

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 150 32459



RECORDS CERTIFICATION



I, the undersigned, an employee of the State of Alaska, do hereby certify that the microfilm images on this microform are accurate reproductions of the original records of the State of Alaska as accumulated during the regular course of business.

Stan Hubbard

Signature of Camera Operator

3-17-2010

Date

LIST OF FILES

SCOMM 150: HOUSE SPECIAL COMMITTEE ON WAYS AND MEANS, 2007-2008

MEMBERS:

REPRESENTATIVE HAWKER, CHAIR
REPRESENTATIVE FAIRCLOUGH, VICE CHAIR
REPRESENTATIVE CISSNA
REPRESENTATIVE GRUJENBERG
REPRESENTATIVE ROSES
REPRESENTATIVE SEATON
REPRESENTATIVE WILSON

Established by HR 5, 2005

Contents: 15 files. See legislative homepage at
<http://www.legis.state.ak.us> for minutes and audio meetings
1/24/07-2/20/08.

LIST OF FILES (PAGE 1)	MICROFICHE #
1. 1/24/07 - OVERVIEW: REVENUE	
2. 1/31/07 - WHERE DID THE FISCAL GAP GO? PT II PRODUCTION DECLINE PROJECTION	
3. 2/5/07 - WHERE DID THE FISCAL GAP GO? PT III OMB: EXPENSE PROJECTION	
4. 2/7/07 - WHERE DID THE FISCAL GAP GO? PT IV WHERE DOES THE MONEY COME FROM NEXT	
5. 3/14/07 - OVERVIEW: MINING TAX	
6. HB 13	
7. HB 61	
8. HB 68	
9. HB 125	
10. HB 156	
11. HB 204	
12. HB 206	
13. HJR 1	

SCOMM 150: HOUSE SPECIAL COMMITTEE ON WAYS AND MEANS, 2007-2008
LIST OF FILES (PAGE 2) MICROFICHE #

14. HJR 5

15. HJR 35

SCOMM

150:1



State Revenue, Crude Oil Production & the PPT

House Ways & Means Committee, January 24, 2007
Alaska Department of Revenue

Agenda

- State Revenue
- Crude Oil Production
- Petroleum Profits Tax



Revenue Projections

- Fall 2006 RSB
- Oil Revenues Dominate
- Variance Analysis
- Non-Oil Revenue



Oil Dependency

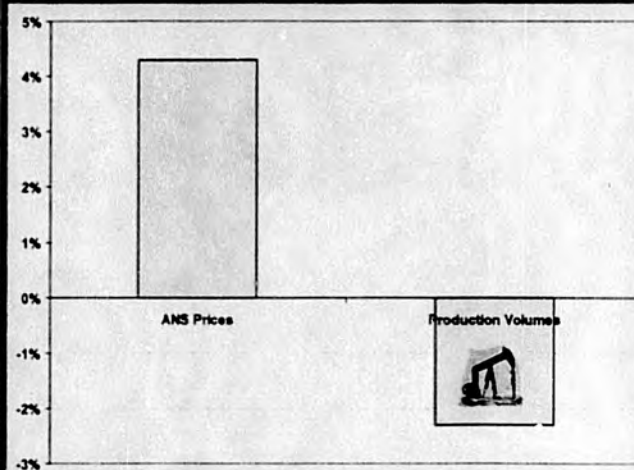
FY 2007 General Fund Unrestricted Revenue, Millions

Royalty – Net PF	1,503.9	30.6%
Production Tax	2,067.2	42.1%
Income Tax	657.2	13.4%
Property	51.7	1.1%
Bonus, Rent, etc	51.4	1.0%
Total Oil	4,331.5	88.2%
Non-Oil	580.8	11.8%
Tot Budget	4,912.3	100.0%

Source: Fall 2006 Revenue Sources Book, page 89.

Variance in Key Factors

For FY 2007, Year-to-Date Changes From Fall Forecast



Note: In the Fall 2006 Revenue Sources Book, ANS prices were forecast to average \$59.15 per barrel for FY 2007. Through January 18, 2007, prices averaged \$61.81 per barrel, which is \$2.66 or 4.3% above the forecast. ANS crude oil production was forecast to average 739,618 bbl. Through January 17, 2007 production averaged 722,845 bbl, which is 16,773 bbl or 2.3% below the forecast.

Non-Oil Revenue

FY 2007 General Fund Unrestricted Revenue, Millions

Sales & Use	155.8	26.8%
Corporate Income Tax	135.7	23.4%
Fish	19.7	3.4%
Charges for Services	23.1	4.0%
Fines & Forfeitures	10.3	1.8%
Licenses & Permits	44.1	7.6%
Rents & Royalty	9.4	1.6%
Investments	124.0	21.3%
Other	58.7	10.1%
Tot Budget	580.8	100.0%

Source: Fall 2006 Revenue Sources Book, pages 8 and 9.

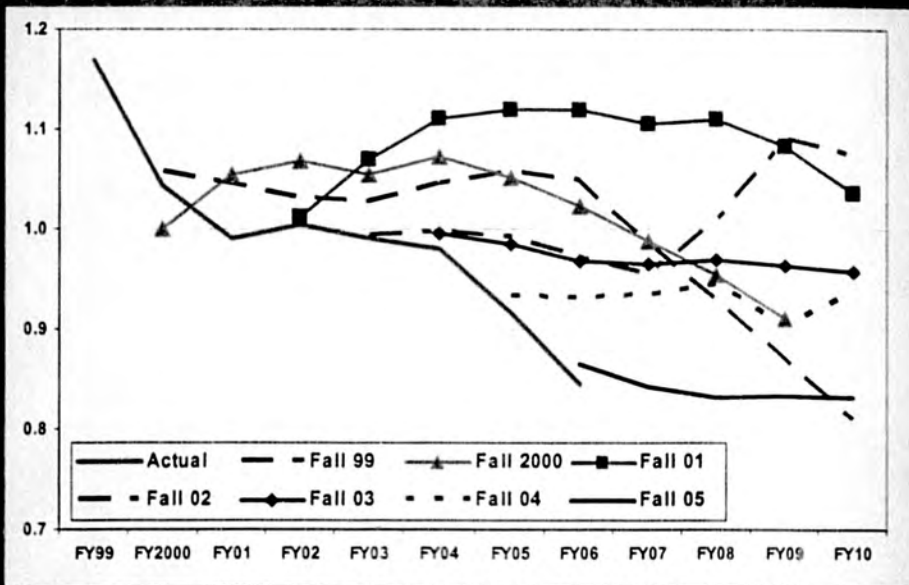
Crude Oil Production

- **Forecasting Accuracy:**
 - Actual Production
 - Historical Projections
- **Current Forecast**



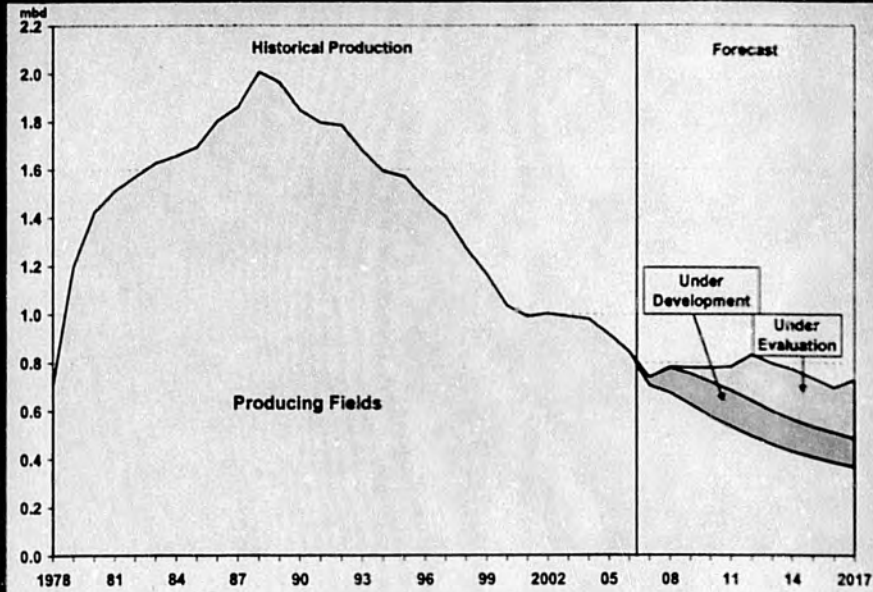
Fall Oil Production Forecasts

ANS, Millions of Barrels per Day



ANS Production Forecast by Category

FY 1978-2006, Forecast FY 2007-2017, Million Barrels per Day



Petroleum Profits Tax

- “True-Up” Payment
- Regulations Status

PPT True-Up Payment

- **Due End of March**
- **Estimate = \$0.95 billion**
 - **April, May = \$0.29 billion**
 - **June – December = \$0.66 billion**

PPT Regulations Status

- **Publicly Noticed Workshops Oct - Nov**
- **Draft Regulations Created**
- **Public Comments & Hearing: Dec 13 – Jan 17**
- **Issues Raised:**
 - **Transfer of Exploration Credits**
 - **Clarification of Lease Expenditures**
 - **Overhead Rates (Too high-Too low)**
 - **Ring Fencing Losses**
 - **Information Reporting Requirements**
 - **Inclusion of Penalty Provisions**

PPT Regulations Status

- **Estimated Revision Time: Mid February**
- **Final Review**
 - DOR Director & Commissioner
 - Department of Law
 - Lieutenant Governor's Office
- **Expected Implementation – April**
- **Second Regulation Project-Spring '07**
(To include: Clarifying allowable lease expenditures and use of operating agreements)



Alaska Department of Revenue

Revenue Sources Book

Alaska Department of Revenue – Tax Division



FALL 2006



Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2006

STATE OF ALASKA

DEPARTMENT OF REVENUE

Tax Division

FRANK MURKOWSKI, GOVERNOR

State Office Building
PO Box 110420

Juneau, AK 99811-0420

907.465.2320

550 W Seventh, Suite 500
Anchorage, AK 99501-3568
907.269.1019

www.tax.state.ak.us

The Honorable Frank H. Murkowski, Governor of Alaska
Governor-Elect Sarah Palin
P.O. Box 110001
Juneau, Alaska 99811-0001

December 1, 2006

Dear Governor Murkowski & Governor-Elect Palin:

I present you, the Legislature and the Alaska public with the Department of Revenue's latest *Revenue Sources Book*. Our fall 2006 report includes an accounting of state revenues received in FY 2006 and provides projections for FY 2007 through FY 2017.

Three factors dominate the forecast: pipeline closures on the North Slope, high crude oil prices, and a new production tax titled the Petroleum Profits Tax or PPT. Taken together, these result in projected oil revenue of about \$4.3 billion for general fund unrestricted revenue for FY 2007 and represent about 88% of the State's discretionary income of about \$4.9 billion.

We project Alaska North Slope crude oil prices will average \$59.15 per barrel for this fiscal year ending June 30, 2007. The fiscal year year-to-date average is currently above \$66 per barrel but price volatility continues and prices are about 20% lower than their peak of \$75 per barrel in July 2006. We believe volatility will continue and there will be continued downward pressure on oil prices. Our forecast for Alaska North Slope crude for FY 2008 is \$51.25 and for FY 2009, \$49.50 a barrel.

Our new long-run ANS crude oil price forecast for FY 2014-beyond is \$41.50 per barrel, increasing at the projected rate of inflation. Yes, this is lower than today's markets and certainly lower than many pundits predict. We are cautious, however, in our approach, and do not frequently change our long-term price forecast. We continue to believe this is an appropriate response to volatile oil markets.

Our forecast for natural gas prices at the Henry Hub for FY 2007 is \$5.93 per million BTU. Natural gas prices have exhibited extreme volatility in the last year – declining over 76% between December 13, 2005 (\$15.39 per million BTU) and September 29, 2006 (\$3.66 per million BTU). Since September 29, prices have more than doubled to \$7.59 per million BTU on November 16. We do not have a separate section on natural gas in the fall forecast; however, historical prices as well as our forecast for natural gas prices can be found in the appendices section of our report.

Letter to Governor Murkowski & Governor-Elect Palin
December 1, 2006

Page 2

Alaska North Slope crude oil production projections have been adjusted and our FY 2007 forecast is 740,000 b/d – about 12% lower than FY 2006. A significant part of this decrease is attributed to pipeline corrosion issues at Prudhoe Bay, Lisburne and Milne Point. Production for FY 2008 is projected to increase to about 782,000 b/d – and we assume there are no pipeline closures of the magnitude seen during calendar year 2006.

Revenue from oil is received from the State's royalty share, production tax, corporate income tax and property tax. The PPT is the production tax that was signed into law in 2006. The structure of the PPT as a tax on net value, and the associated tax credits, was designed to encourage investment in the state's petroleum sector that would lead to higher oil production and thus higher long-run revenues. This system is radically different from the old ELF-based system and the discussion in Section 4 highlights the differences. The Department of Revenue estimates for FY 2007, that the PPT will provide the State with about \$1.2 billion more than production taxes under the ELF-based system.

We hope that this forecast provides you with useful information.

Sincerely,

Bill Corbus

William A. Corbus
Commissioner

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2006

1. Introduction.....	1
2. Executive Summary	3
3. Will Heavy Oil Do the Heavy Lifting for Alaska?	21
Heavy oil is located throughout the world, including Alaska where we have a potential of tens of billions of recoverable barrels. The state currently has five fields producing heavy oil and there is significant potential for additional production.	
4. Oil Revenue.....	27
In FY 2006, oil and gas production tax, corporate income tax, property tax and royalty revenues contributed 88 percent of the state's General Fund unrestricted revenue. Oil revenues will continue to play a key role in Alaska's future.	
5. Other Revenue (except Federal & Investment)	45
Revenue from non-oil sources includes non-oil taxes, charges for services, fines and forfeitures, licenses and permits, rents and royalties and other revenue sources.	
6. Federal Revenue	57
Federal funding continues to be one of Alaska's biggest sources of revenue.	
7. Investment Revenue.....	61
Investment earnings come from the Alaska Permanent Fund, Constitutional Budget Reserve Fund, General Fund and other state investments.	
8. State Endowment Funds	71
Alaska has six endowment funds.	
9. Public Corporations and the University of Alaska	75
Seven public corporations and the University of Alaska are treated as separate component units of state government for financial reporting purposes.	
10. Appendices	83
The appendices provide 10 years of historical data and 10 years of forecast data on oil revenue, prices and production. For a complete set of historical data, please visit our web site at http://www.tax.state.ak.us/sourcesbook/index.asp .	
11. Index	107

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2006

Tax Division Contact Persons

Robynn J. Wilson, Director

907.269.6620

robynn_wilson@revenue.state.ak.us

Michael D. Williams, Chief Economist

907.269.1019

m_w@revenue.state.ak.us

Denise Hawes, Economist

907.269.1020

denise_hawes@revenue.state.ak.us

Beth Leschper, Program Coordinator, Publisher

907.465.2370

beth_leschper@revenue.state.ak.us

Contact Persons for Specific Topics

Alaska Permanent Fund

Chris Phillips, Director of Finance

Alaska Permanent Fund Corporation

907.465.2047

cphillips@alaskapermfund.com

Constitutional Budget Reserve Fund

Tom Boutin, Deputy Commissioner

Alaska Department of Revenue, Treasury Division

907.465.2300

tom_boutin@revenue.state.ak.us

Non-Petroleum Revenue

Dan Stickel, Economist

Alaska Department of Revenue, Tax Division

907.465.3279

daniel_stickel@revenue.state.ak.us

Restricted Revenue

John Boucher, Senior Economist

Office of the Governor, Management and Budget

907.465.4677

john_boucher@gov.state.ak.us

www.tax.state.ak.us

Revenue Sources Book
Alaska Department of Revenue – Tax Division

FALL 2006

1. Introduction

General Discussion

The purpose of the semi-annual Revenue Sources Book is to provide the governor, legislature and citizens of the state with a summary of our past collections of state revenue and a forecast of future revenue. Revenues are categorized into four major components: oil and gas royalties and taxes, income from sources other than oil including non-oil taxes and fees, federal dollars and investment revenues.

