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If yes, by what date are the regulations to be adopted, amended, or repealed? 1/1/2014 Discuss details in analysis section.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.

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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 **BILL NO.** 647
2013 LEGISLATIVE SESSION

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.