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**ALASKA OIL AND GAS ASSOCIATION
TESTIMONY ON COMMITTEE SUBSTITUTE SENATE BILL 21 (VERSION C)
TO THE SENATE FINANCE COMMITTEE**

March 5, 2013

Good Morning. My name is Kara Moriarty and I am the Executive Director of the Alaska Oil and Gas Association, commonly known as "AOGA". AOGA is the professional trade association that represents 15 member companies who account for the majority of oil and gas exploration, development, production, transportation and refining of oil and gas onshore and offshore in Alaska. These comments regarding Senate Bill 21, and specifically Committee Substitute Senate Bill 21 (CSSB 21) version C, have been reviewed by all members and have been approved unanimously.

The industry's greatest challenge today, which we share with the State is the decline of oil production from the North Slope. We believe that the greatest, most urgent issue facing this Legislature in 2013 is how you will address this problem. We cannot fix the basic, inherent properties of any oil and gas field, that is that the resource is finite and production will eventually decline. We can fix some of the economic principles that drive the development of more and new resources. Corrections to the ACES tax regime will remove impediments to development and exploration and assist the industry in investing in projects that could both extend the life of TAPS and open up new resources to long term development. When we look to the future Alaskans see a robust industry on the North Slope growing like it is the rest of the United States. We want the jobs here and not in the Lower 48. We want to create developments that will last for decades more, creating jobs for our children and opportunities for our communities to flourish. Alaskans want to see the industry continue to support the education and skills training that are needed to qualify for many of those jobs. A healthy oil and gas industry is one that sees the economic benefits of continuing to invest in projects in Alaska and keeping its employees

here, where they volunteer their time, talent and treasure to make Alaska a better place to live for us all. Alaskan's, and the Alaskan economy, depends on the industry and its direct and indirect contributions as well as its funding the vast majority of the costs of our government.

Our goal today is to offer insights into how the CSSB21 impacts the industry. Specifically, how the present tax laws are fundamentally broken, and instead of incentivizing investments that benefit us all, are actually hindering the very development and growth Alaskan's deem essential. We have ideas of how the current tax structure can be modified to better suit the needs of the State.

The Tax "Give Away" Fallacy

We hear all too often of the \$2 billion dollars that will be a "give away" to the industry should the tax regime be changed. It is a simple and effective communication that completely misstates the reality of the tax structure and its impact on the industry. It is simple to calculate how a change in a tax rate will impact amount of taxes collected if all "other" things remain constant. For example, if production does not decline further, if lifting costs don't rise, if the \$2 billion dollars of annual investment by the industry to slow that decline continues, and if oil and gas prices do not shift. All of these "other" items seem to be considered a given in these calculations and it is assumed they will remain unchanged in the future – the pundits of the "give away" theory want you to believe it's that simple. But it is not.

However resourceful the State's revenue estimators are, they cannot control decline, lifting costs, future investment, or the price of crude oil. As the rest of the nation swims in new industry investment and development, Alaska languishes. The costs of operations continue to rise as North Slope fields decline. The \$2 billion a year of industry investment spent in wrestling decline must now compete with more lucrative projects elsewhere, and with growing US production and supply of oil and gas the future price of that oil and gas is anyone's guess. Naysayers to these necessary and fundamental changes to our tax structure look only to the downside simple calculations they take from a Revenue Sources Book they forget is only a "guesstimate" of future revenue. The upside potential of that change, though, is very real. If a restructuring and tax rate reduction make investments here more competitive, companies will want to make more investments here for that upside. Deciding to make long term investments in Alaska's North Slope requires the industry to see potential upside to their investments and assessing that the essential risks of those investments are offset by the opportunities afforded in success. Without that potential opportunity in Alaska, investment dollars will be spent elsewhere, where risks are less and

opportunity is greater.

Core Principles to Address North Slope Production Decline

As you consider potential solutions to the challenge that production declines creates for Alaska, AOGA believes Governor Parnell's four "core principles" offer an excellent cornerstone for this:

- "First, tax reform must be fair to Alaskans."
- "Second, it must encourage new production."
- "Third, it must be simple, so that it restores balance to the system."
- "Fourth, it must be durable for the long term."

We believe the addition of a fifth such principle would be required to meet Alaska's goals, because the challenge is not that there are too many companies pursuing opportunities, but that there are too few. Alaska should therefore avoid tax changes that artificially create "winners" and "losers."

With respect to the CS to Senate Bill 21, there are several features in it that we wish to address; such as the elimination of progressivity, an increase in the base tax rate to 35%, changes to the present system of tax credits – including the addition of the manufacturing credit, a gross revenue exclusion for certain new production and the concept of a competitiveness review board. I will also identify some of the issues with the current system that the CS does not address.

1. Repealing Progressivity.

AOGA endorses the elimination of progressivity.

Impact of Progressivity as part of the ACES tax rate in industry investment decision making is the single most influential component of Alaska's tax structure negatively impacting investment decisions related to Alaskan projects. Taxes are paid by the industry in virtually every jurisdiction in which we function and so we are very familiar with how they work. But the uniformity and consistency in the application of tax impacts as they relate to investment decision making found in almost every jurisdiction is missing in Alaska. As my member companies have testified in the past, investment decisions are driven by combining high and low case scenarios where costs and revenues are estimated and best case cash flows and worst case cash flows are measured, risked and analyzed. Each potential project, in every jurisdiction, is measured and compared and only some are funded. As your consultant, Roger Marks pointed out yesterday, the international investment climate is characterized by plenty of opportunities, fluid capital, but finite capital. To choose what they can and cannot fund, companies have compared each potential project, no matter the jurisdiction, by application of a uniform investment

decision measuring formula. When Alaska's tax system is quantified and added to this measure for proposed Alaskan projects the best cases are always burdened with an excessively high tax rate and as the assumed high cases get better, the burden only increases. We can find almost no other jurisdiction that so burdens investment return where the better the cases assumed for the decision, the higher the tax burden that applies. As I will address in a moment, we have no real maximum tax rate, and Alaskan investments are further burdened because the lower the case assumed, the higher the tax burden that applies as well.

EXAMPLE 1 BELOW:

Progressivity brings extraordinary complexity to the tax, not only in calculating what the tax is, but also in analyzing what the amount of the progressivity is for any particular item that affects a taxpayer's Production Tax Value (PTV). This complexity exists because the tax rate for progressivity depends on the taxpayer's PTV per barrel, and then the resulting rate is applied to the very same PTV that set the rate. This circularity in the tax calculation leads to bizarre effects. For instance, simply the fact that oil prices fluctuate during a year instead of remaining perfectly flat increases the tax due even though the average of the fluctuating prices is the same as the flat price — and the greater the fluctuation, the greater the tax from progressivity becomes. There is no objective economic or financial reason for the tax to go up; instead, this occurs entirely because the progressivity calculation is circular.

The repeal of progressivity is consistent with all four core principles outlined above. Its removal improves fairness because operators that increase margins through efficiency would no longer be automatically penalized. Its removal encourages new production because it reduces the tax burden on investment, as discussed above. Its removal is a significant step toward simplicity. And, lastly, its removal enhances durability because it satisfies the three preceding core principles.

2. Increasing the base tax rate from 25 to 35%.

AOGA does not endorse increasing the base tax rate to 35%.

Let's go back to the industry investment decision process again. Increasing the base tax rate, besides burdening every investment case with a higher tax rate, now adds an additional burden to the worst case scenarios when oil prices are low or project costs are high. When applying the current base tax rates to the investment cases for a proposed project, until one assumes a price collapse occurs and the minimum fixed rates apply, even when little revenue is assumed to be generated, the base tax applies. The burden of a 35% versus a 25% rate is easy to envision as every middle case and every

worst case scenario is burdened with an additional 10% tax rate. This assumed cost will negatively impact the potential returns deemed available for any Alaskan project and drive investments to be made elsewhere. Increasing the base tax rate is contrary to the second core principle; there is not any reasonable argument that suggests increasing the base tax rate would encourage new production. Indeed, using the progressivity formula as a benchmark, the ten percentage point increase in the base tax rate could be viewed as equivalent to a sustained reduction in oil price of \$25 per barrel, all else being equal.¹

3. Tax Credits

In general, tax credits, because they act to offset a part of the costs of certain investments when the expenditure is made are an important tool in reducing the deemed risks of those expenditures. Industry makes investments to seek returns. Costs of any kind, including taxes reduce those returns, so the offset of tax cost by a tax credit provides immediate benefit to the investment return calculation. Whether those costs are for drilling a well, building a facility to gather new oil, or installing a pipe to gather oil, a tax credit represents an immediate and direct reduction in the amount that a potential investor puts at risk in spending money on equipment and facilities that benefit production.

Those tax credits are directly related to production as investments must actually be made for the credit to be utilized and those investments will positively impact production. It is important to note that there is no tax credit liability for the State at all until an investor invests here. The investment has no other purpose than creating return by positively influencing production. So it costs the State nothing to offer the credit until the investment is made and at that point the tax credit has already succeeded in what it is supposed to do – namely to attract investment dollars here for investments that will act to increase production and reduce decline. The production impacts of the investments, although partially offset by tax credits, will act in other ways to increase taxes collected.

A. Repeal of the Qualified Capital Expenditure (“QCE”) Tax Credit.

AOGA does not support the repeal of the Qualified Capital Expenditure Tax Credit.

Even while the elimination of progressivity would improve the competitiveness of Alaskan investments from the present ACES tax, the elimination of the QCE Credit would claw back one

¹ In other words, a sustained \$25 per barrel price change would be needed under progressivity to get the same 10% change in the base tax rate. Under progressivity, each \$1 increase in PTV (or price, all else equal) per barrel would result in a 0.4% increase in the tax rate surcharge. Thus, a 10 percentage point change in the tax rate under progressivity would be equivalent to a \$25 change in PTV or price because $25 = 10\% \text{ divided by } 0.4\%$.

important financial incentive and a part of ACES that actually acts to improve the competitive environment. The QCE Credit depends entirely on how much is invested here, and provides benefits for investments even when oil prices are lower. While the benefit from ending progressivity, which depends on the price of oil relative to a producer's lease expenditures, helps when oil prices are higher the QCE provides benefits when prices are not. In this mid-range of oil prices the loss of QCE Credit would outweigh the benefit from the end of progressivity.

Repeal of the QCE credit is contrary to the second core principle. Furthermore, because every producer's costs are different and prices will impact them differentially AOGA, fears the repeal of the QCE Credit is worse than creating "winners" and "losers" because it only creates "losers" artificially among producers, and we see no sound tax policy justification for doing so.

For these reasons, AOGA believes the elimination of the QCE tax credits would be a mistake. Instead of that, one possibility might be to expand the scope of the "well lease expenditure" tax credit under AS 43.55.023(1) so it is available to producers on the North Slope. This credit has several meaningful advantages. First, it focuses investment incentives on subsurface intangible-drilling expenditures, which are a reasonable proxy for direct spending on well activity and, in turn, production. Second, the credit is clear because it uses already established concepts in the federal Internal Revenue Code. Third, it is fair because it applies equally to well-related spending in all areas of the state, without creating winners and losers merely on the basis of geography.

B. The \$5 dollar per barrel tax credit.

AOGA is not certain that the potential benefit of a \$5 dollar per barrel tax credit under AS 43.55.024(i) will be offset by other burdens.

There are multiple issues to balance when taking in the numerous proposed changes found in CSSB21. The removal of progressivity, the increase in base rate, early sunset of the QCE credit all create interrelated issues and while a \$5 dollar per barrel tax credit would provide benefits both in real tax costs and in investment decision making, the weight of the benefit in respect to the other changes is hard to measure. AOGA applauds the concept of tying incentives to the goal of increased production and as such allowing a tax credit per barrel. One must consider, though, what the \$5/bbl credit will mean to a small producer with little production as opposed to the legacy producers that already have established large scale production. In view of the investment decision making process and the Alaskan tax structure's impact on it, we are not certain that this benefit is offset by the other burdens

contemplated when striving for the goal of increasing production.

C. Small-Producer and Exploration Credits.

AOGA endorses the proposal to extend the small-producer tax credit under AS 43.55.024 and exploration tax credits under AS 43.55.025 from the present sunset dates in 2016 to a later date.

The State had sound policy reasons for creating these small producer and exploration tax credits, and those reasons are just as valid today as they were then. AOGA believes these credits have increased the likelihood of participation by new industry players and act to increase the opportunities that could be found by expanding exploration. The purpose of the small-producer tax credit was to attract new players to Alaska who might otherwise have been deterred from coming here by presumptions of increased risks and of higher-than-average costs and expenses. The success of the credit in attracting new participants is a fact that cannot be denied. AOGA sees this success in its own membership, and in other companies that have come here and are now active. Smaller producers often have a different perspective about the opportunities around them, and as such can bring with them new ideas and opportunities. New participants with new ideas can only strengthen and improve the Alaskan petroleum industry and help the state stem the decline in production. We know from testimony that the small-producer tax credit has made a material difference in individual companies' decisions to do business and invest in Alaska.

The purpose and justification for the exploration tax credits under AS 43.55.025 are equally clear. Huge parts of this state remain unexplored or underexplored. Again, these tax credits are only earned when actual expenditures for exploration occur. The credits tangibly reduce the risks faced by an explorer and as such incentivize them to go out and search for oil and gas that is much needed. Increased exploration leads to increased development and these credits act to increase exploration and should be extended as well. Just as with the QCE credits for capital investments, there is no exploration tax credit without real money having first been spent on exploration work that qualifies for these tax credits.

D. Limiting the transferability of "carried-forward annual loss" tax credits.

AOGA does not support the limitation on transferability of these losses.

We have some reservation about the proposal to bar almost completely the transferability of the current "carried-forward annual loss" tax credits under AS 43.55.023(b). New participants and new

explorers are many times not yet producing in the state or only producing small volumes of oil and gas and as such have little or no production tax liabilities. The ability to transfer their losses to others allows them to monetize the investments they have already made, both reducing their cost exposure on the original expenditure and hopefully at the same time acquiring additional capital for more investment. These credits arise every year for any active explorer until it finds oil or gas and finally incurs production taxes to apply the credit against. At present explorers can only realize immediate benefit from these credits by selling them to other taxpayers or cashing them in at the state Oil and Gas Tax Credit Fund established in AS 43.55.028.

Under the Bill as proposed, transfers would cease and explorers would have to hold on to losses for up to 10 years for possible use against taxes on their own production. The potential that a loss could not be offset against tax expenses or monetized in the near term places more risk on the decision to invest and as such makes such activities less likely to occur. If the transferability must cease, then the cost of the expiration of the loss carry forward after only 10 years, where on the North Slope exploration success to production can easily take longer, is another factor that negatively impacts investment decisions. Although the annual addition for interest will allow the losses to retain some value, we also believe that a 15 year period before expiration of the loss carry forward is the minimum timeframe that should apply if transferability is removed.

E. The "Anti-stackable" section

AOGA does not think this new section is necessary.

In Section 22 of the CS, AS 43.55.025 is amended by adding a new subsection to read:

(q) An exploration expenditure incurred after December 31, 2013, to explore for oil or gas located north of 68 degrees North latitude that is the basis for a credit under (a)(1), (2), or (3) of this section may not also be the basis for a credit claimed under AS 43.55.023 or this section.

AOGA does not understand why this new section is being proposed as it is our understanding the concern this new language is to trying address is already covered in existing statutes.

F. New credit for Manufacturing

AOGA supports the new proposed manufacturing credit.

Although this credit is directed to the incentivizing of development and manufacture of drilling and exploration methods and materials, it may not have a great impact on the reduction

of the current production decline. However, it is a step in the right direction to incentivize jobs and additional investment, and having more jobs and investment in Alaska is never a bad thing.

4. Gross Revenue Exclusion.

AOGA endorses the proposed 30% gross revenue exclusion or GRE, but has concerns on breadth of applicability.

The GRE would, in calculation of the taxable Production Tax Value, exclude 30% of the Gross Value at the Point of Production of what we'll call "non-legacy" production. Thus the GRE provides incentive for finding new oil and getting it produced. As much as AOGA supports this proposal we are also concerned that it is too narrowly focused. This narrow focus and application to only certain areas, especially those outside existing Units where the best prospects of new oil are likely to be found, needlessly restricts the benefits that such a proposal could have on increasing production. Fields likely to lose out on getting any GRE are Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Niakuk, Point McIntyre, and Alpine; as well as the Prudhoe Bay satellite fields Aurora, Borealis, Midnight Sun, North Prudhoe Bay, Orion and Polaris and the Kuparuk satellites Meltwater, NEWS, Tabasco, Tarn and West Sak.

Econ One Research, Inc. has previously provided this body a presentation entitled *Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal, HB 72*. In that presentation oil and gas resources described as "Economically Recoverable @ \$90/bbl" total 29.1 billion barrels of oil and barrel-equivalents of gas of which 3 billion are in the central North Slope where all the currently producing and therefore ineligible fields are. Of this 3 billion barrels, an estimated 2.5 billion or more stands to come from Prudhoe Bay, Kuparuk and other legacy fields already in production. The Governor's second "core principle" for tax legislation is that "it must encourage new production." But, in order to get results from such encouragement, the tax legislation must incentivize the best opportunities that Alaska has for getting results. The GRE as proposed may get some results but in terms of what it attempts to "encourage," it leaves out at least 80 – 90 percent of the 3 billion-barrel opportunity in the central North Slope that Econ One has identified.

AOGA is continuing to search for ways to adapt the Gross Revenue Exclusion to include legacy fields in a way that might be acceptable to the Administration and the Legislature. It may turn out, however, that a different approach may be necessary to "encourage new production" from legacy fields.

Oil and Gas Competitiveness Review Board

The proposed Board provides an oversight and review process that we believe would be burdensome to the industry and contravenes the Governor's principles relating durability in the long term. The perspective that the proposed changes found in the Bill would provide a long term solution to problems we know exist are placed in jeopardy because the very certainty that is required for sound investment decision making would be placed in question with each annual report of the Board. Instead of moving forward with projects that might help stem decline, industry resources would be used to assist the Board in collecting and understanding complex information of long term consequence on a quarterly basis. Finally, the documentation and information the Board might request or require is of the highest proprietary value to oil and gas companies and confidentiality concerns and related complexities would hinder the efforts of the industry as well as the Board. While we appreciate the ability to represent industry on the proposed board, our concerns cause AOGA to question both the viability and the effectiveness of the proposed Board and as such we cannot support its proposed formation.

Issues that the current draft does not address.

There are several significant problems in the present ACES tax that are not addressed in CSSB21, and I will address a few of them this morning.

A. Minimum tax for North Slope production. AS 43.55.011(f) sets a minimum tax that is targeted solely against North Slope production. That tax is based on the gross value of that production instead of the regular tax based on "net" Production Tax Value. The rationale for adopting it was to protect the State against low petroleum revenues when prices are low.

The minimum tax only complicates potential new investors' analyses of what their tax would be if they invest here instead of someplace else, and consequently it has, if anything, driven investments away. AS 43.55.011(f) should be repealed or consideration given to significantly reducing the rate of the minimum tax.

B. Statute of limitations & statutory interest. Here we have two concerns that are interrelated, but not in an immediately obvious way.

The statute of limitations under AS 43.55.075(a) is six years from the date when the tax return was filed for the tax being audited, while the limitations period for other taxes under AS 43.05.260(a) is three years from the filing date of the tax return. Under both statutes, the period may be extended by mutual consent of the taxpayer and the Department of Revenue (DOR).

The statutory rate of interest under AS 43.05.225(1) for tax underpayments is “five percentage points above the annual rate charged member banks for advances by the 12th Federal Reserve District as of the first day of that calendar quarter, or at the annual rate of 11 percent, whichever is greater, compounded quarterly as of the last day of that quarter[.]” Currently the Federal Reserve rate is very low, so 11% APR is the applicable rate.

We are asking that, if the Department chooses to not exercise its authority in providing certainty to the taxpayer to allow them to be able to calculate the correct amount of tax due, then the doubling-up of that uncertainty through statutory interest should be lessened — either by shortening the period for making Department “determinations” from six years back to the usual three, or by eliminating the 11% minimum interest rate on the statutory interest rate, or both.

SEE EXAMPLE 2.

C. Joint-interest billings. Our concern about joint-interest billings is also primarily a problem caused by the approach the Department has chosen to take with its tax regulations. Instead of starting with the joint-interest billings that participants in a unit or other joint operation receive from the operator, the regulations reflect an assumption that each non-operating participant has information, in addition to the operator’s billings to them, that allows them to determine which expenditures are deductible as allowed “lease expenditures” under AS 43.55.165 and which are not. This assumption is wholly unrealistic. And even if there were some merit to it, the regulations opt to audit each participant separately regarding that participant’s interpretation of which expenditures are deductible and which are not, instead of auditing the system of accounts used by the operator and telling all participants which cost items in that accounting system are deductible and which are not. In other words, instead of one audit of the expenses by a joint venture for any given period, the Department audits each participant separately for its respective share of the same pool of expenses.

We are not asking for legislation to put the Department’s regulations on a different track. But there are some in the Department who believe that the repeal by the 2007 ACES legislation of AS 43.55.165(c) and (d) — which specifically authorized the Department to rely on joint-interest billings — means the Department cannot legally rely on them now. While we disagree with this position (which is also at odds with what the Department testified to during the enactment of the 2007 ACES legislation), we do think it would be appropriate to restore language specifically authorizing the Department to rely on joint-interest billings if it chooses to do so.

Conclusion.

We support the proposed elimination of progressivity, but we have great concern with the increase in the base tax rate to 35%, and with the mixed proposals for tax credits allowing a new \$5 per barrel credit but removing qualified capital credits. The trade-off between repealing progressivity and losing the QCE credit is not a net benefit for industry at low oil prices, and will create a greater barrier to investment from existing and new independent players.

We also agree with the comment by Roger Marks yesterday when in one slide he pointed out the tax system should not favor investing in certain cost fields over others, which in our view is the same as saying we encourage the legislature not to devise a tax system that creates “winners” and “losers”.

The concept of the Gross Revenue Exclusion has considerable potential, but its narrow focus misses 80 – 90 percent of the opportunity in the central North Slope described by Econ One. We will continue to work with you and the Administration to find a fair and reasonable way to expand its scope, or to find an alternative that will address the central North Slope appropriately.

The reasons that led the State to create the small-producer tax credit under AS 43.55.024 and the exploration tax credits under AS 43.55.025 remain valid today. We are pleased that CSSB21 will provide some minimum extension to the sunset date for the small-producer and exploration tax credits.

We believe it is up to you, and the Governor, to shape a competitive oil fiscal policy that is supported by strong principles that will work to arrest North Slope production decline and will lead Alaska towards a prosperous future for the long-term. Overall, the Bill represents a base for significant and crucial tax structure reform that move toward Governor Parnell’s four “core principles” — fairness for Alaskans, encouraging new production, simplicity with balance, and durability for the long term, but as I have outlined today, AOGA members believe there is still many structural changes that should be included for this bill to truly change investment behaviors to the benefit of Alaskans. You have a difficult task ahead and AOGA stands ready to assist you throughout this process.

EXAMPLE 1:

Progressivity directly attacks and destroys one of the few strategic advantages that Alaska has, which lies in its economic remoteness. It costs \$9.42 on average to ship a barrel of oil from the North Slope to the West Coast, according to the Fall 2012 Revenue Sources Book, Appendix D-1b. This means Alaska starts off with a cost disadvantage of \$9.42 a barrel against Outside competition, so other parts of return on Alaskan investment must be stronger than outside investment in order to overcome this disadvantage. If returns Outside are deemed either less risky or providing more opportunity Alaskan investments won't be made.

If oil prices turn out to be higher than what they were projected to be in the industry investment decision analysis, nearly 100% of each extra dollar in price flows directly into the Gross Value at the Point of Production (GVPP) and then, after royalties and taxes, the remainder flows directly into the investor's bottom line. This, in turn, improves the economic performance of an Alaskan investment relative to an equally competitive one Outside, because the Alaskan baseline was \$9.42-a-barrel lower and an additional dollar in price is a larger percentage of that baseline than for the percentage for the Outside investment. This opportunity can be particularly significant for potential investors who are bullish on oil prices.

Currently, progressivity in conjunction with a 25% base tax will take half of each dollar from higher prices when the West Coast price is \$132.38 (using the Fall 2012 Source Book numbers) — a price that has already been seen, although somewhat higher than today's. So, even for investors who are bullish on oil prices, progressivity destroys half of the one strategic advantage that Alaska's economic remoteness provides. Sadly, the more bullish they are, the more this advantage is undone because they will see ever higher rates for progressivity at those prices in their investment analysis.

EXAMPLE 2:

Taxpayers are required under AS 43.55.020(a)(1)-(3) to make monthly estimated tax payments for each calendar month's taxable production during a year, but the final tax amount for the entire year is reported on March 31 of the following year under AS 43.55.030(a). And AS 43.55.020(a)(4) requires any additional tax to be paid at that time. The statutory interest under AS 43.05.225(1) starts to accrue on any underpayment from that March 31st true-up date.

In practical terms, what these various statutes all mean is this. For each dollar of underpaid tax that the Department of Revenue may claim after an audit, statutory interest on that dollar at the end of three years would be —

$$\begin{aligned} \$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 3 \text{ years})} - 1] &= \$1.00 \times [1.38478 - 1] \\ &= \$0.38. \end{aligned}$$

After six years the statutory interest on the dollar would be —

$$\begin{aligned} \$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 6 \text{ years})} - 1] &= \$1.00 \times [1.91763 - 1] \\ &= \$0.92. \end{aligned}$$

Thus, for each dollar of uncertainty there is in what the taxpayer reports on its March 31st true-up for a given year, there is about 38 cents of additional uncertainty due to statutory interest under a three-year statute of limitations, but 92 cents under a six-year statute.

