

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 86/2
483 SCOMM14: JOINT GAS PIPELINE COMM. (FINANCING) 1979-80

The Honorable Avram Gross
Attorney General
State of Alaska

November 20, 1979
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rector and a small Board consisting of members of the Legislative houses and the Executive Branch be appointed. The Authority would be asked to submit to the State Legislature the final proposal for a commitment of State funds and borrowing authority by no later than January 5, 1981. Obviously, such commitment would be conditioned on the entire ANGTS project proceeding on a satisfactory basis.

Only minimal funds (estimated at \$250,000) would be needed to bring the gas conditioning plant plan to the final Legislature approval stage. When the ANGTS project goes forward, the Authority could be expanded.

Attached is a report prepared by Purvin & Gertz addressing some of the technical issues involved in the construction and ownership of a gas conditioning plant.

Very truly yours,

Lazard Frères & Co.

PAL:g

Joint Gas Pipeline Committee Alaska State Legislature

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EX-OFFICIO MEMBERS

MR. ROBERT LERESCHE MR. JACK BACKMAN

To: Members of the Joint Gas Pipeline Committee
From: Mary Halloran, Research Analyst

Re: Gas Conditioning Costs and Implications for State Revenues

At one point during the national negotiations over the Northwest gas pipeline project financing, it was suggested that the producers and/or the State might be penalized for not participating in project financing through federal manipulation of the gas wellhead price or the conditioning costs. The attached paper by Alexander Hoke of the House Research Agency analyzes the potential penalties to the State from different conditioning costs scenarios. The range between the "best" case and the "worst" case from the State's perspective is \$3.9 billion.

The analysis is based on 53¢/Mcf for all conditioning costs (24.9¢/Mcf for operating costs and 28.1¢/Mcf for capital costs), and a wellhead price of \$1.95/Mcf (1980 value). The field life is estimated to be forty years.

The cases and results are as follows:

Case 1. State and producers bear all conditioning costs, operating and capital, but not through a reduction in the wellhead value. No conditioning costs are passed through to consumers. State revenue = \$16.6 billion.

Case 2. State passes through all conditioning costs; but producers bear all conditioning costs, but not through a reduction in wellhead value. State revenue = \$18.8 billion.

Case 3. State bears all conditioning costs, but not through a reduction in wellhead value; producers pass through operating costs of conditioning, and bear capital costs but not through a reduction in wellhead value. State revenue = \$17.2 billion.

Case 4. State bears all conditioning costs, but not through a reduction in wellhead value; producers pass through all conditioning costs. State revenue = \$17.3 billion.

Case 5. All conditioning costs, both capital and operating, are deducted from the wellhead value for royalty purposes. State revenue = \$15.7 billion.

Case 6. Only operating conditioning costs are deducted from the wellhead value for royalty and severance tax purposes. State revenue = \$15.1 billion.

Case 7. All conditioning costs, both capital and operating, are deducted from the wellhead value for royalty and severance tax purposes. State revenue = \$14.9 billion.

HOUSE RESEARCH AGENCY
Pouch Y - State Capitol
Juneau, Alaska 99811
465-3991

MEMORANDUM

March 10, 1980

TO: Representative Miles
FROM: Alexander Hoke *Alexander Hoke*
RE: Gas Conditioning Costs
Research Request No. 29

The following analysis is offered in response to your question regarding potential "penalties" to the State involving gas conditioning costs if the State does not participate in financing the Alaska Highway Gas Pipeline project. The Federal Energy Regulatory Commission's interpretation of the 1978 Natural Gas Policy Act lays the burden of gas conditioning costs on the producers of gas, which, in effect, precludes the State from being "penalized" with regard to conditioning costs. Our intent in this memorandum is to avoid speculating on the potential with which a "penalty" scenario may come to fruition, but rather direct our efforts to an analysis of the financial implications of a given "penalty" scenario should it occur.

Should the State of Alaska elect not to participate in gas pipeline financing, there appear to be two means by which the State could become the object of a "penalty" by the investors on the pipeline for its failure to bear a portion of the financial risk. The word "penalty" is used loosely here in reference to any disparity in treatment of the State relative to gas producers who participate in pipeline financing. Both "penalties" take the form of a differentiation in the wellhead price of gas produced at the North Slope.

Conditioning Cost Pass-Through for Pipeline Investors

The first means [and the most likely given the timbre of recent Federal Energy Regulatory Commission (FERC) ruling appeals by gas producers and potential sponsors of the Alaska Gas Pipeline] requires that FERC grant a financial hardship ruling which, in effect, permits those who participate in the financial risks of the pipeline to pass some or all of their share of the gas conditioning costs through to the gas purchasers. On the other hand, if the State chose not to participate financially in the pipeline, its share of conditioning costs would likely not be permitted to pass through to gas purchasers, resulting in an effectively lower

wellhead value for the State relative to that for pipeline investors. For example, gas conditioning capital costs amortized over 30-year terms average 28.1¢ per MCF. The operating component of conditioning costs over the productive life of the field average about 24.9¢ per MCF. If sponsors of the gas pipeline were permitted to pass this total conditioning cost of 53¢ per MCF through to the gas purchasers, their effective wellhead price would be increased from \$1.95/MCF to \$2.48/MCF. The State, on the other hand, would not be permitted to pass through the conditioning costs, and consequently, its wellhead value for royalty and severance tax purposes would remain at \$1.95/MCF (gas price ceiling fixed by 1978 Natural Gas Policy Act in 1980 dollars).

Conditioning Cost Deduction from Wellhead Price

The second method for differentiating the wellhead gas price on the basis of non-participation in gas pipeline financing involves a deduction of some, or all of the cost of gas conditioning from the wellhead price ceiling of \$1.95/MCF. In this scenario, the State of Alaska, as a consequence of non-participation in gas pipeline financing, would be "penalized" by deducting up to 24.9¢/MCF for the operating component of conditioning costs (leaving a wellhead price of \$1.70/MCF), or by deducting up to 28.1¢/MCF for capital conditioning costs (resulting in a \$1.67/MCF wellhead price), or by deducting all gas conditioning costs (which results in an effective wellhead price of \$1.42/MCF).

The "No-Penalty" Scenarios

Scenario number 1 of the attached table assumes that conditioning costs are neither deducted from the wellhead price of gas, nor permitted to be passed through to gas purchasers as a special federal allowance to offset the burdensome capital investment risks borne by those who participate in pipeline financing. The wellhead price of gas (\$1.95) is the 1980-dollar value of the price ceiling fixed in the 1978 Natural Gas Policy Act. The 35.5% figure in the fifth column represents the fraction of total industry net cash flow on the attached computer run #1, constituted by the gas net cash flow component [$39,706 \div (39,706 + 72,130) = 35.5\%$]. This percentage is used to calculate the figure for State income tax for gas production from the total State income tax listed on the computer printout.

In the last column, industry net cash flow from gas production is given as a comparative measure of industry profits relative to total State revenue in the adjacent column. The total State revenue in this "no-penalty" scenario run is \$16.6 billion.

Scenario #2 is shown on the attached table to indicate the level of increase in total revenue to the State that would accrue if the State participated in pipeline financing, and if FERC ruled that those bearing financial risk in the pipeline were permitted to pass conditioning costs (operating and capital) through to the gas purchasers. State revenues of \$18.8 billion under this scenario significantly exceed the \$16.6 billion revenues projected in the "no-penalty" scenario #1.

The "Penalty" Scenarios

Conditioning Cost Pass-Through:

Scenario #3 shows the effect of a pass-through of the operating costs of conditioning to gas purchasers allowed for gas producers only. Total State revenues = \$17.2 billion.

Scenario #4 demonstrates the impact of permitting gas producers only the transfer of conditioning costs (operating and capital) to gas purchasers--compare to Scenario #2. Total State revenues = \$17.3 billion.

Conditioning Cost Deduction from Wellhead Gas Price:

Scenario #5 shows the impact of deducting all conditioning costs (capital and operating) from the wellhead price of gas (\$1.95/MCF) for royalty purposes only. Total State revenue = \$15.7 billion.

Scenario #6 demonstrates the effect of deducting only the operating costs of conditioning from the wellhead price of gas for royalty and severance tax purposes. Total State revenue = \$15.1 billion.

Scenario #7 represents the situation in which all conditioning costs (operating and capital) are deducted from the wellhead gas price for royalty and severance tax purposes. Total State revenue = \$14.9 billion.

The Monetary Effect of Conditioning Cost Penalties

The most immediately apparent observation when comparing conditioning cost "penalty" scenarios 3 through 7 to the "no-penalty" scenario #1 are the differences in total State revenue. Scenarios 3 and 4 involving conditioning cost pass-through to gas purchasers result in higher revenues to the State than the \$16.6 billion in the "no-penalty" scenario #1. This is primarily due to the increased State income tax revenue on higher profits earned by the producers when the conditioning costs are assumed by the purchasers of gas. On the other hand, scenarios 5, 6 and 7 have lower totals for State revenue than the "no-penalty" scenario #1, because deductions of gas conditioning costs from the wellhead price of gas directly affects royalty and severance tax revenue.

Conditioning Cost Pass-Through to Gas Purchasers:

Scenario #4 demonstrates the effect of an allowed pass-through of conditioning costs to gas purchasers by the gas producers (effectively raising their wellhead gas price to \$2.48/MCF) while disallowing the pass-through for the State of Alaska (which leaves the State's wellhead value at \$1.95/MCF). Scenario #4 shows a total State revenue of \$17.3 billion indicating a "penalty" from scenario #2 of \$1.48 billion ($18.779 - 17.302 = 1.48$). Curiously, however, the total State revenue under this "penalty" situation is higher than the "no-penalty" scenario #1. In other words, even though the State may be "penalized" by not receiving the conditioning cost pass-through approval from FERC as a result of non-participation in gas pipeline financing, the State's total revenues would increase primarily due to higher income tax revenue on the producers' increased profits.

Conditioning Cost Deductions from Wellhead Gas Prices:

Scenarios 5, 6 and 7 show that total State revenues are significantly lower (than scenario #1) when operating and/or capital conditioning costs are deducted from the wellhead gas price of \$1.95/MCF. In the worst case (scenario #7) average operating costs of 24.9¢/MCF and average capital costs of 28.1¢/MCF deducted from the \$1.95/MCF wellhead price results in an effective wellhead price for State tax purposes of \$1.42/MCF. When this deduction is applicable to royalties and severance taxes, the total State revenue is reduced to \$14.9 billion compared to \$16.6 billion when no deductions are made. The magnitude of the decrease in revenues from the "no-penalty" scenario #1 are somewhat attenuated when only the operating costs of conditioning are deducted from the wellhead price (scenario #6--total revenue = \$15.1 billion), or when conditioning costs are deducted from the wellhead price for royalty purposes only (scenario #5--total revenue = \$15.7 billion).

While the conditioning cost "penalties" described in scenarios 5, 6, and 7 are the most severe of those shown on the attached table, there is ample reason to suggest that the likelihood of their occurrence is remote. The Federal Energy Regulatory Commission Order #45, adopted August 24, 1979, addresses conditioning costs as the responsibility and burden of the producers of gas. Consequently, the fixed price ceiling set in the 1978 Natural Gas Policy Act could be defined as net of conditioning costs. In other words, the present price ceiling already excludes conditioning costs and further deductions from the ceiling price for conditioning cannot be justified. Therefore, scenarios 5, 6 and 7 would seem implausible short of a countermanding rule from FERC on conditioning costs.

Methodology

Calculations made in preparing this analysis revolve around the use of the Eppenbach Producer Benefits computer model. As numerous assumptions have been made about production and price scheduling, debt financing (term, interest rates, amortization mode, etc.) federal tax rates, the proportion and timing of capital investments and many other environmental parameters of the model, discretionary interpretation of the precision of projected revenues is suggested. However, the relative magnitude of the projected State revenues are of greater policy significance, and we believe that the projections shown on the attached table fairly represent an accurate comparison of the relationship of one "penalty" scenario to another.

ALASKA REVENUE FROM NORTH SLOPE GAS PRODUCTION
(Millions of Dollars)

Conditioning Cost Penalty Scenario	Effective Wellhead Gas Price (per MCF) ¹	Royalty	Severance	Property Tax	Gas % of Total Net Cash Flow ²	State Income Tax ³	Total State Revenue	Gas Industry Net Cash Flow
1. Control Scenario no deviation	\$1.95	\$7,206	\$5,044	\$389	35.5%	\$3,971	\$16,610	\$25,004
2. 30-year pass-through for State and producers of operating & capital costs	2.48	8,127	5,689	389	38.9%	4,574	18,779	28,897
3. 30-year pass-through of operating costs for producers only	1.95	7,206	5,044	389	38.6%	4,523	17,162	28,566
4. 30-year pass-through of operating & capital costs for producers only	1.95	7,206	5,044	389	39.4%	4,663	17,302	29,479
5. Operating & capital costs deducted (royalty)	1.42	6,104	5,154	389	36.3%	4,099	15,746	25,829
6. Operating costs deducted (royalty & severance)	1.70	6,285	4,399	389	36.0%	4,062	15,135	25,586
7. Operating & capital costs deducted (royalty & severance)	1.42	6,104	4,273	389	36.3%	4,099	14,865	25,829

¹Effective wellhead price of gas for state tax purposes: 1980-dollar equivalent of the 1978 Natural Gas Policy Act gas price ceiling adjusted up or down by the following average conditioning costs: operating = 24.9¢/MCF capital = 28.1¢/MCF

²Gas component (percentage) of combined oil and gas net cash flows from attached computer runs.

³Multiply percentage in previous column times total state income tax from attached computer runs.

⁴Industry Net Gas Cash Flow from attached computer runs minus State and Federal Income tax multiplied by Gas % in previous column.

ALABAMA STATE REVENUES (MILLIONS OF DOLLARS)

YEAR	PROD. RATE PER BARREL	ROYALTY PAYMENT	UNL. SEVERANCE TAX	PROPERTY TAX	CONSTR. TAX	OIL TOTAL	PROD. RATE PER BARREL	ROYALTY PAYMENT	GAS PRODUCTION SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	393.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	993.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	0.0	0.0	533.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	0.0	0.0	543.6	2,370.5
1984	1.500	1,077.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	0.0	0.0	547.3	2,393.0
1985	1.500	1,037.8	734.5	70.4	0.6	1,863.5	2.000	177.9	124.5	17.6	320.1	574.3	2,458.3
1986	1.300	975.1	649.3	68.7	0.5	1,653.8	2.000	177.9	124.5	17.3	319.8	601.6	2,575.3
1987	1.150	893.7	581.7	66.8	0.5	1,492.9	2.000	177.9	124.5	17.0	319.5	549.6	2,362.1
1988	1.000	748.3	512.7	62.9	0.4	1,324.1	2.000	177.9	124.5	16.5	319.0	495.3	2,138.6
1989	0.750	598.1	390.6	59.0	0.3	1,030.1	2.000	177.9	124.5	16.1	318.6	398.4	1,747.2
1990	0.500	451.6	299.7	55.0	0.2	806.3	2.000	177.9	124.5	15.6	318.1	324.7	1,443.2
1991	0.420	331.5	216.6	51.1	0.1	601.5	2.000	177.9	124.5	15.2	317.7	256.9	1,176.2
1992	0.400	324.0	204.0	47.2	0.1	576.4	2.000	177.9	124.5	14.7	317.2	253.2	1,146.9
1993	0.350	299.2	176.3	43.2	0.1	508.9	2.000	177.9	124.5	14.3	316.8	234.5	1,060.3
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	177.9	124.5	13.8	316.3	230.7	1,019.1
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	177.9	124.5	13.4	315.9	232.5	938.1
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	177.9	124.5	12.9	315.4	202.7	841.0
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	177.9	124.5	12.5	315.0	203.4	751.8
1998	0.200	187.4	0.0	21.6	0.0	208.1	2.000	177.9	124.5	12.0	314.5	191.1	711.8
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	177.9	124.5	11.6	314.1	178.0	670.1
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	177.9	124.5	11.2	313.6	171.3	643.2
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	177.9	124.5	10.7	313.2	165.5	616.5
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	177.9	124.5	10.3	312.8	167.1	606.3
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	177.9	124.5	9.8	312.3	162.2	575.4
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	9.4	311.9	162.8	544.7
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.9	311.4	164.1	515.6
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.5	311.0	165.5	486.5
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.0	310.5	165.5	457.1
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.6	310.1	165.5	427.7
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.1	309.6	165.5	398.3
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.7	309.2	165.5	368.9
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.2	308.7	165.5	339.5
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.8	308.3	165.5	310.1
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.3	307.8	165.5	280.7
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.9	307.4	165.5	251.3
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.4	306.9	165.5	221.9
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.0	306.5	165.5	192.5
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.5	306.0	165.5	163.1
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.1	305.6	165.5	133.7
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.6	305.1	165.5	104.3
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.2	304.7	165.5	74.9
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.7	304.2	165.5	45.5
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.3	303.8	165.5	16.1
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.8	303.3	165.5	-13.3
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.4	302.9	165.5	-43.9
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	88.9	62.2	0.0	151.2	48.4	-93.7
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	-93.7
CUMULATIVE TOTALS													
	7,641	13,570	9,062	1,103	9	23,734	19,865	7,206	5,044	383	12,640	11,186	47,553

INDUSTRY CASH FLOWS (MILLIONS OF DOLLARS)

Run 11

YEAR	WELLHEAD 1-50 PRICE/DOL	CRUDE 1533.0	STATE 415.3	OPERAT 103.0	CAPITAL 122.6	NET OIL 891.4	WELLHEAD PRICE/BOE	CRUDE 1548.0	STATE 0.0	OPERAT 26.0	CAPITAL 0.0	NET GAS -26.0	ST. INC. 0.0	FED. INC. 259.6	NET CASH 605.7
1	4.00	1533.0	415.3	103.0	122.6	891.4	1.95	1548.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.3	140.0	161.9	2007.8	1.95	1548.0	0.0	33.0	0.0	-33.0	137.2	533.2	1244.3
3	9.25	5054.3	1276.8	158.0	187.4	3444.0	1.95	1548.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	167.0	236.6	5450.9	1.95	1548.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7819.3	1778.5	171.0	269.0	5493.7	1.95	1548.0	0.0	41.0	0.0	-41.0	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	311.7	5491.8	1.95	1548.0	0.0	48.0	0.0	-48.0	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	370.3	5501.4	1.95	1548.0	0.0	54.0	0.0	-54.0	547.3	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	462.7	5610.5	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	476.3	5906.4	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
10	15.76	8681.0	1893.8	210.0	476.3	5906.4	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
11	16.08	8750.2	1932.9	195.0	378.3	4671.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
14	17.06	3612.8	806.3	133.0	354.2	2313.2	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
15	17.40	2663.5	601.5	123.0	346.7	1597.6	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
16	17.75	2532.2	576.4	121.0	330.2	1556.5	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
19	18.84	2209.7	439.6	114.0	314.1	1332.9	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
20	19.21	1753.7	332.7	107.0	306.1	1017.8	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
21	19.60	1645.7	233.3	105.0	283.6	1027.6	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
23	20.39	1285.5	177.9	93.0	236.3	752.2	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
24	20.80	1138.0	158.1	97.0	204.1	679.6	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
25	21.21	1066.8	137.7	95.0	168.2	605.8	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
26	21.64	967.9	126.4	94.0	121.7	605.8	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
28	22.51	652.9	0.0	200.0	27.4	-227.4	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
29	22.96	523.42	0.0	100.0	13.5	-113.5	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
30	23.42	423.19	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
31	23.89	344.77	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
32	24.36	284.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
33	24.83	234.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
34	25.30	194.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
35	25.77	164.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
36	26.24	134.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
37	26.71	104.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
38	27.18	74.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
39	27.65	44.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
40	28.12	14.16	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
41	28.59	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
42	29.06	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
43	29.53	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
44	30.00	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
45	30.47	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
46	30.94	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
47	31.41	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
48	31.88	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
49	32.35	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1
50	32.82	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	0.0	60.0	0.0	-60.0	547.3	1426.7	3329.1

AGD 533111

103,567 23,772 4,050 6,654 72,130 62,636 12,640 8,335 2,034 39,706 11,186 30,225 70,425

ALASKA STATE REVENUES (MILLIONS OF DOLLARS)

YEAR	PROD RATE PERIL/DAY	OIL ROYALTY PAYMENT	PRODUCTION SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	PROD RATE PERIL/DAY	GAS ROYALTY PAYMENT	PRODUCTION SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	330.0	332.2	37.3	0.6	810.3	0.000	0.0	0.0	0.0	0.0	197.2	1,003.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	953.1	753.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	936.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	0.0	0.0	533.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,813.2	0.000	0.0	0.0	0.0	0.0	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	0.0	0.0	547.3	2,393.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	200.6	140.4	17.6	358.8	693.4	2,921.8
1986	1.500	935.1	643.3	68.7	0.5	1,653.8	2.000	200.6	140.4	17.3	358.5	626.4	2,638.8
1987	1.150	843.7	581.7	66.8	0.5	1,432.9	2.000	200.6	140.4	17.0	358.1	573.5	2,424.7
1988	1.600	748.3	512.3	62.9	0.4	1,324.1	2.000	200.6	140.4	16.5	357.7	519.1	2,201.0
1989	0.760	580.1	330.6	59.0	0.3	1,030.1	2.000	200.6	140.4	16.1	357.3	422.0	1,809.5
1990	0.580	451.6	239.3	55.0	0.2	806.3	2.000	200.6	140.4	15.6	356.8	347.9	1,511.0
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	200.6	140.4	15.2	356.4	275.8	1,237.8
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	200.6	140.4	14.7	355.9	275.3	1,203.3
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	200.6	140.4	14.3	355.5	257.0	1,121.5
1994	0.370	278.1	154.3	39.3	0.1	472.0	2.000	200.6	140.4	13.8	355.0	253.1	1,080.1
1995	0.320	275.0	129.0	35.4	0.1	433.6	2.000	200.6	140.4	13.4	354.6	254.7	1,048.9
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	200.6	140.4	12.9	354.1	224.7	901.6
1997	0.240	205.7	0.0	27.5	0.1	273.3	2.000	200.6	140.4	12.5	353.7	225.2	812.3
1998	0.290	182.4	0.0	23.6	0.0	206.1	2.000	200.6	140.4	12.0	353.2	212.7	772.1
1999	0.170	153.1	0.0	19.6	0.0	177.9	2.000	200.6	140.4	11.6	352.8	193.5	730.2
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	200.6	140.4	11.2	352.3	185.6	703.1
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	200.6	140.4	10.7	351.9	185.2	675.2
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	200.6	140.4	10.3	351.4	185.5	663.4
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	200.6	140.4	9.8	351.0	179.1	630.3
2004	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	9.4	350.5	117.8	468.3
2005	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.9	350.1	119.1	469.3
2006	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.5	349.6	120.4	470.1
2007	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.0	349.2	120.5	469.7
2008	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	7.6	348.7	120.5	469.3
2009	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	7.1	348.3	120.6	468.9
2010	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	6.7	347.8	120.6	468.5
2011	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	6.2	347.4	120.6	468.1
2012	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	5.8	346.9	120.7	467.7
2013	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	5.3	346.5	120.7	467.3
2014	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.9	346.0	120.8	466.9
2015	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.4	345.6	120.8	466.5
2016	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.0	345.2	103.7	448.9
2017	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	3.5	344.7	103.8	448.5
2018	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	3.1	344.3	103.8	448.1
2019	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	2.6	343.8	103.9	447.3
2020	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	2.2	343.4	103.9	447.3
2021	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	1.7	342.9	104.0	446.9
2022	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	1.3	342.5	104.0	446.5
2023	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	0.8	342.0	104.0	446.1
2024	0.080	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	0.4	341.6	104.1	445.7
2025	0.080	0.0	0.0	0.0	0.0	0.0	1.000	100.3	70.2	0.0	170.5	47.3	217.9
2026	0.080	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
CUMULATIVE TOTALS							7,641T	13,570	9,042	1,109	14,207	11,765	49,705
23,732 23,565T 8,127							9	23,732	5,609	309	14,207	11,765	49,705

