

SB 21
(FILE 4)
PRESENTA
TIONS

<TARGET><BILL>SB 21</BILL><SUBJECT>SB 21 (FILE 4)
PRESENTATIONS</SUBJECT><COMM>SFIN28</COMM></TARGET>

14

CS FOR SENATE BILL NO. 21(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-EIGHTH LEGISLATURE - FIRST SESSION

BY THE SENATE FINANCE COMMITTEE

Offered:

Referred:

Sponsor(s): SENATE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the interest rate applicable to certain amounts due for fees, taxes,**
2 **and payments made and property delivered to the Department of Revenue; relating to**
3 **appropriations from taxes paid under the Alaska Net Income Tax Act; providing a tax**
4 **credit against the corporation income tax for qualified oil and gas service industry**
5 **expenditures; relating to the oil and gas production tax rate; relating to gas used in the**
6 **state; relating to monthly installment payments of the oil and gas production tax;**
7 **relating to oil and gas production tax credits for certain losses and expenditures;**
8 **relating to oil and gas production tax credit certificates; relating to nontransferable tax**
9 **credits based on production; relating to the oil and gas tax credit fund; relating to**
10 **annual statements by producers and explorers; relating to lease expenditures, including**
11 **lease expenditures that are capital lease expenditures; making conforming amendments;**
12 **and providing for an effective date."**

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

2 * **Section 1.** AS 05.15.095(c) is amended to read:

3 (c) A delinquent fee bears interest at the rate set by AS 43.05.225(2)
4 [AS 43.05.225].

5 * **Sec. 2.** AS 29.60.850(b) is amended to read:

6 (b) Each fiscal year, the legislature may appropriate an amount to the
7 community revenue sharing fund [AN AMOUNT EQUAL TO 20 PERCENT OF
8 THE MONEY RECEIVED BY THE STATE DURING THE PREVIOUS
9 CALENDAR YEAR UNDER AS 43.55.011(g)]. The amount may not exceed

10 (1) \$60,000,000; or

11 (2) the amount that, when added to the fund balance on June 30 of the
12 previous fiscal year, equals \$180,000,000.

13 * **Sec. 3.** AS 34.45.470(a) is amended to read:

14 (a) A person who fails to pay or deliver property within the time prescribed by
15 this chapter may be required to pay to the department interest at the annual rate
16 calculated under AS 43.05.225(2) [AS 43.05.225] on the property or the value of it
17 from the date the property should have been paid or delivered.

18 * **Sec. 4.** AS 43.05.225 is amended to read:

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

20 (1) when a tax levied in this title becomes delinquent, it bears interest
21 in a calendar quarter at the rate of three [FIVE] percentage points above the annual
22 rate charged member banks for advances by the 12th Federal Reserve District as of the
23 first day of that calendar quarter, or at the annual rate of 11 percent, whichever is
24 lesser [GREATER], compounded quarterly as of the last day of that quarter;

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

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

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

29 * **Sec. 5.** AS 43.20.046(i) is amended to read:

30 (i) The issuance of a refund under this section does not limit the department's
31 ability to later audit or adjust the claim if the department determines, as a result of the

1 audit, that the person that claimed the credit was not entitled to the amount of the
 2 credit. The tax liability of the person receiving the credit under this chapter is
 3 increased by the amount of the credit that exceeds that to which the person was
 4 entitled. If the tax liability is increased under this subsection, the increase bears
 5 interest under AS 43.05.225(1) [AS 43.05.225] from the date the refund was issued.

6 * **Sec. 6.** AS 43.20.047(i) is amended to read:

7 (i) The issuance of a refund under this section does not limit the department's
 8 ability to later audit or adjust the claim if the department determines, as a result of the
 9 audit, that the person that claimed the credit was not entitled to the amount of the
 10 credit. The tax liability of the person receiving the credit under this section is
 11 increased by the amount of the credit that exceeds that to which the person was
 12 entitled. If the tax liability is increased under this subsection, the increase bears
 13 interest at the rate set by AS 43.05.225(1) [AS 43.05.225] from the date the refund
 14 was issued.

15 * **Sec. 7.** AS 43.20 is amended by adding a new section to read:

16 **Sec. 43.20.049. Qualified oil and gas industry service expenditure credit.**

17 (a) For a tax year ending after the effective date of this section, a taxpayer is entitled to
 18 a credit against the tax due under this chapter in the amount of 10 percent of a
 19 qualified oil and gas service industry expenditure of the taxpayer incurred in the state.
 20 A taxpayer may not, in one tax year, apply more than \$10,000,000 in tax credits
 21 received under this section. A tax credit under this section may not be used to reduce a
 22 tax liability under this chapter below zero.

23 (b) A tax credit under this section may be transferred to a taxpayer subject to
 24 tax under this chapter upon filing notice with the department in a format prescribed by
 25 the department. The department shall issue a certificate in the amount of the tax credit
 26 received under this section. A taxpayer receiving the transfer of a certificate under this
 27 subsection may not apply more than \$10,000,000 in tax credits authorized by this
 28 section in a single tax year and may not use a tax credit authorized by this section to
 29 reduce a tax liability under this chapter below zero. Transfer of a credit does not limit
 30 the ability of the department to audit a tax credit claim and adjust the credit if the
 31 department determines, as a result of the audit, that the taxpayer that incurred the

1 expenditure that is the basis of the credit was not entitled to the amount of the credit
2 claimed. If, as a result of the audit, the department determines that the amount of the
3 credit exceeds the proper amount, the department may, at the time the credit is used,
4 increase by the amount determined to exceed the proper value of the credit the taxes
5 calculated under this chapter for the taxpayer whose expenditure was the basis of the
6 credit.

7 (c) A tax credit certificate issued under this section may not be applied against
8 a tax liability more than seven calendar years after the date the credit is claimed.

9 (d) An expenditure that is the basis of the credit under this section

10 (1) may not be the basis for a credit or reduction in tax liability
11 claimed under another provision of this title; or

12 (2) may not be the basis for any federal credit claimed under this title.

13 (e) Notwithstanding any contrary provision of AS 40.25.100(a) or
14 AS 43.05.230(e), for a year that three or more taxpayers claim a tax credit under this
15 section, the department may publish the total amount of tax credits claimed under this
16 section and a description of the qualified oil and gas service industry expenditures that
17 were the basis for a tax credit under this section.

18 (f) In this section,

19 (1) "manufacture" means to perform substantial industrial operations in
20 the state to transform raw material into tangible personal property with a useful life of
21 three years or more for use in the exploration, development, or production of oil and
22 gas;

23 (2) "modification" means an adjustment, equipping, or other alteration
24 to existing tangible personal property that has a useful life of three years or more and
25 is for use in the exploration, development, or production of oil and gas reserves;
26 "modification" does not include minor product alterations or inventory activities;

27 (3) "qualified oil and gas service industry expenditure" means an
28 expenditure directly attributable to an in-state manufacture or in-state modification of
29 tangible personal property used in the exploration, development, or production of oil
30 or gas, but does not include components or equipment used for or in the process of that
31 manufacturing or modification.

1 * **Sec. 8.** AS 43.50.570 is amended to read:

2 **Sec. 43.50.570. Interest.** A licensee who fails to pay an amount due for the
3 purchase of stamps within the time required

4 (1) is considered to have failed to pay the cigarette taxes due under this
5 chapter; and

6 (2) shall pay interest at the rate established under AS 43.05.225(1)
7 [AS 43.05.225] from the date on which the amount became due until the date of
8 payment.

9 * **Sec. 9.** AS 43.55.011(e) is amended to read:

10 (e) There is levied on the producer of oil or gas a tax for all oil and gas
11 produced each calendar year from each lease or property in the state, less any oil and
12 gas the ownership or right to which is exempt from taxation or constitutes a
13 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), (o), and
14 (p) of this section, the tax is equal to [THE SUM OF

15 (1)] the annual production tax value of the taxable oil and gas as
16 calculated under AS 43.55.160(a) [AS 43.55.160(a)(1)] multiplied by 30 [25] percent
17 [; AND

18 (2) THE SUM, OVER ALL MONTHS OF THE CALENDAR YEAR,
19 OF THE TAX AMOUNTS DETERMINED UNDER (g) OF THIS SECTION].

20 * **Sec. 10.** AS 43.55.011(o) is amended to read:

21 (o) Notwithstanding other provisions of this section, for a calendar year before
22 2022, the tax levied under (e) of this section for each 1,000 cubic feet of gas for gas
23 produced from a lease or property outside the Cook Inlet sedimentary basin and used
24 in the state, other than gas subject to (p) of this section, may not exceed the amount
25 of tax for each 1,000 cubic feet of gas that is determined under (j)(2) of this section.

26 * **Sec. 11.** AS 43.55.020(a) is amended to read:

27 (a) For a calendar year, a producer subject to tax under AS 43.55.011
28 [AS 43.55.011(e) - (i) OR (p)] shall pay the tax as follows:

29 (1) an installment payment of the estimated tax levied by
30 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
31 month of the calendar year on the last day of the following month; except as otherwise

1 provided under (2) of this subsection, the amount of the installment payment is the
2 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
3 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
4 of the installment payment may not be less than zero:

5 (A) for oil and gas not subject to AS 43.55.011(o) or (p)
6 produced from leases or properties in the state outside the Cook Inlet
7 sedimentary basin [BUT NOT SUBJECT TO AS 43.55.011(o) OR (p)], other
8 than leases or properties subject to AS 43.55.011(f), the greater of

9 (i) zero; or

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

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

20 (i) zero;

21 (ii) zero percent, one percent, two percent, three
22 percent, or four percent, as applicable, of the gross value at the point of
23 production of the oil and gas produced from the [ALL] leases or
24 properties during the month for which the installment payment is
25 calculated; or

26 (iii) the sum of 25 percent and the tax rate calculated for
27 the month under AS 43.55.011(g) multiplied by the remainder obtained
28 by subtracting 1/12 of the producer's adjusted lease expenditures for the
29 calendar year of production under AS 43.55.165 and 43.55.170 that are
30 deductible for the oil and gas [THOSE LEASES OR PROPERTIES]
31 under AS 43.55.160 from the gross value at the point of production of

1 the oil and gas produced from those leases or properties during the
2 month for which the installment payment is calculated;

3 (C) for oil or [AND] gas [PRODUCED FROM EACH LEASE
4 OR PROPERTY] subject to AS 43.55.011(j), (k), or (o) [, OR (p)], for each
5 lease or property, the greater of

6 (i) zero; or

7 (ii) the sum of 25 percent and the tax rate calculated for
8 the month under AS 43.55.011(g) multiplied by the remainder obtained
9 by 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 under AS 43.55.160 for the oil or gas, respectively,
12 produced from the lease or property from the gross value at the point of
13 production of the oil or gas, respectively, produced from the lease or
14 property during the month for which the installment payment is
15 calculated;

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

17 (i) the sum of 25 percent and the tax rate calculated
18 for the month under AS 43.55.011(g) multiplied by the remainder
19 obtained by subtracting 1/12 of the producer's adjusted lease
20 expenditures for the calendar year of production under
21 AS 43.55.165 and 43.55.170 that are deductible for the oil and gas
22 under AS 43.55.160 from the gross value at the point of production
23 of the oil and gas produced from the leases or properties during the
24 month for which the installment payment is calculated, but not less
25 than zero; or

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

29 (2) an amount calculated under (1)(C) of this subsection for oil or gas
30 [PRODUCED FROM A LEASE OR PROPERTY

31 (A)] subject to AS 43.55.011(j), (k), or (o) may not exceed the

1 product obtained by carrying out the calculation set out in AS 43.55.011(j)(1)
2 or (2) or 43.55.011(o), as applicable, for gas or set out in AS 43.55.011(k)(1)
3 or (2), as applicable, for oil, but substituting in AS 43.55.011(j)(1)(A) or (2)(A)
4 or 43.55.011(o), as applicable, the amount of taxable gas produced during the
5 month for the amount of taxable gas produced during the calendar year and
6 substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the amount of
7 taxable oil produced during the month for the amount of taxable oil produced
8 during the calendar year;

9 [(B) SUBJECT TO AS 43.55.011(p) MAY NOT EXCEED
10 FOUR PERCENT OF THE GROSS VALUE AT THE POINT OF
11 PRODUCTION OF THE OIL OR GAS;]

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

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

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

24 (4) any amount of tax levied by AS 43.55.011 [AS 43.55.011(e) OR
25 (i)], net of any credits applied as allowed by law, that exceeds the total of the amounts
26 due as installment payments of estimated tax is due on March 31 of the year following
27 the calendar year of production.

28 * **Sec. 12.** AS 43.55.020(a), as amended by sec. 11 of this Act, is amended to read:

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

31 (1) an installment payment of the estimated tax levied by

1 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
2 month of the calendar year on the last day of the following month; except as otherwise
3 provided under (2) of this subsection, the amount of the installment payment is the
4 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
5 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
6 of the installment payment may not be less than zero:

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

11 (i) zero; or

12 (ii) 30 [THE SUM OF 25] percent of [AND THE TAX
13 RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)
14 MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the
15 producer's adjusted lease expenditures for the calendar year of
16 production under AS 43.55.165 and 43.55.170 that are deductible for
17 the oil and gas under AS 43.55.160 from the gross value at the point of
18 production of the oil and gas produced from the leases or properties
19 during the month for which the installment payment is calculated;

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

22 (i) zero;

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

27 (iii) 30 [THE SUM OF 25] percent of [AND THE TAX
28 RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)
29 MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the
30 producer's adjusted lease expenditures for the calendar year of
31 production under AS 43.55.165 and 43.55.170 that are deductible for

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31

oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from those leases or properties during the month for which the installment payment is calculated, except that, for the purposes of this calculation, the gross value at the point of production of oil and gas subject to AS 43.55.160(f) is reduced by 30 percent:

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

(i) zero; or

(ii) 30 [THE SUM OF 25] percent of [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible under AS 43.55.160 for the oil or gas, respectively, produced from the lease or property from the gross value at the point of production of the oil or gas, respectively, produced from the lease or property during the month for which the installment payment is calculated;

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

(i) 30 [THE SUM OF 25] percent of [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated, but not less than zero; or

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

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

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

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

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

22 (4) any amount of tax levied by AS 43.55.011, net of any credits
23 applied as allowed by law, that exceeds the total of the amounts due as installment
24 payments of estimated tax is due on March 31 of the year following the calendar year
25 of production.

26 * **Sec. 13.** AS 43.55.020(d) is amended to read:

27 (d) In making settlement with the royalty owner for oil and gas that is taxable
28 under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable
29 royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the
30 time the tax becomes due to the amount of the tax paid. If the total deductions of
31 installment payments of estimated tax for a calendar year exceed the actual tax for that

1 calendar year, the producer shall, before April 1 of the following year, refund the
2 excess to the royalty owner. Unless otherwise agreed between the producer and the
3 royalty owner, the amount of the tax paid under AS 43.55.011(e) [AS 43.55.011(e) -
4 (g)] on taxable royalty oil and gas for a calendar year, other than oil and gas the
5 ownership or right to which constitutes a landowner's royalty interest, is considered to
6 be the gross value at the point of production of the taxable royalty oil and gas
7 produced during the calendar year multiplied by a figure that is a quotient, in which

8 (1) the numerator is the producer's total tax liability under
9 AS 43.55.011(e) [AS 43.55.011(e) - (g)] for the calendar year of production; and

10 (2) the denominator is the total gross value at the point of production
11 of the oil and gas taxable under AS 43.55.011(e) [AS 43.55.011(e) - (g)] produced by
12 the producer from all leases and properties in the state during the calendar year.

13 * **Sec. 14.** AS 43.55.020(g) is amended to read:

14 (g) Notwithstanding any contrary provision of AS 43.05.225, an unpaid
15 amount of an installment payment required under (a)(1) - (3) of this section that is not
16 paid when due bears interest (1) at the rate provided for an underpayment under 26
17 U.S.C. 6621 (Internal Revenue Code), as amended, compounded daily, from the date
18 the installment payment is due until March 31 following the calendar year of
19 production, and (2) as provided for a delinquent tax under AS 43.05.225(1)
20 [AS 43.05.225] after that March 31. Interest accrued under (1) of this subsection that
21 remains unpaid after that March 31 is treated as an addition to tax that bears interest
22 under (2) of this subsection. An unpaid amount of tax due under (a)(4) of this section
23 that is not paid when due bears interest as provided for a delinquent tax under
24 AS 43.05.225(1) [AS 43.05.225].

25 * **Sec. 15.** AS 43.55.023(a) is amended to read:

26 (a) A producer or explorer may take a tax credit for a qualified capital
27 expenditure as follows:

28 (1) notwithstanding that a qualified capital expenditure may be a
29 deductible lease expenditure for purposes of calculating the production tax value of oil
30 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
31 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or

1 explorer that incurs a qualified capital expenditure may also elect to apply a tax credit
2 against a tax levied by AS 43.55.011(e) in the amount of 20 percent of that
3 expenditure; [HOWEVER, NOT MORE THAN HALF OF THE TAX CREDIT MAY
4 BE APPLIED FOR A SINGLE CALENDAR YEAR;]

5 (2) a producer or explorer may take a credit for a qualified capital
6 expenditure incurred in connection with geological or geophysical exploration or in
7 connection with an exploration well only if the producer or explorer

8 (A) agrees, in writing, to the applicable provisions of
9 AS 43.55.025(f)(2); and

10 (B) submits to the Department of Natural Resources all data
11 that would be required to be submitted under AS 43.55.025(f)(2);

12 **(3) a credit for a qualified capital expenditure incurred to explore**
13 **for, develop, or produce oil or gas deposits located north of 68 degrees North**
14 **latitude may be taken only if the expenditure is incurred before January 1, 2014.**

15 * Sec. 16. AS 43.55.023(a), as amended by sec. 15 of this Act, is amended to read:

16 (a) **Except as provided in AS 43.55.025(q) and (v), a [A]** producer or
17 explorer may take a tax credit for a qualified capital expenditure as follows:

18 (1) notwithstanding that a qualified capital expenditure may be a
19 deductible lease expenditure for purposes of calculating the production tax value of oil
20 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
21 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or
22 explorer that incurs a qualified capital expenditure may also elect to apply a tax credit
23 against a tax levied by AS 43.55.011(e) in the amount of 20 percent of that
24 expenditure;

25 (2) a producer or explorer may take a credit for a qualified capital
26 expenditure incurred in connection with geological or geophysical exploration or in
27 connection with an exploration well only if the producer or explorer

28 (A) agrees, in writing, to the applicable provisions of
29 AS 43.55.025(f)(2); and

30 (B) submits to the Department of Natural Resources all data
31 that would be required to be submitted under AS 43.55.025(f)(2);

1 (3) a credit for a qualified capital expenditure incurred to explore for,
2 develop, or produce oil or gas deposits located north of 68 degrees North latitude may
3 be taken only if the expenditure is incurred before January 1, 2014.

4 * **Sec. 17.** AS 43.55.023(b) is amended to read:

5 (b) A producer or explorer may elect to take a tax credit in the amount of 30
6 [25] percent of a carried-forward annual loss **for lease expenditures incurred to**
7 **explore for, develop, or produce oil or gas deposits located south of 68 degrees**
8 **North latitude and up to 30 percent of lease expenditures incurred to explore for,**
9 **develop, or produce oil or gas deposits located north of 68 degrees North latitude**
10 **in the immediately preceding calendar year. Except as provided in**
11 **AS 43.55.025(q) and (v), a producer or explorer may elect to take a tax credit in**
12 **the amount of 30 percent of a carried-forward annual loss based on lease**
13 **expenditures incurred after December 31, 2013, to explore for, develop, or**
14 **produce oil or gas deposits located north of 68 degrees North latitude that exceed**
15 **30 percent of lease expenditures incurred during the immediately preceding**
16 **calendar year to explore for, develop, or produce oil or gas deposits located north**
17 **of 68 degrees North latitude.** A credit under this subsection may be applied against a
18 tax levied by AS 43.55.011(e). For purposes of this subsection, a carried-forward
19 annual loss is the amount of a producer's or explorer's adjusted lease expenditures
20 under AS 43.55.165 and 43.55.170 for a previous calendar year that was not
21 deductible in calculating production tax values for that calendar year under
22 AS 43.55.160.

23 * **Sec. 18.** AS 43.55.023(c) is amended to read:

24 (c) A credit or portion of a credit under this section may not be used to reduce
25 a person's tax liability under AS 43.55.011(e) for any calendar year below zero.
26 **Except as otherwise provided under (p) - (v) of this section,** [AND] any unused
27 credit or portion of a credit not used under this subsection may be applied in a later
28 calendar year.

29 * **Sec. 19.** AS 43.55.023(d) is amended to read:

30 (d) Except as limited by (i) of this section, a person that is entitled to take a tax
31 credit under this section that wishes to transfer the unused credit to another person or

1 obtain a cash payment under AS 43.55.028 may apply to the department for a
2 transferable tax credit certificate [CERTIFICATES]. An application under this
3 subsection must be in a form prescribed by the department and must include
4 supporting information and documentation that the department reasonably requires.
5 The department shall grant or deny an application, or grant an application as to a lesser
6 amount than that claimed and deny it as to the excess, not later than 120 days after the
7 latest of (1) March 31 of the year following the calendar year in which the qualified
8 capital expenditure or carried-forward annual loss for which the credit is claimed was
9 incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for
10 the calendar year in which the qualified capital expenditure or carried-forward annual
11 loss for which the credit is claimed was incurred; or (3) the date the application was
12 received by the department. If, based on the information then available to it, the
13 department is reasonably satisfied that the applicant is entitled to a credit, the
14 department shall issue the applicant a [TWO] transferable tax credit certificate for
15 [CERTIFICATES, EACH FOR HALF OF] the amount of the credit. [THE CREDIT
16 SHOWN ON ONE OF THE TWO CERTIFICATES IS AVAILABLE FOR
17 IMMEDIATE USE. THE CREDIT SHOWN ON THE SECOND OF THE TWO
18 CERTIFICATES MAY NOT BE APPLIED AGAINST A TAX FOR A CALENDAR
19 YEAR EARLIER THAN THE CALENDAR YEAR FOLLOWING THE
20 CALENDAR YEAR IN WHICH THE CERTIFICATE IS ISSUED, AND THE
21 CERTIFICATE MUST CONTAIN A CONSPICUOUS STATEMENT TO THAT
22 EFFECT.] A certificate issued under this subsection does not expire.

23 * **Sec. 20.** AS 43.55.023(d), as amended by sec. 19 of this Act, is amended to read:

24 (d) Except for a tax credit based on a lease expenditure incurred after
25 December 31, 2013, to explore for, develop, or produce oil or gas deposits located
26 north of 68 degrees North latitude [AS LIMITED BY (i) OF THIS SECTION], a
27 person that is entitled to take a tax credit under this section that wishes to transfer the
28 unused credit to another person or obtain a cash payment under AS 43.55.028 may
29 apply to the department for a transferable tax credit certificate. An application under
30 this subsection must be in a form prescribed by the department and must include
31 supporting information and documentation that the department reasonably requires.

1 The department shall grant or deny an application, or grant an application as to a lesser
2 amount than that claimed and deny it as to the excess, not later than 120 days after the
3 latest of (1) March 31 of the year following the calendar year in which the qualified
4 capital expenditure or carried-forward annual loss for which the credit is claimed was
5 incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for
6 the calendar year in which the qualified capital expenditure or carried-forward annual
7 loss for which the credit is claimed was incurred; or (3) the date the application was
8 received by the department. If, based on the information then available to it, the
9 department is reasonably satisfied that the applicant is entitled to a credit, the
10 department shall issue the applicant a transferable tax credit certificate for the amount
11 of the credit. A certificate issued under this subsection does not expire.

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

13 (g) The issuance of a transferable tax credit certificate under (d) of this
14 section or former (m) of this section or the purchase of a certificate under
15 AS 43.55.028 does not limit the department's ability to later audit a tax credit claim to
16 which the certificate relates or to adjust the claim if the department determines, as a
17 result of the audit, that the applicant was not entitled to the amount of the credit for
18 which the certificate was issued. The tax liability of the applicant under
19 AS 43.55.011(e) and 43.55.017 - 43.55.180 is increased by the amount of the credit
20 that exceeds that to which the applicant was entitled, or the applicant's available valid
21 outstanding credits applicable against the tax levied by AS 43.55.011(e) are reduced
22 by that amount. If the applicant's tax liability is increased under this subsection, the
23 increase bears interest under AS 43.05.225(1) [AS 43.05.225] from the date the
24 transferable tax credit certificate was issued. For purposes of this subsection, an
25 applicant that is an explorer is considered a producer subject to the tax levied by
26 AS 43.55.011(e).

27 * **Sec. 22.** AS 43.55.023(n) is amended to read:

28 (n) For the purposes of (l) [AND (m)] of this section, a well lease expenditure
29 incurred in the state south of 68 degrees North latitude is a lease expenditure that is
30 (1) directly related to an exploration well, a stratigraphic test well, a
31 producing well, or an injection well other than a disposal well, located in the state

1 south of 68 degrees North latitude, if the expenditure is a qualified capital expenditure
2 and an intangible drilling and development cost authorized under 26 U.S.C. (Internal
3 Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made
4 under 26 U.S.C. 263(c); in this paragraph, an expenditure directly related to a well
5 includes an expenditure for well sidetracking, well deepening, well completion or
6 recompletion, or well workover, regardless of whether the well is or has been a
7 producing well; or

8 (2) an expense for seismic work conducted within the boundaries of a
9 production or exploration unit.

10 * **Sec. 23.** AS 43.55.023 is amended by adding new subsections to read:

11 (p) A tax credit under (b) of this section that is based on a lease expenditure
12 incurred after December 31, 2013, to explore for, develop, or produce oil or gas
13 deposits located north of 68 degrees North latitude may not be applied against a tax
14 liability for a calendar year that is

15 (1) two or more calendar years later than the calendar year during
16 which the lease expenditure was incurred, unless the producer has complied with the
17 requirements of AS 43.55.030(g);

18 (2) more than 10 calendar years later than the calendar year during
19 which the lease expenditure was incurred.

20 (q) A person may not apply a tax credit under (b) of this section that is based
21 on a lease expenditure incurred after December 31, 2014, to explore for, develop, or
22 produce oil or gas deposits located north of 68 degrees North latitude against a
23 person's tax liability unless the person has applied against the person's tax liability the
24 entire amount of all available tax credits under (b) of this section that are based on
25 lease expenditures incurred after December 31, 2013, and before the calendar year in
26 which the person seeks to apply the credit to explore for, develop, or produce oil or
27 gas deposits located north of 68 degrees North latitude.

28 (r) Except as otherwise provided under (s) of this section, a tax credit or a
29 portion of a tax credit subject to (p)(1) of this section that is carried forward in
30 compliance with AS 43.55.030(g) increases at a rate of 15 percent, compounded
31 annually, as provided in this subsection. A tax credit or a portion of a tax credit begins

1 to increase under this subsection on January 1 of the second calendar year immediately
2 following the calendar year during which the lease expenditure on which the credit is
3 based was incurred, unless that second calendar year is the calendar year for which the
4 credit or portion of a credit is applied against the person's tax liability. A tax credit or a
5 portion of a tax credit stops increasing under this subsection on December 31 of the
6 calendar year immediately preceding the calendar year for which the credit or a
7 portion of the credit is applied against the person's tax liability. An increase in the
8 amount of a tax credit under this subsection has no value except as applied against the
9 person's tax liability within the time period described in (p)(2) of this section.

10 (s) A tax credit or a portion of a tax credit subject to (p)(1) of this section does
11 not increase under (r) of this section for a period during or after a calendar year for
12 which the credit or portion of the credit could have been applied against a person's tax
13 liability. For purposes of this subsection, the portion of a tax credit subject to (p)(1) of
14 this section that could have been applied against a person's tax liability for a calendar
15 year is determined by performing the following calculation, as applicable:

16 (1) subtract the amount, if any, of the person's tax credits under
17 AS 43.55.019 and 43.55.024 that has been applied against the person's tax liability for
18 the calendar year under AS 43.55.011(e) from the amount, if any, of that tax; if the
19 remainder is less than zero, the portion of the tax credit subject to (p)(1) of this section
20 that could have been applied against a person's tax liability for the calendar year is
21 zero;

22 (2) if the remainder obtained under (1) of this subsection is greater
23 than zero, subtract that remainder from the total amount of the person's tax credits
24 under (b) of this section that are based on lease expenditures incurred after
25 December 31, 2013, to explore for, develop, or produce oil or gas deposits located
26 north of 68 degrees North latitude that was available, without regard to the limitation
27 under (q) of this section, to be applied against the person's tax liability for the calendar
28 year under AS 43.55.011(e), including any increase in the amount of the tax credits
29 under (r) of this section through December 31 of the previous calendar year; if the
30 remainder is less than zero, the portion of the tax credit is considered to be equal to
31 zero for purposes of this paragraph;

1 (3) subtract the remainder obtained under (2) of this subsection from
2 the amount, if any, of the person's tax credits under (b) of this section that are based on
3 lease expenditures incurred after December 31, 2013, to explore for, develop, or
4 produce oil or gas deposits located north of 68 degrees North latitude that was
5 available, without regard to the limitation under (q) of this section, to be applied
6 against the tax levied on the person for the calendar year under AS 43.55.011(e),
7 including any increase in the amount of the tax credits under (r) of this section through
8 December 31 of the previous calendar year, but that was not applied against that tax;
9 the remainder is the portion of a tax credit subject to (p)(1) of this section that could
10 have been applied against the person's tax liability for the calendar year.

11 (t) A tax credit under (b) of this section based on a lease expenditure incurred
12 after December 31, 2013, to explore for, develop, or produce oil or gas deposits
13 located north of 68 degrees North latitude is not transferable except as provided in this
14 subsection. A person that is entitled to take a tax credit under (b) of this section based
15 on a lease expenditure incurred after December 31, 2013, to explore for, develop, or
16 produce oil or gas deposits located north of 68 degrees North latitude may transfer the
17 tax credit to another person that acquires from the transferor an operating right,
18 operating interest, or working interest in a lease or property in the state that includes
19 land north of 68 degrees North latitude in which the transferor owned an operating
20 right, operating interest, or working interest at the time the lease expenditure was
21 incurred. A transferee may transfer the tax credit to another person that acquires from
22 the transferee an operating right, operating interest, or working interest in that lease or
23 property. A transferee's use of a tax credit is subject to the provisions of (u) of this
24 section. A transfer is conditioned on the filing with the department by the transferor
25 and transferee of notices or a joint notice in a form and manner prescribed by the
26 department and the providing of information and certifications required by the
27 department by regulation. A transferee's application of a tax credit against the
28 transferee's production tax liability is subject to audit by the department to the same
29 extent as a tax credit that has not been transferred.

30 (u) The provisions of this subsection apply to a tax credit under (b) of this
31 section based on a lease expenditure incurred after December 31, 2013, to explore for,

1 develop, or produce oil or gas deposits located north of 68 degrees North latitude
2 when the tax credit is used by a producer to which the tax credit has been transferred
3 under (t) of this section, by a producer or the successor of a producer that has acquired
4 the person that incurred the lease expenditure on which the tax credit is based, or by a
5 producer or the successor of a producer created by the merger of the person that
6 incurred the lease expenditures on which the tax credit is based with another person.
7 The total amount of a producer's tax credits subject to this subsection that may be
8 applied against the producer's tax liability under AS 43.55.011(e) for a calendar year
9 may not exceed 20 percent of the sum of the amounts calculated by applying the
10 following formula for each lease or property in the state that includes land north of 68
11 degrees North latitude from which the producer produces oil or gas during the
12 calendar year and in which the person that incurred the lease expenditure on which the
13 tax credit is based had owned an operating right, operating interest, or working interest
14 when the lease expenditure was incurred:

15 GV X OS

16 where GV = the gross value at the point of production of the oil and gas taxable under
17 AS 43.55.011(e) produced by the producer during the calendar year from the lease or
18 property; and OS = the percentage operating right, operating interest, or working
19 interest in the lease or property that had been owned by the person that incurred the
20 lease expenditure on which the tax credit is based when the lease expenditure was
21 incurred.

22 (v) A person may not apply for a tax credit under (b) of this section in an
23 amount that exceeds the amount of the credit claimed under (b) of this section in the
24 immediately preceding calendar year.

25 * **Sec. 24.** AS 43.55.024(d) is amended to read:

26 (d) A producer may not take a tax credit under (c) of this section for any
27 calendar year after the later of

28 (1) 2022 [2016]; or

29 (2) if the producer did not have commercial oil or gas production from
30 a lease or property in the state before April 1, 2006, the ninth calendar year after the
31 calendar year during which the producer first has commercial oil or gas production

1 before May 1, 2022 [2016], from at least one lease or property in the state.

2 * **Sec. 25.** AS 43.55.024(e) is amended to read:

3 (e) On written application by a producer that includes any information the
4 department may require, the department shall determine whether the producer
5 qualifies for a calendar year under (a) and (c) of this section. To qualify under (a) and
6 (c) of this section, a producer must demonstrate that its operation in the state or its
7 ownership of an interest in a lease or property in the state as a distinct producer would
8 not result in the division among multiple producer entities of any production tax
9 liability under AS 43.55.011(e) that reasonably would be expected to be attributed to a
10 single producer if the tax credit provisions of (a) or (c) of this section did not exist.

