

AMERICAN BAR ASSOCIATION, 2007-2008

11019 HOUSE RULES

1 (Internal Revenue Code); and

2 (4) depreciation shall be computed on the basis of 26 U.S.C. 167
3 (Internal Revenue Code) as that section read on June 30, 1981.

4 * **Sec. 5.** AS 43 55.011 is amended by adding new subsections to read:

5 (e) There is levied on the producer of oil or gas a tax for all oil and gas
6 produced each calendar year from each lease or property in the state, less any oil and
7 gas the ownership or right to which is exempt from taxation or constitutes a
8 landowner's royalty interest. Except as otherwise provided under (j) and (k) of this
9 section, the tax is equal to the annual production tax value of the taxable oil and gas as
10 calculated under AS 43.55.160 multiplied by the tax rate determined under (f) of this
11 section.

12 (f) For the purposes of (e) of this section,

13 (1) the tax rate for a calendar year under (e) of this section is the
14 weighted average of the percentage rate under (2) of this subsection applicable to the
15 producer's base production, if any, for the calendar year and the percentage rate under
16 (3) of this subsection applicable to the producer's incremental production, if any, for
17 the calendar year, with each percentage rate weighted proportionally to the amount of
18 the production to which it applies; however, the tax rate for 2006, 2007, and 2008 may
19 not exceed 22 1/2 percent;

20 (2) the percentage rate for each year applicable to a producer's base
21 production is 25 percent;

22 (3) the percentage rate applicable to a producer's incremental
23 production is

24 (A) for 2006 through and including 2011, 15 percent;

25 (B) for 2012 through and including 2030, one-half percentage
26 point greater than the percentage rate for the immediately preceding year;

27 (C) for 2031 and later years, 25 percent;

28 (4) except as otherwise provided under (6) of this subsection, a
29 producer's base production

30 (A) for a calendar year earlier than 2031 is

31 $.75 \times TP \times (.95)^{\exp(n)}$

1 where: TP = the total amount of taxable and nontaxable oil and gas, in BTU
2 equivalent barrels, produced by the producer from leases or
3 properties in the state during 2005; and

4 n = the number that represents the calendar year subsequent to 2005 for
5 which the tax is being computed, with the number that represents
6 calendar year 2006 being 1, the number that represents calendar year
7 2007 being 2, and so on;

8 (B) for 2031 and later years, is zero;

9 (5) a producer's incremental production for a calendar year is the total
10 amount of taxable and nontaxable oil and gas, in BTU equivalent barrels, produced by
11 the producer from leases or properties in the state during the calendar year, less the
12 producer's base production for the calendar year, but the incremental production may
13 not be less than zero;

14 (6) if a working interest in a lease or property from which oil or gas
15 was produced during 2005 is transferred after 2005, the amount of 2005 oil and gas
16 production attributable to that interest is considered, from the date of the transfer, to
17 have been produced by the producer acquiring the working interest, for the purposes
18 of computing the term TP under (4) of this subsection.

19 (g) In addition to the tax levied under (e) of this section, during each calendar
20 year for which the price index determined under (h) of this section is greater than zero
21 for one or more months, there is levied on the producer of oil or gas a tax for all oil
22 and gas produced during that calendar year from each lease or property in the state,
23 less any oil and gas the ownership or right to which is exempt from taxation or
24 constitutes a landowner's royalty interest. Except as otherwise provided under (j) and
25 (k) of this section, the tax levied under this subsection is equal to the sum, over all
26 months in the calendar year, of the amounts calculated for each month as follows:
27 _____ percent of the monthly production tax value of the taxable oil and gas as
28 calculated under AS 43.55.160, multiplied by the price index determined under (h) of
29 this section. However, the amount calculated under this subsection for any month may
30 not exceed _____ percent of the monthly production tax value of the taxable oil and
31 gas as calculated under AS 43.55.160.

1 (h) For purposes of (g) of this section, the price index for a month is calculated
2 by subtracting _____ from the number that is equal to the quotient of the total monthly
3 production tax value of the taxable oil and gas produced by the producer during that
4 month, as calculated under AS 43.55.160, divided by the total amount of the taxable
5 oil and gas produced by the producer during that month, in BTU equivalent barrels.
6 However, a price index may not be less than zero.

7 (i) There is levied on the producer of oil or gas a tax for all oil and gas
8 produced each calendar year from each lease or property in the state the ownership or
9 right to which constitutes a landowner's royalty interest, except for oil and gas the
10 ownership or right to which is exempt from taxation. The provisions of this subsection
11 apply to a landowner's royalty interest as follows:

12 (1) the tax levied for oil is equal to five percent of the gross value at
13 the point of production of the oil;

14 (2) the tax levied for gas is equal to 1.667 percent of the gross value at
15 the point of production of the gas;

16 (3) if the department determines that, for purposes of reducing the
17 producer's tax liability under (1) or (2) of this subsection, the producer has received or
18 will receive consideration from the royalty owner offsetting all or a part of the
19 producer's royalty obligation, other than a deduction under AS 43.55.020(d) of the
20 amount of a tax paid, then notwithstanding (1) and (2) of this subsection, the tax is
21 equal to 25 percent of the gross value at the point of production of the oil and gas.

22 (j) For a calendar year earlier than 2022, the total tax levied by (e) and (g) of
23 this section on gas produced from a lease or property in the Cook Inlet sedimentary
24 basin may not exceed

25 (1) for a lease or property that first commenced commercial production
26 of gas before April 1, 2006, the product obtained by multiplying (A) the amount of
27 taxable gas produced during the calendar year from the lease or property, times (B) the
28 average rate of tax that was imposed under this chapter on taxable gas produced from
29 the lease or property for the 12-month period ending on March 31, 2006, times (C) the
30 quotient of the total gross value at the point of production of the taxable gas produced
31 from the lease or property during the 12-month period ending March 31, 2006, divided

1 by the total amount of that gas:

2 (2) for a lease or property that first commences commercial production
3 of gas after March 31, 2006, the product obtained by multiplying (A) the amount of
4 taxable gas produced during the calendar year from the lease or property, times (B) the
5 average rate of tax that was imposed under this chapter on taxable gas produced from
6 all leases or properties in the Cook Inlet sedimentary basin for the 12-month period
7 ending on March 31, 2006, times (C) the average prevailing value for gas delivered in
8 the Cook Inlet area for the 12-month period ending March 31, 2006, as determined by
9 the department under AS 43.55.020(f).

10 (k) For a calendar year earlier than 2022, the total tax levied by (e) and (g) of
11 this section on oil produced from a lease or property in the Cook Inlet sedimentary
12 basin may not exceed

13 (1) for a lease or property that first commenced commercial production
14 of oil before April 1, 2006, the product obtained by multiplying (A) the amount of
15 taxable oil produced during the calendar year from the lease or property, times (B) the
16 average rate of tax that was imposed under this chapter on taxable oil produced from
17 the lease or property for the 12-month period ending on March 31, 2006, times (C) the
18 quotient of the total gross value at the point of production of the taxable oil produced
19 from the lease or property during the 12-month period ending March 31, 2006, divided
20 by the total amount of that oil;

21 (2) for a lease or property that first commences commercial production
22 of oil after March 31, 2006, the product obtained by multiplying (A) the amount of
23 taxable oil produced during the calendar year from the lease or property, times (B) the
24 average rate of tax that was imposed under this chapter on taxable oil produced from
25 all leases or properties in the Cook Inlet sedimentary basin for the 12-month period
26 ending on March 31, 2006, times (C) the average prevailing value for oil delivered in
27 the Cook Inlet area for the 12-month period ending March 31, 2006, as determined by
28 the department under AS 43.55.020(f).

29 (l) When a limitation under (j) or (k) of this section on the tax levied by (e)
30 and (g) of this section has the effect of reducing the producer's tax on gas or oil
31 produced from a lease or property below the amount of tax that would be levied in the

1 absence of that limitation, the amount of the reduction is applied first against the tax
2 levied by (g) of this section, but that tax may not be reduced below zero.

3 (m) Notwithstanding any contrary provision of AS 38.05.180(i),
4 AS 41.09.010, AS 43.20.043, or 43.55.025, tax credits under AS 38.05.180(i),
5 AS 41.09.010, AS 43.20.043, and 43.55.025 that are allocated to gas produced from
6 leases or properties in the Cook Inlet sedimentary basin and that are available to be
7 applied against a tax levied by (e) of this section on gas produced from leases or
8 properties in the Cook Inlet sedimentary basin during a calendar year may be applied
9 only against the tax levied by (e) of this section on that gas. The amount by which the
10 amount of tax credits that are allocated to gas produced from leases or properties in the
11 Cook Inlet sedimentary basin and that the producer would otherwise be allowed to use
12 for a later calendar year or transfer to another person exceeds the amount of tax credits
13 whose application would reduce the tax levied by (e) of this section on that gas to
14 zero, if any, is considered the amount of excess tax credits and the excess tax credits
15 are subject to the following:

16 (1) for each lease or property for which a limitation under (j) or (k) of
17 this section on the tax levied by (e) and (g) of this section has the effect of reducing
18 the producer's tax below the amount of tax that would be levied in the absence of that
19 limitation, the producer shall calculate the amount of that reduction;

20 (2) the producer shall calculate the total of the reductions calculated
21 under (1) of this subsection for all affected leases or properties;

22 (3) the producer shall reduce the amount of excess tax credits by the
23 total calculated under (2) of this subsection, but not to less than zero;

24 (4) any amount of excess tax credits remaining after reduction under
25 (3) of this subsection may be used for a later calendar year, transferred to another
26 person, or applied against a tax levied on oil or gas produced from a lease or property
27 located anywhere in the state to the extent otherwise allowed under applicable law
28 governing the tax credits.

29 (n) Allocation of credits under (m) of this section shall be made under
30 regulations adopted by the department that provide for reasonable methods of
31 allocating tax credits to gas produced from leases or properties in the Cook Inlet

1 sedimentary basin.

2 (o) The department shall by regulation establish sampling, testing, and
3 averaging methods for determining the heating value of a producer's gas. In the
4 absence of sufficient sampling and testing of gas produced during 2005 or 2006, the
5 department may provide for the heating value of the gas to be estimated based on
6 sampling and testing of later-produced gas or on other information.

7 * Sec. 6. AS 43.55.017(a) is amended to read:

8 (a) Except as provided in this chapter, the taxes imposed by this chapter are in
9 place of all taxes now imposed by the state or any of its municipalities, and neither the
10 state nor a municipality may impose a tax on [UPON]

11 (1) producing oil or gas leases;

12 (2) oil or gas produced or extracted in the state;

13 (3) the value of intangible drilling and development costs, as
14 described in 26 U.S.C. 263(c) (Internal Revenue Code), as amended through
15 January 1, 1974 [EXPLORATION EXPENSES].

16 * Sec. 7. AS 43.55.020(a) is repealed and reenacted to read:

17 (a) The tax levied on a producer for a calendar year by AS 43.55.011(e), (g),
18 and (i) must be paid as follows:

19 (1) an installment payment of the estimated tax levied by
20 AS 43.55.011(e) and (g), net of any tax credits applied as allowed by law, is due for
21 each month of the calendar year on the last day of the following month: the amount of
22 the installment payment is the sum of the amounts calculated under (2) and (3) of this
23 subsection, but not less than zero;

24 (2) the first of the two amounts used to calculate the installment
25 payment for a month under (1) of this subsection is equal to the remainder obtained by
26 subtracting

27 (A) 1/12 of the tax credits that are allowed by law to be applied
28 against the tax levied by AS 43.55.011(e) for the calendar year, from

29 (B) the total of the monthly production values calculated under
30 AS 43.55.160(a)(2) of all oil and gas taxable under AS 43.55.011(e) and
31 produced by the producer from leases or properties in the state during the

1 month, multiplied by the tax rate determined under AS 43.5.011(f) for the
2 calendar year assuming that the producer's incremental production for the
3 calendar year is the amount calculated according to the following formula but
4 not less than zero:

$$5 \quad IP = 12 \times (MP - 1/12 \times BP)$$

6 where: IP = the producer's assumed incremental production for the calendar
7 year;

8 MP = the total amount of taxable and nontaxable oil and gas, in BTU
9 equivalent barrels, produced by the producer from leases or
10 properties in the state during the month; and

11 BP = the producer's base production for the calendar year:

12 (3) the second of the two amounts used to calculate the installment
13 payment for a month under (1) of this subsection is the amount calculated for the
14 month under AS 43.55.011(g);

15 (4) an installment payment of the estimated tax levied by
16 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
17 on the last day of the following month; the amount of the installment payment is the
18 sum of

19 (A) the applicable percentage rate for oil provided under
20 AS 43.55.011(i) multiplied times the gross value at the point of production of
21 the oil taxable under AS 43.55.011(i) and produced from the lease or property
22 during the month; plus

23 (B) the applicable percentage rate for gas provided under
24 AS 43.55.011(i) multiplied times the gross value at the point of production of
25 the gas taxable under AS 43.55.011(i) and produced from the lease or property
26 during the month;

27 (5) any amount of tax levied by AS 43.55.011(e), (g), and (i), net of
28 any credits applied as allowed by law, that exceeds the total of the amounts due as
29 installment payments of estimated tax is due on March 31 of the year following the
30 calendar year of production.

31 * Sec. 8. AS 43.55.020(b) is amended to read:

1 (b) The production tax on oil and [OR] gas shall be paid to the department
2 by or on behalf of the producer.

3 * Sec. 9. AS 43.55.020(d) is amended to read:

4 (d) In making settlement with the royalty owner for oil and gas that is
5 taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on
6 taxable royalty oil and [OR] gas, or may deduct taxable royalty oil or gas equivalent
7 in value at the time the tax becomes due to the amount of the tax paid. If the total
8 deductions of installment payments of estimated tax for a calendar year exceed
9 the actual tax for that calendar year, the producer shall, no later than March 31
10 of the following year, refund the excess to the royalty owner. Unless otherwise
11 agreed between the producer and the royalty owner, the amount of the tax paid
12 under AS 43.55.011(e) and (g) on taxable royalty oil and gas for a calendar year,
13 other than oil and gas the ownership or right to which constitutes a landowner's
14 royalty interest, is considered to be the gross value at the point of production of
15 the taxable royalty oil and gas produced during the calendar year multiplied by a
16 figure that is a quotient, in which

17 (1) the numerator is the producer's total tax liability under
18 AS 43.55.011(e) and (g) for the calendar year of production; and

19 (2) the denominator is the total gross value at the point of
20 production of the oil and gas taxable under AS 43.55.011(e) and (g) produced by
21 the producer from all leases and properties in the state during the calendar year.

22 * Sec. 10. AS 43.55.020(e) is repealed and reenacted to read:

23 (e) Gas flared, released, or allowed to escape in excess of the amount
24 authorized by the Alaska Oil and Gas Conservation Commission is considered, for the
25 purpose of AS 43.55.011 - 43.55.180, as gas produced from a lease or property. Oil or
26 gas used in the operation of a lease or property in the state in drilling for or producing
27 oil or gas, or for repressuring, except to the extent determined by the Alaska Oil and
28 Gas Conservation Commission to be waste, is not considered, for the purpose of
29 AS 43.55.011 - 43.55.180, as oil or gas produced from a lease or property.

30 * Sec. 11. AS 43.55.020(f) is amended to read:

31 (f) If oil or gas is produced but not sold, or if oil or gas is produced and

1 sold under circumstances where the sale price does not represent the prevailing value
2 for oil or gas of like kind, character, or quality in the field or area from which the
3 product is produced, the department may require the tax to be paid upon the basis of
4 the value of oil or gas of the same kind, quality, and character prevailing for that field
5 or area during the calendar month of production or sale [FOR THAT FIELD OR
6 AREA].