It is the combination of a six-year statute of limitations plus a minimum statutory interest

rate of 11% APR that is so harmful for a taxpayer and any would-be investor. Each dollar of uncertainty in the amount of tax will nearly be doubled by statutory interest after six years.

When we speak about uncertainty and audit assessments six years after the filing of tax returns, many people will think the oil companies could calculate their correct tax liability under the ACES tax if they wanted to. Frankly, so did I before I got this job. So let us take a few moments to illustrate why this is not the case.

As amended by ACES, AS 43.55.150 (captioned “Determination of gross value at the point of production”) says the Gross Value at the Point of Production (GVPP) “is calculated using the actual costs of transportation” from the field to market unless the “shipper ... is affiliated with the transportation carrier[,]” or the “contract for the transportation ... is not a[t] arm’s length[,]” or the “method or terms of [the] transportation ... are not reasonable in view of existing alternative transportation options.” “If the department finds that” any of these situations exists, then the GVPP “is calculated using the actual costs ... or the reasonable costs of [the] transportation ..., whichever is lower.”

The immediate questions about the statute are — How does the Department of Revenue get the information to make such a finding? What is the procedure for making them; is there a hearing, an investigation or what? How does a taxpayer ascertain what the Department has found?

15 AAC 55.193 is the regulation with an important part of the Department’s answers to these questions. Before getting to those answers, we note that subsection (a) seems to disregard the statutory distinction between “actual” and “reasonable” costs, by declaring that “Costs of transportation are the ordinary and necessary costs incurred to transport the oil or gas”² — which could get to the same result as the statutory terms, but not necessarily.

Subsection (e) of the regulation starts answering our questions. It says “a tariff rate ... adjudicated as just and reasonable by the Regulatory Commission of Alaska ... establishes the reasonable costs of the pipeline transportation[.]” So, suppose there has been full-blown tariff dispute before the Regulatory Commission of Alaska, and the RCA has “adjudicated [a tariff] as just and reasonable[.]” And suppose also that a producer ships its oil through its pipeline-company affiliate and pays that RCA-approved tariff. Is this “reasonable” cost under (e) of the regulation the same as the “ordinary and necessary” cost for it for purposes of subsection (a)? Apparently so, but the inconsistent terms in the two subsections prevent this from being completely clear. Moreover, if the transportation occurs “later than five years after the end of the test period on which the tariff rate is based[.]” then even subsection (e) says the tariff ceases to “establish [the] reasonable costs” for the transportation. But it doesn’t say what the right tariff is after those five years are up, or even how to find out or calculate what it is. It is utterly silent.

The very next sentence in subsection (e) after the one speaking about that five-year period starts, “If a complaint challenging [a] tariff rate has been filed with [the RCA] and accepted for investigation” — this is not a situation involving an already “adjudicated” tariff, but one that deals with a new tariff that has been filed for RCA’s approval, which is then challenged. Here, too, the tariff on file is not allowed as the transportation cost under (e) of the regulation. Instead, the cost that is allowed is “103 percent of the costs of transportation calculated by the department using the methodology under 15 AAC 55.197, for the period [while the complaint is being heard and adjudicated by the RCA.]”^{*} Note that it is the Department of Revenue, not the

² Emphasis added.

taxpayer that makes the calculation under 15 AAC 55.197. It is impossible for the taxpayer to know beforehand what the Department's calculation will turn out to be.

Now it is true that 15 AAC 197(m) says a taxpayer may each year "request in writing the department's determination of the applicable after-tax rate of return under (f) of this section [and t]he department will provide the department's determination to the producer no later than the later of July 1 of the calendar year or 90 days after the department receives the producer's request." But the "after-tax rate of return" that the Department promises to provide is only one of the parameters in the cost-based tariff calculation under 15 AAC 55.197. The taxpayer is left on its own to find the correct numbers for the other parameters. More importantly, subsection (m) applies only to "a producer [that] expects to produce oil or gas the actual costs of transportation of which are required by 15 AAC 55.193(b)(6)[.]" Section -193(b)(6) applies only to "transportation of oil or gas by a nonregulated pipeline facility ... that is owned or effectively owned ... by the producer of th[e] oil or gas[.]" In the situation I'm describing, it is a regulated pipeline, not an unregulated one, so this promise in 197(m) does not apply.


We find nothing else in the calculation-methodology regulation, 15 AAC 55.197, nor in 15 AAC 55.193(e), the transportation-cost regulation, that commits the Department to make the cost-based tariff calculation called for in 193(e) and inform the producer of that result before the producer has to report and pay estimated tax each month, or before it makes its annual true-up on March 31st of the following year. The only deadline for informing the producer of the Department's calculated tariff is the six years under the statute of limitations.

And the same or very similar unknowable answers — including tariff calculations by the Department under 15 AAC 55.197 — arise under 15 AAC 55.193(f) regarding tariffs for new transportation facilities that are just being placed in service, and under -193(g)–(h) regarding tariffs set under a settlement agreement to which the State of Alaska is a party.

And just to prevent any misunderstanding, although I have been testifying about proceedings and adjudications by the RCA, these regulations also apply to proceedings and adjudications by some "other regulatory agency" — which would include FERC.

There is a built-in uncertainty created by these regulations, and others that is beyond a taxpayer's allowed authority to answer and beyond its ability to know before the Department gives the answer. And to see a "Technicolor[®]" version where essential elements of the tax calculation are being reserved for the Department to "determine" in its discretion with no specific deadline, one should look at all the crucial "determinations" in 15 AAC 55.173 ("Prevailing value for gas") that are reserved for the Department to make regarding the valuation of natural gas that would be transported to markets outside Alaska.

We are not asking for a statutory fix to the regulations. But we are asking that, if the Department chooses to defer making calculations and similar determinations that are necessary in order even to be able to calculate the correct amount of tax at all, then the doubling-up of that uncertainty through statutory interest should be lessened — either by shortening the period for making those "determinations" from six years back to the usual three, or by eliminating the 11% minimum interest rate on the statutory interest rate, or both.



AOGA

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

**Senate Finance
Committee
CSSB 21**
March 5, 2013
Kara Moriarty, Executive Director

AOGA Member Companies



PIONEER
NATURAL RESOURCES ALASKA

Statoil

XTO
ENERGY

REPSOL

Apache

Hicorp Alaska, LLC

ExxonMobil

TESORO

petro STAR INC

bp

Alyeska pipeline
SERVICE COMPANY

eni

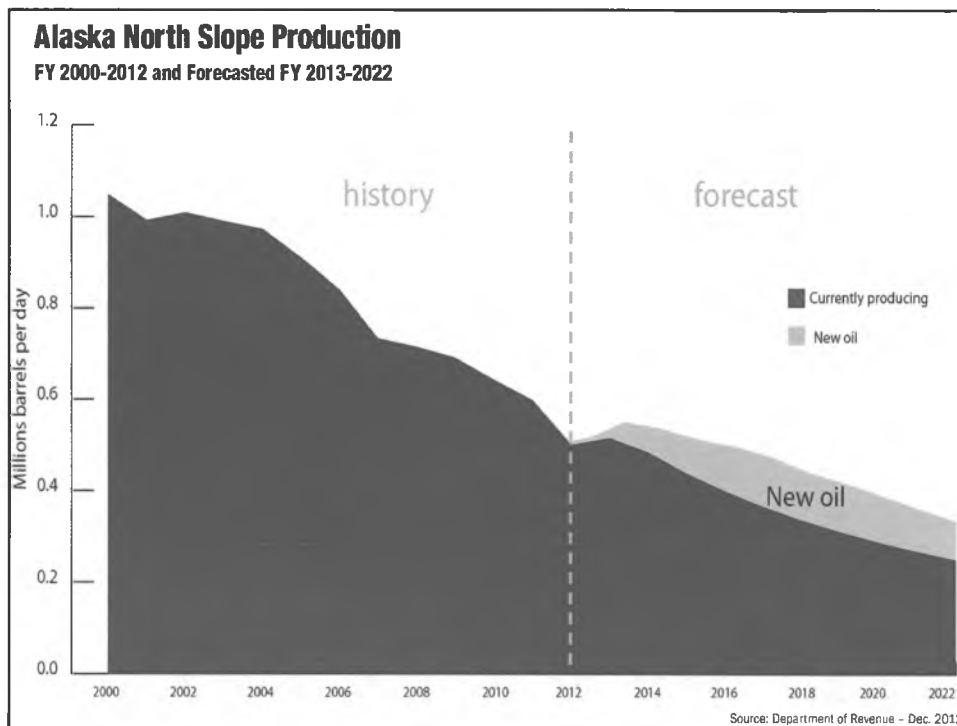
petroleum

Chevron

FLINT HILL
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Shell

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Governor Lays out Principles for Oil Tax Reform

Anchorage Daily News, Jan. 6, 2013:

Reform must:

- Be fair to Alaskans
- Encourage new oil production
- Be simple and restore balance
- Be durable and long-term in nature

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Reform must:

- Be fair to Alaskans
- Encourage new oil production
- Be simple and restore balance
- Be durable and long-term in nature
- *AOGA Recommendation: Avoid changes that artificially creates "winners & losers"*

AOGA

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CSSB 21 (RES) Component: Progressivity

- *AOGA supports the elimination of progressivity*
 - 1) Progressivity is the single most influential component of Alaska's tax structure negatively impacting investment decisions.
 - 2) Progressivity bring extraordinary complexity to the tax.
 - 3) The repeal of progressivity is consistent with all of the Governor's core principles.

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***CSSB 21 (RES) Component:
Increasing the Base Tax Rate***

- *AOGA does not endorse increasing the base tax rate to 35%*
 - 1) Increasing the base tax rate adds an additional burden to the worst case scenario when oil prices are low or project costs are high.
 - 2) Increasing the base tax rate is contrary to the Governor's second principle. It would not encourage new production.

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CSSB 21 (RES) Component: Tax Credits

There is no tax credit liability for the State until the investor invests here

- 1) *AOGA does not support repeal of Qualified Capital Expenditure Credits (QCE)*
 - a) Elimination of QCE would undo significant part of competitive environment
 - b) Repeal likely creates "winners & losers"
 - c) Consider expanding the scope of the "well lease expenditure" tax credit

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CSSB 21 (RES) Component: Tax Credits

2) AOGA is not certain that the potential benefit of a \$5/bbl tax credit will be offset by other burdens

- a) Weight of the benefit in respect to other changes is hard to measure.
- b) Applaud the concept of tying incentives to the goal of increased production.
- c) Consider what the credit will mean to a small producer with little production as opposed to the legacy producers that already have established large scale production.

CSSB 21 (RES) Component: Tax Credits

3) AOGA supports extension of Small-producer & exploration tax credits

- a) Attracts new players to Alaska
- b) From testimony...has made a material difference for some companies
- c) Exploration credits bring about exploration in a timely fashion

CSSB 21 (RES) Component: Tax Credits

4) AOGA opposes the current proposal to bar almost completely the transferability of "Loss Carry Forward" credit

- 10 year shelf life is unrealistically short
- AOGA Recommendation:
Increase the shelf life to 15 years

CSSB 21 (RES) Component: Tax Credits

5) AOGA does not think the "anti-stackable" section is necessary

- Current statute already addresses this concern

6) AOGA supports the new proposed manufacturing credit

- May not have great impact on the reduction of the current production decline.
- Step in the right direction in creating more Alaska jobs and investment.

**CSSB 21 (RES) Component:
Gross Revenue Exclusion (GRE)**

AOGA supports concept, but concerned it will be not apply to majority of current production

- Misses 80-90 percent of potential production
- Fields likely to lose out from GRE: Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Niakuk, Point McIntyre, Alpine, PBU Satellite fields (Aurora, Borealis, Midnight Sun, North Prudhoe Bay, Orion, and Polaris) and Kuparuk satellites (Meltwater, NEWS, Tabasco, Tarn and West Sak)

*AOGA Recommendation:
More needs to be done for these fields*

**CSSB 21 (RES) Component:
Competitiveness Review Board**

AOGA does not support the concept of a Competitiveness Review Board

- a) Does not meet Governor's principle for durability
- b) Tax certainty is in jeopardy with each annual report
- c) Confidentiality concerns

Components Not Addressed in CSSB 21 (RES)

1) Minimum Tax

- AOGA Recommendation: Minimum Tax should be repealed.

2) Statute of Limitations & Statutory Interest

- AOGA Recommendation: Either shorten the period for DOR determinations from 6 years back to 3 years, or eliminate the 11% minimum interest rate, or both

3) Joint Interest Billings

- AOGA Recommendation: Restore language specifically authorizing DOR to rely on joint-interest billings if it chooses to do so.

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AOGA Supports Components of CSSB 21 (RES)

Cornerstone for significant and crucial tax reform

- Support the elimination of progressivity
- Support the concept of gross revenue exclusions
- Support the extension of the small producer & exploration tax credits
- Support the manufacturing credit

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AOGA Concerns with CSSB 21 (RES)

- Base tax rate is too high, even at 25%
- Serious concerns with how the bill addresses tax credits (QCE elimination, changing the loss carry forward credit, “anti-stackable” provision)
- Does not support the Competitiveness Review Board
- Gross Revenue Exclusions should be expanded to fit the majority of projects in legacy fields
- Identified other ways to improve policy (repeal minimum tax, change statute of limitations/interest rate, and allow DOR to use joint-interest billings)

Alaska Oil and Gas Association

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**ALASKA OIL AND GAS ASSOCIATION
TESTIMONY ON COMMITTEE SUBSTITUTE SENATE BILL 21 (VERSION C)
TO THE SENATE FINANCE COMMITTEE**

March 5, 2013

Good Morning. My name is Kara Moriarty and I am the Executive Director of the Alaska Oil and Gas Association, commonly known as "AOGA". AOGA is the professional trade association that represents 15 member companies who account for the majority of oil and gas exploration, development, production, transportation and refining of oil and gas onshore and offshore in Alaska. These comments regarding Senate Bill 21, and specifically Committee Substitute Senate Bill 21 (CSSB 21) version C, have been reviewed by all members and have been approved unanimously.

The industry's greatest challenge today, which we share with the State is the decline of oil production from the North Slope. We believe that the greatest, most urgent issue facing this Legislature in 2013 is how you will address this problem. We cannot fix the basic, inherent properties of any oil and gas field, that is that the resource is finite and production will eventually decline. We can fix some of the economic principles that drive the development of more and new resources. Corrections to the ACES tax regime will remove impediments to development and exploration and assist the industry in investing in projects that could both extend the life of TAPS and open up new resources to long term development. When we look to the future Alaskans see a robust industry on the North Slope growing like it is the rest of the United States. We want the jobs here and not in the Lower 48. We want to create developments that will last for decades more, creating jobs for our children and opportunities for our communities to flourish. Alaskans want to see the industry continue to support the education and skills training that are needed to qualify for many of those jobs. A healthy oil and gas industry is one that sees the economic benefits of continuing to invest in projects in Alaska and keeping its employees

here, where they volunteer their time, talent and treasure to make Alaska a better place to live for us all. Alaskan's, and the Alaskan economy, depends on the industry and its direct and indirect contributions as well as its funding the vast majority of the costs of our government.

Our goal today is to offer insights into how the CSSB21 impacts the industry. Specifically, how the present tax laws are fundamentally broken, and instead of incentivizing investments that benefit us all, are actually hindering the very development and growth Alaskan's deem essential. We have ideas of how the current tax structure can be modified to better suit the needs of the State.

The Tax "Give Away" Fallacy

We hear all too often of the \$2 billion dollars that will be a "give away" to the industry should the tax regime be changed. It is a simple and effective communication that completely misstates the reality of the tax structure and its impact on the industry. It is simple to calculate how a change in a tax rate will impact amount of taxes collected if all "other" things remain constant. For example, if production does not decline further, if lifting costs don't rise, if the \$2 billion dollars of annual investment by the industry to slow that decline continues, and if oil and gas prices do not shift. All of these "other" items seem to be considered a given in these calculations and it is assumed they will remain unchanged in the future – the pundits of the "give away" theory want you to believe it's that simple. But it is not.

However resourceful the State's revenue estimators are, they cannot control decline, lifting costs, future investment, or the price of crude oil. As the rest of the nation swims in new industry investment and development, Alaska languishes. The costs of operations continue to rise as North Slope fields decline. The \$2 billion a year of industry investment spent in wrestling decline must now compete with more lucrative projects elsewhere, and with growing US production and supply of oil and gas the future price of that oil and gas is anyone's guess. Naysayers to these necessary and fundamental changes to our tax structure look only to the downside simple calculations they take from a Revenue Sources Book they forget is only a "guesstimate" of future revenue. The upside potential of that change, though, is very real. If a restructuring and tax rate reduction make investments here more competitive, companies will want to make more investments here for that upside. Deciding to make long term investments in Alaska's North Slope requires the industry to see potential upside to their investments and assessing that the essential risks of those investments are offset by the opportunities afforded in success. Without that potential opportunity in Alaska, investment dollars will be spent elsewhere, where risks are less and

opportunity is greater.

Core Principles to Address North Slope Production Decline

As you consider potential solutions to the challenge that production declines creates for Alaska, AOGA believes Governor Parnell's four "core principles" offer an excellent cornerstone for this:

- "First, tax reform must be fair to Alaskans."
- "Second, it must encourage new production."
- "Third, it must be simple, so that it restores balance to the system."
- "Fourth, it must be durable for the long term."

We believe the addition of a fifth such principle would be required to meet Alaska's goals, because the challenge is not that there are too many companies pursuing opportunities, but that there are too few. Alaska should therefore avoid tax changes that artificially create "winners" and "losers."

With respect to the CS to Senate Bill 21, there are several features in it that we wish to address; such as the elimination of progressivity, an increase in the base tax rate to 35%, changes to the present system of tax credits – including the addition of the manufacturing credit, a gross revenue exclusion for certain new production and the concept of a competitiveness review board. I will also identify some of the issues with the current system that the CS does not address.

1. Repealing Progressivity.

AOGA endorses the elimination of progressivity.

Impact of Progressivity as part of the ACES tax rate in industry investment decision making is the single most influential component of Alaska's tax structure negatively impacting investment decisions related to Alaskan projects. Taxes are paid by the industry in virtually every jurisdiction in which we function and so we are very familiar with how they work. But the uniformity and consistency in the application of tax impacts as they relate to investment decision making found in almost every jurisdiction is missing in Alaska. As my member companies have testified in the past, investment decisions are driven by combining high and low case scenarios where costs and revenues are estimated and best case cash flows and worst case cash flows are measured, risked and analyzed. Each potential project, in every jurisdiction, is measured and compared and only some are funded. As your consultant, Roger Marks pointed out yesterday, the international investment climate is characterized by plenty of opportunities, fluid capital, but finite capital. To choose what they can and cannot fund, companies have compared each potential project, no matter the jurisdiction, by application of a uniform investment

decision measuring formula. When Alaska's tax system is quantified and added to this measure for proposed Alaskan projects the best cases are always burdened with an excessively high tax rate and as the assumed high cases get better, the burden only increases. We can find almost no other jurisdiction that so burdens investment return where the better the cases assumed for the decision, the higher the tax burden that applies. As I will address in a moment, we have no real maximum tax rate, and Alaskan investments are further burdened because the lower the case assumed, the higher the tax burden that applies as well.

EXAMPLE 1 BELOW:

Progressivity brings extraordinary complexity to the tax, not only in calculating what the tax is, but also in analyzing what the amount of the progressivity is for any particular item that affects a taxpayer's Production Tax Value (PTV). This complexity exists because the tax rate for progressivity depends on the taxpayer's PTV per barrel, and then the resulting rate is applied to the very same PTV that set the rate. This circularity in the tax calculation leads to bizarre effects. For instance, simply the fact that oil prices fluctuate during a year instead of remaining perfectly flat increases the tax due even though the average of the fluctuating prices is the same as the flat price — and the greater the fluctuation, the greater the tax from progressivity becomes. There is no objective economic or financial reason for the tax to go up; instead, this occurs entirely because the progressivity calculation is circular.

The repeal of progressivity is consistent with all four core principles outlined above. Its removal improves fairness because operators that increase margins through efficiency would no longer be automatically penalized. Its removal encourages new production because it reduces the tax burden on investment, as discussed above. Its removal is a significant step toward simplicity. And, lastly, its removal enhances durability because it satisfies the three preceding core principles.

2. Increasing the base tax rate from 25 to 35%.

AOGA does not endorse increasing the base tax rate to 35%.

Let's go back to the industry investment decision process again. Increasing the base tax rate, besides burdening every investment case with a higher tax rate, now adds an additional burden to the worst case scenarios when oil prices are low or project costs are high. When applying the current base tax rates to the investment cases for a proposed project, until one assumes a price collapse occurs and the minimum fixed rates apply, even when little revenue is assumed to be generated, the base tax applies. The burden of a 35% versus a 25% rate is easy to envision as every middle case and every

worst case scenario is burdened with an additional 10% tax rate. This assumed cost will negatively impact the potential returns deemed available for any Alaskan project and drive investments to be made elsewhere. Increasing the base tax rate is contrary to the second core principle; there is not any reasonable argument that suggests increasing the base tax rate would encourage new production. Indeed, using the progressivity formula as a benchmark, the ten percentage point increase in the base tax rate could be viewed as equivalent to a sustained reduction in oil price of \$25 per barrel, all else being equal.¹

3. Tax Credits

In general, tax credits, because they act to offset a part of the costs of certain investments when the expenditure is made are an important tool in reducing the deemed risks of those expenditures. Industry makes investments to seek returns. Costs of any kind, including taxes reduce those returns, so the offset of tax cost by a tax credit provides immediate benefit to the investment return calculation. Whether those costs are for drilling a well, building a facility to gather new oil, or installing a pipe to gather oil, a tax credit represents an immediate and direct reduction in the amount that a potential investor puts at risk in spending money on equipment and facilities that benefit production.

Those tax credits are directly related to production as investments must actually be made for the credit to be utilized and those investments will positively impact production. It is important to note that there is no tax credit liability for the State at all until an investor invests here. The investment has no other purpose than creating return by positively influencing production. So it costs the State nothing to offer the credit until the investment is made and at that point the tax credit has already succeeded in what it is supposed to do – namely to attract investment dollars here for investments that will act to increase production and reduce decline. The production impacts of the investments, although partially offset by tax credits, will act in other ways to increase taxes collected.

A. Repeal of the Qualified Capital Expenditure (“QCE”) Tax Credit.

AOGA does not support the repeal of the Qualified Capital Expenditure Tax Credit.

Even while the elimination of progressivity would improve the competitiveness of Alaskan investments from the present ACES tax, the elimination of the QCE Credit would claw back one

¹ In other words, a sustained \$25 per barrel price change would be needed under progressivity to get the same 10% change in the base tax rate. Under progressivity, each \$1 increase in PTV (or price, all else equal) per barrel would result in a 0.4% increase in the tax rate surcharge. Thus, a 10 percentage point change in the tax rate under progressivity would be equivalent to a \$25 change in PTV or price because $25 = 10\% \text{ divided by } 0.4\%$.

important financial incentive and a part of ACES that actually acts to improve the competitive environment. The QCE Credit depends entirely on how much is invested here, and provides benefits for investments even when oil prices are lower. While the benefit from ending progressivity, which depends on the price of oil relative to a producer's lease expenditures, helps when oil prices are higher the QCE provides benefits when prices are not. In this mid-range of oil prices the loss of QCE Credit would outweigh the benefit from the end of progressivity.

Repeal of the QCE credit is contrary to the second core principle. Furthermore, because every producer's costs are different and prices will impact them differentially AOGA, fears the repeal of the QCE Credit is worse than creating "winners" and "losers" because it only creates "losers" artificially among producers, and we see no sound tax policy justification for doing so.

For these reasons, AOGA believes the elimination of the QCE tax credits would be a mistake. Instead of that, one possibility might be to expand the scope of the "well lease expenditure" tax credit under AS 43.55.023(1) so it is available to producers on the North Slope. This credit has several meaningful advantages. First, it focuses investment incentives on subsurface intangible-drilling expenditures, which are a reasonable proxy for direct spending on well activity and, in turn, production. Second, the credit is clear because it uses already established concepts in the federal Internal Revenue Code. Third, it is fair because it applies equally to well-related spending in all areas of the state, without creating winners and losers merely on the basis of geography.

B. The \$5 dollar per barrel tax credit.

AOGA is not certain that the potential benefit of a \$5 dollar per barrel tax credit under AS 43.55.024(i) will be offset by other burdens.

There are multiple issues to balance when taking in the numerous proposed changes found in CSSB21. The removal of progressivity, the increase in base rate, early sunset of the QCE credit all create interrelated issues and while a \$5 dollar per barrel tax credit would provide benefits both in real tax costs and in investment decision making, the weight of the benefit in respect to the other changes is hard to measure. AOGA applauds the concept of tying incentives to the goal of increased production and as such allowing a tax credit per barrel. One must consider, though, what the \$5/bbl credit will mean to a small producer with little production as opposed to the legacy producers that already have established large scale production. In view of the investment decision making process and the Alaskan tax structure's impact on it, we are not certain that this benefit is offset by the other burdens

contemplated when striving for the goal of increasing production.

C. Small-Producer and Exploration Credits.

AOGA endorses the proposal to extend the small-producer tax credit under AS 43.55.024 and exploration tax credits under AS 43.55.025 from the present sunset dates in 2016 to a later date.

The State had sound policy reasons for creating these small producer and exploration tax credits, and those reasons are just as valid today as they were then. AOGA believes these credits have increased the likelihood of participation by new industry players and act to increase the opportunities that could be found by expanding exploration. The purpose of the small-producer tax credit was to attract new players to Alaska who might otherwise have been deterred from coming here by presumptions of increased risks and of higher-than-average costs and expenses. The success of the credit in attracting new participants is a fact that cannot be denied. AOGA sees this success in its own membership, and in other companies that have come here and are now active. Smaller producers often have a different perspective about the opportunities around them, and as such can bring with them new ideas and opportunities. New participants with new ideas can only strengthen and improve the Alaskan petroleum industry and help the state stem the decline in production. We know from testimony that the small-producer tax credit has made a material difference in individual companies' decisions to do business and invest in Alaska.