Oil revenues continue to dominate the unrestricted revenue picture—and will continue to provide at least 85% of Unrestricted General Purpose Revenue through FY 2010. However, North Slope oil production is declining. In FY

2006, ANS output was 0.845 million barrels per day compared to a peak of 2.006 million barrels a day in FY 1988. While production declined by almost 58% over that period, the market price of oil has more than tripled. For FY 2007, we project oil production will continue to decrease to 0.740 million barrels per day.

Before the run-up in crude oil prices, beginning in about 2003, the Constitutional Budget Reserve Fund (CBRF) was used to balance the state's budget in 10 of 15 years. Even if prices remain high, the rapid fall in 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 the Permanent Fund, federal revenue and reserves in the CBRF. We hope that the information provided in this book provides greater insight not only into the sources of revenue that support the state today, but also into future revenues from potential new sources on the horizon.

Please note that totals in the tables throughout this publication may not equal the sum of components due to rounding.

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2006

1. Introduction

General Discussion

The purpose of the semi-annual Revenue Sources Book is to provide the Governor, Legislature and citizens of the state with a summary of our past collection of state revenue and a forecast of future revenue. Revenues are categorized into four major components: oil and gas royalties and taxes, income from sources other than oil including non-oil taxes and fees, federal dollars and investment revenues.

Oil revenues continue to dominate the transferred revenue picture – and will continue to provide at least 65% of Unrestricted General Fund Revenue through FY 2010. However, North Slope oil production is declining in FY CBRP.

2006 AAS output was 845 million barrels per day compared to a peak of 1,000 million barrels a day in FY 1988. While production declined by almost 58% over that period, the market price of oil has more than tripled. For FY 2007, we project production will continue to decrease to 670 million barrels per day.

Before the run-up in crude oil prices beginning in about 2003, the Coastal National Budget Reserve Fund (CBRF) was used to balance the state budget in 10 of 15 years. Even if prices remain high, the rapid fall in North Slope crude oil volumes could lead to future budget shortfalls and draw on the CBRF.

Alaska's total revenue picture also includes earnings from the Permanent Fund, federal income and reserves in the CBRF. We hope that the information provided in this book provides key stakeholders with insight not only into the sources of revenue that support the state today, but also into future revenues from potential new sources on the horizon.

Please note that totals in the tables throughout this publication may not equal the sum of components due to rounding.

Figure 2-2. Total Governmental Revenue by Major Component, FY 2006 and Forecasted FY 2007-2008 (\$ million)

Oil Revenue	Forecast	
	FY 2007	FY 2008
Subtotal	3,352.9	4,341.5
Royalties (including bonuses, rents & interest)	1,784.1	1,722.4
Production tax	1,199.3	2,007.2
Corporate income tax	601.1	623.2
Property tax	24.2	21.7

2. Executive Summary

Total Government Revenue

Figure 2-1. FY 2006 Total Revenue \$10.5 billion

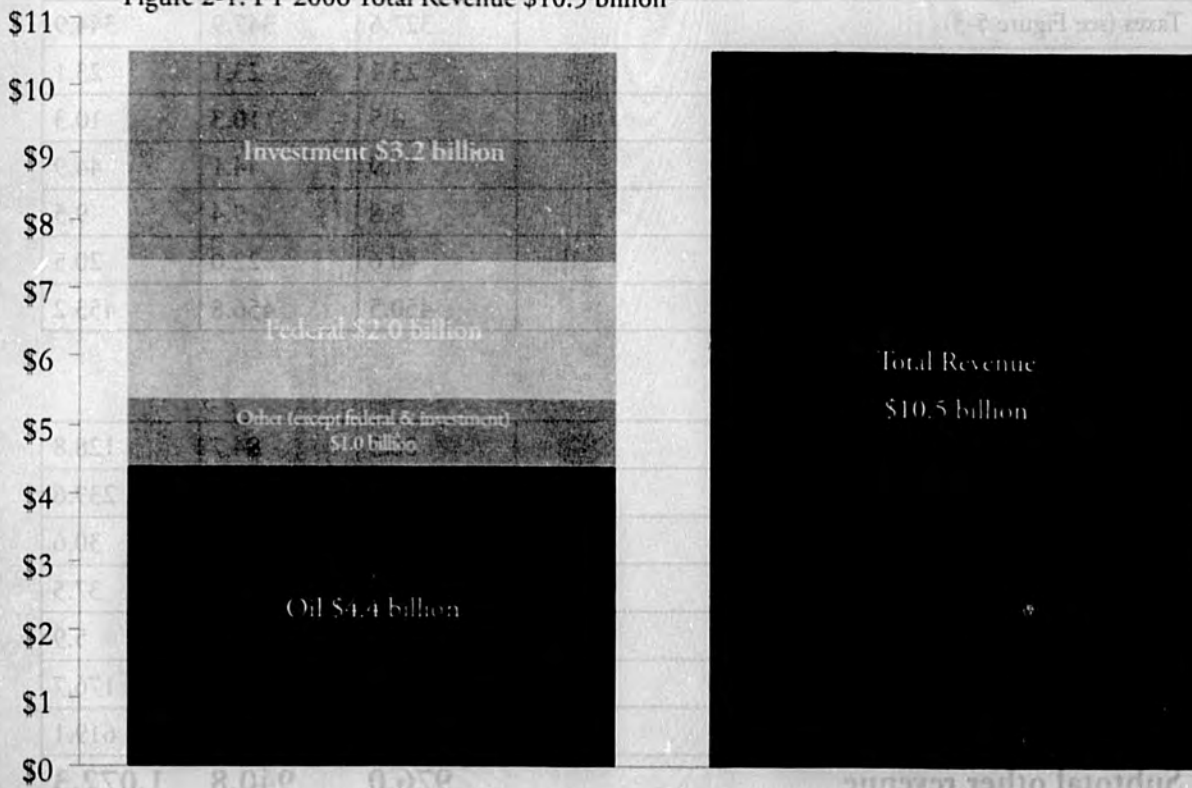


Figure 2-2. Total Governmental Revenue by Major Component, FY 2006 and Forecasted FY 2007-2008 (\$ million)

Oil Revenue	History		Forecast	
	FY 2006	FY 2007	FY 2008	
Unrestricted				
Property tax	54.5	51.7	51.4	
Corporate income tax	661.1	657.2	493.7	
Production tax	1,199.2	2,067.2	1,476.1	
Royalties (including bonuses, rents, & interest)	1,784.1	1,555.4	1,336.0	
Subtotal	3,698.9	4,331.5	3,357.2	
Restricted				
Royalties (including bonuses, rents & interest)	611.5	518.6	447.8	
Tax settlements to CBRF	43.7	90.0	20.0	
NPR-A royalties, rents and bonuses	2.9	6.4	7.6	
Subtotal	658.1	615.0	475.4	
Subtotal oil revenue	4,357.0	4,946.5	3,832.6	

Other Revenue (Except Federal & Investment)

Other Revenue (Except Federal & Investment)	History		Forecast	
	FY 2006	FY 2007	FY 2008	
Unrestricted				
Taxes (see Figure 5-3)	327.6	347.9	344.9	
Charges for services (see Figure 5-4)	23.1	23.1	23.1	
Fines and forfeitures	8.5	10.3	10.3	
Licenses and permits	41.9	44.1	44.9	
Rents and royalties	8.8	9.4	9.5	
Other	40.6	22.0	20.5	
Subtotal	450.5	456.8	453.2	
Restricted				
Taxes (see Figure 5-3)	86.3	84.7	128.8	
Charges for services (see Figure 5-4)	225.0	235.8	239.6	
Fines and forfeitures	21.0	20.1	30.6	
Licenses and permits	30.6	37.1	37.5	
Rents and royalties	5.9	5.9	5.9	
Other	156.7	100.4	176.7	
Subtotal	525.5	484.0	619.1	
Subtotal other revenue	976.0	940.8	1,072.3	

Figure 2-2. Continued

Federal Revenue	History	Forecast	
	FY 2006	FY 2007	FY 2008
Restricted	1,971.5	3,048.5	3,048.5
Subtotal federal revenue	1,971.5	3,048.5	3,048.5
Investment Revenue			
Unrestricted			
Investments	51.9	122.6	99.3
Interest paid by others	1.4	1.4	1.4
Subtotal	53.3	124.0	100.7
Restricted			
Investments	14.4	37.9	29.1
Constitutional Budget Reserve Fund	73.3	176.1	176.5
Other treasury managed funds	13.4	22.3	23.0
Alaska Permanent Fund (GASB)	3,072.3	2,512.5	2,673.9
Subtotal	3,173.3	2,748.8	2,902.5
Subtotal investment	3,226.7	2,872.8	3,003.2
Grand total	10,531.2	11,808.6	10,956.6

Figure 2-3. Total Government by Major Component, FY 2006

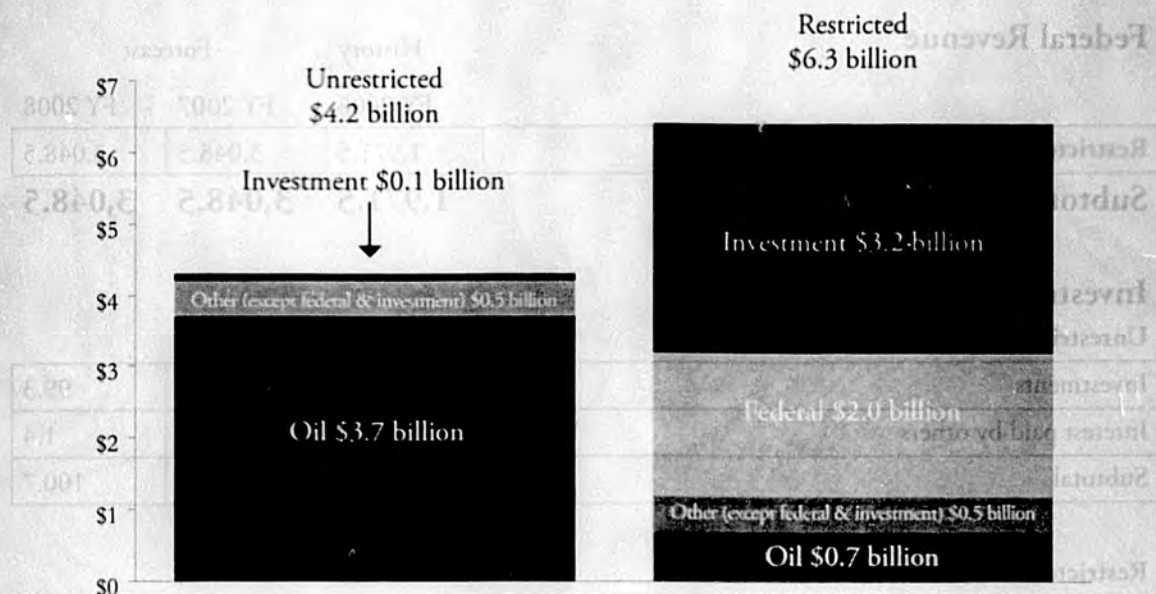


Figure 2-4. Total Governmental State Revenue, FY 2006 and Forecasted FY 2007-2008 (\$ million)

Revenue Source	History	Forecast	
	FY 2006	FY 2007	FY 2008
Unrestricted			
Oil revenue	3,698.9	4,331.5	3,357.2
Other revenue (except federal & investment)	450.5	456.8	453.2
Investment earnings	53.3	124.0	100.7
Subtotal	4,202.7	4,912.3	3,911.1
Restricted			
Oil revenue	658.1	615.0	475.4
Other revenue (except federal & investment)	525.5	484.0	619.1
Investment earnings	3,173.3	2,748.8	2,902.5
Federal revenue	1,971.5	3,048.5	3,048.5
Subtotal	6,328.4	6,896.3	7,045.5
Grand total	10,531.2	11,808.6	10,956.6

Figure 2-5. Unrestricted General Purpose Revenue, FY 2006 and Forecasted FY 2007-2008 (\$ million)

	History	Forecast	
	FY 2006	FY 2007	FY 2008
Property tax	24.5	31.3	31.4
Corporate income tax	661.1	657.3	493.7
Production tax			
Oil & gas production	1,191.4	1,057.2	1,456.3
Oil & gas production lease	7.8	9.7	9.8
Subtotal production tax	1,199.2	1,067.2	1,466.1
Royalties (including business taxes & interest)			
Mineral bonuses & rents	11.6	41.4	17.3
Oil & gas royalties	1,572.2	1,500.9	1,317.2
Interest	0.3	10.0	1.9
Subtotal royalties	1,584.1	1,551.3	1,336.4
Total oil revenue	3,683.9	2,618.5	2,802.5

Other revenue (except federal & investment)

Sales & use			
Alcoholic beverages	15.8	17.8	18.2
Tobacco products - cigarettes	26.4		
Tobacco products - other	7.8		

Unrestricted General Purpose Revenue

Unrestricted General Purpose Revenue is the amount generally used for budget planning purposes and designated in budget documents as General Fund revenue. Figure 2-5 on the next two pages sets out FY 2006 Unrestricted General Purpose Revenue and our forecast for FY 2007 and 2008.

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

Step 1. We estimate all unrestricted revenues in the Alaska State Accounting System (AKSAS), 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 Purpose Revenue.

- Reductions might include: (a) 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.

Subtotal other taxes	327.6	347.9	344.9
Charitable gaming	2.4	2.4	2.4
Other	21.6	20.2	21.9
Subtotal other	331.6	370.5	369.2

Figure 2-5. Unrestricted General Purpose Revenue, FY 2006 and Forecasted FY 2007-2008 (\$ million)

	History	Forecast	
	FY 2006	FY 2007	FY 2008
Oil Revenue			
Property tax	54.5	51.7	51.4
Corporate income tax	661.1	657.2	493.7
Production tax			
Oil & gas production	1,191.4	2,057.5	1,466.3
Oil & gas hazardous release	7.8	9.7	9.8
Subtotal production tax	1,199.2	2,067.2	1,476.1
Royalties (including bonuses, rents, & interest)			
Mineral bonuses & rents	11.6	41.4	17.3
Oil & gas royalties	1,772.2	1,503.9	1,317.2
Interest	0.3	10.0	1.4
Subtotal royalties	1,784.1	1,555.4	1,336.0
Total oil revenue	3,698.9	4,331.5	3,357.2
Other revenue (except federal & investment)			
Sales & use			
Alcoholic beverages	17.6	17.8	18.2
Tobacco products – cigarettes ⁽¹⁾	26.4	32.1	36.2
Tobacco products – other	7.6	7.9	8.3
Insurance premium	44.3	45.4	45.9
Electric and telephone cooperative	0.2	0.2	0.2
Motor fuel tax	42.0	42.9	43.4
Vehicle rental	7.7	7.8	8.0
Tire fee	1.6	1.7	1.7
Subtotal sales & use	147.4	155.8	161.9
Corporate income tax⁽²⁾	137.6	135.7	128.7
Fish			
Fisheries business ⁽³⁾	15.2	15.6	16.1
Fishery resource landing ⁽³⁾	5.8	4.1	4.3
Subtotal fish	21.0	19.7	20.4
Other			
Mining	18.6	34.3	31.5
Estate	0.6	0.0	0.0
Charitable gaming	2.4	2.4	2.4
Subtotal other	21.6	36.7	33.9
Subtotal other taxes	327.6	347.9	344.9

Figure 2-5. Continued

Other revenue (except federal & investment)	History	Forecast	
	FY 2006	FY 2007	FY 2008
Charges for services			
General government	21.0	21.0	21.0
Natural resources	1.9	1.9	1.9
Other	0.2	0.2	0.2
Subtotal charges for services	23.1	23.1	23.1
Fines & forfeitures	8.5	10.3	10.3
Licenses & permits			
Motor vehicle	37.7	39.8	40.6
Alcoholic beverage licenses	1.0	1.1	1.1
Other	3.2	3.2	3.2
Subtotal licenses & permits	41.9	44.1	44.9
Rents & royalties			
Land leasing, rental & sales	7.4	7.9	7.9
Coals royalties	1.1	1.2	1.3
Cabin rentals	0.3	0.3	0.3
Subtotal rents & royalties	8.8	9.4	9.5
Other			
Miscellaneous	30.6	16.5	16.5
Unclaimed property	10.0	5.5	4.0
Subtotal other	40.6	22.0	20.5
Total other (except federal & investment)	450.5	456.8	453.2
Investment Revenue			
Investments	51.9	122.6	99.3
Interest paid by others	1.4	1.4	1.4
Subtotal investment revenue	53.3	124.0	100.7
Total unrestricted revenue	4,202.7	4,912.3	3,911.1

(1) The tobacco (cigarette) tax reported here differs slightly from the amount recorded in the Tax Division's Fiscal Year 2006 Annual Report because of timing issues. Some tax returns are not received and processed until after the state accounting system has closed, resulting in their being counted in the following fiscal year.

