

03 / 22 / 16
PRELIMINARY
SPRING
REVENUE
FORECAST,
DEPARTMENT
OF REVENUE

<TARGET><BILL></BILL><SUBJECT>03-22-16 PRELIMINARY
SPRING REVENUE FORECAST, DEPARTMENT OF
REVENUE</SUBJECT><COMM>HF IN29</COMM></TARGET>



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Revenue

COMMISSIONER'S OFFICE
State Office Building
333 Willoughby Avenue, 11th Floor
PO Box 110400
Juneau, Alaska 99811-0400
Main: 907.465.2300
Fax: 907.465.2389

March 26, 2016

The Honorable Mark Neuman and the Honorable Steve Thompson
Alaska State Representatives
Co-Chairs, House Resources Committee
State Capitol Rooms 505 and 515
Juneau AK 99801

Dear Co-Chairs Neuman and Thompson,

The purpose of this letter is to provide you with responses to the questions asked of the Department of Revenue regarding the preliminary Spring 2016 revenue forecast during our presentation to the House Finance Committee on March 22, 2016. Please see questions in italics and our responses immediately below the questions.

1. *At what price do GVR-eligible fields begin to pay production tax?*

The attached analysis prepared for Representative Gara and dated February 2, 2016 estimated that, for an illustrative GVR-eligible field, there is not a production tax liability until the oil price exceeds about \$72 per barrel. See responses to questions 4 and 7 in the attached analysis for details of this estimate. The exact price will vary depending on specific economics for different fields and producers. At prices below \$72 per barrel, companies may still contribute other revenue to the state such as royalty, property tax, and corporate income tax.

2. *Does the revenue forecast include any additional significant investments in the Trans-Alaska Pipeline System (TAPS) to allow it to operate at lower production levels as indicated in the forecast?*

Yes, our TAPS tariff model does incorporate additional capital and operating expenses associated with operating the pipeline at lower production levels, down to about 300,000 barrels per day. Incorporating these additional expenses into the cost of service model, combined with lower throughput, results in the estimated weighted average TAPS tariff in the preliminary Spring 2016 forecast increasing from \$6.11 per barrel in FY 2015 to \$13.02 per barrel in FY 2026.

Currently, the TAPS operator has not defined what additional capital and operating expenditures, or technical changes, would be needed to operate at levels below 300,000 barrels per day. As such, our TAPS tariff model does not at this time incorporate additional expenses associated with operating the pipeline below 300,000 barrels per day.

3. *What is the current balance of the Oil & Gas Tax Credit Fund established under AS 43.55.028?*

As of March 23, 2016, the balance of the Oil & Gas Tax Credit Fund is approximately \$28 million. This amount represents remaining funds for FY 2016, after \$500 million was transferred at the beginning of the fiscal year. This remaining balance was incorporated into the estimate of credits eligible for refund in FY 2017, as presented in the preliminary Spring 2016 forecast.

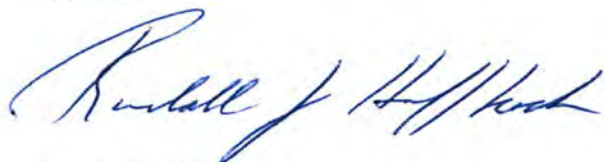
The Honorable Mark Neuman and the Honorable Steve Thompson

March 26, 2016

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I hope you find this information to be useful. Please do not hesitate to contact me if you have further questions.

Sincerely,

A handwritten signature in blue ink, appearing to read "Randall J. Hoffbeck". The signature is fluid and cursive, with a large initial "R" and "H".

Randall Hoffbeck
Commissioner

Attachments:

Director Alper to Representative Gara 2/2/16



THE STATE
of ALASKA
GOVERNOR BILL WALKER

Department of Revenue

TAX DIVISION

Juneau Office
333 Willoughby Ave, 11th Floor
Juneau, AK 00801
Main: 907.465.2320
www.tax.alaska.gov

February 2, 2016

The Honorable Les Gara
Alaska State Representative
State Capitol, Room 400
Juneau AK 99801

Representative Gara,

This letter is in response to your email dated January 13, 2016, in which you posed several questions about the state's oil and gas production tax. Your questions are restated in *italics* below and our answers follow.

- 1. Please confirm whether North Slope oil companies are allowed to deduct 35% of their capital and operating costs from their net income before paying a net profits tax (it's from their taxable income, right, not from their tax payments?).***

Companies exploring for, developing, or producing oil and/or gas in the state, including the North Slope, are allowed to deduct 100% of their qualified capital and non-capital expenditures (collectively known as "lease expenditures") from their gross value at the point of production to arrive at the production tax value for purposes of the state oil and gas production tax. Lease expenditures are broadly defined in AS 43.55.165 as the "direct costs of exploring for, developing, or producing, as applicable, oil or gas deposits" in the state. AS 43.55.165(e) lists several types of costs that are not considered lease expenditures, and are therefore not deductible for the production tax, such as depreciation or depletion costs, lease acquisition costs, and costs for dismantlement or abandonment of an oil or gas facility.

As stated above, when calculating a tax due under the state's oil and gas production tax, 100% of qualified lease expenditures are subtracted from the company's gross value at the point of production to arrive at the production tax value, or "taxable base." Gross value at the point of production (GVPP) for oil is the value of the taxable oil at point where it is produced, which is generally calculated as the sales price minus the costs to transport the oil to the point where it is sold. Lease expenditures are deducted from the GVPP to arrive at the taxable base. A production tax of 35% is multiplied by the taxable base to arrive at the production tax before credits. If this number is greater than zero, sliding scale per-taxable-barrel credits cannot reduce this amount below the minimum tax, which at current oil prices is 4% of the gross value at the point of production. At low oil prices, the minimum tax effectively limits the benefit that companies receive from the deductibility of lease expenditures.

To summarize, they are able to deduct all of their qualified expenses, not 35%. But the amount remaining after the deduction is subject to the 35% production tax. Therefore, unless there is a limit due to the minimum tax, each dollar of qualified expenditures reduces the producer's taxes by 35 cents.