The purpose and justification for the exploration tax credits under AS 43.55.025 are equally clear. Huge parts of this state remain unexplored or underexplored. Again, these tax credits are only earned when actual expenditures for exploration occur. The credits tangibly reduce the risks faced by an explorer and as such incentivize them to go out and search for oil and gas that is much needed. Increased exploration leads to increased development and these credits act to increase exploration and should be extended as well. Just as with the QCE credits for capital investments, there is no exploration tax credit without real money having first been spent on exploration work that qualifies for these tax credits.

D. Limiting the transferability of "carried-forward annual loss" tax credits.

AOGA does not support the limitation on transferability of these losses.

We have some reservation about the proposal to bar almost completely the transferability of the current "carried-forward annual loss" tax credits under AS 43.55.023(b). New participants and new

explorers are many times not yet producing in the state or only producing small volumes of oil and gas and as such have little or no production tax liabilities. The ability to transfer their losses to others allows them to monetize the investments they have already made, both reducing their cost exposure on the original expenditure and hopefully at the same time acquiring additional capital for more investment. These credits arise every year for any active explorer until it finds oil or gas and finally incurs production taxes to apply the credit against. At present explorers can only realize immediate benefit from these credits by selling them to other taxpayers or cashing them in at the state Oil and Gas Tax Credit Fund established in AS 43.55.028.

Under the Bill as proposed, transfers would cease and explorers would have to hold on to losses for up to 10 years for possible use against taxes on their own production. The potential that a loss could not be offset against tax expenses or monetized in the near term places more risk on the decision to invest and as such makes such activities less likely to occur. If the transferability must cease, then the cost of the expiration of the loss carry forward after only 10 years, where on the North Slope exploration success to production can easily take longer, is another factor that negatively impacts investment decisions. Although the annual addition for interest will allow the losses to retain some value, we also believe that a 15 year period before expiration of the loss carry forward is the minimum timeframe that should apply if transferability is removed.

E. The "Anti-stackable" section

AOGA does not think this new section is necessary.

In Section 22 of the CS, AS 43.55.025 is amended by adding a new subsection to read:

(q) An exploration expenditure incurred after December 31, 2013, to explore for oil or gas located north of 68 degrees North latitude that is the basis for a credit under (a)(1), (2), or (3) of this section may not also be the basis for a credit claimed under AS 43.55.023 or this section.

AOGA does not understand why this new section is being proposed as it is our understanding the concern this new language is to trying address is already covered in existing statutes.

F. New credit for Manufacturing

AOGA supports the new proposed manufacturing credit.

Although this credit is directed to the incentivizing of development and manufacture of drilling and exploration methods and materials, it may not have a great impact on the reduction

of the current production decline. However, it is a step in the right direction to incentivize jobs and additional investment, and having more jobs and investment in Alaska is never a bad thing.

4. Gross Revenue Exclusion.

AOGA endorses the proposed 30% gross revenue exclusion or GRE, but has concerns on breadth of applicability.

The GRE would, in calculation of the taxable Production Tax Value, exclude 30% of the Gross Value at the Point of Production of what we'll call "non-legacy" production. Thus the GRE provides incentive for finding new oil and getting it produced. As much as AOGA supports this proposal we are also concerned that it is too narrowly focused. This narrow focus and application to only certain areas, especially those outside existing Units where the best prospects of new oil are likely to be found, needlessly restricts the benefits that such a proposal could have on increasing production. Fields likely to lose out on getting any GRE are Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Niakuk, Point McIntyre, and Alpine; as well as the Prudhoe Bay satellite fields Aurora, Borealis, Midnight Sun, North Prudhoe Bay, Orion and Polaris and the Kuparuk satellites Meltwater, NEWS, Tabasco, Tarn and West Sak.

Econ One Research, Inc. has previously provided this body a presentation entitled *Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal, HB 72*. In that presentation oil and gas resources described as "Economically Recoverable @ \$90/bbl" total 29.1 billion barrels of oil and barrel-equivalents of gas of which 3 billion are in the central North Slope where all the currently producing and therefore ineligible fields are. Of this 3 billion barrels, an estimated 2.5 billion or more stands to come from Prudhoe Bay, Kuparuk and other legacy fields already in production. The Governor's second "core principle" for tax legislation is that "it must encourage new production." But, in order to get results from such encouragement, the tax legislation must incentivize the best opportunities that Alaska has for getting results. The GRE as proposed may get some results but in terms of what it attempts to "encourage," it leaves out at least 80 – 90 percent of the 3 billion-barrel opportunity in the central North Slope that Econ One has identified.

AOGA is continuing to search for ways to adapt the Gross Revenue Exclusion to include legacy fields in a way that might be acceptable to the Administration and the Legislature. It may turn out, however, that a different approach may be necessary to "encourage new production" from legacy fields.

Oil and Gas Competitiveness Review Board

The proposed Board provides an oversight and review process that we believe would be burdensome to the industry and contravenes the Governor's principles relating durability in the long term. The perspective that the proposed changes found in the Bill would provide a long term solution to problems we know exist are placed in jeopardy because the very certainty that is required for sound investment decision making would be placed in question with each annual report of the Board. Instead of moving forward with projects that might help stem decline, industry resources would be used to assist the Board in collecting and understanding complex information of long term consequence on a quarterly basis. Finally, the documentation and information the Board might request or require is of the highest proprietary value to oil and gas companies and confidentiality concerns and related complexities would hinder the efforts of the industry as well as the Board. While we appreciate the ability to represent industry on the proposed board, our concerns cause AOGA to question both the viability and the effectiveness of the proposed Board and as such we cannot support its proposed formation.

Issues that the current draft does not address.

There are several significant problems in the present ACES tax that are not addressed in CSSB21, and I will address a few of them this morning.

A. Minimum tax for North Slope production. AS 43.55.011(f) sets a minimum tax that is targeted solely against North Slope production. That tax is based on the gross value of that production instead of the regular tax based on "net" Production Tax Value. The rationale for adopting it was to protect the State against low petroleum revenues when prices are low.

The minimum tax only complicates potential new investors' analyses of what their tax would be if they invest here instead of someplace else, and consequently it has, if anything, driven investments away. AS 43.55.011(f) should be repealed or consideration given to significantly reducing the rate of the minimum tax.

B. Statute of limitations & statutory interest. Here we have two concerns that are interrelated, but not in an immediately obvious way.

The statute of limitations under AS 43.55.075(a) is six years from the date when the tax return was filed for the tax being audited, while the limitations period for other taxes under AS 43.05.260(a) is three years from the filing date of the tax return. Under both statutes, the period may be extended by mutual consent of the taxpayer and the Department of Revenue (DOR).

The statutory rate of interest under AS 43.05.225(1) for tax underpayments is “five percentage points above the annual rate charged member banks for advances by the 12th Federal Reserve District as of the first day of that calendar quarter, or at the annual rate of 11 percent, whichever is greater, compounded quarterly as of the last day of that quarter[.]” Currently the Federal Reserve rate is very low, so 11% APR is the applicable rate.

We are asking that, if the Department chooses to not exercise its authority in providing certainty to the taxpayer to allow them to be able to calculate the correct amount of tax due, then the doubling-up of that uncertainty through statutory interest should be lessened — either by shortening the period for making Department “determinations” from six years back to the usual three, or by eliminating the 11% minimum interest rate on the statutory interest rate, or both.

SEE EXAMPLE 2.

C. Joint-interest billings. Our concern about joint-interest billings is also primarily a problem caused by the approach the Department has chosen to take with its tax regulations. Instead of starting with the joint-interest billings that participants in a unit or other joint operation receive from the operator, the regulations reflect an assumption that each non-operating participant has information, in addition to the operator’s billings to them, that allows them to determine which expenditures are deductible as allowed “lease expenditures” under AS 43.55.165 and which are not. This assumption is wholly unrealistic. And even if there were some merit to it, the regulations opt to audit each participant separately regarding that participant’s interpretation of which expenditures are deductible and which are not, instead of auditing the system of accounts used by the operator and telling all participants which cost items in that accounting system are deductible and which are not. In other words, instead of one audit of the expenses by a joint venture for any given period, the Department audits each participant separately for its respective share of the same pool of expenses.

We are not asking for legislation to put the Department’s regulations on a different track. But there are some in the Department who believe that the repeal by the 2007 ACES legislation of AS 43.55.165(c) and (d) — which specifically authorized the Department to rely on joint-interest billings — means the Department cannot legally rely on them now. While we disagree with this position (which is also at odds with what the Department testified to during the enactment of the 2007 ACES legislation), we do think it would be appropriate to restore language specifically authorizing the Department to rely on joint-interest billings if it chooses to do so.

Conclusion.

We support the proposed elimination of progressivity, but we have great concern with the increase in the base tax rate to 35%, and with the mixed proposals for tax credits allowing a new \$5 per barrel credit but removing qualified capital credits. The trade-off between repealing progressivity and losing the QCE credit is not a net benefit for industry at low oil prices, and will create a greater barrier to investment from existing and new independent players.

We also agree with the comment by Roger Marks yesterday when in one slide he pointed out the tax system should not favor investing in certain cost fields over others, which in our view is the same as saying we encourage the legislature not to devise a tax system that creates “winners” and “losers”.

The concept of the Gross Revenue Exclusion has considerable potential, but its narrow focus misses 80 – 90 percent of the opportunity in the central North Slope described by Econ One. We will continue to work with you and the Administration to find a fair and reasonable way to expand its scope, or to find an alternative that will address the central North Slope appropriately.

The reasons that led the State to create the small-producer tax credit under AS 43.55.024 and the exploration tax credits under AS 43.55.025 remain valid today. We are pleased that CSSB21 will provide some minimum extension to the sunset date for the small-producer and exploration tax credits.

We believe it is up to you, and the Governor, to shape a competitive oil fiscal policy that is supported by strong principles that will work to arrest North Slope production decline and will lead Alaska towards a prosperous future for the long-term. Overall, the Bill represents a base for significant and crucial tax structure reform that move toward Governor Parnell’s four “core principles” — fairness for Alaskans, encouraging new production, simplicity with balance, and durability for the long term, but as I have outlined today, AOGA members believe there is still many structural changes that should be included for this bill to truly change investment behaviors to the benefit of Alaskans. You have a difficult task ahead and AOGA stands ready to assist you throughout this process.

EXAMPLE 1:

Progressivity directly attacks and destroys one of the few strategic advantages that Alaska has, which lies in its economic remoteness. It costs \$9.42 on average to ship a barrel of oil from the North Slope to the West Coast, according to the Fall 2012 Revenue Sources Book, Appendix D-1b. This means Alaska starts off with a cost disadvantage of \$9.42 a barrel against Outside competition, so other parts of return on Alaskan investment must be stronger than outside investment in order to overcome this disadvantage. If returns Outside are deemed either less risky or providing more opportunity Alaskan investments won't be made.

If oil prices turn out to be higher than what they were projected to be in the industry investment decision analysis, nearly 100% of each extra dollar in price flows directly into the Gross Value at the Point of Production (GVPP) and then, after royalties and taxes, the remainder flows directly into the investor's bottom line. This, in turn, improves the economic performance of an Alaskan investment relative to an equally competitive one Outside, because the Alaskan baseline was \$9.42-a-barrel lower and an additional dollar in price is a larger percentage of that baseline than for the percentage for the Outside investment. This opportunity can be particularly significant for potential investors who are bullish on oil prices.

Currently, progressivity in conjunction with a 25% base tax will take half of each dollar from higher prices when the West Coast price is \$132.38 (using the Fall 2012 Source Book numbers) — a price that has already been seen, although somewhat higher than today's. So, even for investors who are bullish on oil prices, progressivity destroys half of the one strategic advantage that Alaska's economic remoteness provides. Sadly, the more bullish they are, the more this advantage is undone because they will see ever higher rates for progressivity at those prices in their investment analysis.

EXAMPLE 2:

Taxpayers are required under AS 43.55.020(a)(1)-(3) to make monthly estimated tax payments for each calendar month's taxable production during a year, but the final tax amount for the entire year is reported on March 31 of the following year under AS 43.55.030(a). And AS 43.55.020(a)(4) requires any additional tax to be paid at that time. The statutory interest under AS 43.05.225(1) starts to accrue on any underpayment from that March 31st true-up date.

In practical terms, what these various statutes all mean is this. For each dollar of underpaid tax that the Department of Revenue may claim after an audit, statutory interest on that dollar at the end of three years would be —

$$\begin{aligned} \$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 3 \text{ years})} - 1] &= \$1.00 \times [1.38478 - 1] \\ &= \$0.38. \end{aligned}$$

After six years the statutory interest on the dollar would be —

$$\begin{aligned} \$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 6 \text{ years})} - 1] &= \$1.00 \times [1.91763 - 1] \\ &= \$0.92. \end{aligned}$$

Thus, for each dollar of uncertainty there is in what the taxpayer reports on its March 31st true-up for a given year, there is about 38 cents of additional uncertainty due to statutory interest under a three-year statute of limitations, but 92 cents under a six-year statute.

It is the combination of a six-year statute of limitations plus a minimum statutory interest

rate of 11% APR that is so harmful for a taxpayer and any would-be investor. Each dollar of uncertainty in the amount of tax will nearly be doubled by statutory interest after six years.

When we speak about uncertainty and audit assessments six years after the filing of tax returns, many people will think the oil companies could calculate their correct tax liability under the ACES tax if they wanted to. Frankly, so did I before I got this job. So let us take a few moments to illustrate why this is not the case.

As amended by ACES, AS 43.55.150 (captioned “Determination of gross value at the point of production”) says the Gross Value at the Point of Production (GVPP) “is calculated using the actual costs of transportation” from the field to market unless the “shipper ... is affiliated with the transportation carrier[,]” or the “contract for the transportation ... is not a[t] arm’s length[,]” or the “method or terms of [the] transportation ... are not reasonable in view of existing alternative transportation options.” “If the department finds that” any of these situations exists, then the GVPP “is calculated using the actual costs ... or the reasonable costs of [the] transportation ..., whichever is lower.”

The immediate questions about the statute are — How does the Department of Revenue get the information to make such a finding? What is the procedure for making them; is there a hearing, an investigation or what? How does a taxpayer ascertain what the Department has found?

15 AAC 55.193 is the regulation with an important part of the Department’s answers to these questions. Before getting to those answers, we note that subsection (a) seems to disregard the statutory distinction between “actual” and “reasonable” costs, by declaring that “Costs of transportation are the ordinary and necessary costs incurred to transport the oil or gas”² — which could get to the same result as the statutory terms, but not necessarily.

Subsection (e) of the regulation starts answering our questions. It says “a tariff rate ... adjudicated as just and reasonable by the Regulatory Commission of Alaska ... establishes the reasonable costs of the pipeline transportation[.]” So, suppose there has been full-blown tariff dispute before the Regulatory Commission of Alaska, and the RCA has “adjudicated [a tariff] as just and reasonable[.]” And suppose also that a producer ships its oil through its pipeline-company affiliate and pays that RCA-approved tariff. Is this “reasonable” cost under (e) of the regulation the same as the “ordinary and necessary” cost for it for purposes of subsection (a)? Apparently so, but the inconsistent terms in the two subsections prevent this from being completely clear. Moreover, if the transportation occurs “later than five years after the end of the test period on which the tariff rate is based[,]” then even subsection (e) says the tariff ceases to “establish [the] reasonable costs” for the transportation. But it doesn’t say what the right tariff is after those five years are up, or even how to find out or calculate what it is. It is utterly silent.

The very next sentence in subsection (e) after the one speaking about that five-year period starts, “If a complaint challenging [a] tariff rate has been filed with [the RCA] and accepted for investigation” — this is not a situation involving an already “adjudicated” tariff, but one that deals with a new tariff that has been filed for RCA’s approval, which is then challenged. Here, too, the tariff on file is not allowed as the transportation cost under (e) of the regulation. Instead, the cost that is allowed is “103 percent of the costs of transportation calculated by the department using the methodology under 15 AAC 55.197, for the period [while the complaint is being heard and adjudicated by the RCA.]”^{*} Note that it is the Department of Revenue, not the

² Emphasis added.

taxpayer that makes the calculation under 15 AAC 55.197. It is impossible for the taxpayer to know beforehand what the Department's calculation will turn out to be.

Now it is true that 15 AAC 197(m) says a taxpayer may each year "request in writing the department's determination of the applicable after-tax rate of return under (f) of this section [and t]he department will provide the department's determination to the producer no later than the later of July 1 of the calendar year or 90 days after the department receives the producer's request." But the "after-tax rate of return" that the Department promises to provide is only one of the parameters in the cost-based tariff calculation under 15 AAC 55.197. The taxpayer is left on its own to find the correct numbers for the other parameters. More importantly, subsection (m) applies only to "a producer [that] expects to produce oil or gas the actual costs of transportation of which are required by 15 AAC 55.193(b)(6)[.]" Section -193(b)(6) applies only to "transportation of oil or gas by a nonregulated pipeline facility ... that is owned or effectively owned ... by the producer of th[e] oil or gas[.]" In the situation I'm describing, it is a regulated pipeline, not an unregulated one, so this promise in 197(m) does not apply.

We find nothing else in the calculation-methodology regulation, 15 AAC 55.197, nor in 15 AAC 55.193(e), the transportation-cost regulation, that commits the Department to make the cost-based tariff calculation called for in 193(e) and inform the producer of that result before the producer has to report and pay estimated tax each month, or before it makes its annual true-up on March 31st of the following year. The only deadline for informing the producer of the Department's calculated tariff is the six years under the statute of limitations.

And the same or very similar unknowable answers — including tariff calculations by the Department under 15 AAC 55.197 — arise under 15 AAC 55.193(f) regarding tariffs for new transportation facilities that are just being placed in service, and under -193(g)–(h) regarding tariffs set under a settlement agreement to which the State of Alaska is a party.

And just to prevent any misunderstanding, although I have been testifying about proceedings and adjudications by the RCA, these regulations also apply to proceedings and adjudications by some "other regulatory agency" — which would include FERC.

There is a built-in uncertainty created by these regulations, and others that is beyond a taxpayer's allowed authority to answer and beyond its ability to know before the Department gives the answer. And to see a "Technicolor[®]" version where essential elements of the tax calculation are being reserved for the Department to "determine" in its discretion with no specific deadline, one should look at all the crucial "determinations" in 15 AAC 55.173 ("Prevailing value for gas") that are reserved for the Department to make regarding the valuation of natural gas that would be transported to markets outside Alaska.

We are not asking for a statutory fix to the regulations. But we are asking that, if the Department chooses to defer making calculations and similar determinations that are necessary in order even to be able to calculate the correct amount of tax at all, then the doubling-up of that uncertainty through statutory interest should be lessened — either by shortening the period for making those "determinations" from six years back to the usual three, or by eliminating the 11% minimum interest rate on the statutory interest rate, or both.

7



BP Testimony to Senate Finance

Damian Bilbao, Head of Finance

March 5, 2013

BP in Alaska



BP presence in Alaska since 1959

- **Operating area**
 - 250 miles north of the Arctic Circle
 - 1200 sq. miles (approximately the size of Rhode Island)
 - Winter temperatures average minus 30 degrees F
- **People**
 - 2,300 BP Alaska employees
 - 6,000 contract employees
- **Facilities (start-up 1977)**
 - 11 major production facilities
 - 2 major gas facilities
 - 3 water handling facilities
 - 2000 production/injection wells
- **Prudhoe Bay**
 - Original production estimate ~9.6 bn bbls
 - Cumulative production has exceeded 12 billion bbls
 - Largest field in North America – 35 years
 - COP ~36%, XOM ~36%, BP ~26%, CVX ~2%

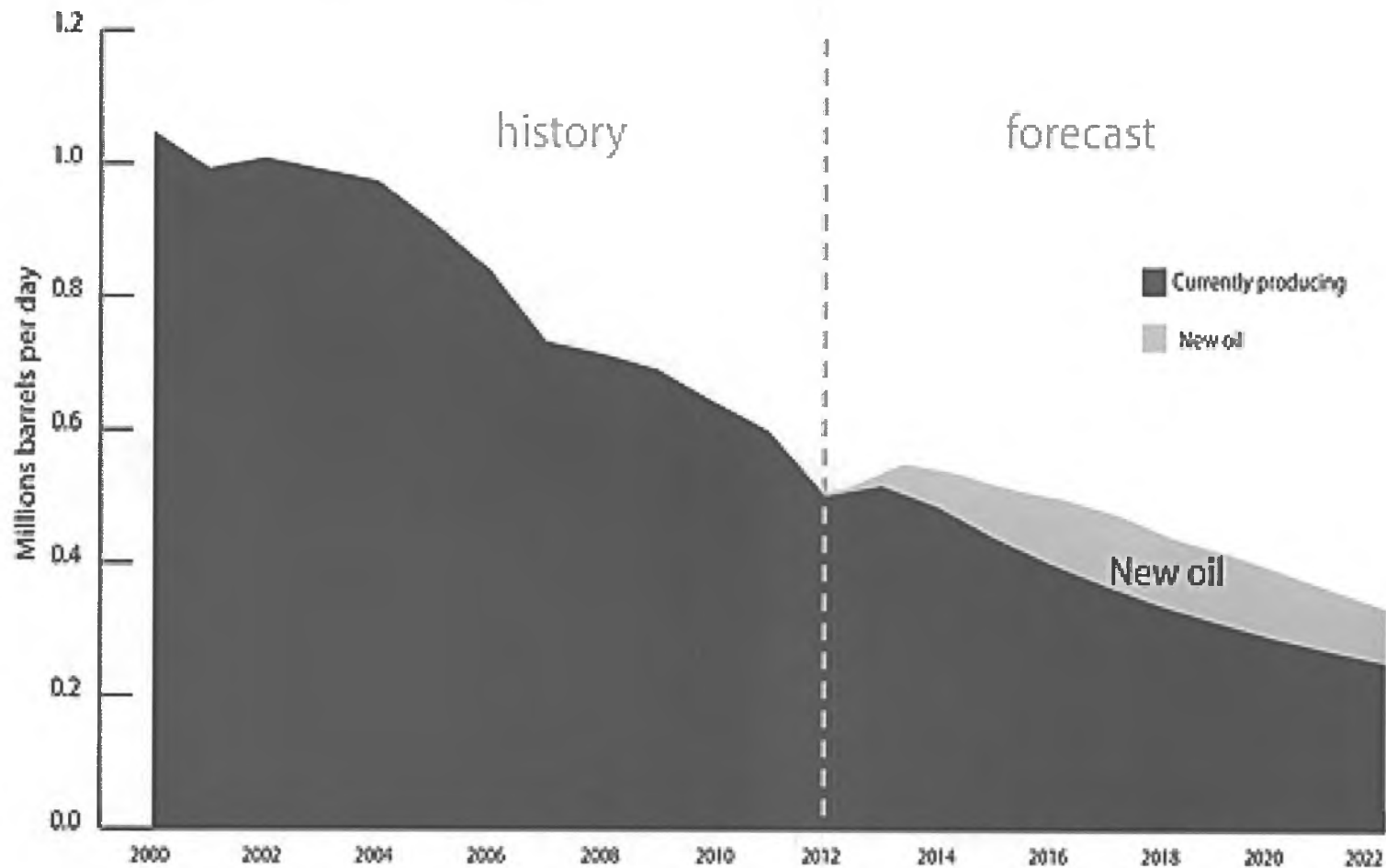


Decline is enemy #1



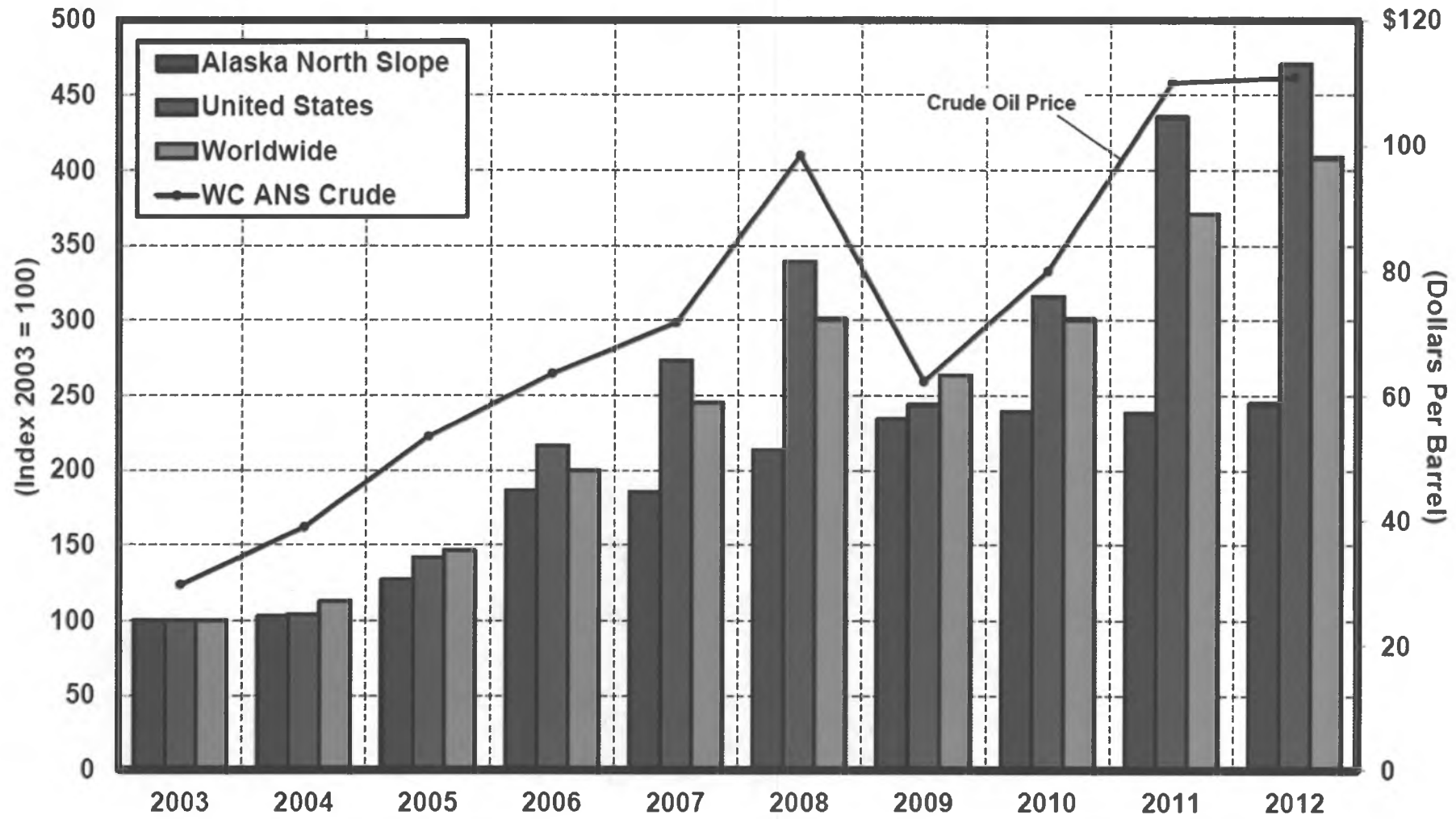
Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



