Commission

EXHIBITS FOR TESTIMONY
OF
W. JOHN LEE

CASE NO. 9111

BEFORE THE OIL CONSERVATION COMMISSION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

MARCH 17, 1988

SUMMARY

Introduction

This testimony addresses the two major requirements for Expansion of the Pressure Maintenance Project Area in the Canada Ojitos Unit (COU):

1. Proof of effective pressure communication between the existing pressure maintenance project area and the expansion area.

2. Evidence that pressure maintenance - gas injection has increased recovery in the project area and can be expected to continue to do so in the expanded project area.

In addition, the testimony addresses an additional benefit made possible by an expanded pressure maintenance project area: additional liquid hydrocarbon recovery from gas cycling.

Conclusions

The major conclusions reached in this study are summarized below:

Pressure Communication

1. The existing pressure maintenance project area and the expansion area are in effective pressure communication, as evidenced by interference tests and other data. In fact, no interference test run between wells in the unit has ever failed to show communication.

Improved Recovery Caused by Pressure Maintenance - Gas Injection

1. Gravity drainage (i.e., migration of gas upstructure and oil downstructure) is occurring in the COU. Clear evidence is provided by production of oil at low GOR's in the expansion area in C-zone completions despite reservoir pressures below 1000 psia, which is well below the bubble point pressure. If gravity segregation and migration of gas were not occurring and if solution gas drive were the dominant drive mechanism, GOR's would be increasing because of increasing free gas saturation in the oil column.

2. Simulator calculations show greater recovery at a given production rate with pressure maintenance than without pressure maintenance except at very high rates (at which solution-gas drive becomes more dominant).

3. Simulator calculations show that recovery increases in the COU as rate decreases because gas and oil can segregate efficiently under the influence of gravity at low rates but not at high rates.

Gas Cycling

1. Expansion of the COU would provide the opportunity to build a gas plant with attractive economics. This would permit the COU reservoir gas - gas cap to be replaced by residue gas from the gas plant. Simulation indicates hydrocarbon liquid recovery could be increased by about 700,000 barrels with this process.

PRESSURE COMMUNICATION

Conclusion

The existing pressure maintenance project area and the expansion area are in effective pressure communication. In addition, wells in the expansion area are in effective pressure communication.

Evidence and Discussion

1. Interference tests show pressure communication over widespread areas within the expansion area and between wells in the existing unit and the proposed expansion area. The map from Section G of Mr. A. R. Greer's Black Exhibit Book summarizes the tests in which pressure communication has been established (Figure PC-1).

2. Not only was pressure response observed in wells offsetting wells being fractured hydraulically, it was observed rapidly over large distances, indicating very high formation permeability. Results from the response in COU A-20 to the fracture treatment in COU D-17 (from Mr. Greer's Black Exhibit Book, Section P) are attached (Figure PC-2). For this typical well pair, communication was established within 4 to 5 hours between these wells which are more than one mile apart.

3. In no case has an interference test run between wells in the unit failed to show communication.

4. Mr. Greer has offered other evidence to show pressure communication between the existing unit and the expansion area (Brown Book, Part IV, Sections F, G, H, I, J, and K). The types of evidence and the references to Mr. Greer's exhibits are summarized below:

   a. Overinjection (Section F) - The central point here is that gas injection into the existing pressure maintenance project area exceeded oil and gas withdrawals from the project area by the following average amounts:

Time Period	Average Rate of Overinjection (RB/D)
7/87 to 11/87	3300
11/87 to 2/88	1900

   Despite the overinjection, average reservoir pressure did not increase during either time period, leading to the conclusion that oil and gas migrated from the existing project area to the proposed expansion area on the west, proving communication.

b. Pressure Gradients (Section G) - The central point here is that pressures near individual wells decrease in a regular fashion from the gas injection wells on the east of the unit, through the existing pressure maintenance project area, and on into the proposed expansion area. This regular pattern in pressures strongly suggests pressure communication throughout the unit.

c. Pressure Increase in Shut-In Wells (Section H) - The main issue in this case is that pressures continued to build up in observation wells (B-29 and B-32) in the proposed expansion area following the three-day shut in period set by the NMOCC for November 16 to 19, 1987, and during an additional 10 days in which most COU wells remained shut in. The source of this continued increase in pressure was higher pressures in the existing project area caused by gas injection; this flow of gas from the existing project area to the expansion area indicates pressure communication between the two areas in the reservoir.

d. Gas-Oil Ratios (Section I) - This section of the exhibit book shows that, on the average, producing GOR's in the proposed pressure maintenance project expansion area are substantially lower than those in the adjoining Gavilan wells. This implies that the

COU wells are being fed oil by gravity drainage from unit wells to the east and upstructure, which requires pressure communication.

e. C-34 Pressure History (Section J) - This section of the Exhibit Book shows that the pressure in shut-in observation wells C-34 (in the existing pressure maintenance project area) and D-17 (in the proposed expansion area) both responded rapidly to changes in injection and production rates in the unit. This rapid response implies pressure communication throughout these areas of the unit including the proposed project expansion area.

f. Pressure Decline in Expansion Area (Section K) - The central point of this section is that the pressure maintenance project in fact maintains pressure in the proposed expansion area. This is particularly reflected in the pressures in the observation well D-17 in the expansion area at times of reduced withdrawals from Gavilan (such as February, 1988).

