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COMPARING ALASKA'S OIL PRODUCTION TAXES: INCENTIVES AND ASSUMPTIONS[1]

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In a recent analysis comparing the current oil production tax, More Alaska Production Act (MAPA, also known as SB 21) to the tax it replaced, Alaska's Clear and Equitable Share (ACES), Scott Goldsmith, professor emeritus of economics at ISER, found that MAPA would produce higher revenues in the future, if changing to MAPA causes producers to make investments that lead to more production than would have occurred under ACES.[2]

Professor Goldsmith did not advocate for either tax, but projected effects of each under a range of different future oil prices, production rates, and costs. He noted that comparative revenues are highly sensitive to future costs and oil prices. Oil prices are notoriously difficult to forecast. Future North Slope oil production, as well as lease costs that can be deducted from producers' tax liabilities under both ACES and MAPA, are also highly uncertain. Proponents of either MAPA or ACES appear to make assumptions about prices, production, and costs that support their arguments.

Given the inherent uncertainty about oil prices, new production, and expenditures for capital and operating costs, what assumptions would be most reasonable to make for assessing outcomes of the tax regimes? This note critically examines the relevant assumptions for projecting tax outcomes, and explores how the different taxes compare under a set of assumptions that seem most reasonable, given our best current information.

The comparisons address not only the amount of revenue the state would collect, but also how the taxes differently share risk between the industry and the state, and administrative issues affecting the nature of the relationship between the oil industry and state government. The analysis also places the debate about MAPA vs. ACES in the longer term context of Alaska oil production taxes, comparing MAPA and ACES to the original petroleum profits tax (PPT) that preceded ACES, and to the old severance tax PPT replaced.

1 This research was funded in part by ISER's *Investing for Alaska's Future* research initiative, under a grant from Northrim Bank. The findings are those of the author, not of ISER, the University of Alaska Anchorage, or Northrim Bank.

2 Scott Goldsmith, "Alaska's Oil Production Tax: Comparing the Old and the New," ISER Web Note No. 17, May 2014.

Major Findings

- Since Prudhoe Bay production started in the 1970s, Alaska state government has generally collected between 30 and 40 cents of every dollar of gross wellhead production value. The percentage state take exceeded 45 percent of gross wellhead value, however, for two of the six years under ACES when oil prices were high. The state take under MAPA currently falls within the 30-40 percent range, but could fall below the 30 percent threshold as production from new fields takes an increasing share of North Slope production.

- The assumptions about prices and costs that Professor Goldsmith used for his analysis are similar to those projected by the Alaska Department of Revenue Tax Division for fiscal year 2015 in the most recent comprehensive revenue forecast, published in spring 2014.[3] Projected lease capital costs are much higher for that year than for previous years. Much if not all of the increased capital expenditure is related to one-time development expenditures for the Pt. Thomson field, as part of a negotiated settlement of a lease dispute with the state that has nothing to do with oil taxes.

- Rather than basing cost assumptions on one-time development activities, this analysis uses cost assumptions based on Department of Revenue assumptions for the next five years—which better reflect likely future conditions. Under those assumptions, ACES would collect $1.3 billion more than MAPA over the next five years—a difference of about 12 percent.

- Oil prices will likely fluctuate in the future as they have in the past. The progressive rate structure of ACES causes it to collect more revenue relative to MAPA when there is greater volatility of oil prices. ACES would collect 6 percent more revenue if the oil price averaged $100 per barrel but fluctuated between $80 and $120 than if it stayed constant at $100, while MAPA revenues would be essentially unchanged if the price fluctuated.

- No independent evidence exists that changing from ACES to MAPA has caused or will cause oil industry investment to increase. Replacing the tax credit for capital expenditures in ACES with a tax credit for production (per-barrel credit) in MAPA eliminates a risk-sharing mechanism while offering producers an inefficient incentive to increase production. The same loss of state revenue under MAPA as under ACES gives an oil company a less valuable benefit, because the firm doesn't get the production credit until many years after it incurs the investment expenses.

Alaska Oil Production Taxes in Historical Context

Ballot Measure One offers the first opportunity for Alaska voters to have a direct role in determining Alaska oil revenues. However, the debate over MAPA versus ACES represents only the latest round of a political conversation that has continued since Prudhoe Bay oil started flowing through the trans-Alaska pipeline (TAPS) nearly 40 years ago. When analyzing trends in oil taxes over a long period of time, it is important

[3] Revenue Sources Book: 2014 Spring. Alaska Department of Revenue, Tax Division. http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?1048r (retrieved July 10, 2014).

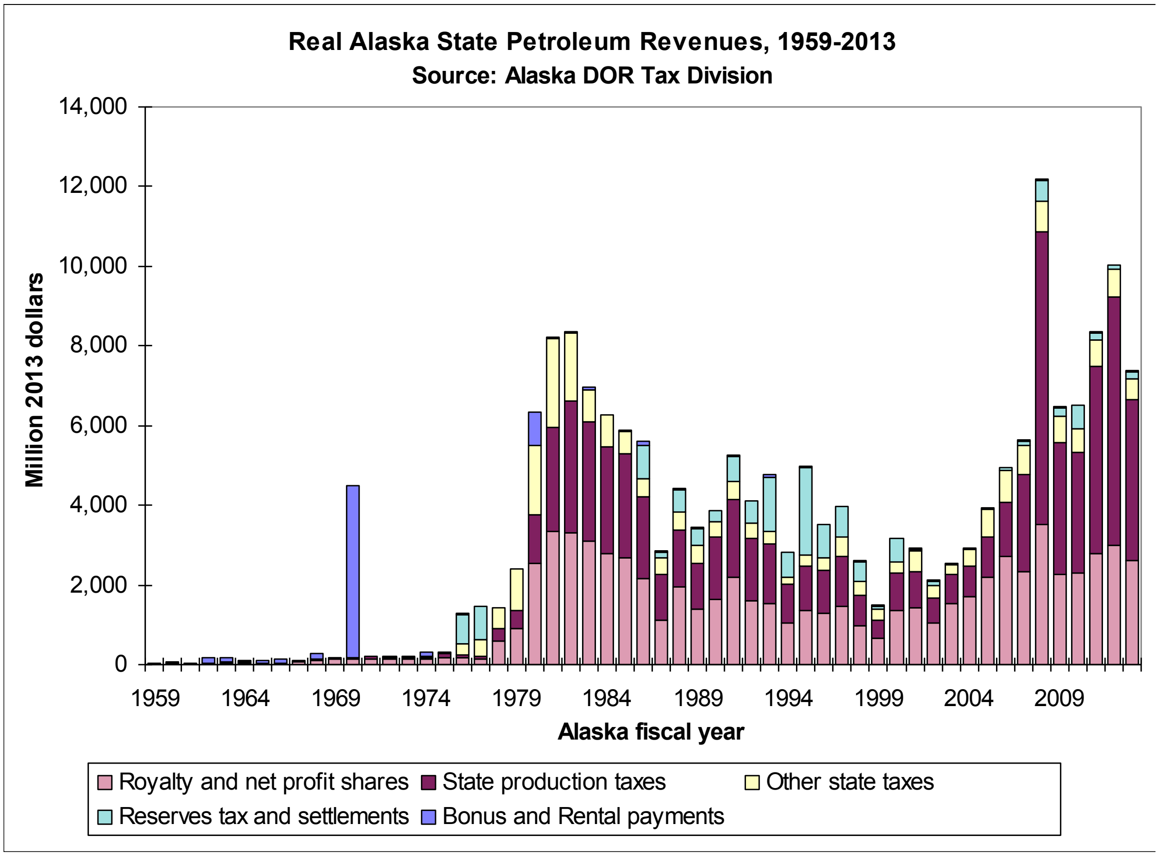
to keep in mind that governments obtain petroleum revenues by exercising two fundamentally different roles. As a sovereign entity, the state can tax activities within its borders. As a landowner, the state can accept payments from oil companies for the rights to exploit resources that the state owns. Such landowner payments often come in the form of lease revenues such as bonus bids and royalties, since states typically lease rights to exploit oil and gas rather than sell the resource deposits outright. The *petroleum fiscal regime* is the term often used to refer to the entire portfolio of lease and tax mechanisms that share revenue or other valuable resources between the oil industry and the government.

THE PETROLEUM FISCAL REGIME

People often confuse the different nature of the revenues accruing from the two separate state roles. The United States is one of the few nations in the world where petroleum rights may be owned by private parties such as farmers, ranchers, and Alaska Native regional corporations. Nearly everywhere else, only governments may own mineral rights, so the difference between landowner and sovereign is easily blurred. In the United States, however, it is important to keep the two forms of revenue separate. While a sovereign may change taxes unilaterally at any time, lease payments, once established, are essentially contracts, and may only be changed by mutual agreement.

Figure 1 summarizes annual Alaska state petroleum revenues by major revenue category since statehood in 1959. The figures are adjusted for inflation to represent 2013 price levels using the U.S. Gross Domestic Product Implicit Price Deflator. The figure shows clearly that since fiscal year 1982, royalties and production taxes have provided the vast majority of petroleum revenues. (Alaska fiscal year 1982 started July 1, 1981 and ended June 30, 1982.) In fiscal year 1970, Alaska collected $900 million in bonus bids from a single North Slope lease sale—an amount worth more than $4 billion in today's dollars. The figure also illustrates the volatility of Alaska's oil revenue. Inflation-adjusted revenues were one-fourth as large in 1999 as in 1982, due to low oil prices as well as declining production. Since 1999, revenues have recovered, but fluctuating oil prices, combined with a revised production tax structure, have generated even more inter-annual volatility.

Figure 1.



