APPENDIX A

STATUS OF NORTH SLOPE DEVELOPMENT AND PRODUCTION

A.1 Overview

This section includes an update of the status of the currently producing fields on the North Slope and a review of the status of the recent and planned developments that provide the basis for conclusions concerning the effects that major gas sales could have on oil recovery and provides a basis for evaluating the effects a viable gas-to-liquids technology could have on the future of the North Slope resources.

The known gas resource on the North Slope is currently being used very effectively for enhancing oil recovery in the Prudhoe Bay field and other fields. ARCO received approval from the Alaska Oil and Gas Conservation Commission in September 1995 to institute a miscible gas injection project in the Kuparuk River Unit, the second highest producing rate field in the U.S. (AOGCC, 1995b). ARCO proposes to use miscible injectant derived from the gas in the Prudhoe Bay Unit in this project. Hence, it is necessary to know the status and plans for oil recovery from the North Slope in any consideration of gas resource development and sales.

Recent decisions by British Petroleum (BP) and other companies to aggressively pursue development of satellite fields around the Prudhoe Bay Unit (PBU) infrastructure, the purchase by BP of the Milne Point Unit from Conoco, and announced plans to pursue development of Badami, are examples of potential that exists for North Slope development. The policy change by the State of Alaska to allow the commissioner of the Department of Natural Resources to change the royalty and severance tax on field on the North slope to encourage development is a sign that the State is willing to pursue a more aggressive approach to North Slope development.

A.2 Producing Fields

A.2.1 Prudhoe Bay Unit - Oil Production

The Prudhoe Bay field, the largest oil field in North America, is located adjacent to the Beaufort Sea coastline about 200 mi east of Point Barrow (see **Figures 2.1 and 2.2**).

The field was discovered in 1968 when oil and gas were tested in the Prudhoe Bay State No. 1. Hydrocarbons are present in three Permo-Triassic sand intervals, the Ivishak sandstone of the Sadlerochit Group, Sag River, and Shublik, with the Ivishak the most prolific. OOIP is about 23 billion BBL oil. OGIP is about 46 TCF. Of this volume, 30 TCF is in the gas cap and the remainder is in solution in the oil rim.

The Prudhoe Bay field was unitized in 1977 and the Permo-Triassic participating area (PBU) was placed on production in June 1977. Total liquids recovery (oil, condensate, and NGL) from PBU was 8.822 billion BBL oil through December 1994. Production has declined from a peak average rate of about 1,600 MBPD during 1987 to an average of 1,057 MBPD during December 1994 (see **Figure A.1**).

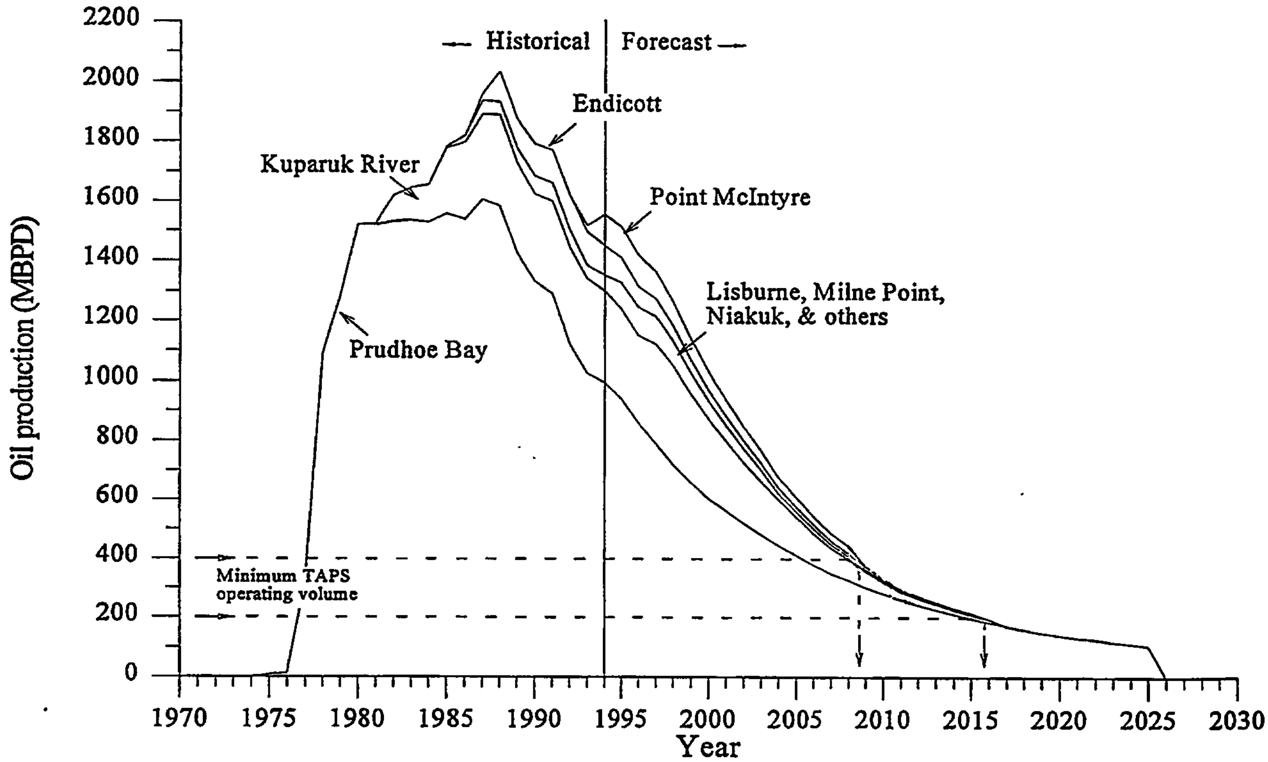

Figure A.1. The Alaska North Slope historical production and production forecast at the Energy Information Administration (EIA) Reference Oil Price (economically recoverable oil).

Total recovery estimates range from 12.2 to about 12.9 billion BBL oil, which is between 53% and 56% of OOIP, (ADNR, 1995c; AOGCC, 1992; DOE, 1993). The possibility of recovering over 13 billion BBL oil of crude oil in addition to condensate and NGL recoveries has been suggested (Platts, 1993). This higher recovery requires drilling of wells in addition to those included in current operating plans.

A.2.1.1 Development Plan. Current PBU development plans (ADNR, 1994j) are consistent with previous plans to enhance ultimate recovery through continuation of infill well drilling, well workovers and redrills, and expansion of the Prudhoe Bay miscible gas project (PBMGP) in the Sadlerochit and Sag River, and continued development in the Eileen West End area. These plans include:

- Continue drilling and redrill programs with six rigs.
- Expansion of PBMGP will potentially include about 110 additional miscible injection (MI) wells.
- In the Eileen area, waterflood (WF) and MI development may commence in 1996. Peripheral area development is planned for 1996. Expansion of WF/MI will be evaluated in 1998.

A.2.1.2 Input Data - No Major Gas Sales. Published information and field production history are the basis for most PBU input data. Recent reports to the ADNR and the Alaska Oil and Gas Conservation Commission (AOGCC) (AOGCC, 1991; ADNR, 1991; ADNR, 1992f; ADNR, 1993f; ADNR, 1994j; ADNR, 1994o) were also used in development of the forecasts of recoveries and costs used in this study.

A.2.1.2.1 Recoverable Oil--The ultimate recoverable reserves forecast in the previous DOE publication (1993) was about 12.9 billion BBL oil (oil, condensate, and NGLs). Public records (ADNR, 1995; AOGCC, 1992) list ultimate reserve volumes of from 12.2 billion BBL oil to 12.6 billion BBL oil. Any of these reserves volumes are reasonable. A recent suggestion (Platts, 1993) that reserves might exceed 13 billion BBL oil are not substantiated at present. The ultimate reserve volume from the previous DOE publication (1993) is revised to 13 billion BBL oil by addition of the anticipated sale of 100 MMBBLS of NGLs to the Kuparuk River Unit as reported in Petroleum Information Corporation (PIC, 1994a) (see **Appendix A.2.4.2.2**). It is assumed that this NGL volume is in addition to those volumes currently being utilized (i.e., fuel, sales, or MI production). The excess NGLs are blended with the gas being reinjected into the gas cap. Remaining reserves at 1/1/95 are about 4.2 billion BBL oil (oil, condensate, and NGLs) with cumulative recovery of about 8.8 billion BBL oil as of 1/1/95 (ADNR, 1995c).

A.2.1.2.2 Production Forecast--PBU production is continuing to decline but the rate of decline is not yet clearly established. The extensive efforts to increase recovery throughout the life of the PBU have been highly successful. However, future efforts are not expected to have significant mitigating effects on the decline rate.

The expansion of existing facilities; the expansion of the PBMGP; and the drilling, redrilling and workover of wells and their expected impact on production rate were considered in development of the production forecast needed to recover the estimated future recovery. The production average of 992 MBPD during the first quarter of 1995 was slightly lower than the yearly average of 1,026 MBPD for 1994. Production was curtailed in 1994 during the expansion of gas handling facilities. It is too early to determine the effect of this expansion on the production rate. Monthly production rates during 1993, 1994, and the first quarter of 1995 indicate production is continuing to decline. The production forecast is patterned after that in the previous DOE publication (1993). Modifications were made to reflect current production volumes and anticipated results of current unit plans. The volume of NGLs assumed to be sold to KRU (see **Appendix A.2.4.2.2**) are not included in the production forecast, but are treated as a separate outside sales in the evaluation. The production forecast prepared represents the estimated volumes being delivered to PS No. 1. The production forecast, with a productive life through 2025 is given in **Table A.1**.

Table A.1. PBU production forecast.

YEAR	MBPD	YEAR	MBPD	YEAR	MBPD
1995	940	2006	380	2017	172
1996	860	2007	350	2018	160
1997	790	2008	326	2019	150
1998	720	2009	302	2020	140
1999	660	2010	280	2021	132
2000	605	2011	260	2022	126
2001	563	2012	243	2023	117
2002	520	2013	227	2024	111
2003	482	2014	212	2025	105
2004	446	2015	198		
2005	412	2016	185		

A.2.1.2.3 Investments--Estimates of future investments are based on the most current unit plans (ADNR, 1994j; Platts, 1993). Review of the future investments in the previous DOE publication indicated that some adjustments were needed. The cost to drill wells is assumed to be unchanged at $2.2 million (1995$) and is used in the evaluation. The investment schedule is shown on **Table A.2.**

Table A.2. PBU drilling and investment schedule.

	Drilling	Investments (1995$, millions)		
Year	No. Wells	Wells	Facilities	Total
1995	50	110	535	645
1996	50	110	210	320
1997	50	110	210	320
1998	40	88	73	161
1999	30	66	96	162
2000	20	44	24	68
2001	10	22	0	22
2001	10	22	0	22
2003	10	22	0	22
2004	10	22	0	22
2005	10	22	0	22
Total	290	639	1,148	1,786

A.2.1.2.4 Operating Costs--Operating costs are estimated by using a cost per barrel of total fluid (BTF) produced. The water cut versus percent recovery data used in the previous DOE publication (1993) was revised after review of the recent PBU oil and water production data. The revised data are shown in **Table A.3** and in graphical form on **Figure A.2**. No public data were found concerning operating costs for PBU. The operating cost factor used in the previous DOE publication (1993) was $1.03/BTF in 1/1/92 dollars. That cost factor, $1.098/BTF in 1/1/95 dollars, is used in PBU evaluations.

A.2.1.2.5 TAPS Tariff--PBU oil sales will be subject to a TAPS tariff as listed in **Table B.3** of **Appendix B.1.1.1.2.**

A.2.1.2.6 Future Producers--The number of future active producing wells is required for annual severance tax calculations. The Set A equations listed in **Appendix C.1.1.6** are used to project the decline of future active producing wells for PBU.

Table A.3. PBU Percent Water Cut and Percent Recovery Data.

Recovery-%	Water Cut-%
0.0	0.0
4.4	0.0
10.7	0.9
16.7	2.6
28.6	7.5
42.8	20.0
52.6	33.5
60.0	44.0
70.0	59.0
80.0	70.0
90.0	79.0
102.0	80.0

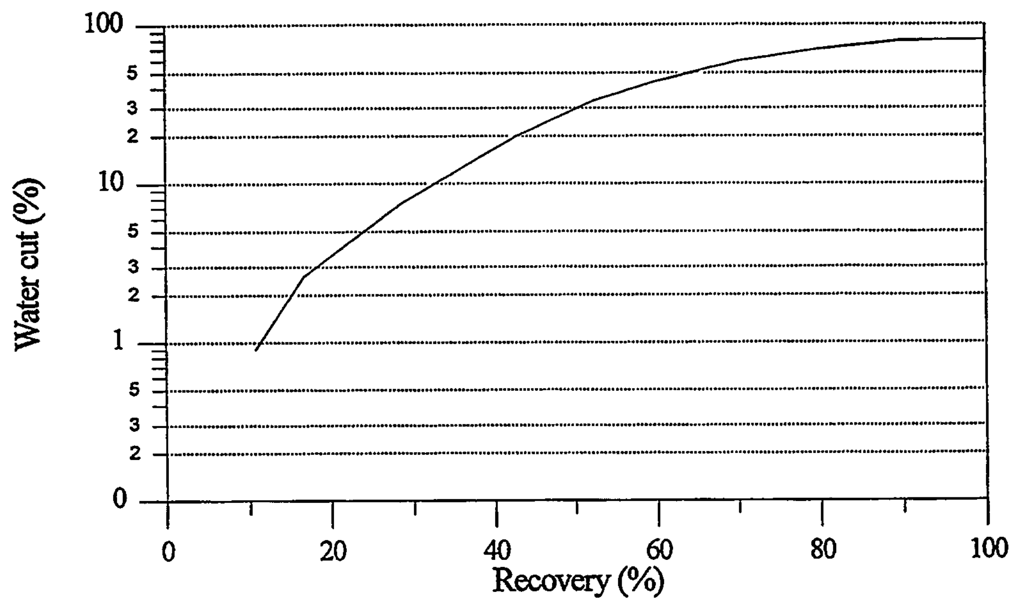

Figure A.2. PBU Permo-Triassic percent water cut versus percent recovery curve.

A.2.1.3 Summary. The PBU Permo-Triassic oil pool, the largest in the United States, has experienced declining production since a peak of about 1.6 MMBO per day during 1987. There are no development or production enhancement projects that can arrest the decline in production that had reached about 1.0 MMBO per day in December 1994. The oil pool is still expected to recover more than 50% of OOIP. The estimate of future recoverable liquids as of 1/1/95 is 4,200 MMBBLS (oil, condensate and NGLs) including the sale of NGLs to KRU.

A.2.2 Prudhoe Bay - With Gas Sales to an LNG Project.

Under major gas sales to an independently owned LNG system there are some changes in the operation of PBU. Oil recovery may be less than that discussed in **Appendix A.2.1** due to more rapid reservoir pressure decline; the loss in oil recovery is dependent on the start-up date of major gas sales.[a] The estimated loss in recovery ranges from 0.9 billion BBL oil with start of gas sales in 2000 to no loss with start-up in 2015. Currently, the earliest anticipated start-up date is 2005 with lost reserves being about 0.4 billion BBL oil. A start-up date of 2005 is used in the evaluation.

A.2.2.1 Input Data - Gas Sales to LNG Project. Based on the start-up of major gas sales in 2005, some of the PBU economic parameters discussed in **Appendix A.2.1** require modification, and a gas production forecast and gas pricing determination are needed. Economic parameters that are modified are listed below along with the sections where they are discussed for the no major gas sales scenario.

- Recoverable oil (**Appendix A.2.1.2.1**)
- Production forecast-oil (**Appendix A.2.1.2.2**)
- Operating costs (**Appendix A.2.1.2.4**)
- Investments (**Appendix A.2.1.2.3**)
- TAPS tariff (**Appendix B.1.1.1.2**)

A.2.2.1.1 Recoverable Oil--The assumed loss of 0.4 billion BBL oil of PBU oil recovery (oil, condensate, and NGLs) reduces future recovery from about 4.2 billion BBL oil (**Appendix A.2.1.2.1**) to about 3.8 billion BBL oil.

A.2.2.1.2 Oil Production Forecast--The loss of oil recovery as a result of major gas sales in 2005 is assumed to commence in 2007 at low volumes and increase over time. The revised production

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a. ARCO Alaska, Inc., personal communication, March 7, 1995.

schedule resulted in a shortening of the oil recovery period by 4 years. The revised PBU oil forecast is given in **Table A.4**.

Table A.4 PBU production forecast - with major gas sales.

Year	MBPD	Year	MBPD	Year	MBPD
1995	940	2004	446	2013	180
1996	860	2005	412	2014	163
1997	790	2006	380	2015	145
1998	720	2007	340	2016	128
1999	660	2008	308	2017	115
2000	605	2009	278	2018	102
2001	563	2010	250	2019	95
2002	520	2011	226	2020	85
2003	482	2012	205	2021	80

A.2.2.1.3 Production Forecast-Gas--Based on available data, the net hydrocarbon gas available for sale is determined as follows:

Recoverable gas volume:	Gas Cap, 30.0 TCF * 0.80 RF	= 24.0 TCF
	Oil Rim, 16.0 TCF * 0.60 RF	= 9.6 TCF
	Total	= 33.6 TCF
Total lease use, local sales, and shrinkage (estimated)		= 8.8 TCF
Net gas produced (includes CO_2)		= 24.8 TCF
Net hydrocarbon gas available for sale (after CO_2 removal)		= 21.8 TCF

A 2005 start-up of major gas sales is assumed and the rate is ramped up at 20%/yr over a 5-yr period to a maximum assumed sales rate of 2.05 billion cubic feet per day (BCFPD) in 2009. The gas production forecast to recover the total estimated recoverable gas of 21.8 TCF is given in **Table A.5** and has a project life of 32 yrs. It is assumed that PBU will be capable of delivering the forecasted volumes throughout the project life without a falloff in the last few years of production because of the high productivity of PBU wells. It is also assumed that if other sources of gas are available for delivery to the LNG system, those volumes will not reduce the sales from PBU.

A.2.2.1.4 Gas Price--Gas prices paid to PBU are based on a gas product net back share of the sale price of LNG in Asian markets. The LNG total project retains enough of the Asian sale price to give the project an assumed 10% rate of return on investment, as discussed in **Section 5.2** and **Appendix B.1.3.**

Table A.5. PBU gas sales forecast - with LNG project.

Year	BCFPD	Year	BCFPD	Year	BCFPD	Year	BCFPD
2005	0.41	2013	2.05	2021	2.05	2029	2.05
2006	0.82	2014	2.05	2022	2.05	2030	2.05
2007	1.23	2015	2.05	2023	2.05	2031	2.05
2008	1.64	2016	2.05	2024	2.05	2032	2.05
2009	2.05	2017	2.05	2025	2.05	2033	2.05
2010	2.05	2018	2.05	2026	2.05	2034	2.05
2011	2.05	2019	2.05	2027	2.05	2035	2.05
2012	2.05	2020	2.05	2028	2.05	2036	0.28

A.2.2.1.5 Operating Costs--PBU operation, with major gas sales, will go from oil-only sales (except for minor sales of gas to TAPS and for local use) to eventually gas-only sales. To simplify project economic evaluations, operating costs are determined differently for the three phases of operation: (1) oil-only sales, (2) gas and oil sales, and (3) gas-only sales.

During the oil-only phase, PBU operating costs are determined by the method discussed in **Appendix A.2.1.2.4.**

During the oil and gas phase, operating costs are based on the following:

- The gas operating cost in the first year of gas sales is assumed to be 5% of the operating cost in the last year of oil-only sales.
- The gas operating cost determined for the first year of gas sales is used in subsequent years of oil and gas sales after applying a 2.5% per year escalation. This escalation is to account for the relative increase in gas production that occurs as the oil rate declines.
- The total operating cost for PBU continues to be determined by the method discussed in

Appendix A.2.1.2.4, until oil sales cease.

- The oil operating cost is the difference between total operating cost and the gas operating cost.