2. ***Do lower tax rate GVR fields include Pt. Thomson, all production in NPR-A that has/will come on line, and Ooogaruk and Nikiatchiq? Of the categories of GVR fields, one is all fields that were unitized after 2002, correct? Or is it (participating) areas created after 2002?***

The gross value reduction (GVR) provision under the oil and gas production tax is applicable to oil or gas produced on the North Slope from leases, properties or acreage meeting one or more of these criteria:

- (1) the lease or property does not contain a lease that was within a unit on January 1, 2003;
- (2) for properties in a unit before January 1, 2003, the lease or property is from a participating area established after December 31, 2011; or
- (3) the acreage was added to an existing participating area on and after January 1, 2014, and the producer demonstrates to the department that the volume of oil or gas produced is from acreage added to an existing participating area.

So to answer the second part of your question, oil or gas produced from leases or properties that were not unitized as of January 1, 2003 are eligible for the GVR under the first criteria. Among existing producing areas, this includes production from the Oooguruk Unit and from the Nikaichuq Unit. Production from the Point Thomson unit will be eligible for the GVR based on the second criteria, in that it will be from a participating area that was established after December 31, 2011. Other future fields such as Mustang, and fields under development in the NPR-A will also be eligible for the GVR. Production from new fields not yet in our production forecast likely will also be eligible.

3. ***Do lower-tax rate GVR fields enjoy the same 35% deduction rate for operating and capital costs as non-GVR fields?***

Fields that are eligible for the GVR are allowed to deduct their lease expenditures from their GVPP. After this deduction, they are then able to deduct the Gross Value Reduction to reduce their production tax value prior to the application of the 35% tax rate. However, the gross minimum tax may limit this benefit at lower oil prices.

4. ***What is the approximate effective profits tax rate (the percentage of net profits actually taxed) for GVR, and for Non- GVR discounted North Slope Fields at the following prices: \$60, \$70, \$80, \$90, \$100, \$110, \$120, \$130, \$140, and \$150/bbl?***

Please see table below for approximations of effective production tax rates on net value of some "typical" fields with specific assumptions. For this analysis, we assume a "typical" field with \$10 per barrel transportation costs and \$36 per barrel deductible lease expenditures. We do not account for credits other than the per-taxable-barrel credits. Note

that due to the nuances in the tax calculation, these results may not exactly match the Fall 2015 forecast.

Effective Tax Rates on Net Value using Current Assumptions*		
Oil Price	Non-GVR	20% GVR Eligible
\$60	14.3%	0.0%
\$70	10.0%	0.0%
\$80	11.5%	5.9%
\$90	19.1%	10.9%
\$100	23.9%	14.1%
\$110	27.2%	16.3%
\$120	29.6%	17.8%
\$130	31.4%	19.0%
\$140	32.9%	20.0%
\$150	34.0%	20.8%

*Current assumptions include transport costs of \$10 per barrel and deductible lease expenditures of \$36 per taxable barrel, that are typical but will not match exactly Fall 2015 assumptions. For this table, net value is the same as "production tax value," defined in AS 43.55.160. The effective tax rates in this table are calculated by dividing the production tax after credits by the production tax value.

5. *At what price does the 35% tax rate kick in for non-GVR fields?*
6. *At what price does the profits tax fall so low that the 4% minimum gross tax becomes the tax rate?*

We interpret your questions 5 and 6 to be related, and we have reframed them as follows: For non-GVR fields, at what price does the minimum tax of 4% of gross value at the point of production exceed the base tax of 35% of production tax value minus per-taxable-barrel credits? In other words, at what price point do non-GVR fields begin to lose their sliding scale per-taxable-barrel credits? And secondarily, at what price point do non-GVR fields lose all of their sliding scale per-taxable-barrel credits? We have answered these questions with the example below. Please let us know if we misinterpreted your questions.

Using assumptions of about \$10 in transport costs and \$36 per taxable barrel in deductible lease expenditures, applied to a typical field, we estimate that the minimum tax of 4% of gross value at the point of production exceeds 35% of production tax value minus sliding scale per-taxable-barrel credits at about \$76 per barrel. This is illustrated in the calculation below.

Minimum Tax threshold - Base Tax and Minimum Tax using Current Assumptions*	
West Coast Price (\$/tax bbl)	\$76
Transportation (\$/tax bbl)	-\$10
Wellhead Value (\$/tax bbl)	\$66
Lease Expenditures (\$/tax bbl)	-\$36
Net Value (\$/tax bbl)	\$30
Base Tax Rate (%)	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$10.50
Sliding Scale Credit per-Tax-Barrel (\$/tax bbl)	-\$8
Base Production Tax after credits (\$/tax bbl)	\$2.50
Minimum Tax Rate (%)	4%
Wellhead Value (\$/tax bbl)	x \$66
Minimum Tax (\$/tax bbl)	\$2.64

Greater of base production tax after credits and minimum tax

*Current assumptions include transport costs of \$10 per barrel and deductible lease expenditures of \$36 per taxable barrel, that are typical but will not match exactly Fall 2015 assumptions. For this table, net value is the same as "production tax value," defined in AS 43.55.160. The effective tax rates in this table are calculated by dividing the production tax after credits by the production tax value.

Note that in the illustration above, some but not the entirety of sliding scale per-taxable-barrel credits can be used. Because the minimum tax is 14 cents higher per barrel than the base production tax after credits, and the sliding scale credit cannot reduce the tax liability below the minimum tax, this means that the sliding scale credit is reduced by 14 cents per barrel, from \$8 to \$7.86 per barrel. Under these assumptions, at prices greater than \$76 per barrel, producers are able to take their entire sliding scale credit without going below the minimum tax. The exact price will vary depending on specific economics for different fields and producers

Using the same assumptions for transportation costs and lease expenditures, non-GVR fields lose the entire \$8 per-taxable-barrel credit at oil prices of \$50.62 per barrel and lower. At this price, the base tax before credits equals the minimum tax. This is illustrated in the calculation below. The exact price will vary depending on specific economics for different fields and producers.