Detailed tax and lease terms can be highly complex, so it can be useful to summarize and evaluate the petroleum fiscal regime along three dimensions: *government take*, *risk sharing*, and *administrative distance*. Ideally, the government take should be measured as the state's share of economic rent.[4] However, defining and obtaining consistent, objective measurements of capital and operating costs over a long period of time or across different geographic areas is very difficult. Consequently, a much simpler, if potentially less accurate measure of government take, is state revenues expressed as a ratio or percentage of the total wellhead market value of production.

It may often seem from the political rhetoric that the government take is the only important issue in the fiscal regime. However, the other two dimensions of the fiscal regime—the way the regime shares revenue risk between the government and industry and the nature of the government-industry relationship—may be equally important.

Oil development is an inherently risky proposition, involving a wide range of geological, economic, and political uncertainties, and the fiscal regime provides an opportunity to transfer some of that risk from one party to the other. Risk-sharing is closely linked to the

[4] Economic rent for a natural resource is defined as the value of production less the value of the capital and labor required to achieve that production. Economic rent for oil and gas typically excludes operating and capital costs but includes payments to landowners and taxes such as production taxes that the oil industry pays but most other industries do not pay, as well as profits from resource production that exceed competitive returns.

concept of progressivity, which refers to the degree to which the government take increases as the returns from development increase (see box below). The percentage government take from a progressive fiscal regime is higher if investment in an oil prospect turns out to be very lucrative than if it turns out to be less profitable. The opposite is true for a regressive regime: the percentage take is higher from a given prospect if returns are lower. Progressive regimes therefore shift some of the oilfield risk from industry to the government, while regressive regimes shield the government from risk and instead shift more risk to industry.

PROGRESSIVE, NEUTRAL, AND REGRESSIVE TAXES

A *progressive* tax collects a higher percentage of net income at a higher level of income than it collects at a lower income level. For a tax to be considered progressive, the *tax rate* has to rise as income rises.

A *regressive* tax has the opposite effect: the percentage of net income taxed is lower when income is higher.

A *neutral* tax collects the same percentage of income at all income levels.

A constant percentage tax on gross wellhead production value is a regressive tax, because it does not take costs into account. If higher oil prices cause gross wellhead value to rise by 10 percent, for example, net income (after subtracting costs) rises by more than 10 percent. The production tax levied on gross value goes down as a percentage of net income.

In comparison with gross revenues taxes and other regressive taxes, profit taxes shift risk from companies to the state. Progressive profits taxes shift even more risk from companies to the state.

Table 1 summarizes common petroleum tax and lease mechanisms by categories of progressivity. Highly regressive instruments collect revenue that is unrelated or even inversely related to production, shielding the government from risk while increasing risk for industry. Highly regressive lease payments include bonus bids (lump sum payments) and rental fees. Examples of highly regressive taxes include property taxes (if based on physical investments) and reserves taxes. Basing the payment on production value rather than physical production quantity moderates the regressive nature somewhat, but does not eliminate it as long as costs are ignored. Taxes based on a fixed percentage of net income and lease payments based on a fixed share of net profits are neutral, with relatively little effect on the investor’s risk pattern one way or the other. For progressive mechanisms, the rate on net income or share of net profits rises as the percentage return rises.

Table 1. Relative Progressivity of Different Lease Payments and Taxes

Progressivity class	*Explanation*	*Lease terms*	*Taxes*
Highly regressive	Revenue unrelated or negatively related to production	Bonus bids, rental payments, work commitments	Property tax, reserves tax
Moderately regressive	Based on production, ignoring price or cost	Fixed dollar per barrel royalty	Apportioned income tax, fixed dollar per barrel tax
Somewhat regressive	Based on gross production value, ignoring cost	Fixed percentage ad valorem royalty	Fixed rate ad valorem severance tax
Neutral	Fixed percentage of net income	Fixed net profit share	Fixed rate producer profits tax
Progressive	Percentage of net income rises as income rises	Variable rate net profit share	Variable rate producer profits tax, producer profits tax with investment credit

The third fiscal dimension, *administrative distance*, qualitatively expresses the degree to which governments act unilaterally to determine the fiscal regime, versus negotiate terms jointly with industry. Jurisdictions around the world differ dramatically in their approach to administrative distance. In some countries, national oil companies participate in joint ventures or as equity partners with private firms, while in others, such as most U.S. states, governments approach industry only on an arm's-length basis.[5]

Table 2 summarizes processes for determining and implementing taxes and lease terms in the fiscal regime under three levels of administrative distance. High and low administrative distance each have advantages and disadvantages. Low distance provides parties with the opportunity to be more flexible with developing the fiscal regime and adjusting it over time as conditions evolve. High distance, on the other hand, provides greater certainty for investors—provided the state does not change the terms—and reduces opportunities for corruption of public officials. A fiscal regime with low distance can operate in the public interest if there is both a high level of public trust and a depth of professional expertise in the civil service working on petroleum lease and tax administration.

[5] Kenneth W. Dam, in his book *Oil Resources: Who Gets What How?* (Chicago: University of Chicago Press, 1976) compared the government take and administrative distance of North Sea fiscal regimes with that of the U.S. federal Outer Continental Shelf in the 1960s and 1970s. He concluded that the government take from the arm's-length U.S. auction system would be likely be higher than from the European negotiated licensing systems. Because Dam's analysis largely ignored the effects of the risk-sharing provisions of the different systems, his findings might have differed if he had considered performance under the upheavals in world oil markets that began shortly after his book was published.

Table 2. Administrative Distance of Industry-Government Relations

Distance of relationship	*Lease terms*	*Taxes*
High	Competitive lease auctions, state sets lease terms and bid method	State sets tax regime unilaterally
Medium	Solicitation of competitive development proposals	Industry participates in drafting proposals for tax changes; legislature may amend before ratification
Low	Negotiated development and revenue terms, government participation as equity investor	Negotiated settlements of tax disputes

Political ideologies, economic interests, and changing opportunities are constantly attempting to push the regime towards one direction or the other along all three dimensions of the fiscal regime. Opposing forces favor more or less government take, more or less progressivity, and more or less administrative distance. The prevailing regime is therefore a political equilibrium of these forces over time, similar in many ways to a market price that represents an equilibrium of supply and demand.

Historical Trends in Government Take, Progressivity, and Administrative Distance

Tables 3 summarizes major changes in Alaska's oil and gas fiscal regime with respect to government take, risk sharing, and administrative distance since North Slope oil started to be developed. Changes that involved large amounts of state revenue are highlighted for emphasis. Even before oil was discovered on Alaska's North Slope, Cook Inlet oil and gas provided one-fourth of state General Fund revenues, mostly in the form of bonus and royalty payments from state offshore leases and shared federal revenues from onshore production.[6] Since North Slope oil began flowing through the trans-Alaska pipeline (TAPS) in 1977, the legislature has faced the challenge of how to collect a "fair share" of the enormous rent from the giant fields while providing sufficient incentives for new exploration and development. For nearly three decades after 1977, the state relied on a production, or severance tax, with a variable rate determined by the so-called economic limit factor (ELF) based on average daily production per well. After a significant change in the corporate income tax in 1981, the legislature made a number of relatively minor adjustments to the system without changing the basic structure of the severance tax. These changes had the cumulative effect of making the Alaska fiscal regime increasingly regressive, but with decreased distance.

[6] Jerry McBeath, Matthew Berman, Jonathan Rosenberg, and Mary Ehrlander, *Political Economy of Oil in Alaska: Multinationals vs. the State* (Boulder, CO: Lynne Rienner Publishers, 2008) contains a more detailed history of changes in the state's petroleum fiscal regime.

As Prudhoe Bay oil production declined in the 1990s, the ELF formula began to reduce the effective tax rate significantly. By 2003, the effective tax rate was less than half the nominal rate of 15 percent of wellhead value, and even the oil companies recognized that the tax structure was unsustainable in its current form. Pushed by Governor Frank Murkowski and his tax consultant Pedro Van Meurs, the Alaska Legislature in 2006 enacted a major change in the oil and gas production tax, replacing the ELF-based severance taxes on gross wellhead value with the so-called petroleum profits tax, or PPT, a tax on net income earned at the wellhead.

The PPT was progressive as initially enacted, and was amended the next year under Governor Sarah Palin to increase both the government take and progressivity. The 2007 tax, called “Alaska’s Clear and Equitable Share” (ACES), remained in effect until replaced in 2013 by the “More Alaska Production Act” (MAPA). MAPA retained the concept of a profits-based production tax, but substantially reduced progressivity and introduced lower tax rates for production from “new” fields.

