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**SB 21 and Petroleum Revenue Policy: Six Subjects Requiring Further Consideration
(A Report on Pending Legislation)**

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[Revised]*

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* This revised version of the original report contains the following minor changes to the original, which was distributed April 6:

- Insertion of minor phrasing changes for clarification in Parts A and B of Section 6, as well addition of the final paragraph of Section 6.B (inadvertently omitted from the original version).
- Deletion of a superfluous comment on Exhibit 8 (removed from original draft but inadvertently appended to original report following Exhibit 9).

– RAF, April 8, 2013

SB 21 and Petroleum Revenue Policy: Six Subjects Requiring Further Consideration A Report on Pending Legislation

by
Richard A. Fineberg

This communiqué reviews six subjects associated with state petroleum revenue policy that warrant consideration during current deliberations on SB 21. Footnotes and documents are provided for ease of reference, along with comments based on insights gained by this writer as an observer and participant in state petroleum development issues since TAPS construction.

Tax cut advocates say they are focused on one thing they can fix – tax rates. But they overlook data problems resulting from state failure to compile verifiably accurate numbers on petroleum development, production and transportation costs. In the resulting confusion, the tax policy dialogue is confounded by the absence of clear and comprehensive information.

The geological reality of declining North Slope oil production and the uncertainty of future oil prices have prompted public officials to try to do something to fix this bleak picture. Representatives of the oil industry assure panicked legislators that lower taxes will spur increased production. But they make no commitments. Long story short: The proposed tax cuts may not be necessary and are unlikely to work for this simple reason: Geology rules.

1. Failure to Audit Effectively

Alaska has been unable to complete timely audits of operating and capital costs, which are estimated (a) to have increased by more than 73% since 2006, compared to modest general inflation increase over the same period of approximately 10% and (b) to have reached levels to levels that far exceed estimated Lower-48 costs ([Exhibit 1](#), attached).¹ At least some administration officials do not seem to understand the importance of the confusion created by poorly reported, superficially audited and sometimes inconsistent numbers on petroleum costs, price and the disposition of net revenue (see Section 6). In the ensuing chaos, important factors such as the following are overlooked:

1. Producer-owners can benefit from over-stating field costs, as demonstrated by the TAPS experience documented by the RCA in the TAPS tariff case ([Exhibit 2](#)).²
2. New barrels of oil in the legacy fields do not bear discovery costs; nor is it clear whether the cost of additional facilities in a legacy field (a) exceed the cost of new facilities in an undeveloped field or (b) are reduced by the use of existing infrastructure.
3. Economies of scale that benefit the large legacy fields on the North Slope, often overlooked, figure into producer economics and therefore warrant consideration.

To determine whether the proposed measures will be successful, an important first step is to assure accurate field cost, oil price and petroleum revenue reporting.

¹ For source data and calculations, see Alaska Department of Revenue, *Fall 2007 Revenue Sources Book*, p. 36 and *Fall 2012 Revenue Sources Book*, p. 35; PFC Energy, "Alaska's Days of 'Easy Oil' Are Gone: High Costs and High Government Take Present challenges" (in "Hydrocarbons Fiscal Systems," presented to Senate TAPS Throughput Committee, January 31, 2013, Slide 47) and the data sheet at Exhibit 1.

² See, for example, Regulatory Commission of Alaska, *Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates: Setting Just and Reasonable Rates; Required Refunds and Filings; And Outlining Phase II Issues* (Docket P-97-4, Order No. 151), Nov. 27, 2002, p. 131. (This finding on TAPS overcharges was upheld by the state Supreme Court in 2008, was cited in 2011 in the state Superior Court decision on TAPS property tax valuation and was presented to state Senate Resources Committee in 2012 by Robin Brena, the lead trial attorney in both case. (See Exhibit 2.) .

2. Why Estimated Percentages of Government Take Are Liable to be Inaccurate

In this era of information overload, there is a notable tendency for legislators to rely on simplified charts that may be based on bad data. Without considering data problems associated with oversimplification, note the focus on shares of government take during deliberations on SB 21 ([Exhibit 3](#)). The attempt to compare Alaska to other production areas in terms of the percentage of total net profit the revenue producer pays is liable to distract from fundamental economic and geological considerations. For example:

1. As noted in Section 1, above, Alaska has been unable to complete audits on operating and capital costs, which are estimated (a) to have increased dramatically since 2006, compared to the modest general inflation increase over the same period and (b) to have reached levels to levels that far exceed estimated Lower-48 costs.
2. Also as noted in Section 1, the calculations of company profits treats transportation costs as a deduction from profits, which tariff proceedings have shown are often significantly overstated, thereby (a) reducing production tax payments to the state and (b) enabling TAPS owners to shift those profits from one pocket to another (production arm to transportation arm) as shipper-owners, while competitors pay those costs to the owners out of pocket.
3. Percentage figures on government take assume federal income tax payments at the nominal 35% rate for pre-tax net profits, but tax deductions frequently lower that tax rate significantly. For example: [a] in some years ExxonMobil's deductions for foreign tax payments bring its domestic federal income tax to zero; and [b] a former North Slope official has estimated his company's North Slope federal income tax at 21% ([Exhibit 4](#)).³

For these reasons, the percentage measurement of government take may not be a reliable indicator of what the industry gains from investment. Moreover, the industry's primary concern is its bottom line and the rate of return on investment, but the percentage of government take doesn't tell you anything about the relationship between project investment and project pay-off. That's another reason the computed percentage of government take may be an unfortunately blunt tool for assessing Alaska's competitiveness.

3. Questionable Accounting Practices: What Is Going On Here?

In an introductory chapter to a 2007 book he co-edited on multinational oil corporations and resource development, Nobel Laureate Joseph Stiglitz portrayed Alaska as the poster-child of corporate cheating. Stiglitz's discussion of Alaska and the oil industry was based on his first-hand experience as a consultant to the state on Alaska royalty litigation during the 1980's. He wrote:

By overestimating their costs by just a few pennies per gallon (and multiplying those pennies by hundreds of millions of gallons) the oil companies would increase their profits enormously. They could not resist the temptation.

They also found other ways to cheat, such as selling their oil to their own subsidiaries, recording a lower than fair market value (see chapter 4 [of *Escaping the Resource Curse*]); or using other subsidiaries to ship their oil out and then reporting fictionally high shipping cost. Each piece of the cheating was hard to detect.⁴

³ For additional discussion of estimated federal income tax rates on North Slope production, see Richard A. Fineberg, *The Profitability and Economic Viability of Alaska North Slope and Associate Pipeline Operations*, Prince William Sound Regional Citizens' Advisory Council (April 2005), pp. 55-58.

⁴ Joseph E. Stiglitz, "What Is the Role of the State?" Macartan Humphreys, Jeffrey D. Sachs and Joseph E. Stiglitz (eds.), *Escaping the Resource Curse* (Columbia Univ. Press, 2007), pp. 24-25 (footnotes omitted).

When the preceding passage was published, Alaska state settlements were running at a four-year average of \$25.7 million per year; since then, settlements have increased ten-fold, averaging \$267.17 million per year between FY 2007 and 2012 ([Exhibit 5](#)).⁵

The significantly increased level of revenue underpayment collections since 2006 should be examined to determine the nature of those underpayments and their cause.

Without jumping to the conclusion that the sharp increase in underpayments constitutes a reason to change the petroleum revenue fiscal system, underpayments should be examined on a case-by-case basis to determine whether the creation of new payment categories would increase confusion, increasing the probability of underpayments while making them more difficult to identify and correct.

It is also reasonable to ask:

Would improvement of the audit process result in accelerated collection of revenue underpayments?

Would settlement amounts be significantly higher if the audit process were functioning effectively?

4. Implementation of Gross Revenue Exclusion Introduced in CSSB 21(FIN), Version Y, March 14, 2013

CSSB 21(FIN) was introduced Thursday, March 14 and passed out of Senate Finance that day in an unusual evening session. One of the changes from the previous version of this bill is in Sec. 30, at p. 22, where the proposed amendment to AS 43.55.160 adding language to the new subsection (f) at clause (3), lines 12 through 19; the same language appears in the version now in House Resources at Sec. 29 of CSSB 21(FIN) am(efd fld) at p. 21, line 17 through p. 22, line 1. This new language replaces the “participating area” requirement with language requiring that the new oil subject to the 20% gross revenue exclusion (GRE) must be accurately metered and measured by the operator to the satisfaction of the commissioner of Natural Resources and that the metered well must drain a reservoir or portion of a reservoir that was not contributing to production before January 1, 2013.

This new procedure warrants careful review to make sure that: (a) an operator will not elect not to produce old oil because the operator would rather receive the GRE; (b) the oil produced by a well qualified for the GRE is coming from a portion of the reservoir that would not have been produced without the GRE; and (c) the state expense of field monitoring this inherently complicated subsection is covered by a carefully analyzed fiscal note. The answers to these questions depend heavily on informal assessment by administration personnel. In this regard it must be noted that testimony of Department of Revenue officials before the House Resources Committee on Friday, March 22 regarding auditing issues raises concerns that administration officials may not be fully cognizant of the difficulties of implementing the legislation they are proposing. (See discussion of auditing issues in Section 6.) The fact that past oil and gas legislation that has not worked out as some legislators intended⁶ underscores the need to review new proposals for administrative practicality, fiscal effects and unintended consequences.

While I have not had the opportunity to review modifications to SB 21 such as those proposed by the administration before the House Resources Committee April 2 and 3, I believe that similar caveats apply.

⁵ See Alaska Department of Revenue, *Fall 2012 Revenue Sources Book*, p. 96 and data sheet attached to Exhibit 5.

⁶ See, Senator John Coghill's candid remarks on the capital credits provision of ACES at the Senate Majority Press Availability (Juneau), March 5, 2013 (http://www.360north.org/gavel-archives/?event_id=2147483647_2013031064).

5. Obscuring Federal Securities and Exchange Commission (SEC) Data: A Case Study in Two Parts

A. ConocoPhillips Historical Profitability Data (“Hurricane Gulch” Chart)

ConocoPhillips economic data on Alaska petroleum economics, as reported annually by the company to the federal Securities and Exchange Commission (SEC), enables analysts to cut through conflicting claims about North Slope profitability.⁷ Since 2005, I have occasionally prepared and presented these data for consideration. For example, in a 2011 report I compared CP’s remarkably consistent Alaska profits during the first years of the ACES cost-based production tax to that company’s erratic global performance, which included a dramatic, multi-billion-dollar loss in 2008. I referred to this graphic as the “Hurricane Gulch chart” because CP’s Alaska profits since 2006, when graphed, resemble the Parks Highway crossing over that dramatic ravine, while the company’s global loss in 2008 of approximately \$16 billion looked like the bottom of the gulch.

When I updated the “Hurricane Gulch” chart in October 2012 for publication in newspaper opinion columns in the *Anchorage Daily News* and *Fairbanks Daily News-Miner* ([Exhibit 6](#)), CP Vice-President for External Affairs Scott Jepsen responded, presenting a chart that removed the graphic line showing his company’s 2008 global earnings nose dive ([Exhibit 7](#)).⁸ The revised chart replaced CP global profits data with lines showing the oil price and the company’s estimate of the growing Alaska share of net income at high prices. Although I thought this substitution was a self-serving distraction from focus on the company’s bottom-line profits on investment. But I did not discover the significant defects in the substituted chart information until CP used the same graphic in testimony before both the Senate and House Resources Committees, on Feb. 20 and March 26 of this year ([Exhibit 8](#)).⁹

As presented to both Resources Committees, the revised chart (“Earnings Per Barrel – ConocoPhillips Alaska and State of Alaska”) appeared directly below a bar chart, “Government and Industry Marginal Share in Alaska” in a slide headed, “North Slope Investment Challenges.” While percentage shares of net revenue are liable to be misleading for reasons summarized in Section 2, above, marginal revenue indicators are liable to take viewers even further away from the bottom-line cost and profit data that form the basis for assessing company profitability. Moreover, neither chart on the CP slide provided information on the costs that must be subtracted to determine the net revenue against which investment is measured to determine profitability. CP also failed to provide supporting information for its graphic depiction of the Alaska share, which was once again displayed in the lower chart, soaring above CP profits, in tandem with oil prices.

On March 26, CP used the chart to help frame tax issues for the House Resources Committee. Discussing that chart, Vice President of Finance Bob Heinrich said “The effects of progressivity and the high marginal tax rates are best illustrated through the CP Alaska earnings.” According to Heinrich, the slide showed that between 2007 and 2011 Alaska took “nearly all that upside... through the progressivity feature of ACES, which is represented by the orange line . . . on a per-barrel basis” as prices moved between \$60 and \$110 dollars per barrel but CP earnings hardly moved, staying between \$22 and \$25 per barrel. In contrast to Heinrich’s statement that CP earnings “hardly moved between 2007 and 2011, back in November, CP’s Jepsen wrote – and

⁷ The SEC requires oil companies to report financial data from regions in which they are heavily invested. CP, which is a large company but smaller than ExxonMobil and BP, is the only major North Slope producer required to break out detailed information on its Alaska operations under these requirements.

⁸ Richard A. Fineberg, “Oil profits weather ‘Hurricane,’” *Fairbanks Daily News-Miner*, Oct. 14, 2012, p. F2 (Community Perspective); Scott Jepsen, “The numbers show why oil tax reform is needed,” *Fairbanks Daily News-Miner*, Nov. 2, 2012 (Community Perspective). (See Exhibit 7.)

⁹ ConocoPhillips Alaska, “ACES Observations” (in “SB21,” presented to the Senate Resources Committee, February 20, 2013, Slide 8 and “CSSB21,” House Resources Committee, March 26, 2013). (See Exhibit 8.)

the chart he submitted to the press indicated – that over that period ConocoPhillips' net income from Alaska "increased from about \$22 per barrel to about \$25 per barrel."¹⁰

The fact that CP has used this chart to present inconsistent versions of the company earnings is only one of the problems associated with this chart. On review, it appears that the key figures associated with this chart simply don't add up. Here are two basic problems:

- The data displayed in the October 2012 press version of the chart indicated that between 2007 and 2011 the state share of net profits rose to take \$51 per barrel at an average price of \$106 per barrel. When these figures are coupled with the Department of Revenue's field costs of \$21 per barrel and transportation costs of \$9, the state's share of \$25 per barrel consumes the entire \$106 per barrel. But where were federal income tax payments? At the 35% nominal federal income tax rate analysts use to compare net revenue shares, the federal government would have taken approximately \$13.50 per barrel out of the \$106 per barrel average price.¹¹ Did CP pay no federal income tax in 2011 due to previous losses, or could CP's chart – and the company's vice president of finance – have mis-stated the facts when CP stated that Alaska's share of net revenue was \$51 per barrel?
- Comparison between CP's reported per-barrel revenue to the total petroleum revenue the state reported receiving in 2011 in the Fall 2012 *Revenue Sources Book* shows that CP estimate of state revenue exceed state figure by significant amounts; I estimate that CP's chart indicated industry payments to the state on North Slope production of somewhere between \$0.6 billion and \$2.8 billion more than the state reported receiving in 2011. Due to CP's lack of supporting data and idiosyncrasies in the state's fiscal year system, I have not been able to identify either the cause or the exact amount of the discrepancy between CP and state figures.¹²

(For more information on these problems, see the data sheet for Exhibit 8, which immediately follows those exhibits.)