When oil sales cease to be economical, gas operations are assumed to pay all PBU operating costs. PBU operating costs are assumed to be less during gas-only operations than during both oil and gas sales. It is recognized that certain fixed costs will be incurred even though the very large oil operations are shut down. This operating cost is assumed to be 50% of the oil-only operating cost during the last year of oil and gas operations. The total operating cost for the first year of gas-only operations is the sum of the assumed fixed cost and the gas operating cost as determined above. The determination of future PBU operating costs are shown schematically in **Figure A.3.**

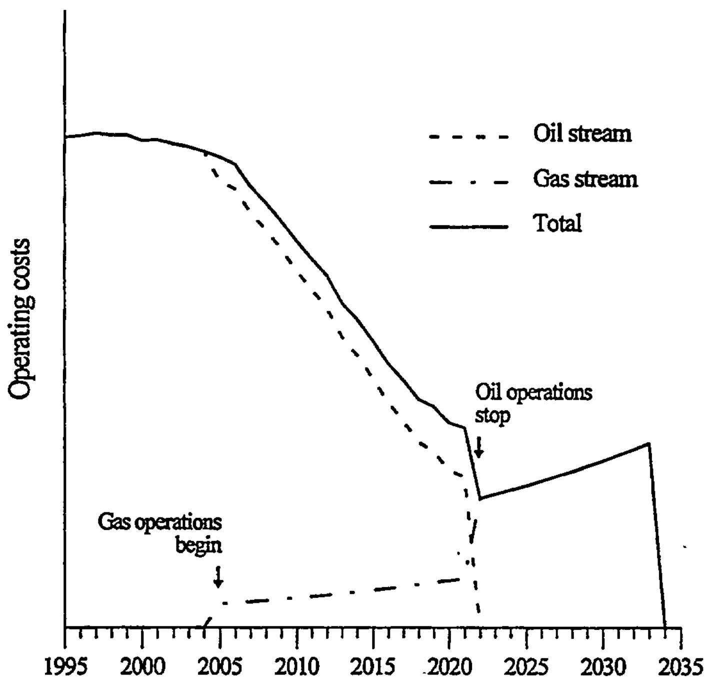

Figure A.3. Curve illustrating the determination of future PBU operating costs.

A.2.2.1.6 Investments--As a result of the facilities in place to handle the 7.5 BCFPD of gas being recycled (e.g., gas conditioning, compression, wells, and lines), it is assumed that no additional investments are required at PBU for major gas sales.

A.2.2.1.7 TAPS Tariff--A revised TAPS tariff is determined for 2005 and subsequent years using the revised PBU oil production schedule given in **Table A.4**. TAPS tariff calculation is discussed in **Appendix B.1.1.1.2.**

A.2.2.2. Summary. Results of the economics evaluation of the LNG scenario are summarized in **Section 5.2.**

A.2.3 Prudhoe Bay Unit - With Gas Sales to a GTL Project

Under major gas sales for conversion of natural gas to liquid hydrocarbons, it is assumed that gas is sold to an independently owned conversion plant. Although GTL technology is not economically proven at the scale required for effective North Slope operations (see **Section 3**), it is assumed for comparative economics that initial start-up of a gas-to-liquid conversion plant occurs in 2005.

As discussed in **Appendix A.2.2** for the LNG project, reduced oil recovery of 0.4 billion BBL oil will also occur in this operating scenario. The produced gas forecast developed in **Appendix A.2.2** is used in this evaluation.

A.2.3.1 Input Data - Gas Sales to GTL Plant. All economic parameters discussed in **Appendix A.2.2** for major gas sales are adopted except for gas prices and TAPS tariffs. These two parameters are discussed below.

A.2.3.1.1 Gas Price-GTL Plant--Gas prices paid to PBU are a gas product net back share of the liquid sales value that would result in a 10% rate of return on investment for the GTL plant owners. The gas product net back share is related to gas volumes on a BTU basis. Details of this method are in **Appendix B.1.3.2.**

A.2.3.1.2 TAPS Tariff--A revised TAPS tariff is determined for 2005 and later years using the revised PBU oil production forecast (**Table A.4**) and the volumes of converted hydrocarbon liquids given in **Table B.12** from PBU and PTU gas sales. The TAPS tariff calculation is discussed in **Appendix B.1.1.1.2.**

A.2.3.2 Summary. Details of the economics of the GTL scenario are summarized in **Section 5.** Results shown in **Table A.6** compare PBU operations under the three scenarios. As a result of reduced effectiveness of field recovery systems with the removal of large volumes of gas from the reservoir, both gas sales scenarios reduce oil recovery by 400 million barrels from the case without major gas sales.

Table A.6. Prudhoe Bay Unit economics - summary (1995$).

Economic Factor	**PBU Cases (AEO95 Reference Oil Price)**		
	No Major Gas Sales	**LNG Sales**	**GTL Sales**
Remaining Oil Project Life (1995 - 2025 or 2021) Gas Project Life (2005 - 2036)	31 0	27 32	27 32
Remaining Oil Reserves - billion BBL Gas Reserves - TCF (Sales)	4.2 0	3.8 21.8	3.8 21.8
Investments for oil production ($, millions) Investments for gas production ($, millions)	1,790 0	1,790 0	1,790 0
Gas Product Net Back (%)	—	28.1	15.1
Revenue From Oil Sales ($, millions) Maximum Revenue From Gas Sales ($, millions) Total Oil and Gas Sales Revenue ($, millions)	56,100 0 56,100	48,800 31,500 80,300	51,300 21,700 73,000
After-Tax Cash Flow ($, millions)	17,600	31,500	27,400
Discounted Cash Flow - NPV_{10} ($, millions)	8,600	11,100	10,400
Incremental NPV_{10} ($, millions)	0	2,500	1,800

A.2.4 Kuparuk River Unit

The Kuparuk River field is located west of and adjacent to PBU. It was discovered by Sinclair and BP in 1969 in the Ugnu State No. 1 well. The Kuparuk River Unit was formed in 1981 with ARCO as unit operator. The unit covers about 200 square miles. The KRU and the Kuparuk Participating Area (KPA) are shown on **Figure A.4**. KPA production began in December 1981 from two members of the Kuparuk River formation of Lower Cretaceous Age.

ARCO and BP hold major interests in the unit along with minor interest owners Amoco, Chevron, Exxon, Mobil, and Unocal. All leases carry a 12.5% royalty and five leases along the northern border also carry a net profit interest.

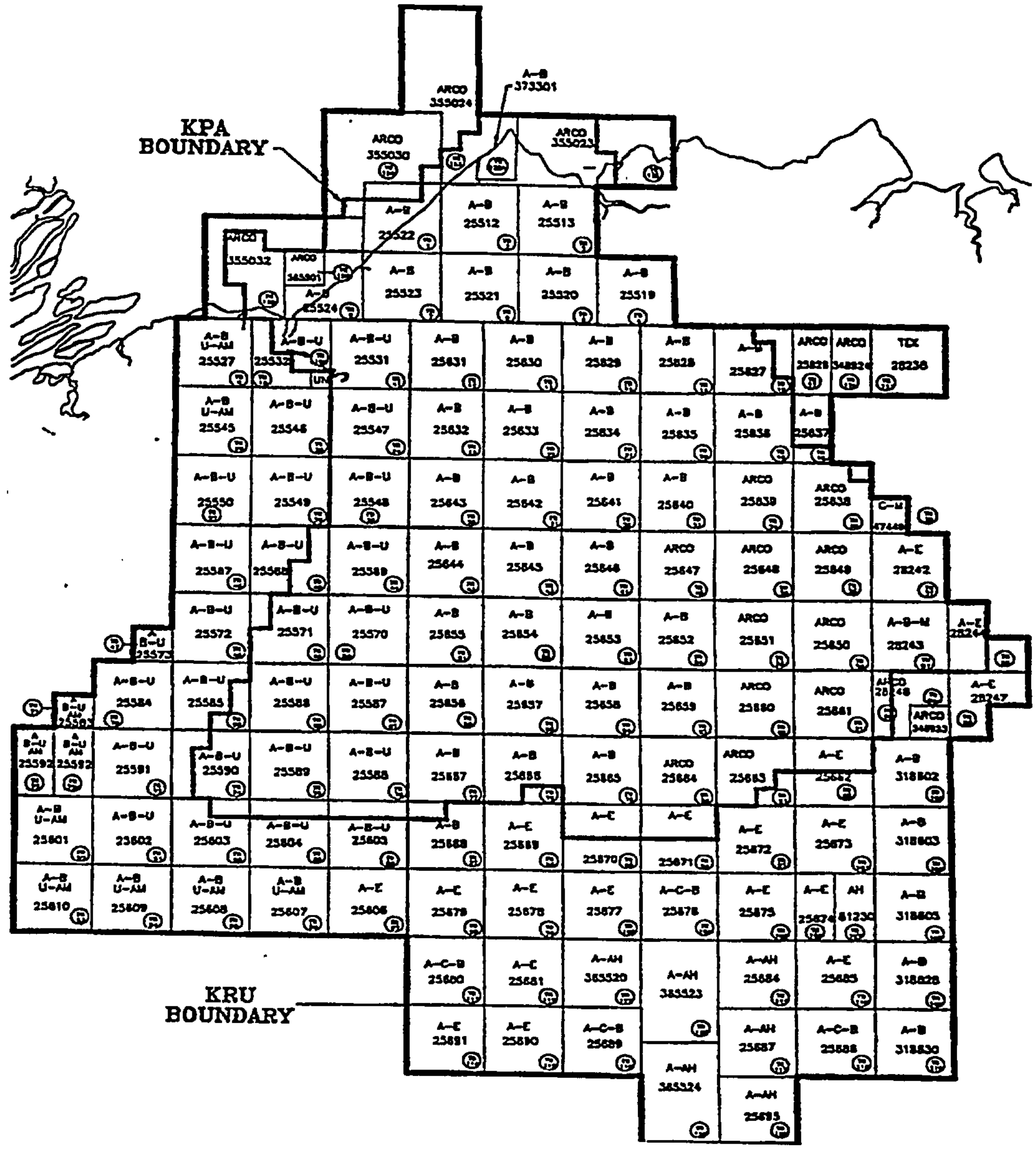

Figure A.4 KRU and KPA outline.[a]

a. Alaska Department of Natural Resources, personal communication, December 1992.

Production from KPA during 1994 averaged 306 MBPD (including oil and NGL) with 1,185 MMBO cumulative production as of 1/1/95 (AOGCC, 1994c). Remaining recovery from KPA as of 1/1/95 is estimated to be 1,131 MMBO for an ultimate recovery of 2,316 MMBO. In addition, it is estimated that 33 MMBBLS of injected offsite NGL (used as enriched gas injectant) will be recovered.

A.2.4.1 Development Plans. According to the 1994 Update to the Unit Plan of Development (POD) for the Kuparuk River Unit (ADNR 1994m), future development drilling will continue to focus on peripheral and infill drilling. Future development drilling opportunities include expansions to the periphery of approximately 12 existing drill sites, development of 2 new drill sites, and selective 80-acre infill drilling at most drill sites. Expansion of immiscible water-alternating-gas from 15 drill sites to 20 drill sites during the next 2 years is planned. Conceptual plans include a large scale enriched gas injection (LSMI) project at 10 to 15 existing drill sites.

Based on the discouraging results of delineation drilling in the southern and southeastern portions of the field, no additional development is planned for these areas at this time.

No major central facility expansions are planned beyond those related to the enhanced oil recovery process.

Portions of KRU contain shallow, oil-bearing reservoirs. Three of these (Colville, West Sak, and Ugnu) have been the object of evaluation to determine their commercial potential. Colville and West Sak have greater near-term development potential than Ugnu, which has potential only in the long-term.

A.2.4.2 Input Data. Evaluation input data are developed using history, current development plans, published information, and personal communications.

A.2.4.2.1 Recoverable Oil--Ultimate KPA recovery was listed as 2,130 MMBO in the previous DOE publication (1993). This estimate did not include any incremental recovery from the LSMI project discussed in **Appendix A.2.4.1.** It is assumed that the LSMI project will be approved (PIC, 1994a) and is included in this analysis. The revised production forecast results in a remaining recovery of 971 MMBO (herein referred to as the KPA production forecast, meaning that it excludes LSMI production) and 160 MMBO of LSMI production for a total remaining recovery of 1,131 MMBO and an ultimate recovery of 2,316 MMBO. In addition, it is estimated that 33 MMBBLS of the injected offsite NGLs used in the LSMI project is recovered along with the KPA production.

A.2.4.2.2 Production Forecast--Actual KPA production for 1992, 1993, and 1994 (AOGCC, 1992a; AOGCC, 1993j; AOGCC, 1994c) was greater than forecasted in the previous DOE publication (1993). However, the actual 1992, 1993, and 1994 annual average production results in a decline that ties in well to the previous DOE publication (1993) KRU forecast starting at 1/1/95. With the exception of the LSMI project, no significant new information is available to indicate or to justify revision of the previous forecast beyond 1995. Therefore, the production forecast from the previous DOE publication (1993) is used in this analysis for 1995 and later years for KPA production (excluding LSMI). For the KPA production forecast, the 1994 annual average production rate of 306 MBPD is declined at 2% through 1997, 11% from 1998 through 2003, and 17% thereafter. This forecast, **Table A.7**, results in remaining recoverable oil of 971 MMBO as of 1/1/95.

A separate incremental forecast is developed for the LSMI project using the following assumptions:

- LSMI injection is initiated in 1996 and injected at a constant rate over 10 years.
- 4 billion BBL oil OOIP.
- 4% of OOIP recovered by LSMI (2% to 5% recovery is typical for recovery processes of this type).
- One-third of the injected offsite NGL is recovered and sold along with KRU oil production.
- 20 year production life with production response starting in 1997.
- The purchase cost of offsite NGL used in the previous DOE (1993) publication of $1 billion (1992$), escalated to $1.066 billion (1995$) is adopted for this publication and allocated on a barrel of injected offsite NGL basis.
- NGL purchase price is about 70% of the TAPS PS No. 1 price for PBU crude oil, resulting in 100 MMBBLS of offsite NGL purchased for the project.

The LSMI oil production forecast is developed by starting the production in 1997, ramping-up to 1998, and then declined at 17% per year to recover 160 MMBO (4% of OOIP) over 20 years. The LSMI NGL production forecast is developed by ramping-up NGL production for 5 years starting in 1997, then declined at 15% per year to recover 33 MMBBLS of NGL over 20 years. The LSMI oil and NGL production forecasts are combined into a single LSMI production forecast (**Table A.7**) and results in remaining recovery of 193 MMBO. The KPA forecast and the LSMI forecast (which includes LSMI NGL production) are combined into the single Total KPA production forecast shown in **Table A.7**.

A.2.4.2.3 Investments--According to information contained in the 1994 POD (ADNR, 1994m), the scope of future development has been reduced from that considered for the previous DOE publication (1993). Development drilling, facility (new drill sites), and facility capacity expansion plans have each been reduced in scope. It is assumed that LSMI project investment will be minimal.

Table A.7. KPA production forecast.

Year	KPA (MBPD)	LSMI (MBPD)	TOTAL KPA (MBPD)
1995	299	0	299
1996	292	0	292
1997	285	47	332
1998	260	72	332
1999	235	63	298
2000	210	57	267
2001	185	50	235
2002	165	42	207
2003	145	35	180
2004	125	30	155
2005	105	25	130
2006	85	21	106
2007	71	17	88
2008	57	15	72
2009	43	12	55
2010	30	10	40
2011	18	8	26
2012	14	7	21
2013	12	6	18
2014	10	4	14
2015	8	4	12
2016	7	3	10

The number of future wells to be drilled during 1995 through 1997 is reduced from 154 wells in the previous DOE publication (1993) to 116 for this analysis. The $2.2 MM/well (1992$) estimate used in the previous DOE publication (1993), escalated to $2.3 MM/well (1995$), is used in this analysis.

Facility costs are reduced by three southern and southeastern drill sites and by the facility capacity expansions considered in the previous DOE publication (1993). Facility expansion costs are reduced 50% after backing out one new drill site per year. The drill site cost of $8 MM/drill site (1992$) from the previous DOE (1993) publication is used in this analysis. The facility costs used in the previous DOE publication (1993) are reduced by an additional $20.4 million (1992$) for this analysis. Drilling and facility investment schedules are shown in **Table A.8.**

Table A.8. KPA drilling and investment schedule

Year	Drilling No. Wells	Investment - 1995$, millions		
		Wells	Facilities	Total
1995	40	92.0	116.2	208.2
1996	40	92.0	116.2	208.2
1997	36	82.8	74.2	157.0
1998	0	0	21.7	21.7
1999	0	0	21.7	21.7
2000	0	0	21.7	21.7
Total	116	266.8	371.7	638.5

A.2.4.2.4 Operating Costs--In the previous DOE publication (1993), operating costs were determined using a cost per BTF. Total fluid production was based on a relationship between water cut and percent of ultimate recovery using past production history. Current water cut versus cumulative recovery is reasonably close to the predicted relationship used in the previous DOE publication (1993); therefore, that relationship is adopted for this analysis (**Figure A.5**).

The cost per BTF used in the previous DOE publication (1993) of $1.27/BTF (1992$), adjusted for inflation to $1.35/BTF (1995$), is used to calculate operating cost in this analysis.

The MI costs to KPA for expansion of the WAG project at KPA from the previous DOE publication (1993) of $1 billion (ARCO 1991a), escalated to $1.066 billion (1995$) allocated on a barrel of injected offsite NGL basis, is added to the operating cost in this publication as the offsite NGL costs to KPA for the LSMI project.

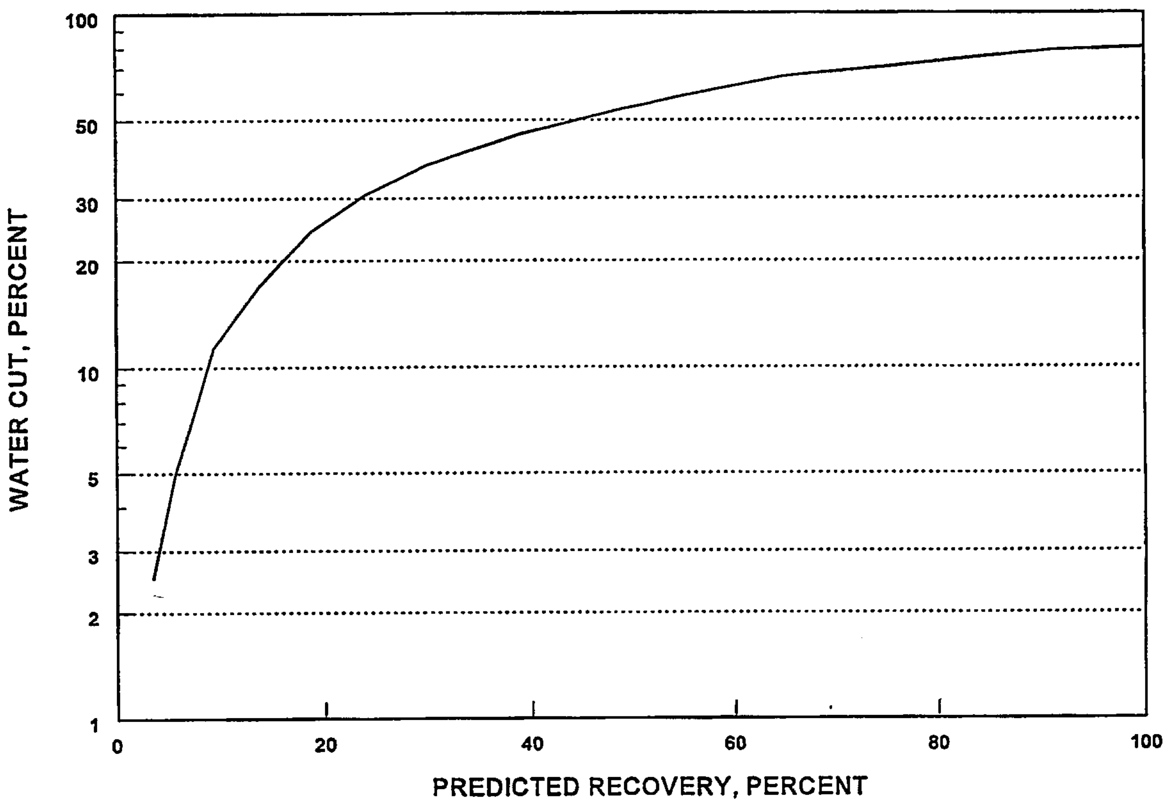

Figure A.5. KRU water cut versus cumulative production as percent of ultimate production.

A.2.4.2.5 Kuparuk Pipeline Tariff--The pipeline tariff listed in the previous DOE publication (1993) of $0.19/BBL (1995$) is used in this analysis (see **Appendix B.1.1.1.4**).

A.2.4.2.6 Future Producing Wells--The number of future active producing wells, required for annual severance tax calculations from the Set B equations in **Appendix C.1.1.6** is used for this analysis.

A.2.4.3 Summary. The KRU Kuparuk field began production in 1981. As of June 1994, 754 wells were active in the KPA. There were 42 developed drill sites; including 22 drill sites under waterflood, 15 drill sites under immiscible WAG, and three drill sites under LMSI. It is assumed that a large scale enriched gas injection project will be approved and that the project will be started in early 1996. Annual average production for 1994 was 306 MBPD. Cumulative production through 1/1/95 was 1,185 MMBO. Remaining recovery as of 1/1/95 is estimated to be 1,131 MMBO, including 160 MMBO of incremental LSMI production, for an ultimate recovery of 2,316 MMBO. In addition it is estimated that 33 MMBBLS of the injected offsite NGL as part of the LSMI project will be recovered along with KPA production, for a total remaining recovery of 1,164 MMBBLS.