**Minimum Tax Equal to Base Tax before
 Credits, using Current Assumptions***

West Coast Price (\$/tax bbl)	\$50.62
Transportation (\$/tax bbl)	<u>-\$10.00</u>
Wellhead Value (\$/tax bbl)	\$40.62
Lease Expenditures (\$/tax bbl)	<u>-\$36.00</u>
Net Value (\$/tax bbl)	\$4.62
Base Tax Rate (%)	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$1.62
Sliding Scale Credit per-Tax-Barrel (\$/tax bbl)	<u>xxx</u>
Base Production Tax after credits (\$/tax bbl)	\$1.62
Minimum Tax Rate (%)	4%
Wellhead Value (\$/tax bbl)	x \$40.62
Minimum Tax (\$/tax bbl)	\$1.62

Base production tax before credits equals minimum tax, therefore no sliding scale credits can be used

*Current assumptions include transport costs of \$10 per barrel and deductible lease expenditures of \$36 per taxable barrel, that are typical but will not match exactly Fall 2015 assumptions. For this table, net value is the same as "production tax value," defined in AS 43.55.160. The effective tax rates in this table are calculated by dividing the production tax after credits by the production tax value.

7. Can big companies (Exxon/Conoco/BP) reduce their payments of the 4% minimum floor by using the Net Operating Loss credit?

Yes. The only credits that cannot be used to reduce a production tax liability below the minimum tax are the per-taxable-barrel credits for non-GVR production under AS 43.55.024(j), also known as the sliding scale credits. All other credits, including net operating loss credits authorized at AS 43.55.023(b) and per-taxable-barrel credits for GVR-eligible production under AS 43.55.024(i), can be used to reduce a production tax liability below the minimum tax.

8. I understand GVR fields have no minimum tax rate, and their taxes can fall to 0%. Please confirm that.

The minimum tax in AS 43.55.011(f) applies to all North Slope production, so fields that are eligible for a GVR are in principle also subject to the minimum tax. However, the per-taxable-barrel credits earned for those fields, under AS 43.55.024(i) can be used to reduce a production tax liability below the minimum tax down to a minimum of \$0. This credit cannot be used to reduce a production tax liability below \$0.

9. What is the effective profits tax rate GVR fields pay at \$30, \$40, \$50 and \$60/bbl? When does that rate hit 0%?

As shown in the answer to question 4 above, the effective tax rates on net value for 20% GVR-eligible fields reach 0% at oil prices of approximately \$72 per barrel and lower for an illustrative field. The exact price will vary depending on specific economics for different fields and producers.

We hope you find this information to be useful. Please do not hesitate to contact me if you have questions or need additional information.

Sincerely,

A handwritten signature in blue ink, appearing to read "Ken Alper", with a long horizontal flourish extending to the right.

Ken Alper
Tax Division Director

Detail of FY 2017 refunded credits estimate in preliminary Spring 2016 forecast

Prepared 3/22/16 by Dan Stickel

Detail of FY 2017 refunded credits estimate (\$ millions)	
Refundable credits already in queue (based primarily on CY 2015 spending)	
Credit certificates / cases in progress as of March 8, 2016	\$ 900
Credit applications expected March 31 based on 2015 monthly reporting	\$ 160
Total credits already earned for activity through 2015	\$ 1,060
FY 2016 refunded credits appropriation	\$ 500
FY 2017 refundable credits already in queue	\$ 560
Additional credits expected to be available for refund in FY 2017 (based primarily on CY 2016 spending)	
Credits under AS 43.55.023 (NOL, capital, well lease)	\$ 186
Credits under AS 43.55.025 (exploration credits)	\$ 57
Credits under AS 43.20 (LNG storage, refinery investment)	\$ 18
Sum of additional FY 2017 refundable credits expected	\$ 261
Total forecast of credits eligible for refund in FY 2017	\$ 821
<i>(note, this number is rounded up to the nearest \$5 million)</i>	

Discussion

For FY 2017, expected credits for refund increased by \$200 million to \$825 million. This is largely due to two factors:

1. Lower oil prices more than offset reductions in overall spending, resulting in an increase to net operating losses subject to NOL credits.
2. Claimed exploration credits and spending that qualifies for exploration credits has exceeded expectations, as companies complete projects ahead of the July 1, 2016 sunset for North Slope and Cook Inlet.

The increase in refunded credits would be expected given the reduced price assumption. Note that applying the revised price assumption to the Fall 2015 forecast would also yield an estimate of \$825 million for FY 2017 refunded credits.

Reduced price expectations also impacted credits for companies not eligible for refunds (those with greater than 50,000 BOE of production). Expected carryforward NOL credit balance for such companies is now forecast at approximately \$600 million at end of FY 2017, compared to only \$1 million under Fall 2015 forecast.

Estimates are preliminary and may be revised for final spring forecast which will be released in early April. That forecast will incorporate information received in annual tax returns due March 31.



Revenue Sources Book 2016 Spring

PRELIMINARY FORECAST
MARCH 21, 2016

**PRELIMINARY
FORECAST
MARCH 21, 2016**

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PRELIMINARY FORECAST MARCH 21, 2016

Executive Summary

General Discussion

This document is a preliminary version of the Spring 2016 revenue forecast. The final version will be released in early April. The Department anticipates that potential revisions to the forecast will primarily be related to oil and gas production tax and most likely will not exceed \$100 million in any given year. The final forecast will incorporate information received in annual production tax returns due on March 31, 2016.

The spring forecast is an annual update of the fall forecast of state revenues for the Governor, the Alaska Legislature, and the Alaska public. This update is a collaborative effort among the Department of Revenue, the Alaska Permanent Fund Corporation, and the Office of Management and Budget.

State revenue comes from four major sources:

1) oil revenue; 2) income from sources other than oil, such as taxes, charges for services, licenses, permits, fines and forfeitures; 3) federal revenue; and 4) investment revenue, primarily from the Alaska Permanent Fund and the Constitutional Budget Reserve Fund (CBRF).

General fund unrestricted revenue (GFUR) is now forecast to be \$1.3 billion in fiscal year (FY) 2016 and \$1.2 billion in FY 2017. The revenue forecast is driven by an expectation of oil production of at least 500 thousand barrels per day and an average price of oil remaining between \$30 and \$40

per barrel for the next 15 months. The FY 2016 forecast represents a decrease in expected GFUR of nearly \$300 million, or about a 17% decrease, compared to the projection in the fall 2015 forecast. Compared to the fall 2015 forecast, the revenue forecast for spring 2016 projects lower revenue over each of the next ten years to reflect a lower expected price path.

