ALASKA PETROLEUM PRODUCTION TAX

A PRIMER

INTRODUCTION

Alaska receives oil and gas revenue from four sources: royalties, oil and gas production tax, corporate income tax and property tax. Royalties provide the most state revenues with production taxes coming in second. [1]

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.

Alaska's current production tax is a tax on the gross value of produced oil or gas at the point of production. The Economic Limit Factor (ELF) is an adjustment to the tax rate that adjusts for the productivity and size of each field. Theoretically, the ELF formula provides low tax rates for small, low productive fields and higher rates for large, highly productive fields. The ELF tax system is referred to as "broken" because, based on the formula, more than half of all fields in Alaska are paying no severance tax, including very large fields.

Through HB 488 and SB 305, the approach taken by the administration is a 20% tax on a producer's net profit value of produced oil and gas (gross value minus expenses). In addition to deducting operating, development and exploration expenses and capital expenditures, credits in the amount of 20% of qualified capital expenditures can also be applied against the tax due. The proposal also allows a deduction for investments made in the five years before the new tax takes affect. Finally, a yearly standard deduction of $73 million is allowed.

Because North Slope oil production is declining, the administration sought to design a tax system that encourages new exploration and development while still bringing in more revenue for the state. During committee hearings, questions have been raised whether the proposed system is the right

[1] In FY 2005, the state received unrestricted oil revenue for each tax as follows ($ Million):

Royalties:	1,419.8
Production Tax:	863.2
Corporate Petroleum Tax:	524.0
Property Tax:	42.5

balance and the right approach for ensuring the state gets the maximum benefit from Alaska's oil and gas resources.

An explanation of the administration's proposal follows this section. The next section provides an overview of issues raised.

THE ADMINISTRATION'S PETROLEUM PRODUCTION TAX (PPT) – HB 488/SB 305

The production tax proposed in the administration's version of HB 488 and SB 305 is based on the net profit value of produced oil and gas at the point of production (as compared to the current gross value system). The same system and rates apply to both oil and gas (oil and gas are treated separately under current law). [2] Unlike the current system which taxes producers on a field by field basis, the proposed tax applies to a producer's combined net profit from all oil and gas production in the state.

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 following from the gross value:
- deductible lease expenditures[3]
- transitional investment expenditures (from the previous five years)
- $73 million as a standard deduction

Step 3: Apply 20% of the qualified capital expenditures as credits against the taxable net value.

Step 4: Apply 20% of a carried-forward prior year loss as a credit against the taxable net value.

Step 5: The producer pays 20% of the taxable net value as calculated above.

---

[2] Section 5, 43.55.011(a):

> There is levied upon the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation. The tax is equal to 20 percent of the net value of the taxable oil and gas as calculated under AS 43.55.160.

[3] Deductible lease expenditures include operating and capital expenses. The lease expenditures must be reduced by any reimbursements that a taxpayer receives from other taxpayers (such as for the use of facilities). See Sec. 21, AS 43.55.160(e) in the Administration's proposal.

Determining the Gross Value at the Point of Production [4]

The "point of production" can be anywhere from the wellhead to where the oil or gas enters the main carrier pipeline (such as TAPS or the gasline). 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, deductible 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 earning credits.

For oil, the point of production is where it is metered before entering the carrier pipeline. For gas, there are four possible points of production depending on whether or how the gas is processed. A legislative consultant has 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.[5]

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

---

[4] Section 31, AS 43.55.900(7):

> "gross value at the point of production" means
> (A) for oil, the value of the oil at the automatic custody transfer meter or device through which the oil enters into the facilities of a carrier pipeline or other transportation carrier in a condition of pipeline quality; in the absence of an automatic custody transfer meter or device, "gross value at the point of production" means the value of the oil at the mechanism or device to measure the quantity of oil that has been approved by the department for that purpose, through which the oil is tendered and accepted in a condition of pipeline quality into the facilities of a carrier pipeline or other transportation carrier or into a field topping plant;
> (B) for gas, other than gas described in (C) of this paragraph, that is (i) not subjected to or recovered by mechanical separation or gas processing, the value of the gas at the first point where the gas is accurately metered; (ii) subjected to or recovered by mechanical separation but not gas processing, the value of the gas at the first point where the gas is accurately metered after completion of mechanical separation; (iii) subjected to or recovered by gas processing, the value of the gas at the first point where the gas is accurately metered after completion of gas processing;
> (C) for gas run through an integrated gas processing and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, the value of the gas at the first point where gas processing is completed or where gas treatment begins, whichever is further upstream.