While it may be the case that the level of progressivity at high oil prices under ACES needs to be adjusted, the data problems identified here suggest that the simplified charts being used in Juneau may not provide a reliable basis for estimating effects of proposed tax changes. In this chart, for example, ConocoPhillips replaced historical information on its annual profits reported by the company to the SEC, with graphics on estimated Alaska revenues that were (1) presented without supporting hard data, (2) apparently erroneous in significant respects and (3) inappropriate for understanding of company investment outcomes, which cannot be meaningfully assessed without information on field costs and bottom-line earnings.

¹⁰ "The numbers show why oil tax reform is needed" and accompanying chart (see Exhibit 7).

¹¹ The federal income tax and income tax base can be calculated from an after-tax profit using the following formula: Tax base = ([after-tax profit]/[1-[tax rate]]). In this case, assuming a per-barrel after-tax profit of \$25.00 and a tax rate of 35%, the pre-tax income would be \$38.46 and the federal income tax would be \$13.46 per barrel.

¹² The state's peculiar habit of presenting petroleum revenue on a fiscal year basis makes it difficult to compare state information to other data on petroleum economics, which is generally reported on a calendar year basis. For this analysis, I assumed that payments for CY 2011 would fall somewhere between FY 2011 and FY 2012 totals; ADOR data, as reported in the 2012 *Revenue Sources Book* show total petroleum revenue in FY 2011 of approximately \$8.3 billion; petroleum revenue collections paid at \$51 per barrel would have generated more than \$11.1 billion; for FY 2012, the state reported receiving \$10.2 billion in petroleum revenue, but receipt of \$51 per barrel would have produced nearly \$10.8 billion. (In order to estimate per-barrel shares of production revenue from the *Revenue Sources Book*, it is necessary to make sure that company payments that fall into the state's restricted funds category – e.g., royalties dedicated to the Alaska Permanent Fund and property taxes collected on behalf of municipal governments [often omitted from ADOR petroleum revenue figures because they are not unrestricted General Funds available for appropriation] – are included, while company payments to the Constitutional Budget Reserve Fund are not included.)

B. ConocoPhillips Future Profitability Estimates

SEC also asks companies required to file annual 10-K reports to present, in standardized form, company estimate of future costs and returns from the major producing regions in which the company is invested; for CP, one of those regions is Alaska. To permit comparison with other firms by investors, the SEC requires that the forward-looking analysis must be presented in terms of the fiscal regime and continued oil prices in place at the end of the current year. In the 2011 report and my October 2012 newspaper columns mentioned above, I also reported that analysis of these CP's filed data indicate that the company anticipates that Alaska, under the ACES tax regime, will outperform all other regions in the company's global portfolio in terms of return on investment.¹³ In his response, which appeared under the distracting and apparently erroneous chart discussed in the preceding section, Jepsen wrote:

Those who want to leave ACES unchanged frequently cite ConocoPhillips' earnings reports to support their arguments by comparing ConocoPhillips' Lower 48 earnings to its Alaska earnings. (*Editor's note: See Richard Fineberg, Daily News-Miner, Oct. 14, page F3*) But that is an apples-to-oranges comparison. In the Lower 48, natural gas and natural gas liquids make up a large part of ConocoPhillips' portfolio. Those products have lower value and margins than oil, especially after recent steep declines in natural gas prices. Conversely, the vast majority of our production in Alaska is oil, which has a relatively high value. This type of comparison to the Lower 48 provides no real insight into the relative health of Alaska's investment climate.

A better measure is capital investment,,,,

The CP vice-president's arguments do not answer the fundamental questions raised by the data his company presented to the SEC:

If CP did not anticipate strong future returns from Alaska, how could his company report its expectation, under the ACES regime, that this region will outperform all other regions?

Others followed Jepsen in arguing that CP's high ranking of its North Slope petroleum operations should be dismissed as an apples-to-oranges comparison because Alaska's strong economic performance is not hampered by the less attractive economics of natural gas. In response, it should be noted that the "Hurricane Gulch" chart was explicitly designed to show the contrast between CP's strong Alaska performance and the company's natural gas failures elsewhere.¹⁴ The fact that CP's Alaska North Slope holdings under the ACES regime rank first among the company's annual analyses of the future performance of global regions affirms the conclusion that Alaska's petroleum economics are unusual, if not unique.

As for Jepsen's assertion that capital investment would be a better economic measure: This argument might be worthy of consideration if North Slope development took place in theory. But not in the real world, where the three major North Slope producers can withhold investment to get a better deal from Alaska. Consider in this regard another slide that Jepsen and Heinrich presented in their February 20 testimony, following the company's profits charts discussed in Section 5.A., above. According to the follow-up slide, "ConocoPhillips Capital Allocation," in the last three years CP's "Investment has remained flat in Alaska," while "Investment has tripled in the Lower 48" ([Exhibit 9](#)). In response to this argument, the following questions should be asked

¹³ For CP data on Alaska current and future operations, as filed with the Securities and Exchange Commission in January 2011, see Richard A. Fineberg, [Establishing a Rational Foundation for Review, Formulation and Implementation of Alaska's Oil and Gas Fiscal Policy](#), April 7, 2011 (rev. April 2012), pp. 5-7 and Appendix A (historical data) and pp. 33-41 and Appendix D (future profitability).

¹⁴ It was natural gas that created CP's global losses, displayed in the "Hurricane Gulch" chart. Moreover, the article introducing that chart explicitly noted that "In contrast to ... excellent returns from Alaska, overall CP suffered a severe profit collapse in 2008 due to a loss attributed to natural gas investments in the Lower-48 that went sour as natural gas prices crashed" (see Exhibit 6).

– and answered – with substantive data and careful consideration to help resolve confusion regarding the economic attractiveness of North Slope exploration and development:

Does North Slope oil (benefiting from economies of scale and advancement on the economically important learning curve, and from significant infrastructure in place) enable the major producers at the legacy fields to continue to invest profitably at a lower level in Alaska than in the Lower-48, thereby continuing to compete with the Lower-48 investments?

Even if sweet spots in the Lower-48 temporarily out-perform North Slope legacy fields (perhaps in small volumes and/or for short periods of time), what would prevent CP from accepting a major Alaska tax cut, then using that revenue to invest in those sweet spots, when they might be willing to continue long-term investment in the North Slope (perhaps with a minor, modest correction to ACES)?

The history of large oil field development suggests that at some point – perhaps soon, perhaps (say) 20 years from now – the major producers may abandon their declining legacy fields, leaving the North Slope to producers experienced in coaxing smaller production quantities from the legacy fields and companies eager to explore.

Under these circumstances, does it make sense for the state to reduce taxes in hopes of inducing major oil companies to stay, instead of assuring a level playing field for independent developers?

To assure that level playing field, on which independent developers might to invest in Alaska, the state should focus on audit completion to ensure that independent companies are not handicapped by (1) continued overcharges by the TAPS owners on pipeline shipments (income omitted from most “Alaska share” analyses, which treat transportation as a cost and ignore its profit component) and (2) overcharges at legacy field facilities. Put otherwise:

Have state agencies developed audit procedures to identify and correct (1) transportation overcharges and (2) North Slope field facility overcharges?

6. Department of Revenue Representations to House Resources Committee March 22 Regarding Audits: Another Case Study in Two Parts

As the House Resources Committee welcomed senior Department of Revenue personnel to begin dealing with what Co-Chairman Eric Feige called “the long-awaited oil and gas production tax bill” March 22, there were some revealing moments. The fact that misinformation about audits from went uncorrected during that hearing provides another indication that members of the House majority leadership were no better informed than their counterparts in the Senate about petroleum audit problems and their significance.

A. Federal Transportation Regulations Cause Amended Tax Returns That “Go Both Ways”

Mike Pawlowski, who advises the department’s commissioner on oil tax issues, was walking the committee through the of the amended version of SB 21 that had just arrived in the House. The first change to provisions discussed March 22 was a reduction in interest rates on delinquent taxes. House Democratic minority member Rep. Chris Tuck asked whether lower interest rates on delinquent taxes might lead corporate tax payers to be “a little bit loose” calculating their taxes, Pawlowski balked at the use of the word “loose.” Noting that the deputy commissioner could talk about audit under-payments and over-payments, he observed, “it goes both ways.” For example, Pawlowski continued, transportation regulations at the Federal Energy Regulatory Commission (FERC) recently led to amendments to tax returns. The federal government, he said, can change tariffs, resulting in changes to taxes that were paid over time. “And in a complex net system where the tax rate varies monthly,” he continued, “an outside action by a federal agency could

have an impact on tax payments going back years.” Returning to the theme that it goes both ways, he noted that “both the state and the industry’s at risk on that type of thing.”

In portraying changes in tax payments as revenue-neutral matters that occur due to regulatory changes that cut both ways, Mr. Pawlowski’s assessment of the petroleum revenue collection process seems to fly in the face of the facts that include::

- (1) the history of TAPS tariff overcharges and resulting state underpayments, cited in Section 2, above (see Exhibit 2); and
- (2) the increase since 2006 of revenue settlement payments to the Constitutional Budget Reserve Fund (see Section 3 and Exhibit 5, sheet 3)

Pawlowski repeated that he preferred to let Deputy Commissioner Tangeman talk about the audit issue; Co-Chair Feige asked Tangeman to “shed some light on that.”

B. Misconceptions About Audits That “Couldn’t Be Further from the Truth”

Deputy Commissioner Bruce Tangeman shed light on this subject by offering the following comments:

“There’s a lot of misconceptions out there right now regarding audits. . . . since we’re auditing 2007, the misconception is that we have no clue what happened in 2008, 09, 10, 11 or 12. And it couldn’t be further from the truth.” Because oil companies pay taxes monthly, he continued, “we receive a vast amount of information on a monthly basis, and all an audit is, merely . . . a true-up of the previous twelve months of information we’ve already received . . . we have information from last month, two months ago, let alone 2007, 2008. So I’m glad I had the opportunity to get that on the record, that we have a vast amount of information from the monthly tax payments and it is in their best interest to be as accurate as possible. And it’s in our best interest to do a review of those monthly payments to make sure they’re accurate as possible. And then, in that true up that’s done on the 13th month, again we look at the previous 12 months . . . and then it gets in the cue for the audit.”

The deputy commissioner’s discussion of the petroleum audit process reflects an apparent lack of recognition of

- (1) the importance of quality assurance measures to verify the results of petroleum reporting audits; and
- (2) the distinction between narrowly-focused financial audits and broader audits that seek to shed light on the effectiveness and the consequences of the activities under review.

When asked if he had noticed systematic underpayment of taxes, Tangeman responded:

“They seem to be fairly accurate and they go both ways. As Mr. Pawlowski mentioned, there are some over-payments, some under-payments, and that is why it’s a two-way street for the interest rate provision.”

Rep. Tuck asked: Are we able to make corrections month by month? Tangeman responded:

“The monthly payments are an estimated payment. They estimate their capital and operating expenditures, so you’re automatically going to see pluses and minuses month to month. They are not going to be large swings but you are going to see a natural plus give and take month to month.”

These responses from the Department of Revenue representatives in the March 22 House Resources Committee hearing reflect lack of recognition of the history of significant pipeline tariff overcharges and revenue underpayments (noted in Section 1; documented in Exhibit 2), as well as the significant increase in revenue settlements paid to the Constitutional Budget Reserve Fund since 2006 (noted in Section 3; documented in Exhibit 5).

7. Conclusion and Recommendation: SB 21 Is Not A Practical Measure. Nor Does the Percentage of Government Take Work. Fix Data Systems First.

The issues discussed in this communiqué reflect the importance of understanding the complexity of (a) geological structures below ground and (b) organizational (industrial and government) structures above the ground. Both subjects require common sense and judicious application of economic data to the inherently complex situation Alaska now confronts. In the current, panic-prone situation, SB 21 represents a false hope that is neither practical nor adequately supported by the available data on North Slope production.

North Slope production decline is a geological reality, while the rise of Lower-48 investment in new shale oil and gas results from geology, technological innovation and high oil prices. Against this backdrop, review of Alaska's petroleum litigation history reveals that teams of industry personnel are well paid to help their companies to maximize the company bottom line. To serve the public interest under these circumstances, legislators would be well advised to pay careful attention to the details of the changes to petroleum revenue system they propose to enact.

In 2006, when Alaska switched its production tax base from the price of oil to the price of oil minus costs, some observers (this writer included) wondered whether the state would be able to audit production costs to assure compliance and evaluate the performance of the new, cost-based production tax. No worries, senior Department of Revenue personnel responded at the time; the Revenue Department was said to be quite capable of auditing. Moreover, oil and gas litigation was no longer a problem but was merely an artifact of the past, caused by the fact that during the 1970's our relatively young state was dealing with unprecedented oil price spikes.

However well-intended they may have been, in 2006 Revenue Department personnel were wrong: As the Legislature now knows, despite those assurances, the department has not been able to complete audits of cost-based taxes since 2006, while production costs have escalated dramatically, far exceeding both Lower-48 cost increases and the modest general inflation effect (see Section and Exhibit 1). During this period, petroleum revenue settlements have increased ten-fold. (See Exhibit 5, Source Sheet 1.) In this regard, as discussed in the preceding section it should be noted that financial audits are much simpler than performance audits that look at the operation under review in terms of its efficiency and its results. For these reasons, in dealing with petroleum policy, the Legislature would be well advised to examine litigation cases to determine the sources of contention.

