

HB 247
INTRO &
EXECUTIVE
BRANCH
MATERIALS
(FILE 1)

<TARGET><BILL>HB 247</BILL><SUBJECT>HB 247 INTRODUCTION
and EXECUTIVE BRANCH MATERIALS (FILE
1)</SUBJECT><COMM>HRES29</COMM></TARGET>

HOUSE BILL NO. 247

IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-NINTH LEGISLATURE - SECOND SESSION

BY THE HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced: 1/19/16
Referred:

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to confidential information status and public record status of
2 information in the possession of the Department of Revenue; relating to interest
3 applicable to delinquent tax; relating to disclosure of oil and gas production tax credit
4 information; relating to refunds for the gas storage facility tax credit, the liquefied
5 natural gas storage facility tax credit, and the qualified in-state oil refinery
6 infrastructure expenditures tax credit; relating to the minimum tax for certain oil and
7 gas production; relating to the minimum tax calculation for monthly installment
8 payments of estimated tax; relating to interest on monthly installment payments of
9 estimated tax; relating to limitations for the application of tax credits; relating to oil and
10 gas production tax credits for certain losses and expenditures; relating to limitations for
11 nontransferable oil and gas production tax credits based on oil production and the
12 alternative tax credit for oil and gas exploration; relating to purchase of tax credit

1 certificates from the oil and gas tax credit fund; relating to a minimum for gross value at
 2 the point of production; relating to lease expenditures and tax credits for municipal
 3 entities; adding a definition for "qualified capital expenditure"; adding a definition for
 4 "outstanding liability to the state"; repealing oil and gas exploration incentive credits;
 5 repealing the limitation on the application of credits against tax liability for lease
 6 expenditures incurred before January 1, 2011; repealing provisions related to the
 7 monthly installment payments for estimated tax for oil and gas produced before
 8 January 1, 2014; repealing the oil and gas production tax credit for qualified capital
 9 expenditures and certain well expenditures; repealing the calculation for certain lease
 10 expenditures applicable before January 1, 2011; making conforming amendments; and
 11 providing for an effective date."

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

13 * **Section 1.** AS 38.05.036(a) is amended to read:

14 (a) The department may conduct audits regarding royalty and net profits under
 15 oil and gas contracts, agreements, or leases under this chapter and regarding costs
 16 related to exploration licenses entered into under AS 38.05.131 - 38.05.134 and
 17 exploration incentive credits under this chapter [OR UNDER AS 41.09]. For purposes
 18 of audit under this section,

19 (1) the department may examine the books, papers, records, or
 20 memoranda of a person regarding matters related to the audit; and

21 (2) the records and premises where a business is conducted shall be
 22 open at all reasonable times for inspection by the department.

23 * **Sec. 2.** AS 38.05.036(b) is amended to read:

24 (b) The Department of Revenue may obtain from the department information
 25 relating to royalty and net profits payments and to exploration incentive credits under
 26 this chapter [OR UNDER AS 41.09], whether or not that information is confidential.
 27 The Department of Revenue may use the information in carrying out its functions and

1 responsibilities under AS 43, and shall hold that information confidential to the extent
2 required by an agreement with the department or by AS 38.05.035(a)(8) [,
3 AS 41.09.010(d),] or AS 43.05.230.

4 * **Sec. 3.** AS 38.05.036(c) is amended to read:

5 (c) The department may obtain from the Department of Revenue all
6 information obtained under AS 43 relating to royalty and net profits and to exploration
7 incentive credits. The department may use the information for purposes of carrying out
8 its responsibilities and functions under this chapter [AND AS 41.09]. Information
9 made available to the department that was obtained under AS 43 is confidential and
10 subject to the provisions of AS 43.05.230.

11 * **Sec. 4.** AS 38.05.036(f) is amended to read:

12 (f) Except as otherwise provided in this section or in connection with official
13 investigations or proceedings of the department, it is unlawful for a current or former
14 officer, employee, or agent of the state to divulge information obtained by the
15 department as a result of an audit under this section that is required by an agreement
16 with the department or by AS 38.05.035(a)(8) [OR AS 41.09.010(d)] to be kept
17 confidential.

18 * **Sec. 5.** AS 38.05.036(g) is amended to read:

19 (g) Nothing in this section prohibits the publication of statistics in a manner
20 that maintains the confidentiality of information to the extent required by an
21 agreement with the department or by AS 38.05.035(a)(8) [OR AS 41.09.010(d)].

22 * **Sec. 6.** AS 40.25.100(a) is amended to read:

23 (a) Information in the possession of the Department of Revenue that discloses
24 the particulars of the business or affairs of a taxpayer or other person, including
25 information under AS 38.05.020(b)(11) that is subject to a confidentiality agreement
26 under AS 38.05.020(b)(12), is not a matter of public record, except as provided in
27 AS 43.05.230(i) - (l) [AS 43.05.230(i) OR (k)] or for purposes of investigation and
28 law enforcement. The information shall be kept confidential except when its
29 production is required in an official investigation, administrative adjudication under
30 AS 43.05.405 - 43.05.499, or court proceeding. These restrictions do not prohibit the
31 publication of statistics presented in a manner that prevents the identification of

1 particular reports and items, prohibit the publication of tax lists showing the names of
 2 taxpayers who are delinquent and relevant information that may assist in the collection
 3 of delinquent taxes, or prohibit the publication of records, proceedings, and decisions
 4 under AS 43.05.405 - 43.05.499.

5 * **Sec. 7.** AS 43.05.225 is amended to read:

6 **Sec. 43.05.225. Interest.** Unless otherwise provided,

7 (1) a delinquent tax under this title,

8 [(A) BEFORE JANUARY 1, 2014, BEARS INTEREST IN
 9 EACH CALENDAR QUARTER AT THE RATE OF FIVE PERCENTAGE
 10 POINTS ABOVE THE ANNUAL RATE CHARGED MEMBER BANKS
 11 FOR ADVANCES BY THE 12TH FEDERAL RESERVE DISTRICT AS OF
 12 THE FIRST DAY OF THAT CALENDAR QUARTER, OR AT THE
 13 ANNUAL RATE OF 11 PERCENT, WHICHEVER IS GREATER,
 14 COMPOUNDED QUARTERLY AS OF THE LAST DAY OF THAT
 15 QUARTER; OR

16 (B) ON AND AFTER JANUARY 1, 2014,] bears interest in
 17 each calendar quarter at the rate of seven [THREE] percentage points above
 18 the annual rate charged member banks for advances by the 12th Federal
 19 Reserve District as of the first day of that calendar quarter compounded
 20 quarterly as of the last day of that quarter;

21 (2) the interest rate is 12 percent a year for

22 (A) delinquent fees payable under AS 05.15.095(c); and

23 (B) unclaimed property that is not timely paid or delivered, as
 24 allowed by AS 34.45.470(a).

25 * **Sec. 8.** AS 43.05.230 is amended by adding a new subsection to read:

26 (l) The name of each person claiming a credit under AS 43.55, the aggregate
 27 amount of credits under AS 43.55, except for the credit in AS 43.55.024(j), claimed by
 28 the taxpayer in the calendar year, and a description of the taxpayer's activities that
 29 generated the credits claimed are public information.

30 * **Sec. 9.** AS 43.20.046(e) is amended to read:

31 (e) The department may use available money in the oil and gas tax credit fund

1 established in AS 43.55.028 to make the refund applied for under (d) of this section in
2 whole or in part if the department finds that (1) the claimant does not have an
3 outstanding liability to the state [FOR UNPAID DELINQUENT TAXES UNDER
4 THIS TITLE]; and (2) after application of all available tax credits, the claimant's total
5 tax liability under this chapter for the calendar year in which the claim is made is zero.
6 [IN THIS SUBSECTION, "UNPAID DELINQUENT TAX" MEANS AN AMOUNT
7 OF TAX FOR WHICH THE DEPARTMENT HAS ISSUED AN ASSESSMENT
8 THAT HAS NOT BEEN PAID AND, IF CONTESTED, HAS NOT BEEN FINALLY
9 RESOLVED IN THE TAXPAYER'S FAVOR.]

10 * **Sec. 10.** AS 43.20.047(e) is amended to read:

11 (e) The department may use money available in the oil and gas tax credit fund
12 established in AS 43.55.028 to make a refund or payment under (d) of this section in
13 whole or in part if the department finds that

14 (1) the claimant does not have an outstanding liability to the state
15 [FOR UNPAID DELINQUENT TAXES UNDER THIS TITLE]; and

16 (2) after application of all available tax credits, the claimant's total tax
17 liability under this chapter for the calendar year in which the claim is made is zero. [IN
18 THIS SUBSECTION, "UNPAID DELINQUENT TAX" MEANS AN AMOUNT OF
19 TAX FOR WHICH THE DEPARTMENT HAS ISSUED AN ASSESSMENT THAT
20 HAS NOT BEEN PAID AND, IF CONTESTED, HAS NOT BEEN FINALLY
21 RESOLVED IN THE TAXPAYER'S FAVOR.]

22 * **Sec. 11.** AS 43.20.053(e) is amended to read:

23 (e) The department may use money available in the oil and gas tax credit fund
24 established in AS 43.55.028 to make a refund or payment under (d) of this section in
25 whole or in part if the department finds that

26 (1) the claimant does not have an outstanding liability to the state
27 [FOR UNPAID DELINQUENT TAXES UNDER THIS TITLE]; and

28 (2) after application of all available tax credits, the claimant's total tax
29 liability under this chapter for the calendar year in which the claim is made is zero.

30 * **Sec. 12.** AS 43.55.011(f) is repealed and reenacted to read:

31 (f) The levy of tax under (e) of this section for

1 (1) oil and gas produced before January 1, 2022, from leases or
 2 properties that include land north of 68 degrees North latitude, other than gas subject
 3 to (o) of this section, may not be less than five percent of the gross value at the point
 4 of production; and

5 (2) oil produced on and after January 1, 2022, from leases or properties
 6 that include land north of 68 degrees North latitude, may not be less than five percent
 7 of the gross value at the point of production.

8 * **Sec. 13.** AS 43.55.020(a) is amended to read:

9 (a) For a calendar year, a producer subject to tax under AS 43.55.011 shall pay
 10 the tax as follows:

11 (1) for oil and gas produced before January 1, 2014, an installment
 12 payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied
 13 as allowed by law, is due for each month of the calendar year on the last day of the
 14 following month; except as otherwise provided under (2) of this subsection, the
 15 amount of the installment payment is the sum of the following amounts, less 1/12 of
 16 the tax credits that are allowed by law to be applied against the tax levied by
 17 AS 43.55.011(e) for the calendar year, but the amount of the installment payment may
 18 not be less than zero:

19 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
 20 produced from leases or properties in the state outside the Cook Inlet
 21 sedimentary basin, other than leases or properties subject to AS 43.55.011(f),
 22 the greater of

23 (i) zero; or

24 (ii) the sum of 25 percent and the tax rate calculated for
 25 the month under AS 43.55.011(g) multiplied by the remainder obtained
 26 by subtracting 1/12 of the producer's adjusted lease expenditures for the
 27 calendar year of production under AS 43.55.165 and 43.55.170 that are
 28 deductible for the oil and gas under AS 43.55.160 from the gross value
 29 at the point of production of the oil and gas produced from the leases or
 30 properties during the month for which the installment payment is
 31 calculated;

1 (B) for oil and gas produced from leases or properties subject
2 to AS 43.55.011(f), the greatest of

3 (i) zero;

4 (ii) zero percent, one percent, two percent, three
5 percent, or four percent, as applicable, of the gross value at the point of
6 production of the oil and gas produced from the leases or properties
7 during the month for which the installment payment is calculated; or

8 (iii) the sum of 25 percent and the tax rate calculated for
9 the month under AS 43.55.011(g) multiplied by the remainder obtained
10 by subtracting 1/12 of the producer's adjusted lease expenditures for the
11 calendar year of production under AS 43.55.165 and 43.55.170 that are
12 deductible for the oil and gas under AS 43.55.160 from the gross value
13 at the point of production of the oil and gas produced from those leases
14 or properties during the month for which the installment payment is
15 calculated;

16 (C) for oil or gas subject to AS 43.55.011(j), (k), or (o), for
17 each lease or property, the greater of

18 (i) zero; or

19 (ii) the sum of 25 percent and the tax rate calculated for
20 the month under AS 43.55.011(g) multiplied by the remainder obtained
21 by subtracting 1/12 of the producer's adjusted lease expenditures for the
22 calendar year of production under AS 43.55.165 and 43.55.170 that are
23 deductible under AS 43.55.160 for the oil or gas, respectively,
24 produced from the lease or property from the gross value at the point of
25 production of the oil or gas, respectively, produced from the lease or
26 property during the month for which the installment payment is
27 calculated;

28 (D) for oil and gas subject to AS 43.55.011(p), the lesser of

29 (i) the sum of 25 percent and the tax rate calculated for
30 the month under AS 43.55.011(g) multiplied by the remainder obtained
31 by subtracting 1/12 of the producer's adjusted lease expenditures for the

1 calendar year of production under AS 43.55.165 and 43.55.170 that are
 2 deductible for the oil and gas under AS 43.55.160 from the gross value
 3 at the point of production of the oil and gas produced from the leases or
 4 properties during the month for which the installment payment is
 5 calculated, but not less than zero; or

6 (ii) four percent of the gross value at the point of
 7 production of the oil and gas produced from the leases or properties
 8 during the month, but not less than zero;

9 (2) an amount calculated under (1)(C) of this subsection for oil or gas
 10 subject to AS 43.55.011(j), (k), or (o) may not exceed the product obtained by
 11 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
 12 applicable, for gas or set out in AS 43.55.011(k)(1) or (2), as applicable, for oil, but
 13 substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the
 14 amount of taxable gas produced during the month for the amount of taxable gas
 15 produced during the calendar year and substituting in AS 43.55.011(k)(1)(A) or
 16 (2)(A), as applicable, the amount of taxable oil produced during the month for the
 17 amount of taxable oil produced during the calendar year;

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

22 (A) the applicable tax rate for oil provided under
 23 AS 43.55.011(i), multiplied by the gross value at the point of production of the
 24 oil taxable under AS 43.55.011(i) and produced from the lease or property
 25 during the month; and

26 (B) the applicable tax rate for gas provided under
 27 AS 43.55.011(i), multiplied by the gross value at the point of production of the
 28 gas taxable under AS 43.55.011(i) and produced from the lease or property
 29 during the month;

30 (4) any amount of tax levied by AS 43.55.011, net of any credits
 31 applied as allowed by law, that exceeds the total of the amounts due as installment

1 payments of estimated tax is due on March 31 of the year following the calendar year
2 of production;

3 (5) for oil and gas produced on and after January 1, 2014, and before
4 January 1, 2022, an installment payment of the estimated tax levied by
5 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
6 month of the calendar year on the last day of the following month; except as otherwise
7 provided under (6) of this subsection, the amount of the installment payment is the
8 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
9 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
10 of the installment payment may not be less than zero:

11 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
12 produced from leases or properties in the state outside the Cook Inlet
13 sedimentary basin, other than leases or properties subject to AS 43.55.011(f),
14 the greater of

15 (i) zero; or

16 (ii) 35 percent multiplied by the remainder obtained by
17 subtracting 1/12 of the producer's adjusted lease expenditures for the
18 calendar year of production under AS 43.55.165 and 43.55.170 that are
19 deductible for the oil and gas under AS 43.55.160 from the gross value
20 at the point of production of the oil and gas produced from the leases or
21 properties during the month for which the installment payment is
22 calculated;

23 (B) for oil and gas produced from leases or properties subject
24 to AS 43.55.011(f), the greatest of

25 (i) zero;

26 (ii) **five** [ZERO PERCENT, ONE PERCENT, TWO
27 PERCENT, THREE PERCENT, OR FOUR] percent [, AS
28 APPLICABLE,] of the gross value at the point of production of the oil
29 and gas produced from the leases or properties during the month for
30 which the installment payment is calculated; or

31 (iii) 35 percent multiplied by the remainder obtained by

1 subtracting 1/12 of the producer's adjusted lease expenditures for the
2 calendar year of production under AS 43.55.165 and 43.55.170 that are
3 deductible for the oil and gas under AS 43.55.160 from the gross value
4 at the point of production of the oil and gas produced from those leases
5 or properties during the month for which the installment payment is
6 calculated, except that, for the purposes of this calculation, a reduction
7 from the gross value at the point of production may apply for oil and
8 gas subject to AS 43.55.160(f) or (g);

9 (C) for oil or gas subject to AS 43.55.011(j), (k), or (o), for
10 each lease or property, the greater of

11 (i) zero; or

12 (ii) 35 percent multiplied by the remainder obtained by
13 subtracting 1/12 of the producer's adjusted lease expenditures for the
14 calendar year of production under AS 43.55.165 and 43.55.170 that are
15 deductible under AS 43.55.160 for the oil or gas, respectively,
16 produced from the lease or property from the gross value at the point of
17 production of the oil or gas, respectively, produced from the lease or
18 property during the month for which the installment payment is
19 calculated;

20 (D) for oil and gas subject to AS 43.55.011(p), the lesser of

21 (i) 35 percent multiplied by the remainder obtained by
22 subtracting 1/12 of the producer's adjusted lease expenditures for the
23 calendar year of production under AS 43.55.165 and 43.55.170 that are
24 deductible for the oil and gas under AS 43.55.160 from the gross value
25 at the point of production of the oil and gas produced from the leases or
26 properties during the month for which the installment payment is
27 calculated, but not less than zero; or

28 (ii) four percent of the gross value at the point of
29 production of the oil and gas produced from the leases or properties
30 during the month, but not less than zero;

31 (6) an amount calculated under (5)(C) of this subsection for oil or gas

1 subject to AS 43.55.011(j), (k), or (o) may not exceed the product obtained by
 2 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
 3 applicable, for gas or set out in AS 43.55.011(k)(1) or (2), as applicable, for oil, but
 4 substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the
 5 amount of taxable gas produced during the month for the amount of taxable gas
 6 produced during the calendar year and substituting in AS 43.55.011(k)(1)(A) or
 7 (2)(A), as applicable, the amount of taxable oil produced during the month for the
 8 amount of taxable oil produced during the calendar year;

9 (7) for oil and gas produced on or after January 1, 2022, an installment
 10 payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied
 11 as allowed by law, is due for each month of the calendar year on the last day of the
 12 following month; the amount of the installment payment is the sum of the following
 13 amounts, less 1/12 of the tax credits that are allowed by law to be applied against the
 14 tax levied by AS 43.55.011(e) for the calendar year, but the amount of the installment
 15 payment may not be less than zero:

16 (A) for oil produced from leases or properties that include land
 17 north of 68 degrees North latitude, the greatest of

18 (i) zero;

19 (ii) **five** [ZERO PERCENT, ONE PERCENT, TWO
 20 PERCENT, THREE PERCENT, OR FOUR] percent [, AS
 21 APPLICABLE,] of the gross value at the point of production of the oil
 22 produced from the leases or properties during the month for which the
 23 installment payment is calculated; or

24 (iii) 35 percent multiplied by the remainder obtained by
 25 subtracting 1/12 of the producer's adjusted lease expenditures for the
 26 calendar year of production under AS 43.55.165 and 43.55.170 that are
 27 deductible for the oil under AS 43.55.160(h)(1) from the gross value at
 28 the point of production of the oil produced from those leases or
 29 properties during the month for which the installment payment is
 30 calculated, except that, for the purposes of this calculation, a reduction
 31 from the gross value at the point of production may apply for oil

1 subject to AS 43.55.160(f) or 43.55.160(f) and (g);

2 (B) for oil produced before or during the last calendar year
3 under AS 43.55.024(b) for which the producer could take a tax credit under
4 AS 43.55.024(a), from leases or properties in the state outside the Cook Inlet
5 sedimentary basin, no part of which is north of 68 degrees North latitude, other
6 than leases or properties subject to AS 43.55.011(p), the greater of

7 (i) zero; or

8 (ii) 35 percent multiplied by the remainder obtained by
9 subtracting 1/12 of the producer's adjusted lease expenditures for the
10 calendar year of production under AS 43.55.165 and 43.55.170 that are
11 deductible for the oil under AS 43.55.160(h)(2) from the gross value at
12 the point of production of the oil produced from the leases or properties
13 during the month for which the installment payment is calculated;

14 (C) for oil and gas produced from leases or properties subject
15 to AS 43.55.011(p), except as otherwise provided under (8) of this subsection,
16 the sum of

17 (i) 35 percent multiplied by the remainder obtained by
18 subtracting 1/12 of the producer's adjusted lease expenditures for the
19 calendar year of production under AS 43.55.165 and 43.55.170 that are
20 deductible for the oil under AS 43.55.160(h)(3) from the gross value at
21 the point of production of the oil produced from the leases or properties
22 during the month for which the installment payment is calculated, but
23 not less than zero; and

24 (ii) 13 percent of the gross value at the point of
25 production of the gas produced from the leases or properties during the
26 month, but not less than zero;

27 (D) for oil produced from leases or properties in the state, no
28 part of which is north of 68 degrees North latitude, other than leases or
29 properties subject to (B) or (C) of this paragraph, the greater of

30 (i) zero; or

31 (ii) 35 percent multiplied by the remainder obtained by

1 subtracting 1/12 of the producer's adjusted lease expenditures for the
2 calendar year of production under AS 43.55.165 and 43.55.170 that are
3 deductible for the oil under AS 43.55.160(h)(4) from the gross value at
4 the point of production of the oil produced from the leases or properties
5 during the month for which the installment payment is calculated;

6 (E) for gas produced from each lease or property in the state,
7 other than a lease or property subject to AS 43.55.011(p), 13 percent of the
8 gross value at the point of production of the gas produced from the lease or
9 property during the month for which the installment payment is calculated, but
10 not less than zero;

11 (8) an amount calculated under (7)(C) of this subsection may not
12 exceed four percent of the gross value at the point of production of the oil and gas
13 produced from leases or properties subject to AS 43.55.011(p) during the month for
14 which the installment payment is calculated;

15 (9) for purposes of the calculation under [(1)(B)(ii),] (5)(B)(ii) [,] and
16 (7)(A)(ii) of this subsection, the [APPLICABLE] percentage of the gross value at the
17 point of production is determined under AS 43.55.011(f)(1) or (2) but substituting the
18 phrase "month for which the installment payment is calculated" in AS 43.55.011(f)(1)
19 and (2) for the phrase "calendar year for which the tax is due."

20 * **Sec. 14.** AS 43.55.020(g) is repealed and reenacted to read:

21 (g) Notwithstanding any contrary provision of AS 43.05.225, an unpaid
22 amount of an installment payment required under (a)(3), (5), (6), or (7) of this section
23 that is not paid when due bears interest (1) at the rate provided for an underpayment
24 under 26 U.S.C. 6621 (Internal Revenue Code), as amended, compounded daily, from
25 the date the installment payment is due until March 31 following the calendar year of
26 production; and (2) as provided for a delinquent tax under AS 43.05.225 after that
27 March 31, interest accrued under (1) of this subsection that remains unpaid after that
28 March 31 is treated as an addition to tax that bears interest under (2) of this subsection,
29 an unpaid amount of tax due under (a)(4) of this section that is not paid when due
30 bears interest as provided for a delinquent tax under AS 43.05.225.

31 * **Sec. 15.** AS 43.55.020(h) is amended to read:

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

2 (1) an overpayment of an installment payment required under (a)(3)
 3 [(a)(1), (2), (3)], (5), (6), or (7) of this section bears interest at the rate provided for an
 4 overpayment under 26 U.S.C. 6621 (Internal Revenue Code), as amended,
 5 compounded daily, from the later of the date the installment payment is due or the date
 6 the overpayment is made, until the earlier of

7 (A) the date it is refunded or is applied to an underpayment; or

8 (B) March 31 following the calendar year of production;

9 (2) except as provided under (1) of this subsection, interest with
 10 respect to an overpayment is allowed only on any net overpayment of the payments
 11 required under (a) of this section that remains after the later of March 31 following the
 12 calendar year of production or the date that the statement required under
 13 AS 43.55.030(a) is filed;

14 (3) interest is allowed under (2) of this subsection only from a date that
 15 is 90 days after the later of March 31 following the calendar year of production or the
 16 date that the statement required under AS 43.55.030(a) is filed; interest is not allowed
 17 if the overpayment was refunded within the 90-day period;

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

20 * **Sec. 16.** AS 43.55.020(i) is amended to read:

21 (i) Notwithstanding any contrary provision of AS 43.05.225 or (g) or (h) of
 22 this section, if the amount of a tax payment, including an installment payment, due
 23 under (a)(3) - (5) [(a)(1) - (4)] of this section is affected by the retroactive application
 24 of a regulation adopted under this chapter, the department shall determine whether the
 25 retroactive application of the regulation caused an underpayment or an overpayment of
 26 the amount due and adjust the interest due on the affected payment as follows:

27 (1) if an underpayment of the amount due occurred, the department
 28 shall waive interest that would otherwise accrue for the underpayment before the first
 29 day of the second month following the month in which the regulation became
 30 effective, if

31 (A) the department determines that the producer's

1 underpayment resulted because the regulation was not in effect when the
2 payment was due; and

3 (B) the producer demonstrates that it made a good faith
4 estimate of its tax obligation in light of the regulations then in effect when the
5 payment was due and paid the estimated tax;

6 (2) if an overpayment of the amount due occurred and the department
7 determines that the producer's overpayment resulted because the regulation was not in
8 effect when the payment was due, the obligation for a refund for the overpayment does
9 not begin to accrue interest earlier than the following, as applicable:

10 (A) except as otherwise provided under (B) of this paragraph,
11 the first day of the second month following the month in which the regulation
12 became effective;

13 (B) 90 days after an amended statement under AS 43.55.030(a)
14 and an application to request a refund of production tax paid is filed, if the
15 overpayment was for a period for which an amended statement under
16 AS 43.55.030(a) was required to be filed before the regulation became
17 effective.

18 * **Sec. 17.** AS 43.55 is amended by adding a new section to read:

19 **Sec. 43.55.022. Limitations on tax credits.** (a) Notwithstanding any contrary
20 provision of AS 43.55, the application of tax credits under AS 43.55 is subject to the
21 limitations set out in this section.

22 (b) A tax credit or a fraction of a tax credit under AS 43.55.023, 43.55.024,
23 and 43.55.025 may not be subtracted in calculating an installment payment of
24 estimated tax required under AS 43.55.020(a) if the resulting amount of the
25 installment payment would be less than the amount in AS 43.55.020(a)(5)(B)(ii) or
26 43.55.020(a)(7)(A)(ii), as applicable.

27 (c) The total amount of tax credits under AS 43.55.023, 43.55.024, and
28 43.55.025 that may be applied against a tax levied by AS 43.55.011(e) for a calendar
29 year may not exceed the sum of the amount of the tax credits or fractions of tax credits
30 that are allowed under (b) of this section to be subtracted in calculating the installment
31 payments of estimated tax for each month in the calendar year.

1 * **Sec. 18.** AS 43.55.023(b) is amended to read:

2 (b) [BEFORE JANUARY 1, 2014, A PRODUCER OR EXPLORER MAY
3 ELECT TO TAKE A TAX CREDIT IN THE AMOUNT OF 25 PERCENT OF A
4 CARRIED-FORWARD ANNUAL LOSS. FOR LEASE EXPENDITURES
5 INCURRED ON AND AFTER JANUARY 1, 2014, AND BEFORE JANUARY 1,
6 2016, TO EXPLORE FOR, DEVELOP, OR PRODUCE OIL OR GAS DEPOSITS
7 LOCATED NORTH OF 68 DEGREES NORTH LATITUDE, A PRODUCER OR
8 EXPLORER MAY ELECT TO TAKE A TAX CREDIT IN THE AMOUNT OF 45
9 PERCENT OF A CARRIED-FORWARD ANNUAL LOSS.] For lease expenditures
10 incurred on and after January 1, 2016, to explore for, develop, or produce oil or gas
11 deposits located north of 68 degrees North latitude, a producer or explorer may elect to
12 take a tax credit in the amount of 35 percent of a carried-forward annual loss. For lease
13 expenditures incurred on or after January 1, 2014, to explore for, develop, or produce
14 oil or gas deposits located south of 68 degrees North latitude, a producer or explorer
15 may elect to take a tax credit in the amount of 25 percent of a carried-forward annual
16 loss. A credit under this subsection may be applied against a tax levied by
17 AS 43.55.011(e). For purposes of this subsection, a carried-forward annual loss is the
18 amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.165
19 and 43.55.170 for a previous calendar year that was not deductible in calculating
20 production tax values for that calendar year under AS 43.55.160. **For the purpose of**
21 **a credit under this subsection, any reduction under AS 43.55.160(f) or (g) is**
22 **added back to the calculation of production tax values for that calendar year**
23 **under AS 43.55.160 for the determination of a carried-forward annual loss.**

24 * **Sec. 19.** AS 43.55.023(c) is amended to read:

25 (c) A credit or portion of a credit under this section may not be used to reduce
26 a person's tax liability under AS 43.55.011(e) for any calendar year below **the amount**
27 **calculated under AS 43.55.011(f)** [ZERO], and any unused credit or portion of a
28 credit not used under this subsection may be applied in a later calendar year. **An**
29 **unused credit or portion of a credit may not be applied in a calendar year later**
30 **than the 10th calendar year in which the carried-forward annual loss for which**
31 **the credit is claimed was incurred.**

1 * **Sec. 20.** AS 43.55.023(d) is amended to read:

2 (d) A person that is entitled to take a tax credit under this section that wishes
3 to transfer the unused credit to another person or obtain a cash payment under
4 AS 43.55.028 may apply to the department for a transferable tax credit certificate. An
5 application under this subsection must be in a form prescribed by the department and
6 must include supporting information and documentation that the department
7 reasonably requires. The department shall grant or deny an application, or grant an
8 application as to a lesser amount than that claimed and deny it as to the excess, not
9 later than 120 days after the latest of (1) March 31 of the year following the calendar
10 year in which the [QUALIFIED CAPITAL EXPENDITURE OR] carried-forward
11 annual loss for which the credit is claimed was incurred; (2) the date the statement
12 required under AS 43.55.030(a) or (e) was filed for the calendar year in which the
13 [QUALIFIED CAPITAL EXPENDITURE OR] carried-forward annual loss for which
14 the credit is claimed was incurred; or (3) the date the application was received by the
15 department. If, based on the information then available to it, the department is
16 reasonably satisfied that the applicant is entitled to a credit, the department shall issue
17 the applicant a transferable tax credit certificate for the amount of the credit. A
18 certificate issued under this subsection **expires after 10 years from the calendar**
19 **year in which the carried-forward annual loss for which the credit is claimed was**
20 **incurred** [DOES NOT EXPIRE].

21 * **Sec. 21.** AS 43.55.023(e) is amended to read:

22 (e) A person to which a transferable tax credit certificate is issued under (d) of
23 this section may transfer the certificate to another person, and a transferee may further
24 transfer the certificate. Subject to the limitations set out in **(b) - (d)** [(a) - (d)] of this
25 section, and notwithstanding any action the department may take with respect to the
26 applicant under (g) of this section, the owner of a certificate may apply the credit or a
27 portion of the credit shown on the certificate only against a tax levied by
28 AS 43.55.011(e). However, a credit shown on a transferable tax credit certificate may
29 not be applied to reduce a transferee's total tax liability under AS 43.55.011(e) for oil
30 and gas produced during a calendar year to less than 80 percent of the tax that would
31 otherwise be due without applying that credit. Any portion of a credit not used under

1 this subsection may be applied in a later period.

2 * **Sec. 22.** AS 43.55.023 is amended by adding a new section to read:

3 (q) A producer or explorer shall comply with the notice and information
4 provision requirements in AS 43.55.025(f)(2) for the lease expenditures incurred
5 towards a credit under this section. The Department of Natural Resources shall hold
6 the confidential information under AS 43.55.025(f)(2)(C). For a producer or explorer
7 required to comply with the notice and information requirements of this section, the
8 Department of Natural Resources may publish the name of the producer or explorer,
9 the location of the well or seismic exploration, and the date on which information
10 required to be submitted under this section may be released.