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

The “gross value at the point of production” is determined through existing statutes and regulations, except that the administration’s proposal allows the commissioner of revenue to allow producers to calculate the gross value using alternative methods. [6] One of these methods involves using royalty settlement agreements.[7] A legislative consultant is concerned that royalty settlement agreements generally have provided a lower value to the state and that allowing their use in the context of the PPT could result in lower revenue to the state.[8]

Determining Net Value [9]

The amount of production revenue that may be taxed under the PPT is determined by subtracting from the gross value the deductible lease expenditures, transitional investment expenditures and a $73 million standard deduction.

Deductible Lease Expenditures

Deductible lease expenditures are the total costs upstream of the point of production of oil and gas that are the “direct, ordinary, and necessary costs” of exploring for, developing, or producing oil or gas in the state. [10]

---

[6] In current law, downstream costs (such as transportation costs) are deductible from the destination sales price in order to arrive at the gross value at the point of production.

[7] The state and producers developed these agreements to settle lengthy litigation over how much royalty is owed the state for different leases. The settlements have been driven by the language contained in the lease agreements at the time the leases were signed.

[8] Jim Eason memo dated March 2, 2006.

[9] Sec. 21, AS 43.55.160(a):

> Except as provided in (f) and (i) of this section, for purposes of AS 43.55.011, the net value of the taxable oil and gas produced during a month is the total of the gross value at the point of production of the oil and gas taxable under AS 43.55.011 and produced by the producer from all leases or properties in the state, less (1) first, the producer's lease expenditures for the month as adjusted under (e) of this section, and (2) second, to the extent allowed under (g) of this section and until the total amount of the producer's transitional investment expenditures has been deducted, an amount equal to 1/72 of the producer's transitional investment expenditures. However, the net value calculated under this subsection may not be less than zero.

[10] Sec. 21, AS 43.44.160(c):

> For purposes of this section, a producer's lease expenditures for a period are the total costs upstream of the point of production of oil and gas that are incurred on or after July 1, 2006, by the producer during the period and that are direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas deposits located within the producer's leases or properties in the state or, in the case of land in which the producer owns no working interest, direct, ordinary, and necessary costs of exploring for oil or gas deposits located within other land in the state. However, lease expenditures do not include the

To determine whether costs are "direct, ordinary, and necessary," the department of revenue is directed to give "substantial weight" to (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 1, 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 the agreement is the operation costs the unit operator can bill to the owners. In the context of the PPT, these types of costs shall be given "substantial weight" by the department of revenue when determining what lease expenditures are deductible. 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" to audit the billings. This means that the state can rely on the industry to verify its own deductions.[11]

Under the current Net Profit Share Lease (NPSL) statutes, a lessee recovers development and operating costs for the lease from production revenue before any net profit share payments are due to the state. In the context of the PPT, the department of revenue is directed to give substantial weight to costs that a lessee may deduct under a net profit share lease. These costs include: lease rentals, labor,

---

> costs incurred to satisfy a work commitment under an exploration license under AS 38.05.132. In determining whether costs are direct, ordinary, and necessary costs of exploring for, developing, or producing an oil or gas deposit located within a lease or property or other land in the state, the department shall give substantial weight to (1) the typical industry practices and standards in the state and in the United States as to costs that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements that were in effect on or before December 1, 2005, and were subject to negotiation with working interest owners, not the operator, with substantial bargaining power; and (2) the standards adopted by the Department of Natural Resources as to the costs, other than interest, that a lessee is allowed to deduct from revenue in calculating net profits under a lease issued under AS 38.05.180(f)(3)(B), (D), or (E). The Department of Revenue may authorize a producer to treat as its lease expenditures under this section the costs paid by the producer that are billed to the producer by an operator in accordance with the terms of a unit operating agreement or similar operating agreement, if the Department of Revenue finds that the pertinent provisions of the operating agreement are substantially consistent with the Department of Revenue's determinations and standards otherwise applicable under this subsection and that at least one working interest owner party to the agreement, other than the operator, has substantial incentive and ability to effectively audit billings under the agreement.