YEAR	WELLHEAD	GROSS	STATE	OPERAT	CAPITAL	NET	GAS	SI, INC.	FED. INC.	NET
1-50	PRODUCTION	PRICE/BOE	TAX	COSTS	COSTS	CASH FLOW	PRODUCTION	TAX	COSTS	CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	831.4	1.35	0.0	0.0	26.0
2	6.00	3120.7	810.9	140.0	161.3	2007.8	1.35	0.0	0.0	33.0
3	9.25	5054.3	1276.3	156.0	187.4	3444.0	1.35	0.0	0.0	32.0
4	14.60	7885.0	1760.4	163.0	230.6	5450.3	1.35	0.0	0.0	36.0
5	14.28	7818.3	1778.5	171.0	269.0	5493.7	1.35	0.0	0.0	41.0
6	14.56	7974.6	1797.8	173.0	311.3	5491.8	1.35	0.0	0.0	40.0
7	14.85	8134.1	1819.2	174.0	350.3	5550.4	1.35	0.0	0.0	54.0
8	15.15	8292.8	1839.5	178.0	388.8	5610.5	1.35	0.0	0.0	60.0
9	15.45	8462.7	1863.5	230.0	462.7	5306.4	1.35	1850.8	358.8	132.0
10	15.76	8638.0	1883.5	210.0	476.3	5140.8	1.35	1850.6	358.5	212.0
11	16.08	8810.0	1903.8	195.0	370.3	4683.9	1.35	1839.0	358.1	219.0
12	16.40	8987.1	1924.1	181.0	370.3	4411.7	1.35	1839.0	357.3	192.0
13	16.73	9164.2	1939.1	157.0	362.3	3091.7	1.35	1837.0	357.3	192.0
14	17.06	9341.2	1950.3	133.0	354.2	2313.2	1.35	1833.5	356.8	192.0
15	17.40	9518.5	1961.5	121.0	346.2	1537.6	1.35	1830.1	356.4	192.0
16	17.75	9692.2	1974.4	121.0	338.2	1556.5	1.35	1828.2	355.9	192.0
17	18.11	9863.6	1989.9	116.0	330.2	1358.4	1.35	1826.3	355.5	192.0
18	18.47	10032.0	2007.0	115.0	322.2	1315.8	1.35	1824.4	355.0	192.0
19	18.84	10200.7	2026.6	114.0	314.1	1332.9	1.35	1822.5	354.6	192.0
20	19.21	10373.7	2047.7	107.0	306.1	1017.8	1.35	1820.5	354.1	192.0
21	19.60	10551.7	2069.3	105.0	298.6	1023.6	1.35	1818.6	353.7	192.0
22	19.99	10734.6	2092.4	102.0	291.7	831.7	1.35	1816.7	353.2	192.0
23	20.39	10922.5	2117.9	99.0	284.3	752.2	1.35	1814.8	352.8	192.0
24	20.80	11115.9	2145.1	97.0	276.3	679.6	1.35	1812.9	352.3	192.0
25	21.21	11314.3	2174.7	95.0	268.2	605.9	1.35	1810.1	351.9	192.0
26	21.64	11518.8	2206.4	94.0	260.7	538.3	1.35	1808.3	351.4	192.0
27	22.07	11729.7	2240.7	92.0	253.7	474.4	1.35	1806.5	350.5	192.0
28	22.51	11946.7	2277.4	90.0	247.4	413.5	1.35	1804.8	350.1	192.0
29	22.96	12169.6	2316.1	100.0	241.5	355.9	1.35	1803.1	349.6	192.0
30	23.42	12400.0	2357.4	0.0	236.3	301.7	1.35	1801.4	349.2	192.0
31	23.89	12638.0	2401.9	0.0	231.2	252.2	1.35	1800.1	348.7	192.0
32	24.37	12883.0	2449.6	0.0	226.3	207.6	1.35	1798.3	348.3	192.0
33	24.86	13135.0	2500.6	0.0	221.7	167.9	1.35	1796.5	347.8	192.0
34	25.36	13394.0	2554.9	0.0	217.4	133.2	1.35	1794.8	347.4	192.0
35	25.86	13659.0	2612.4	0.0	21					

ALASKA STATE REVENUES (MILLIONS OF DOLLARS)

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YEAR	WELL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONCRV. TAX	UIL TOTAL	PROD RATE	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.3	0.000	0.0	0.0	0.0	0.0	0.0	415.3
1978	1.425	300.0	367.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	753.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	520.6	2,281.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	936.8	750.1	50.1	0.6	1,737.8	0.000	0.0	0.0	0.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,393.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	177.9	124.5	17.6	320.1	631.7	2,875.4
1986	1.500	935.1	649.3	68.7	0.5	1,653.8	2.000	177.9	124.5	17.3	319.8	618.7	2,592.4
1987	1.150	843.7	581.7	66.8	0.5	1,432.9	2.000	177.9	124.5	17.0	319.5	566.7	2,379.2
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	177.9	124.5	16.5	318.0	512.4	2,155.7
1989	0.760	530.1	330.6	53.0	0.3	1,030.1	2.000	177.9	124.5	15.6	318.1	415.5	1,764.4
1990	0.580	451.6	239.3	55.0	0.2	806.3	2.000	177.9	124.5	15.2	317.7	341.8	1,466.3
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	177.9	124.5	14.7	317.7	274.0	1,193.3
1992	0.330	278.1	154.3	33.3	0.1	472.0	2.000	177.9	124.5	13.8	316.3	247.8	1,036.2
1993	0.330	278.1	154.3	33.3	0.1	472.0	2.000	177.9	124.5	13.4	315.9	219.8	1,005.2
1994	0.330	278.1	154.3	33.3	0.1	472.0	2.000	177.9	124.5	12.9	315.4	220.5	858.1
1995	0.250	219.2	71.9	27.5	0.1	232.7	2.000	177.9	124.5	12.0	314.5	208.2	768.9
1996	0.230	205.7	0.0	23.6	0.0	206.1	2.000	177.9	124.5	11.6	314.1	195.1	687.2
1997	0.200	182.4	0.0	19.6	0.0	177.3	2.000	177.9	124.5	11.2	313.6	188.4	660.3
1998	0.170	158.1	0.0	15.7	0.0	158.1	2.000	177.9	124.5	10.7	313.2	182.6	633.6
1999	0.150	142.3	0.0	11.8	0.0	137.7	2.000	177.9	124.5	10.3	312.8	184.2	623.4
2000	0.130	125.8	0.0	7.8	0.0	126.4	2.000	177.9	124.5	9.8	312.3	179.3	592.5
2001	0.120	118.4	0.0	0.0	0.0	100.7	2.000	177.9	124.5	9.4	311.9	119.3	431.8
2002	0.100	100.7	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.9	311.4	121.3	432.7
2003	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.5	311.0	122.6	433.6
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.0	310.5	122.7	432.8
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.6	309.6	122.7	432.4
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.1	309.2	122.7	432.4
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.7	308.7	122.8	431.5
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.2	308.3	122.8	431.1
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.8	307.8	122.9	430.7
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.3	307.4	122.9	430.3
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.9	306.9	122.9	429.9
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.4	306.5	122.9	412.4
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.0	306.0	122.9	412.0
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.5	305.6	122.9	411.6
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.1	305.1	122.9	411.2
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.6	304.7	122.9	410.8
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.2	304.2	122.9	410.4
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.7	303.8	122.9	410.0
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.3	303.3	122.9	409.6
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.8	302.9	122.9	409.2
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.4	302.5	122.9	408.8
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.0	302.1	122.9	408.4
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.0	301.7	122.9	408.0
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.0	301.3	122.9	407.6
2025	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.0	300.9	122.9	407.2
2026	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.0	300.5	122.9	406.8
7,641	13,570	9,042	1,103	9	23,732	23,565	7,206	5,044	383	12,640	11,717	48,030	

AGD 533114

INDUSTRY CASH FLOWS (MILLIONS OF DOLLARS)

YEAR	WELLHEAD PRICE/BL	WELLHEAD PRICE/MCF	GROSS INCOME	GROSS INCOME	STATE TAX	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1-50	1-50	1-50	1-50	1-50	1-50	1-50	1-50	1-50	1-50	1-50	1-50
1	4.00	1533.0	415.9	103.0	122.6	831.4	1.95	0.0	0.0	0.0	253.6
2	6.00	3120.7	810.3	140.0	161.9	2007.8	1.95	0.0	0.0	197.2	605.7
3	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	333.4	1244.3
4	14.28	7665.0	1760.4	163.0	230.6	5450.9	1.95	0.0	0.0	520.6	2155.0
5	14.56	7974.6	1797.8	173.0	363.0	5493.7	1.95	0.0	0.0	535.3	3420.3
6	14.85	8134.1	1813.2	174.0	511.9	5491.8	1.95	0.0	0.0	535.3	3420.3
7	15.15	8296.8	1839.5	173.0	590.3	5550.4	1.95	0.0	0.0	543.6	3420.3
8	15.45	8462.7	1863.5	173.0	668.8	5610.5	1.95	0.0	0.0	547.3	3420.3
9	15.76	8631.0	1883.8	173.0	746.3	5666.4	1.95	0.0	0.0	618.7	3420.3
10	16.08	8799.2	1902.9	173.0	823.3	5722.9	1.95	0.0	0.0	618.7	3420.3
11	16.40	8967.4	1922.1	173.0	900.8	5779.6	1.95	0.0	0.0	618.7	3420.3
12	16.72	9135.6	1941.2	173.0	978.3	5836.3	1.95	0.0	0.0	618.7	3420.3
13	17.04	9303.8	1960.4	173.0	1055.8	5893.0	1.95	0.0	0.0	618.7	3420.3
14	17.36	9472.0	1979.6	173.0	1133.3	5949.7	1.95	0.0	0.0	618.7	3420.3
15	17.68	9640.2	1998.8	173.0	1210.8	6006.4	1.95	0.0	0.0	618.7	3420.3
16	18.00	9808.4	2018.0	173.0	1288.3	6063.1	1.95	0.0	0.0	618.7	3420.3
17	18.32	9976.6	2037.2	173.0	1365.8	6119.8	1.95	0.0	0.0	618.7	3420.3
18	18.64	10144.8	2056.4	173.0	1443.3	6176.5	1.95	0.0	0.0	618.7	3420.3
19	18.96	10313.0	2075.6	173.0	1520.8	6233.2	1.95	0.0	0.0	618.7	3420.3
20	19.28	10481.2	2094.8	173.0	1598.3	6289.9	1.95	0.0	0.0	618.7	3420.3
21	19.60	10649.4	2114.0	173.0	1675.8	6346.6	1.95	0.0	0.0	618.7	3420.3
22	19.92	10817.6	2133.2	173.0	1753.3	6403.3	1.95	0.0	0.0	618.7	3420.3
23	20.24	10985.8	2152.4	173.0	1830.8	6460.0	1.95	0.0	0.0	618.7	3420.3
24	20.56	11154.0	2171.6	173.0	1908.3	6516.7	1.95	0.0	0.0	618.7	3420.3
25	20.88	11322.2	2190.8	173.0	1985.8	6573.4	1.95	0.0	0.0	618.7	3420.3
26	21.20	11490.4	2210.0	173.0	2063.3	6630.1	1.95	0.0	0.0	618.7	3420.3
27	21.52	11658.6	2229.2	173.0	2140.8	6686.8	1.95	0.0	0.0	618.7	3420.3
28	21.84	11826.8	2248.4	173.0	2218.3	6743.5	1.95	0.0	0.0	618.7	3420.3
29	22.16	11995.0	2267.6	173.0	2295.8	6800.2	1.95	0.0	0.0	618.7	3420.3
30	22.48	12163.2	2286.8	173.0	2373.3	6856.9	1.95	0.0	0.0	618.7	3420.3
31	22.80	12331.4	2306.0	173.0	2450.8	6913.6	1.95	0.0	0.0	618.7	3420.3
32	23.12	12500.0	2325.2	173.0	2528.3	6970.3	1.95	0.0	0.0	618.7	3420.3
33	23.44	12668.2	2344.4	173.0	2605.8	7027.0	1.95	0.0	0.0	618.7	3420.3
34	23.76	12836.4	2363.6	173.0	2683.3	7083.7	1.95	0.0	0.0	618.7	3420.3
35	24.08	13004.6	2382.8	173.0	2760.8	7140.4	1.95	0.0	0.0	618.7	3420.3
36	24.40	13172.8	2402.0	173.0	2838.3	7197.1	1.95	0.0	0.0	618.7	3420.3
37	24.72	13341.0	2421.2	173.0	2915.8	7253.8	1.95	0.0	0.0	618.7	3420.3
38	25.04	13509.2	2440.4	173.0	2993.3	7310.5	1.95	0.0	0.0	618.7	3420.3
39	25.36	13677.4	2459.6	173.0	3070.8	7367.2	1.95	0.0	0.0	618.7	3420.3
40	25.68	13845.6	2478.8	173.0	3148.3	7423.9	1.95	0.0	0.0	618.7	3420.3
41	26.00	14013.8	2498.0	173.0	3225.8	7480.6	1.95	0.0	0.0	618.7	3420.3
42	26.32	14182.0	2517.2	173.0	3303.3	7537.3	1.95	0.0	0.0	618.7	3420.3
43	26.64	14350.2	2536.4	173.0	3380.8	7594.0	1.95	0.0	0.0	618.7	3420.3
44	26.96	14518.4	2555.6	173.0	3458.3	7650.7	1.95	0.0	0.0	618.7	3420.3
45	27.28	14686.6	2574.8	173.0	3535.8	7707.4	1.95	0.0	0.0	618.7	3420.3
46	27.60	14854.8	2594.0	173.0	3613.3	7764.1	1.95	0.0	0.0	618.7	3420.3
47	27.92	15023.0	2613.2	173.0	3690.8	7820.8	1.95	0.0	0.0	618.7	3420.3
48	28.24	15191.2	2632.4	173.0	3768.3	7877.5	1.95	0.0	0.0	618.7	3420.3
49	28.56	15359.4	2651.6	173.0	3845.8	7934.2	1.95	0.0	0.0	618.7	3420.3
50	28.88	15527.6	2670.8	173.0	3923.3	7990.9	1.95	0.0	0.0	618.7	3420.3
TOTAL											74,003

(MILLIONS OF DOLLARS)

AGO 533116

INDUSTRY CASH FLOWS

(MILLIONS OF DOLLARS)

YEAR	WELLHEAD 1-50 PRICE/DOL	GROSS INCOME	STATE TAKE	OPERAT COSTS	WELLHEAD PRICE/NCV	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1	4.00	1533.0	415.9	103.0	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5064.3	1276.8	156.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	1.95	1834.9	320.1	192.0	104.9	1217.8	701.5	1926.8	4495.8
10	15.75	7481.0	1653.8	210.0	1.95	1834.7	319.8	212.0	104.7	1198.1	628.5	1713.1	3937.3
11	16.08	7502.2	1492.9	195.0	1.95	1825.2	319.5	219.0	95.2	1191.5	575.7	1589.9	3709.8
12	16.40	5987.1	1324.1	181.0	1.95	1823.1	319.0	193.0	93.1	1217.9	521.2	1442.5	3365.8
13	16.73	4641.2	1030.1	157.0	1.95	1821.1	318.6	192.0	91.1	1219.8	424.1	1166.1	2720.9
14	17.06	3612.8	806.3	133.0	1.95	1817.6	318.1	192.0	87.6	1219.8	350.0	954.9	2228.1
15	17.40	2668.5	601.5	123.0	1.95	1814.2	317.7	192.0	84.2	1220.2	281.9	760.7	1775.1
16	17.75	2592.2	576.4	121.0	1.95	1812.3	317.2	192.0	82.3	1220.7	278.0	749.7	1749.4
17	18.11	2313.6	508.9	116.0	1.95	1810.4	316.8	192.0	80.4	1221.1	259.2	696.1	1624.2
18	18.47	2200.7	479.6	114.0	1.95	1808.5	316.3	192.0	78.5	1221.6	255.2	684.6	1597.5
19	18.84	2200.7	479.6	114.0	1.95	1806.6	315.9	192.0	76.6	1222.1	256.8	683.4	1608.7
20	19.21	1753.7	322.7	107.0	1.95	1804.6	315.4	192.0	74.6	1222.4	226.8	604.0	1409.3
21	19.60	1645.7	233.3	105.0	1.95	1802.7	315.0	192.0	72.7	1222.9	227.3	605.7	1413.4
22	19.99	1459.6	206.1	102.0	1.95	1800.8	314.5	192.0	70.8	1223.3	214.8	570.0	1330.2
23	20.39	1265.5	177.9	93.0	1.95	1798.9	314.1	192.0	68.9	1223.8	201.6	532.3	1242.1
24	20.80	1138.9	158.1	97.0	1.95	1797.0	313.6	192.0	67.0	1224.3	194.7	512.7	1196.4
25	21.21	1006.8	137.7	95.0	1.95	1794.2	313.2	192.0	54.2	1224.7	187.7	492.8	1150.0
26	21.64	947.9	126.4	94.0	1.95	1787.1	312.8	192.0	37.1	1225.1	187.7	492.9	1150.2
27	22.07	805.7	100.7	92.0	1.95	1750.6	312.3	192.0	20.6	1225.6	181.3	474.7	1107.8
28	22.51	0.0	0.0	200.0	1.95	1730.0	311.9	192.0	0.0	1226.1	119.9	263.6	615.1
29	22.96	0.0	0.0	100.0	1.95	1730.0	311.4	192.0	0.0	1226.5	121.3	237.5	634.2
30	23.42	0.0	0.0	0.0	1.95	1730.0	311.0	192.0	0.0	1227.0	122.6	331.3	773.1
31	23.89	0.0	0.0	0.0	1.95	1730.0	310.5	192.0	0.0	1227.4	122.6	331.4	773.3
32	24.37	0.0	0.0	0.0	1.95	1730.0	310.1	192.0	0.0	1227.9	122.7	331.5	773.6
33	24.86	0.0	0.0	0.0	1.95	1730.0	309.6	192.0	0.0	1228.3	122.7	331.6	773.9
34	25.35	0.0	0.0	0.0	1.95	1730.0	309.2	192.0	0.0	1228.8	122.7	331.8	774.2
35	25.86	0.0	0.0	0.0	1.95	1730.0	308.7	192.0	0.0	1229.2	122.8	331.9	774.5
36	26.38	0.0	0.0	0.0	1.95	1730.0	308.3	192.0	0.0	1229.7	122.8	332.0	774.8
37	26.91	0.0	0.0	0.0	1.95	1730.0	307.8	192.0	0.0	1230.1	122.9	332.1	775.0
38	27.44	0.0	0.0	0.0	1.95	1730.0	307.4	192.0	0.0	1230.6	122.9	332.3	775.3
39	27.99	0.0	0.0	0.0	1.95	1730.0	306.9	192.0	0.0	1231.0	122.9	332.4	775.6
40	28.55	0.0	0.0	0.0	1.95	1548.0	306.5	192.0	0.0	1049.5	105.9	283.0	660.5
41	29.12	0.0	0.0	0.0	1.95	1548.0	306.0	192.0	0.0	1049.9	105.9	283.2	660.8
42	29.71	0.0	0.0	0.0	1.95	1548.0	305.6	192.0	0.0	1050.4	106.0	283.3	661.0
43	30.30	0.0	0.0	0.0	1.95	1548.0	305.1	192.0	0.0	1050.8	106.0	283.4	661.3
44	30.91	0.0	0.0	0.0	1.95	1548.0	304.7	192.0	0.0	1051.3	106.0	283.5	661.6
45	31.53	0.0	0.0	0.0	1.95	1548.0	304.2	192.0	0.0	1051.7	106.1	283.6	661.9
46	32.16	0.0	0.0	0.0	1.95	1548.0	303.8	192.0	0.0	1052.2	106.1	283.8	662.2
47	32.80	0.0	0.0	0.0	1.95	1548.0	303.3	192.0	0.0	1052.6	106.2	283.9	662.5
48	33.46	0.0	0.0	0.0	1.95	1548.0	302.9	192.0	0.0	1053.1	106.2	284.0	662.8
49	34.12	0.0	0.0	0.0	1.95	774.0	151.2	96.0	0.0	526.7	48.4	143.4	334.8
50	34.81	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
CUMULATIVE TOTALS													
		108,587	23,737	4,050		69,782	12,640	8,335	2,094	46,793	11,952	32,151	74,919

ALASKA STATE REVENUES (MILLIONS OF DOLLARS)

YEAR	PRICE PER BARREL / DAY	OIL ROYALTY PAYMENT	PRODUCTION SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	PRICE PER BARREL / DAY	GAS ROYALTY PAYMENT	PRODUCTION SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	101.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	330.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.1	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	938.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	0.0	0.0	539.7	2,337.5
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	0.0	0.0	544.1	2,363.9
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	0.0	0.0	548.0	2,391.9
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	0.000	142.0	128.1	6.7	276.9	678.9	2,539.5
1986	1.500	935.1	649.3	68.7	0.5	1,653.2	0.000	142.1	128.1	7.5	277.8	605.9	2,537.5
1987	1.150	843.7	581.7	66.8	0.5	1,432.9	0.000	143.2	128.0	8.3	279.6	553.7	2,326.3
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	0.000	143.5	127.9	8.0	279.6	499.4	2,103.2
1989	0.700	580.1	390.6	59.0	0.3	1,030.1	0.000	143.8	127.9	7.8	279.6	402.4	1,712.2
1990	0.500	451.6	299.3	55.0	0.2	806.3	0.000	144.2	127.9	7.6	279.8	328.6	1,414.7
1991	0.400	333.5	216.6	51.1	0.1	601.5	0.000	144.6	127.8	7.4	279.9	257.0	1,142.3
1992	0.350	289.2	176.3	43.2	0.1	508.9	0.000	145.1	127.8	7.2	279.9	238.3	1,027.2
1993	0.330	278.1	154.3	39.3	0.1	472.0	0.000	145.3	127.8	6.9	279.9	234.4	936.4
1994	0.370	275.0	129.0	35.4	0.1	439.6	0.000	145.6	127.7	6.7	279.9	236.2	955.8
1995	0.250	219.2	71.9	31.4	0.1	332.7	0.000	145.8	127.7	6.3	279.9	206.4	809.1
1996	0.210	205.7	0.0	27.5	0.1	233.3	0.000	146.1	127.7	6.1	279.9	207.0	720.3
1997	0.200	182.4	0.0	23.6	0.0	206.1	0.000	146.3	127.7	5.9	279.9	194.6	680.7
1998	0.170	156.1	0.0	19.6	0.0	177.9	0.000	146.5	127.6	5.6	279.9	181.5	639.4
1999	0.150	142.3	0.0	15.7	0.0	158.1	0.000	146.8	127.6	5.4	279.9	174.8	612.9
2000	0.130	125.8	0.0	11.8	0.0	137.7	0.000	148.4	127.5	5.2	281.1	169.8	587.7
2001	0.120	118.4	0.0	7.8	0.0	126.4	0.000	150.5	127.2	5.0	282.8	170.2	579.5
2002	0.100	100.7	0.0	0.0	0.0	100.7	0.000	152.6	127.0	4.8	284.5	165.1	550.4
2003	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	4.5	286.6	105.4	392.0
2004	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	4.3	286.3	106.7	393.1
2005	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	4.1	286.1	108.0	394.2
2006	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	3.9	285.9	108.0	394.0
2007	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	3.7	285.7	108.0	393.6
2008	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	3.4	285.5	108.1	393.4
2009	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	3.2	285.2	108.1	393.2
2010	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	3.0	285.0	108.1	393.0
2011	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	2.8	284.8	108.1	392.8
2012	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	2.6	284.6	108.2	392.6
2013	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	2.4	284.4	108.2	392.4
2014	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	2.1	284.2	108.2	392.2
2015	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	1.9	283.9	108.2	392.0
2016	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	1.7	283.7	108.2	391.8
2017	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	1.5	283.5	108.3	391.6
2018	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	1.3	283.3	108.3	391.4
2019	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	1.0	283.1	108.3	391.2
2020	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	0.8	282.8	108.3	391.0
2021	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	0.6	282.6	108.3	390.8
2022	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	0.4	282.4	108.4	390.6
2023	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	0.2	282.2	108.4	390.5
2024	0.000	0.0	0.0	0.0	0.0	0.0	0.000	155.1	126.8	0.0	282.0	108.4	390.5
2025	0.000	0.0	0.0	0.0	0.0	0.0	0.000	177.5	63.4	0.0	141.0	49.5	190.5
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
TOTALS	7,641	13,570	9,042	1,109	9	23,739	29,565	6,104	5,154	184	11,443	11,309	46,485

