

Alaska's Clear and Equitable Share (ACES)  
Status Report  
Alaska Department of Revenue  
January 14, 2010

## Introduction

In November 2007, the Alaska Legislature passed House Bill 2001, known as Alaska's Clear and Equitable Share (ACES). ACES made modifications to the prior production tax called the Petroleum Profits Tax (PPT), enacted in 2006. The changes made first with PPT and later with ACES represented substantial production tax reform in that the basis of the tax shifted from the *gross value* to the *net value* of oil and gas production. The gross tax which had been in place prior to the PPT is generally referred to as the Economic Limit Factor (ELF).

This report was prepared at the request of the Commissioner of Revenue in order to evaluate whether ACES is meeting its intended goals of providing a fair share of oil and gas revenue to the state, and encouraging investment in the exploration and development of new oil and gas resources in Alaska.

Following are the key findings of this report:

- 1) State revenues under ACES in FY 2009 exceeded amounts which would have been generated under either the PPT or ELF systems. The crossover point at which ACES is projected to provide more revenue than ELF is \$51 per barrel west coast price in FY 2010.
- 2) Activation of the progressive surcharge is estimated to occur when west coast sales prices reach \$56 per barrel.
- 3) Capital spending on the North Slope totaled over \$2.2 billion in FY 2009 an increase over FY 2008. This is nearly the highest level of capital spending in nominal dollars since oil production began in the state.
- 4) The impact of the production tax modifications on industry investment cannot be clearly determined due to the influence of other factors and given the limited timeframe during which ACES has been in place.

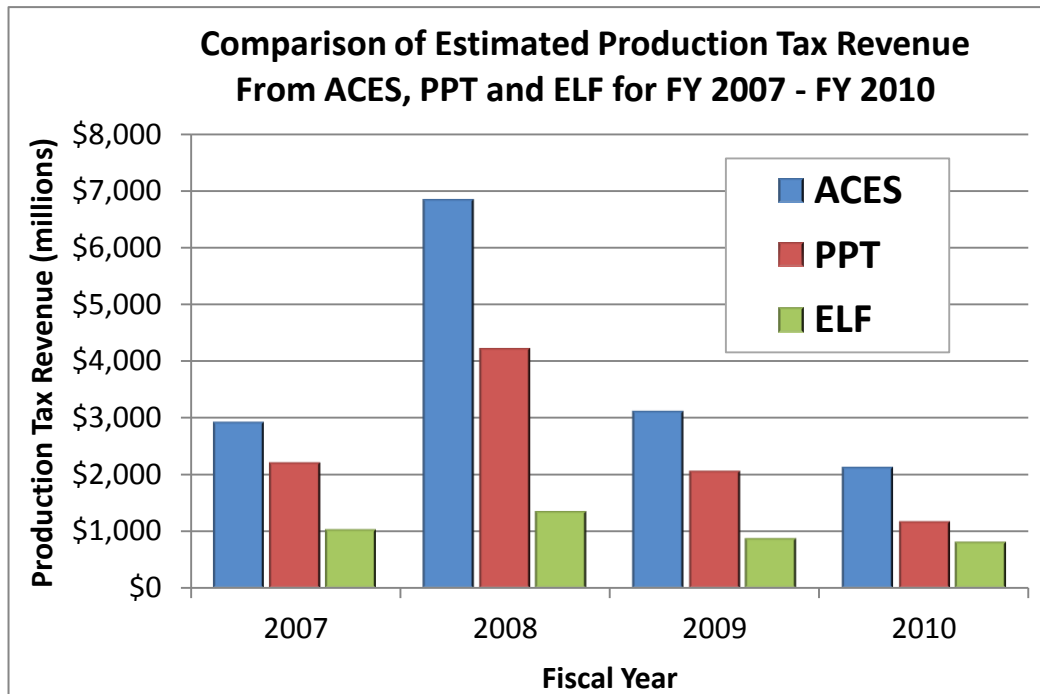
- 5) Operating costs have risen since the enactment of PPT and ACES, but the impact of these cost increases to state tax revenues was moderated by the “standard deduction” provision of ACES, which expired December 31, 2009.
- 6) Increased reporting requirements, particularly of forward looking expenditure information, has greatly enhanced the accuracy of the Department’s revenue forecasting efforts.
- 7) The Department has made significant progress in implementing ACES regulations, but there will be challenges to both the department and taxpayers as the regulations are implemented. Preliminary audits of taxpayers under the new profits-based system (formerly PPT) have begun, consistent with the normal audit timeframe.

### **Comparison of Revenues under ACES, PPT and ELF**

The net tax structure – first enacted under PPT (2006) and later with ACES (2007) – represents a significant change from the oil and gas tax structure used for much of Alaska’s history. Under the earlier tax, known as the Economic Limit Factor (ELF), production tax was levied on oil and gas producing properties, regardless of whether operations were profitable. The current production tax structure requires companies to pay tax only when they are making profits from oil and gas production in the state. In addition, tax credits are provided for capital expenditures, with higher credits available for certain oil and gas exploration investments.