7 * **Sec. 12.** AS 43.55.020 is amended by adding new subsections to read:

8 (g) Notwithstanding any contrary provision of AS 43.05.225, an unpaid
9 amount of an installment payment required under (a)(1) – (4) of this section that is not
10 paid when due bears interest (1) at the rate provided for an underpayment under
11 26 U.S.C. 6621 (Internal Revenue Code), as amended, compounded daily, from the
12 date the installment payment is due until the March 31 described in AS 43.55.030(a),
13 and (2) as provided for a delinquent tax under AS 43.05.225 after that March 31.
14 Interest accrued under (1) of this subsection that remains unpaid after that March 31 is
15 treated as an addition to tax that bears interest under (2) of this subsection. An unpaid
16 amount of tax due under (a)(5) of this section that is not paid when due bears interest
17 as provided for a delinquent tax under AS 43.05.225.

18 (h) Notwithstanding any contrary provision of AS 43.05.280,

19 (1) an overpayment of an installment payment required under (a)(1) –
20 (4) of this section bears interest at the rate provided for an overpayment under
21 26 U.S.C. 6621 (Internal Revenue Code), as amended, compounded daily, from the
22 later of the date the installment payment is due or the date the overpayment is made,
23 until the earlier of (A) the date it is refunded or is applied to an underpayment, or (B)
24 the March 31 described in AS 43.55.030(a);

25 (2) except as provided under (1) of this subsection, interest with
26 respect to an overpayment is allowed only on any net overpayment of the payments
27 required under (a) of this section that remains after the later of the March 31 described
28 in AS 43.55.030(a) or the date that the statement required under AS 43.55.030(a) is
29 filed;

30 (3) interest is allowed under (2) of this subsection only from a date that
31 is 90 days after the later of the March 31 described in AS 43.55.030(a) or the date that

1 the statement required under AS 43.55.030(a) is filed; interest is not allowed if the
2 overpayment was refunded within the 90-day period:

3 (4) interest under (2) and (3) of this subsection is paid at the rate and in
4 the manner provided in AS 43.05.225(1).

5 * Sec. 13. AS 43.55 is amended by adding new sections to read:

6 **Sec. 43.55.023. Tax credits for certain losses and expenditures.** (a) A
7 producer or explorer may take a tax credit for a qualified capital expenditure as
8 follows:

9 (1) notwithstanding that a qualified capital expenditure may be a
10 deductible lease expenditure for purposes of calculating a production tax value of oil
11 or gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
12 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or
13 explorer that incurs a qualified capital expenditure may also elect to take a tax credit
14 against a tax due under AS 43.55.011(e) in the amount of 20 percent of that
15 expenditure:

16 (2) a producer or explorer may take a credit for a qualified capital
17 expenditure incurred in connection with geological or geophysical exploration or in
18 connection with an exploration well only if the producer or explorer provide to the
19 department, as part of the statement required under AS 43.55.030(a) for the calendar
20 year for which the credit is sought to be taken, the producer's or explorer's written
21 agreement

22 (A) to notify the Department of Natural Resources, within 30
23 days after completion of the geological or geophysical data processing or
24 completion of the well, or within 30 days after the statement is filed, whichever
25 is the latest, of the date of completion and to submit a report to that department
26 describing the processing sequence and provide a list of data sets available:

27 (B) to provide to the Department of Natural Resources, within
28 30 days after the date of a request, specific data sets, ancillary data, and reports
29 identified in (A) of this paragraph:

30 (C) that, notwithstanding any provision of AS 38, the
31 Department of Natural Resources shall hold confidential the information

1 provided to that department under this paragraph for 10 years following the
2 completion date, after which the department shall publicly release the
3 information after 30 days' public notice.

4 (b) A producer or explorer may elect to take a tax credit in the amount of 20
5 percent of a carried-forward annual loss. A credit under this subsection may be
6 applied against a tax due under AS 43.55.011(e). For purposes of this subsection, a
7 carried-forward annual loss is the amount of a producer's or explorer's adjusted lease
8 expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was
9 not deductible for that calendar year under AS 43.55.160(b) and (e).

10 (c) A credit or portion of a credit under this section may not be used to reduce
11 a person's tax liability under AS 43.55.011(e) for any calendar year below zero, and
12 any unused credit or portion of a credit not used under this subsection may be applied
13 in a later calendar year.

14 (d) Except as limited by (i) of this section, a person entitled to take a tax credit
15 under this section that wishes to transfer the unused credit to another person may
16 apply to the department for a transferable tax credit certificate. An application under
17 this subsection must be in a form prescribed by the department and must include
18 supporting information and documentation that the department reasonably requires.
19 The department shall grant or deny an application, or grant an application as to a lesser
20 amount than that claimed and deny it as to the excess, not later than 60 days after the
21 latest of (1) March 31 of the year following the calendar year in which the qualified
22 capital expenditure or carried-forward annual loss for which the credit is claimed was
23 incurred; (2) if the applicant is required under AS 43.55.030(a) to file a statement on
24 or before March 31 of the year following the calendar year in which the qualified
25 capital expenditures or carried-forward annual loss for which the credit is claimed was
26 incurred, the date the statement was filed; or (3) the date the application was received
27 by the department. If, based on the information then available to it, the department is
28 reasonably satisfied that the applicant is entitled to a credit, the department shall issue
29 the applicant a transferable tax credit certificate for the amount of the credit. A
30 certificate issued under this subsection does not expire.

31 (e) A person to which a transferable tax credit certificate is issued under (d) of

1 this section may transfer the certificate to another person, and a transferee may further
2 transfer the certificate. Subject to the limitations set out in (a) - (c) of this section, and
3 notwithstanding any action the department may take with respect to the applicant
4 under (g) of this section, the owner of a certificate may apply the credit or a portion of
5 the credit shown on the certificate only against a tax due under AS 43.55.011(e).
6 However, a credit shown on a transferable tax credit certificate may not be applied to
7 reduce a transferee's total tax due under AS 43.55.011(e) on oil and gas produced
8 during a calendar year to less than 80 percent of the tax that would otherwise be due
9 without applying that credit. Any portion of a credit not used under this subsection
10 may be applied in a later period.

11 (f) Under standards established in regulations adopted by the department and
12 subject to appropriations made by law, the department, on the written application of
13 the person to whom a transferable tax credit has been issued under (d) of this section
14 and whose average amount of oil and gas produced a day taxable under
15 AS 43.55.011(e) is not more than 50,000 BTU equivalent barrels a day for the
16 preceding calendar year, shall issue a cash refund, in whole or in part, for the
17 certificate if the department finds

18 (1) within 24 months after having applied for the transferable tax credit
19 certificate, that the applicant incurred a qualified capital expenditure or was the
20 successful bidder on a bid submitted for a lease on state land under AS 38.05.180(f);

21 (2) that the amount of the refund would not exceed the total of
22 qualified capital expenditures and successful bids described in (1) of this subsection
23 that have not been the subject of a finding made under this paragraph for purposes of a
24 previous refund;

25 (3) that the applicant does not have an outstanding liability to the state
26 for unpaid delinquent taxes under this title; and

27 (4) that the sum of the amount of the refund applied for and amounts
28 previously refunded to the applicant during the calendar year under this subsection
29 would not exceed \$25,000,000.

30 (g) The issuance of a transferable tax credit certificate under (d) of this section
31 or the issuance of a cash refund for a certificate under (f) of this section does not limit

1 the department's ability to later audit a tax credit claim to which the certificate relates
2 or to adjust the claim if the department determines as a result of the audit that the
3 applicant was not entitled to the amount of the credit for which the certificate was
4 issued. The tax liability of the applicant under AS 43.55.011(e) and 43.55.017 -
5 43.55.180 is increased by the amount of the credit that exceeds that to which the
6 applicant was entitled, or the applicant's available valid outstanding credits applicable
7 against the tax levied by AS 43.55.011(e) are reduced by that amount. If the
8 applicant's tax liability is increased under this subsection, the increase bears interest
9 under AS 43.05.225 from the date the transferable tax credit certificate was issued. For
10 purposes of this subsection, an applicant that is an explorer is considered a producer
11 subject to the tax levied by AS 43.55.011(e).

12 (h) Regulations adopted to implement this section shall include provisions
13 prescribing reporting, record keeping, and certification procedures and requirements to
14 verify the accuracy of credits claimed and to ensure that a credit is not used more than
15 once.

16 (i) For the purposes of this section,

17 (1) a producer's or explorer's transitional investment expenditures are
18 the sum of the expenditures the producer or explorer incurred on or after April 1,
19 2001, and before April 1, 2006, that would be qualified capital expenditures if they
20 were incurred on or after April 1, 2006, less the sum of the payments or credits the
21 producer or explorer received before April 1, 2006, for the sale or other transfer of
22 assets, including geological, geophysical, or well data or interpretations, acquired by
23 the producer or explorer as a result of expenditures the producer or explorer incurred
24 before April 1, 2006, that would be qualified capital expenditures, if they were
25 incurred on or after April 1, 2006;

26 (2) a producer or explorer may elect to take a tax credit against a tax
27 due under AS 43.55.011(e) in the amount of 20 percent of the producer's or explorer's
28 transitional investment expenditures, but only to the extent that the amount does not
29 exceed 1/10 of the producer's or explorer's qualified capital expenditures that are
30 incurred during the calendar year for which the credit is taken;

31 (3) a producer or explorer may not take a tax credit for a transitional

1 investment expenditure

2 (A) for any calendar year after the later of

3 (i) 2013; or

4 (ii) the sixth calendar year after the calendar year for
5 which the producer first applies a credit under this subsection against a
6 tax due under AS 43.55.011(e), if the producer did not have
7 commercial production of oil or gas from a lease or property in the state
8 before April 1, 2006;

9 (B) more than once; or

10 (C) if a credit for that expenditure was taken under
11 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025;

12 (4) notwithstanding (d), (e), and (g) of this section, a producer or
13 explorer may not transfer a tax credit or obtain a transferable tax credit certificate for a
14 transitional investment expenditure.

15 (j) As a condition of receiving a tax credit under this section, a producer or
16 explorer that obtains the tax credit for or directly related to a pipeline, facility, or other
17 asset that is or becomes subject to regulation by the Federal Energy Regulatory
18 Commission or the Regulatory Commission of Alaska, or a successor regulatory body
19 shall at all times support and in all rate proceedings file to flow through 100 percent of
20 the tax credits to ratepayers as a reduction in the costs of service for the pipeline,
21 facility, or other asset.

22 (k) In this section, "qualified capital expenditure"

23 (1) means, except as otherwise provided in (2) of this subsection, an
24 expenditure that is a lease expenditure under AS 43.55.165 and is

25 (A) incurred for geological or geophysical exploration; or

26 (B) treated as a capitalized expenditure under 26 U.S.C.
27 (Internal Revenue Code), as amended, regardless of elections made
28 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is

29 (i) treated as a capitalized expenditure for federal
30 income tax reporting purposes by the person incurring the expenditure;

31 or

1 (ii) eligible to be deducted as an expense under 26
2 U.S.C. 263(c) (Internal Revenue Code), as amended:

3 (2) does not include an expenditure incurred to acquire an asset

4 (A) the cost of previously acquiring which was a lease
5 expenditure under AS 43.55.165 or would have been a lease
6 expenditure under AS 43.55.165 if it had been incurred on or after
7 April 1, 2006; for purposes of this subparagraph, "asset" includes
8 geological, geophysical, and well data and interpretations; or

9 (B) that has previously been placed in service in the state; an
10 expenditure to acquire an asset is not excluded under this paragraph if
11 not more than an immaterial portion of the asset meets a description
12 under this paragraph..

13 **Sec. 43.55.024. Additional nontransferable tax credits.** (a) For a calendar
14 year for which a producer's tax liability under AS 43.55.011(e) on oil and gas
15 produced from leases or properties outside the Cook Inlet sedimentary basin and south
16 of 68 degrees North latitude exceeds zero before application of any credits under this
17 chapter, a producer that is qualified under (c) of this section may apply a tax credit
18 against that liability of up to \$6,000,000.

19 (b) A producer may not take a tax credit under this section for any calendar
20 year after the later of

21 (1) 2016; or

22 (2) the ninth calendar year after the calendar year during which the
23 producer first has commercial oil or gas production before May 1, 2016, from at least
24 one lease or property in the state outside the Cook Inlet sedimentary basin and south of
25 68 degrees North latitude, if the producer did not have commercial oil or gas
26 production from a lease or property in the state outside the Cook Inlet sedimentary
27 basin and south of 68 degrees North latitude before April 1, 2006.

28 (c) On written application by a producer, including any information the
29 department may require, the department shall determine whether the producer
30 qualifies under this section for a calendar year. To qualify under this section, a
31 producer must demonstrate that its operation in the state or its ownership of an interest

1 in a lease or property in the state as a distinct producer entity would not result in the
2 division among multiple producer entities of any production tax liability under
3 AS 43.55.011(e) that would be reasonably expected to be attributed to a single
4 producer entity if the tax credit provisions of (a) of this section did not exist.

5 (d) A tax credit authorized by this section may not be applied to reduce a
6 producer's tax liability for any calendar year under AS 43.55.011(e) on oil and gas
7 produced from leases or properties outside the Cook Inlet sedimentary basin and south
8 of 68 degrees North latitude below zero.

9 (e) An unused tax credit or portion of a tax credit under this section is not
10 transferable and may not be carried forward to or used in a later calendar year.

11 * **Sec. 14.** AS 43.55.025(a) is amended to read:

12 (a) Subject to the terms and conditions of this section, [ON OIL AND GAS
13 PRODUCED ON OR AFTER JULY 1, 2004, FROM AN OIL AND GAS LEASE,
14 OR ON GAS PRODUCED FROM A GAS ONLY LEASE.] a credit against the
15 production tax due under AS 43.55.011(e) [THIS CHAPTER] is allowed for
16 exploration expenditures that qualify under (b) of this section in an amount equal to
17 one of the following:

18 (1) 20 percent of the total exploration expenditures that qualify only
19 under (b) and (c) of this section;

20 (2) 20 percent of the total exploration expenditures for work performed
21 before July 1, 2007, and that qualify only under (b) and (d) of this section;

22 (3) 40 percent of the total exploration expenditures that qualify under
23 (b), (c), and (d) of this section; or

24 (4) 40 percent of the total exploration expenditures that qualify only
25 under (b) and (e) of this section.

26 * **Sec. 15.** AS 43.55.025(b) is amended to read:

27 (b) To qualify for the production tax credit under (a) of this section, an
28 exploration expenditure must be incurred for work performed on or after July 1, 2003,
29 and before July 1, 2016 [2007], except that an exploration expenditure for a Cook Inlet
30 prospect must be incurred for work performed on or after July 1, 2005, [AND
31 BEFORE JULY 1, 2010, AND EXCEPT THAT AN EXPLORATION

1 EXPENDITURE, IN WHOLE OR IN PART, SOUTH OF 68 DEGREES, 15
2 MINUTES, NORTH LATITUDE, AND NOT PART OF A COOK INLET
3 PROSPECT MUST BE INCURRED FOR WORK PERFORMED ON OR AFTER
4 JULY 1, 2003, AND BEFORE JULY 1, 2010.] and

5 (1) may be for seismic or geophysical exploration costs not connected
6 with a specific well;

7 (2) if for an exploration well,

8 (A) must be incurred by an explorer that holds an interest in the
9 exploration well for which the production tax credit is claimed;

10 (B) may be for either an oil or gas discovery well or a dry hole;
11 and

12 (C) must be for goods, services, or rentals of personal property
13 reasonably required for the surface preparation, drilling, casing, cementing,
14 and logging of an exploration well, and, in the case of a dry hole, for the
15 expenses required for abandonment if the well is abandoned within 18 months
16 after the date the well was spudded:

17 (3) may not be for testing, stimulation, or completion costs;
18 administration, supervision, engineering, or lease operating costs; geological or
19 management costs; community relations or environmental costs; bonuses, taxes, or
20 other payments to governments related to the well; or other costs that are generally
21 recognized as indirect costs or financing costs; and

22 (4) may not be incurred for an exploration well or seismic exploration
23 that is included in a plan of exploration or a plan of development for any unit on
24 May 13, 2003.