(2) The amount of corporate income tax reported here differs slightly from the amount recorded in the Tax Division's FY 2006 Annual Report because of timing issues. A small amount of revenue was moved to this account after the close of the fiscal year. This correction is reflected in the Annual Report, but is not included here because it is not included in the state accounting system.

(3) The fisheries taxes reported here differ slightly from the amounts recorded in the Tax Division's FY 2006 Annual Report because of timing issues. Some tax returns are not received and processed until after the state accounting system has closed, resulting in their being counted in the following fiscal year.

Crude Oil Price

Forecast

Oil revenue will provide at least 85% of forecasted Unrestricted General Purpose Revenue through FY 2010. Two elements are critical to the oil revenue forecast: price and volume.

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) is calculated by subtracting a market differential from the price of West Texas Intermediate (WTI) quoted on the NYMEX. Four different assessment services estimate that market differential and report a daily spot price for ANS.

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.

The table below contains crude oil prices for FY 2006 and the Department of Revenue's forecast of prices for the 11-year period beginning with the current fiscal year FY 2007 and continuing through FY 2017. The oil price forecast is based on a subjective assessment of market dynamics and trend analysis by participants at a Department of Revenue price scenario meeting.

Figure 2-6. WTI, ANS West Coast and ANS Wellhead, FY 2006 and Forecasted FY 2007-2017 (Nominal \$ per barrel)

Fiscal Year	WTI	ANS West Coast	ANS Wellhead
2006	63.01	60.80	55.33
2007	61.45	59.15	52.35
2008	53.75	51.25	44.97
2009	52.00	49.50	44.84
2010	51.50	49.00	44.09
2011	52.50	50.00	44.98
2012	50.00	47.50	42.24
2013	47.50	45.00	39.62
2014	44.00	41.50	35.88
2015	45.00	42.50	36.66
2016	46.00	43.50	37.51
2017	47.00	44.50	38.34

(1) The NYMEX futures market is one source for a WTI quote. A daily WTI spot quote could also be determined by a reporting service's daily assessment of the WTI spot market.

Figure 2-7 shows: (1) the monthly ANS West Coast market price from July 1997 through September 2006, (2) the 60-month moving average West Coast market price for the same period and (3) the derived NYMEX crude oil futures price of ANS from October 2006 to January 2011.

The figure illustrates a number of issues with respect to oil prices including:

- month-to-month crude oil price volatility—monthly ANS West Coast prices during this time period ranged from just under \$9.39 per barrel to \$73.10 per barrel.
- the 60-month moving average is \$39.52 per barrel and has increased dramatically since 1999.

- the derived futures market price of October 2006 shows prices have slipped a bit from July 2006 record highs.

We assume that over the medium-term, ANS oil prices will average \$49 per barrel in FY 2010, \$50 per barrel in FY 2011, and \$47.50 per barrel in FY 2012 (in nominal terms). Over the long run, beginning in FY 2014, prices will increase at 2.75% per year. This long-run price assumption was changed this year for the first time since our fall 2004 forecast based on Tax Division protocol.⁽²⁾

Figure 2-7. ANS West Coast and Futures Market Oil Prices (\$ per barrel)



(2) According to the department's price forecasting protocol, long-run crude oil price projections can only be changed every two years if price Delphi forecasting participants agree to a change over the prior two consecutive fall forecasting sessions.

Crude Oil Production Forecast

Alaska North Slope crude oil production peaked at 2.006 million barrels per day in FY 1988 and has steadily declined since. In FY 2006, ANS production averaged 0.845 million barrels per day, and we project production to decrease by about 12% to 0.740 million barrels per day in FY 2007. A significant portion of this decrease is attributable to pipeline corrosion issues at Prudhoe Bay, Lisburne and Milne Point. For this forecast, we have decreased our expectation of future production, based on recent historical events. The North Slope is a mature oil province with aging infrastructure. Looking into the future, it is the aging infrastructure—with additional potential down time—that is prompting an additional reduction in crude oil production volumes. We see up to 10% of the production being at risk because

of the aging infrastructure problem and project delays in heavy oil and satellite field development.

This production forecast has been revised since last spring. For the first time, we offer a discrete forecast for offshore fields Oooguruk and Nikaitchuq. Oooguruk is expected to come on line in FY 2008 at approximately 3,000 barrels per day peaking at about 17,000 barrels per day; Nikaitchuq in FY 2009 at 4,000 barrels per day peaking at about 14,000 barrels per day. We expect Alpine West to add almost 7,000 barrels per day by FY 2010, peaking at about 12,000 barrels per day in FY 2012. We have not changed our production forecast for the National Petroleum Reserve-Alaska (NPR-A). We still anticipate that the NPR-A will add 10,000 barrels per day by FY 2011

peaking at 65,000 barrels per day by FY 2015. We delayed Point Thomson one year in keeping with our ten-year development lead-time assumption, which may be conservative. For this forecast, we have not linked the development of Point Thomson to any gas pipeline project or contract.

More discussion of this fall 2006 oil production forecast can be found in Section 4. Oil Revenue. Also, a detailed field-by-field production forecast is included in the appendices of this forecast.

We continue to present the ANS production forecast in three parts: (1) currently producing, (2) currently under development and (3) currently being evaluated for development. We do this so that the reader will have an understanding about the uncertainty

Figure 2-8. Alaska North Slope Production, FY 2006 and Forecasted FY 2007-2017⁽¹⁾ (million barrels/day)

Fiscal Year	Currently Producing	Under Development	Under Evaluation	Total ANS
2006	0.845	0.000	0.000	0.845
2007	0.705	0.034	0.000	0.740
2008	0.676	0.102	0.004	0.782
2009	0.626	0.128	0.025	0.779
2010	0.577	0.143	0.059	0.779
2011	0.535	0.150	0.098	0.782
2012	0.495	0.147	0.190	0.831
2013	0.460	0.139	0.196	0.795
2014	0.432	0.133	0.208	0.772
2015	0.408	0.127	0.201	0.737
2016	0.387	0.124	0.186	0.696
2017	0.369	0.119	0.242	0.730

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

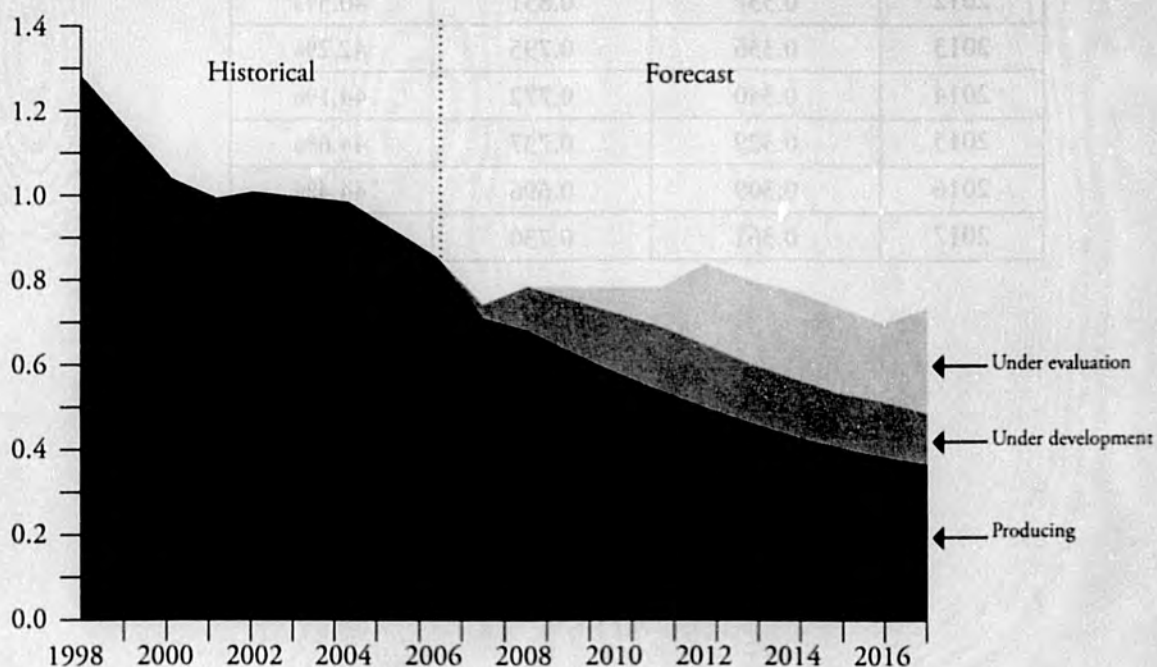
associated with the production forecast. We continue to forecast production of those reserves that have already been discovered and at minimum are being evaluated for development.

Just as important as what we do forecast for production is what we don't forecast. This production projection does not include any viscous oil from the 20 billion barrel Ugnu field, which is in the evaluation mode, and less

than 5% of the viscous oil known to exist in the 10 billion barrel West Sak field. Also absent is any production from known federal offshore oil fields Hammerhead, Kuvlum and Sandpiper, all of which could provide revenue-sharing to the state and help sustain the Trans-Alaska Pipeline System (TAPS) throughput. Lastly, we withhold any estimate of future production from un-announced discoveries or undiscovered

fields, including ANWR and NPR-A. We believe our forecast of 6.5-7.5 billion barrels of recoverable oil by FY 2040-2050, respectively, represents a conservative estimate of the remaining potential in Alaska.

Figure 2-9. ANS Production Forecast by Category, FY 1998-2006, Forecasted FY 2007-2017⁽¹⁾ (million barrels/day)



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

New Oil Development

As production from the Prudhoe Bay and Kuparuk fields continue to decline, some of the decline will be offset by new oil development. In our refer-

ence-case forecast, new oil is defined as crude already discovered and under evaluation or under development. By FY 2010, as Figure 2-10 shows, one-

quarter of our projected oil production will come from projects requiring significant new investment.

Figure 2-10. New Oil as a Percentage of Total Oil (million barrels/day)

Fiscal Year	Total New Oil	ANS Total	Percentage New Oil
2007	0.034	0.740	4.6%
2008	0.106	0.782	13.6%
2009	0.153	0.779	19.7%
2010	0.201	0.779	25.9%
2011	0.248	0.782	31.7%
2012	0.337	0.831	40.5%
2013	0.336	0.795	42.2%
2014	0.340	0.772	44.1%
2015	0.329	0.737	44.6%
2016	0.309	0.696	44.4%
2017	0.361	0.730	49.5%

Petroleum Profits Tax (PPT) Replaces ELF-Based Severance Tax

The Petroleum Profits Tax (PPT), a major rewrite of the State's oil and gas production tax system (also known as the "severance tax"), was signed into law by Governor Murkowski on August 19, 2006. The PPT system replaces the prior production tax system based on the Economic Limit Factor (ELF), portions of which had been in place since the 1970s. The tax change was the end result of intense analysis and debate during the 24th Legislative Session that encompassed the regular legislative session and two 30-day special sessions. To view the PPT legislation in its entirety, see <http://www.legis.state.ak.us/PDF/24/Bills/HB3001Z.PDF>.

How the PPT Works

The PPT is a significant departure from the prior production tax system, based on the Economic Limit Factor (ELF). The ELF-based system taxed oil and gas on its value at the point of production (also called the "wellhead value"), after being adjusted by the property's ELF, making it a tax that was specific to a property. The ELF for a particular property was calculated using a complex formula that compared production levels with the number of wells for that property. The resulting ELF value was always between 0 and 1, meaning that properties could have been assessed for as little as zero production tax or they have been taxed at the highest nominal tax rate of 15% of the property's wellhead value.

Rather than being a tax from a specific property, the PPT is a tax on the "profits" of oil and gas produced by a company. Like the ELF-based tax, the PPT starts with the value at the point

of production, but it then departs from the ELF tax by recognizing the costs a company incurs to produce that oil or gas. By subtracting costs from the value of production, a company arrives at its "production tax value," a term very similar in concept to a company's net income. The production tax value is multiplied by the PPT tax rate—22.5%—to arrive at the base tax. Should the production tax value exceed \$40 per barrel of oil produced (or the equivalent in gas), the tax rate increases 0.25% for every dollar the per-barrel production tax value is over \$40.

A company's PPT tax liability is reduced to the extent that the company invests in equipment, projects, or other items that are deemed "capital expenditures." Capital expenditures generally include costs related to the purchase of drill rigs or other equipment, infrastructure, exploration, and facility expansion. These costs, which are capitalized on company financial statements, are immediately expensed under the PPT to arrive at the production tax value. Capital costs are also eligible for a 20% credit against the company's PPT liability. In order to protect the state from crediting companies for unmet maintenance obligations, the Legislature specifically disallowed capital expenditures up to \$0.30 per barrel

under the PPT.

The 20% capital investment credit is intended to encourage re-investment in Alaska. It has been the administration's view, as well as the Legislature's, that capital investments, whether directly or indirectly related to exploration, may ultimately lead to increased future oil or gas production.

Two other significant credits round out the PPT system: the transition credit, and the base allowance. Both credits are temporary, lasting 10 years or less, and each has specific limitations on its availability. The transition credit allows companies credits for capital expenditures made within 5 years prior to the enactment of the PPT, but requires current capital investment. The base allowance is a credit of \$12 million per year or less, granted to small producers that have a tax liability under the PPT. Neither of these credits can be used to reduce a taxpayer's liability to less than zero.

Companies with operations in Cook Inlet, or in areas of the state other than the North Slope and Cook Inlet, have special tax provisions that apply under the PPT. For example, Cook Inlet operators pay the lower of the ELF-based tax or the PPT. Such special exceptions are not discussed in detail here.

The PPT tax liability formula can be illustrated as a relatively simple equation as follows:

$$\text{PPT Tax Liability} = [(\text{Value} - \text{Costs}) \times \text{Tax Rate}] - \text{Credits}$$

The terms used in the equation are defined as follows:

Value = Volume of Oil and Gas Produced x Wellhead Value

Costs = Operating Expenditures + Capital Expenditures

Tax Rate = 22.5% + 0.25% for every \$1 per barrel that this "net income" exceeds \$40

Credits = (20% x Capital Expenditures) + (20% x Eligible Transition Expenditures) + Base Allowance (as described above)

Estimated Revenue Under the PPT

Tax revenues generated under the PPT will vary by price and by production levels, just like the ELF-based tax did. Because the PPT includes costs in the tax calculation as well, there is a third variable upon which tax revenues will depend. The revenues the State receives from the PPT will be contingent on oil prices, on North Slope production, and on how much it costs to produce the oil.

Preliminary estimates by the Department of Revenue indicate that the PPT will generate more production tax revenue than the ELF-based tax at ANS prices above (about) \$25 per barrel. When prices are below \$25 per barrel, or when costs are high relative to the price of oil, a tax floor is triggered, which protects some level of tax

revenue for the State. If prices average around \$60 per barrel for FY07, and with currently projected production and cost estimates, the PPT could generate over \$2 billion in production tax revenue this year—over \$1 billion dollars more than the ELF-based tax would generate at that price.