11 * **Sec. 26.** AS 43.55.024 is amended by adding a new subsection to read:

12 (i) A producer may apply a tax credit of \$5 for each barrel of oil taxable under
13 AS 43.55.011(e) produced during a calendar year against the producer's tax liability
14 for the calendar year under AS 43.55.011(e). A tax credit authorized by this subsection
15 may not reduce a producer's tax liability for a calendar year under AS 43.55.011(e) to
16 below zero.

17 * **Sec. 27.** AS 43.55.025(b) is amended to read:

18 (b) To qualify for the production tax credit under (a) of this section, an
19 exploration expenditure must be incurred for work performed after June 30, 2008, and
20 before July 1, 2022 [2016], and

21 (1) may be for seismic or other geophysical exploration costs not
22 connected with a specific well;

23 (2) if for an exploration well,

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

26 (B) may be for either a well that encounters an oil or gas
27 deposit or a dry hole;

28 (C) must be for a well that has been completed, suspended, or
29 abandoned at the time the explorer claims the tax credit under (f) of this
30 section; and

31 (D) must be for goods, services, or rentals of personal property

1 reasonably required for the surface preparation, drilling, casing, cementing,
2 and logging of an exploration well, and, in the case of a dry hole, for the
3 expenses required for abandonment if the well is abandoned within 18 months
4 after the date the well was spudded;

5 (3) may not be for administration, supervision, engineering, or lease
6 operating costs; geological or management costs; community relations or
7 environmental costs; bonuses, taxes, or other payments to governments related to the
8 well; costs, including repairs and replacements, arising from or associated with fraud,
9 wilful misconduct, gross negligence, criminal negligence, or violation of law,
10 including a violation of 33 U.S.C. 1319(c)(1) or 1321(b)(3) (Clean Water Act); or
11 other costs that are generally recognized as indirect costs or financing costs; and

12 (4) may not be incurred for an exploration well or seismic exploration
13 that is included in a plan of exploration or a plan of development for any unit before
14 May 14, 2003.

15 * **Sec. 28.** AS 43.55.025(c) is amended to read:

16 (c) To be eligible for a production tax credit authorized by (a)(1), (3), or (6) of
17 this section, exploration expenditures must

18 (1) qualify under (b) of this section; and

19 (2) be for an exploration well, subject to the following:

20 (A) before the well is spudded,

21 (i) the explorer shall submit to the commissioner of
22 natural resources the information necessary to determine whether the
23 geological objective of the well is a potential oil or gas trap that is
24 distinctly separate from any trap that has been tested by a preexisting
25 well;

26 (ii) at the time of the submittal of information under (i)
27 of this subparagraph, the commissioner of natural resources may
28 request from the explorer that specific data sets, ancillary data, and
29 reports including all results, and copies of well data collected and data
30 analyses for the well be provided to the Department of Natural
31 Resources upon completion of the drilling; in this sub-subparagraph,

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31

well data include all analyses conducted on physical material, and well logs collected from the well and sample analyses; testing geophysical and velocity data including vertical seismic profiles and check shot surveys; testing data and analyses; age data; geochemical analyses; and access to tangible material; and

(iii) the commissioner of natural resources must make an affirmative determination as to whether the geological objective of the well is a potential oil or gas trap that is distinctly separate from any trap that has been tested by a preexisting well and what information under (ii) of this subparagraph must be submitted by the explorer after completion, abandonment, or suspension under AS 31.05.030; the commissioner of natural resources shall make that determination within 60 days after receiving all the necessary information from the explorer based on the information received and on other information the commissioner of natural resources considers relevant;

(B) [FOR AN EXPLORATION WELL OTHER THAN A WELL TO EXPLORE A COOK INLET PROSPECT, THE WELL MUST BE LOCATED AND DRILLED IN SUCH A MANNER THAT THE BOTTOM HOLE IS LOCATED NOT LESS THAN THREE MILES AWAY FROM THE BOTTOM HOLE OF A PREEXISTING WELL DRILLED FOR OIL OR GAS, IRRESPECTIVE OF WHETHER THE PREEXISTING WELL HAS BEEN COMPLETED, SUSPENDED, OR ABANDONED;

(C)] after completion, suspension, or abandonment under AS 31.05.030 of the exploration well, the commissioner of natural resources must determine that the well was consistent with achieving the explorer's stated geological objective.

* **Sec. 29.** AS 43.55.025 is amended by adding a new subsection to read:

(q) An exploration expenditure incurred after December 31, 2013, to explore for oil or gas located north of 68 degrees North latitude that is the basis for a credit under (a)(1), (2), or (3) of this section may not also be the basis for a credit claimed under AS 43.55.023 or this section.

1 * **Sec. 30.** 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)** [(m)] or to whom a production tax credit certificate has been issued
5 under 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 for
11 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 purchase is consistent with this section and regulations adopted
19 under this section.

20 * **Sec. 31.** AS 43.55.028(g) is amended to read:

21 (g) The department may adopt regulations to carry out the purposes of this
22 section, including standards and procedures to allocate available money among
23 applications for purchases under this chapter and claims for refunds and payments
24 under AS 43.20.046 or 43.20.047 when the total amount of the applications for
25 purchase and claims for refund exceed the amount of available money in the fund. The
26 regulations adopted by the department may not, when allocating available money in
27 the fund under this section, distinguish an application for the purchase of a credit
28 certificate issued under **former** AS 43.55.023(m) or a claim for a refund or payment
29 under AS 43.20.046 or 43.20.047.

30 * **Sec. 32.** AS 43.55.030(e) is amended to read:

31 (e) An explorer or producer that incurs a lease expenditure under

1 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar
 2 year but does not produce oil or gas from a lease or property in the state during the
 3 calendar year shall file with the department, on March 31 of the following year, a
 4 statement, under oath, in a form prescribed by the department, giving, with other
 5 information required, the following:

6 (1) the explorer's or producer's qualified capital expenditures, as
 7 defined in AS 43.55.023, other lease expenditures under AS 43.55.165, and
 8 adjustments or other payments or credits under AS 43.55.170; and

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

12 * **Sec. 33.** AS 43.55.030 is amended by adding a new subsection to read:

13 (g) A person that intends to carry forward a tax credit subject to
 14 AS 43.55.023(p)(1) so that the credit will be available to be applied against the
 15 person's tax liability for a calendar year that is two or more calendar years later than
 16 the calendar year during which the lease expenditure on which the credit is based was
 17 incurred, subject to the limitation of AS 43.55.023(p)(2), shall file with the department
 18 a statement, under oath, in a form prescribed by the department, on March 31 of the
 19 year immediately following the calendar year during which the lease expenditure on
 20 which the credit is based was incurred, and on March 31 of each subsequent year,
 21 including the last calendar year for which the credit or a portion of the credit is applied
 22 against the person's tax liability. The statement must include

23 (1) documentation of the nature and amount of adjusted lease
 24 expenditures for which a credit is claimed and intended to be carried forward, unless
 25 provided in a previously filed statement under this subsection;

26 (2) calculation of the amount of the claimed credit, unless provided in
 27 a previously filed statement under this subsection, and of any increase in an amount of
 28 credit under AS 43.55.023(r) and documentation of compliance with the limitations
 29 provided in AS 43.55.023(s);

30 (3) identification of the portion of the credit that was applied against
 31 the person's tax liability for the calendar year preceding the year for which the

1 statement is due and of the amount of the credit that continues to be carried forward;

2 (4) other information required by the department.

3 * **Sec. 34.** AS 43.55.160(a) is amended to read:

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

5 (1) AS 43.55.011(e), the annual production tax value of the taxable oil,
6 gas, or oil and gas subject to this paragraph produced during a calendar year is the
7 gross value at the point of production of the oil, gas, or oil and gas taxable under
8 AS 43.55.011(e), less the producer's lease expenditures under AS 43.55.165 for the
9 calendar year applicable to the oil, gas, or oil and gas, as applicable, produced by the
10 producer from leases or properties, as adjusted under AS 43.55.170; this paragraph
11 applies to

12 (A) oil and gas produced from leases or properties in the state
13 that include land north of 68 degrees North latitude, other than gas produced
14 before 2022 and used in the state;

15 (B) oil and gas produced from leases or properties in the state
16 outside the Cook Inlet sedimentary basin, no part of which is north of 68
17 degrees North latitude; this subparagraph does not apply to [GAS]

18 (i) gas produced before 2022 and used in the state; or

19 (ii) oil and gas subject to AS 43.55.011(p);

20 (C) oil produced before 2022 from each [A] lease or property
21 in the Cook Inlet sedimentary basin;

22 (D) gas produced before 2022 from each [A] lease or property
23 in the Cook Inlet sedimentary basin;

24 (E) gas produced before 2022 from each [A] lease or property
25 in the state outside the Cook Inlet sedimentary basin and used in the state,
26 other than gas subject to AS 43.55.011(p);

27 (F) oil and gas subject to AS 43.55.011(p) produced from
28 leases or properties in the state;

29 (G) oil and gas produced from a lease or property in the state
30 no part of which is north of 68 degrees North latitude, other than oil or gas
31 described in (B), (C), (D), (E), or (F) of this paragraph;

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

2 (A) oil and gas produced during a month from leases or
3 properties in the state that include land north of 68 degrees North latitude is the
4 gross value at the point of production of the oil and gas taxable under
5 AS 43.55.011(e) and produced by the producer from those leases or properties,
6 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
7 calendar year applicable to the oil and gas produced by the producer from
8 those leases or properties, as adjusted under AS 43.55.170; this subparagraph
9 does not apply to gas subject to AS 43.55.011(o);

10 (B) oil and gas produced during a month from leases or
11 properties in the state outside the Cook Inlet sedimentary basin, no part of
12 which is north of 68 degrees North latitude, is the gross value at the point of
13 production of the oil and gas taxable under AS 43.55.011(e) and produced by
14 the producer from those leases or properties, less 1/12 of the producer's lease
15 expenditures under AS 43.55.165 for the calendar year applicable to the oil and
16 gas produced by the producer from those leases or properties, as adjusted under
17 AS 43.55.170; this subparagraph does not apply to gas subject to
18 AS 43.55.011(o);

19 (C) oil produced during a month from a lease or property in the
20 Cook Inlet sedimentary basin is the gross value at the point of production of
21 the oil taxable under AS 43.55.011(e) and produced by the producer from that
22 lease or property, less 1/12 of the producer's lease expenditures under
23 AS 43.55.165 for the calendar year applicable to the oil produced by the
24 producer from that lease or property, as adjusted under AS 43.55.170;

25 (D) gas produced during a month from a lease or property in
26 the Cook Inlet sedimentary basin is the gross value at the point of production
27 of the gas taxable under AS 43.55.011(e) and produced by the producer from
28 that lease or property, less 1/12 of the producer's lease expenditures under
29 AS 43.55.165 for the calendar year applicable to the gas produced by the
30 producer from that lease or property, as adjusted under AS 43.55.170;

31 (E) gas produced during a month from a lease or property

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

7 * **Sec. 35.** AS 43.55.160(a) is repealed and reenacted to read:

8 (a) Except as provided in (b) and (f) of this section, for the purposes of
9 AS 43.55.011(e), the annual production tax value of taxable oil, gas, or oil and gas
10 produced by a producer during a calendar year in a specific category for which a
11 separate production tax value is required to be calculated under this subsection is equal
12 to the gross value at the point of production of that oil, gas, or oil and gas,
13 respectively, taxable under AS 43.55.011(e), less the producer's lease expenditures
14 under AS 43.55.165 for the calendar year that are applicable to the oil, gas, or oil and
15 gas, respectively, in that category produced by the producer during the calendar year,
16 as adjusted under AS 43.55.170. A separate annual production tax value must be
17 calculated for

18 (1) oil and gas produced from leases or properties in the state that
19 include land north of 68 degrees North latitude, other than gas produced before 2022
20 and used in the state;

21 (2) oil and gas produced from leases or properties in the state outside
22 the Cook Inlet sedimentary basin, no part of which is north of 68 degrees North
23 latitude, during a calendar year before or during the last calendar year under
24 AS 43.55.024(b) for which the producer could take a tax credit under
25 AS 43.55.024(a); this paragraph does not apply to

26 (A) gas produced before 2022 and used in the state; or

27 (B) oil and gas subject to AS 43.55.011(p);

28 (3) oil produced before 2022 from each lease or property in the Cook
29 Inlet sedimentary basin;

30 (4) gas produced before 2022 from each lease or property in the Cook
31 Inlet sedimentary basin;

1 (5) gas produced before 2022 from each lease or property in the state
2 outside the Cook Inlet sedimentary basin and used in the state, other than gas subject
3 to AS 43.55.011(p);

4 (6) oil and gas subject to AS 43.55.011(p) produced from leases or
5 properties in the state;

6 (7) oil and gas produced from a lease or property in the state no part of
7 which is north of 68 degrees North latitude, other than oil or gas described in (2), (3),
8 (4), (5), or (6) of this subsection.

9 * **Sec. 36.** AS 43.55.160(e) is amended to read:

10 (e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that
11 would otherwise be deductible by a producer in a calendar year but whose deduction
12 would cause an annual production tax value calculated under (a) [(a)(1)] of this
13 section of taxable oil or gas produced during the calendar year to be less than zero
14 may be used to establish a carried-forward annual loss under AS 43.55.023(b).
15 However, the department shall provide by regulation a method to ensure that, for a
16 period for which a producer's tax liability is limited by AS 43.55.011(j), (k), (o), or
17 (p), any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that would
18 otherwise be deductible by a producer for that period but whose deduction would
19 cause a production tax value calculated under (a)(3), (4), (5), or (6) [(a)(1)(C), (D),
20 (E), OR (F)] of this section to be less than zero are accounted for as though the
21 adjusted lease expenditures had first been used as deductions in calculating the
22 production tax values of oil or gas subject to any of the limitations under
23 AS 43.55.011(j), (k), (o), or (p) that have positive production tax values so as to
24 reduce the tax liability calculated without regard to the limitation to the maximum
25 amount provided for under the applicable provision of AS 43.55.011(j), (k), (o), or (p).
26 Only the amount of those adjusted lease expenditures remaining after the accounting
27 provided for under this subsection may be used to establish a carried-forward annual
28 loss under AS 43.55.023(b). In this subsection, "producer" includes "explorer."

29 * **Sec. 37.** AS 43.55.160 is amended by adding a new subsection to read:

30 (f) In the calculation of an annual production tax value of a producer under
31 (a)(1) of this section, the gross value at the point of production of oil or gas from a

1 well meeting one or more of the following criteria is reduced by 20 percent for the 10
2 years following the commencement of production from the well: (1) the oil or gas is
3 produced from a well within a lease or property that does not contain a lease that was
4 within a unit on January 1, 2003; (2) the oil or gas is produced from a well within a
5 participating area established after December 31, 2011, that is within a unit formed
6 under AS 38.05.180(p) before January 1, 2003, if the participating area does not
7 contain a reservoir that had previously been in a participating area established before
8 December 31, 2011; (3) the oil or gas is produced from a well that the producer
9 demonstrates to the department drains a reservoir or portion of a reservoir that the
10 Department of Natural Resources has certified, upon review of a plan of development,
11 was not contributing to production before December 31, 2012. A reduction in gross
12 value at the point of production under this subsection may not reduce the production
13 tax value of a producer below zero. In this subsection, "participating area" means a
14 reservoir or portion of a reservoir contributing to production approved by the
15 Department of Natural Resources.

16 * **Sec. 38.** AS 43.56.160 is amended to read:

17 **Sec. 43.56.160. Interest and penalty.** When the tax levied by AS 43.56.010(a)
18 becomes delinquent, a penalty of 10 percent shall be added. Interest on the delinquent
19 taxes, exclusive of penalty, shall be assessed at the rate specified in AS 43.05.225(1)
20 [A RATE OF EIGHT PERCENT A YEAR].

21 * **Sec. 39.** AS 43.77.020(d) is amended to read:

22 (d) A person subject to the tax under this chapter shall make quarterly
23 payments of the tax estimated to be due for the year, as required under regulations
24 adopted by the department. A taxpayer will be subject to an estimated tax penalty,
25 determined by applying the interest rate specified in AS 43.05.225(1) [AS 43.05.225]
26 to the underpayment for each quarter, unless the taxpayer makes estimated tax
27 payments in equal installments that total either

28 (1) at least 90 percent of the taxpayer's tax liability under this chapter
29 for the tax year; or

30 (2) at least 100 percent of the taxpayer's tax liability under this chapter
31 for the prior tax year.

1 * **Sec. 40.** AS 43.90.430 is amended to read:

2 **Sec. 43.90.430. Interest.** When a payment due to the state under this chapter
3 becomes delinquent, the payment bears interest at the rate applicable to a delinquent
4 tax under AS 43.05.225(1) [AS 43.05.225].

5 * **Sec. 41.** AS 43.55.023(m) is repealed.

6 * **Sec. 42.** AS 43.55.011(g), 43.55.023(i), and 43.55.160(c) are repealed January 1, 2014.

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

9 APPLICABILITY. (a) Sections 9, 12, 13, and 35 - 37 of this Act apply to oil and gas
10 produced after December 31, 2013.

11 (b) Sections 10 and 34 of this Act apply to oil and gas produced after December 31,
12 2012.

13 (c) Sections 15 and 19 - 22 of this Act and AS 43.55.023(a)(1), as amended by sec. 15
14 of this Act, apply to expenditures incurred after December 31, 2012.

15 (d) Sections 16 - 18, 20, 23, 28 - 30, and 33 of this Act apply to expenditures incurred
16 after December 31, 2013.

17 * **Sec. 44.** The uncodified law of the State of Alaska is amending by adding a new section to
18 read:

19 TRANSITION: REGULATIONS. The Department of Revenue may adopt regulations
20 to implement this Act. The regulations take effect under AS 44.62 (Administrative Procedure
21 Act), but not before the effective date of the respective provision of this Act.

22 * **Sec. 45.** The uncodified law of the State of Alaska is amended by adding a new section to
23 read:

24 RETROACTIVITY. Sections 10, 19, 21, 22, 30, 34, and 41 of this Act and
25 AS 43.55.023(a)(1), as amended by sec. 15 of this Act, are retroactive to January 1, 2013.

26 * **Sec. 46.** Sections 1 - 6, 8, 9, 12 - 14, 16 - 18, 20, 23, 25, 26, 28, 29, 33, 35 - 40, and 42 of
27 this Act take effect January 1, 2014.

28 * **Sec. 47.** Except as provided in sec. 46 of this Act, this Act takes effect immediately under
29 AS 01.10.070(c).

15



Senate Finance Committee

CS SB21 Analysis

March 12 2013

Janak Mayer

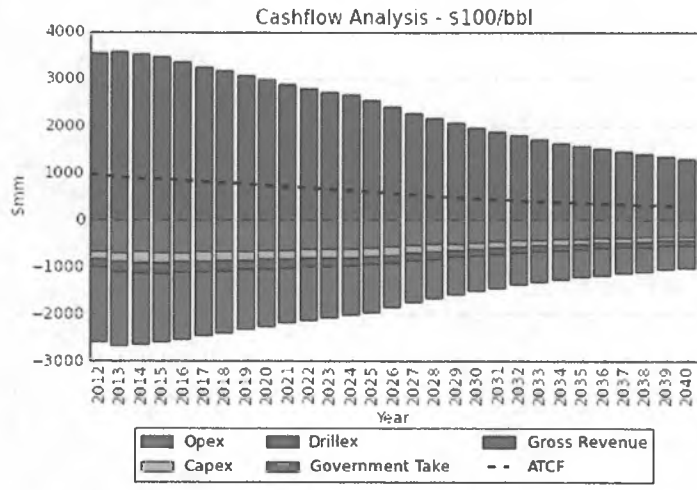
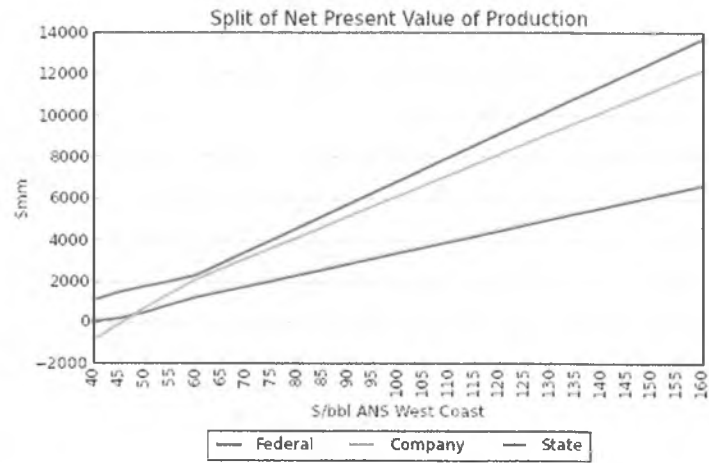
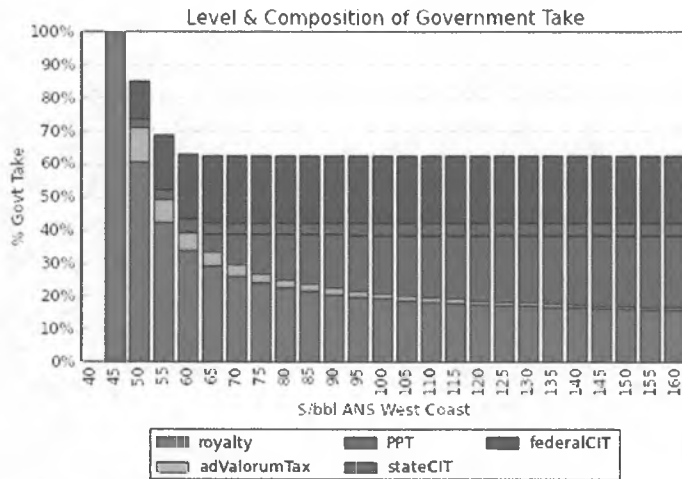
Manager, Upstream

PFC Energy

PFC Energy

Base Production

30% Rate, \$5/bbl Allowance

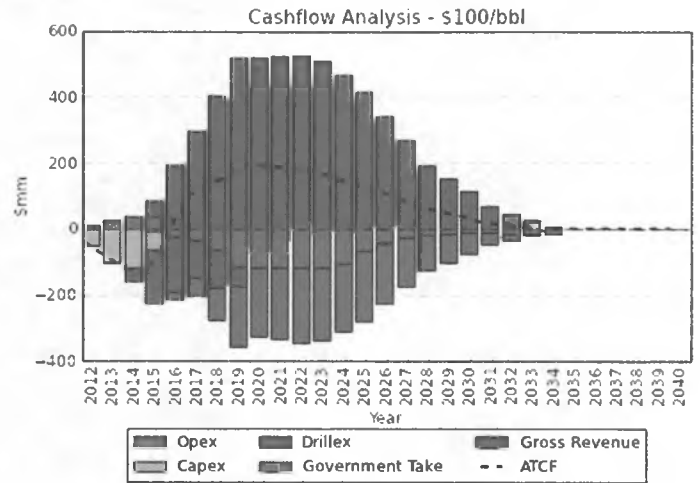
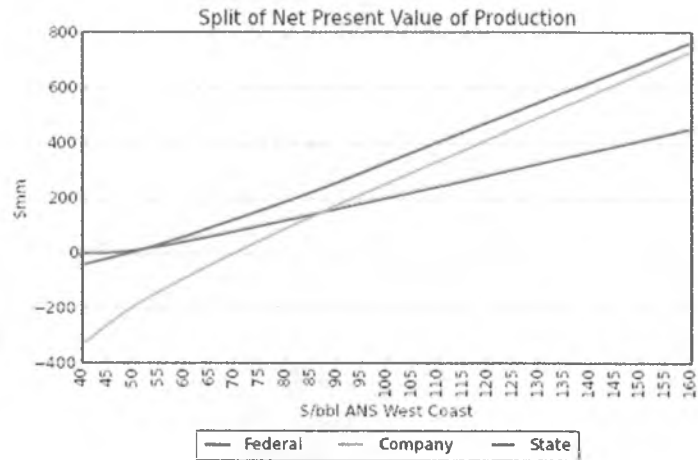
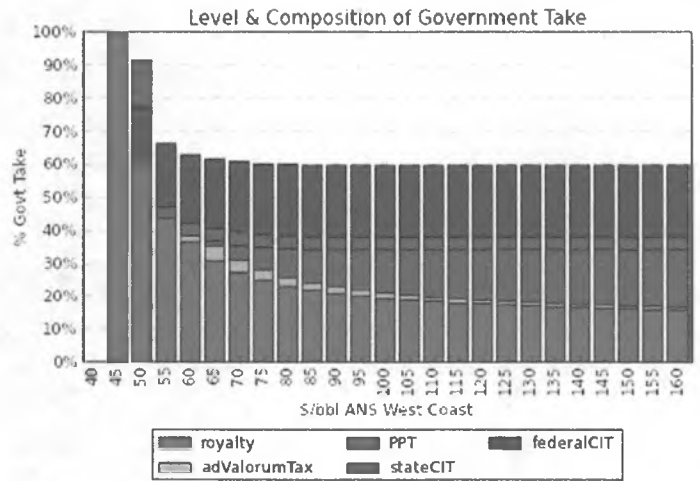


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	62.56%	3.98		17.92
\$100/bbl	62.57%	5.94		26.9
\$120/bbl	62.57%	7.89		35.88
\$140/bbl	62.57%	9.85		44.86

\$18/bbl New Development with GRE, Standalone

30% Rate, \$5/bbl Allowance, 20% GRE

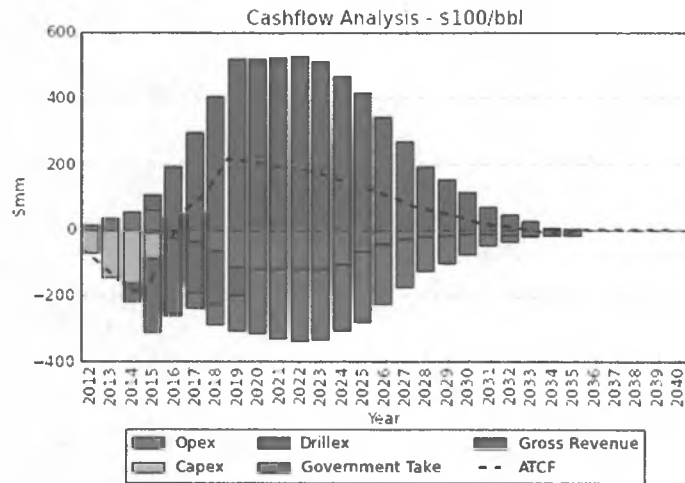
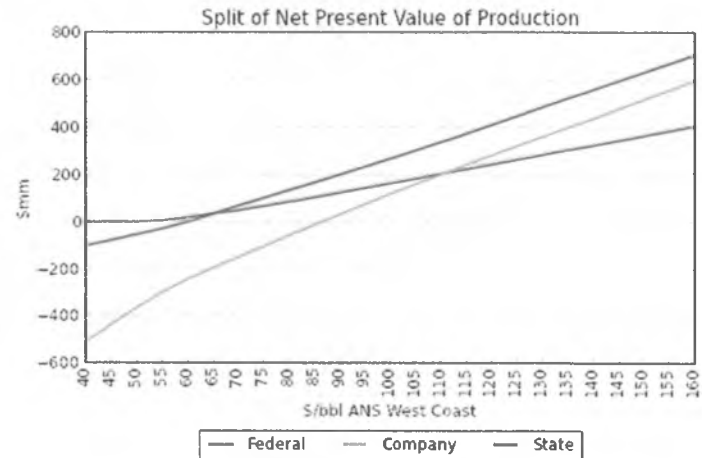
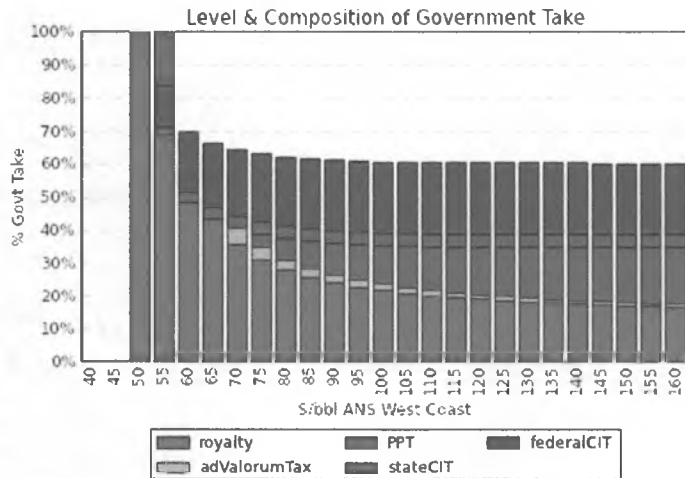


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	60.27%	1.77	16.07%	27.24
\$100/bbl	59.99%	5.05	22.69%	37.02
\$120/bbl	60.02%	8.22	28.25%	46.36
\$140/bbl	59.99%	11.4	33.19%	55.65

\$25/bbl New Development with GRE, Standalone

30% Rate, \$5/bbl Allowance, 20% GRE

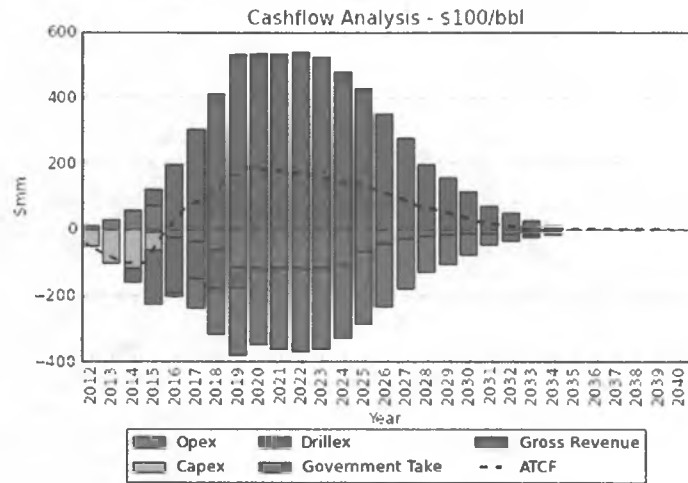
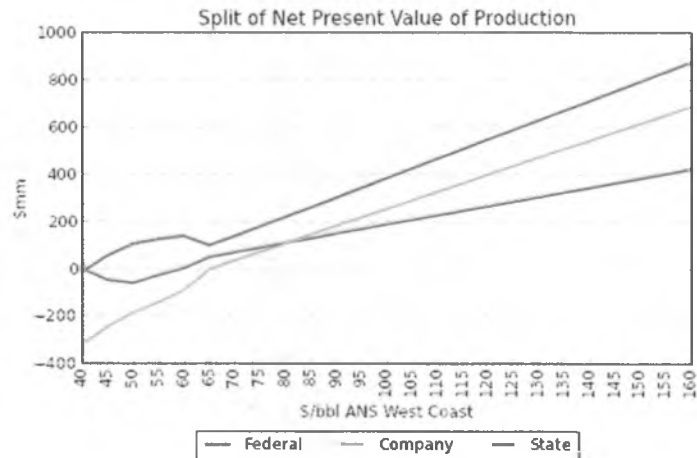
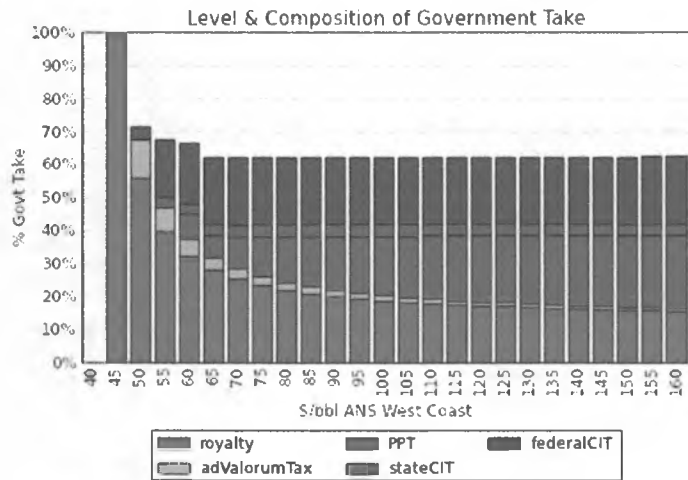


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	62.44%	-1.16	9.95%	27.51
\$100/bbl	60.94%	2.34	15.89%	37.68
\$120/bbl	60.62%	5.6	20.75%	47.3
\$140/bbl	60.56%	8.73	24.89%	56.71