25 * Sec. 16. AS 43.55.025(f) is amended to read:

26 (f) For a production tax credit under this section,

27 (1) an explorer shall, in a form prescribed by the department and
28 within six months of the completion of the exploration activity, claim the credit and
29 submit information sufficient to demonstrate to the department's satisfaction that the
30 claimed exploration expenditures qualify under this section:

31 (2) an explorer shall agree, in writing,

1 (A) to notify the Department of Natural Resources, within 30
2 days after completion of seismic or geophysical data processing, completion of
3 a well, or filing of a claim for credit, whichever is the latest, for which
4 exploration costs are claimed, of the date of completion and submit a report to
5 that department describing the processing sequence and providing a list of data
6 sets available; if, under (c)(2)(B) of this section, an explorer submits a claim
7 for a credit for expenditures for an exploration well that is located within three
8 miles of a well already drilled for oil and gas, in addition to the submissions
9 required under (i) of this subsection, the explorer shall submit the information
10 necessary for the commissioner of natural resources to evaluate the validity of
11 the explorer's claim that the well is directed at a distinctly separate exploration
12 target, and the commissioner of natural resources shall, upon receipt of all
13 evidence sufficient for the commissioner to evaluate the explorer's claim, make
14 that determination within 60 day.

15 (B) to provide to the Department of Natural Resources, within
16 30 days after the date of a request, specific data sets, ancillary data, and reports
17 identified in (A) of this paragraph:

18 (C) that, notwithstanding any provision of AS 38, information
19 provided under this paragraph will be held confidential by the Department of
20 Natural Resources for 10 years following the completion date, at which time
21 that department will release the information after 30 days' public notice:

22 (3) if more than one explorer holds an interest in a well or seismic
23 exploration, each explorer may claim an amount of credit that is proportional to the
24 explorer's cost incurred:

25 (4) the department may exercise the full extent of its powers as though
26 the explorer were a taxpayer under this title, in order to verify that the claimed
27 expenditures are qualified exploration expenditures under this section, and

28 (5) if the department is satisfied that the explorer's claimed
29 expenditures are qualified under this section, the department shall issue to the explorer
30 a production tax credit certificate for the amount of credit to be allowed against
31 production taxes due under AS 43.55.011(e) [THIS CHAPTER; HOWEVER,

1 NOTWITHSTANDING ANY OTHER PROVISION OF THIS SECTION, THE
2 DEPARTMENT MAY NOT ISSUE TO AN EXPLORER A PRODUCTION TAX
3 CREDIT CERTIFICATE IF THE TOTAL OF PRODUCTION TAX CREDITS
4 SUBMITTED FOR COOK INLET PRODUCTION, BASED ON EXPLORATION
5 EXPENDITURES FOR WORK PERFORMED DURING THE PERIOD
6 DESCRIBED IN (b) OF THIS SECTION FOR THAT PRODUCTION, THAT HAVE
7 BEEN APPROVED BY THE DEPARTMENT EXCEEDS \$20,000,000].

8 * Sec. 17. AS 43.55.025(h) is amended to read:

9 (h) A producer that purchases a production tax credit certificate may apply the
10 credits against its production tax liability under AS 43.55.011(e) [THIS CHAPTER].
11 Regardless of the price the producer paid for the certificate, the producer may receive
12 a credit against its production tax liability for the full amount of the credit, but for not
13 more than the amount for which the certificate is issued. A production tax credit
14 allowed under this section may not be applied more than once.

15 * Sec. 18. AS 43.55.025(i) is amended to read:

16 (i) For a production tax credit under this section,

17 (1) the amount of the credit that may be applied against the production
18 tax for each calendar year may not exceed the total production tax liability under
19 AS 43.55.011(e) of the taxpayer applying the credit for the same calendar year; and

20 (2) an amount of the production tax credit that is greater than the total
21 tax liability under AS 43.55.011(e) of the taxpayer applying the credit for a calendar
22 year may be carried forward and applied against the taxpayer's production tax liability
23 under AS 43.55.011(e) in one or more immediately following calendar years.

24 * Sec. 19. AS 43.55.030(a) is amended to read:

25 (a) The [TAX SHALL BE PAID TO THE DEPARTMENT, AND THE]
26 person paying the tax shall file with the department on March 31 of the year
27 following the calendar year for which the tax was levied [AT THE TIME THE
28 TAX IS REQUIRED TO BE PAID] a statement, under oath, in a form [ON FORMS]
29 prescribed by [OR ACCEPTABLE TO] the department, giving, with other
30 information required, the following:

31 (1) a description of each [THE] lease or property from which the oil

1 and [OR] gas were [WAS] produced, by name, legal description, lease number, or
2 [BY] accounting codes [CODE NUMBERS] assigned by the department;

3 (2) the names of the producer and the person paying the tax;

4 (3) the gross amount of oil and the gross amount of [OR] gas
5 produced from each [THE] lease or property, and the percentage of the gross amount
6 of oil and gas owned by each producer for whom the tax is paid;

7 (4) the gross [TOTAL] value at the point of production of the oil
8 and of the [OR] gas produced from each [THE] lease or property owned by each
9 producer for whom the tax is paid; [AND]

10 (5) the name of the first purchaser and the price received for the oil
11 and for the [OR] gas, unless relieved from this requirement in whole or in part by
12 the department;

13 (6) the producer's base production under AS 43.55.011(f); and

14 (7) the producer's lease expenditures and adjustments as
15 calculated under AS 43.55.160 - 43.55.170 [IF SOLD IN THE STATE].

16 * Sec. 20. AS 43.55.030(d) is amended to read:

17 (d) Reports by or on behalf of the producer are delinquent the first day
18 following the day the report [TAX] is due. [EACH PRODUCER IS SUBJECT TO A
19 PENALTY OF \$25 A DAY FOR EACH LEASE OR PROPERTY UPON WHICH
20 THE REPORT IS NOT FILED. THE PENALTY FOR FAILURE TO FILE A
21 REPORT IS IN ADDITION TO THE PENALTY FOR DELINQUENT TAXES,
22 AND IS A LIEN AGAINST THE ASSETS OF THE PRODUCER.]

23 * Sec. 21. AS 43.55.040 is amended to read:

24 **Sec. 43.55.040. Powers of Department of Revenue.** Except as provided in
25 AS 43.05.405 - 43.05.499, the department may

26 (1) require a person engaged in production and the agent or employee
27 of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil
28 or gas to furnish, whether by the filing of regular statements or reports or
29 otherwise, additional information that is considered by the department as necessary to
30 compute the amount of the tax; notwithstanding any contrary provision of law, the
31 disclosure of additional information under this paragraph to the producer

1 obligated to pay the tax does not violate AS 40.25.100(a) or AS 43.05.230(a);
2 before disclosing information under this paragraph that is otherwise required to
3 be held confidential under AS 40.25.100(a) or AS 43.05.230(a), the department
4 shall

5 (A) provide the person that furnished the information a
6 reasonable opportunity to be heard regarding the proposed disclosure and
7 the conditions to be imposed under (B) of this paragraph; and

8 (B) impose appropriate conditions limiting

9 (i) access to the information to those legal counsel,
10 consultants, employees, officers, and agents of the producer who
11 have a need to know that information for the purpose of
12 determining or contesting the producer's tax obligation; and

13 (ii) the use of the information to use for that
14 purpose:

15 (2) examine the books, records, and files of such a person;

16 (3) conduct hearings and compel the attendance of witnesses and the
17 production of books, records, and papers of any person; and

18 (4) make an investigation or hold an inquiry that is considered
19 necessary to a disclosure of the facts as to

20 (A) the amount of production from any oil or gas location, or of
21 a company or other producer of oil or gas; and

22 (B) the rendition of the oil and gas for taxing purposes.

23 * Sec. 22. AS 43.55.080 is amended to read:

24 **Sec. 43.55.080. Collection and deposit of revenue.** Except as otherwise
25 provided under art. IX, sec. 17, Constitution of the State of Alaska, the [THE]
26 department shall deposit in the general fund the money collected by it under
27 AS 43.55.011 - 43.55.180 [AS 43.55.011 - 43.55.150].

28 * Sec. 23. AS 43.55.135 is amended to read:

29 **Sec. 43.55.135. Measurement.** For the purposes of AS 43.55.011 - 43.55.180
30 [AS 43.55.011 - 43.55.150], except where otherwise provided, oil is [SHALL BE]
31 measured in terms of a "barrel of oil" and gas is [SHALL BE] measured in terms of a

1 "cubic foot of gas."

2 * **Sec. 24.** AS 43.55.150(a) is amended to read:

3 (a) For the purposes of **AS 43.55.011 - 43.55.180** [AS 43.55.011 - 43.55.150],
4 the gross value **at the point of production is** [SHALL BE] calculated using the
5 reasonable costs of transportation of the oil or gas. The reasonable costs of
6 transportation **are** [SHALL BE] the actual costs, except **when the**

7 (1) [WHEN THE] parties to the transportation of oil or gas are
8 affiliated;

9 (2) [WHEN THE] contract for the transportation of oil or gas is not an
10 arm's length transaction or is not representative of the market value of that
11 transportation; **and**

12 (3) [WHEN THE] method of transportation of oil or gas is not
13 reasonable in view of existing alternative methods of transportation.

14 * **Sec. 25.** AS 43.55 is amended by adding new sections to article 1 to read:

15 **Sec. 43.55.160. Determination of production tax value of oil and gas.** (a)

16 Except as provided in (b) of this section, for the purposes of

17 (1) AS 43.55.011(e), the annual production tax value of the taxable

18 (A) oil and gas produced during a calendar year from a lease or
19 property in the state that includes land north of 68 degrees North latitude is the
20 gross value at the point of production of the oil and gas taxable under
21 AS 43.55.011(e) and produced by the producer from that lease or property, less
22 the producer's lease expenditures under AS 43.55.165 for the calendar year
23 applicable to the oil and gas produced by the producer from that lease or
24 property, as adjusted under AS 43.55.170;

25 (B) oil and gas produced during a calendar year from a lease or
26 property in the state outside the Cook Inlet sedimentary basin and south of 68
27 degrees North latitude is the gross value at the point of production of the oil
28 and gas taxable under AS 43.55.011(e) and produced by the producer from that
29 lease or property, less the producer's lease expenditures under AS 43.55.165
30 for the calendar year applicable to the oil and gas produced by the producer
31 from that lease or property, as adjusted under AS 43.55.170;

1 (C) oil produced during a calendar year from a lease or property
2 in the Cook Inlet sedimentary basin is the gross value at the point of
3 production of the oil taxable under AS 43.55.011(e) and produced by the
4 producer from that lease or property, less the producer's lease expenditures
5 under AS 43.55.165 for the calendar year applicable to the oil produced by the
6 producer from that lease or property, as adjusted under AS 43.55.170;

7 (D) gas produced during a calendar year from a lease or
8 property in the Cook Inlet sedimentary basin is the gross value at the point of
9 production of the gas taxable under AS 43.55.011(c) and produced by the
10 producer from that lease or property, less the producer's lease expenditures
11 under AS 43.55.165 for the calendar year applicable to the gas produced by the
12 producer from that lease or property, as adjusted under AS 43.55.170;

13 (2) AS 43.55.011(g), the monthly production tax value of the taxable

14 (A) oil and gas produced during a month from a lease or
15 property in the state that includes land north of 68 degrees North latitude is the
16 gross value at the point of production of the oil and gas taxable under
17 AS 43.55.011(g) and produced by the producer from that lease or property, less
18 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar
19 year applicable to the oil and gas produced by the producer from that lease or
20 property, as adjusted under AS 43.55.170;

21 (B) oil and gas produced during a month from a lease or
22 property in the state outside the Cook Inlet sedimentary basin and south of 68
23 degrees North latitude is the gross value at the point of production of the oil
24 and gas taxable under AS 43.55.011(g) and produced by the producer from that
25 lease or property, less 1/12 of the producer's lease expenditures under
26 AS 43.55.165 for the calendar year applicable to the oil and gas produced by
27 the producer from that lease or property, as adjusted under AS 43.55.170;

28 (C) oil produced during a month from a lease or property in the
29 Cook Inlet sedimentary basin is the gross value at the point of production of
30 the oil taxable under AS 43.55.011(g) and produced by the producer from that
31 lease or property, less 1/12 of the producer's lease expenditures under

1 AS 43.55.165 for the calendar year applicable to the oil produced by the
2 producer from that lease or property, as adjusted under AS 43.55.170;

3 (D) gas produced during a month from a lease or property in the
4 Cook Inlet sedimentary basin is the gross value at the point of production of
5 the gas taxable under AS 43.55.011(g) and produced by the producer from that
6 lease or property, less 1/12 of the producer's lease expenditures under
7 AS 43.55.165 for the calendar year applicable to the gas produced by the
8 producer from that lease or property, as adjusted under AS 43.55.170.

9 (b) A production tax value calculated under (a) of this section may not be less
10 than zero.

11 (c) Notwithstanding any contrary provision of AS 43.55.150, for purposes of
12 calculating a monthly production tax value under (a)(2) of this section, the gross value
13 at the point of production of the oil and gas taxable under AS 43.55.011(g) is
14 calculated under regulations adopted by the department that provide for using an
15 appropriate monthly share of the producer's costs of transportation for the calendar
16 year.

17 (d) Irrespective of whether a producer produces taxable oil or gas during a
18 calendar year or month, the producer is considered to have generated a positive
19 production tax value if a calculation described in (a) of this section yields a positive
20 number because the producer's adjusted lease expenditures for a calendar year under
21 AS 43.55.165 and 43.55.170 are less than zero as a result of the producer's receiving a
22 payment or credit under AS 43.55.170 or otherwise. An explorer that has taken a tax
23 credit under AS 43.55.024(b) or that has obtained a transferable tax credit certificate
24 under AS 43.55.024(d) for the amount of a tax credit under AS 43.55.024(b) is
25 considered a producer, subject to the tax levied under AS 43.55.011(e), to the extent
26 that the explorer generates a positive production tax value as the result of the
27 explorer's receiving a payment or credit under AS 43.55.170.

28 (e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that
29 would otherwise be deductible by a producer in a calendar year but whose deduction
30 would cause an annual production tax value calculated under (a)(1) of this section of
31 taxable oil or gas produced during the calendar year to be less than zero may be used

1 to establish a carried-forward annual loss under AS 43.55.024(b).

2 **Sec. 43.55.165. Lease expenditures.** (a) Except as provided under (c) - (e) of
3 this section, for the purposes of AS 43.55.160, a producer's lease expenditures for a
4 calendar year are the ordinary and necessary costs upstream of the point of production
5 of oil and gas that are incurred during the calendar year by the producer on or after
6 April 1, 2006, and that are direct costs of exploring for, developing, or producing oil
7 or gas deposits located within the producer's leases or properties in the state or, in the
8 case of land in which the producer does not own a working interest, that are direct
9 costs of exploring for oil or gas deposits located within other land in the state. In
10 determining whether costs are lease expenditures, the department shall consider,
11 among other factors,

12 (1) the typical industry practices and standards in the state that
13 determine the costs, other than items listed in (e) of this section, that an operator is
14 allowed to bill a working interest owner that is not the operator, under unit operating
15 agreements or similar operating agreements that were in effect on or before
16 December 1, 2005, and were subject to negotiation with at least one working interest
17 owner with substantial bargaining power, other than the operator; and

18 (2) the standards adopted by the Department of Natural Resources that
19 determine the costs, other than items listed in (e) of this section, that a lessee is
20 allowed to deduct from revenue in calculating net profits under a lease issued under
21 AS 38.05.180(f)(3)(B), (D), or (E).