ALASKA STATE REVENUES (MILLIONS OF DOLLARS)

June 16

YEAR	PROD RATE MBO/DAY	OIL ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	PROD RATE MBO/DAY	GAS ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.010	191.6	187.7	36.0	0.4	415.3	0.000	0.0	0.0	0.0	0.0	0.0	415.3
1978	1.425	330.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	0.0	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	0.0	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	0.0	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	0.0	2,313.8
1982	1.500	996.0	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	0.0	0.0	0.0	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	0.0	0.0	0.0	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	0.0	0.0	0.0	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	0.000	0.0	0.0	0.0	0.0	0.0	2,421.7
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	0.000	0.0	0.0	0.0	0.0	0.0	2,538.8
1987	1.150	843.7	581.7	66.8	0.5	1,492.3	0.000	0.0	0.0	0.0	0.0	0.0	2,325.5
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	0.000	0.0	0.0	0.0	0.0	0.0	2,102.0
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	0.000	0.0	0.0	0.0	0.0	0.0	1,710.7
1990	0.580	451.6	293.3	55.0	0.2	806.3	0.000	0.0	0.0	0.0	0.0	0.0	1,412.6
1991	0.420	333.5	216.6	51.1	0.1	601.5	0.000	0.0	0.0	0.0	0.0	0.0	1,139.7
1992	0.400	324.0	205.0	47.2	0.1	576.4	0.000	0.0	0.0	0.0	0.0	0.0	1,110.4
1993	0.350	289.2	176.3	43.2	0.1	508.9	0.000	0.0	0.0	0.0	0.0	0.0	982.6
1994	0.330	278.1	154.3	39.3	0.1	472.0	0.000	0.0	0.0	0.0	0.0	0.0	882.9
1995	0.330	275.0	129.0	35.4	0.1	439.6	0.000	0.0	0.0	0.0	0.0	0.0	804.4
1996	0.250	219.2	71.9	31.4	0.1	322.7	0.000	0.0	0.0	0.0	0.0	0.0	715.2
1997	0.230	205.7	0.0	27.5	0.1	233.3	0.000	0.0	0.0	0.0	0.0	0.0	675.3
1998	0.200	182.4	0.0	23.6	0.1	206.1	0.000	0.0	0.0	0.0	0.0	0.0	633.5
1999	0.170	158.1	0.0	19.6	0.0	177.9	0.000	0.0	0.0	0.0	0.0	0.0	606.6
2000	0.150	142.3	0.0	15.7	0.0	158.1	0.000	0.0	0.0	0.0	0.0	0.0	579.9
2001	0.130	125.8	0.0	11.8	0.0	137.7	0.000	0.0	0.0	0.0	0.0	0.0	563.8
2002	0.120	118.4	0.0	7.8	0.0	126.4	0.000	0.0	0.0	0.0	0.0	0.0	538.8
2003	0.100	100.7	0.0	0.0	0.0	100.7	0.000	0.0	0.0	0.0	0.0	0.0	516.4
2004	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	494.9
2005	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	472.7
2006	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	451.1
2007	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	430.6
2008	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	410.6
2009	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	391.1
2010	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	371.8
2011	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	351.1
2012	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	331.1
2013	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	311.1
2014	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	291.1
2015	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	271.1
2016	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	251.1
2017	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	231.1
2018	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	211.1
2019	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	191.1
2020	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	171.1
2021	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	151.1
2022	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	131.1
2023	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	111.1
2024	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	91.1
2025	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	71.1
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	51.1
7,611	13,570	9,042	1,103	3	23,732	29,565	6,285	4,399	209	11,074	11,273	46,080	

AGD 533119

INDUSTRY CASH FLOWS (MILLIONS OF DOLLARS)

YEAR	WELLHEAD PRICE/BL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	NET CASH FLOW
1-50	4.00	1533.0	415.9	103.0	123.6	831.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	253.6	605.7
1	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
2	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
3	14.00	7665.0	1760.4	163.0	230.6	5450.3	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
4	14.28	7818.3	1778.5	171.0	269.0	5439.7	1.95	0.0	0.0	41.0	0.0	-41.0	535.3	1449.2	3381.5
5	14.56	7974.6	1797.8	173.0	511.9	5431.8	1.95	0.0	3.0	48.0	148.5	-193.6	539.5	1425.8	3326.8
6	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
7	15.15	8295.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3320.1
8	15.45	8462.7	1863.5	230.0	462.7	5306.4	1.95	1537.1	281.4	102.0	104.3	953.6	676.7	1855.0	4328.3
9	15.76	8750.2	1892.9	210.0	476.3	5140.8	1.95	1532.1	281.1	212.0	104.7	934.2	603.7	1641.3	3823.9
10	16.08	9087.1	1924.1	181.0	370.3	4683.9	1.95	1532.1	280.4	193.0	95.2	937.0	551.7	1520.7	3543.4
11	16.40	9441.2	1930.1	157.0	362.3	4111.7	1.95	1532.1	279.9	192.0	93.1	965.5	497.5	1373.9	3205.8
12	16.73	9812.8	1930.1	133.0	354.2	2313.2	1.95	1532.1	279.5	192.0	87.6	972.9	400.6	1098.0	2562.1
13	17.06	10200.7	1930.1	123.0	346.2	1597.6	1.95	1532.1	279.0	192.0	84.2	976.8	326.8	887.8	2071.5
14	17.40	10683.5	1930.1	116.0	338.2	1358.4	1.95	1532.1	278.6	192.0	80.4	979.1	255.3	604.1	1596.2
15	17.75	11175.3	1930.1	115.0	330.2	1315.8	1.95	1532.1	277.7	192.0	78.5	983.9	232.9	630.9	1446.7
16	18.11	11675.0	1930.1	114.0	314.1	1332.3	1.95	1532.1	277.2	192.0	76.6	986.2	234.6	625.3	1459.1
17	18.47	12180.7	1930.1	107.0	306.1	1023.6	1.95	1532.1	276.8	192.0	74.6	988.6	204.9	540.4	1261.0
18	18.84	12700.7	1930.1	105.0	283.6	891.7	1.95	1532.1	276.3	192.0	72.7	990.9	205.5	507.5	1186.3
19	19.21	13232.7	1930.1	102.0	259.3	891.7	1.95	1532.1	275.4	192.0	68.9	993.7	180.1	470.3	1097.4
20	19.60	13779.9	1930.1	97.0	236.3	752.2	1.95	1532.1	275.0	192.0	67.0	998.0	173.4	451.2	1052.9
21	20.00	14345.6	1930.1	93.0	204.1	605.8	1.95	1532.1	274.5	192.0	54.2	1011.3	169.2	434.6	1025.7
22	20.40	14930.9	1930.1	90.0	168.2	465.8	1.95	1532.1	274.1	192.0	37.1	1028.8	164.4	425.9	993.8
23	20.80	15537.7	1930.1	86.0	121.7	338.3	1.95	1532.1	273.6	192.0	20.6	1045.8	164.4	425.9	993.8
24	21.21	16166.8	1930.1	82.0	74.7	213.6	1.95	1532.1	273.2	192.0	0.0	1066.9	164.4	425.9	993.8
25	21.64	16829.9	1930.1	78.0	27.4	100.0	1.95	1532.1	272.7	192.0	0.0	1067.3	164.4	425.9	993.8
26	22.07	17527.7	1930.1	74.0	0.0	-113.5	1.95	1532.1	272.3	192.0	0.0	1067.7	164.4	425.9	993.8
27	22.51	18269.9	1930.1	70.0	0.0	0.0	1.95	1532.1	271.8	192.0	0.0	1068.2	164.4	425.9	993.8
28	23.00	19045.6	1930.1	66.0	0.0	0.0	1.95	1532.1	271.4	192.0	0.0	1068.6	164.4	425.9	993.8
29	23.49	19866.8	1930.1	62.0	0.0	0.0	1.95	1532.1	270.9	192.0	0.0	1069.1	164.4	425.9	993.8
30	23.98	20733.9	1930.1	58.0	0.0	0.0	1.95	1532.1	270.5	192.0	0.0	1069.5	164.4	425.9	993.8
31	24.47	21647.7	1930.1	54.0	0.0	0.0	1.95	1532.1	270.1	192.0	0.0	1070.0	164.4	425.9	993.8
32	24.96	22609.9	1930.1	50.0	0.0	0.0	1.95	1532.1	269.6	192.0	0.0	1070.4	164.4	425.9	993.8
33	25.45	23629.9	1930.1	46.0	0.0	0.0	1.95	1532.1	269.1	192.0	0.0	1070.9	164.4	425.9	993.8
34	25.94	24707.7	1930.1	42.0	0.0	0.0	1.95	1532.1	268.7	192.0	0.0	1071.3	164.4	425.9	993.8
35	26.43	25845.6	1930.1	38.0	0.0	0.0	1.95	1532.1	268.3	192.0	0.0	1071.8	164.4	425.9	993.8
36	26.92	27045.6	1930.1	34.0	0.0	0.0	1.95	1532.1	267.8	192.0	0.0	1072.2	164.4	425.9	993.8
37	27.41	28307.7	1930.1	30.0	0.0	0.0	1.95	1532.1	267.4	192.0	0.0	1072.7	164.4	425.9	993.8
38	27.90	29633.9	1930.1	26.0	0.0	0.0	1.95	1532.1	266.9	192.0	0.0	1073.1	164.4	425.9	993.8
39	28.39	31033.9	1930.1	22.0	0.0	0.0	1.95	1532.1	266.5	192.0	0.0	1073.6	164.4	425.9	993.8
40	28.88	32507.7	1930.1	18.0	0.0	0.0	1.95	1532.1	266.0	192.0	0.0	1074.0	164.4	425.9	993.8
41	29.37	34057.7	1930.1	14.0	0.0	0.0	1.95	1532.1	265.6	192.0	0.0	1074.5	164.4	425.9	993.8
42	29.86	35683.5	1930.1	10.0	0.0	0.0	1.95	1532.1	265.1	192.0	0.0	1074.9	164.4	425.9	993.8
43	30.35	37387.7	1930.1	6.0	0.0	0.0	1.95	1532.1	264.7	192.0	0.0	1075.4	164.4	425.9	993.8
44	30.84	39170.9	1930.1	2.0	0.0	0.0	1.95	1532.1	264.2	192.0	0.0	1075.8	164.4	425.9	993.8
45	31.33	41033.9	1930.1	0.0	0.0	0.0	1.95	1532.1	263.7	192.0	0.0	1076.3	164.4	425.9	993.8
46	31.82	42987.7	1930.1	0.0	0.0	0.0	1.95	1532.1	263.2	192.0	0.0	1076.8	164.4	425.9	993.8
47	32.31	45033.9	1930.1	0.0	0.0	0.0	1.95	1532.1	262.7	192.0	0.0	1077.3	164.4	425.9	993.8
48	32.80	47183.5	1930.1	0.0	0.0	0.0	1.95	1532.1	262.2	192.0	0.0	1077.8	164.4	425.9	993.8
49	33.29	49433.9	1930.1	0.0	0.0	0.0	1.95	1532.1	261.7	192.0	0.0	1078.3	164.4	425.9	993.8
50	34.78	51883.5	1930.1	0.0	0.0	0.0	1.95	1532.1	261.2	192.0	0.0	1078.8	164.4	425.9	993.8
CUMULATIVE TOTALS	108,567	23,732	4,050	8,654	72,130	62,051	11,074	8,335	2,094	40,628	11,273	30,475	71,009		

AGG 533120

ALASKA STATE REVENUES (MILLIONS OF DOLLARS)

Run 17

YEAR	OIL PRODUCTION						GAS PRODUCTION						STATE INCOME TAX	TOTAL STATE RETURN
	PROD RATE MMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	PROD RATE MMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL			
1977	1.050	191.6	187.7	35.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	330.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	936.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	0.9	0.9	539.7	2,338.5	
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	2.5	2.5	544.1	2,365.9	
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	4.3	4.3	548.0	2,391.9	
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	142.0	99.4	6.7	248.2	678.9	2,790.8	
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	142.1	99.4	7.5	249.1	605.9	2,508.9	
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	143.2	100.3	8.3	251.9	553.7	2,298.5	
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	143.5	100.4	8.0	252.1	499.4	2,075.6	
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	143.8	100.6	7.8	252.3	402.4	1,684.9	
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	144.2	100.9	7.6	252.8	328.6	1,387.8	
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	144.6	101.2	7.4	253.3	260.8	1,115.7	
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	144.9	101.4	7.2	253.5	257.0	1,087.0	
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	145.1	101.5	6.9	253.7	238.3	1,001.0	
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	145.3	101.7	6.7	253.9	234.4	960.4	
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	145.6	101.9	6.5	254.1	236.2	929.9	
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	145.8	102.1	6.3	254.3	206.4	783.4	
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	146.1	102.2	6.1	254.4	207.0	694.8	
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	146.3	102.4	5.9	254.6	194.6	655.4	
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	146.5	102.6	5.6	254.8	181.5	614.3	
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	146.8	102.7	5.4	255.0	174.8	588.0	
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	148.4	103.8	5.2	257.5	168.8	564.1	
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	150.5	105.3	5.0	260.9	170.2	557.5	
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	152.6	106.8	4.8	264.2	165.1	530.1	
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.5	268.4	105.4	373.8	
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.3	268.1	106.7	374.9	
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.1	267.9	108.0	376.0	
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.9	267.7	108.0	375.8	
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.7	267.5	108.0	375.6	
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.4	267.3	108.1	375.4	
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.2	267.0	108.1	375.2	
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.0	266.8	108.1	375.0	
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.8	266.6	108.1	374.8	
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.6	266.4	108.2	374.6	
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.4	266.2	108.2	374.4	
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.1	266.0	108.2	374.2	
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.9	265.7	108.2	374.0	
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.7	265.5	108.2	373.8	
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.5	265.3	108.3	373.6	
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.3	265.1	108.3	373.4	
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.0	264.9	108.3	373.2	
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.8	264.6	108.3	373.0	
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.6	264.4	108.3	372.8	
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.4	264.2	108.4	372.6	
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.2	264.0	108.4	372.4	
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	77.5	54.3	0.0	131.9	49.5	181.4	
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0	

	7,641T	13,570	9,042	1,109	9	23,732	29,565T	6,104	4,273	184	10,561	11,309	45,603	
CUMULATIVE TOTALS														

AGO 533121

(MILLIONS OF DOLLARS)

AG0 533122

STATE OF ALASKA

OIL AND GAS CONSERVATION COMMISSION

THREE DIMENSIONAL RESERVOIR STUDY SADLEROGHIT FORMATION PRUDHOE BAY FIELD

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Juneau, Alaska 99811

MARCH, 1980

AGO 533123

THREE-DIMENSIONAL RESERVOIR STUDY
SADLEROGHIT FORMATION
PRUDHOE BAY FIELD

Prepared for
STATE OF ALASKA
JAY S. HAMMOND, GOVERNOR
ALASKA OIL AND GAS CONSERVATION COMMISSION
Hoyle H. Hamilton, Chairman
Harry W. Kugler
Lonnie C. Smith

by
H. K. van Poolen and Associates, Inc.

March 1980

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- | | |
|---|---------------------------|
| A | North-South Cross Section |
| B | East-West Cross Section |

ACKNOWLEDGEMENT

This study was performed under contract for and in cooperation with the Alaska Oil and Gas Conservation Commission, State of Alaska. Data were made available by operators in the field for the purpose of this overall field-wide performance study.

H. K. van Poollen
H. K. van Poollen and Associates, Inc.

Joseph P. Green, Reservoir Engineer
and Project Director for
State of Alaska

INTRODUCTION

This report describes the results of a three-dimensional (3-D) model study of the Sadlerochit Formation of the Prudhoe Bay Field. The objectives of the study were to determine the effect on ultimate oil recovery of:

1. A source water injection program.
2. Reservoir gas voidage of 2.7 billion cubic feet per day (2.0 billion cubic feet available for sales).

The available reservoir data included:

- Individual well completion data
- Production rate data
- Pressure data
- Core analyses
- Well logs

All data were originally released by the operators to the State of Alaska Oil and Gas Conservation Commission. The cutoff for most historical data was June 1979, however production figures were matched to August 1979. Using current volumetric data, the 1974 oil-in-place and gas-in-place volumes were updated as indicated in Table I. Next a three-dimensional, three-phase reservoir model was used to study the reservoir performance under various producing plans.

CONCLUSIONS

1. Oil recovery can be substantially increased by effective source water injection. For the cases studied, an average increased recovery of 1.5 billion barrels (1.1 to 1.9), representing an average difference in recovery of 7.4% of the stock tank oil-in-place (5.3% to 9.5%), may be attributed to source water injection.
2. Gas voidage of 2.7 billion cubic feet per day in the presence of source water injection should not materially affect ultimate oil recovery. Differences in recovery varied between 0.4% and 0.7% (0.08 to 0.14 billion barrels). These small variations are considered to be less than the average range of comparison sensitivity of the model.

3. Since all comparisons showed greater ultimate recovery with source water injection, it should be implemented as soon as feasible.
4. Ultimate oil recoveries range from 36% to 46% of the original-oil-in-place (O.O.I.P.). The low value was from a case without source water injection or optimized recompletions in the later field life. The high value was with source water injection and assumed no gas coning or adverse permeability variations.
5. While the boundary conditions were limited because of budget and time constraints they were sufficient to accomplish the basic study objectives.

RECOMMENDATIONS

Now that the State has a working 3-D model, additional studies should be made which include:

1. Different values of oil production rate, gas production rate and source water injection rate.
2. Updating the model using new production data, well data (logs, etc.) and pressures.
3. Monitoring field behavior.
4. Further study of the possible effects of gas coning/fingering and adverse permeability variations on ultimate recovery.
5. Fine-grid simulation to evaluate alternate injection patterns, shale effects, and well MER (maximum efficient rate).
6. Capillary pressure values in shaley areas.
7. The effects of lower producing bottom-hole pressures and different well densities.
8. The effects of source water injection into the gas cap.
9. The effect of increased gas recycling.

LIMITATION

Generally, accurate forecasting is limited to two or three times the actual production history. A data cutoff point of August 1, 1979 meant only 790 days of actual production history, or less than 2,000 days of effective prediction (five years). In the case of Prudhoe Bay, this effective prediction period may be longer because of the excellent

nature of well data and density of wells. Even so, the ultimate recovery indicated for any group of comparative cases run may have a tolerance of as much as 5% of the O.O.I.P. (i.e., an indicated recovery of 40% might be as low as 35% or as high as 45%). The low range of production might be due to erroneous end values on relative permeability, coning and/or fingering effects, and adverse permeability variations. The high range might be due to better reservoir continuity, more favorable mobility and benefits of gas cycling. Nevertheless, the relative recoveries of the different processes should be valid (i.e., source water injection versus no source water injection and the relative effect of gas sales). Ultimate recovery estimates may vary as more history is gained and additional data become available from full field development. Conditions which might affect a change would affect comparative cases proportionately so that the conclusions remain valid.

The shale descriptions in the model are coarse, and a more detailed refinement is necessary for precise understanding of fingering and coning. Shale members in the eastern portion of the field sometimes occur more closely spaced than the vertical dimension of the grid blocks. This had to be accounted for mathematically as indicated on page 6.

BOUNDARY CONDITIONS

In-Place Volumes

In order to have a basis for comparing the cases, certain parameters were fixed. The original hydrocarbons in-place are 20.6 billion barrels of stock tank oil, 14.9 trillion standard cubic feet of solution gas and 23.4 trillion standard cubic feet of gas cap gas. The maximum field offtake rate was set at 1.5 million barrels of stock tank oil (STO) per day.

Ratios

Individual wells were allowed to produce at gas-oil ratios up to 100,000 cubic feet per barrel. This gas-oil ratio limit was not the major boundary condition as gas production limitation was prorated

based on the actual maximum field gas handling capacity. It was assumed for all cases that 10% of the gas produced would be utilized as fuel for lease and pipeline operations. For the no-gas-sales cases, the remaining 90% of all produced gas was returned to the gas cap. The water-oil ratio limitation for individual wells was set at twenty barrels of water per barrel of stock tank oil, but was never reached because of the pronounced effect of three-phase relative permeability. In all cases, the field was shut-in when the total oil producing rate had declined to 100,000 barrels stock tank oil per day.

When applicable, gas voidage rates were set at 2.7 billion standard cubic feet of gas per day and started in mid-1985.

Productivity Index

Existing wells were assigned actual values for productivity index (PI). For a well with a full oil column this value ranged from less than 5 to over 100 with an average of 14.6 barrels per day per psi. For wells with less oil column a value of 3.65 was assigned to each "exposed" grid interval. All new wells were assigned this average value for each exposed layer.

Pressure

The minimum producing bottom-hole pressure for all wells was set at 2,000 psi. This was intended to simulate using artificial lift and a low pressure gathering system. There may be a possibility of reducing this to 1,500 psi which would improve ultimate recovery and could affect producing gas-oil ratios. Further work is needed in this regard.

Injection

In each case, all produced water was reinjected into peripheral water injection wells starting in mid-1981 and source water, where applicable, was initiated in mid-1984. While the number of produced water injection wells was increased as necessary to accommodate the produced water volume, all source water injection wells were activated in mid-1984. For the cases which had source water injection, it was limited to a maximum injection rate of two million barrels per day, or a maximum reservoir pressure of 3,950 psi.

Wells

Producing wells were located on 160-acre spacing and generally had multiple intervals exposed. Injection wells were also on 160-acre spacing located above the heavy oil-tar zone (HO-T) with single interval completions.

INPUT DATA

The volumetric determination of oil- and gas-in-place was updated from the 1974 report using data from wells logged through the end of 1978. The same approach was used as in the 1974 report and the comparisons are depicted in Table I.

HO-T Zone

The heavy oil-tar zone (HO-T) has been discussed in prior reports. Because of the high viscosity of the oil in this zone it will probably result in higher residual oil saturations and adversely affect the relative permeability to water.

In this study the HO-T zone was represented as having an average thickness of 50 ft ranging from 8,990 to 9,040 ft, a total oil-in-place volume of 1.9 billion barrels, a residual oil saturation of 40%, a reduced relative permeability to water by a factor of 10, and an increased oil viscosity by a factor of 10. The oil recovery from this interval is essentially zero.

Both operators conducted independent water injectivity tests which confirmed high injectivity into both the light oil and aquifer intervals but poor injectivity into the HO-T interval. It was determined that sufficient injection water could be passed through the HO-T interval to allow effective peripheral flooding from aquifer injection, barrier faults along the western field boundary precluded its use in that area. This, together with the more realistic response time of "in zone" injection, led us to place all water injection intervals above the HO-T zone.

Aquifer

Based on previous studies and field observation, the aquifer is only slightly effective. A 1.7 trillion barrel aquifer was used in this model.

Faults

The field has been cut by several vertical faults. Where these faults appear to be fluid barriers they were simulated in the model as a plane of zero horizontal transmissibility.

Shales

An extensive study by the operators gave an excellent description of shales. This study, together with work done by the A.O.G.C.C. geological staff aided in the simulation of the shales. The thickness of the grid blocks used in this study varied. All thicknesses were in excess of 30 ft while shales were found as closely spaced as 5 ft. The mathematics of the model dictate that all shales had to be moved to their respective grid block boundary (either up or down, whichever was closer). Hence, our grid block dimensions may have been too coarse to truly evaluate detailed fingering. We found that, in general, when shales were present, the vertical permeabilities of the shale should be reduced by a factor of 0.01 times the vertical permeability of the adjacent sands. In some instances, this was modified based on relative shale strengths in individual grid blocks and ranged from 0.02 for blocks with partial single shales to 0.003 for blocks with multiple shales. On the east side of the field where the shales are thicker and more extensive, a vertical permeability of zero was sometimes used.