Source: Department of Revenue - Dec. 2012

Estimated Capital Spending for Exploration and Development Alaska North Slope vs. United States and Worldwide Spending* 2003 - 2012

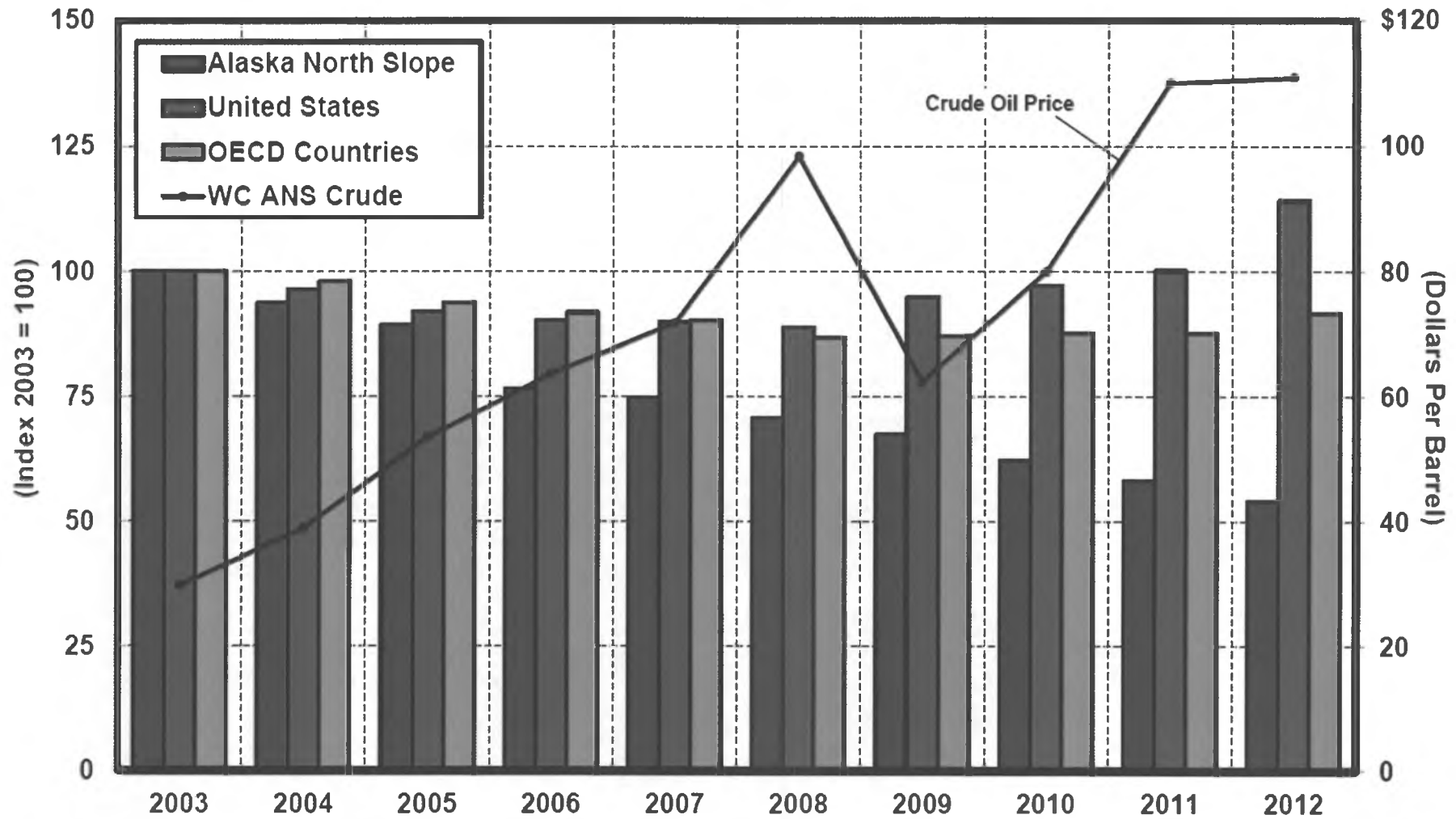


* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

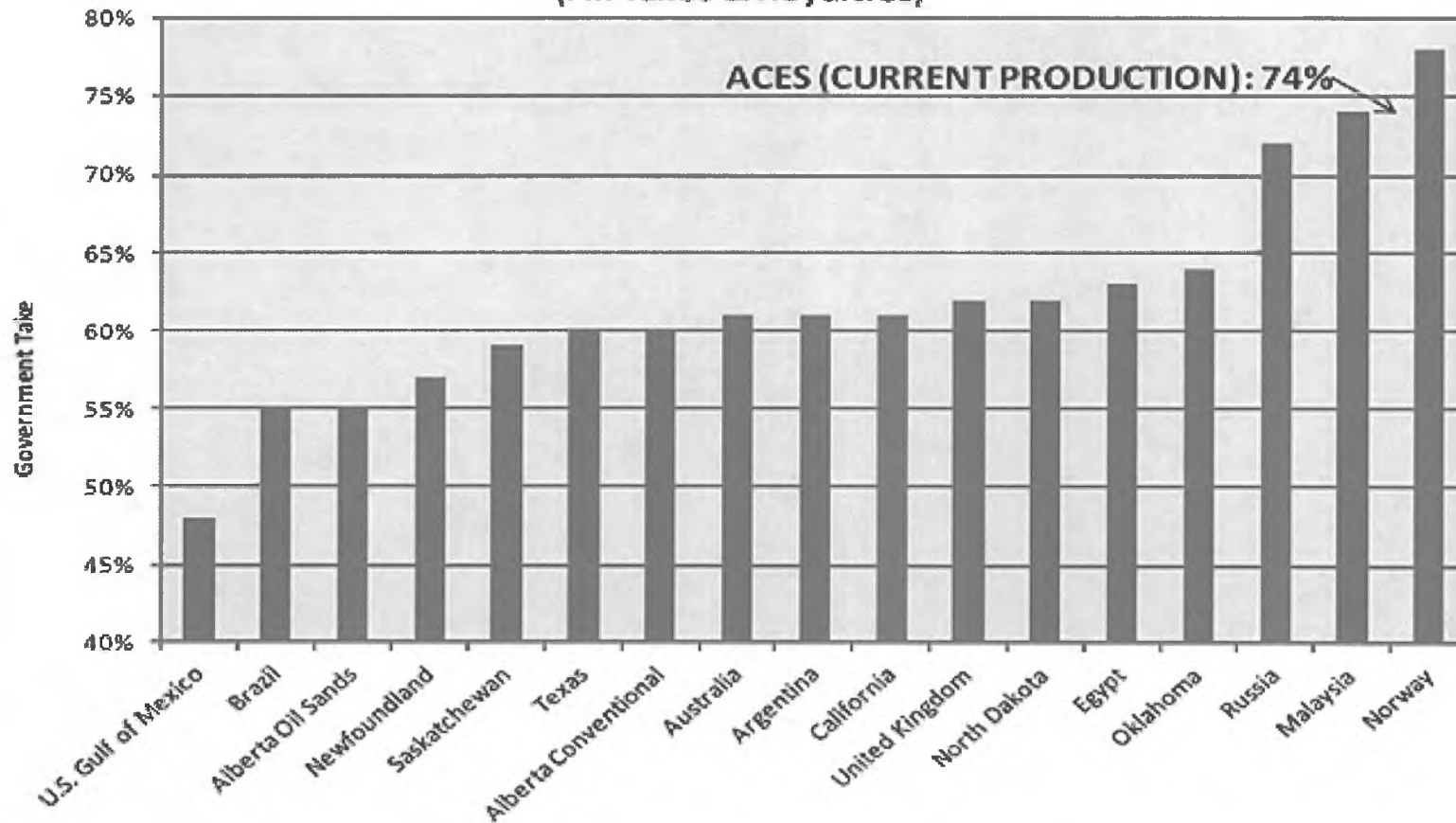
Crude Oil Production

Alaska North Slope vs. United States and OECD Countries

2003 - 2012



Alaska Peer Group*
Government Take at \$110/bbl Market Price
 (Total Taxes as a Percentage of Net Value)
 (All Taxes & Royalties)



* North America regimes (U.S. states & Canadian provinces with greater than 200,000 bbl/day prod)
 Tax & royalty regimes
 Arctic regimes
 Regimes with similar production and reserves (between 400,000-800,000 bbl/day prod and between 2-6 billion bbls proved reserves)

Source: PFC Energy except Newfoundland, Saskatchewan, California, Oklahoma

In summary



- Alaska currently fails to compete globally for investment
- Positive shift in the conversation to a policy that focuses on Alaska's future
- The CSSB 21(RES) structure could work, however:
 - the base rate is too high
 - the GRE does not apply to legacy fields

8

TESTIMONY OF EXXONMOBIL
ON ALASKA'S INVESTMENT CLIMATE
TO THE ALASKA SENATE FINANCE COMMITTEE
MARCH 5, 2013

Mister Chairman, members of the Committee:

For the record, my name is Dan Seckers. I am ExxonMobil's Tax Counsel, based in Anchorage. I want to thank the Committee for the opportunity to express ExxonMobil's views on Alaska's current investment climate and the impacts of Alaska's oil and gas production tax or ACES.

Let me begin by underscoring what many of you have likely heard ExxonMobil say throughout the years - that Alaska has been and continues to be an important component of ExxonMobil's world-wide investment portfolio. We have had a presence in Alaska for over 50 years and have been a key player in Alaska's oil industry development. We are the operator of Point Thomson, hold the largest working interest at Prudhoe Bay (36.4%) and are the largest lease holder of discovered Alaska gas resources. We are committed to Alaska and its future and expect to be involved here for many years to come.

Let me also state that ExxonMobil continues to support Governor Parnell's efforts toward substantive reform of ACES. We appreciate his willingness to champion this

difficult issue for the past two years and his committed effort again this legislative session. The need for Alaska to develop a competitive, stable fiscal regime that attracts the levels of investments that Alaska's North Slope requires is one of the most, if not the most, important issues facing the State. We believe the Governor's four core "principles", as emphasized in his State of the State speech that any reform of ACES:

- Be fair to Alaskans
- Encourage new oil production
- Simplify and restore balance to Alaska's fiscal system
- Make Alaska competitive for the long term

can form the foundation of a successful, long-term taxation policy for the State.

The Governor has not been alone in his efforts. Many members of the Legislature have worked hard the past two years to examine and understand the impact of ACES on Alaska's global competitiveness. That hard work has been having a positive effect as it appears legislators and most Alaskans now recognize that Alaska's production tax system is not well designed to tackle the production decline and attracting investments to develop new production.

Consistent with the testimony we have given over the past several years, ExxonMobil believes that the changes made to Alaska's oil and gas production tax since 2005 have had a negative impact on business activity in Alaska and Alaska's overall investment

climate. Fundamentally, the progressivity component of the ACES tax regime, on top of an already high base tax rate, creates a major disincentive to invest in the high-risk, high-cost opportunities available in Alaska. These two features must be addressed for any tax policy to be successful in meeting the State's desired production and long-term revenue goals.

Two aspects of the current tax policy, however, are pro-development. The deduction of operating and capital expenditures before applying the tax rates recognizes the high cost of doing business in Alaska. The further tax credit for capital expenditures rewards those who invest in future production and infrastructure. These are key components of the current ACES whose benefits should be reflected in any revised tax policy the State is considering.

As the Legislature's and State's own consultants have indicated over the previous two legislative sessions and during recent hearings in your Committee and other committees, Alaska has one of the highest and most punitive tax systems in the world. The high progressivity is directly impeding Alaska's global competitiveness. To significantly grow state revenues, secure jobs and stem the production decline, it is essential that Alaska's tax structure encourages long-term development of all of Alaska's resource potential.

As the Governor has stated, Alaska's fiscal regime must be competitive and durable for the long term. ExxonMobil values a predictable fiscal environment in which to make

long term investment decisions. Our investments are capital intensive and are evaluated over timeframes of decades. Any change in the fiscal regime has a direct impact on how we view stability of the Alaskan fiscal environment, which in turn impacts how we evaluate the risk basis of future investment decisions. Because of the nature and magnitude of the risks associated with any oil or gas investment, coupled with the long lead time required to recoup that investment, stable fiscal terms are key to any investment decision.

To date, Alaska has produced more than 16 billion barrels of oil from the North Slope, and according to the Department of Natural Resources there are over 5 billion barrels of known resources remaining. These undeveloped resources represent a substantial opportunity, but their development is at risk under the current ACES tax system. Oil production today is less than one-third of the peak oil production of more than 2 million barrels per day in 1988, and annual production continues to decline.

You have heard about the continued and alarming decline of North Slope oil production from the Department of Revenue, State consultants and individuals that have testified earlier. But it is important to reemphasize that industry currently invests more than \$1 billion per year just to maintain current North Slope oil production decline at six to seven percent. The substantial majority of that annual investment is in the legacy fields – Prudhoe Bay and Kuparuk. Absent that continued investment, the annual production decline would likely be in the range of 12 to 15 percent annually. Without meaningful

tax reform that includes Alaska's legacy fields, Alaska can expect production declines to continue.

Production from the legacy fields not only provides the majority of the State's revenues, it sustains the current North Slope infrastructure and the operation of TAPS, which are critical to enabling new production. The infrastructure from these legacy fields has been leveraged historically for satellite developments, such as Pt. McIntyre, Orion, Borealis and other non-legacy fields to economically process and transport their oil from the North Slope to refinery destinations. If the large legacy fields did not exist, it is unlikely any of these other developments would have been economic.

Without healthy legacy fields, the prospects of any future new fields or developments become even more economically challenged and the probabilities of Alaska reaching its desired goal of long-term sustained production levels more difficult.

Encouraging increasing investment to keep these key fields healthy is therefore at least as important as encouraging investment in exploration and development of new fields. For any tax reform to contribute to the Governor's stated objectives for Alaska's long-term production, it must also be applicable to the legacy fields where the State's near and long term economic future rests.

Considerable attention has been placed on making Alaska more competitive relative to other regimes. While that focus is extremely important, it is only part of the overall

picture. Benchmarking government take against other producing areas is a useful tool for gauging basic competitiveness, but does not provide the full picture of investment health. As the Department of Revenue and various consultants have testified, spending on the North Slope has remained relatively flat since the enactment of ACES. But what needs to be clarified is that the majority of that spending has been for maintenance and upkeep to sustain existing operations, not for new development. Under ACES, the State has not attracted the new investment needed to increase production.

Complicating Alaska's production decline is its high exploration, development and production costs. Alaska is one of the most expensive places in the world to develop and produce oil and gas. Many factors contribute to Alaska's higher costs including:

- Severe arctic conditions, placing limitations on when drilling and other operations can be undertaken
- Environmental challenges
- Remote location of the resource and distance to market
- Restriction of exploration opportunities

These are complications that Alaska faces that most other areas do not; but they do factor into the economic decisions being taken by investors and need to be considered when assessing what is Alaska's optimum production tax regime.

ExxonMobil is willing to accept the risks of long-term, capital intensive investments when a stable tax structure allows and encourages investment and ensures a corresponding opportunity for upside potential. Upside factors such as increased production and higher prices can compensate for risks taken by investors, because companies are certainly negatively impacted when lower than expected production or prices occur. The high marginal tax rates under the progressive structure of ACES take away the upside potential and reduce the attractiveness of those capital intensive investments, compared to other locations where the upside benefit can be retained.

Alaska faces significant challenges. As I mentioned, costs are high and production continues to decline. We all need to work together to achieve the right balance – as Governor Parnell stated - a balance that maximizes the benefit to Alaskans while encouraging industry to continue to invest in Alaska.

ExxonMobil recognizes the difficulty you face as policy makers in tackling the State's tax policy while protecting current revenue streams and addressing the revenue problems just over the horizon due to the production decline. We appreciate how hard and difficult that task is.

Today's production rates are the product of government policies, technical work, and investment decisions that in many cases were made decades ago. Increasing production rates in the decades to come will result from sound policies, decisions, and commitments that are made by this Legislature. As policy makers, you will need to

decide whether Alaska's current high production tax regime is the right course for Alaska or if another course is necessary to harness the remaining resource potential, given the high costs and steadily declining oil production rates we as Alaskans face.

It is important to recognize that any decision made by this Legislature impacts much more than tax revenue in the near term and in the future. Decisions made today will influence the life of production in existing fields and investments required to develop Alaska's remaining resource potential. This will in turn impact jobs for Alaskan workers, revenue for many Alaska businesses, infrastructure that benefits Alaskan communities, and set the stage for the future of Alaska for many generations to come.

As I indicated, ExxonMobil fully supports the Governor's and this Legislature's efforts to reform ACES and to make Alaska's investment climate globally competitive. To maximize its resource potential while receiving a fair share of the resource revenues, Alaska needs a long-term resource development policy that will encourage increasing investment. The reform of ACES needs to result in a competitive, stable and predictable fiscal environment that will encourage investment at all price levels and incentivize the development of remaining resources that are economically challenged, including both new fields and resource development opportunities in existing fields. ExxonMobil believes the key focus of the reform needs to create a balanced program using a combination of changes to progressivity, the base tax rate and capital expenditure tax credits to provide a competitive balance of government take across all price bands.

ExxonMobil Testimony to the Alaska Senate Finance Committee
March 5, 2013

Let me conclude by reiterating that ExxonMobil is committed to Alaska and to pursuing competitive investment opportunities here in the future. Unfortunately, the resource and cost structure in Alaska is becoming increasingly challenging. It is ExxonMobil's firm belief that passage of meaningful changes to ACES this year will support additional investments in Alaska that will lead to greater development and production as well as economic opportunities for Alaskans.

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

Thank you again Mister Chairman for the opportunity to present these written comments to you and your Committee.

9

Senate Finance Committee

CSSB21

Bob Heinrich, VP Finance

Scott Jepsen, VP External Affairs

ConocoPhillips Alaska

March 5, 2013

Topics

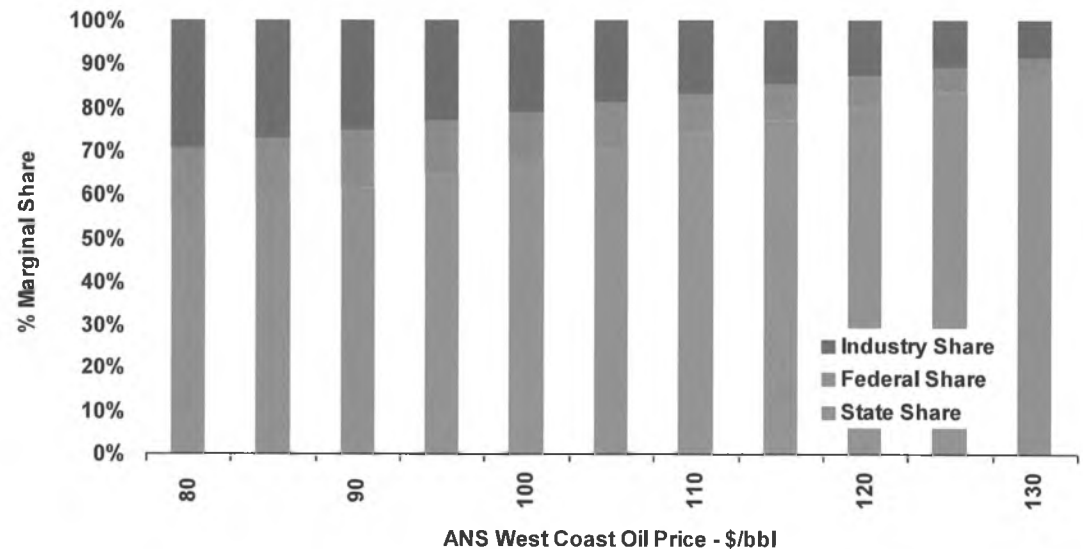
- Alaska Challenges
- CSSB21 vs ACES
- Observations

North Slope Investment Challenges

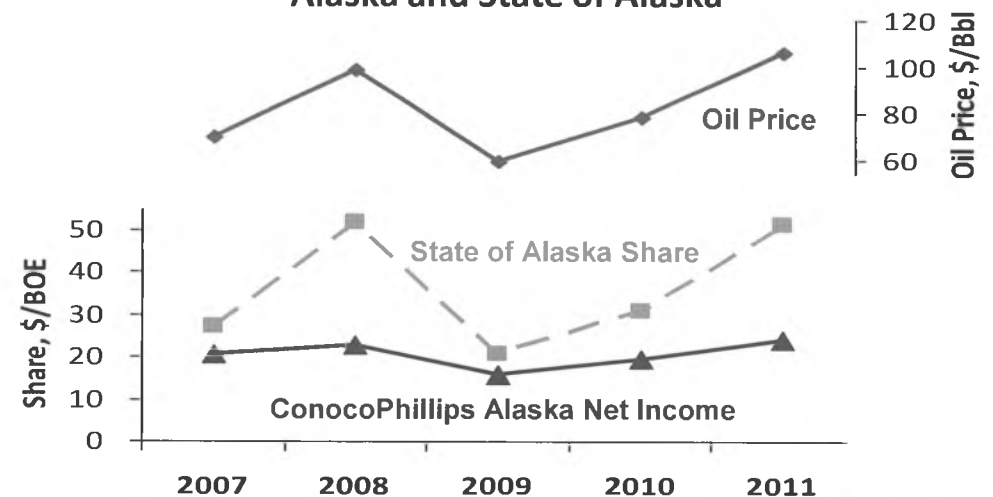
- Challenged oil remains
 - Complex, high cost wells
 - Smaller reserve targets
 - Fault blocks, flank oil
 - Satellites, viscous oil
 - Facilities handling ~ three times as much water as oil
 - Significant resource

- ACES tax structure
 - High average & marginal tax rates
 - Progressivity eliminates upside
 - Tax credits attempt to offset high tax rates and high costs. Applies to both new and legacy fields

Government and Industry Marginal Share in Alaska





Earnings Per Barrel – ConocoPhillips Alaska and State of Alaska



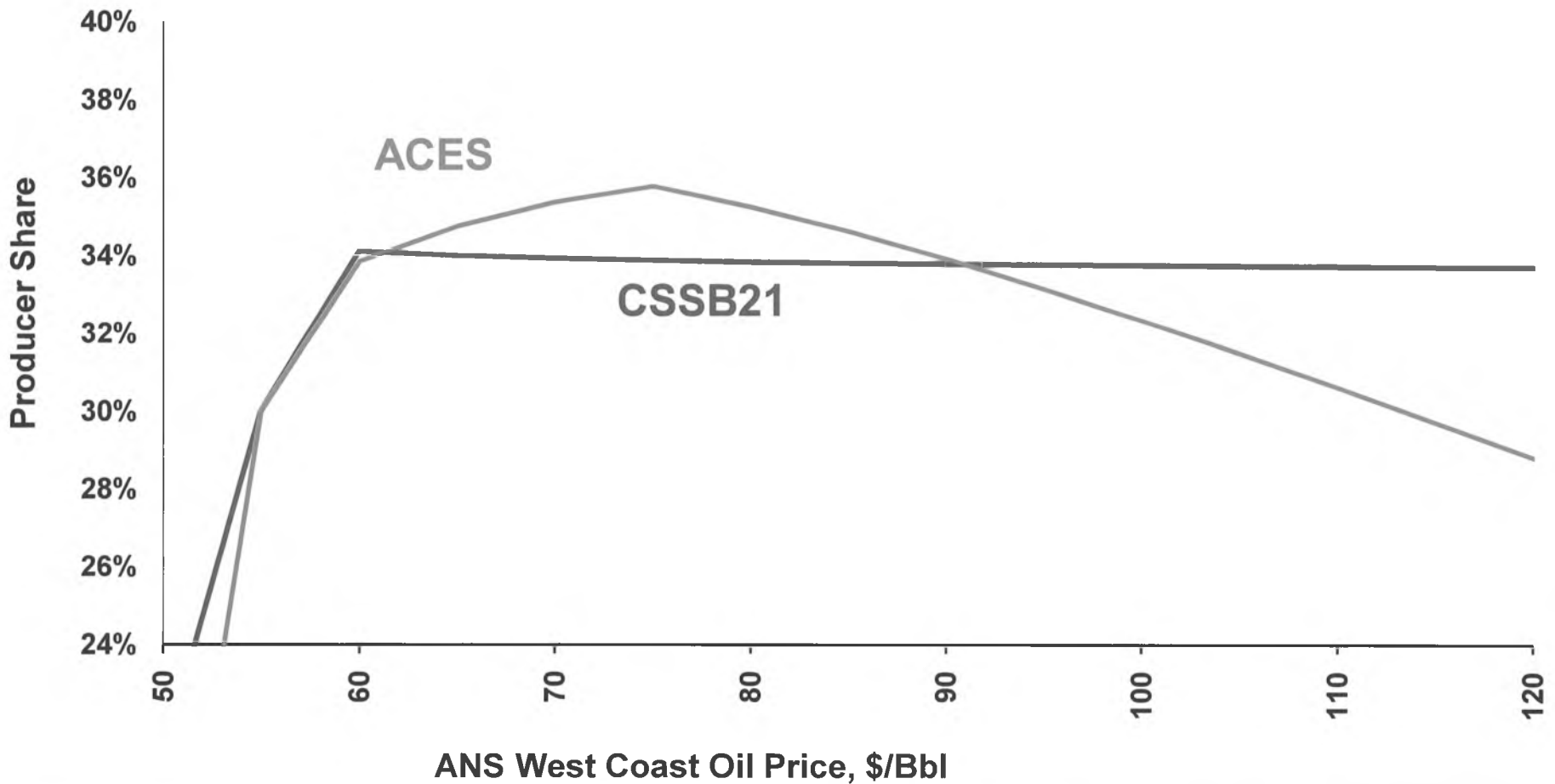
Upper right plot based on Fall 2012 Revenue Sources Book data for FY2014

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 realized prices on the West Coast

Changes to ACES to Improve Alaska's Investment Climate

Change	CSSB21
<ul style="list-style-type: none"> • Eliminate progressivity 	
<ul style="list-style-type: none"> • Create a flatter tax rate over a broad range of prices <ul style="list-style-type: none"> ➤ Producer and State share proportionately as prices fluctuate and margins change 	
<ul style="list-style-type: none"> • Establish a tax structure creating an attractive investment climate <ul style="list-style-type: none"> ➤ Competitive tax rate ➤ Provide the incentives to balance Alaska's high cost environment ➤ Incentives for both legacy and new field investments 	<ul style="list-style-type: none"> • Issues <ul style="list-style-type: none"> ➤ Tax increase at lower prices – base rate too high ➤ GRE will have minimal impact on legacy fields.