Since its enactment in 2007, ACES has generated more state revenue than would have been generated under either PPT or ELF. In FY 2008, a period of very high oil prices and profits, ACES generated \$6.8 billion in production tax revenue, compared with \$4.2 billion which would have been received under PPT and \$1.3 billion which would have been received under ELF. In fiscal year 2009, during which west coast oil prices average \$68.34, ACES generated just over \$3.1 billion. This compares with roughly \$2 billion that would have been generated under PPT and \$858 million under the earlier ELF system.

**Figure A** compares revenue from ACES, PPT and ELF for FY 2007-2010. The FY 2009 revenues are preliminary. Estimates for FY 2010 are based on the Department’s fall 2009 forecast of an average west coast oil price of \$66.93 per barrel.

Figure A<sup>1</sup>

The progressive feature in ACES means that the state receives more production tax revenue when oil prices are high relative to underlying costs. Similarly, it significantly lessens the state's share of revenues when per-barrel margins decline. This effect was illustrated in 2008, when oil prices reached a high of \$140 per barrel in July, bringing in \$900 million in production tax for the month, and later plunged to below \$30 per barrel in December, producing a total of \$50 million in production tax for the month. Over the course of the full year, ANS crude oil averaged over \$92 per barrel, resulting in five times more revenue than would have been realized under the ELF system.

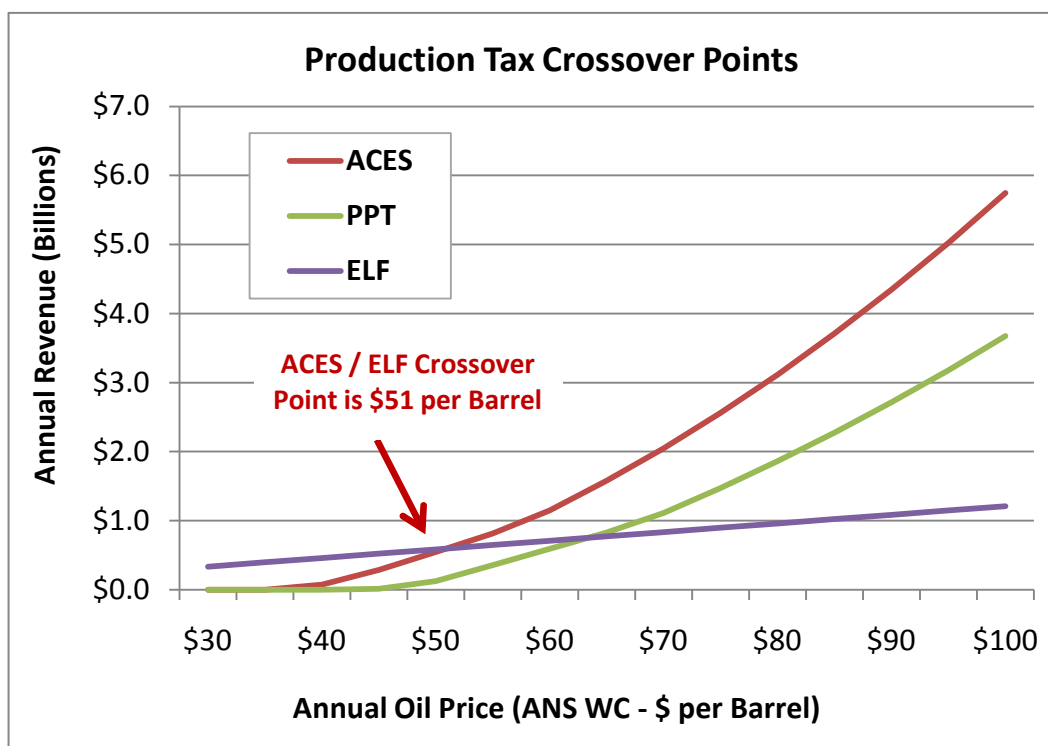
**Figure B** shows estimated revenues that would be received under ACES, ELF and PPT at various oil prices.<sup>2</sup> The oil price crossover point at which the state receives more revenue under ACES than the ELF system is roughly \$51 per barrel. The crossover point has increased over prior

<sup>1</sup> Production tax revenue includes surcharges but does not include any settlements which go to the Constitutional Budget Reserve Fund. FY 2007 PPT revenue includes true-up payments for the period of April 2006 through December 2006. FY 2007 ACES revenue assumes similar true-up payments for comparison purposes. For FY 2007 - FY 2009, assumes actual data for oil price, production, costs and other variables. For FY 2010, assumes oil price, production, costs and other variables as of the fall 2009 forecast. Costs under PPT for FY 2010 for Prudhoe Bay and Kuparuk are based on aggregated company forecasts. For ACES only, assumes that standard deduction would apply for all of FY 2007-FY 2009 and first half of FY 2010. Actual tax revenue, as opposed to modeled revenue, is used for PPT in FY 2007 and ACES in FY 2008-FY 2009.

<sup>2</sup> This analysis assumes a constant oil price for the entire year, production of 655,000 barrels per day, deductible lease expenditures of \$20 per barrel and transit costs of \$6 per barrel.

years because lease expenditures, which are deductible under ACES, have increased since ACES was passed. It is expected that lease expenditures will decrease as costs decline in delayed response to the decline in oil prices from their 2008 levels.