\$18/bbl New Development with GRE, Incremental to Incumbent

30% Rate, \$5/bbl Allowance, 20% GRE

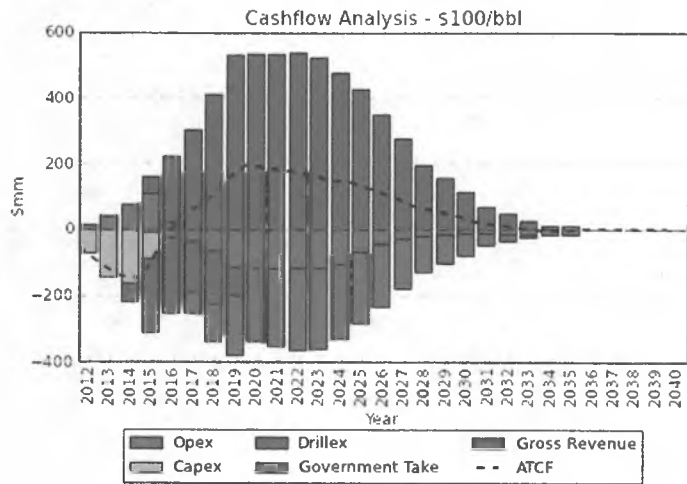
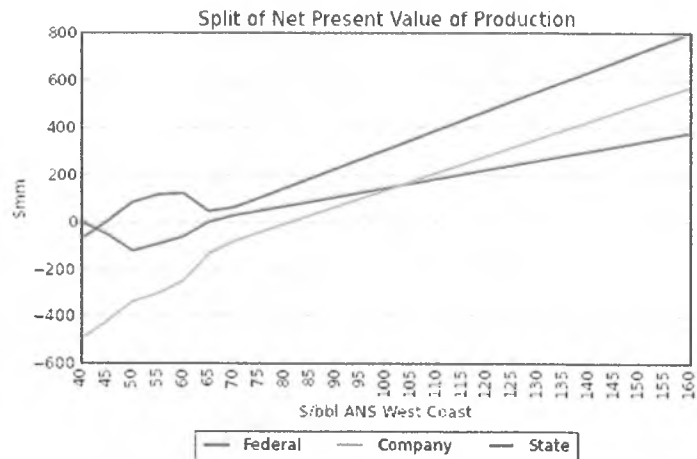
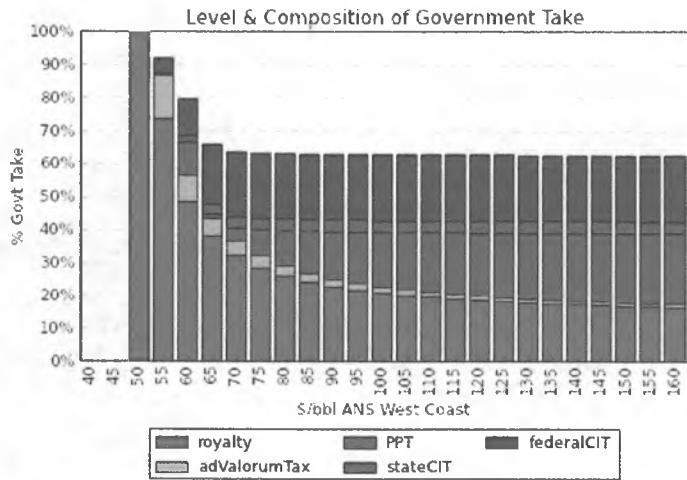


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	62.34%	2.17	17.49%	23.71
\$100/bbl	62.42%	5.06	23.63%	32.77
\$120/bbl	62.46%	7.95	28.89%	41.83
\$140/bbl	62.49%	10.84	33.55%	50.9

\$25/bbl New Development with GRE, Incremental to Incumbent

30% Rate, \$5/bbl Allowance, 20% GRE

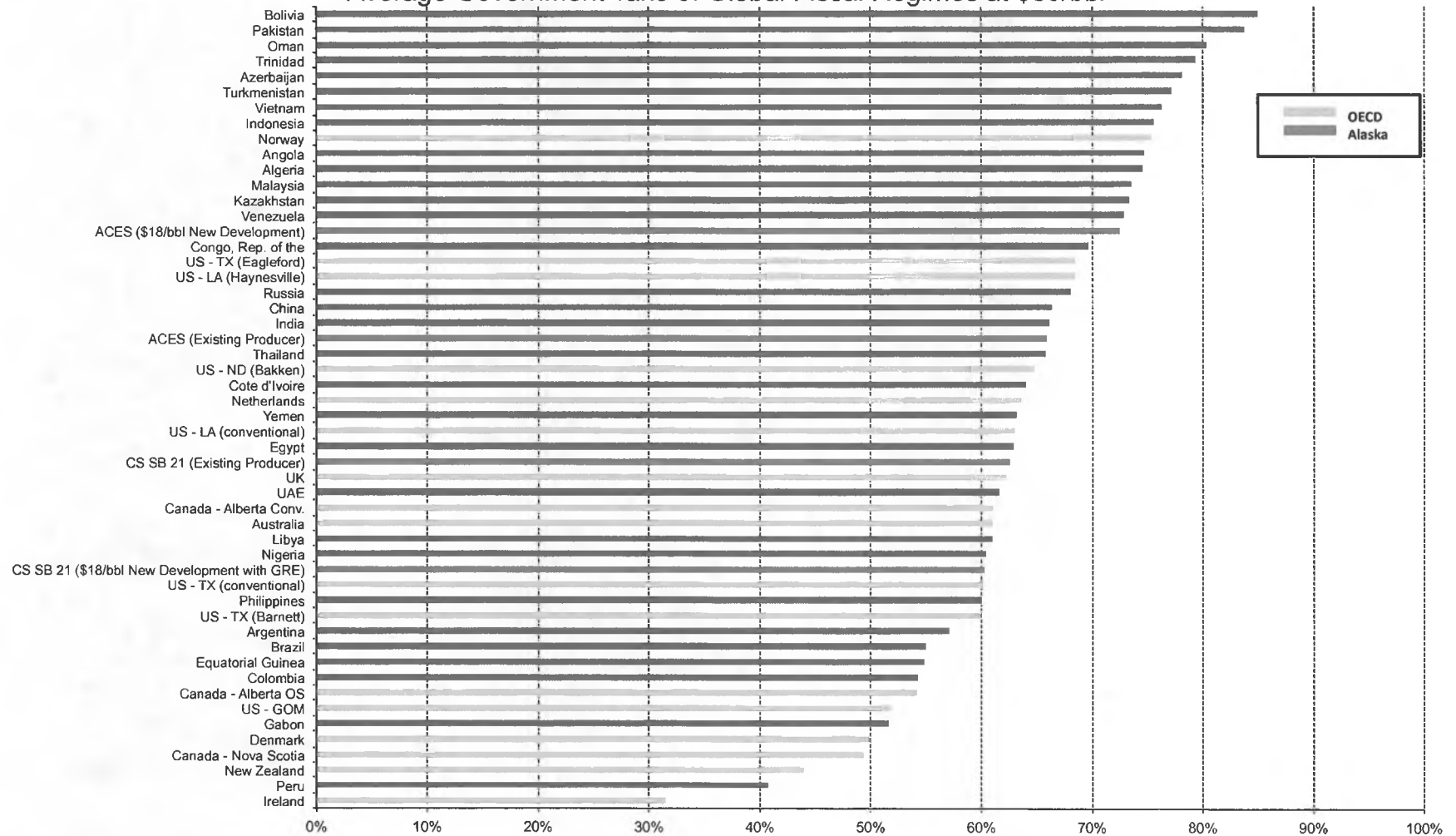


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	63.32%	-0.17	11.65%	23.2
\$100/bbl	63.04%	2.72	16.98%	32.26
\$120/bbl	62.91%	5.6	21.55%	41.33
\$140/bbl	62.84%	8.49	25.60%	50.39

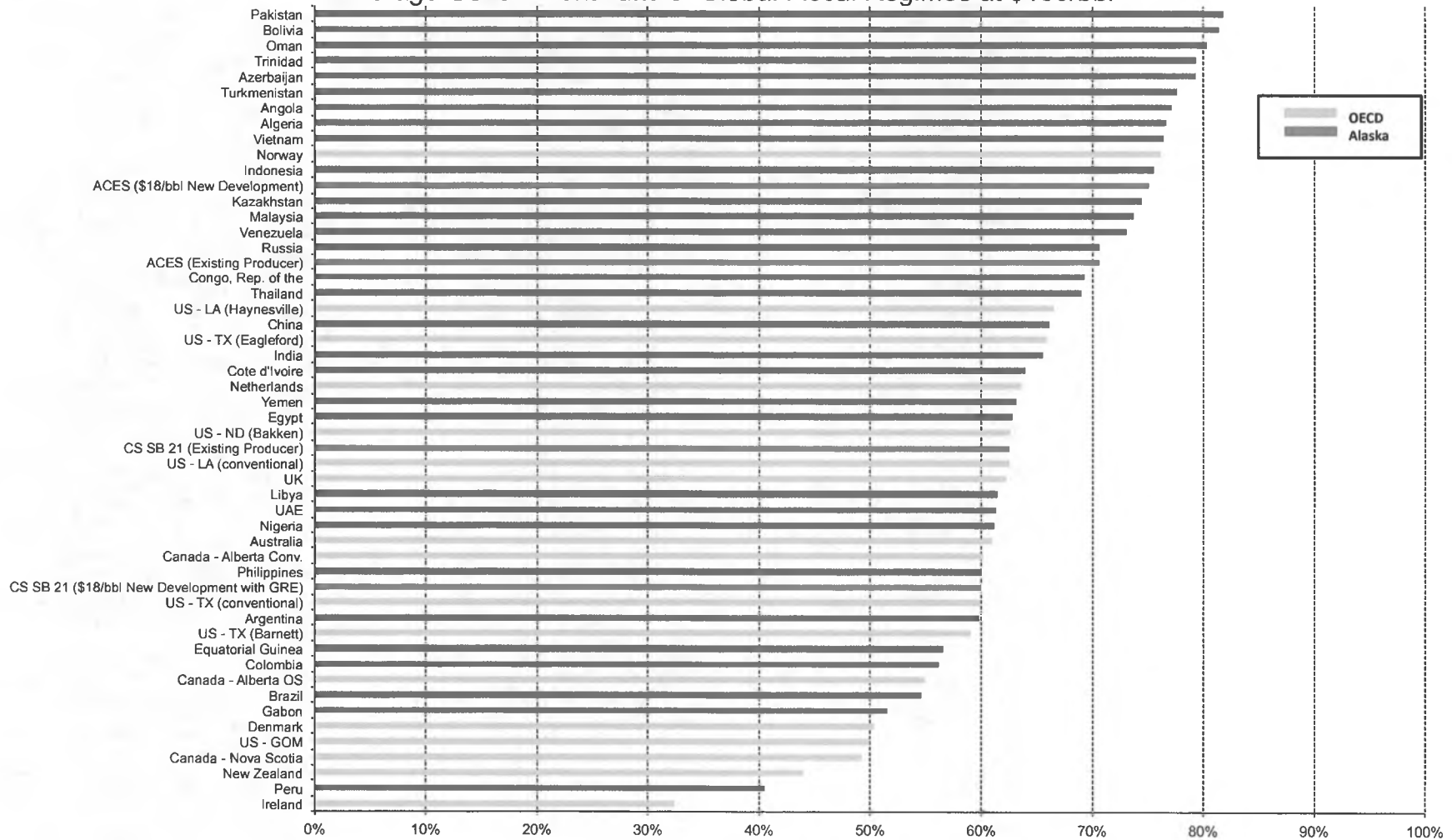
Government Take Competitiveness - \$80/bbl

Average Government Take of Global Fiscal Regimes at \$80/bbl



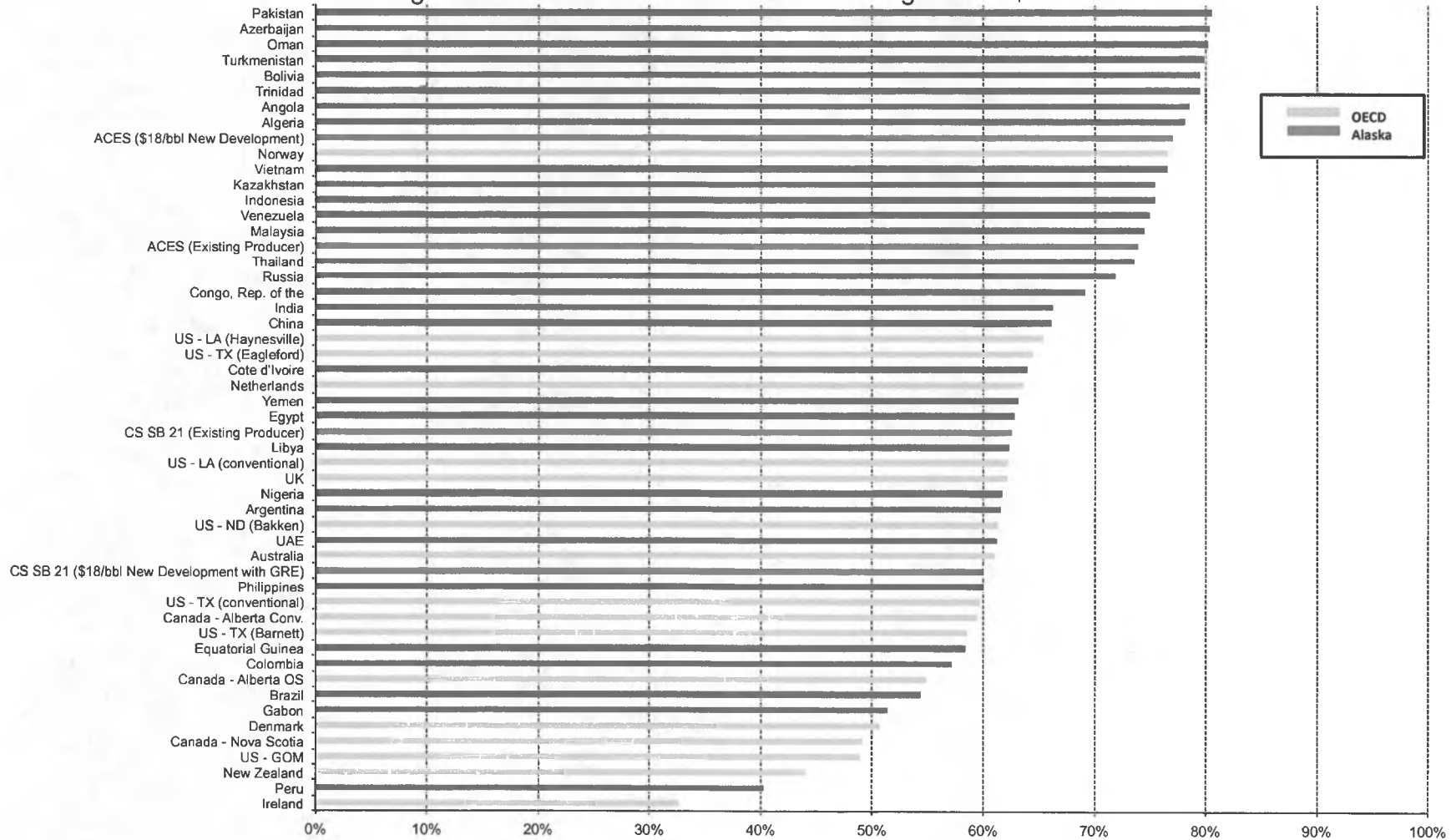
Government Take Competitiveness - \$100/bbl

Average Government Take of Global Fiscal Regimes at \$100/bbl

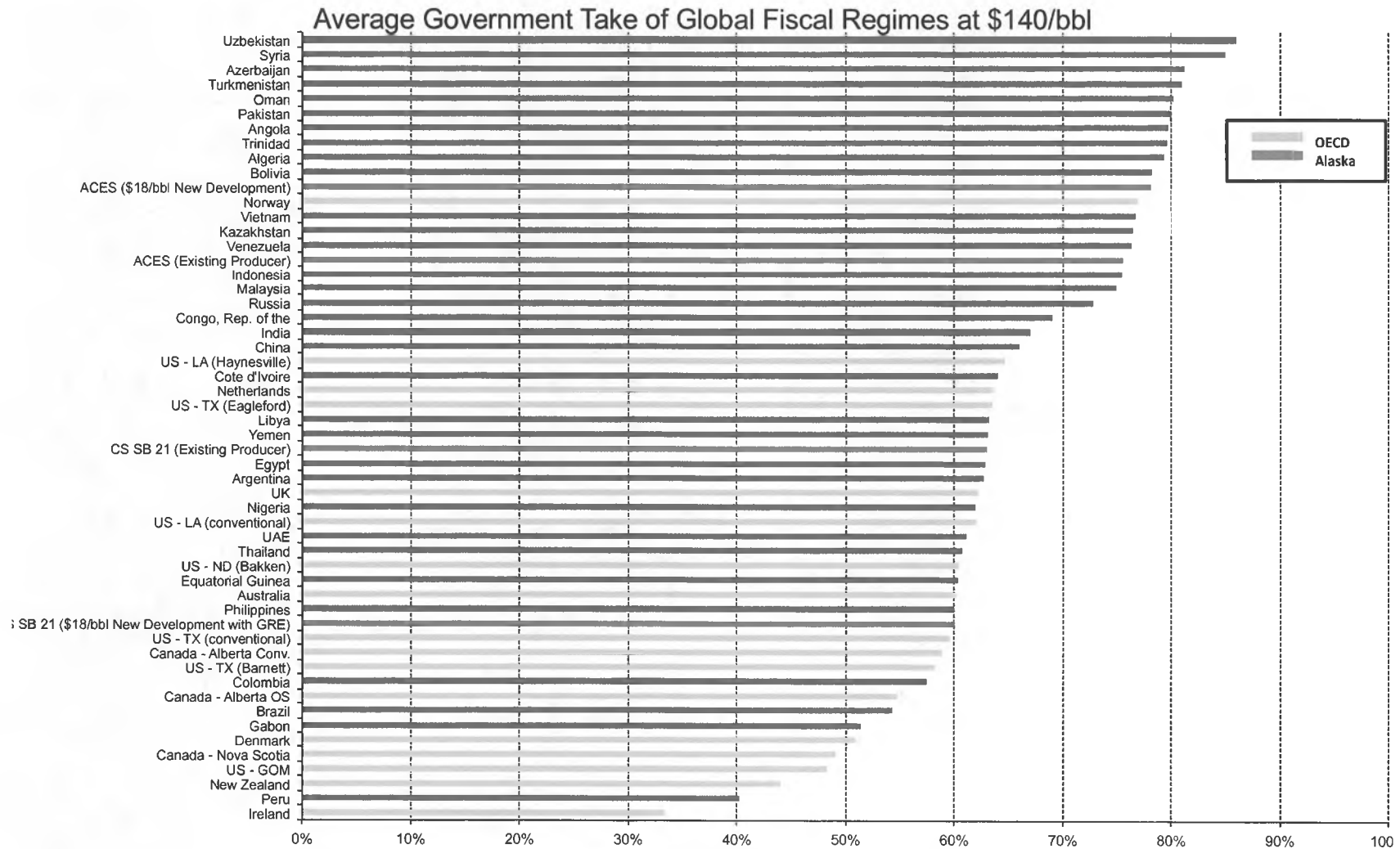


Government Take Competitiveness - \$120/bbl

Average Government Take of Global Fiscal Regimes at \$120/bbl

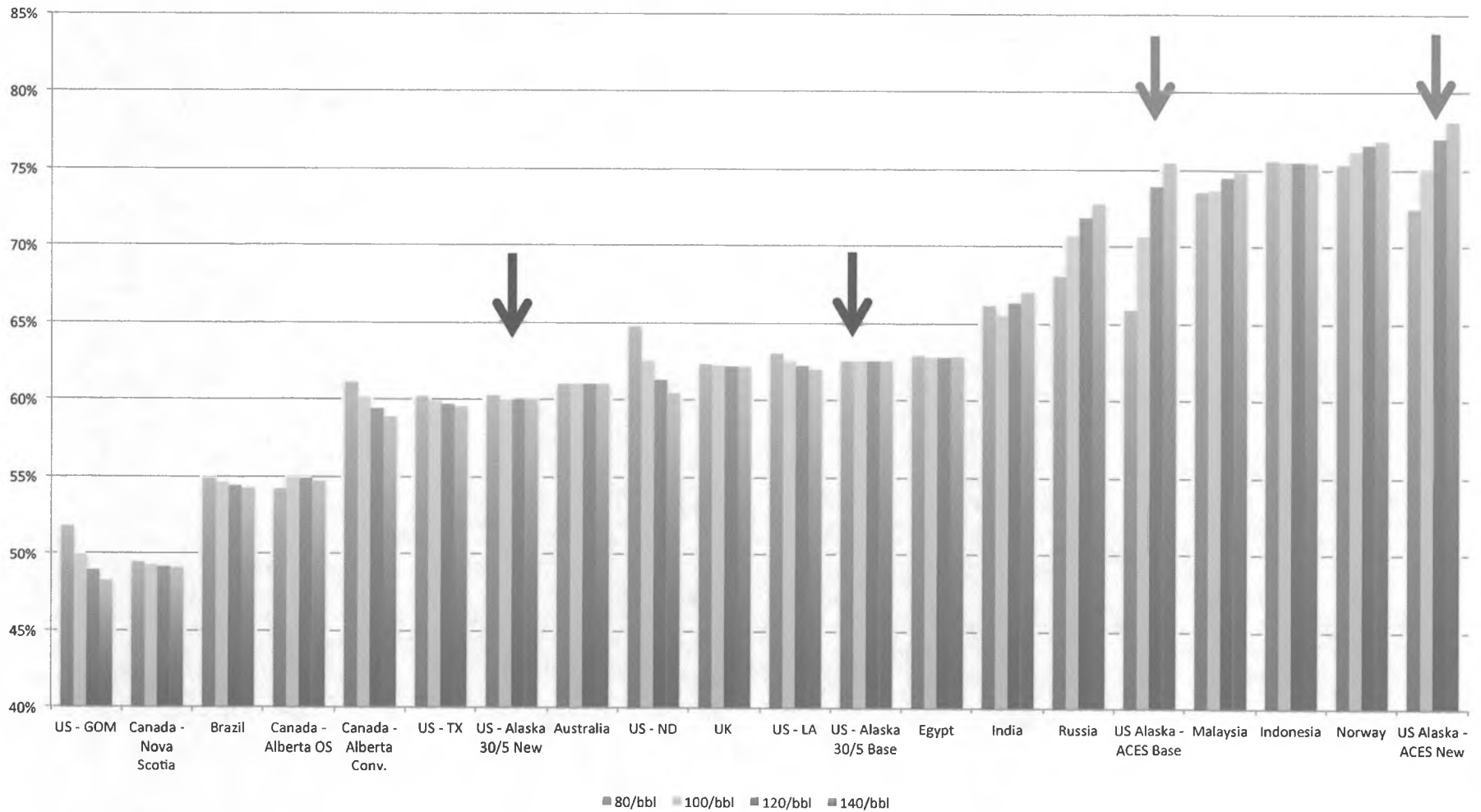


Government Take Competitiveness - \$140/bbl



Government Take Competitiveness

Alaska Government Take Competitiveness - Comparable Regimes



Notice

This material is protected by United States copyright law and applicable international treaties including, but not limited to, the Berne Convention and the Universal Copyright Convention. Except as indicated, the entire content of this publication, including images, text, data, and look and feel attributes, is copyrighted by PFC Energy. PFC Energy strictly prohibits the copying, display, publication, distribution, or modification of any PFC Energy materials without the prior written consent of PFC Energy.

These materials are provided for the exclusive use of PFC Energy clients (and/or registered users), and may not under any circumstances be transmitted to third parties without PFC Energy approval.

PFC Energy has prepared the materials utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice, based on information available at the time such materials were created. To the extent these materials contain forecasts or forward looking statements, such statements are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen, including the actions of governments, individuals, third parties and market competitors. **ACCORDINGLY, THESE MATERIALS AND THE INFORMATION CONTAINED THEREIN ARE PROVIDED "AS IS" WITHOUT WARRANTY OF ANY KIND, EITHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO THE IMPLIED WARRANTIES OF MERCHANTABILITY, ACCURACY, OR FITNESS FOR A PARTICULAR PURPOSE.** Conclusions presented herein are intended for information purposes only and are not intended to represent recommendations on financial transactions such as the purchase or sale of shares in the companies profiled in this report.

PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

© PFC Energy, Inc. License restrictions apply. Distribution to third parties requires prior written consent from PFC Energy.

PFC Energy Locations and Contact Information

NORTH AMERICA

PFC Energy, Washington
1300 Connecticut Avenue, NW
Suite 800
Washington, DC 20036, USA
Tel +1 202 872 1199
Fax +1 202 872 1219

PFC Energy, Houston
2727 Allen Parkway, Suite 1300
Houston, Texas 77019, USA
Tel +1 713 622 4447
Fax +1 713 622 4448

EUROPE

PFC Energy, France
19 rue du Général Foy
75008 Paris, France
Tel +33 1 4770 2900
Fax +33 1 4770 5905

RUSSIA

PFC Energy, Moscow
10 Vozdvizhenka Street
Voentorg building, Suite 341
Moscow, 125009
Russian Federation
Tel +7 (495) 797 3733

ASIA

PFC Energy, Kuala Lumpur
Level 27, UBN Tower #21
10 Jalan P. Ramlee
50250 Kuala Lumpur, Malaysia
Tel +60 3 2172 3400
Fax +60 3 2072 3599

PFC Energy, China
89 Jianguo Road
China Central Place # 4-1602
Chaoyang District, Beijing 100025, China
Tel +86 10 6530 7010
Fax +86 10 6530 5093

PFC Energy, Singapore
15 Scotts Road
Thong Teck Building, #08-04
Singapore 228218
Tel +65 6736 4317

www.pfcenergy.com | info@pfcenergy.com

16

Draft - Provisions in CSSB21(FIN) and their Estimated Fiscal Impact as compared to Fall 2012 Forecast (\$millions)¹

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-\$800	-\$1,500	-\$1,700	-\$1,800	-\$1,750	-\$1,650
2. Base tax rate changed to 30% of production tax value	\$275	\$525	\$550	\$550	\$500	\$475
3. Limitation of credits for qualified capital expenditures for North Slope	\$300	\$700	\$650	\$550	\$475	\$400
4. Net operating loss credit rate increased to 30%, monetizable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for certain wells	\$0 to -\$50	-\$25 to -\$175	-\$25 to -\$225	-\$50 to -\$250	-\$50 to -\$250	-\$50 to -\$250
6. Small producer credit extended to 2022	\$0	\$0	\$0	-\$25	-\$25	-\$50
7. Provision requiring credits be taken over 2 years eliminated ²	-\$250					
8. Amendment to the community revenue sharing fund	\$0	\$0	\$0	\$0	\$0	\$0
9. Allowance of \$5 per taxable barrel	-\$425	-\$825	-\$775	-\$750	-\$700	-\$675
10. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -\$50 million annually)					
11. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -\$25 million annually, increasing over time)					
12. Exploration incentive credit extended to 2022; requirements changed ³	Indeterminate (possibly up to -\$100 million annually)					
Total Revenue Impact	-\$900 to -\$1125	-\$1125 to -\$1450	-\$1300 to -\$1675	-\$1525 to -\$1900	-\$1550 to -\$1925	-\$1550 to -\$1925
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-\$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		\$150	\$150	\$150	\$150	\$150
Impact on Operating Budget of increase in Net Operating Loss credits		-\$25	-\$25	-\$25	-\$25	-\$25
Total Fiscal Impact⁴	-\$1050 to -\$1275	-\$1000 to -\$1325	-\$1175 to -\$1550	-\$1400 to -\$1775	-\$1425 to -\$1800	-\$1425 to -\$1800

Gray shading indicates provisions that changed with the Finance Committee's CS.

¹The impacts listed are based on production and prices as forecasted in our Fall 2012 revenue forecast. The forecasted oil prices are between \$109.61 and \$118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²Provision 7 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is \$400 million, with \$250 million taken against tax liability as a revenue impact and \$150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

³Provision 12 above, which extends and changes requirements for exploration incentive credits, would increase both credits applied against tax liability and credits available for refund. To simplify presentation, the entire impact is shown here as a revenue impact.

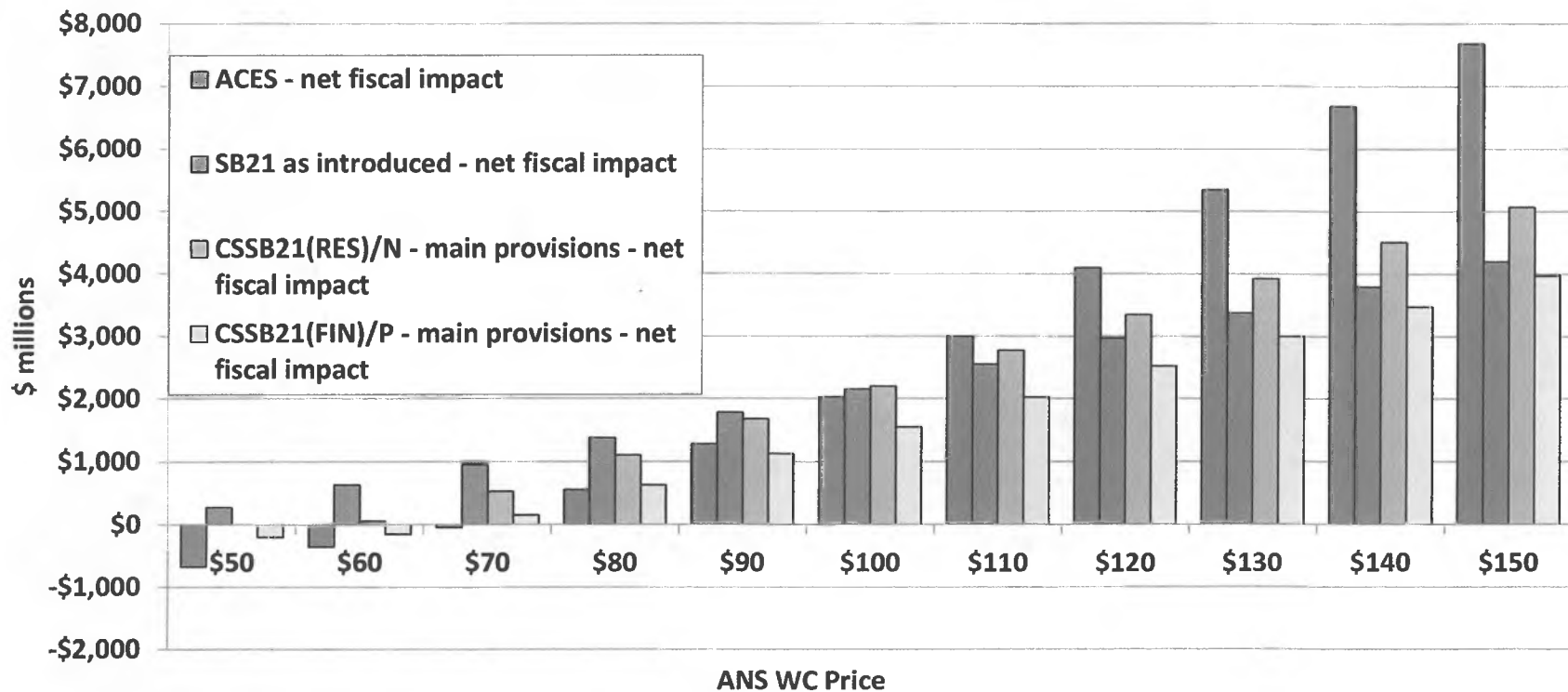
⁴NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope.



Production Tax Revenue, less refunded and carried-forward credits



**FY15 ACES, SB21, CSSB21(RES) and CSSB21(FIN)-
Production Tax Revenue with certain adjustments**



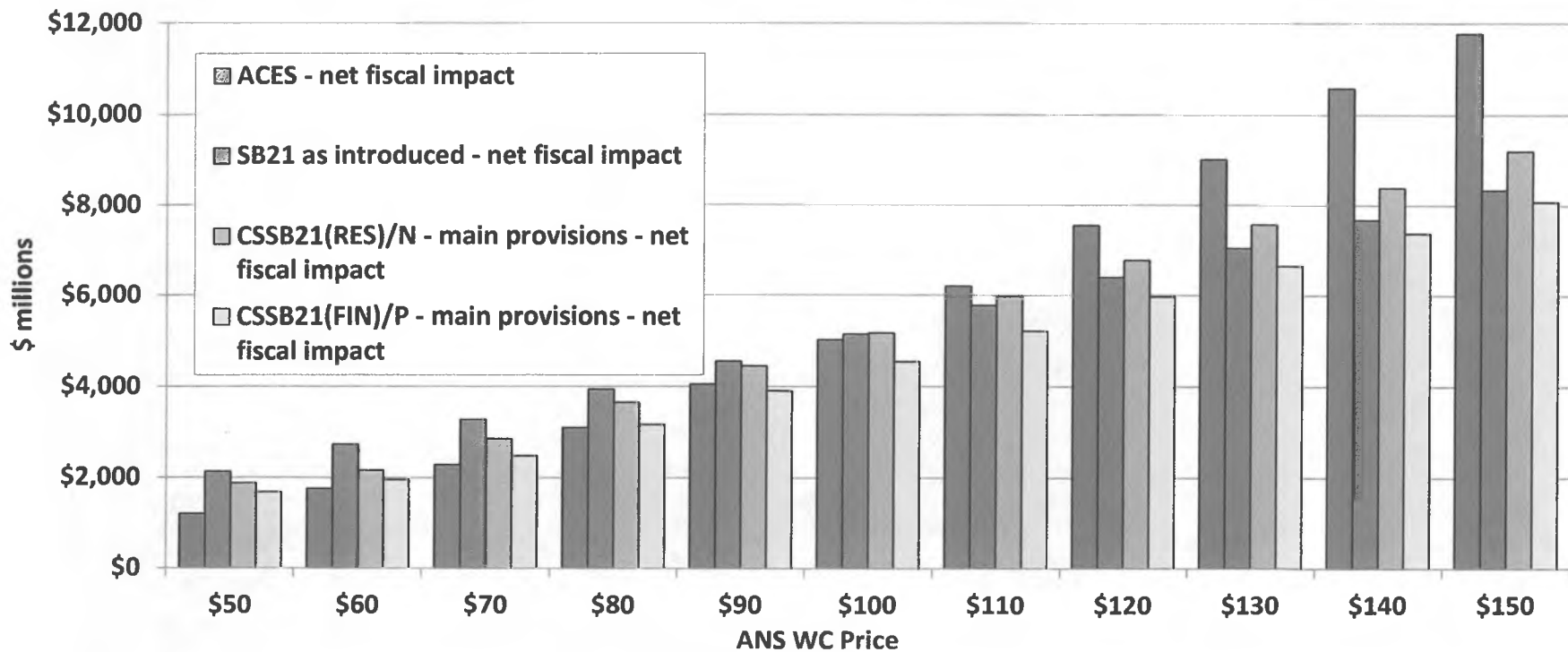
Source: Fall 2012 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. For \$50, also includes expected liability for carried forward credits in excess tax liability for major producers. CSSB21(RES)/N "Main Provisions" does not include impact of new service industry CIT credit, or expansion of exploration credit. CSSB21(FIN)/P "Main Provisions" does not include impact of new service industry CIT credit, or expansion of exploration credit, or reduced interest rate for late payments and assessments on most taxes.