[11] 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 and the terms may not always be in the state's interests.

contract services, costs of using lessee-owned equipment and facilities, general overhead and administrative expenses and abandonment costs.[12]

The proposed PPT includes three specific deductible lease expenditures (including overhead costs), and eleven excluded items.[13] Given the open-ended nature of the possible deductions, some legislators have said that deductible lease expenditures should be better defined in law to prevent future disputes and problems with auditing.

Transitional Investment Expenditures

The deduction for transitional investment expenditures is the so-called "claw-back" provision.[14] For the first six years after the PPT is enacted, for any month where the Alaska North Slope (ANS) spot

---

[12] Abandonment costs are generally considered a cost of doing business and the state usually does not share in the expense. Abandonment costs could exceed $100 million on some leases. If the costs are deductible under the PPT, the state will take on a share of the costs through reduced tax revenue.

[13] Section 21, AS 43.55.160(d):

For purposes of (c) of this section, direct costs

(1) include

(A) outlays for capital assets;
(B) payments in lieu of property taxes;
(C) a reasonable allowance, as determined under regulations adopted by the department, for overhead expenses directly related to exploring for, developing, and producing oil or gas deposits located within leases or properties or other land in the state;

(2) do not include

(A) depreciation or amortization of capital assets;
(B) royalty payments;
(C) taxes based on or measured by net income;
(D) interest or other financing charges or costs of raising equity or debt capital;
(E) acquisition costs for a lease or property or exploration license;
(F) costs arising from fraud, willful misconduct, or negligence;
(G) fines or penalties imposed by law;
(H) costs of arbitration, litigation, or other dispute resolution activities that involve the state or concern the rights or obligations among owners of interests in, or rights to production from, one or more leases or properties or a unit;
(I) donations;
(J) costs incurred in organizing a partnership, joint venture, or other business entity or arrangement;
(K) amounts paid for purposes of indemnification.

[14] Sec. 21,AS 43.55.160(a):

Except as provided in (f) and (i) of this section, for purposes of AS 43.55.011, the net value of the taxable oil and gas produced during a month is the total of the gross value at the point of production of the oil and gas taxable under AS 43.55.011 and produced by the producer from all leases or properties in the state, less … to the extent allowed under (g) of this section and until the total amount of the producer's transitional investment expenditures has been deducted, an amount equal to 1/72 of the producer's transitional investment expenditures. However, the net value calculated under this subsection may not be less than zero.

price is above $40 a barrel, a producer may deduct from the net value a pro rata amount (1/72) of capital costs incurred in the five years before the new tax system takes effect. Deductible expenditures are qualified capital expenditures as defined by the PPT and incurred between July 1, 2001 and July 1, 2006, less payments or credits received for the sale or transfer of assets. [15] Deduction of a transitional investment expenditure that would cause the net value to be less than zero can be deducted in a later month during the calendar year, but cannot be carried forward to a future year.[16]

<u>$73 Million Standard Deduction</u>

Each producer is granted a standard deduction up to $73 million a year.[17] This means that, after calculating the net value, up to $73 million can be deducted to reduce any tax owed (the tax can be reduced to zero, but not any lower). An unused deduction may not be carried forward or used to establish a carried-forward annual loss. In order to benefit from the $73 million, a producer must

---

[15] Sec. 21, AS 43.55.160(g):

> For the purposes of this section, a producer's transitional investment expenditures are (1) the sum of the expenditures the producer incurred on or after July 1, 2001, and before July 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024(h), if they were incurred on or after July 1, 2006, less (2) the sum of the payments or credits the producer received before July 1, 2006, for the sale or other transfer of assets, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of expenditures the producer incurred on or after July 1, 2001, and before July 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024(h), if they were incurred on or after July 1, 2006. An amount of transitional investment expenditures may not be deducted under (a) of this section for a month for which the average price of Alaska North Slope oil delivered on the United States West Coast, as determined under (h) of this section, is equal to or less than $40 per barrel, as adjusted for inflation under (h) of this section.

