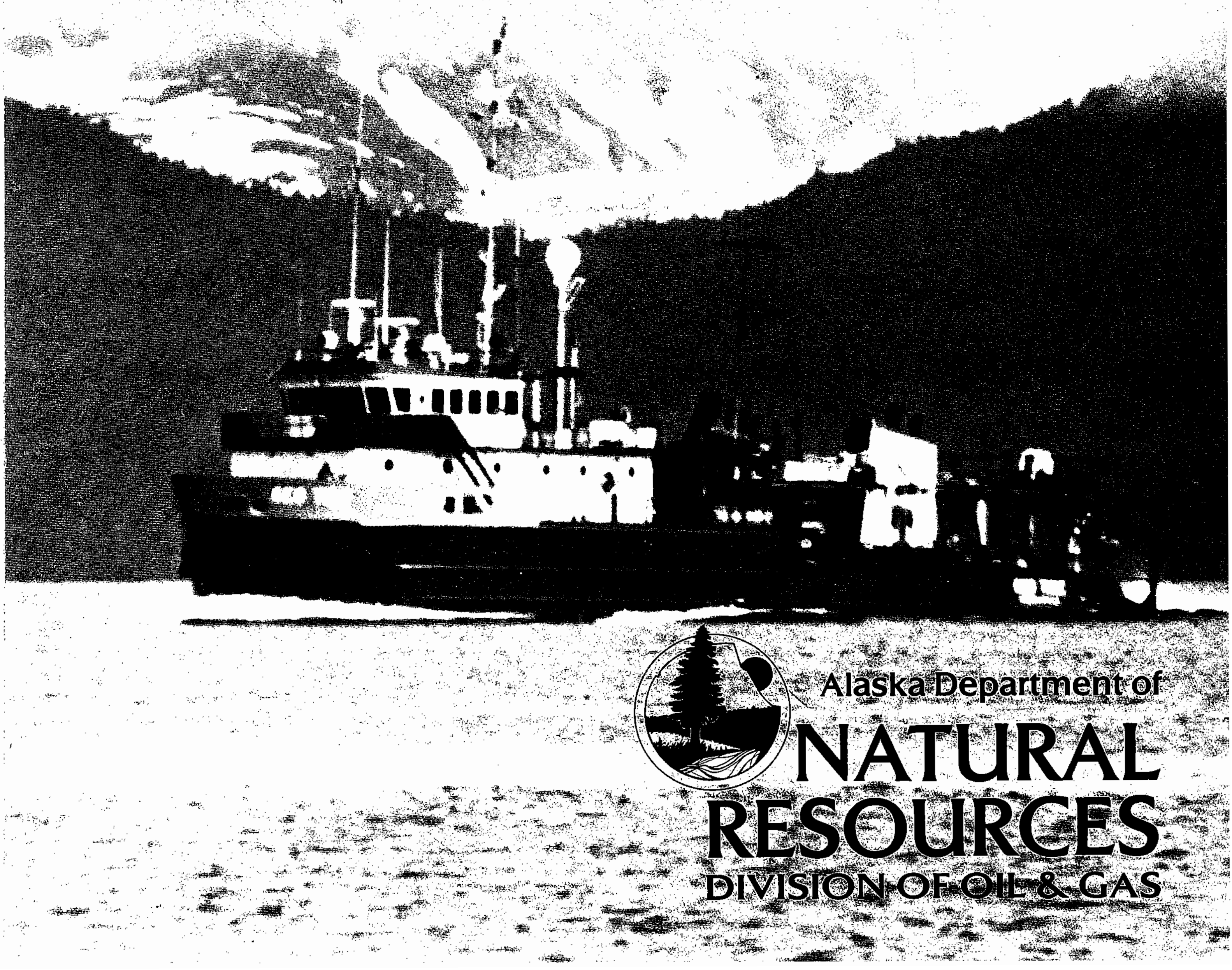
HISTORICAL AND PROJECTED OIL AND GAS CONSUMPTION

JANUARY 1989



Alaska Department of
NATURAL RESOURCES
DIVISION OF OIL & GAS

STATE OF ALASKA

HISTORICAL AND PROJECTED OIL AND GAS CONSUMPTION

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Governor

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Commissioner
Department of Natural Resources

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EXECUTIVE SUMMARY

This report compares estimates of the quantity of available Alaskan oil and natural gas reserves with estimates of how much oil (refined products) and gas Alaska will consume in the 15 year period between 1988 and 2002. A revised supply and demand report is issued each year to comply with AS 38.05.183(d), which states:

"(d) Oil or gas taken in kind by the state as its royalty share may not be sold or otherwise disposed of for export from the state until the commissioner determines that the royalty-in-kind oil or gas is surplus to the present and projected intrastate domestic and industrial needs. The commissioner shall make public, in writing, the specific findings and reasons on which his determination is based and shall, within 10 days of the convening of a regular session of the legislature, submit a report showing the immediate and long-range domestic and industrial needs of the state for oil and gas and an analysis of how these needs are to be met." [1]

Chapter 1 describes the state's royalty oil program and reviews pending federal legislation which might affect prices of state royalty oil.

Chapter 2 lists high, middle and low estimates of oil and gas reserves, and their respective royalty shares. High estimates assume increasing oil prices and additional enhanced oil recovery efforts, whereas middle and low estimates assume relatively stable oil prices. The lower figures, therefore, are prudent values for long range policy considerations. The middle range oil estimate is 6.8 billion barrels of oil, yielding an 850 million barrel state royalty share. Of this royalty share, 99.0% is attributable to reserves on the North Slope. The middle range estimate of gas is 32.1 trillion cubic feet. The state's share is 3.9 trillion cubic feet. Again, 90.9% of the gas will come from North Slope reserves.

The chapter includes production estimates for a 25 year period. North Slope oil production has peaked at about 2.3 million barrels per day and is expected to begin declining in the next year or two to about 435 thousand barrels per day by the year 2003.

Chapter 3 presents historical data on production and consumption of Alaska oil and gas. Fuel consumption between 1977 and 1988 grew by an average of 9.5% per year from 0.7 to 2.0 billion gallons, while gas consumption in the same period grew an average of 7.5% per year from 205 to 388 billion cubic feet.

1 See Appendix D for discussion of statutory definitions.

Chapter 4 reveals forecasts of expected in-state oil and gas consumption from 1989 to 2003. Alaska will probably consume about 24 billion gallons of fuels and 3.9 trillion cubic feet of gas during that period. Consumption growth rates are forecast to be considerably lower than they have been until now; and between 1989 and 2003, estimated annual growth in consumption will be 1% for both oil and gas.

Chapter 5 compares estimates of state reserves and future production with estimates of future consumption. The comparison shows that Alaska's total supply of oil and gas will be greater than in-state consumption for the next 15 years.

The supply and demand projections in this report are accurate only if their underlying assumptions approximate future events. The demand side of the equation is probabilistic because in-state consumption will be influenced by economic and population growth which in turn will be influenced in a large part by world energy and natural resource prices. For example, development of a new southcentral hydroelectric project (other than Bradley Lake) or a coal-fired electric generation project could dramatically affect the in-state demand for natural gas, particularly after the late 1990s. Future expansion of the natural gas, ammonia-urea or petrochemical export market would similarly affect in-state natural gas availability, as well as prices.

The supply side of the equation is also probabilistic. The middle range estimates of oil and gas reserves, 6.8 billion barrels and 32.1 trillion cubic feet, respectively, are likely outcomes, though the timing of a gas pipeline from the North Slope remains very uncertain and the development of certain proven oil and gas fields beyond the Prudhoe Bay - Kuparuk infrastructure appears unfeasible at today's oil prices. Estimates of undiscovered resources are highly speculative and are not relevant to this projection. Even if these undiscovered resources exist (which they may not), there is no guarantee that they will be discovered or developed in time (or if ever) to assure long-run continuity. For the most part, major oil and gas firms will search for and develop reserves in response to world market conditions, not because of surplus or deficit conditions in Alaska's relatively small intrastate market. In summary,

CHAPTER 2
RESERVE ESTIMATES AND ROYALTY SHARE

Introduction

This chapter discusses estimates of oil and gas reserves in the state and the state's royalty share of these reserves. The reserve estimates have been developed for three different cases. The specific royalty terms of individual oil and gas lease contracts were used to calculate the state's royalty share of the respective reserves in each field. The low range estimates assume falling oil and gas prices and/or poorer-than-predicted reservoir performance. The high range estimates assume rising oil and gas prices and/or better-than-predicted reservoir performance. The middle range estimates assume relatively stable oil and gas prices and predicted reservoir performance.

The estimated reserves and royalty share for oil and gas are shown in Table 2.1. The estimates have been developed separately for Cook Inlet and the North Slope, as different information sources were used for each category. In addition to categorizing reserves by region, reserves are sub-categorized as either "proven and developed" or "proven but undeveloped or shut-in." These sub-categories distinguish those volumes of oil and gas which are readily marketable from those which need additional investment in facilities and transportation systems which will delay bringing the reserves on line.

Oil reserves as of January 1, 1989 are 6.80 billion barrels. For comparison, the U. S. Department of Energy estimate for January 1, 1988 was 7.38 billion barrels; the Table 2.1 figure extrapolated back to January 1, 1988 is 7.45 billion barrels.

Cook Inlet

Considerable historical and subsurface information is available about the oil and gas reserves and potential in the Cook Inlet area. While there has been a renewed interest in Cook Inlet exploration and remedial field work, it is not anticipated that significant new reserves will be added in the near future. Recent changes in working interest ownership of several Cook Inlet gas fields will likely result in development of these currently shut-in fields. The reserves are assumed to remain constant for low, middle and high range estimates. Cook Inlet reserves account for about 1.8% of the low, 1.2% of the middle, and 0.8% of the high estimates of statewide total oil and gas reserves.

North Slope

Oil and gas reserve estimates shown in Table 2.1 are for currently leased state lands. North Slope oil is produced from the Sadlerochit and the Lisburne reservoirs in the Prudhoe Bay Unit, the Kuparuk River reservoir in the Kuparuk River Unit, and the Endicott reservoir in the Duck Island Unit. Production from the Kuparuk River reservoir in the Milne Point Unit was shut-in January 1987 and remains shut-in.

Additional enhanced oil recovery operations at Prudhoe Bay Unit, over and above those already planned, recovery of additional gas condensate and gas liquids from the Sadlerochit and Lisburne gas caps and enhanced oil recovery from the Kuparuk and Lisburne reservoirs represent an oil resource (versus oil reserves) of about two billion additional barrels of liquids which may or may not be economically recoverable sometime in the future. The economics of enhanced oil recovery operations are extremely sensitive to incremental capital costs, changing markets and expected wellhead crude oil prices. Systematic recovery of liquids from the Sadlerochit and Lisburne gas caps (and absent major gas sales, simultaneous reinjection of the dry gas back into the reservoirs) would require additional investment by the respective gas cap owners. Depending on the nature of the liquids recovered and intended for sale, the owners of the Trans-Alaska Pipeline System (TAPS) may also have to invest in additional infrastructure, as well as retrofit existing pipeline, storage and shipping facilities to ship these gas liquids. In the fall of 1988, the three major gas owners in the Prudhoe Bay Unit (ARCO, Exxon and BP America) announced that a major new gas project they were reviewing (called "Super Spike") did not appear to be economically feasible at that time.

Installation of the world's largest central gas facility at Prudhoe Bay in 1986 is designed to recover gas liquids and gas condensate from the produced gas stream and it is a major step in establishing the infrastructure that will be needed to proceed with any future large-scale gas sales or expanded gas cycling or liquid recovery project.

ESTIMATED REMAINING RECOVERABLE RESERVES AND ROYALTY SHARE **TABLE 2.1**

	OIL (Millions of Barrels)						GAS (Billion Cubic Feet)					
	Recoverable Reserves			Royalty Share			Recoverable Reserves			Royalty Share		
COOK INLET [1]												
Proven and Developed												
Beaver Creek		1			0			165			0	
Beluga River		--			--			720 [2]			54	
Cannery Loop		--			--			150 [2]			6	
Granite Point		16			2			13			2	
Ivan River, Lewis River, Pretty Creek and Stump Lake		--			--			500 [2]			63	
Kenai		--			--			640 [2]			13	
McArthur River		40			5			620 [2]			78	
Middle Ground Shoal		8			1			5			1	
North Cook Inlet		--			--			730 [2]			91	
Swanson River		8			0			245			0	
Trading Bay		1			<1			30			[3]	
Proven but Undeveloped or Shut-In												
Birch Hill		--			--			11			0	
Falls Creek		--			--			13			2	
Nicolai Creek		--			--			3			<1	
North Fork		--			--			12			<1	
Sterling		--			--			23			<1	
West Foreland		--			--			20			0	
West Fork		--			--			6			<1	
SUBTOTAL		74			8			3,906			308	
NORTH SLOPE [2]	LOW	MID	HIGH	LOW	MID	HIGH	LOW	MID	HIGH	LOW	MID	HIGH
Proven and Developed												
East Barrow [1]	--	--	--	--	--	--	8	8	8	--	--	--
Endicott	230	330	410	32	46	57	590	790	1,190	83	111	167
Kuparuk River Unit	545	845	1,045	68	106	131	420	570	720	53	71	90
Lisburne reservoir	100	165	400	13	21	50	790	890	990	99	111	124
Milne Point Area	0	60	95	0	11	17	--	--	--	--	--	--
Prudhoe Bay Unit	4,000	4,700	5,900	500	588	738	26,000 [4]	26,000 [4]	26,000 [4]	3,250	3,250	3,250
South Barrow [1]	--	--	--	--	--	--	8	8	8	--	--	--
Proven but Undeveloped or Shut-In												
Beaufort Sea	0	0	150	0	0	30	--	--	--	--	--	--
Point Thomson Area and Flaxman Island Area [3]	0	0	300	0	0	38	0	0	5,000	0	0	625
Shallow Cretaceous Sands (West Sak)	0	500	3,000	0	63	375	--	--	--	--	--	--
North Slope Other and Niakuk	75	130	225	9	16	28	--	--	--	--	--	--
SUBTOTAL	4,950	6,730	11,525	622	850	1,463	27,816	28,266	33,916	3,484	3,543	4,255
STATE TOTAL	5,024	6,804	11,599	630	858	1,471	31,722	32,172	37,822	3,792	3,851	4,564

[1] As of 1/1/89. Alaska Oil and Gas Conservation Commission, "Estimate of Oil Reserves in Alaska" and "Estimate of Gas Reserves in Alaska", adjusted for 1988 production.
[2] As of 1/1/89. William Van Dyke.
[3] Oil and gas condensate.
[4] Reduced for CO2 content relative to 1988 report; not reduced for future in-field fuel use.
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The currently configured plant will recover propane, butane and heavier hydrocarbon liquids from the produced gas stream and it could be modified to recover ethane. Significant volumes of these three products could be shipped through TAPS if the pipeline system and the storage and loading facilities at Valdez were modified. However, until a long term market can be identified for some or all of these three products, no major new gas liquids project will go forward.

The possibility for conversion of any of the above mentioned resources to the proven reserves category and the timing of that conversion must be viewed with extreme caution at this time. However, because billions of barrels of oil will remain in the ground at the Prudhoe Bay and Kuparuk River Units after completion of primary and secondary oil recovery operations, sufficient economic incentives to develop additional economic means of enhanced oil recovery will exist well into the future. For instance, in the Prudhoe Bay Unit Sadlerochit Reservoir, some 12 billion barrels of oil will remain in place if the current ultimate recovery estimate of 10.8 billion barrels holds true. The original ultimate recovery estimate of 9.6 billion barrels has slowly increased to the current 10.8 billion barrel level - hopefully, new enhanced oil recovery technologies, increased infill drilling and horizontal drilling advances can increase the 10.8 billion barrel figure even further. New techniques of using the gas liquids in the reservoir gas caps could also add significantly to the ultimate recovery figure.

Various North Slope leaseholders continue to experiment with techniques to economically produce the vast amounts of "heavy," low gravity oil held in the shallow Tertiary and Cretaceous age sands primarily located west of Prudhoe Bay field. Technology and equipment already exist to produce these types of oil deposits in more temperate, less costly operating and marketing climates. However, permafrost considerations, surface-related permitting, construction and operating constraints, and the projected wellhead price of the produced oil to date have combined to stymie any commercial development of these relatively shallow (but very large) resources. One major pilot production project has been completed by ARCO in the Kuparuk River Unit and laboratory research continues in an effort to improve project performance and economics. ARCO has applied for permits to conduct a second major "West Sak" pilot production project in the Kuparuk River Unit. A larger well spacing pattern will be used relative to the first pilot and various well bore completion techniques will again be tested in an attempt to improve individual oil well production rates. A water flood will also be conducted to test the influence of the wider well spacing on oil recovery and well performance.

Conoco has received approval to drill two test wells in Milne Point Unit to test the extensive shallow oil sands in that unit. Conoco has also applied to continue the suspension of production at Milne Point Unit through 1989. Shut-in production in Milne Point Unit comes from the deeper Kuparuk Formation.

Technology exists to produce in the range of 300,000 bpd of oil from the shallow north slope oil sands, but current economics do not appear to favor full-scale development. In the Kuparuk River Unit, the Kuparuk River reservoir owners and the West Sak reservoir owners need to approve a facilities-sharing agreement because it will greatly reduce the future West Sak development costs. As Kuparuk oil production facilities become underused and available in the 1990s, it is anticipated that the West Sak reservoir can be brought on line to fill them. Development of the West Sak reserves will also require drilling many hundreds of additional wells and the construction of many more drillsites and pipelines. If and when Milne Point Unit resumes production, the unit's two groups of owners might share facilities in a similar way.

Tables 2.2 and 2.3 list production forecasts for some of the fields listed in Table 2.1. Figure 2.1 graphically portrays these estimates. North Slope oil production is expected to decline in 1989. The decline will begin earlier and will be more gradual than earlier forecasts indicated. Oil production from state-owned lands will decline through the 1990s.