Some legislators seem to equate getting rid of progressivity with simplicity. But because SB 21 retains a net profits tax system, this bill still requires cost accounting to determine the tax base. Moreover, this proposed bill also introduces new accounting systems with various new technical provisions that would make both the implementation of the statute and the reckoning of its financial effects more difficult to accomplish. Consider, for example, the gross revenue exclusion tax break allowed by Sec. 29 of CSSB 21(FIN) am(efd fld). Will this new tax break induce producers to claim that oil is new, rather than already existing? Have the technical difficulties of determining whether an oil source is actually new, or whether the industry simply got around to producing from an existing source, been carefully examined? In view of the history of petroleum litigation, putting this provision into law without assurance that it will not generate more litigation seems like a potential recipe for litigation disaster.

Corporate federal income taxes vary from the nominal 35% rate to zero (and sometimes even negative tax with rebates) and production costs increase at rates somewhere between inflation and the volatile price of oil. Since the percentage of government take is dependent on these variables, it makes little sense to rely on the percentage of government take as a benchmark for fiscal policy. On the other hand, once we have obtained a solid understanding of costs and profits under the state's existing tax structure, the principal problem – that ACES may take too much of the marginal gains at high prices – can be corrected with a very simple statutory adjustment to the progressivity regime.

LIST OF EXHIBITS

- Exhibit 1. North Slope Field Cost Increases**
- Exhibit 2. Trans-Alaska Pipeline System Overcharges**
- Exhibit 3. Average Government Take**
- Exhibit 4. Nominal v. Actual Federal Income Tax Rates**
- Exhibit 5. Prof. Joseph Stiglitz on Corporate Conduct in Alaska
(Supplement: Current Constitutional Budget Reserve Fund
Settlement Payments)**
- Exhibit 6. “Oil profits weather ‘Hurricane’,” *Fairbanks Daily News-Miner*,
Oct. 14, 2012**
- Exhibit 7. “The numbers show why oil tax reform is needed,” *Fairbanks
Daily News Miner*, Nov. 2, 2012**
- Exhibit 8. Filling the Gaps: ConocoPhillips Presentations to Senate
Resources and House Resources Committees (Feb. 20 and Mar.
26, 2013)**
- Exhibit 9. ConocoPhillips Capital Allocation (Slide)**

Exhibit 1.

North Slope Field Cost Increases

North Slope Field Cost Increases

North Slope Field Cost Increases (2006 v. 2012)

[Exhibit 1 Data Sheet]

Estimates of Current North Slope v. Lower-48 Field Costs

[Exhibit 1 Source, Sheet 1]

ADOR Fall 2007 Revenue Sources Book, p. 36

[Exhibit 1 Source, Sheet 2]

ADOR Fall 2012 Revenue Sources Book, p. 35

[Exhibit 1 Source, Sheet 3]

North Slope Field Cost Increases (2006 v. 2012)

Exhibit 1 Data Sheet

1. Estimated North Slope Field Costs, FY 2007 (History)	\$3,659,000,000 (1)
2. Estimated North Slope Field Costs, FY 2013 (Forecast)	\$6,341,800,000 (2)
3. Percentage Increase (FY 2013 v. FY 2007)	73.3% (3)
4. CPI-U Indexed Inflation Factor (2007 – 2012)	9.2% (4)
<hr/>	
5. Current Lower-48 costs per barrel (operating + capital)	\$6.00 - \$22.00 (5)
6. Current Alaska costs per barrel (operating + capital)	\$32.00 - \$49.00 (5)
<hr/>	

Sources and Notes:

(1) Alaska Dept. of Revenue, *Fall 2007 Revenue Sources Book*, p. 36. $(\$3,659 / [739.7] * 365 = \$ 13.55 \text{ per bbl.}) *$

(2) Alaska Dept. of Revenue, *Fall 2012 Revenue Sources Book*, p. 35. $(6,341.8 / [552.8 * 365] = \$31.43 \text{ per bbl.}) *$

(3) (Line 2 / Line 1) - 1.00.

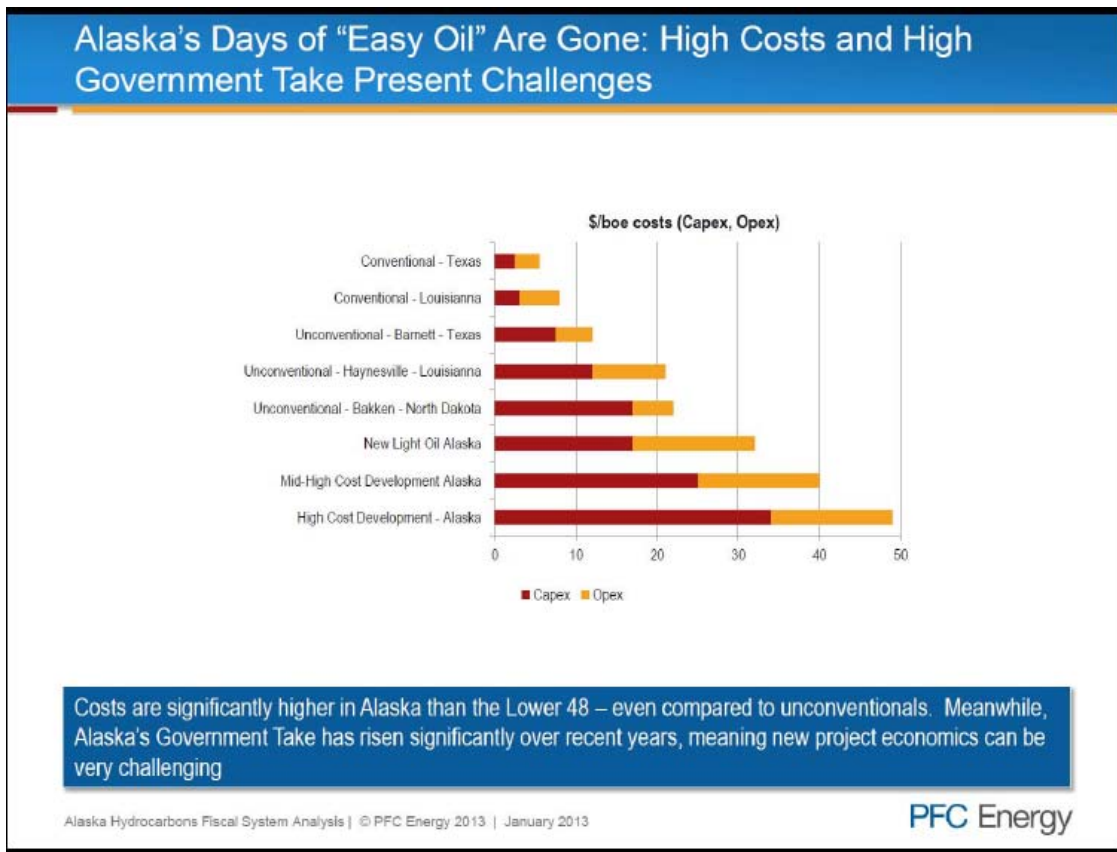
Note: The result shown above is calculated independent of production decline to present field expenditure increases on a per-dollar basis for comparison to inflation. If calculated on a per-barrel basis, between FY 2007 and FY 2013 estimated costs per barrel increased by 132.0%, calculated as follows: $([\$31.43 / \$13.55] - 1.00) = 131.96\%$.

(4) Calculated from CPI-U (U.S. Dept. of Labor Bureau of Labor Statistics, accessed Oct. 20, 2011; updated with EIA data).

(5), (6) PFC Energy, "Alaska's Days of 'Easy Oil' Are Gone: High Costs and High Government Take Present Challenges" (in "Alaska Hydrocarbons Fiscal Systems Analysis," presented to the Alaska Senate TAPS Throughput Committee, January 31, 2013, Slide 47. *

* See following exhibits.

Estimates of Current North Slope v. Lower-48 Field Cost



- PFC Energy, "Alaska's Days of 'Easy Oil' Are Gone: High Costs and High Government Take Present Challenges" (in "Hydrocarbons Fiscal Systems," presented to the Alaska Senate TAPS Throughput Committee, January 31, 2013, Slide 47.

"Days of Easy Oil
Are Gone"
(Above)

ADOR, Revenue
Sources Book
(Unaudited)

/ - - - - \$ / boe (operating and capital) - - - - /

Lower-48:

Conventional (Texas) \$6.00 / bbl.

Unconventional Bakken (North Dakota) . . . \$22.00 / bbl.

Alaska

FY 2007 (Fall 2007 *Revenue Sources Book*) \$13.55 / bbl. *

FY 2013 (Fall 2012 *Revenue Sources Book*) \$31.43 / bbl. **

New Light Oil (Alaska) \$32.00 / bbl.

High Cost Development (Alaska) \$49.00 / bbl.

* (3,659 / [739.7 * 365])
Fall 2007 *Revenue Sources Book*, p. 36 (history)

** (6,341.8 / [552.8 * 365])
Fall 2012 *Revenue Sources Book*, p. 35 (forecast)

Figure 4-6. Basic Data Used for ANS Oil & Gas Production Taxes

	FY 2007 History	FY 2008 Forecast	FY 2009 Forecast
State Production Tax Revenue from the North Slope			
Millions of Dollars	2,286.3	3,398.0	2,195.0
Key North Slope Assumptions			
Price of ANS WC in dollars per barrel	61.63	72.64	66.32
Transit Costs & Other in dollars per barrel	5.96	6.34	6.80
ANS Wellhead in dollars per barrel	55.67	66.30	59.32
Production in barrels per day	739,702	730,942	700,686
Royalty barrels per day	92,463	91,368	87,586
Taxable barrels per day	647,239	639,574	613,100
Lease Expenditures in Millions of Dollars			
Operating Expenditures [OPEX]	2,081	2,149	2,354
Capital Expenditures [CAPEX]	1,578	2,188	2,002
Total Expenditures	3,659	4,337	4,356
Implied North Slope Data			
Credits from CAPEX in Millions of dollars	315.6	219.0	418.9
Lease Expenditures per barrel of oil produced			
OPEX	7.71	8.05	9.21
CAPEX	5.84	8.20	7.83
Total Expenditures	13.55	16.25	17.03
Average Production Value per Barrel [Pre-Tax]	42.12	50.05	42.49
Production Tax Collected per Taxable Barrel	9.68	14.56	9.81

Notes

- 1 Costs for FY 2007 are unaudited and for the entire North Slope. Cost data reported July 2006 through December 2006 are actuals. January 2007 through June 2007 are estimates
- 2 Costs for FY 2008 and FY 2009 are estimated after having reviewed the annual filings from oil companies and incorporating adjustments based on our assessment of future cost increases.
- 3 Assumptions for the transitional credits and the \$12 million credits are not included in the table.
- 4 The average production value per barrel presented in this table would differ from estimates the oil companies would prepare for tax liability purposes for several reasons: [a] the data in the chart are North Slope wide averages; [b] different companies have different cost structures and operate in different fields; [c] a company computing this average for tax liability purposes would only include the barrels it gets to keep, i.e., the company would exclude the barrels it pays in royalty.
- 5 FY 2008 ANS West Coast price forecast is as of November 30, 2007.

Figure 4-7. Basic Data Used for ANS Oil & Gas Production Taxes⁽¹⁾

	History	Forecast	
	FY 2012	FY 2013	FY 2014
North Slope Price and Production			
Price of ANS WC in dollars per barrel	112.65	108.67	109.61
Transit Costs & Other in dollars per barrel	8.81	9.43	8.81
ANS Wellhead in dollars per barrel	103.84	99.24	100.80
Total ANS Production in thousands of barrels per day	579.1	552.8	538.4
Royalty and federal thousands of barrels per day ⁽²⁾	76.4	71.4	70.7
Taxable thousands of barrels per day	502.7	481.4	467.7

North Slope Lease Expenditures⁽³⁾⁽⁴⁾

Total North Slope Lease Expenditures in \$ millions			
Operating Expenditures [OPEX]	3,001.2	3,078.9	2,817.4
Capital Expenditures [CAPEX]	2,383.4	3,262.9	3,845.1
Total North Slope Expenditures	5,384.6	6,341.8	6,662.5
Deductible North Slope Lease Expenditures in \$ millions			
Operating Expenditures [OPEX]	2,862.2	2,832.8	2,779.0
Capital Expenditures [CAPEX]	1,543.0	2,393.0	3,338.6
Deductible North Slope Expenditures	4,405.3	5,225.8	6,117.6

State Production Tax Revenue ⁽¹⁾

Millions of Dollars	6,146.1	4,353.2	3,778.8
Production Tax Collected per Taxable Barrel	33.4	24.8	22.1

State Wide Production Tax Credits ⁽³⁾⁽⁵⁾

Credits Used against Tax Liability in \$ millions	360.0	490.0	615.0
Credits for Potential Purchase in \$ millions	353.0	360.0	400.0

⁽¹⁾ Production tax is calculated on a company specific basis, therefore the aggregated data reported here will not generate the total tax revenue shown. For an illustration of the tax calculation, see Appendix D.

⁽²⁾ Royalty and Federal barrels represents DOR's best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, and barrels produced from federal offshore property.

⁽³⁾ Lease expenditures and credits used against tax liability for FY 2012 were prepared using unaudited company-reported estimates.

⁽⁴⁾ Expenditure data for FY 2013 and FY 2014 are compiled from company submitted expenditure forecast estimates and other documentation as provided to the DOR. Expenditures shown here are shown in two ways: (1) total estimated expenditures including for those companies with no tax liability; and (2) estimated deductible expenditures for only those companies with a tax liability.

⁽⁵⁾ Production tax credits shown include all production tax credits and all areas of the state. North Slope CAPEX credits are spread out over two years as specified in the ACES production tax. Assumptions for the \$12 million credits for small Alaska producers are included in the table.

Exhibit 2.

