SB 21

(FILE 1)

<TARGET><BILL>SB 21</BILL><SUBJECT>SB 21 (FILE 1)</SUBJECT><COMM>SRES28</COMM></TARGET>

SENATE COMMITTEE REPORT

DATE: 2/8/13

FURTHER: Finance

DATE TURNED IN TO OFFICE: 2/27/13

Resources Committee considered SENATE BILL NO. 21

SB 21 OIL AND GAS PRODUCTION TAX

"An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

and recommends:

[✓] be **replaced** with **CS** SB 21 (RES) *[ ] Same Title* *[✓] New Title*

[ ] adopt **previous CS** ________ (____) *[ ] Same Title* *[ ] New Title*

[ ] attached amendment(s)

[✓] adopt RES Letter of Intent

[ ] further referral to ________ Committee

Dept Abbr.	
ADM	LWF
CED	LAW
COR	LEG
CRT	MVA
EED	DNR
DEC	DPS
DFG	REV
GOV	DOT
DHS	UA

NEW FISCAL NOTE(S)

Dept.	Fiscal	Indet.	Zero	FN #
REV	✓			3
REV		✓		4
DNR		✓		5

PREVIOUS FISCAL NOTE(S)

Dept.	Fiscal	Indet.	Zero	FN #

[ ] **APPROPRIATION - no fiscal note**

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	DO PASS	DO NOT PASS	NO REC	AMEND
[signature]	French		X		
[signature]	MICCICHE			X	
[signature]	BISHOP	✓		X	
[signature]	McGuire	✓			
[signature]	FAIRCLOUGH				✓
[signature]	DYSON	X			
CHAIR: [signature]	Giessel	✓			

ALASKA STATE LEGISLATURE

SENATE RESOURCES COMMITTEE

Sen. Cathy Giessel, Chair
Sen. Fred Dyson, Vice Chair
Sen. Click Bishop
Sen. Anna Fairclough
Sen. Lesil McGuire
Sen Peter Micciche
Sen. Hollis French

State Capitol, Room 427
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Official Business

Letter of Intent

It is the intent of the Legislature that Alaska's decline in oil production be arrested and reversed; and that the State become competitive within its peer group in the global market of oil and gas resources.

The legislature intends, through passage of SB 21, to: (1) put in place a system for the taxation of oil and gas that is fair, stable, predictable, durable, balanced, and free from complexity across a wide range of oil prices; (2) promote a long-term, competitive, and vibrant oil and gas industry in the state; (3) acknowledge that the oil and gas industry plays an historic and crucial role in the state, providing revenue for and underpinning the resource-based economy of the state; (4) attract the necessary capital investment from the industry to increase oil and gas production, increase the throughput of the Trans Alaska Pipeline System, incentivize the exploration and development of new oil, provide a bridge to production for the challenged and stranded oil and gas resources in the state, return the state to a leadership position in national domestic oil production, and ensure the prosperity of future generations of Alaskans; (5) reflect the policy determination that the legislature chooses opportunity over decline.

Adopted by the Senate
Date: ______________

Senate Bill No. 21

ALASKA STATE LEGISLATURE

Sen. Cathy Giessel, Chair
Sen. Fred Dyson, Vice Chair
Sen. Lesil McGuire
Sen. Anna Fairclough
Sen. Click Bishop
Sen. Peter Micciche
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State Capitol, Room 427
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Senate Resources Committee

MEMORANDUM

Date: February 27, 2013
To: Senate Finance Committee
Re: CSSB21 (RES)

The CS we pass to the Senate Finance Committee reflects adherence to the Governor's four guiding principles (for which we have heard unanimous approval), input from an array of experts and stakeholders, including the public, and stands on its own merit. This Committee does, however, wish to offer for your consideration, the following subjects that we believe merit further evaluation under the jurisdiction of the Senate Finance Committee before inclusion in, or exclusion from, Alaska's oil and gas laws:

- **Royalty Relief – consider whether DNR needs broader authority to offer royalty relief.**
- **Exploration Credits (AS43.55.025) – should they be conditioned upon DNR's prior determination of an explorer's qualifications?**
- **Manufacturing Credit – consider whether the per-taxpayer cap needs adjusting as it relates to the impact on the treasury.**
- **Oil and Hazardous Substance Release Prevention Fund – provide for adequate future funding (AS 43.55.300).**
- **Gross Revenue Exclusion – in consideration of the life cycle economics of a project, does it need to be time limited?**

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Governor Sean Parnell
STATE OF ALASKA

January 15, 2013

The Honorable Charlie Huggins
President of the Senate
Alaska State Legislature
State Capitol, Room 111
Juneau, AK 99801-1182

Dear President Huggins,

To create more economic opportunity for Alaskans, we must proactively choose a future of more oil production. Therefore, under the authority of Article III, Section 18 of the Alaska Constitution, I am transmitting a bill relating to oil production taxation.

Alaska's oil belongs to Alaskans, and increased oil production will mean increased private sector opportunity for Alaskans. Alaska engineers, contractors, and maintenance personnel earn their livelihoods from oil production; indirectly so do business owners, retailers, and working men and women of all trades. Oil production also provides revenue and drives public sector opportunities for schools, public safety, roads and ferries, energy infrastructure, and many other services for Alaskans.

Need for Legislation

Alaskans are well aware that oil production from legacy fields is declining. Not because we are running out of oil, but because we are running behind the competition. Alaska's North Slope has billions of proven barrels of oil, but we do not have a tax system designed to attract new investment for more production. At high oil prices, the current progressive tax rate structure creates highly variable tax rates and takes far more profit from investors than other competing jurisdictions. Investors take their money where they get a greater return, and they are investing new capital elsewhere. Legislation is necessary to drive new investment to create new Alaska production and new opportunities for Alaskans.

Under current law, the generous tax credits for capital expenditures support company spending now, but on spending not necessarily targeted for new production. Consequently, the State experiences the short-term risk of writing large checks from the treasury for those credits with no corresponding increase in production. Legislation is necessary to mitigate this risk, and focus company investment on long-term, new Alaska production.

Guiding Principles

Tax policy must be fair to Alaskans. Any changes to oil taxes should, when taken together, be geared to foster new production. Changes should result in a more simple tax system and restore balance to our fiscal system. And, tax policy must make Alaska competitive for the long-term. If these guiding principles are met, I believe we will more fully maximize the benefit of Alaskans' oil resources for Alaskans.

Legislation Summary
The bill maintains a 25 percent base tax rate with a 20 percent gross revenue exclusion for new oil. It eliminates the progressivity calculation, and eliminates the qualified capital expenditure credits for North Slope expenditures. The bill reforms the remaining credits so that they are taken when there is production.

Fair to Alaskans and Fosters New Production
The legislation provides more downside price protection for Alaskans in exchange for more upside price revenue to the companies. Under the current tax system, State revenues depend primarily on the price of oil, but the current qualified capital expenditure credits depend on the level of company spending. If prices fall, State revenues are reduced but the State retains the obligation to pay credits. Further, if additional development occurs, under the current system, the credit obligation could grow substantially. Given the State's other obligations like public safety and schools, this imbalance exposes the State to substantial financial risks. By reforming the credit system, this bill rebalances the current tax structure to ensure revenues to the State in low price environments.

The legislation targets new Alaska production rather than just company spending, thus unlocking more of Alaskans' oil for more Alaskan private sector and public sector opportunities. This goal is accomplished by eliminating the current 20 percent tax credit under AS 43.55.023(a) for qualified capital expenditures incurred after December 31, 2013, to explore for, develop, or produce oil and gas deposits located on the North Slope. The bill would amend the 25 percent tax credit issued under AS 43.55.023(b) for a carried-forward annual loss based on expenditures incurred after December 31, 2013, to explore for, develop, or produce oil and gas deposits located on the North Slope by limiting the transferability and monetization of the tax credit. The amendment to AS 43.55.023(b) will encourage investment aimed at production by requiring a producer or explorer to carry the credit forward to offset future tax liabilities. Additionally, the bill extends the small producer tax credit available under AS 43.55.024(c). The small producer tax credit is nontransferable.

The bill creates additional incentives for new production on the North Slope by providing for a 20 percent revenue exclusion based on the gross value at the point of production of oil and gas produced from a lease or property that was not, as of January 1, 2003, within a unit. It also proposes the same 20 percent revenue exclusion for oil and gas production from new participating areas in units that were formed before January 1, 2003. Similar to the new North Slope carried-forward annual loss tax credit and the extended tax credit for small producers, these incentives only would apply to a company when it has production.

More Simple. Restores Balance
The bill simplifies the oil and gas production tax by repealing the progressive tax rate structure in Alaska's current tax system by levying a flat rate tax of 25 percent on oil and gas production statewide, subject to current tax ceilings on certain oil and gas, for production beginning January 1, 2014. The repeal of the progressive tax rate structure in this bill encourages the type of long-term planning and investment needed to promote new investment in new production in Alaska.

Long-Term Competitiveness
By shifting the incentives away from spending and towards new production we assure these tax changes are for the long run. Producers get the benefit of tax changes later – after they produce new oil when they can offset earlier liabilities against new production. Additionally, by giving back more

of the high side at high oil prices (while better protecting Alaskans against the downside of lower oil prices), we assure companies will make their investments for the long haul because they are more likely to take short-term risk with capital if they are assured greater return over time at higher prices.

In summary, this bill provides a path to more Alaskan opportunity through more Alaskan oil production. I urge your prompt and favorable action on this measure.

Sincerely,

Sean Parnell

Sean Parnell
Governor

Enclosure

ALASKA STATE LEGISLATURE

Trans Alaska Pipeline Throughput Committee

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LETTER OF INTENT

The Senate Special Committee on Trans Alaska Pipeline System (TAPS) Throughput was formed specifically to evaluate solutions designed to reverse or significantly reduce the historical decline in the quantity of oil produced from leases or properties north of 68 degrees North latitude and shipped through the Trans Alaska Pipeline System. The Committee recognizes that oil revenue is extremely important to the State of Alaska and currently funding over 90% of Alaska's essential services and critical infrastructure including education, public safety, health and social services and transportation. The Committee is also aware that projected declines in the Trans Alaska Pipeline System throughput may compound the operational and cost issues that could jeopardize the viability and safe operation of the Trans Alaska Pipeline System.

The Committee was the first to consider SENATE BILL 21 "An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

The Committee held six meetings with the intent of framing the discussion around SB 21 through a lens of evaluating direct impacts to the TAPS production decline. The Committee process was designed for fairness and equal participation by majority and minority members. The Committee included expert consultant, agency, the Alaskan public and industry testimony in the process through many productive hours and publicly-available meetings evaluating the potential positive and negative effects on production through revised Alaska oil tax policy. Most importantly, the Committee provided over five hours of Committee time for public testimony from every LIO in the state, as well as telephonically from any location. Every Alaskan that chose to address the Committee was warmly welcomed and given the opportunity to share their support and/or concerns.

The Committee has arrived at several key findings after completing the process of evaluating SB 21 and the effects of oil tax on production. They include:

- Regarding oil revenue that funds the vast majority of governmental functions for the people of Alaska, there are many factors in which the State has little control, including the price of North Slope oil. Total government take through oil taxation is the only lever under the control of the people of Alaska.
- The ACES tax structure has likely contributed to advancing the decline of oil production and throughput in TAPS, primarily due to a lack of competitiveness with other OECD producing regions.
- When evaluating with increased production as a primary objective, ACES credits should have been more specifically directed toward projects resulting in production and less toward general spending.
- Specific incentives and a competitive oil tax regime in Alaska will likely result in additional production-related spending.
- There has been a direct correlation in other OECD producing regions between production-related spending and increased production.
- Current fiscal spending policies appear to have an adverse effect on the business climate and willingness to invest in the State of Alaska. Policies must deliver the clear message to the business community that Alaska will not continue taxing to fund unsustainable levels of government spending.
- Although SB 21 is an adequate platform from which a respectful dialogue can begin, in the current form the bill may not adequately provide production credit incentives and opportunities; a level revenue proportion for Alaskans; and protections for Alaska hire and re-investment.

The Committee's intent to pass the bill to the Senate Resources Committee in the original form for further processing is in no way an expression of support by Committee members for SB 21 in current form. In fact, most members have expressed concern for key concepts that would require revision prior to supporting the bill as it moves through the legislative process.

Key concerns being passed through this letter with an expectation of consideration moving forward will be communicated in two sections. The first section below includes throughput-related Committee recommendations:

- Evaluate providing a guarantee of investment in Alaska and a further incentive for stemming production decline from leases or properties north of 68 degrees North latitude by fixing the amount of production used in determining the reasonable transportation costs to determine transportation deduction costs for pipelines and gas treatment plants under the Oil and Gas Production Tax and Oil Surcharge, AS 43.55, so that producers receive a benefit for increased oil production and throughput in the Trans Alaska Pipeline System but incur a corresponding limitation on deductions due to throughput declines after December 31, 2015.
- Evaluate expanding the application of the Gross Revenue Exclusion in units formed before 2003 (Legacy Areas). The Senate Resources Committee should specifically inquire about expansions of existing Participating Areas, increasing recovery factors in

existing Participating Areas, and Participating Areas that contain oil with an API gravity of 20 degrees or less.
- Evaluate specific production-related credits allowed under ACES for inclusion in SB 21 as a direct incentive for costs that deliver production. Require that credits are charged against actual production to eliminate currently-existing negative revenue liability to the State.

The Committee is united in several philosophies that are also recommendations to be considered in SB 21, not related to throughput, including:

- Firm incentives for Alaska Hire and Alaska Purchase,
- Evaluating significant and specific incentives for unconventional and heavy oil,
- Evaluating a production credit system for producers willing to provide propane fuels for the people of rural Alaska in areas unlikely to receive natural gas distribution if/when a natural gas pipeline is constructed, and
- Evaluating employing progressivity as a tool to level the proportion of take for Alaskans across the various oil price environments.

Although not supported unanimously by the Committee, yet in the spirit of fairness for all Committee members, the Minority Committee member has requested the following considerations to be passed onto the Senate Resource Committee:

- Evaluate a time limit into the future for the 20% Gross Revenue Exclusion.
- Evaluate removing the Net Operating Loss provision in SB 21.
- Evaluate adding a 10% minimum gross tax at the gross value at the point of production.
- Consider bracketing progressivity at varying rates as the price of oil varies.

The Senate Special Committee on Trans Alaska Pipeline System (TAPS) Throughput will continue to convene to identify and evaluate additional mitigation solutions for operational and regulatory TAPS production-related obstacles in the future. The Committee looks forward to the constructive dialogue and additional processing that will occur within the Legislature related to SB 21 the remainder of this session.

Respectfully submitted to the Senate Resource Committee on February 7, 2013,

Sen. Peter A. Micciche, Co-Chair

Sen. Mike Dunleavy, Co-Chair

28-GS1647\N.10
Nauman/Bullock
2/27/13

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 21(RES), Draft Version "N"

Page 11, following line 18:

Insert a new bill section to read:

"* **Sec. 9.** AS 43.55.023(a), as amended by sec. 8 of this Act, is amended to read:

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

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

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

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

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

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

L

Renumber the following bill sections accordingly.

Page 11, line 20, following "**<u>in</u>**":

Insert "**<u>AS 43.55.025(q) and</u>**"

Page 12, line 30:

Delete "sec. 11"

Insert "sec. 12"

Page 20, following line 28:

Insert a new bill section to read:

"* **Sec. 22.** AS 43.55.025 is amended by adding a new subsection to read:

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

Renumber the following bill sections accordingly.

Page 30, line 2:

Delete "26 - 28"

Insert "28 - 30"

Page 30, line 4:

Delete "25"

Insert "27"

Page 30, line 6:

Delete "11, 13, and 14"

Insert "12, 14, and 15"

Page 30, line 8:

Delete "Sections 9, 10, 12, 15, and 24"

Insert "Sections 9 - 11, 13, 16, 22, and 26"

Page 30, line 14:

Delete "sec. 29"

Insert "sec. 31"

Page 30, line 27:

Delete "11, 13, 14, 21, 25, and 30"

Insert "12, 14, 15, 23, 27, and 32"

Page 30, line 29:

Delete "9, 10, 12, 15, 17, 18, 24, and 26 - 28"

Insert "9 - 11, 13, 16, 18, 19, 22, 26, and 28 - 30"

Page 30, line 31:

Delete "sec. 37"

Insert "sec. 39"

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 21(RES), Draft Version "N"

Page 11, lines 20 - 22:

Delete "**Except as provided in (p) - (u) of this section for a tax credit based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude, a** [A]"

Insert "A"

Page 11, line 23:

Delete "**35** [25]"

Insert "25"

Page 11, line 24, following "loss":

Insert "**based on lease expenditures incurred to explore for, develop, or produce oil or gas deposits located south of 68 degrees North latitude. A producer or explorer subject to the requirements in (p) - (u) of this section may elect to take a tax credit in the amount of 35 percent of a carried-forward annual loss based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude**"

28-GS1647\N.7
Bullock
2/26/13

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 21(RES), Draft Version "N"

Page 2, line 21, following "section.":

Insert "A taxpayer receiving the transfer of a certificate under this subsection may not apply more than $10,000,000 in tax credits authorized by this section in a single tax year and may not use a tax credit authorized by this section to reduce a tax liability under this chapter below zero."

Page 3, line 12:

Delete the first occurrence of "and"

Insert "or"

Page 3, line 13:

Delete ", regardless of whether the oil and gas is located in the state"

Page 3, line 16:

Delete the first occurrence of "and"

Insert "or"

Page 3, lines 16 - 17:

Delete ", regardless of whether the oil and gas is located in the state"

Page 3, line 21:

Delete "and"

Insert "or"

Page 3, line 22:

Delete "regardless of whether the oil and gas is located in the state,"

Page 8, line 22:

Delete "**20**"

Insert "**30**"

Page 15, line 12:

Delete "in"

Insert "for"

Page 15, line 23:

Delete "43.55.024(c)"

Insert "43.55.024"

Page 17, line 2:

Delete "again"

Insert "against"

Page 18, line 15:

Delete "taxable oil"

Insert "oil taxable under AS 43.55.011(e)"

Page 22, line 24:

Delete the first occurrence of "an"

Insert "any"

Page 27, line 4:

Delete "an area"

Insert "acreage"

Page 27, line 7:

Delete "an area"

Insert "acreage"

Page 27, line 8:

Delete "production tax value"

Insert "gross value at the point of production"

Page 30, line 8:

Delete "Sections 9, 10, 12, 15, and 24"

Insert "Sections 9, 10, 12, 15, 20, 21, and 24"

Page 30, line 29:

Delete "Sections 1, 3, 6, 7, 9, 10, 12, 15, 17, 18, 24, and 26 - 28"

Insert "Sections 1, 3, 6, 7, 9, 10, 12, 15, 17, 18, 20, 21, 24, and 26 - 28"

28-GS1647\N
Nauman/Bullock
2/22/13

CS FOR SENATE BILL NO. 21(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-EIGHTH LEGISLATURE - FIRST SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered:
Referred:

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

A BILL

FOR AN ACT ENTITLED

"An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; providing a tax credit against the corporation income tax for qualified oil and gas service industry expenditures; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax value including adjustments based on a percentage of gross value at the point of production from certain leases or properties; establishing the Oil and Gas Competitive Review Board; making conforming amendments; and providing for an effective date."

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

* **Section 1.** AS 29.60.850(b) is amended to read:

(b) Each fiscal year, the legislature may appropriate to the community revenue sharing fund [AN AMOUNT EQUAL TO 20 PERCENT OF THE] money received by the state during the previous calendar year under **AS 43.20.030(c)** [AS 43.55.011(g)]. The amount may not exceed

(1) $60,000,000; or

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

* **Sec. 2.** AS 43.20 is amended by adding a new section to read:

Sec. 43.20.049. Qualified oil and gas industry service expenditure credit. (a) For a tax year ending after the effective date of this section, a taxpayer is entitled to a credit against the tax due under this chapter in the amount of 10 percent of a qualified oil and gas service industry expenditure of the taxpayer incurred in the state. A taxpayer may not, in one tax year, apply more than $10,000,000 in tax credits received under this section. A tax credit under this section may not be used to reduce a tax liability under this chapter below zero.

(b) A tax credit under this section may be transferred to a taxpayer subject to tax under this chapter upon filing notice with the department in a format prescribed by the department. The department shall issue a certificate in the amount of the tax credit received under this section. Transfer of a credit does not limit the ability of the department to audit a tax credit claim and adjust the credit if the department determines, as a result of the audit, that the taxpayer that incurred the expenditure that is the basis of the credit was not entitled to the amount of the credit claimed. If, as a result of the audit, the department determines that the amount of the credit exceeds the proper amount, the department may, at the time the credit is used, increase by the amount determined to exceed the proper value of the credit the taxes calculated under this chapter for the taxpayer whose expenditure was the basis of the credit.

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

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

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

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

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

(f) In this section,

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

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

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

* **Sec. 3.** AS 43.55.011(e) is amended to read:

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

(1)] the annual production tax value of the taxable oil and gas as calculated under **<u>AS 43.55.160(a)</u>** [AS 43.55.160(a)(1)] multiplied by **<u>35</u>** [25] percent [; AND

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

* **Sec. 4.** AS 43.55.011(o) is amended to read:

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

* **Sec. 5.** AS 43.55.020(a) is amended to read:

(a) For a calendar year, a producer subject to tax under **<u>AS 43.55.011</u>** [AS 43.55.011(e) - (i) OR (p)] shall pay the tax as follows:

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

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

(i) zero; or

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

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

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

(i) zero;

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

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

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

(i) zero; or

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

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

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

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

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

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

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

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

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

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

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

* **Sec. 6.** AS 43.55.020(a), as amended by sec. 5 of this Act, is amended to read:

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

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

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

(i) zero; or

(ii) **<u>35</u>** [THE SUM OF 25] percent **<u>of</u>** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated;

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

(i) zero;

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

(iii) **35** [THE SUM OF 25] percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from those leases or properties during the month for which the installment payment is calculated**, except that, for the purposes of this calculation, the gross value at the point of production of oil and gas subject to AS 43.55.160(f) is reduced by 20 percent**;

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

(i) zero; or

(ii) **35** [THE SUM OF 25] percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible under AS 43.55.160 for the oil or gas, respectively, produced from the lease

or property from the gross value at the point of production of the oil or gas, respectively, produced from the lease or property during the month for which the installment payment is calculated;

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

(i) **35** [THE SUM OF 25] percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated, but not less than zero; or

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

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

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

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

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

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

* **Sec. 7.** AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner for oil and gas that is taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. If the total deductions of installment payments of estimated tax for a calendar year exceed the actual tax for that calendar year, the producer shall, before April 1 of the following year, refund the excess to the royalty owner. Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under **AS 43.55.011(e)** [AS 43.55.011(e) - (g)] on taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or right to which constitutes a landowner's royalty interest, is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the calendar year multiplied by a figure that is a quotient, in which

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

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

* **Sec. 8.** AS 43.55.023(a) is amended to read:

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

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

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

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

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

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

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

(b) **Except as provided in (p) - (u) of this section for a tax credit based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude, a** [A] producer or explorer may elect to take a tax credit in the amount of **35** [25] percent of a carried-forward annual loss. A credit under this subsection may be applied against a tax levied by AS 43.55.011(e). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was not deductible in calculating production tax values for that calendar year under AS 43.55.160.

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

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

* **Sec. 11.** AS 43.55.023(d) is amended to read:

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

* **Sec. 12.** AS 43.55.023(d), as amended by sec. 11 of this Act, is amended to read:

(d) Except **for a tax credit based on a lease expenditure incurred after**

December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude [AS LIMITED BY (i) OF THIS SECTION], a person that is entitled to take a tax credit under this section that wishes to transfer the unused credit to another person or obtain a cash payment under AS 43.55.028 may apply to the department for a transferable tax credit certificate. An application under this subsection must be in a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

* **Sec. 13.** AS 43.55.023(g) is amended to read:

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

* **Sec. 14.** AS 43.55.023(n) is amended to read:

(n) For the purposes of (*l*) [AND (m)] of this section, a well lease expenditure incurred in the state south of 68 degrees North latitude is a lease expenditure that is

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

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

* **Sec. 15.** AS 43.55.023 is amended by adding new subsections to read:

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

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

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

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

which the person seeks to apply the credit to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude.

(r) Except as otherwise provided under (s) of this section, a tax credit or a portion of a tax credit subject to (p)(1) of this section that is carried forward in compliance with AS 43.55.030(g) increases at a rate of 15 percent, compounded annually, as provided in this subsection. A tax credit or a portion of a tax credit begins to increase under this subsection on January 1 of the second calendar year immediately following the calendar year during which the lease expenditure on which the credit is based was incurred, unless that second calendar year is the calendar year for which the credit or portion of a credit is applied against the person's tax liability. A tax credit or a portion of a tax credit stops increasing under this subsection on December 31 of the calendar year immediately preceding the calendar year in which the credit or a portion of the credit is applied against the person's tax liability. An increase in the amount of a tax credit under this subsection has no value except as applied against the person's tax liability within the time period described in (p)(2) of this section.

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

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

(2) if the remainder obtained under (1) of this subsection is greater than zero, subtract that remainder from the total amount of the person's tax credits under (b) of this section that are based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located

north of 68 degrees North latitude that was available, without regard to the limitation under (q) of this section, to be applied against the person's tax liability for the calendar year under AS 43.55.011(e), including any increase in the amount of the tax credits under (r) of this section through December 31 of the previous calendar year; if the remainder is less than zero, the portion of the tax credit is considered to be equal to zero for purposes of this paragraph;

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

(t) A tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude is not transferable except as provided in this subsection. A person that is entitled to take a tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude may transfer the tax credit to another person that acquires from the transferor an operating right, operating interest, or working interest in a lease or property in the state that includes land north of 68 degrees North latitude in which the transferor owned an operating right, operating interest, or working interest at the time the lease expenditure was incurred. A transferee may transfer the tax credit to another person that acquires from the transferee an operating right, operating interest, or working interest in that lease or property. A transferee's use of a tax credit is subject to the provisions of (u) of this section. A transfer is conditioned on the filing with the department by the transferor and transferee of notices or a joint notice in a form and manner prescribed by the

department and the providing of information and certifications required by the department by regulation. A transferee's application of a tax credit again the transferee's production tax liability is subject to audit by the department to the same extent as a tax credit that has not been transferred.

(u) The provisions of this subsection apply to a tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude when the tax credit is used by a producer to which the tax credit has been transferred under (t) of this section, by a producer or the successor of a producer that has acquired the person that incurred the lease expenditure on which the tax credit is based, or by a producer or the successor of a producer created by the merger of the person that incurred the lease expenditures on which the tax credit is based with another person. The total amount of a producer's tax credits subject to this subsection that may be applied against the producer's tax liability under AS 43.55.011(e) for a calendar year may not exceed 20 percent of the sum of the amounts calculated by applying the following formula for each lease or property in the state that includes land north of 68 degrees North latitude from which the producer produces oil or gas during the calendar year and in which the person that incurred the lease expenditure on which the tax credit is based had owned an operating right, operating interest, or working interest when the lease expenditure was incurred:

GV X OS

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

* **Sec. 16.** AS 43.55.024(d) is amended to read:

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

(1) **<u>2022</u>** [2016]; or

(2) if the producer did not have commercial oil or gas production from a lease or property in the state before April 1, 2006, the ninth calendar year after the calendar year during which the producer first has commercial oil or gas production before May 1, **<u>2022</u>** [2016], from at least one lease or property in the state.

* **Sec. 17.** AS 43.55.024(e) is amended to read:

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

* **Sec. 18.** AS 43.55.024 is amended by adding a new subsection to read:

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

* **Sec. 19.** AS 43.55.025(b) is amended to read:

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

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

(2) if for an exploration well,

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

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

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

section; and

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

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

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

* **Sec. 20.** AS 43.55.025(c) is amended to read:

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

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

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

(A) before the well is spudded,

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

(ii) at the time of the submittal of information under (i) of this subparagraph, the commissioner of natural resources may request from the explorer that specific data sets, ancillary data, and reports including all results, and copies of well data collected and data analyses for the well be provided to the Department of Natural Resources upon completion of the drilling; in this sub-subparagraph, well data include all analyses conducted on physical material, and well logs collected from the well and sample analyses; testing geophysical and velocity data including vertical seismic profiles and check shot surveys; testing data and analyses; age data; geochemical analyses; and access to tangible material; and

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

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

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

* **Sec. 21.** AS 43.55.028(e) is amended to read:

(e) The department, on the written application of a person to whom a transferable tax credit certificate has been issued under AS 43.55.023(d) or **<u>former</u>**

AS 43.55.023(m) [(m)] or to whom a production tax credit certificate has been issued under AS 43.55.025(f), may use available money in the oil and gas tax credit fund to purchase, in whole or in part, the certificate if the department finds that

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

(2) the applicant does not have an outstanding liability to the state for unpaid delinquent taxes under this title;

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

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

(5) the purchase is consistent with this section and regulations adopted under this section.

* **Sec. 22.** AS 43.55.028(g) is amended to read:

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

* **Sec. 23.** AS 43.55.030(e) is amended to read:

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

(1) the **<u>explorer's or</u>** producer's qualified capital expenditures, as defined in AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other payments or credits under AS 43.55.170; and

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

* **Sec. 24.** AS 43.55.030 is amended by adding a new subsection to read:

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

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

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

(3) identification of the portion of the credit that was applied against the person's tax liability for the calendar year preceding the year for which the statement is due and of the amount of the credit that continues to be carried forward;

(4) other information required by the department.

* **Sec. 25.** AS 43.55.160(a) is amended to read:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(E) gas produced during a month from a lease or property outside the Cook Inlet sedimentary basin and used in the state is the gross value at the point of production of that gas taxable under AS 43.55.011(e) and produced by the producer from that lease or property, less 1/12 of the

producer's lease expenditures under AS 43.55.165 for the calendar year applicable to that gas produced by the producer from that lease or property, as adjusted under AS 43.55.170.

* **Sec. 26.** AS 43.55.160(a) is repealed and reenacted to read:

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

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

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

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

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

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

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

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

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

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

* **Sec. 27.** AS 43.55.160(e) is amended to read:

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

* **Sec. 28.** AS 43.55.160 is amended by adding a new subsection to read:

(f) In the calculation of an annual production tax value of a producer under (a)(1) of this section, the gross value at the point of production of oil or gas meeting one or more of the following criteria is reduced by 30 percent: (1) the oil or gas is produced from a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) the oil or gas is produced from a participating area established

after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before December 31, 2011; (3) the oil or gas is produced from an area that was not in a participating area before December 31, 2011, but was added to an existing participating area by the Department of Natural Resources after December 31, 2011, and the producer demonstrates to the department that the volume of oil and gas produced is from an area added to an existing participating area. A reduction in production tax value under this subsection may not reduce the production tax value of a producer below zero. In this subsection, "participating area" means a reservoir or portion of a reservoir contributing to production approved by the Department of Natural Resources.

* **Sec. 29.** AS 43.98 is amended by adding new sections to read:

Article 2. Oil and Gas Competitiveness Review Board.

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

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

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

(2) the chair of the Alaska Oil and Gas Conservation Commission;

(3) three members of the public appointed by the governor, including at least one member who is a petroleum engineer, one member who is a geologist, and one member who is an economist, each of whom has at least three years of experience in the member's field;

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

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

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

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

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

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

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

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

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

(i) The board shall meet at least four times each calendar year.

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

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

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

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

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

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

(6) in order to facilitate the work of the board, establish procedures to accept and keep confidential information that is beneficial to the work of the board, including the creation of a secure data room and confidentiality agreements to be signed by individuals having access to confidential information;

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

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

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

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

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

(b) At the request of the board, and except for information that is confidential under AS 40.25.100(a) or AS 43.05.230, a commissioner may disclose to the board information that is otherwise confidential after each member of the board and each staff member for the board with access to the information signs a confidentiality agreement prepared by the commissioner making the disclosure. Information that is confidential under AS 43.05.230 may not be disclosed to the board.

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

* **Sec. 30.** AS 43.55.023(m) is repealed.

* **Sec. 31.** AS 43.55.011(g), 43.55.023(i), and 43.55.160(c) are repealed January 1, 2014.

* **Sec. 32.** AS 43.98.040, 43.98.050, 43.98.060, and 43.98.070 are repealed December 31, 2022.

* **Sec. 33.** The uncodified law of the State of Alaska is amended by adding a new section to

read:

APPLICABILITY. (a) Sections 3, 6, 7, and 26 - 28 of this Act apply to oil and gas produced after December 31, 2013.

(b) Sections 4 and 25 of this Act apply to oil and gas produced after December 31, 2012.

(c) Sections 8, 11, 13, and 14 of this Act and AS 43.55.023(a)(1), as amended by sec. 8 of this Act, apply to expenditures incurred after December 31, 2012.

(d) Sections 9, 10, 12, 15, and 24 of this Act apply to expenditures incurred after December 31, 2013.

* **Sec. 34.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITION: OIL AND GAS COMPETITIVENESS REVIEW BOARD. The governor shall appoint the initial members of the Oil and Gas Competitive Review Board, established in sec. 29 of this Act, before January 1, 2014 or as soon thereafter as is practicable. The initial terms of the members of the board appointed under AS 43.98.040(b)(1) and (b)(3) shall be set by the governor and staggered so that one member serves one year, two members serve four years, and two members serve six years. The first written findings and recommendations, together with suggested legislation, shall be delivered to the Alaska State Legislature on December 1, 2015, or as soon thereafter as is practicable.

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

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

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

RETROACTIVITY. Sections 4, 11, 13, 14, 21, 25, and 30 of this Act and AS 43.55.023(a)(1), as amended by sec. 8 of this Act, are retroactive to January 1, 2013.

* **Sec. 37.** Sections 1, 3, 6, 7, 9, 10, 12, 15, 17, 18, 24, and 26 - 28 of this Act take effect January 1, 2014.

* **Sec. 38.** Except as provided in sec. 37 of this Act, this Act takes effect immediately under

AS 01.10.070(c).

AMENDMENT

OFFERED IN THE SENATE BY SENATOR FRENCH

TO: CSSB 21(RES), Draft Version "N"

Page 1, line 11, following "**Board;**":

Insert "**relating to the financing of oil processing facilities on the North Slope by the Alaska Industrial Development and Export Authority;**"

Page 29, following line 26:

Insert new bill sections to read:

"* **Sec. 30.** AS 44.88.080 is amended by adding a new paragraph to read:

(32) to acquire an interest in a project as necessary or appropriate to provide working or venture capital for an oil or natural gas development project under AS 44.88.800 and 44.88.810, whether by purchase, gift, or lease.

* **Sec. 31.** AS 44.88 is amended by adding new sections to read:

Article 9A. Interest in Oil and Gas Resources.

Sec. 44.88.800. Acquisition of interest in businesses. (a) The authority may acquire, through purchase or other means, an interest in a lease held by a corporation or other business entity in an oil or natural gas field in the state that has been explored, but only if the authority determines the leaseholder has made reasonable efforts to obtain financing from the private sector to develop the lease and those efforts have, in whole or part, been unsuccessful. The authority shall exercise due diligence in acquiring a leasehold interest under this section.

(b) If the authority acquires a leasehold interest under this section, the authority may use the authority's assets, as appropriate, to aid in the development of the oil or natural gas field in which the business entity has a leasehold interest.

Sec. 44.88.810. Alaska resource development fund. (a) The Alaska resource development fund is established in the authority for the purpose of developing oil and gas resources, and consists of appropriations to the fund. The authority shall manage the fund and may create separate accounts within it. Income of the fund or of enterprises of the authority shall be separately accounted for and may be appropriated to the fund.

(b) The authority may use money from the fund to carry out the purpose of the fund set out in (a) of this section.

* Sec. 32. AS 44.88.900(10) is amended to read:

(10) "project" means

(A) a plant or facility used or intended for use in connection with making, processing, preparing, transporting, or producing in any manner, goods, products, or substances of any kind or nature or in connection with developing or utilizing a natural resource, or extracting, smelting, transporting, converting, assembling, or producing in any manner, minerals, raw materials, chemicals, compounds, alloys, fibers, commodities and materials, products, or substances of any kind or nature;

(B) a plant or facility used or intended for use in connection with a business enterprise;

(C) commercial activity by a business enterprise;

(D) a plant or facility demonstrating technological advances of new methods and procedures and prototype commercial applications for the exploration, development, production, transportation, conversion, and use of energy resources;

(E) infrastructure for a new tourism destination facility or for the expansion of a tourism destination facility; in this subparagraph, "tourism destination facility" does not include a hotel or other overnight lodging facility;

(F) a plant or facility, other than a plant or facility described in (D) of this paragraph, for the generation, transmission, development, transportation, conversion, or use of energy resources;

(G) a plant or facility that enhances, provides for, or promotes economic development with respect to transportation, communications, community public purposes, technical innovations, prototype commercial applications of intellectual property, or research;

(H) a plant or facility used or intended for use as a federal facility, including a United States military, national guard, or coast guard facility;

(I) infrastructure for an area that is designated as a military facility zone under AS 26.30;

(J) development of an oil and gas field by providing working or venture capital in exchange for an equity interest;"

Renumber the following bill sections accordingly.

Page 30, line 27:

Delete "30"

Insert "33"

Page 30, line 31:

Delete "sec. 37"

Insert "sec. 40"

28-GS1647\N.1
Bullock
2/22/13

AMENDMENT

OFFERED IN THE SENATE BY SENATOR FRENCH

TO: CSSB 21(RES), Draft Version "N"

Page 26, line 28, following "section,":

Insert "for the first seven years immediately following the commencement of production subject to tax under AS 43.55.011(e),"

28-GS1647\N.2
Bullock
2/23/13

AMENDMENT

OFFERED IN THE SENATE BY SENATOR FRENCH

TO: CSSB 21(RES), Draft Version "N"

Page 1, line 3:

Delete "rate"

Insert "rates"

Page 2, following line 9:

Insert a new bill section to read:

"* Sec. 2. AS 29.60.850(b), as amended by sec. 1 of this Act, is amended to read:

(b) Each fiscal year, the legislature may appropriate to the community revenue sharing fund **<u>an amount equal to 20 percent of the</u>** money received by the state during the previous calendar year under **<u>AS 43.55.011(g)</u>** [AS 43.20.030(c)]. The amount may not exceed

(1) $60,000,000; or

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

Renumber the following bill sections accordingly.

Page 4, following line 4:

Insert a new bill section to read:

"* Sec. 5. AS 43.55.011(e), as amended by sec. 4 of this Act, is amended to read:

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

(1) the annual production tax value of the taxable oil and gas as calculated under **AS 43.55.160(a)(1)** [AS 43.55.160(a)] multiplied by **25** [35] percent**; and**

(2) the sum, over all months of the calendar year, of the tax amounts determined under (q) of this section."

Renumber the following bill sections accordingly.

Page 4, following line 10:

Insert new bill sections to read:

"* Sec. 7. AS 43.55.011(o), as amended by sec. 6 of this Act, is amended to read:

(o) Notwithstanding other provisions of this section, for a calendar year before 2022, the tax levied under (e) of this section for each 1,000 cubic feet of gas for gas produced from a lease or property outside the Cook Inlet sedimentary basin and used in the state [, OTHER THAN GAS SUBJECT TO (p) OF THIS SECTION,] may not exceed the amount of tax for each 1,000 cubic feet of gas that is determined under (j)(2) of this section.

* Sec. 8. AS 43.55.011 is amended by adding a new subsection to read:

(q) For each month of the calendar year for which the producer's average monthly production tax value under AS 43.55.160(a)(2) of a BTU equivalent barrel of the taxable oil and gas is more than $30, the amount of tax for purposes of (e)(2) of this section is determined by multiplying the monthly production tax value of the taxable oil and gas produced during the month by the tax rate calculated as follows:

(1) if the producer's average monthly production tax value of a BTU equivalent barrel of the taxable oil and gas for the month is not more than $92.50, the tax rate is 0.4 percent multiplied by the number that represents the difference between that average monthly production tax value of a BTU equivalent barrel and $30; or

(2) if the producer's average monthly production tax value of a BTU equivalent barrel of the taxable oil and gas for the month is more than $92.50, the tax

rate is the sum of 25 percent and the product of 0.1 percent multiplied by the number that represents the difference between the average monthly production tax value of a BTU equivalent barrel and $92.50, except that the sum determined under this paragraph may not exceed 50 percent."

Renumber the following bill sections accordingly.

Page 7, line 13:

Delete "sec. 5"

Insert "sec. 9"

Page 10, following line 10:

Insert a new bill section to read:

"* Sec. 11. AS 43.55.020(a), as amended by secs. 9 and 10 of this Act, is repealed and reenacted to read:

(a) For a calendar year, a producer subject to tax under AS 43.55.011(e), (f), (h), (i), (p), or (q) shall pay the tax as follows:

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

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

(i) zero; or

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

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

(i) zero;

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

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

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

(i) zero; or

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

(2) an amount calculated under (1)(C) of this subsection for oil or gas produced from a lease or property

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

(B) subject to AS 43.55.011(p) may not exceed four percent of the gross value at the point of production of the oil or gas;

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

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

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

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

Renumber the following bill sections accordingly.

Page 10, following line 28:

Insert a new bill section to read:

"* **Sec. 13.** AS 43.55.020(d), as amended by sec. 12 of this Act, is amended to read:

(d) In making settlement with the royalty owner for oil and gas that is taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. If the total deductions of installment payments of estimated tax for a calendar year exceed the actual tax for that calendar year, the producer shall, before April 1 of the following year, refund the excess to the royalty owner. Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under **AS 43.55.011(e), (f), and (g)** [AS 43.55.011(e)] on taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or right to which constitutes a landowner's royalty interest, is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the calendar year multiplied by a figure that is a quotient, in which

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

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

Renumber the following bill sections accordingly.

Page 11, following line 18:

Insert a new bill section to read:

"* Sec. 15. AS 43.55.023(a), as amended by sec. 14 of this Act, is amended to read:

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

(1) notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the production tax value of oil and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or explorer that incurs a qualified capital expenditure may also elect to apply a tax credit against a tax levied by AS 43.55.011(e) in the amount of 20 percent of that expenditure; **however, not more than half of the tax credit may be applied for a single calendar year;**

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

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

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

(3) A CREDIT FOR A QUALIFIED CAPITAL EXPENDITURE INCURRED TO EXPLORE FOR, DEVELOP, OR PRODUCE OIL OR GAS DEPOSITS LOCATED NORTH OF 68 DEGREES NORTH LATITUDE MAY BE TAKEN ONLY IF THE EXPENDITURE IS INCURRED BEFORE JANUARY 1, 2014]."

Renumber the following bill sections accordingly.

Page 11, following line 29:

Insert a new bill section to read:

"* Sec. 17. AS 43.55.023(b), as amended by sec. 16 of this Act, is amended to read:

(b) **A** [EXCEPT AS PROVIDED IN (p) - (u) OF THIS SECTION FOR A TAX CREDIT BASED ON LEASE EXPENDITURES INCURRED AFTER

DECEMBER 31, 2013, TO EXPLORE FOR, DEVELOP, OR PRODUCE OIL OR GAS DEPOSITS LOCATED NORTH OF 68 DEGREES NORTH LATITUDE, A] producer or explorer may elect to take a tax credit in the amount of 25 [35] percent of a carried-forward annual loss. A credit under this subsection may be applied against a tax levied by AS 43.55.011(e). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was not deductible in calculating production tax values for that calendar year under AS 43.55.160."

Renumber the following bill sections accordingly.

Page 12, following line 4:

Insert a new bill section to read:

"* **Sec. 19.** AS 43.55.023(c), as amended by sec. 18 of this Act, is amended to read:

(c) A credit or portion of a credit under this section may not be used to reduce a person's tax liability under AS 43.55.011(e) for any calendar year below zero, and [. EXCEPT AS OTHERWISE PROVIDED UNDER (p) - (u) OF THIS SECTION,] any unused credit or portion of a credit not used under this subsection may be applied in a later calendar year.

Renumber the following bill sections accordingly.

Page 12, line 30:

Delete "sec. 11"

Insert "sec. 20"

Page 13, following line 18:

Insert a new bill section to read:

"* **Sec. 22.** AS 43.55.023(d), as amended by secs. 20 and 21 of this Act, is amended to read:

(d) A [EXCEPT FOR A TAX CREDIT BASED ON A LEASE

EXPENDITURE INCURRED AFTER DECEMBER 31, 2013, TO EXPLORE FOR, DEVELOP, OR PRODUCE OIL OR GAS DEPOSITS LOCATED NORTH OF 68 DEGREES NORTH LATITUDE, A] person that is entitled to take a tax credit under this section that wishes to transfer the unused credit to another person or obtain a cash payment under AS 43.55.028 may apply to the department for [A] transferable tax credit **certificates** [CERTIFICATE]. An application under this subsection must be in a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant **two** [A] transferable tax credit **certificates, each for half of** [CERTIFICATE FOR] the amount of the credit. **The credit shown on one of the two certificates is available for immediate use. The credit shown on the second of the two certificates may not be applied against a tax for a calendar year earlier than the calendar year following the calendar year in which the certificate is issued, and the certificate must contain a conspicuous statement to that effect.** A certificate issued under this subsection does not expire."

Renumber the following bill sections accordingly.

Page 14, following line 1:

Insert a new bill section to read:

"* Sec. 24. AS 43.55.023(g), as amended by sec. 23 of this Act, is amended to read:

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

Renumber the following bill sections accordingly.

Page 14, following line 15:

Insert a new bill section to read:

"* **Sec. 26.** AS 43.55.023(n), as amended by sec. 25 of this Act, is amended to read:

(n) For the purposes of (*l*) **<u>and (v)</u>** of this section, a well lease expenditure incurred in the state south of 68 degrees North latitude is a lease expenditure that is

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

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

Renumber the following bill sections accordingly.

Page 17, following line 27:

Insert a new subsection to read:

"(v) For a lease expenditure incurred in the state south of 68 degrees North latitude after December 31, 2017, that qualifies for tax credits under (a) and (b) of this section, and for a well lease expenditure incurred in the state south of 68 degrees North latitude that qualifies for a tax credit under (*l*) of this section, the department shall issue transferable tax credit certificates to the person entitled to the credit for the full amount of the credit. The transferable tax credit certificates do not expire."

Page 20, following line 28:

Insert a new bill section to read:

"* Sec. 33. AS 43.55.025(c), as amended by sec. 32 of this Act, is amended to read:

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

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

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

(A) before the well is spudded,

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

(ii) at the time of the submittal of information under (i) of this subparagraph, the commissioner of natural resources may request from the explorer that specific data sets, ancillary data, and reports including all results, and copies of well data collected and data analyses for the well be provided to the Department of Natural Resources upon completion of the drilling; in this sub-subparagraph, well data include all analyses conducted on physical material, and well logs collected from the well and sample analyses; testing geophysical and velocity data including vertical seismic profiles and check shot surveys; testing data and analyses; age data; geochemical analyses; and access to tangible material; and

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

(B) **for an exploration well other than a well to explore a Cook Inlet prospect, the well must be located and drilled in such a manner that the bottom hole is located not less than three miles away from the bottom hole of a preexisting well drilled for oil or gas, irrespective of whether the preexisting well has been completed, suspended, or abandoned;**

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

Page 21, following line 16:

Insert a new bill section to read:

"* **Sec. 35.** AS 43.55.028(e), as amended by sec. 34 of this Act, is amended to read:

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

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

(2) the applicant does not have an outstanding liability to the state for unpaid delinquent taxes under this title;

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

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

(5) the purchase is consistent with this section and regulations adopted under this section."