For those blocks without measured shale values (either no well present or no log available), a contour method was devised for estimation of these data.

Permeability

The permeability within each grid block was determined from both pressure build-up curves and core analyses. Individual core plugs show that vertical permeability is about 0.5 times the horizontal

permeability. On the basis of permeability variation, vertical permeability in the presence of thin shale laminae is reduced. The vertical permeability value of 0.35 times the horizontal permeability was used throughout.

Pressure build-up curves were evaluated for both radial and spherical flow and shale breaks. Calculated values were corrected for saturation effects prior to introduction into the model.

A statistical approach was used to determine the values for the undrilled grids. Permeability values for wells having data were posted on a map. In areas of adequate representation of data derived from build-up tests, a ten point average was taken. This enabled assignment of permeability values to surrounding grid blocks. In areas where actual data were limited, one average value determined from the available data was used.

Relative Permeability

A thorough review and analysis of two-phase relative permeability data resulted in selecting the values shown in Figures 1 and 2.

Three-phase relative permeability was determined by the model using the Modified Stone's* Formula shown below:

$$k_{ro} = k_{ro\text{cw}} \left[\left(\frac{k_{row}}{k_{ro\text{cw}}} + k_{rw} \right) \left(\frac{k_{rog}}{k_{ro\text{cw}}} + k_{rg} \right) - \left(k_{rw} + k_{rg} \right) \right]$$

where:

k_{ro} = relative permeability to oil in the presence of both gas and water

k_{row} = relative permeability to oil in the presence of water

k_{rw} = relative permeability to water

k_{rog} = relative permeability to oil in the presence of gas

*Dietrich, J.K., and Bonder, P.L., "Three-Phase Oil Relative Permeability Models," preprint of SPE 6044, presented at the 51st Annual Fall Meeting of SPE, October 3 - 6, 1976, New Orleans, LA.

k_{rg} = relative permeability of gas

$k_{ro_{cw}}$ = relative permeability to oil at connate water saturation

Water Compressibility

An average water compressibility value of 3.3×10^{-6} per psi was used.

Rock Compressibility

An average rock compressibility value of 3.4×10^{-6} per psi was used.

Pressure-Volume-Temperature (PVT)

The possibility exists that PVT properties may vary both vertically and horizontally. For the purpose of this study, only the vertical variation was considered and is shown in Figures 3, 4 and 5.

Individual Well Data

Perforated intervals and shale breaks were graphically compared. Productivity indices were determined for all existing wells and assigned to the appropriate intervals. New wells or recompletions were assigned a value of 3.65 barrels per day per psi for each grid-interval exposed.

Pressure Build-Up

A total of 249 pressure build-up tests was analyzed to determine reservoir pressure and permeability. These tests were distributed over 137 wells. The method used by the authors gave values that compared favorably with static pressure tests and with core measured permeability values.

RESERVOIR MODELING

The approach was to model the field with six layers generally in vertical communication. The modeling blocks were 160 acres throughout the oil-bearing portion of the field and were gradually increased to a

maximum of 2,560 acres in the far corners of the aquifer and gas cap. This eventually resulted in a 52 x 23 x 6 model containing 4,858 active and 2,318 passive grid blocks as shown in Figure 6.

The objective was to match the 26 months of reservoir performance and to make reservoir and individual well forecasts under different sets of producing conditions.

Empirical functions for relative permeability, capillary pressure and vertical permeability were derived using fine- and coarse-grid cross sections to adjust for numerical dispersion effects.

Cross Sections

Two major cross sections were made, as indicated in Figure 7. The fine-grid cross sections are depicted on Exhibits A and B. The cells below shale breaks were assigned a partially segregated relative permeability curve.

Shales were represented as reductions in vertical permeability as described on page 6. Modifications in horizontal permeabilities had very little or no effect on trying to duplicate gas fingering. Eventually the right combination of values was found and the NS cross section was matched. This combination was then used in the EW section and a nearly instantaneous match was obtained.

Once a match was obtained on the fine-grid cross sections, a forecast was made for each cross section. Future well rates were assumed to be equal to the last rates. Some additional runs were performed with these fine-grid cross sections using water injection and gas sales. These forecasts then became the artificial history for the derivation of the model modifiers using coarse-grid cross sections.

The coarse-grid sections (indicated by the heavy lines on Exhibits A and B) have the same dimensions as were used in the oil column of the 3-D model (i.e., six layers and 160 acres). To obtain a match for the artificial history from the fine-grid sections, the following parameters were modified:

1. Cell to cell relative permeability
2. Individual well relative permeability to represent the limited perforated intervals, perforation standoff from fluid contacts and coning or fingering effects

3. Capillary pressure
4. Vertical permeability to represent shales.

The first two functions are shown in Figures 8 and 9. Functions and their modifications were deliberately kept simple to allow for a random use in the 3-D work.

Three Dimensional

The 3-D network was assigned all reservoir functions derived from the coarse-grid cross sections in addition to the general input data. Next, individual wells, or in some instances clusters of wells, were matched. Basically, the only modifications were in the change of assigned shales in areas of lesser control. In some instances, well relative permeabilities were modified.

After the 3-D history match was obtained, forecasts were made using a predicted drilling schedule which would allow for full field development attempting to use the same general guidelines used by the operators. The new wells were assigned similar relative permeability curves as the wells which were producing during the history match.

During the forecast, wells were recompleted as follows. When gas-oil ratio from a layer reached 100,000 cubic feet per barrel, that layer and all layers above it were shut-in. After all layers of a well were shut-in, that well was reviewed for recompletion by opening those layers having sufficient oil saturation for further production. Table II shows a schedule of this type of recompletion. A similar shut-in process was used for high water-oil ratios; however, this did not become a problem as wells were not shut-in because of water production.

INDIVIDUAL RUNS

Four major runs are described in this report and shown diagrammatically on Figure 10. With the exception of Case C, all cases were optimally recompleted in the later project life. It is conceivable that such optimization would provide some additional recovery for Case C. Even with significant improvement, however, the ultimate recovery for this case would still be too low to be an acceptable method of field exploitation.

All cases were normalized to a field abandonment producing rate of 100,000 barrels of oil per day. The variations in operating conditions would probably cause each case to have a different economic limit. Minor variations in the economic limits would not have a significant impact on ultimate recoveries. A much larger impact would result from the energy required to reinject gas that might otherwise be sold. This could exceed 100 million barrels of oil in equivalent BTU content.

The reader should refer to the section entitled Boundary Conditions for other common parameters to the following cases:

Case A - had no gas sales and no source water injection. Total oil recovery was 8.42 billion stock tank barrels representing 40.8% OOIP in 36.3 years.

Case B - had no gas sales with source water injection of 2 million barrels per day or less, governed by reservoir pressure. Total oil recovery was 9.51 billion stock tank barrels representing 46.1% OOIP in 37.5 years.

Case C - had gas sales of 2 billion cubic feet per day and no source water injection. Total oil recovery was 7.42 billion stock tank barrels representing 35.9% OOIP in 24.2 years.

Case D - had gas sales of 2 billion cubic feet per day and source water injection of 2 million barrels per day. Total oil recovery was 9.37 billion stock tank barrels representing 45.4% OOIP in 26.6 years.

The results of these four cases are plotted on Figures 11 through 22.

EFFECTS OF GAS CYCLING AND CONING

Some additional runs were made to evaluate the effect of added gas recycling capacity. Results are not yet conclusive and additional work is recommended.

The effect of gas coning was also evaluated. This was done by increasing the well gas-oil relative permeability ratio. Gas coning

effects in the runs used in this study reduced recovery percentages from 3 to 6. While these are valid numbers, additional runs are necessary using adverse gas-oil relative permeability values and permeability variations to further determine the sensitivity to gas coning.

TABLE I
ORIGINAL HYDROCARBONS IN-PLACE
SADLEROCHIT FORMATION
PRUDHOE BAY FIELD

Zone	Stock Tank Oil		Solution Gas		Gas Cap Gas		Gas Cap	
	Billion	Barrels	Trillion	Standard	Trillion	Standard	Condensate	Stock Tank Oil
Study Date	1974	1978	1974	1978	1974	1978	1974	1978
Upper	8.6	9.0	6.3	6.5	10.4	10.3	358	354
Middle	5.0	5.7	3.6	4.1	6.0	7.0	206	241
Lower	5.5	5.9	4.0	4.3	4.8	6.1	165	210
TOTALS	19.1	20.6	13.9	14.9	21.2	23.4	729	805

TABLE II
RECOMPLETION SCHEDULE FOR CASES A, B, C, D
PRUDHOE BAY FIELD

Days	Yrs	Case A	Case B	Case C	Case D
1,855	5	8 wells, *	8 wells, *	8 wells, *	8 wells, *
		8 wells, **	8 wells, **	8 wells, **	8 wells, **
2,220	6	152 wells, **	152 wells, **	152 wells, **	152 wells, **
		1 well, *	1 well, *	1 well, *	1 well, *
2,585	7	189 wells, **	189 wells, **	189 wells, **	189 wells, **
		1 well, *	1 well, *	1 well, *	1 well, *
2,950	18	24 wells, **	10 wells, *	8 wells, *	11 wells, *
		9 wells, *			
3,315	9	392 wells, **	8 wells, *	12 wells, *	13 wells, *
		21 wells, *			
3,680	10	37 wells, **	19 well, *	14 wells, *	20 wells, *
		8 wells, *			
4,045	11	99 wells, **	22 wells, *	14 wells, *	38 wells, *
		11 wells, *			
4,410	12	20 wells, *	19 wells, *	19 wells, *	24 wells, *
4,775	13	11 wells, *	21 wells, *	5 wells, *	23 wells, *
5,140	14	9 wells, *	13 wells, *	20 wells, *	17 wells, *
5,505	15	5 wells, *	10 wells, *	6 wells, *	13 wells, *
		102 wells, **	102 wells, **	102 wells, **	331 wells, **
5,870	16	9 wells, *	4 wells, *	11 wells, *	2 wells, *
6,235	17	5 wells, *	11 wells, *	11 wells, *	12 wells, *
6,600	18	6 wells, *	7 wells, *	9 wells, *	12 wells, *
6,965	19	2 wells, *	5 wells, *	10 wells, *	5 wells, *
7,330	20	9 wells, *	9 wells, *	13 wells, *	8 wells, *
7,695	21	5 wells, *	6 wells, *	14 wells, *	11 wells, *
8,060	22	6 wells, *	6 wells, *	3 wells, *	17 wells, *
8,425	23	3 wells, *	11 wells, *	11 wells, *	15 wells, *
8,790	24	5 wells, *	2 wells, *		26 wells, *
9,155	25	1 well, *	5 wells, *		27 wells, *
9,520	26				34 wells, *
9,885	27		3 wells, *		38 wells, *
10,250	28	2 wells, *	13 wells, *		
10,615	29		3 wells, *		
10,980	30		2 wells, *		
11,345	31	1 well, *	5 wells, *		
11,710	32	2 wells, *	5 wells, *		
12,075	33	2 wells, *	3 wells, *		
12,440	34	1 well, *	3 wells, *		
12,805	35	1 well, *			

* Model automatically shuts in individual layers due to excessive GOR

** Recompletion of individual layers based on moveable oil

¹ Year 8 is the break for the specific cases of A-D. Some recompletions were made prior to that time.

FIGURE 1
A.O.G.C.C.
Prudhoe Bay Field
Two Phase Relative Permeability
 K_{ro} and K_{rw} vs S_w

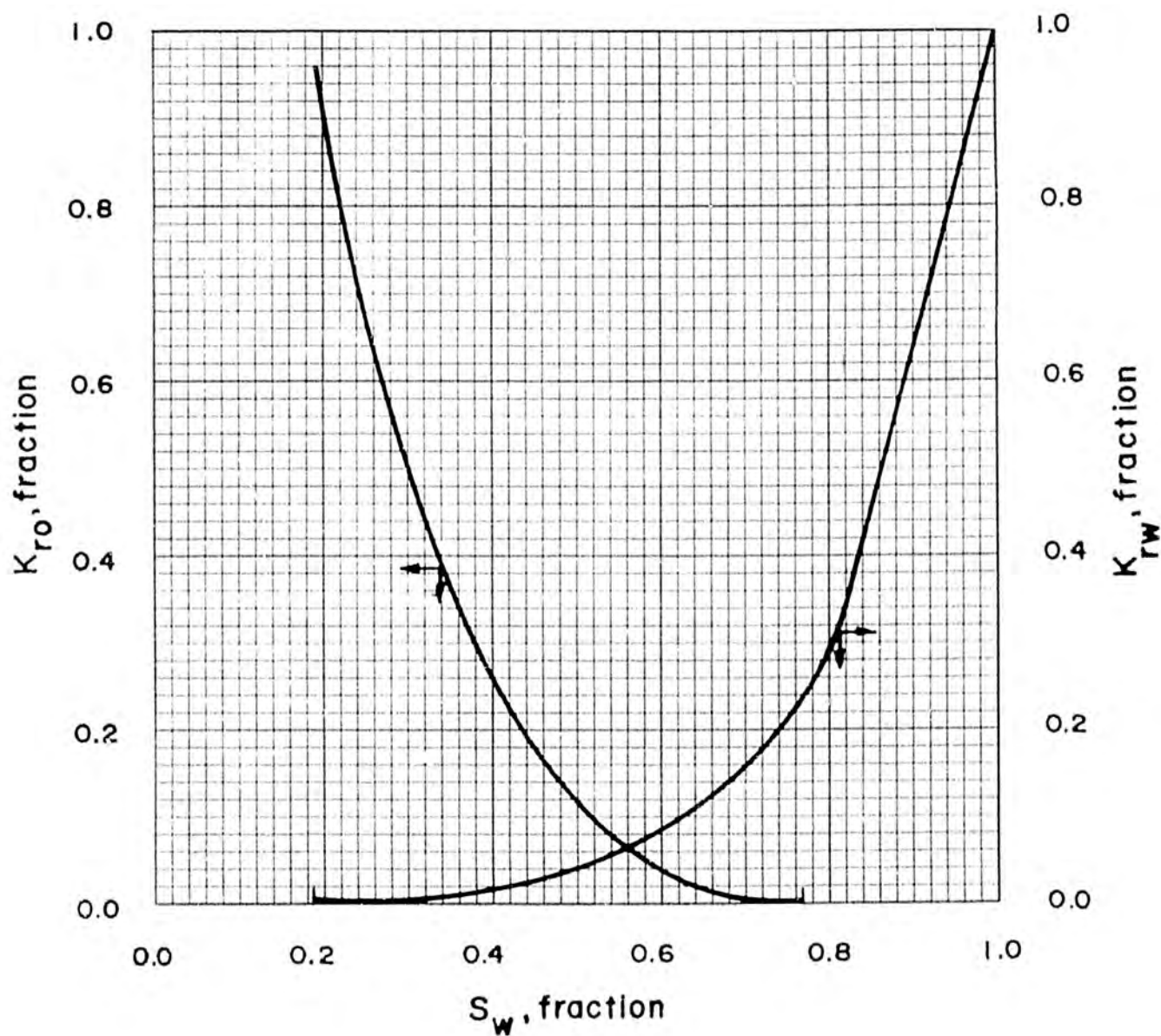


FIGURE 2
A.O.G.C.C.
Prudhoe Bay Field
Two Phase Relative Permeability
 K_{rg} and K_{rL} vs S_L

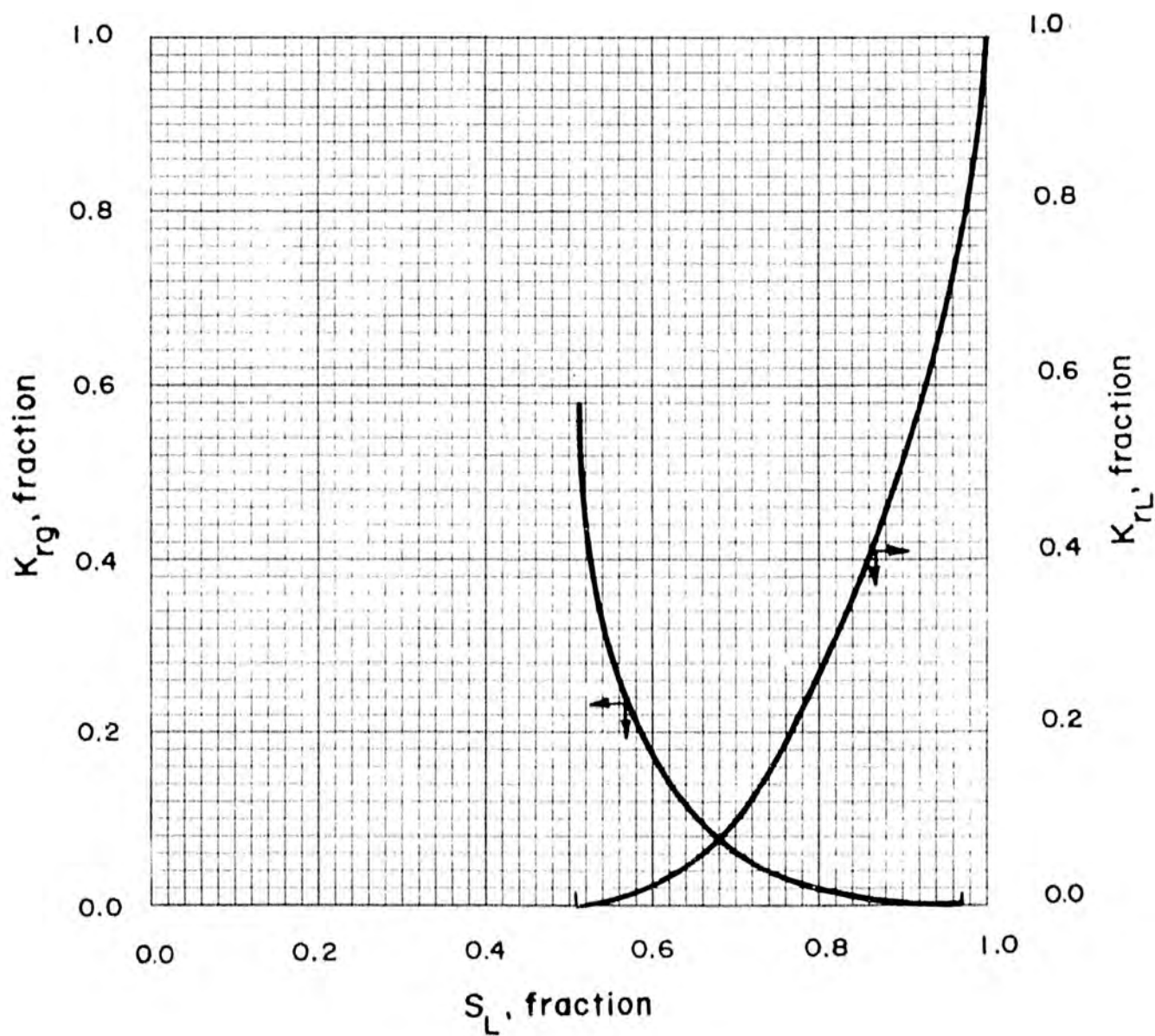


FIGURE 3
 A.O.G.C.C.
 Prudhoe Bay Field
 Oil PVT Table #1
 Oil Properties vs Pressure

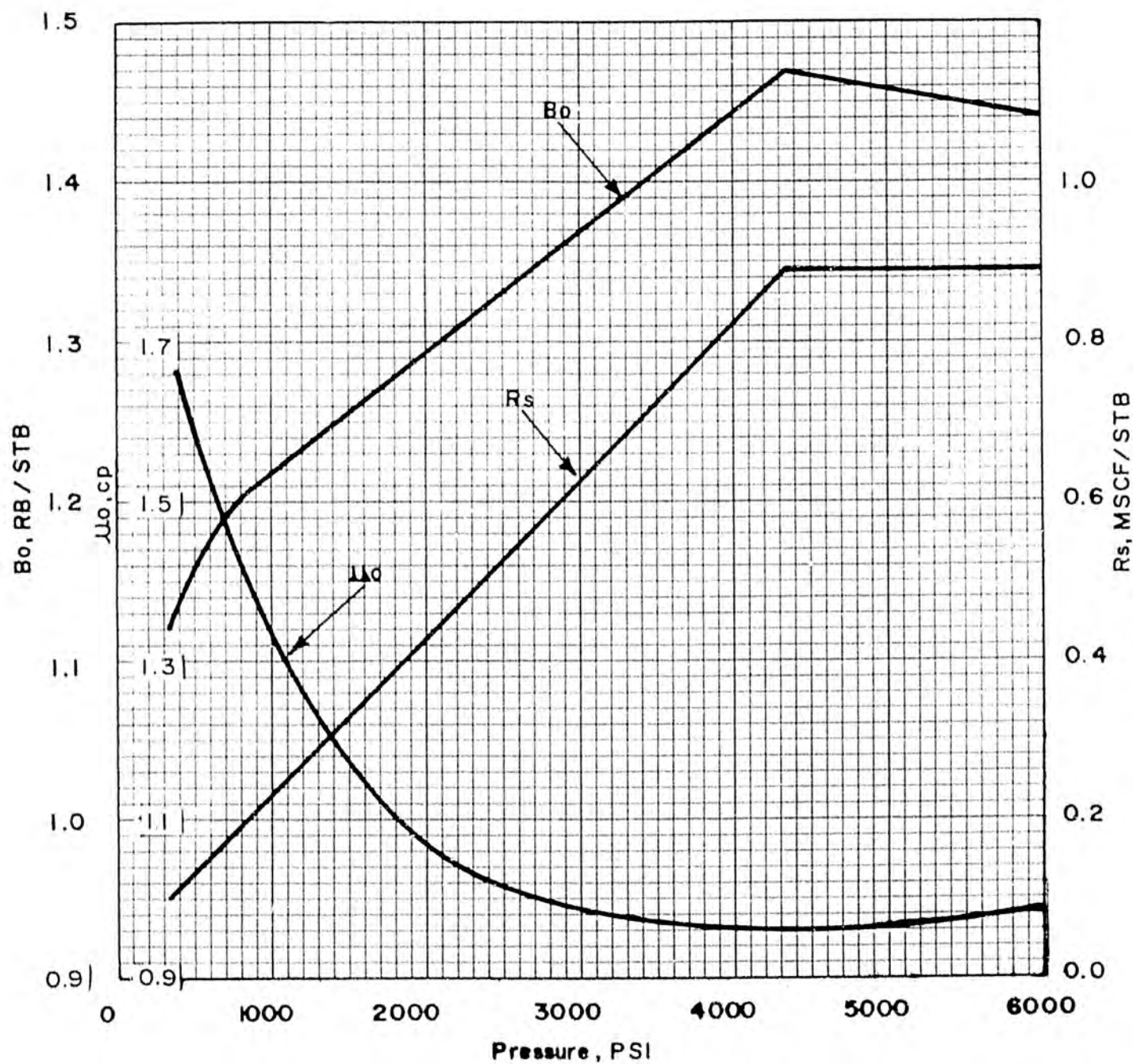


FIGURE 4
 A.O.G.C.C.
 Prudhoe Bay Field
 Oil PVT Table #2
 Oil Properties vs Pressure