Analysis using the four price forecasts listed in **Table B.1, Appendix B.1.1** show that all of the forecasted liquids can be economically recovered using the EIA reference and high oil price forecasts. About 340 MMBO of forecasted recovery is lost under the low price case scenario. The evaluation results are given in **Table A.9**. About 50 MMBBLS is lost using the flat oil price.

Table A.9. KPA economics.

Economic Factor	**Oil Price Forecasts**			
	AEO95 Low	**AEO95 Reference**	**AEO95 High**	**Flat Oil Price $18/BBL**
Remaining Project Life - yrs	8	22	22	15
Remaining Reserves - MMBBLS[a] - TCF (Sales)	825 0	1,164 0	1,164 0	1,113 0
Investments - as spent ($, millions)	663	663	663	663
Operating Costs - as spent ($, millions)	3,615	6,811	7,009	6,126
Cash Flow - NPV_{10} (1995$, millions)	432	2,347	3,150	1,732

a. Liquid reserves limited by project economics only.

A.2.5 Duck Island Unit

The Endicott reservoir, the productive zone of the Endicott Participating Area (Endicott) of the Duck Island Unit (DIU) (**Figure A.6**), was discovered in 1978 by the Sohio (BP) Sag Delta No. 4 well. The field is located 10 miles east of the Prudhoe Bay Unit in offshore waters of the Beaufort Sea off the Sagavanirktok River delta in water depths ranging from 2 to 14 feet and was the world's first arctic offshore commercial oil field. Production is from the Kekiktuk formation of Mississippian age and was initiated in October 1987 from two man-made gravel islands connected to the mainland by a breached causeway.

During 1989, BP Exploration tested the Sag Delta No. 9 well to evaluate the development potential of the Sag Delta North accumulation in a separate fault block north of the Endicott Kekiktuk reservoir. The well was originally drilled as a wildcat well from Endeavor Island, a gravel-filled drilling island connected by a bridge to the main Endicott production island. In 1991, BP Exploration applied to the State of Alaska

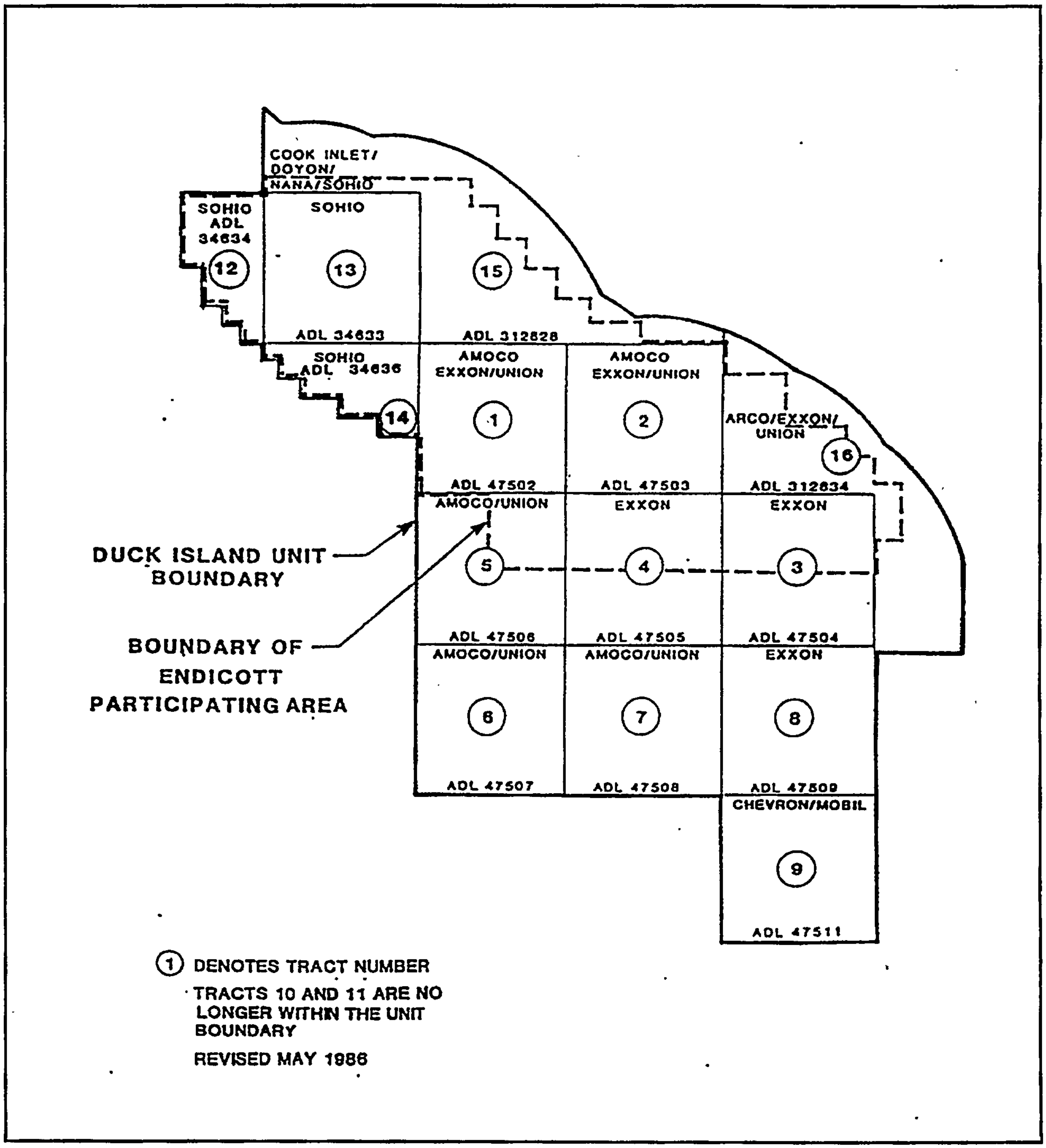

Figure A.6. Endicott Participating Area of the Duck Island Unit (AOGCC 1986).

for the formation of the Sag Delta North Participating Area (SDNPA) as a new participating area of the DIU (**Figure A.7**) to develop and produce the Alapah (Mississippian carbonate) and the Ivishak (Permo-Triassic sandstone) reservoirs. SDNPA production is commingled downhole with production from the Ivishak and Alapah reservoirs and produced through the Endicott production facilities.

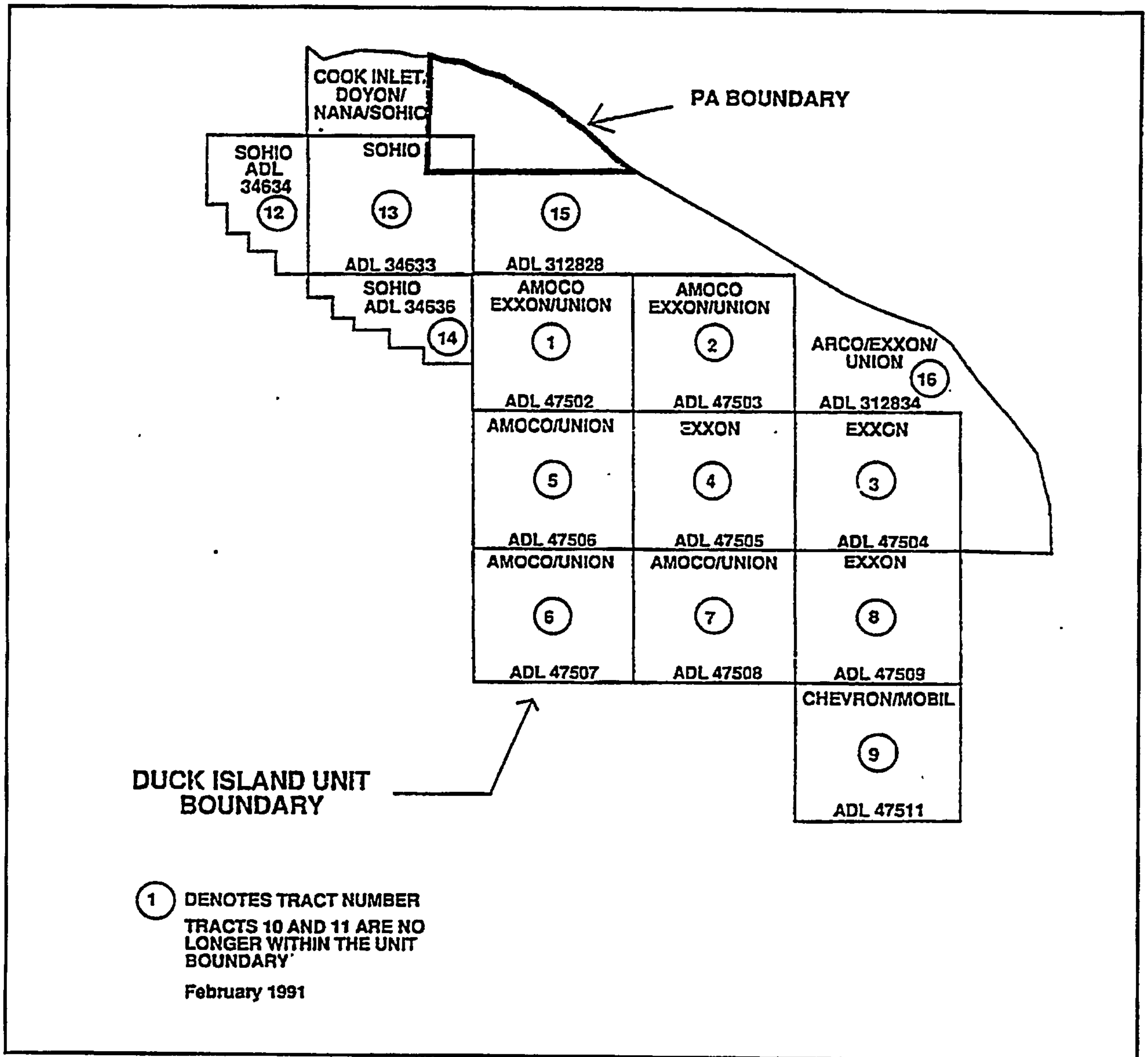

Figure A.7. Sag Delta North Participating Area (AOGCC 1991a).

Production from the Endicott pool during 1994 averaged 97 MBPD (including oil and NGL) with 278 MMBO cumulative production as of 1/1/95 (AOGCC, 1994c). Remaining recovery from the Endicott pool as of 1/1/95 is estimated to be 194 MMBO for an ultimate recovery of 472 MMBO.

Production from the SDNPA Ivishak pool during 1994 averaged 1.019 MBPD (including oil and NGL) with 6.5 MMBO cumulative production as of 1/1/95 (AOGCC, 1994c). Remaining recovery from the SDNPA Ivishak pool as of 1/1/95 is estimated to be 0.4 MMBO for an ultimate recovery of 6.9 MMBO.

The combined production from the Endicott pool and SDNPA during 1994 averaged 98 MBPD (including oil and NGLs) with a combined cumulative recovery of 284.5 MMBO as of 1/1/95. The combined remaining recovery from Endicott and SDNPA as of 1/1/95 is estimated to be 194.4 MMBO for a combined ultimate recovery of 478.9 MMBO.

A.2.5.1 Development Plans. According to the Endicott Reservoir Plan of Development (ADNR, 1995a) and the Sag Delta North Plan of Development (ADNR, 1995b) the development plans for Endicott and SDNPA, from the previous DOE publication (1993) are still valid and thus remain unchanged.

A.2.5.2 Input Data. Input data are developed using history, current development plans, published information, and personal communications.

A.2.5.2.1 Recoverable Oil--Ultimate recovery for the Endicott pool of 416 MMBO was used in the previous DOE publication (1993). That estimate was based on forecasted 1994 average annual production of 71.9 MBPD whereas production actually averaged 97 MBPD for 1994. Assuming an annual decline of 15% from 1994 production, the remaining recovery at 1/1/95 from the Endicott pool is now estimated to be 194 MMBO for the ultimate recovery of 472 MMBO adopted for this analysis. Additional production history is needed before further revision should be considered.

No additional development has occurred in SDNPA since the previous DOE publication (1993) and the water cut has increased to 89%. Assuming an annual decline rate of 40% from 1994 production, the remaining recovery at 1/1/95 from SDNPA is now estimated to be 0.4 MMBO for the ultimate recovery of 6.9 MMBO. Production history is limited and this ultimate recovery value is slightly lower than the previous DOE publication (1993) estimate. Actual production for 1992, 1993, and 1994 has been lower than the previous forecast. The revised ultimate recovery of 6.9 MMBO is adopted for this analysis.

The combined remaining recovery from the Endicott pool and SDNPA is now estimated to be 194.4 MMBO for the combined ultimate recovery of 478.9 MMBO.

A.2.5.2.2 Production Forecast--The Endicott and the Sag Delta North production forecasts have been combined for the total DIU production forecast used for the economic evaluations in this analysis as shown in **Table A.10.** The Endicott production forecast was developed using a 15% annual decline rate from the 1994 average annual production rate of 97 MBPD for 1995 and later years. The Sag Delta North production forecast was developed using a 40% annual decline rate, consistent with the previous DOE publication (1993), from the 1994 average production rate of 1.019 MBPD for 1995 and later years.

Table A.10. Endicott and Sag Delta North production forecast (MBPD).

Year	Endicott	Sag Delta North	Total DIU
1995	82.4	0.6	83.0
1996	70.1	0.4	70.5
1997	59.6	0.2	59.8
1998	50.6	0.0	50.6
1999	43.0	0.0	43.0
2000	36.6	0.0	36.6
2001	31.1	0.0	31.1
2002	26.4	0.0	26.4
2003	22.5	0.0	22.5
2004	19.1	0.0	19.1
2005	16.2	0.0	16.2
2006	13.8	0.0	13.8
2007	11.7	0.0	11.7
2008	10.0	0.0	10.0
2009	8.5	0.0	8.5
2010	7.2	0.0	7.2
2011	6.1	0.0	6.1
2012	5.2	0.0	5.2
2013	4.4	0.0	4.4
2014	3.8	0.0	3.8
2015	3.2	0.0	3.2

A.2.5.2.3 Investments--With the completion of the Endicott Causeway Breach Project in 1994, the majority of investments have been made. Future investment, adjusted for inflation, is assumed to remain unchanged from the investment schedule set forth in the previous DOE publication (1993), using the techniques set forth in that publication.

The investment schedule (**Table A.11**) for this analysis has been developed using the following assumptions:

- Endicott well costs are $3.2 million (1995$) per well.
- Two wells per year will be drilled during 1995 and 1996.
- Facility investments are $5.4 million (1995$) per year.
- Facility investments will be made during 1995 and 1996.

Table A.11. Endicott drilling and investment schedule.

Year	Drilling No. Wells	Investment - $, millions (1995$)		
		Wells	Facilities	Total
1995	2	6.5	5.4	11.9
1996	2	6.5	5.4	11.9
Total	4	13.0	10.8	23.8

A.2.5.2.4 Operating Costs--Operating costs are based on a cost factor per BTF using a water cut versus percent cumulative recovery relationship to forecast total produced fluid. The cost per barrel factor, adjusted for inflation, from the previous DOE publication (1993) is used for this analysis.

The cost per barrel factor used in the previous DOE publication (1993) was $1.50/BTF (1992$). Adjusted for inflation, the operating cost factor is $1.60/BTF (1995$), and is used in this analysis.

Production performance during 1994 indicates the water cut versus percent cumulative recovery is consistent with the relationship developed in the previous DOE publication (1993) (**Figure A.8**). That relationship is used in this analysis.

A.2.5.2.5 Pipeline Tariff--Endicott liquids (including Sag Delta North liquids) are delivered to TAPS PS No. 1 through a separate 26-mile common carrier pipeline. The pipeline tariff calculated for the DIU from the previous DOE publication (1993) was $0.76/BBL (1992$). A new pipeline tariff, adjusted for increased volumes, is $0.68/BBL (1995$) (see **Appendix B.1.1.1.4**) and is used in this analysis.

A.2.5.2.6 Future Producers--The number of future active producing wells is determined using the Set B equations of **Appendix C.1.1.6.**

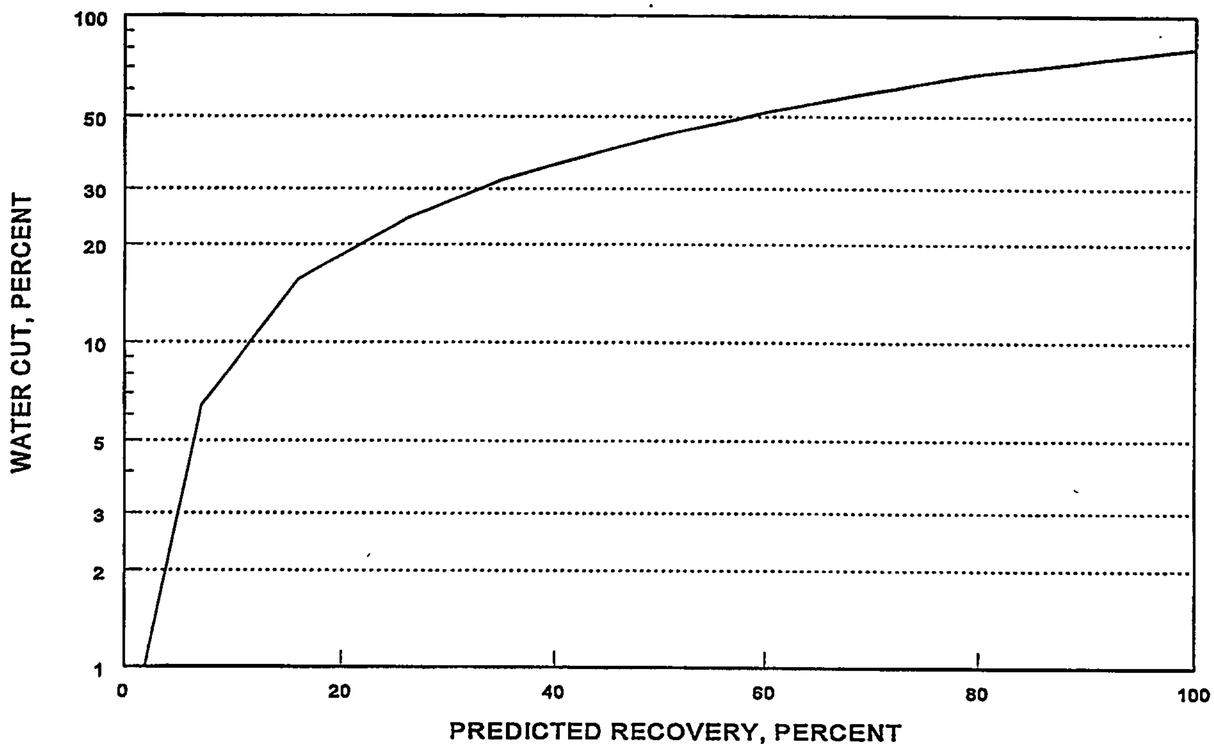

Figure A.8. Endicott formation - percent water cut versus percent recovery.

A.2.5.2.7 Net Profits Interest--Two leases in the DIU have net profits interests (NPI) in addition to a 20% royalty, the remaining eight leases have a 12.5% royalty only. The estimated NPI share used in the previous DOE publication (1993) to reflect the State of Alaska and industry share of revenue is adopted for this analysis. The NPI share is estimated to be 14% (ADNR, 1995c) of income before federal income tax. That percentage factor, for simplicity, is used over the remaining project life for this analysis.

A.2.5.3 Summary. Endicott, the world's first commercial arctic offshore oil field, began production in 1987. Sag Delta North began production in 1991 through the Endicott production facilities. Both Endicott and Sag Delta North are separate participating areas within DIU. As of February 1995, a total of 98 Endicott development wells and five Sag Delta North wells have been drilled. Endicott production (including Sag Delta North production) peaked at 124 MBPD in 1992 and has declined to an annual average of 98 MBPD for 1994. Combined Endicott and SDNPA cumulative production through 1/1/95 was 284.5 MMBO. Combined Endicott and SDNPA remaining recovery as of 1/1/95 is estimated to be 194.4 MMBO for an ultimate recovery of 478.9 MMBO.

Analysis using the four price forecasts listed in **Table B.1, Appendix B.1.1** show that all of the forecasted liquids can be economically recovered using the EIA reference and high oil price forecasts. About 160 MMBBLS of forecasted recovery is lost using the low price case forecast as shown in **Table A.12.** Using the flat oil price, lost recovery is estimated at about 25 MMBBLS

Table A.12. DIU economics.

