

ALASKA LEGISLATURE

2453

HOUSE and SENATE FINANCE COMMITTEE FILES, 2003-2004

PERS Summary of Benefits

Public Employees' Retirement System Schedule of Benefit Expenses by Type (000's Omitted)								
Year Ended June 30	Service	Disability	Survivor	Dependent ⁽¹⁾	COLA ⁽²⁾	PRPA ⁽³⁾	Medical	Total
1994	\$90,388	\$3,895	\$ 4,668	\$ -	\$7,099	\$15,817	\$36,046	\$157,913
1995	97,730	4,073	5,431	-	7,597	16,800	40,687	172,321
1996	107,082	4,608	5,546	-	8,244	17,559	47,964	191,003
1997 ⁽¹⁾	160,103	6,228	10,314	683	-	-	48,361	225,689
1998	177,556	6,598	10,823	567	-	-	55,165	250,709
1999	195,605	7,195	12,141	229	-	-	64,486	279,656
2000	216,118	9,669	13,650	4	-	-	83,794	323,235
2001	239,814	8,185	11,772	-	-	-	103,846	363,617
2002	258,189	8,379	13,163	-	-	-	124,805	404,536
2003	283,927	8,827	14,930	-	-	-	143,331	451,015

(1) Due to the implementation of a new computer system, COLA and PRPAs can now be combined with the appropriate base benefit and dependent benefits can be separated from survivor and disability benefits.

(2) Cost-of-Living in Alaska (COLA)

(3) Post-Retirement Pension Adjustment (PRPA)

TRS Summary of Benefits

Teachers' Retirement System Schedule of Benefit Expenses by Type (000's omitted)

Year Ended June 30	Service	Disability	Survivor	Dependent ⁽¹⁾	COLA ⁽²⁾	PRPA ⁽³⁾	Healthcare	Total
1994	\$ 76,735	\$2,579	\$2,260	\$ -	\$4,991	\$14,202	\$15,725	\$116,492
1995	85,933	2,546	2,513	-	5,642	14,864	18,264	129,762
1996	93,089	2,798	2,618	-	6,082	15,362	21,655	141,604
1997 ⁽¹⁾	147,259	3,943	6,322	43	-	-	22,653	180,220
1998	160,409	3,693	5,691	38	-	-	26,123	195,954
1999	176,800	3,775	6,384	96	-	-	30,987	218,072
2000	191,138	4,601	7,059	129	-	-	40,183	243,110
2001	201,338	3,410	5,784	413	-	-	48,928	259,873
2002	213,106	2,979	6,320	492	-	-	56,946	279,843
2003	234,253	2,872	6,901	492	-	-	65,898	310,416

⁽¹⁾ Due to the implementation of a new computer system, COLA and PRPAs can now be combined with the appropriate base benefit and dependent benefits can be separated from survivor and disability benefits.

⁽²⁾ Cost-of-Living in Alaska (COLA)

⁽³⁾ Post-Retirement Pension Adjustment (PRPA)

PRS/TRS

Tier IV - Tier III

Subcommittee



State of Alaska Employer Newsletter

Public Employees' Retirement System (PERS)
Teachers' Retirement System (TRS)

Message from Commissioner Miller

On September 22, 2003, I assigned an important project to the Public Employees' Retirement Board (PERB) and Teachers' Retirement Board (TRB) members involving the future system design for Tiers. My request was made in order to address the increasing costs for employers associated with funding the retirement systems for the Public Employees' Retirement System (PERS) and Teachers' Retirement System (TRS). I requested a subcommittee be formed to analyze and provide recommendations that would in turn form the basis for designing a new Tier IV for PERS and Tier III for TRS.

When making this request of the PERS and TRS Board members Mike Miller, Commissioner, Department of Administration stated, "while the State may be short on dollars, it is not short on talent."

—PERB/TRB Meeting, September 23, 2003

As most of you are aware, the employer rates for FY05 were adopted by the PERB and TRB on _____.

The PERB adopted an 11.77% average employer rate for PERS employers, which represents a 5% increase from the FY04 6.77% rate. The TRB adopted an employer rate of 16% for FY05, which represents a 4% increase from the FY04 12% rate.



Mike Miller, Commissioner
Dept. of Administration

I participated in the first "kick off" meeting on November 19, 2003, with the Tier IV PERS and Tier III TRS Subcommittee. I am confident the Tier Subcommittee will work hard to identify, develop, and provide recommendations for future Tier design.

—Mike Miller

In Search of Your Ideas

Draft

PERS/TRS Tier Subcommittee
(from left to right)

Bob Boko—Chair, Alyce Hanley,
Richard Solie, and Frank Narusch.



The purpose of this issue of the Employer Newsletter is to solicit employer comments on how the Public Employees' (PERS) and Teachers' Retirement Systems (TRS) could be changed to deal with increasing costs while still allowing employers to attract and retain employees to the workforce. That means a new benefit structure for future employees.

The Boards of both systems have formed a joint committee to review what might be considered in the design of a new "tier." This new tier would affect new employees hired after the passage of a new tier and does not represent an immediate solution to rising employer costs. However, putting cost containment measures in place now will slow the inevitable rise in costs for the future. The present three tiers in PERS and two tiers in TRS still do not provide enough opportunity to control

employer retirement costs. Without some further changes, costs will inevitably rise.

We want to consider all types of input. **That means any ideas you may have to restructure future retirement benefits.** On the following pages of this newsletter is a questionnaire / comment form we would like you to fill out in order to provide the boards with your suggestions. Please mail it back to the address, or fax it to the number indicated in the survey by _____.

PLEASE give us your comments and suggestions. It's your retirement system, and we need your input. **Although several issues and suggestions are listed, you are not restricted to this list. If you have ideas that are not listed there, by all means include them.**

EMPLOYER TIER SURVEY—2004
PUBLIC EMPLOYEES' AND TEACHERS' RETIREMENT SYSTEMS

Following are several areas that could be considered for changes in a new tier. (Any changes would affect new members hired after the date of a new tier only; benefits for current members would not change.)

- ☛ After each question, please select one of the three answers.
- ☛ Please respond to all the questions in a particular section that apply.
- ☛ There is a section at the end of the survey to supply whatever comments or suggestions you may have.

Please return this survey by _____ to: Mail: Melanie Millhorn, Director,
 Division of Retirement & Benefits
 PO Box 110203, Juneau, Alaska, 99811-0203
 Fax: 907-465-3086

I. Changes to the Current Benefit Structure

1. Change the basis of salary computation:

	System	Yes	No	Neutral
a. The TRS uses any 3 high years; change that to 3 consecutive high years.	TRS			
b. Eliminate overtime from inclusion in salaries considered for benefit calculation	PERS			
c. Eliminate geographic differential from inclusion in salaries considered for benefit calculation. (State of Alaska only)	PERS			
d. Change the formula to an average of <u>all</u> years earnings, not just a series of high years.	PERS			
	TRS			
e. Eliminate the use of any kind of bonus from inclusion in salaries considered for benefit calculation. (A bonus granted at the end of a person's employment that is eligible for inclusion in salary calculation creates a substantial unfunded liability to the employer.)	PERS			
	TRS			

System	Yes	No	Neutral
PERS			
TRS			
PERS			
TRS			
PERS			
TRS			

2. Change the retirement eligibility requirements.

a. Make the normal retirement age 65, and early retirement age 60.

b. Change the service eligibility requirements from 20 to 25 years (retire at any age) for teachers and police/fire members.

c. Retain a 20 year service retirement option for teachers and police/fire members but members must elect the option and pay a contribution surcharge.

3. Change the rate of service accrual:

a. Increase the number of hours a PERS employee must work to be considered full-time from 30 to 35 or higher. Redefine this to require actual full-time work for full-time credit and give proportionately less credit for less than actual full time.

b. Increase the number of hours a PERS part-time employee must work per week from a minimum of 15 to 20 or higher. Redefine this to give proportionately less credit for less than standard part-time service.

4. Change the employee and/or employer contribution rate:

a. Currently, employee contribution rates are set in statute and do not vary. Increase the percentage the employee pays. Current percentages are: PERS All other— 6.75%, PERS Police/Fire—7.5%, TRS—8.65%

b. Base the employee contribution rate on a percentage of the total cost to fund benefits. Employee rates would vary each year.

c. Change the TRS from a shared employer rate to an employer specific rate similar to the PERS. Each employer would pay contributions based on their liability for their own employees.

PERS			
TRS			
PERS			
TRS			
TRS			

5. Change Retiree Health Insurance Coverage:

	System	Yes	No	Neutral
a. Provide system-paid premiums for insurance coverage for members only. Members would pay extra to cover spouses and dependents.	PERS			
	TRS			
b. Require ten years of TRS service in order to be eligible for system-paid insurance premiums. (Already a provision of PERS Tier III.)	TRS			
c. Require more than 10 years of service in order to be eligible for system-paid insurance premiums.	PERS			
	TRS			
d. Graduated health premium coverage based on years of service.	PERS			
	TRS			
e. Raise the deductibles and co-pays on retiree health insurance coverage.	PERS			
	TRS			
f. Require the use of generic drugs wherever available.	PERS			
	TRS			
g. Develop a cafeteria style plan where the system offers minimum health care and retirees can purchase increased coverage.	PERS			
	TRS			
h. Retiree pays full premium until age 65 and Medicare eligible.	PERS			
	TRS			

6. Change interest accruals:

a. Make the mandatory interest rate paid on employee accounts variable with actual earnings. Presently it is set at 4.5%, irrespective of whether the system has positive investment returns. That means that in years of no earnings / losses, employers must fund a 4.5% interest rate on employee accounts through increased future employer rates.	PERS			
	TRS			
b. Increase the interest rate employees pay on an indebtedness to buy back service previously cashed out, or to purchase permissible service credits. The present rate is 7% and is below the rate the system must use for long term funding.	PERS			
	TRS			

System	Yes	No	Neutral

II. Change the Entire Plan

1. Change the basis of salary computation:

Are you in favor of a total change in the type of retirement plan offered by each system, i.e., a change to a defined contribution plan or a hybrid plan that retains some aspects of the defined benefit plan but adds a defined contribution component?

a. Change to a defined contribution plan. New employees would enroll in a 401(k) type plan where the contributions and the earnings become the benefit. Unlike the present PERS or TRS, the benefit would be the account balance, and employers would have no further liability for future cost increases once the employee terminates. The employee gets the account balance, not an annuity type payment for a lifetime. No health care would be provided by the system, the employee funds their own health care from the rollover eligible account balance. The moneys in such a plan would be rollover eligible to similar plans, can be moved from employer to employer (if the other employer allows), or placed in an IRA.

PERS			
TRS			

b. Change to a hybrid plan. Hybrid plans offer a compromise between defined benefit plans and defined contribution plans. Examples of a few hybrid plans are:

Cash Balance Plan. Offers simplicity, portability, equity and cost control. This type of plan bears a close resemblance to a defined contribution plan but contains standards for vesting and still determines the participant's future benefit using a specific formula.

PERS			
TRS			

Pension Equity Plan. Bears a close resemblance to a defined contribution plan but defines benefits based on final-average pay and pays a lump sum benefit.

PERS			
TRS			

Floor-Offset Plan. Consists of two separate but associated plans. A defined benefit floor plan and a defined contribution base plan. The defined benefit plan uses a standard formula to establish a minimum benefit level. If the defined contribution plan provides a benefit that equals or exceeds the minimum established by the defined benefit floor, then the participant receives the benefit equal to the defined contribution account only; if the defined contribution plan provides less than the minimum benefit, the floor plan makes up the difference between what the defined contribution plan can provide and the minimum benefit.

PERS			
TRS			

Sent By:

Employer: _____ PERS _____ TRS _____

Contact Person: _____

Address: _____

City: _____ State: _____ ZIP: _____

Phone: _____

Fax: _____

E-Mail: _____



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 Juneau, AK 99811-0203

**Now call
 toll-free
 1-800-821-2251**

Inside this issue

In Search of Your Ideas	1
Message from Commissioner Miller	1
Employer Tier Survey—2004	2

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Comparison of
Other Systems
Funding
Health Care

Public Fund Survey - Funding Levels

Note: The following systems 123 systems identified only 8 retirement systems prefund the post-retirement health care.

- Alaska PERS / TRS
- Kentucky ERS / TRS
- Michigan SERS / Public Schools
- Ohio PERS / TRS

Dollars are in 000's

Aggregate for the 123 Plans shown here	Actuarial Funding Ratio	Actuarial Assets	Actuarial Liabilities	Unfunded Liability (Surplus)
	96.4%	\$2,043,166,050	\$2,119,562,494	\$76,396,444

No.	State	Plan Name	Actuarial Funding Ratio	Actuarial Assets	Actuarial Liabilities	Unfunded Liability (Surplus)	Valuation Date
1	AK	<u>Alaska PERS</u>	100.9%	\$7,941,756	\$7,868,574	(\$73,182)	6/30/2001
2	AK	<u>Alaska Teachers</u>	95.0%	\$4,372,229	\$4,603,147	\$230,918	6/30/2001
3	AL	<u>Alabama ERS</u>	100.2%	\$8,028,471	\$8,010,123	(\$18,348)	6/30/2001
4	AL	<u>Alabama Teachers</u>	97.4%	\$17,904,881	\$18,374,174	\$469,293	6/30/2002
5	AR	<u>Arkansas PERS</u>	100.1%	\$4,404,000	\$4,398,000	(\$6,000)	6/30/2002
6	AR	<u>Arkansas Teachers</u>	91.9%	\$9,328,451	\$9,061,500	\$733,049	6/30/2002
7	AZ	<u>Arizona Public Safety Personnel</u>	113.0%	\$4,684,386	\$4,144,711	(\$540,175)	6/30/2002
8	AZ	<u>Arizona SRS</u>	104.6%	\$23,623,016	\$22,586,921	(\$1,036,095)	6/30/2002
9	CA	<u>California PERF</u>	111.9%	\$166,860,000	\$149,155,000	(\$17,705,000)	6/30/2001
10	CA	<u>California Teachers</u>	98.0%	\$107,861,000	\$110,094,000	\$2,233,000	6/30/2001
11	CA	<u>LA County ERS</u>	100.0%	\$26,490,000	\$26,489,976	(\$24)	6/30/2001
12	CA	<u>San Francisco City & County</u>	129.0%	\$10,797,024	\$8,371,843	(\$2,425,181)	6/30/2001
13	CO	<u>Colorado Municipal</u>	93.6%	\$1,839,632	\$1,966,143	\$126,511	12/31/2002
14	CO	<u>Colorado State & School</u>	87.9%	\$28,551,607	\$32,463,918	\$3,912,311	12/31/2002
15	CO	<u>Denver Schools</u>	90.9%	\$2,470,000	\$2,710,000	\$240,000	1/1/2003
16	CT	<u>Connecticut SEKS</u>	61.6%	\$7,893,700	\$12,806,100	\$4,912,400	6/30/2002
17	CT	<u>Connecticut Teachers</u>	75.9%	\$10,387,300	\$13,679,900	\$3,292,600	6/30/2002
18	DC	<u>DC Police & Fire</u>	100.0%	\$1,097,300	\$1,097,300	\$0*	10/1/2000

19	DC	<u>DC Teachers</u>	100.0%	\$798,900	\$798,900	\$0*	10/1/2000
20	DE	<u>Delaware State Employees</u>	109.6%	\$4,956,156	\$4,521,732	(\$434,424)	6/30/2002
21	FL	<u>Florida RS</u>	114.8%	\$99,405,677	\$86,469,774	(\$12,935,903)	7/1/2002
22	GA	<u>Georgia ERS</u>	101.7%	\$11,750,624	\$11,557,255	(\$193,369)	6/30/2001
23	GA	<u>Georgia Teachers</u>	102.0%	\$40,502,333	\$39,706,523	(\$795,810)	6/30/2002
24	HI	<u>Hawaii ERS</u>	84.0%	\$9,415,160	\$11,210,226	\$1,795,066	6/30/2002
25	IA	<u>Iowa PERS</u>	92.6%	\$15,613,114	\$16,868,559	\$1,255,445	6/30/2002
26	ID	<u>Idaho PERS</u>	84.9%	\$6,133,800	\$7,209,500	\$1,075,700	7/1/2002
27	IL	<u>Chicago Teachers</u>	96.3%	\$10,619,061	\$11,025,482	\$406,421	6/30/2002
28	IL	<u>Illinois Municipal</u>	101.5%	\$16,800,196	\$16,559,907	(\$240,289)	12/31/2002
29	IL	<u>Illinois SERS</u>	53.7%	\$7,673,893	\$14,291,044	\$6,617,151	6/30/2002
30	IL	<u>Illinois Teachers</u>	49.3%	\$23,124,823	\$46,933,432	\$23,808,609	7/1/2003
31	IL	<u>Illinois Universities</u>	58.9%	\$9,814,700	\$16,654,000	\$6,839,300	6/30/2002
32	IN	<u>Indiana PERF</u>	105.0%	\$8,723,304	\$8,305,672	(\$417,632)	7/1/2001
33	IN	<u>Indiana Teachers</u>	42.1%	\$6,176,574	\$14,664,661	\$8,488,087	6/30/2001
34	KS	<u>Kansas PERS</u>	83.6%	\$8,603,150	\$10,294,455	\$1,691,305	12/31/2001
35	KS	<u>Wichita Employees</u>	117.0%	\$433,366	\$370,399	(\$62,967)	12/31/2002
36	KS	<u>Wichita Fire & Police</u>	106.2%	\$361,687	\$340,524	(\$21,163)	12/31/2002
37	KY	<u>Kentucky County</u>	125.3%	\$6,883,299	\$5,492,646	(\$1,390,653)	6/30/2002
38	KY	<u>Kentucky ERS</u>	110.7%	\$7,030,468	\$6,348,164	(\$682,304)	6/30/2002
39	KY	<u>Kentucky Teachers</u>	86.6%	\$13,588,847	\$15,695,574	\$2,106,727	6/30/2002
40	LA	<u>Louisiana SERS</u>	70.2%	\$6,460,594	\$9,206,734	\$2,746,140	6/30/2002
41	LA	<u>Louisiana Teachers</u>	73.9%	\$12,019,552	\$16,263,239	\$4,243,687	6/30/2002
42	MA	<u>Massachusetts SERS</u>	79.5%	\$13,947,271	\$17,550,939	\$3,603,668	1/1/2003
43	MA	<u>Massachusetts Teachers</u>	76.2%	\$15,712,000	\$20,620,000	\$4,908,000	1/1/2002
44	MD	<u>Maryland PERS</u>	98.0%	\$11,162,265	\$11,385,749	\$223,484	6/30/2002
45	MD	<u>Maryland Teachers</u>	92.0%	\$19,424,000	\$21,117,047	\$1,693,047	6/30/2002
46	ME	<u>Maine Local</u>	101.1%	\$1,381,356	\$1,366,485	(\$14,871)	6/30/2001
47	ME	<u>Maine State and Teacher</u>	72.9%	\$5,801,423	\$7,958,810	\$2,157,387	6/30/2001
48	MI	<u>Michigan Municipal</u>	84.3%	\$4,034,400	\$4,783,900	\$749,500	12/31/2001
49	MI	<u>Michigan Public Schools</u>	96.5%	\$38,399,000	\$39,774,000	\$1,375,000	9/30/2001