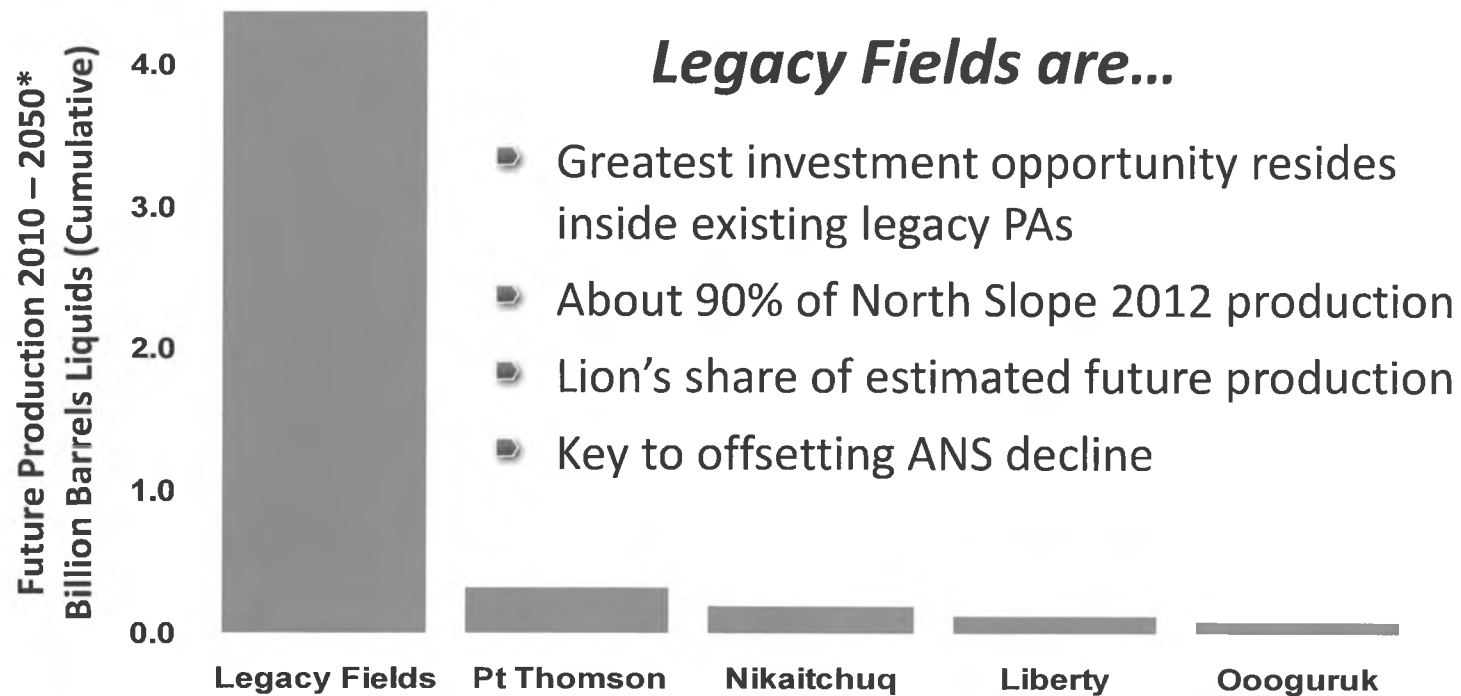
ACES vs CSSB21



CSSB21 is a tax increase relative to ACES at lower prices

Gross Revenue Exclusion

- GRE targeted primarily at new fields and extensions of existing fields
 - Extensions identified as participating area (PA) expansions
 - Legacy field PA expansions included
 - Increase to 30% is an improvement, but less effective than tax credits
- GRE will likely not have significant impact on legacy fields



*Source: DOR 2009 production forecast 2010 – 2050 volumes

Observations

- CSSB21 an improvement over ACES
 - Provides relatively flat tax rate with slightly progressive nature over a broad price range
 - Elimination of progressivity solves the high marginal tax problem
 - Makes Alaska more attractive for investment at \$100+ prices
 - Increase in GRE positive

- CSSB21 changes for an improved investment climate
 - Reduce base tax rate
 - Create incentives for both new and legacy fields
 - Few legacy field projects would qualify for GRE
 - Consider tax credits associated with production

10

Senate Finance Committee

Testimony re: CS SB 21(RES)

March 5, 2013

Todd Abbott, President
Pioneer Natural Resources Alaska



NYSE: PXD
www.pxd.com



Pioneer Natural Resources, Alaska

Forward Looking Statements

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

Presentation Overview

- Pioneer overview
- Importance of a healthy industry
- Competition for capital
- CS SB 21(RES)
- Incentives for Alaskan investments
- Closing thoughts



Corporate overview:

- \$19 Billion enterprise value
- Member of the S&P 500
- Investment grade rating
- ~3,500 employees
- \$3 Billion capital budget
- \$2 Billion cash flow from operations
- Leading performer in peer group



Alaska Operations Overview:

- 1st independent operator on North Slope
- 70+ full-time Alaska employees
- \$14+ million in annual wages (employees)
- 150 - 300 Alaska contract workers
- ~\$180 million 2013 capital budget
- ~6,000 BOPD gross production
- Net investor in Alaska

Pioneer Alaska Profile: Oooguruk

Exploration:

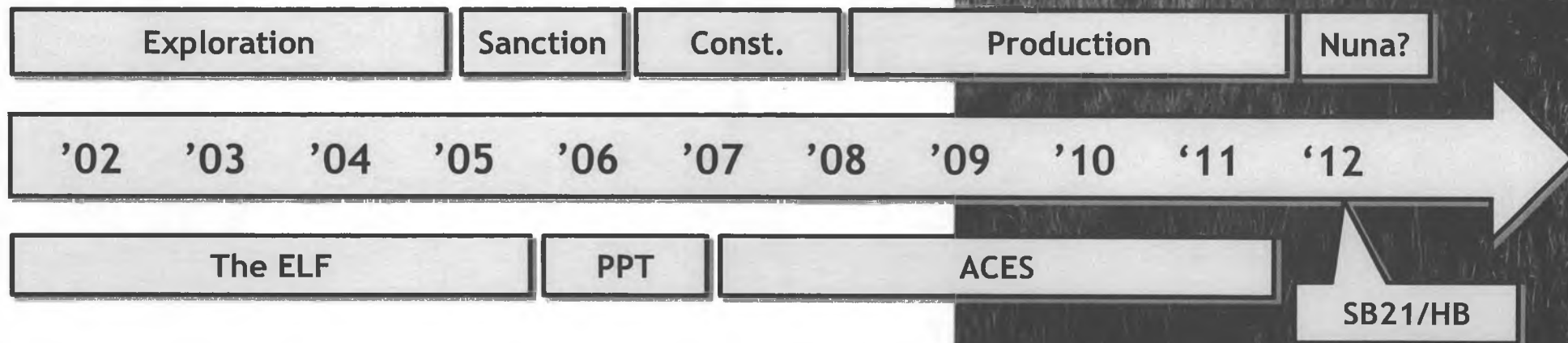
- 11 exploration wells '02 - '05
- 1 commercial project

Oooguruk Quick Facts:

- 70% Pioneer (operator) : 30% Eni
- ~\$1 billion capital invested
- 12+ million barrels produced
- ~\$270 million in credits received
(~7 % of total credits issued by the state)

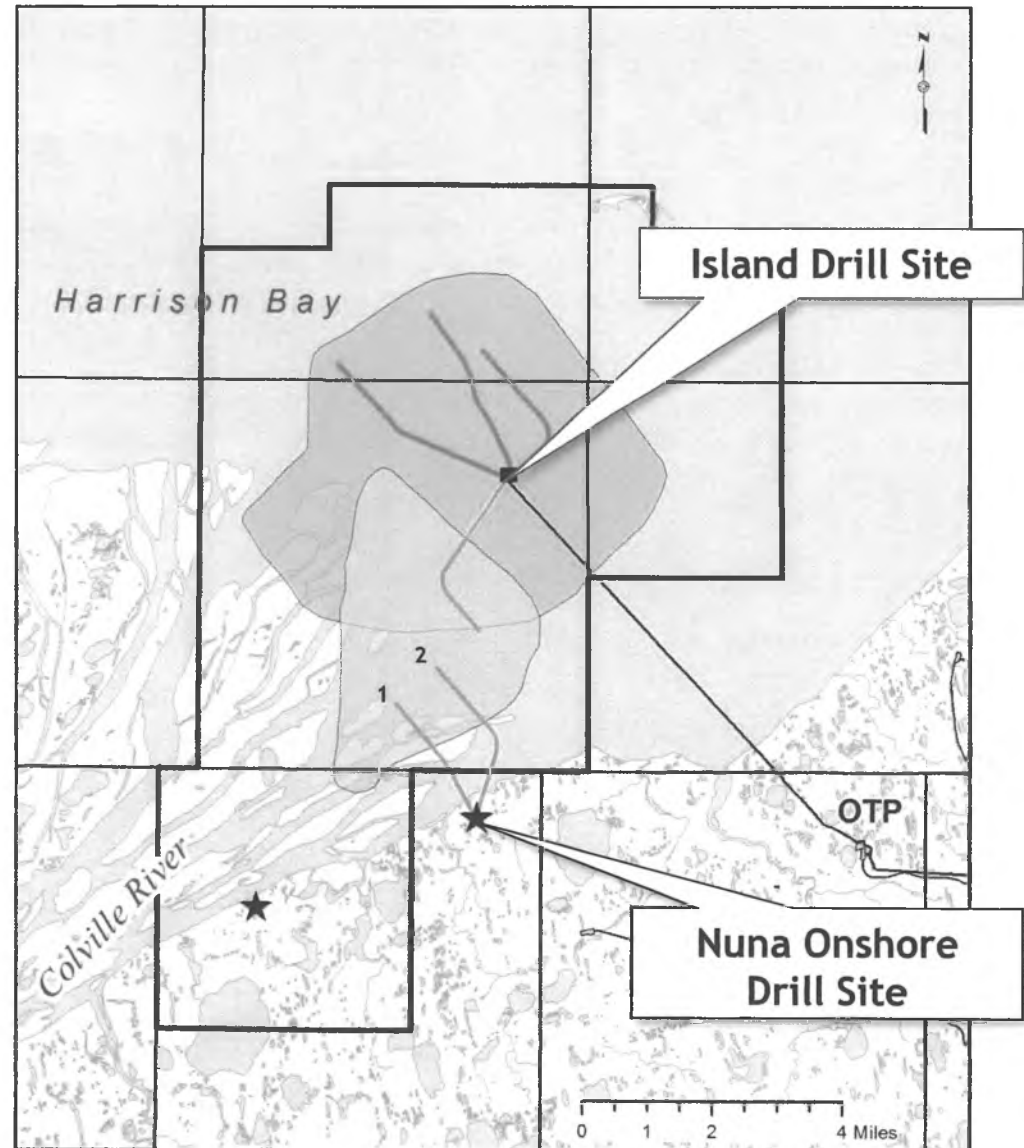


Oooguruk Project and Fiscal Policy Timeline



Nuna Project:

- Nuna-1 well drilled in 2012
- ~50 MMBO of resource potential
- Nuna-2 drilling underway
- Phase I development overview
 - Q3 2013 sanction decision
 - ~\$1 Billion capital required
 - 2015 first oil
 - 14 MBOPD peak production
 - Jobs and economic impact
- Potential for 2nd drill site
- **Must compete for limited capital against low-risk, fast-cycle projects in Lower 48**



Pioneer Competitive Resource Opportunities

WOLFCAMP / SPRABERRY

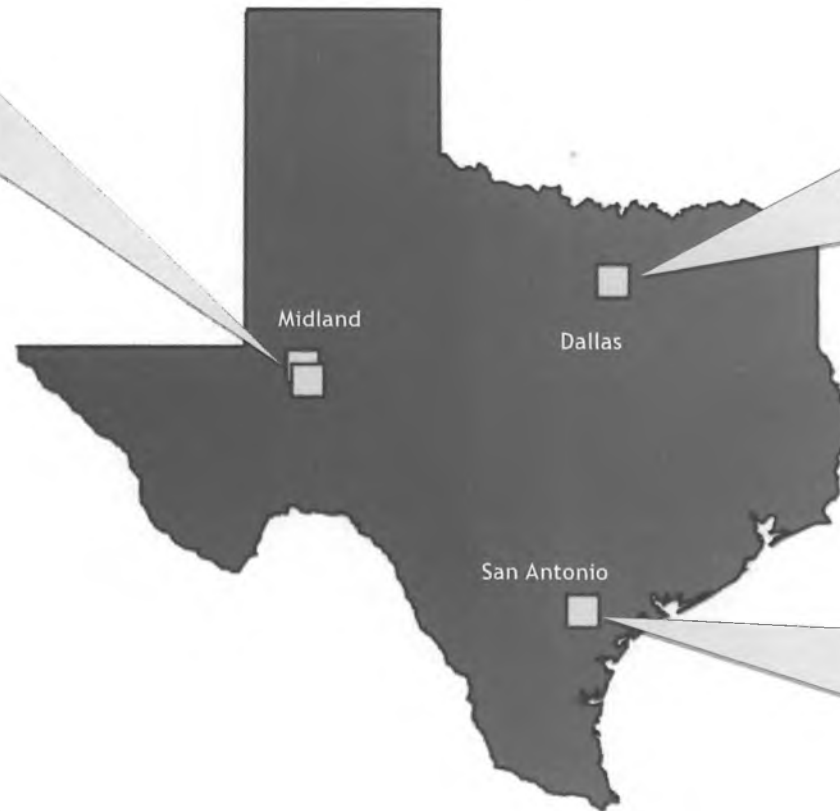
\$1,650 MM Drilling Program
627 MMBOE Proven

2013 Production (Growth):
75-80 MBOEPD (+14 - 21%)

Barnett Shale Combo

\$185 MM Drilling Program
33 MMBOE Proven

2013 Production (Growth):
9-12 MBOEPD (+22 - 41%)



Eagle Ford Shale

\$575 MM Drilling Program
116 MMBBOE Proven

2013 Production (Growth):
38-42 MBOEPD (+36% - 50%)

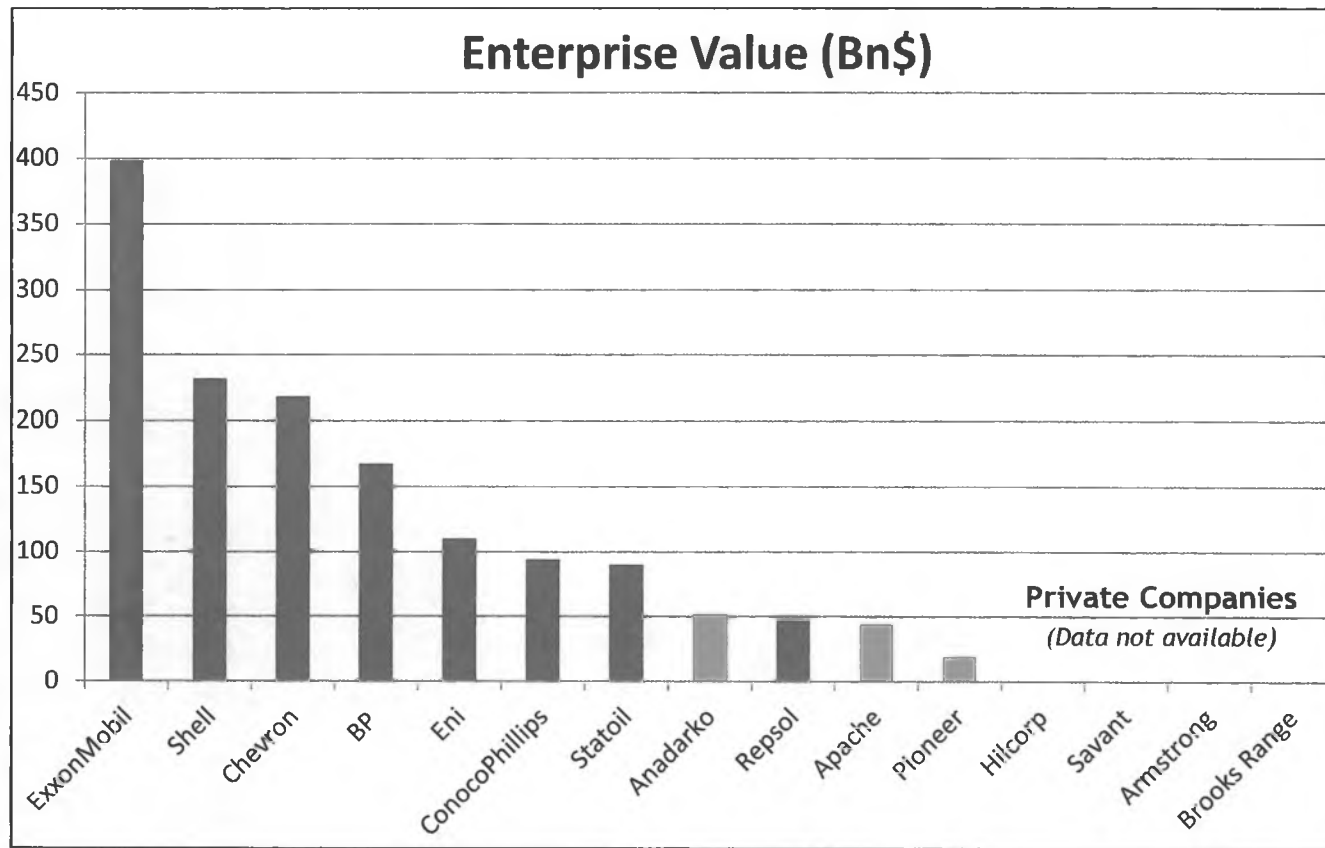
> 40 rigs running
> 20,000 drilling locations

Governor's Guiding Principles

- Tax policy must be fair to Alaskans
- Any changes to oil taxes should, when taken together, be geared to foster new production
- Changes should result in a more simple tax system and restore balance to our fiscal system
- Tax policy must make Alaska competitive for the long-term

- **Positives:**
 - Elimination of progressivity
 - Small producer credit extension
 - Gross revenue exclusion (GRE)
 - Escalating loss carry forward credit
 - \$5 per barrel tax credit
- **Negatives:**
 - Loss of capital credits
 - Increased base tax rate
 - Complicated carry-forward loss calculation
 - Disadvantages new entrants

Relative Rankings and Policy Considerations



Financial Market Drivers

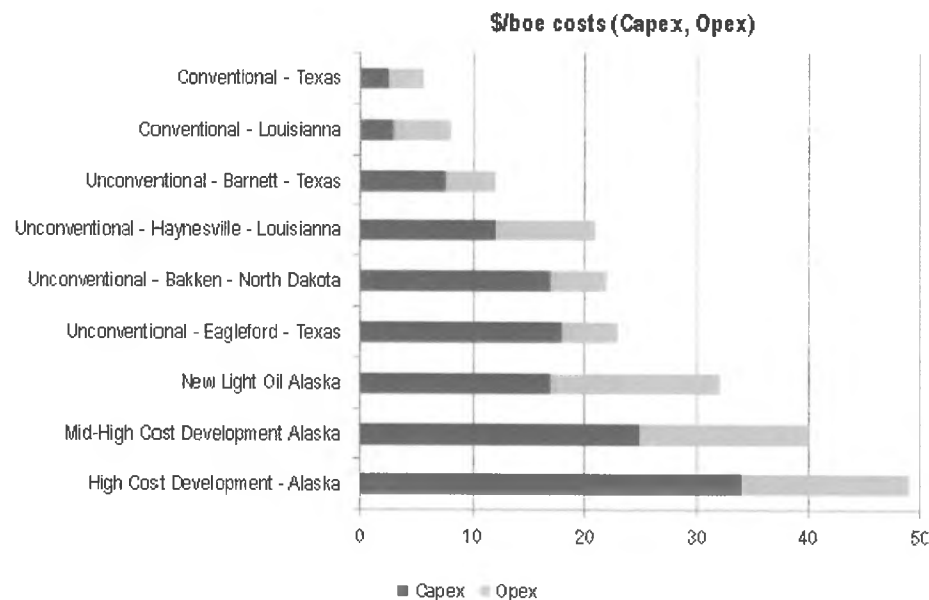
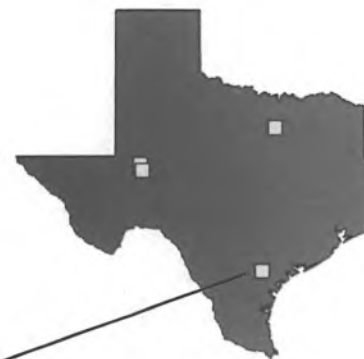
Traditional Independents are rewarded for production growth and debt management

“While their [smaller Independents] production may not seem significant, their economic impact is. Some companies would have had to move their work to North Dakota if it wasn’t for them.”