Renumber the following bill sections accordingly.

Page 21, following line 26:

Insert a new bill section to read:

"* **Sec. 37.** AS 43.55.028(g), as amended by sec. 36 of this Act, is amended to read:

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

Renumber the following bill sections accordingly.

Page 22, following line 8:

Insert a new bill section to read:

"* Sec. 39. AS 43.55.030(e), as amended by sec. 38 of this Act, is amended to read:

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

(1) the [EXPLORER'S OR] producer's qualified capital expenditures, as defined in AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other payments or credits under AS 43.55.170; and

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

Renumber the following bill sections accordingly.

Page 26, following line 5:

Insert a new bill section to read:

"* Sec. 43. AS 43.55.160(a), as amended by secs. 41 and 42 of this Act, is repealed and reenacted to read:

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

(1) AS 43.55.011(e), the annual production tax value of the taxable oil, gas, or oil and gas subject to this paragraph produced during a calendar year is the gross value at the point of production of the oil, gas, or oil and gas taxable under AS 43.55.011(e), less the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil, gas, or oil and gas, as applicable, produced by the

producer from leases or properties, as adjusted under AS 43.55.170; this paragraph applies to

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

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

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

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

(C) oil produced before 2022 from a lease or property in the Cook Inlet sedimentary basin;

(D) gas produced before 2022 from a lease or property in the Cook Inlet sedimentary basin;

(E) gas produced before 2022 from a lease or property in the state outside the Cook Inlet sedimentary basin and used in the state;

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

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

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

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

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

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

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

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

Renumber the following bill sections accordingly.

Page 26, following line 25:

Insert a new bill section to read:

"* **Sec. 45.** AS 43.55.160(e), as amended by sec. 44 of this Act, is amended to read:

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

Renumber the following bill sections accordingly.

Page 27, following line 11:

Insert a new bill section to read:

"* **Sec. 47.** AS 43.55.160 is amended by adding a new subsection to read:

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

Renumber the following bill sections accordingly.

Page 29, following line 28:

Insert a new bill section to read:

"* Sec. 50. AS 43.55.023(p), 43.55.023(q), 43.55.023(r), 43.55.023(s), 43.55.023(t), 43.55.023(u), 43.55.024(i), 43.55.030(g), and 43.55.160(f) are repealed January 1, 2018."

Renumber the following bill sections accordingly.

Page 30, line 2:

Delete "Sections 3, 6, 7, and 26 - 28"

Insert "Sections 4, 10, 12, 42, 44, and 46"

Page 30, line 4:

Delete "Sections 4 and 25"

Insert "Sections 6 and 41"

Page 30, line 6:

Delete "Sections 8, 11, 13, and 14 of this Act and AS 43.55.023(a)(1), as amended by sec. 8"

Insert "Sections 14, 20, 23, and 25 of this Act and AS 43.55.023(a)(1), as amended by sec. 14"

Page 30, line 8:

Delete "Sections 9, 10, 12, 15, and 24"

Insert "Sections 16, 18, 21, 27, and 40"

Page 30, following line 9:

Insert new subsections to read:

"(e) Sections 5, 7, 8, 11, 13, 43, and 45 of this Act apply to oil and gas produced after December 31, 2017.

(f) Sections 15, 17, 19, 22, 24, and 26 of this Act and AS 43.55.023(v), enacted by sec. 27 of this Act, apply to expenditures incurred after December 31, 2017."

Page 30, line 14:

Delete "sec. 29"

Insert "sec. 48"

Page 30, line 27:

Delete "Sections 4, 11, 13, 14, 21, 25, and 30 of this Act and AS 43.55.023(a)(1), as amended by sec. 8"

Insert "Sections 6, 20, 23, 25, 34, 41, and 49 of this Act and AS 43.55.023(a)(1), as amended by sec. 14"

Page 30, line 29:

Delete "Sections 1, 3, 6, 7, 9, 10, 12, 15, 17, 18, 24, and 26 - 28 of this Act"

Insert "Sections 1, 4, 10, 12, 16, 18, 21, 29, 30, 40, 42, 44, 46, and 50 of this Act, and AS 43.55.023(p) - (u), enacted by sec. 27 of this Act,"

Page 30, following line 30:

Insert a new bill section to read:

"* **Sec. 57.** Sections 2, 5, 7, 8, 11, 13, 15, 17, 19, 22, 24, 26, 33, 35, 37, 39, 43, 45, 47, and 51 of this Act, and AS 43.55.023(v), enacted by sec. 27 of this Act, take effect January 1, 2018."

Renumber the following bill section accordingly.

Page 30, line 31:

Delete "sec. 37"

Insert "secs. 57 and 58"

28-GS1647\N.3
Nauman/Bullock
2/25/13

AMENDMENT

OFFERED IN THE SENATE BY SENATOR FRENCH

TO: CSSB 21(RES), Draft Version "N"

Page 1, lines 1 - 2:

Delete "**relating to appropriations from taxes paid under the Alaska Net Income Tax Act; providing a tax credit against the corporation income tax for qualified oil and gas service industry expenditures;**"

Page 1, lines 3 - 4:

Delete "**relating to gas used in the state;**"

Page 1, lines 5 - 8:

Delete "**for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers**"

Insert "**; amending the minimum tax on oil and gas production; relating to oil and gas leases**"

Page 1, lines 11 - 12:

Delete "**establishing the Oil and Gas Competitive Review Board; making conforming amendments**"

Insert "**; relating to the financing of the development of oil and gas resources by the Alaska Industrial Development and Export Authority**"

Page 2, line 2, through page 31, line 1:

Delete all material and insert:

"* **Section 1.** AS 38.05.180(h) is amended to read:

(h) The commissioner **shall** [MAY] include terms in **a** [ANY] lease **that impose** [IMPOSING] a minimum work commitment on the lessee **to implement the plan of development submitted by the lessee with a bid for an oil and gas or gas only lease. The terms of the minimum work commitment must** [. THESE TERMS SHALL BE MADE PUBLIC BEFORE THE SALE, AND MAY] include appropriate penalty provisions to take effect in the event the lessee does not fulfill the minimum work commitment. If it is demonstrated that a lease has been proven unproductive by actions of adjacent lease holders, the commissioner may set aside a work commitment. The commissioner may waive for a period not to exceed one two-year period any term of a minimum work commitment if the commissioner makes a written finding either that conditions preventing drilling or exploration were beyond the lessee's reasonable ability to foresee or control or that the lessee has demonstrated through good faith efforts an intent and ability to drill or develop the lease during the term of the waiver.

* **Sec. 2.** AS 38.05.180(x) is amended to read:

(x) A lessee conducting or permitting any exploration for, or development or production of, oil or gas on state land shall provide the commissioner access to all noninterpretive data obtained from that lease**; shall provide the commissioner access to all information necessary to perform an economic analysis under (ii)(2) of this section, including the capital, operating, production, and development costs and an estimate of total reserves;** and shall provide copies of that data **and information,** as the commissioner may request. The confidentiality provisions of AS 38.05.035 apply to the information obtained under this subsection.

* **Sec. 3.** AS 38.05.180 is amended by adding new subsections to read:

(hh) The commissioner shall require each bidder for an oil and gas lease or gas only lease and each lessee applying for an extension or renewal of an oil and gas lease or gas only lease to submit a plan of development for exploring, developing, and producing from the lease within the period of the lease or the extension or renewal of the lease. The commissioner shall review each plan of development and determine whether the proposed plan of development is reasonably expected to develop the lease in the best interest of the state. The plan of development shall be included in a lease along with penalties for failing to comply with the plan of development and other terms of the lease. A bidder may not be a qualified bidder for the purposes of (f)(1) of this section if the commissioner finds that the bidder has not submitted a proposed plan of development that is in the best interest of the state or that the person that submitted the plan of development is not reasonably capable of implementing the plan.

(ii) The commissioner shall

(1) review each oil and gas lease or gas only lease each year for the purpose of determining whether a lease is being developed in the best interest of the state, whether the lessee is complying with the plan of development applicable to the lease, and whether revision of a plan of development, including the planned rate of development, would provide the maximum benefit to the people of the state;

(2) every five years, perform an economic analysis on each participating area and determine whether the participating area is capable of increased production in paying quantities over the current rate of production or plan of development;

(3) enforce the terms of each oil and gas lease or gas only lease, including imposing any applicable penalty or other remedy for noncompliance, within a reasonable time after finding that a lessee is out of compliance with the terms of the lease;

(4) submit a report to the legislature before the first day of each regular session that lists each oil and gas or gas only lessee that is found to be out of compliance and the action by the commissioner to bring the lessee back into compliance or to terminate the lease.

(jj) For the purposes of (hh) and (ii) of this section, a plan of development for a cooperative or unit under (p) of this section is the plan of development for a lease within the cooperative or unit, except where a different plan of development is established for a lease within the cooperative or unit.

(kk) For purposes of (ii) of this section,

(1) "participating area" means that part of an oil and gas lease unit area to which production is allocated in the manner described in a unit agreement;

(2) "production in paying quantities" means production in quantities sufficient to yield a return in excess of drilling, development, and operating costs.

* Sec. 4. AS 43.55.011(e) is amended to read:

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

(1) the annual production tax value of the taxable oil and gas as calculated under AS 43.55.160(a)(1)**, as adjusted by AS 43.55.162,** multiplied by 25 percent; and

(2) the sum, over all months of the calendar year, of the tax amounts determined under (g) of this section.

* Sec. 5. AS 43.55.011(f) is repealed and reenacted to read:

(f) Except for oil and gas subject to (i) of this section and gas subject to (o) of this section, the provisions of this subsection apply to oil and gas produced from each lease or property within a unit or nonunitized reservoir that has cumulatively produced 1,000,000,000 BTU equivalent barrels of oil or gas by the close of the most recent calendar year and from which the average daily oil and gas production from the unit or nonunitized reservoir during the most recent calendar year exceeded 100,000 BTU equivalent barrels. Notwithstanding any contrary provision of law, a producer may not apply tax credits to reduce its total tax liability under (e) and (g) of this section for oil and gas produced from all leases or properties within the unit or nonunitized reservoir below 10 percent of the total gross value at the point of production of that oil and gas. If the amount of tax calculated by multiplying the tax rates in (e) and (g) of this section by the total production tax value of the oil and gas taxable under (e) and (g) of this section produced from all of the producer's leases or properties within the unit or nonunitized reservoir is less than 10 percent of the total gross value at the point of production of that oil and gas, the tax levied by (e) and (g) of this section for that oil and gas is equal to 10 percent of the total gross value at the point of production of that oil and gas.

* Sec. 6. AS 43.55.011(g) is amended to read:

(g) For each month of the calendar year for which the producer's average monthly production tax value under AS 43.55.160(a)(2) **of a** [PER] BTU equivalent barrel of the taxable oil and gas is more than $30, the amount of tax for purposes of (e)(2) of this section is determined by multiplying the monthly production tax value of the taxable oil and gas produced during the month**, as adjusted by AS 43.55.162,** by the tax rate calculated as follows:

(1) if the producer's average monthly production tax value **of a** [PER] BTU equivalent barrel of the taxable oil and gas for the month is not more than $92.50, the tax rate is 0.4 percent multiplied by the number that represents the difference between that average monthly production tax value **of a** [PER] BTU equivalent barrel and $30; or

(2) if the producer's average monthly production tax value **of a** [PER] BTU equivalent barrel of the taxable oil and gas for the month is more than $92.50, the tax rate is the sum of 25 percent and the product of 0.1 percent multiplied by the number that represents the difference between the average monthly production tax value **of a** [PER] BTU equivalent barrel and $92.50, except that the sum determined under this paragraph may not exceed **30** [50] percent.

* Sec. 7. AS 43.55.020(a) is amended to read:

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

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

(A) for oil and gas produced from leases or properties in the state outside the Cook Inlet sedimentary basin but not subject to AS 43.55.011(o) or (p), other than leases or properties subject to

AS 43.55.011(f), the greater of

(i) zero; or

(ii) the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the leases or properties under AS 43.55.160 **and 1/12 of the adjustment to production tax value for the calendar year under AS 43.55.162** from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated;

(B) for oil and gas produced from leases or properties subject to AS 43.55.011(f), **10 percent of the gross value at the point of production of that oil and gas** [THE GREATEST OF

(i) ZERO;

(ii) ZERO PERCENT, ONE PERCENT, TWO PERCENT, THREE PERCENT, OR FOUR PERCENT, AS APPLICABLE, OF THE GROSS VALUE AT THE POINT OF PRODUCTION OF THE OIL AND GAS PRODUCED FROM ALL LEASES OR PROPERTIES DURING THE MONTH FOR WHICH THE INSTALLMENT PAYMENT IS CALCULATED; OR

(iii) THE SUM OF 25 PERCENT AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY THE REMAINDER OBTAINED BY SUBTRACTING 1/12 OF THE PRODUCER'S ADJUSTED LEASE EXPENDITURES FOR THE CALENDAR YEAR OF PRODUCTION UNDER AS 43.55.165 AND 43.55.170 THAT ARE DEDUCTIBLE FOR THOSE LEASES OR PROPERTIES UNDER AS 43.55.160 FROM THE GROSS VALUE AT THE POINT OF PRODUCTION OF THE OIL AND GAS PRODUCED FROM THOSE LEASES OR PROPERTIES DURING THE MONTH FOR WHICH THE

INSTALLMENT PAYMENT IS CALCULATED];

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

(i) zero; or

(ii) the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible under AS 43.55.160 **<u>and 1/12 of the adjustment to production tax value for the calendar year under AS 43.55.162</u>** for oil or gas, **<u>as applicable</u>** [RESPECTIVELY], produced from the lease or property from the gross value at the point of production of the oil or gas, **<u>as applicable</u>** [RESPECTIVELY], produced from the lease or property during the month for which the installment payment is calculated;

(2) an amount calculated under (1)(C) of this subsection for oil or gas produced from a lease or property

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

(B) subject to AS 43.55.011(p) may not exceed four percent of the gross value at the point of production of the oil or gas;

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

sum of

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

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

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

* **Sec. 8.** AS 43.55.024(d) is amended to read:

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

(1) **2022** [2016]; or

(2) if the producer did not have commercial oil or gas production from a lease or property in the state before April 1, 2006, the ninth calendar year after the calendar year during which the producer first has commercial oil or gas production before May 1, **2022** [2016], from at least one lease or property in the state.

* **Sec. 9.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.026. Heavy oil research and development tax credit. (a) A taxpayer may apply 20 percent of the taxpayer's expenditure attributable to this state for research and development related to improving methods of producing heavy oil in the state for the taxable year that exceeds the base amount, but not to exceed $10,000,000, as a credit against the state tax liability imposed on the taxpayer under this chapter.

(b) Research and development expenditures in this section are attributable to this state if the research and development is being conducted in this state or the payroll of employees conducting the research and development is in this state. In this subsection, payroll of an employee is in this state if compensation is paid to an employee in this state and reported as paid in this state in the quarterly contribution report under AS 23.20 to the Department of Labor and Workforce Development.

(c) If the tax credit under this section exceeds the taxpayer's tax liability after other tax credits are taken under this chapter for the year in which the expenditure is incurred, the excess of the tax credit over the liability may be carried forward for up to seven years. If an unused credit is carried forward to a tax year from an earlier year, the credit arising in the earliest year is applied first against the tax liability for the year.

(d) A person may not claim a credit under this section for research and development expenditures that were deducted in the calculation of tax liability under AS 43.55.011(e).

(e) Each year, if three or more taxpayers claim the credit authorized under this section during the immediately preceding year, the department shall report to the legislature the number of taxpayers who claimed credits under this section in the prior year, the total cumulative amount of credits granted to all taxpayers under this section for the prior tax year, a description of the research and development projects for which the credit was granted, and the total cumulative number of employees conducting the research and development for which all taxpayers claim the credit.

(f) The commissioner shall establish in regulation a method for apportioning research expenditures of a producer related to heavy oil production in and outside of the state. When developing the regulations, the commissioner may consider the relative amounts of heavy oil the producer is seeking to produce in areas in and outside of the state or consider another reasonable basis on which fairly to apportion costs for research related to in-state oil production and oil produced outside of the state.

(g) In this section, "base amount" means the average of research and development expenditures related to improving methods of producing heavy oil and attributable to this state for the three tax years immediately preceding the taxable year for which the credit is being claimed.

*** Sec. 10.** AS 43.55.030(a) is amended to read:

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

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

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

(3) the gross amount of oil and the gross amount of gas produced from each lease or property, and the percentage of the gross amount of oil and gas owned by the producer;

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

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

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

(7) the production tax values of the oil and gas under AS 43.55.160;

(8) any claims for tax credits to be applied; [AND]

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

(10) for each expenditure that is the basis for a credit claimed under AS 43.55.023 or 43.55.025, a description of the expenditure, a detailed description of the purpose of the expenditure, and a description of the lease or property for which the expenditure was incurred; notwithstanding AS 40.25.100(a) and AS 43.05.230(a), information submitted under this

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paragraph may be disclosed to the public and shall be disclosed to the legislature in a report submitted within 10 days after the convening of the next regular legislative session following the date a statement is filed under this section.

* **Sec. 11.** AS 43.55.030(e) is amended to read:

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

(1) the producer's qualified capital expenditures, as defined in AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other payments or credits under AS 43.55.170; [AND]

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

(3) for each expenditure that is the basis for a credit claimed under this chapter, a description of the expenditure, a detailed description of the purpose of the expenditure, and a description of the lease or property for which the expenditure was incurred; notwithstanding AS 40.25.100(a) and AS 43.05.230(a), information submitted under this paragraph may be disclosed to the public and shall be disclosed to the legislature in a report submitted within 10 days after the convening of the next regular legislative session following the date a statement is filed under this section.

* **Sec. 12.** AS 43.55.160(a) is amended to read:

(a) Except as provided in (b) of this section, **and subject to adjustment under AS 43.55.162,** for the purposes of

(1) AS 43.55.011(e), the annual production tax value of the taxable oil, gas, or oil and gas subject to this paragraph produced during a calendar year is the gross value at the point of production of the oil, gas, or oil and gas taxable under

AS 43.55.011(e), less the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil, gas, or oil and gas, as applicable, produced by the producer from leases or properties, as adjusted under AS 43.55.170; this paragraph applies to

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

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

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

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

(C) oil produced before 2022 from a lease or property in the Cook Inlet sedimentary basin;

(D) gas produced before 2022 from a lease or property in the Cook Inlet sedimentary basin;

(E) gas produced before 2022 from a lease or property in the state outside the Cook Inlet sedimentary basin and used in the state;

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

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

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

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

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

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

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

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

*** Sec. 13.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.162. Adjustments to production tax value. (a) The annual production tax value of oil produced from a lease or property north of 68 degrees North latitude by the producer is reduced, during the first seven consecutive years after the start of commercial production by 20 percent of the gross value at the point of production of oil produced during the calendar year. This subsection does not apply to a lease or property that

(1) was in commercial production before January 1, 2007;

(2) is located within a unit area that has never had commercial production; or

(3) is located within a unit for more than 20 years before the first commercial production on the lease or property.

(b) The annual production tax value of oil or gas produced by a producer is reduced during the first five consecutive years after the start of commercial production by 10 percent if the oil or gas is produced from a participating area established after December 31, 2012, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before January 1, 2012. This subsection does not apply to production from a lease or property located within a unit for more than 20 years before the first commercial production on the lease or property.

(c) The annual production tax value of heavy oil produced by a producer is reduced by 10 percent of the gross value at the point of production of heavy oil produced, for the calendar year, from a lease or property that is located within a unit area existing on January 1, 2014.

(d) For a calendar year after 2012, the annual production tax value of oil produced by a producer that produced oil in 2012 is reduced by 10 percent of the gross value at the point of production of the volume of oil produced during the calendar year in excess of the total volume produced by the producer in 2012. The volume of oil produced by a producer in 2012 is the average daily statewide production of the producer, excluding from the calculation the days on which production is significantly reduced, multiplied by the number of days in the calendar year. For the purposes of this subsection, production is significantly reduced when the production volume of oil for the day is less than one-half of the quotient of the total volume of oil production that is produced by the producer for the year and the number of days in the calendar year. A producer that increases its volume of production through the purchase, merger, or other acquisition of another producer is the sum of the producer's total target volume and the total target volume for the producer that is purchased, merged with, or otherwise acquired; however, if the producer that is purchased, merged with, or otherwise acquired did not have a target volume determined under this section, the volume of the increased production that is attributable to the purchase, merger, or other acquisition may not be considered for the purpose of determining whether the producer that acquired the additional production has increased the volume of production above its target volume.

(e) A reduction in production tax value provided by this section may not be combined with any other reduction in production tax value provided by this section in the same year. Oil or gas from a lease or property that produces oil or gas that results in a production tax reduction under (a) of this section is ineligible for a production tax reduction under (b) and (c) of this section and may not be used in the calculation of production volume under (d) of this section.

(f) A reduction in production tax value provided by this section may not reduce the production tax value of a producer below zero.

(g) The rate of tax under AS 43.55.011(g) shall be determined before the application of the adjustment provided by this section.

(h) In this section,

(1) "commercial production" means the production of oil for the purpose of sale or other beneficial use, except when the sale or beneficial use is incidental to the testing of an unproved well or unproved completion interval;

(2) "participating area" means that part of an oil and gas lease unit to which production is allocated in the manner described in a unit agreement.

* Sec. 14. AS 43.55.990 is amended by adding a new paragraph to read:

(14) "heavy oil" means oil with an American Petroleum Institute gravity of less than 18 degrees.

* Sec. 15. AS 44.88.080 is amended by adding a new paragraph to read:

(32) to acquire an interest in a project as necessary or appropriate to

provide working or venture capital for an oil or natural gas development project under AS 44.88.800 and 44.88.810, whether by purchase, gift, or lease.

* **Sec. 16.** AS 44.88 is amended by adding new sections to read:

Article 9A. Interest in Oil and Gas Resources.

Sec. 44.88.800. Acquisition of interest in businesses. (a) The authority may acquire, through purchase or other means, an interest in a lease held by a corporation or other business entity in an oil or natural gas field in the state that has been explored, but only if the authority determines the leaseholder has made reasonable efforts to obtain financing from the private sector to develop the lease and those efforts have, in whole or part, been unsuccessful. The authority shall exercise due diligence in acquiring a leasehold interest under this section.

(b) If the authority acquires a leasehold interest under this section, the authority may use the authority's assets, as appropriate, to aid in the development of the oil or natural gas field in which the business entity has a leasehold interest.

Sec. 44.88.810. Alaska resource development fund. (a) The Alaska resource development fund is established in the authority for the purpose of developing oil and gas resources, and consists of appropriations to the fund. The authority shall manage the fund and may create separate accounts within it. Income of the fund or of enterprises of the authority shall be separately accounted for and may be appropriated to the fund.

(b) The authority may use money from the fund to carry out the purpose of the fund set out in (a) of this section.

* **Sec. 17.** AS 44.88.900(10) is amended to read:

(10) "project" means

(A) a plant or facility used or intended for use in connection with making, processing, preparing, transporting, or producing in any manner, goods, products, or substances of any kind or nature or in connection with developing or utilizing a natural resource, or extracting, smelting, transporting, converting, assembling, or producing in any manner, minerals, raw materials, chemicals, compounds, alloys, fibers, commodities and materials, products, or substances of any kind or nature;

(B) a plant or facility used or intended for use in connection with a business enterprise;

(C) commercial activity by a business enterprise;

(D) a plant or facility demonstrating technological advances of new methods and procedures and prototype commercial applications for the exploration, development, production, transportation, conversion, and use of energy resources;

(E) infrastructure for a new tourism destination facility or for the expansion of a tourism destination facility; in this subparagraph, "tourism destination facility" does not include a hotel or other overnight lodging facility;

(F) a plant or facility, other than a plant or facility described in (D) of this paragraph, for the generation, transmission, development, transportation, conversion, or use of energy resources;

(G) a plant or facility that enhances, provides for, or promotes economic development with respect to transportation, communications, community public purposes, technical innovations, prototype commercial applications of intellectual property, or research;

(H) a plant or facility used or intended for use as a federal facility, including a United States military, national guard, or coast guard facility;

(I) infrastructure for an area that is designated as a military facility zone under AS 26.30;

(J) development of an oil and gas field by providing working or venture capital in exchange for an equity interest;

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

APPLICABILITY. (a) Section 1 of this Act and AS 38.05.180(hh), enacted by sec. 3 of this Act, apply to a proposed lease sale and the renewal or extension of a lease on or after the effective date of this Act.

(b) The reduction in production tax value under AS 43.55.162, enacted by sec. 13 of this Act, applies to oil or gas produced after December 31, 2013.

*** Sec. 19.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LEGISLATIVE APPROVAL; NORTH SLOPE OIL PROCESSING FACILITY. (a) The Alaska Industrial Development and Export Authority may issue a loan to a producer of oil or gas to finance the construction and improvement of an oil processing facility on the Alaska North Slope and flow lines and other surface infrastructure for the facility. A loan under this section shall

(1) be issued to a producer that produces less than 100,000 barrels of oil a day;

(2) be issued for the purpose of financing a facility to facilitate production from a unit established after January 1, 2014; and

(3) have an interest rate that does not exceed the prime rate of interest plus one percent.

(b) In this section, "prime rate" means the lowest United States money center prime rate of interest that is published in the Wall Street Journal.

*** Sec. 20.** Section 19 of this Act is repealed June 30, 2017. Repeal of sec. 19 of this Act does not affect loans issued by the Alaska Industrial Development and Export Authority under sec. 19 of this Act before June 30, 2017.

*** Sec. 21.** This Act takes effect January 1, 2014."

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Nauman/Bullock
2/22/13

CS FOR SENATE BILL NO. 21( )

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-EIGHTH LEGISLATURE - FIRST SESSION

BY

Offered:
Referred:

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

A BILL

FOR AN ACT ENTITLED

"An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; providing a tax credit against the corporation income tax for qualified oil and gas service industry expenditures; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax value including adjustments based on a percentage of gross value at the point of production from certain leases or properties; establishing the Oil and Gas Competitive Review Board; making conforming amendments; and providing for an effective date."

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

* **Section 1.** AS 29.60.850(b) is amended to read:

(b) Each fiscal year, the legislature may appropriate to the community revenue sharing fund [AN AMOUNT EQUAL TO 20 PERCENT OF THE] money received by the state during the previous calendar year under **AS 43.20.030(c)** [AS 43.55.011(g)]. The amount may not exceed

(1) $60,000,000; or

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

* **Sec. 2.** AS 43.20 is amended by adding a new section to read:

Sec. 43.20.049. Qualified oil and gas industry service expenditure credit. (a) For a tax year ending after the effective date of this section, a taxpayer is entitled to a credit against the tax due under this chapter in the amount of 10 percent of a qualified oil and gas service industry expenditure of the taxpayer incurred in the state. A taxpayer may not, in one tax year, apply more than $10,000,000 in tax credits received under this section. A tax credit under this section may not be used to reduce a tax liability under this chapter below zero.

(b) A tax credit under this section may be transferred to a taxpayer subject to tax under this chapter upon filing notice with the department in a format prescribed by the department. The department shall issue a certificate in the amount of the tax credit received under this section. Transfer of a credit does not limit the ability of the department to audit a tax credit claim and adjust the credit if the department determines, as a result of the audit, that the taxpayer that incurred the expenditure that is the basis of the credit was not entitled to the amount of the credit claimed. If, as a result of the audit, the department determines that the amount of the credit exceeds the proper amount, the department may, at the time the credit is used, increase by the amount determined to exceed the proper value of the credit the taxes calculated under this chapter for the taxpayer whose expenditure was the basis of the credit.

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

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

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

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

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

(f) In this section,

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

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

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

* **Sec. 3.** AS 43.55.011(e) is amended to read:

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

(1)] the annual production tax value of the taxable oil and gas as calculated under **<u>AS 43.55.160(a)</u>** [AS 43.55.160(a)(1)] multiplied by **<u>35</u>** [25] percent [; AND

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

* **Sec. 4.** AS 43.55.011(o) is amended to read:

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

* **Sec. 5.** AS 43.55.020(a) is amended to read:

(a) For a calendar year, a producer subject to tax under **<u>AS 43.55.011</u>** [AS 43.55.011(e) - (i) OR (p)] shall pay the tax as follows:

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

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

(i) zero; or

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

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

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

(i) zero;

(ii) zero percent, one percent, two percent, three percent, or four percent, as applicable, of the gross value at the point of production of the oil and gas produced from **<u>the</u>** [ALL] leases or properties during the month for which the installment payment is calculated; or

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

(C) for oil **<u>or</u>** [AND] gas [PRODUCED FROM EACH LEASE OR PROPERTY] subject to AS 43.55.011(j), (k), **<u>or</u>** (o) [, OR (p)], **<u>for each lease or property,</u>** the greater of

(i) zero; or

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

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

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

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

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

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

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

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

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

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

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

* **Sec. 6.** AS 43.55.020(a), as amended by sec. 5 of this Act, is amended to read:

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

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

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

(i) zero; or

(ii) **<u>35</u>** [THE SUM OF 25] percent **<u>of</u>** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated;

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

(i) zero;

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

(iii) <u>**35**</u> [THE SUM OF 25] percent <u>**of**</u> [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from those leases or properties during the month for which the installment payment is calculated<u>**, except that, for the purposes of this calculation, the gross value at the point of production of oil and gas subject to AS 43.55.160(f) is reduced by 20 percent**</u>;

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

(i) zero; or

(ii) <u>**35**</u> [THE SUM OF 25] percent <u>**of**</u> [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible under AS 43.55.160 for the oil or gas, respectively, produced from the lease

or property from the gross value at the point of production of the oil or gas, respectively, produced from the lease or property during the month for which the installment payment is calculated;

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

(i) **35** [THE SUM OF 25] percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated, but not less than zero; or

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

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

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

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

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

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

* **Sec. 7.** AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner for oil and gas that is taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. If the total deductions of installment payments of estimated tax for a calendar year exceed the actual tax for that calendar year, the producer shall, before April 1 of the following year, refund the excess to the royalty owner. Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under **AS 43.55.011(e)** [AS 43.55.011(e) - (g)] on taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or right to which constitutes a landowner's royalty interest, is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the calendar year multiplied by a figure that is a quotient, in which

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

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

* **Sec. 8.** AS 43.55.023(a) is amended to read:

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

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

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

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

(B) submits to the Department of Natural Resources all data that would be required to be submitted under AS 43.55.025(f)(2)**<u>;</u>**

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

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

(b) **<u>Except as provided in (p) - (u) of this section for a tax credit based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude, a</u>** [A] producer or explorer may elect to take a tax credit in the amount of **<u>35</u>** [25] percent of a carried-forward annual loss. A credit under this subsection may be applied against a tax levied by AS 43.55.011(e). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was not deductible in calculating production tax values for that calendar year under AS 43.55.160.

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

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

* **Sec. 11.** AS 43.55.023(d) is amended to read:

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

* **Sec. 12.** AS 43.55.023(d), as amended by sec. 11 of this Act, is amended to read:

(d) Except **for a tax credit based on a lease expenditure incurred after**

December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude [AS LIMITED BY (i) OF THIS SECTION], a person that is entitled to take a tax credit under this section that wishes to transfer the unused credit to another person or obtain a cash payment under AS 43.55.028 may apply to the department for a transferable tax credit certificate. An application under this subsection must be in a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

* **Sec. 13.** AS 43.55.023(g) is amended to read:

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

* **Sec. 14.** AS 43.55.023(n) is amended to read:

(n) For the purposes of (*l*) [AND (m)] of this section, a well lease expenditure incurred in the state south of 68 degrees North latitude is a lease expenditure that is

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

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

* **Sec. 15.** AS 43.55.023 is amended by adding new subsections to read:

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

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

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

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

which the person seeks to apply the credit to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude.

(r) Except as otherwise provided under (s) of this section, a tax credit or a portion of a tax credit subject to (p)(1) of this section that is carried forward in compliance with AS 43.55.030(g) increases at a rate of 15 percent, compounded annually, as provided in this subsection. A tax credit or a portion of a tax credit begins to increase under this subsection on January 1 of the second calendar year immediately following the calendar year during which the lease expenditure on which the credit is based was incurred, unless that second calendar year is the calendar year for which the credit or portion of a credit is applied against the person's tax liability. A tax credit or a portion of a tax credit stops increasing under this subsection on December 31 of the calendar year immediately preceding the calendar year in which the credit or a portion of the credit is applied against the person's tax liability. An increase in the amount of a tax credit under this subsection has no value except as applied against the person's tax liability within the time period described in (p)(2) of this section.

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

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

(2) if the remainder obtained under (1) of this subsection is greater than zero, subtract that remainder from the total amount of the person's tax credits under (b) of this section that are based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located

north of 68 degrees North latitude that was available, without regard to the limitation under (q) of this section, to be applied against the person's tax liability for the calendar year under AS 43.55.011(e), including any increase in the amount of the tax credits under (r) of this section through December 31 of the previous calendar year; if the remainder is less than zero, the portion of the tax credit is considered to be equal to zero for purposes of this paragraph;

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

(t) A tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude is not transferable except as provided in this subsection. A person that is entitled to take a tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude may transfer the tax credit to another person that acquires from the transferor an operating right, operating interest, or working interest in a lease or property in the state that includes land north of 68 degrees North latitude in which the transferor owned an operating right, operating interest, or working interest at the time the lease expenditure was incurred. A transferee may transfer the tax credit to another person that acquires from the transferee an operating right, operating interest, or working interest in that lease or property. A transferee's use of a tax credit is subject to the provisions of (u) of this section. A transfer is conditioned on the filing with the department by the transferor and transferee of notices or a joint notice in a form and manner prescribed by the

department and the providing of information and certifications required by the department by regulation. A transferee's application of a tax credit again the transferee's production tax liability is subject to audit by the department to the same extent as a tax credit that has not been transferred.

(u) The provisions of this subsection apply to a tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude when the tax credit is used by a producer to which the tax credit has been transferred under (t) of this section, by a producer or the successor of a producer that has acquired the person that incurred the lease expenditure on which the tax credit is based, or by a producer or the successor of a producer created by the merger of the person that incurred the lease expenditures on which the tax credit is based with another person. The total amount of a producer's tax credits subject to this subsection that may be applied against the producer's tax liability under AS 43.55.011(e) for a calendar year may not exceed 20 percent of the sum of the amounts calculated by applying the following formula for each lease or property in the state that includes land north of 68 degrees North latitude from which the producer produces oil or gas during the calendar year and in which the person that incurred the lease expenditure on which the tax credit is based had owned an operating right, operating interest, or working interest when the lease expenditure was incurred:

GV X OS

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

* **Sec. 16.** AS 43.55.024(d) is amended to read:

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

(1) **<u>2022</u>** [2016]; or

(2) if the producer did not have commercial oil or gas production from a lease or property in the state before April 1, 2006, the ninth calendar year after the calendar year during which the producer first has commercial oil or gas production before May 1, **2022** [2016], from at least one lease or property in the state.

* **Sec. 17.** AS 43.55.024(e) is amended to read:

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

* **Sec. 18.** AS 43.55.024 is amended by adding a new subsection to read:

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

* **Sec. 19.** AS 43.55.025(b) is amended to read:

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

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

(2) if for an exploration well,

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

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

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

section; and

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

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

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

* **Sec. 20.** AS 43.55.025(c) is amended to read:

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

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

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

(A) before the well is spudded,

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

(ii) at the time of the submittal of information under (i) of this subparagraph, the commissioner of natural resources may request from the explorer that specific data sets, ancillary data, and reports including all results, and copies of well data collected and data analyses for the well be provided to the Department of Natural Resources upon completion of the drilling; in this sub-subparagraph, well data include all analyses conducted on physical material, and well logs collected from the well and sample analyses; testing geophysical and velocity data including vertical seismic profiles and check shot surveys; testing data and analyses; age data; geochemical analyses; and access to tangible material; and

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

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

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

* **Sec. 21.** AS 43.55.028(e) is amended to read:

(e) The department, on the written application of a person to whom a transferable tax credit certificate has been issued under AS 43.55.023(d) or **<u>former</u>**

__AS 43.55.023(m)__ [(m)] or to whom a production tax credit certificate has been issued under AS 43.55.025(f), may use available money in the oil and gas tax credit fund to purchase, in whole or in part, the certificate if the department finds that

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

(2) the applicant does not have an outstanding liability to the state for unpaid delinquent taxes under this title;

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

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

(5) the purchase is consistent with this section and regulations adopted under this section.

* **Sec. 22.** AS 43.55.028(g) is amended to read:

(g) The department may adopt regulations to carry out the purposes of this section, including standards and procedures to allocate available money among applications for purchases under this chapter and claims for refunds and payments under AS 43.20.046 or 43.20.047 when the total amount of the applications for purchase and claims for refund exceed the amount of available money in the fund. The regulations adopted by the department may not, when allocating available money in the fund under this section, distinguish an application for the purchase of a credit certificate issued under **__former__** AS 43.55.023(m) or a claim for a refund or payment under AS 43.20.046 or **__43.20.047__** [AS 43.20.047].

* **Sec. 23.** AS 43.55.030(e) is amended to read:

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

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

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

* **Sec. 24.** AS 43.55.030 is amended by adding a new subsection to read:

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

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

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

(3) identification of the portion of the credit that was applied against the person's tax liability for the calendar year preceding the year for which the statement is due and of the amount of the credit that continues to be carried forward;

(4) other information required by the department.

* **Sec. 25.** AS 43.55.160(a) is amended to read:

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

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

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

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

(i) **<u>gas</u>** produced before 2022 and used in the state; or

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

(C) oil produced before 2022 from **<u>each</u>** [A] lease or property in the Cook Inlet sedimentary basin;

(D) gas produced before 2022 from **<u>each</u>** [A] lease or property in the Cook Inlet sedimentary basin;

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

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

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

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

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

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

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

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

(E) gas produced during a month from a lease or property outside the Cook Inlet sedimentary basin and used in the state is the gross value at the point of production of that gas taxable under AS 43.55.011(e) and produced by the producer from that lease or property, less 1/12 of the

producer's lease expenditures under AS 43.55.165 for the calendar year applicable to that gas produced by the producer from that lease or property, as adjusted under AS 43.55.170.

* **Sec. 26.** AS 43.55.160(a) is repealed and reenacted to read:

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

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

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

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

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

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

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

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

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

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

* **Sec. 27.** AS 43.55.160(e) is amended to read:

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

* **Sec. 28.** AS 43.55.160 is amended by adding a new subsection to read:

(f) In the calculation of an annual production tax value of a producer under (a)(1) of this section, the gross value at the point of production of oil or gas meeting one or more of the following criteria is reduced by 30 percent: (1) the oil or gas is produced from a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) the oil or gas is produced from a participating area established

after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before December 31, 2011; (3) the oil or gas is produced from an area that was not in a participating area before December 31, 2011, but was added to an existing participating area by the Department of Natural Resources after December 31, 2011, and the producer demonstrates to the department that the volume of oil and gas produced is from an area added to an existing participating area. A reduction in production tax value under this subsection may not reduce the production tax value of a producer below zero. In this subsection, "participating area" means a reservoir or portion of a reservoir contributing to production approved by the Department of Natural Resources.

* **Sec. 29.** AS 43.98 is amended by adding new sections to read:

Article 2. Oil and Gas Competitiveness Review Board.

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

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

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

(2) the chair of the Alaska Oil and Gas Conservation Commission;

(3) three members of the public appointed by the governor, including at least one member who is a petroleum engineer, one member who is a geologist, and one member who is an economist, each of whom has at least three years of experience in the member's field;

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

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

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

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

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

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

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

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

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

(i) The board shall meet at least four times each calendar year.

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

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

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

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

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

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

(6) in order to facilitate the work of the board, establish procedures to accept and keep confidential information that is beneficial to the work of the board, including the creation of a secure data room and confidentiality agreements to be signed by individuals having access to confidential information;

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

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

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

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

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

(b) At the request of the board, and except for information that is confidential under AS 40.25.100(a) or AS 43.05.230, a commissioner may disclose to the board information that is otherwise confidential after each member of the board and each staff member for the board with access to the information signs a confidentiality agreement prepared by the commissioner making the disclosure. Information that is confidential under AS 43.05.230 may not be disclosed to the board.

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

* **Sec. 30.** AS 43.55.023(m) is repealed.

* **Sec. 31.** AS 43.55.011(g), 43.55.023(i), and 43.55.160(c) are repealed January 1, 2014.

* **Sec. 32.** AS 43.98.040, 43.98.050, 43.98.060, and 43.98.070 are repealed December 31, 2022.

* **Sec. 33.** The uncodified law of the State of Alaska is amended by adding a new section to

read:

APPLICABILITY. (a) Sections 3, 6, 7, and 26 - 28 of this Act apply to oil and gas produced after December 31, 2013.

(b) Sections 4 and 25 of this Act apply to oil and gas produced after December 31, 2012.

(c) Sections 8, 11, 13, and 14 of this Act and AS 43.55.023(a)(1), as amended by sec. 8 of this Act, apply to expenditures incurred after December 31, 2012.

(d) Sections 9, 10, 12, 15, and 24 of this Act apply to expenditures incurred after December 31, 2013.

* **Sec. 34.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITION: OIL AND GAS COMPETITIVENESS REVIEW BOARD. The governor shall appoint the initial members of the Oil and Gas Competitive Review Board, established in sec. 29 of this Act, before January 1, 2014 or as soon thereafter as is practicable. The initial terms of the members of the board appointed under AS 43.98.040(b)(1) and (b)(3) shall be set by the governor and staggered so that one member serves one year, two members serve four years, and two members serve six years. The first written findings and recommendations, together with suggested legislation, shall be delivered to the Alaska State Legislature on December 1, 2015, or as soon thereafter as is practicable.

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

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

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

RETROACTIVITY. Sections 4, 11, 13, 14, 21, 25, and 30 of this Act and AS 43.55.023(a)(1), as amended by sec. 8 of this Act, are retroactive to January 1, 2013.

* **Sec. 37.** Sections 1, 3, 6, 7, 9, 10, 12, 15, 17, 18, 24, and 26 - 28 of this Act take effect January 1, 2014.

* **Sec. 38.** Except as provided in sec. 37 of this Act, this Act takes effect immediately under

AS 01.10.070(c).

FISCAL NOTE

STATE OF ALASKA
2013 LEGISLATIVE SESSION

Bill Version	647
Fiscal Note Number	1
() Publish Date	

Identifier (file name)	0647-DOR-TAX-01-15-13
Title	Production Tax on Oil and Gas
Sponsor	Rules by Request of the Governor
Requester	Governor

Dept. Affected	Revenue
Appropriation	Treasury and Taxation
Allocation	Tax Division
OMB Component Number	2476

Expenditures/Revenues (Thousands of Dollars)

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

	FY14 Appropriation Requested	Included in Governor's FY14 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY14**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF							
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
	TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0

POSITIONS							
Full-time							
Part-time							
Temporary							

CHANGE IN REVENUES	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY13) operating costs ______ *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY14) costs ______ *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? yes

If yes, by what date are the regulations to be adopted, amended, or repealed? 1/1/2014 Discuss details in analysis section.

Why this fiscal note differs from previous version (if initial version, please note as such)

Initial version.

Prepared by	Cherie Nienhuis, Ed King and Michael Pawlowski	Phone	907-269-1019
Division	Tax Division	Date/Time	1/15/2013, 11:39 pm
Approved by	Bryan Butcher, Commissioner	Date	1/15/2013
	Department of Revenue		

(Revised 11/5/12 OMB)

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. 647

Analysis

This bill limits the provision that the State of Alaska purchase transferable tax credit certificates for credits earned from leases or properties that contain land that is north of 68 degrees North latitude to credits based on expenditures incurred before January 1, 2014. The operating portion of the long-term fiscal plan anticipates an average of $400 million in refundable credits through 2023. It is anticipated that the limitation of this provision would reduce those future appropriations, beginning in FY 2015.

Regulations: The bill does not direct DOR to adopt new regulations to implement its provisions, but existing regulations may need to be amended to conform to changes in eligibility for redeemable tax credits, and to account for repeal of some sections. There may be additional regulations required, but not before January 1, 2014.

*****The revenue impact of this bill is an estimate based on Fall 2012 Forecast.**
This bill makes several changes to the oil and gas production tax system. Each of the major changes, along with its potential revenue impact, is discussed separately below. The effective date of each of the bill's provisions listed below is January 1, 2014, with the exception of provision 6 (bill section 7), which is effective for expenditures beginning January 1, 2013.

1. The progressive portion of the production tax at AS 43.55.011(g) is repealed, and the production tax at AS 43.55.011(e) is retained at a tax rate of 25% of production tax value. Based on our Fall 2012 forecast, this change decreases production tax revenue over the forecast period analyzed. Please see detailed summary table on page 3 of this fiscal note.

2. Production tax credits under AS 43.55.023(a) for qualified capital expenditures are limited to expenditures incurred before January 1, 2014 on leases or properties that contain land north of 68 degrees North latitude. Based on our Fall 2012 forecast, this change increases production tax revenue annually over the forecast period analyzed. Please see detailed summary table on page 3 of this fiscal note.

3. Companies that incur net losses from leases or properties that contain land north of 68 degrees North latitude will earn a credit of 25% of those losses to be carried forward for a maximum period of ten years. These net loss carry-forwards will increase at an annual rate of 15 percent beginning on January 1 of the second calendar year following the year of the loss. The revenue impact of this provision is confidential under our forecast, however, the impact is expected to be minimal.

4. A gross revenue exclusion (GRE) is applicable to production from leases or properties containing land that is north of 68 degrees North latitude and meets one or both of two criteria: (1) is produced from a lease or property that does not contain land that was within a unit on January 1, 2003; or (2) is produced from a participating area established after December 31, 2011 for lease or properties in a unit formed before January 1, 2003. This provision is intended to incentivize future production and the revenue impact of this provision based on the current production forecast is minimal.

5. The small producer credit at AS 43.55.024 is extended to the later of 2022 or the ninth calendar year after the calendar year that the producer first has commercial production. This provision extends the small producer credit six years from the original sunset date of 2016. The revenue impact based on the current revenue forecast is minimal.

6. The provision requiring that credits be taken over two years is eliminated. This provision would result in companies using credits earlier than they would without this change, and except for the time value of money impact, it is revenue neutral. This provision applies to expenditures after December 31, 2012

7. The community revenue sharing fund is amended to allow the legislature to make appropriations from the tax revenue collected under AS 43.20, as opposed to revenue collected under AS 43.55.011(g). The impact of this provision is indeterminate.

Analysis Continued

Provisions in the Bill and their Estimated Fiscal Impact as compared to Fall 2012 Forecast ($millions)

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$800	-$1,500	-$1,700	-$1,800	-$1,750	-$1,650
2. Limitation of credits for qualified capital expenditures for North Slope	$300	$700	$650	$550	$475	$400
3. Net operating losses carried forward and increased at 15% per year	Less than -$50 million per year under Fall 2012 forecast					
4. Gross revenue exclusion for certain areas						
5. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
6. Provision requiring credits be taken over 2 year eliminated*	-$250					
7. Amendment to the community revenue sharing fund	Indeterminate					
Total Revenue Impact	-$750	-$800	-$1,050	-$1,275	-$1,300	-$1,300
Impact on Operating Budget	-$150	$250	$250	$250	$250	$250
Total Fiscal Impact	**-$900**	**-$550**	**-$800**	**-$1,025**	**-$1,050**	**-$1,050**

*Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $400 million, with $250 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

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

Analysis Continued

Differences in General Fund Unrestricted Revenue under Proposed Bill from Current Tax System in $Millions*

*Note: These hypothetical examples of additional production assess the impacts from the **change in tax rates and credits only** and do not attempt to quantify impacts of other parts of the bill, such as the removal of the credit split or the impact on the long-range budget.

