ALASKA PETROLEUM PROFITS TAX
A PRIMER – 2007 (REVISED & UPDATED)

INTRODUCTION

Alaska receives oil and gas revenue from four sources: royalties, oil and gas production tax, corporate income tax and property tax. Historically, royalties have provided the most state revenues with production taxes coming in second.

A production tax (also known as a severance tax) is a tax levied when natural resources are severed from the soil or water of a state. The revenues are intended to compensate a state and its citizens for depletion of their natural resource wealth.

Until 2006, Alaska's production tax was a tax on the gross value of oil or gas at the point of production.[1] The Economic Limit Factor (ELF) adjusted the tax rate for the productivity and size of each field. The ELF formula was intended to provide low tax rates for small, less productive fields and higher rates for large, highly productive fields. The ELF tax system was considered "broken" because, based on the formula, more than half of all fields in Alaska paid no severance tax, including some very large fields.

In the 2006 legislative session, the Murkowski administration introduced Petroleum Profits Tax (PPT) legislation to change the oil and gas tax to one based on net profits.[2] The administration proposed a 20% tax on a producer's net profit value of produced oil and gas. In addition to deducting operating, development and exploration expenses and capital expenditures, tax credits in the amount of 20% of qualified capital expenditures could also be applied against the tax due.[3] The proposal also allowed a deduction for investments made in the five years before the new tax would take affect. Finally, a yearly standard deduction of $73 million was allowed.

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[1] A gross tax is a tax on the gross value of oil and gas at the point it is measured; in Alaska, the gross value is determined by subtracting transportation costs from the destination sales price (transportation costs include pipeline tariffs). With a net tax, the net income value of oil and gas is determined by subtracting from the gross value the costs of exploring for, developing and producing the resource.

[2] The PPT has its beginnings in the negotiations for a gas pipeline contract under the Stranded Gas Development Act between the Murkowski administration and BP, ConocoPhillips, ExxonMobil. In August 2005, the administration agreed to fiscal certainty for oil taxes under the contract if the oil and gas production tax was revised.

[3] In 2005, the administration's consultant, Pedro van Meurs, initially proposed a 20% tax rate with a 15% tax credit. The producers made a counter-proposal with a 12.5% tax rate and credits ranging from 15% to 25%. The administration countered with a 20% tax rate, a 15% tax credit and a 35% tax credit on the gas treatment plant. In February 2006, van Meurs made a presentation to the Legislative Budget and Audit committee where he supported a 25% tax rate with a 20% credit. Later that month, the producers, the governor and the gas cabinet agreed to a net profits production tax with a 20% tax rate and a 20% investment tax credit. The administration presented the PPT legislation to the legislature with the 20/20 proposal.

The Murkowski administration's proposal was debated through the 2006 regular session and two special sessions. The primary debate was over the tax rate and tax credit rate. However, there was also considerable discussion over whether the tax should be one based on the gross value or net profits; and whether there should be a progressive feature to the tax. In the end, a net profits tax was passed with a 22.5% tax rate and a 20% tax credit, as well as an additional progressive surtax of up to 25%.[4] An explanation of the major features of the final bill follows.

PETROLEUM PROFITS TAX (PPT) – ENACTED BY SCS CSHB 3001 (NGD)[5]

The new production tax is based on the net profit value of produced oil and gas at the point of production. The same system and rates apply to both oil and gas (oil and gas were treated separately under the former law). Different calculation systems are applied separately to gas and oil produced from the Cook Inlet sedimentary basin to lessen the tax burden for the region.[6] For North Slope production and areas outside the Cook Inlet region, the taxable amount is determined as follows:

Step 1: Determine the "gross value at the point of production."

Step 2: Determine the taxable net value by subtracting the deductible lease expenditures from the gross value at the point of production.[7]

Step 3: The taxpayer owes 22.5% of the taxable net value as calculated above (plus a surtax not to exceed an additional 25% for a possible total tax rate of 47.5%).

Step 4: Apply 20% of the qualified capital expenditures as credits against the tax due.

Step 5: Apply 20% of a carried-forward prior year loss as a credit against the tax due.[8]

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[4] Progressive taxation is where the tax rate goes up or down as oil and gas prices go. The Murkowski administration's original proposal was not progressive because the rate did not change. The progressive surtax in the final PPT is triggered when the price of oil is $40 net profit per barrel (estimated to occur when West Coast prices exceed $55 per barrel). The surtax rate is .25 percent of the net value per dollar in excess of $40. A tax cap of 25% was added so that, when added to the PPT base tax rate of 22.5%, the surtax rate cannot exceed 47.5%. See AS 43.55.011(f).