General Fund Unrestricted Revenue, less refunded and carried-forward credits



FY15 ACES, SB21, CSSB21(RES) and CSSB21(FIN)-
GF Unrestricted Revenue with certain adjustments



Source: Fall 2012 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. For \$50, also includes expected liability for carried forward credits in excess tax liability for major producers. CSSB21(RES)/N "Main Provisions" does not include impact of new service industry CIT credit, or expansion of exploration credit. CSSB21(FIN)/P "Main Provisions" does not include impact of new service industry CIT credit, or expansion of exploration credit, or reduced interest rate for late payments and assessments on most taxes.



Production Scenarios



Scenario A:

- New 50 Million barrel field developed by small producer without tax liability
- Peak production = 10,000 bbls/day
- Development costs = \$500,000,000
- Qualifies for GRE and NOL



Production Scenarios



Scenario B:

- Operators of existing units add 4 drill rigs to current plans
- Each rig adds 4,000 bbls/day in new production each year
 - Which each then decline at 15% per year
- Does not qualify for GRE



Production Scenarios



Scenario C:

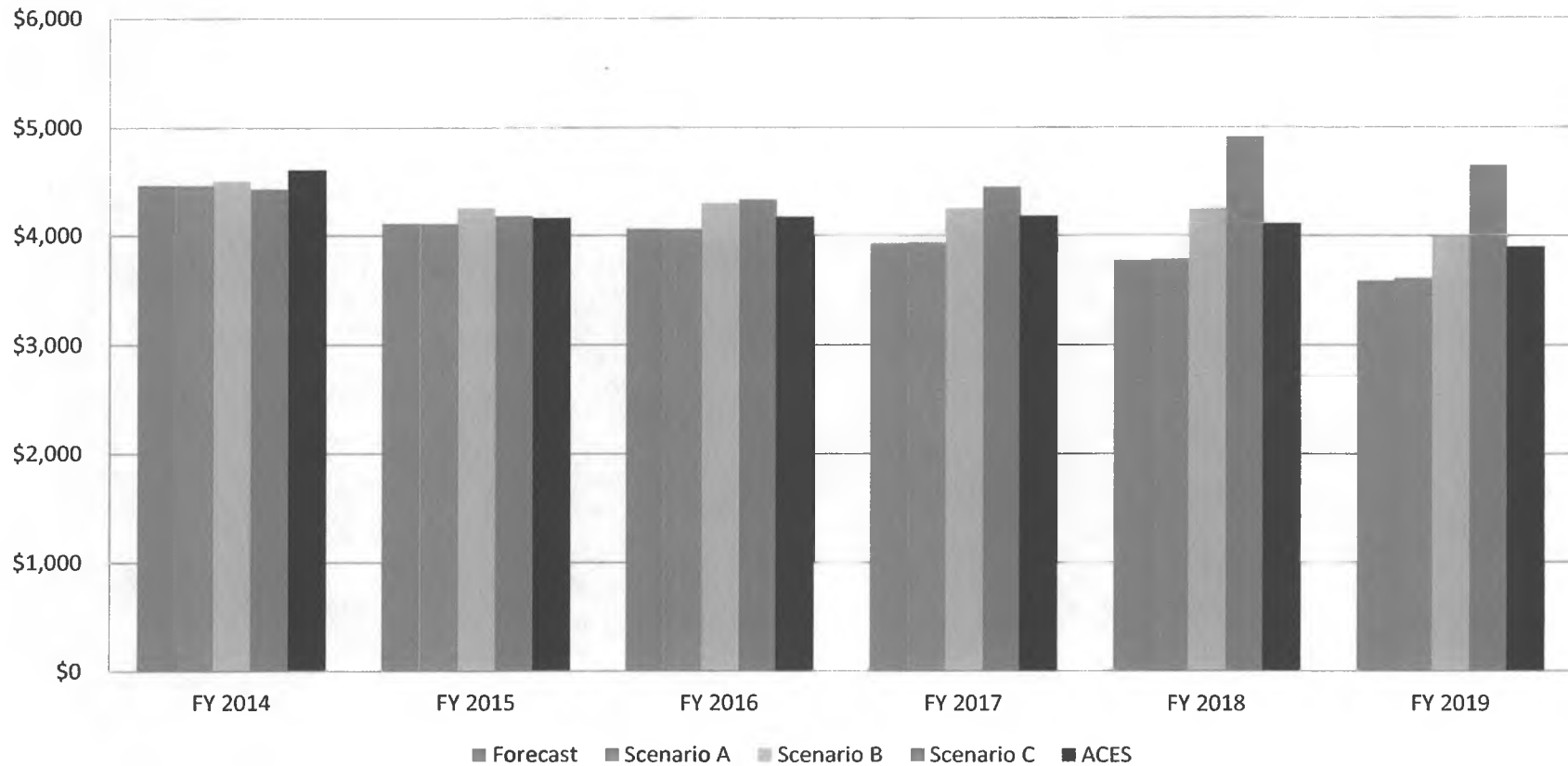
- Operator of existing legacy unit builds new drill pad
- Development cost = \$5 billion
- Adds 15,000 bbls/day in 2014 increasing to peak rate of 90,000 bbls/day in 2018
- Does not qualify for GRE



Projected revenues under production scenarios – at \$90 / barrel ANS



AT \$90 ANS WC



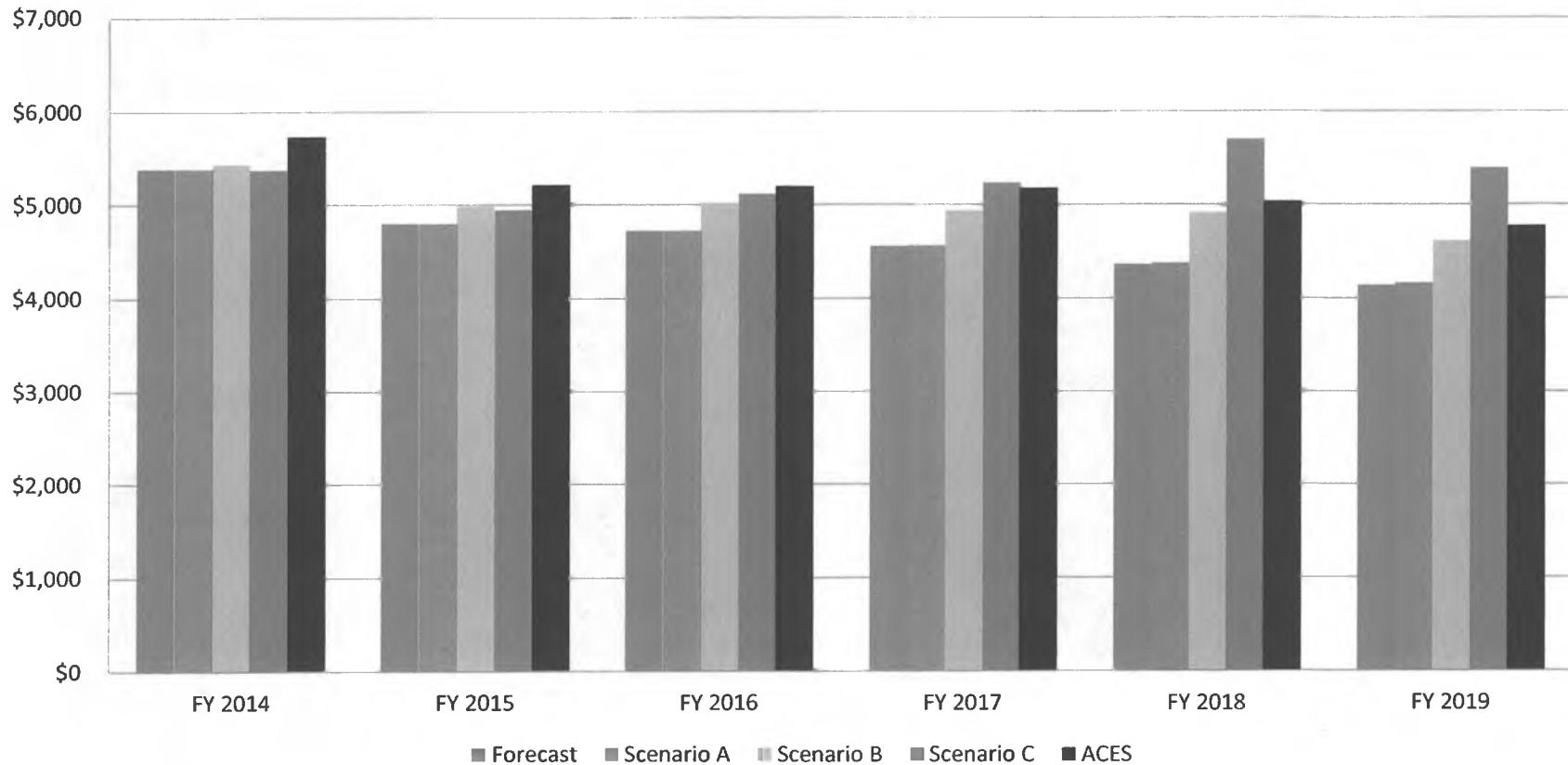
Note: Compares CSSB21(FIN) under several production scenarios, to ACES under forecast production.



Projected revenues under production scenarios – at \$100 / barrel ANS



AT \$100 ANS WC



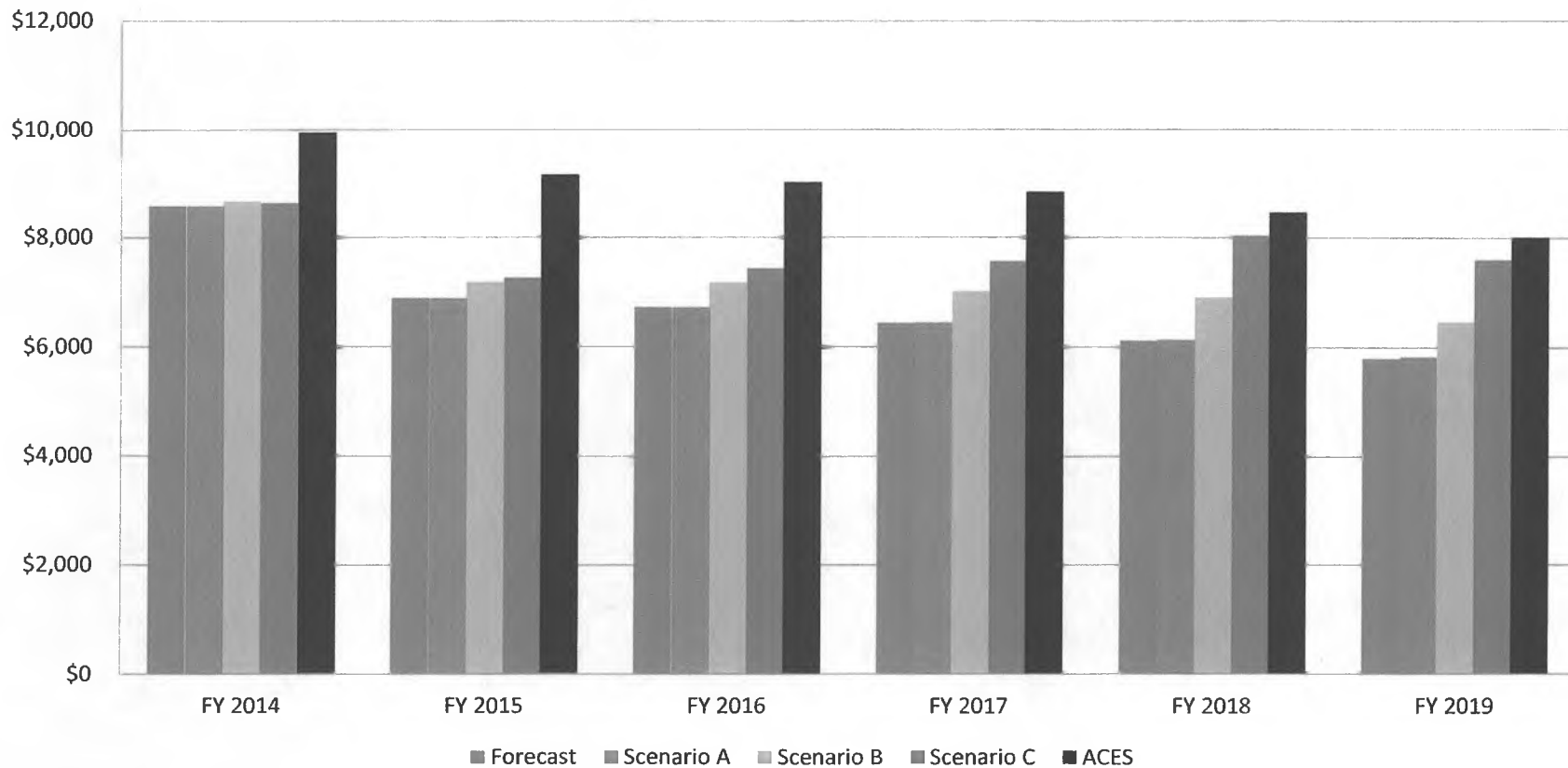
Note: Compares CSSB21(FIN) under several production scenarios, to ACES under forecast production.



Projected revenues under production scenarios – at \$120 / barrel ANS



AT \$120 ANS WC



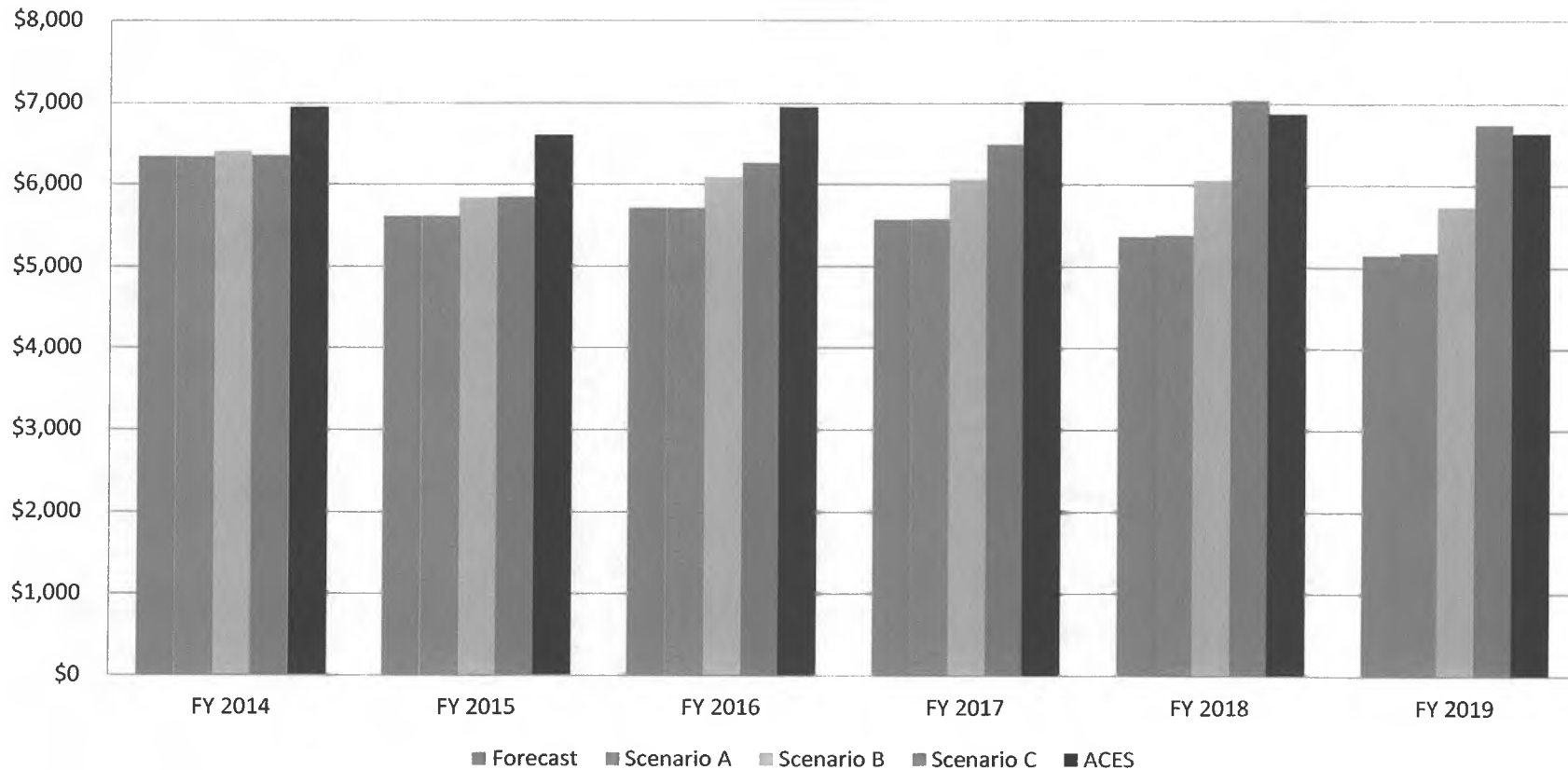
Note: Compares CSSB21(FIN) under several production scenarios, to ACES under forecast production.



Projected revenues under production scenarios – at forecast ANS price



At Forecast Price



Note: Compares CSSB21(FIN) under several production scenarios, to ACES under forecast production.

17

Comments on Senate Finance CS SB21

**Barry Pulliam
Managing Director
Econ One Research, Inc.**

March 12, 2013

Summary of Investment Measures

New Participant Investment in 50 MMBO Field

\$20/Bbl Development Capex, 12.5% Royalty Rate



Real \$2012 West Coast ANS Price	Alaska Project					Unconventional Lower-48		Canada	Norway	United Kingdom	
	ACES	SB21	SRES	SFIN	Eagle Ford	Bakken	Oil Sands SAGD	Pre-1993		Post-1993	
			CS SB21	CS SB21				w/ Brownfield Allowance*		w/ Brownfield Allowance*	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$1.18	\$1.27	\$1.35	\$2.36	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62	
\$100	\$2.54	\$5.32	\$5.79	\$5.97	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25	
\$120	\$4.36	\$9.12	\$9.98	\$9.48	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88	
Profitability Index-12											
\$80	1.07	1.08	1.08	1.14	1.25	1.04	0.88	1.01	1.22	1.21	
\$100	1.15	1.32	1.35	1.36	1.47	1.28	1.06	1.14	1.33	1.38	
\$120	1.26	1.55	1.60	1.57	1.78	1.60	1.26	1.27	1.42	1.55	
IRR (Percent)											
\$80	14.6%	14.1%	14.2%	16.3%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%	
\$100	17.5%	20.3%	20.8%	22.4%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%	
\$120	21.1%	25.8%	26.7%	27.9%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%	
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
\$80	\$27.96	\$39.95	\$39.95	\$39.73	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35	
\$100	\$31.04	\$52.60	\$52.60	\$48.33	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82	
\$120	\$35.62	\$61.22	\$65.25	\$57.14	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30	
Government Take (Percent)											
\$80	69.0%	58.1%	56.9%	57.4%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%	
\$100	74.6%	57.6%	55.0%	58.5%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%	
\$120	76.0%	57.6%	55.1%	59.1%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%	
State/Municipal NPV-12/BOE (Dollars Per BOE)											
\$80	\$5.27	\$5.13	\$5.02	\$3.45	-	-	-	-	-	-	
\$100	\$11.82	\$7.55	\$6.82	\$6.55	-	-	-	-	-	-	
\$120	\$17.67	\$10.34	\$9.02	\$9.79	-	-	-	-	-	-	

* Brownfield Allowance applied to 100 MMBOE development.
\$20 Per Barrel Development Capex and \$14 Per Barrel Opex.

Summary of Investment Measures

Incumbent Investment in 50 MMBO Field

\$20/Bbl Development Capex, 12.5% Royalty Rate



Real \$2012 West Coast ANS Price	Alaska Project				Unconventional Lower-48		Canada	Norway	United Kingdom	
	ACES	SB21	SRES	SFIN	Eagle Ford	Bakken	Oil Sands SAGD		Pre-1993	Post-1993
			CS SB21	CS SB21					w/ Brownfield Allowance*	w/ Brownfield Allowance*
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
Producer NPV-12 / BOE (Dollars Per BOE)										
\$80	\$3.17	\$1.62	\$3.12	\$2.44	\$3.61	\$0.67	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$5.98	\$5.28	\$6.55	\$5.87	\$6.75	\$4.29	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$9.07	\$8.95	\$9.99	\$9.30	\$11.17	\$9.16	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12										
\$80	1.19	1.10	1.19	1.15	1.25	1.04	0.88	1.01	1.22	1.21
\$100	1.36	1.32	1.40	1.35	1.47	1.28	1.06	1.14	1.33	1.38
\$120	1.55	1.54	1.60	1.56	1.78	1.60	1.26	1.27	1.42	1.55
IRR (Percent)										
\$80	21.9%	15.2%	18.6%	17.1%	29.9%	13.6%	9.7%	12.4%	34.5%	24.7%
\$100	35.3%	21.7%	25.0%	23.5%	46.3%	22.7%	13.1%	16.0%	45.2%	32.9%
\$120	57.1%	27.6%	30.9%	29.3%	73.6%	37.0%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)										
\$80	\$26.44	\$33.23	\$34.71	\$34.54	\$23.39	\$28.39	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$29.48	\$43.35	\$44.26	\$44.16	\$29.99	\$36.48	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$33.68	\$53.47	\$53.81	\$53.77	\$36.87	\$44.91	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)										
\$80	65.7%	61.3%	55.6%	59.7%	71.7%	77.1%	63.4%	67.8%	61.0%	52.0%
\$100	70.4%	60.0%	57.1%	60.1%	67.9%	72.1%	63.5%	71.7%	68.6%	55.8%
\$120	71.3%	59.4%	57.9%	60.3%	65.1%	68.7%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)										
\$80	\$2.21	\$4.59	\$2.29	\$3.34	-	-	-	-	-	-
\$100	\$6.53	\$7.60	\$5.65	\$6.71	-	-	-	-	-	-
\$120	\$10.42	\$10.61	\$9.00	\$10.07	-	-	-	-	-	-

Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

* Brownfield Allowance applied to 100 MMBOE development.

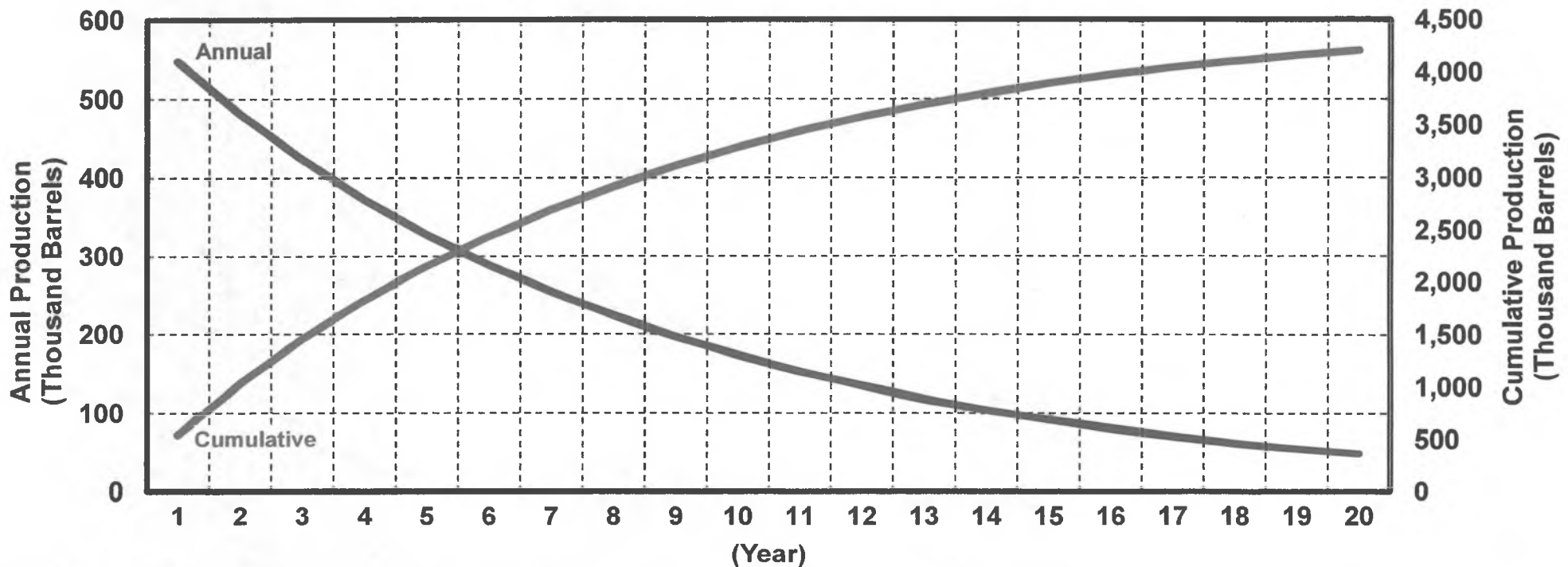
\$20 Per Barrel Development Capex and \$14 Per Barrel Opex.

Duration of the GRE

- **GRE Has the Effect of Reducing Tax Rate**
- **Removing GRE During Life of a Well is a Tax Increase on That Production (to the Nominal Rate)**
- **Increase Occurs as Well Productivity is Declining and Per Unit Costs Are Rising**
- **Can Shorten Productive Life of Well and Total Recoveries**
- **Better Alternative Would be a Lower GRE Over Life of Well That Provides Same Economics to Producer**

Well Production Profile

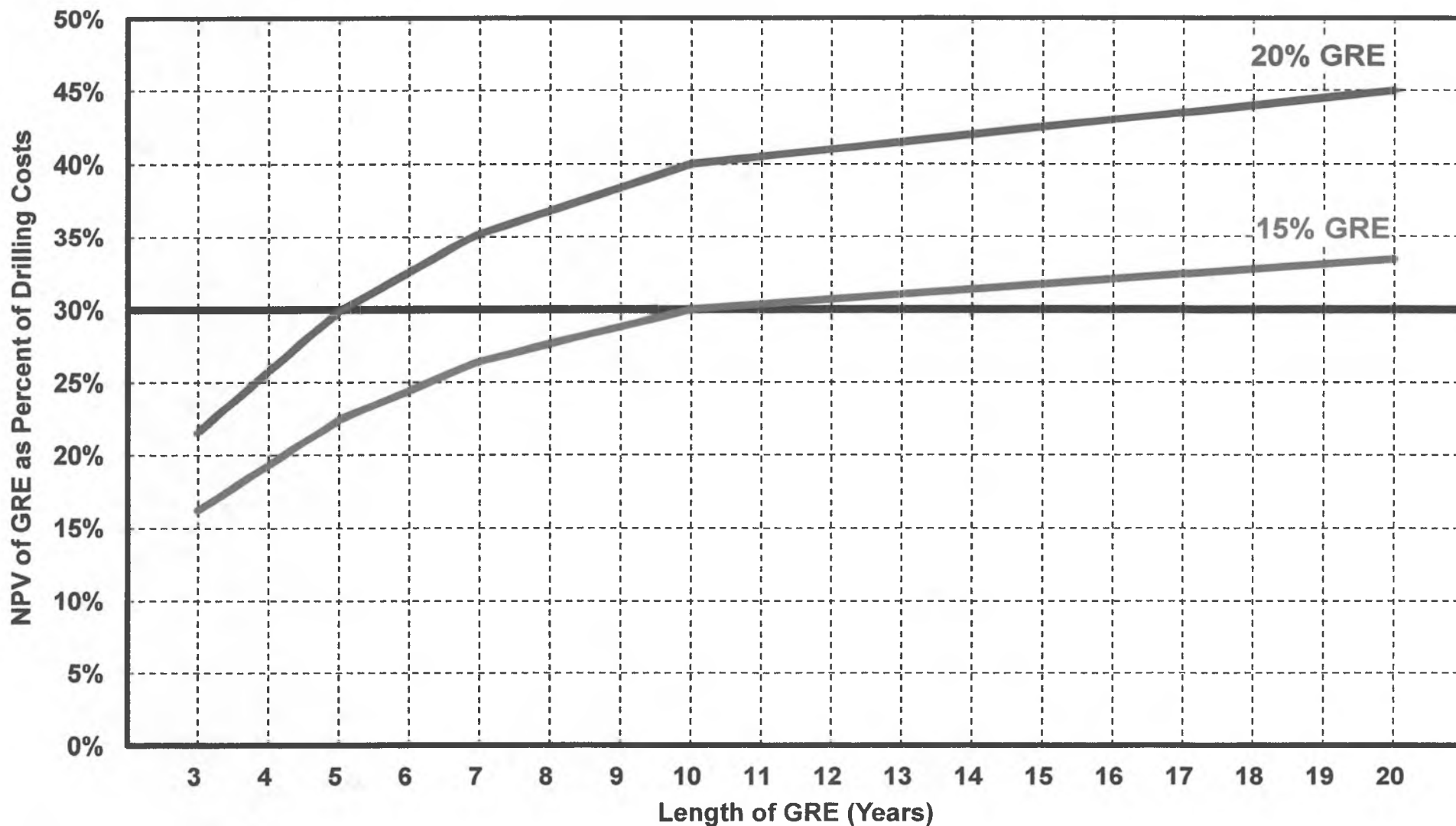
Initial 1,500 BPD, 12% Decline Rate



- **Approximately 50% of Oil Produced During First 5-7 Years of Well Life**
- **Well Productivity Declines, While \$/Bbl Operating Costs Rise Over Time**
- **Maintenance and Workovers Extend the Production Life of a Well**

Relationship Between Length of GRE and Percent of NPV of Drilling Cost

Initial 1,500 BPD, 12% Decline Rate



Example of Tax Calculation With and Without GRE

	<u>Production Without GRE</u>		<u>Production With 20% GRE</u>		<u>Production With 15% GRE</u>	
Gross Barrels		100,000		100,000		100,000
Royalty Barrels	-	12,500	-	12,500	-	12,500
Taxable Barrels	=	87,500	=	87,500	=	87,500
West Coast Value (\$/Bbl)		\$110.00		\$110.00		\$110.00
Transportation Costs (\$/Bbl)	-	10.00	-	10.00	-	10.00
Wellhead Value (\$/Bbl)	=	\$100.00	=	\$100.00	=	\$100.00
Gross Revenue Exclusion (%)	0% -	0.00	20% -	20.00	15% -	15.00
Lease Expenses (\$/Bbl)	-	30.00	-	30.00	-	30.00
Taxable Value (\$/Bbl)	=	\$70.00	=	\$50.00	=	\$55.00
Production Tax Value (\$)		\$6,125,000		\$4,375,000		\$4,812,500
Tax Rate (%)	30%	\$1,837,500	30%	\$1,312,500	30%	\$1,443,750
Production Allowance (\$/Bbl)	\$5.00 -	437,500	\$5.00 -	437,500	\$5.00 -	437,500
Tax Due (\$)	=	\$1,400,000	=	\$875,000	=	\$1,006,250
Tax as % of Net Value of Production		22.9%		14.3%		16.4%
Tax as % of Gross Value of Production		16.0%		10.0%		11.5%

Example of NOL Credit Related to New Investment of \$1 Billion

<u>Year</u>	<u>Capital Spending</u>	<u>Tax Loss</u>	<u>Loss Available To Monetize</u>	<u>Loss Carried Forward</u>
1	\$25,000,000	\$7,500,000	\$0	\$7,500,000
2	150,000,000	45,000,000	7,500,000	37,500,000
3	500,000,000	150,000,000	45,000,000	105,000,000
4	300,000,000	90,000,000	90,000,000	0
5	25,000,000	7,500,000	7,500,000	0
	<u>\$1,000,000,000</u>	<u>\$300,000,000</u>	<u>\$150,000,000</u>	<u>\$150,000,000</u>

