

ALASKA LEGISLATURE

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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(j), 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 ( ) 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 provides 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(e) (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 (1) 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 days:

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(e) 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 (c) 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 (e) 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, u. it, 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:

1 (B) does not include gas treatment:  
2 (22) "gas processing plant" means a facility that  
3 (A) extracts and recovers liquid hydrocarbons from a gaseous  
4 mixture of hydrocarbons by gas processing; and  
5 (B) is located upstream of any gas treatment and upstream of  
6 the inlet of any gas pipeline system transporting gas to a market:  
7 (23) "gas treatment"  
8 (A) means conditioning gas and removing from gas  
9 nonhydrocarbon substances for the purpose of rendering the gas acceptable for  
10 tender and acceptance into a gas pipeline system.  
11 (B) includes incidentally removing liquid hydrocarbons from  
12 the gas:  
13 (C) does not include  
14 (i) dehydration required to facilitate the movement of  
15 gas from the well to the point where gas processing takes place;  
16 (ii) the scrubbing of liquids from gas to facilitate gas  
17 processing;  
18 (24) "heating value" means the gross number of BTUs evolved by  
19 complete combustion of an amount of gas;  
20 (25) "landowner's royalty interest" means  
21 (A) a lessor's royalty interest under an oil and gas lease; or  
22 (B) a royalty interest that is  
23 (i) held by a surface owner of land from which oil or  
24 gas is produced; and  
25 (ii) granted in exchange for the right to use the surface  
26 of that land or as compensation for damage to the surface of that land;  
27 (26) "oil and gas lease" includes an oil and gas lease, a gas only lease,  
28 and an oil only lease;  
29 (27) "point of production" means  
30 (A) for oil, the automatic custody transfer meter or device  
31 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 (!) 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(e), 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(e), 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(e), as amended by sec. 28 of this Act.

15 (g) For purposes of taxes to be calculated and due under (e)(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 sees. 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(e).

**HB**

**3003**

**HFIN**

**FILE**

# FISCAL NOTE

STATE OF ALASKA  
2006 LEGISLATIVE SESSION

Fiscal Note Number: \_\_\_\_\_  
Bill Version: HB3003-DNR-O&G-07-26-0  
( ) Publish Date: \_\_\_\_\_

Revision Date/Time (Note if correction): \_\_\_\_\_ Dept. Affected: Natural Resources  
Title Oil and Gas Taxes/Adjustment/ELF RDU Resource Development  
Component Oil and Gas Development  
Sponsor Reps. Croft, Crawford, Gruenberg  
Requester Finance 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						
<b>TOTAL OPERATING</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>

<b>CAPITAL EXPENDITURES</b>						
-----------------------------	--	--	--	--	--	--

<b>CHANGE IN REVENUES ( )</b>						
-------------------------------	--	--	--	--	--	--

**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)						
<b>TOTAL</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>

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 to the Department of Natural Resources.

Prepared by: William Van Dyke, Acting Director  
Division: Oil and Gas  
Approved by: Michael Mongo, Commissioner  
Agency: Natural Resources

Phone: 269-8800  
Date/Time: 7/26/2006  
Date: 7/26/2006

# FISCAL NOTE

STATE OF ALASKA  
2006 LEGISLATIVE SESSION

Fiscal Note Number: \_\_\_\_\_  
Bill Version: HB 3003  
( ) Publish Date: \_\_\_\_\_

Revision Date/Time (Note if correction): \_\_\_\_\_ Dept. Affected: Revenue  
Title An Act Relating to the Oil and Gas Properties RDU Tax and Treasury  
Production Tax Component Tax  
Sponsor Rep. Croft  
Requester \_\_\_\_\_ 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	98.4	98.4	98.4	98.4	98.4	98.4
Travel	7.2	7.2	7.2	7.2	7.2	7.2
Contractual	112.5	3.1	3.1	3.1	3.1	3.1
Supplies	5.3	0.3	0.3	0.3	0.3	0.3
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous (OH office, etc)						
<b>TOTAL OPERATING</b>	<b>223.4</b>	<b>109.0</b>	<b>109.0</b>	<b>109.0</b>	<b>109.0</b>	<b>109.0</b>