22 (b) For purposes of (a) of this section,

23 (1) direct costs include

24 (A) an expenditure, when incurred, to acquire an item if the
25 acquisition cost is otherwise a direct cost, notwithstanding that the expenditure
26 may be required to be capitalized rather than treated as an expense for financial
27 accounting or federal income tax purposes;

28 (B) payments of or in lieu of property taxes, sales and use
29 taxes, motor fuel taxes, and excise taxes;

30 (C) a reasonable allowance, as determined under regulations
31 adopted by the department, for overhead expenses directly related to exploring

1 for, developing, and producing oil or gas deposits located within leases or
2 properties or other land in the state;

3 (2) an activity does not need to be physically located on, near, or
4 within the premises of the lease or property within which an oil or gas deposit being
5 explored for, developed, or produced is located in order for the cost of the activity to
6 be a cost upstream of the point of production of the oil or gas.

7 (c) Subject to (g) and (h) of this section, if the department finds that the
8 pertinent provisions of a unit operating agreement or similar operating agreement are
9 substantially consistent with the department's determinations and standards under (a)
10 of this section concerning whether costs are lease expenditures, the department may
11 authorize or require a producer, subject to conditions prescribed under regulations
12 adopted by the department, to treat as that portion of its lease expenditures for a
13 calendar year applicable to oil and gas produced from a lease or property in the state
14 only

15 (1) the costs, other than items listed in (e) of this section, that are
16 incurred by the operator during the calendar year and that

17 (A) are billable to the producer by the operator in accordance
18 with the terms of the agreement to which that lease or property is subject;

19 (B) for a producer that is the operator, would be billable to the
20 producer by the operator in accordance with the terms of the agreement to
21 which that lease or property is subject if the producer were not the operator;

22 (C) would be billable to the producer by the operator in
23 accordance with the terms of the agreement if that lease or property were
24 subject to the agreement; or

25 (D) for a producer that is the operator, would be billable to the
26 producer by the operator in accordance with the terms of the agreement if that
27 lease or property were subject to the agreement and if the producer were not
28 the operator; and

29 (2) a reasonable percentage, as determined under regulations adopted
30 by the department, of the costs that are billable under (1) of this subsection as an
31 allowance for overhead expenses directly related to exploring for, developing, and

1 producing oil or gas deposits located within the lease or property, to the extent those
2 expenses are not billable under the agreement.

3 (d) Subject to (g) and (h) of this section, if the department makes the finding
4 described in (c) of this section with respect to a unit operating agreement or similar
5 operating agreement and, in addition, finds that at least one working interest owner
6 party to the agreement, other than the operator, with substantial incentive and ability to
7 effectively audit billings under the agreement in fact is effectively auditing billings
8 under the agreement, the department may authorize or require a producer, subject to
9 conditions prescribed under regulations adopted by the department, to treat as that
10 portion of its lease expenditures for a calendar year applicable to oil and gas produced
11 from a lease or property in the state only

12 (1) the costs, other than items listed in (c) of this section, that are
13 incurred by the operator during the calendar year and that

14 (A) are billed to the producer by the operator under the
15 agreement to which that lease or property is subject and are either not disputed
16 by a working interest owner party to the agreement or are finally determined to
17 be properly billable as a result of dispute resolution; or

18 (B) for a producer that is the operator, would be billable to the
19 producer by the operator in accordance with the terms of the agreement to
20 which that lease or property is subject if the producer were not the operator;
21 and

22 (2) a reasonable percentage, as determined under regulations adopted
23 by the department, of the costs that are billed under (1) of this subsection as an
24 allowance for overhead expenses directly related to exploring for, developing, and
25 producing oil or gas deposits located within the lease or property, to the extent those
26 expenses are not billable under the agreement.

27 (e) For purposes of this section, lease expenditures do not include

28 (1) depreciation, depletion, or amortization;

29 (2) oil or gas royalty payments, production payments, lease profit
30 shares, or other payments or distributions of a share of oil or gas production, profit, or
31 revenue;

- 1 (3) taxes based on or measured by net income;
- 2 (4) interest or other financing charges or costs of raising equity or debt
- 3 capital;
- 4 (5) acquisition costs for a lease or property or exploration license;
- 5 (6) costs arising from fraud, wilful misconduct, or gross negligence;
- 6 (7) fines or penalties imposed by law;
- 7 (8) costs of arbitration, litigation, or other dispute resolution activities
- 8 that involve the state or concern the rights or obligations among owners of interests in,
- 9 or rights to production from, one or more leases or properties or a unit;
- 10 (9) donations;
- 11 (10) costs incurred in organizing a partnership, joint venture, or other
- 12 business entity or arrangement;
- 13 (11) amounts paid to indemnify the state; the exclusion provided by
- 14 this paragraph does not apply to the costs of obtaining insurance or a surety bond from
- 15 a third-party insurer or surety;
- 16 (12) surcharges levied under AS 43.55.201 or 43.55.300;
- 17 (13) for a transaction that is an internal transfer or is otherwise not an
- 18 arm's length transaction, expenditures incurred that are in excess of fair market value;
- 19 (14) an expenditure incurred to purchase an interest in any corporation,
- 20 partnership, limited liability company, business trust, or any other business entity,
- 21 whether or not the transaction is treated as an asset sale for federal income tax
- 22 purposes;
- 23 (15) a tax levied under AS 43.55.011;
- 24 (16) the portion of costs incurred for dismantlement, removal,
- 25 surrender, or abandonment of a facility, pipeline, well pad, platform, or other
- 26 structure, or for the restoration of a lease, field, unit, area, body of water, or right-of-
- 27 way in conjunction with dismantlement, removal, surrender, or abandonment, that is
- 28 attributable to production of oil or gas occurring before April 1, 2006; the portion is
- 29 calculated as a ratio of the amount of oil and gas production in barrels of oil equivalent
- 30 associated with the facility, pipeline, well pad, platform, or other structure, lease, field,
- 31 unit, area, body of water, or right-of-way occurring before April 1, 2006, to the total

1 amount of oil and gas production in barrels of oil equivalent associated with that
2 facility, pipeline, well pad, platform, or other structure, lease, field, unit, area, body of
3 water, or right-of-way through the end of the calendar month before commencement
4 of the dismantlement, removal, surrender, or abandonment; a cost is not excluded
5 under this paragraph if the dismantlement, removal, surrender, or abandonment for
6 which the cost is incurred is undertaken for the purpose of replacing, renovating, or
7 improving the facility, pipeline, well pad, platform, or other structure; for the purposes
8 of this paragraph, "barrel of oil equivalent" means

9 (A) in the case of oil, one barrel;

10 (B) in the case of gas, 6,000 cubic feet;

11 (17) losses or damages resulting from an unpermitted oil discharge that
12 is not confined to a pad, platform, or other structure, or costs to contain, clean up, or
13 remediate such an unpermitted oil discharge to the extent that those costs exceed the
14 routine costs of operation for a producer or explorer that would otherwise be incurred
15 as lease expenditures in the absence of the unpermitted oil discharge; this paragraph
16 does not apply to the cost of developing and maintaining an oil discharge prevention
17 and contingency plan under AS 46.04.030;

18 (18) costs incurred to satisfy a work commitment under an exploration
19 license under AS 38.05.132.

20 (f) For purposes of AS 43.55.024(a) and (b) and only as to expenditures
21 incurred to explore for an oil or gas deposit located within land in which an explorer
22 does not own a working interest, the term "producer" in this section, in
23 AS 43.55.160(e), and in AS 43.55.170 includes "explorer."

24 (g) The department shall specify or approve a reasonable allocation method
25 for determining the portion of a cost that is appropriately treated as a lease expenditure
26 under this section if a cost that would otherwise constitute a lease expenditure under
27 this section is incurred to explore for, develop, or produce

28 (1) both an oil or gas deposit located within land outside the state and
29 an oil or gas deposit located within a lease or property, or other land, in the state; or

30 (2) an oil or gas deposit located partly within land outside the state and
31 partly within a lease or property, or other land, in the state.

1 (h) The department shall adopt regulations that provide for reasonable
2 methods of allocating costs between oil and gas and between leases or properties in
3 those circumstances where the determination of the lease expenditures that are
4 applicable to oil or to gas, or that are applicable to oil and gas produced from different
5 leases or properties, requires an allocation of costs.

6 (i) The department may adopt regulations that establish additional standards
7 necessary to carrying out the purposes of this section and AS 43.55.170, including the
8 incorporation of the concepts of 26 U.S.C. 482 (Internal Revenue Code), as amended,
9 the related or accompanying regulations of that provision, and any ruling or guidance
10 issued by the United States Internal Revenue Service that relates to that provision.

11 (j) For purposes of this section,

12 (1) "explore" includes conducting geological or geophysical
13 exploration, including drilling a stratigraphic test well;

14 (2) "ordinary and necessary" has the meaning given in 26 U.S.C. 162
15 (Internal Revenue Code), as amended, and regulations adopted under that section;

16 (3) "stratigraphic test well" means a well drilled for the sole purpose of
17 obtaining geological information to aid in exploring for an oil or gas deposit and the
18 target zones of which are located in the state.

19 **Sec. 43.55.170. Adjustments to lease expenditures.** (a) Unless the payment
20 or credit has already been subtracted in calculating billable or billed costs under
21 AS 43.55.165(c) or (d), a producer's lease expenditures under AS 43.55.165 must be
22 adjusted by subtracting payments or credits, other than tax credits, received by the
23 producer or by an operator acting for the producer for

24 (1) the use by another person of a production facility in which the
25 producer has an ownership interest or the management by the producer of a production
26 facility under a management agreement providing for the producer to receive a
27 management fee;

28 (2) a reimbursement or similar payment that offsets the producer's
29 lease expenditures, including an insurance recovery from a third-party insurer and a
30 payment from the state or federal government for reimbursement of the producer's
31 upstream costs, including costs for gathering, separating, cleaning, dehydration,

1 compressing, or other field handling associated with the production of oil or gas
2 upstream of the point of production;

3 (3) the sale or other transfer of

4 (A) an asset, including geological, geophysical, or well data or
5 interpretations, acquired by the producer as a result of a lease expenditure or an
6 expenditure that would be a lease expenditure if it were incurred on or after
7 April 1, 2006; for purposes of this subparagraph,

8 (i) if a producer removes from the state, for use outside
9 the state, an asset described in this subparagraph, the value of the asset
10 at the time it is removed is considered a payment received by the
11 producer for sale or transfer of the asset;

12 (ii) for a transaction that is an internal transfer or is
13 otherwise not an arm's length transaction, if the sale or transfer of the
14 asset is made for less than fair market value, the amount subtracted
15 must be the fair market value; and

16 (B) oil or gas

17 (i) that is not considered produced from a lease or
18 property under AS 43.55.020(e); and

19 (ii) the cost of acquiring which is a lease expenditure
20 incurred by the person that acquires the oil or gas.

21 (b) Except as otherwise provided under this subsection, if one or more
22 payments or credits subject to this section are received by a producer or by an operator
23 acting for the producer during a calendar year and if either the total amount of the
24 payments or credits exceeds the amount of the producer's applicable lease
25 expenditures for that calendar year or the producer has no lease expenditures for that
26 calendar year, the producer shall nevertheless subtract those payments or credits from
27 the lease expenditures or from zero, respectively, and the producer's applicable
28 adjusted lease expenditures for that calendar year are a negative number and shall be
29 applied to the pertinent calculation under AS 43.55.160(a) as a negative number.

30 **Sec. 43.55.180. Required report.** (a) The department shall study

31 (1) the effects of the provisions of this chapter on oil and gas

1 exploration, development, and production in the state, on investment expenditures for
2 oil and gas exploration, development, and production in the state, on the entry of new
3 producers into the oil and gas industry in the state, on state revenue, and on tax
4 administration and compliance, giving particular attention to the tax rates provided
5 under AS 43.55.011, the tax credits provided under AS 43.55.023 – 43.55.025, and the
6 deductions for and adjustments to lease expenditures provided under AS 43.55.160 –
7 43.55.170; and

8 (2) the effects of the tax rates under AS 43.55.011(i) on state revenue
9 and on oil and gas exploration, development, and production on private land, and the
10 fairness of those tax rates for private landowners.

11 (b) The department shall prepare a report on or before the first day of the 2011
12 regular session of the legislature on the results of the study made under (a) of this
13 subsection, including recommendations as to whether any changes should be made to
14 this chapter. The department shall notify the legislature that the report prepared under
15 this subsection is available.

16 * Sec. 26. AS 43.55.201 is amended to read:

17 Sec. 43.55.201. Surcharge levied. (a) Every producer of oil shall pay a
18 surcharge of \$.01 [~~\$.02~~] per barrel of oil produced from each lease or property in the
19 state, less any oil the ownership or right to which is exempt from taxation.

20 (b) The surcharge imposed by (a) of this section is in addition to the tax
21 imposed by AS 43.55.011 and is due on the last day of the month on oil produced
22 from each lease or property during the preceding month. The surcharge [SHALL
23 BE PAID IN THE SAME MANNER AS THE TAX IMPOSED BY AS 43.55.011 -
24 43.55.150; AND] is in addition to the surcharge imposed by AS 43.55.300 -
25 43.55.310.

26 (c) A producer of oil shall make a report [REPORTS] of production on
27 March 31 of the year following the calendar year of production and in the same
28 manner and under the same penalties as required under AS 43.55.011 - 43.55.180
29 [AS 43.55.011 - 43.55.150].

30 * Sec. 27. AS 43.55.201 is amended by adding a new subsection to read:

31 (d) Oil not considered under AS 43.55.020(e) to be produced from a lease or

1 property is not considered to be produced from a lease or property for purposes of this
2 section.

3 * **Sec. 28.** AS 43.55.300 is amended to read:

4 **Sec. 43.55.300. Surcharge levied.** (a) Every producer of oil shall pay a
5 surcharge of \$~~.04~~ [~~\$.03~~] per barrel of oil produced from each lease or property in the
6 state, less any oil the ownership or right to which is exempt from taxation.

7 (b) The surcharge imposed by (a) of this section is in addition to **the tax**
8 **imposed by AS 43.55.011 and is due on the last day of the month on oil produced**
9 **from each lease or property during the preceding month. The surcharge** [SHALL
10 BE PAID IN THE SAME MANNER AS THE TAX IMPOSED BY AS 43.55.011 -
11 43.55.150; AND] is in addition to the surcharge imposed by AS 43.55.201 -
12 43.55.231.

13 (c) A producer of oil shall make **a report** [REPORTS] of production **on**
14 **March 31 of the year following the calendar year of production and** in the same
15 manner and under the same penalties as required under **AS 43.55.011 - 43.55.180**
16 [AS 43.55.011 - 43.55.150].

17 * **Sec. 29.** AS 43.55.300 is amended by adding a new subsection to read:

18 (d) Oil not considered under AS 43.55.020(e) to be produced from a lease or
19 property is not considered to be produced from a lease or property for purposes of this
20 section.