* 50	MI	<u>Michigan SERS</u>	107.6%	\$10,633,000	\$9,878,000	(\$755,000)	9/30/2001
51	MN	<u>Duluth Teachers</u>	95.7%	\$278,467	\$291,109	\$12,642	7/1/2003
52	MN	<u>Minneapolis ERF</u>	92.3%	\$1,540,221	\$1,667,871	\$127,650	7/1/2002
53	MN	<u>Minneapolis Teachers</u>	61.9%	\$1,027,883	\$1,659,512	\$631,629	6/30/2002
54	MN	<u>Minnesota PERF</u>	85.0%	\$11,017,414	\$12,958,105	\$1,940,691	6/30/2002
55	MN	<u>Minnesota State Employees</u>	104.5%	\$7,673,028	\$7,340,397	(\$332,631)	6/30/2002
56	MN	<u>Minnesota Teachers</u>	105.3%	\$17,378,994	\$16,503,099	(\$875,895)	7/1/2002
57	MN	<u>St. Paul Teachers</u>	78.8%	\$899,572	\$1,141,300	\$241,728	6/30/2002
58	MO	<u>Missouri DOT and Highway Patrol</u>	66.0%	\$1,520,800	\$2,301,403	\$780,603	6/30/2001
59	MO	<u>Missouri Local</u>	100.4%	\$2,623,611	\$2,613,088	(\$10,523)	2/28/2002
60	MO	<u>Missouri Non-Teachers</u>	97.6%	\$1,810,619	\$1,855,982	\$45,363	6/30/2002
61	MO	<u>Missouri State Employees</u>	90.9%	\$6,057,329	\$6,662,291	\$604,962	6/30/2003
62	MO	<u>Missouri Teachers</u>	95.3%	\$22,236,105	\$23,333,937	\$1,097,832	6/30/2002
63	MO	<u>St. Louis School Employees</u>	89.3%	\$861,128	\$964,833	\$103,705	1/1/2002
64	MS	<u>Mississippi PERS</u>	83.4%	\$16,823,185	\$20,280,347	\$3,457,162	6/30/2002
65	MT	<u>Montana PERS</u>	100.0%	\$3,076,781	\$3,077,764	\$983	6/30/2002
66	MT	<u>Montana Teachers</u>	83.4%	\$2,484,800	\$2,980,100	\$495,300	7/1/2002
67	NC	<u>Charlotte Firefighters</u>	93.9%	\$261,022	\$277,843	\$16,821	7/1/2003
68	NC	<u>North Carolina Local Government</u>	99.3%	\$10,764,034	\$10,836,460	\$72,426	12/31/2001
69	NC	<u>North Carolina Teachers and State Employees</u>	111.6%	\$42,104,086	\$37,713,663	(\$4,390,423)	12/31/2001
70	ND	<u>North Dakota PERS</u>	98.1%	\$1,166,500	\$1,188,800	\$22,300	6/30/2003
71	ND	<u>North Dakota Teachers</u>	91.6%	\$1,443,500	\$1,575,800	\$132,300	7/1/2002
72	NE	<u>Nebraska Schools</u>	n/a				
73	NH	<u>New Hampshire Retirement System</u>	82.1%	\$3,443,395	\$4,196,314	\$752,919	6/30/2002
74	NJ	<u>New Jersey PERS</u>	107.3%	\$27,728,804	\$25,842,457	(\$1,886,347)	6/30/2002
75	NJ	<u>New Jersey Police & Fire</u>	100.8%	\$18,074,454	\$17,922,587	(\$151,867)	6/30/2001
76	NJ	<u>New Jersey Teachers</u>	100.0%	\$35,192,180	\$35,190,526	(\$1,654)	6/30/2001
77	NM	<u>New Mexico PERF</u>	103.1%	\$8,769,254	\$8,505,931	(\$263,303)	6/30/2002
78	NM	<u>New Mexico Teachers</u>	86.8%	\$7,595,591	\$8,747,971	\$1,152,380	6/30/2002
79	NV	<u>Nevada Police and Firemen</u>	78.1%	\$2,763,283	\$3,536,980	\$773,697	6/30/2002

80	NV	<u>Nevada Regular Employees</u>	83.5%	\$12,289,048	\$14,722,878	-\$2,433,830	6/30/2002
81	NY	<u>New York City ERS</u>	99.8%	\$43,015,355	\$43,087,570	\$72,215	6/30/2001
82	NY	<u>New York City Teachers</u>	100.0%	\$35,410,230	\$35,414,490	\$4,260	6/30/2001
83	NY	<u>New York State Teachers</u>	125.0%	\$87,295,300	\$69,817,000	(\$17,478,300)	6/30/2001
84	NY	<u>NY State & Local ERS</u>	100.0%	\$107,610,000	\$107,610,000	\$0*	4/1/2002
85	NY	<u>NY State & Local Police & Fire</u>	100.0%	\$19,412,000	\$19,412,000	\$0*	4/1/2002
* 86	OH	<u>Ohio PERS</u>	102.6%	\$48,749,000	\$47,492,000	(\$1,257,000)	12/31/2001
87	OH	<u>Ohio Police & Fire</u>	92.8%	\$9,076,469	\$9,785,766	\$709,297	1/1/2002
* 88	OH	<u>Ohio School Employees</u>	89.0%	\$8,879,000	\$9,986,000	\$1,107,000	6/30/2002
89	OH	<u>Ohio Teachers</u>	77.4%	\$48,958,824	\$63,215,643	\$14,256,819	6/30/2002
90	OK	<u>Oklahoma PERS</u>	79.8%	\$5,299,781	\$6,639,720	\$1,339,939	7/1/2002
91	OK	<u>Oklahoma Teachers</u>	51.4%	\$6,310,900	\$12,275,900	\$5,965,000	6/30/2002
92	OR	<u>Oregon PERS</u>	89.9%	\$35,537,100	\$39,520,500	\$3,983,400	12/31/2002
93	PA	<u>Pennsylvania School Employees</u>	114.4%	\$54,830,300	\$47,917,399	(\$6,912,901)	6/30/2001
94	PA	<u>Pennsylvania SERS</u>	107.2%	\$27,497,640	\$25,650,389	(\$1,847,251)	12/31/2002
95	RI	<u>Rhode Island ERS</u>	77.6%	\$5,859,719	\$7,234,787	\$1,375,068	6/30/2000
96	RI	<u>Rhode Island Municipal</u>	81.0%	\$895,475	\$758,090	(\$137,385)	6/30/2000
97	SC	<u>South Carolina Police</u>	94.6%	\$2,177,982	\$2,324,257	\$126,275	7/1/2001
98	SC	<u>South Carolina RS</u>	87.4%	\$18,486,773	\$21,162,147	\$2,675,374	7/1/2001
99	SD	<u>South Dakota PERS</u>	96.7%	\$4,425,392	\$4,576,949	\$151,557	6/30/2002
100	TN	<u>TN Political Subdivisions</u>	90.4%	\$3,187,990	\$3,528,137	\$340,147	7/1/2001
101	TN	<u>TN State and Teachers</u>	99.6%	\$20,760,989	\$20,842,216	\$81,227	7/1/2001
102	TX	<u>Houston Firefighters</u>	112.9%	\$1,863,100	\$1,650,800	(\$212,300)	7/1/2001
103	TX	<u>Texas County & District</u>	88.7%	\$8,779,300	\$9,898,400	\$1,119,100	12/31/2002
104	TX	<u>Texas ERS</u>	97.6%	\$19,478,555	\$19,959,112	\$480,557	8/31/2003
105	TX	<u>Texas LECOS</u>	131.6%	\$647,757	\$492,127	(\$155,630)	
106	TX	<u>Texas Municipal</u>	84.2%	\$9,998,700	\$11,868,100	\$1,869,400	12/31/2002
107	TX	<u>Texas Teachers</u>	96.3%	\$86,035,000	\$89,322,000	\$3,287,000	8/31/2002
108	UT	<u>Utah Noncontributory</u>	93.6%	\$10,888,518	\$11,628,203	\$739,685	12/31/2002
109	VA	<u>Fairfax County Schools</u>	103.0%	\$1,599,219	\$1,552,558	(\$46,661)	6/30/2001
110	VA	<u>Virginia Retirement System</u>	107.3%	\$37,968,000	\$35,384,000	(\$2,584,000)	6/30/2001

111	VT	<u>Vermont State Employees</u>	97.4%	\$990,450	\$1,017,129	\$26,679	6/30/2002
112	VT	<u>Vermont Teachers</u>	89.5%	\$1,169,294	\$1,307,202	\$137,908	6/30/2002
113	WA	<u>Washington LEOFF Plan 1</u>	129.3%	\$5,368,900	\$4,153,000	(\$1,215,900)	9/30/2001
114	WA	<u>Washington LEOFF Plan 2</u>	100.0%	\$2,575,600	\$2,575,600	\$0*	9/30/2001
115	WA	<u>Washington PERS 1</u>	90.9%	\$10,989,900	\$12,088,400	\$1,098,500	9/30/2001
116	WA	<u>Washington PERS 2/3</u>	100.0%	\$11,031,600	\$11,031,600	\$0*	9/30/2001
117	WA	<u>Washington School Employees Plan 2/3</u>	100.0%	\$1,471,700	\$1,471,700	\$0*	9/30/2001
118	WA	<u>Washington Teachers Plan 1</u>	94.4%	\$9,341,800	\$9,894,900	\$553,100	9/30/2001
119	WA	<u>Washington Teachers Plan 2/3</u>	100.0%	\$3,547,200	\$3,547,200	\$0*	9/30/2001
120	WI	<u>Wisconsin Retirement System</u>	97.1%	\$57,861,900	\$59,618,800	\$1,756,900	12/31/2002
121	WV	<u>West Virginia PERS</u>	75.4%	\$2,588,700	\$3,429,675	\$840,975	7/1/2002
122	WV	<u>West Virginia Teachers</u>	19.2%	\$1,098,400	\$5,708,900	\$4,610,500	7/1/2002
123	WY	<u>Wyoming Public Employees</u>	92.2%	\$4,352,424	\$4,718,618	\$366,194	1/1/2003

*Funds with an unfunded liability of zero use the aggregate cost actuarial valuation method. Under this method, the actuarial value of liabilities is equal to the act of assets and no unfunded liability is identified.

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1/27/04

OVERVIEW:

OIL PRICE

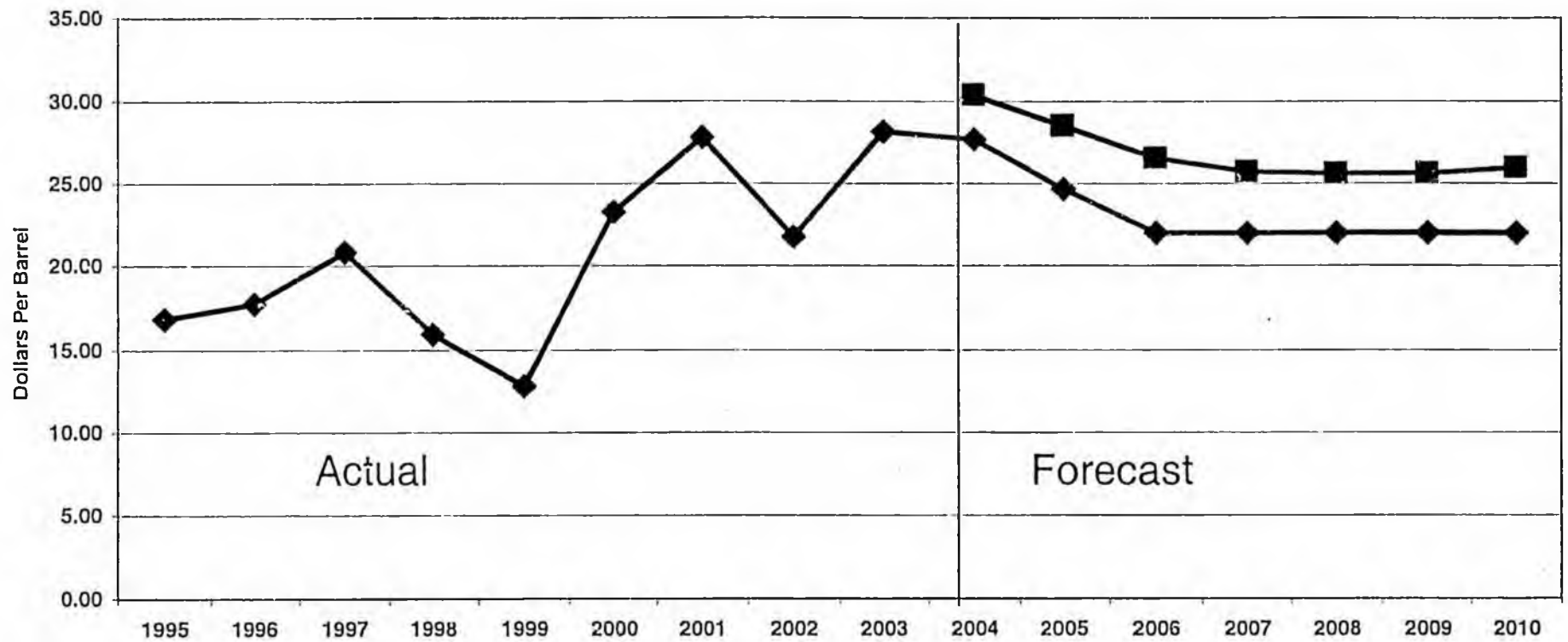
REVENUE

FORECAST

HFIN

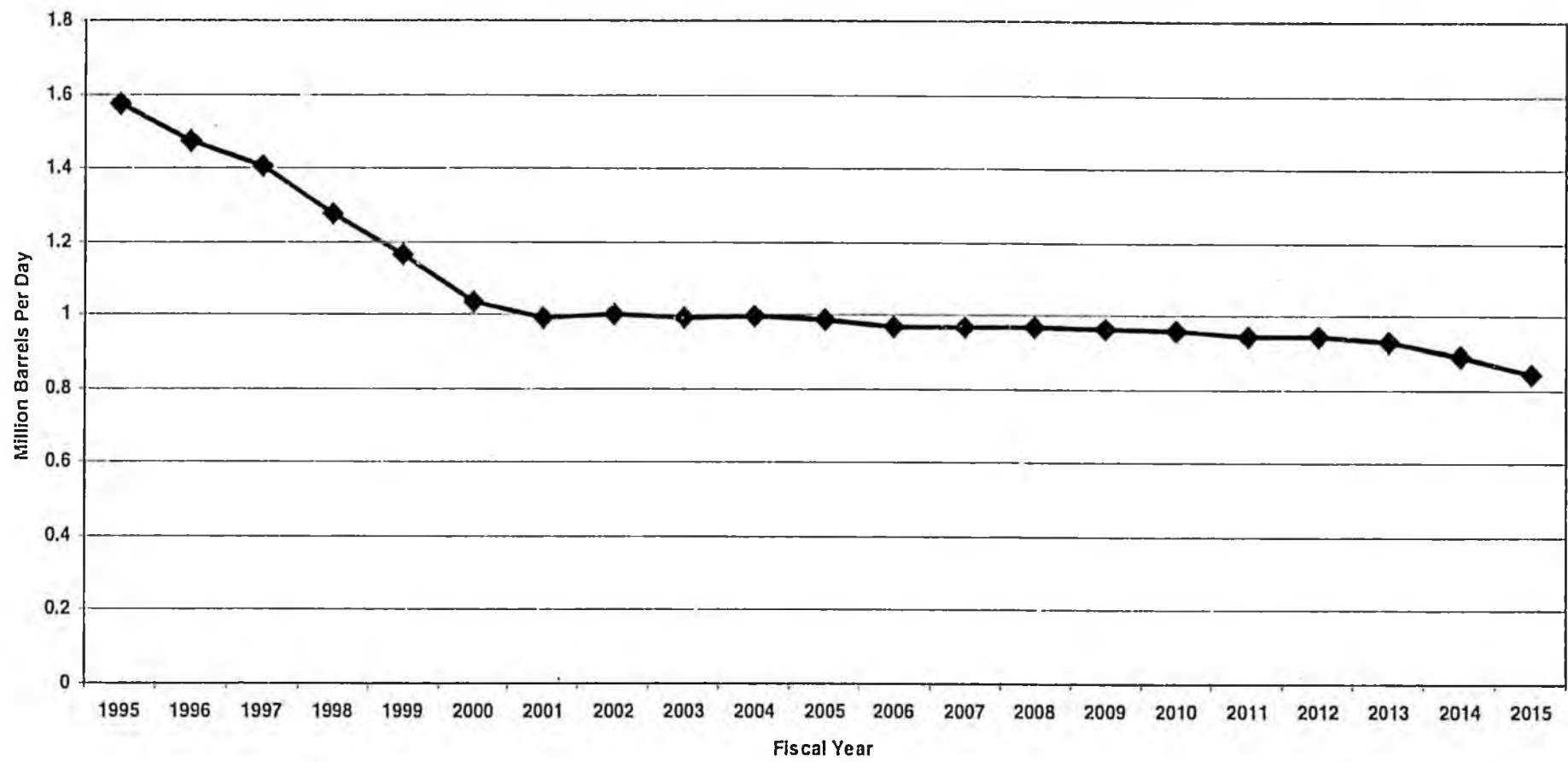
FILE

ANS Spot Price and Forecasted Prices Fall 2003 and January NYMEX Future Implied

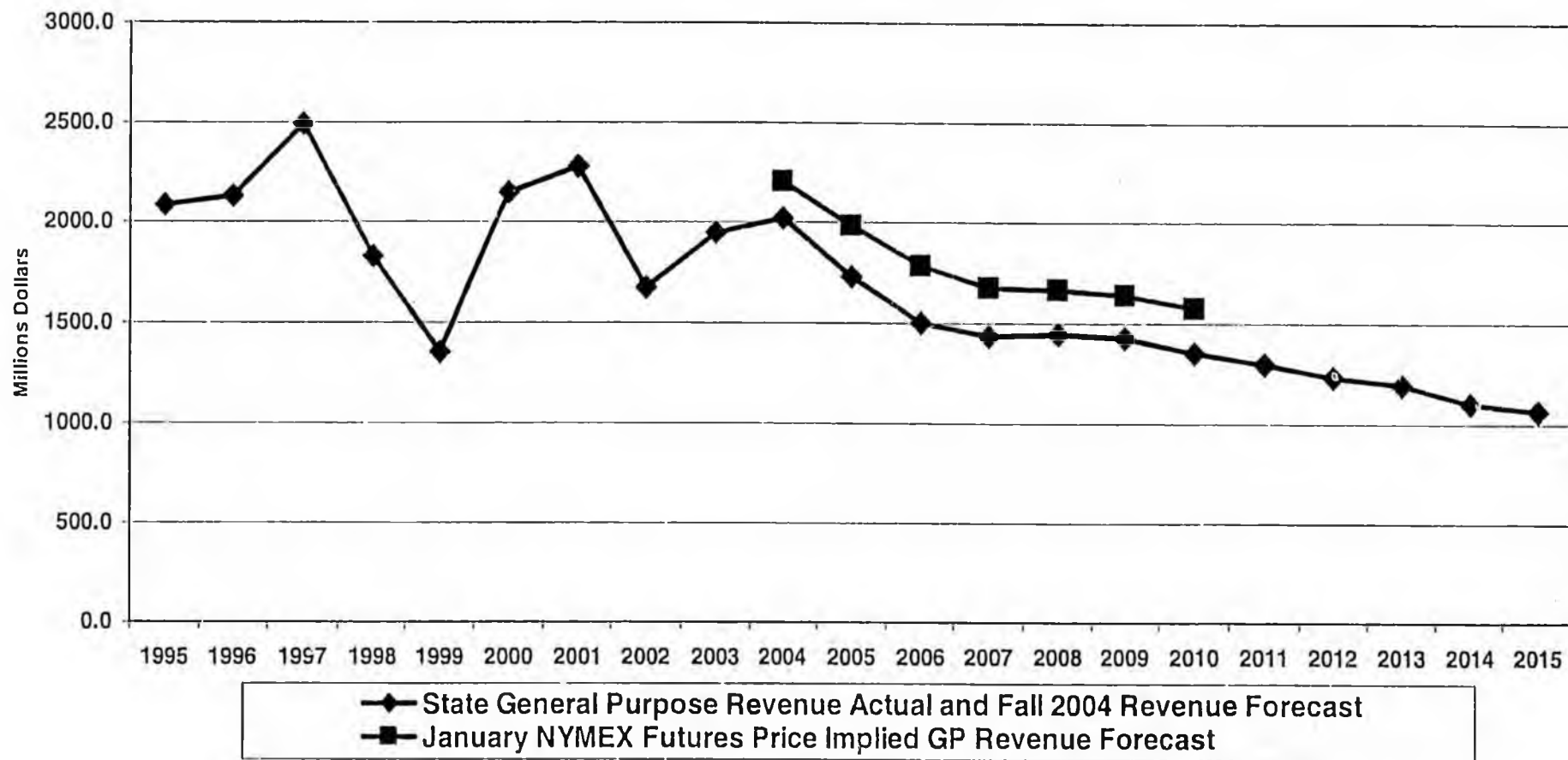


◆ ANS Spot Price Actual and Fall 2003 Forecast ■ January NYMEX Futures Strip Implied ANS Price Jan 26, 2004