<b>CAPITAL EXPENDITURES</b>						
-----------------------------	--	--	--	--	--	--

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

1002 Federal Receipts						
1003 GF Match						
1004 GF	223.4	109.0	109.0	109.0	109.0	109.0
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
<b>TOTAL</b>	<b>223.4</b>	<b>109.0</b>	<b>109.0</b>	<b>109.0</b>	<b>109.0</b>	<b>109.0</b>

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	1	1	1	1	1	1
Part-time						
Temporary						

**ANALYSIS:** (Attach a separate page if necessary)

This bill would amend the oil and gas production tax by establishing a minimum tax rate on most North Slope oil and gas production. With the exception of heavy oil, a base tax rate of 15% would apply to all North Slope oil production. From this tax base, each oil operating unit as defined by the Department of Natural Resources would be allowed an exemption of 10,000 barrels per day from taxation. A surcharge of 0.2% would be applied to every dollar or fraction of a dollar by which the gross value at point of production exceeds \$50, to a maximum of total tax rate (including surcharge) of 25%. Heavy oil production, defined as crude oil with an assay of 18 degrees or less using the American Petroleum Institute (API) scale) would be subject to a lower base tax rate, reduced by 5% for every 1 degree API gravity that the oil falls below the API gravity threshold of 18.

The bill would also amend the tax rate on natural gas production by establishing a base tax rate of 10%. Each gas operating unit would be allowed an exemption of 60,000 mcf per day from taxation. There is no surcharge on gas production under this proposal.

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

Phone 269-1019  
Date/Time 7/25/06 1:00 PM

Approved by: Jerry Burnett  
Agency: Department of Revenue

Date 7/25/2006

## FISCAL NOTE

STATE OF ALASKA  
2006 LEGISLATIVE SESSION

BILL NO. HB 3003

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### ANALYSIS CONTINUATION

The Department of Natural Resources currently defines 11 oil production operating units on the North Slope. These are the following units: Prudhoe Bay, Colville River, Kuparuk River, Milne Point, Duck Island, North Star, Badami, Point Thomson, Ooguruk, Nikaitchuq, and Tuvaq. Most of the fields in our oil production forecast fall into one of these units. Federal properties, however, including the Liberty field and parts of the NPR-A, have not yet been utilized. Fields that do not currently belong in a unit were considered single field units for the purposes of this analysis.

The 10,000 barrel per day exemption per unit translates to about 70,000 tax-free barrels per day in FY 2007, building to 120,000 barrels per day in FY 2012, with the startup of the Liberty, NPR-A, and offshore fields. At \$60 per barrel, 120,000 tax-free barrels per day in FY 2012 equal close to \$400 million of foregone revenue.

Problems associated with identifying, measuring, and monitoring heavy oil (as described below) make a realistic assessment of the tax treatment of heavy oil extremely difficult to complete. Due to these difficulties and to the relatively negligible tax impacts of the heavy oil tax calculation, we have chosen not to attempt to model heavy oil separately. This fiscal note also does not attempt to assess the impacts this tax would have on revenue from Cook Inlet oil and gas production.

There are four issues related to heavy oil in HB 3003 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 HB 3003, 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 degrees or less. While this appears to be a "clean" definition, it omits the fact that crude oils with an API of 18 degrees 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 centi Poise [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 force to move than less viscous materials.

## FISCAL NOTE

STATE OF ALASKA  
2006 LEGISLATIVE SESSION

BILL NO. HB 3003

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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. Oil produced at one level may be classified as heavy [less than 18 degrees 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.

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.

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.

Costs associated with this bill fall into three categories: (1) A one-time information technology/database change estimated to be \$50,000; (2) A one-time expenditure of about \$60,000 for assistance with drafting regulations; and (3) two half-time equivalent individuals for additional engineering and audit work pertinent to the heavy oil designation and to North Slope fields that currently pay little or no tax.

The bill would be effective September 1, 2006.

FISCAL NOTE

STATE OF ALASKA  
2006 LEGISLATIVE SESSION

BILL NO. HB 3003

**ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)**

The figures in the table below reflect the revenues that would be received from the bill relative to the status quo for FY 2007-2012 at the DOR forecast prices, 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.) The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. The status quo tax figures assume the January 2005 ELF aggregation decision by the Department of Revenue for Prudhoe Bay continues.

