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SENATE COMMITTEE REPORT

First Committee of Referral

DATE: 3/25/10

FURTHER: Finance

Date of 5-Day Notice: _____
(in accordance with Uniform Rule 23)

DATE TURNED
IN TO OFFICE: _____

Resources Committee considered SENATE BILL NO. 309

SB 309 GAS EXPLORATION/DEVELOPMENT TAX CREDIT

"An Act amending and extending the exploration and development incentive tax credit under the Alaska Net Income Tax Act for operators and working interest owners directly engaged in the exploration for and development of gas from a lease or property in the state; providing for an effective date by amending the effective date for sec. 2, ch. 61, SLA 2003; and providing for an effective date."

and recommends:

- be replaced with SCS or CS SB 309 (RES)
- adopt previous SCS or CS _____
- attached amendment(s)
- adopt _____ Letter of Intent
- further referral to _____ Committee

SENATE BILL:	
<input type="checkbox"/> Same Title	
<input checked="" type="checkbox"/> New Title	
<hr/>	
HOUSE BILL:	
<input type="checkbox"/> Same Title	
<input type="checkbox"/> Technical Title Change	
<input type="checkbox"/> New Title w/ SCR # _____	


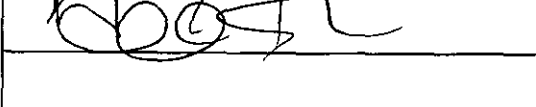
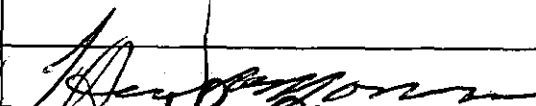
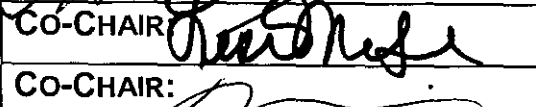
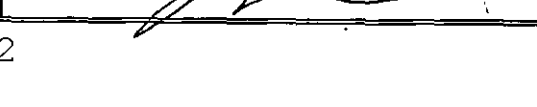
NEW FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#
REV	4/10		✓		

PREVIOUS FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#

APPROPRIATION - no fiscal note

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	DO PASS	DO NOT PASS	NO REC	AMEND
	STORA			✓	
	FRENCH			✓	✓
	WAGONER	✓			
CO-CHAIR: 	McBure	✓			
CO-CHAIR: 	wielechowski				✓

26-LS1629\B
Bullock
4/8/10

CS FOR SENATE BILL NO. 309(RES)
IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-SIXTH LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): SENATE RULES COMMITTEE BY REQUEST

~~PROPOSED AMENDMENT~~

1 "An Act amending and extending the exploration and development incentive tax credit
2 under the Alaska Net Income Tax Act for operators and working interest owners
3 directly engaged in the exploration for and development of gas from a lease or property
4 in the state; relating to a credit against the tax on the production of oil and gas for a
5 qualified capital expenditure and for certain losses and expenditures; providing a credit
6 against the tax on the production of oil and gas for drilling certain exploration wells in
7 the Cook Inlet sedimentary basin; providing for an effective date by amending the
8 effective date for sec. 2, ch. 61, SLA 2003; and providing for an effective date."

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

10 * Section 1. AS 43.20.043(a) is amended to read:

11 (a) Subject to the terms and conditions of this section, and in addition to any
12 other credit authorized to the taxpayer by this chapter, a taxpayer that is an operator or

1 working interest owner directly engaging in the exploration for and development of
 2 gas may apply as a credit against the state tax liability that may be imposed on the
 3 taxpayer under this chapter,

4 (1) for a tax year beginning after December 31, 2002, and before
 5 January 1, 2010,

6 (A) [(1)] 10 percent of the taxpayer's qualified capital
 7 investment; and

8 (B) [(2)] 10 percent of the annual cost incurred by the taxpayer
 9 for qualified services in the state during each tax year for which a credit is
 10 allowable for a qualified capital investment for any gas reserve of the
 11 taxpayer or for each year that qualified costs are incurred for a gas
 12 reserve for which the taxpayer previously elected to claim a credit(A) of
 13 this paragraph; and

14 (2) for a tax year beginning after December 31, 2009,

15 (A) 25 percent of the taxpayer's qualified capital
 16 investment; and

17 (B) 25 percent of the annual cost incurred by the taxpayer
 18 for qualified services in the state during each tax year for which a credit is
 19 allowable for a qualified capital investment for any gas reserve of the
 20 taxpayer or for each year that qualified costs are incurred for a gas
 21 reserve for which the taxpayer previously elected to claim a credit under
 22 (A) of this paragraph [UNDER (1) OF THIS SUBSECTION].

23 * Sec. 2. AS 43.20.043(b) is amended to read:

24 (b) Expenditures qualifying for the taxpayer's qualified investment credit
 25 under (a)(1)(A) or (a)(2)(A) [(a)(1)] of this section must be

26 (1) cash expenditures or binding payment agreements entered into after

27 (A) June 30, 2003, and before January 1, 2010, if the claim
 28 of the credit is made under (a)(1)(A) of this section; or

29 (B) December 31, 2009, if the claim of the credit is made
 30 under (a)(2)(A) of this section; and

31 (2) made for assets first placed in service in the state in or before the

1 tax year in which the credit is claimed through the date the

2 (A) wells [RESERVES] produce gas for sale and delivery; for
3 purposes of this subparagraph [PARAGRAPH], "placed in service in the
4 state" means that the first use of the qualified investment is in this state; if the
5 property on which the claim of the credit is based has been used elsewhere in
6 the tax year of acquisition and is brought to this state during that year or a
7 subsequent year, the property does not qualify for the investment credit; or

8 (B) a gas well is determined not to be capable of production
9 in commercial quantities.

10 * Sec. 3. AS 43.20.043(c) is amended to read:

11 (c) The credit each [PER] tax year allowed by (a) of this section may not
12 exceed [50 PERCENT OF] the taxpayer's total tax liability under this chapter, but
13 shall be calculated before the application of any other credits allowed under this
14 chapter. An unused portion of the credit for the tax year

15 (1) may be carried forward into one or more of the following tax years,
16 except that the unused credit from one tax year may not be carried forward for more
17 than five following tax years;

18 (2) shall be applied to the taxpayer's tax liability under this chapter
19 during the following tax year before allowance of a credit allowed by (a) of this
20 section for that following tax year.

21 * Sec. 4. AS 43.20.043(e) is amended to read:

22 (e) A taxpayer entitled to a credit under this section

23 (1) may not convey, assign, or transfer the credit to another taxpayer or
24 business entity unless the conveyance, assignment, or transfer of the credit is part of
25 the conveyance, assignment, or transfer of the taxpayer's business;

26 (2) forfeits the credit to which the taxpayer is entitled during the tax
27 year and any carryover of it under (c) of this section, but does not forfeit the portion of
28 the credit that accrued in a previous taxable year that may be carried over under (c) of
29 this section, if the taxpayer

30 (A) disposes of the qualified capital investment;

31 (B) takes the qualified investment out of service; or

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(C) transfers the qualified investment out of this state;

(3) may not include in any rate base for a regulated facility submitted to a regulatory agency charged with determining an appropriate tariff the cost of any qualified capital investment or qualified service that has been offset by receipt of a credit under this chapter.

* Sec. 5. AS 43.20.043(f) is amended to read:

~~(f) A taxpayer is not entitled to a credit under this section for expenditures that are made or incurred for the qualified capital investment or for qualified services made for exploration and development of gas that occur in the area of Alaska lying north of 68 degrees North latitude or that are made or incurred to transport gas from reserves located in the area of Alaska lying north of 68 degrees North latitude or for the delivery of Alaska North Slope natural gas to tidewater below 68 degrees North latitude.~~

Amend #2
Remove Sec 5

* Sec. 6. AS 43.20.043(g) is amended to read:

(g) A taxpayer that [WHO] obtains a credit for a qualified capital investment or cost incurred for qualified services under this section may not also claim a tax credit or royalty modification for the same qualified capital investment or cost incurred for qualified services under AS 38.05.180(i), AS 41.09.010, AS 43.55.023, or 43.55.025 [PROVIDED FOR UNDER ANY OTHER TITLE]. However, a taxpayer may elect not to obtain [, AT THE TAXPAYER'S ELECTION, FORGO] a credit under this section in order [TO CONTINUE] to qualify for a credit provided under AS 38.05.180(i), AS 41.09.010, AS 43.55.023, or 43.55.025 [FOR IN ANOTHER TITLE].

* Sec. 7. AS 43.20.043(i)(1) is amended to read:

(1) "qualified capital investment" means a cash expenditure or binding payment agreement, as described in (b)(1) of this section, for real property or tangible personal property used in this state in the exploration and development of any gas reserve regardless of whether there has been commercial production in the area or whether the exploration and development activity results in the production of gas or a well not capable of production in commercial quantities [RESERVES IN A GAS RESERVOIR FOR WHICH THERE HAS NOT BEEN COMMERCIAL

1 PRODUCTION IF THE RESERVES PRODUCE GAS FOR SALE AND
2 DELIVERY]; in this paragraph, "property" includes

3 (A) property used in the operation or maintenance of facilities
4 for exploration or development of gas;

5 (B) property that is placed in use under a capitalized lease or an
6 operating lease; and

7 (C) the following property used for the exploration and
8 development of gas:

9 (i) machinery, appliances, supplies, and equipment;

10 (ii) drilling rigs, wells, gathering lines and transmission
11 lines, pumping stations, compressor stations, power plants designed
12 for field operations, gas processing plants, and gas treatment
13 plants, but not including liquefied natural gas or manufacturing
14 plants [, TOPPING PLANTS, AND PROCESSING UNITS];

15 (iii) roads, docks and other port facilities, and helicopter
16 pads;

17 (iv) maintenance equipment and facilities, and
18 maintenance camps and other related facilities; and

19 (v) communications facilities owned by a person whose
20 principal business in the state is the exploration for or development of
21 gas and whose operation of the communications facilities directly
22 relates to the conduct of that business;

23 * Sec. 8. AS 43.20.043 is amended by adding a new subsection to read:

24 (j) A taxpayer shall claim the credit authorized in (a) of this section on a
25 timely filed tax return for the year in which the qualified capital investment is made,
26 on a timely filed amended tax return, or on a timely filed tax return for the year
27 immediately following the year in which the qualified capital investment is made. The
28 election to apply the credit authorized in (a) of this section may not be an irrevocable
29 election.

30 * Sec. 9. AS 43.55.023(a) is amended to read:

31 (a) A producer or explorer may take a tax credit for a qualified capital

1 expenditure as follows:

2 (1) notwithstanding that a qualified capital expenditure may be a
3 deductible lease expenditure for purposes of calculating the production tax value of oil
4 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under
5 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or
6 explorer that incurs a qualified capital expenditure may also elect to apply a tax credit
7 against a tax levied by AS 43.55.011(e) in the amount of 20 percent of that
8 expenditure; [HOWEVER, NOT MORE THAN HALF OF THE TAX CREDIT MAY
9 BE APPLIED FOR A SINGLE CALENDAR YEAR;]

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

13 (A) agrees, in writing, to the applicable provisions of
14 AS 43.55.025(f)(2);

15 (B) submits to the Department of Natural Resources all data
16 that would be required to be submitted under AS 43.55.025(f)(2).

17 * Sec. 10. AS 43.55.023(d) is amended to read:

18 (d) Except as limited by (i) of this section, a person that is entitled to take a tax
19 credit under this section that wishes to transfer the unused credit to another person or
20 obtain a cash payment under AS 43.55.028 may apply to the department for a
21 transferable tax credit certificate [CERTIFICATES]. An application under this
22 subsection must be in a form prescribed by the department and must include
23 supporting information and documentation that the department reasonably requires.
24 The department shall grant or deny an application, or grant an application as to a lesser
25 amount than that claimed and deny it as to the excess, not later than 120 days after the
26 latest of (1) March 31 of the year following the calendar year in which the qualified
27 capital expenditure or carried-forward annual loss for which the credit is claimed was
28 incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for
29 the calendar year in which the qualified capital expenditure or carried-forward annual
30 loss for which the credit is claimed was incurred; or (3) the date the application was
31 received by the department. If, based on the information then available to it, the

1 department is reasonably satisfied that the applicant is entitled to a credit, the
2 department shall issue the applicant a [TWO TRANSFERABLE] tax credit certificate
3 [CERTIFICATES, EACH FOR HALF OF THE AMOUNT OF THE CREDIT]. The
4 credit shown on [ONE OF] the certificate [TWO CERTIFICATES] is available for
5 immediate use. [THE CREDIT SHOWN ON THE SECOND OF THE TWO
6 CERTIFICATES MAY NOT BE APPLIED AGAINST A TAX FOR A CALENDAR
7 YEAR EARLIER THAN THE CALENDAR YEAR FOLLOWING THE
8 CALENDAR YEAR IN WHICH THE CERTIFICATE IS ISSUED, AND THE
9 CERTIFICATE MUST CONTAIN A CONSPICUOUS STATEMENT TO THAT
10 EFFECT.] A certificate issued under this subsection does not expire.

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

12 (a) Subject to the terms and conditions of this section, a credit against the
13 production tax levied by AS 43.55.011(e) is allowed for exploration expenditures that
14 qualify under (b) of this section in an amount equal to one of the following:

15 (1) 30 percent of the total exploration expenditures that qualify only
16 under (b) and (c) of this section;

17 (2) 30 percent of the total exploration expenditures that qualify only
18 under (b) and (d) of this section;

19 (3) 40 percent of the total exploration expenditures that qualify under
20 (b), (c), and (d) of this section; [OR]

21 (4) 40 percent of the total exploration expenditures that qualify only
22 under (b) and (e) of this section; or

23 (5) 80, 90, or 100 percent, or a lesser amount described in (m) of
24 this section, of the total exploration expenditures described in (b)(1) and (2) of
25 this section and not excluded by (b)(3) and (4) of this section that qualify only
26 under (m) of this section.

27 * Sec. 12. AS 43.55.025 is amended by adding a new subsection to read:

28 (m) The first three unaffiliated persons that each drill an offshore exploration
29 well for the purpose of discovering oil or gas in Cook Inlet that penetrates and
30 evaluates a prospect in the pre-Tertiary zone using a jack-up drill rig are eligible for
31 the credit under this subsection. The person that drills the first exploration well is

1 entitled to a credit in the amount of 100 percent of its exploration expenditures or
2 \$25,000,000, whichever is less; the person that drills the second exploration well using
3 the same jack-up drill rig is entitled to a credit in the amount of 90 percent of its
4 exploration expenditures or \$22,500,000, whichever is less; and the person that drills
5 the third exploration well using the same jack-up drill rig is entitled to a credit in the
6 amount of 80 percent of its exploration expenditures or \$20,000,000, whichever is
7 less. A person or an affiliate of a person drilling an exploration well is not entitled to a
8 credit for more than one exploration well under this subsection. The department shall
9 make a determination of the order in which the wells are drilled based on the date and
10 time that the drill bit first turns to the right against the seafloor for the purpose of
11 drilling the well. Exploration expenditures eligible for the credit in this subsection may
12 include the necessary and reasonable costs to modify an existing jack-up rig for use in
13 Cook Inlet, may not include the cost to construct or manufacture a jack-up rig, and,
14 notwithstanding (b) of this section, must be incurred for work performed after June 30,
15 2010. If the exploration well for which a credit is received under this subsection
16 results in sustained production of oil or gas from a reservoir discovered by the
17 exploration well, and notwithstanding that the credit may have been transferred under
18 (g) of this section, 50 percent of the amount of the credit received shall be repaid to
19 the department by the person that received the credit in equal monthly installments
20 over a 10-year period commencing 60 days after the start of sustained production of
21 oil or gas. Whether the exploration well for which a credit is requested under this
22 subsection penetrated and evaluated a prospect in the pre-Tertiary zone and the
23 exploration well resulted in sustained production of oil or gas from a reservoir
24 discovered by the exploration well shall be determined by the commissioner of natural
25 resources and reported to the commissioner. A taxpayer that obtains a credit under this
26 subsection may not claim a tax credit under AS 43.55.023 or another provision in this
27 section for the same exploration expenditure. In this subsection,

28 (1) "jack-up rig" means a mobile drilling platform with extendible legs
29 for support on the ocean floor;

30 (2) "reservoir" means an oil and gas accumulation, discovered and
31 evaluated by testing, that is separate from any other accumulation of oil and gas;

1 (3) "sustained production" means production of oil or gas from a
2 reservoir into a pipeline or other means of transportation to market, but does not
3 include testing, evaluation, or pilot production.

