Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2011

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STATE OF ALASKA

DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

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December 15, 2011

The Honorable Sean Parnell, Governor of Alaska
P.O. Box 110001
Juneau, Alaska 99811-0001

Dear Governor Parnell,

I am pleased to present to you the Department of Revenue's Fall 2011 *Revenue Sources Book* (RSB)—a compilation of revenues received in Fiscal Year 2011 and projections of revenues for FY 2012 through FY 2021. The RSB is an annual publication that provides detailed state revenue projections, based on a collaborative effort between the Department of Revenue Tax and Treasury divisions, the Permanent Fund Corporation, and the Office of Management and Budget. The purpose of the publication is to inform you, the Alaska Legislature, and the public of future revenue expectations.

As in previous years, oil revenue dominates the state's revenue outlook. In FY 2011, approximately 92% of all unrestricted revenue was attributable to oil. The forecast for FY 2012 through FY 2016 shows oil revenue contributing at least 90% of unrestricted revenues. High oil prices are driving the oil revenue forecast, and together with high production tax rates, these two factors are masking the underlying production decline. North Slope oil production declined 6.3% in FY 2011 and another 4.7% decline is expected in FY 2012, assuming that the oil production included in the "under development" and "under evaluation" layers of our production forecast come to fruition. Without these layers, the production decline in FY 2012 could be as high as 9.1%. This contrasts with the production estimates we anticipated in the Fall of 2007, shortly after the passage of ACES. In Fall 2007, the Department of Revenue projected that ANS production in FY 2012 would be 675,000 barrels per day. Four years later our production forecast has changed, with 100,000 fewer barrels per day anticipated in FY 2012. More information about our production forecast is contained in Chapter 4 of this publication.

Oil prices are a significant factor in the calculation of oil revenues. Following a short-term dip in oil prices in FY 2009-2010, prices for Alaska North Slope crude have rebounded and have averaged more than $110 per barrel for several months. Our oil price forecast for FY 2012 and

FY 2013 is $109.33 and $109.47, respectively. Forecasted oil prices remain above $100 throughout our forecast period to 2021.

Because our oil price forecast assumes high oil prices into the future, we also assume that for lease expenditure purposes, several oil and gas projects that were publicly announced this fall will proceed as planned. This includes proposals to develop Alaska's shale resources, the Umiat field, and other North Slope and Cook Inlet prospects. Although the lease expenditures and associated credits for these projects are included in our forecast, only the Umiat field meets the criteria to be included in our production forecast. Any new developments such as these will require extensive capital and continued commitment by the developers throughout the entire projects.

Unrestricted revenues totaled $7.7 billion in FY 2011, and we forecast unrestricted revenue of $8.9 billion and $8.2 billion for FY 2012 and FY 2013, respectively. Non-oil revenues will contribute slightly more than $700 million of those totals for FY 2012 and FY 2013. In FY 2011, non-oil revenues represented just over 8% of the FY 2011 unrestricted revenues, totaling $624 million.

Chapter three of this RSB is devoted to rare earth elements—what they are, how they are used, where they are produced, and how they may be very important to Alaska's resource development future. There is still very little known about these elements, although they are used in the manufacture of many of the common items we rely upon today, such as cell phones, rechargeable batteries and DVDs. Chapter three provides some insight into the exciting new developments taking place in Alaska that involve these valuable elements.

This RSB continues revenue classification modifications made in last year's RSB. In the appendix to this RSB, we have also provided an updated summary of tax credits, and a presentation of revenues using the income statement format.

We hope you find the information provided in the Fall 2011 *Revenue Sources Book* to be useful. We will be providing a forecast update in the spring of 2012.

Sincerely,

Bryan Butcher
Commissioner

In Memoriam

Senator Ted Stevens

The Fall 2011 Revenue Sources Book is dedicated to Theodore Fulton Stevens, U.S. Senator for Alaska for forty years, who died August 10, 2010 at the age of 86.

Ted Stevens was a founding father of Alaska as an attorney arguing for statehood at the Department of Interior in 1958. Returning to Alaska to practice law in 1961, Ted was later appointed to the U.S. Senate by Governor Walter Hickel, upon the death of Senator E. L. Bartlett, on Christmas Eve, 1968.

Throughout his 40 year career in the U.S. Senate, he became the longest serving Republican Senator, was voted "Alaskan of the Century," and was appointed President Pro Tempore. Through his position on the Appropriations Committee, Senator Stevens was able to advance our very young state by acquiring the hundreds of millions of federal dollars necessary to build the infrastructure we now enjoy. This money resulted in projects that employed thousands of Alaskans, matching funds for construction projects statewide for state and local governments and was an amazing economic driver for local businesses.

Virtually every federal project throughout Alaska has Stevens' name on it from the International Airport in Anchorage to the Trans Alaska Pipeline that runs from Prudhoe to Valdez, the oil from which provides royalty payments and dividends to Alaskan residents.

We wish to express our sincere gratitude to the late Senator, in the words of his family "He was a guiding light through statehood and the development of the 49th State. Now that light is gone but the warmth and radiance of his life and his work will shine in the last frontier. His legacy is the 49th star in the American flag."

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1. Introduction

General Discussion

The purpose of the Revenue Sources Book is to provide the governor, legislature and citizens of the state a summary of our past collections of state revenue and a forecast of future revenue. Revenues are categorized into four major components: oil revenue, income from sources other than oil, federal revenue and investment revenue.

Oil revenue continues to be the most significant source of revenue to the state, and it is projected to provide more than 88% of General Purpose Unrestricted Revenue through FY 2021. However, production of oil and natural gas liquids on the North Slope is declining. In FY 2011, Alaska North Slope (ANS) output averaged 0.603 million barrels per day compared to a peak of 2.01 million barrels per day in FY 1988. While production declined by about 70% over that period, the market price of oil has increased over 500%. For FY 2012, we project ANS oil production will decrease to an average of 0.574 million barrels per day.

The Constitutional Budget Reserve Fund (CBRF), created in 1990, has served the state well as a budget stabilization fund in years of low oil revenue. High oil prices in recent years combined with a higher production tax rate on oil have masked the impacts of declining oil production. Lower oil prices combined with declining North Slope crude oil volumes could lead to future budget shortfalls and draws on the CBRF.

Alaska's total revenue picture also includes earnings from investments in the Permanent Fund and CBRF, federal revenue, and other sources, such as taxes, charges for services, licenses, permits, fines and forfeitures. The information provided in this book will provide greater insight not only into the sources of revenue that support the state today, but also into future revenue from potential new sources.

Please note that the totals in some tables throughout this publication may not equal the sum of components due to rounding. Fiscal year 2011 totals should be considered preliminary and will be updated in the spring of 2012.

Revenue Sources Book

Alaska Department of Revenue – Tax Division

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2. Executive Summary

Total State Revenue

Figure 2-1. FY 2011 Total State Revenue: $19.5 billion

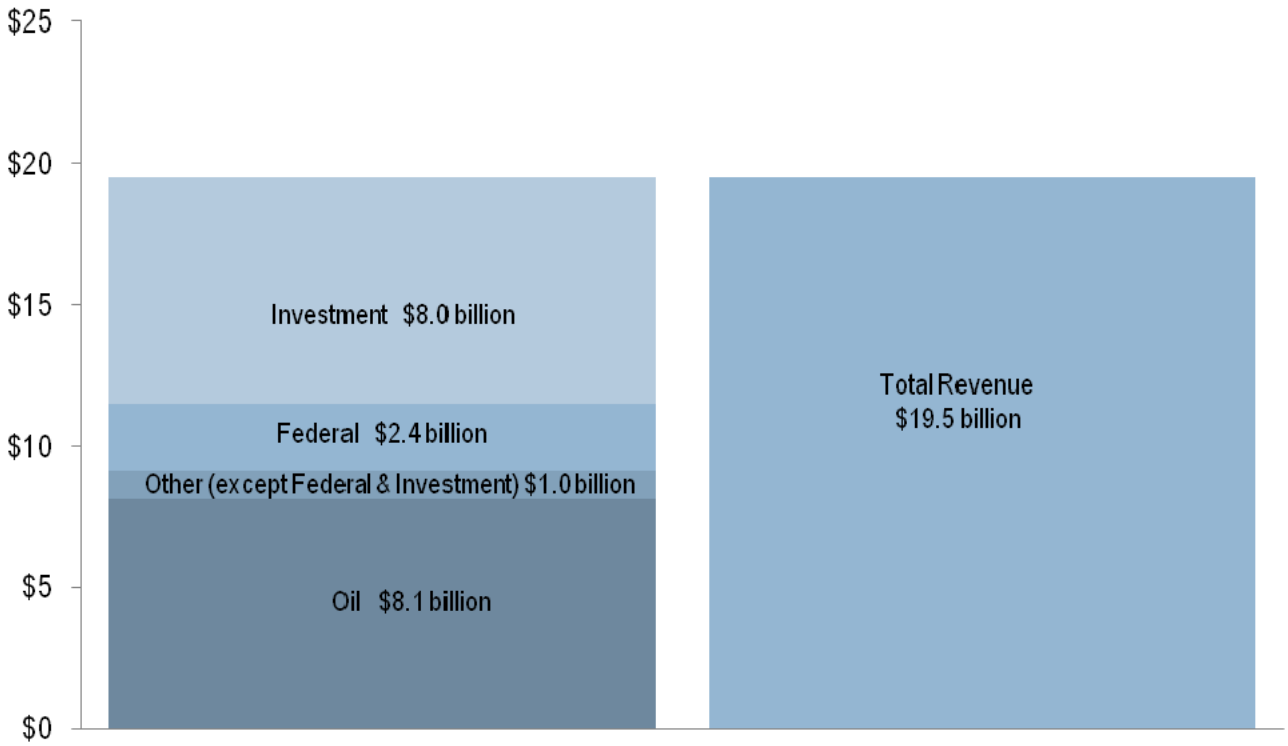


Figure 2-2. Total State Revenue by Major Component, FY 2011 and Forecasted FY 2012-2013 ($ million)

Unrestricted General Fund Revenue	History	Forecast	
Oil Revenue	FY 2011	FY 2012	FY 2013
Petroleum Property Tax	110.7	91.7	89.7
Petroleum Corporate Income Tax	542.1	662.1	728.4
Production Tax	4,552.9	5,376.4	4,715.8
Royalties (including Bonuses, Rents, & Interest)	1,843.3	2,085.2	1,962.0
Subtotal	**7,049.0**	**8,215.3**	**7,496.0**
Other Sources (Except Federal & Investment)			
Taxes	402.7	388.5	398.1
Charges for Services	18.5	17.8	17.8
Fines and Forfeitures	7.0	8.7	8.7
Licenses and Permits	42.8	42.6	41.5
Rents and Royalties	17.6	16.9	17.1
Other	39.1	61.2	55.9
Subtotal	**527.7**	**535.7**	**539.1**
Investment Revenue			
Investments	93.2	174.5	180.2
Interest Paid by Others	3.1	2.4	2.4
Subtotal	**96.3**	**176.9**	**182.6**
Subtotal Unrestricted General Fund Revenue	**7,673.0**	**8,927.9**	**8,217.7**
Designated General Fund Revenue			
Other Sources (Except Federal & Investment)			
Taxes	52.1	51.6	51.6
Charges for Services	196.8	219.8	220.0
Fines and Forfeitures	6.9	8.2	8.1
Licenses and Permits	0.1	0.1	0.1
Rents and Royalties	4.0	4.4	4.5
Other	22.7	23.8	23.8
Subtotal	**282.6**	**307.9**	**308.1**
Investment Revenue			
Investments - Designated GF	8.6	14.4	15.1
Other Treasury Managed Funds	63.8	(2.0)	26.7
Subtotal	**72.4**	**12.4**	**41.8**
Subtotal Designated General Fund Revenue	**355.0**	**320.3**	**349.9**

Figure 2-2. Continued

Other Restricted Revenue

	History	Forecast	
Oil Revenue	FY 2011	FY 2012	FY 2013
Royalties to Perm Fund & School Fund (includes Bonuses & Rents)	870.9	927.0	871.9
Tax and Royalty Settlements to CBRF	167.3	31.0	20.0
Subtotal	**1,038.2**	**958.0**	**891.9**
Other Sources (Except Federal & Investment)			
Taxes	83.8	70.5	70.6
Charges for Service	35.5	62.8	62.8
Fines and Forfeitures	23.9	23.7	23.5
Licenses and Permits	30.4	31.2	31.2
Rents and Royalties	6.3	6.5	6.7
Other	11.1	8.4	8.4
Subtotal	**191.0**	**203.1**	**203.2**
Investment Revenue			
Investments - Other Restricted	17.4	29.2	30.6
Constitutional Budget Reserve Fund	1,026.9	20.0	538.7
Alaska Permanent Fund (GASB)[1]	6,811.8	2,942.6	3,176.7
Subtotal	**7,856.1**	**2,991.8**	**3,746.0**
Subtotal Other Restricted Revenue	**9,085.3**	**4,152.9**	**4,841.0**

Federal Revenue

Oil Revenue			
NPR-A Royalties, Rents and Bonuses	3.0	4.0	4.0
Subtotal	**3.0**	**4.0**	**4.0**
Federal Receipts			
Federal Receipts	2,407.9	3,102.5	3,102.5
Subtotal	**2,407.9**	**3,102.5**	**3,102.5**
Subtotal Federal Revenue	**2,410.9**	**3,106.5**	**3,106.5**

Total State Revenue 19,524.2 16,507.7 16,515.1

[1] Both realized and unrealized gains and losses are included per GASB 34 as interpreted by the Finance Division of the Department of Administration in its Comprehensive Annual Financial Report.

Figure 2-3. Total State Revenue, FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
Unrestricted General Fund	FY 2011	FY 2012	FY 2013
Oil Revenue	7,049.0	8,215.3	7,496.0
Other Sources (Except Federal and Investment)	527.7	535.7	539.1
Investment Revenue	96.3	176.9	182.6
Subtotal	**7,673.0**	**8,927.9**	**8,217.7**
Designated General Fund			
Other Sources (Except Federal and Investment)	282.6	307.9	308.1
Investment Revenue	72.4	12.4	41.8
Subtotal	**355.0**	**320.3**	**349.9**
Other Restricted Revenue			
Oil Revenue	1,038.2	958.0	891.9
Other Sources (Except Federal and Investment)	191.0	203.1	203.2
Investment Revenue	7,856.1	2,991.8	3,746.0
Subtotal	**9,085.3**	**4,152.9**	**4,841.0**
Federal Revenue			
Oil Revenue[(1)]	3.0	4.0	4.0
Federal Receipts	2,407.9	3,102.5	3,102.5
Subtotal	**2,410.9**	**3,106.5**	**3,106.5**
Total State Revenue	**19,524.2**	**16,507.7**	**16,515.1**

Unrestricted Revenue and Restricted Revenue

Throughout this forecast, we report two categories of revenue: Unrestricted General Fund Revenue (frequently referred to as unrestricted revenue) and restricted revenue. Unrestricted General Fund Revenue is based on the unrestricted component of the General Fund in the Department of Revenue Tax Accounting System, with certain adjustments. Restricted revenue represents remaining revenue and can be further categorized as Designated General Fund, Other State Revenue, or Federal Revenue.

Unrestricted General Fund Revenue

Unrestricted General Fund Revenue reflects revenue that is not restricted by the constitution, state or federal law, trust or debt restrictions or customary practice. Most legislative and public debate centers on this category of revenue, and this is the amount generally used for budget planning purposes and designated in budget documents as unrestricted general funds. Unrestricted General Fund Revenue reported in this forecast includes funds deposited into the unrestricted component of the General Fund, with certain adjustments:

- Reductions might include: (a)

[(1)] Oil revenue shown in the Federal category includes the state share of rents, royalties and bonuses received from the National Petroleum Reserve in Alaska.

revenue earmarked for specific programs, (b) pass-through revenue for qualified regional aquaculture and dive fishery associations, and (c) revenue shared with municipal governments and organizations (e.g., fisheries taxes).

- Additions might include transfers from the unclaimed property trust to the state treasury.

The Department of Revenue uses a three-step process to make its final estimate of Unrestricted General Fund Revenue.

Step 1. We estimate all forecast revenue for the unrestricted component of the General Fund, as well as certain program receipts, by using our forecast models and obtaining estimates from other state agencies.

Step 2. We then consult the Governor's Office of Management and Budget and Legislative Finance for their input.

Step 3. Finally, following analysis, we adjust our initial projection to derive a forecast of total Unrestricted General Fund Revenue.

Figure 2-4 on the next two pages sets out FY 2011 Unrestricted General Fund Revenue and our forecast for FY 2012 and 2013.

Restricted Revenue

Restricted revenue represents any revenues that are not considered Unrestricted General Fund Revenue. This includes revenue restricted by the constitution, state or federal law, trust or debt restrictions, or customary practice. Restricted revenue reported in this forecast includes money deposited into the Restricted Component of the General Fund, with certain additions. Additions might include: (a) receipts deposited in funds other than the General Fund, and (b) receipts deposited in the General Fund but restricted by statute or customarily appropriated for a particular purpose or program, such as sharing of fish tax revenue with municipalities.

Article IX, Section 15 of the Alaska constitution requires that at least 25% of all mineral lease rentals, royalties, royalty sale proceeds, federal mineral revenue sharing payments and bonuses received by the state be placed in the permanent fund. Until 2003, Alaska Statutes 38.13.010 required the placement of 50% of royalties from certain leases into the permanent fund. House Bill 11, passed by the legislature in 2003, changed the law so that only 25% from all leases would be placed into the permanent fund, contingent on the impact of this change to the permanent fund dividend. On October 1, 2008, the impact of HB 11 on the permanent fund dividend had exceeded the limitations provided in HB 11, and HB 11 was repealed. As of October 1, 2008, the applicable leases will pay 50% of royalties to the permanent fund, while others will pay 25% to the fund. On average, approximately 30% of oil and gas royalties go into the principal of the Permanent Fund. This change will be reflected in this and future revenue forecasts as a decrease in unrestricted revenue and an increase in restricted revenue.

This is the second year in which the restricted revenue component of actual and forecasted revenues reflects new fund categories of restricted revenue. These fund categories were developed by the Division of Legislative Finance and the Office of Management and Budget in 2010 to provide additional information on the level of legislative discretion in the budget process. The restricted revenue fund categories are as follows: (1) Designated General Fund; (2) Other State Revenue; and (3) Federal Revenue. These categories will be evident in tables depicting restricted revenue throughout this book.

In addition to adding categories of restricted revenue, revenues from the large passenger vessel (LPV) gambling tax and from corporate dividends were reclassified from restricted to unrestricted revenue. Corporate dividends include revenues returned to the state by state-owned corporations such as the Alaska Housing Finance Corporation.

The Department of Revenue worked cooperatively with representatives of the Legislative Finance Division and the Office of Management and Budget to make these changes. These changes will be continued in future Revenue Sources Books.

Figure 2-4. Unrestricted General Fund Revenue, FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
Oil Revenue	FY 2011	FY 2012	FY 2013
Petroleum Property Tax	110.7	91.7	89.7
Petroleum Corporate Income Tax	542.1	662.1	728.4
Production Tax			
Oil & Gas Production	4,543.2	5,367.0	4,706.8
Oil & Gas Hazardous Release	9.7	9.4	9.1
Subtotal Production Tax	**4,552.9**	**5,376.4**	**4,715.8**
Royalties (including Bonuses, Rents, & Interest)			
Mineral Bonuses & Rents	10.3	21.2	21.2
Oil & Gas Royalties	1,821.3	2,054.0	1,930.8
Interest	11.7	10.0	10.0
Subtotal Royalties	**1,843.3**	**2,085.2**	**1,962.0**
Total Oil Revenue	**7,049.0**	**8,215.3**	**7,496.0**
Other Revenue (except Federal & Investment)			
Taxes			
Excise Tax			
Alcoholic Beverage	19.4	19.8	20.4
Tobacco Product – Cigarette	34.8	33.4	32.4
Tobacco Product – Other	11.7	12.6	13.6
Insurance Premium	49.6	49.9	50.1
Electric and Telephone Cooperative	0.1	0.1	0.1
Motor Fuel	39.5	37.6	37.8
Vehicle Rental	8.3	8.4	8.6
Tire Fee	1.5	1.4	1.5
Subtotal Excise Tax	**164.9**	**163.2**	**164.5**
Subtotal Corporate Income Tax	**157.7**	**149.7**	**152.5**
Fisheries Tax			
Fisheries Business	20.1	18.6	18.6
Fishery Resource Landing	2.7	5.8	5.8
Subtotal Fisheries Tax	**22.8**	**24.4**	**24.4**
Other Tax			
Charitable Gaming	2.5	2.4	2.5
Estate	0.0	0.0	0.0
Large Passenger Vessel Gambling	5.8	5.8	5.8
Mining	49.0	43.0	48.4
Subtotal Other Tax	**57.3**	**51.2**	**56.7**
Subtotal Taxes	**402.7**	**388.5**	**398.1**

Figure 2-4. Continued

Other Revenue (except Federal & Investment)	History FY 2011	Forecast FY 2012	FY 2013
Charges for Services			
General Government	9.2	9.0	9.0
Natural Resources	2.1	2.0	2.0
Other	7.2	6.8	6.8
Subtotal Charges for Services	**18.5**	**17.8**	**17.8**
Subtotal Fines & Forfeitures	**7.0**	**8.7**	**8.7**
Licenses & Permits			
Alcoholic Beverage Licenses	1.0	1.0	1.0
Motor Vehicle	38.9	39.7	38.6
Other	2.9	1.9	1.9
Subtotal Licenses & Permits	**42.8**	**42.6**	**41.5**
Rents & Royalties			
Other Non-Petroleum Rents & Royalties	9.0	9.2	9.4
Coal Royalties	8.6	7.7	7.7
Subtotal Rents & Royalties	**17.6**	**16.9**	**17.1**
Other			
Miscellaneous	18.7	14.1	14.1
Alaska Housing Finance Corporation	14.3	17.0	16.5
Alaska Industrial Development & Export Authority	0.0	25.4	20.4
Alaska Municipal Bond Bank Authority	0.0	0.9	0.9
Alaska Student Loan Corporation	2.5	0.0	0.0
Alaska Energy Authority	0.0	0.0	0.0
Mental Health Trust	0.1	0.0	0.0
Unclaimed Property	3.5	3.8	4.0
Subtotal Other	**39.1**	**61.2**	**55.9**
Total Other Revenue (except Federal & Investment)	**527.7**	**535.7**	**539.1**
Investment Revenue			
Investments	93.2	174.5	180.2
Interest Paid by Others	3.1	2.4	2.4
Total Investment Revenue	**96.3**	**176.9**	**182.6**
Grand Total Unrestricted Revenue	**7,673.0**	**8,927.9**	**8,217.7**

Crude Oil Price Forecast

Oil revenue is projected to provide at least 89% of forecasted Unrestricted General Fund Revenue through FY 2021. Three elements are critical to the oil revenue forecast: price, volume, and, to a lesser extent, lease expenditures.

There is no price for Alaska crude oil on the New York Mercantile Exchange (NYMEX)[1] or other commodity exchanges. The spot price of Alaska North Slope (ANS) crude oil is calculated by applying a market differential from the price of West Texas Intermediate (WTI) quoted on the NYMEX. We use three different assessment services that estimate the market differential and report a daily spot price for ANS in the calculation of our ANS West Coast "prevailing value" for oil price.

All of Alaska's oil production is delivered to refineries on the U.S. West Coast (including Alaska and Hawaii). Consequently, Alaska's royalty and production tax revenue depends in large part on the average market price of ANS crude oil at U.S. West Coast refining centers.

Figure 2-5 shows crude oil prices for FY 2011 and the Department of Revenue's forecast of prices for the 10-year period beginning with the current fiscal year FY 2012 and continuing through FY 2021. The oil price forecast is based on both a subjective assessment of market dynamics and trend analysis by participants at a Department of Revenue price forecasting seminar, and other commercial price forecasting sources.

Figure 2-6 shows the monthly actual ANS West Coast market prices from October 2006 through October 2011. Also shown are the Department of Revenue ANS oil price forecast, along with

Figure 2-5. Nominal WTI, ANS West Coast and ANS Wellhead, FY 2011 and Forecasted FY 2012-2021 ($ per barrel)

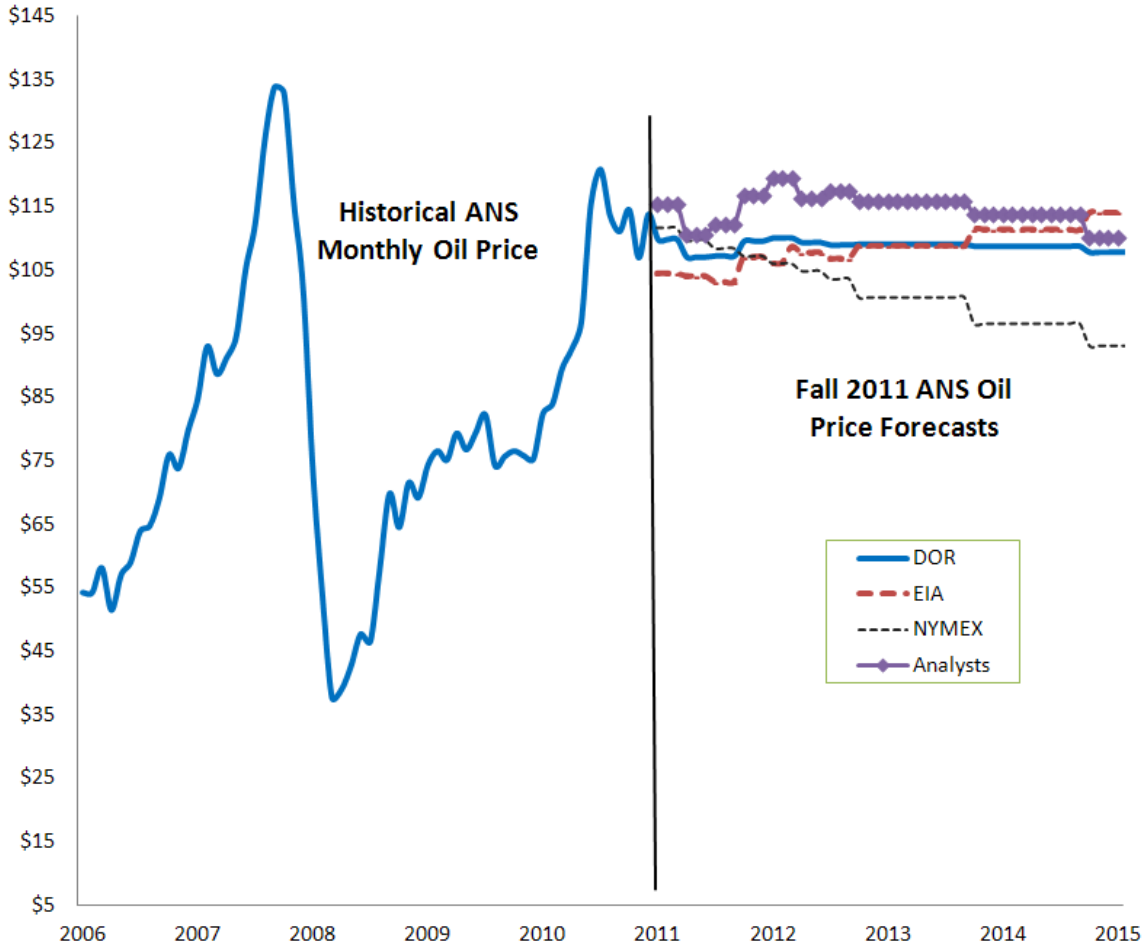
Fiscal Year	WTI	ANS West Coast	ANS Wellhead
2011	89.39	94.49	87.32
2012	90.92	109.33	100.61
2013	96.62	109.47	100.91
2014	99.88	109.08	100.25
2015	103.21	108.75	99.61
2016	105.90	107.79	98.23
2017	108.55	106.05	96.27
2018	111.26	108.76	98.76
2019	114.04	111.54	101.19
2020	116.89	114.39	103.63
2021	119.81	117.31	106.15

[1] The NYMEX futures market is one source for a WTI quote. Several reporting services also report a daily WTI price quote.

recent WTI oil price forecasts provided by the Energy Information Administration (EIA), the New York Mercantile Exchange (NYMEX), and a survey of analysts from Bloomberg services, all as adjusted with our forecasted differential to arrive at an oil price forecast for ANS. These outside forecasts were incorporated into our Fall 2011 ANS oil price forecast. More detail on our oil price forecast methodology is provided in Chapter 4 of this publication.

We project that, in the short term, ANS oil prices will average $109.33 per barrel in FY 2012 and $109.47 per barrel in FY 2013. In the mid term, we forecast ANS to remain in the same range as the previous years, with a FY 2014 price of $109.08 and a FY 2015 price of $108.75.

Figure 2-6. Historical ANS and DOR, EIA, Nymex and Analysts ANS Oil Price Forecasts[1]



[1] DOR, EIA, NYMEX, and Analysts forecasts represent WTI forecasts with differential applied. Differential described in detail in Chapter 4 of this publication.

Figure 2-7. Alaska Crude Oil and NGL Production, FY 2011 and Forecasted FY 2012-2013 (million barrels per day)

	History	Forecast	
Alaska North Slope	**FY 2011**	**FY 2012**	**FY 2013**
Prudhoe Bay (1)	0.296	0.276	0.269
PBU Satellites (2)	0.030	0.036	0.034
GPMA (3)	0.031	0.026	0.024
Kuparuk	0.091	0.087	0.083
Kuparuk Satellites (4)	0.032	0.030	0.027
Endicott (5)	0.012	0.012	0.016
Alpine (6)	0.084	0.079	0.071
Offshore (7)	0.027	0.027	0.031
NPR-A	0.000	0.000	0.000
Point Thomson	0.000	0.000	0.000
PTU Satellites	0.000	0.000	0.000
Total Alaska North Slope	0.603	0.574	0.555
increase/decrease from prior period	(0.041)	(0.028)	(0.019)
% change from prior period	(6.3%)	(4.7%)	(3.3%)
Total Cook Inlet	**0.010**	**0.010**	**0.009**
increase/decrease from prior period	0.001	0.000	(0.001)
% change from prior period	12.1%	2.5%	(11.5%)
Total Alaska	**0.613**	**0.585**	**0.564**
increase/decrease from prior period	(0.040)	(0.028)	(0.020)
% change from prior period	(6.1%)	(4.6%)	(3.5%)

(1) Includes NGLs from the Central Gas Facility shipped to TAPS, Milne Point, Sag River and Schrader Bluff

(2) Aurora, Borealis, Midnight Sun, Orion and Polaris

(3) Lisburne Niakuk, North Prudhoe Bay State, Point McIntyre, Raven, West Beach and West Niakuk

(4) Meltwater, Tobasco, Tarn and West Sak

(5) Includes Badami, Eider and Sag Delta

(6) Includes Fiord, Fiord Kuparuk, Nanuq, Nanuq-Kuparuk, Alpine West and Qannik

(7) Northstar (all ownership), OCS production, Liberty, Nikaitchuq and Oooguruk

* Totals may show slight differences from other sources due to rounding and aggregation differences

Crude Oil Production Forecast

Alaska North Slope crude oil production peaked at 2.01 million barrels per day in FY 1988 and has steadily declined since. We anticipate volumes will decline by 4.7% in FY 2012 to about .574 million barrels per day due to declining fields and increased planned and unplanned maintenance on aging North Slope facilities, flowlines, pipeline and wells. For FY 2013, we project a 3.3% decrease in North Slope production. More discussion of the Fall 2011 oil production forecast can be found in Chapter 4 Oil Revenue. Also, a detailed field-by-field production forecast is included in the appendices of this forecast.

Crude Oil Expenditures Forecast

A third component of oil production revenue forecasting is the lease expenditures forecast. Under the ACES production tax, companies are allowed to deduct certain lease expenditures from the gross value of their production before applying the tax rate. Future tax collections, therefore, are dependent not only on the oil price and the level of production, but on the cost of that production. Costs of production may include fixed and variable operating expenses, such as the costs of labor and the expense to run a facility, and they may include costs to acquire production equipment or to drill a well—usually deemed to be capital expenses. A portion of capital expenses is also allowed as a credit against the ACES production tax.

Lease expenditures for the exploration for and production of crude oil rose during the first couple of years that they were reported and leveled off in FY 2009 through FY 2011 at $4.9 billion when total lease expenditures are considered (not standard deduction). It is important to note that these are unaudited, company-reported lease expenditures. We project spending in FY 2012 to increase, with capital and operating expenditures projected to total $5.3 billion. For FY 2013, we expect capital spending to increase, with totals for capital and operating expenditures reaching $5.4 billion. These increased spending estimates reflect investment in new and developing fields and are also contingent on oil prices maintaining current levels or increasing.

Long-Term Unrestricted Revenue Outlook

Using the price, volume, and lease expenditure components developed for this fall forecast, Figure 2-8 summarizes the department's forecast of total Unrestricted General Fund Revenue through FY 2021.

Figure 2-8. Total Unrestricted General Fund Revenue, FY 2011 and Forecasted FY 2012-2021 ($ million)

Fiscal Year	Unrestricted Oil Revenue	Unrestricted Other Revenue (except Federal & Investment)	Unrestricted Investment Revenue	Total Unrestricted Revenue	Percent From Oil
2011	7,049.0	527.7	96.3	7,673.0	92%
2012	8,215.3	535.7	176.9	8,927.9	92%
2013	7,496.0	539.1	182.6	8,217.7	91%
2014	7,018.8	541.4	182.6	7,742.8	91%
2015	6,313.5	547.3	182.6	7,043.4	90%
2016	6,327.9	555.0	182.6	7,065.5	90%
2017	5,984.6	571.7	182.6	6,738.9	89%
2018	6,363.4	579.0	182.6	7,125.0	89%
2019	6,298.4	589.4	182.6	7,070.4	89%
2020	6,225.8	603.7	182.6	7,012.1	89%
2021	6,129.5	605.4	182.6	6,917.5	89%

Spending, Revenue Forecast, and the Constitutional Budget Reserve Fund

As approved by voters in 1990, all receipts from oil and gas tax and royalty settlements are deposited into the Constitutional Budget Reserve Fund (CBRF). As of September 30, 2011, since the fund's inception, the state has deposited about $14.5 billion into the fund and generated another $2.5 billion in investment earnings. A cumulative total of approximately $3.9 billion has been borrowed from the CBRF to balance the budget during prior fiscal years, but has been fully repaid to the CBRF. The current net asset value in the CBRF as of September 30, 2011 is about $10 billion. Since the increase in oil prices beginning in 2003, no significant CBRF withdrawals have been necessary to balance the state's budget, however given price volatility and the decline in expected oil volumes from the North Slope, the state may have to depend on the CBRF in the future.