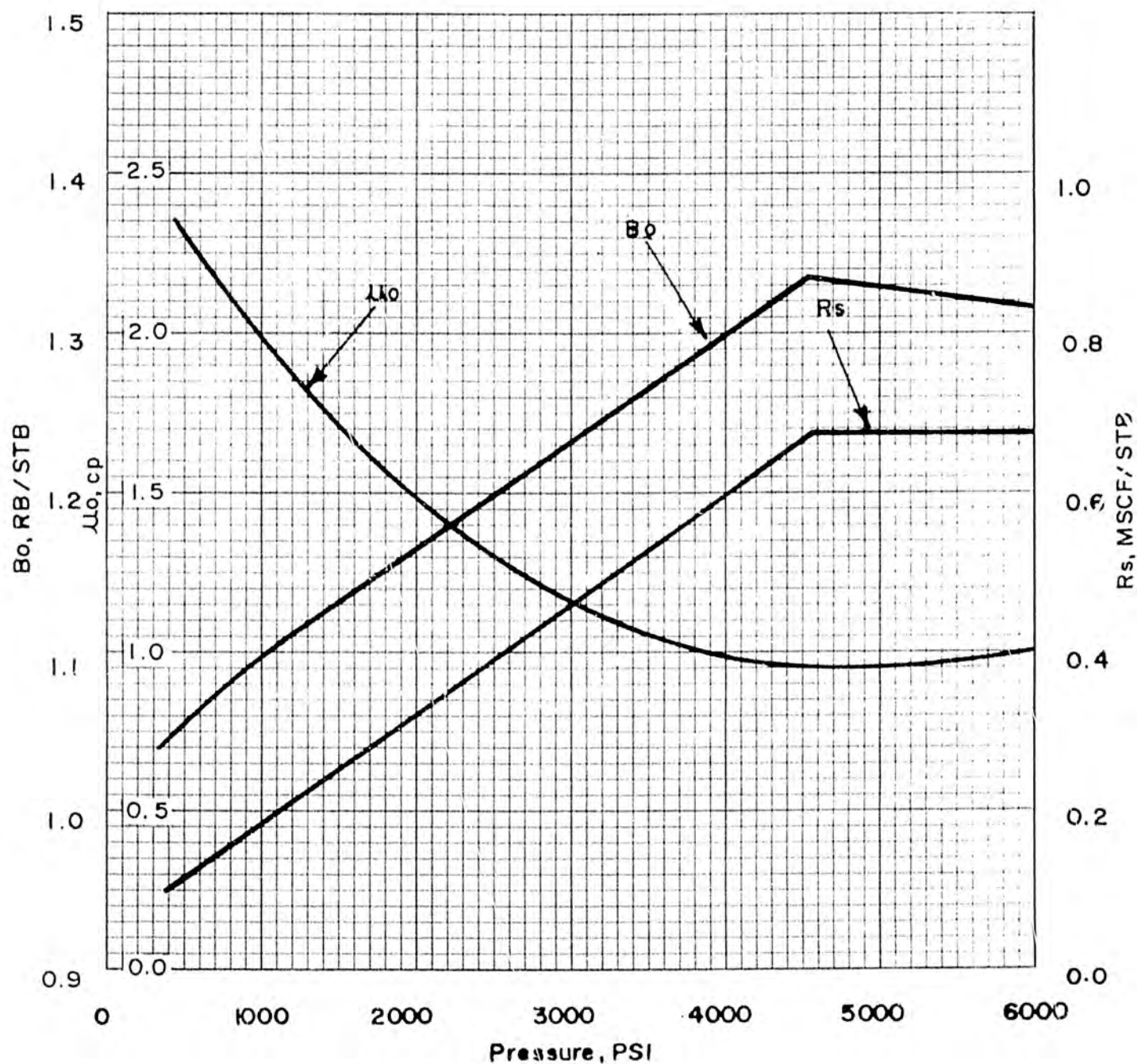
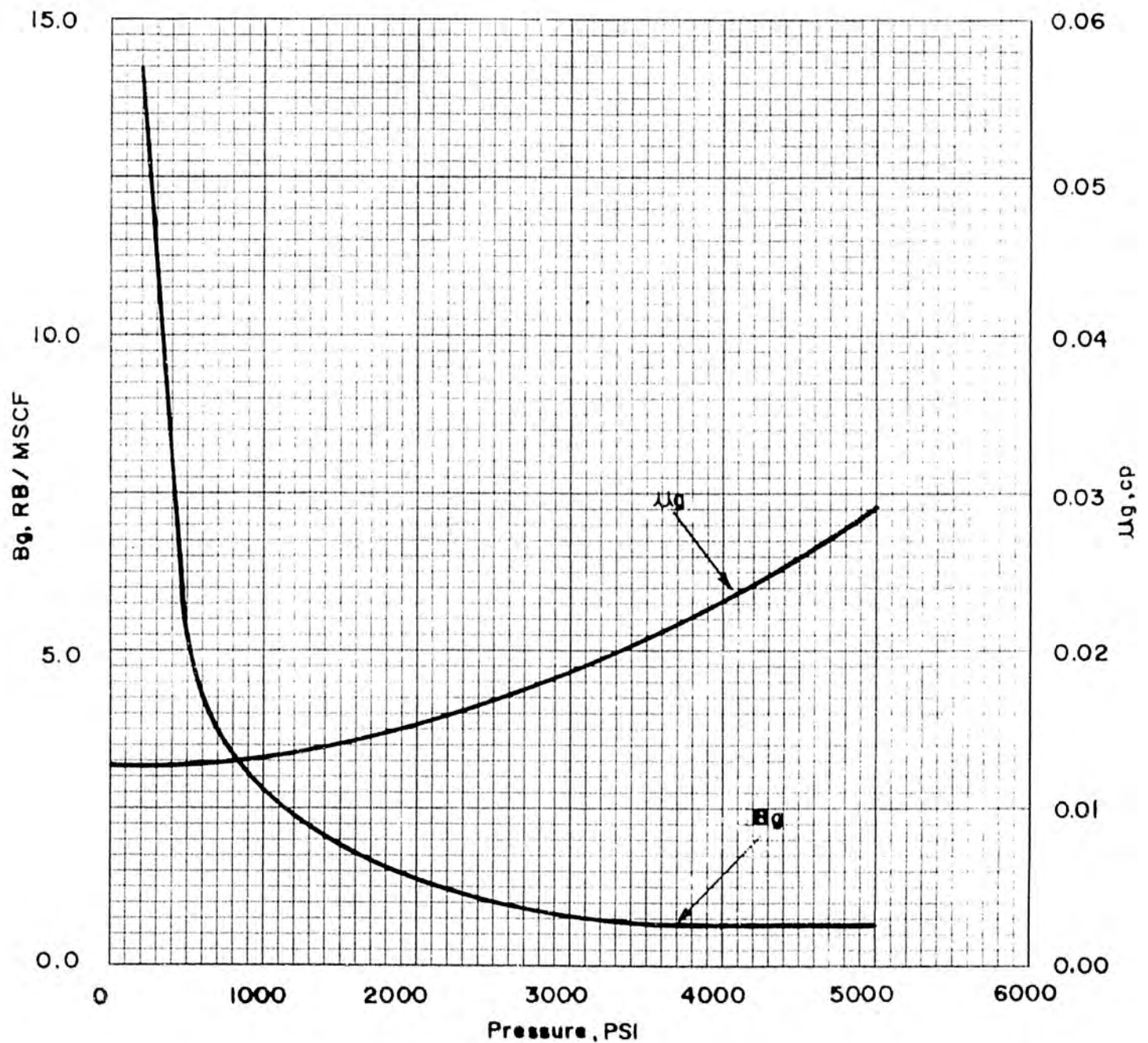


FIGURE 5
A.O.G.C.C.
Prudhoe Bay Field
Gas PVT Table # I
Gas Properties vs Pressure



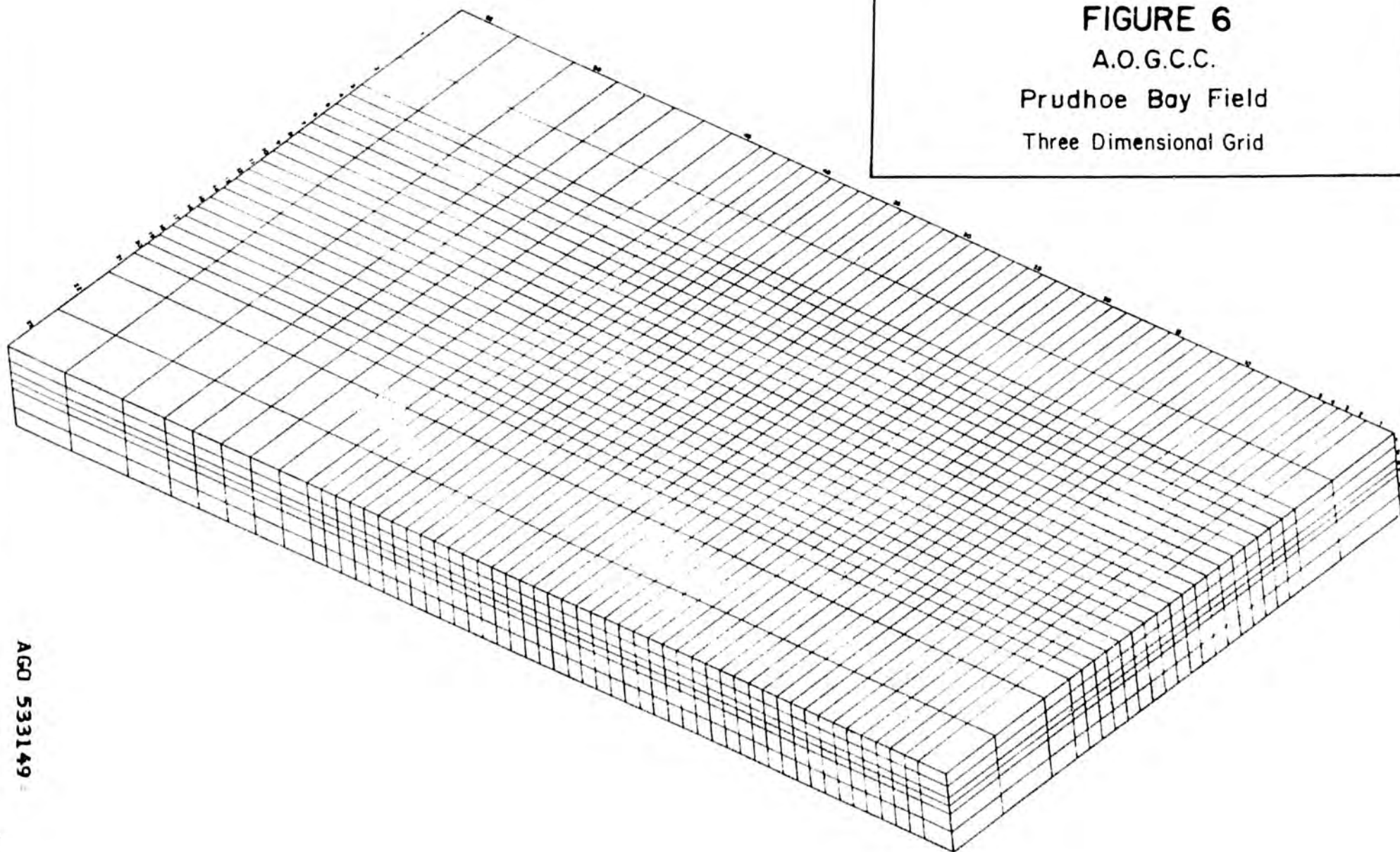


FIGURE 6

A.O.G.C.C.

Prudhoe Bay Field

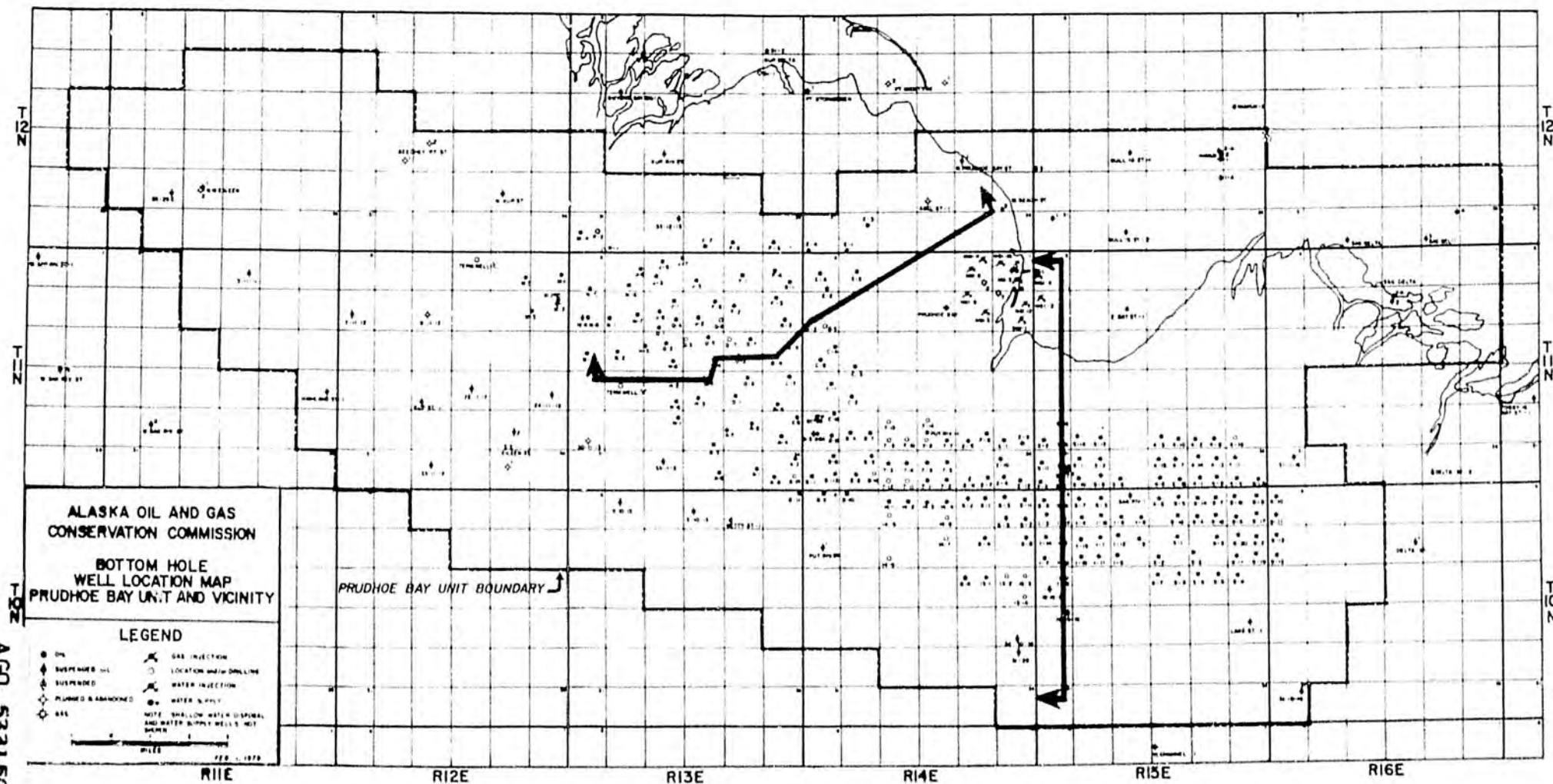
Three Dimensional Grid

FIGURE 7

A.O.G.C.C.

Prudhoe Bay Field

Cross-Section Model Locations



AGO 533150

FIGURE 8
A.O.G.C.C.
Prudhoe Bay Field
Cell to Cell Relative Permeability
 K_{rg} and K_{rL} vs S_L

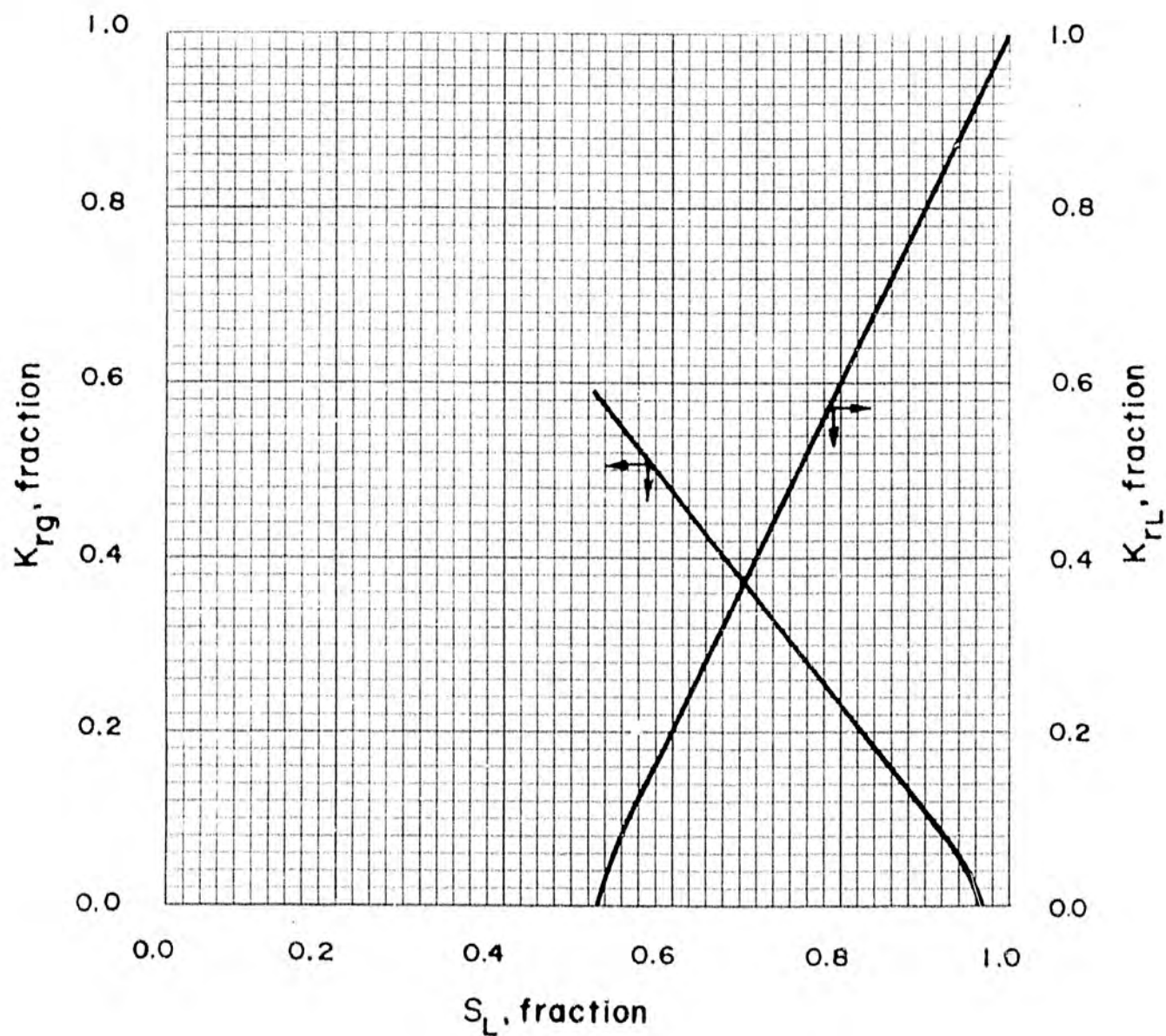


FIGURE 9
A.O.G.C.C.
Prudhoe Bay Field
Individual Well Relative Permeability
 K_{rg} and K_{rL} vs S_L