Economic Factor[a]	Oil Price Forecasts			
	AEO95 Low	AEO95 Ref.	AEO95 High	Flat Oil Price
Remaining Project Life - yrs	1	21	21	11
Remaining Reserves - MMBBLS - TCF (Sales)	30.2 0	194.4 0	194.4 0	167.4 0
Investments - as spent ($, millions)	12	24	24	24
Operating Costs - as spent ($, millions)	120	1,237	1,237	956
Cash Flow - NPV_{10} (1995$, millions)	20	336	487	252

a. Liquid reserves limited by project economics only.

A.2.6 Milne Point Kuparuk Participating Area.

The Milne Point Kuparuk Participating Area is a participating area within the Milne Point Unit (MPU). The MPU, which lies 30 miles northwest of PBU and adjacent to the Kuparuk River Unit, consists of the Milne Point Kuparuk Participating Area (MPKPA), the Schrader Bluff Participating Area (SBPA), and the Northwest Milne Point area (NWMP) (**Figure A.9**). Each participating area will be covered in separate sections with this section covering MPKPA.

The Kuparuk sandstone is the producing formation of the MPKPA. The Kuparuk zone was first discovered in 1969 by the Sinclair East Ugnu No. 1 well. MPU was unitized in 1979 and production from the MPKPA began in 1985. Production from MPKPA was shut-in in January 1987, due to low oil prices, and restarted in April 1989. BP Exploration Alaska Inc. (BP) acquired Conoco's interest in MPU and became operator in 1994.

Production from MPKPA during 1994 averaged 15.3 MBPD with 39.6 MMBO cumulative production as of 12/31/94 (AOGCC, 1994c). Remaining recovery from MPKPA as of 1/1/95 is estimated

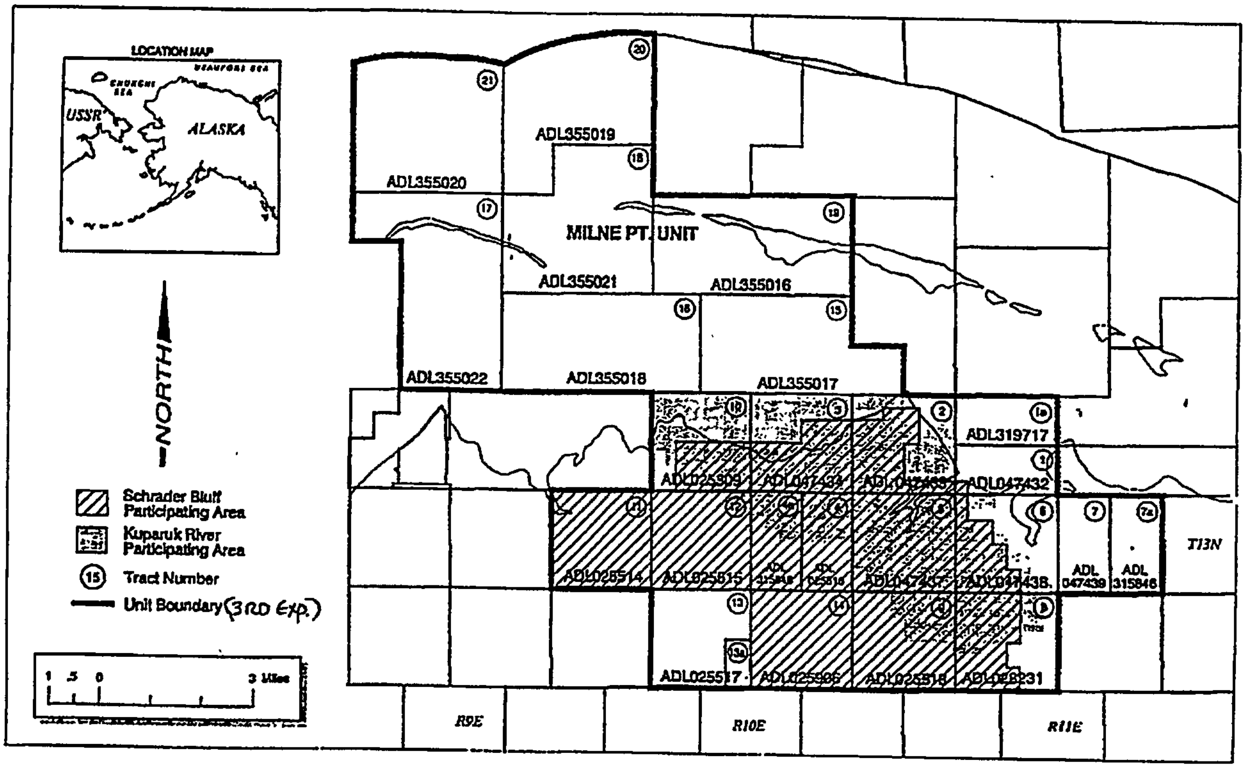

Figure A.9. MPKPA of the Milne Point Unit (ADNR, 1994.).

to be 97.8 MMBO for an ultimate recovery of 137.4 MMBO.

A.2.6.1 Development Plans. Development plans for MPU have changed significantly since the previous DOE publication (1993). Current plans are to conduct limited additional development drilling for MPKPA with 17 new producing wells and 7 injection wells into the Kuparuk formation planned during 1995 (ADNR, 1994s; Alaska Journal of Commerce, 1995b). Plans for development drilling beyond 1995 are contingent up the results of the 1995 development drilling program. Current plans are to expand MPKPA processing facility capacity from 30 MBBLS per day to 53 MBBLS per day by the end of 1995 (ADNR, 1994s). The MPKPA processing facilities are being shared with SBPA and will be shared with NWMP when it begins production.

Additional potential, "best case scenario", exists to increase MPU production to as much as 100 MBPD by the year 2000 with an increase in ultimate recovery to possibly as much as 600 MMBO (Anchorage Daily News, 1995c). No information is available to indicate which field or fields this estimate is attributed to.

A.2.6.2 Input Data. Input data are developed using history, current development plans, published information, and personal communications. The additional potential referred to in **Appendix A.2.6.1** is not included in this evaluation.

A.2.6.2.1 MPKPA Recoverable Oil--Ultimate recovery from the MPKPA of 62.5 MMBO was carried in the previous DOE publication (1993). Actual annual production for 1992, 1993, and 1994 was approximately 2,500 BOPD lower than forecasted. The remaining forecast was based on no additional development drilling beyond 1993. Current development drilling plans call for drilling 17 additional producing wells in 1995. Assuming an annual decline of 12% per year from 1994 production plus production from 16 additional wells, each with an initial rate of 1.2 MBPD declined at 12% per year, the remaining recovery at 1/1/95 is estimated to be 97.8 MMBO for the ultimate recovery of 137.4 MMBO.

A.2.6.2.2 MPKPA Production Forecast--The MPKPA production forecast shown in **Table A.13** was developed using the procedure described in **Appendix A.2.6.2.1.**

Table A.13. MPKPA production forecast

Year	(BOPD)
1995	30,856
1996	30,856
1997	27,153
1998	23,895
1999	21,028
2000	18,504
2001	16,284
2002	14,330
2003	12,610
2004	11,097
2005	9,765
2006	8,593
2007	7,562
2008	6,655
2009	5,856
2010	5,153
2011	4,535
2012	3,991
2013	3,512
2014	3,090
2015	2,720

A.2.6.2.3 MPKPA Investments--Seventeen development producing wells and seven injection wells are currently planned (Alaska Journal of Commerce, 1995b) to be drilled from existing pads in 1995. Development drilling beyond 1995 is contingent upon the results of the 1995 drilling program. The only investments forecasted are those associated with drilling the 24 wells currently planned and expansion of the MPKPA processing facility capacity from 30 MBBLS per day to 53 MBBLS per day. Using the operator's North Slope infrastructure and experience it is assumed that each well can be drilled at a cost of $2.0 MM/well (1995$). It is assumed that production facility costs, in addition to the production facility expansion costs, of $2.0 million (1995$) per year would be invested for three years.

The operator expects to invest $220 million (1995$) over a 3-year period for MPU development, including $120 million (1995$) during 1995 and 1996 for MPKPA processing facility capacity expansion and NWMP development.[a] It is assumed that $100 million (1995$) will be spent for MPKPA and SBPA development and that $43 million (1995$) will be invested for NWMP development, excluding MPKPA processing facility expansion. It is assumed that MPKPA will make the investment in the processing facility capacity expansion and charge SBPA and NWMP a facility sharing fee for that investment. The MPKPA processing facility capacity expansion from 30 to 60 MBOPD is assumed to cost a total of $77 million (1995$) with 80% being spent in 1995 and the remainder in 1996. The MPKPA drilling and investment schedule is shown in **Table A.14**.

Table A.14. MPKPA drilling and investment schedule

Year	Drilling No. Wells	Investment - 1995$, millions		
		Wells	Facilities	Total
1995	24	48	63.6	111.6
1996	0	0	17.4	17.4
1997	0	0	2.0	2.0
Total	24	48	83.0	131.0

A.2.6.2.4. MPKPA Operating Costs--It is expected that the operator can reduce total operating costs from the operating costs used in the previous DOE publication (1993) as a results of their North Slope infrastructure and experience. A $/BTF operating cost factor is assumed to be $1.54/BTF

a. BP Exploration (Alaska) Inc., personal communication, March 20, 1995.

(1995$) which includes $0.55/BTF (1995$) for well workover cost plus $0.07/BTF (1995$) for lease maintenance operating cost plus $0.92 (1995$) for processing facility operating cost. The total operating cost of $1.54/BTF (1995$) is used in this analysis and is applied to the MPKPA BTF production.

Estimates of MPKPA total fluid volumes are determined using a relationship of water cut versus percent of ultimate recovery. The 1994 water cut versus percent cumulative recovery is reasonably consistent with the MPU model water cut versus percent cumulative recovery relationship developed in the previous DOE publication (1993). That relationship (**Figure A.10**), with slight modification, is used in this analysis.

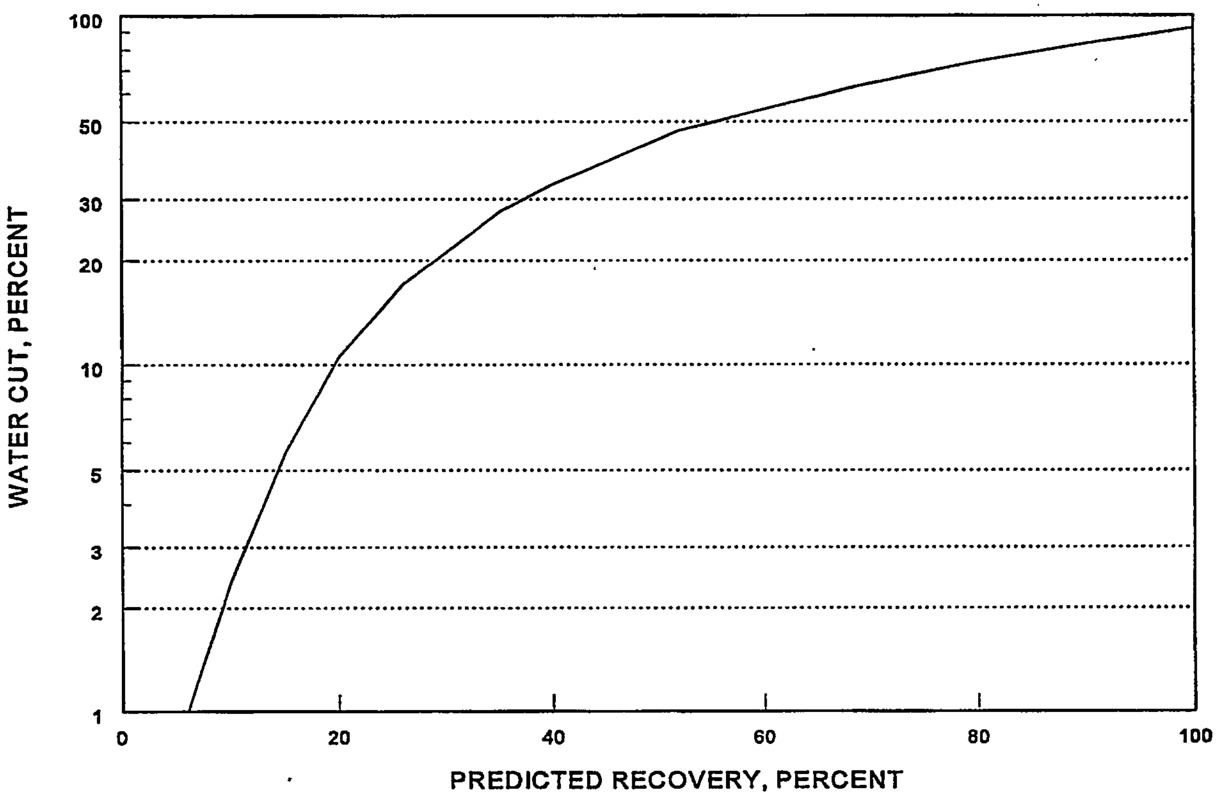

Figure A.10. MPU - model data of percent water cut versus percent of ultimate recovery.

A.2.6.2.7 Future Producing Wells--The number of future active producing wells is determined using the Set B equations from **Appendix C.1.1.6.**

A.2.6.3 Summary. Production from MPKPA of the MPU began in November 1985, but was shut-in between January 1987 and April 1989 due to low oil prices. Current development plans are to conduct limited development drilling and continued waterflood of the formation. Current plans are to expand the MPKPA processing facility capacity from 30 to 60 MBOPD. The MPKPA processing facilities are being shared with SBPA and NWMP. Average annual production from MPKPA for 1994 was 15.3 MBPD from 37 producing wells. Cumulative production as of 12/31/94 was 39.6 MMBO. Remaining recovery as of 1/1/95 is estimated to be 97.8 for an ultimate recovery of 137.4 MMBO.

Analysis using the four price forecasts listed in **Table B.1, Appendix B.1.1** show that all of the forecasted liquids can be economically recovered using the EIA reference and high oil price forecasts. About 22 MMBO recovery is lost in the flat oil price scenario, and none of the recoverable oil is economically recovered using the EIA low price forecast. The evaluation results are given in **Table A.15.**

Table A.15. MPKPA economics.

Economic Factor[a]	**Oil Price Forecasts**			
	AEO95 Low	**AEO95 Ref.**	**AEO95 High**	**Flat Oil Price**
Remaining Project Life - yrs	0	21	21	10
Remaining Reserves - MMBBLS - TCF (Sales)	0 0	97.8 0	97.8 0	75.4 0
Investments - as spent ($, millions)	0	133	133	133
Operating Costs - as spent ($, millions)	0	803	803	418.4
Cash Flow - NPV_{10} (1995$, millions)	0	160.7	235	113.7

a. Liquid reserves limited by project economics only.

A.2.7 Schrader Bluff Participating Area.

The Schrader Bluff Participating Area (SBPA) is a participating area within the MPU **(Figure A.9).** The Schrader Bluff Sands, correlating to the lower Ugnu sands and to an eastern extension of the West Sak sands of the KRU to the southwest and sometimes referred to as West Sac or Ugnu sands, were first encountered in 1969 by the Sinclair East Ugnu No.1 well. The Schrader Bluff sands were also encountered in Chevron's Kavearak Point well the same year. The State approved the pool rules for the Schrader Bluff pool in 1990 and production was started from the Schrader Bluff sands in 1991.

Production from SBPA during 1994 averaged 3.0 MBPD with 4.0 MMBO cumulative production as of 1/1/95 (AOGCC, 1994c), Remaining recovery from SBPA as of 1/1/95 is estimated to be 34.0 MMBO for an ultimate recovery of 38.0 MMBO.

A.2.7.1 Development Plans. Development plans for MPU have changed significantly since the previous DOE publication (1993). Current plans are to increase Schrader Bluff well production and conduct limited additional development drilling for SBPA. These development plans include:

- Increase Schrader Bluff average well production from currently 200 BOPD per well to 500 BOPD per well through improved gravel filter technology (Anchorage Daily News, 1995c; Alaska Journal of Commerce, 1995b).
- Drill six new Schrader Bluff formation development wells and two water source wells in 1995 (ADNR, 1994s; Alaska Journal of Commerce, 1995b).
- Depending on the results of the 1995 MPKPA and SBPA drilling program, as many as 12 additional MPU development wells are planned for 1996 (Anchorage Daily News, 1995c). It is assumed that these will be SBPA development wells.
- Depending on the results of the SBPA development drilling program, the potential exists to construct a maximum of seven new MPU drilling pads, one per 4 square miles (Alaska Journal of Commerce, 1995b). It is assumed that these pads will be for SBPA development.

A.2.7.2 Input Data. Input data are developed using history, current development plans, published information, and personal communications.

A.2.7.2.1 SBPA Recoverable Oil--Ultimate recovery from the SBPA of 209.5 MMBO carried in the previous DOE publication (1993) was based on an extensive development drilling program, adding 44 wells during 1992 through 1994 and 252 producing wells from 1995 through 2012. The scope of SBPA development drilling has been significantly reduced from the assumptions used in the previous publication. Eleven development wells were drilled between 1992 and 1994, six development wells are planned for 1995, and 12 development wells are tentatively planned for 1996. It was assumed that the per well production rates will be increased to 500 BOPD, that 15 producing wells existed from 1994, that six producing wells would be drilled in 1995, and that 12 producing wells would be drilled in 1996. The SBPA annual production rate was prorated with NWMP annual production rate such that total MPU production was less than or equal to the expanded MPKPA production facility capacity of 53 MBBLS per day. The 1997

SBPA annual production rate was declined at 15% per year (**Table A.16**). The remaining recovery at 1/1/95 is estimated to be 34.0 MMBO for the ultimate recovery of 38.0 MMBO.

Table A.16. SBPA production forecast

Year	(BOPD)
1995	10,500
1996	11,382
1997	13,286
1998	11,293
1999	9,599
2000	8,159
2001	6,935
2002	5,898
2003	5,011
2004	4,259
2005	3,620
2006	3,077

A.2.7.2.2 SBPA Investments--Investments of $120 million (1995$) are planned over the next 3 years (Anchorage Daily News, 1995a, Anchorage Daily News, 1995c) for MPU development (assumed for drilling wells). Development plans call for the drilling of eight SBPA wells in 1995 and 12 more SBPA wells in 1996. Utilizing the operators North Slope infrastructure and experience, it is assumed that each well can be drilled for $2.0 MM/well (1/1/95). It is assumed that additional production facility costs will be $2.0 million per year for 1995, 1996 and 1997. The SBPA drilling and investment schedule is shown in **Table A.17.**

Table A.17. SBPA drilling and investment schedule

Year	Drilling No. Wells	Investment - 1995$, millions		
		Wells	Facilities	Total
1995	8	16	2.0	18.0
1996	12	24	2.0	26.0
1997	0	0	2.0	2.0
Total	20	40	6.0	46.0

A.2.7.2.3 SBPA Operating Costs--It is expected that the operator will be able to lower operating costs due to it's North Slope infrastructure and experience and by application of revised production technology. The $/BTF basic operating cost is assumed to be $0.62/BTF (1995$) and is used as the SBPA operating cost in addition to the facilities cost sharing fee paid by SBPA to MPKPA.

The facilities cost sharing fee paid by SBPA to MPKPA from the previous DOE publication (1993) of $1.24/BTF (1992$), adjusted for inflation to $1.32/BTF (1995$) is used in this analysis and is applied to the SBPA BTF production. It is assumed that this cost includes $0.92/BTF incremental shared facility operating cost and $0.40/BTF shared facility access fee based on the cost savings to SBPA.

The total fluid production, BBTF, used to determine SBPA operating cost and cost sharing fee is determined from the MPU model water cut versus percent cumulative recovery relationship (**Figure A.10**), slightly modified to reflect SBPA production characteristics.

A.2.7.2.4 Field Pipeline Tariff--The pipeline tariff of $0.90/BBL (1995$) discussed in **Appendix A.2.6.2.6** is used in the SBPA analysis.

A.2.7.2.5 Future Producing Wells--The Set B equations in **Appendix C.1.1.6** are used to estimate future annual producing wells.

A.2.7.3 Summary. The Schrader Bluff pool, which correlates to the lower Ugnu sands and upper West Sak sands, began producing in 1991. Cumulative production as of 1/1/95 was 4.0 MMBO. Remaining recovery as of 1/1/95 is 34.0 MMBO for an ultimate recovery of 38.0 MMBO. Development plans for SBPA have been revised significantly by the operator since 1994.

Analysis using the four price forecasts listed in **Table B.1, Appendix B.1.1** show that all of the forecasted liquids can be recovered using the EIA reference and high case price forecasts. About 8 MMBO is lost using the flat oil price scenario and none of the forecasted liquids are economically recovered using the EIA low price forecast as shown in **Table A.18**.