21 * **Sec. 30.** AS 43.55.900(6) is repealed and reenacted to read:

22 (6) "gas" means

23 (A) all natural, associated, or casinghead gas:

24 (B) all hydrocarbons that

25 (i) are recovered by mechanical separation of well
26 fluids or by gas processing in a gas processing plant; and

27 (ii) exist in a gaseous phase at the completion of
28 mechanical separation and any gas processing in a gas processing plant;

29 and

30 (C) all other hydrocarbons produced from a well not defined as

31 oil;

1 * **Sec. 31.** AS 43.55.900(7) is repealed and reenacted to read:

2 (7) "gross value at the point of production" means

3 (A) for oil, the value of the oil at its point of production
4 without deduction of any costs upstream of that point of production;

5 (B) for gas, the value of the gas at its point of production
6 without deduction of any costs upstream of that point of production;

7 * **Sec. 32.** AS 43.55.900(10) is repealed and reenacted to read:

8 (10) "oil" means

9 (A) crude petroleum oil; and

10 (B) all liquid hydrocarbons that are recovered by mechanical
11 separation of well fluids or by gas processing in a gas processing plant;

12 * **Sec. 33.** AS 43.55.900 is amended by adding new paragraphs to read:

13 (17) "British thermal unit" means the quantity of heat required to raise
14 the temperature of one pound of water from 58.5 degrees Fahrenheit to 59.5
15 degrees Fahrenheit at a constant pressure of one atmosphere;

16 (18) "BTU equivalent barrel" means

17 (A) in the case of oil, one barrel,

18 (B) in the case of gas, the amount of gas that has a heating value
19 of 6,000,000 British thermal units;

20 (19) "Cook Inlet sedimentary basin" has the meaning given in
21 regulations adopted to implement AS 38.05.180(f)(4);

22 (20) "explorer" means a person who, in exploring for new oil or gas
23 reserves, incurs expenditures;

24 (21) "gas processing"

25 (A) means processing a gaseous mixture of hydrocarbons

26 (i) by means of absorption, adsorption, externally
27 applied refrigeration, artificial compression followed by adiabatic
28 expansion using the Joule-Thomson effect, or another physical process
29 that is not mechanical separation; and

30 (ii) for the purpose of extracting and recovering liquid
31 hydrocarbons;

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(B) does not include gas treatment;

(22) "gas processing plant" means a facility that

(A) extracts and recovers liquid hydrocarbons from a gaseous mixture of hydrocarbons by gas processing; and

(B) is located upstream of any gas treatment and upstream of the inlet of any gas pipeline system transporting gas to a market;

(23) "gas treatment"

(A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system;

(B) includes incidentally removing liquid hydrocarbons from the gas;

(C) does not include

(i) dehydration required to facilitate the movement of gas from the well to the point where gas processing takes place;

(ii) the scrubbing of liquids from gas to facilitate gas processing;

(24) "heating value" means the gross number of BTUs evolved by complete combustion of an amount of gas;

(25) "landowner's royalty interest" means

(A) a lesser's royalty interest under an oil and gas lease; or

(B) a royalty interest that is

(i) held by a surface owner of land from which oil or gas is produced; and

(ii) granted in exchange for the right to use the surface of that land or as compensation for damage to the surface of that land;

(26) "oil and gas lease" includes an oil and gas lease, a gas only lease, and an oil only lease;

(27) "point of production" means

(A) for oil, the automatic custody transfer meter or device through which the oil enters into the facilities of a carrier pipeline or other

1 transportation carrier in a condition of pipeline quality; in the absence of an
2 automatic custody transfer meter or device, "point of production" means the
3 mechanism or device to measure the quantity of oil that has been approved by
4 the department for that purpose, through which the oil is tendered and accepted
5 in a condition of pipeline quality into the facilities of a carrier pipeline or other
6 transportation carrier or into a field topping plant;

7 (B) for gas, other than gas described in (C) of this paragraph,
8 that is

9 (i) not subjected to or recovered by mechanical
10 separation or run through a gas processing plant, the first point where
11 the gas is accurately metered;

12 (ii) subjected to or recovered by mechanical separation
13 but not run through a gas processing plant, the first point where the gas
14 is accurately metered after completion of mechanical separation;

15 (iii) run through a gas processing plant, the first point
16 where the gas is accurately metered downstream of the plant;

17 (C) for gas run through an integrated gas processing plant and
18 gas treatment facility that does not accurately meter the gas after the gas
19 processing and before the gas treatment, the first point where gas processing is
20 completed or where gas treatment begins, whichever is further upstream

21 * Sec. 34. AS 43.55.011(a), 43.55.011(b), 43.55.011(c), 43.55.012, 43.55.013, 43.55.016,
22 43.55.025(k)(1), 43.55.025(k)(3), 43.55.900(1), 43.55.900(8), 43.55.900(11), 43.55.900(12),
23 and 43.55.900(16) are repealed.

24 * Sec. 35. The uncodified law of the State of Alaska is amended by adding a new section to
25 read:

26 APPLICABILITY. (a) Sections 5, 7 - 10, 12 - 14, 16 - 20, 24, and 26 - 34 of this Act
27 and AS 43.55.160 - 43.55.170, enacted by sec. 25 of this Act, apply to oil and gas produced
28 after March 31, 2006.

29 (b) Section 11 of this Act applies to oil and gas produced before, on, or after the
30 effective date of sec. 11 of this Act.

31 * Sec. 36. The uncodified law of the State of Alaska is amended by adding a new section to

1 read:

2 TRANSITIONAL PROVISIONS. (a) Notwithstanding any contrary provision of
3 AS 43.55.023(i), enacted by sec. 13 of this Act, for oil and gas produced after March 31,
4 2006, and before January 1, 2007, the phrase "20 percent" in AS 43.55.023(i)(2), enacted by
5 sec. 13 of this Act, shall be replaced by the phrase "15 percent".

6 (b) For oil and gas produced before April 1, 2006, the provisions of AS 43.55, and
7 regulations adopted under AS 43.55, that were in effect before April 1, 2006, and that were
8 applicable to the oil and gas continue to apply to that oil and gas.

9 (c) Notwithstanding any contrary provision of AS 43.55.020(a), as repealed and
10 reenacted by sec. 7 of this Act, for oil and gas produced after March 31, 2006, and before
11 January 1, 2007,

12 (1) the amount of the taxes that would have been levied on the producer by
13 AS 43.55, as the provisions of that chapter read on March 31, 2006, is due on the last day of
14 each calendar month on the oil and gas that was produced from each lease or property during
15 the preceding month;

16 (2) the amount, if any, of the taxes levied by AS 43.55.011(e), (g), and (i),
17 enacted by sec. 5 of this Act, net of any credits applied as allowed by law, that exceeds the
18 amount due under (1) of this subsection, is due on March 31, 2007.

19 (d) Notwithstanding any contrary provision of AS 43.55.030(a), as amended by sec.
20 19 of this Act, for oil and gas produced after March 31, 2006, and before January 1, 2007, the
21 person paying the tax shall file with the Department of Revenue, at the time an amount of tax
22 is due

23 (1) under (c)(1) of this section, the statement required under former
24 AS 43.55.030(a), as that subsection read on March 31, 2006; and

25 (2) under (c)(2) of this section, the statement required under AS 43.55.030(a),
26 as amended by sec. 19 of this Act.

27 (e) Notwithstanding any contrary provision of AS 43.55.201(a) or (b), as amended by
28 sec. 26 of this Act, or AS 43.55.300(a) or (b), as amended by sec. 28 of this Act, for oil
29 produced after March 31, 2006, and before January 1, 2007,

30 (1) the amount of the surcharges that would have been imposed on the
31 producer under AS 43.55, as the provisions of that chapter read on March 31, 2006, is due on

1 the last day of each calendar month on oil produced from each lease or property during the
2 preceding month:

3 (2) the amount, if any, of the surcharges imposed under AS 43.55.201(a), as
4 amended by sec. 26 of this Act, and AS 43.55.300(a), as amended by sec. 28 of this Act, that
5 exceeds the amount due under (1) of this subsection, is due on March 31, 2007.

6 (f) Notwithstanding any contrary provision of AS 43.55.201(c), as amended by sec.
7 26 of this Act, or AS 43.55.300(c), as amended by sec. 28 of this Act, for oil produced after
8 March 31, 2006, and before January 1, 2007, at the time an amount of surcharge is due

9 (1) under (e)(1) of this section, the producer shall file the report of production
10 required under former AS 43.55.201(c) and 43.55.300(c), as those provisions read on
11 March 31, 2006; and

12 (2) under (e)(2) of this section, the producer shall file on March 31, 2007, the
13 report of production otherwise required under AS 43.55.201(c), as amended by sec. 26 of this
14 Act, and AS 43.55.300(c), as amended by sec. 28 of this Act.

15 (g) For purposes of taxes to be calculated and due under (c)(1) of this section and
16 statements to be filed under (d)(1) of this section, regulations that were adopted by the
17 Department of Revenue under AS 43.55, as the provisions of that chapter read on March 31,
18 2006, and that were in effect on that date apply to those taxes and statements.

19 (h) Notwithstanding any contrary provision of AS 43.55.160 a)(2), enacted by sec. 25
20 of this Act, for oil and gas produced after March 31, 2006, and before January 1, 2007, the
21 phrase "1/12" in AS 43.55.160(a)(2)(A) - (D), enacted by sec. 25 of this Act, shall be
22 replaced by the phrase "1/9".

23 * **Sec. 37.** The uncodified law of the State of Alaska is amended by adding a new section to
24 read:

25 **TRANSITION: RETROACTIVITY OF REGULATIONS.** Notwithstanding any
26 contrary provision of AS 44.62.240, a regulation adopted by the Department of Revenue to
27 implement, interpret, make specific, or otherwise carry out the provisions of secs. 5, 7 - 10, 12
28 - 14, 16 - 20, 24 - 34, and 36 of this Act may apply retroactively as of April 1, 2006, if the
29 Department of Revenue expressly designates in the regulation that the regulation applies
30 retroactively to that date.

31 * **Sec. 38.** The uncodified law of the State of Alaska is amended by adding a new section to

1 read:

2 REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the
3 heading of

4 (1) AS 43.55 from "Oil and Gas Production Taxes and Oil Surcharge" to "Oil
5 and Gas Production Tax and Oil Surcharge";

6 (2) article 1 of AS 43.55 from "Oil and Gas Properties Production Taxes" to
7 "Oil and Gas Production Tax";

8 (3) AS 43.55.011 from "Oil production tax" to "Oil and gas production tax";

9 (4) AS 43.55.025 from "Tax credit for oil and gas exploration or gas only
10 exploration" to "Alternative tax credit for oil and gas exploration";

11 (5) AS 43.55.150 from "Determination of gross value" to "Determination of
12 gross value at the point of production."

13 * **Sec. 39.** The uncodified law of the State of Alaska is amended by adding a new section to
14 read:

15 RETROACTIVITY OF PROVISIONS OF ACT. Sections 5, 7 - 10, 12- -14, 16 - 19,
16 and 24 - 36 of this Act are retroactive to April 1, 2006.

17 * **Sec. 40.** This Act takes effect immediately under AS 01.10.070(c).

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: 1
 Bill Version: HB 3001
 (H) Publish Date: 7/12/06

Revision Date/Time (Note if correction): _____ Dept. Affected: Natural Resources
 Title: Repealing the oil production tax and gas RDU: Resource Development
production tax etc. Component: Oil & Gas Development
 Sponsor: Rules by Request of Governor
 Requester: Governor Component No. 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
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CHANGE IN REVENUES ()						
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2006) cost: 0.0

Mark this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

There is no anticipated fiscal impact for DNR associated with implementation of this legislation.

Prepared by: Bill VanDyke, Acting Director
 Division: Oil & Gas
 Approved by: Michael Menge, Commissioner
 Agency: Natural Resources

Phone: 907-269-8800
 Date/Time: 7/11/2006
 Date: 7/11/2006

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number: 2 **CORRECTED**
 Bill Version: HB 3001
 (H) Publish Date: 7/13/06

Revision Date/Time (Note if correction): _____ Dept. Affected: Revenue
 Title: An Act Relating to the Production Tax on RDU: Tax and Treasury
Oil and Gas Component: Tax
 Sponsor: Rules Committee
 Requester: Governor Component No.: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services	875.0	892.5	910.4	928.6	947.1	966.1
Travel						
Contractual	525.0	487.9	118.2	110.6	121.0	123.4
Supplies	42.0					
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous (OH office, etc)	53.0	53.0	53.0	53.0	53.0	53.0
TOTAL OPERATING	1,495.0	1,433.4	1,081.6	1,100.2	1,121.1	1,142.5

CAPITAL EXPENDITURES						
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CHANGE IN REVENUES ()	<i>See analysis section</i>
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	1,495.0	1,433.4	1,081.6	1,100.2	1,121.1	1,142.5
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	1,495.0	1,433.4	1,081.6	1,100.2	1,121.1	1,142.5

Estimate of any current year (FY2006) cost: _____

Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time	10	10	10	10	10	10
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

Relative to Status Quo

This bill would amend the oil and gas production tax by basing the tax on the net value of the oil and gas. The net value is the wellhead value (net of royalty) less all qualified lease expenditures, including capital and operating costs, and property taxes. The net profit would be subject to a 20% tax, less a credit of 20% which applies to capital costs upstream of the point of production. There would be an additional allowance of up to \$12 million per company for companies producing less than 50,000 barrels of oil equivalent per day; this amount is reduced as production reaches 100,000 boe per day, the point at which no allowance is authorized. The allowance expires in 2016. In addition, as a transition provision, there would be a 20% credit for capital costs incurred over the period April 1, 2001 through April 1, 2006, recoverable at \$1 for every \$2 in capital expenditures. Transition costs cannot be recovered after 2013.

Prepared by: Robynn Wilson, Michael Williams, Roger Marks, and Cheryl Nienhuis
 Division: Tax Division

Phone 269-1019
 Date/Time 7/13/06 7:00 AM

Approved by: Jerry Burnett
 Agency: Department of Revenue

Date 7/13/2006

STATE OF ALASKA
2006 LEGISLATIVE SESSIONBILL NO. HB 3001**ANALYSIS CONTINUATION**

The additional conservation surcharge on oil is increased from 3 cents to 4 cents.

The bill would be effective April 1, 2006.

The figures in the table on the next page reflect the revenues that would be received from the bill relative to the status quo under various prices. The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. The status quo assumes the January 2005 ELF aggregation decision by the Department of Revenue for Prudhoe Bay continues.

The cost assumptions are as follows:

- \$100 mm/yr exploration
- \$1/bbl on-going capital on all barrels
- \$3.50/bbl developmental capital on 2/3 of existing conventional oil
- \$8/bbl developmental capital on 2/3 of existing heavy oil
- \$3.50/bbl developmental capital on new conventional oil
- \$8/bbl developmental capital on new heavy oil
- \$3/bbl operating cost on conventional oil
- \$5/bbl operating cost on heavy oil

The table shows the 2007-2012 receipts from the bill, sensitive to different oil prices. These include the Department of Revenue forecast, a \$40 price, and a \$60 price. (Note that the status quo numbers are slightly different from what is reflected in the Spring 2006 Revenue Sources Book because of volume adjustments from the oil spill, and because of some differences between what some taxpayers actually remit and what is ultimately expected to be collected.)

Operating expenditures include costs for 8 additional positions for auditors: 1 O & G Specialist (Range 23), 3 O & G Revenue Auditor IV (Range 22), and 4 O & G Revenue Auditor III (Range 20). These positions would be used to fulfill additional audit responsibilities inherent in a net profits tax. In addition, we request 2 additional Tax Tech III positions (Range 14) to process additional information and tax returns that will be required, and additional credit applications anticipated. Personal Services reflect a 2% yearly increase.

Contractual expenditures include \$100,000 and \$70,000 for programming in FY 07 and FY 08, respectively. \$300,000 in each of FY 07 and FY 08 for help in writing regulations, \$100,000 in each year for consulting services and an estimate of chargeback costs. Supplies include computers and other supplies necessary for new positions

FISCAL NOTE 2 **CORRECTED**

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. HB 3001

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

The revenues provided in the table below do not reflect increased revenues in FY06 that would result from an effective date of 4/1/06. At a preliminary estimated quarter end price of \$65, the bill would provide approximately \$260 million over the status quo system.