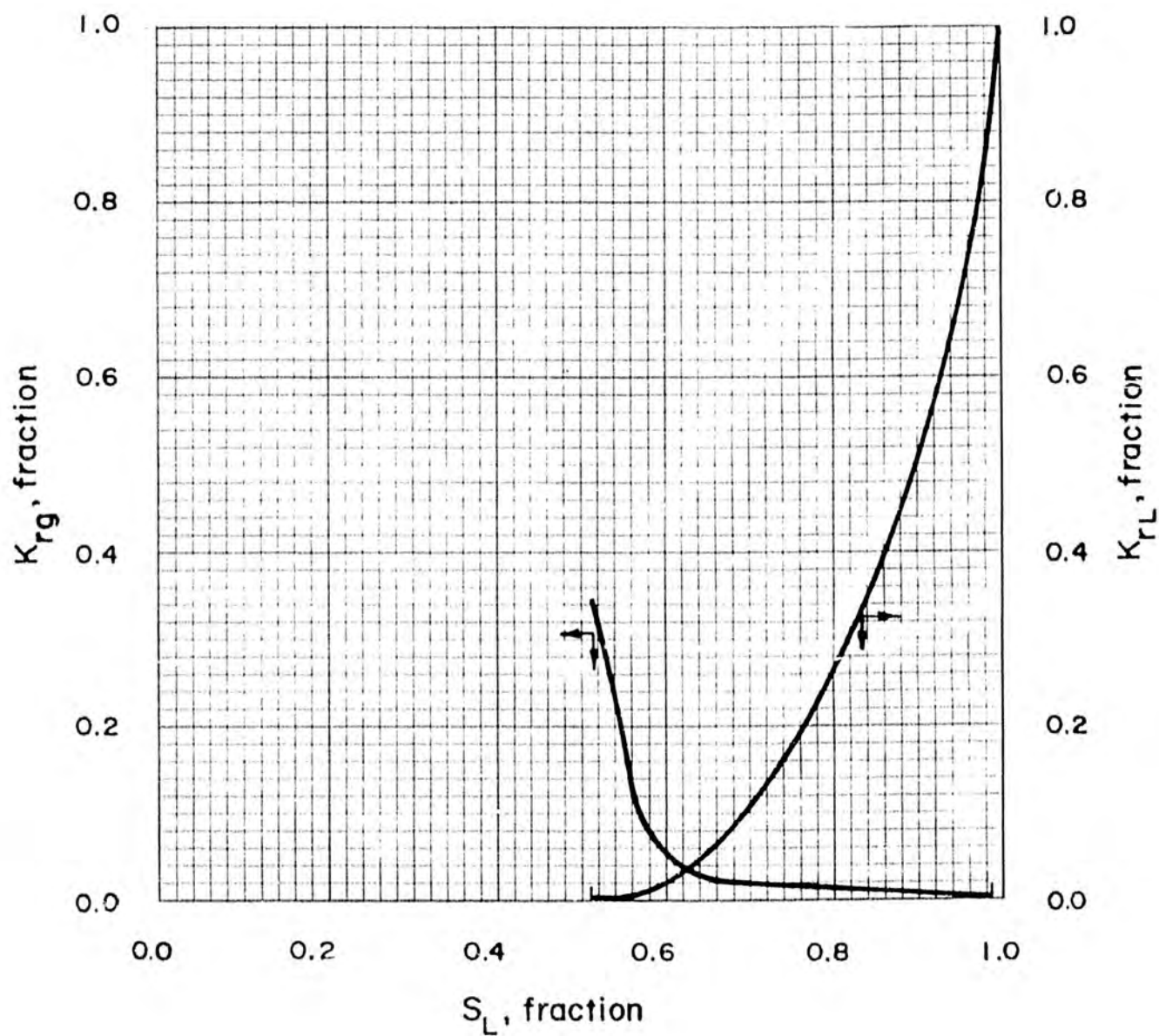
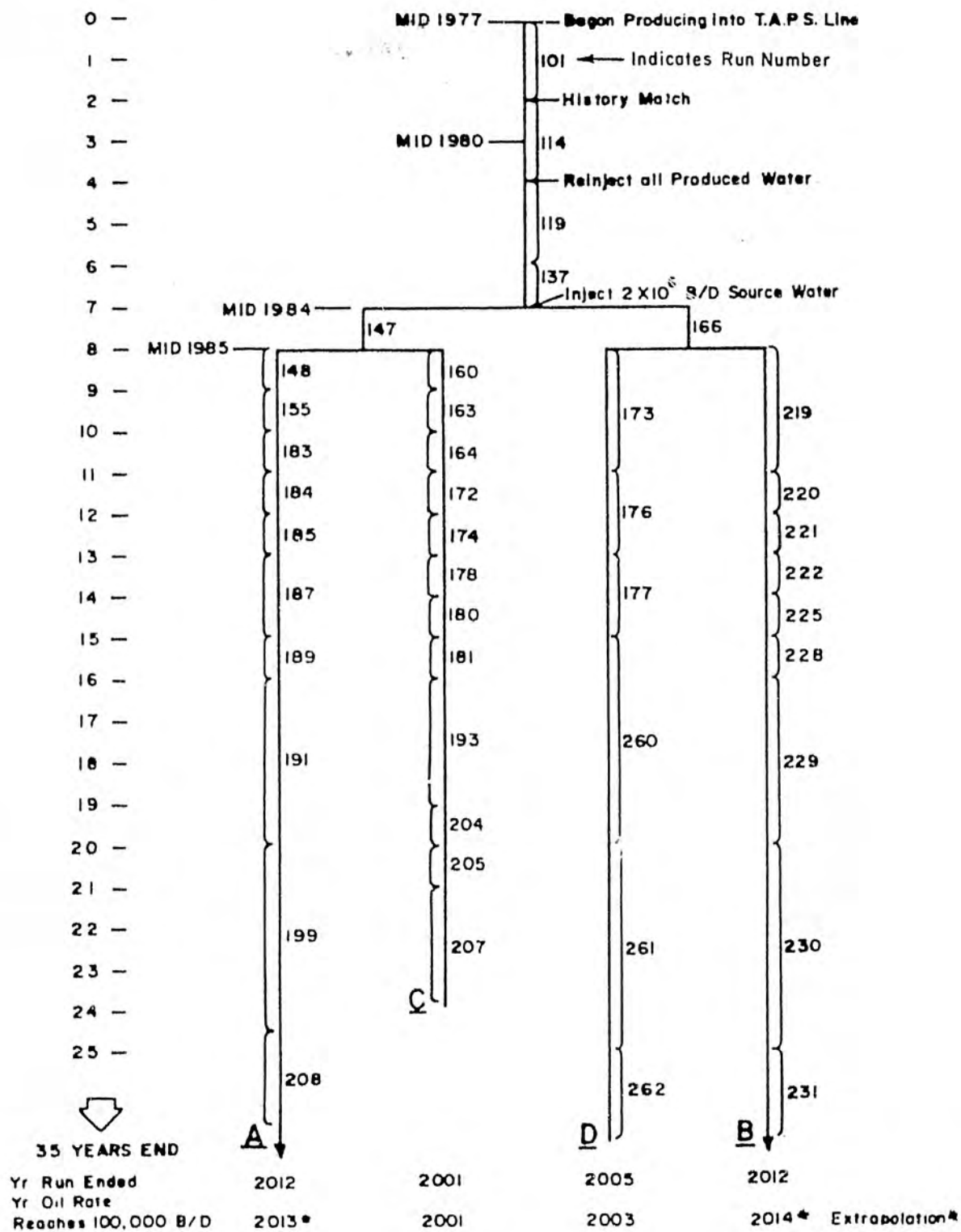
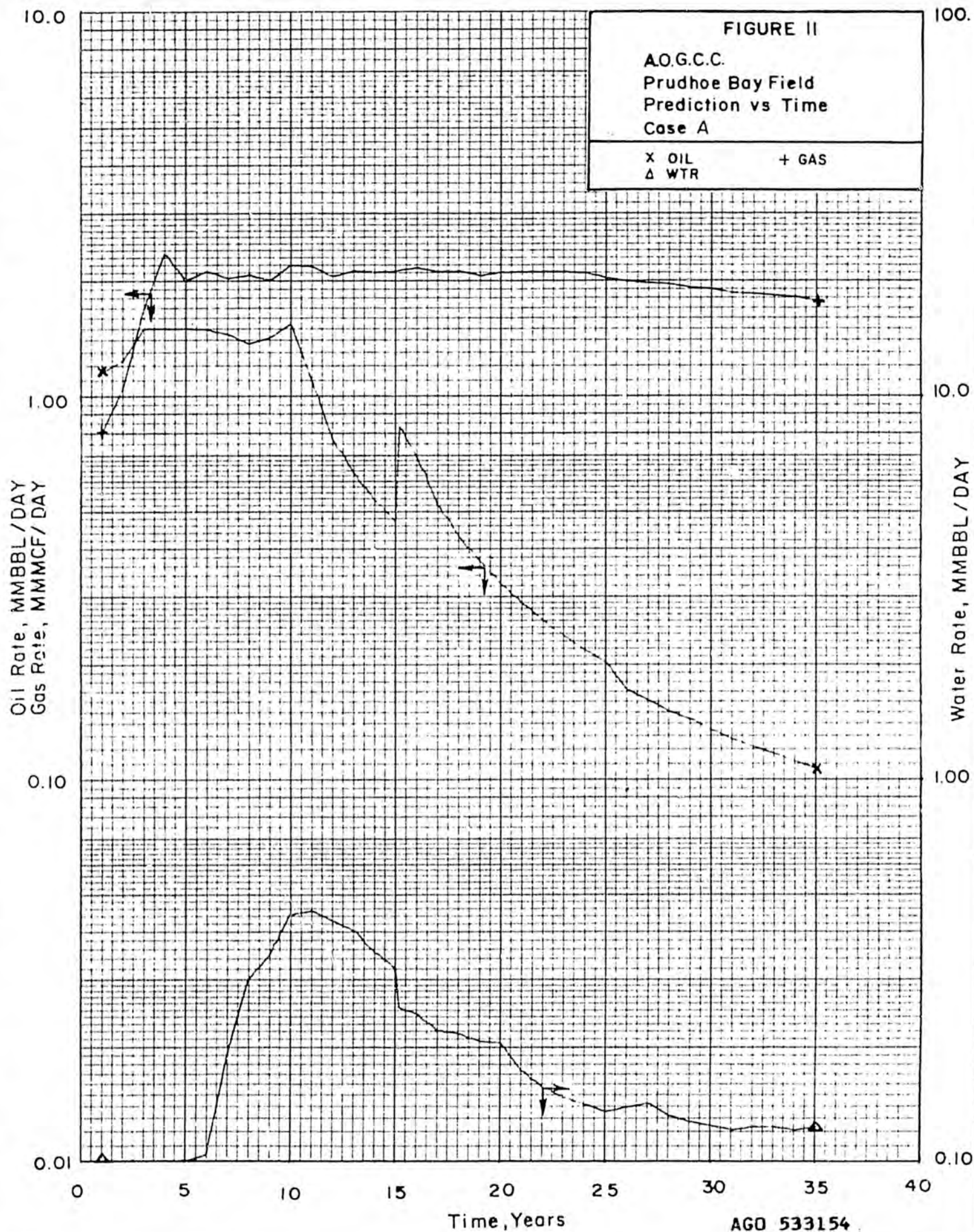
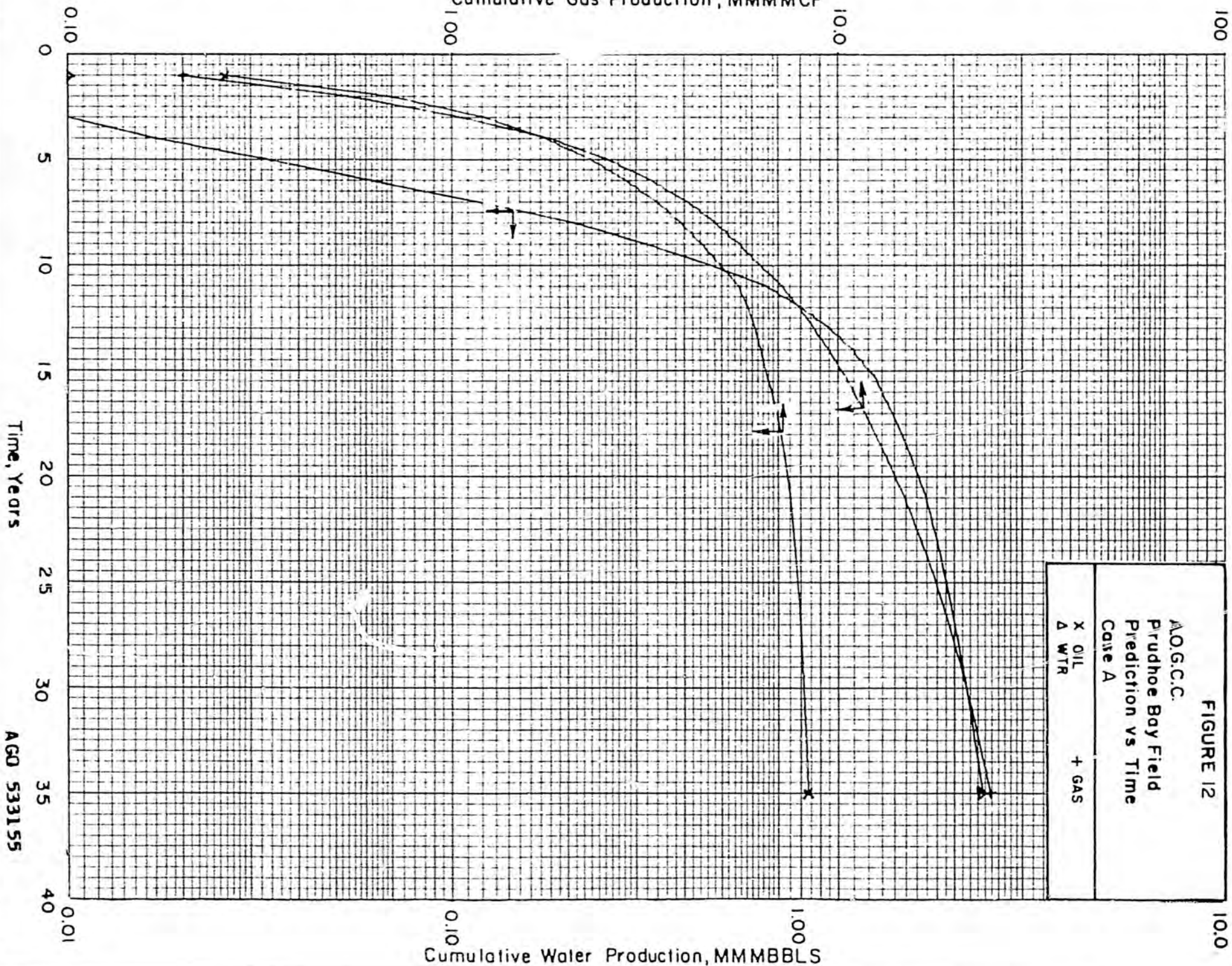


FIGURE 10
A.O.G.C.C.
Prudhoe Bay Field
Schematic Representation of
Cases A, B, C and D





Cumulative Oil Production, MMMBBLs
 Cumulative Gas Production, MMMMCF



100000.

FIGURE 13

10.0

A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case A

X OIL RATE + GOR
Δ WOR

100000

1.00

Oil Rate, MBL/DAY
GOR

WOR

1000.00

0.10

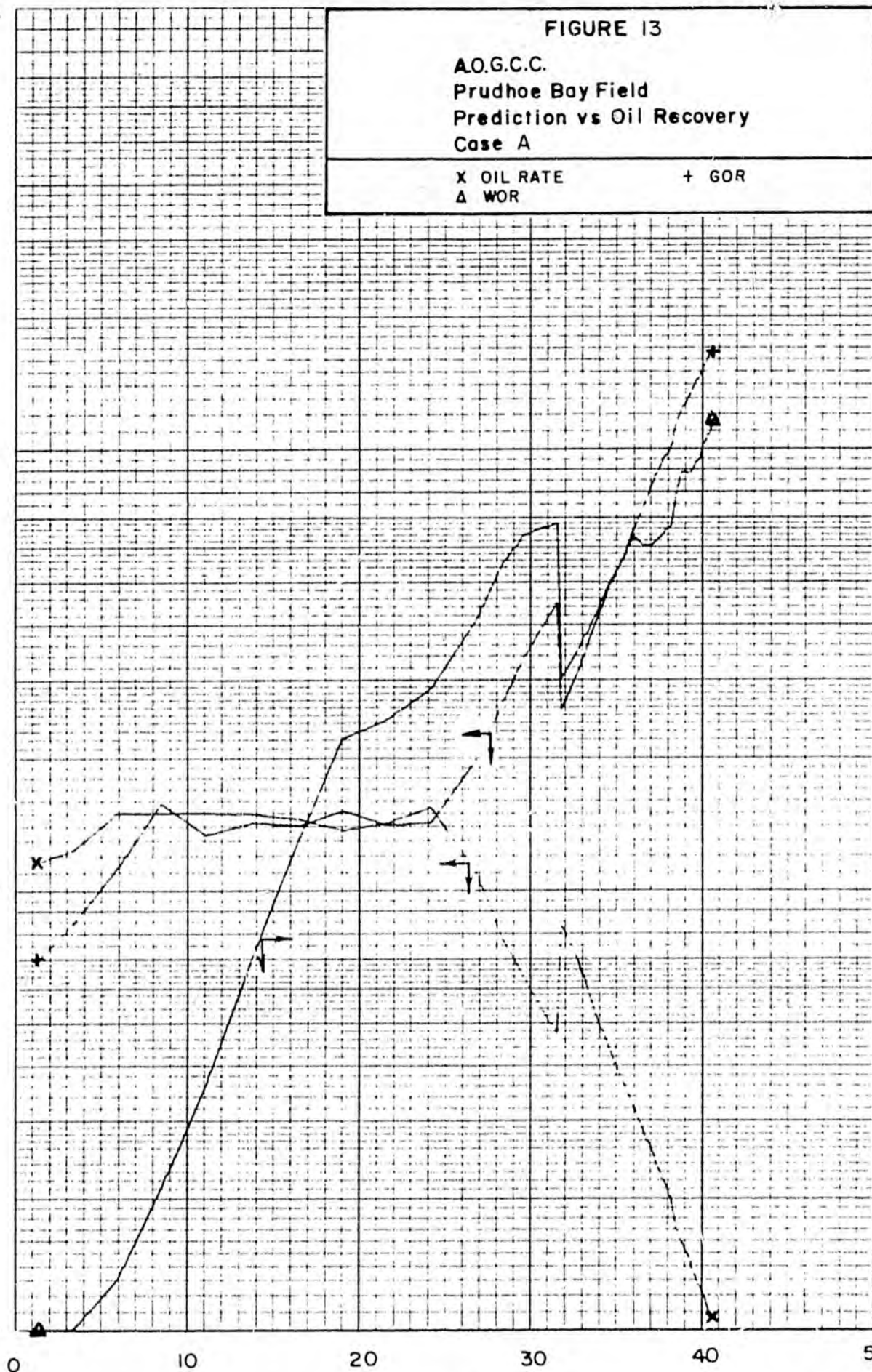
100.000

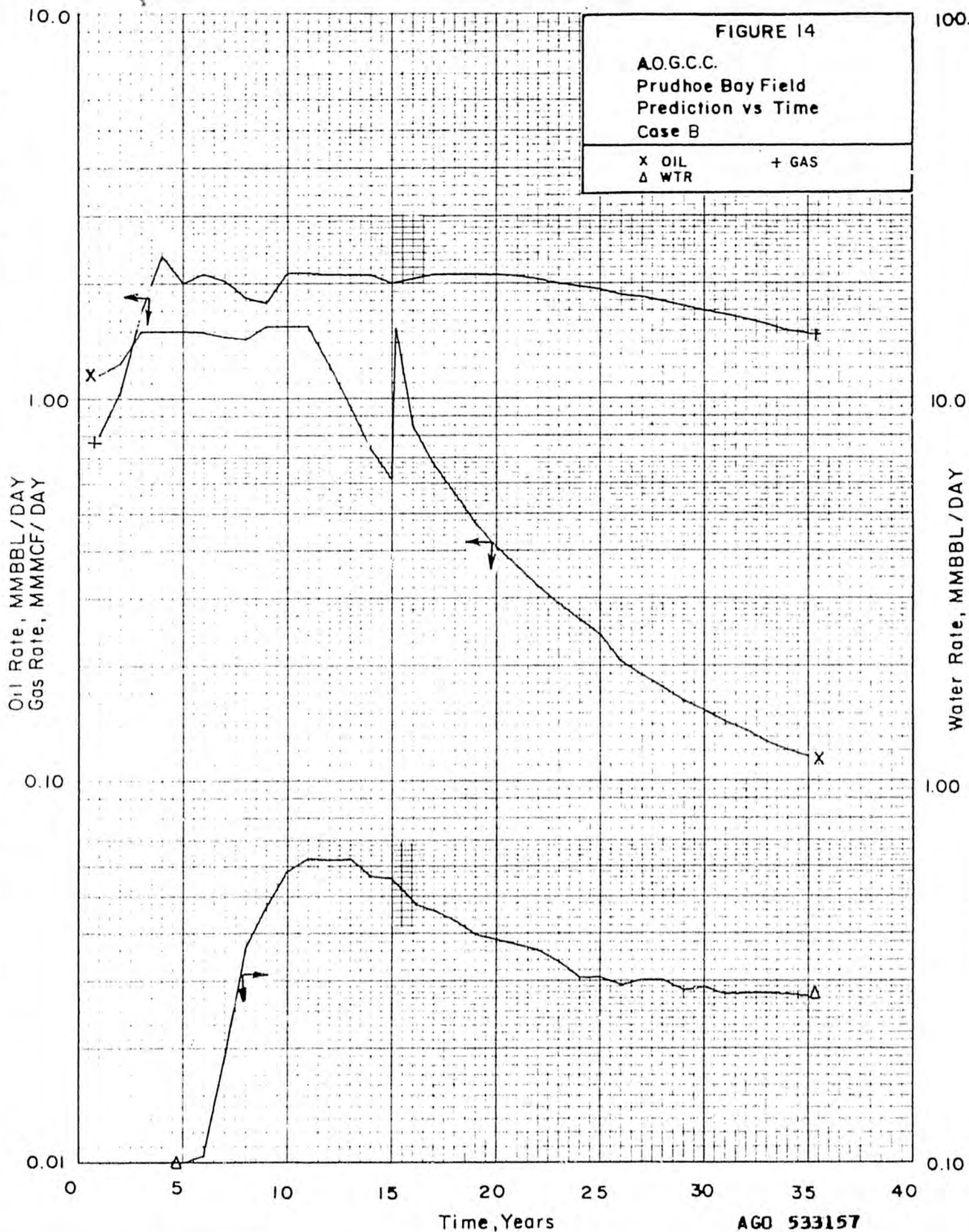
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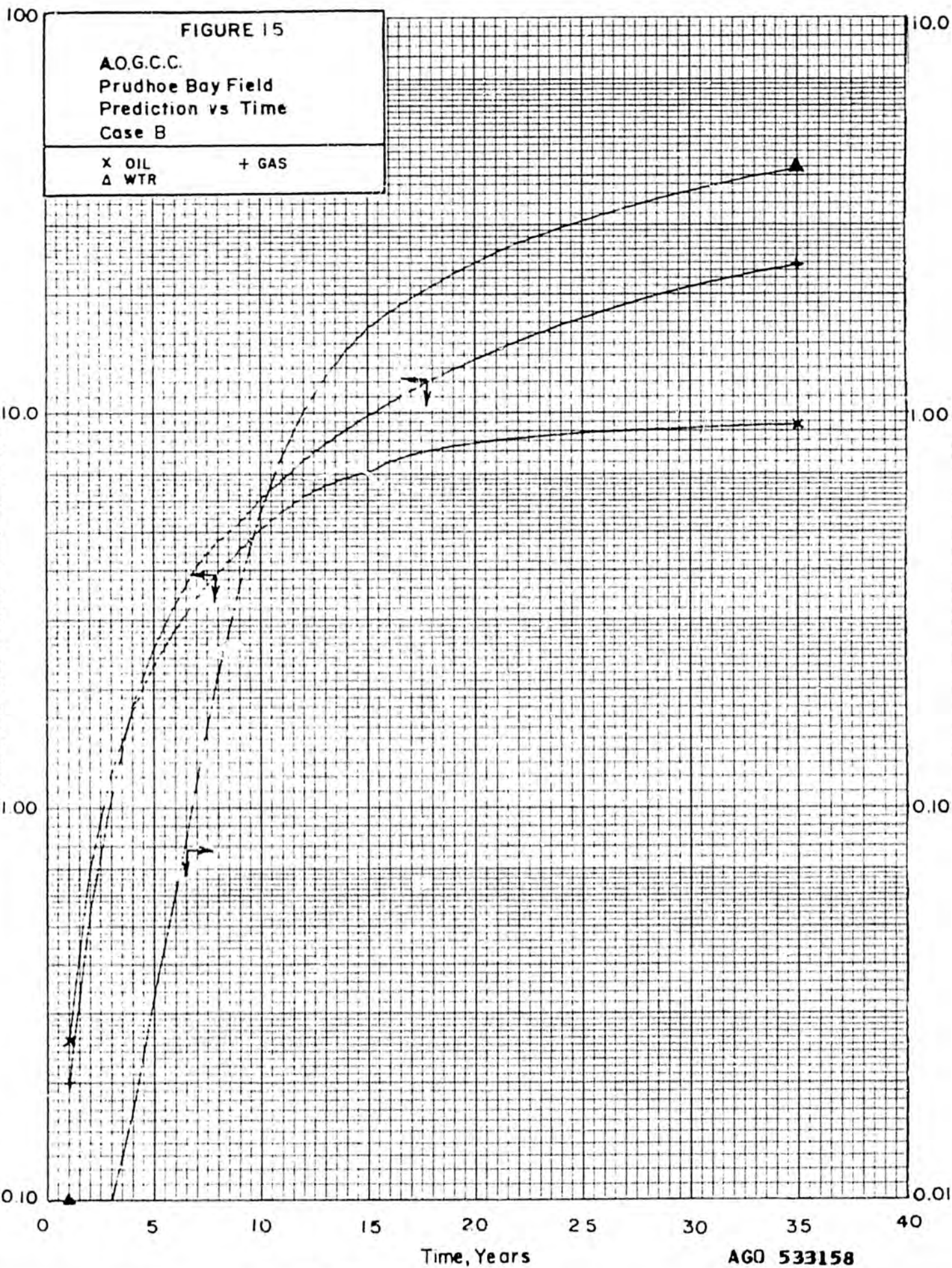
0 10 20 30 40 50

