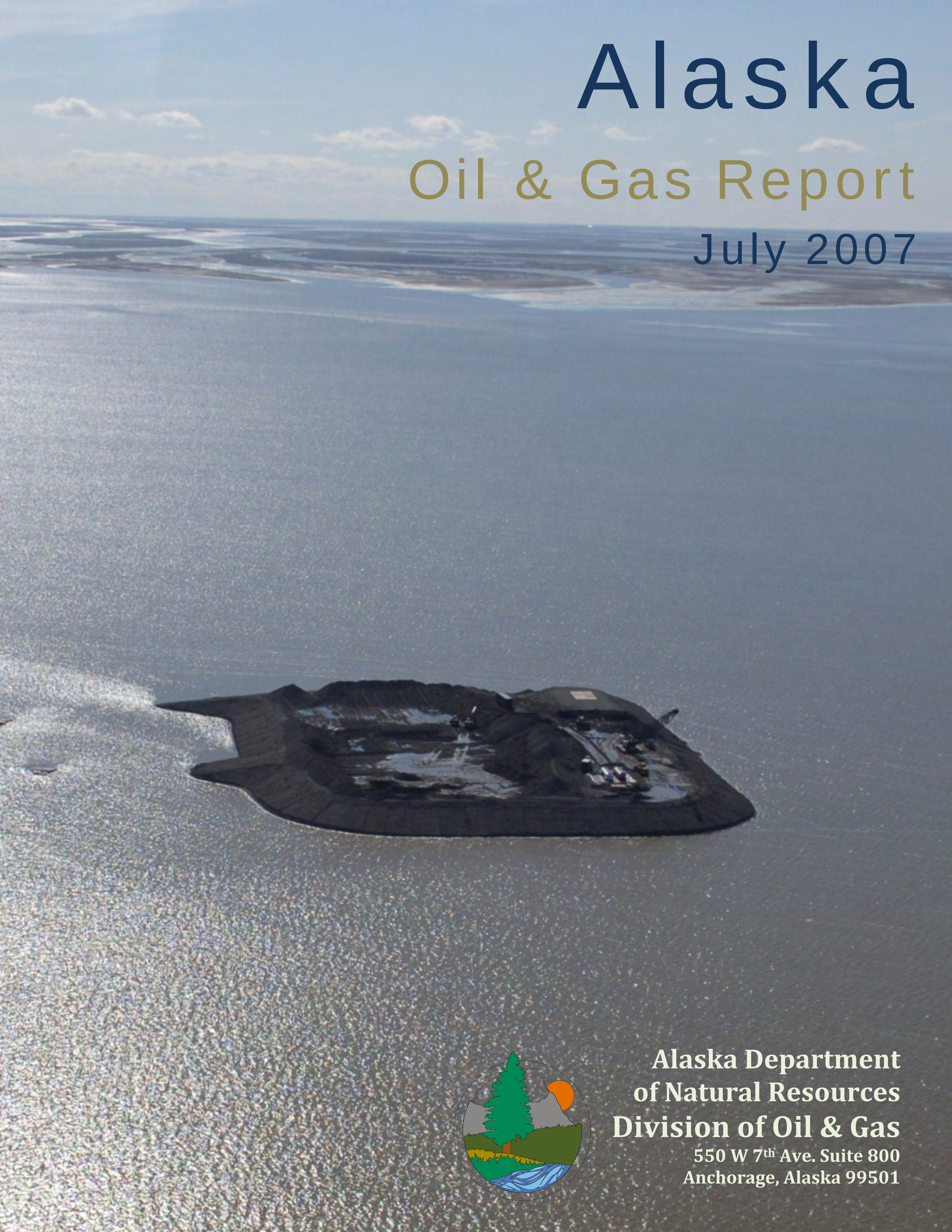
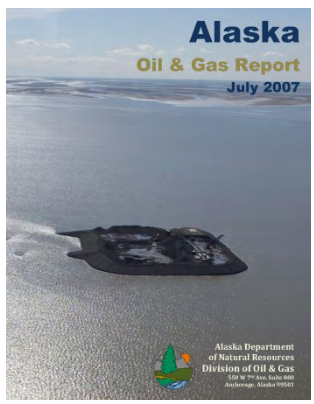


Alaska

Oil & Gas Report

July 2007

Alaska Department
of Natural Resources
Division of Oil & Gas
550 W 7th Ave. Suite 800
Anchorage, Alaska 99501



Front cover:
Pioneer Natural Resources, Alaska, Inc. gravel island for the Oooguruk oil field, Beaufort Sea.
Aaron Weaver

STATE OF ALASKA
Governor Sarah Palin

ALASKA DEPARTMENT OF NATURAL RESOURCES
Thomas P. Irwin, Commissioner

DIVISION OF OIL AND GAS
Kevin R. Banks, Acting Director

This publication was released by the Division of Oil and Gas, Anchorage, Alaska. For more information, contact the Division of Oil and Gas, 550 W. 7th Ave., Suite 800, Anchorage, Alaska 99501-3560. This report can be downloaded at http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report htm

Acknowledgements:
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Forward

This 2007 Oil & Gas Report, released July 2007, includes production information through December 31, 2006, and contains the most recent Division of Oil and Gas oil production forecasts by field and reserve estimates. The division did not release an annual report in 2005 or 2001. Reports are available on the Division of Oil and Gas Web site at www.dog.dnr.state.ak.us/oil

2007 Oil and Gas Report

For the period ending December 31, 2006

Alaska Department of Natural Resources
Division of Oil and Gas

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List of Tables

Section One

Leasing, Incentives, Licensing, and Other Programs

Leasing

Areawide Leasing

Oil and gas lease sales are the initial step in a process that generates more than 85 percent of the state's general fund revenue. Since 1959 the state has held more than 100 competitive lease sales in which it has offered millions of acres throughout Alaska. Although the primary purpose of leasing state lands is to provide for oil and gas development and the subsequent economic benefits, the program in itself has been a significant revenue source. Through lease sale bonus bids alone, the state has received more than $2 billion in revenue.

Since 1998, state oil and gas lease sales have been conducted on an areawide basis. This means that each sale includes all un-leased state oil and gas resources within the lease sale area. The five geographic regions subject to areawide leasing and typical sale month are listed below.

Areawide leasing
ADNR, DO&G

Sale	Held In
Alaska Peninsula Areawide	February
North Slope Foothills Areawide	February
Cook Inlet Areawide	May
Beaufort Sea Areawide	October
North Slope Areawide	October

Areas outside these regions are available for exploration through exploration licensing, discussed later in this section.

Best Interest Finding Process

Prior to an area being subject to an areawide lease sale, the commissioner must determine that it is in the state's best interest to hold such a sale in the area. The best interest finding is valid for up to 10 years; however, prior to each sale, the commissioner must solicit information from the public comment and determine if substantial new information has become available that justifies supplementing the best interest finding. If no new substantial information is received, a sale announcement — including the sale terms, bidding method, and tract map — will be issued at least 45 days prior to that sale. If a best interest finding or a supplement to a previous finding is required, it will be released at least 90 days prior to the sale.

The Division of Oil and Gas annually issues a new *Five-Year Oil and Gas Leasing Program* that sets out the sale schedule for the succeeding five years. Also included in this document are maps with results from the most recent areawide sales, a summary report of all previous state oil and gas lease sales, and an update on exploration licensing in the state. In addition, full information on each previous areawide lease sale is available on the division's Web site (http://www.dog.dnr.state.ak.us/oil/).

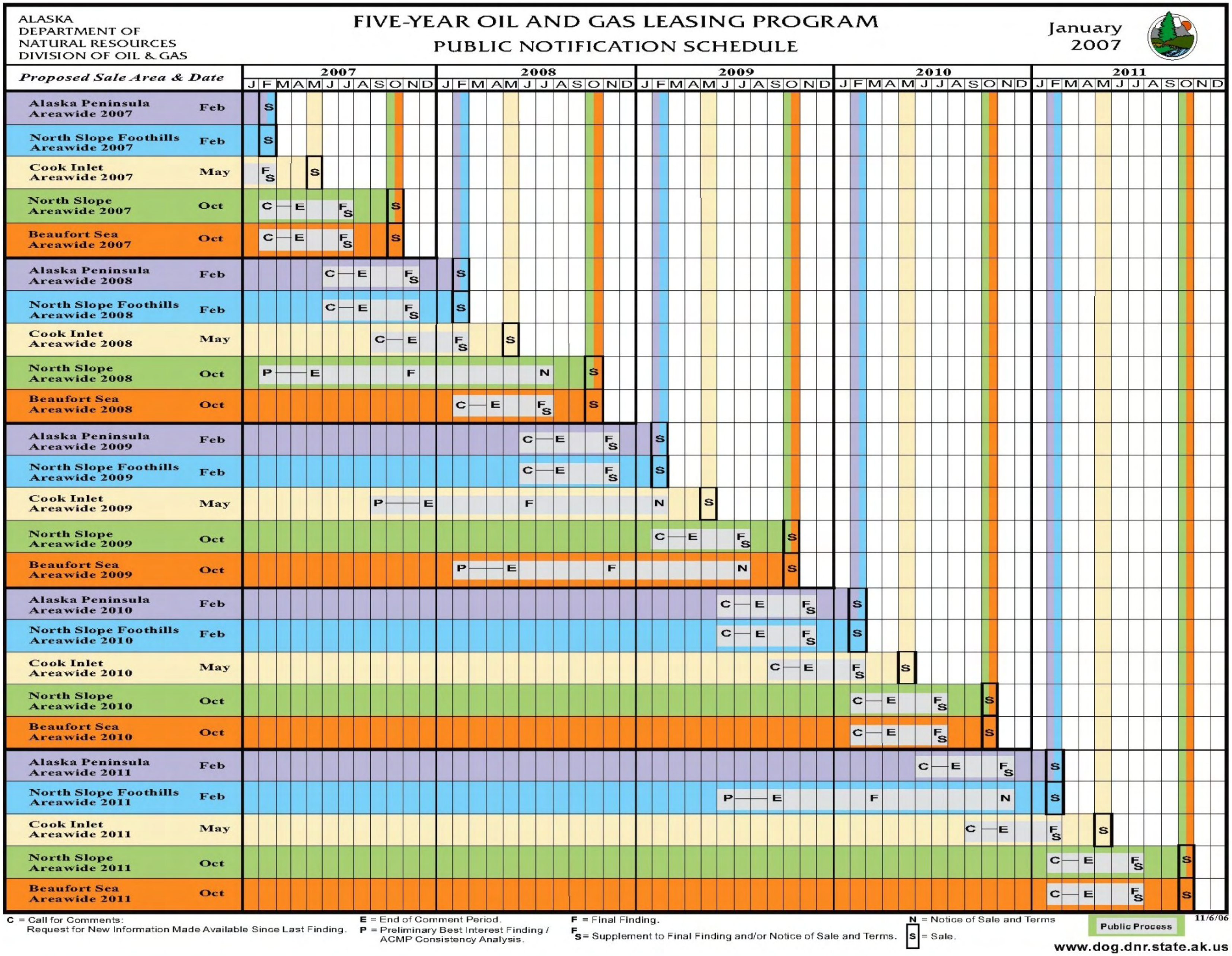
Leasing Methods

Several leasing methods, authorized under AS 38.05, have been used to encourage responsible oil and gas exploration and development and maximize state revenue, including combinations of fixed and variable bonus bids, royalty shares, and net profit shares. The fixed lease terms generally involve an obligation to remit royalty payments in the form of a 12 1/2 percent or 16 2/3 percent share of gross production paid in-kind or in-value. Occasionally, the state has imposed a fixed royalty rate of 20 percent. The state has also used sliding-scale royalty terms in its leases based on production or oil price or gross revenue.

The most common bid variable used by the state is the cash bonus. The state may require minimum bids of $5 to $10 per acre (and sometimes higher). The state may also use the royalty rate or the net profit share as the bidding variable, though this has happened only rarely (Sale 30, the joint Federal-State Beaufort Sea sale held in 1979, was one of these occasions).


Lease Processing
ADNR, DO&G


North Kenai, Cook Inlet
ADNR, DO&G


ALASKA
DEPARTMENT OF
NATURAL RESOURCES
DIVISION OF OIL & GAS
FIVE-YEAR OIL AND GAS LEASING PROGRAM
PUBLIC NOTIFICATION SCHEDULE
January 2007
Proposed Sale Area & Date
2007
2008
2009
2010
2011
J F M A M J J A S O N D
Alaska Peninsula Areawide 2007 Feb
North Slope Foothills Areawide 2007 Feb
Cook Inlet Areawide 2007 May
North Slope Areawide 2007 Oct
Beaufort Sea Areawide 2007 Oct
Alaska Peninsula Areawide 2008 Feb
North Slope Foothills Areawide 2008 Feb
Cook Inlet Areawide 2008 May
North Slope Areawide 2008 Oct
Beaufort Sea Areawide 2008 Oct
Alaska Peninsula Areawide 2009 Feb
North Slope Foothills Areawide 2009 Feb
Cook Inlet Areawide 2009 May
North Slope Areawide 2009 Oct
Beaufort Sea Areawide 2009 Oct
Alaska Peninsula Areawide 2010 Feb
North Slope Foothills Areawide 2010 Feb
Cook Inlet Areawide 2010 May
North Slope Areawide 2010 Oct
Beaufort Sea Areawide 2010 Oct
Alaska Peninsula Areawide 2011 Feb
North Slope Foothills Areawide 2011 Feb
Cook Inlet Areawide 2011 May
North Slope Areawide 2011 Oct
Beaufort Sea Areawide 2011 Oct
C = Call for Comments: Request for New Information Made Available Since Last Finding.
E = End of Comment Period.
P = Preliminary Best Interest Finding / ACMP Consistency Analysis.
F = Final Finding.
FS = Supplement to Final Finding and/or Notice of Sale and Terms.
N = Notice of Sale and Terms
S = Sale.
Public Process
11/6/06
www.dog.dnr.state.ak.us

Summary of State Competitive Lease Sales

Sale Date	Sale	Sale Area	Acres Offered	Acres Leased	Percent Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received	Bid Variable	Fixed Terms
12/10/1959	1	Cook Inlet	88,055	77,191	87.66%	$52.08	37	31	$4,020,342	Bonus; No Min	12.5% Royalty
7/13/1960	2	Cook Inlet	17,568	16,506	93.96%	$24.70	27	26	$407,655	Bonus; No Min	12.5% Royalty
12/7/1960	3	Mixed	73,048	22,867	31.30%	$1.54	26	9	$35,325	Bonus; No Min	12.5% Royalty
1/25/1961	4	Cook Inlet	400	400	100.00%	$679.04	3	3	$271,614	Bonus; No Min	12.5% Royalty
5/23/1961	5	Mixed	97,876	95,980	98.06%	$74.71	102	99	$7,170,465	Bonus; No Min	12.5% Royalty
8/4/1961	6	Gulf Ak	13,257	13,257	100.00%	$8.35	6	6	$110,672	Bonus; No Min	12.5% Royalty
12/19/1961	7	Mixed	255,708	187,118	73.18%	$79.43	68	53	$14,863,049	Bonus; No Min	12.5% Royalty
4/24/1962	8	Cook Inlet	1,062	1,062	100.00%	$4.80	8	8	$5,097	Bonus; No Min	12.5% Royalty
7/11/1962	9	Mixed	315,669	264,437	83.77%	$59.42	89	76	$15,714,113	Bonus; No Min	12.5% Royalty
5/8/1963	10	Cook Inlet	167,583	141,491	84.43%	$29.23	200	158	$4,136,225	Bonus; No Min	12.5% Royalty
12/11/1963	12	Cook Inlet	346,782	247,089	71.25%	$12.31	308	207	$3,042,681	Bonus; No Min	12.5% Royalty
12/9/1964	13	Mixed	1,194,373	721,224	60.39%	$7.68	610	341	$5,537,100	Bonus; No Min	12.5% Royalty
7/14/1965	14	North Slope	754,033	403,000	53.45%	$15.25	297	159	$6,145,473	Bonus; $1/acre Min	12.5% Royalty
9/28/1965	15	Cook Inlet	403,042	301,751	74.87%	$15.49	293	216	$4,674,344	Bonus; $1/acre Min	12.5% Royalty
7/19/1966	16	Mixed	184,410	133,987	72.66%	$52.55	205	153	$7,040,880	Bonus; $1/acre Min	12.5% Royalty
11/22/1966	17	Cook Inlet	19,230	18,590	96.67%	$7.33	36	35	$136,280	Bonus; $1/acre Min	12.5% Royalty
1/24/1967	18	Mixed	47,729	43,657	91.47%	$33.90	23	20	$1,479,906	Bonus; $1/acre Min	12.5% Royalty
3/28/1967	19	Kachemak Bay	2,560				RULED INVALID 12/9/74				
7/25/1967	20	Cook Inlet	311,250	256,447	82.39%	$73.14	295	220	$18,757,341	Bonus; $1/acre Min	12.5% Royalty
3/26/1968	21	AK Peninsula	346,623	164,961	47.59%	$18.24	308	147	$3,009,224	Bonus; $1/acre Min	12.5% Royalty
10/29/1968	22	Cook Inlet	111,199	60,272	54.20%	$17.29	230	125	$1,042,220	Bonus; No Min	12.5% Royalty
9/10/1969	23	North Slope	450,858	412,548	91.50%	$2,181.66	179	164	$900,041,605	Bonus; No Min	12.5% Royalty
5/12/1971	24	Cook Inlet	196,635	92,618	47.10%	$4.92	244	106	$455,641	Bonus; No Min	12.5% Royalty
9/26/1972	25	Cook Inlet	325,401	178,245	54.78%	$7.43	259	152	$1,324,673	Bonus; No Min	12.5% Royalty
12/11/1972	26	Cook Inlet	399,921	177,973	44.50%	$8.75	218	105	$1,557,849	Bonus; No Min	12.5% Royalty
5/9/1973	27	Cook Inlet	308,401	113,892	36.93%	$9.92	210	96	$1,130,325	Bonus; No Min	12.5% Royalty
12/13/1973	28	Cook Inlet	166,648	97,804	58.69%	$253.77	98	62	$24,819,190	Bonus; No Min	16.67% Royalty
10/23/1974	29	Cook Inlet	278,269	127,120	45.68%	$8.19	164	82	$1,040,910	Bonus; No Min	16.67% Royalty
7/24/1979	29B	Copper River	34,678	34,678	100.00%	$4.56	20	20	$158,042	Bonus; No Min	20% Royalty
12/12/1979	30	Beaufort Sea	341,140	296,308	86.86%	$1,914.87	71	62	$567,391,497	Net Profit Share (NPS)	20% Royalty; $850 & $1750/acre
9/16/1980	31	North Slope	196,268	196,268	100.00%	$63.12	78	78	$12,387,470	Bonus; No Min	20% Royalty; 30% NPS
5/13/1981	33	Cook Inlet	815,000	429,978	52.76%	$10.00	202	103	$4,299,782	Royalty; 20% Min	$10/acre Bonus
8/25/1981	32	Cook Inlet	202,837	152,428	75.15%	$10.00	78	59	$1,524,282	Royalty; 20% Min	$10/acre Bonus
2/2/1982	35	Cook Inlet	601,172	131,191	21.82%	$10.00	149	31	$1,311,907	Royalty; 12.5% Min	$10/acre Bonus
5/26/1982	36*	Beaufort Sea	56,862	56,862	100.00%	$573.02	13	13	$32,583,452	Bonus; No Min	12.5% Royalty & 40% NPS
8/24/1982	37*	Copper River	852,603	168,849	19.80%	$3.33	217	33	$562,944	Bonus; No Min	12.5% Royalty & 30% NPS
8/24/1982	37A	Cook Inlet	1,875	1,875	100.00%	$52.00	1	1	$97,479	Bonus; No Min	43% Royalty
9/28/1982	34*	North Slope	1,231,517	571,954	46.44%	$46.70	261	119	$26,713,018	Bonus; No Min	Royalty:16.67%-40%NPS; 12.5%-30%NPS
5/17/1983	39*	Beaufort Sea	211,988	211,988	100.00%	$99.05	42	42	$20,998,101	Bonus; $10/acre Min	12.5% Royalty & 30% or 40% NPS
9/28/1983	40	Cook Inlet	1,044,745	443,355	42.44%	$7.17	284	140	$3,177,178	Bonus; $1/acre Min	12.5% Royalty
5/22/1984	43	Beaufort Sea	298,074	281,784	94.53%	$114.32	69	66	$32,214,794	Bonus; $10/acre Min	16.67% Royalty
5/22/1984	43A*	North Slope	76,079	76,079	100.00%	$125.44	15	15	$1,612,583	Bonus; $10/acre Min	12.5% Royalty & 30% NPS
9/18/1984	41	Bristol Bay	1,437,930	278,939	19.40%	$3.03	308	63	$843,965	Bonus; No Min	12.5% Royalty
2/26/1985	46A	Cook Inlet	248,585	190,042	76.45%	$13.28	65	50	$2,523,334	Bonus; $1/acre Min	12.5% & 16.67% Royalty
9/24/1985	45A	North Slope	606,385	164,885	27.19%	$28.25	113	32	$4,657,478	Bonus; $5/acre Min	16.67% Royalty
9/24/1985	47	North Slope	192,569	182,560	94.80%	$63.79	50	48	$11,645,003	Bonus; $5/acre Min	12.5% Royalty
2/25/1986	48	North Slope	526,101	266,736	50.70%	$9.16	104	54	$2,444,342	Bonus; $5/acre Min	12.5% Royalty
2/25/1986	48A	Beaufort Sea	42,053	42,053	100.00%	$12.13	11	11	$510,255	Bonus; $5/acre Min	12.5% Royalty
6/24/1986	49	Cook Inlet	1,189,100	394,881	33.21%	$2.40	260	98	$947,171	Bonus; $1/acre Min	12.5% & 16.67% Royalty
1/27/1987	51	North Slope	592,142	100,632	16.99%	$2.88	119	26	$289,625	Bonus; $2/acre Min	12.5% Royalty
6/30/1987	50	Beaufort Sea	118,147	118,147	100.00%	$56.05	35	35	$6,621,723	Bonus; $5/acre Min	16.67% Royalty
1/26/1988	54*	North Slope	421,809	338,687	80.29%	$13.83	89	72	$4,683,388	Bonus; $5/acre Min	12.5% Royalty
9/28/1988	55	Beaufort Sea	201,707	96,632	47.91%	$152.13	56	25	$14,700,602	Bonus; $10&$25/ac Min	12.5% & 16.67% Royalty
9/28/1988	69A	North Slope	775,555	368,490	47.51%	$16.61	155	75	$6,119,135	Bonus; $5/acre Min	12.5% Royalty
1/24/1989	52	Beaufort Sea	175,981	52,463	29.81%	$33.12	43	15	$1,737,513	Bonus; $10/acre Min	12.5% Royalty
1/24/1989	72A	North Slope	677	677	100.00%	$671.90	1	1	$454,977	Bonus; $10/acre Min	12.5% Royalty
1/29/1991	67A*	Cook Inlet	549,364	191,588	34.87%	$28.77	140	55	$5,511,338	Bonus; $5/acre Min	12.5% Royalty
1/29/1991	70A*	North Slope	532,153	420,568	79.03%	$65.88	135	109	$27,707,541	Bonus; $5/acre Min	12.5% Royalty
6/4/1991	64	North Slope	754,542	34,143	4.52%	$7.10	141	6	$242,389	Bonus; $5/acre Min	12.5% Royalty
6/4/1991	65*	Beaufort Sea	491,091	172,865	35.20%	$40.46	108	36	$6,993,949	Bonus; $5/acre Min	16.67% Royalty
9/24/1991	74A*	Cook Inlet	605,851	26,605	4.39%	$12.06	134	5	$320,853	Bonus; $5/acre Min	12.5% Royalty

*Economic Incentive Credits were offered for these sales.

SUMMARY OF STATE COMPETITIVE LEASE SALES (cont)

Sale Date	Sale	Sale Area	Acres Offered	Acres Leased	Percent Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received	Bid Variable	Fixed Terms
1/22/1992	61	North Slope	991,087	260,550	26.29%	$9.32	181	46	$2,429,551	Bonus; $5/acre Min	12.5% Royalty
6/2/1992	68	Beaufort Sea	153,445	0	0.00%	$0.00	36	0	$0	Bonus; $10/acre Min	12.5% Royalty
12/8/1992	75	North Slope	217,205	124,832	57.47%	$78.11	90	55	$9,750,111	Bonus; $10/acre Min	Royalty: State =12.5% & ASRC =16.67%
1/26/1993	76	Cook Inlet	393,025	141,504	36.00%	$461.25	86	36	$65,269,167	Bonus; $5/acre Min	12.5% Royalty
1/26/1993	67 A-W	Cook Inlet	282,577	129,810	45.94%	$18.75	69	33	$2,433,864	Bonus; $5/acre Min	12.5% Royalty
5/25/1993	77	North Slope	1,260,146	45,727	3.63%	$25.47	228	8	$1,164,555	Bonus; $5/acre Min	12.5% Royalty
5/25/1993	70 A-W	North Slope	37,655	28,055	74.51%	$48.41	11	8	$1,358,027	Bonus; $10/acre Min	12.5% Royalty
9/21/1993	57	North Slope	1,033,248	0	0.00%	$0.00	196	0	$0	Bonus; $5/acre Min	12.5% Royalty
9/21/1993	75A	North Slope	14,343	14,343	100.00%	$31.36	11	11	$449,847	Bonus; $10/acre Min	16.67% Royalty
10/30/1994	78	Cook Inlet	396,760	136,307	34.36%	$12.14	90	34	$1,654,137	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	67A-W2	Cook Inlet	152,768	13,804	9.04%	$7.29	36	3	$100,638	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	74W	Cook Inlet	66,703	17,015	25.51%	$31.76	16	4	$540,406	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	76W	Cook Inlet	251,614	14,220	5.65%	$5.61	50	4	$79,722	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	78W	Cook Inlet	260,453	36,478	14.01%	$7.06	56	11	$257,583	Bonus; $5/acre Min	12.5% Royalty
12/5/1995	80	North Slope	951,302	151,567	15.93%	$22.02	202	42	$3,337,485	Bonus; $10/acre Min	12.5% Royalty
10/1/1996	86A**	North Slope	15,484	5,901	38.11%	$343.40	13	5	$2,026,247	Bonus; $100/acre Min	16.67%&16.67-33.33% Sliding Scale Rylty
12/18/1996	85A	Cook Inlet	1,061,555	173,503	16.33%	$17.92	234	44	$3,109,603	Bonus; $5/acre Min	12.5% Royalty
11/18/1997	86	Beaufort Sea	365,054	323,835	88.70%	$86.42	181	162	$27,985,125	Bonus, $10/acre Min	16.67% Royalty
2/24/1998	85A-W	Cook Inlet	757,878	98,011	12.90%	$8.46	157	24	$828,807	Bonus, $5/acre Min	12.5% Royalty
6/24/1998	87	North Slope	Areawide	518,689	N/A	$99.86	N/A	137	$51,794,173	Bonus, $5/acre Min	12.5% Royalty
2/24/1999	NS 1999	North Slope	Areawide	174,923	N/A	$14.85	N/A	40	$2,596,838	Bonus; $5/acre Min	12.5% Royalty
4/21/1999	CI 1999	Cook Inlet	Areawide	114,514	N/A	$10.75	N/A	41	$1,436,685	Bonus; $5/acre Min	12.5% Royalty
8/16/2000	CI 2000	Cook Inlet	Areawide	100,480	N/A	$9.15	N/A	27	$919,750	Bonus; $5/acre Min	12.5% Royalty
11/15/2000	BS 2000	Beaufort Sea	Areawide	25,840	N/A	$13.13	N/A	11	$338,922	Bonus; $10/acre Min	12.5% & 16.67% Royalty
11/15/2000	NS 2000	North Slope	Areawide	652,355	N/A	$15.41	N/A	145	$10,052,665	Bonus; $5/acre Min	12.5% & 16.67% Royalty
5/9/2001	CI 2001	Cook Inlet	Areawide	102,523	N/A	$9.05	N/A	29	$928,085	Bonus; $5/acre Min	12.5% Royalty
5/9/2001	NSF 2001	NS Foothills	Areawide	858,811	N/A	$11.41	N/A	170	$9,799,277	Bonus; $5/acre Min	12.5% Royalty
10/24/2001	BS 2001	Beaufort Sea	Areawide	36,331	N/A	$94.90	N/A	24	$3,447,734	Bonus; $10/acre Min	12.5% & 16.67% Royalty
10/24/2001	NS 2001	North Slope	Areawide	434,938	N/A	$15.89	N/A	146	$6,911,572	Bonus; $5/acre Min	12.5% & 16.67% Royalty
5/1/2002	CI 2002	Cook Inlet	Areawide	64,923	N/A	$7.05	N/A	21	$421,841	Bonus; $5/acre Min	12.5% Royalty
5/1/2002	NSF 2002‡	NS Foothills	Areawide	213,374	N/A	$14.32	N/A	51	$2,889,532	Bonus; $5/acre Min	12.5% Royalty
10/24/2002	BS 2002	Beaufort Sea	Areawide	19,226	N/A	$26.34	N/A	15	$506,405	Bonus; $10&$100/ac Min	12.5%, 16.67% & 20% Royalty
10/24/2002	NS 2002	North Slope	Areawide	32,315	N/A	$17.94	N/A	12	$579,728	Bonus; $10/acre Min	12.5%,16.67%&16.67-33.33% Sliding Scale Rylty
5/7/2003	CI 2003	Cook Inlet	Areawide	73,869	N/A	$9.34	N/A	27	$689,949	Bonus; $5/acre Min	12.5% Royalty
5/7/2003	NSF 2003	NS Foothills	Areawide	5,760	N/A	$6.35	N/A	1	$36,576	Bonus; $5/acre Min	12.5% Royalty
10/29/2003	BS 2003	Beaufort Sea	Areawide	36,995	N/A	$36.71	N/A	20	$1,358,187	Bonus; $5 & $10/ac Min	12.5 % & 16.67% Royalty
10/29/2003	NS 2003**	North Slope	Areawide	210,006	N/A	$17.08	N/A	75	$3,586,400	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
5/19/2004	CI 2004*	Cook Inlet	Areawide	227,475	N/A	$7.33	N/A	72	$1,667,967	Bonus; $5/acre Min	12.5% Royalty
5/19/2004	NSF 2004	NS Foothills	Areawide	19,796	N/A	$5.37	N/A	5	$106,305	Bonus; $5/acre Min	12.5% Royalty
10/27/2004	BS 2004	Beaufort Sea	Areawide	113,570	N/A	$36.90	N/A	28	$4,190,782	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
10/27/2004	NS 2004**	North Slope	Areawide	197,916	N/A	$38.40	N/A	57	$7,599,193	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
5/18/2005	CI 2005*	Cook Inlet	Areawide	174,661	N/A	$5.98	N/A	55	$1,044,661	Bonus; $5/acre Min	12.5% Royalty
5/18/2005	NSF 2005	NS Foothills	Areawide	55,505	N/A	$5.76	N/A	12	$319,959	Bonus; $5/acre Min	12.5% Royalty
10/26/2005	AK PEN 2005	Alaska Peninsula	Areawide	190,494	N/A	$6.03	N/A	37	$1,149,253	Bonus; $5/acre Min	12.5% Royalty
3/1/2006	BS 2006	Beaufort Sea	Areawide	204,260	N/A	$63.27	N/A	62	$7,685,032	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
3/1/2006	NS 2006	North Slope	Areawide	564,600	N/A	$27.88	N/A	145	$15,741,677	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
5/24/2006	CI 2006***	Cook Inlet	Areawide	364,160	N/A	$13.19	N/A	71	$4,802,650	Bonus; $10/acre Min	12.5% Royalty
5/24/2006	NSF 2006***	NS Foothills	Areawide	246,400	N/A	$7.50	N/A	45	$1,849,229	Bonus; $5/acre Min	12.5% Royalty
10/25/2006	BS 2006A***	Beaufort Sea	Areawide	33,280	N/A	$20.57	N/A	13	$684,723	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
10/25/2006	NS 2006A***	North Slope	Areawide	177,280	N/A	$14.27	N/A	44	$2,530,534	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
TOTAL: 111 Sales				**18,827,405**		**$111.67**		**6,625**	**$2,102,398,466**		

* Economic Incentive Credits were offered for these sales.
** Sale 86A: State received $259,435; ASRC received $1,766,812
‡ NSF 2002 Bonus does not include 20% of Bonus bid ($1.25 million) retained by the state for relinquished tracts.
** NS 2003: State received $3,546,578; ASRC received $39,822.
** NS 2004: State received $7,496,152; ASRC received $103,040
*** Acres Leased, Average $/Acre, and Bonus Received are preliminary figures.

Exploration Licensing

Mat-Su coring program
C. Ruff

Exploration licenses are designed to stimulate exploration in Alaska's frontier basins and complement the state's areawide leasing program. All acreage subject to the state's competitive areawide leasing program remains off limits to exploration licensing.

Several large sedimentary basins, however, exist within Interior Alaska, some of which are virtually unexplored. The highly variable structural geology of these basins offers the potential for structural traps in overthrust belts and strike slip systems. Various types of clastic and carbonate stratigraphic traps may also be present. Exploration licensing allows companies to explore these frontier basins with minimal costs added by the state.

Susitna basin aeromagnetic survey
K. Dirks

Licensing Process

An area selected for exploration licensing must be between 10,000 and 500,000 acres. The licensing process is initiated in one of two ways:

- Each year during the month of April, applicants may submit to the commissioner a proposal to conduct exploratory activity within an area they have specified; or
- The commissioner can, at any time, issue a notice requesting proposals to explore an area designated by the commissioner. Once a request for proposals has been issued, applicants will have 20 days to notify the commissioner of their intent to submit a proposal, and 60 days to submit the proposal.

Submitted proposals must: (1) describe the area proposed to be subject to the license; (2) state the specific minimum work commitment expressed in dollars; (3) describe the amount and form of security to be posted based on the projected cost of the planned exploration work; (4) propose the term of the license (unless already established by the commissioner); and (5) verify that a prospective licensee meets minimum qualifications.

Within 30 days of receiving any proposal, the commissioner will either reject it in a written decision or give public notice of the intent to evaluate the proposal's acceptability. This notice will solicit public comments on the proposal(s) and request competing proposals. The commissioner may also modify any proposal and request a new one based on those modifications.

After considering all submitted proposals and public comment on those proposals, the commissioner will issue a written finding determining whether granting the exploration license is in the state's best interests. The finding must describe the limitations, conditions, stipulations, or changes from the initiating proposal or competing proposals that are required to make the issuance of the license conform to the best interests of the state. If only one proposal was submitted, the finding must also identify the prospective licensee.

If the finding concludes that an exploration license should be awarded and there has only been a single applicant, that applicant will have 30 days after issuance of the finding to execute the license. If competing proposals are submitted and the commissioner determines that an exploration license should be awarded, the successful licensee will be determined by a sealed bid process, with the license awarded to the applicant who has committed the most dollars to an exploration program.

The recipient of a license must post a bond in the amount of the work commitment and pay a $1 per acre license fee. There are no additional charges during the term of the license, which can be up to 10 years. During its term, and following satisfaction of the required work commitment, any portion of the licensed area may be converted to oil and gas leases. The term of the leases can extend beyond the original term of the license. If converted, annual lease rentals are set at $3 per acre.

Relinquishment of Lands

If by the fourth anniversary of the exploration license the licensee has completed less than 25 percent of the total work commitment, the license will be terminated, with the remainder of the security forfeited to the state. If the licensee has completed less than 50 percent of the total work, 25 percent of the licensed area will be relinquished, with an additional 10 percent relinquished each successive year until half of the original acreage has been relinquished.

Current Exploration Licenses and Pending Applications

The state has issued four exploration licenses covering 1.66 million acres and has received applications for three other areas.

Licenses Issued:

Copper River

Licensee:	Forest Oil Corporation
Size:	318,756.35 Acres
Exploration Commitment:	$1,420,000
Term:	5 years
Effective Date:	October 1, 2000
Status:	Lease conversion pending

Nenana Basin

Licensee:	Andex Resources
Size:	483,942 Acres
Exploration Commitment:	$2,525,000
Term:	7 years
Effective Date:	October 1, 2002
Status:	Active; work commitment has been met.

Susitna Basin I

Licensee:	Forest Oil Corporation
Size:	386,204 Acres
Exploration Commitment:	$2,520,000
Term:	7 years
Effective Date:	November 1, 2003
Status:	Active

Susitna Basin II

Licensee:	Forest Oil Corporation
Size:	471,474 Acres
Exploration Commitment:	$3,000,000
Term:	7 years
Effective Date:	November 1, 2003
Status:	Active

License Not Executed by Licensee:

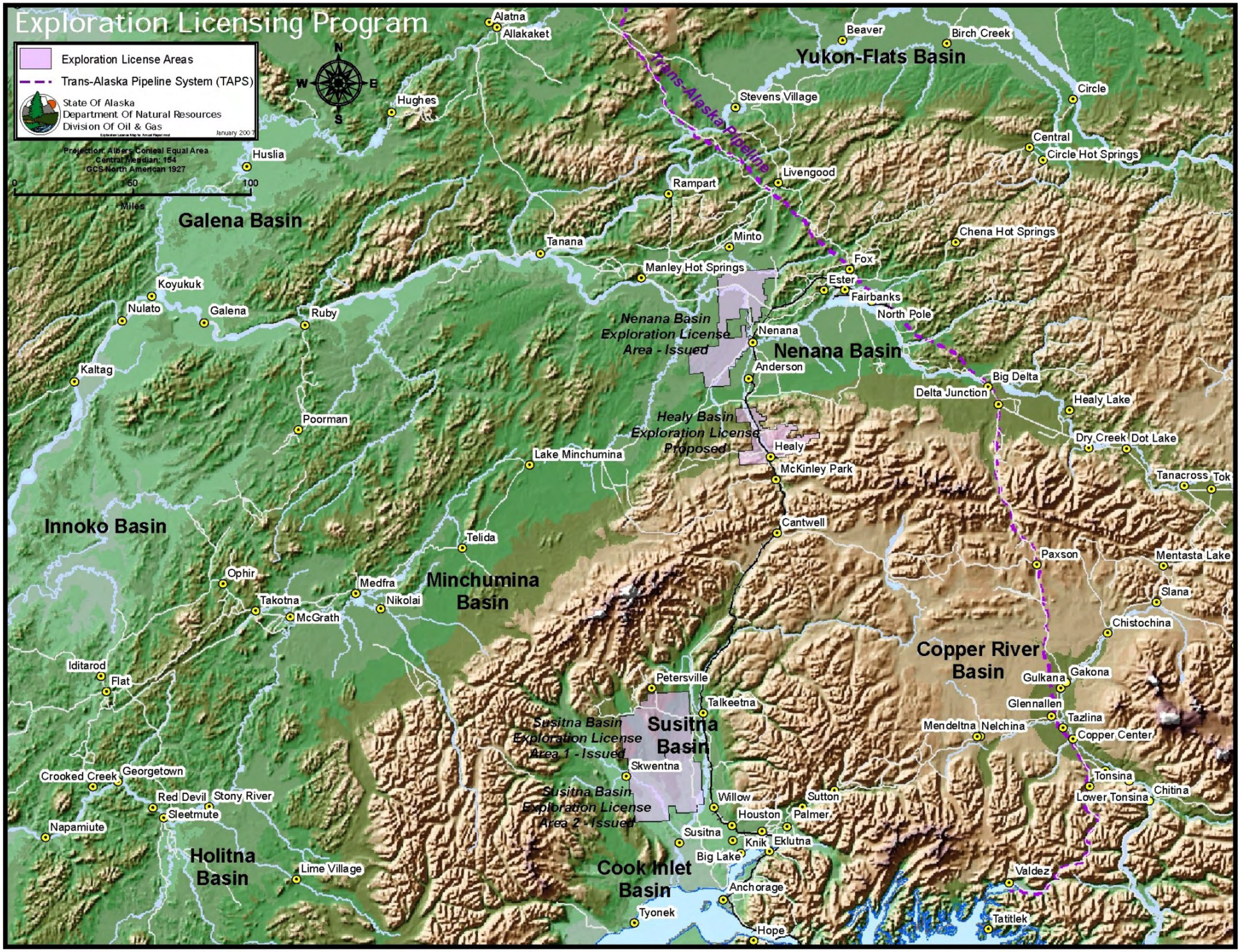
Bristol Bay (Proposed)

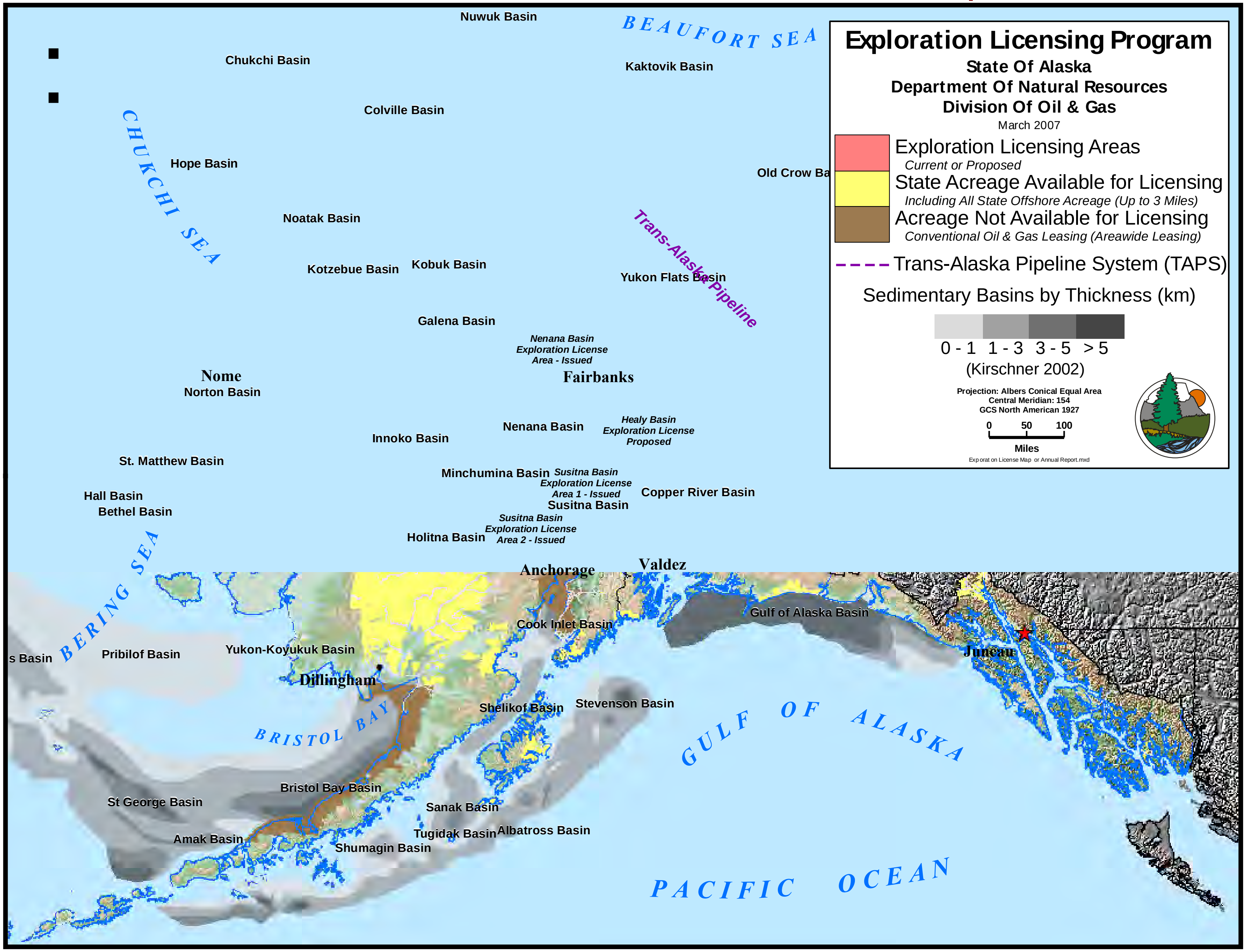
Licensee:	Bristol Shores LLC
Size:	329,113 Acres
Exploration Commitment:	$3,200,000
Term:	7 years
Status:	License Issued but not executed by Licensee; file closed

License Application and Best Interest Finding Pending:

Healy Basin (Proposed)

Licensee:	Usibelli Coal Mine, Inc.