Figure B<sup>3</sup>



## Lease Expenditures

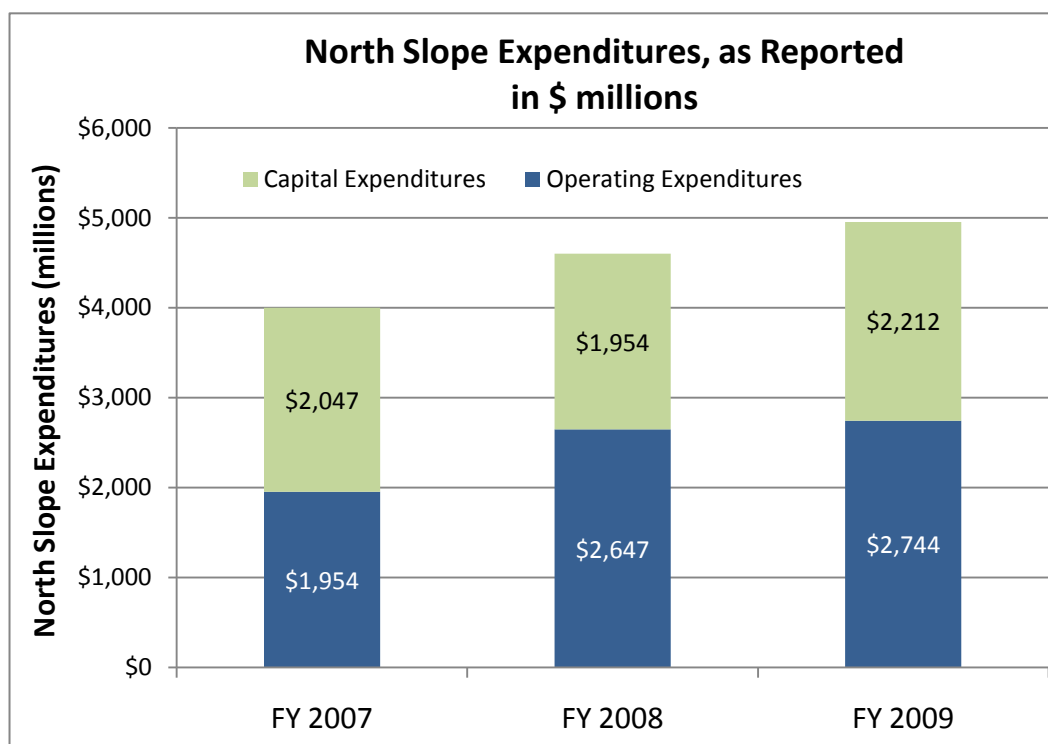
With the introduction of the net tax, it became necessary for the state to identify and forecast allowable lease expenditures for purposes of the tax calculation. Prior to the passage of PPT, the department had not been required to track or audit oil and gas production costs in Alaska. Some early cost data had been acquired directly from producing companies and through preliminary examination of federal tax returns. However, even during the debate over PPT, the state did not have access to comprehensive, Alaska-specific data that would enable policymakers to analyze the effects of the proposed tax over the life of a project. With much more information now being provided under the new tax structure, the department is developing a better understanding of oil and gas costs in Alaska, which will significantly benefit future policy deliberations.

<sup>3</sup> Assumes fixed operating and capital cost of \$20 per barrel.

Lease expenditures fall into two general categories that constitute the major deductions under the ACES tax system. Operating expenditures are the costs to operate an oil or gas production facility on a day-to-day basis. These include labor, heat and light for the facilities, and some well work and minor equipment repairs. Capital expenditures are costs incurred to enhance or improve the reserve base, level of production, or facilities. Drilling is one of the most common forms of capital costs, as is facility construction or expansion.

**Figure C** shows the operating and capital expenditures, as reported on company tax returns and monthly reports, for their North Slope operations, from FY 2007 through FY 2009. Note that the graph represents all reported expenditures for all North Slope properties, regardless of whether or not they are subject to the “standard deduction” provisions of AS 43.55.165(j).

**Figure C<sup>4</sup>**



### *Operating Expenditures*

Operating costs have risen significantly in recent years for the oil and gas industry worldwide. This has often been linked to the corresponding rise in oil prices beginning around 2002. Projects around the world that were once marginally economic have become viable, increasing the demand for limited supplies of engineering, procurement and construction services, as well