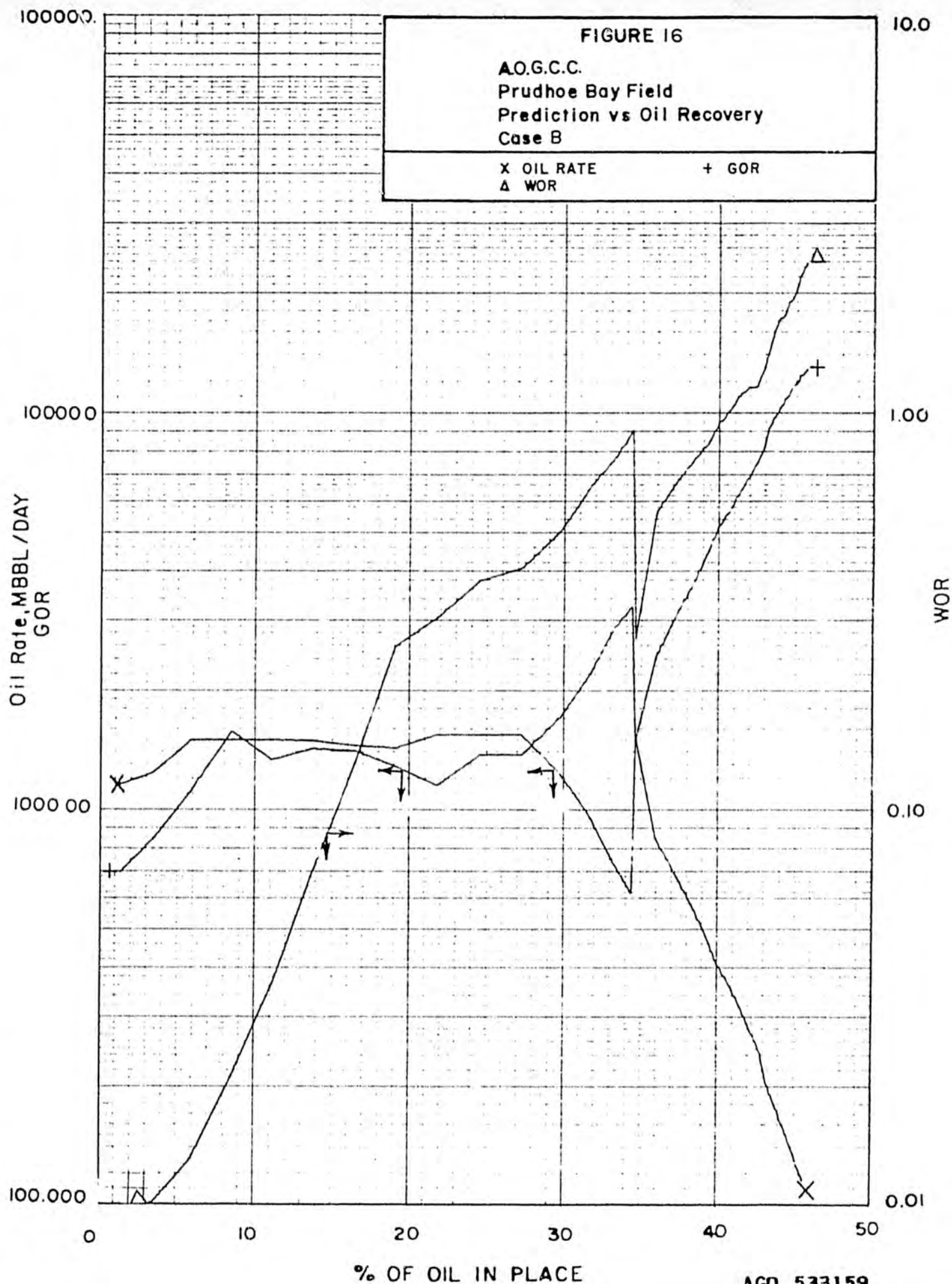
% OF OIL IN PLACE

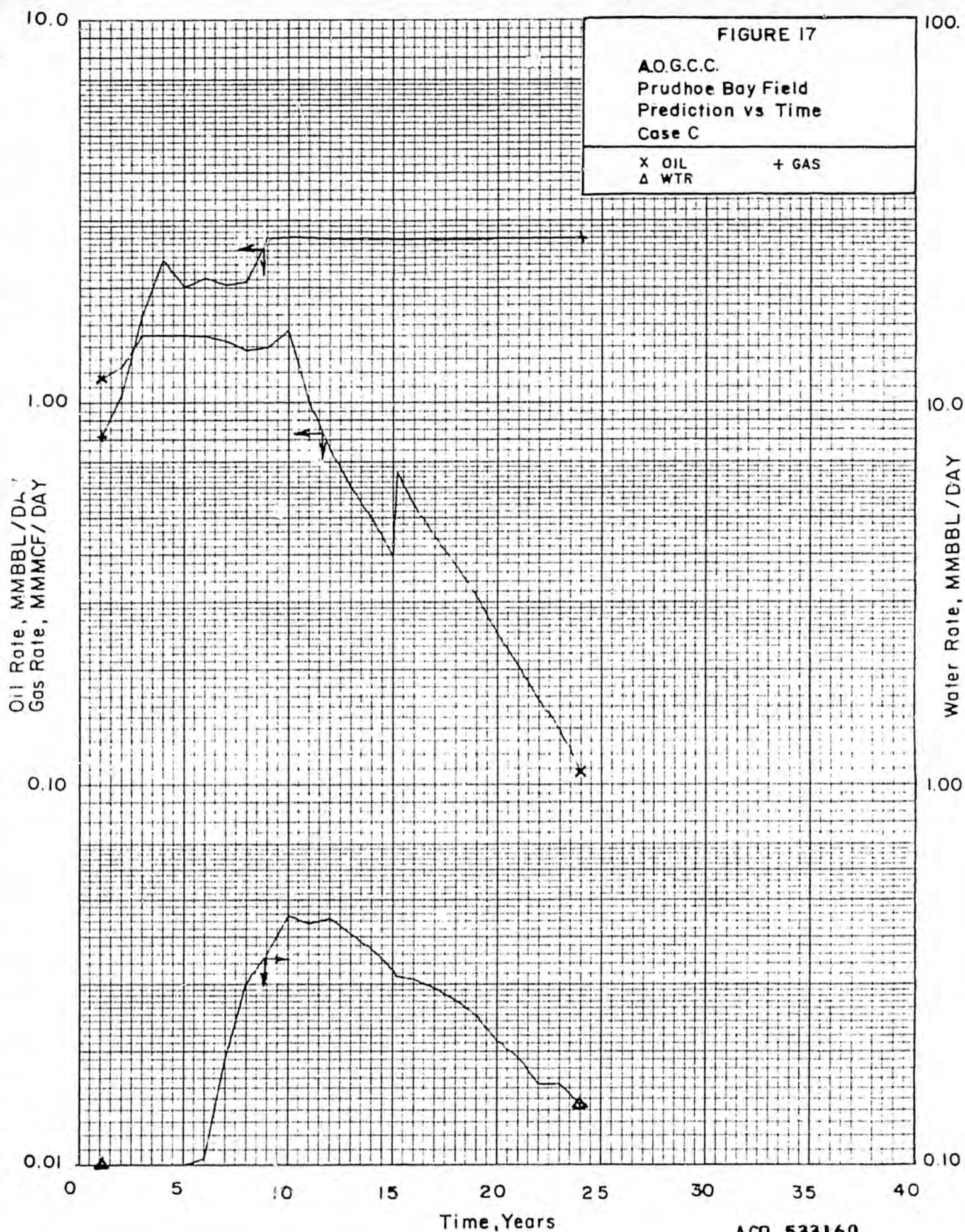
AGO 533156

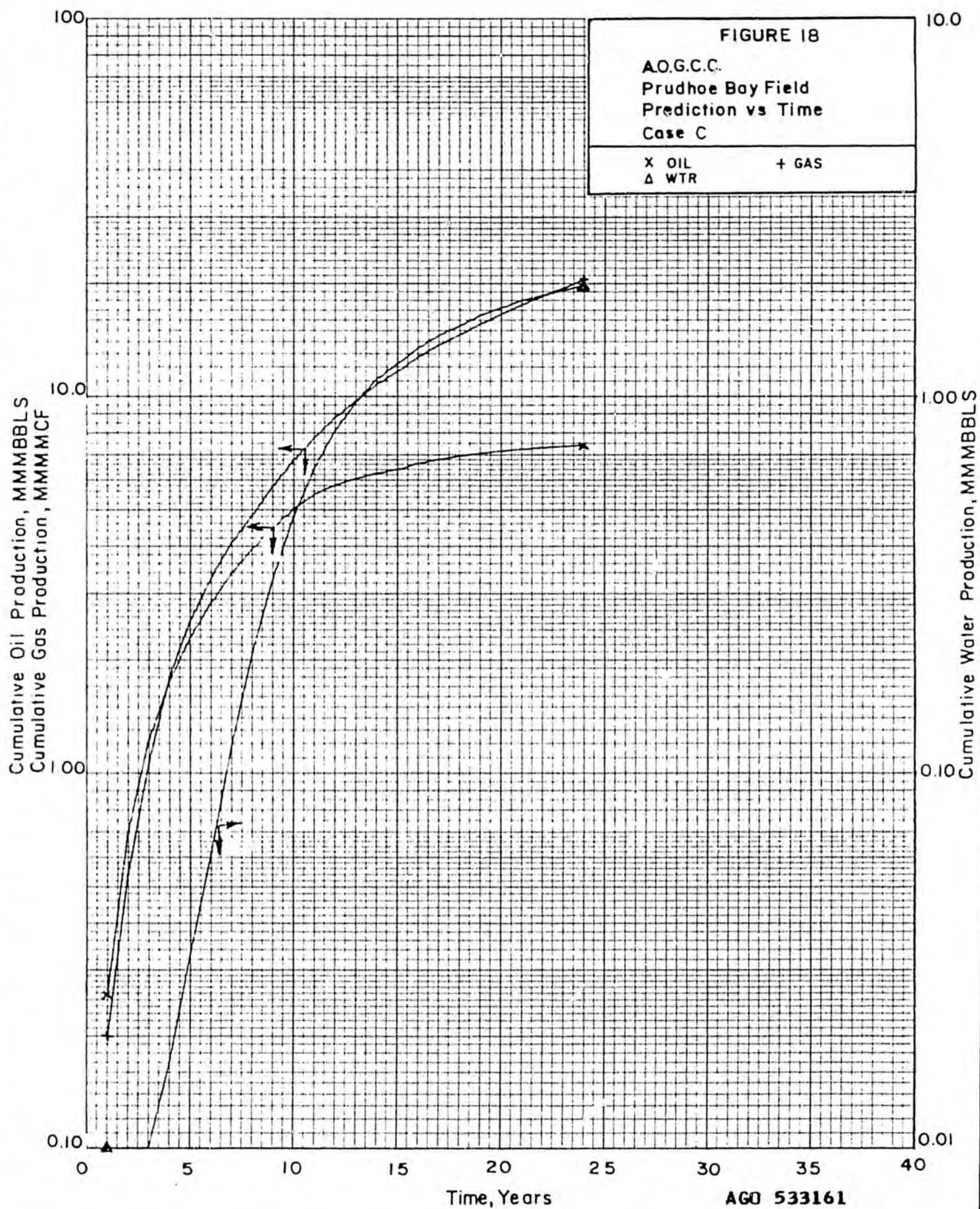


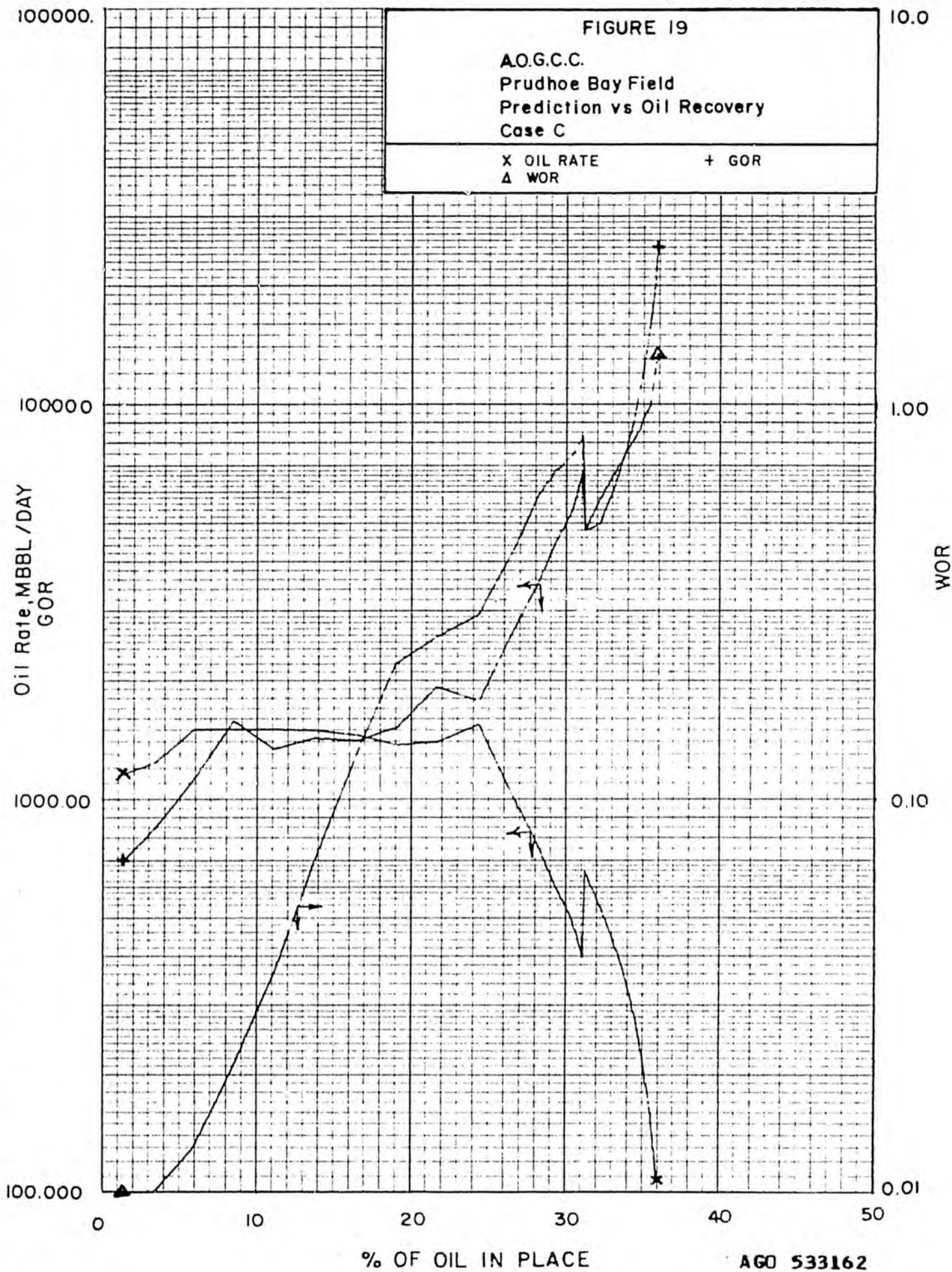


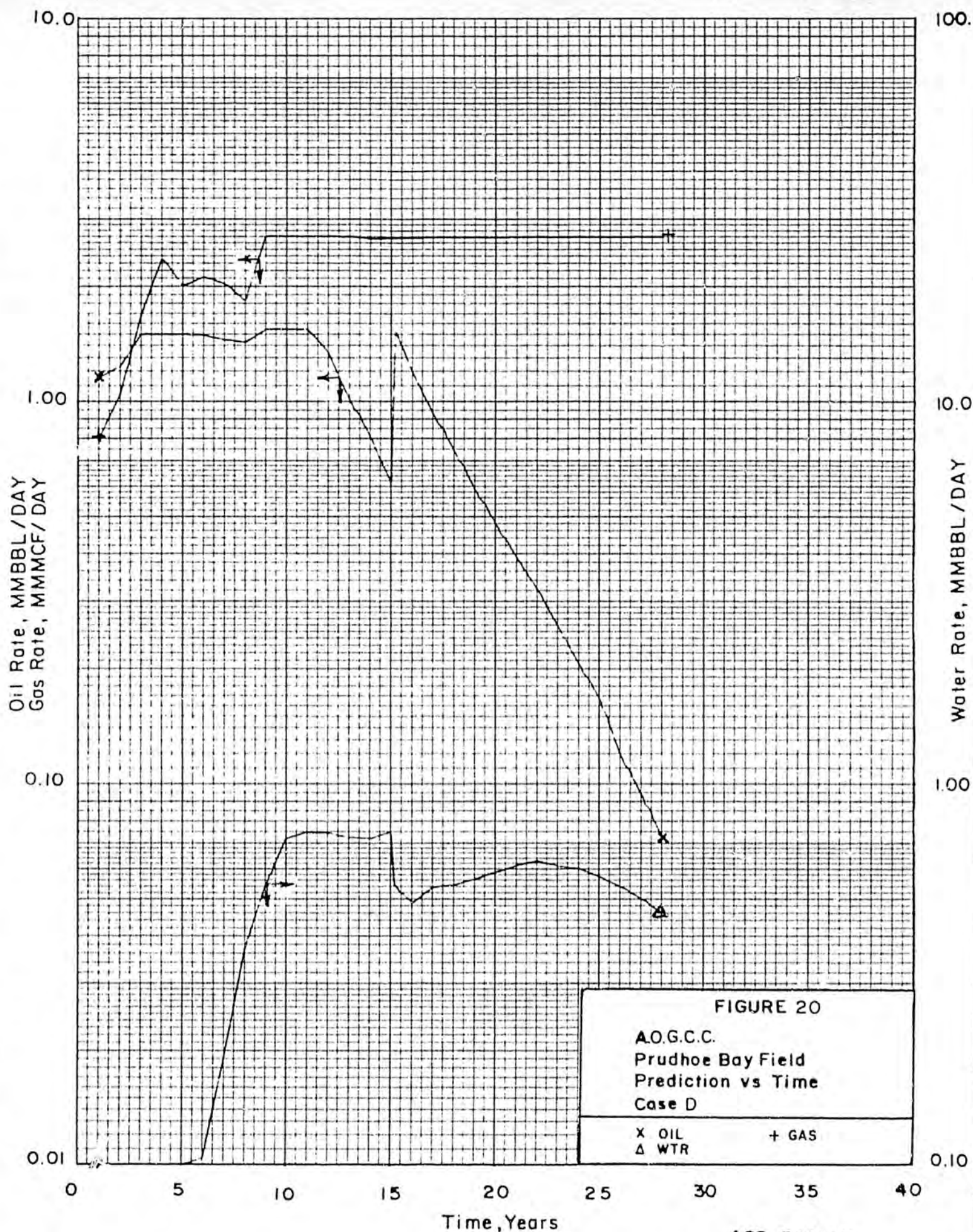










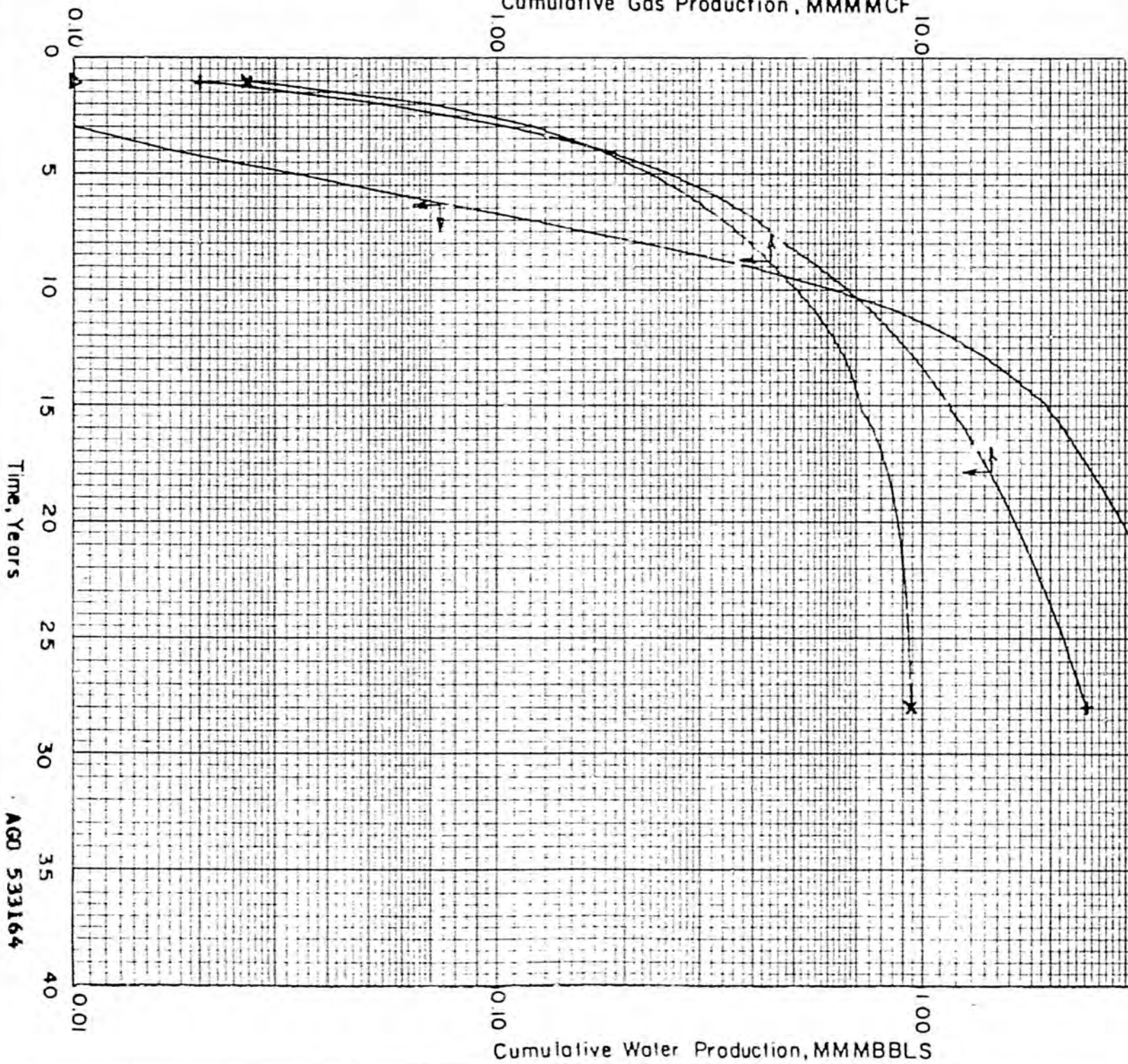


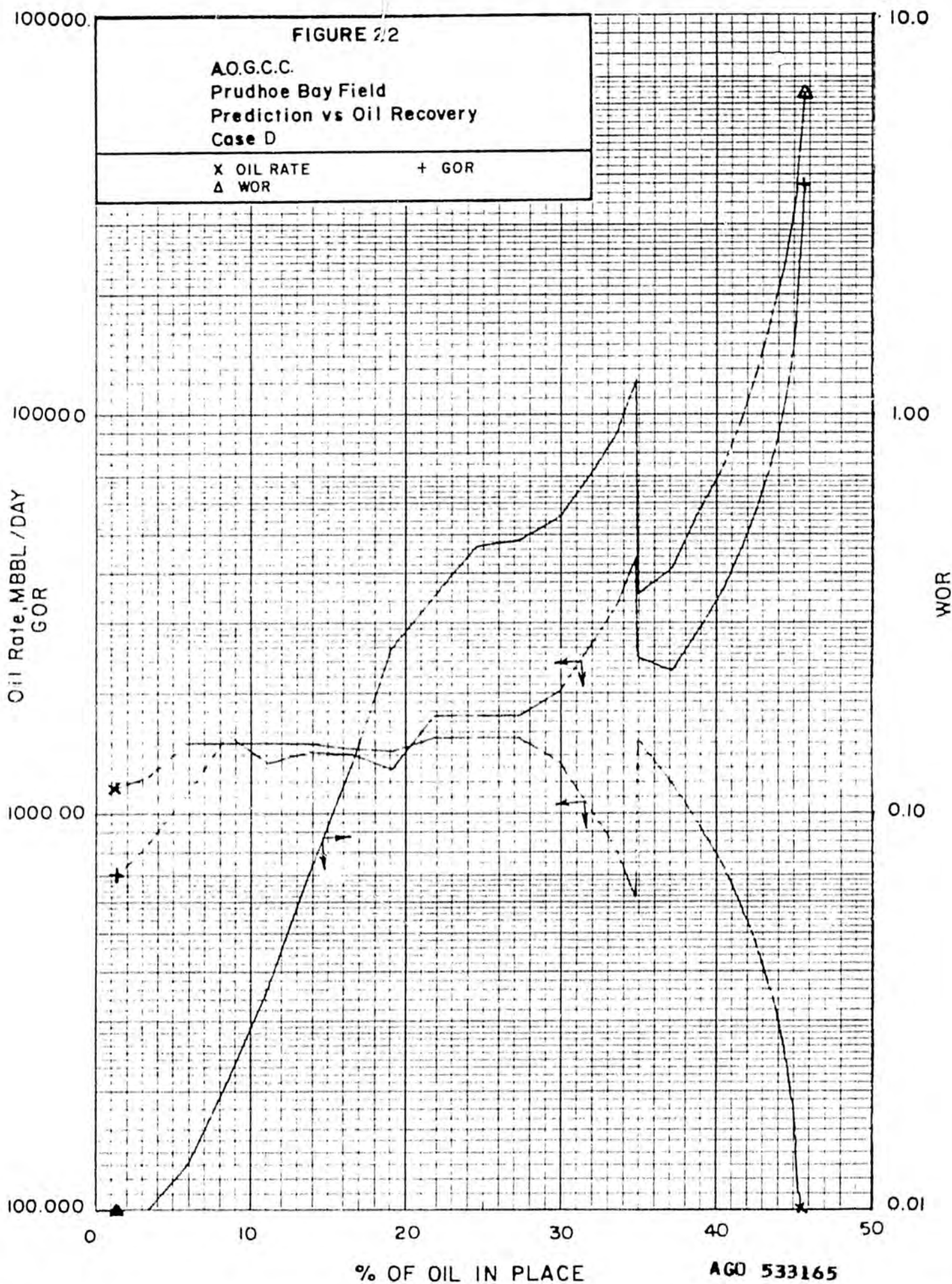
100

FIGURE 21

A.O.G.C.C.
Purdhoe Boy Field
Prediction vs Time
Case D

x OIL + GAS
Δ WTR



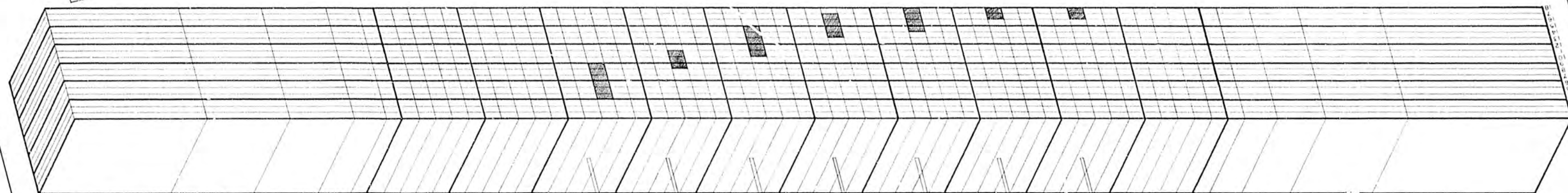


A60533166

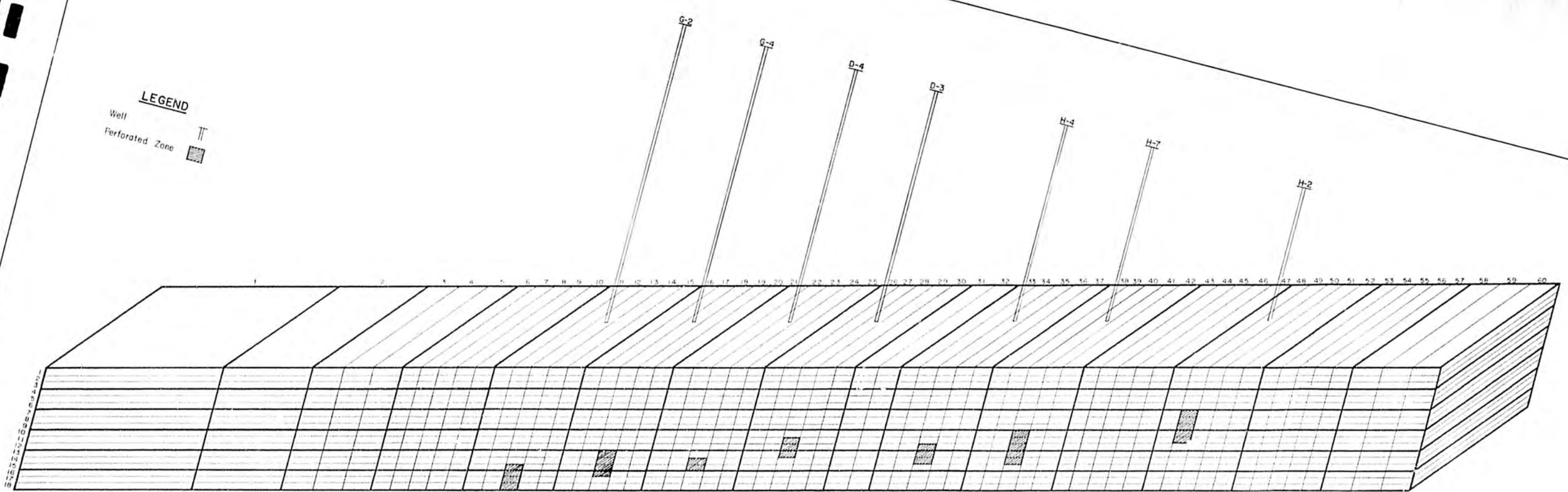
EXHIBIT A
H. K. VAN HOUTEN AND ASSOCIATES, INC.
AOGCC
PRUDHOE BAY FIELD
North-South Cross Section

A60 533166

LEGEND
Well
Perforated Zone



LEGEND
 Well
 Perforated Zone



AGO 533167

EXHIBIT B
 H. K. VAN FULLEN AND ASSOCIATES, INC.
 A.G.C.C.
 PRUDHOE BAY FIELD
 East-West Cross Section

AGO 533167



Oil & Gas new

Alaska State Legislature

Senate

JUNEAU, ALASKA

5/10/77

TO: Senator Rader
FR: Connie Barlow, Assistant
RE: Materials distributed at May 5 Royalty Board meeting
cc: Poland, Croft, Huber, Golletta
Malone, Osterback, Gruening

Don Wold, executive director of the Royalty Board supplied our office with materials relating to the Royalty Board meeting that took place on May 5, 6. I asked for a few extra copies to pass on to interested legislators. These are attached:

(1) Final Policies for Disposition of Royalty Oil & Gas

The Board adopted a set of 8 policies following testimony on 10 draft policies by Hammond, Rader, Osterback, and Silides.

(2) Statement of Governor Hammond on Royalty Oil Disposition

(Note: Osterback and Silides supplied written statements too.)

(3) "Criteria Document" (lead agency in preparation was DPDP)

Board hopes to use this document for determining the "net benefit" of the various refinery proposals; and in order to specify how the existing proposals need to be more detailed.

(Phase I questions are to be incorporated in the final solicitation notice of May 15) Don Wold is looking for comments on this document by Board members, purchasers, and legislators.

SCHEDULE

The Board informally adopted a schedule for completing a large-volume refinery sale:

- May 15 - final solicitation of proposals (specific questions pulled out of "Criteria Document")
- Aug 1 - preliminary proposals due
- Nov 1 - final proposals due
- Dec 1 - final selection of proposal, negotiation begin
- Feb 1 - contract submitted for legislative approval.

POLICY STATEMENT MADE BY

The Alaska Royalty Oil and Gas
Development Advisory Board

May 5 & 6, 1977

1. The Royalty Oil and Gas Board shall recommend disposition of royalty oil and gas (through in-value taking, in-kind taking, sales, and sales conditions) in such a manner to maximize net benefits to the State. These net benefits include not only price, but also the various economic, social, and environmental ramifications, including employment, local training, Alaskan ownership, secondary effects, tax base, and many other factors.
2. The baseline price for any royalty oil or gas sale shall not be less than the price that would be received for that oil or gas if taken "in-value".
3. Preference will be given first to existing in-state facilities with no alternate sources of oil or gas, and second to those who will construct new in-state facilities or expand existing in-state facilities.
4. A portion of royalty oil will be withheld ^{to meet} from long-term commitment in order to ~~anticipate~~ future small local demands.
5. With the exception of small sales to public utilities, sales will be for specified volumes or proportions of production, constant throughout the year, rather than for flexible volume "options" to be called by the purchaser.
6. Sales of royalty oil and gas for in-state processing will attempt to insure that products for in-state use are priced at the lowest possible price, within the limits of the general net benefit policy and the pricing policy.
7. Products produced from royalty oil and exported from the State must be surplus to the State's domestic and industrial product needs.
8. In general royalty oil and gas will be disposed of in long-term contracts, rather than in "piece lots" as may be done by a private-sector trader or dealer.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.

COMMENTS BY GOVERNOR JAY S. HAMMOND
ALASKA ROYALTY OIL AND GAS BOARD
May 5, 1977

MR. CHAIRMAN AND MEMBERS OF THE BOARD, I AM DELIGHTED TO .
TAKE THIS OPPORTUNITY TO DISCUSS PRESENT AND FUTURE POLICIES
REGARDING DISPOSITION OF OUR ROYALTY SHARE OF ALASKA'S OIL
AND NATURAL GAS. I FEEL AN OPEN PUBLIC DISCUSSION OF WHAT
OUR POLICIES AS ALASKAN CITIZENS SHOULD BE IS ESPECIALLY
GERMANE AT THIS TIME, AS THE BOARD ENTERS INTO CONSIDERATION
OF HOW TO DERIVE MAXIMUM BENEFIT OF OUR ROYALTY SHARE OF
PRUDHOE BAY OIL. ANY SALE OF THIS OIL WILL INDEED BE A
MAJOR ACTION BY THE PEOPLE OF ALASKA, INVOLVING IN ALL
LIKELIHOOD MORE THAN A BILLION BARRELS OF OIL AND POSSIBLY
UPWARDS OF \$10 BILLION. THE PEOPLE OF ALASKA ARE INDEED
FORTUNATE THAT A GROUP SUCH AS YOURSELF HAS AGREED TO LEND

YOUR CONSIDERABLE WISDOM AND EXPERTISE TO THIS SUBJECT, IN
SOME CASES WITHOUT COMPENSATION WHATSOEVER. I CERTAINLY
COMMEND THE PUBLIC MEMBERS OF THIS BOARD FOR THEIR DEDICATION
TO THE PEOPLE OF ALASKA IN THESE IMPORTANT TIMES.
I HOPE WE CAN HAVE A USEFUL DISCUSSION TODAY REGARDING THE
PRINCIPLES WHEREBY WE CAN, IN THE NAME OF THE PEOPLE OF
ALASKA, BEST USE THIS GREAT AMOUNT OF MINERAL WEALTH THAT IS
OURS BY VIRTUE OF THE ROYALTY PROVISIONS OF THE PRUDHOE BAY
LEASES. I FEEL THAT THE PRINCIPLES THE BOARD AND THE
LEGISLATURE ESTABLISH NOW, WITH THE HELP OF THE PEOPLE OF THE
STATE, SHOULD APPLY TO ALL FORESEEABLE FUTURE USE OF ROYALTY
OIL AND GAS. THEREFORE, IT IS EXTREMELY CRITICAL THAT WE
DEFINE REALLY WHAT WE WANT TO GAIN FROM ANY DISPOSITION OF
THIS OIL AND GAS.

AGD 533170 +

THE ALASKA PUBLIC FORUMS THAT I HAVE ATTENDED THROUGHOUT THE STATE HAVE, AS I AM SURE YOU ARE AWARE, ADDRESSED THIS VERY PROBLEM. MY PARTICIPATION IN THE FORUM HAS GIVEN ME SOME DEFINITE IMPRESSIONS REGARDING WHAT THE PEOPLE OF THE STATE WANT DONE WITH ROYALTY OIL AND GAS. THE PEOPLE'S UNDERLYING GOALS SEEM TO BE TO ENCOURAGE IN-STATE USE, AND WHATEVER POSITIVE DEVELOPMENTAL SPINOFFS MAY OCCUR FROM IT,

SHORT OF SELLING AT CUT-RATE PRICES.

THE PEOPLE, IT IS OBVIOUS TO ME, WANT TO ENCOURAGE HEALTHY INDUSTRY, AND DECIDEDLY DO NOT WISH TO ENCOURAGE INDUSTRY THAT MUST BE SUBSIDIZED FROM OUR NONRENEWABLE RESOURCE WEALTH (IN THE FORM OF REDUCED PRICE FOR ROYALTY OIL AND GAS). THEREFORE, I SUGGEST THAT THE BOARD NOT CONSIDER ANY SALES OF ROYALTY OIL AND GAS AT BELOW THE PRICE THE STATE WOULD GET WERE IT TO TAKE THE OIL OR GAS IN VALUE. THIS SHOULD BE THE BOTTOM LINE.

THIS, THEN, SHOULD BE OUR "BOTTOM LINE" REGARDING PRICING. BUT WHAT SHOULD THAT "BOTTOM LINE" BE REGARDING IN-STATE USE OF THE ROYALTY OIL AND GAS? I THINK BOTH THE STATUTE AND THE PEOPLE ARE VERY CLEAR ON THIS POINT: IN-STATE USES THAT PROVIDE A HEALTHY NET BENEFIT TO THE STATE AS A WHOLE SHOULD BE UNABASHEDLY ENCOURAGED. THOSE THAT PROVIDE A NET LOSS SHOULD NOT BE AIDED WITH OUR ROYALTY OIL AND GAS. IT IS BECOMING CLEAR THAT OUR ROYALTY OIL AND GAS PROVIDE NOT ONLY A VERY VALUABLE LIQUID ASSET, BUT ALSO AN EXTREMELY VALUABLE LEVER WHICH, IF WE ACT INTELLIGENTLY, WE MAY USE TO ENCOURAGE THE TYPES OF INDUSTRY WE ALL WANT IN THE STATE. THESE ARE THE INDUSTRIES THAT EMPLOY RESIDENT ALASKANS, THAT ARE CLEAN AND NOT POLLUTING, THAT RETURN TO THE PEOPLE OF THE STATE MORE IN TAXES AND OTHER BENEFITS THAN THEY TAKE FROM US IN INCREASED PUBLIC SERVICES, STATE PAYROLLS, CRIME, SOCIAL PROBLEMS, ETC.

THERE CERTAINLY ARE INDUSTRIES THAT WILL PROVIDE A CLEAR NET
BENEFIT TO ALASKANS, WHEN ALL ECONOMIC, SOCIAL, ENVIRONMENTAL,
AND OTHER FACTORS ARE TAKEN INTO ACCOUNT, AND THESE ARE THE
INDUSTRIES THAT WE SHOULD USE OUR ROYALTY OIL AND GAS TO ENCOURAGE.

I THINK THAT THE APPROACH BEFORE YOU IS A GOOD ONE. AS I
UNDERSTAND IT, THIS APPROACH WOULD ASK ALL POTENTIAL PURCHASERS
OF OUR PRUDHOE BAY OIL IN THIS CASE TO ANSWER A LONG SERIES OF
TOUGH QUESTIONS. IN THEIR AGGREGATE, THESE ANSWERS WILL ALLOW
US TO CALCULATE WHICH, IF ANY, OF THESE FIRMS IS OFFERING THE
"DEAL" THAT IS IN THE BEST NET BENEFIT OF THE PEOPLE OF THE
STATE, CONSIDERING ALL THESE FACTORS. I FEEL THAT THESE