A.2.8 Northwest Milne Point Area.

The Northwest Milne Point Area (NWMP), a currently undeveloped northwestern area of MPU, is

Table A.18. SBPA economics.

Economic Factor[a]	Oil Price Forecasts			
	AEO95 Low	**AEO95 Ref.**	**AEO95 High**	**Flat Oil Price**
Remaining Project Life - yrs	4	12	12	7
Remaining Reserves - MMBBLS - TCF (Sales)	17 0	34 0	34 -	26 0
Investments - as spent ($, millions)	47.2	47.2	47.2	47.2
Operating Costs - as spent ($, millions)	49.3	180.1	180.1	98.8
Cash Flow - NPV_{10} (1995$, millions)	-29.6	33.5	59.4	21.5

a. Liquid reserves limited by project economics only.

a proposed participating area within the MPU (**Figure A.9**). The NWMP Kuparuk sand accumulation was encountered by Conoco's NW Milne No. 1 well, drilled in 1992. 3-D seismic data and three more exploratory wells in NWMP have extended the Milne Point Unit structure into this offshore area (AOGCC 1994d). The four exploratory wells encountered oil bearing sands stratigraphically equivalent to the MPKPA Kuparuk River sand. The operator plans to initiate development activities at NWMP in 1995.

Production from the NWMP is expected to begin by the end of 1995. Ultimate recovery from the undeveloped NWMP is estimated to be 37.7 MMBO based on a limited amount of available information. The NWMP accumulation is estimated to contain 70 MMBO to 80 MMBO (Alaska Journal of Commerce, 1995b).

A.2.8.1 Development Plans. The previous DOE publication (1993) did not address development of the NWMP. Current development plans (ADNR 1994s; Alaska Journal of Commerce, 1995b) include:

- Expand MPU facility capacity from currently 30 MBBLS per day to 53 MBBLS per day by the end of 1995.
- Complete construction of F Pad for development of NWMP and connect to MPU production facilities by the end of 1995.[a]
- Drill 10 development wells from F Pad at NWMP in 1995.

a. BP Exploration (Alaska) Inc., personal communication, March 20, 1995.

- Begin NWMP production by the end of 1995.

A.2.8.2 Input Data. Input data are developed using history, current development plans, published information, and personal communications.

A.2.8.2.1 NWMP Recoverable Oil--The previous DOE publication (1993) did not address the NWMP as there were no plans at that time to develop this accumulation. For this analysis, it was assumed that NWMP wells would be produced at an initial rate of 1200 BOPD per well. It was assumed that production at that rate would occur for half of the first year (1995). The production is prorated with SBPA to 53 MBBLS per day excess capacity above MPKPA production. Production is declined at 15% per year. The ultimate recovery is estimated to be 37.7 MMBO from the production schedule shown in **Table A.19.** This recovery is 47% of the 80 MMBO estimated for the NWMP accumulation by (Alaska Journal of Commerce, 1995b).

Table A.19. NWMP production forecast

Year	(BOPD)
1995	7,800
1996	10,762
1997	12,561
1998	11,054
1999	9,727
2000	8,560
2001	7,533
2002	6,629
2003	5,833
2004	5,133
2005	4,517
2006	3,975
2007	3,498
2008	3,078
2009	2,709

A.2.8.2.2 NWMP Investments--It is estimated that each of the 10 wells planned for 1995 will cost \$3.1 MM/per well (1995\$), that F Pad will cost \$8.0 million (1995\$) to construct in 1995, and that additional production facility costs are \$2.0 million (1995\$) for 1996 and 1997. The NWMPU drilling and investment schedule is shown in **Table A.20.**

Table A.20. NWMP drilling and investment schedule

Year	Drilling No. Wells	Investment - 1995$, millions		
		Wells	Facilities	Total
1995	10	31.0	8.0	39.0
1996	0	0	2.0	2.0
1997	0	0	2.0	2.0
Total	10	31.0	12.0	43.0

A.2.8.2.3 NWMP Operating Costs--It is assumed that the NWMP per barrel of total fluid operating costs are similar to MPKPA operating cost of $0.62/BTF (1995$) and is used as the NWMP basic operating cost in addition to the facility cost sharing fee paid by NWMP to MPKPA.

The NWMP will pay to MPKPA a facilities cost sharing fee. It is estimated that this cost sharing fee is the same as that paid by SBPA. Therefore, the NWMP cost sharing fee is $1.32/BTF (1995$) in this analysis and is applied to the NWMP BTF production. The total fluid production, BTF, used to determine NWMPU operating cost and cost sharing fee is determined from the MPU model water cut versus percent cumulative recovery relationship (**Figure A.10**), slightly modified to reflect the NWMP anticipated production characteristics.

A.2.8.2.4 Field Pipeline Tariff--The field pipeline tariff of $0.90/BBL (1995$) assumed for MPKPA in **Appendix A.2.6.2.6** is used in the NWMP analysis.

A.2.8.2.5 Future Producing Wells--The Set B equations in **Appendix C.1.1.6** are used to estimate future annual producing wells.

A.2.8.3 Summary. Plans are to develop the NWMP accumulation from a gravel pad (F Pad) located at No Point with connections to existing MPU production facilities. A total of 10 wells are currently planned. Ultimate recover is estimated to be 37.7 MMBO with production beginning by the end of 1995.

Analysis using the four price forecasts listed in **Table B.1, Appendix B.1.1** show that all of the forecasted liquids can be economically recovered using the EIA reference and high case price forecasts.

About 6.5 MMBO recovery is lost using the flat oil price scenario, and about 10.5 MMBO is lost using the EIA low price forecast case. The evaluation results are given in **Table A.21.**

Table A.21. NWMP economics.

Economic Factor[a]	**Oil Price Forecasts**			
	AEO95 Low	**AEO95 Ref.**	**AEO95 High**	**Flat Oil Price**
Remaining Project Life - yrs	8	15	15	10
Remaining Reserves - MMBBLS - TCF (Sales)	27.2 0	37.7 0	37.7 0	31.2 0
Investments - as spent ($, millions)	43.6	43.6	43.6	43.6
Operating Costs - as spent ($, millions)	92	208.9	208.9	125.6
Cash Flow - NPV_{10} (1995$, millions)	3.1	63.7	92.3	46

a. Liquid reserves limited by project economics only.

A.2.9 Lisburne Participating Area

The Lisburne Participating Area (LPA) of the Prudhoe Bay Unit produces from the Lisburne group which is subdivided into the Alapah of Mississippian age and the overlying Wahoo of Pennsylvanian age. The Lisburne pool was discovered in 1968 by the ARCO/Humble (Exxon) Prudhoe Bay State No. 1 well, the discovery well for the shallower Prudhoe Bay field. The State approved formation of the LPA of PBU in 1986 (**Figure A.11**). The LPA is located in the northeastern corner of PBU.

A.2.9.2 Input Data--Input data are developed using history, current development plans, published information, and personal communications.

A.2.9.2.1 Production Forecast--The Alapah production forecast has been combined with Lisburne production forecast for the LPA production forecast shown in **Table A.22**. Remaining recovery from LPA is estimated to be 40.0 MMBO as of 1/1/95. Recovery to date is 115.1 MMBO. The 1994 average annual production rate was declined at 12% per year. This decline results in an estimated ultimate recovery of 155.1 MMBO.

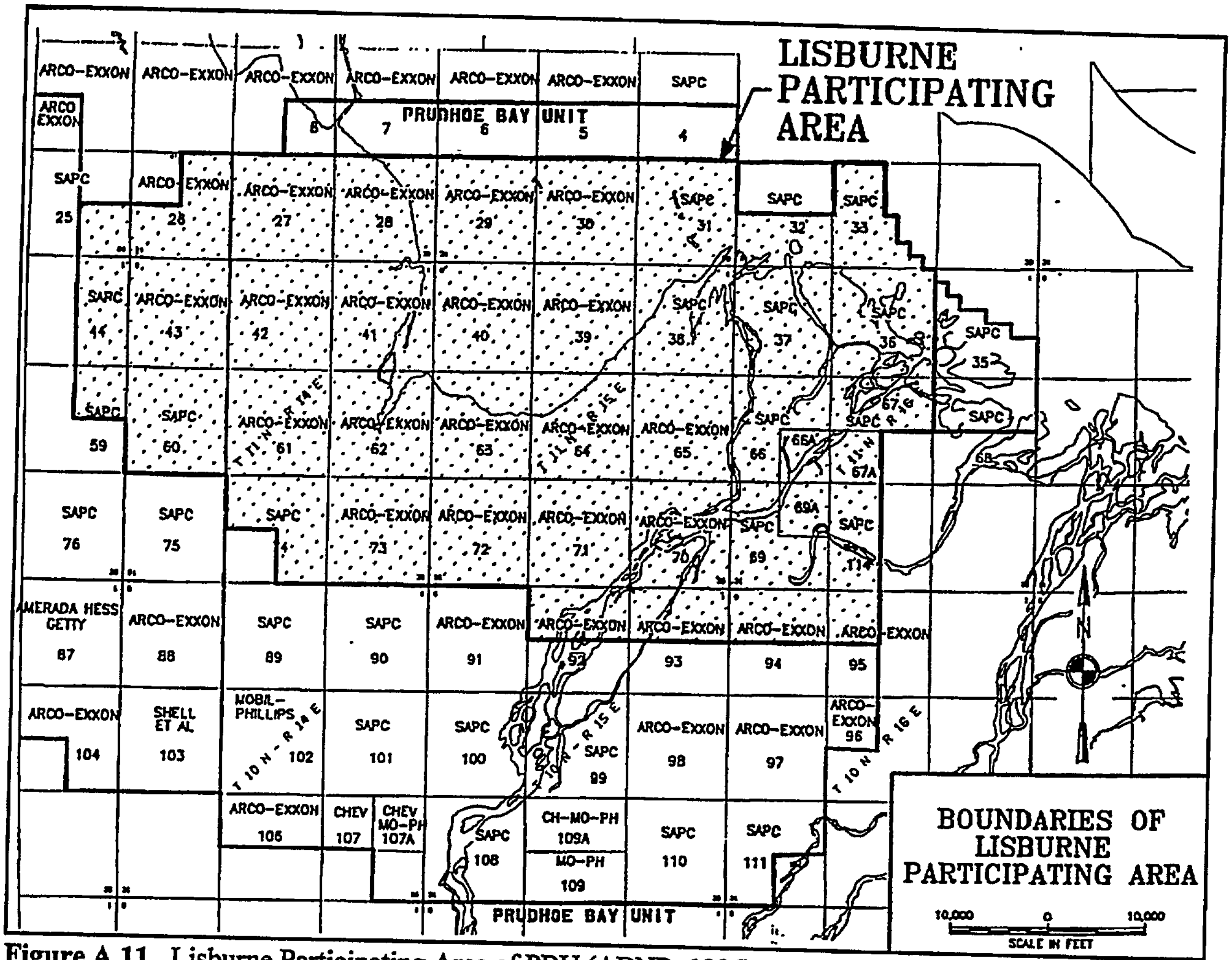

Figure A.11. Lisburne Participating Area of PBU (ADNR, 1986).

Table A.22. LPA production forecast

Year	(MBPD)
1995	19.3
1996	17.0
1997	14.9
1998	13.2
1999	11.5
2000	10.2
2001	8.9
2002	7.9
2003	6.8

A.2.9.2.2 Investments--Future development of the LPA appears to be limited and no future development wells are currently planned. The LPA drilling and investment schedule is shown in **Table A.23.**

Table A.23. LPA drilling and investment schedule.

Year	Drilling No. Wells	Investment - 1995$, millions		
		Wells	Facilities	Total
1995	0	0	2.0	2.0
1996	0	0	1.0	1.0
Total	0	0	3.0	3.0

A.2.9.2.3 Operating Costs--The operating cost used in the previous DOE publication (1993) of $1.50/BTF (1992$), adjusted for inflation to $1.60/BTF (1995$) is used in this analysis and applied to LPA BTF to determine LPA operating cost.

The water cut relationship used in the previous DOE publication (1993) is used in this analysis to determine LPA BTF.

The LPA processing facilities and some infrastructure components are being used by Point McIntyre Participating Area (PMPA), Niakuk Participating Area (NPA), West Beach Participating Area (WBPA), and North Prudhoe Bay State Participating Area (NPBSPA) under a facilities sharing arrangement. The incremental cost to operate the LPA facilities due to the use by the other PAs is added to the LPA operating cost. Seventy % of the cost sharing fee that LPA receives from each of these other PAs is added to the LPA operating cost as an estimate of that incremental cost.

A.2.9.2.4 Facilities Cost Sharing--The cost sharing fee paid to LPA by PMPA, NPA, WBPA, and NPBSPA is included as income to LPA and is subject to State and federal income taxes, but is not subject to royalty or State production taxes.

A.2.9.2.5 Field Pipeline Tariff--Lisburne pipeline tariff has been revised as information indicates that Niakuk did not buy into the LPA pipeline (ADNR, 1991g) and for a revised throughput of 564.56 MMBBL. The initial Lisburne pipeline investment is estimated at $43.29 million (1992$), adjusted for inflation to \$46.16 million (1995\$). The resulting revised total Lisburne pipeline cost, with no Niakuk buy-in, is \$53.16 million (1995\$). The revised Lisburne pipeline tariff is \$0.32/BBL (1995\$) (see **Appendix B.1.1.1.4**) and is used in this analysis.

A.2.9.2.6 Future Producing Wells--The Set B equations in **Appendix C.1.1.6** are used to estimate the future active producing wells.

A.2.9.3 Summary. Production from the Lisburne field began in 1986. As of November 1994, a total of 87 Lisburne wells had been drilled, of which 48 are producing. Annual average production for 1994 was 21.8 MBPD. Cumulative production as of 1/1/95 was 115.1 MMBO. Remaining recovery as of 1/1/95 is estimated to be 40.0 MMBO for an ultimate recovery of 155.1 MMBO.

Analysis using the four price forecasts listed in **Table B.1, Appendix B.1.1** show that all of the forecasted liquids can be economically recovered using the EIA reference and high oil price forecasts. About 12.3 MMBO of forecasted recovery will be lost using the flat oil price scenario, and about 16.9 MMBO will be lost using the EIA low oil price forecast. The life of LPA is extended beyond the life of economic oil recovery as a result of the facility sharing fee income collected at LPC. The evaluation results are given in **Table A.24.**

Table A.24. LPA economics (1995\$).

Economic Factor[a]	Oil Price Forecasts			
	AEO95 Low	AEO95 Ref.	AEO95 High	Flat Oil Price
Remaining Project Life - yrs - Due to LPA production only - With LPC sharing income	 4 7	 9 14	 9 14	 5 10
Remaining Reserves - MMBBLS - TCF (Sales)	13.3 0	40 0	40 0	27.7 0
Investments - as spent (\$, millions)	3	3	3	3
Operating Costs - as spent (\$, millions)	856	1,473	1,473	1,168
Cash Flow - NPV_{10} (1995\$, millions)	74	200	231	156

a. Liquid reserves limited by project economics only.

A.2.10 Point McIntyre

Point McIntyre was discovered in February 1989 and was one of the largest oil field discovered in the United States during the decade of the 1980's. Hydrocarbons have been tested in the Cretaceous Seabee and Kuparuk River Sand formations. The Kuparuk is the main productive horizon. A more complete discussion of Point McIntyre is given in the previous DOE publication (1993).

The accumulation lies mostly offshore in Prudhoe Bay, located about 10 miles north of TAPS PS No. 1 (**Figure 1.2**). The Prudhoe Bay Unit was expanded to include all the acreage within the Point McIntyre productive area (ADNR, 1992n).

Point McIntyre is a separate participating area within the Prudhoe Bay unit. Development of the PMPA commenced during 1993 by the drilling of 15 wells (AT 1992). Total investment to develop PMPA will be reduced by the sharing of facilities owned by the Lisburne participating area (ADNR, 1992n).

A.2.10.1 Input Data. Evaluation input data are developed using published information, early production performance and empirical relationships.

A.2.10.1.1 Recoverable Oil--Estimated recovery volumes for Point McIntyre vary from a low of about 340 MMBO (AOGCC, 1993b), to a high of about 450 MMBO (ADNR, 1995c). These recovery volumes range from about 42.5% to 56.3% of OOIP. Production performance may justify the higher reserve estimate, however the lower estimate, 340 MMBO, is used in this Point McIntyre evaluation.

A.2.10.1.2 Investments--Estimates of future investments and the schedule of these investments are based on the most current unit plans and published industry estimates of total investments (Anchorage Daily News, 1994; AOGCC, 1993b; Anchorage Times, 1992). An estimated development cost of $764.5 million (1995$) is used as the investment required under the facilities sharing agreement with LPA (Anchorage Daily News, 1994). The cost to drill wells in the previous DOE publication (1993) is used in this evaluation and is $3.25 million in 1995$. With no published data available, it is assumed that about 60% of the total investment was spent in the first two years of operation. The drilling and investment schedules for PMPA are given in **Table A.25.**

Table A.25. PMPA drilling and investment schedule.

	Drilling	Investments (1995$, millions)		
Year	No. Wells	Wells	Facilities	Total
1995	12	39.0	64.0	103.0
1996	11	35.8	42.1	77.9
1997	9	29.3	21.3	50.6
1998	8	26.0	6.4	32.4
1996	6	19.5	6.4	25.9
2000	3	9.8	6.0	15.8
Total	49	159.4	146.4	305.8

A.2.10.1.3 Production Forecast--The Point McIntyre production forecast is based on the following:

- Published information (AOGCC, 1993b; ADNR, 1995c)
- Production history to date (AOGCC, 1993j; AOGCC, 1994c)
- Production decline rate of about 12%
- Peak production rate over 3-year period.

Cumulative production through December 1994 is about 45.7 MMBO. The remaining reserves of 294.3 MMBO are forecasted to be recovered over a 14-year period. The PMPA production forecast is given in **Table A.26.**

Table A.26 PMPA production forecast.

Year	MBPD	Year	MBPD
1995	104.0	2002	47.5
1996	104.0	2003	42.0
1997	91.0	2004	37.0
1998	81.0	2005	33.0
1999	71.0	2006	29.0
2000	62.0	2007	25.8
2001	54.0	2008	25.0

A.2.10.1.4 Operating Costs--Operating costs are divided between field operating costs and facilities sharing costs (ADNR 1992n). Field operating costs are based on a BTF cost factor and a water-cut relationship to determine total fluid produced. The smoothed Milne Point Unit model results **(Figure A.10)** are used for PMPA. As operating cost estimates are not in public records, the following assumptions are used:

- $1.00/BBL oil for well workovers
- $0.50/BBL oil for maintenance and repairs
- $0.25/BBL oil for field expenses.

To relate these assumptions to total fluid production, it is assumed that 732 MMBBLS of water will be produced during recovery operations. This results in a field operating cost of $0.55/BTF (1995$) and is used in the PMPA evaluation.

A.2.10.1.5 Point McIntyre Facilities Sharing Fees--PMPA production and injection fluids are processed through the LPA facilities and there are various facilities sharing fees. There is a charge of $2.00/BBL of hydrocarbons produced. This charge totals $680 MM, and is applied to the annual oil production volumes in the evaluations.

For simplification, the following sharing fees are estimated on a BTF basis.

- $0.17/BBL water handling cost. This will apply to the estimated 723 MMB water produced and a to reservoir voidage fill volume of 510 MMBBLS of water. The voidage fill volume is assumed as 1.5 BBL water/1.0 BBL oil produced. This results in a total water handling cost of $209.61 MM. On a BTF basis, this is $0.20/BTF (1995$).

- A share of the LPC operating costs is assumed at $1.00/BBL oil or a total of $340 MM. On a BTF basis this charge is $0.32/BTF (1995$).

The total facilities cost sharing fee paid by Point McIntrye is $0.52/BTF (1995$) plus the hydrocarbon charge of $2.00/BBL oil produced.

A.2.10.1.6 **Field Pipeline Tariff**--A tariff of $0.32/BBL is used in the PMPA evaluation (see **Appendix B.1.1.1.4**).

A.2.10.1.7 **Future Producers**--The Set B equations in **Appendix C.1.1.6** is used to estimate future annual producers.

A.2.10.2 **Summary.** The Point McIntyre Field was discovered in 1989. The Prudhoe Bay Unit was expanded to include Point McIntyre acreage as a new participating area. Initial development and production began in 1993. The development was made more attractive by the utilization of excess LPA facilities capacity. Ultimate reserves are estimated at 340 MMBO.