4 * Sec. 13. The uncodified law of the State of Alaska enacted by sec. 3, ch. 61, SLA 2003, is
5 amended to read:

6 Sec. 3. CLAIM OF GAS EXPLORATION AND DEVELOPMENT TAX
7 CREDIT CONTINUED. A taxpayer who, on the effective date of repeal of
8 AS 43.20.043 by secs. 2 and 5, ch. 61, SLA 2003, as amended by sec. 15 [SEC. 2] of
9 this 2010 Act, claims the balance of any unused portion of the gas exploration and
10 development tax credit as a carry-forward under AS 43.20.043(c), may,
11 notwithstanding the repeal of that subsection, continue to claim the balance of the
12 credit until the claim of the credit is exhausted or until the tax year ending
13 December 31, 2024 [2017], whichever occurs earlier. The provisions of AS 43.20.043
14 as they read on the day immediately preceding the effective date of the repeal of that
15 section apply to the claim of the credit if carried forward under this section.

16 * Sec. 14. AS 43.55.028(e)(2) and 43.55.028(e)(3) are repealed.

17 * Sec. 15. Section 5, ch. 61, SLA 2003, is amended to read:

18 Sec. 5. Section 2, ch. 61, SLA 2003, [OF THIS ACT] takes effect January 1,
19 2020 [2013].

20 * Sec. 16. This Act takes effect immediately under AS 01.10.070(c).

ALASKA STATE LEGISLATURE

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Chair
Senate Special Committee on Energy
Senate Committee on World Trade,
Technology and Innovations

Co-Chair
Senate Resources Committee

Member
Senate Judiciary Committee

SENATOR LESIL MCGUIRE

Sectional Analysis of Senate Bill 309: 26-LS 1629\A

Please note that a sectional analysis is not an authoritative interpretation of a bill. The bill itself is the best statement of its contents.

- Section 1** amends AS 43.20.043(a) to increase the tax credit for qualified expenditures and annual costs to 25 percent for tax years following December 31, 2009 from the current 10 percent.
- Section 2** amends AS 43.20.043(b) to clarify the application of the proposed credits and that "wells" rather than "reserves" are developed.
- Section 3** amends AS 43.20.043(c) to remove the 50% cap on the application of a credit against a taxpayer's liability.
- Section 4** amends AS 43.20.043(f) to clarify that the credit does not apply to gas delivered from the Alaska North Slope.
- Section 5** amends AS 43.20.043(i)(1) to include development activity in the definition of qualified investment.
- Section 6** amends AS 43.20.043 by adding a new subsection to specify when a taxpayer may claim the credit.
- Section 7** amends the uncodified law enacted by sec. 3, ch. 61, SLA 2003 to extend the repeal of the provisions related to the exhaustion of credits.
- Section 8** extends the sunset of the tax credit to January 1, 2020.
- Section 9** provides an immediate effective date.

Prepared By: Michael Pawlowski, Aide to Senator McGuire

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 1
 Bill Version: CSSB 309(RES)
 (S) Publish Date: 4/10/10

Identifier (file name): CSSB309(RES)-REV-TAX-04-10-10 Dept. Affected: Revenue
 Title Gas Exploration / Development Tax Credit RDU Taxation and Treasury
 Component Tax Division
 Sponsor Rules by Request
 Requester Senate Resources Committee Component Number 2476

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2011	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
OPERATING EXPENDITURES								
Personal Services								
Travel								
Contractual								
Supplies								
Equipment								
Land & Structures								
Grants & Claims								
Miscellaneous								
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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

1002 Federal Receipts								
1003 GF Match								
1004 GF								
1005 GF/Program Receipts								
1037 GF/Mental Health								
Other Interagency Receipts								
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2010) cost: _____

POSITIONS

Full-time								
Part-time								
Temporary								

ANALYSIS: (Attach a separate page if necessary)

*** Revenue impact is indeterminate. Please see attached for analysis.

Prepared by: Cherie Nienhuis, Petroleum Economist/Johanna Bales, Deputy Director
 Division: Tax Division
 Approved by: Ginger Blaisdell, Director
Administrative Services Division, Department of Revenue

Phone (907) 269-1019
 Date/Time 04-10-10; 12:25am
 Date 04-10-10; 8:39am

FISCAL NOTE #1

STATE OF ALASKA
2010 LEGISLATIVE SESSION

BILL NO. CSSB 309(RES)

ANALYSIS CONTINUATION

Bill Language:

This bill makes several changes to credits to both the production tax system and the oil and gas corporate income tax system as follows.

The bill extends the existing Gas Exploration and Development tax credit for investment in qualified capital expenditures and related qualified services, dealing with those capital expenditures. The Gas Exploration and Development tax credit is taken against the Corporate Income Tax (CIT), before any other federal or state credits are taken. One hundred percent of a company's tax liability can be offset by this credit in a given tax year. Additionally, credits from prior years must be used before current year credits can be used. A credit must be used within five years, otherwise it expires.

Currently, 10% of qualifying capital expenditures and operating expenditures can be taken as capital credits, sunsetting in 2013. The bill would increase the credit rate to 25% for qualifying capital and service expenditures incurred after June 30, 2011 for tax years beginning after December 31, 2010. The 25% rate would sunset on January 1, 2020. Under existing law all remaining tax credits under AS 43.20.043 expire December 31, 2017. This bill would change the sunset date to expire the tax year ending December 31, 2024.

In order for an expenditure to qualify for the 10% rate, cash expenditures or binding payment agreements must be made between June 30, 2003 and before July 1, 2011. Expenditures qualify for the 25% rate cash expenditures or binding payment agreements must be made after June 30, 2011.

The credit is limited to activities south of 68 degrees North latitude and exempts delivery of Alaska North Slope natural gas to tidewater.

It is difficult to determine the number of taxpayers who would take advantage of the corporate income tax credit, the degree to which the credit would be utilized, and other exogenous variables impacting the revenues the state would collect. Reduction in CIT are indeterminate at this time.

The bill also expands the production tax credit authorized at AS 43.55.025 to a maximum credit of 100 percent of the total exploration expenditures for drilling in the Cook Inlet basin. The bill proposes to grant the full 100 percent credit of exploration expenditures to the first person to qualify under this credit, 90 percent to the second person, and 80 percent to the third person. Only expenditures occurring after July 1, 2010 and before July 1, 2016 would qualify under the bill. If the exploration well for which credit is received results in paying quantities of production, the person who received the credit will pay back to the state 50 percent of the credit received in monthly installments over 10 years.

The fiscal impact of this provision of the bill is indeterminate. Several companies have sought credits under the .025 exploration incentive credit in the Cook Inlet basin, for which the state has reimbursed up to 40 percent of the companies' capital costs. Our records indicate that total costs for drilling in the Cook Inlet basin could be as high as \$5 million or more. A recent study by the Petrotechnical Resources of Alaska (PRA) indicates that the cost of drilling 128 wells in the Cook Inlet basin over the period from 2001 through 2009 cost between \$1.0 and \$1.2 billion. This figure includes not just exploration wells, but presumably cheaper development wells. At the high end of the range, this amounts to a per-well cost of \$9.4 million. PRA further reports that over the next decade 185 new wells will need to be drilled to meet demand, and that capital costs will increase to \$1.85 to 2.8 billion, with per-well costs of \$10- \$15 million. If their report is correct, three persons receiving credit under this provision will cost the state up to \$40 million in tax credits. If all three of the persons found paying quantities of oil or gas, the state could be reimbursed about \$20 million of the \$40 million in credits.

(continued on next page)

FISCAL NOTE #1

STATE OF ALASKA
2010 LEGISLATIVE SESSION

BILL NO. CSSB 309(RES)

ANALYSIS CONTINUATION

The bill also removes from law two existing requirements relating to production tax credits. First, it removes the limitation that credits received for capital expenditures for oil and gas operations be taken over two years. The calculation of the revenue impact for this provision is difficult for two reasons: (1) the timing of the revenue impact will depend upon when the bill is signed into law; and (2) the amount the state may potentially be expected to pay to purchase credits is conditioned in part on removing the reinvestment requirement discussed in #2 above, and the timing of the payment will depend on whether companies will immediately seek reimbursement for their credits.

We assume for this provision a worse-case scenario where all credits held by companies with production tax liabilities are used in FY 2010 or FY 2011. This would cost the state approximately \$225 million in reduced taxes between the two years. For companies that are holding credit certificates and are not expected to incur a tax liability in FY 2010 or FY 2011, we estimate an additional liability of up to \$150 million over previous expectations for the two fiscal years. These impacts could spill into FY 2012, should companies delay seeking reimbursement. Beyond FY 2012, revenue impacts are expected to be negligible.

Second, it removes the requirement that companies that seek cash refunds from the state for credits reinvest in capital expenditures an amount equivalent to the cash reimbursement sought. This provision is expected to be revenue neutral, as credits are either taken against tax liabilities or as a refund in full, with no differential impact to the state.

Expenditures: The provisions of this bill could be implemented with existing state resources. No additional personnel or resources would be needed, since the DOR is already performing these duties.

Cook Inlet Gas Study - An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers

prepared for



March 2010

Peter J. Stokes, PE
William Grether & Thomas P. Walsh

Petrotechnical Resources of Alaska
3601 C Street Suite 822
Anchorage, AK 99503
(907) 272-1232



Due to the uncertainties of drilling and producing activities of operating and exploration companies and what Alaska state agencies do and do not do in influencing those activities, this study should be considered a best estimate based on current data. It was prepared using generally accepted engineering and geological predictive methods. As such, Petrotechnical Resources of Alaska can make no warranty as to actual future Cook Inlet gas drilling and production.

Executive Summary prepared by Cook Inlet Utilities

ENSTAR Natural Gas Company, Chugach Electric Association, and Anchorage Municipal Light and Power (Cook Inlet Utilities) commissioned Petrotechnical Resources of Alaska (PRA) to study Cook Inlet natural gas reserves and forecast annual natural gas production. We asked PRA to estimate the cost of the development necessary to meet the immediate needs of Cook Inlet utility customers from 2010 to 2020. The PRA study includes a review of estimated reserves and deliverability of Cook Inlet gas wells drilled between 2001 and 2009, scenarios for potential development activity, a review of a December 2009 Alaska Department of Natural Resources (DNR) reserves analysis, and an analysis of when it might be necessary to rely on non-Cook Inlet natural gas sources, such as liquefied natural gas (LNG) imports or other in-state resources.

In the future, Cook Inlet utility customers should expect to pay more for the gas used by Cook Inlet Utilities to generate heat and electricity. PRA examined results from all of the gas wells drilled in Cook Inlet between 2001 and 2009 and determined that producers spent approximately \$1.0 to \$1.2 billion in development costs to add reserves of approximately 519 billion cubic feet (Bcf) of natural gas. If the current trends for well success rates and costs continue, producers will need to spend two to three times that amount, an estimated \$1.9 to \$2.8 billion, to meet projected Cook Inlet utility demand from 2010 to 2020. Producers will invest the necessary capital in future drilling activity only if they have a reasonable expectation of a return that is competitive with other investment opportunities. In order to assure continued drilling activities, increased development costs must be reflected in the market price utilities pay for the gas and ultimately pass onto their customers. Cook Inlet Utilities will also require storage services to deliver gas to their customers on the coldest days and enable producers to optimize gas production rates. The estimated cost of a storage facility is \$150 to \$200 million¹. These storage costs will also be borne by utility customers.

¹ Storage cost estimates based on ENSTAR's development assessment.

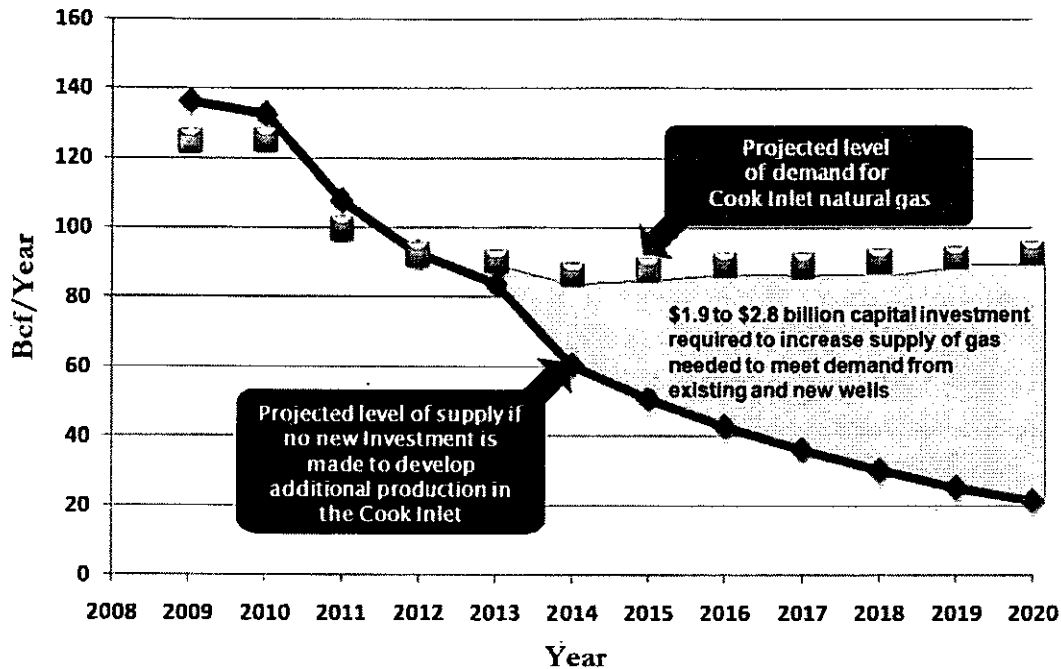


Figure 1 – Cook Inlet Supply & Demand

PRA used a decline curve analysis to review the same underlying data analyzed in the 2009 DNR reserves study and reached a similar conclusion regarding when the supply of gas from existing wells will not meet demand². The PRA study took the next step, estimating the cost of bringing the undeveloped gas resources to market³. PRA determined that if significant efforts are undertaken to develop gas from the resources identified by DNR and if the current trends in drilling success rates continue, gas might be available through 2020. However, even if an aggressive development effort were undertaken immediately, that effort may fail to bring new gas to market quickly enough to provide needed gas when demand is projected to exceed supply as soon as 2013. Utilities need to plan for an alternative supply to meet their customers' needs. Having undeveloped gas resources in the ground will not enable Cook Inlet Utilities to provide heat and power to their customers. The gas resources will only be developed and brought to market at prices that incentivize the producers to justify their investment. Contracts with these higher prices will require RCA approval.

Cook Inlet Utilities need a viable option if additional Cook Inlet development does not materialize. To provide a stable gas supply, non-Cook Inlet sources such as gas delivered from the North Slope or LNG imports, are alternatives that must be pursued. The "easy" gas has been found in the challenging geology of Cook Inlet. The future costs of developing additional reserves will be substantial. As the cost of continued Cook Inlet gas production increases, alternative gas supply sources may become more economically attractive. Regulatory uncertainty has also discouraged Cook Inlet producers from exploring for and developing Cook

² PRA's study estimates remaining reserves of 729 Bcf from existing wells, compared with DNR's forecast of 863 Bcf of Proven Developed Producing reserves.

³ The DNR study did not address the cost of bringing undeveloped resources to the market. (see DNR Study Figure 14 Description)

Inlet reserves⁴. In the current regulatory environment, two of the three major Cook Inlet producers have publicly stated that they intend to drill only to meet current contract obligations. Future development depends on a change in the regulatory climate to one where consistent standards are applied to approve negotiated utility gas supply agreements, even if those agreements reflect the increased costs of resource development.