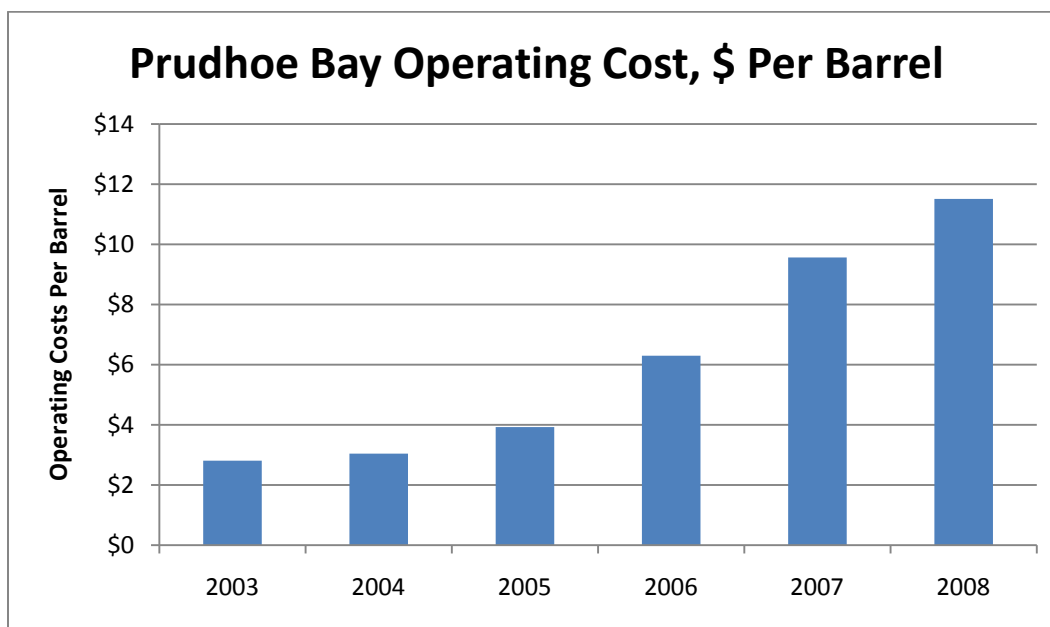
<sup>4</sup> Operating expenditures includes total reported costs, not standard deduction; FY 2007 estimated based on incomplete reporting

as raw materials. Cambridge Energy Research Associates (CERA) reports the upstream operating cost index rose for oil and gas field operations roughly 67% between 2002 and the end of 2008.<sup>5</sup> Meanwhile, the global capital cost index rose over 100% during the same period.<sup>6</sup>

Alaska-specific information obtained through public sources and shared in confidence during the Stranded Gas Development Act negotiations and through ACES reporting shows similar trends on the North Slope. Estimates of operating costs prior to PPT ranged from \$3 to \$5 per barrel. More recent information indicates that operating costs on the North Slope have doubled, and in some cases nearly tripled. Following the Prudhoe Bay corrosion incidents in 2006, operating expenditures on major repairs increased. However, since that time, the proportion of total operating expenditures directed to major repairs does not appear to have been a key driver in the growth of total operating expenditures.

**Figure D** shows the upward trend in per-barrel operating costs at Prudhoe Bay from 2003 to 2008. The chart shows a dramatic increase over the six-year period, consistent with cost increases seen in the oil and gas sector worldwide.

**Figure D**



The recent downturn of the global economy has started to push operating costs back down again. In June of 2009, CERA reported that worldwide, operating costs had declined 8 percent

<sup>5</sup> IHS CERA Upstream Operating Cost Index (UOCI), <http://www.ihsindexes.com> (Accessed December 11, 2009)

<sup>6</sup> IHS CERA Upstream Capital Cost Index (UOCI), <http://www.ihsindexes.com> (Accessed December 11, 2009)

over the previous 6 months.<sup>7</sup> The most recent information reported to the department under the new ACES requirements shows this trend to also be developing on the North Slope.

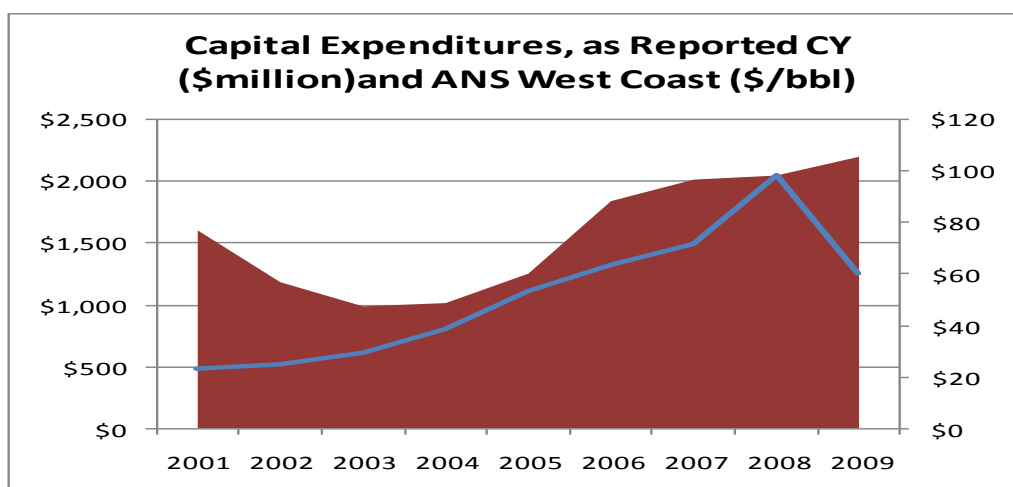
Much of this change can once again be linked to recent trends in oil prices. Lower oil prices led to a slackening of worldwide project activity, driving down the costs of transportation and various consumables. Despite this correlation, however, operating costs have not fallen at the same rate as oil prices. While the department anticipates that per-barrel operating costs will continue to decline under the lower oil price forecast for FY 2009 and FY 2010, they are expected to remain relatively high compared with those from five or more years ago.