Table 3. Major Changes in Alaska's Oil and Gas Fiscal Regime, 1973-2013[a]

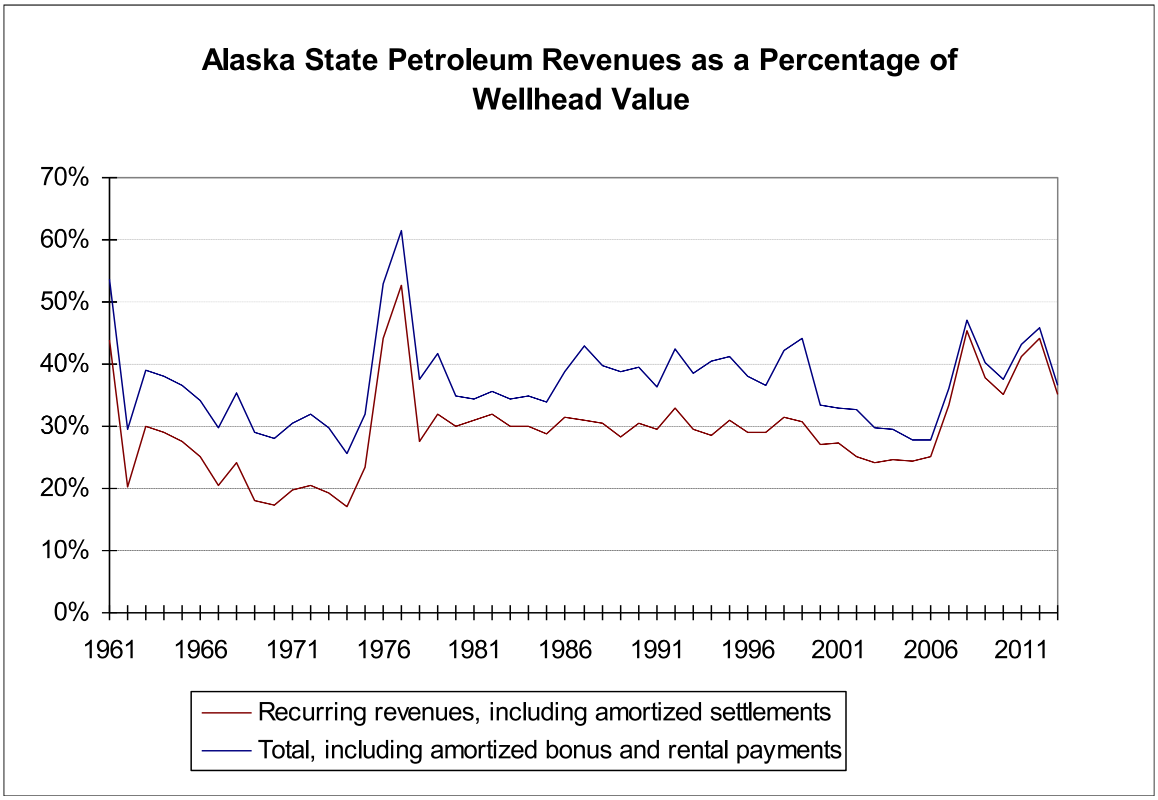
Year	*Authority*	*Brief description*	*Administrative distance*	*Effect on state take*	*Risk-sharing effect*
1973	AS43.56	Enact property tax	High	Increase	Highly regressive
1975	AS43.58	Reserves tax (temporary)	High	Exceeds 100%	Highly regressive
1977	AS43.55	Severance tax with ELF	High	Large increase	Somewhat regressive
1978	AS 43.21	Separate accounting income tax	High	Large increase	Change from regressive to neutral
1979	AS38.05	Expanded lease bidding options	High	Neutral	Options to increase progressivity used in major lease sale
1981	AS 43.55; AS 43.20; repeal AS 43.21	Change income tax and severance tax	High	Decrease	From neutral to regressive
1989	AS 43.55	Change in ELF	High	Increase	Regressive
1990	AS 38.05	Royalty reduction option	Decrease	Decrease	Less regressive
1994	AS 43.55	Make hazardous release tax permanent	High	Increase	Regressive
1994	AS 38.05	Exploration licensing, credit	Decrease	Decrease	Progressive
1986-2000	Attorney general	Settlement of major tax and royalty disputes	Low	Unknown	Highly regressive
1996	Ch. 139 SLA	1996 Northstar lease renegotiation	Low	Neutral	Change from progressive to regressive
1998	AS 43.82	Stranded Gas Development Act	Decrease	Decrease	Neutral
2003	AS 55.025	Exploration tax credit expanded	Decrease	Decrease	Progressive
2005	Administra-tive	Aggregation of small field ELF	High	Increase	Neutral
2006	AS 43.55	Petroleum Profits Tax (Profit-based Production Tax)	Moderate	Neutral	Change from regressive to progressive
2007	AS 43.90	Alaska Gasline Inducement Act	Low	Neutral	Progressive
2007	AS 43.55	Alaska's Clear and Equitable Share (ACES) Production Tax	Moderate	Increase	Slightly more progressive
2013	AS 43.55	More Alaska Production Act (MAPA)	Moderate	Decrease	Less progressive

[a]Adapted from Jerry McBeath, Matthew Berman, Jonathan Rosenberg, and Mary Ehrlander, *Political Economy of Oil in Alaska: Multinationals vs. the State* (Boulder, CO: Lynne Rienner Publishers, 2008)

When expressed as a percentage of wellhead oil and gas production value, the Alaska state government take has been relatively constant over time, as Figure 2 illustrates.

While most petroleum revenues are assessed annually, certain revenues such as lease bonus bids are one-time events. The inherently sporadic and unpredictable nature of these one-time revenues presents a challenge to representing government take over time. In Figure 2 these non-recurring revenues are amortized—essentially spreading them out over time—in proportion to the percentage of total oil production occurring each year. The lower line in Figure 2 shows the percentage of wellhead value collected by all revenues except bonus and rental payments, with the 1976-1977 conservation tax (prepayment of Prudhoe Bay severance taxes before production started), and legal settlements of tax and royalty disputes represented by their amortized values.[7] The upper line adds the percentage of wellhead value in amortized bonus and rental payments.

Figure 2.



The spike in the state take per barrel in the 1970s is due to North Slope and TAPS petroleum property taxes collected before Prudhoe Bay began commercial production, and the wellhead value was composed almost entirely of Cook Inlet oil and gas. Once North Slope commercial production started, the take stabilized at a higher percentage of wellhead value than before. During the 1980s and 1990s, the state take was nearly constant at about 30 percent of wellhead value in recurring revenues and 35-40 percent, considering all petroleum revenues. During the entire period through fiscal year 2006, when the ELF-based severance tax was in effect, the state take from all petroleum revenues never reached 45 percent. The years with the highest take all corresponded to

7 Recognizing the erratic nature of legal settlements, the Alaska Legislature has directed that these funds be placed in the Constitutional Budget Reserve Fund, where they are more difficult to access for current spending.

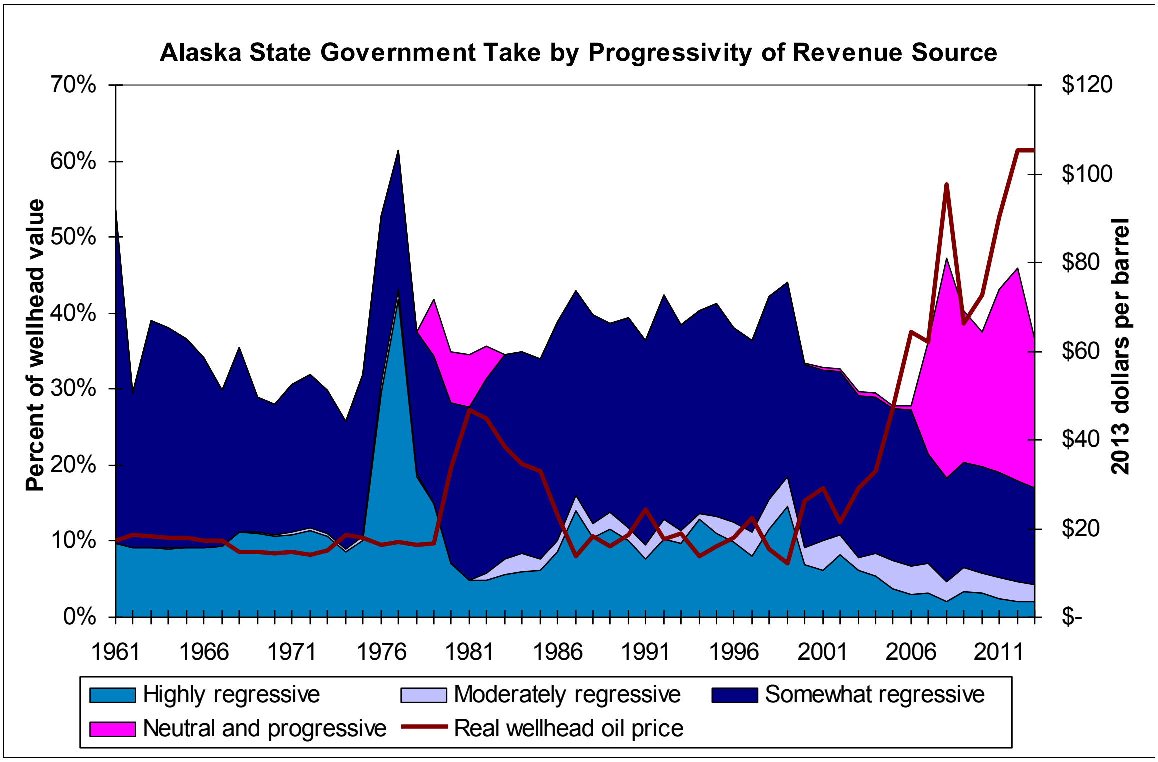
years of low oil prices, illustrating the regressive nature of the overall fiscal regime. However, the state take exceeded 45 percent of gross wellhead value in both 2008 and 2012 under the ACES production tax. Oil prices adjusted for inflation reached their highest levels in these years, illustrating the effect of the highly progressive rate structure of the ACES tax structure.

As the percentage government take increases, fewer investments in enhanced recovery, exploration, and development remain profitable, suggesting that production over the long term could fall. Oil producers obviously have an incentive to argue that reducing government take leads to higher investment and production. Determining the validity of these claims independently is difficult, due to the many uncertainties in the oil business, and objective empirical evidence is lacking. A complicating factor is that the expected government take is not the only aspect of a tax that affects profitability of new investment and, by implication, future production. The way the fiscal regime shares risk also matters.

REVENUE RISK (PROGRESSIVITY)

Figure 3 shows the Alaska state government take distributed among the various categories of progressivity. The height of the graph—the total take as a percent of wellhead value—is the same as the top line in Figure 2. Figure 3 illustrates how moderately regressive sources—mainly royalties and severance taxes—dominated state revenue collections until 2006, when the PPT replaced the ELF-based severance tax. The first of two previous anomalies occurred during TAPS construction, when the reserves tax and pipeline property taxes increased highly regressive revenues before North Slope commercial production commenced. The second anomaly came right afterward during the first few years of North Slope production, when the state used the “separate accounting” method for the petroleum corporate income tax. The progressive features of the PPT and ACES meant that the state was poised to benefit from the historically high oil prices that have occurred since 2006.