[16] Sec. 21, AS 43.55.160(b):

> … An amount of transitional investment expenditures that would otherwise be deductible in a month but whose deduction would cause the net value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero (1) may be deducted in a later month during any calendar year to the extent allowed under (g) of this section, but no more than 1/72 of a producer's transitional investment expenditures may be deducted in any month; (2) may not be used to establish a carried-forward annual loss under AS 43.55.024(b).

[17] Sec. 21, AS 43.55.160(i):

> For a month for which the net value of the taxable oil and gas produced during the month calculated under (a) of this section exceeds zero, a producer that is qualified under (j) of this section may reduce the net value by deducting an allowance in an amount calculated such that (1) the net value for the month is not reduced below zero; and (2) the total of the allowances deducted for all months during the calendar year does not exceed $73,000,000. An unused allowance or portion of an allowance under this subsection may not be carried forward to a later calendar year or used to establish a carried-forward annual loss under
> AS 43.55.024(b).

qualify with the department of revenue – this is to prevent producers from forming new entities who could benefit from the deduction.[18]

The deduction is intended to help small companies and encourage them to explore and develop in Alaska because it will allow an exemption equal to $73 million even if the company does not have $73 million in expenses. Concerns have been raised that the benefit to large producers is unwarranted because it is like getting to take a standard deduction and to itemize deductions.

Determining Applicable Credits[19]

Tax credits are available for 20% of a producer's "qualified capital expenditures." Credits may be used only against the production tax under the Act. Deductions and credits can be applied to the same expense. "Qualified capital expenditures" are 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. Some asset acquisition costs do not qualify for credits.[20] Similar to lease expenditures, qualified capital expenditures are not clearly defined in the Act.

---

[18] Sec. 21, AS 43.55.160(j):

> Upon written application by a producer, including any information the department may require, the department shall determine whether the producer qualifies under this subsection for a calendar year. To qualify under this subsection, a producer must demonstrate that its operation in the state or its ownership of an interest in a lease or property in the state as a distinct producer entity would not result in the division among multiple producer entities of any net value of taxable oil and gas, as defined under (a) of this section, that would be reasonably expected to be attributed to a single producer entity if the allowance provision of (i) of this section did not exist.

[19] Sec. 12, AS 43.55.024(a):

> Notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the net value of oil and gas under AS 43.55.160(a), a producer or explorer that incurs a qualified capital expenditure may also elect to take a tax credit in the amount of 20 percent of that expenditure, unless a credit for that expenditure is taken under AS 43.55.025. A credit under this subsection may be applied only against a tax due under AS 43.55.011 - 43.55.160. Only for a calendar year for which the producer makes an election under AS 43.55.160(f), a producer that incurs a qualified capital expenditure during that year and that wishes to apply a credit based on that expenditure against a tax due under AS 43.55.011 - 43.55.160 shall calculate and apply every month an annualized tax credit in an amount equal to one and two-thirds percent of the total qualified capital expenditures incurred during that year and for which the tax credit is taken for that year, instead of taking a tax credit of 20 percent of each separate qualified capital expenditure after it has been incurred.

