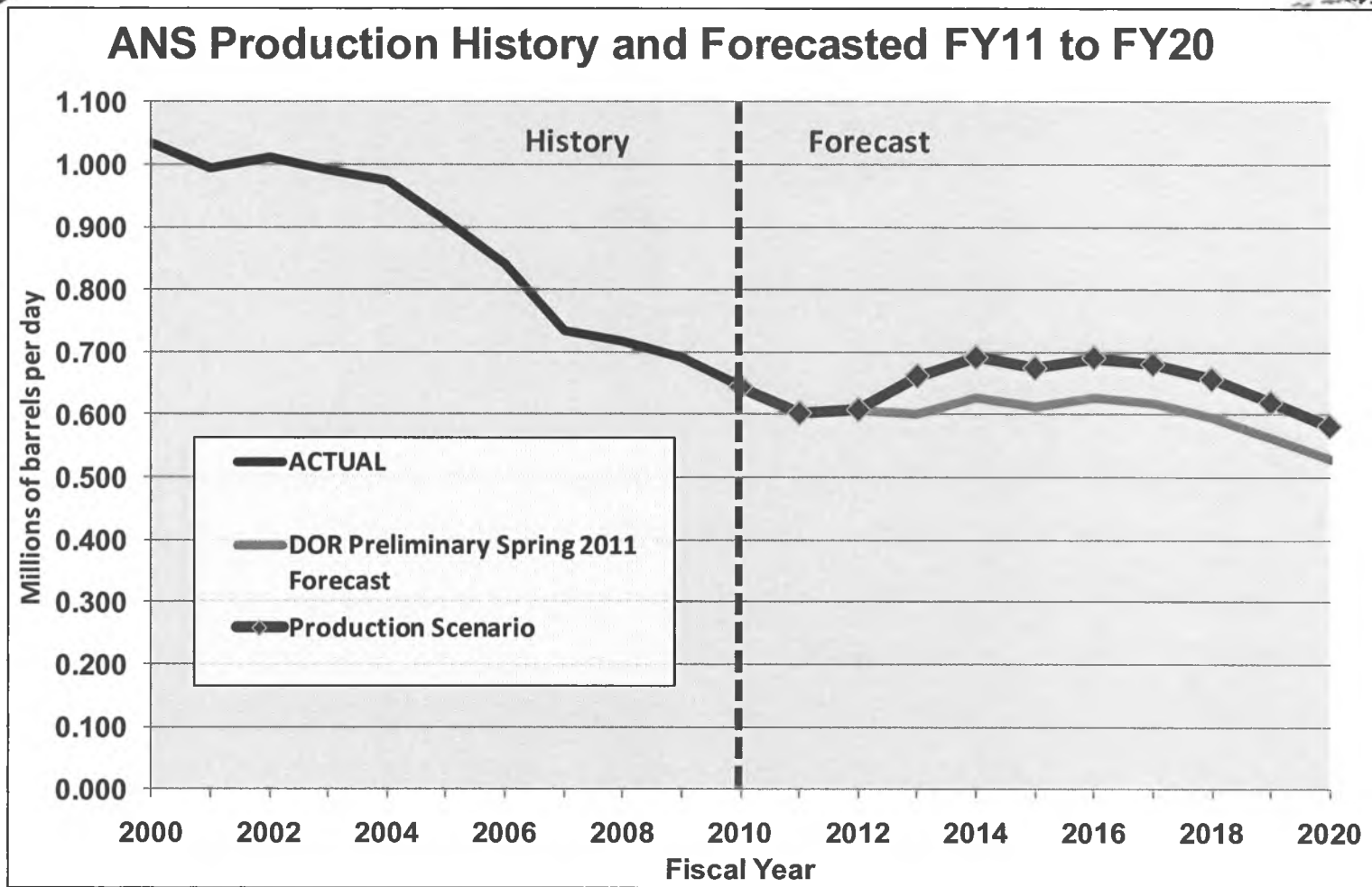
Annual appropriations exclude deposits to Public Education Fund and other special purpose appropriations such as to the Constitutional Budget Reserve or Statutory Budget Reserve.

| | FY 2011 | FY 2012 | FY 2013 | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| Forecast Oil Production (barrels / day) | 602,377 | 607,848 | 601,371 | 628,307 | 612,925 | 627,681 | 618,455 | 596,802 | 563,130 | 529,665 |
| Forecast Oil Price (ANS \$ / bbl) | \$ 91.13 | \$ 94.70 | \$ 95.79 | \$ 96.33 | \$ 100.76 | \$ 103.60 | \$ 106.52 | \$ 109.52 | \$ 112.60 | \$ 115.76 |
| <i>(Amounts below in \$ Millions)</i> | | | | | | | | | | |
| General Fund Revenues | \$ 7,207 | \$ 6,754 | \$ 5,603 | \$ 5,354 | \$ 5,724 | \$ 6,331 | \$ 6,615 | \$ 6,736 | \$ 6,535 | \$ 6,323 |
| General Fund Expenses | \$ 5,403 | \$ 5,596 | \$ 5,894 | \$ 6,286 | \$ 6,752 | \$ 7,224 | \$ 7,664 | \$ 8,132 | \$ 8,629 | \$ 9,164 |
| Budget Surplus / (Deficit) | \$ 1,804 | \$ 1,159 | \$ (292) | \$ (932) | \$ (1,028) | \$ (893) | \$ (1,049) | \$ (1,396) | \$ (2,094) | \$ (2,841) |
| TOTAL RESERVES (CBRF & SBR) | \$ 13,283 | \$ 15,033 | \$ 15,367 | \$ 15,099 | \$ 14,775 | \$ 14,628 | \$ 14,369 | \$ 13,782 | \$ 12,477 | \$ 10,378 |

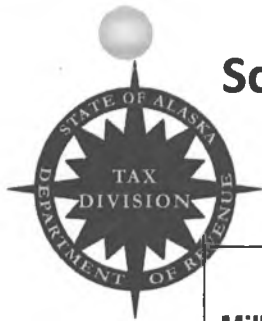
*Assumes the DOR Preliminary Spring 2011 production forecast



Scenario 3: 10% Additional Production From All Fields*



*Assumes that production is 10% higher than DOR forecast beginning in FY 2013

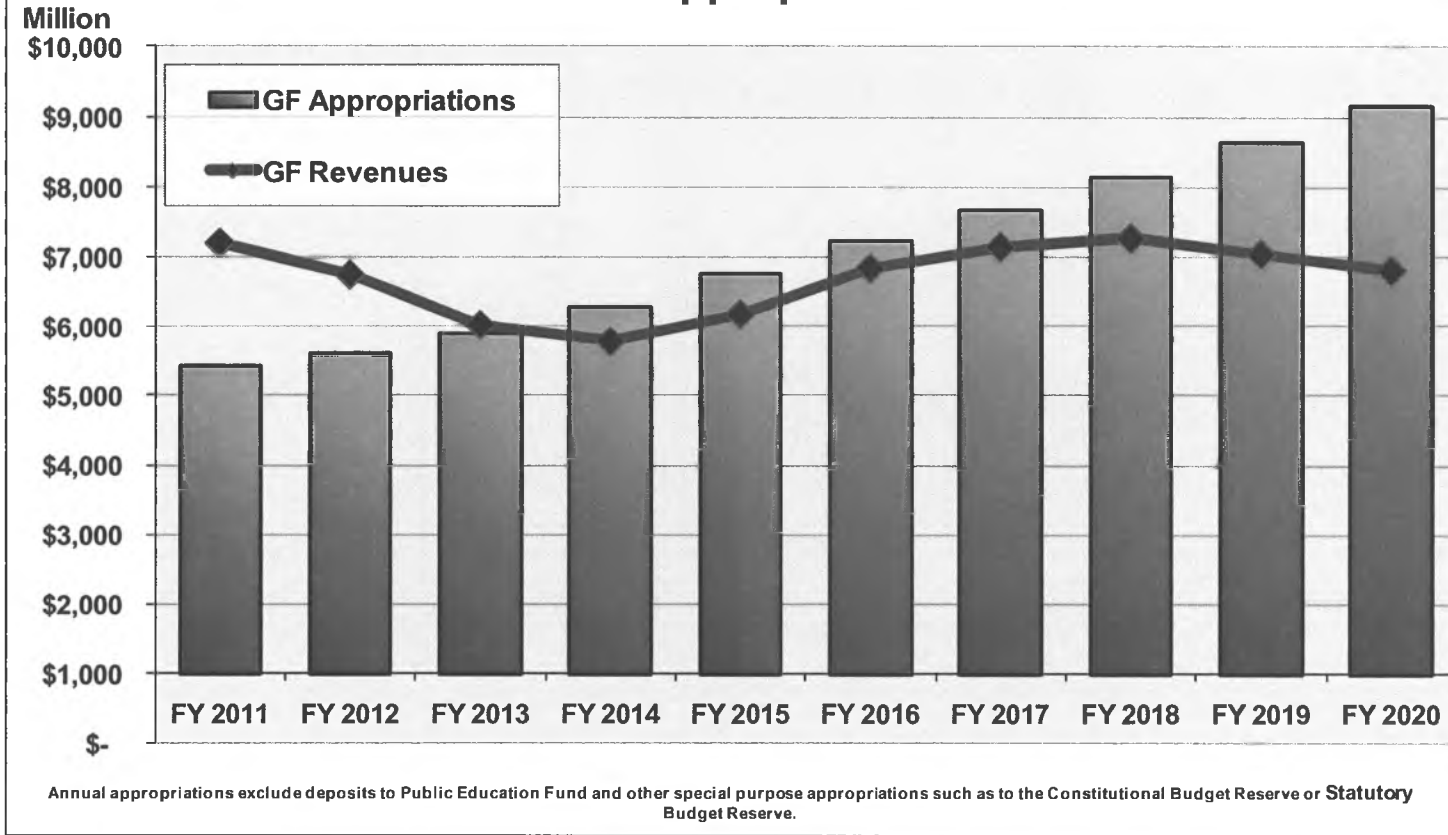


Scenario 3: Impact of HB 110 on Preliminary Spring 2011 Forecast with 10% Additional Production From All Fields*