Fiscal Year	DOR Forecast	Status Quo Tax	Tax from Bill	Gain from Bill
2007*	\$53.60	989	1,525	537
2008	\$46.90	759	1,361	602
2009	\$25.50	355	647	292
2010	\$25.50	315	610	294
2011	\$25.50	281	582	301
2012	\$25.50	271	569	298

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill
2007*	\$40.00	708	1,088	380
2008	\$40.00	655	1,135	480
2009	\$40.00	631	1,160	529
2010	\$40.00	582	1,128	546
2011	\$40.00	544	1,110	566
2012	\$40.00	536	1,102	566

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill
2007*	\$60.00	1,120	1,811	691
2008	\$60.00	1,032	1,892	861
2009	\$60.00	978	1,948	971
2010	\$60.00	901	1,896	995
2011	\$60.00	842	1,866	1,024
2012	\$60.00	831	1,856	1,025

\*FY 2007 revenues were adjusted for September 1, 2006 start date

4-27-06

# **HB 3003**

## **The “True Value / Shelf the ELF” Bill**

**Representative Eric Croft  
House Finance Committee  
July 27, 2006**

**Yesterday's presentation did an excellent job of explaining the benefit of gross vs. net, and the need to reform the system this year.**

**This will be much more brief.**

# A Tax on the Gross is Better

- Simple and Understandable
- Easier to administer and audit
- Preferred by general public
- Can raise the same revenue as any PPT without the risk of manipulation
- Continues to raise revenue during gas field development without the problem of gas credits wiping out oil revenue

## **Oil production taxes are not like a “tax” on other kinds of business**

- Not a manufacturing process
- Not a service
- Oil companies are privatizing a publicly-owned resource. The portion received by the state is not a “tax,” it is the price we receive for selling our resources
- Selling our resources based on the “net” creates the possibility we can get nothing

# **Incentivizing new development is important. So is stopping the bleeding.**

Several factors why North Slope development expenditures are flat, that are beyond the scope of this bill:

1. New resources in unstable regimes in Central Asia and Africa must be developed quickly while there are still friendly governments
2. Other oil provinces enforce a much stronger “duty to develop”
3. Weak facility access works against new producers
4. High pipeline tariffs on TAPS system owned by the Big Three discourages new development

# What HB 3003 Does:

1. Raises same amount as 20/20 PPT at \$60 oil
2. Eliminates the complex and obsolete ELF language in AS 43.55.012-013
3. Base 15% tax on wellhead value
4. Progressivity of up to 25% at higher prices
5. Protects smaller fields and Cook Inlet with volume exclusion (“standard deduction”) of first 10,000 barrels per day per operating unit
6. Reduced rate for heavy oil
7. Broadens ability to challenge TAPS tariffs
8. Four pages long

# 1. Raises same amount as 20/20 PPT at \$60 oil

## Est. Revenue of Various Oil Tax Bills (\$ millions)

	\$40	\$60
Existing ELF	\$708	\$1,120
House Adopted SB 305 (21.5)	\$926	\$2,284
House Adopted SB 2001 (23.5)	\$1,171	\$2,881
Conf. Committee SB 2001 (22.8)	\$1,141	\$2,515
Governor's HB 3001 (20)	\$972	\$1,994
Rep. Gara's HB 3004	\$1,556	\$2,938
HB 3003 (begin progressivity at \$50)	\$1,188	\$1,995
HB 3003 (begin progressivity at \$35)	\$1,188	\$2,366

**Is 20 / 20 Too Low?**

**Yes.**

## **2. Eliminates the complex and obsolete ELF language in AS 43.55.012-013**

- Pedro Van Meurs says he attempted to fix the ELF in 2001
- Any “gross” tax reform that preserves the ELF formula will continue to have major distortion and unfairness
- At projected oil prices we don’t need the extreme tax breaks some fields receive with ELF

### 3. Base 15% tax on wellhead value

- Only auditable item is transportation, just like at present
- Eliminates 12.25% rate for first five years and obsolete “cents per barrel” tax

## 4. Progressivity of up to 25% at higher prices

- Uses similar mechanism as many of the PPT versions
- Increases tax rate by 0.2% per dollar above \$50 / barrel at the wellhead
- (Tax rate is 17% at \$60, 19% at \$70, etc)
- Hits maximum 25% rate at \$50 above trigger point, \$100 at the wellhead
- Easy to adjust bill to desired revenue by changing the trigger point