Figure 2-9 is presented to help the reader understand the time period in which the CBRF would be depleted, based on the current forecast and the assumption that the unobligated balance of the operating general fund would be deposited upon appropriation into the Statutory Budget Reserve Fund (SBRF) (AS 37.05.540). In the occurrence of a budget deficit, the SBRF would be the first fund to be drawn down, and upon depletion, would be followed with draws upon the Constitutional Budget Reserve Fund. This figure shows that, given the current oil price and production forecast and up to 10% in budget growth from FY 2013 levels, the CBRF would not be depleted before 2021. If oil prices were to fall below our forecasted levels and stay at that level, and oil production remains constant, we could expect the CBRF to be depleted as early as 2015, if the budget increases at a rate of 8% per year. A further decline in forecasted oil production would also have a negative impact on future revenue generation.

[1] For a complete schedule, see the State of Alaska 2010 CAFR, Note 2 – Budgeting, Budgetary Control, and Legal Compliance, Constitutional Budget Reserve Fund, pg. 56

Figure 2-9. CBRF Run-Out Date With Revenue Surpluses Deposited into SBRF[1]

Annual State Budget (% change)	Fall 2011 Oil Price Forecast	Fiscal Model of Oil Revenue & CBRF Performance at Selected Prices[2] ($ per barrel)					
		$50	$60	$70	$80	$90	$100
(2%)	Jun-2022	Aug-2016	Jul-2017	Dec-2018	Jun-2022	Jun-2022	Jun-2022
(0%)	Jun-2022	Jul-2016	Mar-2017	Mar-2018	May-2020	Jun-2022	Jun-2022
2%	Jun-2022	Apr-2016	Nov-2016	Sep-2017	Mar-2019	Nov-2021	Jun-2022
4%	Jun-2022	Feb-2016	Aug-2016	Apr-2017	Jul-2018	Jun-2020	Jun-2022
6%	Jun-2022	Jan-2016	Jul-2016	Jan-2017	Jan-2018	Jul-2019	Jun-2021
8%	Apr-2022	Nov-2015	Apr-2016	Oct-2016	Aug-2017	Oct-2018	May-2020
10%	Jan-2021	Oct-2015	Feb-2016	Aug-2016	Apr-2017	Apr-2018	Aug-2019

[1] Based on thecurrent forecast, and the assumption that the unobligated balance of the operating general fund would be deposited upon appropriation into the Statutory Budget reserve Fund (SBRF) (AS 37.05.540). In the occurrence of a budget deficit, the SBRF would be the first fund to be drawn down, and upon depletion, would be followed with draws upon the CBRF.

[2] Matrix allows reader to select specific fiscal year price (from FY 2012-beyond) to determine CBRF exhaustion date. Fall 2011 forecasted production volumes are used. A date of Jun-2022 indicates that the CBRF does not run out before 2022.

Fall 2011 Official Price Forecast

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
$109.33	$109.47	$109.08	$108.75	$107.79	$106.05	$108.76	$111.54	$114.39	$117.31

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2011

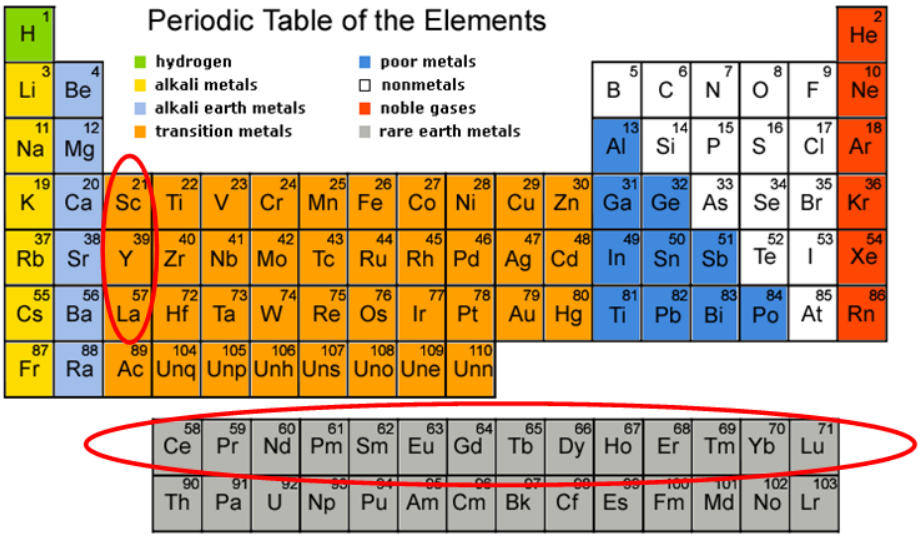
3. Rare Earth Elements

What are Rare Earth Elements?

In recent years Rare Earth Elements (REEs) have become an increasing focus of worldwide attention. To understand why REEs are important to Alaska, it may help to give them a closer look. Alaska has multiple deposits of these elements and their development could help reshape Alaska's economy. REEs are used in many high tech products and there are few, if any, available substitutes for these elements.

REEs often have unique properties, including chemical, catalytic, magnetic, optical, electrical, and metallurgical characteristics. They are used in magnets, batteries, auto catalysts, lighting, polishing powders, and other metallurgical applications. Finished products in which REEs are critical include smart phones, hybrid cars, windmills, military hardware, advanced consumer electronics, fiber optics, water treatment technologies, and other emerging technologies.

Figure 3-1. Periodic Table of the Elements



The REE group consists of the 15 lanthanides (see elements 57-71 in Figure 3-1), plus Yttrium (element 39) and Scandium (element 21). The lanthanides are cerium, lanthanum, neodymium, praseodymium, promethium (not naturally occurring), samarium, europium, gadolinium, terbium, dysprosium, holmium, erbium, thulium, ytterbium and lutetium. Scandium and Yttrium are considered REEs since they tend to occur in the same ore deposits as the lanthanides and exhibit similar chemical properties. In the Periodic Table of Elements in Figure 3-1, the REEs are circled.

The term "Rare Earth Elements" is somewhat misleading: most REEs are 200 times more common than gold in the earth's crust. However, due to geochemical properties (electron configuration), REEs tend to be more widely dispersed than other commonly used minerals. Therefore, relatively few ore deposits exist, and economically viable ore bodies are "rare." For example, cerium is the 25th most abundant element in Earth's crust (similar to copper), yet it is extremely difficult to find a cerium deposit. When REE deposits

are found however, all 17 REEs tend to be found together.

Due to the similar geochemical properties of the 17 REEs, extraction of each individual element is difficult. The Manhattan Project developed the techniques to extract, separate and purify REEs in order to obtain plutonium and neptunium for nuclear bombs. Commercial production and industrial use of these elements did not occur until the late 1950's and early 1960's. Since then, REEs have been incorporated in many high tech products, and the trend is accelerating.

Global Demand

Demand for critical REEs is forecasted to remain robust in the short and long term. "Critical" REEs mean more of these elements are being consumed than produced. (Methodology regarding which elements are critical is discussed later in the chapter.) According to the U.S. Geological Survey (USGS), in 2010, U.S. imports totaled $161 million of refined REE products, up from $113 million in 2009. This figure is expected to increase again in 2011, as both REE prices and production have increased. On a global basis, the value of Rare Earth Oxides (REO) is estimated at $2-3 billion annually. By the middle of the decade, Ernst & Young's "Technology Minerals" publication, expects Rare Earths to be a $4-6 billion industry annually.

Three main factors drive demand for REEs: total units produced, market share of applications using REEs, and intensity of usage in each unit produced. REEs are used in a variety of applications and industries. For example, rare earth magnets are heavily used in both energy efficient windmills and vehicles. In 2010, neodymium-iron-boron (Nd-Fe-B) magnets dominated the market for high-efficiency traction motors in hybrid electric vehicles. Prices for neodymium have increased over the past year causing car and windmill manufactures to examine intensity of neodymium usage, to minimize manufacturing costs.

To understand the markets for REEs today and in the future, it is important to understand which finished goods use these minerals. Figure 3-2 lists some of the items REEs are used to make.

Supply

REEs are relatively abundant in the earth's crust, but discovered minable concentrations are less common than most other ores. Figure 3-3 shows the countries in which there are known REE reserves and 2010 production of REEs in those countries.

Countries that are currently producing rare earth metals include China, India, Brazil, and Malaysia and some states of the former Soviet Union. Ore production in the U.S. is limited to a single mine in Mountain Pass, California, where they are currently processing stockpiled ore. Ore production from Mountain Pass is slated to restart in 2011. Historically, Mountain Pass was the world's largest supplier of REEs, but in 2001 the mine went out of business due in large part to increased competition from China. Figure 3-4 compares historical U.S. production to global production of REOs.

China currently produces more than 95% of the world's supply of REEs.

Figure 3-2. Current Demand and Projected Growth Rates

Demand Forecast By Application

Application	Demand - 2010 Percent	Demand - 2010 Metric Tonnes	Demand - 2014 Annual Growth	Demand - 2014 Metric Tonnes
Magnets	25%	31,500	12%	49,600
Battery Alloy	15%	18,600	15%	32,500
Metallurgy (Excluding Batteries)	9%	11,700	2%	12,700
Auto Catalysts	7%	9,000	8%	12,200
Fluid Cracking Catalysts	17%	21,300	4%	24,900
Polishing Powder	11%	14,000	10%	20,600
Glass Additives	6%	7,800	0%	7,800
Phosphors	6%	7,900	8%	10,800
Other	4%	5,700	8%	6,100
	100%	127,500	8%	177,200

Figure 3-3. World Production and Reserves of REE Minerals in 2010

	2010			
	Reserves		Production	
Country	TREO (metric tons)	Share (percent)	TREO (metric tons)	Share (percent)
Austrailia	1,600,000	1.4%	-	0.0%
Brazil	48,000	0.0%	550	0.4%
China	**55,000,000**	**48.3%**	**130,000**	**95.5%**
Commonwealth of Independent States	19,000,000	16.7%	2,500	1.8%
India	3,100,000	2.7%	2,700	2.0%
Malaysia	30,000	0.0%	350	0.3%
United States	13,000,000	11.4%	-	0.0%
Other	22,000,000	19.3%	-	0.0%
Total	113,778,000		136,100	

China implemented export quotas in 1999 citing the need for environmental and resource conservation. Export quotas have continued to decrease: from 2005 to 2010 exports decreased by 54%. China's 2011 export quota is set at 15,738 tonnes (Bloomberg, 7/11), nearly a 50% decrease from 2010. The announcement stated resource conservation and environmental concerns as the basis for the cuts in export quotas (Bloomberg, 12/10). Figure 3-5 contains China's historical REE export quotas. There is a significant discrepancy between higher REE production and the reasons given for reduced export quotas.

Strategically, China appears to be retooling its REE industry from one of basic supply of REEs to a more fully integrated supply chain for finished products. It is actively encouraging foreign companies that use REEs to relocate their manufacturing operations within China's borders. Typically these jobs involve advanced manufacturing of high-tech goods. A low cost and stable supply of REEs in China will create an environment for an economically viable industry. Alleged improprieties within China include illegal mining and smuggling of REEs, environmental damage and a program to stockpile 300,000 tonnes of REES within five years.

Figure 3-4. Graph of Historical Supply

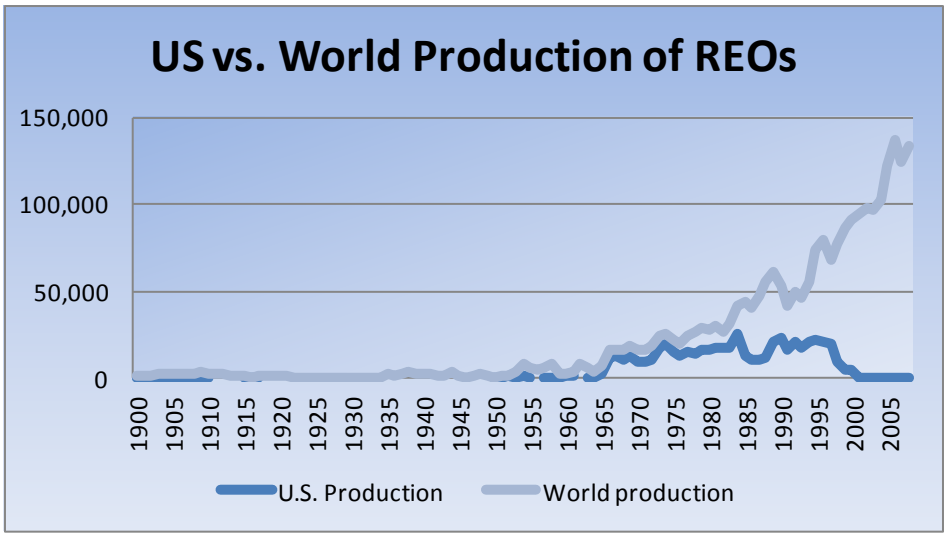


Figure 3-5. Historical Chinese REE Export Quotas

Year	Export Quotas (tonnes REO)	Change from Previous Year	Rest of World Demand (tonnes)	Rest of World Supply (tonnes)	Difference (tonnes)
2005	65,609	0%	46,000	3,850	23,459
2006	61,821	-6%	50,000	3,850	15,671
2007	59,643	-4%	50,000	3,730	13,373
2008	56,939	-5%	50,000	3,730	10,669
2009	50,145	-12%	25,000	3,730	28,875
2010	30,258	-40%	48,000	5,700-7,700	(12,042)-(10,042)

According to published reports, the mining of REEs in China is causing severe environmental damage (National Geographic, 6/11). Efforts to reduce environmental damage are underway, but these efforts are slowed by regional variances in environmental regulations.

Ramifications of having one global supplier of REEs are significant. Without a stable supply of REEs available, national security, jobs, technology transfers, and manufacturing could all be impacted.

Estimated production for all REEs in 2010, and from new non-Chinese mines expected to come online before 2015 can be found in Figure 3-6. Italic and bolded elements are considered "critical" elements (Seredin, 2005).

Pricing

Clear and accurate REE pricing information is difficult to obtain due to the nature of the market. In volume terms, REEs make up about 1% of all metals produced and consumed in the world's metal markets. Because the market for REEs is relatively small, transparent and accurate pricing information is hard to obtain. REE markets typically operate under contract, reflecting a range of factors between the suppliers and consumers. Factors that affect price include supply, demand, contract length, export quotas, market dominance, credit profile and the confidential nature of pricing in contracts. When these factors are combined, reliability of price data can vary widely.

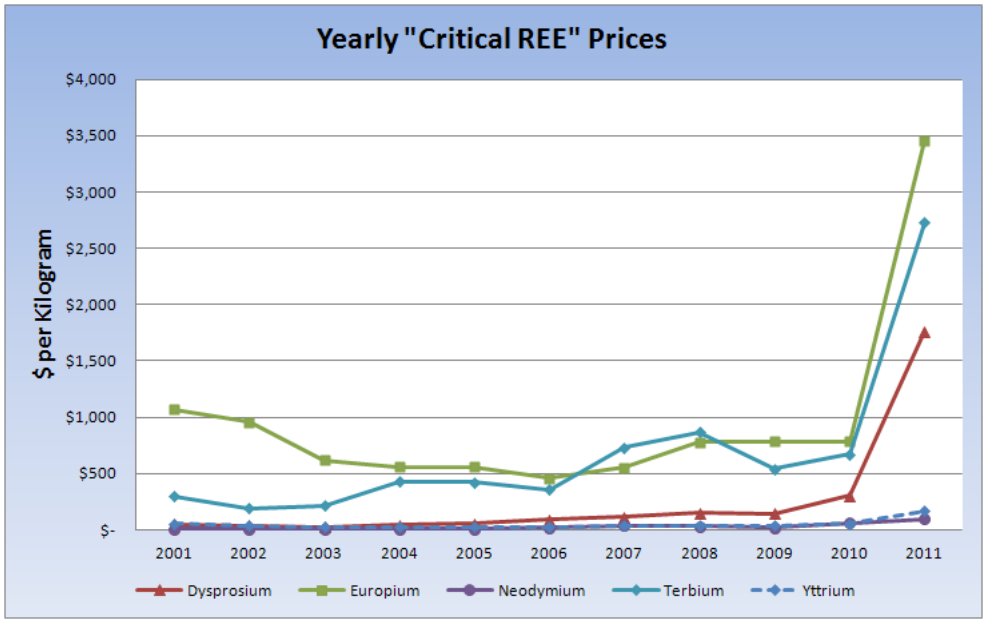
Historical Pricing

REEs are a commodity product, reflecting economic cycles and other exogenous variables. The graph in Figure 3-7 and the table located in Figure 3-8, reflect these economics from 2001 through 2011. Generally, each

Figure 3-6. Estimated 2010 and 2015 REE production.[1]

Rare Earth Supply by Element: Production Sources and Volume (tonnes/yr)										
		Assumed Additional Production - 2015								
	Estimated 2010 Production	Mountain Pass (USA)	Mt. Weld (Australia)	Nolans Bore (Australia)	Nechalacho (Canada)	Dong Pao (Vietnam)	Hoidas Lake (Canada)	Dubbo Zirconia (Australia)	Total Additional Production by 2015	Estimated 2015 Production
Cerium	49,935	9,820	7,650	4,820	2,070	2,520	1,368	1,101	29,349	79,284
Dysprosium	***1,377***	-	***30***	***30***	***35***	-	***12***	***60***	***167***	***1,544***
Europium	***592***	***20***	***60***	***40***	***20***	-	***18***	***3***	***161***	***753***
Erbium	***430***	*	*	*	*	*	*	*	***70***	***500***
Gadolinium	2,257	40	150	100	145	-	39	63	537	2,794
Lanthanum	33,887	6,640	3,900	2,000	845	1,620	594	585	16,184	50,071
Neodymium	***21,307***	***2,400***	***2,250***	***2,150***	***935***	***535***	***657***	***423***	***9,350***	***30,657***
Praseodymium	6,292	868	600	590	240	200	174	120	2,792	9,084
Samarium	2,666	160	270	240	175	45	87	75	1,052	3,718
Terbium	***252***	-	***15***	***10***	***90***	-	***3***	***9***	***127***	***379***
Yttrium	***8,750***	***20***	-	-	***370***	***4***	***39***	***474***	***907***	***9,657***
TOTAL	**127,745**	19,968	14,925	9,980	4,925	4,924	2,991	2,913	**60,696**	**188,441**

Figure 3-7. Chart of Historical REE Prices



REE exhibits its own pricing trends as unique factors impact each of these elements. For example, Europium pricing stayed steady between 2008 and 2009, while other REEs decreased in price.

Analysis of the historical price data shows both the effects of two recessions and China's export quota impacts on the REE markets. Selected REEs (see "Critical" REEs below) in Figure 3-7 and Figure 3-8 reflect both the 2000-2001 and 2008-2009 recessions. The first recession affected prices until 2003. Between 2003 and 2006 prices remained stable to increasing depending on the element. After 2006, an upward pricing trend started for all REEs. The rising prices were interrupted by the 2008-2009 recession, which was more severe than the first, but pricing rebounded much more quickly. The U.S. Department of Energy believes both the upward trend and the quick rebound can be attributed to Chinese export quotas and greater Chinese demand.

Exchanges and Future Pricing

Future prices of REEs are likely to remain opaque, although to somewhat of a lesser degree. Additional participants (both suppliers and manufacturers) are likely to enter the market as additional goods are created from these elements, but the market is expected to fundamentally remain the same. The reason seems to be that there is not enough market liquidity or volume to support an active market on a commodities exchange outside of China. Furthermore, the newest suppliers in the market are vertically integrating the supply chain

(1) Erbium production figures are estimated. Mountain Pass and Mt. Weld contain little Erbium within their deposits. Estimated production figures assume 3% growth in Chinese production per year. If all announced REE deposits are brought into production, estimated Erbium production could reach 1,360 tonnes / year.

Figure 3-8. Table of Historical REE Prices

Year	Dysprosium	Europium	Neodymium	Terbium	Yttrium
2001	48	1,067	11	301	56
2002	36	957	7	195	37
2003	29	620	7	214	29
2004	45	560	8	432	28
2005	57	559	10	425	25
2006	94	459	20	359	24
2007	115	552	39	733	36
2008	151	778	35	865	41
2009	143	785	21	542	40
2010	305	785	60	672	55
2011	1761	3,462	97	2,727	167

to produce finished goods, which further obscures the intrinsic value of the raw goods.

REE prices have increased rapidly over the past few years, and are expected to remain high until additional sources of supply become available. It is likely that prices will remain elevated until the middle of the decade, when enough supply is brought online to meet demand.

China

Recent actions taken by the Chinese government may affect future pricing of REEs. First, China recently announced that it is planning on consolidating the fragmented REE industry into a few large companies inside of China. These companies will control 80% of China's supply in the next few years. Second, China has also announced the creation of an exchange to actively trade REEs. Finally, China is implementing a new tax regime to more heavily tax "critical" elements that are exported as non-finished goods. Collectively, these actions could be seen as an attempt to consolidate pricing of REEs within China.

"Critical" REEs

In economic terms, not all REEs are created equal. Certain REEs have properties creating high demand for those elements. In order to determine which of these elements are more economically important ("critical"), a simple methodology was published by V.V. Seredin, in "A New Method for Primary Evaluation of the Outlook for Rare Earth Element Ores", (Figure 3-9). Seredin evaluated REE production versus demand at the global level, creating three classes of REEs based upon economic fundamentals. Seredin calls these three REE classifications "Critical," "Uncritical," and "Excess."

"Critical" REEs consist of Neodymium, Dysprosium, Terbium, Yttrium, Europium and Erbium. In Figure 3-9 a ratio exceeding 1.0 indicates that more REEs are being produced than consumed. Neodymium, Dysprosium, Terbium, & Yttrium all have a ratio of less than 1.0, meaning there is more forecasted demand than supply in 2014. Seredin adds Europium and Erbium to the above group due to the uncertainly of the forecast (±15%). These six elements are classified as "critical or potentially critical".

"Excessive" REEs consist of Holmium, Thulium, Ytterbium, Lutetium and Cerium. These elements are forecasted to exceed demand by 6.5 times in 2014. These rare earths are often stockpiled where they are produced, because there is no economic end market for these elements. Cerium is classified as an excessive rare earth, because of "maximal overproduction". In this case, Seredin references the difference category, rather than the ratio category in Figure 3-9.

"Uncritical" REEs consist of Lanthanum, Praseodymium, Samarium, and Gadolinium. These elements are in relative balance with economic supply and demand, and are forecasted to remain in balance.

Figure 3-9. Forecasted Production and Consumption in 2014

Periodic Symbol	REE_2O_3	Production	Demand	Difference	Ratio
La	Lanthanum	55.10	51.05	4.05	1.08
Ce	Cerium	82.40	65.75	16.65	1.25
Pr	Praseodymium	10.00	7.90	2.10	1.27
Nd	Neodymium	33.30	34.90	-1.60	0.95
Sm	Samarium	4.00	1.39	2.61	2.88
Eu	Europium	0.90	0.84	0.06	1.07
Gd	Gadolinium	3.15	2.30	0.85	1.37
Tb	Terbium	0.40	0.59	-0.19	0.68
Dy	Dysprosium	1.80	2.04	-0.24	0.88
Y	Yttrium	11.65	12.10	-0.45	0.96
Er	Erbium	1.00	0.94	0.06	1.06
Ho+Tm+Yb +Lu	Holmium, Thulium, Ytterbium, Lutetium	1.30	0.2	1.10	6.50
	Total	205.00	180.00	25.00	1.14

Deposits in Alaska

Rare Earth deposits are located throughout Alaska, from the Seward Peninsula to the Arctic North Slope and Southeast Alaska. Most of Alaska's REE deposits were initially located by the National Uranium Resource Evaluation (NURE) program run by the USGS in 1974. For almost all of these deposits, very little is known about their composition and size. Currently, the Alaska Division of Geological & Geophysical Surveys (DGGS) has received special funding to further detail Alaska's REE resources. DGGS is using the funding to compile government publications on REEs, prepare a limited field program and analyze samples located in DGGS's Eagle River Geologic Materials Center. Private sector REE efforts in Alaska are mainly centered on prospecting, land staking, and exploration of known deposits.

Advanced Projects

Alaska's most advanced project is Bokan Mountain, in Southeast Alaska near Ketchikan. The deposit is located in the Tongass National Forest on U.S. Forest Service lands designated for mineral exploration. Inferred resources for Bokan Mountain vary between 1.0 and 6.7 million tonnes (1 tonne = 1 metric ton) of Total Rare Earth Oxide (TREO). Published reports estimate the value of the deposit to be more than $1 billion.[1]

Bokan Mountain has higher Heavy Rare Earth Oxide content than most REE mines in the world. This is important to Alaskans because Heavy Rare Earth Oxides tend to be more valuable than Light Rare Earth Oxides. The most important REEs in the deposit are Neodymium, Terbium, Dysprosium, Erbium, and Yttrium.

Other Prospects

Prince of Wales Island contains a trend of REE occurrences, including the Bokan deposit. The deposits exist over a 135 mile stretch of Prince of Wales Island. Three properties worth noting on Prince of Wales Island are Salmon Bay, Stone Rock Bay, and Dora Lake. The Salmon Bay property is 940 acres and is located on the northern shores of Prince of Wales Island. The Stone Rock Bay property is 2,540 acres and is located 12 miles to the south of Bokan Mountain. The Dora Lake vein, with an inferred resource of 500,000 tons of REEs, runs between Dora Lake and Dora Bay. Like Bokan, the Dora Lake vein contains high concentrations of "critical" REEs . Salmon Bay and Stone Rock Bay are both currently under exploration.

Ninety miles east of Nome there is a band of granites which contain REEs and share similar geologic characteristics to Bokan Mountain. This trend of granites stretches for 50 miles with multiple occurrences.

Mount Prindle in Alaska's interior is another REE trend worth noting. It is located 60 miles north of Fairbanks in the White Mountain National Recreation area. Samples taken from this deposit have up to 15% REE content. REE extraction at Mt. Prindle is not currently a commercial prospect since

Figure 3-10. Inferred Bokan Mt. REO Cut-off Resource Grades

TREO CUT-OFF (%)	TONNES	Light Rare Earth Oxide (%)	Heavy Rare Earth Oxide (%)	Total Rare Earth Oxide (%)
0.20	6,701,900	0.341	0.239	0.580
0.30	6,126,400	0.364	0.250	0.612
0.40	5,275,500	0.392	0.262	0.654
0.50	3,669,000	0.458	0.288	0.746
0.60	2,489,400	0.504	0.330	0.834
0.70	1,548,500	0.592	0.358	0.950
0.80	1,020,800	0.667	0.387	1.054

Figure 3-11. Bokan Mt. Inferred Resource Estimate

TREO CUT-OFF (%)	TONNES	La_2O_3 (%)	Ce_2O_3 (%)	Pr_2O_3 (%)	Nd_2O_3 (%)	Sm_2O_3 (%)	Eu_2O_3 (%)	Gd_2O_3 (%)	Tb_2O_3 (%)
0.20	6,701,900	0.05	0.17	0.02	0.08	0.02	0.00	0.02	0.00
0.30	6,126,400	0.06	0.18	0.02	0.09	0.02	0.00	0.02	0.00
0.40	5,275,500	0.06	0.19	0.02	0.09	0.02	0.00	0.02	0.00
0.50	3,669,000	0.08	0.22	0.03	0.11	0.03	0.00	0.03	0.01
0.60	2,489,400	0.09	0.24	0.03	0.12	0.03	0.00	0.03	0.01
0.70	1,548,500	0.11	0.28	0.03	0.14	0.04	0.00	0.03	0.01
0.80	1,020,800	0.12	0.32	0.04	0.16	0.04	0.00	0.04	0.01

TREO CUT-OFF (%)	TONNES	Dy_2O_3 (%)	Ho_2O_3 (%)	Er_2O_3 (%)	Tm_2O_3 (%)	Yb_2O_3 (%)	Lu_2O_3 (%)	Y_2O_3 (%)
0.20	6,701,900	0.02	0.01	0.01	0.00	0.01	0.00	0.15
0.30	6,126,400	0.03	0.01	0.01	0.00	0.01	0.00	0.16
0.40	5,275,500	0.03	0.01	0.01	0.00	0.01	0.00	0.17
0.50	3,669,000	0.03	0.01	0.02	0.00	0.01	0.00	0.19
0.60	2,489,400	0.03	0.01	0.02	0.00	0.01	0.00	0.22
0.70	1,548,500	0.04	0.01	0.02	0.00	0.01	0.00	0.23
0.80	1,020,800	0.04	0.01	0.02	0.00	0.02	0.00	0.25

[1] Grushkin, Daniel. "Alaska's Billion Dollar Mountain." Bloomberg. *Business Week*, October 27, 2011.

mining is not a designated land use activity for this area.

Another prospect in the Interior includes Spooky Valley, located 50 miles east of Mount Prindle. Manley Hot Springs is another source of REEs and Niobium, although this mineral deposit occurs in a slightly different set of geologic strata.

More information on REE deposits in Alaska can be found at DGGS's website.[1]

Strategic Economic Opportunities for Alaska

Only one prospect in Alaska is close to production of REEs, Bokan Mountain. Figure 3-11 shows an estimate of the inferred resources at Ucore Rare Metals', Bokan Mountain. As the deposit is further explored and expanded, the resource is likely to increase.

Based upon the composition of the deposit and focusing only on critical REEs, Alaska's best opportunities lie in Neodymium, Dysprosium, Erbium, and Yttrium. Dysprosium is the stand out element in this deposit in both strategic and economic terms.

China currently controls the market for Dysprosium, meaning it produces and consumes almost all the Dysprosium in the world. This control enables China to maximize employment and bring advanced technology and manufacturing into the country. Therefore, any alternative Dysprosium source produced outside of China becomes strategic, to both governments and the private sector.

REE experts and analysts have concluded that the best way to develop and maintain a successful REE mine is through vertical integration of the supply chain. Vertical integration would include: 1) producing ore from the mine, 2) extracting REEs from the ore concentrate, 3) making metal products (metallurgy), and 4) creating a value-added product. The first two steps are necessary to develop an REE mine, and the economics of the project would be significantly improved by the final two steps—using the mine products to create a value-added product.

Dr. Jack Lifton and Michael Silver, both speakers at the "Alaska Strategic and Critical Minerals Summit", held in Fairbanks, Alaska, in September 2011, indicated that using REEs to manufacture finished goods in Alaska is a possibility.[2] Both speakers mentioned extracting the elements could be done in a building the size of a large warehouse.

Mr. Silver believes a metallurgy and manufacturing facility could be built in Alaska, and that the processes, facilities, and technology would not act as a barrier to an Alaskan REE industry. In Dr. Lifton's speech, he suggested the most obvious value-added product Bokan Mountain could easily produce is the Neodymium-Dysprosium-Iron-Boron magnet, which is currently used in windmills, internal combustion engines, military hardware, and other applications.

Other possible value added goods are listed in Figure 3-12.

Figure 3-12. REE Manufactured Goods

Element	Manufactured Goods
Dysprosium	Military Equipment, Windmills, Internal Combustion Engines, Lasers, Lighting
Erbium	Nuclear Technology, Fiber Optic Amplifier, Lasers, Healthcare (Dermatology, Dentistry)
Europium	Lighting (TVs, electronic displays)
Neodymium	Military Equipment, Windmills, Internal Combustion Engines, Lasers, Lighting, Appliances
Terbium	Fuel Cells, Military Hardware, Lighting, Hard drives, Magnets
Yttrium	Lighting, Metallurgy Enhancer, Military Hardware, Healthcare

Economic Benefits of REEs

An REE mine in Alaska could provide benefits to the state's economy. Alaska's residents and its economy would benefit from the creation of new jobs, economic diversification, economic growth, potential export of value-added goods, improved infrastructure, and increased utilization of resources located within the state. Alaskans would be able to get jobs linked to REE mining, refining, metallurgy and advanced manufacturing which would require an educated and skilled workforce. The state would benefit from increased revenues and economic diversification.

For integrated REE mining, process-

[1] http://www.dggs.alaska.gov/webpubs/dggs/ic/text/ic061.PDF

[2] Dr. Lifton, a founding principal of Technology Metals Research, LLC. He is also a consultant, author, and lecturer on the "market fundamentals of the technology metals," a term describing those strategic rare metals whose electronic properties make our technological society possible. Michael Silver is President and Chairman of the Board of American Elements. American Elements has supplied rare earths and other strategic metals for two decades. The company produces in the U.S., Mexico, China, and the United Kingdom. Today, American Elements manufactures engineered and advance materials for all U.S. Military branches, all U.S. national labs, and one third of Fortune 50 companies, among thousands of customers globally.

ing and manufacturing to be successful, Alaska needs to focus on its competitive advantages. Alaska's competitive advantages include, but are not limited to: location, abundant energy sources, large mineral deposits, capital, and stability.

Bokan Mountain provides an ideal example of how Alaska could benefit from a REE mine. The Bokan Mountain deposit is just a few miles from tidewater, giving the project easy access to global shipping routes. Ketchikan is 35 miles from the deposit, providing mine labor, supplies and possibly power to the mine and/or its facilities. Governor Parnell has instructed state agencies to explore ways to support the development of Bokan Mountain and another unrelated mining exploration site with shared facilities built on state land. Alaska Industrial Development and Export Authority could provide capital for infrastructure funding and development. Incentives for creation of value added goods within the state could be legislated, helping Alaska become more competitive and economically more diverse.

Conclusion

REEs are critical to today's high tech and green technologies. While REEs make up a small portion of the world's metal consumption, they have unique characteristics that make them irreplaceable in today's manufactured goods. Currently, China controls 95% of the world's production and close to 50% of the known reserves. China has begun a program to not only supply these elements, but to turn them into finished products. Alaska could do the same with its REE deposits.

With an REE industry, Alaska has an opportunity to participate in the creation of a new export industry in the state, adding economic diversity and growth. Alaska's residents would benefit through the creation of new jobs, better infrastructure, a broader tax base, and a more valuable export-driven economy. Nationally, an Alaskan REE mine would reduce U.S. dependence on foreign sources for these elements.