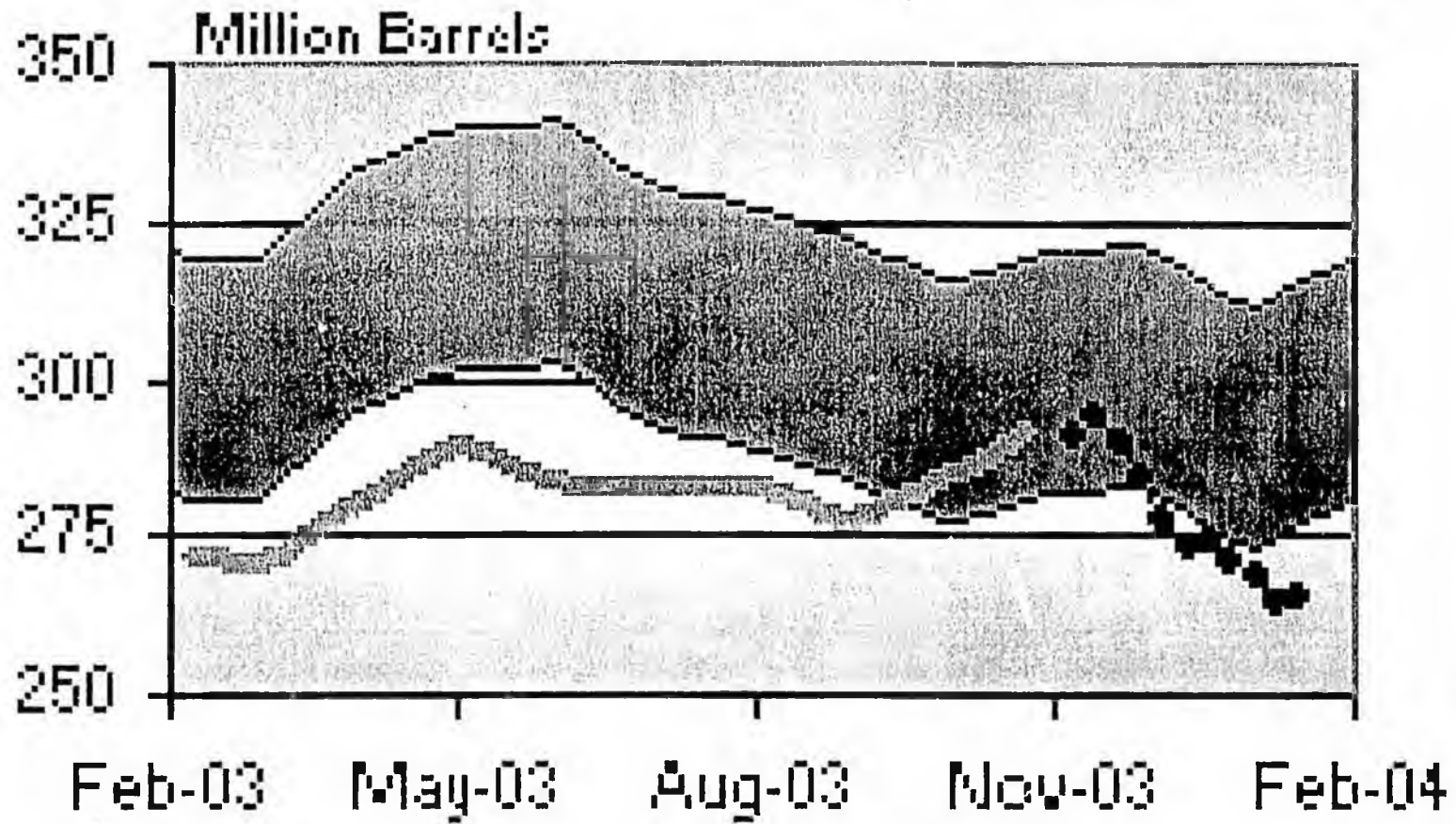
ANS Oil Production Actual and Fall 2003 Forecast



**State General Purpose Revenue Actual and Forecasted--Fall 2003
Forecast and NYMEX Futures Price Implied Jan. 26, 2004**

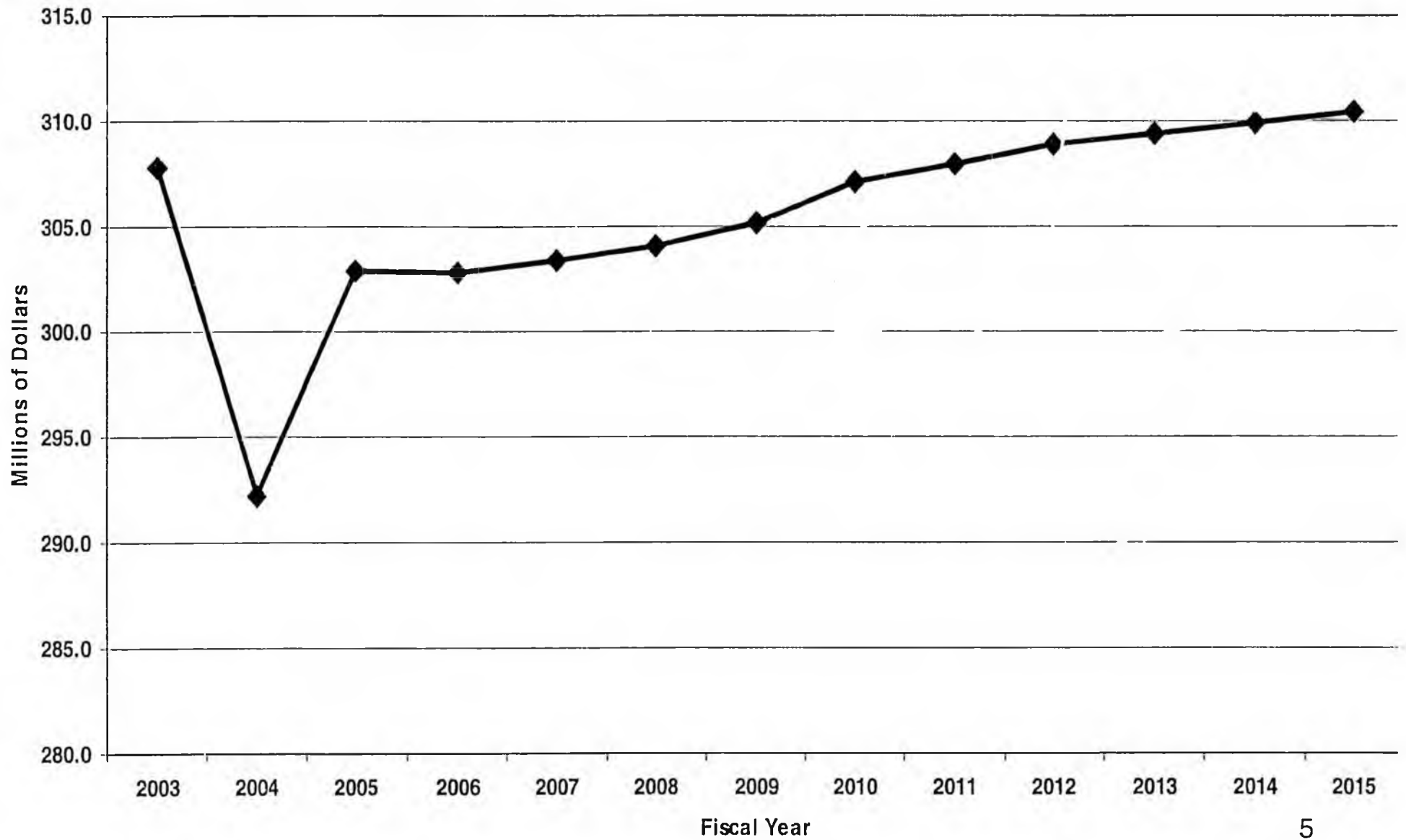


U.S. Crude Oil Stocks



Legend:
Average Range (stippled area)
Monthly (dotted line)
Weekly (solid line with diamond markers)

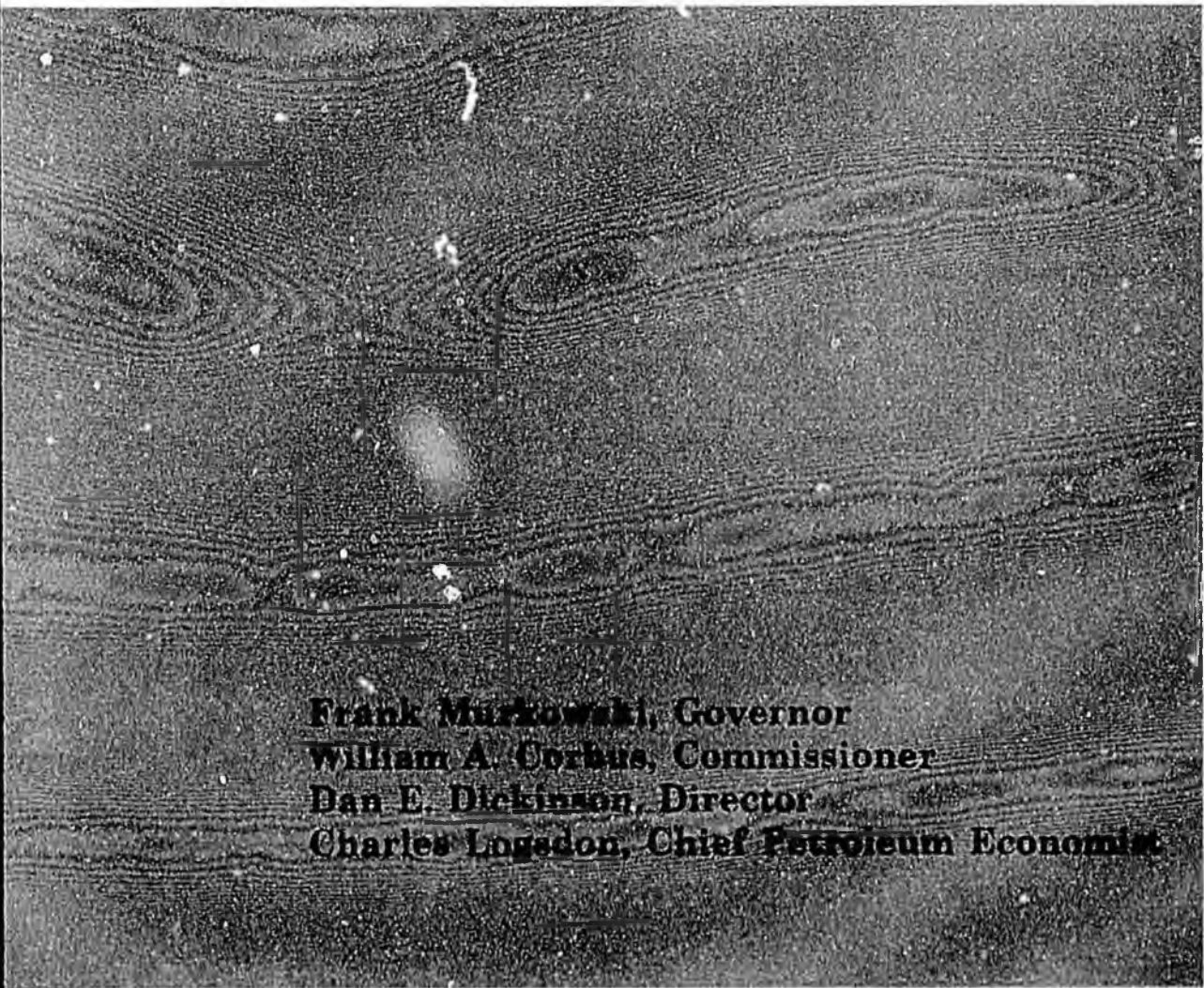
State General Purpose Other Revenue (Except Federal) Actual and Fall 2003 Forecasts



DOR review
1/27/04

Alaska Department of Revenue Tax Division

December 2003



Frank Murkowski, Governor
William A. Orrhus, Commissioner
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REVENUE SOURCES BOOK
FALL 2003

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DEPARTMENT OF REVENUE

OFFICE OF THE COMMISSIONER

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December 12, 2003

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

Dear Governor Murkowski:

Enclosed is the Department of Revenue's Fall 2003 Revenue Sources Book. This publication includes a preliminary accounting of revenues received in FY 2003, as well as our projections for FY 2004 through FY 2015.

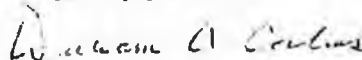
Petroleum revenues will continue to play a key role in financing Alaskan government, accounting for approximately 80% of the Unrestricted General Purpose Revenue through FY 2009 and 75% through FY 2012.

We project oil prices will average \$27.70 per barrel this fiscal year, the third highest price in almost two decades. We project a price for FY 2005 of \$24.65 per barrel. Over the longer term, (FY 2006-FY 2015), we anticipate that ANS prices will average \$22 per barrel.

On the production side, we continue to make a reference forecast that looks only at oil fields that have already been discovered. Some of these fields have not yet been developed and others will be more intensively developed over time. We forecast production will average 0.996 million barrels a day in Fiscal 2004 and stay above 0.9 million barrels a day through FY 2014. Production from the super-giant Prudhoe Bay continues to decline, but new smaller fields have been discovered and are being brought on line. In this forecast, we also examine oil and gas exploration and development opportunities that could significantly improve our revenue outlook.

The Fall 2003 Revenue Sources Book documents actual revenue collections and provides our best estimates of future revenue. We have included an analysis of promising resource development opportunities with a focus on oil and gas. We have also included a section that reconciles the revenues sources used in three different budget documents published by three separate state agencies. Historical data is included in the appendices section at the very end of this publication.

Very truly yours,



William A. Corbus
Commissioner

Enclosure

TABLE OF CONTENTS

Table of Contents

1. Introduction	1
Foreword	2
Fall 2003 Forecast	3
2. Executive Summary	5
A. Total Governmental Revenue	6
B. Unrestricted General Purpose Revenue	11
C. Oil Price Forecast	13
D. Oil Production Forecast	14
E. Longer-Term Unrestricted Revenue Outlook	18
F. Budget Gap and the Constitutional Budget Reserve	19
3. Resource Development Opportunities	21
Looking for New Oil Reserves	22
Developing New Oil Fields	26
Gas Line	31
Conclusion	32
Minerals	33
4. Oil Revenue	36
General Discussion	37
Unrestricted Oil Revenue	38
Restricted Oil Revenue	50
5. Other Revenue (Except Federal & Investment)	52
Other Taxes	53
Charges for Services	57
Fines and Forfeitures	59
Licenses and Permits	60
Rents and Royalties	61
Other	62
6. Federal Revenue	64
7. Investment Revenue	67
Investment Forecast	69
Unrestricted Investment Revenue	71
Restricted Investment Revenue	72
8. State Endowment Funds	77
9. Public Corporations and the University of Alaska	83
Public Corporations	84
University of Alaska	90
10. Rosetta Stone	91
Introduction	92
Reconciling This Revenue Sources Book With the State's Annual Budget	95
11. Appendices	107
A. General Fund Unrestricted Sensitivity Matrices	A2
B. Unrestricted Petroleum Production Tax and Royalty Revenue Forecast	A3
C. Historical and Projected Crude Oil Prices	A4
D. Historical and Projected ANS Production	A5
E. Historical General Fund Unrestricted Revenue	A6
F. Historical Petroleum Revenue	A8
G. Glossary of Terms Used in Revenue Sources Book	A9

1.

INTRODUCTION

Foreword

The purpose of the semi-annual Revenue Sources Book is to provide the governor, legislature and citizens of the State of Alaska with a summary of our past collections of state revenue and a forecast of future revenue. Our revenue collections are categorized into four major components: oil taxes, non-oil taxes and fees, federal dollars and investment revenues.

Oil revenues continue to dominate the revenue picture — providing over 80% of Unrestricted General Purpose Revenue. Oil production levels, however, are roughly half of Alaska's peak production in 1989. As a result, oil revenues are much lower now than in the past.

We continue to focus on the bigger picture of state revenues, including the earnings from the Permanent Fund, federal revenue and our reserves in the Constitutional Budget Reserve Fund (CBRF). The CBRF will continue to play a large role in Alaska's financial future.

Oil production has fallen to just under 1 million barrels per day (from its peak of 2 million barrels a day in 1989), and as a result, we face a structural deficit that requires annual expenditures from the CBRF — even when oil prices are over \$30 per barrel. This publication outlines some new resource development opportunities that could reverse the decline in oil production. We have also included a section on the mineral industry.

We hope this information is helpful in answering the questions about where Alaska gets its revenue and what our revenue future looks like from today's perspective.

Fall 2003 Forecast

This Fall 2003 Revenue Sources Book is organized into 11 sections:

1. **Introduction**
2. **Executive Summary**
3. **Resource Development Opportunities**
Opportunities available for new oil and gas production and Alaska's mineral industry are discussed.
4. **Oil Revenue**
Revenue from oil and gas production taxes, corporate income taxes, property taxes and royalties continues to play a big role in Alaska's revenue picture.
5. **Other Revenue (Except Federal & Investment)**
Revenue from non-oil sources includes alcohol, tobacco, fisheries, estate, motor fuel taxes, non-oil corporate income taxes, user fees and several other revenue sources.
6. **Federal Revenue**
Federal revenue received by state government is one of Alaska's biggest sources of revenue.
7. **Investment Revenue**
Investment earnings come from the Alaska Permanent Fund, the Constitutional Budget Reserve Fund, the General Fund and other state investments.
8. **State Endowment Funds**
Basic policies governing six of the state's endowment funds are examined.
9. **Public Corporations and the University of Alaska**
The University of Alaska and seven public corporations are treated as separate component units of state government for financial reporting purposes.
10. **Rosetta Stone**
Three different documents published by three separate agencies — the Department of Revenue's Revenue Sources Book, Legislative Finance Division's Summary of Appropriations and Department of Administration, Finance Division's Comprehensive Annual Financial Report (CAFR) are reconciled.
11. **Appendices**
Historical price, production and revenue data is provided. A glossary of terms used in this Revenue Sources Book, General Fund sensitivity matrices and an unrestricted petroleum production and royalty revenue forecast are included.

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2.

EXECUTIVE SUMMARY

A. Total Governmental Revenue

The table below summarizes the state's governmental ⁽¹⁾ total revenue outlook by major revenue component (preliminary FY 2003 and projected FY 2004-2005).

Table 2-1. Total Governmental Revenue \$ Million	Preliminary		
	FY 2003	FY 2004	FY 2005
Oil Revenue			
Unrestricted			
Property Tax	48.7	48.5	45.6
Corporate Income Tax	151.1	220.0	195.0
Production Tax	599.0	563.6	427.1
Royalties (including Bonuses and Interest)	<u>840.3</u>	<u>898.6</u>	<u>753.7</u>
Subtotal	1,639.1	1,730.7	1,421.4
Restricted			
Royalties to Permanent Fund and School Fund	403.8	313.9	266.9
Settlements to CBRF	22.3	20.0	20.0
NPRA Royalties, Rents and Bonuses	<u>34.6</u>	<u>2.9</u>	<u>12.9</u>
Subtotal	460.7	336.8	299.8
Subtotal Oil	2,099.8	2,067.5	1,721.3
Other Revenue (Except Federal & Investment)			
Unrestricted			
Taxes	179.4	181.1	196.7
Charges for Services	13.9	18.4	18.4
Fines and Forfeitures	7.0	7.0	7.0
Licences and Permits	32.9	45.5	47.9
Rents and Royalties	6.2	7.0	7.2
Other	<u>9.4</u>	<u>21.5</u>	<u>14.0</u>
Subtotal	248.8	280.5	291.2
Restricted			
Taxes	67.3	74.3	73.0
Charges for Services	195.9	251.7	250.7
Fines and Forfeitures	26.8	23.6	23.8
Licenses and Permits	29.1	29.9	30.8
Rents and Royalties	4.7	4.7	4.7
Other	<u>212.9</u>	<u>119.9</u>	<u>119.9</u>
Subtotal	536.7	504.1	502.9
Subtotal Other (Except Federal & Investment)	785.5	784.6	794.1

(continued on next page)

(1) GASB 34 as interpreted by the Finance Division of the Department of Administration in their Comprehensive Annual Financial Report.