11 * **Sec. 23.** AS 43.55.024(g) is amended to read:

12 (g) A tax credit authorized by (c) of this section may not be applied to reduce
13 a producer's tax liability for any calendar year under AS 43.55.011(e) below the
14 amount calculated under AS 43.55.011(f) [ZERO].

15 * **Sec. 24.** AS 43.55.024(i) is amended to read:

16 (i) A producer may apply against the producer's tax liability for the calendar
17 year under AS 43.55.011(e) a tax credit of \$5 for each barrel of oil taxable under
18 AS 43.55.011(e) that meets one or more of the criteria in AS 43.55.160(f) or (g) and
19 that is produced during a calendar year after December 31, 2013. A tax credit
20 authorized by this subsection may not reduce a producer's tax liability for a calendar
21 year under AS 43.55.011(e) below the amount calculated under AS 43.55.011(f)
22 [ZERO].

23 * **Sec. 25.** AS 43.55.025(i) is amended to read:

24 (i) For a production tax credit under this section,
25 (1) a credit may not be applied to reduce a taxpayer's tax liability under
26 AS 43.55.011(e) below the amount calculated under AS 43.55.011(f) [ZERO] for a
27 calendar year; and
28 (2) an amount of the production tax credit in excess of the amount that
29 may be applied for a calendar year under this subsection may be carried forward and
30 applied against the taxpayer's tax liability under AS 43.55.011(e) in one or more later
31 calendar years.

1 * **Sec. 26.** AS 43.55.028(e) is amended to read:

2 (e) The department, on the written application of a person to whom a
3 transferable tax credit certificate has been issued under AS 43.55.023(d) or former
4 AS 43.55.023(m) or to whom a production tax credit certificate has been issued under
5 AS 43.55.025(f), may use available money in the oil and gas tax credit fund to
6 purchase, in whole or in part, the certificate if the department finds that

7 (1) the calendar year of the purchase is not earlier than the first
8 calendar year for which the credit shown on the certificate would otherwise be allowed
9 to be applied against a tax;

10 (2) the applicant does not have an outstanding liability to the state
11 [FOR UNPAID DELINQUENT TAXES UNDER THIS TITLE];

12 (3) the applicant's total tax liability under AS 43.55.011(e), after
13 application of all available tax credits, for the calendar year in which the application is
14 made is zero;

15 (4) the applicant's average daily production of oil and gas taxable
16 under AS 43.55.011(e) during the calendar year preceding the calendar year in which
17 the application is made was not more than 50,000 BTU equivalent barrels; [AND]

18 (5) the applicant's revenues generated from the applicant's oil and
19 gas business, including the revenues of the applicant's affiliates if the applicant is
20 part of an affiliated group, during the calendar year preceding the calendar year
21 in which the application is made were less than \$10,000,000,000;

22 (6) the amount expended for the purchase and amounts previously
23 purchased from the applicant during the calendar year the sum of which would
24 not exceed \$25,000,000; and

25 (7) the purchase is consistent with this section and regulations adopted
26 under this section.

27 * **Sec. 27.** AS 43.55.028 is amended by adding a new subsections to read:

28 (j) The percentage of a transferable tax credit certificate or a production tax
29 credit certificate purchased by the department may not exceed the percentage of the
30 applicant's workforce in the state in the previous calendar year that were resident
31 workers. The applicant's workforce in the state includes resident workers employed by

1 the applicant's contractors. An amount of a credit not purchased due to application of
 2 this subsection may be applied against the applicant's tax liability under this chapter.
 3 In this subsection, "resident worker" has the meaning given in AS 43.40.092(b).

4 * **Sec. 28.** AS 43.55.029(a) is amended to read:

5 (a) An explorer or producer that has applied for a production tax credit under
 6 AS 43.55.023(b) [AS 43.55.023(a), (b), OR (l)] or 43.55.025(a) may make a present
 7 assignment of the production tax credit certificate expected to be issued by the
 8 department to a third-party assignee. The assignment may be made either **when** [AT
 9 THE TIME] the application is filed with the department or not later than 30 days after
 10 the date of filing with the department. Once a notice of assignment in compliance with
 11 this section is filed with the department, the assignment is irrevocable and cannot be
 12 modified by the explorer or producer without the written consent of the assignee
 13 named in the assignment. If a production tax credit certificate is issued to the explorer
 14 or producer, the notice of assignment remains effective and shall be filed with the
 15 department by the explorer or producer together with any application for the
 16 department to purchase the certificate under AS 43.55.028(e).

17 * **Sec. 29.** AS 43.55.030(a) is amended to read:

18 (a) A producer that produces oil or gas from a lease or property in the state
 19 during a calendar year, whether or not any tax payment is due under AS 43.55.020(a)
 20 for that oil or gas, shall file with the department on March 31 of the following year a
 21 statement, under oath, in a form prescribed by the department, giving, with other
 22 information required, the following:

23 (1) a description of each lease or property from which oil or gas was
 24 produced, by name, legal description, lease number, or accounting codes assigned by
 25 the department;

26 (2) the names of the producer and, if different, the person paying the
 27 tax, if any;

28 (3) the gross amount of oil and the gross amount of gas produced from
 29 each lease or property, separately identifying the gross amount of gas produced from
 30 each oil and gas lease to which an effective election under AS 43.55.014(a) applies,
 31 the amount of gas delivered to the state under AS 43.55.014(b), and the percentage of

1 the gross amount of oil and gas owned by the producer;

2 (4) the gross value at the point of production of the oil and of the gas
3 produced from each lease or property owned by the producer and the costs of
4 transportation of the oil and gas;

5 (5) the name of the first purchaser and the price received for the oil and
6 for the gas, unless relieved from this requirement in whole or in part by the
7 department;

8 (6) the producer's qualified capital expenditures, [AS DEFINED IN
9 AS 43.55.023,] other lease expenditures under AS 43.55.165, and adjustments or other
10 payments or credits under AS 43.55.170;

11 (7) the production tax values of the oil and gas under AS 43.55.160(a)
12 or of the oil under AS 43.55.160(h), as applicable;

13 (8) any claims for tax credits to be applied; and

14 (9) calculations showing the amounts, if any, that were or are due
15 under AS 43.55.020(a) and interest on any underpayment or overpayment.

16 * **Sec. 30.** AS 43.55.030(e) is amended to read:

17 (e) An explorer or producer that incurs a lease expenditure under
18 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar
19 year but does not produce oil or gas from a lease or property in the state during the
20 calendar year shall file with the department, on March 31 of the following year, a
21 statement, under oath, in a form prescribed by the department, giving, with other
22 information required, the following:

23 (1) the explorer's or producer's qualified capital expenditures, [AS
24 DEFINED IN AS 43.55.023,] other lease expenditures under AS 43.55.165, and
25 adjustments or other payments or credits under AS 43.55.170; and

26 (2) if the explorer or producer receives a payment or credit under
27 AS 43.55.170, calculations showing whether the explorer or producer is liable for a
28 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount.

29 * **Sec. 31.** AS 43.55.150 is amended by adding a new subsection to read:

30 (d) The gross value at the point of production may not be less than zero.

31 * **Sec. 32.** AS 43.55.165(a) is amended to read:

1 (a) **For** [EXCEPT AS PROVIDED IN (j) AND (k) OF THIS SECTION,
2 FOR] purposes of this chapter, a producer's lease expenditures for a calendar year are

3 (1) costs, other than items listed in (e) of this section, that are

4 (A) incurred by the producer during the calendar year after
5 March 31, 2006, to explore for, develop, or produce oil or gas deposits located
6 within the producer's leases or properties in the state or, in the case of land in
7 which the producer does not own an operating right, operating interest, or
8 working interest, to explore for oil or gas deposits within other land in the
9 state; and

10 (B) allowed by the department by regulation, based on the
11 department's determination that the costs satisfy the following three
12 requirements:

13 (i) the costs must be incurred upstream of the point of
14 production of oil and gas;

15 (ii) the costs must be ordinary and necessary costs of
16 exploring for, developing, or producing, as applicable, oil or gas
17 deposits; and

18 (iii) the costs must be direct costs of exploring for,
19 developing, or producing, as applicable, oil or gas deposits; and

20 (2) a reasonable allowance for that calendar year, as determined under
21 regulations adopted by the department, for overhead expenses that are directly related
22 to exploring for, developing, or producing, as applicable, the oil or gas deposits.

23 * **Sec. 33.** AS 43.55.165(e) is amended to read:

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

25 (1) depreciation, depletion, or amortization;

26 (2) oil or gas royalty payments, production payments, lease profit
27 shares, or other payments or distributions of a share of oil or gas production, profit, or
28 revenue, except that a producer's lease expenditures applicable to oil and gas produced
29 from a lease issued under AS 38.05.180(f)(3)(B), (D), or (E) include the share of net
30 profit paid to the state under that lease;

31 (3) taxes based on or measured by net income;

- 1 (4) interest or other financing charges or costs of raising equity or debt
2 capital;
- 3 (5) acquisition costs for a lease or property or exploration license;
- 4 (6) costs arising from fraud, wilful misconduct, gross negligence,
5 violation of law, or failure to comply with an obligation under a lease, permit, or
6 license issued by the state or federal government;
- 7 (7) fines or penalties imposed by law;
- 8 (8) costs of arbitration, litigation, or other dispute resolution activities
9 that involve the state or concern the rights or obligations among owners of interests in,
10 or rights to production from, one or more leases or properties or a unit;
- 11 (9) costs incurred in organizing a partnership, joint venture, or other
12 business entity or arrangement;
- 13 (10) 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 (11) surcharges levied under AS 43.55.201 or 43.55.300;
- 17 (12) an expenditure otherwise deductible under (b) of this section that
18 is a result of an internal transfer, a transaction with an affiliate, or a transaction
19 between related parties, or is otherwise not an arm's length transaction, unless the
20 producer establishes to the satisfaction of the department that the amount of the
21 expenditure does not exceed the fair market value of the expenditure;
- 22 (13) an expenditure incurred to purchase an interest in any corporation,
23 partnership, limited liability company, business trust, or any other business entity,
24 whether or not the transaction is treated as an asset sale for federal income tax
25 purposes;
- 26 (14) a tax levied under AS 43.55.011 or 43.55.014;
- 27 (15) costs incurred for dismantlement, removal, surrender, or
28 abandonment of a facility, pipeline, well pad, platform, or other structure, or for the
29 restoration of a lease, field, unit, area, tract of land, body of water, or right-of-way in
30 conjunction with dismantlement, removal, surrender, or abandonment; a cost is not
31 excluded under this paragraph if the dismantlement, removal, surrender, or

1 abandonment for which the cost is incurred is undertaken for the purpose of replacing,
2 renovating, or improving the facility, pipeline, well pad, platform, or other structure;

3 (16) costs incurred for containment, control, cleanup, or removal in
4 connection with any unpermitted release of oil or a hazardous substance and any
5 liability for damages imposed on the producer or explorer for that unpermitted release;
6 this paragraph does not apply to the cost of developing and maintaining an oil
7 discharge prevention and contingency plan under AS 46.04.030;

8 (17) costs incurred to satisfy a work commitment under an exploration
9 license under AS 38.05.132;

10 (18) that portion of expenditures, that would otherwise be qualified
11 capital expenditures, [AS DEFINED IN AS 43.55.023,] incurred during a calendar
12 year that are less than the product of \$0.30 multiplied by the total taxable production
13 from each lease or property, in BTU equivalent barrels, during that calendar year,
14 except that, when a portion of a calendar year is subject to this provision, the
15 expenditures and volumes shall be prorated within that calendar year;

16 (19) costs incurred for repair, replacement, or deferred maintenance of
17 a facility, a pipeline, a structure, or equipment, other than a well, that results in or is
18 undertaken in response to a failure, problem, or event that results in an unscheduled
19 interruption of, or reduction in the rate of, oil or gas production; or costs incurred for
20 repair, replacement, or deferred maintenance of a facility, a pipeline, a structure, or
21 equipment, other than a well, that is undertaken in response to, or is otherwise
22 associated with, an unpermitted release of a hazardous substance or of gas; however,
23 costs under this paragraph that would otherwise constitute lease expenditures under (a)
24 and (b) of this section may be treated as lease expenditures if the department
25 determines that the repair or replacement is solely necessitated by an act of war, by an
26 unanticipated grave natural disaster or other natural phenomenon of an exceptional,
27 inevitable, and irresistible character, the effects of which could not have been
28 prevented or avoided by the exercise of due care or foresight, or by an intentional or
29 negligent act or omission of a third party, other than a party or its agents in privity of
30 contract with, or employed by, the producer or an operator acting for the producer, but
31 only if the producer or operator, as applicable, exercised due care in operating and

1 maintaining the facility, pipeline, structure, or equipment, and took reasonable
 2 precautions against the act or omission of the third party and against the consequences
 3 of the act or omission; in this paragraph,

4 (A) "costs incurred for repair, replacement, or deferred
 5 maintenance of a facility, a pipeline, a structure, or equipment" includes costs
 6 to dismantle and remove the facility, pipeline, structure, or equipment that is
 7 being replaced;

8 (B) "hazardous substance" has the meaning given in
 9 AS 46.03.826;

10 (C) "replacement" includes renovation or improvement;

11 (20) costs incurred to construct, acquire, or operate a refinery or crude
 12 oil topping plant, regardless of whether the products of the refinery or topping plant
 13 are used in oil or gas exploration, development, or production operations; however, if
 14 a producer owns a refinery or crude oil topping plant that is located on or near the
 15 premises of the producer's lease or property in the state and that processes the
 16 producer's oil produced from that lease or property into a product that the producer
 17 uses in the operation of the lease or property in drilling for or producing oil or gas, the
 18 producer's lease expenditures include the amount calculated by subtracting from the
 19 fair market value of the product used the prevailing value, as determined under
 20 AS 43.55.020(f), of the oil that is processed;

21 (21) costs of lobbying, public relations, public relations advertising, or
 22 policy advocacy.

23 * **Sec. 34.** AS 43.55.165(f) is amended to read:

24 (f) For purposes of AS 43.55.023(b) [AS 43.55.023(a) AND (b)] and only as
 25 to expenditures incurred to explore for an oil or gas deposit located within land in
 26 which an explorer does not own a working interest, the term "producer" in this section
 27 includes "explorer."

28 * **Sec. 35.** AS 43.55.170(c) is amended to read:

29 (c) For purposes of AS 43.55.023(b) [AS 43.55.023(a) AND (b)] and only as
 30 to expenditures incurred to explore for an oil or gas deposit located within land in
 31 which an explorer does not own a working interest, the term "producer" in this section

1 includes "explorer."

2 * **Sec. 36.** AS 43.55.890 is amended to read:

3 **Sec. 43.55.890. Disclosure of tax information.** Notwithstanding any contrary
4 provision of AS 40.25.100, and regardless of whether the information is considered
5 under AS 43.05.230(e) to constitute statistics classified to prevent the identification of
6 particular returns or reports, the department may publish the following information
7 under this chapter, if aggregated among three or more producers or explorers, showing
8 by month or calendar year and by lease or property, unit, or area of the state:

9 (1) the amount of oil or gas production;

10 (2) the amount of taxes levied under this chapter or paid under this
11 chapter;

12 (3) the effective tax rates under this chapter;

13 (4) the gross value of oil or gas at the point of production;

14 (5) the transportation costs for oil or gas;

15 (6) qualified capital expenditures [, AS DEFINED IN AS 43.55.023];

16 (7) exploration expenditures under AS 43.55.025;

17 (8) production tax values of oil or gas under AS 43.55.160;

18 (9) lease expenditures under AS 43.55.165;

19 (10) adjustments to lease expenditures under AS 43.55.170;

20 (11) tax credits applicable or potentially applicable against taxes levied
21 by this chapter.

22 * **Sec. 37.** AS 43.55.895(b) is amended to read:

23 (b) A municipal entity subject to taxation because of this section is eligible for
24 [ALL] tax credits **proportionate to its production taxable under AS 43.55.011(e). A**
25 **municipal entity shall allocate its lease expenditures in proportion to its**
26 **production taxable under AS 43.55.011(e)** [UNDER THIS CHAPTER TO THE
27 SAME EXTENT AS ANY OTHER PRODUCER].

28 * **Sec. 38.** AS 43.55.900 is amended by adding a new paragraph to read:

29 (26) "qualified capital expenditure"

30 (A) means except as otherwise provided in (B) of this
31 paragraph, an expenditure that is a lease expenditure under AS 43.55.165 and

1 is

2 (i) incurred for geological or geophysical exploration;
 3 (ii) treated as a capitalized expenditure under 26 U.S.C.
 4 (Internal Revenue Code), as amended, regardless of elections made
 5 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is
 6 treated as a capitalized expenditure for federal income tax reporting
 7 purposes by the person incurring the expenditure; or

8 (iii) treated as a capitalized expenditure under 26 U.S.C.
 9 (Internal Revenue Code), as amended, regardless of elections made
 10 under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and is
 11 eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal
 12 Revenue Code), as amended;

13 (B) does not include an expenditure incurred to acquire an asset

14 (i) the cost of previously acquiring which was a lease
 15 expenditure under AS 43.55.165 or would have been a lease
 16 expenditure under AS 43.55.165 if it had been incurred after March 31,
 17 2006; or

18 (ii) that has previously been placed in service in the
 19 state; an expenditure to acquire an asset is not excluded under this
 20 paragraph if not more than an immaterial portion of the asset meets a
 21 description under this paragraph; for purposes of this subparagraph,
 22 "asset" includes geological, geophysical, and well data and
 23 interpretations.

24 * **Sec. 39.** AS 43.99.950 is amended by adding a new paragraph to read:

25 (3) "outstanding liability to the state" means an amount of tax, interest,
 26 penalty, fee, rental, royalty, or other charge for which the state has issued a demand
 27 for payment that has not been paid when due and, if contested, has not been finally
 28 resolved against the state.

29 * **Sec. 40.** AS 38.05.180(i); AS 41.09.010, 41.09.020, 41.09.030, 41.09.090;
 30 AS 43.20.053(j)(4); AS 43.55.011(m), 43.55.020(a)(1), 43.55.020(a)(2), 43.55.023(a),
 31 43.55.023(l), 43.55.023(n), AS 43.55.023(o), 43.55.028(i), 43.55.075(d)(1), 43.55.165(j), and

1 43.55.165(k) are repealed.

2 * **Sec. 41.** The uncodified law of the State of Alaska is amended by adding a new section to
3 read:

4 APPLICABILITY. (a) Section 17 of this Act applies to credits against the oil and gas
5 production tax levied by AS 43.55.011(e) for oil and gas produced on and after January 1,
6 2016.

7 (b) Sections 8 - 11 and 26 - 28 of this Act, and the repeal of AS 43.55.023(a) and (l)
8 in sec. 40 of this Act, apply to expenditures incurred on and after July 1, 2016.

9 (c) Sections 12, 13, and 16 of this Act apply to oil and gas produced on and after
10 July 1, 2016.

11 (d) For the purpose of determining the last calendar year that a credit or an unused
12 portion of a credit under AS 43.55.023(c) or credit certificate under AS 43.55.023(d) may be
13 carried forward due to the limitations in AS 43.55.023(c) and (d), as amended by secs. 19 and
14 20 of this Act,

15 (1) the carried-forward annual loss for a tax credit under AS 43.55.023(c), for
16 expenditures incurred before July 1, 2016, is considered to have been incurred on July 1,
17 2016;

18 (2) the carried-forward annual loss for a tax credit certificate under
19 AS 43.55.023(d), for expenditures incurred before July 1, 2016, is considered to have been
20 incurred on the later of July 1, 2016, or the date the tax credit certificate is issued.

21 * **Sec. 42.** The uncodified law of the State of Alaska is amended by adding a new section to
22 read:

23 TRANSITION: REGULATIONS. The Department of Revenue and the Department of
24 Natural Resources may adopt regulations necessary to implement the changes made by this
25 Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not
26 before the effective date of the law implemented by the regulation. The Department of
27 Revenue shall adopt regulations governing the use of tax credits under AS 43.55 for a
28 calendar year for which the applicable tax credit provisions of AS 43.55 differ as between
29 parts of the year as a result of this Act.

30 * **Sec. 43.** The uncodified law of the State of Alaska is amended by adding a new section to
31 read:

1 TRANSITION: RETROACTIVITY OF REGULATIONS. Notwithstanding any
2 contrary provision of AS 44.62.240,

3 (1) if the Department of Revenue expressly designates in a regulation that the
4 regulation applies retroactively, a regulation adopted by the Department of Revenue to
5 implement, interpret, make specific, or otherwise carry out this Act may apply retroactively to
6 January 1, 2016 or July 1, 2016, as applicable;

7 (2) a regulation adopted by the Department of Natural Resources to
8 implement, interpret, make specific, or otherwise carry out statutory provisions for the
9 administration of oil and gas leases issued under AS 38.05.180(f)(3)(B), (D), or (E), to the
10 extent the regulation relates to the treatment of oil and gas production taxes in determining net
11 profits under those leases, may apply retroactively to January 1, 2016, or July 1, 2016, as
12 applicable, if the Department of Natural Resources expressly designates in the regulation that
13 the regulation applies retroactively to one of those dates.

14 * **Sec. 44.** The uncodified law of the State of Alaska is amended by adding a new section to
15 read:

16 RETROACTIVITY. Section. 17 of this Act is retroactive to January 1, 2016.

17 * **Sec. 45.** Sections 17 and 42 - 44 of this Act take effect immediately under
18 AS 01.10.070(c).

19 * **Sec. 46.** Except as provided in sec. 45 of this Act, this Act takes effect July 1, 2016.

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Governor Bill Walker
STATE OF ALASKA

January 15, 2016

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

Dear Speaker Chenault:

Under the authority of Article III, Section 18 of the Alaska Constitution, I am transmitting a bill relating to oil and gas tax credits and the minimum tax amount for certain oil and gas production.

This bill proposes through four elements to protect the State's fiscal future while instituting cautious reforms to the oil and gas tax credit system. First, the bill would simplify the oil and gas tax credit system by repealing numerous narrowly targeted credits. The bill would repeal the 20 percent tax credit under AS 43.55.023(a) for qualified capital expenditures incurred for exploration, development, or production of oil and gas south of 68 degrees North latitude and the 40 percent well lease expenditure credit under AS 43.55.023(j) for well lease expenditures incurred south of 68 degrees North latitude. The oil and gas tax credit system with the changes in the bill would move towards a system based on nontransferable production-based credits and transferable credits based on carried-forward annual losses. The bill would repeal unused exploration incentive credits under AS 38.05.180(i) and AS 41.09. Also, the bill would limit the lease expenditures and tax credits available to municipal entities in proportion to the taxable production of the municipal entity.

Second, the bill would strengthen the minimum tax amount for certain oil and gas produced north of 68 degrees North latitude ("North Slope") to protect the State's tax revenue stream. The bill would require the minimum tax amount on certain oil and gas produced on the North Slope to equal at least five percent of the gross value at the point of production regardless of the price of the oil and gas. The oil and gas tax credits would no longer be able to reduce the tax levied in AS 43.55.011(e) below the minimum amount calculated in AS 43.55.011(f). This credit limitation would take effect on January 1, 2016.

Third, the bill would reinvigorate the State's investment strategy in purchases of oil and gas tax credit certificates under AS 43.55.028(e) to focus on small companies that hire state residents. The State would only purchase tax credit certificates from an applicant with revenues of less than \$10,000,000,000 from its oil and gas business during the previous calendar year. The State would not purchase a certificate from an applicant with an outstanding liability to the State. Outstanding

The Honorable Mike Chenault
Transmittal Tax Credit Reform
January 15, 2016
Page 2

liabilities to the State would include unpaid taxes, penalties, royalties, rental, interest, and fees. The State's purchases from each applicant would be limited to \$25,000,000 a year. The bill would limit the percentage of the State's purchase of a tax credit certificate to the percentage of the applicant's workforce in the state, in the previous calendar year, that were resident workers. This builds on my commitment to promote healthy and safe communities by encouraging employment of state residents in the state's vital natural resources industry.

Finally, the bill would institute a number of changes to promote good governance in tax administration. The bill would delete a number of inapplicable provisions from the tax statutes to provide greater clarity. The bill would increase the interest rate applicable to delinquent taxes. The bill would make public more information about taxpayers that claim oil and gas production tax credits. Most provisions of the bill would take effect on July 1, 2016.

The bill is an integral component of the New Sustainable Alaska Plan to provide a balanced and sustainable budget for Alaska's long-term fiscal stability.

I urge your prompt and favorable action on this measure.

Sincerely,

A handwritten signature in blue ink that reads "Bill Walker". The signature is written in a cursive, flowing style.

Bill Walker
Governor

Enclosure



Key Goals and Features of HB 247
Governor's Oil and Gas Tax Credit Reform Bill
January 20, 2016

Major Bill Goals

1. Reduce the state's annual cash outlay
2. Protect Net Operating Loss credits as essential playing field leveler between incumbent producers and newcomers
3. Limit repurchases to companies who meet certain financial criteria
4. Strengthen the minimum tax
5. Be more open and transparent
6. Honor and pay credits earned to date and through a transition period

Major Bill Features

Exploration Credits

- Most credits (other than "middle earth," which has been extended to 2022) expire 7/1/16. Allow them to sunset
- Add current DNR data requirements as a condition of the Net Operating Loss credit
- Preemptively repeal other dormant exploration credit programs

Non-North Slope Credits

- Repeal the 20% "capital" and 40% "well" expenditure credits
- Maintain state cash support for Cook Inlet development at 25% of net operating losses while eliminating cash credits to profitable companies

Repurchase Limits

- Credits must be held until there is a tax liability for companies with global revenue greater than \$10 billion
- Repurchase limit of \$25 million per company per year
- Percentage of repurchase tied to percentage of Alaska resident hire
- Net operating loss credits expire after 10 years

Remove Exceptions / Loopholes

- Eliminate ability to use Gross Value Reduction (new oil tax reduction) to increase the size of a net operating loss
- For municipal entities who own production, limit credits to only the pro-rata share of expenses for that share of production that is sold

Strengthen Minimum Tax "Floor"

- Limit the use of net operating loss and other credits such that they cannot reduce tax payments below the minimum tax. Unused credits can be carried into a future tax year
- Limit the use of the \$5 per-taxable-barrel credit for GVR-eligible "new oil" so that payments cannot be reduced below the minimum tax
- Prevent per-barrel credits used in one month from being used against another month's taxes at annual true up
- Increase minimum tax rate from 4% (at prices above \$25) to 5% (at all prices)

Other Provisions

- Increase interest rates to the state's rate of investment return
- Limited confidentiality waiver so the state can report which companies receive credits as well as the amount
- Gross Value can't be reduced below zero by transportation costs
- Credits must first be used to pay obligations to the state

Transition

- Bill has a 7/1/16 effective date for nearly all changes
- On the effective date there will be nearly \$1 billion in anticipated in credit liability. This is the total of any remaining FY16 credits in excess of the governor's veto, in addition to all credits earned in 2015 that will be expected to be paid in FY17, as well as those credits earned in the first half of 2016
- Fiscal note increases appropriation to Tax Credit Fund to \$1 billion to pay this liability

Fiscal Impact in First Full Year is \$500 million

- \$200 million from repeal of certain credits and elimination of loopholes
- \$200 million in deferred payments due to certificates having to be held against future tax liability, due to new repurchase limits
- \$100 million in additional revenue primarily from strengthening the minimum tax



Key Goals and Features of SB 130 / HB 247
Governor's Oil and Gas Tax Credit Reform Bill
January 20, 2016

Major Bill Goals

1. Reduce the state's annual cash outlay
2. Protect Net Operating Loss credits as essential playing field leveler between incumbent producers and newcomers
3. Limit repurchases to companies who meet certain financial criteria
4. Strengthen the minimum tax
5. Be more open and transparent
6. Honor and pay credits earned to date and through a transition period

Major Bill Features

Exploration Credits

- Most credits (other than "middle earth," which has been extended to 2022) expire 7/1/16. Allow them to sunset
- Add current DNR data requirements as a condition of the Net Operating Loss credit
- Preemptively repeal other dormant exploration credit programs

Non-North Slope Credits

- Repeal the 20% "capital" and 40% "well" expenditure credits
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Repurchase Limits

- Credits must be held until there is a tax liability for companies with global revenue greater than \$10 billion
- Repurchase limit of \$25 million per company per year
- Percentage of repurchase tied to percentage of Alaska resident hire
- Net operating loss credits expire after 10 years

Remove Exceptions / Loopholes

- Eliminate ability to use Gross Value Reduction (new oil tax reduction) to increase the size of a net operating loss
- For municipal entities who own production, limit credits to only the pro-rata share of expenses for that share of production that is sold

Strengthen Minimum Tax "Floor"

- Limit the use of net operating loss and other credits such that they cannot reduce tax payments below the minimum tax. Unused credits can be carried forward into a future tax year
- Limit the use of the \$5 per-taxable-barrel credit for GVR-eligible "new oil" so that payments cannot be reduced below the minimum tax
- Prevent per-barrel credits used in one month from being used against another month's taxes at annual true up
- Increase minimum tax rate from 4% (at prices above \$25) to 5% (at all prices)

Other Provisions

- Increase interest rates to the state's rate of investment return
- Limited confidentiality waiver so the state can report which companies receive credits as well as the amount

Transition

- Bill has a 7/1/16 effective date for nearly all changes
- On the effective date there will be nearly \$1 billion in anticipated in credit liability. This is the total of any remaining FY16 credits in excess of the governor's veto, in addition to all credits earned in 2015 that will be expected to be paid in FY17, as well as those credits earned in the first half of 2016
- In the operating budget, \$1 billion is deposited into a transition fund to pay this liability

Fiscal Impact in First Full Year is \$500 million

- \$200 million from repeal of certain credits and elimination of loopholes
- \$200 million in deferred payments due to certificates having to be held against future tax liability, due to new repurchase limits
- \$100 million in additional revenue primarily from strengthening the minimum tax



Sectional Analysis, HB 247
Governor's Oil and Gas Tax Credit Reform Bill
January 22, 2016

- Sec. 1-5.** Conforming language related to the repeal of AS 41.09 in Sec. 40 of the bill. The repeal is a currently unused exploration incentive credit program.
- Sec. 6.** Conforming language related to changes to reporting requirements and confidentiality rules in Sec. 8 of the bill.
- Sec. 7.** Changes the interest rate for delinquent taxes from 3 percent above the Federal Reserve Discount Rate to 7 percent above. This would currently result in an interest rate of about 8%; about halfway between the current 4% and the 11% that was in place before the passage of SB21 in 2013.
- If the state were to begin using earnings from our major savings account, the Permanent Fund, to fund government operations, there would be an "opportunity cost" that comes from unpaid taxes. Our interest rate on these unpaid taxes should reflect the expected rate of earnings on our savings.
- Sec. 8.** Provides an exception to the general taxpayer confidentiality statutes, so that the name of each company claiming credits, the amount they claim, and a general description of their activities can be made public.
- Sec. 9-11.** Amends the Gas Storage Facility, LNG Facility, and In-State Refinery Tax Credits so that these cannot be paid if the taxpayer has any outstanding liability to the state. Currently this is restricted to only a tax liability.
- Sec. 12.** Increases the minimum tax rate in AS 43.55.011(f) to 5% at all oil prices. Currently it is 4% at any oil price above \$25 per barrel, stepping down at lower prices. The minimum tax applies only to production from the North Slope.
- Sec. 13.** Changes the description of monthly installment payments in AS 43.55.020(a), to conform with the higher minimum tax rate in Sec. 12. (*long technical section*)
- Sec. 14-16.** Conforming language related to the repeal of AS 43.55.020(a)(1) and (2) in Sec. 40 of the bill. The repeal is obsolete installment payment language related to production prior to 2014.
- Sec. 17.** Strengthens the minimum tax in two distinct ways:

(b) Prevents several credits that currently can be used to reduce payments below the 4% level from being used for this purpose. Those credits would be carried-forward until the taxpayer had sufficient tax liability against which to use them.