[20] Sec. 12, AS 43.55.024(h)(2):

> (2) "qualified capital expenditure"
>
> > (A) means, except as otherwise provided under (B) of this paragraph, an expenditure that is a lease expenditure under AS 43.55.160 and is (i) incurred for geological or geophysical exploration; or (ii) treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue

Tax credits are also available for 20% of a carried-forward annual loss.[21] Losses are lease expenditures that would be deductible except that 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.[22]

If use of a credit will reduce the tax liability below zero, the credit can be used in a later month. An unused credit may be sold to other producers by applying to the department of revenue for a transferable tax credit certificate. A credit certificate does not expire. Credit certificates are endlessly transferable. Transferred credits may be used to offset up to 20% of the purchasing producer's tax. The department can investigate or audit transferable tax credits. If a credit is in excess of what an applicant is entitled to, the applicant's tax liability will be increased by that amount and interest will be charged. According to the administration, the purchaser of the certificate would still be able to rely on and use the certificate in full.[23]

Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and either is treated as a capitalized expenditure by the person incurring the expenditure or is eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal Revenue Code), as amended;

(B) does not include an expenditure to acquire an asset (i) the cost of previously acquiring which was a lease expenditure under AS 43.55.160(c) or would have been a lease expenditure under AS 43.55.160(c) if it had been incurred on or after July 1, 2006; or (ii) that has previously been placed in service in the state; an expenditure to acquire an asset is not excluded under this subparagraph if no more than an immaterial portion of the asset meets a description under (i) or (ii) of this subparagraph; for purposes of this subparagraph, "asset" includes geological, geophysical, and well data and interpretations.

[21] Sec. 12, AS 43.55.024(b):

A producer may elect to take a tax credit in the amount of 20 percent of a carried-forward annual loss. A credit under this subsection may be applied only against a tax due under AS 43.55.011 - 43.55.160. For purposes of this subsection, a carried-forward annual loss is the amount of a producer's adjusted lease expenditures under AS 43.55.160 for a previous calendar year that was not deductible in any month under AS 43.55.160(a) and (b).

[22] Sec. 21, AS 43.55.160(b):

Any adjusted lease expenditures that would otherwise be deductible in a month but whose deduction would cause the net value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero may be added to the producer's adjusted lease expenditures for one or more other months in the same calendar year. The total of any adjusted lease expenditures that are not deductible in any month during a calendar year because their deduction would cause the net value calculated under (a) of this section of the taxable oil and gas produced during one or more months to be less than zero may be used to establish a carried-forward annual loss under AS 43.55.024(b)…

[23] Sec. 12, AS 43.55.024(c)-(f):

There is an option to take the existing tax credit under AS 43.55.025 in place of the PPT credit for certain expenditures. AS 43.55.025 provides for credits up to 40% for qualified exploration expenditures.[24]

During testimony, small companies have said that it appears that the biggest benefit of transferable credits is to the big producers with higher tax liability. That is, many small producers and explorers will not have a tax against which to apply the credit and they will likely get a reduced price when

---

(c) A credit under this section may not be used to reduce a person's tax liability under AS 43.55.011-43.55.160 for any month below zero; any portion of a credit not used for that reason may be applied in a later month.

(d) A person entitled to take a tax credit under this section that wishes to transfer the unused credit to another person may apply to the department for a transferable tax credit certificate. An application under this subsection must be on a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall either grant or deny an application, or grant it as to a lesser amount than that claimed and deny it as to the excess, no later than 60 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) if the applicant is required under AS 43.55.030(a) and 43.55.030(e) to file a statement on or before the March 31 described in (1) of this subsection, the date the statement was filed; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a tax credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

(e) A person to which a transferable tax credit certificate is issued under (d) of this section may transfer the certificate to another person, and a transferee may further transfer the certificate. Subject to the limitations set out in (a) - (c) of this section, and notwithstanding any action the department may take with respect to the applicant under (f) of this section, the owner of a certificate may apply the credit or a portion of the credit shown on the certificate only against a tax due under AS 43.55.011 - 43.55.160. However, credits shown on transferable tax credit certificates may not be applied so as to reduce a producer's total tax due under AS 43.55.011 - 43.55.160 on oil and gas produced during a calendar year to less than 80 percent of the tax that would otherwise be due without applying those credits. Any portion of a credit not used for that reason may be applied in a later period.
(f) The issuance of a transferable tax credit certificate under (d) of this section does not limit the department's ability to later investigate or audit a tax credit claim to which the certificate relates or to adjust or deny the claim if the department determines that the applicant was not entitled to the amount of the credit for which the certificate was issued. The tax liability of the applicant under AS 43.55.011 - 43.55.160 is increased by the amount of the credit that is in excess of that to which the applicant was entitled. That amount bears interest under AS 43.05.225 from the date the transferable tax credit certificate was issued. For purposes of this subsection, an applicant that is an explorer is considered a producer subject to the tax levied under AS 43.55.011.