Exploration Licensing Program
Exploration License Areas
Trans-Alaska Pipeline System (TAPS)
State Of Alaska
Department Of Natural Resources
Division Of Oil & Gas
January 2007
Projection: Albers Conical Equal Area
Central Meridian: 154
GCS North American 1927
0
50
100
Miles
N
S
E
W
Galena Basin
Yukon-Flats Basin
Nenana Basin
Nenana Basin Exploration License Area - Issued
Healy Basin Exploration License Proposed
Innoko Basin
Minchumina Basin
Copper River Basin
Susitna Basin
Susitna Basin Exploration License Area 1 - Issued
Susitna Basin Exploration License Area 2 - Issued
Holitna Basin
Cook Inlet Basin
Trans-Alaska Pipeline
Alatna
Allakaket
Hughes
Huslia
Beaver
Birch Creek
Stevens Village
Circle
Central
Circle Hot Springs
Livengood
Rampart
Tanana
Minto
Chena Hot Springs
Manley Hot Springs
Fox
Ester
Fairbanks
North Pole
Koyukuk
Nulato
Galena
Ruby
Nenana
Anderson
Kaltag
Big Delta
Delta Junction
Healy Lake
Poorman
Healy
McKinley Park
Lake Minchumina
Dry Creek
Dot Lake
Tanacross
Tok
Cantwell
Telida
Paxson
Mentasta Lake
Ophir
Medfra
Takotna
Nikolai
McGrath
Slana
Chistochina
Iditarod
Flat
Petersville
Talkeetna
Gulkana
Gakona
Glennallen
Tazlina
Mendeltna
Nelchina
Copper Center
Skwentna
Crooked Creek
Georgetown
Red Devil
Stony River
Sleetmute
Napamiute
Willow
Sutton
Houston
Palmer
Susitna
Knik
Eklutna
Tonsina
Lower Tonsina
Chitina
Big Lake
Lime Village
Anchorage
Valdez
Tyonek
Hope
Tatitlek



Exploration Licensing Program
State Of Alaska
Department Of Natural Resources
Division Of Oil & Gas
March 2007
Exploration Licensing Areas
Current or Proposed
State Acreage Available for Licensing
Including All State Offshore Acreage (Up to 3 Miles)
Acreage Not Available for Licensing
Conventional Oil & Gas Leasing (Areawide Leasing)
Trans-Alaska Pipeline System (TAPS)
Sedimentary Basins by Thickness (km)
0 - 1 1 - 3 3 - 5 > 5
(Kirschner 2002)
Projection: Albers Conical Equal Area
Central Meridian: 154
GCS North American 1927
0 50 100
Miles
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
BRISTOL BAY
GULF OF ALASKA
PACIFIC OCEAN
Trans-Alaska Pipeline
Nuwuk Basin
Chukchi Basin
Kaktovik Basin
Colville Basin
Hope Basin
Old Crow Ba
Noatak Basin
Kotzebue Basin
Kobuk Basin
Yukon Flats Basin
Galena Basin
Nenana Basin Exploration License Area - Issued
Nome
Norton Basin
Fairbanks
Nenana Basin
Healy Basin Exploration License Proposed
Innoko Basin
St. Matthew Basin
Minchumina Basin
Susitna Basin Exploration License Area 1 - Issued
Copper River Basin
Susitna Basin
Hall Basin
Bethel Basin
Susitna Basin Exploration License Area 2 - Issued
Holitna Basin
Anchorage
Valdez
Gulf of Alaska Basin
Cook Inlet Basin
s Basin
Pribilof Basin
Yukon-Koyukuk Basin
Juneau
Dillingham
Shelikof Basin
Stevenson Basin
Bristol Bay Basin
St George Basin
Sanak Basin
Tugidak Basin
Albatross Basin
Amak Basin
Shumagin Basin

Exploration Incentive Credit (EIC) and Tax Credit Programs

AS 38.05.180(i): Exploration Incentive Credit

This EIC may be included as a term of an oil and gas lease. AS 38.05.18(i) provides for a system in which a lessee drilling an exploratory well on state-owned land may earn credits depending on the footage drilled and the region in which the well is located. If demonstrated by the lessee as necessary, confidentiality may be extended. The statute also provides for an EIC for geophysical work on state land if that work is performed during the two seasons immediately preceding an announced lease sale and is on land included within the sale area. The geophysical information obtained is made public after the sale. A credit may not exceed 50 percent of the costs of the drilling or geophysical work. Credits may be applied against state royalty and rental payments or taxes, or they may be assigned. Since the state began offering this program, lessees have earned $54.7 million in credits for exploratory drilling.

AS 41.09.010: Exploration Incentive Credit

This EIC, adopted in 1994, allows the commissioner to grant an EIC for exploratory drilling, the drilling of a stratigraphic test well, and for geophysical work on land in the state, regardless of whether the minerals are state-owned. This program is designed to encourage oil and gas exploration within remote parts of the state and to provide a means for the state to obtain exploration data from federal, private, and Native corporation lands. As with the Title 38 program, the credits may be applied against oil and gas royalties, rentals, lease sale bonus bids and taxes, or they may be assigned. Drilling data will be kept confidential for two years, with no extension. Copies of geophysical data may be shown to interested parties by the state, but may not be transferred to third parties. Credits may be as high as 50 percent of eligible costs if performed on state land, and as high as 25 percent when performed on federal or private land. A credit may not exceed $5 million per eligible project, and the total of all credits issued under this program may not exceed $30 million. Drilling credits are based upon the footage (measured depth) drilled. All activity qualifying for this EIC must be completed by July 1, 2007.

AS 43.55.025: Oil and Gas Exploration Tax Credit

This program, adopted in 2003, allows for a production tax credit of 20 percent of the cost of an exploratory well if the bottom hole location is three or more miles from the bottom hole location of a pre-existing well that was spud more than 150 days, but less than 35 years, prior to the spud date of the eligible exploration well. The program also allows for an additional production tax credit of 20 percent of the cost of an exploratory well if the bottom hole location is 25 miles or more from the boundary of any unit under a plan of development as of July 1, 2003. The program also offers seismic exploration tax credits of 40 percent of eligible costs for those portions of activities outside of a unit that is under a plan of development or plan of exploration. Seismic data qualifying for this credit will be held confidential for 10 years and 30 days. This tax credit is transferable. This program only applies to exploration expenditures incurred prior to July 1, 2007, for the North Slope, or July 1, 2010, for elsewhere. Expenses qualifying for credits under this tax program cannot be claimed as qualified capital expenditures under AS 43.55.011 (Petroleum Profits Tax, discussed below).

Imnaitchiak Cherts
P. Decker

AS 43.20.043: Gas Exploration and Development Tax Credit

This program, adopted in 2003, is applicable only to operators and working interest owners engaged in exploration for and development of gas resources and reserves south of 68 degrees north latitude (excludes North Slope and Beaufort Sea). The program allows for a 10 percent tax credit equivalent of qualified capital investments made after June 30, 2003, and 10 percent of the annual cost of activity in the state during each tax year. The total allowable yearly tax credit may not exceed 50 percent of the taxpayer's total tax liability. Unused tax credits may be carried forward for up to five years. Credit is transferable only as part of a conveyance, assignment, or transfer of the taxpayer's business. Credit under this program may be used in conjunction with any other credit authorized by AS 43.20, but not for tax credit or royalty modification provided under any other title. This program expires January 1, 2013.

AS 43.55.011: Petroleum Profits Tax

In 2006, the Legislature replaced the oil and gas production tax with a tax based on oil and gas profits. The new regime also includes an additional 20 percent tax credit for certain oil-and gas-related expenses. The expenses that qualify for credits under this tax program are exclusive of the other EIC programs, so an expense cannot qualify for multiple credits. Explorers interested in pursuing these tax credits are encouraged to contact the Alaska Department of Revenue for more information on the program. In addition, the Commercial Section of the Division of Oil and Gas is available to provide information on the application of the program to oil and gas projects.

Royalty Reduction

Since 1995, AS 38.05.180(j) has allowed the commissioner of Natural Resources to adjust the royalty reserved to the state in order to encourage otherwise uneconomic production of oil and gas. If a delineated field or pool has not previously produced, the royalty can be lowered to 5 percent. In an existing producing field or pool, the royalty may be reduced to as low as 3 percent, in order to prolong its economic life as costs per barrel or barrel equivalent increase. In order to establish production of shut-in oil or gas, the royalty may also be reduced to as low as 3 percent. These royalty reduction provisions expire on July 1, 2015.

Discovery Royalty

Alaska law permits the granting of reduced royalty for wells in the Cook Inlet sedimentary basin that have discovered oil or gas in a previously undiscovered oil or gas pool, providing that the wells are capable of producing in paying quantities. The discovery royalty is established at 5 percent for 10 years following the discovery of a pool. The discovery royalty applies to all oil or gas from that pool that is attributable to the lease.

Cook Inlet Royalty Reduction

In 1998, the governor signed legislation granting a 5 percent temporary royalty rate on the first 25 million barrels of oil and the first 35 billion cubic feet of gas produced in the first 10 years of production from six specified fields in the Cook Inlet sedimentary basin. The six fields eligible for royalty reduction were discovered before January 1, 1988 and had been undeveloped or shut in. The fields identified in the law were Falls Creek, Nicolai Creek, North Fork, Point Starichkof, Redoubt Shoal, and West Foreland. Production from these fields had to begin before January 1, 2004, to be eligible for the royalty reduction.

Tree Row
S. Schmitz

Polar Resolution
PTI

Cook Inlet platform
D. Colley

Permitting in Alaska

Lessees and licensees must obtain approval of a detailed plan of operations from the Director, Division of Oil and Gas, before conducting exploration, development, or production activities. A plan of operations must identify the sites for planned activities and the specific measures, design criteria, construction methods, and operational and maintenance standards to be employed. It must also address any potential geophysical hazards that may exist at the site, and must identify how the project complies with the "Mitigation Measures" identified as project requirements in the Final Best Interest Finding for the areawide lease sale or exploration license. Additional measures may be required, based on the enforceable policies of an affected coastal district or the statewide standards of the Alaska Coastal Management Program.

The division's approval process usually includes a 30-day public review and comment period, but can vary depending on the complexity of the project and the environmental sensitivity of the proposed project area. Additional local, state and federal permits may also be required, depending on project location and details.

Gas Storage

Gas storage is a new area of interest in the Cook Inlet basin. Gas storage is used when the rate and timing of production of natural gas does not match the local demand. When production exceeds demand, the gas can be injected back into the ground to be later extracted when demand exceeds production. Depleted gas reservoirs with good seals are ideal candidates for use as gas storage locations. The Division of Oil and Gas has issued two gas storage leases in Cook Inlet at Pretty Creek and Kenai gas fields.

Kenai Storage Well
B. Havelock

Section Two

Oil and Gas Units

North Slope
Northwest
Cook Inlet
Non-Unitized Lease Production
Alaska Fields and Pools

TABLE II.1 OIL & GAS UNITS

NORTH SLOPE	COOK INLET
Arctic Fortitude	Beaver Creek
Badami	Beluga River
Colville River	Birch Hill
Cronus	Cannery Loop
Duck Island	Corsair
Jacob's Ladder	Cosmopolitan
Kuparuk River	Deep Creek
Milne Point	Ivan River
NE Storms	Kasilof
Nikaitchuq	Kenai River
Northstar	Kitchen
Oooguruk	Lewis River
Point Thomson	Lone Creek
Prudhoe Bay	Moquawkie
Rock Flour	Nicolai Creek
Tuvaaq	Nikolaevsk
Whiskey Gulch	Ninilchik
	North Alexander
	North Cook Inlet
	North Fork
NORTHWEST	North Trading Bay
	Pretty Creek
Sakaan	Redoubt
	South Granite Point
	South Middle Ground Shoal
	South Ninilchik
	Sterling
	Stump Lake
	Swanson River
	Three Mile Creek
	Trading Bay
	West McArthur River
	LEASE PRODUCTION
	Granite Point
	Kustatan
	Middle Ground Shoal
	North Trading Bay
	West Foreland
	Wolf Lake

Notes: Unit ownership and acreage figures are current as of February 1, 2007. Some units included in this report terminated in 2006 and some were created in early 2007 as noted in the text.

Ownership percentages for producing units are based on entitlement schedules and may not reflect actual offtake volumes. Ownership percentages for non-producing units are based on leased surface acreage.

Unit acreage figures may differ from previous annual reports because prior years included total leased acres held by the unit, not just acreage within the unit boundary that is reported herein.

This report includes all known oil and gas units in Alaska; however information on units having no State ownership is limited. The State of Alaska is sole royalty owner where royalty ownership is not indicated.

* indicates working interest ownership is aligned over the unit area, except as noted.

Oil and Gas Units

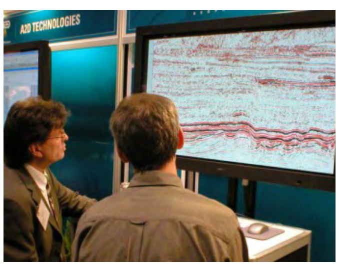
Unitization

Unitization is the grouping or pooling of working interest and royalty ownership in oil and gas leases that overlay a common petroleum reservoir. It is a method for developing an oil or gas pool that maximizes ultimate recovery, prevents economic and physical waste, and protects the rights of all parties with an ownership interest in the accumulation. A unit agreement defines a contractual relationship between the state, the royalty owners, and the working interest owners of the oil and gas leases included in the unit area. When leases are unitized, operators can eliminate redundancy and waste by sharing infrastructure and facilities, splitting development costs, and adopting unified reservoir management plans. Without unitization, competitive development can result in overly dense drilling, rapid loss of reservoir pressure, and undesired production of formation fluids. Unitization minimizes impacts to the environment, protects the value of leases, and ensures efficient and equitable recovery of hydrocarbons. Unitization can optimize value from public resources. The unit agreement entrusts the unit operator with duties, responsibilities, and obligations. A unit operator must be qualified to hold a lease and to fulfill the duties and obligations prescribed in the unit agreement. A performance bond is normally required before commencing drilling operations in Alaska.

Unit Formation

The unitization process begins when lessees identify a prospect or pool. The lessees in the proposed unit area select a unit operator. The unit application includes a plan of exploration and other terms for developing the entire unit area safely and responsibly (11 AAC 83.341). All lessees who hold an interest in the reservoir must be invited to join the unit. The commissioner of the Alaska Department of Natural Resources then publishes a Decision and Finding approving or disapproving the unit application. Unitization extends a lease beyond its initial primary term. After delineation drilling and testing, the unit operator may propose a participating area within the boundaries of the unit.

Osprey Platform
J. Patrick



TGS at North American Prospect Expo 2004

Participating Areas

At least 90 days before sustained production from a reservoir, the unit operator must apply to form a participating area. The participating area may include only those lands that are reasonably estimated to be underlain with hydrocarbons in quantities sufficient to pay well costs (11 AAC 83.351).The unit operator and state agree on a tract allocation schedule for the participating area that divides production shares fairly. An oil and gas unit can have one or more participating areas within its boundaries, depending on the geology of the area. Participating areas are described laterally and limited or defined by depth. The boundaries of the participating area should conform as closely as possible to the boundaries of the oil or gas pool.

Unitization Criteria

The director of the Division of Oil and Gas considers the following criteria when evaluating a unit or participating area application. The application should:

- promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;
- promote the prevention of economic and physical waste; and
- provide for the protection of all parties of interest, including the state.

In evaluating the above criteria, the director considers:

- the environmental costs and benefits of unitized exploration or development;
- the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;
- prior exploration activities in the proposed unit area;
- the applicant's plans for exploration or development of the unit area;
- the economic costs and benefits to the state; and
- any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

Unit Application

Before a 30-day public review of the unit application can begin, it must be complete and include the following:

1) the unit agreement, including exhibits required under 11 AAC 83.341 or 11 AAC 83.343, executed by the proper parties;
2) the unit operating agreement executed by the working-interest owners, which is submitted for information only and does not require the commissioner's approval for adoption or amendment;
3) evidence of reasonable effort made to obtain joinder of any proper party who has refused to join the unit agreement;
4) all pertinent geological, geophysical, engineering, and well data, and interpretations of those data directly supporting the application;
5) an explanation of proposed modifications, if any, of the standard state unit agreement form; and
6) the application fee prescribed by 11 AAC 05.010.

Within 10 days of receipt of a complete application, a public notice initiates a 30-day comment period. The Division of Oil and Gas will issue a decision within 60 days of the close of the comment period.

Plans of Exploration and Development

The unit operator and state must also agree on an initial unit plan of exploration or development 11 AAC 83. In concert with the unit agreement and plans of exploration, development, and operation, a unit operating agreement is drafted describing how expenses and revenues are distributed or paid among the working interest owners in the unit. Unit operators must submit an annual plan of exploration or development for approval (11 AAC 83.341-.343). Often unit areas are explored and developed at the same time. Failure to meet the goals, objectives, and commitments in the plan of exploration or development can result in default and unit termination.

Steelhead Platform
R. Warthen

Alaska has almost 50 units in various stages of exploration, development, production, and post-production field life stages.

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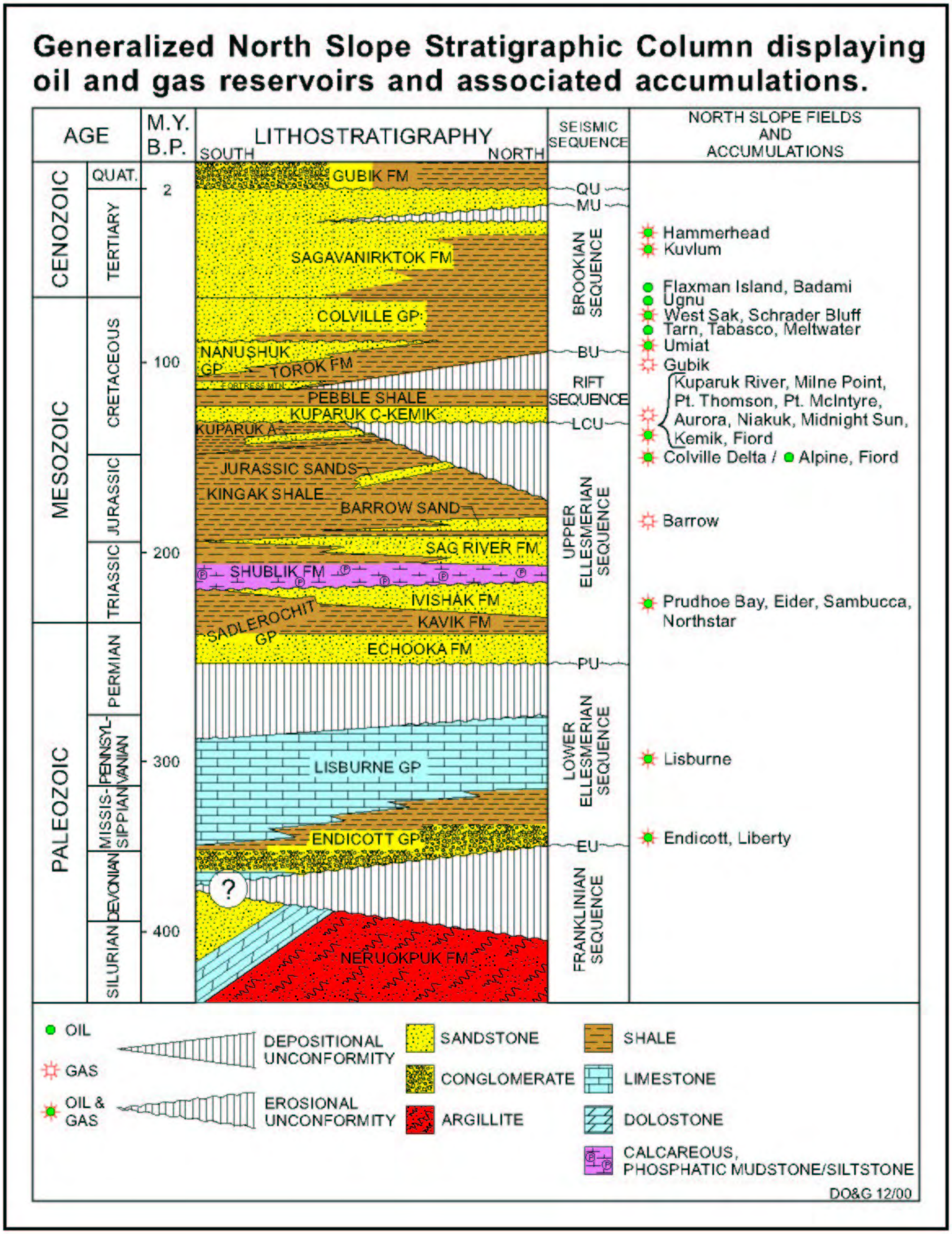
Generalized North Slope Stratigraphic Column



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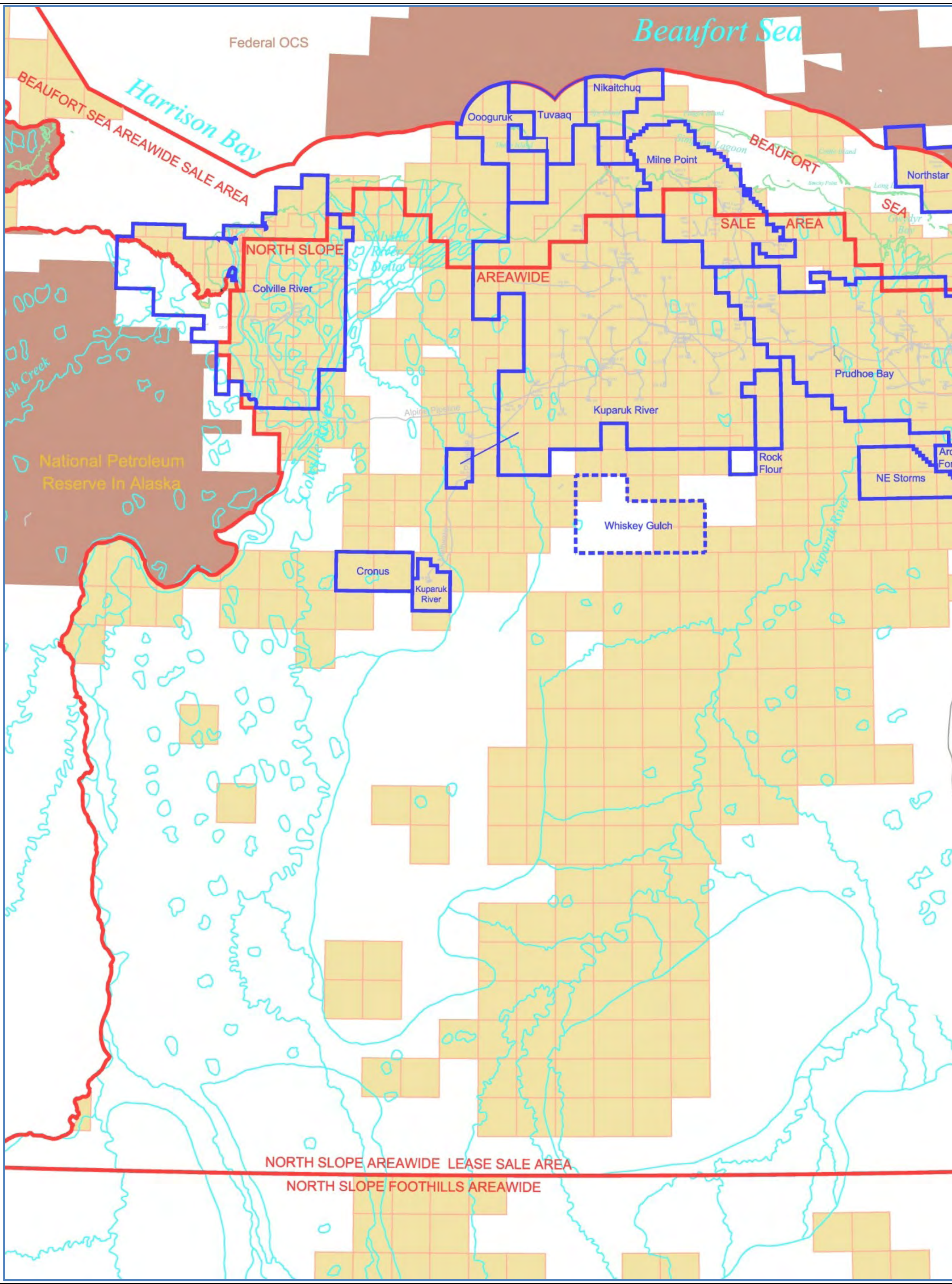
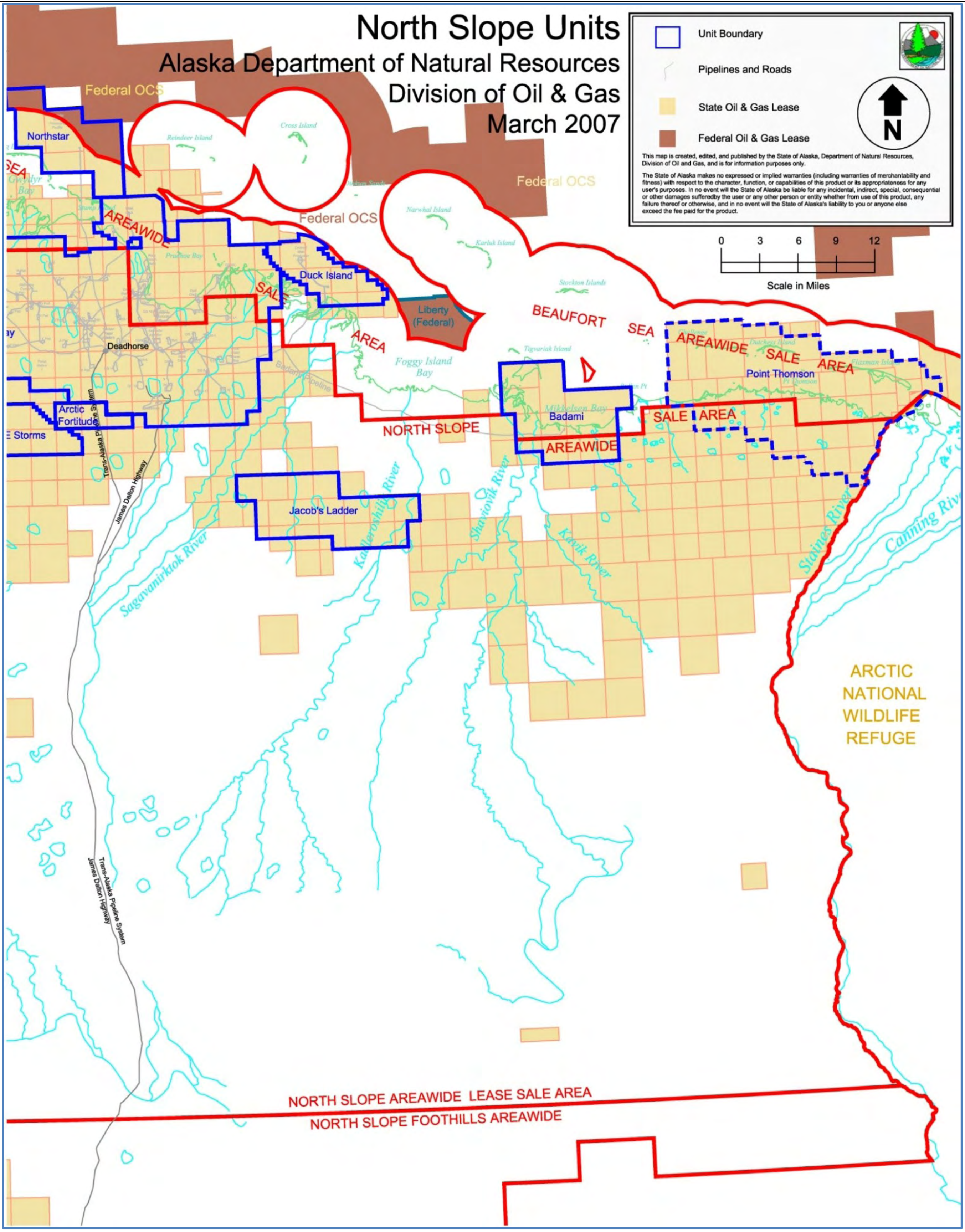
North Slope


Federal OCS
Beaufort Sea
Harrison Bay
BEAUFORT SEA AREAWIDE SALE AREA
Nikaitchuq
Oooguruk
Tuvaaq
Milne Point
BEAUFORT
SEA
SALE
AREA
Northstar
NORTH SLOPE
AREAWIDE
Colville River
Prudhoe Bay
Kuparuk River
Rock Flour
NE Storms
National Petroleum Reserve In Alaska
Whiskey Gulch
Cronus
Kuparuk River
NORTH SLOPE AREAWIDE LEASE SALE AREA
NORTH SLOPE FOOTHILLS AREAWIDE

North Slope


North Slope Units
Alaska Department of Natural Resources
Division of Oil & Gas
March 2007
Unit Boundary
Pipelines and Roads
State Oil & Gas Lease
Federal Oil & Gas Lease
N
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0 3 6 9 12
Scale in Miles
Federal OCS
Federal OCS
Federal OCS
Northstar
Duck Island
Liberty (Federal)
Deadhorse
Arctic Fortitude
Storms
Badami
Point Thomson
Jacob's Ladder
BEAUFORT SEA
Foggy Island Bay
Mikkelsen Bay
AREAWIDE SALE AREA
NORTH SLOPE AREAWIDE
SALE AREA
Sagavanirktok River
Kadleroshilik River
Shaviovik River
Kavik River
Staines River
Canning River
Trans-Alaska Pipeline System
James Dalton Highway
ARCTIC NATIONAL WILDLIFE REFUGE
NORTH SLOPE AREAWIDE LEASE SALE AREA
NORTH SLOPE FOOTHILLS AREAWIDE

North Slope

Arctic Fortitude

Status:	Exploration
Operator:	Alaskan Crude Corporation
Working Interest:	James A. White 79.89%
	James W. White 20.11%
Total Acres:	6,363

Badami
A. Weaver

Badami Unit

Status:	Production
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	BP Exploration (Alaska), Inc. 100%
Total Acres:	37,402
First Production:	1998

Badami Sands PA

Status:	Producing Oil and Gas
Reservoir:	Tertiary Canning Formation
	Badami sandstone (-9,900 ft)

Alpine flare
A. Weaver

Colville River Unit

Status:	Production
Operator:	ConocoPhillips Alaska, Inc.
*Working Interest:	ConocoPhillips Alaska, Inc. 78%
	Anadarko Petroleum Corp. 22%
Total Acres:	127,827
State Acres:	100,844
Royalty Ownership:	State of Alaska
	Arctic Slope Regional Corporation
First Production:	2000

Alpine PA

Status:	Producing Oil and Gas
Reservoir:	Jurassic Kingak Formation,
	Alpine sandstone (-6,850 ft.)

North Slope

Colville River Unit, Cont.

Nanuq Nanuq PA

Status: Producing Oil and Gas
Reservoir: Nanuq sandstone, Cretaceous Torok Fm.
(7,043 ft. and 7,223 ft. md in the Nanuk No.2 well)

Nanuq Kuparuk PA

Status: Producing Oil and Gas
Reservoir: Nanuq Reservoir, Kuparuk sandstone
(7,956 ft. and 7,972 ft. md in the Nanuk No.2 well)


Alpine CD 2 Pad
A. Weaver

Fiord Kuparuk PA

Status: Producing Oil and Gas
Reservoir: Kuparuk sandstone
(6,876 ft. and 6,892 ft.md in the Fiord No.5 well)

Fiord Nechelik PA

Status: Producing Oil and Gas
Reservoir: Nechelik sandstone
(Upper Jurassic Kingak Formation)
(7,021 ft. and 7,172 ft. md in the Fiord No.5 well)

Cronus Unit

Status: Exploration
Operator: Pioneer Natural Resources AK, Inc.
Working Interest: Pioneer Natural Resources AK, Inc. 90%
AVCG LLC 10%
Total Acres: 11,343

North Slope

Duck Island Unit

Endicott MPI
A. Weaver

Status:	Production
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	BP Exploration (Alaska), Inc. 68.39% ExxonMobil AK Production Inc. 20.7% Chevron (Unocal) 10.36% ConocoPhillips Alaska, Inc. 0.02% NANA Regional Corporation, Inc. 0.39% Doyon Ltd. 0.02%
Total Acres:	17,588
First Production:	1994

Eider PA

Status:	Producing Oil and Gas
Reservoir:	Triassic Ivishak Sandstone (-9,700' subsea)
Working Interest:	BP Exploration (Alaska), Inc. 100%

Endicott PA

Status:	Producing Oil and Gas
Reservoir:	Mississippian Kekiktuk Conglomerate (-10,000 ft subsea)
Working Interest:	BP Exploration (Alaska), Inc. 67.92% ExxonMobil AK Production Inc. 21.02% Chevron (Unocal) 10.52% NANA Regional Corporation, Inc. 0.39% ConocoPhillips Alaska, Inc. 0.02% Doyon Ltd. 0.13%

Northstar drill pipe
A. Weaver

Sag Delta North PA

Status:	Producing Oil and Gas
Reservoir:	Triassic Ivishak (-10,000' subsea)
Working Interest:	BP Exploration (Alaska), Inc. 98.13% NANA Regional Corporation, Inc. 1.40% Doyon Ltd. 0.47%

Jacob's Ladder Unit

Status:	Exploration
Operator:	Anadarko Petroleum Corporation
Working Interest:	Anadarko Petroleum Corp. 50% BG Alaska E&P, Inc. 40% Arctic Slope Regional Corporation 10%
Total Acres:	37,982

North Slope

Kuparuk River Unit


Kuparuk Pad
A. Weaver

Status:	Production
Operator:	ConocoPhillips Alaska, Inc.
*Working Interest:	ConocoPhillips Alaska, Inc. 55.04%
	BP Exploration (Alaska), Inc. 39.03%
	Chevron (Unocal) 4.95%
	ExxonMobil AK Production Co. 0.98%
Total Acres:	252,894
First Production:	1981

Kuparuk PA

Status:	Producing Oil and Gas
Reservoir:	Cretaceous Kuparuk Formation (-5,600 ft subsea)

Meltwater PA

Status:	Producing Oil and Gas
Reservoir:	Late Cretaceous Seabee Fm. Bermuda/Cairn sand)

Tabasco PA

Status:	Producing Oil and Gas
Reservoir:	Cretaceous Colville Group Tabasco sand

Tarn PA

Status:	Producing Oil and Gas
Reservoir:	Late Cretaceous Seabee Fm., Bermuda sand (-4,376 to -5,990 ft)


Kuparuk Pad
A. Weaver

West Sak PA

Status:	Producing Oil and Gas
Reservoir:	Cretaceous Colville Group Tabasco sand
Working Interest:	BP Exploration (Alaska), Inc. 68.39%
	ExxonMobil AK Production Inc. 20.7%
	Chevron (Unocal) 10.36%
	ConocoPhillips Alaska, Inc. 0.02%
	NANA Regional Corporation, Inc. 0.39%
	Doyon Ltd. 0.02%

North Slope

Milne Point Unit


Milne Point Unit F-Pad
S. Schmitz

Status: Production
Operator: BP Exploration (Alaska), Inc.
Working Interest: BP Exploration (Alaska), Inc. 100%
Total Acres: 49,668
First Production: 1985

Kuparuk PA

Status: Producing Oil and Gas
1993, BP Cascade #1
Reservoir: Cretaceous Kuparuk Formation
(-7,200 ft subsea)

Schrader Bluff PA

Status: Producing Oil and Gas
Reservoir: Cretaceous Colville Group
Schrader Bluff Fm.

Sag River PA

Status: Producing Oil and Gas
Reservoir: Sag River and Ivishak formations

NE Storms Unit

Status: Exploration
Operator: Pioneer Natural Resources AK, Inc.
Working Interest: Pioneer Natural Resources AK, Inc. 50%
ConocoPhillips Alaska, Inc. 50%
Total Acres: 16,456


Nabors Rig 27E
C. Ruff

Nikaitchuq Unit

Status: Exploration
Operator: ENI Petroleum US LLC
Working Interest: ENI Petroleum US LLC 100%
Total Acres: 12,968

North Slope

Northstar Unit

Northstar Island
S. Schmitz

Status:	Production
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	BP Exploration (Alaska), Inc. 100%
Total Acres:	28,024
State Acres:	17,599
Royalty Ownership:	State of Alaska/United States
First Production:	2001

Northstar PA

Status:	Producing Oil
Reservoir:	Ivishak and Shublik "D" Formations (-11,000 ft. subsea)

Oooguruk Unit

Oooguruk island construction
A. Weaver

Status:	Exploration
Operator:	Pioneer Natural Resources AK, Inc.
Working Interest:	Pioneer Natural Resources, AK 70%
	ENI Petroleum US LLC 30%
Total Acres:	20,394

Point Thomson Unit

Status:	Terminated
Operator:	ExxonMobil
Working Interest:	ExxonMobil 52.58%
	BP Exploration Alaska, Inc. 29.19%
	Chevron U.S.A., Inc. 14.31%
	ConocoPhillips Alaska, Inc. 2.82%
	Others 1.10%
Total Acres:	106,201
	(Unit terminated December 2006)

Badami Sales Line
A. Weaver

North Slope

Prudhoe Bay Unit

Status:	Production
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	ExxonMobil AK Production, Inc. 36.40%
(Aligned for all PA's	ConocoPhillips Alaska, Inc. 36.08%
~December 2001)	BP Exploration (Alaska), Inc. 26.36%
	Chevron U.S.A., Inc. 1.16%
Total Acres:	248,677
First Production:	1977


BPXA I-100
A. Weaver

Aurora PA

Status:	Producing Oil and Gas
Reservoir:	Cretaceous Kuparuk Formation

Borealis PA

Status:	Producing Oil and Gas
Reservoir:	Cretaceous Kuparuk Formation

Gas Cap and Oil Rim Initial PA(IPA)

Status:	Producing Oil
Reservoir:	Triassic Ivishak Sandstone (-8,800 ft subsea)

Lisburne PA

Status:	Producing Oil and Gas
Reservoir:	Mississippian Lisburne Group

Midnight Sun PA

Status:	Producing Oil and Gas
Reservoir:	Cretaceous Kuparuk Formation

Niakuk PA

Status:	Producing Oil and Gas
Reservoir:	Cretaceous Kuparuk Formation (-9,350 ft.)

North Slope

Prudhoe Bay Unit, Cont.

Calista Rig 3
A. Weaver

North Prudhoe Bay PA

Status: Shut-In
Reservoir: Triassic Sadlerochit Group

Orion PA

Status: Producing Oil and Gas
Reservoir: Cretaceous Schrader Bluff Fm (-4,500 ft.ss)

Polaris PA

Status: Producing Oil and Gas
Reservoir: Cretaceous Colville Group, Schrader Bluff Fm.

Point McIntyre PA

Status: Producing Oil and Gas
Reservoir: Cretaceous Kuparuk Formation

Prudhoe Bay Oilfield
A. Motschenbacher

West Beach PA

Status: Suspended
Reservoir: Cretaceous Kuparuk Formation

Western Niakuk PA

Status: Producing Oil and Gas
Reservoir: Cretaceous Kuparuk Formation (-9,350 ft.)

Raven Tract Operation

Status: Producing Oil and Gas
Reservoir: Ivishak and Sag River formations
(10,628 ft. md to 11,165 ft. md in the NK-05 well)

North Slope

Rock Flour Unit

Meter Turbine
S. Schmitz

Status: Exploration
Operator: ENI Petroleum US LLC
Working Interest: ENI Petroleum US LLC 100%
Total Acres: 10,843

Tuvaaq Unit

Status: Exploration
Operator: ENI Petroleum US LLC
Working Interest: ENI Petroleum US LLC 100%
Total Acres: 14,561

Arktos train
S. Schmitz

Whiskey Gulch Unit

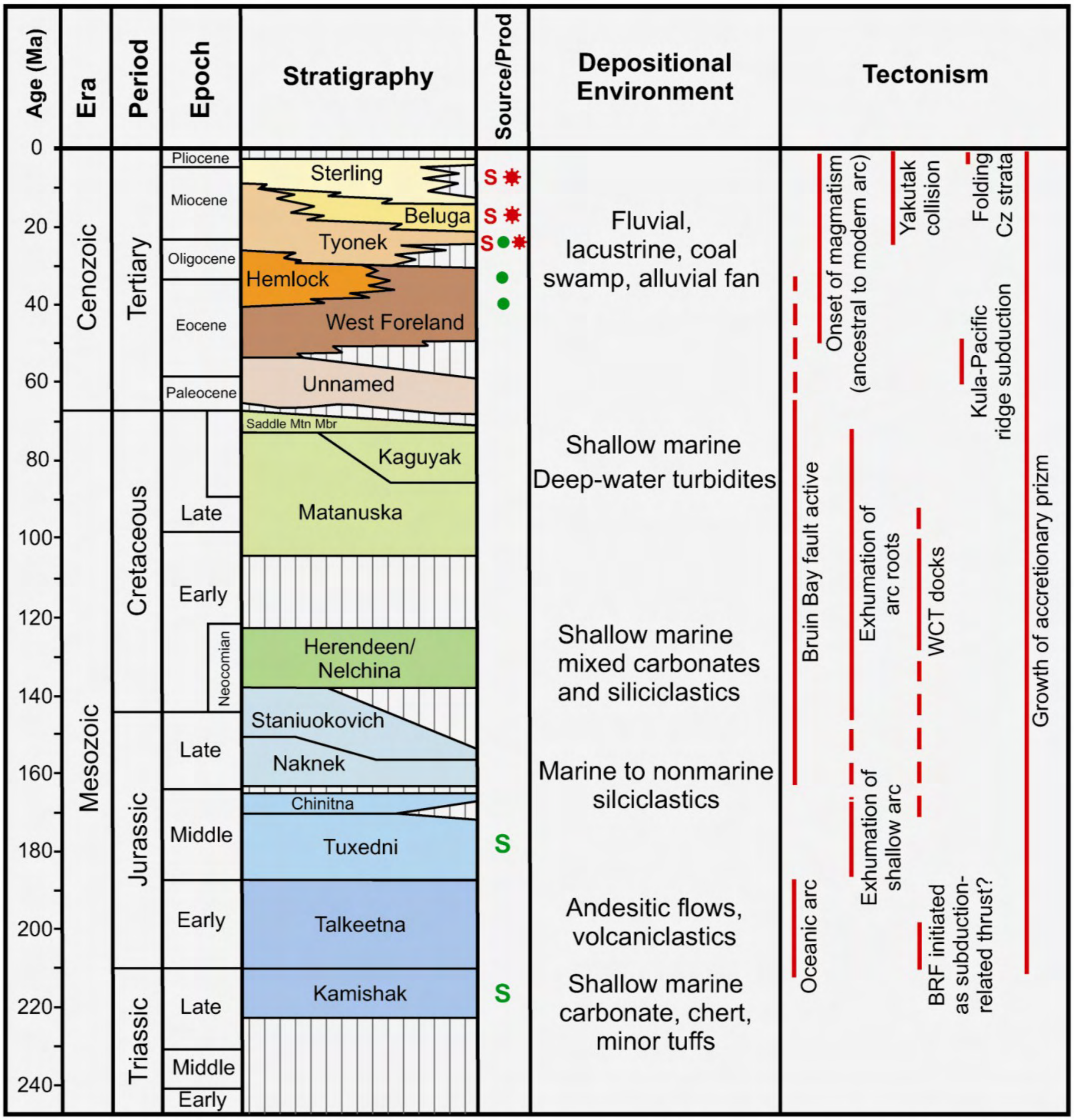
Status: Terminated
Operator: AVCG LLC
Working Interest: AVCG LLC 100%
Total Acres: 30,651
(Unit Terminated November 2006)

Northwest

Sakaan Unit

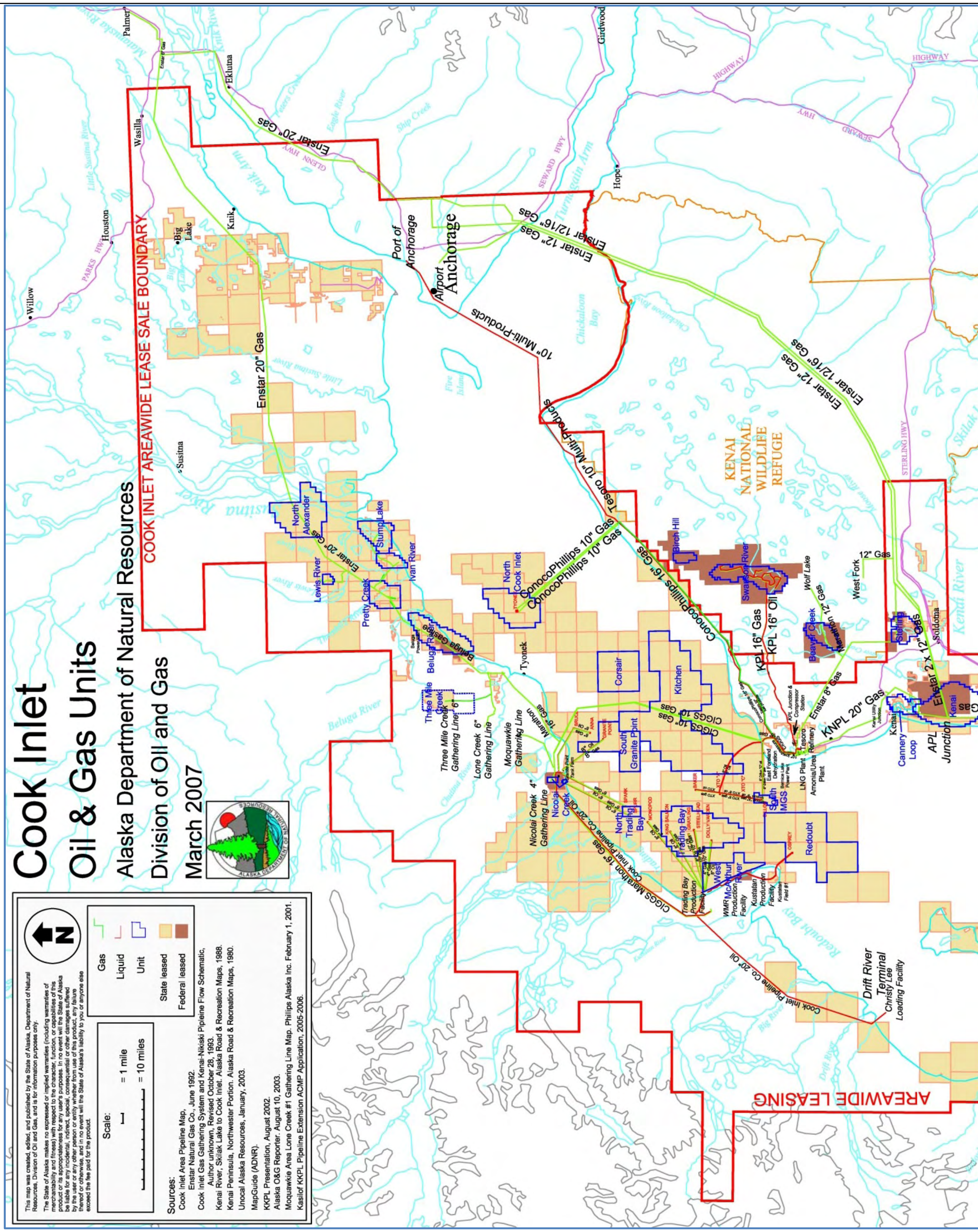
Status: Exploration
Operator: Teck Cominco Alaska Inc.
Working Interest: Teck Cominco Alaska Inc. 100%
Total Acres: 19,200
Sakaan is an exploratory coalbed methane unit located at Red Dog Zinc Mine in Northwest Alaska.