**5. Protects smaller fields and Cook Inlet with volume exclusion (“standard deduction”) of first 10,000 barrels per day per operating unit**

- The lower a unit’s production, the greater the tax benefit
- Value of the exclusion would be pro-rated among unit participants based upon percentage of volume produced
- Operating Unit is defined by DNR approval in AS 38.05.180(p)
- Using the Unit Agreement aggregates any satellite fields with the main field

**5. Protects smaller fields and Cook Inlet with volume exclusion (“standard deduction”) of first 10,000 barrels per day per operating unit**

**Currently seven oil producing units on the North Slope**

<b>Unit</b>	<b>Jan. 2006 daily production</b>	<b>Base Tax Rate under HB 3003</b>	<b>Current Rate with ELF</b>
Prudhoe Bay	473,700	14.7%	12.4%
Kuparuk	159,400	14.0%	0.0%
Colville River (Alpine)	122,700	13.8%	11.9%
Milne Point	42,100	11.4%	0.0%
Northstar	40,700	11.3%	6.1%
Duck Island (Endicott)	19,200	7.2%	0.0%
Badami	1,570	0.0%	0.0%

**5. Protects smaller fields and Cook Inlet with volume exclusion (“standard deduction”) of first 10,000 barrels per day per operating unit**

**Currently four oil producing units in Cook Inlet**

**All will pay zero production tax under HB 3003**

## 6. Reduced rate for heavy oil

- Oil with API gravity of 18 or more pays the full rate
- For each point below 18, the tax rate is decreased by 5%
- (Thus API 17 oil pays 95% the taxes of API 18 oil)

## 7. Broadens ability to challenge TAPS tariffs

- Tariff and transportation costs are the only “fudgeable” numbers in the gross tax system
- Currently, “gross value at the point of production” equals market price less reasonable transportation
- Existing law says that “reasonable” costs equals “actual” costs unless three conditions exist
  1. Producer and transporter are “affiliated”
  2. Not an “arms length transaction”
  3. Method of transportation is not reasonable
- Bill clarifies that only one of three needs to exist for DOR to intervene in determining reasonable costs

## 8. Four pages long

- Simple, readable, understandable bill
- No hidden surprises in the language
- No new powers or processes
- No hidden surprises in the language

## Similarities between HB 3003 and HB 3004

- Both based on gross wellhead value
- Both use a base 15% rate, with lower rates for certain oil fields
- Both have progressivity with maximum rates between 25% and 27.5% that are reached at about \$100 oil

# Differences between HB 3003 and HB 3004

- HB 3003 goes to a flat 15% rate  
HB 3004 keeps the ELF but substitutes a 5% alternative minimum “floor”
- HB3003 has the 15% rate for all prices up to the progressivity trigger point  
HB 3004 has “reverse progressivity” below \$16 and the ability to apply for tax relief
- HB 3003 addresses tariff issues  
HB 3004 addresses facility access issues
- Different revenue, but both bills can be adjusted to generate desired revenue

# Possible alternative approach: capital development credits

- 20% tax credit for well development and construction
- Broadens the existing 40% exploration tax credit
- May not reduce taxes by more than  $\frac{1}{2}$ , but can be carried forward
- Must be for well construction and related capital expenditures
- May not be used for administration, management, and other indirect costs

# Conclusion

## Legislative Wisdom

1. Law of Unintended Consequences  
*Minimum Action to Fix Known Problem*
2. If You Don't Understand It, Vote No  
*Get A Bill We Understand*
3. Politics Gets in the Way of Good Policy  
*We Can Do Great Things if We Don't Care  
Who Gets the Credit*

## HB 3003 Croft True Value "Shelf the ELF" Bill

### Bill Summary:

- Eliminates ELF multiplier, keeping base 15% tax rate on wellhead value. Royalty oil is excluded
- Progressivity of 0.2% per dollar over \$50 wellhead value, with a maximum tax rate of 25% reached at \$100 oil
- Standard deduction for oil of 10,000 barrels per day per operating unit. The net effect is, smaller units pay significantly less than Prudhoe Bay and Cook Inlet operators pay zero
- Standard deduction for gas of 60,000 Mcf per day per operating unit. This preserves our existing taxes for future North Slope production, and taxes less than 1/3 of Cook Inlet gas
- Tax rate reduced by 5% per degree for heavy oil below 18 degrees API
- Broadens the state's ability to challenge TAPS tariffs
- Estimated revenue is comparable to what the oil companies agreed to in the Governor's original 20 / 20 PPT bill
- Fair and simple bill easy to implement and regulate