(c) Prevents the circumstance in which per-taxable-barrel credits that could not be used in the month in which they were earned, because of the limitations of the minimum tax, could be claimed at annual tax true-up. This effectively turns the per-taxable-barrel credit into a monthly rather than an annual calculation. Currently if there is substantial price volatility within a year it could result in large tax refunds.

- Sec. 18.** Modifies the carried-forward annual loss credit in AS 43.55.023(b) so that, for “new” oil production eligible to receive the Gross Value Reduction (GVR), the GVR cannot be used to increase the size of an annual loss. Thus, if a company has oil production but is operating at a loss, their loss credit is limited to the actual size of the loss. Currently there are circumstances in which a company could receive credit refunds for amounts in excess of 100% of their loss.
- Sec. 19.** Amends AS 43.55.023 so that credits in that section cannot reduce tax liability below the minimum tax, rather than zero as in current statute. Also establishes a sunset when certain credits must be carried forward instead of being cashed out; in these circumstances the credits can only be carried forward for 10 years.
- Sec. 20.** Establishes a sunset in which credit certificates can only be held for 10 years before they expire.
- Sec. 21.** Conforming language related to the repeal of AS 43.55.023(a) in Sec. 40 of the bill. The repeal is the “qualified capital expenditure” credit outside of the North Slope.
- Sec. 22.** New language adding the notice and data sharing requirements that are currently part of the alternative credit for exploration, and applying them to other credits. This will enable DNR to continue to receive seismic and downhole information after the sunset of the exploration credits.
- Sec. 23.** Amends AS 43.55.024 so that the small producer credit cannot be used to reduce tax liability below the minimum tax. Although this credit will be closed to new recipients in May of 2016, some companies will continue to receive this benefit until approximately 2024.
- Sec. 24.** Amends AS 43.55.024 so that the \$5 per-taxable-barrel credit received by GVR-eligible North Slope oil production cannot reduce tax liability below the minimum tax. Currently this can be reduced to zero; only the sliding-scale credit for non-GVR oil is limited by the minimum tax.
- Sec. 25.** Amends AS 43.55.025 so that exploration credits cannot reduce tax liability below the minimum tax.

- Sec. 26.** Amends AS 43.55.028(e) to add limitations on which companies can receive refunded tax credits versus which must hold their certificates and use them against tax liability:
- (2) Companies with any liability to the state are ineligible to receive payment for their tax credit certificates. Currently this is restricted to only a tax liability.
 - (5) Limits cash repurchase to only companies whose gross revenues in the previous year were less than \$10 billion.
 - (6) Limits annual per-company repurchase to \$25 million.
- Sec. 27.** Adds a new limitation to a company's ability to receive a cash repurchase of their tax credits. The state can only repurchase that percentage of a certificate that equals that company's percentage of Alaska resident hire in the previous calendar year.
- Sec. 28-30.** Conforming language related to the repeal of AS 43.55.023(a) and / or (l) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" and "well lease expenditure" credits outside of the North Slope.
- Sec. 31.** New section specifying that the Gross Value at the Point of Production, defined as sales price less eligible transportation costs, may not be less than zero
- Sec. 32.** Conforming language related to the repeal of AS 43.55.165(j) and (k) in Sec. 40 of the bill. The repeal is the "standard deduction" limitation on lease expenditure inflation that expired in 2010.
- Sec. 33-36.** Conforming language related to the repeal of AS 43.55.023(a) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" credit outside of the North Slope.
- Sec. 37.** In the case where a municipal entity has an interest in oil and gas production, and sells only a portion of that production to an outside party, their ability to deduct lease expenditures and claim credits is limited in proportion to their taxable production.
- Sec. 38.** Adds a definition for "qualified capital expenditure" to the general definitions section of AS 43.55. This replicates the definition that was in AS 43.55.023 which is repealed because the .023 "qualified capital expenditure" credit is also being repealed in Sec. 40. Most of the conforming sections that currently reference AS 43.55.023(a) use this definition.
- Sec. 39.** Adds a definition for "outstanding liability to the state." This conforms with the changes made in Sections 9, 10, 11, and part (2) of 26.
- Sec. 40.** Repeals multiple sections. All of these have been specifically referenced elsewhere in this analysis or are technical repeals that conform with other repealed statutes.

- Sec. 41.** Applicability section with multiple sub-parts. In general, ensures that the changes only apply to production after the effective date. Also provides that applications that come in later for credits related to expenditures before the effective date are protected under the former program. Clarifies the timing related to the new 10-year sunset for carried-forward annual loss credits.
- Sec. 42-43.** Transition language enabling DOR and DNR to draft regulations to implement the changes in this Act, and establishing that regulations may be retroactive to the effective date if they are finalized after the effective date.
- Sec. 44.** Section 17 is retroactive to January 1, 2016. This is the key floor-hardening provision preventing certain credits from being used against the minimum tax, and is related to the specific concern that one or more major producers could have an operating loss in 2015 and use the carried-forward credit to reduce 2016 tax payments below the minimum tax to zero.

This is the only provision of the bill for which we are seeking this retroactivity.

- Sec. 45.** Immediate effective date for the transition and regulatory language.
- Sec. 46.** Effective date of July 1, 2016 for the rest of the Act.



Key Terms Used in HB 247 Sectional Analysis Oil and Gas Tax Credits

Carried-Forward Annual Loss Credit (also called the Net Operating Loss Credit)

Under AS 43.55.023(b), this credit allows companies to carry forward 35% of their North Slope annual loss or 25% of their loss in other areas of the state to apply against a future tax liability. This credit is transferable and refundable and can reduce tax liability below the minimum tax in annual tax calculations. In practice, most companies receive cash refunds from the state for these credits. Companies with greater than 50,000 BTU-equivalent barrels of production are not eligible for refunds and instead must carry the credits forward to a future liability.

Confidential Information Held by Department of Natural Resources

Under AS 43.55.025(f)(2)(C), the Department of Natural Resources keeps well data confidential for two years and seismic or geophysical data confidential for 10 years, at which point the data can be released to the public.

Confidentiality statutes

Currently under AS 40.25.100, any "particulars of the business or affairs of a taxpayer or other person" are confidential, which include the amounts, recipients, and types of credits issued by the department.

Credits used against tax liability/Refundable credits/Transferable credits

Depending on the credit, production tax credits can be applied against a tax liabilities, "refunded" via cash purchase by the state, or transferred to another company. Only companies with fewer than 50,000 BOE per day of production are eligible for refunded credits, and only certain credits are eligible for refund. In particular, the small producer credit and per-taxable-barrel credits can only be used against a tax liability; any unused amount is forfeited.

Exploration Credits under AS 43.55.025

These include:

Alternative Credit for Exploration

- For 30% or 40% for certain seismic or drilling costs based on the location of the unit.
- Expires 7/1/2016 for North Slope and Cook Inlet and 1/1/2022 everywhere else,

Frontier Basin Credit

- The lesser of 80% of qualified exploration or drilling expenses or \$25 million per well, or

- The lesser of 75% of seismic exploration expenditures or \$7.5 million
- For areas other than the North Slope and Cook Inlet
- Expires 7/2/2016

Cook Inlet Jack-Up Rig Credit

- A credit for exploration expenses for the first three wells drilled by the first jack-up rig brought to Cook Inlet
- Ranges from up to 100% of expenses for the first well, 90% for the second, 80% for the third
- If wells are brought into production, operators must repay 50% of the credit
- Expires 7/1/2016.

These credits can reduce tax liability below the minimum tax in annual tax calculations and can be refunded as cash. These credits also can be transferred to another company.

Exploration Incentive Credit under AS 41.09

- This credit is up to 50% of drilling or seismic work, not to exceed 50% of tax liability.
- This credit must be pre-approved by the Commissioner of the Department of Natural Resources
- This credit has not been utilized in recent years

Gas Storage Facility Credit/LNG Facility Credit/In-State Refinery Credit

These credits can be applied against Corporate Income Tax or refunded through the Oil and Gas Tax Credit Fund.

The Gas Storage Facility Credit

- \$1.50 per thousand cubic feet for the costs incurred to establish a natural gas storage facility
- Must be for a facility used by public utilities
- Maximum credit was the lesser of \$15 million or 25% of the costs to establish the facility
- Was taken in 2014 and is no longer available

The LNG facility Credit

- Non-transferable and refundable
- For the costs incurred to establish a storage facility for liquefied natural gas
- Is the lesser of \$15 million or 50% of costs incurred to establish the facility

The In-State Refinery Tax Credit

- Can be applied to tax liability or purchased by the state
- For qualified infrastructure expenditures for in-state refineries
- For costs incurred between December 31, 2014 and January 1, 2020
- May not exceed 40% of total qualifying expenditures or \$10 million per tax year per refinery

Gross Minimum Tax

The gross minimum tax (AS 43.55.011(f)) was first established with the 2006 switch to a net profits-based tax under the Petroleum Profits Tax (PPT) and was based on a percentage of gross value at the point of production (GVPP). A minimum tax of 4% of gross wellhead value was imposed if the ANS oil

price was greater than \$25 per barrel and the minimum tax was greater than the calculated tax liability. When oil prices are lower than \$25, the minimum taxes are as follows:

- 3% when price is between \$20 but less than \$25
- 2% when price is between \$17.50 but less than \$20
- 1% when price is between \$15 but less than \$17.50
- 0% when the price is \$15 or less

Under PPT, the primary tax credit, for qualified capital expenditures, could not be used to reduce a tax liability below the minimum tax. With the switch to the Alaska's Clear and Equitable Share (ACES) tax in 2007, the minimum tax was not changed, but tax credits could reduce the minimum tax to zero. Under SB 21, taking effect in 2014, the minimum tax remained the same. However it was partially "hardened," in that some of the new per-taxable-barrel credits, added by SB 21, could not reduce liability below the minimum tax. Only per-taxable-barrel credits from GVR-eligible oil can reduce the minimum tax to zero in the monthly calculations. In contrast, per-taxable-barrel credits for non-GVR eligible oil, which represent the vast majority of such credits, cannot reduce a liability below the minimum tax.

Gross Value at the Point of Production (GVPP)

The Gross Value at the Point of Production (AS 43.55.150) is calculated by taking the West Coast oil price for Alaska oil and subtracting transportation costs (such as pipeline tariffs, marine costs, and quality adjustments) to arrive at a value at the unit boundary.

Gross Value Reduction (GVR)

For oil that qualifies as "new oil" under AS 43.55.160(f), a 20% reduction of GVPP is allowed in the tax calculation. "New oil" is oil from either a new unit, a new participating area in an existing unit, or oil from certain acreage added to a participating area, as defined in statute.

Interest rate for delinquent taxes

Pre-SB 21 delinquent taxes, assessments, and refunds (from before January 1, 2014) are charged an interest rate of either five percentage points above the Federal Reserve Discount Rate or 11%, whichever is greater. Post SB-21 (after January 1, 2014) interest rates for delinquent taxes are three percentage points above the Federal Reserve Discount Rate. The interest rate specified in AS 43.05.225 applies to most tax types, including production taxes. These rates apply not only to delinquent taxes, but the same rates apply to the state's refunds to these taxpayers. Most interest for oil and gas taxes accrues to the Constitutional Budget Reserve Fund; the General Fund also receives some oil and gas interest as well as interest for non-minerals taxes.

Lease Expenditures

Lease expenditures are defined under statute in AS 43.55.165. They are costs incurred by a producer to explore for, develop, or produce oil or gas deposits located within the producer's leases or properties in the state or costs for costs to explore for oil or gas in other areas of the state. They must be upstream costs, they must be considered "ordinary and necessary" costs of exploring, developing, or producing oil and gas, and they must be a "direct" cost.

Monthly Installment Payments

Monthly installed payments are established under AS 43.55.020 and require producers to pay monthly estimated taxes by the last day of the month following the tax period month. The estimated tax is net of allowable tax credits. Monthly payments cannot be below zero. Per-taxable-barrel credits are calculated on a monthly basis and only per-taxable-barrel GVR-eligible credits may reduce payments past the minimum tax. However, any unused per-taxable-barrel credits in a given month can potentially be applied against other month's liability when filling the annual tax return (sometimes referred to as the "annual true up.")

Oil & Gas Tax Credit Fund

The Oil and Gas Tax Credit Fund was established under AS 43.55.028 by the ACES bill, and it allows the state to buy certain tax credits subject to availability of funds. The legislature has customarily appropriated money into this fund every year.

Per-Taxable-Barrel Credit

The per-taxable-barrel credits, though referred to as "credits," differ from other tax credits as they are actually a component of the tax structure. They are a step in the calculation that determine tax payments. AS 43.55.024(i) is a \$5 per-taxable-barrel credit for oil that qualifies as "new" oil or oil eligible for the GVR, which can reduce tax liability below the minimum tax, and AS 43.55.024(j) is a sliding \$0 to \$8 per barrel credit for oil that is not classified as "new." During FY 2016, approximately 7% of oil production is expected to qualify as "new" oil.

Production Tax Value

Production tax value is the gross value at the point of production minus deductible lease expenditures, which include operating expenditures and capital expenditures with certain adjustments. All capital expenditures can be deducted in the year they were earned.

Qualified Capital Expenditure Credit/Well Lease Expenditure Credit

These credits are for 20% of qualified capital expenditures or 40% of well lease expenditures in areas other than the North Slope. These credits are transferable and refundable and can essentially be "stacked" with other credits. These credits can currently reduce tax liability below the minimum tax in annual tax calculations. Beginning with 2014, the 20% capital expenditure credit was eliminated for the North Slope and replaced with the per-taxable-barrel credit as part of the SB 21 tax change.

Small Producer Credit

This credit is up to \$12 million per year for producers with less than 50,000 BTU-equivalent barrels per day of production, and phases out from \$12 million to zero between 50,000 and 100,000 BTU-equivalent barrels of production. Qualified companies who have oil production before May 1, 2016 can receive the credit for up to nine years after their first production of oil or gas. This credit is not transferable or refundable, but can be used to reduce tax liability below the minimum tax in annual tax calculations.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version: HB 247
Fiscal Note Number: _____
() Publish Date: _____

Identifier: HB247-DOR-OGTCF-1-27-16
Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: Governor

Department: Fund Capitalization
Appropriation: Fund Capitalization (no approps out)
Allocation: Oil and Gas Tax Credit Fund
OMB Component Number: 2894

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates					
			FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES								
Personal Services								
Travel								
Services								
Commodities								
Capital Outlay								
Grants & Benefits	926,575.0	73,425.0	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)
Miscellaneous								
Total Operating	926,575.0	73,425.0	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)

Fund Source (Operating Only)

1004 Gen Fund	926,575.0	73,425.0	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)
Total	926,575.0	73,425.0	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues							
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Estimated SUPPLEMENTAL (FY2016) cost: 0.0 (separate supplemental appropriation required)
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 0.0 (separate capital appropriation required)
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? Yes
If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/17

Why this fiscal note differs from previous version:

Initial version showing funding to Oil and Gas Tax Credit Fund. This will be reflected in the Governor's amended appropriation bill

Prepared By:	Ken Alper, Director	Phone:	(907)465-8221
Division:	Tax	Date:	02/01/2016 01:00 PM
Approved By:	Jerry Burnett, Deputy Commissioner	Date:	02/01/16
Agency:	Department of Revenue		

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. HB 247

Analysis

The legislation would make substantial changes to Alaska's oil and gas tax credit system. The net effect would be to reduce the expected future expenditures to approximately \$50-\$100 million per year.

Most provisions of the bill will take effect on July 1, 2016. The intent of the fund transfer described in this fiscal note is to provide adequate funds to repurchase all tax credit certificates that are earned in advance of the effective date. It is also to provide initial capitalization of the new oil and gas infrastructure development fund which is being created via separate legislation.

The fund transfer appropriation, which is identified in the capital appropriation section on the face of the fiscal note, which will be funded via the Constitutional Budget Reserve Fund (art. IX, sec. 17, Constitution of the State of Alaska), shall be distributed as follows:

Oil and Gas Tax Credit Fund (AS 43.55.028)	\$926,575.0
<u>AIDEA Oil and Gas Infrastructure Development Fund</u>	<u>\$200,000.0</u>
Total	\$1,126,575.0

Sec. 21(q) of the proposed Operating Budget, SB139 / HB256, includes an appropriation to the oil and gas tax credit fund of \$73,425.0. This is the amount required by statute, according to AS 43.55.028(c), and is the amount expected to be made available in the absence of credit reform legislation.

The \$926,575.0 appropriation to the Tax Credit Fund is the amount necessary, when added to the amount in the Operating Budget to equal \$1 billion in transition funds. This appropriation shall be contingent on passage of a version of this bill. Additionally, the appropriation to the AIDEA fund shall be contingent on the passage of both this bill and the bill creating the new AIDEA fund, SB129 or HB246.

The demand for a \$1 billion transition fund is based on our estimate of the state's expected liability to repurchase tax credit certificates earned through the effective date. This is estimated as follows:

FY16- DOR estimates a total demand for the current fiscal year of \$700 million. The appropriation to the Tax Credit Fund was capped at \$500 million due to a line item veto of the FY16 operating budget (sec. 8(b), ch1, SSSLA15). Based on this limitation, approximately \$200 million in additional credit liability is expected to be outstanding at the end of the fiscal year.

FY17- DOR estimates total demand for FY17 of \$425 million. The bulk of these credits will be based on actual industry expenditures made during calendar year 2015, which will be applied for after the annual Production Tax returns are filed on approximately March 31, 2016. Under current law, most of those credit certificates would be issued in July of 2016 and refunded early in FY17.

FY18- DOR estimates total demand for FY18 of \$375 million. This estimate is largely based upon known and planned company activity for calendar year 2016, with the same time delay and process as described for FY17, above. A portion of that demand, representing activity through the July 1, 2016, will also be paid via the transition fund. The preliminary estimate for this is \$200 million.

The sum total of the credit demand for these three fiscal years is \$825 million (\$825,000.0). Because of potential uncertainty over the timing of the transition, as well as out of a desire to provide better certainty to the lenders who have historically depended on the credit fund for repayment, the recommended total transition funding is \$1 billion

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version:	HB 247
Fiscal Note Number:	2
(H) Publish Date:	1/19/2016

Identifier: DOR-TAX-01-13-16
 Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
 Sponsor: RLS BY REQUEST OF THE GOVERNOR
 Requester: Governor

Department: Department of Revenue
 Appropriation: Taxation and Treasury
 Allocation: Tax Division
 OMB Component Number: 2476

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates					
			FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES								
Personal Services								
Travel								
Services								
Commodities								
Capital Outlay								
Grants & Benefits								
Miscellaneous		(400,000.0)	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)
Total Operating	0.0	(400,000.0)	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)

Fund Source (Operating Only)

1004 Gen Fund		(400,000.0)	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)
Total	0.0	(400,000.0)	(325,000.0)	(200,000.0)	(200,000.0)	(200,000.0)	(200,000.0)

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues		100,000.0	100,000.0	50,000.0	50,000.0	50,000.0	50,000.0
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Estimated SUPPLEMENTAL (FY2016) cost: 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 1,500.0 *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? yes
 If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/17

Why this fiscal note differs from previous version:

Not applicable, initial version.

Prepared By: Ken Alper, Director
 Division: Tax Division
 Approved By: Jerry Burnett
 Agency: Deputy Commissioner, DOR

Phone: (907)465-8221
 Date: 01/13/2016 12:00 PM
 Date: 01/13/16

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

Analysis

Bill Background

This legislation is a comprehensive attempt to reform and reduce the cost of Alaska's current program of providing direct tax credit rebates and other advantages to oil and gas companies. Various credits have been added to statute since 2003, with state repurchase beginning in 2007. Through the end of FY 2015, about \$7.4 billion in tax credits were received by companies. This includes both credits used against tax liability and credits repurchased by the state; it also includes activity on both the North Slope and other areas of the state.

A substantial number of companies rely on these credits to support and subsidize their Alaska operations. Currently, in many cases the state is paying 55%-65% of the cost of a project during the development phase, and up to 85% of exploration costs. These large numbers result from "stacking" multiple credits. With the transition towards a system based mostly on operating loss credits, and the repeal of the expenditure credits that are stacked with those loss credits, the state's contribution towards many projects will be reduced roughly by half.

There are several themes, or goals, of this legislation. These include:

- * Reduce the state's annual cash outlay
- * Protect Net Operating Loss credits especially for exploration activity
- * Limit repurchases to companies who need the support
- * Strengthen the minimum tax and prevent abuses to the system
- * Be more open and transparent
- * Honor and pay credits earned to date and through any transition period.

To address the final bullet point, above, separate legislation will be proposing an appropriation to cover any tax credits earned through the effective date. This includes the last of the credits that would have been paid in FY 2016 if not for the \$500 million limit established by the governor's line-item veto, all estimated credits that would be paid in FY 2017, and credits earned in the first part of calendar year 2016 before the effective date of the bill. The transition funds will total nearly \$1 billion.

In addition, separate legislation is being developed to establish a direct loan program administered by the Alaska Industrial Development and Export Authority (AIDEA). The loans will support the development of proven oil and gas reserves, providing an attractive alternative to conventional financing. The transition appropriation, as described in the prior paragraph, will endow this new loan fund with an initial deposit of \$200 million.

Summary of Fiscal Impact

DOR's estimate is that this legislation will have an initial fiscal impact of \$500 million per year. Of this, \$400 million would be saved through reduced operating budget expenditures and \$100 million would come from increased revenues. In subsequent years, the estimated impact particularly on the total amount of refunded credits is limited by DOR's current revenue and credit forecasts. DOR uses a conservative methodology to estimate future credits, and typically these figures are revised upwards as we get closer to a given forecast year.

The savings and new revenues come via three different mechanisms:

- 1) About \$200 million in reduced expenditures, as some tax credit certificates would no longer be earned due to the repeal of certain specific credits as well as the closing of certain loopholes.

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. 0 _____

Analysis Continued

2) About \$200 million in reduced expenditures, as some tax credit certificates would continue to be earned by companies but would not be immediately eligible to be turned into cash. In most cases, credit certificates would have to be held by the companies until such time as they had tax liability. At that time the certificates could be used to reduce their liability.

3) About \$100 million would be earned in additional revenue. About half of this would come through "hardening" the minimum tax floor, thus reducing the ability of companies to offset the 4% payment. The other half would come from increasing the minimum tax rate from 4% to 5%. Also, the proposed change to interest rates would raise a small amount of additional revenue.

Based on DOR's oil price forecast, prices should be sufficiently recovered by FY 2019 that it would be unlikely that one or more of the major oil producers would have a net operating loss. That will eliminate the impact of one specific floor hardening provision, reducing the additional revenue estimate.

Implementation Cost

The changes anticipated in this bill will require somewhat substantial reprogramming of the Tax Revenue Management System and Revenue Online tax portal. We have requested an estimate from the software developer, and currently assume a one-time cost of about \$1,500,000 to accomplish this. We do not anticipate any additional costs to administer the tax program.

There will also be a need for substantial amendments to existing regulations to fully implement the changes.

Detail of Specific Provisions

1) Repeal of certain credits and closing of loopholes

The bill repeals the Qualified Capital Expenditure Credit (AS 43.55.023(a)) and the Well Lease Expenditure Credit (AS 43.55.023(l)). These credits of 20% and 40% respectively apply only outside of the North Slope. For companies without a tax liability, they are generally "stacked" with the carried-forward annual loss credit (AS 43.55.023(b)) resulting in total state contribution to projects in the 45%-65% range. Companies who do not have an operating loss are also eligible to receive these credits. This provides large cash subsidies to potentially profitable companies who, due to existing tax caps, effectively pay no production taxes.

The bill also eliminates a loophole that enables companies who have production of "new oil" on the North Slope but also claim a net operating loss. With the changes, companies will no longer be able to use a Gross Value Reduction to increase the size of a net operating loss credit. Current law can result in situations where the credit received can be greater than 100% of a company's actual loss.

It also eliminates another loophole that has been used by municipal utilities who also own oil or gas production. If a portion of that production is sold to an outside party, the proposed change ensures that these entities are only able to deduct or claim a pro-rated portion of their lease expenditures for the purpose of applying for credits.

2) Deferral or loss of eligibility for credit repurchase

Currently any company with less than 50,000 bbl / day of production in Alaska is eligible to have tax credit certificates repurchased by the state without limit, subject to appropriation. This legislation adds several other restrictions to repurchase. Companies that do not meet these restrictions will be required to hold their certificates until they have a tax liability. Alternatively, they can transfer their certificates to another company to use against that company's liability. The additional restrictions are:

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. 0 _____

Analysis Continued

- * Any company with global annual revenue of greater than \$10 billion in the past calendar year;
- * Annual per-company limit of \$25 million;
- * Companies with any current outstanding liability to the state;
- * The percentage of a given certificate that can be repurchased is limited by that company's percentage of Alaska resident hire;
- * Credit certificates expire after ten years.

3) Floor hardening and other revenue increasing measures

Currently, the production tax on North Slope oil from fields not eligible for the Gross Value Reduction is limited by the 4% gross minimum tax, or "floor." Specifically, the sliding scale per-barrel credit cannot be used to reduce taxes below that level. However, there are several other credits that can reduce tax payments below the level of the floor, as far as zero. The bill makes several changes to prevent this and thus guarantee a minimum tax payment to the state.

- * Prevents several credits including carried-forward annual loss credit (NOL) from being used to reduce a minimum tax payment. If one or more of the three major producers has an operating loss at the end of a tax (calendar) year, under current law, they could use their NOL credit to offset their minimum tax payments beginning in January of the next calendar year. Our current projections show this happening in 2016 and 2017. With this change, the loss credit would be held until a future year when the producer had adequate tax liability against which to offset it. This specific change is being made retroactive to January 1, 2016.
- * Prevent per-taxable-barrel credits that cannot be used in a month, due to the limitation of the minimum tax, from being claimed at annual true-up of the monthly tax payments. Without this change, in years where there is substantial price volatility the state could be paying large refunds at the end of the year.
- * Extends the 4% minimum tax to all North Slope production, including fields eligible for the Gross Value Reduction.

The bill also increases the tax rate of the floor itself from a variable tax rate that is 4% if the price of oil is greater than \$25 per barrel, to 5% at all oil prices.

One final change that will generate additional revenue is to increase the interest rate for delinquent taxes, underpayments, and tax assessments. The new rate is designed to roughly equal the state's rate of return on its investment assets, thus reimbursing the state for its opportunity cost due to unpaid taxes.

4) Technical and non-revenue changes

The bill makes several other changes without a specific fiscal impact:

- * Repeals several older and currently unused exploration incentive credit programs
- * Repeals several obsolete or superseded statutory sections that refer to oil and gas production from prior years
- * Ensures that the Department of Natural Resources continues to receive appropriate seismic and downhole data as a condition of receiving state credits, despite the sunset of the exploration incentive credit program
- * Provides a confidentiality waiver so the state can release specific information about tax credits repurchased from individual companies.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version: HB 247
Fiscal Note Number: _____
() Publish Date: _____

Identifier: HB247-DOR-TAX-2-1-16
Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: Governor

Department: Department of Revenue
Appropriation: Taxation and Treasury
Allocation: Tax Division
OMB Component Number: 2476

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates					
			FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES								
Personal Services								
Travel								
Services								
Commodities								
Capital Outlay								
Grants & Benefits								
Miscellaneous								
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None								
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time								
Part-time								
Temporary								

Change in Revenues		100,000.0	100,000.0	50,000.0	50,000.0	50,000.0	50,000.0
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Estimated SUPPLEMENTAL (FY2016) cost: 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 1,500.0 *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? yes
If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/17

Why this fiscal note differs from previous version:

Revised to conform to the fiscal note that capitalizes the Oil and Gas Tax Credit Fund. That note includes adequate funds to transition from the existing program as the changes in this bill are implemented. Reductions to expenditures are removed from this note because they are contained in the Credit Fund note.

Prepared By:	Ken Alper, Director	Phone:	(907)465-8221
Division:	Tax Division	Date:	02/01/2016 01:00 PM
Approved By:	Jerry Burnett, Deputy Commissioner	Date:	02/01/16
Agency:	Department of Revenue		

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. HB247

Analysis

Bill Background

This legislation is a comprehensive attempt to reform and reduce the cost of Alaska's current program of providing direct tax credit rebates and other advantages to oil and gas companies. Various credits have been added to statute since 2003, with state repurchase beginning in 2007. Through the end of FY 2015, about \$7.4 billion in tax credits were received by companies. This includes both credits used against tax liability and credits repurchased by the state; it also includes activity on both the North Slope and other areas of the state.

A substantial number of companies rely on these credits to support and subsidize their Alaska operations. Currently, in many cases the state is paying 55%-65% of the cost of a project during the development phase, and up to 85% of exploration costs. These large numbers result from "stacking" multiple credits. With the transition towards a system based mostly on operating loss credits, and the repeal of the expenditure credits that are stacked with those loss credits, the state's contribution towards many projects will be reduced roughly by half.

There are several themes, or goals, of this legislation. These include:

- * Reduce the state's annual cash outlay
- * Protect Net Operating Loss credits especially for exploration activity
- * Limit repurchases to companies who need the support
- * Strengthen the minimum tax and prevent abuses to the system
- * Be more open and transparent
- * Honor and pay credits earned to date and through any transition period.

To address the final bullet point, above, separate legislation will be proposing an appropriation to cover any tax credits earned through the effective date. This includes the last of the credits that would have been paid in FY 2016 if not for the \$500 million limit established by the governor's line-item veto, all estimated credits that would be paid in FY 2017, and credits earned in the first part of calendar year 2016 before the effective date of the bill. The transition funds will total nearly \$1 billion.

In addition, separate legislation is being developed to establish a direct loan program administered by the Alaska Industrial Development and Export Authority (AIDEA). The loans will support the development of proven oil and gas reserves, providing an attractive alternative to conventional financing. The transition appropriation, as described in the prior paragraph, will endow this new loan fund with an initial deposit of \$200 million.

Summary of Fiscal Impact

DOR's estimate is that this legislation will have an initial fiscal impact of \$500 million per year. Of this, \$400 million would be saved through reduced operating budget expenditures and \$100 million would come from increased revenues. In subsequent years, the estimated impact particularly on the total amount of refunded credits is limited by DOR's current revenue and credit forecasts. DOR uses a conservative methodology to estimate future credits, and typically these figures are revised upwards as we get closer to a given forecast year.

The savings and new revenues come via three different mechanisms:

- 1) About \$200 million in reduced expenditures, as some tax credit certificates would no longer be earned due to the repeal of certain specific credits as well as the closing of certain loopholes.

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

BILL NO. HB247

Analysis Continued

2) About \$200 million in reduced expenditures, as some tax credit certificates would continue to be earned by companies but would not be immediately eligible to be turned into cash. In most cases, credit certificates would have to be held by the companies until such time as they had tax liability. At that time the certificates could be used to reduce their liability. Items #1 and #2 are addressed in the fiscal note that capitalizes the Tax Credit Fund.

3) About \$100 million would be earned in additional revenue. About half of this would come through "hardening" the minimum tax floor, thus reducing the ability of companies to offset the 4% payment. The other half would come from increasing the minimum tax rate from 4% to 5%. Also, the proposed change to interest rates would raise a small amount of additional revenue.

Based on DOR's oil price forecast, prices should be sufficiently recovered by FY 2019 that it would be unlikely that one or more of the major oil producers would have a net operating loss. That will eliminate the impact of one specific floor hardening provision, reducing the additional revenue estimate.

Implementation Cost

The changes anticipated in this bill will require somewhat substantial reprogramming of the Tax Revenue Management System and Revenue Online tax portal. We have requested an estimate from the software developer, and currently assume a one-time cost of about \$1,500,000 to accomplish this. We do not anticipate any additional costs to administer the tax program.

There will also be a need for substantial amendments to existing regulations to fully implement the changes.

Detail of Specific Provisions

1) Repeal of certain credits and closing of loopholes

The bill repeals the Qualified Capital Expenditure Credit (AS 43.55.023(a)) and the Well Lease Expenditure Credit (AS 43.55.023(l)). These credits of 20% and 40% respectively apply only outside of the North Slope. For companies without a tax liability, they are generally "stacked" with the carried-forward annual loss credit (AS 43.55.023(b)) resulting in total state contribution to projects in the 45%-65% range. Companies who do not have an operating loss are also eligible to receive these credits. This provides large cash subsidies to potentially profitable companies who, due to existing tax caps, effectively pay no production taxes.