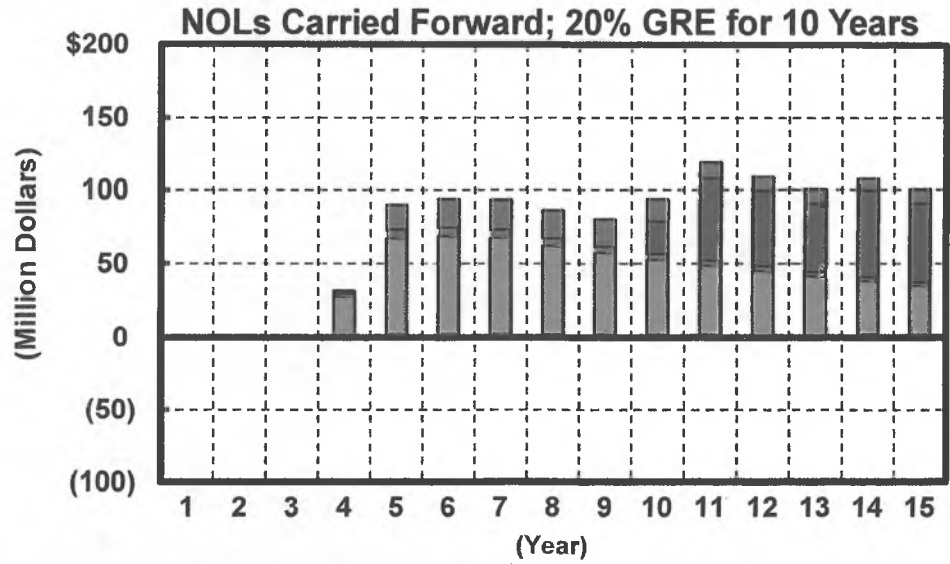
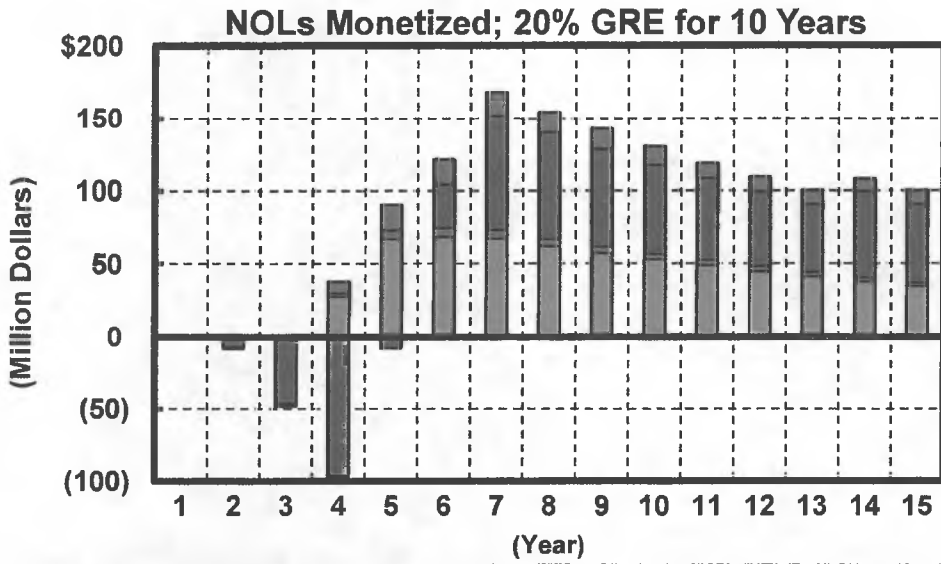
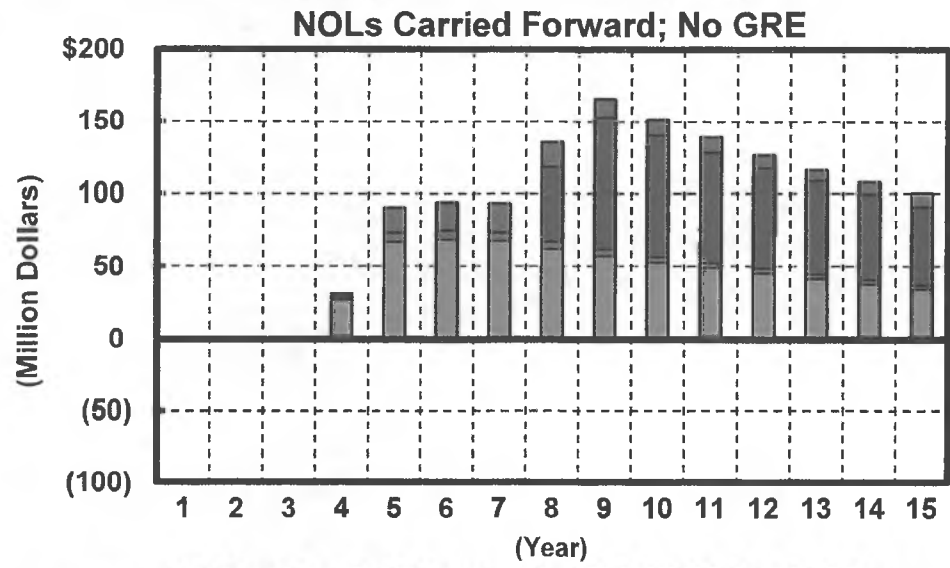
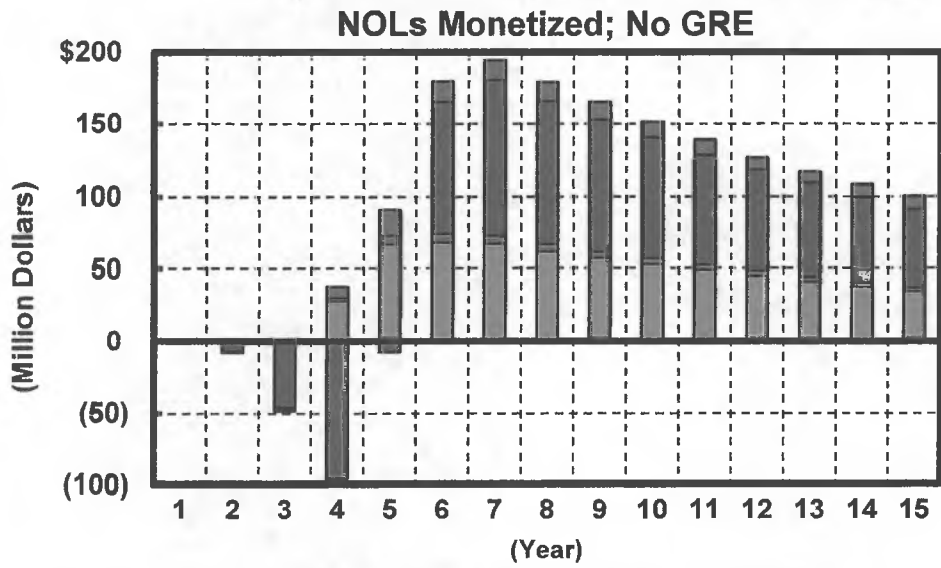
Note: Losses carried forward are increased at 15% per year.

Annual State Cash Flows

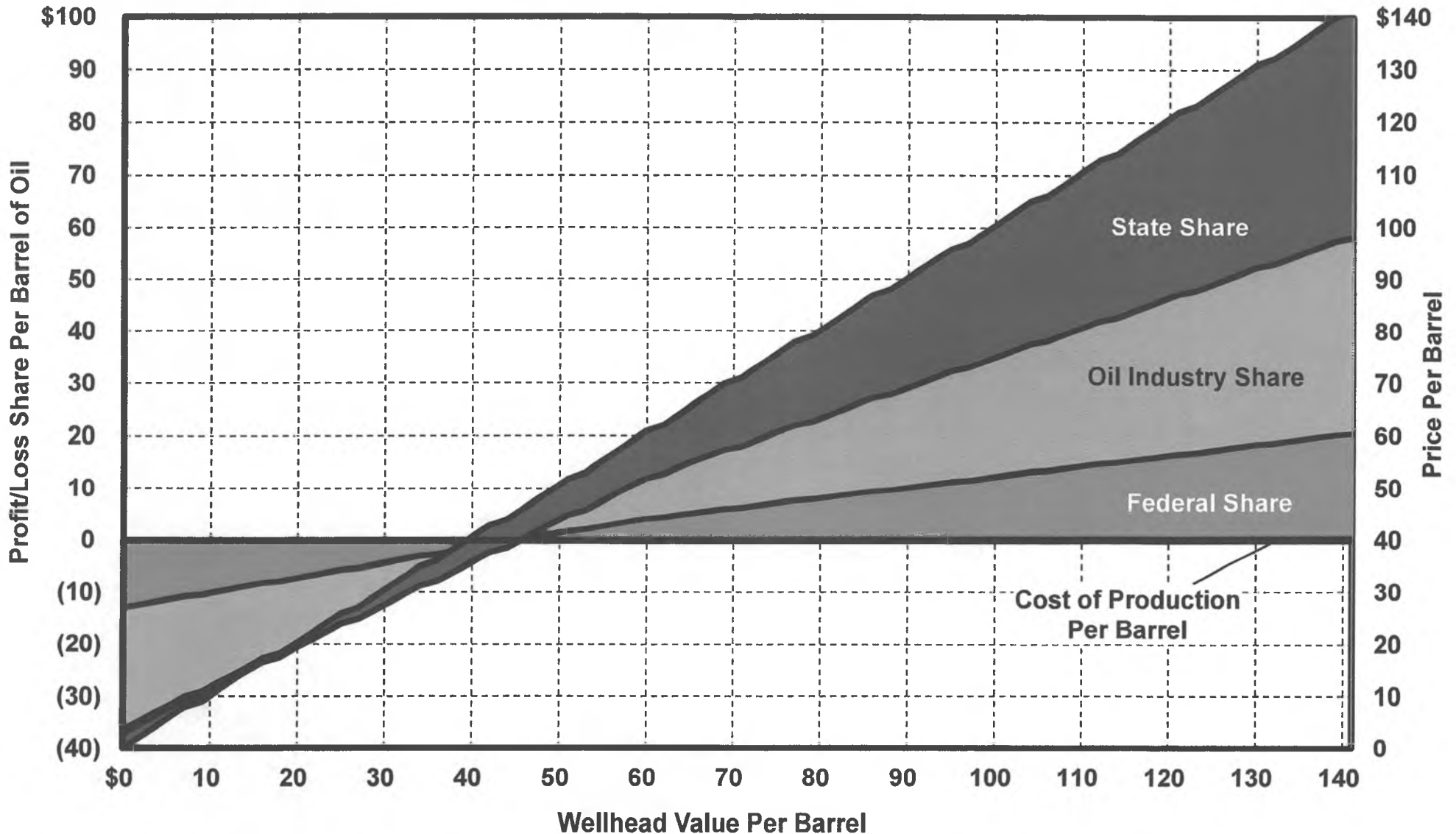
New Participant Investment in 50 MMBO Field

\$20/Bbl Development Capex, 12.5% Royalty Rate

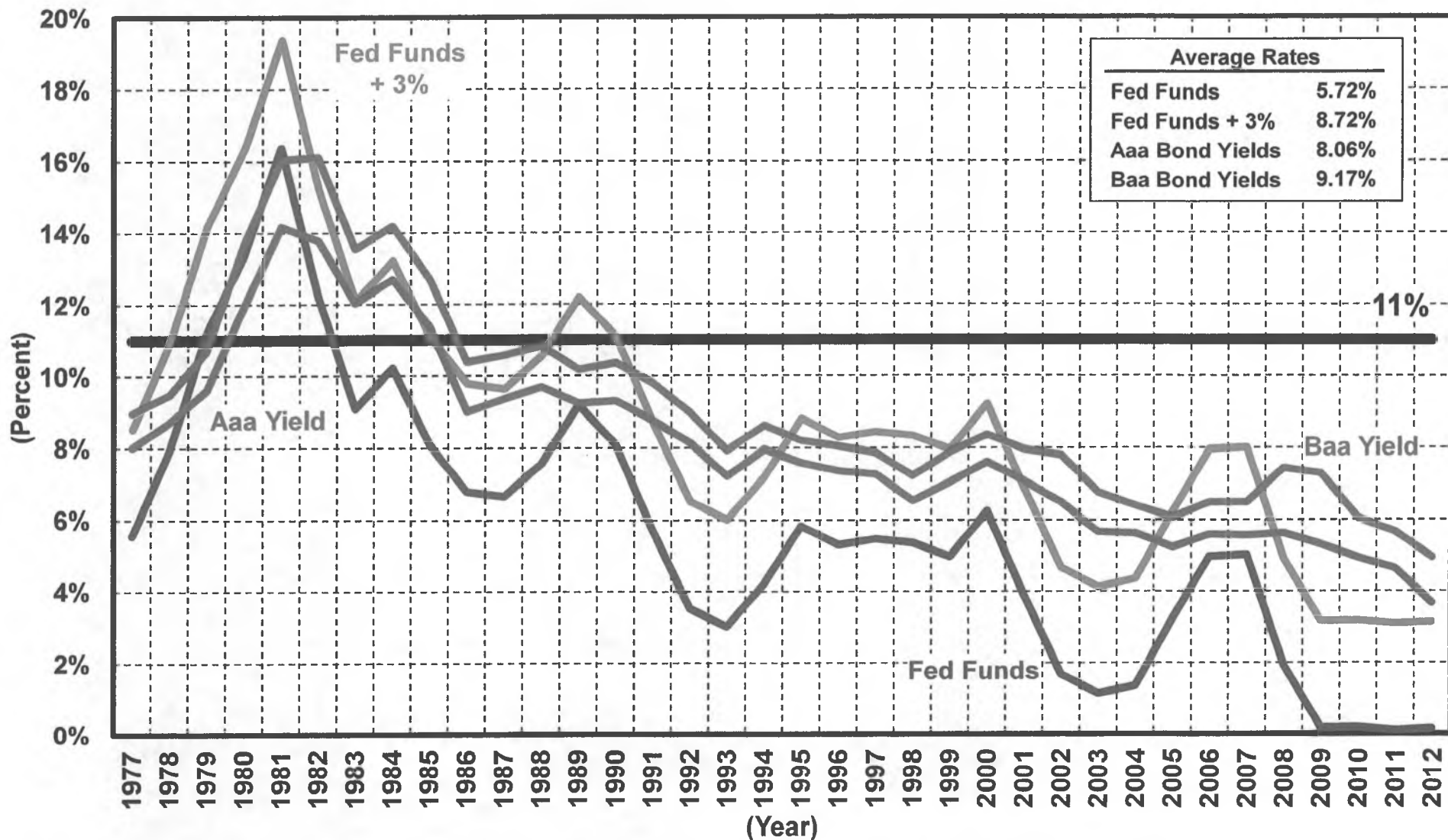
Production Tax Royalties Ad Valorem Tax Income Tax



Shares of Per-Barrel Values Under SFIN CS SB21 (30% Base Rate, \$5/Bbl. Allowance, Losses Monetized) for All Producers (FY 2015 - FY 2019)



Interest Rates 1977 - 2012



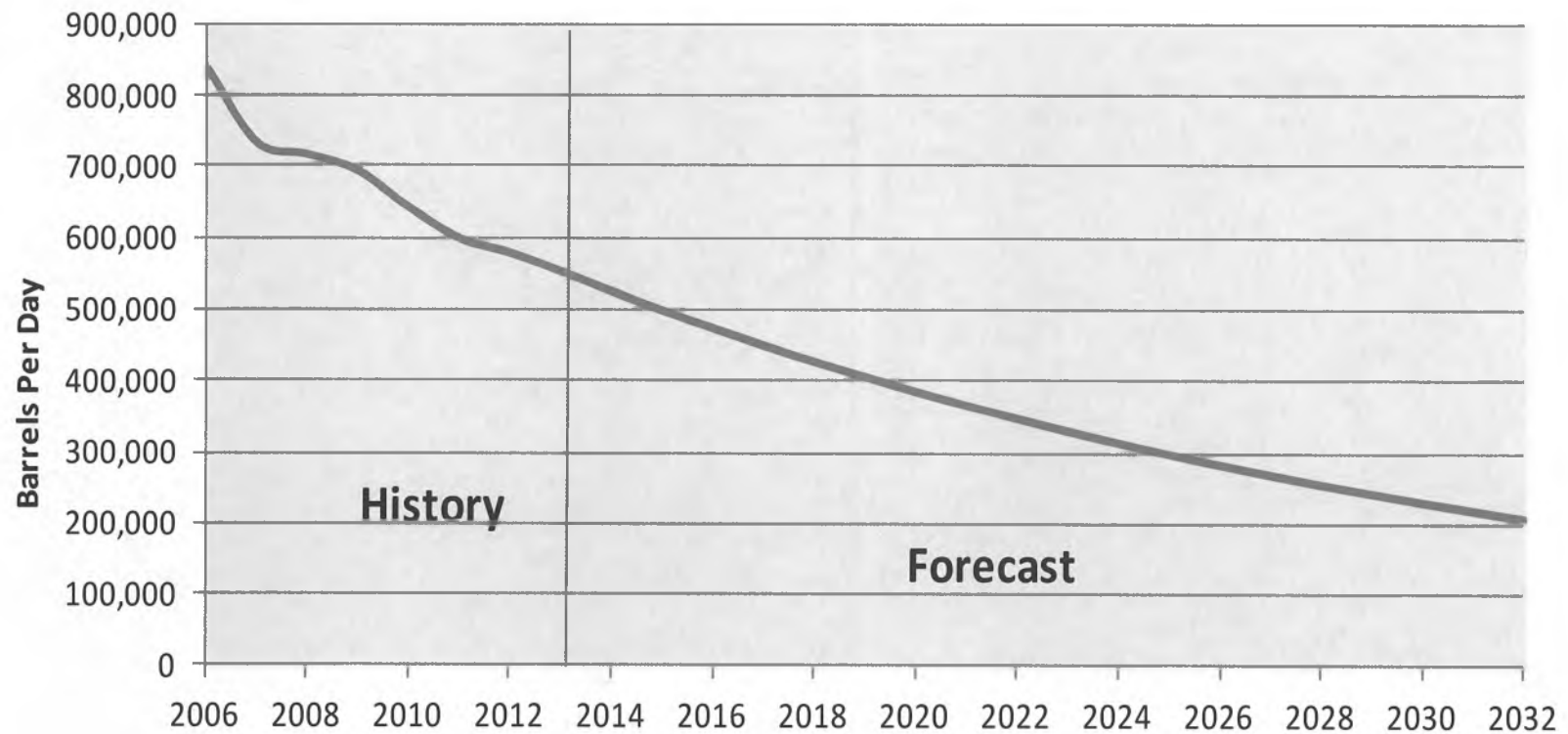
18

SB 21: Long-Run Revenue Scenarios

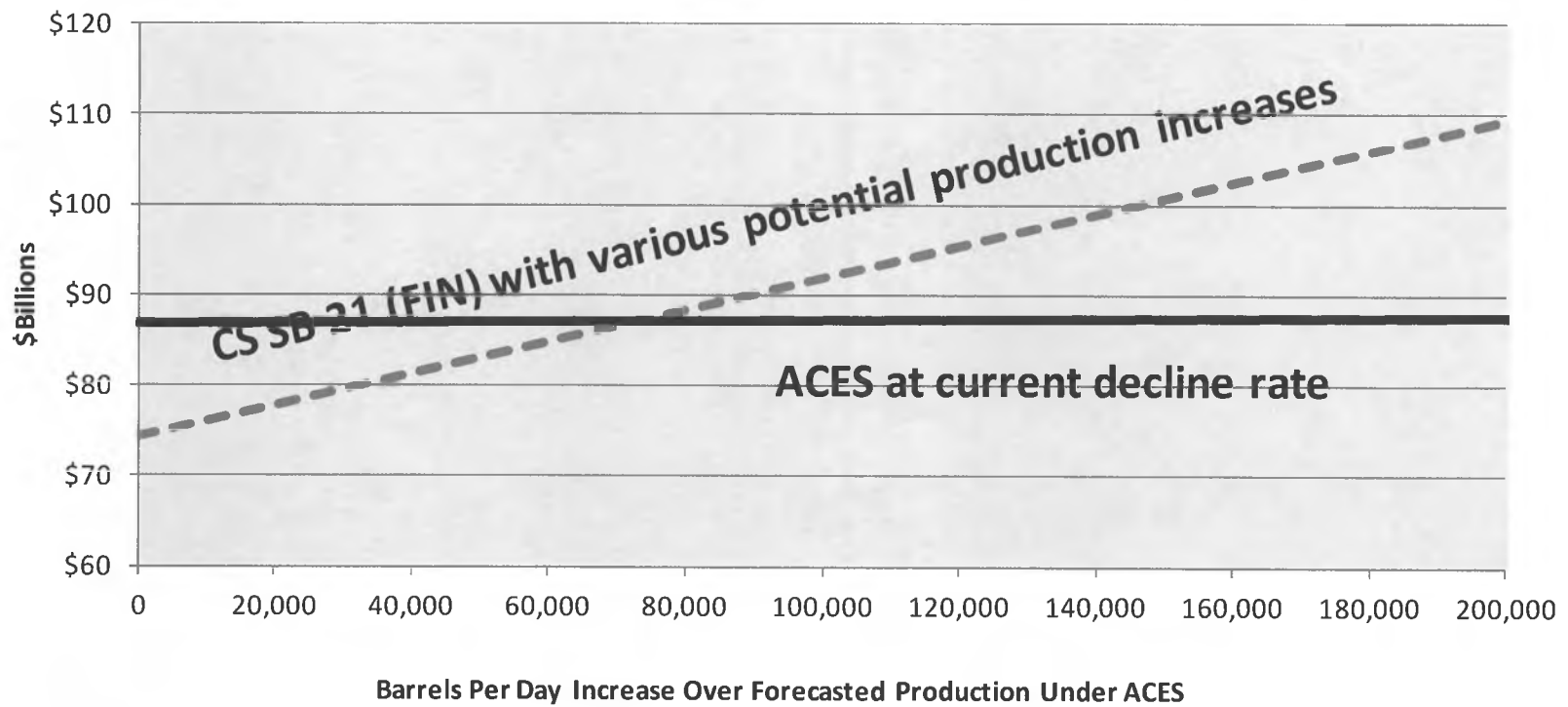
Roger Marks

March 13, 2013

ANS Production under Status Quo Current Decline Rate Extended Out 20 Years

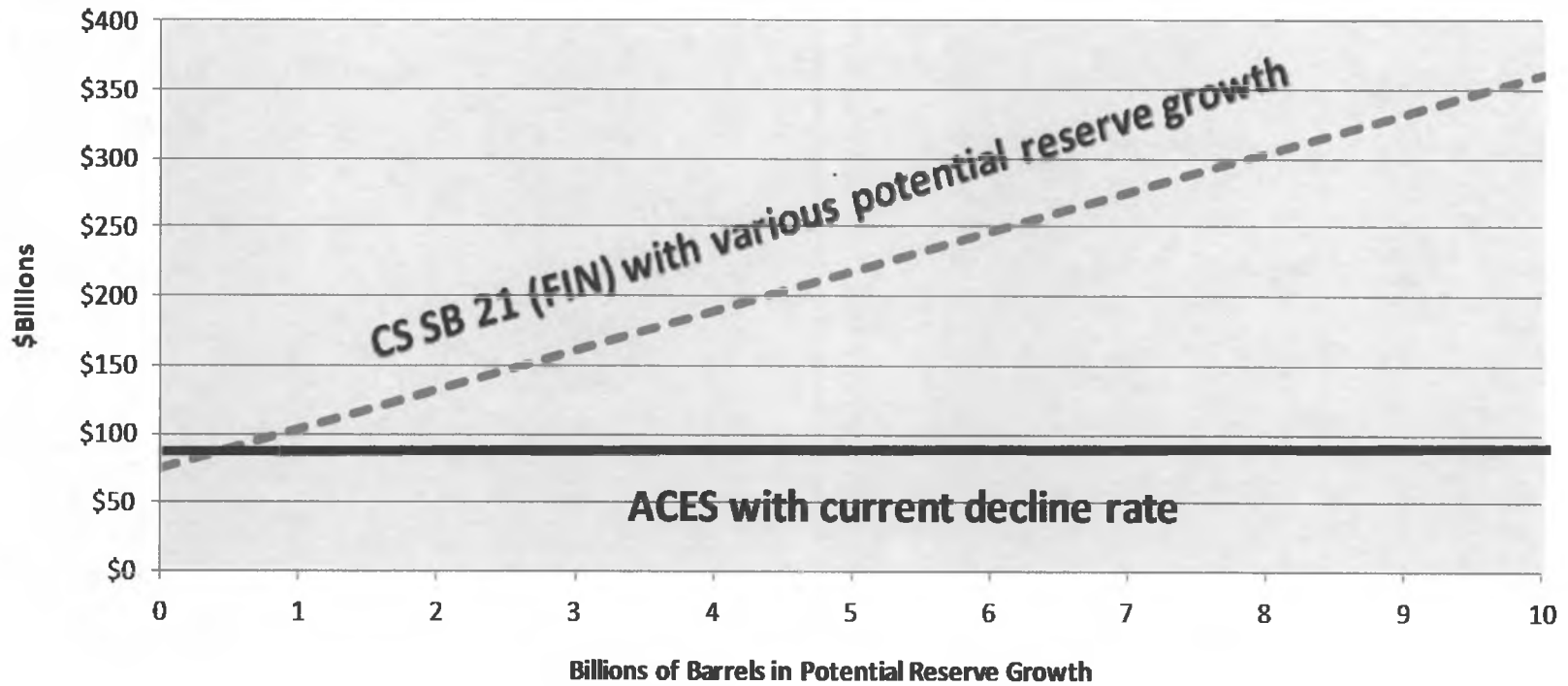


Total Petroleum Revenues over 20 Years*
ACES at Trended Current Production Forecast vs.
CS SB 21 (FIN) with Various Potential Production Increases
\$110/bbl ANS Market Price
(\$billions)



* Royalties, production tax, property tax, state corporate income tax

Total Petroleum Revenues over 20 Years*
ACES at Trended Current Production Forecast vs.
CS SB 21 (FIN) with Various Potential Reserve Growth
\$110/bbl ANS Market Price
(\$Billions)



* Royalties, production tax, property tax, state corporate income tax

19

Proposed Changes in Senate Finance CS SB 21

Version 28-GS1647\Y

Maximum Base Tax Rate:

Established in Section 9 (page 4, lines 30-31 and page 5, lines 1-11)

January 1, 2014 – December 31, 2016 **35%**

Effective January 1, 2017 **33%**

Repeals Progressivity

No Change from Senate Resource Version

No Change from Governor's Version

Per Barrel Allowance:

\$5.00/barrel

Established in Section 23

Gross Revenue Exclusion:

Established in Section 30 (part of Section 12 as Payment of Tax)

- Produced from a lease or property **20%**
not within a unit on January 1, 2003
In Senate Resources Version at 30%
In Governor's Version at 20%

- Produced from a participating area **20%**
established after December 31, 2011
In Senate Resources Version at 30%
In Governor's Version at 20%

- Produced from a well that has been accurately **20%**
metered and measured by an operator and that
DNR has certified was not contributing to
production before January 1, 2013
(certified through required POD)

Net Operating Loss

Monetizable

Section 16, Section 17, Section 19

Monetizable or carry forward annual loss credit (in the amount equivalent to production tax rate)

January 1, 2014 – December 31, 2016: **35%**

January 1, 2017: **33%**

Manufacturing Credit against State Corporate Income Tax

Established in Section 7

Provides for a manufacturing credit applied against a taxpayer's corporate income tax liability for a qualified oil and gas service industry expenditure that occurs in the state.

- The total amount of credit may not exceed the lesser of 10% of expenditures or \$10 million.
- Must be a taxpayer to qualify for the credit.
- Non-transferable
- The expenditure cannot be the basis of another deduction under the Corporate Income Tax Law
- Reduces the shelf life of the credit to five years

Proposed Changes in Senate Finance CS SB 21

Version 28-GS1647\Y

Eliminates Qualified Capital Expenditure Credit: For Expenditures after 1/1/2014

Exploration Incentive Credit

Not extended to 2022

Will sunset July 1, 2016

Small Producer Tax Credits:

Not extended to 2022

Will sunset 2016

*Small producers that currently receive the credit. If production started after April 1, 2006, then the small producer is allowed to take the credit for 9 years after the start of commercial production. Very likely that even though the credit sunsets in 2016, there will be companies that are allowed to take the credit in years after 2016.

Interest Rate for Delinquent Taxes

Amended under Section 4

Adjusts how the interest is calculated on delinquent taxes: 3 percentage points above the annual rate charged member banks for advances by the 12th Federal Reserve District. Alternative to the greater than approach (current statute) or the lesser than approach (in Version 28-GS1647\Y)

Slide by Barry Pulliam of EconOne – 3/12/2013

Conforming Sections: 1, 3, 5, 6, 8, 14, 20, 31, 32, 33

Community Revenue Sharing Provision

Removes reference and tie to corporate income tax receipts. Does not change how the formula works, or distribution of funds.

20

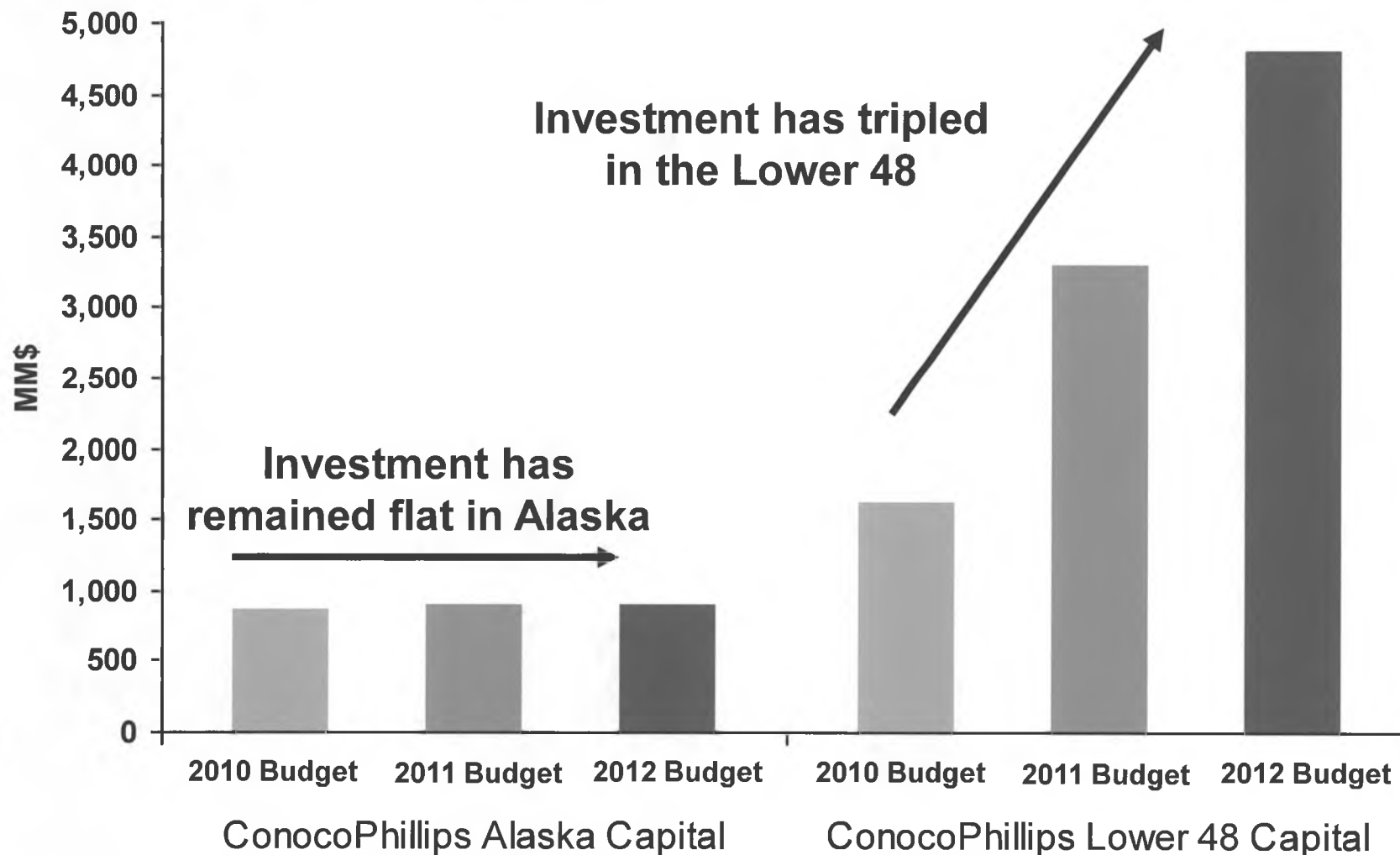
Senate Finance Committee

CSSB21

Bob Heinrich, VP Finance
Scott Jepsen, VP External Affairs
ConocoPhillips Alaska



March 14, 2013

ConocoPhillips Capital Allocation



Investment flows where investor has upside

Changes to ACES to Improve Alaska's Investment Climate

Change	CSSB21
<ul style="list-style-type: none"> • Eliminate progressivity 	
<ul style="list-style-type: none"> • Create a flatter tax rate over a broad range of prices <ul style="list-style-type: none"> ➤ Producer and State share proportionately as prices fluctuate and margins change 	
<ul style="list-style-type: none"> • Establish a tax structure creating an attractive investment climate <ul style="list-style-type: none"> ➤ Competitive tax rate ➤ Provide the incentives to balance Alaska's high cost environment ➤ Incentives for both legacy and new field investments 	<ul style="list-style-type: none"> • Issues <ul style="list-style-type: none"> ➤ Tax increase at lower prices – base rate too high ➤ Uncertainty around GRE application to legacy fields.