### *Capital Expenditures*

Capital expenditures have also increased since PPT and ACES were enacted. While capital expenditures on pipeline repairs at Prudhoe Bay increased after the Prudhoe Bay corrosion incidents in 2006, the majority of growth in capital expenditures is attributable to drilling, seismic and other projects. As shown below, capital spending on the North Slope in CY 2009 was roughly twice the level in either 2003 or 2004. At least some of this increase is due to new development activities. Two major developments – Oooguruk and Nikaitchuq – have gone forward despite recent oil price setbacks. Development of the Point Thomson field is also underway.

**Figure E** shows historical capital expenditures from CY 2001 to 2009 as reported by oil and gas producing companies operating on the North Slope.

**Figure E**



<sup>7</sup> IHS CERA: "Period of Sustained Cost Escalation for Upstream Oil and Gas Facilities Comes to an End," June 5, 2009. <http://www.cera.com/asp/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10388> (Accessed December 11, 2009)

In order to forecast North Slope lease expenditures, the department receives forward looking spending projections from taxpayers, and also consults a variety of information sources, including unit forecasts, plans of development, and federal partnership returns. These data give the department significantly better insight into future development plans, as well as trends in operating and capital expenditures.

This information shows a variety of changes on the North Slope in the years ahead. There is continuing development of newer fields like Oooguruk, Nikaitchuq, and Point Thomson. Growth in capital expenditures at many major North Slope units (i.e. Prudhoe Bay, Kuparuk, Colville River and others) appear to slow slightly or decline in the next year or two and re-surge thereafter to the level of the recent past or higher. This trend is consistent with indicators of worldwide industry activity which show a dramatic drop in capital expenditures from the high levels experienced in 2008. This suggests that recent economic contraction may have caused some North Slope development projects to be delayed as producers hope to form a better idea of where the economy and oil prices may be headed.

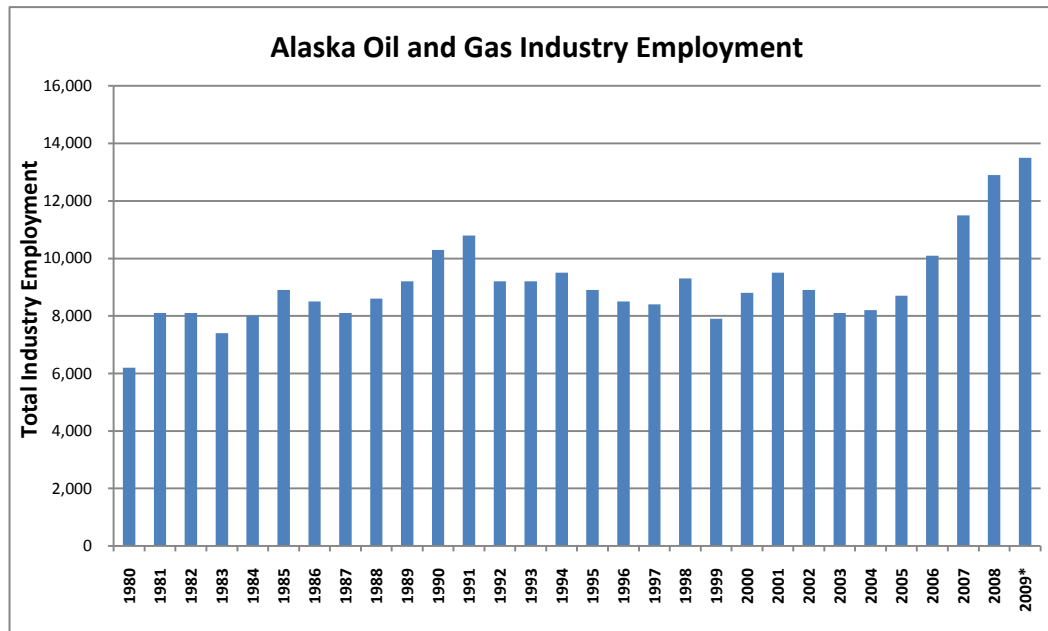
It would be presumptuous to solely attribute the rise in expenditures to the success of the investment incentives found in ACES. Many factors beyond tax policy drive oil and gas investment decisions. However, one of Alaska's new explorers, Savant Alaska, stated in a recent Petroleum News article that ACES had assisted in their development efforts at Badami. "ACES was an important component for Savant in considering investment in Alaska. It definitely had its intended consequence with us." <sup>8</sup>

### *Industry Employment*

Employment in the industry has also increased steadily since the implementation of PPT and ACES, with 2009 forecast to be the highest in state history. It is important to note that this occurred concurrent with a steady rise in the oil prices, which has generally shown a strong correlation with industry activity.