Figure 3.



TRADE-OFF OF RISK AND EXPECTED RETURN

One would ordinarily assume that for any given expected government take, the state would prefer a fiscal regime generating lower revenue risk to one generating higher risk. Less predictable revenues, or wider fluctuations in revenues, creates challenges for budgeting and raises the prospect of revenue shortfalls. Governments therefore would generally give up some expected revenue if they could shift more of the risk from oil revenues to industry. The degree of preference for a risk-expected-return tradeoff would depend on such factors as the amount of government debt and size of state savings accounts relative to the annual budget, amount and volatility of non-petroleum sources of revenue, financial returns from investing surplus government funds, and interest rates in bond markets. An administration with less ability to weather uncertainty of petroleum revenues would be willing to give up more expected revenue to reduce its revenue volatility than would a state with a more diversified revenue base.

Oil companies, too, would have a similar tradeoff of risk for expected return. The firm would presumably be willing to give up some amount of expected revenue if the state were to share some of the risk of exploration and development investments. The tradeoff of risk for expected return is a common assumption in finance. It underlies the Capital Asset Pricing Model that has been a staple of portfolio analysis, or modern portfolio theory, since the 1960s. The degree of the tradeoff depends on the ability of the oil companies to take on risk, which of course differs among oil companies as well as between the industry and the state. The private company might compare expected return and its uncertainty from oil and gas investments in one jurisdiction to expected return and uncertainty from investments in other jurisdictions, as well as from financial returns available to in the securities markets. The company's asset portfolio affects the amount of additional expected return that investors in securities markets would require for a change in the risk.

Large international integrated oil companies typically have a much more diversified portfolio of investments than small independent firms, leading them to place much less value on sharing risk with the government. The more favorable portfolio risk of major oil firms influences them towards favoring more regressive tax and lease terms. More regressive instruments allow them not only to pay less expected revenue to the state, but also help them compete more aggressively against smaller independent firms.

Administrative Distance

The broad pattern that emerges from Table 3 shows a steady decline in administrative distance since the beginning of the North Slope era. The change is likely due to a combination of factors. First, the Alaska state government has built up a significant expertise over the years in a number of areas related to the oil and gas industry in the departments of Revenue, Natural Resources, and Law. The cadre of expertise gives the state much greater ability to participate in negotiations with industry on an ongoing basis rather than having to rely as much on hired outside consultants retained for project-specific tasks. Second, as the state government became dependent on the oil industry for public revenues, the industry has likewise become dependent on the state for access to resources, as the vast majority of oil reserves discovered since Alaska became a state have been found on state-owned lands.

This mutual dependence has certainly increased the incentives for developing a more cooperative relationship. Perhaps most important, however, is the decision the major oil companies operating the main North Slope fields made in the early 1980s to build regional headquarters in Anchorage, move thousands of permanent employees to Alaska, and develop relationships with local contractors to support North Slope operations. This change embedded the oil industry as an integral part of the state economy, fostering an important shift in public perception from the early days, when it was viewed more as an outside interest group seeking to profit from Alaska's resource wealth.

The combined effect of these factors has been to increase the degree to which the state government tends to seek to negotiate rather than fight over terms of the relationship with oil companies. The reduced friction has undoubtedly brought savings in litigation expenses to both sides. However, since detailed terms of contracts and legal settlements remain confidential, the climate of reduced administrative distance has also caused a significant loss of transparency in government. The loss of transparency has a cost, too, of increasing the likelihood of political corruption—or more importantly, the perception of corruption, whether or not it occurs in practice.

Projecting Effects of Different Production Taxes

Professor Goldsmith concluded in Web Note 17 that MAPA could generate more revenue than ACES under a wide range of assumptions. However, not all those assumptions are equally likely to occur in practice. Research carried out by the Alaska Department of Revenue staff provides useful publicly available information for developing realistic assumptions about potential prices and costs.

Another element of controversy in the tax change is the claim by MAPA proponents that the new tax is more likely to increase future production, and, indeed, may already have increased oilfield investment over the level that would have occurred had ACES stayed in effect. It must be emphasized that independent empirical studies of the effects of how the tax change from ACES to MAPA might affect North Slope oil production do not exist.

Such studies would be very difficult if not impossible to perform because there are so many factors that could affect investment in oil exploration and development, all of which must be taken into account in order to isolate the effect of the tax change. Studies of tax changes in other places are not necessarily relevant to the change from ACES to MAPA, because of the unique features of these taxes and unique North Slope conditions. These unique features and conditions also make comparisons of tax takes between Alaska and other supposedly comparable areas potentially misleading and inaccurate. What one can do, however, is to analyze and compare the incentives offered by specific provisions of the different taxes. These incentives are related either indirectly or directly to the way each tax shares risk with the state.

PROJECTING WELLHEAD OIL PRICES

Web Note 17 described how to calculate the tax liability under MAPA and ACES. The focus here is on the assumptions for the various elements that make up the tax structure and could change over time. The old Alaska severance tax provides a useful starting point for the analysis. Under the tax in effect from 1981 to 2006, the tax was calculated as follows:

Tax = base rate * ELF * Wellhead production value

Production tax returns are calculated separately for each taxpayer. However, the Economic Limit Factor (ELF) was calculated by field. The ELF was calculated from a nonlinear formula based on production per day per well. At high production rates, the ELF was 1.0, so the base tax rate of 15 percent applied to that field. As production per well declined, the ELF declined, reaching zero (tax-free status) when production fell to 300 barrels per day per well for the field. Prudhoe Bay was the only field that ever had an ELF of 1.0, but the high production rate from Prudhoe Bay meant that the effective average North Slope tax rate for ELF-based tax remained fairly high for many years. As late as 1993, the average effective tax rate was 13.8 percent of wellhead production value. But as production declined from the Prudhoe Bay and Kuparuk fields in the 1990s, the effective rate began a steady decline. By 2005, the average ELF was less than 0.5, yielding an effective tax rate of 7.1 percent of wellhead production value.[8]

The wellhead production value for the production tax is defined as the wellhead price times taxable production. To obtain taxable production, one subtracts the royalty share from total production. For most Alaska North Slope leases, the royalty share is one-eighth, but it is higher for some fields. Taxable production therefore typically averages somewhat less than the 87.5 percent of total production.

To obtain the wellhead oil price, one subtracts transportation costs from the wellhead to market. Oil prices are notoriously difficult to forecast. Despite a veritable industry of consultants who are able to charge large fees to develop and package the most up-to-date information on world oil markets, none of these forecasts can do better in projecting future oil prices than simply picking the current oil price.[9] In other words, the best characterization of market oil prices is that they follow a “random walk” process, such that the most likely price at any given point in the future is the current price.

Table 4 shows the actual North Slope average annual oil price and transportation costs for fiscal year 2013 and projected prices and transportation costs for fiscal years 2014 and 2015. Alaska North Slope oil prices have been remarkably stable during the past

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8 Data from Alaska Dept. of Revenue, *Revenue Sources Book*, various years.

9 James D Hamilton, “Understanding Crude Oil Prices,” *The Energy Journal*, vol. 30, no. 2: 179-206, 2009.

two years, varying between $100 and $110 per barrel. Transportation costs—pipeline tariffs to Valdez plus tanker costs—historically change relatively slowly from year to year. With average transportation costs amounting to just under $10 per barrel, the Alaska Department of Revenue projects that wellhead oil price during 2013-2015 will average $96.59 per barrel.

Table 4. Alaska North Slope Actual 2013 and Projected 2014 and 2015 Oil Prices and Lease Expenditures.

	FY 2013	FY 2014	FY 2015	average
Price of ANS WC (in $/barrel)	$ 107.57	$ 106.61	$ 105.06	$ 106.41
Transit Costs & Other (in $/barrel)	9.76	9.9	9.82	9.83
ANS Wellhead (in $/barrel)	97.81	96.71	95.24	96.59
Deductible North Slope Lease Expenditures per taxable barrel				.
Operating Expenditures	17.39	19.64	18.05	18.36
Capital Expenditures	12.66	20.33	27.99	20.33
Total North Slope Expenditures	30.05	39.98	46.04	38.69

Source: Alaska Department of Revenue, *Revenue Sources Book*, Spring 2014. http://www.tax.dor.alaska.gov/

ASSUMPTIONS FOR LEASE EXPENDITURES

Since the ELF-based severance tax was replaced with the PPT in 2006, production taxes have been based on *production tax value* (PTV) rather than on the gross wellhead value, specifically,

Tax = (base tax rate * rate adjustment * PTV) - credits.

Each version of the tax based on PTV had a different base rate, different rate adjustment mechanism, and different credits. However, all used the same basic definition of PTV. PTV is calculated by subtracting lease operating expenditures (OPEX) and capital expenditures (CAPEX) from the wellhead production value. In other words, PTV is a measure of before-tax cash flow accruing to the company from operating the lease. For both the original PPT and ACES, the rate adjustment was a “progressivity factor” that raised the tax rate above the base rate when PTV per barrel exceeded a defined threshold amount. For MAPA, there was no rate adjustment. However, a wide variety of new production qualified for gross value reduction (GVR), which reduces the taxable PTV by 20 percent of gross wellhead value (by 30 percent of gross wellhead value if the field royalty share exceeds one-eighth). The credits also differed between MAPA and the predecessor taxes (PPT and ACES). Under ACES and the PPT, the credit was a percentage of capital expenditures, generally 20 percent, while under MAPA, the credit was a specified dollar amount per barrel of production. Table 5 summarizes the base tax rates, rate adjustments, and credits of the three versions of the production tax based on PTV.

