THE STATE
of ALASKA
GOVERNOR BILL WALKER

Department of Revenue
COMMISSIONER'S OFFICE
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February 7, 2017

The Honorable Neal Foster and the Honorable Paul Seaton
Alaska State Representatives
Co-chairs, House Finance Committee
State Capitol Rooms 410 and 505
Juneau, AK 99801

Dear Co-Chairs Foster and Seaton:

The purpose of this letter is to provide you with responses to the questions asked of the Department of Revenue (DOR) during our presentation to the House Finance Committee on January 18, 2017. Please see questions in italics and our responses immediately below the questions.

1. *Provide the slides relating to oil tax credits with North Slope and Cook Inlet credits broken out separately.*

   Please see two attached documents:
   - Oil and Gas Tax Credits vs. Production Tax and Unrestricted Royalties FY 2016-18: North Slope and Non-North Slope
   - Credits Forecast: Outstanding Tax Credit Obligations by North Slope and Non-North Slope

2. *Slide 41 shows transportation costs decreasing by $1.53 per barrel. This would decrease tariffs, which would increase revenue. What was the revenue impact of this cost decrease?*

   According to DOR's model, if the netback costs had been $1.53 per barrel higher, the FY 2016 oil revenue forecast would have been $931 million instead of $967 million. Therefore the revenue impact is $36 million.

3. *What is the state's liability for tax credits in FY 2018 net of payable North Slope credits?*

   Please see the attached chart "North Slope credits forecast compared with North Slope Production Tax and North Slope Unrestricted Petroleum Revenue – Assuming all credits repurchased in FY 2018."

4. *Provide the list of participants in the 2016 oil price forecasting session.*

   Please see the attached list of oil price forecasting session participants.

5. *Provide a list of the DOR-managed funds and how they are invested.*

   Please see the attached snapshot of funds managed by the Department of Revenue as of September 30, 2016. The snapshot also includes the Permanent Fund. The snapshot includes the following information for each fund:
   - Long- vs. short-term investment horizon and risk tolerance
   - Target return and asset allocation
   - Current market value
   - Historical returns

   This is intended to show the investment strategy for each of the DOR-managed funds.

6. *Why is the forecast for federal revenue in FY 2017 $1 billion higher than in FY 2016? Why does the forecast for state matching funds increase by $100 million in FY 2018?*

   The federal forecast for FY 2017 is higher because the forecasts represent the maximum federal revenue that the state will be authorized to receive. In contrast, the actual number for FY 2016 represents DOR's estimate of federal revenue the state actually received. Over the past 15 years, the ratio between actual revenue and the authorized amount has averaged about 79%. Applying this ratio to DOR's official forecasts gives $2,804 million in FY 2017 and $2,484 million in FY 2018.

   The state matching figures rise by $100 million in FY 2018 for two reasons. First, the capital budget match requirements for FY 2016 and 2017 were artificially low because the matching funds came from re-appropriations of funds from older capital projects. In FY 2018, the match amount will increase because of transportation reauthorization (the Fixing America's Surface Transportation or FAST Act), repurposing $25 million in old earmarks (meaning $2.5 million in state matching), and building a new replacement vessel for the Tustumena (a one-time cost of $22 million).

7. *Is there any way of knowing how much money the oil companies are spending on heavy oil research and are these expenses deductible?*

   Based on information that DOR's oil and gas production audit group receives from the taxpayer, there is nothing that breaks out heavy oil research costs. Lease expenditures are reported by unit, so if DOR knows one unit is producing heavy oil, it can compare that unit's expenditures relative to the others, but that information does not break out research costs.

   It is the Department's position that research and development (R&D) costs are not allowable lease expenditures. There is a regulation that says activities that would ordinarily be considered R&D are not allowable lease expenditures. See 15 AAC 55.250(g):

   > For purposes of this section, "designing" is limited to activities specific to an identifiable well, facility, item of equipment, or system, and does not include activities of more general applicability or that would ordinarily be considered research and development.

   There is an Advisory Bulletin (2011-01) from May 3, 2011, that speaks to R&D costs. In order to be lease expenditures, costs must be incurred to explore for, develop, or produce oil or gas deposits on the producer's lease or property, within the meaning of AS 43.55.165(a).

The costs to conduct research that may or may not be used in the future to produce oil or gas and are not allowed as lease expenditures.