-Doug Smith, president, Little Red Services, Testimony before TAPS Throughput Committee Jan 13, 2013

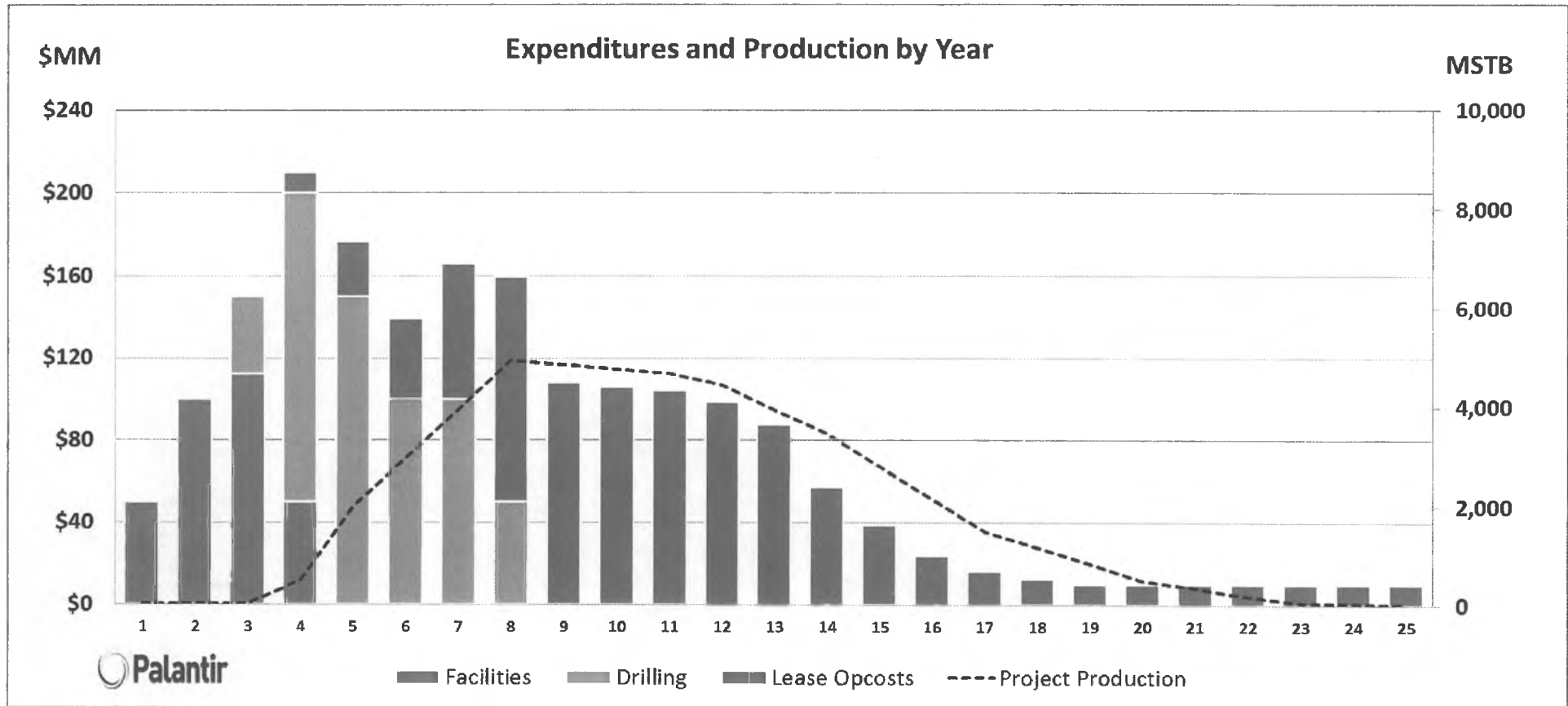
Eagle Ford Operators and Companies

■ Abraxas Petroleum ■ Alta Mesa Holdings ■ Anadarko ■ Apache Corp. ■ Aruba Petroleum ■ Aurora resources ■ Austin Exploration (Aus-Tex Expl.) ■ BHP Billiton ■ BP ■ Cabot Oil & Gas ■ Carrizo Oil & Gas ■ Chaparral Energy ■ Chesapeake Energy ■ Cinco Resources ■ Clayton Williams Energy ■ Comstock Resources ■ ConocoPhillips – (Burlington Resources) ■ CNOOC (China National Offshore Oil Corporation) ■ Crimson Exploration ■ Devon Energy ■ Eagle Ford Oil & Gas Corp. ■ El Paso ■ Enduring Resources ■ Enerjex Resources ■ EOG Resources ■ Escondido Resources ■ Espada Operating ■ Exxon-XTO ■ Forest Oil ■ GAIL (Gas Authority of India Limited) ■ GeoResources Inc. ■ Goodrich Petroleum ■ Global Petroleum ■ Hess Corporation ■ Hilcorp Resources ■ Hunt Oil ■ Jadela Oil ■ Japan Petroleum Exploration ■ KNOC (Korea National Oil Corporation) ■ Laredo Energy ■ Lewis Energy Group (BP Partner) ■ Lonestar Resources ■ Lucas Energy ■ Magnum Hunter Resources ■ Marathon Oil ■ Marubeni Corporation (Hunt Oil Partner) ■ Matador Resources ■ Mitsui ■ Murphy Oil ■ Newfield Exploration ■ NFR Energy ■ Penn Virginia Corp ■ Peregrine Petroleum ■ PetroHawk ■ PetroQuest ■ Pioneer Natural Resources ■ Plains Exploration & Production ■ Redemption Oil & Gas ■ Reliance Industries ■ Riley Exploration ■ Rock Oil Company ■ Rosetta Resources ■ San Isidro Development (Acquired by Chesapeake) ■ Sanchez Energy ■ Sandstone Energy, LLC ■ Saxon Oil Company ■ Shell ■ SM Energy (St. Mary Land & Exploration) ■ Statoil ■ Strand Energy ■ Strike Energy ■ Swift Energy ■ Talisman Energy ■ Texon Petroleum ■ Tidal Petroleum ■ TXCO Resources (Now, Newfield & Anadarko) ■ Unit Corporation ■ U.S. Energy Corp. ■ Weber Energy ■ WEJCO E&P ■ ZaZa Energy



Source: Alaska Discussion Slides, PFC Energy 2012, February 11, 2013

Typical New Project Spend Profile



Typical Project (after discovery):

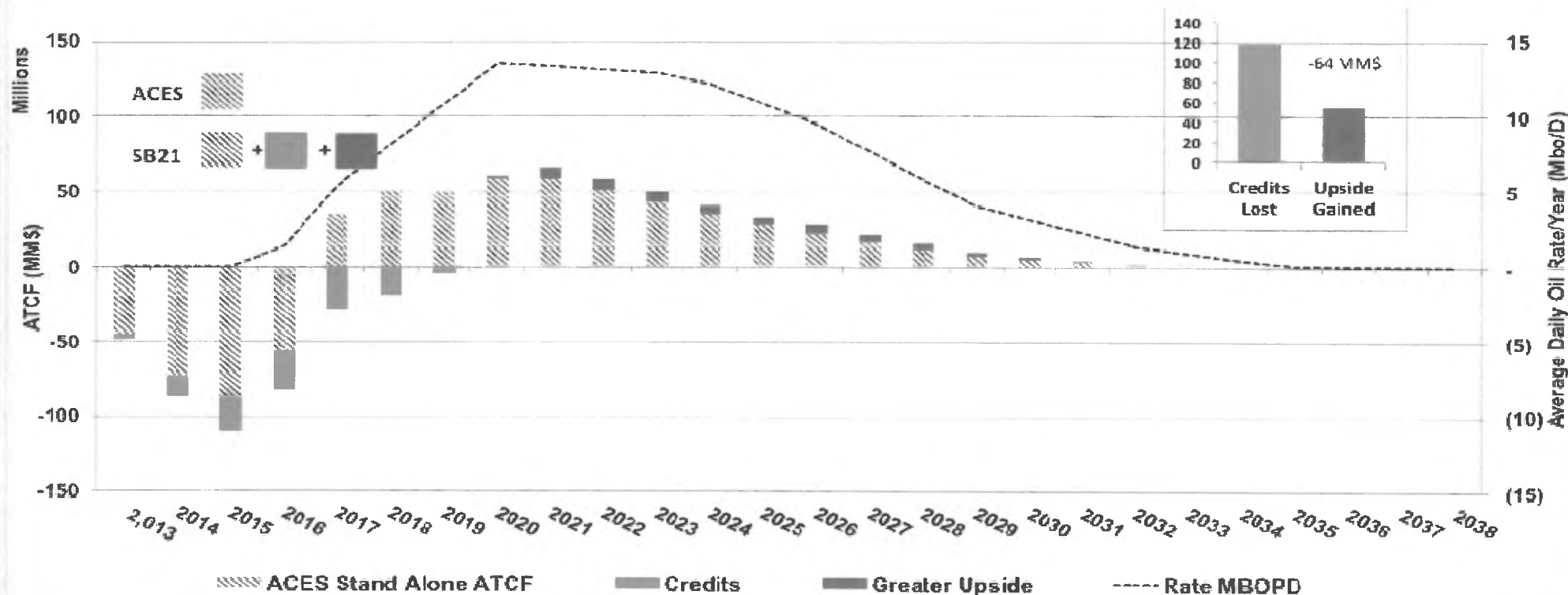
- 1st year: front end engineering work
- 2nd year: 100% of capital spent on facilities
- 3rd year: 75% capital is for facility work
- Drilling begins late in 3rd year, no production until 4th year
- 4th year: production begins
- Peak production rate occurs during 5th year after start of production

Mid-Sized Producer



DISCOUNTED AFTER TAX CASH FLOW (\$100/bbl ANS)

Under CS SB21(RES) a mid-sized producer has to source more upfront capital in exchange for greater upside later



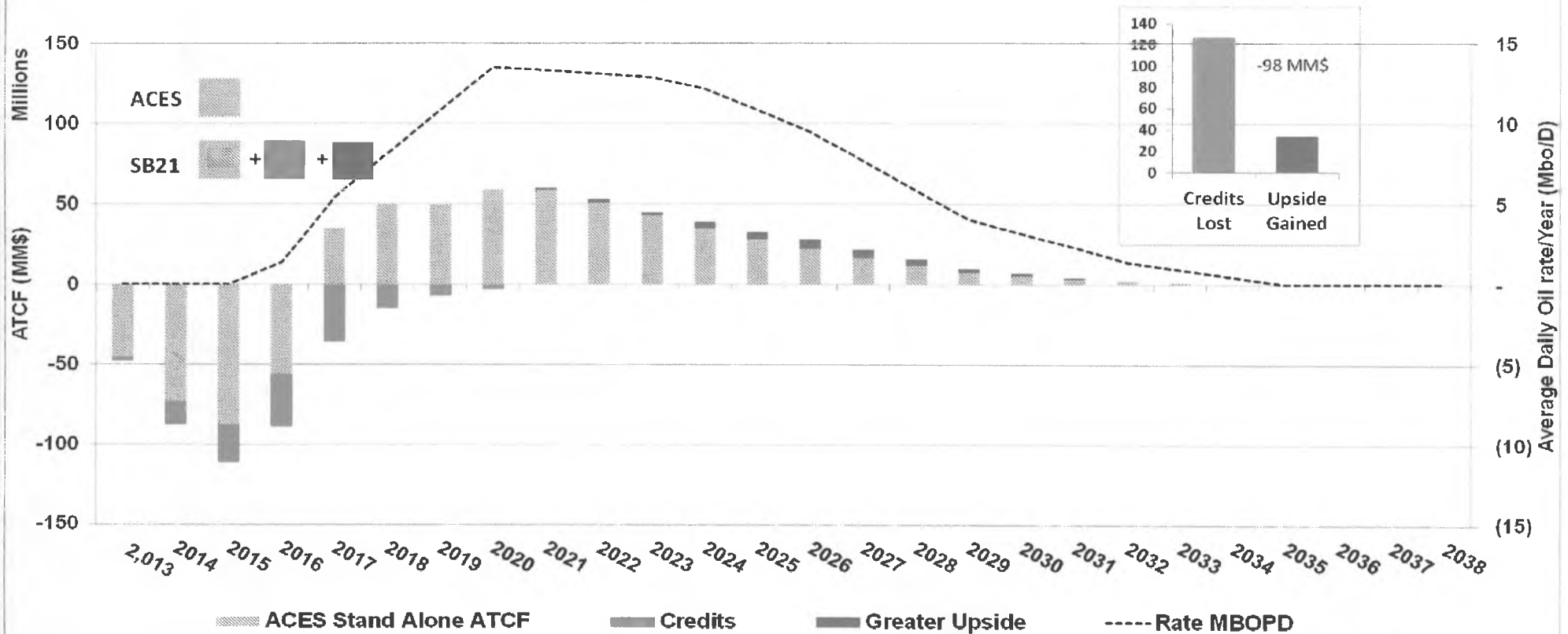
Field assumptions:

- 50 MMBO field
- \$1 Billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast (Nominal)
- 35% base:5% credit
- NPV-10
- 30% Gross Revenue Exclusion
- Small Producer Credit

New Entrant - Stand Alone Project

DISCOUNTED AFTER TAX CASH FLOW (\$100/bbl ANS)

Under CS SB21(RES) a new entrant has to source more upfront capital in exchange for greater upside later



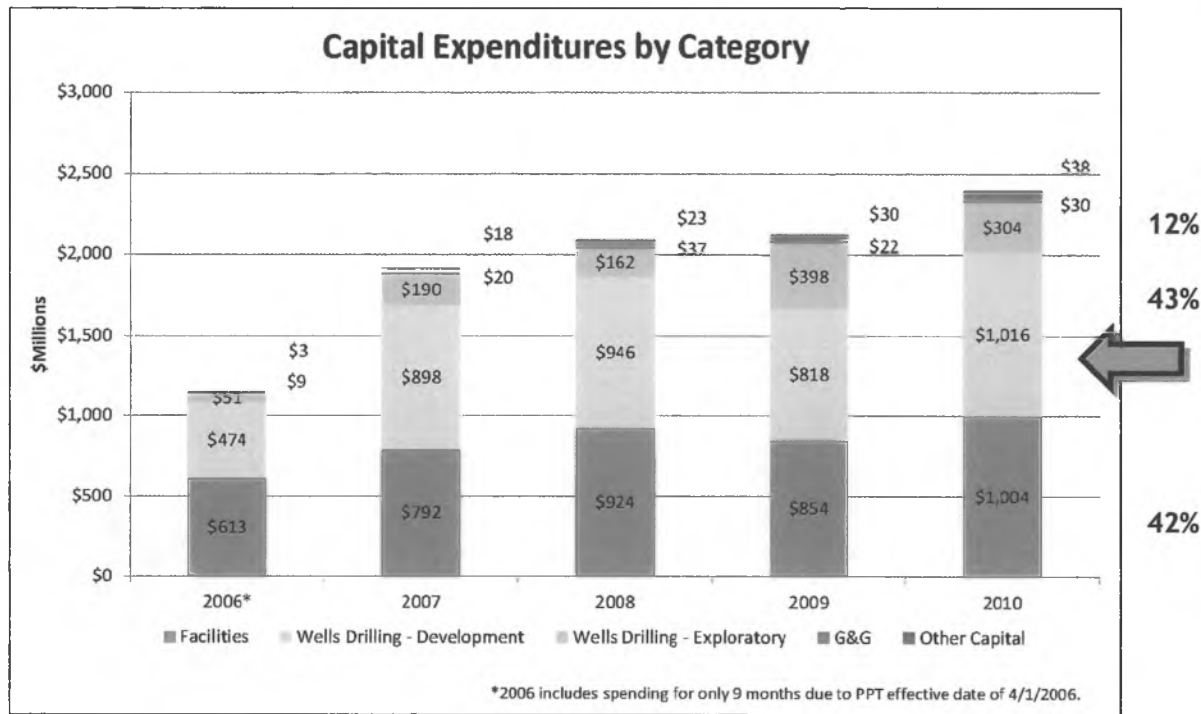
Field assumptions:

- 50 MMBO field
- \$1 Billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast (Nominal)
- 35% base:5% credit
- NPV-10
- 30% Gross Revenue Exclusion
- Small Producer Credit

Industry Spending on North Slope



Historical CAPEX by Category (CY)



Alaska Department of Revenue: 5 year look back

- Goal: to answer capital expenditure questions relating to credits
- Oil industry capital expenditures by category
- Categorized capital expenditure data represents 90% of costs related to credit applications

Source: Dept. of Revenue presentation to the Senate Resources Committee, Feb. 13, 2012

■ Benefits to State

- Credits directly encourage activity in Alaska
 - Jobs, direct and indirect (9x multiplier)
 - More wells
 - More oil
 - More royalties, taxes and throughput

■ Benefits to Developer

- Reduces investor risk
- Improves small project economics
- Improves financial performance
 - Doesn't increase debt
- Builds healthy industry
- Strengthens competitiveness

Purpose of Tax Credit Provisions:

“The fiscal impact of the tax credits was an investment incentive that state must offer to secure a ‘long-term stream of oil.’”

- Senate Finance Committee 5/13/2003

Source: DOR Presentation to Senate Resources Committee 2/13/2012

“Recommend targeted tax credits as being preferable [vs GRE], they provide incentive to invest.”

- Roger Marks, Senate Finance Committee 03/04/2013

CS SB 21(RES) Closing Thoughts:

■ Pros

- Eliminates progressivity
 - Shares upside potential
 - Improves competitiveness
- GRE reduces tax for new oil
- Extends small producer credit

■ Cons

- Elimination of credits increases investor risk
 - Requires more upfront capital
- Increased base tax rates
- Does not simplify tax calculations
 - Complex carry-forward loss calculations
- Does not strongly motivate additional investment

■ CS SB 21(RES) suggestions

- Targeted credits for new facilities/well related costs
- Allow targeted credits to be redeemable / transferable
- Allow credits to be taken against any payment to the state



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Senate Finance Committee Comments on SB 21 CS

Investors: AVCG (Alaska Venture Capital Group)

Operator: Brooks Range Petroleum

Ken Thompson
AVCG Co-Owner/Investor
Former President, ARCO Alaska, Inc.

March 5, 2013

AVCG LLC

Why Consider Our Company's Perspectives ?



- 1) Most active exploration company exploring and developing solely on North Slope state lands
 - a) Drilled 10 of 36 exploration wells on state lands in 2007-12 (more than COP, BP, XOM, ENI, Repsol, Armstrong combined)
 - b) 105,000 leased acres in 3 core areas in JV partnership with Ramshorn Exploration (affiliate of large Nabors Industries)
- 2) ~ \$200 MM invested to date in Alaska North Slope projects...3 discoveries, acquired discovery
- 3) Mustang development project under construction...\$577 MM capital, 44 MMBO, 15,000 BOPD... future level of capital spending/yr same as Pioneer Natural Resources and one-third the level of COP capital spending
- 4) Three other development projects in permitting/conceptual engineering stages...> \$1.5 B capital
- 5) First production and cash flow to state and our companies...startup of Mustang in 3Q 2014
- 6) On investment of \$200 MM, received refunded tax credits totaling \$69 MM but State will receive back this amount+ in the first year of Mustang production...and \$1.2 billion over field life
 - a) All credits have been redeployed on the North Slope for new drilling or seismic to find, develop oil...none sent Outside
 - b) Credits redeployed has allowed in some years the drilling of 3 exploration wells instead of 2...or 2 wells instead of only 1
 - c) Payment of credits in cash versus just an allowance against taxes critical to AVCG which has no current production
- 7) Experience in bringing other independents to Alaska and in raising capital for Alaska
 - a) Seeking additional capital for Mustang and 3-5 year exploration program...started fundraising 18 months ago, Sept 2011
 - b) Sent materials to 210 firms, but only 19 wanted to consider Alaska...and after further review, only 2 firms remain interested
 - c) Biggest hurdles we heard: 1) complex and high gov't take of AK fiscal regime, 2) flow of capital to Lower 48 source rocks
 - d) Two firms remain and we hope to finalize deal...belief in our confidence that Legislature will make positive change in 2013

North Slope Drilling Results And Success



Tofkat Unit

- ~ 40 MMBO Kup C, ~ 20 MMBO Jurassic
- Offset Alpine & Nanuq fields
- Ran 3D after drilling indicates Kup C may extend into Nanuq field
- 3 delineation wells drilled
- Returning to delineate in Q1 2014
- COP drilled 4 wells into Jurassic at Nanuq
- Less than 1 mile to Alpine CC pipeline
- Upside defined in Brookian, new leases Nov 2012
- **FIRST OIL 2015 or 2016**

Beechey Point Unit

- ~ 26 MMBO Kup C & Ivishak
- Adjacent to Prudhoe Bay and Midnight Sun
- 3-D definition on traps
- 3 discovery wells
- Substantial commercial opportunities within drilling reach
- East Shore prospect analog is Midnight Sun
- Lease block win Nov 2011 increases resource expectations
- **FIRST OIL 2016**

Kachemach Unit

3-D seismic evaluation
Exploration drilling planning

S. Miluveach Unit – Mustang / Appaloosa

- 44 MMBO Kup C Mustang, ~ 37 MMBO Appaloosa
- Extension to KRU field
- N Tarn well penetrated reservoir 2011, re-entered & tested 2012 (20+ Kup C discovery)
- N Tarn #1A confirmed quality C sand 10+ ft. oil test
- Drilled confirmation Mustang #1 2012 20+ ft.
- Confirmed communication with KRU 2M
- Common carrier pipeline 700' from production pad
- 200 sq. miles proprietary 3D + 240 WBA license 3D
- **FIRST OIL 2014**

Telemark Discovery...Badami Unit Expansion

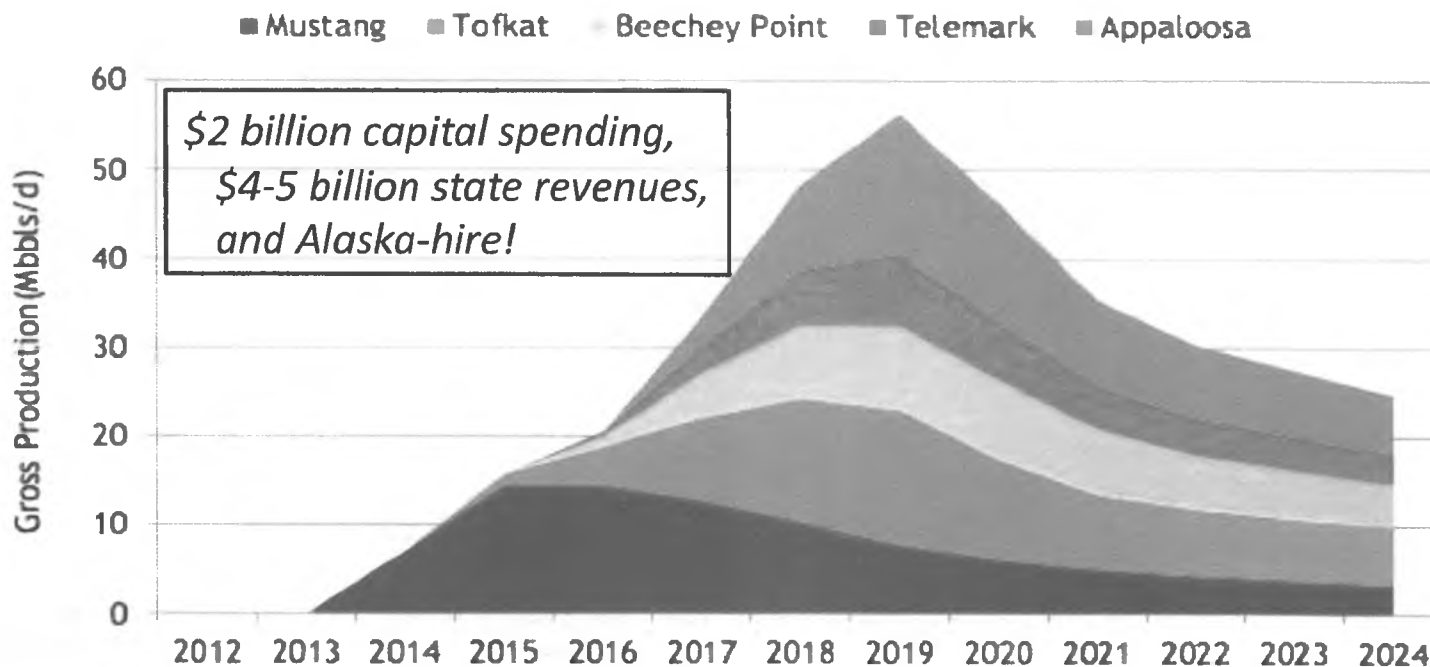
- ~ 16 MMBO Flaxman Sst
- Project area located between Badami & Pt. Thomson
- E Mikkelson #1 tested 250 BOPD un-stimulated
- Improved reservoir setting to Badami
- Horizontal development strategy
- Facilities and pipeline capacity in close proximity- no need to build facilities
- Pt. Thomson sand upside
- **FIRST OIL 2015 or 2016**

What Difference Can Our Company Make?



Production Profile (Mbbbls/d)

“New work in existing fields to increase production above their existing declines will not – by itself – level AK’s oil production. Production from exploration discoveries are needed also. Alaska still needs E&P...not just P!”



*Between 2012 and 2011, North Slope oil production declined 50,768 BOPD. Developments such as the above, if repeated, could help in replacing production fall off...**AND ACHIEVE “NO DECLINE!”***

Note: Mustang delineated and development underway. Tokfat, Beechey Point, Telemark, Appaloosa require delineation before sanctioning...not risked.

We See Positives In SB 21 CS To Help Grow Production



- 1) Increases “Carry Forward Loss Credit (CFL)” from 25% to 35% and interest on unused credits 43.55.023(b)...
 - ✓ *POSITIVE: incrementally more future cash flow to re-deploy into facilities & drilling*
- 2) Extends “Small Producers” Credits from to 2022...reduces small producers’ tax bill by \$12 MM/yr 43.55.024(c)...
 - ✓ *POSITIVE: more cash flow for small producers to re-deploy into facilities & drilling*
- 3) Specifies 20% QCE tax credit certificate payment in single year vs. 2 but does eliminate QCE on 12/31/13 43.55.023(a)
 - ✓ *POSITIVE: more immediate cash to put into Mustang development facilities and drilling 2014*
 - ✓ *NEGATIVE: no QCE payment in 2015 to redeploy into Mustang development drilling...“wish list” is extend QCE and cash payment to 12/31/14...project was sanctioned assuming QCE, requiring less Owners’ funding*
- 4) Eliminates progressivity factor, increases base tax rate from 25% to 35% but provides \$5/bbl produced bbl credit 42.55.011(e)...
 - ✓ *POSITIVE: Eliminating progressivity simplifies tax calculation and will be a public relations plus for AK*
 - ✓ *NEGATIVE: Increase in base tax rate from 25% to 35% not expected...but partially offset by...*
 - ✓ *POSITIVE: \$5/bbl produced bbl credit better balances relative state/producer takes at low oil prices*
- 5) For new oil, increases “20% Gross Revenue Exclusion (GRE) ” to 30% GRE and amends definition of leases that can be included for this GRE 43.55.160...
 - ✓ *POSITIVE: Should incentivize new oil production on more leases, also help during low oil price cycles*
- 6) Removes old distance limitations and allows for a 30% “Exploration Incentive Credit” for exploration wells drilled that target new oil discoveries regardless of location 43.55.023(a)...
 - ✓ *HUGE POSITIVE: For exploration companies like ours-will result in more companies & more oil on State lands*
- 7) Overall? Thanks for the changes in the CS...this should help in attracting new capital & leveling oil production

Photos: Mustang Development Project Underway - \$1.2 B State Revenues



Senate Finance Testimony 3-5-2013

Thank you for giving me the opportunity to speak with the Senate Finance Committee today about the oil and gas industry on the North Slope. We are a strong supporter of SB 21 we believe that the passage of this bill will not only result in significant investment on the North Slope, it will serve as a catalyst to increasing production as well. Some of you may have heard Bill Armstrong make a presentation to the Senate Resources Committee a couple of weeks ago. If you heard that presentation you probably already know that it has been our opinion that you in the Senate have been inundated with so much information that I cannot begin to imagine how you can process it all. I have been in this business for more than 30 years and have experience in numerous states and some various other regions in the world and I have to tell you, it is incredibly difficult to keep up with all of the information that is being provided with regard to SB 21.