The Cook Inlet market is in transition. Current gas fields are in decline and the loss of industrial customers has reduced the producers' incentives to do anything but meet existing contractual obligations. In order for utilities to be able to continue to supply current customers and to accommodate future growth, Cook Inlet Utilities and others must take action.

Immediate Actions Needed:

- New gas supply agreements between Cook Inlet Utilities and Producers must be signed to ensure continued development of Cook Inlet reserves.
- There must be predictable timelines and standards for regulatory approval of gas supply agreements. The Regulatory Commission of Alaska must be willing to approve gas supply contracts negotiated at arm's length, even if prices under those contracts increase.
- Cook Inlet Utilities must develop gas storage to assure deliverability on the coldest days and optimize gas production throughout the year.
- Cook Inlet Utilities should continue raising customer awareness, conservation efforts, and curtailment plans, to prepare for potential shortfalls.
- Additional well-capitalized exploration and development companies must commit to develop Cook Inlet and other Alaska gas reserves.
- To assure certainty of supply, Cook Inlet Utilities must determine how they will bring gas into Cook Inlet within the next five years to ensure the needs of their customers are met. Alternative gas supply sources include LNG imports and North Slope gas delivered by pipeline to south central Alaska.
- Additional regional industrial gas demand must be found to encourage the development of Cook Inlet reserves and spread the increased costs of production.
- Land management processes must be streamlined to encourage and accelerate reserve and infrastructure development.

⁴ Recent favorable regulatory decisions on utility gas supply agreements may be a positive sign.

Technical Summary

ENSTAR Natural Gas Company, Chugach Electric Association, and Anchorage Municipal Light and Power (Cook Inlet Utilities) hired Petrotechnical Resources of Alaska (PRA) to perform a study of Cook Inlet reserves and deliverability. The components of the study included:

- Review the deliverability of Cook Inlet gas wells drilled between 2001 and 2009
- Forecast potential deliverability of future drilled gas wells
- Review Alaska Department of Natural Resources (DNR) reserves analysis
- Analyze timing of demand for a delivery of potential non-Cook Inlet gas sources, such as liquefied natural gas (LNG) imports or other in-state resources

High level findings of the study are:

Cook Inlet Well Drilling Results – 2001 to 2009

- Drivers for Cook Inlet well drilling between 2001 and 2009 included:
 - Newly executed gas contracts
 - Reserves development associated with negotiated gas contracts rejected by the RCA
 - LNG Exports and License Extensions
 - Increasing Regional Natural Gas Prices
 - Industrial Fertilizer Operations
- Results for Cook Inlet well drilling between 2001 and 2009:
 - 128 gas wells were drilled between 2001 and 2009, of which, 105 were completed with an average rate of 3.6 MMSCF/D for the first 12 months of production
 - 97 wells were permitted and drilled as Gas Development wells; 88 of these were completed as gas wells, for a 90.7% success rate
 - 31 wells were permitted and drilled as Gas Exploration wells; 18 were completed as gas wells, for a 58.1% success rate
 - An estimated 519 BCF of gas was developed by these wells
 - Ninilchik, Kenai and Deep Creek Units had the most drilling activity during this period; Ninilchik was very successful; Kenai wells were average and Deep Creek wells were marginal
 - The estimated costs for drilling and facilities of these 128 gas wells are between \$1.0 and \$1.2 billion

Review of DNR Analysis of Available Reserves

- The DNR completed a Cook Inlet Gas Reserves Study in December 2009
- In the DNR study, reserves and resources are systematically estimated, but as stated in the report, the timing of the development of undeveloped reserves is only an estimate as shown in DNR's Figure 14, a "Hypothetical production forecast for Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analysis discussed in text."
- In the DNR study, the only firm deliverabilities are for reserves estimated by decline curve analysis and material balance. The material balance resources would be realized

through the spending of additional capital for development (Beaver Creek) or for compression (Ninilchik). Timing is determined by economic drivers.

- The DNR study forecasted 863 BCF of Proven Developed Producing reserves compared to the decline curve analysis performed by PRA forecasting 729 BCF⁵ of reserves.
 - A major difference in decline curve analysis performed by PRA was apparent at Beluga River Field where the DNR study estimated 377 BCF remaining reserves and PRA estimated 207 BCF.
 - The predicted production from decline curve analysis was similar in both studies; both DNR and PRA showed decline curve analysis predictions from existing wells falling below projected demand in the 2012-2013 timeframe.
- The DNR study forecasted Additional Probable Reserves of 279 BCF based on material balance calculations, while PRA did not perform material balance calculations.
- In both studies, the four (4) Fields identified as having greatest remaining potential and selected for detailed geological analysis were: Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling gas sands.

Reported were:

- Potential gas resources (from geologic analysis of 4 fields above) estimated to be 353 BCF
- Possible gas resources of 643 BCF (50% Risked case) estimated from lower confidence pay intervals

Potential of Future Gas Wells in Cook Inlet:

- Drivers required for future Cook Inlet reserve development include:
 - Execution and RCA approval of gas contracts
 - Predictable timeline and standard for regulatory approval of negotiated gas pricing structures
 - Additional regional industrial gas demand, including LNG exports.
 - Additional well-capitalized exploration and development companies committed to develop Alaskan resources
 - Government action to facilitate and accelerate development of necessary infrastructure and permitting
- Challenges facing future Cook Inlet development include:
 - Possible discontinuation of LNG exports from the region
 - Reduced industrial demand (e.g., regional fertilizer manufacturing)
 - Success rates in exploration and development
 - Higher relative regional costs for exploration, development, and production
 - High level of activity in reserve development needed to meet demand
 - Probable decline in production rates from future wells in existing fields
- Minimum requirements to meet demand in Cook Inlet gas market until 2020:
 - A new source of gas, such as imported LNG or other in-state reserves, could be required as early as 2013, if ongoing drilling or drilling success does not continue at the 2007-2009 pace.

⁵ 762 BCF in Report included 33.7 BCF estimated for 4 remaining 2009 Wells

- Gas storage will maximize Cook Inlet gas deliverability potential and more closely match local demand curves and production rates.
- To meet projected demand for the next decade, 185 new wells will be needed, which is a 45% increase over the number of wells drilled in the 2001-2009 period
- Development costs for this time period are estimated at \$1.85 to \$2.8 billion, an increase in total capital investment of 54-180%
- To incent this substantive increase in investment levels, or to bring a new source of gas to Cook Inlet, utility customers should expect to pay significantly higher gas prices

Figure 2 shows recent history and future wells estimated to meet CI gas demands through 2020. The well count assumes average well performance of 2007-2009 wells, with initial rates and developed reserves degraded by 4.3% per year.

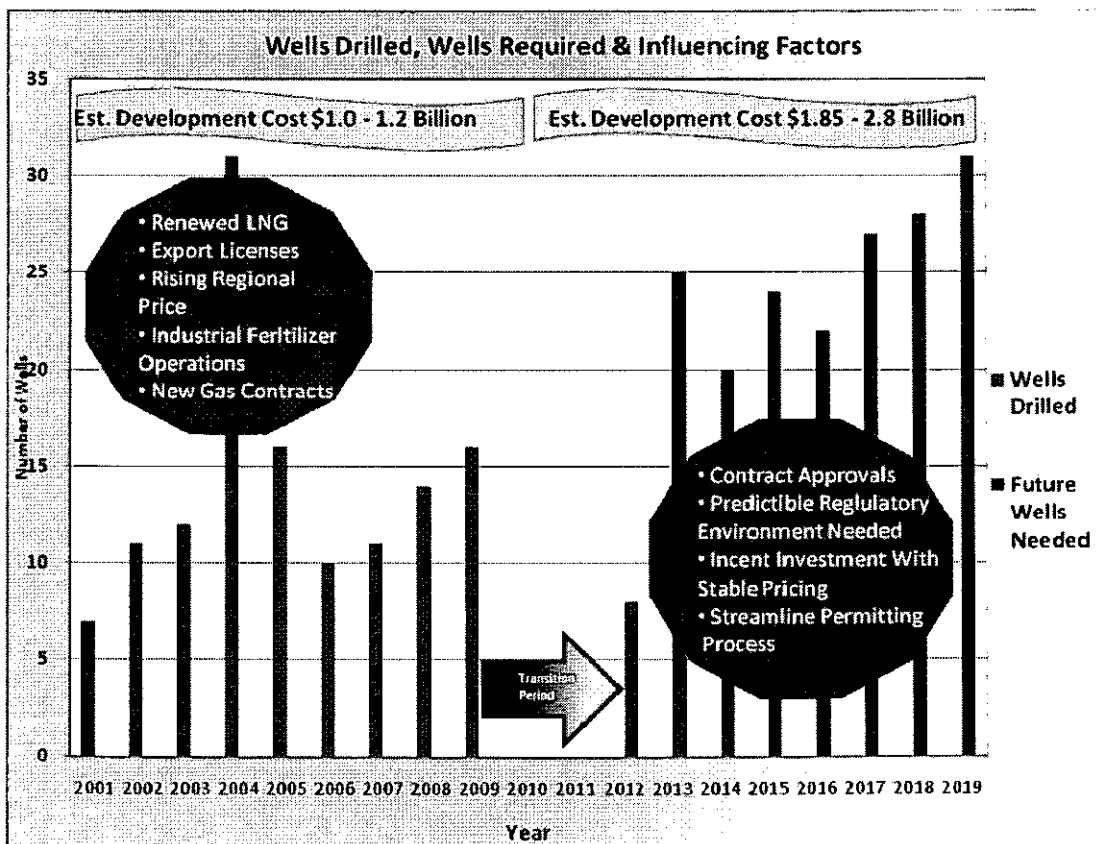


Figure 2: Wells Drilled, Future Wells Required & Influencing Factors



LAWS OF ALASKA

2003

Source
SCS CSHB 61(RES)

Chapter No.

AN ACT

Establishing an exploration and development incentive tax credit for operators and working interest owners directly engaged in the exploration for and development of gas for sale and delivery without reference to volume from a lease or property in the state; and providing for an effective date.

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

THE ACT FOLLOWS ON PAGE 1

AN ACT

1 Establishing an exploration and development incentive tax credit for operators and working
2 interest owners directly engaged in the exploration for and development of gas for sale and
3 delivery without reference to volume from a lease or property in the state; and providing for
4 an effective date.

5
6 * **Section 1.** AS 43.20 is amended by adding a new section to read:

7 **Sec. 43.20.043. Gas exploration and development tax credit.** (a) Subject to
8 the terms and conditions of this section, and in addition to any other credit authorized
9 to the taxpayer by this chapter, a taxpayer that is an operator or working interest owner
10 directly engaging in the exploration for and development of gas may apply as a credit
11 against the state tax liability that may be imposed on the taxpayer under this chapter,
12 for a tax year beginning after December 31, 2002,

13 (1) 10 percent of the taxpayer's qualified capital investment; and

14 (2) 10 percent of the annual cost incurred by the taxpayer for qualified

1 services in the state during each tax year for which a credit is allowable for a qualified
2 capital investment under (1) of this subsection.

3 (b) Expenditures qualifying for the taxpayer's qualified investment credit
4 under (a)(1) of this section must be

5 (1) cash expenditures or binding payment agreements entered into after
6 June 30, 2003; and

7 (2) made for assets first placed in service in the state in or before the
8 tax year in which the credit is claimed through the date the reserves produce gas for
9 sale and delivery; for purposes of this paragraph, "placed in service in the state" means
10 that the first use of the qualified investment is in this state; if the property on which the
11 claim of the credit is based has been used elsewhere in the tax year of acquisition and
12 is brought to this state during that year or a subsequent year, the property does not
13 qualify for the investment credit.

14 (c) The credit per tax year allowed by (a) of this section may not exceed 50
15 percent of the taxpayer's total tax liability under this chapter, but shall be calculated
16 before the application of any other credits allowed under this chapter. An unused
17 portion of the credit for the tax year

18 (1) may be carried forward into one or more of the following tax years,
19 except that the unused credit from one tax year may not be carried forward for more
20 than five following tax years;

21 (2) shall be applied to the taxpayer's tax liability under this chapter
22 during the following tax year before allowance of a credit allowed by (a) of this
23 section for that following tax year.

24 (d) To obtain the credit allowed by this section, the taxpayer shall, with the
25 taxpayer's tax return, submit, on a form prescribed by the department, information that
26 demonstrates that the taxpayer is eligible for the credit and evidence of the expenses
27 that are the basis of the claim of the credit. The taxpayer has the burden of
28 demonstrating compliance with the requirements of this section to entitle the taxpayer
29 to the claim of and the amount of the credit.

30 (e) A taxpayer entitled to a credit under this section

31 (1) may not convey, assign, or transfer the credit to another taxpayer or

1 business entity unless the conveyance, assignment, or transfer of the credit is part of
2 the conveyance, assignment, or transfer of the taxpayer's business;

3 (2) forfeits the credit to which the taxpayer is entitled during the tax
4 year and any carryover of it under (c) of this section, but does not forfeit the portion of
5 the credit that accrued in a previous taxable year that may be carried over under (c) of
6 this section, if the taxpayer

7 (A) disposes of the qualified capital investment;

8 (B) takes the qualified investment out of service; or

9 (C) transfers the qualified investment out of this state.

10 (f) A taxpayer is not entitled to a credit under this section for expenditures that
11 are made or incurred for the qualified capital investment or for qualified services made
12 for exploration and development of gas that occur in the area of Alaska lying north of
13 68 degrees North latitude or that are made or incurred to transport gas from reserves
14 located in the area of Alaska lying north of 68 degrees North latitude.

15 (g) A taxpayer who obtains a credit under this section may not claim a tax
16 credit or royalty modification provided for under any other title. However, a taxpayer
17 may, at the taxpayer's election, forgo a credit under this section in order to continue to
18 qualify for a credit provided for in another title.

19 (h) For purposes of determining allowable credits under this section, the
20 department shall allow only expenditures and payments that are not inconsistent with
21 the expenditures authorized under 26 U.S.C. (Internal Revenue Code) for exploration
22 and development of natural resources.

23 (i) In this section,

24 (1) "qualified capital investment" means a cash expenditure or binding
25 payment agreement, as described in (b)(1) of this section, for real property or tangible
26 personal property used in this state in the exploration and development of gas reserves
27 in a gas reservoir for which there has not been commercial production if the reserves
28 produce gas for sale and delivery; in this paragraph, "property" includes

29 (A) property used in the operation or maintenance of facilities
30 for exploration or development of gas;

31 (B) property that is placed in use under a capitalized lease or an

1 operating lease; and

2 (C) the following property used for the exploration and
3 development of gas:

4 (i) machinery, appliances, supplies, and equipment;

5 (ii) drilling rigs, wells, gathering lines and transmission
6 lines, pumping stations, compressor stations, power plants, topping
7 plants, and processing units;

8 (iii) roads, docks and other port facilities, and helicopter
9 pads;

10 (iv) maintenance equipment and facilities, and
11 maintenance camps and other related facilities; and

12 (v) communications facilities owned by a person whose
13 principal business in the state is the exploration for or development of
14 gas and whose operation of the communications facilities directly
15 relates to the conduct of that business;

16 (2) "qualified services"

17 (A) means expenditures for labor, seismic, and other services
18 that are directly applicable to a qualified capital investment;

19 (B) does not include lease operating expenses.

20 * **Sec. 2.** AS 43.20.043 is repealed.

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

23 CLAIM OF GAS EXPLORATION AND DEVELOPMENT TAX CREDIT
24 CONTINUED. A taxpayer who, on the effective date of repeal of AS 43.20.043 by sec. 2 of
25 this Act, claims the balance of any unused portion of the gas exploration and development tax
26 credit as a carry-forward under AS 43.20.043(c), may, notwithstanding the repeal of that
27 subsection, continue to claim the balance of the credit until the claim of the credit is exhausted
28 or until the tax year ending December 31, 2017, whichever occurs earlier. The provisions of
29 AS 43.20.043 as they read on the day immediately preceding the effective date of the repeal
30 of that section apply to the claim of the credit if carried forward under this section.