4. Oil Revenue

Figure 4-1. FY 2011 Oil Revenue: $8.1 billion

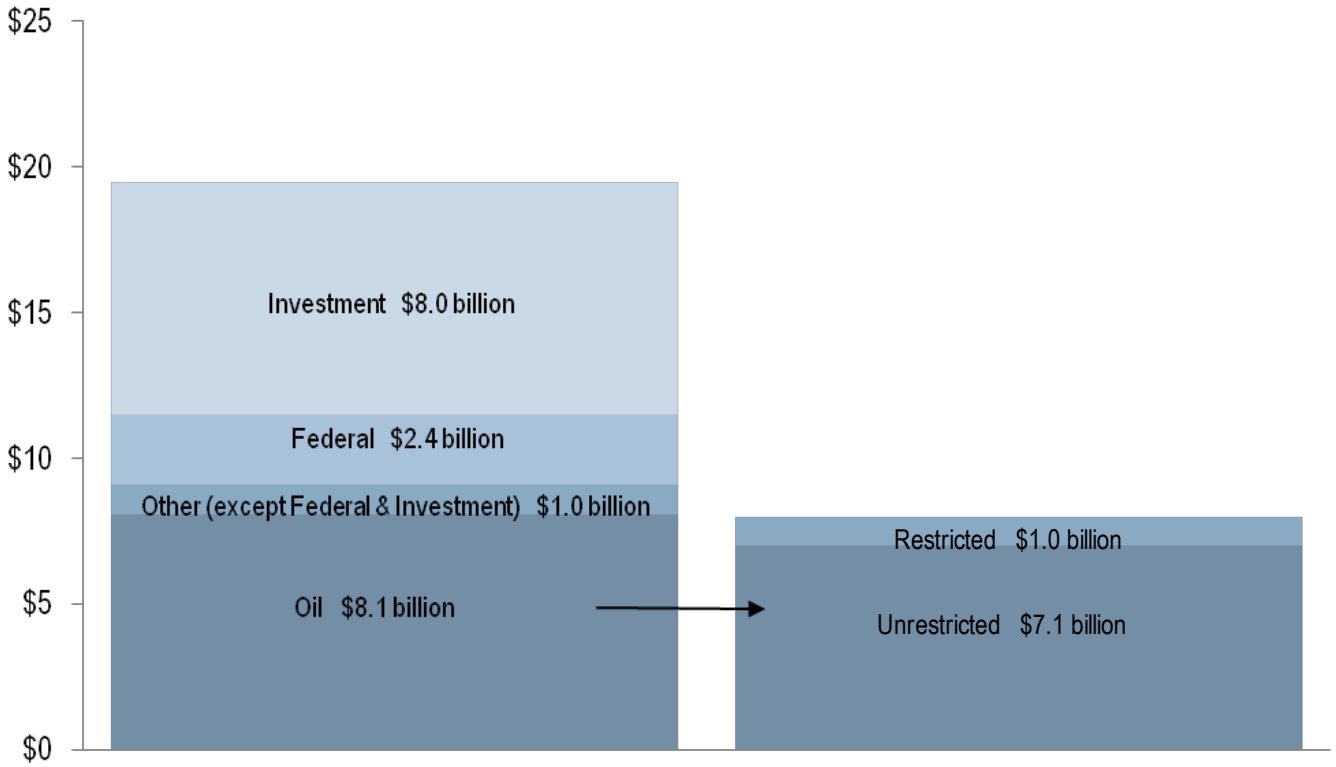


Figure 4-2. Total Oil Revenue, FY 2011 and Forecasted FY 2012-2013 ($ million)

Oil Revenue

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
Petroleum Property Tax	110.7	91.7	89.7
Petroleum Corporate Income Tax	542.1	662.1	728.4
Production Tax	4,552.9	5,376.4	4,715.8
Royalties (including Bonuses, Rents & Interest)	1,843.3	2,085.2	1,962.0
Total Unrestricted	**7,049.0**	**8,215.3**	**7,496.0**
Increase/(Decrease) from Prior Period	2,136.1	1,166.3	(719.4)
% Change from Prior Period	43.5%	16.5%	-8.8%

Restricted

Other Restricted

Royalties to Permanent Fund & School Fund

Royalties, Bonuses & Rents to the Permanent Fund	857.3	912.0	857.7
Royalties, Bonuses & Rents to the School Fund	13.6	15.0	14.1
Tax Settlements to CBRF	167.3	31.0	20.0
Subtotal Other Restricted	**1,038.2**	**958.0**	**891.9**

Federal

NPR-A Royalties, Rents & Bonuses	3.0	4.0	4.0
Subtotal Federal	**3.0**	**4.0**	**4.0**
Total Restricted	**1041.2**	**962.0**	**895.9**
Increase/(Decrease) from Prior Period	(240.0)	(79.2)	(66.1)
% Change from Prior Period	-18.7%	-7.6%	-6.9%
Total Oil Revenue	**8,090.2**	**9,177.3**	**8,391.8**
Increase/(Decrease) from Prior Period	1,896.1	1,087.1	(785.5)
% Change from Prior Period	30.6%	13.4%	-8.6%

Unrestricted Oil Revenue

Figure 4-3. Unrestricted Oil Revenue, FY 2011 and Forecasted FY 2012-2021 ($ million)

Fiscal Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Petroleum Property Tax	110.7	91.7	89.7	87.6	85.6	83.5	81.6	79.5	77.5	75.5	73.4
Petroleum Corporate Income Tax	542.1	662.1	728.4	712.2	704.5	701.6	691.0	706.1	715.2	724.9	735.3
Production Tax	4,552.9	5,376.4	4,715.8	4,252.3	3,634.0	3,736.6	3,559.9	3,887.3	3,849.4	3,807.2	3,746.1
Royalties-Net [1]	1,843.3	2,085.2	1,962.0	1,966.7	1,889.5	1,806.2	1,652.1	1,690.5	1,656.3	1,618.2	1,574.8
Total Oil Revenues	**7,049.0**	**8,215.3**	**7,496.0**	**7,018.8**	**6,313.5**	**6,327.9**	**5,984.6**	**6,363.4**	**6,298.4**	**6,225.8**	**6,129.5**
Increase/(Decrease) from Prior Period	2,136.1	1,166.3	(719.4)	(477.1)	(705.3)	14.4	(343.3)	378.8	(65.0)	(72.6)	(96.3)
% Change from Prior Period	43.5%	16.5%	-8.8%	-6.4%	-10.0%	0.2%	-5.4%	6.3%	-1.0%	-1.2%	-1.5%

[1] Includes bonuses and interest

General Discussion

The state receives oil and gas revenue from four sources: oil and gas production tax, property tax, royalties, and corporate income tax. The bulk of the revenue goes into the General Fund for general purpose spending. With the repeal of HB 11, approximately 30% of oil and gas royalties goes into the principal of the Alaska Permanent Fund and 0.5% goes into the Public School Trust Fund[1]. There are two other funds that receive specific oil and gas revenues: the National Petroleum Reserve-Alaska (NPR-A) Fund[2], which receives the state's share of all lease bonuses from sales in the NPR-A; and the Constitutional Budget Reserve Fund (CBRF), which receives settlements of tax and royalty disputes between the state and oil and gas producers.

Figure 4-2 shows the actual amount of each tax and royalty source in FY 2011 and forecast for FY 2012 and FY 2013. As can be seen from the figure, royalties and production tax constitute the largest part–91%–of restricted and unrestricted oil revenue combined in FY 2012. Figure 4-3 shows the department's unrestricted oil revenue forecast from the current fiscal year through FY 2021 by revenue category.

This section begins with a discussion of production taxes and royalties, both of which are driven by price and volume. We then review the price forecasting methodology that underlies this report, and discuss the linkage between market prices and wellhead values. We also review our production forecast and close this section with a discussion of oil and gas property taxes, oil and gas corporate income taxes, and the restricted portions of oil revenue.

Crude Oil and Natural Gas Production Taxes

All oil and gas production in Alaska, except the federal and state royalty share and a small amount used in production operations, is subject to the state's production tax and to the hazardous release surcharge, which is levied only on crude oil. Taxes and surcharges are estimated and collected on a monthly basis.

[1] For more discussion on deposits to the Permanent Fund and HB 11, see the Executive Summary section.

[2] This fund implements a federal requirement that the state use its share of NPR-A oil revenue to satisfy the needs of local communities most affected by development in the NPR-A. For detailed information on this fund, see Section XII-P of Treasury's Investment Policies and Procedure Manual.

The Production Tax Known as "Alaska's Clear and Equitable Share" (ACES)

In November 2007, the Alaska Legislature passed Alaska's Clear and Equitable Share (ACES), which made changes to the state's production tax system, retroactive to July 1, 2007. The previous production tax, titled the Petroleum Profits Tax (PPT), had been in place for one year prior to the passage of ACES. Both production tax systems are based on net profits of oil and gas production (see Figure 4-4). For more than 20 years prior to the enactment of the PPT, the state used a production tax system that was based on the gross value at the point of production as adjusted by the Economic Limit Factor (ELF).

The ACES tax calculation starts with the value at the point of production and then subtracts upstream costs, including costs capitalized on company financial statements, from this value to arrive at the "production tax value." Each company that produces oil in Alaska has a production tax value based on this calculation, which is conceptually similar to a company's net income, or net profit. The production tax value is multiplied by the tax rate—25%—to arrive at the base tax. Should the production tax value exceed $30 per barrel of oil produced (or the equivalent in gas), the tax rate increases 0.4% for every dollar the per-barrel production tax value exceeds $30. For production tax values greater than $92.50, the progressive factor changes to 0.1% for every additional dollar of profit on a barrel of oil. The maximum total tax rate is 75%.

Under ACES, a company's production tax liability is reduced to the extent that it invests in equipment, projects, or other items that are deemed "capital expenditures." Capital expenditures generally include costs related to the purchase of drilling rigs or other equipment, infrastructure, exploration, and facility expansion. Capital costs are eligible for a 20% credit against the company's ACES liability and the credits must be spread over two years. The 20% capital expenditure credit is intended to encourage investment in Alaska.

Other tax credits are available against the ACES production tax. Companies producing less than 100,000 barrels of oil per day may be eligible for a tax credit of up to $12 million per year. Net losses are eligible for a 25% tax credit in the year following the loss. ACES also expanded the Exploration Incentive Credit, changing the credit rates from 20% and 40% to 30% and 40% of exploration expenditures.

Figure 4-5 shows the capital credits that companies reported on their annual tax returns filed March 31, 2010 and March 31, 2011. Note that most of the credits were applied against tax liabilities; those that could not be immediately applied against a tax liability will be carried forward or sold to the state or another company.

The oil and gas tax credit fund, authorized under AS 43.55.028, was created to fund the state's purchase of production tax credit certificates. In FY 2011, the fund paid out $450 million, and as of November 18, 2011, the fund has paid out $41.6 million to purchase credits in FY 2012. As of November 18, 2011, the fund balance was $94 million.

Hazardous Release Surcharge

The Oil and Hazardous Substance Release Prevention and Response Fund

Figure 4-4. ACES Tax Liability Calculation

ACES Tax Liability = [(Value – Costs) * Tax Rate] – Credits

The terms used in the equation are defined as follows:

Value = Volume of Taxable Oil & Gas Produced * Wellhead Value
Costs = Operating Expenditures + Capital Expenditures
Tax Rate = 25% + 0.4% for every $1 per barrel that this "net income" exceeds $30, up to $92.50, then 0.1%
Credits = (20% * Capital Expenditures)(1) = (20% * Eligible Transition Expenditures)(2) + Base Allowance

(1) Spread over two years (2) Limited to those credits earned while the PPT was in effect and could not be used

was created by the legislature in 1986 to provide a "readily available funding source to investigate, contain, and clean up oil and hazardous releases." An amendment in 1994 divided the fund into two separate accounts comprised of: (1) the Response Account which requires a surcharge on all oil production, except federal and state royalty barrels, that may be used to finance the state's response to an oil or hazardous substance release declared a disaster by the governor; (2) the Prevention Account which is an additional surcharge on all oil production, except federal and state royalty barrels, that may be used for the clean up of oil and hazardous substance releases not declared a disaster by the governor. This account can also be used to fund oil and hazardous substance release prevention programs in Alaska.

The Response surcharge (AS 43.55.201) is $.01 per taxable barrel of oil and the Prevention surcharge (AS 43.55.300) is $.04 per taxable barrel of oil produced.

The Response surcharge is suspended when the balance of the Response account is equal to or exceeds $50 million. As of September 30, 2011, the cumulative balance of the account was $47.9 million. The Response Surcharge was re-imposed effective April 1, 2007, by the Department of Revenue.

Oil Royalties

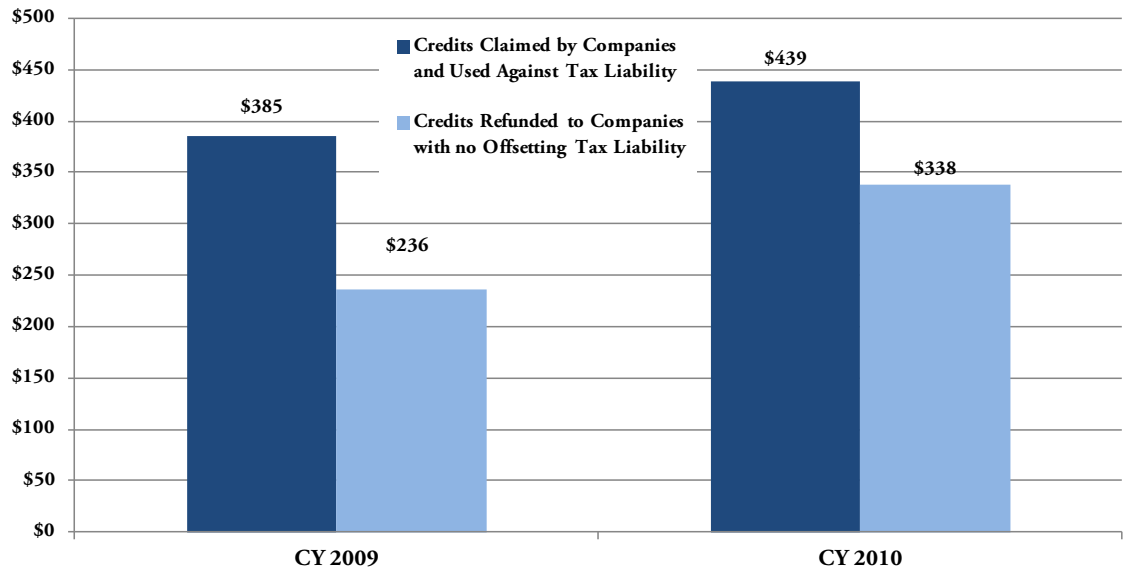
Almost all Alaska oil and gas production occurs on state lands leased for exploration and development. As the land owner, the state earns revenue from leasing as: (1) upfront bonuses, (2) annual rent and (3) a royalty interest in oil and gas production.

Typically the state issues leases based on a competitive bonus bid system. The state generally retains a royalty interest of at least 12.5%. The vast majority of current production is from leases that carry that rate. Some currently producing leases carry rates as high as 27% and some leases also have a net profit-share production agreement.

State oil and gas leases provide that the state may take its oil royalty in barrels (in-kind) or as a percentage of the production value (in-value). In FY 2011, the state took approximately 33,000 barrels per day of North Slope production in-kind and sold it to Flint Hills Resources Alaska, LLC for their refinery at North Pole.

The royalty oil taken in-value is valued according to a formula using a market basket of spot crude oil prices closely approximating the ANS West Coast spot price of oil less a transportation allowance back to the lease. Royalties are based on a destination price—the higher of the actual sales price or the prevailing value[1]. The pipeline and marine transportation costs are de-

Figure 4-5. Production Tax Credits Reported, CY 2009 and CY 2010 ($ million)



[1] ANS West Coast prevailing value per 15 AAC 55.171 is the monthly average of daily spot market prices reported by Platt's Oilgram, Reuters and Dow Jones Energy reporting services. This price is published monthly on the Tax Division website at www.tax.state.ak.us.

ducted from the destination value to derive the taxable netback value of the oil or gas.

Crude Oil Prices, Lease Expenditures, Transportation Costs and Crude Oil Production: Forecasting Methodology & Assumptions

For many years, the level of revenues accruing to the state from oil production have been contingent primarily on (1) oil prices; and (2) production volumes. With the implementation of the production tax on net profits, a third factor influences the level of revenues anticipated from oil production—costs related to exploring for, developing, and producing oil, all or part of which are deductible and/or creditable under the production tax as "lease expenditures."

Estimating oil revenue for the state entails projecting three factors plus the cost to transport the oil to market. These are shown below:

1. Crude oil prices
2. Lease expenditures
3. Transportation charges
4. Crude oil production

This section reviews each of these factors.

To forecast oil prices, the department conducts a day-long price forecasting session to review and discuss petroleum supply and demand oil price drivers. The session includes professionals from the Department of Revenue, Department of Natural Resources, Department of Labor, the Governor's Office of Management and Budget, the Division of Legislative Finance, the University of Alaska and industry experts.

To forecast crude oil production volumes, the Department of Revenue uses an engineering consultant in conjunction with assistance from the Department of Natural Resources and the Alaska Oil and Gas Conservation Commission. The statewide production volume forecast is summed from projections of oil and gas production by well and by field.

To forecast lease expenditures, the department uses data from earlier filings for a base and projects short-term future expenditures from company documents. Mid and long-term expenditure forecasts take into account long-term development plans as detailed in company documents and are intended to coincide with our production forecast.

Transportation charges include tariffs on pipelines, marine transportation and other cost adjustments for moving crude oil to market. ACES allows "reasonable" costs to be subtracted as transportation charges.

Each of these forecasted items play an important role in determining the level of revenue anticipated from oil production. These four items are used as inputs in the department's revenue model. Basic data about expenditures and tax calculations are shown in Figure 4-6.

1. Crude Oil Prices

Methodology for Forecasting Prices

The department compiles its oil price forecast from several sources, including a day-long price forecasting session with attendees from various agencies in the state government. Session attendees are asked for their projections for West Texas Intermediate (WTI) crude oil for three cases–a low case, a high case and a base case. Attendees forecast WTI in real 2011 dollars. Other forecasting sources used by the department are the Energy Information Administration (EIA), the New York Mercantile Exchange (NYMEX) futures market, and industry analysts. The department forecasts the differential between WTI and ANS and uses a projection of inflation to arrive at the nominal dollar forecast used in this publication.

FY 2011 was yet another reminder of the unpredictability of oil prices. Worry over the U.S. economic recovery, the financial crisis facing Europe, and the disruption of Libyan oil supply led to uncertainty and turmoil in oil markets. In looking ahead, these factors are expected to continue to influence prices and drive volatility. The uncertainty surrounding oil prices is evidenced by current oil price forecasts by various agencies and experts. The Energy Information Administration (EIA), for example, projects oil prices to be over $20 per barrel higher in 2016 than did the NYMEX around the same time period. Oil market analysts come in between the EIA and NYMEX, predicting prices $17 higher than the NYMEX, but $4 lower than the EIA. Forecasts for near term oil prices are somewhat more aligned among price forecasters.

Because of the marked differences among forecasts, we continue with our past method of blending different forecasts to generate the department's official forecast. Our Fall 2011 oil price forecast therefore is an equally-weight-

Figure 4-6. Basic Data Used for ANS Oil & Gas Production Taxes

	History FY 2011	Forecast FY 2012	Forecast FY 2013
State Production Tax Revenue from the North Slope			
Millions of Dollars	4,552.9	5,376.4	4,715.8
Key North Slope Assumptions			
Price of ANS WC in dollars per barrel	94.49	109.33	109.47
Transit Costs & Other in dollars per barrel	7.17	8.72	8.56
ANS Wellhead in dollars per barrel	87.32	100.61	100.91
Production in barrels per day	602,723	574,373	555,227
Royalty and federal barrels per day	73,218	77,508	76,503
Taxable barrels per day	529,505	496,866	478,724
Lease Expenditures in Millions of Dollars			
Operating Expenditures (Opex)	2,614.0	2,579.4	2,374.7
Capital Expenditures (Capex)	2,317.0	2,742.7	3,056.6
Total Expenditures	4,931.0	5,322.2	5,431.4
Implied North Slope Data			
Credits Used against Tax Liability in $millions	400.0	400.0	450.0
Credits for Potential Purchase in $millions	450.0	325.0	400.0
Lease Expenditures per barrel of oil produced			
Opex	11.9	12.3	11.7
Capex	10.5	13.1	15.1
Total Expenditures	22.4	25.4	26.8
Average Production Value per Barrel (Pre-Tax)	64.9	75.2	74.1
Production Tax Collected per Taxable Barrel	23.6	29.6	27.0

Notes

1 This table presents a grossly simplified snapshot of the production tax calculation on an average North Slope basis and any use of this data should be viewed accordingly. Additionally, because production tax is calculated on a company basis, any simplification such as this distorts the actual value to companies. For example, a company's pre-tax production value per barrel could be significantly more or less than that shown in this table, depending on the "mix" of petroleum investments they have on the North Slope.

2 Lease expenditures for FY 2011 were prepared using unaudited company reported expenditure estimates.

3 Expenditure data for FY 2012 and FY 2013 are compiled from company submitted expenditure forecast estimates and other documentation as provided to the DOR. Expenditures shown here represent total estimated expenditures including for those companies with no tax liability.

4 CAPEX credits are spread out over two years as specified in the ACES production tax. In addition, the assumptions for the transitional credits and the $12 million credits for small Alaska producers are not included in the table.

5 Royalty, Federal and other barrels represents our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and barrels used in production.

ed average of forecasts from our Fall 2011 oil price forecasting session, the NYMEX as of late-October 2011, oil market analysts' forecasts, and the EIA.

Factors that Influence Oil Prices

Many factors contribute to the pricing of oil on the world market. As shown in Figure 4-7, inventory levels, economic fluctuations, infrastructure constraints, and geopolitical and weather-related events can heavily influence oil prices in the short term. Fluctuations in value of the U.S. dollar and changes in the sentiments of traders buying and selling oil futures and options contracts on the New York Mercantile Exchange (NYMEX) also affect the price of oil. In addition to these factors, there is the influence of a strong oil market cartel—OPEC—which strives to keep oil prices within a pre-determined price band by increasing and decreasing supply.

In the long run, fundamental economic factors of supply and demand ultimately drive oil prices. Predicting future supply and demand requires an understanding of long-term economic growth, demand for refined petroleum products, global crude oil reserves, and the economics and politics of recovering those reserves.

All these factors determine the price of oil in the world market and each of them must be considered in forecasting oil prices.

Oil Price Drivers

The strength and speed of the U.S. economic recovery continues to be an important driver of oil prices. In the 3rd quarter of calendar year 2011, U.S. real Gross Domestic Product (GDP) surpassed pre-recession levels of 2007. The unemployment rate in October 2011 fell 0.1% to 9.0% as companies added to their payrolls. While this may indicate that the economy is growing again, many economic indicators suggest U.S. economic growth will be anemic. Consumer confidence in the U.S., as measured by The Conference Board, has fallen back to levels during the 2008 recession. The Institute for Supply Management's Purchasing Manager's Index (PMI), which indicates the health of the manufacturing sector, has declined in recent months.

Oil demand growth in the advanced economies of Europe looks dim as the continent struggles to deal with an intensifying financial crisis. Many European countries, such as Greece, Ireland, Portugal, and others, exited the recession with heavy debt burdens and lack-luster growth prospects. This vicious combination of high debt and low growth has sparked concern that some countries may default on their debt. Several European and U.S. banks hold European sovereign debt and are thus vulnerable to potential defaults or write-downs. If the sovereign debt crisis in Europe spins out of control, this could trigger chaos in financial markets similar to the crisis in 2008.

Another troubled area of the world economy is Japan. The March 2011 earthquake and tsunami rattled the Japanese economy and disrupted automotive and electronic supply chains around the world. The disaster sent the Nikkei, Japan's stock exchange, into freefall. In the two months following the disaster, the number of cars manufactured worldwide dropped by almost a third, according to some estimates. Despite the devastation of this tragedy, Japan's economy is expected to grow in 2012 as rebuilding of the country provides a stimulus for the stagnate economy.

The emerging economies give reason for optimism about the world economy, but even these bright spots have some caveats. Developing countries in Asia, Latin America, and the Middle East, which fared better during the world recession, have rebounded quickly and are showing solid growth. Although output is up in these regions, in many countries the downside risks are up as well. Inflation has risen sharply in many countries, and a surge of capital flows from foreign creditors resembles past warnings of bubbling asset prices.

This uneven global outlook means uncertainty for near-term oil prices. Weak consumer demand and financial market vulnerabilities in the advanced economies will be a drag on oil prices. On the other hand, robust growth in emerging and developing economies will put upward pressure on prices.

The price of crude oil and the value of the U.S. dollar are interwoven because oil is priced in U.S. dollars. The dollar's value is of little use for predicting oil prices, however, because forecasting exchange rates is as difficult as predicting oil prices. Exchange rates can fluctuate wildly with interest rate changes and various other macroeconomic variables.

As was made evident by events this year, geopolitics and political crises can cause chaos in oil markets. Violence erupting in Tunisia spread through North Africa and the Middle East and triggered concerns about crude oil supplies. Unrest in Egypt prompted worries about the safety of the 5% of world crude oil transported through the Suez Canal. Turmoil in Libya disrupted production and took Libya's 1.5mmbbls/day of supply (2% of global supply) off the world market. Recent attacks on oil facilities in Iraq and Nigeria are a reminder that much of the world's oil is produced and transported through unstable regions and vulnerable to sudden disruptions.

Financial markets are also thought to play a role in driving oil prices. Every

day, hundreds of millions of "paper" barrels of oil are bought and sold on the NYMEX via futures contracts. Investors also trade financial options that offer the right to buy or sell crude oil at a given strike price. The correlation of futures markets trading and the rise of oil prices has led many to suggest these markets are responsible for at least some of the price rise. This issue has seen much debate, and yet there is no definite conclusion about the role of financial markets in setting oil prices.

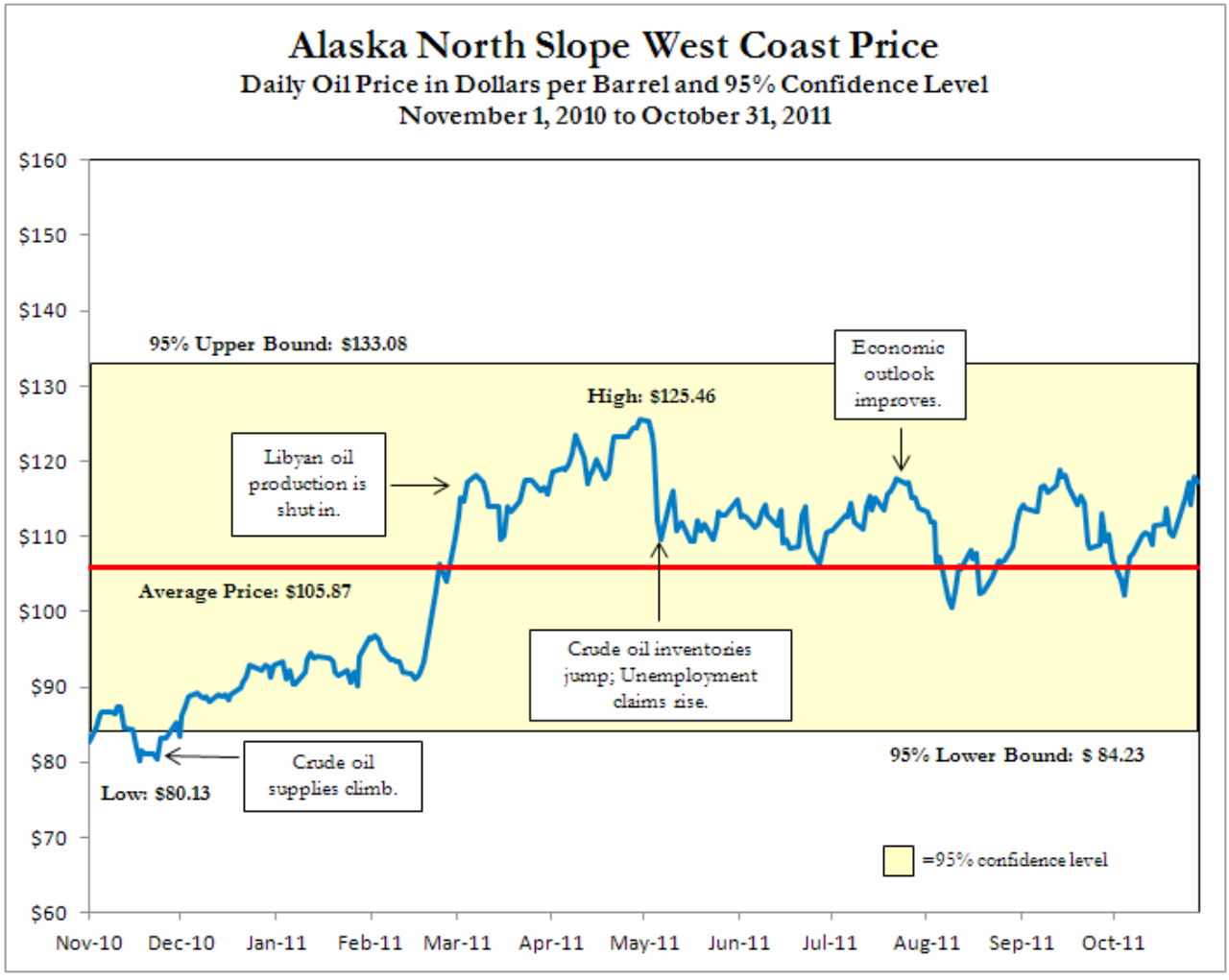
Supply is of course another key determinant of future oil prices, and one cannot mention supply without mentioning OPEC. OPEC, which currently produces around a third of the world's total crude oil supply, is difficult to predict and notorious for not complying with established quotas. OPEC's current willingness and ability to adjust its production to keep oil prices stable is unknown. In its June meeting, OPEC was unable to come to agreement on raising production quotas, and with Libyan production restarting some in OPEC are calling for production cuts. OPEC's ability to maintain current prices partially depends on its spare capacity (the difference between sustainable oil production and current oil production). Spare capacity is currently above the 10-year historical average, but it has declined over the past year and may drop further if oil markets tighten.

Supply and Demand Projections

In the long run, prices are ultimately a function of two factors: the supply of oil and the demand for oil. Oil price forecasting necessarily considers the impact of financial speculation, exchange rate fluctuations, geopolitical and weather-related events, but the underlying fundamentals of supply and demand must also be examined.

In their November 2011 update, the EIA predicted that world oil demand will increase by 1.4mmbbls/day in 2011, which is slightly higher than growth in

Figure 4-7. ANS Crude Price Volatility



2011 of 1.2mmbbls/day. The growth in demand during 2011 is due to increasing consumption in many non-OECD (Organization for Economic Cooperation and Development) countries which will offset falling demand in OECD countries.

On the supply side, the EIA expects OPEC production, which it projects to be 35.5mmbbls/day in 2011, will increase to 36.1mmbbls/day in 2012. OPEC spare capacity is expected to rise close to 4 million barrels per day, which is significantly higher than its pre-recession levels. Non-OPEC oil production, which is projected to average 52.2mmbbls/day in 2011, is projected to increase to 53.3mmbbls/day.

All of the above drivers will likely push oil prices in various directions in the coming year. Robust emerging market economies and stagnate OPEC supply are exerting upward pressure on prices. Geopolitical events, such as the "Arab Spring," could threaten supply and cause yet another price spike. Conversely, sluggish oil demand in the U.S. and other advanced economies are putting a drag on prices. Moreover, if the unfolding financial crisis in Europe intensifies, another oil price crash could be around the corner.

The department's price forecast of WTI and ANS reflects a consensus view of stable oil demand growth and modest supply increases in the short and medium term. In the long term, the forecast reflects stabilizing oil demand growth that puts pressure on world oil production and tightens oil markets.

Forecast for West Texas Intermediate and Alaska North Slope Crude Oil

In following the department's method from prior years, we average the WTI price forecast from the department's oil price forecasting session, the EIA, NYMEX futures market, and industry analysts. We forecast the price for West Texas Intermediate (WTI) crude oil to average $90.92 for FY 2012, $96.62 for FY 2013, and $99.88 for FY 2014.

In the past, the department has assumed the ANS-WTI differential would be -$2.50. That is, ANS would sell at a $2.50 discount to WTI. Due to the divergence in price between WTI and other world crude oils, this assumption is no longer reasonable.

Beginning in January 2011, WTI began to diverge from other world crude oils. WTI, which historically sold at a premium to Brent (the European benchmark), Dubai, ANS, and other crude oils, began to sell at a noticeable discount. Most experts have attributed this divergence to growing supply in the Midwest and Western Canada and logistical constraints around Cushing, Oklahoma, which is the delivery location of WTI. In the last three years, imports from Canada have increased 17% and North Dakota production has more than doubled. This new production has flooded the Midwest and Cushing supply lines.

Insufficient pipeline capacity for transporting this new production to the Gulf Coast has pushed WTI out of sync with other world markets. Moreover, a pipeline project that will relieve this bottleneck is some years away. One such project is the Keystone XL project that will include a connection from Cushing to the Gulf Coast. Keystone XL is, however, very controversial and awaiting regulatory approval. A second project, called the Wrangler Pipeline, is being planned to transport crude from Cushing to the Gulf Coast. At the earliest, these projects could begin flowing crude sometime in 2013 or 2014.

Plans were recently announced to reverse the Seaway pipeline, which currently ships crude from the Gulf Coast to Cushing, by the second quarter of 2012. This reversal will take crude out of Cushing and to refineries in the Gulf Coast. News of the reversal caused the price differential between WTI and other crude oils to narrow sharply. Since this announcement was made after the department's oil price forecast was compiled, the impacts of this project are not reflected in the department's forecast.

As a result of the divergence, the department has changed its ANS-WTI differential assumption. This year, our method uses futures market to forecast the ANS-WTI differential. First, we use the spread between WTI and Brent to forecast a Brent-WTI differential. Second, we use the historical relationship between Brent and ANS to assume a Brent-ANS price differential of $1. Taken together, the Brent-WTI futures market spread and the assumed ANS-Brent differential produces an ANS-WTI price differential forecast. For example, if the Brent and WTI futures markets show Brent selling $20/bbl over WTI futures, and if we assume, based on their historical relationship, that ANS sells for $1 less than Brent, then our forecast of the ANS-WTI differential is $19/bbl. This method allows the department to use market expectations to correct for WTI's disconnect from other crudes, while being consistent with its past method of blending WTI forecasts from the EIA, NYMEX futures market, the department's forecasting session, and industry analysts.

Despite WTI's troubles, it remains a popular benchmark for forecasting and pricing other crudes. Currently, the EIA forecasts WTI but does not forecast other crudes such as Brent or ANS. The NYMEX WTI futures

market is the world's most liquid market for buying and selling crude oil. Moreover, contracts for many crudes, including ANS, are still made based on the price of WTI.

While markets have not yet abandoned WTI, there is no guarantee it will remain a benchmark crude. WTI was not always a benchmark and, as markets change and pricing methods evolve, the department will continue to evaluate other methods for conducting its price forecast.