The spring forecast for North Slope crude oil production revises expected production in FY 2016 from 500.2 thousand barrels per day to 517.7 thousand barrels per day; a meaningful increase of 17,500 barrels per day from the fall 2015 forecast. This change reflects at least eight months of actual daily production levels.

The revenue forecast is based on a revised oil price forecast of about \$40 per barrel versus \$50 for FY 2016, based on actual prices realized over the past several months and an apparent stabilization of ANS oil prices between \$30-40 per barrel. The forecast prices over the next ten years have also been reduced to reflect anticipated lower prices. The average price is now not forecast to reach \$60 until FY 2021.

Petroleum is forecast to be between 55-60% of the unrestricted revenue for FY 16 and 17 (see page 10). This is a significant decrease from what was observed prior to the oil price collapse when oil revenue

represented at least 88% or more of GFUR. State revenues will continue to be sensitive to oil price and oil production, as well as the cost of production.

Expenditures for cash repurchase of tax credits are not included in revenue numbers presented in the forecast but are separately estimated. In FY 2015, the state purchased \$628 million in tax credits through the Oil and Gas Tax Credit Fund (AS 43.55.028), and will purchase \$500 million in FY 2016. In FY 2017, credits subject to purchase are expected to amount to \$825 million under current law. The FY 2017 estimate includes newly earned credits as well as eligible credits beyond the \$500 million cap for FY 2016.

In FY 2015, total state revenue from all sources amounted to \$8.5 billion. Total state revenue for FY 2016 is expected to be only \$3.6 billion, due to large unrealized losses in the Alaska Permanent Fund. In FY 2017, total state revenue is expected to rebound to about \$8.2 billion.

A new presentation of revenue introduced in the Fall 2015 Revenue Sources Book takes into account what revenues are available for appropriation, regardless of customary designations or uses. There is expected to be about \$3.9 billion in current-year revenue available for appropriation for FY 2016 and about \$4.3 billion for FY

⁽¹⁾ Alaska's fiscal year runs from July 1 through June 30.

Table 2-1: Total State Revenue, by restriction and type

	(\$ millions)		
	History	Forecast	
	FY 2015	FY 2016	FY 2017
Unrestricted Revenue Sources			
Unrestricted General Fund Revenue			
Petroleum Revenue	1,687.9	780.0	690.6
Non-Petroleum Revenue	520.7	516.7	506.4
Investment Revenue	47.9	19.0	35.4
Federal Revenue	0.0	0.0	0.0
Unrestricted General Fund Revenue	2,256.5	1,315.7	1,232.4
Restricted Revenue Sources			
Designated General Fund Revenue			
Non-Petroleum Revenue	285.9	323.9	329.7
Investment Revenue	17.7	(6.6)	36.7
Subtotal Designated General Fund Revenue	303.6	317.3	366.4
Other Restricted Revenue			
Petroleum Revenue	667.3	323.8	317.9
Non-Petroleum Revenue	205.3	240.1	277.9
Investment Revenue	2,585.7	(2,020.3)	2,868.7
Subtotal Other Restricted Revenue	3,458.4	(1,456.4)	3,464.5
Federal Revenue			
Petroleum Revenue ⁽¹⁾	3.2	4.3	4.3
Federal Receipts	2,512.7	3,459.2	3,149.4
Subtotal Federal Revenue	2,515.9	3,463.5	3,153.7
Total Restricted Revenue	6,277.8	2,324.3	6,984.6
Total State Revenue	8,534.3	3,640.1	8,217.0

2017. For comparison, the state had \$6.0 billion in current-year revenue available for appropriation in FY 2015. In addition to unrestricted revenue, "current-year revenue available for appropriation" also includes designated general fund

revenue, as well as realized earnings of the Permanent Fund accounted for in the Earnings Reserve, earnings of the CBRF, various royalty and tax deposits to the Constitutional Budget Reserve, and various royalty and tax deposits in excess of the

constitutional minimum into the Permanent Fund.

The totals of some tables in this publication may not equal the sum of components due to rounding.

⁽¹⁾ Petroleum revenue shown in the Federal category includes the state share of rents, royalties, and bonuses received from the National Petroleum Reserve - Alaska, as provided by federal law.

Table 2-2: Unrestricted General Fund Revenue, by type and detail

(\$ millions)

	History	Forecast	
	FY 2015	FY 2016	FY 2017
Unrestricted Petroleum Revenue			
Petroleum Taxes			
Petroleum Property Tax	125.2	133.9	118.3
Petroleum Corporate Income Tax	94.8	0.0	30.0
Oil & Gas Production Tax	389.7	142.0	54.0
Subtotal Petroleum Taxes	609.7	275.9	202.3
Royalties (including Bonuses, Rents, & Interest)			
Mineral Bonuses & Rents	22.4	8.7	8.7
Oil & Gas Royalties	1,052.1	491.2	475.4
Interest	3.7	4.2	4.2
Subtotal Royalties	1,078.2	504.1	488.3
Unrestricted Petroleum Revenue	1,687.9	780.0	690.6
Unrestricted Non-Petroleum Revenue			
Non-Petroleum Taxes			
Excise Tax			
Alcoholic Beverage	17.7	19.8	19.9
Tobacco Product – Cigarette	27.7	28.9	27.2
Tobacco Product – Other	12.8	14.2	14.9
Electric and Telephone Cooperative	0.2	0.2	0.2
Insurance Premium	59.1	60.6	60.0
Marijuana	0.0	0.0	12.0
Motor Fuel Tax	41.9	42.6	43.2
Motor Fuel Tax (conservation surcharge)	0.0	8.0	8.2
Tire Fee	1.5	1.5	1.6
Vehicle Rental	9.7	9.8	9.9
Subtotal Excise Tax	170.6	185.7	197.1
Corporate Income Tax	136.2	109.6	99.3
Fisheries Tax			
Fisheries Business	21.3	13.7	16.0
Fishery Resource Landing	5.1	5.5	6.0
Subtotal Fisheries Tax	26.4	19.3	21.9
Other Tax			
Charitable Gaming	2.5	2.5	2.5
Estate	0.0	0.0	0.0
Large Passenger Vessel Gambling	6.6	6.7	6.7
Mining	38.6	24.4	19.7
Subtotal Other Tax	47.7	33.6	28.9
Subtotal Non-Petroleum Taxes	381.0	348.1	347.2