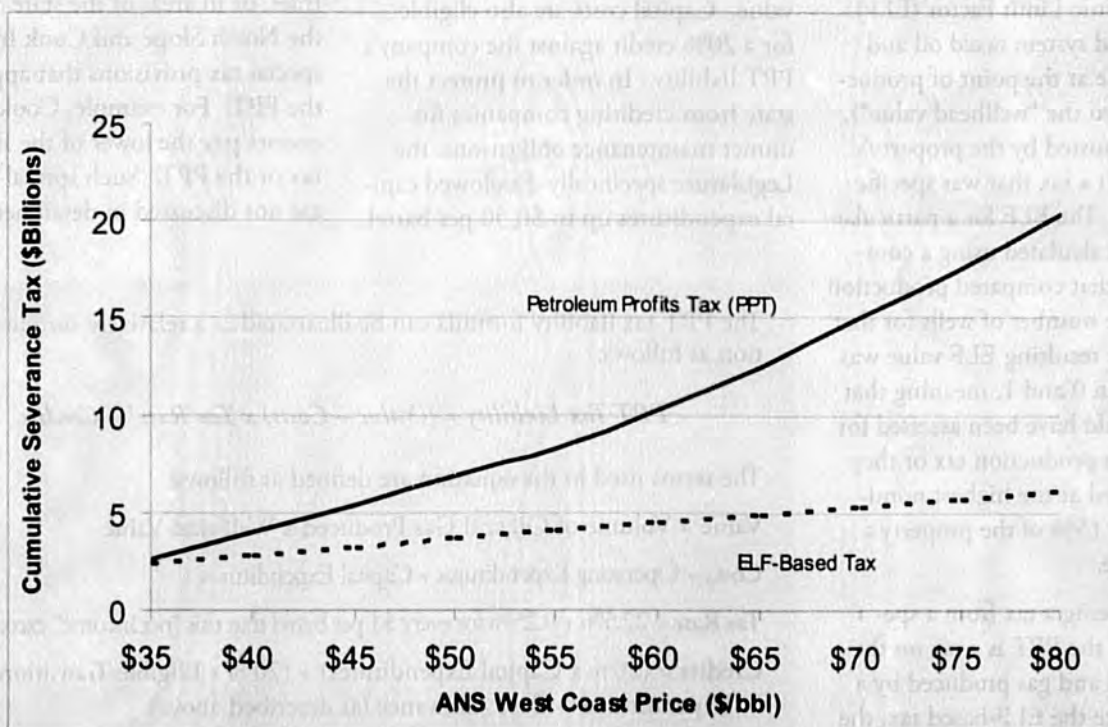
The chart below shows cumulative forecasted production tax revenues under the ELF-based tax and under the PPT for the period of FY 2008 through FY 2012. PPT revenues are lower than previously anticipated because of the additional near-term costs related to pipeline repairs and lower than expected production volumes in FY07 and 08. Over the long-term, we believe that the PPT will generate higher tax revenues than the ELF-based system at prices in the \$25-\$30 per barrel range.

Although the PPT tax changes were

made retroactive to April 1, 2006, taxpayers will make monthly payments based on the ELF tax for the remainder of calendar year 2006. The first tax payment under the PPT will be made at the end of February 2007, for production occurring in January 2007. At the end of March 2007, taxpayers will be expected to make a "true-up" payment for any additional PPT tax liability for the period of April 1 through December 31, 2006.

Administratively, the monthly and annual reporting and payment structure will differ under the PPT from that used under the ELF-based system. Under the PPT, companies will make estimated payments every month and compute their annual tax liability once in a calendar year (in March for the previous calendar year). Under the ELF system, companies made monthly

Figure 2-11. Estimated Cumulative Production Tax, 2008-2012 Under ELF-based Production Tax and PPT Production Tax



payments and filed their returns every month.

Putting the PPT in Place

As with any new legislation, there is still plenty of work to do after the bill is signed into law. Putting a huge tax reform such as the PPT into place requires the coordination of several processes in order to achieve a smooth transition. These processes include writing regulations, designing computer systems and taxpayer forms, providing training to taxpayers and agency staff, and hiring supplemental personnel as needed.

Forecasting revenues under the PPT will pose additional challenges for the Department of Revenue. Under the new system, the department will have to consider cost levels in addition to volumes and prices. Although much about cost levels is known, extraordi-

nary events such as pipeline leaks or other mechanical failures can cause costs to escalate beyond forecasted levels. Similarly, efficiency gains in daily operations will translate to increased revenues for the State.

The change from the ELF tax to the PPT is arguably the biggest change in the history of petroleum production taxation in the state. It is the department's hope that with this change will come increased exploration and production of Alaska's plentiful resources.

Longer-Term Unrestricted Revenue Outlook

Using the price and volume components developed for this fall 2006 forecast, the table below summarizes

the department's forecast of total Unrestricted General Purpose Revenue through FY 2017.

Figure 2-12. Total Unrestricted General Purpose Revenue, FY 2006 and Forecasted FY 2007-2017 (\$ million)

Fiscal Year	Unrestricted Oil Revenue	Unrestricted Other Revenue (except federal & investment)	Unrestricted Investment Revenue	Total Unrestricted Revenue	Percent From Oil
2006	3,698.9	450.5	53.3	4,202.7	88%
2007	4,331.5	456.8	124.0	4,912.3	88%
2008	3,357.2	453.2	100.7	3,911.1	86%
2009	3,224.3	451.6	100.7	3,776.6	85%
2010	3,105.7	462.6	100.7	3,669.0	85%
2011	3,137.4	480.7	100.7	3,718.8	84%
2012	3,002.5	489.0	100.7	3,592.2	84%
2013	2,710.0	496.5	100.7	3,307.2	82%
2014	2,363.4	504.0	100.7	2,968.1	80%
2015	2,223.9	515.0	100.7	2,839.6	78%
2016	2,149.9	524.1	100.7	2,774.7	77%
2017	2,337.9	526.4	100.7	2,965.0	79%

Spending, Forecasted Revenue 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). The state has deposited about \$5.6 billion into the reserve fund, generating about \$1.8 billion in investment earnings. Since the increase in oil prices beginning in about 2003, no CBRF withdrawals have been necessary to balance the state's budget. However, given price volatility and the decline expected in volumes from the North Slope, the state may have to depend on the CBRF in the future. Through September 30, 2006, approximately \$5.1

billion had been borrowed from the CBRF to balance the budget, leaving a balance of \$2.4 billion. According to the State Constitution, the \$5.1 billion must be repaid to the CBRF.

Two tables are presented below to help the reader understand the time period in which the CBRF would be depleted. Figure 2-13(A) presents the case where all surpluses are deposited in the CBRF. Figure 2-13(B) presents the case where no surpluses are deposited in the CBRF. For example, using the DOR price and revenue forecast and assuming a General Fund appropriations budget of \$4.6 billion in FY

2007 and a flat appropriations budget of \$3.7 billion thereafter, the CBRF would not be depleted before 2020 if all budget surpluses were deposited into the CBRF (see Figure 2-13(A)). By contrast, if none of the budget surpluses were deposited into the CBRF, the CBRF would be depleted in February 2018 (see Figure 2-13(B)).

Figure 2-13 (A). CBRF Run-Out Date With Excess Revenue Deposited into CBRF⁽¹⁾

Annual State Budget After FY 07 (\$ billion)	Fall 2006 Oil Price Forecast ⁽²⁾	Fiscal Model of Oil Revenue & CBRF Performance at Selected Prices (\$/barrel) ⁽³⁾				
		\$25	\$35	\$45	\$55	\$65
2.3	Dec 2020	Aug 2015	Dec 2020	Dec 2020	Dec 2020	Dec 2020
2.7	Dec 2020	Mar 2012	Dec 2020	Dec 2020	Dec 2020	Dec 2020
3.0	Dec 2020	Jan 2011	May 2017	Dec 2020	Dec 2020	Dec 2020
3.3	Dec 2020	May 2010	Nov 2013	Dec 2020	Dec 2020	Dec 2020
3.7	Dec 2020	Oct 2009	Jul 2011	Apr 2019	Dec 2020	Dec 2020
4.0	Feb 2017	Jun 2009	Aug 2010	Mar 2015	Dec 2020	Dec 2020
4.3	Sep 2014	Mar 2009	Feb 2010	Sep 2012	Dec 2020	Dec 2020
4.6	Jan 2013	Dec 2008	Sep 2009	Apr 2011	Dec 2017	Dec 2020

(1), (2), (3) see footnotes on next page

Figure 2-13 (B). CBRF Run-Out Date Without Excess Revenue Deposited into CBRF⁽¹⁾

Annual State Budget After FY 07 (\$ billion)	Fall 2006 Oil Price Forecast ⁽²⁾	Fiscal Model of Oil Revenue & CBRF Performance at Selected Prices (\$/barrel) ⁽³⁾				
		\$25	\$35	\$45	\$55	\$65
2.3	Dec 2020	Dec 2013	Dec 2020	Dec 2020	Dec 2020	Dec 2020
2.7	Dec 2020	Mar 2011	Jun 2020	Dec 2020	Dec 2020	Dec 2020
3.0	Dec 2020	Apr 2010	Sep 2015	Dec 2020	Dec 2020	Dec 2020
3.3	Dec 2020	Oct 2009	Aug 2012	Dec 2020	Dec 2020	Dec 2020
3.7	Feb 2018	Mar 2009	Oct 2010	Jan 2017	Dec 2020	Dec 2020
4.0	May 2015	Dec 2008	Jan 2010	Oct 2013	Dec 2020	Dec 2020
4.3	Sep 2013	Oct 2008	Aug 2009	Jul 2011	Mar 2020	Dec 2020
4.6	Feb 2012	Aug 2008	Mar 2009	Aug 2010	Mar 2016	Dec 2020

(1) Matrix starts in FY 2008. Fall 2006 forecasted production volumes are used. The date Dec 2020 indicates that the CBRF does not run out during matrix timeframe.

(2) Fall 2006 forecasted ANS price projections are \$51.25 per barrel in FY 2008, \$49.50 per barrel in FY 2009, \$49 per barrel in FY 2010, \$50 per barrel in FY 2011, \$47.50 per barrel in FY 2012 and \$45 per barrel in FY 2013. For FY 2014-beyond ANS prices are estimated to grow at 2.75%

(3) Matrix allows reader to select specific fiscal year price (from FY 2008-beyond) to determine CBRF exhaustion data.

Figure 2-13 (B) CBRF Run-Out Date Without Excess Revenue Deposited into CBRF

Annual State Budget After FY 07 (\$ billion)	Fall 2006 Oil Price Forecast ⁽¹⁾	Fiscal Model of Oil Revenue & CBRF Performance at Selected Dates (2) (billion)	2006	2007	2008	2009	2010
2.3	Dec 2020	Dec 2013	Dec 2020	Dec 2020	Dec 2020	Dec 2020	Dec 2020
2.7	Dec 2020	Mar 2011	Jan 2020	Dec 2020	Dec 2020	Dec 2020	Dec 2020
3.0	Dec 2020	Apr 2010	Sep 2012	Dec 2020	Dec 2020	Dec 2020	Dec 2020
3.3				Dec 2020	Dec 2020	Dec 2020	Dec 2020
3.7				Dec 2020	Dec 2020	Dec 2020	Dec 2020
4.0				Dec 2020	Dec 2020	Dec 2020	Dec 2020
4.3				Mar 2016	Dec 2020	Dec 2020	Dec 2020
4.6				Mar 2016	Dec 2020	Dec 2020	Dec 2020

Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2006

(1) Alaska state oil price forecast for FY 2006, Fall 2006 forecast production volumes are used. The state Dec 2020 indicates that the CBRF does not run out during month production.

(2) Fall 2006 forecast ANS price projections are \$21.35 per barrel in FY 2006, \$19.10 per barrel in FY 2007, \$19 per barrel in FY 2008, \$19 per barrel in FY 2009, \$20 per barrel in FY 2010, \$20 per barrel in FY 2011, \$21.30 per barrel in FY 2012, and \$21 per barrel in FY 2013. From FY 2014 forward ANS prices are assumed to grow at 2.75%.

(3) This table allows reader to select the fiscal year from FY 2006 forward to determine CBRF expiration date.

Figure 3-1: Potential Heavy Oil Resources: Lower 48 States, Alaska, and the Gulf of Mexico, November 2005, page 20

3. Will Heavy Oil Do The Heavy Lifting for Alaska?

What is heavy oil? Where is it located and how much of the stuff is there? Why aren't the oil companies producing it now? These are some of the questions this section will attempt to answer. Like other crude oils, heavy oil can be refined and used to produce refined petroleum products such as gasoline and jet fuel. Physical problems make its production more challenging than other crude oils. The potential to produce and develop heavy oil has great promise for Alaska.

What is Heavy Oil?

Heavy oil is a type of crude oil which is very viscous and does not flow easily. The common characteristic properties

are the following:

- High specific gravity⁽¹⁾ (very dense)
- Low hydrogen to carbon ratios (chemical characteristic)
- High carbon residues (much left after conversion to refined product)
- High contents of heavy metals, sulphur and nitrogen.

There is no one definition of heavy oil. The term heavy oil refers to oil with a high density and low American Petroleum Institute (API) gravity⁽²⁾ due to the presence of a high proportion of heavy hydrocarbon fractions. This is technical jargon for saying the material is thicker than maple syrup and does not flow easily. The API gravity system implies that the higher the API gravity,

the lighter the liquid, the easier it flows. Using numbers, some definitions classify crude oil as heavy if it has an API gravity of less than 25°, other definitions say it is less than 20°API. All these definitions refer to the crude oil at the surface. In terms of the ability of the oil to flow underground within the formation, heavy oils are generally those with a viscosity greater than 100 centipoise – a measure used to evaluate the ability of a liquid to flow at reservoir conditions. The higher the viscosity number, the slower the flow. Bitumen (very heavy liquid similar to chocolate syrup) has a rating greater than 10,000.

In Alaska, the real issue is not the API gravity, but the ability of the crude oil to flow, or its viscosity. While API

(1) The Specific Gravity of a substance is a comparison of its density to that of water. Imagine a gallon bottle filled with water, a second filled with feathers, a third filled with lead weights. There are equal volumes of material present, but the bottle with the feathers will weigh less than that containing water; the bottle with lead weights will weigh the most. In order of increasing specific gravity, these materials would be: feathers, water, and lead. Specific gravity can be measured precisely, or estimated by a comparison, as above.

(2) API gravity = $[141.5 / \text{Specific Gravity at } 60^\circ \text{ F} - 131.5]$ This parameter has economic significance since it is the main quality criterion for crude oil pricing; the higher the gravity the higher the price of the crude oil.

Figure 3-1. Potential Heavy Oil Resources *Source: International Energy Agency, Resources to Reserves, November 2005, page 76.*



gravity provides a measure of its density (and economic value), it fails to incorporate the more difficult issues surrounding flow. From this perspective, a better descriptor of Alaskan heavy oil would be to call it viscous oil, as it relates to its ability to flow.

One of the major reasons Alaska's oil is viscous is because it is relatively close to the surface of the earth – where there is very thick permafrost. The oil is not located deep in the earth, where the temperatures are warmer, but within six thousand feet of the surface where temperatures are cooler, thereby reducing the oil's viscosity or ability to flow. For oil production in Alaska, API gravity isn't as important as is reservoir temperature. Hence, these deposits are sometimes referred to as viscous oil deposits, rather than heavy oil. Permafrost affects production, as it will cool oil traveling through the permafrost zone.

Worldwide Resources of Heavy Oil

Heavy oil is located throughout the world and the International Energy Agency estimates world heavy oil, or viscous oil resources at more than 6 trillion barrels with about 2 trillion barrels deemed recoverable (see Figure 3-1).

The three largest deposits are in Canada (about 1.86 trillion barrels), Russia, and Venezuela (each with about 1.2 trillion barrels). Alaska is in the next level with the potential for about 100 billion barrels of heavy oil resources. At this time, there are known Alaskan reserves of over 20 billion barrels of viscous oil with the possibility of billions more yet to be identified. The viscous oil in Canada is very similar to that of the viscous oil in Alaska – both are located in cooler climates and both do not flow well in their natural reservoirs.

There are currently five fields producing viscous oil in Alaska: Orion, Polaris, Schrader Bluff, Tabasco and West Sak. Four of these fields are shown in Figure 3-2 on the next page. Not shown is Tabasco, which is a Kuparuk River Unit satellite. Figure 3-3 on the next page reveals the subsurface formation in which the viscous oil lies. At this time, viscous oil is being developed from the oil formation titled "West Sak Schrader Bluff". No oil is being produced from the Ugnu formation.

The North Slope is underlain by permafrost which extends to about 1,800 feet in depth. The shallowest oil bearing formation, named Ugnu, is closest to the permafrost. The temperature in this formation is below freezing, its API gravity is 8° and it has a very high oil viscosity. The billions of barrels of reserves in this formation are not economical to produce now, but someday may be.

Figure 3-2. Alaska's Viscous Oil Reserves Source: BP Exploration Alaska (Inc.) presentation to Alaska Department of Revenue, February 18, 2005.