At Forecasted Production

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$25	$275	$225	$75	$50	$0
$100	-$200	-$100	-$175	-$300	-$350	-$300
$120	-$900	-$1,350	-$1,425	-$1,525	-$1,475	-$1,350

All additional production scenarios below compare additional production under the proposed bill to ACES without the additional production.

Additional Production Scenario A

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

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$50	$375	$300	$175	$75	$75
$100	-$200	-$75	-$150	-$275	-$350	-$300
$120	-$900	-$1,375	-$1,400	-$1,500	-$1,475	-$1,375

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

Additional Production Scenario B

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$100	$550	$575	$525	$550	$475
$100	-$125	$125	$175	$150	$225	$150
$120	-$825	-$1,100	-$1,000	-$975	-$800	-$800

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day beginning in FY 2014, with a maximum production rate of 60,000 barrels per day for a total of 140 million barrels. Development costs for each well assumed to be $20 million.

Additional Production Scenario C

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$50	$525	$675	$800	$1,275	$1,200
$100	-$175	$150	$325	$500	$1,025	$975
$120	-$825	-$1,000	-$725	-$475	$225	$225

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of $5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

FISCAL NOTE

STATE OF ALASKA
2013 LEGISLATIVE SESSION

Bill Version	LL0647
Fiscal Note Number	
() Publish Date	

Identifier (file name)	LL0647-DNR-DOG-1-14-13
Title	Production Tax on Oil and Gas
Sponsor	Rules by Request of the Governor
Requester	Governor
Dept. Affected	Natural Resources
Appropriation	Oil & Gas
Allocation	Oil & Gas
OMB Component Number	439

Expenditures/Revenues (Thousands of Dollars)

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

	FY14 Appropriation Requested	Included in Governor's FY14 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY14**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF							
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		0.0	0.0	0.0	0.0	0.0	0.0	0.0

POSITIONS							
Full-time							
Part-time							
Temporary							

CHANGE IN REVENUES	***		***	***	***	***	***

Estimated SUPPLEMENTAL (FY13) operating costs ________ *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY14) costs ________ *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? No

If yes, by what date are the regulations to be adopted, amended, or repealed? N/A Discuss details in analysis section.

Why this fiscal note differs from previous version (if initial version, please note as such)

Initial Version.

Prepared by	Bill Barron, Director	Phone	269-8800
Division	Division of Oil and Gas	Date/Time	1/14/13 5:00 PM
Approved by	Daniel S. Sullivan, Commissioner	Date	1/14/2013
	Department of Natural Resources		

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. LL0647

Analysis

LL0647 reforms the oil and gas production tax system in Alaska. This bill will not result in any procedural changes in how the Division of Oil and Gas operates and therefore the Department of Natural Resources (DNR) does not anticipate any fiscal impact to the Department's operating budget.

This bill proposes to improve Alaska's competitiveness and encourage producers to invest more by simplifying the oil and gas production tax system. First, this bill repeals the progressive tax structure, which will help encourage the type of long-term planning and investment needed to promote new investment in new production in Alaska. Further, this bill shifts incentives away from spending and provides new incentives to reward new production. At forecasted price ranges, overall government take and marginal tax rates are reduced materially. To the extent that investments are made as a consequence of these changes to the tax regime, royalty revenue may rise.

The fiscal impact on royalty revenue is an indeterminate positive.

Analysis Continued

Differences in Royalty Revenues from New Production Scenarios in $Millions*

*Note: These scenarios are based on Department of Revenue modeling.

At Forecasted Production

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$ 120	$0	$0	$0	$0	$0	$0
$ 100	$0	$0	$0	$0	$0	$0
$ 90	$0	$0	$0	$0	$0	$0

Additional Production Scenario A

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

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$0	$0	$0	$12	$24	$35
$100	$0	$0	$0	$10	$20	$29
$90	$0	$0	$0	$9	$17	$26

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

Additional Production Scenario B

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$57	$106	$147	$181	$212	$179
$100	$47	$87	$120	$148	$173	$146
$90	$42	$77	$107	$132	$154	$130

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day and declining at a rate of 15% per year. Development costs for each well assumed to be $20 million.

Additional Production Scenario C

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$111	$213	$307	$433	$557	$533
$100	$91	$174	$251	$354	$455	$435
$90	$81	$155	$223	$314	$404	$386

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of $5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

Senate Bill 21
Oil and Gas Production Tax
SECTION ANALYSIS

Section 1: AS 29.60.850, relating to certain appropriations to the general fund is amended to allow the legislature to make appropriations based on taxes paid during the previous calendar year under the Alaska Net Income Tax Act, AS 43.20, to conform to the repeal of AS 43.55.011(g) in section 26 of the bill.

Section 2: AS 43.55.011(e), relating to the levy of the oil and gas production tax, is amended to eliminate the reference to AS 43.55.011(g), the monthly progressivity tax, which is repealed in section 26 of the bill. Beginning January 1, 2014, AS 43.55.011(e) would levy on producers of oil and gas produced each calendar year a flat rate tax of 25 percent of the production tax value of taxable oil and gas produced from each lease or property in the state. No change is made to current tax ceilings that apply to Cook Inlet oil and gas, gas produced outside the Cook Inlet basin and used in the state, and oil and gas produced from new fields outside the Cook Inlet basin and south of the North Slope.

Section 3: Amends AS 43.55.011(o), relating to gas used in the state, to clarify that the tax ceiling applicable to gas used in the state does not apply to gas subject to AS 43.55.011(p)(the seven year tax limitation of four percent of gross value at the point of production for oil and gas first produced commercially outside of the Cook Inlet basin and south of 68 degrees North latitude after December 31, 2012, and before January 1, 2022).

Section 4: Amends AS 43.55.020(a), monthly installment payments of estimated tax, to clarify payment provisions relating to the determination of tax due for oil and gas subject to AS 43.55.011(p) and makes other minor clarifying amendments.

Section 5: Amends AS 43.55.020(a), monthly installment payments of estimated tax, for oil and gas produced after January 1, 2014, to conform to the repeal of AS 43.55.011(g), and to amend the calculation of monthly payments based on North Slope oil and gas to conform with the gross revenue exclusion in new subsection (f), AS 43.55.160, in section 24 of the bill.

Section 6: AS 43.55.020(d), related to payment by a producer to a private royalty owner, is amended to refer to the tax levied by AS 43.55.011(e) instead of AS 43.55.011(e)–(g). This amendment does not change the substance or effect of AS 43.55.020(d) although to avoid confusion, the amendment is made effective the same date as the repeal of AS 43.55.011(g).

Section 7: Amends AS 43.55.023(a) to eliminate the current restrictions on use of a tax credit for qualified capital expenditures and allow the full amount of a tax credit to be applied in a single calendar year beginning January 1, 2013 for expenditures after December 31, 2012.

Section 8: Amends AS 43.55.023(a), effective immediately, to limit the 20 percent tax credit for qualified capital expenditures incurred north of 68 degrees North latitude (North Slope) to expenditures incurred before January 1, 2014. Tax credits under AS 43.55.023(a) based on expenditures to explore for, develop, or produce oil and gas deposits south of the North Slope are not affected.

Section 9: Amends AS 43.55.023(b) to provide that the 25 percent tax credit for a carried-forward annual loss based on expenditures incurred after December 31, 2013, to explore for, develop, or produce oil and gas deposits located on the North Slope are no longer redeemable for cash, nor are they transferable except as provided in new AS 43.55.023(t) in section 15 of the bill. Carried-forward annual loss tax credits based on expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located south of the North Slope are not affected.

Section 10: Amends AS 43.55.023(c) to conform with new amendments to AS 43.55.023 in section 15 of the bill, related to the new rules that will apply to the tax credit for carried-forward losses incurred for expenditures related to North Slope activities.

Section 11: Amends AS 43.55.023(d), issuance of transferable and redeemable tax credit certificates for qualified capital expenditures, to conform to the amendments to AS 43.55.023(a) in section 7 of the bill authorizing the Department of Revenue to issue one tax credit certificate for the full amount of a transferable tax credit.

Section 12: Amends AS 43.55.023(d), issuance of transferable and redeemable tax credit certificates for qualified capital expenditures, so that tax credits certificates based on lease expenditures incurred after December 31, 2013 to explore for, develop, or produce oil and gas deposits on the North Slope are no longer redeemable for cash; nor are the tax credits transferable except in limited circumstances. The reference to AS 43.55.023(i), the transitional expenditure credit, is deleted to conform to the repeal of AS 43.55.023(i) in section 26 of the bill. Tax credits based on lease expenditures to explore for, develop, or produce oil and gas deposits south of the North Slope are still transferable and redeemable for cash from the oil and gas tax credit fund.

Section 13: Amends AS 43.55.023(g), issuance of tax credit certificates, to conform to the repeal of AS 43.55.023(m) in section 25 of the bill.

Section 14: Amends AS 43.55.023(n), issuance of tax credit certificates, to conform to the repeal of AS 43.55.023(m) in section 25 of the bill.

Section 15: Amends AS 43.55.023 by adding new subsections (p)–(u), effective January 1, 2014 relating to tax credits for carried-forward annual losses based on adjusted lease expenditures incurred to explore for, develop, or produce oil or gas deposits located on the North Slope.

Subsection (p) limits application of a North Slope carried-forward loss credit to tax liability two or more calendar years after the expenditures on which the credit is based were incurred, but the credit may not be applied later than 10 years after the expenditures were incurred.

Subsection (q) establishes a "first earned, first used" rule by requiring that available North Slope carried-forward loss tax credits must be applied in order of the year the expenditures were incurred, with the earliest year first, against tax liability under AS 43.55.011(e).

Subsection (r) provides an annual 15 percent increase in the amount of a North Slope carried-forward loss tax credit subject to compliance with subsections (p), (q) and (s). An amount of a tax credit subject to this subsection begins to increase on January 1 of the second calendar year immediately following the year the expenditures on which the credit is based were incurred, unless that second calendar year is the year for which the credit is applied. The credit stops increasing on December 31 of the year preceding the year against which the credit is applied against the person's tax liability. The increase under this subsection has no value except as applied against a person's tax liability, and the credit expires if not used within the 10 year period in AS 43.55.023(p) of this section.

Subsection (s) provides that a tax credit will not increase under section (r) if the credit could have been applied to a producer's tax liability and provides the order in which credits must be applied and calculations for the determination of when a tax credit could be applied against a person's tax liability.

Subsection (t) provides that a North Slope carried-forward loss tax credit is not transferable except to another person that acquires an interest in the lease or property owned by the transferee at the time the lease expenditures on which the credit is based were incurred. A transferee's use of the credit is subject to the provisions of (u) of this section, and includes filing information on the transfer with the Department of Revenue. The transferee's use of the credit against its tax liability is subject to audit by the Department of Revenue to the same extent as a tax credit that has not been transferred.

Subsection (u) sets out limitations for use of a North Slope carried-forward loss tax credit where a tax credit is used by a producer to whom a tax credit has been transferred through acquisition of leases or properties, or by a producer that has acquired the person that holds the tax credit. The transferee or successor may use the amount of the tax credit specified in this subsection, but the amount of the credit that may be applied against the transferee's or successor's tax liability under AS 43.55.011(e) for a calendar year may not exceed 20 percent of the sum obtained by an equation based on the taxable gross value at the point of production from the lease or property in a calendar year multiplied by the percentage interest in the lease or property owned by the person that incurred the expenditures on which the tax credit is based.

Section 16: Amends AS 43.55.024(d) to extend for 6 years the time that a producer may take a tax credit under AS 43.55.024(c), the small producer credit. Qualifying producers would have until 2022 (instead of 2016) to take the nontransferable small producer tax credit. The extension also applies to producers that did not have commercial production in the state before April 1, 2006, but that first have commercial production before May 1, 2022. Those producers may take the tax credit for nine calendar years (the same period as in current law) after the start of commercial production.

Section 17: Amends AS 43.55.028(e) to conform to the repeal of AS 43.55.023(m) in section 25 of the bill.

Section 18: Amends AS 43.55.028(g) to conform to the repeal of AS 43.55.023(m) in section 25 of the bill.

Section 19: Amends AS 43.55.030(e) (1), annual statements of qualified capital expenditures, to clarify current practice that both explorers and producers must file statements reporting qualified capital expenditures and other information required under AS 43.55.030(e).

Section 20: Amends AS 43.55.030 by adding new subsection (g) which requires an explorer or producer claiming a tax credit subject to AS 43.55.023(p)–(u) (section 15 of the bill) to file an annual statement with the Department of Revenue reporting the nature and amount of the expenditures on which the North Slope carried- forward loss credit is based, the amount the person intends to carry forward, any increase in the amount of the credit, and other information required by the Department of Revenue.

Section 21: Amends AS 43.55.160(a), calculation of annual production tax values, to clarify and conform to the provisions of AS 43.55.011(p).

Section 22: AS 43.55.160(a), calculation of annual production tax values, is repealed and reenacted to conform to the repeal of the monthly progressivity tax in section 26 of the bill. For oil and gas produced after January 1, 2014, a producer of oil and gas will no longer need to calculate monthly production tax values for oil and for purposes of AS 43.55.011(g), the progressivity tax. Other clarifying amendments are made setting out the categories for which a separate annual production tax value must be calculated, but the method of calculating annual production tax value is not affected.

Section 23: Amends AS 43.55.160(e) to conform to the amendments in section 22 of the bill.

Section 24: Amends AS 43.55.160 by adding new subsection (f) which provides that in calculating the annual production tax value for oil and gas produced north of 68 degrees North latitude the gross value at the point of production of the oil or gas meeting either or both of the following criteria is reduced by 20 percent if (1) produced from a lease or property that does not contain land that was within a unit on January 1, 2003; (2) produced from a participating area established after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before January 1, 2012. The gross value at the point of production is not reduced if it is zero or less before any reduction.

Section 25: Repeals AS 43.55.023(m) relating to tax credit certificates.

Section 26: Repeals AS 43.55.011(g), 43.55.023(i) and 43.55.160(c).

Section 27: Applicability sections.

Section 28: Retroactivity provisions for sections 3, 7, 11, 13, 14, 17, 21 and 25.

Section 29: Transition provision providing the Department of Revenue authority to adopt regulations, to be effective not before the date of the effective date of the provisions of this bill.

Section 30: Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22-24, and 26 take effect January 1, 2014.

Section 31: Except as provided in section 30, the remaining sections of the bill will take effect immediately under AS 01.10.070(c).

THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

Department of Revenue

COMMISSIONER'S OFFICE
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February 7, 2013

The Honorable Berta Gardner
Alaska State Senator
State Capitol, Room 417
Juneau, AK 99801-1182

Dear Senator Gardner:

I am writing in response to your February 1, 2013 letter with questions that arose during the Econ One Research presentation. I have worked with Mr. Pulliam and our economic research staff to answer your questions below. Please see questions in italics and our responses immediately below the questions.

1. *In recent years in Alaska there has been discussion about the majors being in "harvest mode." Is there any reason to believe that this characterization is incorrect?*

   Alaska's majors (defined here as CP, EM and BP) continue to develop their properties, which have billions of additional recoverable barrels in reserves. In addition, they are expanding (in the case of Conoco at CD-5 and Exxon and BP at Pt. Thompson) and have attempted to develop new fields (e.g., Liberty for BP) but have met with technical challenges. In addition, they have invested in recent years in updating older facilities in aging fields, facilities that will enable these fields to produce for many years to come. These activities are not consistent with companies that are in "harvest mode."

2. *Slide 26: Producer spending (in red) between 2007 and 2012 is roughly level while "all other" spending (in green) is doubled over the same period. We don't really know if producers were doing new work or maintenance work, but does the green portion indicate that ACES was successful in bringing new participants to Alaska?*

   Capital spending by large producers (red) grew by approximately $250 million between 2007 and 2012. At the same time, capital spending by all others (green) grew by approximately $320 million. The growth in "all others" over this period overlaps with the development of Oooguruk and Nikaitchuq by Pioneer Natural Resources and ENI, though the (green) spending in Chart 26 encompasses additional companies.

   Pioneer Natural Resources is the operator at Oooguruk and has a 70% working interest, which it acquired in 2002 during the ELF period. ENI holds the remaining 30%, which it acquired through the purchase of the Alaskan assets of Armstrong Oil & Gas in August 2005, also during the ELF period. The project was sanctioned in January 2006.

   ENI is the operator of Nikaitchuq. ENI acquired a 30% interest in Nikaitchuq with the purchase of the Alaskan assets of Armstrong Oil & Gas in August 2005. ENI acquired the remaining 70% interest in the Unit from Anadarko in March 2007. Anadarko in turn acquired its interest from Kerr-McGee.

KMG/Armstrong, ENI's predecessor in interest at Nikaitchuq, began drilling exploration and appraisal wells in the 2003-2004 season and drilled six wells prior to 2006. ENI sanctioned development of Nikaitchuq in February 2008 after receiving royalty relief approval from DNR in the second half of 2007.

ENI also owned interests in the North Tarn field (Mustang), which it acquired from Armstrong in August 2005. ENI farmed out its interests in these properties in 2010 to Brooks Range and a group of independents. Brooks Range and its partners are actively trying to advance Mustang and other projects as well.

With these background facts in mind, I do not believe that the rise in spending by "all others" shown in Slide 26 indicates that ACES (or its provisions) brought new participants to Alaska.

3. *Slide 27: Does this slide show that spending for new units increased 2 ½ times under ACES?*

   Slide 27 shows that spending for units not in production as of 2003 (Oooguruk, Nikaitchuq, Pt. Thomson and others) increased from $426 million in 2007 to $1,091 million in 2012. 2012 spending was approximately 2.5 times the level of 2007 spending. This represents an increase of approximately 150% during the period in which ACES has been in effect.

4. *Slide 38: This is an area profile for Australia. Can you explain why both employment and capital spending increased dramatically during the period 2002-2011 but Drilling/Development dropped beginning in 2006?*

   This slide shows employment and capital spending growing through 2011, while drilling is declining from 2006 forward. I believe these inverse trends are likely the result of two factors. First, the employment data from Australia includes mining operations, not just petroleum operations. We do not have a separate breakout for petroleum employment in Australia. Second, much of the capital spending in Australia has been related to LNG development which will include significant spending on facilities rather than drilling.

5. *Slide 43: Employment is climbing as spending holds steady. Why is this?*

   Slide 43 shows a significant growth in Alaska employment beginning in 2006, flattening between 2008 and 2011 and increasing by approximately 5% in 2012 (see also slide 34). The purpose of this slide is to benchmark employment changes in Alaska against other areas. We do not have 2012 comparative data for regions other than the lower-48. The top right panel shows employment growth in the rest of the US rose by a greater amount than the 5% we enjoyed in Alaska in 2012.

   Chart 34 shows both Alaska spending (top right) and employment (bottom left) over time. The 5% employment growth between 2011 and 2012 is not matched by a similar increase in capital spending. I do not know the reason for this. I do note that we see the reverse happening between 2007 and 2008, with spending rising by a larger amount than employment. Finally, I'd note that I would not necessarily expect to see a match between capital spending and employment changes. Capital reflects spending on facilities and wells. A component of this will show up in Alaska employment, but some portion will not, as the spending (e.g., engineering, fabrication) may take place outside the state.

6. *Slide 45: Attractiveness of Investments: We talked a bit about the role of various factors such as prospectivity, stability, Internal Rates of Return. What other factors might be considered?*

   This slide begins the section on investment analysis. Slide 48 lists the measures or "metrics" we examined in our analysis. I believe these are the significant financial measures that companies consider when making investment decisions. In addition to the measures listed in Slide 48, companies will consider prospectivity, political and fiscal stability, contractual obligations, permitting and access, and environmental and regulatory issues. Companies will also consider whether the project and/or area fits with their overall corporate strategy and operations and their ability of management to adequately focus on the project and/or area. All of these issues matter, though they are not all readily quantifiable. This is why we focused our comparisons on the US, Canada, North Sea and Australia as they share many of the same "non-quantifiable" qualities and are areas in which many of the North Slope producers are active.

7. *Slide 47-52: ACES incumbents have very high IRR. Is it fair to say that this means it is almost impossible to NOT make money under the status quo? If so, why are projects being delayed?*

   The higher IRRs for ACES incumbents result entirely from the "buy-down" effect. Additional investment under ACES allows an incumbent to "buy-down" its tax rate on existing production. Under the ACES system a producer can earn those higher IRRs, but only if it reinvests in Alaska to buy down its tax rate. It cannot earn those returns if it chooses to distribute its profits to shareholders, which is vitally important to management, not to mention shareholders. In this sense, the profits (and associated higher IRRs) are somewhat "captive" and may not be viewed as being of same quality (i.e., comparable) to profits earned in other jurisdictions where no such strings are attached.

   I believe that this is one reason why projects "are delayed" or not started at all, even though the IRRs are so high. Higher IRRs are a good thing, ceteris peribus (meaning all else equal). The challenge here is that all else is not equal, as discussed above.

   Another reason is that IRR does not tell the whole story. IRR is just one measure that investors look at. IRR is an investment decision tool, but should not be used to compare mutually exclusive projects, only to decide whether a single project is worth investing in. Moreover, IRRs are not appropriate for comparing projects with different risk characteristics.

   It is also important to note that IRR assumes reinvestment of interim cash flows in projects with equal rates of return (the reinvestment can be the same project or a different project). Therefore, IRR overstates the annual equivalent rate of return for a project whose interim cash flows are reinvested at a rate lower than the calculated IRR. This presents a problem, especially for high IRR projects, since there is frequently not another project available in the interim that can earn the same rate of return as the first project.

   When the calculated IRR is higher than the true reinvestment rate for interim cash flows, the measure will overestimate, sometimes very significantly, the annual equivalent return from the project. The formula assumes that the company has additional projects, with equally attractive prospects, in which to invest the interim cash flows. This is likely to be the case for the high IRRs indicated for Alaska incumbents.

In short, IRR is one factor, but should not be viewed in isolation. IRR calculations that vary greatly from most other opportunities should probably be taken with "a grain of salt."

8. *Can you show us these IRR slides with a line for SB21 for both incumbent and new participants?*

Charts 62-66 show the same analysis as Charts 49-53 and include SB21.

9. *Slide 47: You indicate development costs of $16/bbl in Eagle Ford and $19 in Bakken. We have heard that development costs were significantly higher than that. A recent study using data from the North Dakota Industrial Commission in July 2012 found that the breakeven price for the "average" well in the Bakken formation is $80-$90/barrel, with an average decline of 40% in the first year. Can you explain the difference between "development costs" and "break-even price"?*

Breakeven price refers to the price of oil in the market that is necessary for an investor to "breakeven" on its investment. Here breakeven would include recovering costs, including the cost of capital. Development costs (indicated at $19/bbl in Slide 47) are the investment that one hopes to break even on. So when the ND Commission says the breakeven price is $80-90/bbl it means that oil prices must be in this range for a producer to plus recover its development costs, including its cost of capital (i.e., a return on capital), operating costs, royalties and taxes.

10. *Slide 49: The cash margins are 2017-2022. This cells looks are cash during the 1st 5 years of production (under SB21 tax would be lower). What would it look like during development when both Incumbents and New Producers have lost the ACES credits and deductions?*

The bottom left box shows margins per-barrel of production. It is cash generation divided by production. It's not possible to look at this metric during development as there is no production (i.e., denominator) during that period. Charts 59 and 60 do show producer cash flows under ACES and SB21. The first 5 years shown in these charts are the period of development.

11. *Slide 50: NPV-12 for ACES Incumbent is higher than NPV-l2 for Bakken at prices below $120. Does this mean that using NPV as a measure tells us that under ACES, oil development on the North Slope is more profitable here than in North Dakota?*

Profit is an accounting concept while Net Present Value is an economic concept. A higher Net Present Value for a given project means that at the specified discount rate (in this case 12%) the project creates more value than a project with a lower Net Present Value. Slide 50 shows that the Net Present Value at a 12% discount rate creates more value to the ACES incumbent at prices below $120. As discussed above for slides 49-53 in the context of IRR, much of the higher NPV associated with the ACES incumbent is due to the tax buy-down on existing production. The ACES New Participant line shows a "break-even" NPV with the Bakken at about $100/bbl. The difference between these two reflects the impact of the buy-down for the incumbent.

The slide shows that ACES Incumbent has a higher NPV than Bakken until about $120/bbl, and a similar NPV to Eagle Ford at prices below $100/bbl. The New Participant has a higher NPV than Bakken until about $100/bbl, but a lower NPV than Eagle Ford at all price levels.

12. *Slide 52: NPV and IRR for ACES are higher than for Norway but reversed for Cash Margins for 2017-2022. What would this comparison look like if it included the years 2007-2017? And, what is the relative importance of NPV/IRR vs Cash Margins in decision-making?*

    The relationships seen in this chart should not change if one looked at 2007-2017 instead, with the potential exception of Canada, where fiscal terms did change during this period. The analysis is based on fiscal terms in place currently, which would apply going forward. NPV, IRR, and Cash Margins are all relevant metrics to producers. Which is more relevant is probably a good question for the producers. I do believe, however, that once a project's IRR is greater than the producer's hurdle rate, differences between IRRs across projects are likely to be viewed as less relevant for the reasons discussed above. I also expect that producers would view NPV as more relevant than IRR for purposes of comparison. Cash margins are important to producers, but they would not likely trump NPV on their own. Put another way, high cash margins, combined with negative NPV's would not lead to investment. PI is also relevant, and would be used to aide management rank projects where budgets or other constraints don't allow them to undertake everything at once, which is common.

13. *Slide 53: Same questions for Canada Oil Sands*

    See answer to question #12.

14. *Page 56: The Gross Revenue Exclusion is forever? Was there consideration of doing a 7 year exclusion as we did in the "middle earth" legislation last session?*

    Yes, consideration was given to a 7-year GRE as well as the life-of-recovery GRE proposed in SB21. Including the GRE for the life of recovery enhances the investment metrics relative to a 7-year GRE. It also encourages continuing investment and recovery from new fields and removes the potential that oil recovery may be "inefficiently" front loaded in a new project.

15. *Slide 57: Does the phrase "eliminates incentives for gold-plating" also mean "eliminates incentive to reinvest Alaskan profits in Alaska"?*

    The term "eliminates incentives for gold plating" refers to the fact that under ACES, the State effectively subsides the majority of capital spending for incumbent producers. As prices rise, that subsidy increases and can exceed 100% of the expenditure. This subsidy reduces a producer's incentive to efficiently manage costs. The term "gold plating" is a term of art that describes this situation.

    I don't think there is any way to read the phrase as also meaning "eliminates incentives to reinvest in Alaska." In my view SB21 will increase producer's incentives to invest in Alaska. Reducing the government's take on the producer's investment will leave the producer with a greater share of the profits from its investment. That greater share is what will enhance their incentive to reinvest (and continue to earn a greater share of the profits).

Along this line of reasoning, the State should not fear that producers will be encouraged to "take their profits elsewhere." If producers can keep a greater share of what they invest in Alaska, they will be encouraged to reinvest in Alaska, and less tempted to reinvest their profits elsewhere. The structure of SB21 enhances the producer's incentives to invest, and reinvest in Alaska relative to ACES.

16. *Slide 58: May we please see this chart extended to $200 oil?*

We have attached a revised Slide 58 showing prices up to $200/bbl as requested. In addition to the price extension, we have shown the figures for the 5-year period FY 2015 - 2019 rather than FY2014-18 as FY 2014 is a transition year.

17. *Slides 59 & 60: Under SB2l, the NPV of the governor's proposal is nearly identical for a new producer ($318m) as an existing producer ($319). It would seem that these numbers should not be quite so close, since the incumbent gets the value of their spending in years 1 as a 25% tax reduction, whereas the new producer must hold their Net Operating Loss credit for several years. Is it the 15% interest payment that makes up the difference?*

Yes, new producers who don't have a tax liability would not be able to deduct their losses during development under SB21. New producers can carry forward their losses, which are increased by 15% per year, and deduct them against their tax liability once production begins. The 15% increase helps to keep their NPV equivalent to that of the incumbent that has the ability to deduct the loss against current tax liabilities.

18. *How many taxpayers were filing for oil and gas credits on the North Slope for each of the years 2002-2012?*

On the following page is a table that shows the number of companies in each year that either (1) applied for tax credit certificates for credits earned under AS 43.55.023 or AS 43.55.025 on the North Slope, or (2) applied credits earned on the North Slope under AS 43.55.023, .024, or .025 against their tax liabilities in the specified years. This analysis captures the vast majority of companies on the North Slope earning tax credits applicable to the ACES production tax.

With respect to the analysis below, we note that the tax credit under AS 43.55.025 was implemented in 2003. Tax credits under AS 43.55.023 and .024 were implemented with PPT and subsequently expanded with ACES in 2006 and 2007, respectively. The expansion of credits available through PPT and ACES was a large contributing factor to the number of companies earning credits under these programs.

Number of taxpayers filing for oil and gas credits on the North Slope, CY 2002 - 2012	
Calendar Year	**Number of Companies**
2002	0
2003	0
2004	3
2005	1
2006	13
2007	20
2008	26
2009	33
2010	33
2011	30
2012*	36

*2012 totals subject to true-up filings due March 31, 2013
Above data reflects number of companies that either applied for tax credit certificates from activity on the North Slope or applied credits against their tax liability for oil and gas production on the North Slope
Includes credits under AS 43.55.023, .024, and .025.

19. *The comparisons used in the presentation rely on jurisdictions where much of the development is shale or gas. Can we please see some of the same comparisons using the locations worldwide where British Petroleum, ConocoPhillips and Exxon are producing and making new investments in conventional oil?*

Within OECD countries, these companies are making significant investments in conventional oil production in the North Sea, the U.S. Gulf and Offshore Eastern Canada. The analysis includes North Sea conventional production (both U.K. and Norway). We will look at adding comparisons with the U.S. Gulf and Eastern Canada offshore.

20. *Barry Pulliam testified that Alaska is viewed as unfriendly to business. Do you think that is an accurate view?*

Mr. Pulliam stated that Alaska is viewed as "a high tax, not always friendly place to do business." Mr. Pulliam did not say Alaska is "unfriendly to business." There would seem to be little doubt that Alaska is a "high tax" jurisdiction, particularly at current prices. Mr. Pulliam testified that Alaska has a very challenging physical environment on the North Slope, which is certainly not a "friendly" place to do business. He also mentioned the challenges associated with permitting new projects such as CD-5, a project that filed its first permits more than 5 years before receiving approval. He also stated that permitting practices by the State of Alaska itself were generally viewed positively by business. In addition, he mentioned the challenges associated with offshore development in the aftermath of the Gulf Horizon incident. In addition to these issues, producers are challenged by environmental lawsuits (e.g., Shell) that seek to delay or discourage development. These are all examples of how Alaska can be viewed as a place that is not always friendly to do business. DOR agrees with Mr. Pulliam's characterization.

21. *During his presentation of SB21 to the Legislature, Commissioner Butcher and Chair Micciche had a conversation about fairness being sharing profits of our oil with 1/3 to state, 1/3 to federal government and 1/3 to producers. Do you think a total government take of 2/3 is a reasonable goal?*

    The administration is seeking a balance of providing enough profit to entice producers to bring Alaska's resources to market and simultaneously maintaining as much of those benefits as possible for Alaskans in accordance with our constitution. Attempting to capture too great a percentage of those benefits results in leaving resources in the ground as producers seek out better opportunities. With this balance in mind, the administration believes that the total government take should not exceed 2/3 of the profits from oil production. However, given investment alternatives available in other areas, this should be viewed as an upper limit on government take rather than a goal.

22. *What about contractual obligations to develop? We saw with Point Thompson that the duty to develop is enforceable. What do you think about the obligations/duty to develop as a factor in development decision-making?*

    Contractual obligations certainly play a role in decision making. The primary lease term is really focused on prudent exploration and delineation. Upon unitization the State has a greater opportunity to leverage operators into development. While over the last decade unitization has been used as a tool to 'extend leases' this paradigm is fundamentally changing and development activities and obligations are becoming standard requirements in new unit approvals. The business decisions for 'explorers' is different than that of 'producers'. Successful exploration doesn't automatically result in development and production. If the economic environment isn't conducive to long term exposure of significant capital funds then developments aren't progressed. This is really a failed opportunity for the industry and the State.

23. *In terms of managing risk, are oil companies more concerned about risk at the low end or about high end?*

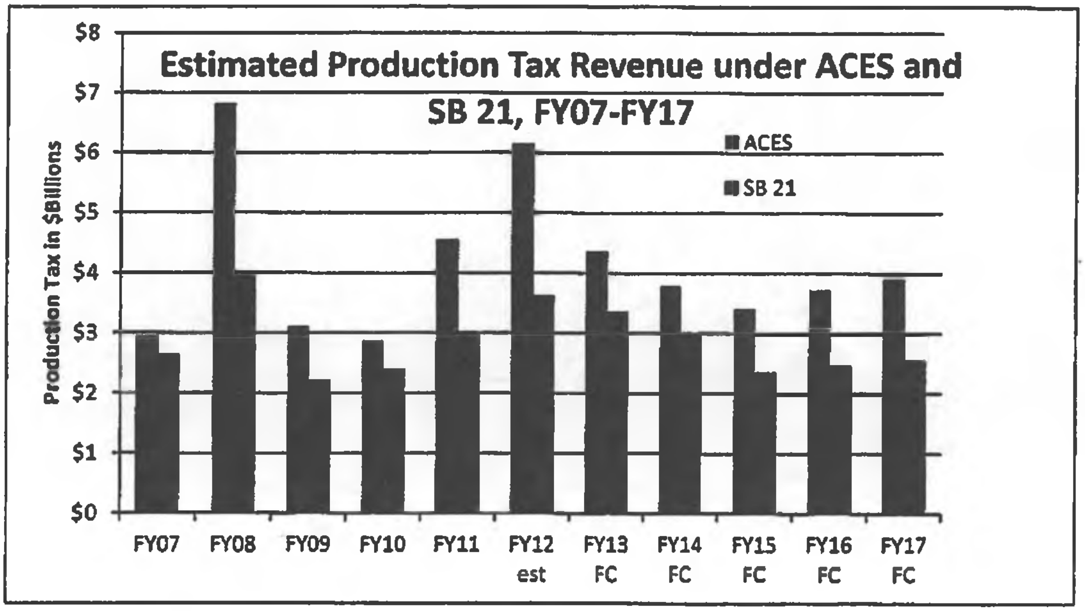
    "Risk" is uncertainty. Uncertainty makes projects more "risky." Producers plan around a set of expected prices, but those expected prices may not prove to be correct. They also examine their economics at lower than expected prices (downside risk) and higher than expected prices (upside risk). They are concerned with both. They don't want to be in a situation where downside risk will cause a project will lose money. And, they will be less willing to take on this downside risk if their exposure to upside risk is limited. High progressivity removes much of the upside risk that might otherwise compensate for downside risk.

24. *What do we know about their hurdle rates or reasonable profits?*

We do not know what a specific company's hurdle rate or view of a reasonable profit is. Mr. Pulliam used a 12% discount rate in his analysis, which is widely viewed as reflecting producer's cost of capital in OECD countries. A hurdle rate would not be below the cost of capital. As an economic matter, we would expect producers to view a "reasonable" profit as one that is at least as good as its alternatives. Assuming all factors equal, if a producer can invest all the funds it has available and earn a 20% rate of return for example, it would likely view other opportunities as providing a reasonable profit as long as they also provided this type of return.

25. *In the 1/17/13 presentation "North Slope Oil Production History & Forecast" page 3 shows a forecast for General Fund Unrestricted Revenues for the Years 2012-2017. Can we please see that forecast (and history) for the years 2007-2017 under ACES, HB110 and SB21?*

Below is a chart showing the estimated production tax revenue under ACES and under SB 21, FY 2007 through FY 2017. What is not shown in this chart is the estimated savings from the state's general fund under SB 21 for not having to refund certain credits. From FY 2007 through FY 2012, that amount was approximately $1.2 billion. From FY 2013 through FY 2017, another savings of approximately $1.2 billion would be anticipated under SB 21, for a total savings over the 10-year period of about $2.4 billion.



I hope that you find this information helpful. I look forward to working together in our continuing efforts through the remainder of this legislative session.

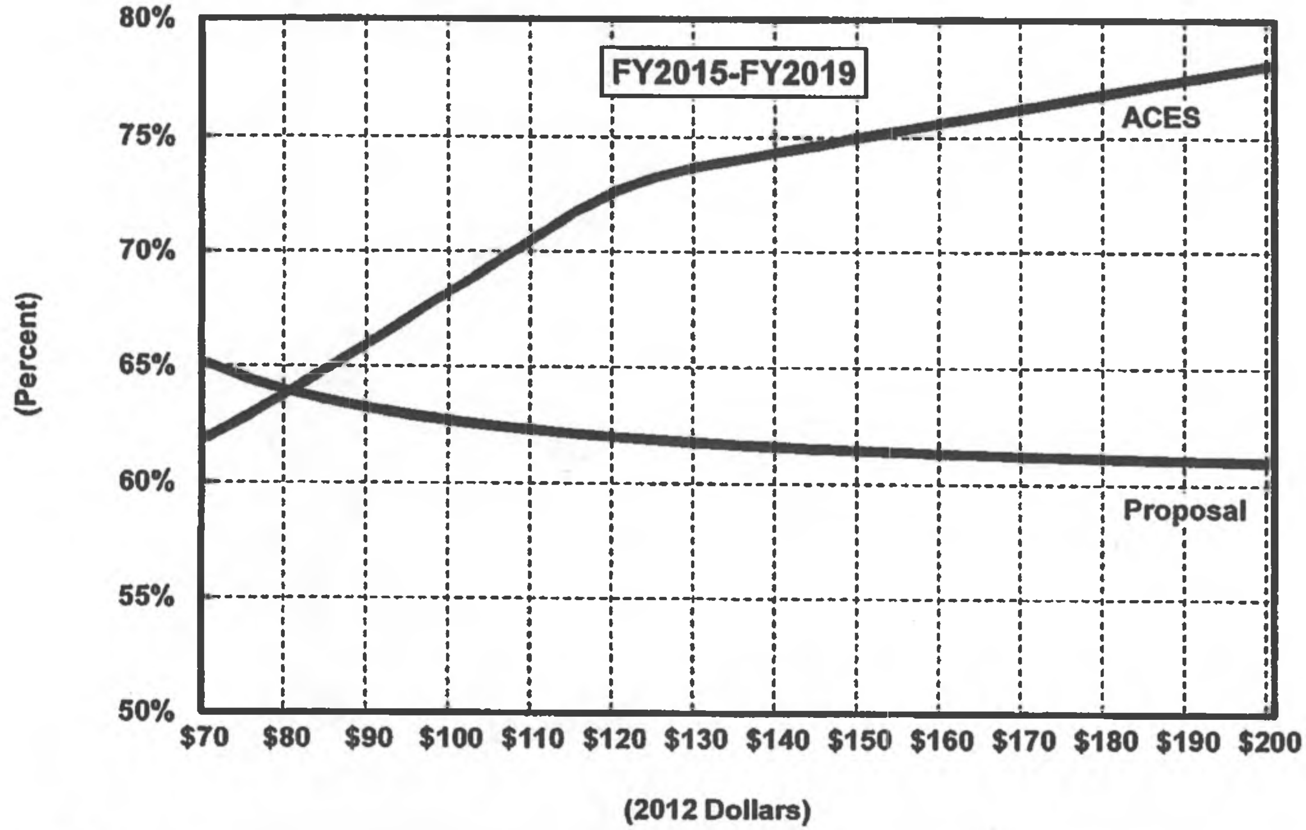
Sincerely,

Bruce Tangeman
Deputy Commissioner

Enclosure: revised slide #58

Key Aspects of Administration's Proposal (cont'd)

➢ **Average Government Take Moves From Progressive to Relatively Neutral Under Proposal**



LEGAL SERVICES

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MEMORANDUM February 22, 2013

SUBJECT: Draft CSSB 21( ) (Work Order No. 28-GS1647\U)

TO: Senator Cathy Giessel
Chair of the Senate Resources Committee
Attn: Margaret Dowling

FROM: Donald M. Bullock Jr.
and
Emily Nauman
Legislative Counsel

Enclosed is a draft of CSSB 21(RES). Please read this draft carefully to ensure that it is consistent with your intent.

I. Style Changes

This version includes style changes to conform to the *Manual of Legislative Drafting* and the style used in the Alaska Statutes. These are non-substantive changes.

II. Substantive Changes

Corporate Income Tax Credits

The bill adds a new corporation income tax credit in sec. 2. The new credit is 10 percent of a "qualified oil and gas service industry expenditure." The credit is provided for an expenditure directly attributable to manufacturing or modification of tangible personal property in the state used for the exploration, development, or production of oil or gas. The credit may be transferred, but must be used within seven years. The Department of Revenue has general authority to adopt regulations in AS 43.05.080 to implement this tax credit as well as for other laws administered by the department, therefore, your language adding this authority explicitly was omitted.

With regard to the new corporation income tax credit, we were not sure of the process for administering the credit. The draft assumes that the department will review the qualified expenditures and then issue a certificate that would be submitted when the credit is claimed by either the person qualifying for the credit or a transferee. Is this consistent with your intent? Please also consider how the seven-year period for using the credit should be described so far as identifying start and end dates, and whether the counted years should be calendar years or fiscal years. Not all income taxpayers file on a calendar-year basis.

Production Tax Rate & Per Barrel Credit

Major changes in this version include increasing the base production tax rate from 25 percent to 35 percent in AS 43.55.011(e) in sec. 3. The increase in tax is also reflected in an increase to carried-forward annual loss from 25 percent to 35 percent in AS 43.55.023(b) in sec. 9. A partial offset to the increase in tax is provided in AS 43.55.024(i) in sec. 18, which provides for a non-transferable credit of $5 for each barrel of taxable oil. An unused amount of per barrel credit may not be used in a later tax period. The per barrel credit was placed in AS 43.55.024 because that section provides for other nontransferable credits. The other credits in that section are provided to smaller producers and are sometimes referred to as the small producer tax credits.

AS 43.55.020(d) in sec. 7 of this version and in sec. 6 of SB 21 replaces AS 43.55.011(e) - (g) with AS 43.55.011(e). Although AS 43.55.011(g) is repealed in sec. 31 of this draft, AS 43.55.011(f) (minimum tax applicable to North Slope Production) is unchanged. Should the change in sec. 7 in this draft delete AS 43.55.011(e) - (g) and insert AS 43.55.011(e) and (f) in its place?

Carried-Forward Annual Loss

The language relating to the special rules for carried-forward annual loss applicable to the North Slope in AS 43.55.023(r) and (s) in sec. 15 has been clarified.

Alternative Credit for Exploration

The exploration incentive credit that had a well-spacing limitation in AS 43.55.025(c) of three miles is amended to remove the minimum distance limitation. You may want to discuss the effect with the Alaska Oil and Gas Conservation because of their responsibilities for well and reservoir management. Also, in AS 43.55.025(b), the period in which certain credits are available has been extended from 2016 to 2022.

Reduction in the Gross Value at the Point of Production

In sec. 28, sec. 43.55.160(f) has been changed by adding a third criterion for qualification, and increases the amount of reduction of the gross value at the point of production from 20 percent to 30 percent. The word "land" has been replaced with the phrase "a lease." We largely deferred to your language because we are not sure whether the focus is to provide a benefit to new participating areas or to new oil pools. The term "participating area" is not currently used in the Alaska statutes, and we modified the language from what you provided to simply state that it is an area determined by the Department of Natural Resources. Although the commissioner of natural resources has specific power with regard to units in AS 38.05.180(p), we could not find general authority for the director of lands or the commissioner to approve participating areas. Accordingly, the bill says they are whatever the department says they are.

Oil and Gas Competitiveness Review Board

The Oil and Gas Competitiveness Review Board is established in AS 43.98.040 - 43.98.070 in sec. 29. Provisions for the initial appointment and terms of the board members, as well as the first written findings and recommendations of the board, are in sec. 34. The board sunsets on December 31, 2022.

Please advise as to any changes you wish to make.

DMB:ELN:ljw
13-112.ljw

Enclosure

28-GS1647\U
Nauman/Bullock
2/22/13

CS FOR SENATE BILL NO. 21( )

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-EIGHTH LEGISLATURE - FIRST SESSION

BY

Offered:
Referred:

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

A BILL

FOR AN ACT ENTITLED

"An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; providing a tax credit against the corporation income tax for qualified oil and gas service industry expenditures; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax value including adjustments based on a percentage of gross value at the point of production from certain leases or properties; establishing the Oil and Gas Competitive Review Board; making conforming amendments; and providing for an effective date."

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

*** Section 1.** AS 29.60.850(b) is amended to read:

(b) Each fiscal year, the legislature may appropriate to the community revenue sharing fund [AN AMOUNT EQUAL TO 20 PERCENT OF THE] money received by the state during the previous calendar year under **<u>AS 43.20.030(c)</u>** [AS 43.55.011(g)]. The amount may not exceed

(1) $60,000,000; or

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

*** Sec. 2.** AS 43.20 is amended by adding a new section to read:

Sec. 43.20.049. Qualified oil and gas industry service expenditure credit. (a) For a tax year ending after the effective date of this section, a taxpayer is entitled to a credit against the tax due under this chapter in the amount of 10 percent of a qualified oil and gas service industry expenditure of the taxpayer incurred in the state. A taxpayer may not, in one tax year, apply more than $10,000,000 in tax credits received under this section. A tax credit under this section may not be used to reduce a tax liability under this chapter below zero.

(b) A tax credit under this section may be transferred to a taxpayer subject to tax under this chapter upon filing notice with the department in a format prescribed by the department. The department shall issue a certificate in the amount of the tax credit received under this section. Transfer of a credit does not limit the ability of the department to audit a tax credit claim and adjust the credit if the department determines, as a result of the audit, that the taxpayer that incurred the expenditure that is the basis of the credit was not entitled to the amount of the credit claimed. If, as a result of the audit, the department determines that the amount of the credit exceeds the proper amount, the department may, at the time the credit is used, increase by the amount determined to exceed the proper value of the credit the taxes calculated under this chapter for the taxpayer whose expenditure was the basis of the credit.