[24] Sec. 12, AS 43.55.024(a):

Notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the net value of oil and gas under AS 43.55.160(a), a producer or explorer that incurs a qualified capital expenditure may also elect to take a tax credit in the amount of 20 percent of that expenditure, unless a credit for that expenditure is taken under AS 43.55.025…

selling credits to the majors. The small producers would like the credits to be refundable so that they could turn credits in to the state for payment.

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 case of the PPT, a choice was made to levy the tax on the net value of produced oil and gas – that is, the value after deducting upstream costs. This creates complexity because determinations must be made on what expenses made by producers can legitimately be deducted from the gross value to get to the net value. A net value tax can be difficult to administer, particularly if there are insufficient resources to audit producers' deduction claims. Unless carefully crafted, this type of tax can give taxpayers the opportunity to reduce their tax obligation through use of loopholes in the law. Concerns have been expressed that the administration's proposal may provide such loopholes because the deductible and creditable expenses are not clearly defined.

It is possible the main reason for the net value tax, and its application to both oil and gas, is so that the costs of developing the gas fields associated with the gasline can be deducted from the tax on produced oil.

Tax Rate

The administration's consultant, Pedro Van Meurs, originally recommended a 25% tax rate with 20% in credits. The Governor proposed a 20% tax rate, with 20% in credits. In testimony before legislative committees, legislative consultants have consistently supported a 25% tax rate stating that it would not deter long-term investments. The difference between a 20% and 25% rate, at current prices, is approximately $600 – 700 million in state revenue.

Progressivity

Progressive taxation is where the tax rates increase as the tax base increases, or vice versa (tax rates go down as the tax base decreases). Put another way, the tax rate goes up or down as oil and gas prices go. The administration's proposal is not progressive because the rate does not change. Legislative consultants recommend a sliding scale, most starting at 25% with the tax rate increasing when the price of oil and gas reaches a certain point.

Cook Inlet

Cook Inlet is an aging gas field. It is generally accepted that the area should be exempt from any tax increase. Under the administration's proposal, the same tax applies statewide. Legislative consultants have expressed concern that it is very difficult to have one tax structure that applies to all situations.

Effective Date

Tax changes frequently take effect retroactively to January 1 of the year in which they are enacted. The administration's proposal takes effect July 1, 2006. Making the tax retroactive to January could provide the state with approximately $600 – 700 million (at a 25% tax rate).

Minimum Tax

If the price of oil falls to the $20 range, the state could find itself with no production tax revenue or less than what the state would receive under current law. By establishing a "floor" or minimum tax, the state can protect itself from the production tax falling to zero. There is no minimum tax in the administration's proposal.

Legacy Fields

The emphasis in the PPT is to encourage new production and exploration to make up for declining production in the North Slope fields. Because the administration's proposal makes no distinction between smaller, newer fields and the well-established, highly productive "legacy" fields, the lower tax rate and $73 million deduction apply across the board. A legislative consultant recommends that the legacy fields be treated differently with a higher tax rate.

Separate Gas

It might be said that oil and gas do not mix. The two resources are measured differently and have different economics. The administration says gas must be included because under the net value system, it would be impossible to determine which capital and lease expenses apply to oil production and which to gas production (because they come out of the same well). However, there may be unintended consequences by lumping them together under the same tax system.

CONCLUSION

The administration's proposal is being considered by both the House and Senate. Both resource committees have made changes and more are anticipated when the bills are heard in their respective finance committees.