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

Sincerely,

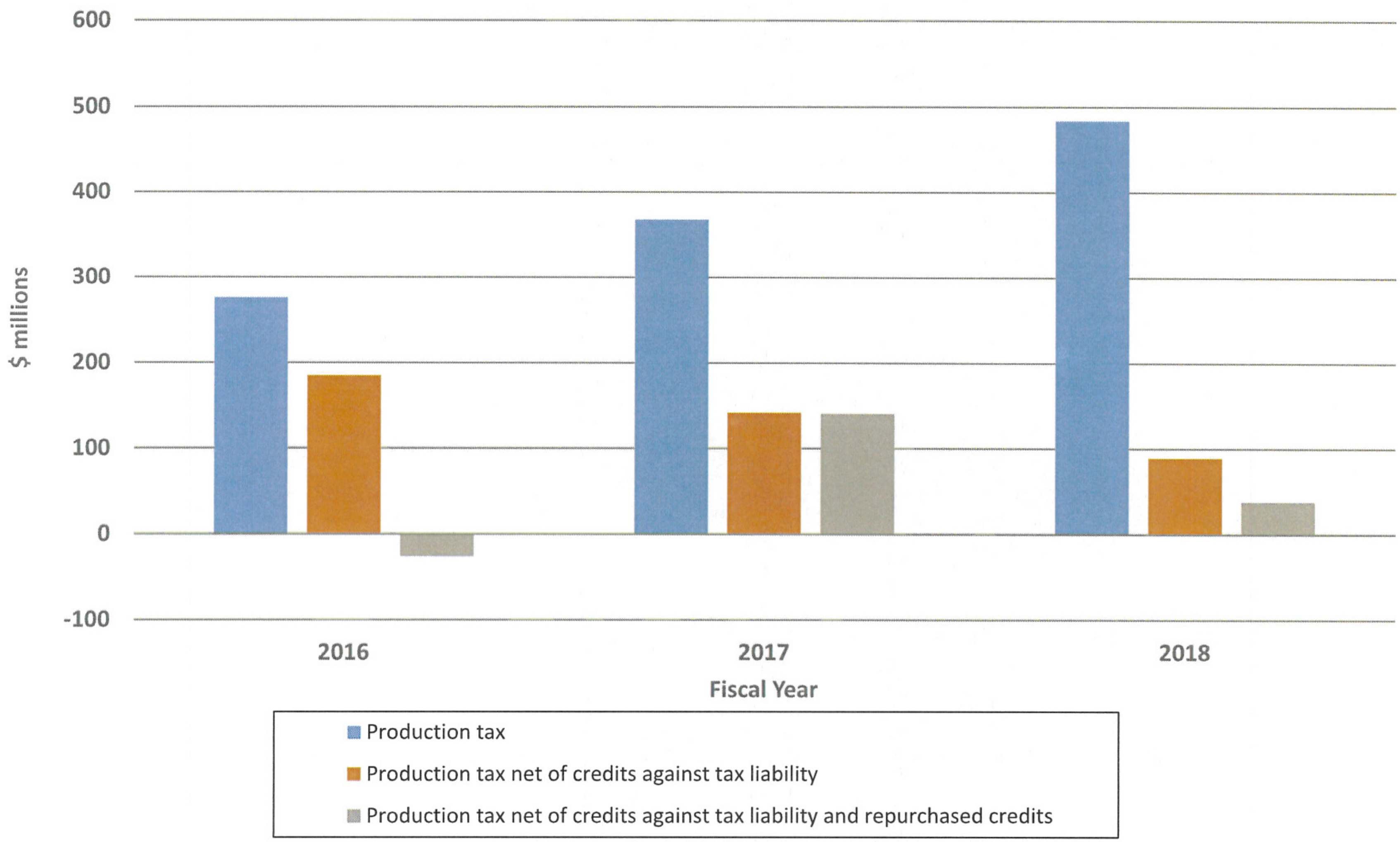
Randall Hoffbeck
Commissioner

Attachments:

- Oil and Gas Tax Credits vs. Production Tax and Unrestricted Royalties FY 2016-18: North Slope and Non-North Slope
- Credits Forecast: Outstanding Tax Credit Obligations by North Slope and Non-North Slope
- North Slope credits forecast compared with North Slope Production Tax and North Slope Unrestricted Petroleum Revenue – Assuming all credits repurchased in FY 2018
- List of 2016 oil price forecasting session participants
- Investment Snapshot September 2016
- 2011 bulletin on R&D expenditures

Title:	**Oil and Gas Tax Credits vs Production Tax and Unrestricted Revenue, FY 2016 - FY 2018: North Slope and Non-North Slope**
Preparer:	Ky Clark, Economist, 465-8222 and Dan Stickel, Chief Economist, 465-3279
Date:	2/2/2017
Purpose:	To show the amount of historical and forecasted North Slope new tax credits repurchased during the fiscal year. To compare North Slope production tax revenue and North Slope unrestricted petroleum revenue to North Slope credits applied against tax liability and repurchased North Slope credits.
Data Source:	Fall 2016 Revenue Sources Book, pgs. 24-25, 77-80, and supporting data/analysis
Key Assumptions:	Repurchased credits for FY 2016 and FY 2017 include only credits actually repurchased during those years. Repurchased credits for FY 2018 represent the North Slope share of the statutory appropriation of $74 million. For the purpose of this analysis, it is assumed that the full amount of corporate income tax paid, an input of unrestricted petroleum revenue, is from the North Slope. It is also assumed that bonus/rents/interest revenue is split, between North Slope and Non-North Slope, in the same proportion as royalty revenue.
History:	An analysis that included charts presenting statewide data was delivered to the House Finance Committee on 1/18/2017. This analysis is revised to include additional charts presenting the same data, but broken out by North Slope and Non-North Slope.
Disclaimer:	The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results. The information contained in this workbook may be privileged, confidential or otherwise protected from disclosure. If you are not the intended recipient, any use, dissemination, disclosure, distribution or copying is strictly prohibited.

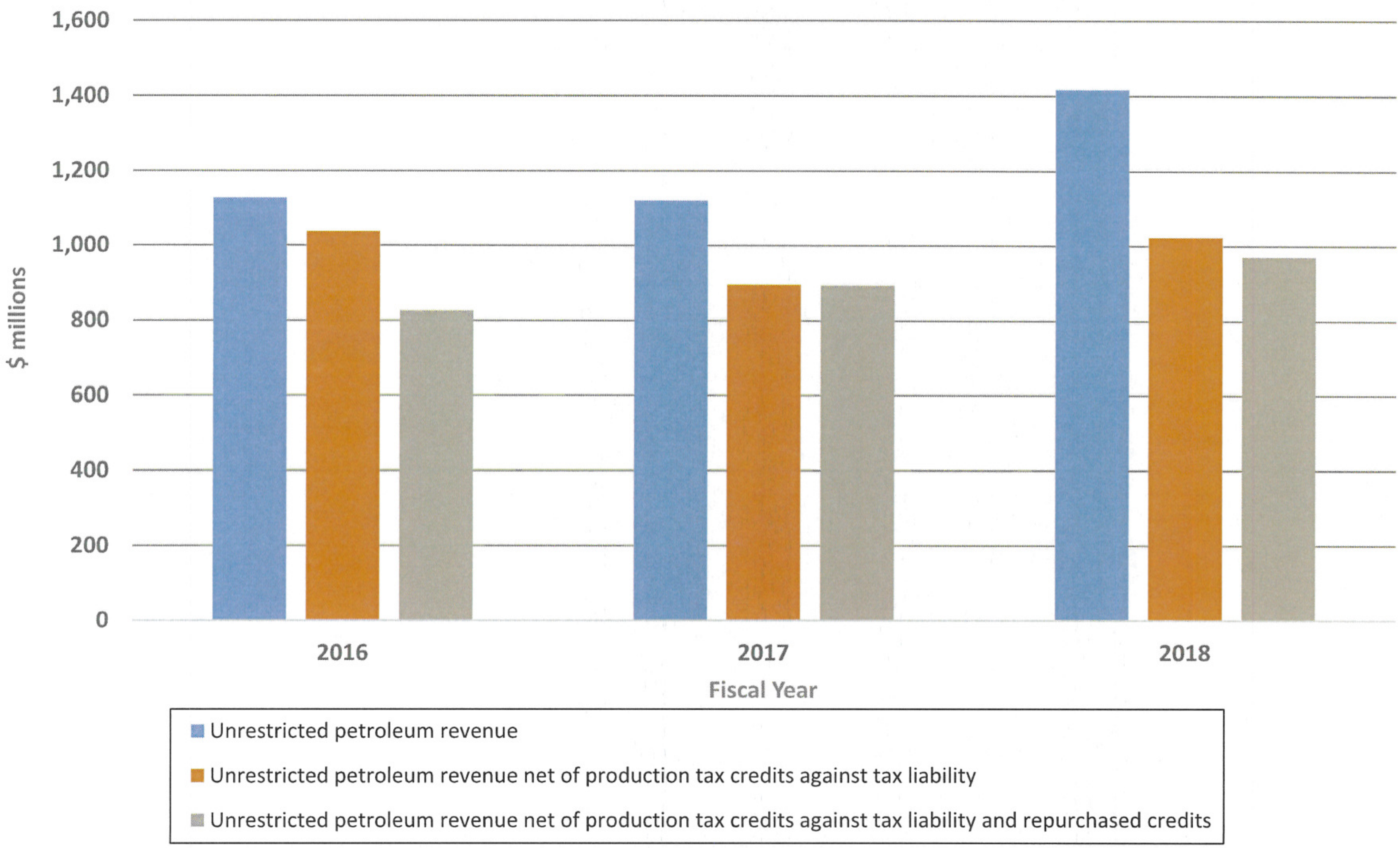
North Slope Credits Forecast: Compared with North Slope Production Tax