Currently, natural gas is not exported from the North Slope. Both the Alaska Natural Gas Transportation System (ANGTS) and the Trans-Alaska Gasline System (TAGS) are proposed means of moving North Slope gas to market. To date, neither project has secured financing or a guaranteed market. The continued volatility and uncertainty in prices for oil and gas, the relatively abundant worldwide supplies of natural gas, and the sheer magnitude and cost of the proposed pipeline projects combine to make the prospective purchasers of the gas, the financial institu-

PRODUCTION FORCAST AND AVAILABLE ROYALTY OIL (Thousand Barrels/Day) TABLE 2.2

YEAR:	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	SUM (Mbbl)
PRODUCTION FORCAST																											
North Slope																											
Prudhoe Bay Oil	1,490	1,415	1,345	1,210	1,090	980	835	708	600	510	435	370	315	254	221	192	167	145	126	110	96	83	72	63	55	50	4,722,005
Prudhoe Bay GL	50	50	47	41	36	31	27	23	20	18	15	13	12	10	9	8	7	6	5	4	4	3	3	2	2	2	163,520
Kuparuk	280	280	250	240	205	175	150	125	105	90	75	65	55	45	40	35	30	25	20	15	15	10	10	10	10	10	865,050
Lisburne	40	40	40	40	40	40	37	34	31	28	25	21	19	13	9	5	0	0	0	0	0	0	0	0	0	0	168,630
Endicott	100	100	100	85	75	70	65	60	55	50	45	40	20	10	0	0	0	0	0	0	0	0	0	0	0	0	319,375
Milne Point	0	11	10	10	7	7	6	5	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21,900
Other	0	0	0	0	20	60	58	56	55	89	83	78	73	64	56	49	38	32	27	23	13	11	9	8	0	0	329,230
West Sak	0	0	6	6	6	6	12	12	25	25	50	50	75	75	100	100	150	150	150	150	140	120	95	75	60	50	616,120
Cook Inlet																											
Granite Point	7.6	7.2	6.5	5.8																							9,892
McArthur River	19.5	18.5	16.7	15.0																							25,441
Trading Bay	2.3	2.1	1.9	1.7																							2,920
Middle Ground Shoal	7.5	7.1	6.4	5.8																							9,782
NGL	0.6	0.0	0.0	0.0																							219
SUBTOTAL-NORTH SLOPE	1,960	1,896	1,798	1,632	1,479	1,369	1,190	1,023	895	810	728	637	569	471	435	389	392	358	328	302	268	227	189	158	127	112	7,205,830
SUBTOTAL-COOK INLET	38	35	32	28																							48,253
TOTAL	1,998	1,931	1,830	1,660	1,479	1,369	1,190	1,023	895	810	728	637	569	471	435	389	392	358	328	302	268	227	189	158	127	112	7,254,083
AVAILABLE ROYALTY OIL AND NGL																											
North Slope																											
Prudhoe Bay Oil	186	177	168	151	136	123	104	89	75	64	54	46	39	32	28	24	21	18	16	14	12	10	9	8	7	6	590,251
Prudhoe Bay GL [1]	6	6	6	5	5	4	3	3	3	2	2	2	2	1	1	1	1	1	1	1	1	0	0	0	0	0	20,440
Kuparuk [1]	35	35	31	30	26	22	19	16	13	11	9	8	7	6	5	4	4	3	3	2	2	1	1	1	1	1	108,131
Lisburne [1]	5	5	5	5	5	5	5	4	4	4	3	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	21,079
Endicott [2]	14	14	14	12	11	10	9	8	8	7	6	6	3	1	0	0	0	0	0	0	0	0	0	0	0	0	44,713
Milne Point [3]	0	2	2	2	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,862
Other [4]	0	0	0	0	3	10	9	9	9	14	13	13	12	10	9	8	6	5	4	4	2	2	1	1	0	0	53,500
West Sak [1]	0	0	1	1	1	1	2	2	3	3	6	6	9	9	13	13	19	19	19	19	18	15	12	9	8	6	77,015
Cook Inlet																											
Granite Point	1.0	0.9	0.8	0.7																							1,236
McArthur River	2.4	2.3	2.1	1.9																							3,180
Trading Bay	0.3	0.3	0.2	0.2																							365
Middle Ground Shoal	0.9	0.9	0.8	0.7																							1,223
NGL [5]	0.0	0.0	0.0	0.0																							14
SUBTOTAL-NORTH SLOPE	247	239	227	206	187	175	152	131	115	105	95	83	74	61	56	50	50	46	42	39	34	29	24	20	16	14	918,990
SUBTOTAL-COOK INLET	5	4	4	4																							6,018
TOTAL	251	243	231	209	187	175	152	131	115	105	95	83	74	61	56	50	50	46	42	39	34	29	24	20	16	14	925,008
ROYALTY OIL SALES (In-Kind)																											
Mapco	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35												191,625
GVEA [6]	5	5	5	4	4	3																					9,473
Tesoro (Old) [7]	47	45	43	38	35	31																					87,139
Tesoro (New) [8]	27	25	24	22	20	18																					49,254
Chevron [9]	18	18	17	15	14	12																					34,098
Petrostar [10]	7	6	5	4	3	3	3																				11,315
Cook Inlet	3																										1,095
TOTAL	143	134	128	118	109	102	38	35	35	35	35	35	35	35	35												383,999
ROYALTY OIL IN VALUE	109	110	103	91	78	73	114	96	80	70	60	48	39	26	21	50	50	46	42	39	34	29	24	20	16	14	541,008

Note: numbers may not sum to totals due to rounding errors.
[1] 12.5% of production.
[2] 14.0% of production (weighted average).
[3] 18.0% of production (weighted average).
[4] 16.25% of production.
[5] 6.25% of production.
[6] 2.667% of Prudhoe Bay production. Contract expires June 30, 1996.
[7] Maximum 24.533% of Prudhoe Bay production. Contract expires January 1995.
[8] Maximum 13.867% of Prudhoe Bay production. Contract expires January 1, 1995. Tesoro commenced deliveries on October 1, 1985 under contract effective December 9, 1983. Tesoro denominated the entire volume under this contract effective August 20,1986 but has the option of renominating on six months notice.
[9] Maximum 9.6% of Prudhoe Bay production. Contract expires January 1, 1995.
[10] 6,500 BPD of Kuparuk River Unit royalty oil. Initial purchase would be 6,000 BPD. Contract expires September 30, 1996.
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PRODUCTION FORCAST AND SALES OF NORTH SLOPE ROYALTY OIL (Thousand Barrels/Day) [1] TABLE 2.3

YEAR:	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	SUM (Mbbl)
PRODUCTION FORCAST																											
Prudhoe Bay Oil	1,490	1,415	1,345	1,210	1,090	980	835	708	600	510	435	370	315	254	221	192	167	145	126	110	96	83	72	63	55	50	4,722,005
Prudhoe Bay GL	50	50	47	41	36	31	27	23	20	18	15	13	12	10	9	8	7	6	5	4	4	3	3	2	2	2	163,520
Kuparuk	280	280	250	240	205	175	150	125	105	90	75	65	55	45	40	35	30	25	20	15	15	10	10	10	10	10	865,050
Lisburne	40	40	40	40	40	40	37	34	31	28	25	21	19	13	9	5	0	0	0	0	0	0	0	0	0	0	168,630
Endicott	100	100	100	85	75	70	65	60	55	50	45	40	20	10	0	0	0	0	0	0	0	0	0	0	0	0	319,375
TOTAL	1,960	1,885	1,782	1,616	1,446	1,296	1,114	950	811	696	595	509	421	332	279	240	204	176	151	129	115	96	85	75	67	62	6,238,580
AVAILABLE ROYALTY OIL AND NGL																											
Prudhoe Bay Oil [2]	186	177	168	151	136	123	104	89	75	64	54	46	39	32	28	24	21	18	16	14	12	10	9	8	7	6	590,251
Prudhoe Bay GL [2]	6	6	6	5	5	4	3	3	3	2	2	2	2	1	1	1	1	1	1	1	1	0	0	0	0	0	20,440
Kuparuk [2]	35	35	31	30	26	22	19	16	13	11	9	8	7	6	5	4	4	3	3	2	2	1	1	1	1	1	108,131
Lisburne [2]	5	5	5	5	5	5	5	4	4	4	3	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	21,079
Endicott [3]	14	14	14	12	11	10	9	8	8	7	6	6	3	1	0	0	0	0	0	0	0	0	0	0	0	0	44,713
TOTAL	247	237	224	203	182	163	140	120	102	88	75	64	53	42	35	30	26	22	19	16	14	12	11	9	8	8	784,613
ROYALTY OIL SALES (In-Kind)																											
Mapco	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35												191,625
GVEA [4]	5	5	5	4	4	3																					9,473
Tesoro (Old) [5]	47	45	43	38	35	31																					87,139
Tesoro (New) [6]	27	25	24	22	20	18																					49,254
Chevron [7]	18	18	17	15	14	12																					34,098
Petro Star/Chevron [8]	7	6	5	4	3	3	3																				11,315
TOTAL	140	134	128	118	109	102	38	35	35	35	35	35	35	35	35												382,904
ROYALTY OIL IN VALUE	107	103	96	85	73	61	102	85	67	53	40	29	18	7	(0)	30	26	22	19	16	14	12	11	9	8	8	401,709

Note: numbers may not sum to totals due to rounding errors.

[1] Includes only North Slope fields in production or planned for production in the near future.

[2] 12.5% of production.

[3] 14.0% of production (weighted average).

[4] 2.667% of Prudhoe Bay production. Contract expires June 30, 1996.

[5] Maximum 24.533% of Prudhoe Bay production. Contract expires January 1995.

[6] Maximum 13.867% of Prudhoe Bay production. Contract expires January 1,1995. Tesoro commenced deliveries on October 1, 1985 under contract effective August 20,1986. Tesoro denominated the entire volume under this contract effective August 20, 1986 but has the option of renominating on six months notice.

[7] Maximum 9.6% of Prudhoe Bay production. Contract expires January 1, 1995.

[8] 6,500 BPD of Kuparuk River Unit royalty oil. Initial purchase would be 6,000 BPD. Contract expires September 30, 1996.

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OIL PRODUCTION FORECAST
(Thousand Barrels/Day)

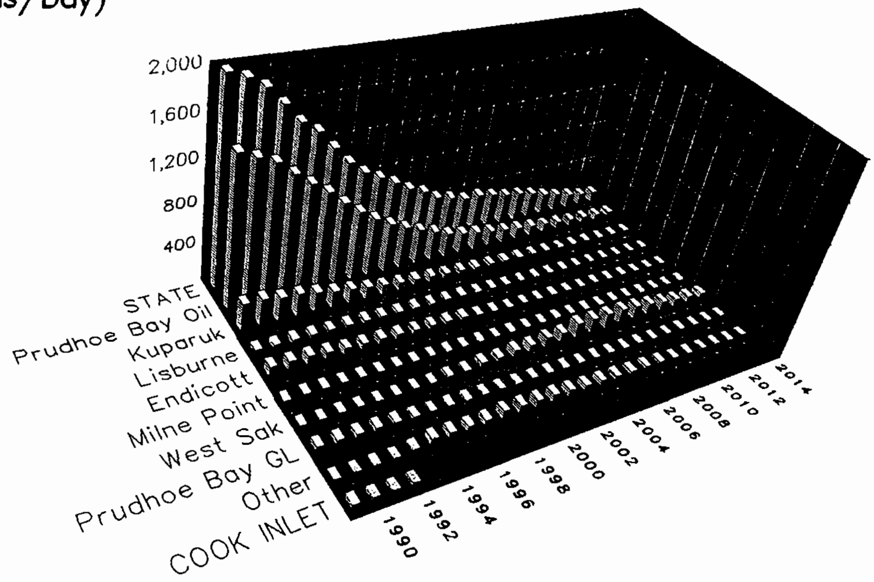
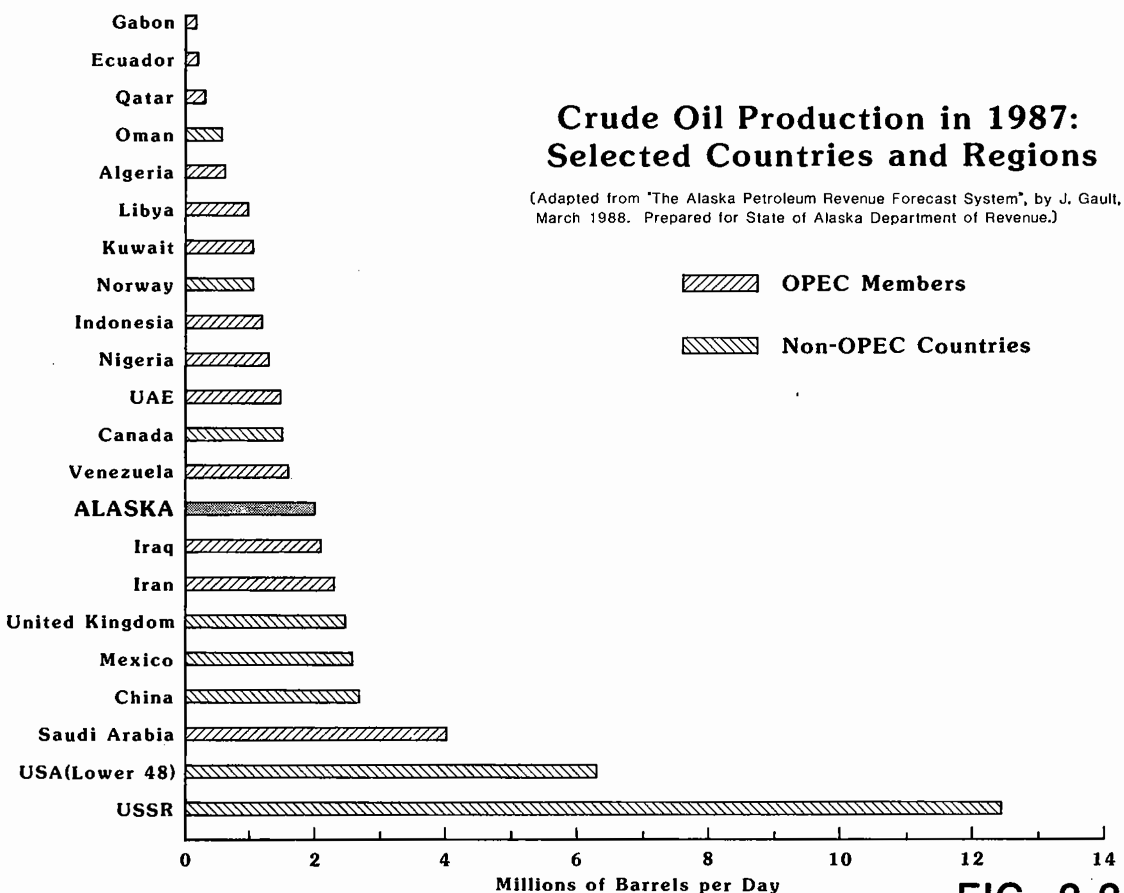


FIG. 2.1



Crude Oil Production in 1987: Selected Countries and Regions

(Adapted from "The Alaska Petroleum Revenue Forecast System", by J. Gault, March 1988. Prepared for State of Alaska Department of Revenue.)

FIG. 2.2

tions, and the projects' sponsors all very cautious at this time. Efforts to secure markets for the gas are continuing. However, start up of the ANGTS or TAGS project cannot be expected until financing for one or both projects is arranged, and financing likely will not be finalized until long-term sales agreements for the gas are guaranteed. In addition, the owners of the gas (primarily ARCO, Exxon and BP America) have not agreed to sell the gas to either pipeline company or any of the potential end users. In addition, pending legislation in Congress which would open ANWR to exploration and development would prohibit the construction of pipelines eastward through designated wilderness areas adjacent to the U. S. - Canada border.

During 1988 Esso Resources Canada and Shell Canada applied to the Canadian National Energy Board for permission to export gas from the Canadian Beaufort Sea and MacKenzie River Delta to the United States. This project, while it would be in direct competition with Alaskan North Slope gas for potential U. S. markets, might be an incentive to re-evaluate the once-proposed gas line from Prudhoe Bay east across the Arctic National Wildlife Refuge to the Canadian MacKenzie River Delta area. Such a pipeline probably would be much cheaper to build than either ANGST or TAGS. At this time no estimates of transportation costs are available for this type of proposal.

Several noteworthy oil and gas related events occurred in 1988. Production at the Milne Point Unit remained suspended. All the facilities have been left in place so that production can be restarted. Conoco, the unit operator, stated that oil prices were not high enough in 1988 to resume day-to-day operations. Conoco also stated that oil prices must be in the 18 to 22 dollar per barrel range for Milne Point field to produce at a profit. On the brighter side, the Endicott field (Duck Island Unit) in the Beaufort Sea completed its first year of operation. Rates are expected to average 100,000 bpd through 1991, then decline.

During 1988 the 8,000th tanker load of oil was shipped from Valdez terminal. Over 6 billion barrels of oil have been shipped from Valdez since 1977.

Standard Alaska Production Company proposes to develop the Niakuk reservoir, located about one mile offshore in the Beaufort Sea just north of Prudhoe Bay. Standard estimates that the reservoir could produce up to 20,000 bpd of oil beginning in 1992 if development plans are approved in a timely manner. The proposal includes a 6,600 foot ground fill causeway which state and federal agencies are now reviewing. The U. S. Army Corps of Engineers has issued a preliminary finding that the causeway is unacceptable as proposed. Standard may have to substantially modify the project to gain approval or the project may not be approved at all.

In early 1988, Alaska became the number one oil producing state in the nation. However, with the recent decline in production at Prudhoe Bay, Texas has again regained the number one producing spot. During October 1988, Texas and Alaska averaged 2.065 and 2.000 million barrels per day of oil, respectively. Alaska continues to supply almost 25 percent of the nation's domestic oil supply. Figure 2.2 compares Alaska's oil production with that of other major oil producing countries. Figure 2.3 compares Alaska's projected oil production with that of the lower 48 states. In February Kuparuk River Field set an in-field production record of 322,000 bpd. Field average for 1988 probably will be 280,000 bpd.