31 * **Sec. 4.** The uncodified law of the State of Alaska is amended by adding a new section to

1 read:

2 REPORT ON EFFECT OF GAS EXPLORATION AND DEVELOPMENT TAX
3 CREDIT. Not later than November 30, 2008, the Department of Revenue shall prepare and
4 publish a report on the effect of the gas exploration and development tax credit authorized by
5 AS 43.20.043, added by sec. 1 of this Act. The department shall advise the legislature of the
6 availability of the report and, within the first 10 days of the First Regular Session of the
7 Twenty-Sixth Alaska State Legislature, transmit copies of the report to the chairs or co-chairs
8 of the House and Senate Resources Committees and the chairs or co-chairs of the House and
9 Senate Special Committees on Oil and Gas, if established. The report must address

10 (1) the number of successful gas discoveries for which a tax credit is provided
11 under AS 43.20.043;

12 (2) the volume or amount of new gas reserves brought into production for
13 which a tax credit is provided under AS 43.20.043;

14 (3) the total credits allowed under AS 43.20.043 that are applied to the tax
15 liability through the date of preparation of the report;

16 (4) the total credits applied for under AS 43.20.043 that are not yet approved
17 as of the date of preparation of the report;

18 (5) royalties obtained and oil and gas property production taxes paid from new
19 gas production and anticipated from gas production for production for which credits are
20 allowed under AS 43.20.043; and

21 (6) any other information that, in the judgment of the commissioner of
22 revenue, would evaluate the effectiveness of the gas exploration and development tax credit
23 authorized under AS 43.20.043.

24 * **Sec. 5.** Section 2 of this Act takes effect January 1, 2013.

25 * **Sec. 6.** Except as provided in sec. 5 of this Act, this Act takes effect immediately under
26 AS 01.10.070(c).

AMENDMENT

OFFERED IN THE SENATE
TO: CSSB 309(RES)

BY SENATOR WIELECHOWSKI

1 Page 4, line 5, following "**chapter**":

2 Insert ":

3 **(4) shall agree, in writing, to the applicable provisions of**
4 **AS 43.55.025(f)(2) and shall submit to the Department of Natural Resources all**
5 **data that would be required to be submitted under AS 43.55.025(f)(2) for a credit**
6 **under AS 43.55.025"**

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Bullock
4/10/10

AMENDMENT

FAILS

OFFERED IN THE SENATE
TO: CSSB 309(RES)

BY SENATOR WIELECHOWSKI

1 Page 4, line 5, following "chapter":

2 Insert ";

3 (4) shall agree, in writing, to the applicable provisions of
4 AS 43.55.025(f)(2) and shall submit to the Department of Natural Resources all
5 data that would be required to be submitted under AS 43.55.025(f)(2) for a credit
6 under AS 43.55.025"

AMENDMENT

OFFERED IN THE SENATE

TO: SB 309

1 Page 1, line 4, following "state;":

2 Insert "relating to credits for certain losses and expenditures against the oil and
3 gas production tax;"

4

5 Page 4, following line 28:

6 Insert new bill sections to read:

7 **** Sec. 7.** AS 43.55.023(d) is amended to read:

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

1 [CERTIFICATES, EACH FOR HALF OF THE AMOUNT OF THE CREDIT]. The
2 credit shown on [ONE OF] the certificate [TWO CERTIFICATES] is available for
3 immediate use. [THE CREDIT SHOWN ON THE SECOND OF THE TWO
4 CERTIFICATES MAY NOT BE APPLIED AGAINST A TAX FOR A CALENDAR
5 YEAR EARLIER THAN THE CALENDAR YEAR FOLLOWING THE
6 CALENDAR YEAR IN WHICH THE CERTIFICATE IS ISSUED, AND THE
7 CERTIFICATE MUST CONTAIN A CONSPICUOUS STATEMENT TO THAT
8 EFFECT.] A certificate issued under this subsection does not expire.

9 * **Sec. 8.** AS 43.55.028(e)(2) and 43.55.028(e)(3) are repealed."
10

11 Renumber the following bill sections accordingly.
12

13 Page 5, line 2:

14 Delete "sec. 8"

15 Insert "sec. 10"

ALASKA STATE LEGISLATURE

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Chair
Senate Special Committee on Energy
Senate Committee on World Trade,
Technology and Innovations

Co-Chair
Senate Resources Committee

Member
Senate Judiciary Committee

SENATOR LESIL MCGUIRE

SPONSOR STATEMENT FOR SENATE BILL 309

"An Act amending and extending the exploration and development incentive tax credit under the Alaska Net Income Tax Act for operators and working interest owners directly engaged in the exploration for and development of gas from a lease or property in the state; providing for an effective date by amending the effective date for sec. 2, ch. 61, SLA 2003; and providing for an effective date."

Senate Bill 309 amends and extends the exploration and development incentive tax credit that was originally enacted in 2003 by the 23rd legislature. This tax credit continues to be applicable, under the Alaska Net Income Tax Act, to operators and working interest owners directly engaged in the exploration for and development of natural gas, primarily in the Cook Inlet area.

To more strongly encourage companies to invest additional capital in exploring for and developing new natural gas reserves, this legislation makes five significant changes to current law:

- Expands the application of the credit to development drilling within an existing field.
- Increases the amount of the credit to 25% (from 10%) of the amount of qualified capital investment and qualified services spending.
- Removes the 50% limitation on the amount of credits that can apply in a single year.
- Removes the "successful efforts" requirement that developers must find and deliver new gas resources to market to qualify for the credit.
- Extends the sunset date of the investment tax credit from January 1, 2013 to January 1, 2020.

Annual natural gas production and supply in the Cook Inlet area have been declining for a number of years. During the same time, domestic demand has been increasing steadily. Therefore, a sharp increase in drilling to find new reserves is drastically needed. The Department of Natural Resources projects that most of the new gas needed will be found in existing fields. The original Investment Tax Credit enacted in 2003, while modestly successful in stimulating new drilling, did not incentivize development drilling in existing fields. These changes will go a long way toward achieving that goal.

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SENATOR LESIL MCGUIRE

Changes to SB 309 in CS SB 309 (RES) Version 26-LS1629R

Please note that this analysis is not an authoritative interpretation of changes to the bill. The bill itself is the best statement of its contents.

- Title** Inserted language on page 1, lines 4-7 to reflect the addition of language from Senate Bill 290 in the bill.
- Section 1** No changes.
- Section 2** No changes.
- Section 3** No changes.
- Section 4** Added a new subsection that amends AS 43.20.043 (e) that prohibits the use of the qualified investment in a rate base for a regulated facility.
- Section 5** No changes.
- Section 6** Added new language clarifying that a taxpayer who claims a credit under AS 43.20.043 may not claim any other credit or royalty modification for the same investment.
- Section 7** Added a new subsection amending the definition of "property" in AS 43.20.043(i)(1) to exclude LNG facilities, topping plants and processing units.
- Section 8** No changes.
- Section 9** Added a new section amending AS 43.55.023 (a) allowing a capital investment tax credit to be taken in a single calendar year.
- Section 10** Added a new section amending AS 43.55.023 (d) to conform to the changes made in section 9.
- Section 11** Added a new section creating a new credit for exploration expenses in the Cook Inlet.

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- Section 12** Added a new section clarifying the application and qualifications for the credit established in section 11.
- Section 13** No changes (previously section 7).
- Section 14** Added new language repealing AS 43.55.028(e)(2) [requiring expenditures within 24 months] and AS 43.55.028(e)(3) [requiring expenditures equal to the credits] in the section related to use of the oil and gas tax credit fund for the purchase of credits from small producers.
- Section 15** No changes (previously section 8).
- Section 16** No changes (previously section 9).

Issues Surrounding Requiring Geologic and Geophysical Data Submissions for ITC Credits

Inclusion of AS 43.55.025 (f)(2) into HB 229 and/or SB 309 will damage the incentives intended in either bill. Under ACES, the statute requires proprietary data sets to be released to the DNR to qualify for the production tax credit. Such data will serve no purpose in assessing qualification in investment tax credit included in HB 229 and SB 309. Rather, the language will create a disincentive instead of delivering an incentive for further resource development to improve the reliability of natural gas production in Cook Inlet – a benefit to all stakeholders and area constituents. Language in the aforementioned statute is very problematic for specific reasons including:

1. The data set as defined is not limited to the data collected as part of the investment used in qualifying for the credit. The required data extends well beyond to include data collected over the entire area, including data collected over non-state leases and proprietary interpretations of the data.

AS 43.55.025(f)(2)(B)

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

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

2. Companies have invested millions of dollars in geologic assessments and sub-surface data over the years. This highly proprietary and very costly data will be released to the public domain within 24 months for well data and 10 years for seismic data. The release of such highly competitive and confidential data will provide other parties access to such data for free allowing them to undesirably encroach in the field operations, creating distractions for the producing entities. Ten years may seem lengthy however it is actually quite short considering the life cycle of a field. For example, Kenai Gas Field has been producing for over 50 years.
3. Due to the confined area of the Cook Inlet and the highly competitive nature of the local environment and market situation, applying this provision to the Cook Inlet would result in a disincentive for pursuing these credits.

Simply put, the requirements under AS 43.55.025 (f)(2)(B) will very likely outweigh any benefits provided for in these investment tax credit bills. This will not be an aid in the solution to the overall natural gas issues in Cook Inlet.

State of Alaska
Department of Natural Resources
Division of Oil and Gas
and
Division of Geological & Geophysical Surveys

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Preliminary Engineering and Geological Evaluation
of Remaining Cook Inlet Gas Reserves

by

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THIS REPORT HAS NOT RECEIVED EXTERNAL REVIEW FOR TECHNICAL CONTENT OR FOR CONFORMITY TO THE EDITORIAL STANDARDS OF THE STATE OF ALASKA, THE DIVISION OF OIL AND GAS, OR THE DIVISION OF GEOLOGICAL & GEOPHYSICAL SURVEYS

EXECUTIVE SUMMARY

Over the past year, there has been widespread concern over whether the existing system of natural gas production and delivery in the Cook Inlet basin can continue to meet the energy demands of south-central Alaska. Of most immediate concern is whether there may soon be shortfalls during brief spikes in peak gas demand brought about by severe winter weather. A thorough understanding of the problem requires consideration of at least two major sets of issues. The first set includes geologic and engineering details regarding how much gas remains to be recovered from Cook Inlet fields, and what steps are required to access it. The other is a complex set of commercial and infrastructure factors that determine the ability to provide gas to the end user. This report addresses geologic and engineering issues regarding gas reserves and resources. Issues regarding the economics of drilling additional wells, recompleting existing wells, optimizing infrastructure, and the ability to sell the gas into the Cook Inlet market are beyond the scope of this paper. Nevertheless, as is the case with most maturing gas provinces, the costs and financial risk associated with accessing and producing the additional reserves and potential reserves identified by this study will increase with time, likely contributing to increases in the price of gas.

Reservoir engineering and geological analyses were undertaken independently of one another to evaluate the volumes of gas remaining in existing fields. These analyses are preliminary, based on data currently available to the Division of Oil and Gas. All 28 of the currently producing Cook Inlet gas fields were evaluated by applying decline curve analysis and material balance engineering methods to publicly available production data obtained from the Alaska Oil and Gas Conservation Commission (AOGCC). Based on extrapolations of production trends, these engineering techniques were used to derive estimates of remaining proved and probable reserves.

Four of the gas fields judged from engineering analyses to have the greatest remaining potential were selected for further study via detailed geologic analyses: Beluga River, North Cook Inlet, Ninilchik, and the McArthur River Grayling gas sands. Development geology techniques yielded volumetric estimates of original gas-in-place and initial recoverable gas (estimated ultimate recovery) for these four large fields, drawing and preserving important distinctions between gas volumes in known pay intervals versus gas in potential pay intervals. Comparison of geologically based recoverable gas with cumulative production yielded estimates of the remaining recoverable gas in the four fields.

The independent engineering and geologic approaches pursued in this study allow the reporting of remaining gas volumes at varying levels of production certainty and readiness. The total proved, developed, producing (PDP) reserves remaining to be produced from all existing fields in the Cook Inlet is estimated at 863 BCF. This volume was identified by decline curve analyses and assumes sufficient investment to maintain existing wells. Additional probable reserves that would be recoverable by increasing investment in existing fields are estimated at 279 BCF. This volume is identified as the basin-wide difference in the results of material balance methods and decline curve analyses. Geologic evaluations of the Beluga River, North Cook Inlet, Ninilchik, and the McArthur River Grayling gas sands reservoirs indicate the potential for an additional increment of 353 BCF in high-confidence pay intervals, and another

possible increment of 643 BCF (in the 50 percent-risked case) from lower-confidence pay intervals, both of which are arguably not in communication with existing wellbores, and thus cannot be estimated from the engineering methods. These incremental volumes are the difference, for these four gas fields, between the remaining recoverable gas estimated in geologically identified high-confidence pay and potential pay minus that estimated by material balance analyses.

These geologically identified volumes of known and potential nonproducing gas represent a significant energy resource, which if developed, have the potential to supply local demand well into the next decade. This forecast assumes that exports of gas from the basin will be curtailed during demand shortfalls, and cease altogether at the closure date of the current export license (March 31, 2011). It also assumes that no new significant demand will be developed until additional resources are discovered in new fields.

We also discuss higher-risk contingent resources that await confirmation and delineation in exploration prospects outside of producing areas where previous well penetrations suggest follow-up drilling may be warranted. Finally, we recognize, but have not attempted to quantify, potential undiscovered gas resources in unexplored areas or underexplored plays within the Cook Inlet basin. Significant work is underway by government and industry stakeholders to analyze this exploration potential, which could be an integral part of the region's energy portfolio well into the future. The findings of this study suggest there are a variety of short-, medium-, and long-term opportunities that have the potential to meet the energy demands of south-central Alaska over the next decade or more.

Section Two: Royalty Production and Revenue

Introduction

The state of Alaska receives a royalty of approximately 12.5 percent of the oil and gas produced from its leases. The state may take its share of oil production "in-kind" or "in-value." When the state takes its royalty share in-kind (RIK), it assumes possession of the oil or gas. The commissioner of Natural Resources may sell the RIK oil or gas in a competitive auction or through a noncompetitive sale negotiated with a single buyer. When the state takes its royalty in-value (RIV), the state's lessees who produce the oil or gas market the state's share along with their own share of production. The lessees remit cash payments on a monthly basis for the state's RIV share.

Over the last 30 years the state has taken about one-half of its royalty oil as RIK. The state has sold nearly 800 million barrels of RIK oil during this time, nearly all of it in-state. Pricing terms have been targeted to provide the state at least as great a price as would have been received had the royalty been taken in value. Volumes to be delivered are typically cast as targets within a defined range, rather than precise specifications of barrels. Lease terms require that when the state elects to take RIK it must provide 90-180 days notice (depending upon the lease) of a percentage of royalty to be taken in kind, rather than a specific number of barrels to be taken in kind; the uncertainty as to future production volumes makes a precise specification of RIK deliveries impossible."

These in-state sales have provided an important supply security, thereby stimulating Alaska's refining industry by providing long-term supplies of oil to each of the state's four refineries. Over the years, state RIK sales fueled many controversies and policy debates over the appropriate use of the state's natural resources.

Cook Inlet

In 1969 the commissioner of Natural Resources negotiated a sale of 100 percent of the state's royalty from Cook Inlet to the Alaska Oil and Refining Company. Within months of signing the contract, Alaska Oil and Refining Company merged with the Tesoro Petroleum Company. Tesoro subsequently built a new refinery in Nikiski on the Kenai Peninsula next to Chevron's refinery, built in 1964. Between 1969 and 1985 the state sold all of its Cook Inlet royalty oil to the Tesoro refinery. By 1980, the production decline in Cook Inlet prompted Tesoro to negotiate the first of several sales contracts with the state for supplies of RIK oil from the North Slope. By the end of 1985 Tesoro had replaced its Cook Inlet RIK volumes with supplies of RIK from the North Slope.