Figure 2-1. FY 2003 Total Revenue
\$5.9 Billion

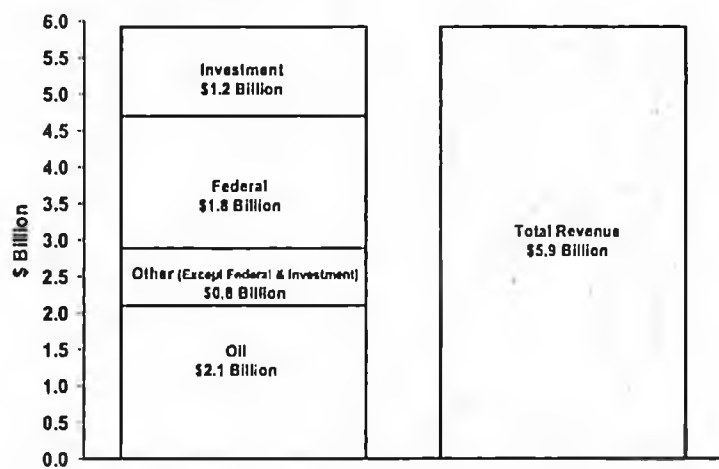


Table 2-1. Total Governmental Revenue, cont.
\$ Million

	Preliminary FY 2003	FY 2004	FY 2005
Federal Revenue			
Restricted			
Federal Receipts	1,812.6	2,427.8	2,427.8
Subtotal Federal Revenue	1,812.6	2,427.8	2,427.8
Investment Revenue			
Unrestricted			
Investments	28.2	7.8	8.9
Interest Paid by Others	30.8	3.9	2.8
Subtotal	59.0	11.7	11.7
Restricted			
Investments	20.3	5.1	6.2
Constitutional Budget Reserve Fund	144.4	58.8	80.4
Other Treasury Managed Funds	24.4	28.7	30.9
Alaska Permanent Fund (GASB) ⁽¹⁾	962.6	2,105.9	1,948.0
Subtotal	1,151.7	2,198.5	2,065.5
Subtotal Investment Revenue	1,210.7	2,210.2	2,077.2
Grand Total	5,908.6	7,490.1	7,020.4

(1) Includes both realized and unrealized gains and losses.

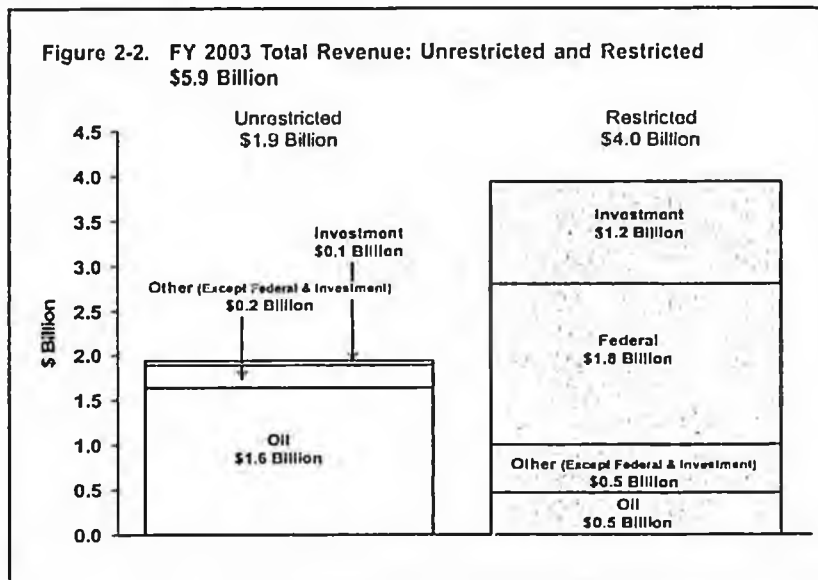


Table 2-2. Total Governmental State Revenue, Preliminary FY 2003 and Projected 2004-2005 Unrestricted ⁽¹⁾ and Restricted by Major Source \$ Million

	Preliminary		
	FY 2003	FY 2004	FY 2005
Unrestricted			
Oil Revenue	1,639.1	1,730.7	1,421.4
Other Revenue (Except Federal & Investment)	248.8	280.5	291.2
Investment Revenue	<u>59.0</u>	<u>11.7</u>	<u>11.7</u>
Subtotal	1,946.9	2,022.9	1,724.3
Restricted			
Oil Revenue	460.7	336.8	299.8
Other Revenue (Except Federal & Investment)	536.7	504.1	502.9
Federal Revenue	1,812.6	2,427.8	2,427.8
Investment Revenue	<u>1,151.7</u>	<u>2,198.5</u>	<u>2,065.5</u>
Subtotal	3,961.7	5,467.2	5,296.0
Grand Total	5,908.6	7,490.1	7,020.4

(1) Total unrestricted revenue as reported for AKSAS (Alaska State Accounting System) with adjustments for certain municipal sharing of statewide taxes and additional spending restrictions.

New Unrestricted General Purpose Revenue Included in This Forecast

In an effort to reduce the budget gap and annual draw on the Constitutional Budget Reserve Fund, new revenue measures were adopted in 2003 by law and/or regulation. These revenue measures included new taxes and fees, as well as certain tax credits and royalty reductions designed to promote natural resource development. These are summarized in the table below.

Table 2-3. Revenue and Credits per Legislation or Regulation
\$ Million

	Enabling Legislation	2004	2005	2006	2007	2008	2009	2010
New Taxes and Fees								
Tire Tax	SB 106	2.4	3.3	3.3	3.3	3.3	3.3	3.3
Vehicle Rental	HB 271	1.0	6.0	6.0	6.0	6.0	6.0	6.0
Motor Vehicle Register	HB 170	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Public Construction Fee	HB 155	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Mutual Fund Agent and Regulation Fees	Regulation	<u>2.0</u>	<u>2.0</u>	<u>2.0</u>	<u>2.0</u>	<u>2.0</u>	<u>2.0</u>	<u>2.0</u>
Total New Tax and Fees		19.9	25.8	25.8	25.8	25.8	25.8	25.8
Permanent Fund to General Fund								
	HB 11	<u>59.7</u>	<u>45.6</u>	<u>47.2</u>	<u>45.6</u>	<u>36.7</u>	<u>33.2</u>	<u>32.1</u>
Total New General Fund		79.6	71.4	73.0	71.4	62.5	59.0	57.9
Credits and Royalty Reductions								
Cook Inlet Gas	HB 61	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Oil and Gas Exploration	SB 185	0.0	30.0	50.0	50.0	0.0	0.0	0.0
Fish Business Credit	HB 90	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Reduce Cook Inlet Royalty	HB 198	0.4	0.8	1.0	0.9	0.6	0.6	0.5
Royalty Gas Agriculture Chemicals	HB 57	<u>0.5</u>	<u>0.5</u>	<u>0.5</u>	<u>0.5</u>	<u>0.5</u>	<u>0.5</u>	<u>0.5</u>
Total Tax Credits and Royalty Reductions		4.4	34.8	55.0	54.9	4.6	4.6	4.5
Net New Unrestricted General Purpose Revenue		75.2	36.6	18	16.5	57.9	54.4	53.4

B. Unrestricted General Purpose Revenue

Unrestricted General Purpose Revenue is the amount generally used for budget planning purposes and is designated in budget documents as general fund revenue. The table on the next two pages sets out preliminary FY 2003 Unrestricted General Purpose Revenue and our revised projections for FY 2004 and 2005.

We forecast Unrestricted General Purpose Revenue by first estimating General Fund Unrestricted Revenue, which includes all unrestricted revenue items in the Alaska State Accounting System (AKSAS), as well as certain program receipts. After consulting with the Governor's Office of Management and Budget and the Legislature, we adjust our forecast of General Fund Unrestricted Revenue to derive a forecast of total Unrestricted General Purpose Revenue. Reductions include: (1) earmarking revenue for specific programs, (2) pass-through revenue for qualified regional aquaculture and dive fishery associations, and (3) revenue shared with local governments and organizations (e.g., fisheries taxes.) Additions include transfers from the unclaimed property trust.

Table 2-4. Unrestricted General Purpose Revenue
\$ Million

	Preliminary FY 2003	FY 2004	FY 2005
OIL REVENUE			
<u>Property Tax</u>	48.7	48.5	45.6
<u>Corporate Income Tax</u>	151.1	220.0	195.0
<u>Production Tax</u>			
Oil and Gas Production	589.8	554.2	417.8
Oil and Gas Hazardous Release	<u>9.2</u>	<u>9.4</u>	<u>9.3</u>
Subtotal Production Tax	599.0	563.6	427.1
<u>Royalties</u>			
Mineral Bonuses and Rents	9.6	12.1	16.1
Oil and Gas Royalties	825.7	881.6	732.7
Interest Paid	<u>5.0</u>	<u>4.9</u>	<u>4.9</u>
Subtotal Royalties	840.3	898.6	753.7
Subtotal Oil Revenue	1,639.1	1,730.7	1,421.4
OTHER REVENUE (EXCEPT FEDERAL & INVESTMENT)			
<u>Other Tax</u>			
Sales and Use			
Alcoholic Beverage	14.1	15.7	15.7
Cigarette	9.6	9.5	9.5
Other Tobacco Product	6.7	6.8	7.2
Insurance Premium	39.0	42.6	44.7
Electric and Telephone Cooperative	0.2	0.2	0.2
Motor Fuel Tax	37.2	39.0	39.0
Rental Vehicle Tax	0.0	1.0	6.0
Tire Fee	<u>0.0</u>	<u>2.4</u>	<u>3.3</u>
Subtotal	106.8	117.2	125.6
Corporate Income Tax	47.7	49.0	53.7
Fish Tax			
Fisheries Business	13.8	8.3	10.3
Fishery Resource Landing	<u>6.9</u>	<u>2.0</u>	<u>2.6</u>
Subtotal	20.7	10.3	12.9
Other			
Mining	0.4	0.7	1.3
Estate	1.2	1.4	0.7
Charitable Gaming	<u>2.6</u>	<u>2.5</u>	<u>2.5</u>
Subtotal	4.2	4.6	4.5
Subtotal Other Tax	179.4	181.1	196.7

(continued on next page)

Table 2-4. Unrestricted General Purpose Revenue, cont.
\$ Million

	Preliminary		
	FY 2003	FY 2004	FY 2005
OTHER REVENUE (EXCEPT FEDERAL & INVESTMENT)			
<u>Charges for Services</u>			
General Government	10.3	14.8	14.8
Natural Resources	1.7	1.7	1.7
Other	<u>1.9</u>	<u>1.9</u>	<u>1.9</u>
Subtotal Charges for Services	13.9	18.4	18.4
<u>Licenses and Permits</u>			
Motor Vehicle	30.9	43.5	45.9
Other	<u>2.0</u>	<u>2.0</u>	<u>2.0</u>
Subtotal Licenses and Permits	32.9	45.5	47.9
<u>Fines and Forfeitures</u>			
Other Settlements	0.9	1.0	1.0
Other Fines and Forfeitures	<u>6.1</u>	<u>6.0</u>	<u>6.0</u>
Subtotal Fines and Forfeitures	7.0	7.0	7.0
<u>Rents and Royalties</u>			
Land Leasing, Rental and Sales	5.4	6.0	6.0
Coal Royalties	0.6	0.8	1.0
Cabin Rentals	<u>0.2</u>	<u>0.2</u>	<u>0.2</u>
Subtotal Rents and Royalties	6.2	7.0	7.2
<u>Other</u>			
Miscellaneous	9.4	10.0	10.0
Unclaimed Property	<u>0.0</u>	<u>11.5</u>	<u>4.0</u>
Subtotal Other	9.4	21.5	14.0
Subtotal Other Revenue (Except Federal & Investment)	248.8	280.5	291.2
INVESTMENT REVENUE			
<u>Investments</u>	28.2	7.8	8.9
<u>Interest Paid by Others</u>	<u>30.8</u>	<u>3.9</u>	<u>2.8</u>
Subtotal Investment Revenue	59.0	11.7	11.7
TOTAL UNRESTRICTED REVENUE	1,946.9	2,022.9	1,724.3

C. Oil Price Forecast

Oil revenue will provide between 70% and 80% of forecasted Unrestricted General Purpose Revenue through FY 2015. Two elements are critical to the oil revenue forecast: price and volume.

The spot price of ANS is quoted by subtracting a market differential from the price of West Texas Intermediate (WTI) on the New York Mercantile Exchange (NYMEX).⁽¹⁾ There is no price for Alaska oil on the NYMEX. All of Alaska's current 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 market price of Alaska North Slope crude oil (ANS) at U.S. West Coast refining centers.

The table below contains preliminary prices for FY 2003 and the Department of Revenue's forecast of oil prices for the 12-year period beginning with the current fiscal year, FY 2004, and continuing through FY 2015. The short-term oil price forecast (FY 2004-2005) is based on a subjective assessment of market dynamics and trend analysis by participants at a Department of Revenue price scenario meeting. Our long-term forecast (FY 2006-2015) is based on the premise that prices will average \$22 per barrel, the low-end of OPEC's current price target range.

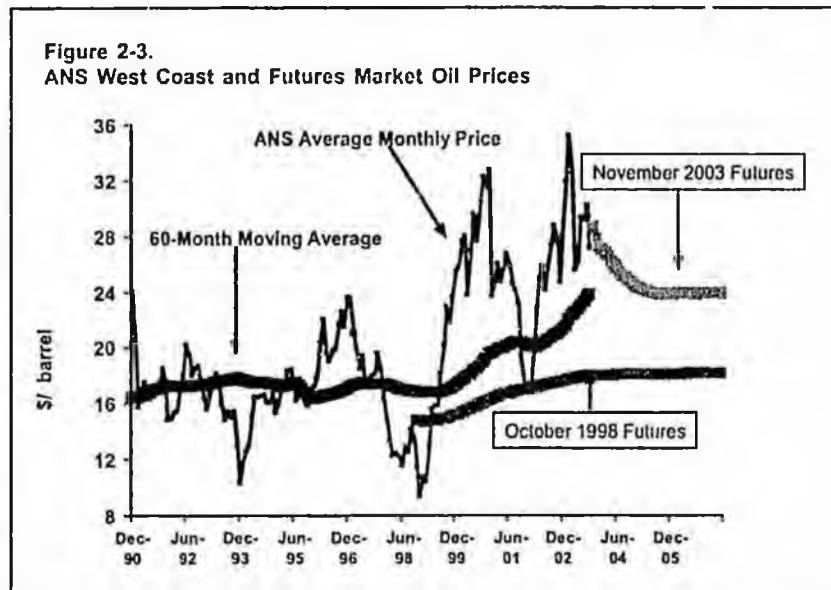
Table 2-5. Delivered Price for ANS Crude Oil
Average WTI, ANS West Coast and ANS Wellhead
\$ per barrel

Fiscal Year	WTI ⁽¹⁾	ANS West Coast	ANS Wellhead
Preliminary 2003	29.47	28.15	23.35
2004	29.23	27.70	22.46
2005	26.35	24.65	19.46
2006	23.70	22.00	16.74
2007	23.70	22.00	16.63
2008	23.70	22.00	16.53
2009	23.70	22.00	16.46
2010	23.70	22.00	16.35
2011	23.70	22.00	16.20
2012	23.70	22.00	16.21
2013	23.70	22.00	16.06
2014	23.70	22.00	15.87
2015	23.70	22.00	15.69

The prices we are forecasting are higher than the average market prices experienced over the 16-year period since the 1986 oil price collapse but are consistent with prices since 1999. The figure on the next page depicts: (1) the monthly West Coast ANS market price from December 1990 through September 2003; (2) the 60-month moving average West Coast market price for the same period; and (3) a set of ANS prices derived from NYMEX crude oil futures prices for October 1998 and November 2003.

(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.

The figure below clearly illustrates the volatility of month-to-month crude oil prices. Monthly ANS West Coast prices during the pertinent time period ranged from just under \$10 per barrel to over \$35 per barrel. The average of the 60-month moving averages shown in the figure below is \$18.08 per barrel. The derived futures market prices reflected below illustrates that the current futures market long-term convergence price has increased by about \$5.75 per barrel since October 1998.



We assume that over the long-term, oil prices will average \$22 per barrel. This price is the lower end of the price range of \$22 to \$28 per barrel that OPEC has by at large successfully defended for the last four years.⁽¹⁾ Choosing the lower end of the range is a conservative assumption to account for the difficulty cartels like OPEC have in managing oil prices. ANS West Coast price averaged \$23.81 per barrel over 60 months, October 1998 to September 2003.

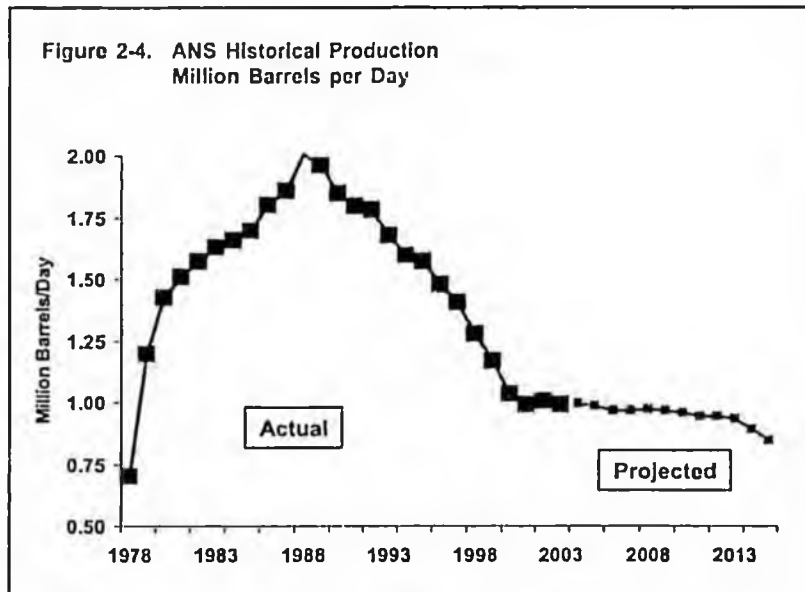
D. Oil Production Forecast

In 1988, ANS production peaked at 2.005 million barrels per day and has steadily declined since. In FY 2002, ANS production averaged 1.003 million barrels per day and in FY 2003, 0.990 million barrels per day.

Our production forecast has been adjusted since it was published last spring due to the reexamination of field reservoir performance and potential. Production from the North Slope will continue to average slightly under 1 million barrels per day through FY 2010 — aided by the future development of the National Petroleum Reserve-Alaska (NPR-A) and the projected development of Nanuk, Point Thompson and Liberty.

(1) OPEC tracks oil prices by averaging the price of a number of sour crudes. Like ANS, this "OPEC basket" price is usually about \$2 less than the WTI spot price.

A detailed field-by-field production forecast can be found in the appendices.



**Table 2-6. ANS Oil and NGL Production
Million Barrels per Day**

Fiscal Year	ANS Production
Preliminary 2003	0.990
2004	0.996
2005	0.985
2006	0.968
2007	0.965
2008	0.969
2009	0.964
2010	0.957
2011	0.941
2012	0.941
2013	0.930
2014	0.889
2015	0.844

New Oil Development

As the volumes from the giant Prudhoe Bay and Kuparuk fields continue to decline, some of the decline in production will be offset by new oil development. In our reference-case forecast, new oil is defined as crude already discovered and likely to be developed. By FY 2011, as the table and figure below show, nearly one-fifth of our forecasted oil production will come from fields not currently producing oil.