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

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

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

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

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

(f) In this section,

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

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

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

* **Sec. 3.** AS 43.55.011(e) is amended to read:

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

(1)] the annual production tax value of the taxable oil and gas as

calculated under **AS 43.55.160(a)** [AS 43.55.160(a)(1)] multiplied by **35** [25] percent [; AND

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

* **Sec. 4.** AS 43.55.011(o) is amended to read:

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

* **Sec. 5.** AS 43.55.020(a) is amended to read:

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

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

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

(i) zero; or

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

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

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

(i) zero;

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

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

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

(i) zero; or

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

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

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

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

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

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

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

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

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

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

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

* **Sec. 6.** AS 43.55.020(a), as amended by sec. 5 of this Act, is amended to read:

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

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

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

(i) zero; or

(ii) **35** [THE SUM OF 25] percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of

production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated;

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

(i) zero;

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

(iii) **35** [THE SUM OF 25] percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from those leases or properties during the month for which the installment payment is calculated**, except that, for the purposes of this calculation, the gross value at the point of production of oil and gas subject to AS 43.55.160(f) is reduced by 20 percent**;

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

(i) zero; or

(ii) **35** [THE SUM OF 25] percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible under AS 43.55.160 for the oil or gas, respectively, produced from the lease

or property from the gross value at the point of production of the oil or gas, respectively, produced from the lease or property during the month for which the installment payment is calculated;

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

(i) **35** [THE SUM OF 25] percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated, but not less than zero; or

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

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

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

(A) the applicable tax rate for oil provided under AS 43.55.011(i), multiplied by the gross value at the point of production of the

oil taxable under AS 43.55.011(i) and produced from the lease or property during the month; and

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

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

* **Sec. 7.** AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner for oil and gas that is taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. If the total deductions of installment payments of estimated tax for a calendar year exceed the actual tax for that calendar year, the producer shall, before April 1 of the following year, refund the excess to the royalty owner. Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under **AS 43.55.011(e)** [AS 43.55.011(e) - (g)] on taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or right to which constitutes a landowner's royalty interest, is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the calendar year multiplied by a figure that is a quotient, in which

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

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

* **Sec. 8.** AS 43.55.023(a) is amended to read:

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

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

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

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

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

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

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

(b) **Except as provided in (p) - (u) of this section for a tax credit based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude, a** [A] producer or explorer may elect to take a tax credit in the amount of **35** [25] percent of a carried-forward annual loss. A credit under this subsection may be applied against a tax levied by AS 43.55.011(e). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was not deductible in calculating production tax values for that calendar year under AS 43.55.160.

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

(c) A credit or portion of a credit under this section may not be used to reduce

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

*** Sec. 11.** AS 43.55.023(d) is amended to read:

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

*** Sec. 12.** AS 43.55.023(d), as amended by sec. 11 of this Act, is amended to read:

(d) Except **for a tax credit based on a lease expenditure incurred after**

December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude [AS LIMITED BY (i) OF THIS SECTION], a person that is entitled to take a tax credit under this section that wishes to transfer the unused credit to another person or obtain a cash payment under AS 43.55.028 may apply to the department for a transferable tax credit certificate. An application under this subsection must be in a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

* **Sec. 13.** AS 43.55.023(g) is amended to read:

(g) The issuance of a transferable tax credit certificate under (d) **of this section** or **former** (m) of this section or the purchase of a certificate under AS 43.55.028 does not limit the department's ability to later audit a tax credit claim to which the certificate relates or to adjust the claim if the department determines, as a result of the audit, that the applicant was not entitled to the amount of the credit for which the certificate was issued. The tax liability of the applicant under AS 43.55.011(e) and 43.55.017 - 43.55.180 is increased by the amount of the credit that exceeds that to which the applicant was entitled, or the applicant's available valid outstanding credits applicable against the tax levied by AS 43.55.011(e) are reduced by that amount. If the applicant's tax liability is increased under this subsection, the increase bears interest under AS 43.05.225 from the date the transferable tax credit certificate was issued. For purposes of this subsection, an applicant that is an explorer

is considered a producer subject to the tax levied by AS 43.55.011(e).

* **Sec. 14.** AS 43.55.023(n) is amended to read:

(n) For the purposes of (*l*) [AND (m)] of this section, a well lease expenditure incurred in the state south of 68 degrees North latitude is a lease expenditure that is

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

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

* **Sec. 15.** AS 43.55.023 is amended by adding new subsections to read:

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

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

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

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

which the person seeks to apply the credit to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude.

(r) Except as otherwise provided under (s) of this section, a tax credit or a portion of a tax credit subject to (p)(1) of this section that is carried forward in compliance with AS 43.55.030(g) increases at a rate of 15 percent, compounded annually, as provided in this subsection. A tax credit or a portion of a tax credit begins to increase under this subsection on January 1 of the second calendar year immediately following the calendar year during which the lease expenditure on which the credit is based was incurred, unless that second calendar year is the calendar year for which the credit or portion of a credit is applied against the person's tax liability. A tax credit or a portion of a tax credit stops increasing under this subsection on December 31 of the calendar year immediately preceding the calendar year in which the credit or a portion of the credit is applied against the person's tax liability. An increase in the amount of a tax credit under this subsection has no value except as applied against the person's tax liability within the time period described in (p)(2) of this section.

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

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

(2) if the remainder obtained under (1) of this subsection is greater than zero, subtract that remainder from the total amount of the person's tax credits under (b) of this section that are based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located

north of 68 degrees North latitude that was available, without regard to the limitation under (q) of this section, to be applied against the person's tax liability for the calendar year under AS 43.55.011(e), including any increase in the amount of the tax credits under (r) of this section through December 31 of the previous calendar year; if the remainder is less than zero, the portion of the tax credit is considered to be equal to zero for purposes of this paragraph;

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

(t) A tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude is not transferable except as provided in this subsection. A person that is entitled to take a tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude may transfer the tax credit to another person that acquires from the transferor an operating right, operating interest, or working interest in a lease or property in the state that includes land north of 68 degrees North latitude in which the transferor owned an operating right, operating interest, or working interest at the time the lease expenditure was incurred. A transferee may transfer the tax credit to another person that acquires from the transferee an operating right, operating interest, or working interest in that lease or property. A transferee's use of a tax credit is subject to the provisions of (u) of this section. A transfer is conditioned on the filing with the department by the transferor and transferee of notices or a joint notice in a form and manner prescribed by the

department and the providing of information and certifications required by the department by regulation. A transferee's application of a tax credit again the transferee's production tax liability is subject to audit by the department to the same extent as a tax credit that has not been transferred.

(u) The provisions of this subsection apply to a tax credit under (b) of this section based on a lease expenditure incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude when the tax credit is used by a producer to which the tax credit has been transferred under (t) of this section, by a producer or the successor of a producer that has acquired the person that incurred the lease expenditure on which the tax credit is based, or by a producer or the successor of a producer created by the merger of the person that incurred the lease expenditures on which the tax credit is based with another person. The total amount of a producer's tax credits subject to this subsection that may be applied against the producer's tax liability under AS 43.55.011(e) for a calendar year may not exceed 20 percent of the sum of the amounts calculated by applying the following formula for each lease or property in the state that includes land north of 68 degrees North latitude from which the producer produces oil or gas during the calendar year and in which the person that incurred the lease expenditure on which the tax credit is based had owned an operating right, operating interest, or working interest when the lease expenditure was incurred:

GV X OS

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

* **Sec. 16.** AS 43.55.024(d) is amended to read:

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

(1) **2022** [2016]; or

(2) if the producer did not have commercial oil or gas production from a lease or property in the state before April 1, 2006, the ninth calendar year after the calendar year during which the producer first has commercial oil or gas production before May 1, **2022** [2016], from at least one lease or property in the state.

* **Sec. 17.** AS 43.55.024(e) is amended to read:

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

* **Sec. 18.** AS 43.55.024 is amended by adding a new subsection to read:

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

* **Sec. 19.** AS 43.55.025(b) is amended to read:

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

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

(2) if for an exploration well,

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

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

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

section; and

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

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

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

* **Sec. 20.** AS 43.55.025(c) is amended to read:

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

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

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

(A) before the well is spudded,

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

(ii) at the time of the submittal of information under (i) of this subparagraph, the commissioner of natural resources may request from the explorer that specific data sets, ancillary data, and reports including all results, and copies of well data collected and data

analyses for the well be provided to the Department of Natural Resources upon completion of the drilling; in this sub-subparagraph, well data include all analyses conducted on physical material, and well logs collected from the well and sample analyses; testing geophysical and velocity data including vertical seismic profiles and check shot surveys; testing data and analyses; age data; geochemical analyses; and access to tangible material; and

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

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

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

* **Sec. 21.** AS 43.55.028(e) is amended to read:

(e) The department, on the written application of a person to whom a transferable tax credit certificate has been issued under AS 43.55.023(d) or **former**

AS 43.55.023(m) [(m)] or to whom a production tax credit certificate has been issued under AS 43.55.025(f), may use available money in the oil and gas tax credit fund to purchase, in whole or in part, the certificate if the department finds that

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

(2) the applicant does not have an outstanding liability to the state for unpaid delinquent taxes under this title;

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

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

(5) the purchase is consistent with this section and regulations adopted under this section.

* **Sec. 22.** AS 43.55.028(g) is amended to read:

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

* **Sec. 23.** AS 43.55.030(e) is amended to read:

(e) An explorer or producer that incurs a lease expenditure under AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar year but does not produce oil or gas from a lease or property in the state during the calendar year shall file with the department**,** on March 31 of the following year**,** a

statement, under oath, in a form prescribed by the department, giving, with other information required, the following:

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

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

* **Sec. 24.** AS 43.55.030 is amended by adding a new subsection to read:

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

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

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

(3) identification of the portion of the credit that was applied against the person's tax liability for the calendar year preceding the year for which the statement is due and of the amount of the credit that continues to be carried forward;

(4) other information required by the department.

* **Sec. 25.** AS 43.55.160(a) is amended to read:

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

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

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

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

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

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

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

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

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

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

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

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

(A) oil and gas produced during a month from leases or properties in the state that include land north of 68 degrees North latitude is the

gross value at the point of production of the oil and gas taxable under AS 43.55.011(e) and produced by the producer from those leases or properties, less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil and gas produced by the producer from those leases or properties, as adjusted under AS 43.55.170; this subparagraph does not apply to gas subject to AS 43.55.011(o);

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

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

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

(E) gas produced during a month from a lease or property outside the Cook Inlet sedimentary basin and used in the state is the gross value at the point of production of that gas taxable under AS 43.55.011(e) and produced by the producer from that lease or property, less 1/12 of the

producer's lease expenditures under AS 43.55.165 for the calendar year applicable to that gas produced by the producer from that lease or property, as adjusted under AS 43.55.170.

* **Sec. 26.** AS 43.55.160(a) is repealed and reenacted to read:

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

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

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

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

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

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

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

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

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

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

* **Sec. 27.** AS 43.55.160(e) is amended to read:

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

* **Sec. 28.** AS 43.55.160 is amended by adding a new subsection to read:

(f) In the calculation of an annual production tax value of a producer under (a)(1) of this section, the gross value at the point of production of oil or gas meeting one or more of the following criteria is reduced by 30 percent: (1) the oil or gas is produced from a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) the oil or gas is produced from a participating area established

after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before December 31, 2011; (3) the oil or gas is produced from an area that was not in a participating area before December 31, 2011, but was added to an existing participating area by the Department of Natural Resources after December 31, 2011, and the producer demonstrates to the department that the volume of oil and gas produced is from an area added to an existing participating area. A reduction in production tax value under this subsection may not reduce the production tax value of a producer below zero. In this subsection, "participating area" means a reservoir or portion of a reservoir contributing to production approved by the Department of Natural Resources.

* **Sec. 29.** AS 43.98 is amended by adding new sections to read:

Article 2. Oil and Gas Competitiveness Review Board.

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

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

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

(2) the chair of the Alaska Oil and Gas Conservation Commission;

(3) three members of the public appointed by the governor, including at least one member who is a petroleum engineer, one member who is a geologist, and one member who is an economist, each of whom has at least three years of experience in the member's field;

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

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

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

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

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

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

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

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

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

(i) The board shall meet at least four times each calendar year.

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

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

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

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

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

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

(6) in order to facilitate the work of the board, establish procedures to accept and keep confidential information that is beneficial to the work of the board, including the creation of a secure data room and confidentiality agreements to be signed by individuals having access to confidential information;

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

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

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

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

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

(b) At the request of the board, and except for information that is confidential under AS 40.25.100(a) or AS 43.05.230, a commissioner may disclose to the board information that is otherwise confidential after each member of the board and each staff member for the board with access to the information signs a confidentiality agreement prepared by the commissioner making the disclosure. Information that is confidential under AS 43.05.230 may not be disclosed to the board.

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

* **Sec. 30.** AS 43.55.023(m) is repealed.

* **Sec. 31.** AS 43.55.011(g), 43.55.023(i), and 43.55.160(c) are repealed January 1, 2014.

* **Sec. 32.** AS 43.98.040, 43.98.050, 43.98.060, and 43.98.070 are repealed December 31, 2022.

* **Sec. 33.** The uncodified law of the State of Alaska is amended by adding a new section to

read:

APPLICABILITY. (a) Sections 3, 6, 7, and 26 - 28 of this Act apply to oil and gas produced after December 31, 2013.

(b) Sections 4 and 25 of this Act apply to oil and gas produced after December 31, 2012.

(c) Sections 8, 11, 13, and 14 of this Act and AS 43.55.023(a)(1), as amended by sec. 8 of this Act, apply to expenditures incurred after December 31, 2012.

(d) Sections 9, 10, 12, 15, and 24 of this Act apply to expenditures incurred after December 31, 2013.

* **Sec. 34.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITION: OIL AND GAS COMPETITIVENESS REVIEW BOARD. The governor shall appoint the initial members of the Oil and Gas Competitive Review Board, established in sec. 29 of this Act, before January 1, 2014 or as soon thereafter as is practicable. The initial terms of the members of the board appointed under AS 43.98.040(b)(1) and (b)(3) shall be set by the governor and staggered so that one member serves one year, two members serve four years, and two members serve six years. The first written findings and recommendations, together with suggested legislation, shall be delivered to the Alaska State Legislature on December 1, 2015, or as soon thereafter as is practicable.

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

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

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

RETROACTIVITY. Sections 4, 11, 13, 14, 21, 25, and 30 of this Act and AS 43.55.023(a)(1), as amended by sec. 8 of this Act, are retroactive to January 1, 2013.

* **Sec. 37.** Sections 1, 3, 6, 7, 9, 10, 12, 15, 17, 18, 24, and 26 - 28 of this Act take effect January 1, 2014.

* **Sec. 38.** Except as provided in sec. 37 of this Act, this Act takes effect immediately under

AS 01.10.070(c).

Fiscal note: Tax Division 3-14-13 12:10pm – pg 4 of fiscal note

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CS FOR SENATE BILL NO. 21(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-EIGHTH LEGISLATURE - FIRST SESSION

BY THE SENATE FINANCE COMMITTEE

Offered:
Referred:

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

community rev. sharing same

A BILL

FOR AN ACT ENTITLED

"An Act relating to the interest rate applicable to certain amounts due for fees, taxes, and payments made and property delivered to the Department of Revenue; providing a tax credit against the corporation income tax for qualified oil and gas service industry expenditures; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; making conforming amendments; and providing for an effective date."

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

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

(c) A delinquent fee bears interest at the rate set by **<u>AS 43.05.225(2)</u>** [AS 43.05.225].

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

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

(1) $60,000,000; or

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

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

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

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

Sec. 43.05.225. Interest. Unless otherwise provided,

delinquent taxes

(1) when a tax levied in this title becomes delinquent, it bears interest in a calendar quarter at the rate of **<u>three</u>** [FIVE] percentage points above the annual rate charged member banks for advances by the 12th Federal Reserve District as of the first day of that calendar quarter [, OR AT THE ANNUAL RATE OF 11 PERCENT, WHICHEVER IS GREATER,] compounded quarterly as of the last day of that quarter;

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

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

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

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

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

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

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

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

Sec. 43.20.049. Qualified oil and gas industry service expenditure credit. (a) For a tax year beginning after the effective date of this section, a taxpayer may apply a credit against the tax due under this chapter for a qualified oil and gas service industry expenditure incurred in the state. The total amount of credit a taxpayer may receive in a tax year may not exceed the lesser of 10 percent of qualified oil and gas industry service expenditures incurred in the state during the tax year or $10,000,000.

no transfer
no stack
carry fwd
5 yrs
(not 10)

(b) A taxpayer may not apply more than $10,000,000 in tax credits under this section in a tax year. A tax credit or portion of a tax credit under this section may not be used to reduce the taxpayer's tax liability under this chapter below zero. Any unused tax credit or portion of a tax credit under this section may be applied in later tax years, except that any unused tax credit or portion of a tax credit may not be carried forward for more than five tax years immediately following the tax year in which the qualified oil and gas service industry expenditures were incurred.

(c) An expenditure that is the basis of the credit under this section may not be the basis for

(1) a deduction against the tax levied under this chapter;

(2) a credit or deduction under another provision of this title; or

(3) any federal credit claimed under this title.

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

(e) In this section,

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

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

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

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

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

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

(2) shall pay interest at the rate established under <u>**AS 43.05.225(1)**</u> [AS 43.05.225] from the date on which the amount became due until the date of payment.

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

(e) There is levied on the producer of oil or gas a tax for all oil and gas produced each calendar year from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation or constitutes a landowner's royalty interest. Except as otherwise provided under (f), (j), (k), (o), and (p) of this section, the tax is equal to **the annual production tax value of the taxable oil and gas as calculated under AS 43.55.160(a) produced during a calendar year** [THE SUM OF]

Gm

(1) **before January 1, 2017,** [THE ANNUAL PRODUCTION TAX VALUE OF THE TAXABLE OIL AND GAS AS CALCULATED UNDER AS 43.55.160(a)(1)] multiplied by **35** [25] percent; and

(2) **after December 31, 2016, multiplied by 33 percent** [THE SUM, OVER ALL MONTHS OF THE CALENDAR YEAR, OF THE TAX AMOUNTS DETERMINED UNDER (g) OF THIS SECTION].

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

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

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

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

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

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

(i) zero; or

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

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

(i) zero;

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

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

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

(i) zero; or

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) zero; or

(ii) **<u>the applicable tax rate in AS 43.55.011(e)</u>** [THE SUM OF 25 PERCENT AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g] multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated;

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

(i) zero;

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

(iii) **<u>the applicable tax rate in AS 43.55.011(e)</u>** [THE SUM OF 25 PERCENT AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)] multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for **<u>the</u>** oil and gas under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from those leases or properties during the month for which the installment payment is calculated**<u>, except that, for the purposes of this calculation, a 20 percent exclusion from the gross value at the point of production may apply for oil and gas subject to AS 43.55.160(f)</u>**;

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

(i) zero; or

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

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

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

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

(2) an amount calculated under (1)(C) of this subsection for oil or gas subject to AS 43.55.011(j), (k), or (o) may not exceed the product obtained by carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the

amount of taxable gas produced during the month for the amount of taxable gas produced during the calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the amount of taxable oil produced during the month for the amount of taxable oil produced during the calendar year;

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

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

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

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

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

(d) In making settlement with the royalty owner for oil and gas that is taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. If the total deductions of installment payments of estimated tax for a calendar year exceed the actual tax for that calendar year, the producer shall, before April 1 of the following year, refund the excess to the royalty owner. Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under <u>**AS 43.55.011(e)**</u> [AS 43.55.011(e) - (g)] on taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or right to which constitutes a landowner's royalty interest, is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the calendar year multiplied by a figure that is a quotient, in which

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

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

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

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

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

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

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

(2) a producer or explorer may take a credit for a qualified capital

expenditure incurred in connection with geological or geophysical exploration or in connection with an exploration well only if the producer or explorer

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

(B) submits to the Department of Natural Resources all data that would be required to be submitted under AS 43.55.025(f)(2)<u>**;**</u>

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

* **Sec. 16.** AS 43.55.023(b) is amended to read:

(b) A producer or explorer may elect to take a tax credit in the amount of 25 percent of a carried-forward annual loss <u>**for lease expenditures incurred to explore for, develop, or produce oil or gas deposits located south of 68 degrees North latitude, and 35 percent of a carried-forward annual loss based on lease expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude**</u>. A credit under this subsection may be applied against a tax levied by AS 43.55.011(e). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was not deductible in calculating production tax values for that calendar year under AS 43.55.160.

* **Sec. 17.** AS 43.55.023(b), as amended by sec. 16 of this Act, is amended to read:

(b) A producer or explorer may elect to take a tax credit in the amount of 25 percent of a carried-forward annual loss for lease expenditures incurred to explore for, develop, or produce oil or gas deposits located south of 68 degrees North latitude, and <u>**33**</u> [35] percent of a carried-forward annual loss based on lease expenditures incurred after December 31, <u>**2016**</u> [2013], to explore for, develop, or produce oil or gas deposits located north of 68 degrees North latitude. A credit under this subsection may be applied against a tax levied by AS 43.55.011(e). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was not deductible in calculating production tax values for that calendar year under AS 43.55.160.

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

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

* **Sec. 19.** AS 43.55.023(d), as amended by sec. 18 of this Act, is amended to read:

(d) **A** [EXCEPT AS LIMITED BY (i) OF THIS SECTION, A] person that is entitled to take a tax credit under this section that wishes to transfer the unused credit to another person or obtain a cash payment under AS 43.55.028 may apply to the department for a transferable tax credit certificate. An application under this subsection must be in a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

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

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

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

(n) For the purposes of (*l*) [AND (m)] of this section, a well lease expenditure incurred in the state south of 68 degrees North latitude is a lease expenditure that is

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

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

* **Sec. 22.** AS 43.55.024(e) is amended to read:

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

* **Sec. 23.** AS 43.55.024 is amended by adding a new subsection to read:

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

* **Sec. 24.** AS 43.55.028(e) is amended to read:

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

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

(2) the applicant does not have an outstanding liability to the state for unpaid delinquent taxes under this title;

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

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

(5) the purchase is consistent with this section and regulations adopted under this section.

* **Sec. 25.** AS 43.55.028(g) is amended to read:

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

* **Sec. 26.** AS 43.55.030(e) is amended to read:

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

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

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

* **Sec. 27.** AS 43.55.160(a) is amended to read:

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

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

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

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

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

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

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

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

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

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

(G) oil and gas produced from **leases or properties in the state** [A LEASE OR PROPERTY] no part of which is north of 68 degrees North latitude, other than oil or gas described in (B), (C), (D), (E), or (F) of this paragraph;

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

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

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

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

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

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

* **Sec. 28.** AS 43.55.160(a) is repealed and reenacted to read:

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

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

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

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

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

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

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

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

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

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

* **Sec. 29.** AS 43.55.160(e) is amended to read:

(e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that would otherwise be deductible by a producer in a calendar year but whose deduction would cause an annual production tax value calculated under <u>**(a)**</u> [(a)(1)] of this section of taxable oil or gas produced during the calendar year to be less than zero may be used to establish a carried-forward annual loss under AS 43.55.023(b). However, the department shall provide by regulation a method to ensure that, for a period for which a producer's tax liability is limited by AS 43.55.011(j), (k), (o), or (p), any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that would otherwise be deductible by a producer for that period but whose deduction would cause a production tax value calculated under <u>**(a)(3), (4), (5), or (6)**</u> [(a)(1)(C), (D), (E), OR (F)] of this section to be less than zero are accounted for as though the adjusted lease expenditures had first been used as deductions in calculating the production tax values of oil or gas subject to any of the limitations under AS 43.55.011(j), (k), (o), or (p) that have positive production tax values so as to reduce the tax liability calculated without regard to the limitation to the maximum amount provided for under the applicable provision of AS 43.55.011(j), (k), (o), or (p).

Only the amount of those adjusted lease expenditures remaining after the accounting provided for under this subsection may be used to establish a carried-forward annual loss under AS 43.55.023(b). In this subsection, "producer" includes "explorer."

* **Sec. 30.** AS 43.55.160 is amended by adding a new subsection to read:

(f) In the calculation of an annual production tax value of a producer under (a)(1) of this section, the gross value at the point of production of oil or gas meeting one or more of the following criteria is reduced by 20 percent: (1) the oil or gas is produced from a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) the oil or gas is produced from a participating area established after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before December 31, 2011; (3) the oil or gas is produced from a well that has been accurately metered and measured by the operator to the satisfaction of the commissioner, and the producer demonstrates to the department that the metered well drains a reservoir or portion of a reservoir that the Department of Natural Resources has certified was not contributing to production before January 1, 2013, and the producer demonstrates to the department that the volume of oil or gas produced from the well was subject to certification by the Department of Natural Resources. An exclusion under this section may not reduce the gross value at the point of production below zero. In this subsection, "participating area" means a reservoir or portion of a reservoir producing or contributing to production as approved by the Department of Natural Resources.

* **Sec. 31.** AS 43.56.160 is amended to read:

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

* **Sec. 32.** AS 43.77.020(d) is amended to read:

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

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

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

* **Sec. 33.** AS 43.90.430 is amended to read:

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

* **Sec. 34.** AS 43.55.023(m) is repealed.

* **Sec. 35.** AS 43.55.011(g), 43.55.023(i), and 43.55.160(c) are repealed January 1, 2014.

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

APPLICABILITY. (a) Sections 9, 12, 13, and 28 - 30 of this Act apply to oil and gas produced after December 31, 2013.

(b) Sections 10 and 27 of this Act apply to oil and gas produced after December 31, 2012.

(c) Sections 15 and 18 - 21 of this Act and AS 43.55.023(a)(1), as amended by sec. 15 of this Act, apply to expenditures incurred after December 31, 2012.

(d) Sections 16, 19, and 24 of this Act apply to expenditures incurred after December 31, 2013.

(e) Section 17 of this Act applies to expenditures incurred after December 31, 2016.

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

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

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

RETROACTIVITY. Sections 10, 18, 20, 21, 24, 27, and 34 of this Act and AS 43.55.023(a)(1), as amended by sec. 15 of this Act, are retroactive to January 1, 2013.

* **Sec. 39.** Sections 1 - 6, 8, 9, 12 - 14, 16, 19, 22, 23, 28 - 33, and 35 of this Act take effect January 1, 2014.

* **Sec. 40.** Section 17 of this Act takes effect January 1, 2017.

* **Sec. 41.** Except as provided in secs. 39 and 40 of this Act, this Act takes effect immediately under AS 01.10.070(c).

FISCAL NOTE

STATE OF ALASKA
2013 LEGISLATIVE SESSION

Bill Version	647
Fiscal Note Number	1
() Publish Date	

Identifier (file name)	0647-DOR-TAX-01-15-13	Dept. Affected	Revenue
Title	Production Tax on Oil and Gas	Appropriation	Treasury and Taxation
		Allocation	Tax Division
Sponsor	Rules by Request of the Governor		
Requester	Governor	OMB Component Number	2476

Expenditures/Revenues (Thousands of Dollars)

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

	FY14 Appropriation Requested	Included in Governor's FY14 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY14**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF							
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
	TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0

POSITIONS							
Full-time							
Part-time							
Temporary							

CHANGE IN REVENUES	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY13) operating costs ______ *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY14) costs ______ *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? yes

If yes, by what date are the regulations to be adopted, amended, or repealed? 1/1/2014 Discuss details in analysis section.

Why this fiscal note differs from previous version (if initial version, please note as such)

Initial version.

Prepared by	Cherie Nienhuis, Ed King and Michael Pawlowski	Phone	907-269-1019
Division	Tax Division	Date/Time	1/15/2013, 11:39 pm
Approved by	Bryan Butcher, Commissioner	Date	1/15/2013
	Department of Revenue		

(Revised 11/5/12 OMB)

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. 647

Analysis

This bill limits the provision that the State of Alaska purchase transferable tax credit certificates for credits earned from leases or properties that contain land that is north of 68 degrees North latitude to credits based on expenditures incurred before January 1, 2014. The operating portion of the long-term fiscal plan anticipates an average of $400 million in refundable credits through 2023. It is anticipated that the limitation of this provision would reduce those future appropriations, beginning in FY 2015.

Regulations: The bill does not direct DOR to adopt new regulations to implement its provisions, but existing regulations may need to be amended to conform to changes in eligibility for redeemable tax credits, and to account for repeal of some sections. There may be additional regulations required, but not before January 1, 2014.

*****The revenue impact of this bill is an estimate based on Fall 2012 Forecast.**
This bill makes several changes to the oil and gas production tax system. Each of the major changes, along with its potential revenue impact, is discussed separately below. The effective date of each of the bill's provisions listed below is January 1, 2014, with the exception of provision 6 (bill section 7), which is effective for expenditures beginning January 1, 2013.

1. The progressive portion of the production tax at AS 43.55.011(g) is repealed, and the production tax at AS 43.55.011(e) is retained at a tax rate of 25% of production tax value. Based on our Fall 2012 forecast, this change decreases production tax revenue over the forecast period analyzed. Please see detailed summary table on page 3 of this fiscal note.

2. Production tax credits under AS 43.55.023(a) for qualified capital expenditures are limited to expenditures incurred before January 1, 2014 on leases or properties that contain land north of 68 degrees North latitude. Based on our Fall 2012 forecast, this change increases production tax revenue annually over the forecast period analyzed. Please see detailed summary table on page 3 of this fiscal note.

3. Companies that incur net losses from leases or properties that contain land north of 68 degrees North latitude will earn a credit of 25% of those losses to be carried forward for a maximum period of ten years. These net loss carry-forwards will increase at an annual rate of 15 percent beginning on January 1 of the second calendar year following the year of the loss. The revenue impact of this provision is confidential under our forecast, however, the impact is expected to be minimal.

4. A gross revenue exclusion (GRE) is applicable to production from leases or properties containing land that is north of 68 degrees North latitude and meets one or both of two criteria: (1) is produced from a lease or property that does not contain land that was within a unit on January 1, 2003; or (2) is produced from a participating area established after December 31, 2011 for lease or properties in a unit formed before January 1, 2003. This provision is intended to incentivize future production and the revenue impact of this provision based on the current production forecast is minimal.

5. The small producer credit at AS 43.55.024 is extended to the later of 2022 or the ninth calendar year after the calendar year that the producer first has commercial production. This provision extends the small producer credit six years from the original sunset date of 2016. The revenue impact based on the current revenue forecast is minimal.

6. The provision requiring that credits be taken over two years is eliminated. This provision would result in companies using credits earlier than they would without this change, and except for the time value of money impact, it is revenue neutral. This provision applies to expenditures after December 31, 2012

7. The community revenue sharing fund is amended to allow the legislature to make appropriations from the tax revenue collected under AS 43.20, as opposed to revenue collected under AS 43.55.011(g). The impact of this provision is indeterminate.

Analysis Continued

Provisions in the Bill and their Estimated Fiscal Impact as compared to Fall 2012 Forecast ($millions)

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$800	-$1,500	-$1,700	-$1,800	-$1,750	-$1,650
2. Limitation of credits for qualified capital expenditures for North Slope	$300	$700	$650	$550	$475	$400
3. Net operating losses carried forward and increased at 15% per year	Less than -$50 million per year under Fall 2012 forecast					
4. Gross revenue exclusion for certain areas						
5. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
6. Provision requiring credits be taken over 2 year eliminated*	-$250					
7. Amendment to the community revenue sharing fund	Indeterminate					
Total Revenue Impact	-$750	-$800	-$1,050	-$1,275	-$1,300	-$1,300
Impact on Operating Budget	-$150	$250	$250	$250	$250	$250
Total Fiscal Impact	**-$900**	**-$550**	**-$800**	**-$1,025**	**-$1,050**	**-$1,050**

*Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $400 million, with $250 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

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

FISCAL NOTE ANALYSIS

STATE OF ALASKA — BILL NO. 647

2013 LEGISLATIVE SESSION

Analysis Continued

Differences in General Fund Unrestricted Revenue under Proposed Bill from Current Tax System in $Millions*

*Note: These hypothetical examples of additional production assess the impacts from the **change in tax rates and credits only** and do not attempt to quantify impacts of other parts of the bill, such as the removal of the credit split or the impact on the long-range budget.

At Forecasted Production

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$25	$275	$225	$75	$50	$0
$100	-$200	-$100	-$175	-$300	-$350	-$300
$120	-$900	-$1,350	-$1,425	-$1,525	-$1,475	-$1,350

All additional production scenarios below compare additional production under the proposed bill to ACES without the additional production.

Additional Production Scenario A

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

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$50	$375	$300	$175	$75	$75
$100	-$200	-$75	-$150	-$275	-$350	-$300
$120	-$900	-$1,375	-$1,400	-$1,500	-$1,475	-$1,375

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

Additional Production Scenario B

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$100	$550	$575	$525	$550	$475
$100	-$125	$125	$175	$150	$225	$150
$120	-$825	-$1,100	-$1,000	-$975	-$800	-$800

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day beginning in FY 2014, with a maximum production rate of 60,000 barrels per day for a total of 140 million barrels. Development costs for each well assumed to be $20 million.

Additional Production Scenario C

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$50	$525	$675	$800	$1,275	$1,200
$100	-$175	$150	$325	$500	$1,025	$975
$120	-$825	-$1,000	-$725	-$475	$225	$225

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of $5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

FISCAL NOTE

STATE OF ALASKA
2013 LEGISLATIVE SESSION

Bill Version	LL0647
Fiscal Note Number	
() Publish Date	

Identifier (file name)	LL0647-DNR-DOG-1-14-13	Dept. Affected	Natural Resources
Title	Production Tax on Oil and Gas	Appropriation	Oil & Gas
		Allocation	Oil & Gas
Sponsor	Rules by Request of the Governor		
Requester	Governor	OMB Component Number	439

Expenditures/Revenues (Thousands of Dollars)

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

	FY14 Appropriation Requested	Included in Governor's FY14 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY14**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF							
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		0.0	0.0	0.0	0.0	0.0	0.0	0.0

POSITIONS							
Full-time							
Part-time							
Temporary							

CHANGE IN REVENUES	***		***	***	***	***	***

Estimated SUPPLEMENTAL (FY13) operating costs ________ *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY14) costs ________ *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? No

If yes, by what date are the regulations to be adopted, amended, or repealed? N/A Discuss details in analysis section.

Why this fiscal note differs from previous version (if initial version, please note as such)

Initial Version.

Prepared by	Bill Barron, Director	Phone	269-8800
Division	Division of Oil and Gas	Date/Time	1/14/13 5:00 PM
Approved by	Daniel S. Sullivan, Commissioner	Date	1/14/2013
	Department of Natural Resources		

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. LL0647

Analysis

LL0647 reforms the oil and gas production tax system in Alaska. This bill will not result in any procedural changes in how the Division of Oil and Gas operates and therefore the Department of Natural Resources (DNR) does not anticipate any fiscal impact to the Department's operating budget.

This bill proposes to improve Alaska's competitiveness and encourage producers to invest more by simplifying the oil and gas production tax system. First, this bill repeals the progressive tax structure, which will help encourage the type of long-term planning and investment needed to promote new investment in new production in Alaska. Further, this bill shifts incentives away from spending and provides new incentives to reward new production. At forecasted price ranges, overall government take and marginal tax rates are reduced materially. To the extent that investments are made as a consequence of these changes to the tax regime, royalty revenue may rise.

The fiscal impact on royalty revenue is an indeterminate positive.

Analysis Continued

Differences in Royalty Revenues from New Production Scenarios in $Millions*

*Note: These scenarios are based on Department of Revenue modeling.

At Forecasted Production

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$ 120	$0	$0	$0	$0	$0	$0
$ 100	$0	$0	$0	$0	$0	$0
$ 90	$0	$0	$0	$0	$0	$0

Additional Production Scenario A

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

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$0	$0	$0	$12	$24	$35
$100	$0	$0	$0	$10	$20	$29
$90	$0	$0	$0	$9	$17	$26

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

Additional Production Scenario B

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$57	$106	$147	$181	$212	$179
$100	$47	$87	$120	$148	$173	$146
$90	$42	$77	$107	$132	$154	$130

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day and declining at a rate of 15% per year. Development costs for each well assumed to be $20 million.

Additional Production Scenario C

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$111	$213	$307	$433	$557	$533
$100	$91	$174	$251	$354	$455	$435
$90	$81	$155	$223	$314	$404	$386

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of $5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

Fiscal Note

State of Alaska
2013 Legislative Session

Bill Version: SB 21
Fiscal Note Number:
() Publish Date:

Identifier: SB021CS(RES)-DOR-COMM-02-26-13
Title: OIL AND GAS PRODUCTION TAX
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: Senate Resources

Department: Department of Revenue
Appropriation: Administration and Support
Allocation: Commissioner's Office
OMB Component Number: 123

Expenditures/Revenues

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

	FY2014 Appropriation Requested	Included in Governor's FY2014 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY 2014**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**	**FY 2019**
Personal Services		157.8	157.8	157.8	157.8	157.8	157.8
Travel	18.6		36.7	36.7	36.7	36.7	36.7
Services	835.0		835.0	835.0	835.0	835.0	835.0
Commodities	50.0		20.0	20.0	20.0	20.0	20.0
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	**903.6**	**157.8**	**1,049.5**	**1,049.5**	**1,049.5**	**1,049.5**	**1,049.5**

Fund Source (Operating Only)

1004 Gen Fund	903.6	157.8	1,049.5	1,049.5	1,049.5	1,049.5	1,049.5
Total	**903.6**	**157.8**	**1,049.5**	**1,049.5**	**1,049.5**	**1,049.5**	**1,049.5**

Positions

Full-time		1.0	1.0	1.0	1.0	1.0	1.0
Part-time							
Temporary							

Change in Revenues							

Estimated SUPPLEMENTAL (FY2013) cost: 0.0

Estimated CAPITAL (FY2014) cost: 0.0

ASSOCIATED REGULATIONS

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

Why this fiscal note differs from previous version:

Initial version. Committee substitute added language requiring an additional fiscal note from Revenue.

Prepared By: Jerry Burnett, Director — Phone: (907)465-2312
Division: Administrative Services — Date: 02/26/2013 09:15 AM
Approved By: Bryan D. Butcher, Commissioner — Date: 02/26/13
Department of Revenue

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. SB 21 CS (RES)

Analysis

The bill establishes a nine member Oil and Gas Competitiveness Review Board, in the Department of Revenue, which is charged with establishing and maintaining a salient collection of information related to oil and gas exploration, development, and production in the state and related to tax structures, rates, and credits in other regions with oil and gas resources; evaluating and suggesting changes to state laws and regulations reviewing historical, current, and potential levels of investment in the state's oil and gas sector; identifying factors that affect investment in oil and gas exploration, development, and production in the state, including tax structure, rates, and credits; royalty requirements; infrastructure; workforce availability; and regulatory requirements; reviewing the competitive position of the state to attract and maintain investment in the oil and gas sector in the state as compared to the competitive position of other regions with oil and gas resources. The Board is required to meet at least four times per year and to provide a report by December 1 of each year regarding means for increasing the state's ability to attract and maintain investment in and development of the state's oil and gas resources.

To accomplish these tasks the Department would use existing professional staff, primarily the Oil and Gas Program Coordinator currently in the Commissioner's Office, and funding to provide board meeting and travel, space and overhead costs associated with the data room and funding for professional services contracts.

The fiscal note assumes four board meetings per year, two in Anchorage, one each in Juneau and Fairbanks.

Professional service costs are estimated based on previous consulting contracts for oil and gas related issues that have been executed by the Department of Revenue.

Fiscal Note

State of Alaska
2013 Legislative Session

Bill Version: SB 21
Fiscal Note Number:
() Publish Date:

Identifier: SB021CS(RES)-DOR-TAX-02-26-13
Title: OIL AND GAS PRODUCTION TAX
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: Senate Resources

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

Expenditures/Revenues

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

	FY2014 Appropriation Requested	Included in Governor's FY2014 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY 2014**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**	**FY 2019**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None							
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY2013) cost: 0.0

Estimated CAPITAL (FY2014) cost: 0.0

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? yes
If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/14

Why this fiscal note differs from previous version:

Version N. Committee substitute made amendments to the previous version, the details of which require lengthy explanation.

Prepared By: Cherie Nienhuis, Ed King and Dan Stickel
Phone: (907)269-1019
Division: Tax Division
Date: 02/26/2013 08:00 AM
Approved By: Bryan D. Butcher, Commissioner
Department of Revenue
Date: 02/26/13

FISCAL NOTE ANALYSIS

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. SB 21 CS (RES)

Analysis

Operating expenditures: This bill limits the provision that the State of Alaska purchase transferable tax credit certificates for credits earned from leases or properties that contain land that is north of 68 degrees North latitude to credits based on expenditures incurred before January 1, 2014. The operating portion of the long-term fiscal plan anticipates an average of $400 million in refundable credits through 2023. It is anticipated that the limitation of this provision would reduce those future appropriations, beginning in FY 2015.

Regulations: The bill does not direct DOR to adopt new regulations to implement its provisions, but existing regulations may need to be amended to conform to changes in eligibility for redeemable tax credits, and to account for repeal of some sections. There may be additional regulations required, but not before January 1, 2014.

*****The revenue impact of this bill is an estimate based on Fall 2012 Forecast.**
This bill makes several changes to the oil and gas production tax system. Each of the major changes, along with its potential revenue impact, is discussed separately below. The effective date of each of the bill's provisions listed below is January 1, 2014, with the exception of provision 7, which is effective for expenditures beginning January 1, 2013.

1. The progressive portion of the production tax at AS 43.55.011(g) is repealed. Based on our Fall 2012 forecast, this change decreases production tax revenue over the forecast period analyzed. Please see detailed summary table on page 4 of this fiscal note.

2. The production tax rate under AS 43.55.011(e) has been increased to a tax rate of 35% of production tax value. Based on our Fall 2012 forecast, this change increases production tax revenue over the forecast period analyzed from this portion of the tax. Please see detailed summary table on page 4 of this fiscal note.

3. Production tax credits under AS 43.55.023(a) for qualified capital expenditures are limited to expenditures incurred before January 1, 2014 on leases or properties that contain land north of 68 degrees North latitude. Based on our Fall 2012 forecast, this change increases production tax revenue annually over the forecast period analyzed. Please see detailed summary table on page 4 of this fiscal note.

4. Companies that incur net losses from leases or properties that contain land north of 68 degrees North latitude will earn a credit of 35% of those losses to be carried forward for a maximum period of ten years. These net loss carry-forwards will increase at an annual rate of 15% beginning on January 1 of the second calendar year following the year of the loss. The revenue impact of this provision is confidential under our forecast, however, the impact is expected to be minimal.

5. A gross revenue exclusion (GRE) of 30% of the gross value at the point of production is applicable to production from certain areas. The GRE applies to production from leases or properties containing land that is north of 68 degrees North latitude and meets one or more of three criteria: (1) is produced from a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) is produced from a participating area established after December 31, 2011, in a unit formed before January 1, 2003, if the participating area does not contain a reservoir that had been in a participating area established before December 31, 2011; or (3) is produced from an area not in a participating area prior to December 31, 2011 and added to an existing participating area DNR after December 31, 2011. This provision is intended to incentivize future production and the revenue impact of this provision based on the current production forecast is indeterminate.

6. The small producer credit at AS 43.55.024 is extended to the later of 2022 or the ninth calendar year after the calendar year that the producer first has commercial production. This provision extends the small producer credit six years from the original sunset date of 2016. The revenue impact based on the current revenue forecast is minimal.

7. The provision requiring that credits be taken over two years is eliminated. This provision would result in companies using credits earlier than they would without this change, and except for the time value of money impact, it is revenue neutral. This provision applies to expenditures after December 31, 2012.

(Analysis continued on following pages)

Analysis Continued

8. The community revenue sharing fund is amended to allow the legislature to make appropriations from the tax revenue collected under AS 43.20, as opposed to revenue collected under AS 43.55.011(g). The impact of this provision is indeterminate.

9. An allowance of $5 per taxable barrel may be applied against a producer's production tax liability. The allowance is not transferable, cannot be carried forward, and cannot reduce the producer's tax liability to less than zero. Please see detailed summary table on page 4 of this fiscal note for the revenue impact of this provision.

10. A credit of 10% of qualified oil and gas industry service expenditures may be applied to tax liabilities under AS 43.20 in amounts up to $10 million per taxpayer per year. The credit applies to qualified oil and gas service expenditures that are for in-state manufacture or in-state modification of oil and gas tangible personal property with a service life of 3 years or more. Any amount of the credit that exceeds the taxpayer's liability under AS 43.20 may be carried forward for up to seven years or transferred. We have no data with which to quantify the revenue impact of this provision, although it is possible that the impact may range from -$50 million to -$100 million annually. The revenue impact of this provision is indeterminate.

11. An Oil and Gas Competitiveness Review Board is established in the Department of Revenue. The board will be tasked with collecting and evaluating data on oil and gas development and providing recommendations to the Legislature annually on proposed changes to the state's oil and gas fiscal regime.

12. The exploration incentive credit at AS 43.55.025(b) has been extended to 2022 and the requirements regarding proximity to other wells has been repealed. We have no data with which to quantify the revenue impact of this provision, although it is possible that the impact may range up to -$100 million annually. The revenue impact of this provision is indeterminate.

Analysis Continued

Provisions in CSSB21(RES) and their Estimated Fiscal Impact as compared to Fall 2012 Forecast ($millions)[1]

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$800	-$1,500	-$1,700	-$1,800	-$1,750	-$1,650
2. Base tax rate changed to 35% of production tax value	$550	$1,075	$1,100	$1,075	$1,025	$975
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$700	$650	$550	$475	$400
4. Net operating loss credit rate increased to 35%, carried forward and increased at 15% per year	Indeterminate up to -$50 million annually under Fall 2012 forecast					
5. Gross revenue exclusion for certain areas						
6. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
7. Provision requiring credits be taken over 2 year eliminated[2]	-$250	$0	$0	$0	$0	$0
8. Amendment to the community revenue sharing fund	Indeterminate					
9. Allowance of $5 per taxable barrel	-$425	-$825	-$775	-$750	-$700	-$675
10. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly -$50 million to -$100 million annually)					
11. Oil and Gas Competitiveness Review Board	$0	$0	$0	$0	$0	$0
12. Exploration incentive credit extended to 2022; requirements changed[3]	Indeterminate (possibly up to -$100 million annually)					
Total Revenue Impact	**-$650 to -$750**	**-$600 to -$800**	**-$775 to -$975**	**-$1000 to -$1200**	**-$1025 to -$1225**	**-$1050 to -$1250**
Impact on Operating Budget of Limitation of qualified capital expenditures for North Slope[4]	-$150	$250	$250	$250	$250	$250
Total Fiscal Impact[4]	**-$800 to -$900**	**-$350 to -$550**	**-$525 to -$725**	**-$750 to -$950**	**-$775 to -$975**	**-$800 to -$1000**

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

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

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

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

Analysis Continued

Differences in General Fund Unrestricted Revenue under Proposed Bill from Current Tax System in $Millions*

*Note: These hypothetical examples of additional production assess the impact from the **change in tax rates, capital and NOL credits, and per-barrel allowance only** and do not attempt to quantify impacts of other parts of the bill, such as the removal of the credit split, the impact on the long-range budget, changes to exploration credits, or the new service industry credit. **All estimates shown here are produced using a scenario model that may provide slightly different numbers than the full revenue model, although all numbers fall within reasonable bounds of acceptable error.**

At Forecasted Production

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$25	$275	$225	$125	$0	$0
$100	-$125	-$25	-$50	-$175	-$275	-$250
$120	-$675	-$975	-$1,025	-$1,125	-$1,150	-$1,075

All additional production scenarios below compare additional production under the proposed bill to ACES without the additional production.

Additional Production Scenario A

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

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$25	$275	$225	$125	$25	$25
$100	-$125	-$25	-$50	-$175	-$250	-$225
$120	-$675	-$975	-$1,025	-$1,100	-$1,125	-$1,050

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

Additional Production Scenario B

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$75	$450	$500	$475	$550	$475
$100	-$75	$200	$275	$275	$375	$300
$120	-$600	-$700	-$575	-$525	-$325	-$400

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day declining at 9% beginning in FY 2014, with a maximum production rate of 60,000 barrels per day for a total of 140 million barrels. Development costs for each well assumed to be $20 million.