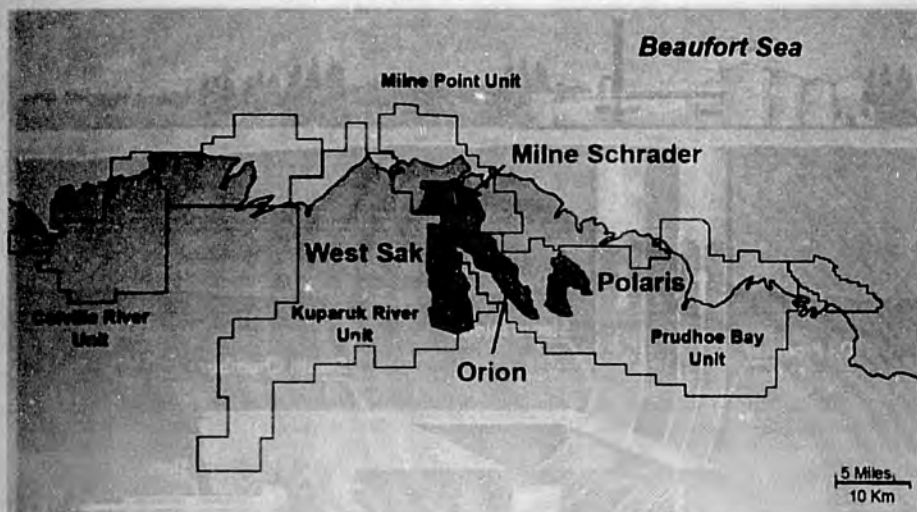
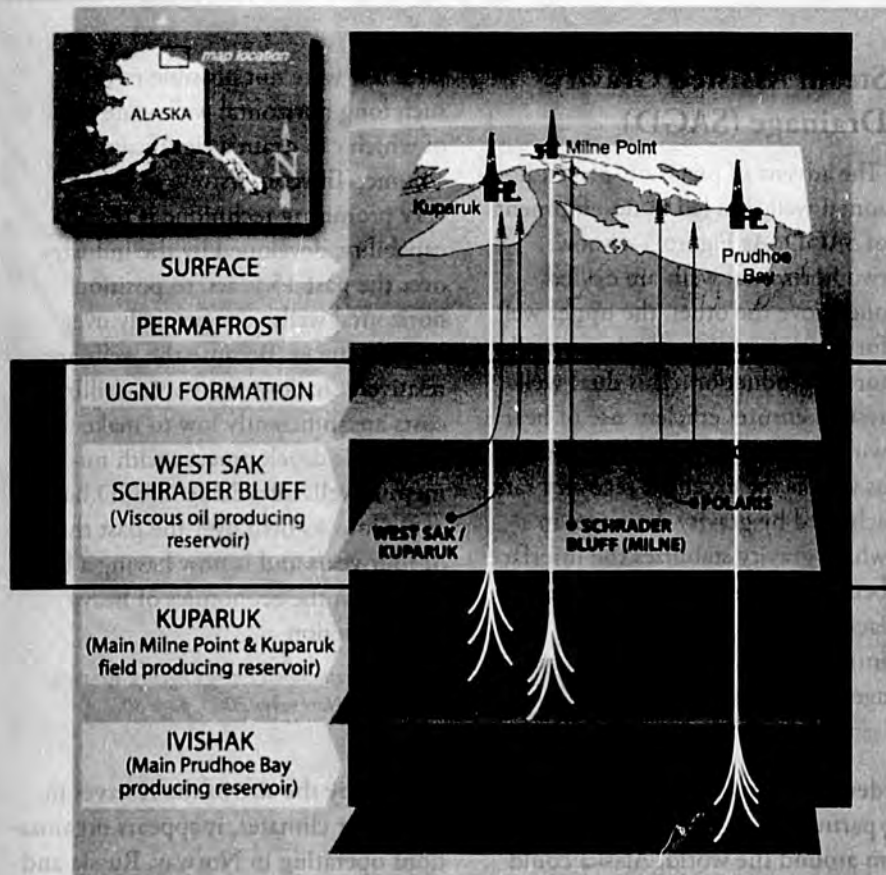


Figure 3-3. Alaska's Viscous Oil Deposits Source: International Energy Agency, *Resources to Reserves*, November 2005, page 76.



Developing Viscous Oil Resources

Developing viscous oil is difficult and expensive. Some heavy oils and bitumens are too viscous to flow at reservoir conditions. They are usually found at relatively shallow depths that are too deep to be mined. At such depths, temperatures are low, so that viscosity is high. They need special production technologies to facilitate their flow from reservoir to well head. Traditionally, these have been "steam flooding" techniques, which involve injecting hot steam to heat the oil in-situ, thereby reducing its viscosity and allowing it to flow. But the last ten years have seen the advent of many new approaches such as steam-assisted gravity drainage – see Figure 3-4 on page 24.

Also being used are techniques involving CO₂ or natural gas injection. All of these techniques require facility and energy expenses that are well beyond the requirements for producing traditional oil reserves.

Another problem faced by Alaska's viscous oil producers is solid waste – significant solids (sand) are produced in conjunction with the oil and must be disposed. Some of the facilities on the North Slope were not developed with sand disposal in mind and must be periodically closed to remove the sand. As newer facilities are developed, they will likely integrate solid waste disposal.

While large-scale implementation of Steam Assisted Gravity Drainage (SAGD) and other techniques is just beginning, it is expected to significantly boost production over the next few years. Indeed, recent technology has improved the economics to the point where Canadian heavy oil and bitumen deposits can be produced through in-situ techniques at oil prices below

\$20 per barrel (see Figure 3-5 on page 25). Current production of heavy oil and bitumen in Canada, for example, is close to 1 million barrels per day and could double by 2012.

The Outlook

At the time of this writing, about 5% of the oil produced in Alaska is considered viscous. Will this resource be developed to a larger extent in the future?

While this question cannot be answered unequivocally, there are several indicators that greater development of viscous oil on Alaska's North Slope is likely to occur. These facts are divided into two broad categories – the fiscal regime and technology.

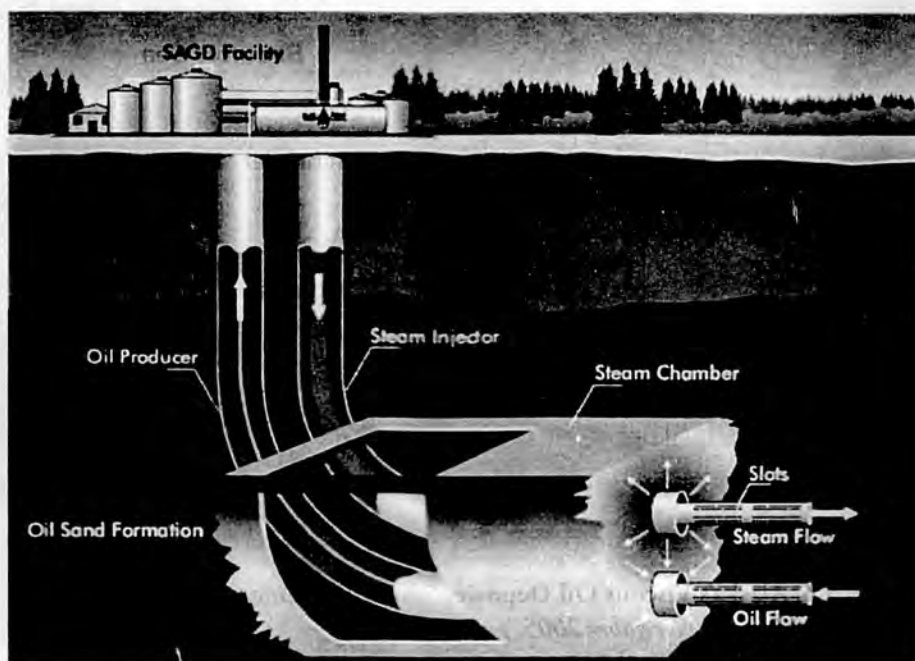
- **Fiscal Regime** – Canada's recent experience with oil sands and heavy oil bears witness to the powerful force of a stable and attractive tax and royalty regime, combined with higher oil prices, to catalyze fresh investment. With the passage of the new Petroleum Profits Tax (PPT) in Alaska, similar incentives are in place and are expected to stimulate investment. Companies will be able to claim deductions and earn credits for their higher costs of producing heavy and viscous oil that will lower their tax burden.

- **Technology** – the oil industry is continually developing new techniques and technologies to enhance oil production. Such technological advances are pushing back the frontiers of operating capability in difficult temperature and geographical situations.

Taken together, these two aspects paint a picture of future development of Alaska's viscous oil.

Finally, Alaska has the opportunity to take the lead in viscous oil research and create an Arctic Resources Research Center that could serve as a central research facility for heavy and viscous

Figure 3-4. Schematic of SAGD. Source: International Energy Agency, *Resources to Reserves*, November 2005, page 76.



Steam Assisted Gravity Drainage (SAGD)

The advent of precision-placed horizontal wells has led to development of SAGD. As Figure 3-4 shows, two horizontal wells are drilled, one above the other, the upper well for steam injection, the lower well for oil production. This dual-well system ensures efficient use of heat within a virtual "steam chamber", as well as the excellent recovery rate achieved by gravity drainage, in which gravity stabilizes the interface between oil and steam. Recovery factors can be as high as 60%. The intrinsic slowness of gravity drainage would mean low production

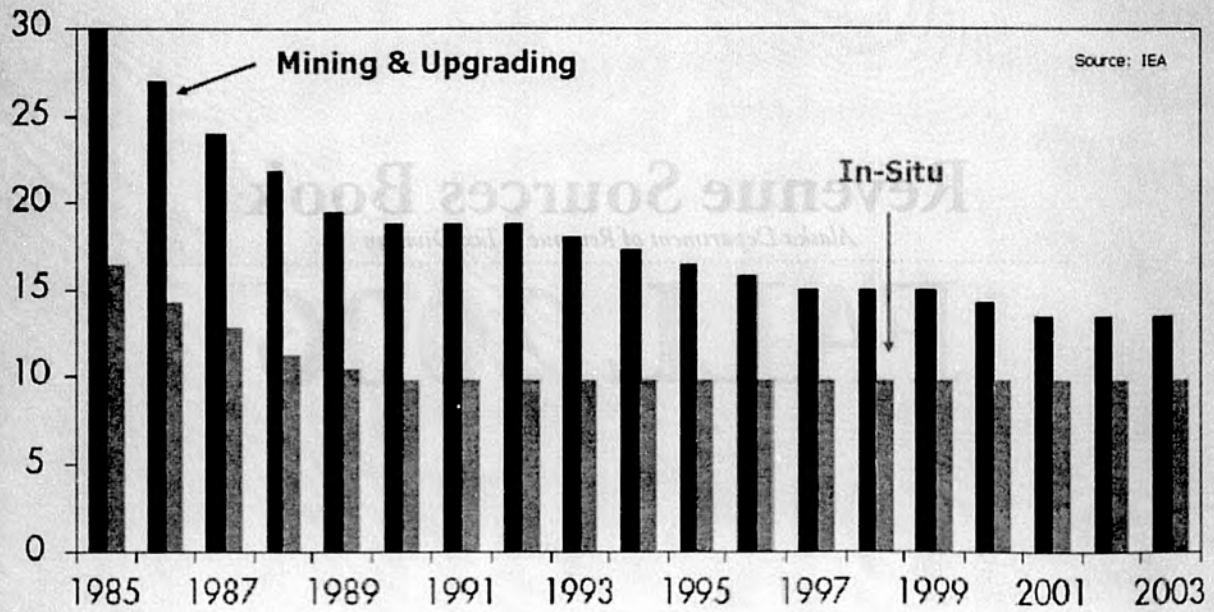
rates if it were not possible to drill such long horizontal wells, one pair of which can drain a significant volume. The cornerstone in this very promising technique is the capability, developed by the industry over the past 15 years, to position horizontal wells very precisely over long distances. Because the wells are relatively shallow, moreover, drilling costs are sufficiently low to make large-scale developments with numerous wells affordable. SAGD has come into its own over the past three or four years and is now having a big impact on the economics of heavy oil production.

Source: International Energy Agency, *Resources to Reserves*, November 2005, page 80.

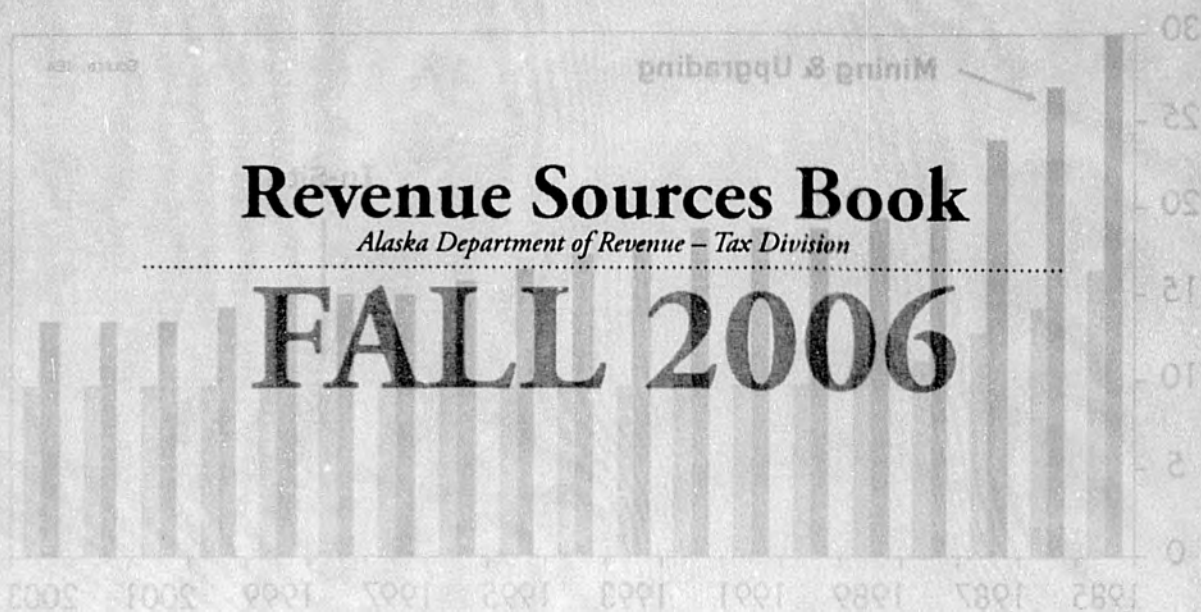
oil development worldwide. By engaging partners with heavy oil resources from around the world, Alaska could facilitate research and provide insights into viscous oil development and environmental issues to all involved.

Judging by the size of the reserves in the colder climates, it appears organizations operating in Norway, Russia and Canada would be interested as potential partners.