	Existing ELF	Governor's PPT HB-3001	Conference Committee PPT SB 2001	Croft's True Value Plan HB 3003
Base Oil Tax	15%	20%	22.8%	15%
Base Gas Tax	10%	6.67%	20%	10%
Tax Basis	Gross Value	Reported Profits	Reported Profits	Gross Value
Heavy Oil Benefit	None if oil over about \$10 / bbl	None	None	5% tax break for each degree below API 18
Complexity	Moderate	High	Extreme	Low
Verifiable?	Yes	No	No	Yes
Playground for Lawyers?	Moderate	High	High	Low
2007 Revenue at \$40 Oil	\$708 million	\$972 million	\$1,140 million	\$1,188 million
2007 Revenue at \$60 Oil	\$1,120 million	\$1,994 million	\$2,515 million	\$1,995 million

**HB 3003**  
**Croft True Value "Shelf the Elf" Bill**  
**Sectional Analysis**

**Section 1**

Eliminates tax rate reference to ELF multiplier and alternative cents-per-barrel tax on oil.

**Section 2**

Eliminates 12.25% tax rate for first five years of production, leaving only the base 15% rate. Adds a progressivity multiplier by which the tax rate increases by 0.2% per dollar above \$50 / barrel, calculated on gross value at the wellhead. Maximum rate is 25% is reached when oil value reaches \$100 / barrel.

**Section 3**

Adds exclusion from oil taxes for first 10,000 barrels per day per operating unit. Value of exclusion is pro-rated among unit participants. Creates multiplier for heavy oil; the tax is reduced by 5% of the total per point of API for each point below 18.

**Section 4**

Eliminates alternative cents-per-Mcf tax on gas.

**Section 5**

Clarifies base 10% tax rate on gas, adding the word "taxable" so as to enable exclusion described in Section 6.

**Section 6**

Adds exclusion from gas taxes for first 60,000 Mcf per day per operating unit. Value of exclusion is pro-rated among unit participants.

**Section 7**

Clarifies that "gross value at the point of production" is based on reasonable transportation costs, and broadens the circumstances under which "actual cost" is not the appropriate measure.

**Section 8**

When actual cost is inappropriate, generally when the producer and pipeline owner are affiliated entities, the state shall determine reasonable transportation costs.

**Section 9**

Creates a definition of "operating unit" for the purpose of the Section 3 and Section 6 exclusions.

**Section 10**

Repeals chapters related to the ELF multiplier calculation and related definitions.

**Section 11**

Effective date

7/27/06

## CPF Testimony before House Finance on HB3004

1. Before proceeding, I want to disclose to you that, immediately prior to serving on the AOGCC, I worked as an engineering consultant and, as such, I participated in preparing the "North Slope of Alaska Facility Sharing Study" performed by Petrotechnical Resources of Alaska for the Division of Oil and Gas of the Department of Natural Resources. I discussed this participation with the other AOGCC commissioners and they agreed that this did not represent a conflict of interest. However, I did want to disclose the information to you.
2. My comments will be limited to Section 1 of HB 3004 addressing facility access.
3. The AOGCC recognizes the need to enable new operators to acquire reasonable access to existing facility infrastructure.
4. If the Legislature adopts HB3004, the AOGCC will do our best to implement it.
5. That said, there are a few challenges to implementing this bill as it is currently written and, if you'll bear with some technical description from me, I'll explain what those are with some suggested ways around them.
6. The bill requires working interest owners to provide access to production or other facilities "only if the commission finds that the facility has excess capacity and that directing the working interest owner to provide access by or for the benefit of others would not materially interfere with the owner's paramount use of the facility." The AOGCC has two concerns with this wording.

- a. First, there will never be excess capacity in the oil production facilities that this bill is targeting. Let me explain why I say this.