Table 5. Summary of Alaska Profits-Based Production Tax Terms

	PPT (2006)	ACES (2007-2013)	MAPA (2014)
Base tax rate (percentage of PTV)	22.50%	25%	35%
Rate adjustment	0.25%*PTV > $30	0.4%*PTV > $30; 0.1%*PTV > $92.50	for new (GVR) oil, PTV reduced by 20%*gross revenue
Credit	20% of qualified CAPEX	20% of qualified CAPEX	$5/barrel for GVR oil; $8/per barrel, declining to $0 at $150/barrel wellhead oil price for other oil
Minimum Tax	4% of gross wellhead value if oil price>$25	4% of gross wellhead value if oil price>$25	4% of gross wellhead value if oil price>$25
Credits reduce minimum tax	Yes	Yes	Yes, GVR oil; no, other oil

Changing the tax base of the production tax from gross wellhead revenue to net production tax value complicated the task of revenue forecasting. Now projections of lease capital and operating costs were also required. Future lease expenditures that would be deductible from PTV, like future oil prices, are unknown and uncertain. Capital expenditures in particular are difficult to project, because they depend on company decisions to invest in new field development and exploration. Because ACES and its predecessor PPT allowed a tax credit for capital expenditures, projecting revenues for these taxes also required separate estimates of capital and operating costs.

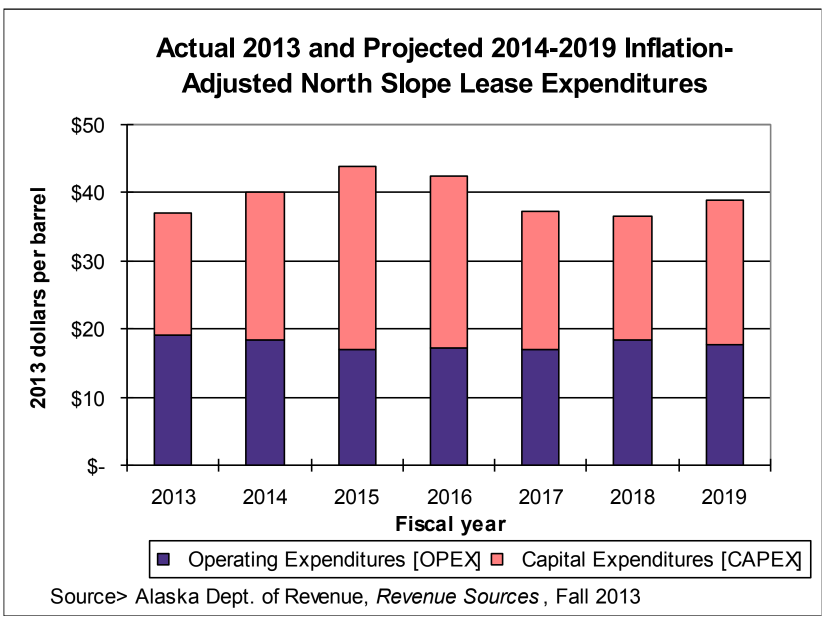
Not even the oil companies know what other firms will spend in Alaska. However, the Alaska Department of Revenue does have an advantage for making relatively short term forecasts due to its access to confidential tax returns for all firms operating in Alaska. These returns may provide insight into plans over the next three to five years. Department staff publish projections of total area-wide lease expenditures with revenue forecasts. Although production taxes, and therefore the relevant lease costs, are calculated separately for each taxpayer, average values will not represent the true situation for any particular company, and the nonlinear tax structure means that the average tax rate of all taxpayers' individual returns will also differ from the tax calculated from the average values. ACES' progressive rate structure causes the average per barrel tax on PTV to exceed tax on the average PTV per barrel. Revenue projections based on average PTV per barrel will therefore slightly understate revenue from ACES relative to MAPA. Nevertheless, taxes estimated with North Slope average wellhead oil prices and lease costs provide useful benchmarks and will closely follow actual tax collections.

In addition to the wellhead oil price averages, Table 4 also shows actual operating and capital expenditures for fiscal Year 2013 and Department of Revenue projections for lease expenditures for fiscal years 2014 and 2015 that can be deducted from PTV. What stands out from the table is that while operating costs are relatively constant over time, capital expenditures vary widely. In particular, projected capital expenditures per barrel for fiscal year 2015 are more than double the expenditures recorded in 2013. The major reason for the increased capital expenditures projected for fiscal year 2015 is development activity associated with the Pt. Thomson field. ExxonMobil expects to spend about $2 billion over the next two years, which amounts to about $5.50 per barrel produced over that period.

It should be noted that the decision to develop Pt. Thomson and the associated expenditures resulted from a settlement of a legal dispute with the state that was unrelated to the contemporary production tax debate.[10] Pt. Thomson is a special case because it is basically a huge natural gas field with a relatively limited potential to produce petroleum liquids until there is a market for North Slope gas. Developing the field requires a large capital investment per barrel of liquids production. If oil could be produced from the field with capital spending per barrel as low as from other North Slope prospects, the state would not have needed to sue Exxon to get it to develop the field.

A good illustration of the effect of Pt. Thomson development on anticipated lease expenditures comes from Figure 4, which shows the Alaska Department of Revenue projections for lease expenditures after removing the effects of inflation, using their assumed rate of 2.5 percent per year. The figure shows that operating expenditures per barrel, adjusted for inflation, are relatively constant over time, while capital expenditures are much more volatile. The temporary increase in capital spending for fiscal years 2015 and 2016 is readily apparent in the figure. Exxon has announced plans to begin 10,000 barrels per day of production in 2016, which is reflected in the Department of Revenue production and revenue forecasts.

Figure 4.



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10 Elwood Brehmer, "Point Thomson-TAPS connection complete," *Alaska Journal of Commerce*, June 5, 2014. http://www.alaskajournal.com/Alaska-Journal-of-Commerce/June-Issue-2-2014/Point-Thomson-TAPS-connection-complete/ (accessed June 14, 2014).

COMPARING GOVERNMENT TAKE

The Alaska Department of Revenue forecasts contain the best publicly available information about North Slope capital and operating expenditures over the next 3-5 years. Using assumptions derived from these published projections offers the best strategy for comparing the effects of different tax regimes. Development decisions for new fields such as Pt. Thomson that would come into production within the next five years involve substantial capital expenditures, and be large enough to have a significant effect on operating expenditures, have likely already been made. Projections of lease expenditures beyond 5 years, not to mention projections of wellhead oil prices and production volumes, are much more uncertain and therefore less useful for comparing tax instruments, the effects of which depend on lease expenditures as well as production rates and prices.

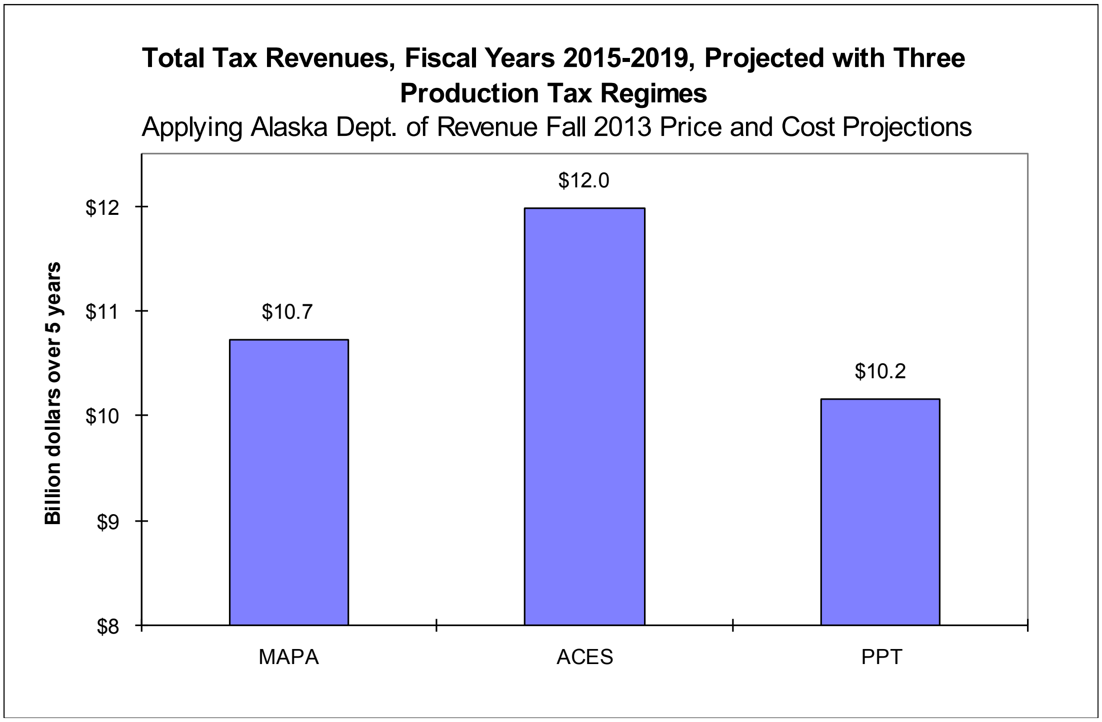
Figure 5 projects revenues over the next five state fiscal years from the three production tax regimes based on production tax value: MAPA (2014), ACES (2007-2013), and PPT (2006). The projections all use the same assumptions for oil production, prices, and lease expenditures, shown in Table 6. These assumptions are all derived from Department of Revenue forecasts. Lease expenditures represent published area-wide projections from the Fall 2013 forecast—the latest currently available—adjusted to estimate deduction from PTV using the percentage of total capital and operating expenditures that the department projects will be deducted in fiscal years 2014 and 2015. Oil price and production forecasts, including production of new (GVR) oil are also those of the Department of Revenue. The five-year totals are not adjusted for inflation or discounted. Making these adjustments would change the total numbers but have no effect on the relative magnitudes.