ANS prices for FY 2012-2014 are forecasted to be $109.33, $109.47, and $109.08, respectively. The corresponding ANS-WTI differential for these years, based on the forecast method discussed above, are $18.41, $12.85, and $9.19. Our blended WTI with the differential forecast is used for FY 2012 through FY 2016. For FY 2017 and beyond, we assume the ANS-WTI differential will return to its historical long-run average of -$2.50, and we forecast oil prices will stay flat in real terms and increase in nominal terms by the projected 2.5% Callan Associates capital market inflation assumption.

2. Lease Expenditures

The implementation of a production tax on net profits requires the Department of Revenue to forecast lease expenditures, in addition to oil prices and production. Lease expenditures are defined in part as the upstream costs that are the direct costs of exploring for, developing, or producing oil or gas deposits. The production tax under ACES allows the deduction of lease expenditures in arriving at a taxable base. The production tax system also allows a partial credit against the tax liability for certain lease expenditures known as qualified capital expenditures. For more information how ACES production tax is calculated, see Figure 4-4.

Methodology for Forecasting Lease Expenditures

The Department of Revenue has received five annual filings of tax returns under a net profits production tax, under PPT in 2006, and under ACES in 2007 through 2010. Additionally, the department receives monthly information filings from oil and gas companies operating in the state that provide estimated monthly lease expenditures by property. Semi-annually, the department receives projections of lease expenditures by property for up to 5 years in the future. These reports have greatly enhanced the department's ability to prepare better revenue forecasts.

The department also uses several other means to forecast lease expenditures, including consulting other taxpayer-submitted information, such as plans of development, federal partnership returns, and other documentation. Production profiles are reviewed, as well as publicly available information on estimated costs to bring new fields online and projected start-up dates.

Forecast for Lease Expenditures

In FY 2011, the following unaudited lease expenditures were reported by companies producing or exploring for oil and/or gas on the North Slope on monthly information forms: $2.6 billion in operating expenditures and $2.3 billion in capital expenditures. For FY 2012, we forecast operating expenditures at about $2.6 billion and capital expenditures at $2.7 billion. For FY 2013, we forecast operating expenditures at $2.4 billion and capital expenditures at $3.1 billion. For FY 2012 and 2013, we are forecasting higher capital expenditures with the majority of the increase occurring in currently undeveloped areas of the state. Exploration and development plans by several newcomers to the state were publicly announced this fall and, despite the speculative nature of those plans, the associated expenditures are included in our forecast. Work in established units continues with investment ongoing at Point Thomson and at the Oooguruk and Nikaitchuq units.

3. Transportation Charges and Other Production Costs

Taxpayers subtract marine transportation costs, the Trans Alaska Pipeline System (TAPS) tariff, feeder pipeline tariffs and an adjustment for Quality Bank charges from the appropriate destination value. This netback calculation is shown in Figure 4-8 for FY 2011-2021.

Marine Transportation Costs

Crude oil delivered to Valdez through TAPS is shipped by tanker to refineries in Washington, California, Hawaii and the Kenai Peninsula. Most North Slope crude is delivered to Puget Sound, San Francisco and Los Angeles to meet the demand of Washington and California refineries. These voyages take about two weeks depending on loading/unloading time and potential delays.

The majority of crude oil delivered is by "Alaska Class" and "Endeavour Class" tankers, all of which are state-of-the-art double-hulled tankers. Double-hulled tankers have an inner hull containing the tanker's crude oil and a surrounding outer hull to offer additional protection against oil spills. These tankers range from about 140 to 195 deadweight tons and can carry over a million barrels at full capacity.

Allowable costs for oil transported by a vessel not owned or effectively owned by the producer of the transported oil are the total costs under the charter or contract and other allowable costs borne by the producer.

For crude oil shipped on tankers that are owned or effectively owned by the producer of the transported oil, which is typically the case, the bulk of allowable costs are the following:

- depreciation,
- return on investment,
- fuel for the vessel,
- wages and benefits,
- routine maintenance,
- tug and pilotage fees and
- drydocking costs.

We forecast a modest increase in tanker transportation costs per barrel will be necessary in order to maintain the integrity of the fleet.

Trans Alaska Pipeline System (TAPS) Tariff

A cost-based model is used to forecast the tariff rate to transport a barrel of oil on TAPS. The idea is to calculate the total revenue required to operate and maintain the pipeline while providing a reasonable return on the investment in the pipeline. This return includes both a return of the investment through depreciation and a return on the investment from debt and equity.

The forecasting model emulates a regulatory approach and simulates what the tariff would be using Opinion 154-B methodology with data from Opinion 502, tariff filings and FERC Form6. Assumptions and statistical relationships move the components of the model forward. Forecasts of the cost components are summed each year to estimate the total cost or total revenue required to operate the pipeline which is linked to the production forecast to calculate the tariff per barrel for each year in the forecast. We do not attempt to predict the outcome of pending litigation or estimate the level and timing of protested tariffs. Corrections between filed, charged and allowed rates are not part of this forecast.

The beginning rate base for TAPS is established and depreciated according to Opinion 502 which also extended the life of the line from 2011 to 2034 and specified treatment of dismantlement, removal and restoration costs. The proxy based capital structure and discounted cash flow method for determining the return on equity are consistent with the FERC policy for determining rates of return for oil pipelines. Projections reflect assumptions regarding those components and adjustments to the rate base from:

- trending,
- deferred return,
- working capital,
- capital additions, and
- depreciation.

Cost components for operating the pipeline and providing a reasonable return include:

- operating expenses,
- property tax,
- depreciation expense,
- amortization of deferred return,
- return on equity,
- cost of debt, and
- income tax allowance.

Total revenue requirement for the pipeline is estimated as the sum of the cost components. To calculate a dollar per barrel tariff, the value is divided by the annual volume of oil shipped through

Figure 4-8. Fall 2011 Forecast Assumptions, FY 2011 and Forecasted FY 2012-2021 (nominal $ per barrel)

Fiscal Year	2011	2012[1]	2013	2014	2015	2016	2017	2018	2019	2020	2021
ANS West Coast Price	94.49	109.33	109.47	109.08	108.75	107.79	106.05	108.76	111.54	114.39	117.31
ANS Marine Transportation	2.45	2.71	2.70	2.76	2.83	2.90	2.98	3.05	3.13	3.20	3.28
TAPS Tariff	4.02	5.16	4.96	5.17	5.39	5.58	5.73	5.87	6.09	6.38	6.69
Other Deductions & Adjustments [2]	0.70	0.85	0.91	0.90	0.93	1.07	1.07	1.08	1.13	1.18	1.19
ANS Wellhead Price	87.32	100.61	100.91	100.25	99.61	98.23	96.27	98.76	101.19	103.63	106.15

[1] FY 2012 values include two months of actual data.
[2] Includes other adjustments such as quality bank charges, feeder pipeline tariffs, location differentials and company-amended information.

the pipeline. Dividing by throughput makes the tariff sensitive to the production profile.

The tariff escalates as production declines and operating costs are spread over fewer units. TAPS is an old pipeline with operating expenses accounting for 80-85 percent of the total revenue requirement and declining throughput means higher tariffs as costs are spread over fewer units. The weighted average tariff on TAPS is about $5.16 per barrel in FY 2012.

Feeder Pipeline Tariffs and Other Adjustments

These costs include feeder pipeline tariff rates, feeder pipeline losses and other adjustments to account for the different qualities of oil entering the pipelines.

Producers shipping crude oil through a pipeline from various North Slope production fields to Pump Station No.1 of TAPS pay a tariff rate to the owner of the pipeline. In general, tariff rates are calculated for each of the six feeder pipelines according to each pipeline's particular settlement agreement.

The tariff rate forecast for each pipeline is based on a cost-of-service model tailored to match each pipeline's settlement agreement. The tariff rate, under a cost-of-service ratemaking approach, allows the pipeline to recover a return of capital investment, a return on capital investment and other incurred costs. The return of capital investment is the yearly depreciation expense, which allows a pipeline to recover the capital investment it has undertaken to provide its service. The return on capital investment is compensation for the use of its capital to finance the investment. Other costs the pipeline can recover typically include operating expenses, a dismantling, removal and restoration (DR&R) allowance, and an allowance for income taxes and other costs.

To forecast the per barrel tariff rates for each pipeline, projected total costs are summed and allocated across the different connections, if there is more than one, and divided over the projected throughput of each connection.

Wellhead Price

The combination of ANS wellhead value and production volumes forms the basis for both state production taxes and royalties. The wellhead value is calculated by subtracting the relevant marine transportation and pipeline tariff costs (as well as adjustments for North Slope feeder pipelines and pipeline Quality Bank) from the appropriate destination value. Figure 4-8 reflects this calculation for FY 2011-2021.

4. Crude Oil Production

For the Fall 2011 forecast we have added discussion regarding our production forecasting methodology.

Methodology for Forecasting Crude Oil Production

When developing the production forecast for the North Slope, we do not include any estimates for undiscovered oil, including future potential from the Alaska National Wildlife Refuge (ANWR), most of the National Petroleum Reserve-Alaska (NPR-A), and the federal Outer Continental Shelf (OCS). We exclude from our estimates production from most of the known heavy or viscous oil deposits; in fact we consider none of the approximately 20 billion barrels from the giant Ugnu deposit, although one operator has initiated a pilot project at Milne Point to evaluate new technology termed CHOPS (Cold Heavy Oil Production with Sand), and another operator is evaluating thermal recovery technology for Ugnu at Kuparuk. We exclude more than 97% of the viscous/heavy oil from the large West Sak field, projecting roughly 137 million barrels recovery out of roughly 10 billion barrels in place. We also exclude more than 93% of the heavy oil at Schrader Bluff, projecting roughly 95 million barrels recovery out of over 2 billion barrels in place. Additionally, none of the known oil discoveries in the Federal Outer Continental Shelf, in fields such as Sivilluq, Kuvlum and Sandpiper, potentially totaling hundreds of millions of barrels of recoverable oil, are considered in the forecast.

We exclude these resources, both known and unknown, in order to avoid speculation and to reduce the uncertainty typically associated with the commercialization, timing and magnitude of resource development. Accordingly, we believe that our current estimates of ultimate recovery from the North Slope are reasonable.

For the production forecasting process, we engage a petroleum engineering consultant to perform a "bottom- up" well-by-well evaluation at each of the individual fields that yields a forecast of three types of oil production, all of which will require significant operating and capital expenditures to be realized: (1) oil that is currently being produced, (2) potential oil production that is possible to realize from projects currently under development and (3) potential oil production that is possible from projects under evaluation. A detailed description of each type of production is provided later in this section. The engineering consultant employs decline curve analysis, applying a best-fit decline trend for each producing well, augmented by generally accepted engineering principals, discussions with field operators, and public and private information in order to assemble our long range production forecast.

When reviewing forecasted production

versus actual production in previous production forecasts, it is apparent there has been a significant trend towards higher anticipated levels of production than those actually realized. This trend was particularly noticeable four years or greater out from the forecast date. In order to address this, our production forecast methodology incorporated a more in-depth review of forecasts provided by North Slope operators than was done in prior years. The currently producing portion of the forecast is the least speculative, and the well-by-well analysis our petroleum engineering consultant now incorporates should lead to more accurate forecasts of this section. However, the under development layer is more uncertain than the currently producing layer, and the under evaluation layer has an even higher level of uncertainty. All three sections will require significant on-going operating and capital expenditures, but the under development and evaluation portions are where the most competition for investment dollars will be realized when companies are comparing all possible opportunities worldwide.

Production Forecast Assumptions

We continue to make adjustments to our production expectations from the North Slope in this Fall 2011 forecast. As always, we examined reservoir performance, reviewed the uncertainty associated with the pace and scope of development of new fields and new projects within existing fields, and re-evaluated planned and unplanned downtime for all fields. Our review indicates that, with minor exceptions, and notwithstanding planned and unplanned surface disruptions, all reservoirs are performing as expected. Through fiscal year 2060, we expect to produce almost 4.5 billion barrels of liquid hydrocarbons.

In the next ten years, we anticipate possible new developments on state and federal lands, both of which benefit the state. Most of the opportunities to add production from state lands are from expanded heavy/viscous oil development (Orion), continued satellite development at Alpine (Nanuq and Alpine West fields), and continued developments at Oooguruk and Nikaitchuq. Production from the Oooguruk field began during the summer of 2008 and is progressing as expected. The Nikaitchuq field began production on schedule in February of 2011. Production at Point Thomson is currently forecast based on a gas cycling production profile consistent with recent publicly available statements on the project. Production at the Umiat field is expected to begin within approximately five years. Umiat was discovered in the late 1940's by the U.S. Navy. It is estimated to have one billion barrels of oil in place with approximately 200 million recoverable barrels. It has not

Figure 4-9. Alaska North Slope Production, FY 2001-2011 and Forecasted FY 2012-2021

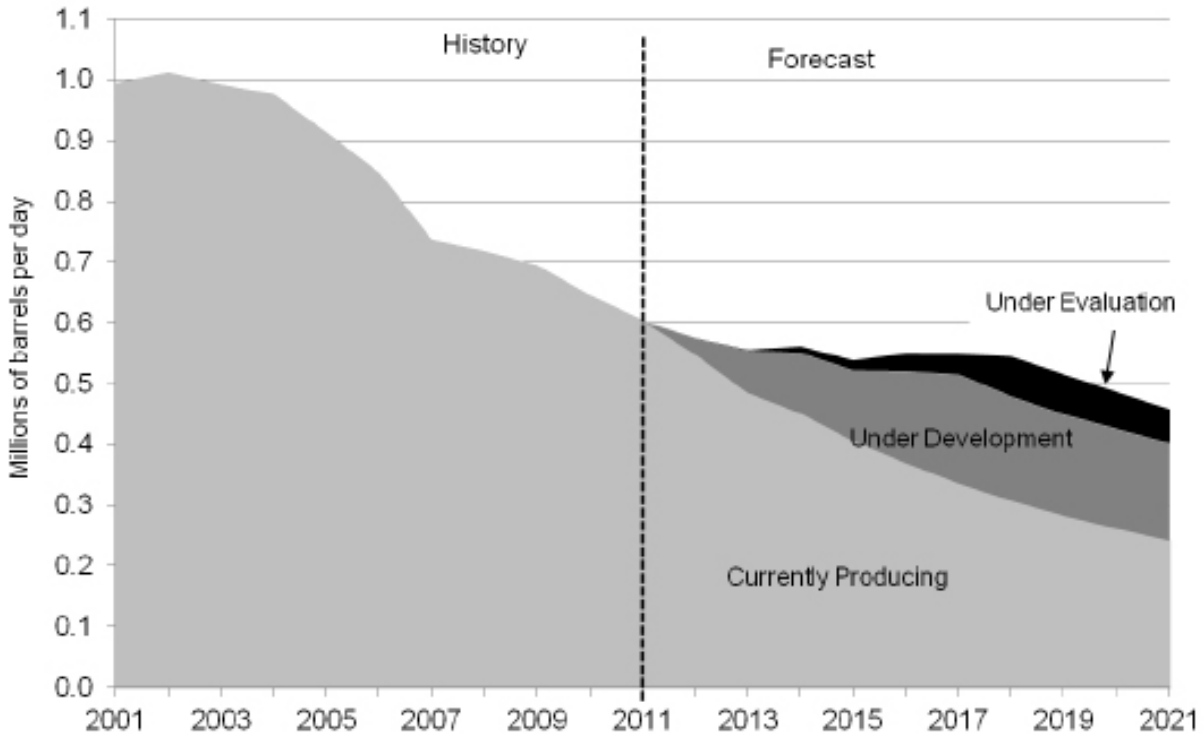


Figure 4-10. Alaska North Slope Forecasted Production and Taxable Barrels FY 2012-2021

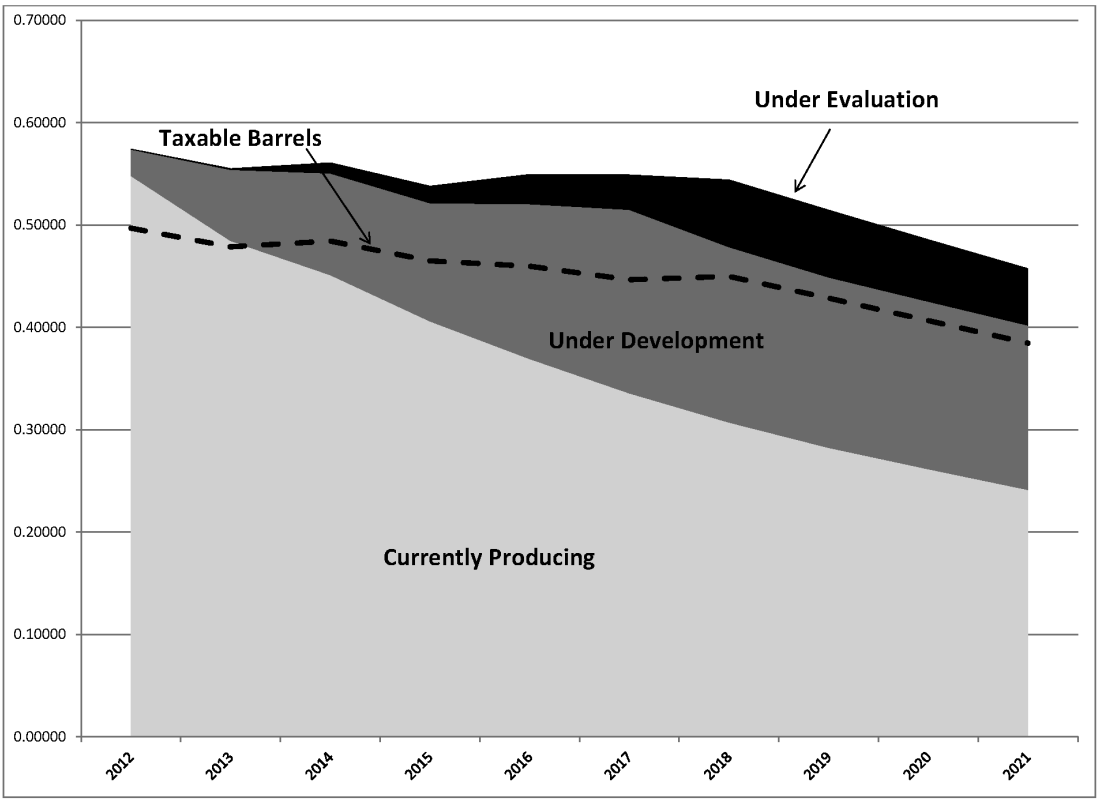


Figure 4-11. Alaska North Slope Production, FY 2011 and Forecasted FY 2012-2021[1] (million barrels per day)

Fiscal Year	Currently Producing	Percent Change from Prior Yr.	Under Development	Under Evaluation	Total ANS	Percent Change from Prior Yr.
2011	0.603	(6.3%)	0.000	0.000	0.603	(6.3%)
2012	0.548	(9.1%)	0.026	0.001	0.574	(4.7%)
2013	0.485	(11.6%)	0.069	0.001	0.555	(3.3%)
2014	0.451	(6.9%)	0.099	0.010	0.561	1.0%
2015	0.406	(10.0%)	0.115	0.017	0.538	(4.1%)
2016	0.369	(9.1%)	0.151	0.029	0.550	2.1%
2017	0.336	(9.1%)	0.179	0.034	0.549	(0.1%)
2018	0.307	(8.5%)	0.171	0.066	0.544	(0.9%)
2019	0.282	(8.1%)	0.166	0.066	0.515	(5.4%)
2020	0.262	(7.4%)	0.164	0.061	0.486	(5.6%)
2021	0.241	(7.7%)	0.161	0.056	0.458	(5.8%)

[1] Some of the oil forecasted in the Under Development and Under Evaluation categories are from new projects in fields currently producing.

been developed due to its remoteness. The Umiat field is approximately 92 miles from the Trans Alaska Pipeline System, but plans are being made to develop the field and we have included it in this year's Under Evaluation forecast. Liberty development is underway with anticipated production starting in FY 2016.

Our forecast includes production from state lands as well as from federal lands. From a revenue standpoint, the State of Alaska benefits in at least five ways, albeit to a lesser degree, from new developments on federal lands: (1) shared royalties (27.5% of federal share) from federal OCS fields such as Liberty; (2) production taxes on federal oil produced onshore within Alaska (NPR-A); (3) increased property tax on any infrastructure on state lands required to produce and transport federal oil; (4) corporate income taxes; and (5) lower pipeline transportation tariffs, which increase wellhead prices. In addition, any oil processed through the Endicott facility (Liberty field) may increase net profits payments to the state. Federal oil produced from non-state lands provides a revenue benefit limited to decreased transportation tariffs and increased property taxes.

Although we anticipate possible new developments from state and federal lands over the next 10 years to contribute to overall production and partially mitigate base decline, we continue to make adjustments near term to reflect ongoing infrastructure renewal projects.

Crude Oil Production Forecast

The department's forecast of North Slope oil production is not a reserve estimate, proved or otherwise. Rather, the department forecasts oil production that is technically recoverable based on a decline curve analysis of historical production for currently producing fields, an analysis of production expected from development currently underway, and production that has a high likelihood of occurring over the forecast term. These three projections are aggregated into a single forecast of future production.

Our three categories of North Slope production are illustrated in Figures 4-9, 4-10 and 4-11. We present the three layers graphically so that the reader will have an understanding about the uncertainty associated with the production forecast. We forecast production of only those fields that have already been discovered and at a minimum are being evaluated for development.

Currently Producing

Production characterized as "currently producing" includes baseline production and presumes a continued level of expenditure sufficient to promote safe, environmentally sound operations. Such expenditures include the following: well diagnostic and remedial work, data acquisition and rate-enhancing expenditures such as perforating, acid stimulation, well workovers, fracture treatments, artificial lift optimization

Figure 4-12. New Oil as a Percentage of Total Oil (million barrels per day)

Fiscal Year	Total New Oil	ANS Total	Percent New Oil
2012	0.026	0.574	4.6%
2013	0.071	0.555	12.7%
2014	0.110	0.561	19.6%
2015	0.132	0.538	24.5%
2016	0.180	0.550	32.8%
2017	0.213	0.549	38.9%
2018	0.237	0.544	43.6%
2019	0.232	0.515	45.1%
2020	0.224	0.486	46.2%
2021	0.216	0.458	47.2%

Figure 4-13. Technically Recoverable North Slope Oil and Gas Potential

Exploration Area	Mean Technically Recoverable Oil (BBO)	Mean Technically Recoverable Gas (TCF)
ANWR	10.4	3.8
Beaufort Sea OCS	6.9	32.1
Chukchi Sea OCS	15.5	60.1
Colville-Canning Area (& adjacent state waters)	4.5	37.5
NPR-A	0.9[1]	53[1]
TOTAL	**38.2[1]**	**186.5[1]**

Source: U.S. Department of Energy, August 2007; Addendum April 2009.

[1] Reflects new estimates by USGS 2010 Updated Assessment of Undiscovered Oil and Gas Resources of the NPR-A (October, 2010).

and production profile optimization. This category of production also presumes continued gas and water injection for pressure support.

Currently Under Development

Production characterized as "currently under development" is based on new projects either currently funded or awaiting project sanctioning in the very near future. It includes projects that may be in the design/construction phase, as well as development drilling and enhanced oil recovery (miscible or immiscible injection) projects, currently funded or underway, but not included in the "currently producing" category. Examples of production currently under development include the Nanuq, and Alpine West satellites at Alpine, the Borealis and Orion satellites at Prudhoe Bay, development drilling at Liberty, Oooguruk, and Nikaitchuq, and ongoing development drilling at Prudhoe Bay and Kuparuk.

Currently Under Evaluation

Production characterized as "currently under evaluation" includes technically viable projects that are currently unfunded by the operators but are being actively evaluated and have a high chance of being brought to fruition. Examples include longer term Orion drilling, long-term production from Pt. Thomson and associated satellites, and pools within the NPR-A. Confidence levels vary for this category of production.

As Figure 4-12 shows, by FY 2016 one-third of our projected oil production will come from projects requiring significant new investment.

Undiscovered Potential

The forecasted revenue published in this book is based on our forecast of production from known hydrocarbon deposits that are recoverable under current regulations, using current technologies. However, it is important to consider the potential for future production from known (discovered but undeveloped) and unknown (undiscovered) hydrocarbon resources in northern Alaska.

Two significant public studies of undiscovered conventional hydrocarbon resources in the Alaska North Slope have been conducted in the last five years. In August 2007, the U.S. Department of Energy released "Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline?" – a report that assessed the potential for Alaska to remain a major producer of oil and gas under various development scenarios.[(1)] The report looked at near-term potential (2005-2015) and long-term potential (2015-2050), mostly under a major gas sale scenario. According to the report, the North Slope is a relatively underexplored petroleum province that may provide oil and increasingly, natural gas, for years to come. In October 2010, the U.S. Department of Interior released "2010 Updated USGS Assessment of Undiscovered Oil and Gas Resources of the National Petroleum Reserve in Alaska" (NPRA), a report that substantially reduced their estimate of technically recoverable conventional oil in NPRA.

This recent assessment estimates a mean technically recoverable conventional oil resource in the NPRA of 896 million barrels, compared to the 2002 estimate of 10.56 billion barrels. Estimates of non-associated natural gas were reduced as well, but the change was much smaller in magnitude. It is important to note that the revision in estimated undiscovered conventional oil in NPRA is based on data from wells drilled over the last decade in NPRA and is not expected to be reflected in revised estimates for other regions of Alaska.

The 2007 U.S. Department of Energy report evaluated geologic and commercial viability of future oil and gas production from five areas or provinces: 1) the central Arctic area between the Colville and Canning Rivers (and adjacent state waters), 2) the 1002 area of ANWR, 3) the National Petroleum Reserve Alaska (NPR-A), 4) the Beaufort Sea Outer Continental Shelf (OCS), and 5) the Chukchi Sea OCS. Under the most optimistic scenario, DOE reported mean technically recoverable oil resources of 38.2 billion barrels and mean technically recoverable gas resources of 186.5 TCF from these five areas. Figure 4-13 shows the breakout by province.

Petroleum Property Tax

An annual tax is levied each year on the full and true value of property taxable under AS 43.56. The tax on oil and gas property is the only statewide property tax. The valuation procedure for three distinct classes of property—exploration, production and pipeline transportation—is described below.

Exploration Property

Value is based on the estimated price that the property would bring in an open market under prevailing market conditions in a sale between a willing seller and a willing buyer, both conversant with the property and with prevailing general price levels.

The Department gathers raw data for determining market value by reviewing

[(1)] http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/ANSSummaryReportFinalAugust2007.pdf

the details of equipment sales in Alaska when available and reviewing trade journals. If available, the Department will consider recent sales transactions in Alaska for this classification of property. The Department also considers market costs in Alaska as of the lien date. This data is then applied to the taxable property, taking into account age, capacity, and physical and functional obsolescence.

Production Property

Value is determined on the basis of replacement cost new less depreciation, based on the economic life of the proven reserves.

Pipeline Transportation Property

The full and true value of taxable pipeline property is determined with due regard to the economic value of the property based on the estimated life of the proven reserves of gas or unrefined oil that will be transported by the pipeline. The Department relies upon standard appraisal techniques to value pipelines in Alaska. When market rents are available, we analyze the income method under which the value is the net present worth of all future income streams of the pipeline. When sales transactions are available, the Department takes those into consideration as well. The Department primarily relies on replacement cost new less depreciation based on the economic life of the reserves that feed the pipeline. This is especially useful when rents are constrained by the regulatory process or when market rents cannot be obtained for use in the income method.

Figure 4-14 illustrates the property tax distribution between local communities and the state for FY 2011. The property value is assessed by the state. A local tax is levied on the state's assessed value for oil and gas property within a city or borough, and is subject to the local property tax limitations established in AS 29.45.080 and AS 29.45.100. The state's mill rate is effectively 20 mills minus the local rate.

Petroleum Corporate Income Tax

Alaska levies two types of corporate income tax. This section focuses on the oil and gas corporate income tax. Forecasts and discussion of the corporate income tax as applied to corporations other than oil and gas corporations can be found in the Other Revenue section of this forecast.

An oil and gas corporation's Alaska income tax liability depends on the relative size of its Alaska and worldwide activities, and the corporation's total worldwide net earnings. The corporation's Alaska taxable income is derived by apportioning its worldwide taxable income to Alaska based on the average of three factors as they pertain to the corporation's Alaska operations: (1) tariffs and sales, (2) oil and gas production and (3) oil and gas property.

Historically, oil and gas corporate income tax revenue has varied greatly along with oil prices and oil industry profits. In FY 1982, revenue from this tax was $668.9 million. In FY 1994, the oil and gas corporate income tax generated a mere $17.8 million. For the past several years, revenues from the oil and gas corporate income tax have benefitted from high oil prices and oil industry profits. Actual revenues collected totaled $446.1 million in FY 2010 and $542.1 million in FY 2011, representing an increase of $96 million or about 21%.

We produce our forecast of oil and gas corporate income tax collections using an economic model based on the statistical relationships between historical tax payments, crude oil prices, North Slope oil production and refinery margins. We then adjust for refunds, credits and carry-forwards which cause actual collections to differ from estimated payments.

We forecast oil and gas corporate income tax collections of $662.1 million in FY 2012, benefitting from high oil prices. Projected revenues for FY 2013 are expected to increase to $728.4 million.

Restricted Oil Revenue

According to Article IX, Section 15 of the Alaska Constitution, a minimum of 25% of all mineral lease rentals, royalties, royalty sale proceeds, federal mineral revenue sharing payments and bonuses received by the state must be deposited into the Alaska Permanent Fund. In addition, AS 37.14.110 requires a contribution of 0.5% of all royalties and bonuses to the Public School Fund Trust. Settlements with, or judgments against, the oil industry involving tax and royalty disputes must be deposited in the Constitutional Budget Reserve Fund (CBRF).

The state is entitled to 50% of all bonuses, rents and royalties from oil development activity in the federal NPR-A, all of which flows into the NPR-A Special Revenue Fund. Revenue in the fund each year is available for appropriation in the form of grants to municipalities that demonstrate present or future impact from NPR-A oil development. Of the revenue not appropriated to the municipalities, 25% goes to the Permanent Fund, 0.5% goes to the Public School Trust Fund, and the rest may be appropriated to the Power Cost Equalization and Rural Electric Capitalization Fund. Any remaining revenue after these appropriations is placed into the General Fund.

Figure 4-15 reflects restricted oil and gas revenue.

Figure 4-14. Petroleum Property Tax, FY 2011 ($ million)[1]

Municipalities	Gross Tax	Local Share	State Share
Anchorage	5.1	3.9	1.2
Fairbanks	14.1	9.9	4.9
Kenai	14.0	6.5	6.9
North Slope	331.8	306.9	24.9
Other[2]	0.4	0.2	0.2
Unorganized	72.2	-	72.2
Valdez	38.9	38.9	-
Total	**476.5**	**366.3**	**110.2**

[1] Amounts shown here do not include the supplemental property tax roll and as a result may not exactly match data presented elsewhere in this forecast.

[2] Includes Matanuska-Susitna Borough, Cordova, Northwest Arctic Borough and Whittier.

Figure 4-15. Restricted Oil Revenue, FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
Other Restricted Oil Revenue	FY 2011	FY 2012	FY 2013
Royalties, Bonuses & Rents to the Permanent Fund	857.3	912.0	857.7
Royalties, Bonuses & Rents to the School Fund	13.6	15.0	14.1
Settlements to CBRF	167.3	31.0	20.0
Subtotal Other Restricted	**1,038.2**	**958.0**	**891.9**
Federal			
NPRA Royalties, Rents & Bonuses	3.0	4.0	4.0
Subtotal Federal	**3.0**	**4.0**	**4.0**
Total Restricted	**1,041.2**	**962.0**	**895.9**

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2011

5. Other Revenue (except Federal & Investment)

Figure 5-1. FY 2011 Other Revenue: $1.0 billion

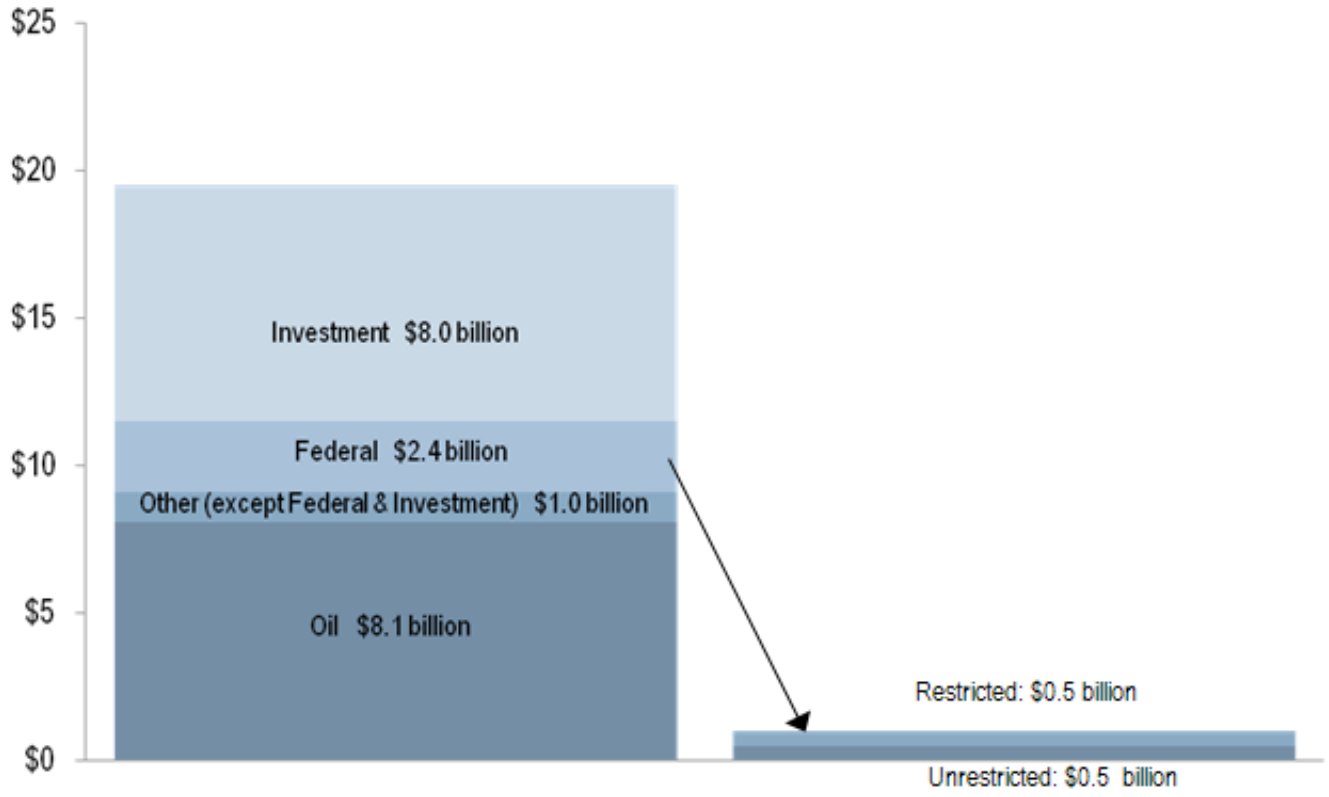


Figure 5-2. Total Other Revenue (except Federal & Investment), FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
Taxes	402.7	388.5	398.1
Charges for Services	18.5	17.8	17.8
Fines & Forfeitures	7.0	8.7	8.7
Licenses & Permits	42.8	42.6	41.5
Rents & Royalties	17.6	16.9	17.1
Other	39.1	61.2	55.9
Total Unrestricted	**527.7**	**535.7**	**539.1**
Restricted			
Designated General Fund			
Taxes	52.1	51.6	51.6
Charges for Services	196.8	219.8	220.0
Fines & Forfeitures	6.9	8.2	8.1
Licenses & Permits	0.1	0.1	0.1
Rents & Royalties	4.0	4.4	4.5
Other	22.7	23.8	23.8
Subtotal	**282.6**	**307.9**	**308.1**
Other Restricted			
Taxes	83.8	70.5	70.6
Charges for Services	35.5	62.8	62.8
Fines & Forfeitures	23.9	23.7	23.5
Licenses & Permits	30.4	31.2	31.2
Rents & Royalties	6.3	6.5	6.7
Other	11.1	8.4	8.4
Subtotal	**191.0**	**203.1**	**203.2**
Total Restricted	**473.6**	**511.0**	**511.3**
Total Other Revenue	**1,001.3**	**1,046.7**	**1,050.4**

General Discussion

Revenue from sources other than oil include state investments, federal receipts, non-oil taxes, charges for services, fines and forfeitures, licenses and permits, rents and royalties and other revenue sources. Federal revenues are discussed in Chapter 6 and Investment revenues are the subject of Chapter 7. This chapter addresses the remaining "other revenue sources." These revenue sources are each subcategorized into unrestricted, designated General Fund and other restricted revenues. The amounts of each are reflected in Figures 5-2 through 5-8 throughout this chapter. Other restricted revenue includes money deposited in funds other than the General Fund, as well as receipts that are restricted by statute or that the legislature customarily appropriates for a particular purpose or program.