Analysis using the four price forecasts in **Table B.1, Appendix B.1.1** show that all of the forecasted liquid can be economically recovered using the EIA reference and high oil price forecasts. Using the EIA low oil price forecast, PMPA loses about 87 MMBO. About 40 MMBO are lost using the flat oil price scenario. The evaluation results are given in **Table A.27.**

Table A.27 PMPA economics.

Economic Factor	**Oil Price Forecasts**			
	AEO95 Low	**AEO95 Reference**	**AEO95 High**	**Flat Oil Price $18/BBL**
Remaining Project Life - yrs	7	14	14	10
Remaining Reserves - MMBBLS[a] - TCF (Sales)	207 0	294 0	294 0	254 0
Investments - as spent ($, millions)	282	282	282	282
Operating Costs - as spent ($, millions)	879	1,929	1,929	1,309
Cash Flow -NPV_{10} (1995$, millions)	175	649	867	532

a. Liquid reserves limited by project economics only.

A.2.11 Niakuk

The Niakuk oil pool was discovered in early 1985, by the drilling of Niakuk No. 5. Production is from the Kuparuk River sand formation. The oil pool is within the Prudhoe Bay Field (AOGCC 1994) and is located offshore north of Heald Point (**Figure 2.2**).

After efforts to develop Niakuk from an offshore gravel island were abandoned, the development of the field by directional drilling from a pad on Heald Point was initiated in 1993 (Alaska Journal of Commerce, 1993). Production began in April 1994, at about 12 MBPD. Production averaged about 15 MBPD during January 1995 (AOGCC, 1995). Peak rate of about 23 MBPD is expected by January 1996 (AOGCC, 1993h). Production is processed through the LPC (AOGCC, 1993h).

A.2.11.1 Development Plan. Future development plans include the Alapah formation (AOGCC, 1993h; ADNR, 1991g). The Alapah is included in the evaluation. Consideration will be given to development of a potential Kuparuk River oil accumulation north of the Niakuk pool (AOGCC, 1993h). A potential extension of the Kuparuk River reservoir to the west has apparently been proven and may be included in the development area (AOGCC, 1994).

Initial development is in the Kuparuk formation from a 20-well drilling pad on Heald Point. In January 1995, there were seven producers and no injectors (AOGCC, 1995). Current development plans include about 10 wells producing for 1 year. At that time, about April 1995, four or five of these wells will be converted to water injectors (AOGCC, 1995a). Ultimate development plans may include a total of nine producers and five injectors for the Niakuk Kuparuk reservoir (AOGCC, 1994). The potential reserves of the north accumulation are not included in the evaluation.

Production is processed through the LPC and excess gas above lease use are injected into the Lisburne gas cap. Pressured water for enhanced oil recovery will be obtained from PBU (AOGCC, 1993h).

A.2.11.2 Input Data. The evaluation data are developed using production history, current development plans and published information.

A.2.11.2.1 Recoverable Oil--Current estimates of OOIP for the Kuparuk River formation is 137.4 MMSTB. Original gas-in-place is estimated at 90.9 billion cubic feet (BCF) (AOGCC, 1993h). Anticipated ultimate recovery under waterflood operations is about 40% of OOIP or 54 MMBO (AOGCC, 1993h; Anchorage Daily News, 1994a). This recovery volume is adopted for evaluation.

Estimates of OOIP for the Alapah are not available. Per well recovery of 1.75 MMBO used in the previous DOE publication (1993) is adopted for this evaluation. Ultimate recovery from the Alapah in Niakuk is about 5.0 MMBO, with development commencing in 1997.

A.2.11.2.2 Investments--The previous DOE publication (1993) used total development costs of $186 million (1992$), with some facilities sharing at LPC and a buy-in of the LPA oil sales line. Since then the estimated total cost for of the project has been reduced to $130 million (1993$) (Alaska Journal of Commerce, 1993) and later to $110 million (1994$) (Alaska Daily News, 1994a). The $110 million (1994$) is adopted for evaluation. The investment total in 1995$ is $112.4 MM. Funds are not included for a buy-in of the LPA pipeline as current information indicates this did not occur (ADNR, 1991g; AOGCC, 1993h). It is assumed that technical advances have reduced drilling costs to $3.88 million (1995$) from the $6.15 million (1992$) used in the previous DOE publication (1993).

Alapah development costs are assumed to be for drilling wells only and the cost to drill Kuparuk River wells is used for the Alapah wells.

It is assumed that seven Kuparuk wells were drilled prior to 1/1/95 (AOGCC, 1995) and that about 90% of the facilities investments were spent prior to 1/1/95. The estimated future investments for the Kuparuk River and Alapah developments are given in **Table A.28.**

Table A.28. Niakuk drilling and investment schedule.

Year	Wells		Investments - 1995$, millions		
	Kuparuk	Alapah	Wells	Facilities	Total
1995	7	0	27.2	5.6	32.8
1996	0	0	0	0	0
1997	0	2	7.8	0	7.8
1998	0	1	3.9	0	3.9
Total	7	3	38.9	5.6	44.5

A.2.11.2.3 Production Forecasts--Published information indicate a productive life of 15 years for the Kuparuk River (Alaska Journal of Commerce, 1993; Alaska Daily News, 1993). Peak oil rate is expected to be between 20 MBPD and 25 MBPD (ADNR, 1991g; Alaska Daily News, 1994a). The State has limited the oil rate to 23 MBPD (AOGCC, 1994), and that rate is used in the evaluation. A Kuparuk

River production forecast was provided to the state in October 1993 (AOGCC, 1993h). The Kuparuk forecast is determined using a 2 year peak rate of 23 MBPD and a decline rate of about 17% per year over a 9 year life. The production rate forecast for the Alapah is patterned after the forecast developed in the previous DOE publication (1993).

The individual production forecasts for the Kuparuk River sands and the Alapah, and the total project forecast are given in **Table A.29.** Total volume forecasted is about 56.0 MMBO. With cumulative production of about 3.4 MMBO, ultimate recovery totals 59.4 MMBO.

Table A.29. Niakuk production forecast (MBPD)

Year	Kuparuk	Alapah	Total
1995	18.5	0	18.5
1996	23.0	0	23.0
1997	23.0	0.5	23.5
1998	19.1	2.5	21.6
1999	15.8	2.5	18.3
2000	13.1	2.5	15.6
2001	10.9	2.1	13.0
2002	9.0	1.8	10.8
2003	7.5	1.6	9.1

A.2.11.2.4 Operating Costs--In the previous DOE publication (1993), operating costs were divided between field costs (well operation, maintenance, and well workovers) and cost sharing fees for use of the LPC facilities. Both operating costs were based on a BTF cost factor, using the Milne Point Unit model water cut relationship (**Figure A.10**) to determine total fluid produced.

The operating cost factor of $1.13/BTF (1995$) (DOE 1993) was determined by using estimated reductions in facilities costs due to sharing in LPA facilities. Recent information indicates the LPA operator is performing some of the maintenance and other day-to-day operations (Anchorage Daily News, 1993), and a reduction of the operating cost factor is made. However, well workover costs of $18.85 million (1995$) (DOE 1993) are not reduced. The previous operating cost without well workovers is $1.07/BTF (1995$).

It is assumed that the Niakuk operator will incur only 25% or \$0.27/BTF of this well workover cost. The well workover cost related to a total produced fluid volume of 236 MMBBLS is \$0.08/BTF. The total of these two cost factors gives a revised operating cost of \$0.35/BTF (1995\$) that is used in the evaluation.

A.2.11.2.5 Facilities Sharing Fees--The provisions for Niakuk to share in the LPA facilities are not known. The facilities sharing fees for Niakuk are patterned after the cost sharing agreement between Point McIntyre and the LPC (ADNR, 1992n), that sets out various individual fees. There is a charge of \$2.00/BBL for hydrocarbons processed. This charge is applied to the annual produced oil volumes, and for Niakuk, totals about \$118 million (1995\$).

For simplification, the following sharing fees are estimated on a BTF basis:

- \$0.17/BBL water handling costs. This is applied to the estimated 177 million barrels of water (MMBW) water produced and a reservoir voidage fill volume of 89 MMBW. Voidage fill is assumed at 1.5 BBL of water per 1.0 BBL oil produced. This results in a total water handling cost of \$45.2 MM. On a BTF basis, this is \$0.19/BTF (1995\$).

- \$1.00/BBL oil for a share of facilities operating costs, including gas handling, gas lift, maintenance and repairs. On a BTF basis this is \$0.25/BTF (1995\$).

- Assume the reduction of \$0.81/BTF in Niakuk operating costs resulting from the LPA's performance of field operations, less the above sharing fees, will apply as a facilities sharing cost.

The facilities sharing fee on a BTF basis totals \$0.81/BTF (1995\$) and is used in the evaluation.

A.2.11.2.6 Future Producers--The Set B equations in **Appendix C.1.1.6** is used to forecast future annual producers.

A.2.11.2.7 Field Pipeline Tariff--Niakuk oil production is shipped to PS No. 1 through the Lisburne pipeline. The estimated tariff used in the evaluation is \$0.32/BBL (1995\$) (see **Appendix B.1.1.1.4**).

A.2.11.3 Summary. The Niakuk oil pool was discovered in 1985. Production is from the Kuparuk

River sand formation. The oil pool is within the Prudhoe Bay Unit and is located offshore north of Heald Point. Initial plans to develop from an offshore island were abandoned in 1991. Later plans to develop from a shore site were initiated. Final plans included utilizing excess processing capacity at LPC. With engineering improvements, the total cost to develop Niakuk, including the Alapah, was reduced from about $200 million (1995$) estimated in the previous DOE publication (1993), to the current estimate of $123.7 million (1995$) total investment. The estimated remaining recoverable oil volume is 55.6 MMBO (proven reserves).

Analysis using the four price forecasts listed in **Table B.1, Appendix B.1.1** show that all of the forecasted liquids can be economically recovered using the EIA reference and high oil price forecast. About 18 MMBO are lost using the EIA low oil price forecast. The project loses about 7 MMBO when the flat oil price scenario is used in the project economics. The evaluation results are shown in **Table A.30.**

Table A.30 Niakuk economics.

Economic Factor[a]	**Oil Price Forecasts**			
	AEO95 Low	**AEO95 Reference**	**AEO95 High**	**Flat Oil Price $18/BBL**
Remaining Project Life - yrs	5	9	9	7
Remaining Reserves - MMBBLS - TCF (Sales)	38.3 0	55.6 0	55.6 0	48.7 0
Investments - as spent ($, millions)	45.6	45.6	45.6	45.6
Operating Costs - as spent ($, millions)	161.2	378	378	259
Cash Flow - NPV_{10} (1995$, millions)	18.6	100	146	93
a. Liquid reserves limited by project economics only.				

A.2.12 Other Fields

The West Beach and North Prudhoe Bay State are two small PAs within PBU. Currently each has one producing well. These two PAs are discussed in the following sections.

A.2.12.1 West Beach Participating Area. WBPA is located offshore, north of the Lisburne Production Center. WBPA became effective during 1993 (AOGCC, 1993c), with initial production from the Kuparuk River sand formation in April 1993. Cumulative recovery, from WBPA No. 4, totaled about 1.25 MMBBLS (oil and NGLs), through (12/31/95) (AOGCC, 1994c).

A.2.12.1.1 Recoverable Oil--Estimates of OOIP in the Kuparuk formation range from 12 to 65 MMBO (AOGCC, 1993). Potential wells for recovery ranging from 1 for the lower OOIP volume to 12 wells if the upper OOIP volume is proven. Information indicates a very minor gas cap is present (AOGCC,1993a). Based on performance to date, future recovery from Well No. 4 is estimated at about 0.620 MMBO (oil and NGLs) over the next four years. Ultimate recovery is about 1.87 MMBO or about 15% of OOIP (of 12 MMBO). That is a reasonable recovery for primary operation only.

A.2.12.1.2 Current Operations--All produced fluids are processed through LPC facilities (AOGCC, 1993). Excess gas is injected into the Lisburne gas cap (AOGCC 1993a). No details of the facilities sharing arrangement with LPC are available, however, it is assumed such fees would be similar to those set out for Point McIntyre (ADNR, 1992n).

A.2.12.1.3 Future Plans--At present, there are no published plans for additional development nor have any additional wells been permitted through February 1995 (AOGCC, 1995).

A.2.12.1.4 Summary--Ultimate recovery from WPBA No. 4 is expected to total about 1.87 MMBO. Based on available information, it is concluded that further development of the WBPA would result in marginal economics. Lacking information on future development plans, it is assumed that further development will not occur.

Because of the small amount of future reserves (0.620 MMBO), WBPA is not included in the economics evaluations of producing North Slope fields. Its exclusion will have a minimal effect on the study results.

A.2.12.2 North Prudhoe Bay State Participating Area. NPBSPA is located on the Prudhoe Bay shoreline north of the Lisburne Production Center. NPBSPA became effective in 1994 (ADNR, 1994p). However, initial production began in October 1993, to aid in determining the potential of the Ivashak, Sag River, and Shublik reservoirs. Production is from North Prudhoe Bay State No. 3.

A.2.12.2.1 Recoverable Oil--Cumulative production through 12/31/94 totaled about

1.2 MMBO, however, monthly history is incomplete and difficult to analyze (AOGCC, 1994c). An indicated OOIP of 12.13 MMB is given in the Tract Participation Table presented in the application to form the participating area (ADNR, 1994p). Other information indicates an OOIP of 12 MMBO and an OGIP of 31 BCF (AOGCC, 1994c). Expected ultimate recovery (% of OOIP) is not available. An assumed 35% recovery factor gives total recovery of about 4.2 MMBO. This recoverable oil volume is adopted for this study and results in future recoverable oil of about 3.0 MMBO.

A.2.12.2.2 Current Operations--All Produced fluids are processed through LPC facilities (ADNR, 1994p). Excess gas is injected into "another Greater Point McIntyre Area reservoir" (ADNR, 1994p), which is assumed to be the Lisburne gas cap. No information is available on the facilities sharing agreement with LPC, however, it is assumed sharing fees are similar to those set out for Point McIntyre (ADNR, 1992n).

A.2.12.2.3 Future Plans--At present there no published plans for additional development at NPBSPA, nor have any additional wells been permitted through February 1995 (AOGCC 1995).

A.2.12.2.4 Summary--Ultimate recovery for NPBSPA is estimated to total about 4.2 MMBO (oil and NGLs). Based on available information, it is believed that further development of the NPBSPA would result in marginal economics. Lacking information on future development plans, it is assumed that further development will not occur.

Because of the small amount of future reserves (3.0 MMBO), NPBSPA is not included in the economic evaluations of producing North Slope fields. Its exclusion will have a minimal effect on the study results.

A.2.13 Summary of Producing Fields.

The Prudhoe Bay field was discovered in 1968, with initial production occurring in 1977. Since then an additional 9 oil pool have been developed for production in the immediate area, with the most recent being Niakuk in 1994. Annual average production peaked in 1988 at just over 2 MMBOPD, when PBU production began to decline. The other developed oil pools were not large enough - in comparison - to offset the decline at PBU. The ten active projects on the North Slope produced about 1,700 MBOPD at the start of 1995. Cumulative ANS recover of oil, condensate, and NGLs totaled about 10,500 MMBBLS at 12/31/94.

Future recoverable oil, at 1/1/95, is estimated at about 6,100 MMBBLS through 2025. The historic and projected oil production from the developed fields on the North Slope is shown in **Figure A.1.**

Project evaluations show that all of the forecasted liquid hydrocarbons can be economically recovered using the EIA reference and high oil price forecasts. The use of the EIA low oil price scenario results in a reduction of about 2,200 MMBO recovery and the shortening of the producing life to 2006. The use of the flat oil price scenario results in a reduction of about 370 MMBO with a productive life through 2015. This demonstrates the sensitivity of ANS oil production to oil pricing, and also to the obvious need to discover and develop potential ANS reserves before the PBU and TAPS infrastructures are lost.

The composite North Slope production forecasts for the case without major gas sales, with major gas sales, and with a GTL converted liquids sales case are shown in **Figures 2.3, 2.4**, and **2.9**, respectively. As indicated by the analysis and discussion in this section, the interest and commitment to the North Slope area continues to be high. However, it is clear that without additional development and new discoveries, the existing fields will reach the lower limits of TAPS operation in 2009 for a minimum throughput rate of 400 MBOPD and in 2016 for a minimum of 200 MBOPD. The effects of an economic GTL conversion technology on maintaining the viability of the North Slope oil production capability is clearly demonstrated in **Figure 2.9.**.

A.3 Fields with Development Potential

The North Slope has many discovered, but undeveloped fields with resources totaling over 1 billion BBL oil and 4 TCF gas. They range from very small fields to large fields with billions of barrels of liquids in place and 3 TCF gas. Oil fields included are West Sak, Ugnu, Fish Creek, Umiat, Simpson, Gwydyr Bay, Northstar, Hammerhead, Colville Delta, Sandpiper, Badami, Kuvlum, Sourdough, and Cascade (see **Figure 2.1**). Gas fields included are Meade, Wolf Creek, Gubik, Square Lake, Kavik, Kemik, Point Thomson/Flaxman Island, and Walakpa (see **Figure 2.1** and **Figure 2.2**) (Bird, 1990; AOGR, 1995e; OGJ, 1995c; ADNR, 1995c).

Although these fields are small by North Slope standards, they would most likely have been developed if located in the Lower 48. However, with the apparent cooperation between the State and operators, combined with the State of Alaska's need for additional revenues, and the declining North Slope production, several of the marginal oil fields are getting renewed study for development possibilities

(AOGR, 1995e). Development of the more promising of these resources, could extend the life of the North Slope producing properties, which would allow more time for additional oil exploration and potential development, as well as, allowing time for the development of a gas sales scenario.

It is probable that most, if not all, of the gas resource accumulations were discovered by exploration efforts looking for oil. Based on gas discoveries to date, it is likely that many more gas accumulations could be discovered that might allow facilities sharing arrangements similar to those currently being employed in the PBU area.

Several of the more prominent oil and gas resource accumulations are discussed in the following sections. The first discussion is for the Point Thomson Unit (PTU), which contains the second largest gas resource on the ANS.

A.3.1 Point Thomson Unit

The Point Thomson Unit (PTU) covers a gas condensate field about 50 mi east of TAPS PS No. 1. The unit contains about 83,800 acres, much of which is offshore (**Figure 2.2**). Discussions are apparently in progress on possible contraction of the unit area; however, the outcome of these discussions is not known at this time (ADNR, 1994t). [A detailed description of the Point Thomson field is contained in the previous DOE publication (1993)]. Early estimates of PTU reserves carried by the ADNR (1991a) were 5 TCF gas and 300 MMBBLS of oil and condensate. The possibility of a reduced reservoir size was mentioned in a letter from the unit operator to the ADNR (1991e). The current reserve estimates for the PTU carried by the ADNR (1995c) are 3 TCF gas and 200 MMBBLS of oil and condensate. The Alaska Department of Revenue (ADOR) does not include major North Slope gas sales in their Spring 1995 forecast of revenue (ADOR, 1995).

A.3.1.1 Date of Initial Production. The date of initial production is unknown. A number of articles have been published that discuss sale of North Slope gas with possible dates of first gas sales varying from 1997, at the earliest, to beyond 2010 at the latest (Anchorage Times, 1991a; Anchorage Times, 1991b; Anchorage Times, 1991c; Anchorage Daily News, 1992). The date of first gas sales from PTU is dependent on gas sales from PBU or some large undiscovered gas field with PBU-size reserves to justify a gas sales market. Any gas sales scenario is dependent on an end-point market willing to pay a price to justify the total project. The following assumptions are made concerning the development of PTU.

1. Gas is sold in the PBU area for transport to an LNG plant at Valdez for shipment to Asian markets or to a GTL plant that is expanded to handle PTU gas as well as the PBU gas.
2. A gas sales system is completed by 2005 (Anchorage Daily News, 1992).
3. PBU gas becomes available during the year 2005. A ramp-up of 5 years is used for gas sales to reach 2.05 BCF/D.
4. PTU development begins in 2002 with first production about 2008.

A.3.1.2 Evaluation Data. Public data are used where available; otherwise, best judgement estimates are made. Well and test information are used extensively.

A.3.1.3 Reservoir Volume. The reserves carried by the ADNR (1995c) are used as a guide in developing the base case.

A.3.1.3.1 Reservoir Area--To obtain an independent estimate of field reserves an approximate field size is required and used to determine the number of wells for field development. Information obtained from the exploratory wells in the Point Thomson area is used to estimate a possible reservoir limit boundary. This limit is shown by the solid line on **Figure A.12** and contains 23,800 acres.