QUESTIONS SHOULD BE ASKED SPECIFICALLY, THAT THE ANSWERS CAN
BE GIVEN WITHOUT PUTTING TOO MUCH EXTRA STRESS ON THE
APPLICANTS, AND THAT THE DECISION CAN BE MADE PUBLICLY AND

EXPEDITIOUSLY ONCE THE ANSWERS ARE IN. I HOPE THAT THE BOARD
ADOPTS THIS APPROACH AND USES IT TO NEGOTIATE A SALE THAT IS
CLEARLY IN THE NET BEST INTERESTS OF THE PEOPLE OF ALASKA.
I HAVE BEEN REPEATEDLY ASKED "DO YOU FAVOR A REFINERY IN
ALASKA?" MY ANSWER HAS ALWAYS BEEN, YES I DO FAVOR A REFINERY
IN ALASKA AS LONG AS IT PAYS ITS OWN WAY ON A NET BASIS, AND
IS ENVIRONMENTALLY SOUND. I THINK THAT IF THE BOARD APPROACHES
THESE POTENTIAL OIL PURCHASERS THROUGH THE METHOD OUTLINED
ABOVE, WE WILL ALL KNOW VERY CLEARLY WHICH PROPOSALS WILL PAY
THEIR OWN WAY AND ARE ENVIRONMENTALLY SOUND. I AM EQUALLY SURE
THAT THE FACILITY WE ENCOURAGE THROUGH COMMITMENT OF OUR ROYALTY
OIL WILL BE A VERY WELCOME CORPORATE CITIZEN OF THE STATE OF
ALASKA.

I HAVE ALWAYS FELT THAT A MAJOR PART OF ANY ROYALTY OIL OR GAS CONTRACT SHOULD BE THE BENEFITS THAT ALASKAN CITIZENS GAIN IN THE FORM OF LOWER PRICES FOR HEATING FUEL, GASOLINE, AIRCRAFT FUEL, WATERCRAFT FUEL, AND OTHER PETROLEUM PRODUCTS. IT HAS ALWAYS SEEMED TO ME A SINGULAR TRAVESTY THAT THE NATION'S MOST ENERGY-RICH STATE SHOULD PAY TWO-WAY TRANSPORTATION FOR OUR FUELS AND PETROLEUM PRODUCTS. I HAVE HEARD SEVERAL INTRIGUING SUGGESTIONS AS TO HOW IN-STATE PRODUCT PRICE MAY BE AFFECTED BY ROYALTY OIL AND GAS SALES, BUT DO NOT KNOW WHAT THE BEST ANSWER IS AT THIS POINT. I HAVE INSTRUCTED COMMISSIONER LERESCHE, AND WOULD HOPE THAT THE BOARD CONCURS, TO SEEK AN APPROPRIATE BENEFICIAL SOLUTION TO IN-STATE PRODUCT PRICES AS PART OF A LARGE SALE OF PRUDHOE OIL. I HOPE THAT THIS DOES NOT INVOLVE THE STATE ASSUMING ROLES, SUCH AS DISTRIBUTOR, WHICH MORE PROPERLY BELONG IN THE PRIVATE

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SECTOR, BUT WOULD HOPE THE BOARD CONSIDERS ALL SUGGESTIONS FOR SOLUTIONS TO THIS IN-STATE PRICE PROBLEM.

I MENTIONED BEFORE THAT OUR ROYALTY OIL IS A LEVER FOR ACHIEVING THE KIND OF GROWTH WE WANT IN ALASKA. AS A COROLLARY TO THIS, IT WOULD SEEM APPROPRIATE TO ME TO RESERVE THIS LEVER FOR USE WHERE IT DOES THE MOST GOOD. IN GENERAL, I WOULD EXPECT PERSPECTIVE PURCHASERS OF ROYALTY OIL AND GAS TO EXHAUST POSSIBILITIES OF PURCHASING OIL OR GAS FROM THE OTHER PRODUCERS, BEFORE THEY APPROACH THE STATE FOR OUR ONE-EIGHTH SHARE. IF WE DO NOT GRANT CUT-RATE PRICES, WHICH I THINK WE SHOULD NOT, THERE IS NO REASON FOR PERSPECTIVE PURCHASERS TO PREFER US TO OTHER PRODUCERS, AND I FEEL WE SHOULD RESERVE OUR ROYALTY PORTION FOR USE WHEN OTHER ALTERNATIVES ARE NOT AVAILABLE. I THINK IT ALSO FOLLOWS

FROM THIS THAT EXISTING FACILITIES IN-STATE, WITH EXISTING
SUPPLY CONTRACTS, SHOULD NOT GENERALLY BE PURCHASERS OF OUR
ROYALTY OIL AND GAS, UNLESS, OF COURSE, THEY EXPAND IN SUCH
A WAY THAT MEETS THE NET BENEFIT CRITERIA WE HAVE ALREADY
DISCUSSED. OF COURSE, PUBLIC UTILITIES ARE AN EXCEPTION TO
THIS.

PUBLIC UTILITIES ARE NONPROFIT INSTRUMENTS OF THE CITIZENS
OF ALASKA, AND THEREFORE SHOULD RECEIVE SOME MANNER OF
SPECIAL TREATMENT FROM THE ROYALTY OIL AND GAS BOARD. I
PERSONALLY FEEL, HOWEVER, THAT THIS SPECIAL TREATMENT SHOULD
NOT INCLUDE SPECIAL CUT-RATE PRICING WHICH WOULD MERELY BE
A SUBSIDIZATION OF CONSUMERS IN ONE AREA OF THE STATE AT
THE EXPENSE OF THE POCKETBOOKS OF ALL ALASKANS. THERE ARE
WAYS AROUND THIS WHICH THE LEGISLATURE MIGHT EXPLORE,

INCLUDING ENERGY TAX CREDITS FOR ALL CITIZENS, DISCOUNTED BY
THE AMOUNT OF LOCAL SUBSIDY TO PUBLIC UTILITIES THROUGH CUT-
RATE ROYALTY OIL AND GAS PRICING, BUT UNTIL THESE ARE INSTITUTED,
WE SHOULD GIVE NO SELECT GROUP OF ALASKANS SPECIAL TREATMENT
OVER ALL OTHERS.

I DO FEEL, THOUGH, THAT PUBLIC UTILITIES SHOULD HAVE FIRST
CALL ON ROYALTY OIL AND GAS AT THE GOING PRICE, AND THEREFORE
THAT SOME REASONABLE PROPORTION SHOULD BE HELD FROM ANY
LARGE-SCALE SALE OF PRUDHOE BAY ROYALTY OIL. IN ADDITION, I
FEEL IT APPROPRIATE THAT MAXIMUM FLEXIBILITY IN VOLUME BE
ALLOWED TO PUBLIC UTILITIES, WHEN SUCH FLEXIBLE VOLUME SALES
ARE SMALL ENOUGH TO NOT DISRUPT THE ENTIRE ROYALTY OIL OR
GAS PICTURE.

IN SUMMARY, OUR ROYALTY OIL AND GAS IS NOT ONLY A HUGE

FINANCIAL ASSET, BUT ALSO A VERY SIGNIFICANT SOCIAL LEVER,

WHEREBY WE MAY ENCOURAGE THAT HEALTHY TYPE OF ALASKAN INDUSTRY

THAT SERVES TO THE BENEFIT OF US ALL, AND THAT WHICH ALL

ALASKANS WELCOME INTO OUR STATE.

I VERY MUCH APPRECIATE THE OPPORTUNITY TO SHARE MY THOUGHTS

WITH YOU THIS MORNING, AND HOPE WE CAN USE THE REST OF MY

TIME TO DISCUSS IN DETAIL THE POINTS I HAVE MENTIONED OR

ANY OTHER MATTERS YOU WOULD LIKE TO BRING UP.

THANK YOU VERY MUCH.

AGO 533175

ALASKA ROYALTY OIL AND GAS
In-State Use - A Developers Guide

DRAFT

Prepared For:
Alaska Royalty Oil and Gas Development Advisory Board

INTRODUCTION

This guide includes the following components:

- A. State Information Needs - Phase I Preliminary Submittal
- B. State Information Needs - Phase II Pre-Proposal Submittal
- C. Preliminary Siting Criteria
- D. State Evaluation Factors
- E. State Permitting Requirements

The purpose of the guide is to provide a means for improving the flow of information between the State and a prospective developer, in order to generate a mutually acceptable proposal for in-state facilities making use of Alaska's non-renewable resources. This is not a formal Request for Proposal, nor does it in any way supercede applicable State and local leasing, permitting or regulatory requirements. It is intended solely to:

- 1. ensure that the State receives, on a timely basis, the necessary information to evaluate a potential development;
- 2. provide a prospective bidder with information on how the State will be evaluating a project as well as some of the requirements and criteria that a developer will be expected to meet.

A. State Information Needs - Phase I Preliminary Submittal

The preliminary list includes basic types of information that a developer should provide the State in order to initiate the evaluation process. The State will utilize this information to perform a preliminary analysis of the proposed project. The State will make this evaluation available to the developer along with any additional questions and/or concerns.

B. State Information Needs - Phase II Pre-Proposal Submittal
Following the Phase I evaluation, a more detailed analysis of the potential project will be undertaken by the State. A prospective developer will be expected to provide a more specific set of information to satisfy the Phase II evaluation. After satisfactory completion of this phase, efforts can be geared to finalizing a mutually acceptable proposal package and, subsequently, a formal contract.

C. Preliminary Siting Criteria

In order to assist a developer in preparing a description of the proposed facility and locating potential acceptable sites, a preliminary set of State siting criteria is included in the guide.

D. State Evaluation Factors

The State will perform a formal two phase evaluation process. The particular areas of State concern, examples of evaluation factors and agency evaluation responsibilities are described in this internal document. This information should assist developers in understanding how their inputs will be utilized by the State, and the key factors of concern to the State. A more formalized comprehensive interagency project evaluation procedure is now in the process of being developed.

E. State Permitting Requirements

A draft inventory of State permits is included to assist the prospective developer in understanding the scope of required actions necessary prior to development activities. The applications for the appropriate State permits are not a part of the above information flow and evaluation process. If a proposal is accepted, formal applications must be submitted.

A working committee of key State personnel has been established to assist in the information exchange/evaluation process. This group will be available to respond to particular questions, clarify the procedures, provide available data (environmental standards and regulations, site-specific land uses, critical habitat areas, local socioeconomic characteristics, to name just a few), as well as to expedite State evaluation of a proposed project. Following is a tentative timing schedule of activities.