#### Explain Facility Capacity

However, there is a way that new production can, and in fact already does, get access:

#### Explain Back Out

That's how it looks for the existing owners' new production. For a new player, this is how it would look:

Show how the DNR study suggests letting someone new in

- b. Even if we get past the "excess capacity" wording, there is a second complication. Since the owner's paramount use of the facility is to separate the associated gas and water from their oil, any back out for another operator would interfere with their "paramount use of the facility."
7. Supposing that we work our way past these two concerns, let's next take a look at the fiscal impact.
    - a. First, a primary role here is a rate-setting role, and the AOGCC has no staffing or experience in rate setting. Therefore, to take on this rate-setting role we would have to hire accountants and/or other financial expertise.

- b. Second, we would need someone on staff who understands and can oversee facility optimization; we currently have no one on staff to perform that function.
- 8. We have one final concern with placing this authority within the AOGCC. And that is the potential for conflict with the AOGCC's role implementing the Oil & Gas Conservation Act. The commission is charged with preventing waste, ensuring greater ultimate recovery, protecting correlative rights, and protecting ground waters. Decisions under this bill may be in conflict with the commission's responsibility to prevent waste of hydrocarbon resources and ensure greater ultimate recovery. For example, granting access to a production facility for one WIO's high-oil-rate well may result in the permanent loss of oil from the WIO whose marginal well is backed out of the facility.
- 9. Our recommendation would be to give this rate-setting responsibility to either a new or an existing agency that is intended as a rate-setting agency.
- 10. I want to conclude by reiterating what I said first: The AOGCC recognizes the need to enable new operators to acquire reasonable access to existing facility infrastructure, and if the Legislature adopts HB3004, the AOGCC will do our best to implement it.

Judy  
Brady

**Testimony of the  
Alaska Oil & Gas Association  
to the  
House Finance Committee  
July 27, 2006**

**HB 3003 and HB 3004**

Thank you for the opportunity to comment on the proposed production tax legislation you've been discussing – proposed legislation that increases oil production taxes substantially.

My name is Judy Brady. I am testifying today as executive director of the Alaska Oil & Gas Association (AOGA). With me is Michael Hurley, chairman of AOGA's Tax Committee. AOGA is a private non-profit trade association whose 18 member companies represent the majority of the oil and gas exploration, production, transportation, refining and marketing activities in Alaska.

HB 3003 and HB 3004 are tax bills introduced for the first time in this special session. Both proposed bills go back to the present production tax – and add some new twists, in order to increase taxes; HB 3004 adds complications to the present tax system, and raises policy issues that are arguably outside the call of this special session; both are strictly tax increases on the gross production at a level that fails to address the critical need for Alaska to attract new investment at the same time as the state's share in oil revenues increases.

You have heard us say many times that declining production is the eight hundred pound gorilla in Alaska's future. Tax legislation must be configured to attract the new investment necessary to increase production. Incentives for new investment and reasonable tax rates that keep Alaska competitive with like oil and gas regions must be part of the package. Any legislation that overreaches on tax rates or neglects real world incentives will simply be a black hole that leaves Alaska as a backwater in worldwide oil and gas regions.

There are now 14 days left in this special session – and four tax bills on the table. HB 3003 and HB 3004 you've just been hearing. HB 3005 was introduced two days ago. We understand two other bills are being drafted. Of the four tax bills presently on the table, only one has been the subject of long and intense review and scrutiny – and that is HB 3001, the Petroleum Production Tax legislation. The PPT legislation was the subject of hundreds of hours of hearings in the last legislative session and in the last special session. It has been reviewed and critiqued by consultants hired by the legislature, the administration and the oil and gas companies affected. The parameters of this legislation are well understood.

We ask you to consider focusing the remaining days in this special session on reviewing, finalizing and adopting HB 3001. The fact of the matter is that developing clear, fair tax legislation that both incentivizes investment and brings a larger share of revenue to the state...is rocket science. Those of you who have spent hundreds of hours trying to develop fair, equitable legislation, are well aware of this fact. Rocket science takes time. The legislature has spent that time on a new approach for oil production tax in Alaska - a tax that

reflects real production economics. A tax that substitutes real cost figures for the proxy Economic Limit Factor. The promise is that this tax will increase revenues to Alaska by over one billion dollars a year. The promise is that in addition to increased revenues, this tax will provide incentives for new investments for the new production so desperately needed.