In 1987 the state began to export Cook Inlet RIK oil to the Chinese Petroleum Company. These volumes were produced from fields on the west side of the Cook Inlet after the federal government exempted Cook Inlet production from export administration regulations. The state sold 97 percent of the royalty production from the McArthur River, Trading Bay, North Trading Bay, and Granite Point fields in a series of one-year competitive auctions. In 1991 deliveries under the last Chinese Petroleum contract were halted under force majeure following the December 1989 eruption of the Mount Redoubt volcano. There have been no Cook Inlet RIK sales since (See Table IV.8.).

North Slope

Over the past 25 years, the state has held nine RIK sales involving portions of its Alaska North Slope (ANS) royalty oil production. These sales are summarized in Table IV.7 and Figure IV.3. In 1976, the state signed a six-year contract with Golden Valley Electric Association (GVEA), the electric utility in Fairbanks, to sell approximately 3,300 barrels of ANS crude oil per day as turbine fuel. GVEA did not exercise its option to take RIK until 1981 and it traded these volumes with Mapco (now Williams Alaska) in exchange for refined fuel. The state subsequently sold RIK ANS to GVEA in two other contracts until 1992. As in the first contract, GVEA traded these volumes with Mapco.

In 1978 the state contracted with Earth Resources Company of Alaska, predecessor to Mapco Alaska and Williams Alaska Petroleum Company, to supply 15 percent of Prudhoe Bay RIK oil production less the quantity dedicated to GVEA. This 25-year contract expired in December 2003. Williams received a maximum of 35,000 barrels per day of RIK

oil produced from the Prudhoe Bay Unit under this contract and supplemented this supply with new agreements for another 28,000 barrels per day.

Tesoro has been an important North Slope RIK customer. Tesoro negotiated and bid for several contracts that supplied it with RIK supplies from 1980 to 1998. Chevron was another big purchaser of North Slope RIK for oil supplied to its Nikiski refinery from 1980 through 1991, when it finally shut down its Nikiski refinery. Petro Star Inc. purchased North Slope RIK from 1986 through 1991 for its new refinery at North Pole. In 1992 Petro Star negotiated a 10-year contract with the state for a supply of RIK from the Kuparuk River Unit. With this contract in hand, Petro Star was able to build the state's newest refinery in Valdez. As it happened, Petro Star elected to take no oil under this contract and the contract expired automatically nine months after it had been signed.

The state also held competitive auctions of RIK oil during the early 1980s as part of a program to routinely offer RIK short-term contracts. Winners of these sales included in-state refineries but also several refineries located outside the state. Many of these buyers were also ANS producers. About 46 million barrels of Alaska North Slope RIK crude oil were sold in these auctions but the program was interrupted after the general collapse of oil prices in the mid-1980s. In January 2000, the Division of Oil and Gas published a Notice of Interest in Sale of State Royalty Oil. The response to this notice by prospective RIK purchasers prompted the division to plan for a competitive bid auction for volumes of RIK oil produced from several North Slope fields. The sale was subsequently held in August 2000 but no bids were offered.

In September 2003, the state negotiated a temporary contract with Williams for the period January 1, 2004, through March 31, 2004. The state also negotiated a new 10-year contract with Flint Hills Resources Alaska, LLC (FHR), signed by the Governor on March 9, 2004, enabling FHR to take over the Williams' North Pole refinery on March 31. Deliveries of royalty oil under the new RIK contract began April 1, 2004. The state sold approximately 57,537 barrels per day to FHR, or more than 64 percent of the total royalty oil produced on the North Slope for the period January 1 through December 31, 2008.

The contract contained special conditions which serve as additional consideration for FHR's purchase of the state's royalty oil. FHR will maintain gasoline wholesale rack price parity between Anchorage and Fairbanks. FHR has invested approximately \$100 million to install clean fuels processing equipment and facilities in the North Pole Refinery and/or elsewhere in Alaska. It has fulfilled and enhanced the previous commitments made by Williams to the Government Hill Community Council in Anchorage to address concerns about gasoline storage tanks near Government Hill and has undertaken additional projects to improve the Anchorage Tank Farm Facility. FHR will also continue to ship refined products to Anchorage via the Alaska Railroad, (FHR shipments represented 41 percent of the total freight loadings for the Alaska Railroad for 2008).

In Fairbanks, FHR has studied the use and viability of the hydrant fueling system at the Fairbanks International airport (FIA), concentrating on promoting FIA to cargo carriers, evaluating and upgrading FIA fuel distribution facilities, and charging a jet fuel customer in Fairbanks the same or lower price as FHR charges that same customer in Anchorage. FHR met all of these conditions for 2008 and has performed upgrades of their fueling facilities at FIA, primarily related to environmental remediation and compliance on their lease lot.

Royalty-in-Kind Policy

The earliest RIK sales, notably Tesoro's first Cook Inlet contract, the first GVEA contract, and the Alpetco contract, generated controversy and debate in the state. Several issues arose as the RIK program evolved. Is the state better off negotiating sales one-on-one or auctioning RIK through competitive tenders? How much public input should be encouraged? Should the state subsidize the local refining industry through price breaks? What kind of oversight should be required? The debates of these questions led to the present program as set out in statutes and regulations.

When disposing royalty oil or gas, the commissioner is bound by AS 38.05.182 and AS 38.05.183. Further, the Legislature established the Alaska Royalty Oil and Gas Development Board (Royalty Board) under AS 38.06 to oversee the department's RIK program. Regulations under Title 11, Chapters 3 and 26 govern the actual disposition of royalty and the sale of RIK. (See <http://www.legis.state.ak.us/folhome.htm> for more information).

The rules that govern the sale of RIK may be reduced to a few principles:

- Any disposition of the state's royalty must be in the state's best interest. The state should sell its royalty rather than take it in-value as long as the best interests of the state are served.

Royalty-In-Kind

- The state must receive a price for its RIK that is at least as much as it receives when the state takes its royalty in-value.
- Under certain circumstances, the state may sell its oil in a negotiated sale, but competitive sales are preferred.
- Although the price of RIK must equal or exceed the price of RIV, a review of each sale must consider economic, social, and environmental effects. In this way, benefits may be attributed to the sale of RIK to local refineries that would not be generated by sales to outside purchases.
- The public is a part of the process. Depending on the terms of the sale, the commissioner will publish best interest findings and solicit comments on the sale from the public.
- The Royalty Board must be notified of any disposition of RIK. For supply contracts of more than one year, the Royalty Board must evaluate the economic, social, and environmental effects of the sale, convene a public hearing, and recommend approval of the sale to the Legislature.
- The Legislature approves long-term contracts by enacting legislation
- The near-universal practice of the Department is to make its sales at or near the location of production. The RIK buyers take title upstream of necessary transportation infrastructure, and must arrange for transportation themselves. In this way, transportation risks are borne by the purchaser, and the state minimizes its need for staffing to administer RIK sales.

Table II.1 Recent Royalty Oil Production & Revenues

Lease Operation	Badami Unit RIV	Badami Unit RIK	TOTAL Badami Unit	Colville River Unit RIV	Colville River Unit RIK	TOTAL Colville River Unit	Duck Island Unit RIV	*Duck Island Unit RIK*	*TOTAL Duck Island Unit*	*Kuparuk River Unit RIV	*Kuparuk River Unit RIK*	*TOTAL Kuparuk River Unit*
Production (Thousands of Barrels)												
1997	-	-	-	-	-	-	3,324.4	-	3,324.4	10,978.3	-	10,978.3
1998	-	106.1	-	106.1	-	-	2,692.5	-	2,692.5	10,886.2	-	10,886.2
1999	-	179.2	-	179.2	1.3	-	1.3	-	2,263.3	10,822.0	-	10,822.0
2000	-	144.6	-	144.6	196.6	-	196.6	-	1,943.1	9,897.9	-	9,897.9
2001	-	104.0	-	104.0	2,785.5	-	2,785.5	-	1,696.9	9,076.4	-	9,076.4
2002	-	87.0	-	87.0	3,403.4	-	3,403.4	-	1,483.5	8,921.6	-	8,921.6
2003	0.6	42.1	-	42.1	3,777.1	-	3,777.1	-	1,535.1	8,905.8	-	8,905.8
2004	-	-	-	-	3,642.3	-	3,642.3	390.2	1,224.5	7,976.8	305.3	8,282.1
2005	2.1	22.2	-	22.2	4,262.4	-	4,262.4	51.2	1,026.3	1,077.5	3,138.0	7,636.6
2006	-	56.3	15.9	72.2	3,273.9	404.6	3,678.5	43.8	819.3	863.1	2,120.3	5,080.6
2007	-	33.7	-	33.7	3,469.1	936.4	4,405.5	27.1	752.1	779.3	918.0	5,693.7
2008	-	-	-	-	2,320.5	1,587.3	3,907.8	29.1	761.9	790.9	402.0	5,695.7
Revenues (Thousands of Dollars)												
1997	-	-	-	-	-	-	\$42,866	-	\$42,866	\$150,137	-	\$150,137
1998	-	\$572	-	\$572	-	-	\$18,147	-	\$18,147	\$82,772	-	\$82,772
1999	-	\$1,992	-	\$1,992	\$57	-	\$26,461	-	\$26,461	\$136,802	-	\$136,802
2000	-	\$2,612	-	\$2,612	\$4,539	-	\$4,539	-	\$42,350	\$220,539	-	\$220,539
2001	-	\$1,051	-	\$1,051	\$47,972	-	\$47,972	-	\$31,796	\$160,694	-	\$160,694
2002	-	\$108	-	\$108	\$62,818	-	\$62,818	-	\$27,128	\$173,379	-	\$173,379
2003	\$15	\$46	-	\$46	\$89,684	-	\$89,684	-	\$35,753	\$211,369	-	\$211,369
2004	-	\$0	-	\$0	\$122,667	-	\$122,667	\$14,219	\$38,674	\$255,120	\$11,578	\$266,699
2005	\$85	\$876	-	\$876	\$201,866	-	\$201,866	\$6,831	\$47,365	\$54,197	\$186,238	\$159,863
2006	-	\$2,070	\$484	\$2,554	\$193,449	\$21,825	\$215,274	-\$2,937	\$46,279	\$43,343	\$109,198	\$295,880
2007	\$25	\$899	-	\$899	\$248,989	\$72,853	\$321,843	\$1,451	\$48,036	\$49,486	\$56,131	\$373,458
2008	-	\$273	\$1	\$274	\$207,408	\$155,372	\$362,779	\$7,161	\$71,112	\$78,273	\$47,425	\$515,948

Revenues include interest from revisions and settlements in the year received.

	Milne Point Unit RIV	*Milne Point Unit RIK*	*TOTAL Milne Point Unit*	Northstar Unit RIV	Northstar Unit RIK	TOTAL Northstar Unit	*Prudhoe Bay Unit RIV*	*Prudhoe Bay Unit RIK*	*TOTAL Prudhoe Bay Unit*	*TOTAL North Slope*
Production (Thousands of Barrels)										
1997	2,657.0	-	2,657.0	-	-	-	18,399.6	26,139.6	44,539.2	61,498.8
1998	2,833.4	-	2,833.4	-	-	-	11,810.5	27,981.6	39,792.1	56,310.2
1999	2,699.2	-	2,699.2	-	-	-	15,508.5	19,070.7	34,579.2	50,544.1
2000	2,613.9	-	2,613.9	-	-	-	13,053.5	19,290.3	32,343.8	47,140.0
2001	2,687.9	-	2,687.9	212.9	-	212.9	13,643.5	15,187.0	28,830.6	45,394.3
2002	2,570.7	-	2,570.7	4,009.3	-	4,009.3	11,794.8	15,509.5	27,304.4	47,779.8
2003	2,569.7	-	2,569.7	5,236.7	-	5,236.7	5,489.2	20,630.5	26,119.8	48,186.9
2004	1,534.2	1,039.7	2,573.9	2,661.6	3,004.6	5,666.2	5,641.0	18,478.1	24,119.2	45,508.2
2005	111.5	2,088.1	2,199.7	5,065.9	-	5,065.9	5,547.1	16,545.2	22,092.3	42,358.7
2006	193.4	1,635.8	1,829.2	1,235.8	3,030.4	4,266.2	6,467.6	11,287.2	17,754.8	35,665.0
2007	527.4	1,158.0	1,685.3	1,786.3	1,349.1	3,135.4	345,910.4	846,510.8	18,286.2	34,937.2
2008	58.7	1,563.1	1,621.7	2,325.1	-	2,325.1	568,727.7	1,054,475.7	18,025.0	32,800.3
Revenues (Thousands of Dollars)										
1997	\$33,777	-	\$33,777	-	-	-	\$242,341	\$383,701	\$626,042	\$852,822
1998	\$18,608	-	\$18,608	-	-	-	\$73,462	\$227,032	\$296,313	\$416,413
1999	\$31,596	-	\$31,596	-	-	-	\$170,204	\$259,246	\$429,450	\$626,358
2000	\$56,730	-	\$56,730	-	-	-	\$275,928	\$461,464	\$737,392	\$1,064,162
2001	\$47,356	-	\$47,356	\$1,584	-	\$1,584	\$236,464	\$279,804	\$516,268	\$806,722
2002	\$48,818	-	\$48,818	\$75,797	-	\$75,797	\$201,726	\$320,378	\$522,104	\$910,151
2003	\$61,255	-	\$61,255	\$123,753	-	\$123,753	\$114,558	\$507,952	\$622,509	\$1,144,385
2004	\$44,971	\$37,287	\$82,258	\$7,502	109,196	196,698	\$172,637	\$631,864	\$804,501	\$1,511,495
2005	\$4,786	\$94,638	\$99,424	243,095	104	243,199	\$239,535	\$805,939	\$1,045,474	\$1,991,222
2006	\$9,858	\$92,003	\$101,860	73,483	183,156	256,639	\$369,888	\$651,728	\$1,021,616	\$2,046,364
2007	\$35,921	\$69,239	\$105,160	148,025	88,623	236,647	\$345,910	\$846,511	\$1,192,421	\$2,336,071
2008	\$12,494	\$142,604	\$155,098	221,582	2,184	223,767	\$568,728	\$1,054,476	\$1,623,203	\$3,008,793

Table II.1 Recent Royalty Oil Production & Revenues

	Granite Point Field	*South Granite Point Unit*	*North Middle Ground Shoal*	*Middle Ground Shoal*	*South Middle Ground Shoal*	*Trading Bay Field*	*Trading Bay Unit*	*West McArthur Unit*	Redoubt Unit	Cosmopolitan Unit	*TOTAL Cook Inlet*	TOTAL STATE
Production (Thousands of Barrels)												
1997	303.5	-	42.0	150.6	26.8	75.1	632.4	80.6	-	-	1,311.0	62,809.8
1998	259.8	-	44.7	196.0	28.8	87.1	602.4	116.2	-	-	1,335.0	57,645.2
1999	172.4	51.0	38.2	181.9	24.6	82.7	587.2	114.3	-	-	1,252.2	51,796.3
2000	119.2	98.5	43.5	170.5	22.8	79.6	602.8	111.6	-	-	1,248.6	48,388.5
2001	109.3	92.9	39.7	194.4	19.8	72.3	671.1	152.9	-	-	1,352.4	46,746.7
2002	105.2	85.8	27.1	197.1	20.8	74.6	697.0	127.3	2.3	-	1,337.2	49,117.1
2003	98.8	80.0	11.8	177.4	-	68.7	538.6	106.1	45.5	1.0	1,127.9	49,314.8
2004	84.0	77.4	-	165.3	-	58.0	424.6	83.7	28.0	-	920.8	46,429.0
2005	75.2	67.5	-	164.7	-	51.8	340.3	64.6	15.6	-	779.7	43,138.4
2006	73.7	46.9	-	148.9	-	49.1	284.0	54.6	13.4	-	670.6	36,335.5
2007	64.1	48.6	-	114.0	-	34.4	230.5	48.1	7.7	-	547.3	35,484.5
2008	61.3	44.9	-	109.2	-	19.9	174.7	39.6	4.7	-	454.4	33,254.7
Revenues (Thousands of Dollars)												
1997	\$5,175	-	\$764	\$3,655	\$490	\$1,192	\$10,561	\$1,795	-	-	\$23,633	\$876,456
1998	\$2,813	-	\$544	\$2,244	\$346	\$853	\$5,902	\$1,107	-	-	\$13,809	\$430,222
1999	\$2,090	\$1,388	\$662	\$3,073	\$406	\$1,261	\$8,917	\$1,583	-	-	\$19,380	\$645,738
2000	\$4,201	\$3,840	\$1,491	\$4,647	\$821	\$2,632	\$17,073	\$2,790	-	-	\$37,495	\$1,101,657
2001	\$2,515	\$2,051	\$959	\$4,338	\$476	\$1,522	\$13,908	\$2,941	-	-	\$28,710	\$835,432
2002	\$2,337	\$1,850	\$619	\$5,428	\$494	\$1,609	\$14,992	\$2,680	\$54	-	\$30,062	\$940,214
2003	\$2,633	\$2,249	\$349	\$5,103	\$2	\$1,876	\$14,693	\$2,736	\$1,140	\$19	\$30,801	\$1,175,186
2004	\$3,066	\$2,764	-	\$11,544	-	\$2,021	\$14,732	\$2,807	\$900	-	\$37,835	\$1,549,330
2005	\$3,712	\$3,354	-	\$8,710	-	\$2,509	\$16,641	\$3,089	\$802	-	\$38,819	\$2,030,041
2006	\$4,287	\$2,855	-	\$9,328	-	\$2,905	\$17,020	\$3,299	\$754	-	\$40,449	\$2,086,813
2007	\$4,581	\$3,259	-	\$8,028	-	\$1,632	\$15,851	\$3,098	\$485	-	\$36,944	\$2,373,015
2008	\$5,974	\$4,485	-	\$10,880	-	\$2,104	\$17,483	\$3,929	\$521	-	\$45,406	\$3,054,199

Revenues include interest from revisions and settlements in the year received.