The current 1.45 million bpd crude oil production rate at Prudhoe Bay (an additional 0.1 million bpd of gas condensate and liquids are also produced) is expected to continue its slow decline in 1989. The actual rate of the decline will be influenced by the level of infill development drilling, rate of development of the West End and P Pad areas of the field, scheduling of well workovers and equipment repairs, water and miscible gas injection rates, and the capabilities of the installed and to-be-installed gas handling facilities. The Prudhoe Bay owners have approved the construction of GHX-1, a major new gas handling expansion project. The project is designed to boost the amount of gas that can be produced, handled and reinjected from about 3.5 billion cubic feet per day to just over 5 billion cubic feet per day. Bottlenecks in gas processing facilities and insufficient gas compressor capacity are causing a gas overload in the field production facilities. Oil production rates are being cut back bacause the gas processing facilities cannot handle all the gas associated with the higher oil rates. The oil production rate in 1989 is not expected to reach the allowed annual average 1.5 million barrels per day. Start up of the GHX-1 facilities in the fall of 1990 will alleviate some of the gas overload. The producers are already studying a second project, GHX-2, which would be designed to boost the gas handling capacity in the field to about 7.5 billion cubic feet per day.

Start-up of the GHX-1 project (and the potential for the GHX-2 project) will help slow the decline of oil production at Prudhoe Bay. If additional gas handling facilities are not installed, the decline will be much more rapid than currently anticipated. In relative terms, more and more gas will be produced along with each barrel of oil as oil production continues over the years. If this additional gas cannot be processed and reinjected, the oil production rate will have to be cut back even further.

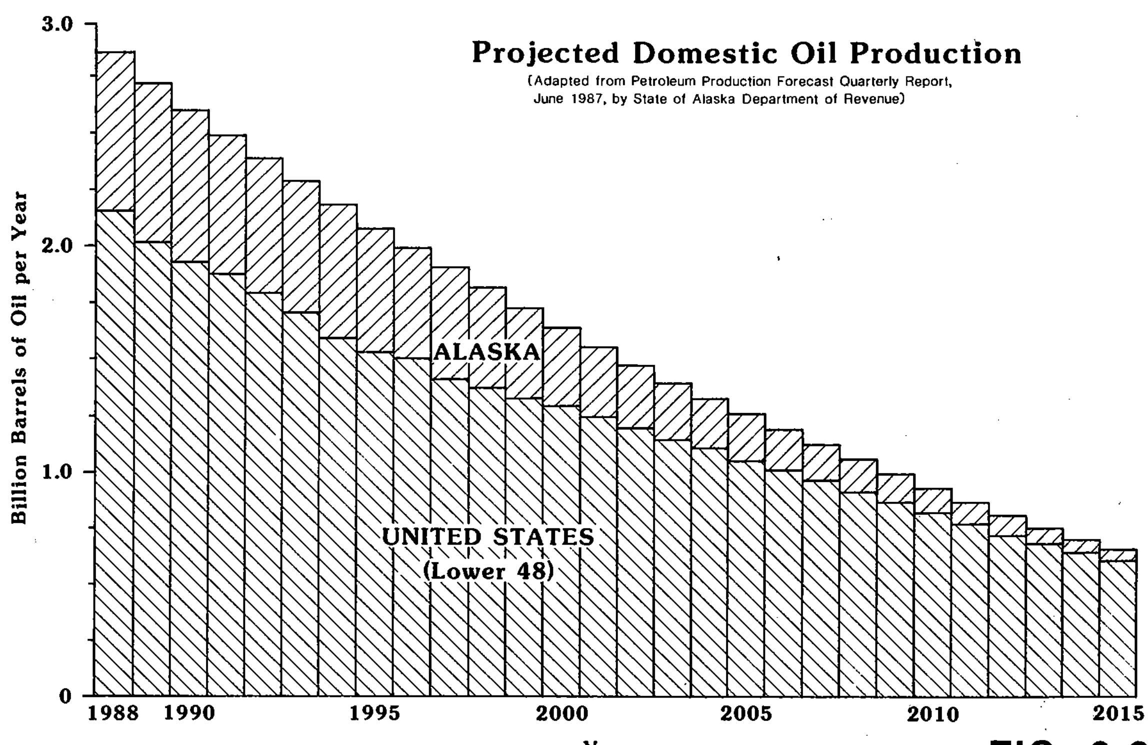


FIG. 2.3

CHAPTER 3
HISTORICAL OIL AND GAS PRODUCTION AND CONSUMPTION

Oil Production

All Alaska oil is produced from Cook Inlet and the North Slope. Cook Inlet fields began production in the late 1950s and peaked by 1970; some of the fields are now near depletion. The region has produced a cumulative total of 1.1 billion barrels of crude oil, but for the last ten years, annual production has fallen from 56 million barrels in 1977 to 16 million barrels in 1988. Prudhoe Bay began commercial production when the Trans-Alaska Pipeline System (TAPS) opened in 1977. Since then the region has produced 6.6 billion barrels of crude oil. Production from this region is expected to peak in 1988 at 706 million barrels per year. Regional and state production data are presented in Table 3.1 and Figure 3.1.

Oil Consumption

All the oil consumed in Alaska is consumed as refined fuels, some of which is refined in-state and some of which is imported. Though no data source satisfactorily reports how much fuel is refined in state nor how much is imported, Department of Revenue (DOR) reports of fuel sales for 1977 to 1988 indicate how much fuel is consumed in state. Data quality from 1977 to about 1984 are unconfirmed, but data from 1985 to 1988 are considered good. Throughout the 11 year reporting period, consumption goes from 750 million gallons per year to 1,961 million gallons per year. Fuel sale data are reported in Table 3.2 and Figure 3.2.

Gas Production

As with oil production, virtually all of Alaska's natural gas is produced from Cook Inlet and the North Slope immediately adjacent to the Prudhoe Bay Unit complex. Production from two small gas fields near Barrow is the only exception. Cook Inlet produces both casinghead and dry gas from a mix of oil fields, gas fields and oil fields with gas caps. Gas production from this region began in the late 1950s and peaked between 1982 and 1984. Cumulative production is 3.4 trillion cubic feet, net of injection, including the 191 billion cubic feet produced in 1988.

North Slope gas production is a by-product of oil field development. The only market for the gas is as fuel for field and pipeline operations and consequently, operators inject 80% of the gas back into the reservoirs. A cumulative 1 trillion cubic feet, net of injection, have been produced, including 209 billion cubic feet produced in 1988. Table 3.3 and Figure 3.3 show state and regional gas production from 1971 to 1988.

Gas Consumption

The Cook Inlet region's major natural gas feature is its pipeline connections to local markets which this past year consumed 171 billion cubic feet, net of injection. The major users were: LNG, 31% of net production; ammonia-urea production, 20%; electricity generation, 19%; and gas utilities, 13%. An additional 20 Bcf were consumed in field operations.

In contrast to the Cook Inlet region, the North Slope region produces an immense amount of casinghead gas but, as mentioned above, the only market for this gas is as fuel for the oil production facilities. Field operations consumed most of the 1988 net North Slope production (150 billion cubic feet) and an additional 18 billion cubic feet were sold to TAPS. Table 3.4 and Figure 3.4 show state and regional gas consumption data from 1971 to 1987. It is interesting to note that, in 1987 and 1988, field operations alone in the Prudhoe Bay region consumed more gas than total commercial use in Cook Inlet.

HISTORICAL OIL PRODUCTION (Million Barrels/Year) TABLE 3.1

YEAR:	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988[1]
STATE [2]	83.614	78.785	73.561	73.139	72.244	71.980	67.009	171.352	447.805	511.335	591.646	587.336	618.910	625.527	630.401	666.233	681.372	715.955	737.691
RAILBELT (Cook Inlet)[2]	82.415	77.628	72.638	72.196	70.074	69.111	62.404	56.094	50.126	42.923	36.252	31.072	27.405	24.763	21.986	16.946	17.630	24.944	15.727
NON-RAILBELT (North Slope)[2]	1.199	1.157	0.922	0.944	2.170	2.870	4.604	115.258	397.679	468.412	555.394	556.264	591.506	600.764	608.415	649.287	663.741	691.011	721.965
ITEM:																			
TAPS throughput, PS#1 [3]								112.315	397.149	467.939	554.934	556.067	591.142	600.859	608.836	649.887	665.435	716.662	743.302

[1] Estimated from part-yearly reports.
[2] Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", monthly report. Does not include NGL.
[3] 1977-81: Alaska Oil and Gas Conservation Commission, "Statistical Report."
1982-88: Alyeska Pipeline Service Co., personal communication.
31;1/3/89

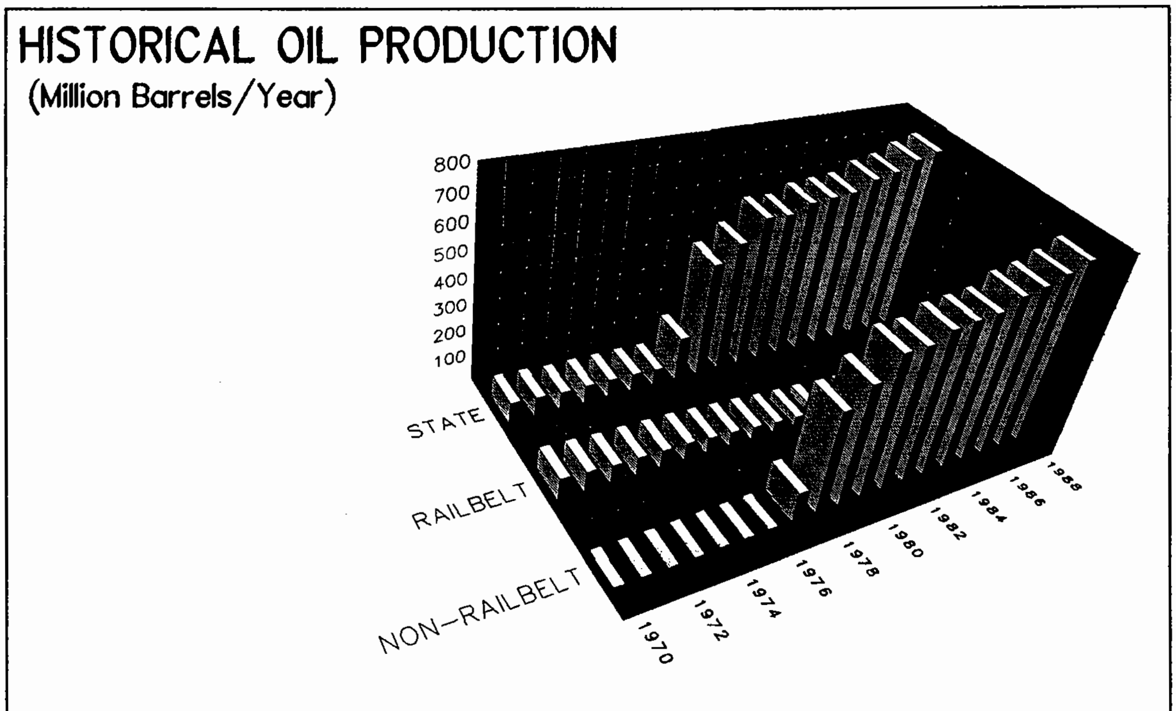


FIG. 3.1

HISTORICAL OIL CONSUMPTION - SALES AND SHIPMENTS

TABLE 3.2

YEAR:	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988[1]
FUEL SALES [2] (Million Gallons/Year)												
Aviation Gas	16.770	15.830	16.925	16.912	18.754	16.596	15.244	17.399	17.997	17.815	18.492	19.185
Exempt	1.521	0.685	0.552	0.558	0.574	0.589	0.498	0.574	0.515	0.858	0.384	0.894
Taxable	15.249	15.145	16.373	16.354	18.180	16.007	14.746	16.825	17.482	16.957	18.108	18.291
Aviation Jet	330.744	363.607	415.164	416.184	400.177	432.366	517.575	611.314	518.092	592.620	644.477	665.105
Exempt	227.581	250.601	288.974	286.110	247.619	99.957	242.815	311.820	223.635	280.654	318.349	335.624
Taxable	103.163	113.006	126.190	130.074	152.558	332.409	274.760	299.494	294.457	311.966	326.128	329.481
Marine Gas	11.766	7.714	8.296	7.598	7.602	7.878	8.568	8.955	14.664	10.464	11.510	11.000
Exempt	5.707	0.554	0.292	0.025	0.085	0.032	0.052	0.120	0.251	0.291	0.183	0.078
Taxable	6.059	7.160	8.004	7.573	7.517	7.846	8.516	8.835	14.413	10.173	11.327	10.922
Marine Diesel	38.613	51.985	59.492	67.711	72.282	99.443	147.569	124.416	98.675	105.218	171.769	165.501
Exempt	6.396	10.116	6.325	5.370	5.153	30.443	75.395	50.874	9.724	10.097	83.120	42.754
Taxable	32.217	41.869	53.167	62.341	67.129	69.000	72.174	73.542	88.951	95.121	88.649	122.747
Other Gas	186.213	187.359	181.329	177.353	186.446	210.644	197.968	223.178	235.081	234.482	221.259	224.184
Exempt	5.094	8.290	7.527	8.162	9.084	12.809	10.887	11.028	15.353	21.558	17.541	19.040
Taxable	181.119	179.069	173.802	169.191	177.362	197.835	187.081	212.150	219.728	212.924	203.718	205.144
Other Diesel	165.752	184.876	269.377	302.647	326.440	411.125	420.279	436.308	643.430	897.970	843.045	876.503
Exempt	46.160	54.050	120.960	120.939	117.074	187.856	178.494	190.891	369.279	559.413	583.305	605.228
Taxable	119.592	130.826	148.417	181.708	209.366	223.269	241.785	245.113	274.151	338.557	259.740	271.275
TOTAL FUEL SALES	749.858	811.371	950.583	988.405	1,011.701	1,178.052	1,307.203	1,421.570	1,527.939	1,858.569	1,910.552	1,961.478
SHIPMENTS [3] (MMbbl/Year)												
Liftings at Valdez	96.669	394.080	464.394	548.895	547.026	583.370	592.319	596.588	643.512	603.028	700.878	736.047

[1] Estimated from part-yearly reports.
[2] Alaska Department of Revenue, "Report of Motor Fuel Sold or Distributed in Alaska."
[3] 1977-81: Alaska Oil and Gas Conservation Commission, "Statistical Report."
1982-88: Alyeska Pipeline Service Co., personal communication.
32;12/20/88

HISTORICAL OIL CONSUMPTION
(Million Gallons/Year)

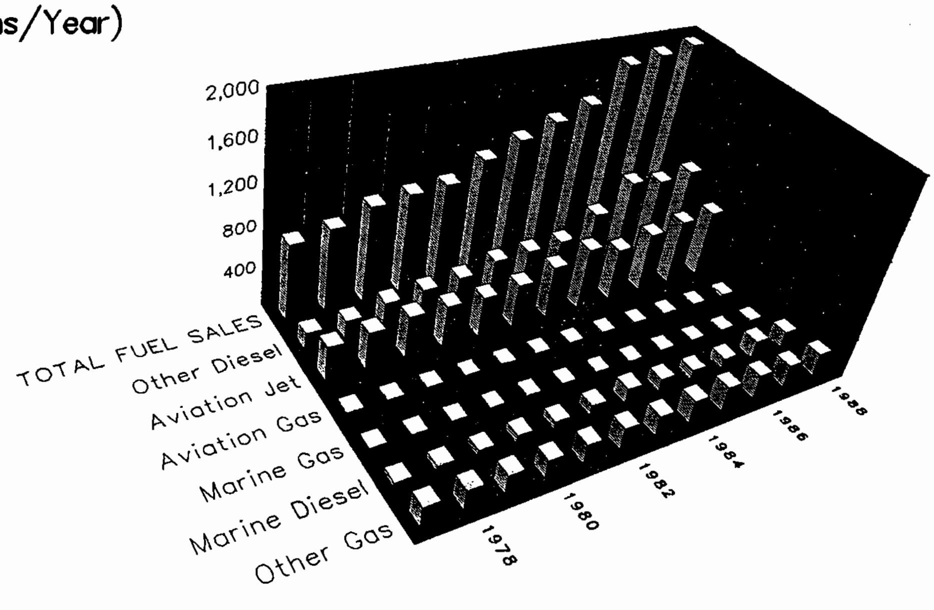


FIG. 3.2

HISTORICAL GAS PRODUCTION (Billion Cubic Feet/Year) TABLE 3.3

YEAR:	1971	1972	1973	1974	1975	1976	1977	1978	1979
STATE [2]									
Production	227.94	222.79	225.24	232.97	256.399	271.162	375.832	602.687	738.485
Injection [3]	73.88	76.13	87.78	49.04	83.007	97.077	171.188	375.405	503.003
Net Production	154.06	146.66	137.46	183.93	173.392	174.085	204.644	227.282	235.482
RAILBELT (Cook Inlet) [2]									
Production	227.94	222.79	225.24	230.18	252.554	265.253	279.961	293.800	305.075
Injection [3]	73.88	76.13	87.78	49.04	83.007	97.077	103.108	103.551	112.868
Net Production	154.06	146.66	137.46	181.14	169.547	168.176	176.853	190.249	192.207
NON-RAILBELT (North Slope)									
Production	---	---	---	2.79	3.845	5.909	95.871	308.887	433.410
Injection	---	---	---	0.00	0.000	0.000	68.080	271.854	390.136
Net Production	---	---	---	2.79	3.845	5.909	27.791	37.033	43.274

YEAR:	1980	1981	1982	1983	1984	1985	1986	1987	1988[1]
STATE [2]									
Production	898.155	948.554	1,090.655	1,171.121	1,212.705	1,350.884	1,381.930	1,704.124	1,896.060
Injection [3]	661.947	695.515	817.863	886.364	909.617	1,021.459	1,067.147	1,326.635	1,508.257
Net Production	236.208	253.039	272.792	284.757	303.088	329.425	314.783	377.489	387.803
RAILBELT (Cook Inlet) [2]									
Production	299.942	299.051	309.119	306.343	306.956	306.937	285.186	276.205	286.085
Injection [3]	115.437	100.410	102.248	94.385	93.687	89.025	92.136	80.016	95.732
Net Production	184.505	198.641	206.871	211.958	213.269	217.912	193.050	196.189	190.353
NON-RAILBELT (North Slope)									
Production	598.214	649.504	781.536	864.778	905.749	1,043.911	1,096.734	1,427.919	1,609.975
Injection	546.509	595.106	715.615	791.979	815.929	932.434	975.011	1,246.619	1,412.525
Net Production	51.705	54.398	65.921	72.799	89.820	111.477	121.723	181.300	197.450