Tax: HB 110 / Prices: Prelim Spring 2011 / Budget: LFD projection



GF Revenue versus Appropriations FY11 to FY20

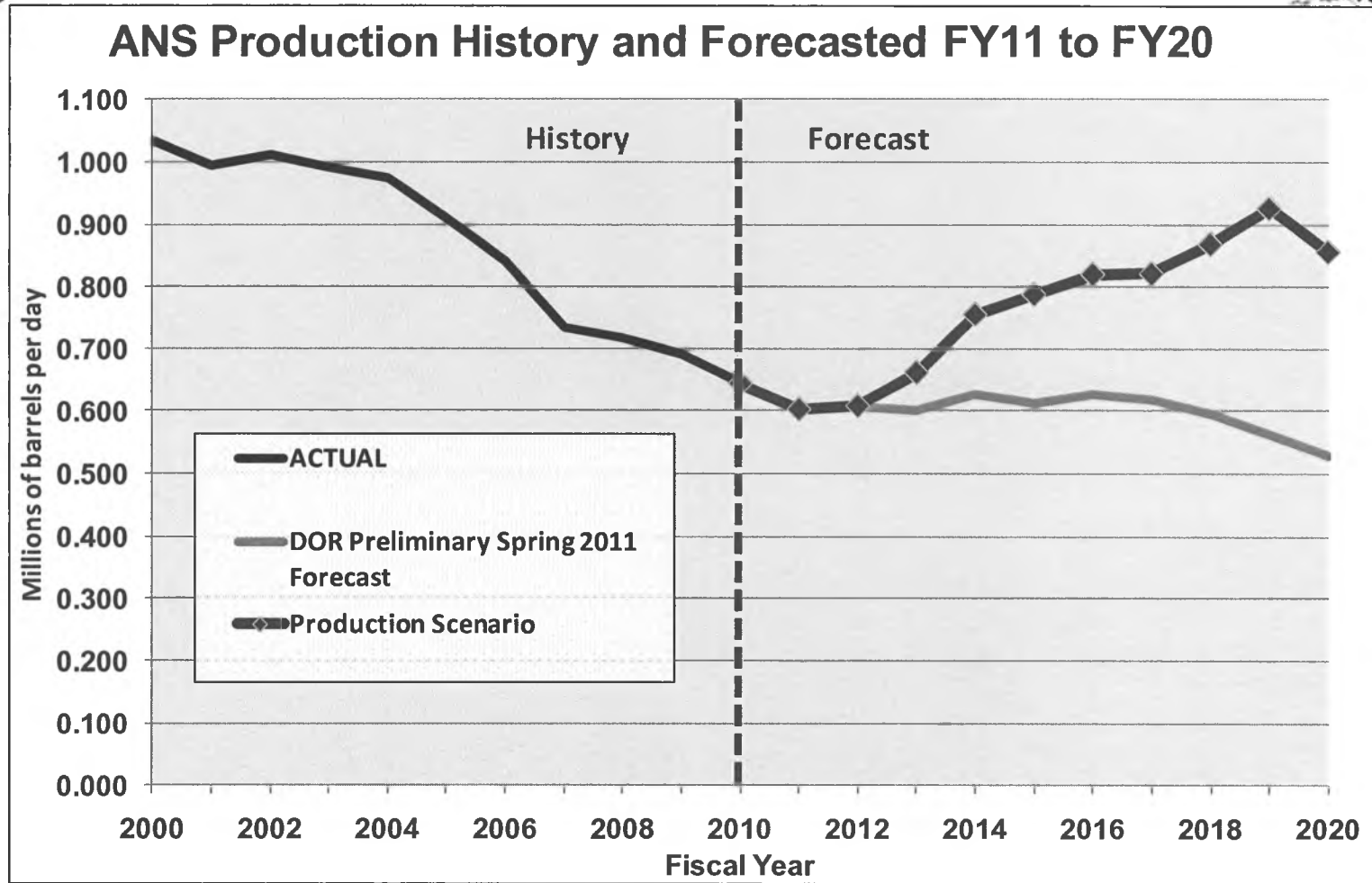


| | FY 2011 | FY 2012 | FY 2013 | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| Forecast Oil Production (barrels / day) | 602,377 | 607,848 | 661,508 | 691,138 | 674,218 | 690,449 | 680,300 | 656,482 | 619,443 | 582,632 |
| Forecast Oil Price (ANS \$ / bbl) | \$ 91.13 | \$ 94.70 | \$ 95.79 | \$ 96.33 | \$ 100.76 | \$ 103.60 | \$ 106.52 | \$ 109.52 | \$ 112.60 | \$ 115.76 |
| <i>(Amounts below in \$ Millions)</i> | | | | | | | | | | |
| General Fund Revenues | \$ 7,207 | \$ 6,754 | \$ 6,027 | \$ 5,781 | \$ 6,180 | \$ 6,838 | \$ 7,144 | \$ 7,269 | \$ 7,043 | \$ 6,807 |
| General Fund Expenses | \$ 5,403 | \$ 5,596 | \$ 5,894 | \$ 6,286 | \$ 6,752 | \$ 7,224 | \$ 7,664 | \$ 8,132 | \$ 8,629 | \$ 9,164 |
| Budget Surplus / (Deficit) | \$ 1,804 | \$ 1,159 | \$ 133 | \$ (505) | \$ (572) | \$ (386) | \$ (520) | \$ (863) | \$ (1,586) | \$ (2,357) |
| TOTAL RESERVES (CBRF & SBR) | \$ 13,283 | \$ 15,033 | \$ 15,792 | \$ 15,950 | \$ 16,082 | \$ 16,443 | \$ 16,714 | \$ 16,690 | \$ 15,991 | \$ 14,524 |

*Assumes that production is 10% higher than DOR forecast beginning in FY 2013



Scenario 4: 10% Additional + New Alpine-Size Field + New Fields Development*

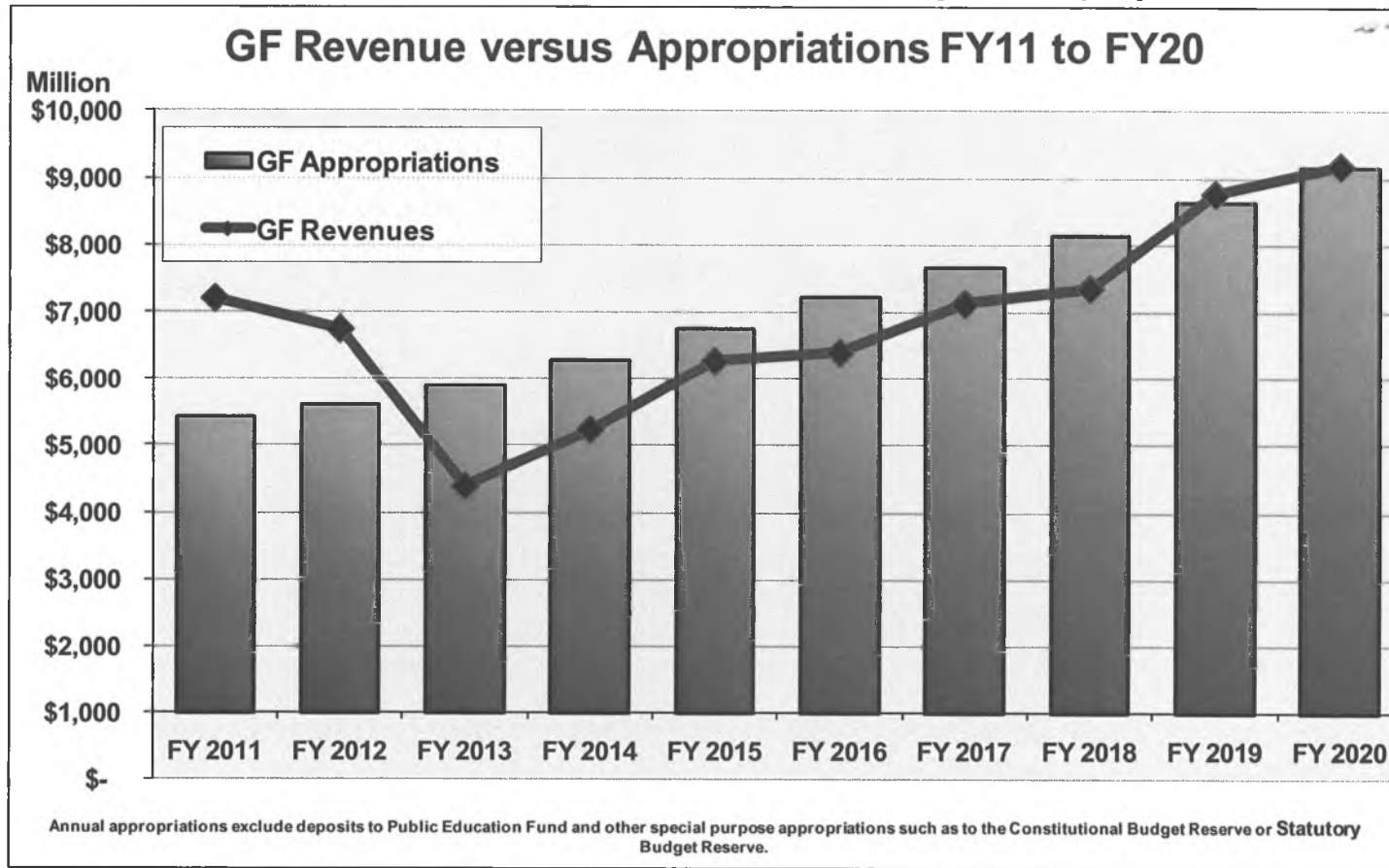


*Assumes 10% increment to forecast beginning in FY 2013, hypothetical new Alpine-size field on line in FY 2018 as presented by AOGCC, and hypothetical new fields development as presented by Brooks Range.



Scenario 4: 10% Additional + New Alpine-Size Field + New Fields Development*

Tax: HB 110 / Prices: Prelim Spring 2011 / Budget: LFD projection



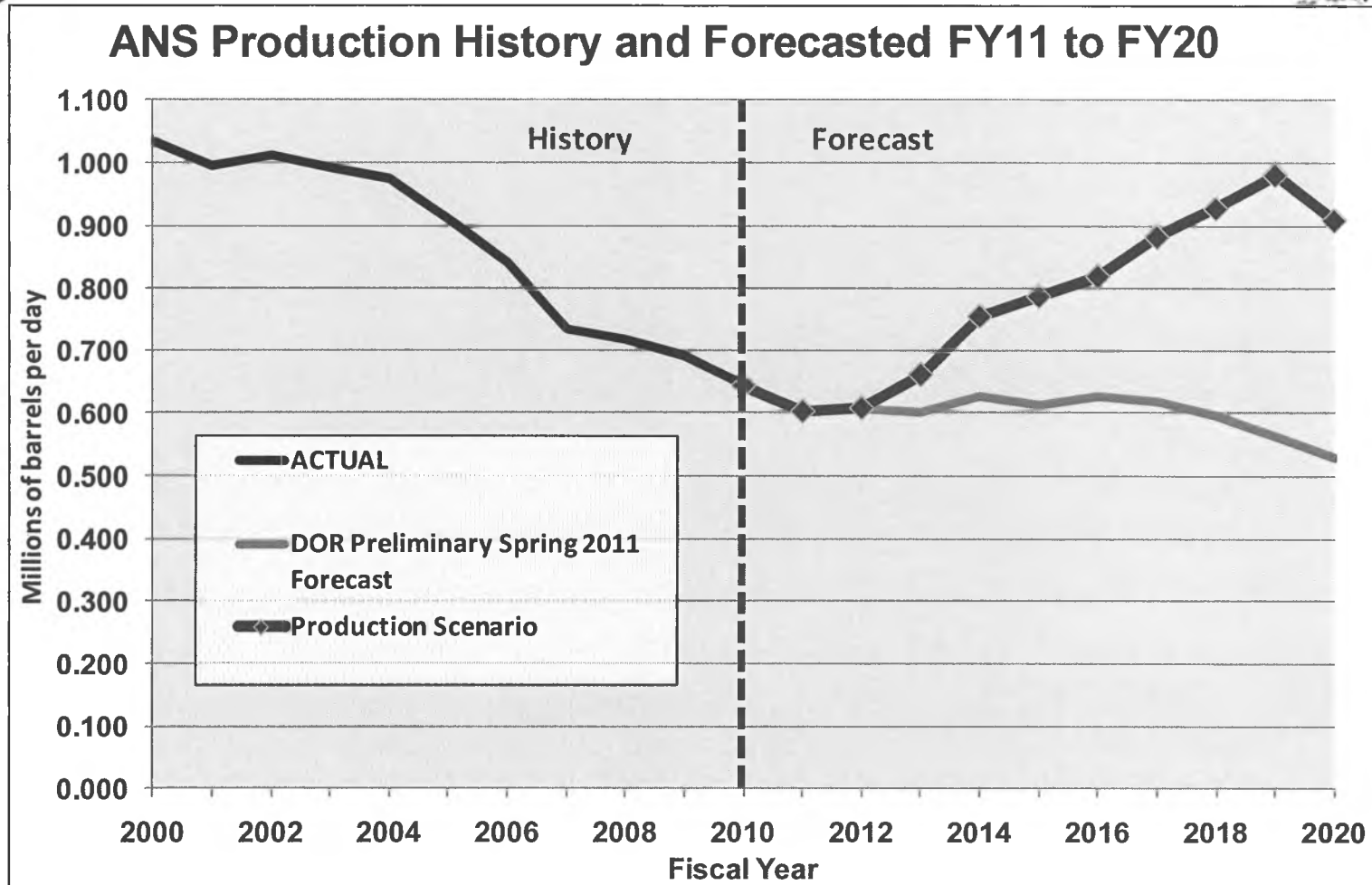
| | FY 2011 | FY 2012 | FY 2013 | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| Forecast Oil Production (barrels / day) | 602,377 | 607,848 | 661,508 | 755,438 | 787,918 | 819,949 | 820,900 | 868,182 | 925,543 | 856,032 |
| Forecast Oil Price (ANS \$ / bbl) | \$ 91.13 | \$ 94.70 | \$ 95.79 | \$ 96.33 | \$ 100.76 | \$ 103.60 | \$ 106.52 | \$ 109.52 | \$ 112.60 | \$ 115.76 |
| <i>(Amounts below in \$ Millions)</i> | | | | | | | | | | |
| General Fund Revenues | \$ 7,207 | \$ 6,754 | \$ 4,389 | \$ 5,236 | \$ 6,268 | \$ 6,398 | \$ 7,132 | \$ 7,356 | \$ 8,769 | \$ 9,184 |
| General Fund Expenses | \$ 5,403 | \$ 5,596 | \$ 5,894 | \$ 6,286 | \$ 6,752 | \$ 7,224 | \$ 7,664 | \$ 8,132 | \$ 8,629 | \$ 9,164 |
| Budget Surplus / (Deficit) | \$ 1,804 | \$ 1,159 | \$ (1,506) | \$ (1,050) | \$ (484) | \$ (827) | \$ (533) | \$ (776) | \$ 140 | \$ 20 |
| TOTAL RESERVES (CBRF & SBR) | \$ 13,283 | \$ 15,033 | \$ 14,153 | \$ 13,767 | \$ 13,987 | \$ 13,907 | \$ 14,160 | \$ 14,198 | \$ 15,187 | \$ 16,110 |

*Assumes 10% increment to forecast beginning in FY 2013, hypothetical new

Alpine-size field on line in FY 2018 as presented by AOGCC, and hypothetical new fields development as presented by Brooks Range.