Notes: Repurchased credits for FY 2016 and FY 2017 include only credits actually repurchased during those years.
Repurchased credits for FY 2018 represents the North Slope share, $51 million, of the total statutory appropriation of $74 million.
Under this scenario, estimated North Slope credits available for repurchase are $414 million at end of FY17 and $488 million at end of FY18.

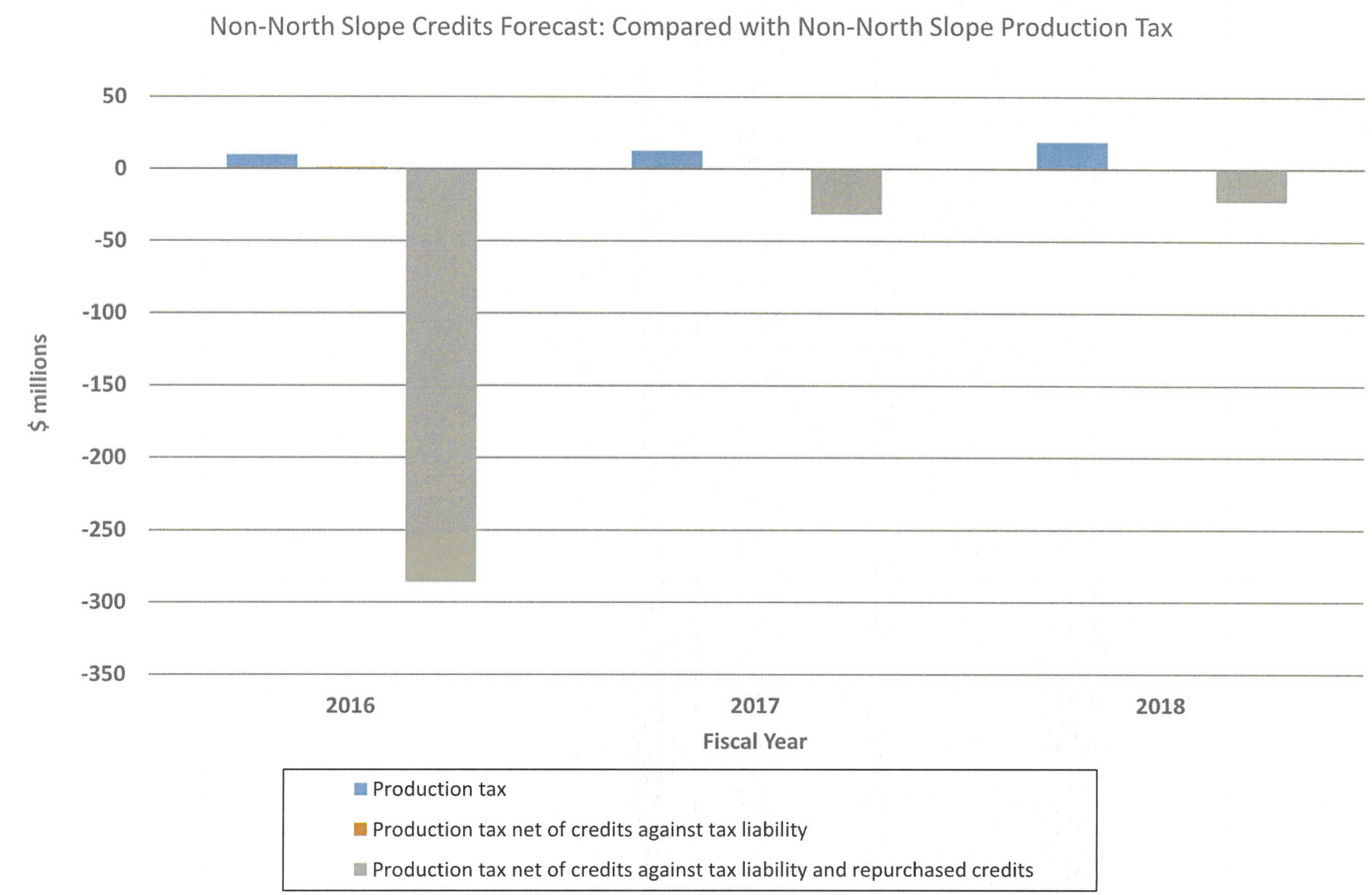
Source: Department of Revenue - Revenue Sources Book Fall 2016

North Slope Credits Forecast: Compared with North Slope Unrestricted Petroleum Revenue



Notes: Repurchased credits for FY 2016 and FY 2017 include only credits actually repurchased during those years.
Repurchased credits for FY 2018 represents the North Slope share, $51 million, of the total statutory appropriation of $74 million.
Under this scenario, estimated North Slope credits available for repurchase are $414 million at end of FY17 and $488 million at end of FY18.