Trans-Alaska Pipeline System Overcharges

Trans-Alaska Pipeline System Overcharges

**Trans-Alaska Pipeline System Overcharges,
1977-1996 (RCA 2002 Decision and Finding)**

[Exhibit 2 Data Sheet]

RCA, Order No. 151 (Docket P-97-4), Nov. 27, 2002

[Exhibit 2 Source, Sheet 1]

RCA, Order No. 151 (Docket P-97-4), Nov. 27, 2002

[Exhibit 2 Source, Sheet 2]

Trans-Alaska Pipeline System Overcharges, 1977-1996 (RCA 2002 Decision and Finding)

Exhibit 2 Data Sheet

1. TAPS Overcharges, 1977-1996	\$13,500,000,000.00 (1)
2. Barrels Shipped, 1977-1996 (estimated)	11,479,980,000 (2)
3. Carrier Overcharge per barrel, 1997- 1996 (1997 \$)	\$1.18 (3)
4. CPI-U Indexed Inflation Factor (1997 – 2012)	1.386 (4)
5. TAPS Overcharge per barrel, 1977 – 1996 (2012 \$)	\$1.63 (5)

6. Estimated Reduced Payments to State, 1977 - 1996 (2012 \$)	\$5,316,710 ,220.00 (6)
7. Est. Non-TAPS Owner Overpayments (1977 - 1996 (2012 \$)	\$1,216 ,303 ,881.00 (7)

Sources and Notes

(1) Regulatory Commission of Alaska, *Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates: Setting Just and Reasonable Rates; Required Refunds and Filings; And Outlining Phase II Issues* (Docket P-97-4, Order No. 151), Nov. 27, 2002, p. 131.

(2) Estimated from Alaska Department of Revenue, *Fall 2002 Revenue Sources Book*, Appendix E (p. 130).

(3) = (Line 1 / Line 2)

(4) Calculated from CPI-U (U.S. Dept. of Labor Bureau of Labor Statistics, accessed Oct. 20, 2011; updated with U.S. Energy Information Administration data)

(5) = (Line 3 * Line 4)

(6) = (Line 2 * Line 5) * 0.3

(7) = (Line 2 * Line 5) * 0.1 * 0.65

Lines (1) through (5): the \$13.5 billion in 1997 dollars represents TAPS overpayments over a 20-year period in real or inflation-adjusted dollars, calculations 1 through 5 represent an estimate of these amounts in nominal (2013) dollars.

Line (6). This line represents the total reduced payments to the state resulting from the TAPS tariff overcharges from 1977 through 1996 (based on the assumption that over this 20-year period the state collected approximately 30% of net petroleum revenue in royalty and taxes). Since three TAPS shipper-owners accounted for approximately 90% of the North Slope production shipped through TAPS, over this 20-year period they retained approximately 90% of the overcharge total.

Line (7). This line represents the portion of TAPS overcharges paid out-of-pocket by independent TAPS shippers to the TAPS owners between 1977 and 1996, with payments reduced by an assumed 35% federal income tax rate on profits, as determined in the November 2002 TAPS tariff decision. (In this case, the RCA was not collecting refunds for the 1977-1996 period. Rather, the RCA was quantifying past tariffs to estimate the rate base for future TAPS tariffs and post-1996 refunds permitted by the statute of limitations. (Put otherwise: The TAPS owners did not refund the overcharges collected from shippers between 1977 and 1996.)

1		<u>STATE OF ALASKA</u>	
2		<u>THE REGULATORY COMMISSION OF ALASKA</u>	
3	Before Commissioners:	G. Nanette Thompson, Chair	
4		Bernie Smith	
5		Patricia M. DeMarco	
		Will Abbott	
		James S. Strandberg	
6	In the Matter of the Correct Calculation and		P-97-4
7	Use of Acceptable Input Data To Calculate the		
8	1997, 1998, 1999, 2000, 2001, and 2002		ORDER NO. 151
9	Tariff Rates for the Intrastate Transportation of		
10	Petroleum over the Trans Alaska Pipeline		
11	System Filed by AMERADA HESS PIPELINE		
12	CORPORATION; ARCO TRANSPORTATION		
13	ALASKA, INC.; BP PIPELINES (ALASKA)		
14	INC.; EXXON PIPELINE COMPANY; MOBIL		
15	ALASKA PIPELINE COMPANY;		
16	EXXONMOBIL PIPELINE COMPANY;		
17	PHILLIPS ALASKA PIPELINE		
18	CORPORATION; UNOCAL PIPELINE		
19	COMPANY; PHILLIPS TRANSPORTATION		
20	ALASKA, INC.; and WILLIAMS ALASKA		
21	PIPELINE COMPANY, L.L.C., and the Protest		
22	by TESORO ALASKA PETROLEUM		
	COMPANY of the 1997 and 1999 Tariff Rates		
23	In the Matter of the Petition of TESORO		P-97-7
24	ALASKA PETROLEUM COMPANY for an		ORDER NO. 110
25	Investigation into the Amounts Collected by		
26	AMERADA HESS PIPELINE CORPORATION;		
	ARCO TRANSPORTATION ALASKA, INC.;		
	BP PIPELINES (ALASKA) INC.; EXXON		
	PIPELINE COMPANY; MOBIL ALASKA		
	PIPELINE COMPANY; PHILLIPS ALASKA		
	PIPELINE CORPORATION; and UNOCAL		
	PIPELINE COMPANY for Dismantling,		
	Removal, and Restoration of the Trans Alaska		
	Pipeline System		
	<u>ORDER REJECTING 1997, 1998, 1999 AND 2000 FILED TAPS RATES;</u>		
	<u>SETTING JUST AND REASONABLE RATES; REQUIRING REFUNDS</u>		
	<u>AND FILINGS; AND OUTLINING PHASE II ISSUES</u>		
	BY THE COMMISSION:		
	P-97-4(151)/P-97-7(110) – (11/27/02)		

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

1 B. Comparing From the Beginning of Pipeline Operation, the Annual Past
2 Revenue Requirements of a DOC Methodology With the Annual Past Revenue
3 Requirements of TSM, Demonstrates That the Year-end 1996 Rate Base of \$669
4 Million Is Reasonable

5 We now compare the past annual DOC revenue requirements shown at
6 Exhibit 33 with the past annual TSM revenue requirements. Exhibit 7, Schedule 2
7 reveals that TSM has, on a cumulative basis,⁵⁴⁷ provided the Carriers with an
8 opportunity to recover \$9.9 billion more than their costs as determined by the DOC
9 revenue requirements.⁵⁴⁸ In 1997 dollars, the net present value⁵⁴⁹ of the cumulative
10 stream of revenue requirement differences is \$13.5 billion, far in excess of the \$669
11 million year-end 1996 DOC rate base.

12 Because the revenue requirements determined under TSM have been
13 higher than costs as determined under a DOC methodology applied consistently from
14 the beginning of pipeline operations, we find that the Carriers have had ample
15 opportunity to recover costs and no taking of Carrier property occurs if we adopt a \$669
16

17 ⁵⁴⁷Our finding regarding the appropriateness of TSM depreciation and the year-
18 end 1996 rate base is properly tested with reference to the Carriers' *cumulative*
19 historical opportunity to recover their full costs of service. In *Re Amerada Hess Pipeline*
20 *Corporation*, Order P-97-4(79), April 10, 2000, we directed the Carriers to show that
21 1997-2000 rates reflect costs. We found that evidence that rates are just and
22 reasonable over the life of the line is not sufficient to prove that the rates for specific
23 years are just and reasonable. *Id.*, at 11. The Carriers' "life of the line" argument
24 requires, among other things, a projection of costs of service into the future. Moreover,
25 it fails to address whether 1997-2000 costs are reflected in 1997-2000 filed rates. We
26 evaluate *historical* costs; we do so to determine whether 1997-2000 rates reflect the
costs of providing service for the years in question.

⁵⁴⁸Exhibit 7, Schedule 2, Line 1.

⁵⁴⁹Exhibit 7, Schedule 2, Line 2. The net present value calculation uses interest
rates equal to the Commission's overall weighted rate of return in each year. See
Exhibit 7, Schedule 1, Line 6. We note that the present value comparative revenue
requirement analysis indexes 1997 dollars, because those are the dollars with which the
remaining rate base is measured.

Exhibit 3.

Average Government Take

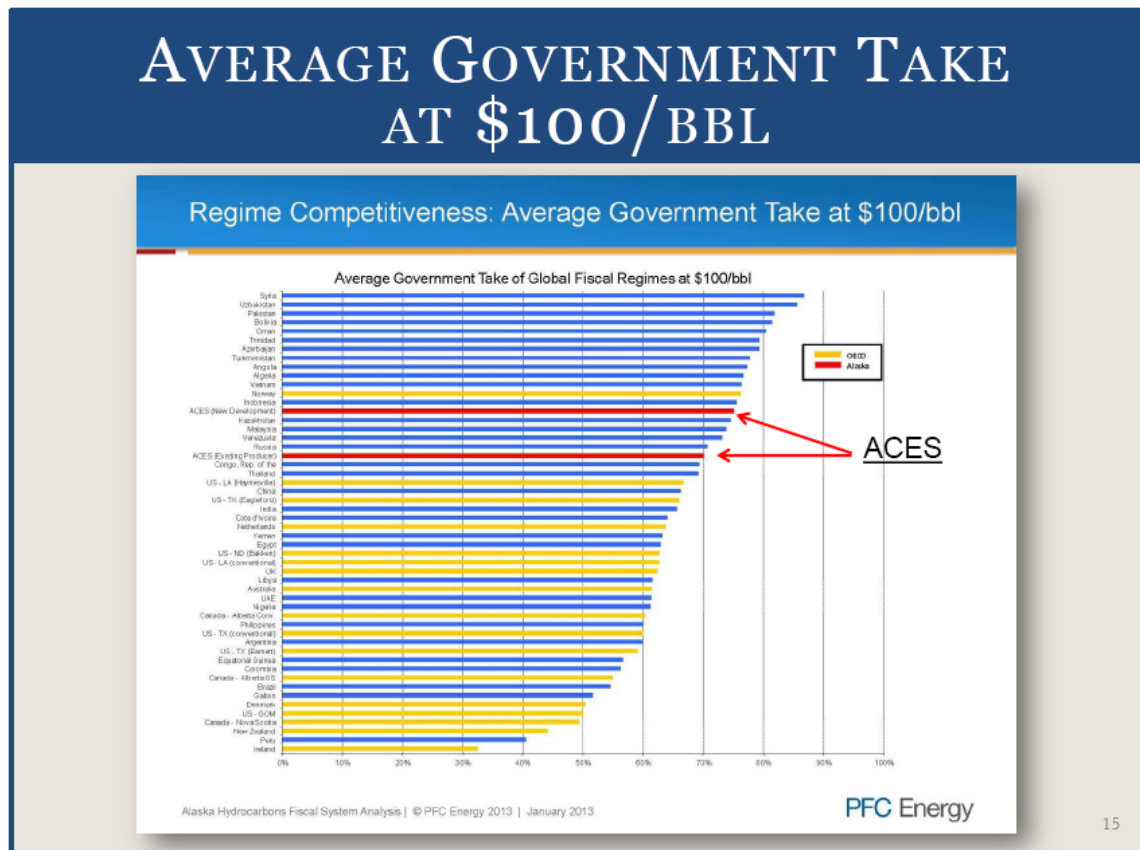
Average Government Take

Average Government Take at \$100 / bbl

Exhibit 3 (Sample Regime Competitiveness Slide)

Average Government Take at \$100 / bbl

Exhibit 3 (Sample Regime Competitiveness Slide)



- PFC Energy, “Regime Competitiveness: Average Government Take at \$100 / bbl” (from PFC Energy, “Alaska Hydrocarbons Fiscal Systems Analysis,” January 2013; presented to the Alaska House Resources Committee by Commissioners Daniel S. Sullivan [DNR] and Bryan Butcher [DOR], in “Oil Tax Reform – Arresting TAPS Throughput Decline” (slide presentation), March 28, 2013, Slide 15).

The red bars in this chart estimate average North Slope government take of 70% (Existing Production) and 75% (New Development). These estimates: (1) reflect greatly increased field costs, (2) assume a nominal 35% federal income tax rate and (3) treat TAPS and marine shipments as costs excluding estimates of transportation profits. All three factors affect regime competitiveness. For example:

- If escalating but essentially unaudited field costs contain overcharges, independent producers, who must pay these costs out of pocket, will be handicapped.
- At a market price of \$100 per barrel, 2% reduction from the assumed nominal federal income tax rate of 35% would reduce a producing company’s government take by approximately 1%. (Therefore, a company paying a 21% federal income tax would see a reduction in net revenue take percentages of approximately 7% and a company that paid no federal income tax on current-year operations due to offsetting overseas tax payments would see a reduction in government take of approximately 17%).
- Inclusion of transportation profits would lower the average government take slightly at \$100.00 per barrel and would have greater effect at low oil prices by providing guaranteed profit. Producers who do not own these transportation systems pay these costs out of pocket and are therefore subject to competitive handicap.

Exhibit 4.

Nominal v. Actual Federal Income Tax Rates

Nominal v. Actual Federal Income Tax Rates

Nominal v. Actual Federal Income Tax Rates: The Problem

[Exhibit 4]

Analysis: Gas price spike revives fight over energy taxes

[Exhibit 4 Background Information, Sheet 1]

[Exhibit 4 Background Information, Sheet 2]

[Exhibit 4 Background Information, Sheet 3]

Nominal v. Actual Federal Income Tax Rates: The Problem

Exhibit 4

Most informed observers would probably agree that corporations are not likely to pay taxes at the nominal corporate federal income tax rate of 35%. But exactly what each corporation pays annually is by no means clear. Due to loopholes in this system and tax information shielded by confidentiality, it is difficult to determine exactly what corporations do pay annually. Citizens for Tax Justice (CTJ) joined the Institution on Taxation and Economic Policy to take what it called “a hard look at the federal income taxes paid or not paid by 280 of America’s largest and most profitable corporations in 2008, 2009 and 2010.” The companies covered in that report – all from the *Fortune 500* and profitable in each of the three years analyzed – were ostensibly required to pay a 35 percent corporate income tax rate but only paid, on average, about half that amount. CTJ reported that “a quarter of the companies in our study paid effective federal tax rates on their U.S. profits of less than 10 percent, while some paid nothing at all.” However, CTJ was quick to add, “an almost equal number of our companies paid close to the full 35 percent official corporate tax rate.” CTJ concluded that “corporate tax loopholes are so out of control that most Americans can rightfully complain, ‘I pay more federal income taxes than General Electric, Boeing, DuPont, Wells Fargo, Verizon, etc., etc., all put together.’ That’s an unacceptable situation.”¹

Federal tax breaks identified by CTJ include accelerated depreciation, industry-specific tax breaks (including oil and gas), domestic deductions and credits offsetting foreign tax payments.² Assignment of tax returns to specific years is complicated by tax loss carry-forward and carry-back provisions. According to an on-line tax advisor:

A tax loss carry forward is a provision in the Tax Code to allow a business to use a to use a net operating loss in one year to offset a profit in one or more future years....You can elect to carry forward an NOL up to 20 years.