Table 6. Assumptions for Revenue Projections Comparing Different Production Taxes

	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Total production (barrels/day)	498.39	487.64	482.72	459.49	429.09
GVR production (barrels/day)	37.6	37.9	47.6	46.9	41.7
West coast price	$105.06	$107.69	$110.38	$115.40	$121.19
Transport Cost	$ 9.82	$ 9.82	$ 10.06	$ 10.34	$ 10.78
Royalty share	12.8%	12.8%	12.8%	12.8%	12.8%
CAPEX per taxable barrel	$ 28.17	$ 27.26	$ 22.35	$ 20.63	$ 24.59
OPEX per taxable barrel	$ 17.87	$ 18.54	$ 18.76	$ 20.74	$ 20.64

Source: Alaska Department of Revenue, Revenue Sources, Fall 2013, and Spring 2014.

Figure 5.



As shown in Figure 5, applying Department of Revenue assumptions for average North Slope prices and costs will generate a projected $10.7 billion under MAPA for fiscal years 2015-2019. If MAPA is repealed and ACES reinstated, the corresponding revenue estimate is $12.0 billion, or 12 percent more. ACES clearly generates more revenue under these assumptions, but the difference is relatively modest. A major factor holding down the difference between MAPA and ACES is the large capital expenditures related to Pt. Thomson development, much of which would be eligible for a tax credit under ACES—while the per-barrel production credit under MAPA would be much smaller. Interestingly, if the original PPT enacted during the administration of Governor Frank Murkowski were in effect, the projected state tax take would be about $0.5 billion lower than under MAPA. That tax also had a tax credit for capital expenditures similar to the credit in ACES, but lower tax rates (see Table 5).

The difference between ACES and MAPA would have been much greater under the conditions prevailing in the historical period 2008-2013, when the high oil prices and resulting high PTV per barrel caused ACES' highly progressive rate structure to generate high average tax rates. MAPA, which lacks the investment tax credit of ACES, collects more in years of high investment (such as projected for FY15 and FY16), while ACES collects more otherwise. The relative effects are clearly apparent when considering the progressivity of the different taxes.

COMPARING EFFECTS ON RISK SHARING (PROGRESSIVITY)

Both MAPA and ACES are progressive. ACES (and the PPT before it) have progressive rate structures based on changes in PTV driven by changes in capital and operating costs per barrel as well as wellhead oil prices. Progressivity in MAPA, however, is limited to changes in the per-barrel production credit rather than the tax rate on PTV. Consequently, MAPA progressivity is greater with respect to changes in oil prices than it is with respect to changes in costs. Figures 6 and 7 illustrate the progressivity of ACES and MAPA with respect to oil prices, showing the effective tax rates as a percentage of PTV and as a percentage of gross wellhead revenue, respectively. Dr. Goldsmith discussed and illustrated this progressivity in Web Note 17, but the figures here differ by using actual 2013 and projected 2014 and 2015 deductible capital and operating costs per barrel from the Department of Revenue Spring 2014 forecast.

Using these cost figures, ACES always collects more revenue than MAPA for legacy fields if oil prices exceed $70 per barrel. MAPA collects about the same revenue as the 2006 PPT for legacy fields, but is clearly much less progressive. MAPA collects more than the PPT did when oil prices fall between $75 and $125 per barrel. The stair-stepped effective rate for MAPA reflects the ratcheting down of the per-barrel tax credit for legacy fields as oil prices reach the various threshold levels.

The MAPA effective tax rate for new fields (GVR oil) is much lower. This currently has relatively little impact on MAPA revenues, but the effect will steadily increase as new development takes place and legacy fields continue to decline. Figures 6 and 7 also show the effective tax rate for the old severance tax in 1993, when the effective tax rate was 13.8 percent of gross revenue, as well as the year before it was replaced by the PPT, when revenues were lowest. These two figures provide useful benchmarks for comparing the taxes based on PTV. The regressive effects of the ELF-based tax are clear in Figure 6. The figures show that at the average wellhead oil price projected for fiscal years 2013-2015, new oil qualifying for the 20 percent GVR would provide only a little more revenue per barrel than the old severance tax when it reached its lowest effective rate, about 7 percent per barrel. Oil qualifying for the 30 percent GVR would pay even less. Wellhead oil prices have to exceed $130 per barrel before new fields qualifying for the 20 percent GVR would pay as much per barrel as the old severance tax did in 1993, while for 30 percent GVR, the price would have to exceed $160.

Figure 6.

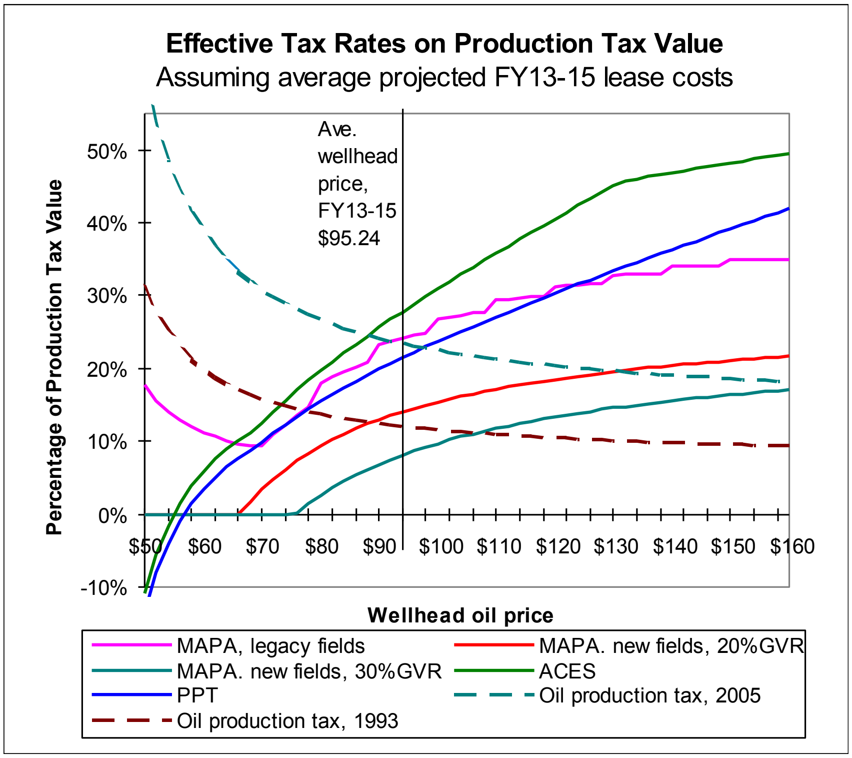
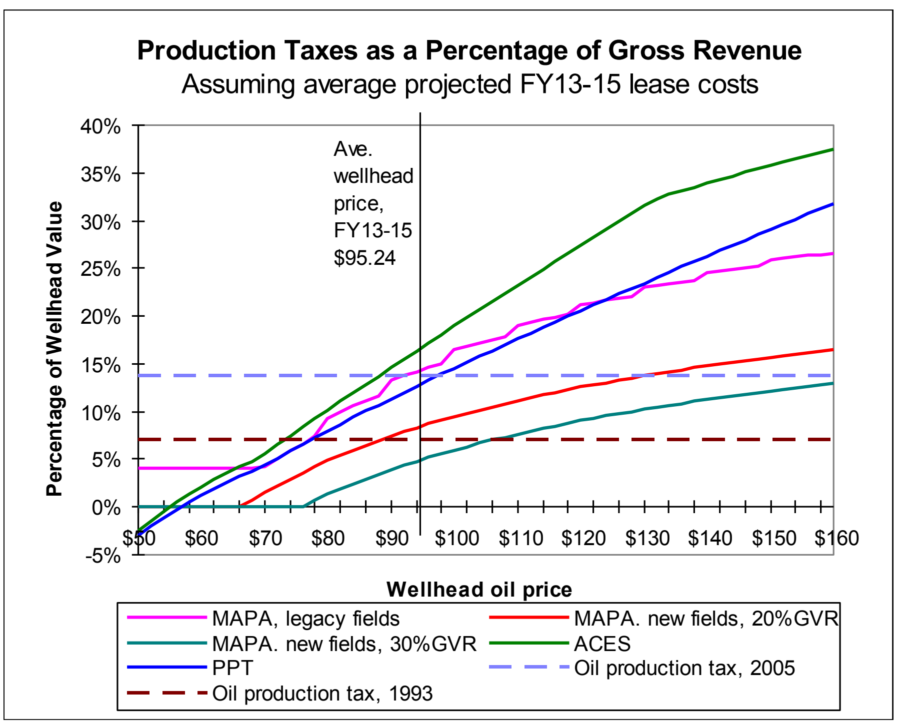


Figure 7.



The $1.3 billion revenue difference in Figure 5 projected over the next five years understates the revenue difference for ACES over MAPA for those cost assumptions because it assumes oil prices remain relatively constant over the period. The only thing we know for certain about future oil prices is that they will fluctuate, even if the average price is similar to the average wellhead price projected for FY2013-2015. The progressivity feature of ACES causes it to collect somewhat more revenue relative to MAPA when oil prices exhibit greater volatility. If lease capital and operating costs are assumed to be the Department of Revenue average projected values for FY2013-2015, ACES would collect 6 percent more revenue if the oil price averaged $100 per barrel but fluctuated between $80 and $120, than if it stayed constant at $100. The older PPT, with somewhat less aggressive progressivity, would generate 4 percent more revenue, while MAPA revenues would be essentially unchanged.