Generalized Cook Inlet Stratigraphic Column

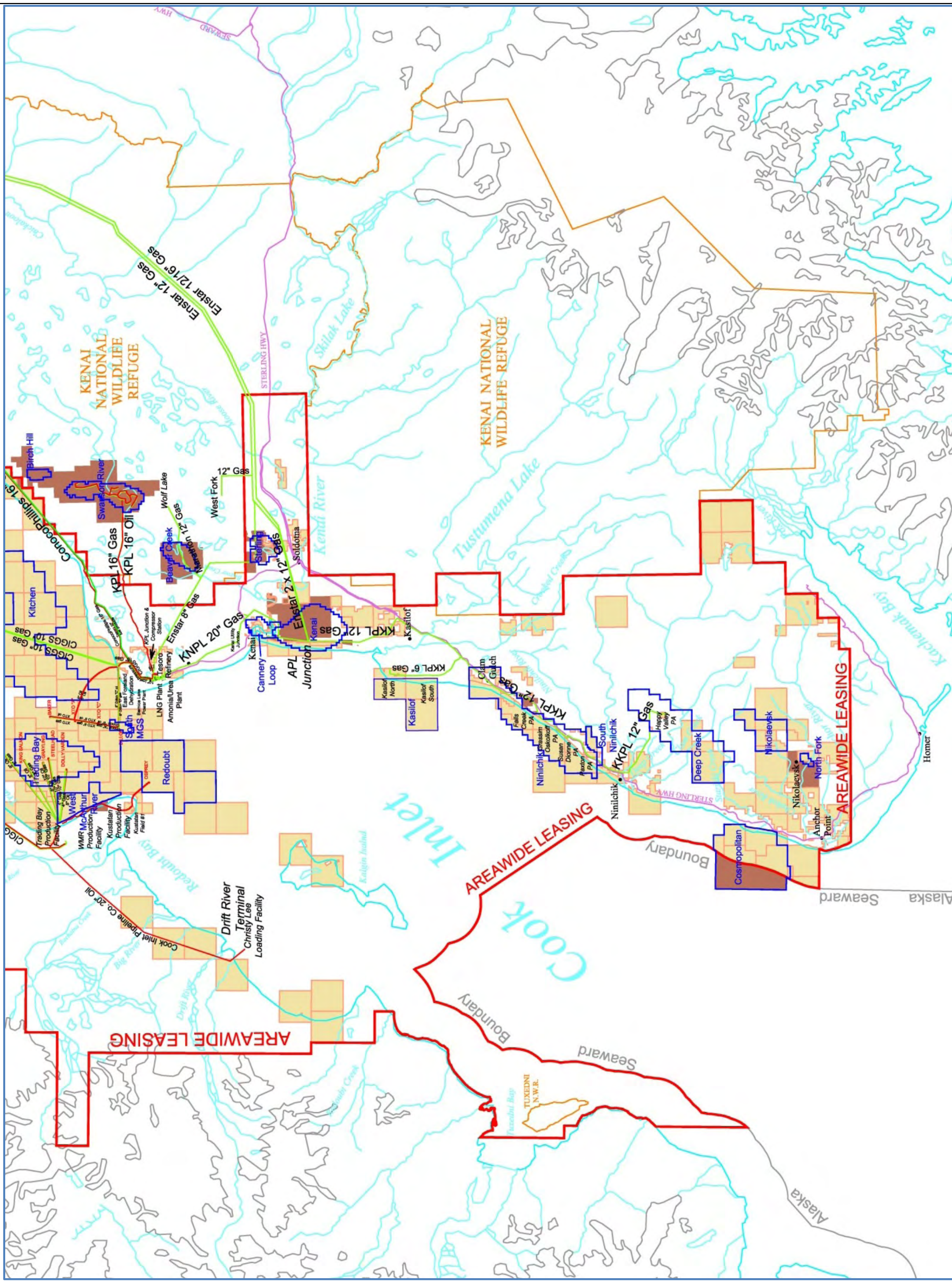


Redrawn from Curry and others (1993) and Swenson (2003); additional information from Plafker and others (1989) and Nokleberg and others (2004)

Cook Inlet


Cook Inlet
Oil & Gas Units
Alaska Department of Natural Resources
Division of Oil and Gas
March 2007
COOK INLET AREAWIDE LEASE SALE BOUNDARY
AREAWIDE LEASING
KENAI NATIONAL WILDLIFE REFUGE
Anchorage
Gas
Liquid
Unit
State leased
Federal leased

Cook Inlet



Enstar 12/16" Gas
Enstar 12" Gas
KENAI NATIONAL WILDLIFE REFUGE
KENAI NATIONAL WILDLIFE REFUGE
STERLING HWY
Skilak Lake
Tustumena Lake
Kenai River
Birch Hill
Swanson River
Wolf Lake
West Fork
12" Gas
KPL 16" Gas
KPL 16" Oil
Beaver Creek
Marathon 12" Gas
Sterling
Soldotna
Enstar 2 x 12" Gas
ConocoPhillips 16"
Kitchen
CIGGS 10" Gas
CIGGS 10" Gas
Enstar 8" Gas
KNPL 20" Gas
Tesoro Refinery
LNG Plant
Amonia/Urea Plant
Kenai
Cannery Loop
APL Junction
KKPL 12" Gas
Kasilof
KKPL 6" Gas
Kasilof North
Kasilof South
Clam Gulch
KKPL 12" Gas
Falls Creek PA
Ninilchik
South Ninilchik
Happy Valley PA
Deep Creek
Nikolaevsk
Nikolaevsk
North Fork
Anchor Point
Homer
AREAWIDE LEASING
Kachemak Bay
MGS
South MGS
Trading Bay
Redoubt
McArthur River
West McArthur River
Trading Bay Production Facility
WMR Production Facility
Kustatan Production Facility
Redoubt Bay
Inlet
Cook
AREAWIDE LEASING
Cosmopolitan
Boundary
Seaward
Alaska
Drift River Terminal
Christy Lee Loading Facility
Cook Inlet Pipeline Co. 20" Oil
Kalgin Island
AREAWIDE LEASING
Boundary
Seaward
TUXEDNI N.W.R.
Alaska

Cook Inlet

Beaver Creek Unit

Status:	Production
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 100%
Total Acres:	3,680
Royalty Ownership:	United States/CIRI
First Production:	1973

Sterling PA, Beluga-Upper Tyonek PA, and Lower Tyonek Oil Pool PA

Status:	Producing Oil and Gas
Reservoir:	Tertiary Hemlock Lower Tyonek and Beluga formations

Beluga River Unit

B. Havelock

Status:	Production
Operator:	ConocoPhillips Alaska, Inc.
Working Interest:	ConocoPhillips Alaska, Inc. 33.33% Chevron USA, Inc. 33.33% Municipality of Anchorage 33.33%
Total Acres:	8,228
State Acres:	6,099
Royalty Ownership:	State of Alaska/United States/Fee
First Production:	1968

Beluga-Sterling Gas Pool PA

Status:	Producing Gas
Reservoir:	Tertiary Sterling Formation

Birch Hill Unit

Status:	Shut-In
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 78.71% CIRI Production Company 19.68% Marathon Oil Company 1.61%
Total Acres:	1,240
Royalty Ownership:	United States/CIRI
First Production:	Shut-in 1965

Gas Pool #1 PA

Status:	Shut-in
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Chevron (Unocal) 78.7%

Cook Inlet

Cannery Loop Unit

Status:	Production
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 100%
Total Acres:	2,640
State Acres:	916
Royalty Ownership:	State of Alaska/United States/Fee
First Production:	1988

Beluga Gas Sands PA

Status:	Producing
Reservoir:	Tertiary Beluga Formation

Sterling Undefined Sands PA

Status:	*Shut-In*
Reservoir:	Tertiary Sterling Formation

Tyonek D Zone Gas Sands PA

Status:	*Suspended*
Reservoir:	Tertiary Tyonek Formation

Upper Tyonek Gas Sands PA

Status:	Producing
Reservoir:	Tertiary Tyonek Formation

Cannery Loop #3
Redoubt Volcano
Marathon Oil Company

Corsair Unit

Status:	Exploration
Operator:	Forest Oil Corporation
Working Interest:	Forest Oil Corporation 100%
Total Acres:	10,185
	(Unit approved January 2007)

Cosmopolitan Unit

Status:	Exploration
Operator:	Pioneer Natural Resources AK, Inc.
Working Interest:	Pioneer Natural Resources AK, Inc. 62.5%
	ConocoPhillips Alaska, Inc. 20%
	Devon Energy Production Co. 17.5%
Total Acres:	24,600
State Acres:	14,835
Royalty Ownership:	State of Alaska/United States

Cook Inlet

Deep Creek Unit

Red Pad
C. Ruff

Status:	Production
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	22,657
State Acres:	9,146
Royalty Ownership:	State of Alaska/CIRI
First Production:	October 2004

Happy Valley PA

Status:	Producing
First Production:	October 2004

Ivan River Unit

Status:	Production
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	2,291
First Production:	1990

Ivan River Gas Pool #1 PA

Status:	Producing
Reservoir:	Tertiary Tyonek Formation

Kenai River
B. Havelock

Kasilof Unit

Status:	Production
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 100%
Total Acres:	13,289

Tyonek Undefined Gas Pool

Status:	Producing
First Production:	November 2006

Cook Inlet

Kenai River Unit

Status:	Production
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company ~100%
Total Acres:	13,238
State Acres:	2,188
Royalty Ownership:	State of Alaska/United States/Fee
First Production:	1961

Car bou at Kenai Gas Field
Marathon Oil Company

Sterling Formation Gas Zone PA (A Zone PA)

Status:	Producing
Reservoir:	Tertiary Sterling Formation Pools 3 and 4

Beluga PA (Beluga Formation Gas Zones PA)

Status:	Producing
Reservoir:	Tertiary Beluga Formation (-4,595 to -5,108 ft. subsea)

Tyonek Undefined PA

Status:	Producing
Reservoir:	Tertiary Tyonek Formation

Upper Tyonek-Beluga Comingled PA

Status:	Producing
Reservoir:	Beluga and Tyonek Formation

Pool 6 Gas Storage Reservoir

Status:	Active State Gas Storage Lease
First Injection:	May 2006
Annual cycle capacity:	6-11 bcf
Max daily deliverability:	60 MMCF
Reservoir:	Nearly Depleted Sterling formation Pool 6

Kitchen Unit

Status:	Exploration
Operator:	Escopeta Oil Company LLC
Working Interest:	Escopeta Oil Company LLC 75% Taylor Minerals, LLC 25%
Total Acres:	40,733
	(Unit approved January 2007)

Cook Inlet

Lewis River Pad
B. Havelock

Lewis River Unit

Status:	Production
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	720
First Production:	1984

Lewis River PA #1

Status:	Suspended
Reservoir:	Tertiary Tyonek and Beluga formations

Lewis River PA #2

Status:	Suspended
Reservoir:	Tertiary Tyonek and Beluga formations

Lone Creek Unit

Status:	Production
Operator:	Aurora Gas, LLC
Working Interest:	Aurora Gas, LLC 100%
Total Acres:	4,607
Reservoir:	Tertiary Beluga and Tyonek formation
Royalty Ownership:	Cook Inlet Region, Inc.
First Production:	June 2003

Moquawkie Unit

Status:	Production
Operator:	Aurora Gas, Inc.
Working Interest:	Aurora Gas, LLC 100%
Total Acres:	2,902
Reservoir:	Tyonek Undefined
Royalty Ownership:	Cook Inlet Region, Inc.
First Production:	May 1967, November 2003

Nicloai Creek drilling
B. Havelock

Nicolai Creek Unit

Status:	Production
Operator:	Aurora Gas, LLC
Working Interest:	Aurora Gas, LLC100%
Total Acres:	411
State Acres:	365
Royalty Ownership:	State of Alaska/United States
First Production:	Shut-in 1977, Restart 2001

Nicolai Creek South Gas Pool "A" PA

Status:	*Shut-In*
Reservoir:	Tertiary Tyonek and Beluga formation

Cook Inlet


Red #1 and #2
J. High

Nicolai Creek North Gas Pool "B" PA

Status:	Producing
Reservoir:	Tertiary Tyonek and Beluga formations

Nicolai Creek Beluga PA

Status:	Producing
Reservoir:	Tertiary Beluga formations

Nikolaevsk Unit

Status:	Exploration
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	7,686
State Acres:	6,908
Royalty Ownership:	State of Alaska/CIRI


Marathon GO well
Marathon Oil Company

Ninilchik Unit

Status:	Production
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 60%
	Chevron (Unocal) 40%
Total Acres:	25,807
State Acres:	19,563
Royalty Ownership:	State of Alaska/United States/ CIRI/University of Alaska/Fee
First Production:	2003

Falls Creek PA

Status:	Producing
Reservoir:	Tertiary Tyonek Formation

Grassim Oskolkoff PA

Status:	Producing
Reservoir:	Tertiary Tyonek Formation


Ninilchik State #2
B. Havelock

Susan Dionne PA

Status:	Producing
Reservoir:	Tertiary Tyonek Formation

Paxton Pool

Status:	Producing
Reservoir:	Tertiary Tyonek Formation

Cook Inlet

North Alexander Unit

Status:	Exploration
Operator:	Escopeta Oil Company LLC
Working Interest:	Escopeta Oil Company LLC 75%
	Taylor Minerals, LLC 25%
Total Acres:	11,313
	(Unit approved January 2007)

Kenai LNG Plant
J. Rogers

North Cook Inlet Unit

Tyonek "A" Platform

Status:	Production
Operator:	ConocoPhillips Alaska, Inc.
Working Interest:	ConocoPhillips Company 100%
Total Acres:	9,782
First Production:	1970

North Cook Inlet Initial PA

Status:	Producing
Reservoir:	Tertiary Tyonek, Beluga and Sterling formations

North Fork Unit

Status:	Development
Operator:	Gas-Pro Alaska, LLC
Working Interest:	Gas Pro Alaska, LLC 60.3%
	IQ Gas, LLC 17.6%
	Alliance Energy Group LLC 13.7%
	Knoll Acres Assoc. LLC 4.7%
Total Acres:	640
Royalty Ownership:	State of Alaska
First Production:	Shut-in in 1965

(Federal leases were transferred to State of Alaska January 2007)

North Fork PA

Status:	Shut-In
Reservoir:	Tertiary Tyonek Formation

Spark Platform
Marathon Oil Company

Cook Inlet

North Trading Bay Unit

Spark and Spurr Platforms

Status:	Production
Operator:	Marathon Oil Company
Working Interest (Gas):	Marathon Oil Company 80.64%
	Chevron (Unocal) 19.36%
State Acres:	1,120
First Production:	1968, Oil Shut-in 1992

Hemlock and "G" Formation PA

Status:	Intermittent Gas Production
Reservoir:	Tertiary Hemlock and Tyonek formations

Pretty Creek Unit

Status:	Production
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	4,659
First Production:	1986

Beluga PA

Status:	Shut-In
Reservoir:	Tertiary Beluga Formation

Beluga Gas Storage Reservoir

Status:	Active State Storage Lease
First Injection:	November 2005
Annual cycle capacity:	0.7 BCF
Max daily deliverability:	20 MMCF
Reservoir:	Depleted Beluga 51-5 Sandstone

Osprey Platform
J. Patrick

Redoubt Unit

Osprey Platform

Status:	Production
Operator:	Forest Oil Corporation
Working Interest:	Forest Oil Corporation 100%
Total Acres:	23,526
First Production:	2002

Hemlock PA

Status:	Producing Oil
Reservoir:	Tertiary Hemlock Conglomerate

G-Ø Gas Sands PA

Status:	Suspended
Reservoir:	Tertiary Tyonek

Cook Inlet

South Granite Point Unit

Cook Inlet Platform
R. Warthen

Granite Point Platform

Status:	Production
Operator:	Chevron (Unocal)
Working Interest:	ExxonMobil AK Production Co. 75%
	Chevron (Unocal) 25%
Total Acres:	10,209
First Production:	1967

South Granite Point Sands PA

Status:	Producing Oil and Gas
Reservoir:	Tertiary Tyonek Formation

Hemlock PA

Status:	Producing Oil
Reservoir:	Tertiary Hemlock Conglomerate

South Middle Ground Shoal Unit

Dillon Platform

Status:	Suspended
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	1,160
First Production:	1967

South Middle Ground Shoal Tertiary System PA

Status:	Suspended
Reservoir:	Tertiary Hemlock and Tyonek formations

South Ninilchik Unit

Status:	Exploration
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	1,266
State Acres:	823
Royalty Ownership:	State of Alaska/CIRI/Fee

Cook Inlet

Sterling Unit

Status:	Production
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 100%
Total Acres:	3,600
State Acres:	409
Royalty Ownership:	State of Alaska/United States/CIRI/Fee
First Production:	1962

"A" Zone PA (Sterling Formation Gas Zone PA)

Status:	Producing
Reservoir:	Tertiary Sterling Formation

Lower Beluga PA

Status:	Producing
Reservoir:	Tertiary Beluga Formation

Tyonek PA

Status:	Producing
Reservoir:	Tertiary Tyonek Formation

Stump Lake Unit

Stump Lake Unit
B. Havelock

Status:	Production
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	4,880
First Production:	1990

Stump Lake Gas Pool #1 PA

Status:	Shut-in 1978, Restart 1990, Shut-in 2000
Reservoir:	Tertiary Beluga Formation

Cook Inlet


Swanson River Field
B. Havelock

Swanson River Unit

Status:	Production
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	8,021
Royalty Ownership:	United States/CIRI
First Production:	1960

Sterling Undefined Gas PA

Status:	Producing Gas
Reservoir:	--

Beluga Undefined Gas PA

Status:	Producing Gas
Reservoir:	Tertiary Beluga Formation

Hemlock Oil PA

Status:	Producing Oil
Reservoir:	Tertiary Hemlock, Lower Tyonek

Tyonek Storage Reservoirs

Status:	Active Federal Gas Storage Agreements
First Injection:	2001
Annual cycle capacity:	2 BCF
Max daily deliverability:	55 MMCF
Reservoir:	Two depleted Tyonek gas pools


Three Mile Creek well
Aurora Gas, LLC

Three Mile Creek Unit

Status:	Terminated
Operator:	Aurora Gas, LLC
Working Interest:	Aurora Gas, LLC 79.21%
	Forest Oil Corporation 20.79%
Total Acres:	8,101
State Acres	3,840
Royalty Ownership:	State of Alaska/CIRI
First Production:	2005

(Three Mile Creek Unit Terminated November 2006 but continues to produce gas from a single State lease)

Three Mile Creek Pool

Status:	Producing Gas
Discovery:	1967, Superior Oil Three Mile Cr. State #1
Reservoir:	Tertiary Beluga Formation

Cook Inlet

Trading Bay Unit

King Salmon, Grayling, Steelhead, Dolly Varden Platforms

Ammonia-Urea Plant
B. Havelock

Status:	Production	
Operator:	Chevron (Unocal)	
Working Interest (Gas):	Chevron (Unocal)	48.8%
	Marathon Oil Company	51.2%
Working Interest (Oil):	Forest Oil Corporation	53.2%
	Chevron (Unocal)	46.8%
Total Acres:	17,860	
First Production:	1967	

Grayling Gas Sands PA

Status: Producing Gas
Reservoir: Tertiary Tyonek Formation (-2,500 to -6,500 ft. subsea)

McArthur River Hemlock Oil Pool PA

Status: Producing Oil
Reservoir: Tertiary Hemlock Conglomerate

McArthur River Middle Kenai G Oil Pool PA

Status: Producing Oil
Reservoir: Tertiary Tyonek Formation

McArthur River West Foreland Oil Pool PA

Status: Producing Oil
Reservoir: Tertiary West Foreland Formation

West McArthur River
J. Patrick

West McArthur River Unit

Status:	Production
Operator:	Forest Oil Corporation
Working Interest:	Forest Oil Corporation 100%
Total Acres:	6,330
First Production:	1994

Area 1 PA

Status: Producing Oil and Gas
Reservoir: Tertiary Hemlock Conglomerate

Lease Production

Granite Point Field

Bruce and Anna Platforms

Kustatan Production Facility
Forest Oil Corporation

Status:	Production
Operator:	Chevron (Unocal)
Reservoir:	Tertiary Hemlock and Tyonek formations
First Production:	1967

Kustatan Field

Status:	Production
Operator:	Forest Oil Corporation.
Reservoir:	Undefined Tyonek Formation
First Production:	November 2005

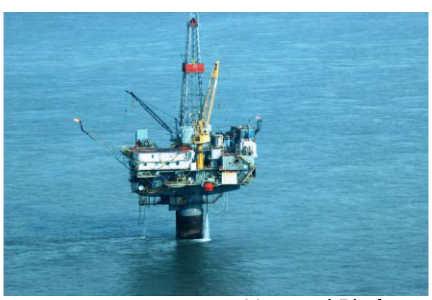
Middle Ground Shoal Field

XTO Energy "A" and "C" Platforms

Status:	Production
Operator:	XTO Energy
Reservoir:	Tertiary Hemlock and Tyonek formations
First Production:	1967

North Trading Bay Field

Monopod Platform



Monopod Platform
R. Warthen

Status:	Production
Operator:	Chevron (Unocal)
Reservoir:	Tertiary Hemlock and Tyonek formations
First Production:	1967

Lease Production

West Foreland Field

Status:	Production
Operator:	Forest Oil Corporation
Royalty Ownership:	Cook Inlet Region, Inc.
Reservoir:	Tyonek Undefined 4.0 and 4.2
First Production:	April 2001

W. McArthur River Production Facility
Forest Oil Corporation

Wolf Lake Pool

Status:	Shut-In
Operator:	Marathon Oil Company
Reservoir:	Beluga-Tyonek Undefined
Royalty Ownership:	Cook Inlet Region, Inc.
First Production:	November 2001

Glacier Rig at Wolf Lake
Marathon Oil Company

Table II.2 Alaska Fields and Pools

FIELD NAME	TYPE OF FIELD	UNIT	DISCOVERED	OPERATOR	STATUS	LOCATION
ALBERT KALOA	GAS		1/4/1968	CIRI	shut-in 1971	CI, west side, onshore
ALPINE	OIL	Colville River	3/27/1994	ConocoPhillips	prod. began 2000, Nov.	NS, Colville Delta, onshore
AURORA	OIL	Prudhoe Bay	8/24/1969	BP	prod. began 2000	NS, central, onshore
BADAMI	OIL & GAS	Badami	4/27/1990	BP	prod. began 1998, Aug. shut in	NS, Canning R., onshore
BEAVER CREEK	OIL & GAS	Beaver Creek	12/17/1972	UNOCAL	prod. began 1973	CI, east side, onshore
BELUGA RIVER	GAS	Beluga River	12/1/1962	ConocoPhillips	prod. began 1968	CI, west side, onshore
BIRCH HILL	GAS	Birch Hill	6/9/1965	ConocoPhillips	shut-in 1965	CI, east side, onshore
BOREALIS	OIL	Prudhoe Bay	8/8/1969	BP	prod. began 2000	NS, central, onshore
BURGER	OIL & GAS		10/14/1989		undeveloped	OCS, Chukchi Sea, offshore
CANNERY LOOP	GAS	Cannery Loop	6/24/1979	Marathon	prod. began 1988	CI, east side, onshore
CANNERY LOOP BELUGA	GAS	Cannery Loop	6/24/1979	Marathon	prod. began 1988	CI, east side, onshore
CANNERY LOOP STERLING	GAS	Cannery Loop	10/23/2000	Marathon	prod. began 2000	CI, east side, onshore
CASCADE	OIL	Milne Point	3/14/1993	BP	prod. began 1996, Aug.	NS, central, onshore
COLVILLE DELTA	OIL		4/26/1985	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
EAST BARROW	GAS	Barrow	5/4/1974	NS Borough	prod. began 1981	NS, western, onshore
EAST KURUPA	GAS		3/1/1976		undeveloped	NS, foothills, onshore
EAST UMIAT	GAS		3/28/1964	UMC Petroleum	shut-in, no production.	NS, foothills, onshore
EIDER	OIL	Duck Island	3/20/1998	BP	prod. began 1998, Jul.	NS, central, onshore
ENDICOTT	OIL	Duck Island	2/14/1978	BP	prod. began 1987	NS, central, onshore
FALLS CREEK	GAS	Falls Creek	4/10/1961	Marathon	shut-in 1961; prod began 2003	CI, east side, onshore
FIORD	OIL	Colville River	4/18/1992	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
FISH CREEK	OIL		9/4/1949	ConocoPhillips	undeveloped	NS, NPRA, onshore
FLAXMAN	OIL	Point Thomson	9/6/1975	Exxon	undeveloped	NS, Canning R., offshore
GRANITE POINT	OIL & GAS		5/16/1965	UNOCAL	prod. began 1967	CI, west side, offshore
GRANITE POINT TYONEK	GAS		8/5/1965	UNOCAL	prod. began 1995	CI, west side, offshore
GRASSIM OSKOLKOFF	GAS	Ninilchik	7/31/2001	Marathon	prod began 2003	CI, east side, offshore
GUBIK	GAS		8/11/1951		undeveloped	NS, foothills, onshore
GWYDYR BAY	OIL	Prudhoe Bay	11/25/1969	BP	undeveloped	NS, central, onshore
HAMMERHEAD	OIL		10/11/1986	Anadarko	undeveloped	OCS, Beaufort Sea, offshore
HAPPY VALLEY	GAS	Deep Creek	7/9/2003	Unocal	prod began 2004	CI, east side, onshore
HEMI SPRINGS	OIL		4/3/1984		undeveloped	NS, central, onshore
IVAN RIVER	GAS	Ivan River	10/8/1966	UNOCAL	prod. began 1990	CI, west side, onshore
KALUBIK	OIL	Alpine	5/1/1992	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
KASILOF	GAS	Kasilof	2004	Marathon	undeveloped	CI, east side, offshore
KATALLA	OIL		1/1/1902		abandoned 1933	Gulf of Alaska, onshore
KAVIK	GAS		11/5/1969	Phillips	undeveloped	NS, foothills, onshore
KEMIK	GAS		6/17/1972	BP	undeveloped	NS, foothills, onshore
KENAI	GAS	Kenai	10/11/1959	Marathon	prod. began 1961	CI, east side, onshore
KENAI STERLING	GAS	Kenai		Marathon		CI, east side, onshore
KUPARUK RIVER	OIL & GAS	Kuparuk River	4/7/1969	ConocoPhillips	prod. began 1981	NS, central, onshore
KUVLUM	OIL		10/1/1992	Union Texas Pet.	undeveloped	OCS, Beaufort Sea, offshore
LEWIS RIVER	GAS	Lewis River	10/1/1975	UNOCAL	prod. began 1984	CI, west side, onshore
LIBERTY	OIL		3/3/1983	BP	undeveloped	OCS, Beaufort Sea, offshore
LISBURNE	OIL & GAS	Prudhoe Bay	12/19/1967	BP	prod. began 1986	NS, central, onshore
LONE CREEK	GAS	Moquawkie	10/12/1998	Anadarko	prod began 2003	CI, west side, onshore
MCARTHUR RIVER	OIL & GAS	Trading Bay	9/29/1965	UNOCAL	prod. began 1967	CI, west side, offshore
MCARTHUR RIVER TYONEK	GAS	Trading Bay		UNOCAL		CI, west side, offshore
MEADE	GAS		8/21/1950		undeveloped	NS, NPRA, onshore
MELTWATER	OIL	Kuparuk River	4/26/2000	ConocoPhillips	prod. began 2001, Nov.	NS, central, onshore
MIDDLE GROUND SHOAL	OIL	N & S MGS	6/10/1962	UNOCAL/XTO	prod. began 1967	CI, mid channel, offshore
MIDNIGHT SUN	OIL	Prudhoe Bay	12/20/1997	BP	prod. began 1998, Oct.	NS, central, onshore
MIKKELSON	OIL		11/11/1978	ExxonMobil	undeveloped	NS, central, onshore
MILNE POINT	OIL	Milne Point	8/9/1969	BP	prod. began 1985	NS, central, onshore
MOQUAWKIE	GAS	Moquawkie	11/28/1965	CIRI	shut-in 1979	CIt, west side, onshore
NIKAITCHUQ	OIL	Nikaitchuq	4/1/2004	Kerr-McGee	undeveloped	NS, central, offshore
N MID GROUND SH (MGS)	GAS	N Mid Ground Sh	6/10/1962	UNOCAL	prod. began 1982	CI, mid channel, offshore
N MIDDLE GROUND SHOAL	GAS		11/15/1964	UNOCAL/Cross Timbe	undeveloped	CI, mid channel, offshore
NANUQ	OIL	Colville River	5/7/2000	ConocoPhillips	prod. began 2000	NS, Colville Delta, onshore
NIAKUK	OIL	Prudhoe Bay	3/7/1985	BP	prod. began 1994	NS, central, offshore
NICOLAI CREEK	GAS	Nicolai Creek	4/28/1966	Aurora Gas LLC	production began 2001	CI, west side, onshore
NORTH COOK INLET	GAS	N Cook Inlet	8/21/1962	ConocoPhillips	prod. began 1970	CI, mid channel, offshore
NORTH FORK	GAS	North Fork	12/20/1965	Alliance LLC	shut-in 1965	CI, east side, onshore
NORTH PRUDHOE	OIL & GAS	Prudhoe Bay	3/31/1970	BP	prod. began 1993, 0ct.	NS, central, onshore
NORTHSTAR	OIL & GAS	Northstar	1/30/1984	BP	prod. began 2001, Oct.	NS, central, offshore
NPRA LOOKOUT	OIL/COND		4/30/2002	ConocoPhillips	undeveloped	NS, NPRA, onshore
NPRA RENDEZVOUS	OIL/COND		4/27/2001	ConocoPhillips	undeveloped	NS, NPRA, onshore
NPRA SPARK	OIL/COND		4/12/2000	ConocoPhillips	undeveloped	NS, NPRA, onshore

Table II.2 Alaska Fields and Pools

FIELD NAME	TYPE OF FIELD	UNIT	DISCOVERED	OPERATOR	STATUS	LOCATION
OOOGURUK	OIL	Oooguruk	3/29/2003	Pioneer	undeveloped	NS, central, offshore
PALM	OIL	Kuparuk River	2/21/2001	ConocoPhillips	prod began 2002	NS, central, onshore
PETE'S WICKED	OIL	Prudhoe Bay	2/24/1997	BP	undeveloped	NSe, central, onshore
POINT MCINTYRE	OIL & GAS	Prudhoe Bay	3/22/1988	BP	prod. began 1993	NS, central, offshore
POINT THOMSON	OIL & GAS	Point Thomson	12/8/1977	ExxonMobil	undeveloped	NS, Canning R., onshore
POLARIS	OIL	Prudhoe Bay	8/24/1969	BP	prod. began 2001	NS, central, onshore
PRETTY CREEK	GAS	Pretty Creek	2/20/1979	UNOCAL	prod. began 1986	CI, west side, onshore
PRUDHOE BAY	OIL & GAS	Prudhoe Bay	12/19/1967	BP	prod. began 1977	NS, central, onshore
REDOUBT SHOAL	OIL	Redoubt Shoal	9/21/1968	Forest	prod. began 2001	CI, west side, offshore
SAG DELTA NORTH	OIL	Duck Island	1/25/1982	BP	prod. began 1989	NS, central, onshore
SAG RIVER	OIL	Milne Point	8/9/1969	BP	prod. began 1994	NSe, central, onshore
SAMBUCCA	OIL	Prudhoe Bay	1/20/1998	BP		NS, central, onshore
SANDPIPER	OIL	Sandpiper	1/25/1986	Murphy	undeveloped	OCS, Beaufort Sea, offshore
SCHRADER BLUFF	OIL	Milne Point	8/9/1969	BP	prod. began 1991	NS, central, onshore
SIKULIK	GAS		4/18/1988	NS Borough	undeveloped	NS, western, onshore
SIMPSON	OIL		10/23/1950		undeveloped	NS, NPRA, onshore
SOURDOUGH	OIL	Point Thomson	4/27/1994	BP	undeveloped	NS, Canning R., onshore
SOUTH BARROW	GAS	Barrow	4/15/1949	NS Borough	prod. began 1950	NS, western, onshore
SQUARE LAKE	GAS		4/18/1952		undeveloped	NS, NPRA, onshore
STARICHKOF	OIL	Cosmopolitan	4/1/1967	ConocoPhillips Alaska	undeveloped	CI, east side, offshore
STERLING	GAS	Sterling	7/11/1961	Marathon	prod. began 1962	CI, east side, onshore
STERLING BELUGA	GAS	Sterling	1/19/1999	Marathon	prod. began 1999	CI, east side, onshore
STERLING TYONEK	GAS	Sterling	1/19/1999	Marathon		CI, east side, onshore
STINSON	confidential		8/20/1990	ConocoPhillips	undeveloped	NS, Canning R., offshore
STUMP LAKE	GAS	Stump Lake	5/14/1978	UNOCAL	prod. began 1990	CI, west side, onshore
SUSAN DIONNE	GAS	Ninilchik	1/23/2002	Marathon	prod began 2003	CI, east side, offshore
SWANSON RIVER	OIL & GAS	Swanson River	7/19/1957	UNOCAL	prod. began 1958	CI, east side, onshore
TABASCO	OIL	Kuparuk River	10/18/1986	ConocoPhillips	prod. began 1998, May	NS, central, onshore
TARN	OIL	Kuparuk River	2/2/1991	ConocoPhillips	prod. began 1998, Aug.	NS, central, onshore
THETIS ISLAND	OIL		4/28/1993	Anadarko	undeveloped	NS, central, offshore
TRADING BAY	OIL	N Trading Bay	6/17/1965	UNOCAL	prod. began 1967	CI, west side, offshore
TRADING BAY TYONEK	GAS	N Trading Bay		UNOCAL		CI, west side, offshore
TYONEK DEEP	OIL	N Cook Inlet	11/5/1991	ConocoPhillips	undeveloped	CI, mid channel, offshore
UGNU	OIL	Kuparuk River	8/9/1969	ConocoPhillips	prod began 2003	NS, central, onshore
UMIAT	OIL		12/26/1946	U.S. Dept Interior	undeveloped	NS, foothills, onshore
WALAKPA	GAS		2/7/1980	NS Borough	prod. began 1992	NS, western, onshore
WEST BEACH	OIL & GAS	Prudhoe Bay	7/22/1976	BP	prod. began 1994, Apr.	NS, central, onshore
WEST FORELAND	GAS		3/29/1962	ConocoPhillips	shut-in 1962; prod began 2001	CI, west side, onshore
WEST FORK	GAS		9/26/1960	CIRI	prod. began 1978	CI, east side, onshore
WEST MCARTHUR RIVER	OIL & GAS	W Mcarthur River	12/2/1991	Forest	prod. began 1994	CI, west side, onshore
WEST SAK	OIL	Kuparuk River	8/9/1969	ConocoPhillips	prod. began 1998	NS, central, onshore
WOLF CREEK	GAS		6/4/1951		undeveloped	NS, NPRA, onshore
WOLF LAKE	GAS		11/12/1983	Maratthon	prod. began 2001	CI east side, onshore

Section Three

Historic and Forecast Production

Introduction

This section enumerates historic and projected oil and gas production for all North Slope and Cook Inlet producing areas, unit participating areas, and lease pools.

Forecast production volumes are based on original oil and gas in-place estimates and expected recovery factors. Original in-place means total volume of oil and gas in-place in a three-dimensional reservoir container, regardless of recoverability. Recoverable means the physical limitations of the reservoir and limits of existing technology, and considering economic factors, like price, volume, and rate of return on capital. Original and recoverable estimates are revised with new data and information on recovery and characteristics of the reservoir. Revised estimates are used to calculate remaining reserves.

Remaining Reserves are oil or gas that are economic and technologically feasible to produce and are expected to produce revenue in the foreseeable future. Total North Slope and Cook Inlet oil and gas reserves are the sum of forecasted production from year end 2006 to 2035 based on year-end 2005 reporting. Most remaining reserves of oil and gas generate royalty and other revenue to the state.

Historic and Forecast Production is summarized by producing area or unit as follows:

	Producing Region	Hydrocarbon Type	Table or Figure
Reserves	North Slope	Oil/Gas	Table III.1
	Cook Inlet	Oil/Gas	Table III.2
Historic	North Slope	Oil	Table III.3
	Incremental Production	Oil	Figures III.1A & B
	Cook Inlet	Oil	Table III.4
	North Slope	Gas	Table III.5
	North Slope	Gas	Figure III.2
	Cook Inlet	Gas	Table III.6
	Cook Inlet	Gas	Table III.10 and Figure III.7
Forecast	North Slope	Oil	Table III.7 and Figures III.3A & B
	Cook Inlet	Oil	Table III.8 and Figure III.4
	North Slope	Gas	Figure III.5
	Cook Inlet	Gas	Table III.9 and Figures III.6
Daily Volume	Alaska	Oil/Gas	Table III.11

Historic information is based on data from the Alaska Oil and Gas Conservation Commission (AOGCC) and the Division of Oil and Gas (DO&G) Royalty Accounting Section. The oil forecasts for North Slope and Cook Inlet are based primarily on estimates prepared by the Alaska Department of Revenue. Forecast gas production is based on DO&G material balance reserve estimates and assumptions about anticipated production on a field-by-field basis. These are enumerated in footnotes to the following tables and charts.

North Slope

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Badami Unit[2]	2	0	14.6%	0	-
Barrow					
East Barrow	-	5	0.0%	-	-
South Barrow	-	4	0.0%	-	-
Walakpa	-	25	0.0%	-	-
TOTAL Barrow	-	34		-	-
Colville River Unit					
Alpine	252	-	9.85%	25	-
CRU Satellite	203	-	14.2%[3]	33	-
TOTAL CRU	455	400		57	60
Duck Island Unit	120	843	12.5-14.4%	15	121
Kuparuk River Unit					
Kuparuk	799	1,000	12.5%	100	125
West Sak[4]	403	100	12.5%	50	13
Tabasco	8	-	12.5%	1	-
Tarn	41	50	12.5%	5	6
Meltwater	6	-	12.5%	1	
Other Kuparuk Satellite	-		12.5%	-	-
TOTAL KRU	1,256	1,150		157	144
Milne Point Unit[4]	331	14	14.6%	48	2
North Star	97	450	16.0%	16	72
Prudhoe Bay Unit					
Prudhoe IPA[5]	2,240	23,000	12.5%	280	2,875
PBU Satellites [4], [6]	504	-	12.5%	63	-
Aurora	43				
Borealis	117				
Orion	232				
Polaris	91				
Midnight Sun	15				
Greater Point McIntyre Area					
Lisburne	71	1,000	12.5%	9	125
Niakuk	15	26	12.5%	2	3
Pt. McIntyre	164	500	13.8%	23	69
TOTAL GPMA	250	1,526		33	197
TOTAL PBU	2,995	24,526		376	3,072
Point Thomson Area	295	8,000	12.5-16.0%	37	1,000
Other Undeveloped[7]	392	-	6%[8]	23	-
TOTAL North Slope (State Lands)	5,943	35,417		694	3,471
NPRA	246				
TOTAL North Slope Alaska	6,189	35,417	-	694	3,471

Notes:
[1] Remaining recoverable oil reserves based on the sum of Alaska Department Revenue forecasted production from 2007 through 2036. Gas reserves estimates from DNR. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.
[2] The Badami field was put in warm shut-in in August, 2003; production resumed in 2005.
[3] Average of royalty rates on State of Alaska lands.
[4] Based on a aggressive heavy oil component.
[5] Prudhoe Bay Initial Participating Area includes Prudhoe Oil Pool oil, gas ,and gas liquids; Gas Cap gas; and gas injected to enhance oil recovery.
[6] Includes Aurora, Borealis, Orion, Polaris , Midnight Sun and Raven Pools.
[7] Includes Liberty and other known off-shore accumulations.
[8] Estimated combined rate for State and Federal on- and off-shore accumulations.

Cook Inlet

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Proved, Developed, Producing					
Albert Kaloa		1.0			
Beaver Creek	1.2	24.7	-	-	-
Beluga River	-	530.4	12.5%	-	66.3
Cannery Loop	-	38.3	12.6%	-	4.8
Deep Creek		9.6	12.5 - 18%		
Ninilchik[2]		61.7	5 - 12.5%	-	7.7
Granite Point	20.7	12.2	12.5%	2.6	1.5
Ivan River, Lewis River, Pretty Creek, Stump Lake	-	5.0	14.3 - 17.7%	-	0.7
Kasilof		23.3			
Kenai	-	143.7	12.5%	-	18.0
Kustatan		0.1			
Lone Creek/Moquawkie	-	1.7	-	-	-
McArthur River	22.0	136.1	12.5%	2.8	17.0
Middle Ground Shoal	18.6	6.2	12.5%	2.3	0.8
Nicolai Creek	-	2.6	5 - 12.5%	-	0.3
North Cook Inlet	-	245.9	12.5%	-	30.7
North Trading Bay	-	0.0	12.5%	-	0.0
Redoubt	3.8	0.5	5 - 12.5%		-
Sterling	-	7.0	12.5%	-	0.9
Swanson River	1.7	7.1	-	-	-
Three Mile Creek	-	0.8	12.5 - 18%		
Trading Bay	5.0	2.9	12.5%	0.6	0.4
West Foreland[3]	-	5.7	9.4%	-	0.5
West Fork		1.2			
West MacArthur River	4.6	1.1	12.5%	0.6	0.1
Wolf Lake[4]	-	0.1	-	-	-
					-
Probable, Undeveloped					-
Birch Hill	-	-	-	-	-
Tyonek Deep[5]	25.0	30.0	12.5%	3.1	3.8
Other Probable/ Under-development[6]		385.6	12.5%		48.2
TOTAL COOK INLET	102.5	1,684.6		12.0	201.7

Notes:
[1] Remaining recoverable reserves are based on the sum of Alaska Department Revenue forecasted production from 2007-2036. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.
[2] Ninilchik Unit includes Falls Creek, Grassim Oskolkoff, Susan Dionne, and Paxton PAs.
[3] West Foreland royalty is 5% on State acreage and 12.5% on Federal acreage.
[4] Subsurface lands owned by Cook Inlet Region, Incorporated.
[5] DNR Estimate.
[6] Includes DNR estimates of non-producing, probable reserves based primarily gas prospectivity in the Nikolaevsk and North Fork exploration areas. Also includes risked probable reserves estimates for the developed-producing fields based on a material balance, plans of development, historic well production rates, and field characteristics.

North Slope (Millions of Barrels per Year)

	Badami	Colville River					Northstar	Duck Island								
		Alpine	Nanuk	Fiord	Qannik	TOTAL Colville River	Northstar (Ivishak)	Eider[1]	Endicott				Sag Delta North[1]			TOTAL Duck Island Unit
	oil	oil	oil	oil	oil		oil	oil	oil	ngl	inj	net	oil	ngl	net	
1958	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1971	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1974	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1975	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1981	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1982	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1983	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1984	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1985	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-
1986	-	-	-	-		-	-	-	0.011	-	0.007	0 004	-	-	-	0.004
1987	-	-	-	-		-	-	-	8.796	0.003	0.014	8.785	-	-	-	8.785
1988	-	-	-	-		-	-	-	37.441	0.492	-	37 933	-	-	-	37.933
1989	-	-	-	-		-	-	-	35.746	0.839	-	36 585	0 349	0 005	0 354	36.939
1990	-	-	-	-		-	-	-	36.181	0.845	-	37 026	1 542	0 028	1 570	38.596
1991	-	-	-	-		-	-	-	38.996	1.170	-	40.166	2 309	0 048	2 357	42.523
1992	-	-	-	-		-	-	-	40.603	1.468	-	42 071	1 002	0 011	1 013	43.084
1993	-	-	-	-		-	-	-	38.433	1.551	-	39 984	0.761	0 007	0.768	40.752
1994	-	-	-	-		-	-	-	33.916	1.481	-	35 397	0 368	0 003	0 371	35.768
1995	-	-	-	-		-	-	-	32.998	1.203	-	34 201	0 235	0 001	0 236	34.437
1996	-	-	-	-		-	-	-	26.450	1.013	-	27.463	0.199	0 001	0 200	27.663
1997	-	-	-	-		-	-	-	21.121	1.550	-	22 671	0 255	0 002	0 257	22.928
1998	0.731	-	-	-		-	-	0.395	16.775	1.265	-	18 040	0.193	0 001	0.194	18.629
1999	1.150	-	-	-		-	-	0.605	13.529	1.371	-	14 900	0.179	0 001	0.180	15.685
2000	0 930	2 231	-	-		2 231	-	0.248	11.622	1.436	-	13 058	0.148	0 001	0.149	13.455
2001	0 675	31 932	0 019	-		31 951	1.266	0.660	9.637	1.324	-	10 961	0.142	0 001	0.143	11.764
2002	0 579	35 041	-	-		35 041	17.903	0.422	8.509	1.202	-	9.711	0.145	0 001	0.146	10.280
2003	0 282	35 582	-	-		35 582	22.968	0.242	9.104	1.189	-	10 293	0 092	0 001	0 092	10.627
2004	-	36 095	0 000	-		36 095	25.078	0.115	7.368	0.971	-	8 339	0 030	0 000	0 030	8.484
2005	0 000	43.797	-	0 016		43 813	22.421	0.032	6.398	0.979	-	7 377	0 043	0 000	0 043	7.451
2006	0.480	41.729	0 680	1.784	0 055	44 247	18.881	0.035	5.082	0.773	-	5 856	0 063	0 000	0 063	5.954
TOTAL	4 828	226.407	0 699	1.799	0 055	228 961	108.517	2.754	438.716	22.127	0.021	460 822	8 055	0.113	8.167	471.743

Notes:

[1] AOGCC combined 1999 production volumes for Eider and Sag Delta North and reported these data in the "Ivishak Pool." Sag Delta North PA includes all oil and NGL production from Ivishak formation sands in the area. Eider also produces oil from the prolific Ivishak sandstone.