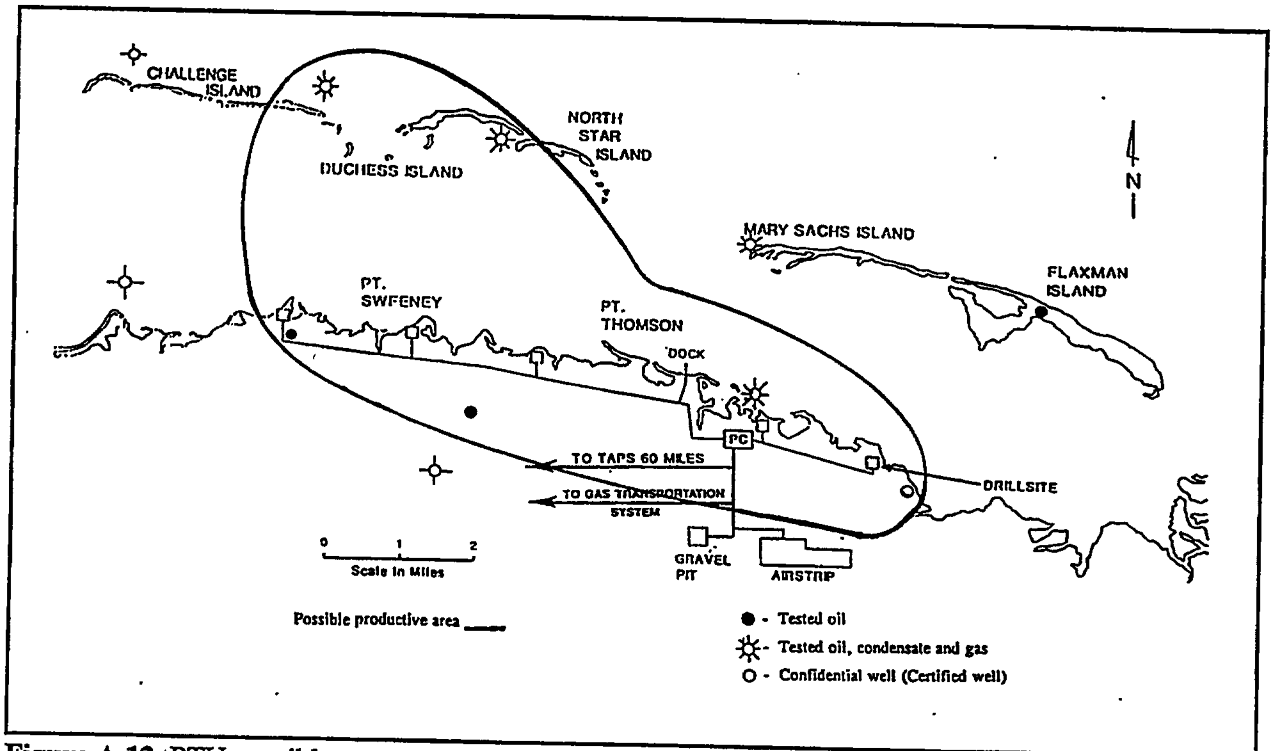

Figure A.12 PTU possible reservoir limit.

A.3.1.3.2 Development Plan. One possible gas sales development scenario is based on the reservoir area of 23,800 acres. This scenario assumes the area can be drained from 32 wells drilled from onshore pads. The five onshore drillsites are connected to a central processing center (**Figure A.13**). Two pipelines are required, one for liquid sales to TAPS PS No. 1, and the other to a gas sales point in the Prudhoe Bay field area. **Figure A.14** shows a possible sales pipeline and main road corridor. **Figure A.14** also shows the five major river crossings that the pipelines and road would encounter.

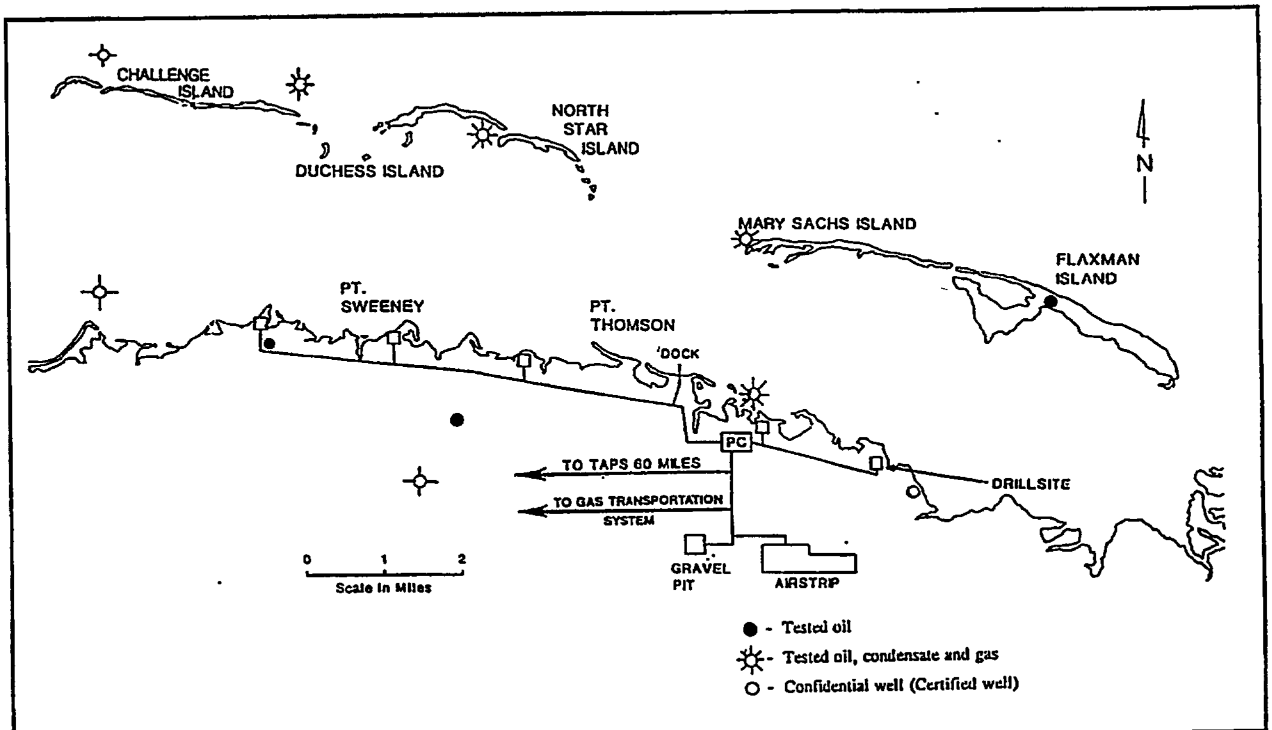

Figure A.13. PTU possible development plan for gas sales.

A.3.1.3.3 Reservoir Parameters--The following reservoir parameters are used to determine gas volumes (ADNR, 1988; USGS, 1987).

- S_w = 35% (Assumed)
- h = 110 ft (The Pt. Thomson sand is up to 300 ft thick. Two hundred feet is assumed as the average thickness. The Flaxman sand is 70 ft thick in one well, but is limited to the northern area. In determining net pay, 70 ft is assigned to 1/4 of the productive area. Pre-Mississippian sand is present in two wells; therefore, 5 ft is assigned to 1/20 of productive area. A net-to-gross ratio of 0.50 is assumed, resulting in an average pay thickness of about 110 ft.)
- ϕ= 20% (Varies by zone: Pt. Thomson - 5 to 25%, Flaxman >20%, Pre-Mississippian - No record. An average of 20% is assumed for all zones.)

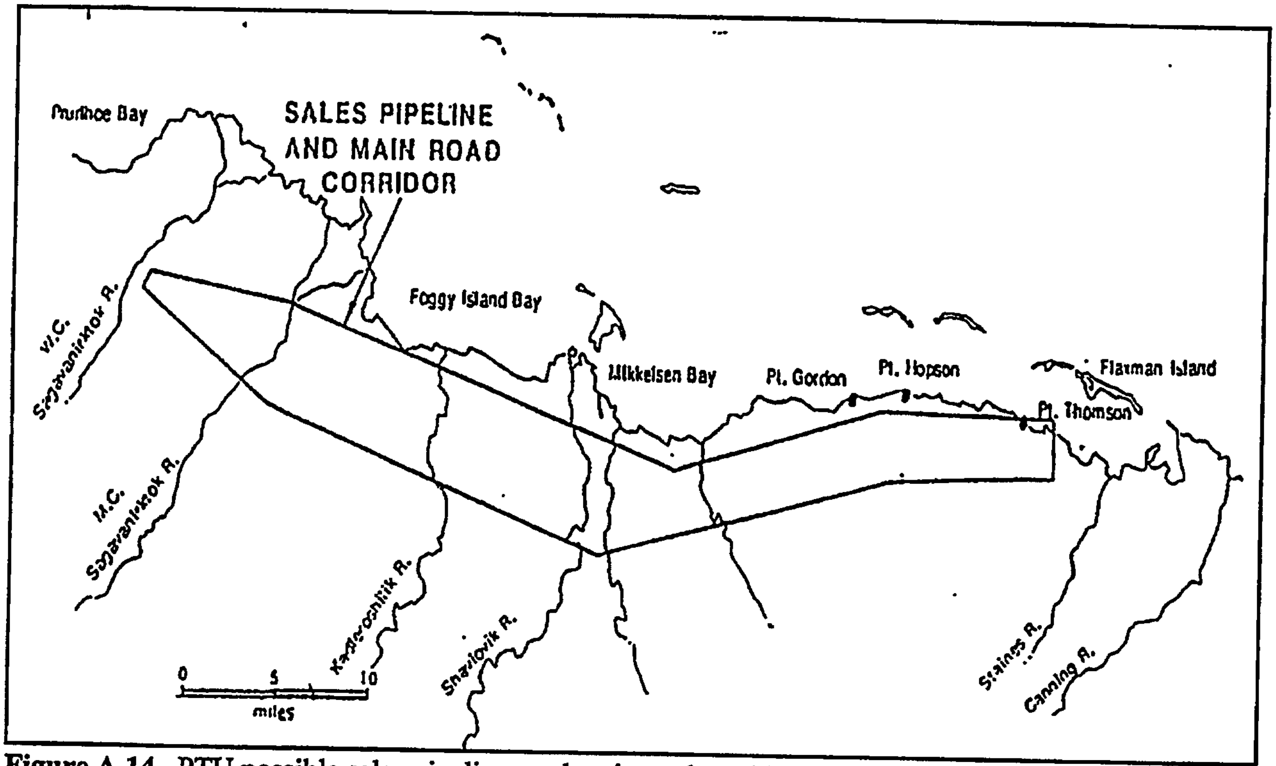

Figure A.14. PTU possible sales pipelines and main road corridor.

- A = 23,800 acres
- Reservoir temperature (T_r) = 238°F or 698°R
- Reservoir pressure (P_r) = 10154.7 PSIA
- Gas gravity = 0.8 (Assumed)
- Gas compressibility at surface (Z_s) = 1.0
- Gas compressibility at reservoir conditions (Z_r) = 1.45 (Assumed)
- Surface pressure (P_s) = 14.7 PSIA
- Surface temperature (T_s) = 60°F or 520°R
- RF = 70%.

A.3.1.3.4 Recoverable Gas--The volume of the reservoir occupied by gas, the volume of that gas at surface conditions, and the estimated recoverable hydrocarbon gas volume using the 23,800-acre reservoir are as follows:

(1) Reservoir gas volume, G_r = 14.83 TCF

(2) Gas volume at surface conditions, G_s = 5.26 TCF

(3) Recoverable gas (including CO_2 + liquids), G_p = 3.68 TCF

(4) G_p = 3.54 TCF w/o CO_2 (at 4%).[a]

Based on available and assumed data, the net gas available for sales is determined as follows:

- Gas-in-place (DOE, 1995) = 5.26 TCF
- Recoverable wet gas volume (70% RF) = 3.68 TCF
- Estimated lease use and shrinkage (10%) = 0.37 TCF
- CO_2 removal (4%) = 0.13 TCF
- Net hydrocarbon gas available for sale = 3.18 TCF

A.3.1.3.5 Recoverable Hydrocarbons--The volumes estimated in **Appendix A.3.1.3.4** are wet gas. The wet gas is reduced for shrinkage from condensate removal and by adjusting for the reservoir occupied by the oil column. With an assumed 10% reduction, the revised gas reserve is in close agreement with reserve estimate of 3 TCF. The States' current reserves estimates of 3 TCF and 200 MMBBL condensate are used as guides in this evaluation.

A.3.1.3.6 Production Forecasts--A possible gas sales scenario is for a maximum production rate of 500 million cubic feet per day (MMCFPD) of wet gas. It is assumed that 60 MMCFPD accounts for fuel, liquid shrinkage, and CO_2 removal. The CO_2 volume is 20 MMCFPD, using a 4% CO_2 concentration. A maximum sustainable dry gas sales rate of 440 MMCFPD is assumed starting in 2008. Gas sales can be continued for 19 yrs at 440 MMCFPD and with a reduction to 350 MMCFPD in the 2027 to match the estimated gas available for sale of 3.18 TCF for a 20-yr life. It is assumed that PTU will be capable of delivering gas at the assumed gas sales rate without a falloff in the last few years of production.

The average oil rate for five drillstem tests (DSTs) is about 650 BOPD (ADNR, 1988; USGS, 1987). It is assumed that oil production averages 400 BOPD/well for the first year and goes on decline at about 20%/yr. The last year of oil recovery will be 2013. This results in oil recovery of 12.8 MMBO.

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a. Exxon Company U.S.A., personal communication, September 12, 1991.

Information on liquid recovery is very limited. Both oil and condensate are produced with the gas. It is assumed that the 40°API condensate and oil mixture can be stabilized to meet TAPS specifications. Based on DST results, the condensate yield could be between 40 and 80 BBLS/per million cubic feet (MMCF) (ADNR 1988, USGS 1987). An initial condensate ratio of 70 BBLS/MMCF of wet gas is assumed in forecasting condensate rates. The estimated condensate production profile follows curve C of **Figure A.15.** A peak condensate ratio of about 80 BBLS/MMCF is reached in years 5 and 6 before declining to about 18.0 BBLS/MMCF in 2027. This rate forecast results in a recoverable volume of condensate of 194.2 MMBBLS over the 20-yr life. Hence, the potentially recoverable oil and condensate is 207.0 MMBBLS. The oil, condensate, and the gas forecasts are given in **Table A.31.** All 207.0 MMBBLS is recovered for the GTL option; however, for the LNG option, no liquids are sold after 2021 because of the shutdown of PBU oil production in 2021 (see **Table A.4**) resulting in a drastic increase in TAPS tariffs. This causes the PTU oil and condensate total recovery to be reduced to 181.4 MMBBLS.

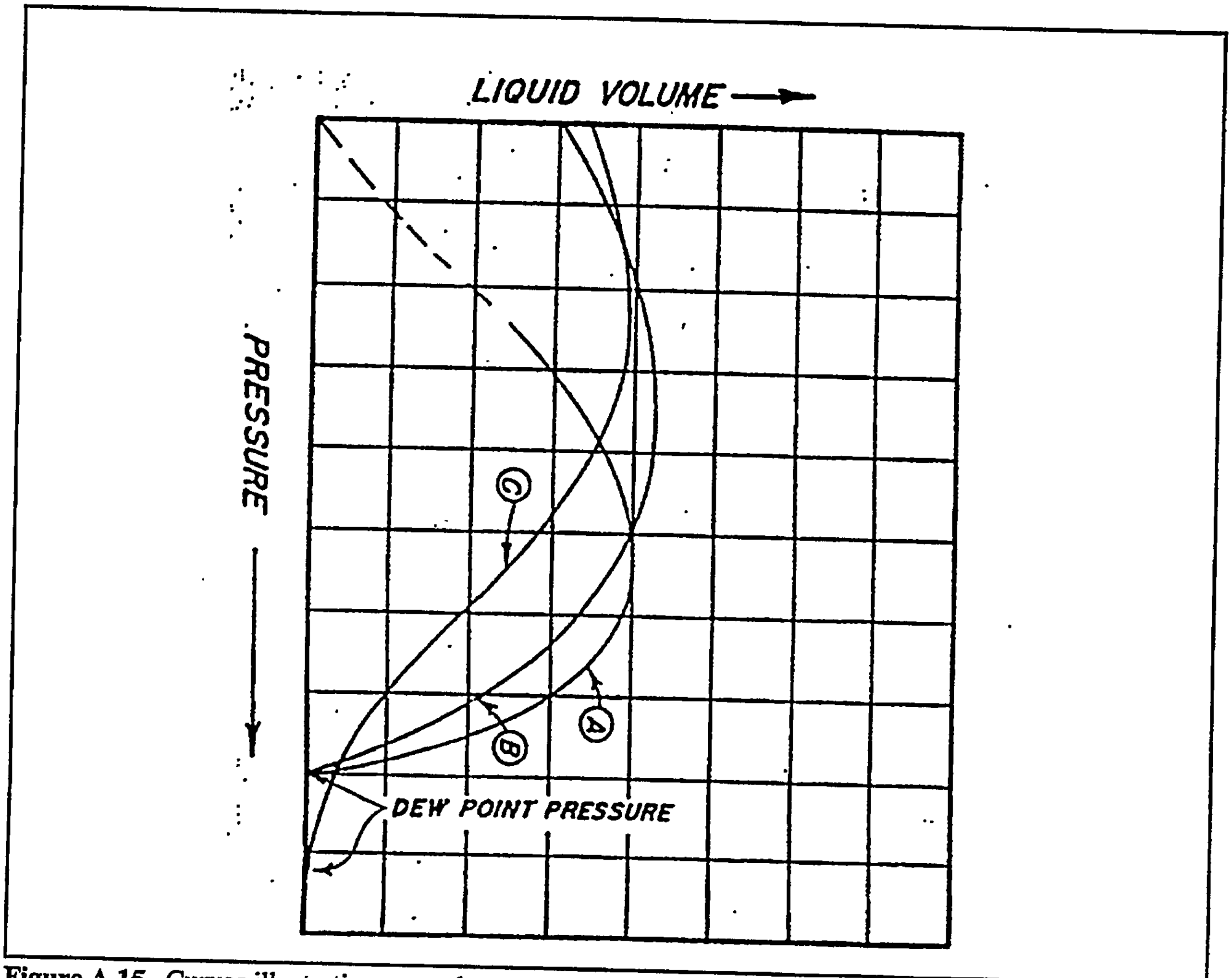

Figure A.15. Curves illustrating several types of liquid behavior of condensate systems (Standing, 1977).

Table A.31. PTU production forecasts.

Year	Condensate		Oil (MBPD)	Sales Liquids (MBPD)	Gas	
	Ratio (BBL/MMCF)	Recoverable (MBPD)			Wet Gas (MMCF/D)	Gas Sales (MMCF/D)
2008	71.1	35.53	9	44.53	500	440
2009	77.6	38.80	8	46.80	500	440
2010	79.5	39.75	6	45.75	500	440
2011	80.0	40.00	5	45.00	500	440
2012	79.9	39.95	4	43.95	500	440
2013	78.2	39.10	3	42.10	500	440
2014	75.8	37.90	0	37.90	500	440
2015	72.0	36.00	0	36.00	500	440
2016	67.5	33.75	0	33.75	500	440
2017	61.9	30.95	0	30.95	500	440
2018	54.2	27.10	0	27.10	500	440
2019	48.2	24.10	0	24.10	500	440
2020	41.5	20.75	0	20.75	500	440
2021	36.7	18.35	0	18.35	500	440
2022	30.9	15.45	0	15.45	500	440
2023	28.1	14.05	0	14.05	500	440
2024	24.7	12.35	0	12.35	500	440
2025	22.0	11.00	0	11.00	500	440
2026	20.0	10.00	0	10.00	500	440
2027	18.0	7.20	0	7.20	400	350

A.3.1.3.7 Investments--Methods to estimate investments for production facilities and field pipelines are discussed in the following section.

A.3.1.3.7.1 Facilities Investments--Facilities investments are estimated using a facility cost factor of $16,210/BBL (1995$) of peak rate of production as discussed in **Appendix B.1.7.1.1.** The peak rate is determined by converting the produced wet gas volume to equivalent barrels using an assumed factor of 13.5:1. Because PTU is at a remote location, the facilities cost is increased by a factor of 1.2. The facilities investment estimated by this approach is $720.4 million (1995$). The estimated cost to drill and complete development wells in an overpressured reservoir, from an onshore drilling pad is about $4.83 million (1995$). The total number of wells is estimated using the area within the dashed line on **Figure A.12.** Spacing of 740 acres/well is assumed. This results in 32 wells for this scenario.