[1] Estimated from part-yearly reports of cited sources.
[2] 1971-73: Stanford Research Institute, "Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of South Central Alaska," Nov. 1977.
1974-88: Alaska Oil and Gas Conservation Commission, "Report of Gas Disposition," monthly reports.
[3] Does not include gas rented from Beaver Creek and Kenai fields for injection into Swanson River field.
33;12/20/88

HISTORICAL GAS PRODUCTION (NET)

(Billion Cubic Feet/Year)

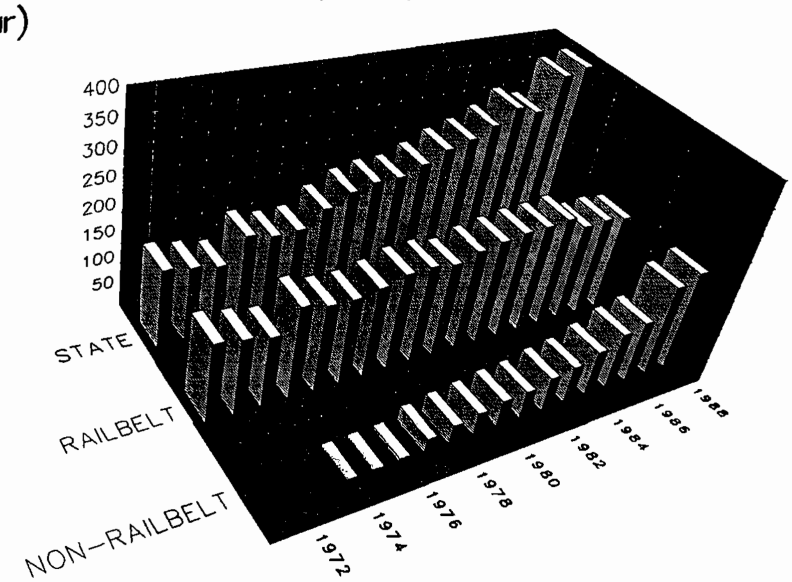


FIG. 3.3

HISTORICAL GAS CONSUMPTION (Billion Cubic Feet/Year)

TABLE 3.4

YEAR:	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988[1]
STATE [2]																		
Total consumption	166.97	160.28	151.84	183.13	173.393	174.085	204.644	227.281	235.481	236.209	253.039	272.790	284.757	303.089	329.425	314.783	377.489	387.809
Field Operations [3]	45.25	36.56	20.90	52.48	31.639	28.322	48.859	55.180	57.865	62.001	62.166	72.876	77.590	95.249	110.025	120.130	157.110	169.506
Vented and Flared	33.18	20.98	6.93	9.05	10.557	6.674	15.729	6.183	4.551	4.846	5.660	6.983	5.084	9.075	6.330	8.897	15.698	9.186
Used on Leases	10.96	14.86	12.42	41.40	17.963	18.424	29.966	35.055	38.123	43.575	44.592	52.724	58.893	68.481	84.654	85.183	123.778	145.418
Shrinkage	1.11	0.72	1.55	2.01	3.119	3.224	3.145	3.426	2.847	2.438	2.434	2.602	2.726	2.657	1.773	1.468	1.130	1.354
Other	0.00	0.00	0.00	0.02	0.000	0.000	0.019	10.516	12.344	11.142	9.480	10.567	10.887	15.036	17.268	24.582	16.504	13.548
Sold [3]	121.72	123.72	130.94	130.65	141.754	145.763	155.785	172.101	177.616	174.208	190.873	199.914	207.167	207.840	219.400	194.653	220.379	218.303
Power generation	14.69	15.38	16.70	17.45	25.461	27.613	28.590	29.937	33.376	33.755	33.947	36.222	36.651	37.000	41.337	44.767	41.242	41.745
Public [4][5]	8.14	8.91	10.63	11.76	19.619	22.189	23.590	24.811	28.390	28.992	29.386	31.392	32.055	32.662	36.807	40.236	36.585	36.977
Military [4]	6.55	6.47	6.07	5.68	5.842	5.424	5.000	5.126	4.986	4.763	4.561	4.830	4.596	4.338	4.530	4.531	4.657	4.768
Gas Utilities	10.24	13.10	14.76	15.13	12.092	12.551	12.683	13.745	14.362	15.921	16.213	19.564	19.518	20.911	24.872	23.721	23.556	24.874
Residential [4][5]	5.44	6.03	6.52	6.72	5.548	5.916	6.010	6.827	7.228	8.173	8.385	10.520	10.609	11.507	12.898	12.421	12.520	13.358
Commercial [4]	4.80	7.07	8.24	8.41	6.544	6.635	6.673	6.918	7.134	7.748	7.828	9.044	8.909	9.404	11.974	11.300	11.036	11.516
LNG [6]	63.24	59.87	60.99	61.87	64.777	63.509	66.912	60.874	64.111	54.844	68.823	64.438	67.729	65.892	65.177	61.906	60.879	58.737
Amonia-Urea [7]	19.49	20.58	20.64	22.10	23.888	24.257	28.620	48.879	51.657	54.699	53.836	55.220	50.338	50.083	50.688	35.733	45.230	38.075
Producers [8]	---	13.40	12.59	10.41	12.477	11.588	6.703	10.523	6.958	5.190	5.601	11.383	12.698	18.362	21.532	14.785	16.733	10.221
Refiners [9]	---	0.56	1.94	2.47	3.268	1.785	0.199	0.237	0.285	0.380	0.316	0.486	0.502	0.938	1.306	1.133	0.669	0.000
TAPS [10]	0.00	0.00	0.00	0.00	0.000	0.000	1.754	6.949	8.648	10.686	11.106	11.952	13.277	12.856	14.381	15.166	16.624	17.949
Unaccounted for [11]	14.06	0.83	3.32	0.89	(0.209)	4.460	10.324	1.467	(1.229)	(0.632)	1.031	0.649	6.454	1.798	0.107	(2.558)	15.446	26.702
RAILBELT																		
Total Consumption	166.97	160.28	151.84	180.34	169.547	168.177	176.853	190.249	192.207	184.505	198.641	206.870	211.958	215.220	217.948	192.971	196.189	190.352
Field Operations [3]	45.25	36.56	20.90	49.83	28.830	24.467	24.416	25.949	24.101	22.304	20.559	20.957	19.380	22.468	18.637	18.408	18.529	19.750
Vented and Flared	33.18	20.98	6.93	7.98	9.496	5.421	4.848	3.870	2.710	3.045	3.175	3.494	2.560	3.260	2.893	3.095	2.746	2.936
Used on Leases	10.96	14.86	12.42	39.85	16.215	15.822	16.404	16.228	14.564	14.608	14.950	14.861	14.056	14.597	13.971	13.845	14.651	15.747
Shrinkage	1.11	0.72	1.55	2.01	3.119	3.224	3.145	3.426	2.847	2.438	2.434	2.602	2.726	2.657	1.773	1.468	1.130	1.067
Other	0.00	0.00	0.00	0.00	0.000	0.000	0.019	2.425	3.980	2.213	0.000	0.000	0.038	1.954	0.000	0.000	0.002	0.000
Sold [3]	121.72	123.72	130.94	130.51	140.717	143.710	152.437	164.300	168.106	162.201	178.082	185.913	192.578	192.752	199.311	174.563	177.660	170.602
Power generation	14.69	15.38	16.70	17.45	25.461	27.613	28.590	29.718	33.141	33.520	33.632	35.818	36.169	36.520	40.851	44.208	40.698	41.142
Public [4]	8.14	8.91	10.63	11.76	19.619	22.189	23.590	24.592	28.155	28.757	29.071	30.988	31.573	32.182	36.321	39.677	36.041	36.374
Military [4]	6.55	6.47	6.07	5.68	5.842	5.424	5.000	5.126	4.986	4.763	4.561	4.830	4.596	4.338	4.530	4.531	4.657	4.768
Gas Utilities	10.24	13.10	14.76	15.13	12.092	12.551	12.683	13.454	14.045	15.521	15.778	19.025	19.111	20.903	24.419	23.235	23.063	24.363
Residential [4]	5.44	6.03	6.52	6.72	5.548	5.916	6.010	6.536	6.911	7.773	7.950	9.981	10.202	10.999	12.445	11.935	12.027	12.847
Commercial [4]	4.80	7.07	8.24	8.41	6.544	6.635	6.673	6.918	7.134	7.748	7.828	9.044	8.909	9.904	11.974	11.300	11.036	11.516
LNG [6]	63.24	59.87	60.99	61.87	64.777	63.509	66.912	60.874	64.111	54.844	68.823	64.438	67.729	65.882	65.177	61.906	60.879	58.737
Amonia-Urea [7]	19.49	20.58	20.64	22.10	23.888	24.257	28.620	48.879	51.657	54.699	53.836	55.220	50.338	50.083	50.688	35.733	45.230	38.075
Producers [8]	---	13.40	12.59	10.41	12.477	11.588	6.703	10.523	6.958	5.190	5.601	11.383	12.698	18.362	21.532	14.785	16.733	10.221
Unaccounted for [11]	14.06	1.39	5.26	3.36	2.022	4.192	8.929	0.852	(1.806)	(1.573)	0.412	0.029	6.533	1.002	(3.356)	(5.304)	2.093	(1.936)
NON-RAILBELT																		
Total Consumption				2.786	3.845	5.910	27.791	37.033	43.275	51.704	54.398	65.921	72.799	89.820	111.477	121.723	181.300	197.457
Field Operations [3]	---	---	---	2.65	2.808	3.856	24.444	29.231	33.763	39.697	41.607	51.921	58.210	74.732	91.388	101.722	138.581	149.756
Vented and Flared	---	---	---	1.08	1.061	1.254	10.882	2.313	1.840	1.801	2.485	3.490	2.524	5.814	3.437	5.802	12.952	6.250
Used on Leases	---	---	---	1.56	1.747	2.602	13.562	18.826	23.559	28.967	29.642	37.864	44.837	53.884	70.683	71.338	109.127	129.671
Shrinkage	---	---	---	0.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.287
Other	---	---	---	0.02	0.000	0.000	0.000	8.092	8.364	8.929	9.480	10.567	10.849	15.034	17.268	24.582	16.502	13.548
Sold [3]	---	---	---	0.14	1.037	2.054	3.347	7.802	9.512	12.007	12.791	14.000	14.589	15.088	20.089	20.001	42.719	47.701
Power generation [5]	---	---	---	---	---	---	---	0.219	0.235	0.235	0.315	0.404	0.482	0.480	0.486	0.559	0.544	0.603
Gas Utilities [5]	---	---	---	---	---	---	---	0.291	0.317	0.400	0.435	0.539	0.407	0.508	0.453	0.486	0.493	0.511
Refiners [9]	---	0.56	1.94	2.47	3.268	1.785	0.199	0.237	0.285	0.380	0.316	0.486	0.502	0.938	1.306	1.133	0.669	0.000
TAPS [10]	0.00	0.00	0.00	0.00	0.000	0.000	1.754	6.949	8.648	10.686	11.106	11.952	13.277	12.856	14.381	15.166	16.624	17.949
Unaccounted for [11]					(2.231)	0.269	1.394	0.616	0.579	0.941	0.619	0.619	(0.079)	0.306	3.463	2.657	24.389	28.638

[1] Estimated from part-yearly reports of cited sources.
[2] Does not include NON-RAILBELT items marked "---".
[3] Alaska Oil and Gas Conservation Commission, "Report of Gas Disposition," monthly reports.
[4] Sum of sales from Beluga gas field in: Alaska Oil and Gas Conservation Commission, "Report of Gas Disposition" and
1971-82: Annual reports from Alaska Pipeline Co., ENSTAR and Kenai Utility Service Co. to Alaska Public Utilities Commission
1983-88: Enstar Natural Gas Co., personal communication.
[5] Barrow Utilities and Electric Cooperative Inc., personal communication.
[6] 1971-74: Stanford Research Institute, "Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of South Central Alaska," Nov. 1977.
1975-79: Sum of 1) production from Kenai and Beaver Creek gas fields in: Alaska Oil and Gas Conservation Commission, "Report of Gas Disposition," and
2) sales from North Cook Inlet gas field in: Alaska Oil and Gas Conservation Commission, "Kenai Gas Sales."
1980-88: Royalty reports from producers to Division of Oil and Gas.
[7] 1971-74: Stanford Research Institute, "Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of South Central Alaska," Nov. 1977.
1975-79: Sum of 1) sales from Kenai and Beaver Creek gas fields to Collier Chemical in: Alaska Oil and Gas Conservation Commission, "Kenai Gas Sales," and
2) sales from McArthur River gas field in: Alaska Oil and Gas Conservation Commission, "Monthly Report of Gas Disposition."
1980-88: Royalty reports from producers to Division of Oil and Gas.
[8] Royalty reports from Union to Division of Oil and Gas, item Rental Gas.
[9] Royalty reports from Union to Division of Oil and Gas, items Alaska Pipeline-Nikiski, Chevron Rental Gas and Metering.
[10] Royalty reports from ARCO to Division of Oil and Gas.
[11] Calculated difference between "Sold" and sum of listed "Sold" items.
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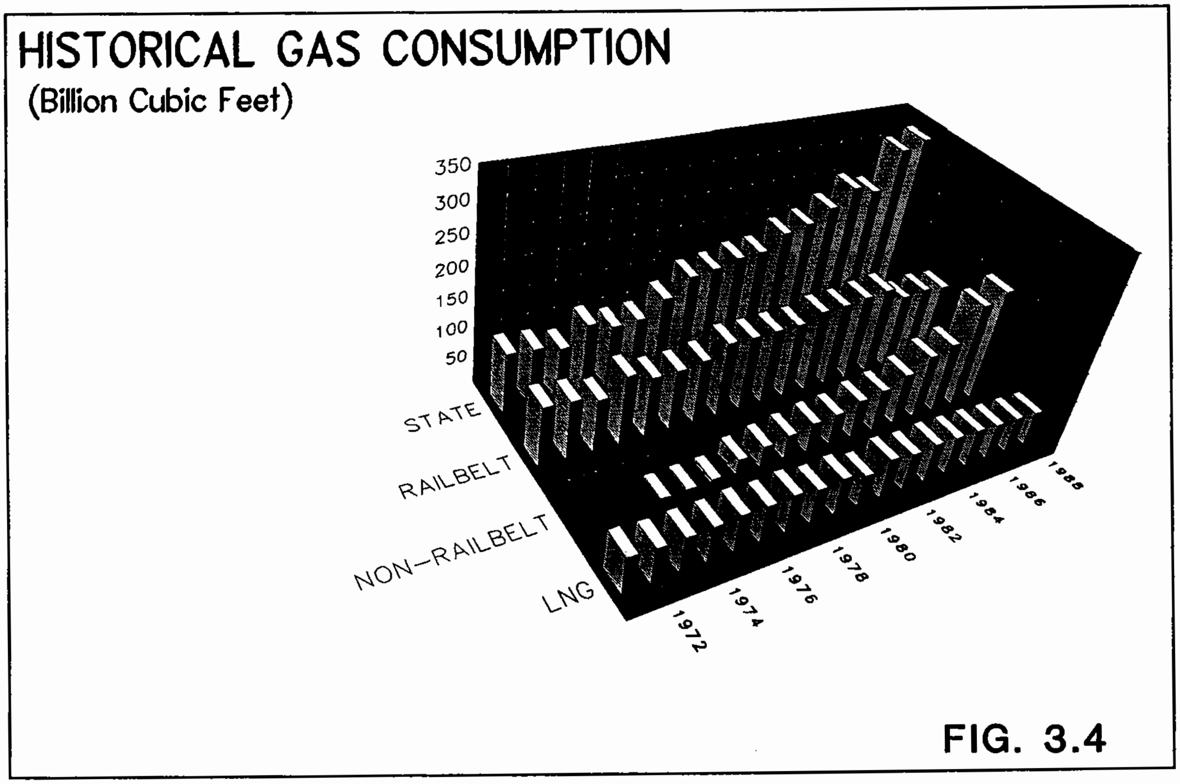

FIG. 3.4

CHAPTER 4
CONSUMPTION FORECAST

Introduction

The Institute of Social and Economic Research (ISER) prepared the following projection for the Division of Oil and Gas (DO&G) in December 1986. The projection has not been recast because most of its assumptions and the long-term forecasts are reasonable and little affected by population and economic changes of the past two years. The methods and assumptions used to generate the forecasts are included in Appendix B of the January 1987 report and are not reprinted in this edition.

DO&G has updated the projection in two ways. First, the gas demand category "Nonrailbelt, Industry: Petroleum Production" has been increased by 87 billion cubic feet per year to account for the very large increase in gas consumption by Prudhoe Bay facilities. Second, the period of the projection has been extended by two years, to 2003; each use category was extended by applying the growth factors in the original projection.

Summary

Consumption of oil and gas in most major categories is forecast to increase at a modest rate in future years.

Total consumption of liquid petroleum will increase from 1,510 million gallons in 1989 to 1,755 million gallons in 2003. This represents a 1 percent annual growth rate. Space heating use of petroleum will be flat. Vehicle transportation use will increase 1 percent annually. The use of fuel oil for electricity generation reflects the recent and planned introduction of several hydroelectric facilities which replace fuel oil generation. However, in the long run, fuel oil consumption increases, and the 15 year growth rate is projected to be 2 percent annually. Industrial use of petroleum liquids will remain constant.

Consumption of natural gas will grow from 341 billion cubic feet in 1989 to 362 billion cubic feet in 2003 (annual growth of less than 1 percent). Industry will continue to consume the majority of natural gas. The consumption of natural gas for industrial uses will grow from 275 billion cubic feet in 1989 to 292 billion cubic feet in 2003 (under 1 percent annual growth). Over the next 15 years, use of gas for space heating will increase very little from 26 billion cubic feet in 1989 to 28 billion cubic feet in 2003. Use of gas for electricity generation will remain constant at 40 billion cubic feet annually.

Transportation Liquid Fuels

Transportation fuel consumption will grow moderately in future years, increasing from 1,208 million gallons in 1989 to 1,431 million gallons in 2003 (Table 4.1). Jet fuel consumption will grow most rapidly (2 percent annually) while diesel fuel consumption will grow slowly, and gasoline use will fall slowly.

Total consumption projected over the 15 year period from 1989 to 2003 is 24.3 million gallons.