Scenario 5: 20% Additional + New Alpine-Size Field + New Fields Development*

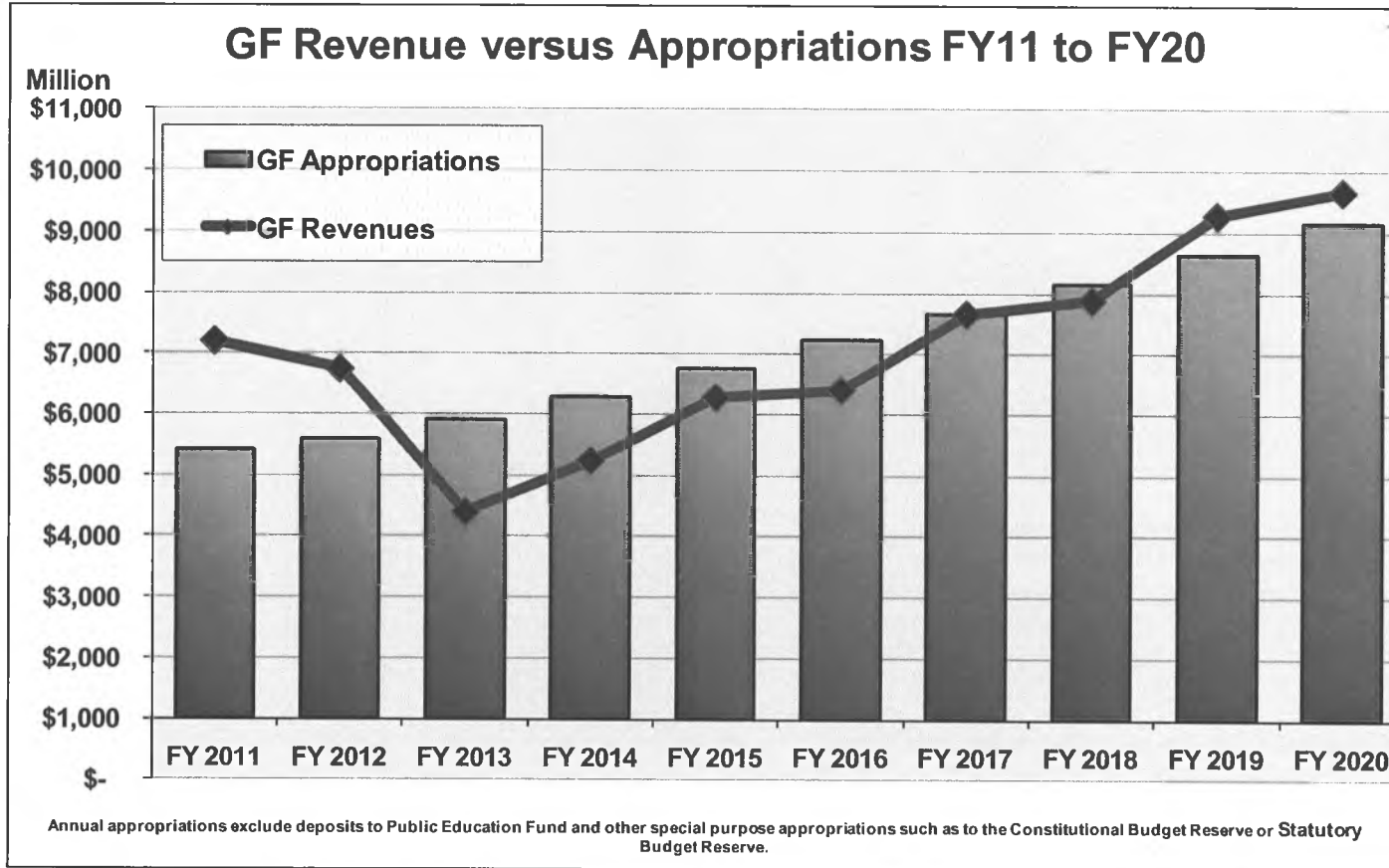


*Assumes 10% increments to forecast beginning in FY 2013 and FY 2017, hypothetical new Alpine-size field on line in FY 2018 as presented by AOGCC, and hypothetical new fields development as presented by Brooks Range.



Scenario 5: 20% Additional + New Alpine-Size Field + New Fields Development*

Tax: HB 110 / Prices: Prelim Spring 2011 / Budget: LFD projection



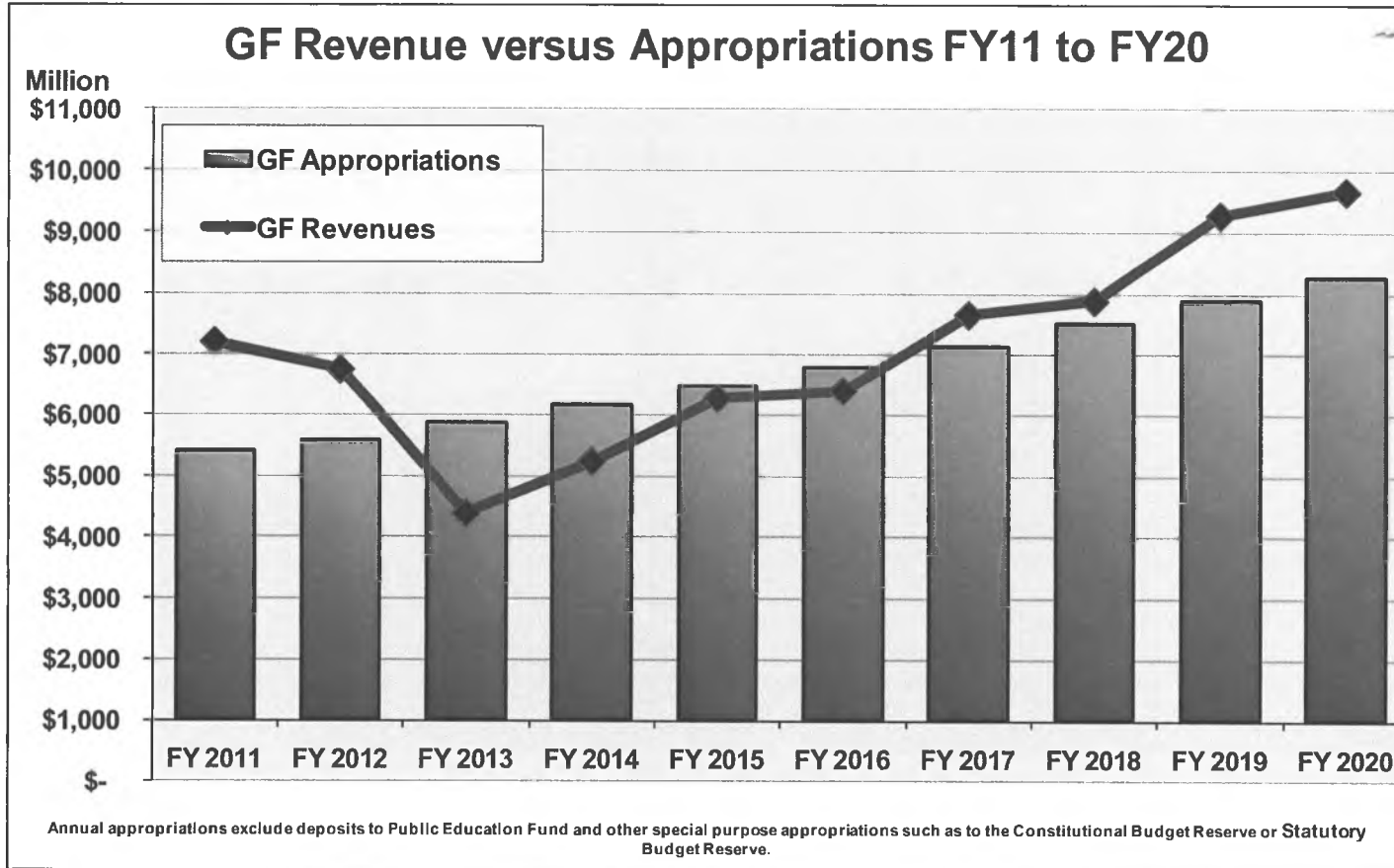
| | FY 2011 | FY 2012 | FY 2013 | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 |
|---|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| Forecast Oil Production (barrels / day) | 602,377 | 607,848 | 661,508 | 755,438 | 787,918 | 819,949 | 882,746 | 927,862 | 981,856 | 908,998 |
| Forecast Oil Price (ANS \$ / bbl) | \$ 91.13 | \$ 94.70 | \$ 95.79 | \$ 96.33 | \$ 100.76 | \$ 103.60 | \$ 106.52 | \$ 109.52 | \$ 112.60 | \$ 115.76 |
| (Amounts below in \$ Millions) | | | | | | | | | | |
| General Fund Revenues | \$ 7,207 | \$ 6,754 | \$ 4,389 | \$ 5,236 | \$ 6,268 | \$ 6,398 | \$ 7,656 | \$ 7,880 | \$ 9,274 | \$ 9,666 |
| General Fund Expenses | \$ 5,403 | \$ 5,596 | \$ 5,894 | \$ 6,286 | \$ 6,752 | \$ 7,224 | \$ 7,664 | \$ 8,132 | \$ 8,629 | \$ 9,164 |
| Budget Surplus / (Deficit) | \$ 1,804 | \$ 1,159 | \$ (1,506) | \$ (1,050) | \$ (484) | \$ (827) | \$ (8) | \$ (252) | \$ 645 | \$ 502 |
| TOTAL RESERVES (CBRF & SBR) | \$ 13,283 | \$ 15,033 | \$ 14,153 | \$ 13,767 | \$ 13,987 | \$ 13,907 | \$ 14,689 | \$ 15,277 | \$ 16,812 | \$ 18,259 |

*Assumes 10% increments to forecast beginning in FY 2012 and FY 2017, hypothetical new Alpine-size field on line in FY 2018 as presented by AOGCC, and hypothetical new fields development as presented by Brooks Range.