A tax loss carry back is a similar type of provision, which allows the business to carry a net operating loss back to offset profits in previous years.³

CTJ’s reportage on ExxonMobil’s earnings gives an indication of the extent to which federal income tax payments can vary from the nominal 35% federal income tax rate of tax payments:

<u>Year</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
Pre-Tax Profit (mm\$)	\$9,745.5	\$2,490.8	\$7,419.4	<n.a.>
Federal Income Tax	\$2,744.5	(\$953.8)	\$992.4	<n.a.>
Rate (%)	28.2%	-38.3%	13.4%	13.0%

2008 – 2010: *Corporate Taxpayers & Corporate Tax Dodgers*, 2008-2010, p. 44;

2011: Citizens for Tax Justice, as reported by Reuters “Big U.S. oil “effective” tax rates, 2011” (see Exhibit 4, Background Information, Sheet 2.

In assessing North Slope profits through 2005, former Atlantic Richfield projects manager who chaired the Trans-Alaska Pipeline Company owners committee wrote that “[t]he effective federal tax rate of 21 percent was approximately one-half the average federal corporate income tax rate over the investment period.”⁴

¹ Robert S. McIntyre (Citizens for Tax Justice), *et al.*, *Corporate Taxpayers & Corporate Tax Dodgers*, 2008-2010 (Citizens for Tax Justice & the Institute on Taxation and Economic Policy), November 2011, p. 1.

² *Corporate Taxpayers & Corporate Tax Dodgers*, 2008-2010, pp. 12-14 and 50-52 and 66.

³ Jean Murray (About.com Guide), “What’s the Difference between a Loss Carry Back and a Loss Carry Forward?” (accessed at <http://biztaxlaw.about.com/od/businessstaxdeductions/f/Difference-Between-A-Loss-Carry-Back-And-A-Loss-Carry-Forward.htm>).

⁴ John M. Miller, *The Last Alaskan Barrel: An Arctic Oil Bonanza that Never Was* (Caseman Publishing, 2011), p. 106.

Exhibit 4.: Background Information

Analysis: Gas price spike revives fight over energy taxes

(Exxon Mobil, the world's most profitable corporation, says it paid more than 45 percent of its 2011 income in taxes, while critics say it paid much less.

**By Kim Dixon– Mar. 26, 2012 (Washington, DC)
(Reuters)**

Accessed April 21, 2012 at <http://www.reuters.com/article/2012/03/26/us-usa-tax-bigoil-idUSBRE82P0DX20120326>

So which is it?

The answer is that it depends on how the calculation is made and who is making it - a point that is becoming more important as gasoline prices and oil company profits soar.

Energy industry taxes are again a political issue, with just months to go before the November 6 congressional and presidential elections. President Barack Obama says he wants to kill \$40 billion in tax breaks enjoyed by giants such as Exxon, Chevron and Conoco.

"Oil companies are making more money right now than they've ever made," Obama said earlier this month. "On top of the money they're getting from you at the gas station every time you fill up, they want some of your tax dollars as well."

But the companies say they already pay among the highest corporate tax rates.

"We're the highest taxed industry that I'm aware of," Chevron Chief Executive John Watson said earlier this month.

The difference between the effective tax rate cited by Exxon and lower rates cited by groups such as Citizens for Tax Justice, a left-leaning tax activist group, has several causes.

One is that the company counts foreign taxes paid, while Citizens for Tax Justice does not. Another is that Exxon counts deferred taxes, as well, but the consumer group does not. Still another is which profits are counted by the company and critics.

There are other technical variations shaping the calculations of effective tax rates, but these subtleties are often lost in the sound bites of the ongoing tax policy debate.

Depending on your perspective, oil industry tax breaks are either a vital part of reducing U.S. dependence on foreign oil or a giveaway to rich and powerful corporations. Politicians from both parties play regularly on these themes.

Either way, as lawmakers slowly move toward revamping the U.S. tax code for the first time in 25 years, the oil industry's tax breaks and tax rates are under growing scrutiny.

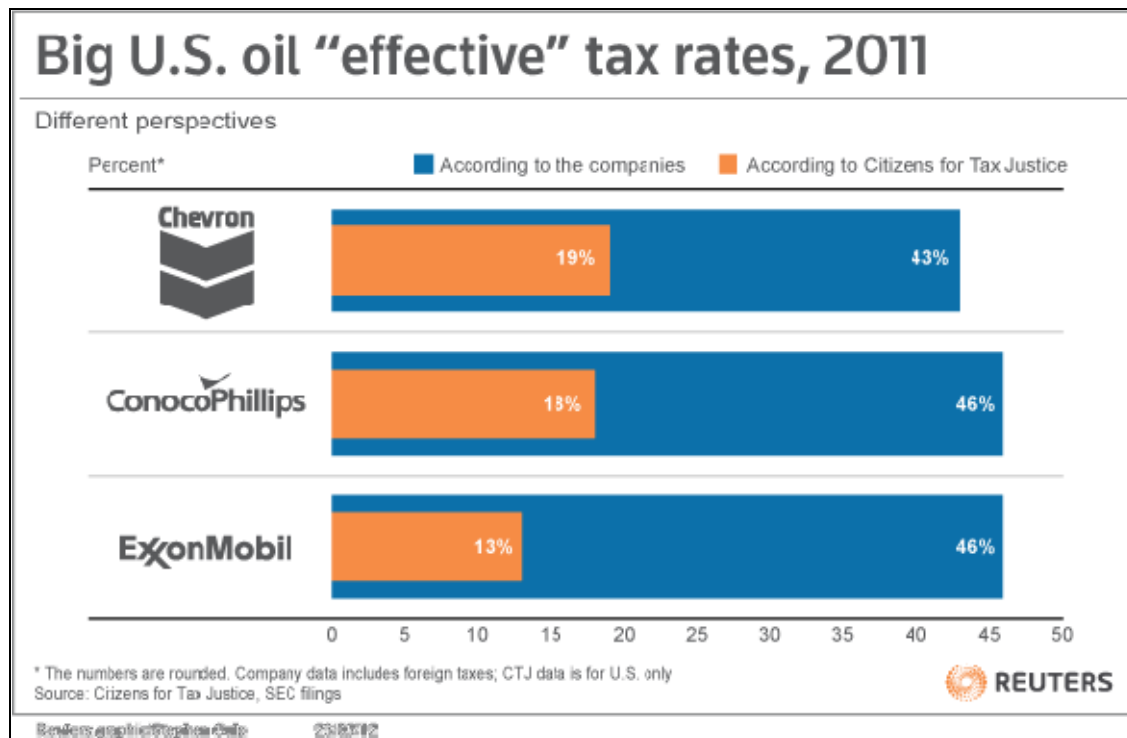
Democrats in the Senate on Monday will begin debate on repealing the tax breaks. There is little chance of repeal happening now, but the issue will carry into the campaign.

Republican presidential hopefuls Mitt Romney and Rick Santorum have blasted Obama for over-regulating the industry.

The next big action on taxes is expected at the end of the year, coinciding with the December 31 expiration of individual tax rates enacted under Republican President George W. Bush.

"That will be crazy and chaotic and anything can happen in that kind of scenario," said Jim Lucier, an analyst at institutional investor advisory Capital Alpha Partners.

Reuters Analysis (Continued)



– GRAPHIC-Big Oil's tax rates link.reuters.com/hyk37s

BIG OIL EARNS BIG

Four of the five biggest oil companies ranked among the top 10 most profitable companies in 2011, according to Fortune, with collective profits of about \$80 billion. BP Plc, beset by costs from the Gulf oil spill, had losses, bringing down the average.

The biggest oil companies' tax rates are relatively high when the foreign taxes that they pay are included. On a U.S.-only basis, their rates vary.

There are many ways to calculate how much a company actually pays in U.S. taxes. One roadblock to making independent tax rate estimates is that tax filings are confidential, and filings with securities regulators use a different accounting method.

"Most of what they are putting on their financial statements doesn't really tie to what they are putting into their tax returns," said George Yin, a former chief of staff at the congressional Joint Committee on Taxation.

When calculating the headline tax rates it displays to the public, the industry lumps together U.S. and foreign taxes. It includes taxes that are deferred and thus not paid yet. U.S. companies must pay taxes on profits earned abroad, but they can defer these taxes until they bring the cash into the country.

That is the method behind the American Petroleum Institute's 41 percent estimate for the industry as a whole.

Citizens for Tax Justice considers U.S. profits and U.S. taxes paid only. By that measure, Exxon Mobil paid 13 percent of its U.S. income in taxes after deductions and benefits in 2011, according to a Reuters calculation of securities filings.

Chevron paid about 19 percent by that method, near CTJ's average for all industries.

Reuters Analysis (Continued)

It is a far cry from the 35 percent top corporate tax rate.

Still, the three-year average for telecom companies is 8 percent; for information technology services companies, it is 2.5 percent, according to CTJ.

"A lot of the techniques that multinationals use to reduce taxes are simply not available to big energy companies," said Howard Gleckman, a fellow at the Tax Policy Center, a centrist think tank.

BIG OIL LACKS IP EDGE

One way big technology and drug companies cut U.S. taxes is by shifting intellectual property income to lower-tax countries. Oil and gas companies, in general, don't benefit from that.

Bob McIntyre, president of Citizens for Tax Justice, said the fact that oil companies still drill in high-tax countries like Saudi Arabia proves they will keep drilling if their U.S. taxes go up. "Their foreign tax rates are very high, and they don't leave Saudi Arabia," McIntyre said.

One major tax break for energy companies is a nearly century-old benefit letting them deduct "intangible drilling costs" (IDC) immediately rather than over time.

Most of the IDC is for the labor costs of drilling a well.

Legislation drafted by Democratic Senator Robert Menendez would limit this break, among others. Ending it completely would raise \$14 billion over a decade, according to the White House.

Energy companies liken this benefit to the research and development tax break employed by companies like Apple Inc.

"All the labor (that) tech companies spend on research and development, everything that Apple spends designing the next new product, they recover," said Brian Johnson, a tax expert at the American Petroleum Institute. "Cost recovery is cost recovery."

Not exactly. Many tax experts across the political spectrum said the IDC is a clear exception made for oil. As a rule, expenses that produce income in the future are not immediately deductible.

LITTLE OIL

Most oil companies are not as big as Exxon or Chevron. Mid-sized, independent producers include Devon Energy Corp and Chesapeake Energy Corp. These companies get even more generous benefits than the giants.

Indeed, the Center for Tax Justice finds Devon recorded a 5.5 percent three-year average tax rate and Chesapeake had an 8.1 percent average over the period.

"What is absolutely critical is the profound distinction between little oil and big oil - the smaller companies receive pretty generous breaks," said economist Alan Viard of the conservative American Enterprise Institute.

For example, the so-called percentage depletion allowance lets these mid-sized companies take an annual 15 percent deduction for depletion of oil and gas resources in the ground, instead of deducting the decline in value over time.

Obama wants to repeal this benefit as well.

The biggest oil companies don't get this benefit. Viard called it an "indefensible loophole."

Exhibit 5.

Prof. Joseph Stiglitz on Corporate Conduct in Alaska

(Supplement: Current Constitutional Budget Reserve Fund Settlement Payments)

***Questionable Accounting Practices and the
Importance of Audits***

Joseph Stiglitz on Corporate Conduct in Alaska
[Exhibit 5, Pages 1 & 2]

ADOR Fall 2012 Revenue Sources Book, p. 96
[Exhibit 5 Source, Sheet 1]

Questionable Accounting Practices and the Importance of Audits¹

The state's petroleum litigation history clearly demonstrates the importance of validating the revenue calculation starting point – particularly when transfer pricing from one arm of a company to another is involved.

In a 2007 study of multinational oil corporations and resource development, noted economist Joseph Stiglitz portrayed Alaska as the poster-child of corporate cheating. Stiglitz described his first-hand experience with Alaska – in royalty litigation during the 1980's – as follows:

“The prospects of cheating are very real and great, and can arise at every stage of the transaction. The government may get less for the lease than it should – there may even be attempts to restrict competition in bidding. Whatever the contract that has been signed, corporations are tempted to cheat – to pay less than they are supposed to – because the amount of money that can sometimes be made by doing so is so large. The occasions to cheat arise not just in developing countries. In the 1980s I worked on a case involving cheating by the major oil companies in Alaska. This oil-rich state had a mineral lease requiring the oil companies to pay at 12.5 percent of the gross receipts, less the cost of transporting the oil out from the far-flung site at Prudhoe Bay on the Arctic Circle. By overestimating their costs by just a few pennies per gallon (and multiplying those pennies by hundreds of millions of gallons) the oil companies would increase their profits enormously. They could not resist the temptation.

They also found other ways to cheat, such as selling their oil to their own subsidiaries, recording a lower than fair market value (see chapter 4); or using other subsidiaries to ship their oil out and then reporting fictionally high shipping cost. Each piece of the cheating was hard to detect, and government prosecutors had to analyze thousands of transactions- – at a cost of tens of millions of dollars. In the end, there was no doubt that cheating had occurred – and on a massive scale. There followed a series of settlements involving a whose who of global companies – including what are now BP, ExxonMobil and ConocoPhillips – for an amount in excess of 6 billion dollars.²

The \$6-billion estimate by Stiglitz was conservatively cast; state records compiled and reported on by this writer in 2003 showed that the Alaska Dept. of Law reported \$6.8 billion in oil and gas settlement payments for underpayments on taxes and royalties through 2001.³ Since that time,

¹ This exhibit has been updated from Richard A. Fineberg, *Establishing a Rational Foundation for Review, Formulation and Implementation of Alaska's Oil and Gas Fiscal Policy* (April 2011), Section VI., pp. 31-33, with data from the Alaska Department of Revenue's *Fall 2012 Revenue Sources Book*, p. 96.

² Joseph E. Stiglitz, “What Is the Role of the State?” Macartan Humphreys, Jeffrey D. Sachs and Joseph E. Stiglitz (eds.), *Escaping the Resource Curse* (Columbia Univ. Press, 2007), pp. 24-25 (footnotes omitted).

³ See: Richard A. Fineberg, [“Securing the Take: Petroleum Litigation in Alaska,”](#) in *Caspian Oil Windfalls: Who Will Benefit?* [New York: Open Society Institute, 2003], pp. 53-69 [Chapter 3]. (Stiglitz cited the author's 2003 compilation as the source for his statement that the state was short-changed and forced to litigate to recoup “in excess of 6 billion dollars.”)