Space Heating

Outside the railbelt, fuel oil is the dominant means of space heating. Fuel oil consumption for this use is approximately constant - 159 million gallons in 1989 and 167 million gallons in 2003. Natural gas use will grow slowly from 26 billion cubic feet in 1989 to 28 billion cubic feet in 2003 (Table 4.2). Barrow, on the North Slope, is the only location outside of the railbelt presently served by natural gas.

Utility Electricity Generation

Fuel oil use for utility electricity generation will grow at an average annual rate of 2 percent. This is due to demand growth in areas where power generation from natural gas and hydroelectric plants is not available.

Natural gas use for utility electricity generation will decline in the near term from its current level of 39 billion cubic feet, when the Bradley Lake hydroelectric project backs out some gas use starting in the 1990s. Subsequently, its use will grow and regain the current level by the year 2000. The projection does not anticipate any new coal-fired generating plants.

Industrial Fuel Use

The major industrial use of fuel oil (not including transportation) is in the petroleum industry. Pipeline fuel for the Alyeska pipeline is the largest element of this use. In addition, a significant amount of fuel is used for electricity generation. Both of these uses are projected at constant levels.

Increased use of natural gas in future years will be related to petroleum production. This increase will be concentrated on the North Slope where more equipment for intensive recovery methods will assume larger amounts of energy. Production of ammonia-urea, the other large use of natural gas, will continue to require a constant amount of natural gas.

PROJECTED DEMAND FOR OIL (Million Gallons/Year) TABLE 4.1

YEAR:	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL, 1989-2003	ANNUAL GROWTH
STATE																	
Vehicle Transportation	1,208	1,216	1,227	1,239	1,255	1,269	1,281	1,296	1,313	1,334	1,354	1,377	1,400	1,415	1,431	19,615	1%
Jet Fuel	576	587	599	611	626	639	652	666	682	699	716	734	753	769	785	10,093	2%
Civilian Domestic	313	321	330	339	351	362	372	384	396	410	424	440	456	469	483	5,850	3%
Military and International	264	266	269	272	274	277	280	283	286	288	291	294	297	300	303	4,245	1%
Gasoline	250	248	247	245	245	244	243	242	241	242	242	242	243	243	244	3,661	<1%
Aviation	18	18	18	18	18	18	18	18	18	18	19	19	19	19	19	277	<1%
Highway	222	220	219	218	217	216	215	214	214	214	214	214	214	214	215	3,241	<1%
Marine	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	143	<1%
Diesel	381	381	382	382	385	386	386	388	390	393	396	400	404	408	412	5,874	<1%
Highway	273	272	272	271	272	272	272	272	273	274	276	277	279	281	283	4,121	<1%
Marine	108	109	110	111	112	113	114	116	117	119	121	123	125	126	127	1,751	1%
Space Heat	159	159	159	159	161	161	162	162	163	164	164	165	166	167	168	2,440	<1%
Utility Generation	37	38	40	41	42	43	44	45	46	47	48	49	50	51	52	672	2%
Industry	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	1,574	<1%
Pipeline Fuel	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	1,260	<1%
Electricity Generation	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	314	<1%
TOTAL	1,510	1,518	1,531	1,544	1,564	1,578	1,591	1,608	1,627	1,650	1,671	1,696	1,720	1,738	1,755	24,300	1%
RAILBELT																	
Vehicle Transportation	889	895	901	909	919	929	940	951	965	981	999	1,017	1,038	1,049	1,060	14,440	1%
Jet Fuel	479	486	494	504	514	524	535	546	559	573	588	604	620	632	644	8,304	2%
Civilian Domestic	258	264	270	278	286	295	303	312	323	334	346	359	373	384	394	4,779	3%
Military and International	221	223	224	226	227	230	232	234	237	239	242	244	247	249	251	3,526	1%
Gasoline	186	184	182	181	180	179	178	178	177	178	178	178	179	180	181	2,700	<1%
Aviation	15	15	15	15	15	15	15	15	15	15	15	15	15	16	16	227	<1%
Highway	165	163	162	160	160	159	158	157	157	157	157	157	158	159	159	2,388	<1%
Marine	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	85	<1%
Diesel	225	224	224	224	225	226	226	227	228	230	233	235	238	241	244	3,449	<1%
Highway	149	148	147	147	147	147	147	147	147	148	149	150	151	153	154	2,230	<1%
Marine	76	76	77	77	78	79	79	80	81	82	84	85	87	88	88	1,217	1%
Space Heat	58	57	57	57	57	57	57	57	57	58	58	59	59	60	60	867	<1%
Utility Generation	10	10	10	10	10	10	10	10	10	10	10	10	10	10	11	151	<1%
Industry	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
TOTAL	958	962	967	975	985	996	1,006	1,018	1,032	1,049	1,067	1,086	1,107	1,119	1,131	15,458	1%
NON-RAILBELT																	
Vehicle Transportation	215	218	221	224	229	231	233	236	239	243	246	250	253	256	260	3,552	1%
Jet Fuel	98	101	105	108	112	114	117	120	123	126	128	131	133	136	140	1,790	3%
Civilian Domestic	55	57	60	62	65	67	69	71	74	76	78	81	83	86	89	1,072	4%
Military and International	43	44	45	46	47	47	48	49	49	50	50	50	50	51	52	719	2%
Gasoline	64	64	64	64	65	65	64	64	64	64	64	64	64	63	63	961	<1%
Aviation	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	51	1%
Highway	57	57	57	57	58	57	57	57	57	57	57	56	56	56	56	853	<1%
Marine	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	58	<1%
Diesel	157	157	158	158	160	160	160	161	162	163	164	165	166	167	168	2,424	1%
Highway	124	124	124	124	125	125	125	126	126	127	127	128	128	128	129	1,891	<1%
Marine	32	33	33	34	34	35	35	36	36	37	37	37	38	38	39	534	1%
Space Heat	101	101	102	103	104	105	105	105	106	106	106	107	107	108	108	1,574	1%
Utility Generation	28	29	30	31	32	33	34	35	36	37	38	38	39	40	42	521	3%
Southeast	8	8	9	10	11	11	12	12	13	13	14	14	15	15	16	181	5%
Rest of State	20	20	21	21	22	22	22	23	23	24	24	24	25	25	26	340	2%
Industry	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	1,574	<1%
TOTAL	348	351	356	359	366	369	372	376	380	385	388	393	397	401	404	5,645	1%

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PROJECTED DEMAND FOR OIL

(Million Gallons/Year)

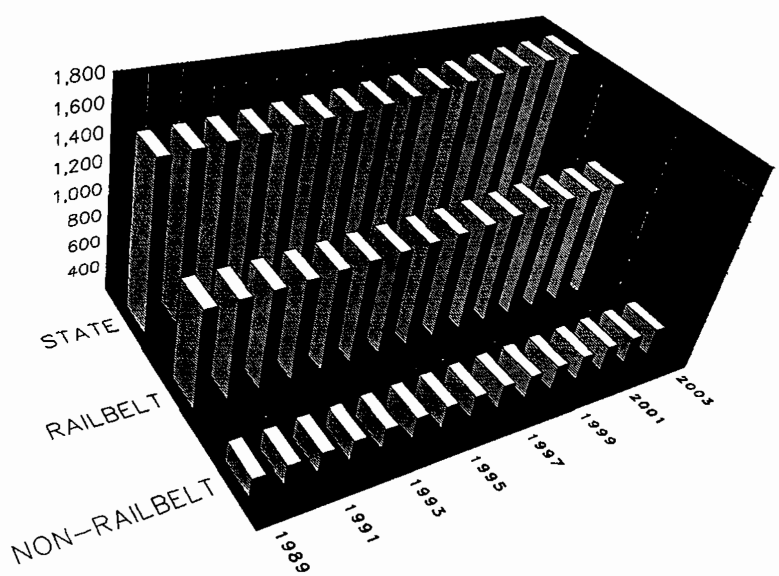

FIG. 4.1

PROJECTED DEMAND FOR GAS (Billion Cubic Feet) Table 4.2

YEAR:	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	TOTAL, 1989-2003	ANNUAL GROWTH
STATE																	
Space Heat	26.1	26.3	26.5	26.8	26.9	26.9	26.9	27.0	27.1	27.2	27.3	27.3	27.4	27.5	27.6	404.8	<1%
Utility Generation	39.4	39.5	39.7	35.5	35.9	36.2	36.6	37.0	37.5	38.1	38.8	39.5	40.3	41.0	41.8	576.9	<1%
Industry	275.4	279.8	284.3	289.1	289.1	289.1	289.1	289.1	289.1	289.1	289.1	289.1	289.1	290.7	292.3	4,313.5	1%
Ammonia-Urea Production	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	750.0	0%
Military Power Generation	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	66.0	0%
Petroleum Production	221.0	225.4	229.9	234.7	234.7	234.7	234.7	234.7	234.7	234.7	234.7	234.7	234.7	236.3	237.9	3,497.5	1%
TOTAL	340.9	345.6	350.5	351.4	351.9	352.3	352.6	353.1	353.7	354.4	355.2	356.0	356.8	359.2	361.7	5,295.2	1%
RAILBELT																	
Space Heat	25.6	25.9	26.1	26.4	26.5	26.5	26.5	26.5	26.6	26.7	26.8	26.8	26.9	27.0	27.1	397.8	<1%
Utility Generation	38.9	39.0	39.1	35.0	35.3	35.7	36.0	36.4	36.9	37.5	38.2	38.9	39.6	40.4	41.2	567.9	<1%
Industry	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	1,303.5	0%
Ammonia-Urea Production	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	750.0	0%
Military Power Generation	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	66.0	0%
Petroleum Production	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	487.5	0%
TOTAL	151.4	151.8	152.1	148.2	148.7	149.0	149.4	149.8	150.4	151.1	151.9	152.6	153.4	153.4	153.4	2,269.2	<1%
NON-RAILBELT																	
Space Heat	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	7.0	2%
Utility Generation	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	9.0	2%
Industry: Petroleum Production	188.5	192.9	197.4	202.2	202.2	202.2	202.2	202.2	202.2	202.2	202.2	202.2	202.2	203.8	205.5	3,010.2	1%
TOTAL	189.5	193.8	198.4	203.2	203.2	203.2	203.2	203.3	203.3	203.3	203.3	203.4	203.4	205.0	206.7	3,026.1	1%

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PROJECTED DEMAND FOR GAS
(Billion Cubic Feet/Year)

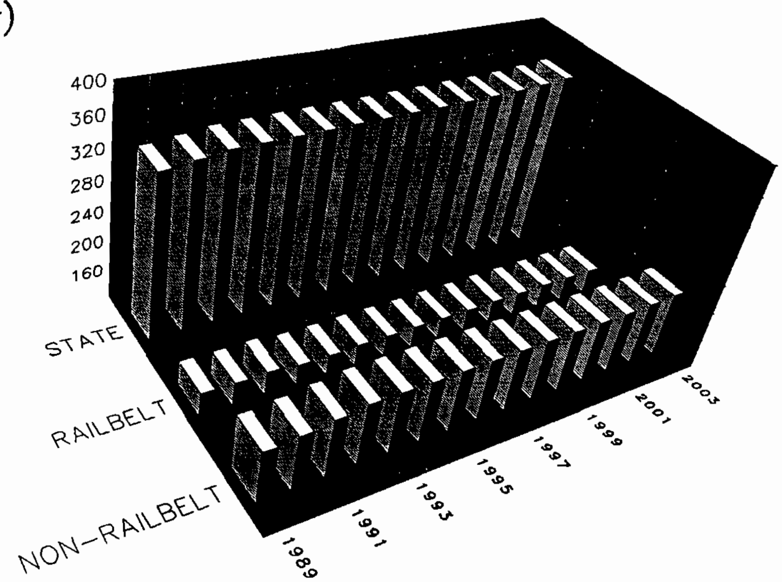


FIG. 4.2

CHAPTER 5
ANALYSIS OF SURPLUS

Introduction

ISER compiled the following analysis of surplus in December 1986 to supplement the consumption projections in Chapter 4. The surplus of state oil and gas which this analysis predicts is probably low because in the analysis the factors which operate to reduce consumption have proved to be understated. Table 5.2 notes that only two variables - reserve estimates and export of LNG - have much influence on calculations of surplus, and Tables 2.1 and 3.2 show no dramatic change in either of these variables over the last two years.

Changes in population and economic factors, on the other hand, though they have small influence on the calculations, have probably declined more than the analysis anticipated. Population was estimated by ISER to decline from 536,000 in 1985 to 523,000 in 1990. Economic decline was incorporated in the analysis of surplus, but the decline is probably greater and of longer duration than the analysis accounted for. The result is that less gas and transportation fuel will be consumed.

Summary

Under reasonable assumptions about available reserves and in-state consumption, the current inventories of both oil and gas are more than adequate for the next 15 years.

Liquid Petroleum

A direct barrel-for-barrel comparison between demand for refined products and availability of crude oil is unrealistic since a barrel of crude oil does not yield a barrel of specific refined products. Outputs and efficiencies differ between refineries, and a given refinery can alter its product output. Tables 4.1 and 5.1 show that the cumulative 15-year Alaska demand for refined petroleum products is approximately 868 million barrels. This is about 10 million barrels more than the reserves of royalty crude oil, but is only 13 percent of total crude oil reserves in the state. Assuming that on a statewide basis the refineries convert two-thirds of their crude oil feedstock into refined products used in Alaska, then the total volume of royalty oil available over the next 15 years more or less equals the projected consumption levels of refined products over that same time period. Because North Slope oil production is expected to begin to decline in 1989 and decline each year thereafter, the annual volume of available royalty oil will fall below the projected refined products consumption level in about 1997 when using unrealistic barrel-for-barrel comparison. Using a conversion factor for crude oil to refined products of two-thirds results in the availability of royalty oil on an annual basis falling below the consumption level of refined products in the mid-1990s.

Historically, in-state refiners have purchased both state royalty oil and oil sold by the individual lessees (Standard, Exxon, ARCO, Texaco, etc.). Price terms, contract length, and transportation considerations are a few of the factors that enter into that decision-making process. It is realistic to assume that in-state refiners will, at least on a limited basis, continue to purchase non-royalty oil as refinery feedstock. However, it is unrealistic to assume that state royalty oil will or should provide the only source of feedstock for in-state refiners over the next 15 years. At present, the state takes approximately 3,500 bpd of Cook Inlet royalty oil in-kind and exports it. The state takes all North Slope royalty in-kind and in-value, but does not export any because of continued federal restrictions on the export of ANS crude oil.

Based on current projections, sufficient feedstocks will be available regardless of the supply sources chosen by the in-state refiners. No attempt has been made to compare the total volume of petroleum products produced at Alaska refineries with the total volume of petroleum products consumed in the state. Currently, the capacity of Alaska refineries exceeds Alaskan consumption. But, owing to technical constraints, the product mix which the refineries can produce does not match the product mix demanded. The resulting cross-hauling of crude oil out of Alaska and refined products (motor oils, specialty lubricants, etc.) into the state is a common feature of petroleum markets, and does not represent an inefficient distribution of refining capacity or mismatch of supply and demand.

Natural Gas

Table 5.1 indicates that the cumulative 15-year Alaska demand for natural gas is 5.3 trillion cubic feet of gas. This is about 1.4 billion cubic feet more than the state royalty share of gas in the combined current inventory at Cook Inlet and on the North Slope.

Since natural gas is traditionally transported by pipeline, analysis of particular markets for gas which are linked or could be linked by pipeline to supplies are relevant for the determination of excess supply. Table 5.1 shows that North Slope royalty gas could meet that region's demand for the next 15 years. It also shows that total Cook Inlet reserves could meet regional demand, though the demand could not be met with royalty gas alone. At present, the state takes no royalty gas in-kind and does not export any. Again, it is unrealistic to assume that state royalty gas should satisfy all in-state consumption of natural gas.

Projections Beyond Current Inventory

We assume reserves represent a 15-year inventory of petroleum in the ground. Because a very sizable investment is required to develop a petroleum reservoir, reserves will be "proven up" at a rate to maintain sufficient inventory consistent with demand. Premature or excessive development, like excessive inventories, results in unnecessary carrying costs to lease (reservoir) owners and will be avoided if possible. This is the basis for the 15-year time horizon for demand used in this analysis. As time passes, consumption will stimulate the search for new reserves to replace those produced, and market forces will work to keep supply and demand in balance.

SENSITIVITY OF RESULTS

The net surpluses of oil and gas calculated in this chapter are largely insensitive to a reasonable range of changes in the assumptions underlying the projections. These are discussed in turn and shown in Table 5.2.

ECONOMIC GROWTH

Faster population growth will accelerate the use of liquid fuels relative to the use of natural gas because a larger portion of liquid fuel use is population sensitive. Even so, the net surplus of petroleum liquids would be reduced only marginally by growth of population based on a rapid economic growth scenario (see Appendix B of the 1986 report).

EXPORT OF GAS

To the extent natural gas is exported, it is unavailable for the local market. Cumulative exports over the next 15 years from current operations are projected to be about 1,005 billion cubic feet. If a new export facility were to be constructed in Cook Inlet, it is anticipated that exploration for natural gas in Cook Inlet would accelerate (it is currently at a near standstill) and additional reserves would likely be discovered, once again creating a demand/supply balance.

NATURAL GAS AVAILABILITY IN FAIRBANKS

If natural gas became available in Fairbanks, at least some space heating in Fairbanks would be converted to gas. This could increase annual natural gas consumption as fuel oil use was backed out. Fuel oil use could fall by 8 million gallons annually.

Natural gas consumption for space heating might eventually capture 75 percent of the market. If gas became available in 1993 and captured this share of the market by 1997, gas consumption for space heat could increase 30 billion cubic feet, and fuel oil consumption could fall by 175 million gallons over the projection period.

The net surplus of gas would fall only marginally as a result of these changes, and the net surplus of liquid fuels would increase only marginally.

SURPLUS OIL AND GAS [1] TABLE 5.1

	OIL (Million Barrels)		GAS (Billion Cubic Feet)	
	Total	State Royalty	Total	State Royalty
STATE				
Estimated reserves	6,804	858	32,172	3,851
Estimated consumption [2]	868	868	5,295	5,295
NET SURPLUS (DEFICIT)	5,936	(10)	26,877	(1,444)
COOK INLET				
Estimated reserves	74	8	3,906	308
Estimated consumption [2]	552	552	2,269	2,269
NET SURPLUS (DEFICIT)	(478)	(544)	1,637	(1,961)
NORTH SLOPE				
Estimated reserves	6,730	850	28,266	3,543
Estimated consumption [2]	202	202	3,026	3,026
NET SURPLUS (DEFICIT)	6,528	648	25,240	517

[1] Reserves from Table 2.1, consumption from Tables 4.2 and 4.3.
[2] Assumes that one barrel of crude oil yields 28 gallons fuel.