The bill also eliminates a loophole that enables companies who have production of "new oil" on the North Slope but also claim a net operating loss. With the changes, companies will no longer be able to use a Gross Value Reduction to increase the size of a net operating loss credit. Current law can result in situations where the credit received can be greater than 100% of a company's actual loss.

It also eliminates another loophole that has been used by municipal utilities who also own oil or gas production. If a portion of that production is sold to an outside party, the proposed change ensures that these entities are only able to deduct or claim a pro-rated portion of their lease expenditures for the purpose of applying for credits.

2) Deferral or loss of eligibility for credit repurchase

Currently any company with less than 50,000 bbl / day of production in Alaska is eligible to have tax credit certificates repurchased by the state without limit, subject to appropriation. This legislation adds several other restrictions to repurchase. Companies that do not meet these restrictions will be required to hold their certificates until they have a tax liability. Alternatively, they can transfer their certificates to another company to use against that company's liability. The

Analysis Continued

- * Any company with global annual revenue of greater than \$10 billion in the past calendar year;
- * Annual per-company limit of \$25 million;
- * Companies with any current outstanding liability to the state;
- * The percentage of a given certificate that can be repurchased is limited by that company's percentage of Alaska resident hire;
- * Credit certificates expire after ten years.

3) Floor hardening and other revenue increasing measures

Currently, the production tax on North Slope oil from fields not eligible for the Gross Value Reduction is limited by the 4% gross minimum tax, or "floor." Specifically, the sliding scale per-barrel credit cannot be used to reduce taxes below that level. However, there are several other credits that can reduce tax payments below the level of the floor, as far as zero. The bill makes several changes to prevent this and thus guarantee a minimum tax payment to the state.

- * Prevents several credits including carried-forward annual loss credit (NOL) from being used to reduce a minimum tax payment. If one or more of the three major producers has an operating loss at the end of a tax (calendar) year, under current law, they could use their NOL credit to offset their minimum tax payments beginning in January of the next calendar year. Our current projections show this happening in 2016 and 2017. With this change, the loss credit would be held until a future year when the producer had adequate tax liability against which to offset it. This specific change is being made retroactive to January 1, 2016.
- * Prevent per-taxable-barrel credits that cannot be used in a month, due to the limitation of the minimum tax, from being claimed at annual true-up of the monthly tax payments. Without this change, in years where there is substantial price volatility the state could be paying large refunds at the end of the year.
- * Extends the 4% minimum tax to all North Slope production, including fields eligible for the Gross Value Reduction.

The bill also increases the tax rate of the floor itself from a variable tax rate that is 4% if the price of oil is greater than \$25 per barrel, to 5% at all oil prices.

One final change that will generate additional revenue is to increase the interest rate for delinquent taxes, underpayments, and tax assessments. The new rate is designed to roughly equal the state's rate of return on its investment assets, thus reimbursing the state for its opportunity cost due to unpaid taxes.

4) Technical and non-revenue changes

The bill makes several other changes without a specific fiscal impact:

- * Repeals several older and currently unused exploration incentive credit programs
- * Repeals several obsolete or superseded statutory sections that refer to oil and gas production from prior years
- * Ensures that the Department of Natural Resources continues to receive appropriate seismic and downhole data as a condition of receiving state credits, despite the sunset of the exploration incentive credit program
- * Provides a confidentiality waiver so the state can release specific information about tax credits repurchased from individual companies.

Fiscal Note

State of Alaska
2016 Legislative Session

Bill Version:	HB 247
Fiscal Note Number:	1
(H) Publish Date:	1/19/2016

Identifier: DNR-DOG-1-11-16
 Title: TAX;CREDITS;INTEREST;REFUNDS;O & G
 Sponsor: RLS BY REQUEST OF THE GOVERNOR
 Requester: Governor

Department: Department of Natural Resources
 Appropriation: Oil & Gas
 Allocation: Oil & Gas
 OMB Component Number: 439

Expenditures/Revenues

Note: Amounts do not include inflation unless otherwise noted below. (Thousands of Dollars)

	FY2017 Appropriation Requested	Included in Governor's FY2017 Request	Out-Year Cost Estimates					
			FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
OPERATING EXPENDITURES								
Personal Services								
Travel								
Services								
Commodities								
Capital Outlay								
Grants & Benefits								
Miscellaneous								
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None								
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time								
Part-time								
Temporary								

Change in Revenues								
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Estimated SUPPLEMENTAL (FY2016) cost: 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY2017) cost: 0.0 *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? No
 If yes, by what date are the regulations to be adopted, amended or repealed?

Why this fiscal note differs from previous version:

Not applicable, initial version.

Prepared By: Corri Feige, Director
 Division: Division of Oil & Gas
 Approved By: Mark Myers, Commissioner
 Agency: Department of Natural Resources

Phone: (907)269-8775
 Date: 01/11/2016 12:00 AM
 Date: 01/11/16

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2016 LEGISLATIVE SESSION

Analysis

No fiscal impact.

Title: Production Tax Credits Detail FY 2007 to FY 2025

Preparer: Mackenzie Merrill, Economist, 465-5636

Purpose: Provide detailed data on refunded production tax credits and production tax credits against liability historically from FY 07 to FY 15, and forecasted from FY 16 to FY 25; broken out by North Slope and Non-North Slope.

Date: 1/19/2016

Data Source: Fall 2015 Revenue Sources Book and supporting data/models.

Key Assumptions: All assumptions are as of the Fall 2015 Revenue Sources Book. Also see notes and comments embedded in the spreadsheet.

History: This version incorporates the Fall 2015 forecast numbers and, based on updated analysis, includes slight revisions to the geographic location of refunded credits in FY 2009 through FY 2012.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Table 8-4: Detail on Historical Production Tax Credits and Forecast

(\$millions)	Historical								Preliminary	Forecast ²									
	FY 07	FY 08	FY 09	FY 10	FY 11	FY 12	FY 13	FY 14	FY 15 ¹	FY 16	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	FY 23	FY 24	FY 25
Refunded Credits³																			
North Slope																			
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b)	55	*	173	223	399	267	*	*	203	224	360	199	89	50	50	50	50	50	50
Credits under AS 43.55.025 ⁴	0	*	14	23	12	53	*	*	21	0	0	0	0	0	0	0	0	0	0
Total North Slope	55	53	187	246	411	320	261	281	224	224	360	199	89	50	50	50	50	50	50
Non-North Slope																			
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b); Well lease expenditure, AS 43.55.023(l)	0	*	*	*	*	29	*	*	384	268	210	136	125	166	167	197	198	198	199
Credits under AS 43.55.025 ⁴	0	*	*	*	*	4	*	*	21	8	8	7	5	4	3	3	2	2	1
Credits under AS 43.20 ⁵	0	*	*	*	*	0	*	15	0	0	45	30	30	30	30	0	0	0	0
Total Non-North Slope	0	1	7	4	39	33	108	312	404	276	263	173	161	200	200	200	200	200	200
Total Refunded Credits	55	54	193	250	450	353	369	592	628	500	625	375	250	250	250	250	250	250	250
Credits Used Against Tax Liability^{6,7}																			
North Slope																			
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b)	292	219	279	339	313	306	486	332	0	40	52	1	0	0	0	0	0	0	0
Transitional investment expenditure: AS 43.55.023(i) ⁸	171	73	0	0	0	*	*	*	*	*	*	*	*	*	*	*	*	*	*
Per taxable barrel credit, AS 43.55.024(i)-(j) ⁹	*	*	*	*	*	*	*	516	595	28	189	367	614	625	703	671	613	584	543
Small producer credit, AS 43.55.024(a)(c)	*	*	*	*	*	*	*	*	*	37	43	37	48	42	36	27	19	5	0
Credits under AS 43.55.025 ⁴	*	*	*	*	*	*	*	*	*	0	0	0	0	0	0	0	0	0	0
Total North Slope	541	368	328	402	345	347	536	907	655	105	284	405	662	666	739	698	632	589	543
Non-North Slope																			
Qualified capital expenditure, AS 43.55.023(a); Carry-forward annual loss, AS 43.55.023(b); Well lease expenditure, AS 43.55.023(l)	*	*	0	*	11	*	*	*	*	17	23	23	23	22	22	21	20	30	34
Small producer credit, AS 43.55.024(a)(c)	*	*	6	*	6	*	*	*	*	0	0	0	0	0	0	0	3	6	6
Total Non-North Slope	16	10	6	10	17	16	14	12	9	17	23	23	23	22	22	21	23	36	40
Total Credits Used Against Tax Liability	557¹⁰	378	334	412	361	363	550	919	664	120	310	430	690	690	760	720	660	630	580
Total Credits North Slope	596	421	*	647	756	667	797	1188	879	329	644	604	752	716	789	748	682	639	593
Total Credits Non-North Slope	16	11	*	14	56	49	122	323	413	292	286	196	184	222	221	223	236	240	240
Total Statewide Production Tax Credits	\$612	\$432	\$526	\$662	\$811	\$716	\$918	\$1,511	\$1,292	\$620	\$935	\$805	\$940	\$940	\$1,010	\$970	\$910	\$880	\$830

Source: Fall 2015 Revenue Sources Book Backup

* An asterisk indicates that the data is confidential.

¹ These numbers are preliminary pending Annual Returns.

² Forecasted refunded credits are rounded to the nearest \$ million. Forecasted credits against liability are rounded to the nearest \$10 million.

³ Forecasted refunded credits in the near-term are based on known projects and company activities. For FY 2020 and beyond, the forecast of credits available for refund is held constant at \$250 million per year.

⁴ Credits under AS 43.55.025 include the Alternative Credit for Exploration, the Frontier Basin Credit, and for Cook Inlet only the Cook Inlet Jack-up Rig Credit.

⁵ Credits under AS 43.20 include the Gas Exploration and Development Credit, Gas Storage Facility Credit, the In-State Gas Refinery Credit, and the LNG Storage Facility Credit.

⁶ The Education Credit, AS 43.55.019, though not reported in its own credit category in the summary was less than \$1 million in each year reported and is calculated in the total.

⁷ For historical credits against tax liability, geographic location was determined by attributing all .023(l) credits to Non-North Slope, all .025 Credits to North Slope, and the other credits were placed according to where the company primarily operated. Since multiple companies had operations in multiple areas, these numbers should be treated as rough estimates.

⁸ The Transitional Investment Expenditure Credit sunset on Dec 31, 2013.

⁹ For FY 2014, the Per Taxable Barrel Credit is for only the last six months of the fiscal year. Credits applied against liability in the forecast are reduced because of the 4% minimum gross tax.

¹⁰ Three months of 2006 credits data are included in the FY 2007 credits used against tax liability number.



Sectional Analysis, HB 247 (29-GH2609\A)

Governor's Oil and Gas Tax Credit Reform Bill

February 2016

AOGA Comments/Questions italicized

- Sec. 1-5.** Conforming language related to the repeal of AS 41.09 in Sec. 40 of the bill. The repeal is a currently unused exploration incentive credit program.
- Sec. 6.** Conforming language related to changes to reporting requirements and confidentiality rules in Sec. 8 of the bill.
- Sec. 7.** Changes the interest rate for delinquent taxes from 3 percent above the Federal Reserve Discount Rate to 7 percent above. This would currently result in an interest rate of about 8%; about halfway between the current 4% and the 11% that was in place before the passage of SB21 in 2013. If the state were to begin using earnings from our major savings account, the Permanent Fund, to fund government operations, there would be an "opportunity cost" that comes from unpaid taxes. Our interest rate on these unpaid taxes should reflect the expected rate of earnings on our savings.

[AOGA Comment]: AOGA supports the current rate and believes it is reasonable particularly considering the lengthy statute of limitation that provides the Department of Revenue with six years to audit a company's production tax return.

Raising the interest rate and returning to compound interest could be an incentive for the State to delay the completion of its audits so more interest can accrue. With the long six-year statute of limitations for auditing, these changes to the calculation of interest will increase unpredictability in Alaska's tax system and undercut Alaska's position in the competition for scarce investment dollars to keep oil flowing through the pipeline.

- Sec. 8.** Provides an exception to the general taxpayer confidentiality statutes, so that the name of each company claiming credits, the amount they claim, and a general description of their activities can be made public.

[AOGA Comment]: This information is currently confidential, and to protect that confidentiality, the law (AS 43.55.890(11)) allows the Department of Revenue ("DOR") to disclose information about tax credits only on an "aggregated" basis for a group of three or more taxpayers. The impetus for Section 8 arises from credits that are being earned by only one or two taxpayers — too few for disclosure on an aggregated basis.

Confidentiality of tax information is the mechanism by which taxpayers' constitutional privileges and immunities regarding private, proprietary and commercially sensitive information and materials are reconciled with DOR's goal of having taxpayers report and pay their taxes correctly, and with its need to audit them to ensure they are correct. Without confidentiality, DOR's

authority to require information and documents from taxpayers would be materially curtailed by these constitutional constraints.

For taxpayers, however, confidentiality is basically an all-or-nothing proposition — the constitution does not prohibit partial waivers of a privilege or immunity that a limited only a specific information or materials, but it does not authorize partial waivers either. Thus a taxpayer cannot agree to the disclosure of specified information or materials for a tax without the risk that doing so will waive the privilege and immunity for all of its tax information for that tax.

Section 8 reflects none of this. Nor does it indicate what the Administration specifically hopes to achieve by this change to confidentiality.

Sec. 9-11. Amends the Gas Storage Facility, LNG Facility, and In-State Refinery Tax Credits so that these cannot be paid if the taxpayer has any outstanding liability to the state. Currently this is restricted to only a tax liability.

[AOGA Comment]: There is an existing limitation on using certain tax credits when the party using them has an outstanding tax liability to the State. Section 39 of the Bill changes the definition of “outstanding liability” so that it is any liability — no matter what the non-tax liability may be, how trivial it is, or whether it is being appealed. Thus this change is overly broad and threatens to lead to denial or delay of valuable redeemable tax credits.

If the taxpayer has valid redeemable tax credits but is issued an audit assessment before applying for cash reimbursement, will the taxpayer now have to wait until resolution of the audit before redeeming the tax credits for what might be critically important funds for current investments?

Sec. 12. Increases the minimum tax rate in AS 43.55.011(f) to 5% at all oil prices. Currently it is 4% at any oil price above \$25 per barrel, stepping down at lower prices. The minimum tax applies only to production from the North Slope.

[AOGA Comment]: An increase of one percentage point in the rate of tax might not sound significant, but it would be a 25 percent increase for each taxpayer subject to the minimum tax because West Coast prices, so far at least, are still over \$25 a barrel — putting the rate for minimum tax at four percent. In fact, according to DOR’s presentation, oil prices would need to climb to approximately \$85 a barrel before the minimum tax will not apply.

For smaller companies or newcomers to the state who have yet to make a profit in Alaska, they don’t pay the 4% tax now, so under this provision they would go from paying zero in production tax because they don’t make a profit, to immediately being hit with a 5% gross tax represents an increase of over 100 percent, or as Director Alper referred to it as “an infinite increase.”

Implementing or raising taxes on companies who are in negative cash flow positions is like kicking someone who is already down. It is not wise, nor feasible, long-term solution to Alaska’s production problem or sound tax policy.

Sec. 13. Changes the description of monthly installment payments in AS 43.55.020(a), to conform with the higher minimum tax rate in Sec. 12. (long technical section)

[AOGA Comment]: This change would require companies to pay the higher of the new 5% minimum tax or regular net tax effective with July 1 production.

Sec. 14-16. Conforming language related to the repeal of AS 43.55.020(a)(1) and (2) in Sec. 40 of the bill. The repeal is obsolete installment payment language related to production prior to 2014.

Sec. 17. Strengthens the minimum tax in two distinct ways:

- (b) Prevents several credits that currently can be used to reduce payments below the 4% level from being used for this purpose. Those credits would be carried-forward until the taxpayer had sufficient tax liability against which to use them.
- (c) Prevents the circumstance in which per-taxable-barrel credits that could not be used in the month in which they were earned, because of the limitations of the minimum tax, could be claimed at annual tax true-up. This effectively turns the per-taxable-barrel credit into a monthly rather than an annual calculation. Currently if there is substantial price volatility within a year it could result in large tax refunds.

[AOGA Comment]: This is nothing more than a disguised tax increase.

The production tax is an annual tax paid in monthly installments, which reflects the fact that producers keep their accounting books and records on an annual basis and do not close and balance them at the end of each month, nor even at the end of each calendar quarter.

Each installment reflects one-twelfth (1/12) of the spending budget for the entire year, but actual expenditures routinely run over or under budget, and no one can forecast how much these variances from the budget will be. Furthermore, the budget can increase or decrease during the year in response to unanticipated factors. And on the revenue side of the ledger, each installment can reflect the actual prices for the current month and prior ones, but can only include one's assumptions about future prices during the rest of the year.

Since these key factors in the calculation of the tax for the full year — including the calculation of whether minimum tax is greater than the normal tax, as well as the calculation or application of tax credits from ongoing expenditures during the year — cannot be known for the full year until after the year is over, the sum of the monthly estimated payments will not equal the total tax for that year except by sheer coincidence. This is why, at the end of the calendar year, the producer is required to file a “true-up” or “final tax installment” reflecting the correct amount of production tax for the entire calendar year of operations.

Section 17 not only disregards these real and unavoidable uncertainties in monthly installments and their respective variances from the full-year figures, it would also punish a producer by locking down the monthly portion of any credit a producer earns or has available to the amount reflected in the installment for that month, instead of the actual and correct monthly amount for that credit as determined at true-up. This limitation creates uncertainty about the actual amount of credits a producer would earn or have available to use during its operations for a year, since the sum of the monthly credits can only be less than the amount for them based on the full-year's figures. And this new, wholly unnecessary and artificial risk about the credits will tend to reduce a company's desire to make investments in the state.

Worse, for those credits which are not allowed to be carried forward or transferred, they would be lost under this provision, which would be a significant and permanent tax increase.

Sec. 18. Modifies the carried-forward annual loss credit in AS 43.55.023(b) so that, for “new” oil production eligible to receive the Gross Value Reduction (GVR), the GVR cannot be used to increase the size of an annual loss. Thus, if a company has oil production but is operating at a loss, their loss credit is limited to the actual size of the loss. Currently there are circumstances in which a company could receive credit refunds for amounts in excess of 100% of their loss.

[AOGA Comment]: This provision represents another tax increase.

The provision would prevent gross revenue reductions — which are incentives critical to encourage “new oil” production — from being utilized to determine the gross value at the point of production when a producer has a net loss, meaning the economic value and attractiveness of that incentive in current policy is dramatically undercut.

The provision would significantly penalize those companies who have made critical investments since the enactment of the GVR incentive in order to produce “new oil,” by preventing them from recovering part of this reward for making that investment.

Sec. 19. Amends AS 43.55.023 so that credits in that section cannot reduce tax liability below the minimum tax, rather than zero as in current statute. Also establishes a sunset when certain credits must be carried forward instead of being cashed out; in these circumstances the credits can only be carried forward for 10 years.

[AOGA Comment]: This provision is still another significant tax increase and represents nothing more than a flagrant money grab at a time when the state should be encouraging industry to continue making vital investments in the state.

For those companies, large and small, that may have exploration, drilling, or tax loss credits from prior year investments and may be in a loss situation due to the low prices and thus are depending on using those tax credits to support continued investment in the state, the proposal would delay or possibly deny that economic recovery at the very time when the companies need it the most.

This change would penalize companies who made important prior year investments in the state and are trying to recoup part of those investments in order to allow them to continue to make more investments in the state at a time when they are losing money — this would be poor tax policy and would lessen the state’s global competitive position to attract investment dollars.

This change is analogous to the federal government not allowing corporate losses to be applied against their corporate income tax.

This provision, especially when accompanied with an increase to the minimum tax floor itself, will represent a significant increase to the amount of taxes paid by companies that are already struggling.

Sec. 20. Establishes a sunset in which credit certificates can only be held for 10 years before they expire.

[AOGA Comment]: This provision, especially when combined with the administration’s proposal to limit the annual amount of redeemable tax credits to \$25M, could put critical redeemable tax credits at risk.

Sec. 21. Conforming language related to the repeal of AS 43.55.023(a) in Sec. 40 of the bill. The repeal is the “qualified capital expenditure” credit outside of the North Slope.

[AOGA Comment]: The provision to remove the “qualified capital expenditure” tax credit for non-North Slope investments is another significant tax increase that will erode capital investment that is critical to the long-term sustainability of oil and gas development in Cook Inlet and Middle Earth.

The qualified capex tax credit was an important and needed incentive that enabled new players and developments in the Cook Inlet. Coupled with the dramatic changes to net operating loss credits and elimination of other Cook Inlet credits, repealing these credits could make it very challenging to attract key investment dollars and projects to Alaska, especially in this low price environment when companies are low on cash.

Sec. 22. New language adding the notice and data sharing requirements that are currently part of the alternative credit for exploration, and applying them to other credits. This will enable DNR to continue to receive seismic and downhole information after the sunset of the exploration credits.

[AOGA Comment]: This appears to now expand the data submission requirements for explorers to now existing producers as well. If that is the case, this requirement on producers could be duplicate to the well data provided to the Alaska Oil and Gas Conservation Commission. This would flood Department of Natural Resources with reams of unnecessary data.

Has DNR requested this information? Why do they need it?

How is the information DNR will make public different than the information being considered for public disclosure by the DOR in proposed section 8?

What tax policy purpose is being served?

Why would producers be required to submit “exploration data”? This could seriously impact activities in existing fields and cause significant administrative burdens as producers may now be required to submit lengthy and potentially proprietary data on virtually all well work being considered.

Sec. 23. Amends AS 43.55.024 so that the small producer credit cannot be used to reduce tax liability below the minimum tax. Although this credit will be closed to new recipients in May of 2016, some companies will continue to receive this benefit until approximately 2024.

[AOGA Comment]: Here is yet another tax increase – this time aimed at smaller companies that may depend on continuing to use the small producer credit against potential minimum tax in order to be able to make critical ongoing investments in the state.

This provision in essence penalizes those smaller companies who made prior year investments despite losing money, by denying them the benefit of the small producer credit which underpinned their original investment decision.

Since these credits are not transferable or redeemable, any lost credits would represent a permanent tax increase.

Sec. 24. Amends AS 43.55.024 so that the \$5 per-taxable-barrel credit received by GVR eligible North Slope oil production cannot reduce tax liability below the minimum tax. Currently this can be reduced to zero; only the sliding-scale credit for non-GVR oil is limited by the minimum tax.

[AOGA Comment]: The \$5 per-taxable-barrel credit for "new oil" is not transferable and cannot be carried forward, so any loss of those credits in a given year represents a permanent tax increase.

This provision — like the limitation on the use of the GVR in Section 18 — is eating the State's seed corn. The "new oil" credit and GVR are significant incentives for developing reservoirs and bringing into production reservoirs that have not yet been developed. They are even more important at this time of low oil prices than they were when they were enacted.

Sec. 25. Amends AS 43.55.025 so that exploration credits cannot reduce tax liability below the minimum tax.

[AOGA Comment]: Another tax increase.

This provision in essence penalizes those companies willing to commit critical and limited exploration dollars to Alaska, by denying them the ability to receive the promised economics of their high risk investments.

This goes against the long-term policy of the state to encourage exploration and development activity and will discourage long-term exploration activity in the state.

Sec. 26. Amends AS 43.55.028(e) to add limitations on which companies can receive refunded tax credits versus which must hold their certificates and use them against tax liability:

(2) Companies with any liability to the state are ineligible to receive payment for their tax credit certificates. Currently this is restricted to only a tax liability.

(5) Limits cash repurchase to only companies whose gross revenues in the previous year were less than \$10 billion.

(6) Limits annual per-company repurchase to \$25 million.

[AOGA Comment]: This proposal lacks a factual foundation and defies common sense. Why should the annual revenues of a company have any bearing on its eligibility to be paid for its tax-credit certificates? How is a large company somehow less worthy than a small one in getting its tax certificates paid? There is no reason why certain dollars invested in Alaska are better for Alaska than others. And whether an explorer/producer is investing or its financier is making the investment possible, a tax certificate cannot exist unless that investment has, in fact, been made. Different producers have different needs and uses for credits, and the size of projects vary tremendously.

Is the administration's goal to prevent larger taxpayers from wanting to invest in Alaska?

Setting arbitrary limits on companies (\$25 million) is unreasonable and will not be an incentive for investment. This size of net operating loss (NOL) tax credit availability is made truly insignificant and will render the NOL credit mostly useless and will most certainly result in chilling existing and new project investments.

Sec. 27. Adds a new limitation to a company's ability to receive a cash repurchase of their tax credits. The state can only repurchase that percentage of a certificate that equals that company's percentage of Alaska resident hire in the previous calendar year.

[AOGA Comment]: Companies try every day to hire as many eligible Alaskans possible. Establishing mandatory local hire requirements as a precondition for a tax credit would make it difficult to plan and evaluate investments and would further challenge new investment to the state. It would also raise significant constitutional issues, as Alaska-hire preference in building the Trans Alaska Pipeline System was struck down by the U.S. Supreme Court.

It is also unjust to single out the oil and gas industry when other industries operating in Alaska employ much higher numbers of non-Alaskans.

Sec. 28-30. Conforming language related to the repeal of AS 43.55.023(a) and / or (l) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" and "well lease expenditure" credits outside of the North Slope.

Sec. 31. New section specifying that the Gross Value at the Point of Production, defined as sales price less eligible transportation costs, may not be less than zero.

[AOGA Comment]: On a superficial level this explanation of Section 31 may seem to be "just common sense," but in fact it is another example where the State would be sacrificing its long-term interests in order to meet its short-term spending needs.

How is this section expected to work or be applied?

If oil prices get to the point where the Gross Value at the Point of Production ("GVPP") for the North Slope is less than zero at one or more fields or units, that would be exactly the wrong time for the State to raise taxes on the producers of that oil. The GVPP of the producers' share of the oil will also be less than zero, which means that none of the cash-flow demands on the producers for continuing to operate the fields or units is being covered by the value of the oil.

A negative GVPP does not necessarily mean the State has to start paying out a "negative tax" to the producers. That would harm the State in much the same way as the producers stand to be harmed under Section 31 — such a payout of "negative tax" would worsen state cash flows.

Instead of having one side or the other cover cash-flow impacts on the other side from negative GVPPs, perhaps the recognition of the negative GVPP could be deferred until GVPP becomes positive and then be taken into account gradually if GVPP then continues to rise. In effect, the negative GVPP would be treated as if it were a "loan" of GVPP to the State that keeps the resulting tax at zero instead of being negative, and this "loan" would be repaid from a portion of future positive GVPPs.

Sec. 32. Conforming language related to the repeal of AS 43.55.165(j) and (k) in Sec. 40 of the bill. The repeal is the "standard deduction" limitation on lease expenditure inflation that expired in 2010.

Sec. 33-36. Conforming language related to the repeal of AS 43.55.023(a) in Sec. 40 of the bill. The repeal is the "qualified capital expenditure" credit outside of the North Slope.

Sec. 37. In the case where a municipal entity has an interest in oil and gas production, and sells only a portion of that production to an outside party, their ability to deduct lease expenditures and claim credits is limited in proportion to their taxable production.

Sec. 38. Adds a definition for “qualified capital expenditure” to the general definitions section of AS 43.55. This replicates the definition that was in AS 43.55.023 which is repealed because the .023 “qualified capital expenditure” credit is also being repealed in Sec. 40. Most of the conforming sections that currently reference AS 43.55.023(a) use this definition.

Sec. 39. Adds a definition for “outstanding liability to the state.” This conforms with the changes made in Sections 9, 10, 11, and part (2) of 26.

[AOGA Comment]: Our comments above regarding Sections 9-11 apply here as well.

Sec. 40. Repeals multiple sections. All of these have been specifically referenced elsewhere in this analysis or are technical repeals that conform to other repealed statutes.

[AOGA Comment]: The provision will lead to reduced capital investment critical to the long-term sustainability of oil and gas development in the Cook Inlet and Middle Earth. Including the repeal of the AS 43.55.023(a) tax credit for the 20% of Qualified Capital Expenditures outside the North Slope and the repeal of the 43.55.023(l) tax credit for 40% of Well Lease Expenditures outside the North Slope, the provision represents another significant tax increase.

Coupled with the dramatic changes to net operating loss credits and elimination of other Cook Inlet credits, repealing these credits will make it very challenging to attract key investment dollars and projects to Alaska, especially in this low price environment.

Continued and significant investments are critical to maintain a reliable gas supply for Alaska's largest population base. Removing these incentives will only deter necessary spending to support Alaskans' energy needs. In a mature basin such as Cook Inlet, natural decline rates range from 15-50% annually.

New entrants to the Cook Inlet basin have already stated that without these credits they will not move ahead with plans to drill for gas. Removing these credits will cause an increase in the already high cost of doing business in Alaska and consequently an increase in energy costs for Alaskans.

Sec. 41. Applicability section with multiple sub-parts. In general, ensures that the changes only apply to production after the effective date. Also provides that applications that come in later for credits related to expenditures before the effective date are protected under the former program. Clarifies the timing related to the new 10-year sunset for carried-forward annual loss credits.

Sec. 42-43. Transition language enabling DOR and DNR to draft regulations to implement the changes in this Act, and establishing that regulations may be retroactive to the effective date if they are finalized after the effective date.

Sec. 44. Section 17 is retroactive to January 1, 2016. This is the key floor-hardening provision preventing certain credits from being used against the minimum tax, and is related to the specific concern that one or more major producers could have an operating loss in 2015 and use the carried-forward credit to

reduce 2016 tax payments below the minimum tax to zero.

This is the only provision of the bill for which we are seeking this retroactivity.

Sec. 45. Immediate effective date for the transition and regulatory language.

Sec. 46. Effective date of July 1, 2016 for the rest of the Act.

[AOGA Comment]: An effective date of July 1, 2016 for implementation of any substantive changes, whatever they may be, is far too soon. It is now February, and companies' operational plans for the entire calendar year 2016 have already begun to be implemented. Contracts have already been entered into, work has commenced, and financial commitments have been made by the companies – all based on the existing tax structure. Any sudden increase in the taxes and/or reduction in the tax credits on such short notice would therefore be, in effect, a retroactive tax change. This would result in a long-term serious impact to Alaska's oil industry, as well as having a strongly negative impact on the state's reputation throughout the global banking and financial community.

Economic Impacts of Alaska's Fiscal Options: Summary of Preliminary Conclusions

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January 20, 2016



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ISER's study of economic impacts of Alaska fiscal options

- ISER is doing a study of economic impacts of Alaska fiscal options
- The study is funded by the Alaska Department of Revenue and the Office of Management and Budget
- The study is primarily looking at:
 - Comparative short-term economic impacts of different Alaska fiscal options per \$100 million of deficit reduction
 - Distributional impacts of Alaska fiscal options: which groups would pay the most and/or experience the greatest impacts on jobs and income
 - Short-run economic impacts of reducing and not reducing the deficit
 - Other economic impacts of fiscal options (we are only discussing these qualitatively)
- We expect to complete a draft study in late January and a final study (after review) in mid-February
- This presentation briefly summarizes some preliminary findings of the study.

The reality of Alaska's fiscal choices

- Alaska faces a \$3.5 billion deficit.
- We will *have to* greatly reduce this deficit within a few years.
- Hoping for oil prices and revenues to rise enough to close the deficit is neither realistic nor responsible.
- Our only real options for closing the deficit are some combination of:
 - Cutting spending
 - New taxes
 - Cutting dividends (and using the money to fund government)
 - Saving less (by cutting Permanent Fund inflation proofing or earnings reserve growth)
- None of these options could fully close a \$3.5 billion deficit.
- There are limits to how much we could get from each option: we may need to use *all* our options.

There is no way to close Alaska's \$3.5 billion deficit without significant short-term economic impacts on Alaska's economy.