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FORECAST
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Table 2-2: Unrestricted General Fund, by type and detail (continued from previous page)

	(\$ millions)		
	History FY 2015	Forecast FY 2016 FY 2017	
Charges for Services			
General Government	13.9	12.8	12.8
Natural Resources	-0.6	1.4	1.4
Other	6.8	7.3	7.3
Subtotal Charges for Services	20.1	21.5	21.5
Fines & Forfeitures	11.5	11.4	11.4
Licenses & Permits			
Alcoholic Beverage Licenses	1.3	1.3	1.3
Motor Vehicle	29.5	38.0	35.5
Other	3.6	3.2	3.2
Subtotal Licenses & Permits	34.4	42.5	40.0
Rents & Royalties			
Mining Rents & Royalties	6.0	5.0	4.7
Other Non-Petroleum Rents & Royalties	30.3	30.3	30.3
Subtotal Rents & Royalties	36.3	35.3	34.9
Miscellaneous Revenues and Transfers			
Miscellaneous	16.4	21.6	21.6
Alaska Housing Finance Corporation	3.1	8.7	13.5
Alaska Industrial Development & Export Authority	10.2	17.7	6.3
Alaska Municipal Bond Bank Authority	0.0	0.9	0.9
Alaska Student Loan Corporation	0.6	0.0	0.0
Alaska Energy Authority	0.2	1.0	1.0
Alaska Natural Gas Development Authority	0.0	0.0	0.0
Mental Health Trust	0.0	0.0	0.0
Unclaimed Property	7.0	8.0	8.0
Subtotal Transfers	37.5	57.9	51.3
Unrestricted Non-Petroleum Revenue, except federal and investment	520.7	516.7	506.4
Investment Revenue			
Investments	46.3	17.4	33.8
Interest Paid by Others	1.6	1.6	1.6
Unrestricted Investment Revenue	47.9	19.0	35.4
Total Unrestricted Revenue	2,256.5	1,315.7	1,232.4

PRELIMINARY
FORECAST
MARCH 21, 2016

Table 2-3: Restricted Revenue, by type and category

	(\$ millions)		
	History	Forecast	
	FY 2015	FY 2016	FY 2017
Designated General Fund Revenue			
Non-Petroleum Revenue			
Taxes	30.4	30.0	29.9
Charges for Services	227.4	260.9	266.9
Fines and Forfeitures	7.6	9.1	9.0
Licenses and Permits	0.1	0.2	0.2
Rents and Royalties	3.4	4.2	4.2
Other	16.9	19.5	19.5
Subtotal	285.9	323.9	329.7
Investment Revenue			
Investments - Designated GF	2.0	2.1	2.7
Other Treasury Managed Funds	15.7	(8.7)	34.0
Subtotal	17.7	(6.6)	36.7
Restricted Designated General Fund Revenue	303.6	317.3	366.4
Other Restricted Revenue			
Oil Revenue			
Royalties to Alaska Permanent Fund & School Fund (includes Bonuses & Rents)	518.3	223.8	217.9
Tax and Royalty Settlements to CBRF	149.0	100.0	100.0
Subtotal	667.3	323.8	317.9
Non-Petroleum Revenue			
Taxes	89.7	83.4	85.4
Charges for Services	45.2	89.1	125.5
Fines and Forfeitures	23.6	23.5	23.3
Licenses and Permits	33.9	32.3	32.3
Rents and Royalties	6.0	5.0	4.7
Other	6.9	6.8	6.8
Subtotal	205.3	240.1	277.9
Investment Revenue			
Investments - Other Restricted	4.1	4.2	5.4
Constitutional Budget Reserve Fund	197.7	57.0	79.1
Alaska Permanent Fund (GASB)(realized earnings) ⁽¹⁾	2,931.4	2,055.9	2,501.1
Alaska Permanent Fund (GASB)(unrealized earnings) ⁽¹⁾	(547.5)	(4,137.4)	283.1
Subtotal	2,585.7	(2,020.3)	2,868.7
Other Restricted Revenue	3,458.4	(1,456.4)	3,464.5

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⁽¹⁾ Both realized and unrealized gains and losses are included per Government Accounting Standards Board(GASB) Statement 34 as interpreted by the Finance Division of the Department of Administration in its *Comprehensive Annual Financial Report*.

Table 2-3: Restricted Revenue, by type and category (continued from previous page)

	(\$ millions)		
	History	Forecast	
	FY 2015	FY 2016	FY 2017
Federal Revenue			
Federal Receipts	2,512.7	3,459.2	3,149.4
Oil Revenue			
NPR-A Royalties, Rents and Bonuses	3.2	4.3	4.3
Restricted Federal Revenue	2,515.9	3,463.5	3,153.7
Total Restricted Revenue	6,277.8	2,324.3	6,984.6

Table 2-4: Ten-Year Forecast of Total Unrestricted General Fund Revenue

FY	(\$ millions)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Unrestricted Oil Revenue	780.0	690.6	787.4	872.5	938.7	1,006.9	1,037.1	1,105.3	1,042.6	1,075.1
Unrestricted Other Revenue (except Federal & Investment)	516.7	506.4	514.8	520.7	522.6	528.4	531.3	541.0	547.3	553.7
Unrestricted Investment Revenue	19.0	35.4	44.0	52.6	61.1	69.7	78.3	86.8	95.4	104.0
Total Unrestricted General Fund Revenue	1,315.7	1,232.4	1,346.2	1,445.8	1,522.5	1,605.0	1,646.6	1,733.2	1,685.2	1,732.8
Total Unrestricted General Fund Revenue from Petroleum	59%	56%	58%	60%	62%	63%	63%	64%	62%	62%

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Table 2-5: Current Year Revenue Subject to Appropriation ⁽¹⁾