[5] NGD stands for the Special Committee on Natural Gas Development. The senate created the special committee to hear gas line contract issues, including oil and gas taxation. The committee was comprised of Senate Finance and Senate Resources committee members.

[6] Most Cook Inlet gas fields were discovered more than 30 years ago and have been in production for over 20 years. During legislative discussions on the PPT, it was generally accepted that the area should be protected from tax increases given the different economics from North Slope gas fields. Provisions dealing with Cook Inlet occur throughout the legislation.

[7] Note that capital expenditures that are less than the product of $0.30 multiplied by each barrel produced are not deductible or creditable. See AS 43.55.165(e)(18).

Step 6: For qualified producers, apply a tax credit against the tax due for 20% of "transitional investment expenditures" made after March 31, 2001 and before April 1, 2006.

Step 7: For qualified producers, apply from $6,000,000 to $12,000,000 in tax credits against the tax due.

Determining the Gross Value at the Point of Production (Step 1)

The gross value at the point of production is the value of the oil or gas at its point of production without deduction of any upstream costs.[9] The "point of production" is the point after the wellhead where the oil or gas is accurately measured and in pipeline quality, such as the point where the oil or gas enters the main carrier pipeline (i.e., the Trans Alaska Pipeline System (TAPS) or the gas line). The location matters because whether a producer's costs are incurred "downstream" (after) or "upstream" (before) the point of production affects the production tax amount. As explained in more detail later, lease expenditures are those that occur upstream of the point of production. Consequently, the further downstream the point of production is from the wellhead, the more upstream costs a producer may be able to deduct for purposes of determining the taxable net value, as well as for earning tax credits.

For oil, the point of production is where it is metered before entering the main carrier pipeline. For gas, there are four possible points of production depending on whether or how the gas is processed.[10] Early in the legislative process, a legislative consultant expressed concern that producers could adjust when and how the gas is processed in order to move the point of production upstream or downstream depending on which point benefits their interests.[11] This concern was not resolved in the final legislation.

Another concern regarding the point of production for gas is that costs associated with gas development for the Point Thomson Unit (a large gas deposit) could be deductible and creditable expenditures. Because of this, the cost of gas development could be deducted from and credited against oil taxes (because taxable gas would not yet be produced and oil and gas

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[8] A carried-forward annual loss is a qualified lease expenditure that was not deductible in a previous calendar year because taking the deduction would have reduced the production tax to less than zero.

[9] See AS 43.55.900(7).

[10] See AS 43.55.900(27).

[11] Bonnie Robson memo dated March 2, 2006.

tax liability is combined). This will matter if a major oil producer develops the Pt. Thomson unit.[12]

Determining the Taxable Net Value (Step 2)

The amount of production revenue that may be taxed under the PPT is determined by subtracting from the gross value the deductible lease expenditures. Deductible lease expenditures are the "ordinary and necessary costs upstream of the point of production" that are incurred during the calendar year by the producer and are "direct costs of exploring for, developing, or producing oil or gas deposits" in the state.[13] An activity need not be physically located on, near, or within the premises of a lease or property for the cost of the activity to be a deductible lease expenditure.[14]

To determine whether costs are deductible lease expenditures, the department of revenue is directed to consider, among other factors, (1) typical industry practices and standards regarding costs that an operator is allowed to bill a working interest owner (who is not an operator) under "unit operating agreements" or similar operating agreements in effect on or before December 2, 2005; and (2) DNR standards for costs that can be deducted from revenue in calculating net profits under Net Profit Share Leases.

"Unit operating agreements" are developed when different producers own leases in the same area. The producers enter into an agreement for an operator to manage all the leases in the unit. One of the matters dealt with in these agreements is the operation costs the unit operator can bill to the owners. In the context of the PPT, these types of costs shall be considered by the department of revenue when determining what lease expenditures are deductible.[15] In addition, the department can rely on operator billings as lease expenditures if at least one owner that is party to the agreement has "substantial incentive and ability to effectively" audit the billings. This means that the industry could police its own deductions rather than the state using its own auditors to ensure deductions are legitimate. Questions were

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[12] Exxon held the majority interest in the Point Thomson unit and was the unit operator. After over 30 years of non-development, the Department of Natural Resources terminated the unit. Litigation is likely, but it is possible independent producers may sometime acquire an interest in the leases.

[13] See AS 43.55.165.

[14] See AS 43.55.165(b)(2).

[15] During his testimony, Jim Eason (legislative consultant) questioned the use of unit operating agreements as a basis for determining deductible lease expenditures because they are private agreements not subject to public review and the terms may not always be in the state's interests.

raised during the legislative process regarding whether allowing the industry to audit itself was in the best interests of the state, but the provision was not changed.