3-5. Oil Production Costs for Canadian Tar Sand (2004 dollars/ barrel) *Source: International Energy Agency, Resources to Reserves, November 2005, page 77.*



3-5. Oil Production Costs for Canadian Tar Sand (2004 dollars) (per barrel) Source: International Energy Agency, Resources for Future, November 2005, page 77



Revenue Sources Book

Alaska Department of Revenue – Tax Division

FALL 2006

4. Oil Revenue

Figure 4-1. FY 2006 Oil Revenue \$4.4 billion

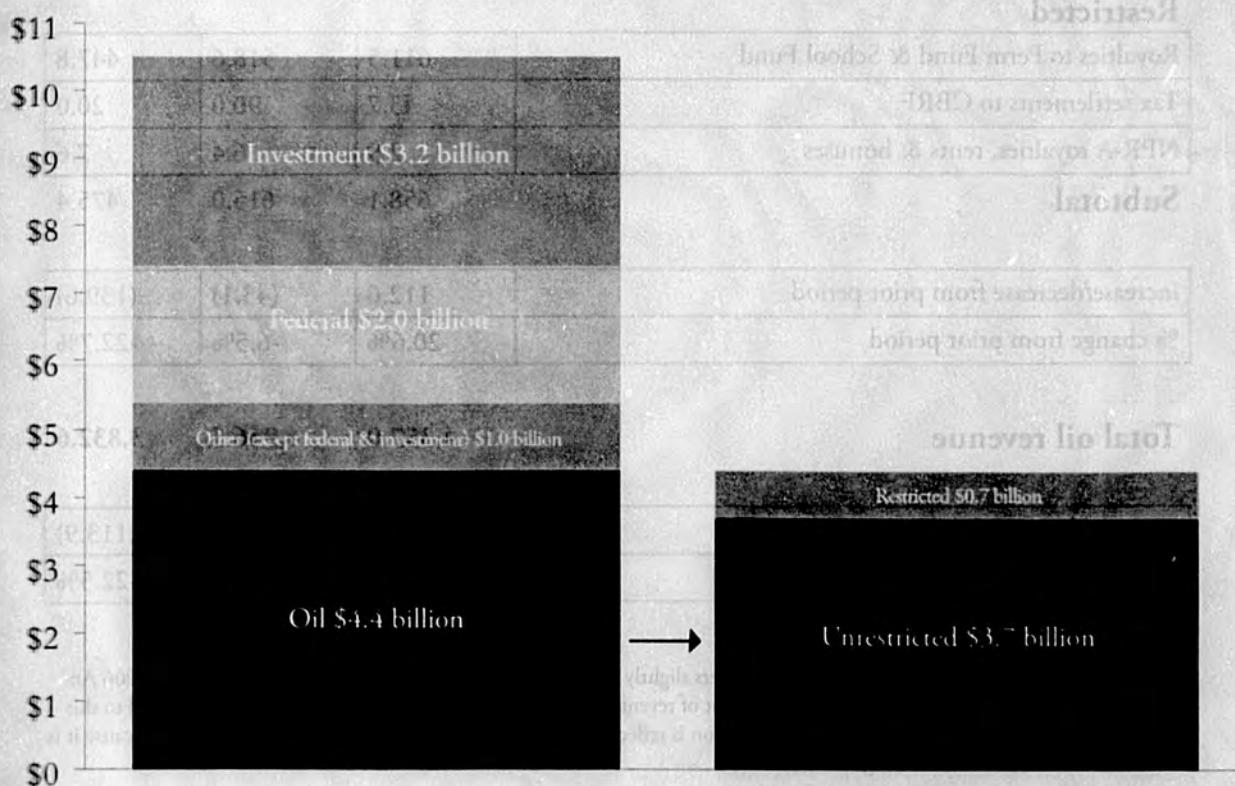
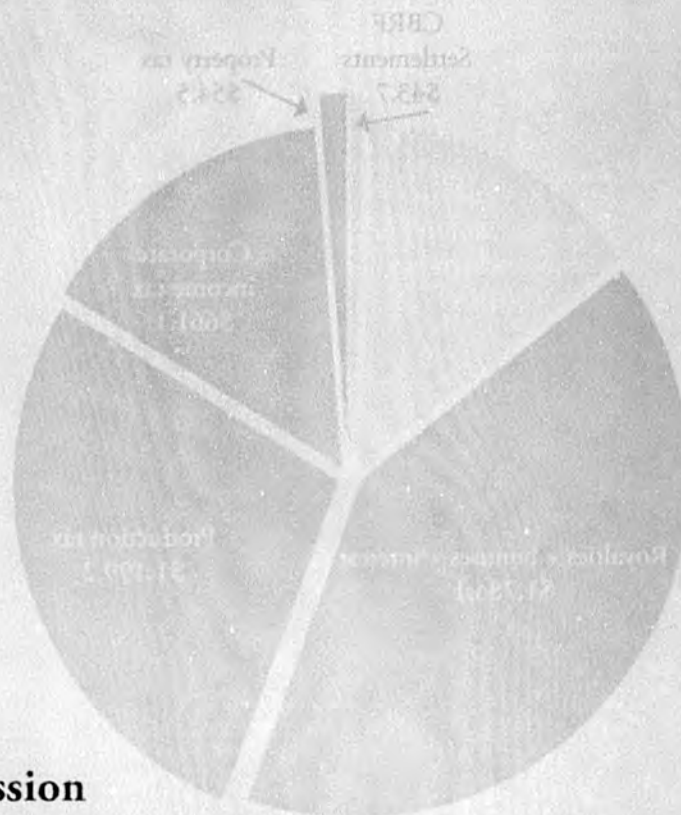


Figure 4-2. Total Oil Revenue, FY 2006 and Forecasted FY 2007-2008 (\$ million)

Oil Revenue	History	Forecast	
	FY 2006	FY 2007	FY 2008
Unrestricted			
Property tax	54.5	51.7	51.4
Corporate income tax	661.1	657.2	493.7
Production tax ⁽¹⁾	1,199.2	2,067.2	1,476.1
Royalties (including bonuses, rents & interest)	1,784.1	1,555.4	1,336.0
Subtotal	3,698.9	4,331.5	3,357.2
increase/decrease from prior period	849.3	632.6	(974.3)
% change from prior period	29.8%	17.1%	-22.5%
Restricted			
Royalties to Perm Fund & School Fund	611.5	518.6	447.8
Tax settlements to CBRF	43.7	90.0	20.0
NPR-A royalties, rents & bonuses	2.9	6.4	7.6
Subtotal	658.1	615.0	475.4
increase/decrease from prior period	112.6	(43.1)	(139.6)
% change from prior period	20.6%	-6.5%	-22.7%
Total oil revenue	4,357.0	4,946.5	3,832.6
increase/decrease from prior period	961.9	589.5	(1,113.9)
% change from prior period	28.3%	13.5%	-22.5%

(1) The amount of production tax reported here differs slightly from the amount recorded in the Tax Division's FY 2006 Annual Report because of timing issues. A small amount of revenue recorded in another account in FY 2006 was moved to this account after the close of the fiscal year. This correction is reflected in the Annual Report, but is not included here because it is not included in the state accounting system.

Figure 4-3. FY 2006 oil revenue by category: \$1,357 million



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. Of the royalties, 25% goes into the principal of the Alaska Permanent Fund and 0.5% goes into the Public School Trust Fund. There also are two other funds that receive specific oil and gas revenues: the National Petroleum Reserve-Alaska (NPR-A) Fund ⁽¹⁾, 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.

The pie chart in Figure 4-3 (next page) shows the actual amount of each tax and royalty source in FY 2006. As can be seen from the figure, royalties and the production tax constitute the largest part—83%—of restricted and unrestricted oil revenue combined. This section begins with a discussion of these two revenue sources, both of which are driven by price and volume. We then review the price forecasting methodology that underlies this biannual report,

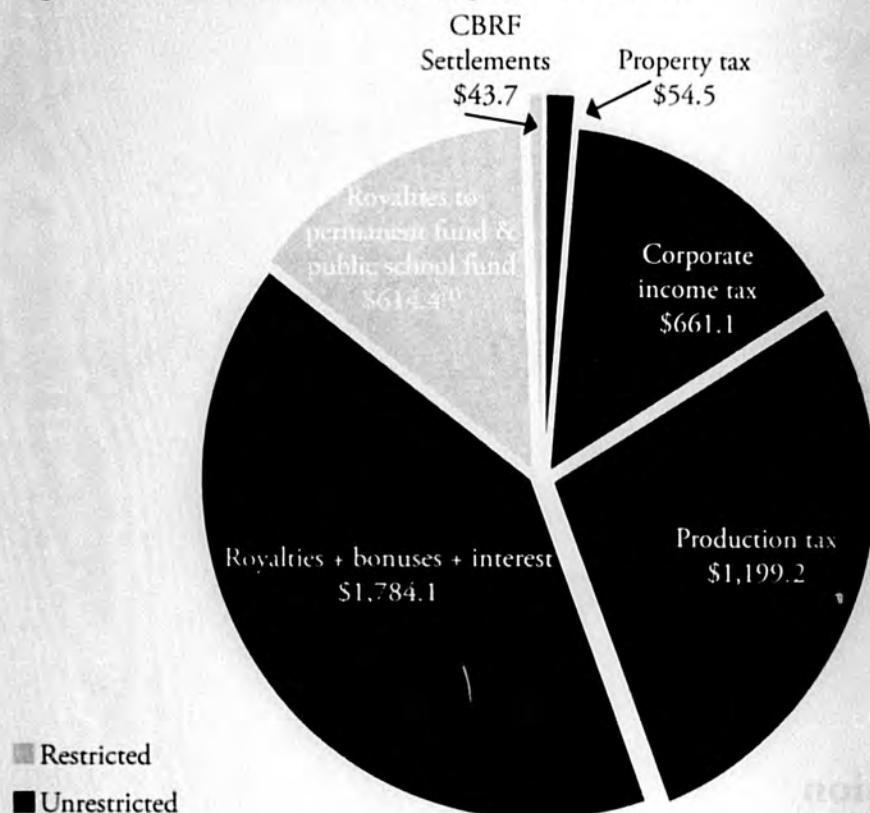
and discuss the linkage between market prices and wellhead values. We also review our production forecast, and close this section with a discussion of oil and gas property taxes, oil and gas corporate income taxes and the restricted portions of oil revenue.

Figure 4-4. Unrestricted Oil Revenue Forecast

Fiscal Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Property Tax	21.7	21.4	21.1	20.8	20.5	20.2	19.9	19.6	19.3	19.0	18.7	18.4	18.1	17.8	17.5	17.2	16.9	16.6	16.3	16.0	15.7	15.4	15.1	14.8
Corporate Income Tax	65.2	65.5	65.8	66.1	66.4	66.7	67.0	67.3	67.6	67.9	68.2	68.5	68.8	69.1	69.4	69.7	70.0	70.3	70.6	70.9	71.2	71.5	71.8	72.1
Production Tax	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3	500.3
Royalties (1)	1,252.4	1,330.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0
Total oil revenue	4,351.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2	4,352.2
Interest/Dividends from prior period	632.6	624.3	615.8	607.3	598.8	590.3	581.7	573.2	564.7	556.2	547.7	539.2	530.7	522.2	513.7	505.2	496.7	488.2	479.7	471.2	462.7	454.2	445.7	437.2
to change from prior period	15.1%	-1.3%	-1.4%	-1.5%	-1.6%	-1.7%	-1.8%	-1.9%	-2.0%	-2.1%	-2.2%	-2.3%	-2.4%	-2.5%	-2.6%	-2.7%	-2.8%	-2.9%	-3.0%	-3.1%	-3.2%	-3.3%	-3.4%	-3.5%

(1) 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.

Figure 4-3. FY 2006 oil revenue by category, \$4,357 million



(1) Includes NPRA rents & bonuses of \$2.9 million

Unrestricted Oil Revenue

Figure 4.4. Unrestricted Oil Revenue Forecast, FY 2007-2017

Fiscal Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Property Tax	51.7	51.4	51.0	50.6	50.4	50.1	49.2	47.9	46.5	46.0	45.3
Corporate Income Tax	657.2	493.7	466.5	455.0	447.1	458.7	430.1	404.0	361.1	367.5	372.7
Production Tax	2,067.2	1,476.1	1,403.1	1,333.5	1,366.8	1,336.2	1,195.5	1,006.2	937.6	875.6	1,000.7
Royalties-Net (1)	1,555.4	1,336.0	1,303.7	1,266.5	1,273.1	1,157.4	1,035.2	905.4	878.7	860.9	919.3
Total oil revenues	4,331.5	3,357.2	3,224.3	3,105.7	3,137.4	3,002.5	2,710.0	2,363.4	2,223.9	2,149.9	2,337.9

Increase/decrease from prior period	632.6	(974.3)	(132.8)	(118.6)	31.7	(135.0)	(292.4)	(346.6)	(139.5)	(74.0)	188.0
% change from prior period	17.1%	-22.5%	-4.0%	-3.7%	1.0%	-4.3%	-9.7%	-12.8%	-5.9%	-3.3%	8.7%

(1) Includes bonuses and interest.

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 for production is subject to the state's production taxes and hazardous release surcharges that are levied only on crude oil. Taxes and surcharges are collected on a monthly basis.

The New Petroleum Profits Tax (PPT) For Crude Oil and Natural Gas Production

In August 2006, the Alaska Legislature passed the Petroleum Profits Tax (PPT), which made major changes to the state's production tax system. A discussion of the PPT is also found in the Executive Summary of this Revenue Sources Book. FY 2006 was the last year that production tax was levied in accordance with the provisions of the Economic Limit Factor (ELF)-based tax, as discussed later.

The PPT is a significant departure from the prior production tax system, based on the ELF. The PPT is a tax based on the "profits" of an oil company and is retroactive to April 1, 2006. The ELF-based system was based on the gross production value of a specific property.

The PPT starts with the value at the point of production, but then subtracts costs from the value of production. By subtracting costs from the value of production, a company arrives at its "production tax value," a term very similar in concept to a company's net income. The production tax value is multiplied by the PPT tax rate—22.5%—to arrive at the base tax. Should the production tax value exceed \$40 per barrel of oil produced (or the equivalent in gas), the

$$\text{PPT Tax Liability} = [(\text{Value} - \text{Costs}) \times \text{Tax Rate}] - \text{Credits}$$

The terms used in the equation are defined as follows:

Value = Volume of Oil and Gas Produced x Wellhead Value

Costs = Operating Expenditures + Capital Expenditures

Tax Rate = 22.5% + 0.25% for every \$1 per barrel that this "net income" exceeds \$40

Credits = (20% x Capital Expenditures) + (20% x Eligible Transition Expenditures) + Base Allowance

tax rate increases 0.25% for every dollar the per-barrel production tax value is over \$40.

A company's PPT 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 drill rigs or other equipment, infrastructure, exploration, and facility expansion. These costs, which are capitalized on company financial statements, are immediately expensed under the PPT to arrive at the production tax value. Capital costs are eligible for a 20% credit against the company's PPT liability. In order to protect the state from crediting companies for unmet maintenance obligations, the legislature specifically disallowed capital expenses up to \$0.30 per barrel under the PPT.

The 20% capital expenditure credit is intended to encourage re-investment in Alaska.

Two other significant credits round out the PPT: The transition credit and the base allowance. Both credits are temporary, lasting 10 years or less, and each has specific limitations on its availability. The transition credit allows credits for capital expenditures made within 5 years prior to the enactment of the PPT, but requires current capital investment. The base allowance is a credit of \$12 million per year or less,

granted to small producers that have a tax liability under the PPT. Neither of these credits can be used to reduce a taxpayer's liability to less than zero.

Comparing the New PPT System with the Old ELF-Based System

To help the viewer understand the differences between the PPT and the ELF, two sets of comparisons are done: (1) Fundamental Differences and (2) Revenue Estimate differences. The focus is on oil taxes because they represent the vast majority of petroleum tax receipts.

1. Fundamental Differences Between the PPT and the ELF

Starting with the tax base, the PPT is based on net value while the ELF was based on gross value at the point of

production. The ELF system applied statewide while the PPT has exceptions for Cook Inlet and new production areas.

The tax rate under the PPT is 22.5% plus a "progressivity tax" that increases the overall tax rate based on the profitability of the oil produced. The tax rate under ELF was either 12.25% or 15% depending on the age of the field.

Under the PPT, there are adjustments to tax liability based on credits for capital expenditures. Under the ELF system, there was an adjustment to tax

liability based on the field's ELF.

Taxpayers make monthly payments under both systems. With the PPT, there is an annual filing in which the taxpayer makes any "final" tax payment based on annual tax liability for the previous calendar year. This annual filing due date is March 31. Under the ELF, there were monthly filings and no annual filing requirements.

Figure 4-5. Fundamental Differences Between PPT and ELF

Component	ELF-based system	PPT-based system
Tax base	Gross value of production	Net value of production
Framework of tax	Property-specific	Company-specific
Geographical framework	Tax applies statewide	Exceptions for Cook Inlet & new production areas
Tax rate	12.25% for first 5 years, then 15% (based on gross value of production)	22.5% + progressivity tax (based on net value of production)
Incentives	Economic Limit Factor (ELF), 0-100%	Credit for capital expenditures, 20% Small producer tax credit up to \$12 million New Area Development credit up to \$6 million
Tax return filing	Monthly	Annual
Tax payments	Monthly	Monthly

2. Revenue Estimate Differences Between the PPT and the ELF for Oil

Following is an example of how the estimated PPT tax would compare to the ELF-based tax in a typical year with about 285 million barrels of oil produced on the North Slope, and an ANS West Coast sales price of \$60 per barrel.