North Slope (Millions of Barrels per Year)

	Prudhoe Bay Unit Initial Participating Areas (IPAs) and Satellites										
	Prudhoe Bay[2]				Midnight Sun	Polaris (Schrader Bluff)	Aurora	Borealis	Orion	Raven	TOTAL PBU IPAs + Satellites
	oil	ngl	inj	net	oil	oil	oil	oil	oil	oil	
1958	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-
1969	0.277	-	0.217	0.060	-	-	-	-	-	-	0.060
1970	1.193	-	0.879	0.314	-	-	-	-	-	-	0.314
1971	1.157	-	0.833	0.324	-	-	-	-	-	-	0.324
1972	0.922	-	0.792	0.130	-	-	-	-	-	-	0.130
1973	0.944	-	0.817	0.127	-	-	-	-	-	-	0.127
1974	2.170	-	1.640	0.530	-	-	-	-	-	-	0.530
1975	2.870	-	2.147	0.723	-	-	-	-	-	-	0.723
1976	4.604	-	3.611	0.993	-	-	-	-	-	-	0.993
1977	115.258	-	2.075	113.183	-	-	-	-	-	-	113.183
1978	397.679	-	-	397.679	-	-	-	-	-	-	397.679
1979	468.412	-	-	468.412	-	-	-	-	-	-	468.412
1980	555.394	0.254	-	555.648	-	-	-	-	-	-	555.648
1981	555.170	0.450	-	555.620	-	-	-	-	-	-	555.620
1982	558.889	0.500	-	559.389	-	-	-	-	-	-	559.389
1983	560.837	0.311	-	561.148	-	-	-	-	-	-	561.148
1984	561.952	0.317	-	562.269	-	-	-	-	-	-	562.269
1985	568.534	0.056	-	568.590	-	-	-	-	-	-	568.590
1986	561.538	0.230	-	561.768	-	-	-	-	-	-	561.768
1987	572.045	14.610	-	586.655	-	-	-	-	-	-	586.655
1988	559.412	19.274	-	578.686	-	-	-	-	-	-	578.686
1989	505.940	16.928	-	522.868	-	-	-	-	-	-	522.868
1990	470.140	16.094	-	486.234	-	-	-	-	-	-	486.234
1991	465.399	21.307	-	486.706	-	-	-	-	-	-	486.706
1992	432.587	23.902	-	456.489	-	-	-	-	-	-	456.489
1993	385.811	23.879	-	409.690	-	-	-	-	-	-	409.690
1994	351.493	22.825	-	374.318	-	-	-	-	-	-	374.318
1995	313.629	26.810	-	340.439	-	-	-	-	-	-	340.439
1996	282.060	30.549	-	312.609	-	-	-	-	-	-	312.609
1997	252.421	31.580	-	284.001	-	-	-	-	-	-	284.001
1998	221.781	30.983	-	252.764	0.061	-	-	-	-	-	252.825
1999	194.338	29.423	-	223.761	1.696	0.027	-	-		-	225.484
2000	187.056	30.145	-	217.200	1.441	0.414	0.261	-	-	-	219.317
2001	166.718	27.526	-	194.244	1.305	0.419	1.738	1.346	-	-	199.052
2002	150.975	26.640	-	177.615	3.157	0.766	2.397	8.439	0.097	-	192.471
2003	141.302	24.972	-	166.274	1.719	0.918	3.782	11.791	0.368	-	184.856
2004	127.610	25.629	-	153.239	1.641	0.995	3.219	9.274	1.844	-	170.213
2005	118.552	21.420	-	139.972	2.132	1.248	3.452	7.077	2.897	0.291	157.069
2006	91.498	19.266	-	110.764	2.083	0.822	3.813	5.737	2.482	0.626	126.327
TOTAL	10,908.567	485.879	13.011	11,381.435	15.237	5.608	18.663	43.663	7.688	0.917	11,473.215

Notes:

[2]Production for the Prudhoe Bay IPA includes oil and condensates and production from the Put River oil pool.

North Slope (Millions of Barrels per Year)

	Greater Point McIntyre Area (GPMA)																TOTAL Prudhoe Bay Unit (IPA+Sats +GPMA)
	Lisburne			Niakuk[3]			North Prudhoe Bay			Point McIntyre			West Beach			TOTAL GPMA	
	oil	ngl	net	oil	ngl	net	oil	ngl	net	oil	ngl	net	oil	ngl	net		
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.060
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.314
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.324
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.130
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.127
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.530
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.723
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.993
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	113.183
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	397.679
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	468.412
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	555.648
1981	0.002	-	0 002	-	-	-	-	-	-	-	-	-	-	-	-	0.002	555.622
1982	0.208	-	0 208	-	-	-	-	-	-	-	-	-	-	-	-	0.208	559.597
1983	0.087	-	0 087	-	-	-	-	-	-	-	-	-	-	-	-	0.087	561.235
1984	0.294	-	0 294	-	-	-	-	-	-	-	-	-	-	-	-	0.294	562.563
1985	1.123	-	1.123	-	-	-	-	-	-	-	-	-	-	-	-	1.123	569.713
1986	3.594	-	3 594	-	-	-	-	-	-	-	-	-	-	-	-	3.594	565.362
1987	16.199	0.458	16 657	-	-	-	-	-	-	-	-	-	-	-	-	16.657	603.312
1988	15.095	1 008	16.103	-	-	-	-	-	-	-	-	-	-	-	-	16.103	594.789
1989	13.737	1 093	14 830	-	-	-	-	-	-	-	-	-	-	-	-	14.830	537.698
1990	14.669	1 204	15 873	-	-	-	-	-	-	-	-	-	-	-	-	15.873	502.107
1991	13.316	1 337	14 653	-	-	-	-	-	-	-	-	-	-	-	-	14.653	501.359
1992	12.517	1.464	13 981	-	-	-	-	-	-	-	-	-	-	-	-	13.981	470.470
1993	8.473	1 277	9.750	-	-	-	0.418	0.015	0.433	7.543	0.090	7 633	0.724	0 009	0.733	18.549	428.239
1994	6.846	0 939	7.785	3 383	0.028	3.411	0.727	0.031	0.758	37.684	0.548	38 232	0 512	0 012	0 524	50.710	425.028
1995	5.454	0 823	6 277	7 004	0.077	7.081	0.702	0.034	0.736	50.225	0.679	50 904	0.163	0 005	0.168	65.166	405.605
1996	4.465	0 674	5.139	10 937	0.108	11.045	0.126	0.003	0.129	57.926	0.825	58.751	0.474	0 025	0.499	75.563	388.172
1997	3.002	0.416	3.418	10 265	0.136	10.401	-	-	-	58.498	1.042	59 540	0 319	0 027	0 346	73.705	357.706
1998	2.468	0 331	2.799	10 356	0.128	10.484	0.001	0.001	0 002	47.553	1.009	48 562	0 096	0 006	0.102	61.949	314.774
1999	2.203	0 326	2 529	9 857	0.131	9.988	0.008	0.001	0 009	33.460	0.831	34 291	0 603	0 067	0 670	47.486	272.970
2000	3.203	0 601	3 804	7 336	0.101	7.437	0.003	0.001	0 003	23.737	0.675	24.413	0.401	0 053	0.454	36.111	255.428
2001	3.054	0 622	3 675	6 978	0.109	7.087	-	-	-	18.094	0.600	18 693	0.110	0 014	0.125	29.580	228.632
2002	3.065	0.484	3 549	5 814	0.055	5.868	-	-	-	14.744	0.472	15 216	0 004	0 000	0 004	24.638	217.109
2003	3.335	0.480	3 816	4 599	0.039	4.638	-	-	-	13.320	0.518	13 838	0 010	0 001	0 011	22.302	207.154
2004	3.300	0 373	3 673	3 803	0.044	3.848	-	-	-	13.322	0.744	14 066	0 005	0 000	0 005	21.592	191.804
2005	3.050	0 320	3 370	2 621	0.048	2.670	0.001	0.000	0 001	11.789	0.844	12 633	0 001	0 000	0 001	18.675	175.745
2006	3.224	0.469	3 693	1 677	0.040	1.717	-	-	-	7.735	0.364	8.100	-	-	-	13.510	139.837
TOTAL	145.982	14.700	160 682	84 631	1.044	85.675	1.985	0.086	2 071	395.631	9.241	404 871	3.421	0 220	3 641	656.941	12,130.152

Notes:

[3]Niakuk production volumes for 1994-1998 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk Pool."

North Slope (Millions of Barrels per Year)

	Kuparuk River Unit								Milne Point Unit				NORTH SLOPE			
	Kuparuk			Tabasco	Tarn	West Sak	Melt-water	TOTAL Kuparuk River Unit	Kuparuk	Sag River	Schrader Bluff	TOTAL Milne Point Unit	TOTAL OIL	TOTAL NGL	TOTAL INJECT-ED	TOTAL NET
	oil	ngl	net	oil	oil	oil	oil		oil	oil	oil					
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	0.277	-	0 217	0.060
1970	0.006	-	0 006	-	-	-	-	0 006	-	-	-	-	1.199	-	0 879	0.320
1971	-	-	-	-	-	-	-	-	-	-	-	-	1.157	-	0 833	0.324
1972	-	-	-	-	-	-	-	-	-	-	-	-	0.922	-	0.792	0.130
1973	-	-	-	-	-	-	-	-	-	-	-	-	0.944	-	0 817	0.127
1974	-	-	-	-	-	-	-	-	-	-	-	-	2.170	-	1 640	0.530
1975	-	-	-	-	-	-	-	-	-	-	-	-	2.870	-	2.147	0.723
1976	-	-	-	-	-	-	-	-	-	-	-	-	4.604	-	3 611	0.993
1977	-	-	-	-	-	-	-	-	-	-	-	-	115.258	-	2 075	113.183
1978	-	-	-	-	-	-	-	-	-	-	-	-	397.679	-	-	397 679
1979	-	-	-	-	-	-	-	-	-	-	-	-	468.412	-	-	468.412
1980	-	-	-	-	-	-	-	-	-	-	-	-	555.394	0.254	-	555 648
1981	1.092	-	1 092	-	-	-	-	1 092	-	-	-	-	556.264	0.450	-	556.714
1982	32.406	-	32.406	-	-	-	-	32.406	-	-	-	-	591.503	0.500	-	592 003
1983	39.876	-	39 876	-	-	0 006	-	39 882	-	-	-	-	600.806	0.311	-	601.117
1984	46.084	-	46 084	-	-	0.124	-	46 208	-	-	-	-	608.454	0.317	-	608.771
1985	78.926	0.761	79 687	-	-	0 326	-	80 013	0.704	-	-	0.704	649.613	0.817	-	650.430
1986	93.900	1 072	94 972	-	-	0 300	-	95 272	4.709	-	-	4.709	664.052	1.302	0 007	665 347
1987	102.448	1 257	103.705	-	-	-	-	103.705	0 040	-	-	0 040	699.528	16.328	0 014	715 842
1988	110.891	0 256	111.147	-	-	-	-	111.147	-	-	-	-	722.839	21.030	-	743 869
1989	109.770	-	109.770	-	-	-	-	109.770	3.715	-	-	3.715	669.257	18.865	-	688.122
1990	107.206	-	107 206	-	-	-	-	107 206	6 624	-	0.004	6 628	636.366	18.171	-	654 537
1991	113.571	-	113 571	-	-	-	-	113 571	6.701	-	0.756	7.457	641.048	23.862	-	664 910
1992	118.506	-	118 506	-	-	-	-	118 506	5 812	-	1.135	6 947	612.162	26.845	-	639 007
1993	115.166	-	115.166	-	-	-	-	115.166	5.704	-	1.060	6.764	564.093	26.828	-	590 921
1994	111.795	-	111.795	-	-	-	-	111.795	5 648	-	1.030	6 678	553.402	25.867	-	579 269
1995	106.999	-	106 999	-	-	-	-	106 999	7 352	0.173	1.167	8 692	526.101	29.632	-	555.733
1996	99.459	-	99.459	-	-	-	-	99.459	12 665	0.346	1.090	14.101	496.197	33.198	-	529 395
1997	95.970	-	95 970	-	-	0 001	-	95 971	17 055	0.363	1.536	18 954	460.806	34.753	-	495 559
1998	91.702	-	91.702	0.483	3.534	0 562	-	96 281	18 314	0.162	1.943	20.419	417.110	33.724	-	450 834
1999	82.394	-	82 394	1.920	9.541	1.190	-	95 045	17.488	0.018	2.178	19 684	372.383	32.151	-	404 534
2000	74.133	-	74.133	1.911	8.767	1 520	-	86 330	16 572	-	2.498	19 069	344.431	33.013	-	377.444
2001	68.265	-	68 265	1.318	8.052	1 998	0.149	79.782	15 273	0.248	3.818	19 339	343.213	30.195	-	373.408
2002	58.903	-	58 903	1.089	12.011	2.472	2.902	77 378	13 314	0.130	5.219	18 663	348.098	28.854	-	376 952
2003	58.536	-	58 536	1.542	12.343	2 857	2.125	77.402	11 604	0.101	7.001	18.707	345.527	27.200	-	372.727
2004	53.215	-	53 215	1.471	10.337	4 281	2.478	71.781	10 996	0.048	7.693	18.737	324.218	27.762	-	351 980
2005	50.442	-	50.442	1.531	8.085	4.175	2.103	66 336	9 508	0.088	6.408	16 004	308.159	23.612	-	331.771
2006	45.503	-	45 503	1.418	7.555	6 617	1.390	62.482	8.496	0.102	4.685	13 284	264.252	20.914	-	285.166
TOTAL	2,067.164	3 346	2,070 510	12.682	80.226	26.428	11.146	2,200.992	198 294	1.780	49.221	249 294	14,870.768	536.755	13 032	15,394.491

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (Monthly Reports).

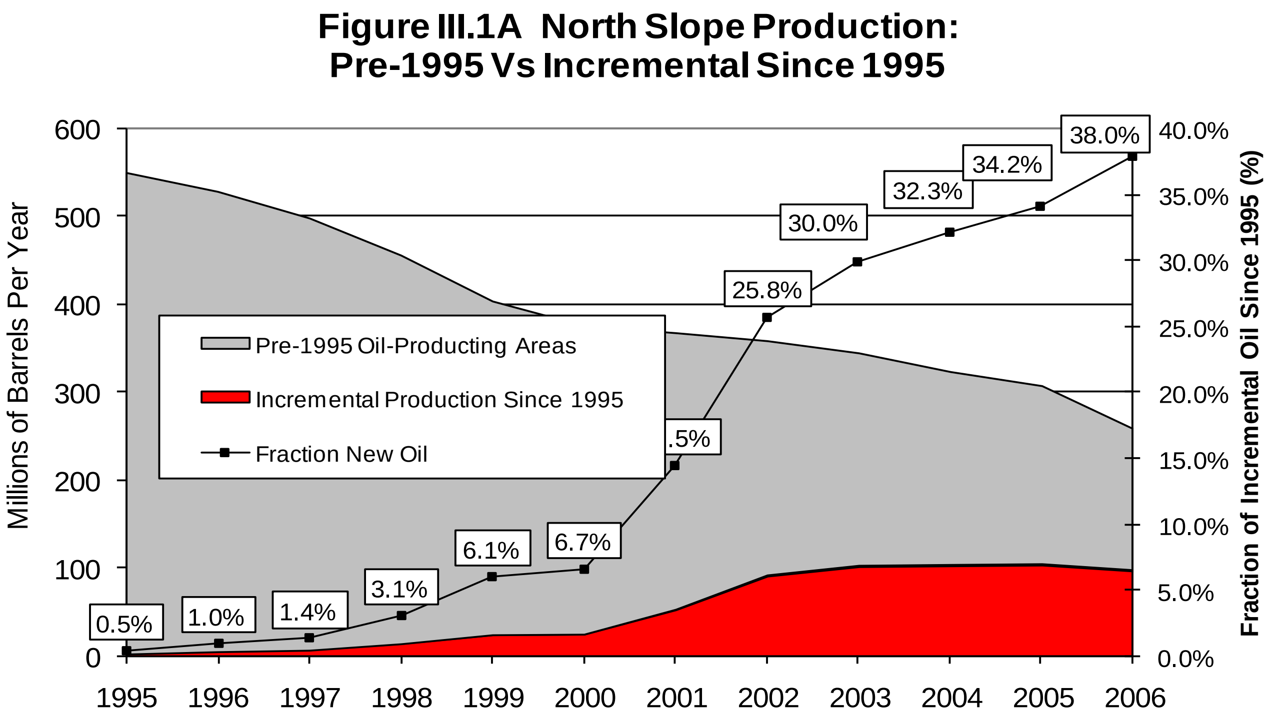


Figure III.1A North Slope Production:
Pre-1995 Vs Incremental Since 1995
Millions of Barrels Per Year
Fraction of Incremental Oil Since 1995 (%)
Pre-1995 Oil-Producting Areas
Incremental Production Since 1995
Fraction New Oil
0.5%
1.0%
1.4%
3.1%
6.1%
6.7%
.5%
25.8%
30.0%
32.3%
34.2%
38.0%
0
100
200
300
400
500
600
0.0%
5.0%
10.0%
15.0%
20.0%
25.0%
30.0%
35.0%
40.0%
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006

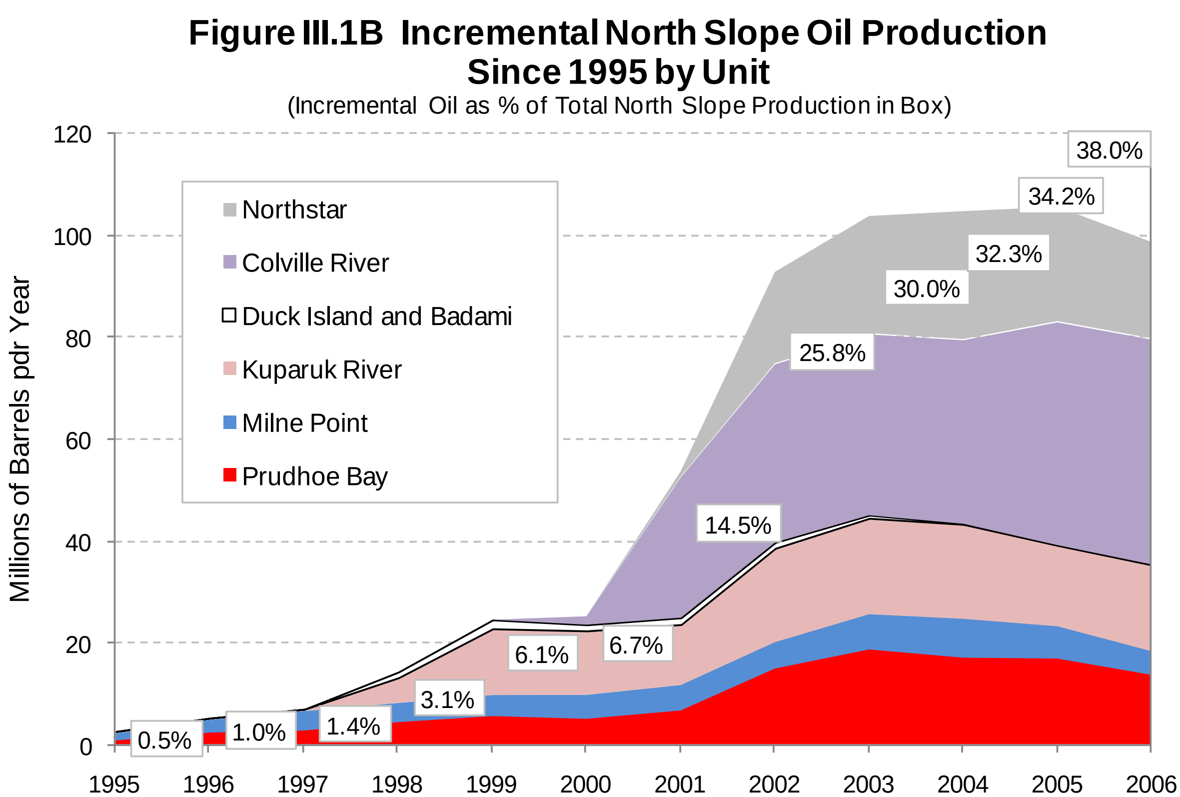


Figure III.1B Incremental North Slope Oil Production
Since 1995 by Unit
(Incremental Oil as % of Total North Slope Production in Box)
Millions of Barrels pdr Year
Northstar
Colville River
Duck Island and Badami
Kuparuk River
Milne Point
Prudhoe Bay
0.5%
1.0%
1.4%
3.1%
6.1%
6.7%
14.5%
25.8%
30.0%
32.3%
34.2%
38.0%
0
20
40
60
80
100
120
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006

Cook Inlet (Millions of Barrels per Year)

	Beaver Creek	Cannery Loop[1]	Granite Point[2]	Kenai[1]	McArthur River[3]			Middle Ground Shoal[4]	North Trading Bay Unit[5]	Redoubt Shoal
	oil	ngl	oil	ngl	oil	ngl	net	oil	oil	oil
1958	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-
1965	-	-	0.002	-	0.001	-	0.001	0.027	-	-
1966	-	-	-	-	0.003	-	0.003	2.649	-	-
1967	-	-	7.052	-	0.749	-	0.749	7.404	0.002	-
1968	-	-	13.131	-	21.782	-	21.782	14.134	0.185	0.002
1969	-	-	9.183	0.002	31.301	-	31.301	10.467	4.310	-
1970	-	-	7.522	0.002	40.165	0.426	40.591	12.719	3.265	-
1971	-	-	5.577	0.001	40.537	0.593	41.130	11.304	2.029	-
1972	0.002	-	4.663	0.002	40.774	0.570	41.344	9.719	2.553	-
1973	0.416	-	4.767	0.001	38.884	0.661	39.545	10.239	2.022	-
1974	0.375	-	4.237	-	39.145	0.654	39.799	9.001	2.127	-
1975	0.322	-	4.361	0.001	40.876	0.644	41.520	8.670	1.530	-
1976	0.302	-	4.471	0.001	35.810	0.653	36.463	8.864	1.096	-
1977	0.276	-	4.711	-	33.235	0.733	33.968	7.617	0.970	-
1978	0.223	-	4.867	0.001	30.223	0.730	30.953	6.382	0.797	-
1979	0.211	-	4.613	-	25.440	0.541	25.981	5.545	0.609	-
1980	0.214	-	4.394	-	20.894	0.412	21.306	4.854	0.372	-
1981	0.180	-	3.975	-	18.022	0.484	18.506	4.291	0.235	-
1982	0.182	-	3.467	-	15.806	0.449	16.255	3.573	0.132	-
1983	0.170	-	3.550	-	13.564	0.332	13.896	3.381	0.117	-
1984	0.159	-	3.287	-	11.707	0.317	12.024	3.238	0.080	-
1985	0.146	-	3.052	-	7.454	0.194	7.648	3.098	0.113	-
1986	0.158	-	3.169	-	7.942	0.228	8.170	3.211	0.220	-
1987	0.185	-	2.803	-	7.375	0.196	7.571	2.834	0.246	-
1988	0.141	-	2.677	-	7.143	0.162	7.305	2.742	0.195	-
1989	0.227	-	2.275	-	6.955	-	6.955	2.769	0.179	-
1990	0.212	-	1.462	-	4.265	-	4.265	2.688	0.121	-
1991	0.179	-	2.064	-	7.247	-	7.247	2.670	0.168	-
1992	0.175	-	2.522	-	7.397	-	7.397	2.423	0.030	-
1993	0.153	-	2.488	-	6.636	-	6.636	2.160	-	-
1994	0.140	<.001	2.209	-	7.091	-	7.091	2.785	-	-
1995	0.132	<.001	2.580	-	6.622	-	6.622	2.823	-	-
1996	0.125	<.001	2.556	-	6.102	-	6.102	2.396	-	-
1997	0.119	-	2.432	-	5.059	-	5.059	2.223	-	-
1998	0.103	-	2.079	-	4.817	-	4.817	2.156	-	-
1999	0.100	-	1.787	-	4.697	-	4.697	1.968	-	-
2000	0.092	-	1.742	-	4.822	-	4.822	1.894	-	0.002
2001	0.085	-	1.620	-	5.353	-	5.353	2.032	-	0.001
2002	0.079	-	1.527	-	5.510	-	5.510	1.959	-	0.046
2003	0.076	-	1.440	-	4.323	-	4.323	1.497	-	0.911
2004	0.068	-	1.433	-	3.373	-	3.373	1.323	-	0.559
2005	0.061	-	1.263	-	2.895	-	2.895	1.318	-	0.312
2006	0.077	-	1.094	-	2.504	-	2.504	1.192	-	0.262
TOTAL	5.866	-	144.106	0.011	624.500	8.979	633.479	194.239	23.703	2.096

Notes:
[1] These gas fields temporarily produced NGLs.
[2] Includes Middle Kenai and Undefined Hemlock pools.
[3] Includes Hemlock, Middle Kenai G, and West Foreland Pools.
[4] Includes A, B, C, D, E, F, and G pools. XTO Energy produces oil from "A" and "C" Platforms. All production is suspended at Baker and Dillon Platforms on the north and south flanks of the field.
[5] North Trading Bay Unit/Field Spark and Spurr Platform oil production has been shut-in since 1992, but some gas is produced from Spark.

Cook Inlet (Millions of Barrels per Year)

	Swanson River[5]			Trading Bay[6]			West McArthur River	COOK INLET TOTAL OIL	COOK INLET TOTAL NGL	COOK INLET TOTAL
	oil	ngl	net	oil	ngl	net	oil			
1958	0.036	-	0.036	-	-	-	-	0.036	-	0.036
1959	0.187	-	0.187	-	-	-	-	0.187	-	0.187
1960	0.558	-	0.558	-	-	-	-	0.558	-	0.558
1961	6.327	-	6.327	-	-	-	-	6.327	-	6.327
1962	10.259	-	10.259	-	-	-	-	10.259	-	10.259
1963	10.740	-	10.740	-	-	-	-	10.740	-	10.740
1964	11.054	-	11.054	-	-	-	-	11.054	-	11.054
1965	11.099	-	11.099	0 002	-	0.002	-	11.131	-	11.131
1966	11.712	-	11.712	-	-	-	-	14.364	-	14.364
1967	12.980	-	12.980	0.727	-	0.727	-	28.914	-	28.914
1968	13.619	0.004	13.623	3 292	-	3.292	-	66.145	0.004	66.149
1969	13.151	0.070	13.221	5.626	-	5.626	-	74.038	0.072	74.110
1970	12.408	0.063	12.471	6 335	0.039	6.374	-	82.414	0.530	82.944
1971	11.466	0.077	11.543	6.714	0.039	6.753	-	77.627	0.710	78.337
1972	8.896	0.012	8.908	6 033	0.025	6.058	-	72.640	0.609	73.249
1973	10.064	0.098	10.162	5 803	0.051	5.854	-	72.195	0.811	73.006
1974	9.765	0.096	9.861	5.425	0.043	5.468	-	70.075	0.793	70.868
1975	8.754	0.089	8.843	4 598	0.031	4.629	-	69.111	0.765	69.876
1976	7.591	0.090	7.681	4 270	0.026	4.296	-	62.404	0.770	63.174
1977	5.981	0.086	6.067	3 306	0.044	3.350	-	56.096	0.863	56.959
1978	4.870	0.065	4.935	2.770	0.019	2.789	-	50.132	0.815	50.947
1979	4.344	0.080	4.424	2 284	0.014	2.298	-	43.046	0.635	43.681
1980	3.724	0.064	3.788	1.794	0.006	1.800	-	36.246	0.482	36.728
1981	2.938	0.048	2.986	1.435	0.005	1.440	-	31.076	0.537	31.613
1982	2.999	0.048	3.047	1 251	0.002	1.253	-	27.410	0.499	27.909
1983	3.017	0.045	3.062	0 964	0.004	0.968	-	24.763	0.381	25.144
1984	2.517	0.039	2.556	0 995	0.005	1.000	-	21.983	0.361	22.344
1985	2.165	0.026	2.191	0 915	0.004	0.919	-	16.943	0.224	17.167
1986	2.055	0.054	2.109	0 826	0.002	0.828	-	17.581	0.284	17.865
1987	2.059	0.030	2.089	0.689	0.001	0.690	-	16.191	0.227	16.418
1988	2.127	0.033	2.160	0.691	-	0.691	-	15.716	0.195	15.911
1989	1.875	0.024	1.899	1 085	-	1.085	-	15.365	0.024	15.389
1990	1.878	0.019	1.897	0 522	-	0.522	-	11.148	0.019	11.167
1991	1.962	0.023	1.985	1 048	-	1.048	0.002	15.340	0.023	15.363
1992	1.773	0.019	1.792	0 856	-	0.856	0.002	15.178	0.019	15.197
1993	1.576	0.018	1.594	0.742	-	0.742	0.098	13.853	0.018	13.871
1994	1.672	0.023	1.695	0.743	-	0.743	0.921	15.561	0.023	15.584
1995	1.712	0.017	1.729	0.722	-	0.722	0.922	15.513	0.017	15.530
1996	1.521	0.019	1.540	0 589	-	0.589	1.296	14.585	0.019	14.604
1997	1.065	0.012	1.077	0.602	-	0.602	0.645	12.145	0.012	12.157
1998	0.911	0.009	0.920	0.700	-	0.700	1.037	11.803	0.009	11.812
1999	0.794	-	0.794	0.645	-	0.645	0.914	10.905	-	10.905
2000	0.638	-	0.638	0.637	-	0.637	0.893	10.720	-	10.720
2001	0.609	-	0.609	0 574	-	0.574	1.222	11.497	-	11.497
2002	0.477	-	0.477	0.666	-	0.666	1.018	11.284	-	11.284
2003	0.425	-	0.425	0 537	-	0.537	0.849	10.059	-	10.059
2004	0.320	-	0.320	0.462	-	0.462	0.669	8.208	-	8.208
2005	0.330	-	0.330	0.414	-	0.414	0.517	7.110	-	7.110
2006	0.262	-	0.262	0 311	-	0.311	0.437	6.140	-	6.140
TOTAL	229.263	1.400	230.663	78.600	0.360	78.960	11.443	1,313.815	10.750	1,324.565

Notes:
[5] Includes Hemlock pool.
[6] Includes Hemlock, Undefined, and B, C, D, and E pools.
Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports) and Alaska Department of Revenue.

North Slope (Billion Cubic Feet per Year)

	Badami			Barrow			Colville River								
	Badami			East Barrow	South Barrow	Walakpa	Alpine			Nanuq			Fiord	Qannik	TOTAL Colville
	gas	inj	net	gas	gas	gas	gas	inj	net	gas	inj	net	gas	gas	
1958	-	-	-	-	0.119	-	-			-			-		-
1959	-	-	-	-	0.132	-	-			-			-		-
1960	-	-	-	-	0.172	-	-			-			-		-
1961	-	-	-	-	0.172	-	-			-			-		-
1962	-	-	-	-	0.197	-	-			-			-		-
1963	-	-	-	-	0.211	-	-			-			-		-
1964	-	-	-	-	0.249	-	-			-			-		-
1965	-	-	-	-	0.389	-	-			-			-		-
1966	-	-	-	-	0.438	-	-			-			-		-
1967	-	-	-	-	0.475	-	-			-			-		-
1968	-	-	-	-	0.504	-	-			-			-		-
1969	-	-	-	-	0.582	-	-			-			-		-
1970	-	-	-	-	0.619	-	-			-			-		-
1971	-	-	-	-	0.627	-	-			-			-		-
1972	-	-	-	-	0.675	-	-			-			-		-
1973	-	-	-	-	0.707	-	-			-			-		-
1974	-	-	-	-	0.765	-	-			-			-		-
1975	-	-	-	-	0.799	-	-			-			-		-
1976	-	-	-	-	0.832	-	-			-			-		-
1977	-	-	-	-	0.879	-	-			-			-		-
1978	-	-	-	-	0.893	-	-			-			-		-
1979	-	-	-	-	0.913	-	-			-			-		-
1980	-	-	-	-	1.027	-	-			-			-		-
1981	-	-	-	0 037	1.009	-	-			-			-		-
1982	-	-	-	0.717	0.532	-	-			-			-		-
1983	-	-	-	0.689	0.541	-	-			-			-		-
1984	-	-	-	0.693	0.650	-	-			-			-		-
1985	-	-	-	0.632	0.678	-	-			-			-		-
1986	-	-	-	0 589	0.589	-	-			-			-		-
1987	-	-	-	0 590	0.622	-	-			-			-		-
1988	-	-	-	0.661	0.598	-	-			-			-		-
1989	-	-	-	0.475	0.758	-	-			-			-		-
1990	-	-	-	0.488	0.733	-	-			-			-	-	-
1991	-	-	-	0 583	0.662	-	-			-			-	-	-
1992	-	-	-	0.439	0.628	0.252	-			-	-		-	-	-
1993	-	-	-	0 259	0.441	0.585	-			-	-	-	-	-	-
1994	-	-	-	0 223	0.261	0.858	-			-	-	-	-	-	-
1995	-	-	-	0 099	0.052	1.109	-			-	-	-	-	-	-
1996	-	-	-	0 064	0.051	1.160	-			-	-	-	-	-	-
1997	-	-	-	0.114	0.041	1.126	-		-	-	-	-	-	-	-
1998	0.459	0.005	0.454	0.146	0.081	1.110	-	-	-	-	-	-	-	-	-
1999	1.693	1.718	-0.025	0.123	0.055	1.281	-	-	-	-	-	-	-	-	-
2000	4.557	4.020	0.537	0 090	0.037	1.352	2.091	-	2.091	-	-	-	-	-	2.091
2001	5.312	0.479	4.834	0 086	0.042	1.348	33.604	-	33.604	-	-	-	-	-	33.604
2002	7.172	6.126	1.045	0 093	0.061	1.251	39.872	35 009	4.863	0 298	-	-	-	-	4.863
2003	3.698	3.363	0.335	0 093	0.089	1.235	41.594	36 315	5.279	-	-	-	-	-	5.279
2004	-	-	-	0.101	0.069	1.245	44.728	39 014	5.714	0 001	-	0.001	-	-	5.716
2005	1.120	0.959	0.161	0 080	0.053	1.255	49.433	43.112	6.321	-	-	-	-	-	6.321
2006	4.202	3.732	0.470	0 018	0.101	1.244	50.607	46.168	4.439	0.466	-	0.466	1.112	0.051	6.067
TOTAL	28.213	20.402	7.811	8.181	22.640	16.411	261.928	199.618	62.311	0.765	-	0.467	1.112	0.051	63.940

North Slope (Billion Cubic Feet per Year)

	Duck Island								Prudhoe Bay Satellites														
	Eider			Endicott[1]			Sag Delta	TOTAL Duck Island	Midnight Sun	Aurora			Borealis			Orion			Polaris			Raven
	gas	inj	net	gas	inj	net	gas		gas	gas	inj	net	gas	inj	net	gas	inj	net	gas	inj	net	gas
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1981	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1982	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1983	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1984	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1985	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1986	-	-	-	0.195	-	0.195	-	0.195	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1987	-	-	-	8.237	5.615	2.622	-	2.622	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1988	-	-	-	34.834	28.023	6.811	-	6.811	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1989	-	-	-	41.194	33.033	8.161	0.236	8.397	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1990	-	-	-	42.490	35.523	6.967	1.416	8.383	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1991	-	-	-	60.246	51.136	9.110	2.347	11.457	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1992	-	-	-	97.047	85.082	11.965	0.703	12.668	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1993	-	-	-	120.116	100.682	19.434	0.529	19.963	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1994	-	-	-	116.810	102.534	14.276	0.259	14.535	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	127.191	113.839	13.352	0.152	13.504	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1996	-	-	-	123.968	111.638	12.330	0.099	12.429	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1997	-	-	-	124.737	111.495	13.242	0.157	13.399	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1998	2.122	-	2.122	119.981	109.440	10.541	0.122	12.785	0.130	-	-	-	-	-	-	-	-	-	-	-	-	-
1999	4.879	-	4.879	126.274	116.944	9.331	0.120	14.329	3.781	-	-	-	-	-	-	-	-	-	-	-	-	-
2000	2.428	-	2.428	140.704	128.599	12.105	0.095	14.628	9.288	1.083	-	1.083	-	-	-	-	-	-	-	-	-	-
2001	6.494	-	6.494	134.122	125.915	8.208	0.093	14.794	6.750	12.052	-	12.052	0.936	-	-	-	-	-	-	-	-	-
2002	3.658	-	3.658	134.693	124.402	10.291	0.096	14.044	9.879	12.609	3.486	9.123	9.681	-	-	0.058	-	-	1.182	-	-	-
2003	2.813	-	2.813	141.556	129.458	12.098	0.064	14.975	3.500	11.971	0.357	11.614	9.466	-	-	0.312	-	-	1.000	-	-	-
2004	0.930	-	0.930	130.206	117.797	12.410	0.020	13.359	6.191	9.869	5.395	4.474	6.997	-	-	1.624	-	-	0.993	-	-	-
2005	1.160	-	1.160	139.143	126.081	13.062	0.032	14.254	5.759	8.663	3.007	5.656	5.610	2.342	3.268	3.703	-	-	1.280	-	-	1.015
2006	2.003	-	2.003	121.004	110.356	10.647	0.046	12.696	3.697	11.460	3.866	7.594	5.801	11.467	-5.666	1.784	0.150	1.634	0.852	0.388	0.464	3.275
TOTAL	26.486	-	26.486	2,084.748	1,867.590	217.157	6.585	250.228	48.974	67.705	16.111	51.595	38.491	13.808	-2.398	7.482	0.150	1.634	5.307	0.388	0.464	4.291

North Slope (Billion Cubic Feet per Year)

	Prudhoe Bay Initial Oil PA				Greater Point McIntyre Area (GPMA)[1]												
	Prudhoe Bay[2]			Total Prudhoe Bay IPA & Satellites	Lisburne			Niakuk[2]	North Prudhoe Bay	Point McIntyre			West Beach			TOTAL GPMA	TOTAL Prudhoe Bay Unit
	gas	inj	net		gas	inj	net	gas	gas	gas	inj	net	gas	inj	net		
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	0.243	-	0.243	0.243	-	-	-	-	-	-	-	-	-	-	-	-	0.243
1970	1.037	-	1.037	1.037	-	-	-	-	-	-	-	-	-	-	-	-	1.037
1971	0.889	-	0.889	0.889	-	-	-	-	-	-	-	-	-	-	-	-	0.889
1972	0.658	-	0.658	0.658	-	-	-	-	-	-	-	-	-	-	-	-	0.658
1973	0.699	-	0.699	0.699	-	-	-	-	-	-	-	-	-	-	-	-	0.699
1974	2.022	-	2.022	2.022	-	-	-	-	-	-	-	-	-	-	-	-	2.022
1975	3.046	-	3.046	3.046	-	-	-	-	-	-	-	-	-	-	-	-	3.046
1976	5.077	-	5.077	5.077	-	-	-	-	-	-	-	-	-	-	-	-	5.077
1977	94.936	68.118	26.818	26.818	-	-	-	-	-	-	-	-	-	-	-	-	26.818
1978	307.966	271.854	36.112	36.112	-	-	-	-	-	-	-	-	-	-	-	-	36.112
1979	432.475	390.136	42.339	42.339	-	-	-	-	-	-	-	-	-	-	-	-	42.339
1980	597.148	546.510	50.638	50.638	-	-	-	-	-	-	-	-	-	-	-	-	50.638
1981	647.768	595.106	52.662	52.662	0.003	-	0.003	-	-	-	-	-	-	-	-	0.003	52.665
1982	756.884	697.812	59.072	59.072	0.374	-	0.374	-	-	-	-	-	-	-	-	0.374	59.446
1983	818.993	754.044	64.949	64.949	0.154	-	0.154	-	-	-	-	-	-	-	-	0.154	65.103
1984	846.674	768.899	77.775	77.775	0.343	-	0.343	-	-	-	-	-	-	-	-	0.343	78.118
1985	936.613	846.786	89.827	89.827	1.902	-	1.902	-	-	-	-	-	-	-	-	1.902	91.729
1986	970.290	882.882	87.408	87.408	8.677	-	8.677	-	-	-	-	-	-	-	-	8.677	96.085
1987	1,228.527	1,105.023	123.504	123.504	64.906	56.741	8.165	-	-	-	-	-	-	-	-	8.165	131.669
1988	1,404.992	1,248.094	156.898	156.898	94.670	87.815	6.855	-	-	-	-	-	-	-	-	6.855	163.753
1989	1,412.853	1,244.284	168.569	168.569	104.746	102.248	2.498	-	-	-	-	-	-	-	-	2.498	171.067
1990	1,481.462	1,317.106	164.356	164.356	107.592	101.542	6.050	-	-	-	-	-	-	-	-	6.050	170.406
1991	1,768.837	1,583.472	185.365	185.365	124.360	112.457	11.903	-	-	-	-	-	-	-	-	11.903	197.268
1992	1,951.156	1,761.397	189.759	189.759	154.468	141.598	12.870	-	-	-	-	-	-	-	-	12.870	202.629
1993	2,116.808	1,921.633	195.175	195.175	130.882	122.991	7.891	-	1.103	5.392	3.979	1.413	0.592	-	0.592	10.999	206.174
1994	2,402.584	2,204.235	198.349	198.349	101.260	99.748	1.512	2.471	2.646	38.795	34.461	4.334	1.119	-	1.119	12.082	210.431
1995	2,716.959	2,497.702	219.257	219.257	80.866	104.272	-23.406	7.241	2.482	46.637	21.687	24.950	0.446	-	0.446	11.713	230.970
1996	2,750.907	2,535.603	215.304	215.304	67.013	93.000	-25.987	8.757	0.206	56.584	30.444	26.140	2.720	-	2.720	11.836	227.140
1997	2,794.735	2,577.617	217.118	217.118	39.999	75.249	-35.250	10.523	-	70.009	35.945	34.064	2.739	-	2.739	12.076	229.194
1998	2,801.402	2,588.527	212.875	213.005	33.111	50.399	-17.288	8.381	0.018	70.828	49.276	21.552	0.545	-	0.545	13.208	226.213
1999	2,772.147	2,566.580	205.567	209.360	33.214	52.187	-18.973	8.469	0.114	62.586	41.672	20.915	4.452	-	4.452	14.976	219.884
2000	2,913.985	2,716.721	197.265	207.953	52.322	62.621	-10.299	5.069	0.049	57.664	43.549	14.115	5.638	-	5.638	14.572	216.887
2001	2,757.974	2,577.173	180.801	200.539	57.490	55.529	1.961	5.836	-	56.251	43.549	12.702	1.453	-	1.453	21.952	221.038
2002	2,761.753	2,570.664	191.090	211.199	63.745	52.214	11.531	4.287	-	57.465	55.078	2.387	0.048	2.606	-2.558	15.647	226.846
2003	2,840.910	2,617.182	223.728	249.619	66.748	52.165	14.583	3.386	-	51.777	64.363	-12.587	0.201	-	0.201	5.584	255.203
2004	2,885.902	2,651.341	234.562	254.219	56.340	48.826	7.514	3.022	-	64.808	72.967	-8.159	0.059	-	0.059	2.436	256.655
2005	2,823.514	2,602.692	220.822	241.503	57.695	42.929	14.765	2.481	0.035	76.822	74.727	2.095	0.017	-	0.017	19.393	260.896
2006	2,444.835	2,230.128	214.707	225.706	65.652	38.448	27.204	2.259	-	42.234	61.106	-18.872	-	-	-	10.592	236.298
TOTAL	53,455.661	48,939.320	4,516.341	4,648.029	1,568.532	1,552.979	15.553	72.183	6.652	757.851	632.803	125.048	20.030	2.606	17.424	236.860	4,873.345

Notes:
[1]Liquids from the Greater Point McIntyre Area flows to both the Lisburne Production Center (LPC) and the Prudhoe Bay Field facilities. At the LPC gas from these liquids is returned and reinjected into the GPMA fields. Consequen ly, production and injection data may appear to be anomalous.
[2]Niakuk production volumes for 1994-1999 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk Pool."