Although I never met Prof. Stiglitz, while serving in the governor's office between 1987 and 1989 I worked on the royalty case that he discusses in this passage. During this period, in addition to serving with the governor's policy review team, I spent time with the state's contractual staff team tallying data on oil transactions; this experience enabled me to give first-hand information to the governor's policy review team. Given this common background, I can confirm the accuracy of Prof. Stiglitz's observations.

the Constitutional Budget Reserve Fund reports taking in another \$1.7 billion in oil and gas settlements, bringing the total revenue gained through petroleum litigation since Prudhoe Bay entered production to \$8.5 billion.⁴

Is trust or verification the wiser policy? It is difficult to answer this question because the critical facts about these settlements remain shielded behind the veils of taxpayer confidentiality and commercial propriety. However, the softness surrounding important numbers that have swirled around the current petroleum tax discussion suggest to me that at this time we do not have a firm grip on this issue. The following empirical indicators tip the scales toward verification:

- The Department of Law has put in a budget request for \$5 million for the coming fiscal year for outside counsel to assist with oil and gas litigation.⁵
- In my experience, litigation has typically yielded a pay-out on state investment conservatively estimated at 10:1.
- In 2006 and 2007, veteran state oil and gas personnel from the Departments of Revenue and Law assured me that the relatively large sums of money at issue in revenue disputes were a thing of the past – an historical artifact that reflected the fact that nation's largest oil field came on-line in the midst of the two significant price spikes of the 1970's, confronting both the industry and the state with a steep learning curve. Balanced against this sanguine historical interpretation is the fact that \$1.6 billion of the \$1.7 billion in litigation revenue collected since FY 2003 has been collected in the last six years.⁶ This six-year collection average of \$267.17 million per year represents a ten-fold increase over the period between 2003 and 2006.

– Richard A. Fineberg

⁴ *Fall 2012 Revenue Sources Book*, p. 96. (Under Article IX, Sec. 17 of the Alaska State Constitution, the state deposits all money received as a result of administrative proceedings or litigation on mineral lease payments or taxes on mineral income into this fund.)

⁵ Alaska Dept. of Law, "Oil and Gas Litigation (Non-Gasline)," Reference No. 51784, Feb. 16, 2011 [FY 2012 Governor Amended Capital Project Summary], pp. 1-2.

⁶ *Fall 2012 Revenue Sources Book*, p. 96. These figures do not include the settlement for revenue last due to the TAPS emergency shutdown in January 2011. Based on the settlement for this amount, the Revenue Department anticipates a deposit of \$255 million to the Constitutional Budget Reserve Fund from BP during FY 2013.

Alaska Department of Revenue • Tax Division

Exhibit 5 (Fall 2012 Revenue Sources Book)

A-5a Total Petroleum Revenue—History (\$ million)

FY	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Unrestricted Petroleum Revenue										
Petroleum Corporate Income Tax	151.1	298.8	524.0	661.1	594.4	605.8	492.2	446.1	542.1	568.8
Oil and Gas Production Tax	589.8	642.7	854.9	1,191.7	2,198.3	6,810.9	3,100.9	2,860.7	4,543.2	6,136.7
Oil and Gas Hazardous Release	9.2	9.2	8.3	7.8	10.1	11.7	11.1	10.3	9.7	9.4
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum Property Tax	48.7	47.3	42.5	54.5	65.6	81.5	111.2	118.8	110.6	111.2
Oil & Gas Royalties	825.7	1,042.8	1,401.1	1,772.2	1,583.8	2,420.6	1,451.2	1,469.0	1,821.3	2,022.8
Bonuses, Rents & Interest	14.6	13.3	18.8	11.9	29.2	25.5	14.4	8.0	22.0	8.9
Total Unrestricted Petroleum Revenue	1,639.1	2,054.1	2,849.6	3,699.2	4,481.4	9,956.0	5,181.0	4,912.9	7,048.9	8,857.8
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	34.6	2.5	31.6	4.5	12.8	5.2	14.8	21.3	3.0	4.8
Royalties to Permanent Fund	397.6	354.7	476.9	599.5	535.0	834.0	659.8	696.1	857.3	904.9
Royalties to Public School Fund	6.2	7.1	9.6	12.0	10.6	16.5	11.0	11.1	13.6	14.7
CBRF Deposits	22.3	8.4	27.4	43.7	101.9	476.4	202.6	552.7	167.3	102.1
Total Restricted Petroleum Revenue	460.7	372.7	545.5	659.7	660.3	1,332.1	888.2	1,281.2	1,041.2	1,026.5
Total Petroleum Revenue	2,099.8	2,426.8	3,395.1	4,358.9	5,141.7	11,288.1	6,069.2	6,194.1	8,090.1	9,884.3

Exhibit 6.

“Oil profits weather ‘Hurricane’”

Fairbanks Daily News-Miner, Oct. 14, 2012

“Oil Profits weather ‘Hurricane’”

**Richard Fineberg “Community Perspective”
column (with “Hurricane Gulch” chart),
Fairbanks Daily News-Miner, Oct. 14, 2012.**

[Exhibit 6, Pages 1 & 2]

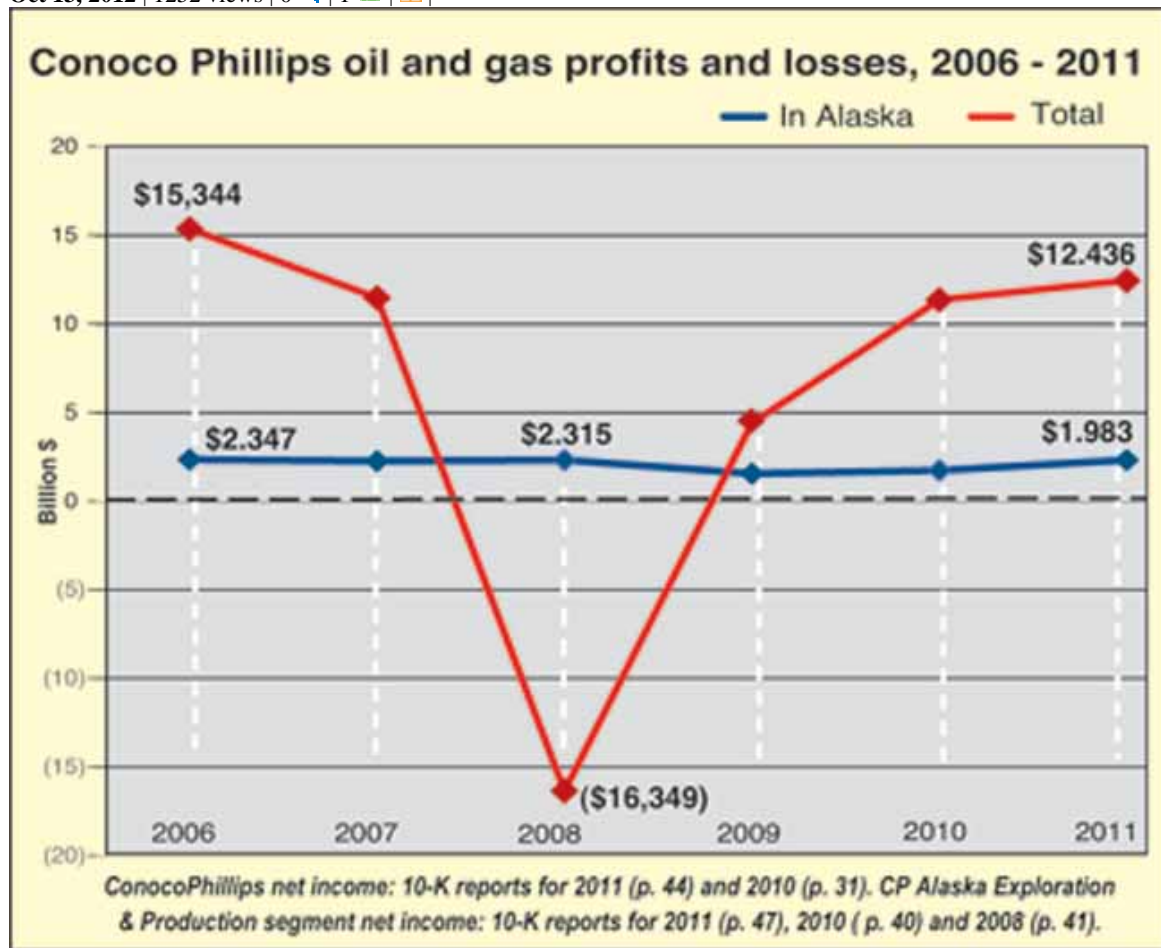
Oct. 14, 2012, p. F3

Oil profits weather 'Hurricane'

ConocoPhillips expects Alaska to outperform every other oil province

by Richard A. Fineberg

Oct 13, 2012 | 1252 views | 0 | 1 | | |



Richard A. Fineberg (Research Associates), October 2012

They say one picture is worth a thousand words, but here's one picture that is worth \$2 billion per year: Using data that ConocoPhillips reports annually, the attached chart highlights the contrast between steady, after-tax profits the company earns in Alaska and the company's erratic results from its operations in the rest of the world.

Since Alaska switched to a cost-based petroleum production tax six years ago, ConocoPhillips has reported net profits from Alaska averaging more than \$1.9 billion per year. But ConocoPhillips is still recovering from a profit collapse outside Alaska in 2008, when it suffered a tremendous loss that was attributed to natural gas investments in the Lower 48 that went sour as natural gas prices crashed. ConocoPhillips' Alaska net profits of \$3.8 billion for 2008 and 2009 compares to the company's total net loss of \$11.9 billion during the same two years, as graphically demonstrated in the chart.

When ConocoPhillips' performance in Alaska and the rest of the world are viewed together, the resulting picture of the last six years looks like the Parks Highway crossing at Hurricane Gulch, 170 miles north of Anchorage. At Hurricane, travelers cruise across a spectacular, steep-sided gulch on a high bridge. ConocoPhillips' Alaska profits resemble the path of the highway, gliding smoothly over the abyss beneath the Hurricane bridge. Beneath the bridge, the steep slopes form a dramatic "V" that matches ConocoPhillips' overall 2008 profit plunge.

These data graphically demonstrate that the major North Slope producers do not need the \$2 billion annual giveaway in Alaska tax cuts that the governor, the industry and misguided citizens have been advocating for the last two years.

As a long-time observer of Alaska oil and gas policy issues, I have noticed that in the confusion that typically swirls around the controversial oil proposals, even the most basic facts can get lost. For example, ConocoPhillips is one of three companies that wield tremendous power by controlling roughly 95 percent of Alaska North Slope crude oil production; the same three companies also own a roughly similar percentage of the trans-Alaska pipeline system.

A host of facts buried in the company's dense reports to the U.S. Securities and Exchange Commission support the challenge to the tax cut proposal. For example:

- In the six years since the state shifted to a net profits tax, ConocoPhillips has raked in \$12.3 billion in after-tax profits from Alaska — an average of nearly \$4,000 per minute, day in and day out.
- During this period, while ConocoPhillips' Alaska production has declined by 34 percent, the company's reported Alaska net income for 2011 — \$1.983 billion — is only 16 percent less than its 2006 Alaska profits.

In addition to these historical facts, another important set of data in the ConocoPhillips SEC reports is also overlooked: Looking forward, ConocoPhillips' estimates of future performance, filed in conformance with SEC requirements, indicate that the company expects its Alaska investments to outperform its investments in every other part of the world by significant margins.

The facts that ConocoPhillips has earned remarkably steady profits from Alaska under the current tax regime and anticipates higher future returns from Alaska than from other regions undermines that company's plea for a big Alaskan oil tax cut.

While ConocoPhillips is required to file public information relevant to its Alaska operations in its annual 10-K report to the SEC, neither of the other two major North Slope producing companies — ExxonMobil and BP — are required to do so. Moreover, legislative hearings have demonstrated that state management entities such as the petroleum audit system are notoriously incapable of producing reliable data on petroleum expenditures.

In this troubled situation, I believe that state senators such as Joe Paskvan and Joe Thomas deserve great credit for their efforts to provide the public with basic facts as they seek constructive solutions to North Slope petroleum development issues.

The picture painted by the accompanying chart is worth \$2 billion per year. Look for candidates with the brains to recognize the significance of the SEC 10-K data on ConocoPhillips and the guts to use this information.

Richard A. Fineberg of Ester is an independent policy analyst who has studied and reported on Alaska oil and gas development issues for nearly four decades.

Accessed Oct. 14, 2012 at http://newsminer.com/view/full_story_opinion/20489500/article-Oilprofits-weather-%E2%80%98Hurricane%E2%80%99?instance=com_perspectives

Exhibit 7.