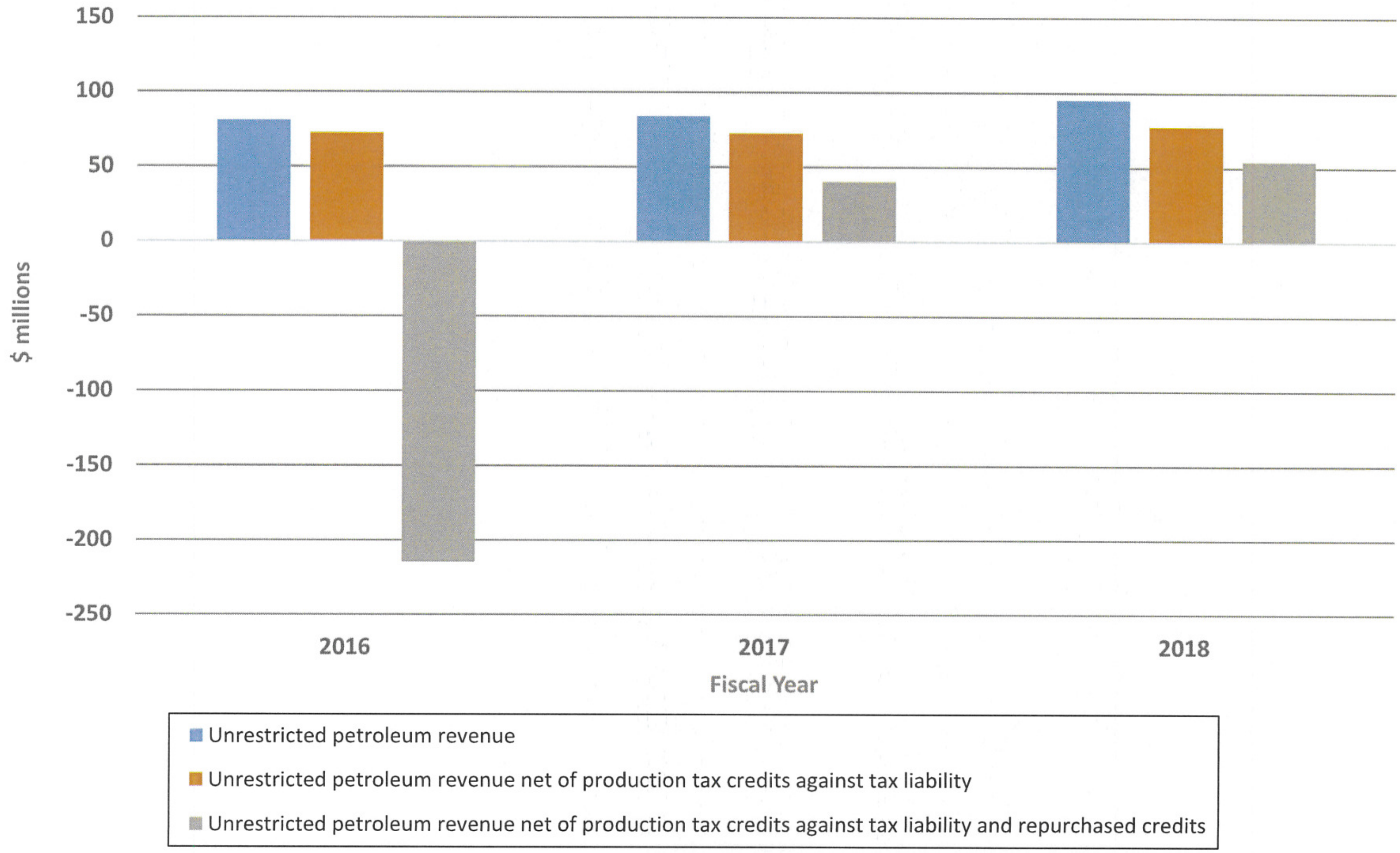
Source: Department of Revenue - Revenue Sources Book Fall 2016



Notes: Repurchased credits for FY 2016 and FY 2017 include only credits actually repurchased during those years.
Repurchased credits for FY 2018 represents the Non-North Slope share, $23 million, of the total statutory appropriation of $74 million.
Under this scenario, estimated Non-North Slope credits available for repurchase are $233 million at end of FY17 and $399 million at end of FY18.

Source: Department of Revenue - Revenue Sources Book Fall 2016

Non-North Slope Credits Forecast: Compared with Non-North Slope Unrestricted Petroleum Revenue