21

Comments on Senate Finance CS SB21

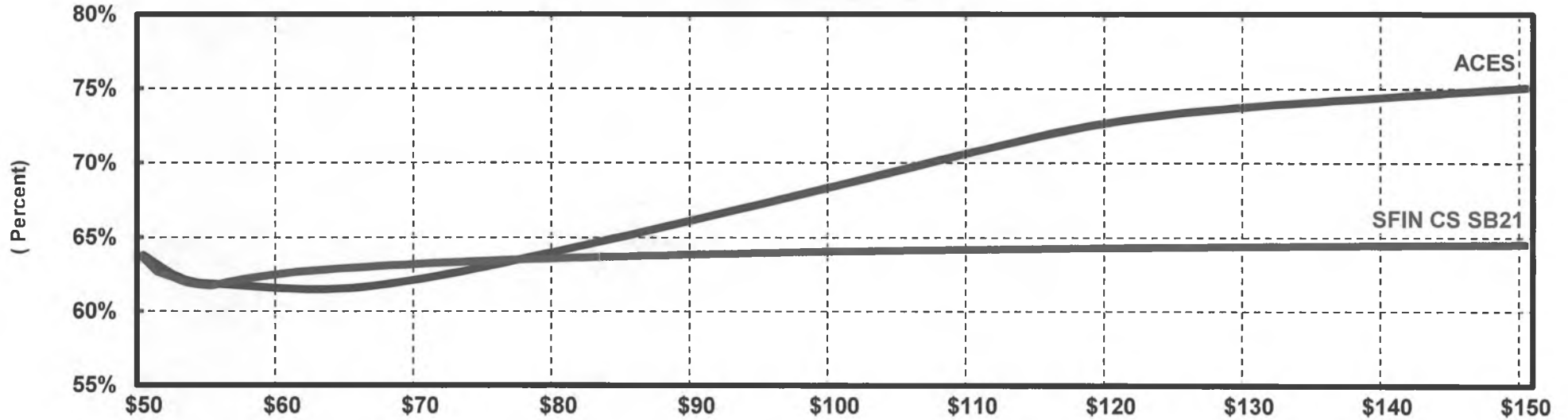
**Barry Pulliam
Managing Director
Econ One Research, Inc.**

March 14, 2013

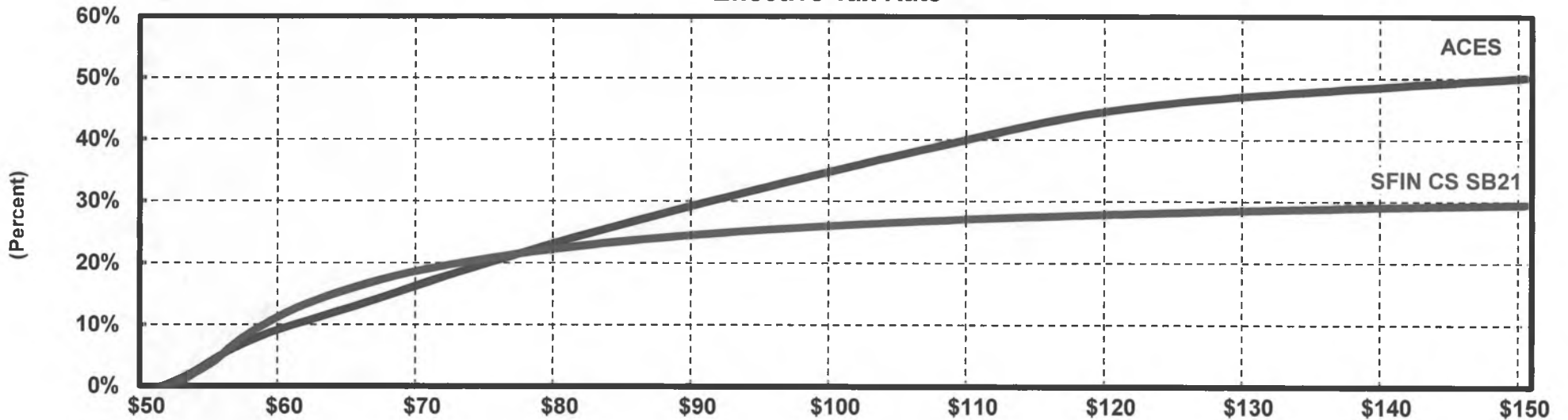
Average Government Take and Effective Tax Rate ACES v. SFIN CS SB21 for All Existing Producers (FY2015-FY2019)



Government Take



Effective Tax Rate



Projected Fiscal Impact of SFIN CS SB21 Assuming No Production Change (FY2014 - FY2043)



Year	Nominal Impact	Real \$2012 Impact	
	(\$ Million)	(\$2012 Million)	
	(1)	(2)	
FY2014	\$825	\$795	DOR Fiscal Impact
FY2015	565	531	
FY2016	765	702	
FY2017	1,115	998	
FY2018	1,205	1,052	
FY2019	1,205	1,026	
FY2020	1,131	940	Additional Fiscal Projection
FY2021	1,061	860	
FY2022	995	787	
FY2023	934	720	
FY2024	876	659	
FY2025	821	603	
FY2026	771	553	
FY2027	725	507	
FY2028	680	464	
FY2029	635	422	
FY2030	593	385	
FY2031	554	351	
FY2032	517	320	
FY2033	483	291	
FY2034	452	266	
FY2035	422	242	
FY2036	395	221	
FY2037	369	202	
FY2038	345	184	
FY2039	323	168	
FY2040	301	153	
FY2041	281	139	
FY2042	263	127	
FY2043	245	115	
Total FY2014 - FY2019 (6 Years)	\$5,700	\$5,100	
Total FY2014 - FY2043 (30 Years)	\$19,900	\$14,800	

Additional Volumes Need to Offset Projected Fiscal Impact of SFIN CS SB21 (FY2014 - FY2043)



Assumptions: \$20/Bbl Development Cost
 Price = \$105/Bbl West Coast ANS Price (\$2012)
 Taxes Per Senate Finance CS SB21: 33% Base Rate, \$5 Allowance, 20% GRE

	<u>16.67% Royalty</u>	<u>12.5% Royalty</u>
State Revenue Per Barrel Developed		
Nominal Dollars	\$35.00	\$31.50
2012 Dollars	\$25.00	\$22.50
Fiscal Note Impact (FY2014 - FY2043)		
Nominal Dollars	\$19,900	\$19,900
2012 Dollars	\$14,800	\$14,800
Total Barrels Needed to Develop (MMBO)	592	658
Annual Barrels Needed (MMBO)	20	22
Central North Slope Undiscovered Conventional Economically Recoverable Resources	3,000	3,000
% of Resources Required Annually	0.7%	0.7%

Additional Volumes Need to Offset Projected Fiscal Impact of SFIN CS SB21 (FY2014 - FY2019)



Assumptions: \$20/Bbl Development Cost
Price = \$105/Bbl West Coast ANS Price (\$2012)
Taxes Per Senate Finance CS SB21: 33% Base Rate, \$5 Allowance, 20% GRE

	<u>16.67% Royalty</u>	<u>12.5% Royalty</u>
State Revenue Per Barrel Developed		
Nominal Dollars	\$35.00	\$31.50
2012 Dollars	\$25.00	\$22.50
Fiscal Note Impact (FY2014 - FY2019)		
Nominal Dollars	\$5,700	\$5,700
2012 Dollars	\$5,100	\$5,100
Total Barrels Needed to Develop (MMBO)	204	227
Annual Barrels Needed (MMBO)	34	38
Central North Slope Undiscovered Conventional Economically Recoverable Resources	3,000	3,000
% of Resources Required Annually	1.1%	1.3%

22



Senate Finance Committee

CS SB21 Analysis

March 14 2013

Janak Mayer

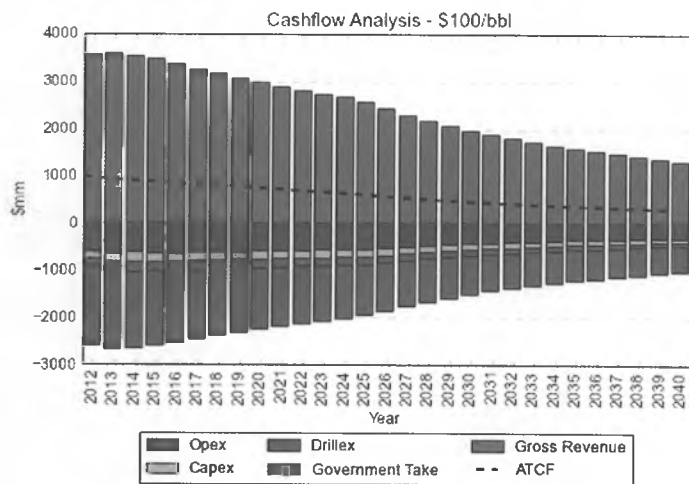
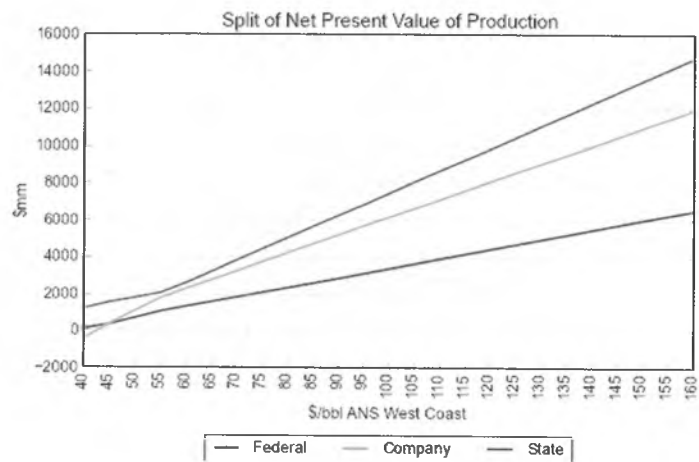
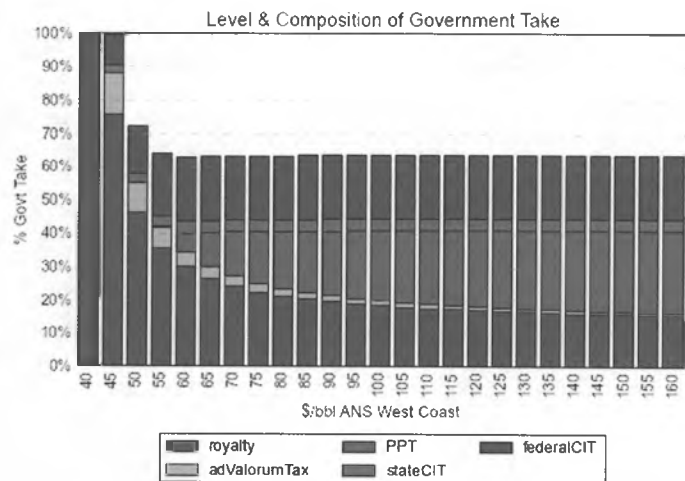
Manager, Upstream

PFC Energy

PFC Energy

33%, \$5/bbl Allowance Base Production

33/5, Base Production

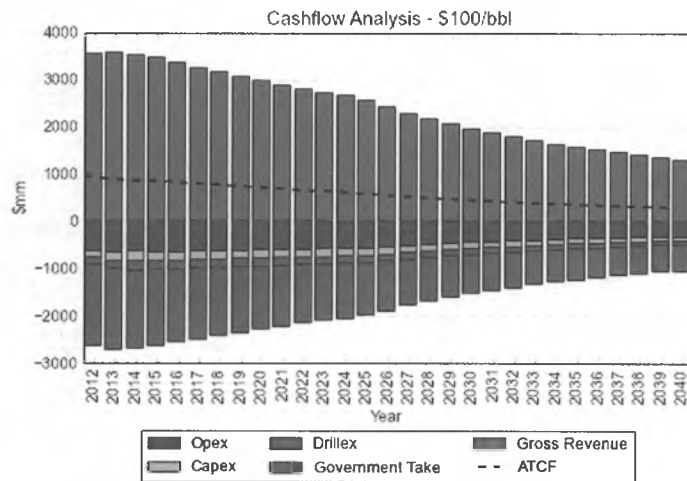
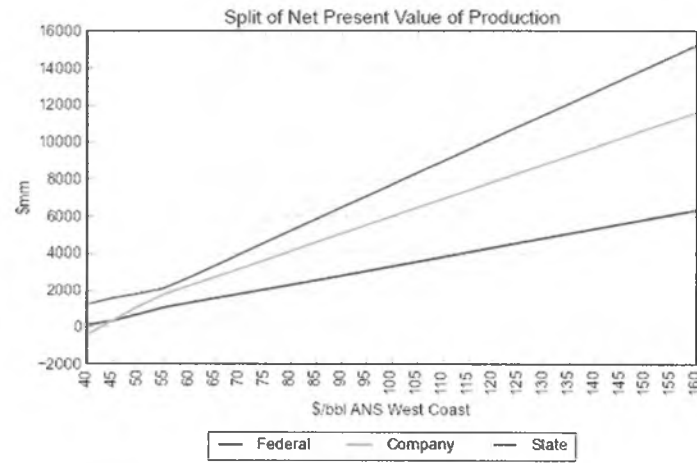
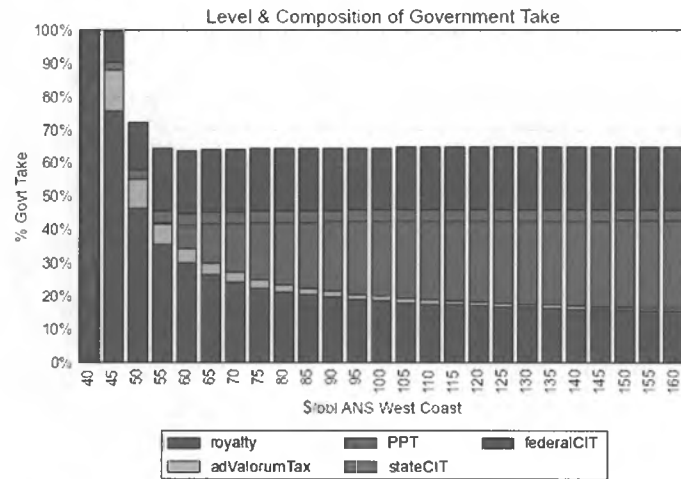


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	63.64%	4.1		18.48
\$100/bbl	63.82%	5.97		27.07
\$120/bbl	63.91%	7.84		35.67
\$140/bbl	63.96%	9.71		44.26

35%, \$5/bbl Allowance Base Production

35/5, Base Production

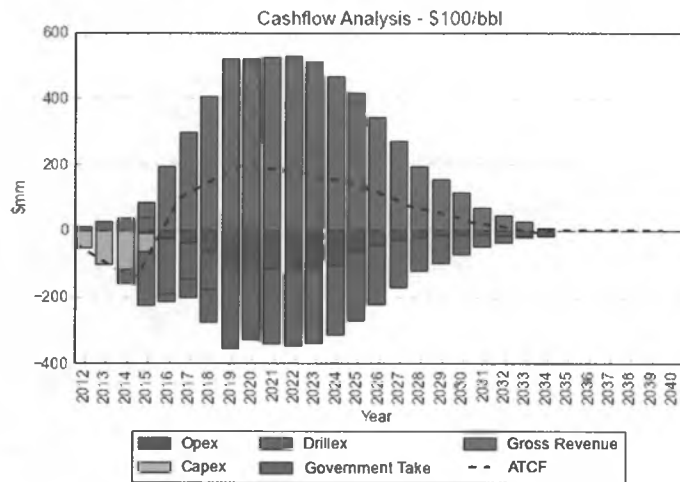
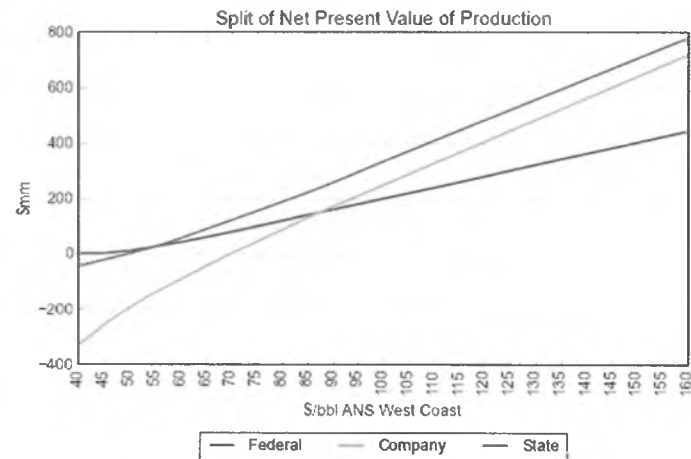
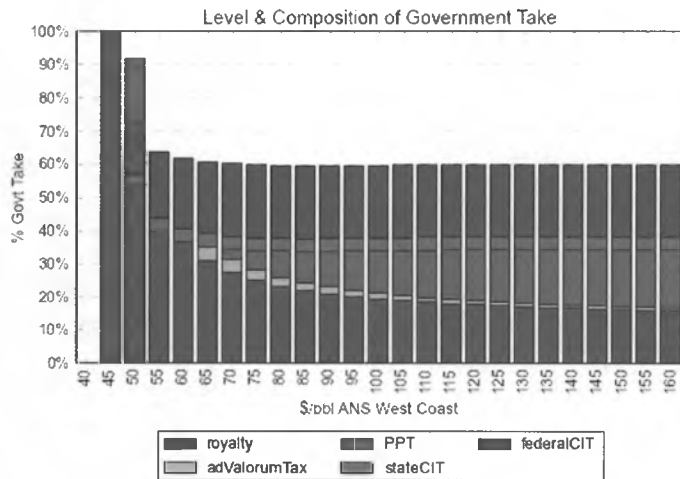


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	64.57%	3.99		18.01
\$100/bbl	64.79%	5.81		26.35
\$120/bbl	64.91%	7.62		34.69
\$140/bbl	64.97%	9.44		43.03

33%, \$5/bbl Allowance, 20% GRE (no time limit) \$18/bbl New Development, Standalone

33/5, 20% GRE, \$18/bbl New Development, Standalone

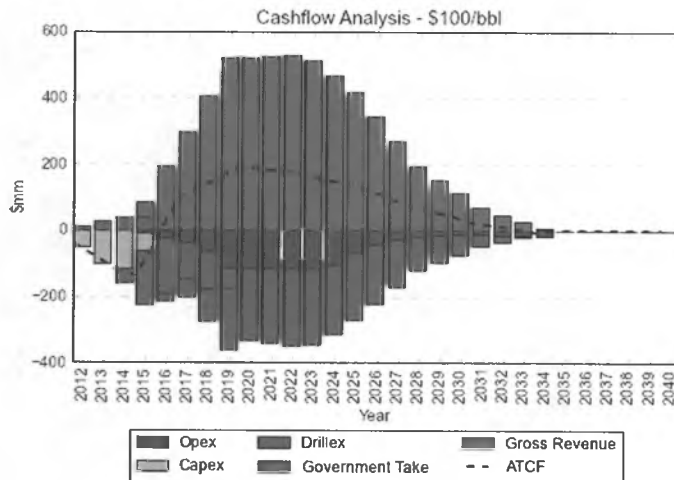
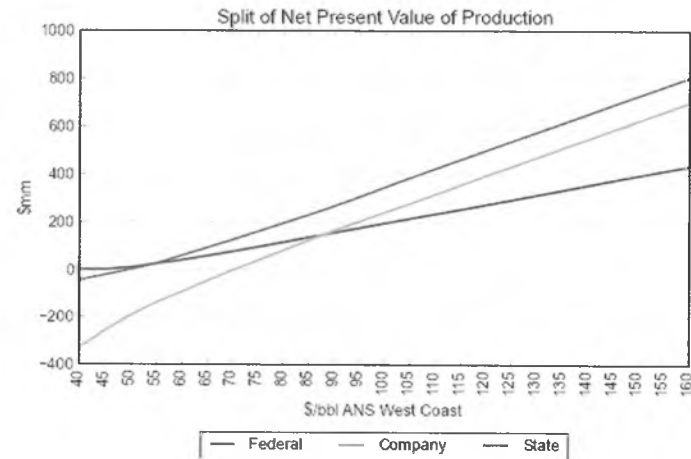
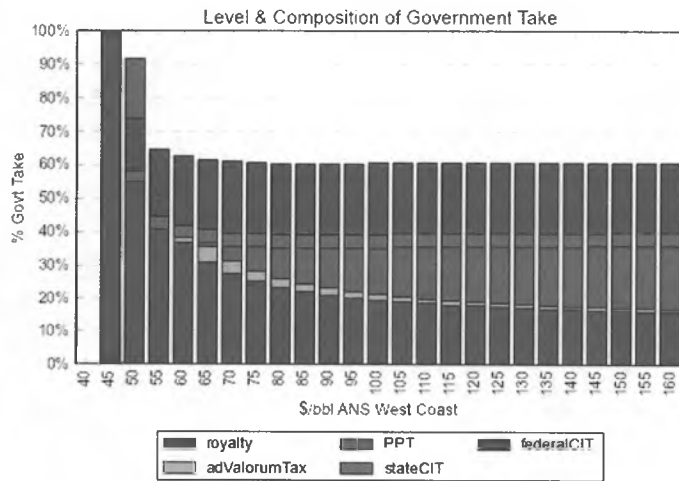


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	59.76%	1.77	16.02%	26.83
\$100/bbl	59.78%	4.98	22.48%	36.27
\$120/bbl	59.94%	8.11	27.94%	45.3
\$140/bbl	59.99%	11.23	32.80%	54.27

35%, \$5/bbl Allowance, 20% GRE (no time limit) \$18/bbl New Development, Standalone

35/5, 20% GRE, \$18/bbl New Development, Standalone

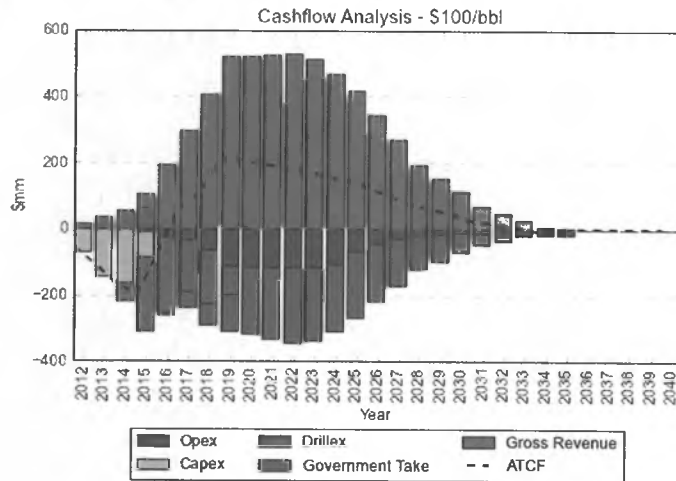
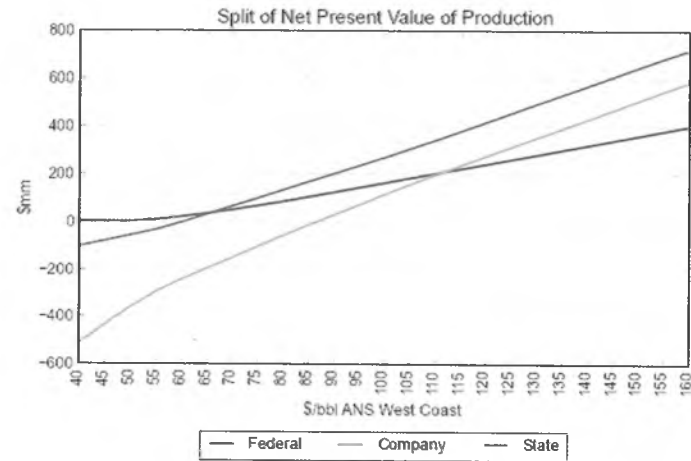
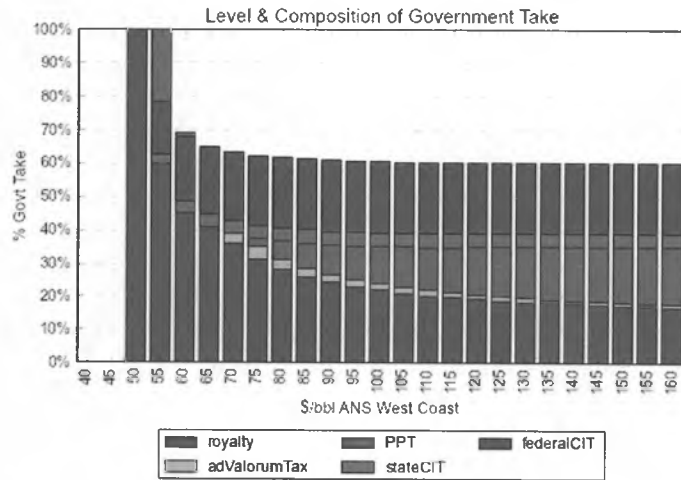


Economic Summary

	GT0	NPV/boe	IRR	Cash Margin
\$80/bbl	60.56%	1.67	15.83%	26.56
\$100/bbl	60.60%	4.83	22.23%	35.76
\$120/bbl	60.76%	7.89	27.63%	44.59
\$140/bbl	60.81%	10.95	32.47%	53.36

33%, \$5/bbl Allowance, 20% GRE (no time limit) \$25/bbl New Development, Standalone

33/5, 20% GRE. \$25/bbl New Development, Standalone

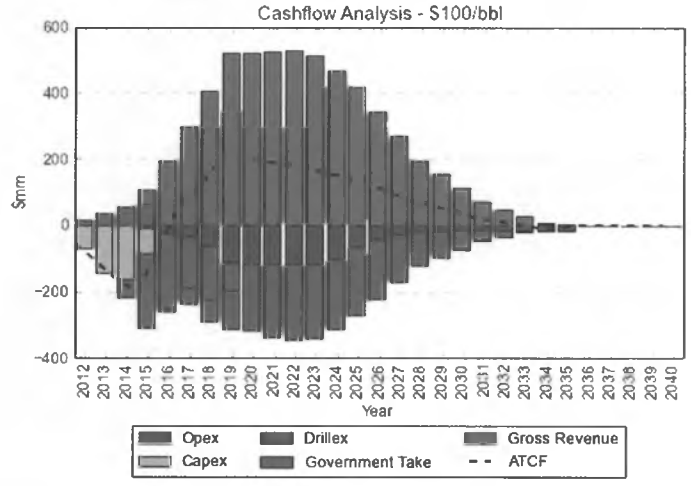
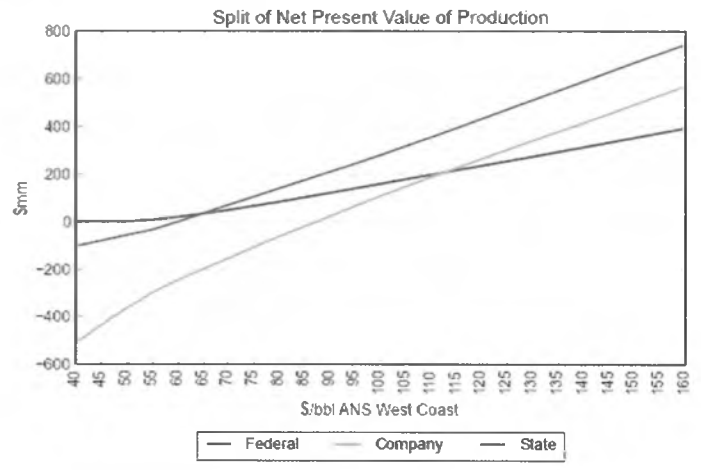
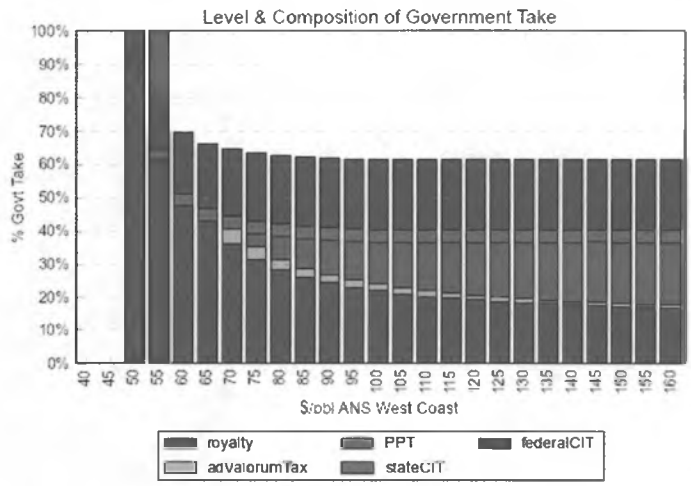


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	61.81%	-1.17	9.96%	27.11
\$100/bbl	60.61%	2.3	15.80%	37.04
\$120/bbl	60.49%	5.5	20.54%	46.31
\$140/bbl	60.53%	8.58	24.61%	55.41

35%, \$5/bbl Allowance, 20% GRE (no time limit) \$25/bbl New Development, Standalone

35/5, 20% GRE, \$25/bbl New Development, Standalone

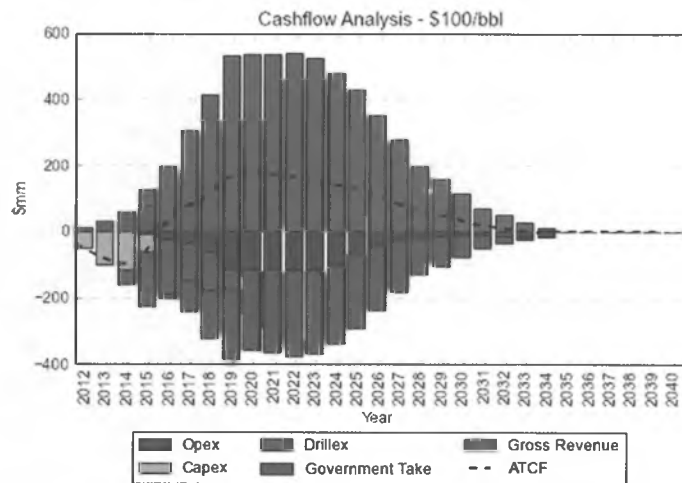
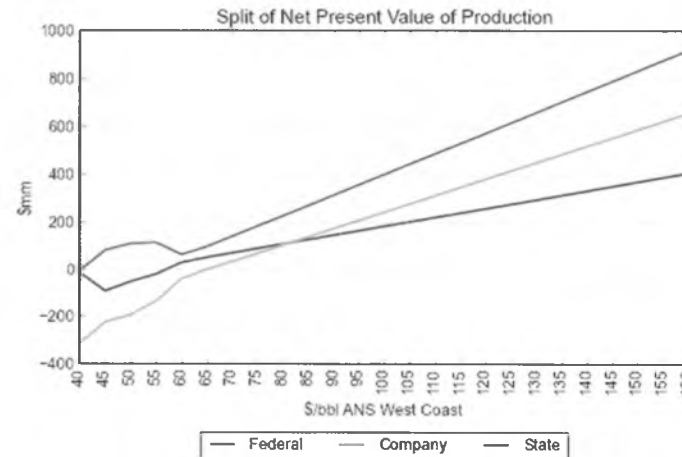
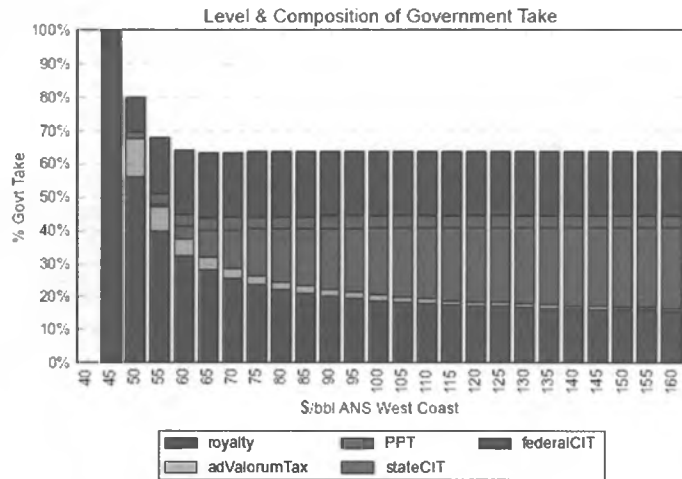


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	62.76%	-1.26	9.79%	26.85
\$100/bbl	61.49%	2.16	15.58%	36.59
\$120/bbl	61.35%	5.29	20.28%	45.66
\$140/bbl	61.38%	8.31	24.31%	54.55

33%, \$5/bbl Allowance, 20% GRE (no time limit) \$18/bbl New Development, Incremental to Incumbent