“The numbers show why oil tax reform is needed”

Fairbanks Daily News-Miner, Nov. 2, 2012

“The numbers show why oil tax reform is needed”

**Scott Jepsen “Community Perspective” column
(with CP v. State Net Revenue Chart)**

Fairbanks Daily News-Miner, Nov. 2, 2012

[Exhibit 7, Pages 1 & 2]

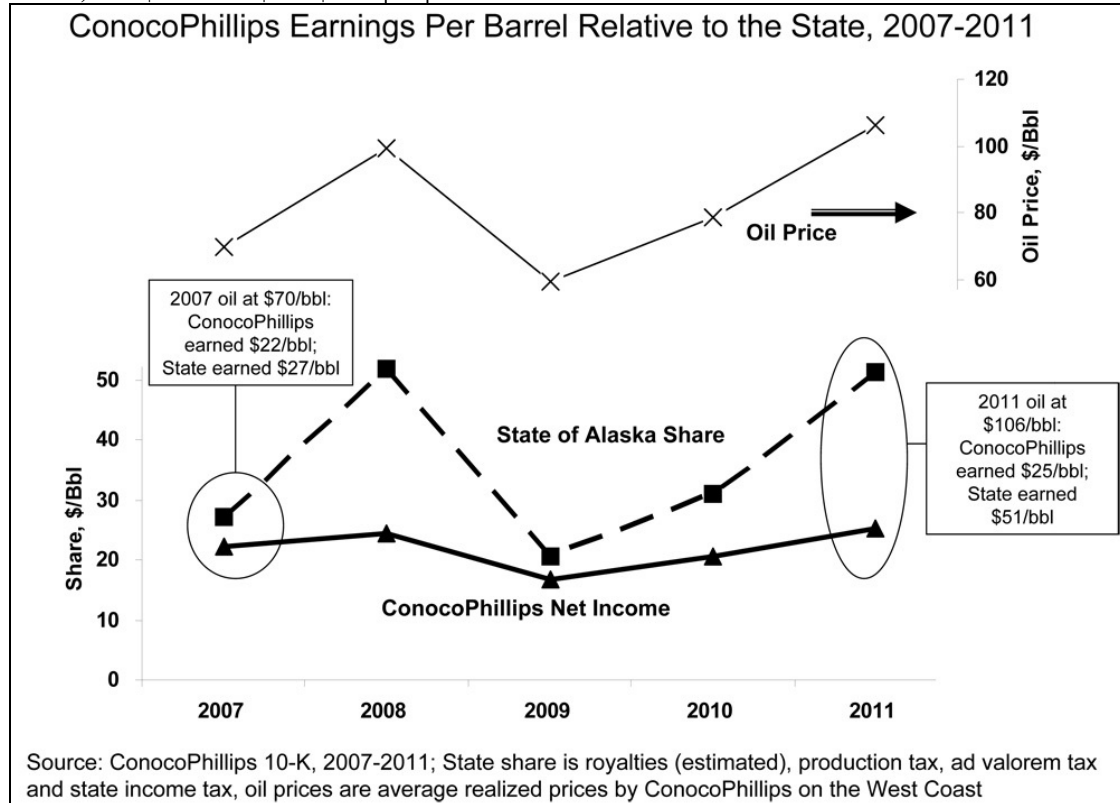
Nov. 2, 2012

The numbers show why oil tax reform is needed:

ConocoPhillips has a profit, but state takes much more

by Scott Jepsen

Nov 02, 2012 | 887 views | 4 | 8 | | |



ConocoPhillips is proud to have been a partner with the state of Alaska in developing Alaska's oil and gas resources for more than 50 years. Today, ConocoPhillips employs more than 1,000 Alaskans directly and supports thousands of other Alaska jobs through our contractors. Working in partnership with the state and its citizens, we hope to continue to operate in Alaska for many more decades. However, high taxes on North Slope oil production, in particular the tax increases passed by the legislature in 2007 under a bill called Alaska's Clear and Equitable Share, are hurting the investment climate on the North Slope and ultimately the long-term health of Alaska's economy.

Like any publicly traded company, we are in business to make a profit to provide for sustained investment and growth. We invest billions in developing and producing oil and natural gas and pay billions in taxes and royalties, but also expect to make returns commensurate with the investment size and risk. Since ACES was enacted in 2007, through to year-end 2011, we have reported almost \$10 billion in net Alaska income.

While this is an impressive figure, it needs to be placed in proper context. During the same period, ConocoPhillips paid approximately \$16 billion in taxes and royalties to the state of Alaska — 60 percent more than we earned. Counting federal income taxes in that period, we paid approximately \$21 billion in taxes and royalties — twice what we earned. The ACES tax increases have skewed the balance between investor risk and reward.

The Legislature's consultant on oil taxes, PFC Energy, has pointed out on numerous occasions that Alaska's marginal tax rate is among the highest in the world.

The accompanying chart demonstrates the impact Alaska's marginal tax rate has on profits. From 2007 through 2011, oil prices rose from about \$70 per barrel to almost \$106 per barrel — an increase of more than 50 percent. But over the same period, ConocoPhillips' net income in Alaska only increased from about \$22 per barrel to about \$25 per barrel.

So, where did most of the price upside go? Due to the "progressivity" feature of ACES, the state's share rose from about \$27 per barrel to a peak of \$51 per barrel, an increase of almost 90 percent. This is the main problem with ACES: Due to its hyper-intensive progressivity element, the state takes the vast majority of the upside.

Those who want to leave ACES unchanged frequently cite ConocoPhillips' earnings reports to support their arguments by comparing ConocoPhillips' Lower 48 earnings to its Alaska earnings. (*Editor's note: See Richard Fineberg, Daily News-Miner, Oct. 14, page F3*) But that is an apples-to-oranges comparison. In the Lower 48, natural gas and natural gas liquids make up a large part of ConocoPhillips' portfolio. Those products have lower value and margins than oil, especially after recent steep declines in natural gas prices. Conversely, the vast majority of our production in Alaska is oil, which has a relatively high value. This type of comparison to the Lower 48 provides no real insight into the relative health of Alaska's investment climate.

A better measure is capital investment. Despite rising oil prices, ConocoPhillips' capital budgets in Alaska in 2010 to 2012 remained flat at about \$900 million per year. In the Lower 48, our capital budgets tripled, from \$1.6 billion in 2010 to \$4.8 billion in 2012, driven by attractive Lower 48 oil plays given today's high oil price environment.

This is the fundamental problem of ACES — it skews the risk-reward balance of investments at high prices, making the North Slope a less favorable place to invest.

Ultimately, oil taxation in Alaska is about the balance the state wants between business activity levels, production and state revenues. Today, the balance is heavily weighted to short-term state revenues and does not provide the incentives for increased investment that will result in more oil production. That does not bode well for the investments needed to help ensure a long-term, healthy state economy. We hope the next Legislature takes up the oil tax issue and enacts an oil tax bill that significantly improves Alaska's business climate.

Scott Jepsen, of Anchorage, is vice president for external affairs at ConocoPhillips Alaska.

Accessed Nov. 3, 2012 at Fairbanks Daily News-Miner - The numbers show why oil tax reform is needed ConocoPhillips has a profit but state takes much more

(For analysis of CP's chart, see Exhibit 8.)

Exhibit 8.

Filling the Gaps:

**ConocoPhillips Presentations to Senate
Resources and
House Resources Committees
(Feb. 20 and Mar. 26, 2013)**

**“ACES Observations” (Senate Resources
Committee, Feb. 20, 2013)**

[Exhibit 8, Sheet 1]

**“North Slope Investment Challenges” (House
Resources Committee, Mar. 26, 2013)**

[Exhibit 8, Sheet 2]

Salient CP Chart Deficiencies

[Analysis of Exhibit 8, Sheet 1]

Questions about the Earnings per Barrel Chart

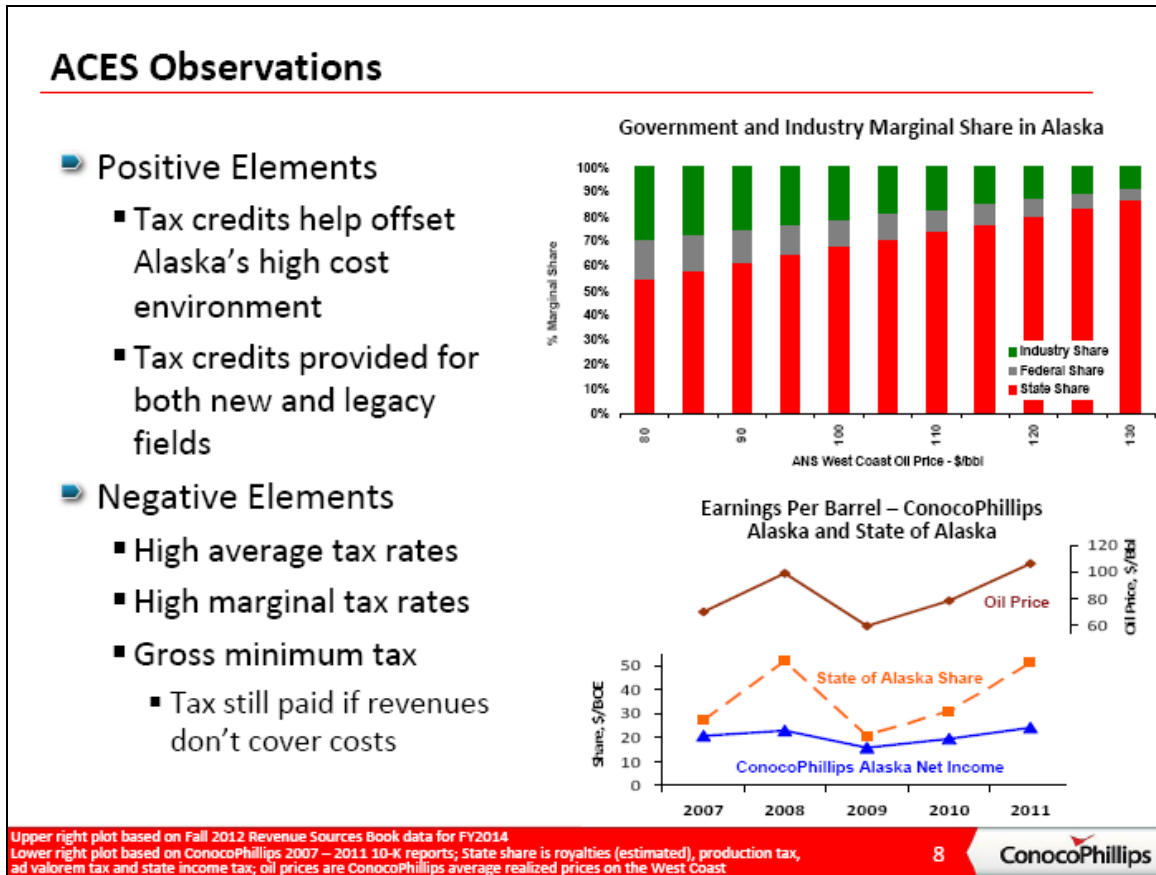
[Analysis of Exhibit 8, Sheet 2]

**Worksheet: Understanding CP’s Earnings Per
Barrel Chart**

[Analysis of Exhibit 8, Sheet 3]

Exhibit 8.

ConocoPhillips: “ACES Observations” (Senate Resources, Feb. 20, 2013)



Senate Resources Committee

SB21

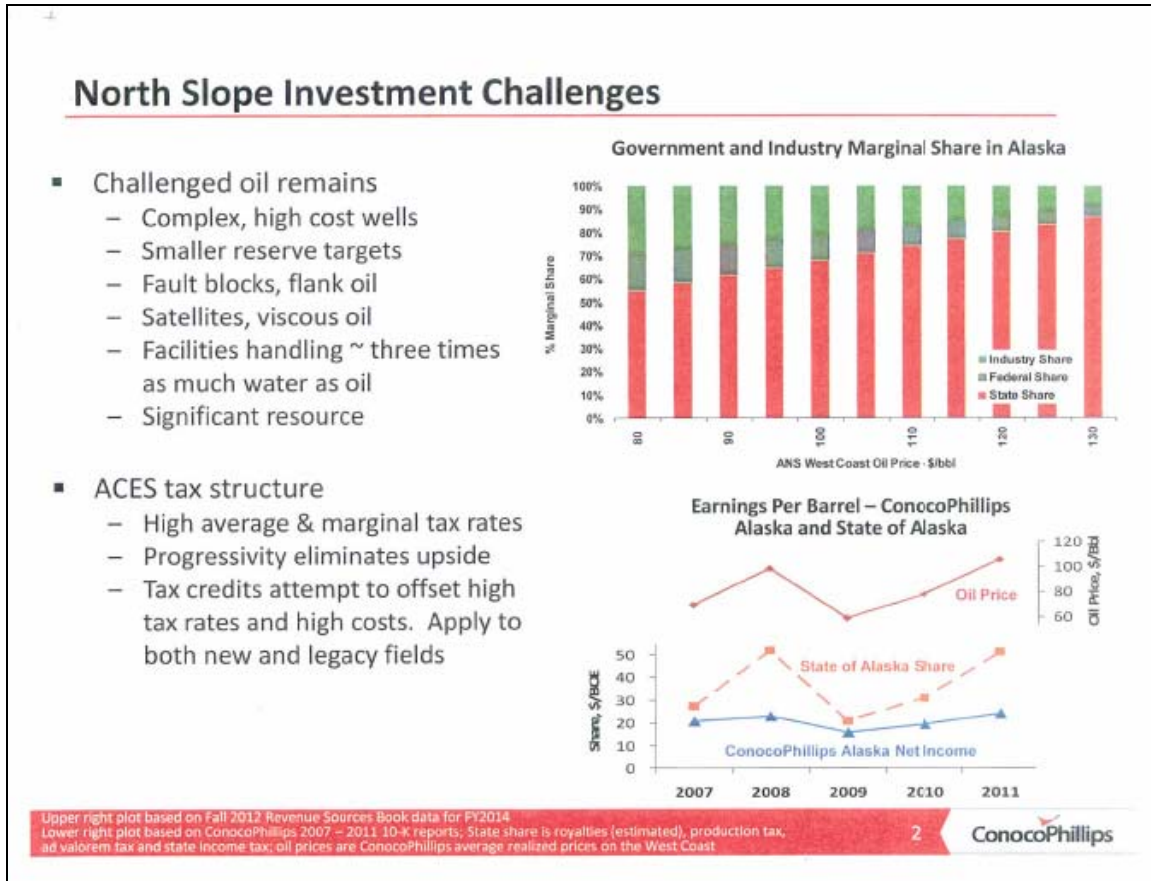
Bob Heinrich, VP Finance
Scott Jepsen, VP External Affairs
ConocoPhillips Alaska

February 20, 2013

ConocoPhillips

Exhibit 8.

ConocoPhillips: “North Slope Investment Challenges” (House Resources, March 26, 2013)



House Resources Committee

CSSB21

Bob Heinrich, VP Finance
Scott Jepsen, VP External Affairs
ConocoPhillips Alaska

March 26, 2013

ConocoPhillips

ConocoPhillips Chart Deficiencies: Filling in the Gaps

Analysis of Exhibit 8 (Sheet 1 of 3)

The background of the CP chart showing “Earnings Per Barrel – ConocoPhillips Alaska and State of Alaska” is discussed in Section 5A of this report; an earlier version of the chart, from the *Fairbanks Daily News-Miner* Nov 2, 2012, is shown in Exhibit 7.

Salient CP Chart Deficiencies

1. Sources of charts ConocoPhillips presented to House Resources, March 26, 2013 (Slide 2) and Senate Resources, February 20, 2013 (Slide 8) are stated without providing hard-number data or specific references. CP's sourcing information on both slides reads:

- “Upper right plot based on Fall 2012 Revenue Sources Book data for FY 2014.”
- “Lower right plot based on ConocoPhillips 2007 – 2011 10-K reports; state share is royalties (estimated), production tax, ad valorem tax and state income tax; oil prices are ConocoPhillips average price realized on the West Coast.”