	(\$ millions)		
	History	Forecast	
	FY 2015	FY 2016	FY 2017
Petroleum Revenue			
Unrestricted General Fund	1,687.9	780.0	690.6
Royalties to Alaska Permanent Fund beyond 25% dedication ⁽²⁾	111.3	38.2	37.8
Tax and Royalty Settlements to CBRF	149.0	100.0	100.0
Federal Revenue	0.0	0.0	0.0
Subtotal Petroleum Revenues	1,948.1	918.1	828.4
Non-Petroleum Revenue			
Unrestricted General Fund	520.7	516.7	506.4
Designated General Fund	285.9	323.9	329.7
Royalties to Alaska Permanent Fund beyond 25% dedication ⁽²⁾	2.9	2.4	2.2
Tax and Royalty Settlements to CBRF	205.3	240.1	277.9
Investment Revenue	0.1	0.1	0.1
Subtotal Non-Petroleum Revenues	809.6	843.1	838.4
Investment Revenue			
Unrestricted General Fund	47.9	19.0	35.4
Designated General Fund	17.7	(6.6)	36.7
Constitutional Budget Reserve Fund	197.7	57.0	79.1
Alaska Permanent Fund - Realized Earnings	2,931.4	2,055.9	2,501.1
Subtotal Investment Revenues	3,194.7	2,125.3	2,652.3
Total Revenue Subject to Appropriation	5,952.4	3,886.5	4,319.1
Total State Revenue	8,534.3	3,640.1	8,217.0

⁽¹⁾ This figure presents only the largest known categories of current year funds subject to appropriation. A comprehensive review of all accounts in the state accounting system would likely reveal additional revenues subject to appropriation beyond those identified here.

⁽²⁾ Estimated based on deposit to Permanent Fund minus 25% of total royalties.

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Table 4-3: ANS Oil & Gas Production Tax Data Summary

	(\$ millions)		
	History	Forecast	
	FY 2015	FY 2016	FY 2017
North Slope Price and Production			
Price of ANS WC (in \$/barrel)	72.58	39.52	38.89
Transit Costs & Other (in \$/barrel)	9.74	10.51	10.88
ANS Wellhead (in \$/barrel)	62.83	29.01	28.01
North Slope Production			
Total ANS Production (in mbbls/day)	500.7	517.7	507.1
Royalty and federal (in mbbls/day) ⁽¹⁾	66.2	66.3	62.0
Taxable Barrels (in mbbls/day)	434.5	451.3	445.2
North Slope Lease Expenditures⁽²⁾⁽³⁾			
Total North Slope Lease Expenditures (in \$ millions)			
Operating Expenditures [OPEX]	3,438.8	3,235.2	3,075.9
Capital Expenditures [CAPEX]	3,992.0	3,315.1	2,970.3
Total North Slope Expenditures	7,430.8	6,550.3	6,046.2
Deductible North Slope Lease Expenditures (in \$ millions)			
Operating Expenditures [OPEX]	3,318.6	2,418.5	2,421.5
Capital Expenditures [CAPEX]	3,595.8	2,206.1	2,039.0
Deductible North Slope Expenditures	6,914.4	4,624.7	4,460.5
State Production Tax Revenue⁽⁴⁾			
Tax Revenue (in \$ millions)	389.7	142.0	54.0
Production Tax Collected per Taxable Barrel	2.5	0.9	0.3
Statewide Production Tax Credits⁽²⁾⁽⁵⁾			
Credits Used against Tax Liability (in \$ millions)	664.0	80.0	150.0
Credits for Potential Purchase (in \$ millions)	628.0	500.0	825.0

⁽¹⁾ Royalty and federal barrels represent the department's best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and other untaxed barrels.

⁽²⁾ Lease expenditures and credits used against tax liability for FY 2015 were prepared using unaudited company-reported estimates.

⁽³⁾ Expenditure data for FY 2016 and FY 2017 are compiled from company submitted expenditure forecast estimates and other documentation as provided to the the department. Expenditures shown here are shown in two ways: (1) total estimated expenditures including for those companies with no tax liability; and (2) estimated deductible expenditures for only those companies with a tax liability.

⁽⁴⁾ Production tax is calculated on a company specific basis, therefore the aggregated data reported here will not generate the total tax revenue shown. For an illustration of the tax calculation, see Appendix E in the 2015 Fall Revenue Sources Book.

⁽⁵⁾ Production tax credits shown include all production tax credits and all areas of the state. Assumptions for the \$12 million credits for small Alaska producers are included in the table. Per-taxable-barrel credits for oil not eligible for the gross value reduction may not reduce a producer's liability below the minimum tax; that limitation is reflected in these estimates.

Table A-3b: Petroleum Revenue Forecast

FY	(\$ millions)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Unrestricted Petroleum Revenue										
Petroleum Property Tax	133.9	118.3	118.5	117.3	116.5	114.9	113.2	111.4	109.4	107.4
Petroleum Corporate Income Tax	0.0	30.0	105.0	135.0	165.0	195.0	190.0	185.0	180.0	175.0
Oil and Gas Production Tax	133.4	45.6	15.7	10.7	12.5	32.2	105.2	216.9	198.0	274.1
Oil and Gas Hazardous Release	8.6	8.4	8.2	8.1	7.7	7.0	6.5	6.0	5.5	5.0
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Royalties-Net ⁽¹⁾	491.2	475.4	527.2	588.6	624.2	645.0	609.3	573.2	536.8	500.8
Bonuses, Rents & Interest-Net ⁽¹⁾⁽²⁾	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Petroleum Special Settlements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unrestricted Petroleum Revenue	780.0	690.6	787.4	872.5	938.7	1,006.9	1,037.1	1,105.3	1,042.6	1,075.1
Cumulative Unrestricted Petroleum Revenue ⁽³⁾	115,830	116,520	117,308	118,180	119,119	120,126	121,163	122,268	123,311	124,386
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	4.3	4.3	4.3	6.5	8.6	7.3	6.2	5.5	5.1	4.9
Royalties to AK Permanent Fund	220.1	214.3	238.7	274.6	291.7	294.4	273.8	255.0	237.6	220.8
Royalties to Public School Fund	3.7	3.6	3.9	4.4	4.7	4.8	4.5	4.2	4.0	3.7
CBRF Deposits	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Restricted Petroleum Revenue	328.1	322.2	347.0	385.5	405.0	406.4	384.5	364.8	346.7	329.4
Total Petroleum Revenue	1,108.0	1,012.8	1,134.3	1,258.0	1,343.8	1,413.4	1,421.6	1,470.1	1,389.2	1,404.6

PRELIMINARY FORECAST MARCH 21, 2016

⁽¹⁾ Net of Permanent Fund Contribution and CBRF deposits.

⁽²⁾ Primarily composed of petroleum revenue.