Fiscal Year	DOR Forecast	Status Quo Tax	Tax from Bill	Gain from Bill*
2007	\$53.60	989	1,718	729
2008	\$46.90	759	1,339	580
2009	\$25.50	355	316	-38
2010	\$25.50	315	285	-30
2011	\$25.50	281	282	0
2012	\$25.50	271	278	6

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill*
2007	\$40.00	708	972	264
2008	\$40.00	655	947	292
2009	\$40.00	631	1,015	384
2010	\$40.00	582	984	402
2011	\$40.00	544	1,006	462
2012	\$40.00	536	1,015	479

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill*
2007	\$60.00	1,120	1,994	875
2008	\$60.00	1,032	1,941	909
2009	\$60.00	978	2,003	1,025
2010	\$60.00	901	1,954	1,053
2011	\$60.00	842	1,995	1,153
2012	\$60.00	831	2,015	1,184

*Numbers may not sum due to rounding.

LIMITED COMPARISON OF PPT BILL VERSIONS and POP draft CS

source: DOR		House CS for SB 2001(FIN) Version X	House CS for SB 2001(FIN) Version X.A	Conference CS for SB 2001 Version C.A	Governor's Bill Version A	POP Plan Draft CS
tax rate	general flat rate	20.0% .011(e) - page 3	23.5% .011(e) - page 3	22.8% .011(e) - page 3	20.0% .011(e) - page 3	n/a blended rate see below; blended rate not to exceed 22.5% in first 3 years .011(l)(1) - page 3
	blended, variable rate	base rate				25.0% .011(l)(2) - page 3
		incremental rate				15% increasing starting 2012, maximum 25% .011(l)(3) - page 3
		Cook Inlet Oil	ELF tax ceiling on Cook Inlet oil .011(j) - page 5	ELF tax ceiling on Cook Inlet oil .011(j) - page 5	ELF tax ceiling on Cook Inlet oil .011(j) - page 5	ELF tax ceiling on Cook Inlet oil .011(h) - page 4
	Cook Inlet Gas	ELF tax ceiling on Cook Inlet gas .011(i) - pages 4-5	ELF tax ceiling on Cook Inlet gas .011(i) - page 4	ELF tax ceiling on Cook Inlet gas .011(i) - page 4	ELF tax ceiling on Cook Inlet gas .011(g) - page 4	ELF tax ceiling on Cook Inlet gas .011(j) - pages 5-6
capex credit rate	20% .024(a) - page 9	20% .024(a) - page 9	20% .024(a) - page 9	20% .024(a)(1)(A) - page 8	20% .023(a)(1) - page 12	
progressivity surcharge	over \$45/bbl (net value/boe) x .00175 x net value with new boe rules PPT rate + prog rate not to exceed 50% .011(g) & (h) - page 4	over \$35/bbl (net value/boe) x .0025 x net value with new boe rules PPT rate + prog rate not to exceed 50% .011(g) & (h) - page 4	over \$35/bbl (net value/boe) x .00175 x net value with new boe rules PPT rate + prog rate not to exceed 50% .011(g) & (h) - page 4	none n/a	yes - particulars in discussion cap under discussion: .011(g), (h) - pages 4-5	
credits for annual loss	yes, at 20% .024(b) - page 10	yes, at 23.5% .024(b) - page 10	yes, at 22.8% .024(b) - page 10	yes, at 20% .024(b) - page 9	yes, at 20% .023(h) - page 13	
credit usage floor	n/a	.024 credits cannot be used to reduce PPT tax to below 4% of gross for ANS region .024(c) - page 10	.024 credits cannot be used to reduce PPT tax to below 3% of gross for ANS region .024(c) - page 10	none	none	
transition (TIE) credit	5 yrs lookback capex 2 for 1 recoupment (CORRECTED) .024(j) - page 12-14	5 yrs lookback capex 2 for 1 recoupment (CORRECTED) .024(j) - page 13	5 yrs lookback capex 2 for 1 recoupment (CORRECTED) .024(j) - page 13	5 yrs lookback capex 2 for 1 recoupment (CORRECTED) .024(j) - page 12	5 yrs lookback capex 2 for 1 recoupment (CORRECTED) .023(i) - pages 15-16	
base allowance credit	\$12M credit (\$1M per month) (equates to \$60M ded.) based on production .170(c) - pages 28-29	\$12M credit (\$1M per month) (equates to \$51M ded.) based on production .170(c) - page 29	\$12M credit (\$1M per month) (equates to \$52.6M ded.) based on production .170(c) - page 29	\$12M credit (\$1M per month) (equates to \$60M ded.) based on production .170(c) - page 27	none	
new area development credit	\$6M credit (\$500,000 per mo) for areas NOT ANS, NOT Cook Inlet .170(a) - page 28	\$6M credit (\$500,000 per mo) for areas NOT ANS, NOT Cook Inlet .170(a) - page 28	\$6M credit (\$500,000 per mo) for areas NOT ANS, NOT Cook Inlet .170(a) - page 28	\$6M credit (\$500,000 per mo) for areas NOT ANS, NOT Cook Inlet .170(a) - page 27	\$6M credit (\$500,000 per mo) for areas NOT ANS, NOT Cook Inlet .024(a) - page 17	

LIMITED COMPARISON OF PPT BILL VERSIONS and POP draft CS

source: DOR	House CS for SB 2001 (FIN) Version X	House CS for SB 2001 (FIN) Version X A	Conference CS for SB 2001 Version C A.	Governor's Bill Version A	POP Plan Draft CS
lease expenditures: authority of industry practices	the department shall give "substantial weight" .160(c)(1)(A)--page 22	the department shall give "substantial weight" .160(c)(1)(A)--page 22	the department shall give "substantial weight" .160(c)(1)(A)--page 22	the department shall give "substantial weight" .160(c)(1)(A)--page 21	the department shall "consider" .165(a)--page 27
lease expenditures: authorized	.160(c)--pages	.160(c)--pages 22-23	.160(c)--pages 22-23	.160(c)--pages 21-22	improved language .165(c)--pages 28-29
DOR reports to the legislature	private royalty rates--2013; certain credits--2015 .180--pages 30-31	private royalty rates--2013; certain credits--2015 .180--pages 30-31	private royalty rates--2013; certain credits--2015 .180--pages 30-31	private royalty rates--2013; certain credits--2015 .180--page 29	oil provisions esp. tax rates, all credits, and lease exps.--2011 .180--page 34
ADMINISTRATIVE PROVISIONS					
effective date	4/1/2006 Sec. 39--page 25	4/1/2006 Sec. 39--page 38	4/1/2006 Sec. 39--page 35	4/1/2006 Sec. 39--page 35	4/1/2006 Sec. 39--page 41
tax returns due	monthly--due end of month following month of production; annual true up return due 3/30 .030(a)	monthly--due end of month following month of production; annual true up return due 3/31 .030(a)--page 18	monthly--due end of month following month of production; annual true up return due 3/32 .030(a)--page 18	monthly--due end of month following month of production; annual true up return due 3/33 .030(a)--page 17	annual return due 3/31 .030(a)--page 22
safe harbor for payments due	95%, annual true-up, no interest .020(a)--page 7	95%, annual true-up, no interest .020(a)--page 7	95%, annual true-up, no interest .020(a)--page 7	95%, annual true-up, no interest .020(a)--page 7	none
Installment payments (estimated tax payments)	n/a	n/a	n/a	n/a	monthly pmts due end of following month based on monthly gross value less 1/12 lease exps.; 1/12 credits .020(a)--pages 8-9
pmt < required payment	interest only .020(a)--page 7	interest only .020(a)--page 7	interest only .020(a)--page 7	interest only .020(a)--page 7	interest at fed. rate .020(g)--page 11
pmt > required payment	no provision	no provision	no provision	no provision	interest at fed. rate .020(h)--pages 11-12
transition payment	10 mos. pymt on old system; true-up in 10th mo. (clarification) Sec. 36(f)(g)--page 36	10 mos. pymt on old system; true-up in 10th mo. (clarification) Sec. 36(g)(h)--pages 36-37	10 mos. pymt on old system; true-up in 10th mo. (clarification) Sec. 36(g)(i)--pages 36-37	10 mos. pymt on old system; true-up in 10th mo. (clarification) Sec. 36(g)(h)--pages 35	pymt on old system through Jan. 07 true-up on 3/31/07 Sec. 36(d)--page 39

Roadmap of modified sections

Comparison of Samuels/Hawker POP proposal
to Conference CS for S. Bill No. 2001 version CA

source: AK DOR
7/31/2006

	Conf. Com. Ver. CA	POP Plan Draft CS
PPT/POP rate	.011(e)	.011(f)(1)
base rate		.011(f)(2)
incremental rate		.011(f)(3)
base production		.011(f)(4)
incremental production		.011(f)(5)
transfers of working interests		.011(f)(6)
progressivity feature	.011(g), (h)	.011(g), (h)
private royalty rates	.011(f)	.011(i)
Cook Inlet gas ELF ceiling	.011(i)	.011(j)
Cook Inlet oil ELF ceiling	.011(j)	.011(k)
clarification of Cook Inlet tax reduction application		.011(L)
application of credits for Cook Inlet	.011(k)	.011(m)
regulations for allocation of credits	.011(L)	.011(n)
regulations for testing heating value	.011(m)	.011(o)
BTU equivalent barrel definition		.900(18)
95% safe harbor	.020(a)	n/a
monthly installment payments		.020(a)
monthly installment rules for private royalties		.020(d)
interest rules for monthly installment payments		.020(g), (h)
capex credits	.024	.023(a)(1)
losses converted to credits	.024(b)	.023(b)
transitional investment credits (TIE)	.024(j)	.023(i)
anti-churning rules	.024(i)	.023(k)(2)(B)
additional non transferable tax credits	.170	.024
New Area Development credit	.170(a), (b)	.024(a)-(e)
Base Allowance credit	.170(c), (d)	n/a
non-arms length (re: IRC §482)	.160(i)	.165(i)
production tax value calculation	.160(a)-(b)	.160
lease expenditures--allowed	.160(c)	.165(c)
lease expenditures--disallowed	.160(d)	.165(e)
adjustments to lease expenditures	.160(e)	.170
election to utilize 1/2 lease expenditures rather than actual	.160(f)	n/a

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July 12, 2006

The Honorable John Harris
Speaker of the House
Alaska State Legislature
State Capitol, Room 208
Juneau, AK 99801-1182

Dear Speaker Harris:

Under the authority of article III, section 18, of the Alaska Constitution, I am transmitting a bill relating to the oil and gas production tax.

This bill is similar to previous versions of oil and gas production tax legislation that the Legislature has considered during both the regular and special sessions this year. I appreciate that legislators have devoted sustained and serious attention and concern to this subject, and there is therefore no need for me to repeat in detail here the reasons why this legislation is urgently needed or how the new tax system set out in this legislation would work. Legislators well understand that the existing production tax law is not adequately serving the interests of Alaskans and that the approach taken by this bill would provide the state with a fairer share of the value of oil and gas production while encouraging vital investment in future production.

I also appreciate that the legislative process this year has led to numerous improvements in the bills that were originally submitted, resulting in increased clarity, predictability, and ease of administration. The bill I am transmitting takes advantage of these improvements by using as its model the most recent versions that were passed by the House and Senate, HCS CSSB 2001(FIN) am H and CCS SB 2001. The following two changes from those versions are reflected in the bill:

1. Because I still believe that a 20 percent tax rate on net value represents a more appropriate balance than either of the higher rates contained in HCS CSSB 2001(FIN) am H or CCS SB 2001, my bill returns to a 20 percent rate.

2. For the same reason, my bill eliminates the additional "progressivity" tax provisions that were in the other versions.

HB 3001

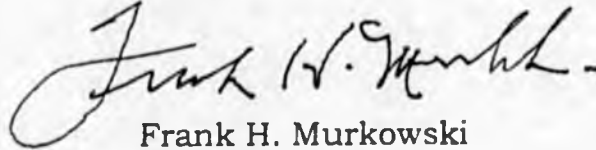
The Honorable John Harris
July 12, 2006
Page 2

3. Similarly, because I believe that the four percent of gross value tax floor on North Slope production that was added by HCS CSSB 2001(FIN) and H and the similar three percent floor that was contained in CCS SB 2001 are inconsistent with the concept of a progressive net value tax system, my bill eliminates that tax floor provision.

As explained more fully in my transmittal letter accompanying the original administration bills, this bill will greatly improve Alaska's oil and gas tax system, encouraging investment in the state, making tax administration more predictable, and better reflecting the variable economics of oil and gas development. This bill will provide Alaskans with a fairer share of the value of the oil and gas taken out of the ground in our state and provide fiscal certainty for future generations of Alaskans.

I urge your prompt and favorable action on the bill.

Sincerely yours,

A handwritten signature in black ink, appearing to read "Frank H. Murkowski". The signature is fluid and cursive, with a long horizontal stroke at the end.

Frank H. Murkowski
Governor

Enclosure

HB 3001

Comments Related To Heavy Oil in Proposed Legislation

There are four issues related to heavy oil in proposed legislation that need to be recognized as critical to the collection of production taxes. These items are the following:

- Definition of Heavy Oil
- Measurement
- Time and Changes Over Time
- Technology and Time

As currently proposed in legislation, the four items listed above would make the collection of taxes challenging and problematic. It is assumed that heavy oil is omitted from tax liability in HB 3003 due to the difficulty and high cost of developing it. As this discussion will show, just because a crude oil is classified as heavy [according to HB 3003] does not mean it will be difficult or expensive to develop and oil not classified as heavy may be very difficult and expensive to develop. What is now classified as expensive to develop, may not be in the future. Each topic is now reviewed.

Definition of Heavy Oil

HB 3003 defines heavy oil as that with an American Petroleum Institute [API] gravity of 18° or less. While this appears to be a "clean" definition, it omits the fact that crude oils with an API of 18° or less are not necessarily difficult to produce. Other factors may be more important. Some basics:

Heavy Oil is a type of crude oil which is very *viscous* and does not flow easily. The common characteristic properties are the following:

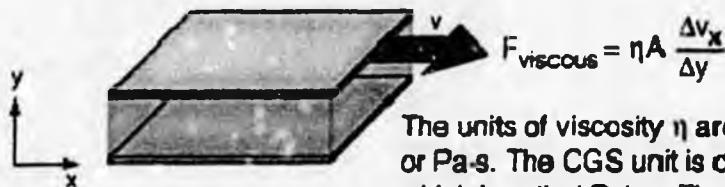
- High specific gravity
- Low hydrogen to carbon ratios
- High carbon residues, and
- High contents of asphaltenes, heavy metal, sulphur and nitrogen

It is not just the gravity that makes the heavy oil difficult to deal with – it is the presence of other factors. There is no one definition of heavy oil, but it refers to oil with a high density and low API gravity due to the presence of a high proportion of heavy hydrocarbon fractions. All these definitions refer to the crude oil at the surface. In terms of the ability of the oil to flow within the formation – the key issue in Alaska – is that heavy oils are generally those with a viscosity greater than 100 centiPoise [cP] at reservoir conditions (although on occasions the term heavy oil has been applied to *in situ* viscosity as low as 4 cP).

Viscosity is the measure of the internal friction of a fluid. This friction becomes apparent when a layer of fluid is made to move in relation to another layer. The greater the friction, the greater the amount of force required to cause this movement, which is called "shear."

Shearing occurs whenever the fluid is physically moved or distributed, as in pouring, spreading, spraying, mixing, etc.

Highly viscous fluids, therefore, require more



The units of viscosity η are then N s/m^2 or $\text{Pa}\cdot\text{s}$. The CGS unit is dyne sec/cm^2 which is called Poise. The viscosity of water at 20°C is 0.01 Poise. The viscosity of blood at body temperature is about 0.03 Poise. The $\text{Pa}\cdot\text{s}$ is called a Poiseuille and is equal to 10 Poise.

force to move than less viscous materials.