Taxes

Alcoholic Beverages Tax

Alcoholic beverage taxes are collected primarily from wholesalers and distributors of alcoholic beverages sold in Alaska. The per-gallon tax rates on alcoholic beverages are $1.07 for beer, $2.50 for wine and $12.80 for liquor. Qualifying small brewers pay tax at a rate of $0.35 per gallon for beer. Revenue is deposited into the General Fund. Fifty percent of the revenue is deposited into a subfund of the General Fund, the Alcohol and Other Drug Abuse Treatment and Prevention Fund and is treated as restricted in this forecast.

In Alaska over the past 10 years, alcohol consumption has grown at an average annual rate of 0.6% for beer, 4.6% for wine, and 3.9% for liquor. Consumption is forecasted to grow at these historical average rates and is reflected in the revenue forecasts.

Charitable Gaming

Under Alaska law, municipalities and qualified nonprofit organizations may conduct certain charitable gaming activities. The purpose of such activities is to derive public benefit in the form of money for charities and revenues for the state. The department collects permit and license fees, a 1% net proceeds fee and a 3% pull-tab tax. We forecast revenues from charitable gaming activity will remain flat in FY 2012 and FY 2013.

Corporate Income Tax

Alaska levies two types of corporate income tax: one that applies to oil and gas corporations and one that applies to corporations other than oil and gas corporations. Forecasts and discussion of the corporate income tax as applied to oil and gas corporations can be found in the Oil Revenue section.

Alaska levies the corporate income tax on corporations doing business in the state. Corporate tax rates are graduated from 1% to 9.4% in $10,000 increments of Alaska taxable income. The maximum rate of 9.4% applies to taxable income over $90,000. S-Corporations and LLCs that file federally as partnerships are generally exempt from corporate income tax. Corporations compute their tax liability based on federal taxable income with Alaska adjustments. Corporations other than oil and gas corporations apportion their income to Alaska by using a three-factor apportionment based on sales, property and payroll. Alaska taxable income is determined by applying the apportionment factor to the corporation's modified federal taxable income.

Forecasts of non-petroleum corporate income tax collections use two economic models: one for the largest sector in terms of collections (mining) and one for all other sectors.

The mining sector model is based on a statistical relationship between historical tax payments, corporate profits and zinc prices. Zinc prices are used because zinc accounts for the largest portion of mineral revenues. The model for all sectors other than mining is based on a statistical relationship between historical tax payments, corporate profits and crude oil prices. Crude oil prices are used because the price of oil influences company profitability in many economic sectors in Alaska. The forecast of estimated payments is then adjusted for refunds, carry-forwards and other payments that cause actual collections to differ from estimated payments.

Over the past few years, income tax revenue from corporations other than oil and gas corporations has increased significantly, albeit with volatility. In FY 2009, revenue was $120.9 million, in FY 2010 revenue decreased to $81.9 million—$39 million less than FY 2009 due to the economic downturn. FY 2011 corporate income tax revenue jumped dramatically to $157.7 million. Looking forward to FY 2012 and FY 2013, collections are expected to be flat. The forecast is uncertain due to changes to the educational tax credit law and uncertainty surrounding economic growth.

Commercial Passenger Vessel Taxes

In August 2006, Alaska voters approved an initiative that imposed new taxes and fees on commercial passenger vessels including:

- The Cruise Ship Passenger Fee is a per-passenger tax of $46 on commercial passenger vessels with 250 or more berths. Revenues are deposited into a subfund of the General Fund, the Commercial Vessel Passenger Tax Account. Five dollars of the tax is distributed to each of the first five ports of call. If a city lies within a borough,

but is not part of a borough, the city qualifies for $2.50 of the levy and the borough qualifies for the remaining $2.50. An additional 25% of the tax was designated for other local governments impacted by the cruise ship industry via the Regional Cruise Ship Impact Fund. The entire passenger fee is considered restricted for purposes of this forecast.

- The Ocean Ranger Fee is an additional per-berth fee of $4 to operate the Ocean Ranger program, which provides for independent observers of engineering, sanitation and health practices. This fee is considered restricted and is included in the Charges for Services section.
- The Large Passenger Vessel Gambling Tax is a tax of 33% on the adjusted gross income from gaming or gambling activities aboard large passenger vessels in the state. Revenue goes to the General Fund and is considered unrestricted.
- The Alaska corporate income tax now applies to large commercial passenger vessels and the revenues are included in the forecast of corporate income taxes.
- There are new penalties for false reporting, violating environmental regulations and failing to make proper disclosures on promotions and shore side activity sales. Revenues from these provisions are included in the Fines and Forfeitures section.

In April 2010, the State of Alaska's Legislature passed SB 236, which took effect October 31, 2010. SB 236 made the following changes to the voter approved initiative:

- The Cruise Ship Passenger Fee decreased from $46 to $34.50. Revenues continues to be deposited into a General Fund subaccount, the Commercial Vessel Passenger Tax Account. Five dollars of the tax can be appropriated to each of the first seven ports of call. If a port of call had a local levy in place before December 17, 2007, then the local tax imposed is allowed as a credit by the cruise ship company. Only Juneau and Ketchikan had qualifying levies in place at that time. Juneau and Ketchikan may now receive $5 per passenger of the tax collected by the state, if they are within the first seven ports of call.
- All funds received from the Cruise Ship Passenger Fee must be spent on port facilities, harbor infrastructure, and other services provided to commercial passenger vessels and the passengers on board those vessels.
- The Regional Impact Fund was eliminated, as of October 31, 2010. Revenue for the fund came from the Cruise Ship Passenger Fee, representing $11.50 of the tax. The $11.50 represents the decrease in the Cruise Ship Passenger Fee from $46 to $34.50.
- Revenues from the Large Passenger Vessel Gambling Tax are deposited within a subaccount of the Commercial Vessel Passenger Tax Account within the General Fund.

In general, impacts from the new law are likely to reduce state revenues in several ways. The state's share of the Cruise Ship Passenger Fee is estimated to fall from $14.1 million in FY 2011 to $1.9 million in FY 2012. The reduction is due to the increase in the number of ports of call which may receive funds, the number of ports visited, the credit allowed for existing local levies, and the reduction in the Cruise Ship Passenger Fee. With the phase out of the Regional Impact Fund the revenues deposited in this fund will fall from $8.8 million in FY 2011 to zero in FY 2012. Revenues shared with local governments will increase from $9.1 million in FY 2011 to $15.3 million in FY 2013 and are treated as restricted revenues.

Estimates of cruise ship passenger counts for CY 2012 and CY 2013 are 840,000 and 848,000 respectively.

Electric Cooperative and Telephone Cooperative Taxes

The electric cooperative tax is based on kilowatt hours furnished by qualified electric cooperatives recognized under Title 10 of the Alaska Statutes. The telephone cooperative tax is levied on gross revenue of qualified telephone cooperatives under Title 10. Revenue from cooperatives located in municipalities is treated as other restricted revenue in this forecast because it is shared 100% with the municipalities. The small amount of revenue collected from cooperatives outside municipalities is retained by the state. Revenues from the electric and telephone cooperative taxes are expected to increase at the overall rate of inflation.

Estate Tax

Estate tax is levied on the transfer of an estate upon death. The Alaska estate tax is tied to the federal tax, with the amount of the state tax equaling the maximum state credit allowed on the estate's federal return. All revenue derived from estate taxes is deposited in the General Fund.

As a result of changes to the federal estate tax, the Alaska estate tax was phased out completely beginning January 1, 2005. The federal estate tax changes that caused the state tax to be phased out are scheduled to sunset after December 31, 2012. Assuming the tax changes sunset as scheduled, Alaska will begin to receive revenue from the estate tax again in FY 2014.

Fisheries Business Tax

The fisheries business tax is levied on businesses that process fisheries resources

in Alaska or export fisheries resources from Alaska. Although the tax is usually levied on the act of processing, the tax is often referred to as a "raw fish tax" because it is based on the value of the raw fishery resource. Tax rates vary from 1% to 5%, depending on whether a fishery resource is classified as "established" or "developing," and whether it was processed by a shore-based or floating processor. Revenue from the tax is deposited in the General Fund. Fifty percent of the revenue (before credits) is shared with qualified municipalities and is treated as other restricted revenue.

Forecasts of fisheries business tax revenues are based on estimated taxable values of the major fisheries in the state and historical effective tax rates. Fisheries business tax revenue retained by the state is reduced by an estimate of tax credits, including Salmon Product Development credits, which apply only to the state portion of the tax.

Fishery Resource Landing Tax

The fishery resource landing tax is based on the unprocessed statewide average price of the resource and is levied on fishery resources processed outside of Alaska and first landed in Alaska. The tax is collected primarily from factory trawlers and floating processors that process fishery resources outside the state's three mile limit and bring their products into Alaska for shipment. The tax rates vary from 1% to 3%, based on whether the resource is classified as "established" or "developing." All revenue derived from the tax is deposited in the General Fund. Fifty percent of the revenue (before credits) is shared with qualified municipalities, and is treated as other restricted revenue.

We forecast fisheries resource landing tax revenues based on estimated taxable values of the major fisheries in the state and historical effective tax rates. Fisheries resource landing tax revenue retained by the state is reduced by a forecast of tax credits which apply only to the state's share of the tax.

Insurance Premium Tax

Insurance companies in Alaska pay an insurance premium tax instead of corporate income tax, sales or other excise taxes. Revenue is deposited into the General Fund and for most types of insurance, the tax is treated as unrestricted revenue. Insurance premium taxes on worker's compensation insurance are deposited into a subfund of the General Fund, the Workers Safety and Compensation Fund, and are reflected as restricted in this forecast. The restricted component also includes service fees paid into the Workers Safety and Compensation Fund by employers who are uninsured or self-insured.

The forecast of insurance premium tax revenues is based on estimates provided by the Department of Commerce, Community and Economic Development's Division of Insurance, which administers the insurance premium tax, and the Department of Labor and Workforce Development's Workers Compensation Division, which collects worker's compensation service fees.

Mining License Tax

The Mining License Tax (MLT) ranges from 0% to 7% on the net income of all mining operations in the state. With the exception of sand and gravel operations, new mining operations are exempt from the MLT for a period of 3.5 years after production begins.

This forecast uses a bottom-up approach to estimate tax payments for each of the major mines in the state based on expected minerals prices and production. Prices for most minerals have been volatile recently, due to uncertain global demand. Gold prices have been increasing, in part due to global economic uncertainty.

Mining license tax revenues increased from $29.7 million in FY 2010 to $49.0 million in FY 2011. Gold and zinc play the largest role in the increase in the MLT. The Department of Natural Resources estimates in 2010 zinc accounted for 42% and gold accounted for 36% of nonpetroleum mineral value produced in Alaska.

Motor Fuel Tax

The motor fuel tax is imposed on all motor fuel sold, transferred or used within Alaska. Per gallon rates are 8 cents for highway use, 5 cents for marine fuel, 4.7 cents for aviation gasoline, 3.2 cents for jet fuel, and 8 cents or 2 cents for gasohol, depending on the season, location and EPA mandate. Motor fuel taxes are collected primarily from wholesalers and distributors licensed as qualified dealers. Various uses of fuel are exempt from tax, including fuel used for heating or flights to or from a foreign country. All revenue derived from motor fuel taxes is deposited in the General Fund. Sixty percent of the taxes attributable to aviation fuel sales at municipal airports are shared with the respective municipalities and are treated as other restricted revenues.

The forecast of motor fuel tax revenue is based on Energy Information Agency projections for U.S. motor fuel consumption growth in FY 2012 and FY 2013.

Tire Fee

The tire fee has two components. The first component is a tax of $2.50 on all new tires sold in Alaska for motor vehicles intended for highway use. The second component is an additional $5 fee per tire on all new tires with heavy

studs sold in Alaska, and a $5 fee per tire on the installation of heavy studs on a previously un-studded tire.

Forecasted revenue from the tire fee is based on the expected number of vehicle registrations in the state.

Seafood Assessments and Taxes

The Department of Revenue administers five different programs that raise money through seafood assessments and taxes. The rates for these assessments and taxes are determined by a vote of the appropriate association within the seafood industry, by members of the Alaska Seafood Marketing Institute, or by the Department of Revenue. The five programs are:

- The seafood marketing assessment, which applies to all seafood products made or first landed in Alaska and all unprocessed products exported from Alaska.
- The dive fishery management assessment, which is levied on the value of fishery resources taken using dive gear in a designated management area.
- The regional seafood development tax, which is levied on the value of fishery resources in a designated management area.

Figure 5-3. Other Taxes, FY 2011 and Forecasted FY 2012-2013 ($ million)

Unrestricted	History	Forecast	
Excise Tax	FY 2011	FY 2012	FY 2013
Alcoholic Beverage	19.4	19.8	20.4
Tobacco Products – Cigarettes	34.8	33.4	32.4
Tobacco Products – Other (General Fund)	11.7	12.6	13.6
Electric & Telephone Cooperative	0.1	0.1	0.1
Insurance Premium	49.6	49.9	50.1
Motor Fuel Tax	39.5	37.6	37.8
Tire Fee	1.5	1.4	1.5
Vehicle Rental	8.3	8.4	8.6
Subtotal	**164.9**	**163.2**	**164.5**
Corporate Income Tax (non oil and gas)	**157.7**	**149.7**	**152.5**
Fish Tax			
Fisheries Business	20.1	18.6	18.6
Fishery Resource Landing	2.7	5.8	5.8
Subtotal	**22.8**	**24.4**	**24.4**
Other Tax			
Charitable Gaming	2.5	2.4	2.5
Estate	0.0	0.0	0.0
Large Passenger Vessel Gambling	5.8	5.8	5.8
Mining License	49.0	43.0	48.4
Subtotal	**57.3**	**51.2**	**56.7**
Total Unrestricted Taxes	**402.7**	**388.5**	**398.1**

Figure 5-3. Continued

Restricted	History	Forecast	
Designated General Fund	FY 2011	FY 2012	FY 2013
Alcoholic Beverage (alcohol & drug treatment)	19.4	19.8	20.4
Tobacco – Cigarettes (tobacco use cessation)	3.4	3.3	3.2
Tobacco – Cigarettes (school fund)	23.2	22.5	21.8
Insurance Premium/Other[1]	6.1	6.0	6.2
Subtotal	**52.1**	**51.6**	**51.6**
Other Restricted			
Cruise Ship Passenger Fee (State Share)	14.1	1.9	1.9
Cruise Ship Passenger Fee (Municipal & Region Share)	9.1	15.3	15.3
Cruise ship Passenger Fee (regional cruise ship impact fund)	8.8	0.0	0.0
Dive Fishery Management Assessment (designated management areas)	0.6	0.6	0.6
Electric and Telephone Cooperative (Municipal Share)	3.8	3.9	4.0
Fisheries Business (Municipal Share)	24.4	23.1	23.1
Fishery Resource Landing (Municipal Share)	4.4	6.9	6.9
Motor Fuel Tax-Aviation (Municipal Share)	0.1	0.2	0.2
Salmon Enhancement (Aquaculture Association Share)	7.9	7.0	7.0
Seafood Development (qualifying regional associations)	2.1	2.1	2.1
Seafood Marketing Assessment (seafood marketing programs)[2]	7.8	9.5	9.5
Settlements to CBRF (non-petroleum taxes)	0.6	0.0	0.0
Subtotal	**83.8**	**70.5**	**70.6**
Total Restricted Taxes	**135.9**	**122.1**	**122.2**
Grand Total	**538.6**	**510.6**	**520.3**

[1] In addition to the worker's compensation insurance premiums for the Insurance Premium Tax, this amount also includes services fees from employers who are self-insured.

[2] FY 2011 Seafood Marketing Assessment was estimated based on preliminary information. Updated figures will be available in the Tax Division's Annual Report and the Spring 2012 revenue forecast.

- The salmon enhancement tax, which is levied on salmon sold or exported from designated aquaculture regions.
- The cost recovery fisheries assessment, a program authorized in 2006. This program allows hatcheries to establish a common property fishery and recoup costs through an assessment on fishery resources taken in the terminal harvest area. So far, no hatcheries have used this program as a funding source. However we expect to see this program utilized in FY 2012.

Revenue received under these assessments is deposited in the General Fund. Funds are treated as other restricted revenue in this forecast because they are set aside for the legislature to appropriate for the benefit of the seafood industry, either in marketing or in management and development of the industry.

The estimated taxable value of Alaska's salmon fishery and historical effective tax rates are used to forecast salmon enhancement tax revenue. Seafood development tax revenue is based on the estimated taxable value of seafood processed in Alaska. Dive fishery taxes are based on the value of the fishery in the prior fiscal year. Seafood assessment taxes are forecasted using estimates of the fisheries business and landing taxes from both the forecasted year and the preceding year.

Tobacco Tax

The tobacco tax is levied on cigarettes and tobacco products sold, imported, or transferred into Alaska. Tobacco taxes are collected primarily from licensed wholesalers and distributors. There are two components to the tobacco tax: the cigarette tax, and the other tobacco products tax.

The tax rate on cigarettes has been $2.00 per pack since July 1, 2007. Of the cigarette tax, $0.76 per pack is deposited into the School Fund, and is considered designated restricted revenue. All cigarette and tobacco products license fees are also deposited in the School Fund. The remainder of the cigarette tax revenue is deposited into the General Fund. Of the General Fund portion, 8.9% is deposited into a subfund of the General Fund, the Tobacco Use Education and Cessation Fund, and is treated as designated restricted revenue.

The forecast for cigarette tax revenue is based on projected average consumption declines of 3% annually.

The tax rate on other tobacco products, such as cigars and chewing tobacco, is 75% of the wholesale price and is deposited entirely in the General Fund. Moderate increases in wholesale prices and consumption will result in revenue from other tobacco products tax continuing to increase at a 10-year average rate of about 8% annually.

Vehicle Rental Tax

Vehicle rental tax is a 10% tax on most passenger vehicle rentals of 90 days or less, and a 3% tax on rentals of recreational vehicles for 90 days or less. The vehicle rental tax provisions became effective January 1, 2004.

Revenue from the vehicle rental tax is expected to increase with the overall rate of inflation.

Charges for Services

The charges for services category includes fees and other program charges for state services. Revenues reported in this category do not include all charges for state services. This category only includes those that do not fit into other categories in this report.

Most of these receipts are considered restricted revenue because they are returned to the program where they were generated. The only unrestricted revenues listed in this category come from charges that do not have program receipt designations, or are not otherwise segregated and appropriated back to a program. Many of the charges for services are small amounts that we have grouped into the broad categories "General Government," "Natural Resources" and "Other." Estimates for these categories are based on fiscal year-to-date collections and historical averages. The largest categories of charges for services are listed separately and are discussed below.

Marine Highway Fund

The Alaska Marine Highway Fund is a subfund of the General Fund and receives revenue from state ferry system operations. The legislature has discretion over how the revenue is allocated. Because revenues are customarily appropriated for Alaska Marine Highway operations, they are considered restricted revenue for this forecast. Revenue projections are based upon revenue expectations provided by the Alaska Marine Highway Division (part of Alaska Department of Transportation).

Commercial Passenger Vessel Fees

Commercial passenger vessel fees paid into the Environmental Compliance Fund come from two sources: Ocean Ranger fees, and environmental compliance fees. All fees paid into the fund are considered restricted for purposes of this forecast and are based on estimated cruise ship passenger levels discussed in the taxes section earlier.

The Ocean Ranger fee is a per-berth fee of $4 that applies to commercial passenger vessels with 250 or more berths. The fee is levied to support the Ocean Ranger program, which provides for independent observers of engineering, sanitation and health practices aboard the vessels. This fee was imposed as

Figure 5-4. Charges for Services, FY 2011 and Forecasted FY 2012-2013
($ million)

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
General Government	9.2	9.0	9.0
Natural Resources	2.1	2.0	2.0
Other	7.2	6.8	6.8
Total Unrestricted	**18.5**	**17.8**	**17.8**
Restricted			
Designated General Fund			
DCCED Business Licenses	7.9	7.9	7.9
Environmental Compliance Fees	0.9	1.0	1.0
General Government - GF Subfunds	6.8	5.0	5.0
Marine Highway Receipts	47.6	54.6	54.8
Natural Resources	0.4	0.5	0.5
Ocean Ranger Fees	3.6	3.4	3.4
Oil and Gas Conservation	4.9	6.3	6.3
RCA Receipts	9.9	10.2	10.2
Receipt Supported Services[1]	114.3	130.0	130.0
Timber Sale Receipts	0.5	0.9	0.9
Subtotal	**196.8**	**219.8**	**220.0**
Other Restricted			
General Government - Special Funds	0.1	0.3	0.3
Statutorily Designated	35.4	62.5	62.5
Subtotal	**35.5**	**62.8**	**62.8**
Total Restricted	**232.3**	**282.6**	**282.8**
Grand Total	**250.8**	**300.4**	**300.6**

[1] Beginning Fall 2011, Test Fisheries receipts are included in the Receipt Supported Services category and are not reported separately.

part of an initiative passed by voters in August 2006, and is covered in more detail in the Taxes section.

Environmental compliance fees are levied on commercial passenger vessels with over 50 berths. Fees range from $75 to $3,750 per vessel based on the number of berths, and funds are used to support environmental compliance programs.

Program Receipts

Under AS 37.05.142 – 37.05.146, receipts from authorized state programs are accounted for separately and appropriated to administer the source program, implement laws related to the program, or cover costs associated with collecting the receipts. Some programs with program receipt authority are not included in our Charges for Services category because they are reported elsewhere in this forecast or because they do not generate revenue available for general appropriation.

Expected revenues from program receipts are based on discussions with the Governor's Office of Management and Budget and analysis of the most recent budget expectations for these categories.

Program receipts listed in this section are:

- Receipt supported services, which include state services such as Pioneers homes and occupational licensing that are funded by program receipts. Some seafood assessments are included in this category.
- Statutorily designated program receipts, which include money received from sources other than the state or federal government and restricted by the terms of a gift, grant, bequest or contract.
- Regulatory Commission of Alaska (RCA) receipts, which are regulatory

Figure 5-5. Fines & Forfeitures, FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
Fines & Forfeitures	7.0	8.7	8.7
Total Unrestricted	**7.0**	**8.7**	**8.7**
Restricted			
Designated General Fund			
Tobacco Settlement (Tobacco Use Education& Cessation Fund)	5.9	5.9	5.8
Other - GF Subfunds	1.0	2.3	2.3
Subtotal	**6.9**	**8.2**	**8.1**
Other Restricted			
Tobacco Settlement (Northern Tobacco Securitization Corporation)	23.6	23.5	23.3
Other - Special Revenue Funds	0.3	0.2	0.2
Subtotal	**23.9**	**23.7**	**23.5**
Total Restricted	**30.8**	**31.9**	**31.6**
Grand Total	**37.8**	**40.6**	**40.3**

cost charges and user fees levied on utilities and pipelines to fund costs of regulation.

- Timber sale receipts, which are used to fund the timber disposal program of the Department of Natural Resources.
- Oil and Gas Conservation Commission receipts, which are fees and charges for regulation of oil and gas wells and pipelines.
- Business license fees collected by the Department of Commerce, Community and Economic Development.

Fines and Forfeitures

Fines and forfeitures include civil and criminal fines and forfeitures and money received by the state from the settlement of civil lawsuits. The largest single source of receipts under this category is the multi-state tobacco settlement often referred to as the MSA. Other sources are forecast based on fiscal year-to-date collections and historical averages.

Tobacco Settlement

The tobacco Master Settlement Agreement (MSA) was signed by 46 states (including Alaska) in November 1998 and dictates annual payments to each of the states. Eighty percent of the settlement revenue is earmarked for the Northern Tobacco Securitization Corporation for payments on bonds that were sold based on the future revenue stream. The revenue for these bonds is considered other restricted revenue. The remaining 20% of the revenue is deposited into the Tobacco Use Education and Cessation Fund, a subfund of the General Fund. Tobacco Use Education and Cessation Fund revenues are considered designated restricted revenues.

Tobacco settlement payments are based on a complex formula that takes into account several factors including declines in cigarette consumption, inflation and certain adjustments for litigation expenses and market share losses related to the settlement.

Licenses and Permits

Licenses and permits represent revenues derived from charges for participating in activities regulated by the state. The majority of the receipts under this category are from motor vehicle registration and fishing and hunting license fees. Several other small license and permit fees are summarized in the Other Fees category. Alcoholic beverage license fees are forecast separately.

Alcoholic Beverage Licenses

Alcoholic beverage licenses are required to manufacture or sell alcoholic beverages in Alaska. Licenses are issued by the

Alcoholic Beverage Control Board and revenue is deposited into the General Fund. All of the revenue from biennial license fees collected within municipalities, excluding annual wholesale fees and biennial wholesale license fees, is shared with the municipalities and treated as other restricted revenues for purposes of this forecast. We expect little change in revenue because the issuance of alcoholic beverage licenses is limited based on population.

Fishing and Hunting License Fees

Fishing and hunting licenses are issued by the Alaska Department of Fish and Game for participation in various fishing, hunting and related activities. The majority of these revenues are appropriated to a special revenue fund called the Fish and Game Fund and are classified as other restricted revenues. Money in the fund can only be spent for fish and game management purposes. Future revenue from fishing and hunting license fees is provided by the Alaska Department of Fish and Game.

Motor Vehicle Registration Fees

Motor vehicle registration fees are collected by the Division of Motor Vehicles within the Department of Administration. Most fees are considered unrestricted license and permit revenue; however, some registration fees are considered restricted receipt supported services and are reflected in the Charges for Services section. Revenue from motor vehicle registration fees is based on data provided by the Division of Motor Vehicles.

Rents and Royalties

Rents and royalties from sources other than oil and gas fall into two categories: mining rents and royalties, and other non-petroleum rents and royalties.

All rents and royalties from oil and gas are reported in the Oil Revenue section.

Mining Rents and Royalites

As with oil and gas production, the state earns revenue from other minerals production that occurs on state lands leased for exploration and development. As the landowner, the state earns revenue from

Figure 5-6. Licenses & Permits, FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
Alcoholic Beverage Licenses	1.0	1.0	1.0
Motor Vehicles	38.9	39.7	38.6
Other Fees	2.9	1.9	1.9
Total Unrestricted	**42.8**	**42.6**	**41.5**
Restricted			
Designated General Fund			
Other Fees - GF Subfunds	0.1	0.1	0.1
Subtotal	**0.1**	**0.1**	**0.1**
Other Restricted			
Alcoholic Beverage License Share	0.8	0.9	0.9
Hunting and Fishing Fees (Fish & Game Fund)	26.0	26.3	26.3
Other Fees - Special Revenue Funds	3.6	4.0	4.0
Subtotal	**30.4**	**31.2**	**31.2**
Total Restricted	**30.5**	**31.3**	**31.3**
Grand Total	**73.3**	**73.9**	**72.8**

leases as: (1) upfront bonuses, (2) annual rent charges, and (3) as a retained royalty interest in minerals production.

Revenue received in this area is from mining rents and royalties is deposited as follows: 49.5% into the General Fund, 50% into the Permanent Fund and the remaining 0.5% into the School Fund. The Permanent Fund and School Fund portions are treated as other restricted revenue.

Future revenues from mining rents and royalties are based on expected changes in minerals prices and mine-specific forecasts for large mines on state land.

Other Non-Petroleum Rents and Royalties

The state receives revenue from the leasing, rental, and sale of state land. While all of these revenues are deposited into the General Fund, some are deposited into sub funds of the General Fund and are treated as designated restricted revenues for purposes of this forecast. This category includes revenues from leasing, rental, and sale of state land that do not fall into the oil and gas or mining royalty categories. Other non-petroleum rents and royalties are based on analysis of fiscal year-to-date and historical collections.

Figure 5-7. Rents & Royalties, FY 2011 and Forecasted FY 2012-2013
($ million)

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
Mining Rents and Royalties	9.0	9.2	9.4
Other Non-Petroleum Rents and Royalties	8.6	7.7	7.7
Total Unrestricted	**17.6**	**16.9**	**17.1**
Restricted			
Designated General Fund			
Other Non-Petroleum Rents and Royalties	4.0	4.4	4.5
Subtotal	**4.0**	**4.4**	**4.5**
Other Restricted			
Mining Rents and Royalties	6.3	6.5	6.7
Subtotal	**6.3**	**6.5**	**6.7**
Total Restricted	**10.3**	**10.9**	**11.2**
Grand Total	**27.9**	**27.8**	**28.3**

Other

This category includes unclaimed property transfers, transfers to the state from component organizations, and miscellaneous revenues. Projections of miscellaneous revenues, which include contributions to the state and other revenues, are based on analysis of fiscal year-to-date and historical collections. Unclaimed property and transfers from component organizations are discussed below.

Unclaimed Property

Alaska's unclaimed property statutes require businesses and corporations to report unclaimed intangible property to the state. Property is reportable if an owner cannot be located, the owner has not cashed a property check, or an account has not had any owner-initiated activity for at least three years. Unclaimed property may include checking accounts, customer deposits and over-payments, gift certificates, unpaid wages, and security related accounts. The state holds the property in trust until the owner or his or her legal heir claims it. Each year the unclaimed property trust account is evaluated and the excess of the working trust balance is transferred to the General Fund.

Transfers from Component Organizations

Each year, the state receives money in the form of transfers from component organizations, such as the Alaska Housing Finance Corporation, frequently in the form of dividends. Component organizations are covered in more detail in the Public Corporations & the University of Alaska section. Some component organizations do not make transfers to the state and, as a result, not all component organizations are listed here.

Actual transfers for FY 2011 are reflected in draft tables from the Comprehen-

sive Annual Financial Report. Forecasts for FY 2012 and FY 2013 transfers are based on discussions with the Governor's Office of Management and Budget, and analysis of the most recent budget expectations for these categories.

Transfers from component organizations presented under this category may differ from those presented in the Public Corporations & University of Alaska section for two reasons: (1) amounts in this section account differently for funds paid over time for multi-year capital projects; and (2) amounts in this section include funds that are transferred to the state and then appropriated to the component unit for operations.

Figure 5-8. Other Revenue, FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
Miscellaneous	18.7	14.1	14.1
Alaska Housing Finance Corporation	14.3	17.0	16.5
Alaska Industrial Development & Export Authority	0.0	25.4	20.4
Alaska Municipal Bond Bank Authority	0.0	0.9	0.9
Alaska Student Loan Corporation	2.5	0.0	0.0
Alaska Energy Authority	0.0	0.0	0.0
Mental Health Trust	0.1	0.0	0.0
Unclaimed Property	3.5	3.8	4.0
Total Unrestricted	**39.1**	**61.2**	**55.9**
Restricted			
Designated General Fund			
Miscellaneous - GF Subfunds[1]	22.7	23.8	23.8
Subtotal	**22.7**	**23.8**	**23.8**
Other Restricted			
Miscellaneous - Special Revenue Funds[1]	11.1	8.4	8.4
Subtotal	**11.1**	**8.4**	**8.4**
Total Restricted	**33.8**	**32.2**	**32.2**
Grand Total	**72.9**	**93.4**	**88.1**

[1] Revenue shown under account codes for "other" or "contributions" in the Alaska State Accounting System for General Fund subfunds and special revenue funds.