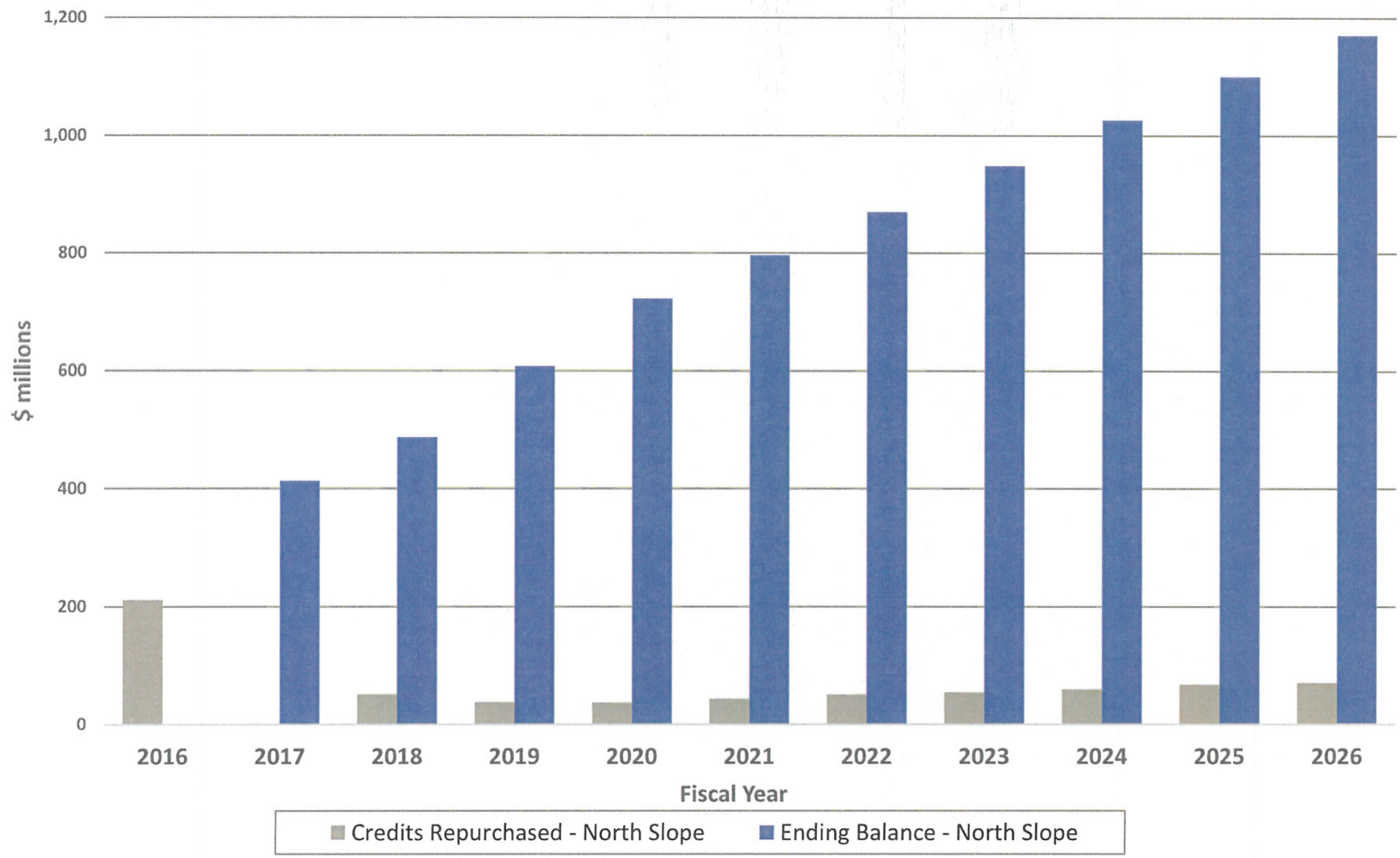


Notes: Repurchased credits for FY 2016 and FY 2017 include only credits actually repurchased during those years.
Repurchased credits for FY 2018 represents the Non-North Slope share, $23 million, of the total statutory appropriation of $74 million.
Under this scenario, estimated Non-North Slope credits available for repurchase are $233 million at end of FY17 and $399 million at end of FY18.

Source: Department of Revenue - Revenue Sources Book Fall 2016

Title:	**Credits Forecast: Outstanding Tax Credit Obligations by North Slope and Non-North Slope, FY 2016 - FY 2026**
Preparer:	Ky Clark, Economist, 465-8222 and Dan Stickel, Chief Economist, 465-3279
Date:	2/2/2017
Purpose:	To show the ending balance of credits available for repurchase each fiscal year, assuming statutory minimum appropriation for FY 2018+, broken out to show North Slope and Non-North Slope credits.
Data Source:	Fall 2016 Revenue Sources Book, pgs. 77-80, and supporting data/analysis
Key Assumptions:	Ending balance for FY 2016 is equal to $4 million. Ending balances for subsequent fiscal years assume the statutory minimum appropriation is paid each fiscal year, against the aggregate balance of credits each fiscal year. For FY 2017 and FY 2018, the ending balances are based on data received as of October 2016. For the purposes of this analysis it is assumed that the statutory minimum appropriation is made for FY 2018+. Based on the previous assumption, it is also assumed that the statutory minimum appropriation will be used to pay credits based on the time they are formally requested, starting with the earliest. A proportion was calculated based on current pending requests for payment of credits and whether those pending credits apply to the North Slope or Non-North Slope. It is assumed that forecasted credits paid per fiscal year to North Slope or Non-North Slope will follow the calculated proportion.
History:	An analysis that included charts presenting statewide data was delivered to the House Finance Committee on 1/18/2017. This analysis is revised to include additional charts presenting the same data, but broken out by North Slope and Non-North Slope.
Disclaimer:	The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results. The information contained in this workbook may be privileged, confidential or otherwise protected from disclosure. If you are not the intended recipient, any use, dissemination, disclosure, distribution or copying is strictly prohibited.

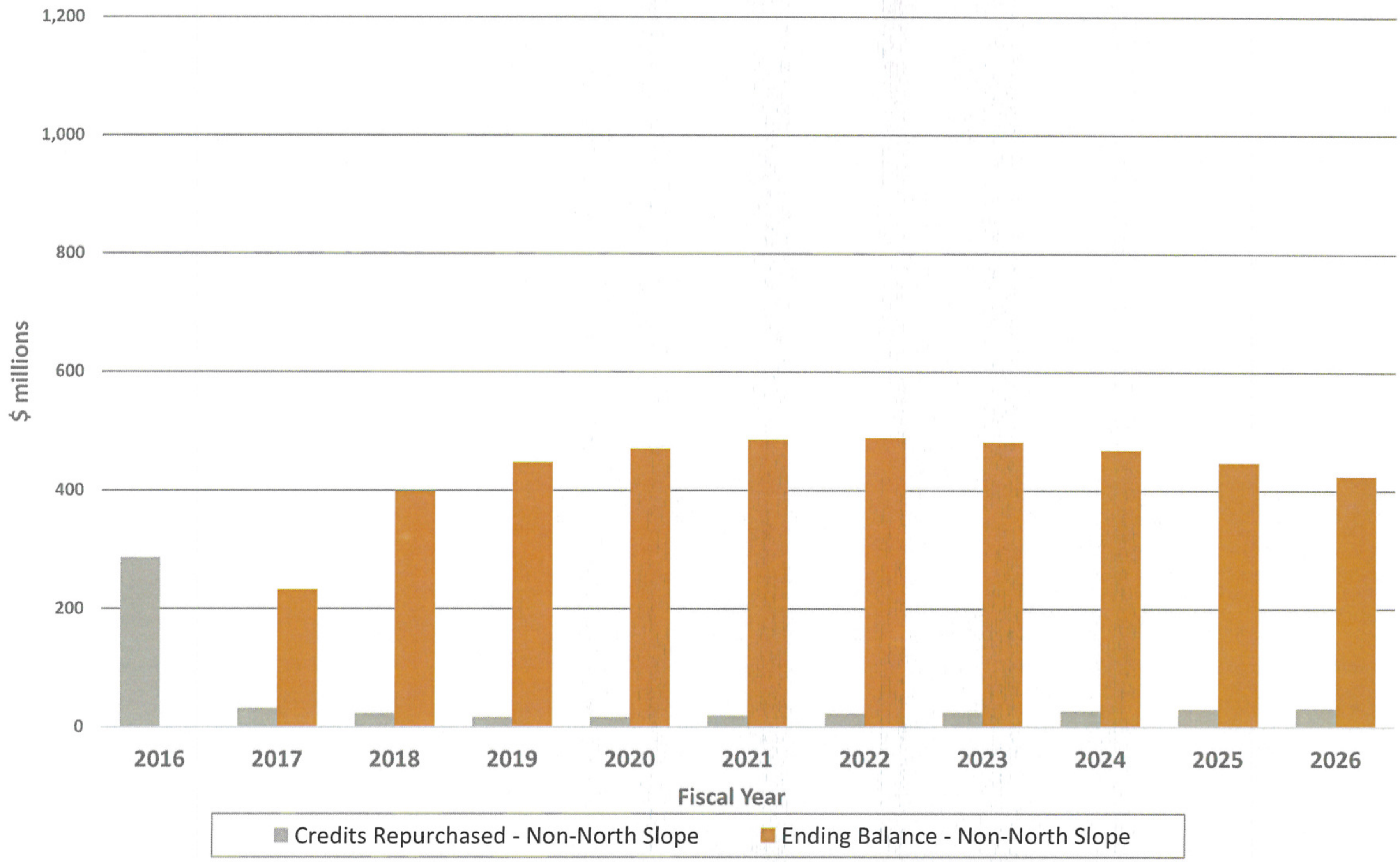
Ending balance of North Slope credits available for repurchase assuming North Slope share of statutory minimum appropriation for FY 2018+