Scenario 5 (b): 20% Additional + New Alpine-Size Field + New Fields Development* (with 5% annual spending growth)

Tax: HB 110 / Prices: Prelim Spring 2011 / Budget: 5% annual growth



| | FY 2011 | FY 2012 | FY 2013 | FY 2014 | FY 2015 | FY 2016 | FY 2017 | FY 2018 | FY 2019 | FY 2020 |
|--|------------------|------------------|-------------------|------------------|------------------|------------------|------------------|------------------|------------------|------------------|
| Forecast Oil Production (barrels / day) | 602,377 | 607,848 | 661,508 | 755,438 | 787,918 | 819,949 | 882,746 | 927,862 | 981,856 | 908,998 |
| Forecast Oil Price (ANS \$ / bbl) | \$ 91.13 | \$ 94.70 | \$ 95.79 | \$ 96.33 | \$ 100.76 | \$ 103.60 | \$ 106.52 | \$ 109.52 | \$ 112.60 | \$ 115.76 |
| <i>(Amounts below in \$ Millions)</i> | | | | | | | | | | |
| General Fund Revenues | \$ 7,207 | \$ 6,754 | \$ 4,389 | \$ 5,236 | \$ 6,268 | \$ 6,398 | \$ 7,656 | \$ 7,880 | \$ 9,274 | \$ 9,666 |
| General Fund Expenses | \$ 5,403 | \$ 5,596 | \$ 5,875 | \$ 6,169 | \$ 6,478 | \$ 6,801 | \$ 7,142 | \$ 7,499 | \$ 7,874 | \$ 8,267 |
| Budget Surplus / (Deficit) | \$ 1,804 | \$ 1,159 | \$ (1,487) | \$ (933) | \$ (209) | \$ (404) | \$ 514 | \$ 381 | \$ 1,400 | \$ 1,399 |
| TOTAL RESERVES (CBRF & SBR) | \$ 13,283 | \$ 15,033 | \$ 14,172 | \$ 13,903 | \$ 14,397 | \$ 14,739 | \$ 16,045 | \$ 17,266 | \$ 19,556 | \$ 21,900 |

*Assumes 10% increments to forecast beginning in FY 2013 and FY 2017, hypothetical new Alpine-size field on line in FY 2018 as presented by AOGCC, and hypothetical new fields development as presented by Brooks Range.



Fiscal Projections Scenario Assumptions



- DOR forecast – uses the full production forecast per Spring 2011 revenue forecast (preliminary) plus associated lease expenditures and credits. These are preliminary numbers based on the forecast which will be released in early April.
- Scenario 1 – removes “Under Evaluation” and 25% of “Under Development” from the forecast along with associated lease expenditures and credits.
- Scenario 2 – 10% production increment – adds an additional 10% to forecast across the board, and an associated increase in lease expenditures and credits.
- Scenarios 3, 4, 5 – Add hypothetical Alpine-size field in 2018, and new fields development
 - Alpine size field in 2018 – production profile developed based on presentation by AOGCC to House Finance on 3/16/11. This development receives the 25% base tax rate under HB 110.
 - New fields development – production profile developed based on presentation by Brooks Range to House Finance on 3/23/11. This development receives the 15% base tax rate under HB 110.
- LFD spending scenario – 10-year spending projections as presented in House Finance on 3/1/11 – averaging 6.4% yearly budget growth FY 13-20.



In Conclusion:



1. Tax rates must be lowered to improve the investment climate in Alaska.
2. Our economy is at risk if we decide to do nothing. Our future is at stake!
3. The decisions made now will affect Alaska's economy for decades to come.
4. Without major new investment, new drilling will continue to suffer in Alaska.
5. Oil exploration and development will create immediate return in jobs for Alaskans.
6. Just one exploratory well creates dozen of direct jobs and hundreds of indirect jobs.
7. Industry investment and exploration should be closely monitored to make sure HB110 has the desired effects.



HB110 Goals



1. Improve investment climate
2. Increase production
3. Create jobs for Alaskans

HB 110 & ACES: Revenue Sensitivities to Production

Roger Marks
Logsdon & Associates
House Finance
March 26, 2010

Framework

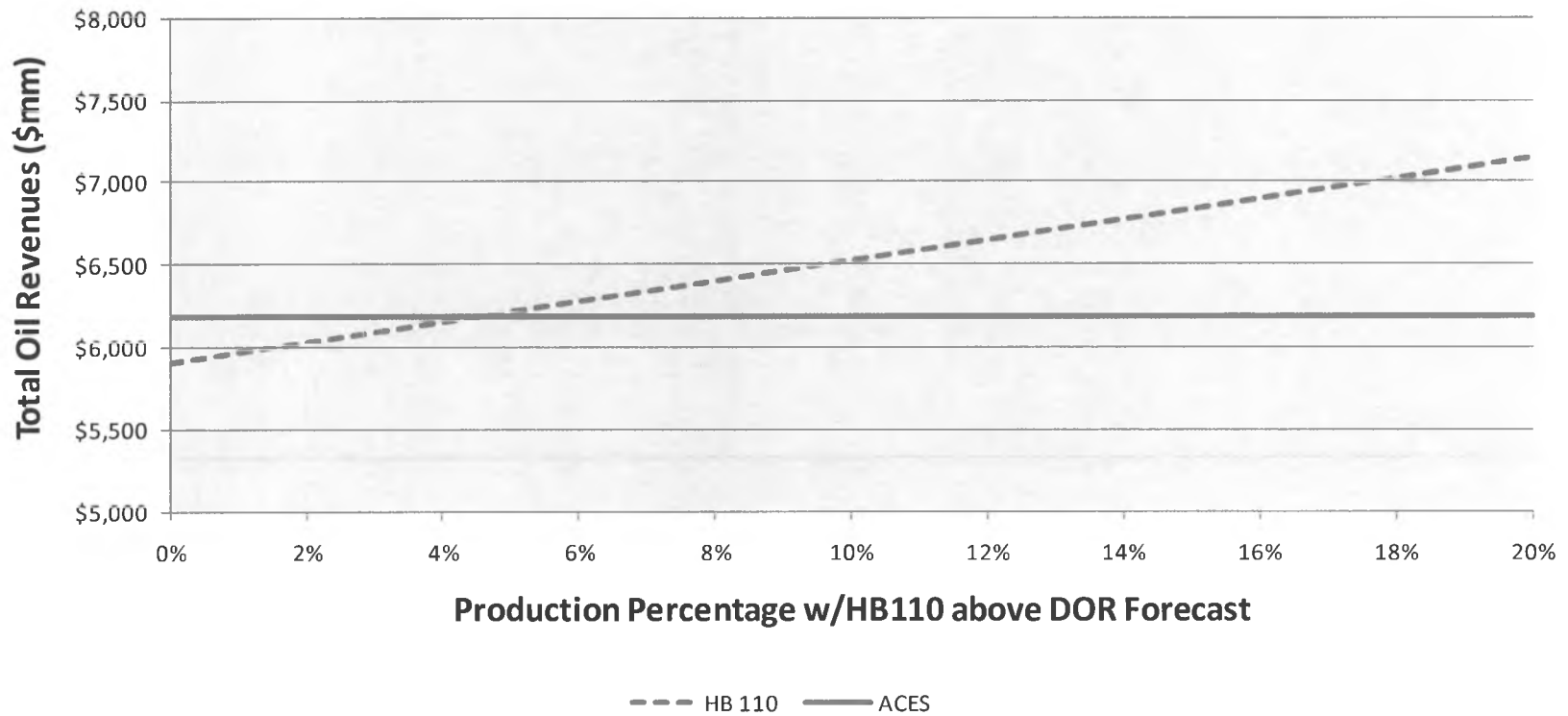
- Over the past 10 years, looking 5 years forward, the DOR production forecast has averaged about 20% too high.
- The DOR forecast does not take the availability of capital into account in the production forecast. The availability of capital is crucial for producing barrels.
- It is plausible due to the relative international un-competitiveness of ACES that capital has been diverted elsewhere and production has been suppressed.
- For this exercise we assume the Fall 2010 production forecast under ACES is 10% too high for 2016, and looked at total oil revenues under ACES.
- It is plausible that with a more competitive fiscal system Alaska would attract more capital and production would be enhanced.
- For this exercise we looked at total oil revenues under HB 110 at a spectrum of percentage production increases over the Fall 2010 forecast for 2016.
- We looked at \$80, \$100, and \$120/bbl prices.
- We looked at HB 110 both with and without the 40% well expenditure credit.
- Total oil revenues include restricted royalties that go to the Permanent Fund.

Total Oil Revenues HB110 vs. ACES: 2016 @ \$100/bbl (\$mm)

ACES Production 10% below DOR Forecast

HB110 Production Percentage Production above Forecast

(Includes restricted royalties; without 40% well credit for HB110)

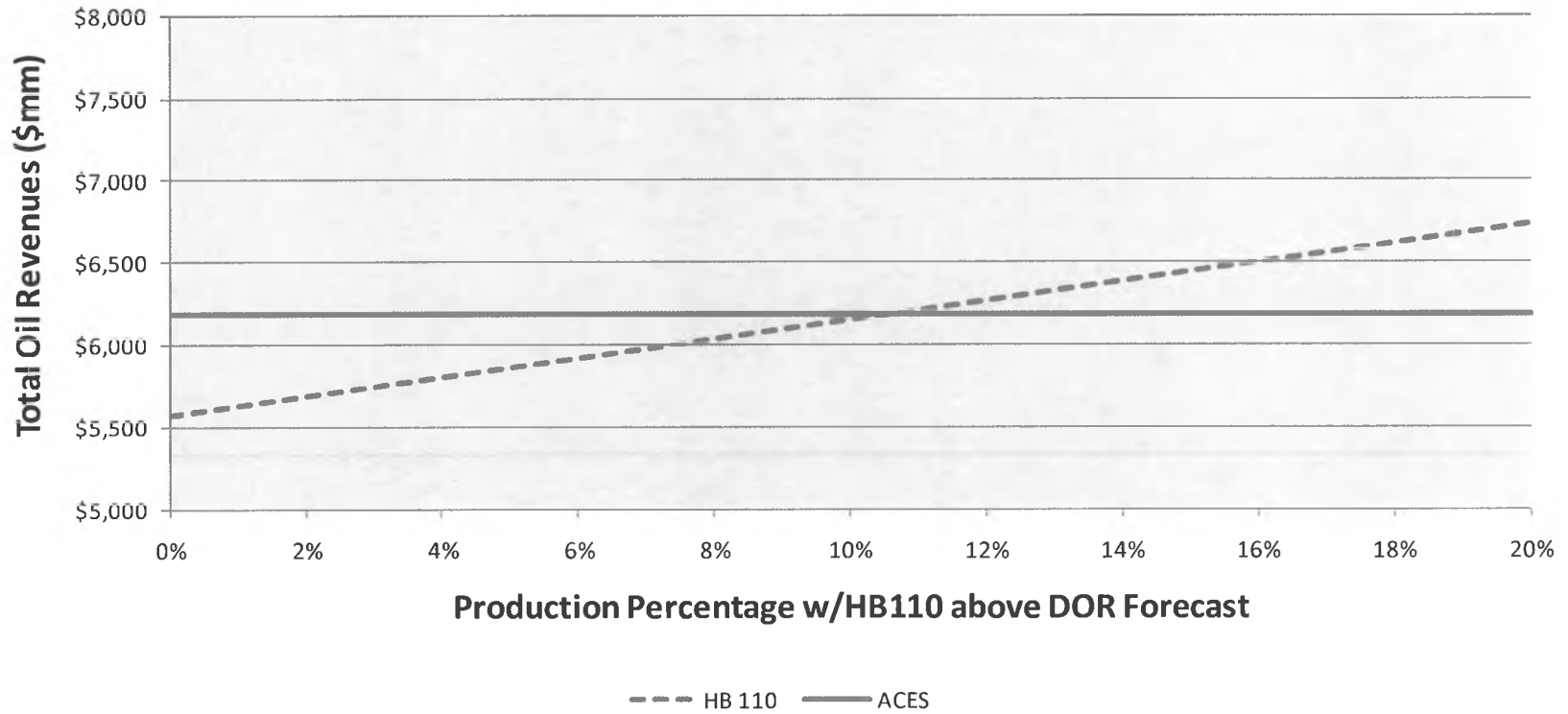


Total Oil Revenues HB110 vs. ACES: 2016 @ \$100/bbl (\$mm)