Figures 8 and 9 show how progressivity under MAPA is much less with respect to changes in PTV caused by changes in capital expenditures, especially for legacy fields. The figures show effective tax rates on PTV and gross revenue, respectively, with increasing capital expenditures per barrel. Since increasing capital expenditures results in lower PTV, progressivity is shown by a downward slope to the effective rate curve. The effective tax rates in the figure assume average wellhead oil prices and operating costs projected for the 2013-2015 fiscal years. The upward slope to the rate curves with respect to PTV for the old ELF-based severance tax indicates, again, the regressive nature of this tax. The figures illustrate the fact that if one uses FY2015 assumptions for capital expenditures, MAPA collects more, primarily because of the ACES capital expenditure tax credit. ACES collects substantially more in the other years, when capital expenditures per barrel were lower.

Figure 8.

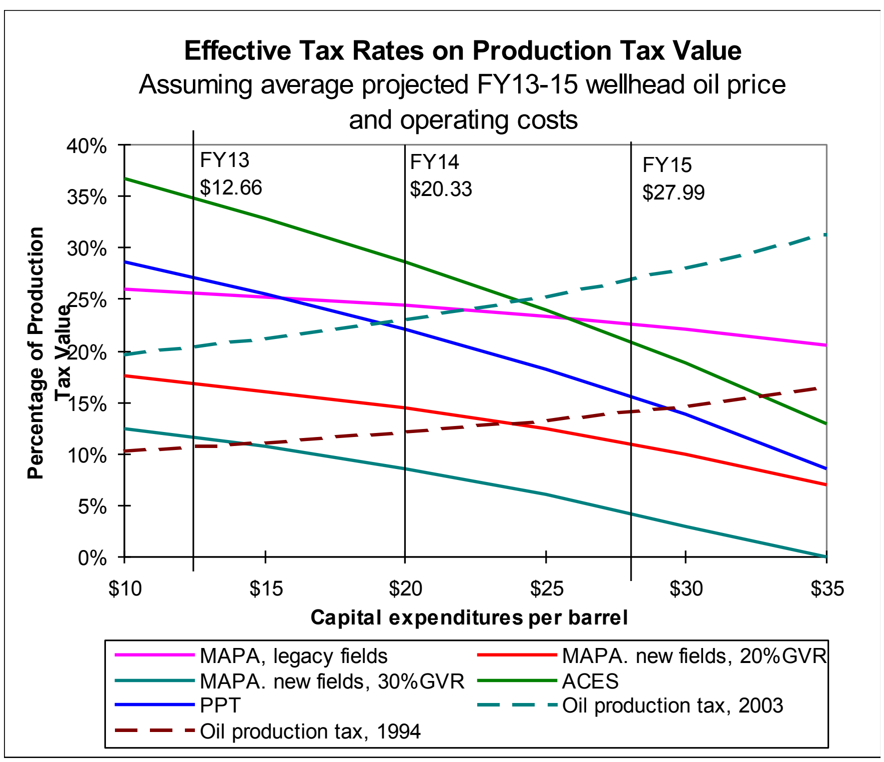
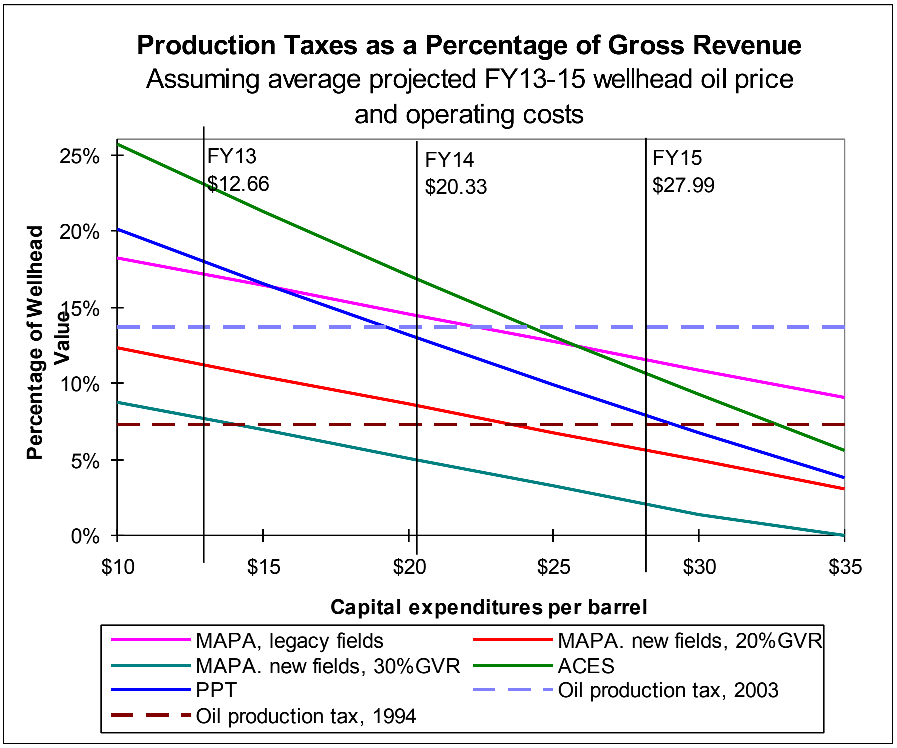


Figure 9.



Changing from a tax credit for capital expenditures under ACES to a per-barrel credit under MAPA has an additional effect on risk sharing beyond that arising from the reduction in progressivity illustrated by the flatter slopes of tax rates in Figures 8 and 9. The per-barrel credit in MAPA offers a tax benefit only if an investment is successful. That is the intended effect, of course. The result is to reduce investment incentives relative to ACES in projects for which production is uncertain. The firm receives the ACES investment tax benefit before it is known whether the investment will be successful. Typically the most uncertain investments, and therefore most favored by ACES over MAPA, are exploration investments.

Furthermore, the argument that MAPA rewards production while ACES rewards spending is somewhat disingenuous. MAPA's per-barrel credits are functionally equivalent to reducing the rate on PTV and adding a tax credit on lease costs. The ACES credit applies only to capital expenditures while the MAPA "credit" applies to operating as well as capital costs. For example, consider a simple case in which the wellhead price is $100 per barrel and operating and capital expenditures are each $20 per barrel. ACES offers a tax credit of $4 (20 percent of $20) per barrel. Under MAPA, the field is eligible for a $5 per barrel credit. That $5 per barrel is also 5 percent of gross revenue per barrel, so a tax of 35 percent of PTV with a $5 per barrel credit is really a tax of 30 percent on PTV with a credit of 5 percent of total lease costs. An equivalent way of describing the tax in this case, therefore, is that it is a tax of 30 percent of PTV with a tax credit of 5 percent of capital and operating expenditures.

ADMINISTRATIVE EFFECTS

MAPA introduces substantial tax relief for production from "new" fields qualifying for the gross value reduction (GVR). The difference in rates is large—nominally 7 percent of gross revenue for 20 percent GVR fields; it could be more or less depending on the effect of oil prices on the per-barrel credit for legacy fields. With such a large difference in effective tax rates, the oil companies clearly have a large incentive to try to qualify as much production oil as possible for GVR status. This places a significant new administrative burden on the Department of Revenue to determine the merit of these claims. The way the department makes these determinations—by developing and enforcing regulations—could change the nature of the administrative relationship toward either greater or lesser distance. If the state policy favors litigation of disputes, then the legal system cost of implementing MAPA could become significantly higher than it is today, as new oil takes on an increasing share of total production. On the other hand, if the state policy favors more negotiations and settlement of claims, then the cost will not rise much, but the public will be far less informed about these important taxing decisions.

One frequently overlooked fact about MAPA is that the per-barrel allowance was designed to apply to oil, whereas the basic concept of a tax on production tax value could accommodate natural gas production just as easily as oil production. The change to MAPA therefore will put more pressure on the legislature to create a separate tax regime for large North Slope natural gas sales.

INCENTIVES FOR INVESTMENT IN EXPLORATION AND DEVELOPMENT

As mentioned before, independent empirical evidence does not exist to show that the specific tax structure of MAPA would generate more investment than that of ACES. Studies of tax changes in other jurisdictions may not be that useful for comparing ACES to MAPA. During the recent period when oil high prices were very high and the progressive ACES tax rates collected a large share of North Slope revenues, investment in Alaska did not increase at the same rate as it did for other parts of the world. However, this earlier period may not represent likely future conditions. The booming world oil business caused by the high prices bid up costs for drilling rigs and other necessary inputs to oilfield operations. With these higher costs, PTV per barrel is now lower than it was a few years ago, even though oil prices remain high, reducing the difference in tax rates between ACES and MAPA.

Lacking relevant empirical studies, the best information about likely effects on production derives from careful analysis of the specific incentive structure of the two taxes. While effective tax rates for ACES and MAPA differ relatively little at current PTV per barrel, the taxes have different effects on risk sharing (progressivity), especially considering the tax credits. The different credits cause the tax incentives to differ depending on the degree to which the source of uncertainty in future in PTV derives from uncertainty about the oil price or uncertainty about costs.

The progressivity feature of ACES has often been portrayed as discouraging investment. However, the problem is not the progressivity of ACES per se, but rather that the aggressive increase in marginal tax rates when PTV exceeds $30 per barrel could lead to very high average tax rates. For example, a wellhead oil price of $130 and lease costs of $40 per barrel would generate a PTV of $90 per barrel, with an associated ACES tax rate of 49 percent of PTV. The rate structure is not adjusted for inflation. That is of relatively little concern over the next several years, but it poses a serious problem for long-term planning.[11]

Another important aspect of incentives concerns the timing of tax credits in the investment life cycle under MAPA and ACES. The 20 percent capital credit in ACES has been criticized for removing the incentive for firms to control costs for capital spending. The effect arises from the combination of the tax credit with the high tax rates on PTV when oil prices are high. With a PTV of $80 per barrel—in the example shown in the box below—and the associated tax rate of 45 percent on PTV, an additional dollar of capital spending reduces the production tax liability by only $0.03, considering the effect of increasing lease costs on lowering the tax rate as well as the tax credit itself. When PTV is close to $90 per barrel, the tax liability could actually fall by more than the investment cost. However, this situation arises because of the high progressive tax rates in ACES, not from the tax credit *per se*.