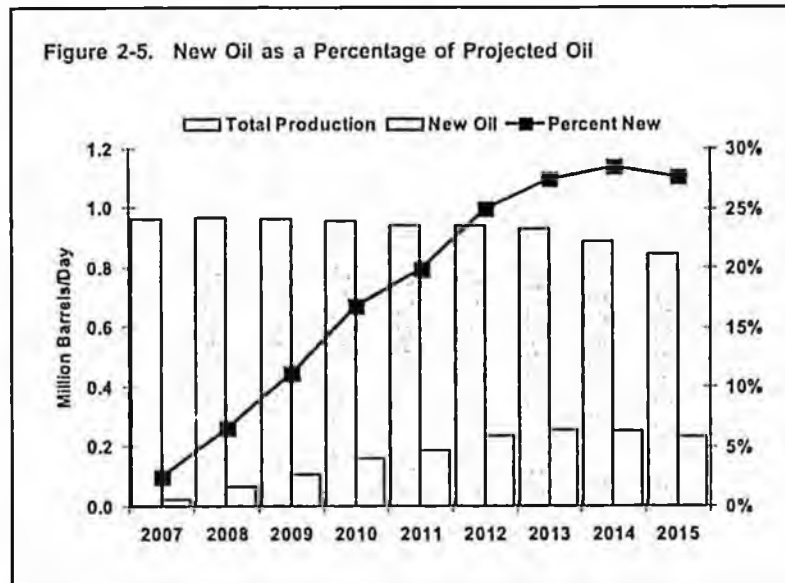


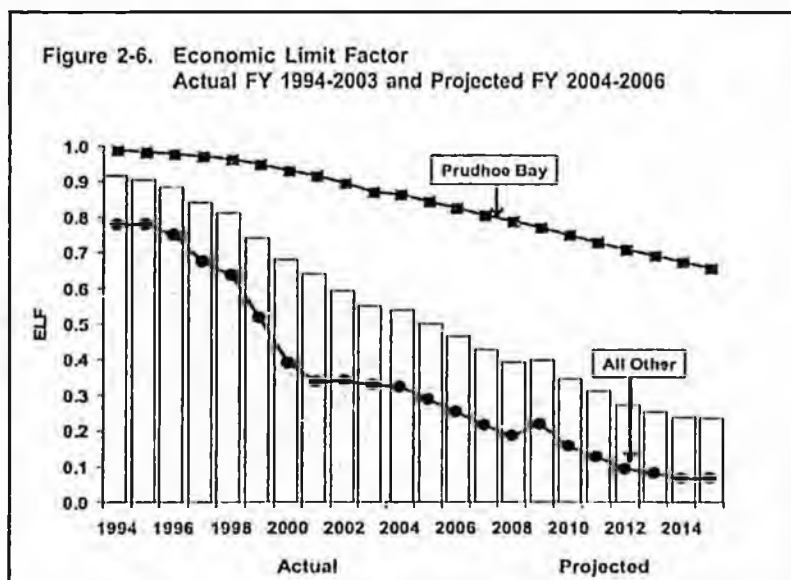
Table 2-7. New Oil as a Percentage of Total Oil
Million Barrels per Day

Fiscal Year	New Oil	Total Oil	New Oil as Percent of Total Oil
2007	0.024	0.965	2.5
2008	0.064	0.969	6.6
2009	0.107	0.964	11.1
2010	0.160	0.957	16.8
2011	0.187	0.941	19.9
2012	0.235	0.941	25.0
2013	0.255	0.930	27.4
2014	0.253	0.889	28.5
2015	0.232	0.844	27.6

Economic Limit Factor

The average production tax rate on the North Slope has been falling as the result of the tax adjustment known as the Economic Limit Factor (ELF). The ELF is a factor that reduces the nominal production tax rate on a producing reservoir based on the average rate of production from the reservoir and the average productivity of the wells producing that reservoir.⁽¹⁾ Since oil production rates and well productivity decline over time as an oil field is being produced, the average production tax rate will fall as well. Further, the ELF reduces the tax rate on smaller oil fields such that most fields producing less than 20,000 barrels per day will pay little or no production tax.

An ever smaller percentage of Alaska's current and projected North Slope oil production will continue to come from old, declining fields, while new production will come from small fields. Therefore, the average tax rate will continue to fall. The average oil production tax rate for North Slope production in FY 1994 was 13.5%; we project that for FY 2004 it will average 7.6%.



The figure above illustrates the actual weighted average ELF for North Slope oil production since 1994 and our projections of that weighted average through FY 2006. The Prudhoe Bay ELF is also shown, as well as the average ELF for all of the other North Slope fields. The spike in the other fields average ELF in FY 2009 illustrates the impact of the assumed startup of production from Point Thomson.

(1) The nominal production tax rate is 15% except during a field's first five years of production, when it is 12.25%.

E. Longer-Term Unrestricted Revenue Outlook

Using the price and volume components developed for this fall 2003 forecast, the table below summarizes the department's forecast of total Unrestricted General Purpose Revenue through FY 2015.

Table 2-8. Total Unrestricted General Purpose Revenue
Preliminary FY 2003 and Projected FY 2004-2015
\$ Million

Fiscal Year	(Section 4) Unrestricted Oil Revenue	(Section 5) Unrestricted Other ⁽¹⁾ Revenue	(Section 7) Unrestricted Investment Revenue	Total Unrestricted Revenue	Percent from Oil
Preliminary 2003	1,639.1	248.9	59.0	1,946.9	84
2004	1,730.7	280.5	11.7	2,022.9	86
2005	1,421.4	291.2	11.7	1,724.3	83
2006	1,189.3	291.1	11.7	1,492.1	80
2007	1,131.5	291.7	11.7	1,434.9	79
2008	1,137.9	292.4	11.7	1,442.0	79
2009	1,119.0	293.5	11.7	1,424.2	79
2010	1,040.1	295.4	11.7	1,347.2	77
2011	983.3	296.3	11.7	1,291.3	76
2012	922.0	297.2	11.7	1,230.9	75
2013	877.1	297.7	11.7	1,186.5	74
2014	792.9	298.2	11.7	1,102.8	72
2015	750.1	298.7	11.7	1,060.5	71

(1) Except Federal and Investment Revenue.

F. Budget Gap and the Constitutional Budget Reserve

The table below reflects the amount needed to make up the difference between the Department of Revenue's forecast of Unrestricted General Purpose Revenue and the annual general fund budget, shown here as a flat \$2.3 billion for all operating, capital, debt service, lease payments and supplemental appropriations. ⁽¹⁾

Table 2-9. Difference Between Unrestricted General Purpose Revenue and General Fund Budget "The Gap" ⁽¹⁾
\$ Million

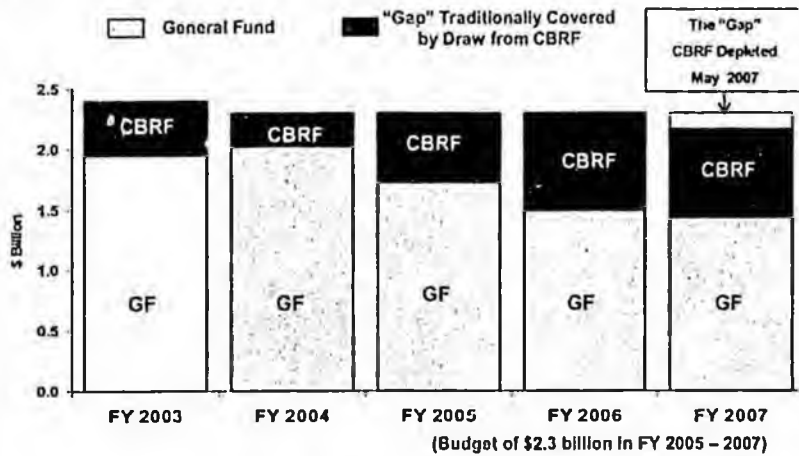
Fiscal Year	Total Unrestricted General Purpose Revenue	Transfer from Alaska Science & Technology	⁽¹⁾ General Fund Appropriation	Difference
Preliminary 2003	1,946.9	95.0	2,496.2 ⁽²⁾	454.3 ⁽²⁾
2004	2,022.9	.	2,297.8	274.9
2005	1,724.3	.	2,297.8	573.5
2006	1,492.1	.	2,297.8	805.7
2007	1,434.9	.	2,297.8	862.9
2008	1,442.0	.	2,297.8	855.8
2009	1,424.2	.	2,297.8	873.6
2010	1,347.2	.	2,297.8	950.6
2011	1,291.3	.	2,297.8	1,006.5
2012	1,230.9	.	2,297.8	1,066.9
2013	1,186.5	.	2,297.8	1,111.3
2014	1,102.8	.	2,297.8	1,195.0
2015	1,060.5	.	2,297.8	1,237.3

(1) The projected FY 2005-2015 budget of \$2.3 billion is simply a reference point for analysis. Any budget estimate used to determine "The Gap" will have its detractors — some will contend spending should be cut, while others will argue just as strongly that spending should be increased to reflect inflation and population growth.

(2) The "Gap", or draw on the CBRF for FY 2003, is shown as the actual cash withdrawal.

(1) http://www.gov.state.ak.us/omb/04_OMB/fy04fiscal_summary.pdf

Figure 2-7. Spending Gap Traditionally Covered by Draw from CBRF Fills Gap FY 2003-2007 ⁽¹⁾



(1) FY 2003 CBRF draw: \$454 million; FY 2004, \$275 million; FY 2005, \$574 million; FY 2006, \$806 million; FY 2007, depleted in May 2007 after a \$734 million draw.

Table 2-10. When Would the CBRF Be Gone? ⁽¹⁾

Annual State Budget	State Spending and Oil Price Variables					
	Fall 2003 DOR					
	\$18/bbl	\$22/bbl	Forecast	\$25/bbl	\$28/bbl	\$30/bbl
\$2.2 billion	Oct-06	Aug-07	Nov-07	Nov-08	Nov-10	May-12
\$2.3 billion	Jun-06	Feb-07	May-07	Dec-07	Jun-09	Dec-10
\$2.4 billion	Mar-06	Sep-06	Nov-06	Apr-07	May-08	Jul-09
\$2.5 billion	Dec-05	May-06	Jul-06	Oct-06	Jul-07	May-08

Source: Department of Revenue fall 2003 forecast, Fiscal Driver Model of Oil Revenue and CBRF Performance.
 (1) FY 2004 price for all scenarios is \$27.70 per barrel. Oil price selected in table above is for FY 2005 and beyond.

As approved by voters in 1990, all money from oil and gas and tax and royalty settlements is deposited into the Constitutional Budget Reserve Fund (CBRF). The state has deposited about \$5.6 billion into the reserve fund and the fund has earned about \$1.6 billion in interest on that money. For 10 of the last 12 years, the state has relied on the CBRF to fill the difference between unrestricted revenue and the annual state budget. Through September 30, 2003, approximately \$5.5 billion had been withdrawn from the CBRF to balance the budget, leaving a balance of \$1.9 billion.

The table above reflects the CBRF depletion matrix and the time period the fund could continue to make up the difference between Unrestricted General Purpose Revenue and the general fund budget at various oil prices and budget levels. For example, assuming no change in the state's fiscal system, if we are correct in our oil price forecast and if we assume a flat total General Fund budget of \$2.3 billion per year, the CBRF will be exhausted in May 2007.

3.

RESOURCE DEVELOPMENT

OPPORTUNITIES

Looking for New Oil Reserves

There are essentially three phases involved in bringing new oil and gas reserves into production: leasing, exploration and development. In this section we will examine current trends in leasing and exploration as well as new development issues on the Alaska North Slope.

Leasing

The state's leasing program continues to be quite successful. There are currently over 4.8 million acres of state land under oil and gas leases. Since 1995, lease sale bonuses and rents have generated over \$200 million for the state. Leases are owned by many different oil companies and private citizens. As of today, ConocoPhillips controls the largest amount of acreage at 925,785 acres. The top ten companies control 3.7 million acres while 90 other entities control the remaining 1.2 million acres.

Table 3-1. State-Owned Leases
Thousands

Company	Acreage	Percent
ConocoPhillips	926	19.0%
Anadarko	514	10.6%
Petro-Canada	411	8.4%
BP	406	8.4%
Union	321	6.6%
Chevron USA	296	6.1%
Encana	236	4.9%
ExxonMobil	191	3.9%
Burlington Resources	184	3.8%
Forest	179	3.7%
All Others	<u>1,201</u>	24.7%
Total	4,863	

Source: Lessee's Acreage Summary, Division of Oil and Gas, Alaska Department of Natural Resources, November 2003.

Since 1995 the total amount of acreage under lease has more than doubled. This suggests a successful ongoing leasing program that is generating state revenue and making a significant amount of acreage available to exploration. The diversity of ownership suggests that some leases are pursued with an eye to selling them to an entity that has the ability to explore or gain access to existing facilities. The bottom line is that considerable acreage is in the hands of lessees and the ownership of leases is diversified between large companies and smaller firms and individuals.

Exploration

In order to produce oil or gas you need to find it. Exploration is driven by many factors but the primary one is the likelihood of finding oil or gas in sufficient quantity to justify commercial production. The North Slope of Alaska has been explored by geologists since the beginning of the last century and ideas about where to drill the next exploration well continue to be refined as new pools are discovered.

The likelihood of finding oil or gas in sufficient quantity to justify commercial production is enhanced first by the availability of acreage with good potential. The use of improved technology provides a higher probability of discovery. The existence of surface facilities to collect, process and move the production to market lowers the cost of developing a discovery, thereby reducing the field size that is necessary to declare commercialization.

Table 3-2. Total Alaska Exploratory Wells, North Slope and Cook Inlet, 1995-2003

	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Total Wells	8	10	13	14	5	8	19	21	14	113
Prudhoe Unit			1	5	1			1		8
Other North Slope Onshore	3	4	4	5	1		4	1	0	22
Other North Slope Offshore			2					1	4	7
NPR-A						4	5	4	1	14
Alpine (Colville River Unit)	4	5		1	2	1	5		1	19
Southwest Kuparuk			4		1	3	2	3		13
Cook Inlet	1	1	2	2			4	3	3	16
Shallow Gas				1				8	5	14

Source: Well data from Alaska Oil and Gas Conservation Commission through November 2003.

Exploratory drilling in Alaska is risky. On the North Slope, since 1994, we estimate that about 70% of the wells failed to discover economically recoverable reserves. There were good years in which over 60% of the wells drilled led to commercial discoveries, interspersed with bad years where drilling failed to yield a commercial discovery.

Table 3-3. North Slope Exploration Summary, 1994-2002

	Total Wells	Oil Discovery	Suspended	Plugged and Abandoned
1994	6	0	1	5
1995	7	4	2	1
1996	9	2	2	5
1997	10	6	1	3
1998	10	6	0	4
1999	5	2	3	0
2000	7	0	0	7
2001	16	3	5	8
2002	10	1	2	7

In addition to being risky, drilling exploration wells in Alaska is expensive, especially "wildcat" wells or wells drilled in remote locations. The United States Geological Survey (USGS) estimates that drilling a wildcat well in a remote area like the National Petroleum Reserve-Alaska (NPR-A) costs over two-and-a-half times what it would cost to drill a development well at Prudhoe Bay.⁽¹⁾ The USGS believes that the accumulations in the NPR-A will be moderate in size, in the reserves range "commonly developed as "stand alone" or satellite fields on the central Alaska North Slope in recent years" of less than 250 million barrels. Large accumulations like Prudhoe Bay "are not expected to occur."⁽²⁾

Between 1995 and 2003 an average of approximately 12 exploratory wells were drilled annually on the North Slope and in Cook Inlet (see Table 3-2 on the prior page.) In 1999, the year of the last major oil price crash, only five North Slope wells were drilled.

A flurry of exploration activity occurred in 2000, 2001 and 2002 as the result of several key events: (1) the discovery of Alpine; (2) the leasing of NPR-A acreage close to the developing Alpine field; (3) discoveries and development of Tarn and Meltwater, southwest of the main Kuparuk field; and (4) high oil prices.

Oil discoveries were announced in the NPR-A but no specific development plans have been made public. The two key factors that underpin exploration activity, attractive acreage and proximity to existing surface facilities were definitely in play during this period. ConocoPhillips drilled 10 of the 14 NPR-A wells drilled over the 2000-2003 time period, with BP drilling two wells and Anadarko drilling one. Drilling in the NPR-A tapered off to one well in 2003 at Puviaq.

Seven offshore wells were drilled over the period 1995-2003: Liberty and Warthog in 1997, McCovey in 2002 and three wells in the Oooguruk Unit and one offshore Kuparuk in 2003. Marginally economic oil reserves lie in Liberty and oil was discovered in the Oooguruk Unit. The other three wells found little or no oil.

BP, as a Prudhoe Bay unit operator, continued a steady program of exploring near existing fields in the late 1990's that resulted in the several new commercial discoveries. BP has announced that they will not be exploring outside of existing units. Other unit partners such as ConocoPhillips and ExxonMobil would have paid a proportional share of the cost of these wells.

In 2002, policymakers decided that something must be done to encourage wildcat exploration on the North Slope. The number of exploratory wells drilled there had declined from 16 in 2001 to six in 2003. The second largest producer in Alaska, BP, swearing off frontier exploration in Alaska, had laid off or sent their exploration people to Houston, and sold off their exploration lands and 3-D seismic. As pointed out previously, wildcat exploration is expensive and risky. To encourage wildcat exploration, the legislature passed and the governor signed into law SB 185, that provides for a credit against exploration expenses for wells drilled far away from other wells or unit infrastructure.

(1) See USGS Open-File Report 03-44, "Economics of Undiscovered Oil in Federal Lands on the National Petroleum Reserve, Alaska," (January 2002) by Emil D. Attanasi [NPR-A Economic Report] at Pages 20-21.

(2) See USGS Fact Sheet 045-02, "U.S. Geological Survey 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPR-A)" [NPR-A Fact Sheet].

Activity in the Cook Inlet saw an average of two wells per year with a total of 10 wells drilled between 2001 and 2003. The effect of higher natural gas prices and seasonal shortages of natural gas to supply industrial demand, as well as royalty incentives, all played a role in encouraging the search for new gas reserves in the Cook Inlet region.

The other major boost to exploration activity is in the drilling of shallow gas wells targeting coal bed methane as evidenced by the 13 shallow gas wells drilled by Evergreen over the last two years. Higher gas prices, proximity to the existing natural gas grid and local market as well as favorable royalty treatment no doubt have contributed to interest in exploring for this resource.

Given the high cost of drilling exploratory wells, it should come as no surprise that nearly 80% of the non-shallow gas exploratory wells over the 1995-2002 period were drilled by the two major producers/operators on the North Slope, ARCO/ConocoPhillips and BP. ARCO/ConocoPhillips accounted for roughly 60% of the exploratory wells drilled. The third major producer, ExxonMobil, did not drill any exploratory wells.

However, other companies have been drilling. In 2003, Pioneer Natural Resources drilled the three wells in the Oooguruk Unit between Kuparuk River Unit and Thetis Island that discovered oil. Winstar drilled offshore from Oliktok Point. Forest Oil has been very active exploring the Redoubt Unit in the Cook Inlet. Marathon and Unocal, as well as ConocoPhillips, have been active exploring for gas in the Cook Inlet.

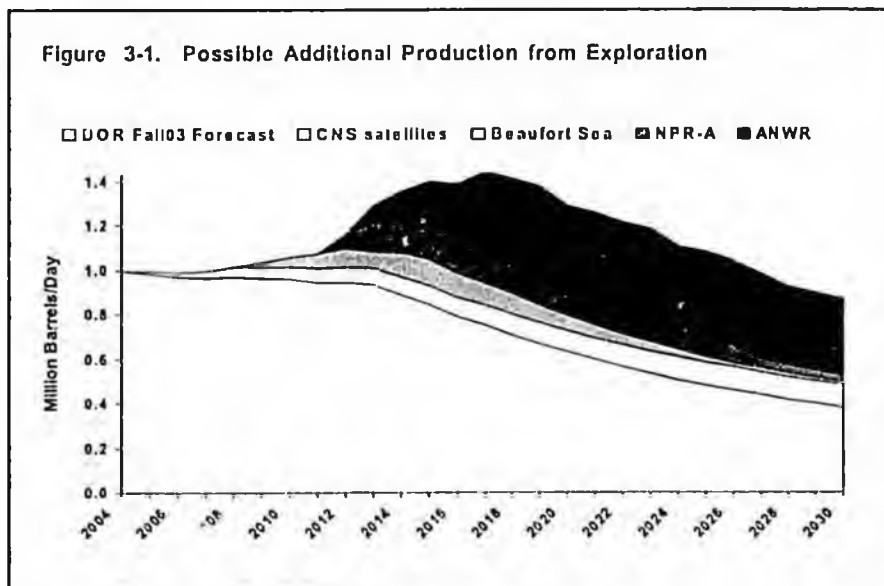
Conclusion

- Recent exploration activity has been relatively concentrated in one firm, ConocoPhillips.
- New entrants, however, are buying leases and in some cases drilling wells (Encana, Winstar and Pioneer Resources)
- Major increases in exploration drilling are going to overwhelmingly be driven by the opening up of new areas that are located close to existing surface infrastructure. The most recent example is the NPR-A, where the eastern area lies close to the western edge of the North Slope oil gathering infrastructure at Alpine.
- Although oil and gas prices can make a difference in terms of cash available to explore, high oil prices alone may not be enough to cause the biggest current producers on the North Slope to drill North Slope exploration wells in 2004.
- Clearly, investment in surface infrastructure can dramatically improve the commerciality of exploring and development. This is the motivation for the initiative by the state to plan for road and bridge access to the NPR-A. Some exploration wells have been drilled recently by companies with little or no access to surface facilities; however most wells are drilled by companies with existing production and facilities.