⁽³⁾ Based on revenue beginning in FY 1959.

Table A-4b: General Fund Unrestricted Revenue Forecast

FY	(\$ millions)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Unrestricted Petroleum Revenue	780.0	690.6	787.4	872.5	938.7	1,006.9	1,037.1	1,105.3	1,042.6	1,075.1
General Fund Unrestricted Non-Petroleum Revenue	535.8	541.8	558.8	573.3	583.7	598.1	609.5	627.9	642.7	657.6
Total Unrestricted General Fund Revenue	1,315.7	1,232.4	1,346.2	1,445.8	1,522.5	1,605.0	1,646.6	1,733.2	1,685.2	1,732.8
Total Unrestricted General Fund Revenue from Petroleum	59%	56%	58%	60%	62%	63%	63%	64%	62%	62%

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Table B-2: Price Differences from Fall 2015 Forecast

FY	(\$ per barrel of oil)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Spring 2016 Forecast										
ANS West Coast	39.52	38.89	43.79	48.89	54.48	60.29	61.64	63.03	64.45	65.90
ANS Wellhead Wtd Average All Destinations	29.01	28.01	32.43	37.02	41.85	46.69	47.12	47.53	47.86	48.11
Fall 2015 Forecast										
ANS West Coast	49.58	56.24	62.73	68.95	71.05	77.68	80.00	81.80	84.53	87.35
ANS Wellhead Wtd Average All Destinations	39.02	45.08	51.22	56.99	58.49	64.19	65.54	66.27	67.77	69.24
Price change from prior forecast										
ANS West Coast	(10.06)	(17.35)	(18.95)	(20.06)	(16.58)	(17.39)	(18.36)	(18.77)	(20.08)	(21.45)
ANS Wellhead Wtd Average All Destinations	(10.01)	(17.07)	(18.80)	(19.97)	(16.64)	(17.50)	(18.41)	(18.74)	(19.92)	(21.13)
Percent change from prior forecast										
ANS West Coast	-20.3%	-30.8%	-30.2%	-29.1%	-23.3%	-22.4%	-23.0%	-22.9%	-23.8%	-24.6%
ANS Wellhead Wtd Average All Destinations	-25.6%	-37.9%	-36.7%	-35.0%	-28.5%	-27.3%	-28.1%	-28.3%	-29.4%	-30.5%

PRELIMINARY FORECAST MARCH 21, 2016

Table C-1: Production Differences from Fall 2015 Forecast

	(thousands of barrels per day)									
FY	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Spring 2016 Forecast										
Alaska North Slope	517.7	507.1	488.8	484.4	454.1	418.6	387.1	356.8	327.0	300.5
Non-North Slope	17.3	16.1	14.7	13.5	12.5	11.7	10.9	10.2	9.6	9.0
Total	535.0	523.2	503.5	498.0	466.7	430.2	397.9	366.9	336.5	309.5
Fall 2015 Forecast										
Alaska North Slope	500.2	504.9	497.7	487.6	460.5	423.9	391.1	359.8	329.2	302.1
Non-North Slope	17.8	16.1	14.7	13.5	12.5	11.7	10.9	10.2	9.6	9.0
Total	518.0	521.0	512.4	501.1	473.0	435.6	402.0	370.0	338.8	311.1
Volume change from prior forecast										
Alaska North Slope	17.5	2.2	(8.9)	(3.2)	(6.4)	(5.3)	(4.0)	(3.0)	(2.2)	(1.6)
Non-North Slope	(0.5)	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Total	17.0	2.2	(8.9)	(3.1)	(6.3)	(5.4)	(4.1)	(3.1)	(2.3)	(1.6)
Percent change from prior forecast										
Alaska North Slope	3.50%	0.44%	(1.79%)	(0.65%)	(1.38%)	(1.26%)	(1.03%)	(0.84%)	(0.67%)	(0.52%)
Non-North Slope	(2.85%)	0.11%	0.03%	0.29%	0.38%	(0.26%)	(0.19%)	(0.21%)	(0.50%)	(0.29%)
Total	3.28%	0.43%	(1.74%)	(0.63%)	(1.34%)	(1.23%)	(1.01%)	(0.83%)	(0.67%)	(0.52%)

PRELIMINARY FORECAST MARCH 21, 2016

Summary of preliminary Spring 2016 forecast data

Prepared 3/21/16 by Dan Stickel

Spring 2016 preliminary forecast											
Fiscal Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ANS WC Sales Price \$/bbl	\$ 39.52	\$ 38.89	\$ 43.79	\$ 48.89	\$ 54.48	\$ 60.29	\$ 61.64	\$ 63.03	\$ 64.45	\$ 65.90	\$ 67.38
ANS Production (including Federal OCS) mmbbls/day	0.517	0.507	0.489	0.484	0.454	0.419	0.387	0.357	0.327	0.301	0.277
ANS Lease Expenditures MM\$	\$ 6,550	\$ 6,046	\$ 6,290	\$ 5,959	\$ 5,589	\$ 5,405	\$ 5,119	\$ 4,830	\$ 4,535	\$ 4,265	\$ 4,022
Total petroleum royalties (including PF/SF share) MM\$	\$ 728	\$ 706	\$ 783	\$ 880	\$ 933	\$ 957	\$ 900	\$ 845	\$ 791	\$ 738	\$ 693
Petroleum Royalties - GF share MM\$	\$ 504	\$ 488	\$ 540	\$ 601	\$ 637	\$ 658	\$ 622	\$ 586	\$ 550	\$ 514	\$ 483
Production tax MM\$	\$ 142	\$ 54	\$ 24	\$ 19	\$ 20	\$ 39	\$ 111	\$ 223	\$ 204	\$ 279	\$ 287
SPRING 2016 GFUR Oil Revenue	\$ 780	\$ 691	\$ 787	\$ 873	\$ 939	\$ 1,007	\$ 1,037	\$ 1,105	\$ 1,043	\$ 1,075	\$ 1,045
SPRING 2016 Total GFUR	\$ 1,316	\$ 1,232	\$ 1,346	\$ 1,446	\$ 1,522	\$ 1,605	\$ 1,647	\$ 1,733	\$ 1,685	\$ 1,733	\$ 1,718
Tax credits for refund	\$ 500	\$ 825	\$ 450	\$ 285	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250