Additional Production Scenario C

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$25	$350	$525	$700	$1,325	$1,225
$100	-$150	$150	$375	$575	$1,250	$1,175
$120	-$650	-$650	-$325	-$25	$825	$750

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of $5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

Fiscal Note

State of Alaska
2013 Legislative Session

Bill Version: SB 21
Fiscal Note Number:
() Publish Date:

Identifier: SB021CS(RES)-DNR-DOG-2-27-13
Title: OIL AND GAS PRODUCTION TAX
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: Senate Resources

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

Expenditures/Revenues

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

	FY2014 Appropriation Requested	Included in Governor's FY2014 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY 2014**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**	**FY 2019**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fund Source (Operating Only)

None							
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Positions

Full-time							
Part-time							
Temporary							

Change in Revenues	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY2013) cost: 0.0

Estimated CAPITAL (FY2014) cost: 0.0

ASSOCIATED REGULATIONS

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

Why this fiscal note differs from previous version:

A committee substitute was adopted by the Senate Resources Committee. Sections 19 and 20 were added that modify AS43.55.025 relating to the Exploration Incentive Credit.

Prepared By:	William C. Barron	Phone:	(907)269-8800
Division	Oil and Gas	Date:	02/27/2013 10:00 AM
Approved By:	Daniel S. Sullivan, Commissioner	Date:	02/27/13
	Department of Natural Resources		

FISCAL NOTE ANALYSIS

STATE OF ALASKA **BILL NO.** CSSB21(RES)
2013 LEGISLATIVE SESSION

Analysis

CSSB21(RES) reforms the oil and gas production tax system in Alaska. This bill will not result in any procedural changes in how the Division of Oil and Gas operates and therefore the Department of Natural Resources (DNR) does not anticipate any fiscal impact to the Department's operating budget.

CSSB21(RES) proposes to improve Alaska's competitiveness and encourage producers to invest more by simplifying the oil and gas production tax system. First, this bill repeals the progressive tax structure, which will help encourage the type of long-term planning and investment needed to promote new investment in new production in Alaska. Further, this bill attempts to shift incentives away from spending and provides new incentives to reward new production.

Section 19 of CSSB21(RES) extends the sunset date of the exploration incentive credit from 2016 to 2022. Section 20 eliminates the 3 mile exclusion zone around pre-existing wells and the Division of Oil and Gas would be responsible for assessing whether or not the wells drilled are in a separate trap. DNR anticipates that there will be more wells that would qualify for the 30 percent or 40 percent credit with the removal of this 3 mile zone.

At forecasted price ranges, overall government take and marginal tax rates are reduced materially. To the extent that investments are made as a consequence of these changes to the tax regime, royalty revenue may rise. The fiscal impact on royalty revenue is an indeterminate positive.

Analysis Continued

Differences in Royalty Revenues from New Production Scenarios in $Millions*

*Note: These scenarios are based on Department of Revenue modeling.

At Forecasted Production	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$ 120	$0	$0	$0	$0	$0	$0
$ 100	$0	$0	$0	$0	$0	$0
$ 90	$0	$0	$0	$0	$0	$0

Additional Production Scenario A

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

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$0	$0	$0	$12	$24	$35
$100	$0	$0	$0	$10	$20	$29
$90	$0	$0	$0	$9	$17	$26

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

Additional Production Scenario B

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$57	$106	$147	$181	$212	$179
$100	$47	$87	$120	$148	$173	$146
$90	$42	$77	$107	$132	$154	$130

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day and declining at a rate of 15% per year. Development costs for each well assumed to be $20 million.

Additional Production Scenario C

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$111	$213	$307	$433	$557	$533
$100	$91	$174	$251	$354	$455	$435
$90	$81	$155	$223	$314	$404	$386

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of $5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

ALASKA STATE LEGISLATURE

Sen. Cathy Giessel, Chair
Sen. Fred Dyson, Vice Chair
Sen. Lesil McGuire
Sen. Anna Fairclough
Sen. Click Bishop
Sen. Peter Micciche
Sen. Hollis French

State Capitol, Room 427
Juneau AK 99801-1182
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Senate Resources Committee

Butrovich Room 205
Monday, February 4, 2013
3:30-6:45 p.m.

AGENDA

- **Oil Resources: Economic Challenges & Opportunities**
  Bradford Keithley, Partner & Co-Head, Oil & Gas Practice, Perkins Coie LLP

- **SB 27 Regulation of Dredge and Fill Activities**

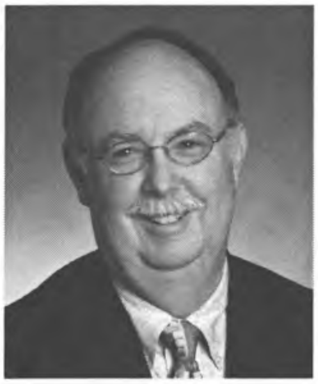
  5:15 p.m. Public Testimony: time limit may be set

- **SB 26 Land Disposals/Exchanges; Water Rights**

  5:45 p.m. DNR continued discussion and analysis

Teleconference

Perkins Coie LLP



Bradford (Brad) G. Keithley | Partner

Brad Keithley is a partner and co-head of the Oil & Gas practice at Perkins Coie. He is based in the firm's Anchorage and Washington, D.C. offices. Prior to joining Perkins Coie, Brad was a partner for 18 years with the global law firm of Jones Day, based primarily in the firm's Dallas and Houston offices, and before that was senior vice president and general counsel of Arkla Inc., at the time the third largest gas company in the United States (and now part of CenterPoint Energy Inc.). Brad started his career as an attorney advisor in the Office of the General Counsel to the Secretary of the Air Force, after which he joined and became a partner with Hall, Estill, Hardwick, Gable, Collingsworth & Nelson, in Tulsa, OK.

Throughout his career, Brad's practice has been concentrated in the areas of oil & gas regulation, commercial transactions and litigation. His clients have included major oil & gas companies, oil & gas pipelines, large and medium independents, as well as major consumers of natural gas. During the last ten years, Brad's practice has focused primarily on matters related to Alaska oil & gas, international and U.S. LNG issues, matters related to oil & gas exploration, and development and production on U.S. federal lands and waters. Brad is a past co-chair of the Institute of Energy Law's Annual Oil & Gas Law Conference and was a founding co-chair of the Institute's Annual Law of LNG Conference.

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EDUCATION

- University of Virginia School of Law, J.D., 1976 Notes Editor, *Journal of International Law*
- University of Tulsa, B.S., 1973

BAR ADMISSIONS

- Virginia
- District of Columbia
- Oklahoma
- Alaska

COURT ADMISSIONS

- U.S. Supreme Court
- U.S. Court of Appeals for the District of Columbia Circuit

PROFESSIONAL RECOGNITION

- Listed in Benchmark Litigation's *Guide to America's Leading Litigation Firms and Attorneys* as a Local Litigation Star in Commercial Litigation
- Ranked by *Chambers USA*, as "America's Leading Business Lawyers", 2004 - 2008, 2010
- Ranked by *Chambers USA*, as "America's Leading Environment & Natural Resources Lawyers", 2011 - 2012

PROFESSIONAL LEADERSHIP

- Center for American and International Law, Institute for Energy Law, Advisory Committee, 2000 - present; Oil & Gas Committee, 2002 - present
- Center for American and International Law, Institute for Energy Law, Annual Conference on the Law of LNG, Co-Chair, 2004 - 2005
- Center for American and International Law, Institute for Energy Law, Oil & Gas

Committee, Chair, 2003

- Center for American and International Law, Institute for Energy Law, Annual Oil & Gas Law Conference, Co-Chair, 2001 - 2002
- Rocky Mountain Mineral Law Foundation
- Energy Bar Association

COMMUNITY INVOLVEMENT

- University of Virginia School of Law Annual Giving Campaign, National Chair, 2010 - present
- Regional University System of Oklahoma, Ad Hoc Committee on System Development, 2005 - 2007

RELATED EMPLOYMENT

- Jones Day, Dallas and Houston, TX, Partner, 1990 - 2008
- Arkla Inc., Little Rock, AR and Shreveport, LA, Senior Vice President & General Counsel, 1987 - 1990; Vice President & General Counsel, 1984 - 1987
- Hall, Hardwick, Gable, Collingsworth & Nelson, Tulsa, OK, Partner, 1981 - 1984; Associate, 1978 - 1981
- Secretary of the Air Force, Office of the General Counsel, Attorney/Advisor, 1976 - 1978

PAST EVENTS

12.01.2011 - 12.02.2011	**Issues Relating to Developing Federal Lands and Waters in Alaska** Speaking Engagement Law Seminars International William A. Egan Civic & Convention Center / Anchorage, AK
12.06.2010 - 12.07.2010	**The Sixth Annual Comprehensive Conference on Energy in Alaska** Speaking Engagement Dena'ina Civic & Convention Center / Anchorage, AK
12.07.2009	**Meeting the Challenge of Extracting and Getting Alaska's Natural Resources to Market** Speaking Engagement William A. Egan Civic & Convention Center / Anchorage, AK

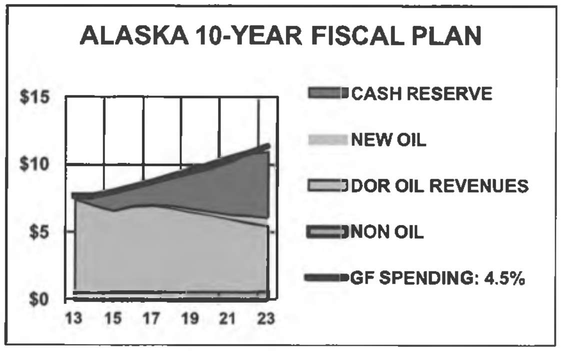
Maximum Sustainable Yield: FY 2014 Update

by Scott Goldsmith

Web Note No. 14 • January 2013

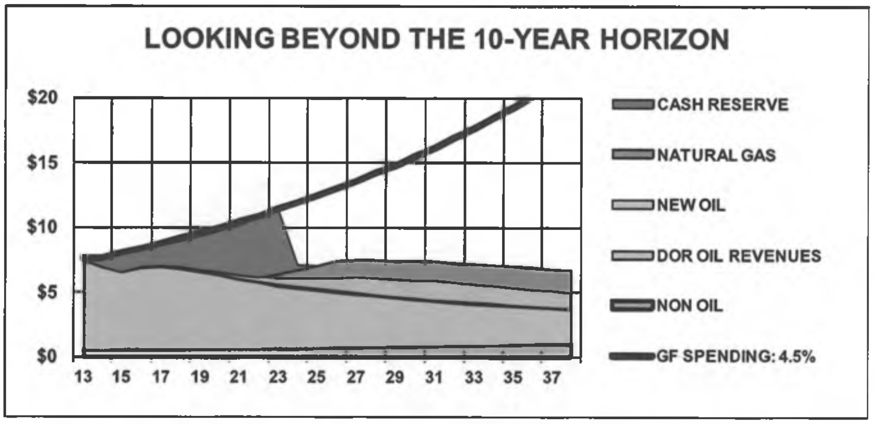
In fiscal year 2014, Alaska's state government can afford to spend about $5.5 billion. That's an estimate of the level of Unrestricted General Fund spending the state can sustain over the long run, based on the current petroleum nest egg of about $149 billion—a combination of state financial assets (the Permanent Fund and cash reserves) and the value of petroleum still in the ground.

The size of that nest egg fluctuates, depending on the state's forecast of petroleum revenues, earnings on investments, and other factors. This Web Note presents the latest in a series of estimates of the maximum amount the state can spend and still stay on a sustainable budget path.

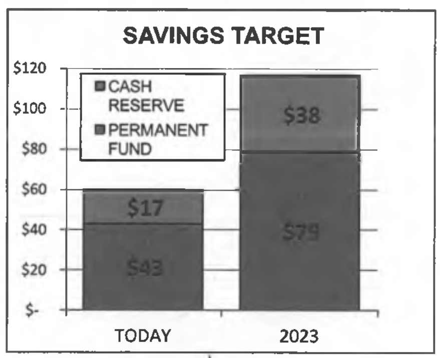


Right now, the state is on a path it can't sustain. Growing spending and falling revenues are creating a widening fiscal gap. In its 10-year fiscal plan, the state Office of Management and Budget (OMB) projects that spending the cash reserves might fill this gap until 2023, as the adjacent figure shows[i]. But what happens after 2023?

Reasonable assumptions about potential new revenue sources suggest we do not have enough cash in reserves to avoid a severe fiscal crunch soon after 2023, and with that fiscal crisis will come an economic crash. The figure on the right shows the growing General Fund fiscal gap—even assuming new revenues from natural gas production and more oil production—if spending increases at a rate of 4.5% annually.



What can the state do to avoid a major fiscal and economic crisis? The answer is to save more and restrict the rate of spending growth. All revenues above the sustainable spending level of $5.5 billion—including Permanent Fund income, except the share that funds the dividend—would be channeled into savings.

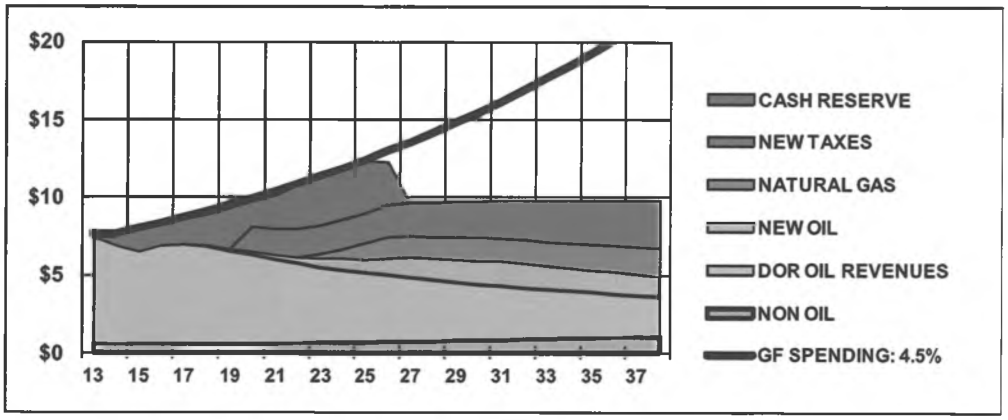


If Alaska had $117 billion in cash reserves and the Permanent Fund by 2023, the state would be on the path to sustainable spending far into the future. But as the adjacent figure shows, that's twice what the state has in financial assets today. So the state needs to sharply step up its savings rate, starting now.

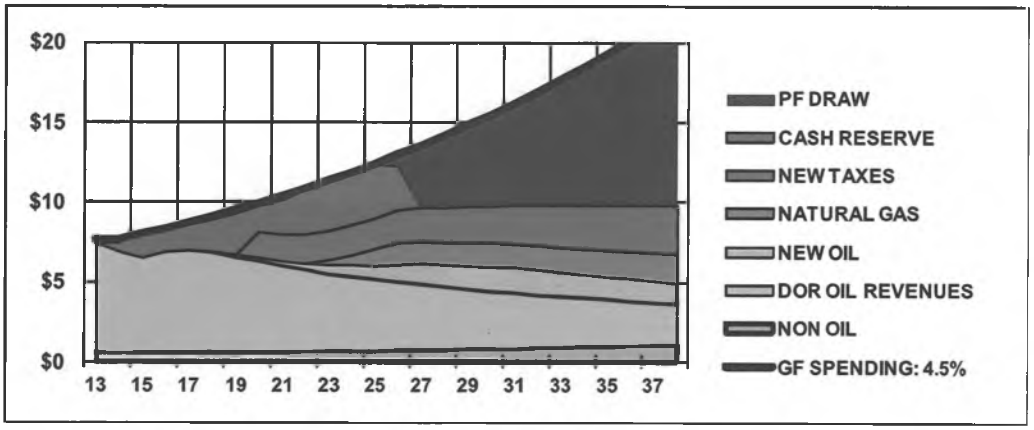
This research is part of ISER's *Investing for Alaska's Future* research initiative, funded by a grant from Northrim Bank.

Northrim Bank

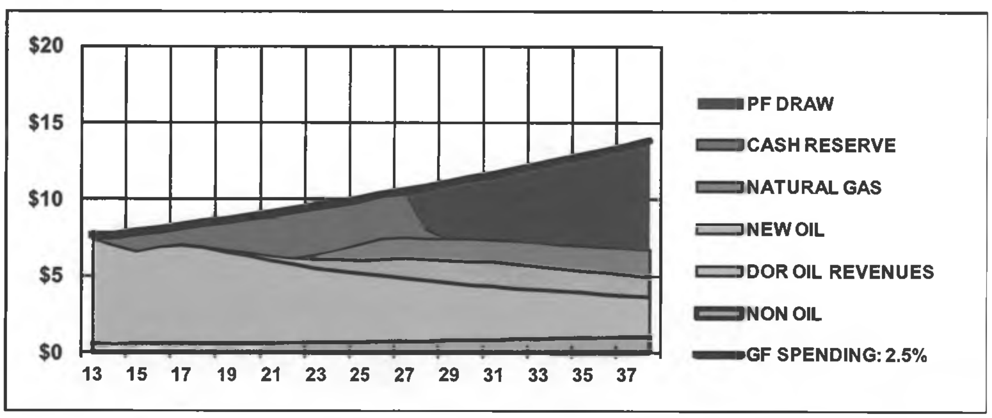
The graphs below show additional evidence of why the state needs to save more and restrict spending. New broad-based income and sales taxes (purple) would postpone but not eliminate the fiscal crunch.



Even using the entire Permanent Fund would not avoid the crunch, with the fund (brown) running out soon after 2038.



Alternatively, holding growth of the budget to the rate of inflation would reduce the size of the crunch when it arrived, but postpone it for only 5 years.[ii]



What is Maximum Sustainable Yield (MSY)?

Maximum sustainable yield is the amount the state can spend each year from its petroleum endowment, or nest egg, and still sustain the value of that nest egg for future generations. The nest egg is a combination of the state's financial assets and the estimated value of petroleum still in the ground. The amount the state can safely spend each year depends on the size of the nest egg, the return it can achieve through prudent management of that nest egg, and the time over which it will need the nest egg to sustain public spending.

The table below shows that if the petroleum nest egg has a value of $149 billion, if it can be managed to generate a 5% return (net of inflation), and if it is to increase over time to account for population growth, the maximum sustainable yield would be $5.95 billion.

MAXIMUM SUSTAINABLE YIELD CALCULATION FOR FY 2014

TOTAL NEST EGG (Billion)	**$148.7**
Financial Assets	$60
Petroleum in the Ground	$88.7
Rate of Earnings (net of inflation)	5%
Draw Rate (Earnings net population growth)	4%
MSY FY2014 (Billion)	**$5.95**

Currently, spending from the petroleum nest egg goes to the General Fund and the Permanent Fund dividend. Constrained to no more than the maximum sustainable yield of $5.95 billion, the split would be $4.99 billion to the General Fund and $.96 billion to the dividend (based on the current formula for determining dividends). Including the $.540 billion of non-petroleum revenues in the General Fund, the maximum sustainable yield for the General Fund would be $5.53 billion.

GENERAL FUND MAXIMUM SUSTAINABLE YIELD SPENDING FOR FY2014

1	**MSY FY2014 (Billion) (2+3)**	**$5.95**
2	PFD	$.96
3	GF	$4.99
4	Non petroleum revenues	$.54
5	**GENERAL FUND MSY FY2014 (Billion) (3+4)**	**$5.53**

The difference between the actual General Fund appropriation and the maximum sustainable yield is the "fiscal burden" passed to a future generation of Alaskans. It is the amount future generations will pay to cover current spending above the sustainable level. The "nest egg deficit" is amount the nest egg falls short of being able to support a sustainable spending path.

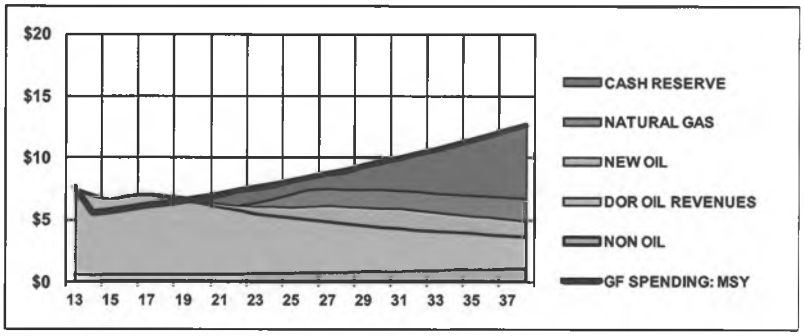
For example, as shown below, if FY 2014 General Fund spending were to be $7 billion, the fiscal burden on future generations would be $1.5 billion. Furthermore, it would take an additional $37.5 billion in the petroleum nest egg for that level of spending to be sustainable.

FISCAL BURDEN AND NEST EGG DEFICIT AT DIFFERENT GF SPENDING LEVELS

FY2014 GF Spending (Billion)	$6	$6.5	$7.0	$7.5	$8.0
Fiscal Burden (Billion)	$.5	$1.0	$1.5	$2.0	$2.5
Nest Egg Deficit (Billion)	$12.5	$25	$37.5	$50	$62.5
Fiscal Burden and Nest Egg Deficit assume future budget growth constrained to be the combined rate of inflation and population increase.					

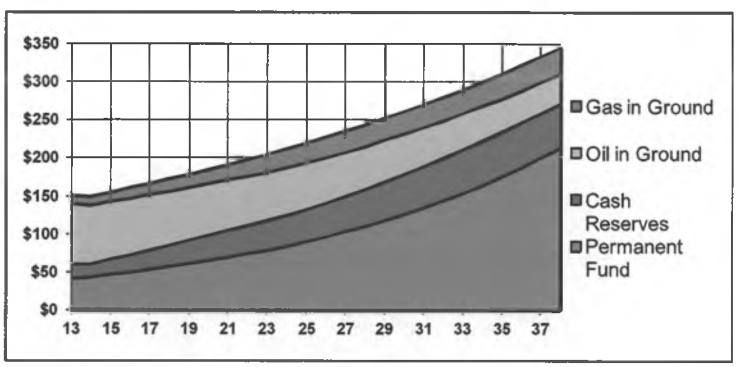
In contrast to business-as-usual, there is no fiscal cliff associated with the maximum sustainable yield strategy. Enhanced financial resources, combined with new revenues from long-term petroleum developments, would be sufficient to cover General Fund spending growing with population.

MAXIMUM SUSTAINABLE YIELD: GENERAL FUND SPENDING (BILLION $)



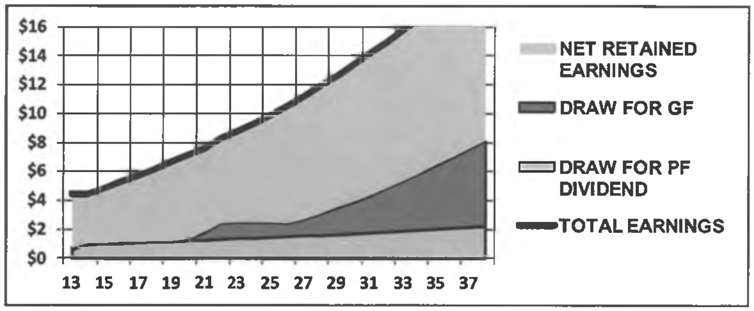
The petroleum nest egg would also increase at the combined rate of inflation and population. Over time, the declining value of oil and gas in the ground would be replaced by the growing value of financial assets.

MAXIMUM SUSTAINABLE YIELD: COMPOSITION OF THE NEST EGG (BILLION $)



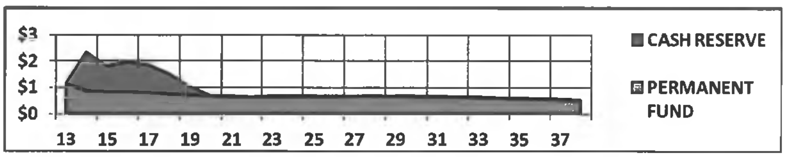
On this sustainable path the combined earnings of all the financial assets (solid black line) would initially all be reinvested, except the amount set aside to pay the Permanent Fund dividend, which would increase with inflation and population (orange)[iii]. The financial assets would gradually become the most important source of revenues for the General Fund (red)[iv]. Retained earnings (light blue) would offset inflation and population growth.

MAXIMUM SUSTAINABLE YIELD: USE OF FINANCIAL EARNINGS (BILLION $)



Financial account deposits would transform depleting petroleum revenues into a sustainable asset.

MAXIMUM SUSTAINABLE YIELD: DEPOSITS IN FINANCIAL ACCOUNTS (BILLION $)



What's In the Nest Egg?

The nest egg consists of financial assets accumulated from past saving of petroleum revenues as well as the current value of the estimated revenues from future petroleum production.

The current value of financial assets is easily estimated at about $60 billion, mostly in the Permanent Fund, and in cash reserves—the Constitutional Budget Reserve and the Statutory Budget Reserve.

The value of revenues from future production is $88.7 billion. We determine this value by estimating future taxes and royalties for 50 years, assuming the current fiscal structure and energy prices as well as reasonable estimates of economically recoverable reserves, both known and unknown. We convert these revenue flows to their net present value at a discount rate equal to the rate of return on financial investments. (This method is similar to monetizing the flow of revenues that assets can produce by calculating their net present value.)

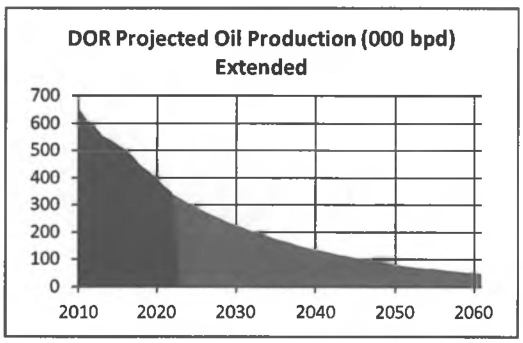
The value of revenues from future production is broken into three categories—oil in known fields, unconventional and new oil, and natural gas.

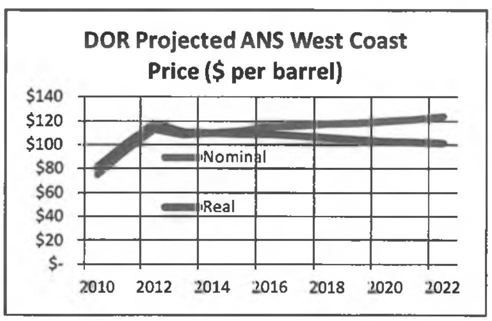
The values for these categories are modest for three reasons. Future production is likely to be more costly than current production on state lands, and production on federal lands generates no royalties directly for the state and is exempt from some state taxes. Therefore, the revenue "take" per barrel will be lower than that on current production. Finally, the discounting of revenues that will not be received for many years reduces their value today.

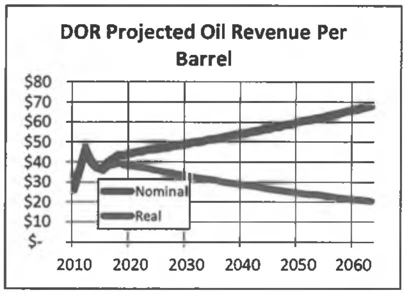
NET PRESENT VALUE: FUTURE PETROLEUM REVENUES, 50-YEAR TIME HORIZON (BILLION $)

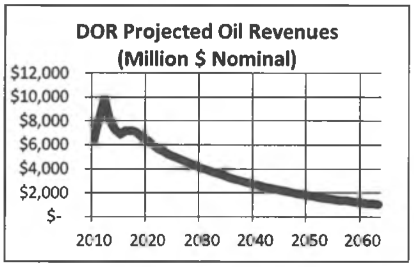
TOTAL	**$88.7**
OIL IN KNOWN FIELDS	**$67.1**
2014-2022	$43.1
2023-2063	$24.0
UNCONVENTIONAL AND NEW OIL	**$9.9**
Conventional from New Fields in Central North Slope	$4.8
Shale Oil	$1.7
Viscous and Heavy Oil	$1.7
OCS	$1.7
ANWR	0
NPRA	0
NATURAL GAS	**$11.7**

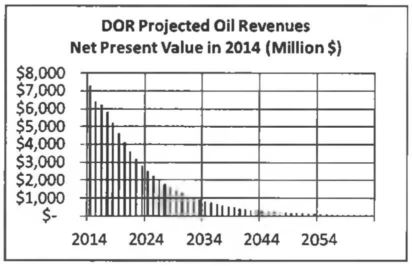
Oil in Known Fields is estimated through 2022 from the annual forecast of the Alaska Department of Revenue. This is almost entirely conventional oil on state lands, but also includes small amounts of production on federal lands (OCS and NPRA) and private lands, as well as some unconventional oil (viscous oil). After 2022, we project production to decline at 5% annually and revenue per barrel to increase at 1%—about half the rate of inflation (2.5%). Based on these assumptions, the 50-year cumulative revenues would be $168 billion (net present value of $67.1 billion), generated from production of 3.5 billion barrels of oil.









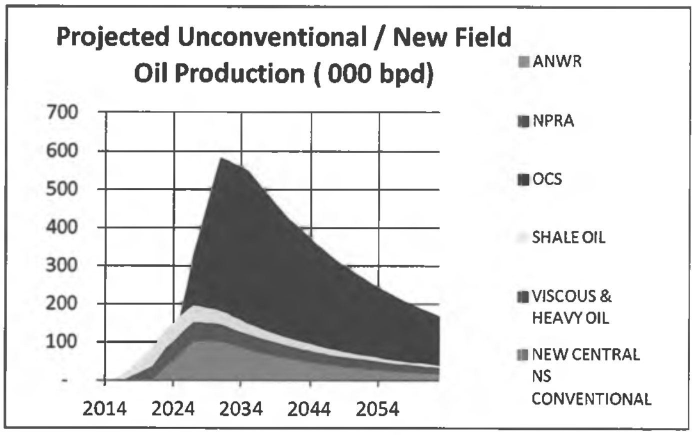


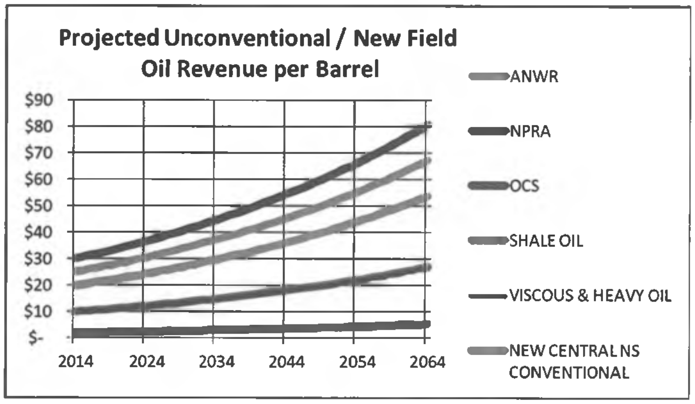
Unconventional and New Oil is divided into six categories, with revenues in each based on production and per barrel revenue—or "take"—assumptions summarized below.

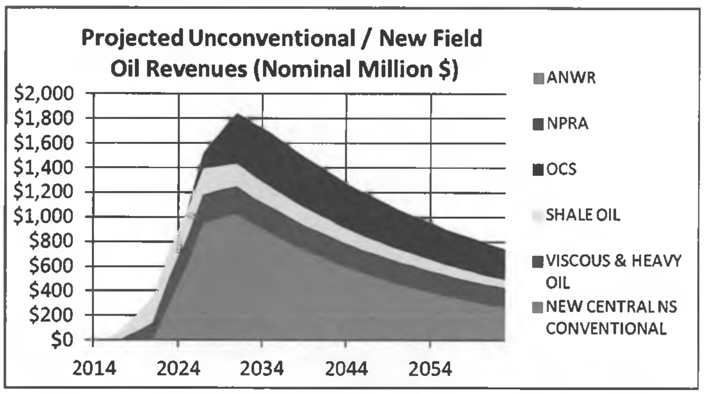
	OCS	Viscous & Heavy Oil	ANWR	NPRA	Shale Oil	New Central NS Conventional
START OF PRODUCTION	2026	2018	2200	2200	2016	2022
PEAK PRODUCTION IN BPD (000)	400	50	500	0	50	100
ANNUAL DECLINE RATE	4.0%	3.0%	5.0%	5.0%	5.0%	6.0%
REVENUE PER BARREL IN 2013	$ 2	$ 10	$ 25	$ 30	$ 10	$ 20
REVENUE PER BARREL GROWTH RATE (Nominal)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

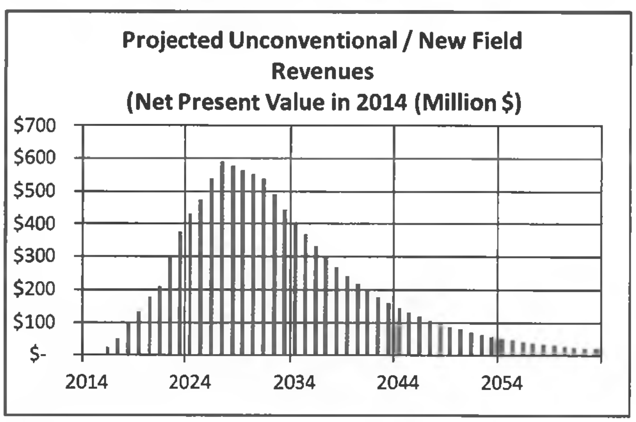
Estimated revenues assume no production from ANWR. OCS revenues exclude royalties and production taxes. And although there is no production separately indicated for NPRA, there is NPRA production, as well as a small amount of viscous oil production, built into the DOR forecast. These assumptions produce an estimate of $52 billion in revenues over the next 50 years (net present value of $9.9 billion), based on production—both on and offshore—of 5.2 billion barrels of oil.

	OCS	Viscous & Heavy Oil	ANWR	NPRA	Shale Oil	New Central NS Conventional	TOTAL
REVENUES FOR 50 YEARS (Billion $)	$ 12.4	$ 8.7	$ -	$ -	$ 6.5	$ 24.8	$ 52.3
PRODUCTION FOR 50 YEARS (Billion Barrels)	3.48	0.53	-	-	0.43	0.77	5.21

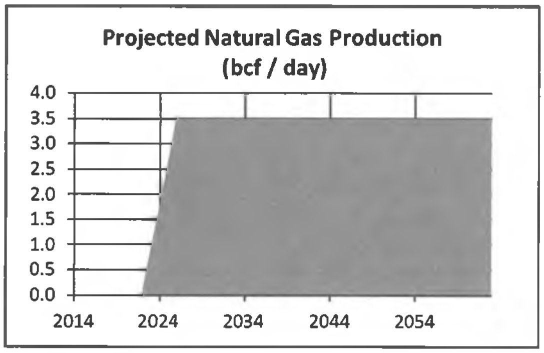

Projected Unconventional / New Field
Oil Production (000 bpd)
700
600
500
400
300
200
100
-
2014
2024
2034
2044
2054
ANWR
NPRA
OCS
SHALE OIL
VISCOUS & HEAVY OIL
NEW CENTRAL NS CONVENTIONAL

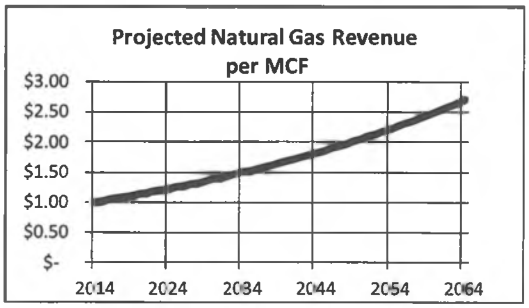

Projected Unconventional / New Field
Oil Revenue per Barrel
$90
$80
$70
$60
$50
$40
$30
$20
$10
$-
2014
2024
2034
2044
2054
2064
ANWR
NPRA
OCS
SHALE OIL
VISCOUS & HEAVY OIL
NEW CENTRAL NS CONVENTIONAL

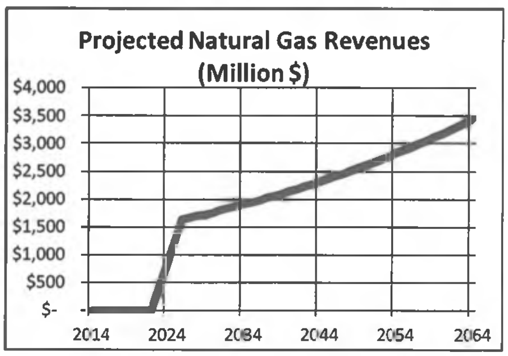

Projected Unconventional / New Field
Oil Revenues (Nominal Million $)
$2,000
$1,800
$1,600
$1,400
$1,200
$1,000
$800
$600
$400
$200
$0
2014
2024
2034
2044
2054
ANWR
NPRA
OCS
SHALE OIL
VISCOUS & HEAVY OIL
NEW CENTRAL NS CONVENTIONAL

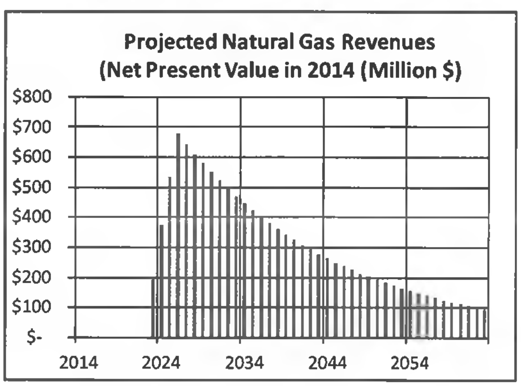

Projected Unconventional / New Field
Revenues
(Net Present Value in 2014 (Million $)
$700
$600
$500
$400
$300
$200
$100
$-
2014
2024
2034
2044
2054

Natural Gas is assumed to be monetized through a pipeline to tidewater, exporting 3.5 bcf per day starting in 2023. Because of the high cost of getting the gas to market, the netback value on the North Slope—which is the basis for taxes and royalties—is small. So the "take" at start-up is about $1.25 per mcf. The net present value of that gas production over the 50-year period is estimated at $11.7 billion.









Tracking Maximum Sustainable Yield (MSY)

The estimated size of the nest egg has fluctuated over time, but it has stayed in a range between $126 and $160 billion. Consequently, the General Fund MSY has varied between $5 billion and $6.4 billion. Part of the reason for the upward revision in the size of the nest egg during FY 2012, from $126 billion to $155 billion, was the strong recovery in value of the Permanent Fund after the financial crash. This investment performance is not likely to be duplicated in future years.

Calculation Year	Nest Egg			General Fund		Fiscal Burden	Source
	Total	Financial Assets	Petroleum in the Ground	MSY	Actual Spend		
FY2012	$126	$45	$81	$5.0	$7.0	$2.0	Feb 2011, WebNote 7 & May 2011, WebNote 8
FY2012	$155	$55	$100	$6.2	$7.0	$.8	March 2012, WebNote 10
FY2013	$160	$60	$100	$6.4	$7.6	$1.2	August 2012, WebNote 13
FY2014	$149	$60	$89	$5.5	?	?	Jan. 2013, WebNote 14

In both FY 2012 and FY 2013, actual spending exceeded the MSY, creating a fiscal burden for future generations. The nest egg estimate for FY 2014 is $11 billion lower than last year's estimate, mostly because the Alaska Department of Revenue's forecast of petroleum revenues between FY 2014 and FY 2022 is $8 billion lower than it was last year. The value of financial assets is the same in FY 2014 as in FY 2013, partly because of the $1.2 billion fiscal burden passed forward from the previous year. The General Fund MSY has also fallen because the expected Permanent Fund dividend amount has increased.

Sensitivity of Estimates

Opinions will differ about the value of the petroleum nest egg, based on different assumptions about future energy prices, production, and government policies. Different assumptions about return on investment and the growth rate of spending also will influence the size of the MSY.

A partial set of possible scenarios generates a range of nest egg values from $145 to $195 billion—shown in the higher and lower scenario tables below—although the value could fall outside that range. Combining different assumptions about return on investment and rate of growth of the budget results in a General Fund MSY that ranges between $2.5 billion and $7.4 billion. Although that range is quite wide, the actual General Fund budget of $7.6 billion in FY 2013 would have been non-sustainable under any of these scenarios.

HIGHER SCENARIOS	NEST EGG	GF MSY FY2014
ANWR @ 500 Thousand Barrels per Day	$175	$7.0
ANWR + OCS @ 500 Thousand Barrels per Day with Shared Royalties	$182	$6.8
Double Estimate of Post 2022 Revenues	$195	$7.4

LOWER SCENARIOS	NEST EGG	GF MSY FY2014
Lower Investment Return (4%)	$160	$4.4
Lower Investment Return (4%) + No Gas Revenue	$145.2	$3.9
Lower Investment Return (4%) + No Gas Revenue + General Fund Growth 1% Real Per Capita (4%)	$145.2	$2.5

Other Forms of Petroleum Wealth

The state has put $45 billion of the $170 billion of petroleum revenues collected through FY 2012 into financial assets that today have a value of $60 billion.

The state has spent much of the rest to enhance the well-being of Alaskans through investments in physical capital like roads, harbors, and utility systems, and in human capital through spending on health care, education, and other services. Estimates of the value of those investments are not available, but they certainly enhance the size of the petroleum nest egg.

And although the value of those investments has not been quantified, the MSY fiscal strategy does not ignore them: the sustainable flow of earnings from the financial nest egg provides the state with the funding to continue to invest in the well-being of both present and future generations of Alaskans.

The strategy also provides a framework for deciding when an investment in physical or human capital would provide more benefit than a financial investment. That would be the case when it could be demonstrated that the flow of benefits from such an investment would exceed the flow of benefits that would come from spending the income from the financial investment.

PETROLEUM WEALTH MANAGEMENT WORKSHEET

		FY 2013	FY 2014	Change	
	PETROLEUM WEALTH	Billion $	Billion $	Billion $	
1	**Financial Assets (2+3+4+5)**	$ 60.00	**$ 60.00**	$ -	
2	Permanent Fund Balance	$ 42.00	$ 43.00	$ 1.0	a
3	+ Constitutional Budget Reserve	$ 16.00	$ 11.00	$ (5.0)	b
4	+ Statutory Budget Reserve	$ 2.00	$ 5.00	$ 3.0	c
5	+ Other	$ -	$ 1.00	$ 1.0	
6	**Petroleum in Ground (7+10+17)--Net Present Value discounted @ 5.0%**	**$ 100.68**	**$ 88.69**	$ (12.0)	
7	Conventional North Slope--State Lands	**$ 80.54**	**$ 67.11**	$ (13.4)	d
8	DOR projection (thru 2022)	$ 50.89	$ 43.11	$ (7.8)	
9	DOR extended	$ 29.65	$ 24.00	$ (5.6)	
10	+ Other Oil	**$ 6.75**	**$ 9.85**	$ 3.1	
11	Conventional	$ 2.14	$ 4.75	$ 2.6	e
12	Viscous/Heavy Oil	$ 1.56	$ 1.72	$ 0.2	
13	Shale Oil	$ 1.57	$ 1.72	$ 0.1	
14	OCS	$ 1.49	$ 1.67	$ 0.2	
15	ANWR	$ -	$ -	$ -	
16	NPRA	$ -	$ -	$ -	
17	+ Gas	**$13**	**$12**	$ (1.7)	f
18	**= TOTAL PETROLEUM WEALTH (1+6)**	**$ 160.7**	**$ 148.7**	$ (12.0)	
	SUSTAINABLE DRAW RATE	Annual Rate	Annual Rate		
19	Real Rate of Return Net of Inflation	5.0%	5.0%		
20	- Projected Population Growth Adjustment	1.0%	1.0%		
21	- Projected Real Per Capita Budget Growth Adjustment	0.0%	0.0%		
22	**= SUSTAINABLE DRAW RATE (19-20-21)**	**4.0%**	**4.0%**		
	MAXIMUM SUSTAINABLE YIELD (MSY)	Billion $	Billion $		
23	**= MAXIMUM SUSTAINABLE YIELD (18 x 22)**	**$ 6.43**	**$ 5.95**	$ (0.5)	
	GENERAL FUND MSY SPENDING CAP	Billion $	Billion $		
24	Maximum Sustainable Yield (=23)	$ 6.43	$ 5.95	$ (0.5)	
25	- Permanent Fund Dividend Distribution	$ 0.57	$ 0.96	$ 0.4	g
26	= General Fund Petroleum Spending Cap (24-25)	$ 5.86	$ 4.99	$ (0.9)	
27	- General Fund Earnings Spending (from Petroleum Wealth)	$ 0.18	$ 0.07	$ (0.1)	h
28	= GENERAL FUND CURRENT PETROLEUM REVENUE SPENDING CAP	$ 5.68	$ 4.92	$ (0.8)	
29	+ General Fund Non-Petroleum Revenues (excluding GF earnings)	$ 0.56	$ 0.54	$ (0.0)	i
30	**= GENERAL FUND MSY SPENDING CAP (27+28+29)**	**$ 6.42**	**$ 5.53**	$ (0.9)	

Source: Institute of Social and Economic Research, University of Alaska Anchorage

Assumptions: No new taxes
Growth of General Fund spending and Permanent Fund Dividend account constrained to the combined rate of population increase and inflation
All financial assets earn maximum rate of return

Notes: Financial Assets valued at start of fiscal year.
Fifty years of revenues from petroleum in the ground discounted to start of fiscal year.

a Growth from new revenues and earnings
b FY2013 GF spending higher and revenues lower than anticipated, resulting in lower surplus

$ 8,218	fall 2011 revenue forecast for FY2013
$ 7,512	fall 2012 revenue forecast for FY2013
$ 7,042	OMB forecast for FY2013 GF spending
$ 7,600	final appropriations for FY2013 spending

c Re-assignment of some surplus to SBR from CBR
d FY2013 revenues spent and DOR forecast lower
e Lower DOR projection leaves more for future production
f Size of pipeline reduced from 4.5 bcf to 3.5 bcf per day
g Larger because of PFD formula mechanics
h Reduction in GF earnings
i No change in non-petroleum GF revenues

		BASE CASE	LOW CASES			HIGH CASES		
		FY 2014	LOW INVESTMENT RETURN	LOW INVESTMENT RETURN + NO GAS REVENUES	LOW INVESTMENT RETURN + NO GAS REVENUES + GF RPC GROW 1%	ANWR @ 500K BPD	ANWR @ 500K BPD + OCS @ 500K BPD WITH SHARED ROYALTIES	DOUBLE POST 2022 REVENUES
	PETROLEUM WEALTH	Billion $	Billion $	Billion $	Billion $	Billion $	Billion $	Billion $
1	Financial Assets (2+3+4+5)	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00	$ 60.00
2	Permanent Fund Balance	$ 43.00	$ 43.00	$ 43.00	$ 43.00	$ 43.00	$ 43.00	$ 43.00
3	+ Constitutional Budget Reserve	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00
4	+ Statutory Budget Reserve	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00
5	+ Other	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
6	Petroleum in Ground (7+10+17)--Net Present Value discounted @ 5.0%	$ 88.69	$ 100.03	$ 85.24	$ 85.24	$ 115.03	$ 121.70	$ 134.55
7	Conventional North Slope--State Lands	$ 67.11	$ 73.37	$ 73.37	$ 73.37	$ 67.11	$ 67.11	$ 91.39
8	DOR projection	$ 43.11	$ 44.91	$ 44.91	$ 44.91	$ 43.11	$ 43.11	$ 43.11
9	DOR extended	$ 24.00	$ 28.46	$ 28.46	$ 28.46	$ 24.00	$ 24.00	$ 48.28
10	+ Other Oil	$ 9.85	$ 11.87	$ 11.87	$ 11.87	$ 36.19	$ 42.87	$ 19.71
11	Conventional	$ 4.75	$ 5.74	$ 5.74	$ 5.74	$ 4.75	$ 4.75	$ 9.50
12	Viscous/Heavy Oil	$ 1.72	$ 2.04	$ 2.04	$ 2.04	$ 1.72	$ 1.72	$ 3.43
13	Shale Oil	$ 1.72	$ 1.98	$ 1.98	$ 1.98	$ 1.72	$ 1.72	$ 3.43
14	OCS	$ 1.67	$ 2.11	$ 2.11	$ 2.11	$ 1.67	$ 8.35	$ 3.34
15	ANWR	$ -	$ -	$ -	$ -	$ 26.34	$ 26.34	$ -
16	NPRA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	+ Gas	$12	$15	$0	$0	$12	$12	$23
18	**= TOTAL PETROLEUM WEALTH (1+6)**	**$ 148.7**	**$ 160.0**	**$ 145.2**	**$ 145.2**	**$ 175.0**	**$ 181.7**	**$ 194.5**
	SUSTAINABLE DRAW RATE	Annual Rate	Annual Rate	Annual Rate	Annual Rate	Annual Rate	Annual Rate	Annual Rate
19	Real Rate of Return Net of Inflation	5.0%	4.0%	4.0%	4.0%	5.0%	5.0%	5.0%
20	- Projected Population Growth Adjustment	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
21	- Projected Real Per Capita Budget Growth Adjustment	0.0%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%
22	**= SUSTAINABLE DRAW RATE (19-20-21)**	**4.0%**	**3.0%**	**3.0%**	**2.0%**	**4.0%**	**4.0%**	**4.0%**
	MAXIMUM SUSTAINABLE YIELD (MSY)	Billion $	Billion $	Billion $	Billion $	Billion $	Billion $	Billion $
23	**= MAXIMUM SUSTAINABLE YIELD (18 x 22)**	**$ 5.95**	**$ 4.80**	**$ 4.36**	**$ 2.90**	**$ 7.00**	**$ 7.27**	**$ 7.78**
	GENERAL FUND MSY SPENDING CAP	Billion $	Billion $	Billion $	Billion $	Billion $	Billion $	Billion $
24	Maximum Sustainable Yield (=23)	$ 5.95	$ 4.80	$ 4.36	$ 2.90	$ 7.00	$ 7.27	$ 7.78
25	- Permanent Fund Dividend Distribution	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96
26	= General Fund Petroleum Spending Cap (24-25)	$ 4.99	$ 3.84	$ 3.40	$ 1.94	$ 6.04	$ 6.31	$ 6.82
27	- General Fund Earnings Spending (from Petroleum Wealth)	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07
28	= GENERAL FUND CURRENT PETROLEUM REVENUE SPENDING CAP	$ 4.92	$ 3.77	$ 3.33	$ 1.88	$ 5.97	$ 6.24	$ 6.75
29	+ General Fund Non-Petroleum Revenues (excluding GF earnings)	$ 0.54	$ 0.54	$ 0.54	$ 0.54	$ 0.54	$ 0.54	$ 0.54
30	**= GENERAL FUND MSY SPENDING CAP (27+28+29)**	**$ 5.52**	**$ 4.38**	**$ 3.93**	**$ 2.48**	**$ 6.58**	**$ 6.84**	**$ 7.36**

[i] The OMB plan includes four illustrative projections, all assuming the FY 2014 General Fund appropriation will be \$6.5 billion—\$1.1 billion below FY 2013. Three are clearly not sustainable. This graph assumes FY 2014 General Fund spending will be the same as last year and that revenues will equal the Alaska Department of Revenue projection published in December 2012.