In determining deductible lease expenditures, the department of revenue is also directed to consider costs allowed under the Net Profit Share Lease (NPSL) statutes. Most leases base royalty and production taxes on the gross value. But, under the NPSL program, some leases are based on the net profit. Under a net profit share lease, a lessee recovers development and operating costs for the lease from production revenue before any net profit share payments are due to the state. Costs that a lessee may deduct under a net profit share lease include: lease rentals, labor, contract services, costs of using lessee-owned equipment and facilities, general overhead and administrative expenses and abandonment costs. These are the types of costs that may be considered deductible lease expenditures for the purpose of PPT implementation.

The PPT includes three specific deductible lease expenditures (including overhead costs), and eighteen excluded items.[16] Though these provisions provide some guidance, there is still considerable uncertainty regarding what expenditures will be allowed as deductible lease expenditures. During the legislative process, amendments were offered to narrow the universe of deductions, or at the very least to require that deductible lease expenditures be better defined in law to prevent future disputes and problems with auditing. These amendments did not pass.

Under the excluded costs is a provision that disallows the taking of deductions and credits until a taxpayer's annual capital expenditure exceeds 30 cents for each barrel of oil, or the BTU equivalent of gas, produced during that calendar year.[17] This means that, for example, a taxpayer that produces 300 million barrels of oil, or the BTU equivalent of gas, could not deduct or get credits for $90 million of its qualified capital expenditures; qualified capital expenditures in excess of the $90 million would be deductible and eligible for tax credits.

Determining Applicable Tax Credits (Steps 3-7)

There are a series of applicable credits that reduce the amount of tax owed. First, tax credits are available for 20% of a producer's "qualified capital expenditures."[18] The same expenditures may qualify for both a deduction and a credit. "Qualified capital expenditures" are

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[16] See AS 43.55.165(b) and (e).

[17] See AS 43.55.165(e)(18). See also AS 43.55.900(17) & (18) for the meaning of BTU (British thermal unit) equivalent.

[18] See AS 43.55.023. Also note, there is an option to take a tax credit through an existing program under AS 43.55.025 for certain expenditures. AS 43.55.025 provides for credits up to 40% for qualified exploration expenditures. A taxpayer cannot take both this credit and a PPT tax credit.

generally defined as lease expenditures that are incurred for geological or geophysical exploration; or expenditures that are treated by the IRS as a capitalized expenditure or as an intangible drilling and development cost.[19] Some asset acquisition costs do not qualify for credits. Similar to lease expenditures, qualified capital expenditures are not clearly defined in the final legislation.

Tax credits are also available for 20% of a carried-forward annual loss. Annual losses are lease expenditures that would be deductible except when the deduction would cause the net value of taxable oil and gas produced during a month to be less than zero. The total of these losses in a calendar year are the carry-forward annual loss for the purpose of a credit under this section.

An unused tax credit may be sold to other producers by applying to the department of revenue for a transferable tax credit certificate.[20] A tax credit certificate does not expire and is endlessly transferable. Transferred credits may be used to offset up to 20% of the purchasing taxpayer's tax. The department can investigate or audit transferable tax credits. If an audit shows that a tax credit certificate is in excess of what the taxpayer is entitled to, the taxpayer's tax liability will be increased by that amount and interest will be charged. According to the administration, the purchaser of the tax certificate would still be able to rely on and use the certificate in full.

During legislative hearings, small companies testified that the biggest benefit of transferable credits was to the big producers with higher tax liability. This is because many small producers and explorers will not be producing enough to have a tax against which to apply the credit and they will likely have to sell credits to the major producers at a reduced rate. In response to this concern, the PPT legislation permits the state to offer a cash refund of up to $25,000,000 for credits issued to companies who produce not more than 50,000 barrels of oil per day, or the BTU equivalent for gas, in the preceding calendar year.[21]

The final legislation included credits for "transitional investment expenditures."[22] The Murkowski administration's original proposal allowed a deduction for transitional investment expenditures. The final bill changed the deduction into a credit and conditioned the amount of

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[19] See AS 43.55.023(k).

[20] See AS 43.55.023(d).

[21] See AS 43.55.023(f).