ACES Production 10% below DOR Forecast

HB110 Production Percentage Production above Forecast

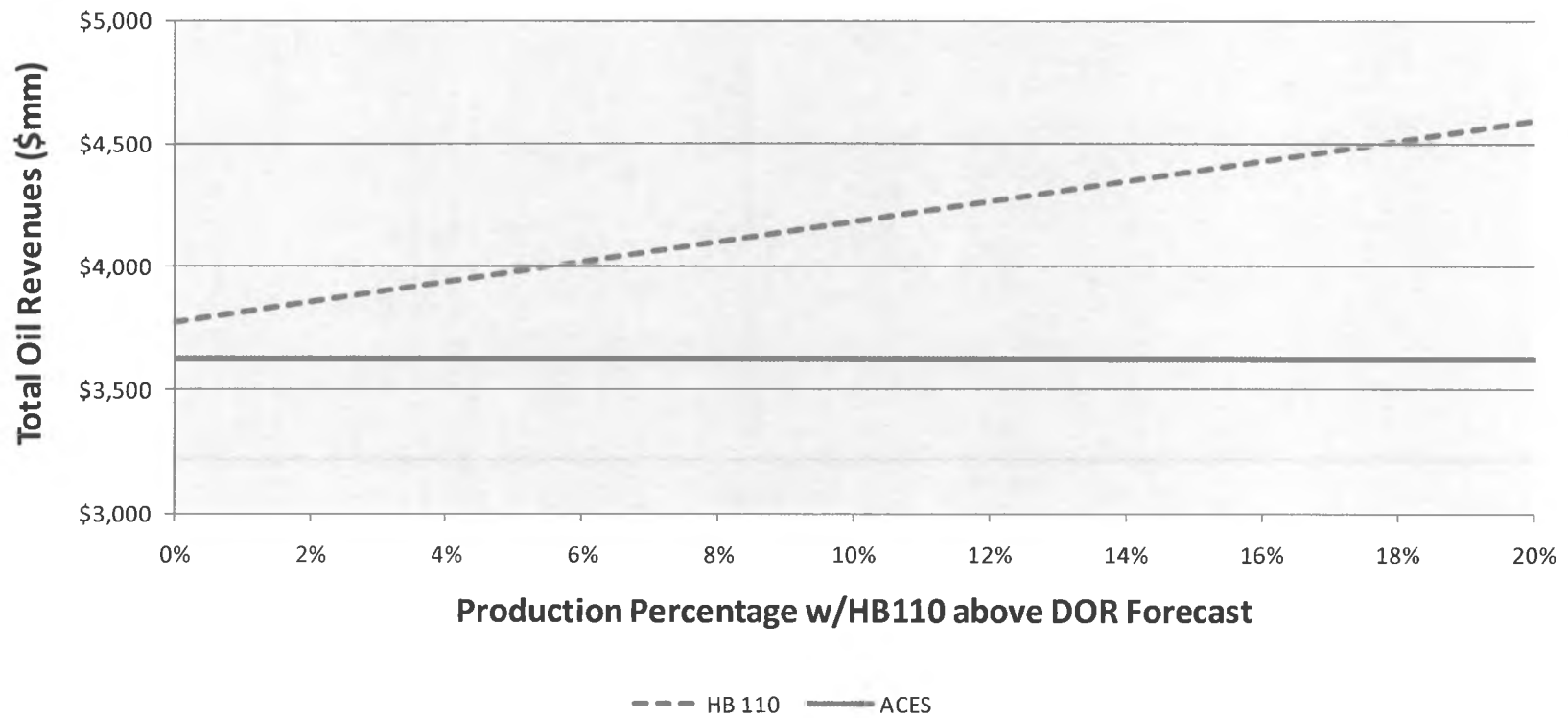
(Includes restricted royalties; with 40% well credit for HB110)



Total Oil Revenues HB110 vs. ACES: 2016 @ \$80/bbl (\$mm)

ACES Production 10% below DOR Forecast

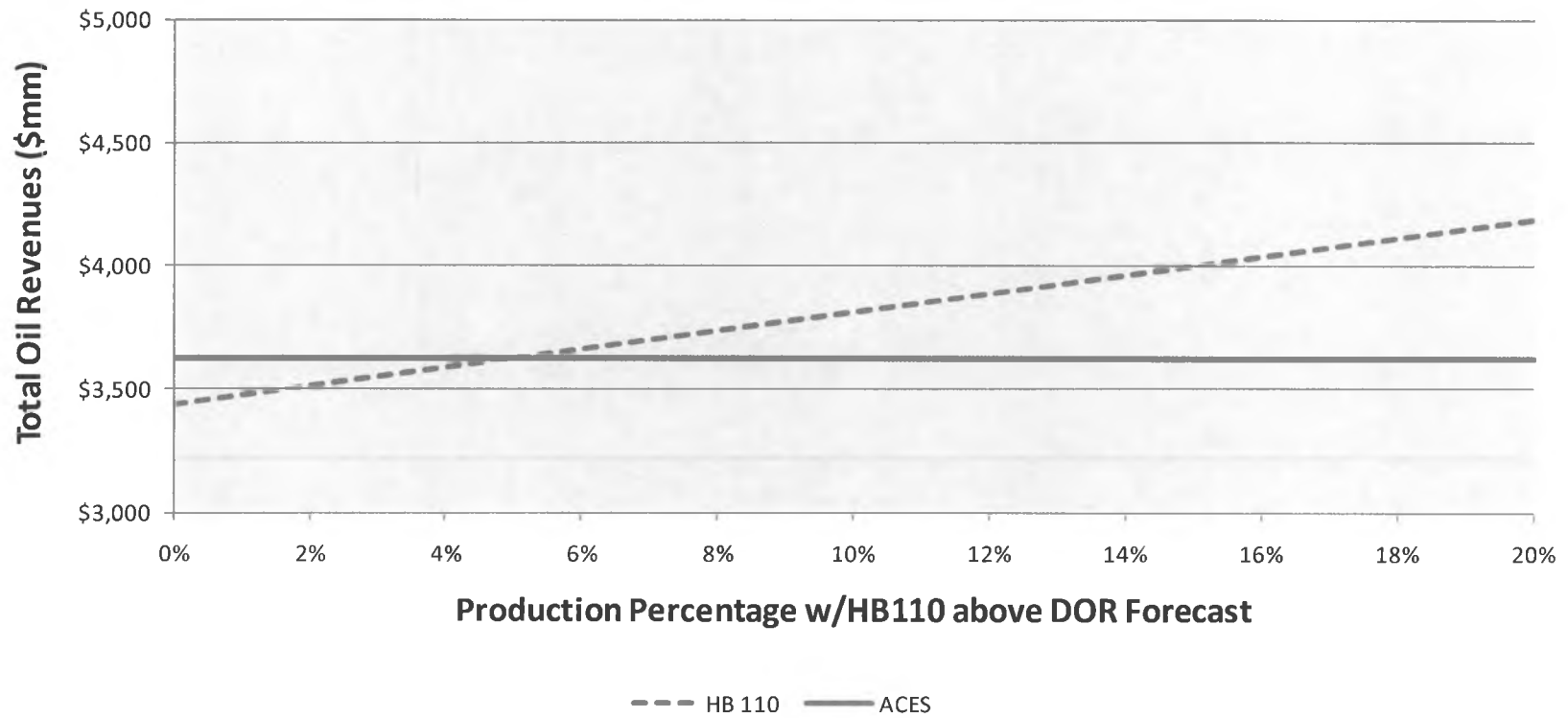
HB110 Production Percentage Production above Forecast
(Includes restricted royalties; without 40% well credit for HB110)



Total Oil Revenues HB110 vs. ACES: 2016 @ \$80/bbl (\$mm)

ACES Production 10% below DOR Forecast

HB110 Production Percentage Production above Forecast
(Includes restricted royalties; with 40% well credit for HB110)

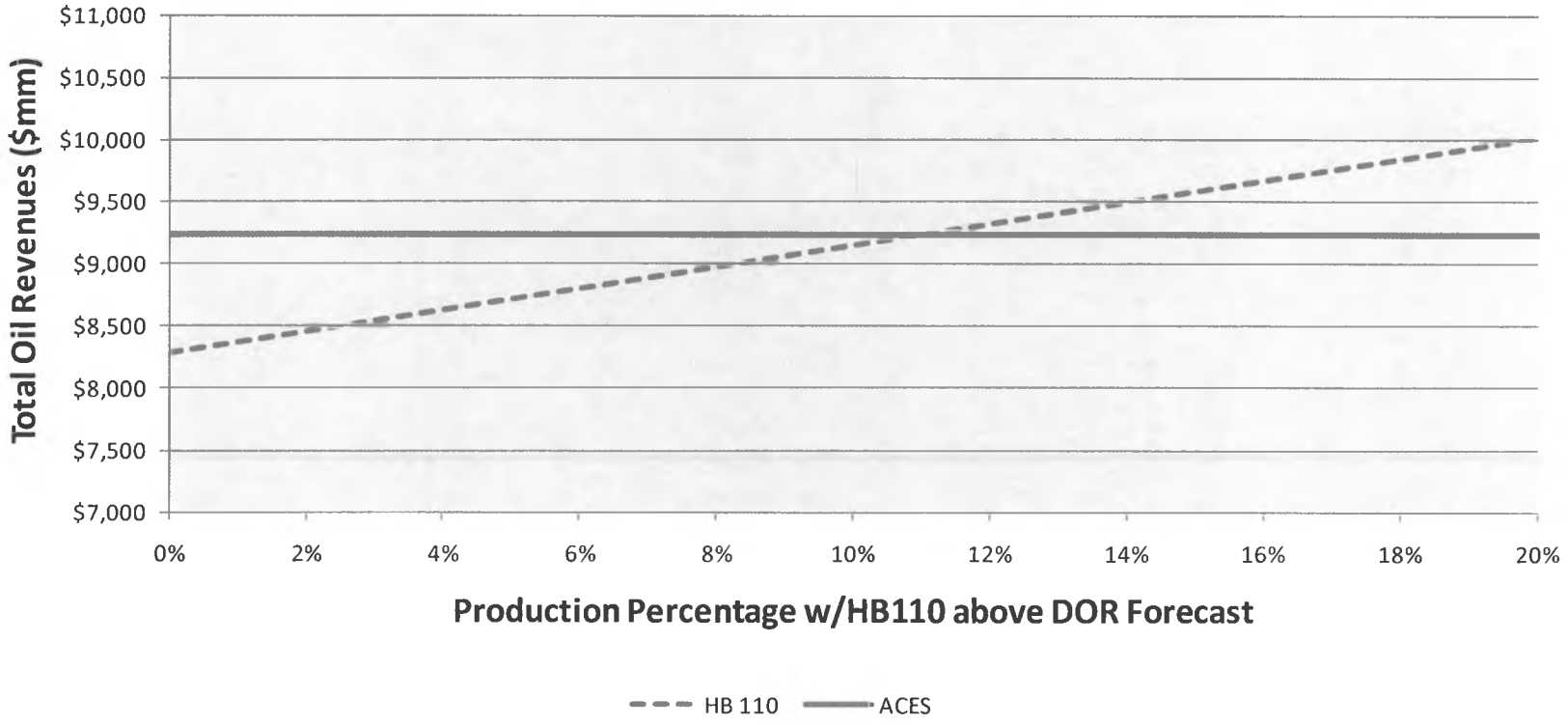


Total Oil Revenues HB110 vs. ACES: 2016 @ \$120/bbl (\$mm)

ACES Production 10% below DOR Forecast

HB110 Production Percentage Production above Forecast

(Includes restricted royalties; without 40% well credit for HB110)