- Closing the deficit in one year could have a large economic impact on an already-weak economy.
- But delaying significant progress on reducing the deficit could also have large economic impacts due to:
 - Business uncertainty and loss of investor confidence
 - Impacts on Alaska's credit rating
- We will *have* to close most of the deficit in the near future.
- We will face a smoother economic transition if we make significant progress this year on reducing the deficit and planning for future reductions than if we
 - Fully close the deficit this year
 - Don't make significant progress this year

Comparative short term economic impacts of Alaska fiscal options . . .

- The economic impacts of **cutting spending** depend critically on what is cut.
 - They would be largest for cutting government workers.
 - They would be smallest for cutting government purchases from outside Alaska.
 - They include the economic impacts of resulting reductions in state services (which would vary widely depending on what is cut).
- **Cutting spending**, **new taxes**, and **cutting dividends** would all have significant short-term economic impacts on Alaska jobs and income.
 - Total job impacts would be greatest for **cutting government workers**.
 - Total income impacts would be similar for all three options
- Of Alaska's fiscal options, only **saving less**—by reducing inflation proofing or adding less to the earnings reserve and using the money instead to fund state government—would have no short-run economic impacts. But:
 - Saving less would reduce future Permanent Fund earnings
 - We can't close the deficit solely by saving less.

Different fiscal options have different distributional implications

- Our fiscal options vary significantly in who would be most affected
- **Cutting spending** would most affect government and contractor workers and regions with high government employment—as well as Alaskans who depend on the government services that are cut.
- Of our other fiscal options:
 - For wealthier Alaskans, the impacts would be greatest for income taxes, followed by sales taxes and dividend cuts.
 - For poorer Alaskans, the impacts would be greatest for dividend cuts, followed by sales taxes and income taxes.
- The impacts of our fiscal options would be partly offset by lower federal tax payments (because dividend cuts reduce income and income and sales taxes would be deductible).
- Income taxes and sales taxes would be partly paid by non-resident workers and visitors.

Short-term economic impacts matter—
but they should probably not drive our fiscal choices.

- Our fiscal options differ with respect to many longer-run economic impacts which are difficult to quantify but which may be very important, such as impacts on:
 - labor and other costs
 - future economic development opportunities
 - the attractiveness of Alaska as a place for people to live and businesses to invest
 - what kinds of people choose to live and work in Alaska
 - Alaska income distribution
- We should think about these kinds of longer-run impacts as we think about our fiscal choices.
- We should think about what we want Alaska to be like in the future



Impacts of Potential Alaska Fiscal Options

Proposal to the Alaska Department of Revenue

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August 17, 2015

Introduction

The state of Alaska faces a very serious fiscal challenge. Current (FY16) state general fund spending greatly exceeds current and projected future general fund revenues: Alaskans are beginning serious conversations on potential options for addressing this challenge. Broadly, these consist of reducing general fund spending or to increasing general fund revenues.

The 2015 legislative session began a major public debate about options for reducing general fund spending, and revealed the issues that are likely to arise in discussions about further potential budget cuts (and the related questions about the appropriate level of state spending).

An Alaska Department of Revenue (ADOR) White Paper (*Potential Fiscal and Revenue Options for the Walker-Mallott Administration*, June 4, 2015) outlined a wide range of potential revenue options. The Conversations on Alaska's Fiscal Future hosted by the Governor in Fairbanks June 5-7, 2015 suggested some of the issues that are likely to arise in discussions about potential future revenue options.

Clearly one very important question with regard to any option is "how much money could it save or raise"? The continuing discussions about state spending are looking at the relative magnitudes of different components of the budgets and how much it might be possible to cut. Similarly, the ADOR white paper offered preliminary analysis of the "revenue potential" associated with different revenue options. However—as the conversations in Fairbanks clearly showed—Alaskans have a wide variety of other questions about potential fiscal options. Many of these relate to the potential impacts of fiscal options: how might they affect the Alaska economy and Alaskans?

This proposal is for an ISER study of impacts of Alaska fiscal options. The study will estimate, to the extent possible given available data and inherent uncertainties (e.g. future oil prices, a range of potential economic and other impacts of importance to Alaskans.

The total cost of the study would be \$60,000. We would complete a preliminary report by September 19, a draft final report by December 18 (for review) and a final report by January 8.

A Neutral and Objective Study

The study will not advocate for or against any specific fiscal option. Our goal is to inform the Alaska fiscal conversation by providing the best possible objective estimates of the potential impacts of different options, in a way that allows Alaskans to systematically compare these impacts across options.

Study Advisory Group

We will form a study Advisory Group to provide advice about the design of the study (early in the study process) and review (near the end of the study). We will seek to include a range of people and perspectives from across the Alaska political spectrum and will invite recommendations from ADOR, the Governor's office, and the legislative leadership. The purpose of the Advisory Group is specific and limited: to invite input about what kinds of fiscal options the study should consider and what kinds of impacts matter to Alaskans, so as to make the study as useful as possible to the ongoing conversations about Alaska's fiscal choices. The Advisory Group will meet by teleconference on two or three occasions as needed, and members will be invited to provide additional input if they wish. However, the study will be independent and ISER will have responsibility for and control over the study design, analysis and findings.

Coordination with Other Analyses

The Alaska Department of Revenue has begun and will continue analysis of revenue options, focusing in particular on the potential revenue they might generate and issues associated with implementation. We will coordinate with the DOR analysts to ensure that to the extent possible our analyses examine the same options, are based on the same assumptions about how the options would be implemented, and use common terminology.

Similarly, we will seek to coordinate with other state agencies involved in analyses of potential spending cuts or other fiscal options.

Fiscal Options to be Studied

We will seek the advice of the Advisory Group as to which fiscal options the study should focus on. These will likely include:

Spending cuts: \$100 million in cuts to the capital budget (generic and specific types of projects); the operating budget (across the board, generic cuts to specific agencies, specific kinds of spending, e.g. personnel); and deferral and/or elimination of oil tax credit payments.

New revenues: most of the revenue options identified in the ADOR June 2015 White Paper, as well as selected other options suggested by the Advisory Group or identified by ISER

Note, as stated above, that the fiscal options to be studied will not represent in any way an endorsement of either the practicality or desirability of these options. Rather, they will only

Impacts to be Studied

We will seek the advice of the Advisory Group as to which impacts the study should focus on. In general, however, our plan is as follows.

We will study three broad types of impacts:

- Economic impacts: Impacts on numbers of jobs and total incomes of Alaskans, by sector (private and public), industry and region
- Distributional impacts: Impacts on incomes of Alaskans by income group, including (a) relative share of total change in income borne by different groups; and (b) relative change in income by group.
- Demographic impacts: Impacts on total Alaska population and migration to and from Alaska, as well as population by region and migration among regions.

We will study impacts on two different time scales:

- Short-run impacts: impacts which would occur in the year of implementation)
- Long-run impacts: impacts which would occur over a longer-time period (5, 10 and 20 years after implementation) in response to longer-term feedback loops in the economy, such as changes in investment.

We will conduct three types of impact analyses:

- Absolute impacts of fiscal options: These will estimate the economic, distributional and demographic impacts associated with each fiscal option. Note that in general “bigger” fiscal options—those which reduce spending or increase revenues by bigger amounts” (e.g. an income tax which raises \$655 million) will tend to have larger impacts than “smaller” fiscal options (e.g. an across-the-board “school tax” which raises \$100 million).
- Relative impacts of fiscal options: These will estimate the *relative* economic, distributional and demographic impacts per \$100 million saved or raised by each fiscal option. Note that relative impacts may differ, potentially substantially, for different fiscal options. For example, the impacts of raising \$100 million through an income tax might be very different than the impacts of raising \$100 million through a school tax—in ways that are not necessarily obvious or intuitive.
- Cumulative impacts of fiscal options: These will estimate the combined impacts of combinations of options. Note that while the purpose of estimating absolute and relative impacts is primarily to help in thinking about which options might be better choices (or less painful choices), the purpose of estimating cumulative impacts is primarily to help in

thinking about how fast to move towards closing the fiscal gap, and what the total impacts of different combinations of spending cuts and revenue options might be.

We will also examine two aspects of the incidence of fiscal options:

- Revenues collected from non-residents. Some revenue options have the potential to collect significant revenues from non-Alaska residents working in or visiting Alaska. These include, for example, income taxes, sales taxes and fisheries taxes. To the extent possible given existing data, we will estimate the extent of potential revenues which would be collected from non-residents.
- Federal income taxes paid by Alaskans. Some fiscal options may affect the extent of federal income taxes paid by Alaskans. For example, state income taxes would be deductible from federal income taxes, so the total tax burden of a state income tax on Alaskans would be less than their state income tax payments. Put differently, the federal government would “help” to pay for state income tax by reducing Alaskans’ federal taxes. In contrast, sales taxes would not be deductible. As another example, because many Alaskans pay taxes on Permanent Fund Dividends, reductions in dividend payments would be partially offset by reductions in Alaskans’ federal taxes.

Methodology

We will use a range of methodologies to develop the best possible estimates of impacts, given the limits of available data and inherent uncertainties (e.g. future oil prices). These will include (but are not limited to):

- Review of major findings of ISER’s past extensive analysis of impacts of fiscal options (numerous studies done during the 1980s, 1990s and early 2000s)
- Updating of past ISER analyses, applying similar methodologies to current data
- Review of other (non-ISER) analyses of impacts of Alaska fiscal options
- Review of available literature on impacts of fiscal options in other states, as well as the theoretical literature on this topic
- Use of IMPLAN and other I-O modeling approaches to estimate short-term economic impacts of options
- Application of ISER’s Alaska Economic and Demographic Model to estimate short-and long-term economic and demographic effects of options by region
- Use of IRS income data to estimate distributional impacts.

Limits to the Analysis

Some options and impacts are much easier to analyze than others. In general, short-term impacts are easier to analyze than long-term impacts, given the complicated feedback loops over time between state spending and revenues, the private economy, investment and economic development, and population and migration.

In general, the hardest options to analyze are those which may affect future investment and Alaska economic development, such as changes to oil tax credits, oil tax progressivity, resource taxes (e.g. fisheries, mining, tourism)—because these effects are inherently uncertain.

For all impacts, we will provide “best available estimates” along with a discussion of the relative level of certainty or uncertainty about their magnitude.

Study Management and Staff

The study will be directed by ISER Director Gunnar Knapp. Other researchers will include (but not be limited to) ISER economists Matthew Berman and Mouhcine Guettabi. ISER Professor Emeritus Scott Goldsmith will provide advice but will not charge this project for his time. We may subcontract with other researchers for some of the project analysis.

Study Timeline and Reports

September 1	Form Advisory Group; submit project plan for review
September 19	Preliminary report based on review of previous studies and available literature
Early December	Draft final report for review by Advisory Report
Start of legislative session	Final report completed
Legislative session	Briefings on report findings as requested

Other Potential Impacts of Fiscal Options

The impacts of fiscal options proposed for analysis in this study are by no means all of the potential impacts important for and of interest to Alaskans. We developed the proposal based on the assumption that a budget of \$60,000 would be available for the study, and that the types of impacts we propose to study are those which would (a) be of greatest interest to Alaskans; and (b) would be most straightforward to study.

With additional funding, there are a wide variety of other impacts that we could also study, potentially in collaboration with other researchers. These include but are not limited to the impacts of different fiscal options on:

- Federal revenues (e.g. impacts related to matching requirements for federal spending)
- Future state spending obligations (e.g. effects of capital spending cuts on future operations and maintenance obligations, effects of education cuts on future corrections spending, etc.)
- Alaska local government revenues and spending obligations
- Short-term and long-term real estate markets
- Short-term and long-term credit ratings and business confidence

If the Department of Revenue or other potential funders are interested, we could prepare an additional or supplementary proposal for studying these or other impacts.

Alternatively or in addition, if additional funding were available to support more staff time, we could expand the scope of the analysis to study some impacts in greater detail.

Study Budget

The total cost of the study would be \$60,000. Details of the budget are in the table on the following page.

Budget for ISER Study on Impacts of Potential Alaska Fiscal Options

ISER staff hours, by task	Knapp	Guettabi	Berman	Senior research professional	Junior research professional	Total
Project planning & management	16					
Advisory group	16					
Development of assumptions for analyses	8	16				
Review of earlier ISER analyses	16					
Short-run economic impact analyses using input-output modeling		60		20	20	
Long-term economic and demographic modeling using ISER Alaska Economic and Demographic Model		60		10	10	
Distributional impacts analyses			60	40	40	
Report writing	24	20	20			
Presentations on report findings	12					
Total ISER staff hours	92	156	80	70	70	
ISER staff rates						
Base rate (hourly)	\$101.40	\$56.85	\$86.83	\$31.01	\$25.94	
Leave percent	17.30%	13.70%	13.70%	20.90%	21.00%	
Benefits percent	28.50%	28.70%	28.70%	41.00%	45.70%	
Full hourly rate (salary plus benefits)	\$152.85	\$83.19	\$127.06	\$52.86	\$45.73	
Total staff costs, before overhead	\$14,061.75	\$12,977.59	\$10,164.74	\$3,700.37	\$3,201.20	\$44,105.65
Travel (a)						\$600.00
Services (b)						\$250.00
Commodities (c)						\$3,050.00
Total direct costs						\$48,005.65
Facilities & administration rate						25%
Facilities & administration cost						\$12,001.41
Total cost						\$60,007.06

(a) Assumes \$800 for one round-trip flight to Juneau and one night lodging and per diem.

(b) Assumes \$50 for long distance telephone and \$200 for teleconference fees.

(c) \$3050 for IMPLAN 2012 software update needed for analysis.



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Revenue

TAX DIVISION

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Juneau, AK 99801
Main: 907.465.2320
www.tax.alaska.gov

February 2, 2016

The Honorable Paul Seaton
Alaska State Representative
State Capitol Room 102
Juneau AK 99801

Representative Seaton,

This letter is in response to a request you made on January 7, 2016 for a second set of revisions to our analysis of a hypothetical North Slope oil project. You requested that we modify one of the net present value tables at the end of the analysis to reflect not only total State/muni revenue, but to also include an approximation of general fund unrestricted revenue. This modification is shown along with a note about the amount of property tax the State gets from North Slope upstream property tax. We have also added graphs showing total production tax to the State over the life cycle of GVR-eligible and non-GVR eligible fields. And lastly, we added net present value totals for the State/muni revenue and for the State production tax to the bottom of each of the life cycle revenue graphs. For the net present value analyses, we used 6.15% as the discount rate, which was the earnings rate for the Permanent Fund Corporation in September 2015.

It is also important to know that the entire analysis was prepared using real 2015 dollars, and assumes no inflation for oil prices or costs.

Analysis requested, assumptions, and description of attached graphs

This letter is in response to your request to the Department of Revenue on January 26, 2015 for modeling of a hypothetical North Slope oil project. Specifically, you requested the following:

An analysis of a new projected lease on a North Slope field producing 15,000 b/d, what would be the potential state investment over 10-year development phase with net operating loss credits if the company had no other production in the state? What is the projected net revenue or loss to the state over the life of the field? Please provide this analysis at oil prices of \$50, \$60, \$80 and \$100.

Thank you for allowing us to make use of the interim to prepare this analysis. Based on the above request, this analysis assumes the development of known resources from a North Slope oil field by a company that has no other business activity in the state. The oil field is a standalone field that is reasonably close to existing pipeline infrastructure. Over the 30-year life of the field, the company produces approximately 50 million barrels of technically and economically recoverable light conventional oil, with oil production peaking at 15,000 barrels per day.

Capital costs to develop the field total approximately \$900 million, or about \$18 per barrel, with most of the costs incurred early in the project life. Operating costs total \$750 million over the 30-year period, and average \$15 per barrel, although during peak production, operating costs are reduced to \$11-\$13 per barrel. These costs are in the range of a "normal field," although many of the fields on the North Slope left to develop likely have specific challenges that may make them more costly to develop. With respect to State revenue, more costly projects generally lower the overall take for the State, since any net operating losses would be greater and there would be fewer net profits on which to levy production tax.

We also assume that the company that develops the field receives cash refunds from the State for production tax credits received in excess of any production tax liability.

On the following pages are some of the results of the 30-year life cycle modeling given the assumptions above. Please note that the charts assume two classes of fields for production tax purposes: (1) Non-Gross Value Reduction fields, sometimes called "legacy" fields, which are presented in graphs 1-9; and (2) Gross Value Reduction (GVR) fields at the 20% GVR level, sometimes called "new" fields, presented in graphs 10-18. The end of the report includes a table showing net present values of total State/Municipal Revenues over the 30-year period, as well as an approximation of State General Fund Unrestricted Revenue (GFUR) over the 30-year period. The discount rate for the net present value calculations is the same as the Permanent Fund Corporation's September 2015 earnings rate of 6.15%.

I hope you find the enclosed analysis to be useful. Please do not hesitate to contact me if you would like further analysis or if you have any questions.

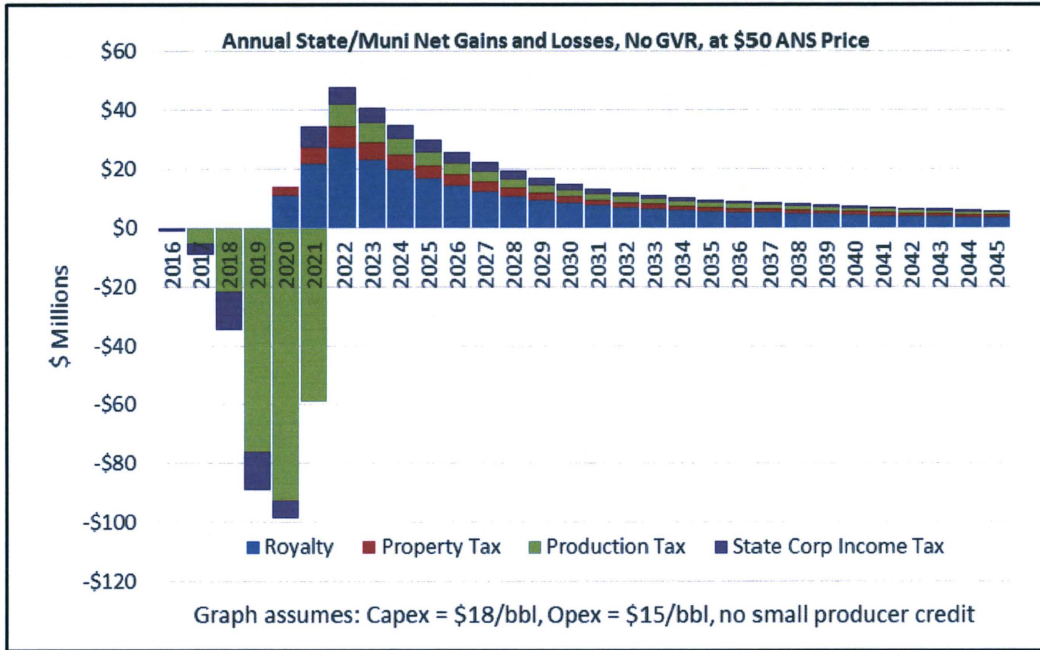
Sincerely,

A handwritten signature in blue ink, appearing to read "Ken Alper". The signature is fluid and cursive, with a long horizontal stroke at the end.

Ken Alper
Tax Division Director

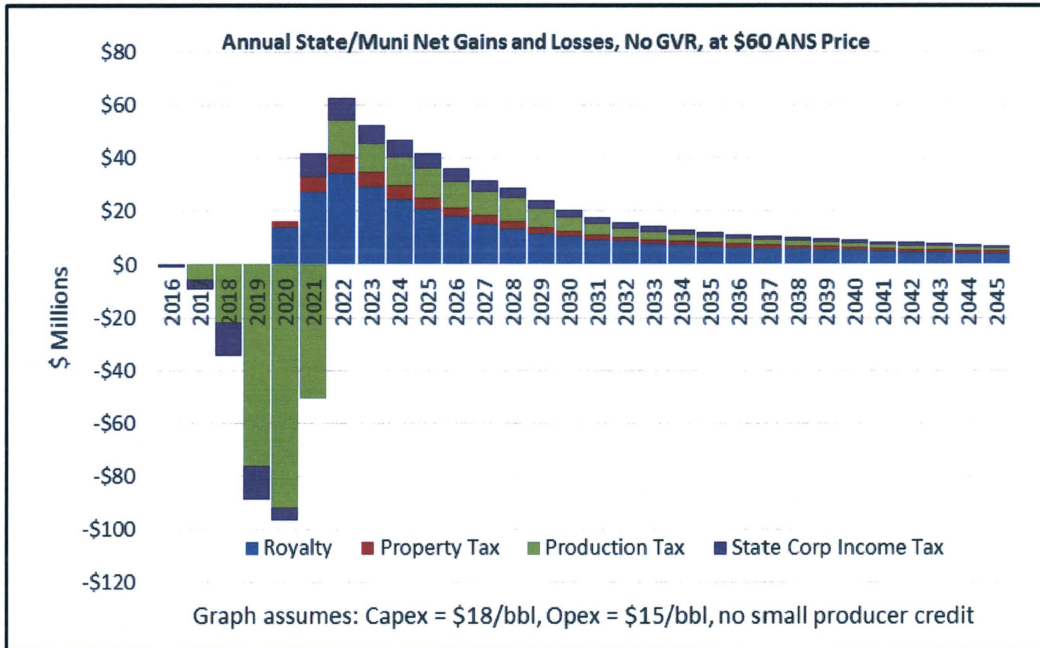
NO GVR, Legacy Fields Analysis

Graph 1: Annual State/Muni Net Gains and Losses and NPV 6.15%, No GVR, \$50 ANS



Total Annual State/Muni Losses = \$243 million
Total Annual State/Muni Gains = \$379 million
Net State/Muni Gain (Loss) = \$136 million
State/Muni NPV 0.0615 = \$-13 million

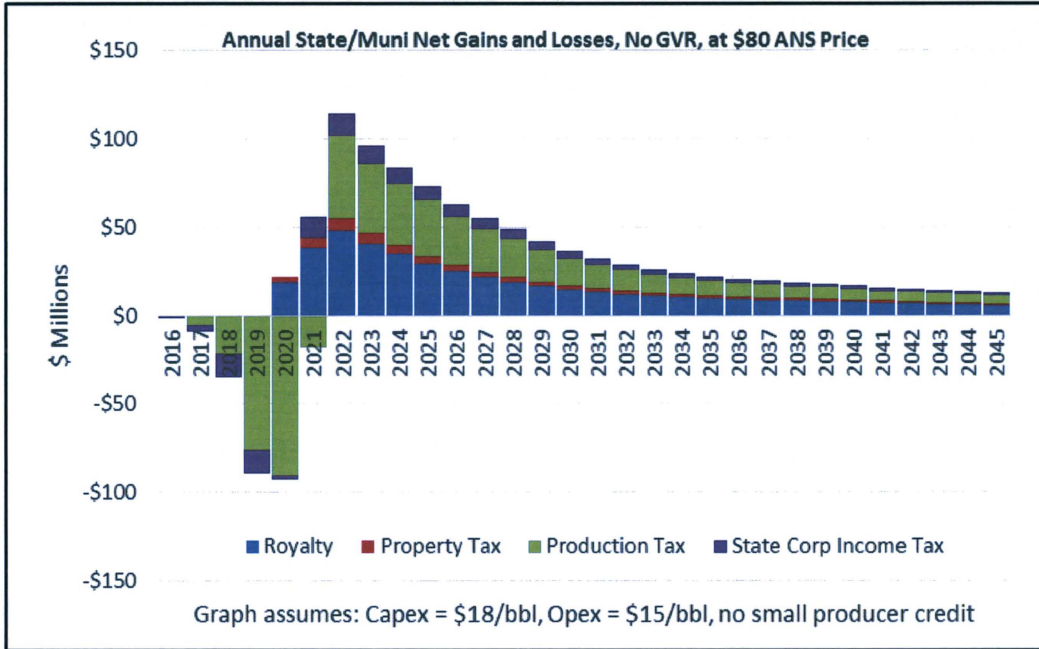
Graph 2: Annual State/Muni Net Gains and Losses and NPV 6.15%, No GVR, \$60 ANS



Total Annual State/Muni Losses = \$222 million
Total Annual State/Muni Gains = \$507 million
Net State/Muni Gain (Loss) = \$285 million
State/Muni NPV 0.0615 = \$63 million

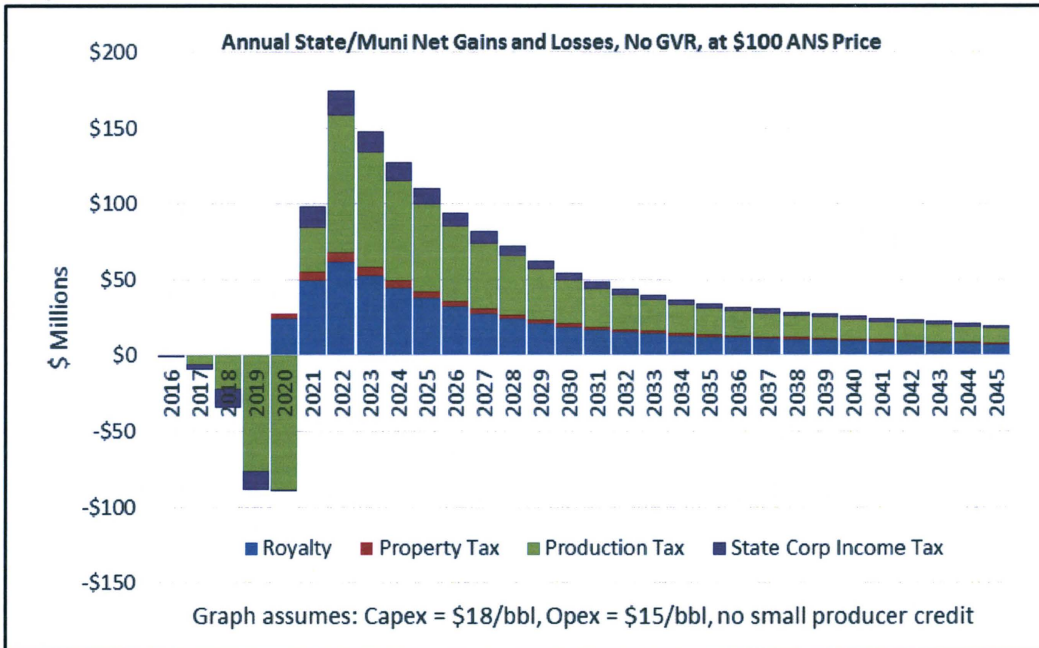
NO GVR, Legacy Fields Analysis

Graph 3: Annual State/Muni Net Gains and Losses and NPV 6.15%, No GVR, \$80 ANS



Total Annual State/Muni Losses = \$204 million
Total Annual State/Muni Gains = \$944 million
Net State/Muni Gain (Loss) = \$740 million
State/Muni NPV 0.0615 = \$288 million

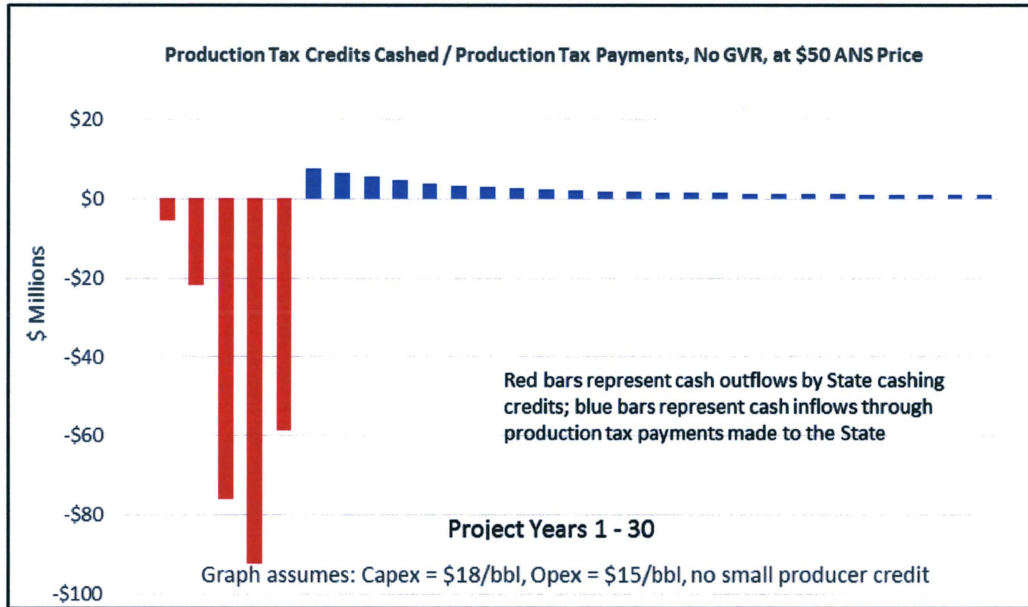
Graph 4: Annual State/Muni Net Gains and Losses and NPV 6.15%, No GVR, \$100 ANS



Total Annual State/Muni Losses = \$195 million
Total Annual State/Muni Gains = \$1481 million
Net State/Muni Gain (Loss) = \$1286 million
State/Muni NPV 0.0615 = \$556 million

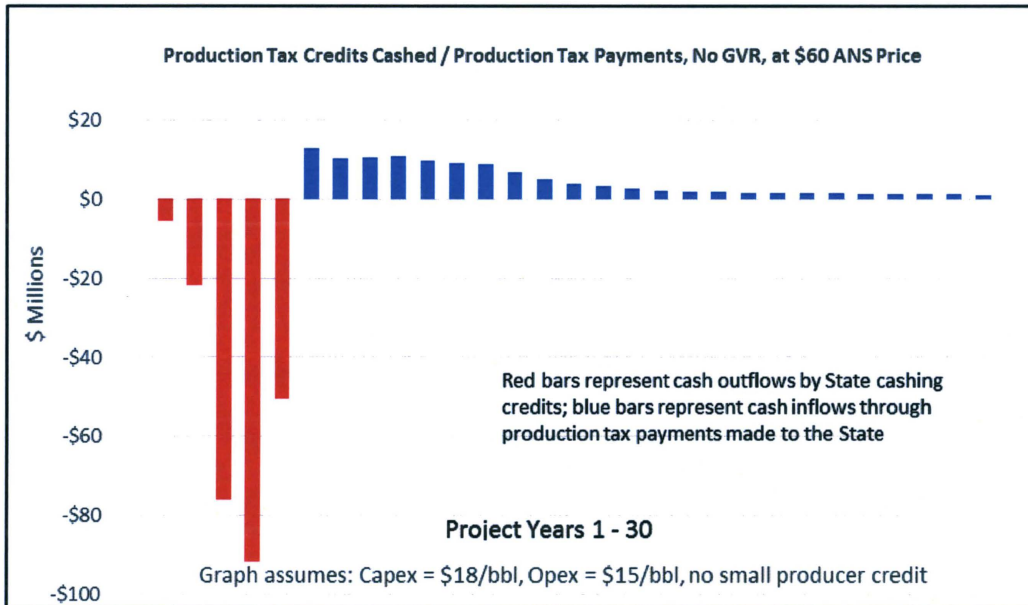
No GVR, Legacy Fields Analysis – Production Tax Specific

Graph 5: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, No GVR, \$50 ANS



Production Tax Credits Used = \$254 million
Production Tax Paid = \$61 million
Net Production Tax = \$-194 million
Production Tax NPV 0.0615 = \$-165 million