As one can see from the hypothetical example, there are more calculations with the PPT, and the tax liability is higher. This example uses a price of \$60 per barrel and assumes certain

costs and credits. If the price was lower or the costs were higher (or both), results could be very different. In general, the PPT is progressive while ELF system was regressive. This means the following: at higher prices tax liability is higher under the PPT than under the ELF. Under lower prices, tax liability is higher under the ELF than the PPT. This assumes the cost structure is the same for both cases.

Figure 4-6. Estimated Production Tax Revenues Under the ELF-based and PPT Systems at \$60 per Barrel, ANS West Coast (\$ millions except where noted)

ELF Tax System		PPT Tax System	
Value at point of production	\$13,750	Value at point of production	\$13,750
Production tax rate	15%	Minus upstream costs	\$2,460
Average economic limit factor	0.529	Production tax value	\$11,290
Effective production tax rate (ELF adjusted)	7.94%	Tax rate	22.5%
Production tax total	\$1,092	Production base tax before credits	\$2,540
Divided by days/year	365	Progressivity tax	\$148
Production tax per day	\$2.99	Minus capital & transition credits & allowances	\$460
		Production tax total for year	\$2,228
		Divided by days/year	365
		Production tax per day	\$6.10

The Old ELF-Based Production Tax for Oil

The tax rate for oil depended on the age of the field and the Economic Limit Factor (ELF). The ELF depended on total daily oil production and average daily per well production from each producing field.

The statutory production tax rate on oil was 12.25% of its value at the point of production for the first five years of field production and 15% thereafter. There was a minimum tax of 80 cents per taxable barrel.

The effective tax rate was calculated by multiplying the statutory tax rate, even if it was the minimum 80 cents per barrel, times the ELF. The ELF formula for oil production is shown in this box.

$$ELF = \left[1 - \frac{(300 \times \text{wells})}{\text{volume}} \right]^{\left[\left(\frac{150,000}{\text{volume}} \right)^{1.53333} \right]}$$

"wells" is the number of producing wells in the field; "volume" is the total daily production for the field

The ELF formula resulted in lower effective tax rates for smaller, low-production fields and higher tax rates for larger, highly productive fields. There was a unique ELF for every combination of total daily field production and average daily per well production.

An examination of this formula reveals that the ELF was very sensitive to the total volume. Under the law, if there was economic interdependence between fields, the department had the discretion to aggregate those fields for purposes of the ELF calculation. That is, the volumes from more than one field ended up in a single ELF calculation. That calculation may have produced an ELF (and tax) for all the combined fields that was higher than

if the ELF were calculated separately for each field (provided there was no extraordinary discrepancy in the per well productivity rates.)

In January 2005, the department aggregated seven fields in the Prudhoe Bay Unit. The decision to aggregate focused on, among other things, the increasing interdependence found in the engineering and operation of the fields.

Under both the ELF and the PPT, the taxable value of oil is determined by deducting allowable marine and pipeline transportation costs from the destination value of the oil at its disposition point. This point is defined as either a third-party sale or delivery to the producer's own refinery. The destination value for most dispositions is tied by regulation to the West Coast spot price of ANS crude oil.

For Alaska, the problem with the ELF-based system was that the ELF was declining, due to lower production and smaller fields. As Figure 4-7 (next page) reveals, future revenue from oil would decrease—even if prices remained high—for two reasons: (1) declining oil production and (2) a declining ELF, which was based on field and well productivity.

Hazardous Release Surcharge

The Department of Administration, Division of Finance, monitors the balance of the Oil and Hazardous Substance Release Prevention and Response Fund. This fund 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.

With the passage of the PPT, the Response surcharge (AS 43.55.201) was changed from \$.02 to \$.01 and the Prevention surcharge (AS 43.55.300) was increased from \$.03 to \$.04. Both of these changes are effective April 1, 2006.

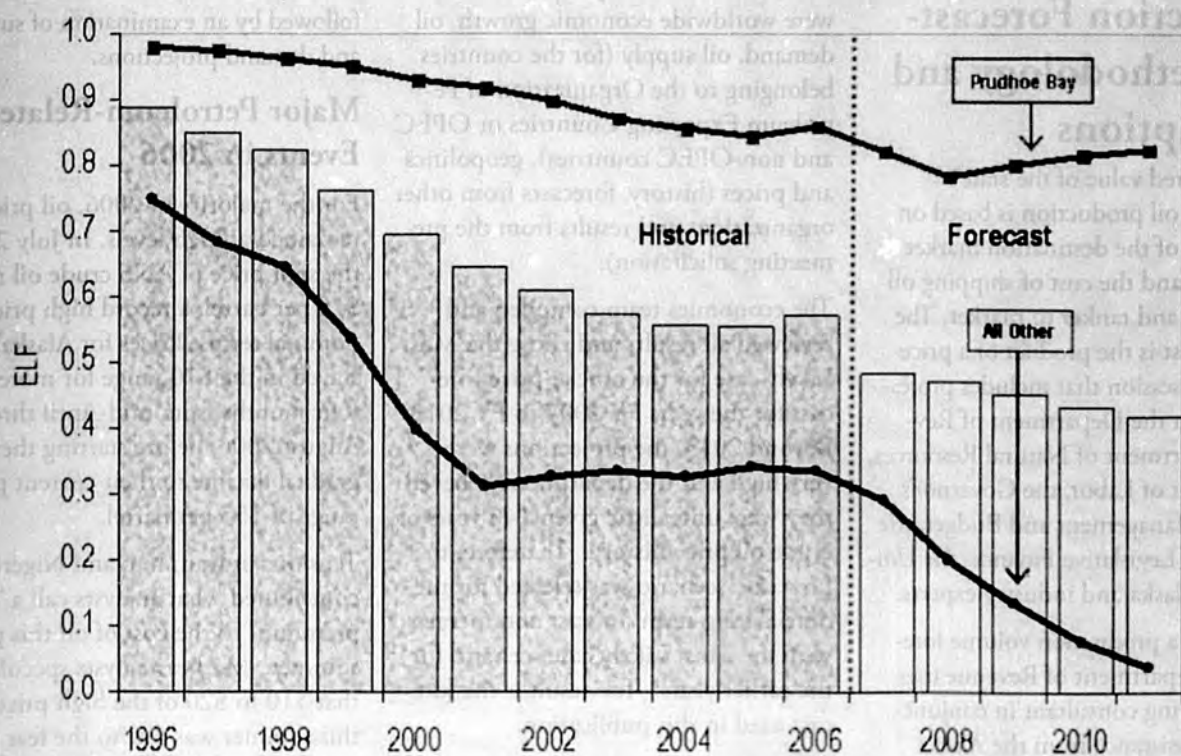
The Response surcharge is suspended when the balance is equal to or exceeds \$50 million. As of June 30, 2006, the cumulative balance of the accounts was \$51.2 million.

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 charges and (3) a retained royalty interest in oil and gas production.

Generally, the state issues leases based on a competitive bonus bid system. It has always retained a royalty interest of at least 12.5%. The vast majority of

Figure 4-7. Economic Limit Factor, FY 1996-2006 and Forecasted FY 2007-2011



The bars in Figure 4-7 illustrate the actual weighted average ELF for North Slope oil production since FY 1996 and our projections of that weighted average through FY 2011. The slight increase in 2006 reflects the effect of the department's January 12, 2005, decision to aggregate seven fields in the Prudhoe Bay Unit for purposes of calculating the ELF. Prudhoe Bay ELF, during the forecast period, includes the Prudhoe Bay-satellites and Pt. McIntyre; the historical represents only the ELF from Prudhoe Bay.

current production is from leases that carry that rate. Some currently producing leases carry rates as high as 20%, 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 2006, the state took approximately 61,000 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.⁽²⁾ The pipeline and marine transportation costs are deducted from the destination value to derive the taxable netback value of the oil or gas.

(2) ANS West Coast prevailing value, per 15AAC 55.171, is the monthly average of daily spot market prices reported by Platt's Oilgram, Reuters and Telerate Price Reporting Services. This price is published monthly on the Tax Division website www.tax.state.ak.us.

Oil Price and Production Forecasting Methodology and Assumptions

The forecasted value of the state's anticipated oil production is based on projections of the destination market price of oil and the cost of shipping oil by pipeline and tanker to market. The price forecast is the product of a price forecasting session that 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 develop a production volume forecast, the Department of Revenue uses an engineering consultant in conjunction with assistance from the Alaska 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 field.

Methodology for Forecasting Prices

The Department uses a modified Delphi technique to create its official price forecast. Participants are asked for their projections for West Texas Intermediate (WTI) crude oil for three cases – a Low case, a High case, and a Most Likely case. The prices that are forecast are in constant 2006 dollars. The Department of Revenue projects the differential between WTI and ANS and uses a projection of inflation to arrive at the nominal dollar forecast used in this publication.

At the forecasting session, key topics are presented to assist the participants

in making their forecasts. For the fall 2006 forecast, the topics reviewed were worldwide economic growth, oil demand, oil supply (for the countries belonging to the Organization of Petroleum Exporting Countries or OPEC and non-OPEC countries), geopolitics and prices (history, forecasts from other organizations and results from the pre-meeting solicitation).

The economics team compiled and reviewed all results and chose the Most Likely case for the official price forecast for the years FY 2007 to FY 2013. Beyond 2013, the projections were very high and the department believed they were unrealistic given 146 years of crude oil price history. Therefore, the Low case scenario was selected for the official long-term forecast and merged with the Most Likely case scenario for the earlier years. The result is the forecast used in this publication.

Oil Price Forecast

Oil prices are arguably the most important component in the determination of state revenues. Using the sensitivity matrix we include in the appendices section of this document, a 1% change in oil prices equates to a 0.75% change in General Fund unrestricted revenues. In comparison, a 1% change in crude oil production volume results in a 0.5% change in revenues. Both price and volume of ANS are clearly important to the State of Alaska budget.

Many factors contribute to the pricing of oil on the world market. There are the fundamental economic factors of supply and demand. There are geopolitical events. There are other related issues, such as the impact of the financial sector, and of refinery capacity and configuration, and weather, that help determine how oil is priced. These factors have all been considered in establishing our oil

price forecast; the major petroleum-related events of 2006 are described below, followed by an examination of supply and demand projections.

Major Petroleum-Related Events in 2006

For the majority of 2006, oil prices remained at high levels. In July 2006, the spot price of ANS crude oil reached \$75 per barrel, a record high price in nominal terms. Prices for Alaska's oil stayed in the \$70 range for more than four months from mid-April through August 2006, before starting their gradual decline to their current price range of \$55 per barrel.

Tensions in Iran, Iraq and Nigeria contributed what analysts call a "fear premium" to the cost of oil this past summer. Market analysts speculate that \$10 to \$20 of the high price of oil this summer was due to the fear premium from political tensions around the globe.

Fears that the U.S. could experience a hurricane season like the one in 2005 also contributed to high oil prices. The summer of 2006 had, in fact, only one hurricane that threatened to do any real damage—Ernesto—and it did not even reach the Gulf of Mexico.

In August, British Petroleum announced it would be shutting in some production from Prudhoe Bay due to pipeline corrosion problems. News of this disruption had a minor, but noticeable and immediate impact on the price of oil. North Slope supplies were restored more quickly than originally predicted, and the shutdown in conjunction with other factors ceased to be much of a factor in setting oil prices.

With the easing of political and weather-related tensions, the price of oil has dropped from its summertime

high of \$75 and is currently in the mid-\$50 range. Analysts suggest that the falling prices have been exacerbated by the number of investors selling off their futures contracts.

Short and Long Term Demand and Supply Projections

The International Energy Agency (IEA) recently released its first medium-term oil demand forecast for calendar years 2006-2011. They state that the past few years of rising prices have resulted in increased upstream spending which is leading to supply increases. The IEA expects non-OPEC supplies, including biofuels, to grow by 2% per year to 56.7 million barrels per day in 2011, while OPEC supplies will rise by a total of 10% over the period to 36.6 million barrels per day. The increased prices are also tempering oil demand growth. They project world demand to grow at 2% per year to 93.7 million barrels per day in 2011. China and the Middle East are expected to contribute 45% of the demand growth during this period.

The U.S. Department of Energy, Energy Information Administration (DOE-EIA) likewise expects an annual 2% growth in worldwide oil demand and expects this until 2030. Nevertheless, due to higher relative oil prices, their 2006 projections reduced oil's share of overall worldwide energy demand. They anticipate worldwide oil consumption to reach 91.6 million barrels a day in 2010 with most of the demand growth originating in developing countries, especially China.

The IEA suggests that most international oil companies seem to be willing to proceed on projects based on prices in the \$30 to \$35 per barrel range, while national oil companies seem to be using a higher price. The IEA itself is utilizing an average real import price

of around \$55 per barrel for the period 2006-2011.

Current ANS Oil Market Situation

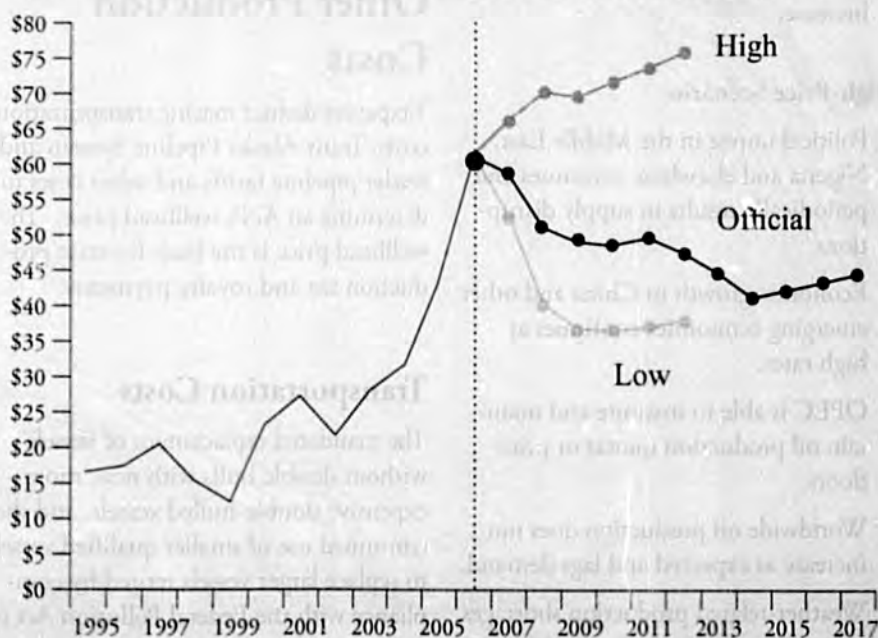
Alaska North Slope crude prices topped out at peak levels this past summer with prices averaging \$73.10 per barrel in July 2006. For FY 2006, ANS averaged \$60.80 per barrel—a whopping \$17.40 per barrel over FY 2005. The price of benchmark West Texas Intermediate averaged just over \$63 per barrel for June 2005-May 2006, implying a FY 2006 average discount for ANS of just over \$2.20 per barrel. More recently, the WTI-ANS differential has widened to \$4.75 per barrel. We believe the market is adequately supplied with a relative abundance of crude oil with similar qualities as ANS. This, and thin trading of ANS, has helped to widen the differential.

ANS prices track the OPEC price basket of internationally traded crude oils and tend to be priced higher than

the basket. The OPEC basket is the benchmark that OPEC uses to gauge prices for the organization. ANS typically sells in direct competition with other waterborne crude oils from Latin America, Asia and the Middle East for delivery to U.S. West Coast refiners in Washington, California and Hawaii.

With our official price scenario we believe that global economic growth is slowing but remains strong. We assume that oil will continue to be a competitive energy resource. And finally, we forecast that the current high price environment will encourage OPEC and non-OPEC oil-producing countries to continue to explore ways to increase production from existing facilities and to seek out new production opportunities.

Figure 4-8. Fall 2006 Official, Low & High ANS Oil Price Scenarios



Factors that could lead to lower or higher prices are:

Low-Price Scenario

- China's internal economic growth slows as does its export growth and energy consumption.
- The price effect from higher oil prices leads to lower overall worldwide oil consumption.
- Crude oil production capacity increases more rapidly than anticipated.
- OPEC does not successfully implement oil production quotas or price floors.
- Weather effects moderate demand by reducing temperature extremes with no production interruptions.
- World peace reduces risk related price premiums.
- Premiums related to financial hedges on oil futures are reduced or disappear.
- Crude oil production worldwide increases as a result of recent investment activity.
- Iraq oil production and exports increase.