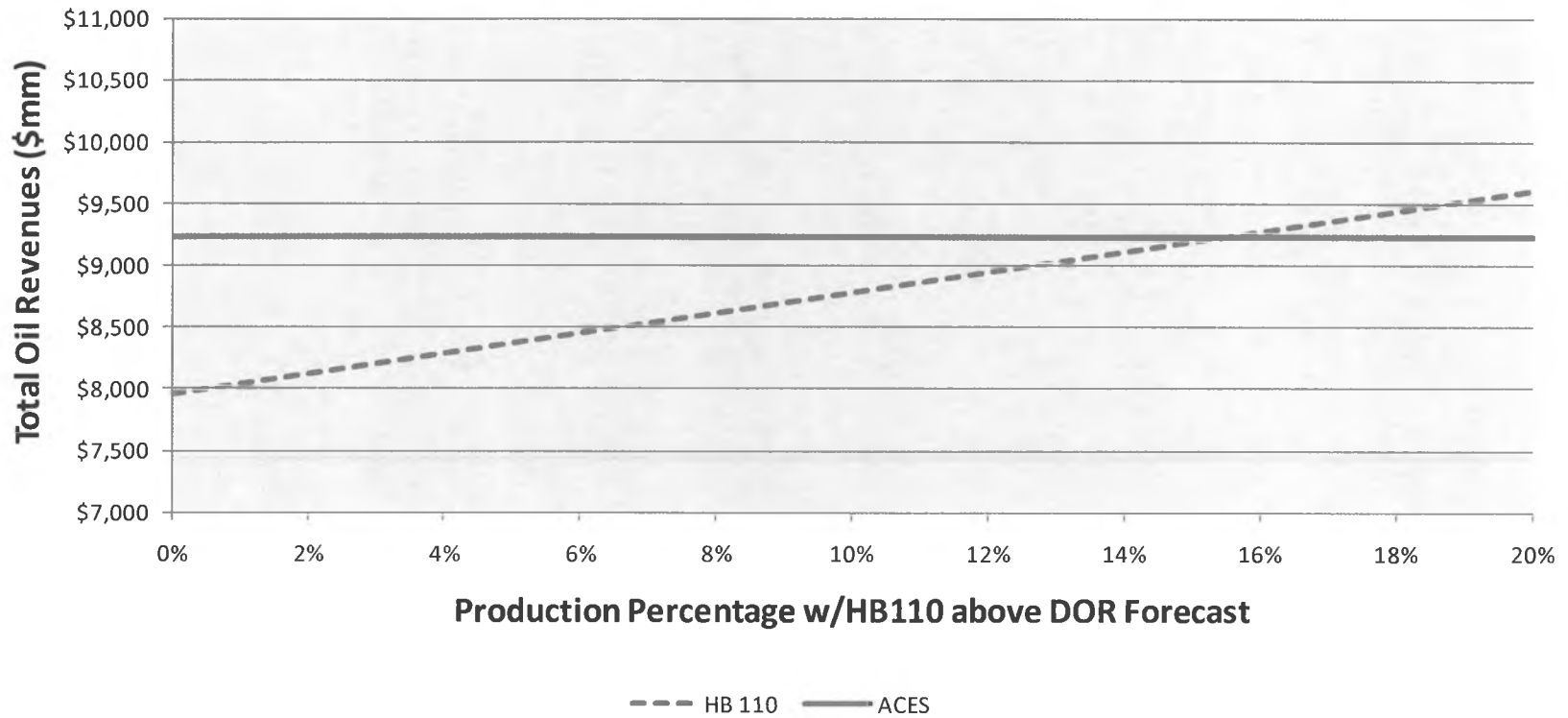


Total Oil Revenues HB110 vs. ACES: 2016 @ \$120/bbl (\$mm)

ACES Production 10% below DOR Forecast

HB110 Production Percentage Production above Forecast

(Includes restricted royalties; with 40% well credit for HB110)



Crossover Points:

Increased Percentage Production where HB 110 Revenues
Exceed ACES Revenues

- Without 40% well expenditure credit
 - \$80/bbl 0%
 - \$100/bbl 4%
 - \$120/bbl 11%
- With 40% well expenditure credit
 - \$80/bbl 5%
 - \$100/bbl 10%
 - \$120/bbl 15%

State of Alaska
Department of Revenue

Commissioner Bryan Butcher



SEAN PARNELL, GOVERNOR

333 Willoughby Avenue, 11th Floor

P.O. Box 110400

Juneau, Alaska 99800-0400

Phone: (907) 465-2300

Fax: (907) 465-2389

March 26, 2011

Representative Les Gara
State Capitol Room 500
Juneau AK, 99801

Re: Answers to questions posed March 16, 2011

Dear Representative Gara:

The purpose of this document is to respond to the questions you raised in our meeting with you on March 16, 2011. The requests/questions and responses follow.

- 1. What would the impact have been had HB110 been in place for the last four Fiscal Years, as well as the first three quarters of FY 2011? Provide an estimate of the fiscal impact of the change from a monthly calculation of taxes to an annual calculation.**

The table on the following page provides our best estimates of the production tax revenue impacts of HB 110 if it were in place in the five fiscal years starting in FY 2007. The estimates consider the impacts of the change in progressivity and the well lease expenditure credit and do not reflect any potential changes in investment or production levels that could have resulted from the lower tax rate in prior years.

Distributed by Rep. Gara 3/26/11

Production Tax Revenue under ACES and the Estimated Impact of HB 110/SB 49 on Production Tax Revenue FY 2007 - FY 2011 (estimated)*

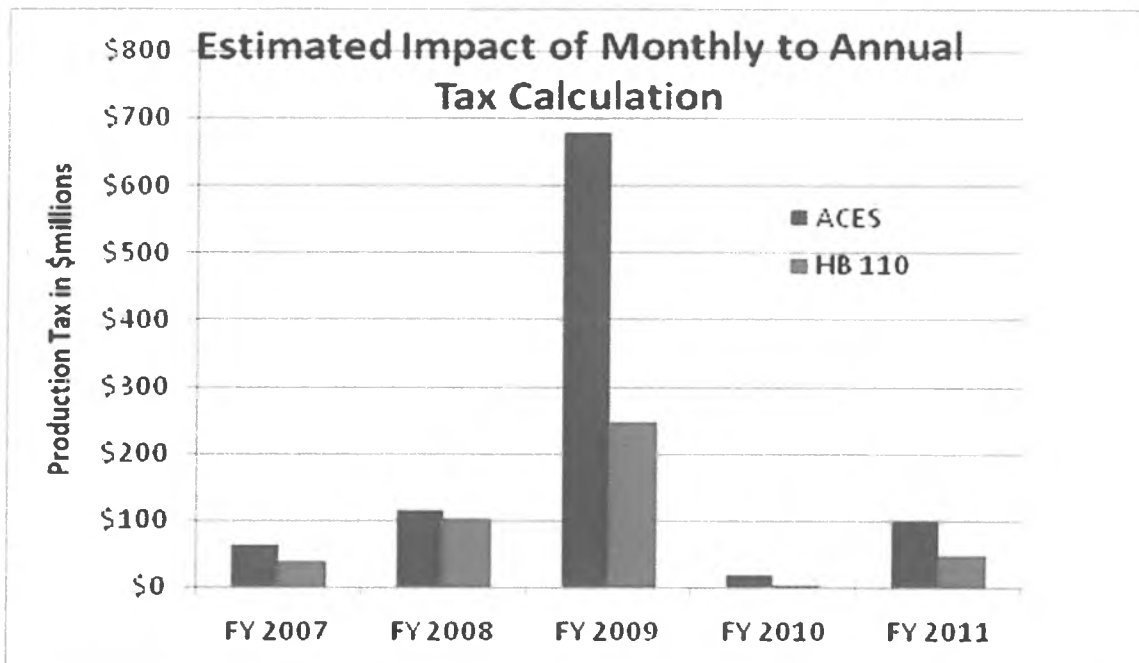
(in \$billions)

| Year | Production Tax Revenue under ACES (PPT in FY07) | Impact of Tax Rate Change | Impact of Well Lease Exp Credit | Total Estimated Impact | Estimated Production Tax Revenue under HB 110/SB 49 |
|---------|---|---------------------------|---------------------------------|------------------------|---|
| FY 2007 | \$2.20 | \$0.25 | -\$0.30 | -\$0.05 | \$2.15 |
| FY 2008 | \$6.81 | -\$2.06 | -\$0.30 | -\$2.36 | \$4.45 |
| FY 2009 | \$3.10 | -\$0.99 | -\$0.30 | -\$1.29 | \$1.81 |
| FY 2010 | \$2.86 | -\$0.60 | -\$0.30 | -\$0.90 | \$1.96 |
| FY 2011 | \$4.32 | -\$1.30 | -\$0.30 | -\$1.60 | \$2.72 |

***Notes regarding this analysis**

This analysis considers revenue impacts of only those provisions of HB 110 and SB 49 that can be reasonably quantified and that are not considered revenue neutral over time (such as the elimination of the credit split). Additionally, because historical models are maintained on a fiscal year basis, fiscal year inputs such as prices, production and costs were used for this analysis, even though annual tax calculations in HB 110 and SB 49 are based on calendar year inputs. For the well lease expenditure credit, we chose a median of the range of \$200 to \$400 million per year as stated in the fiscal note. FY 2007 includes 14 months of production tax; FY 2011 uses actual prices and production through Feb 2011. **This analysis does not consider the likely production increases had HB 110 been in effect.**

The impact of changing from a monthly calculation of the production tax to an annual calculation of the production tax, while significant under the current ACES progressivity structure during years in which oil prices are volatile, is much less significant under the bracketed progressivity structure in HB 110. The following graph provides an estimate of the change from monthly to annual progressivity for the five fiscal years starting in FY 2007 for both the current ACES structure and for HB 110.



*Notes regarding this analysis This analysis considers revenue impacts of only those provisions of HE 110 and SE 49 that can be reasonably quantified and that are not considered revenue neutral over time (such as the elimination of the credit split). Additionally, because historical models are maintained on a fiscal year basis, fiscal year inputs such as prices, production and costs were used for this analysis, even though annual tax calculations in HE 110 and SE 49 are based on calendar year inputs. For the well lease expenditure credit, we chose a median of the range of \$200 to \$400 million per year as stated in the fiscal note. FY 2007 includes 14 months of production tax; FY 2011 uses actual prices and production through Feb 2011. This analysis does not consider the likely production increases had HB 110 been in effect.

A change from monthly to annual progressivity under current ACES law does not always result in less production tax revenue. In a year in which one or more monthly oil prices produce production tax values at or above \$92.50, the monthly calculation could result in less revenue than the annual calculation. Our table below showing hypothetical production and oil prices illustrates this point.

Example of Monthly to Annual Calculation under Current ACES

(Assumes 30 days per month for illustration purposes)

| | Taxable Daily Production (mmb/d) | Price / bbl | Costs / bbl | PTV total (\$M) | PTV / bbl | Tax Rate | Tax Liability (\$M) |
|-----------------------------------|--|----------------|----------------|--------------------|--------------|----------------------------|---------------------------|
| Jan | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Feb | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Mar | 0.600000 | \$150 | \$30 | \$2,160 | \$120 | 52.8% | \$1,139 |
| Apr | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| May | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Jun | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Jul | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Aug | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Sep | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Oct | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Nov | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Dec | 0.600000 | \$120 | \$30 | \$1,620 | \$90 | 49.0% | \$794 |
| Sum of monthly calculation | | | | | | | \$9,871 |
| Calculated Annually | 0.600000 | \$123 | \$30 | \$19,980 | \$93 | 50.0% | \$9,990 |
| | | | | | | <i>Annual over monthly</i> | \$119 |

2. **Provide scenarios showing the fiscal impact of passing HB 110, using Department of Revenue oil price and production estimates, and spending increases based on recent history. Also provide the Department's scenarios showing the impact of increased production if HB 110 passes.**

The Department has prepared fiscal modeling that provides insight into state General Fund revenue, General Fund appropriations, and savings account balances over time, under HB 110 and ACES. We will be presenting this information to the committee in today's hearing.