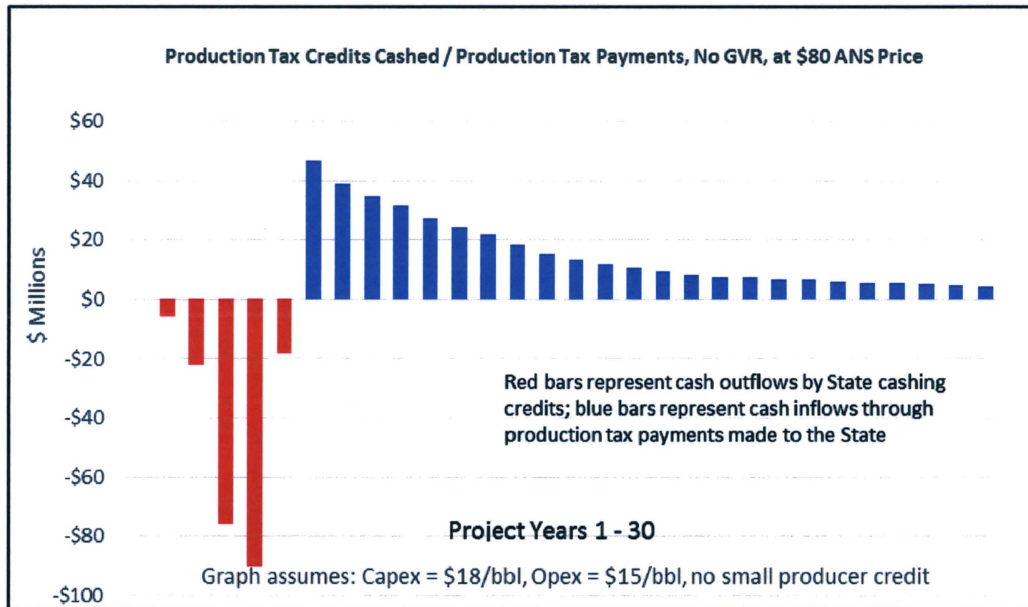
Graph 6: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, No GVR, \$60 ANS



Production Tax Credits Used = \$245 million
Production Tax Paid = \$114 million
Net Production Tax = \$-132 million
Production Tax NPV 0.0615 = \$-132 million

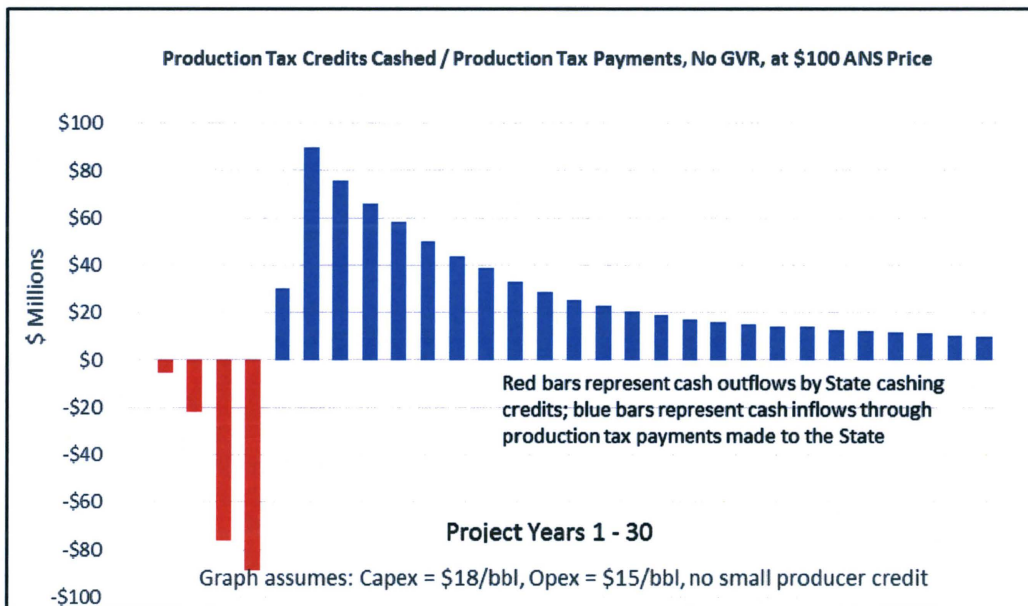
No GVR, Legacy Fields Analysis – Production Tax Specific

Graph 7: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, No GVR, \$80 ANS



Production Tax Credits Used = \$211 million
Production Tax Paid = \$372 million
Net Production Tax = \$161 million
Production Tax NPV 0.0615 = \$13 million

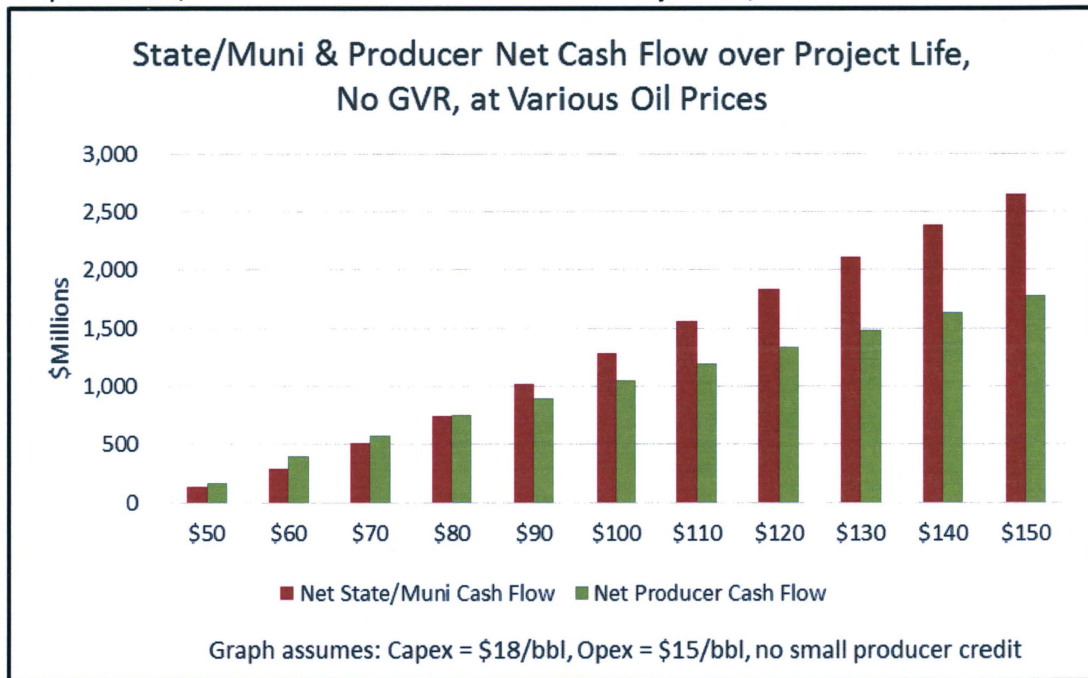
Graph 8: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, No GVR, \$100 ANS



Production Tax Credits Used = \$192 million
Production Tax Paid = \$743 million
Net Production Tax = \$551 million
Production Tax NPV 0.0615 = \$204 million

NO GVR, Legacy Fields Analysis

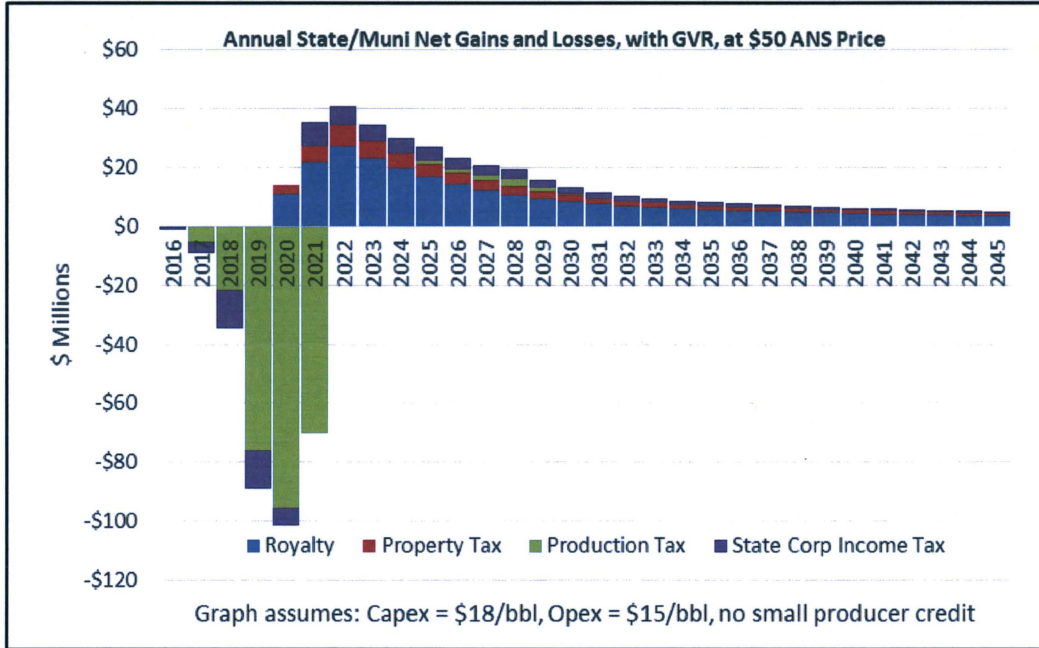
Graph 9: State/Muni & Producer Net Cash Flow over Project Life, No GVR



Please see the following pages for analyses of new fields receiving the Gross Value Reduction of 20%.

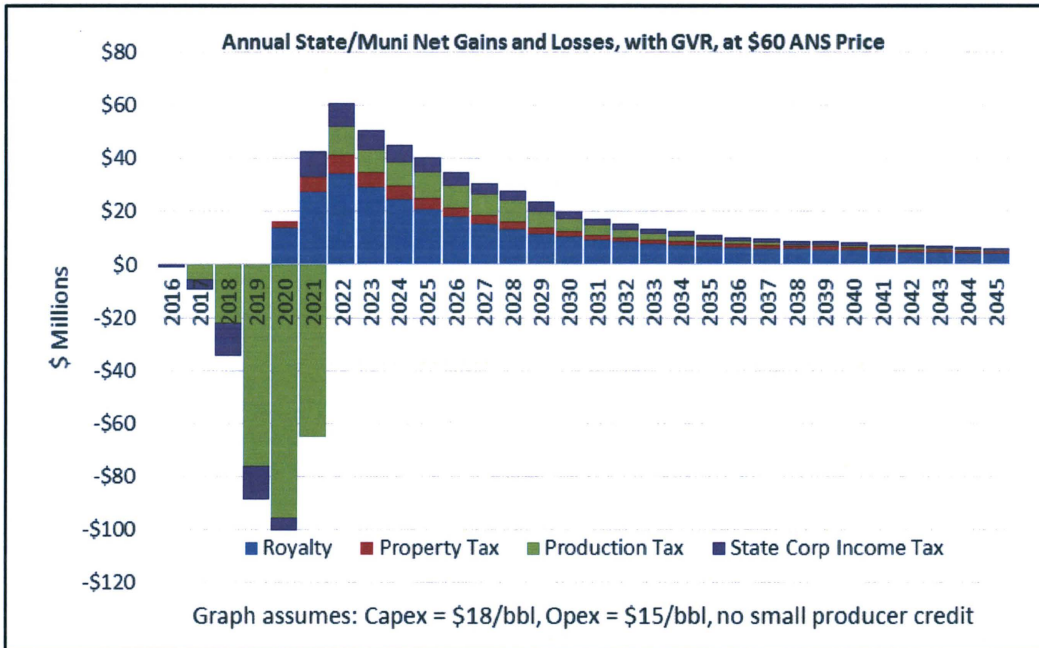
WITH 20% GVR, New Fields Analysis

Graph 10: Annual State/Muni Net Gains and Losses and NPV 6.15%, With 20% GVR, \$50 ANS



Total Annual State/Muni Losses = \$256 million
Total Annual State/Muni Gains = \$331 million
Net State/Muni Gain (Loss) = \$75 million
State/Muni NPV 0.0615 = \$-44 million

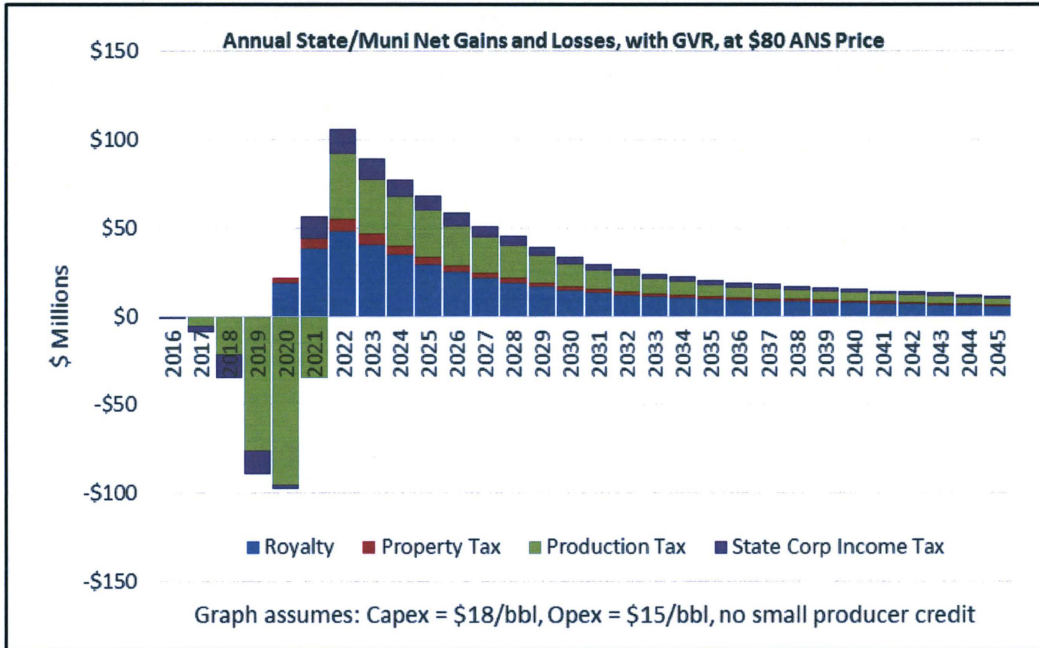
Graph 11: Total Annual State/Muni Net Gains and Losses and NPV 6.15%, With 20% GVR, \$60 ANS



Total Annual State/Muni Losses = \$239 million
Total Annual State/Muni Gains = \$483 million
Net State/Muni Gain (Loss) = \$244 million
State/Muni NPV 0.0615 = \$41 million

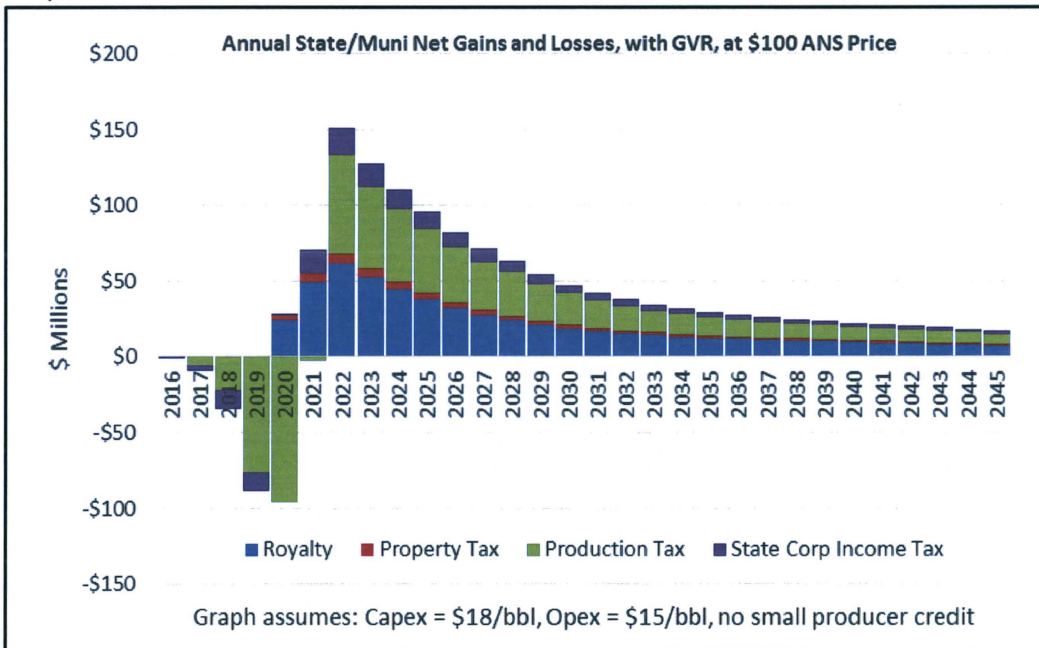
WITH 20% GVR, New Fields Analysis

Graph 12: Total Annual State/Muni Net Gains and Losses and NPV 6.15%, With 20% GVR, \$80 ANS



Total Annual State/Muni Losses = \$209 million
Total Annual State/Muni Gains = \$861 million
Net State/Muni Gain (Loss) = \$652 million
State/Muni NPV 0.0615 = \$242 million

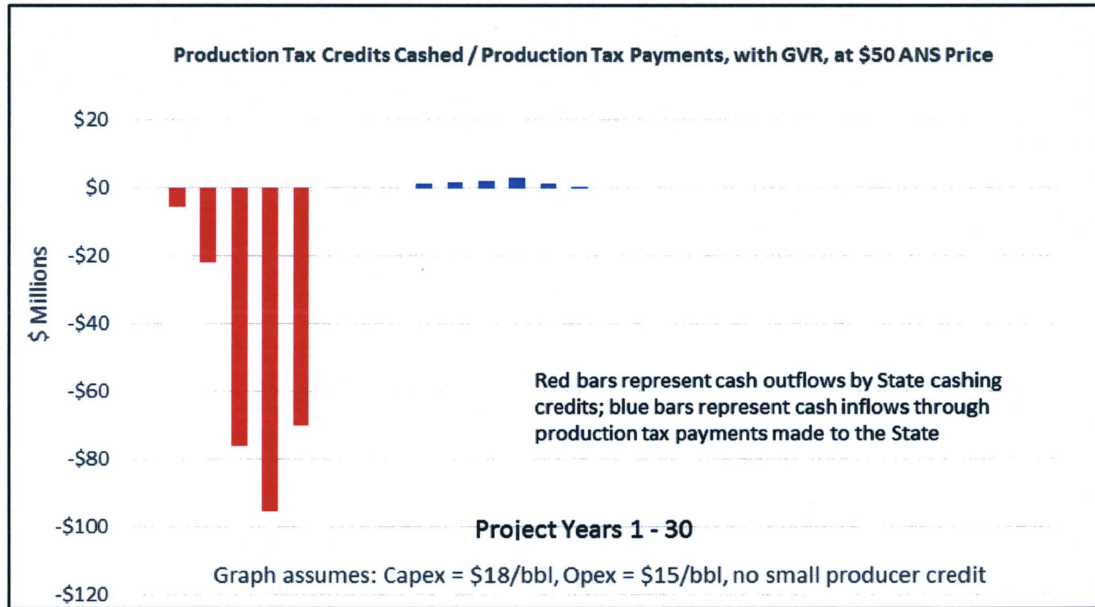
Graph 13: Total Annual State/Muni Net Gains and Losses and NPV 6.15%, With 20% GVR, \$100 ANS



Total Annual State/Muni Losses = \$201 million
Total Annual State/Muni Gains = \$1263 million
Net State/Muni Gain (Loss) = \$1062 million
State/Muni NPV 0.0615 = \$444 million

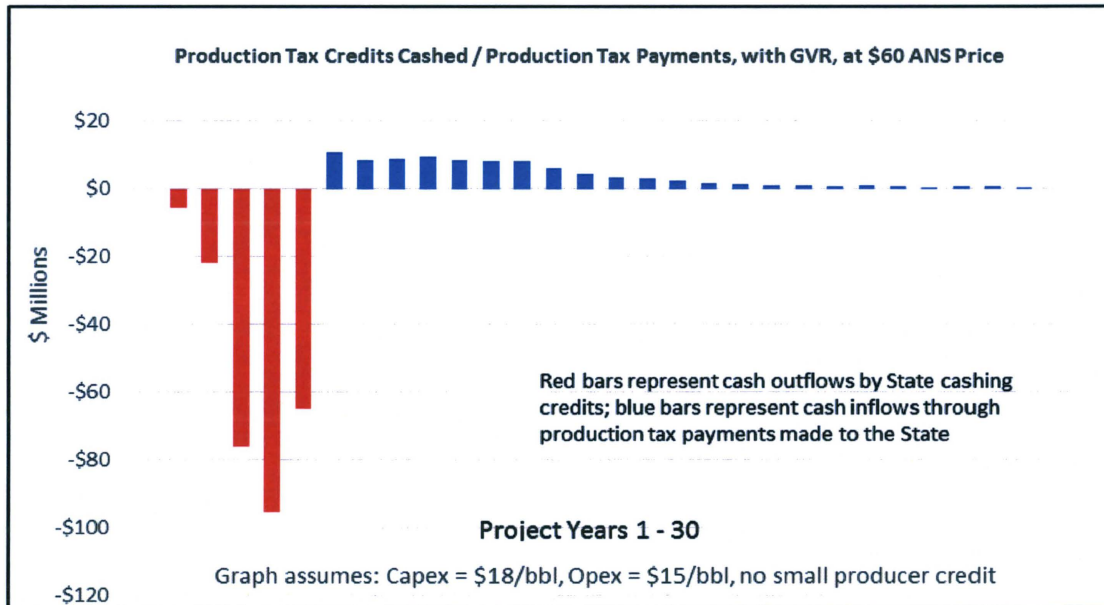
WITH 20% GVR, New Fields Analysis – Production Tax Specific

Graph 14: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, With 20% GVR, \$50 ANS



Production Tax Credits Used = \$269 million
Production Tax Paid = \$9 million
Net Production Tax = \$-260 million
Production Tax NPV 0.0615 = \$-198 million

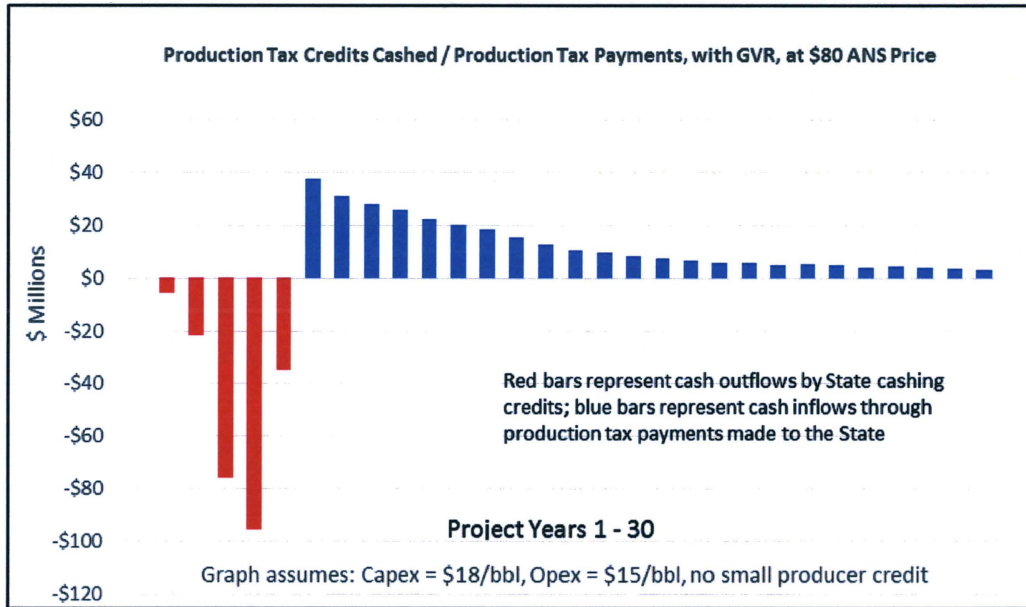
Graph 15: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, With 20% GVR, \$60 ANS



Production Tax Credits Used = \$264 million
Production Tax Paid = \$88 million
Net Production Tax = \$-175 million
Production Tax NPV 0.0615 = \$-155 million

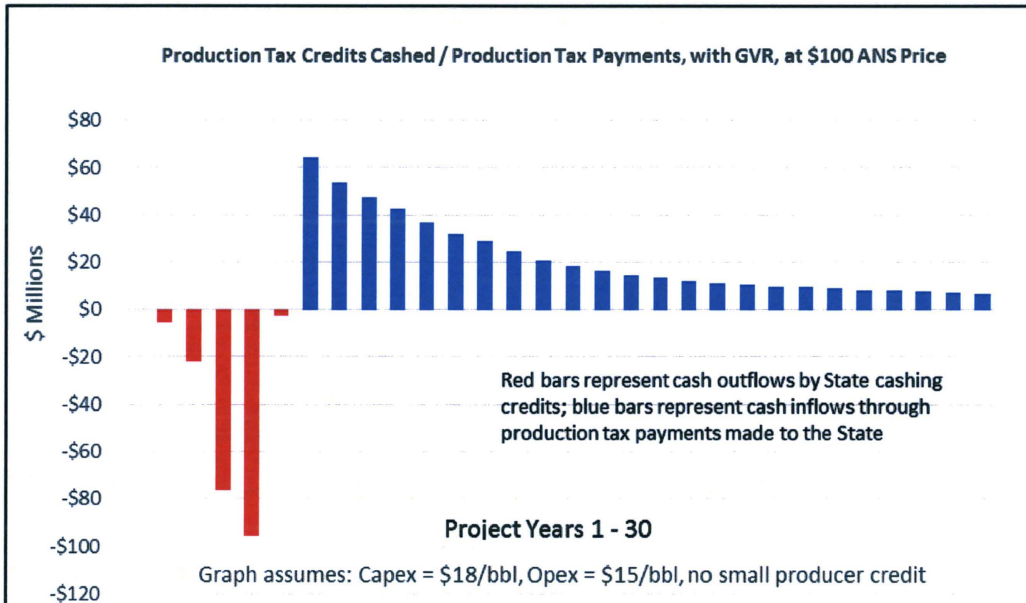
WITH 20% GVR, New Fields Analysis – Production Tax Specific

Graph 16: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, With 20% GVR, \$80 ANS



Production Tax Credits Used = \$234 million
Production Tax Paid = \$300 million
Net Production Tax = \$67 million
Production Tax NPV 0.0615 = \$-36 million

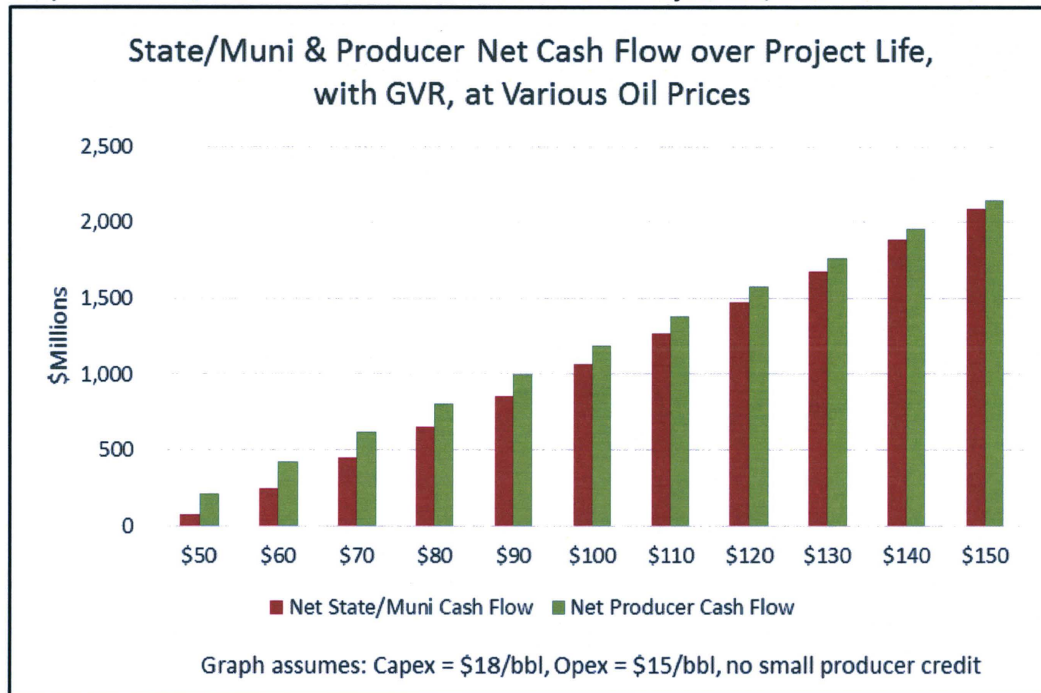
Graph 17: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, With 20% GVR, \$100 ANS



Production Tax Credits Used = \$201 million
Production Tax Paid = \$512 million
Net Production Tax = \$311 million
Production Tax NPV 0.0615 = \$84 million

WITH 20% GVR, New Fields Analysis

Graph 18: State/Muni & Producer Net Cash Flow over Project Life, with GVR



Net present values for State/Muni total revenues and an approximation of General Fund Unrestricted Revenue to the State at the prices you indicated for fields with no GVR and fields with a 20% GVR are shown below. Following that is a table with net present values for production tax only. The discount rate used in the analysis is 6.15% -- the earnings rate used Permanent Fund for investments as of September 2015.

Net Present Value of 30-Year Project Total Revenues to State/Muni at NPV6.15%

Oil Price	NO GVR	With 20% GVR	NO GVR	With 20% GVR
	State/Muni Total Revenues NPV 6.15% in \$Millions	State/Muni Total Revenues NPV 6.15% in \$Millions	GFUR* Approximation NPV 6.15% in \$Millions	GFUR* Approximation NPV 6.15% in \$Millions
\$50	-13	-44	-72	-103
\$60	63	41	-4	-26
\$80	288	242	205	160
\$100	556	444	459	346

Note: The values shown in columns two and three of this table include all State and muni revenues from this project, including all taxes (production, corp income and property), and and all royalties. The fourth and fifth columns are the same as the previous two columns, minus 25% of royalties and minus the municipal share of property tax (about 92.5%), approximating General Fund Unrestricted Revenue from the project. The State currently receives about 7.5% of property tax collected from North Slope properties.

**Net Present Value of 30-Year Project
Production Tax Only to State at NPV6.15%**

Oil Price	NO GVR	With 20% GVR
	Production Tax Only NPV 6.15% in \$Millions	Production Tax Only NPV 6.15% in \$Millions
\$50	-165	-198
\$60	-132	-155
\$80	13	-36
\$100	204	84

Note: The values shown in this table include only production tax revenue.



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Revenue

TAX DIVISION

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February 19, 2016

The Honorable Paul Seaton
Alaska State Representative
State Capitol Room 102
Juneau AK 99801

Representative Seaton,

This letter is in response to your request to the Department of Revenue on December 2, 2015 for life cycle modeling of a hypothetical Cook Inlet oil project. You indicated that you would like modeling of the development of an oil field similar in size to the 50 million barrel field that we modeled for the North Slope life cycle analysis provided to you in a letter dated November 5, 2015 (with subsequent updates containing additional requested information).

Like the development of oil fields on the North Slope, the method and cost to develop one oil field in Cook Inlet could be completely different than the method and cost to develop another. Among the largest influencing factors is whether the oil is located on land or offshore. Whereas some Cook Inlet fields can be developed with conventional drilling or with extended reach drilling methods, there are potential developments that require the installation of offshore drilling platforms. The method in which the field is developed will influence the cost of the project, and therefore it's economic viability. Our Cook Inlet modeling has been prepared with such cost variability in mind. Presented in this analysis is one set of assumptions about production and costs, but we can provide additional analyses as appropriate.

The analysis presented in this letter contemplates the development of known resources from a Cook Inlet oil field by a company that has no other business activity in the state. Over the 30-year life of the field, the company produces approximately 50 million barrels of technically and economically recoverable light conventional oil, with oil production peaking at 16,900 barrels per day. The field pays a 12.5% royalty rate.

Capital costs to develop the field total approximately \$600 million, or about \$12 per barrel, with most of the costs incurred early in the project life. Operating costs average \$20 per barrel and total \$1 billion over the 30-year period. The field is developed under the current Alaska production tax statutes for Cook Inlet oil, which includes credits for exploration, capital expenditures, well lease expenditures, net operating losses, and small producers. We assume that the company that develops the field receives cash refunds from the State for all production tax credits received in excess of any production tax liability. Current statutes also include Cook Inlet production tax limitations, which on oil are currently zero. These limitations are set to expire in

CY 2022, and our modeling incorporates that expiration date. All oil prices and oil development costs are in real 2016 dollars—that is, they are not adjusted in future years for inflation.