FIGURE PC-1

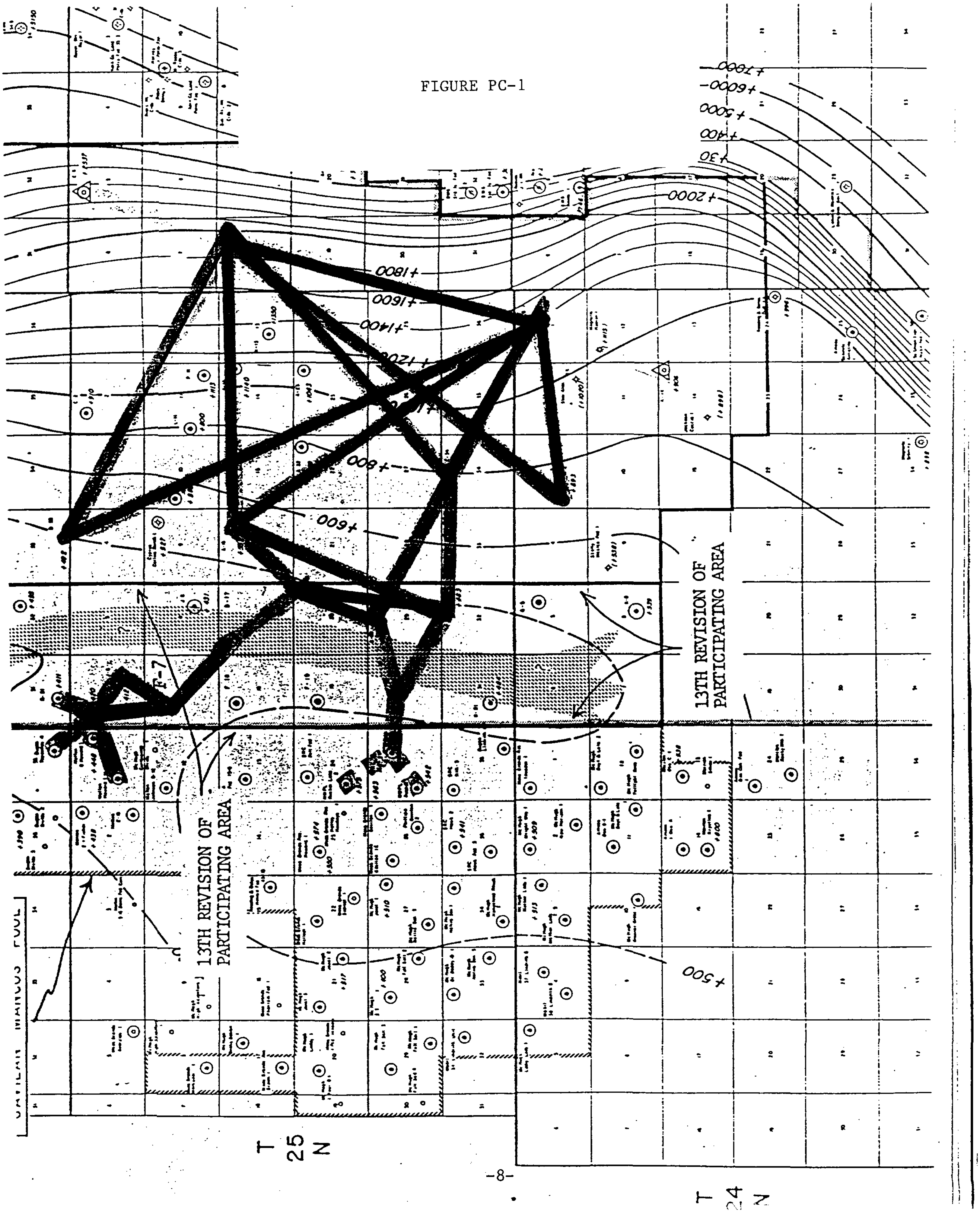
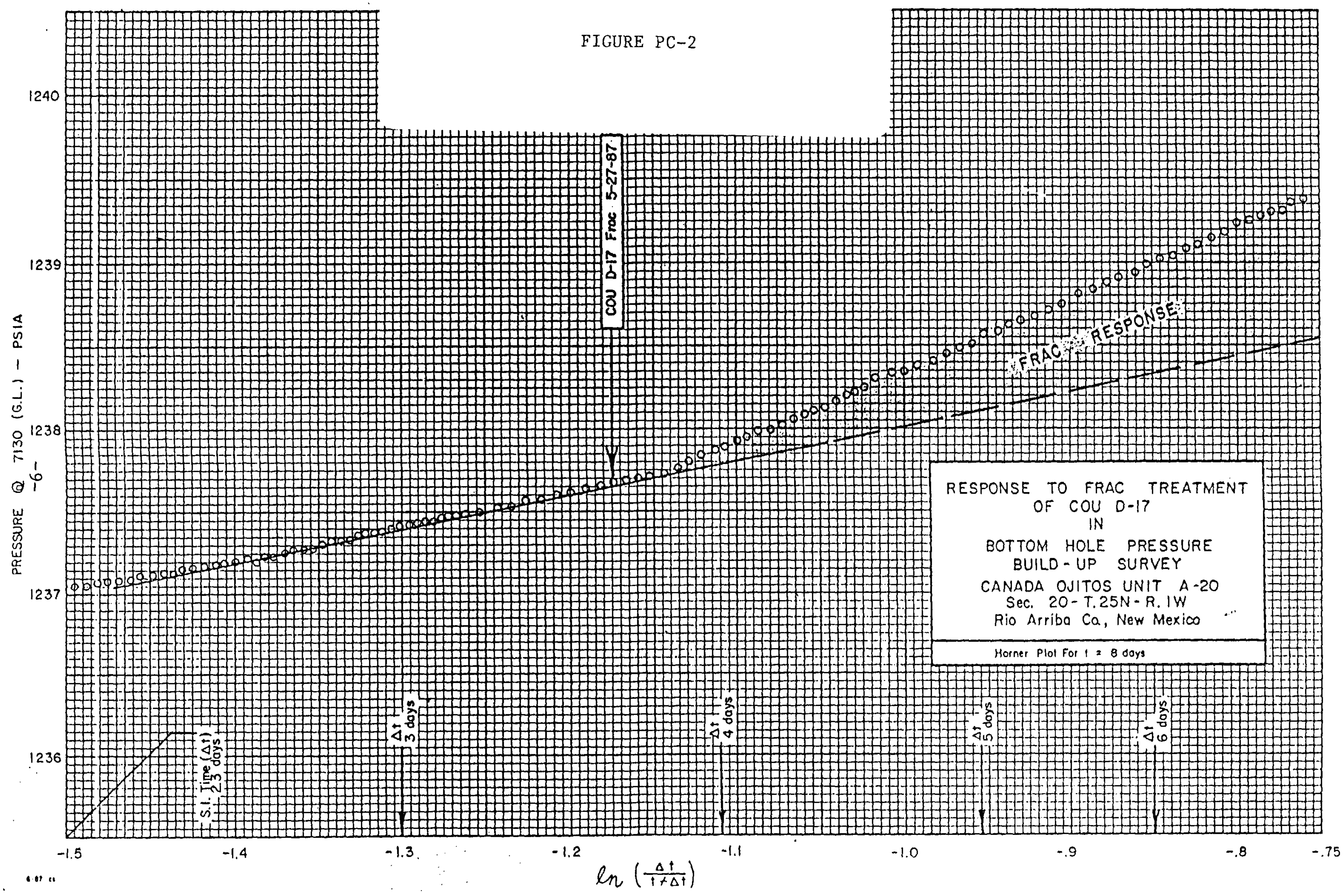