High-Price Scenario

- Political unrest in the Middle East, Nigeria and elsewhere continues and periodically results in supply disruptions.
- Economic growth in China and other emerging economies continues at high rates.
- OPEC is able to institute and maintain oil production quotas or price floors.
- Worldwide oil production does not increase as expected and lags demand.
- Weather-related production shortages

and/or demand increases continue.

- Financial markets continue to exert artificial price wedges in oil futures.
- No or limited growth in spare crude oil production capacity.
- Technology does not become a driving force in long-term supply.

In this forecast, we increased our ANS oil prices for the period FY 2014-beyond, to \$41.50 per barrel increasing with inflation, from \$25.50 per barrel in the Spring 2006 Revenue Sources Book. This follows the department's protocol that participants in a price forecasting Delphi elected to change long-run prices from the prior two consecutive fall forecasts. The inflation rate is 2.75% per year based on Callan Associates Inc. five-year capital market assumptions. In addition to changing the long-run price, the number of years the price is forecast – before the long-run price begins – has also been changed. We now forecast seven (7) individual years. Earlier editions only forecast three (3) years.

Transportation and Other Production Costs

Taxpayers deduct marine transportation costs, Trans-Alaska Pipeline System and feeder pipeline tariffs and other costs to determine an ANS wellhead price. The wellhead price is the basis for state production tax and royalty payments.

Transportation Costs

The mandated replacement of vessels without double hulls with new, more expensive double-hulled vessels, and the continued use of smaller qualified vessels to replace larger vessels retired by compliance with the Federal Pollution Act of

1990 is likely to increase transportation costs in the future.

Trans-Alaska Pipeline System (TAPS) Tariffs

The TAPS tariff is determined according to the TAPS Settlement Methodology, a rate-making method approved by the Federal Energy Regulatory Commission that allows the TAPS owners to recover their costs, including an allowance for profit. Under the agreement, future tariffs will be determined by operating cost trends, the production rate and inflation. Preliminary negotiations between the state and pipeline owners have already started to revisit the TAPS Settlement Method, which is scheduled to expire December 31, 2011.

TAPS tariffs are filed on a calendar year basis, with new tariffs taking effect January 1 each year. The weighted average tariff filing for calendar year 2006 is \$4.06 per barrel. The fall 2006 forecast assumptions in Figure 4-9 (next page) contain projected tariffs for FY 2007-2017.

Feeder Pipeline and Other Adjustments

Additional transportation costs are also incurred to move the various crude oils that comprise ANS from North Slope production fields to Pump Station No. 1 of the Trans-Alaska Pipeline System. These include both feeder pipeline charges and other cost adjustments to account for the different qualities of oil entering the North Slope pipelines as well as market-location differentials for in-state sales. See Figure 4-9 on page 39.

Wellhead Price

The combination of ANS wellhead value and production volume form the

Figure 4-9. Fall 2006 Forecast Assumptions, FY 2007-2017 (Nominal \$ per barrel)

Fiscal Year ⁽¹⁾	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
ANS West Coast Price	59.15	51.25	49.50	49.00	50.00	47.50	45.00	41.50	42.50	43.50	44.50
ANS Marine Transportation	1.76	1.79	1.84	1.89	1.94	1.99	2.04	2.09	2.14	2.19	2.24
TAPS Tariff	4.38	4.11	2.36	2.43	2.48	2.53	2.57	2.71	2.84	2.92	3.01
Other Deductions & Adjustments ⁽²⁾	0.67	0.38	0.46	0.58	0.60	0.73	0.77	0.82	0.86	0.88	0.91
ANS wellhead	52.35	44.97	44.84	44.09	44.98	42.24	39.62	35.88	36.66	37.51	38.34

(1) FY 2007 includes reported information through August 2006.

(2) Includes other adjustments such as quality bank changes, location differentials and company-amended information.

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 4-9 reflects this calculation for FY 2007-2017.

Crude Oil Production

For the fall 2006 forecast, we continue to make adjustments to our production expectations from the North Slope. In the near term, we have incorporated revised reservoir performance analysis on declining fields, reviewed the uncertainty associated with the pace and scope of developing satellite fields and re-evaluated downtime for all fields due to current pipeline closures and related corrosion testing on the North Slope. For the longer term, we have delayed Point Thomson and associated satellite one year to maintain our assumed ten year lead time for development.

Our FY 2007 ANS production forecast has been revised downward to 740,000 barrels per day, which is a 12% decrease from the 845,000 barrels per day produced in FY 2006. This reflects volume

reductions from numerous unplanned events, including pipeline corrosion problems at Prudhoe Bay, Lisburne and Milne Point.

The North Slope is a mature oil province that is in decline. Its aging infrastructure will likely have additional problems as we look into the future and the harsh environment of the North Slope amplifies the likelihood of other occurrences. In addition, the development of fields containing viscous oil is providing challenges to the oil industry. These two factors have been incorporated into our forecast and are the reasons for forecasting lower near term volumes.

We characterize North Slope production three ways, each with discrete, albeit estimated confidence levels: (1) currently producing, (2) currently under development and (3) currently under evaluation. We do this so that the reader will have an understanding about the uncertainty associated with the production forecast. We continue to forecast production of only those reserves that have already been discovered and at 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 and production profile optimization. This category of production also presumes continued gas and water injection for pressure support. Based on historical forecasting performance, we assign a 98% confidence level for the current fiscal year and between 90% to 95% throughout the remainder of our forecast period.

Currently Under Development

Production characterized as "currently under development" is based on new projects currently funded and 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. It also includes incremental oil expected from the long-term gas cap water injection project at Prudhoe Bay and the low salinity waterflood at Endicott. Examples of production "currently under development" include the Fiord Kuparuk and Nanuq Kuparuk satellites at Alpine, near Beaufort fields Oooguruk and Nikaitchuq, J-Pad and K-Pad development at West Sak, near term planned drilling at Milne point and Schrader Bluff and certain satellite development at Prudhoe Bay.

For the fall forecast, we have again slowed the pace of development at all heavy oil fields to allow continued mitigation of challenging commercial and technical issues. Because of timing and scope uncertainty, our subjective confidence for this category of production is approximately 80-85%.

Currently Under Evaluation

Production characterized as "currently under evaluation" includes technically viable projects currently in the "pencil sharpening" stage where engineering, cost, risk and reward are all being actively evaluated. These projects are all currently unfunded by the operators but have a high chance of being brought to fruition. They include enhanced oil recovery at certain satellite fields, development drilling outside the core areas at West Sak and Schrader Bluff, expanded development at Prudhoe Bay satellites Orion, Polaris and Borealis and Alpine West and Qannik development in the Colville River unit. Also included in this category are NPR-A development, Point Thomson, Liberty and development of other known onshore discoveries. Although operator BP is currently evaluating technologies associated with developing the vast viscous oil accumulation known as Ugnu, we do not forecast any production from that field.

Regarding NPR-A, we are forecasting production from four small "puddles" in the vicinity of known discoveries currently named "Lookout", "Moose's Tooth", "Spark" and "Rendezvous". Since these discoveries have been announced, there has been ongoing exploration outside the boundaries of these accumulations, and explorers continue to push further west in search of new development opportunities.

Confidence levels vary for this category of production. Certain heavy oil development drilling for Schrader Bluff, Orion or West Sak in FY 2007 might have confidence levels approaching that of "production under development". Offshore developments such as Liberty, or potentially high cost, scope-challenged developments such as Point Thomson probably deserve lower confidence, and our subjective assessment is in the 70%-75% range. All production from this category is subject to delays and scope changes that might impact reserves or production rates.

Figure 4-10. Alaska North Slope Production, FY 1996-2006 and Forecasted FY 2007-2017

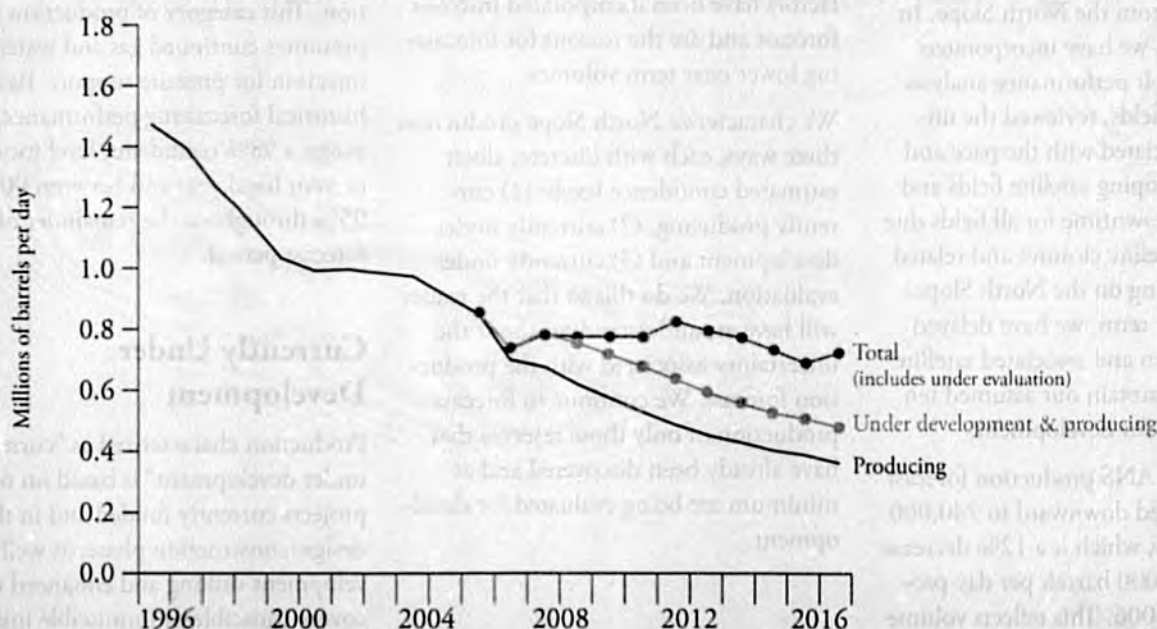


Figure 4-11. Alaska Crude Oil and NGL Production, FY 2006 and Forecast 2007-2008 (millions barrels/day)

Alaska North Slope	FY 2006	FY 2007	FY 2008
Prudhoe Bay ⁽¹⁾	0.340	0.280	0.301
Aurora	0.009	0.012	0.013
Borealis	0.017	0.017	0.017
Midnight Sun	0.006	0.005	0.005
Orion	0.007	0.009	0.012
Polaris	0.003	0.002	0.006
Lisburne	0.009	0.009	0.011
Niakuk ⁽²⁾	0.006	0.004	0.004
Point McIntyre	0.033	0.015	0.027
Raven	0.001	0.002	0.001
Kuparuk	0.134	0.119	0.116
Meltwater	0.005	0.003	0.003
Tabasco	0.004	0.004	0.003
Tarn	0.020	0.019	0.017
West Sak	0.013	0.019	0.030
Milne Point	0.025	0.021	0.024
Schrader Bluff	0.016	0.010	0.013
Endicott	0.019	0.016	0.015
Badami	0.001	0.001	0.001
Alpine ⁽³⁾	0.123	0.106	0.090
Fiord ⁽⁴⁾	0.000	0.010	0.019
Nanuq ⁽⁵⁾	0.000	0.005	0.012
Oooguruk	0.000	0.000	0.0003
Northstar ⁽⁶⁾	0.056	0.051	0.039
Total Alaska North Slope	0.845	0.740	0.782

increase/decrease from prior period

(0.072)

(0.105)

0.043

% change from prior period

-7.9%

-12.4%

5.8%

Cook Inlet	0.018	0.017	0.016
-------------------	--------------	--------------	--------------

increase/decrease from prior period

(0.002)

(0.001)

(0.001)

% change from prior period

-9.0%

-5.9%

-7.0%

Total Alaska	0.863	0.756	0.798
---------------------	--------------	--------------	--------------

increase/decrease from prior year

(0.0534)

(0.1070)

0.0415

% change from prior period

-5.3%

-12.4%

5.5%

(1) Includes NGLs

(3) Includes Qannik

(5) Includes Nanuq-Kuparuk

(2) Includes West Niakuk

(4) Includes Fiord-Kuparuk

(6) Includes OCS Production

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 state appraiser gathers raw data for determining market value by reviewing the details of equipment sales, attending auctions and reviewing trade journals. This data is then applied to the taxable property, taking into account age, capacity, physical and functional obsolescence.

Production Property

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

In the case of an offshore oil or gas platform or onshore facility, the number of years of useful life is determined by estimating the date the facility reaches its economic limit, not on the basis of the projected physical life of the property. The time period until the estimated operating revenue would equal operating expenses plus the current age of the facility equals the total life. The depreciation factor for the facility equals the years of remaining life divided by the total life.

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. We rely upon several

standard appraisal techniques to value Alaska pipelines. When market rents are available, we primarily rely on the income method under which the value is the net present worth of all future income streams of the pipeline. When rents are constrained by the regulatory process or when market rents cannot be obtained, we primarily rely on replacement cost less depreciation based on the economic life of the reserves that feed the pipeline. The Trans-Alaska Pipeline from Prudhoe Bay represents more than 95% of Alaska's taxable pipeline transportation property.

Figure 4-12 illustrates the property tax distribution between local communities and the state for FY 2006. 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.

Figure 4-12. Distribution of Petroleum Property Tax, FY06 (\$ million) ⁽¹⁾

Municipalities	Gross Tax	Local Share	State Share
North Slope	209.1	199.2	9.9
Unorganized	37.5	0.0	37.5
Valdez	18.3	18.3	0.0
Kenai	11.1	7.0	4.1
Fairbanks	7.6	5.8	1.8
Anchorage	4.0	3.1	1.0
Other Municipalities ⁽²⁾	0.2	0.1	0.1
Total	287.8	233.5	54.3

(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 book or in the Tax Division's FY 2006 Annual Report.

(2) Includes Matanuska-Susitna Borough, Cordova and Whittier.

Petroleum Corporate Income Tax

Alaska levies corporate income tax in two ways: 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 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 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. As recently as FY 1994, the oil and gas corporate income tax generated a mere \$17.8 million. For the past three years, revenues

from the oil and gas corporate income tax have risen along with oil prices and oil industry profits, generating \$661.1 million in FY 2006—the highest level for collections since the early 1980's.

We produce our forecast of oil and gas corporate income tax collections by using an economic model. The statistical relationship between historical tax payments, crude oil prices, North Slope oil production and refinery margins are used to estimate corporate income tax payments. We then adjust for refunds and carry-forwards which cause actual collections to differ from payments. Estimated payments so far in FY 2007 have been strong, and we project that for the full fiscal year oil and gas corporate income tax collections will be close to the FY 2006 total. In FY 2008, we expect a 25% decline in collections due to declining oil prices and refining margins.

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 such revenue flows into the NPR-A Special Revenue Fund. All of the 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 lapses into the General Fund.

The table below reflects restricted oil and gas revenue.

Figure 4-13. Restricted Oil Revenue, FY 2006 and Forecasted FY 2007-2008 (\$ million)

Restricted	FY 2006	FY 2007	FY 2008
Royalties to Permanent Fund & School Fund			
Royalties, bonuses & rents to Permanent Fund	599.5	504.7	442.0
Royalties, bonuses & rents to School Fund	12.0	13.9	5.8
Subtotal	611.5	518.6	447.8
Settlements to CBRF	43.7	90.0	20.0
NPRA royalties, rents & bonuses	2.9	6.4	7.6
Total Restricted	658.1	615.0	475.4

Figure 5-1. Total Other Revenue (Except Federal & Investment) FY 2006 and Forecasted FY 2007-2008 (\$ million)

	Forecast	History	
	FY 2007	FY 2006	
Other	20.2	40.6	
Rents & royalties	9.4	8.8	
License & permits	44.1	41.9	
Fines & forfeitures	10.3	8.2	
Change for others	23.1	23.1	
Total	247.9	227.6	Unrestricted

5. Other Revenue (Except Federal & Investment)

Figure 5-1. FY 2006 Other Revenue (Except Federal & Investment) \$1.0 billion