On the following pages are some of the results of the 30-year life cycle modeling given these assumptions. The end of the report includes a table showing Net Present Values (NPV) using the Permanent Fund's September 2015 earnings rate of 6.15% as a discount rate. NPV is shown for Total State and Municipal Revenues, General Fund Unrestricted Revenue to the state, and Total Production Tax Revenues (including credits) over the 30-year period.

I hope you find the enclosed analysis to be useful. Please do not hesitate to contact me if you would like further analysis or if you have any questions.

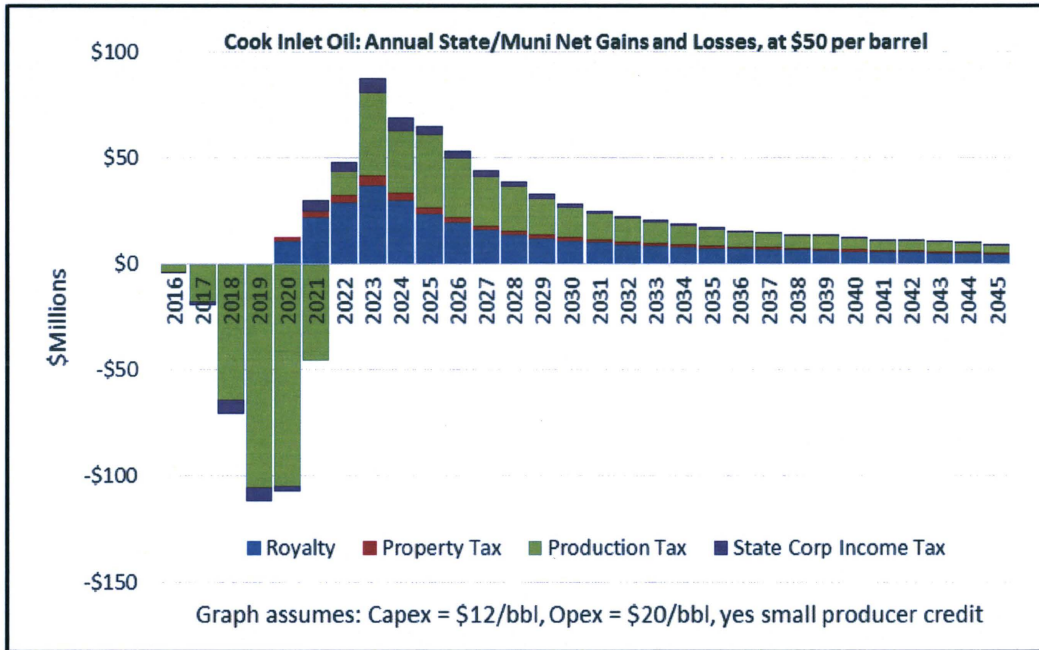
Sincerely,

A handwritten signature in blue ink, appearing to read 'K Alper', is written over the typed name.

Ken Alper
Tax Division Director

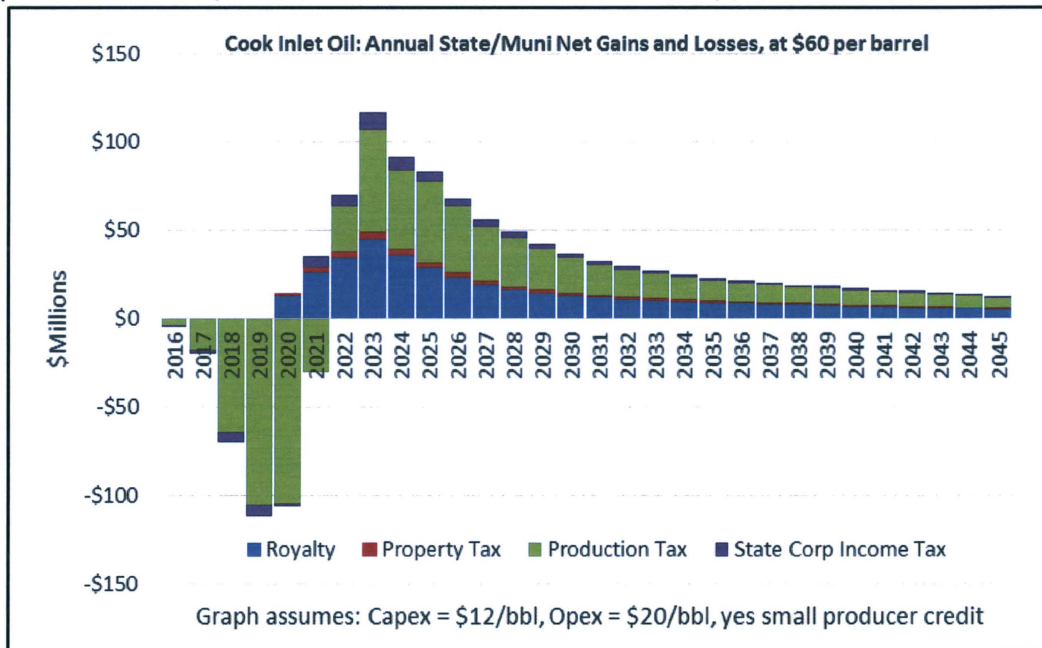
Cook Inlet Oil: Annual State/Muni Net Gains and Losses

Graph 1: Annual State/Muni Net Gains and Losses and NPV 6.15%, \$50 Oil Price



Total Annual State/Muni Losses = \$316 million
Total Annual State/Muni Gains = \$691 million
Net State/Muni Gain (Loss) = \$375 million
Production Tax NPV 0.0615 = \$68 million

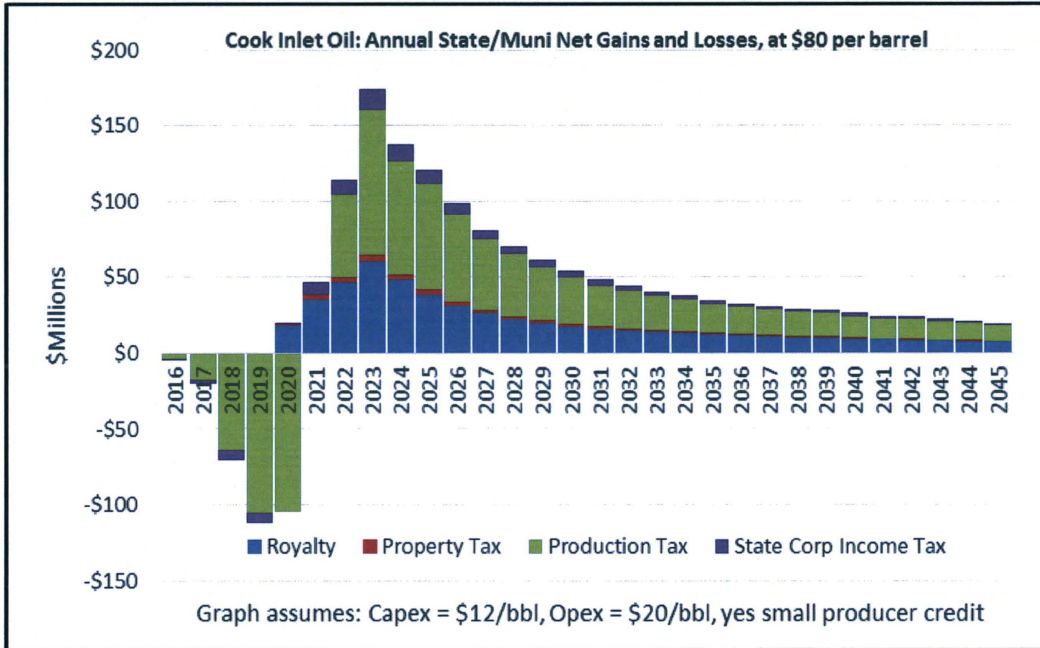
Graph 2: Annual State/Muni Net Gains and Losses and NPV 6.15%, \$60 Oil Price



Total Annual State/Muni Losses = \$297 million
Total Annual State/Muni Gains = \$922 million
Net State/Muni Gain (Loss) = \$625 million
Production Tax NPV 0.0615 = \$190 million

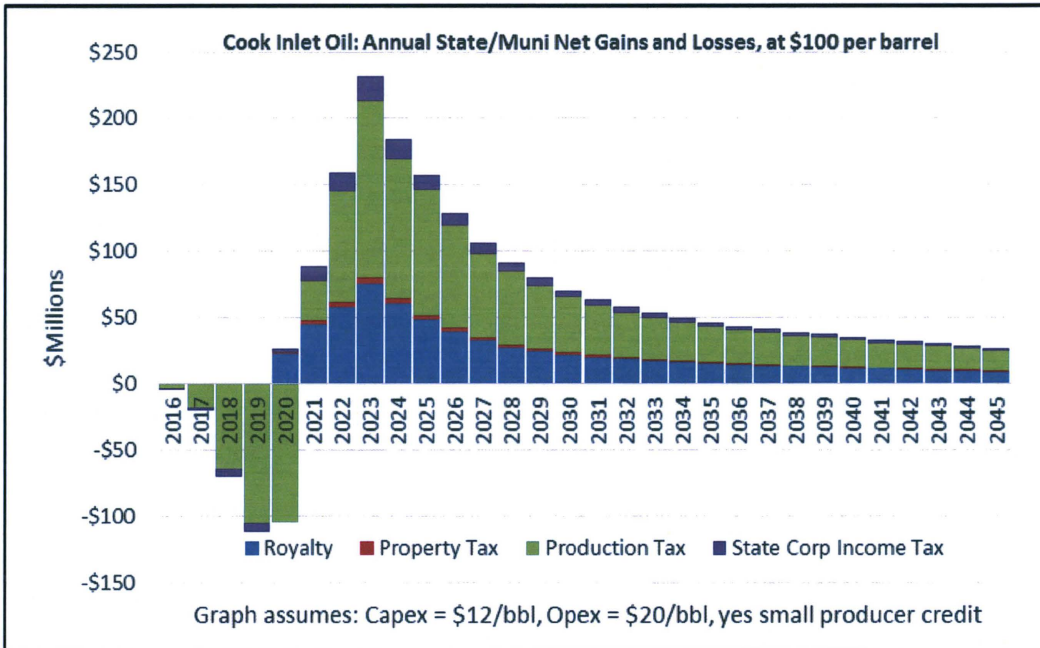
Cook Inlet Oil: Annual State/Muni Net Gains and Losses

Graph 3: Annual State/Muni Net Gains and Losses and NPV 6.15%, \$80 Oil Price



Total Annual State/Muni Losses = \$290 million
Total Annual State/Muni Gains = \$1417 million
Net State/Muni Gain (Loss) = \$1127 million
Production Tax NPV 0.0615 = \$432 million

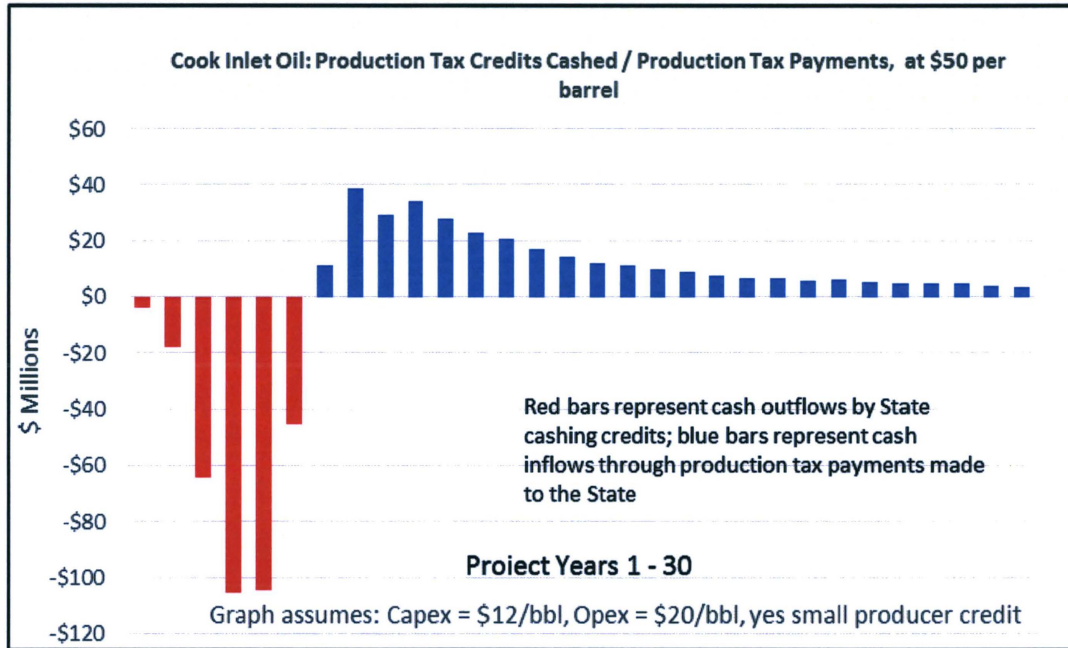
Graph 4: Annual State/Muni Net Gains and Losses and NPV 6.15%, \$100 Oil Price



Total Annual State/Muni Losses = \$284 million
Total Annual State/Muni Gains = \$1911 million
Net State/Muni Gain (Loss) = \$1628 million
Production Tax NPV 0.0615 = \$674 million

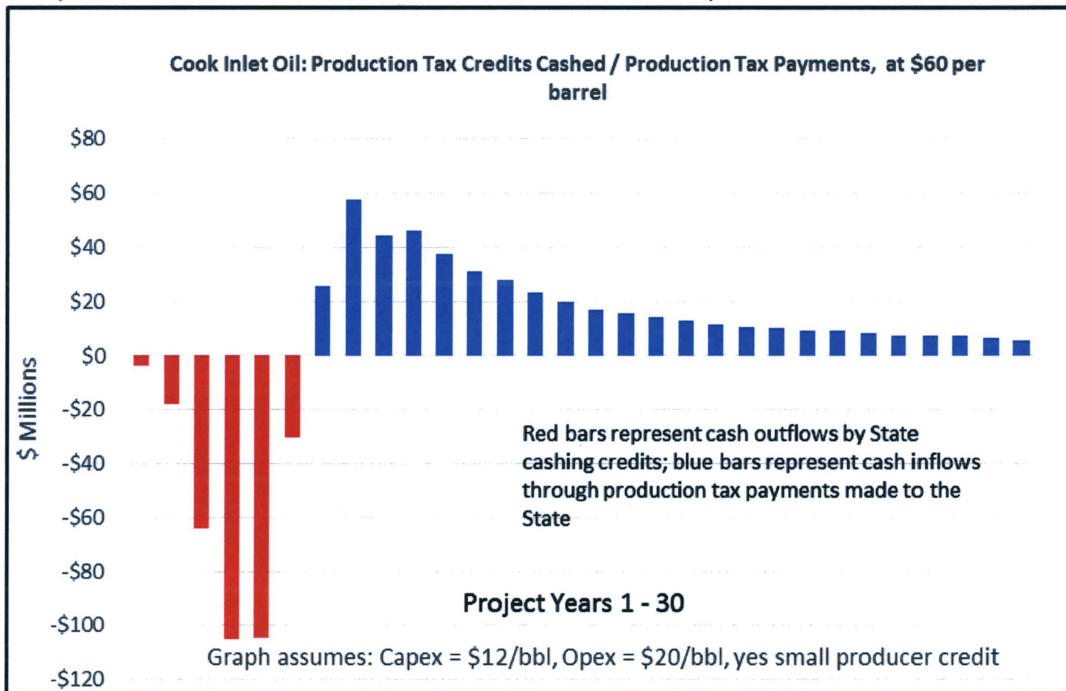
Cook Inlet Oil: Production Tax Credits Cashed and Payments

Graph 5: Production Tax Credits Cashed/Production Tax Payments and NPV 6.15%, \$50 Oil Price



Production Tax Credits Used = \$341 million
Production Tax Paid = \$317 million
Net Production Tax = \$-24 million
Production Tax NPV 0.0615 = \$-121 million

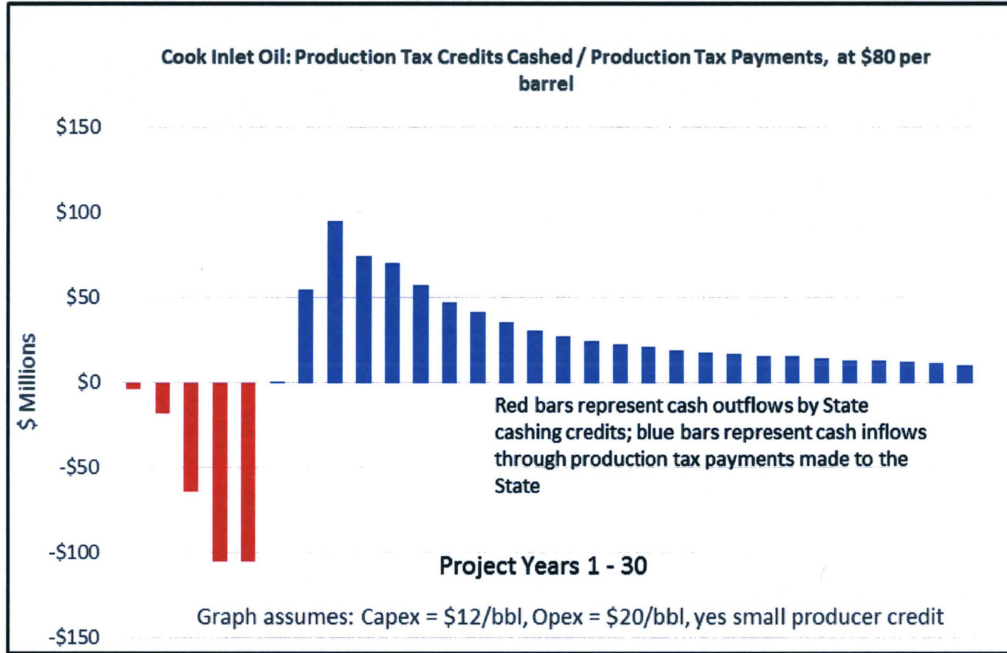
Graph 6: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, \$60 Oil Price



Production Tax Credits Used = \$326 million
Production Tax Paid = \$465 million
Net Production Tax = \$139 million
Production Tax NPV 0.0615 = \$-42 million

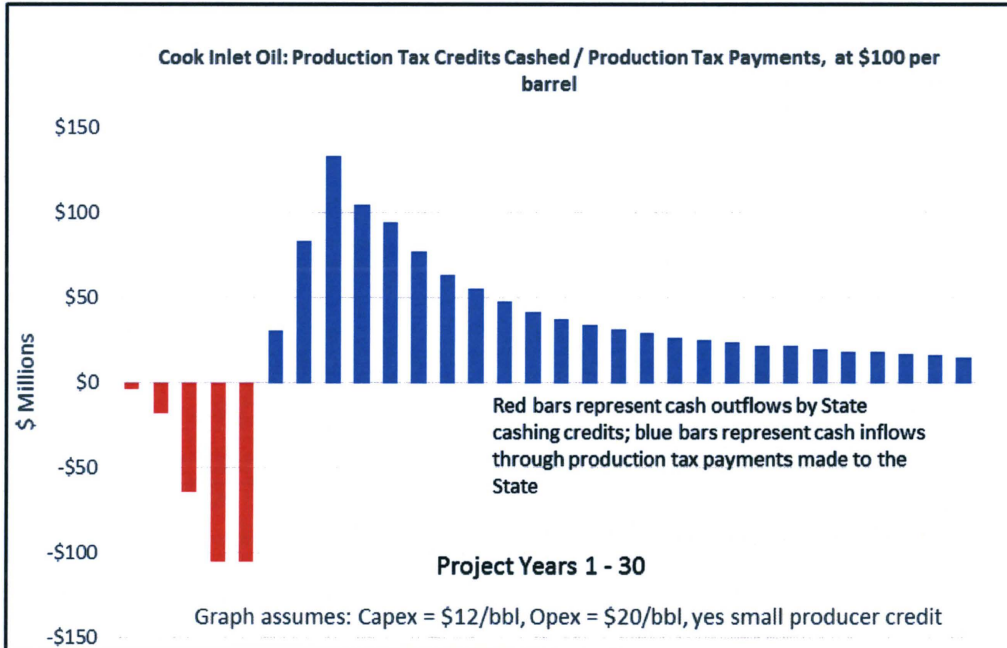
Cook Inlet Oil: Production Tax Credits Cashed and Payments

Graph 7: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, \$80 Oil Price



Production Tax Credits Used = \$296 million
Production Tax Paid = \$761 million
Net Production Tax = \$466 million
Production Tax NPV 0.0615 = \$115 million

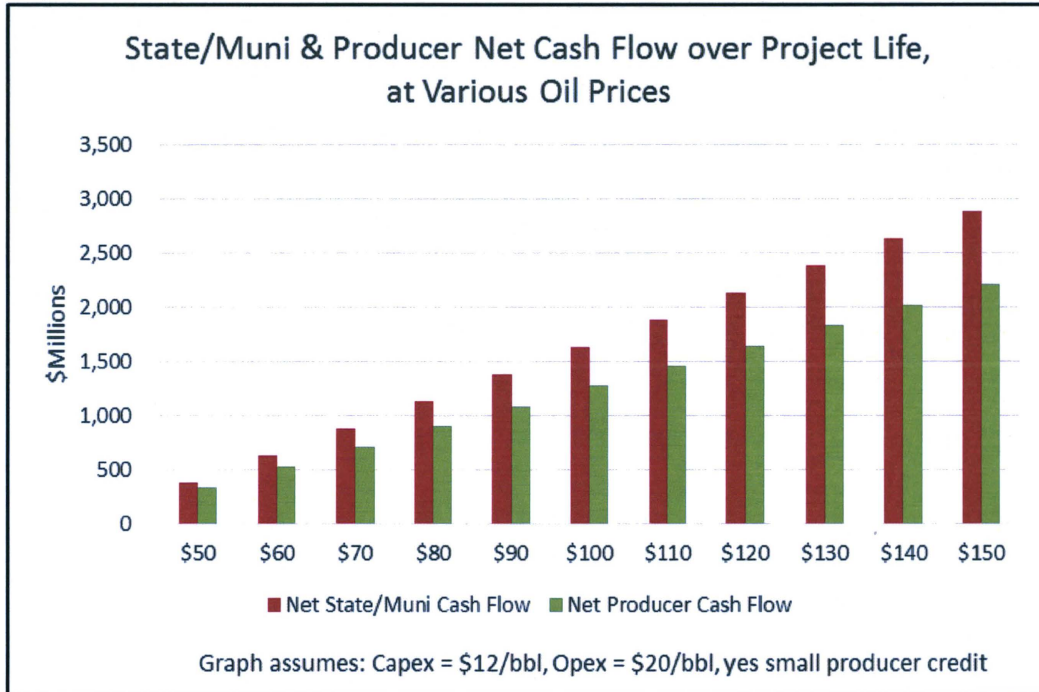
Graph 8: Production Tax Credits Cashed / Production Tax Payments and NPV 6.15%, \$100 Oil Price



Production Tax Credits Used = \$296 million
Production Tax Paid = \$1088 million
Net Production Tax = \$792 million
Production Tax NPV 0.0615 = \$273 million

Cook Inlet Oil: Net Cash Flow over Project Life

Graph 9: State/Muni & Producer Net Cash Flow over Project Life



Net Present Value of 30-Year Project Total Revenues to State/Muni at NPV6.15%

Oil Price	Producer Total Revenues NPV 6.15% in \$Millions	State/Muni Total Revenues NPV 6.15% in \$Millions	GFUR* Approximation NPV 6.15% in \$Millions	Production Tax Only NPV 6.15% in \$Millions
\$50	120	68	20	-121
\$60	211	190	133	-42
\$80	393	432	359	115
\$100	576	674	585	273

Note: *The values shown in columns two and three of this table include all revenue from the project as divided between the Producer and the State/Muni. Total State/Muni revenue includes all taxes (production, corp income and property), and all royalties. The fourth column is the same as the third column minus 25% of royalties and minus the municipal share of property tax (about 49%), approximating General Fund Unrestricted Revenue revenue from the project. The State currently receives about 51% of property tax collected from Kenai Peninsula Borough properties.

Fiscal Impact of Cook Inlet Production Tax Limitations, 2007-2013

This analysis provides estimates of the amount of production tax revenue that could have been collected under the ACES production tax regime in Cook Inlet, but that was not collected due to the Cook Inlet tax limitations in place for calendar years (CY) 2007 through 2013. The estimates provided in this analysis are approximations, provided in ranges to reflect several assumptions made in the calculations and to reflect a level of uncertainty as to the completeness of the data.

Oil and gas production tax changes enacted with the Petroleum Profits Tax (PPT) in 2006 and with Alaska's Clear and Equitable Share (ACES) in 2007 contained provisions limiting the production tax for oil and gas produced in Cook Inlet. These provisions generally limited the production tax to the lower of the tax calculated under PPT and later ACES, and the tax calculated under the ELF tax regime as it existed in the year prior to April 1, 2006. These limitations went through several changes in the years since PPT's passage, with the largest changes occurring with the Cook Inlet Recovery Act in 2010. The Cook Inlet Recovery Act eliminated certain ring-fencing provisions, and provided additional credits for Cook Inlet, which in turn increased and the value of Cook Inlet credits by allowing more of them to be used elsewhere and/or be redeemed for cash from the State.

Due to the numerous changes in law from year to year, we calculated these estimates to the best of our ability using primarily annual estimates of tax liabilities and credits, without regard to certain specific credit provisions and details about taxing jurisdictions specific to Cook Inlet. Data and reporting inconsistencies also hampered our confidence in the estimates. To reflect this uncertainty, we have provided the production tax estimates in terms of ranges of revenue.

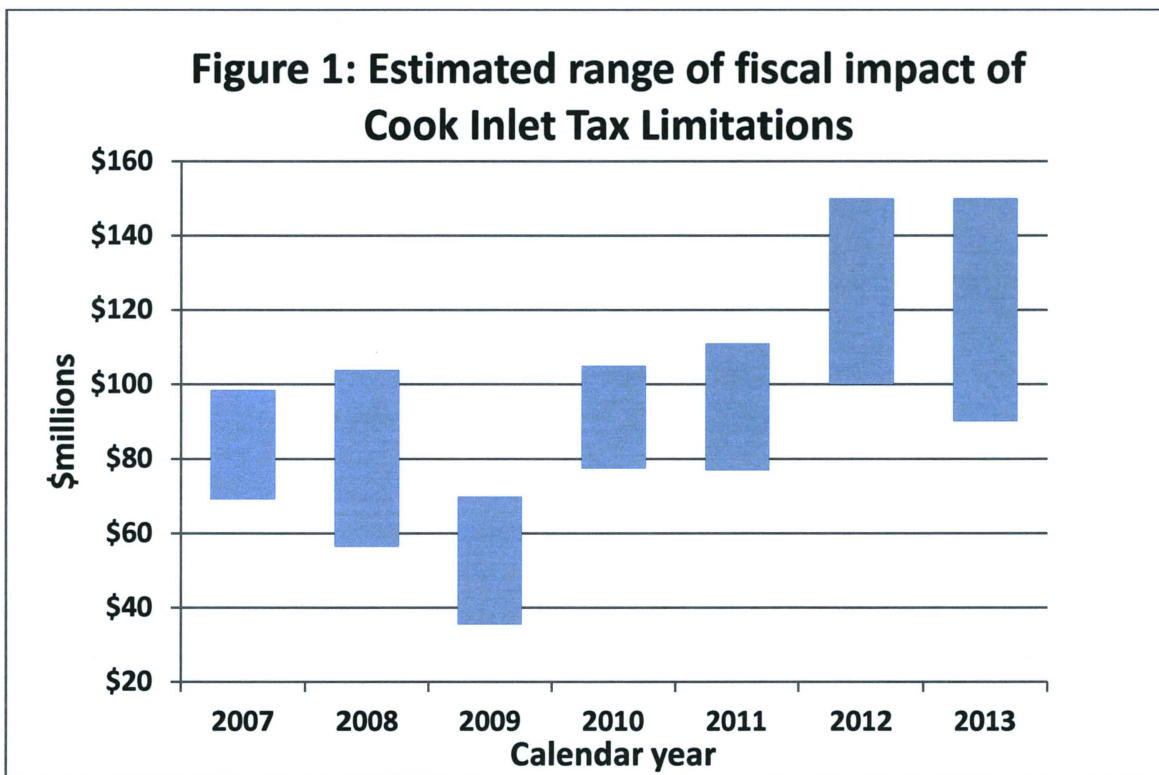
It is important to note that while Cook Inlet producers enjoy very low tax rates under the ELF production tax limitations, if taxed under ACES, many of these same producers would have their entire production tax liability eliminated by the small producer credit under AS 43.55.024(c). The small producer credit, worth \$12 million each year, is a use-or-lose credit that most Cook Inlet producers earn each year. Because the tax liability of many of these small producers, even under ACES, is less than \$12 million, most of them are unable to take full advantage of the credit. Further, in any given year, up to one half of the producers in Cook Inlet spend more in oil and/or gas lease expenditures than they take in revenues. These producers qualify for net operating losses under the production tax credit system.

In the seven years that this analysis covers, the number of companies reporting that they are exploring for and/or producing oil or gas in Non-North Slope areas of the state increased significantly, from 7 companies in 2007 to 21 companies in 2013. The increase in the number of companies with activity in Non-North Slope areas is shown in the table below.¹

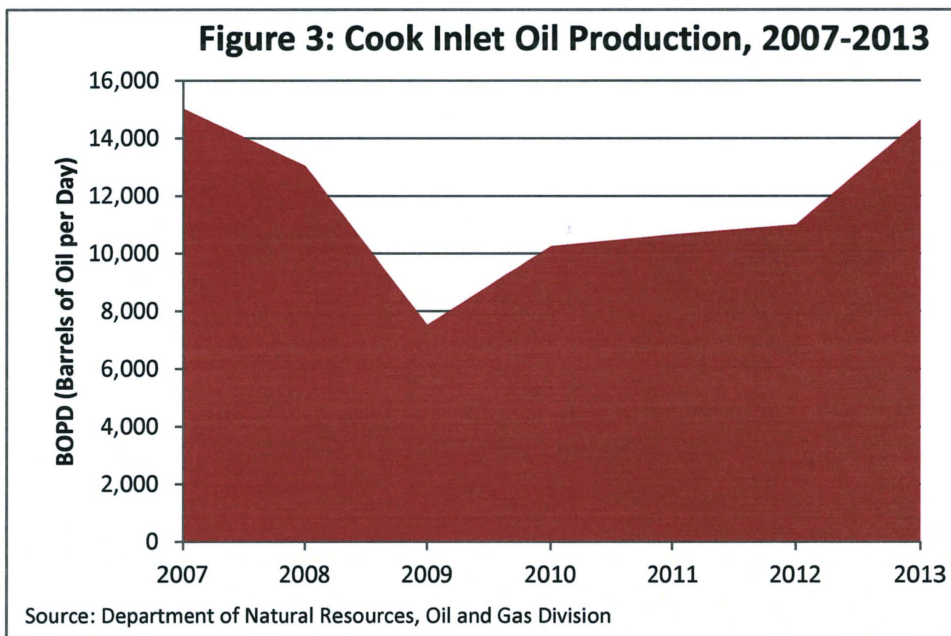
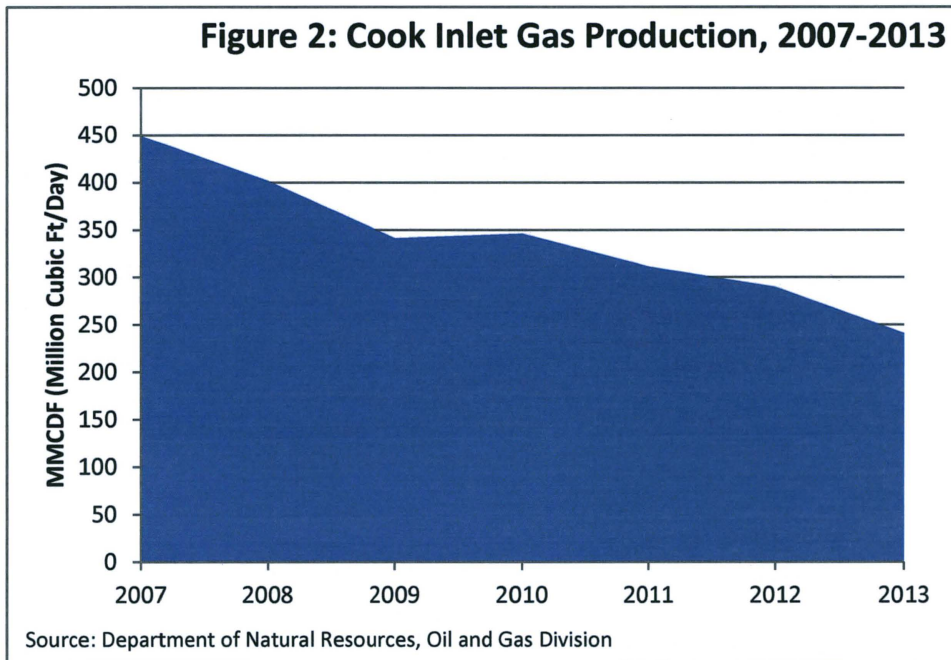
¹ For purposes of public reporting the Department of Revenue combines Cook Inlet figures with those from other Non-North Slope areas in so-called "middle earth." The primary reason for this is the relatively small number of companies and projects in the middle earth area, which could not be reported separately due to confidentiality restrictions. Therefore, to ensure complete statewide data, we combine these few middle earth companies with the much larger Cook Inlet data set. Since there is no commercial oil or gas production in "middle earth," all production and production tax liabilities in this analysis are from Cook Inlet producers.