Fall 2015 forecast											
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ANS WC Sales Price \$/bbl	\$ 49.58	\$ 56.24	\$ 62.73	\$ 68.95	\$ 71.05	\$ 77.68	\$ 80.00	\$ 81.80	\$ 84.53	\$ 87.35	\$ 89.32
ANS Production (including Federal OCS) mmbbls/day	0.500	0.505	0.498	0.488	0.460	0.424	0.391	0.360	0.329	0.302	0.278
ANS Lease Expenditures MM\$	\$ 6,889	\$ 6,465	\$ 6,507	\$ 6,032	\$ 5,592	\$ 5,327	\$ 5,012	\$ 4,723	\$ 4,429	\$ 4,162	\$ 3,923
Total petroleum royalties (including PF/SF share) MM\$	\$ 938	\$ 1,090	\$ 1,208	\$ 1,302	\$ 1,257	\$ 1,269	\$ 1,204	\$ 1,129	\$ 1,067	\$ 1,006	\$ 942
Petroleum Royalties - GF share MM\$	\$ 650	\$ 758	\$ 840	\$ 901	\$ 869	\$ 884	\$ 843	\$ 794	\$ 753	\$ 711	\$ 667
Production tax MM\$	\$ 172	\$ 188	\$ 277	\$ 296	\$ 296	\$ 318	\$ 307	\$ 287	\$ 293	\$ 301	\$ 281
FALL 2015 GFUR Oil Revenue	\$ 1,062	\$ 1,237	\$ 1,443	\$ 1,532	\$ 1,494	\$ 1,535	\$ 1,476	\$ 1,399	\$ 1,362	\$ 1,326	\$ 1,255
FALL 2015 Total GFUR	\$ 1,593	\$ 1,796	\$ 2,021	\$ 2,130	\$ 2,111	\$ 2,173	\$ 2,132	\$ 2,077	\$ 2,061	\$ 2,046	\$ 1,997
Tax credits for refund	\$ 500	\$ 625	\$ 375	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250	\$ 250

Difference Between Fall 2015 to Spring 2016 preliminary											
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
F15 to S16 change: ANS WC Sales Price \$/bbl	\$ (10.06)	\$ (17.35)	\$ (18.95)	\$ (20.06)	\$ (16.58)	\$ (17.39)	\$ (18.36)	\$ (18.77)	\$ (20.08)	\$ (21.45)	\$ (21.94)
F15 to S16 change: ANS Production mmbbls/day	0.016	0.002	(0.009)	(0.003)	(0.006)	(0.005)	(0.004)	(0.003)	(0.002)	(0.002)	(0.001)
F15 to S16 change: ANS Lease Expenditures MM\$	\$ (338)	\$ (419)	\$ (217)	\$ (74)	\$ (2)	\$ 78	\$ 108	\$ 108	\$ 106	\$ 103	\$ 99
F15 to S16 change: Total petro royalties (incl PF/SF) MM\$	\$ (210)	\$ (383)	\$ (425)	\$ (422)	\$ (323)	\$ (312)	\$ (303)	\$ (283)	\$ (276)	\$ (268)	\$ (249)
F15 to S16 change: Petroleum Royalties - GF share MM\$	\$ (146)	\$ (270)	\$ (300)	\$ (300)	\$ (232)	\$ (226)	\$ (221)	\$ (208)	\$ (203)	\$ (198)	\$ (185)
F15 to S16 change: Production tax MM\$	\$ (30)	\$ (134)	\$ (253)	\$ (278)	\$ (275)	\$ (279)	\$ (196)	\$ (64)	\$ (89)	\$ (22)	\$ 6
F15 to S16 change: GFUR Oil Revenue	\$ (282)	\$ (547)	\$ (656)	\$ (660)	\$ (555)	\$ (528)	\$ (439)	\$ (294)	\$ (319)	\$ (250)	\$ (209)
F15 to S16 change: Total GFUR	\$ (277)	\$ (564)	\$ (675)	\$ (684)	\$ (589)	\$ (568)	\$ (485)	\$ (343)	\$ (375)	\$ (313)	\$ (279)
F15 to S16 change: Tax credits for refund	\$ -	\$ 200	\$ 75	\$ 35	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -



ALASKA STATE LEGISLATURE
HOUSE FINANCE COMMITTEE

State Capitol, Room 519

Rep. Mark Neuman, Co-Chair

Rep. Steve Thompson, Co-Chair

Tuesday, March 22, 2016

1:30 PM

SB 74-MEDICAID REFORM;TELEMEDICINE;DRUG DATABASE
Fraud, False Claims, Penalties

4:00 PM:

Preliminary Spring Revenue Forecast
Department of Revenue

HB 143-AIDEA BONDS, LOANS, FUND; AEA LOAN



ALASKA STATE LEGISLATURE
HOUSE FINANCE COMMITTEE

State Capitol, Room 519

Rep. Mark Neuman, Co-Chair

Rep. Steve Thompson, Co-Chair

Tuesday, March 22, 2016

1:30 PM Cont.d

Bills Previously Heard or Scheduled:

4:00 PM: (part of the 1:30 PM meeting)

Preliminary Spring Revenue Forecast

Department of Revenue

Testifying:

Jerry Burnett, Deputy Commissioner, Treasury Division, Department of Revenue

Dan Stickel, Assistant Chief Economist, Tax Division, Department of Revenue

HB 143-AIDEA BONDS, LOANS, FUND; AEA LOAN *public testimony*

Munoz, Terry Harvey, Aide ¹ *FISCAL NOTE - NEW DCCED AIDEA
WILL REPORT OUT FORTHCOMING.*

Testifying in Person:

Gene Therriault, Deputy Director, Statewide Energy Policy Development,
Alaska Energy Authority, Department of Commerce, Community and
Economic Development

Duff Mitchell (or Keith Comstock CEO), Managing Director Juneau
Hydro,-Project Update, questions

John Springsteen, Exec Director AIDEA-Speak to Bonding, answer
questions

Mayor Mary Becker, 2 minute testimony CBJ support for project

Rodney Hesson, IBEW-2 minute testimony in favor representing multi
Unions in attendance

Wayne Zigarlick, General Manager Coeur Alaska, Kensington Mine-
Questions

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