North Slope (Billion Cubic Feet per Year)

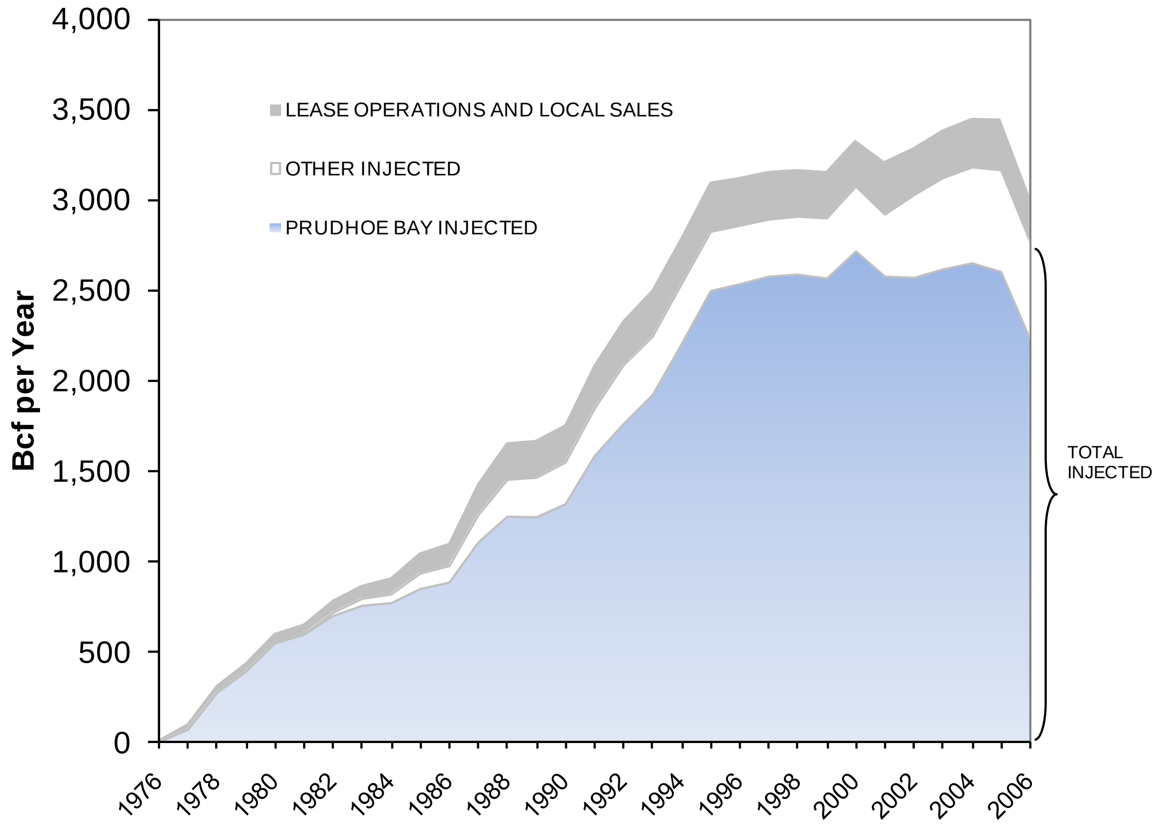
	Kuparuk River Unit													
	Kuparuk			Tabasco	Tarn			West Sak[1]			Meltwater			TOTAL Kuparuk River Unit
	gas	inj	net	gas	gas	inj	net	gas	inj	net	gas	inj	net	
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1981	0.615	-	0.615	-	-	-	-	-	-	-	-	-	-	0.615
1982	22.989	17.822	5.167	-	-	-	-	-	-	-	-	-	-	5.167
1983	44.391	38.277	6.114	-	-	-	-	0.005	-	-	-	-	-	6.114
1984	57.389	47.930	9.459	-	-	-	-	0.079	-	-	-	-	-	9.459
1985	104.279	85.909	18.370	-	-	-	-	0.134	-	-	-	-	-	18.370
1986	114.889	90.449	24.440	-	-	-	-	0.108	-	-	-	-	-	24.440
1987	125.089	89.191	35.898	-	-	-	-	-	-	-	-	-	-	35.898
1988	119.883	87.906	31.977	-	-	-	-	-	-	-	-	-	-	31.977
1989	107.519	83.323	24.196	-	-	-	-	-	-	-	-	-	-	24.196
1990	116.579	91.273	25.306	-	-	-	-	-	-	-	-	-	-	25.306
1991	123.207	95.982	27.225	-	-	-	-	-	-	-	-	-	-	27.225
1992	122.767	96.625	26.142	-	-	-	-	-	-	-	-	-	-	26.142
1993	120.599	94.339	26.260	-	-	-	-	-	-	-	-	-	-	26.260
1994	120.273	93.288	26.985	-	-	-	-	-	-	-	-	-	-	26.985
1995	112.418	84.317	28.101	-	-	-	-	-	-	-	-	-	-	28.101
1996	107.811	83.632	24.179	-	-	-	-	-	-	-	-	-	-	24.179
1997	105.644	85.893	19.751	-	-	-	-	-	-	-	-	-	-	19.751
1998	117.517	103.604	13.913	0.112	4.476	1.195	3.281	0.213	-	-	-	-	-	17.306
1999	117.193	98.330	18.863	0.305	13.395	16.502	-3.107	0.385	-	-	-	-	-	16.061
2000	109.638	97.762	11.875	0.203	17.777	16.552	1.225	0.399	-	-	-	-	-	13.304
2001	105.305	91.823	13.482	0.180	15.538	15.039	0.499	0.429	-	-	0.081	-	0 081	14.241
2002	100.938	81.157	19.782	0.159	13.101	16.755	-3.654	0.635	-	0 635	4.145	6.345	-2 200	14.721
2003	107.454	86.331	21.123	0.188	12.835	18.430	-5.596	0.813	0.171	0 642	5.595	5.562	0 033	16.391
2004	101.523	78.363	23.160	0.183	14.284	17.357	-3.073	2.069	0.121	1 948	7.322	11.596	-4 274	17.944
2005	97.292	71.011	26.281	0.345	13.366	19.331	-5.965	2.743	0.067	2 676	5.368	6.778	-1.410	21.927
2006	90.407	73.013	17.394	0.335	12.286	16.086	-3.800	5.079	0 088	4 990	4.278	4.108	0.170	19.090
TOTAL	2,573.609	2,047.550	526 059	2.009	117.059	137.248	-20.189	13.091	0.447	10.892	26.789	34.389	-7.600	511.170

North Slope (Billion Cubic Feet per Year)

	Milne Point Unit										Northstar			NORTH SLOPE		
	Kuparuk River PA			Sag River			Schrader Bluff			TOTAL Milne Point Unit	Northstar Oil Reservoir[1]			TOTAL GAS	TOTAL INJECTED	TOTAL NET
	gas	inj	net	gas	inj	net	gas	inj	net		gas	inj	net			
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	0.119	-	0.119
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	0.132	-	0.132
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	0.172	-	0.172
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	0.172	-	0.172
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	0.197	-	0.197
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	0.211	-	0.211
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	0.249	-	0.249
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	0.389	-	0.389
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	0.438	-	0.438
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	0.475	-	0.475
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	0.504	-	0.504
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	0.825	-	0.825
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	1.656	-	1.656
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	1.516	-	1.516
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	1.333	-	1.333
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	1.406	-	1.406
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	2.787	-	2.787
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	3.845	-	3.845
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	5.909	-	5.909
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	95.815	68.118	27.697
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	308.859	271 854	37.005
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	433.388	390.136	43.252
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	598.175	546 510	51.665
1981	-	-	-	-	-	-	-	-	-	-	-	-	-	649.432	595.106	54.326
1982	-	-	-	-	-	-	-	-	-	-	-	-	-	781.496	715.634	65.862
1983	-	-	-	-	-	-	-	-	-	-	-	-	-	864.773	792 321	72.452
1984	-	-	-	-	-	-	-	-	-	-	-	-	-	905.828	816 829	88.999
1985	0.253	-	0 253	-	-	-	-	-	-	0.253	-	-	-	1,044.491	932.695	111.796
1986	1.644	0.197	1.447	-	-	-	-	-	-	1.447	-	-	-	1,096.981	973 528	123.453
1987	0.011	-	0 011	-	-	-	-	-	-	0.011	-	-	-	1,427.982	1,256 570	171.412
1988	-	-	-	-	-	-	-	-	-	-	-	-	-	1,655.638	1,451 838	203.800
1989	0.978	0.320	0.658	-	-	-	-	-	-	0.658	-	-	-	1,668.759	1,463 208	205.551
1990	2.718	1.401	1 317	-	-	-	-	-	-	1.317	-	-	-	1,753.478	1,546 845	206.633
1991	3.515	1.704	1 811	-	-	-	0.244	-	0.244	2.055	-	-	-	2,084.001	1,844.751	239.250
1992	3.015	1.632	1 383	-	-	-	0.536	-	0.536	1.919	-	-	-	2,331.011	2,086 334	244.677
1993	2.967	1.836	1.131	-	-	-	0.518	-	0.518	1.649	-	-	-	2,500.791	2,245.460	255.331
1994	3.524	2.305	1 219	-	-	-	0.515	-	0.515	1.734	-	-	-	2,791.598	2,536 571	255.027
1995	4.340	3.399	0 941	0.113	-	-	0.656	-	0.656	1.597	-	-	-	3,100.761	2,825 216	275.545
1996	6.120	4.307	1 813	0.299	-	-	0.464	-	0.464	2.277	-	-	-	3,126.223	2,858.624	267.599
1997	9.463	6.998	2.465	0.437	-	-	0.644	-	0.644	3.109	-	-	-	3,160.368	2,893.197	267.171
1998	8.949	6.351	2 598	0.179	-	-	1.008	-	1.008	3.606	-	-	-	3,170.890	2,908.797	262.093
1999	8.371	6.137	2 234	0.019	-	-	1.199	-	1.199	3.433	-	-	-	3,160.054	2,900 069	259.985
2000	8.207	6.195	2 012	-	-	-	1.480	-	1.480	3.492	-	-	-	3,334.155	3,076 018	258.137
2001	8.631	7.498	1.133	0.228	-	-	2.380	-	2.380	3.513	2.686	3.697	-1.011	3,215.301	2,920.702	294.599
2002	7.054	8.697	-1.643	0.179	0.653	-0.474	9.272	0 927	8.345	6.227	47.616	64.396	-16.781	3,290.999	3,028 516	262.483
2003	5.337	7.757	-2.420	0.121	0.179	-0.058	6.095	-	6.095	3.617	70.862	101.268	-30.407	3,389.711	3,122 902	266.810
2004	6.554	7.964	-1.410	0.028	0.179	-0.042	5.108	-	5.108	3.656	104.383	131.501	-27.118	3,454.559	3,182.420	272.139
2005	5.894	7.610	-1.717	0.125	0.075	0.050	5.285	-	5.285	3.619	142.131	165.712	-23.581	3,451.417	3,166.434	284.983
2006	6.168	5.671	0.496	0.107	-	0.107	2.942	0 061	2.881	3.484	142.193	164.066	-21.873	3,026.496	2,768 902	257.594
TOTAL	97.544	82.308	15 236	1.727	1.087	-0.524	35.404	0 927	37.358	52.673	509.870	630.640	-120.770	61,896.596	56,186.103	5,710.493

Notes:
[1] Gas from Prudhoe Bay Field is sold to Northstar for injec ion.

Figure III.2 ANS Gas Production 1977 - 2006



Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports).

Cook Inlet (Billion Cubic Feet per Year)

	Albert Kaloa	Beaver Creek			Beluga River	Birch Hill	Cannery Loop[1]	Deep Creek	Ninilchik[2]	Granite Point	Ivan River	Kasilof	Kenai[3]	Lewis River	McArthur River (TBU)[4]	Middle Ground Shoal	Moquawkie Lone Creek	Nicolai Creek
	gas	gas	inj	net	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	0.215	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	1.460	-	-	-	-	-
1963	-	-	-	-	0.014	-	-	-	-	-	-	-	3.106	-	-	-	-	-
1964	-	-	-	-	0.137	-	-	-	-	-	-	-	4.493	-	-	-	-	-
1965	-	-	-	-	-	0.065	-	-	-	-	-	-	5.985	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	0.019	-	-	-	33.375	-	-	1.200	-	-
1967	-	-	-	-	0.168	-	-	-	-	4.890	-	-	39.624	-	0.220	3.215	0.034	-
1968	-	-	-	-	2.018	-	-	-	-	10.036	-	-	46.014	-	6.155	6.654	0.353	0.026
1969	-	-	-	-	3.038	-	-	-	-	8.043	-	-	59.340	-	14.194	6.006	0.514	0.387
1970	0.095	-	-	-	3.571	-	-	-	-	9.211	-	-	80.612	-	19.688	6.137	0.083	0.202
1971	0.024	-	-	-	4.055	-	-	-	-	7.753	-	-	72.184	-	19.304	5.147	-	0.141
1972	-	0.002	-	0.002	4.142	-	-	-	-	5.773	-	-	76.007	-	19.722	4.075	-	0.066
1973	-	0.207	-	0.207	4.929	-	-	-	-	4.518	-	-	71.345	-	19.063	4.826	-	0.006
1974	-	0.150	0.019	0.131	5.596	-	-	-	-	3.265	-	-	68.485	-	19.599	4.260	-	0.011
1975	-	0.322	-	0.322	6.980	-	-	-	-	3.390	-	-	77.175	-	21.471	4.199	-	0.083
1976	-	0.261	0.091	0.170	11.211	-	-	-	-	3.205	-	-	79.467	-	19.027	4.347	-	0.108
1977	-	0.203	0.100	0.103	13.353	-	-	-	-	3.634	-	-	81.886	-	19.706	4.108	-	0.032
1978	-	0.329	0.144	0.185	14.253	-	-	-	-	3.860	-	-	97.290	-	18.585	3.290	-	-
1979	-	0.182	0.079	0.103	16.994	-	-	-	-	3.287	-	-	97.029	-	16.605	2.744	-	-
1980	-	0.180	0.029	0.151	17.002	-	-	-	-	3.233	-	-	98.846	-	15.590	2.628	-	-
1981	-	0.217	0.020	0.197	17.248	-	-	-	-	3.509	-	-	105.800	-	15.206	2.502	-	-
1982	-	0.396	0.037	0.359	18.653	-	-	-	-	2.780	-	-	115.913	-	16.240	2.374	-	-
1983	-	8.344	0.031	8.313	18.084	-	-	-	-	2.578	-	-	112.978	-	14.375	2.663	-	-
1984	-	9.335	-	9.335	19.833	-	-	-	-	2.340	-	-	110.109	0.696	15.076	2.726	-	-
1985	-	10.927	-	10.927	22.571	-	-	-	-	2.147	-	-	115.842	1.644	10.676	2.622	-	-
1986	-	17.773	-	17.773	25.357	-	-	-	-	2.415	-	-	82.470	1.338	13.560	1.593	-	-
1987	-	15.528	-	15.528	23.971	-	-	-	-	2.431	-	-	90.014	0.345	13.277	1.586	-	-
1988	-	14.346	-	14.346	25.586	-	9.400	-	-	2.543	-	-	76.299	0.045	16.722	1.635	-	-
1989	-	12.321	-	12.321	30.126	-	11.255	-	-	2.251	-	-	65.706	0.095	31.000	1.965	-	-
1990	-	12.474	-	12.474	39.512	-	12.502	-	-	1.431	0.676	-	38.393	1.485	51.456	2.579	-	-
1991	-	10.403	-	10.403	38.494	-	12.318	-	-	1.586	2.132	-	25.581	1.420	61.196	1.587	-	-
1992	-	7.368	-	7.368	36.534	-	10.635	-	-	2.246	1.774	-	24.187	0.706	70.070	2.377	-	-
1993	-	6.336	-	6.336	31.739	-	9.516	-	-	2.444	8.238	-	23.826	0.383	62.512	2.941	-	-
1994	-	1.304	-	1.304	34.212	-	6.361	-	-	2.077	15.996	-	18.853	0.244	50.027	3.025	-	-
1995	-	1.915	-	1.915	35.645	-	5.535	-	-	1.942	12.027	-	16.484	0.126	54.914	2.138	-	-
1996	-	3.042	-	3.042	36.930	-	2.072	-	-	2.251	6.605	-	13.294	0.114	67.275	0.852	-	-
1997	-	4.626	-	4.626	35.002	-	3.130	-	-	2.551	5.297	-	12.672	0.066	66.838	1.051	-	-
1998	-	3.743	-	3.743	33.391	-	3.021	-	-	2.635	4.532	-	9.736	0.102	73.822	1.882	-	-
1999	-	3.288	-	3.288	35.987	-	2.871	-	-	2.464	3.579	-	9.916	0.246	68.997	2.751	-	-
2000	-	4.793	-	4.793	38.750	-	4.692	-	-	2.209	2.620	-	12.833	0.134	65.016	1.485	-	-
2001	-	5.340	-	5.340	41.786	-	6.304	-	-	1.936	3.799	-	19.964	0.220	62.264	1.319	-	0.278
2002	-	8.548	-	8.548	44.039	-	5.016	-	-	1.658	4.303	-	22.154	0.898	51.515	0.918	-	0.605
2003	-	7.868	-	7.868	56.252	-	6.143	-	3.044	1.378	2.471	-	28.586	0.575	39.216	0.654	1.015	0.262
2004	0.439	8.338	-	8.338	57.618	-	13.640	0.299	12.367	1.332	1.670	-	24.217	0.369	34.408	0.415	2.548	0.983
2005	1.433	5.413	-	5.413	55.860	-	14.822	3.737	14.252	1.191	1.190	-	22.008	0.322	30.777	0.397	1.935	0.188
2006	0.716	5.499	-	5.499	55.364	-	11.517	2.813	17.655	0.989	1.154	0.865	22.342	0.017	25.392	0.306	2.154	0.537
TOTAL	2.707	191.323	0.550	190.773	1,016.004	0.065	150.750	6.849	47.338	129.411	78.063	0.865	2,314.116	11.589	1,310.756	109.178	8.636	3.914

Notes:
[1] Cannery Loop includes CLU Beluga, CLU Upper Tyonek, CLU Tyonek D, and CLU Sterling Undefined in the Kenai formation.
[2] Ninilchik includes Falls Creek, Grassim Oskolk, Susan Dionne, and Paxton Pools.
[3] Kenai produced from Sterling Pools 3, 4, and 6; Tyonek gas pool; and Upper Tyonek-Beluga Pool.
[4] Includes dry gas from Middle Kenai Gas (Grayling Gas Sands), and casing gas from he Hemlock, W Foreland, and Mid Kenai G Oil Pools.

Cook Inlet (Billion Cubic Feet per Year)

	North Cook Inlet	North Fork	North Trading Bay Gas Sands[3]	Pretty Creek	ReDoubt	Sterling	Stump Lake	Swanson River[4]			Three Mile Creek	Trading Bay[5]	West Fork	West Fore-land	West McArthur River	Wolf Lake Kustatan
	gas	gas	gas	gas	gas	gas	gas	gas	inj	net	gas	gas	gas	gas	gas	gas
1958	-	-	-	-	-	-	-	0.006	-	0.006		-	-	-	-	-
1959	-	-	-	-	-	-	-	0.027	-	0.027		-	-	-	-	-
1960	-	-	-	-	-	-	-	0.119	46.482	-		-	-	-	-	-
1961	-	-	-	-	-	-	-	1.293	-	1.293		-	-	-	-	-
1962	-	-	-	-	-	0.025	-	2.071	0 259	1.812		-	-	-	-	-
1963	-	-	-	-	-	0.046	-	7.646	6.478	1.168		-	-	-	-	-
1964	-	-	-	-	-	0.058	-	7.176	5 620	1.556		-	-	-	-	-
1965	-	-	-	-	-	0.120	-	5.973	4 843	1.130		-	-	-	-	-
1966	-	0.105	-	-	-	0.157	-	6.363	28.770	-		-	-	-	-	-
1967	-	-	-	-	-	0.180	-	13.541	37 944	-		0.722	-	-	-	-
1968	-	-	0.045	-	-	0.198	-	25.434	58 316	-		2 916	-	-	-	-
1969	7.881	-	1.175	-	-	0.265	-	40.756	67 215	-		5 944	-	-	-	-
1970	40.947	-	0.725	-	-	0.265	-	50.396	73.139	-		6.430	-	-	-	-
1971	45.024	-	0.419	-	-	0.267	-	66.569	73 892	-		8 678	-	-	-	-
1972	41.580	-	0.635	-	-	0.172	-	67.441	76.133	-		5 033	-	-	-	-
1973	42.709	-	0.588	-	-	0.027	-	74.067	87.482	-		2 951	-	-	-	-
1974	44.238	-	0.600	-	-	0.032	-	80.869	86.793	-		2.712	-	-	-	-
1975	45.622	-	0.478	-	-	0.035	-	90.665	97 976	-		2.134	-	-	-	-
1976	45.091	-	0.318	-	-	0.035	-	101.427	113 279	-		2.155	-	-	-	-
1977	47.201	-	0.272	-	-	0.029	-	106.911	118 279	-		2 619	-	-	-	-
1978	46.757	-	0.217	-	-	0.024	-	106.934	114 557	-		2 211	0.052	-	-	-
1979	49.448	-	0.153	-	-	0.025	-	116.266	120 268	-		1 560	0.770	-	-	-
1980	41.540	-	0.197	-	-	0.026	-	118.855	120 636	-		1 355	0.476	-	-	-
1981	49.486	-	0.264	-	-	0.023	-	103.592	106.137	-		1.160	0.030	-	-	-
1982	45.368	-	0.445	-	-	0.024	-	105.654	113 023	-		1.187	0.086	-	-	-
1983	47.877	-	0.660	-	-	0.022	-	97.505	95 353	2.152		0 896	0.067	-	-	-
1984	46.981	-	0.649	-	-	0.018	-	96.710	93 687	3.023		0 911	0.037	-	-	-
1985	45.819	-	0.526	-	-	0.012	-	92.104	89 025	3.079		1 005	0.022	-	-	-
1986	43.838	-	0.513	0.067	-	0.002	-	95.083	93 602	1.481		0 866	-	-	-	-
1987	42.889	-	0.537	0.776	-	-	-	84.063	87 013	-2.950		0 897	-	-	-	-
1988	44.989	-	0.270	0.871	-	-	-	102.600	99.734	2.866		1 041	-	-	-	-
1989	45.287	-	0.217	0.641	-	-	-	104.094	107 802	-3.708		1 215	-	-	-	-
1990	45.014	-	0.060	0.607	-	-	0 528	104.395	106 031	-1.636		0.407	-	-	-	-
1991	44.695	-	0.079	0.742	-	-	1 608	105.057	105.157	-0.100		0 865	0.460	-	-	-
1992	44.411	-	0.013	0.762	-	-	1 504	104.533	104.724	-0.191		0 692	1.364	-	-	-
1993	45.529	-	-	0.333	-	0.007	0.778	97.701	93 052	4.649		0 619	0.625	-	0 031	-
1994	52.689	-	-	0.203	-	0.224	0.454	124.420	97.148	27.272		0 648	0.206	-	0 216	-
1995	53.541	-	-	0.256	-	0.184	0 288	101.781	73 086	28.695		0 526	0.016	-	0 231	-
1996	55.976	-	0.023	0.301	-	0.037	0.185	76.159	42 820	33.339		0 386	-	-	0 309	-
1997	52.466	-	0.511	0.383	-	0.005	0.132	51.898	23.163	28.735		1.122	-	-	0.152	-
1998	53.964	-	0.695	0.435	-	-	0 080	36.917	11 089	25.828		0 843	-	-	0 241	-
1999	51.629	-	0.241	0.028	-	0.125	0 054	37.483	7.731	29.752		0.445	-	-	0 212	-
2000	52.841	-	0.152	-	-	0.329	0 032	32.421	2.729	29.692		0.469	-	-	0 211	-
2001	55.531	-	-	0.080	-	0.149	0 000	30.405	7 378	23.027		0.420	-	-	0 288	0.114
2002	54.574	-	-	1.359	0 008	0.552	-	14.687	0 959	13.728		0.449	-	0.060	0 239	0.300
2003	47.920	-	0.101	0.428	0 673	0.358	0 000	9.292	0 004	9.287		0 263	-	0.940	0 200	0.240
2004	41.012	-	0.027	0.658	0.138	0.300	-	6.266	-	6.266		0 205	-	1.025	0.158	0.073
2005	45.560	-	0.416	0.411	0 077	1.874	-	4.349	-	4.349	0.453	0 313	0.286	2.604	0.125	0.135
2006	38.155	-	0.012	0.016	0 065	2.204	-	3.486	-	3.486	0.626	0 372	0.639	3.350	0.148	0.233
TOTAL	1,746.080	0.105	12.234	9.358	0 961	8.434	5 644	2,913.460	2,898 808	279.114	1.079	65 642	5.136	7.979	2.760	1.096

Notes:

[3] Includes dry gas quantities from Trading Bay Undefined Gas sands initially produced from Spurr Platform; later from Spark Platform.

[4] Swanson River gas is produced from Hemlock Oil Pool, Sterling Undefined Gas Pool, and Tyonek Undefined Pool. Gas from other fields was injected into the Swanson River Hemlock Oilfield to maintain reservoir pressure and enhance oil recovery until 2003. The very high gas injection volume for 1960 was an accounting adjustment. Gas has been injected into the Tyonek Formation for storage purposes since 2001. In all previous editions of the DOG Annual Report, Swanson River injection volumes included storage gas. As of this 2007 Annual Report, injection for storage purposes is reported separately.

[5] Includes only casing gas produced from the following oil pools: Hemlock, Middle Kenai B through E, and Undefined.

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports).

Cook Inlet (Billion Cubic Feet per Year)

	COOK INLET GAS PRODUCTION			COOK INLET GAS STORAGE								
	TOTAL GROSS	TOTAL NJECTED	TOTAL NET	Swanson River Tyonek[1]			Pretty Creek Beluga[2]			Kenai River Sterling Pool 6[3]		
				inj	wd	net	inj	wd	net	inj	wd	net
1958	0 006	-	0.006	-	-	-	-	-	-	-	-	-
1959	0 027	-	0.027	-	-	-	-	-	-	-	-	-
1960	0.119	46.482	-	-	-	-	-	-	-	-	-	-
1961	1 508	-	1.508	-	-	-	-	-	-	-	-	-
1962	3 556	0.259	3.297	-	-	-	-	-	-	-	-	-
1963	10 812	6.478	4.334	-	-	-	-	-	-	-	-	-
1964	11 864	5.620	6.244	-	-	-	-	-	-	-	-	-
1965	12.143	4.843	7.300	-	-	-	-	-	-	-	-	-
1966	41 219	28.770	12.449	-	-	-	-	-	-	-	-	-
1967	62 594	37.944	24.650	-	-	-	-	-	-	-	-	-
1968	99 849	58.316	41.533	-	-	-	-	-	-	-	-	-
1969	147 543	67.215	80.328	-	-	-	-	-	-	-	-	-
1970	218 362	73.139	145.223	-	-	-	-	-	-	-	-	-
1971	229 565	73.892	155.673	-	-	-	-	-	-	-	-	-
1972	224 648	76.133	148.515	-	-	-	-	-	-	-	-	-
1973	225 236	87.482	137.754	-	-	-	-	-	-	-	-	-
1974	229 817	86.812	143.005	-	-	-	-	-	-	-	-	-
1975	252 554	97.976	154.578	-	-	-	-	-	-	-	-	-
1976	266 652	113.370	153.282	-	-	-	-	-	-	-	-	-
1977	279 954	118.379	161.575	-	-	-	-	-	-	-	-	-
1978	293 802	114.701	179.101	-	-	-	-	-	-	-	-	-
1979	305 063	120.347	184.716	-	-	-	-	-	-	-	-	-
1980	299 928	120.665	179.263	-	-	-	-	-	-	-	-	-
1981	299 037	106.157	192.880	-	-	-	-	-	-	-	-	-
1982	309.120	113.060	196.060	-	-	-	-	-	-	-	-	-
1983	306 049	95.384	210.665	-	-	-	-	-	-	-	-	-
1984	305.421	93.687	211.734	-	-	-	-	-	-	-	-	-
1985	305 917	89.025	216.892	-	-	-	-	-	-	-	-	-
1986	284 875	93.602	191.273	-	-	-	-	-	-	-	-	-
1987	276 314	87.013	189.301	-	-	-	-	-	-	-	-	-
1988	296 347	99.734	196.613	-	-	-	-	-	-	-	-	-
1989	306.173	107.802	198.371	-	-	-	-	-	-	-	-	-
1990	311 519	106.031	205.488	-	-	-	-	-	-	-	-	-
1991	308 223	105.157	203.066	-	-	-	-	-	-	-	-	-
1992	309.176	104.724	204.452	-	-	-	-	-	-	-	-	-
1993	293 558	93.052	200.506	-	-	-	-	-	-	-	-	-
1994	311.159	97.148	214.011	-	-	-	-	-	-	-	-	-
1995	287 549	73.086	214.463	-	-	-	-	-	-	-	-	-
1996	265 811	42.820	222.991	-	-	-	-	-	-	-	-	-
1997	237 902	23.163	214.739	-	-	-	-	-	-	-	-	-
1998	226 039	11.089	214.950	-	-	-	-	-	-	-	-	-
1999	220 318	7.731	212.587	-	-	-	-	-	-	-	-	-
2000	218 988	2.729	216.258	-	-	-	-	-	-	-	-	-
2001	230.197	7.378	222.819	0.897	0.363	0 534	-	-	-	-	-	-
2002	211 882	0.959	210.923	0.951	1.025	-0 074	-	-	-	-	-	-
2003	207 877	0.004	207.873	1.075	0.392	0 683	-	-	-	-	-	-
2004	208 504	-	208.504	0.753	0.448	0 305	-	-	-	-	-	-
2005	210.127	-	210.127	1.340	1.297	0 043	0 215	-	0.215	-	-	-
2006	196 628	-	196.628	2.888	1.785	1.103	0.798	0.008	0.790	1 529	2.493	-0.964
TOTAL	10,161 530	2,899.358	7,308.534	7.903	5.311	2 592	1 012	0.008	1.004	1 529	2.493	-0.964

Notes:
inj = gas injected into the storage formation.
wd = withdrawn gas includes all gas withdrawn from the storage reservoir during the reporting period.
Negative net injec ions mean gas was drawn down from the reservoir's originally in place native or cushion gas volume.

[1] Does not include natural gas injected into the Hemlock Formation for secondary oil recovery. Injections into the Tyonek Formation for the purposes of storage began in June 2001.

[2] Gas Storage Injection into the nearly depleted Beluga Formation began in November 2005.

[3] Gas Storage Injection into the Sterling 6 Gas Pool began in May 2006.

North Slope (Millions of Barrels per Year)

	Badami	Colville River	Northstar	Duck Island Unit	Prudhoe Bay IPAs[2]	Prudhoe Bay Satellites	Greater Pt McIntyre Area[3]	PBU IPA+Sat+GPMA	Kuparuk IPA	Kuparuk Satellites	KRU IPA+Sat	Milne Point Unit	Other North Slope	NPRA[5]	TOTAL North Slope
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	0.1	-	-	0.1	-	-	-	-	-	-	0.1
1970	-	-	-	-	0.3	-	-	0.3	0.0	-	0.0	-	-	-	0.3
1971	-	-	-	-	0.3	-	-	0.3	-	-	-	-	-	-	0.3
1972	-	-	-	-	0.1	-	-	0.1	-	-	-	-	-	-	0.1
1973	-	-	-	-	0.1	-	-	0.1	-	-	-	-	-	-	0.1
1974	-	-	-	-	0.5	-	-	0.5	-	-	-	-	-	-	0.5
1975	-	-	-	-	0.7	-	-	0.7	-	-	-	-	-	-	0.7
1976	-	-	-	-	1.0	-	-	1.0	-	-	-	-	-	-	1.0
1977	-	-	-	-	113.2	-	-	113.2	-	-	-	-	-	-	113.2
1978	-	-	-	-	397.7	-	-	397.7	-	-	-	-	-	-	397.7
1979	-	-	-	-	468.4	-	-	468.4	-	-	-	-	-	-	468.4
1980	-	-	-	-	555.6	-	-	555.6	-	-	-	-	-	-	555.6
1981	-	-	-	-	555.6	-	0.0	555.6	1.1	-	1.1	-	-	-	556.7
1982	-	-	-	-	559.4	-	0.2	559.6	32.4	-	32.4	-	-	-	592.0
1983	-	-	-	-	561.1	-	0.1	561.2	39.9	0.0	39.9	-	-	-	601.1
1984	-	-	-	-	562.3	-	0.3	562.6	46.1	0.1	46.2	-	-	-	608.8
1985	-	-	-	-	568.6	-	1.1	569.7	79.7	0.3	80.0	0.7	-	-	650.4
1986	-	-	-	0.0	561.8	-	3.6	565.4	95.0	0.3	95.3	4.7	-	-	665.3
1987	-	-	-	8.8	586.7	-	16.7	603.3	103.7	-	103.7	0.0	-	-	715.8
1988	-	-	-	37.9	578.7	-	16.1	594.8	111.1	-	111.1	-	-	-	743.9
1989	-	-	-	36.9	522.9	-	14.8	537.7	109.8	-	109.8	3.7	-	-	688.1
1990	-	-	-	38.6	486.2	-	15.9	502.1	107.2	-	107.2	6.6	-	-	654.5
1991	-	-	-	42.5	486.7	-	14.7	501.4	113.6	-	113.6	7.5	-	-	664.9
1992	-	-	-	43.1	456.5	-	14.0	470.5	118.5	-	118.5	6.9	-	-	639.0
1993	-	-	-	40.8	409.7	-	18.5	428.2	115.2	-	115.2	6.8	-	-	590.9
1994	-	-	-	35.8	374.3	-	50.7	425.0	111.8	-	111.8	6.7	-	-	579.3
1995	-	-	-	34.4	340.4	-	65.2	405.6	107.0	-	107.0	8.7	-	-	555.7
1996	-	-	-	27.7	312.6	-	75.6	388.2	99.5	-	99.5	14.1	-	-	529.4
1997	-	-	-	22.9	284.0	-	73.7	357.7	96.0	0.0	96.0	19.0	-	-	495.6
1998	0.7	-	-	18.6	252.8	0.061	61.9	314.8	91.7	4.6	96.3	20.4	-	-	450.8
1999	1.2	-	-	15.7	223.8	1.723	47.5	273.0	82.4	12.7	95.0	19.7	-	-	404.5
2000	0.9	2.2	-	13.5	217.2	2.117	36.1	255.4	74.1	12.2	86.3	19.1	-	-	377.4
2001	0.7	32.0	1.3	11.8	194.2	4.808	29.6	228.6	68.3	11.5	79.8	19.3	-	-	373.4
2002	0.6	35.0	17.9	10.3	177.6	14.856	24.6	217.1	58.9	18.5	77.4	18.7	-	-	377.0
2003	0.3	35.6	23.0	10.6	166.3	18.582	22.3	207.2	58.5	18.9	77.4	18.7	-	-	372.7
2004	-	36.1	25.1	8.5	153.2	16.973	21.6	191.8	53.2	18.6	71.8	18.7	-	-	352.0
2005	0.0	43.8	22.4	7.5	140.0	17.1	18.7	175.7	50.4	15.9	66.3	16.0	-	-	331.8
2006	0.5	44.2	18.9	6.0	110.8	15.6	13.5	139.8	45.5	17.0	62.5	13.3	-	-	285.2
2007	0.4	45.4	14.9	5.6	113.3	17.6	14.5	145.5	43.4	17.3	60.7	12.7	0.6	-	285.8
2008	0.3	43.5	12.0	5.5	115.6	21.0	15.9	152.5	41.6	18.0	59.7	13.3	3.5	-	290.3
2009	0.3	39.6	9.8	5.2	112.4	26.5	15.0	153.9	40.0	18.7	58.8	13.5	7.0	-	288.1
2010	0.3	36.1	8.2	5.1	109.3	31.4	13.9	154.6	38.1	19.9	58.0	14.0	9.4	2.1	287.7
2011	0.3	32.0	6.8	5.0	105.2	33.0	13.0	151.1	36.4	21.0	57.4	14.7	21.0	9.6	297.8
2012	0.2	28.1	5.8	5.1	100.3	31.2	12.1	143.6	34.8	21.8	56.6	15.7	27.5	15.1	297.7
2013	0.2	24.8	4.9	5.2	96.7	28.7	11.4	136.8	33.3	22.2	55.5	16.4	25.0	19.5	288.3
2014	0.2	21.7	4.2	5.4	93.5	26.4	10.7	130.6	32.0	22.6	54.6	16.3	22.0	22.9	277.9
2015	0.2	19.2	3.7	5.7	90.6	24.4	10.1	125.1	30.8	23.0	53.7	15.5	19.2	21.9	264.2
2016	0.1	17.0	3.2	6.0	87.9	22.6	9.6	120.1	29.6	23.3	52.9	14.7	31.7	19.4	265.1
2017	-	15.2	2.8	6.2	85.5	21.0	9.1	115.6	28.6	23.3	51.9	13.9	39.3	17.1	262.0
2018	-	13.7	2.4	6.3	84.6	19.5	8.6	112.7	27.6	23.6	51.2	13.3	38.0	15.1	252.8
2019	-	12.3	2.2	6.2	83.0	18.2	8.2	109.5	26.7	22.5	49.2	12.6	39.8	13.4	245.2
2020	-	11.2	1.9	6.0	73.2	17.0	7.8	98.0	25.8	20.4	46.3	12.0	40.5	11.8	227.6
2021	-	10.2	1.7	5.5	70.6	15.8	7.5	93.9	25.0	18.6	43.6	11.3	38.5	10.5	215.2
2022	-	9.3	1.5	5.0	68.0	14.8	7.2	90.0	24.3	16.8	41.1	10.8	35.5	9.3	202.4
2023	-	8.5	1.4	4.5	65.7	13.8	6.9	86.3	23.6	15.3	38.9	10.3	32.5	8.2	190.5
2024	-	7.8	1.2	3.9	63.4	13.0	6.6	82.9	22.9	13.9	36.8	9.8	29.8	7.3	179.5
2025	-	7.2	1.1	3.2	61.2	12.1	6.3	79.7	22.3	12.6	34.9	9.3	27.4	6.4	169.3
2026	-	6.7	1.0	2.6	59.2	11.4	6.1	76.7	21.7	11.5	33.2	8.9	25.3	5.7	160.1

Notes:

[1] Actual reported production from AOGCC Monthly Production Reports through 2006. Figures include NGLs.
Forecast production is based on sum of remaining recoverable reserves. Forecast horizon is 2006-2036, shown to 2026 in table and related chart.

[2] Oil Rim and Gas Cap. Historic figures include natural gas liquids produced at Prudhoe Bay and surrounding fields.

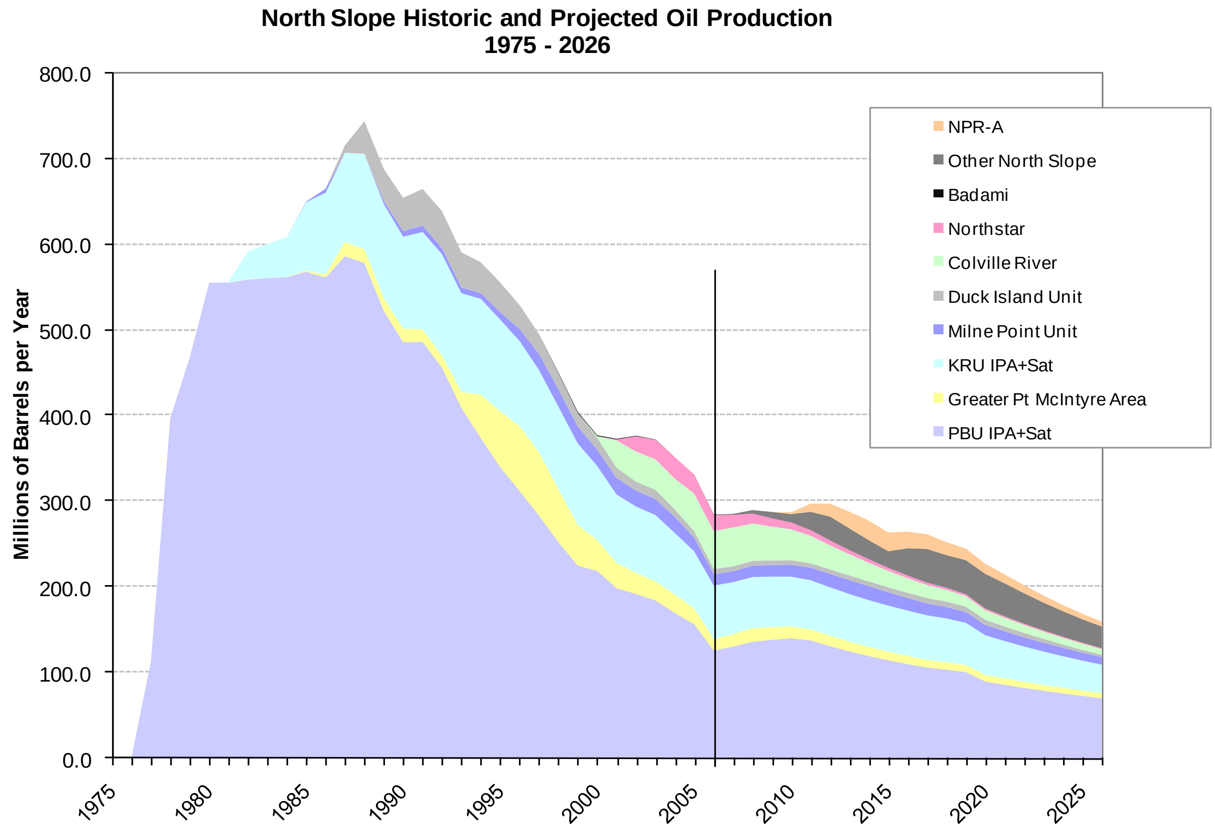
[3] Includes Lisburne, Niakuk, North Prudhoe Bay, Point MacIntyre PA, and West Beach.

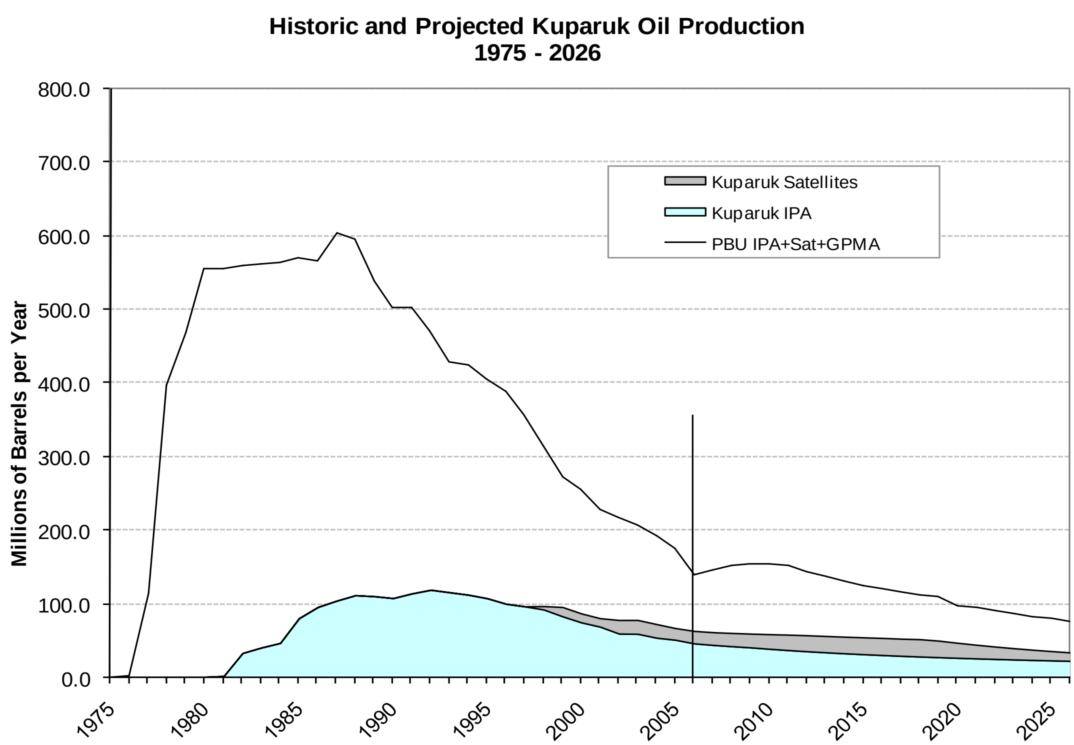
[4] Includes Liberty and other known onshore and offshore reserves.

[5] Based on U.S.G.S. estimates.

Sources: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports) and AK Dept. of Revenue (forecast).

North Slope (Millions of Barrels per Year)





Figures III.3A and III.3B correspond to Table III.7.

Cook Inlet[1] (Millions of Barrels per Year)

	Beaver Creek	Granite Point	McArthur River	Middle Ground Shoal	Redoubt (Osprey)	Swanson River	Trading Bay	West McArthur River	North Trading Bay	TOTAL OIL and NGL[2]
1958	-	-	-	-	-	0.036	-	-	-	0.036
1959	-	-	-	-	-	0.187	-	-	-	0.187
1960	-	-	-	-	-	0.558	-	-	-	0.558
1961	-	-	-	-	-	6.327	-	-	-	6.327
1962	-	-	-	-	-	10.259	-	-	-	10.259
1963	-	-	-	-	-	10.740	-	-	-	10.740
1964	-	-	-	-	-	11.054	-	-	-	11.054
1965	-	0.002	0.001	0.027	-	11.099	0.002	-	-	11.131
1966	-	-	0.003	2.649	-	11.712	-	-	-	14.364
1967	-	7.052	0.749	7.404	-	12.980	0.727	-	0.002	28.914
1968	-	13.131	21.782	14.134	0.002	13.623	3.292	-	0.185	66.149
1969	-	9.183	31.301	10.467	-	13.221	5.626	-	4.312	74.110
1970	-	7.522	40.591	12.719	-	12.471	6.374	-	3.267	82.944
1971	-	5.577	41.130	11.304	-	11.543	6.753	-	2.030	78.337
1972	0.002	4.663	41.344	9.719	-	8.908	6.058	-	2.555	73.249
1973	0.416	4.767	39.545	10.239	-	10.162	5.854	-	2.023	73.006
1974	0.375	4.237	39.799	9.001	-	9.861	5.468	-	2.127	70.868
1975	0.322	4.361	41.520	8.670	-	8.843	4.629	-	1.531	69.876
1976	0.302	4.471	36.463	8.864	-	7.681	4.296	-	1.097	63.174
1977	0.276	4.711	33.968	7.617	-	6.067	3.350	-	0.970	56.959
1978	0.223	4.867	30.953	6.382	-	4.935	2.789	-	0.798	50.947
1979	0.211	4.613	25.981	5.545	-	4.424	2.298	-	0.609	43.681
1980	0.214	4.394	21.306	4.854	-	3.788	1.800	-	0.372	36.728
1981	0.180	3.975	18.506	4.291	-	2.986	1.440	-	0.235	31.613
1982	0.182	3.467	16.255	3.573	-	3.047	1.253	-	0.132	27.909
1983	0.170	3.550	13.896	3.381	-	3.062	0.968	-	0.117	25.144
1984	0.159	3.287	12.024	3.238	-	2.556	1.000	-	0.080	22.344
1985	0.146	3.052	7.648	3.098	-	2.191	0.919	-	0.113	17.167
1986	0.158	3.169	8.170	3.211	-	2.109	0.828	-	0.220	17.865
1987	0.185	2.803	7.571	2.834	-	2.089	0.690	-	0.246	16.418
1988	0.141	2.677	7.305	2.742	-	2.160	0.691	-	0.195	15.911
1989	0.227	2.275	6.955	2.769	-	1.899	1.085	-	0.179	15.389
1990	0.212	1.462	4.265	2.688	-	1.897	0.522	-	0.121	11.167
1991	0.179	2.064	7.247	2.670	-	1.985	1.048	0.002	0.168	15.363
1992	0.175	2.522	7.397	2.423	-	1.792	0.856	0.002	0.030	15.197
1993	0.153	2.488	6.636	2.160	-	1.594	0.742	0.098	-	13.871
1994	0.140	2.209	7.091	2.785	-	1.695	0.743	0.921	-	15.584
1995	0.132	2.580	6.622	2.823	-	1.729	0.722	0.922	-	15.530
1996	0.125	2.556	6.102	2.396	-	1.540	0.589	1.296	-	14.604
1997	0.119	2.432	5.059	2.223	-	1.077	0.602	0.645	-	12.157
1998	0.103	2.079	4.817	2.156	-	0.920	0.700	1.037	-	11.812
1999	0.100	1.787	4.697	1.968	-	0.794	0.645	0.914	-	10.905
2000	0.092	1.742	4.822	1.894	0.002	0.638	0.637	0.893	-	10.720
2001	0.085	1.620	5.353	2.032	0.001	0.609	0.574	1.222	-	11.497
2002	0.079	1.527	5.510	1.959	0.046	0.477	0.666	1.018	-	11.284
2003	0.076	1.440	4.323	1.497	0.911	0.425	0.537	0.849	-	10.059
2004	0.068	1.433	3.373	1.323	0.559	0.320	0.462	0.669	-	8.208
2005	0.061	1.263	2.895	1.318	0.312	0.330	0.414	0.517	-	7.110
2006	0.077	1.094	2.504	1.192	0.262	0.262	0.311	0.437	-	6.140
2007	0.066	1.122	2.108	1.141	0.274	0.222	0.348	0.378	-	5.659
2008	0.063	1.067	1.837	1.079	0.257	0.193	0.320	0.331	-	5.147
2009	0.060	1.018	1.618	1.021	0.242	0.168	0.295	0.295	-	4.716
2010	0.057	0.972	1.438	0.968	0.227	0.146	0.274	0.266	-	4.349
2011	0.055	0.931	1.288	0.919	0.213	0.127	0.255	0.242	-	4.030
2012	0.053	0.893	1.162	0.873	0.200	0.110	0.239	0.222	-	3.752
2013	0.050	0.858	1.055	0.830	0.188	0.096	0.224	0.205	-	3.506
2014	0.048	0.825	0.962	0.791	0.177	0.084	0.211	0.191	-	3.288
2015	0.046	0.795	0.883	0.754	0.166	0.073	0.199	0.178	-	3.093
2016	0.044	0.767	0.813	0.719	0.156	0.063	0.188	0.167	-	2.918
2017	0.043	0.741	0.752	0.686	0.146	0.055	0.178	0.157	-	2.759
2018	0.041	0.717	0.697	0.656	0.138	0.048	0.169	0.149	-	2.615
2019	0.040	0.694	0.649	0.628	0.129	0.042	0.161	0.141	-	2.484
2020	0.038	0.673	0.606	0.601	0.121	0.036	0.154	0.134	-	2.363
2021	0.037	0.653	0.568	0.576	0.114	0.032	0.147	0.128	-	2.252
2022	0.036	0.634	0.533	0.552	0.107	0.027	0.140	0.122	-	2.151
2023	0.034	0.616	0.501	0.529	0.101	0.024	0.134	0.117	-	2.057
2024	0.033	0.599	0.473	0.508	0.095	0.021	0.129	0.112	-	1.969
2025	0.032	0.583	0.447	0.488	0.089	0.018	0.124	0.107	-	1.888
2026	0.031	0.568	0.423	0.470	0.083	0.016	0.119	0.103	-	1.813

Notes:

[1] Forecast horizon 2007-36; forecast based on field-by-field economic assessment prepared by Alaska Department of Revenue. Figure III.4 (shown to 2026) corresponds to Table III.8.