The facilities investment includes onshore facilities, pads, field roads and pipelines, causeway to a dock, airstrip, separation and treatment facilities, and compression (as needed for sales and for CO_2 disposal). The assumed investment schedule spans 6 to 7 years of which about 2 years are for environmental impact statement preparation ($2.8 million in 1995$) and approval followed by 4 to 5 years for design, construction, shipping, installing facilities and pipelines, and for drilling wells. Twenty producing wells are drilled and completed by the date of initial sales with the remaining 12 wells drilled over the next 2 years. The resulting investment schedule is shown in **Table A.32.**

Table A.32. PTU drilling and investment schedule.

Year	Wells	Investments - 1995$, millions		
	No.	Wells	Facilities	Total
2002	0	0	2.8	2.8
2003	0	0	0	0
2004	0	0	17.2	17.2
2005	5	24.2	255.6	279.8
2006	7	33.8	222.4	256.2
2007	8	38.6	222.4	261.0
2008	6	29.0	0	29.0
2009	6	29.0	0	29.0
Totals	32	154.6	720.4	875.0

A.3.1.3.7.2 Pipeline Investments--This development scenario requires both a gas and liquids line. To simplify the economic evaluation, it is assumed an outside concern will build and operate both lines. The estimated cost to construct the gas and oil pipelines to the Prudhoe Bay area is determined using data from

Han-Padron (MMS, 1985). Assumptions used in this estimate are:

- 75% of the lines are below ground.
- One haul road is constructed.
- A reduction of 25% is realized in the investment for the smaller line when two lines are constructed simultaneously.
- The liquid line connects to the Endicott pipeline at the closest point.
- The gas sales line is south of the PBU central gas facility.

The estimated cost to construct the liquids line is $130.2 million (1995$) and the gas line is estimated to cost $154.8 million (1995$). Tariffs for the throughput volumes are discussed in **Appendix A.3.1.3.9.**

A.3.1.3.8 Operating Costs--There are no published estimates of operating costs for PTU. The method using a cost per barrel of total fluid and water-cut percentages related to ultimate recovery are not applicable at PTU because it is primarily a depleting gas condensate reservoir. An empirical method is used to estimate PTU operating costs (**Appendix B.1.5.1**). Cumulative inflated investment and a 5% factor are used to determine annual operating costs. Because all wells are required for deliverability throughout the project life, operating costs are not reduced in late project years.

A.3.1.3.9 Field Pipeline Tariffs--The PTU development scenario assumed for this evaluation, requires that both a gas and a liquids sales line be built and pipeline tariffs charged.

A.3.1.3.9.1 Liquids Line--The PTU liquids pipeline is connected to the Endicott pipeline. A separate and revised field pipeline tariff is calculated for both the PTU liquids pipeline and for the Endicott pipeline for the increased throughput. A tariff is calculated separately for the PTU liquids pipeline segment using the formula in **Appendix B.1.1.1.4**, a pipeline cost of $130.2 million (1995$) and a liquids throughput volume of 181.4 MMBBLS for the LNG option and 207 MMBBLS for the GTL option. The tariffs for the PTU liquids pipeline segment are $2.40/BBL for the LNG option and $2.11/BBL for the GTL option.

It is assumed the closest tie-in point is located about mid-way on the Endicott pipeline or about 12 miles from PS No. 1. Using the currently estimated Endicott pipeline tariff of $0.68/BBL (1995$) for a throughput of 470.6 MMBO (**Appendix B.1.1.1.4**) the adjusted tariff after adding the PTU liquids sales volume of 207 MMBBLS, is \$0.24/BBL (1995\$). That tariff is applicable only to the Point Thomson liquids.

The total field tariff for PTU liquids is the sum of these two tariffs or \$2.64/BBL for the LNG option and \$2.35/BBL for the GTL option.

A.3.1.3.9.2 Gas Line--The PTU gas pipeline is connected to a central plant owned by the gas purchaser. The tariff is calculated by using the formula in **Appendix B.1.1.1.4** with a gas pipeline cost of \$154.8 million (1995\$) and the gas sales volume of 3.18 TCF. The tariff is \$0.16/MCF (1995\$) for both LNG and GTL options.

A.3.1.3.10 Gas Sales Price--The gas sales price is determined by the method discussed in **Appendix B.1.3** for both the LNG and the GTL options.

A.3.1.3.11 Royalty Rate--The majority of tracts carry 12.5% royalty, six tracts carry high NPIs or sliding scale royalty. An average royalty of 14.25% is assumed.

A.3.1.3.12 TAPS Tariff--TAPS tariffs are determined as discussed in **Appendix B.1.1.1.2** for the LNG and GTL options. For the GTL option, this includes the addition of the liquid sales stream from the Prudhoe Bay area GTL plant to the producing fields oil production streams.

A.3.1.4 Summary. The Point Thomson field is a gas condensate resource in a deep overpressured reservoir that is located mostly offshore. It is not located close to the PBU infrastructure, but is 50 miles east of TAPS PS No. 1. It does not appear that development of Point Thomson for sales of liquids alone is economically feasible (ADNR, 1994t). In addition to the technical problems associated with developing a deep overpressured offshore field using highly deviated wells, the size of the resource is still questionable (ADNR, 1994t). Current estimates of recoverable gas reserves is 3.18 TCF.

The estimated Point Thomson reserve volume will not, by itself, justify the development of facilities for sale of North Slope gas. Sales from the much larger PBU gas cap, or a similar size gas reserve, will be required to justify any sales scenario. The earliest this might occur from PBU is about 2005 (**Appendix A.2.2**). However, before any gas sales can occur from the North Slope, a gas market must be available that will provide a purchase price for the gas that can justify development of the gas resources and the required infrastructure and facilities. In addition, the Point Thomson project faces the construction of field delivery lines to the Prudhoe Bay area that will encounter five major river crossings and be in the coastal plain. The impact of these conditions will not be determined until environmental assessments are conducted.

It is assumed that initial startup of a sales to a gas sales project (LNG or GTL) occurs in 2008. PTU oil, condensate, and gas production forecasts were given in **Table A.31.** The project life for PTU for both gas sales projects is 20 years. However, liquid production stops in 2021 for the LNG option due to the loss of PBU oil production that would result very high transportation tariffs and an almost certain shutdown of TAPS under even the most optimistic assumptions about TAPS shutdown rates. The liquid sales forecast for the GTL option continues for the full 20-yr life of gas sales and produces 26 MMBO more liquids than in the LNG sales case. The annual gas and converted liquid sales volumes are shown in **Table B.12.**

Results in **Table A.34** compares the two gas sales scenarios for the PTU. PTU gas sales lag 3 years behind PBU to account for the assumed field development schedule. The economic results are about the same for either gas sales option for PTU. The economic results are discussed in **Section 5.2.4.**

Table A.34. Point Thomson Unit economics - summary (1995$).

Economic Factor	**PTU Cases using AEO95 Reference Oil Price**	
	LNG Sales	**GTL Sales**
Remaining Oil Project Life (yrs) Gas Project Life w/sales beginning in 2008 (yrs)	14 20	20 20
Reserves - million BBL - TCF	181 3.18	207 3.18
Investments at PTU ($, millions)	900	900
Gas Product Net Back (%)	28.1	15.1
Revenue from Condensate & Oil Sales ($, Millions) Maximum Revenue from Gas Sales ($, Millions) Total Revenue ($, millions)	2,300 3,900 6,200	3,400 2,900 6,300
After Tax Cash Flow ($, millions)	2,300	2,300
Discounted Cash Flow - NPV_{10} ($, millions)	350	330

A.3.3 West Sak Oil Pool

The West Sak oil pool is located within the KRU, MPU and PBU (small part) unit boundaries, at depths between 2000 and 4500 ft (See **Figure 2.2**). A detailed history and economic evaluation of West Sak is contained in the 1993 DOE publication (1993). Based on that evaluation, development of West Sak does not appear to be economic under current recovery technology and current oil prices (Anchorage Daily News, 1995a)

With about 16 billion barrels of original oil in place (OGJ, 1995c), the potential is large, but depends on improved technology and higher oil prices. The operator has announced renewed efforts to determine what research should be done to determine if the field is worth developing (Anchorage Daily News, 1995a). Three aspects of the study are reduction of drilling cost, improving completion techniques, and enhanced oil recovery processes. If after completion of these efforts, development is still not commercial, the operator intends to see if there are steps the State (reduced royalty and/or reduced taxes) and federal government (federal assistance program) will take to improve development economics (OGJ, 1995c).

Because of the uncertainties associated with this complicated field, no projection of field development can be made and therefore, no economic evaluation is included in this study.

A.3.4 Badami Field

Badami was discovered in 1990. The discovery well tested at the rate of 4,250 BOPD. A confirmation well was drilled in 1992 and two additional wells were drilled in 1995 (OGJ, 1995c). Badami is located about 35 miles east of Prudhoe Bay (See **Figure 2.1**) and may contain about 150 MMBO recoverable reserves (Alaska Journal of Commerce, 1995c). No information is publicly available on the formation or depth. Most of the reservoir is located offshore under Mikkelsen Bay and, if further drilling confirms the resource to contain at least 100 MMBO recoverable reserves, development could occur from an onshore drilling pad. Current plans call for a total of 60 wells, of which, 40 are for production, 18 are for water injection, and two are for gas injection (Alaska Journal of Commerce, 1995).

Current plans include efforts to reduce total project investments from an initial estimate of \$780 million (1995\$) to about \$320 million (1995\$) (AOGR, 1995m). Initially, produced fluid was to be shipped to Endicott for processing through an elevated pipeline. Revised planning uses a 27.9-mile, below ground, pipeline to move chilled oil to an Endicott pipeline tie-in. The estimated cost of the below ground pipeline is $50 million (1995$) or a savings of about $130 million (1995$) from an elevated line with four river crossings (OGJ, 1995c). The 20-inch pipeline is designed for a minimum 25 year life and would carry in excess of the potential 50 MBOPD from Badami. This would allow production from other possible accumulations to be shipped to PS No. 1 (Alaska Journal of Commerce, 1995).

One other requirement for development was taking steps to reduce operating costs below the best experienced on the North Slope. A crew of 12 would operate the field and there would be no permanent road connecting Badami to Prudhoe Bay (OGJ, 1995c). No other published information is available on the aspect of field operations where additional reductions might be effected (Alaska Journal of Commerce, 1995).

The operator has approached the state to change the way state royalties are determined to encourage development of this potential resource. The average royalty over the Badami leases is about 15% and could impact the development. A proposed sliding scale royalty scheme is being given consideration by the state (Alaska Journal of Commerce, 1995; Anchorage Daily News, 1995b).

The operator's approach could shorten the time between discovery and development by 3 years and allow development as early as 1997 (OGJ, 1995c). However, efforts to confirm the reservoir size are not complete and Badami is not included in the economic evaluation.

A.3.5 Kuukpik Unit

The Kuukpik unit is an exploratory unit in the Colville River delta area comprised of about 90,000 acres. It shares a common unit boundary with the northwest edge of KRU (PIC, 1992).

Exploratory efforts have been conducted in and around the unit area for several years and are continuing (ADNR, 1992d; ADNR, 1994m; PIC, 1992; Anchorage Daily News, 1995a). These efforts include geophysical programs and exploratory drilling. To date nine wells have been drilled, of which six have been reported as testing hydrocarbons. Only one well has been reported as a dry hole (PIC, 1992; ADNR 1992d). Oil recovery from two wells showed a gravity range of 21 to 32° API (ARCO, 1992). Total depth of the wells is believed to be between 9,000 and 10,500 ft (ADNR, 1992e). No data are available on the formation or the intervals tested. The reported depth is consistent with the Kuparuk River sand formation in nearby projects.

Exploratory efforts are continuing as the operator has recently drilled two additional wells in the Colville area (AOGCC, 1994c). The goal is to develop sufficient reserves to justify a stand-alone processing facility to be utilized by several accumulations in the area. Current results indicate no single accumulation is of sufficient size to justify the cost of development alone (ADNR, 1994n).

Kuukpik is not included in the economic evaluation.

A.3.6 Thetis Island Unit

The Thetis Island unit is located adjacent to the northeast boundary of the Kuukpik unit. No information is available on the results of drilling the Thetis Island No. 1. Recent exploratory efforts include a geophysical program between Thetis Island No. 1 and the Kalubik No. 1 (a Kuukpik unit well), and well information trades with the Kuukpik unit (ADNR, 1992d).

Thetis Island could be an extension of the accumulation trend discovered within the Kuukpik unit; however, additional information is required to determine the potential of any hydrocarbon accumulation in the Thetis Island unit.

A.3.7 Kuvlum Field

The Kuvlum Field is located in federal waters, 60 miles northeast of Prudhoe Bay (see **Figure 2.1**). Discovery was made in 1992 and initially was believed to contain up to 6 billion BBL oil recoverable reserves with 1 billion BBL oil as the minimum threshold for development. The field development would require expensive pipelines and other equipment to deal with crushing ice floes in the area. Additional drilling revealed potential geological and producing problems of such magnitude, that most of the original owners decided to abandon the prospect. The field, although a sizable accumulation, was described as not commercial as a stand alone project (OGJ, 1995c). One owner acquired the interests of all other owners with the belief the oil prices would rise sufficiently to make Kuvlum worthwhile to develop (Anchorage Daily News, 1995e; AOGR, 1955g).

The operator was expected to submit a development plan in early 1995 (AOGR, 1995c).

Kuvlum is not included in the economic evaluation.

A.3.8 Cascade Oil Pool

The Cascade oil pool was discovered in March 1993 by the drilling of Cascade No. 1 to a total depth of 10,109 ft in the original hole and to 9,175 ft in the sidetracked hole. The Kuparuk River formation flowed at a sustained rate of 1720 BPD. The Kuparuk sand resource accumulation is located southeast of MPU between PBU, KRU, and MPU (OGJ, 1995c). At present, there are two wells in the oil pool.[a] Expectations are that the operator will request expansion of Milne Point participating area to include the Cascade discovery (Platts, 1995b).

Plans indicate development will be from a new pad, K pad, and include a 3.3-mi road and a 3.8 mile raised pipeline to the MPU E pad. Development from K pad will be in two 20 well phases. Initial development work is expected to begin by mid-year 1995, with a one rig drilling program in late 1995. Potential production from this resource could be from 10 to 15 MBPD and 5 to 10 MCFD gas. It is expected that Cascade production will be processed through MPU facilities, and could begin as early as the second quarter of 1996 (OGJ, 1995c).

Until additional data is available, economics cannot be determined, and Cascade is not included in the economic evaluation.

A.3.9 Northstar Unit

The Northstar Unit (NU) is located in state and federal waters about 6 miles north of MPU (see **Figure 2.2**). The Northstar/Seal Island field was discovered in 1982 with oil recovery from the Sadlerochit formation (Permo-Triassic). Estimated recoverable resource is between 100 and 200 MMB) (AOGR, 1995e; OGJ, 1995c). A more complete discussion of NU is found in the previous DOE publication (1993).

The operator does not plan any additional delineation drilling, but hopes to have the field on production by about the year 2000. If development does occur, the produced fluids may be processed through MPU facilities in an effort to reduce investment costs (AOGR, 1995e; OGJ, 1995c).

A.3.10 Sandpiper Unit

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a. BP Exploration (Alaska) Inc., Personal communication, March 20, 1995.

The Sandpiper field is located about 11 miles northwest of NU in federal waters (see **Figure 2.1**). The field was discovered in 1986 when the discovery well flowed oil and gas from the Sadlerochit formation (OGJ, 1995c). The potential resource may be as large as 150 MMBO (AOGR, 1995e). If NU is developed, then Sandpiper's chance of being developed is enhanced.

A.3.11 Summary of Fields with Potential

None of the fields with potential are expected to be brought on line in the near future unless: a gas market is developed (Point Thomson), a breakthrough in enhanced oil recovery technology is achieved (West Sak), exploratory efforts prove sufficient reserves to justify development under current oil prices (Badami, Kuukpik unit, and Thetis Island unit) or if oil prices increase sufficiently to allow economical development of potential resources (this would apply to all fields with potential). Other actions that could encourage the development of marginal fields could include the reduction of State and federal revenue requirements through such steps as royalty reductions and reduced taxes.

A.4 Summary

ANS oil production started in 1977 with the startup of PBU, peaked at just over 2 MMBOPD in 1988, and averaged about 1.7 MMBOPD from ten active producing fields at the end of 1994 (**Figure A.12**). Cumulative ANS recovery (including crude oil, condensate, and NGL) totaled 10.5 billion BBL oil at the end of 1994. Remaining recoverable oil reserves from the ten developed fields at the beginning of 1995, using the EIA reference oil price forecast, is estimated to be 6.1 billion BBL oil without a major gas sales. The annual production forecasts for the developed fields and for the undeveloped field, PTU, are summarized in **Table A.36.**

Cumulative ANS net gas production (gas, including CO_2, produced and not reinjected) totaled 2.4 BCF at the end of 1994. Remaining potential net gas production at the beginning of 1995 is estimated to be 38 TCF, including 26 TCF (after CO_2 removal, lease usage and local sales, and shrinkage) potential net major gas sales volumes available. However, the ultimate volume of gas sold at the economic limits of the producing fields is estimated to be 25 TCF (including 21.8 TCF from PBU and 3.18 TCF from PTU). With major ANS gas sales, remaining recoverable oil reserves are estimated to be 5.7 billion BBL oil (including 0.4 billion BBL oil reduction in PBU reserves due to the impact of major gas sales on oil recovery) and it is estimated that PTU could add another 0.2 billion BBL oil of potentially recoverable oil for a total of 5.9 billion BBL oil. Developing GTL conversion technology has the potential of utilizing ANS gas resources to produce an additional 300 MBPD of high quality hydrocarbon liquids which could be blended into TAPS along with produced oil and could potentially produce a total of 2.8 billion BBLS of converted hydrocarbon liquids.

Discovered, but undeveloped ANS oil and gas fields (including PTU) are estimated to contain over 1.0 BBLS and 4 TCF of potentially recoverable oil and gas. Several of these undeveloped fields are being reviewed for possible future development, but it is unlikely that at current oil and gas market conditions very many of these undeveloped fields will ever be brought on production, unless a major gas sales market develops or production economics improve dramatically. Current estimates of undiscovered ANS resources are 7 billion BBL oil and 64 TCF of gas (USGS, 1995). ANS exploration activities have been greatly curtailed in recent years due to current oil and gas market conditions and exploration activity restrictions. Unless exploration activities produce positive results before the shutdown of TAPS (estimated to occur in the 2009 to 2016 timeframe), it is unlikely that any of these undiscovered resources will ever be recovered.

Table A.36. Summary ANS production forecasts.

Year	Prudhoe Bay	Kuparuk	Lisburne, M.P., Niakuk, and others	Endicott	Pt McIntyre	Pt. Thomson
1995	940.0	299.0	89.4	83.0	104.0	0.0
1996	860.0	292.0	94.8	70.5	104.0	0.0
1997	790.0	332.0	92.9	59.8	91.0	0.0
1998	720.0	332.0	82.3	50.6	81.0	0.0
1999	660.0	298.0	70.9	43.0	71.0	0.0
2000	605.0	267.0	61.6	36.6	62.0	0.0
2001	563.0	235.0	53.2	31.1	54.0	0.0
2002	520.0	207.0	46.0	26.4	47.5	0.0
2003	482.0	180.0	39.7	22.5	42.0	0.0
2004	446.0	155.0	20.8	19.1	37.0	0.0
2005	412.0	130.0	18.0	16.2	33.0	0.0
2006	380.0	106.0	15.6	13.8	29.0	0.0
2007	350.0	88.0	11.1	11.7	25.8	0.0
2008	326.0	72.0	9.7	10.0	25.0	44.5
2009	302.0	55.0	8.6	8.5	0.0	46.8
2010	280.0	40.0	5.2	7.2	0.0	45.8
2011	260.0	26.0	4.5	6.1	0.0	45.0
2012	243.0	21.0	4.0	5.2	0.0	44.0
2013	227.0	18.0	3.5	4.4	0.0	42.1
2014	212.0	14.0	3.1	3.8	0.0	37.9
2015	198.0	12.0	2.7	3.2	0.0	36.0
2016	185.0	10.0	0.0	0.0	0.0	33.8
2017	172.0	0.0	0.0	0.0	0.0	31.0
2018	160.0	0.0	0.0	0.0	0.0	27.1
2019	150.0	0.0	0.0	0.0	0.0	24.1
2020	140.0	0.0	0.0	0.0	0.0	20.8
2021	132.0	0.0	0.0	0.0	0.0	18.4
2022	126.0	0.0	0.0	0.0	0.0	15.5
2023	117.0	0.0	0.0	0.0	0.0	14.1
2024	111.0	0.0	0.0	0.0	0.0	12.4
2025	105.0	0.0	0.0	0.0	0.0	11.0
2026	0.0	0.0	0.0	0.0	0.0	10.0
2027	0.0	0.0	0.0	0.0	0.0	7.2