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<sup>8</sup> Kay Cashman quoting Savant's Chief Operating Officer Greg Vigil, "Savant Accelerates Badami Drilling Plan," *Petroleum News*, Volume 14, No. 3, January 18, 2009.

Figure F<sup>9</sup>

### *Flexibility of Tax Burden Evidenced*

The increased revenues generated under ACES represent an increased tax burden on Alaska's oil and gas industry. However, there is evidence that ACES effectively adjusts that burden when oil prices drop and profit margins are squeezed. In 2009, a period of relatively low oil prices in comparison to recent years, 35 percent of ConocoPhillips total reported exploration and production profit in the first quarter of the year (Q1), 55 percent in Q2, and 36 percent in Q3, came from its Alaska operations, which only account for 12 percent of the company's worldwide production.<sup>10</sup>

### **ACES Structure and Tax Rate**

The ACES tax consists of a base rate of 25% plus a progressive surcharge, which is triggered when a company's net profits — also known as "production tax value" — exceed \$30 per barrel. Beyond this point, the base tax rate is increased by 0.4% for each additional \$1 increase in per-barrel production tax value. Using current estimated transportation and production costs of roughly \$26 per barrel, the surcharge would begin to be applied when west coast oil prices reach \$56 per barrel. When the combined base rate and progressive surcharge reach 50%

<sup>9</sup> Data from Alaska Department of Labor and Workforce Development, Research and Analysis Section (January 11, 2010). Includes nonagricultural wage and salary data and excludes the self-employed. \*Estimates for 2009 are preliminary.

<sup>10</sup> ConocoPhillips, Form 10-Q Quarterly Reports Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, March 31, 2009, June 30, 2009 and September 30, 2009.

(approximately \$92.50 per-barrel profit or \$118.50 West Coast price) the progressive surcharge is lessened to 0.1% for each additional \$1 increase in per-barrel production tax value. The maximum nominal tax rate is 75%, which would apply at a profit rate of \$342.50 per barrel or \$368.50 West Coast price.

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

The “effective tax rate” is the share of the total gross taxable value at the point of production that is paid in production taxes after credits are applied. It is a good universal measure of the sharing of total petroleum value that can be compared to gross value-based tax systems.

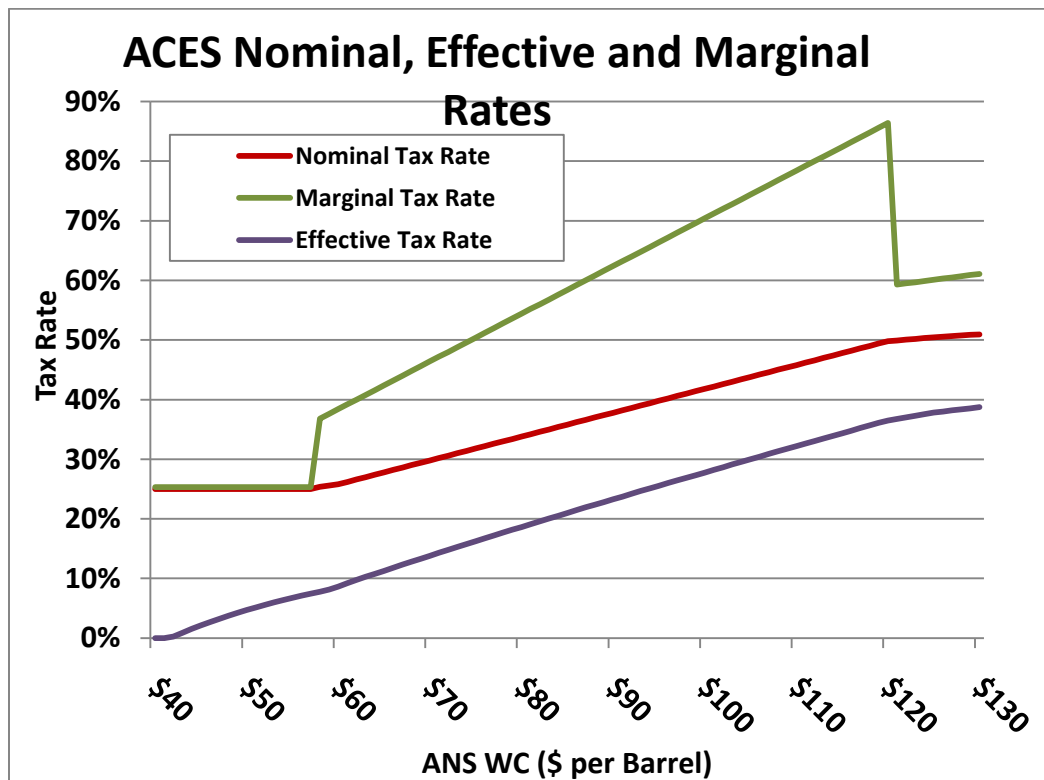
The “nominal tax rate” is the statutory tax rate as applied to the net value of oil and gas production. It does not account for credits or other tax benefits which ultimately impact a company’s bottom line. Under ACES, the nominal tax rate varies with the per-barrel profitability. In addition to a base tax rate of 25%, ACES levies a progressive surcharge that can raise the combined nominal tax rate to 75% at extreme price levels.