Table II.2 Recent Royalty Oil Production by Lessee

NORTH SLOPE

Production (Thousands of Barrels)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Amerada Hess	-	-	-	-	-	-	-	-	-	-	-	-
Amoco	297	237	199	119	-	-	-	-	-	-	-	-
Anadarko	-	-	\$0	43	613	749	831	801	938	720	763	511
Arco	11,120	9,522	10,729	-	-	-	-	-	-	-	-	-
Armstrong	-	-	-	-	-	-	<1	<1	1	-	-	-
BP America Prod Co.	-	-	-	-	-	95	165	-	-	-	-	-
BP Exploration	16,683	13,595	14,233	11,869	11,075	14,451	13,898	9,555	8,527	4,109	4,282	4,409
Chevron	99	64	91	77	81	116	66	60	59	66	52	69
CIRI	30	1	-	-	-	-	-	-	-	-	-	-
ConocoPhillips AK	-	-	-	-	-	11,225	9,250	9,145	7,912	6,269	5,363	4,571
DOYON	6	5	4	4	3	3	3	1	<1	<1	<1	\$0
ENI Petroleum US LLC	-	-	-	-	-	-	-	-	-	-	<1	\$10
Exxon	5,571	3,563	4,815	-	-	-	-	-	-	-	-	-
ExxonMobil	-	-	-	4,596	5,287	4,284	-	-	-	-	-	-
ExxonMobil AK Production	-	-	-	-	-	-	1,926	1,899	1,866	2,118	1,649	2,192
Forest Oil	5	3	4	2	2	2	1	1	1	1	-	-
Kerr McGee	-	-	-	-	-	-	-	1	1	-	5	1
Mapco 1978 Contract	12,652	11,148	12,442	12,718	12,522	12,167	12,583	-	-	-	-	-
Mapco 1997 Contract	466	4,451	-	-	-	-	-	-	-	-	-	-
Marathon	-	-	-	-	-	-	-	-	-	-	-	-
Mobil	237	155	195	-	-	-	-	-	-	-	-	-
NANA	18	14	12	11	8	8	8	4	<1	<1	<1	\$0
Oxy	208	224	212	189	-	-	-	-	-	-	-	-
Petrofina	-	32	54	43	31	-	-	-	-	-	-	-
Phuntlic	190	113	151	10,201	12,482	-	-	-	-	<1	<1	\$0
Phillips	-	-	-	-	-	-	-	-	-	-	-	-
Phillips Alpine Alaska	-	-	-	-	-	749	831	352	-	-	-	-
Pioneer	-	-	-	-	-	-	<1	-	-	-	-	-
Tesoro	13,022	11,498	-	-	-	-	-	-	-	-	-	-
Texaco	52	31	41	35	38	18	-	-	-	-	-	-
TotalFina ELF	-	-	-	-	-	-	-	-	-	-	-	-
Union Texas Petroleum	-	-	-	-	-	-	-	-	-	-	-	-
Unocal	842	771	732	659	587	570	576	468	227	108	85	23
Williams 98 Contract	-	884	6,628	6,572	2,665	3,342	8,056	5,582	-	-	-	-
Flint Hills Resources AK, LLC	-	-	-	-	-	-	-	17,632	22,797	22,274	22,775	20,993
XTOE	-	-	-	-	-	-	-	2	-	-	-	-
North Slope TOTAL	61,499	56,312	50,544	47,140	45,994	47,780	48,194	45,505	42,849	35,665	34,974	32,778

COOK INLET

Production (Thousands of Barrels)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Conoco Phillips AK	-	-	-	-	-	-	1	-	-	-	-	-
Cross Timbers/XTO	-	-	182	170	194	197	177	165	165	149	114	109
Devon	-	-	-	-	-	-	<1	-	-	-	-	-
Forcenergy/Forest Oil	377	436	425	428	495	491	436	337	264	224	180	-
Marathon	-	-	-	-	-	-	-	-	-	-	-	-
Mobil/Exxon Mobil AK Prod	110	91	76	74	70	64	60	58	51	35	36	34
Pacific Energy AK	-	-	-	-	-	-	-	-	-	-	-	142
Pioneer	-	-	-	-	-	-	-	-	-	-	-	<1
Shell	151	196	-	-	-	-	-	-	-	-	-	-
Stewart	30	-	-	-	-	-	-	-	-	-	-	-
Unocal	643	612	569	576	593	585	454	360	301	263	217	169
XTOE	-	-	-	-	-	-	-	-	-	-	-	-
Cook Inlet TOTAL	1,311	1,335	1,252	1,249	1,352	1,337	1,128	921	780	671	547	454

Table II.3 Recent Royalty Oil Revenues by Lessee

NORTH SLOPE												
Revenues (Thousands of Dollars)												
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Amerada Hess	\$34	-	-	-	-	-	-	-	-	-	-	-
Amoco	\$3,674	\$1,556	\$2,404	\$2,562	-\$0	-	-	-	-	-	-	-
Anadarko	-	-	\$12	\$982	\$10,374	\$14,180	\$20,057	\$27,427	\$45,375	\$43,352	\$44,825	\$44,803
Arco	\$155,281	\$72,786	\$135,879	-	-	-	-	-	-	-	-	-
Armstrong	-	-	-	-	-	-	\$4	-	\$26	-	-	-
BPAmerica Prod Co.	-	-	-	-	-	-	\$3,934	-	-	-	-\$266	\$399
BP Exploration	\$216,022	\$85,263	\$158,955	\$249,682	\$208,250	\$267,287	\$325,241	\$301,848	\$391,141	\$318,659	\$295,849	\$463,851
Chevron	\$1,274	\$368	\$1,044	\$1,608	\$1,422	\$2,070	\$1,437	\$1,745	\$2,650	\$10,694	\$2,834	\$6,452
CIRI	\$423	\$12	-	-	-	\$180	-	-	-	-	-	-
ConocoPhillips AK	-	-	-	-	-	\$211,239	\$214,806	\$297,445	\$353,413	\$337,580	\$329,594	\$414,119
DOYON	\$83	\$41	\$39	\$82	\$54	\$44	\$64	\$40	\$4	\$125	\$3	\$5
ENI Petroleum US LLC	-	-	-	-	-	-	-	-	-	-	\$8	\$516
Exxon	\$71,707	\$19,733	\$52,342	-	-	-	-	-	-	-	\$7	\$34
ExxonMobil	-	-	-	\$98,415	\$83,945	-	-	-	-	-	\$5,312	-\$1,899
ExxonMobil AK Production	-	-	-	-	-	\$69,780	\$37,737	\$54,093	\$81,549	\$130,038	\$86,726	\$200,463
Forest Oil	\$63	\$17	\$43	\$50	\$38	\$37	\$18	\$29	\$43	\$19,759	-	-
Kerr McGee	-	-	-	-	-	-	-	\$22	\$60	-	\$372	\$46
Mapco 1978 Contract	\$185,000	\$90,752	\$166,427	\$304,389	\$223,123	\$247,246	\$310,960	-\$179	-	-	-	-
Mapco 1997 Contract	\$6,032	\$38,590	-\$60	\$90	\$1,075	-	-	-	-	-	-	-
Marathon	\$1	-	-	-	-	-	-	-	-	-	-	-
Mobil	\$3,026	\$851	\$2,166	-	-	-	-	-	-	-	-	-
NANA	\$255	\$122	\$120	\$220	\$163	\$131	\$221	\$121	\$12	\$455	\$78	\$14
Oxy	\$2,778	\$1,533	\$2,626	\$4,290	-	-	-	-	-	-	-	-
Petrofina	-	\$185	\$616	\$807	\$284	-	-	-	-	-	-	-
Phuntlic	\$2,377	\$752	\$1,379	\$228,306	\$211,865	-	-	-	-	\$97	\$7	\$11
Phillips	-	-	-	-	-	-	-	-	-	-	-	-
Phillips Alpine Alaska	-	-	-	-	-	\$13,718	\$19,638	\$10,244	-	-	\$4,274	-
Pioneer	-\$5	-	-	-	-	-	\$10	-	-	-	-	\$1,231
Tesoro	\$192,689	\$92,288	\$191	-\$623	\$1,632	\$887	-	-	-	-	-	-
Texaco	\$664	\$149	\$398	\$842	\$653	\$270	-	-	-	-	\$7	\$38
TotalFina ELF	-	-	-	-	-	-	-	-	-	-	-	-
Union Texas Petroleum	-	-	\$12	-	-	-	-	-	-	-	-	-
Unocal	\$11,463	\$6,013	\$9,078	\$14,851	\$9,868	\$10,858	\$13,265	\$14,250	\$8,962	\$5,897	\$4,694	\$2,509
Williams 98 Contract	-	\$5,402	\$92,688	\$157,608	\$53,975	\$72,245	\$196,991	\$162,716	-	-	\$15,012	\$21,895
Flint Hills Resources AK, LLC	-	-	-	-	-	-	-	\$641,607	\$1,107,909	\$1,179,502	\$1,483,777	\$1,933,190
XTOE	-	-	-	-	-	-	-	\$87	\$78	\$205	\$6	-
North Slope TOTAL	\$852,822	\$416,412	\$626,358	\$1,064,162	\$806,721	\$910,151	\$1,144,385	\$1,511,495	\$1,991,222	\$2,046,364	\$2,273,118	\$3,087,678

COOK INLET												
Revenues (Thousands of Dollars)												
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2007
Conoco Phillips AK	-	-	-	-	-	-	\$13	-	-	-	-	-
Cross Timbers/XTO	-	-	\$3,073	\$4,647	\$4,338	\$5,428	\$5,103	\$6,406	\$8,710	\$8,695	-	-
Devon	-	-	-	-	-	-	\$1	-	-	-	-	-
Forcenergy/Forest Oil	\$6,166	\$4,209	\$6,296	\$10,950	\$9,831	\$10,522	\$11,521	\$11,509	\$12,867	\$13,696	\$7,318	\$767
Marathon	-\$7	-	-	-	-	-	-	-	-	-	-	-
Mobil/Exxon Mobil AK Prod	\$1,882	\$1,094	\$1,165	\$1,824	\$1,525	\$1,348	\$1,692	\$2,068	\$2,511	\$2,253	\$2,361	\$3,542
Pacific Energy AK	-	-	-	-	-	-	-	-	-	-	\$4,685	\$14,565
Pioneer	-	-	-	-	-	-	-	-	-	-	-	<1
Shell	\$3,655	\$2,244	-	-	-	-	-	\$5,138	-	-	-	-
Stewart	\$1,104	-	-	-	-	-	-	-	-	-	-	-
Unocal	\$10,834	\$6,262	\$8,846	\$20,074	\$13,016	\$12,764	\$12,471	\$12,714	\$14,731	\$15,805	\$13,933	\$17,637
XTOE	-	-	-	-	-	-	-	-	-	-	\$7,879	\$11,370
Cook Inlet TOTAL	\$23,633	\$13,809	\$19,380	\$37,495	\$28,710	\$30,062	\$30,801	\$37,835	\$38,819	\$40,449	\$36,177	\$47,880

Revenues include principal and interest from revisions and settlements in the year received.

Table II.4 Recent Royalty Gas Production and Revenues

NORTH SLOPE						
	Duck Island Unit	Colville River Unit	Kuparuk River Unit	Milne Point Unit	Prudhoe Bay Unit	TOTAL North Slope
Production (Thousand Cubic Feet)						
1997	35,605	-	90,487	26,034	1,337,301	1,489,427
1998	36,255	-	79,552	27,156	1,178,761	1,321,724
1999	168,919	-	78,783	27,611	1,092,217	1,367,530
2000	31,785	-	135,929	27,436	1,061,761	1,256,911
2001	30,780	-	98,806	28,978	1,341,442	1,500,006
2002	32,108	-	82,610	29,718	3,711,424	3,855,861
2003	33,192	-	79,039	28,845	5,572,705	5,713,781
2004	29,424	-	76,746	29,639	5,260,659	5,396,467
2005	36,975	-	70,082	29,362	4,872,422	5,008,840
2006	33,750	56,501	56,033	28,612	4,509,689	4,884,585
2007	45,234	53,053	57,481	28,273	3,854,182	4,038,223
2008	35,722	58,797	74,246	29,664	3,011,092	3,209,521
Revenues (Thousands of Dollars)						
1997	\$31	-	\$63	\$28	\$1,155	\$1,278
1998	\$28	-	\$32	\$24	\$950	\$1,033
1999	\$150	-	\$51	\$26	\$938	\$1,165
2000	\$40	-	\$161	\$34	\$1,156	\$1,390
2001	\$33	-	\$119	\$32	\$1,114	\$1,298
2002	\$37	-	\$79	\$34	\$3,592	\$3,742
2003	\$45	-	\$91	\$40	\$6,508	\$6,685
2004	\$57	-	\$123	\$54	\$8,296	\$8,529
2005	\$87	-	\$163	\$72	\$10,801	\$11,123
2006	\$104	\$33	\$154	\$84	\$11,943	\$12,318
2007	\$127	\$102	\$184	\$95	\$11,395	\$11,903
2008	\$162	\$78	\$343	\$132	\$12,110	\$12,825

Revenues include principal and interest from revisions and settlements in the year received.