[ii] This case would be sustainable with the inclusion of income and sales taxes.

[iii] This assumes all financial assets would be invested to generate an average over time of 5% (net of inflation).

[iv] Earnings to fund General Fund appropriations would come from any combination of cash reserves and the Permanent Fund.

AK "lucky"

Arctic Oil and Natural Gas Potential

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Office of Integrated Analysis and Forecasting
Oil and Gas Division

October, 2009

Introduction

The Arctic is defined as the Northern hemisphere region located north of the Arctic Circle, the circle of latitude where sunlight is uniquely present or absent for 24 continuous hours on the summer and winter solstices, respectively. The Arctic Circle spans the globe at 66.56° (66°34′) north latitude (Figure 1).[1]

The Arctic could hold about 22 percent of the world's undiscovered conventional oil and natural gas resources. The prospects for Arctic oil and natural gas production are discussed taking into consideration the nature of the resources, the cost of developing them, and the political and environmental issues associated with their development.

Background

The area above the Arctic Circle encompasses about 6 percent of the Earth's surface area. While the Arctic is about the size of the African continent, most of the Arctic is oceanic.[2] About one-third of the Arctic is occupied by land. Another one-third of the Arctic consists of offshore continental shelves located in less than 500 meters (1,640 feet) of Arctic Ocean water. The remaining one-third of the Arctic is in Arctic Ocean waters deeper than 500 meters.

Jurisdictionally, the Arctic contains portions of eight countries - Canada, Denmark (Greenland), Finland, Iceland, Norway, Russia, Sweden, and the United States. Finland and Sweden do not border the Arctic Ocean and are the only Arctic countries without jurisdictional claims in the Arctic Ocean and adjacent seas.[3]

The sun does not rise above the Arctic horizon for days or weeks during the winter, depending on how far north of the Arctic Circle you are. Sunlight hits Arctic surfaces at an angle of much less than 90 degrees over much of the year, further diminishing the amount of incident solar radiation. As a consequence, the Arctic experiences freezing temperatures for most of the year with brief interludes above freezing. For example, at

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[1] U.S. Geological Survey, "Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle," USGS Fact Sheet 2008-3049, Washington, DC (2008), page 1. USGS website URL is: http://pubs.usgs.gov/fs/2008/3049/

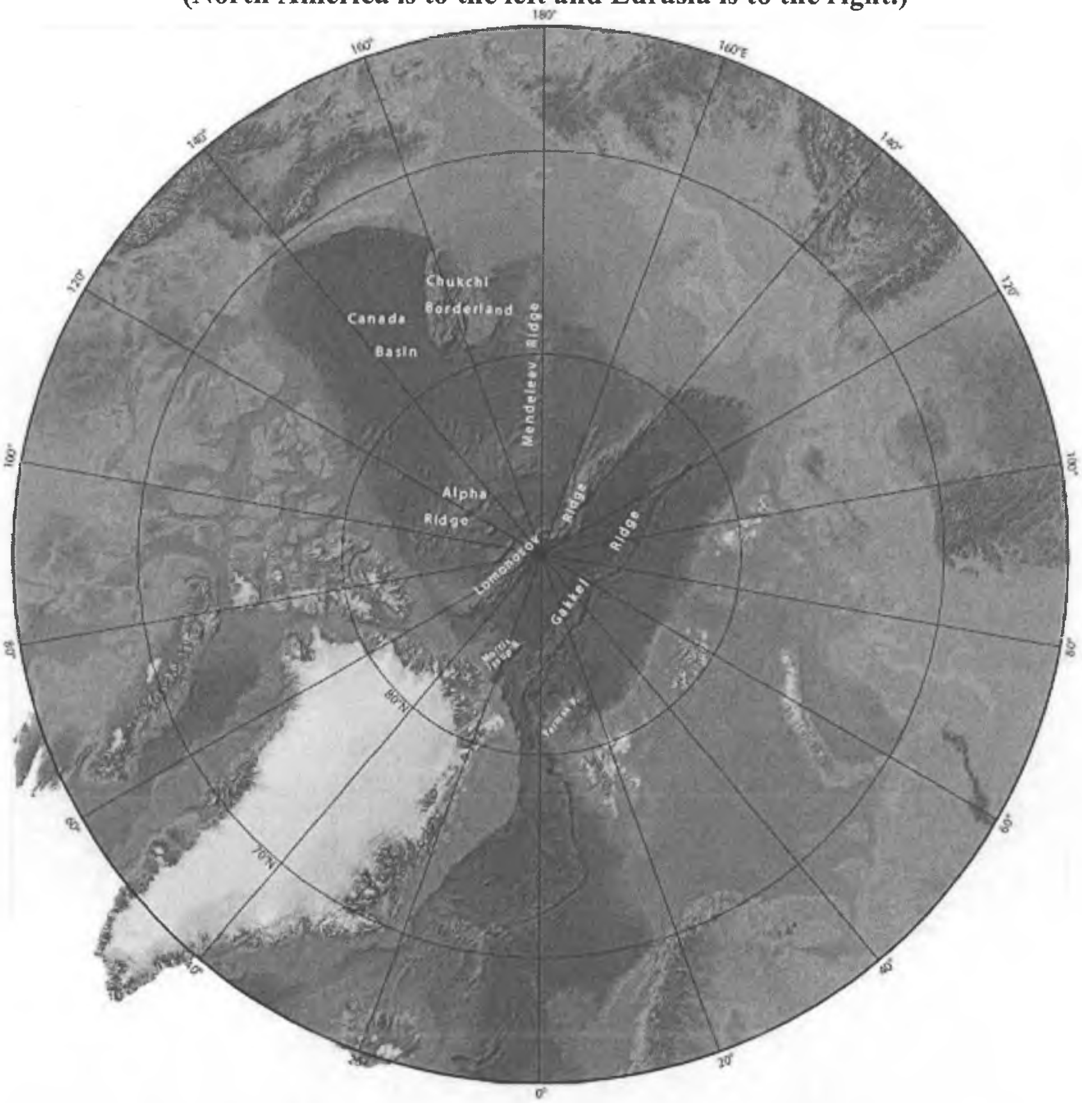
[2] Donald L. Gautier, et. al., "Assessment of Undiscovered Oil and Gas in the Arctic," *Science*, May 29, 2009, Volume 324, page 1175 - 1179.

[3] Sweden and Finland have onshore territory in the Arctic but none with any known or projected oil and natural gas resources.

Prudhoe Bay, Alaska,[4] winter temperatures can fall below −50 °F (−45 °C), while July temperatures range between 37 and 54 °F (3 to 12 °C) (Appendix A). The central Arctic Ocean is ice-covered year-round, and snow and ice are present on land for most of the year.[5]

The cold Arctic air inhibits evaporation so little precipitation occurs, with much of the Arctic having an average annual precipitation rate of 100 mm (4 inches) or less,[6] mostly in the form of snow.

FIGURE 1
Region within the Arctic Circle
(North America is to the left and Eurasia is to the right.)



Source: National Geophysical Data Center, Marine Geology and Geophysics Division, website: http://www.ngdc.noaa.gov/mgg/bathymetry/arctic/arctic.html

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[4] Latitude: 70.2552778 (70-15'19" N) and Longitude: -148.3372222 (148-20'14" W); source: http://www.lat-long.com/Latitude-Longitude-1408327-Alaska-Prudhoe_Bay.html
[5] National Snow and Ice Data Center website at: http://nsidc.org/arcticmet/basics/arctic_definition.html
[6] Arctic Council, "Arctic Climate Impact Assessment," Cambridge University Press, 2005, page 10.

Because limited sunlight, limited heat, and snow and ice are all unsupportive of plant and animal metabolism, biological activity is limited. Harsh weather and low biological fecundity has limited human activity in the Arctic. In 2000, about 3.5 million humans lived in the Arctic,[7] mostly on lands bordering the Arctic Ocean.

> "In the 20th century, immigration to the Arctic has increased dramatically, to the point where non-indigenous persons outnumber indigenous ones in many regions. The new immigrants have been drawn by the prospect of developing natural resources, from fishing to gold to oil, as well as by the search for new opportunities and escape from the perceived and real constraints of their home areas."[8]

Discovered Arctic Oil and Natural Gas Resources

The best place to find oil and natural gas is where oil and natural gas have already been found. So the large, existing Arctic oil and natural gas fields are reviewed prior to the discussion of the undiscovered Arctic oil and natural gas resource base. In this review, "large" oil and natural gas fields are those that exceed 500 million barrels of oil equivalent of recoverable oil and natural gas.[9]

Large Arctic oil and natural gas fields are particularly crucial with respect to future oil and natural gas development because the cost of developing oil and natural gas fields in the Arctic is so high that large fields are initially necessary to pay for the infrastructure required to later develop the smaller oil and natural gas deposits. For example, the Prudhoe Bay Field with 13.6 billion barrels of recoverable oil[10] made the construction of the Alyeska Oil Pipeline[11] commercially viable. Without the Prudhoe Bay Field, it is unlikely that the smaller Alaska North Slope oil fields would have been developed.

Arctic infrastructure development is sufficiently expensive that many large Arctic fields remain undeveloped. For example, 35.4 trillion cubic feet[12] (6.3 billion barrels of oil equivalent) of the discovered Alaska North Slope natural gas resources remain unexploited due to the absence of transportation infrastructure. About two-thirds of this natural gas is in the Prudhoe Bay Field.

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[7] Ibid. Table 1.1, page 14.

[8] Ibid. page 13.

[9] The exact recovery of oil and natural gas from a field is not known with certainty until that field has been permanently abandoned. Actual recovery is often greater than the original estimate, as the producer learns how to apply technology to enhance recovery rates. Ultimate field recovery rates are also affected by oil and natural gas prices, with higher prices resulting in higher recovery rates. Consequently, the exact number of large discovered fields above the Arctic Circle can only be approximate. Large field data source: Petroleum Source to Reservoir, Giant Oil and Gas Fields database, Version 14, 2009, website address: http://www.sourcetoreservoir.com/index.html

[10] Figure does not include natural gas. Source: Alaska Department of Natural Resource, Division of Oil & Gas, *Alaska Oil and Gas Report*, July 2007, Anchorage, Alaska, Table III.1(Oil and Gas Reserves), page 3-2 and Table III.3 (Oil Production – Historic), page 3-5.

[11] Also known as the TransAlaska Pipeline System (TAPS).

[12] Op. cit. Alaska Department of Natural Resources, Table III.1, page 3-2.

Large Arctic oil and natural gas discoveries began in Russia with the discovery of the Tazovskoye[13] Field in 1962 and in the United States with the Alaskan Prudhoe Bay Field in 1967. Approximately 61 large oil and natural gas fields have been discovered within the Arctic Circle in Russia, Alaska, Canada's Northwest Territories, and Norway.[14] Fifteen of these 61 large Arctic fields have not yet gone into production; 11 are in Canada's Northwest Territories, 2 in Russia, and 2 in Arctic Alaska.

Forty-three of the 61 large Arctic fields are located in Russia. Thirty-five of these large Russian fields (33 natural gas and 2 oil) are located in the West Siberian Basin.[15] Of the eight remaining large Russian fields, five are in the Timan-Pechora Basin, two are in the South Barents Basin, and one is in the Ludlov Saddle.

Of the 18 large Arctic fields outside Russia, 6 are in Alaska, 11 are in Canada's Northwest Territories, and 1 is in Norway.

Arctic Undiscovered Technically Recoverable, Conventional Oil and Natural Gas Resources

In 2008, the United States Geological Survey (USGS) released an assessment of Arctic undiscovered technically recoverable,[16] conventional oil and natural gas resources.[17] The assessment excluded from consideration any sedimentary provinces that were less than 3 kilometers deep. Of the 33 Arctic provinces that surpassed this depth and that were evaluated by the USGS, 8 were not "quantitatively assessed" because they had less than a 10-percent probability of having an oil and/or natural gas deposit larger than 50 million barrels of oil equivalent in any of their assessment units.[18] The USGS therefore provided quantitative estimates of undiscovered oil and natural gas resources for 25 Arctic sedimentary provinces.

Because some of the sedimentary provinces evaluated by the USGS lay both above and below the Arctic Circle, the USGS apportioned the total resource base within those provinces into estimated resources above and below the Arctic Circle. Only the Arctic portion of each province's resource estimate is shown in Table 1.

[13] There are often multiple variations for the English spelling of foreign oil and natural gas fields.
[14] This number is approximate because it depends on the latitude coordinates provided in the Giant Oil and Gas Fields database. The oil and natural gas fields' latitude in the database had to be greater than the 66.56° latitude to qualify as Arctic fields.
[15] All sedimentary province names are those used by the United States Geological Survey.
[16] Technically recoverable resources are resources that can be produced using current technology.
[17] U.S. Geological Survey, "Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle," USGS Fact Sheet 2008-3049, Washington, DC (2008). The USGS is currently preparing a more extensive report regarding their Arctic assessment.
[18] Source: Personal communication with Ronald R. Charpentier of the USGS on May 12, 2009. Seven of the eight provinces that were not quantitatively assessed have only one assessment unit. The Franklinian Shelf province has three separate assessment units

TABLE 1
Arctic Mean Estimated Undiscovered
Technically Recoverable, Conventional Oil and Natural Gas Resources
By Arctic Province, Ranked by Total Oil Equivalent Resources

USGS Petroleum Province Name	Crude Oil (billion barrels)	Natural Gas (trillion cubic feet)	Natural Gas Liquids 1/ (billion barrels)	Total Resources, Oil Equivalent 2/ (billion barrels)
West Siberian Basin	3.66	651.50	20.33	132.57
Arctic Alaska	29.96	221.40	5.90	72.77
East Barents Basin	7.41	317.56	1.42	61.76
East Greenland Rift Basins	8.90	86.18	8.12	31.39
Yenisey-Khatanga Basin	5.58	99.96	2.68	24.92
Amerasia Basin	9.72	56.89	0.54	19.75
West Greenland-East Canada	7.27	51.82	1.15	17.06
Laptev Sea Shelf	3.12	32.56	0.87	9.41
Norwegian Margin	1.44	32.28	0.50	7.32
Barents Platform	2.06	26.22	0.28	6.70
Eurasia Basin	1.34	19.48	0.52	5.11
North Kara Basins and Platforms	1.81	14.97	0.39	4.69
Timan-Pechora Basin	1.67	9.06	0.20	3.38
North Greenland Sheared Margin	1.35	10.21	0.27	3.32
Lomonosov-Makarov	1.11	7.16	0.19	2.49
Sverdrup Basin	0.85	8.60	0.19	2.48
Lena-Anabar Basin	1.91	2.11	0.06	2.32
North Chukchi-Wrangel Foreland Basin	0.09	6.07	0.11	1.20
Vilkitskii Basin	0.10	5.74	0.10	1.16
Northwest Laptev Sea Shelf	0.17	4.49	0.12	1.04
Lena-Vilyui Basin	0.38	1.34	0.04	0.64
Zyryanka Basin	0.05	1.51	0.04	0.34
East Siberian Sea Basin	0.02	0.62	0.01	0.13
Hope Basin	0.002	0.65	0.01	0.12
Northwest Canadian Interior Basins	0.02	0.31	0.02	0.09
Total	**89.98**	**1,668.66**	**44.06**	**412.16**

Source: U.S. Geological Survey, "Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle," USGS Fact Sheet 2008-3049 Washington, DC (2008), Table 1, page 4.
Note: The column totals do not equal the sum of the rows due to rounding. USGS website URL is: http://pubs.usgs.gov/fs/2008/3049/. The relative location of these provinces is identified in Appendix B.
1/ Natural gas liquids are composed of ethane, propane, and butane.
2/ The USGS uses a natural gas to oil conversion factor in which 6 thousand cubic feet of natural gas equals 1 barrel of crude oil.

The USGS Arctic assessment estimated a total oil and natural gas resource of 412 billion barrels of oil equivalent, with 78 percent of those resources expected to be natural gas and natural gas liquids (NGL). The composition of undiscovered Arctic hydrocarbons is largely determined by the West Siberian Basin and East Barents Basin, which hold 47 percent of the undiscovered Arctic resources, with 94 percent of those resources being natural gas and NGL.

According to the USGS mean estimate, the Arctic holds about 22 percent of the world's undiscovered conventional oil and natural gas resource base, about 30 percent of the world's undiscovered natural gas resources, about 13 percent of the world's undiscovered oil resources, and about 20 percent of the world NGL resources.[19]

The fact that the Arctic is particularly rich in natural gas and NGL may impede the exploitation of its resources, because the world's natural gas consumers live far from the Arctic and the long-distance transportation of natural gas and NGL is considerably more expensive than oil transportation due to the significantly lower energy density of these fuels relative to crude oil. Although the low energy density of natural gas and NGL can be offset by liquefaction or pressurization, transportation as liquefied natural gas (LNG) is particularly expensive due to the large capital costs required to build the liquefaction facilities and the LNG tankers.

While the Arctic is rich in undiscovered oil and natural gas resources, the resources are concentrated in just a few sedimentary provinces. Table 2 illustrates the Arctic's cumulative oil and natural gas resource concentration for those provinces with the largest share of the Arctic resource base. For example, the 3 largest Arctic provinces account for 65 percent of the total Arctic oil and natural gas resources, and the largest 10 oil and natural gas provinces account for 93 percent of the total. The remaining 15 provinces (out of 25 qualitatively evaluated provinces) are estimated to hold only 7 percent of the Arctic resource base.

TABLE 2
Arctic Crude Oil, Natural Gas, and Natural Gas Liquids Resource Concentration for Provinces with the Greatest Share of Total Resources, Based on the USGS Mean Estimates

Largest Arctic Resource Provinces	Cumulative Percent of Total Arctic Oil, Natural Gas, & NGL Resources (Percent)
Largest Resource Province	32
Largest 2 Resource Provinces	50
Largest 3 Resource Provinces	65
Largest 5 Resource Provinces	78
Largest 10 Resource Provinces	93

Source: Table 1.

[19] USGS Newsroom release dated July 23, 2008. USGS website URL: http://www.usgs.gov/newsroom/article.asp?ID=1980&from=rss_home. Figures do not include or consider world unconventional oil and natural gas resources, such as Rocky Mountain oil shale, Canadian oil sands, Venezuelan Orinoco heavy oil, etc. Inclusion of these unconventional resources would reduce the Arctic proportion of total world oil and natural gas resources.

Arctic oil and natural gas resources are not evenly distributed among the Eurasian and North American continents (Table 3). Eurasia is estimated to hold about 63 percent of the total Arctic resource base, while North America holds about 36 percent. The Eurasian resource base is predominantly natural gas and NGL, which account for about 88 percent of the total Eurasian resource base. The Eurasian West Siberia Basin and East Barents Basin account for 194.3 billion barrels of oil equivalent of undiscovered resources, which is 74 percent of the total Eurasian resource base.

TABLE 3
Regional Concentration of Arctic Oil and Natural Gas Resources By Continental Land Mass, Based on the USGS Mean Estimates

Region	Crude Oil (billion barrels)	Natural Gas (trillion cubic feet)	Natural Gas Liquids (billion barrels)	Total Resources, Oil Equivalent (billion bbl)
Eurasia	30.70	1,219.39	27.55	261.49
North America	58.09	435.40	16.20	146.85
Indeterminate	1.20	13.87	0.31	3.82
Total	**89.98**	**1,668.66**	**44.06**	**412.16**
Eurasia	34.1 %	73.1 %	62.5 %	63.4 %
North America	64.6 %	26.1 %	36.8 %	35.6 %
Indeterminate	1.3 %	0.8 %	0.7 %	0.9 %
Total	**100.0 %**	**100.0 %**	**100.0 %**	**100.0 %**

Source: Table 1. The column totals might not equal the sum of the rows due to rounding.
Indeterminate regions are those that could not conclusively be assigned to either continent; includes: Lomonosov-Makarov, Hope Basin, and North Chukchi-Wrangel Foreland Basin.

While the Eurasian side of the Arctic is more natural-gas-prone, the North American side is more oil-prone. The North American side of the Arctic is estimated to have about 65 percent of the undiscovered Arctic oil, but only 26 percent of the undiscovered Arctic natural gas.

The Arctic Alaska region is estimated to hold the largest undiscovered Arctic oil deposits, about 30 billion barrels. The second largest oil province in the Arctic is the Amerasia Basin, located just north of Canada, and estimated to have about 9.7 billion barrels of undiscovered oil. The third largest Arctic oil province is the East Greenland Rift, which is estimated to hold about 8.9 billion barrels of undiscovered oil. Collectively, these 3 North American provinces are expected to hold about 48.6 billion barrels of undiscovered oil, which is about 54 percent of the total undiscovered Arctic oil. Approximately 2.5 billion barrels of oil have already been discovered in large fields in both the Amerasia Basin and the Northwest Canadian Interior Basins that are not yet being produced.[20]

There is considerable uncertainty regarding undiscovered Arctic oil and natural gas resources. Table 4 illustrates the wide variation in oil and natural gas resource estimates for the 2 assessment units within the most prolific Arctic province, the West Siberian

[20] Op. cit. Source to Reservoir.

Basin.[21] In both assessment units, the 95-percent probability estimates are about one-fourth the mean estimate, while the 5-percent probability estimates are over twice the mean estimate and about 10 times greater than the 95-percent probability estimate. [22]

TABLE 4
USGS Assessment of the Oil and Natural Gas Resource Probability Distribution For the Arctic Portion of the West Siberian Basin[23]

Resource Category	Mean Estimate	95-Percent Probability Estimate	5-Percent Probability Estimate
	Assessment Unit 1		
Crude Oil (billion barrels)	1.15	0.22	2.93
Natural Gas (trillion cubic feet)	29.28	7.48	68.39
Natural Gas Liquids (billion barrels)	0.85	0.22	1.98
	Assessment Unit 2		
Crude Oil (billion barrels)	2.51	0.57	6.02
Natural Gas (trillion cubic feet)	622.22	157.86	1,409.29
Natural Gas Liquids (billion barrels)	19.48	4.86	44.85

Note: The 95-percent and 5-percent probability figures cannot be arithmetically added, whereas the mean estimates can be added together. With respect to the 95-percent and 5-percent probabilities, the proper interpretation of these probability estimates is that they represent an "X" probability of finding "Y" **or greater** volume of undiscovered resources. For example, there is a 95 percent probability that the West Siberian Assessment Unit 1 will contain 0.22 billion barrels **or greater** of undiscovered oil resources.

Though there is considerable resource uncertainty, the allure of the Arctic is great because of the significant oil and natural gas deposits that have already been found and the large areas that have not yet been explored. For example, Cairn Energy PLC[24] notes that the sedimentary provinces offshore of West Greenland are three times larger in extent than the North Sea basin and yet only six oil and natural gas exploration wells have been drilled off of West Greenland.[25] Offshore West Greenland is particularly intriguing to Cairn Energy due to extensive offshore oil seeps, thick organic shale beds, and oil shows in prior drilling. The company currently plans to commence a West Greenland exploratory drilling program in 2011. Only as more wildcat exploration wells are drilled in the Arctic will the actual Arctic oil and natural gas resource base become apparent.

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[21] Ibid.

[22] From the perspective of mathematical probability and statistics, the resource probability distribution is skewed, such that the median value is less than the mean value.

[23] Donald L. Gautier, et. al., "Assessment of Undiscovered Oil and Gas in the Arctic," *Science*, May 29, 2009, Volume 324, page 1175 - 1179. Specific numbers came from the Excel spreadsheet file associated with the *Science* article, labeled as: "1169467TableS1s.xls".

[24] Cairn Energy PLC is headquartered in Edinburgh, Scotland.

[25] Cairn Energy PLC presentation, "Oil, Deserts, and Ice: A Focus on Challenges and Rewards in India and Greenland," presented by Dr. Michael Watts at the Scottish Oil Club on May 26, 2009, Slide 38. Available at: http://www.cairn-energy.plc.uk/downloads/ScottishOilClubwebopt.pdf

Arctic Development Costs and Risks

Even if the Arctic oil and natural gas resources eventually prove to be considerably greater than the USGS estimates, they will be expensive to develop. As noted earlier, 15 large Arctic oil and natural gas fields are awaiting development. Most were discovered in the 1970s and 1980s. Thirteen of the undeveloped fields are located in North America, where oil and natural gas field development is governed by market-based economics, with fields only being developed if and when they are expected to generate sufficient profits. Of the 17 large Arctic fields located in North America, only 3 have been so-developed, all located in Alaska, around the Prudhoe Bay Field complex.

In contrast, Russia's Arctic resources were predominantly developed under a Soviet command-and-control economy. Many of Russia's large producing Arctic fields might not have been commercially viable under market-based economics, when they were originally developed.[26]

Finding large Arctic oil and natural gas deposits is difficult and expensive; developing them as commercially profitable ventures is even more challenging. Arctic oil and natural gas resource exploration and development are expensive because:

- Harsh winter weather requires that the equipment be specially designed to withstand the frigid temperatures
- On Arctic lands, poor soil conditions can require additional site preparation to prevent equipment and structures from sinking
- The marshy Arctic tundra can also preclude exploration activities during the warm months of the year
- In Arctic seas, the icepack can damage offshore facilities, while also hindering the shipment of personnel, materials, equipment, and oil for long time periods
- Long supply lines from the world's manufacturing centers require equipment redundancy and a larger inventory of spare parts to insure reliability
- Limited transportation access and long supply lines reduce the transportation options and increase transportation costs
- Higher wages and salaries are required to induce personnel to work in the isolated and inhospitable Arctic.

Economic studies involving onshore Alaska North Slope project development costs invoke a capital cost factor ranging from 1.5 to 2.0 relative to similar oil and natural gas projects undertaken in Texas.[27] The development of new Alaska North Slope fields near existing fields is economically benefited by the ability to use whatever infrastructure already exists, for example, roads, railroads, harbor facilities, air fields, electric power generation, and living quarters. Even so, Arctic oil and natural gas project costs and schedules can prove to be significantly greater than originally planned due to supply

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[26] The future development of Russia's Arctic resources in a market-based economy is greatly facilitated by the extensive Arctic oil and natural gas infrastructure that was built under the Soviet regime.

[27] E.P. Robertson, Idaho National Engineering and Environmental Laboratory (Bechtel BWXT Idaho, LLC), "Options for Gas-To-Liquids Technology in Alaska," INEEL/EXT-99-01023, December 1999, page vii.; and Charles B. Thomas, et. al., Idaho National Engineering and Environmental Laboratory (Lockheed Martin), "Economics of Alaska North Slope Utilization Options," INEL-96/0322, August 1996, page B-19.

chain delays, abnormal weather conditions, and court challenges emanating from environmental concerns.

As an example of supply chain difficulties, the multinational Italian-based petroleum company, Eni S.p.A. originally announced that the Nikaitchuq oil field on the Alaska North Slope would start production by year-end 2009.[28] More recently, Eni announced that the field would not begin production until year-end 2010 partly because the company had missed the summer season opportunity to ocean barge the field's processing and operations modules to the North Slope from a Louisiana fabrication yard. Such supply chain delays increase project costs and reduces the rates of return as expensive equipment remains idle.

Abnormal weather can increase costs by hindering transportation and drilling activity. The early onset of warm weather on the Alaska North Slope during April of 2009 stranded equipment and precluded some exploration well drilling.[29] Similarly, a late onset of winter weather delays construction of the ice roads required to transport heavy equipment across the tundra.[30]

Court challenges stemming from environmental concerns can also increase Arctic project costs. Shell Oil has paid over $2.2 billion since 2005 to secure Federal oil and natural gas development leases offshore of Alaska (Appendix C) and was planning to drill three wells in its Beaufort Sea leases during the summer of 2007. On July 19, 2007, those plans were suspended by the Ninth Circuit Court of Appeals in response to law suits, filed by the North Slope Borough and the Alaska Eskimo Whaling Commission, regarding the potential impact of Shell's offshore drilling on subsistence hunting and on the environment.[31]

As part of its 2007 Beaufort Sea exploration drilling program, Shell had reactivated and towed the Kulluk arctic drilling ship to the Beaufort Sea,[32] constructed the Nanuq, a 300-foot, ice-strengthened oil-spill response vessel, and chartered the Arctic Endeavor, a 200-foot, 500,000-barrel, double-hulled tanker to hold any oil recovered from a spill.[33] In total, Shell Oil employed 24 vessels and hundreds of people just for the purpose of responding to an accidental offshore oil spill. Although public figures are not available, it would be reasonable to assume that Shell had also already spent hundreds of millions of dollars on its Beaufort Sea exploration program, in addition to the lease bonus payments. Shell currently hopes to begin its Beaufort Sea and Chukchi Sea drilling

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[28] Eric Lidji, "Nikaitchuq oil in 2010," *Petroleum News*, Volume 14, Number 21, May 24, 2009, pages 1, 13.

[29] Yereth Rosen, "Sudden Spring jolts Alaska's oil exploration," Thomson Reuters, June 3, 2009.

[30] The movement of heavy equipment in the Arctic to drilling locations is usually confined to the winter months when the tundra is frozen. During the rest of the year, the tundra is too marshy and boggy to permit the off-road transportation of heavy equipment.

[31] Alan Bailey, "9th Circuit suspends Shell's Beaufort Sea drilling program," *Petroleum News*, Volume 12, Number 30, July 29, 2007, pages 1, 15.

[32] Alan Bailey, "Shell wells still possible," *Petroleum News*, Volume 12, Number 37, September 16, 2007, pages 1, 22.

[33] Alan Bailey, "Shell: Prepared for the worst," *Petroleum News*, Volume 12, Number 35, September 2, 2007, pages 9 - 11.

program in 2010.[34] If these drilling plans come to fruition, the drilling program will have been delayed 3 years at a substantial cost.

The long lead-times required for Arctic projects also add considerable risk because the business environment can change dramatically between a project's initiation and completion dates. For example, oil and natural gas prices could be considerably lower when an Arctic project begins producing than was anticipated at the planning stage. Also, at a given level of capital investment, longer lead-times reduce the return on that investment, all else being equal. Arctic oil and natural gas projects can exacerbate this problem by requiring considerably larger investments than comparably productive projects pursued elsewhere in the world.

As the Shell and Eni experiences demonstrate, already long lead-times can become even longer. A Deutsche Bank (DB) analysis notes that development of the Russian Shtokman natural gas project in the Barents Sea could take 5 to 8 years from the initiation of substantial capital investment to full production.[35] The DB analysis notes that "With the technical and environmental complexities involved in the development, we see a high risk of delays and cost over-runs."[36]

The Arctic physical environment presents special challenges not experienced elsewhere in the world. Several oil and natural gas fields have been discovered on Russia's Yamal Peninsula but have not been developed because of the daunting physical challenges. As noted in a Cambridge Energy Research Associates report[37] on this matter:

> "Intermittent permafrost becomes continuous, winds rise to a steady 40 m per second, wind-driven water up to 10 m deep covers the low-lying land several months of the year, and solid ground gives way to friable sand that offers little support to drill pads or to pipelines and other infrastructure. In winter, instead of soil there is a frozen mixture of one part sand to four parts of ice, shot through with salt. At greater depths one encounters cryopegs—liquid saltwater lenses that slide under pressure, further weakening the load-bearing capacity of the soil….The most difficult part is getting gas and liquids to market as well as getting equipment and materiel in."

Currently, Gazprom is considering the construction of a new railroad line and a new harbor to move men and material into the Yamal Peninsula. The requirement to undertake such expensive efforts as a precursor to actual development underscores the high cost of developing the Yamal Peninsula oil and natural gas fields.

Arctic operating costs are also increased by the ice-pack conditions that extend over much of the Arctic Ocean. The requirement for ice-resistant tankers and ice-breaker

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[34] Kay Cashman, "Shell pushes drilling out to 2010, '11," *Petroleum News*, Volume 13, Number 52, December 28, 2008, page 3.
[35] Dave Thomas, et.al., "Shtokman – The big cod," Deutsche Bank Company Research, March 22, 2006, pages 14 – 16, 19.
[36] Ibid, page 19.
[37] Cambridge Energy Research Associates, "Conquering Yamal," October, 2007, Cambridge, Massachusetts, page 14.

escorts adds to the cost of transporting oil and natural gas through Arctic waters. To deal with the ice-pack, Russian companies use ice-resistant tankers in conjunction with ice-breaker escorts to transport oil in Arctic waters throughout the year.[38] For example, Rosneft purchased 30,000 deadweight double-hulled, ice-reinforced shuttle tankers to transport oil to the Russian port of Arkhangelsk.[39] As of 2008, the Russian Arctic ice-breaker fleet consisted of 28 ice-breakers.[40]

Additional costs might be imposed on future oil and natural gas development if a warming of the Arctic region melts the permafrost and turns currently firm soils into marshes and bogs. On the other hand, warmer Arctic temperatures would shrink the ocean icepack,[41] thereby facilitating and reducing the cost of water transportation and offshore drilling.

The high cost of doing business in the Arctic suggests that only the world's largest oil companies, most likely as partners in joint venture projects, have the financial, technical, and managerial strength to accomplish the costly, long-lead-time projects dictated by Arctic conditions.

Arctic Oil and Natural Gas Development Issues

Arctic oil and natural gas development also faces political and environmental issues. Political issues stem from the overlapping and disputed claims of economic sovereignty. The environmental issues pertain to the preservation of animal and plant species unique to the Arctic, particularly tundra vegetation, caribou, polar bears, seals, whales, and other Arctic sea life.

Arctic Economic Sovereignty Claims

Denmark, Canada, Norway, Russia, and the United States have overlapping economic sovereignty claims in Arctic waters. The existence of these offshore boundary disputes could forestall Arctic oil and natural gas resource development in areas where the sovereignty claims overlap.

Some of the competing claims stem from the fact that the 1982 United Nations Convention on the Law of the Sea (UNCLOS) permits countries to claim economic sovereignty as much as 350 nautical miles (403 U.S. statutory miles) beyond the point where the sea depth exceeds 2,500 meters (8,200 feet) of water.[42] The existence of extensive Arctic continental margins[43] and numerous subsea ridges possibly related to those continental margins, permit the littoral nations to make competing claims for most Arctic waters (Figure 1).

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[38] Sarah Hurst, "Varandey Arctic oil terminal starts up," *Petroleum News*, Volume 13, Number 25, June 22, 2008, page 10.
[39] Norwegian Barents Secretariat, "Oil transport from the Russian part of the Barents Region, Status per January 2009," Kirkenes, Norway, 2009, page 50.
[40] Ibid., Norwegian Barents Secretariat, page 31.
[41] National Snow and Ice Data Center, "Arctic Sea Ice Down to Second-Lowest Extent; Likely Record-Low Volume," Boulder, Colorado, October 2, 2008.
[42] Part VI, Article 76, at http://www.un.org/Depts/los/convention_agreements/texts/unclos/unclos_e.pdf
[43] Defined in the UNCLOS, ANNEX II as being any water depth less than 200 meters (~656 feet).

Denmark, Norway, and Russia have made claims of economic sovereignty in Arctic waters under the auspices of the UNCLOS. Norway's recent territorial claims are separately located in the Barents Sea, the Norwegian Sea, and Arctic Ocean.[44] Russia's UNCLOS claims of economic sovereignty extend through much of the Arctic Ocean, based on the existence of the Lomonosov Ridge that extends from Russia's coast across the Arctic Ocean to Greenland.[45] Viewed in reverse, this situation makes Denmark a potential claimant to the same Arctic regions claimed by Russia.

Although the existence of the UNCLOS has increased the number of overlapping claims of economic sovereignty in Arctic waters, two pre-existing claims also remain unresolved.[46] One disputed offshore boundary exists in the Barents Sea between Norway and Russia. The other disputed offshore boundary exists between Canada and the United States in the Beaufort Sea.

Arctic Environmental Policies and Regulations

The extent to which environmental laws and regulations impact Arctic oil and natural gas development will depend on the specific laws and regulations of each nation having economic sovereignty over Arctic areas. However, the experience in the United States indicates that such policies can preclude the development of significant Arctic oil and natural gas resources.

In the Alaska Arctic, oil and natural gas development is banned within the Arctic National Wildlife Refuge (ANWR). ANWR is located on the northern coast of Alaska due east of Prudhoe Bay. ANWR was created by the Alaska National Interest Lands Conservation Act (ANILCA) in 1980. Section 1002 of ANILCA deferred a decision on the management of oil and natural gas exploration and development of 1.5 million acres of potentially productive lands in the coastal plain of ANWR. The coastal plain area represents about 8 percent of the total area of ANWR.

In 1998, the USGS estimated that between 5.7 and 16.0 billion barrels of technically recoverable oil are in the coastal plain area of ANWR, with a mean estimate of 10.4 billion barrels. These USGS resource estimates include State and Native lands in and adjacent to the Federal lands in ANWR.

Several legislative attempts have been made to open ANWR to oil and natural gas development, but none have been successful. The lack of support to open ANWR to oil and natural gas development comes from the concern that caribou migration and breeding could be detrimentally affected by ANWR oil and natural gas development and the concern that the ANWR is a unique, yet fragile wilderness that would be damaged by oil and natural gas development and production.

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[44] Norwegian Petroleum Directorate, "Continental Shelf Submission of Norway," 2006, http://www.regjeringen.no/upload/kilde/ud/prm/2006/0374/ddd/pdfv/299461-sokkel.pdf

[45] Associated Press, "Russian Navy Staking Arctic Ocean Sea Bed," *Petroleum News*, Volume 12, Number 30, July 29, 2007, page 17.

[46] International Boundaries Research Unit, "Maritime jurisdiction and boundaries in the Arctic region," Durham University, United Kingdom, August 15, 2008. http://www.dur.ac.uk/resources/ibru/arctic.pdf

Similarly, the environmental challenge to Shell's offshore drilling program was motivated by concern that noise and potential oil spills could be harmful to migratory whales and the Beaufort Sea ecosystem.

Conclusions

The Arctic presents a "good news, bad news" situation for oil and natural gas development. The good news is that the Arctic holds about 22 percent of the world's undiscovered conventional oil and natural gas resources, based on the USGS mean estimate. The bad news is that: (1) the Arctic resource base is largely composed of natural gas and natural gas liquids, which are significantly more expensive to transport over long distances than oil; (2) the Arctic oil and natural gas resources will be considerably more expensive, risky, and take longer to develop than comparable deposits found elsewhere in the world; (3) unresolved Arctic sovereignty claims could preclude or substantially delay development of those oil and natural gas resources where economic sovereignty claims overlap; and (4) protecting the Arctic environment will be costly. The high cost and long lead-times of Arctic oil and natural gas development undercut the immediate importance of these sovereignty claims, while at the same time diminishing the economic incentive to develop these resources.

Given that the Arctic resource base is predominantly composed of natural gas and natural gas liquids, the importance of Arctic oil and natural gas resources is likely to be affected by the growing realization that shale beds in existing petroleum provinces around the world might be capable of producing 5,000 to 16,000 trillion cubic feet of natural gas.[47] This potentially large shale gas resource could significantly defer the future development of Arctic natural gas resources. Of course, there could be exceptions. Hypothetically, growing European demand for natural gas, the depletion of existing North Sea and Russian natural gas fields, and disappointing European shale gas exploration and development results could act as a strong incentive to develop Russia's Arctic natural gas resources in the West Siberian Basin and East Barents Basin.

Other aspects of the estimated Arctic oil and natural gas resource base are more neutral in character. For example, the fact that the expected undiscovered Arctic resource base is largely confined to a few sedimentary provinces might be more reflective of the fact that little, if any, oil and natural gas exploration drilling has been conducted in those provinces with low resource estimates. On the other hand, if the estimates for these unexplored and underexplored provinces prove correct, and they have little or no oil and natural gas, then the drive by nations to claim economic sovereignty over these offshore provinces would diminish.

The bottom line for Arctic oil and natural gas potential is that high costs, high risks, and lengthy lead-times can all serve to deter their development in preference to the development of less challenging oil and natural gas resources elsewhere in the world. Also, the less abundant Arctic oil resources will be more readily developed than the Arctic's natural gas resources. Thus, while the Arctic has the potential to be a more

---

[47] Barbara Shook and Leslie Palti, "Shale Gas Developed in U.S., Canada; Yet to be Exploited Worldwide," *Oil Daily*, April 7, 2009, page 4.

important source of global oil and natural gas production sometime in the future; the timing of a significant expansion in Arctic production is difficult to predict.

Appendix A
Weather Conditions at Prudhoe Bay, Alaska

	Average High Temperature	Average Low Temperature	Mean Temperature	Average Precipitation	Record High Temperature (Year)	Record Low Temperature (Year)
January	- 11°F	- 23°F	- 17°F	0.15 in.	35°F (1991)	- 62°F (1989)
February	- 13°F	- 26°F	- 20°F	0.13 in.	39°F (1989)	- 57°F (1987)
March	- 7°F	- 22°F	- 15°F	0.14 in.	34°F (1998)	- 54°F (1995)
April	7°F	- 8°F	- 1°F	0.10 in.	43°F (1988)	- 47°F (1986)
May	27°F	16°F	22°F	0.08 in.	55°F (1996)	- 19°F (1992)
June	44°F	31°F	37°F	0.37 in.	83°F (1991)	18°F (1997)
July	54°F	37°F	46°F	0.72 in.	82°F (1994)	28°F (1996)
August	51°F	36°F	44°F	0.95 in.	80°F (1994)	23°F (1996)
September	38°F	28°F	33°F	0.65 in.	67°F (1986)	1°F (1996)
October	21°F	10°F	15°F	0.40 in.	45°F (1991)	- 30°F (1996)
November	2°F	- 10°F	- 4°F	0.14 in.	39°F (1997)	- 45°F (1986)
December	- 7°F	- 19°F	- 13°F	0.19 in.	34°F (1998)	- 47°F (1990)
Total				4.02 in.		

Source: http://www.weather.com/weather/wxclimatology/monthly/USAK0197

Appendix B
Location of U.S. Geological Survey Arctic Provinces
Based on the Maps Shown in the USGS Arctic Assessment

USGS Petroleum Province Name	Countries Located Nearest To USGS Petroleum Province	Onshore/Offshore
West Siberian Basin	Russia	Onshore and Offshore
Arctic Alaska	United States	Onshore and Offshore
East Barents Basin	Norway, Russia	Offshore
East Greenland Rift Basins	Greenland (Denmark)	Mostly Offshore
Yenisey-Khatanga Basin	Russia	Onshore
Amerasia Basin	Canada, United States	Offshore
West Greenland-East Canada	Canada, Greenland (Denmark)	Offshore
Laptev Sea Shelf	Russia	Mostly Offshore
Norwegian Margin	Norway	Offshore
Barents Platform	Norway	Offshore
Eurasia Basin	Norway, Russia	Offshore
North Kara Basins and Platforms	Russia	Offshore
Timan-Pechora Basin	Russia	Mostly Onshore
North Greenland Sheared Margin	Greenland (Denmark)	Offshore
Lomonosov-Makarov	Canada, Greenland (Denmark), Russia	Offshore
Sverdrup Basin	Canada	Onshore and Offshore
Lena-Anabar Basin	Russia	Onshore
North Chukchi-Wrangel Foreland Basin	Russia, United States	Offshore
Vilkitskii Basin	Russia	Offshore
Northwest Laptev Sea Shelf	Russia	Offshore
Lena-Vilyui Basin	Russia	Onshore
Zyryanka Basin	Russia	Onshore
East Siberian Sea Basin	Russia	Offshore
Hope Basin	Russia, United States	Offshore
Northwest Canadian Interior Basins	Canada	Onshore

Note: The designation of the closest country or countries does not imply territorial or economic sovereignty by these countries over the petroleum province associated with them. Source: Op.cit. USGS, "Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle"

Appendix C
Shell Oil Offshore North Alaska Lease Purchases

MMS Lease Sale Number	Date of MMS Lease Sale	Offshore Region	Value of Winning Bids (million dollars)
195	March 30, 2005	Beaufort Sea	$44.4
202	April 18, 2007	Beaufort Sea	$39.3
193	February 7, 2008	Chukchi Sea	$2,117.8
Total Bonus Bids			**$2,201.5**

Source: U.S. Minerals Management Alaska leasing website at http://www.mms.gov/ld/AKsales.htm

Oil Resources: Economic Challenges and Opportunities

Senate Resources Committee
February 4, 2013

Bradford G. Keithley
Partner & Co-Head, Oil & Gas Practice
Perkins Coie LLC
Anchorage, Alaska & Washington, D.C.