[2] Figures include natural gas liquids (NGL) and are net of injections.

Source: Historic data: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports). Forecast prepared by Alaska DNR.

Cook Inlet

Figure III.4 Cook Inlet Historic and Forecast Oil Production 1958 - 2026[1]

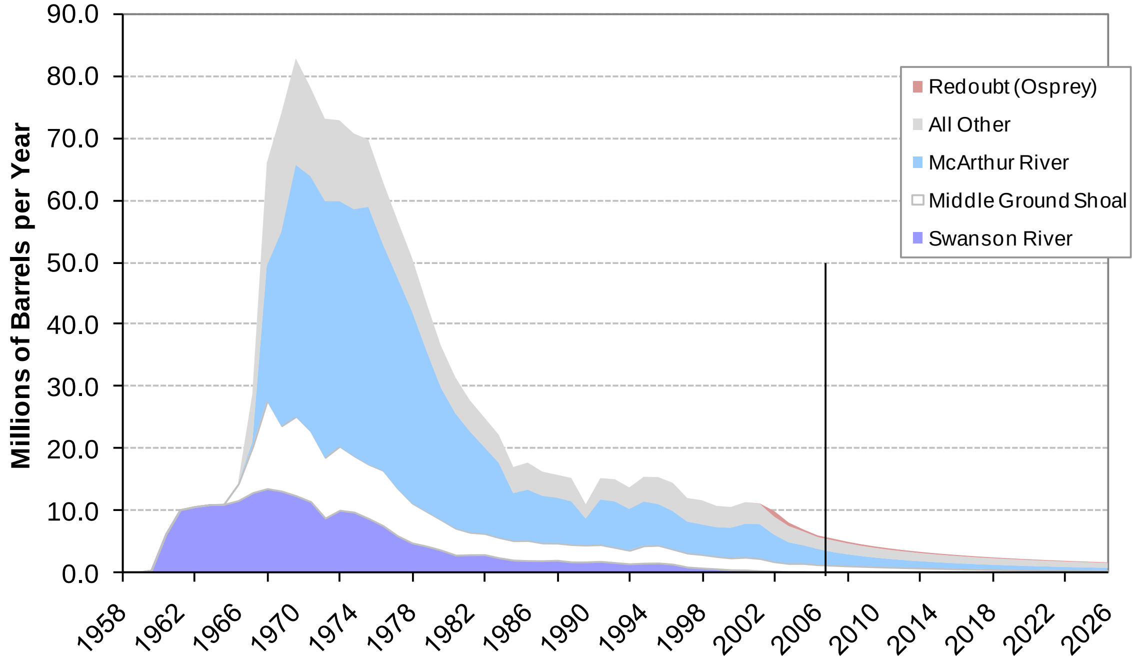
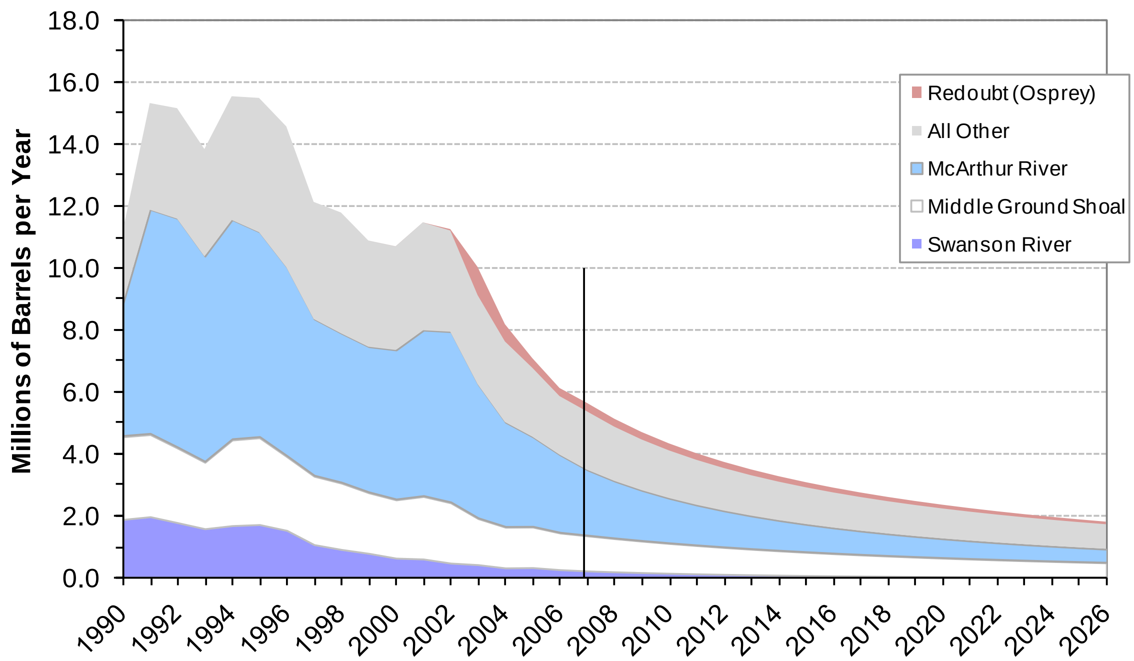
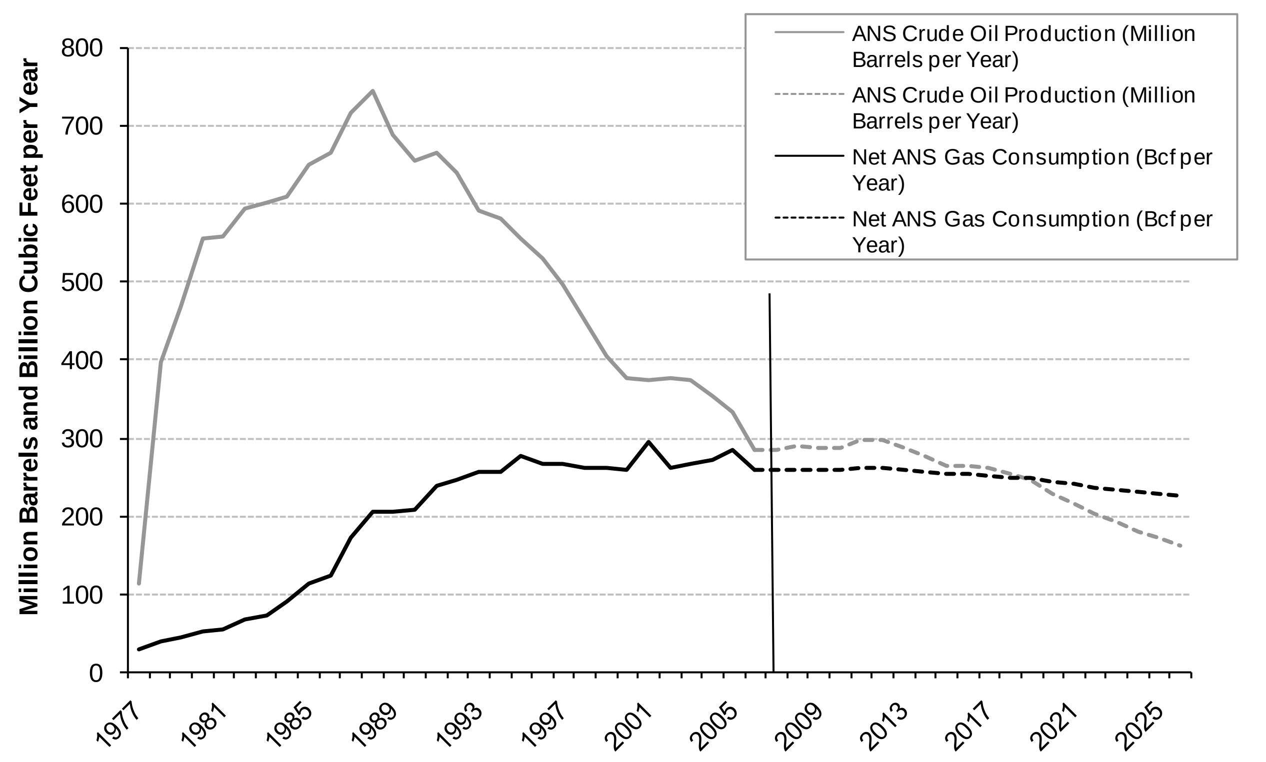


Figure III.4 Cook Inlet Historic and Forecast Oil Production 1990 - 2026[1]



North Slope

Figure III.5 Forecast of Net ANS Gas Consumption for Lease Operations and Local Gas Sales



Net Gas Consumption on the North Slope

Year	bcf	Year	bcf
2006	257.0	2017	251.1
2007	257.2	2018	248.8
2008	258.3	2019	246.9
2009	257.7	2020	242.4
2010	257.6	2021	239.3
2011	260.2	2022	236.0
2012	260.2	2023	233.0
2013	257.8	2024	230.2
2014	255.2	2025	227.6
2015	251.7	2026	225.3
2016	251.9		

Notes:

Net ANS Gas consumption refers to gas produced for lease operations and for local sales to North Slope utilities and pipelines. Most gas produced is re-injected into the field for enhanced oil recovery and recycling. Historic quanti ies of injected gas are shown in Table III.5. Gas injection is expected to remain fairly constant at about 8 Bcf per day for the foreseeable future. Many factors influence the quantity of gas used for lease operations, including demand for power, oil field compression and pipeline pump stations. New field and satellite development will, to some extent, offset the decline in gas used for lease operations and pipelines in mature fields. Also, many North Slope fields are "gas constrained" meaning that oil production is limited by gas handling capacity. The forecast of net ANS gas consumption is based on an ordinary least squares regression of the historic relationship between net ANS gas consumption and ANS crude oil production, taking into account major additions to gas handling capacity in 1990 (GHX1), 1995 (GHX2), and 2001 (MIX). Detailed estimation results are available on request.

Cook Inlet

	Beluga River[1]	McArthur River (TBU)[1]	North Cook Inlet[1]	Swanson River [1, 2]	Kenai/ Cannery Loop [1, 3]	Ninilchik/ Deep Creek[1]	All Other [1,]	Under-Development [5]	TOTAL NET[6]
1958	-	-	-	0.0	-	-	-	-	0.0
1959	-	-	-	0.0	-	-	-	-	0.0
1960	-	-	-	-	-	-	-	-	-
1961	-	-	-	1.3	0.2	-	-	-	1.5
1962	-	-	-	1.8	1.5	-	0.0	-	3.3
1963	0.0	-	-	1.2	3.1	-	0.0	-	4.3
1964	0.1	-	-	1.6	4.5	-	0.1	-	6.2
1965	-	-	-	1.1	6.0	-	0.2	-	7.3
1966	-	-	-	-	33.4	0.0	1.5	-	12.4
1967	0.2	0.2	-	-	39.6	-	9.0	-	24.7
1968	2.0	6.2	-	-	46.0	-	20.2	-	41.5
1969	3.0	14.2	7.9	-	59.3	-	22.3	-	80.3
1970	3.6	19.7	40.9	-	80.6	-	23.1	-	145.2
1971	4.1	19.3	45.0	-	72.2	-	22.4	-	155.7
1972	4.1	19.7	41.6	-	76.0	-	15.8	-	148.5
1973	4.9	19.1	42.7	-	71.3	-	13.1	-	137.8
1974	5.6	19.6	44.2	-	68.5	-	11.0	-	143.0
1975	7.0	21.5	45.6	-	77.2	-	10.6	-	154.6
1976	11.2	19.0	45.1	-	79.5	-	10.3	-	153.3
1977	13.4	19.7	47.2	-	81.9	-	10.8	-	161.6
1978	14.3	18.6	46.8	-	97.3	-	9.8	-	179.1
1979	17.0	16.6	49.4	-	97.0	-	8.6	-	184.7
1980	17.0	15.6	41.5	-	98.8	-	8.1	-	179.3
1981	17.2	15.2	49.5	-	105.8	-	7.7	-	192.9
1982	18.7	16.2	45.4	-	115.9	-	7.3	-	196.1
1983	18.1	14.4	47.9	2.2	113.0	-	15.2	-	210.7
1984	19.8	15.1	47.0	3.0	110.1	-	16.7	-	211.7
1985	22.6	10.7	45.8	3.1	115.8	-	18.9	-	216.9
1986	25.4	13.6	43.8	1.5	82.5	-	24.6	-	191.3
1987	24.0	13.3	42.9	(3.0)	90.0	-	22.1	-	189.3
1988	25.6	16.7	45.0	2.9	85.7	-	20.8	-	196.6
1989	30.1	31.0	45.3	(3.7)	77.0	-	18.7	-	198.4
1990	39.5	51.5	45.0	(1.6)	50.9	-	20.2	-	205.5
1991	38.5	61.2	44.7	(0.1)	37.9	-	20.9	-	203.1
1992	36.5	70.1	44.4	(0.2)	34.8	-	18.8	-	204.5
1993	31.7	62.5	45.5	4.6	33.3	-	22.7	-	200.5
1994	34.2	50.0	52.7	27.3	25.2	-	24.6	-	214.0
1995	35.6	54.9	53.5	28.7	22.0	-	19.6	-	214.5
1996	36.9	67.3	56.0	33.3	15.4	-	14.1	-	223.0
1997	35.0	66.8	52.5	28.7	15.8	-	15.9	-	214.7
1998	33.4	73.8	54.0	25.8	12.8	-	15.2	-	215.0
1999	36.0	69.0	51.6	29.8	12.8	-	13.4	-	212.6
2000	38.7	65.0	52.8	29.7	17.1	-	12.4	-	215.8
2001	41.8	62.3	55.5	23.0	24.1	-	13.9	-	220.7
2002	44.0	51.5	54.6	13.7	27.2	-	19.9	0.0	210.9
2003	56.3	39.2	47.9	9.3	34.7	3.0	17.4	3.0	210.9
2004	57.6	34.4	41.0	6.3	37.9	12.7	18.7	-	208.5
2005	55.9	30.8	45.6	4.3	36.8	18.0	18.8	-	210.1
2006	55.4	25.4	38.2	3.5	33.9	20.5	19.9	-	196.6
2007	54.9	20.9	32.0	1.9	28.8	18.4	22.2	11.3	190.4
2008	54.9	17.7	26.1	1.3	23.5	13.2	14.3	39.3	190.4
2009	51.9	15.0	21.8	0.9	19.4	9.6	11.0	46.3	176.0
2010	45.7	12.7	18.4	0.7	16.2	7.1	8.6	39.0	148.4
2011	40.2	10.8	15.8	0.5	13.5	5.3	6.8	33.2	126.1
2012	35.4	9.1	13.7	0.4	11.4	4.0	5.5	28.4	107.8
2013	31.1	7.7	12.0	0.3	9.7	3.1	4.4	24.4	92.7
2014	27.4	6.6	10.6	0.2	8.2	2.4	3.6	21.0	80.0
2015	24.1	5.6	9.4	0.2	7.0	1.8	3.0	18.2	69.3
2016	21.2	4.7	8.4	0.1	6.0	1.4	2.4	15.8	60.2
2017	18.7	4.0	7.6	0.1	5.2	1.1	2.0	13.8	52.5
2018	16.4	3.4	6.9	0.1	4.5	0.9	1.7	12.1	46.0
2019	14.5	2.9	6.2	0.1	3.9	0.7	1.5	10.6	40.3
2020	12.7	2.5	5.7	0.1	3.4	0.5	1.2	9.3	35.4
2021	11.2	2.1	5.2	0.0	3.0	0.4	1.0	8.2	31.2
2022	9.9	1.8	4.8	0.0	2.6	0.3	0.9	7.2	27.5
2023	8.7	1.5	4.4	0.0	2.3	0.3	0.8	6.4	24.4
2024	7.6	1.3	4.1	0.0	2.0	0.2	0.7	5.7	21.6
2025	6.7	1.1	3.8	0.0	1.7	0.1	0.6	5.0	19.1
2026	5.9	0.9	3.5	0.0	1.5	0.1	0.5	4.5	17.0

Notes:

1 Produc ion forecasts based on decline and material balance analysis of proved, developed reserves. Forecast horizon is 2036; shown through 2026 in table and related chart.

2 Net gas injections reported for Swanson River 1966-82.

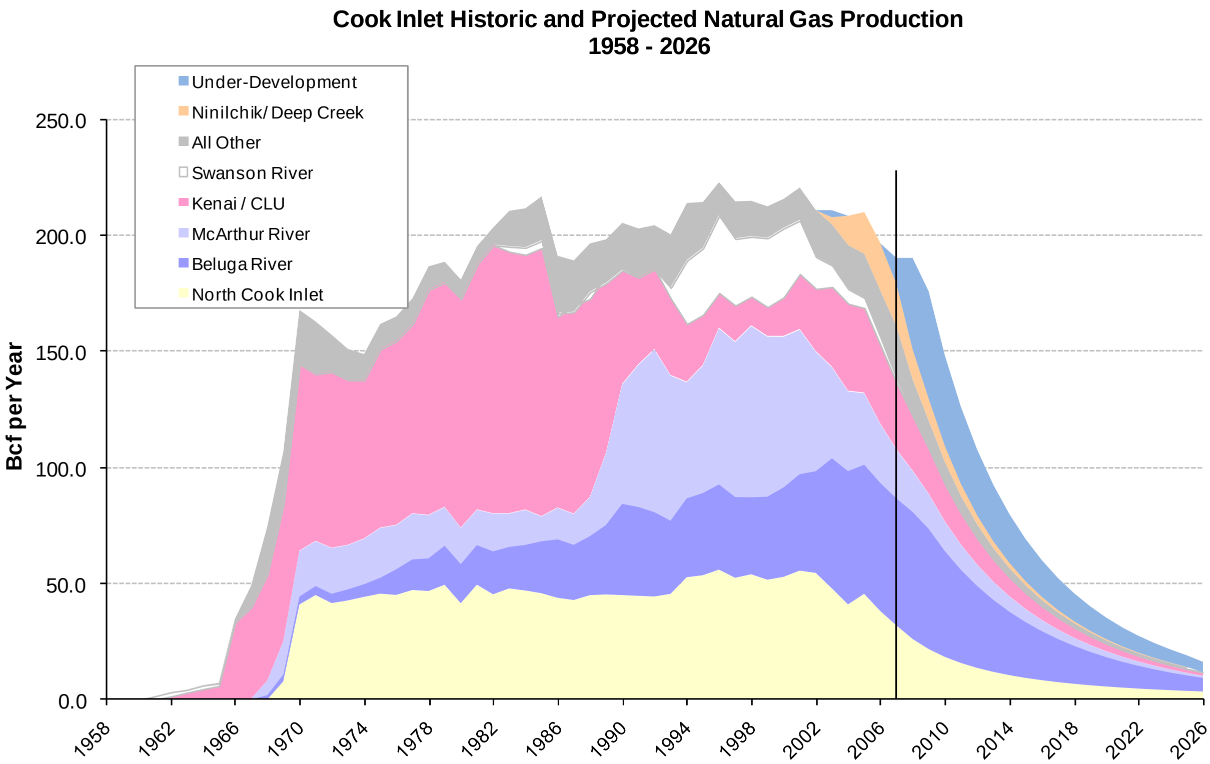
3 Includes Kenai pools: Sterling 3, 4, 5.1, 5.2, 6, Upper Tyonek-Beluga, Tyonek, and Beluga Undefined; plus all Cannery Loop pools.

4 All O her includes proved developed producing reserves of Albert Kaloa, Beaver Creek, Granite Point, Ivan River, Lewis River, Pretty Creek, Stump Lake, Kasilof, Kustatan, Lone Creek, MGS, Moquawkie, Nicolai Creek, North Fork, North Trading Bay, Redoubt, Sterling, Three-Mile Creek, Trading Bay, West Foreland, West Fork, West McArthur River and Wolf Lake.

5 Includes DNR estimates of non-producing, probable reserves based primarily gas prospectivity in the Nikolaevsk and North Fork explora ion areas. Also includes risked probable reserves estimates for the developed-producing fields based on a material balance, plans of development, historic well production rates, and individual field characteristics.

Source of Historic Data 1985-2006: Alaska Oil and Gas Conserva ion Commission, "Alaska Production Summary by Field and Pool", Monthly Reports.

Cook Inlet



Note:
Figure III.6 corresponds to Table III.9 and represents the Division's current estimate of proved producing and probable reserves. Actual produced volumes will be greater than those projected here as new reserves are discovered, developed and produced to meet demand.

Figure III.7 Cook Inlet Historic Gas Consumption by Major Disposition Group 1971 - 2006

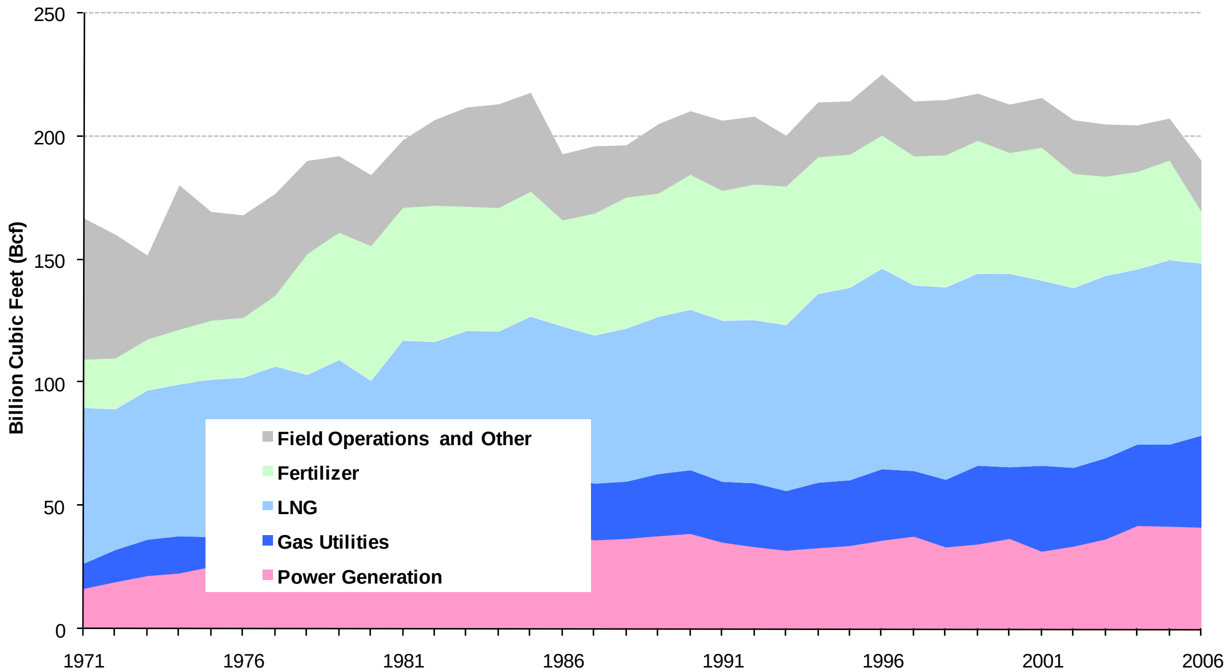


Table III.10 Cook Inlet Historic Gas Consumption by Major Group, 1991-2006

Billions of Cublic Feet Per Year

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1990-	Average 1997-	Average 2001-
Power Generation	38.9	35 3	33 5	32 0	33.0	34.0	36.1	37.7	33.4	34.6	36.8	31.6	33.7	36 6	42.1	41.8	41.4	**34.7**	**35.6**	**37.9**
Gas Utilities	25.9	24.7	25 9	24 2	26.6	26.7	29.0	26.6	27.4	32.0	29.1	34.9	32 0	33 0	33.1	33.3	37.4	**26.2**	**28.8**	**33.9**
LNG	65.1	65.4	66 2	67 3	76.7	78.1	81.4	75.4	78.1	78.0	78.5	75.2	73 0	74 0	71.1	74.9	69.9	**71.5**	**77.5**	**73.0**
Ammonia-Urea	54.8	52 6	55 0	56 2	55.4	54.0	54.0	52.3	53.6	53.9	49.0	53.9	46 3	40 2	39 5	40.4	21.0	**54.6**	**52.2**	**40.2**
Field Ops and Other	25.8	28 6	27 6	20.7	22.3	21.6	24.8	22.4	22.5	19.1	19.7	20.2	21 9	21 2	18 9	17.1	20.7	**24.5**	**20.9**	**20.0**
	210.4	206 6	208 2	200 5	214.0	214.5	225.4	214.5	215.0	217.6	213.1	215.8	206 8	205.1	204.7	207.4	190.4	**211.4**	**215.0**	**205.0**

Percent of the Total in Each Year (%)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1990-	Average 1997-	Average 2001-
Power generation	18 5	17.1	16.1	16.0	15.4	15.8	16.0	17.6	15 5	15 9	17 3	14.7	16.3	17.8	20.6	20.1	21.8	**16.4**	**16.6**	**18.5**
Gas Utilities	12 3	12.0	12.5	12.1	12.4	12.5	12.9	12.4	12 8	14.7	13.7	16 2	15.5	16.1	16.2	16.1	19.6	**12.4**	**13.4**	**16.6**
LNG	31 0	31.7	31.8	33.6	35.8	36.4	36.1	35.1	36 3	35 8	36 8	34 8	35.3	36.1	34.7	36.1	36.7	**33.8**	**36.0**	**35.6**
Fertilizer	26 0	25.5	26.4	28.0	25.9	25.2	24.0	24.4	24 9	24 8	23 0	25 0	22.4	19.6	19.3	19.5	11.0	**25.8**	**24.3**	**19.6**
Field Ops and Other	12 3	13.8	13.2	10.3	10.4	10.1	11.0	10.4	10.4	8 8	9 2	9.4	10.6	10.4	9.3	8.2	10.9	**11.6**	**9.7**	**9.8**
	100 0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100 0	100 0	100 0	100 0	100.0	100.0	100.0	100.0	100.0	**100.0**	**100.0**	**100.0**

Alaska

Field, Pool	Oil barrels per day	Gas million cu. ft. per day
ALBERT KALOA, UNDEFINED GAS	-	2.0
BADAMI, BADAMI OIL	1,316	11.5
BARROW, EAST BARROW GAS	-	0.1
BARROW, SOUTH BARROW GAS	-	0.3
BEAVER CREEK, BEAVER CREEK OIL	212	0.1
BEAVER CREEK, BELUGA GAS	-	14.6
BEAVER CREEK, STERLING GAS	-	0.1
BEAVER CREEK, TYONEK UNDEF GAS	-	0.3
BELUGA RIVER, UNDEFINED GAS	-	151.7
BIRCH HILL, UNDEFINED GAS	-	-
COLVILLE RIVER, ALPINE OIL	114,326	138.6
COLVILLE RIVER, FIORD OIL	4,886	3.0
COLVILLE RIVER, NANUQ OIL	15	0.0
COLVILLE RIVER, NANUQ-KUPK OIL	1,848	1.3
COLVILLE RIVER, QANNIK OIL	150	0.1
DEEP CREEK, HAPPY VALLEY BELUGA/TYONEK GAS	-	7.7
ENDICOTT, EIDER OIL	96	5.5
ENDICOTT, ENDICOTT OIL	16,043	331.5
ENDICOTT, IVISHAK OIL	174	0.1
GRANITE PT, HEMLOCK UNDEFINED OIL	84	0.1
GRANITE PT, MIDDLE KENAI OIL	2,914	2.6
GRANITE PT, UNDEFINED GAS	-	-
IVAN RIVER, UNDEFINED GAS	-	3.2
KASILOF, TYONEK UNDEFINED GAS	-	2.4
KENAI, BELUGA UNDEFINED GAS	-	-
KENAI, STERLING 3 GAS	-	2.2
KENAI, STERLING 4 GAS	-	4.5
KENAI, STERLING 5.1 GAS	-	-
KENAI, STERLING 5.2 GAS	-	-
KENAI, STERLING 6 GAS	-	12.8
KENAI, TYONEK GAS	-	2.8
KENAI, UP TYONEK BELUGA GAS	-	38.3
KENAI CANNERY LOOP, BELUGA GAS	-	18.7
KENAI CANNERY LOOP, STERLING UNDEFINED GAS	-	7.6
KENAI CANNERY LOOP, TYONEK D GAS	-	-
KENAI CANNERY LOOP, UPPER TYONEK GAS	-	5.3
KUPARUK RIVER, KUPARUK RIVER OIL	124,665	247.7
KUPARUK RIVER, MELTWATER OIL	3,808	11.7
KUPARUK RIVER, TABASCO OIL	3,885	0.9
KUPARUK RIVER, TARN OIL	20,698	33.7
KUPARUK RIVER, UGNU UNDEFINED OIL	-	0.0
KUPARUK RIVER, WEST SAK OIL	18,128	13.9
KUSTATAN, UNDEFINED GAS	-	0.6
LEWIS RIVER, UNDEFINED GAS	-	0.05
LONE CREEK, UNDEFINED GAS	-	3.8
MCARTHUR RIVER, HEMLOCK OIL	4,476	2.4
MCARTHUR RIVER, MIDKENAI G OIL	0	0.8
MCARTHUR RIVER, MIDDLE KENAI GAS (GRAYLING GAS SANDS)	-	66.3
MCARTHUR RIVER, UNDEFINED OIL	-	-
MCARTHUR RIVER, WEST FORELAND OIL	222	0.04
MIDDLE GROUND SHOAL, A OIL	-	-
MIDDLE GROUND SHOAL, B,C,D OIL	-	-
MIDDLE GROUND SHOAL, E,F,G OIL	3,265	0.8
MIDDLE GROUND SHOAL, UNDEF GAS	-	0.01
MILNE POINT, KUPARUK RIVER OIL	23,277	16.9
MILNE POINT, SAG RIVER OIL	281	0.3
MILNE POINT, SCHRADER BLFF OIL	12,836	8.1
MILNE POINT, UGNU UNDEFINE OIL	-	-
MOQUAWKIE, UNDEFINED GAS	-	2.1

Alaska

Field, Pool	Oil barrels per day	Gas million cu. ft. per day
NICOLAI CREEK, BELUGA UNDEFINED GAS	-	0.9
NICOLAI CREEK, NORTH UNDEFINED GAS	-	0.2
NICOLAI CREEK, SOUTH UNDEFINED GAS	-	0.3
NINILCHIK, FC TYONEK UNDEFINED GAS	-	14.2
NINILCHIK, GO TYONEK UNDEFINED GAS	-	14.4
NINILCHIK, PAX TYONEK UNDEFINED GAS	-	1.3
NINILCHIK, SD TYONEK UNDEFINED GAS	-	18.5
NORTH COOK INLET, TERTIARY GAS	-	104.5
NORTH FORK, UNDEFINED GAS	-	-
OOOGURUK, UNDEFINED OIL	-	-
PRETTY CREEK, UNDEFINED GAS	-	0.05
NORTHSTAR, KUPARUK C UNDEFINED GAS	11	0.3
NORTHSTAR, NORTHSTAR OIL	51,718	389.6
PRUDHOE BAY, AURORA OIL	10,448	31.4
PRUDHOE BAY, BOREALIS OIL	15,718	15.9
PRUDHOE BAY, LISBURNE OIL	10,119	179.9
PRUDHOE BAY, MIDNIGHT SUN OIL	5,707	10.1
PRUDHOE BAY, N PRUDHOE BAY OIL	-	-
PRUDHOE BAY, NIAKUK OIL	4,704	6.2
PRUDHOE BAY, ORION SCHRADER BLUFF OIL	6,799	4.9
PRUDHOE BAY, POINT MCINTYRE UNDEFINED OIL	-	-
PRUDHOE BAY, POLARIS OIL	2,251	2.3
PRUDHOE BAY, PRUDHOE OIL	303,077	6,698.0
PRUDHOE BAY, PT MCINTYRE OIL	22,191	115.7
PRUDHOE BAY, PUT RIVER OIL	386	0.2
PRUDHOE BAY, RAVEN OIL	1,824	9.0
PRUDHOE BAY, W BEACH OIL	-	-
REDOUBT SHOAL, UNDEFINED G-Ø GAS	-	-
REDOUBT SHOAL, UNDEFINED OIL	732	0.2
REDOUBT SHOAL, UNDEFINED TYONEK GAS	-	-
STERLING, BELUGA UNDEFINED GAS	-	6.0
STERLING, STERLING UNDEFINED GAS	-	-
STERLING, TYONEK UNDEFINED GAS	-	-
STUMP LAKE, UNDEFINED GAS	-	0.0
SWANSON RIVER, BELUGA UNDEFINED GAS	-	0.9
SWANSON RIVER, HEMLOCK OIL	719	0.9
SWANSON RIVER, STERLING UNDEFINED GAS SANDS	-	2.9
SWANSON RIVER, TYONEK UNDEFINED GAS	-	4.9
SWANSON RIVER, UNDEFINED OIL	-	-
THREE MILE CK, BELUGA UNDEFINED GAS	-	1.7
TRADING BAY, G-NE/HEMLOCK-NE OIL	-	0.0
TRADING BAY, HEMLOCK OIL	284	0.5
TRADING BAY, MIDDLE KENAI UNALLOCATED	-	-
TRADING BAY, MID KENAI B OIL	214	0.1
TRADING BAY, MID KENAI C OIL	173	0.2
TRADING BAY, MID KENAI D OIL	231	0.1
TRADING BAY, MID KENAI E OIL	80	0.03
TRADING BAY, UNDEFINED GAS	-	0.03
TRADING BAY, UNDEFINED OIL	102	0.03
TRADING BAY, WEST FORELAND OIL	-	-
WALAKPA, WALAKPA GAS	-	3.4
WEST FORELAND, TYONEK UNDEFINED 4.0 GAS	-	5.9
WEST FORELAND, TYONEK UNDEFINED 4.2 GAS	-	3.3
WEST FORK, STERLING A GAS	-	-
WEST FORK, STERLING B GAS	-	-
WEST FORK, UNDEFINED GAS	-	1.8
WEST MCARTHUR RIVER, W MCARTHUR RIVER OIL	1,197	0.4
WOLF LAKE, BELUGA-TYONEK UNDEFINED GAS	-	0.002
TOTAL STATEWIDE DAILY PRODUCTION VOLUME	**796,289**	**8,831**
TOTAL COOK INLET	**14,904**	**539**
TOTAL NORTH SLOPE	**781,385**	**8,292**

Section Four

Royalty Production and Revenue

Introduction

The state of Alaska receives a royalty of approximately 12.5 percent of the oil and gas produced from its leases. The state may take its share of oil production “in-kind” or “in-value.” When the state takes its royalty share in-kind (RIK), it assumes possession of the oil or gas. The commissioner of Natural Resources may sell the RIK oil or gas in a competitive auction or through a noncompetitive sale negotiated with a single buyer. When the state takes its royalty in-value (RIV), the state’s lessees who produce the oil or gas market the state’s share along with their own share of production. The lessees remit cash payments on a monthly basis for the state’s RIV share.

Over the last 30 years the state has taken about one-half of its royalty oil as RIK.[1] The state has sold nearly 800 million barrels of RIK oil during this time, most of it in-state. These in-state sales provided an important stimulus to Alaska’s refining industry by providing long-term supplies of oil to each of the state’s four refineries. Over the years, state RIK sales fueled many controversies and policy debates over the appropriate use of the state’s natural resources.

Cook Inlet

In 1969 the commissioner of Natural Resources negotiated a sale of 100 percent of the state’s royalty from Cook Inlet to the Alaska Oil and Refining Company. Within months of signing the contract, Alaska Oil and Refining Company merged with the Tesoro Petroleum Company. Tesoro subsequently built a new refinery in Nikiski on the Kenai Peninsula next to Chevron’s refinery, built in 1964. Between 1969 and 1985 the state sold all of its Cook Inlet royalty oil to the Tesoro refinery. By 1980, the production decline in Cook Inlet prompted Tesoro to negotiate the first of several sales contracts with the state for supplies of RIK oil from the North Slope. By the end of 1985 Tesoro had replaced its Cook Inlet RIK volumes with supplies of RIK from the North Slope.

In 1987 the state began to export Cook Inlet RIK oil to the Chinese Petroleum Company. These volumes were produced from fields on the west side of the Cook Inlet after the federal government exempted Cook Inlet production from export administration regulations. The state sold 97 percent of the royalty production from the McArthur River, Trading Bay, North Trading Bay, and Granite Point fields in a series of one-year competitive auctions. In 1991 deliveries under the last Chinese Petroleum contract were halted under force majeure following the December 1989 eruption of the Mount Redoubt volcano. There have been no Cook Inlet RIK sales since (See Table IV.8.).

[1] The state also sold 10.4 Bcf of RIK gas in a contract to Alaska Pipeline Company (Enstar) from 1977 through 1984 from Cook Inlet royalty production. In a bid to encourage development of the gas resource in Prudhoe Bay, the state entered 20-year contracts in January 1977 to supply El Paso Natural Gas Co., Tenneco Alaska Inc., and Southern Natural Gas Co. with 25 percent, 50 percent, and 25 percent, respectively, of Prudhoe Bay Unit RIK gas. The contracts terminated in May 1978 when the proposed El Paso Trans-Alaska Gas Pipeline did not receive federal certification.

North Slope

Over the past 25 years, the state has held nine RIK sales involving portions of its Alaska North Slope (ANS) royalty oil production. These sales are summarized in Table IV.7 and Figure IV.3. In 1976, the state signed a six-year contract with Golden Valley Electric Association (GVEA), the electric utility in Fairbanks, to sell approximately 3,300 barrels of ANS crude oil per day as turbine fuel. GVEA did not exercise its option to take RIK until 1981 and it traded these volumes with Mapco (now Williams Alaska) in exchange for refined fuel. The state subsequently sold RIK ANS to GVEA in two other contracts until 1992. As in the first contract, GVEA traded these volumes with Mapco.

In 1978 the state contracted with Earth Resources Company of Alaska, predecessor to Mapco Alaska and Williams Alaska Petroleum Company, to supply 15 percent of Prudhoe Bay RIK oil production less the quantity dedicated to GVEA. This 25-year contract expired in December 2003. Williams received a maximum of 35,000 barrels per day of RIK oil produced from the Prudhoe Bay Unit under this contract and supplemented this supply with new agreements for another 28,000 barrels per day.

In September 2003, the state negotiated a temporary contract with Williams for the period January 1, 2004, through March 31, 2004. The state also negotiated a new 10-year contract with Flint Hills Resources Alaska, LLC (FHR), signed by the Governor on March 9, 2004, enabling FHR to take over the Williams' North Pole refinery on March 31. Deliveries of royalty oil under the new RIK contract began April 1, 2004. The state sold approximately 62,476 barrels per day to FHR, or more than 54 percent of the total royalty oil produced on the North Slope for the period January 1 through December 31, 2005.

The contract contained special conditions which serve as additional consideration for FHR's purchase of the state's royalty oil. FHR will maintain gasoline wholesale rack price parity between Anchorage and Fairbanks. FHR will invest approximately $100 million to install clean fuels processing equipment and facilities in the North Pole Refinery and/or elsewhere in Alaska, fulfill and enhance the previous commitments made by Williams to the Government Hill Community Council in Anchorage to address concerns about gasoline storage tanks near Government Hill and undertake additional projects to improve the Anchorage Tank Farm Facility. FHR will also continue to ship refined products to Anchorage via the Alaska Railroad, (FHR shipments represented 48 percent of the total freight loadings for the Alaska Railroad for 2005).

In Fairbanks, FHR will study the use and viability of the hydrant fueling system at the Fairbanks International airport (FIA), concentrate on promoting FIA to cargo carriers, evaluate and possibly upgrade FIA fuel distribution facilities, and charge a jet fuel customer in Fairbanks the same or lower price as FHR charges that same customer in Anchorage. FHR met all of these conditions for 2005.

Tesoro has been an important North Slope RIK customer. Tesoro negotiated and bid for several contracts that supplied it with RIK supplies from 1980 to 1998. Chevron was another big purchaser of North Slope RIK for oil supplied to its Nikiski refinery from 1980 through 1991, when it finally shut down its Nikiski refinery. In one of these contracts Chevron took RIK barrels from Tesoro in exchange. Petro Star Inc. purchased North Slope RIK from 1986 through 1991 for its new refinery at North Pole. In 1992 Petro Star negotiated a 10-year contract with the state for a supply of RIK from the Kuparuk River Unit. With this contract in hand, Petro Star was able to build the state's newest refinery in Valdez. As it happened, Petro Star elected to take no oil under this contract and the contract expired automatically nine months after it had been signed.

The state also held competitive auctions of RIK oil during the early 1980s as part of a program to routinely offer RIK short-term contracts. Winners of these sales included in-state refineries but also several refineries located outside the state. Many of these buyers were also ANS producers. About 46 million barrels of Alaska North Slope RIK crude oil were sold in these auctions but the program was interrupted after the general collapse of oil prices in the mid-1980s. In January 2000, the Division of Oil and Gas published a Notice of Interest in Sale of State Royalty Oil. The response to this notice by prospective RIK purchasers prompted the division to plan for a competitive bid auction for volumes of RIK oil produced from several North Slope fields. The sale was subsequently held in August 2000 but no bids were offered.

Royalty-in-Kind Policy

The earliest RIK sales, notably Tesoro's first Cook Inlet contract, the first GVEA contract, and the Alpetco contract, generated controversy and debate in the state. Several issues arose as the RIK program evolved. Is the state better off negotiating sales one-on-one or auctioning RIK through competitive tenders? How much public input should be encouraged? Should the state subsidize the local refining industry through price breaks? What kind of oversight should be required? The debates of these questions led to the present program as set out in statutes and regulations.

When disposing royalty oil or gas, the commissioner is bound by AS 38.05.182 and AS 38.05.183. Further, the Legislature established the Alaska Royalty Oil and Gas Development Board (Royalty Board) under AS 38.06 to oversee the department's RIK program. Regulations under Title 11, Chapters 3 and 26 govern the actual disposition of royalty and the sale of RIK. (See www.legis.state.ak.us/folhome.htm for more information).

The rules that govern the sale of RIK may be reduced to a few principles:

- Any disposition of the state's royalty must be in the state's best interest. The state should sell its royalty rather than take it in-value as long as the best interests of the state are served.
- The state must receive a price for its RIK that is at least as much as it receives when the state takes its royalty in-value.
- Under certain circumstances, the state may sell its oil in a negotiated sale, but competitive sales are preferred.
- Although the price of RIK must equal or exceed the price of RIV, a review of each sale must consider economic, social, and environmental effects. In this way, benefits may be attributed to the sale of RIK to local refineries that would not be generated by sales to outside purchases.
- The public is a part of the process. Depending on the terms of the sale, the commissioner will publish best interest findings and solicit comments on the sale from the public.
- The Royalty Board must be notified of any disposition of RIK. For supply contracts of more than one year, the Royalty Board must evaluate the economic, social, and environmental effects of the sale, convene a public hearing, and recommend approval of the sale to the Legislature.
- The Legislature approves long-term contracts by enacting legislation.