SENSITIVITY ANALYSIS OF OIL AND GAS SURPLUS TABLE 5.1

	Reduction in Net Surplus	
	Oil	Gas
Low reserve estimate	24%	1%
Rapid population growth	1%	<1%
Export of LNG	--	9%
Natural Gas available in Fairbanks	<1%	<1%

APPENDIX A
OIL AND GAS FIELD DATA

BELUGA RIVER

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION	Cook Inlet, onshore, west side				
BEGAN PRODUCTION	1/68				
OPERATOR	ARCO				
PURCHASER	Chugach Electric	MONTHLY PRODUCTION [1]	---	---	2,066,000
	ENSTAR	CUMULATIVE PRODUCTION [2]	---	---	277,975,000
		RESERVES [2]	---	---	720,000,000
		PERCENT OF FIELD DEPLETED [2]	---	---	28%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

COMMENTS
- Chugach Electric uses this gas onsite for generation of electricity which is delivered to the Anchorage market.
- Enstar has recently purchased Beluga River gas under contract from Shell and transports the gas by pipeline from the field through the Mat-Su Valley to Anchorage.
- Due to the existence of several Federal leases in the field, the state's effective royalty share is 7.555%.

CANNERY LOOP

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION	Cook Inlet, onshore, east side				
BEGAN PRODUCTION	1988				
OPERATOR	Union				
		MONTHLY PRODUCTION [1]	---	---	550,000
		CUMULATIVE PRODUCTION [2]	---	---	6,589,000
		RESERVES [2]	---	---	150,000,000
		PERCENT OF FIELD DEPLETED [2]	---	---	2%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

DUCK ISLAND UNIT (ENDICOTT RESERVOIR)

			OIL (Bbl)	CsngHd GAS -Gross (Mcf)	CsngHd GAS -Net (Mcf)
LOCATION	North Slope, onshore/offshore				
BEGAN PRODUCTION	1987				
OPERATOR	BP				
		MONTHLY PRODUCTION [1]	3,197,000 [3]	2,934,000	617,000
		CUMULATIVE PRODUCTION [2]	47,169,000 [3]	43,639,000	10,216,000
		RESERVES [2]	330,000,000	790,000,000	---
		PERCENT OF FIELD DEPLETED [2]	12%	1%	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

FALLS CREEK

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION	Cook Inlet, onshore, east side				
BEGAN PRODUCTION	Shut-in 1961				
OPERATOR	Chevron				
		MONTHLY PRODUCTION [1]	---	---	---
		CUMULATIVE PRODUCTION [2]	---	---	19,000
		RESERVES [2]	---	---	13,000,000
		PERCENT OF FIELD DEPLETED [2]	---	---	<1%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

GRANITE POINT

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION	Cook Inlet, offshore, west side				
BEGAN PRODUCTION	12/67				
OPERATOR	Union, Amoco				
PURCHASER	Tesoro	MONTHLY PRODUCTION [1]	220,000	205,000	---
	ARCO *	CUMULATIVE PRODUCTION [2]	109,476	94,755	---
	AMOCO *	RESERVES [2]	16,000,000	13,000,000	---
	Union *	PERCENT OF FIELD DEPLETED [2]	87%	88%	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

* Small amount of casinghead gas sold to AMOCO for use on platform.

GWYDYR BAY UNIT AREA

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION	North Slope, onshore/offshore				
BEGAN PRODUCTION	Field delineation underway				
OPERATOR	Arco				
PURCHASER		MONTHLY PRODUCTION [1]	---	---	---
		CUMULATIVE PRODUCTION [2]	---	---	---
		RESERVES [2]	---	---	---
		PERCENT OF FIELD DEPLETED [2]	---	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

HEMI SPRINGS UNIT AREA

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION	North Slope, onshore				
BEGAN PRODUCTION	Field delineation underway.				
OPERATOR	ARCO				
		MONTHLY PRODUCTION [1]	---	---	---
		CUMULATIVE PRODUCTION [2]	---	---	---
		RESERVES [2]	---	---	---
		PERCENT OF FIELD DEPLETED [2]	---	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

IVAN RIVER

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION	Cook Inlet, onshore, west side				
BEGAN PRODUCTION	Shut-in 1966, suspended				
OPERATOR	Chevron				
		MONTHLY PRODUCTION [1]	---	---	---
		CUMULATIVE PRODUCTION [2]	---	---	---
		RESERVES [2]	---	---	[3]
		PERCENT OF FIELD DEPLETED [2]	---	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Ivan River, Lewis River, Pretty Creek and Stump Lake reserves are combined under Lewis River reserves.

KAVIK

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION	North Slope, onshore				
BEGAN PRODUCTION	Suspended				
OPERATOR	ARCO				
		MONTHLY PRODUCTION [1]	---	---	---
		CUMULATIVE PRODUCTION [2]	---	---	---
		RESERVES [2]	---	---	---
		PERCENT OF FIELD DEPLETED [2]	---	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

KENAI

			OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
LOCATION					
BEGAN PRODUCTION					
OPERATOR					
PURCHASER	Alaska Pipeline	MONTHLY PRODUCTION [1]	---	---	6,605,000
	Chevron	CUMULATIVE PRODUCTION [2]	11,877 [3]	---	1,909,883,000
	City of Kenai	RESERVES [2]	---	---	640,000,000
	Marathon LNG	PERCENT OF FIELD DEPLETED [2]	---	---	75%
	Rental gas (Swanson River oil field)	[1] 1/1/88 thru 7/31/88.			
	Union	[2] Estimated as of 1/1/89.			
	Union-Chevron exchange	[3] Natural gas liquids.			

COMMENTS

- Effective royalty rates are: Kenai, 2.06875%; Kenai Deep, 0.0%. The state does not receive the full 12.5% royalty share because of the predominance of Federal leases in the unit and the conveyance of land to Cook Inlet Region Inc.

KUPARUK

LOCATION North Slope, onshore
BEGAN PRODUCTION 12/81
OPERATOR ARCO
PURCHASER All owners

	OIL (Bbl)	CsngHd GAS -Gross (Mcf)	CsngHd GAS -Net (Mcf)
MONTHLY PRODUCTION [1]	9,128,000 [3]	9,967,000	2,675,000
CUMULATIVE PRODUCTION [2]	507,446 [4]	589,368,000	132,286
RESERVES [2]	845,000,000	---	570,000,000
PERCENT OF FIELD DEPLETED [2]	39%	---	19%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Includes 37,000 BPM NGL.
[4] Includes 3,529,000 Bbl NGL

LEWIS RIVER

LOCATION Cook Inlet, onshore, west side
BEGAN PRODUCTION 1984
OPERATOR UNOCAL

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	---
CUMULATIVE PRODUCTION [2]	---	---	4,022,000
RESERVES [2]	---	---	500,000,000 [3]
PERCENT OF FIELD DEPLETED [2]	---	---	<1%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Ivan River, Lewis River, Pretty Creek and Stump Lake reserves are combined under Lewis River reserves.

COMMENTS
- Short term gas sales to Enstar began in 1984.

LISBURNE RESERVOIR

LOCATION North Slope, onshore/offshore
BEGAN PRODUCTION 1986
OPERATOR ARCO

	OIL (Bbl)	CsngHd GAS -Gross (Mcf)	CsngHd GAS -Net (Mcf)
MONTHLY PRODUCTION [1]	1,343,000 [3]	7,459,000	669,000
CUMULATIVE PRODUCTION [2]	38,011,000 [4]	9,180,428,000	874,865,000
RESERVES [2]	165,000,000	890,000,000	---
PERCENT OF FIELD DEPLETED [2]	9%	3%	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Includes 70,000 BPM GL.
[4] Includes 1,301,000 Bbl GL.

MCARTHUR RIVER

LOCATION Cook Inlet offshore, west side
BEGAN PRODUCTION 12/69
OPERATOR Union, Marathon, ARCO
PURCHASER Tesoro

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	622,000 [3]	318,000	853,000
CUMULATIVE PRODUCTION [2]	537,968,000 [4]	197,972,000	143,778,000
RESERVES [2]	40,000,000	[5]	620,000,000
PERCENT OF FIELD DEPLETED [2]	93%	---	36%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Includes 18,000 BPM NGL.
[4] Includes 9,033,000 Bbl NGL.
[5] Included with DRY GAS reserves.

COMMENTS
- Major gas sales to commence in late 1988 from the new Steelhead platform.

MIDDLE GROUND SHOAL

LOCATION Cook Inlet, offshore, east side
BEGAN PRODUCTION 9/67
OPERATOR AMOCO, Shell

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	222,000	98,000	38,000
CUMULATIVE PRODUCTION [2]	155,761,000	77,915,000	2,638,000
RESERVES [2]	8,000,000	5,000,000	[3]
PERCENT OF FIELD DEPLETED [2]	95%	94%	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Included with Casinghead reserves.

MILNE POINT

LOCATION: North Slope, onshore
BEGAN PRODUCTION: Production commenced in 1985.
OPERATOR: Conoco

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	---
CUMULATIVE PRODUCTION [2]	5,453,000	1,915	---
RESERVES [2]	60,000,000	---	---
PERCENT OF FIELD DEPLETED [2]	8%	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

COMMENTS
- Production temporarily suspended in 1987 and 1988.
- Estimated effective royalty rate: 18%

NICOLAI CREEK

LOCATION: Cook Inlet, onshore-offshore, west side
BEGAN PRODUCTION: 10/68, now shut-in
OPERATOR: Texaco
PURCHASER: AMOCO

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	---
CUMULATIVE PRODUCTION [2]	---	---	1,062,055
RESERVES [2]	---	---	3,000,000
PERCENT OF FIELD DEPLETED [2]	---	---	26%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

COMMENTS
- Gas from this small field, when produced, was used only by platform and shore production facilities.

NORTH COOK INLET

LOCATION: Cook Inlet, offshore, mid-channel
BEGAN PRODUCTION: 3/69
OPERATOR: Phillips
PURCHASER: Phillips, Alaska Pipeline

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	3,521,000
CUMULATIVE PRODUCTION [2]	---	---	862,551,000
RESERVES [2]	---	---	730,000,000
PERCENT OF FIELD DEPLETED [2]	---	---	54%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

COMMENTS
- Gas from this field is primarily delivered to the Phillips LNG plant and subsequently sold in Japan.

NORTH FORK

LOCATION: Cook Inlet, onshore, east side
BEGAN PRODUCTION: Shut-in 1965
OPERATOR: Chevron

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	---
CUMULATIVE PRODUCTION [2]	---	---	104,595
RESERVES [2]	---	---	12,000,000
PERCENT OF FIELD DEPLETED [2]	---	---	<1%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

POINT THOMSON UNIT AND FLAXMAN ISLAND

LOCATION: North Slope, onshore/offshore
BEGAN PRODUCTION: Shut-in
OPERATOR: EXXON

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	---
CUMULATIVE PRODUCTION [2]	---	---	---
RESERVES [2]	[3]	[3]	---
PERCENT OF FIELD DEPLETED [2]	---	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Oil and gas condensate.

COMMENTS
- Unit Area expansion approved in 1984. Market analysis underway to determine development potential of gas condensate and gas liquids from the unit.

PRETTY CREEK UNIT AREA

LOCATION Cook Inlet, onshore, west side
BEGAN PRODUCTION 1986
OPERATOR Union

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	87,000
CUMULATIVE PRODUCTION [2]	---	---	1,884,000
RESERVES [2]	---	---	[3]
PERCENT OF FIELD DEPLETED [2]	---	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Ivan River, Lewis River, Pretty Creek and Stump Lake reserves are combined under Lewis River reserves.

PRUDHOE BAY - SADLEROCHIT RESERVOIR

LOCATION North Slope, onshore
BEGAN PRODUCTION 10/69
OPERATOR ARCO, Sohio
PURCHASER Mapco-GVEA
Tesoro
Chevron

	OIL (Bbl)	CsngHd GAS -Gross (Mcf)	CsngHd GAS -Net (Mcf)
MONTHLY PRODUCTION [1]	48,171,000 [3]	113,557,000	13,117,000
CUMULATIVE PRODUCTION [2]	6,084,935,000 [4]	9,014,628,000	847,281,000
RESERVES [2]	4,700,000,000	---	26,000,000,000
PERCENT OF FIELD DEPLETED [2]	59%	---	3%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Includes 1,568,000 BPM GL.
[4] Includes 35,529,000 Bbl GL.

STERLING

LOCATION Cook Inlet, onshore, east side
BEGAN PRODUCTION 5/62; currently shut in.
OPERATOR Union
PURCHASER Sport Lake Greenhouse

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	---
CUMULATIVE PRODUCTION [2]	---	---	2,088,000
RESERVES [2]	---	---	23,000,000
PERCENT OF FIELD DEPLETED [2]	---	---	8%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

COMMENTS
-Since Federal and Cook Inlet Region Inc. leases are included, the state's royalty share is approximately 1.6%.

STUMP LAKE UNIT AREA

LOCATION Cook Inlet, onshore, west side
BEGAN PRODUCTION Suspended
OPERATOR Chevron

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	---
CUMULATIVE PRODUCTION [2]	---	---	---
RESERVES [2]	---	---	[3]
PERCENT OF FIELD DEPLETED [2]	---	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[1] Ivan River, Lewis River, Pretty Creek and Stump Lake reserves are combined under Lewis River reserves.

TRADING BAY

LOCATION Cook Inlet, offshore, west side
BEGAN PRODUCTION 12/67
OPERATOR Union
PURCHASER Tesoro

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	74,000 [3]	89,000	19,000
CUMULATIVE PRODUCTION [2]	90,315,000 [3]	61,933,000	3,439,000
RESERVES [2]	1,000,000	30,000,000	[4]
PERCENT OF FIELD DEPLETED [2]	99%	68%	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.
[3] Includes 360,000 BPM NGL.
[4] Included under Casinghead reserves.

WEST FORK

LOCATION Cook Inlet, onshore, east side

BEGAN PRODUCTION Shut-in gas field.

OPERATOR

	OIL (Bbl)	CsngHd GAS (Mcf)	DRY GAS (Mcf)
MONTHLY PRODUCTION [1]	---	---	0
CUMULATIVE PRODUCTION [2]	---	---	1,542,000
RESERVES [2]	---	---	6,000,000
PERCENT OF FIELD DEPLETED [2]	---	---	20%

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

WEST SAK RESERVOIR

LOCATION North Slope, onshore

BEGAN PRODUCTION

OPERATOR ARCO, Conoco

	OIL (Bbl)	GAS (Mcf) Casinghead	GAS (Mcf) Dry Gas
MONTHLY PRODUCTION [1]	---	---	---
CUMULATIVE PRODUCTION [2]	3,365	4,980	---
RESERVES [2]	---	---	---
PERCENT OF FIELD DEPLETED [2]	---	---	---

[1] 1/1/88 thru 7/31/88.
[2] Estimated as of 1/1/89.

COMMENTS

- Reservoir delineation and engineering/geological studies continuing. Covers areas in the Kuparuk River, Prudhoe Bay and Milne Point Units.

A;12/20/88

APPENDIX B
CRUDE OIL ANALYSES

NORTH SLOPE [1]:	SADLEROCHIT	KUPARUK	WEST SAK[2]
CRUDE			
Gravity, °API	26.4	23	22.4
Kin.Vis. @ 60 °F	42.42	cSt 79.98	95.92
Sulfur wt%	1.06	1.76	1.82
Nitrogen, ppm	2090	1980	--
Carbon residue wt%	4.4	7.37	7.62
H2S, lb/1,000 bbl	0.35	<5	--
Salt, lb/1,000 bbl	32.7	--	--
Ni/V, ppm	11/26	19/57	22/61
RVP, psi	3.55	2.6	2.7
Pour Pt, °F	0	-55	-50
Neut. no. (D974)	1.12	--	0.68
C4 AND LIGHTER			
Yield, vol%	1.17	--	0.63
C5 AND LIGHTER			
Yield, vol%	--	2.12	--
C5 - 150 °F			
Yield, vol%	2.2	1.6	1.9
Sulfur, wt%	<0.001	0.006	0.004
RON clear	71.5	--	--
MON clear	69.8	--	--
RON + 0.5g TEL/gal.	78.4	--	--
150 - 380 °F			
Yield, vol%	15.6	14.5	14.4
Sulfur, wt%	0.013	0.018	0.018
Paraffins, vol%	39.7	38.3	36.4
Napthenes, vol%	43.3	47	48.2
Aromatics, vol%	17.0	14.7	15.4
380 - 650 °F			
Yield, vol%	28.6	26.9	27.5
Gravity, API	33.1	--	31.6
Sulfur, wt%	0.414	0.66	0.700
Pour Pt, °F	-25	-25	-35
Cetane No.	45.8	45.4	42.1
N2, total, ppm	79	--	--
Vis. cSt @ 100 °F	--	3.083	3.34
Aromatics, vol%	33.6	30.0	31.4
650 - 840 °F			
Yield, vol%	16.4	18.9	16.6
Gravity, API	23.8	20.5	21.1
Sulfur, wt%	1.10	1.79	1.81
Aniline Pt, °C	74.7	104.3	--
Pour Pt, °F	70	50	60
Kin.Vis. @ 100 °F	--	34.2	43.99
Carbon Residue, %	0.012	wt% 0.01	--
Total Nitrogen, ppm	950	600	840
Basic Nitrogen	0.03	wt% 0.02	0.023
V/Ni, ppm	--	<1	--
650 + RESIDUAL			
Yield, vol%	52.4	56	55.6
Gravity, API	15	11.7	10.8
Sulfur, wt%	1.63	2.59	2.53
Carbon Residue, %	8.82	wt% 12.61	wt% 13.15
Total Nitrogen, ppm	3600	--	--
Pour Pt, °F	80	40	45
Kin.Vis. @ 210 °F	47.54	97.15	135.3
Kin.Vis. @ 275 °F	15.55	--	--
Pentane insoluble, wt%	--	--	14.97

[1] Aalund, L.R., "Guide to Export Crudes for the '80s," Oil and Gas Journal, Dec.19,1983.