#### AOGA Supports HB3001 – Governor's PPT

- Even Though many of our members remain concerned that the increased level of state take reflected in this bill will result in reduced investment in Alaska. This bill would raise taxes on the industry over \$1 billion a year at \$60/bbl.
- There continues to be a sense of astonishment in oil and gas financial circles about this agreement to a tax increase of this size.
- And would raise total government take to around 60%.
- "Government take" – royalty; production tax, corporate Income tax; property tax, federal taxes
- What do "costs" have to do with it– costs have to be counted-either directly or as a proxy to conserve oil in the ground in maturing fields
- PPT more accurately reflects true production economics
- The balance in the PPT is the higher tax rate counterbalanced by the reinvestment incentive.
- The balance is essential – throughout the hearings on PPT there have been references to countries with a "higher" government take than Alaska – as Pedro Van Muers and other consultants have pointed out, many of those countries either have government-owned oil companies or are using production sharing contracts. In both cases the governments take a bigger share of risk for a bigger share of profits.
- Some policy makers seem to be frozen between the concepts of "risk" and "profits". They want a lot more of the share of the profits; they don't want any share of the risk.
- This one-sided "two for me – one for you" won't work in the worldwide competitive market. Under those terms, Alaska's won't even place for new investment in any serious way.

Gross Versus Net tax – Criticisms of a Net system seem to be based on a misunderstanding of how the present system works and how the PPT would work.

- The ELF in the current system is a proxy for costs. So in that sense the current system is a form of "net" tax. The PPT simply substitutes real costs for the proxy.
- Some legislators have expressed the concern that the state does not have the capability to determine real costs. However the State currently audits the costs in the netback in a lot of detail.
- Operating and capital costs are in our state income tax return and Property tax renderings

#### AOGA Does Not Support either HB3003 or HB3004

- These bills are simply tax increases- with no counterbalance
- No re-investment incentives, do nothing to stem decline or encourage investment, there's no structural change in the risk sharing.
- With HB3003 ELF disappears so there's no recognition of costs at all.

FINAL

- HB3004 is a band-aid approach -- a higher rate, with much more complexity . It seemed puzzling that the sponsor spent so much of his time providing figures about the industries profits, yet was proposing a tax that has nothing to do with the profits.

#### Oil and Gas Tax Legislation Is Not a Game of Texas Hold 'Em

- Whether it is political one-ups-man-ship during an election year – or real belief that Alaska does not have to be competitive to attract new investment – the bidding up of how much the State of Alaska can "make" or "take" from oil production is going to lose the game for all of us.

The end game for Oil and Gas Tax Legislation can be About a Higher Return for the State of Alaska but must recognize the need for Incentives that foster additional Investment – Bottom Line – It is About Increasing Production and keeping Alaska competitive.

7/27/06  
Cathy Foerster

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4. If the Legislature adopts HB3004, the AOGCC will do our best to implement it.
5. That said, there are a few challenges to implementing this bill as it is currently written and, if you'll bear with some technical description from me, I'll explain what those are with some suggested ways around them.
6. The bill requires working interest owners to provide access to production or other facilities "only if the commission finds that the facility has **excess capacity** and that directing the working interest owner to provide access by or for the benefit of others would not **materially interfere with the owner's paramount use of the facility.**" The AOGCC has two concerns with this wording.

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7. Supposing that we work our way past these two concerns, let's next take a look at the fiscal impact.
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9. Our recommendation would be to give this rate-setting responsibility to either a new or an existing agency that is intended as a rate-setting agency.
10. I want to conclude by reiterating what I said first: The AOGCC recognizes the need to enable new operators to acquire reasonable access to existing facility infrastructure, and if the Legislature adopts HB3004, the AOGCC will do our best to implement it.