Table IV.1 Recent Royalty Oil Production and Revenues

North Slope, 1997-2006

	Lease Operation	Badami Unit RIV	Badami Unit RIK	TOTAL Badami Unit	Colville River Unit RIV	Colville River Unit RIK	TOTAL Colville River Unit	Duck Island Unit RIV	Duck Island Unit R K	TOTAL Duck Island Unit	Kuparuk River Unit RIV	Kuparuk River Unit R K	TOTAL Kuparuk River Unit
Production (Thousands of Barrels)													
1997	-	-	-	-	-	-	-	3,324.4	-	3,324.4	10,978 3	-	10,978.3
1998	-	106.1	-	106.1	-	-	-	2,692.5	-	2,692.5	10,886 2	-	10,886.2
1999	-	179 2	-	179 2	1.3	-	1.3	2,263.3	-	2,263.3	10,822 0	-	10,822.0
2000	-	144 6	-	144 6	196.6	-	196.6	1,943.1	-	1,943.1	9,897 9	-	9,897.9
2001	-	104 0	-	104 0	2,785.5	-	2,785.5	1,696.9	-	1,696.9	9,076.4	-	9,076.4
2002	-	87 0	-	87 0	3,403.4	-	3,403.4	1,483.5	-	1,483.5	8,921 6	-	8,921.6
2003	0 6	42.1	-	42.1	3,777.1	-	3,777.1	1,535.1	-	1,535.1	8,905 8	-	8,905.8
2004	-	-	-	-	3,642.3	-	3,642.3	834.3	390.2	1,224.5	7,976 8	305 3	8,282.1
2005	2.1	22 2	-	22 2	4,262.4	-	4,262.4	51.2	1,026.3	1,077.5	4,498 6	3,138 0	7,636.6
2006	-	56 3	15.9	72 2	3,273.9	404.6	3,678.5	43.8	819.3	863.1	2,120 3	5,080 6	7,200.8
Revenues (Thousands of Dollars)													
1997	-	-	-	-	-	-	-	-	-	-	-	-	-
1998	-	-	-	-	-	-	-	$42,866	-	$42,866	$150,137	-	$150,137
1999	-	$572	-	$572	-	-	-	$18,147	-	$18,147	$82,772	-	$82,772
2000	-	$1,992	-	$1,992	$57	-	$57	$26,461	-	$26,461	$136,802	-	$136,802
2001	-	$2,612	-	$2,612	$4,539	-	$4,539	$42,350	-	$42,350	$220,539	-	$220,539
2002	-	$1,051	-	$1,051	$47,972	-	$47,972	$31,796	-	$31,796	$160,694	-	$160,694
2003	-	$108	-	$108	$62,818	-	$62,818	$27,128	-	$27,128	$173,379	-	$173,379
2004	$15	$46	-	$46	$89,684	-	$89,684	$35,753	-	$35,753	$211,369	-	$211,369
2005	-	-$0	-	-$0	$122,667	-	$122,667	$24,455	$14,219	$38,674	$255,120	$11,578	$266,699
2006	$85	$876	-	$876	$201,866	-	$201,866	$6,831	$47,365	$54,197	$186,238	$159,863	$346,101

Revenues include interest from revisions and settlements in the year received.

	Milne Point Unit RIV	Milne Point Unit RIK	TOTAL Milne Point Unit	Northstar Unit RIV	Northstar Unit RIK	TOTAL Northstar Unit	Prudhoe Bay Unit RIV	Prudhoe Bay Unit RIK	TOTAL Prudhoe Bay Unit	**TOTAL North Slope**
Production (Thousands of Barrels)										
1997	2,657.0	-	2,657.0	-	-	-	18,399.6	26,139.6	44,539.2	61,498.8
1998	2,833.4	-	2,833.4	-	-	-	11,810.5	27,981.6	39,792.1	56,310.2
1999	2,699.2	-	2,699.2	-	-	-	15,508.5	19,070.7	34,579.2	50,544.1
2000	2,613.9	-	2,613.9	-	-	-	13,053.5	19,290.3	32,343.8	47,140.0
2001	2,687.9	-	2,687.9	212.9	-	212.9	13,643.5	15,187.0	28,830.6	45,394.3
2002	2,570.7	-	2,570.7	4,009.3	-	4,009.3	11,794.8	15,509.5	27,304.4	47,779.8
2003	2,569.7	-	2,569.7	5,236.7	-	5,236.7	5,489.2	20,630.5	26,119.8	48,186.9
2004	1,534.2	1,039.7	2,573.9	2,661.6	3,004.6	5,666.2	5,641.0	18,478.1	24,119.2	45,508.2
2005	111.5	2,088.1	2,199.7	5,065.9	-	5,065.9	5,547.1	16,545.2	22,092.3	42,358.7
2006	193.4	1,635.8	1,829.2	1,235.8	3,030.4	4,266.2	6,467.6	11,287.2	17,754.8	35,665.0
Revenues (Thousands of Dollars)										
1997	-	-	-	-	-	-	-	-	-	$852,822
1998	$33,777	-	$33,777	-	-	-	$242,341	$383,701	$626,042	$416,413
1999	$18,608	-	$18,608	-	-	-	$73,462	$227,032	$296,313	$626,358
2000	$31,596	-	$31,596	-	-	-	$170,204	$259,246	$429,450	$1,064,162
2001	$56,730	-	$56,730	-	-	-	$275,928	$461,464	$737,392	$806,722
2002	$47,356	-	$47,356	$1,584	-	$1,584	$236,464	$279,804	$516,268	$910,151
2003	$48,818	-	$48,818	$75,797	-	$75,797	$201,726	$320,378	$522,104	$1,144,385
2004	$61,255	-	$61,255	123,753	-	123,753	$114,558	$507,952	$622,509	$1,511,495
2005	$44,971	$37,287	$82,258	87,502	109,196	196,698	$172,637	$631,864	$804,501	$1,991,222
2006	$4,786	$94,638	$99,424	243,095	104	243,199	$239,535	$805,939	$1,045,474	$2,046,364

Table IV.1 Recent Royalty Oil Production and Revenues

Cook Inlet & Statewide, 1997-2006

	Granite Point Field	South Granite Point Unit	North Middle Ground Shoal	Middle Ground Shoal	South Middle Ground Shoal	Trading Bay Field	Trading Bay Unit	West McArthur Unit	Redoubt Unit	Un-defined	**TOTAL Cook Inlet**	**TOTAL STATE**
Production (Thousands of Barrels)												
1997	303.5	-	42.0	150.6	26.8	75.1	632.4	80.6	-	-	1,311 0	62,809.8
1998	259.8	-	44.7	196.0	28.8	87.1	602.4	116.2	-	-	1,335 0	57,645.2
1999	172.4	51.0	38.2	181.9	24.6	82.7	587.2	114.3	-	-	1,252 2	51,796.3
2000	119.2	98.5	43.5	170.5	22.8	79.6	602.8	111.6	-	-	1,248.6	48,388.5
2001	109.3	92.9	39.7	194.4	19.8	72.3	671.1	152.9	-	-	1,352.4	46,746.7
2002	105.2	85.8	27.1	197.1	20.8	74.6	697.0	127.3	2.3	-	1,337 2	49,117.1
2003	98.8	80.0	11.8	177.4	-	68.7	538.6	106.1	45.5	1.0	1,127 9	49,314.8
2004	84.0	77.4	-	165.3	-	58.0	424.6	83.7	28.0	-	920 8	46,429.0
2005	75.2	67.5	-	164.7	-	51.8	340.3	64.6	15.6	-	779.7	43,138.4
2006	73.7	46.9	-	148.9	-	49.1	284.0	54.6	13.4	-	670.6	36,335.5
Revenues (Thousands of Dollars)												
1997	$5,175	-	$764	$3,655	$490	$1,192	$10,561	$1,795	-	-	$23,633	$876,456
1998	$2,813	-	$544	$2,244	$346	$853	$5,902	$1,107	-	-	$13,809	$430,222
1999	$2,090	$1,388	$662	$3,073	$406	$1,261	$8,917	$1,583	-	-	$19,380	$645,738
2000	$4,201	$3,840	$1,491	$4,647	$821	$2,632	$17,073	$2,790	-	-	$37,495	$1,101,657
2001	$2,515	$2,051	$959	$4,338	$476	$1,522	$13,908	$2,941	-	-	$28,710	$835,432
2002	$2,337	$1,850	$619	$5,428	$494	$1,609	$14,992	$2,680	$54	-	$30,062	$940,214
2003	$2,633	$2,249	$349	$5,103	$2	$1,876	$14,693	$2,736	$1,140	$19	$30,801	$1,175,186
2004	$3,066	$2,764	-	$11,544	-	$2,021	$14,732	$2,807	$900	-	$37,835	$1,549,330
2005	$3,712	$3,354	-	$8,710	-	$2,509	$16,641	$3,089	$802	-	$38,819	$2,030,041
2006	$4,287	$2,855	-	$9,328	-	$2,905	$17,020	$3,299	$754	-	$40,449	$2,086,813

Revenues include interest from revisions and settlements in the year received.

Table IV.2 Recent Royalty Oil Production by Lessee

North Slope

Production (Thousands of Barrels)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Amerada Hess	-	-	-	-	-	-	-	-	-	-
Amoco	297	237	199	119	-	-	-	-	-	-
Anadarko	-	-	$0	43	613	749	831	801	938	720
Arco	11,120	9,522	10,729	-	-	-	-	-	-	-
Armstrong Resources	-	-	-	-	-	-	<1	<1	1	-
BPAmerica Prod Co.	-	-	-	-	-	95	165	-	-	-
BP	16,683	13,595	14,233	11,869	11,075	14,451	13,898	9,555	8,527	4,109
Chevron	99	64	91	77	81	116	66	60	59	66
CIRI	30	1	-	-	-	-	-	-	-	-
ConocoPhillips AK	-	-	-	-	-	11,225	9,250	9,145	7,912	6,269
DOYON	6	5	4	4	3	3	3	1	<1	<1
Exxon	5,571	3,563	4,815	-	-	-	-	-	-	-
ExxonMobil	-	-	-	4,596	5,287	4,284	-	-	-	-
ExxonMobil AK Prod	-	-	-	-	-	-	1,926	1,899	1,886	2,118
Forcenergy/Forest Oil	5	3	4	2	2	2	1	1	1	1
Kerr McGee	-	-	-	-	-	-	-	1	1	-
Mapco 1978 Contract	12,652	11,148	12,442	12,718	12,522	12,167	12,583	-	-	-
Mapco 1997 Contract	466	4,451	-	-	-	-	-	-	-	-
Marathon	-	-	-	-	-	-	-	-	-	-
Mobil	237	155	195	-	-	-	-	-	-	-
NANA	18	14	12	11	8	8	8	4	<1	<1
Oxy	208	224	212	189	-	-	-	-	-	-
Petrofina	-	32	54	43	31	-	-	-	-	-
PetroHunt	190	113	151	10,201	12,482	-	-	-	-	<1
Phillips	-	-	-	-	-	-	-	-	-	-
Phillips Alpine Alaska	-	-	-	-	-	749	831	352	-	-
Pioneer	-	-	-	-	-	-	<1	-	-	-
Tesoro	13,022	11,498	-	-	-	-	-	-	-	-
Texaco	52	31	41	35	38	18	-	-	-	-
TotalFina ELF	-	-	-	-	-	-	-	-	-	-
Union Texas Petroleum	-	-	-	-	-	-	-	-	-	-
Unocal	842	771	732	659	587	570	576	468	227	108
Williams 98 Contract	-	884	6,628	6,572	2,665	3,342	8,056	5,582	-	-
Flint Hills	-	-	-	-	-	-	-	17,632	22,797	22,274
XTO Energy	-	-	-	-	-	-	-	2	-	-
North Slope TOTAL	**61,499**	**56,312**	**50,544**	**47,140**	**45,394**	**47,780**	**48,194**	**45,505**	**42,349**	**35,665**

Cook Inlet

Production (Thousands of Barrels)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Conoco Phillips AK	-	-	-	-	-	-	1	-	-	-
Cross Timbers/XTO	-	-	182	170	194	197	177	165	165	149
Devon	-	-	-	-	-	-	<1	-	-	-
Forcenergy/Forest Oil	377	436	425	428	495	491	436	337	264	224
Marathon	-	-	-	-	-	-	-	-	-	-
Mobil/Exxon Mobil AK Prod	110	91	76	74	70	64	60	58	51	35
Shell	151	196	-	-	-	-	-	-	-	-
Stewart	30	-	-	-	-	-	-	-	-	-
Unocal	643	612	569	576	593	585	454	360	301	263
Cook Inlet TOTAL	**1,311**	**1,335**	**1,252**	**1,249**	**1,352**	**1,337**	**1,128**	**921**	**780**	**671**

Table IV.3 Recent Royalty Oil Revenue by Lessee

North Slope

Revenues (Thousands of Dollars)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Amerada Hess	$34	-	-	-	-	-	-	-	-	-
Amoco	$3,674	$1,556	$2,404	$2,562	-$0	-	-	-	-	-
Anadarko	-	-	$12	$982	$10,374	$14,180	$20,057	$27,427	$45,375	$43,352
Arco	$155,281	$72,786	$135,879	-	-	-	-	-	-	-
Armstrong Resources	-	-	-	-	-	-	$4	-	$26	-
BPAmerica Prod Co.	-	-	-	-	-	-	$3,934	-	-	-
BP	$216,022	$85,263	$158,955	$249,682	$208,250	$267,287	$325,241	$301,848	$391,141	$318,659
Chevron	$1,274	$368	$1,044	$1,608	$1,422	$2,070	$1,437	$1,745	$2,650	$10,694
CIRI	$423	$12	-	-	-	$160	-	-	-	-
ConocoPhillips AK	-	-	-	-	-	$211,239	$214,806	$297,445	$353,413	$337,580
DOYON	$83	$41	$39	$82	$54	$44	$64	$40	$4	$125
Exxon	$71,707	$19,733	$52,342	-	-	-	-	-	-	-
ExxonMobil	-	-	-	$98,415	$83,945	-	-	-	-	-
ExxonMobil AK Prod	-	-	-	-	-	$69,780	$37,737	$54,093	$81,549	$130,038
Forcenergy/Forest Oil	$63	$17	$43	$50	$38	$37	$18	$29	$43	$19,759
Kerr McGee	-	-	-	-	-	-	-	$22	$60	-
Mapco 1978 Contract	$185,000	$90,752	$166,427	$304,389	$223,123	$247,246	$310,960	-$179	-	-
Mapco 1997 Contract	$6,032	$38,590	-$60	$90	$1,075	-	-	-	-	-
Marathon	$1	-	-	-	-	-	-	-	-	-
Mobil	$3,026	$851	$2,166	-	-	-	-	-	-	-
NANA	$255	$122	$120	$220	$163	$131	$221	$121	$12	$455
Oxy	$2,778	$1,533	$2,626	$4,290	-	-	-	-	-	-
Petrofina	-	$185	$616	$807	$284	-	-	-	-	-
PetroHunt	$2,377	$752	$1,379	$228,306	$211,865	-	-	-	-	$97
Phillips	-	-	-	-	-	-	-	-	-	-
Phillips Alpine Alaska	-	-	-	-	-	$13,718	$19,638	$10,244	-	-
Pioneer	-$5	-	-	-	-	-	$10	-	-	-
Tesoro	$192,669	$92,288	$191	-$623	$1,632	$887	-	-	-	-
Texaco	$664	$149	$398	$842	$653	$270	-	-	-	-
TotalFina ELF	-	-	-	-	-	-	-	-	-	-
Union Texas Petroleum	-	-	$12	-	-	-	-	-	-	-
Unocal	$11,463	$6,013	$9,078	$14,851	$9,868	$10,858	$13,265	$14,250	$8,962	$5,897
Williams 1998 Contract	-	$5,402	$92,688	$157,608	$53,975	$72,245	$196,991	$162,716	-	-
Flint Hills	-	-	-	-	-	-	-	$641,607	$1,107,909	$1,179,502
XTO Energy	-	-	-	-	-	-	-	$87	$78	$205
North Slope TOTAL	**$852,822**	**$416,412**	**$626,358**	**$1,064,162**	**$806,721**	**$910,151**	**$1,144,385**	**$1,511,495**	**$1,991,222**	**$2,046,364**

Cook Inlet

Revenues (Thousands of Dollars)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Conoco Phillips AK	-	-	-	-	-	-	$13	-	-	-
Cross Timbers/XTO	-	-	$3,073	$4,647	$4,338	$5,428	$5,103	$6,406	$8,710	$8,695
Devon	-	-	-	-	-	-	$1	-	-	-
Forcenergy/Forest Oil	$6,166	$4,209	$6,296	$10,950	$9,831	$10,522	$11,521	$11,509	$12,867	$13,696
Marathon	-$7	-	-	-	-	-	-	-	-	-
Mobil/Exxon Mobil AK Pro	$1,882	$1,094	$1,165	$1,824	$1,525	$1,348	$1,692	$2,068	$2,511	$2,253
Shell	$3,655	$2,244	-	-	-	-	-	$5,138	-	-
Stewart	$1,104	-	-	-	-	-	-	-	-	-
Unocal	$10,834	$6,262	$8,846	$20,074	$13,016	$12,764	$12,471	$12,714	$14,731	$15,805
Cook Inlet TOTAL	**$23,633**	**$13,809**	**$19,380**	**$37,495**	**$28,710**	**$30,062**	**$30,801**	**$37,835**	**$38,819**	**$40,449**

Revenues include principal and interest from revisions and settlements in the year received.

Table IV.4 Recent Royalty Gas Production and Revenues

North Slope, 1997-2006

	Duck Island Unit	Colville River Unit	Kuparuk River Unit	Milne Point Unit	Prudhoe Bay Unit	**TOTAL North Slope**
Production (Thousand Cubic Feet)						
1997	35,605	-	90,487	26,034	1,337,301	1,489,427
1998	36,255	-	79,552	27,156	1,178,761	1,321,724
1999	168,919	-	78,783	27,611	1,092,217	1,367,530
2000	31,785	-	135,929	27,436	1,061,761	1,256,911
2001	30,780	-	98,806	28,978	1,341,442	1,500,006
2002	32,108	-	82,610	29,718	3,711,424	3,855,861
2003	33,192	-	79,039	28,845	5,572,705	5,713,781
2004	29,424	-	76,746	29,639	5,260,659	5,396,467
2005	36,975	-	70,082	29,362	4,872,422	5,008,840
2006	33,750	56,501	56,033	28,612	4,509,689	4,684,585
Revenues (Thousands of Dollars)						
1997	$31	-	$63	$28	$1,155	$1,278
1998	$28	-	$32	$24	$950	$1,033
1999	$150	-	$51	$26	$938	$1,165
2000	$40	-	$161	$34	$1,156	$1,390
2001	$33	-	$119	$32	$1,114	$1,298
2002	$37	-	$79	$34	$3,592	$3,742
2003	$45	-	$91	$40	$6,508	$6,685
2004	$57	-	$123	$54	$8,296	$8,529
2005	$87	-	$163	$72	$10,801	$11,123
2006	$104	$33	$154	$84	$11,943	$12,318

Revenues include principal and interest from revisions and settlements in the year received.

Table IV.4 Recent Royalty Gas Production and Revenues

Cook Inlet, 1997-2006

	Beluga River Unit	Cannery Loop Unit	South Granite Point Unit	Granite Point Field	Ivan River Unit	Kenai Unit	Lewis River Unit	Nicolai Creek Unit	Kasilof Unit	North Middle Ground Shoal Unit	North Cook Inlet Unit	Pretty Creek Unit
Production (Thousand Cubic Feet)												
1997	2,628,297	186,477	-	141,763	935,228	140,655	7,057	-	-	17,965	6,490,318	53,928
1998	2,508,785	163,775	1,127	162,690	800,046	111,751	11,959	-	-	131,092	6,665,243	61,640
1999	2,704,980	167,759	28,102	67,573	631,597	111,459	29,916	-	-	246,030	6,372,036	3,982
2000	2,913,658	236,492	55,787	73,754	461,437	149,187	16,232	-	-	72,167	6,548,758	-
2001	3,143,083	318,033	5,491	59,671	667,307	234,786	26,852	32,297	-	52,739	6,732,002	11,471
2002	3,313,302	286,118	3,859	34,936	756,028	233,375	111,535	28,957	-	14,404	6,537,260	193,370
2003	4,236,014	395,810	2,042	10,580	432,649	321,372	71,284	9,601	-	11,688	5,773,799	60,292
2004	4,339,085	745,310	169	15,573	289,865	191,573	45,255	29,235	-	-	5,012,401	93,122
2005	4,206,401	767,320	-	5,717	206,552	170,820	39,710	5,369	-	-	5,457,333	57,945
2006	4,167,893	593,894	-	4,374	191,634	136,643	5,227	15,193	107,898	-	4,566,013	1,311
Revenues (Thousands of Dollars)												
1997	$4,598	$325	-	$192	$1,319	$249	$10	-	-	$24	$12,054	$76
1998	$4,265	$232	$1	$221	$1,071	$157	$16	-	-	$160	$8,874	$82
1999	$3,783	$272	$30	$82	$758	$294	$36	-	-	$301	$8,914	$5
2000	$4,657	$483	$58	$215	$5,339	$298	$508	-	-	$808	$14,058	$678
2001	$6,947	$1,216	$6	$82	$933	$476	$38	$62	-	$89	$14,301	$18
2002	$7,586	$748	$4	$50	$1,057	$454	$160	$18	-	$21	$12,562	$276
2003	$9,479	$836	$6	$179	$2,904	$701	$335	$17	-	$60	$12,159	$379
2004	$11,706	$1,984	$1	$44	$814	$460	$126	$38	-	-	$11,600	$263
2005	$15,257	$2,837	<1	$20	$742	$534	$139	$35	-	-	$14,987	$196
2006	$15,275	$3,139	-	$19	$1,171	$502	$18	$60	$463	-	$14,546	$13

	Spark Platform	Sterling Unit	North Trading Bay Unit	Stump Lake Unit	Trading Bay Field	Trading Bay Unit	Redoubt Unit	Ninilchik Unit	West Mcarthur River Unit	Deep Creek Unit	Three Mile Creek Unit	**TOTAL Cook Inlet**	**TOTAL State**
Production													
1997	62,872	81	-	30,942	19,031	6,982,452	-	-	-	-	-	17,697,067	19,186,494
1998	85,882	4	-	18,332	-	7,841,950	-	-	-	-	-	18,564,277	19,886,001
1999	28,044	15	-	11,978	-	7,333,019	-	-	-	-	-	17,736,489	19,104,019
2000	-	4,384	18,632	6,839	-	6,802,700	-	-	-	-	-	17,360,027	18,616,938
2001	-	8,820	-	56	-	6,509,275	-	-	-	-	-	17,801,883	19,301,889
2002	-	11,655	-	-	-	5,198,621	-	-	2,655	-	-	16,726,074	20,581,934
2003	-	7,195	11,954	69	-	4,016,601	12,954	287,241	19,673	-	-	15,680,818	21,394,599
2004	-	6,921	2,130	-	-	3,360,804	-	1,094,310	22,119	4,191	-	15,252,063	20,648,530
2005	-	60,491	50,616	-	-	3,155,258	5,299	1,225,767	38,432	54,600	48,533	15,556,163	20,565,004
2006	-	71,748	210	-	-	2,500,006	29,082	1,701,051	58,436	48,568	67,010	14,266,190	18,950,775
Revenues													
1997	$94	$0	-	-	$23	$10,148	-	-	-	-	-	29,112	$30,390
1998	$118	$8	-	$0	-	$10,769	-	-	-	-	-	25,974	$27,007
1999	$32	$0	-	$13	-	$8,918	-	-	-	-	-	23,436	$24,601
2000	-	$7	$26	$1,254	$2	$10,743	-	-	-	-	-	39,134	$40,524
2001	-	$16	$6	$0	-	$12,636	-	-	-	-	-	36,826	$38,124
2002	-	$26	-	-	-	$9,632	-	-	-	-	-	32,595	$36,337
2003	-	$16	$28	$5	-	$14,806	$16	$681	-	-	-	42,606	$49,290
2004	-	$19	$5	-	-	$9,042	-	$3,165	$90	$17	-	39,373	$47,903
2005	-	$209	$161	-	-	$10,787	$19	$4,302	$117	$235	$143	50,721	$61,844
2006	-	$337	$4	-	-	$10,761	$128	$8,014	$247	$240	$221	55,157	$67,475

Revenues include principal and interest from revisions and settlements in the year received.

Table IV.5 Recent Royalty Gas Production by Lessee

North Slope

Production (Thousand Cubic Feet)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Anadarko	-	-	-	-	-	-	-	-	-	12,430
Arco	400,895	393,981	412,016	-	-	-	-	-	-	-
BP Am Prod. Co	-	-	-	-	-	-	1,852	-	-	-
BPXA	657,646	560,854	627,551	488,604	735,945	3,132,995	4,986,713	4,708,681	4,311,221	4,011,579
Chevron	16,561	5,070	-	-	1	3	2	1	-	-
ConocoPhillips AK	-	-	-	-	-	462,503	462,875	428,672	414,914	432,522
Exxon	284,187	264,969	241,821	-	-	-	-		-	-
ExxonMobil	-	-	-	298,217	293,045	260,295	262,275	259,052	282,640	227,982
Forest Oil	-	-	-	-	3	-	-	-	-	-
Mobil	84,433	78,519	74,713	-	-	-	-	-	-	-
NANA	25,930	-	-	-	-	-	-	-	-	-
Oxy	1,988	2,134	2,203	1,997	-	-	-	-	-	-
PetroHunt						-	-	-	-	9
Phillips	17,786	16,197	9,226	468,093	470,986	-	-	-	-	-
Unocal	-	-	-	-	27	65	65	61	66	64
North Slope TOTAL	**1,489,427**	**1,321,724**	**1,367,530**	**1,256,911**	**1,500,007**	**3,855,861**	**5,713,781**	**5,396,467**	**5,008,841**	**4,684,586**

Cook Inlet

Production (Thousand Cubic Feet)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Arco	812,591	760,156	902,501	-	-	-	-	-	-	-
Aurora Power	-	-	-	-	32,296	28,957	9,601	29,235	39,342	62,100
Chevron	830,436	843,072	1,026,724	1,002,570	1,303,514	1,459,992	1,698,230	1,721,402	1,768,844	1,194,777
ConocoPhillips AK	-	-	-	-	-	1,287,322	1,950,417	1,982,764	1,808,634	1,545,363
Conoco Phillips Co.	-	-	-	-	-	-	5,773,799	5,012,401	5,457,333	4,566,013
Forest Oil	-	-	-	-	-	2,655	32,627	22,119	58,291	107,621
Marathon	3,995,784	4,062,765	4,347,695	4,358,280	4,234,315	3,281,087	3,182,443	3,425,973	3,568,563	3,376,350
ExxonMobil	50,177	55,372	21,509	52,341	4,118	2,895	1,532	-	-	-
Anchorage M, L & P	-	905,557	775,755	677,169	617,794	565,987	587,367	634,919	628,924	1,427,753
Phillips	6,490,318	6,665,243	6,372,036	7,782,678	7,953,777	6,537,260	-	-	-	-
Shell	985,270	-	-	-	-					
Unocal	4,532,490	5,272,111	4,290,269	3,486,988	3,656,068	3,559,919	2,444,802	2,423,250	2,226,234	1,986,214
Cook Inlet TOTAL	**17,697,067**	**18,564,277**	**17,736,489**	**17,360,026**	**17,801,882**	**16,726,074**	**15,680,818**	**15,252,063**	**15,556,164**	**14,266,190**

Table IV.6 Recent Royalty Gas Revenues by Lessee

North Slope

Revenue (Thousands of Dollars)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Anadarko	-	-	-	-	-	-	-	-	-	$7
Arco	$325	$297	$344	-	-	-	-	-	-	-
BP Am Prod. Co	-	-	-	-	-	-	$3	-	-	-
BPXA	$543	$451	$540	$539	$593	$3,054	$5,844	$7,527	$9,750	$10,835
Chevron	$33	$7	-	-	<1	<1	<1	<1	-	-
ConocoPhillips AK	-	-	-	-	-	$446	$538	$643	$865	$983
Exxon	$207	$183	$185	-	-	-	-	-	-	-
ExxonMobil	-	-	-	$318	$265	$242	$300	$360	$508	$493
Forest Oil	-	-	-	-	-	-	-	-	-	-
Mobil	$128	$80	$87	-	-	-	-	-	-	-
NANA	$23	-	-	-	-	-	-	-	-	-
Oxy	$2	$2	$2	$2	-	-	-	-	-	-
PetroHunt										<1
Phillips	$15	$13	$7	$531	$440	-	-	-	-	-
Unocal	-	-	-	-	-	-	<1	<1	<1	<1
North Slope TOTAL	**$1,278**	**$1,033**	**$1,165**	**$1,390**	**$1,298**	**$3,742**	**$6,685**	**$8,529**	**$11,123**	**$12,318**

Cook Inlet

Revenue (Thousands of Dollars)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Arco	$1,411	$1,262	$1,170	-	-	-	-	-	-	-
Aurora Power	-	-	-	-	$62	$18	$17	$38	$135	$222
Chevron	$1,551	$1,560	$1,605	$1,698	$3,136	$3,740	$4,373	$5,020	$6,293	$5,516
ConocoPhillips AK	-	-	-	-	-	$2,530	$3,747	$4,562	$6,766	$6,491
Conoco Phillips Co.			-	-	-	-	$12,159	$11,600	$14,987	$14,546
Forest Oil	-	-	-	-	-	-	$16	$90	$179	$433
Marathon	$6,061	$5,737	$5,557	$6,795	$10,429	$7,433	$6,777	$8,761	$12,113	$14,982
ExxonMobil	$47	$55	$22	-$0	$4	$3	$2	$0	-	-
Anchorage M, L & F	-	$1,443	$1,008	$1,082	$1,416	$1,316	$1,358	$2,022	$2,198	$3,268
Phillips	$12,054	$8,874	$8,914	$15,934	$16,697	$12,562	-	-	-	-
Shell	$1,636	-	-	-	-	-	-	$103	-	
Unocal	$6,351	$7,035	$5,161	$13,624	$5,083	$4,993	$14,157	$7,178	$8,050	$9,699
Cook Inlet TOTAL	**$29,112**	**$25,966**	**$23,436**	**$39,134**	**$36,826**	**$32,595**	**$42,606**	**$39,373**	**$50,721**	**$55,157**

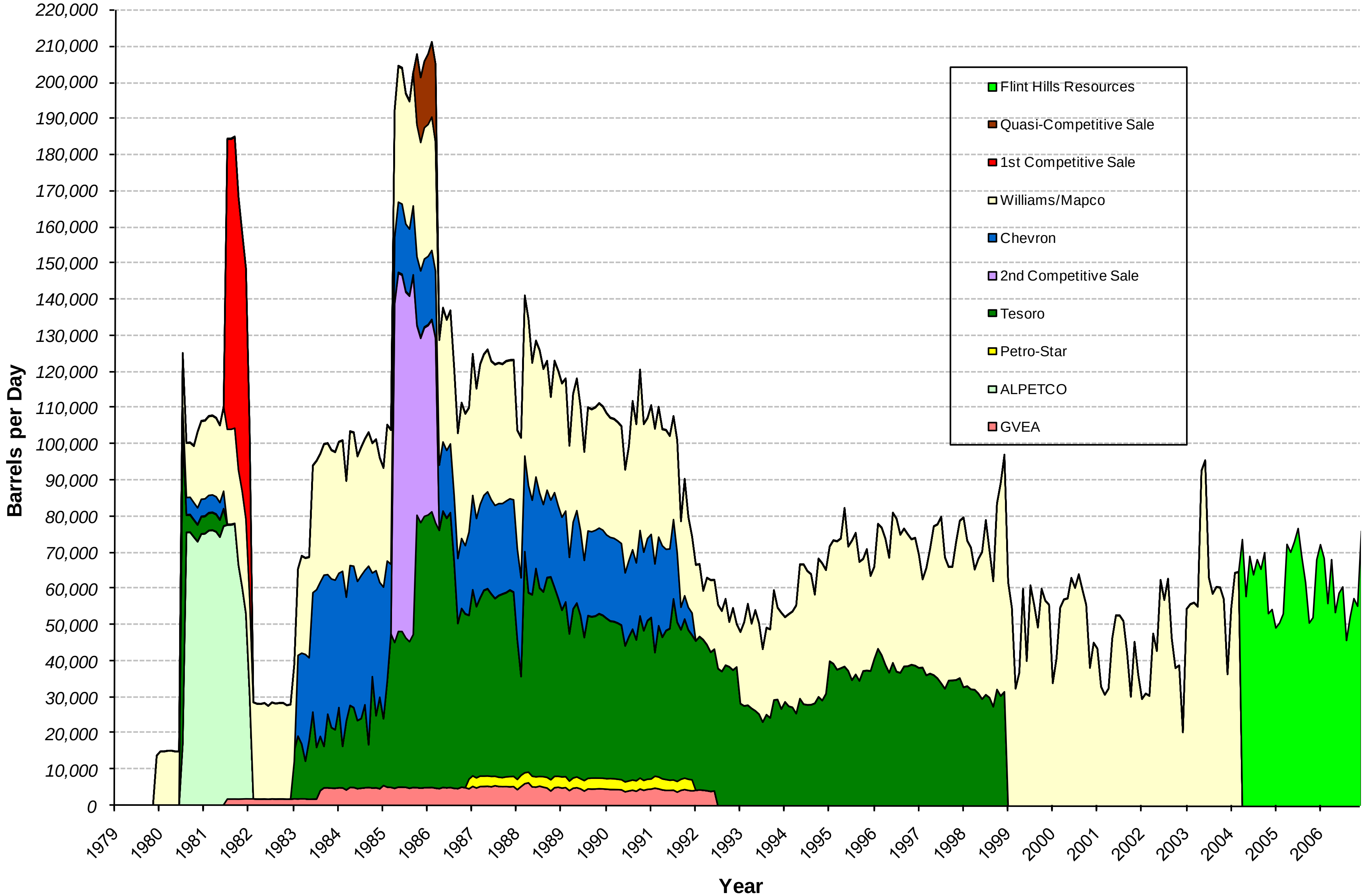
Revenues include principal and interest from revisions and settlements in the year received.

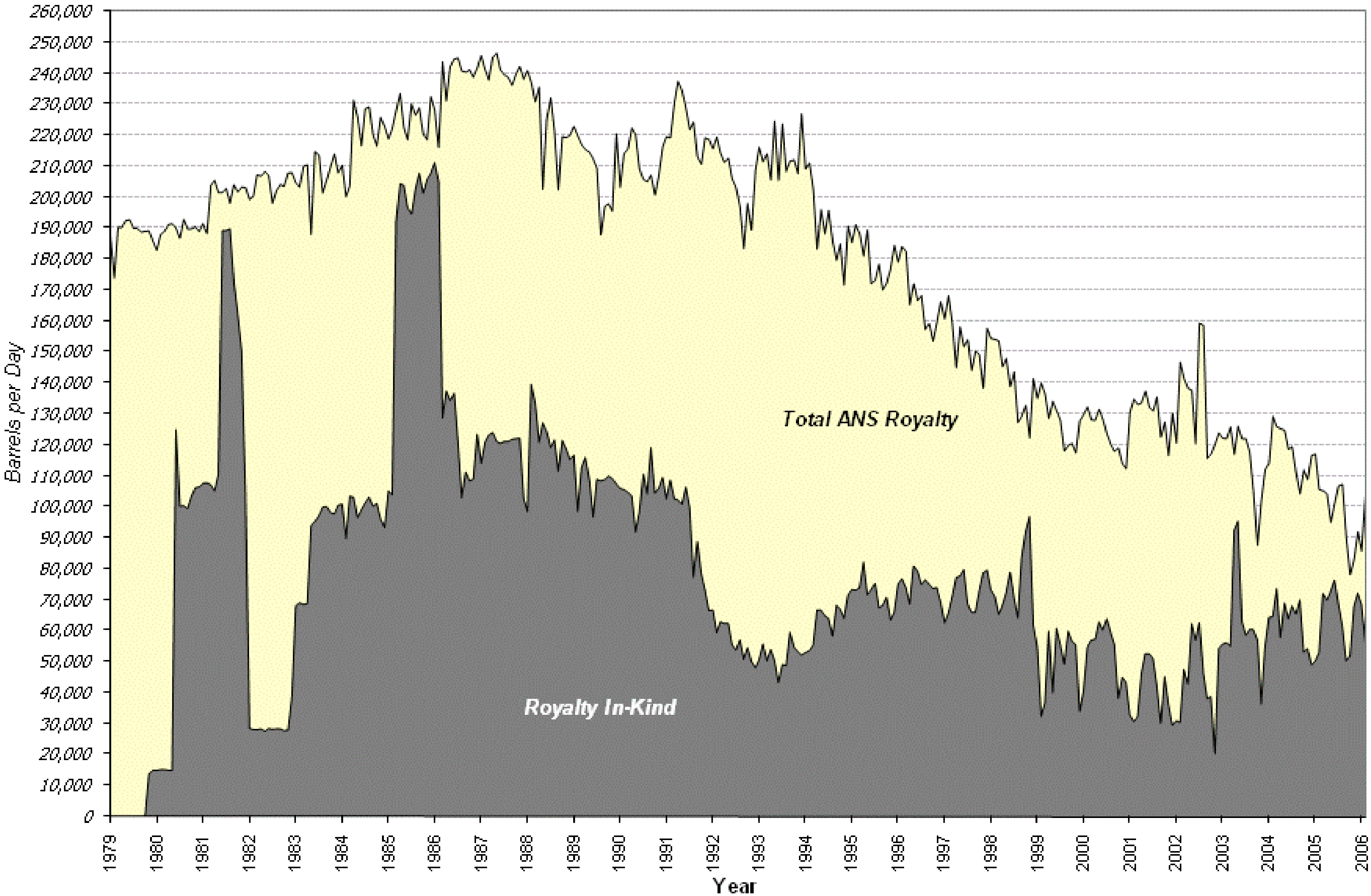
Table IV.7 North Slope Royalty in-Kind Sales

1979-2006 (Barrels per Year)

	Alpetco	Chevron	Williams (Mapco)	Flint Hills Resources, (FHR)	Golden Valley Elec Assoc	Tesoro	Petro Star	1st Comp Sale	2nd Comp Sale	Quasi-Comp Sale	**ANS TOTAL RIK**	**ANS TOTAL RIV**	**ANS TOTAL RIK + RIV**
1979	-	-	446,996		-	-	-	-	-	-	446,996	10,584,481	11,031,477
1980	12,020,950	882,414	5,976,024		-	3,427,388	-	-	-	-	22,306,777	47,047,583	69,354,360
1981	26,046,878	859,928	8,808,400		398,051	1,661,385	-	14,046,953	-	-	51,821,595	17,666,128	69,487,723
1982	898,714	-	9,632,099		764,762	36,841	-	1,432,108	-	-	12,764,524	61,136,212	73,900,736
1983	-	11,674,998	11,723,755		1,208,406	5,793,973	-	-	-	-	30,401,132	44,599,235	75,000,367
1984	-	14,053,279	13,093,397		1,870,505	7,531,155	-	-	-	-	36,548,337	39,396,031	75,944,369
1985	-	7,804,392	13,260,754		1,928,544	17,218,912	-	-	22,511,409	1,716,754	64,440,764	16,633,246	81,074,010
1986	-	6,934,482	13,168,483		1,881,232	23,538,192	52,667	-	4,686,801	1,862,051	52,123,907	30,262,661	82,386,568
1987	-	9,330,563	14,094,537		2,013,539	18,404,806	539,575	-	-	-	44,383,020	43,899,311	88,282,331
1988	-	9,315,264	13,814,522		1,981,998	18,307,014	590,832	-	-	-	44,009,630	44,068,971	88,078,602
1989	-	8,611,606	12,529,175		1,784,782	16,387,093	607,468	-	-	-	39,920,122	40,833,646	80,753,768
1990	-	8,099,292	12,735,412		1,670,494	15,368,565	621,220	-	-	-	38,494,983	37,242,490	75,737,473
1991	-	6,290,546	11,183,462		1,670,699	15,336,301	618,247	-	-	-	35,099,255	42,537,362	77,636,617
1992	-	-	6,285,005		803,407	14,412,460	-	-	-	-	21,500,871	52,754,222	73,680,092
1993	-	-	9,086,280		-	9,812,084	-	-	-	-	18,898,364	49,269,042	68,294,256
1994	-	-	11,986,495		-	10,452,726	-	-	-	-	22,439,221	50,657,903	73,097,124
1995	-	-	12,680,470		-	13,703,946	-	-	-	-	26,384,415	43,664,553	70,048,968
1996	-	-	13,027,646		-	14,345,621	-	-	-	-	27,373,267	39,396,515	66,769,782
1997	-	-	13,117,502		-	13,021,628	-	-	-	-	26,139,130	35,359,848	61,498,978
1998	-	-	16,483,695		-	11,497,629	-	-	-	-	27,981,324	28,316,894	56,298,218
1999	-	-	19,070,664		-	-	-	-	-	-	19,070,664	31,473,201	50,543,865
2000	-	-	19,290,298		-	-	-	-	-	-	19,290,298	27,849,804	47,140,102
2001	-	-	15,187,012		-	-	-	-	-	-	15,187,012	30,207,251	45,394,263
2002	-	-	15,509,592		-	-	-	-	-	-	15,509,592	32,287,247	47,796,839
2003	-	-	22,749,221		-	-	-	-	-	-	22,749,221	25,336,333	48,085,554
2004	-	-	5,582,299	17,635,994	-	-	-	-	-	-	23,218,293	22,260,150	45,478,443
2005	-	-	-	22,796,740	-	-	-	-	-	-	22,796,740	19,552,414	42,349,154
2006	-	-	-	22,180,915	-	-	-	-	-	-	22,180,915	13,269,288	35,450,203
	38,966,543	83,856,765	320,523,194	62,613,649	17,976,419	230,257,719	3,030,009	15,479,061	27,198,210	3,578,804	803,480,372	977,562,023	1,780,594,243

Figure IV.1 ANS Royalty-in-Kind Contract Volumes

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1999
2000
2001
2002
2003
2004
2005
2006
Year

Table IV.8 Cook Inlet and Statewide Royalty in-Kind Sales

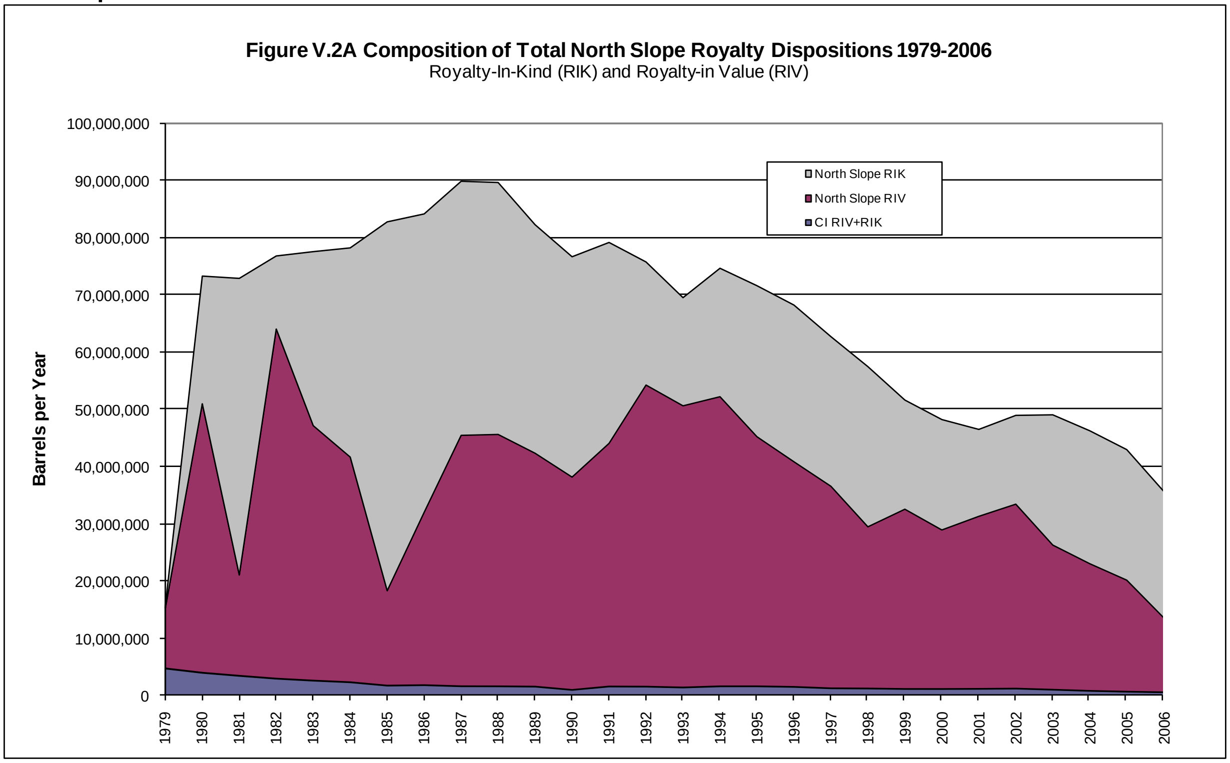
1979-2006 (Barrels per Year)

	COOK INLET					STATEWIDE		
	Tesoro[1]	Chinese Petroleum[2]	Cook Inlet RIK	Cook Inlet RIV	Cook Inlet Total Royalty Volume	ALASKA RIK	ALASKA RIV	ALASKA Total Royalty Volume
1979	4,849,631	-	4,849,631	-	4,849,631	5,296,627	10,584,481	15,881,108
1980	4,094,229	-	4,094,229	-	4,094,229	26,401,006	47,047,583	73,448,589
1981	3,560,736	-	3,560,736	-	3,560,736	55,382,331	17,666,128	73,048,459
1982	3,065,159	-	3,065,159	-	3,065,159	15,829,683	61,136,212	76,965,895
1983	2,719,044	-	2,719,044	-	2,719,044	33,120,176	44,599,235	77,719,411
1984	2,431,987	-	2,431,987	-	2,431,987	38,980,324	39,396,031	78,376,356
1985	1,382,740	-	1,382,740	462,245	1,844,985	65,823,504	17,095,491	82,918,995
1986	-	-	-	1,922,101	1,922,101	52,123,907	32,184,762	84,308,669
1987	-	615,305	615,305	1,113,805	1,729,110	44,998,325	45,013,116	90,011,441
1988	-	799,938	799,938	917,208	1,717,146	44,809,569	44,986,179	89,795,748
1989	-	1,274,479	1,274,479	392,313	1,666,792	41,194,601	41,225,959	82,420,561
1990	-	566,825	566,825	522,456	1,089,282	39,061,808	37,764,947	76,826,755
1991	-	330,540	330,540	1,357,687	1,688,227	35,429,795	43,895,049	79,324,844
1992	-	-	-	1,661,526	1,661,526	21,500,871	54,415,748	75,916,620
1993	-	-	-	1,514,651	1,514,651	18,898,364	50,783,693	69,682,057
1994	-	-	-	1,717,758	1,717,758	22,439,221	52,375,662	74,814,882
1995	-	-	-	1,718,805	1,718,805	26,384,415	45,383,358	71,767,773
1996	-	-	-	1,618,157	1,618,157	27,373,267	41,014,672	68,387,940
1997	-	-	-	1,369,478	1,369,478	26,139,130	36,729,326	62,868,456
1998	-	-	-	1,335,030	1,335,030	27,981,324	29,651,924	57,633,248
1999	-	-	-	1,252,231	1,252,231	19,070,664	32,725,432	51,796,096
2000	-	-	-	1,248,564	1,248,564	19,290,298	29,098,368	48,388,666
2001	-	-	-	1,273,518	1,273,518	15,187,012	31,480,769	46,667,780
2002	-	-	-	1,320,281	1,320,281	15,509,592	33,607,528	49,117,120
2003	-	-	-	1,127,749	1,127,749	22,749,221	26,464,082	49,213,303
2004	-	-	-	920,535	920,535	23,218,293	23,180,685	46,398,978
2005	-	-	-	779,749	779,749	22,796,740	20,332,163	43,128,902
2006	-	-	-	669,212	669,212	22,180,915	13,938,500	36,119,415
	22,103,526	3,587,088	25,690,614	26,215,059	51,905,672	829,170,986	1,003,777,082	1,832,948,067

Notes:

[1] East and west side.