The “marginal tax rate” is the rate theoretically applied to each dollar increase in oil price. In the case of ACES, the marginal tax rate is 25% until per barrel profit reaches \$30 per barrel (about \$56 per barrel in west coast spot price under the current cost structure), at which point it increases for every additional dollar up to a marginal tax rate of 87% when the profit reaches \$92.50 per barrel (about \$118.50 per barrel on the west coast). Following this peak, the marginal tax rate drops off significantly as the profit level continue to rise. With a net based tax system, this metric shows a company the impact of making additional investment, because each dollar they invest is “subsidized” by the government based on the amount of marginal tax they have avoided paying on that dollar.

Each of these metrics has their limitations when considered in isolation from other metrics, or when only one data point on the curve is presented. For example, a marginal tax rate of up to 87% initially sounds excessive. However, at that same price level, the effective tax rate (the tax burden) is less than 40%. The marginal rate of 87% actually represents the state’s “portion” of any new investment made at such high prices.

**Figure G** shows the nominal, effective and marginal tax rates under ACES using a wide range of west coast spot prices.

**Figure G**



## Production Tax Administration and Implementation

The passage of ACES presented significant challenges for tax administration and implementation because it involved comprehensive structural changes to the tax on the heels of the prior year's legislative changes through PPT. These challenges are experienced both on the taxpayer and on the state side.

### *Tax Credit Successes and Difficulties*

The increased spending levels reported earlier in this document, may be due in part to the expansion of capital and exploration credits provided under ACES for reinvestment in the state. Credits can be applied against tax liabilities, sold to other companies or, for companies producing less than 50,000 boe/day, can be purchased by the state. Nearly \$550 million in credits were claimed in FY 2009. Approximately \$193 million was paid to oil and gas companies

to purchase oil and gas tax credits, while an additional \$350 million in tax credits were used to offset tax liabilities.

Some administrative difficulties have arisen due to the requirement that the 20% capital credit be spread out over two years. It has taken a substantial amount of time and resources to develop a database with which the division can track the issuance and staged application of these credits for each taxpayer. This detailed tracking was made necessary by the transferability and use of the credits, and some confusion by taxpayers and their transferees regarding how the credits could be applied. In addition, the two-year spread in the application of the capital credits diminishes their value to taxpayers who look for quick return of their investment dollars. Finally, one of the reasons for the two-year spread in credits was to assist the department in forecasting future revenues. However, the department has found that the information provisions in ACES have been extremely valuable and successful in improving the volume and quality of spending projection data provided to the department by operators. This forward looking spending information has been much more valuable to the revenue forecasting process than the two-year spread in credits.

The Department has also received feedback regarding the reinvestment requirements for new explorers. Under current law, companies generally receive a financial benefit of over 45 percent of exploration expenditures incurred in the state. However, a new entrant to Alaska (with no production to immediately apply the credit against) can only get full value for their expenditures by applying to the state for cash payment for their credits earned. In order to receive such a payment, the company must continue to make expenditures in future years. Although this provision was originally created to support new explorers, it appears to be a limiting factor for companies that have fewer financial resources and are only considering a single exploration investment. In application, this requirement creates a “double standard” where new entrants to Alaska are provided less value for their credits compared to incumbent companies.

*“Standard Deduction” provision at AS 43.55.165(j)*

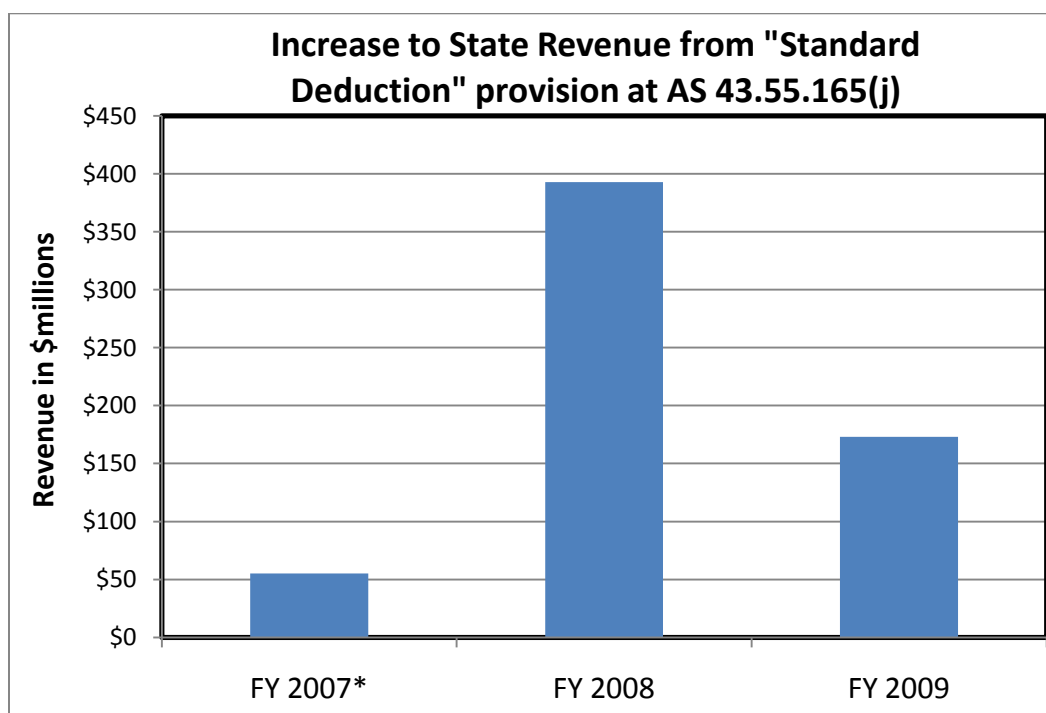
The ACES tax reform made modifications to the deductibility of operating expenditures for certain fields on the North Slope. Alaska Statute 43.55.165(j) limited the deduction of operating expenditures at leases or properties that have produced a cumulative 1 billion barrels of oil and NGLs since the lease or property began oil production. The Prudhoe Bay Unit and the Kuparuk River Unit are subject to these provisions based on their cumulative production. The provision, coined the “standard deduction,” limits the deduction of operating expenditures to the amount deducted on the first PPT returns, filed April 1, 2007, for calendar year 2006 expenditures, adjusted annually. This provision, which was effective through December 31,