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2011

6. Federal Revenue

Figure 6-1. FY 2011 Federal Revenue: $2.4 billion

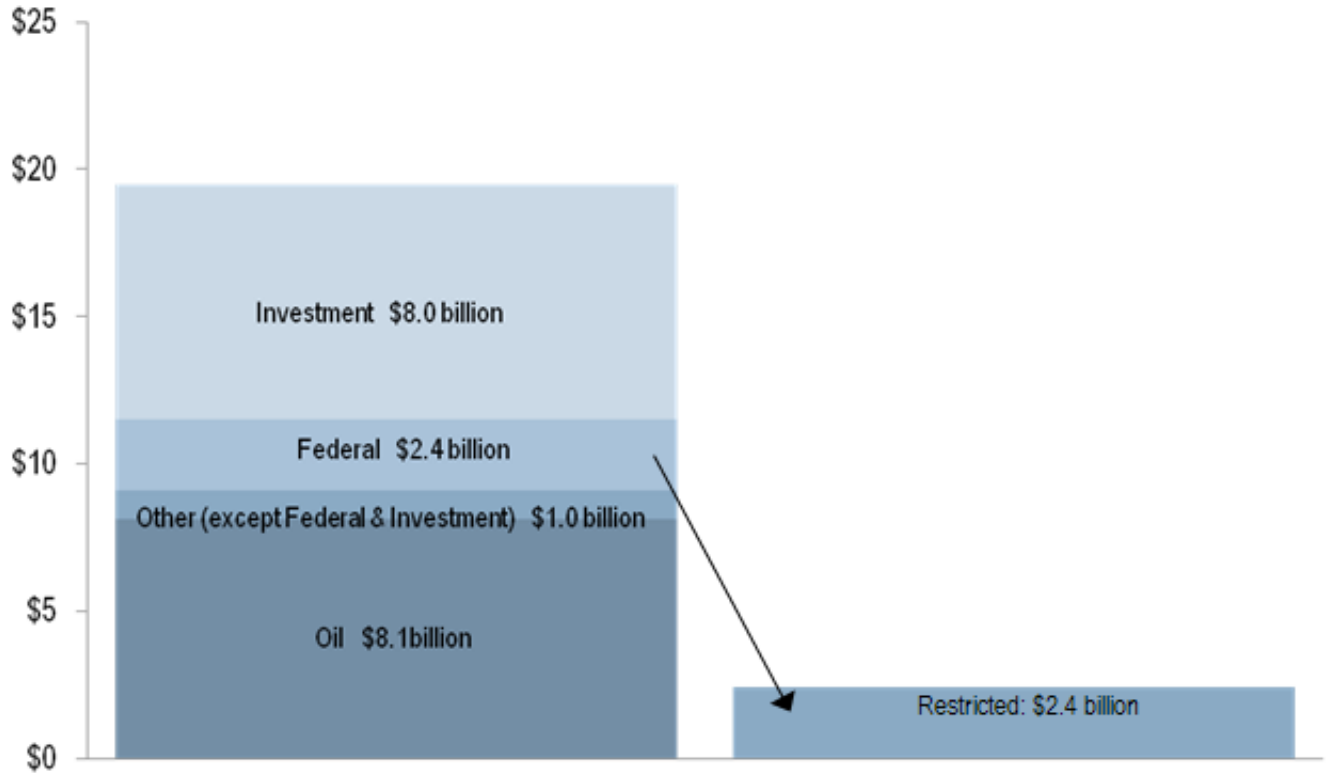


Figure 6-2. Total Federal Revenue to the State, FY 2011 and Forecasted FY 2012-2013 ($ million)[1]

	History	Forecast	
Unrestricted General Fund	FY 2011	FY 2012	FY 2013
Federal Receipts	0.0	0.0	0.0
Restricted (Federal)			
Federal Receipts	2,407.9	3,102.5	3,102.5
Grand Total	**2,407.9**	**3,102.5**	**3,102.5**

[1] This amount includes federal receipts other than Alaska's share of NPR-A oil royalties, which are presented in Chapter 2.

General Discussion

The federal government continues to play a significant role in Alaska's economy. In Federal Fiscal Year (FFY) 2010 the federal government spent $12.6 billion in total direct expenditures in Alaska.[2] This was a 6% increase from FFY 2009 when the federal government spent a reported $11.9 billion in Alaska.[3] The $0.7 billion increase in federal spending in Alaska was primarily due to higher outlays for salaries and wages, which offset a decline in grant and procurement spending.

Alaska is often first in per capita federal spending, and that was the case in FFY 2010 as the federal government spent close to $18,000 dollars per Alaskan. The Department of Defense is a major reason why federal spending in Alaska ranks among the top states. The Defense Department spent more in Alaska, on a per capita basis, in FFY 2010 than any other state except Hawaii. The Department of Health and Human Services also makes up a sizable share of federal spending in Alaska. Together, these two departments account for over 50 percent of all federal direct expenditures in the state.

Federal expenditures in Alaska come in the form of direct payments for retirement and disability benefits, other direct payments, grants, procurement and salaries and wages. Salaries and wages is the largest of these categories, making up almost a third of total federal government expenditures. Retirement and disability payments and other direct payments are 21% of federal government spending. Grants and procurement payments represent 27% and 20%, resepectively of expenditures by the federal government in Alaska.

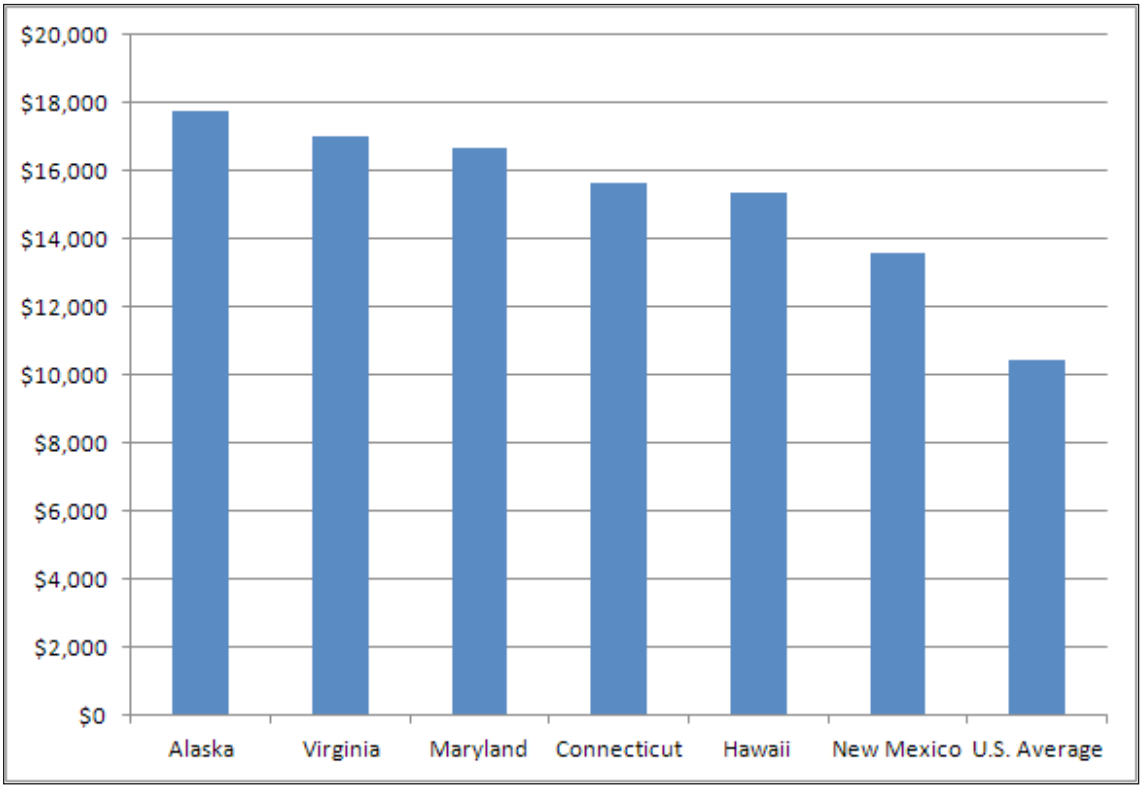
In FY 2011, the State of Alaska received and spent over $2.4 billion in federal funds. This federal funding is generally restricted to specific uses such as road improvements, Medicaid payments, and aid to schools. Potential changes to federal law, differing federal and state fiscal years, and varying numbers of eligible Alaskans in certain programs make forecasting federal revenue difficult. The estimates for FY 2012 and FY 2013 are from the Office of Management and Budget and are based on state agency projections of potential federal revenues.

For FY 2012, the state was budgeted to receive more than $3.1 billion in fed-

[2] U.S. Census Bureau Consolidated Federal Funds Report for FY 2010, U.S. Department of Commerce, Washington, D.C. 20233, http://www.census.gov/prod/2011pubs/cffr-10.pdf

[3] In the Fall 2010 Revenue Sources Book, it was reported that total federal government expenditures were $14.2 billion. Due to a methodology change, the Census Borough has revised this number to $11.2 billion.

Figure 6-3. FFY 2010 Federal Spending per Capita, Top Six States and U.S. Average



eral receipts. The American Recovery and Reinvestment Act (ARRA), which played an important role in the overall level of federal funding in the FY 2011 state budget, will have a much smaller impact in FY 2012. ARRA represented approximately $280 million (12%) of all federal funds in FY 2011. In FY 2012, only $57 million or about 2% of all federal funds is expected to come as a result of the Act.

Most federal funding requires state-matching money. The budgeted state match, and the top three budgeted categories for federal spending in Alaska for FY 2012 and FY 2013 are included in Figure 6-5.

It is important to note that the state routinely budgets for federal funds in excess of expected allotments. The legislature authorizes state agencies to receive and spend the maximum that federally funded programs might receive, while the actual appropriation amounts are generally less. In addition, some of the funding granted for multi-year capital projects is received and spent in years following the one in which the money is procured. All federal funds, whether spent in the operating or capital budget, are restricted by legislative appropriation to specific uses.

Figure 6-4. Total Federal Spending in Alaska, FFY 2010

By Distributing Agency

	$ Million	Percent
Defense	5,211.4	41%
Health & Human Services	1,660.7	13%
Social Security	1,062.3	8%
Other Agencies	4,681.0	37%
Total	**12,615.3**	**100%**

By Appropriation Category

	$ Million	Percent
Grants	3,465.2	27%
Salaries & Wages	4,055.1	32%
Procurement	2,464.3	20%
Retirement & Disability	1,590.7	13%
Other Direct Payments	1,040.0	8%
Total	**12,615.3**	**100%**

Figure 6-5. Federal Spending and State Match Requirement, FY 2011 and Budgeted FY 2012-2013 ($ million)

	History FY 2011	Budgeted FY 2012	Budgeted FY 2013
State Match Requirement			
Operating Budget	477.8	518.9	518.9
Capital Budget	64.7	79.0	79.0
Total	**542.5**	**597.9**	**597.9**
Top Spending Categories			
Transportation Projects	896.8	871.2	871.2
Medicaid	933.5	872.7	872.7
Education (K-12, University of Alaska)	382.9	453.4	453.4
Total	**2,213.1**	**2,197.2**	**2,197.2**

7. Investment Revenue

Figure 7-1. FY 2011 Net Investment Revenue: $8.0 billion

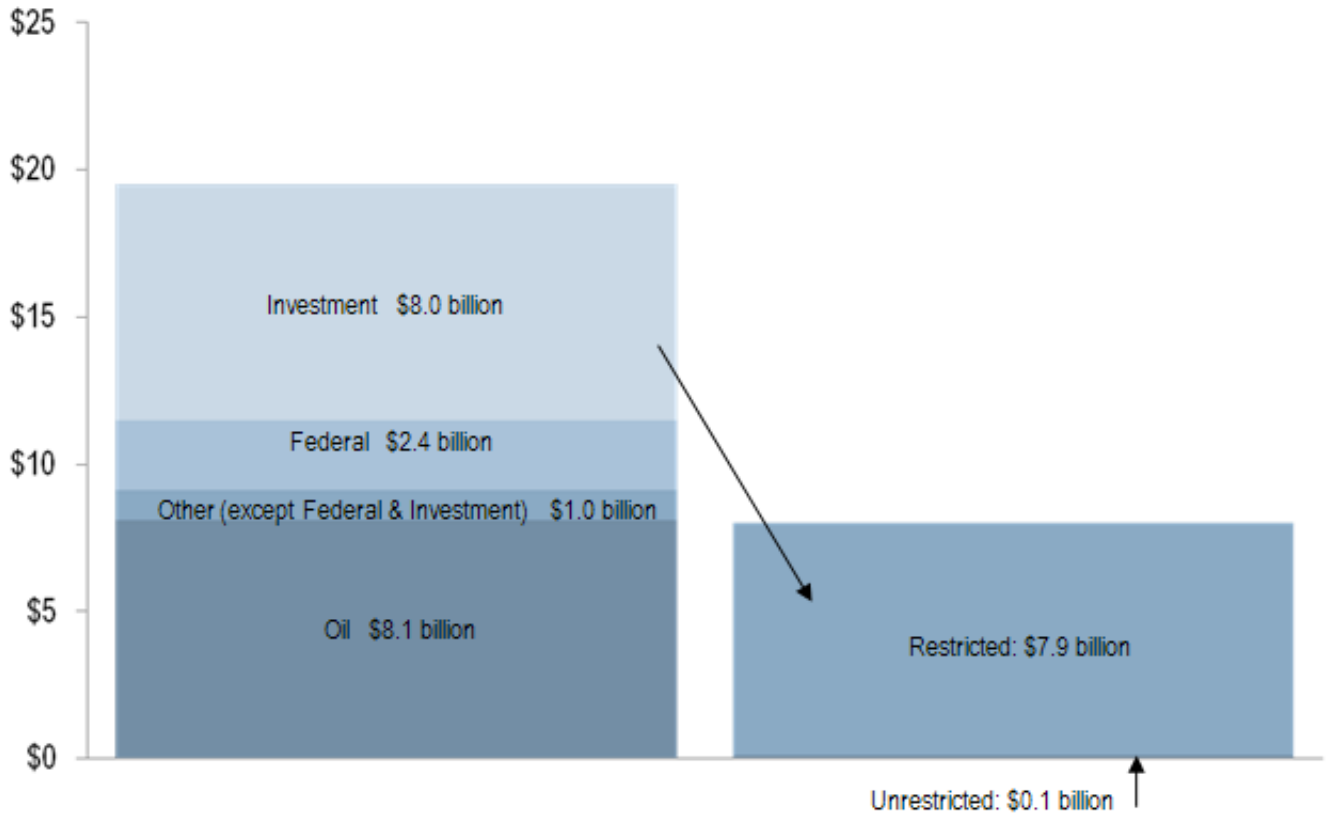


Figure 7-2. Total Investment Revenue, FY 2011 and Forecasted FY 2012-2013 ($ million) [1]

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
Investments	93.2	174.5	180.2
Interest Paid by Others	3.1	2.4	2.4
Total Unrestricted	**96.3**	**176.9**	**182.6**
Restricted			
Designated General Fund			
Investments - Designated GF	8.6	14.4	15.1
Other Treasury Managed Funds	63.8	(2.0)	26.7
Subtotal	**72.4**	**12.4**	**41.8**
Other Restricted			
Investments - Other Restricted	17.4	29.2	30.6
Constitutional Budget Reserve Fund	1,026.9	20.0	538.7
Alaska Permanent Fund	6,811.8	2,942.6	3,176.7
Subtotal	**7,856.1**	**2,991.8**	**3,746.0**
Subtotal Restricted	**7,928.6**	**3,004.3**	**3,787.8**
Total	**8,024.9**	**3,181.2**	**3,970.4**

[1] Governmental Accounting Standards Board (GASB) principles require the recognition of changes in the value of investments as income or losses at the end of each trading day, whether the investment is actually sold or not.

Investment Forecast

To forecast investment revenue for the current fiscal year, we combine actual performance through September 30, 2011, with a projection for the remainder of the year. Forecasts and estimated capital market median returns are based on information supplied by the state's investment consultant, Callan Associates Inc., and their 5-year capital market estimated returns.

Unrestricted Investment Revenue

Unrestricted investment revenue is earned on the General Fund non-segregated investments managed by the Treasury Division. Interest Paid by Others is interest received by the state other than on its investments. Oil and gas royalty interest, production tax interest, and corporate income tax interest are included in the Oil Revenue section of this forecast.

Restricted Investment Revenue

Restricted investment revenue consists of earnings from governmental funds, the Constitutional Budget Reserve Fund (CBRF), other Treasury-managed governmental funds, and the Alaska Permanent Fund.

Figure 7-3. Callan Associates Inc.'s 5-year Capital Market Estimated Returns, as of October 31, 2011

Asset Class	Benchmark for Asset Class	%/Year Median Expected Return	%/Year Expected Risk[1]
Equities			
Broad Domestic Equity	Russell 3000 Index	8.00%	18.12%
ACWI ex-US	MSCI ACWI ex-U.S.	8.20%	20.87%
Fixed Income			
Broad Market Fixed-Income	Barclays Aggregate	3.75%	4.50%
High Yield	CSFB High Yield	5.60%	11.55%
Intermediate Treasury	Barclays Intermediate Treasury	3.55%	4.20%
U.S. TIPS	Barclays U.S. TIPS	3.50%	5.90%
Government 1-5	Barclays Gov't 1-5 Year	3.45%	3.50%
Non-U.S. Fixed	Citi Non-U.S. Gov't	3.35%	9.70%
Other			
Private Equity	VE Post Venture Cap	9.05%	30.00%
Absolute Return	Callan Hedge FoF	5.90%	10.00%
Real Estate	Callan Real Estate	6.75%	16.35%
Cash Equivalents	3 Month T-Bill	3.00%	0.90%
Inflation	CPI-U	2.50%	1.40%

[1] The continued volatility in the world's financial markets makes focus on the "Expected Risk" column (far right in the table above) particularly appropriate. The numbers in the Expected Risk column represent a statistical measure called standard deviation, which is the most commonly used measure of risk in the investment world. The standard deviation is a measure of the dispersion of data around its mean. The analyst can use this measure of dispersion to provide a range of possible outcomes at any desired level of confidence. In the data on this table, the level of confidence is set at 67% or one standard deviation. A higher level of confidence would require a broader range. For example, Callan estimates an average annual return for the Intermediate Treasury asset class of 3.55% and an expected risk for that asset class of 4.20%. That means Callan is forecasting that two-thirds of the time the annual return for the domestic broad fixed-income asset class will fall between -0.65% (the median expected average annual return of 3.55% minus the expected risk of 4.20%) and 7.75% (the median expected return plus the expected risk). A prediction at 95% confidence would run from -4.20% to 11.30%, too broad a range to be useful. The probability that a particular asset class or portfolio will have a negative return over a given period of time is another way to reflect the riskiness of that asset class or portfolio.

Figure 7-4. Investment Revenue Summary, FY 2011 and Forecasted FY 2012-2013 ($ million)

Asset Allocation

Treasury Pool	Percent Allocation	Performance Benchmark
Short-term, Fixed-Income Pool	53%	Three-Month U.S. Treasury Bill
Intermediate-Term, Fixed-Income Pool	47%	Bank of America 1- to 5-Year Government Index
Alaska Student Loan Corporation Note	0%	

Investment Balance September 30, 2011	$8,656.6
Projected Annual Rate of Return	3.21%
Probability of Negative Return Over 1 Year	4.05%

Actual Total Investment Income, FY 2010	220.1
Actual Total Investment Income, FY 2011	119.2
Projected Total Investment Income, FY 2012	218.1

	History	Forecast	
	FY 2011	FY 2012	FY 2013
Investment Revenue Unrestricted	93.2	174.5	180.2
Investment Revenue Restricted- Designated GF[(1)]	8.6	14.4	15.1
Investment Revenue Restricted - Other	17.4	29.2	30.6
Total	**119.2**	**218.1**	**225.9**

[(1)] Includes subfunds of the General Fund.

Figure 7-5. Constitutional Budget Reserve Fund Cash Flows Investment Revenue Summary, FY 2011 and Forecasted FY 2012-2013 ($ million)

Asset Allocation Regular Account

Treasury Pool	Percent Allocation	Performance Benchmark
Short-term, Fixed-income pool	19%	Three-Month U.S. Treasury Bill
Intermediate-term, Fixed-income Pool	61%	Bank of America 1- to 5-Year Government Index
Broad Market Fixed-income Pool	20%	Barclays US Aggregate

Regular Balance September 30, 2011	$5,257.9
Projected Annual Rate of Return	3.40%
Probability of Negative Return Over 1 Year	12.39%

Asset Allocation Special Subaccount

Treasury Pool	Percent Allocation	Performance Benchmark
Broad Market Fixed Income Pool	41%	Barclays US Aggregate
Domestic Equity Pool	27%	Russell 3000 Index
International Equity Pool	32%	MSCI EAFE Index

Special Subaccount Balance September 30, 2011	$4,723.8
Projected Annual Rate of Return	6.85%
Probability of Negative Return Over 1 Year	24.95%

Total Investment Income	History	Forecast	
	FY 2011	FY 2012	FY 2013
Regular Account	125.9	213.7	187.2
Special Subaccount	901.0	(193.7)	351.5
Total	**1,026.9**	**20.0**	**538.7**

Figure 7-6. Constitutional Budget Reserve Fund Cash Flows, FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
	FY 2011	FY 2012	FY 2013
Beginning Cash Balance CBRF	8,663.9	10,330.0	10,381.0
Beginning Main Account Balance	4,398.9	5,164.0	5,408.7
Earnings on Main Account Balance [1]	125.9	213.7	187.2
Petroleum Tax, Royalty Settlements [2][3]	237.6	31.0	20.0
(Loan to GF)/Repayment to CBRF	401.6	0.0	0.0
Draw from/to GF	0.0	0.0	0.0
Ending Main Account Balance	**5,164.0**	**5,408.7**	**5,615.9**
Beginning Special Subaccount Balance	4,265.0	5,166.0	4,972.3
Earnings on Special Subaccount Balance [1]	901.0	(193.7)	351.5
Transfer from Main Account	0.0	0.0	0.0
Ending Special Subaccount Balance	**5,166.0**	**4,972.3**	**5,323.8**
Total CBRF Balance	**10,330.0**	**10,381.0**	**10,939.7**

[1] The earnings estimate for the main account is 3.40% and the earnings estimate for the special subaccount is 6.85%. These projections are based on 2011 Callan's capital market assumptions and Department of Revenue, Treasury Division's asset allocation.

[2] The petroleum tax, royalty settlements number on this sheet is shown on a cash basis. Please note the state accounting system numbers presented elsewhere in this book include accruals and therefore may differ from the numbers presented here.

[3] Settlement estimates are provided by the Department of Revenue and Department of Law, net of annual Federal Minerals Management Service payments.

Figure 7-7. Public School Trust Investment Revenue Summary, FY 2011 and Forecasted FY 2012-2013 ($ million)

Asset Allocation

Treasury Pool	Percent Allocation	Performance Benchmark
Broad Market Fixed-Income Pool	54%	Barclays US Aggregate
Domestic Equity Pool	46%	Russell 3000 Index

Public School Fund Balance September 30, 2011	$420.8
Projected Annual Rate of Return	6.36%
Probability of Negative Return Over 1 Year	23.30%

Total Investment Income & Distributable Income ($ million)

	History	Forecast	
Unrestricted	FY 2011	FY 2012	FY 2013
Public School Trust Total Investment Income	62.0	(2.0)	26.7
Public School Trust Distributable Income	10.2	11.6	13.4

Figure 7-8. Alaska Children's Trust Investment Revenue Summary, FY 2011 ($ million)

Asset Allocation

Alaska Children's Fund Balance September 30, 2011*	$7.99

Total Investment Income & Distributable Income ($ million)

	History
Unrestricted	FY 2011
Alaska Children's Trust Total Investment Income	1.84
Alaska Children's Trust Distributable Income	To Grant Acct[(1)]

[(1)] With the appropriation outlined below, the unexpended and unobligated balance was moved at the beginning of FY2012 into the grant account. A small residual of cash remains in the trust, and is in the process of being transferred to the grant account.

FY12:
Per the FY12 Capital Budget, SB46, Chapter 5, FSSLA 11:
Sec. 16. ALASKA CHILDREN'S TRUST. The unexpended and unobligated balance on July 1, 2011, estimated to be $7,800,000, of the Alaska children's trust (AS 37.14.200) is appropriated from the Alaska children's trust (AS 37.14.200) to the Alaska children's trust grant account (AS 37.14.205) for payment as a grant to the Alaska Community Foundation for Friends of the Alaska Children's Trust to aid in the prevention of child abuse and neglect, for the fiscal years ending June 30, 2012, June 30, 2013, and June 30, 2014.

Figure 7-9. Alaska Permanent Fund Managed by the Alaska Permanent Fund Corporation, FY 2011 and Forecasted FY 2012-2013 ($ million)

	History	Forecast	
Nonspendable Assets — Principal	FY 2011	FY 2012[1]	FY 2013
Total Nonspendable Assets – Beginning Balance	**32,045.0**	**37,832.4**	**40,378.9**
Contributions & Appropriations			
Contributions & Appropriations – Beginning Balance	31,624.1	33,044.3	34,811.8
Dedicated Petroleum Revenue	887.0	918.5	864.4
Inflation Proofing Transfer from Realized Earnings	533.2	849.1	891.9
Subtotal Contributions & Appropriations	**33,044.3**	**34,811.8**	**36,568.2**
Unrealized Appreciation/Depreciation			
Appreciation/Depreciation – Beginning Balance	420.9	4,788.1	5,567.1
Annual Unrealized Gain/Loss	4,367.2	779.0	800.4
Subtotal Unrealized Appreciation/Depreciation	4,788.1	5,567.1	6,367.5
Total Nonspendable Assets – Ending Balance	**37,832.4**	**40,378.9**	**42,935.7**
Assigned Assets — Realized Earnings Account			
Total Assigned assets - beginning balance	1,209.8	2,307.8	2,946.9
Realized Earnings Account			
Realized Earnings Account – Beginning Balance	1,193.9	2015.7	2540.6
Annual Realized Earnings	2,168.4	2049.4	2214.0
Dividend Payment to State of Alaska [2]	(800.6)	(653.0)	(575.0)
Inflation Proofing Transfer to Reserved Assets	(533.2)	(849.1)	(891.9)
Other Appropriations Out of Fund	(12.8)	(22.5)	(22.5)
Realized Earnings Account – Ending Balance	2,015.7	2,540.6	3,265.2
Unrealized appreciation/depreciation [3]			
Appreciation/depreciation - beginning balance	15.9	292.1	406.3
Annual unrealized gain/loss	276.2	114.2	162.3
Sub total - unrealized appreciation/depreciation	292.1	406.3	568.6
Total Assigned Assets – Ending Balance	**2,307.8**	**2,946.9**	**3,833.7**
Market Value – Total Fund Invested Assets Value			
Nonspendable Fund Balance - end of year	37,832.4	40,378.9	42,935.7
Assigned Fund Balance - end of year	2,307.8	2,946.9	3,833.7
Fund Balance (market value) End-of-year Balance	**40,140.2**	**43,325.8**	**46,769.4**
Total Reported Earnings			
Annual Unrealized Gain/Loss	4,643.4	893.2	962.7
Annual Realized Earnings	2,168.4	2,049.4	2,214.0
Reported Earnings	**6,811.8**	**2,942.6**	**3,176.7**

[1]FY2012-13 data projected using Callan 2011 capital market assumptions and current asset allocation policy, resulting in a 7.50% median expected total return, a 5.30% realized rate of return, and an inflation rate of 2.50%.

[2] The permanent fund dividend payment is recorded as a liability at fiscal year end, and is paid out the following month.

[3] Beginning in FY2009, and applied retroactively, Department of Law opinion required an allocation of unrealized gains and losses to the assigned fund balance of the Fund.

8. State Endowment Funds

This section compares important attributes of six endowment funds. The University of Alaska endowment is included in this comparison because it is one of Alaska's public endowment funds that uses the annual distribution calculation method typical of the vast majority of endowments in the United States and Canada.[1]

The fiduciary for each of these endowment funds has the responsibility for establishing an asset-allocation policy for the fund. Figure 8-1 on the next page compares the asset-allocation policies for these endowments.

Under the standards adopted by the Governmental Accounting Standards Board (GASB), public funds calculate and report their income by recognizing changes in the value of securities as income, or losses, as they occur at the end of each trading day. They do this regardless of whether the securities are actually sold, and the income, or losses, are taken or realized. All six of these endowments report annual income on this basis. However, as reflected in Figure 8-2 on the next page, four of them use other measures of annual income for determining their distributions. These include the Alaska Permanent Fund, and the Mental Health Trust Fund, both administered by the Alaska Permanent Fund Corporation, the Public School Trust, and the Alaska Children's Trust.

In determining the amount of income available for distribution each year for the two funds managed by the Alaska Permanent Fund Corporation, gains or losses on individual investments are not recognized until the investment is sold. For calculating distributable income for the Public School Trust, only interest earned and dividends received are treated as income. Gains and losses in the value of individual investments are never recognized as income. By law, those gains and losses remain with the principal of the fund. Figure 8-3 explains how distributable income for each of the endowments is determined.

[1] The predominant practice, making annual distributions of 4% to 5% of the market value of the endowment, developed following a 1968 Ford Foundation study. See The Ford Foundation Managing Educational Endowments (New York, New York; 1968).

Figure 8-1. Target Percent Asset Allocation—State Endowment Funds*

	Cash	U.S. Bonds	International Bonds	U.S. Equities	International Equities	Global Equities	Real Estate	Alternative Investments	Total
Alaska Permanent Fund	2	16	8	16	8	13	12	25	100
Mental Health Trust	2	16	8	16	8	13	12	25	100
Public School Trust	0	54	0	46	0	0	0	0	100
Alaska Children's Trust	0	25	0	60	15	0	0	0	100
Power Cost Equalization	0	33	0	44	23	0	0	0	100
University of Alaska Endowment	3	20	0	17	0	30	5	25	100

Risk Based	Cash	Interest Rate Class	Company Exposure	Real Assets	Special Opportunities
Alaska Permanent Fund	2	6	55	19	18
Mental Health Trust	2	6	55	19	18

*In 2009, the Board of Trustees for the Alaska Permanent Fund Corporation elected to move to a new asset allocation grouping based on risk and return profiles. The Alaska Permanent Fund and Mental Health Trust funds are broken out above using both the traditional asset allocation and the new risk-based asset allocation. For more information please see the Alaska Permanent Fund Corporation Website: http://www.apfc.org/home/Content/investments/assetAllocation2009.cfm

Figure 8-2. Calculation of Annual Income—State Endowment Funds

	Financial Reporting of Income	Distributable Income
Alaska Permanent Fund	GASB (recognize gains and losses based on change in market value)	Interest earnings + dividends paid + gains and losses on investments actually sold
Mental Health Trust	GASB (recognize gains and losses based on change in market value)	Interest earnings + dividends paid + gains and losses on investments actually sold
Public School Trust	GASB (recognize gains and losses based on change in market value)	Interest earnings + dividends paid; gains and losses on value of securities are never income, they become part of principal
Power Cost Equalization Endowment	GASB (recognize gains and losses based on change in market value)	GASB (recognize gains and losses based on change in market value)
University of Alaska Endowment	GASB (recognize gains and losses based on change in market value)	GASB (recognize gains and losses based on change in market value)

Figure 8-3. Distributable Income Determination—State Endowment Funds

Alaska Permanent Fund
The annual distribution for the Permanent Fund Dividend follows the formula in AS 37.13.140-.145, which specifies that 10.5% of the past five years' total realized income shall be paid out as dividends but also sets the limitation that the annual distribution may never exceed 50% of the balance in the fund's Realized Earning Account (REA). The 50% limitation has never been triggered.

Mental Health Trust
Current statute requires net income earned on the cash principal of the fund to be calculated by the Alaska Permanent Fund Corporation in the same manner used to determine the net income of the Alaska Permanent Fund. Accumulated undistributed earnings in one year are available for distribution in subsequent years. Aside from the statutory limits on income distribution, the Mental Health Trust Board has established an asset management policy that limits actual distributions in any given year to 4.25% of the four year moving average of total fund ending net assets plus certain adjustments including interest earned on the budget reserve account, and income earned on land assets as well as lapsing appropriations back to the fund.

Public School Trust
The annual distribution is 4.75% of a five-year moving average of the Trust's principal market value so long as that amount does not exceed the interest and dividend earnings available in the earnings account. The Trust has accumulated a sizable earnings account balance, providing a cushion for the fund to maintain its annual distributions in a sustained bear market.

Alaska Children's Trust
Per the FY12 Capital Budget, SB46, Chapter 5, FSSLA11, Sec. 16, the unexpended and unobligated balance on July 1, 2011 of the Alaska Children's Trust (ACT) (AS 37.14.200) was appropriated from the ACT to the Alaska Children's Trust grant account (AS 37.14.205) for payment as a grant to the Alaska Community Foundation for Friends of the ACT to aid in the prevention of child abuse and neglect, for the fiscal years ending June 30, 2012, June 30, 2013, and June 30, 2014.

Power Cost Equalization Endowment
The annual distribution is 7% of the fund's market value. For the initial transition years, state statute specifies that the fund shall use the market value on February 1 for the subsequent fiscal year's distribution. Thereafter, the fund is to distribute each year 7% of the monthly average market value for a specified 36-month period.

University of Alaska Endowment
The annual distribution is 4.5% of a 5-year moving average of the market value of the fund.

Figure 8-4. Inflation-Proofing Procedures—State Endowment Funds

Alaska Permanent Fund

An annual appropriation is needed to "inflation proof" the principal of the Permanent Fund (but not the accumulated earnings) pursuant to AS 37.13.145. The legislative appropriation requires a transfer from the Realized Earnings Account to the fund's principal an amount equal to the calculated U.S. Consumer Price Index's effect on the value of the principal, comprised of oil and gas royalty contributions and legislative appropriations. The Alaska Permanent Fund Corporation's Trustees have proposed a constitutional amendment that would inflation proof the entire fund—the principal and accumulated earnings—by limiting the annual distribution of earnings to 5% of a five-year moving average of the market value of the fund.

Mental Health Trust

The asset management policy adopted by the Board of Trustees currently limits distributions of accumulated earnings on the fund to a percentage of total net assets that is periodically reviewed for sufficiency. To the extent retained investment earnings exceed distributions, total fund balance grows accordingly. The authority also has adopted a policy transferring funds from the reserve account to principal whenever the reserve account exceeds four times the annual distribution.

Public School Trust

The asset-allocation policy is such that—when combined with the requirement that the fund's capital gains and losses remain part of the principal—the retained capital gains are adequate to inflation proof the fund.

Power Cost Equalization Endowment

The legislature, in selecting a 7% distribution policy, expressly elected not to inflation proof this fund, but rather to distribute all, or almost all, of its anticipated annual earnings.

University of Alaska Endowment

The University's distribution policy of 4.5% of the moving five-year average of the fund's market value should allow for retained earnings to inflation proof the fund.

9. Public Corporations & University of Alaska

Public Corporations

The state has established the following public corporations to carry out certain public policies:

- Alaska Housing Finance Corporation (AHFC)
- Alaska Industrial Development and Export Authority (AIDEA)
- Alaska Energy Authority (AEA)
- Alaska Student Loan Corporation (ASLC)
- Alaska Municipal Bond Bank Authority (AMBBA)
- Alaska Aerospace Corporation (AAC)
- Alaska Railroad Corporation (ARC)

These seven corporations and the University of Alaska are components of state government whose activities are accounted for in the state's Comprehensive Annual Financial Report separately from the activities of primary state government. Information in this section is provided by these corporations.

Four of these corporations pay, or may elect to pay, some portion of their income as an annual "dividend" to the state. They include the Alaska Housing Finance Corporation, Alaska Industrial Development and Export Authority, Alaska Student Loan Corporation and Alaska Municipal Bond Bank Authority.