Temperature also plays a key role in viscosity. Higher temperatures imply lower viscosity with the fluid flowing more easily. In oil formations, the deeper in the ground the oil formation, the warmer the temperature, the lower the viscosity, the easier the flow. In Alaska, the viscous oils tend to be in shallower depths, which mean the oil is cooler, more viscous, and does not flow as easily. Also, the Alaska oil is found in less consolidated formations which produce a lot of sand as the oil is produced.

The combination of temperature, viscosity, and additional components in the oil [carbon residues, heavy metals, sulphur, nitrogen and sand] make for difficulty in developing of heavy oil – not necessarily API gravity.

Measurement

To accurately interpret HB 3003, all oil coming from the North Slope would have to be examined and evaluated to determine if it is heavy. This would imply measuring all oil produced from each well. A well may be multi-lateral with different bores going to different levels [see Figure 1]. Oil produced at one level may be classified as heavy [less than 18° API] while crude produced from a different formation [same well, same field, different depth] may not be classified as heavy. Measurement could be a nightmare.

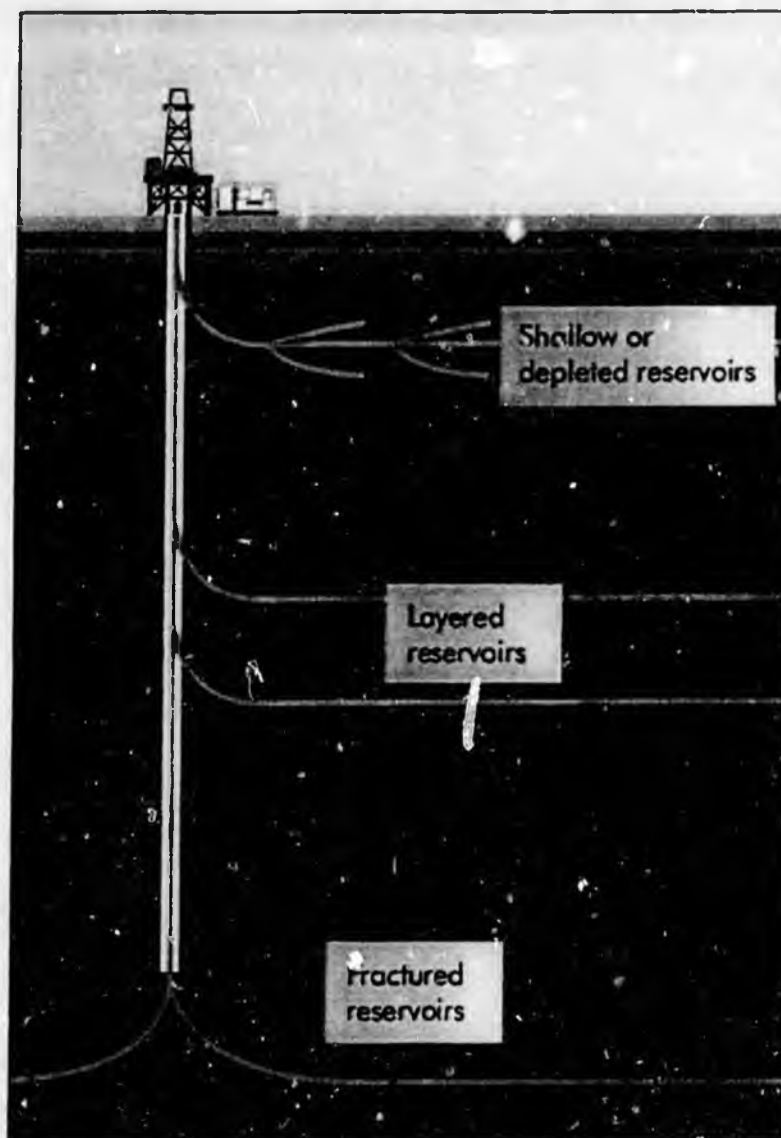
Time and Changes Over Time

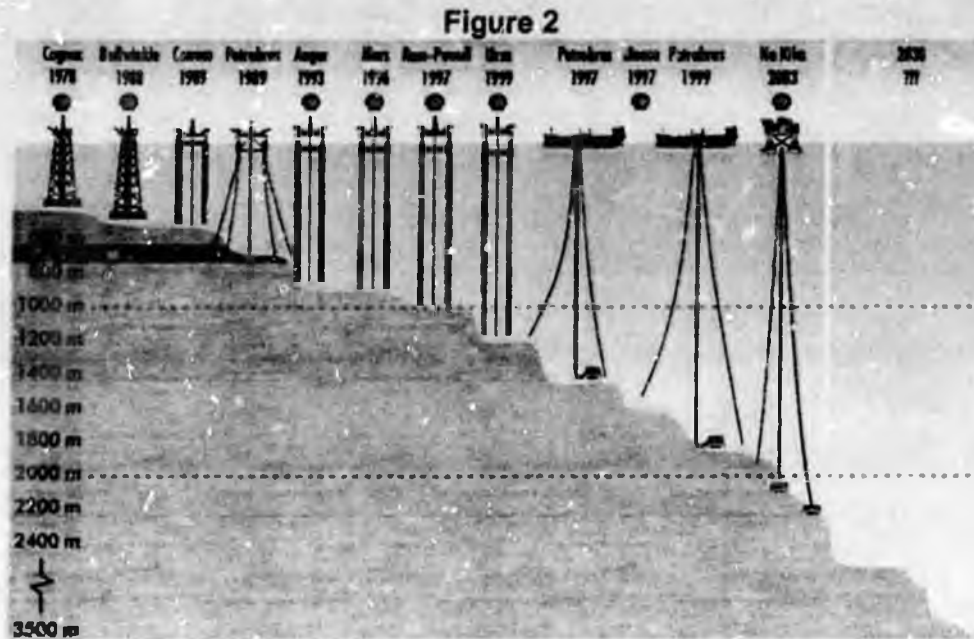
The production would have to be measured and monitored on a monthly basis. Changes in field operations occur all the time. A well may be producing oil classified as heavy today, and that classification could change in a day, a week, a month, or a year as new bores are drilled into different layers. Thus, the measurement aspect would have to be an on-going monthly event.

Technology and Time

What may be difficult and expensive to produce today, may well be commonplace and cheaper to produce in the future. The oil industry has shown tremendous ingenuity in developing techniques to find and develop oil. For example, in the case of deepwater offshore oil development, it was impossible to produce oil from depths greater than 600 meters in the early 1970s. By 2003, oil companies were regularly producing oil at depths below 1,500 meters. New systems and techniques were developed to access the oil deeper and deeper under the ocean [see Figure 2 following page].

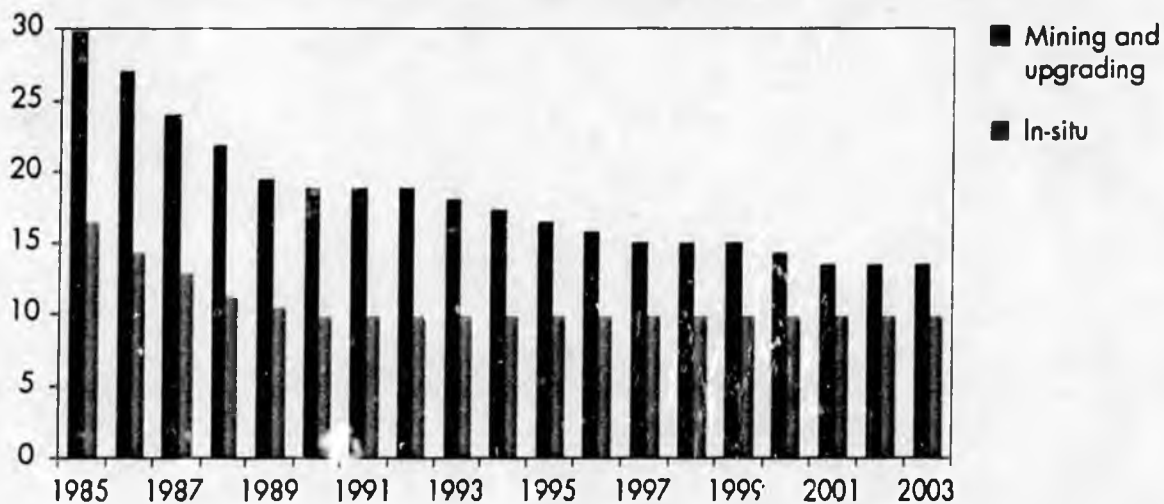
Figure 1





In North America, similar results can be found in Canada where new techniques have been introduced to develop heavy oil. As the new techniques were developed, the per barrel costs of developing heavy oil decreased [see Figure 3].

Figure 3
Oil Production Costs from Canadian Tar Sands, 2004 Dollars per Barrel



In summary, oil that is difficult and expensive to produce today may well be less expensive to produce in the future. Any legislation that assumes heavy oil will always be expensive to develop does not take into account the dynamic nature of the oil industry and its ability to develop new methods and techniques to produce hydrocarbons, and reduce costs in the process.

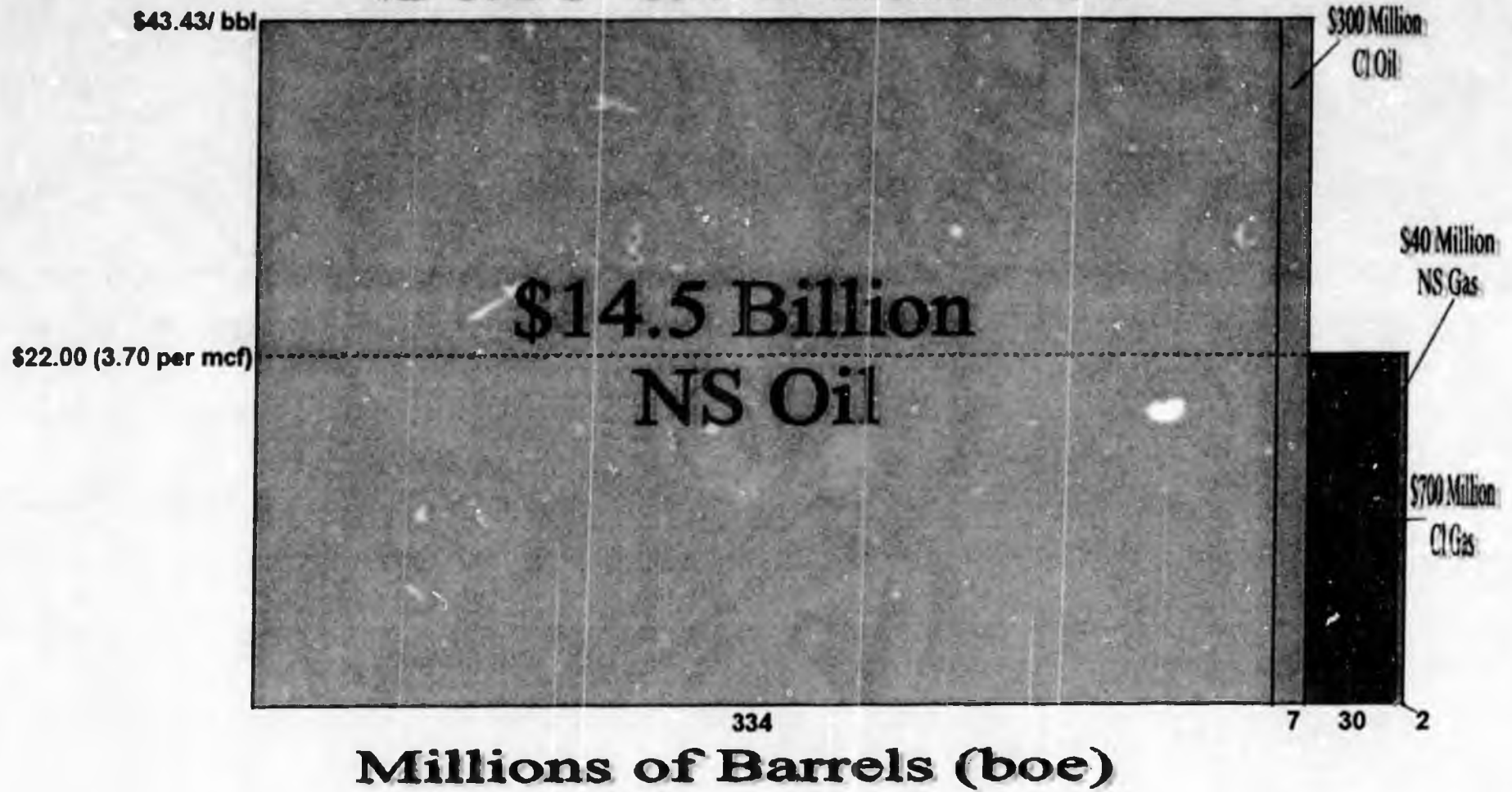
Conclusions

Legislation that seeks to tax oil production using API gravity as a means to determine tax liability has a high likelihood of being difficult to administer while offering real challenges to measure and enforce. Changes in methods and technology over time will likely allow heavy oil to be recovered and often developed at a lower per barrel cost as time marches on. This means the very rationale for using heavy oil as a discriminating factor will lose its basis over time. It is recommended that another option be used for tax legislation purposes.