PROGRESSIVE RATE STRUCTURE OF ACES

When production tax value (PTV) falls between $30 and $92.50 per barrel, a $1 increase in PTV causes the tax rate to rise by 0.4% above the base rate of 25 percent of PTV. For example, consider the case where the wellhead oil price is $100, and capital and operating expenditures are each $20 per barrel. PTV is $60 per barrel, and the ACES tax rate is 25% + 0.4%*(60-30) = 37%. The tax liability is 37%*$60 = $22.50.

Now suppose the oil price rises to $101 and costs do not change. PTV is now $61 per barrel, and the tax rate is 25% + 0.4%*(61-30) = 37.4%. The tax liability rises from $22.50 to 37.4%*$61 = $22.81. The $1 increase in PTV caused taxes to increase by $0.31 per barrel.

If the company reduces expenditures by $1 per barrel, the effect is the same as if the oil price rises by $1 per barrel. However, if the $1 cost savings represents a $1 reduction in capital expenditures eligible for a 20 percent tax credit, then the $1 reduction in capital expenditures would increase taxes due by $0.20 more, or $0.51 per barrel.

As PTV per barrel increases toward the $92.50 upper threshold, the effect of the progressive rate structure on the ACES tax liability increases. At a PTV of $80 per barrel, for example, the tax rate is 25% + .4%*(80-30) = 45%, and the tax liability is 45%*$80 = $36.00. A $1 increase in PTV per barrel dollar to $81, taxed at the new tax rate of 45.4% incurs a tax liability of $36.77. If the increase in PTV comes from a reduction of $1 per barrel in capital expenditures, there would be another $0.20 savings. The firm would pay $0.97 in additional taxes if it spent $1 less on capital costs, hardly an incentive to keep costs down.

The tax base—PTV—is a measure of cash flow from North Slope operations. The tax liability for a firm in any given year arises from a combination of investment projects at different stages of their life cycle. Decisions to proceed with an investment project are based on that particular project's contribution to overall profits. As viewed from a project basis, expenditures for exploration and development take place first. Production, if the

[11] Companies considering investment decisions to develop new fields need to consider a 20-30 year time horizon. If inflation averages a modest 2.5 percent per year and oil prices and lease costs just increase with inflation from average fiscal year 2013-2015 amounts per barrel, PTV in 30 years would be $90 per barrel, with the associated 49 percent tax rate under ACES.

investment is successful, arrives later—typically a number of years later. A dollar of credits for exploration or development expenditures contributes more to the project's expected profits from a given investment than a dollar of credits for production. During the time between the capital spending and the return from additional production, the firm could have invested the money elsewhere. The cost of a year's delay in receiving the return is essentially the firm's cost of capital.

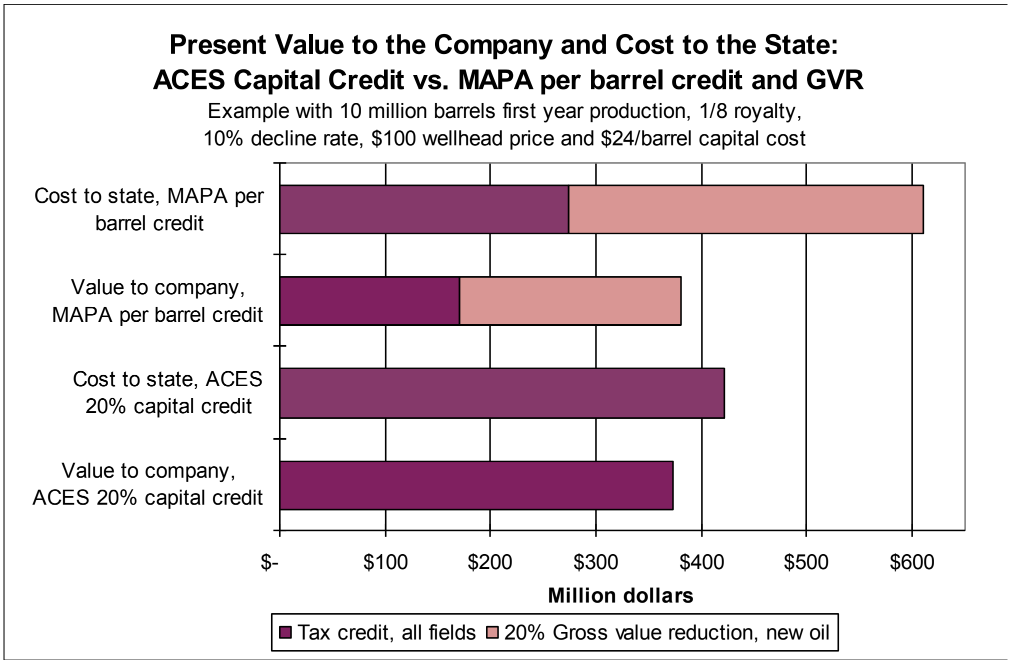
The timing of giving the tax credit out also matters to the state, but the state's opportunities, and therefore the state's relevant cost of capital, are generally much less than industry's. The cost of capital for an oil company would be based on pre-tax returns available from other potential investments in oil development, both in Alaska and elsewhere. The firm's investment portfolio will generally have high expected returns and relatively high risk. The state has a different set of options. Changes in Alaska's budget surplus or deficit would involve deposits or withdrawals from the Constitutional Budget Reserve and other state savings accounts. The portfolios of these accounts are mainly investment grade securities, which carry much lower risk and lower returns than oil company pre-tax investment portfolios.

Because the cost of capital for industry is high, delaying tax credits from the time when exploration and development investments are made (ACES) to the time when production occurs (MAPA) reduces the value of the credit for stimulating new investment relative to the loss of revenue. Giving the credit now instead of later is better for the state, because oil revenues will likely be lower in the future than they are today. This does not mean that MAPA provides less overall incentives than ACES for new production. Rather, it means that the incentives MAPA does provide—through the per-barrel allowance and for new fields, the gross value reduction—are *inefficient*. Assuming the laws generate the same investments, a greater loss of revenue is required under MAPA to get the same benefit for new production. The per barrel credit in MAPA in essence gives companies a tax break for investments that they already made—in some cases many years ago.

Figure 10 provides an example that illustrates the magnitude of the effects of changing the incentive for new production from a tax credit on capital expenditures to a per-barrel tax credit. In this example, the company considers spending $24 per barrel of reserves to develop a field with 100 million barrels of reserves ($2.4 billion total capital spending). Production starts in year 5, with 10 percent of capital spending in year 1 and the remaining 90 percent spread evenly in years 3, 4, and 5. The wellhead price is assumed to be $100 per barrel, and operating costs are assumed to be $20 per barrel. The cost of capital to the industry is assumed to be 10 percent, and the cost of funds to the state is assumed to be 5 percent. All figures represent real inflation-adjusted numbers.

The figure shows that the value to industry of the ACES capital credit is somewhat lower than the cost to the state, because much of it is delayed several years and therefore discounted by a higher cost of capital. The nominal credit is $480 million, but the discounting causes it to have a present worth of $374 million to industry and $421 to the state. The per-barrel allowance is nominally worth $500 million (at $100 wellhead the per-barrel allowance is $5 per barrel for both legacy and GVR fields), but the delay in receiving it until production occurs causes it to be worth much less to the oil company today, as it contemplates making the investment in the field. The 20 percent gross value reduction likewise is spread out over the course of oil production, some of which is delayed until many years in the future. Because of the delay, the value to the company of both the per-barrel allowance and the 20 percent GVR adds to about the same as the 20 percent capital credit under ACES. However, from the state's perspective, the present value of the loss of revenue is about $200 million greater—almost 50 percent more—with the two MAPA credits combined than from the ACES credit. Changing the incentive for investment from a tax credit on investment to a tax credit on production swaps an efficient incentive in terms of “bang for the buck” for an inefficient incentive.

Figure 10.



The numbers generated in the example in Figure 10 are just illustrative of the general issue of timing of the investment incentives. Because small independent firms are likely to have fewer investment options and less ability to diversify risk, they will likely benefit more from the investment incentives offered under ACES than would large integrated producers. Of course, development has to be profitable before any production taxes are due under either ACES or MAPA. The reduction in MAPA of the ability of firms to monetize tax losses also affects small independent firms and new entrants to Alaska in general relative to the established producers.

Conclusions

MAPA as production tax legislation suffers from a number of significant drawbacks compared to its predecessors. The reduced progressivity of the effective tax rates increases the riskiness of industry investments on Alaska’s North Slope for any given after-tax expected return. The per-barrel credit in MAPA, despite its appearance as an incentive for increasing production, offers a very inefficient incentive for investment that would produce that new production. Effective tax rates for new (GVR) oil are quite low, meaning that the state take as a percentage of wellhead value is likely to decline over time, possibly to historic low levels. The creation of radically different tax rates for different oil fields offers a large incentive for industry to seek the most favorable treatment available, increasing administrative challenges and opportunities for conflict.

ACES has many fewer problems. However, the one major problem that it does have—high effective tax rates—could significantly hamper new investment. ACES has a very efficient incentive for new investment in the form of the 20 percent credit for capital expenditures. But when the credit is combined with ACES' high effective tax rates, incentives to control costs (and therefore maintain tax collections) are impaired.

Progressive tax rates under the original PPT were significantly lower than under MAPA. The PPT had neither the high marginal rates of ACES or MAPA's administrative complexity and inefficient incentives. Alaskans now must choose between keeping a flawed tax or reverting to a tax with different but considerable flaws. It is unfortunate that the original PPT is not an option on the ballot, as it arguably represents a better fit for Alaska's production tax regime than either of the two current choices.