The members of the AIDEA Board of Directors also serve as Board of Directors of AEA, though AIDEA and AEA continue to exist as separate legal entities. AEA has no employees, and AEA contracts to have AIDEA employees administer AEA programs. ASLC has its own board of directors but contracts with the Alaska Commission on Postsecondary Education (ACPE) to service its loan portfolio and to provide staff support to the ASLC. Other corporations have their own staffs and boards. While neither the sale of bonds nor the expenditure of bond proceeds, or proceeds from other debt by these corporations are subject to the state's Executive Budget Act, expenditures for the day-to-day administration of all of these corporations except the ASLC and ARC are subject to the Executive Budget Act.

ASLC provides funding to ACPE for loan servicing and staff support. ACPE's expenditures are subject to the Executive Budget Act.

The seven figures that follow in this section summarize the activities of these corporations.

Figure 9-1. Public Corporations—Missions. What does the corporation do and how does it do it?

Alaska Housing Finance Corporation

Using proceeds from the sale of bonds backed by its corporate assets, AHFC purchases home mortgages from Alaska banks. Income from payments on these mortgages repays bond holders and adds to the corporation's income, thereby enabling the corporation, since FY 1991, to pay an annual dividend and/or return of capital to the state. In addition to ensuring that Alaskans, especially Alaskans of low and moderate income and those in remote and underdeveloped areas of the state, have adequate housing at reasonable cost, the corporation administers federally and state funded multi-residential, senior and low-income housing, residential energy and home weatherization programs. In recent years, the legislature has authorized AHFC to finance the construction of schools, University of Alaska housing and other capital projects identified by the legislature.

Alaska Industrial Development and Export Authority

By lending money, guaranteeing loans or becoming an owner, AIDEA makes financing available for industrial, export, and other business enterprises in Alaska. The corporation earns money from interest on its loans, investments, leases, and operations of its properties. The corporation has paid an annual dividend to the state since FY 1997.

Alaska Energy Authority

AEA provides loans to utilities, communities, and individuals to pay for the purchase or upgrade of equipment, and for bulk fuel purchases. Additionally, the agency administers the Power Cost Equalization program, subsidizing rural electric costs with the Power Cost Equalization Endowment. AEA also receives federal and state money to provide technical advice and assistance in energy planning, emergency response management, energy infrastructure construction and conservation in rural Alaska. AEA owns, and operates and maintains (under contractual agreements) state-owned power projects, such as Bradley Lake and the Alaska Intertie.

Alaska Student Loan Corporation

The Alaska Student Loan Corporation issues debt and recycles education loan payments to finance education loans. Education loan payments satisfy bond obligations and provide funding for operations. Alaska statutes authorize the board of directors to return capital to the state based on net income. The corporation has returned capital to the state each year beginning in FY 2001 through FY 2009 based on net income in FY 1999 through FY 2007. Alaska statutes also authorize the corporation to issue bonds for the purpose of financing projects of the state. Those bonds in aggregate may not exceed $280 million. The corporation issued $163 million in bonds, the proceeds of which have been appropriated to fund capital projects of the state.

Alaska Municipal Bond Bank Authority

The Bond Bank loans money to Alaska municipalities for capital improvement projects. The bank's larger capital base, its reserve funds and its credit rating enable it to sell bonds at lower interest rates than the municipalities could obtain on their own. The Bond Bank earns interest on the money it holds in reserve and has returned a dividend to the state every year but one since 1977.

Alaska Aerospace Corporation

The corporation operates and maintains a commercial spaceport in Kodiak, Alaska and provides commercial rocket vehicle launch support services. It promotes space-related business, research, education, and economic growth in the State of Alaska.

Alaska Railroad Corporation

The corporation operates freight and passenger rail services between Seward and Fairbanks, including a spur line to Whittier. In addition, the corporation generates revenues from real estate it owns.

Figure 9-2. Public Corporations—State Capitalization. How did the state capitalize the corporation?

Alaska Housing Finance Corporation
The legislature appropriated $739.9 million in cash and $292.5 million in mortgages held by the General Fund to the corporation between 1976 and 1984. The payments on those mortgages and additional mortgages purchased with the cash have helped build the corporation's asset base and allow it to return some capital to the state each year. In 1993, AHFC received an additional $27.7 million in cash and $9.3 million in equity when the legislature merged the Alaska State Housing Authority with this corporation.

Alaska Industrial Development and Export Authority
Between 1981 and 1991, the State of Alaska transferred various loan portfolios worth $297.1 million and $69.2 million in cash to this corporation.

Alaska Energy Authority
The legislature established the AEA in 1976 to finance and operate power projects. This corporation has also administered rural energy programs at various times, including the present. As a result of legislatively mandated reorganizations, capital has moved into and out of the corporation. At the end of FY 2001, this corporation reported contributed capital of $963.5 million

Alaska Student Loan Corporation
In FY 1988, the state transferred $260 million of existing student loans to this corporation. Additional appropriations of cash between FY 1988 and FY 1992 totaled $46.7 million.

Alaska Municipal Bond Bank Authority
Between 1976 and 1986, the legislature appropriated $18.6 million to the Bond Bank to be used for backing bond issues. In addition, the legislature gave the Bond Bank $2.5 million in 1981 to fund a direct loan by a municipality. The municipality repaid the loan and the Bond Bank retained the appropriation.

Alaska Aerospace Corporation
Since 1993, the state has contributed $10.9 million from the Science and Technology Endowment and $11 million in capital project funding for facility maintenance and construction.

Alaska Railroad Corporation
The state bought the railroad from the federal government in 1985. The purchase price of $22.7 million was recorded as the state's capitalization.

Figure 9-3. Public Corporations—Financial Facts, FY 2011 ($ million)

	Total Assets	Assets Less Liabilities Book Value	Unrestricted Net Assets	FY 2011 Operating Budget	Total Positions [1]
Alaska Housing Finance Corporation	4,542.0	1,593.8	723.6	55.3	355.0
Alaska Industrial Development & Export Authority	1,249.1	1,039.5	948.6	11.2	76.0
Alaska Energy Authority	1,216.8	1,075.9	913.0	46.9	See AIDEA [2]
Alaska Student Loan Corporation [3]	736.8	216.8	97.7	12.6	96.0
Alaska Municipal Bond Bank Authority	776.6	46.3	13.5	0.8	0.5
Alaska Aerospace Corporation [4]	95.7	90.6	7.1	28.8	50.0
Alaska Railroad Corporation [5]	886.0	232.6	0.0	94.8	641.0

[1] Permanent Full Time (PFT), Permanent Part Time (PPT) and Temporary (TMP) are included in total positions.

[2] The Alaska Industrial Development and Export Authority (AIDEA) provides staff for the activities of the Alaska Energy Authority (AEA). A significant portion of AIDEA's 76 member staff is engaged in AEA programs.

[3] The Alaska Student Loan Corporation (ASLC) contracts with the Alaska Commission on Postsecondary Education (ACPE) to service its loan portfolio and provide staff support. Budget and positions reported are those of ACPE's funded by ASLC.

[4] Alaska Aerospace Corporation based on audited financial statements.

[5] The Alaska Railroad Corporation reports financial data on a calendar year basis. Assets and book value shown in this table are from audited December 31, 2010, financial statements. The operating budget figure shown here is for CY 2010.

Figure 9-4. Public Corporations—Revenue & Net Income, FY 2011 ($ million)

	Revenue	Operating Income	Net Income
Alaska Housing Finance Corporation	385.7	(12.9)	(30.2)
Alaska Industrial Development & Export Authority [1]	78.0	41.1	27.3
Alaska Energy Authority [1]	551.5	(71.4)	432.9
Alaska Student Loan Corporation	37.6	10.2	7.6
Alaska Municipal Bond Bank Authority	30.1	(0.5)	2.0
Alaska Aerospace Corporation[2]	14.2	(4.7)	(4.5)
Alaska Railroad Corporation [3]	170.0	5.6	13.5

[1] The Alaska Industrial Development and Export Authority and Alaska Energy Authority report financial data on a fiscal year basis, and are increases (decreases) in Net Assets. Revenue, operating income and net income in the table are from audited June 30, 2011, financial statements.

[2] The Alaska Aerospace Corporation financial data include depreciation of $6.76 million and are based on audited June 30, 2011 financial statements.

[3] The Alaska Railroad Corporation reports financial data on a calendar year basis. Revenue and Operating Income shown in this table are for CY 2010.

Figure 9-5. Public Corporations—Dividends to the State. How, if at all, does the corporation pay dividends to the state?

Alaska Housing Finance Corporation
The Twenty-Third Legislature, in 2003, enacted SCSHB 256 (the "2003 Act") which added language to the Alaska Statutes to modify and incorporate the Transfer Plan. As approved and signed into law by the Governor, the Transfer Plan calls for annual transfers as follows: FY 2005, $103 million; FY 2006, $103 million; FY 2007, the lesser of 95% net income or $103 million; FY 2008, the lesser of 85% net income or $103 million; FY 2009 and thereafter, the lesser of 75% of the corporation's net income or $103 million.

Alaska Industrial Development and Export Authority
By statute, AIDEA must make available to the state each year not less than 25% and not more than 50% of its total net income for a base year, defined as the year two years prior to the dividend year. The dividend is further limited to no more than the total amount of its unrestricted net income in the base year (AS 44.88.088). Net income is defined in the statutes.

Alaska Energy Authority
AEA does not pay a dividend or return capital to the state on a regular basis. However, in FY 2000, this corporation returned $55.6 million of contributed capital to the Railbelt Energy Fund and the General Fund.

Alaska Student Loan Corporation
This corporation, at the discretion of its board of directors, may make available to the state a return of contributed capital or dividend for any base year in which the net income of the corporation is $2 million or more. A base year is defined as the year two years before the payment year. If the board authorizes a payment, it must be between 10% and 35% of net income for the base year (AS 14.42.295). The corporation may also issue bonds in an aggregate amount not to exceed $280 million, for the purpose of financing projects of the state as those projects (AS 14.42.220). Investment earnings on proceeds of bonds issued in 2004 under this statute are also used to finance projects of the state.

Alaska Municipal Bond Bank Authority
By statute, the Bond Bank annually returns earnings or income of its reserve fund, in excess of expenses, to the state.

Alaska Aerospace Corporation
AAC does not pay a dividend or return capital to the state.

Alaska Railroad Corporation
The corporation does not pay a cash dividend to the General Fund.

Figure 9-6. Public Corporations—Operating Expenses & Dividends ($ million)

	Expenses		Dividends	
	Actual FY 2011	Budget FY 2012	Actual FY 2011	Budget FY 2012
Alaska Housing Finance Corporation [1]	88.6	88.5	42.5	23.1
Alaska Industrial Development & Export Authority[2]	10.5	12.7	23.4	29.4
Alaska Energy Authority [2]	39.8	47.5	na	na
Alaska Student Loan Corporation[3]	12.2	12.9	0.1	0.1
Alaska Municipal Bond Bank Authority	0.7	0.8	0.1	0.1
Alaska Aerospace Corporation [4]	18.9	33.0	na	na
Alaska Railroad Corporation	na	na	na	na

[1] Because some of this money is earmarked for multi-year capital projects, actual cash transfers in any given year may vary.

[2] The Alaska Industrial Development and Export Authority and Alaska Energy Authority report financial data on a fiscal year basis. Actual operating expenses and dividends are for the fiscal year ended June 30, 2011.

[3] The Alaska Student Loan Corporation (ASLC) did not pay a dividend to the state in FY 2011 as allowed for in AS14.42.295. The amounts reported above represent bond proceed investment earnings which are used to finance state projects under AS 14.42.220. Chapter 5 shows a transfer to the state of $2.5 million from ASLC which is part of a capital project authorized in a prior year and not a current year dividend.

[4] The Alaska Aerospace Corporation financial data include depreciation of $6.76 million and are based on audited June 30, 2011 financial statements.

University of Alaska

Figure 9-7. University of Alaska ($ million)

Lands & Facilities June 30,2011	Total Assets June 30, 2011	Unrestricted Net Assets	FY 2012 Operating Budget	FY 2012 Total Positions
$952.9 [1]	$1,358.5	$126.9	$870.4	4,916

[1] Includes depreciation of $807.4 million.

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2011

10. Appendices

A. Revenue

B. Prices

C. Production

D. Income Statement Approach to Production Tax

E. Credits

Revenue. A-1

Glossary of Terms

Constitutional Budget Reserve Fund (CBRF)

Created by voters in 1990, the Constitutional Budget Reserve Fund receives proceeds from settlements of oil, gas, and mining tax and royalty disputes. The legislature may, with a three-quarters majority vote in each chamber, withdraw money from the fund.

Designated General Fund Revenue

General Fund revenue that is designated for a specific purpose, typically using a General Fund subaccount. The legislature can at any time remove the restrictions on this category of revenue as they are solely imposed by either Alaska statute or customary practice. At times, this category of revenue may be included in legislative and public debate over the budget.

Federal Revenue

When the federal government gives money to states, it typically restricts how that money can be used. For example, highway and airport construction funds, Medicaid, and education funding cannot be used for other purposes. In addition to restricting how the money is spent, the federal government often requires states to put up matching funds to qualify for the federal funding.

General Fund Revenue

General Fund Revenue has different meanings in different contexts. In the state's official financial reports, General Fund Revenue is used to designate the sum of General Fund Unrestricted Revenue, General Fund sub-account revenue, program receipts and other funds spent through the General Fund. In budget reports, General Fund revenue is split into revenue with no specific purpose, and revenue with a specific purpose. These categories are called unrestricted general funds and designated general funds, respectively.

Unrestricted General Fund Revenue/General Purpose Unrestricted Revenue

Revenue not restricted by the constitution, state or federal law, trust or debt restrictions, or customary practice. This revenue is deposited into the state's unrestricted General Fund and most legislative and public debate over the budget each year centers on this category of revenue. In deriving our unrestricted revenue figure from total General Fund revenues, we have excluded General Fund subaccount revenue, as well as customarily restricted revenues such as shared taxes and pass-through revenue for qualified fisheries associations. We have also added certain revenues such as transfers to the state treasury from the Unclaimed Property Trust and dividends from component units.

Other Restricted State Revenue

Non-federal revenue that is not deposited to the General Fund or a subaccount of the General Fund. This revenue is restricted by the constitution, state or federal law, trust or debt restrictions, or by customary practice.

Permanent Fund GASB (or Market) Income

Under standards adopted by the Governmental Accounting Standards Board, the Permanent Fund's income—and that of any other government fund—is the difference between the purchase price of the investments and their market value at a given point in time, plus any dividends, interest or rent earned on those investments. Under GASB standards, the Permanent Fund does not have to sell the investment to count the gain or loss as it changes value. It is called "marking to market," that is, measuring the value of the fund's investments by the current market price. This can produce a much different picture than Permanent Fund statutory income, which does not reflect fluctuating investment values until the assets are sold.

Permanent Fund Statutory Income

The annual Permanent Fund dividend is based on statutory income. This is the sum of realized gains and losses of all Permanent Fund investment transactions during the year, plus interest, dividends and rents earned by the fund. Though the legislature may appropriate the earnings for any purpose it chooses, the historical practice has been to use realized income primarily for dividends and inflation proofing and, then either leave the excess in the Realized Earnings Account, or transfer it to the principal of the Permanent Fund.

Restricted Program Receipts

This revenue is earmarked in state statute or by contract for specific purposes and is usually appropriated back to the program that generated the revenue. Examples include University of Alaska tuition payments, marine highway receipts, payments to various revolving loan funds, and public corporation receipts. Some of this revenue is actually dedicated as a consequence of the provisions of Article 18, Section 11 of the Alaska Constitution. The remainder, while statutorily earmarked, may be appropriated to purposes other than those reflected in statute if the legislature so chooses. These earmarked funds are categorized as designated general funds.

Restricted Revenue

Restricted revenue represents revenue that is restricted by the constitution, state or federal law, trust or debt restrictions, or by customary practice. The legislature can at any time remove restrictions that are solely imposed by either Alaska statute or customary practice. Program receipts, revenues allocated to sub-accounts of the General Fund, and General Fund revenues customarily shared with other entities are all considered restricted revenues for the purposes of this report. In this report, we present three categories of restricted revenue: Designated General Fund Revenue, Other Restricted State Revenue, and Federal Revenue.

Revenue. A-2

General Fund Unrestricted Revenue Matrices, with Price and Cost Sensitivity, FY 2012-2014 ($ million)

FY 2012

At forecasted production of 0.574 mmbbls/day

ANS $/barrel[1]	Deductible capital & operating expenditures in $/bbl[2]		
	$15.00	FC ($20)	$25.00
$50	$3,377	$3,182	3,144
$60	$4,073	$3,790	3,465
$70	$4,779	$4,461	4,221
$80	$5,785	$5,226	4,893
$90	$6,981	$6,341	5,858
$100	$8,368	$7,607	7,022
$109.33	$9,792	$8,928	8,245
$110	$9,962	$9,081	8,393
$120	$11,468	$10,710	9,919
$130	$12,793	$12,088	11,504
$140	$14,166	$13,431	12,821
$150	$15,587	$14,821	14,186

FY 2013

At forecasted production of 0.555 mmbbls/day

ANS $/barrel[1]	Deductible capital & operating expenditures in $/bbl[2]		
	$15.00	FC ($22)	$25.00
$50	$2,366	$2,124	1,635
$60	$3,072	$2,830	2,566
$70	$3,949	$3,551	3,235
$80	$4,999	$4,523	4,055
$90	$6,187	$5,634	5,081
$100	$7,514	$6,883	6,246
$109.47	$8,922	$8,218	7,501
$110	$9,001	$8,292	7,571
$120	$10,580	$9,794	8,988
$130	$12,044	$11,455	10,567
$140	$13,336	$12,737	12,098
$150	$14,662	$14,044	13,384

FY 2014

At forecasted production of 0.561 mmbbls/day

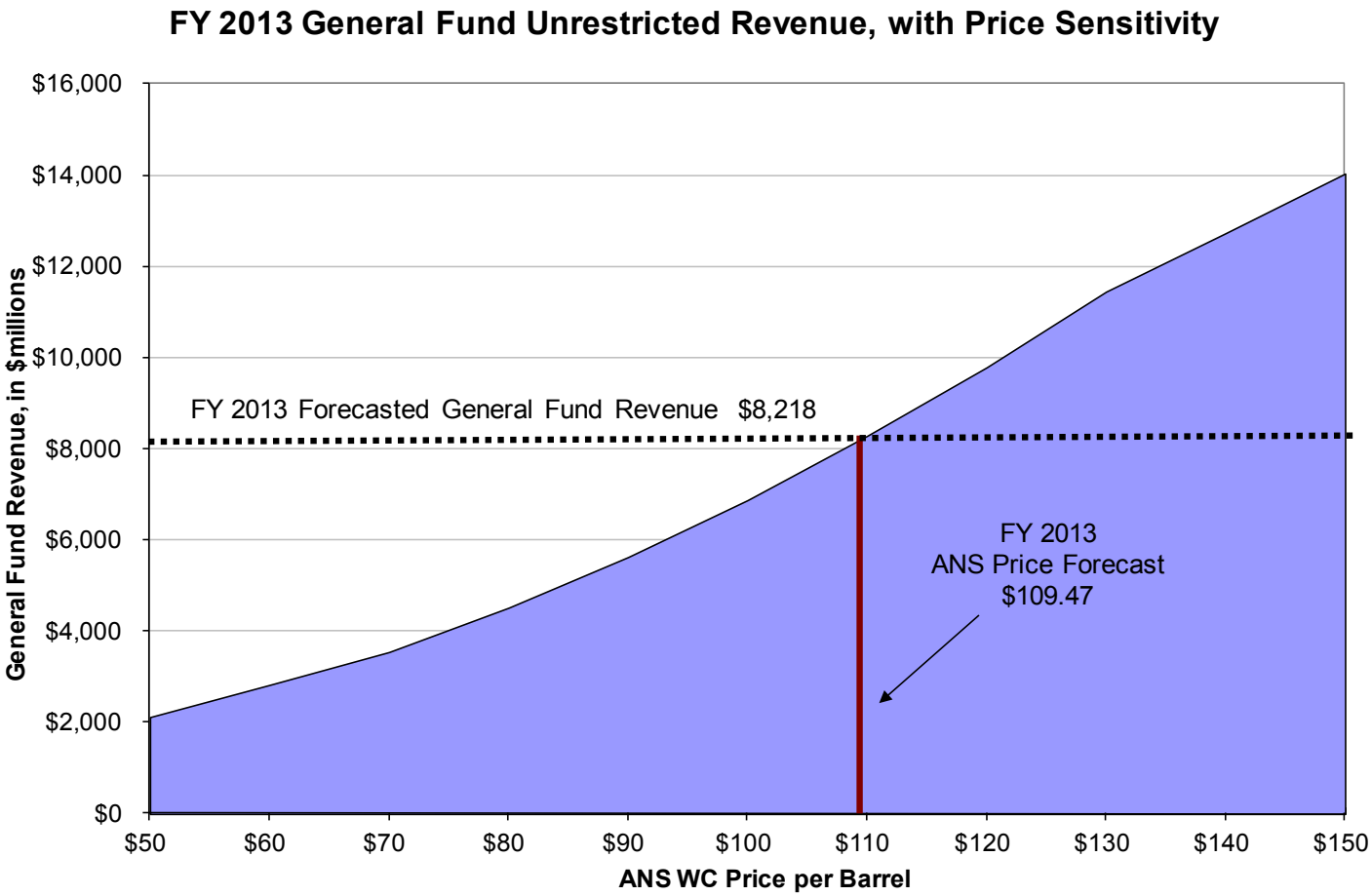
ANS $/barrel[1]	Deductible capital & operating expenditures in $/bbl[2]		
	$15.00	FC ($24)	$25.00
$50	$2,247	$1,906	1,527
$60	$2,956	$2,615	2,445
$70	$3,824	$3,287	3,117
$80	$4,874	$4,221	3,926
$90	$6,062	$5,300	4,951
$100	$7,389	$6,517	6,114
$109.08	$8,714	$7,743	7,290
$110	$8,855	$7,874	7,415
$120	$10,458	$9,368	8,856
$130	$11,946	$11,002	10,434
$140	$13,242	$12,403	11,992
$150	$14,573	$13,707	13,282

[1] ANS $/barrel values are fiscal year averages that incorporate actual prices for the first 3 months of FY 2012. Because oil prices were in the mid-$70 range in the first 3 months, it can take a different price for the remainder of the year to bring the fiscal year average to levels in the table. For example, a fiscal year price of $50 per barrel would require 9 months of oil prices around $30 per barrel.

[2] This table includes a best estimate of only those capital and operating expenditures that will have an impact on the amount of production tax revenue collected in each year, at the forecast price. In other words, we have sought to exclude expenditures made by companies that are unlikely to have a production tax liability. Also included are the level of forecasted expenditures that will have a tax impact, shown as FC in each of the years. These estimates do not consider how some companies may or may not have a tax liability, or how company investment decisions may change, with an increase or a decrease in oil price. Per-barrel amounts are based on all barrels of oil produced, whether or not taxable.

Revenue. A-2

General Fund Unrestricted Revenue Matrices, with Price and Cost Sensitivity, FY 2013 ($ million)



Revenue. A-3

Unrestricted General Fund Revenue—History

($ million)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
TAX REVENUE										
Petroleum Property Tax	**49.6**	**48.7**	**47.3**	**42.5**	**54.5**	**65.6**	**81.5**	**111.2**	**118.8**	**110.7**
Excise Tax										
Alcoholic Beverages	12.9	14.1	16.4	17.3	17.6	17.1	20.0	19.5	19.5	19.4
Tobacco Products	15.5	16.3	16.0	25.1	35.4	43.8	44.9	46.6	45.1	46.5
Insurance Premium	34.1	39.0	43.7	45.9	44.3	46.5	47.1	45.5	50.4	49.6
Electric and Telephone Cooperative	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1
Motor Fuel Tax	40.2	37.2	41.2	39.4	42.0	39.2	41.8	10.1	28.8	39.5
Vehicle Rental tax	0.0	0.0	2.7	7.5	7.7	8.0	8.5	8.0	7.3	8.3
Tire Fee	0.0	0.0	0.8	1.6	1.6	1.5	1.5	1.5	1.4	1.5
Total	**102.8**	**106.8**	**121.0**	**137.0**	**148.8**	**156.3**	**164.0**	**131.3**	**152.6**	**164.9**
Income Tax										
General Corporate	53.4	47.7	39.6	61.8	138.0	176.9	182.7	120.9	81.9	157.7
Petroleum Corporate	178.4	151.1	298.8	524.0	661.1	594.4	605.8	492.2	446.1	542.1
Total	**231.8**	**198.8**	**338.4**	**585.8**	**799.1**	**771.3**	**788.5**	**613.1**	**528.0**	**699.8**
Oil and Gas Production Tax										
Oil and Gas Production Tax	486.7	589.8	642.7	854.9	1,191.7	2,198.3	6,810.9	3,100.9	2,860.7	4,543.2
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 Hazardous Release	9.6	9.2	9.2	8.3	7.8	10.1	11.7	11.1	10.3	9.7
Total	**496.3**	**599.0**	**651.9**	**863.2**	**1,199.5**	**2,208.4**	**6,822.6**	**3,112.0**	**2,871.0**	**4,552.9**
Fisheries Tax										
Fisheries Business Tax	12.7	13.8	14.9	10.7	15.4	17.1	14.7	19.3	14.0	20.1
Fishery Landing	2.6	6.9	2.5	3.9	4.7	5.3	7.9	4.7	8.3	2.7
Total	**15.3**	**20.7**	**17.4**	**14.6**	**20.1**	**22.4**	**22.6**	**24.0**	**22.3**	**22.8**
Other Tax										
Estate	3.1	1.2	2.3	1.5	0.6	0.1	0.0	0.2	0.0	0.0
Mining	0.5	0.4	3.2	10.3	18.6	79.1	54.4	15.5	29.7	49.0
Charitable Gaming	2.5	2.6	2.4	2.5	2.4	2.5	2.7	2.8	2.6	2.5
Large Passenger Vessel Gambling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.3	5.8
Total	**6.1**	**4.2**	**7.9**	**14.3**	**21.6**	**81.7**	**57.1**	**18.5**	**38.6**	**57.3**
TOTAL TAX REVENUE	**901.9**	**978.2**	**1,183.9**	**1,657.4**	**2,243.6**	**3,305.7**	**7,936.3**	**4,010.1**	**3,731.3**	**5,608.4**

(continued on next page)

Unrestricted General Fund Revenue—History (continued from prior page)

($ million)[1]

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
NON TAX REVENUE										
Licenses and Permits	**42.2**	**33.6**	**41.8**	**42.7**	**41.0**	**42.0**	**38.9**	**35.5**	**39.5**	**42.8**
Intergovernmental Receipts										
Federal Shared Revenues	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Charges for Services	**19.1**	**13.9**	**11.1**	**17.9**	**21.8**	**28.5**	**29.3**	**19.3**	**17.1**	**18.5**
Fines and Forefeitures	**6.6**	**7.0**	**16.0**	**9.4**	**8.5**	**7.8**	**8.9**	**10.5**	**10.4**	**7.0**
Rents and Royalties										
Oil and Gas Royalties-Net	575.7	825.7	1,042.8	1,401.1	1,772.2	1,583.8	2,420.6	1,451.2	1,469.0	1,821.3
Oil and Gas Bonuses, Rents, Interest[2] [3]	20.1	14.6	13.3	18.8	11.9	29.2	25.5	14.4	8.0	22.0
Other [4]	9.3	6.2	7.8	9.3	8.8	11.8	14.6	15.6	13.2	17.6
Total	**605.1**	**846.5**	**1,063.9**	**1,429.2**	**1,792.9**	**1,624.8**	**2,460.7**	**1,481.2**	**1,490.2**	**1,860.9**
Investment Earnings[3]	**43.1**	**59.0**	**9.7**	**24.7**	**53.3**	**140.1**	**248.8**	**247.6**	**184.0**	**96.3**
Miscellaneous Revenue[5]	**42.3**	**9.4**	**19.2**	**7.5**	**39.3**	**9.7**	**26.2**	**27.0**	**40.8**	**39.1**
Sub-Total NON-TAX REVENUE	**758.4**	**969.4**	**1,161.7**	**1,531.4**	**1,956.8**	**1,852.9**	**2,812.8**	**1,821.1**	**1,782.0**	**2,064.6**
Petroleum Special Settlements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL NON-TAX REVENUE	**1,010.9**	**758.4**	**969.4**	**1,161.7**	**1,531.4**	**1,956.8**	**1,852.9**	**2,792.9**	**1,821.1**	**1,781.3**
TOTAL TAX REVENUE	**901.9**	**978.2**	**1,183.9**	**1,657.4**	**2,243.6**	**3,305.7**	**7,936.3**	**4,010.1**	**3,731.3**	**5,608.4**
TOTAL UNRESTRICTED GENERAL FUND REVENUE	**1,660.3**	**1,947.6**	**2,345.6**	**3,188.8**	**4,200.4**	**5,158.6**	**10,749.1**	**5,831.2**	**5,513.3**	**7,673.0**

(1) Unrestricted General Fund Revenue includes those revenues that are not restricted by statute or custom, as reported elsewhere in this publication. A summary of historical Unrestricted General Fund Revenue can be found on the Tax Division's web site at: www.tax.alaska.gov/sourcesbook/GeneralFundUnrestrictedRevenueHistory.pdf

(2) These categories are primarily composed of petroleum.

(3) Starting in FY 2001, interest earnings are included in oil and gas royalties and excluded from investment earnings.

(4) Includes non-petroleum rents and royalites.

(5) Starting in FY 2010, dividends and payments from state-owned corporations are included in unrestricted miscellaneous revenue.

Revenue. A-4a

Unrestricted General Fund Petroleum Revenue—History [1]

($ million)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Petroleum Corporate Income Tax	178.4	151.1	298.8	524.0	661.1	594.4	605.8	492.2	446.1	542.1
Production Tax	496.3	599.0	651.9	863.2	1,199.5	2,208.4	6,822.6	3,112.0	2,871.0	4,552.9
Petroleum Property Tax	49.6	48.7	47.3	42.5	54.5	65.6	81.5	111.2	118.8	110.7
Oil and Gas Royalties-Net[2]	575.7	825.7	1,042.8	1,401.1	1,772.2	1,583.8	2,420.6	1,451.2	1,469.0	1,821.3
Bonuses, Rents & Interest-Net[2][3]	20.1	14.6	13.3	18.8	11.9	29.2	25.5	14.4	8.0	22.0
Petroleum Special Settlements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Petroleum Revenue	**1,320.1**	**1,639.1**	**2,054.1**	**2,849.6**	**3,699.2**	**4,481.4**	**9,956.0**	**5,181.0**	**4,912.9**	**7,049.0**
Cumulative Unrestricted Petroleum Revenue[4]	**51,567.2**	**53,206.3**	**55,260.4**	**58,110.0**	**61,809.2**	**66,290.6**	**76,246.6**	**81,427.6**	**86,340.5**	**93,389.5**
Total Unrestricted General Fund Revenue	**1,660.3**	**1,947.6**	**2,345.6**	**3,188.8**	**4,200.4**	**5,158.6**	**10,749.1**	**5,831.2**	**5,513.3**	**7,673.0**
% Petroleum of Total UGF Revenue	80%	84%	88%	89%	88%	87%	93%	89%	89%	92%

(1) Historical Unrestricted General Fund petroleum revenue can be found on the Tax Division's web site at: http://www.tax.alaska.gov/sourcesbook/PetroleumRevenueHistory.pdf. The table on Tax web site includes historical Reserve Tax (FY 1976-1977) and Petroleum Special Settlements (FY 1986-1995). These revenues are included in the cumulative totals shown in Appendix A-4a.

(2) Royalties, bonuses, rents and interest are net of Permanent Fund contribution and Constitutional Budget Reserve Fund (CBRF) deposits.

(3) This category is primarily composed of petroleum revenue.

(4) The cumulative unrestricted petroleum revenue total is based on revenue beginning in FY 1959.

Revenue. A-4b

Unrestricted General Fund Petroleum Revenue—Forecast

($ million)

FY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Petroleum Corporate Income Tax	662.1	728.4	712.2	704.5	701.6	691.0	706.1	715.2	724.9	735.3
Oil and Gas Production Tax	5,376.4	4,715.8	4,252.3	3,634.0	3,736.6	3,559.9	3,887.3	3,849.4	3,807.2	3,746.1
Petroleum Property Tax	91.7	89.7	87.6	85.6	83.5	81.6	79.5	77.5	75.5	73.4
Oil and Gas Royalties-Net[1]	2,054.0	1,930.8	1,935.5	1,858.3	1,775.0	1,620.9	1,659.3	1,625.1	1,587.0	1,543.6
Bonuses, Rents & Interest-Net[1][2]	31.2	31.2	31.2	31.2	31.2	31.2	31.2	31.2	31.2	31.2
Petroleum Special Settlements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Petroleum Revenue	**8,215.3**	**7,496.0**	**7,018.8**	**6,313.5**	**6,327.9**	**5,984.6**	**6,363.4**	**6,298.4**	**6,225.8**	**6,129.5**
Cumulative Unrestricted Petroleum Revenue[3]	**101,604.8**	**109,100.8**	**116,119.6**	**122,433.2**	**128,761.1**	**134,745.7**	**141,109.1**	**147,407.5**	**153,633.3**	**159,762.8**
Total Unrestricted General Fund Revenue	**8,927.9**	**8,217.7**	**7,742.8**	**7,043.4**	**7,065.5**	**6,738.9**	**7,125.0**	**7,070.4**	**7,012.1**	**6,917.5**
% Petroleum of Total UGF Revenue	92%	91%	91%	90%	90%	89%	89%	89%	89%	89%

(1) Royalties, bonuses, rents and interest are net of Permanent Fund contribution and Constitutional Budget Reserve Fund (CBRF) deposits.
(2) This category is primarily composed of petroleum revenue.
(3) The cumulative Unrestricted General Fund petroleum revenue total is based on revenue beginning in FY 1959.