33/5, 20% GRE. \$18/bbl New Development, Incremental to Incumbent

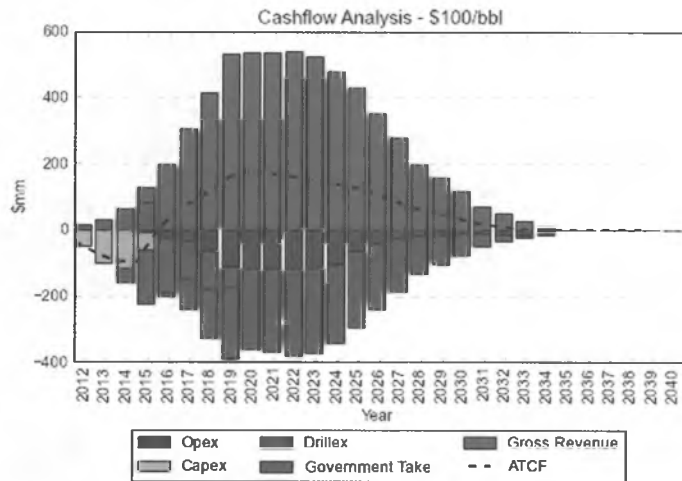
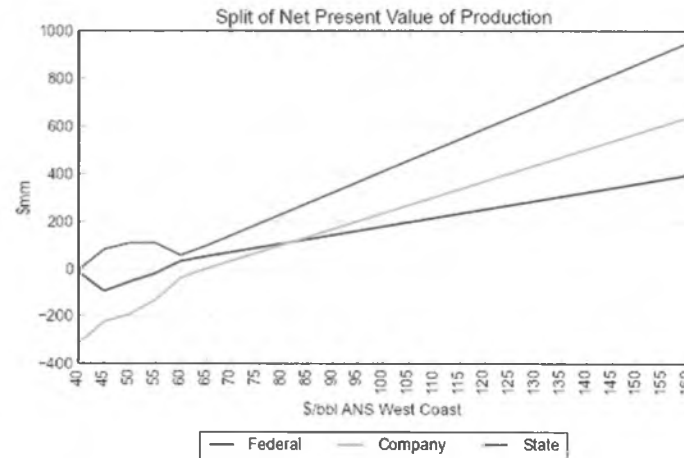
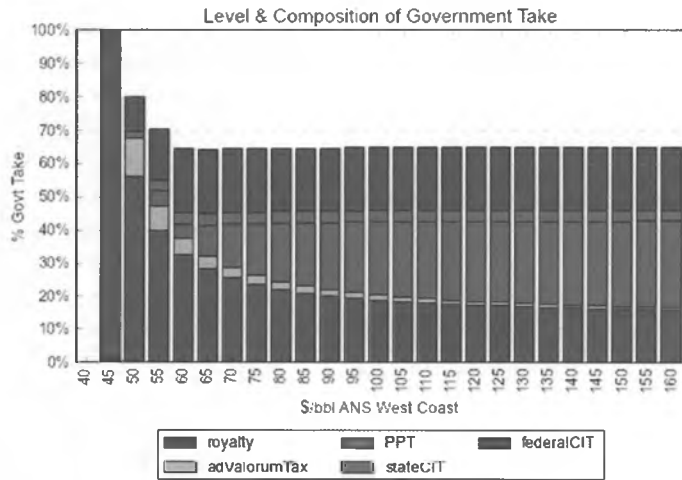


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	63.73%	2.07	17.43%	22.96
\$100/bbl	63.88%	4.84	23.50%	31.63
\$120/bbl	63.96%	7.61	26.71%	40.3
\$140/bbl	64.00%	10.37	33.32%	48.97

35%, \$5/bbl Allowance, 20% GRE (no time limit) \$18/bbl New Development, Incremental to Incumbent

35/5, 20% GRE. \$18/bbl New Development, Incremental to Incumbent

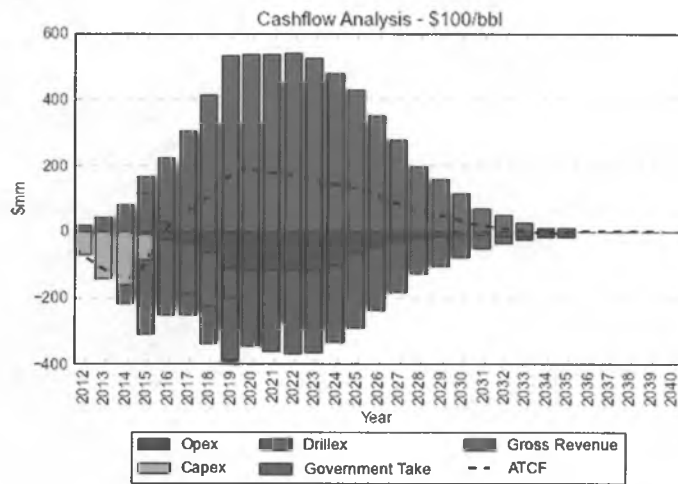
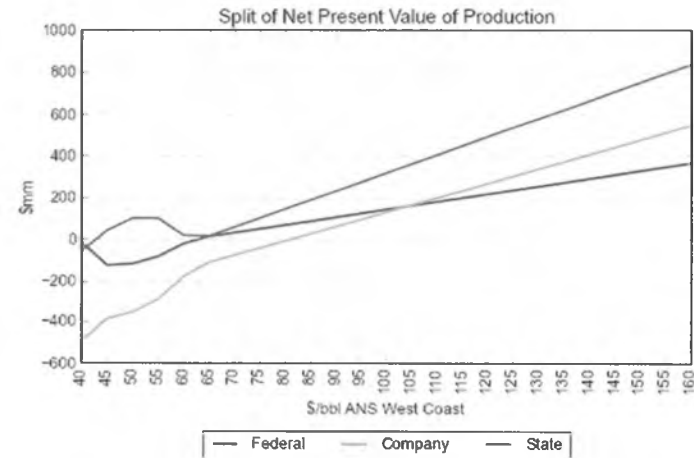
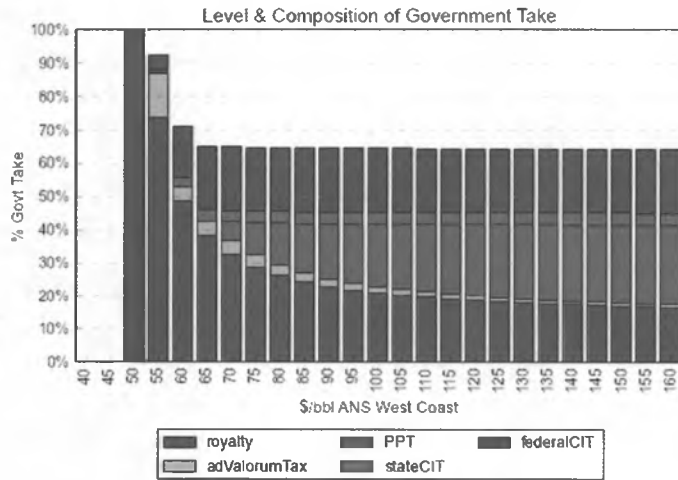


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	64.65%	2.01	17.39%	22.45
\$100/bbl	64.85%	4.7	23.41%	30.87
\$120/bbl	64.95%	7.38	28.58%	39.28
\$140/bbl	65.01%	10.06	33.17%	47.69

33%, \$5/bbl Allowance, 20% GRE (no time limit) \$25/bbl New Development, Incremental to Incumbent

33/5, 20% GRE, \$25/bbl New Development, Incremental to Incumbent

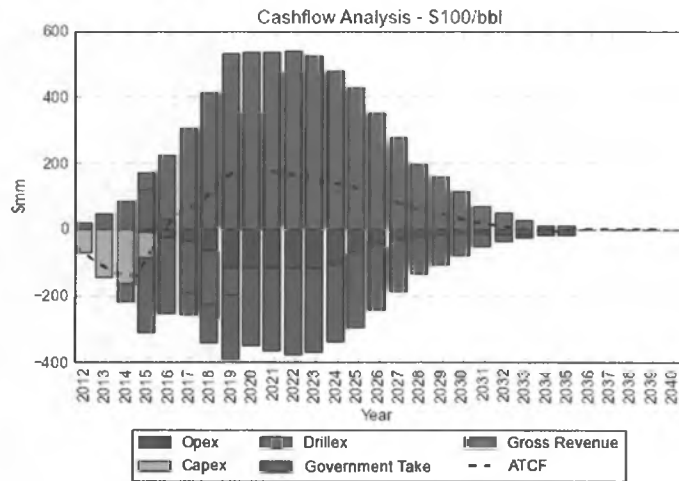
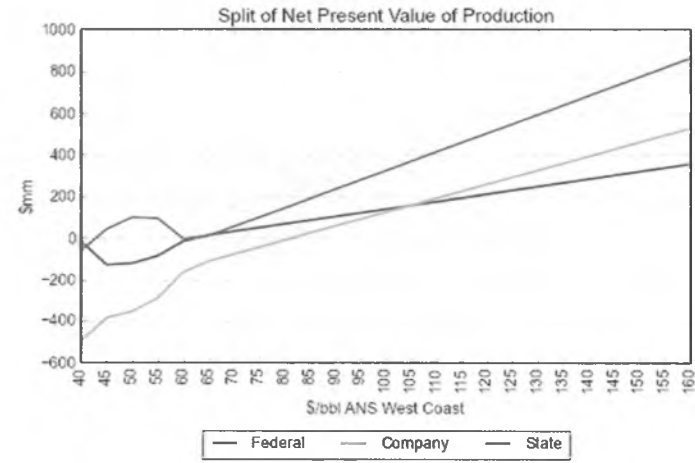
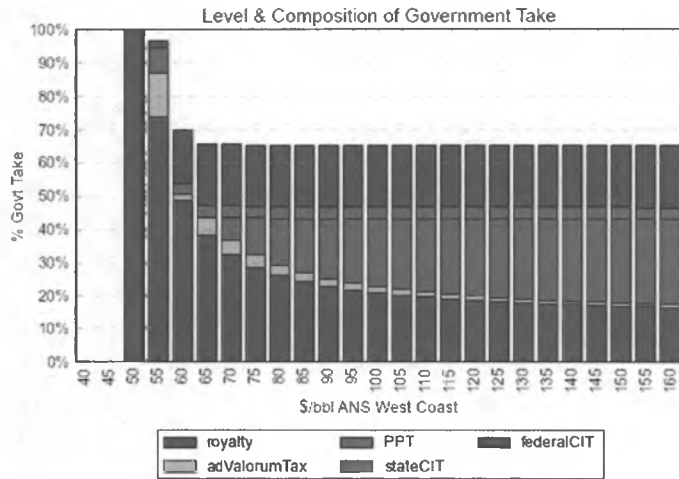


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	64.62%	-0.18	11.62%	22.53
\$100/bbl	64.45%	2.58	16.90%	31.2
\$120/bbl	64.38%	5.35	21.42%	39.87
\$140/bbl	64.33%	8.12	25.43%	48.54

35%, \$5/bbl Allowance, 20% GRE (no time limit) \$25/bbl New Development, Incremental to Incumbent

35/5, 20% GRE, \$25/bbl New Development, Incremental to Incumbent

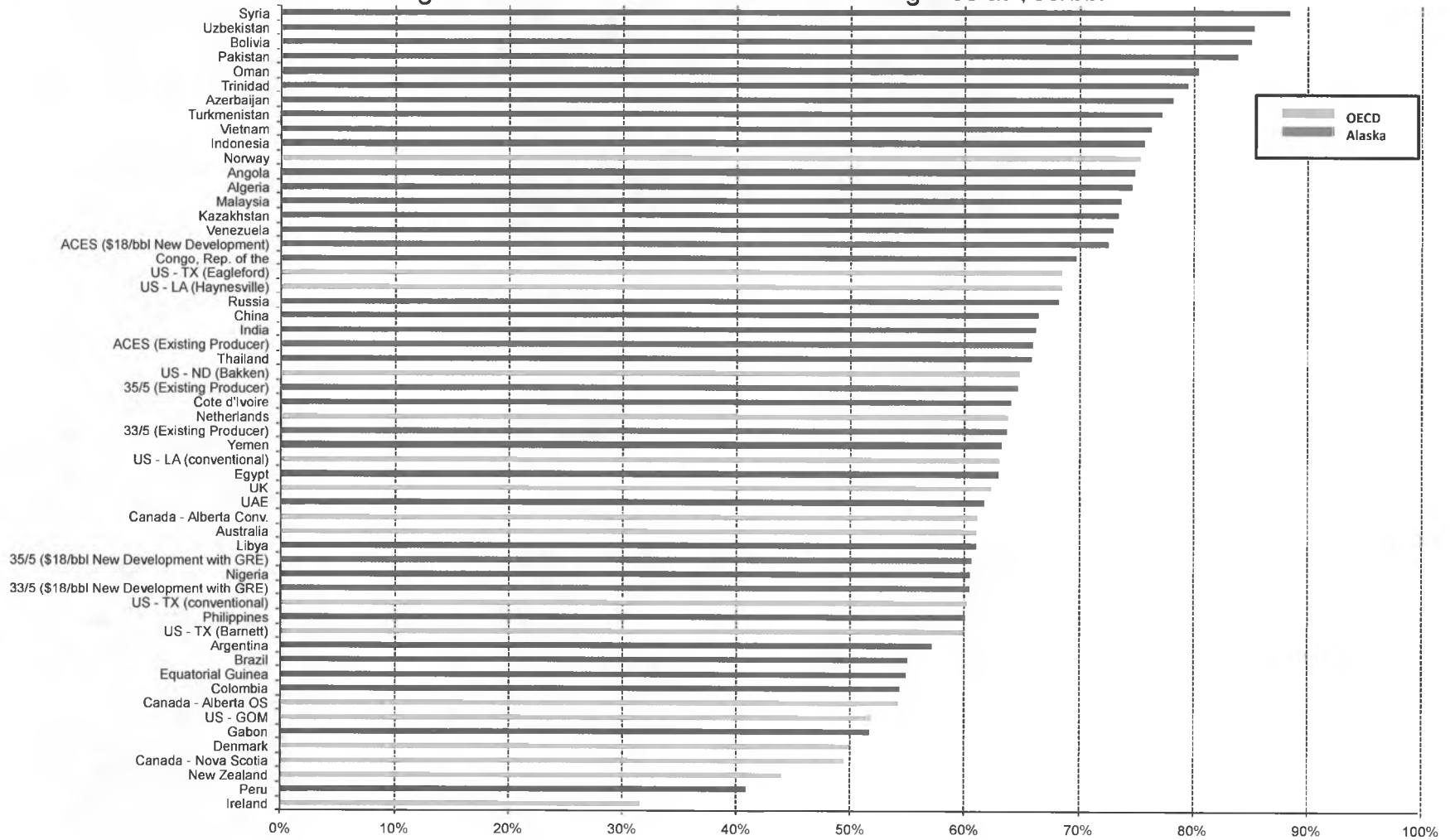


Economic Summary

	GTO	NPV/boe	IRR	Cash Margin
\$80/bbl	65.48%	-0.19	11.61%	22.07
\$100/bbl	65.39%	2.5	16.84%	30.49
\$120/bbl	65.35%	5.18	21.33%	38.9
\$140/bbl	65.33%	7.86	25.31%	47.32

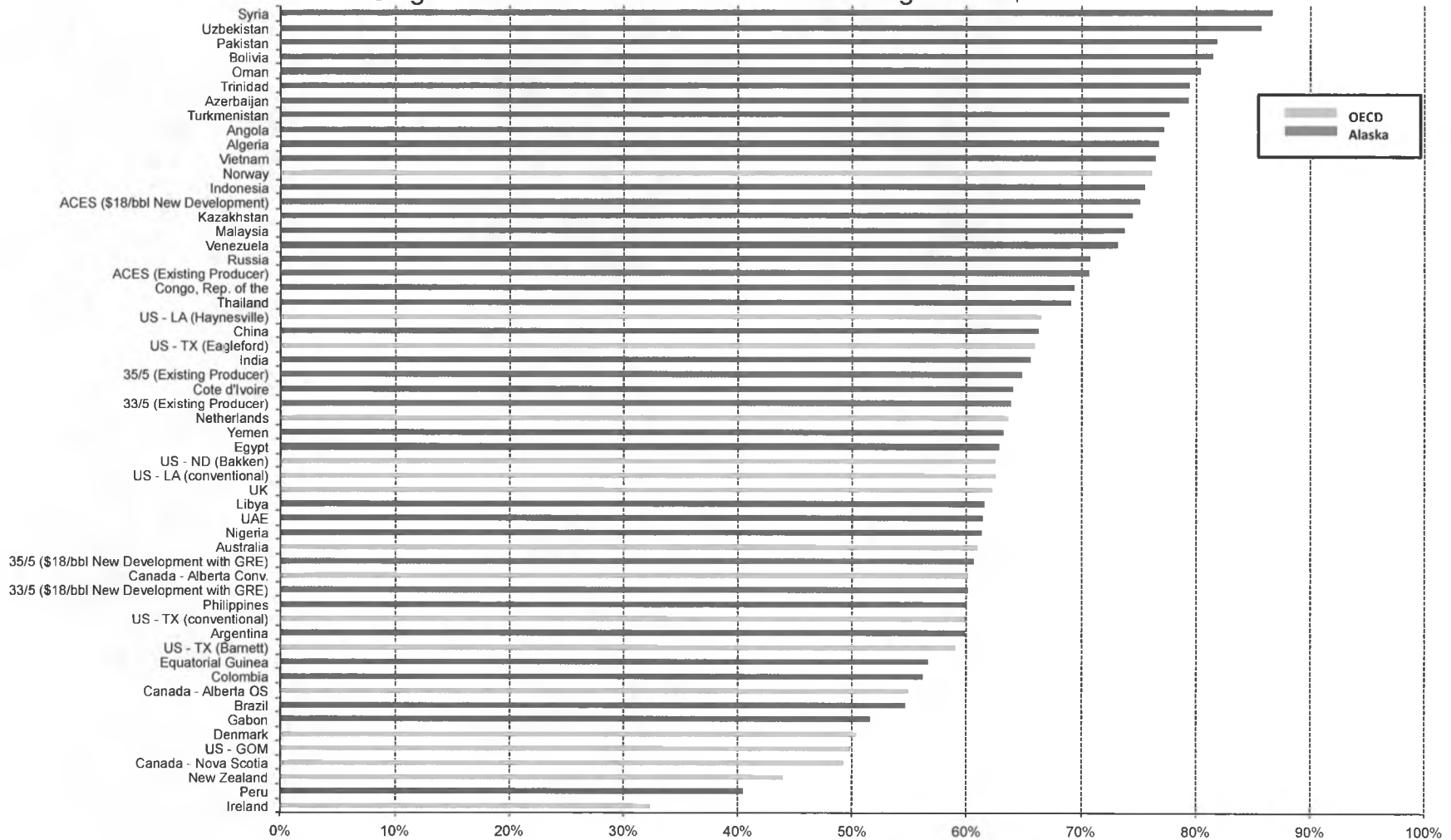
Government Take Competitiveness - \$80/bbl

Average Government Take of Global Fiscal Regimes at \$80/bbl



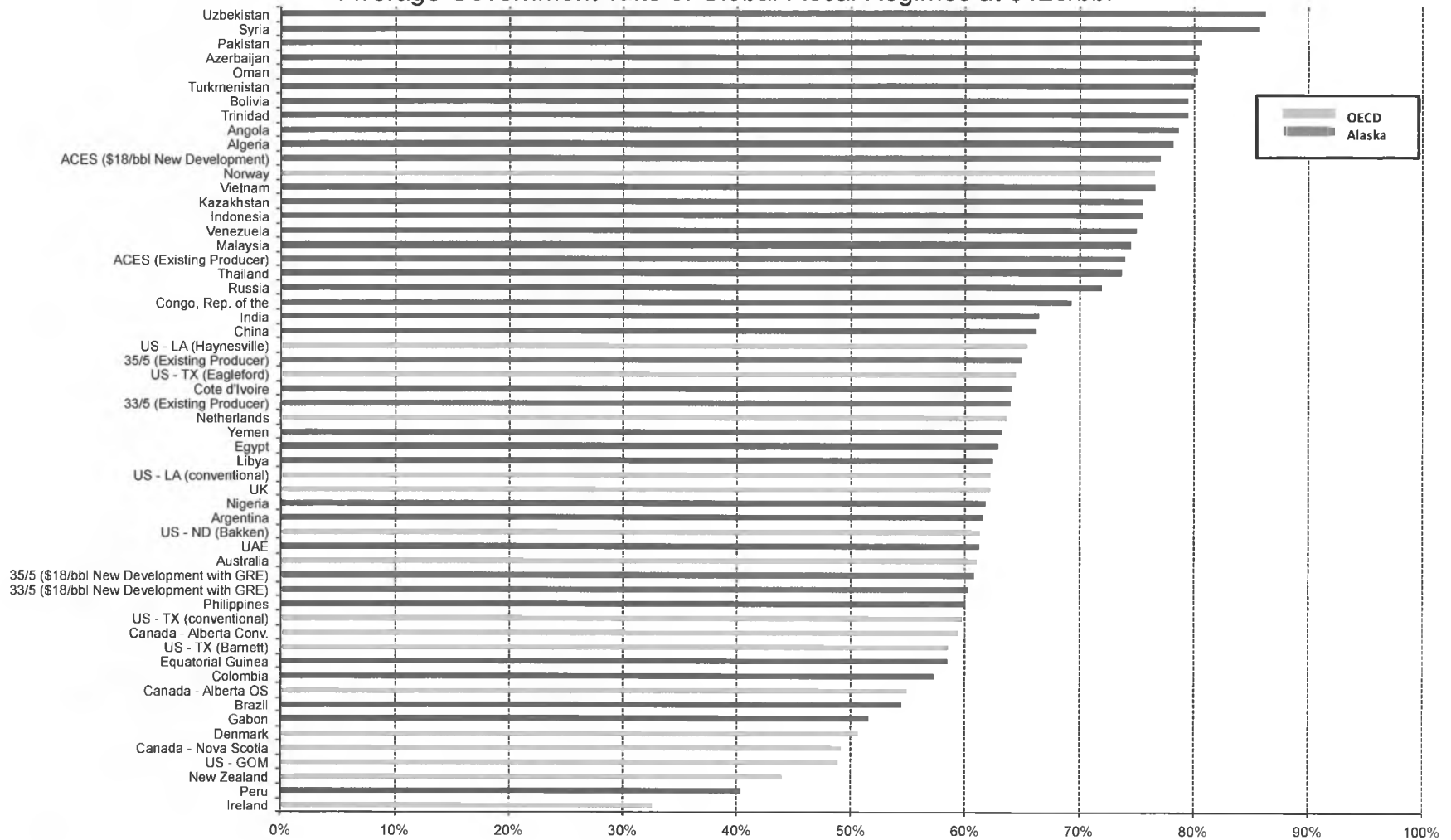
Government Take Competitiveness - \$100/bbl

Average Government Take of Global Fiscal Regimes at \$100/bbl



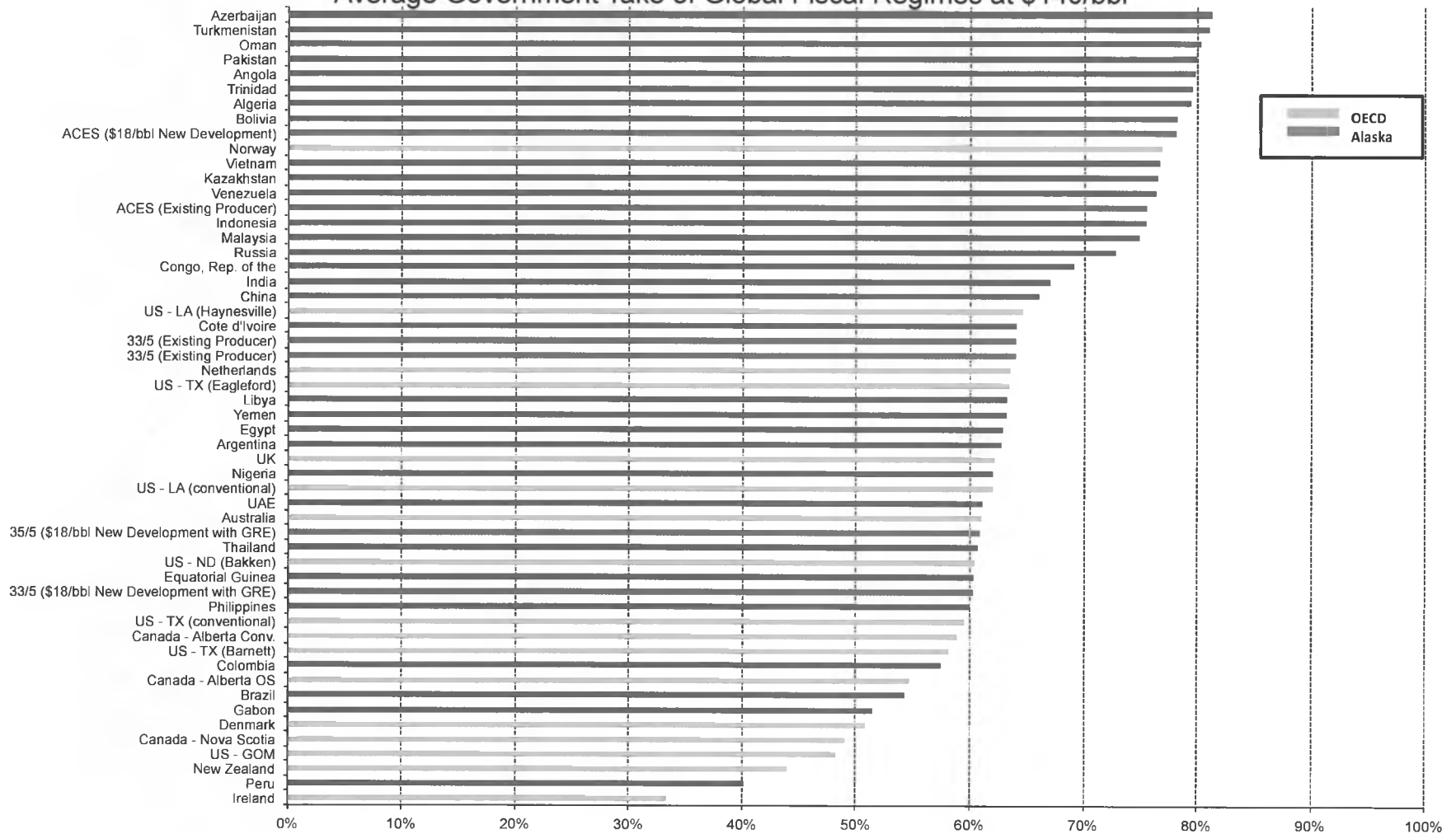
Government Take Competitiveness - \$120/bbl

Average Government Take of Global Fiscal Regimes at \$120/bbl



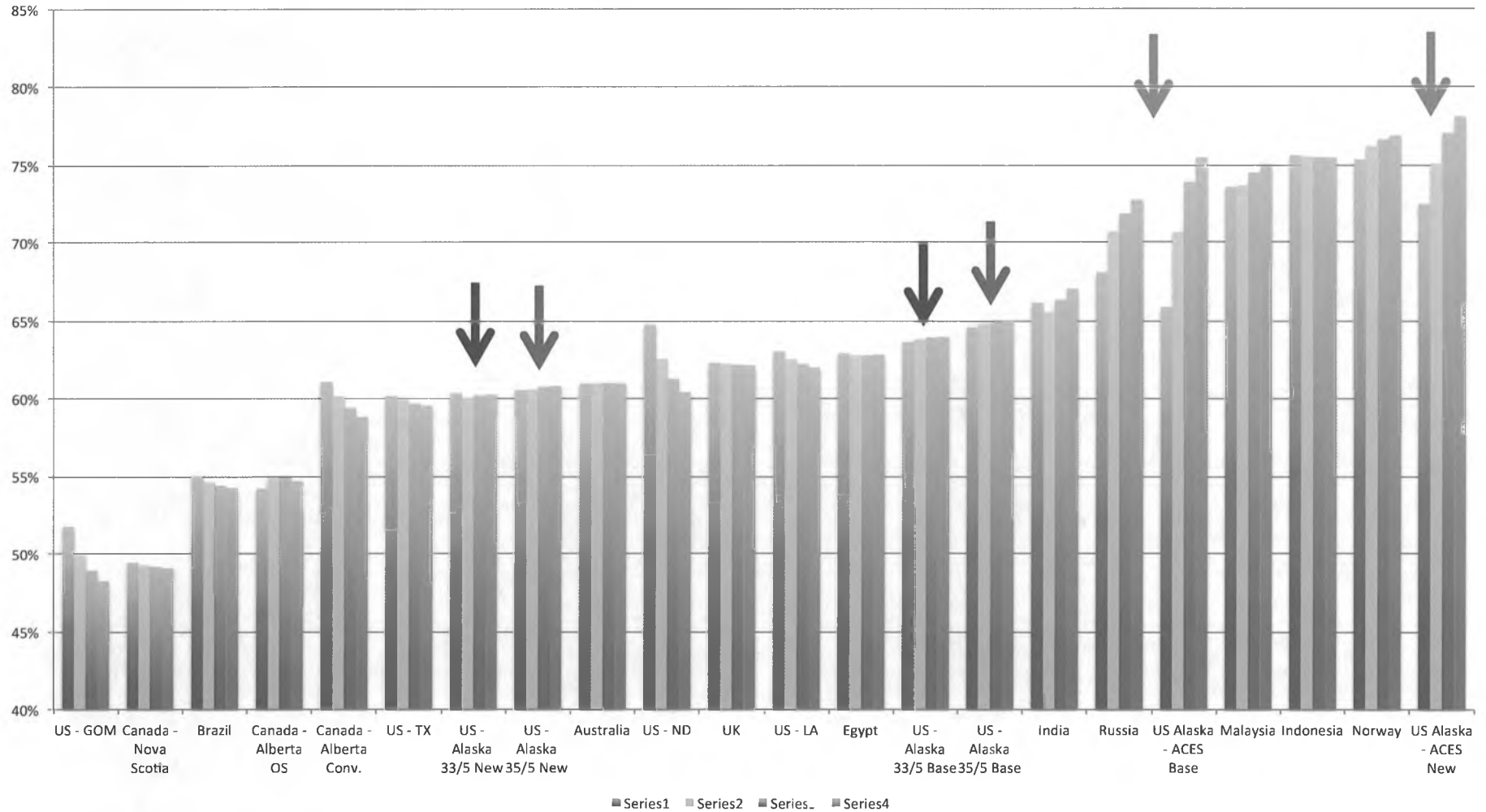
Government Take Competitiveness - \$140/bbl

Average Government Take of Global Fiscal Regimes at \$140/bbl



Government Take Competitiveness

Alaska Government Take Competitiveness - Comparable Regimes



Notice

This material is protected by United States copyright law and applicable international treaties including, but not limited to, the Berne Convention and the Universal Copyright Convention. Except as indicated, the entire content of this publication, including images, text, data, and look and feel attributes, is copyrighted by PFC Energy. PFC Energy strictly prohibits the copying, display, publication, distribution, or modification of any PFC Energy materials without the prior written consent of PFC Energy.

These materials are provided for the exclusive use of PFC Energy clients (and/or registered users), and may not under any circumstances be transmitted to third parties without PFC Energy approval.

PFC Energy has prepared the materials utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice, based on information available at the time such materials were created. To the extent these materials contain forecasts or forward looking statements, such statements are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen, including the actions of governments, individuals, third parties and market competitors. **ACCORDINGLY, THESE MATERIALS AND THE INFORMATION CONTAINED THEREIN ARE PROVIDED "AS IS" WITHOUT WARRANTY OF ANY KIND, EITHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO THE IMPLIED WARRANTIES OF MERCHANTABILITY, ACCURACY, OR FITNESS FOR A PARTICULAR PURPOSE.** Conclusions presented herein are intended for information purposes only and are not intended to represent recommendations on financial transactions such as the purchase or sale of shares in the companies profiled in this report.

PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

© PFC Energy, Inc. License restrictions apply. Distribution to third parties requires prior written consent from PFC Energy.