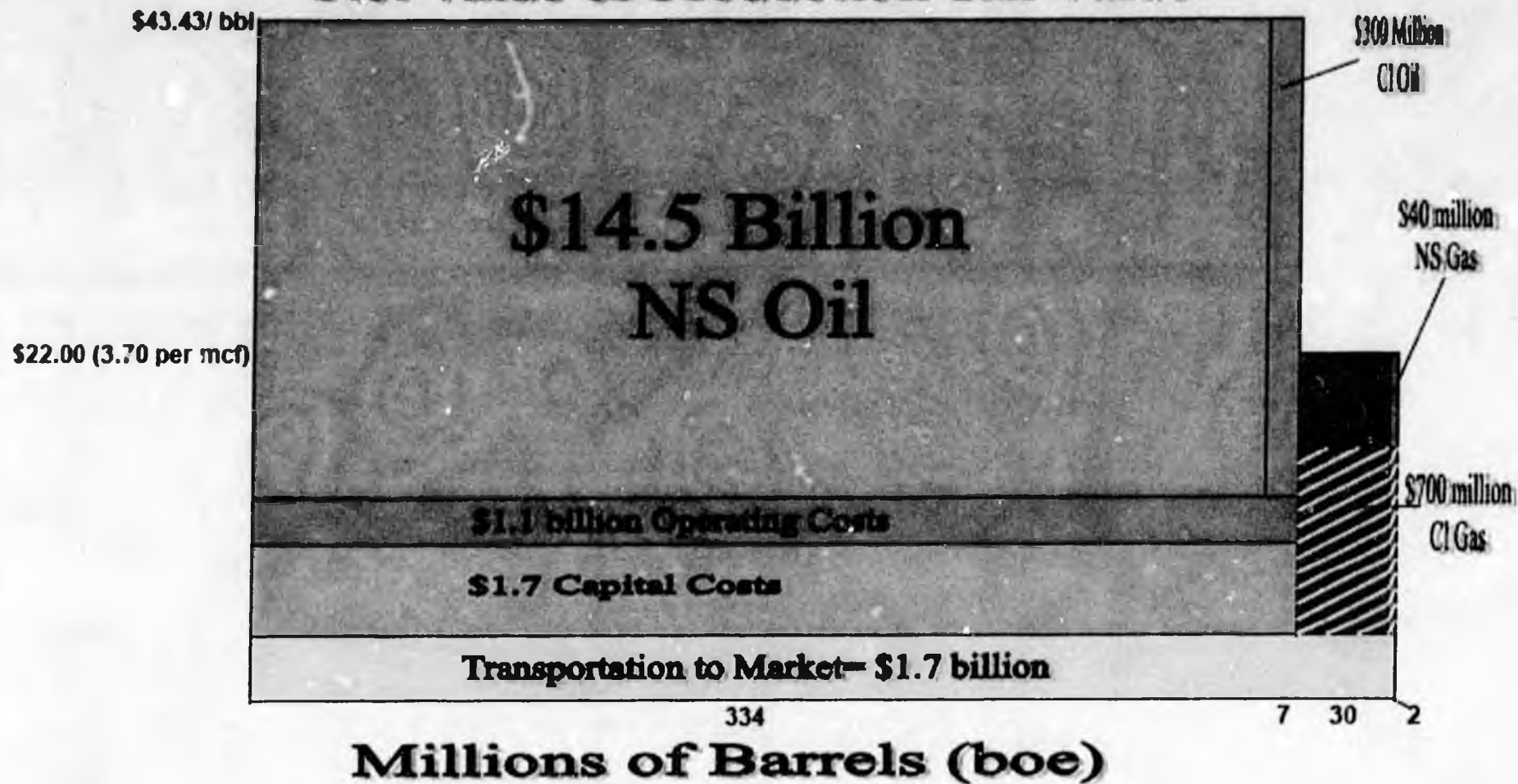
LIMITED COMPARISON OF PPT BILL VERSIONS-

source: DOR	CSSB 2001 (FIN) Version F	House CS for SB 2001(FIN) Version X.A	Conference CS for SB 2001 Version C.A.	Governor's Bill Version A
general	22.5% .011(e) - page 3	23.5% .011(e) - page 3	22.8% .011(e) - page 3	20.0% .011(e) - page 3
tax rate				
Cook Inlet Oil	3/4 rev. excl for Cook Inlet oil .160(a) - page 19	ELF tax ceiling on Cook Inlet oil .011(j) - page 5	ELF tax ceiling on Cook Inlet oil .011(j) - page 5	ELF tax ceiling on Cook Inlet oil .011(h) - page 4
Cook Inlet Gas	ELF tax ceiling on Cook Inlet gas .011(i) - page 4	ELF tax ceiling on Cook Inlet gas .011(i) - page 4	ELF tax ceiling on Cook Inlet gas .011(i) - page 4	ELF tax ceiling on Cook Inlet gas .011(g) - page 4
progressivity surcharge	over \$35/bbl (net value/boe) x .001 x net value with new boe rules PPT rate + prog rate not to exceed 50% .011(g) & (h) - page 4	over \$35/bbl (net value/boe) x .0025 x net value with new boe rules PPT rate + prog rate not to exceed 50% .011(g) & (h) - page 4	over \$35/bbl (net value/boe) x .00175 x net value with new boe rules PPT rate + prog rate not to exceed 50% .011(g) & (h) - page 4	none n/a
credits for annual loss	yes, at 22.5% .024(b) - page 8	yes, at 23.5% .024(b) - page 10	yes, at 22.8% .024(b) - page 10	yes, at 20% .024(b) - page 9
credit usage floor	n/a	.024 credits cannot be used to reduce PPT tax to below 4% of gross for ANS region .024(c) - page 10	.024 credits cannot be used to reduce PPT tax to below 3% of gross for ANS region .024(c) - page 10	none
Gas (GRE)	ANS gas 2/3 included (1/3 excl.); CI gas 1/3 included; new gas 1/2 included .160(a) pages 19-20	n/a	n/a	n/a
transition (TIE) credit	5 yrs. lookback capex 2 for 1 recoupment .024(j) - pages 11-12	5 yrs. lookback capex 2 for 1 recoupment (CORRECTED) .024(j) - page 13	5 yrs. lookback capex 2 for 1 recoupment (CORRECTED) .024(j) - page 13	5 yrs. lookback capex 2 for 1 recoupment (CORRECTED) .024(j) - page 12
base allowance credit	\$12M credit (\$1M per month) (equates to \$53.3M ded.) NOT based on production .170(a) - page 26	\$12M credit (\$1M per month) (equates to \$51M ded.) based on production .170(c) - page 29	\$12M credit (\$1M per month) (equates to \$52.6M ded.) based on production .170(c) - page 29	\$12M credit (\$1M per month) (equates to \$60M ded.) based on production .170(c) - page 27
new area development credit	n/a	\$6M credit (\$500,000 per mo) for areas NOT ANS, NOT Cook Inlet .170(a) - page 28	\$6M credit (\$500,000 per mo) for areas NOT ANS, NOT Cook Inlet .170(a) - page 28	\$6M credit (\$500,000 per mo) for areas NOT ANS, NOT Cook Inlet .170(a) - page 27
sunset of new area development credit	n/a	10 yr rolling .170(b) - page 28	10 yr rolling .170(b) - page 28	10 yr rolling .170(b) - page 28
oil spill	any oil spill cleanup costs not ded. (exception for gravel pad) .160(d)(17) - page 24	any oil spill cleanup costs not ded. (improved pad language) .160(d)(17) - page 25	any oil spill cleanup costs not ded. (improved pad language) .160(d)(17) - page 25	any oil spill cleanup costs not ded. (improved pad language) .160(d)(17) - page 24
transition payment	10 mos. pymt on old system; true- up in 11th mo. Sec. 37(f)(g) - pages 33-34	10 mos. pymt on old system; true-up in 10th mo. (clarification) Sec. 36(g)(h) - pages 36-37	10 mos. pymt on old system; true-up in 10th mo. (clarification) Sec. 36(g)(h) - pages 36-37	10 mos. pymt on old system; true-up in 10th mo. (clarification) Sec. 36(g)(h) - pages 35

Sale at Market



Net Value or Production Tax Value



Tax Before Credits

2.4 billion

Tax After Credits

Tax After Credits 1.7 billion

5,000bbl equivalent credit B users at max of 14 million = 112 million

TIE credit $1.7 \times .5 \times .2 = 170$ million

$1.7b \times .25 = 425$ million Qualified Capital Expenditure Credits

Tax After Credits

Tax After Credits 1.7 billion

5,000 bbl equivalents credit 8 users at max of 14 million = 112 million

RIS credit $1.7 \times .5 \times .3 = 170$ million

$1.7b \times .25 = 425$ million Qualified Capital Expenditure Credits

Tax Under Status Quo ~ .9 billion

Gross vs. Net: Two Aspects
Heavy Oil
Exploration Economics

Alaska Department of Revenue
July 25, 2006

GROSS VS. NET - HEAVY OIL

	Light Oil	Heavy Oil
West Coast ANS Price	\$40.00	\$40.00
Shipping	\$2.00	\$2.00
Pipeline	\$3.00	\$3.00
GROSS	\$35.00	\$35.00
Royalty	\$4.38	\$4.38
UPSTREAM COSTS	\$7.50	\$15.00
NET	\$23.13	\$15.63

SUPPOSE THE TAX IS 15% OF GROSS:

Tax on Gross (15% X \$35.00)	\$5.25	\$5.25
Tax as Percent of Net	22.7%	33.6%

GROSS VS. NET - EXPLORATION ECONOMICS

field target size (barrels)	40,000,000
net price	\$10.00
total value	\$400,000,000
discount factor	0.4
net present value	\$160,000,000

probability of finding oil	15%
expected value	\$24,000,000
exploration cost	\$20,000,000

TAX ON GROSS

expected value	\$24,000,000
exploration cost	(\$20,000,000)
full cycle expected value	\$4,000,000

TAX ON NET

expected value	\$24,000,000
exploration cost	(\$20,000,000)
credit (20% of exploration cost)	\$4,000,000
deduction (20% of exploration cost)	\$4,000,000
full cycle expected value	\$12,000,000

Gross vs Net Production Tax

A back ground discussion

July 25, 2006

Presentation to
The House Finance Committee
Pedro van Meurs



General Comments

HB 3004 contains several elements of a proposal which I made on April 29, 2001 to the Knowles administration for changes in the production tax.

However, there are also important differences between HB 3004 and my earlier proposal. These differences are central to the understanding of "gross vs net".

General Comments

My 2001 proposal was a modification of the then existing ELF based production tax. It contained:

- Stronger tax rates in case of small fields with low productivities.
- A strongly price sensitive tax, which much higher rates under high prices and zero tax under low prices.
- Provisions for heavy oil incentives
- Tax credits in order to encourage re-investment in the State.

Revenues versus Structure

In order to understand the various concepts it is very important to distinguish clearly between:

- The structure of the production tax, and
- The level of revenues that the State would receive.

This presentation deals with the **structure** of the production tax.

Under any structure the level of revenues can be set higher or lower depending on the perception of the competitive international framework.

Three Fiscal Options

The three different options reflect the three main choices that the Government of Alaska has in creating a new production tax:

- A structure based on tax credits:
 - Based on State wide net revenues, or
 - Based on gross revenues per “field” with no deductions for capital and operating costs.
- No or minor tax credits:
 - A structure based on gross revenues per “field”.

Three Fiscal Options

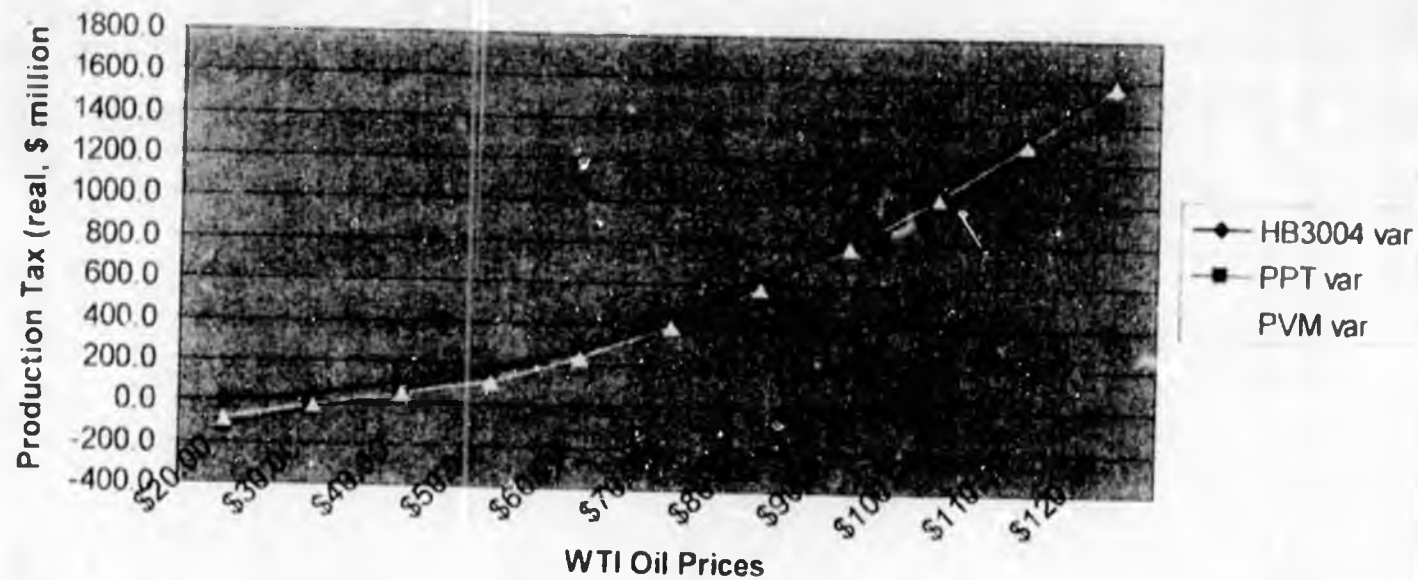
In order to evaluate the various **structures** three fiscal options were prepared which result in identical production tax revenues to the State based on the high cost 50MM-Low (\$13.50/bbl) and 150MM-Low (\$ 11/bbl) fields:

- With tax credits:
 - A PPT variation with a progressive feature
 - A variation of my 2001 proposal
- No or minor tax credits:
 - A variation of HB 3004

Three Fiscal Options

50MM-Low-high cost

Production Tax for 50MM-LOW for three options

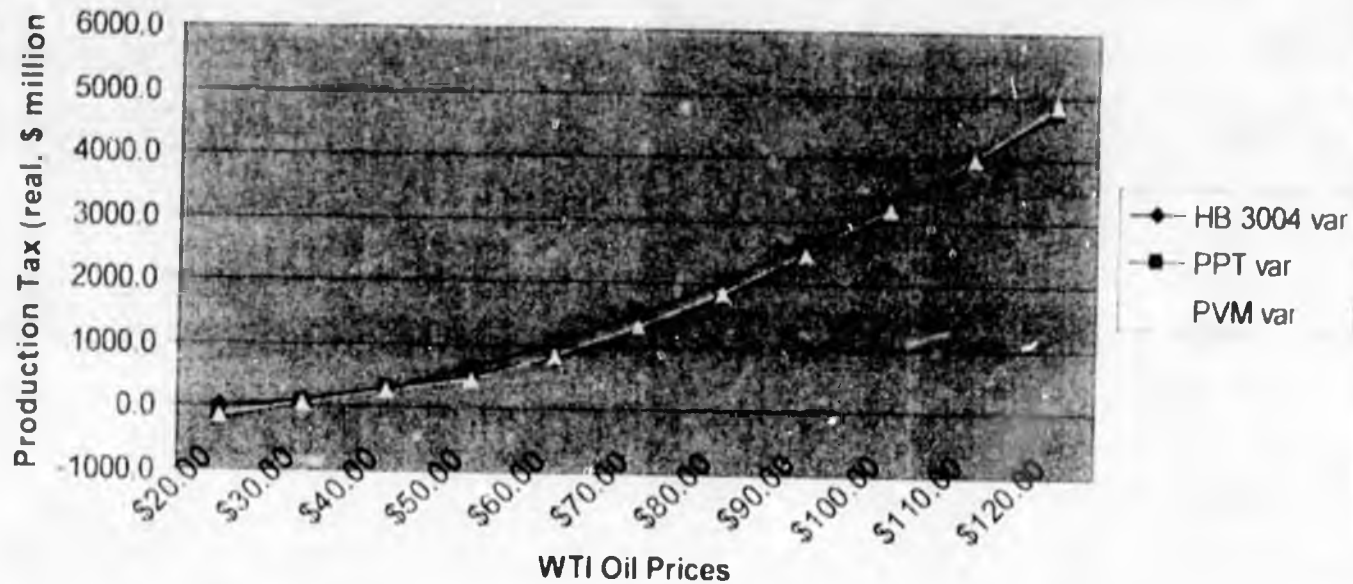


The Three fiscal options are calibrated to create almost the same undiscounted revenues to the State for the 50 MM-Low case.

Three Fiscal Options

150MM-Low-high cost

Production Tax for 150 MM-LOW for three options



The Three fiscal options are calibrated to create almost the same undiscounted revenues to the State under the 150 MM-Low case.

Three Fiscal Options

PPT variation

- Tax rate: 20%
- Tax credit: 20%
- Progressive feature based on net, starting at \$ 35 per barrel, increasing with 0.2% for every dollar.
- Maximum rate: 50%
- No corporate wide basic allowance.

Three Fiscal Options

PVM 2001 variation

- Flat nominal rate of 15%.
- Investment tax credits of 40% on all capital expenditures
- Price adjustment factor starting at \$ 50 per barrel based on ANS/50, price adjustment includes escalation.
- Maximum rate: 40%

Three Fiscal Options

HB 3004 variation

- Existing nominal rates and existing ELF
- Minimum rate of 6.5%
- Rate reduction below \$ 35 by 6% to \$ 20 per barrel.
- Price adjustment factor starting at \$ 35 per barrel based on ANS/35, price adjustment includes escalation.
- Extra percentage increase by 3% between \$ 70 and \$ 120 per barrel.
- Maximum rate: 40%