Per AS 43.55.028, minimum appropriation is 10% of production tax levied, before credits, when ANS price forecast is $60 or higher. Minimum appropriation is 15% of production tax levied, before credits, when ANS price forecast is below $60.
Does not include changes in company behavior or credit transfers beyond FY 2018 as a result of only making minimum appropriation.

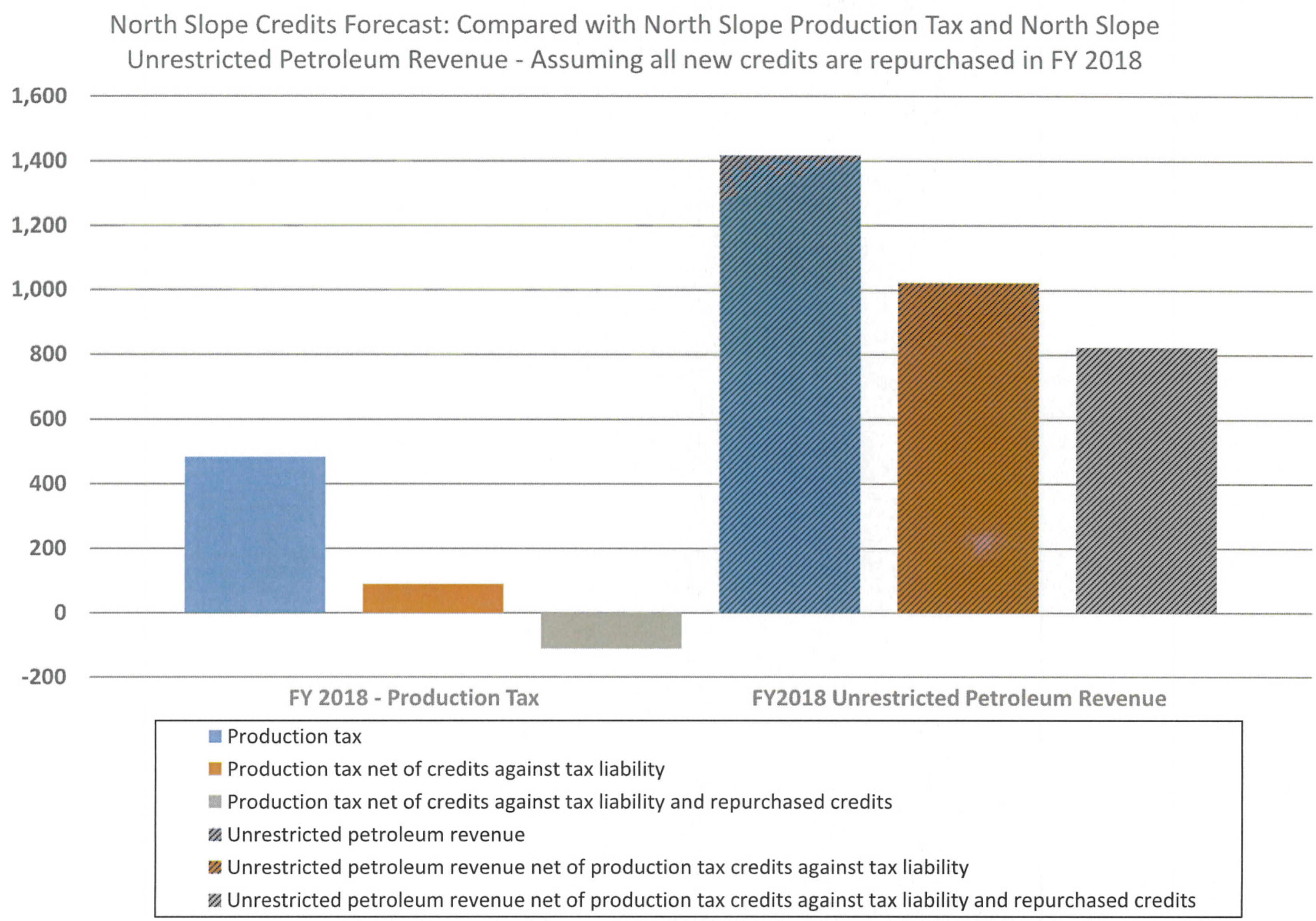
Source: Department of Revenue - Revenue Sources Book Fall 2016

Ending balance of Non-North Slope credits available for repurchase assuming Non-North Slope share of statutory minimum appropriation for FY 2018+



Per AS 43.55.028, minimum appropriation is 10% of production tax levied, before credits, when ANS price forecast is $60 or higher. Minimum appropriation is 15% of production tax levied, before credits, when ANS price forecast is below $60.
Does not include changes in company behavior or credit transfers beyond FY 2018 as a result of only making minimum appropriation.

Source: Department of Revenue - Revenue Sources Book Fall 2016



Note: It is assumed that in FY 2018 all new North Slope credits, forecast to be $200 million, are repurchased.