[2] Crude not in production, but pilot program is underway in Kuparuk area to determine feasibility. Assay sample obtained during drill stem test and may not be representative of the entire accumulation.

COOK INLET:	DRIFT RIVER	NIKISKI
CRUDE		
Gravity, °API @ 60 °F	35.3	34.6
Spec.Grav. @ 60 °F	0.8483	0.8519
Kin.Vis. @ 65 °F	6.94	7.34
@ 90 °F	6.77	7.17
@122 °F	3.39	3.55
Sulfur, wt%	0.09	0.10
Nitrogen wt%	0.13	0.14
Carbon wt%	86.83	87.09
Hydrogen wt%	12.81	12.80
Oxygen wt%	0.09	0.15
Sed. and water, vol%	0.05	0.1
Water, by dist., vol%	Nil	0.05
RVP, psi	7.5	7.85
Pour Pt, °F	0	-5
Flash Pt., PMCC, °F	<0	<0
BADGER DISTILATION		
C5 AND LIGHTER		
Yield, vol%	0.4	0.7
Composition		
Methane	0.02	Traces
Ethane	11.07	7.75
Propane	61.74	59.81
Iso-Butane	11.72	12.46
Normal Butane	13.00	16.83
Iso-Pentane	1.52	2.03
Normal Pentane	0.93	1.12
IBP - 120 °F		
Yield vol%	1.3	2.0
Gravity, API @ 60 °F	X	X
120 - 374 °F		
Yield vol%	31.4	29.5
Gravity, API @ 60 °F	59.3	57.2
374 - 440 °F		
Yield vol%	6.0	6.5
Gravity, API @ 60 °F	40.9	40.6
440 - 610 °F		
Yield vol%	17.6	15.7
Gravity, API @ 60 °F	35.3	35.5
610 + Resid		
Yield vol%	41.3	43.9
Gravity, API @ 60 °F	18.1	18.2
DISTILATION CURVE, VOL, %		
IBP	86	84
2%	131	120
4%	134	130
6%	140	145
8%	150	165
10%	163	195
12%	192	213
14%	211	219
16%	220	239
18%	240	254
20%	257	272
22%	273	292
24%	292	307
26%	309	324
28%	325	341
30%	340	361
32%	361	390
34%	395	420
36%	420	430
38%	430	440
40%	440	460
42%	455	475
44%	475	490
46%	495	510
48%	510	525
50%	525	540
52%	545	555
54%	601	X
56%	607	X

APPENDIX C
DEFINITIONS OF STATUTORY TERMS

AS 38.05.183 states that oil and gas taken in-kind as the state's royalty share of production may not be sold or otherwise disposed of for export from the state until the Commissioner of Natural Resources determines that the royalty-in-kind oil or gas is surplus to the present and projected intrastate domestic and industrial needs for oil and gas.

The statute contains several key terms whose meaning must be resolved before an estimate can be made of oil and gas surplus to the state's needs. These key terms are: 1) "oil and gas," 2) "export," 3) "present," 4) "projected," 5) "domestic," 6) "industrial," 7) "intrastate," and 8) "how these needs are to be met." Each key term affects the size of the estimated demand for oil and gas in Alaska and consequently, the size of the projected surplus or deficit. The meaning of each term is discussed below.

"OIL AND GAS"

Crude oil and natural gas are fluids containing hydrocarbon compounds produced from naturally occurring petroleum deposits. Typical crude oil contains several hundred chemical compounds. The lightest of these are gases at normal temperatures and pressure, described as "natural gas." These light fractions of the crude oil stream include both hydrocarbon and non-hydrocarbon gases, such as water, carbon dioxide, hydrogen sulfide, helium, or nitrogen. The principal hydrocarbons are methane (CH_4), ethane (C_2H_6), propane (C_3H_8), butanes (C_4H_{10}), and pentanes (C_5H_{12}). The gaseous component found most often and in largest volumes is, typically, methane. Heavier fractions of the crude stream are usually liquids. If a given hydrocarbon fraction is gaseous at reservoir temperatures and pressures, but is recoverable by condensation (cooling and pressure reduction), absorption, or other means, it is classified by the American Gas Association (AGA) as a natural gas liquid (NGL)[2]. Natural gas liquids include ethane if ethane is recovered from the gas stream as a liquid. A related term is liquefied petroleum gas (LPG), composed of hydrocarbons which liquefy under moderate pressure under normal temperatures. LPG usually refers to propane and butane. A second related term is condensate, which refers to LPG plus heavier NGL component (natural gasoline). The lightest hydrocarbon fraction is methane, which is almost never recovered as a liquid, and which makes up the bulk of pipeline gas. If a natural gas stream contains few hydrocarbons which are commercially recoverable as liquids, it is considered "dry gas" or "lean gas." The distinction between "wet" and "dry" is usually a legal one, which varies from state to state. "Crude oil" usually means the non-gaseous portion of the crude oil stream.

Natural gas may occur in reservoirs which are predominately gas-bearing or in reservoirs in which the gas is in contact with petroleum liquids. Non-associated gas is natural gas from a reservoir where the gas is neither in contact with nor dissolved in crude oil. Associated gas occurs in contact with crude oil, but is not dissolved in it. A gas cap on a crude oil reservoir is a typical example of associated gas. Dissolved gas is dissolved in petroleum liquids and is produced along with them. Dissolved and asssociated gases are usually good sources of NGL while non-associated gases are often "dry."

The distinction between natural gas and its NGL components is important to a study of the supply and demand of royalty oil and gas because natural gas liquids have a multitude of uses when separated from the gas stream. For example, propane is both produced in Alaska and sold in Alaska as bottled gas for residential, commercial, and limited transportation uses, while butane is used for blending in gasoline and military jet fuel and as a refinery fuel. In addition, Marathon Oil uses LPG to enrich crude oil at its Trading Bay facility. It ships the combined fluids to the Drift River terminal for export[3]. Potential uses for NGL also include the enriching ("spiking") of pipeline gas and crop drying. Several years ago the Dow-Shell Petrochemical Group and Exxon studied the feasibility of utilizing the NGL contained in Prudhoe Bay natural gas as the basis for an Alaska petrochemicals industry. Since the state has the option of considering NGL separate-

2 Definitions vary with process.

3 Kramer, L., Williams, B., Erickson, G., In-State Use Study for Propane and Butane. Prepared for the Department of Natural Resources by Kramer Associates, Juneau, October 1981.

ly from the gas stream, two definitions of natural gas consumption and reserves are possible. One of these would consider natural gas liquids as part of the gas stream. The second definition would treat the markets for LPG and ethane separately from those for gas. This requires a separate estimate of LPG consumption and gas liquids reserves. In this report, demand for LPG and ethane is estimated separately from that for gas; however, no separate estimate is made of gas liquids reserves.

"EXPORT"

Taken in context, this term appears to mean the direct physical shipment of oil and gas out of the state. However, when one considers the fact that much of Alaska's industrial use of oil and gas is processed directly for export markets, the meaning of export versus "intrastate" is not so obvious. For example, it appears that processing of gas into another product, e.g., anhydrous ammonia, would probably be an "industrial" use rather than "export" of gas, even though the ammonia is mostly exported. Liquefication to change the phase of the gas is a less obvious case. The liquefication of natural gas is considered a transportation process in this report. Still more troublesome is the use of gas and oil for transportation related to export. Is the gas and oil consumed in TAPS pipeline pump stations, for example, an "industrial" use in state? Or is it really "export" of that energy, since it is consumed in the exporting process? There is no reason why the state may not be approached in the future to commit royalty oil and gas to quasi-export uses. Indeed, ALPETCO (later, Alaska Oil Company) made a top dollar offer for royalty oil ultimately destined (as petrochemical products) for out-of-state markets. Though they made the offer, they did not make payments in full. Also, the state once committed royalty gas to the El Paso gas pipeline proposal for export of Prudhoe Bay gas, which involved liquefication. Neither proposal was clearly for in-state industrial use. In this report, industrial demand is treated with multiple definitions as outlined later in the chapter to show how different definitions of "export" affect the estimate of total consumption in Alaska.

"PRESENT"

The problem here is that the term "present" may mean "latest year" consumption, "average recent year" consumption, "weather-adjusted" consumption, or "worst case" consumption. In the residential and commercial sector particularly, each definition gives a somewhat different answer because of the variability of weather.

The "worst case" consumption calculation can result in considerably higher gas consumption than the most recent year, if the most recent year happens to have been a relatively warm one. While it is not correct forecasting procedure to make long run forecasts of intrastate residential consumption of natural gas which assume worst case forecasts for every year, it may be prudent in practice to reserve part of the the State's gas and oil supply for bad weather. For forecasting, variability of weather makes the picking of a starting value for consumption somewhat tricky. In this report, Rail Belt consumption is based on average weather years. For the remainder of the state, trended per capita consumption is used, which approximates average weather conditions.

"PROJECTED"

This is a very difficult concept, since many different projections of consumption would be possible even if it were possible to agree on a single concept defining consumption. Rates of economic development, population growth, and relative energy prices are key features of any consumption forecast, but assumptions concerning any of these variables are necessarily controversial. This report describes a range of possible consumption figures under precisely articulated definitions of consumption and varying paces of economic, population, and fuel price growth.

"DOMESTIC"

Domestic consumption appears to mean Alaska residential consumption. As we saw above under the subheading "present", it is not at all obvious which definition of domestic consumption is the most appropriate, even when the identity of the customer is not in dispute. Some multifamily residential use may be described as "commercial", obscuring the definition of the customer and causing forecasting problems for natural gas. The definition of "domestic" considered in this report includes multifamily residential in "residential" or "domestic" use.

"INDUSTRIAL"

As described above, "industrial" energy use has a number of potential definitions. Since one intent of giving in-state industrial needs priority over export uses of royalty oil and gas seems to be encourage in-state economic activity,[4] a day-to-day working definition of this industrial priority is

4 However, see the short discussion of legislative intent beginning on page 9 of Kramer, Williams and Erickson, op.cit. That study raises many of the issues regarding surplus gas and oil discussed in this report.

that the royalty reserves be committed to the market which has the largest potential economic impact in Alaska. For forecasting purposes, however, it is difficult to say which markets will prove to be of the most economic benefit to the state. As a compromise, we will adopt four alternative definitions of "industrial" in this study.

The four alternative definitions of industrial use of oil and gas used in this report are outlined below, beginning with the most restrictive and moving to the most liberal.

DEFINITION 1: Industrial use consists of any consumption of natural gas, petroleum, or their products in combustion (except that required to export oil or gas); or the chemical transformation of natural gas, petroleum, or their products into refined products for local markets. This definition explicitly excludes the exported products from refineries, as well as uses which merely change the physical form of the product (gas conditioning or liquefaction) for export, or which move the product to an export market (pipeline fuel, fuel used on lease, shrinkage, injection, vented and flared gas).

DEFINITION 2: Industrial use consists of ;any consumption of natural gas, petroleum, or their products in combustion (except in oil and gas production and transportation); or the chemical transformation of natural gas, petroleum, or their products into refined products. This definition counts feedstocks for petrochemical plants and refineries as industrial consumption. It also counts energy consumed by an LNG facility as industrial consumption. It excludes the feedstocks of LNG plants; and fuel consumption by conditioning plants, pump stations, fuel used on lease, shrinkage, injection and flared gas.

DEFINITION 3: Industrial use consists of any consumption of natural gas, crude oil, or their products in combustion (except in oil and gas transport and extraction) or their chemical transformation into refined products. This definition permits the feedstocks of refineries to be counted as industrial consumption. It excludes fuels used in pump stations, in conditioning plants, fuel used on lease, and gas shrinkage, injection, or venting.

DEFINITION 4: Industrial use consists of any use of natural gas, crude oil, or their products in combustion, or their transformation into chemically different products. This definition permits feedstocks of refineries to be counted as industrial consumption, as well as energy consumption in conditioning plants and pump stations. It excludes injected gas, which is ultimately recoverable for other uses, and LNG processing, which is considered an export. Definition 4 will be used for the purposes of this report.

None of the four definitions treats industrial use (including transportation) to include gas injected to enhance oil recovery, since in theory this gas remains part of the ultimately recoverable gas reserves of the state. Thus, it is not "consumed."

"INTRASTATE"

It is unclear what is meant by intrastate consumption. Some uses, such as combustion of oil and gas products in fixed capital facilities in Alaska, are reasonably easy to categorize as intrastate. There are several uses in transportation which are not obviously within Alaska. These categories include the fuel burned in marine vessels such as cargo vessels, ferries, and fishing boats, and fuel burned in international interstate air travel. There are multiple ways to approach the definition of this consumption. The first is a sales definition: the fuel used in transportation which is sold in Alaska. The second approach is to base consumption on fuel used in Alaska or related to Alaska's economy and population, regardless of the point of sale. This results in three logical definitions, described below:

DEFINITION 1: Intrastate consumption in transportation includes all sales of fuels to motor vehicles, airplanes, and vessels in Alaska, including bonded fuels. It excludes fuel consumed by motor vessels which was purchased in other states, and fuel consumed by airlines between Alaska locations unless the fuel was sold in Alaska. It also excludes out of state military fuel purchases.

DEFINITION 2: Intrastate consumption includes fuel consumed by motor vessels, airlines, and vehicles engaged in Alaskan economic activity. It includes use of fuel by American fishing boats in Alaskan waters regardless of where the fuel was purchased, use of fuel purchased in Washington State by Alaska State ferries, and fuel consumed by ships and aircraft involved in Alaska trade. It excludes sales to aircraft on international flights (bonded and unbonded), but includes military out of state purchases.

DEFINITION 3: The final definition is a compromise between the first two. It includes all fuel purchased within the state, plus military uses, but excludes fuel purchased out of state except for military uses.

The basic definition in this report is the third definition. By excluding bonded and exempt jet fuel, the report also approximates Definition 2. Lack of data on out-state purchases by the military makes Definition 1 impractical.

"HOW THESE NEEDS ARE TO BE MET"

Any analysis of how the oil and gas needs of the intrastate domestic and industrial sector are to be met could include several sources of supply: state royalty oil and gas, in-state oil and gas reserves under other ownership, probable extensions of proven reserves, and imports of crude oil, petroleum products, and (in theory) natural gas.

APPENDIX D
ALASKA REFINERIES AND TRANSPORTATION FACILITIES

SURVEY OF OPERATING REFINERIES IN THE U.S. [1]

STATE	No. Plants	---Crude Capacity---- b/cd	b/sd	Vacuum Distil.	Thermal Operations	---Cat Cracking--- Fresh Feed	Recycle	Cat Reforming	Cat Hydro-cracking	Cat Hydro-refining	Cat Hydro-treating	Alkyl-ation	Aromatic Isomer-ization	Lubes	Asphalt	Hydrogen (MMcf/d)	Coke (t/d)
				---Charge Capacity (b/sd)---								---Production Capacity (b/sd)---					
Alabama	2	124,500	128,900	34,000	10,000	---	---	27,000	---	13,000	43,500	---	6,000	---	10,500	8.0	400
Alaska *	6	225,000	239,093	6,000	---	---	---	12,000	9,000	---	12,000	---	6,500	---	8,000	12.8	---
Arizona	1	5,700	6,000	2,000	---	---	---	---	---	---	---	---	---	---	1,160	---	---
Arkansas	3	58,570	61,000	30,500	---	18,500	775	9,000	---	---	20,000	4,800	---	4,000	9,700	2.8	---
California	30	2,317,793	2,426,939	1,291,265	492,800	628,000	34,600	533,300	378,000	433,000	900,780	109,000	17,900	30,200	76,854	908.4	19,622
Colorado	2	76,500	80,000	23,000	---	23,500	1,000	17,500	---	---	27,500	---	---	---	4,000	---	---
Delaware	1	140,000	150,000	95,000	46,000	65,000	5,000	56,000	19,000	---	110,000	8,000	3,370	---	---	40.0	2,180
Georga	2	34,500	37,500	---	---	---	---	---	---	---	---	---	---	---	26,500	---	---
Hawaii	2	116,000	120,500	68,000	13,000	22,000	---	12,000	16,000	---	3,500	7,000	1,500	---	1,300	2.5	---
Illinois	6	920,600	977,000	358,500	103,400	339,000	40,600	294,300	66,000	35,000	531,300	83,000	18,800	4,600	36,600	64.3	6,175
Indiana	4	424,600	438,500	232,200	27,500	167,000	12,100	99,000	---	80,000	153,300	33,900	35,500	6,400	45,500	---	1,550
Kansas	7	352,600	371,183	119,650	52,000	125,000	15,450	89,600	3,190	44,000	133,000	36,200	37,469	2,500	5,200	---	2,070
Kentucky	2	218,900	226,300	90,000	57,600	100,000	---	53,500	---	40,000	147,300	12,000	17,400	7,900	30,000	20.0	---
Louisiana	17	2,273,015	2,374,300	906,300	408,500	824,000	22,800	499,300	149,000	286,000	893,600	174,500	71,800	37,000	55,500	162.6	14,275
Michigan	4	120,100	127,094	30,000	---	45,000	1,300	31,500	---	14,000	44,800	4,000	6,000	---	10,000	---	---
Minnesota	2	222,143	229,220	132,000	54,000	78,000	1,000	49,500	---	86,500	127,000	17,700	23,300	---	49,000	20.0	2,800
Mississippi	5	358,600	379,404	285,600	70,000	74,000	7,400	95,800	68,000	189,000	59,800	19,700	5,500	2,000	40,600	215.0	3,450
Montana	4	137,200	143,000	55,250	7,700	50,600	7,700	35,500	4,900	14,000	100,200	11,400	5,400	---	23,500	19.3	435
Nevada	1	4,500	4,700	2,500	---	---	---	---	---	---	---	---	---	---	---	---	---
New Jersey	6	435,000	456,368	251,900	21,500	256,000	37,000	77,500	---	65,000	216,800	23,000	28,400	8,500	73,000	11.0	1,010
New Mexico	3	72,800	77,107	6,000	---	27,200	3,400	16,600	---	---	28,300	3,600	4,000	---	3,400	---	---
North Dakota	1	58,000	60,000	---	---	26,000	5,200	12,100	---	---	16,600	3,400	4,000	---	---	---	---
Ohio	4	482,650	508,000	255,000	29,900	176,000	16,500	156,000	86,000	23,000	157,000	26,100	64,900	2,100	19,000	72.0	1,250
Oklahoma	6	387,000	403,815	131,500	20,500	134,500	11,840	90,000	5,000	---	139,000	35,400	28,700	9,500	12,300	10.0	1,040
Oregon	1	15,000	15,789	16,000	---	---	---	---	---	---	---	---	---	---	11,500	---	---
Pennsylvania	8	727,200	771,000	319,180	---	259,300	8,300	208,820	51,000	50,000	434,050	44,000	20,250	21,310	33,000	43.5	---
Tennessee	1	57,000	60,000	12,000	---	30,000	---	10,000	---	---	31,000	3,000	4,000	---	3,500	---	---
Texas	31	4,090,800	4,339,600	1,850,100	362,000	1,608,500	174,750	1,129,400	257,500	825,000	2,192,550	286,000	297,365	93,500	78,400	623.0	21,669
Utah	6	154,500	160,768	45,550	8,500	55,800	9,600	29,100	---	7,100	32,100	12,800	6,350	---	1,700	---	350
Virginia	1	51,000	53,000	29,000	13,500	27,500	2,000	9,500	---	---	25,000	---	---	---	---	---	825
Washington	7	458,175	477,043	220,000	68,000	100,000	19,500	119,800	52,000	25,500	165,500	23,400	2,750	---	16,600	80.0	3,280
West Virginia	1	10,500	10,800	8,850	---	---	---	3,400	4,500	---	3,900	---	---	4,440	---	1.2	---
Wisconsin	1	32,000	34,000	20,500	---	9,700	1,000	8,000	---	---	15,000	1,200	2,000	---	13,500	---	---
Wyoming	6	165,300	170,689	62,600	7,000	63,000	7,200	32,350	---	14,350	49,050	10,100	1,200	1,500	11,000	---	380
Total		15,327,746	16,118,612	6,989,945	1,873,400	5,333,100	446,015	3,817,370	1,169,090	2,244,450	6,813,430	993,200	720,354	235,450	710,814	2,316.4	82,761