Background

- Testifying on my own behalf
  - Not representing a client or being paid
  - Bearing my own expenses
- My background
  - Corporate executive (1984 – 1990)
  - Attorney
    - Thirty five years total (full time oil)
    - Been part of regional, national and global law firms
    - During my career, have advised major oil companies, mid-majors, small independents, industrial consumers

Overview

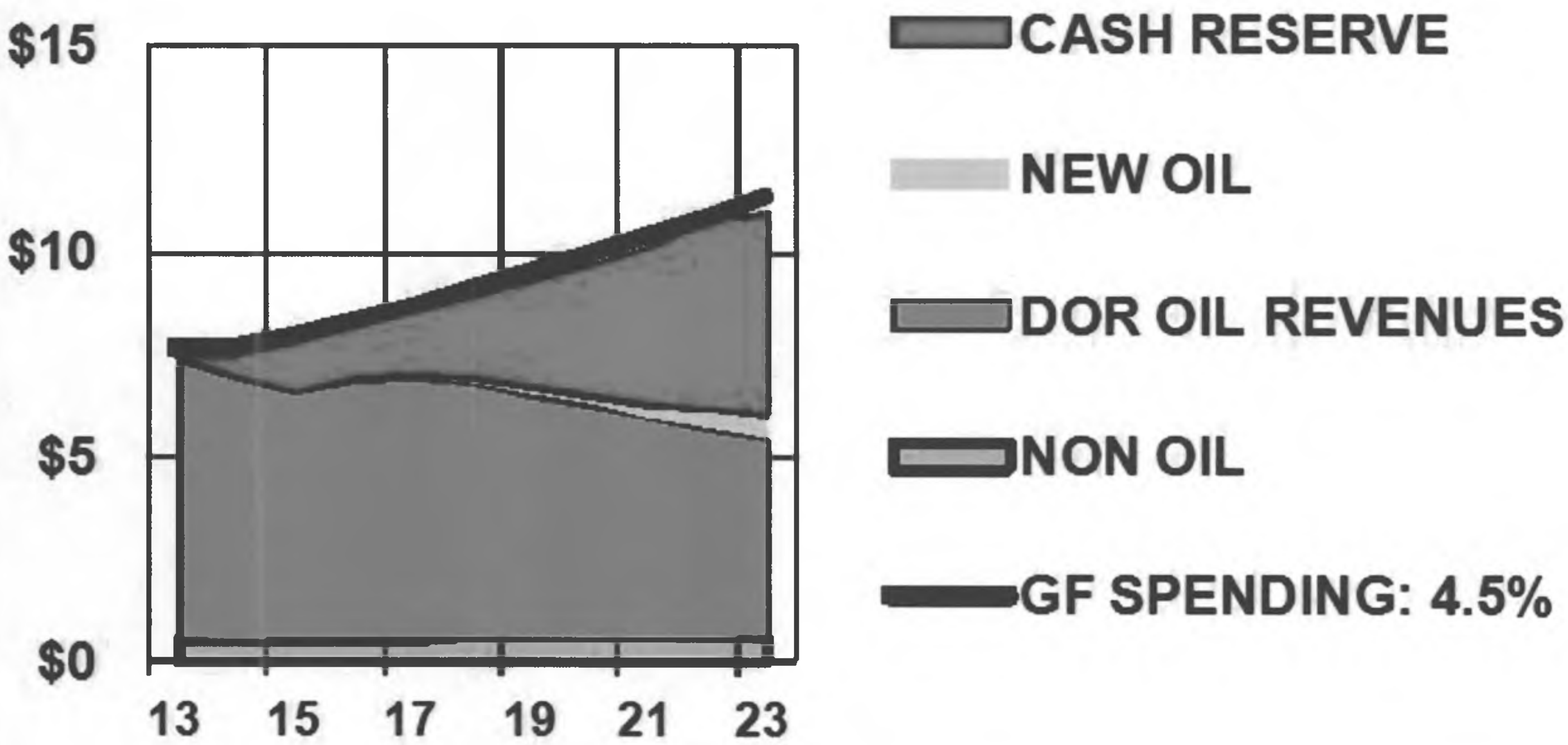
Purpose: Provide an overview of where Alaska is currently, what the opportunities are and how to move toward them

- Why do I care
- Understanding the global oil & gas industry
- What is happening in Alaska – and why
- Where do we go from here

Why Do I Care?

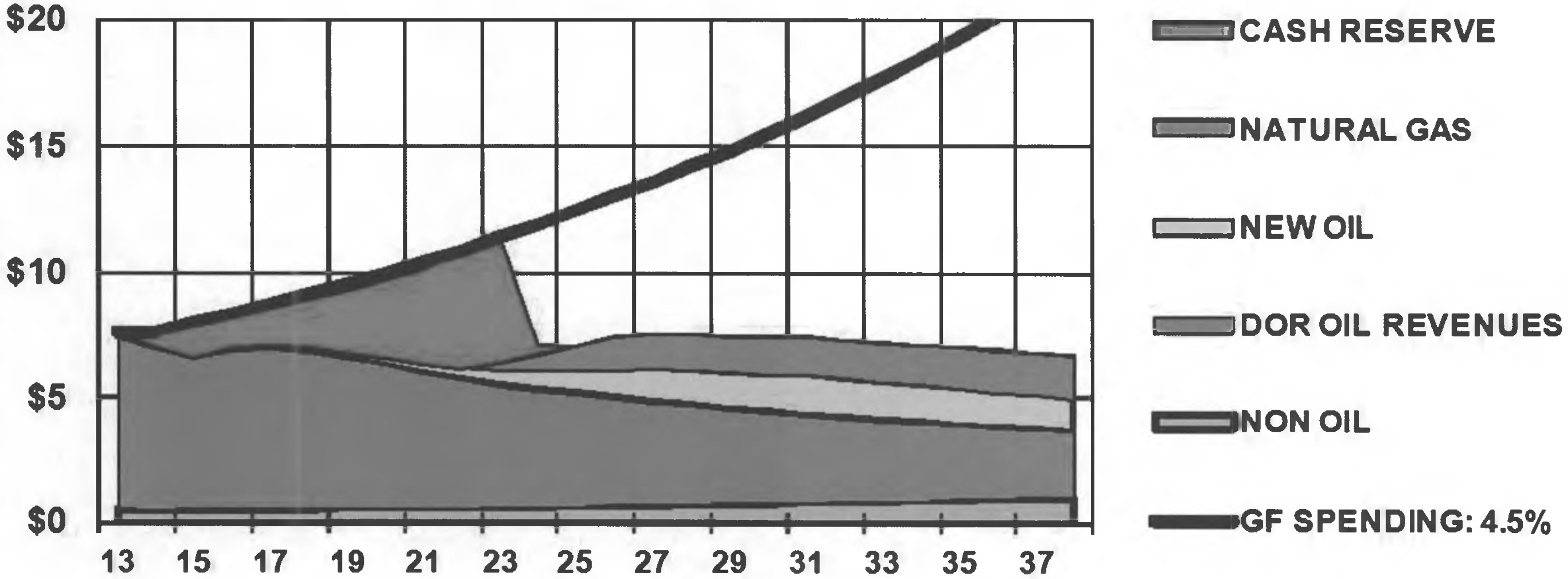
- Part of the Alaska economy: experiencing the decline in activity
  - Not as many oil & gas-related transactions and related issues
- Very concerned about where Alaska is headed on its current course
  - UAA's Institute of Social and Economic Research, *"Maximum Sustainable Yield: FY 2014 Update"* (January 2013)

ALASKA 10-YEAR FISCAL PLAN



"In its 10-year fiscal plan, the state Office of Management and Budget (OMB) projects that spending the cash reserves might fill this gap until 2023 …. ***But what happens after 2023***?"

LOOKING BEYOND THE 10-YEAR HORIZON



"Reasonable assumptions about potential new revenue sources suggest *we do not have enough cash in reserves to avoid a severe fiscal crunch soon after 2023, and with that fiscal crisis will come an economic crash.* "

Why Do I Care?

- Increased production alone doesn't solve the problem
- Will come back to that curve later, when talking about the issues affecting Alaska's competitiveness for investment

Understanding the Global Industry

- Useful to break the modern industry into four eras
- Pre-oil embargo (before 1973)
  - Significant access by major oil companies (the so-called "Seven Sisters") to global opportunities (other than Communist Bloc), but identified opportunities relatively limited
  - Some, but very limited activity by non-majors outside of the US

Understanding the Global Industry

- Oil embargo to end of the Soviet era (1973 – early 1990's)
  - Significantly reduced access for both majors and others to opportunities outside of the West
  - Increased emphasis on the development of opportunities in the West (e.g., North Sea, GOM, Alaska)

Understanding the Global Industry

- Post-Soviet era (early 1990's – early 2000's)
  - Steadily increased access for both majors and independents to opportunities beyond the West
  - As access has increased, so has the level of global competition among nations for oil investment
- The technology era (mid 2000's -)
  - Technology has always been a factor, but has steadily increased access to new opportunities for both majors and independents
  - Examples: deep water and shale

Understanding the Global Industry

- How do companies decide among projects?
- A number of factors are involved (Fraser Institute, *Global Petroleum Survey 2012*)
  - Commercial environment
  - Regulatory climate
  - Geopolitical risk

Understanding the Global Industry

- Each category has several subfactors
- Commercial environment
  - Fiscal terms
  - Taxation regime
  - Trade barriers
  - Quality of infrastructure
  - Labor availability
  - Corruption

Understanding the Global Industry

- Regulatory climate
  - The cost of regulatory compliance
  - Uncertainty regarding the administration, interpretation, and enforcement of regulations
  - Uncertainty concerning the basis for and/or anticipated changes in environmental regulations
  - Labor regulations, employment agreements, and local hiring requirements
  - Regulatory duplication and inconsistencies
  - Legal system fairness and transparency

Understanding the Global Industry

Figure 4: **2012 GLOBAL INVESTMENT CLIMATE** for petroleum upstream development

Understanding the Global Industry

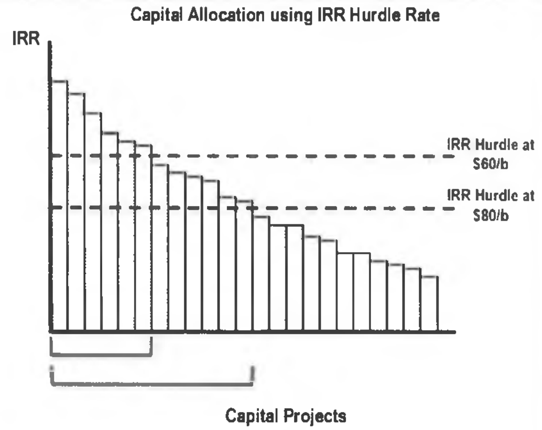
- But there are other factors as well
  - Size of potential reserves ("materiality")
  - Size of required investment
  - Sense of strategic importance
  - Capital availability (debt, dividends, buybacks)
- No one factor is determinative, but ultimately economics are the key driver
  - Projects are reduced to some measure of economic performance and then compared

Understanding the Global Industry

- PFC 1-31-2013 Presentation before the Special Committee
- A fair representation of what is involved in evaluating projects – some effort is made to incorporate the various factors into the economics

Capital Allocation: IRR Hurdle Rate

- **Issues with IRR Hurdle Rate:**
  - Increase in free cash flow (due to, say, rise in energy prices) => increased capital budget => lower Hurdle rate in order to undertake additional projects => reduce overall portfolio quality and lower efficiency of capital employed.
  - Evidenced in *cycles of value destruction* within the industry
    - E&P companies will create capital scarcity by increasing share buyback programs, paying down debt, and/or increasing dividends
  - *Gaming the system*: Project managers have an incentive to overstate the "size of the prize" or understate costs, in order to attract investment capital to proposed projects
  - IRR ranking does not speak to *materiality* => equivalent IRR's can have substantially different capex and revenue profiles



Alaska Hydrocarbons Fiscal System Analysis | © PFC Energy 2013 | January 2013

PFC Energy

What is happening in Alaska

- What is the historical context for Alaska
  - Large scale Alaska investment occurred largely during the era between the 1973 Oil Embargo and the fall of the Soviet Union
  - Limited competition for capital; focus on Western projects

What is happening in Alaska

- Indeed, Alaska is relatively lucky

*Large Arctic oil and natural gas fields are particularly crucial with respect to future oil and natural gas development because the cost of developing oil and natural gas fields in the Arctic is so high that large fields are initially necessary to pay for the infrastructure required to later develop the smaller oil and natural gas deposits. For example… **[w]ithout the Prudhoe Bay Field, it is unlikely that the smaller Alaska North Slope oil fields would have been developed.***

Energy Information Administration, *Arctic Oil and Natural Gas Potential* (Oct. 19, 2009)

What is happening in Alaska

- Alaska has not fared well in capital competition beyond Prudhoe Bay and Kuparuk during post-Soviet era
- Reasons
  - Even before taking into account fiscal terms, Alaska is a challenged environment
  - Remote; high cost; extreme environmental conditions

What is happening in Alaska

- Alaska's situation is consistent with global reality

  "[As of 2009 … and still] 15 large Arctic oil and natural gas fields are awaiting development. Most were discovered in the 1970s and 1980s. ***Thirteen of the undeveloped fields are located in North America, where oil and natural gas field development is governed by market-based economics, with fields only being developed if and when they are expected to generate sufficient profits.*** *Of the 17 large Arctic fields located in North America, only 3 have been so-developed, all located in Alaska, around the Prudhoe Bay Field complex."*

  Energy Information Administration, *Arctic Oil and Natural Gas Potential* (Oct. 19, 2009)

What is happening in Alaska

- Where Alaska has been successful is in attracting capital to Prudhoe and Kuparuk
  - Focus has been on increasing recovery rates
  - Prudhoe was originally predicted at 40% recovery
  - Through significant investment, current projections are 60%

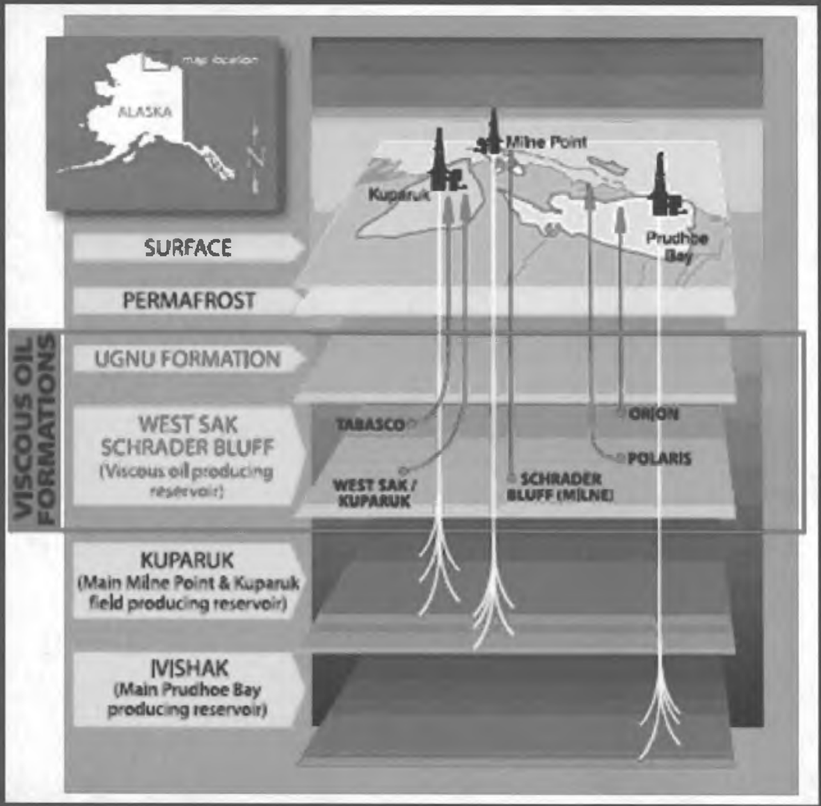
- Frankly, Alaska also has been fortunate because of the companies involved

The high cost of doing business in the Arctic suggests that only the world's largest oil companies, most likely as partners in joint venture projects, have the financial, technical, and managerial strength to accomplish the costly, long-lead-time projects dictated by Arctic conditions.

Energy Information Administration, Arctic Oil and Natural Gas Potential (Oct. 19, 2009)

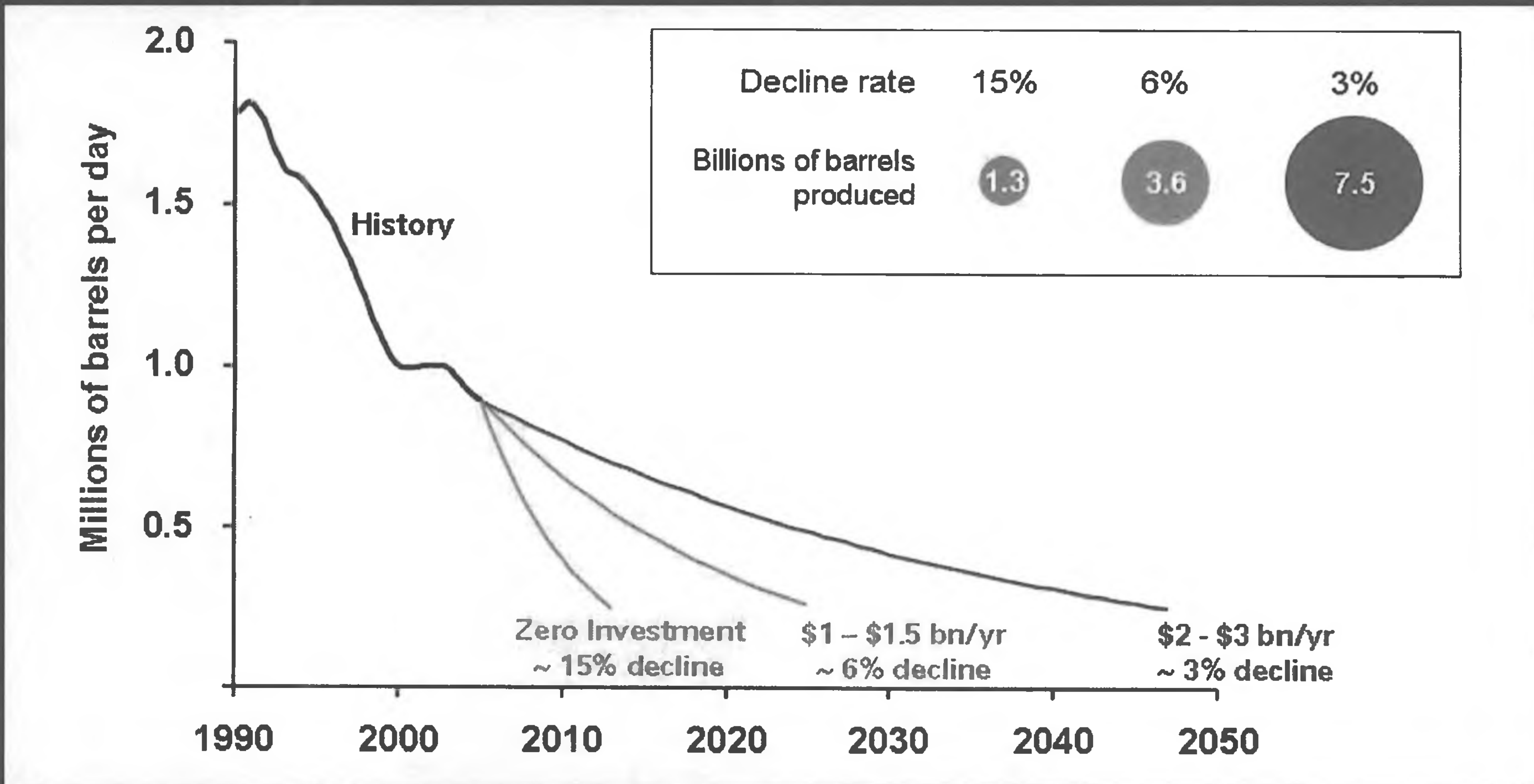
What is happening in Alaska

- There is significant remaining potential in Alaska, even in existing areas
- From *EconOne*: Viscous and Heavy Oil (Includes All Schrader/West Sak and Ugnu Reservoirs in the Kuparuk River, Prudhoe Bay, Milne Point and Nikaitchuq Units, Not Just PAs or Areas Under Development)
  - Total In-Place Resource: 24 - 27 Billion Bbls
  - Economically Recoverable: 3.6 - 5.6 Billion Bbls (at 15%)
- Satellites and recovery rates



What is happening in Alaska

- But it requires investment…



What is happening in Alaska

- Commissioner Dan Sullivan

"The petroleum industry has to ratchet up Alaska investments in ***new exploration and development*** *to at least $4 billion a year if the decline in oil production is to be reversed, state Commissioner of Natural Resources Dan Sullivan says.*

'We need $4 billion minimum, and we're not even close to that now,' *Sullivan told the Resource Development Council in Anchorage Sept. 15. RDC is natural resource development advocacy group. The number could be higher, too.*

The industry is now spending about $2.5 billion a year in capital investment, according to the state Department of Revenue, but most of that is related to facility upgrades in existing fields and not in new drilling or developments that add new production."

Alaska-Journal-of-Commerce, September 22, 2011

What is happening in Alaska

- …and that is not happening

Capital Spending

		Millions of Dollars		
	2012 Budget	**2011**	2010	2009
Capital Expenditures and Investments				
E&P				
United States—Alaska	$ 900	**775**	730	810
United States—Lower 48	4,800	**3,880**	1,855	2,664
International	7,600	**7,350**	5,908	5,425
	13,300	**12,005**	8,493	8,899
Midstream	-	**17**	3	5
R&M				
United States	1,000	**768**	790	1,299
International	200	**226**	266	427
	1,200	**994**	1,056	1,726
LUKOIL Investment	-	-	-	-
Chemicals	-	-	-	-
Emerging Businesses	100	**30**	27	97
Corporate and Other	200	**220**	182	134
	$ 14,800	**13,266**	9,761	10,861
United States	$ 7,000	**5,679**	3,576	4,921
International	7,800	**7,587**	6,185	5,940
	$ 14,800	**13,266**	9,761	10,861

What is happening in Alaska

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2009 Budget	**2008**	2007	2006
E&P				
United States—Alaska	$ 832	**1,414**	666	820
United States—Lower 48	2,668	**3,836**	3,122	2,008
International	5,959	**11,206**	6,147	6,685
	9,459	**16,456**	9,935	9,513
Midstream	7	**4**	5	4
R&M				
United States	1,409	**1,643**	1,146	1,597
International	577	**626**	240	1,419
	1,986	**2,269**	1,386	3,016
LUKOIL Investment	—	**—**	—	2,715
Chemicals	—	**—**	—	—
Emerging Businesses	100	**156**	257	83
Corporate and Other	150	**214**	208	265
	$ 11,702	**19,099**	11,791	15,596
United States	$ 5,076	**7,111**	5,225	4,735
International	6,626	**11,988**	6,566	10,861
	$ 11,702	**19,099**	11,791	15,596

Where do go from here …

- The best tool that Alaska has is fiscal policy
  - Can't change environment, remoteness, can only have a limited effect on cost
  - Can try to affect, but can't control federal actions
  - *But* can affect the economics
- Important elements of fiscal policy
  - Competitiveness
  - Durability
  - Neutrality
  - Simplicity/Predictability
  - Alignment

Where do we go from here …

- Competitiveness
  - Competitive with alternative investments
- Durability
  - *No* prospect of "bait and switch"
- Neutrality
  - Government not trying to pick "winners"
  - Can't outguess technology and investment dynamics
  - Law of unintended consequences (undermines durability)

Where do we go from here …

- Simplicity/predictability
  - Avoid "surprises" (e.g., regulations to follow, need for interpretation)
- Alignment
  - Alaska needs to remain aligned with its investors

Where do we go from here …

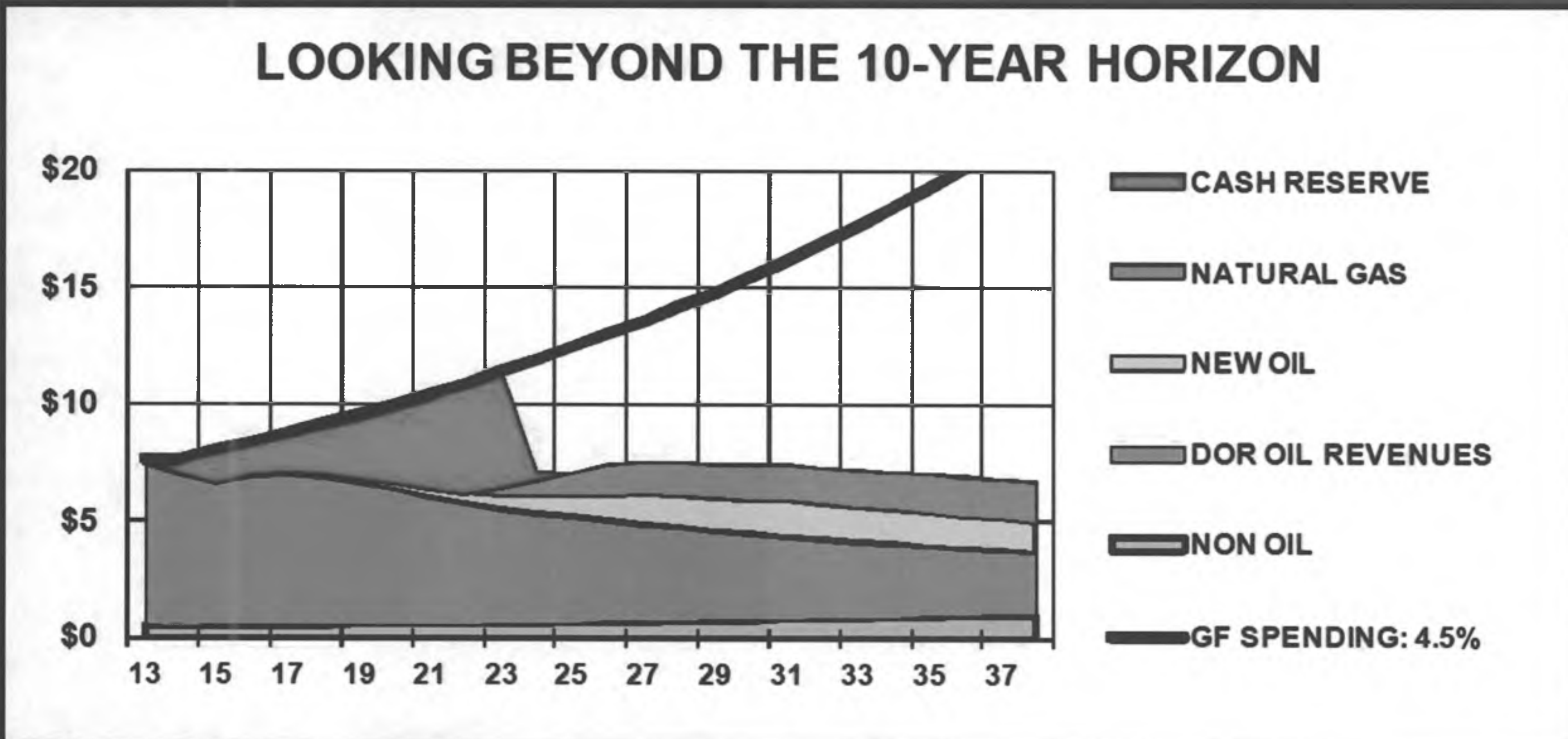
- Alignment
  - In all fairness, Alaska does not have a good mechanism for remaining aligned with investors
  - Not that important during the height of Prudhoe and Kuparuk, and relatively low tax rates – investment took care of itself
  - But alignment is increasingly critical to maintain and attract new investment – especially at the levels suggested by Commissioner Sullivan

Where do we go from here …

- Alignment (con't)
  - Best approach in the world in my experience is Norway
  - *Not* Statoil (an operating oil company), but Petoro
- Petoro
  - Co-invests alongside industry: sees the same opportunities and challenges as industry – able to help inform the state
  - Helps identify and maintain focus on local opportunities that make economic sense
  - Helps maintain other criteria: competitiveness, durability , neutrality and simplicity
  - ***And***, brings additional capital to the development of resources
- Suggest this Committee include as part of its review

Where do we go from here …

- Durability
  - Involves more than just tax or royalty policy; necessarily involves overall fiscal policy



Where do we go from here …

- Dealing with spending and the fiscal gap is key to attracting long-term investment
  - Resolving tax rates might attract short term investment
  - Investors can see the same thing as ISER, however; unless the spending and the fiscal gap is resolved, long-term investment (i.e., big projects) will continue to look elsewhere
  - Alaska's history is that each time the state has needed more revenue, the state has changed the tax structure
- Looking at even best case investment and production levels (see graph at p. 23), investors will not believe that increased production alone will close the gap
- As a result, from the standpoint of significant long-term investment, ***dealing with this issue is as important as dealing with current tax rates***

Conclusion

- There are significant opportunities, especially in existing fields
- The opportunities are significantly challenged, however, by global competition for capital

The bottom line for Arctic oil and natural gas potential is that high costs, high risks, and lengthy lead-times can all serve to deter their development in preference to the development of less challenging oil and natural gas resources elsewhere in the world. … while the Arctic has the potential to be a more important source of global oil and natural gas production sometime in the future; the timing of a significant expansion in Arctic production is difficult to predict.

Energy Information Administration, *Arctic Oil and Natural Gas Potential* (Oct. 19, 2009)

Conclusion

- The key lever available to Alaska for attracting investment is its fiscal policy
- While dealing with tax rates is important, it alone isn't sufficient to attract significant, long term investment
  - State needs to align with investors
  - Address the coming fiscal gap now

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February 7, 2013

The Honorable Senator Cathy Giessel
Chair, Senate Resources Committee
State Capitol, RM 427 465-3875
Juneau, Alaska 99801-1182

Re: Supplemental Materials to February 4, 2013 Hearing

Dear Senator Giessel:

Thank you for the invitation to testify before the Senate Resources Committee on Monday, February 4, 2013, on "Oil Resources: Economic Challenges & Opportunities." The purpose of this letter is to provide supplemental materials which were requested and I offered to provide during the course of the hearing.

The first is the source document for the graph which I included at Slide 23 of my testimony. That graph is from testimony submitted before Senate Resources in 2006 and shows the anticipated North Slope oil decline curve under three investment scenarios. During the course of the testimony Senator Micciche asked for the source of the graph and I promised to provide it.

Attached as Appendix A is a document entitled, "BP Presentation on Proposed PPT, Alaska State Legislature, House & Senate Resources Committees, 28th February 2006." The document is publicly available at http://www.akrepublicans.org/houres/24/pdfs/houres_hb488_12.pdf. The graph included with my testimony appears at page 9 of the testimony. The testimony accompanying the graph is as follows:

> The black line on this chart shows the history of North Slope production. The coloured lines look forward to the future.
>
> With no investment the natural decline of the fields would be the lower red line and with in (sic) 10 years the business would be gone.
>
> With the current levels of investment of $1 – 1.5 billion/year (which assumes the current tax regime), history tells us that decline will be around six percent per year. With that

91004-0002/ADMIN31043547.1

> trajectory we can expect the business to last around 25 years, but nowhere near long enough to enable gas.
>
> In order to enable gas we must reduce the rate of decline even more. 3% decline would require twice as much capital as is being spent today ($2 - $3 bn dollars per year). That is $20 to $30 billion dollars over the next decade alone. Alaska must compete to attract these dollars!

As I said during the hearing, an additional chart going to a similar point was submitted during last year's session. That chart appears at page 9 of the testimony attached as Appendix B. The testimony is publicly available at http://www.legis.state.ak.us/basis/get_documents.asp?session=27&docid=13139.

In addition to these charts, I promised also to submit an additional piece that I had written previously which explained further the points I raised at Slides 27 – 29 of my testimony ("Where do we go from here"). That piece, "Five things to look for in oil tax reform …," is attached at Appendix C. It is publicly available at http://bgkeithley.com/2012/11/23/five-things-to-look-for-in-oil-tax-reform/.

I have provided a copy of this letter and the attached materials by email to the other members of the Committee and Ms. Long. Because the materials are referred to during the course of the testimony, I would request also, if appropriate, that the materials be included additionally in the online folder appropriate to the hearing.

Please do not hesitate to advise me if further materials or explanation are appropriate. Thank you again for the opportunity to appear before the hearing.

Very truly yours,

Bradford G. Keithley

cc: Senator Dyson, Vice Chair
Senator Micciche
Senator Bishop
Senator McGuire
Senator Fairclough
Senator French
Ms. Sharon Long

BP Presentation on Proposed PPT

Alaska State Legislature
House & Senate Resource Committees
28th February 2006

Introduction – Ken Konrad

My name is Ken Konrad. I am Vice President, Gas for BP Alaska. We are here today to talk to you about the proposed PPT legislation – HB488 / SB305. I will make a few opening comments and then turn things over to Angus Walker and our PPT team.

Agenda

bp

- How we got here
- Current realities of the Alaska North Slope
- Global perspective
- Impact of PPT on BP Alaska

Ken Konrad	*Gas Vice President BP Alaska*
Angus Walker	*Commercial Vice President BP Alaska*
Ray Hall	*Senior Tax Economist BP Group*
Tom Williams	*Alaska Tax Counsel BP Alaska*

2

How we got here

Last week, after more then two years of negotiations, and a lot of hard work on all sides, we reached a very finely balanced agreement with the administration on a predictable and durable Fiscal Contract with Alaska. The Fiscal Contract will establish clear rules governing payments-in-lieu of taxes we would make to the State, including a PPT payment incorporated by reference from this legislation. Once ratified, the Fiscal Contract will enable a gas pipeline to advance in partnership with the State as an equity participant.

Much of what is contained in the PPT legislation was born in part out of the Fiscal Contract negotiations we've been in with the administration. I thought it would be useful to share an overview as to how and why we arrived at this point given that many of the discussions to date have been confidential as stipulated in the SGDA.

Mother Nature - oil and gas are unavoidably linked
Oil and gas form together when plants (and dinosaurs) are buried deep beneath the Earth's surface and, under great heat and pressure, are transformed into oil and gas.

The oil and gas co-exist in the same underground reservoirs, they are produced together through the same wells, flow together through the same flowlines and are processed together in the same facilities. Some fields have more oil than gas and some fields have more gas than oil or condensate. But it is exceedingly rare that one is produced without the other.

Because oil and gas co-exist physically, and are produced together through the same investments made in wells and facilities, they are also linked economically.

This inextricable physical and economic linkage is widely recognized by both governments and investors around the world.

North American royalty contracts cover both oil and gas. Internationally, production sharing contracts include terms for both oil and gas. General oil and gas tax laws across the U.S. and internationally always address both oil and gas.

Governments want to know how much money they will receive from oil and gas production. Similarly, investors need to know how much they will pay governments when oil and gas is produced and sold and make their investment decisions accordingly.

The economic linkage of oil and gas is particularly acute here in Alaska when considering a gas pipeline given the unique operating challenges on the North Slope and the criticality of economies of scale.

Oil Decline - additional oil investment needed to support ANS gas development
We, the producers and the State, currently have a problem. ANS oil production has been declining for over 15 years and *has been on an unsustainable trajectory.* Investment by all of industry has been insufficient to limit decline.

Unless we, and here I mean the entire industry in partnership with the State, are able to maintain economic levels of oil production to support and maintain vital North Slope infrastructure for many decades to come, a gas project can't be successful – it simply cannot be burdened with the cost of uneconomic oil production.

Investors need confidence that the fiscal regime will be sufficiently competitive to attract the enormous amounts of additional capital needed to maintain economic levels of ANS oil production for decades. Providing this confidence benefits both the State and investors against our common enemy – *production decline.*

Building a gas pipeline is effectively a commitment by the major producers to maintain vital North Slope infrastructure for another 40-50 years – This is a daunting challenge.

- Will there be enough investment to stem the long term decline in ANS production?
- Will there be sufficient oil production to keep the unit costs of operating TAPS at an economically viable level?
- Will there be sufficient oil production to cover the operating and maintenance investment costs of operating aging production facilities?

The answer can be yes. We know the oil is up there. Billions of barrels of oil that might otherwise be left behind in producing fields can be accessed. Viscous oil in and around existing infrastructure that was discovered decades ago holds promise. Exploration near existing fields and beyond in areas like NPRA may have potential.

But it is all very difficult. ANS production is declining for a reason – not for lack of oil, but for a lack of profitable ways to extract it. The totality of industry costs and taxes are high. But, we do believe with the right technology and the right fiscal regime, these historically unprofitable investments can be made viable so industry can convert resources into production to sustain ANS infrastructure.

This is why oil taxation policy should *appropriately balance risks and rewards* to enable this additional investment. Even prior to this proposed tax increase, investment has been insufficient to prevent ongoing production decline. The legislature needs to very carefully consider the impacts of a very large tax increase on future investment and long term production.

This is an important decision. And it should not and cannot be a shortsighted decision based on next year's budget or political calculus – this is our collective future.

Are we feeding or starving the golden goose? Will North Slope investment increase or decrease as a result of significantly higher taxes? Will the long term decline in oil production increase or decrease as a result?

What are the knock-on revenue effects on royalty, State Corporate Income Tax, and AVT taxes if investment is impacted? Is a high tax rate at modest prices appropriate?

The evolution of PPT and the Fiscal Contract negotiations
There has been a lot of speculation and innuendo about positions taken by both sides through the negotiation on the PPT. Unfortunately, this appears to be driving perceptions about what the tax rate should be rather than what is right for Alaska and what is right for industry.

I'd like to briefly give you an overview of how the PPT negotiation unfolded to hopefully clear the air and help us focus directly on the real issues at hand.

Since the onset of the fiscal contract negotiations, and indeed years before, BP has sought to make clear the importance of having a competitive and durable fiscal platform for both oil and gas to underpin a massive gas investment. Including both in the Fiscal Contract is important for two fundamental reasons among others.

First, it provides confidence that the level of taxation will be competitive to enable the additional investments needed to mitigate the ongoing decline in ANS oil production so vital infrastructure can be maintained for another 40-50 years.

Second, it protects us from after the fact tax increases on our business after a gas pipeline has been built and we have no choice but to pay and produce regardless. This is what happened as TAPs entered service some 30 years ago.

In summary, both a competitive and durable oil tax regime are essential and should align well with State goals.

In the summer of 2005, the administration advised us that although they respected the importance to investors of having competitive and durable rules for both oil and gas in the Fiscal Contract, they did not see the ELF regime as properly suited as a long term solution. The concern being the tax base underpinning ELF was declining with time.

The concept of a PPT type structure was proposed by the administration to fix the so called ELF problem. We responded to the administration that if populated with balanced numbers, the PPT could be a viable long term structure with potentially positive attributes for both the State and industry.

In this regard we agreed to move off our preferred position which was to simply utilize the existing ELF based system for the duration of the fiscal contract and consider the PPT structure.

At that time, the mutually agreed goals of both sides for the PPT included:

1. all barrels should be subject to taxation
2. provide the State a balanced and proportionate share of the price / profit upside
3. stimulate additional investment critical to reduce long term production decline

Proposals were discussed intermittently through yearend and it was clear that there was a significant difference of opinion as to what numbers would create a balanced PPT that met these goals.

During that time, the State initially proposed and held to a 20% tax rate. The Sponsor Group had proposed a tax rate of 12.5% which we estimated would have increased State revenues by hundreds of millions of dollars per year at current prices and tens of billions of dollars over the long term relative to ELF. It would also have, we believe, stimulated more investment, more jobs and most critically more long term production.

On Saturday, February 18th, following a long and at times difficult negotiation, we were able to agree and conclude the gas portion of the Fiscal Contract with the State. The following day, we made another PPT proposal for the State to consider in advance of the planned executive meeting, including our Chief Executive, Dr. Tony Hayward.

This proposal made a very substantial move towards the administration's position while providing more support for investors at low to moderate prices where everyone agrees Alaskan investments are extremely challenged.

On Monday morning, February 20th, the Governor outlined to Dr. Hayward and the other executives his 20 / 20 PPT proposal. The proposal we had made to the administration the day before was rejected.

BP has agreed with the Governor that we will not oppose the rates and figures in the proposed PPT legislation before you today. Our Chief Executive and others have made the extremely difficult decision to accept the Governor's terms as a means to finalize a Fiscal Contract. We do believe that this PPT is at the far outer fringe of what should be seen as a reasonable or plausible range of outcomes.

We also need to be very frank with this legislature by saying upfront that we do not believe the 20% rate will maximize investment or in turn maximize long term production. Although the PPT structure has significant merit, and we support it, the overall size of the tax increase outweighs, we believe, the other benefits and goes well beyond optimum.

I hope this context has been helpful. We genuinely hope that this bill can be progressed in a thoughtful and objective manner. Alaska is at a crossroads.

I'll now turn things over to Angus Walker and our PPT team.

Introduction – Angus Walker

I am Angus Walker and I am the Commercial Vice President of BP Alaska.

I would like to start by thanking this Committee for this opportunity to provide testimony on the very important matter of House Bill 488 / Senate Bill 305

We recognise that between PPT and in due course the Gas Fiscal Contract you have decisions to make of great importance for the future of Alaska. We respect the responsibility that the Legislature has to do the right thing for Alaska and hope that we can inform those decisions through our testimony.

I would like to introduce my associates –

Ray Hall: Senior Tax Economist with BP Group in London

An economist by background, Ray has worked with BP since 1988, initially in commercial roles but latterly as a senior adviser on fiscal issues. Ray has held positions in organizations outside of BP including the United Kingdom Offshore Operators Association (UKOOA) and the International Association of Oil & Gas Producers (OGP). His most recent focus areas have been UK, Norway, Egypt and Trinidad.

Tom Williams: Tax Counsel for BP Alaska

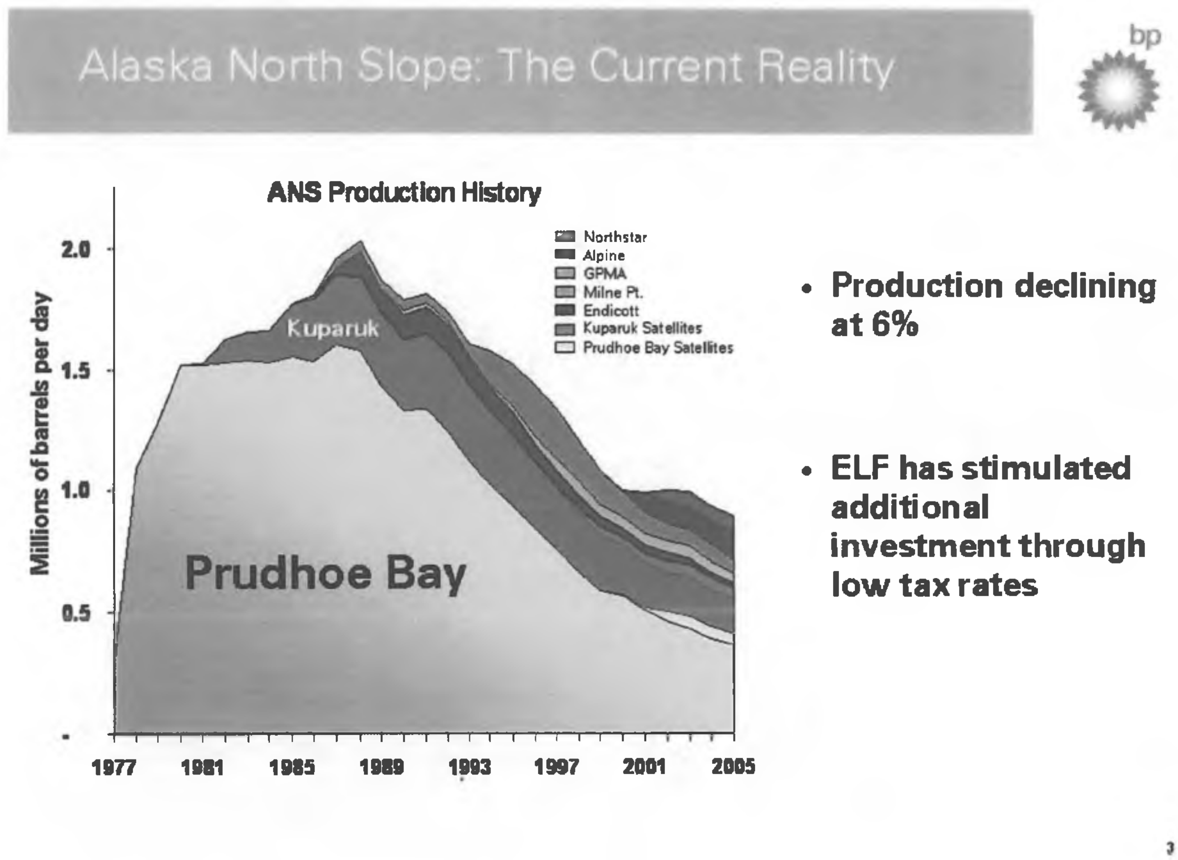
It is particularly appropriate to have Tom here. He was Commissioner of Revenue for Governor Hammond and is widely recognised as the creator of ELF.

Our testimony will be in three parts, all of which are directly relevant to PPT and the issues before you:

- I will start by describing the current realities of our business and the remaining resources of the North Slope
- Ray will provide a global perspective by comparing fiscal regimes in a selection of the countries in which we do business
- I will conclude by describing the impact of this PPT legislation on BP's business in Alaska

It should be noted that since BP only has leases on the North Slope and in the Beaufort Sea, our remarks will be confined to that business and not other basins like the Cook Inlet in which we do not participate.

Current realities of the Alaska North Slope



We're looking at a profile of historical production from 1977 through 2005. The North Slope has produced over 15 billion barrels of oil to date, and while we look back with envy at the days of peak production it is clear that the business today is very different than it was 20 years ago.

To date BP has invested $24 billion to create the Alaska business we have today. We have paid over $32 billion of tax to the State of Alaska and $24 billion of tax to the federal government.

In total we estimate that the North Slope participants have generated $120 billion in taxes for Alaska & the Federal Government since first production in 1977. In addition, as an industry, we generate more than 34,000 jobs in Alaska every year.

But the harsh reality is that since production peaked in 1988, production has declined at an average 6%.

What this doesn't show is the underlying decline which would have occurred without the tens of billions of dollars industry has invested to stem decline. Natural decline of these fields is around 15%. As an industry we've managed to stem that decline to, on average, 6% over the last ten years by investing between 1 and 1.5 billion dollars a year in the North Slope business.