For this reason I will not have a power point, I would rather talk to you and see if you think I have anything to add with respect to how Alaska can increase its production in a manner that is fair to Alaskans and is something that the oil companies can work with. Today I would like to keep things pretty simple and keep to the fundamentals. The only thing that really tells the story on the North Slope is what does its production profile look like and is there anything on the horizon that will help it.

As I was trying to get ready to talk with you about this I had an internal fight with myself. It reminded me of my high school English class when we read the Dickens classic, A Tale of Two Cities. The first part of opening line of the book is "It was the best of times, it was the worst of times." Guys this describes the oil industry on North Slope and where it is at this point in time better than anything I can think of.

I know revenues to the State have been up over the last few years and I know that you as members of the legislature have an important duty to make

certain that the State gets its fair share and maximizes the state's fiscal position. The hard part of the story is when you look to the future and the fact that while the North Slope is one of the most remarkable petroleum provinces in the world, it is the only petroleum province in the US that is not enjoying the benefit of the amazing technological advancements in horizontal drilling and stage frac technology. I know you have seen the same graph in probably ten different presentations of the North Slope's production decline while Texas and North Dakota have production increases. Last Friday the ADN reported on the front page that Texas has doubled its production since 2010, doubled its production in 3 years, amazing (especially given the fact that Alaska has experienced about a 6% annual decline during that period), and we all know North Dakota passed Alaska last year to become the second largest producer in the United States. I never thought I would see that. I know someone can look at that data set and feel that this is the worst of times because as we all know the states revenue is only as good as the production and if the production keeps dropping at this rate, soon the state will have big issues with its budget.

I don't know how long TAPS can last at the current decline rate and frankly that's not the question anyone should be asking, we should be asking, "How in the heck can we have one of the greatest petroleum provinces in the world and get beat out by North Dakota in daily production. Guys as a petroleum system North Dakota is a Jr. High team and Alaska is Professional team, there is no way this should happen, but it has and we have to ask ourselves how did we get to this spot and what will it take for Alaska to take its rightful spot as the top producing state in the nation.

Before I give you anymore of my thoughts I should probably take a second to tell you a little about Armstrong Oil & Gas and what we have done in Alaska. We are an independent oil and gas company headquarter in Denver, Colorado. We would probably be considered a bit of new type of company for the North Slope as we are privately owned, we carry no debt and as such

we do everything out of our own pockets, every decision we make is based on the bottom line and not what some stock analyst on Wall Street thinks or says.

I am a minority owner in Armstrong and have been involved in Alaska since the beginning. We began studying the North Slope diligently in the late 90s, we made our first lease acquisition in the early 2000s. Our business model is to establish significant exploration and development projects through the utilization of all of the technology available to our industry. It is our opinion that we have the best scientist in the world these scientists have an extremely broad and diverse experience level that affords us a perspective that most people do not have. Most of our Geoscientist spent their early years with Exxon.

At any rate the first concept we pulled together on the North Slope was what is today the O3 field. We initially established the concept through acquisition of leasehold and technical data and then we brought in Pioneer to help us develop the field. Subsequently we brought a company called Kerr McGee into to help us define and develop what is today known as the Nikaitchuq field that is operated by ENI. We currently operate the North Fork Gas Field in South Central Alaska and on the North Slope we are partners with Repsol E&P USA where we currently have 3 rigs running on the North Slope.

If I can I would like to take second to apologize for the lack of a polished presentation for you today. The fact is I am not that good of a public speaker and I didn't know I was coming here until a few days ago, so my apologies. What you will hear from me are observations of what we as a company have found is the number one critical attribute any area needs in order to have a successful thriving oil and gas industry that will either sustain itself or grow even larger.

The most critical barometer for the health of a producing region is the rig count (it is the canary in the mine). Depending on the week, you see Alaska's fluctuate between 6 to 14. Let me put that in perspective, the Permian Basin not all of Texas, just the Permian Basin is at 430. That is around 43 times greater than all of Alaska by itself. Assuming each area drills and completes a well in a couple of months that means in one year the Permian Basin brings on an additional 2580 wells while all of Alaska would bring on about 60. With this metric in mind it is easy to see how Alaska is drifting the wrong direction with its production. You can apply this metric to any basin or state and you will get the same answer (North Dakota is at 178 rigs, Oklahoma has 190), in order for Alaska to continue to be considered relevant in the petroleum industry something must be done to make it competitive with the other states and regions of the world.

When I look at some of the public companies I see such amazing results. Pioneer recently reported it had over 36,000 net resource locations with potential in excess of 8BBO. EOG Resources has had oil production growth of 35% in 2010, 52% in 2011 and 39% in 2012, they have a drilling inventory that will keep them busy for the next 15 years even if they do no new business. My point is that this story is occurring in tons of companies all through the lower 48, states like Pennsylvania are on the rise and the state of Alaska needs to do something to make itself more competitive. We feel like SB 21 is a great start to getting Alaska competitive with the rest of the world.

I think it is important to note that SB 21 needs to be passed as it is and possibly with some minor improvements in order to make certain Alaska becomes competitive with the rest of the world. We need to make certain the GRE stays in place as it is and is not limited to the first 7 years. A study of the new fields on the North Slope show how time consuming and difficult it is to bring fields on line and as such you need the GRE to be effective

throughout the life of the field. The monetizing of the EIC will serve to continue to encourage new entrants with new ideas to come to the North Slope.

The fact is the North Slope is remote, cold, expensive, with tremendous regulatory issues and SB 21 is needed or Alaska will not be considered competitive with the rest of the world. It is next to impossible to convince a substantial company to come to the North Slope to develop new fields when the states own experts rate the state of Alaska worse than Kazakhstan for new field development. It is important to note that by supporting SB 21 as a new entrant we are actually helping the state's fiscal position. We are walking away from the cash reimbursement from the state of the LCF and QCE, so that we can have a stable tax regime. At the end of the day the state has only upside with regard to the new field portion of SB 21.

We do think SB 21 simplifies the tax code, we think it is fair to Alaskans, that it is durable and that it makes Alaska competitive. I believe that you need all parts of SB 21 for the state to be successful. The state needs the legacy field provisions of SB 21 to pass so that the fields like Prudhoe Bay and KRU can provide quick immediate barrels into TAPS and keep the transportation costs on TAPS from increasing.

The state also desperately needs SB 21 to pass so that new entrants will be encouraged to come to the NS and invest, this is the future of the North Slope. Currently 92% of all production from the North Slope comes from 2 operators, I know of no other significant petroleum province in the world that has this fact set. As a comparison the top 20 operators in Permian make up 47% of the basins production and when I asked our research guys how many make up 92%, I was told that the number was so high that it would take a tremendous amount of time to figure that out. On the North Slope

the top two operators drilled 86% of all of the wells in the basin, in the Permian Basin the top 20 operators make up 35% of all wells drilled.

None of this is the operators fault they are doing their job, but it does show that there is a desperate need for more players on the North Slope and in order to have any impact this change needs to be done now. As an example from the time we started working on O3 until the first production came out of the field it took 10 years, so as you can see something needs to be done right now.

Further evidence of the North Slope not being competitive can be found within its leasesales. Since we made our first bid in Alaska in 2001, a very successful sale would be one that is considered to bring in around \$10MM with around 6 successful bidders, compare this against the GOM sales that have more bidders and as an example on the last Central GOM sale had one tract that brought in \$157MM that one tract being well in excess of the last 10 state North Slope Leasesales. This is evidence of a system that needs fixing.

So enough about the negative news. The good news is I can tell you from the perspective of the company that brought Pioneer, ENI and Repsol to the North Slope that there are a lot of companies that would desperately like to do business on the North Slope but they have shied away because of the ACES tax system. To be sure the costs concern them and I believe we need to work hard to streamline the permitting of projects on the North Slope, but I believe the primary thing that keeps them away is the current ACES tax system.

SB 21 is a huge step in the right direction to getting new entrants on the North Slope as well as getting production from new fields up and running,

increasing the life of TAPS and providing high paying jobs for Alaskans in the process. There is an incredible step function change in our industry that is going on right before our eyes and if Alaska doesn't make the changes provided for in the Governor's bill this revolution has the potential to pass over Alaska. So these are my thoughts, but I would really like to talk about this with all of you. This is an amazing time in our business and I want to make certain that you guys ask any question at all that you feel should be discussed. I love this business and think that is the best way to get the heart of the discussion so please ask me any questions you want about taxes, permitting, potential of the North Slope (it is huge) or anything else you want to talk about.

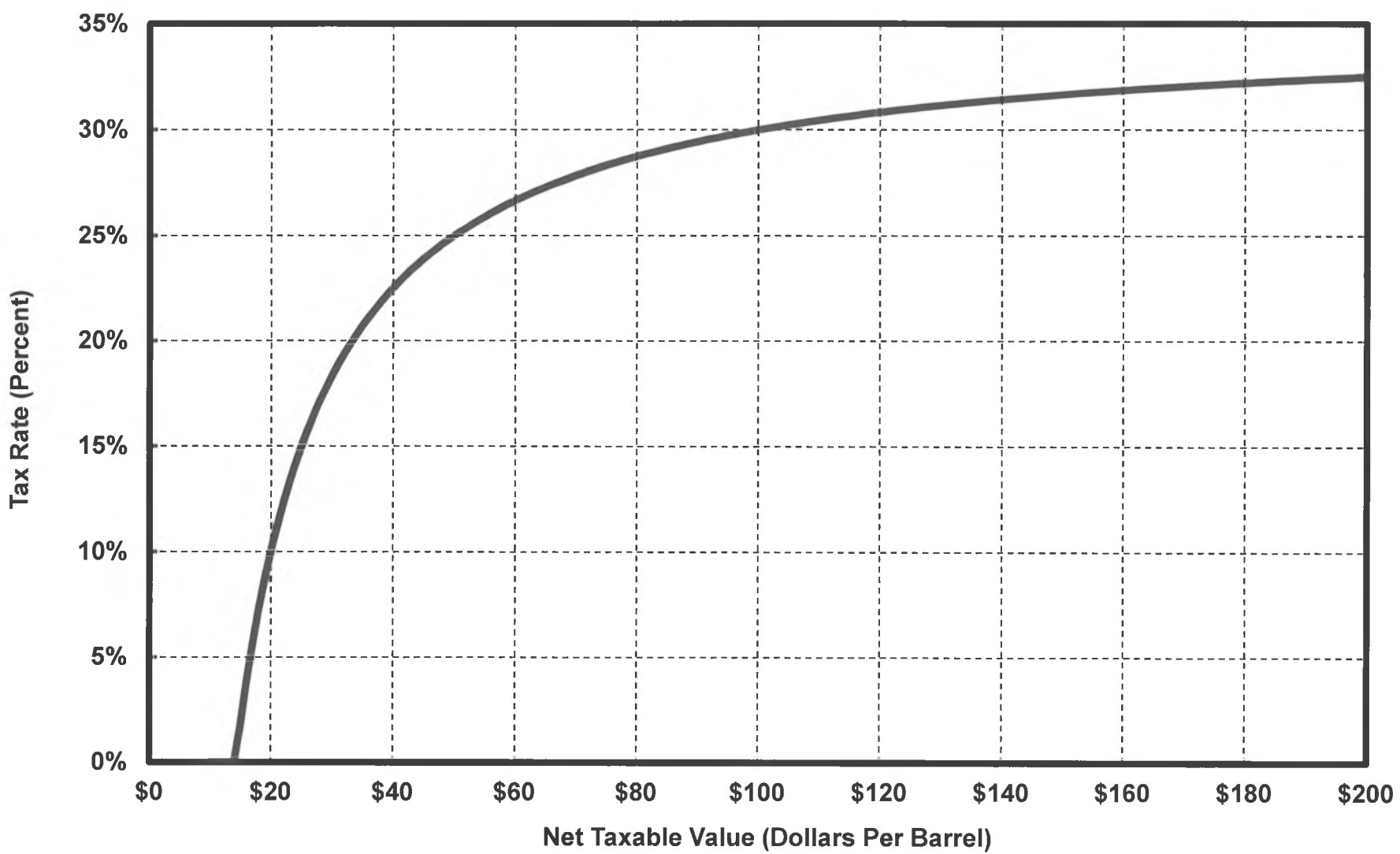
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Comments To Senate Finance SB21 / SRES CS SB21

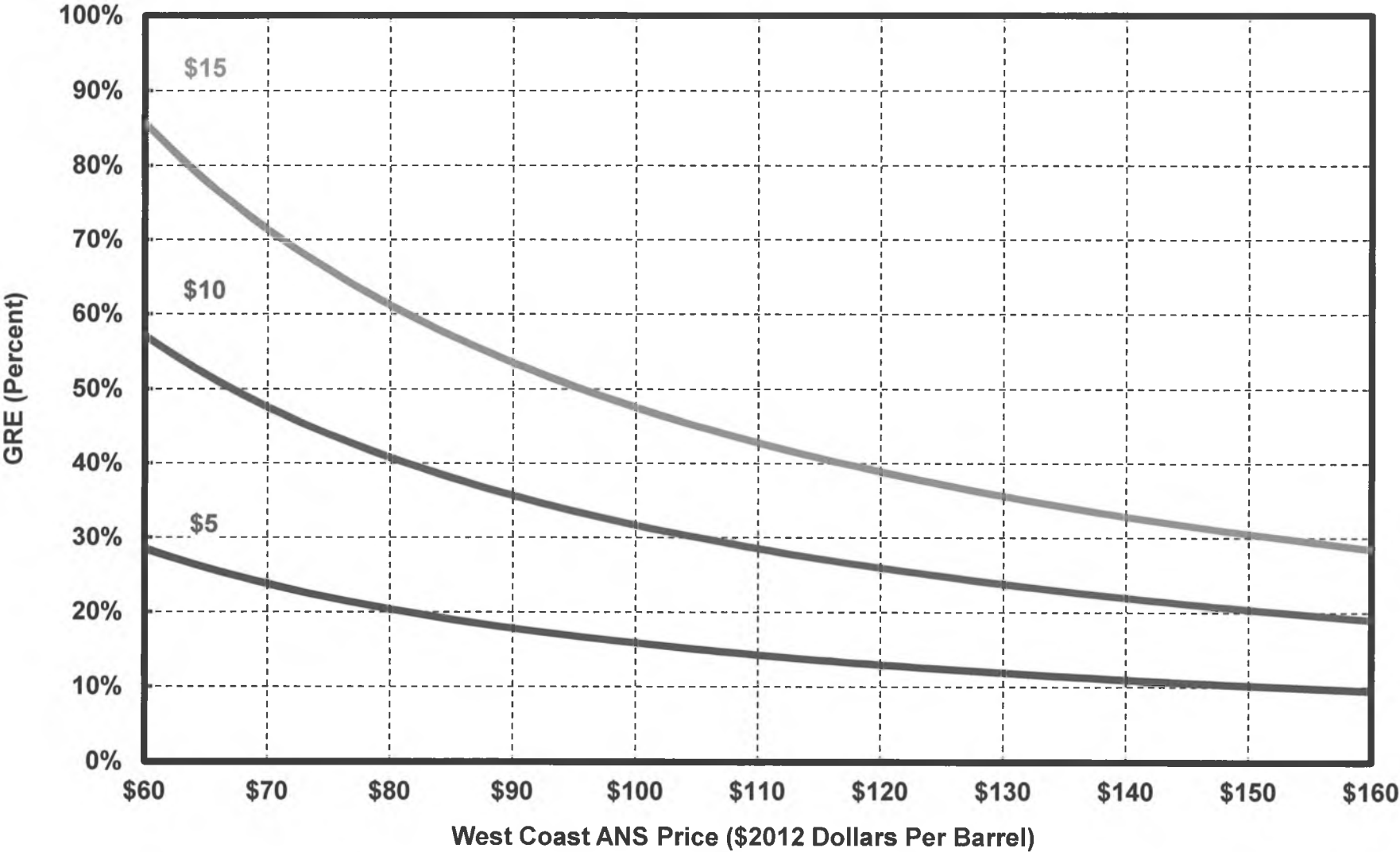
**Barry Pulliam
Managing Director
Econ One Research, Inc.**

March 6, 2013

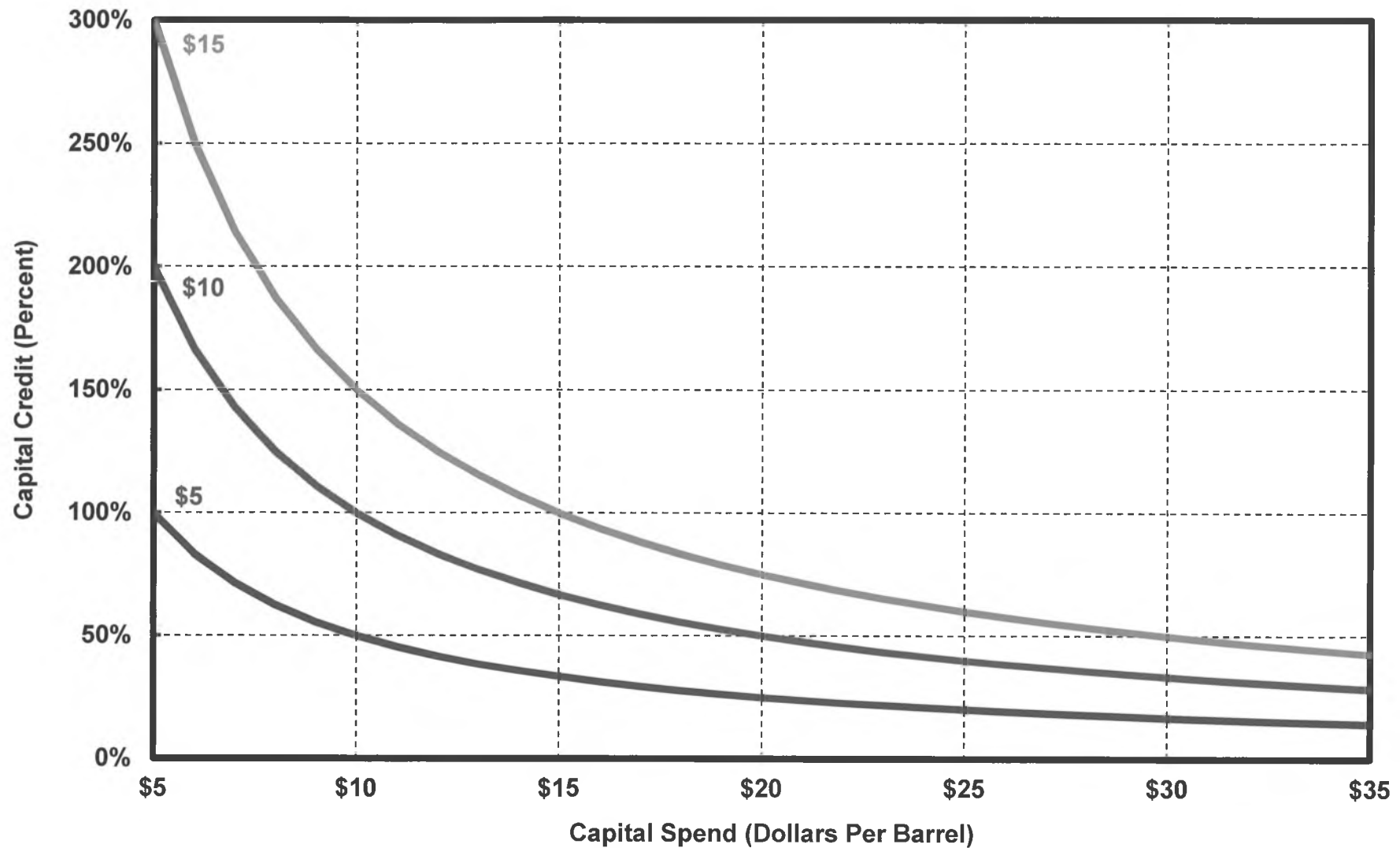
North Slope Tax Rate Under SRES CS SB21 With \$5/Bbl Production Allowance



GRE Equivalent Value From Specified Production Allowance (35% Tax Rate)



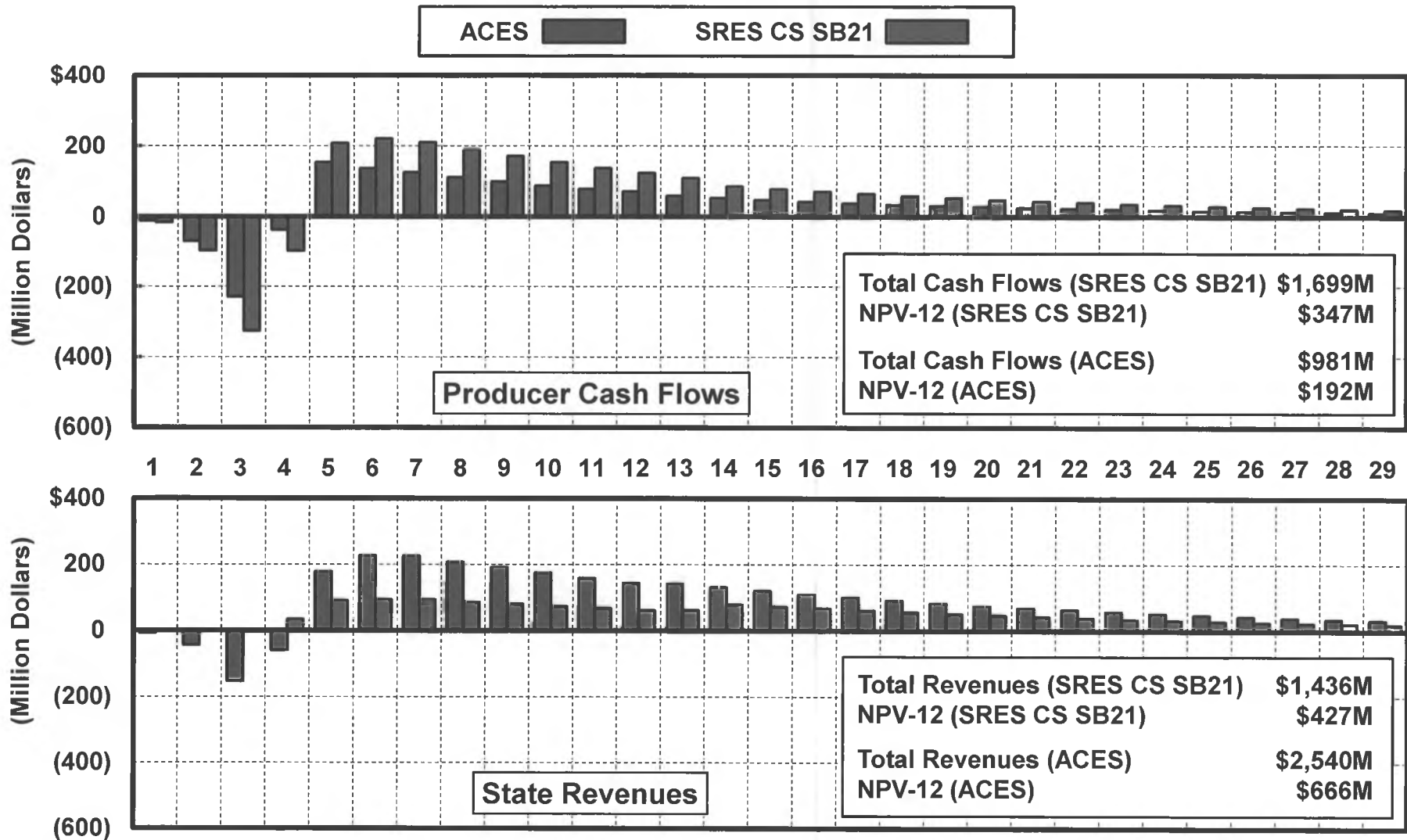
Capital Credit Equivalent Value at Specified Production Allowance



Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012)