Developing New Oil Fields

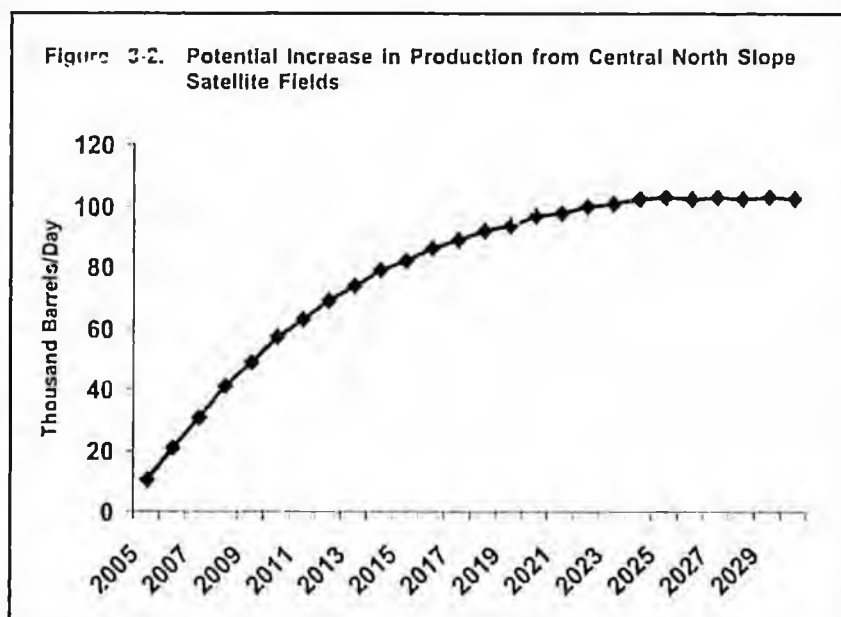
Exploration and aggressive development of found oil reserves could place ANS production on an increasing path by the end of this decade. Here, we have highlighted four areas that could be sources for such growth: the Central North Slope satellites, Beaufort Sea, NPR-A and ANWR. ANWR could provide as much — or more — in oil reserves and production as the other three areas combined. Oil exploration incentives, as provided in the recently adopted exploration tax credit, as well as the initiative to build a new year-round access road to the NPR-A are designed to encourage the exploration necessary to realize this additional oil production.

Also, exploration is not the only way to add reserves. For instance, more aggressive development of heavy oil resources could add reserves and production. Whether we reach this higher production path depends crucially on the level of exploration and development spending, something which must increase from depressed 2002 and 2003 levels.



Central North Slope Satellites

In its last slope-wide evaluation of oil and gas resources, the USGS estimated that there were 2.3 billion barrels of technically recoverable, undiscovered oil reserves in the Central coastal regions of the North Slope. The USGS believed this oil would mainly be in the "Turbidite" and "Barrow Arch Beaufortian" geological plays.⁽¹⁾ Since that evaluation in 1995, producers have discovered and put into production more Turbidite (Meltwater, Tarn, Tabasco, Midnight Sun and Aurora) and Barrow Arch Beaufortian (Alpine and Polaris) reservoirs.⁽²⁾ Adjusting these technically recoverable barrels to take into account recent discoveries, we estimate that there are about 1.9 billion barrels of technically recoverable oil still remaining to be found in the Central Coastal regions. The USGS also felt that around half of this technically recoverable oil would be economically recoverable.⁽³⁾ Of the estimated 1.9 billion barrels of technically recoverable oil remaining net of post-1995 discoveries, 880 million barrels should be economically recoverable.



(1) USGS Open-File Report 95-751, Emil Attanasi and Ken Bird, "Economics and undiscovered conventional oil and gas accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Alaska," [USGS95], Table 3, Page 37.

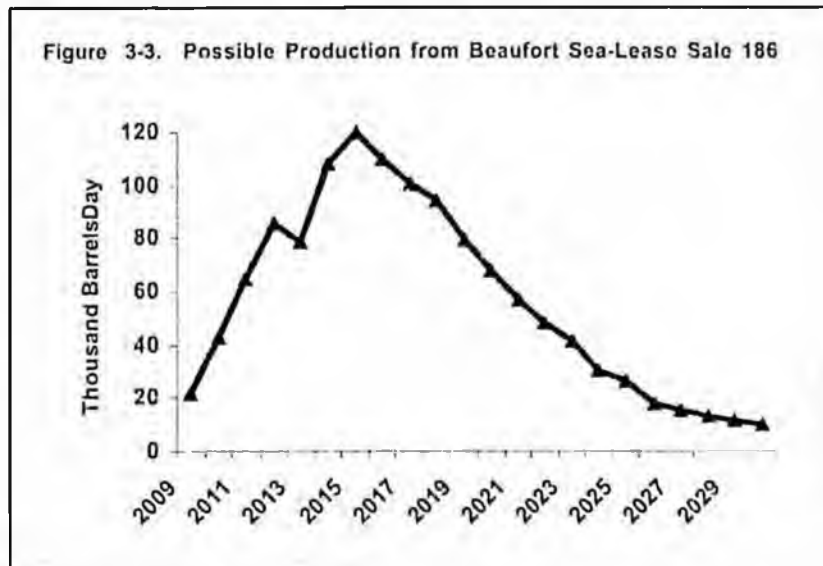
(2) Since these barrels were put into production and therefore economically recoverable, we could have adjusted the economically recoverable, rather than technically recoverable, reserve numbers down. However, recent discoveries will not only turn undiscovered barrels into discovered barrels. They will add geological information that increases the estimate of undiscovered, technically recoverable, reserves. To roughly offset this effect we have kept constant the percentage of technically recoverable barrels that are economically recoverable.

(3) Of the Central Coastal region's 1.9 billion barrels of remaining technically recoverable reserves, 45.75% (916 million barrels) should be economically recoverable. The economic recovery factors reflect mid-points between the \$18 and \$30 cases of USGS[95] Table 3.

Finding and producing these reserves will require further investments in exploration and development. Due to capital constraints, these reserves will come on slowly. We derive a conservative production forecast for these satellites and fields by assuming that 75 million barrels of additional Central North Slope reserves will be put into production every other year starting in 2005. The 75 million barrels assumption is conservative because in 2001 and 2002 the producers put three satellites with about 300 million barrels of reserves into production. However, in 2003 there were no new satellite discoveries put into production. Exploration efforts continue though. Pioneer recently announced an oil find just north of Kuparuk in the newly formed Oooguruk unit. By 2010, currently unannounced satellite developments could add around 50,000 barrels a day to our forecast.

Beaufort Sea

In total, U.S. Minerals Management Service (MMS) estimates that there are 8.82 billion barrels of technically recoverable reserves and 2.27 billion barrels of economically recoverable oil at \$18 per barrel oil prices and around 2.5 billion barrels at \$22 per barrel. The MMS recently held Beaufort Sea Lease Sale 186 that garnered \$10 million in bonus bids. For the Beaufort Shelf area, the MMS projects that the three fields developed from areas leased in this sale will yield 460 million barrels of reserves. See James D. Craig, "Economic Results, Beaufort Shelf Province."



NPR-A

In 2001, ConocoPhillips announced an oil discovery in the NPR-A. Currently, the Bureau of Land Management (BLM) is completing an environmental impact statement (EIS) for possible development of these discoveries as Alpine satellites. We estimate that the NPR-A will yield 430 million barrels of oil in our production forecast. Production starts in FY 2009 and ramps up to 60,000 barrels a day by 2015.

The NPR-A might yield more oil reserves, oil reserves that could be produced at a higher rate. The USGS evaluated the oil and gas resources in the NPR-A in 2002, and concluded that there were 9.3 billion barrels of technically recoverable reserves there. Of that amount, the USGS concluded that 1.3 billion barrels would be economic to explore for and produce at a \$22 per barrel ANS West Coast oil price — our long run price forecast.⁽¹⁾ In the EIS, BLM envisions a development of multiple drill sites along with two new central processing facilities in the NPR-A. Provisionally, the BLM estimates the NPR-A reserves from this development would be around 1.4 billion barrels, slightly higher than the USGS's 2002 number.

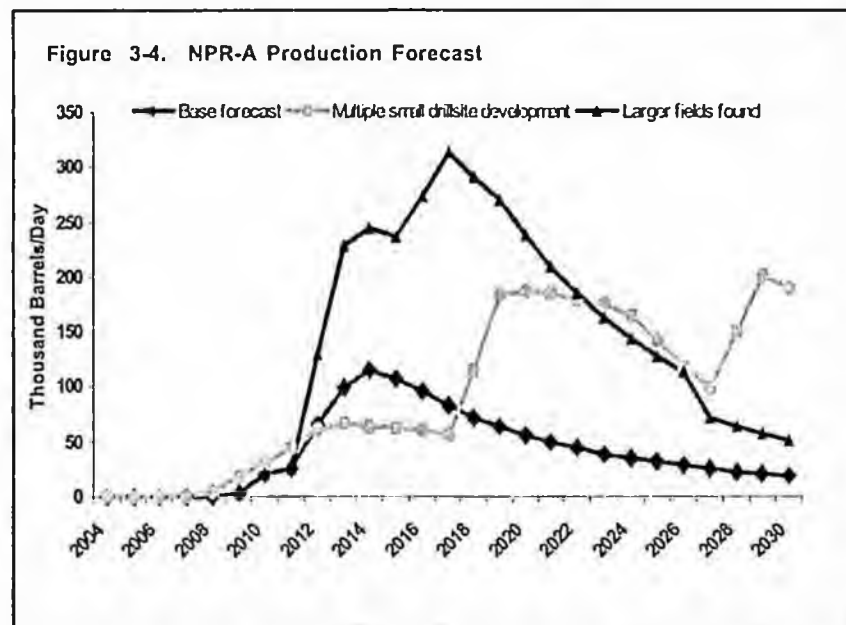
How quickly these reserves are produced depends on the pace of exploration and the size of the fields discovered. Since 2000, 14 exploration drills have been drilled in the NPR-A and a further three or four are planned for the 2003-2004 drilling season. The USGS assumed that there were about eight accumulations with 256 to 512 million barrels in the NPR-A, three of which were in "Subarea 110" of the NPR-A, the area closest to Alpine and TAPS.⁽²⁾ For the NPR-A these are large fields, and these larger fields would be produced before smaller accumulations since they are easier to find and more economic to develop.⁽³⁾ After an initial round of exploration (assuming 20 wildcat wells), the USGS believes that one of these three 256-512 million barrel fields would result in a 430 million barrel field discovery. Under the USGS's cost and development assumptions, to overcome the challenges facing NPR-A development requires that the potential prize of a larger field (400 million barrels or more) is needed for exploration at \$22 per barrel oil prices. Once found, a relatively small field (250 million barrel) will be economic. Explorers just will not incur high exploration costs to look for those fields.

(1) See NPR-A fact sheet.

(2) See USGS fact sheet histogram. The USGS divided the NPR-A into eight subareas for the purpose of estimating product transportation costs to TAPS. See Economic report at Page 17.

(3) See USGS fact sheet, "The economic analysis simulates exploration by assuming that larger accumulations will be discovered early..."

The graph illustrates the production from the NPR-A in our forecast, and the additional production from the NPR-A if a larger field is found or, alternatively, if smaller fields are found and can be economically produced. Lowering exploration costs (through the recently enacted SB 185 or through a permanent road) make the higher forecast more likely to occur. The USGS estimates that the initial finding costs per barrel for the NPR-A is \$0.39, or \$168 million.⁽¹⁾ Explorers pay out these millions of dollars years before first production. Decreasing the cost of this frontier exploration by roughly 30% due to the passage of SB 185 will increase the rate of return on a 430 million barrel field a full percentage point — from 13% to 14% — at \$22 per barrel oil prices.

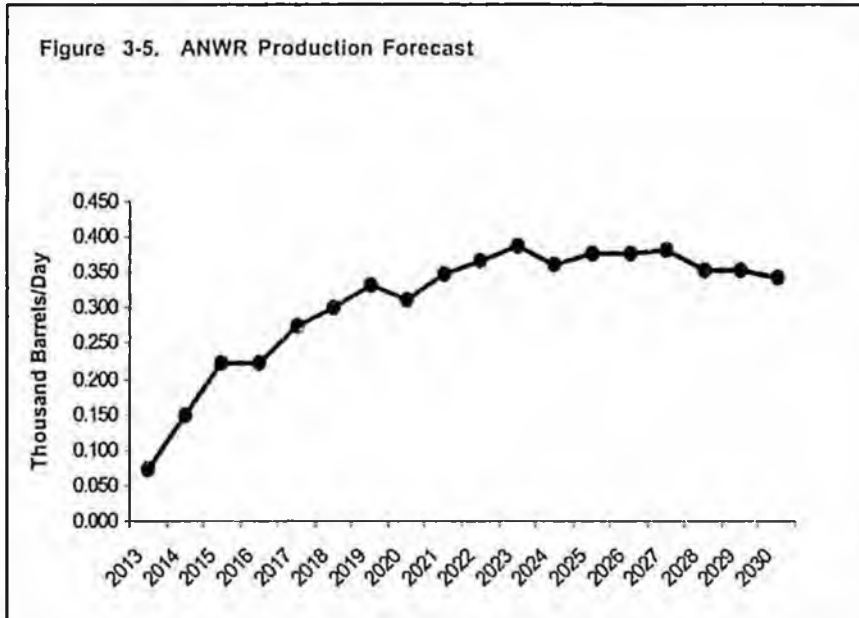


ANWR

The USGS estimates that there are 10.3 billion barrels of technically recoverable reserve in the Arctic National Wildlife Refuge (ANWR), or more barrels than the original estimate for the giant Prudhoe Bay field. At our forecast price of \$22 per barrel, the USGS estimates that 4.4 billion barrels are economically recoverable from federal lands, and almost another billion from non-federal lands. Since ANWR production will probably come from larger fields (with an 80% chance of there being a 1.024 to 2.048 billion barrel field), production should ramp up quickly. We estimate that once Congress opens ANWR to oil exploration and development it will take seven years for the first oil to be produced from the area. If opened in 2006, ANWR is assumed to add between 200 and 400 thousand barrels a day of production by the middle of the next decade.

(1) See NPR-A Economic Report, Table 4, Page 37.

Figure 3-5. ANWR Production Forecast



Gas Line

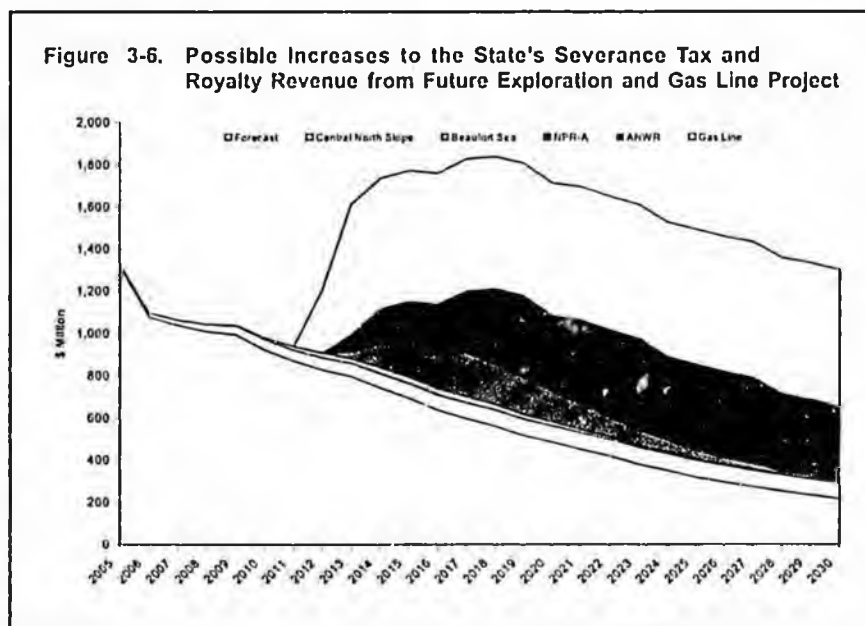
The producers, the state and other interested parties continue to explore ways to monetize the over 30 trillion cubic feet of natural gas on the North Slope.⁽¹⁾ The three largest producers on the North Slope (BP, ConocoPhillips, and ExxonMobil) have looked at a project to pipe about 4.5 billion cubic feet of gas per day to markets in the Lower 48 or Canada. Many hurdles must be overcome for the project to proceed. If these hurdles are overcome, the state stands to receive around \$600 million a year in royalty and severance tax payments per year. Including corporate income tax and property tax, revenues to the state and municipalities increase to around \$1 billion per year.⁽²⁾

(1) Producers on the North Slope currently use the natural gas there to enhance oil production through miscible injection (EOR) projects, cycling and pressure maintenance. Natural gas also is used as field fuel, to fuel some of the pump stations on the Trans-Alaska pipeline and is sold in small quantities to local utilities.

(2) For purposes of this analysis, we have assumed a \$4 per mMBtu price at market. We have not factored in possible changes to the state fiscal system. The state and municipal-take is based on the current fiscal structure. We also have not taken into account oil losses due to gas voidage from an oil and gas reservoir.

Conclusion

In our forecast of oil and gas base revenue (production tax and royalty), we project a decline of 30% by FY 2010 and almost 50% by FY 2015. However, by FY 2015 revenue from future oil exploration and a gas line could more than offset this anticipated decline in oil and gas base revenue from currently producing or discovered fields. With a very active oil and gas exploration and development effort, by FY 2015 our oil and gas base revenue could be 30% higher than it is today.



**Table 3-4. Cumulative Revenue from New Oil Exploration and Gas Line Project to FY 2030
\$ Millions (Undiscounted Dollars)**

	Central North Slope and Satellites	Beaufort Sea	Additional NPR-A	ANWR	Gas Line	Total
2006	27	0	0	0	0	27
2010	174	18	0	0	0	192
2015	480	145	261	484	2,156	3,526
2020	854	268	1,145	2,122	5,282	9,672
2030	1,622	338	1,644	6,058	11,671	21,332

Minerals

Alaska's traditional resource-based industries in mining, fish, tourism and timber all have potential for growth. In this Revenue Sources Book, we have chosen to examine the mining industry. Most of this information comes from the "Alaska Minerals Industry 2002" report, Department of Natural Resources, 2003.

Mining

Between 2001 and 2002, the production value of industrial, energy and metal minerals increased 10% to over \$1 billion. Industrial minerals (e.g., sand and gravel) increased from \$82.4 million to \$152.2 million, mostly as a result of increased road repair and construction. Energy minerals (e.g., coal) decreased from \$48.3 million to \$37.6 million, mostly due to the loss of exports to Korea. Metal minerals increased from \$788.6 million to \$823.1 million, mostly as a result of an increase in the price of gold.

In 2002, zinc prices decreased by more than 12% from 2001 but, as production increased, the total value of zinc decreased only by 1%. Even with prices dropping since the first half of 2001, zinc still accounted for over 60% of the production value for all metals.

Both gold and silver prices increased by 14% and 5%, respectively in 2002 and have continued to rise in 2003. In fact the price of gold in 2003 (January-October) is currently 16% higher and zinc prices are 3% higher than in 2002. According to Andrew Keen at the London Metal Exchange, lead and zinc prices should improve slowly in 2004. Additionally, Korea has signed a new two-year agreement to once again import coal from Alaska.

Employment in the minerals industry in 2002 was 2,824 full-time equivalent jobs, down by 11 from 2001. Average annual earnings in 2002 of \$63,763 were among the highest in the state.

Producing Mines

The four largest producing mines in Alaska are:

Red Dog: Is a joint venture between Nana Regional Corporation and Teck-Cominco and the largest producer of zinc concentrate in the world. Out of a total of 718,106 tons of zinc produced in Alaska in 2002, Red Dog accounted for 637,800 or 89%. Red Dog has almost 550 employees.

Fort Knox: Is owned by Kinross Gold Corporation and produced 410,519 ounces of gold in 2002. This is 73% of the total production of gold in the state. Fort Knox has almost 400 employees.

Greens Creek: Is a joint venture between Kennecott Minerals and Hecla mining and is the third largest silver producer in North America. Out of a total of 17,858,183 ounces of silver produced in Alaska in 2002, Greens Creek produced 10,913,183 or 61%. Greens Creek has over 260 employees.