Companies Reporting Production and Companies Receiving Refunded Credits in Non-North Slope Areas of Alaska							
Calendar Year	2007	2008	2009	2010	2011	2012	2013
Count of Producers reporting production in Cook Inlet	7	7	8	9	13	14	13
Count of Companies Receiving Refunded Credits in Non-North Slope	0	0	1	8	12	13	17
Count of Total Non-North Slope Companies	7	7	9	16	18	18	21

Figure 1 below illustrates ranges of estimated foregone revenue of Cook Inlet companies. Unrealized production tax revenue dipped from 2007 to 2009, due primarily to lower oil and gas prices, then steadily began increasing, growing even more in 2012 and 2013. The total fiscal impact of these limitations over the seven years analyzed is estimated to be between \$550 million and \$800 million.



The results in Figure 1 can be partially explained by commodity prices and partially explained by production volumes. Oil prices varied from the \$60 per barrel range in 2007 to over \$100 per barrel in 2008, to lows of \$40 per barrel in 2009. The lower values contribute to lower tax liabilities in 2009. With regard to production volumes, although Cook Inlet gas production has been declining since 2008 (see Figure 2), Cook Inlet oil production almost doubled from lows of 7,500 barrels per day in 2009 to close to 15,000 barrels per day in 2013 (see Figure 3). During this time, capital lease expenditures for Non-North Slope more than tripled from around \$120 million in CY 2010 to close to \$400 million in CY 2012, and increased further to close to \$500 million in CY 2013. Refunded credits to Non-North Slope companies increased from around \$15 million in CY 2010 to around \$94 million in CY 2012, then doubling to around



\$191 million in CY 2013.

Because many Cook Inlet companies do not incur a tax liability, or their tax liability is eliminated by non-refundable credits, any remaining credits are generally cashed out by the State. The table below shows the amount of credits that were earned by oil and gas activity in Non-North Slope areas of the state that were redeemed for cash from the State treasury. Note the significant increase beginning in CY 2011, for a total of over \$300 million over the seven years. Refunded credits for Non-North Slope activity in CY 2014 are even higher, estimated to be in excess of \$300 million.

Historical Refunded Credits in Non-North Slope							
(\$millions)	CY 07	CY 08	CY 09	CY 10	CY 11	CY 12	CY 13
Non- North Slope Refunded Credits							
Credits under AS 43.55.023 ¹	0	0	*	*	34	*	*
Credits under AS 43.55.025 ²	0	0	*	*	3	*	*
Credits under AS 43.20 ³	0	0	0	0	0	0	15
Total Non-NS Refunded Credits	0	0	*	15	36	94	191

***An asterisk indicates that a number is confidential.

¹Credits under AS 43.55.023 include the Qualified capital expenditure, the Carried-forward annual loss, and the Well lease expenditure Credit.

²Credits under AS 43.55.025 include the Alternative Credit for Exploration, the Frontier Basin Credit, and for Cook Inlet only, the Cook Inlet Jack-up Rig Credit

³Credits under AS 43.20 include the Gas Exploration and Development Credit, Gas Storage Facility Credit, the In-State Gas Refinery Credit, and the LNG Storage Facility Credit.



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Natural Resources

Division of Oil & Gas
Anchorage Office

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Anchorage, Alaska 99501-3560
Main: 907.269.8800
Fax: 907.269.8939

Representative Geran Tarr
State Capital
Juneau, AK 99801
Rep.Geran.Tarr@akleg.gov

Dear Representative Tarr,

In response to your recent questions regarding the value of tax credit derived seismic data received by DNR and potential industry impacts of data confidentiality changes as proposed in HB247, I offer the following responses.

- 1.) "...During your testimony you indicated you had a rough estimate of the dollar value of the 2D and 3D seismic data the Department of Natural Resources receives from companies who qualify for certain credits. Can you provide this information to the committee?"
 - o In preparation for Senator Giessel's Tax Credit Working Group meetings held during the last interim period, the Division compiled data on the total number of 2D line miles and 3D square miles of seismic data acquired under the exploration tax credit programs that deliver data to the Division of Oil and Gas, namely the AS 43.55.023(a)(2), AS 43.55.023(I)(2), AS 43.55.025. The Division looked at the period from 2004 through 2014 and focused on data acquired in all three areas of the state: Cook Inlet, North Slope and Frontier/Interior basins. The totals only include data associated with a tax credit and does not include the in-unit data acquired or any data that companies acquired and for which they did not claim a tax credit.
 - o In determining a "value" for the data, the Division looked just at what it would cost the state to hire a contractor to go gather the data in the field, just as companies would do. We were able to calculate these "acquisition costs" by simply using an average estimated cost figure per line mile (2D) or square mile (3D) for each area, and for either onshore or offshore data acquisition. Therefore, our acquisition cost number does NOT include the cost of permitting the field surveys or the cost of data processing. Data processing can be very expensive depending upon the intended application -- often as much as 40-50% again the cost of acquiring the data.
 - o The breakdown of data-mile totals associated with tax credit programs in the period 2004 -2014 and estimated acquisition cost is as follows:
 - o North Slope:
 - o 2D data (onshore & shorezone ice) = ~870 line miles of data
 - o 3D data (onshore & shorezone ice) = ~9,945 square miles
 - o Total estimated "acquisition" cost (2D + 3D) = \$1.98 billion dollars
 - o Cook Inlet:
 - o 2D data (onshore & offshore) = ~725 line miles
 - o 3D data (onshore & offshore) = ~660 square miles
 - o Total estimated "acquisition" cost (2D + 3D) = \$266 million dollars
 - o Frontier/Interior Basin Areas:
 - o 2D data (all onshore) = ~1,220 line miles
 - o 3D data (all onshore) = ~340 square miles
 - o Total estimated "acquisition" cost (2D + 3D) = \$367 million dollars

2.) "...Additionally, in your opinion as director of the Oil and Gas Division of the Department of Natural Resources, what taxpayer information can be made public without jeopardizing the industry?"

This is a hard question to address as DOG can only speculate about what is potentially harmful to a company. So, I'll try for a general response.

Section 8 of HB247, as written, does not change the release terms for technical (seismic or well) data, though it does release taxpayer confidential financial information. It would add a subsection to AS 43.55.230 that would let the public know who is receiving exploration or development credits, the dollar amount they are getting, and a description of the activity that generated the credit. Currently, the DNR has the ability (through AS 43.55.025) to publish a basic list of who acquired data and where, and what kind of data is slated for release to the public at the appropriate time. Seismic data on that list will go public 10 years after receipt by DNR and well data will go public in 2 years. This provision would be extended under 43.55.023 (by Section 22) in HB247.

It is most likely that industry is going to object to the release of the financial information proposed in Section 8. Companies hold their financial information confidential for a number of important reasons. Public companies' valuations are determined by several factors, not the least of which is related to their stockholders' expectations for the company in the future. There are standards of practice for reporting financial data about a company so that investors have a common basis of reference about a company's performance. Reporting partial financial information or reporting financial information in a non-standard way could negatively influence the market value of a company, as the partial or non-standard reporting can be inadvertently misleading or create confusion about how the reported information fits into the company's overall performance. Given that many companies conduct their business on a global scale – not just in AK – it is possible that releasing information about just AK activities/expenditures could expose a strategy or future plans that a company may have and which they do not wish their competitors to know about.

The industry will object to the state requiring and publicizing information that the state does not need to do its job as regulator or to promote the state's resources. The state has a responsibility to gather the data that we need to do our job, carefully protect the information we require, and only use it in a meaningful way to accomplish our job. For example, the fact that companies are required to submit confidential (trade secret) exploration data to DNR does NOT mean that DNR owns that data. DNR merely holds the data under conditions of strict confidentiality until, and only if, it can later be released under the provisions of a statutory program like the exploration credit programs. The delayed release of the tax credit data, for example, is aimed at enabling the companies to realize the economic benefits of their exploration investments. This protection helps prevent the public release of the data from discouraging exploration investments in the state. If a company is somehow prevented from or inhibited in its ability to realize a reasonable return on their investments, they will invest elsewhere.

I hope this information is helpful. The Division is happy to assist should you require additional clarification.

Sincerely,



Corri A. Feige
Director



THE STATE
of ALASKA
GOVERNOR BILL WALKER

Department of Revenue

COMMISSIONER'S OFFICE

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333 Willoughby Avenue, 11th Floor

PO Box 110400

Juneau, Alaska 99811-0400

Main: 907.465.2300

Fax: 907.465.2389

March 20, 2016

The Honorable Benjamin Nageak and the Honorable David Talerico
Alaska State Representatives
Co-Chairs, House Resources Committee
State Capitol Rooms 126 and 104
Juneau AK 99801

Dear Co-Chairs Nageak and Talerico,

The purpose of this letter is to provide you with responses to the questions asked of the Department of Revenue regarding House Bill 247 during our presentations to the House Resources Committee on March 7-8, 2016. Please see questions in italics and our responses immediately below the questions.

- 1. Clarify whether annual State revenues shown in conjunction with the life cycle modeling reflected all State revenues or only general fund unrestricted revenues and whether they reflected State and municipal property tax or only State property tax.*

The State revenues shown with the life cycle modeling include all State revenues, including restricted royalties, and only the State share of the property tax.

- 2. Provide individual and summary slides for life cycle modeling of the following:*
 - a. A field with a 1/6 royalty share and 30% GVR*
 - b. A field where a portion of the leases are privately owned*
 - c. A Cook Inlet gas development*
 - d. A field in "middle earth" including consideration of the LNG storage facility and refinery infrastructure credit*

Supplemental slides with the requested analysis are attached.

Note that for the Cook Inlet gas analysis, we created a representative cost and production profile that is similar in magnitude to a representative gas field presented by Enalytica. For the "middle earth" analysis, we used this same Cook Inlet gas field profile, and simply applied the middle earth fiscal regime to that field. For middle earth, we did not directly account for LNG storage facility and refinery infrastructure credits. The reason for this is that the life cycle model is intended to model an upstream development from the standpoint of a producer, and these credits would likely fall outside the scope of any particular upstream development. They are, however, important components of the state's overall regime regarding oil and gas development.

3. *Provide the committee with land ownership and credits analysis as referenced by Director Alper in committee hearings.*

The requested analyses are attached. Note that the land ownership analysis is slightly revised from an earlier version provided to the committee. This analysis includes a simple model that enables the user to estimate the state’s royalty revenue (and, if applicable, production tax on private royalties) for a given project.

We also include below a summary of the revenue from oil and gas operations on federal lands in Alaska. The table summarizes the revenue disbursed to the State of Alaska for its share of the revenues received by the federal government.

Federal Disbursements to Alaska for Oil and Gas Royalties			
Federal Land Designation	FFY 2013	FFY 2014	FFY 2015
Federal Offshore (8g)	\$2,940,962	\$2,519,780	\$1,957,767
Federal Onshore	\$15,695,140	\$17,624,835	\$16,200,909
Total Federal Disbursements	\$18,636,102	\$20,144,615	\$18,158,676
Source: Office of Natural Resources Revenue			

4. *Provide an example of Section 18 of the bill applied to a 750 million barrel field. Also provide an example of Section 18 of the bill applied to a field with 1/6 royalty.*

The question was asked to determine the potential “upside” cost of the circumstance in which the Gross Value Reduction (GVR) is used to increase the size of a net operating loss (NOL) and associated credit. The examples below show how a \$10 per barrel loss couples with the 20% GVR and the 30% GVR scenarios to create even larger net operating losses for credit purposes. When multiplied by production of 100,000 taxable barrels per day, the size of the credit is increased substantially. Such scenarios could occur in an environment similar to our current one, in which oil prices sharply decline in a relatively short period of time. Specifically, the 20% GVR scenario could result in a NOL credit that equaled 56% of the actual loss, or \$77 million more than a NOL credit based on 35% of the actual loss. The 30% GVR scenario could result in a NOL credit that equaled 67% of the actual loss, or \$115 million more than a NOL credit based on 35% of the actual loss.

**750 mmbo Field - 20% GVR-Eligible Production increasing
Size of a Net Operating Loss and Proposed Change***

	Current Law	Proposed Change
West Coast Price (\$/tax bbl)	\$40	\$40
Transportation (\$/tax bbl)	-\$10	-\$10
Wellhead Value (\$/tax bbl)	\$30	\$30
Lease Expenditures (\$/tax bbl)	-\$40	-\$40
Net Value before GVR (\$/tax bbl)	-\$10	-\$10
Wellhead Value from above (\$/tax bbl)	\$30	\$30
Gross Value Reduction Rate (%)	<u>x 20%</u>	<u>x 20%</u>
Gross Value Reduction (\$/tax bbl)	\$6	\$6
GVR-Adjusted Net Value (\$/tax bbl)	-\$16	-\$16
Base Tax Rate (%)	<u>x 35%</u>	<u>x 35%</u>
Base Production Tax before Credits (\$/tax bbl)	\$0.00	\$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value (\$/tax bbl)	\$30	\$30
Minimum Tax (\$/tax bbl)	\$1.20	\$1.20
GVR Credit per-Tax-Barrel (\$/tax bbl)	\$5	\$5
Production Tax after credits (\$/tax bbl)	\$0.00	\$0.00
Net Operating Loss Credit Rate (%)	<u>x 35%</u>	<u>x 35%</u>
Net Operating Loss Credit (\$/tax bbl)	-\$5.60	-\$3.50
NOL per barrel times 100,000 taxable b/d (\$M)	-\$204	-\$128
Difference (\$M)		-\$77

*Assumes oil price decrease when field is producing at near peak rate. Proposed change here includes only changes to the law on the GVR creating or increasing a net operating loss.

**750 mmbo Field - 30% GVR-Eligible Production increasing
Size of Net Operating Loss and Proposed Change***

	Current Law	Proposed Change
West Coast Price (\$/tax bbl)	\$40	\$40
Transportation (\$/tax bbl)	-\$10	-\$10
Wellhead Value (\$/tax bbl)	\$30	\$30
Lease Expenditures (\$/tax bbl)	-\$40	-\$40
Net Value before GVR (\$/tax bbl)	-\$10	-\$10
Wellhead Value from above (\$/tax bbl)	\$30	\$30
Gross Value Reduction Rate (%)	x 30%	x 30%
Gross Value Reduction (\$/tax bbl)	\$9	\$9
GVR-Adjusted Net Value (\$/tax bbl)	-\$19	-\$19
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$0.00	\$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value (\$/tax bbl)	\$30	\$30
Minimum Tax (\$/tax bbl)	\$1.20	\$1.20
GVR Credit per-Tax-Barrel (\$/tax bbl)	\$5	\$5
Production Tax after credits (\$/tax bbl)	\$0.00	\$0.00
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit (\$/tax bbl)	-\$6.65	-\$3.50
NOL per barrel times 100,000 taxable b/d (\$M)	-\$243	-\$128
Difference (\$M)		-\$115

*Assumes oil price decrease when field is producing at near peak rate. Proposed change here includes only changes to the law on the GVR creating or increasing a net operating loss.

5. *Provide possible language for a revised Section 22 that would limit data collected to only what is currently collected.*

We have been working with the Department of Law and the Department of Natural Resources, Division of Oil and Gas, and have developed language that we believe will resolve the committee's concerns that the publicly released data is the same as what currently occurs.

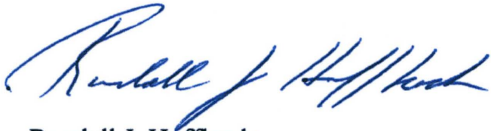
The requested language was provided to the co-chair's staff on 3/14; a copy is attached with this memo. Please note that this revision substantially adds to the length of the current Section 22, because instead of referencing data sharing language in AS 43.55.025 it creates new language in AS 43.55.023.

Additional clarification from the hearings:

During our presentations, a question was asked regarding how costs are allocated between oil and gas production for tax calculation purposes, and was answered incorrectly. Per Department of Revenue regulation, in instances where allocation of lease expenditures is necessary, those lease expenditures are allocated based on BTU-equivalent barrels of oil produced.

I hope you find this information to be useful. Please do not hesitate to contact me if you have further questions.

Sincerely,

A handwritten signature in blue ink, appearing to read "Randall J. Hoffbeck". The signature is fluid and cursive, with a large initial "R" and "H".

Randall J. Hoffbeck
Commissioner

Attachments:

- Supplemental Life-cycle modeling analysis slides
- Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land. with Royalty Revenue model
- Proposed rewrite of Sec. 22 of HB247, DNR data sharing and public release

Title: **Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land**

Preparer: Dan Stickel, Assistant Chief Economist, 465-3279

Date: 3/4/2016

Purpose: To provide a summary of applicability of royalty and taxes for land with various geographic location and ownership.

Data Source: All information is per state and federal law.

Key Assumptions: All laws in place as of March 2016.

History: This is the first version of this document.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land

Prepared 3/4/16 by Dan Stickel

Land status	Revenue component			
	Production tax / credits	Royalty	Corporate Income Tax	Property Tax
Offshore beyond 6 miles - Federal OCS	Do not apply	Federal royalties applies; zero shared back to state (in Alaska; other states do receive shared royalties)	Not included in apportionment factor	Does not apply
Offshore 3-6 miles - Federal OCS 8(g) area	Do not apply	Federal royalties applies; 27% shared back to state with no restrictions	Not included in apportionment factor	Does not apply
State lands	All credits available; tax applies to all taxable production	State royalty applies	All property, production, and sales included in apportionment factor	Applies to all oil and gas property
NPR-A - federal owned	All credits available; tax applies to all taxable production	Federal royalty applies; 50% of royalties are shared back to state but must be used for benefit of local communities	All property, production, and sales included in apportionment factor	Applies to all oil and gas property
ANWR	All credits available; tax applies to all taxable production	Federal royalty applies; 90% shared back to state with no restrictions (under current law)	All property, production, and sales included in apportionment factor	Applies to all oil and gas property
Other federal land	All credits available; tax applies to all taxable production	Federal royalties applies; 90% shared back to state with no restrictions	All property, production, and sales included in apportionment factor	Applies to all oil and gas property
Private land (including Alaska Native Corporation)	All credits available; tax applies to all taxable production	Privately negotiated royalty applies; not shared with state. However state levies 5% gross tax on the value of private landowner royalty interest as part of production tax	All property, production, and sales included in apportionment factor	Applies to all oil and gas property

Notes:

Offshore submerged lands in the 0-3 miles category treated same as similar onshore land.

Title: **Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land**

Preparer: Dan Stickel, Assistant Chief Economist, 465-3279

Date: 3/12/2016

Purpose: To provide a summary of applicability of royalty and taxes for land with various geographic location and ownership.

Data Source: All information is per state and federal law.

Key Assumptions: All laws in place as of March 2016.

History: This is the second version of this document; updated to clarify tax rate that applies to private landowner royalties for gas production.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Assumptions for Revenue Estimates	Price of Oil	\$50
	Transport Cost	\$10
	Volume in BBL / Day	10,000
	Royalty Rate	12.50%

Applicability of State Royalty, Tax, and Credits by Geographic and Legal Ownership of Land

Revised 3/12/16 by Dan Stickel

Land status	Revenue component				Royalty or Tax on Pvt. Royalty (revenue in \$millions)
	Production tax / credits	Royalty	Corporate Income Tax	Property Tax	
Offshore beyond 6 miles - Federal OCS	Do not apply	Federal royalties applies; zero shared back to state (in Alaska; other states do receive shared royalties)	Not included in apportionment factor	Does not apply	\$ -
Offshore 3-6 miles - Federal OCS 8(g) area	Do not apply	Federal royalties applies; 27% shared back to state with no restrictions	Not included in apportionment factor	Does not apply	\$ 4.9
State lands	All credits available; tax applies to all taxable production	State royalty applies	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 18.3
NPR-A - federal owned	All credits available; tax applies to all taxable production	Federal royalty applies; 50% of royalties are shared back to state but must be used for benefit of local communities	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 9.1
ANWR	All credits available; tax applies to all taxable production	Federal royalty applies; 90% shared back to state with no restrictions (under current law)	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 16.4
Other federal land	All credits available; tax applies to all taxable production	Federal royalties applies; 90% shared back to state with no restrictions	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 16.4
Private land (including Alaska Native Corporation)	All credits available; tax applies to all taxable production	Privately negotiated royalty applies; not shared with state. However state levies 5% (oil) or 1.667% (gas) gross tax on the value of private landowner royalty interest as part of production tax	All property, production, and sales included in apportionment factor	Applies to all oil and gas property	\$ 0.9

Notes:

Offshore submerged lands in the 0-3 miles category treated same as similar onshore land.

Table of Tax Credits under AS 43.55 - The Alaska Oil and Gas Production Tax and Comparison to Proposed Changes in HB 247

Below is a table relating to credits under AS 43.55, the Oil and Gas Production Tax, for the State of Alaska. This is intended as an informational guide only. The State of Alaska makes no warranty, expressed or implied, of the accuracy of this. To be certain of the current statutes and regulations, refer to the official printed version of the statutes and regulations. This information only relates to credits in effect on January 1, 2016.

Statute for Credit	Credits that May be Issued as Certificates and Submitted to the State for Cash Purchase								Credits that may only be used to offset a tax liability					
	AS 43.55.023(b)	AS 43.55.023(a)(1)	AS 43.55.023(a)(2)	AS 43.55.023(f)(1)	AS 43.55.023(f)(2)	AS 43.55.025(a)(1-4)	AS 43.55.025(a)(5)	AS 43.55.025(a)(6) & (7)	AS 43.55.019	AS 43.55.024(a)	AS 43.55.024(c)	AS 43.55.024(i)	AS 43.55.024(j)	AS 38.05.180(i) / AS 41.09.010
Informal Title	Carried-Forward Annual Loss Credit; NOL Credit	Qualified Capital Expenditures (QCE) Credit	Qualified Capital Expenditures (QCE) Credit for Exploration	Well Lease Expenditure (WLE) Credit	Well Lease Expenditure (WLE) Credit for Exploration	Alternative Credit for Exploration	Exploration - Jack-up Rig	Exploration - Frontier Basins	Education Credit	New Area Development ("Middle Earth") Credit	Small Producer Credit	Credit on GVR Oil	Sliding Scale Credit	(DNR) Exploration Incentive Credits
Initial and Most Recent Effective Date(s)	4/1/2006, amended 7/1/2007 & 1/1/2014	4/1/2006, amended 7/1/2007, 1/1/2013 & 1/1/2014		7/1/2010		9/9/2003, amended 7/1/2008 & 1/1/2013	5/10/2010	1/1/2013	1987, amended 1/1/2011	4/1/2006	4/1/2006	1/1/2014	1/1/2014	
Expiration Date	No expiration	North Slope QCEs expire on 12/31/2013		No expiration		7/1/2016 for projects in North Slope and Cook Inlet; 1/1/2022 for "Middle Earth"	7/1/2016	7/1/2016	Changes 1/1/2021, no expiration	If started before 5/1/16, after 9th calendar year of production	If started before 5/1/16, after 9th calendar year of production	No expiration	No expiration	
Credit Percentage / Amount	North Slope 35%; rest of state 25%	20%		40%		30% or 40% (pre-7/1/08 20% or 40%)	80%, 90%, or 100% (up to \$20, \$22.5 or \$25 million)	80% (up to \$25 million) for wells; 75% (up to \$7.5 million) for seismic	Max of \$5,000,000	\$6,000,000	\$12,000,000	\$5 per bbl	\$0-\$8 per bbl	N/A
Description	Calculated for each segment by taking 25% or 35% of excess lease expenditures.	A QCE must be a lease expenditure and treated as a capitalized cost under 26 IRC.	A QCE must be a lease expenditure and related to exploration.	A WLE must be a lease expenditure, QCE, and an Intangible Drilling and Development Cost (IDC)	A WLE must be a lease expenditure, QCE, and an Intangible Drilling and Development Cost (IDC) related to exploration	Costs directly related to drilling an exploration well or performing a seismic shoot; amount depends on location	For the first 3 unaffiliated wells drilled by the same jack-up rig in Cook Inlet pre-Tertiary zone	The first two qualified exploration wells and the first seismic project in each basin	A part of cash donations to qualified educational institutes or foundations	For production south of 68 degrees North latitude and outside of Cook Inlet	Full credit if the taxpayer produces less than 50,000 BTU equiv. barrels. Prorated between 50,000-100,000 BTU equiv. barrels	\$5 per barrel, based on oil produced that meets one of the criteria for "new oil"	Sliding scale of \$0-\$8, based on average monthly gross value, for oil that does not meet the criteria for "new oil"	DNR administers this credit, two statutes depend on state land vs. non-state land
DNR Data Requirements	No	No	Yes	No	Yes	Yes	Yes	Yes	No	No	No	No	No	
Location Requirements	No	Effective 1/1/2014, no QCEs on North Slope		Must be south of 68 degrees North latitude		Some have distance requirements from other wells and units	Yes - must be a jack-up rig in Cook Inlet	Yes - six basins defined in AS 43.55.025(o)	No	Outside North Slope and Cook Inlet	No	Must be north of 68 degrees North latitude (North Slope)		N/A
Regulations**	15 AAC 55.310-320 and 15 AAC 55.250-260	15 AAC 55.310-320 and 15 AAC 55.250-260		15 AAC 55.310-320 and 15 AAC 55.250-260		15 AAC 55.350-360			None	15 AAC 55.335				15 AAC 55.520(f)
Combinations	May be "stacked" with credits under AS 43.55.023(a), (f), or 025(a)	Same expenditures may also qualify for credit under AS 43.55.023(b)					None of the expenditures included in this credit may receive a credit under any other section of this chapter			Credit may be in addition to all other credits	Not for specific expenditures - credit may be in addition to all other credits			N/A
Uses of Credit	Applied directly to tax or issued as a certificate. The certificate may be transferred to another company, applied against tax liability, or "cashed" out with the State under AS 43.55.028								Applied directly to tax at 1/12 each month and may not be carried forward or transferred				Applied to tax at actual amount earned each month. Can't be carried forward or transferred	Applied against royalty, rental payments, or tax liability

Proposed Changes to Credits in HB 247

See below	These credit are repealed	Cannot reduce tax liability below the minimum tax under AS 43.55.011(f), retroactive to 1/1/16. (Sec. 17, 19, and 44)	No change	Credits cannot reduce tax liability below the minimum tax under AS 43.55.011(f), retroactive to 1/1/16. (Sec. 17(b) and 19)	This credit is repealed
				The Per-Taxable-Credits are monthly calculations instead of annual. (Sec. 17(c))	
Changes to Carried-Forward Annual Loss (NOL) Credit					
1) If a company producing at a loss is producing oil that qualifies as "new oil" that is eligible for the Gross Value Reduction (GVR), the GVR is added back into the production tax value calculation for determining the NOL credit. (Sec. 18)					
2) Any unused portion of this credit can only be used up to the 10th calendar year after the carried-forward annual lost was incurred. (Sec 19)					
3) Applies the current DNR seismic and well data sharing requirements currently mandated for exploration credits (Sec. 22)					
Proposed Changes (General for All Credits)					
General Changes					
1) The name of each company claiming credits, the aggregate amount of credits in a calendar year, and the general description of the activities which generated the credit will be public information. (Sec. 8)					
2) Companies with a non-tardy liability to the state cannot receive a cash refund for a credit from the state; it must be applied towards that liability					
Changes Impacting Repurchase of Certificates					
1) Companies can only receive \$25 million in cashed out credits annually.					
2) Only companies whose gross revenues in the previous year were less than \$10 billion can get a cash refund for a credit					
3) The state will only repurchase a percentage of a credit certificate equal to the percentage of a company's Alaska resident hire in the previous calendar year. (Sec. 9, 10, 11, 26, 27, & 39)					

AMENDMENT

OFFERED IN THE HOUSE

BY _____

TO: HB 247

1 Page 18, line 2:

2 Delete "section"

3 Insert "subsection"

4

5 Page 18, lines 3 - 10:

6 Delete all material and insert:

7 "(q) For a credit under this section,

8 (1) a producer or explorer shall comply with the notice and information
9 requirements in this subsection for lease expenditures incurred for

10 (A) a seismic survey, except that seismic data collected within the
11 boundaries of a unit by a producer in that unit is not subject to the notice and
12 information requirements of this subsection;

13 (B) an exploration or stratigraphic test well;

14 (2) a producer or explorer shall

15 (A) notify the Department of Natural Resources, within 30 days
16 after completion of seismic or geophysical data processing or completion of well
17 drilling, whichever is the latest, for which the lease expenditures are claimed, of
18 the date of completion and submit a report to the department describing the
19 processing sequence and providing a list of data sets available;

20 (B) provide to the Department of Natural Resources, within 30
21 days after the date of a request, unless a longer period is provided by the

1 Department of Natural Resources, specific data sets, ancillary data, and reports
2 identified in (A) of this paragraph; in this subparagraph,

3 (i) a seismic or geophysical data set includes the data for
4 an entire seismic survey irrespective of whether the survey area covers
5 nonstate land in addition to state land or land in a unit in addition to land
6 outside a unit;

7 (ii) well data includes all analyses conducted on physical
8 material, and well logs collected from the well, results, and copies of data
9 collected and data analyses for the well, including well logs; sample
10 analyses; testing geophysical and velocity data including seismic profiles
11 and check shot surveys; testing data and analyses; age data; geochemical
12 analyses; and tangible material;

13 (3) that, notwithstanding any provision of AS 38, information provided
14 under this subsection will be held confidential by the Department of Natural Resources,

15 (A) in the case of well data, until the expiration of the 24-month
16 period of confidentiality described in AS 31.05.035(c), at which time the
17 Department of Natural Resources will release the information after 30 days'
18 public notice unless, in the discretion of the commissioner of natural resources, it
19 is necessary to protect information relating to the valuation of unleased acreage in
20 the same vicinity, or unless the well is on private land and the owner, including
21 the lessor but not the lessee, of the oil and gas resources has not given permission
22 to release the well data;

23 (B) in the case of seismic or other geophysical data, for 10 years
24 following the completion date, at which time the Department of Natural
25 Resources will release the information after 30 days' public notice, except as to
26 seismic or other geophysical data acquired from private land, unless the owner,
27 including a lessor but not a lessee, of the oil and gas resources in the private land
28 gives permission to release the seismic or other geophysical data associated with
29 the private land;

30 (4) notwithstanding any contrary provision of AS 38, AS 40.25.100, or
31 AS 43.05.230, the following information is not confidential after the credit, based on the

1 lease expenditures, has been applied or, in the case of a transferable certificate, after the
2 certificate has been issued:

- 3 (A) the producer or explorer's name;
4 (B) the location of the well or seismic exploration;
5 (C) the date on which the information required to be submitted
6 under this subsection will be released."