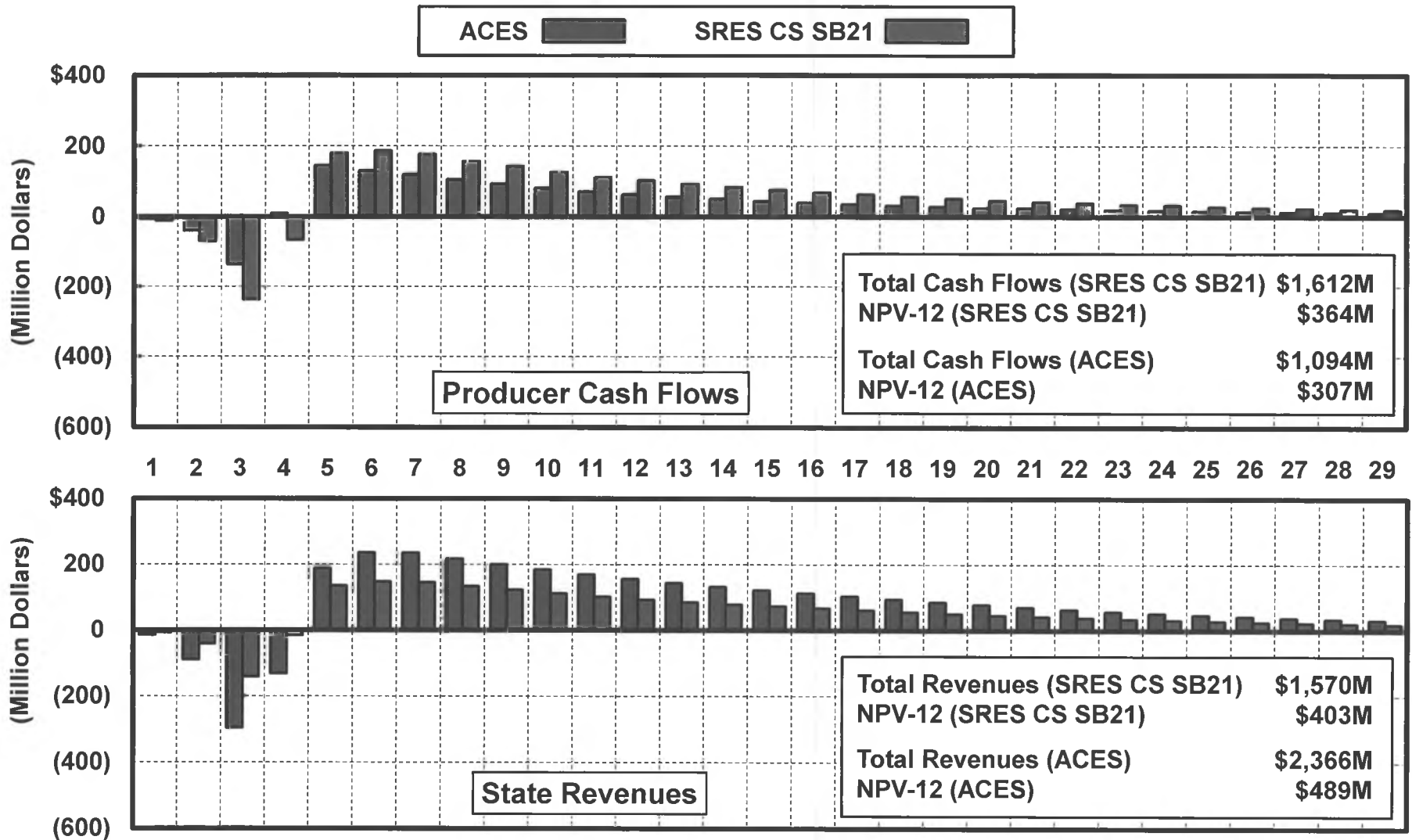
Lower Cost Oil Alaska Development

New Participant in Alaska



Lower Cost: \$16 Per Barrel Development Capex and \$14 Per Barrel Opex

Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012) Lower Cost Oil Alaska Development Incumbent Participant in Alaska



Lower Cost: \$16 Per Barrel Development Capex and \$14 Per Barrel Opex

Producer and State Economics Under Alternative Systems

Incumbent Investment in 50 MMBO Field

\$20/Bbl Development Capex, 12.5% Royalty Rate

Real \$2012 West Coast ANS Price	Base	GRE at 30%		Additional \$5/Bbl Allowance		Additional \$10/Bbl Allowance		Capital Credit Percentage		ACES	No Production Tax
	35% Rate, \$5/Bbl Allowance	10 Years	Life	10 Years	Life	10 Years	Life	10%	20%		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$1.58	\$2.85	\$3.12	\$2.28	\$2.53	\$2.71	\$3.08	\$2.54	\$3.49	\$3.17	\$1.52
\$100	\$4.57	\$6.21	\$6.55	\$5.27	\$5.52	\$6.09	\$6.46	\$5.52	\$6.48	\$5.98	\$6.12
\$120	\$7.56	\$9.57	\$9.99	\$8.26	\$8.50	\$9.08	\$9.45	\$8.51	\$9.46	\$9.07	\$10.72
Government Take (Percent)											
\$80	65.2%	59.5%	55.6%	63.5%	60.0%	59.1%	53.8%	62.7%	60.2%	65.7%	54.3%
\$100	65.3%	60.5%	57.1%	64.2%	61.8%	61.9%	58.4%	63.6%	62.0%	70.4%	51.7%
\$120	65.3%	60.9%	57.9%	64.5%	62.8%	62.8%	60.2%	64.1%	62.9%	71.3%	50.5%
NPV-12 of State Production Tax (Million 2012 Dollars)											
\$80	(\$5)	(\$110)	(\$131)	(\$62)	(\$83)	(\$98)	(\$128)	(\$83)	(\$162)	(\$135)	\$0
\$100	\$127	(\$8)	(\$36)	\$70	\$50	\$2	(\$28)	\$49	(\$29)	\$11	\$0
\$120	\$260	\$94	\$59	\$202	\$182	\$135	\$104	\$181	\$103	\$135	\$0
NPV-12 of Total State Cash (Million 2012 Dollars)											
\$80	\$232	\$135	\$115	\$179	\$160	\$146	\$117	\$159	\$86	\$111	\$237
\$100	\$435	\$309	\$282	\$381	\$362	\$318	\$290	\$362	\$288	\$327	\$316
\$120	\$637	\$482	\$450	\$584	\$565	\$521	\$492	\$564	\$491	\$521	\$394
NPV-12 of Total State Cash Where State Receives 50% of Royalties (Million 2012 Dollars)											
\$80	\$140	\$43	\$23	\$87	\$68	\$54	\$25	\$67	(\$6)	\$19	\$145
\$100	\$316	\$190	\$163	\$262	\$243	\$199	\$171	\$243	\$169	\$208	\$197
\$120	\$491	\$336	\$304	\$438	\$419	\$375	\$346	\$418	\$345	\$375	\$249

Producer and State Economics Under Alternative Systems

New Participant Investment in 50 MMBO Field

\$20/Bbl Development Capex, 12.5% Royalty Rate

Real \$2012 West Coast ANS Price	Base	GRE at 30%		Additional \$5/Bbl Allowance		Additional \$10/Bbl Allowance		Capital Credit Percentage		ACES	No Production Tax
	35% Rate, \$5/Bbl Allowance	10 Years	Life	10 Years	Life	10 Years	Life	10%	20%		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$1.13	\$1.13	\$1.35	\$1.03	\$1.23	\$1.03	\$1.33	\$1.13	\$1.13	\$1.68	\$1.52
\$100	\$4.26	\$5.52	\$5.79	\$4.89	\$5.13	\$5.42	\$5.71	\$5.01	\$5.52	\$3.04	\$6.12
\$120	\$7.37	\$9.25	\$9.68	\$8.00	\$8.25	\$8.75	\$9.13	\$8.08	\$8.90	\$4.76	\$10.72
Government Take (Percent)											
\$80	60.4%	60.4%	56.9%	61.9%	58.8%	61.9%	57.3%	60.4%	60.4%	68.7%	54.3%
\$100	63.2%	58.0%	55.0%	61.7%	59.3%	59.0%	56.0%	60.5%	58.0%	74.4%	51.7%
\$120	63.9%	59.2%	56.1%	63.0%	61.3%	61.1%	58.5%	62.4%	60.3%	76.0%	50.5%
NPV-12 of State Production Tax (Million 2012 Dollars)											
\$80	\$32	\$32	\$14	\$40	\$24	\$40	\$16	\$32	\$32	(\$13)	\$0
\$100	\$153	\$50	\$27	\$101	\$81	\$58	\$33	\$91	\$50	\$253	\$0
\$120	\$275	\$120	\$86	\$223	\$203	\$161	\$131	\$217	\$150	\$490	\$0
NPV-12 of Total State Cash (Million 2012 Dollars)											
\$80	\$267	\$267	\$251	\$275	\$260	\$275	\$252	\$267	\$267	\$225	\$237
\$100	\$459	\$362	\$341	\$411	\$392	\$370	\$347	\$401	\$362	\$553	\$316
\$120	\$652	\$507	\$474	\$603	\$584	\$545	\$517	\$597	\$534	\$853	\$394
NPV-12 of Total State Cash Where State Receives 50% of Royalties (Million 2012 Dollars)											
\$80	\$175	\$175	\$159	\$183	\$168	\$183	\$160	\$175	\$175	\$133	\$145
\$100	\$340	\$243	\$222	\$292	\$273	\$251	\$228	\$282	\$243	\$434	\$197
\$120	\$506	\$361	\$329	\$457	\$438	\$399	\$371	\$451	\$388	\$707	\$249

Producer and State Economics Under Alternative Systems

New Participant Investment in 50 MMBO Field

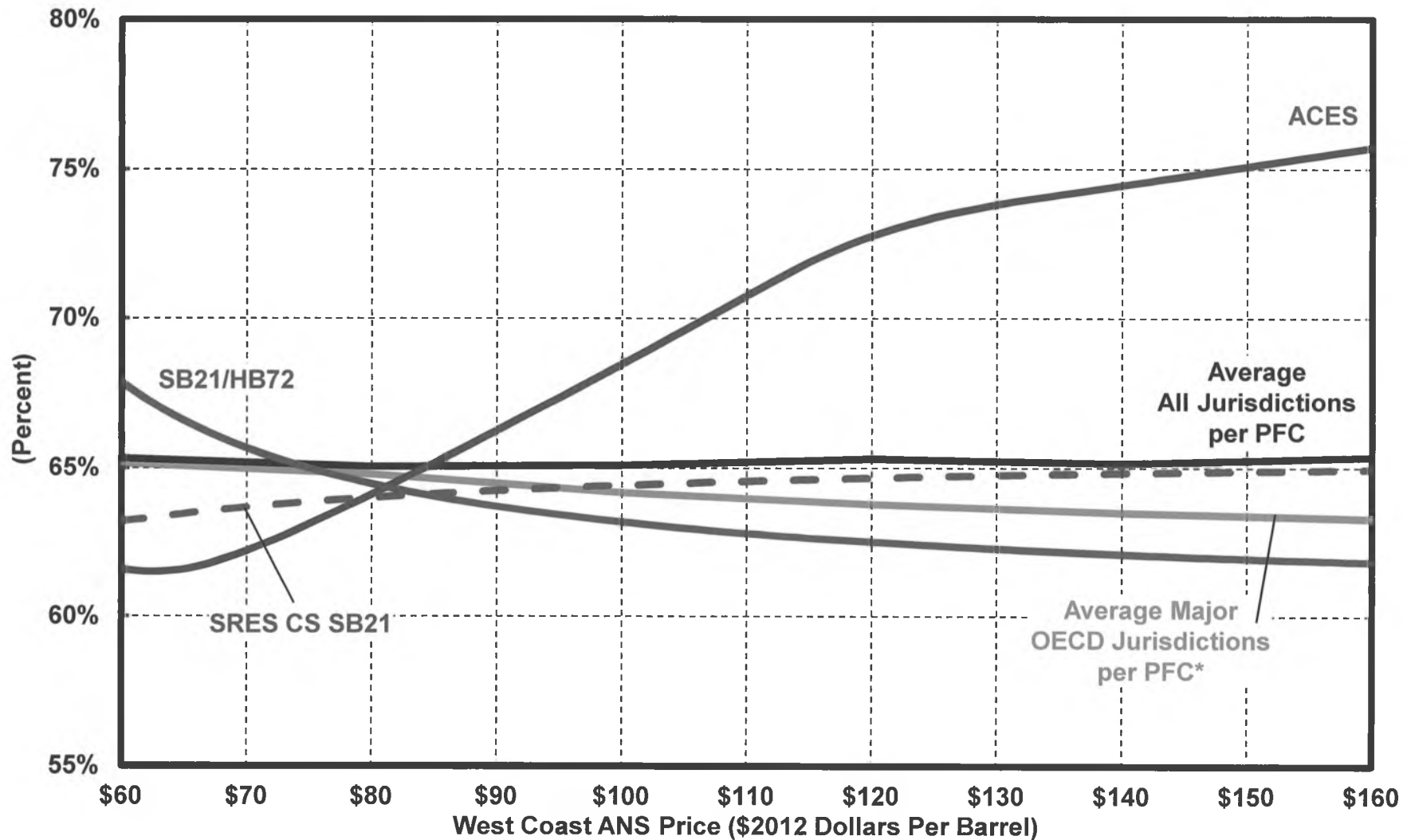
\$20/Bbl Development Capex, 16.67% Royalty Rate

Real \$2012 West Coast ANS Price	Base 35% Rate, \$5/Bbl Allowance (1)	GRE at 30%		Additional \$5/Bbl Allowance		Additional \$10/Bbl Allowance		Capital Credit Percentage		ACES (10)	No Production Tax (11)
		10 Years (2)	Life (3)	10 Years (4)	Life (5)	10 Years (6)	Life (7)	10% (8)	20% (9)		
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$0.42	\$0.42	\$0.62	\$0.32	\$0.51	\$0.32	\$0.60	\$0.42	\$0.42	\$1.26	\$0.78
\$100	\$3.60	\$4.59	\$4.86	\$4.15	\$4.39	\$4.50	\$4.78	\$4.31	\$4.59	\$2.57	\$5.15
\$120	\$6.49	\$8.31	\$8.71	\$7.15	\$7.39	\$7.84	\$8.20	\$7.27	\$8.05	\$4.19	\$9.53
Government Take (Percent)											
\$80	64.4%	64.4%	61.1%	65.9%	62.9%	65.9%	61.4%	64.4%	64.4%	71.1%	58.8%
\$100	65.7%	61.4%	58.6%	64.2%	62.0%	62.4%	59.5%	62.9%	61.4%	76.2%	55.5%
\$120	66.4%	61.7%	58.8%	65.4%	63.7%	63.5%	61.1%	64.7%	62.5%	77.6%	54.0%
NPV-12 of State Production Tax (Million 2012 Dollars)											
\$80	\$30	\$30	\$13	\$37	\$22	\$37	\$14	\$30	\$30	(\$40)	\$0
\$100	\$128	\$46	\$25	\$82	\$63	\$54	\$31	\$70	\$46	\$213	\$0
\$120	\$251	\$100	\$68	\$196	\$176	\$139	\$110	\$186	\$122	\$440	\$0
NPV-12 of Total State Cash (Million 2012 Dollars)											
\$80	\$322	\$322	\$307	\$330	\$315	\$330	\$308	\$322	\$322	\$257	\$295
\$100	\$510	\$433	\$413	\$467	\$449	\$441	\$419	\$455	\$433	\$589	\$390
\$120	\$720	\$579	\$549	\$669	\$650	\$615	\$588	\$659	\$599	\$897	\$485
NPV-12 of Total State Cash Where State Receives 50% of Royalties (Million 2012 Dollars)											
\$80	\$200	\$200	\$184	\$207	\$193	\$207	\$185	\$200	\$200	\$135	\$172
\$100	\$351	\$275	\$254	\$309	\$290	\$282	\$260	\$297	\$275	\$430	\$231
\$120	\$525	\$385	\$354	\$474	\$456	\$421	\$394	\$465	\$405	\$702	\$291

Impact of "Interest" on Loss Carry Forward 50 MMBO New Field With 16.67% Royalty \$20/BBL Development Cost, New Participant

Real \$2012 West Coast ANS Price	RES CS SB21 Rate Loss Carry Forward Increase					RES CS SB21 Loss Deductible/ Refundable When Spent	ACES	No Production Tax
	0%	5%	10%	15%	20%			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Producer NPV-12 / BBL (Dollars Per BOE)								
\$80	\$0.62	\$0.62	\$0.62	\$0.62	\$0.62	\$2.51	\$1.27	\$0.78
\$100	\$4.61	\$4.73	\$4.85	\$4.85	\$4.85	\$5.29	\$2.57	\$5.15
\$120	\$8.25	\$8.37	\$8.52	\$8.71	\$8.99	\$9.06	\$4.19	\$9.53
Total State NPV-12 (Million 2012 Dollars)								
\$80	\$307	\$307	\$307	\$307	\$307	\$161	\$257	\$295
\$100	\$432	\$422	\$413	\$413	\$413	\$341	\$589	\$390
\$120	\$584	\$575	\$563	\$549	\$527	\$522	\$897	\$486

Average Government Take ACES v. SB21/HB72 and SRES CS SB21 for All Existing Producers (FY2015-FY2019) and Other Jurisdictions



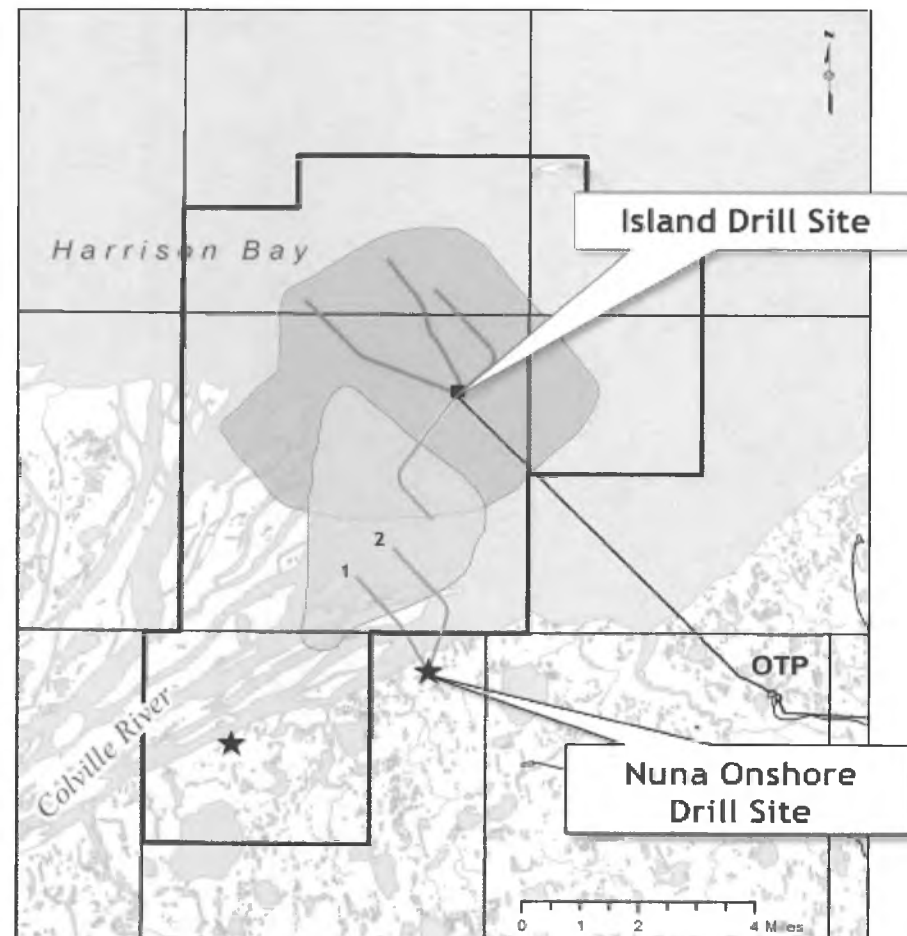
* Australia, Canada (Alberta Conventional), Norway, United Kingdom and United States.

Slides From Pioneer Presentation For Discussion

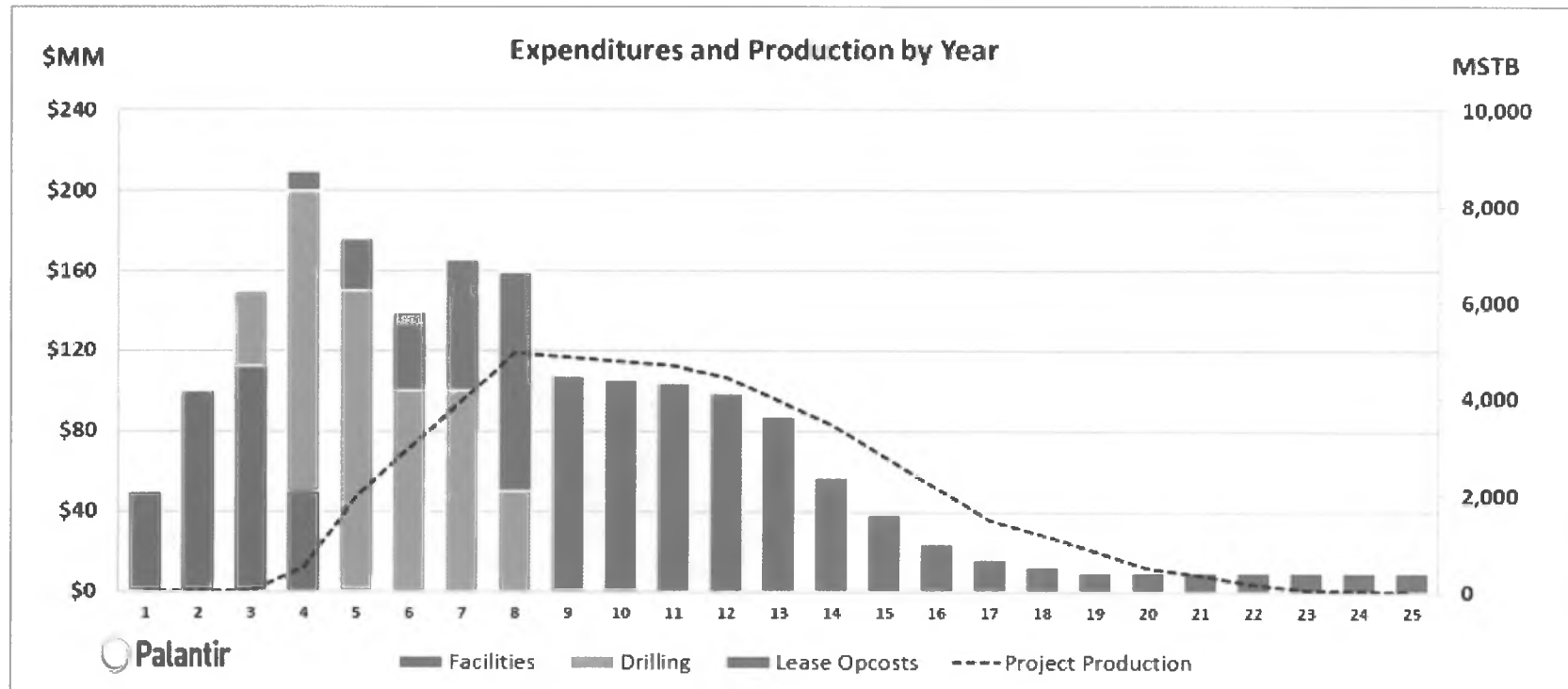
What's Next?

Nuna Project:

- Nuna-1 well drilled in 2012
- ~50 MMBO of resource potential
- Nuna-2 drilling underway
- Phase I development overview
 - Q3 2013 sanction decision
 - ~\$1 Billion capital required
 - 2015 first oil
 - 14 MBOPD peak production
 - Jobs and economic impact
- Potential for 2nd drill site
- **Must compete for limited capital against low-risk, fast-cycle projects in Lower 48**



Typical New Project Spend Profile



Typical Project (after discovery):

- 1st year: front end engineering work
- 2nd year: 100% of capital spent on facilities
- 3rd year: 75% capital is for facility work
- Drilling begins late in 3rd year, no production until 4th year
- 4th year: production begins
- Peak production rate occurs during 5th year after start of production

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Production Tax Revenue Impacts of Various Base Tax Rates FY 14 – FY 19



*A supplemental slide for the
Senate Finance Committee*

March 6, 2013



Impact of Various Base Tax Rates



ACES Production Tax Forecast and Production Tax Estimates at Various Base Tax Rates (\$M)						
	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
ACES Production Tax ⁽¹⁾	\$3,779	\$3,407	\$3,723	\$3,891	\$3,835	\$3,663
Base Tax at Various Tax Rates under Forecasted Oil Prices, Production and Expenditures ⁽²⁾						
Base Tax Rate	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
25%	\$3,300	\$2,675	\$2,725	\$2,700	\$2,550	\$2,425
26%	\$3,350	\$2,775	\$2,825	\$2,800	\$2,650	\$2,525
27%	\$3,400	\$2,875	\$2,950	\$2,900	\$2,750	\$2,600
28%	\$3,475	\$2,975	\$3,050	\$3,000	\$2,850	\$2,700
29%	\$3,525	\$3,100	\$3,150	\$3,125	\$2,950	\$2,800
30%	\$3,575	\$3,200	\$3,275	\$3,225	\$3,050	\$2,900
31%	\$3,625	\$3,300	\$3,375	\$3,325	\$3,150	\$3,000
32%	\$3,700	\$3,425	\$3,475	\$3,450	\$3,250	\$3,100
33%	\$3,750	\$3,525	\$3,600	\$3,550	\$3,350	\$3,200
34%	\$3,800	\$3,625	\$3,700	\$3,650	\$3,450	\$3,300
35%	\$3,850	\$3,725	\$3,800	\$3,775	\$3,550	\$3,375
Delta from ACES Production Tax at Various Tax Rates						
Base Tax Rate	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
25%	-\$479	-\$732	-\$998	-\$1,191	-\$1,285	-\$1,238
26%	-\$429	-\$632	-\$898	-\$1,091	-\$1,185	-\$1,138
27%	-\$379	-\$532	-\$773	-\$991	-\$1,085	-\$1,063
28%	-\$304	-\$432	-\$673	-\$891	-\$985	-\$963
29%	-\$254	-\$307	-\$573	-\$766	-\$885	-\$863
30%	-\$204	-\$207	-\$448	-\$666	-\$785	-\$763
31%	-\$154	-\$107	-\$348	-\$566	-\$685	-\$663
32%	-\$79	\$18	-\$248	-\$441	-\$585	-\$563
33%	-\$29	\$118	-\$123	-\$341	-\$485	-\$463
34%	\$21	\$218	-\$23	-\$241	-\$385	-\$363
35%	\$71	\$318	\$77	-\$116	-\$285	-\$288

FY14 numbers include ½ year of ACES (with progressivity) and ½ year of tax at new base rate

(1) ACES Production Tax estimates include progressivity, credits and all other tax mechanisms under current law. ACES Production Tax estimates do not include refunded credits

(2) Base Tax at Various Tax Rates includes only the revenue from the base tax. It does not include any expansion of credit programs, nor does it include the removal of the 2-year credit split.

Source: Fall 2012 forecast model modified for CSSB21