3. **Provide an revised fiscal note which shows the effects of the monthly-to-annual provisions of the bill.**

As stated by the department several times, we do not forecast price or production on a monthly basis therefore it is not feasible to predict the impacts going forward. We will however be addressing this issue in the fiscal note that will be included in the next committee substitute.

4. **Provide a list of oil companies doing business in North Dakota.**

Please find below a list of the companies currently drilling in North Dakota, according to the North Dakota Department of Mineral Resources, Oil and Gas Division (<https://www.dmr.nd.gov/oilgas/riglist.asp>). This list is not exhaustive, as certain companies who have been investing in North Dakota may not be currently drilling, but this does provide an indication as to the range of companies that are currently active in North Dakota. Note that ExxonMobil and ConocoPhillips are active in North Dakota through their recent acquisitions XTO and Burlington Resources.

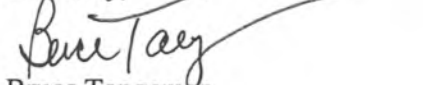
| | |
|--|--|
| AMERICAN OIL & GAS INC ANSCHUTZ EXPL CORP ARSENAL ENERGY USA INC. BAYTEX ENERGY USA LTD BRIGHAM OIL & GAS LP BURLINGTON RES O&G CO CONTINENTAL RESOURCES CORNERSTONE NAT RES LLC DENBURY ONSHORE EOG RESOURCES INC FIDELITY EXPL & PROD CO FRAM OPERATING LLC G3 OPERATING LLC HELIS OIL & GAS CO. LLC HESS CORPORATION HUNT OIL COMPANY KODIAK OIL & GAS (USA) INC MARATHON OIL CO MUREX PETROLEUM CORP NEWFIELD PROD CO | NORTH PLAINS ENERGY LLC OASIS PETRO NO AMER OIL FOR AMERICA OXY USA INC PEAK NO DAK LLC PETRO HUNT LLC QEP ENERGY CO SAMSON RESOURCES CO SBG TIOGA FACILITY SEQUEL ENERGY LLC SINCLAIR OIL & GAS CO SLAWSON EXPLORATION SM ENERGY CO TRACKER RES DEVMNT TRUE OIL LLC WHITING OIL AND GAS CORP XTO ENERGY INC ZAVANNA LLC ZENERGY OPERATING CO LLC ZENITH PRODUCED WATER |
|--|--|

5. **Provide information about royalty relief.**

Royalty relief is one possible tool to help encourage oil production on state land. The royalty program for state lands is managed by the Department of Natural Resources and we understand that DNR has provided the committee with testimony on royalty relief provisions.

We hope our responses fully answer your questions.

Sincerely,



Bruce Tangeman
Deputy Commissioner

Alaska State Legislature
HOUSE FINANCE COMMITTEE

Agenda
5:00 PM

Thursday, March 24, 2011

5:00 PM - 8:00PM*

HB 110-PRODUCTION TAX ON OIL AND GAS

Public Testimony

Statewide and LIO's

*Time contingent upon amount of testimony

Chairman and members of the committee:

My name is Matthew Fagnani, and I am representing myself. I have been involved in the Alaskan oil patch now for more than 20 years. I truly believe that with the current ACES tax policy that we are killing the oil industry years before they would naturally look to other markets to develop.

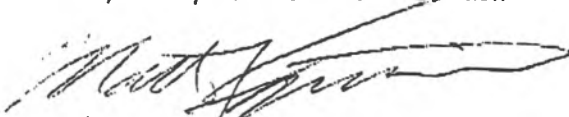
It is my belief that the recession and loss of oil field jobs that Alaska is feeling today is self imposed by the ACES tax regime and regulations. As you all have heard, any new dollars being spent on the North Slope are primarily for maintenance and spill repair. Not from new development, not from new field exploration. This is a bad precedent, and it is having a very negative impact on the service industry jobs of many Alaskans including many personal friends and colleagues.

I agree with the experts who believe that without new production or a new Prudhoe Bay size fielded being discovered, that the Trans Alaskan Pipeline future is in jeopardy. Bottom line is we need more oil in the pipe. That would be a shame knowing that we have known oil that should be developed, yet stymie that development, and our state's future, by onerous fiscal and public policy. It's time to save Alaska from itself.

For years now, I have been a supporter of responsible oil and gas development. In Alaska, we need to start acting like an oil and gas providence. We need to be proud of the fact that companies like ConocoPhillips, BP, ExxonMobil, Pioneer, and other want to work with us in Alaska. However, because we have been shortsighted in our fiscal tax policies, the industry is doing what any other free market entity would do - find a better place to do business. Well guess what? That's what is happening and its negative effect on jobs and our economy is real.

In closing, we need to honor that relationship with the oil and gas industry and realize that a healthy oil industry keep us producing a healthy Alaska.

Thank you for your time and consideration.



Matthew Fagnani
2559 Loussac Dr
Anchorage, Alaska 99517

My name is Jerry McCutcheon and I have followed development on the North Slope for since 1969. I bought property in Valdez before the destination the terminus of the oil line, TAPS, was announced.

When considering HB110 you must consider the best long term interests of the State of Alaska and the veracity of those for whom you propose to give tax breaks in hopes obtaining development of Alaska's resources, which under the lease agreements and the law they are already obligated produce. The duty to produce has been lost in HB110 . The legislature must the weigh the likely hood that anything will come of the gross loss of revenue.

HB110 would never, ever pass the Harvard Business school's risk investment standard. The Harvard risk assessment supports some very high risk gambles. Not only would HB110 would fail the Harvard test but also the oil companies own test of Monty Carlo simulation and decision tree analysis. HB110 would not even get out of the starting gate on the oil companies standards.

I also brought about a Congressional hearing on the then proposed gasline in 1977. The Energy Committee hearing by Senator Henry "Scoop" Jackson was held Oct 30, 1977. Exxon represented the North Slope producers. Public Document 95 -73

At the conclusion of the hearing Chairman Jackson declined to support the North Slope producers 2 bcf/d gasline. Because of serious questions raised about the adverse effects of the gasline on North Slope oil production, which were not only proven to be true thirty years later but also far exceeded the estimated the loss oil by 10 billion and maybe 15 billions of barrels of oil.

Exxon et al peddled the fact Prudhoe Bay would only produce 9 billion barrels of oil with or without a gasline. The lie that the production would be same with

or without gasline flew in the fact of long, well established reservoir engineering.

The Exxon deliberately lied not only to Alaskans but also Sen. Jackson's committee. Exxon wound up Alaskans and the legislature like toys into demanding a gasline just like today. Reason, like today, did not have chance. The mob prevailed until it hit a congressional committee.

What Alaska and Alaskans almost lost came out in the legislative gasline hearings in Anchorage in 2007. The AOGCC, Alaska Oil and Gas Conservation Commission testified that because the gasline, only 2 bcf/d, was not constructed in the 1980s Prudhoe Bay had already produced an additional 6 billion barrels of oil as of 2006 because the 1980s gasline was not constructed with more additional oil to be produced.

The AOGCC also testified that Alaska would be broke today if the 2 bcf/d gasline been constructed. That should have been a sobering thought, but its affect on the legislature is like rain on ducks back. The Alaska Legislature continues to pursue one ruse after another ruse as if throwing money at it would somehow bring whatever it is into being.

Exxon and the other North Slope producers were quite will to render more oil unrecoverable that they were going to produce. Just like the Cook inlet platform producers did to Cook Inlet oil where there is now more once recoverable oil under the platforms that is now unrecoverable than was produced.

Exxon et al and were actively trying to deprive Alaska and the USA billions of barrels of oil.

No Alaska exploratory wells in 2011, company says

The Associated Press

(11/18/10 10:37:20)

FAIRBANKS, Alaska (AP) - ConocoPhillips Alaska has no plans to drill any exploratory wells in the state in 2011.

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ConocoPhillips and BP announced one year ago at the same event that they would trim development budgets for 2010 on the Alaska North Slope.

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"We have some work to do to make sure we ensure we keep oil flowing through the pipeline," he said.

BP Exploration, Alaska, will hold to the same budget this year as last year, president John Minge said Thursday.

Spending around \$800 million on capital, for things like safety programs and new infrastructure, and \$1.3 billion for operations would halt a slide in capital investment.

Minge said capital spending had shrunk 20 percent this year from 2009.

He said BP also sees long-term potential in hard-to-develop viscous and heavy oil resources. The company this year wrapped up a \$100 million heavy oil pilot project at Milne Point.

Information from: Fairbanks Daily News-Miner, <http://www.newsminer.com>

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ConocoPhillips plans no new exploratory wells in Alaska in 2011

[print](#)

by Christopher Eshleman / ceshleman@newsminer.com

11.18.10 - 08:50 am

Updated: 12:05 a.m. Nov. 18

ANCHORAGE — The president of ConocoPhillips Alaska said Wednesday that his company will not drill any exploratory wells in the state for a second straight year.

Trond-Erik Johansen made the statement at the Resource Development Council's annual convention here.

ConocoPhillips and BP announced one year ago, at the same forum, that they would trim development budgets for 2010 on the North Slope, where high marginal costs compound the reality that the easy oil is already pumped.

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That type of viscous oil production would take thousands of wells at 50 development pads, Minge said. The state, however, would need to adapt to that potential with taxes aimed at enabling development, he said.

"We have great opportunities. We have some challenges that aren't too daunting if we grab hands and try to do this together," Minge said.

Contact staff writer Chris Eshleman at 459-7582.

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Page 2 of 5

3/23/2011

Thur. March 24^t

Conoco/Bp Article(Nov. 18th , 2010)

The tenet of HB110 is ;
reverse the decline in oil production.
Conoco and Bp claim that State taxes has prevented
this reversal.

If the answer is tax reduction, then why didn't the
producers explore and develop when there were
virtually no taxes such as ,while ELF was in effect ?
(Tax structure named- Economic Limiting Factor).

Conoco and BP have stated they will maintain North
Slope investments--there will be no increases.
Why would anyone give money away with nothing in
return. No guarantee , not an assurance, nothing that
says "We will fill the Pipe". The only thing we know
right now, because the producers have put that in
black and white, is investment and exploration will
be "Status Quo". They are not putting any more
money into the North Slope than they have for the
last few years. We can believe that.

Incedently, both Bp and Conoco have reported over 7

Page 3 of 5

billion in profits from 2007 through 2010

Why does the Governor want to give his former employer our money when he swore an oath to represent the residents.

No where in either the US. Constitution or The Constitution of the State of Alaska is there language that gives ownership to corporations.

Article 8, section 2 of the Alaska Constitution is concise. There is no question as to who shall benefit from Alaska's resources. "It's People".

Just handing over money would mean reduced Capitol budgets causing;

Reductions in the construction now being realized in the rest of Alaska ,

Renewable energy projects would not go forward, There would be no opportunity to offset high fuel prices,

Basic services would diminish if funds were reduced.

Currently, Alaska is financially positioned better than any other state, giving money away with nothing in return is not prudent. Stewardship calls for careful administration of revenues, depletion now with no return , leaves no future for Alaskans.

Solutions;

Exploration , Production, and Royalty credits require that investment take place in Alaska.

**Pioneer (Oooguruk) and Eni (Nikaitchuq) have enjoyed royalty relief via;
AS38.05.180j**

The first quarter of this year has seen a great deal of activity in seeking both 025 credits (Remote site production relief) and 023 credits (Development-Exploration reductions) [May have come directly from the ACES legislation]

Thoughts;

I don't see where industry can say we are not promoting their opportunities when the major producers have enjoyed huge profits, they've made more money in the last five years than in the previous 20.

Harvesting huge profits while blaming the State for not exploring and developing is a distraction that averts attention from industries' bulging bottom line as well as the increase in spills and shut-downs caused by lack of pipeline maintenance.

Thank you members of the committee, my name is David Gottstein of 733 West 4th Avenue, Anchorage, Alaska. I am the Chief Investment Officer of Dynamic Capital Management, Inc., a Registered Investment Advisory firm, and I have been active in Alaskan oil and gas politics for thirty years.