ELF has worked as intended

Each of the small wedges on this production profile represents the contribution from one of the North Slope's smaller fields. Many of these fields would not have been developed without ELF. And yes, whilst much but not all of this production pays Production Tax, it <u>all</u> pays property tax, royalty and state income tax and helps keeps TAPS operational and economic.

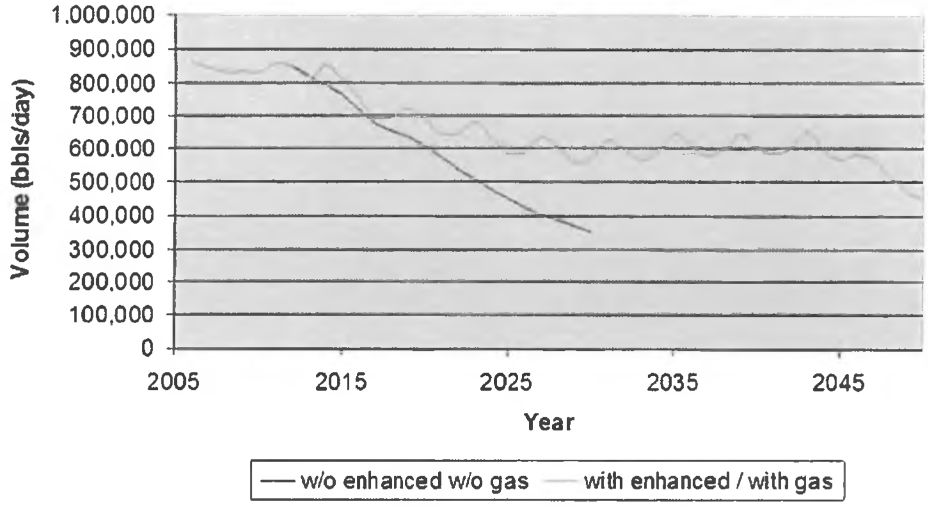
ELF <u>has and continues to</u> encourage investment in these small or less productive fields, and has played a significant role in stemming overall North Slope decline.

However, we recognise that ELF was designed as a surrogate for profitability and while it has been effective it is not perfect in today's price environment. And it is for that reason that we are supportive of adopting the PPT structure proposed by the Administration.

One of the most important issues for this committee to consider is the impact PPT will have on the decline of the Alaska North Slope.

DOR Scenarios

Figure 1
Volume Scenarios



Source: *DOR Testimony: PPT Analysis020106 (DOR).ppt*

4

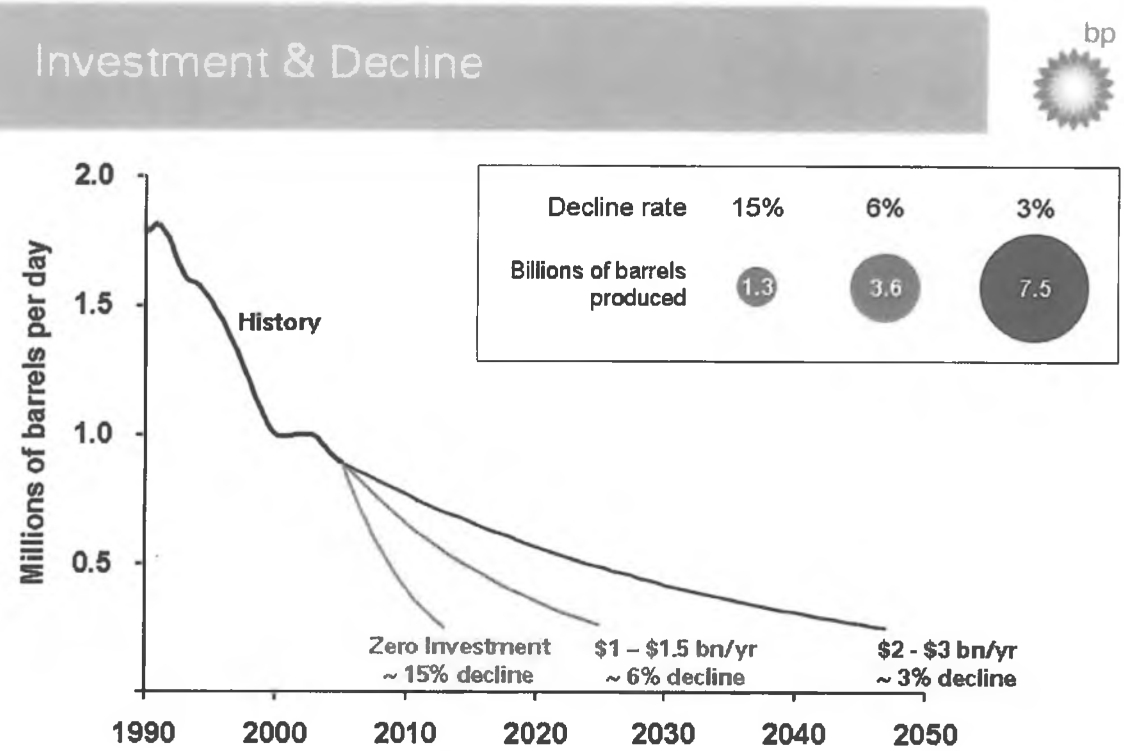
You will recognise the above slide from Roger Marks' presentation last week. It shows two forecasts of future production – the lower blue forecast represents a future without gas, the upper pink line represents a future where the oil business is revitalised by gas.

We agree that the futures with and without Gas look very different. A future without Gas is very much shorter and far less exciting than a future with gas!

But, for Gas to work, it must be built on the foundations of a healthy oil business, a business which must remain healthy for 45 years.

So what will it take to keep the oil business healthy?

Investment & Decline



We share the challenge of keeping Alaska competitive

5

The simple answer is to stem decline.

The black line on this chart shows the history of North Slope production. The coloured lines look forward to the future.

With no investment the natural decline of the fields would be the lower red line and with in 10 years the business would be gone.

With the current levels of investment of $1-1.5 billion / year) (which assumes the current tax regime), history tells us that decline will be around six percent per year. With that trajectory we can expect the business to last around 25 years, but nowhere near long enough to enable gas.

In order to enable gas we must reduce the rate of decline even more. 3% decline would require twice as much capital as is being spent today ($2 - $3 bn dollars per year). That is $20 to $30 billion dollars over the next decade alone. Alaska must compete to attract these dollars!

We share the challenge of keeping Alaska competitive: the State's part is to maintain stability and keep Alaska attractive to investors; our part is to provide the technology, innovation and investment.

The tax regime you approve will directly impact how attractive Alaska is and what the future decline will be. It is in the interest of all (industry and Alaska) that we focus on growing the pie rather than taking an increasing share of a declining pie.

So where will we find all this oil to stem decline?

The good news for Alaska is that we have a huge resource base!

Alaska has lots of oil and gas!

bp

		Billion barrels equivalent
Produced		**15**
Known Remaining		**17.5**
Developed	- Light	3.5
	- Viscous	0.3
Undeveloped	- Light	4
	- Viscous	0.7
	- Heavy	3
	- Gas	6
Yet to Find (Exploration)		**5**

Recoverable Resource

Source: DOR / USGS / BP

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To date we have produced 15 billion barrels, but there are 17.5 billion barrels remaining that we already know about, 3.8 billion barrels of which have been developed to date.

The remaining 14 billion barrels consists of:

3.5 billion bbls of light oil remaining in the existing reservoirs
1 billion bbls of viscous oil which we have started to produce
3 billion bbls of heavy oil lying in shallow formations below the permafrost
6 billion bbls of gas which we are working so hard to get to market

The scale of this known resource greatly exceeds that expected from future exploration. Future discoveries are expected to be of the order of 50-150 million barrels. It's not to say you should stop exploring, but you cannot rely on exploration to stem the decline of the North Slope.

While BP isn't exploring in the conventional sense, we are adding barrels. We're not only looking at develop our share of the 17.5 billion barrels, but we're looking to make it even bigger.

To put that in perspective, every time we increase the recovery efficiency by just 1% we access an additional 600 million barrels (400 mmbbls light oil and an additional 200 mmbbls heavy oil)….. Every 1% is equivalent to another Alpine!

It is for this reason we're investing in technology. We're exploring within our existing fields.

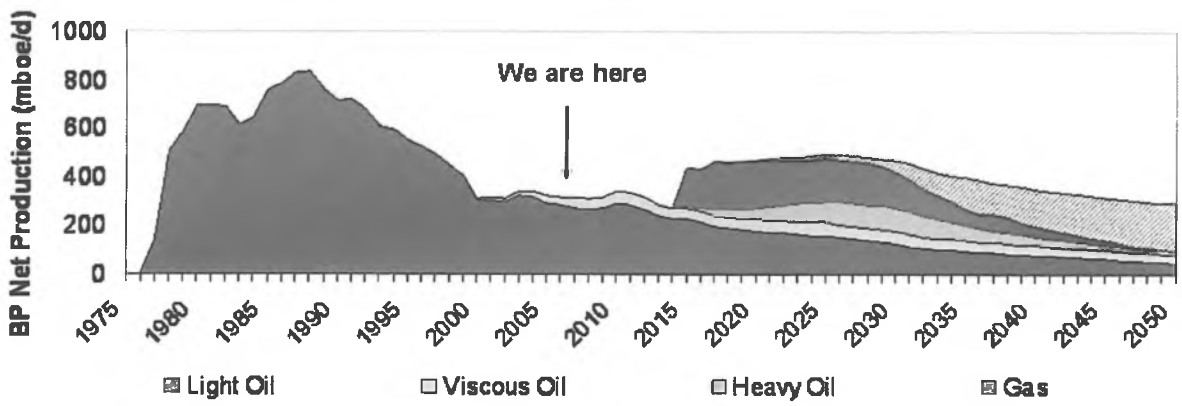
One example is that we're spending in excess of $100 million implementing innovative technology to increase recovery at Endicott. If we're successful at Endicott it could add hundreds of millions of barrels of production across the North Slope. (Another Alpine?)

To develop the 14 billion barrels we know about would require well in excess of $100 billion. And that kind of investment can only come from the Major oil companies of the world a fact supported by Pedro Van Meurs testimony. It thus mystifies us why so much of the testimony given to this Committee by Pedro Van Meurs focussed on the impact of PPT on new entrants when the future of the North Slope is dependant on making Alaska attractive to Major oil companies.

This is the reality of our business and the reality of the North Slope today.

It's the reality we encourage you to look at as you consider House Bill 488 / Senate Bill 305.

A 50 year vision



This is the graphic we use when we describe our vision for our business in Alaska.

It shows BP's production both historical and future. A few points we always make when we talk to this are:

a) The future will be very different to the past.
b) Three businesses built on top of each other all of which must be healthy.
c) We face enormous challenges in creating this future
d) Attractive and stable fiscal terms are key to making this happen, without it our vision will not come true.

I will now hand over to Ray Hall, who is going to provide a global perspective after which I will describe the impact of PPT on BP's business in Alaska.

Global Perspective

Refer to Raymond Hall's slides
[2006-02-28 BP Testimony - Global Perspective.pdf]

Impact of PPT on BP in Alaska

Much of the analysis presented to this committee has been based on specific cases – (50, 150, 500 mmbbl fields). These are of course academic examples and what I will do is to clarify the impact of implementing PPT on BP's business in Alaska.

I will do this through the lens of Government take.

Government Take

bp

$$\text{Government Take} = \frac{\text{Total Taxes}}{(\text{Total Taxes} + \text{Industry Profit})}$$

Government Take in Alaska comprises 5 elements:-

• Royalty • Production Tax • Property Tax • Income Tax	State Taxes
• Federal Income Tax	Federal Taxes

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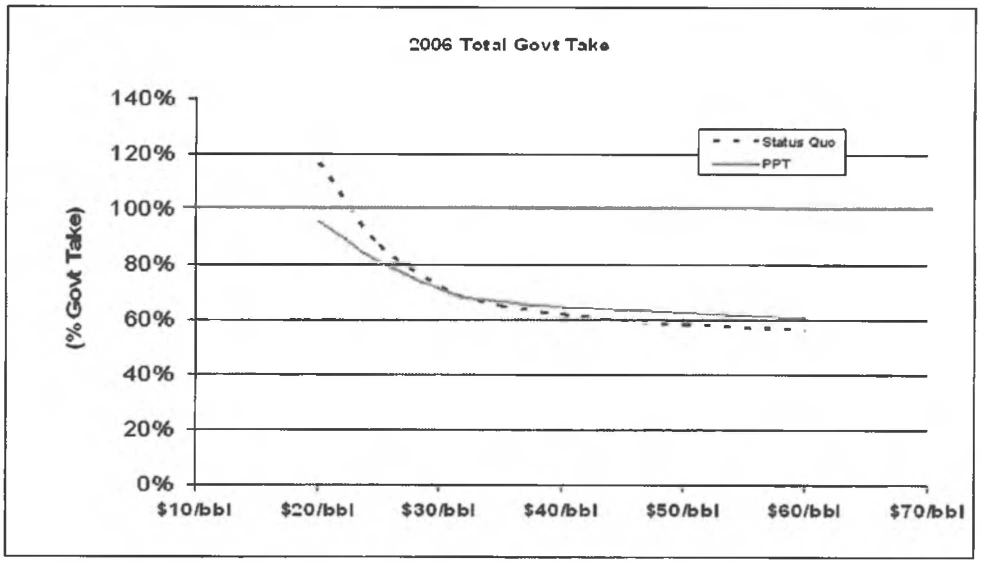
Government take is the percentage of total profit which is taken by government (in this case both State & Federal) with the remaining being the profit which goes to the investor.

Government Take is made up of a total of five elements: State income tax, property tax, royalties, production tax, and Federal income tax. The Investor's take is the investor's profit.

PPT Impacts on BP Alaska
Government Take vs. Price



- ***Government Take extremely high at low & medium prices***
- ***Investors must make a reasonable return at medium to high prices for Alaska to be attractive***

This chart shows the total Government take at different oil prices for the current Elf based system and PPT.

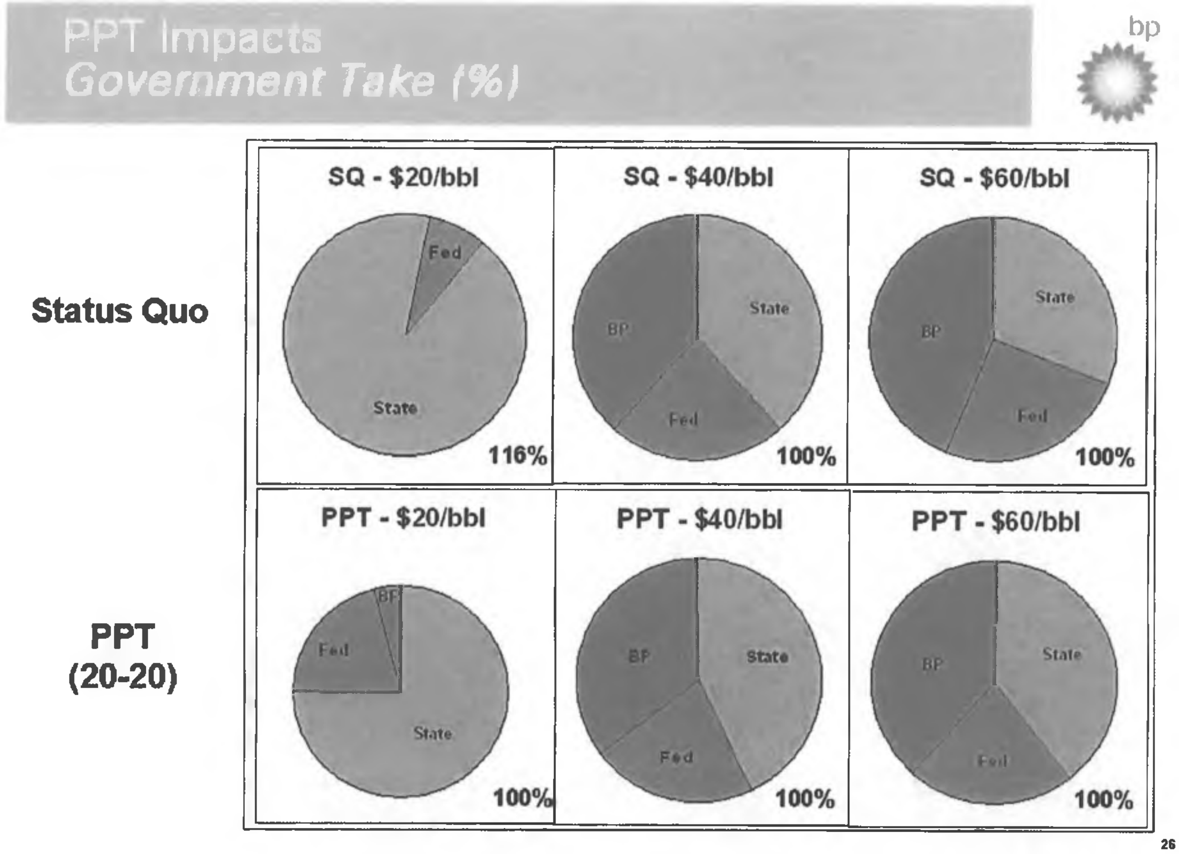
That's the real Government take on BP's business in Alaska.

The first point to note is that at low prices we do not make a profit. We make a loss. But regardless we continue to pay Royalty, Property Taxes and State income tax, which results in a government take of greater than 100%.

Under PPT, the Government take is around 70% at the moderately high price of $30 / bbl. This is very high & especially considering the very high cost of doing business in Alaska.

We absolutely must make a good profit in Alaska when prices are high. We make no profit when prices are low. Alaska is a price play and if you take away the upside price incentive then there is no reason for us to be here.

Alaska is a mature business with a challenged resource. In our opinion you should be concerned about overtaxing the industry rather than undertaxing it.



Here we can see the split between State, Federal and BP take under the current regime and PPT at low, medium and high prices.

The left hand pies illustrate the problem for BP at low prices. Under the current system BP makes a loss at $20 / bbl.

At $60 / bbl the current system provides a higher % to the industry than to the State, but that is not new news. Alaska's fiscal system was designed to protect the state at low prices and compensate the industry at high prices. That is the nature of a regressive tax regime.

Under PPT, we would make an extremely modest profit at $20. At $40 the state gets a considerably higher share than BP. At $60 the State's and BP's take is balanced.

Introduction of PPT squeezes our profit at higher prices, and let's not forget we make the investments, we take the risks and absolutely we have to make a good profit at high prices for Alaska to be attractive.

PPT Impacts
Project Cash Flow

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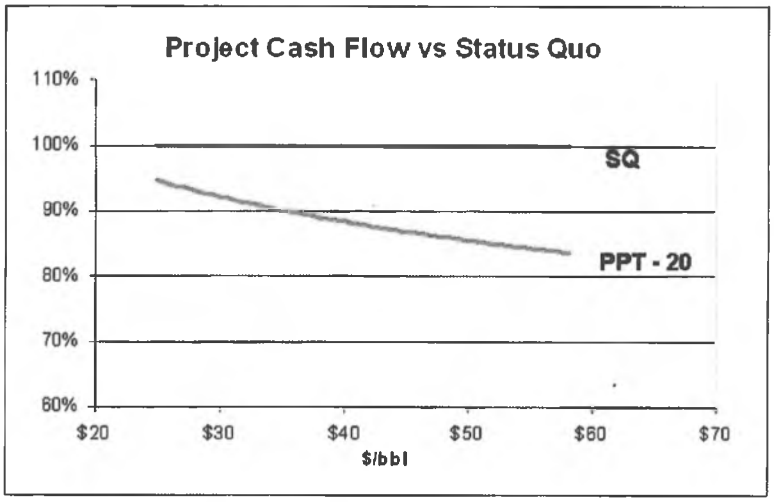

- ***Rate of Return improves, but it's only one measure***
- ***Project Cash is lower at all prices***

So what about future investments? We agree with Pedro Van Meurs, PPT will tend to increase the rate of return on many new projects, but we look at many metrics when making decisions about investing (Net Present Value (NPV), Net Income, and cash flow per barrel are but a few examples).

This graphic shows how PPT (20/20) impacts a new investment.

Rate of return is increased due to the positive impact of the capital credits on the upfront investment, but

Total return to the investor (after tax cash flow) is decreased due to the increased state take. This project takes the same effort / capacity to execute regardless of the tax regime. Increasing State take reduces total returns to investors making investments less attractive.

It is thus our sincere belief that the best result for Alaska is to implement a Petroleum Production Tax with a tax rate less than the 20% proposed by the Administration.

I would like to leave with you the key messages from this testimony.

PPT: Key Messages

- **Decline is a problem**
  Alaska has been in decline because profitability has been insufficient to attract capital, not due to a lack of resources
- **Large increases in investment are required**
  To stem ongoing decline and attract the required investment ($50 - $100bn), PPT must work for the major investors
- **Capital is mobile**
  International investment flows to basins where it can earn a profit
- **Profit-based taxes are superior to revenue-based taxes**
  The PPT structure has merit and could serve Alaska well for the long term
- **Higher taxes means less investment**
  The 20% rate is very high and will not maximize investment and production
- **Oil needs Gas . . . and Gas needs Oil**
  For Gas to work, the Oil business must be healthy

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On behalf of BP I would like to thank you for this opportunity to testify and wish you well with your deliberations.

We will of course be available to provide further testimony as appropriate.

BP Testimony to House Resources and House Energy

Damian Bilbao, Head of Finance, Developments and Resources

April 25, 2012

APPENDIX B
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Agenda

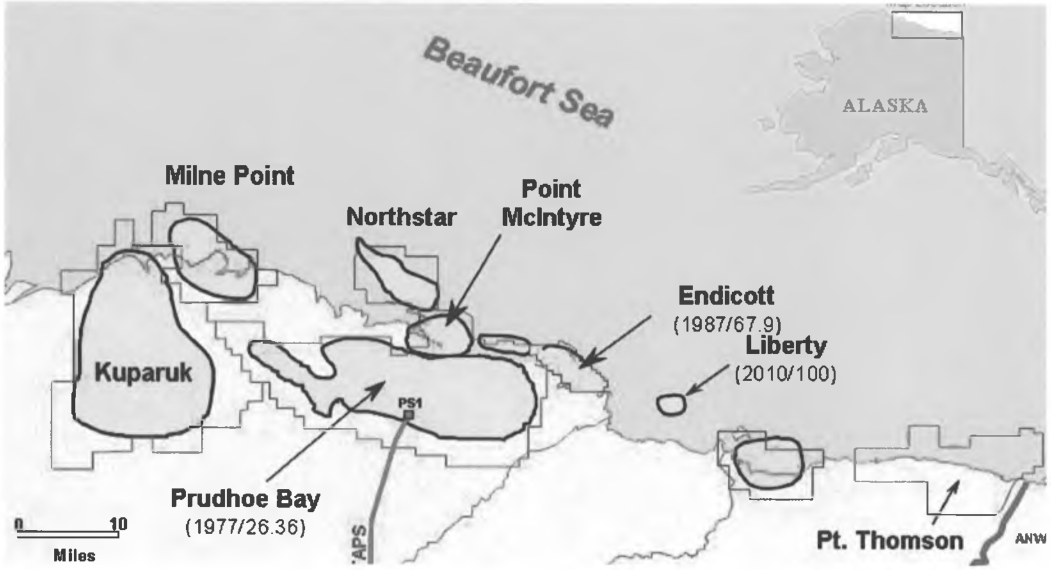
BP in Alaska

How BP makes investment decisions

What could growth in investment mean for Alaska's future

BP in Alaska since 1959

- 53 years in Alaska
  - ➢ Office opened in 1959
- $13.4 billion in upstream spend with Alaska Firms the last 10 years
- 2,100 Employees (82% Alaska residents)
  - ➢ 275 APICC students hired in last 10 years
  - ➢ 54 internships, 100+ fulltime jobs in last 5 years
- 6,000+ Contractors
- $70 million of direct community investment since 2001



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Agenda

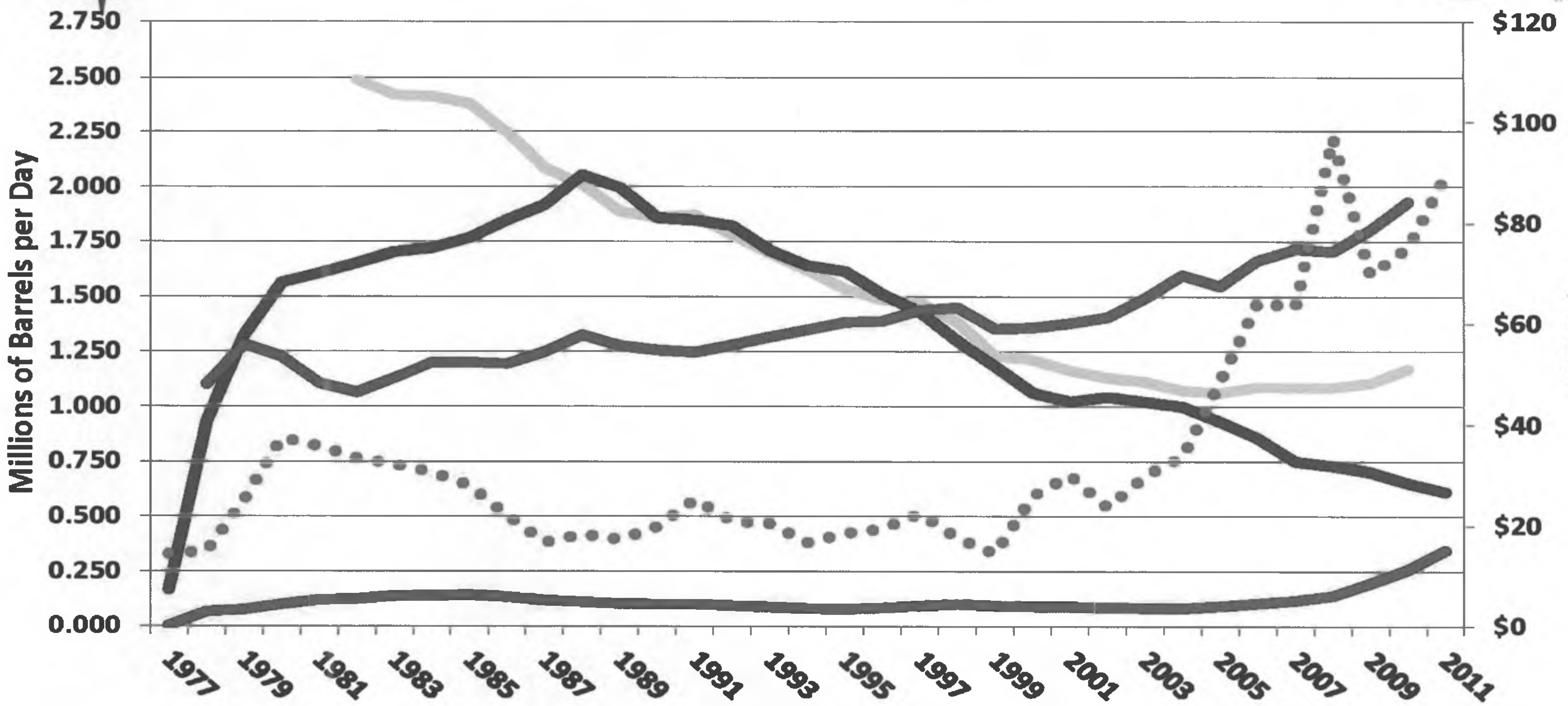
BP in Alaska

How BP makes investment decisions

What could growth in investment mean for Alaska's future

Global investment is limited and goes to the most attractive regions

Historical Oil Production:
How Did Our Competition Fare When Prices Spiked?



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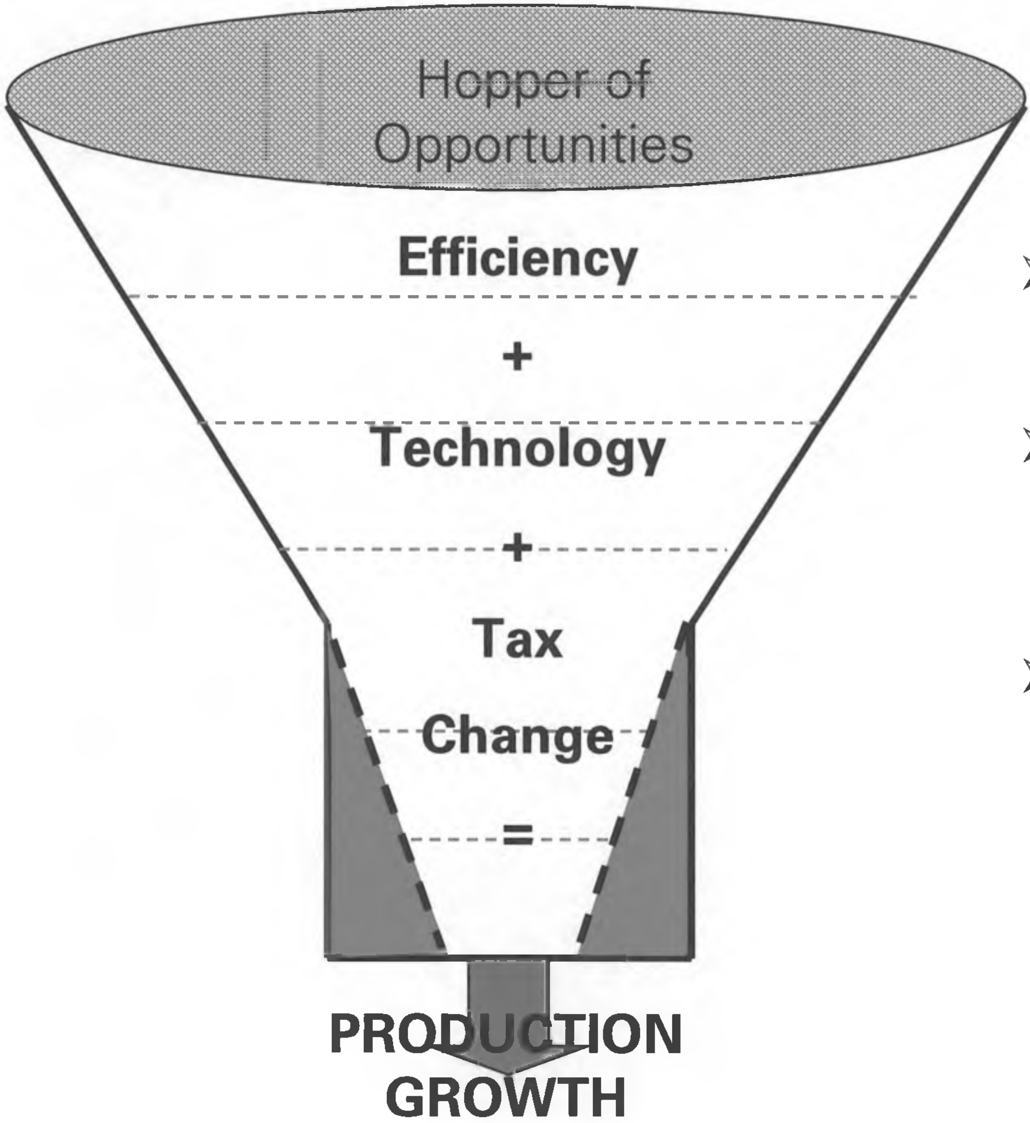
Source: DOR presentation to House Resources, April 21, 2012

The tax policy will greatly influence how many projects move forward



➢ Healthy base business

➢ Brightwater, Multi-lateral drilling, Lo Sal, etc.

➢ $5 billion in potential new investment

- Prudhoe I Pad
- Kuparuk Eastern NEWS
- Prudhoe Sag @ scale
- Add'l drilling in legacy fields

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Agenda

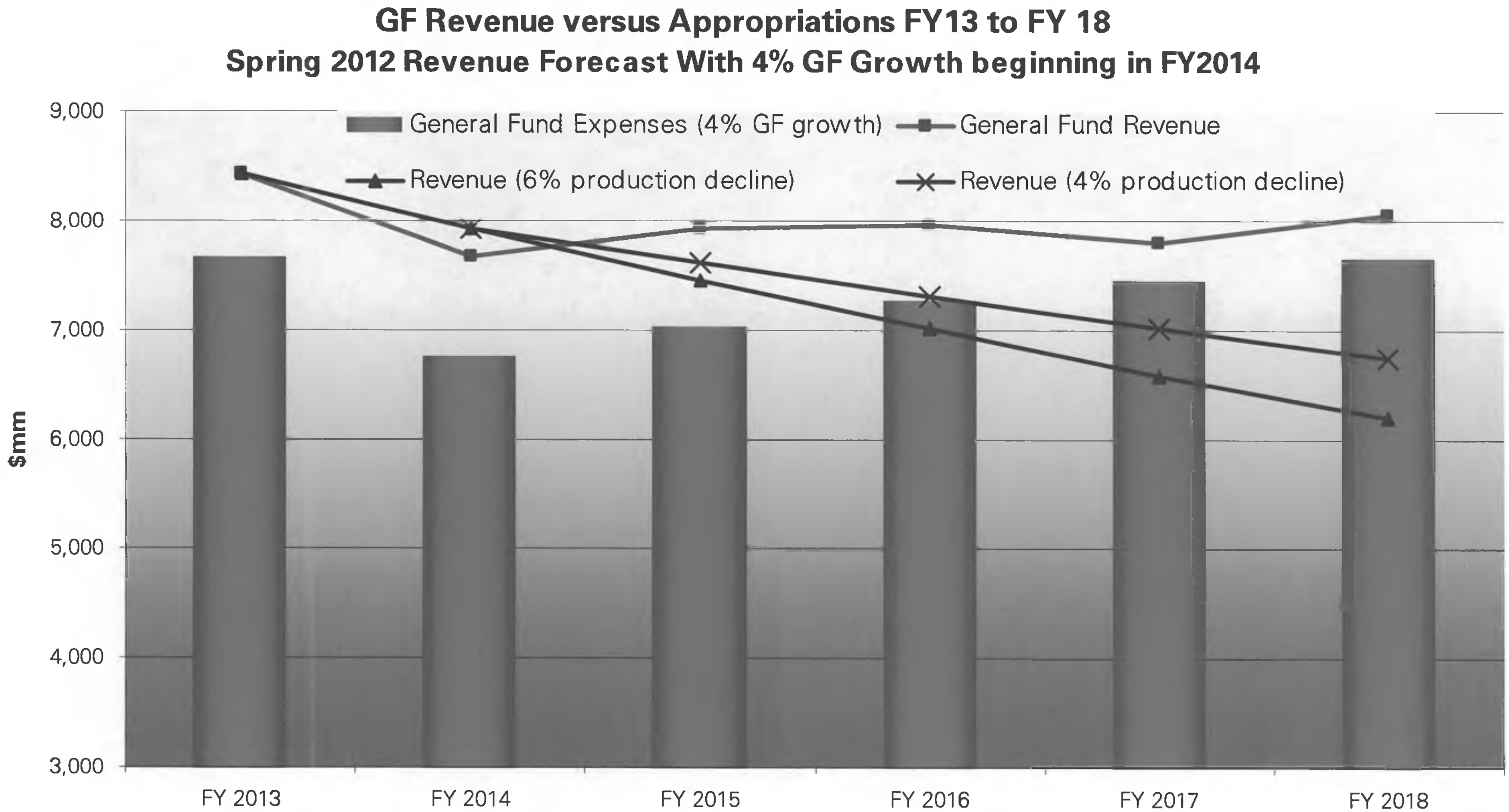
BP in Alaska

How BP makes investment decisions

What could growth in investment mean for Alaska's future

Declining production is a crisis

bp



Source: Office and Management and Budget presentation to House Resources, April 25, 2012

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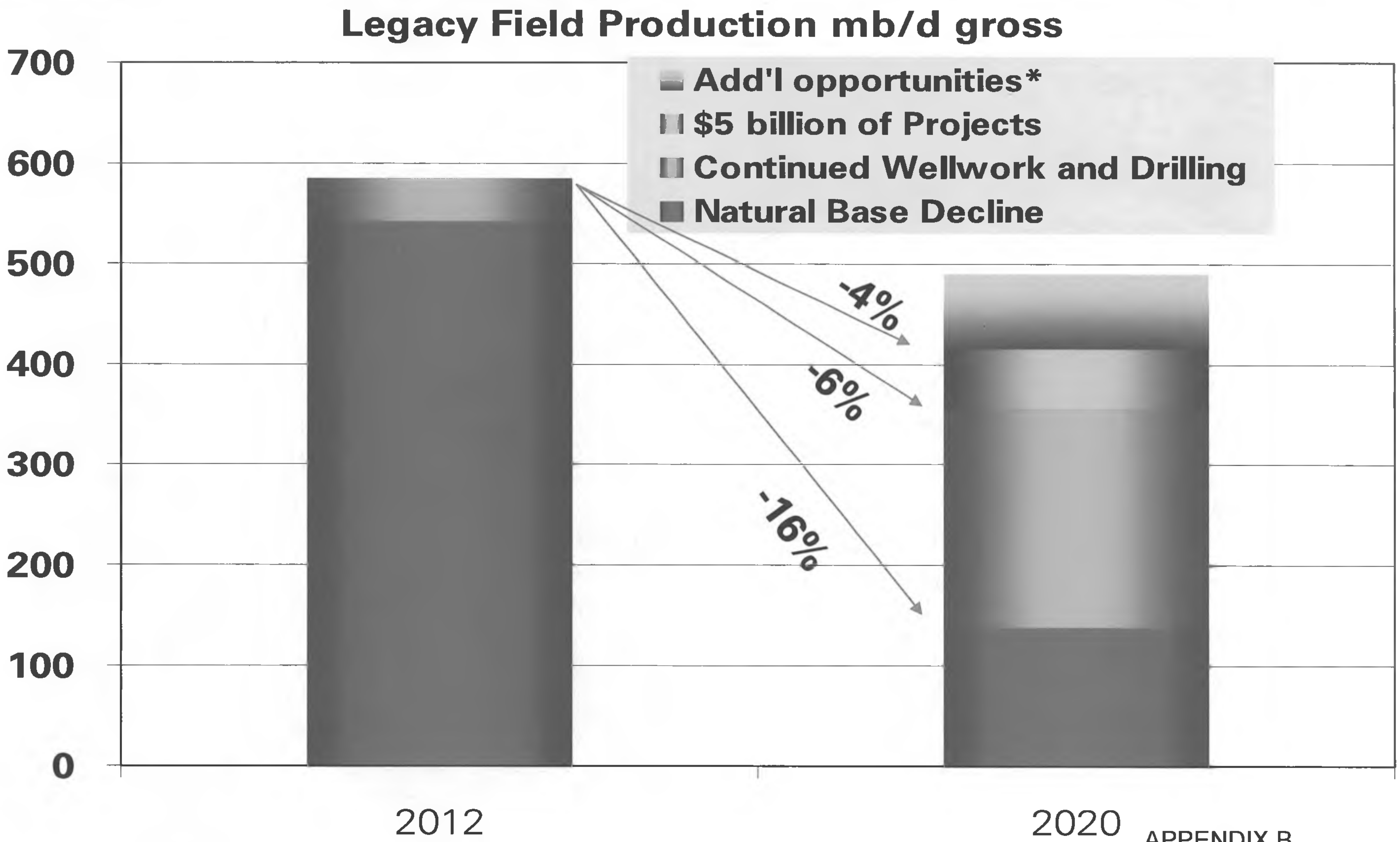
Two-thirds of production in 2020 derives from activity performed from 2012 to 2020



* Indicative

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Key Messages

- ACES is a no growth policy that bets Alaska's future on high oil prices
- Legacy fields are the only near-term option for new production
- If taxes do not change, our business will have to
- Other regions, like Alberta, have lowered taxes and increased investment and production

Thoughts on Alaska Oil & Gas

Brad Keithley's Blog

Five things to look for in oil tax reform ...

Posted on November 23, 2012 | 1 Comment |

Politico, a mostly online newspaper that covers national political affairs — and with which I often open my mornings — routinely attempts to provide readers with a guide to significant upcoming events with a list — usually five — of what they consider the most important things to look for as the event unfolds.

As Alaska begins to consider changing its approach to oil taxes in the upcoming session, I have developed a list of five characteristics that I will look for in evaluating various proposals. I share them for whatever value that may have to others.

1. ***Competitive Rates.*** As a number of other commentators have observed, one of the most important characteristics of ACES that needs to be addressed in order to restore investment is the level of tax — the "tax rate." As former Division of Revenue economist Roger Marks summarizes in a recent piece in the *Oil & Gas Finance Journal*, Alaska's current tax rate under ACES is "fourth highest out of 24 [comparable] regimes." A "comparable regime" means a place "with a comparable risk/reward balance [to Alaska], in terms of features such as reserves, costs, and geological risk."

"For 17 of those regimes Alaska's effective tax rate ranged from 12 to 37 percentage points higher. At a $118/bbl market price, and a $91/bbl net value, each percentage point difference is worth 91 cents/bbl after-tax."

Marks concludes, "because of taxes, ... producers can demonstrably make considerably more money nearly anywhere else in the other comparable jurisdictions than in Alaska."

Achieving tax rates *competitive with comparable jurisdictions* is critical if Alaska is to reestablish significant investment. But rates aren't the only characteristic that is important. Read on ...

2. ***Durability.*** While Alaska previously had made occasional adjustments to its tax policy prior to 2007, none came close to the sea change created by ACES. Compared with ACES, the previous changes mostly could be described as tweaks. By some estimates, ACES increased oil taxes by over 400%.

Because the revised tax applied equally to both old and new investments, ACES had the effect of dramatically altering the economics of investments made not only subsequent to its passage, but also those that were made prior to 2007. At least from the perspective of investors, the 2007 passage of the tax had the effect of retroactively confiscating a significant portion of the return which they had anticipated earning from prior investment decisions.

Going forward, investors will evaluate any proposed change in Alaska's tax structure not only from the perspective of what the change is, but also whether the change is likely to be durable. Now that Alaska has demonstrated an inclination to apply tax changes retroactively to prior investments, investors will be highly concerned about being caught again in a situation where they make long term investment decisions and the state thereafter once again increases the tax structure after a few more years. Investors will be much less likely to invest if that potential remains.

While some legislators (including Republicans) have suggested that the legislature is not able to provide certainty about its tax policy, that is not the case. The state clearly has the power to enter into long term, binding contracts with investors, such as it does with unions and has with investors through oil & gas leases.

Some suggest that the power to tax is unique and one legislature cannot contract away a subsequent legislature's ability to exercise that power. Even if that is true, however, there are other ways of stabilizing total state take, such as by providing that any future increases in taxes can be taken as a credit against royalty. Such "economic stabilization" clauses are common throughout the world.

The extent to which the legislation provides for durability is important. Investors will be ***much*** less likely to commit to substantial, long term projects — the very type of projects that result in significant additions to the supply base — without some assurance that the revised system is durable.

3. *Neutrality.* As I have written elsewhere, one of the worst characteristics of ACES is its vastly differing treatment of various sources of supply. Production from existing units is taxed at a significantly higher rate than is otherwise needed in order to fund direct state subsidies (what some refer to euphemistically as "credits") of up to 60% of total costs for activities undertaken outside of the units.

The result is that activity inside existing units is artificially suppressed while activity outside of existing units is artificially subsidized, appearing to make those activities economic, when they likely are not. ***No*** activity is left to respond to pure market signals.

This approach makes no sense in Alaska's current situation. As I have previously explained, by far the largest new production potential lies inside of Alaska's existing units, and the sources of supply inside the existing units likely can be brought on line faster than those that are located farther from existing infrastructure. As a result, if anything Alaska should favor higher tax credits for the development of new fields located inside of existing units than outside. Currently, however, ACES produces the opposite result.

At their core, credits are a way of substituting government's judgment for business in picking economic winners and losers. Through tax policy, the government favors investment in some activities — the winners – and discourages investment in others — the losers — by raising their costs. ACES backs the wrong horses.

Rather than attempt to outguess the market, the government should adopt a neutral stance between fields and let the market decide which are the most economic to produce.

4. ***Simplicity/Predictability***. One of the most consistent complaints from current and potential investors about ACES is its complexity. While companies can employ people and computing power to deal with complex equations, generally speaking simple tax structures attract more investment than complex structures.

There largely are two reasons for that. The first is that investors generally are concerned that complex tax structures have a greater potential for producing surprises than simple ones — and their experience is that, when they arise, surprises generally produce bad things.

The second reason is that complex tax structures usually are the result of a lot of fine tuning, and that once legislators and regulators start down the road of "managing" investments through the use of the tax code, they can't resist the temptation to continue fiddling with the knobs as the tax structure fails to produce the results that they intended. As a result, complex tax structures tend to be changed more often than simple ones, making them much less predictable.

ACES, literally, is one of, if not the most complex oil tax structures in the world. (With the exception of the 1970 -80's era federal windfall profits tax, ACES is by farthe most complex structure with which I have dealt.) It also is one of the least predictable. Even five years after its passage, very few, if any, audits have been completed and the implementing regulations, which at times are extremely vague, have yet to be interpreted. As a consequence, even now, five years after passage, investors are not certain how ACES ultimately will be applied to investments.

Investors understandably favor simplicity and predictability. To help improve the investment climate in Alaska, the coming changes to the Alaska tax structure should make a ***significant*** move in that direction.

5. ***Alignment.*** As I explain in a recent piece in the *Alaska Business Monthly*, Alaska's current oil policy is significantly out of alignment with the state's own objectives. Certainly part of that relates to the tax code. As explained above, ACES attempts significantly to tilt private investment in Alaska away from the state's largest and best defined new prospects to smaller, uncertain and unknown opportunities. By overcharging potential production from its best prospects in order to subsidize exploration of others, Alaska's policies impair the achievement of its own objectives.

But the misalignment between policies and objectives goes much further. The state's recent actions regarding the Pt. Thomson leases provide another good example.

After protracted legal proceedings, this year the Pt. Thomson owners agreed to pursue the development of the field.

Like its approach to tax credits, however, the state's efforts at directing these investment decisions have created unintended consequences. As operator, Exxon already has spent in excess of $1 billion on the Pt. Thomson project and estimates that, before completion, it will spend billions more. At the same time, investment in the development of the oil available in other existing North Slope units has declined.

In the absence of developing a major gas market, the maximum production anticipated from Point Thomson is 10,000 barrels of liquids per day, which is significantly smaller than other potential opportunities available in the existing units and a minor offset to the anticipated net loss of 50,000 barrels per day of production projected by the state between 2011 and 2015.

As a consequence, the effect of the state's efforts at Pt. Thomson essentially has been to focus investment on one project on the North Slope, likely at the expense of others offering significantly greater potential.

The reason that the state pursues such counter productive efforts is that the state currently does not have either the ability — or, seemingly, even a compelling economic interest — in determining which projects make the most economic sense. Instead, the state's decisions are driven largely by political reasoning. In essence, the state acts as a back seat driver, attempting to steer industry investment indirectly and towards non-economic objectives.

Recently, a co-author and I proposed a means of better achieving alignment between the state's actions and objectives that has proven highly successful in other parts of the world and, I firmly believe, would have the same result in Alaska. While the proposal met some criticism, I anticipate that support will grow as others come to realize that a revised tax policy alone will be insufficient to attract the levels of investment – estimated by DNR Commissioner Dan Sullivan to be a minimum of $4 billion/year – required to realize Alaska's full oil potential.

Any tax reform proposal should progress toward alignment.

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ONE RESPONSE TO FIVE THINGS TO LOOK FOR IN OIL TAX REFORM …

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