North Slope and Cook Inlet



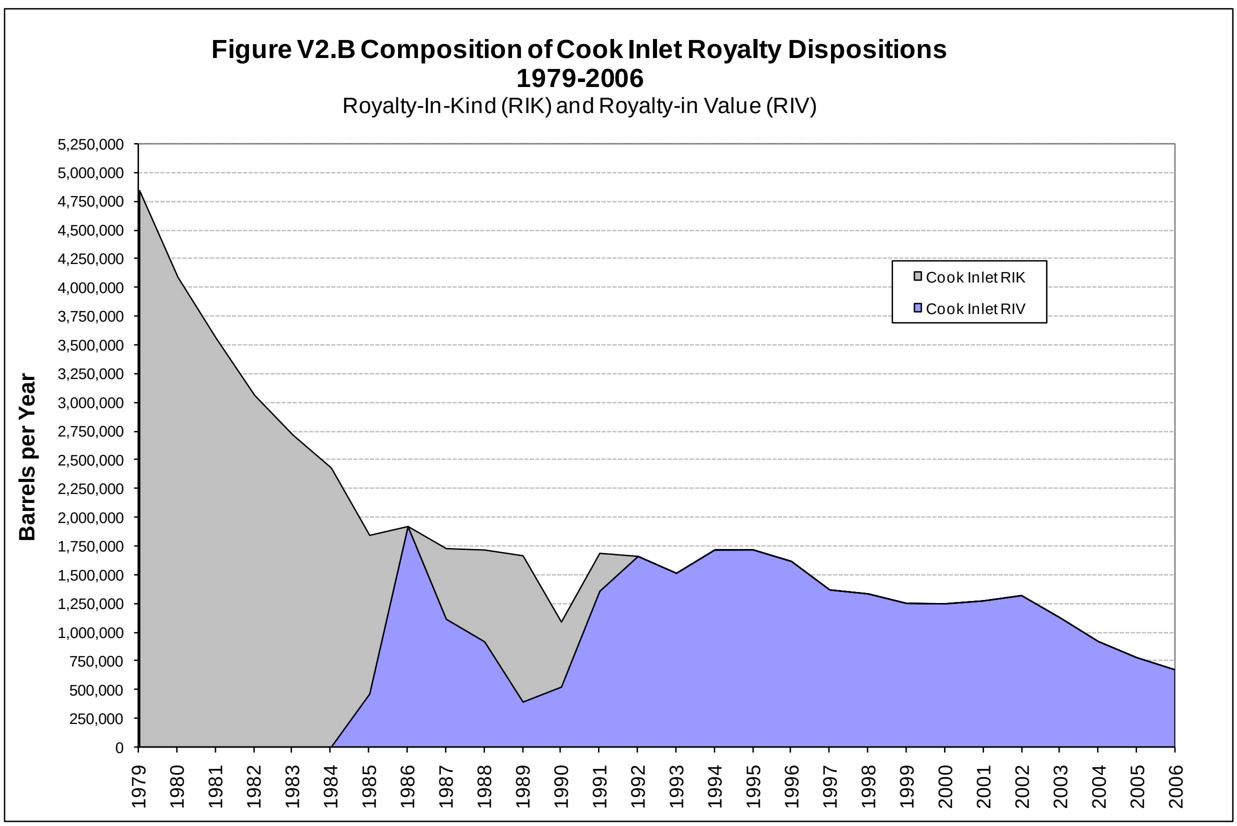
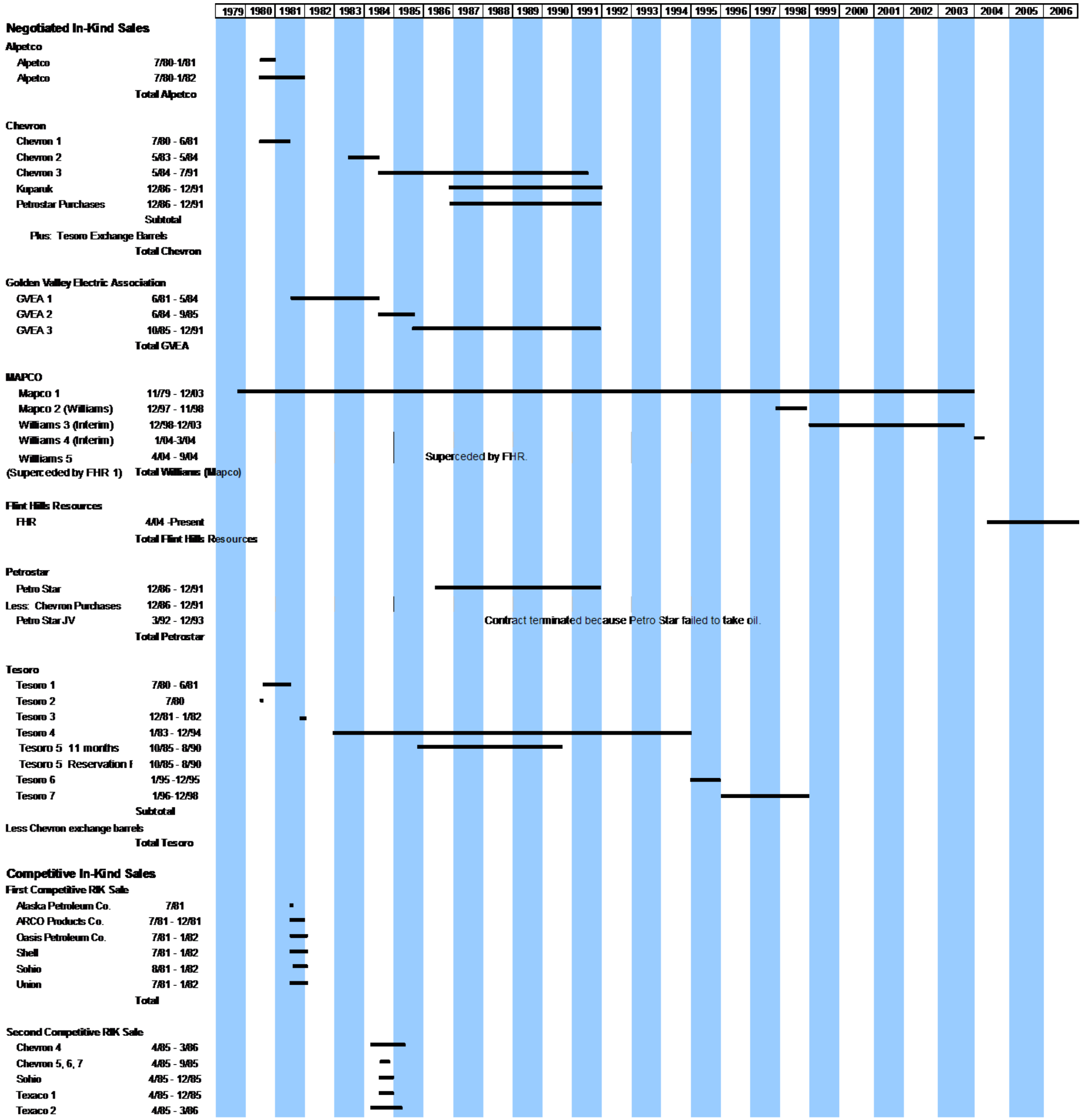


Figure IV.3 Major North Slope Royalty in-Kind Sales Contracts

1979-2006



Section Five

Alaska Refining
Sales and Consumption

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Alaska Refineries

Alaska is a leading supplier of United States crude oil, ranking second in crude oil production (excluding federal offshore production), according to the U.S. Department of Energy, Energy Information Administration. Prudhoe Bay on Alaska's North Slope is the highest yielding oil field in the United States, producing approximately 400,000 barrels per day. The trans-Alaska oil pipeline system (TAPS) throughput peaked at 2.1 million barrels of crude oil per day from North Slope oil fields to the Port of Valdez in 1988. In 2006, North Slope production had dropped to 781,000 barrels per day. From Valdez, North Slope crude is shipped primarily to refineries in Washington and California.

The state's six refineries have a combined crude distillation capacity of about 373,500 barrels per day. Five of the six facilities are "topping" plants which only remove the lighter, higher valued transportation fuels from the crude oil stream while injecting the degraded bottoms back into the crude oil in the pipelines serving the refineries.

As shown in Table V.1, two small refineries, owned by the Prudhoe Bay Unit and the Kuparuk River Unit, are located on the North Slope. The remaining four refineries are located in North Pole near Fairbanks, Nikiski on the Kenai Peninsula, and at Valdez near the TAPS marine terminal. These refineries serve a variety of residential, commercial, industrial, and transportation sectors across the state.

Table V.1 Alaska Refineries and Service Stations

Refinery	**Location**	**Distillation Capacity (Barrels Per Day)**
Flint Hills Resources AK LLC (FHR)	North Pole	210,000
Tesoro Petroleum Corp.	Nikiski (Kenai)	72,000
Petro Star Inc.	Valdez	48,000
Petro Star Inc.	North Pole	17,000
ConocoPhillips AK, Inc.	Kuparuk	14,000
BP Exploration (Alaska) Inc.	Prudhoe Bay	12,500
Total Distillation Capacity		*373,500*
Gasoline Service Stations	Statewide	460 Outlets

Alaska North Slope (ANS) oil comes from several units. The quality of the crude produced from each unit is somewhat different. To properly account for the difference in quality and value of the streams coming from the different units, each unit is assigned a quality bank value. The quality bank is the method of making monetary adjustments among shippers of ANS oil which either compensates or charges a shipper for the difference in quality between the crude oil tendered by that shipper at the unit LACT meter and the crude oil received by that shipper at the destination point. Through the quality bank process, the total payments paid by shippers equal the total payments received by shippers. The current methodology values the tendered crude oil on the value of the components of the oil. Similarly, the refineries in North Pole and Valdez take oil out of TAPS, extract the valuable components of the oil in manufacturing petroleum products, and inject into the pipeline a mixture of lower-valued components. The return streams from the refineries bear a quality bank payment to each of the shippers of the passing TAPS stream.

Flint Hills Resources Alaska (FHR) acquired its North Pole refinery – Alaska's largest – from Williams Alaska Petroleum, Inc., in 2004. FHR also owns a 700,000-barrel jet fuel terminal in Anchorage, and a 20,000-barrel jet fuel terminal in Fairbanks. The North Pole refinery, expanded in 1998, receives North Slope crude via TAPS and has a crude oil throughput of about 226,500 barrels per day; however, only about 60,000 barrels per day was refined into products for sale and the rest was injected back into TAPS. FHR processes North Slope crude and supplies gasoline, jet fuel, heating oil, diesel, gas oil, and asphalt to local and international markets. About 60 percent of the refinery's production goes to the aviation market. The company also owns and operates products terminals in Fairbanks and Anchorage that store and distribute asphalt, diesel, jet fuel, and gasoline produced at the North Pole refinery.

Constructed in 1965, the FHR Anchorage Terminal receives products from the North Pole Refinery via tank cars delivered by the Alaska Railroad. In 2006, more than 25,000 tank cars were delivered and offloaded. Each tank car holds approximately 550 barrels of product. Product from the FHR Anchorage terminal is distributed via pipeline, truck and rail racks locally and to locations throughout Alaska. The FHR Anchorage terminal facility can store more than 700,000 barrels of refined products. A pipeline system extends from the terminal one-half mile away to the Port of Anchorage and enables bulk fuel transfers to and from other terminals and vessels berthed at the Port of Anchorage municipal docks. The terminal loads an average of 60 to 80 vessels annually with refined product. The Fairbanks Terminal stores, in bulk, jet fuel that is delivered by tanker truck from the refinery. Jet fuel is loaded from tanks into 10,000-gallon aircraft refueling trucks called fuel tenders, or "DARTS," and delivered to airline customers. The DARTS fuel 18 to 24 flights per day. The Fairbanks Terminal was built in the early 1970s. The company produces low-sulfur gasoline at the North Pole Refinery and purchases ultra-low-sulfur diesel from other sources to meet local demand. FHR has also retrofitted its fuel terminals in North Pole and Anchorage to handle low-sulfur fuels.

Flint Hills North Pole refinery production by volume:

Gasoline & Naphtha	10%
Jet Fuel/#1 Fuel Oil	77
#2 Diesel	8
Gas Oil	4
Asphalt	1
Total	100%

FHR transported about 1.4 million gallons per day of jet fuel in 2006, and about 70,000 gallons per day of gasoline by rail to Southcentral Alaska. The North Pole refinery accounts for more than half of Anchorage jet fuel consumption. FHR purchases between 56,000 and 77,000 barrels per day of Alaska royalty oil per its state royalty contract.[1]

[1] Flint Hills Resources, LP; www.fhr.com/alaska/
and ADNR, Division of Oil and Gas http://www.dog.dnr.state.ak.us/oil/programs/royalty/rik_sale/flint_appx_a.pdf

Tesoro Corporation operates Alaska's first oil refinery, which opened in Nikiski in 1969 and currently has a throughput capacity of 72,000 barrels per day. The refinery processes all of the oil produced in Cook Inlet and supplements this supply primarily with Alaska North Slope and foreign crudes. In December 1994, Tesoro completed installation of a vacuum unit at Nikiski. The vacuum unit reduces the volume of bottoms and residual production by approximately half. The Nikiski refinery produces an average of approximately 55,000 barrels per day of petroleum products to serve its 125 Tesoro-branded retail stations and other customers across the state. Process units at the refinery include a hydrocracker that is used to maximize the production of jet fuel for sale at Ted Stevens Anchorage International Airport, where the refinery serves about 40 percent of the total monthly jet fuel demand. A 75-mile, 10-inch, multi-product pipeline traverses Cook Inlet from Nikiski to Tesoro's terminal facility located at the Port of Anchorage. A pipeline spur allows direct delivery into the airport's tank farm.

Asphalt produced at Nikiski is sold in Alaska. Nearly all of the remaining heavy oil, for which there is no local market, is exported to other states. Tesoro sells all of its summer gasoline production in the state, but must ship gasoline and diesel to markets in the Pacific Northwest during the winter season. As an example of the synergies, Tesoro capitalizes on its refineries by shipping heavy vacuum gas oil to its Anacortes, Wash., refinery where it is used as a feedstock to produce gasoline.

Tesoro Nikiski refinery production by volume:

<table>
<tr><td>Gasoline & Naphtha</td><td>28%</td></tr>
<tr><td>Jet Fuel</td><td rowspan="3">45-55</td></tr>
<tr><td>Diesel</td></tr>
<tr><td>Gas Oil</td></tr>
<tr><td>Bottoms/Resid (Asphalt)</td><td>22</td></tr>
<tr><td>Total</td><td>100%</td></tr>
</table>

Petro Star Inc. (PSI) operates refineries in North Pole and Valdez and is owned by the Arctic Slope Regional Corp. Petro Star was founded in 1984 to process light fuels for heating homes and operating businesses in rural Alaska and built its first refinery at North Pole in 1984. Petro Star acquired fuel distribution companies, including Sourdough Fuel in 1986, and began to distribute its products throughout Interior Alaska and the Arctic Slope, including Prudhoe Bay. In 1991, Petro Star expanded into the lubricants market with the purchase of Alaska Lube and Fuel, now known as PSI Lubricants. Also that year, plans for a larger refinery in Valdez got under way. By 1993, the PSI Valdez Refinery began continuous operations. PSI began servicing military and commercial aviation clients in Anchorage in 1994. Today, jet fuel production is the refinery's largest business sector. The company acquired Valdez Petroleum Terminal in the mid-1990s and began serving customers in western Alaska with the purchase of Kodiak Oil Sales in 1997 and North Pacific Fuel in 1998.

PSI's smaller North Pole refinery has throughput capacity of 18,000 barrels per day; while the Valdez refinery processes 48,000 barrels per day. Both refineries are relatively small scale, located adjacent to TAPS and process ANS crude oil. Approximately 25 percent of the throughput is retained as product and refinery fuel with the balance returned to TAPS in a similar manner to the Flint Hills North Pole refinery.

Petro Star North Pole and Valdez refinery production by volume:

Jet Fuel / # 1 Fuel Oil	68%
Diesel / # 2 Heating Oil	32
Total	100%

The main function of the BP-operated Prudhoe Bay Unit Crude Oil Topping Unit (COTU) is to provide arctic heating fuel (AHF) for the operation of North Slope equipment and drilling operations. The COTU currently receives crude oil for processing from the Endicott/Badami/FS2 oil transit line (OTL). After the AHF is distilled from the crude, all remaining residual oil, naptha and trace water are re-injected into the OTL. The supply and return volumes are metered and recorded.

The COTU consists of two parallel distillation plants that are very similar in equipment and operation. The incoming crude is split between the two plants. Each plant then heats the crude to approximately 550 degrees Fahrenheit and distills off the AHF in a simple distillation tower. This AHF is sent to their storage tanks and the remaining fluids are recombined and re-injected back into the OTL. Each plant is capable of processing approximately 7,000 to 8,000 Bbls per day of crude oil with a production of 1,200 to 1,400 Bbls per day of AHF. The production of Jet-A is done on a periodic batch basis and is the same operation with similar production figures. AHF and Jet-A are the only products the COTU produces for distribution. As stated, the main function of the COTU is to provide AHF for the Prudhoe Bay operation. The majority of the production is distributed for this purpose. The remaining production that is in excess of the unit's requirements is distributed to non-Prudhoe Bay operations. The COTU does not ship any AHF or Jet-A south of the Brooks Range for sale or distribution.

BP Prudhoe Bay Crude Oil Topping Unit production by volume:

Arctic Heating Fuel (Diesel)	97%
3% Jet–A	3
Total	100%

The ConocoPhillips-operated Kuparuk Unit Topping Plant is designed to process pipeline-quality crude oil feedstock from Central Processing Facility #1 (CPF1) for support of drilling and production operations. This feedstock is sent through a distillation process to extract AHF. The AHF is extracted from the distillation tower and further processed to control the flashpoint of the fuel before being transferred to a storage facility where the various users can take delivery. The plant processes approximately 14,500 barrels per day of crude-oil feedstock, which results in a yield of 1,700 to 2,400 barrels per day of AHF, depending on specific end product requirements.

ConocoPhillips – Kuparuk Crude Oil Topping Unit production by volume:

Arctic Heating Fuel	100%

Statewide Total Fuel Consumption

In-state consumption of refined products includes in-state production and imports. Sales volumes, a proxy indicator for consumption, are reported by the U.S. Department of Energy, Energy Information Administration[2] (EIA) in its *Petroleum Marketing Annual* and the Alaska Department of Revenue (ADOR) in its fuel sales tax reports. Total or gross annual fuel sales volume and price by major product type are summarized in Tables V.2.A and B. Annual gross fuel sales volumes increase over time for most products, except for No. 2 diesel fuel. Annual jet fuel sales volumes show a steady increase over the time period, despite slight declines in 2001 and 2003. The jet fuel decline in 2003 was probably related to a sharp nationwide decline in commercial aviation. Alaska's refineries supply approximately 88 percent of in-state jet fuel consumed based on EIA data on prime supplier sales.

Table V.2.A Prime Supplier Sales for Alaska, 1995 – 2006

(Thousands of Gallons per Day) Alaska Prime Supplier Sales Volumes of Petroleum Products

Year	Total Gasoline[a]	Aviation Gasoline	Kerosene Type Jet Fuel	Propane	No. 1 Distillate	No. 2 Diesel Fuel	No. 2 Fuel Oil	Total Fuel Sold
1995	691.9	49.9	1,714.7	W	243.2	W	280.2	2979.9
1996	698.8	46.4	1,935.3	40.2	219.6	W	277.1	3217.4
1997	694.6	47.4	2,193.2	W	255.0	W	421.7	3611.9
1998	771.4	57.6	2,285.2	W	254.8	427.7	357.4	4154.1
1999	784.4	58.7	2,434.4	W	276.6	467.2	295.9	4317.2
2000	744.8	58.7	2,502.9	W	216.7	396.5	287.6	4207.2
2001	761.2	61.2	2,461.9	W	233.6	462.5	227.4	4207.8
2002	755.2	55.3	2,777.1	W	233.9	512.8	W	4334.3
2003	784.0	W	2,627.4	W	185.9	551.8	W	4149.1
2004	826.8	W	2,970.9	W	162.8	361.9	263	4585.4
2005	838.0	W	3,201.9	32.3	W	298.9	300.7	4671.8
2006	778.9	W	3,080.9	30.9	W	W	270.4	4161.1

In the last 10 years, all product prices have nearly doubled. Propane sales volume data is limited, but a flattening consumption trend is evident since the mid-1990s. Alaska propane price data are not available.

Table V.2.B Prime Supplier Alaska Petroleum Product Prices, 1995 – 2006

(Dollars per Gallon – Taxes Excluded) Alaska Prices, Sales Volumes and Stocks

Year	Total Gasoline[a]	Aviation Gasoline	Kerosene Type Jet Fuel	No. 1 Distillate	No. 2 Diesel Fuel	No. 2 Fuel Oil
1995	1.13	W	0.61	0.75	0.82	0.83
1996	1.20	W	0.71	0.74	1.06	0.91
1997	1.18	W	0.67	0.67	1.08	0.97
1998	0.99	W	0.49	0.57	0.91	0.85
1999	1.00	W	0.61	0.81	0.81	0.97
2000	1.33	1.49	0.96	1.02	W	1.34
2001	1.38	W	0.81	0.83	1.26	1.38
2002	1.29	W	0.76	0.84	1.10	1.09
2003	1.48	W	0.90	W	1.29	1.24
2004	1.70	W	1.30	1.26	1.54	1.52
2005	2.09	W	1.77	W	2.04	2.06
2006	2.40	W	2.05	W	2.42	2.40

Table Notes:
[a] Includes regular, mid-grade, and premium blends of motor gasoline.
[W] Withheld to avoid disclosure of individual company data. Source: Energy Information Administration, U.S. DOE, Prime Supplier Sales in Alaska

[2] Fuel consumed is based on EIA data on prime supplier sales. Prime suppliers include firms that produce, import, or transport petroleum products across state boundaries and local marketing areas and sell the products to local distributors, local retailers, or end users. According to the EIA, prime supplier sales within a given state may serve as a proxy for consumption but may not equal actual consumption by the end-users in the state because a product may be sold by a prime supplier in one state and transported by local distributors to another state for final consumption. Price data for 2006 may be subject to revision upon final publication in the Petroleum Marketing Annual.
No. 2 diesel fuel and No. 2 fuel oil prices and sales volumes are classified in accordance to what the product was sold as, regardless of the actual specifications of that product (i.e., if a No. 2 distillate was sold as a hea ing oil or fuel oil, the volume and price would be published in the category "No. 2 Fuel Oil" even if the product conformed to the higher specifications of a diesel fuel.

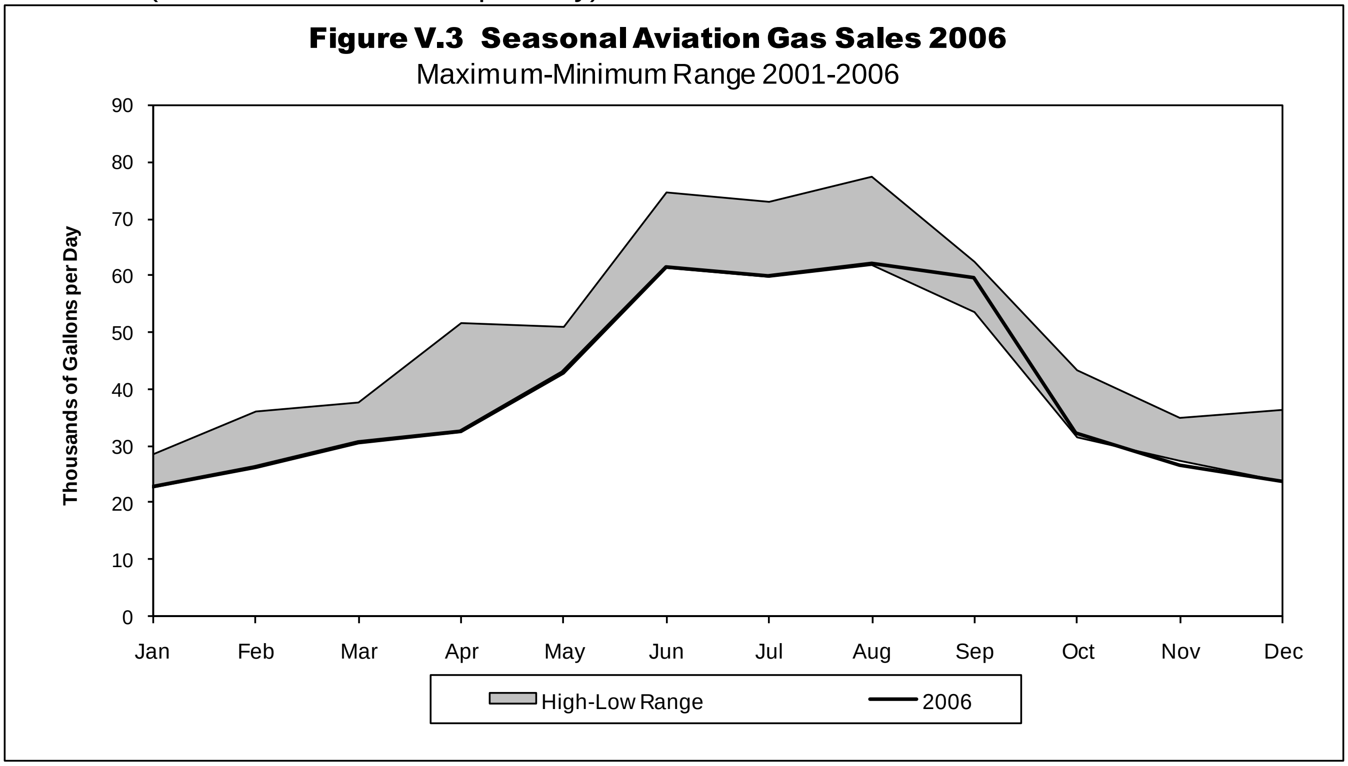
Seasonal Taxable Aviation Gas, Jet Fuel, Motor Gas and Diesel Sales

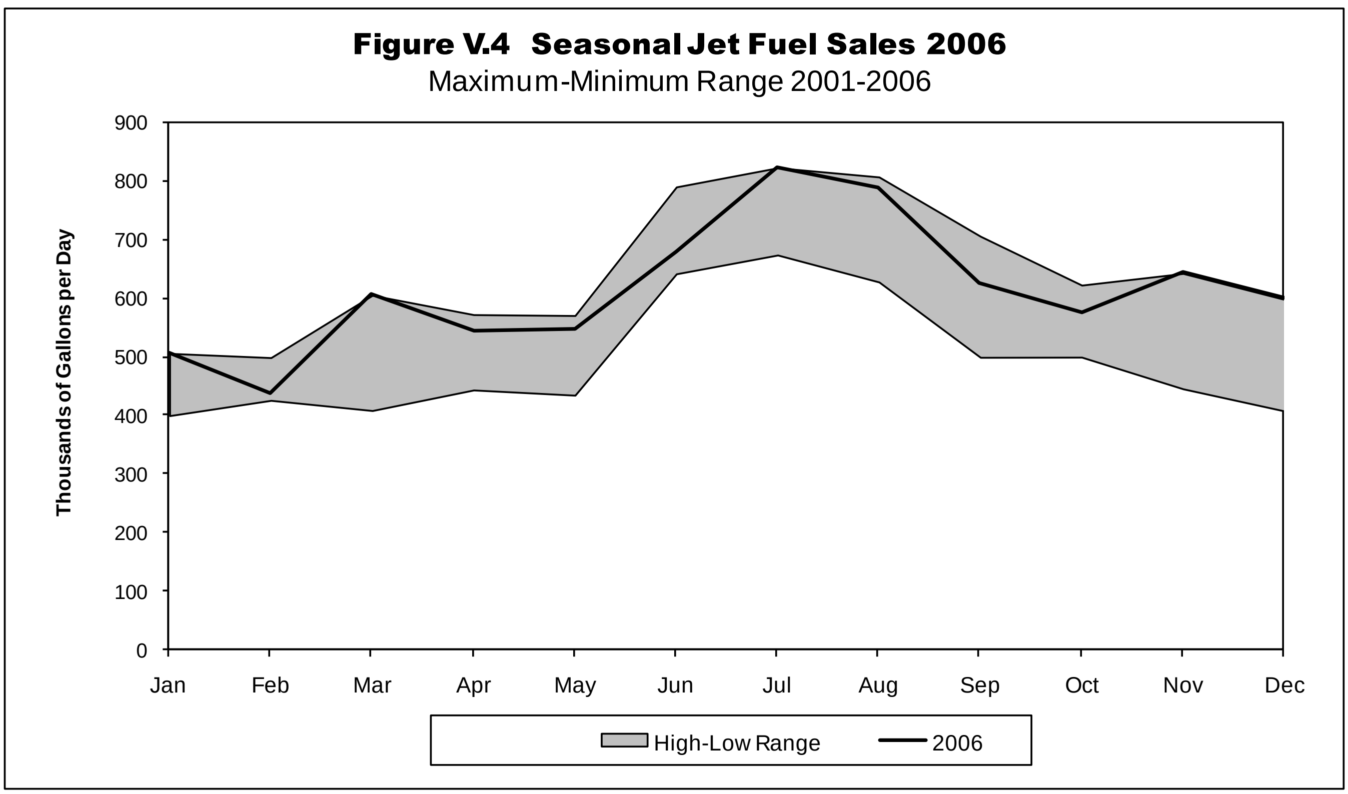
Seasonal fuel sales shown in Figures V.3 through V.6 represent taxable sales only and are less than the total sold in any given month. The range (maximum and minimum values) of monthly sales over the six-year period 2001–2006 is presented as the shaded region in each of the four figures. Monthly sales during 2006 are shown with a black line within the shaded high-low range. Aviation gas sales for 2006 were near the historic low for the six-year period, whereas jet fuel sales in 2006 were high compared to previous years during the period. Motor gas sales tend to fluctuate between the upper and lower limits of its range while diesel sales tend to be at the peak range.

ADOR reported fuel sales totals do not match the monthly figures published by the EIA.[3] The primary reason for the difference is the ADOR totals represent taxable values, whereas the EIA prime supplier sales volumes are based on total sales volumes. The EIA reported prime supplier sales include firms that produce, import, or transport petroleum products across state boundaries and local marketing areas and sell the products to local distributors, local retailers, or end users. According to the EIA, prime supplier sales within a given state may serve as a proxy for consumption but may not equal actual consumption by the end-users in the state because a product may be sold by a prime supplier in one state and transported by local distributors to another state for final consumption. The largest discrepancy between EIA and ADOR data is in jet fuel, and is probably due to jet fuel used in commercial foreign flights.[4] ADOR data excludes jet fuel purchased in Alaska that is used in commercial flights that originated in a foreign country or where the next destination is a foreign country. For example, several international airlines refuel in Anchorage where the flight originated, say, in Korea or Hong Kong. Even if the flight is then destined for a U.S. city, the fuel is tax-exempt under AS 43.40.100(2)(B)(i). ADOR data includes only that fuel upon which the excise tax was due or collected. [5,6]

[3] The mon hly EIA data contain numerous missing values, which limits its applicability.
[4] The primary reason for the difference is ADOR totals only count taxable volume, whereas, the EIA, Prime Supplier Sales Volumes are based on total or gross statewide sales. For the period 2001 through 2006, the ADOR taxable portion averages approximately 80% of the EIA total for all products except Jet Fuel, which averages 20 percent of the EIA reported total.
[5] Source: Energy Information Administration, U.S. DOE, Prime Supplier Sales in Alaska: http://tonto.eia.doe.gov/dnav/pet/pet_cons_prim_dcu_SAK_a.htm
[6] Motor Fuel tax is levied on motor fuel sold, transferred or used within Alaska. Motor fuel taxes are collected primarily from wholesalers and distributors who are licensed as qualified dealers. Persons who first transfer or sell motor fuel in the state are subject to the tax. Motor fuel tax rates are as follows: gasoline, diesel, and gasohol - highway 8¢ / marine 5¢; aviation gas 4.7¢; and jet fuel 3.2¢ per gallon. Motor fuel tax returns are filed monthly and are due with payment of tax by the last day of the month following the month in which sales were made, or taxable use occurred. See http://www.tax.state.ak.us/programs/motorfuel/index.asp. More information on AS 43.40, Motor Fuel Tax, can be found at: http://www.tax.state.ak.us/programs/motorfuel/reports/2005_MF_Annual_Report.pdf .

Statewide (Thousands of Gallons per Day)

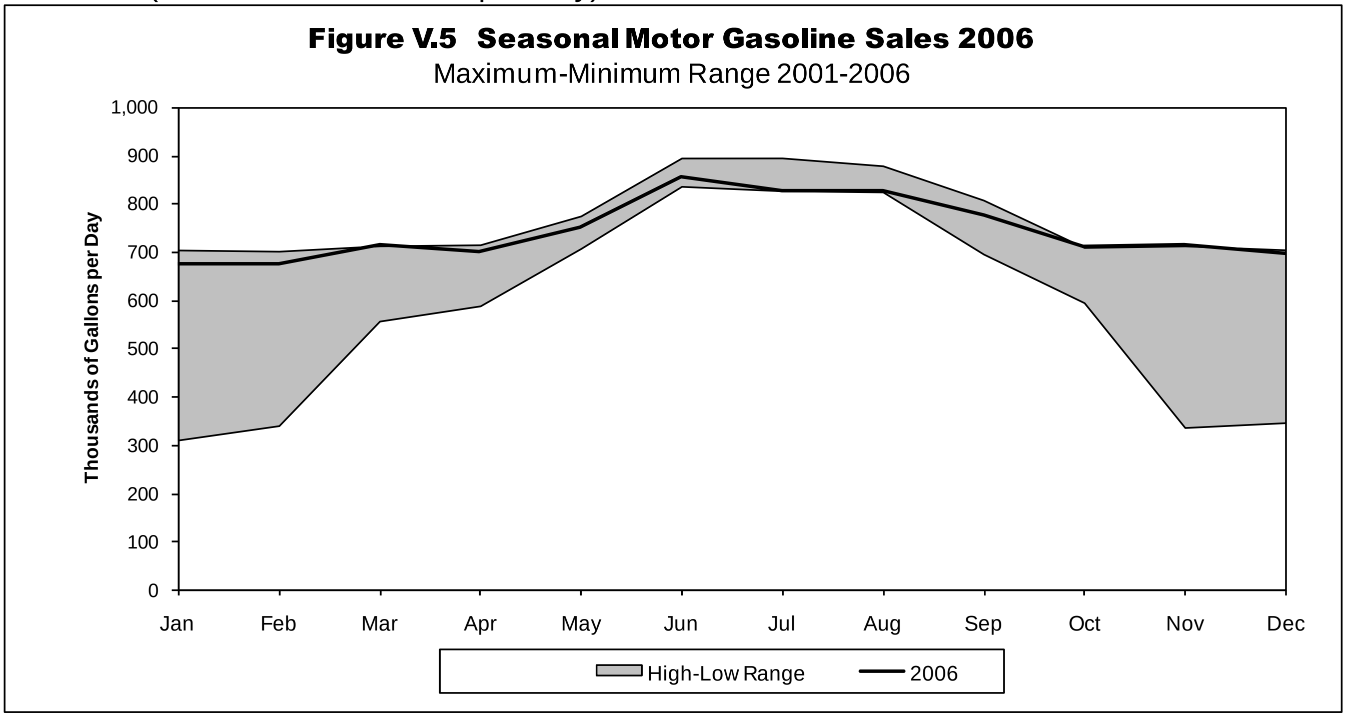


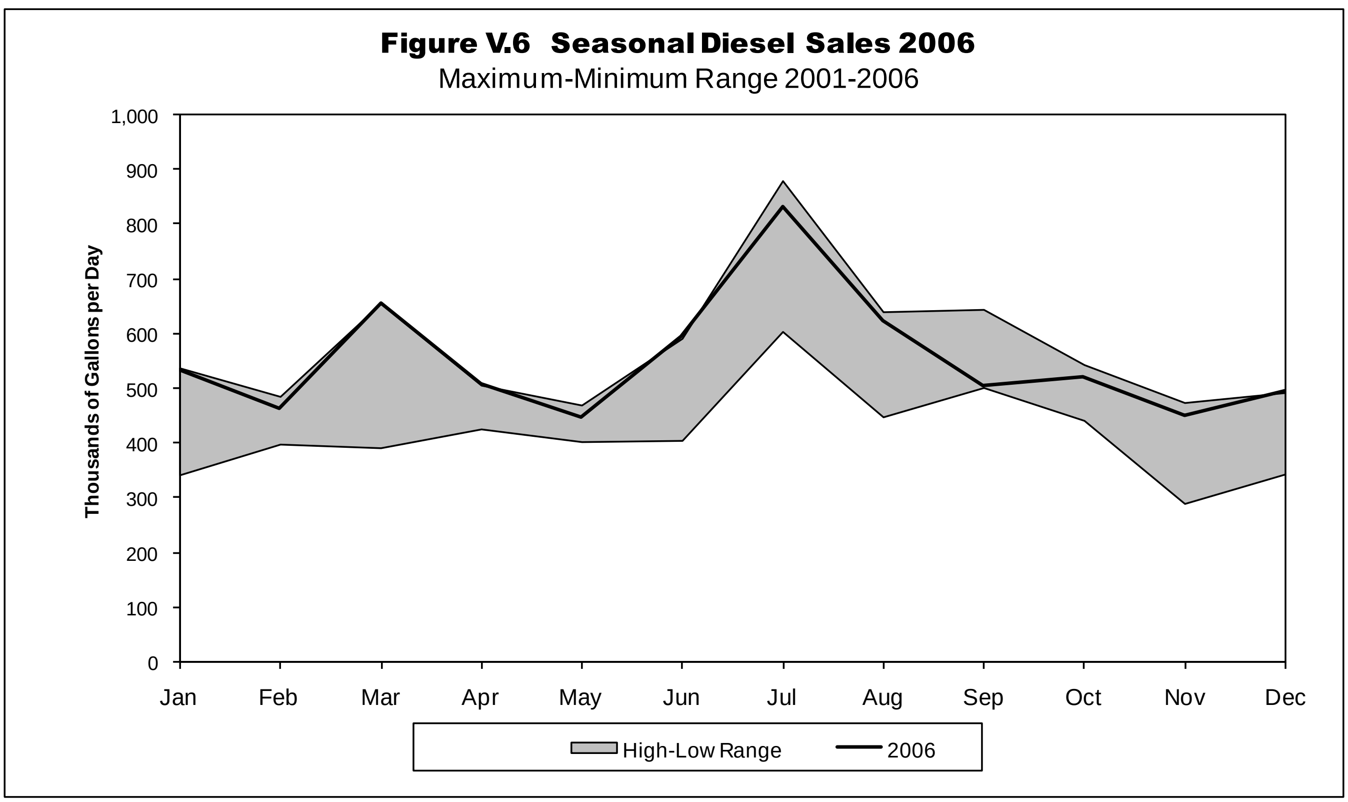


Source: State Of Alaska - Department of Revenue (Special Tabulations from Tax Division)

Figures V.5 and V.6 Seasonal Motor Gasoline and Diesel Sales

Statewide (Thousands of Gallons per Day)





Source: State Of Alaska - Department of Revenue (Special Tabulations from Tax Division)

Key Terms	Department of Energy Definitions*
Aviation Gasoline (Finished)	A complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in aviation reciprocating engines. Fuel specifications are provided in ASTM Specification D 910 and Military Specification MIL-G-5572. Note: Data on blending components are not counted in data on finished aviation gasoline.
Catalytic Hydrocracking	A refining process that uses hydrogen and catalysts with relatively low temperatures and high pressures for converting middle boiling or residual material to high-octane gasoline, reformer charge stock, jet fuel, and/or high-grade fuel oil. The process uses one or more catalysts, depending upon product output, and can handle high sulfur feedstocks without prior desulfurization.
Gas Oil	European and Asian designation for No. 2 heating oil and No. 2 diesel fuel.
Kerosene-Type Jet Fuel	A kerosene-based product having a maximum distillation temperature of 400 degrees Fahrenheit at the 10 percent recovery point and a final maximum boiling point of 572 degrees Fahrenheit and meeting ASTM Specification D 1655 and Military Specifications MIL-T-5624P and MIL-T-83133D (Grades JP-5 and JP-8). It is used for commercial and military turbojet and turboprop aircraft engines.
Motor Gasoline	A complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline, as defined in ASTM Specification D 4814 or Federal Specification VV-G-1690C, is characterized as having a boiling range of 122 to 158 degrees Fahrenheit at the 10 percent recovery point to 365 to 374 degrees Fahrenheit at the 90 percent recovery point. Motor Gasoline includes conventional gasoline; all types of oxygenated gasoline, including gasohol; and reformulated gasoline, but excludes aviation gasoline. Note: Volumetric data on blending components, such as oxygenates, are not counted in data on finished motor gasoline until the blending components are blended into the gasoline. Finished motor gasoline includes all ethanol blended gasoline (e.g. E10, E85).
No. 1 Distillate	A light petroleum distillate that can be used as either a diesel fuel (see No. 1 Diesel Fuel) or a fuel oil. No. 1 Diesel Fuel: A light distillate fuel oil that has distillation temperatures of 550 degrees Fahrenheit at the 90 percent point and meets the specifications defined in ASTM Specification D 975. It is used in high-speed diesel engines generally operated under frequent speed and load changes, such as those in city buses and similar vehicles. No. 1 Fuel Oil: A light distillate fuel oil that has distillation temperatures of 400 degrees Fahrenheit at the 10-percent recovery point and 550 degrees Fahrenheit at the 90 percent point and meets the specifications defined in ASTM Specification D 396. It is used primarily as fuel for portable outdoor stoves and portable outdoor heaters.
No. 2 Diesel Fuel	A fuel that has distillation temperatures of 500 degrees Fahrenheit at the 10 percent recovery point and 640 degrees Fahrenheit at the 90 percent recovery point and meets the specifications defined in ASTM Specification D 975. It is used in high-speed diesel engines that are generally operated under uniform speed and load conditions, such as those in railroad locomotives, trucks, and automobiles.
No. 2 Distillate	A petroleum distillate that can be used as either a diesel fuel (see No. 2 Diesel Fuel) or a fuel oil (see No. 2 Fuel Oil).
No. 2 Fuel Oil (Heating Oil)	A distillate fuel oil that has a distillation temperature of 640 degrees Fahrenheit at the 90 percent recovery point and meets the specifications defined in ASTM Specification D 396. It is used in atomizing type burners for domestic heating or for moderate capacity commercial/industrial burner units.
PADD	Petroleum Administration for Defense District **PADD V** (West Coast): Alaska (North Slope and Other Mainland), Arizona, California, Hawaii, Nevada, Oregon, Washington.

*Source for Terms and Definitions: United States Department of Energy, Energy Information Administration; www.eia.doe.gov/glossary/glossary_a.htm

Petroleum Products	Petroleum products are obtained from the processing of crude oil (including lease condensate), natural gas, and other hydrocarbon compounds. Petroleum products include unfinished oils, liquefied petroleum gases, pentanes plus, aviation gasoline, motor gasoline, naphtha-type jet fuel, kerosene-type jet fuel, kerosene, distillate fuel oil, residual fuel oil, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt, road oil, still gas, and miscellaneous products.
Prime Supplier	A firm that produces, imports, or transports selected petroleum products across state boundaries and local marketing areas, and sells the product to local distributors, local retailers, or end users.
Propane (Consumer Grade)	A normally gaseous paraffinic compound (C_3H_8), which includes all products covered by Natural Gas Policy Act Specifications for commercial and HD-5 propane and ASTM Specification D 1835. It is a colorless paraffinic gas that boils at a temperature of -43.67 degrees Fahrenheit. It does not include the propane portion of any natural gas liquid mixes, i.e., butane-propane mix.
Refiner	A firm or the part of a firm that refines products or blends and substantially changes products, or refines liquid hydrocarbons from oil and gas field gases, or recovers liquefied petroleum gases incident to petroleum refining and sells those products to resellers, retailers, reseller/retailers or ultimate consumers. "Refiner" includes any owner of products that contracts to have those products refined and then sells the refined products to resellers, retailers, or ultimate consumers. For the purposes of this survey, gas plant operator data are included in this category.
Reformulated	Finished motor gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under Section 211(k) of the Clean Air Act. This category includes oxygenated fuels program reformulated gasoline (OPRG) but excludes reformulated gasoline blendstock for oxygenate blending (RBOB).
Regular	Gasoline having an antiknock index (average of the research octane rating and the motor octane number) greater than or equal to 85 and less than 88. Note: Octane requirements may vary by altitude.
Reseller	A firm (other than a refiner) that is engaged in a trade or business that buys refined petroleum products and then sells them to a purchaser who is not the ultimate consumer of those refined products.
Residual Fuel Oil	A general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. It conforms to ASTM Specifications D 396 and D 975 and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.
Retailer	A firm (other than a refiner, reseller, or reseller/retailer) that carries on the trade or business of purchasing refined petroleum products and reselling them to ultimate consumers without substantially changing their form.
Topping Plant	Facilities that top off the lighter products from the crude stream that are used for internal refinery fuel use.

*Source for Terms and Definitions: United States Department of Energy, Energy Information Administration; www.eia.doe.gov/glossary/glossary_a.htm