Usibelli Coal: Is owned by Usibelli Coal Mines Inc. and has among the lowest sulfur coal in the world. Usibelli produced 1,157,879 tons of coal which is essentially all of the commercial coal produced in Alaska. Usibelli had approximately 80 employees in 2002. In 2003, Korea signed a contract valued at \$20 million with Usibelli to resume importing coal from Korea.

Advanced Stage Projects

The three largest advanced stage projects are:

Pogo: Is a joint venture between Sumitomo and Teck-Cominco and the closest of the three projects to construction. Start of construction should be by late 2003 or early 2004 and production should begin in late 2005 or early 2006. The mine should produce greater than 375,000 ounces of gold per year and should employ about 360 employees during production.

Kensington: Is owned by Coeur d'Alene mines and still has some hurdles to overcome before construction can begin. However, if production does occur, then the mine should produce approximately 85,000 ounces of gold per year and have about 225 employees.

Donlin Creek: Is a joint venture between Placer Dome, NovaGold Resources, Calista Corporation and TKC and has the largest gold resource in Alaska. According to the Alaska Journal of Commerce (Bradner, 2003) the largest "challenge" to overcome for Donlin Creek to become a producing mine is to find enough power to operate the mine.

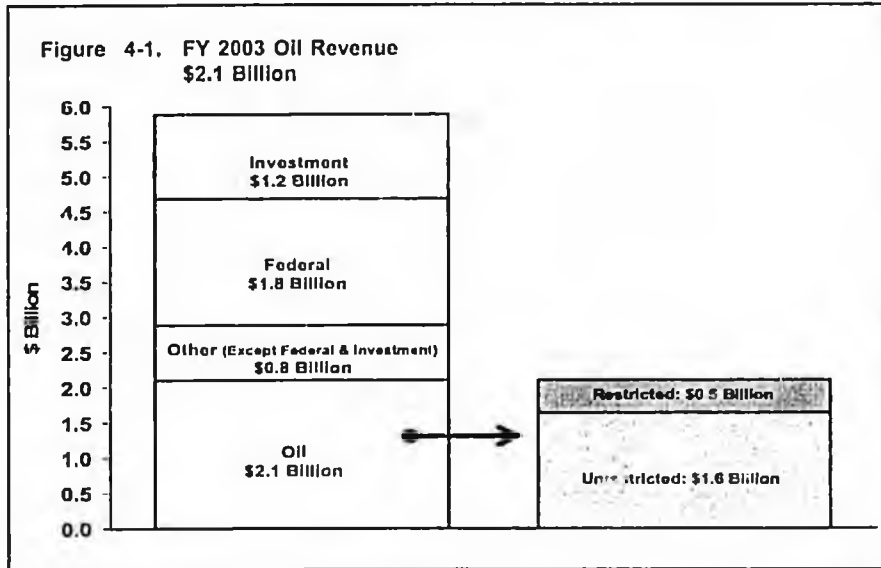
Revenue

According to the Department of Natural Resources, the mining industry paid \$15.2 million to the state and municipalities in 2002. Most of this revenue was from payments to municipalities (\$9.7 million.) The mining industry makes revenue payments to the state in the form of rents and royalties, corporation income taxes (if the businesses are subchapter C corporations) and mining license taxes. We do expect some increase in the state revenues as a result of strong gold prices, improving zinc prices, a new coal contract with South Korea and in the long run from new developments.

The only advanced stage project development that we included in the forecast was Pogo because this project is the closest to construction and is the most likely to begin production within the next five years. No tax revenue would be realized in the two-year forecast window because production is not slated to begin until early 2006. Additionally, because of the 3½-year tax holiday after production starts, we would not see any mining license revenue until FY 2010 or 2011 at the earliest. Exploration credits may be applied against 50% of royalties and tax liabilities and further reduce revenue.

4.

OIL REVENUE



**Table 4-1. Total Oil Revenue
Preliminary Actual FY 2003 and Projected FY 2004-2005
\$ Million**

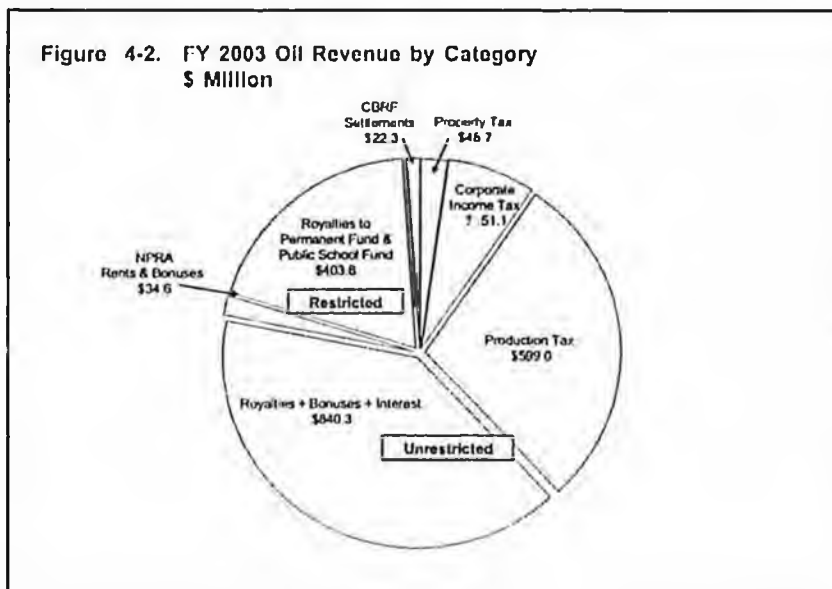
	Preliminary		
	FY 2003	FY 2004	FY 2005
Unrestricted			
Property Taxes	48.7	48.5	45.6
Corporate Income Taxes	151.1	220.0	195.0
Production Taxes	599.0	563.6	427.1
Royalties (including Bonuses and Interest)	<u>340.3</u>	<u>898.6</u>	<u>753.7</u>
Subtotal	1,639.1	1,730.7	1,421.4
Restricted			
Royalties to Permanent Fund & School Fund	403.8	313.9	266.9
Settlements to CBRF	22.3	20.0	20.0
NPRA Royalties, Rents and Bonuses	<u>34.6</u>	<u>2.9</u>	<u>12.9</u>
Subtotal	460.7	336.8	299.8
Total	2,099.8	2,067.5	1,721.3

General Discussion

The state receives its oil and gas revenue from four sources: oil and gas production tax, property tax, royalties and corporate income tax. The bulk of the revenue received from taxes and royalties goes into the General Fund for general purpose spending. The passage of HB 11 last spring calls for 25% of the royalty revenue to go into the principal of the Permanent Fund and 0.5% of mineral bonuses and royalties to go into the Public School Trust Fund. Currently, the state's share of all lease bonuses from the National Petroleum Reserve-Alaska (NPR-A) goes into the NPR-A Fund.⁽¹⁾ Settlements of tax and royalty disputes between the State of Alaska and oil and gas producers go into the Constitutional Budget Reserve Fund (CBRF).

The figure below shows the actual amount of oil revenue from each source in FY 2003.

As can be seen from the figure, royalties and production taxes constitute the largest part of oil revenue — both restricted and unrestricted. 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 our forecast, as well as explore how those market prices determine wellhead value. We also review our volume 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.



(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 Procedures Manual.

Unrestricted Oil Revenue

Table 4-2 . Unrestricted Oil Revenue Projections
Preliminary FY 2003 and Projected FY 2004-2015
\$ Million

Fiscal Year	Property Taxes	Corporate Income Taxes	Production Taxes	Royalties Including Bonuses & Interest	Total Oil
Preliminary 2003	48.7	151.1	599.0	840.3	1,639.1
2004	48.5	220.0	563.6	898.6	1,730.7
2005	45.6	195.0	427.1	753.7	1,421.4
2006	42.4	179.0	330.2	637.7	1,189.3
2007	40.2	172.0	303.2	616.0	1,131.5
2008	37.7	164.0	330.6	605.6	1,137.9
2009	37.5	157.0	326.4	598.1	1,119.0
2010	37.0	150.0	285.6	567.5	1,040.1
2011	36.3	143.0	258.0	545.9	983.3
2012	35.5	135.0	231.4	520.1	922.0
2013	34.7	128.0	221.1	493.3	877.1
2014	34.0	121.0	201.5	436.5	792.9
2015	33.3	113.0	189.7	414.1	750.1

Oil and Gas Production Taxes

All oil and gas production in Alaska except the federal and state royalty share is subject to the state's production taxes. The taxes consist of the oil and gas production tax and a hazardous release surcharge levied only on oil. All of these taxes are collected on a monthly basis.

Oil Production Tax

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

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

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

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

"Wells" is the number of producing wells in the field and "volume" is the total daily production for the field.

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

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.

Natural Gas Production Tax

The statutory production tax rate on natural gas is 10% of its value at the point of production, regardless of the age of the field. There is a minimum tax of 6.4 cents per thousand cubic feet.

To calculate the effective tax rate, multiply the statutory tax rate, even if it is the minimum 6.4 cents per thousand cubic feet, by the ELF. The ELF formula for natural gas production is:

$$ELF = 1 - (3000/PPW)$$

PPW = average gas production per well per day in the field in thousand cubic feet

If the average daily per well gas production from a field is less than 3,000 cubic feet, the ELF is zero and no gas production taxes are assessed.

The taxable value of natural gas depends on the location of its disposition and its use. For Cook Inlet production, the value for gas sent to Japan as LNG is based on the sales price in Japan less marine, processing and pipeline costs; the value for sales to the Nikiski fertilizer plant is indexed to the current market price of anhydrous ammonia; the value for sales for local use is based on the average sales price for the contracts in effect each month. The small volume of taxable North Slope gas production is valued for tax purposes using the following formula linking it to the value for North Slope crude oil:

$$\text{ANS Gas Taxable Value/mcf} = 0.10 (\text{average ANS oil per barrel netback value})$$

Hazardous Release Surcharge

This tax was enacted following the 1989 grounding of the Exxon Valdez to provide an emergency fund to deal with hazardous substance spills.

The surcharge is comprised of two components: (1) a 3 cents per barrel charge on all oil production, except federal and state royalty barrels, and (2) an additional 2 cents per barrel charge on all oil production except federal and state royalty barrels whenever the balance in the state Oil and Hazardous Substance Release Prevention and Response Fund falls below \$50 million. The balance of the fund was \$50 million or greater for all of FY 2003, so the surcharge was 3 cents per barrel for the entire fiscal year.

Oil Royalties

Almost all Alaska oil and gas production occurs on lands leased by the state for exploration and development of oil and gas resources. As the land owner, the state earns revenue from leasing state-owned land 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 current production is from leases that carry that rate. Some currently producing leases carry rates as high as 20%. 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 2003, the state took approximately 50,500 barrels per day of Prudhoe Bay production in-kind and sold it to the Williams Alaska Petroleum Company, for its refinery in North Pole. The state's royalty share of Alaska North Slope production amounts to about 125,000 barrels per day.

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.

Oil Production Revenue 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 forecast is the product of a formal oil price scenario meeting that includes state economists and financial professionals from the Department of Revenue, Department of Natural Resources, Department of Labor, the Governor's Office of Management and Budget and the University of Alaska.

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. This production volume forecast is developed from estimates of oil and gas production by field.

Oil Price Forecast

Our spring oil price forecast, which tracked the market well through August, has been considerably below actual prices since September due in large part to rapidly growing global demand.

Quick Review of What Has Happened Since the Spring Revenue Forecast

- The end of major combat in Iraq came quickly. However, restoration of basic infrastructure in Iraq has taken longer than anticipated. Although the oil fields themselves are mostly undamaged, the basic infrastructure and transportation systems necessary to bring oil production back up to prewar levels are not yet all functional, particularly in the northern part of the country. Current exports, however, are estimated at over 1.5 million barrels per day.
- As Iraq production began ramping up this past fall, oil prices began to correct back into the OPEC \$22-\$28 range through mid-November. Global inventory levels were beginning to rise from extremely low levels — primarily in response to growing non-OPEC production and relatively flat OPEC production. Recent concern about the adequacy of supply relative to burgeoning demand has once again pushed prices over \$30 per barrel.
- OPEC production increased enough in the spring and summer to offset the loss of Iraqi barrels. OPEC production heading into the fall was flat with concerns that production cuts were needed to prevent a price collapse as Iraq and more non-OPEC barrels came into the market. OPEC approved new reductions of 900,000 barrels per day at its September meeting. By its December 4 meeting, the oil market had tightened considerably and members decided to not increase production. OPEC's official view is that the market is well supplied and the weakening dollar is lowering the purchasing power of dollar-denominated oil sales. An OPEC meeting has been scheduled for February 10 to review price and production policies again.

Short-Term Oil Price Forecast

Looking ahead 18 months, we have put together two oil price scenarios. The low price scenario assumes factors which lead to lower oil prices. Accordingly, the high price scenario factors lead to higher oil prices. The components of each scenario are in the table below.

Table 4-3. Fall 2003 Oil Price Scenarios

Low Price Factors

- Iraq production increases to 3.0 million barrels per day by spring 2005.
- OPEC struggles to accommodate this increase in production by Iraq.
- Non-OPEC production also increases as increases in Russia and West Africa more than offset declines elsewhere.
- The global economy grows slowly.

High Price Factors

- Iraq exports peak at 1.5 million barrels per day as political instability disrupts production growth.
- OPEC's task of managing the price band is made easier by this development.
- Additional growth in non-OPEC production slows.
- The global economy picks up as recovery occurs.

Our reference case scenario is based on an average of the prices that we associated with the two scenarios outlined above.

Organization of Petroleum Exporting Countries

In September, OPEC announced that it would be lowering its quota by 900,000 barrels per day — back to 24.5 million barrels per day. (The OPEC quota is exclusive of production from Iraq.) It is the cartel's view that the market is currently well supplied and the prospect of economic growth continues. Increased production from Iraq and the non-OPEC countries will require an output reduction in order to prevent oil prices from falling.

OPEC continues to demonstrate a willingness to actively manage its production to maintain oil prices in a band between \$22 and \$28 per barrel. The October OPEC basket averaged \$28.54 per barrel. Our reference case oil price forecast relies heavily on this continued behavior by OPEC.

Current ANS Oil Market Situation

Alaska North Slope prices have been very strong so far in FY 2004, averaging roughly \$29 per barrel since June. The price of benchmark West Texas Intermediate (WTI) has averaged roughly \$30.40 per barrel implying an average discount for ANS of \$1.40 per barrel — \$0.25 per barrel, better than the five-year average of \$1.70 per barrel. Recently however, the WTI differential has widened out to \$2 per barrel suggesting increased competition for ANS quality crude oil on the U.S. West Coast as a result of the reentry of Iraqi oil into the market.

ANS prices closely track the OPEC price basket of internationally traded crude oils. The OPEC basket is the benchmark that OPEC uses to gauge the success of its production policy. Since January 2000, the average ANS price has been \$0.68 per barrel higher than the average OPEC basket price. ANS typically sells in direct competition with other waterborne crude oils for sales to U.S. West Coast refiners in Washington, California and Hawaii.

ANS has a locational advantage over other waterborne crude oils since it is the nearest waterborne source of crude oil for West Coast refiners. Typically, ANS sells at a discount to benchmark WTI. This discount can be quite volatile, but since January 1998 has averaged close to \$1.70 per barrel, trading in a range of \$1 to \$2.60 per barrel 70% of the time. Our price assumptions assume that over time, the differential will average \$1.70 per barrel.

Prices Over the Longer Term

In the fall 2003 revenue forecast, our assumption for ANS oil prices over the longer term was increased to \$22 per barrel. We believed that the accumulated evidence of OPEC's commitment to managing the market from 1999 through 2002 supported this increase. At that time, we chose to benchmark our price to the low end of OPEC's target range. Experience had shown that the OPEC cartel is not perfect and that some cheating does occur. Like all cartels, production discipline in an organization — with only voluntary compliance — creates strong economic incentives for individual members to overproduce.

Figure 4-3. General Fund Unrestricted Revenue Forecast Reference Case Compared to \$18 and \$28 per Barrel Oil \$ Million

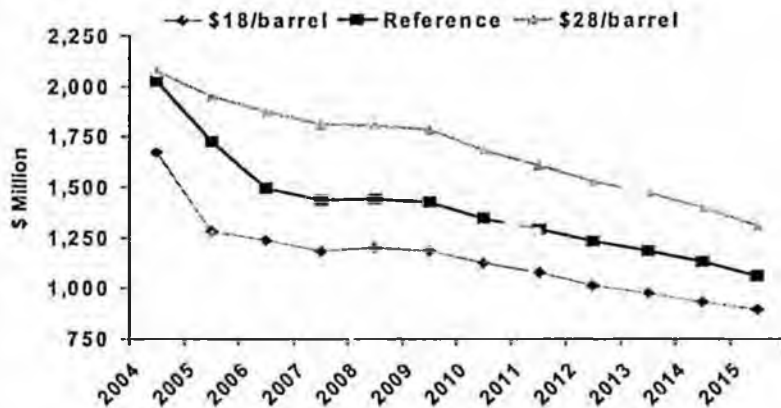


Table 4-4. General Fund Unrestricted Revenue Reference Case Compared to \$18 and \$28 Per Barrel Oil Price \$ Million

FY	\$18/ barrel	Reference Case ⁽¹⁾	\$28/ barrel
2004	1,668.8	2,022.9	2,074.7
2005	1,279.9	1,724.3	1,948.2
2006	1,235.1	1,492.1	1,877.6
2007	1,185.9	1,434.9	1,808.5
2008	1,199.2	1,442.0	1,806.2
2009	1,184.3	1,424.2	1,784.0
2010	1,124.2	1,347.2	1,681.7
2011	1,079.1	1,291.3	1,609.5
2012	1,013.2	1,230.9	1,528.3
2013	976.8	1,186.5	1,471.5
2014	931.3	1,102.8	1,396.6
2015	896.4	1,060.5	1,305.6

(1) See Executive Summary, Table 2-4 for reference case price per barrel.

Although major oil companies are careful about publicly stating what they believe oil prices will be in the future, conventional wisdom is that many continue to use oil prices less than \$20 per barrel to evaluate oil development projects. The other thing we know is that the major oil companies change their views about long-run oil prices slowly. Following the oil price crash of 1999, many companies started to use oil prices around \$15 per barrel or even lower to run development project economics. As oil prices climb higher in the 21st century, it is likely some companies may be using prices closer to our assumed \$22 per barrel for longer-term planning purposes. The U.S. Department of Energy's reference case forecast of oil prices, shown in the table below, is a bit higher than our reference price forecast of \$22 for the long term.

Scenario	2010	2020	2025
Low Price	19.04	19.04	19.04
Reference Price	23.99	25.48	26.57
High Price	32.51	33.02	33.05

Other Transportation and Production Costs

Transportation Costs

The forced 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. Negotiations to revisit the TAPS Settlement Method will begin in January 2007.

TAPS tariffs are filed on a calendar year basis, with new tariffs taking effect January 1 each year. The expected tariff filing for calendar year 2003 is \$3.24 per barrel. The fall 2003 forecast assumptions table on the next page contains projected tariffs for FY 2004-2015.

Feeder Pipeline Costs

Certain 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 the table below.

Wellhead Price

The combination of ANS wellhead value and production volume by field form the basis for both state production taxes and royalties. The wellhead value by field 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. The table below reflects this calculation for FY 2003-2015.

Table 4-6. Fall 2003 Forecast Assumptions
\$ per barrel

FY	ANS West Coast Price	ANS Marine Transportation	TAPS Tariff	Other ⁽¹⁾ Deductions & Adjustments	ANS Wellhead
Preliminary 2003	28.15	1.68	3.34	(0.22)	23.35
2004	27.70	1.66	3.28	0.29	22.46
2005	24.65	1.71	3.25	0.24	19.46
2006	22.00	1.76	3.27	0.23	16.74
2007	22.00	1.81	3.31	0.25	16.63
2008	22.00	1.86	3.35	0.26	16.53
2009	22.00	1.91	3.35	0.28	16.46
2010	22.00	1.96	3.36	0.33	16.35
2011	22.00	2.01	3.44	0.35	16.20
2012	22.00	2.06	3.31	0.42	16.21
2013	22.00	2.11	3.37	0.47	16.06
2014	22.00	2.16	3.49	0.48	15.87
2015	22.00	2.21	3.63	0.47	15.69

(1) Other deductions include other pipeline tariffs, quality bank charges, location differentials and amended information.