Source: Department of Revenue - Revenue Sources Book Fall 2016

Fall 2016 Oil Price Forecasting Session

Tuesday, October 4, 2016

GUEST SPEAKERS and PANEL

Chris Carter, Managing Partner	**NGP**
Damien Courvalin, Managing Director	**Goldman, Sachs & Co.**
Douglas Reynolds, Professor	**University of Alaska Fairbanks**
Larry Persily, Former DOR Deputy Commissioner	**Kenai Borough Mayor's Office**
Paul Strand, Portfolio Manager	**Allianz Global Investors**
Randall Hoffbeck, Commissioner	**Department of Revenue**

PARTICIPANTS

Department of Natural Resources

Alex Nouvakhov, Commercial Analyst
Greg Bidwell, Commercial Analyst
Jhonny Meza, Economist
Michael Redlinger, Commercial Analyst
Pascal M. Umekwe, Petroleum Economist

Department of Revenue

Brandon Spanos, Tax Division Deputy Director
Dan Debartolo, Admin. Service Director
Dan Stickel, Chief Economist
David Herbert, Economist
Dona Keppers, DOR Deputy Commissioner
Joyce Lofgren, Petroleum Economist
Ken Alper, Tax Division Director
Jodi Gatti, Intern
Michael Malin, Economist
Ryan Williams, Research Analyst
Tim Harper, Petroleum Economist
Will Bishop, Economist

Other State Agencies and Departments

Alexei Painter, Fiscal Analyst
Neal Fried, DOL Economist
Rob Carpenter, Fiscal Analyst
Brian Fechter, OMB Policy Analyst

University of Alaska

Alex James, UAA Professor
John Alevy, UAA Professor
Lance Howe, UAA Professor
Tim Cason, Rasmuson Chair of Economics
Steve Colt, UAA Professor Emeritus

Investment Fund Snapshot

9/30/2016

Board Managed Funds	Investment Horizon	Risk Tolerance	10 Year Geometric Return Target	Projected Standard Deviation	Market Value 9/30/2016	Returns 1 Year	Returns 3 Year	Returns 5 Year	Target Asset Allocation Short Term Fixed Income	Medium Term Fixed Income	Long Term Fixed Income	U.S. Equity	Non-US Equity	REIT Pool
Alaska Permanent Fund	Long	High	CPI + 5%	10% - 12%	54,778,500,000.00	9.75%	6.83%	9.10%	http://www.apfc.org/home/Content/investments/assetAllocation2009.cfm					
ARMB Non-Participant Directed *	Long	High	8.00%	15.00%	23,841,328,878.00	9.49%	6.28%	9.45%	http://treasury.dor.alaska.gov/Portals/3/docs/FY2017%20Asset%20Allocation.pdf					

Intermediate - Long-term State Investment Funds

Fund	Investment Horizon	Risk Tolerance	10 Year Geometric Return Target	Projected Standard Deviation	Market Value 9/30/2016	1 Year	3 Year	5 Year	Short Term Fixed Income	Medium Term Fixed Income	Long Term Fixed Income	U.S. Equity	Non-US Equity	REIT Pool
Constitutional Budget Reserve Fund	Interm.	Moderate	2.89%	1.59%	6,662,286,990.00	2.59%	1.44%	1.30%	69%		24%	4%	2%	1%
GeFONSI	Short to Interm.	Moderate	2.36%	1.08%	3,178,838,949.00	0.78%	0.58%	0.63%	68%	32%				
PCE Endowment Fund	Long	High	6.55%	12.95%	943,944,277.00	10.39%	7.07%	11.13%			32%	38%	27%	3%
Public School - Principal	Long	Moderate	6.08%	10.77%	589,099,187.00	9.38%	5.49%	8.00%			43%	32%	22%	3%
RHIF LTC Insurance	Long	High	5.25%	7.52%	431,194,308.00	8.21%	5.51%	6.55%			61%	21%	15%	3%
AK Higher Education Investment	Long	High	6.55%	12.95%	353,816,101.00	10.30%	6.08%				32%	38%	27%	3%
EVOS Habitat Investment	Long	High	6.60%	13.23%	106,429,255.00	10.66%	7.27%	11.13%			30%	47%	23%	
EVOS Research Investment	Long	High	6.60%	13.23%	97,676,482.00	10.44%	7.21%	11.10%			30%	47%	23%	
Int'l Airport Revenue Fund	Interm.	Moderate	2.89%	1.59%	71,527,379.00	2.70%	1.20%	1.05%	69%		24%	4%	2%	1%
AK Mental Health Trust Reserve	Long	High	6.17%	11.54%	40,381,641.00	9.12%	6.41%	9.67%	10%		29%	40%	21%	
Illinois Creek Mine Reclamation	Long	Low	6.55%	12.95%	984,515.00	10.22%	2.74%	3.43%			32%	38%	27%	3%
					12,476,179,084.00									

	Short Term Fixed Income	Medium Term Fixed Income	Long Term Fixed Income	U.S. Equity	Non-US Equity	REIT Pool
1 Year Benchmark Re	0.27%	0.89%	5.19%	14.96%	6.50%	20.87%
3 Year Benchmark Re	0.12%	0.87%	4.03%	10.44%	0.48%	13.84%
5 Year Benchmark Re	0.10%	0.82%	3.08%	16.36%	7.38%	15.96%

Short -term State Investment Funds

Fund	Investment Horizon	Risk Tolerance	10 Year Geometric Return Target	Projected Standard Deviation	Market Value 9/30/2016	1 Year	3 Year	5 Year	Short Term Fixed Income
Permanent Fund Dividend Holding Account	Short	Low	2.25%	0.90%	708,858,446.00	0.61%	0.36%	0.35%	100%
2016B-2012 Transportation Bonds	Short	Low	2.25%	0.90%	155,564,737.00				100%
2013-B GO Bonds	Short	Low	2.25%	0.90%	45,706,177.00	0.68%	0.41%		100%
Public School - Income	Short	Low	2.25%	0.90%	21,252,960.00	0.68%	0.41%	0.39%	100%
AIA Series 2002 Reserve Account	Short	Low	2.25%	0.90%	15,350,449.00	0.68%	0.41%	0.39%	100%
RHIF Major Medical	Short	Low	2.25%	0.90%	14,875,355.00	0.68%	0.41%	0.39%	100%
2016A-2012 Transportation Bonds	Short	Low	2.25%	0.90%	13,288,797.00	0.68%	0.41%		100%
AIA Series 2003 Reserve	Short	Low	2.25%	0.90%	9,838,519.00	0.68%	0.41%	0.40%	100%
International Airports 2010-C	Short	Low	2.25%	0.90%	8,386,899.00	0.68%	0.41%	0.39%	100%
Intl Arpt 2006 Non-AMT	Short	Low	2.25%	0.90%	7,395,649.00	0.68%	0.41%	0.39%	100%
2008 Transportation Project Bonds	Short	Low	2.25%	0.90%	6,810,591.00	0.68%	0.41%	0.39%	100%
Intl Arpt 2006 Variable	Short	Low	2.25%	0.90%	5,648,714.00	0.68%	0.41%	0.39%	100%
International Airports 2010-D	Short	Low	2.25%	0.90%	2,783,191.00	0.68%	0.41%	0.39%	100%
Investment Loss Trust Fund	Short	Low	2.25%	0.90%	2,598,355.00	0.68%	0.41%	0.39%	100%
Int'l Airport Repair & Replacement Fund	Short	Low	2.25%	0.90%	500,927.00	0.68%	0.41%	0.39%	100%
2010-C GO Bonds	Short	Low	2.25%	0.90%	182,019.00	0.68%	0.41%	0.39%	100%
2010-A GO Bonds	Short	Low	2.25%	0.90%	8,678.00	0.68%	0.41%	0.39%	100%
					1,019,050,463.00				