**HB**

**30004**

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**SPONSOR SUBSTITUTE FOR HOUSE BILL NO. 3004  
IN THE LEGISLATURE OF THE STATE OF ALASKA  
TWENTY-FOURTH LEGISLATURE - THIRD SPECIAL SESSION**

**BY REPRESENTATIVES GARA, Berkowitz, Gardner, Keritula, Grueberg, Guttberg**

Introduced:  
Referred:

**A BILL**

**FOR AN ACT ENTITLED**

1 "An Act relating to oil and gas, and to the oil and gas properties production (severance)  
2 tax as it applies to oil; providing for an adjustment to increase the tax collected when oil  
3 prices exceed \$20 per barrel and to reduce the tax collected when oil prices fall below  
4 \$16 per barrel; providing for relief from the tax when the price per barrel is low or  
5 when the taxpayer demonstrates that a reduction in the tax is necessary to establish or  
6 reestablish production from an oil field or pool that would not otherwise be  
7 economically feasible; delaying until July 1, 2016, the deadline for certain exploration  
8 expenditures that form the basis for a credit against the tax on oil and gas produced  
9 from a lease or property in the state; amending the powers and duties of the Alaska Oil  
10 and Gas Conservation Commission; relating to the conservation surcharge and  
11 additional conservation surcharge on oil; and providing for an effective date."

12 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

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1 \* Section 1. AS 31.05.030(d) is amended to read:

2 (d) The commission may require

3 (1) identification of ownership of wells, producing leases, tanks,  
4 plants, and drilling structures;

5 (2) the making and filing of reports, well logs, drilling logs, electric  
6 logs, lithologic logs, directional surveys, and all other subsurface information on a  
7 well drilled for oil or gas, or for the discovery of oil or gas, or for geologic  
8 information, and the required reports and information shall be filed within 30 days  
9 after the completion, abandonment, or suspension of the well;

10 (3) the drilling, casing, and plugging of wells in a manner that will  
11 prevent the escape of oil or gas out of one stratum into another, the intrusion of water  
12 into an oil or gas stratum, the pollution of fresh water supplies by oil, gas, or salt  
13 water, and prevent blowouts, cavings, seepages and fires;

14 (4) the furnishing of a reasonable bond with sufficient surety  
15 conditions for the performance of the duty to plug each dry or abandoned well or the  
16 repair of wells causing waste;

17 (5) the operation of wells with efficient gas-oil and water-oil ratios,  
18 and may fix these ratios;

19 (6) the gauging or other measuring of oil and gas to determine the  
20 quality and quantity of oil and gas;

21 (7) every person who produces oil or gas in the state to keep and  
22 maintain for a period of five years in the state complete and accurate records of the  
23 quantities of oil and gas produced, which shall be available for examination by the  
24 Department of Natural Resources or its agents at all reasonable times;

25 (8) the measuring and monitoring of oil and gas pool pressures;

26 (9) the filing and approval of a plan of development and operation for  
27 a field or pool in order to prevent waste, ensure [INSURE] a greater ultimate recovery  
28 of oil and gas, and protect the correlative rights of persons owning interests in the  
29 tracts of land affected;

30 (10) working interest owners to provide, at cost plus a reasonable  
31 rate of return determined under regulations adopted by the commission and

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1 without causing substantial injury to the owner, access to production and other  
2 facilities whenever necessary; for purposes of this paragraph, the commission's  
3 regulations must be consistent with the standards of the Regulatory Commission  
4 of Alaska adopted to implement AS 42.05.311(a); the commission may act under  
5 this paragraph

6 (A) to

7 (i) maximize the economic and physical recovery of  
8 the state's oil and gas resources;

9 (ii) maximize competition among parties seeking to  
10 explore and develop the state's oil and gas resources;

11 (iii) minimize the adverse effects of exploration,  
12 development, production, and transportation activity; or

13 (iv) otherwise protect the best interest of the state;

14 and

15 (B) only if the commission finds that the facility has excess  
16 capacity and that directing the working interest owner to provide access  
17 by or for the benefit of others would not materially interfere with the  
18 owner's paramount use of the facility.

19 \* Sec. 2. AS 36.30.850(b)(33) is amended to read:

20 (33) contracts between the Department of Natural Resources or the  
21 Department of Revenue, as appropriate, and contractors qualified to evaluate  
22 hydrocarbon development, production, transportation, and economics, to assist the  
23 commissioner of natural resources or the commissioner of revenue, as appropriate,  
24 in evaluating applications for

25 (A) royalty increases or decreases or other royalty adjustments,  
26 and evaluating the related financial and technical data, entered into under  
27 AS 38.05.180(j); or

28 (B) tax reductions, and evaluating the related financial and  
29 technical data, as authorized by AS 43.55.011(i) and (j);

30 ^ Sec. 3. AS 43.55.011(a) is amended to read:

31 (a) There is levied upon the producer of oil a tax for all oil produced from