Table II.4 Recent Royalty Gas Production and Revenues

COOKINLET												
	Beluga River Unit	Cannery Loop Unit	South Granite Point Unit	Granite Point Field	Ivan River Unit	Kenai Unit	Lewis River Unit	Nicolai Creek Unit	Kasilof Unit	North Middle Ground Shoal Unit	North Cook Inlet Unit	Pretty Creek Unit
Production (Thousand Cubic Feet)												
1997	2,628,297	186,477	-	141,763	935,228	140,655	7,057	-	-	17,965	6,490,318	53,928
1998	2,508,785	163,775	1,127	162,690	800,046	111,751	11,959	-	-	131,092	6,665,243	61,640
1999	2,704,980	167,759	28,102	67,573	631,597	111,459	29,916	-	-	246,030	6,372,036	3,982
2000	2,913,658	236,492	55,787	73,754	461,437	149,187	16,232	-	-	72,167	6,548,758	-
2001	3,143,083	318,033	5,491	59,671	667,307	234,786	26,852	32,297	-	52,739	6,732,002	11,471
2002	3,313,302	286,118	3,859	34,936	756,028	233,375	111,535	28,957	-	14,404	6,537,260	193,370
2003	4,236,014	395,810	2,042	10,580	432,649	321,372	71,284	9,601	-	11,688	5,773,799	60,292
2004	4,339,085	745,310	169	15,573	289,865	191,573	45,255	29,235	-	-	5,012,401	93,122
2005	4,206,401	767,320	-	5,717	206,552	170,820	39,710	5,369	-	-	5,457,333	57,945
2006	4,167,893	593,894	-	4,374	191,634	136,643	5,227	15,193	107,898	-	4,566,013	1,311
2007	3,573,844	455,194	-	753	157,080	105,502	-	17,367	217,101	-	3,457,438	8,643
2008	3,181,489	323,424	-	-	80,285	40,391	28,718	7,102	63,813	-	2,776,690	3,737
Revenues (Thousands of Dollars)												
1997	\$4,598	\$325	-	\$192	\$1,319	\$249	\$10	-	-	\$24	\$12,054	\$76
1998	\$4,265	\$232	\$1	\$221	\$1,071	\$157	\$16	-	-	\$160	\$8,874	\$82
1999	\$3,783	\$272	\$30	\$82	\$758	\$294	\$36	-	-	\$301	\$8,914	\$5
2000	\$4,657	\$483	\$58	\$215	\$5,339	\$298	\$508	-	-	\$808	\$14,058	\$678
2001	\$6,947	\$1,216	\$6	\$82	\$933	\$476	\$38	\$62	-	\$89	\$14,301	\$18
2002	\$7,586	\$748	\$4	\$50	\$1,057	\$454	\$160	\$18	-	\$21	\$12,562	\$276
2003	\$9,479	\$836	\$6	\$179	\$2,904	\$701	\$335	\$17	-	\$60	\$12,159	\$379
2004	\$11,706	\$1,984	\$1	\$44	\$814	\$460	\$126	\$38	-	-	\$11,600	\$263
2005	\$15,257	\$2,837	<1	\$20	\$742	\$534	\$139	\$35	-	-	\$14,987	\$196
2006	\$15,275	\$3,139	-	\$19	\$1,171	\$502	\$18	\$463	-	-	\$14,546	\$13
2007	\$14,892	\$1,991	-	\$4	\$1,249	\$467	-	\$105	\$877	-	\$8,601	\$158
2008	\$14,263	\$1,609	-	-\$0	\$618	\$197	\$221	\$42	\$129	-	\$13,564	\$29

	Spark Platform	Sterling Unit	North Trading Bay Unit	Stump Lake Unit	Trading Bay Field	Trading Bay Unit	Redoubt Unit	Nilnichik Unit	West Mearthur River Unit	Deep Creek Unit	Three Mile Creek Unit	TOTAL Cook Inlet	TOTAL State
Production													
1997	62,872	81	-	30,942	19,031	6,982,452	-	-	-	-	-	17,697,067	19,186,494
1998	85,882	4	-	18,332	-	7,841,950	-	-	-	-	-	18,564,277	19,886,001
1999	28,044	15	-	11,978	-	7,333,019	-	-	-	-	-	17,736,489	19,104,019
2000	-	4,384	18,632	6,839	-	6,802,700	-	-	-	-	-	17,360,027	18,616,938
2001	-	8,820	-	56	-	6,509,275	-	-	-	-	-	17,801,883	19,301,889
2002	-	11,655	-	-	-	5,198,621	-	-	2,655	-	-	16,726,074	20,581,934
2003	-	7,195	11,954	69	-	4,016,601	12,954	287,241	19,673	-	-	15,680,818	21,394,599
2004	-	6,921	2,130	-	-	3,360,804	-	1,094,310	22,119	4,191	-	15,252,063	20,648,530
2005	-	60,491	50,616	-	-	3,155,258	5,299	1,225,767	38,432	54,600	48,533	15,556,163	20,565,004
2006	-	71,748	210	-	-	2,500,006	29,082	1,701,051	58,436	48,568	67,010	14,266,190	18,950,775
2007	-	56,191	92	-	-	2,116,402	5,664	1,877,107	34,700	42,572	33,253	12,158,901	16,197,125
2008	-	41,873	-	-	-	2,112,878	1,600	1,841,946	15,785	34,557	28,275	10,582,563	13,792,084
Revenues													
1997	\$94	\$0	-	-	\$23	\$10,148	-	-	-	-	-	29,112	\$30,390
1998	\$118	\$8	-	\$0	-	\$10,769	-	-	-	-	-	25,974	\$27,007
1999	\$32	\$0	-	\$13	-	\$8,918	-	-	-	-	-	23,436	\$24,601
2000	-	\$7	\$26	\$1,254	\$2	\$10,743	-	-	-	-	-	39,134	\$40,524
2001	-	\$16	\$6	\$0	-	\$12,636	-	-	-	-	-	36,826	\$38,124
2002	-	\$26	-	-	-	\$9,632	-	-	-	-	-	32,595	\$36,337
2003	-	\$16	\$28	\$5	-	\$14,806	\$16	\$681	-	-	-	42,606	\$49,290
2004	-	\$19	\$5	-	-	\$9,042	-	\$3,165	\$90	\$17	-	39,373	\$47,903
2005	-	\$209	\$161	-	-	\$10,787	\$19	\$4,302	\$117	\$235	\$143	50,721	\$61,844
2006	-	\$337	\$4	-	-	\$10,761	\$128	\$8,014	\$247	\$240	\$221	55,157	\$67,475
2007	-	\$304	\$0	-	-	\$10,808	\$31	\$10,833	\$188	\$313	\$233	51,055	\$62,958
2008	-	-\$288	-	-	-	\$12,105	\$9	\$8,528	\$144	\$211	\$113	51,492	\$64,316

Revenues include principal and interest from revisions and settlements in the year received.

Table II.5 Recent Royalty Gas Production by Lessee

NORTH SLOPE												
Revenue (Thousands of Dollars)												
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Anadarko	-	-	-	-	-	-	-	-	-	\$7	\$15	\$17
Arco	\$325	\$297	\$344	-	-	-	-	-	-	-	-	-
BP Am Prod. Co	-	-	-	-	-	-	\$3	-	-	-	-	-
BPXA	\$543	\$451	\$540	\$539	\$593	\$3,054	\$5,844	\$7,527	\$9,750	\$10,835	\$9,868	\$11,225
Chevron	\$33	\$7	-	-	<1	<1	<1	<1	-	-	-	-
ConocoPhillips AK	-	-	-	-	-	\$446	\$538	\$643	\$865	\$983	\$1,187	\$1,679
Exxon	\$207	\$183	\$185	-	-	-	-	-	-	-	-	-
ExxonMobil	-	-	-	\$318	\$265	\$242	\$300	\$360	\$508	\$493	\$526	\$704
Forest Oil	-	-	-	-	-	-	-	-	-	-	-	-
Kerr-McGee	-	-	-	-	-	-	-	-	-	-	\$1	\$1
Mobil	\$128	\$80	\$87	-	-	-	-	-	-	-	-	-
NANA	\$23	-	-	-	-	-	-	-	-	-	-	-
Oxy	\$2	\$2	\$2	\$2	-	-	-	-	-	-	-	-
PetroHunt	-	-	-	-	-	-	-	-	-	<1	-	-
Phillips	\$15	\$13	\$7	\$531	\$440	-	-	-	-	-	-	-
Unocal	-	-	-	-	-	-	<1	<1	<1	<1	-	-
North Slope TOTAL	\$1,278	\$1,033	\$1,165	\$1,390	\$1,298	\$3,742	\$6,685	\$8,529	\$11,123	\$12,318	\$11,596	\$13,625
COOK INLET												
Revenue (Thousands of Dollars)												
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Arco	\$1,411	\$1,262	\$1,170	-	-	-	-	-	-	-	-	-
Aurora Power	-	-	-	-	\$62	\$18	\$17	\$38	\$135	\$222	\$289	\$113
Chevron	\$1,551	\$1,560	\$1,605	\$1,698	\$3,136	\$3,740	\$4,373	\$5,020	\$6,293	\$5,516	\$6,725	\$4,354
ConocoPhillips AK	-	-	-	-	-	\$2,530	\$3,747	\$4,562	\$6,766	\$6,491	\$5,070	\$5,318
Conoco Phillips Co.	-	-	-	-	-	-	\$12,159	\$11,600	\$14,987	\$14,546	\$8,870	\$12,926
Forest Oil	-	-	-	-	-	-	\$16	\$90	\$179	\$433	\$219	\$39
Marathon	\$6,061	\$5,737	\$5,557	\$6,795	\$10,429	\$7,433	\$6,777	\$8,761	\$12,113	\$14,982	\$14,708	\$11,104
ExxonMobil	\$47	\$55	\$22	\$0	\$4	\$3	\$2	\$0	-	-	-	-
Anchorage M, L & P	-	\$1,443	\$1,008	\$1,082	\$1,416	\$1,316	\$1,358	\$2,022	\$2,198	\$3,268	\$3,251	\$4,398
Pacific Energy AK	-	-	-	-	-	-	-	-	-	-	\$80	\$157
Phillips	\$12,054	\$8,874	\$8,914	\$15,934	\$16,697	\$12,562	-	-	-	-	-	-
Shell	\$1,636	-	-	-	-	-	-	\$103	-	-	-	-
Unocal	\$6,351	\$7,035	\$5,161	\$13,624	\$5,083	\$4,993	\$14,157	\$7,178	\$8,050	\$9,699	\$12,412	\$12,599
Cook Inlet TOTAL	\$29,112	\$25,966	\$23,436	\$39,134	\$36,826	\$32,595	\$42,606	\$39,373	\$50,721	\$55,157	\$51,622	\$51,008

Revenues include principal and interest from revisions and settlements in the year received.

Table II.6 Recent Royalty Gas Revenues by Lessee

NORTH SLOPE												
Revenue (Thousands of Dollars)												
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Anadarko	-	-	-	-	-	-	-	-	-	\$7	\$15	\$17
Arco	\$325	\$297	\$344	-	-	-	-	-	-	-	-	-
BP Am Prod. Co	-	-	-	-	-	-	\$3	-	-	-	-	-
BPXA	\$543	\$451	\$540	\$539	\$593	\$3,054	\$5,844	\$7,527	\$9,750	\$10,835	\$9,868	\$11,225
Chevron	\$33	\$7	-	-	<1	<1	<1	<1	-	-	-	-
ConocoPhillips AK	-	-	-	-	-	\$446	\$538	\$643	\$865	\$983	\$1,187	\$1,679
Exxon	\$207	\$183	\$185	-	-	-	-	-	-	-	-	-
ExxonMobil	-	-	-	\$318	\$265	\$242	\$300	\$360	\$508	\$493	\$526	\$704
Forest Oil	-	-	-	-	-	-	-	-	-	-	-	-
Kerr-McGee	-	-	-	-	-	-	-	-	-	-	\$1	\$1
Mobil	\$128	\$80	\$87	-	-	-	-	-	-	-	-	-
NANA	\$23	-	-	-	-	-	-	-	-	-	-	-
Oxy	\$2	\$2	\$2	\$2	-	-	-	-	-	-	-	-
PetroHunt	-	-	-	-	-	-	-	-	-	<1	-	-
Phillips	\$15	\$13	\$7	\$531	\$440	-	-	-	-	-	-	-
Unocal	-	-	-	-	-	-	<1	<1	<1	<1	-	-
North Slope TOTAL	\$1,278	\$1,033	\$1,165	\$1,390	\$1,298	\$3,742	\$6,685		\$11,123	\$12,318	\$11,596	\$13,625

COOK INLET												
Revenue (Thousands of Dollars)												
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Arco	\$1,411	\$1,282	\$1,170	-	-	-	-	-	-	-	-	-
Aurora Power	-	-	-	-	\$62	\$18	\$17	\$38	\$135	\$222	\$289	\$113
Chevron	\$1,551	\$1,560	\$1,605	\$1,698	\$3,136	\$3,740	\$4,373	\$5,020	\$6,293	\$5,516	\$6,725	\$4,354
ConocoPhillips AK	-	-	-	-	-	\$2,530	\$3,747	\$4,562	\$6,766	\$6,491	\$5,070	\$5,318
Conoco Phillips Co.	-	-	-	-	-	-	\$12,159	\$11,600	\$14,987	\$14,546	\$8,870	\$12,926
Forest Oil	-	-	-	-	-	-	\$16	\$90	\$179	\$433	\$219	\$39
Marathon	\$6,061	\$5,737	\$5,557	\$6,795	\$10,429	\$7,433	\$6,777	\$8,761	\$12,113	\$14,982	\$14,708	\$11,104
ExxonMobil	\$47	\$55	\$22	-\$0	\$4	\$3	\$2	\$0	-	-	-	-
Anchorage M, L & P	-	\$1,443	\$1,008	\$1,082	\$1,416	\$1,316	\$1,358	\$2,022	\$2,198	\$3,268	\$3,251	\$4,398
Pacific Energy AK	-	-	-	-	-	-	-	-	-	-	\$80	\$157
Phillips	\$12,054	\$8,874	\$8,914	\$15,934	\$16,697	\$12,562	-	-	-	-	-	-
Shell	\$1,636	-	-	-	-	-	-	\$103	-	-	-	-
Unocal	\$6,351	\$7,035	\$5,161	\$13,624	\$5,083	\$4,993	\$14,157	\$7,178	\$8,050	\$9,699	\$12,412	\$12,599
Cook Inlet TOTAL	\$29,112	\$25,966	\$23,436	\$39,134	\$36,826	\$32,595	\$42,606	\$39,373	\$50,721	\$55,157	\$51,622	\$51,008

Revenues include principal and interest from revisions and settlements in the year received.