I can offer to you that I was an active participant in the development of ACES. The net profits approach to taxation offered by ACES provided the State and the oil & gas industry a powerful mechanism in the pricing of our non-renewable oil resources. We want to provide incentives for the oil and gas industry to bring their capital and operational expertise to Alaska in their quest for competitive returns. The ACES platform adds wealth as compared to the old tax on the gross by allowing for the deduction against taxes for later stage higher lifting costs. The mechanisms of a floor tax rate, a base to begin progressivity, and the progressivity itself, allows for a flexible formulaic way to parse out rewards for contributions and risks taken.

We want the oil companies to make competitive returns, and make more money at higher prices. And we don't want our pricing to be too aggressive

such that the oil companies make less money at higher prices. The devil is in the details. Or rather the percentages and base levels embraced.

We also don't want to sell our resource too cheaply. The oil industry acts as a rational gate-keeper that works in our favor, keeping resources stored for higher value. Whereby we both profit from higher prices. Our selling or taxing mechanisms determines the apportionment of those profits.

If a purveyor raises their prices 10%, and they lose 5% of their customers, they are money ahead. If he raises prices by 10%, and loses 15% of his customers, he is money behind. It is extremely important for the State to test where the cusp of too high of taxes or resource selling price is. Independent of what the oil companies say, as legitimate distributors of information with extreme prejudice.

Let me say that ACES and the mechanisms of ACES work. What needs to be fixed is the progressivity level. It is too aggressive. At about \$120-130, even though state taxes are deductible at the federal level, the combination of state and federal taxes crimps the generation of marginal profits at higher prices, and therefore limits

upside potential. We don't want to do that, as the winners have to more than pay for all the losers.

On the other hand, we don't want to sell our resources too cheaply. Because of the inherent power of ACES, the answer to our too high of selling price is elegant, and rationally accomplished.

First, we need to change the rate of progressivity from its current .4% linear step function formula to a less aggressive one that decays in value as oil prices rise. Two examples of possible solutions would be to instead of having .4, .4., .4, .4, perhaps as prices rise, .4,.398, .396, .394 or .4, .395, .39, .385, etc. And we should know how much each would gain or lose us, and change the choke point price where margins for the oil companies gets too this. Whereby if in the future, oil prices rise to a new choke point, the progressivity, or base price where progressivity kicks in, can be raised.

That is how ACES was supposed to work, and how it can be used in a powerful way moving forward. Adjusting the pricing levers within ACES I believe is where the debate should be. Not by throwing out the baby with the bath water, and lowering our resource selling price by tens of billions of dollars willy nilly without proper due diligence. This is

worth tens of billions of dollars over time to the State. And the numbers used in the calculations become the critical price determinants.

I strongly urge you to stick with the ACES platform, and to take the time to study the impacts of adjusting the powerful tools you currently have. Of changing the progressivity to a polynomial rather than a step function in order to price Alaska's gas more competitively, and to apportion profits in a manner that serves all parties. I would also keep the taxation of oil and gas separate, and bring an equally rational mechanism forward to price our gas resources.

03-24-11

Additional Docs in H Finance Email



Alaska State Legislature

Please enter into the record my testimony to the House Finance
Committee name

Committee on HB 110, dated MARCH 24, 2011
Bill/Subject

House Finance Co-Chairs Rep. Stolize and Rep. Thomas, I am unable to attend tonight's public hearing on the subject bill. Therefore, I respectfully request that my written testimony, which follows, be entered in the public record of tonight's hearing on HB110.

First, I wish to thank you and the other members of the House Finance Committee for your service on-behalf of the people of Alaska. The Alaska Legislature is an esteemed institution, and your job of charting a fiscally sound course for our great State is a daunting responsibility.

Second, I am pleased to have this opportunity to submit my testimony, albeit in writing, on HB110. Specifically, with respect to Governor Parnell's proposed tax reductions and incentives to the big oil producers, ConocoPhillips, BP, Exxon, Shell, et al., I have the following concerns and comments:

1. What exactly is the Governor's justification for Alaska giving some the largest, most profitable corporations on the planet tax breaks and incentives to find and produce a product that, by all accounts, is in high demand and for which there is a limited supply globally?
2. By the Governor's own estimation, his tax breaks and incentives to the oil companies will cost Alaska \$5 billion in revenue over the next five fiscal years. Some in the Legislature have estimated that his proposal could cost the State, depending on the price of oil, as much as \$2 billion in revenue annually. Can Alaska afford the Governor's plan? I suggest it cannot.
3. Where are the data, analyses, and oil industry commitments that would lend credibility to the Governor's proposed fiscal strategy for creating more jobs and increasing future oil revenues for the State if his planned is approved by the Legislature?
4. I am just a four-acre farmer, but the last time I checked, the Governor's wishful thinking-cross your fingers approach to fiscal planning is not sound policy. Don't Alaskans deserve a more fiscally prudent plan than our Governor's roll of the dice?
5. To offset his projected loss in State revenue, Governor Parnell proposes that Alaska dip into its savings to cover any deficits necessary to balance its annual operating budgets. Would it not be more prudent to forego his tax breaks and incentives to the oil companies in favor of the more conservative fiscal policy of paying for current year expenditures from current year revenues? Using one-time, non-recurring savings to cover budget deficits, as the Governor proposes, is a slippery slope fiscally.
6. According to the National Petroleum Council's Global Oil & Gas Study, which was made available July 18, 2007, "The major oil and gas companies are increasingly turning their attention to overseas development opportunities, leaving U.S. production largely in the hands of independent oil and gas companies." Proof of this can be seen in North Dakota per that State's active drilling list (see Attachment). So, that being the case, one might ask just how practical is Governor Parnell's proposal to attract more exploration and production activities from the major oil companies, like ConocoPhillips, BP, Exxon, and Shell?

Per the concerns and comments expressed above, I am opposed to HB110 and urge you to vote against it.

Signed: JAMES ELLIOTT
Testifier

Representing (Optional)

JWELLIOTT@AOL.COM
Address

adn.com

Anchorage Daily News

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(11/18/10 10:37:20)

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Information from: Fairbanks Daily News-Miner, <http://www.newsminer.com>

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3/23/2011

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ConocoPhillips plans no new exploratory wells in Alaska in 2011

by Christopher Eshleman / ceshleman@newsminer.com

11.18.10 - 08:50 am

Updated: 12:05 a.m. Nov. 18

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Contact staff writer Chris Eshleman at 459-7582.

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Thur. March 24^t

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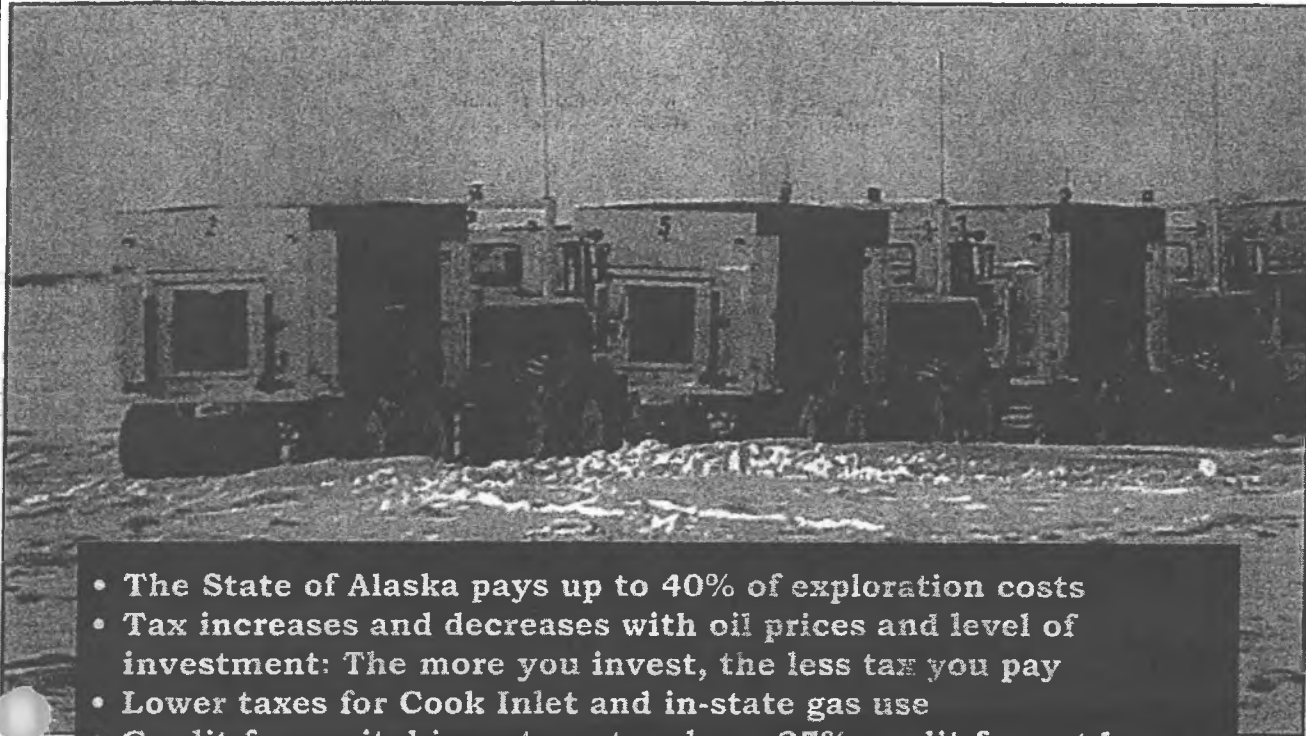
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3/29/11

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

Savant Resources, 2009



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

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

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

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

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

(Brooks Petroleum Corporation, 2008)

Alaska: We’re Open For Business!



Alaska Department of
**NATURAL
RESOURCES**
DIVISION OF OIL & GAS

Division of Oil and Gas
550 West 7th Avenue, Suite 1100
Anchorage, Alaska 99501-3560
tel: 907-269-8800
<http://www.dog.dnr.state.ak.us/oil/>

3/29/11

| Regular UI Claimants Oil & Gas related Industry(s), CY2006-CY2010 | | | | | | |
|---|--|--------------|--------------|--------------|--------------|------------|
| NAICS Sub Sector | Sector Name | 2010 | 2009 | 2008 | 2007 | 2006 |
| 211, 213111, 213112 | All Oil and Gas Industry related claimants | 2,540 | 2,708 | 1,362 | 1,084 | 904 |
| | Weeks Paid | 28,688 | 35,879 | 15,283 | 11,090 | 9,017 |
| | Resident | 2,058 | 2,215 | 1,208 | 928 | 793 |
| | Non-resident | 482 | 493 | 154 | 156 | 111 |
| 211 | Oil and Gas Extraction | 71 | 63 | 12 | 17 | 27 |
| | Weeks Paid | 965 | 861 | 115 | 151 | 367 |
| | Resident | 57 | 51 | 10 | 14 | 22 |
| | Non-resident | 14 | 12 | 2 | 3 | 5 |
| 213111 | Support Activities for Drilling Oil&Gas wells Total | 332 | 413 | 188 | 153 | 121 |
| | Weeks Paid | 3,738 | 6,136 | 1,920 | 1,554 | 1,044 |
| | Resident | 255 | 341 | 170 | 135 | 109 |
| | Non-resident | 77 | 72 | 18 | 18 | 12 |
| 213112 | Support Activities for Oil&Gas operations Total | 2,137 | 2,232 | 1,162 | 914 | 756 |
| | Weeks Paid | 23,985 | 28,882 | 13,248 | 9,385 | 7,606 |
| | Resident | 1,746 | 1,823 | 1,028 | 779 | 662 |
| | Non-resident | 391 | 409 | 134 | 135 | 94 |

Prepared by: Alaska Department of Labor and Workforce Development, Research and Analysis Section, March 29, 2011

R. E. E. V. I. N.

Alaska State Legislature
HOUSE FINANCE COMMITTEE

Agenda

1:30 PM

Monday, March 28 . 2011

HB 110 – Production Tax on Oil and Gas