* ALASKA

	b/cd	b/sd	Vacuum Distil.	Thermal Operations	Fresh Feed	Recycle	Cat Reforming	Cat Hydro-cracking	Cat Hydro-refining	Cat Hydro-treating	Alkyl-ation	Aromatic Isomer-ization	Lubes	Asphalt	Hydrogen (MMcf/d)	Coke (t/d)
ARCO, Kuparuk	12,000	12,000	---	---	---	---	---	---	---	---	---	---	---	---	---	---
ARCO, Prudhoe Bay	22,000	22,000	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Chevron, Kenai	22,000	NR	---	---	---	---	---	---	---	---	---	---	---	6,000	---	---
Mapco, North Pole	90,000	NR	6,000	---	---	---	---	---	---	---	---	2,500	---	2,000	---	---
Petro Star,North Pole	7,000	7,200	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Tesoro, Kenai	72,000	80,000	---	---	---	---	12,000	9,000	---	12,000	---	4,000	---	---	12.8	---
Total	225,000	239,093	6,000	---	---	---	12,000	9,000	---	12,000	---	6,500	---	8,000	12.8	---

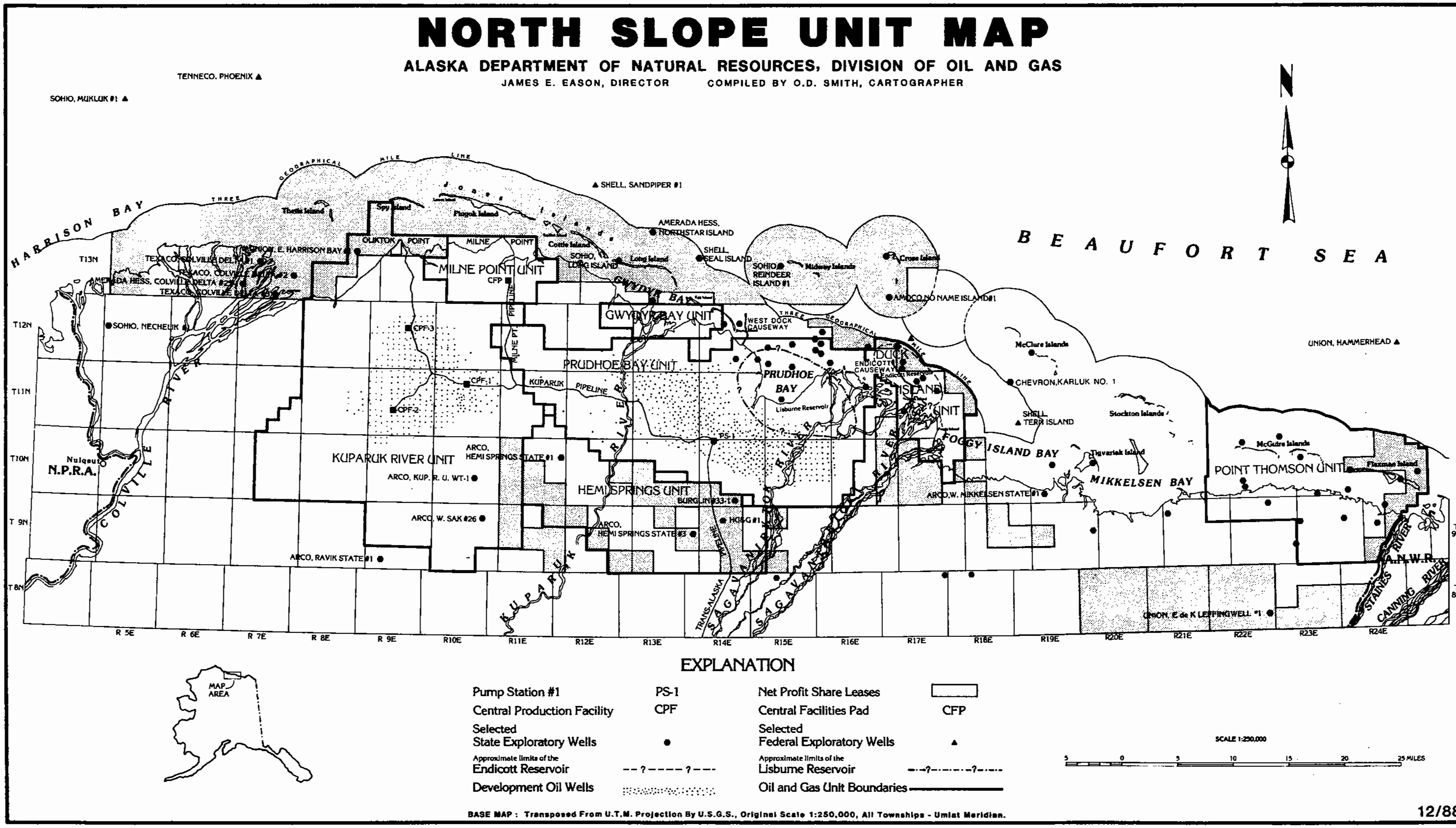
[1] "Annual Refining Survey," Oil & Gas Journal, p. 52, v. 86, no. 12, March 21, 1988.
D2;12/29/88

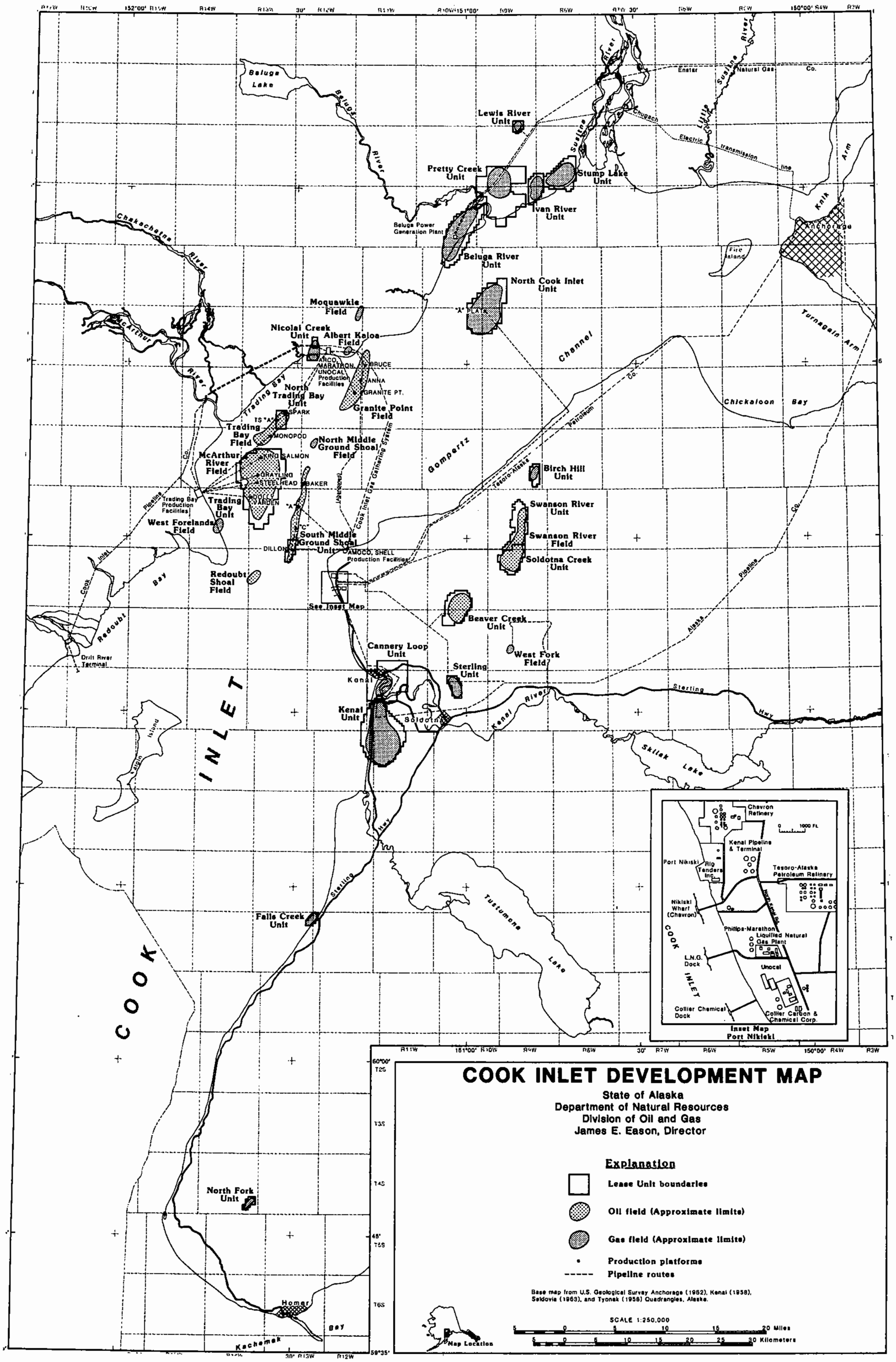
PETROLEUM AND GAS PROCESSING PLANTS

PLANT	UNIT	UNIT CAPACITY	PRODUCT	PRODUCT DESTINATION
Chevron Refinery	Crude	25,000 Bbl/d	Gasoline, unfinished	lower 48
Nikiski, 1963			JP 4	Alaska
			Jet A	Alaska
			Furnice Oil	Alaska
			Diesels	Alaska
			Fuel Oil	lower 48
			Asphalt	Alaska
Mapco Refinery	Crude	90,000 Bbl/d	Gasolene, leaded	Fairbanks area, Nenana River villages,
North Pole, 1977			Gasoline, unleaded	Eilson AFB, Delta Junction, Tok,
			JP 4	Glenallen and Anchorage area
			Jet A	
			Diesel, #1	
			Diesel, #2	
			Diesel, #4	
			Asphalt	
Tesoro Refinery	Crude	80,000 Bbl/d	Propane	Alaska
Nikiski, 1969	Hydrocracker	9,000 Bbl/d	Gasoline, unleaded	Alaska
	PowerFormer	12,000 Bbl/d	Gasoline, regular	Alaska
	PRIP	4,000 Bbl/d	Gasoline, premium	Alaska
	LPG	2,800 Bbl/d	JP 4	Alaska
	Hydrogen	12,800 Mcf/d	Jet A	Alaska
	Sulfur	15 T/d	Diesel, #2	Alaska
			Fuel Oil, #6	lower 48
			Sulfur	lower 48
Petro Star Refinery	Crude	7,000 Bbl/d	Kerosine	80% to Fairbanks area,
North Pole, 1985			Diesel, #2	rest to Fairbanks region
Phillips-Marathon				
LNG Plant				
Nikiski, 1969	LNG	230,000 Mcf/d	LNG	Japan: 440,000 Bbl/10 days
Unocal Chemical	Ammonia	1,300,000 T/yr	Anhydrous Ammonia	West Coast and export
Nikiski, 1969	Urea	1,300,000 T/yr	Urea prills, granules	

D1;12/1/88

APPENDIX E
OIL AND GAS FIELD MAPS


NORTH SLOPE UNIT MAP
ALASKA DEPARTMENT OF NATURAL RESOURCES, DIVISION OF OIL AND GAS
JAMES E. EASON, DIRECTOR
COMPILED BY O.D. SMITH, CARTOGRAPHER
BEAUFORT SEA
HARRISON BAY
GWYDYR BAY
PRUDHOE BAY
FOGGY ISLAND BAY
MIKKELSEN BAY
MILNE POINT UNIT
GWYDYR BAY UNIT
PRUDHOE BAY UNIT
DUCK ISLAND UNIT
KUPARUK RIVER UNIT
HEMI SPRINGS UNIT
POINT THOMSON UNIT
N.P.R.A.
A.N.W.R.
COLVILLE RIVER
KUPARUK RIVER
SAGAVANIRKTOK RIVER
CANNING RIVER
STAINES RIVER
TRANS-ALASKA PIPELINE
KUPARUK PIPELINE
MILNE PT. PIPELINE
WEST DOCK CAUSEWAY
ENDICOTT CAUSEWAY
THREE GEOGRAPHICAL MILE LINE
SOHIO, MUKLUK #1
TENNECO, PHOENIX
SHELL, SANDPIPER #1
AMERADA HESS, NORTHSTAR ISLAND
SHELL, SEAL ISLAND
SOHIO, REINDEER ISLAND #1
AMOCO NO NAME ISLAND #1
CHEVRON, KARLUK NO. 1
SHELL, TERN ISLAND
UNION, HAMMERHEAD
UNION, E de K LEFFINGWELL #1
ARCO, W. MIKKELSEN STATE #1
ARCO, HEMI SPRINGS STATE #1
ARCO, HEMI SPRINGS STATE #3
ARCO, KUP. R. U. WT-1
ARCO, W. SAK #26
ARCO, RAVIK STATE #1
BURGLIN #33-1
HOGG #1
SOHIO, NECHELIK #1
SOHIO, LONG ISLAND
UNION, E. HARRISON BAY
OLIKTOK POINT
MILNE POINT
CPF-1
CPF-2
CPF-3
CFP
PS-1
Lisburne Reservoir
Nuiqsut
R 5E
R 6E
R 7E
R 8E
R 9E
R10E
R11E
R12E
R13E
R14E
R15E
R16E
R17E
R18E
R19E
R20E
R21E
R22E
R23E
R24E
T13N
T12N
T11N
T10N
T 9N
T8N
MAP AREA
EXPLANATION
Pump Station #1 PS-1
Central Production Facility CPF
Selected State Exploratory Wells
Approximate limits of the Endicott Reservoir
Development Oil Wells
Net Profit Share Leases
Central Facilities Pad CFP
Selected Federal Exploratory Wells
Approximate limits of the Lisburne Reservoir
Oil and Gas Unit Boundaries
SCALE 1:250,000
5 0 5 10 15 20 25 MILES
BASE MAP: Transposed From U.T.M. Projection By U.S.G.S., Original Scale 1:250,000, All Townships - Umiat Meridian.
12/88


COOK INLET DEVELOPMENT MAP
State of Alaska
Department of Natural Resources
Division of Oil and Gas
James E. Eason, Director
Explanation
Lease Unit boundaries
Oil field (Approximate limits)
Gas field (Approximate limits)
Production platforms
Pipeline routes
Base map from U.S. Geological Survey Anchorage (1962), Kenai (1958), Seldovia (1963), and Tyonek (1958) Quadrangles, Alaska.
SCALE 1:250,000
Map Location
Beluga Lake
Beluga River
Lewis River Unit
Pretty Creek Unit
Stump Lake Unit
Ivan River Unit
Beluga Power Generation Plant
Beluga River Unit
North Cook Inlet Unit
Moquawkie Field
Nicolai Creek Unit
Albert Kaloa Field
North Trading Bay Unit
Granite Point Field
Trading Bay Field
North Middle Ground Shoal Field
McArthur River Field
Trading Bay Unit
West Forelands Field
South Middle Ground Shoal Unit
Redoubt Shoal Field
See Inset Map
Birch Hill Unit
Swanson River Unit
Swanson River Field
Soldotna Creek Unit
Beaver Creek Unit
West Fork Field
Cannery Loop Unit
Sterling Unit
Kenai Unit
Kenai
Soldotna
Falls Creek Unit
North Fork Unit
Homer
Kachemak Bay
Chakachatna River
McArthur River
Trading Bay
Redoubt Bay
Drift River Terminal
Kalgin Island
COOK INLET
Gompertz Channel
Chickaloon Bay
Turnagain Arm
Knik Arm
Anchorage
Fire Island
Susitna River
Little Susitna River
Enstar Natural Gas Co.
Chugach Electric transmission line
Tesoro-Alaska Petroleum Co.
Alaska Pipeline Co.
Kenai River
Sterling Hwy
Skilak Lake
Tustumena Lake
Inset Map Port Nikiski
Chevron Refinery
Kenai Pipeline & Terminal
Port Nikiski
Rig Tenders Inc.
Tesoro-Alaska Petroleum Refinery
Nikiski Wharf (Chevron)
Phillips-Marathon Liquified Natural Gas Plant
L.N.G. Dock
Unocal
Collier Chemical Dock
Collier Carbon & Chemical Corp.

APPENDIX F
ACKNOWLEDGEMENTS

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