2. These two ConocoPhillips charts are incomplete because neither one shows estimated costs, (which increased dramatically during the years covered by these charts (see Exhibit 1).

- This is an important omission because Alaska's production tax has been cost-based since 2006.
- Costs generally rise and fall with oil prices, but do not necessarily vary directly. It is therefore important to explore the relationships between oil price and field costs and their effect on the producer's bottom line?

3. The bar chart in the upper panel of both slides is not drawn to scale.

- The bar chart shows percentages of total revenue rather than dollars (for example, showing the \$80 bar at the left to be equal to the \$120 bar at the right). This panel therefore presents a distorted picture that makes it appear that ConocoPhillips net revenue per barrel decreased dramatically between 2007 and 2011 – contrary to the ConocoPhillips Net Income from Alaska production shown on the chart below in blue.
- On March 26, 2013 CP's Bob Heinrich told House Resources that between 2007 and 2011, “Our earning stayed between \$22 to \$25 per barrel” and “have essentially hardly moved “ But when CP displayed a similar chart last November, Scott Jepsen wrote that over the same period ConocoPhillips' net income from Alaska “increased from about \$22 per barrel to about \$25 per barrel” – an increase of approximately 14 percent (exceeding inflation, despite declining production). .

4. ConocoPhillips has presented data in the top chart forecasted for a different year (fiscal year 20 14) from the years covered in the bottom chart (2007 through 2011), making analysis difficult.

- The presentation of different fiscal years in the two charts shown on this slide makes it difficult to assess hard-dollar impacts of the changing oil prices.
- The failure to present specific data makes it even more difficult to assess hard-dollar impacts of the increasing oil prices shown in the top chart.

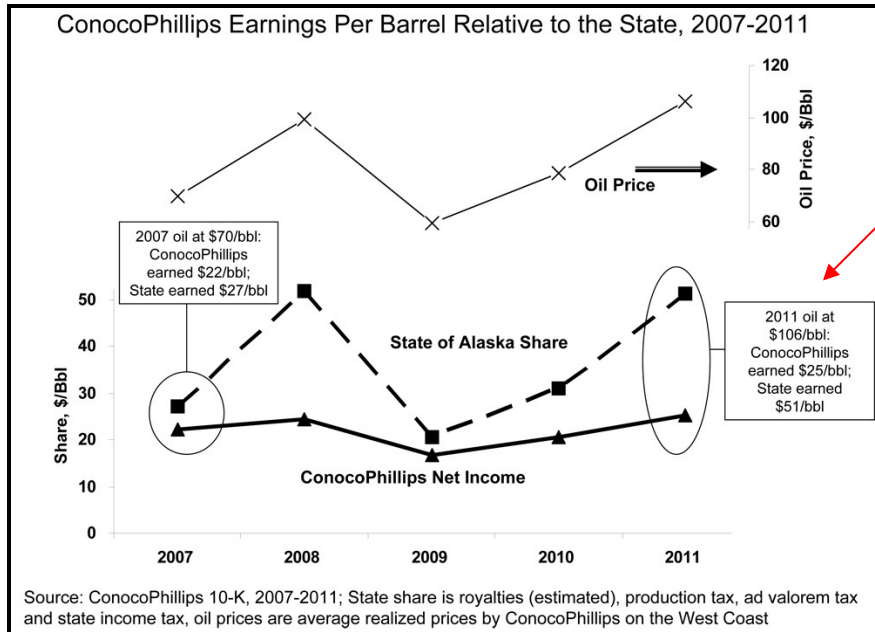
While the level of progressivity at high oil prices under ACES may need to be adjusted, the simplified charts being used in Juneau lack data. Legislators therefore do not have sufficient basis for estimating effects of proposed tax changes, which cannot be meaningfully assessed without field cost and bottom-line earnings information (not to mention a clear understanding of the importance of geology and economies of scale).

ConocoPhillips Chart Deficiencies: Filling in the Gaps

Analysis of Exhibit 8 (Sheet 2 of 2)

Questions about the Earning Per Barrel Chart

"The numbers show why oil tax reform is needed," *Fairbanks Daily News-Miner* (Nov. 2, 2012)



"2011 oil at \$106/bbl: ConocoPhillips earned \$25/bbl; State earned \$51/bbl"

With billions of dollars at stake and 3 companies in control of North Slope production, here are questions that deserve consideration:

Why don't CP's Alaska revenue "take" figures match State data? (See *Worksheet 2*.)

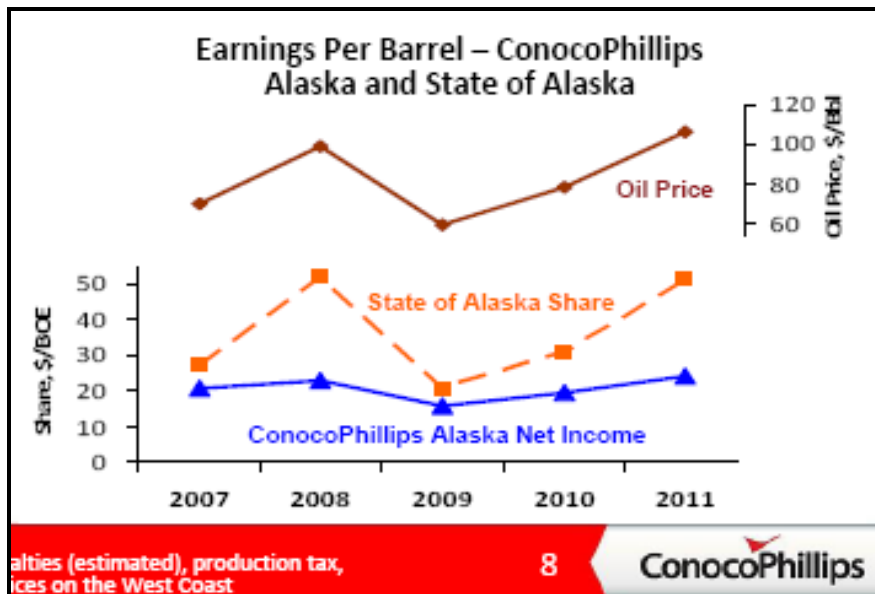
Why do these charts omit field costs, which have increased since 2007 at approximately eight times the rate of general inflation? (See *Exhibit 1*.)

Do CP profit totals count the smaller but significant profits from pipeline tariffs? (See *Exhibit 2*.)

Has the State determined whether pipeline overcharges, which reduce State revenue, might also inhibit North Slope Development?

Have CP numbers been verified by audits with quality control checks?

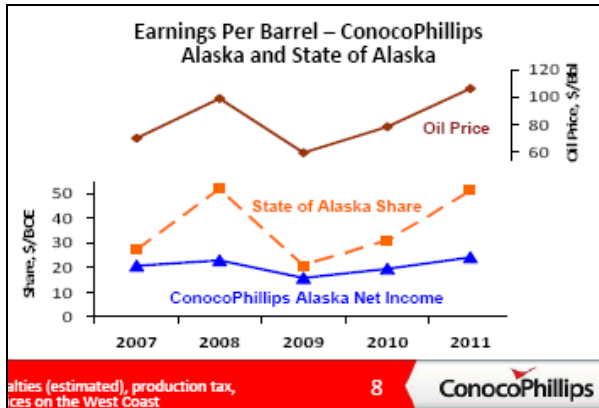
"ACES Observations" and "North Slope Investment Challenges," CP Presentations to the Senate and House Resource Committees (Feb. 20 and March 26, 2013)



ConocoPhillips Chart Deficiencies: Filling in the Gaps

Analysis of Exhibit 8 (Sheet 3 of 3)

Worksheet: Understanding CP's Earnings Per Barrel Chart



Due to fluctuating prices and production, State fiscal year (FY) data may not be comparable to calendar year (CY) data. When ADOR does not provide comparable CY data, conversion to CY display uses the following weighted average formula:

$$CY13 = ([FY12]*5 + FY13*7)/12$$

Trial Calendar Year 2011 Cost Estimates

	Cost Estimate A	Cost Estimate B *
1. Price per barrel (CP estimate)	\$106.00	\$106.00
2. Transportation (TAPS plus Marine)	\$8.13	\$8.13
3. Field Costs (Unaudited OPEX + CAPEX) *	\$24.20	\$22.45
4. Alaska Share (CP estimate)	\$51.00	\$51.00
5. CP Profits (CP Estimate)	\$25.00	\$25.00
6. Federal Income Tax *	\$13.46	\$6.65
7. Sum of Implied Cost Elements	\$121.79	\$113.23
8. Estimated Unaccounted Cost per-barrel	\$15.79	\$7.23
9. Annualized North Slope Unaccounted Costs	\$3,394,158,770.00	\$1,554,190,909,940.00

* For differences in Trial Cost Estimates A and B, see notes to Lines (3) and (6), below..

(1) Scott Jepsen, "ConocoPhillips Earnings Per Barrel Relative to the State, 2007-2011" (chart with "The numbers show why tax reform is needed: ConocoPhillips has a profit, but state takes much more" (Community Perspective), *Fairbanks Daily News-Miner*, Nov. 2, 2012 (see Exhibit 7).

(2) Weighted average transportation cost estimates from Alaska Dept. of Revenue, *Fall 2011 Revenue Sources Book*, p. 31 (FY 2011 history) and *Fall 2012 Revenue Sources Book*, p. 35 (FY 2012 history).

(3) Weighted average operating and capital cost estimates from Alaska Dept. of Revenue, *Fall 2011 Revenue Sources Book*, p. 31 (FY 2011 history) and *Fall 2012 Revenue Sources Book*, p. 35 (FY 2012 history). Field costs calculated as: (North Slope operating and capital expenditures) / ([Total ANS daily production] * 365).

Note: Trial Cost Estimate B subtracts \$360 million credits used against tax liability from field costs.

(4) "ConocoPhillips Earnings Per Barrel Relative to the State, 2007-2011."

(5) "ConocoPhillips Earnings Per Barrel Relative to the State, 2007-2011."

(6) Federal income payments are calculated from CP's stated after-tax profit (ATP) using the following formula: Income tax = ((ATP / [1 - tax rate]) - ATP).

Note: Trial Cost Estimate A FIT calculated at nominal 35%; Cost Estimate B estimated at effective 21%.

(7) Sum of lines (2) through (6).

(8) Line (7) - Line (1).

(9) Line (8) * (estimated CY 2011 production, derived from weighted average fiscal year totals).

Exhibit 9.

ConocoPhillips Capital Allocation (Slide)

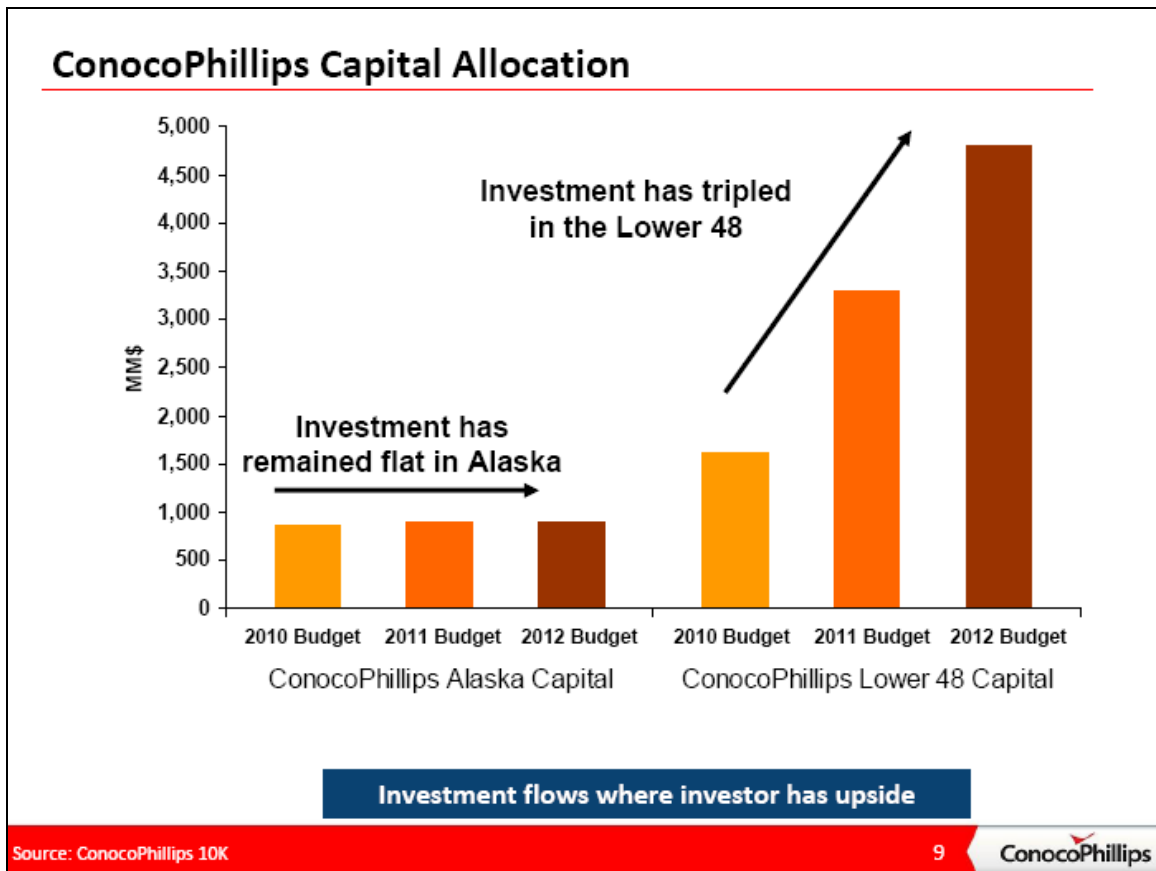
**“ConocoPhillips Capital Allocation” (Senate
Resources Committee, Feb. 20, 2013)**

[Exhibit 9, Sheet 1]

Exhibit 9.

ConocoPhillips: “ConocoPhillips Capital Allocation”

(Senate Resources Committee, Feb. 20, 2013)



Richard A. Fineberg is an independent, Alaska-based analyst who has reported on economic and environmental issues associated with Alaska petroleum development for more than three decades. In addition to the numerous reports he has prepared for non-government organizations (available on-line at <http://www.finebergresearch.com>), he has served as a senior advisor to the governor of Alaska on oil and gas policy, and as an occasional consultant to various state and federal agencies, including the U.S. Internal Revenue Service, the Alaska Department of Revenue and the Regulatory Commission of Alaska.

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