* Weighted average return for PERS & TRS, return target for ARMB is the actuarial assumed rate of 8%

ALASKA DEPARTMENT OF REVENUE
TAX DIVISION
ADVISORY BULLETIN 2011-01

Re: Research and development costs and AS 43.55.170 reimbursements

Request: A producer has requested that the Department issue an advisory bulletin as to (1) whether certain testing costs for testing an experimental technology for recovering gas hydrates are lease expenditures; and (2) if not, whether the producer must adjust its lease expenditures under AS 43.55.170 to reflect reimbursements from a research grant for a portion of the gas hydrates test costs.

Short Answer: According to AS 43.55.165(a)(1)(A) only those costs that are, "to explore for, develop, or produce oil or gas deposits" are considered to be lease expenditures. Under the facts presented, the costs do not qualify as lease expenditures under AS 43.55.165 since they are not for exploring for, developing, or producing oil or gas deposits. Therefore, those costs may not be deducted in calculating monthly or annual production tax values. Since the costs are not lease expenditures, the fact that a portion of the costs will be reimbursed will not trigger the requirement under AS 43.55.170 to treat the reimbursements as an adjustment to the producer's lease expenditures. However, without knowing the exact nature of the costs in question, the Department is unable to rule out the possibility that a portion of the reimbursements might offset the producer's actual lease expenditures incurred for purposes other than the research project at issue here, in which case an adjustment could be required under AS 43.55.170.

Background: A producer has partnered with a federal government agency to test an experimental methane hydrate production technology and to gather scientific data for improved characterization of naturally occurring methane hydrates. The evaluation includes field testing of a technology developed at the laboratory level to determine if the method is viable for commercial production of methane. The testing will be done as a tract operation in a unit north of 68 degrees North latitude. Only one unit owner will be conducting the testing and paying 100 percent of testing costs. That unit owner will be reimbursed for 80 percent of its project related costs. No other working interest owners within the unit will incur costs, or receive reimbursement for costs of the hydrate testing. According to the producer, no taxable gas will be produced, and the planned well will be abandoned after testing.

Analysis: First, the producer requests the Department's opinion whether the gas hydrate test costs will be lease expenditures. The producer acknowledges that those costs will be incurred upstream of the point of production and are the type of costs –drilling, testing, plugging, and abandoning a well – that would reasonably be incurred in exploration, development and production of oil and gas. Typically those types of upstream costs would be considered ordinary and necessary costs of exploration, development and production.
AS 43.55.165(a)(1)(B)(ii) and (*l*). The producer suggests that although these costs are ordinary and necessary for purposes of the gas hydrates testing project, they are not direct costs, but research and development costs disallowed under 15 AAC 55.250(g).

The Department agrees with the conclusion that the project costs are not lease expenditures, but for a more fundamental reason than suggested in the request for the advisory bulletin.[1] The costs of gas hydrate testing are not lease expenditures because the costs will not be incurred "to explore for, develop, or produce oil or gas deposits" on the producer's lease or property, within the meaning of AS 43.55.165(a).[2] Rather, the costs will be incurred to conduct a research project on an experimental technology that may or may not be used in the

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[1] The producer is correct, however, in noting that 15 AAC 55.250(g) reflects the Department's recognition that research and development costs are not direct costs of exploring for, developing, or producing oil or gas deposits.

[2] AS 43.55.165(a)(1)(A) and (*l*) (explore includes conducting geological or geophysical exploration, including a stratigraphic test well).

future to produce gas. The testing, including drilling a well, is to evaluate the effects of injecting CO_2 into the reservoir and exchanging for methane. The technology has only been tested in the laboratory and has not yet been tested, or proven, in the field.

Second, although the producer will pay 100 percent of the gas hydrate testing costs, it will be reimbursed for 80 percent of those costs by the federal Department of Energy. The producer requests assurance that it will not be required to adjust its lease expenditures to reflect the "reimbursement or similar payment that offsets the producer's lease expenditures." AS 43.55.170(a)(2). The producer suggests that if the hydrate test expenditures were claimed as lease expenditures, it would be required to make an adjustment to reflect any reimbursements received. However, if the gas hydrate expenditures are not claimed as lease expenditures, the producer contends that it should not be required to make any adjustments under AS 43.55.170

The Department agrees that a payment received as reimbursement of a cost of the research project does not become a payment that offsets the producer's lease expenditures simply because it reimburses that cost, since that cost is not a lease expenditure for the reasons discussed above. However, in the absence of more detailed information, the Department cannot exclude the possibility that a payment received as a reimbursement of a research project cost might *also* constitute a payment that offsets the producer's lease expenditures. Consider the following example. Suppose that the producer has previously spent $1,000,000 to acquire certain equipment to use in its oil and gas production operations and has deducted that cost as a lease expenditure. Now the producer decides it can temporarily spare that equipment for use in the research project and allocates as a cost to the research project $50,000 for use (i.e, capital recovery) of the equipment.[3]

[3] Note that the producer would not be allowed to treat as a lease expenditure such an allocation for use of the equipment in its actual production operations, since

Whatever portion of the $50,000 is reimbursed by the Department of Energy would offset the producer's $1,000,000 in lease expenditures and would have to be treated as an adjustment under AS 43.55.170.

Scope and Non-binding nature of this bulletin: This advisory bulletin is issued for the information and guidance of producers, explorers, and other interested persons. Opinions expressed here are strictly limited to the proposed conditions as presented above interpreted in accordance with existing Alaska oil and gas production tax law. These interpretations do not address other possible effects under other scenarios or types of tax laws, and as provided in AS 43.55.110(g), interpretations stated in this advisory bulletin are not binding on the Department or others.

Bruce Tang

Bruce Tangeman
Deputy Commissioner
Alaska Department of Revenue

Issued: May 3, 2011

that would be double-counting (the acquisition cost of the equipment already having been treated as a lease expenditure).