Table II.7 North Slope Royalty-in-Kind Sales

	Alpetco	Chevron	Total GVEA	Total Williams (Mapco)	Flint Hills Resources, (FHR)	Tesoro	PetroStar	1st Competitive Sale	2nd Compet- itive Sale	Quasi-Compet- itive Sale	Total ANS RIK by year
1979	0	0	0	446,996	0	0	0	0	0	0	446,996
1980	12,020,950	882,414	0	5,976,024	0	3,427,388	0	0	0	0	22,306,777
1981	26,046,878	859,928	398,051	8,808,400	0	1,661,385	0	14,046,953	0	0	51,821,595
1982	898,714	0	764,762	9,632,099	0	36,841	0	1,432,108	0	0	12,764,524
1983	0	11,674,998	1,208,406	11,723,755	0	5,793,973	0	0	0	0	30,401,132
1984	0	14,053,279	1,870,505	13,093,397	0	7,531,155	0	0	0	0	36,548,337
1985	0	7,804,392	1,928,544	13,260,754	0	17,218,912	0	0	22,511,409	1,716,754	64,440,765
1986	0	6,934,482	1,881,232	13,168,483	0	23,538,192	52,667	0	4,686,801	1,862,051	52,123,908
1987	0	9,330,563	2,013,539	14,094,537	0	18,404,806	539,575	0	0	0	44,383,020
1988	0	9,315,264	1,981,998	13,814,522	0	18,307,014	590,833	0	0	0	44,009,631
1989	0	8,611,606	1,784,782	12,529,175	0	16,387,093	607,467	0	0	0	39,920,122
1990	0	8,099,292	1,670,494	12,735,412	0	15,368,565	621,220	0	0	0	38,494,983
1991	0	6,290,546	1,670,699	11,183,462	0	15,336,301	618,247	0	0	0	35,099,255
1992	0	0	803,407	6,285,005	0	14,412,460	0	0	0	0	21,500,872
1993	0	0	0	9,086,282	0	9,812,084	0	0	0	0	18,898,367
1994	0	0	0	11,986,495	0	10,452,726	0	0	0	0	22,439,220
1995	0	0	0	12,680,470	0	13,703,946	0	0	0	0	26,384,415
1996	0	0	0	13,027,646	0	14,345,621	0	0	0	0	27,373,267
1997	0	0	0	13,117,503	0	13,021,628	0	0	0	0	26,139,130
1998	0	0	0	16,483,695	0	11,497,629	0	0	0	0	27,981,324
1999	0	0	0	19,070,664	0	0	0	0	0	0	19,070,664
2000	0	0	0	19,290,297	0	0	0	0	0	0	19,290,297
2001	0	0	0	15,187,012	0	0	0	0	0	0	15,187,012
2002	0	0	0	15,509,591	0	0	0	0	0	0	15,509,591
2003	0	0	0	22,749,221	0	0	0	0	0	0	22,749,221
2004	0	0	0	5,582,299	17,639,276	0	0	0	0	0	23,221,574
2005	0	0	0	0	22,803,644	0	0	0	0	0	22,803,644
2006	0	0	0	0	22,186,071	0	0	0	0	0	22,186,071
2007	0	0	0	0	22,779,999	0	0	0	0	0	22,779,999
2008					21,001,166						21,001,166
Cu- mula- tive	38,966,543	83,856,765	17,976,419	320,523,196	106,410,155	230,257,719	3,030,009	15,479,061	27,198,210	3,578,805	847,276,881

[Redacted]

Figure II.1 ANS Royalty-in-Kind Contract Volumes

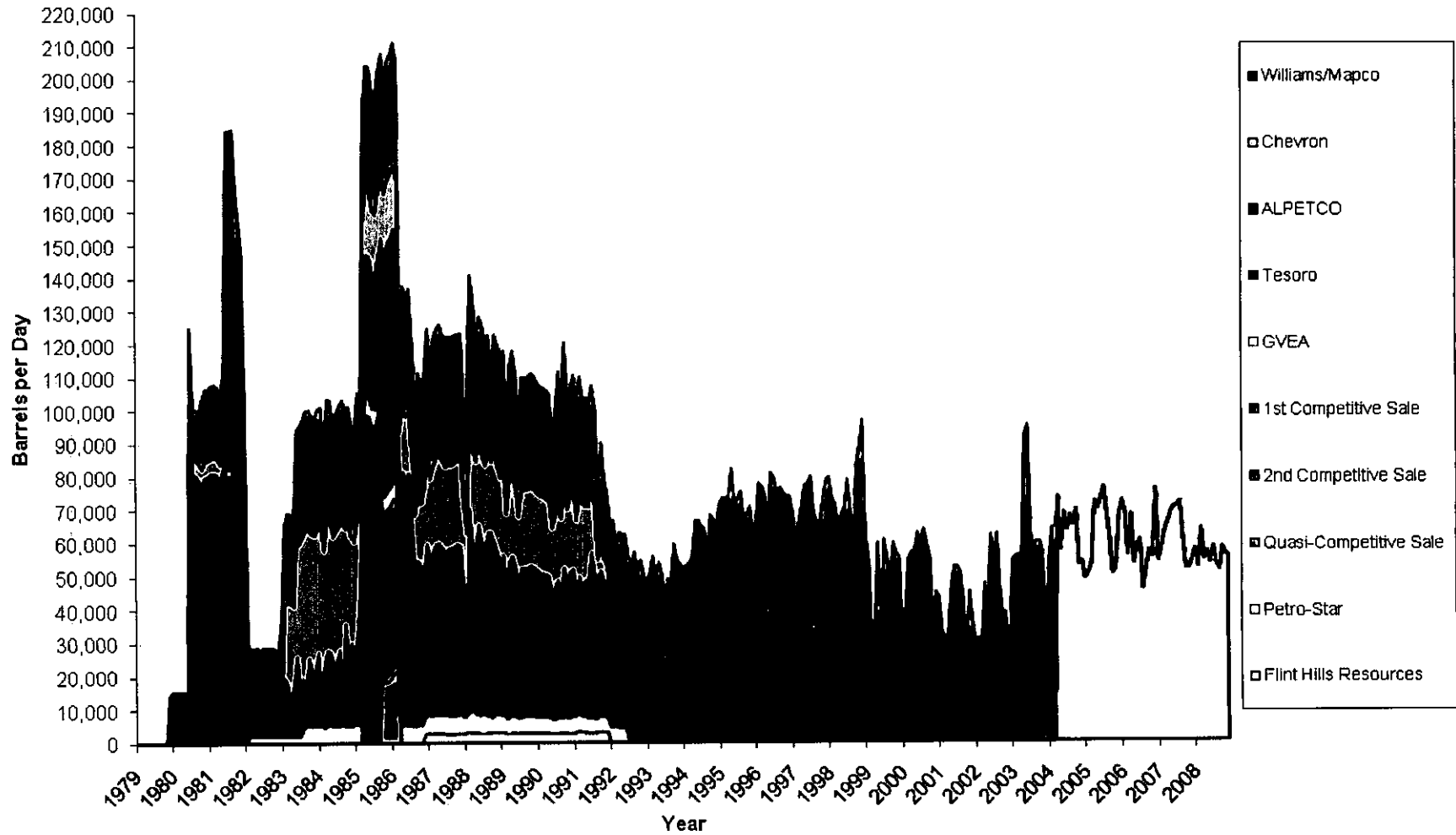


Figure II.2 State of Alaska Royalty Contract Volumes

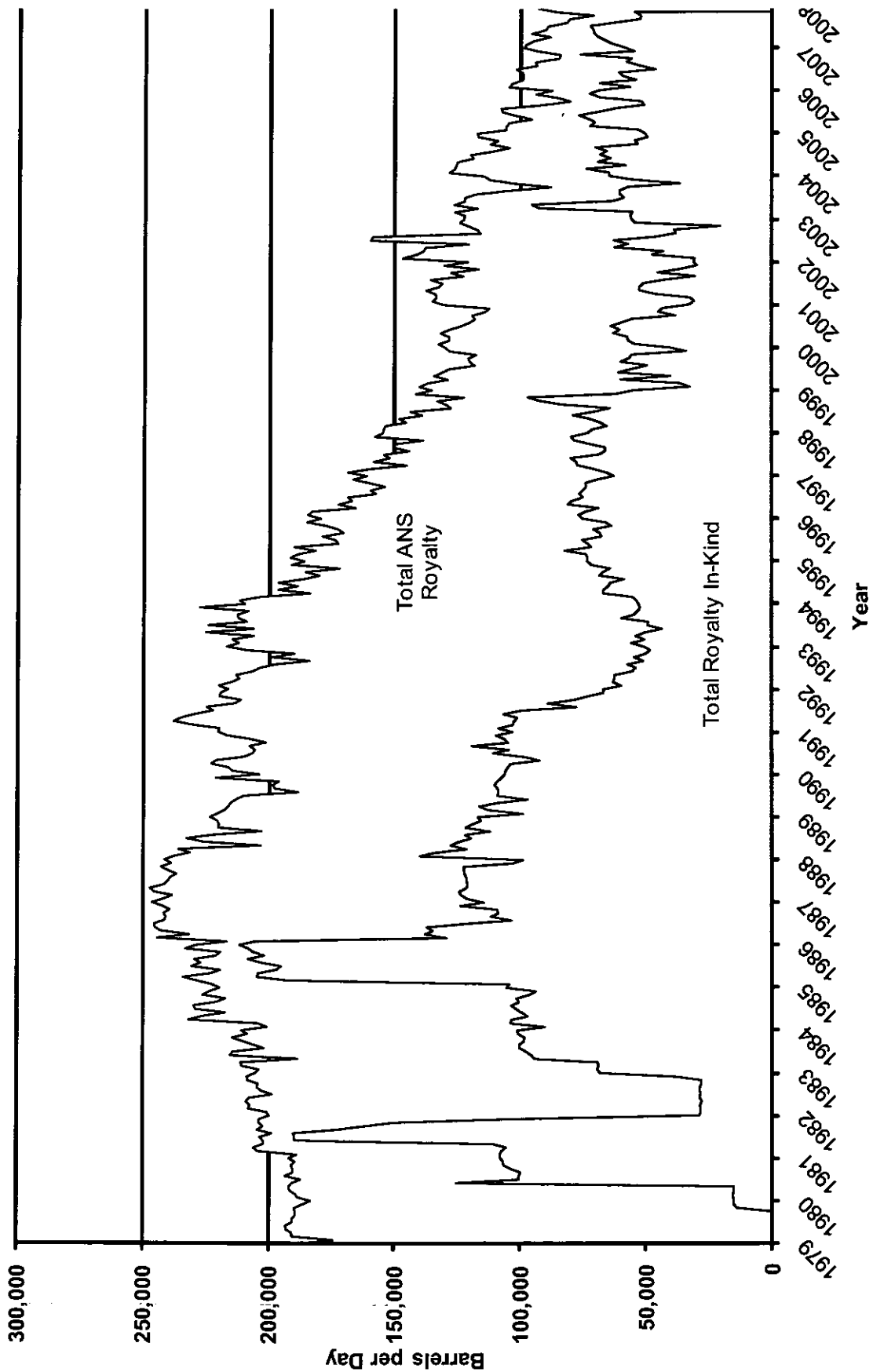


Table II.8 Cook Inlet & Statewide Royalty-in-Kind Sales

	COOK INLET					STATEWIDE		
	Tesoro ¹	Chinese Petroleum ²	Cook Inlet RIK	Cook Inlet RIV	Cook Inlet Total Royalty Volume	ALASKA RIK	ALASKA RIV	ALASKA Total Royalty Volume
1979	4,849,631	-	4,849,631	-	4,849,631	5,296,627	10,584,481	15,881,108
1980	4,094,229	-	4,094,229	-	4,094,229	26,401,006	47,047,583	73,448,589
1981	3,560,736	-	3,560,736	-	3,560,736	55,382,331	17,666,128	73,048,459
1982	3,065,159	-	3,065,159	-	3,065,159	15,829,683	61,136,212	76,965,895
1983	2,719,044	-	2,719,044	-	2,719,044	33,120,176	44,599,235	77,719,411
1984	2,431,987	-	2,431,987	-	2,431,987	38,980,324	39,396,031	78,376,356
1985	1,382,740	-	1,382,740	462,245	1,844,985	65,823,504	17,095,491	82,918,995
1986	-	-	-	1,922,101	1,922,101	52,123,907	32,184,762	84,308,669
1987	-	615,305	615,305	1,113,805	1,729,110	44,998,325	45,013,116	90,011,441
1988	-	799,938	799,938	917,208	1,717,146	44,809,569	44,986,179	89,795,748
1989	-	1,274,479	1,274,479	392,313	1,666,792	41,194,601	41,225,959	82,420,561
1990	-	566,825	566,825	522,456	1,089,282	39,061,808	37,764,947	76,826,755
1991	-	330,540	330,540	1,357,687	1,688,227	35,429,795	43,895,049	79,324,844
1992	-	-	-	1,661,526	1,661,526	21,500,871	54,415,748	75,916,620
1993	-	-	-	1,514,651	1,514,651	18,898,364	50,783,693	69,682,057
1994	-	-	-	1,717,758	1,717,758	22,439,221	52,375,662	74,814,882
1995	-	-	-	1,718,805	1,718,805	26,384,415	45,383,358	71,767,773
1996	-	-	-	1,618,157	1,618,157	27,373,267	41,014,672	68,387,940
1997	-	-	-	1,369,478	1,369,478	26,139,130	36,729,326	62,868,456
1998	-	-	-	1,335,030	1,335,030	27,981,324	29,651,924	57,633,248
1999	-	-	-	1,252,231	1,252,231	19,070,664	32,725,432	51,796,096
2000	-	-	-	1,248,564	1,248,564	19,290,298	29,098,368	48,388,666
2001	-	-	-	1,273,518	1,273,518	15,187,012	31,480,769	46,667,780
2002	-	-	-	1,320,281	1,320,281	15,509,592	33,607,528	49,117,120
2003	-	-	-	1,127,749	1,127,749	22,749,221	26,464,082	49,213,303
2004	-	-	-	920,535	920,535	23,221,574	23,180,685	46,402,259
2005	-	-	-	779,749	779,749	22,803,644	20,332,163	43,135,806
2006	-	-	-	669,212	669,212	22,186,071	13,938,500	36,124,570
2007	-	-	-	551,302	551,302	22,779,999	12,719,397	35,499,396
2008	-	-	-	454,367	454,367	21,001,166	12,260,768	33,261,934
	22,103,526	3,587,088	25,690,614	27,220,729	52,911,342	872,967,491	1,028,757,247	1,901,724,738

Figure II.2A Composition of Total North Slope Royalty Dispositions 1979-2008

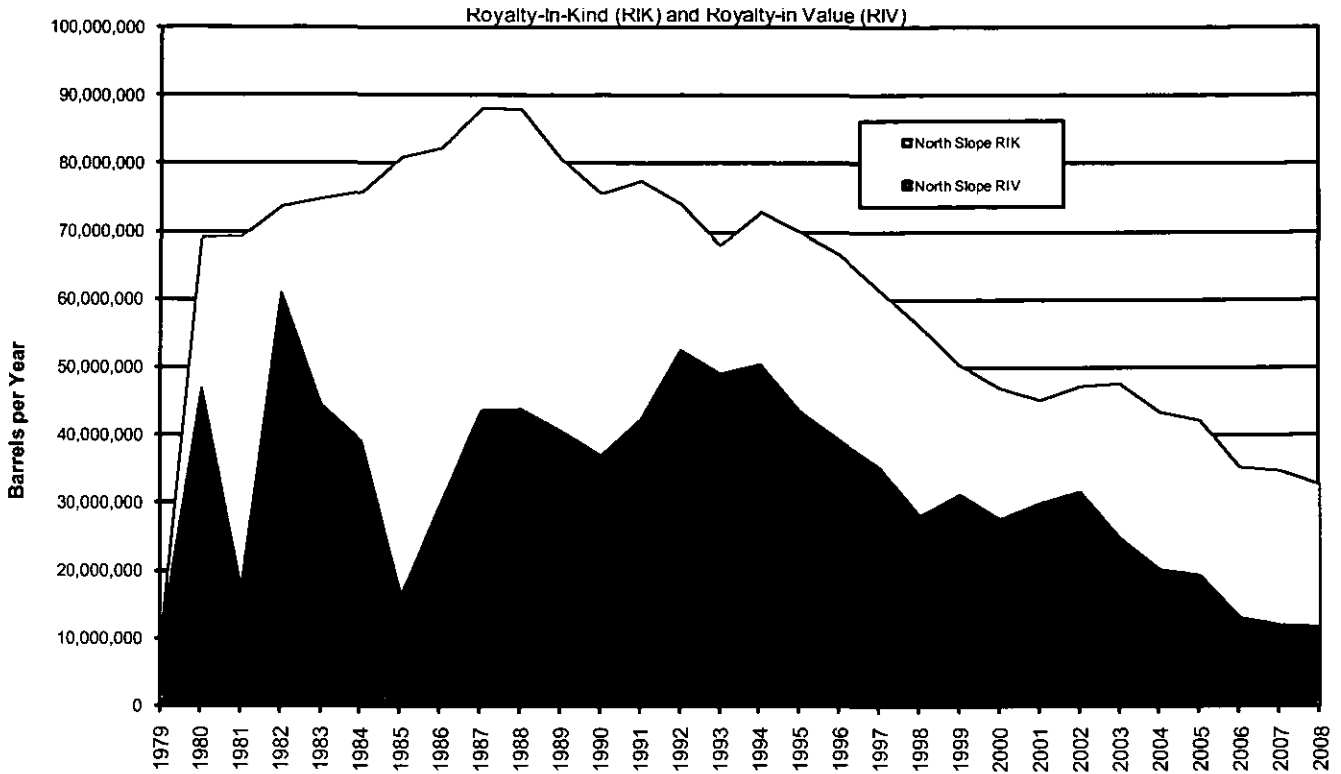


Figure II.2B Composition of Total Cook Inlet Royalty Dispositions 1979-2008