[22] See AS 43.55.023(i).

the credit for the prior expenditures on a percentage of the amount of current investment expenditures. A taxpayer may take a tax credit in the amount of 20% of certain investments made after March 31, 2001 and before April 1, 2006 (transitional investment expenditures). However, they may only take the credit at a rate not to exceed 1/10 of the taxpayer's current year's qualified capital expenditures. In other words, a taxpayer may get a 20% credit for its 2001-2006 qualified expenditures, but may use it only at the rate of 10% of its current qualifying expenditures. For example, assume a taxpayer incurred $10,000,000 in transitional investment expenditures between March 3, 2001 and April 1, 2006, and has qualified capital expenditures in 2007 of $1,000,000. The taxpayer has a total potential creditable amount of transitional investment expenditures of $2,000,000 ($10,000,000 x .20), and is allowed to take a portion of that total amount equal to $100,000 ($1,000,000 x .10) in 2007, leaving a remaining balance of $1,900,000 to be taken as a credit in future years. The option to take these credits expires after 2013 or the sixth calendar year after a producer applies for a credit for the first time if the producer did not have commercial production before April 1, 2006. These credits are not transferable.

The final legislation included another credit of $6,000,000 for production from leases outside Cook Inlet and the North Slope; $12,000,000 for producers of not more than 50,000 barrels for oil or BTU equivalent barrels for gas; and for producers of more than 50,000 and less than 100,000 barrels or BTU equivalent, there is a reduced credit based on a production multiplier.[23] The targeted nature of these credits ensures that they are available for exploration and development in frontier areas and to small producers. The option to take the credits expires in 2016 or the ninth year after a producer first has commercial oil or gas production if the producer did not have production before April 1, 2006. These credits are not transferable.

Additional Notable Provisions

Minimum Tax. A minimum tax can protect state revenues during times of low oil prices. The Murkowski administration's original proposal did not have a minimum tax. The final legislation establishes a minimum tax of not less than 4% of the gross value at the point of production when the average price for Alaska North Slope crude for sale on the West Coast during a calendar year is more than $25 per barrel. The minimum tax steps down to three

[23] See AS 43.55.024.

percent for prices between $20 and $25; two percent between $17.50 and $20; one percent between $15 and $17.50; and zero percent when the average price is $15 or less.[24]

Effective Date. Tax changes frequently take effect retroactively to January 1 of the year in which they are enacted. The Murkowski administration's proposal took effect July 1, 2006. The final legislation split the difference and the changes are effective as of April 1, 2006.

Continuing Issues of Concern

Taxing the Net Value. Most severance or production taxes are levied as a percentage of the gross value of the resource. In the PPT, the Murkowski administration and a majority of the legislature chose to levy the tax on the net value of produced oil and gas – that is, the value after deducting upstream costs from the gross value. Alaska is the first state to have its production tax based on net profits. A net profits tax adds complexity because determinations must be made on what taxpayer expenses can legitimately be deducted from the gross value to get to the net value and also credited against the tax. A net value tax can be difficult to administer, particularly if there are insufficient resources to audit producers' deduction claims.[25] Unless carefully crafted, this type of tax can give taxpayers the opportunity to reduce their tax obligation through "gaming" and the use of loopholes in the law. There remains concern that the new tax law may provide such loopholes because the deductible and creditable expenses are not clearly defined. In addition, there are continuing concerns about some of the expenditures that are deductible and creditable, such as North Slope pipeline corrosion repair costs.

Separate Gas. It might be said that oil and gas do not mix. The two resources are measured differently and have different economics. The Murkowski administration argued that gas must be included because, under the net value system, it would be difficult to determine whether certain capital and lease expenses apply to oil production or to gas production (because they come out of the same well). However, there may be harmful consequences by lumping the two resources together under the same tax system. For example, gas field development could result in large deductions and credits against the tax on produced oil and significantly reduce state revenues.

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[24] See AS 43.55.011(f).

[25] The Palin Transition Team Report for the Department of Revenue states the department does not have the auditors or the funding to hire the auditors and economists necessary to implement the new tax. The report points out that the work of state auditors "can significantly affect the State's revenues…"and that the lack of auditors "is a significant problem and a great deal of attention should be paid to improve this situation."

Status as of May 2007

In April 2007, the department of revenue enacted regulations to implement the new tax law. In January 2007, the department testified to the House Finance committee that they planned to develop a second set of regulations that would include clarifying allowable lease expenditures and use of unit operating agreements. Such regulations have not yet been public noticed.

The first PPT payment was made in April 2007. The department of revenue had anticipated total payments of approximately $950 million. The actual payment was $813 million. Of the $137 million shortfall, the department explained that $66 million came from higher than expected tax payments under the old ELF tax system (this means the state received the funds, just at a different time), and $50 million from higher than expected deductions for operating expenses. The remaining $21 million is still unexplained.

With the indictment of two former legislators and one sitting legislator and the guilty pleas of two VECO executives over bribery for PPT votes, Governor Palin said the department of revenue will review the PPT. She also announced there will a special session in the fall to deal with the issue.