Fiscal Note

State of Alaska
2013 Legislative Session

Bill Version: SB 21
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Identifier: SB021CS(FIN)-DOR-TAX-03-14-13
Title: OIL AND GAS PRODUCTION TAX
Sponsor: RLS BY REQUEST OF THE GOVERNOR
Requester: Senate Finance

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	100.0						
Commodities							
Capital Outlay							
Grants & Benefits							
Miscellaneous							
Total Operating	**100.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Fund Source (Operating Only)

1004 Gen Fund	100.0						
Total	**100.0**	**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If yes, by what date are the regulations to be adopted, amended or repealed? 01/01/14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:

The Senate Finance Committee substitute made numerous amendments to the previous version, the details of which require lengthy explanation.

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Date: 03/14/2013 12:10 PM
Approved By: Bryan D. Butcher, Commissioner
Department of Revenue
Date: 03/14/13

FISCAL NOTE ANALYSIS

STATE OF ALASKA **BILL NO.** CSSB 21(FIN)
2013 LEGISLATIVE SESSION

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.

The change to the interest rate for delinquent taxes are expected to require changes to our tax accounting systems to accommodate the changes. We estimate that this change will require a one-time appropriation of $100,000 in FY14 for contractor costs.

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, 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 for calendar years 2014 - 2016, and then to 33% of production tax value for calendar years 2017 on. 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 for calendar years 2014 - 2016, and a credit of 33% of those losses for calendar year 2017 and beyond. These losses are transferable and eligible for refund by the state. The impact of this provision is on the operating budget and is expected to increase credit refunds appropriated through the operating budget by $30 to $40 million per year over the amount anticipated under current law.

5. A gross revenue exclusion (GRE) of 20% of the gross value at the point of production is applicable to production from certain areas. The GRE applies to oil or gas production from wells north of 68 degrees North Latitude that meet one or more of the following criteria: (1) is produced within a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) is produced within 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 a well that has been accurately metered and measured and the producer demonstrates to the department that the metered well drains a reservoir or portion of a reservoir that DNR has certified was not contributing to production before January 1, 2013. Please see detailed summary table on page 4 of this fiscal note for revenue impacts of this provision.

(Analysis continued on following pages)

Analysis Continued

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 an appropriation from any source as opposed to tying the appropriation to revenue collected under AS 43.55.011(g). This provision has no revenue impact under our Fall 2012 forecast.

8. A credit of $5 per taxable barrel may be applied against a producer's production tax liability. The credit is not transferable, cannot be carried forward, and cannot reduce the producer's tax liability to less than zero. The credit is applicable statewide, but we expect that over the time horizon of this fiscal note, the revenue impact will be limited to the North Slope. Please see detailed summary table on page 4 of this fiscal note for the revenue impact of this provision.

9. 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. The credit is not transferable, however, any amount of the credit that exceeds the taxpayer's liability under AS 43.20 may be carried forward for up to five years. We have no data with which to quantify the revenue impact of this provision, although it is possible that the impact may be as high as -$25 million per year. The revenue impact of this provision is indeterminate.

10. The interest rate on delinquent taxes is changed from the greater of 5 percentage points above the annual rate of interest charged by the 12th Federal Reserve District or 11 percent, to 3 percentage points above the annual rate of interest charged by the 12th Federal Reserve District. There will be one-time contractor costs to implement this change in our accounting system. Over the past five fiscal years (FY 2008-FY 2012), interest on delinquent taxes and refunds has resulted in a net positive revenue to the state. The average annual net revenue to the state in these years was $26 million in revenue to the General Fund and $71 million in revenue to the Constitutional Budget Reserve Fund. The Department of Revenue does not forecast interest on taxes. Over the time horizon of this fiscal note, this provision is estimated to impact state revenues in amounts up to -$25 million per year. The impact will increase over time as more delinquent taxes are calculated under the new interest rates established with this provision. Our fiscal impact estimates do not take into account changes in taxpayer behavior as a result of this reduction in interest rate.

Analysis Continued

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

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$800	-$1,500	-$1,700	-$1,800	-$1,750	-$1,650
2. Base tax rate changed to 35% of production tax value for CY14-16, 33% of production tax value for CY17 on	$550	$1,075	$1,100	$950	$800	$775
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% for CY14-16, 33% for CY17 on; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for certain areas and certain new wells	$0 to -$50	-$25 to -$175	-$25 to -$225	-$50 to -$250	-$25 to -$225	-$50 to -$250
6. Provision requiring credits be taken over 2 years eliminated[2]	-$250					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Allowance of $5 per taxable barrel	-$425	-$825	-$775	-$750	-$700	-$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
Total Revenue Impact	**-$625 to -$725**	**-$575 to -$775**	**-$750 to -$1000**	**-$1100 to -$1350**	**-$1200 to -$1450**	**-$1200 to -$1450**
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits		-$40	-$40	-$40	-$30	-$30
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$775 to -$875**	**-$465 to -$665**	**-$640 to -$890**	**-$990 to -$1240**	**-$1080 to -$1330**	**-$1080 to -$1330**

[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 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.

[3]NOTE: "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. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

Analysis Continued

Differences in General Fund Unrestricted Revenue under CSSB21(FIN) from Current Tax System in $Millions*

*Note: These hypothetical examples of additional production assess the impacts from the **change in tax rates, per barrel allowance and gross revenue exclusions 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 from the elimination of QCE credits or changes to NOL credits. Values are generated from a scenario model and may vary slightly from other models.

At Forecasted Production

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$75	$325	$250	$25	-$150	-$150
$100	-$100	$50	-$50	-$300	-$450	-$425
$120	-$625	-$925	-$975	-$1,250	-$1,375	-$1,300

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	$75	$325	$250	$25	-$125	-$125
$100	-$100	$50	-$50	-$275	-$425	-$400
$120	-$625	-$925	-$975	-$1,250	-$1,375	-$1,250

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

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$100	$450	$475	$325	$325	$250
$100	-$50	$225	$250	$75	$100	$25
$120	-$550	-$650	-$575	-$750	-$700	-$700

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

Additional Production Scenario C

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

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$0	$300	$425	$425	$900	$825
$100	-$150	$100	$250	$250	$775	$700
$120	-$625	-$700	-$475	-$400	$200	$200

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