2009, was intended to moderate the risk associated with adopting a profits based tax without substantial historical data on which to rely for future cost estimates.

Based on company-reported expenditure data, the provision has resulted in a substantially greater tax liability to the state during the time it has been in place. The total liability in FY 2008 was substantially larger than the liability for FY 2009 due to the higher tax rate in FY2008 because of higher net profits realized due to high oil prices.

**Figure H** shows the increased revenue to the state from the standard deduction from FY 2007 through FY 2009.

**Figure H<sup>11</sup>**



### *Regulations*

The ACES tax included new restrictions and guidance on allowable lease expenditures, requiring complex regulations. The department has actively sought industry input on the structure of the regulations to ensure they continue to achieve their intended purposes, while avoiding undue burdens for either side. The process has included numerous public workshops pertaining to credit regulation, conforming regulatory changes required by ACES, lease expenditures, facility sharing costs and transportation costs. As a result, the regulation drafting process has been

<sup>11</sup> \*Standard Deduction was only in place for half of FY 2007.

lengthy and complex. However, the regulations to define allowable lease expenditures are expected to be finalized this month.

Under the statute the regulations are retroactive to various 2007 dates. To the extent additional taxes are due, taxpayers would be required to pay interest on what would now be late tax payments. The department has discretion to waive any penalties for late payments. However, a statutory change would be needed in order for the department to provide a waiver from interest payments.

### *Reporting and Revenue Forecasting*

ACES requires that companies exploring for or producing oil and gas in the state submit a monthly information report to the department. This report includes estimated data on production volumes, the value of the production, and the operating and capital expenditures related to production. The monthly report is used primarily by state economists to monitor company production and spending. Included with the monthly report is an estimate of taxes owed and credits earned. Twice annually, companies are asked to provide the department with forward-looking expenditure information, along with future production plans to aid the department in providing the legislature with state revenue forecasts.

These reports, in combination with the monthly information reports and the annual tax returns, have significantly enhanced the quality of the department's revenue forecasts.

### *Audit Compliance*

The ACES legislation extended from three to six years, the period in which the department is required to assess production taxes owed. The extension was seen as necessary to assure proper tax assessments, particularly given the complexity of overlapping ELF, PPT and ACES tax laws. The new tax law also included funding for four new "Audit Masters" within the department. The department is still experiencing significant difficulties recruiting and filling audit positions. The department has successfully recruited three Audit Masters, and these individuals have been placed within sections of the Tax Division to assist with implementation and administration of the tax. The recruitment of the fourth Audit Master, and Oil and Gas Revenue Auditors is ongoing.

During 2008, the department's auditors began auditing tax returns that were submitted for calendar year 2006 under the PPT program.

## Conclusion

The ACES production tax has been effective in allowing the state to share in the benefits of high oil profitability. It has also responded well to lower oil prices by reducing state tax burden on Alaska's oil and gas producers. Over \$2 billion in new capital investment was reported in fiscal year 2009 reaching near-record levels. While these and other indicators suggest that the profits-based tax system has supported North Slope exploration and development, it would be misleading to suggest that ACES alone influences the level of investment. While tax is recognized as being an important factor in investment decisions, it is not the primary determinant. Long-term price forecasts, as well as the resources themselves, have proven to be much more significant drivers of industry activity.

The department is continuing to analyze ACES to identify opportunities to improve the tax framework in order to support additional exploration and development in the state, while not harming the state's revenue base.

The new reporting requirements under ACES are helping the department develop a better understanding of industry expenditures and activity, and have assisted in the state's revenue forecasting efforts. Development of new tax regulations is progressing, though several challenges remain for both the state and taxpayers. Numerous workshops have been held to solicit industry input and these will continue as the department continues to work through outstanding issues. In 2008, the production tax audit group began auditing taxpayers who submitted annual returns for CY 2006 under PPT.

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