Revenue. A-5a

Total Alaska Government Petroleum Revenue—History

($ million)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Unrestricted Petroleum Revenue										
Petroleum Corporate Income Tax	178.4	151.1	298.8	524.0	661.1	594.4	605.8	492.2	446.1	542.1
Oil and Gas Production Tax	486.7	589.8	642.7	854.9	1,191.7	2,198.3	6,810.9	3,100.9	2,860.7	4,543.2
Oil and Gas Hazardous Release	9.6	9.2	9.2	8.3	7.8	10.1	11.7	11.1	10.3	9.7
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum Property Tax	49.6	48.7	47.3	42.5	54.5	65.6	81.5	111.2	118.8	110.7
Oil & Gas Royalties	575.7	825.7	1,042.8	1,401.1	1,772.2	1,583.8	2,420.6	1,451.2	1,469.0	1,821.3
Bonuses, Rents & Interest	20.1	14.6	13.3	18.8	11.9	29.2	25.5	14.4	8.0	22.0
Total Unrestricted Petroleum Revenue	**1,320.1**	**1,639.1**	**2,054.1**	**2,849.6**	**3,699.2**	**4,481.4**	**9,956.0**	**5,181.0**	**4,912.9**	**7,049.0**
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	1.7	34.6	2.5	31.6	4.5	12.8	5.2	14.8	21.3	3.0
Royalties to Permanent Fund	257.7	397.6	354.7	476.9	599.5	535.0	834.0	659.8	696.1	857.3
Royalties to Public School Fund	4.3	6.2	7.1	9.6	12.0	10.6	16.5	11.0	11.1	13.6
CBRF Deposits	90.2	22.3	8.4	27.4	43.7	101.9	476.4	202.6	552.7	167.3
Total Restricted Petroleum Revenue	**353.9**	**460.7**	**372.7**	**545.5**	**659.7**	**660.3**	**1,332.1**	**888.2**	**1,281.2**	**1,041.2**
Total Petroleum Revenue	**1,674.0**	**2,099.8**	**2,426.8**	**3,395.1**	**4,358.9**	**5,141.7**	**11,288.1**	**6,069.2**	**6,194.1**	**8,090.2**

Revenue. A-5b

Total Alaska Government Petroleum Revenue—Forecast

($ million)

FY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Unrestricted Petroleum Revenue										
Petroleum Corporate Income Tax	662.1	728.4	712.2	704.5	701.6	691.0	706.1	715.2	724.9	735.3
Oil and Gas Production Tax	5,367.0	4,706.8	4,243.1	3,625.2	3,728.0	3,551.5	3,878.9	3,841.3	3,799.6	3,738.9
Oil and Gas Hazardous Release	9.4	9.1	9.2	8.8	8.7	8.4	8.5	8.1	7.6	7.2
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petroleum Property Tax	91.7	89.7	87.6	85.6	83.5	81.6	79.5	77.5	75.5	73.4
Oil & Gas Royalties	2,054.0	1,930.8	1,935.5	1,858.3	1,775.0	1,620.9	1,659.3	1,625.1	1,587.0	1,543.6
Bonuses, Rents & Interest	31.2	31.2	31.2	31.2	31.2	31.2	31.2	31.2	31.2	31.2
Total Unrestricted Petroleum Revenue	**8,215.3**	**7,496.0**	**7,018.8**	**6,313.5**	**6,327.9**	**5,984.6**	**6,363.4**	**6,298.4**	**6,225.8**	**6,129.5**
Restricted Petroleum Revenue										
NPR-A Rents, Royalties, Bonuses	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Royalties to Permanent Fund	912.0	857.7	866.7	824.2	778.1	709.8	717.6	695.9	673.4	649.6
Royalties to Public School Fund	15.0	14.1	14.2	13.6	12.9	11.8	12.1	11.8	11.5	11.1
CBRF Deposits	31.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Total Restricted Petroleum Revenue	**962.0**	**895.9**	**904.9**	**861.8**	**815.1**	**745.7**	**753.7**	**731.7**	**708.8**	**684.8**
Total Petroleum Revenue	**9,177.3**	**8,391.8**	**7,923.7**	**7,175.3**	**7,143.0**	**6,730.3**	**7,117.1**	**7,030.0**	**6,934.6**	**6,814.3**

Prices. B-1a

Crude Oil and Natural Gas Prices—History [1]

NOMINAL [2]

WTI, ANS West Coast, ANS and Cook Inlet Wellhead Prices
($ per barrel)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
WTI	23.70	29.90	33.73	48.72	64.22	63.35	97.02	69.71	75.21	89.39
ANS West Coast Spot	21.65	28.59	32.36	44.85	62.12	61.60	96.51	68.34	74.90	94.49
ANS Wellhead Wtd Average All Destinations	17.04	23.42	27.46	40.12	56.69	56.20	90.46	61.86	68.89	87.32
Cook Inlet Wellhead	19.37	25.32	28.41	41.72	58.26	57.31	82.26	62.51	65.70	78.15

Henry Hub Natural Gas Prices
($ per million Btu)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Henry Hub	2.76	4.84	5.41	6.26	9.12	6.88	8.30	5.92	4.25	4.16

REAL 2011 $ [3]

WTI, ANS West Coast, ANS and Cook Inlet Wellhead Prices
($ per barrel)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
WTI	29.73	36.75	40.14	56.54	71.45	68.81	100.08	72.95	77.88	89.39
ANS West Coast Spot	27.16	35.13	38.50	52.05	69.11	66.91	99.55	71.52	77.57	94.49
ANS Wellhead Wtd Average All Destinations	21.38	28.78	32.68	46.56	63.07	61.05	93.32	64.74	71.34	87.32
Cook Inlet Wellhead	24.31	31.11	33.81	48.42	64.81	62.25	84.85	65.42	68.04	78.15

Henry Hub Natural Gas Prices
($ per million Btu)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Henry Hub	3.46	5.94	6.44	7.26	10.15	7.47	8.56	6.20	4.40	4.16

(1) Data from Platt's Oilgram Price Report, Wood McKenzie and Alaska Department of Revenue's prevailing value and tax return data. Historical real and nominal crude oil and natural gas prices can be found on the Tax Division's web site at: www.tax.alaska.gov/sourcesbook/OilGasPrices.pdf.

(2) Adjustment to "nominal" dollars is required to prepare the crude oil and natural gas price forecasts. Callan Associates Inc.'s inflation rate of 2.5% was used for FY 2012 and beyond.

(3) Adjustment to "real 2011" dollars is useful to compare prices across time excluding inflation. These prices data are adjusted to real 2011 dollars based on inflation rates provided by the U.S. Department of Labor, Bureau of Labor Statistics. The data series used is the Consumer Price Index for all Urban Consumers (CPI-U) which can be found at: www.bls.gov/cpi/home.htm.

Prices. B-1b

Crude Oil Prices—Forecast

NOMINAL[1]

WTI, ANS West Coast, ANS and Cook Inlet Wellhead Prices
($ per barrel)

FY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
WTI	90.92	96.62	99.88	103.21	105.90	108.55	111.26	114.04	116.89	119.81
ANS West Coast Spot	109.33	109.47	109.08	108.75	107.79	106.05	108.76	111.54	114.39	117.31
ANS Wellhead Wtd Average All Destinations	100.61	100.91	100.25	99.61	98.23	96.27	98.76	101.19	103.63	106.15
Cook Inlet Wellhead	104.68	107.59	107.20	106.88	105.92	104.18	106.90	109.69	112.54	115.47

REAL 2011 $[2]

WTI, ANS West Coast, ANS and Cook Inlet Wellhead Prices
($ per barrel)

FY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
WTI	88.71	91.97	92.75	93.50	93.60	93.60	93.60	93.60	93.60	93.60
ANS West Coast Spot	106.66	104.20	101.29	98.52	95.27	91.44	91.49	91.55	91.60	91.65
ANS Wellhead Wtd Average All Destinations	98.16	96.05	93.09	90.24	86.82	83.01	83.08	83.05	82.98	82.93
Cook Inlet Wellhead	102.13	102.40	99.55	96.83	93.62	89.84	89.93	90.03	90.12	90.20

(1) Adjustment to "nominal" dollars is required to prepare the crude oil and natural gas price forecasts. Callan Associates Inc.'s inflation rate of 2.5% was used for FY 2012 and beyond.

(2) Adjustment to "real 2011" dollars is useful to compare prices across time excluding inflation. These prices data are adjusted to real 2011 dollars based on inflation rates provided by the U.S. Department of Labor, Bureau of Labor Statistics. The data series used is the Consumer Price Index for all Urban Consumers (CPI-U) which can be found at: www.bls.gov/cpi/home.htm.

Prices. B-2a

Nominal Netback Costs—History [1]

Marine Costs, TAPS Tariff, and Other Adjustment Charges

($ per barrel)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
ANS West Coast	21.65	28.59	32.36	44.85	62.12	61.60	96.51	68.34	74.90	94.49
Marine Costs	1.58	1.70	1.69	1.79	1.65	1.63	1.93	2.05	2.21	2.45
TAPS Tariff	3.50	3.37	3.16	3.33	3.55	4.51	5.08	4.59	3.81	4.02
Other Deductions and Adjustments[2]	(0.48)	0.09	0.05	(0.40)	0.23	(0.74)	(0.96)	(0.15)	(0.00)	0.70
ANS Wellhead Value	**17.04**	**23.42**	**27.46**	**40.12**	**56.69**	**56.20**	**90.46**	**61.86**	**68.89**	**87.32**

[1] Historical netback costs can be found on the Tax Division web site: www.tax.alaska.gov/sourcesbook/NetbackCosts.pdf.
[2] Includes TAPS and feeder pipeline quality bank adjustments, pipeline losses, feeder pipeline tariffs and a location adjustment.

Prices. B-2b

Nominal Netback Costs—Forecast [1]

Marine Costs, TAPS Tariff, and Other Adjustment Charges

($ per barrel)

FY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ANS West Coast	109.33	109.47	109.08	108.75	107.79	106.05	108.76	111.54	114.39	117.31
Marine Costs	2.71	2.70	2.76	2.83	2.90	2.98	3.05	3.13	3.20	3.28
TAPS Tariff	5.16	4.96	5.17	5.39	5.58	5.73	5.87	6.09	6.38	6.69
Other Deductions and Adjustments[2]	0.85	0.91	0.90	0.93	1.07	1.07	1.08	1.13	1.18	1.19
ANS Wellhead Value	**100.61**	**100.91**	**100.25**	**99.61**	**98.23**	**96.27**	**98.76**	**101.19**	**103.63**	**106.15**

[1] Data from the Department of Revenue's Forecast Model.
[2] Includes TAPS and feeder pipeline quality bank adjustments, pipeline losses, feeder pipeline tariffs and a location adjustment.

Prices. B-3

Price Changes from Spring 2011 Forecast

(nominal $ per barrel)

FY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Fall 2011 Forecast										
WTI	90.92	96.62	99.88	103.21	105.90	108.55	111.26	114.04	116.89	119.81
ANS West Coast	109.33	109.47	109.08	108.75	107.79	106.05	108.76	111.54	114.39	117.31
ANS Wellhead Wtd Average All Destinations	100.61	100.91	100.25	99.61	98.23	96.27	98.76	101.19	103.63	106.15
Cook Inlet Wellhead	104.68	107.59	107.20	106.88	105.92	104.18	106.90	109.69	112.54	115.47
Spring 2011 Forecast										
WTI	97.20	98.29	98.83	103.26	106.10	109.02	112.02	115.10	118.26	121.52
ANS West Coast	94.70	95.79	96.33	100.76	103.60	106.52	109.52	112.60	115.76	119.02
ANS Wellhead Wtd Average All Destinations	88.51	89.45	89.85	94.11	96.74	99.53	102.33	105.14	107.94	110.79
Cook Inlet Wellhead	92.82	93.91	94.46	98.90	101.74	104.66	107.67	110.75	113.92	117.18
$ change from prior forecast										
WTI	(6.28)	(1.67)	1.05	(0.05)	(0.20)	(0.48)	(0.76)	(1.06)	(1.37)	(1.70)
ANS West Coast	14.63	13.68	12.74	7.99	4.18	(0.48)	(0.76)	(1.06)	(1.37)	(1.70)
ANS Wellhead Wtd Average All Destinations	12.10	11.46	10.40	5.49	1.49	(3.26)	(3.58)	(3.95)	(4.31)	(4.64)
Cook Inlet Wellhead	11.86	13.67	12.74	7.98	4.18	(0.48)	(0.76)	(1.06)	(1.38)	(1.71)
% change from prior forecast										
WTI	(6.5%)	(1.7%)	1.1%	(0.1%)	(0.2%)	(0.4%)	(0.7%)	(0.9%)	(1.2%)	(1.4%)
ANS West Coast	15.4%	14.3%	13.2%	7.9%	4.0%	(0.4%)	(0.7%)	(0.9%)	(1.2%)	(1.4%)
ANS Wellhead Wtd Average All Destinations	13.7%	12.8%	11.6%	5.8%	1.5%	(3.3%)	(3.5%)	(3.8%)	(4.0%)	(4.2%)
Cook Inlet Wellhead	12.8%	14.6%	13.5%	8.1%	4.1%	(0.5%)	(0.7%)	(1.0%)	(1.2%)	(1.5%)

Production. C-1

Production Differences from Spring 2011 Forecast

(million barrels per day)

FY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Fall 2011 Forecast										
ANS	0.574	0.555	0.561	0.538	0.550	0.549	0.544	0.515	0.486	0.458
Cook Inlet	0.010	0.009	0.008	0.007	0.007	0.006	0.006	0.005	0.005	0.004
ALASKA	0.585	0.564	0.569	0.545	0.556	0.555	0.550	0.520	0.491	0.462
Spring 2011 Forecast										
ANS	0.610	0.603	0.630	0.614	0.629	0.619	0.598	0.564	0.530	0.503
Cook Inlet	0.009	0.008	0.008	0.007	0.007	0.006	0.006	0.006	0.005	0.005
ALASKA	0.620	0.612	0.638	0.622	0.636	0.626	0.604	0.570	0.536	0.508
Volume change from prior forecast										
ANS	(0.036)	(0.048)	(0.069)	(0.076)	(0.079)	(0.070)	(0.053)	(0.049)	(0.045)	(0.045)
Cook Inlet	0.001	0.001	0.000	0.000	(0.000)	(0.000)	(0.000)	(0.001)	(0.001)	(0.001)
ALASKA	(0.035)	(0.047)	(0.069)	(0.076)	(0.079)	(0.071)	(0.054)	(0.050)	(0.045)	(0.046)
Percent change from prior forecast										
ANS	(5.9%)	(8.0%)	(10.9%)	(12.4%)	(12.6%)	(11.3%)	(8.9%)	(8.7%)	(8.4%)	(9.0%)
Cook Inlet	12.0%	7.1%	3.4%	0.3%	(2.2%)	(4.9%)	(7.3%)	(9.4%)	(11.1%)	(13.1%)
ALASKA	(5.6%)	(7.8%)	(10.8%)	(12.2%)	(12.5%)	(11.3%)	(8.9%)	(8.7%)	(8.4%)	(9.1%)

Production. C-2a

Crude Oil Production—History [1]

(million barrels per day)

FY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Prudhoe Bay[2]	0.538	0.481	0.465	0.429	0.376	0.303	0.324	0.322	0.305	0.296
PBU Satellites[3]	0.030	0.045	0.052	0.043	0.041	0.043	0.034	0.037	0.036	0.030
GPMA[4]	0.073	0.065	0.060	0.055	0.048	0.037	0.044	0.038	0.034	0.031
Kuparuk	0.174	0.160	0.154	0.141	0.133	0.121	0.113	0.106	0.099	0.091
Kuparuk Satellites[5]	0.041	0.052	0.049	0.051	0.043	0.044	0.038	0.036	0.035	0.032
Endicott[6]	0.033	0.029	0.028	0.020	0.021	0.016	0.014	0.014	0.013	0.012
Alpine[7]	0.096	0.099	0.099	0.105	0.123	0.124	0.115	0.107	0.094	0.084
NPR-A	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Offshore[8]	0.025	0.059	0.066	0.068	0.055	0.045	0.034	0.031	0.029	0.027
Total ANS	**1.010**	**0.991**	**0.974**	**0.911**	**0.840**	**0.734**	**0.716**	**0.693**	**0.644**	**0.603**
Cook Inlet	**0.033**	**0.030**	**0.025**	**0.020**	**0.018**	**0.015**	**0.014**	**0.010**	**0.009**	**0.010**
Total Alaska	**1.043**	**1.021**	**0.999**	**0.932**	**0.858**	**0.750**	**0.730**	**0.703**	**0.652**	**0.613**

(1) A summary of historical crude oil production can be found on the Tax Division's web site at: www.tax.alaska.gov/sourcesbook/AlaskaProduction.pdf.
(2) Includes NGLs from Central Gas Facility shipped to TAPS, Milne Point , Sag River and Schrader Bluff.
(3) Aurora, Borealis, Midnight Sun, Orion and Polaris.
(4) Lisburne, Niakuk, North Prudhoe Bay State, Point McIntyre, Raven, West Beach and West Niakuk.
(5) Meltwater, Tabasco, Tarn and West Sak.
(6) Includes Badami, Eider and Sag Delta.
(7) Includes Fiord, Fiord-Kuparuk, Nanuq, Nanuq-Kuparuk, Alpine-West and Qannik.
(8) Northstar (all ownership), OCS production, Liberty, Nikaitchuq and Oooguruk.

Production. C-2b

Crude Oil Production—Forecast [1]

(million barrels per day)

FY	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Prudhoe Bay[2]	0.276	0.269	0.273	0.264	0.263	0.254	0.243	0.233	0.225	0.216
PBU Satellites[3]	0.036	0.034	0.035	0.033	0.029	0.025	0.023	0.020	0.018	0.017
GPMA[4]	0.026	0.024	0.022	0.019	0.018	0.016	0.015	0.014	0.012	0.011
Kuparuk	0.087	0.083	0.081	0.078	0.077	0.075	0.073	0.072	0.071	0.069
Kuparuk Satellites[5]	0.030	0.027	0.024	0.021	0.019	0.018	0.016	0.015	0.014	0.013
Endicott[6]	0.012	0.016	0.017	0.018	0.019	0.018	0.017	0.017	0.015	0.014
Alpine[7]	0.079	0.071	0.072	0.065	0.062	0.059	0.050	0.043	0.038	0.034
NPR-A	0.000	0.000	0.000	0.000	0.000	0.007	0.040	0.042	0.038	0.035
Offshore[8]	0.027	0.031	0.039	0.038	0.054	0.068	0.058	0.050	0.045	0.040
Point Thomson	0.000	0.000	0.000	0.001	0.009	0.009	0.009	0.009	0.009	0.009
Total ANS	**0.574**	**0.555**	**0.561**	**0.538**	**0.550**	**0.549**	**0.544**	**0.515**	**0.486**	**0.458**
Cook Inlet	**0.010**	**0.009**	**0.008**	**0.007**	**0.007**	**0.006**	**0.006**	**0.005**	**0.005**	**0.004**
Total Alaska	**0.585**	**0.564**	**0.569**	**0.545**	**0.556**	**0.555**	**0.550**	**0.520**	**0.491**	**0.462**

(1) A summary of historical crude oil production can be found on the Tax Division's web site at: www.tax.alaska.gov/sourcesbook/AlaskaProduction.pdf.
(2) Includes NGLs from Central Gas Facility shipped to TAPS, Milne Point , Sag River and Schrader Bluff.
(3) Aurora, Borealis, Midnight Sun, Orion and Polaris.
(4) Lisburne, Niakuk, North Prudhoe Bay State, Point McIntyre, Raven, West Beach and West Niakuk.
(5) Meltwater, Tabasco, Tarn and West Sak.
(6) Includes Badami, Eider and Sag Delta.
(7) Includes Fiord, Fiord-Kuparuk, Nanuq, Nanuq-Kuparuk, Alpine-West and Qannik.
(8) Northstar (all ownership), OCS production, Liberty, Nikaitchuq and Oooguruk.

Income Statement. D-1a

FY 2011 Production Tax Estimate using Income Statement Format

Note: This table presents an approximation of the production tax calculation, and does not match production tax estimates throughout this publication. Please use accordingly.

	Price	Barrels	Value ($ million)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$94.49	602,723	$56.9
Annual Production (bbl)			
Total		219,993,895	$20,786.7
Royalty, Federal and other barrels[1]		-29,505,505	($2,787.9)
Taxable barrels [2]		**190,488,390**	**$17,998.8**
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	($2.45)		
TAPS Tariff	($4.02)		
Other	($0.70)		
Total Transportation Costs	**($7.17)**	**190,488,390**	**($1,365.8)**
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	($13.22)		($2,517.4)
Deductible Capital Expenditures	($8.52)		($1,622.9)
Total Lease Expenditures	**($21.74)**	**190,488,390**	**($4,140.3)**
Production Tax			
Production Tax Value (PTV)			$12,492.6
Base Tax (25%*PTV)			$3,123.2
Production Tax Value per barrel	$65.58		
Progressive Tax = (14.2% * PTV)			$1,778.1
Total Tax before credits			**$4,901.2**
Credits			($400.0)
Estimated Total Tax after credits[4]			**$4,501.2**

[1] Royalty, Federal and other barrels represents our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and barrels used in production. For purposes of this calculation, it also includes barrels produced by companies with negative PTV.

[2] For purposes of this illustration, "taxable barrels" shown here exclude barrels produced by companies expected to have zero tax liability.

[3] Deductible Lease Expenditures represents our best estimate of lease expenditures that are applicable to currently producing fields that are likely to produce a tax liability for the company or companies producing them. The per-barrel expenditures reflect expenditures **per taxable barrel** and do not reflect expenditures per all barrels produced.

[4] Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Income Statement. D-1b

FY 2012 Production Tax Estimate using Income Statement Format

Note: This table presents an approximation of the production tax calculation, and does not match production tax estimates throughout this publication. Please use accordingly.

	Price	Barrels	Value ($ million)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$109.33	574,373	$62.6
Annual Production (bbl)			
Total		209,646,327	$22,848.2
Royalty, Federal and other barrels[1]		-33,702,389	($3,673.0)
Taxable barrels [2]		**175,943,938**	**$19,175.1**
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	($2.71)		
TAPS Tariff	($5.16)		
Other	($0.85)		
Total Transportation Costs	**($8.72)**	**175,943,938**	**($1,534.6)**
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	($14.03)		($2,468.1)
Deductible Capital Expenditures	($10.25)		($1,804.0)
Total Lease Expenditures	**($24.28)**	**175,943,938**	**($4,272.1)**
Production Tax			
Production Tax Value (PTV)			$13,368.5
Base Tax (25%*PTV)			$3,342.1
Production Tax Value per barrel	$75.98		
Progressive Tax = (18.4% * PTV)			$2,458.8
Total Tax before credits			**$5,800.9**
Credits			($400.0)
Estimated Total Tax after credits[4]			**$5,400.9**

[1] Royalty, Federal and other barrels represents our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and barrels used in production. For purposes of this calculation, it also includes barrels produced by companies with negative PTV.

[2] For purposes of this illustration, "taxable barrels" shown here exclude barrels produced by companies expected to have zero tax liability.

[3] Deductible Lease Expenditures represents our best estimate of lease expenditures that are applicable to currently producing fields that are likely to produce a tax liability for the company or companies producing them. The per-barrel expenditures reflect expenditures **per taxable barrel** and do not reflect expenditures per all barrels produced.

[4] Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Income Statement. D-1c

FY 2013 Production Tax Estimate using Income Statement Format

Note: This table presents an approximation of the production tax calculation, and does not match production tax estimates throughout this publication. Please use accordingly.

	Price	Barrels	Value ($ million)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$109.47	555,227	$60.8
Annual Production (bbl)			
Total		202,657,895	$22,185.1
Royalty, Federal and other barrels[1]		-30,158,081	($3,301.4)
Taxable barrels [2]		**172,499,814**	**$18,883.7**
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	($2.70)		
TAPS Tariff	($4.96)		
Other	($0.91)		
Total Transportation Costs	**($8.56)**	**172,499,814**	**($1,477.0)**
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	($13.75)		($2,372.5)
Deductible Capital Expenditures	($15.36)		($2,648.9)
Total Lease Expenditures	**($29.11)**	**172,499,814**	**($5,021.5)**
Production Tax			
Production Tax Value (PTV)			$12,385.2
Base Tax (25%*PTV)			$3,096.3
Production Tax Value per barrel	$71.80		
Progressive Tax = (16.7% * PTV)			$2,070.7
Total Tax before credits			**$5,167.0**
Credits			($450.0)
Estimated Total Tax after credits[4]			**$4,717.0**

[1] Royalty, Federal and other barrels represents our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and barrels used in production. For purposes of this calculation, it also includes barrels produced by companies with negative PTV.

[2] For purposes of this illustration, "taxable barrels" shown here exclude barrels produced by companies expected to have zero tax liability.

[3] Deductible Lease Expenditures represents our best estimate of lease expenditures that are applicable to currently producing fields that are likely to produce a tax liability for the company or companies producing them. The per-barrel expenditures reflect expenditures **per taxable barrel** and do not reflect expenditures per all barrels produced.

[4] Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2011

Credits. E-1a

Summary of Alaska Tax Credits in Current Law ($ millions)

Description of Credit	Credit Rate and Maximum Credit	Amount of Credit Claimed		
		FY 2009	FY 2010	FY 2011
Credits Applicable to the Oil and Gas Production Tax (see Note A)				
Exploration Incentive Credit, AS 38.05.180(i) A non-transferrable credit for the cost of drilling or seismic work performed under a limited time period established by the Commissioner of the Department of Natural Resources.	Up to 50% of the cost of drilling or seismic work, not to exceed 50% of the tax liability to which it is being applied. This credit may also be applied against the state royalty.	$0	$0	$0
Qualified Capital Expenditure Credit, AS 43.55.023(a) and (l) A transferable tax credit for qualified oil and gas capital expenditures in the state. Taken in lieu of exploration incentive credits under AS 43.55.025 and gas exploration credits under AS 43.20.043.	Credit is 20% of eligible expenditures, or 40% for well related expenses outside the North Slope. For credits earned for North Slope capital expenditures under AS 43.55.023 (a), no more than half the credit may be applied in a single calendar year.	Includes Carried-Forward Loss Credits $391	$585	$640
Carried-Forward Annual Loss Credit, AS 43.55.023(b) A transferable credit for a carried-forward annual loss, as defined as a producer or explorer's adjusted lease expenditures that are not deductible in calculating production tax values for the calendar year.	Credit is 25% of the carried-forward annual loss. If a transferable credit certificate is applied for North Slope losses, not more than half may be taken in one year.	Totals included in Qualified Capital Expenditure Credits above		
Small Producer / New Area Development Credit, AS 43.55.024(a) and (c) A non-transferable credit for oil and gas produced by small producers, defined as having average taxable oil and gas production of less than 100,000 BTU equivalent barrels per day, or for oil or gas produced on leases outside Cook Inlet and below 68 degrees North latitude, providing the producer has a positive tax liability on that production before the application of other credits. Credit is available until the later of 2016 or 9 years after first commercial production of oil and gas on the properties for which the credit applies.	Credit is 100% of tax liability for eligible oil and gas production. The credit is capped at $12,000,000 annually under the small producer credit for producers with no more than 50,000 BTU equivalent barrels per day. The credit then phases out, reaching zero for producers with 100,000 or more BTU equivalent barrels per day. Under the new area development credit, credit is available up to $6,000,000 per company annually.	$21	$34	$38
Transitional Investment Expenditure Credit, AS 43.55.023(i) A non-transferable credit for qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006. Only available to companies that did not have production in commercial quantities prior to January 1, 2008. Credit may not be used after December 31, 2013.	Credit is 20% of qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006, not to exceed 10% of the capital expenditures incurred between March 31, 2006 and January 1, 2008.	Cannot be reported due to taxpayer confidentiality		
Alternative Credit for Exploration, AS 43.55.025 A transferable credit for expenditures for certain oil and gas exploration activities. Expires 7/1/2016.	Outside of Cook inlet, credit is 40% for seismic costs outside an existing unit, 30% for drilling costs greater than 25 miles from an existing unit, 30% for pre-approved new targets greater than 3 miles from an existing well, and 40% for pre-approved new targets greater than 3 miles from a well and greater than 25 miles from an existing unit. For Cook Inlet, credit is 40% for seismic costs outside an existing unit, 30% for drilling costs greater than 10 miles from an existing unit, 30% for pre-approved new targets, and 40% for drilling costs that are greater than 10 miles from an existing unit and pre-approved new targets.	$18	$41	$13

Note A: Credits under these programs are calculated and tracked on a calendar year basis. Totals represent CY 2009, 2010, and 2011.

Credits. E-1b

Summary of Alaska Tax Credits in Current Law ($ millions)

Description of Credit	Credit Rate and Maximum Credit	Amount of Credit Claimed		
		FY 2009	FY 2010	FY 2011
Cook Inlet Jack-Up Rig Credit, AS 43.55.025(a)(5) and (l)				
A credit for exploration expenses for the first three wells drilled by the first jack-up rig brought in to Cook Inlet. Expenses only for drilling of wells from a jack-up rig for wells that test pre-Tertiary; all three wells must be drilled by unaffiliated parties.	Credit is 100% of costs for the first well up to $25 million, 90% of costs for the second well up to $22.5 million, and 80% of costs for the third well up to $20 million. If exploration well is brought into production, operator shall repay 50% of the credit over ten years following production start-up.	Credit program began in 2011		
Credits Applicable to the Corporate Income Tax				
Internal Revenue Code Credits Adopted by Reference, AS 43.20.021				
Under Alaska's blanket adoption of the IRC, taxpayers can claim all federal incentive credits. Federal credits that refund other federal taxes are not allowed. Multistate taxpayers apportion their total federal incentive credits.	For most credits, credit is limited to 18% of the amount of the credit determined for federal income tax purposes which is attributable to Alaska.	Not tracked		
Gas Exploration and Development Credit, AS 43.20.043				
A non-transferable credit for qualified expenditures for exploration and development of non-North Slope natural gas reserves.	Credit is 25% of qualified expenditures for investment after January 1, 2010; investments in existing units qualify. Credit is capped at 75% of tax liability as calculated before applying other credits.	Cannot be reported due to taxpayer confidentiality		
Gas Storage Facility Credit, AS 43.20.046				
A credit for the costs incurred to establish a gas storage facility. Does not apply to gas storage related to a gas sales pipeline on the North Slope. Facility shall operate as a public utility regulated by the Alaska RCA with open access for 3rd parties. Effective for facilities placed into service between January 1, 2011 and December 31, 2015.	Credit is $1.50 per thousand cubic feet of "working gas" storage capacity as determined by AOGCC. Maximum credit is the lesser of $15 million or 25% of costs incurred to establish the facility.	Credit program began in 2011		
Film Production Credit, AS 43.98.030				
A transferable credit for expenditures on eligible film production activities in Alaska. Producer must spend at least $100,000 in a consecutive 24-month period to qualify. Expires the earlier of 7/1/2013 or once $100 million of credits have been approved.	Credit is 30% of eligible film production expenditures, plus an additional 10% credit for wages paid to Alaska residents, plus an additional 2% credit for filming in a rural area, plus an additional 2% credit for filming between October 1 and March 30. Program is capped at $100 million for all projects.	$0	<$1	<$1
Credits Applicable to Multiple Tax Programs				
Education Credit, AS 21.89.070 and .075, AS 43.20.014, AS 43.55.019, AS 43.56.018, AS 43.65.018, AS 43.75.018, AS 43.77.045 - Applicable to Corporate Income Tax, Fisheries Business Tax, Fishery Resource Landing Tax, Insurance Premium Tax, Mining License Tax, Oil and Gas Production Tax, Oil and Gas Property Tax				
A non-transferable credit for contributions to vocational educational programs, accredited Alaska universities or colleges for educational purposes or facilities, annual intercollegiate sports tournaments, AK Native educational programs, facilities that qualify under the Coastal American Partnership; under AS 21.89.075 contributions to the Alaska Fire Standards Council also qualify.	Credit is 50% of annual contributions up to $100,000, 100% of the next $200,000 and 50% of annual contributions beyond $300,000. The credit cannot exceed $5,000,000 annually across all eligible tax types. The credit at these rates is effective from January 1, 2011 until December 31, 2020, at which point the maximum credit for any taxpayer is $150,000 per year.	$2	$2	$3

Credits. E-1c

Summary of Alaska Tax Credits in Current Law ($ millions)

Description of Credit	Credit Rate and Maximum Credit	Amount of Credit Claimed		
		FY 2009	FY 2010	FY 2011
Minerals Exploration Incentive Credit, AS 27.30.030, AS 43.20.044 - Applicable to Corporate Income Tax, Mining License Tax and Mineral Production Royalty				
A non-transferable credit for eligible costs of mineral or coal exploration activities. Credit must be used within 15 years.	Credit is 100% of allowable exploration costs with a maximum of $20 million. Credit is limited to: (1) for mining license tax, the lesser of 50% of the MLT liability at the mining operation at which the exploration occurred or 50% of total MLT liability; (2) for corporate income tax, the lesser of 50% of the MLT liability at the mining operation at which the exploration occurred or 50% or total CIT liability, and (3) for mineral royalty, 50% of royalty liability from the mining operation at which the exploration activity occurred.	$0	<$1	<$1
Credits Applicable to Fisheries Taxes				
Scholarship Contributions Credit, AS 43.75.032, AS 43.77.035 - Applicable to the Fisheries Business Tax and Fishery Resource Landing Tax				
A non-transferable credit for contributions to the A.W. "Winn" Brindle memorial education loan account established under AS 14.43.250.	Credit is 100% of contribution amount up to a maximum of 5% of tax liability.	<$1	<$1	<$1
Salmon Product Development Credit, AS 43.75.035 A non-transferable credit for eligible capital expenditures to expand value-added processing of Alaska salmon including ice-making machines. Credit expires December 31, 2015 and may be carried forward for three years.	Credit is 50% of qualified investment up to 50% of tax liability incurred for processing of salmon during the tax year.	$3	$4	$2
Community Development Quota Credit, AS 43.77.040 A non-transferable credit for contributions to an Alaska nonprofit corporation that are dedicated to fisheries industry-related expenditures. Credit is available only for fishery resources harvested under a community development quota (CDQ).	Credit is 100% of contribution amount up to a maximum of 45.45% of tax liability on fishery resources harvested under a CDQ.	$0	<$1	<$1
Other Taxes Credit, AS 43.77.030 A non-transferable credit for taxes paid to another jurisdiction on fishery resources landed in Alaska.	Credit is 100% of taxes paid with a maximum of 100% of the Alaska tax liability on the fishery resources.	Not tracked		
Total All Credits		**$436**	**$670**	**$700**

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2011

In accordance with AS 37.07.060 (b)(4), the Revenue Sources Book is compiled annually by the Alaska Department of Revenue to assist the governor in formulating a proposed comprehensive financial plan for presentation to the Alaska State Legislature. Within the publication are shown prior year actuals, revised current year estimates and future year projections.

Anticipated state income is projected through the use of a number of data sources:

(1) Econometric models developed by the Department of Revenue to forecast unrestricted non-petroleum revenues;

(2) A petroleum revenue model created by the department's Tax Division;

(3) Estimates from individual state agencies.

We thank the various state agencies for their cooperation in computing anticipated revenues for publication in this Fall 2010 Revenue Sources Book.

The Department of Revenue complies with Title II of the Americans With Disabilities Act of 1990. This publication is available in alternative communication formats upon request. Please contact the division's representative at 907-465-3692 or 907-465-3678 (TDD) to make necessary arrangements.

This publication, required by law (AS 37.07.060), was printed in Anchorage, Alaska at a cost of about $5 per copy.

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2011

Forecast & Historical Data

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