PFC Energy Locations and Contact Information

NORTH AMERICA

PFC Energy, Washington
1300 Connecticut Avenue, NW
Suite 800
Washington, DC 20036, USA
Tel +1 202 872 1199
Fax +1 202 872 1219

PFC Energy, Houston
2727 Allen Parkway, Suite 1300
Houston, Texas 77019, USA
Tel +1 713 622 4447
Fax +1 713 622 4448

EUROPE

PFC Energy, France
19 rue du Général Foy
75008 Paris, France
Tel +33 1 4770 2900
Fax +33 1 4770 5905

RUSSIA

PFC Energy, Moscow
10 Vozdvizhenka Street
Voentorg building, Suite 341
Moscow, 125009
Russian Federation
Tel +7 (495) 797 3733

ASIA

PFC Energy, Kuala Lumpur
Level 27, UBN Tower #21
10 Jalan P. Ramlee
50250 Kuala Lumpur, Malaysia
Tel +60 3 2172 3400
Fax +60 3 2072 3599

PFC Energy, China
89 Jianguo Road
China Central Place # 4-1602
Chaoyang District, Beijing 100025, China
Tel +86 10 6530 7010
Fax +86 10 6530 5093

PFC Energy, Singapore
15 Scotts Road
Thong Teck Building, #08-04
Singapore 228218
Tel +65 6736 4317

www.pfcenergy.com | info@pfcenergy.com

23



DOR Additional Information requested



Prepared for Senate Finance

March 14, 2013



Lease Expenditures Forecast and projects included therein



Lease Expenditure Forecast Methodology



- Request capital and operating lease expenditure projections from North Slope unit operators in the fall and the spring of each year in writing for the next five years from the current year
- Meet with and request spending projections from companies that are not currently producing but have announced drilling and/or development plans
- Review and coordinate with production forecast regarding anticipated developments outside the five-year time horizon received from operators
- Update long-term capital and operating expenditure projections based on new information



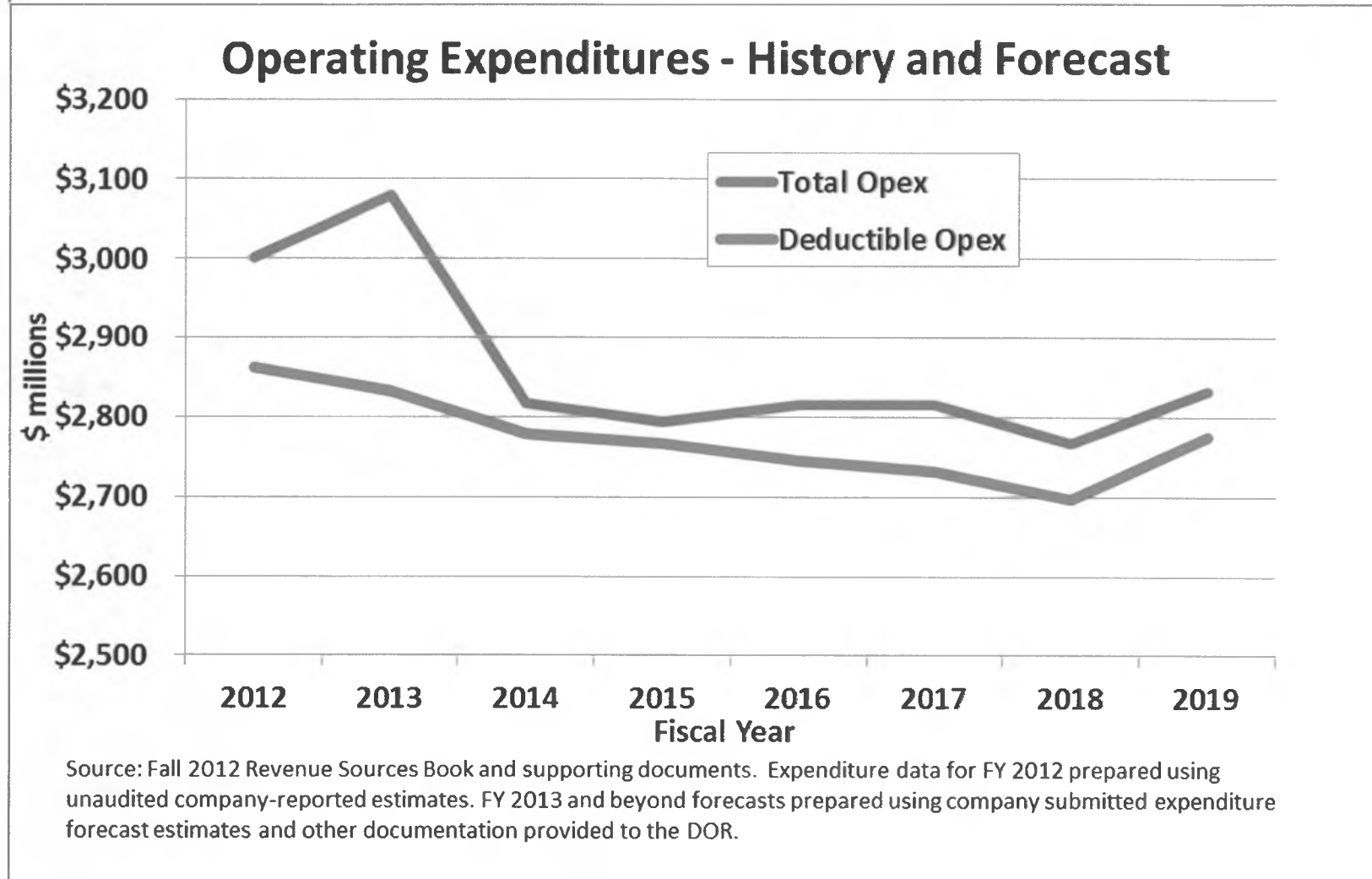
North Slope Projects Included in Fall 2012 Lease Expenditures Forecast



- Currently producing legacy fields
 - Includes ongoing cost of operating fields & maintenance capital
 - Includes facility upgrades and debottlenecking
 - Includes new wells and projects in legacy fields
 - Targeting new oil not in reach of production wells
 - Work-overs of existing wells
 - Advanced EOR projects
- Four new fields in Fall 2012 production forecast
 - Point Thomson
 - CD-5 (Alpine West)
 - Mustang
 - Umiat
- Exploration work at other prospects
 - Includes primarily announced exploration work only
 - Includes spending plans announced by companies like Repsol, Great Bear, and others
 - Does not include costs for development of possible discoveries



North Slope Operating Expenditures

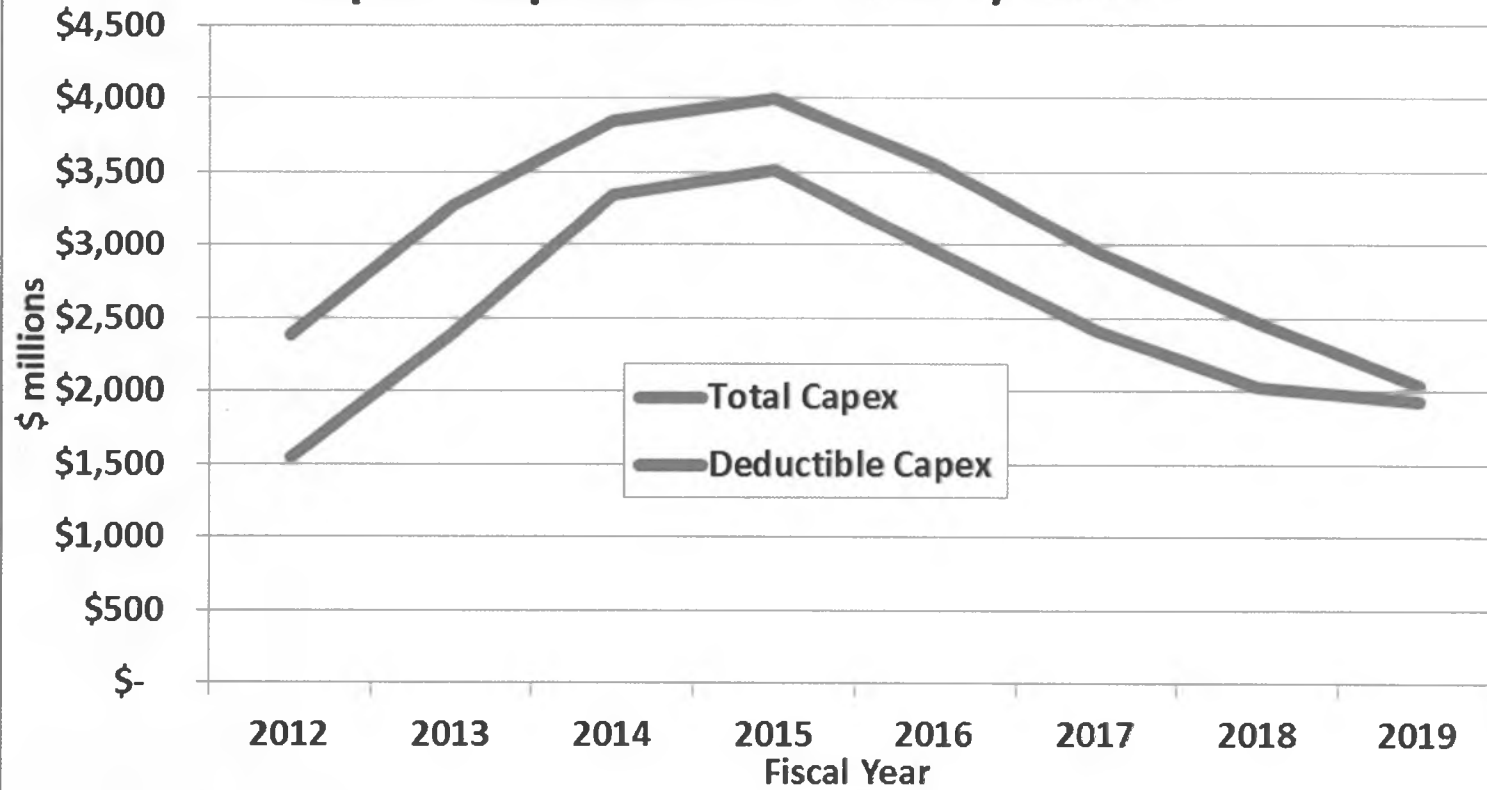




North Slope Capital Expenditures



Capital Expenditures - History and Forecast



Source: Fall 2012 Revenue Sources Book and supporting documents. Expenditure data for FY 2012 prepared using unaudited company-reported estimates. FY 2013 and beyond forecasts prepared using company submitted expenditure forecast estimates and other documentation provided to the DOR.



Fiscal Note Production Scenarios



Additional Oil Production amounts



Average Daily Production – thousands of barrels per day

Total Production	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Fall 2012 Forecast	538.4	518.6	499.7	476.1	442.9	421.6
Scenario A	538.4	518.6	499.7	479.4	449.6	431.6
Scenario B	554.4	548.2	540.9	527.1	502.2	472.0
Scenario C	569.4	578.2	585.9	597.9	598.9	572.0

Additional Daily Production – thousands of barrels per day

Added Production	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Scenario A	0.0	0.0	0.0	3.3	6.7	10.0
Scenario B	16.0	29.6	41.2	51.0	59.3	50.4
Scenario C	31.0	59.6	86.2	121.8	156.0	150.4



Scenarios: At forecasted production



At Forecasted Production

Oil Price in \$/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$90	\$75	\$325	\$250	\$25	-\$150	-\$150
\$100	-\$100	\$50	-\$50	-\$300	-\$450	-\$425
\$110	-\$325	-\$375	-\$450	-\$725	-\$875	-\$800
\$120	-\$625	-\$925	-\$975	-\$1,250	-\$1,375	-\$1,300
\$130	-\$1,000	-\$1,600	-\$1,650	-\$1,925	-\$2,000	-\$1,875



Scenarios: Scenario A



Additional Production Scenario A

Forecasted production plus 50 million barrel field developed by a New Entrant

Oil Price in \$/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$90	\$75	\$325	\$250	\$25	-\$125	-\$125
\$100	-\$100	\$50	-\$50	-\$275	-\$425	-\$400
\$110	-\$325	-\$375	-\$450	-\$700	-\$850	-\$775
\$120	-\$625	-\$925	-\$975	-\$1,250	-\$1,375	-\$1,250
\$130	-\$1,000	-\$1,600	-\$1,650	-\$1,900	-\$1,975	-\$1,850

Assumes field outside of a current unit and subject to gross revenue exclusion, first oil in 2017 and peak production of 10,000 barrels per day in 2019. Total development cost of \$500 million.



Scenarios: Scenario B



Additional Production Scenario B

With addition of 4 oil rigs to legacy fields drilling from 2014-2019

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$90	\$100	\$450	\$475	\$325	\$325	\$250
\$100	-\$50	\$225	\$250	\$75	\$100	\$25
\$110	-\$275	-\$175	-\$100	-\$275	-\$250	-\$275
\$120	-\$550	-\$650	-\$575	-\$750	-\$700	-\$700
\$130	-\$925	-\$1,300	-\$1,200	-\$1,350	-\$1,225	-\$1,225

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day beginning in FY 2014, with a maximum production rate of 60,000 barrels per day for a total of 140 million barrels. Development costs for each well assumed to be \$20 million. One half of this oil is assumed to qualify for the GRE under the provisions of the CS (FIN)



Scenarios: Scenario C



Additional Production Scenario C

With new well pad and 4 additional rigs in legacy fields, plus new 10,000 bopd field starting in 2017

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$90	\$0	\$300	\$425	\$425	\$900	\$825
\$100	-\$150	\$100	\$250	\$250	\$775	\$700
\$110	-\$350	-\$250	-\$50	\$0	\$550	\$500
\$120	-\$625	-\$700	-\$475	-\$400	\$200	\$200
\$130	-\$975	-\$1,300	-\$1,025	-\$925	-\$225	-\$225

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of \$5 billion, all of which is assumed to qualify for the GRE. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new field.



Production forecast data



Forecasted Oil Production on Alaska's North Slope

thousands of barrels per day



FY	Currently Producing	Decline Rate of Currently Producing	Risk Adjusted New Oil	Risk Adj Total Forecast	Net Decline	Percent New Oil
2013	517.6	-10.6%	35.3	552.8	-4.5%	6.4%
2014	486.1	-6.1%	52.3	538.4	-2.6%	9.7%
2015	440.0	-9.5%	78.6	518.6	-3.7%	15.2%
2016	401.1	-8.8%	98.6	499.7	-3.6%	19.7%
2017	367.4	-8.4%	108.7	476.1	-4.7%	22.8%
2018	337.9	-8.0%	105.0	442.9	-7.0%	23.7%
2019	312.2	-7.6%	109.4	421.6	-4.8%	25.9%
2020	289.9	-7.2%	104.9	394.8	-6.4%	26.6%
2021	269.6	-7.0%	96.3	365.9	-7.3%	26.3%
2022	251.2	-6.8%	87.3	338.5	-7.5%	25.8%



Crude Oil Production – Forecast

thousand barrels per day



FY	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Prudhoe Bay	267.5	256.1	250.0	240.3	228.8	218.1	207.8	197.0	186.9	177.3
PBU Satellites ⁽¹⁾	46.5	44.4	41.4	38.9	36.3	33.3	30.5	27.7	25.8	23.8
GPMA ⁽²⁾	26.8	25.5	23.3	21.1	19.1	17.7	16.4	15.2	14.2	13.4
Kuparuk	85.0	84.8	82.8	79.0	75.3	71.7	68.3	65.0	61.3	56.2
Kuparuk Satellites ⁽³⁾	23.9	23.4	21.9	21.8	20.8	18.6	16.4	14.7	13.2	11.9
Endicott ⁽⁴⁾	10.1	10.0	10.9	10.5	8.9	7.6	6.7	6.1	5.5	4.9
Alpine ⁽⁵⁾	67.3	64.3	60.3	60.5	55.4	47.3	40.0	34.4	29.8	26.0
Offshore ⁽⁶⁾	25.6	29.9	28.0	26.3	24.3	21.8	19.6	17.9	16.5	15.1
NPR-A	0.0	0.0	0.0	0.0	0.0	0.1	9.8	11.2	7.5	5.1
Point Thomson	0.0	0.0	0.0	1.3	7.2	6.7	6.1	5.6	5.2	4.8
Total ANS	552.8	538.4	518.6	499.7	476.1	442.9	421.6	394.8	365.9	338.5
Cook Inlet	10.4	9.6	8.9	8.3	7.7	7.2	6.7	6.3	5.9	5.6
Total Alaska	563.2	548.0	527.5	508.0	483.8	450.1	428.3	401.1	371.8	344.1

⁽¹⁾ Aurora, Borealis, Midnight Sun, Orion, Polaris, Milne Point, Sag River, Schrader Bluff, Ugnu

⁽²⁾ Lisburne, Niakuk, Point McIntyre, Raven, West Beach, West Niakuk

⁽³⁾ Meltwater, NEWS, Tabasco, Tarn, West Sak

⁽⁴⁾ Endicott, Minke, Sag Delta, Eider, Badami

⁽⁵⁾ Alpine, Fiord, Nanuq, Qannik, Mustang (after 2016)

⁽⁶⁾ Northstar, Oooguruk, Nikaitchuq, Liberty (delayed)



North Slope Lease Expenditures Fall 2012 Revenue Forecast

FY	Total		Deductible	
	OPEX	CAPX	OPEX	CAPX
2013	3,079	3,263	2,833	2,393
2014	2,817	3,845	2,779	3,339
2015	2,794	3,992	2,767	3,507
2016	2,815	3,549	2,746	2,953
2017	2,815	2,958	2,733	2,421
2018	2,768	2,474	2,697	2,031
2019	2,833	2,046	2,776	1,932
2020	2,817	1,841	2,769	1,734
2021	2,680	1,756	2,639	1,655
2022	2,557	1,682	2,523	1,586

24

Adopted
3/14/13

28-GS1647\Y.7
Nauman/Bullock
3/14/13

AMENDMENT # 1

OFFERED IN THE SENATE

BY SENATOR KELLY

TO: CSSB 21(FIN), Draft Version "Y"

1 Page 1, line 9, following "explorers;":

2 Insert "establishing the Oil and Gas Competitiveness Review Board;"

3

4 Page 23, following line 11:

5 Insert a new bill section to read:

6 "** Sec. 34. AS 43.98 is amended by adding new sections to read:

7 **Article 2. Oil and Gas Competitiveness Review Board.**

8 **Sec. 43.98.040. Oil and Gas Competitiveness Review Board.** (a) The Oil and
9 Gas Competitiveness Review Board is established in the department.

10 (b) The board shall consist of nine members as follows:

11 (1) two members nominated by the two leading nonprofit trade
12 associations representing the oil and gas industry in the state and appointed by the
13 governor, with one member nominated by each association;

14 (2) the chair of the Alaska Oil and Gas Conservation Commission or
15 the chair's designee;

16 (3) three members of the public appointed by the governor, including
17 one member who is a petroleum engineer, one member who is a geologist, and one
18 member who is an economist;

19 (4) the commissioner of environmental conservation or the
20 commissioner's designee;

21 (5) the commissioner of natural resources or the commissioner's
22 designee; and

23 (6) the commissioner of revenue or the commissioner's designee.

1 (c) The governor shall, every two years, designate one of the members as
2 chair.

3 (d) Members of the board appointed under (b)(1) and (b)(3) of this section
4 serve for six years. An individual who has served on the board may be reappointed.

5 (e) A vacancy on the board shall be filled in the manner of the original
6 appointment.

7 (f) A member of the board may be removed and replaced at the discretion of
8 the governor.

9 (g) The members of the board appointed under (b)(1) and (b)(3) of this section
10 serve without compensation but shall receive per diem and travel expenses authorized
11 for boards and commissions under AS 39.20.180.

12 (h) The board may enter into contracts for professional services and may
13 employ staff for administrative support for the board.

14 (i) The board may not meet more than once in a calendar year.

15 **Sec. 43.98.050. Duties.** The duties of the board include the following:

16 (1) establish and maintain a salient collection of information related to
17 oil and gas exploration, development, and production in the state and related to tax
18 structures, rates, and credits in other regions with oil and gas resources;

19 (2) evaluate and suggest changes to state laws and regulations
20 governing the oil and gas industry;

21 (3) review historical, current, and potential levels of investment in the
22 state's oil and gas sector;

23 (4) identify factors that affect investment in oil and gas exploration,
24 development, and production in the state, including tax structure, rates, and credits;
25 royalty requirements; infrastructure; workforce availability; and regulatory
26 requirements;

27 (5) review the competitive position of the state to attract and maintain
28 investment in the oil and gas sector in the state as compared to the competitive
29 position of other regions with oil and gas resources;

30 (6) in order to facilitate the work of the board, establish procedures to
31 accept and keep confidential information that is beneficial to the work of the board,

1 including the creation of a secure data room and confidentiality agreements to be
2 signed by individuals having access to confidential information;

3 (7) make written findings and recommendations, together with
4 suggested legislation, to the Alaska State Legislature before December 1 of each year,
5 or as soon thereafter as practicable, regarding

6 (A) changes to the state's regulatory environment that would be
7 conducive to encouraging increased investment while protecting the interests
8 of the people of the state and the environment;

9 (B) changes to the state's fiscal regime that would be conducive
10 to increased and ongoing long-term investment in and development of the
11 state's oil and gas resources; and

12 (C) alternative means for increasing the state's ability to attract
13 and maintain investment in and development of the state's oil and gas
14 resources.

15 **Sec. 43.98.060. Information to be provided to board.** (a) The commissioner
16 of natural resources, the commissioner of revenue, the commissioner of environmental
17 conservation, and other commissioners and state agencies that have responsibility for
18 and maintain information related to oil and gas investment and activity in the state
19 shall, at the request of the board, provide information required by the board to carry
20 out the duties described in AS 43.98.050.

21 (b) At the request of the board, and except for information that is confidential
22 under AS 40.25.100(a) or AS 43.05.230 and information required to be held
23 confidential by the Alaska Oil and Gas Conservation Commission, a commissioner
24 may disclose to the board information that is otherwise confidential after each member
25 of the board and each staff member for the board with access to the information signs
26 a confidentiality agreement prepared by the commissioner making the disclosure.
27 Information that is confidential under AS 43.05.230 may not be disclosed to the board.

28 **Sec. 43.98.070. Definition.** In AS 43.98.040 - 43.98.070, "board" means the
29 Oil and Gas Competitiveness Review Board."
30

31 Renumber the following bill sections accordingly.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31

Page 23, following line 13:

Insert a new bill section to read:

**** Sec. 37.** AS 43.98.040, 43.98.050, 43.98.060, and 43.98.070 are repealed December 31, 2022."

Renumber the following bill sections accordingly.

Page 23, following line 29:

Insert a new bill section to read:

**** Sec. 40.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITION: OIL AND GAS COMPETITIVENESS REVIEW BOARD. The governor shall appoint the initial members of the Oil and Gas Competitiveness Review Board, established in sec. 34 of this Act, before January 1, 2014. The initial terms of the members of the board appointed under AS 43.98.040(b)(1) and (b)(3) shall be set by the governor and staggered so that one member serves one year, two members serve four years, and two members serve six years. The first written findings and recommendations, together with suggested legislation, shall be delivered to the Alaska State Legislature on December 1, 2015, or as soon thereafter as practicable."

Renumber the following bill sections accordingly.

Page 24, line 1:

Delete "34"

Insert "35"

Page 24, line 3:

Delete "35"

Insert "36"

- 1 Page 24, line 6:
- 2 Delete "secs. 39 and 40"
- 3 Insert "secs. 42 and 43"

25

Senate Finance Testimony 3-5-2013

Thank you for giving me the opportunity to speak with the Senate Finance Committee today about the oil and gas industry on the North Slope. We are a strong supporter of SB 21 we believe that the passage of this bill will not only result in significant investment on the North Slope, it will serve as a catalyst to increasing production as well. Some of you may have heard Bill Armstrong make a presentation to the Senate Resources Committee a couple of weeks ago. If you heard that presentation you probably already know that it has been our opinion that you in the Senate have been inundated with so much information that I cannot begin to imagine how you can process it all. I have been in this business for more than 30 years and have experience in numerous states and some various other regions in the world and I have to tell you, it is incredibly difficult to keep up with all of the information that is being provided with regard to SB 21.

For this reason I will not have a power point, I would rather talk to you and see if you think I have anything to add with respect to how Alaska can increase its production in a manner that is fair to Alaskans and is something that the oil companies can work with. Today I would like to keep things pretty simple and keep to the fundamentals. The only thing that really tells the story on the North Slope is what does its production profile look like and is there anything on the horizon that will help it.

As I was trying to get ready to talk with you about this I had an internal fight with myself. It reminded me of my high school English class when we read the Dickens classic, A Tale of Two Cities. The first part of opening line of the book is "It was the best of times, it was the worst of times." Guys this describes the oil industry on North Slope and where it is at this point in time better than anything I can think of.

I know revenues to the State have been up over the last few years and I know that you as members of the legislature have an important duty to make

certain that the State gets its fair share and maximizes the state's fiscal position. The hard part of the story is when you look to the future and the fact that while the North Slope is one of the most remarkable petroleum provinces in the world, it is the only petroleum province in the US that is not enjoying the benefit of the amazing technological advancements in horizontal drilling and stage frac technology. I know you have seen the same graph in probably ten different presentations of the North Slope's production decline while Texas and North Dakota have production increases. Last Friday the ADN reported on the front page that Texas has doubled its production since 2010, doubled its production in 3 years, amazing (especially given the fact that Alaska has experienced about a 6% annual decline during that period), and we all know North Dakota passed Alaska last year to become the second largest producer in the United States. I never thought I would see that. I know someone can look at that data set and feel that this is the worst of times because as we all know the states revenue is only as good as the production and if the production keeps dropping at this rate, soon the state will have big issues with its budget.

I don't know how long TAPS can last at the current decline rate and frankly that's not the question anyone should be asking, we should be asking, "How in the heck can we have one of the greatest petroleum provinces in the world and get beat out by North Dakota in daily production. Guys as a petroleum system North Dakota is a Jr. High team and Alaska is Professional team, there is no way this should happen, but it has and we have to ask ourselves how did we get to this spot and what will it take for Alaska to take its rightful spot as the top producing state in the nation.

Before I give you anymore of my thoughts I should probably take a second to tell you a little about Armstrong Oil & Gas and what we have done in Alaska. We are an independent oil and gas company headquarter in Denver, Colorado. We would probably be considered a bit of new type of company for the North Slope as we are privately owned, we carry no debt and as such

we do everything out of our own pockets, every decision we make is based on the bottom line and not what some stock analyst on Wall Street thinks or says.

I am a minority owner in Armstrong and have been involved in Alaska since the beginning. We began studying the North Slope diligently in the late 90s, we made our first lease acquisition in the early 2000s. Our business model is to establish significant exploration and development projects through the utilization of all of the technology available to our industry. It is our opinion that we have the best scientist in the world these scientists have an extremely broad and diverse experience level that affords us a perspective that most people do not have. Most of our Geoscientist spent their early years with Exxon.

At any rate the first concept we pulled together on the North Slope was what is today the O3 field. We initially established the concept through acquisition of leasehold and technical data and then we brought in Pioneer to help us develop the field. Subsequently we brought a company called Kerr McGee into to help us define and develop what is today known as the Nikaitchuq field that is operated by ENI. We currently operate the North Fork Gas Field in South Central Alaska and on the North Slope we are partners with Repsol E&P USA where we currently have 3 rigs running on the North Slope.

If I can I would like to take second to apologize for the lack of a polished presentation for you today. The fact is I am not that good of a public speaker and I didn't know I was coming here until a few days ago, so my apologies. What you will hear from me are observations of what we as a company have found is the number one critical attribute any area needs in order to have a successful thriving oil and gas industry that will either sustain itself or grow even larger.

The most critical barometer for the health of a producing region is the rig count (it is the canary in the mine). Depending on the week, you see Alaska's fluctuate between 6 to 14. Let me put that in perspective, the Permian Basin not all of Texas, just the Permian Basin is at 430. That is around 43 times greater than all of Alaska by itself. Assuming each area drills and completes a well in a couple of months that means in one year the Permian Basin brings on an additional 2580 wells while all of Alaska would bring on about 60. With this metric in mind it is easy to see how Alaska is drifting the wrong direction with its production. You can apply this metric to any basin or state and you will get the same answer (North Dakota is at 178 rigs, Oklahoma has 190), in order for Alaska to continue to be considered relevant in the petroleum industry something must be done to make it competitive with the other states and regions of the world.

When I look at some of the public companies I see such amazing results. Pioneer recently reported it had over 36,000 net resource locations with potential in excess of 8BBO. EOG Resources has had oil production growth of 35% in 2010, 52% in 2011 and 39% in 2012, they have a drilling inventory that will keep them busy for the next 15 years even if they do no new business. My point is that this story is occurring in tons of companies all through the lower 48, states like Pennsylvania are on the rise and the state of Alaska needs to do something to make itself more competitive. We feel like SB 21 is a great start to getting Alaska competitive with the rest of the world.

I think it is important to note that SB 21 needs to be passed as it is and possibly with some minor improvements in order to make certain Alaska becomes competitive with the rest of the world. We need to make certain the GRE stays in place as it is and is not limited to the first 7 years. A study of the new fields on the North Slope show how time consuming and difficult it is to bring fields on line and as such you need the GRE to be effective

throughout the life of the field. The monetizing of the EIC will serve to continue to encourage new entrants with new ideas to come to the North Slope.

The fact is the North Slope is remote, cold, expensive, with tremendous regulatory issues and SB 21 is needed or Alaska will not be considered competitive with the rest of the world. It is next to impossible to convince a substantial company to come to the North Slope to develop new fields when the states own experts rate the state of Alaska worse than Kazakhstan for new field development. It is important to note that by supporting SB 21 as a new entrant we are actually helping the state's fiscal position. We are walking away from the cash reimbursement from the state of the LCF and QCE, so that we can have a stable tax regime. At the end of the day the state has only upside with regard to the new field portion of SB 21.

We do think SB 21 simplifies the tax code, we think it is fair to Alaskans, that it is durable and that it makes Alaska competitive. I believe that you need all parts of SB 21 for the state to be successful. The state needs the legacy field provisions of SB 21 to pass so that the fields like Prudhoe Bay and KRU can provide quick immediate barrels into TAPS and keep the transportation costs on TAPS from increasing.

The state also desperately needs SB 21 to pass so that new entrants will be encouraged to come to the NS and invest, this is the future of the North Slope. Currently 92% of all production from the North Slope comes from 2 operators, I know of no other significant petroleum province in the world that has this fact set. As a comparison the top 20 operators in Permian make up 47% of the basins production and when I asked our research guys how many make up 92%, I was told that the number was so high that it would take a tremendous amount of time to figure that out. On the North Slope

the top two operators drilled 86% of all of the wells in the basin, in the Permian Basin the top 20 operators make up 35% of all wells drilled.

None of this is the operators fault they are doing their job, but it does show that there is a desperate need for more players on the North Slope and in order to have any impact this change needs to be done now. As an example from the time we started working on O3 until the first production came out of the field it took 10 years, so as you can see something needs to be done right now.

Further evidence of the North Slope not being competitive can be found within its leasesales. Since we made our first bid in Alaska in 2001, a very successful sale would be one that is considered to bring in around \$10MM with around 6 successful bidders, compare this against the GOM sales that have more bidders and as an example on the last Central GOM sale had one tract that brought in \$157MM that one tract being well in excess of the last 10 state North Slope Leasesales. This is evidence of a system that needs fixing.

So enough about the negative news. The good news is I can tell you from the perspective of the company that brought Pioneer, ENI and Repsol to the North Slope that there are a lot of companies that would desperately like to do business on the North Slope but they have shied away because of the ACES tax system. To be sure the costs concern them and I believe we need to work hard to streamline the permitting of projects on the North Slope, but I believe the primary thing that keeps them away is the current ACES tax system.

SB 21 is a huge step in the right direction to getting new entrants on the North Slope as well as getting production from new fields up and running,

increasing the life of TAPS and providing high paying jobs for Alaskans in the process. There is an incredible step function change in our industry that is going on right before our eyes and if Alaska doesn't make the changes provided for in the Governor's bill this revolution has the potential to pass over Alaska. So these are my thoughts, but I would really like to talk about this with all of you. This is an amazing time in our business and I want to make certain that you guys ask any question at all that you feel should be discussed. I love this business and think that is the best way to get the heart of the discussion so please ask me any questions you want about taxes, permitting, potential of the North Slope (it is huge) or anything else you want to talk about.

~~Paul Curtis dearth~~

26

Senate Finance Committee

Oil Tax and Credits Comparison - ACES to Senate Bill 21

	ACES	SB 21	CS for SB 21 (RES)	CS for SB 21 (FIN)
Base Tax	25%	25%	35%	30%
Govt. Take (New)				
\$80	69%	55%	60%	60%
\$100	73%	58%	56%	60%
\$120	76%	58%	60%	60%
\$140	77%	58%	60%	60%
Govt. Take (Existing)				
\$80	66%	64%	64%	63%
\$100	71%	63%	65%	63%
\$120	74%	62%	65%	63%
\$140	75%	62%	65%	63%
Progressivity	Yes, .4% above \$30, .1% above \$92.5 (net calculation)	No	No	No
Credits	Qualified Capital Expenditure (QCE) Credits 20%	Gross Revenue Exclusion (GRE) 20%	Gross Revenue Exclusion (GRE) 30% - New Production, New and Expanded Participating Area	Gross Revenue Exclusion (GRE) 20% - New Production, New Participating Area, New Production in Legacy Fields
	Net Operating Loss (NOL) Credit 25%, Monetizable	Net Operating Loss (NOL) Credit 25%, Carried Forward to Production, 15% interest	Net Operating Loss (NOL) Credit 35%, Carried Forward to Production, 15% interest	Net Operating Loss (NOL) Credit 30%, Monetizable
	Small Producer Credit \$12mm, expires 2016	Small Producer Credit \$12mm, extended to 2022	Small Producer Credit \$12mm, extended to 2022	Small Producer 12mm, extended to 2022
	Exploration Credit up to 40%	Exploration Credit up to 40%	Exploration Credit up to 40%	Exploration Credit up to 40%
	~	~	\$5/bbl	\$5/bbl