(2) FY 2004 includes reported information through September 2003.

Oil Production

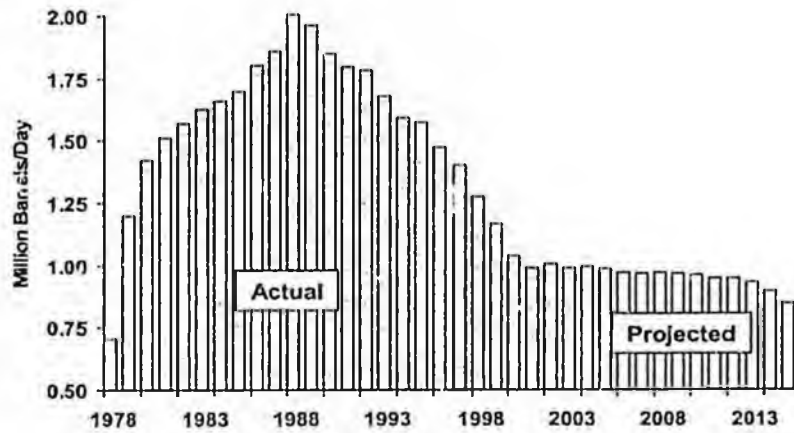
Our ANS oil production forecast is changed only modestly from our spring 2003 projection for FY 2004-2007. Heavy oil development at West Sak and incremental production from the Pressure Support Initiative at Prudhoe Bay will help mitigate baseline decline from the mature producing fields on the North Slope. During this period, we expect oil production on the North Slope to average 977,000 barrels per day.

We have reduced our expectations for ANS production from FY 2008-2013. ANS oil production is forecast to average 945,000 barrels per day during this time period, a reduction of 34,000 barrels per day from our spring 2003 projection. Enhanced oil recovery from the Milne Point Unit was eliminated because of costs associated with procuring off lease solvent. The production from prospective, undiscovered satellite fields in the Greater Kuparuk Area has also been eliminated in this forecast.

After review of development plans with the Department of Natural Resources, the start-up dates for the undeveloped oilfields on the North Slope have been reevaluated. The Liberty and Sandpiper fields have been delayed one year to allow operators to determine the best development scope and to secure the associated permitting. Likewise, satellite fields in the vicinity of the Point Thomson Unit have been delayed two years.

All producing fields have been reviewed for reservoir performance and potential and our expectations have been adjusted based on information acquired since the spring 2003 forecast. The near term outlook for the Kuparuk River field has been reduced due to greater than expected backout impacts from satellite fields sharing the limited capacity in the production facilities there. Field sizes and production rates at Prudhoe Bay satellites Aurora and Borealis have been increased and expectations from Polaris, decreased. The Meltwater and Tabasco production forecast has been increased due to planned development drilling. Implementing the Water Wheel project at Point McIntyre will add 5,000 barrels per day in fourth quarter 2003.

Figure 4-4. ANS Production

Table 4-7. Alaska Oil and NGL Production
Million Barrels per Day

	Preliminary	FY 2004	FY 2005
	FY 2003		
Prudhoe Bay	0.4328	0.4201	0.4011
Midnight Sun	0.0069	0.0048	0.0042
Polaris	0.0026	0.0027	0.0054
Orion	0.0004	0.0032	0.0097
Aurora	0.0082	0.0104	0.0101
Borealis	0.0271	0.0353	0.0365
Kuparuk	0.1595	0.1547	0.1520
West Sak	0.0068	0.0101	0.0204
Tabasco	0.0036	0.0053	0.0052
Tarn	0.0338	0.0331	0.0263
Meltwater	0.0081	0.0048	0.0093
Milne Point	0.0344	0.0322	0.0318
Schrader Bluff	0.0170	0.0210	0.0220
Endicott	0.0265	0.0294	0.0287
Eider	0.0010	0.0005	0.0003
Badami	0.0014	0.0000	0.0000
Lisburne	0.0088	0.0103	0.0094
Point McIntyre	0.0410	0.0417	0.0423
Niakuk	0.0145	0.0117	0.0099
Alpine	0.0983	0.0990	0.0980
Northstar	<u>0.0574</u>	<u>0.0657</u>	<u>0.0630</u>
Total ANS	0.9903	0.9961	0.9855
Cook Inlet	<u>0.0293</u>	<u>0.0296</u>	<u>0.0285</u>
Total Alaska	1.0196	1.0257	1.0140

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 raw data for market value is gathered by the state appraiser 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 new 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 when the facility would reach 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. We primarily rely on the income method under which the value is the present worth of all future income streams of the pipeline. Over 95% of pipeline transportation property is accounted for by the Trans-Alaska Pipeline from Prudhoe Bay to Valdez.

The table on the next page illustrates the property tax distribution between local communities and the state for FY 2003. 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 43.29.080 and AS 43.29.100. If a municipality has a tax rate of 20 mills or less, the state's mill rate is effectively 20 mills minus the local rate. If the local rate is greater than 20 mills, the state will receive nothing on that property and may receive less on other property belonging to that taxpayer in other jurisdictions.

Table 4-8. FY 2003, Distribution of the Petroleum Property Tax
\$ Million

Municipalities	Gross Tax	Local Share	State Share
North Slope	209.3	194.2	15.1
Unorganized	27.2	0.0	27.2
Valdez	13.2	13.2	0.0
Kenai	12.8	7.7	5.1
Fairbanks	5.4	4.4	1.1
Anchorage	0.9	0.8	0.2
Other Municipalities ⁽¹⁾	0.1	0.1	0.0
Total	268.9	220.4	48.7

(1) Other municipalities include Matanuska-Susitna, Cordova and Whittier.

Petroleum Corporate Income Tax

A petroleum corporation's Alaska income tax depends on the relative size of its Alaska vs. worldwide activities and the corporation's total worldwide net earnings. The corporation's Alaska taxable income is derived by apportioning the corporation's worldwide taxable income to Alaska using the average of three factors: the proportion of the corporation's (1) tariffs and sales, (2) oil and gas production, and (3) oil and gas property in Alaska.

We begin our forecast by estimating the statistical relationship between historical collections of tax and the value of Alaska oil production. We then adjust the forecast for carryforwards and refunds. In FY 2004, the carryforward and refund adjustment is close to \$50 million. This adjustment is a result of oil companies overpaying their income taxes. We are forecasting FY 2004 petroleum corporate income tax revenue to be 46% higher due to higher crude oil prices and higher marketing and refining margins in 2003. Additionally, refunds and carry forwards are lower in FY 2004. In FY 2005, we are projecting that revenue will decrease as a result of lower oil and gas prices.

Restricted Oil Revenue

The table below reflects restricted oil and gas 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. As explained earlier, settlements with or judgments against the oil industry involving tax and royalty disputes must be deposited in the 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 to the General Fund.

	Preliminary FY 2003	FY 2004	FY 2005
Restricted Oil Revenue			
Royalties to Permanent Fund & Public School Fund			
Royalties, Bonuses and Rents to the Permanent Fund	397.6	307.9	261.9
Royalties, Bonuses and Rents to the Public School Fund	<u>6.2</u>	<u>6.0</u>	<u>5.0</u>
Subtotal	403.8	313.9	266.9
Settlements to the CBRF	22.3	20.0	20.0
NPR-A Royalties, Rents and Bonuses	<u>34.6</u>	<u>2.9</u>	<u>12.9</u>
Total	460.7	336.8	299.8

5.

OTHER REVENUE
(EXCEPT FEDERAL & INVESTMENT)

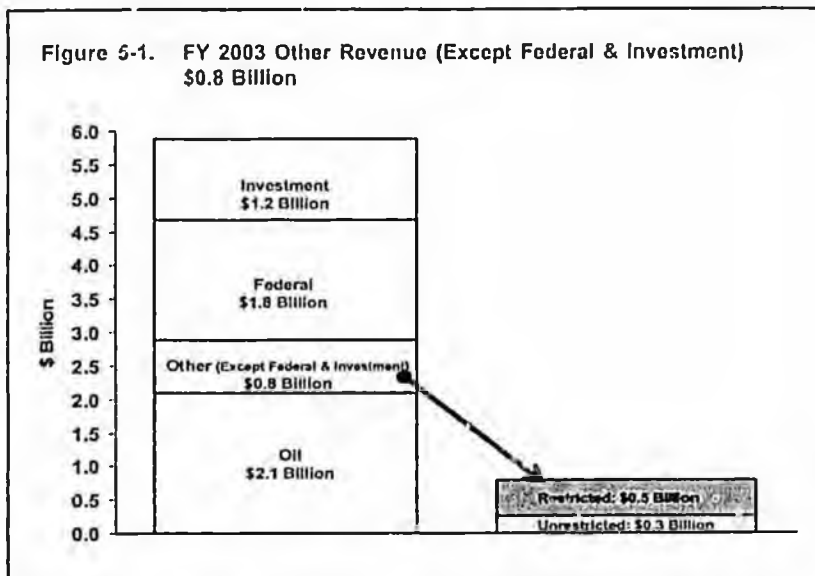


Table 5-1. Other Revenue (Except Federal & Investment)
Preliminary FY 2003 and Projected FY 2004-2005
\$ Million

	Preliminary FY 2003	FY 2004	FY 2005
Unrestricted			
Taxes	179.4	181.1	196.7
Charges for Services	13.9	18.4	18.4
Fines and Forfeitures	7.0	7.0	7.0
Licenses and Permits	32.9	45.5	47.9
Rents and Royalties	6.2	7.0	7.2
Other	9.4	21.5	14.0
Total Unrestricted	248.8	280.5	291.2
Restricted			
Taxes	67.3	74.3	73.0
Charges for Services	195.9	251.7	250.7
Fines and Forfeitures	26.8	23.6	23.8
Licenses and Permits	29.1	29.0	30.8
Rents and Royalties	4.7	4.7	4.7
Other	212.9	119.9	119.9
Total Restricted	536.7	504.1	502.9
Total	785.5	784.6	794.1

Income from sources other than oil and investments includes non-oil taxes, user fees and licenses. Many of these revenue sources are divided between unrestricted and restricted revenues; the amounts of each are reflected in the tables. Restricted revenue includes money deposited in funds other than the Unrestricted General Fund. For purposes of this forecast, restricted revenue also includes receipts that the legislature consistently appropriates or sets aside for a particular purpose or program, such as sharing of fish tax revenue with municipalities.

Other Taxes

Alcoholic Beverages Tax

Alcoholic beverage taxes are collected primarily from wholesalers and distributors of alcoholic beverages sold in Alaska. On October 1, 2002, per gallon tax rates on alcoholic beverages were increased from \$0.35 to \$1.07 for beer, \$0.85 to \$2.50 for wine and \$5.60 to \$12.80 for liquor. Also, starting October 1, 2002, 50% of the revenue is deposited in the Alcohol and Other Drug Abuse Treatment and Prevention Fund. Because the legislature "may use the annual estimated balance in the fund to make appropriations to the Department of Health and Social Services," this revenue is reflected as restricted in the Revenue Sources Book.

Corporate Income Tax

Corporations that do business in Alaska pay the Corporate Net Income Tax unless they are organized under a special IRS rule (Subchapter S) that generally applies to small, closely held companies. A corporation that does business both inside and outside Alaska must apportion its income to determine how much income it earned here. Corporations other than oil and gas corporations apportion their income to Alaska by using a three-factor formula based on sales, property and payroll. Alaska taxable income is determined by applying the apportionment factor to the corporation's modified federal taxable income. Corporate tax rates are graduated from 1% to 9.4% in \$10,000 increments of Alaska taxable income. The maximum rate of 9.4% applies to income over \$90,000.

Electric Cooperative and Telephone Cooperative Taxes

The electric cooperative and telephone cooperative taxes date back to 1959, when the first Alaska Legislature enacted the Electric and Telephone Cooperative Act to promote cooperatives around the state. The Electric Cooperative Tax is based on kilowatt-hours furnished by qualified electric cooperatives recognized under Title 10 of the Alaska statutes; the Telephone Cooperative Tax is levied on gross revenue of qualified telephone cooperatives under Title 10. All revenue from the co-op taxes is deposited in the General Fund, but revenue from co-ops located in municipalities is treated as restricted revenue in this forecast because it is shared 100% with the municipalities.

Estate Tax

This tax is levied on the transfer of an estate upon death. The Alaska estate tax is tied to the federal tax. The amount of the state tax equals the maximum state credit allowed on the estate's federal return. As a result of changes to the federal estate tax, the Alaska estate tax will be phased out by FY 2006. All revenue derived from estate taxes is deposited in the General Fund.

Fisheries Business Tax

The Fisheries Business Tax is the oldest tax in Alaska, dating from 1913. The tax is levied on businesses that process or export fisheries resources from Alaska. Although the tax usually is levied on the act of processing, the tax is often referred to as a "raw fish tax" because it is generally based on the value paid to commercial fishers for the raw fishery resource. Tax rates vary from 1% to 5%, depending on whether a fishery resource is classified as "established" or "developing," and whether it was processed by an on-shore or floating processor. All revenue from the Fisheries Business Tax is deposited in the General Fund, but not all of it is considered unrestricted for the purposes of this forecast. Each year, the legislature appropriates half the revenue from the tax to qualified municipalities. Given that this sharing formula is in statute, and that the legislature consistently follows the statutory formula, this forecast considers the shared revenues to be restricted.

Fishery Resource Landing Tax

The Fishery Resource Landing Tax was enacted in 1993. The tax is levied on processed fishery resources first landed in Alaska, and is based on the unprocessed statewide average value of the resource. Fishery Resource Landing Taxes are collected primarily from factory trawlers and floating processors that process fishery resources outside of the state's 3-mile limit and bring their products into Alaska for transshipment. Fishery Resource Landing Tax rates vary from 1% to 3%, based on whether the resource is classified as "established" or "developing." All revenue derived from the Fishery Resource Landing Tax is deposited in the General Fund but by statute, 50% is available for sharing with municipalities along the same lines as the Fisheries Business Tax. The revenue to be shared is considered restricted.

Insurance Premium Tax

Insurance companies in Alaska do not pay corporate income tax or sales or other excise taxes. Instead, they pay an Insurance Premium Tax. Receipts from this tax are deposited in the General Fund. However, receipts from the Insurance Premium Tax that are accounted for in the "Workers Safety and Compensation Fund" are shown as restricted.

Mining License Tax

This tax is on the net income of mining property in the state, ranging from 0% to 7%, less exploration and other credits. Except for sand and gravel operations, new mining operations are exempt from the Mining License Tax for a period of 3½ years after production begins.

Motor Fuel Tax

The Motor Fuel Tax dates from 1945 when a tax of 1 cent per gallon was imposed on all motor fuel. The Motor Fuel Tax is levied on motor fuel sold, transferred or used within Alaska. Motor Fuel Taxes are collected primarily from wholesalers and distributors licensed as qualified dealers. Current per gallon rates are 8 cents for highway use, 5 cents for marine use, 4.7 cents for aviation gasoline, 3.2 cents for jet fuel, and a variable rate of 8 cents to 2 cents, depending on the season, for gasohol. Various uses of fuel are exempt from tax, including fuel used for heating or in flights to or from a foreign country. All revenue derived from Motor Fuel Taxes is deposited in the General Fund, but 60% of taxes attributable to aviation fuel sales at municipal airports are shared with the respective municipalities, and hence considered restricted for purposes of this forecast.

Seafood Assessments and Taxes

The Department of Revenue administers several different programs that raise money through seafood assessments. The money raised is then set aside for the legislature to appropriate for the benefit of the seafood industry — either in marketing or in management/development of the industry. The four programs are the Salmon Marketing Tax, Seafood Marketing Assessment, Salmon Enhancement Tax and Dive Fishery Management Assessment. The rates for many of these assessments are actually determined by a vote of the appropriate association within the seafood industry. Although all revenue received under these assessments is deposited in the General Fund, for purposes of this forecast it is treated as restricted revenue. With the exception of the Salmon Enhancement Tax, all other seafood assessments are reflected under the Charges for Services section.

Tobacco Tax

The Tobacco Tax dates from 1949, when a tax of 3 cents per pack of cigarettes and 2 cents per ounce of tobacco was enacted. The Tobacco Tax is levied on cigarettes and tobacco products sold, imported or transferred into Alaska. Tobacco Taxes are collected primarily from licensed wholesalers and distributors. The tax rate on cigarettes is \$1 per pack of 20 cigarettes. The tax rate on other tobacco products — such as cigars and chewing tobacco — is 75% of the wholesale price. Seventy-six percent of cigarette tax revenue is deposited in the School Fund; 24% in the General Fund. All tobacco products tax revenue is deposited in the General Fund; all cigarette and tobacco products license fees are deposited in the School Fund. Revenue deposited in the School Fund is dedicated to the rehabilitation, construction, repair and insurance costs of school facilities.

Charitable Gaming

Under Alaska law, municipalities and qualified non-profit organizations may conduct certain charitable gaming activities. The purpose of these activities is to derive public benefit in the form of money for the charities and revenues for the state. The Department of Revenue collects permit and license fees, a 1% net proceeds fee, and a 3% pull-tab tax.

Table 5-2. Other Tax (Except Federal & Investment)
Preliminary FY 2003 and Projected FY 2004-2005
\$ Million

	Preliminary		
	FY 2003	FY 2004	FY 2005
Unrestricted			
Sales and Use Tax			
Alcoholic Beverage	14.1	15.7	15.7
Cigarette	9.6	9.5	9.5
Other Tobacco Product	6.7	6.8	7.2
Insurance Premium	39.0	42.6	44.7
Electric and Telephone Cooperative	0.2	0.2	0.2
Motor Fuel	37.2	39.0	39.0
Rental Vehicle Tax	0.0	1.0	6.0
Tire Fee	0.0	2.4	3.3
Subtotal	106.8	117.2	125.6
Corporation Income Tax	47.7	49.0	53.7
Fish Tax			
Fisheries Business	13.8	8.3	10.3
Fishery Resource Landing	6.9	2.0	2.6
Subtotal	20.7	10.3	12.9
Other			
Mining	0.4	0.7	1.3
Estate	1.2	1.4	0.7
Charitable Gaming	2.6	2.5	2.5
Subtotal	4.2	4.6	4.5
Total Unrestricted	179.4	181.1	196.7
Restricted			
Sales and Use Tax			
Alcoholic Beverage (Alcohol & Drug Treatment)	11.2	15.7	15.7
Insurance Premium (Workers Safety & Compensation)	4.3	4.3	4.6
Electric and Telephone Cooperative (Municipal Share)	3.5	3.5	3.5
Cigarette (School Fund)	30.6	30.2	30.2
Motor Fuel - Aviation (Municipal Share)	0.2	0.2	0.2
Subtotal	49.8	53.9	54.2
Fish Tax			
Fisheries Business (Municipal Share)	12.2	12.1	12.1
Fishery Resource Landing (Municipal Share)	2.9	5.6	4.0
Salmon Enhancement (Aquaculture Assoc. Share)	2.4	2.7	2.7
Subtotal	17.5	20.4	18.8
Total Restricted	67.3	74.3	73.0
Grand Total	246.7	255.4	269.7

Charges for Services

The charges for services reported in the next table do not include all charges for state services — they just reflect those that do not fit into other categories in this report. Most of these receipts are restricted revenue because they are returned to the program from which they were generated.

The only unrestricted revenue listed under charges for services in this report comes from fees and other program charges that do not have program receipt designations, or are not otherwise segregated and appropriated back to the program.

Marine Highway Fund

The revenue from certain transportation enterprises is reported here as a charge for state services. The Alaska Marine Highway Fund is in the General Fund and receives the revenue from operations of the state ferry system. The legislature has discretion over how the revenue is spent, but because it is customarily spent on Alaska Marine Highway operations, it is considered restricted.

Program Receipts

The definition of program receipts under AS 37.05.146 is “fees, charges, income earned on assets and other state money received by a state agency in connection with the performance of its functions.” The statute then lists all programs with program receipt authority. The statutory list includes many programs that are not included in Charges for Services because they are elsewhere in this forecast — such as federal receipts, trust funds and the Permanent Fund — or not state money, such as the public employee retirement funds. The table on the next page lists some of the larger individual programs and the receipts from those programs.

“Statutorily Designated” program receipts are those receipts from contracts, grants, gifts or bequests. “Receipt Supported Services” are, in general, appropriated back to state agencies to administer the programs generating the receipts. Those not listed separately, or not described elsewhere in this forecast, are included in the catchall “Other.”