13TH REVISION OF
PARTICIPATING AREA
13TH REVISION OF
PARTICIPATING AREA
F-7
+2000
+1800
+1600
+1400
+800
+600
+500
T
25
N
T
24
N

FIGURE PC-2



RESPONSE TO FRAC TREATMENT
OF COU D-17
IN
BOTTOM HOLE PRESSURE
BUILD-UP SURVEY
CANADA OJITOS UNIT A-20
Sec. 20-T.25N-R.1W
Rio Arriba Co., New Mexico
Horner Plot For t = 8 days
COU D-17 Frac 5-27-87
FRAC RESPONSE
S.I. Time (Δt) 23 days
Δt 3 days
Δt 4 days
Δt 5 days
Δt 6 days
PRESSURE @ 7130 (G.L.) - PSIA
1240
1239
1238
1237
1236
-1.5
-1.4
-1.3
-1.2
-1.1
-1.0
-.9
-.8
-.75
ln (Δt / t+Δt)

IMPROVED RECOVERY CAUSED BY PRESSURE MAINTENANCE-GAS INJECTION

Conclusions

1. Gravity drainage (or gravity segregation; i.e., migration of gas upstructure and oil downstructure) is occurring in the Canada Ojitos Unit.

2. Simulator calculations show greater recovery at a given production rate with pressure maintenance than without pressure maintenance.

3. Simulator calculations show that recovery increases in the COU as rate decreases because gas and oil can segregate efficiently under the influence of gravity at low rates but not at high rates.

Evidence and Discussion

1. The attached Figure IR-1 illustrates the mechanics of gravity drainage. The essential points are the following:

   a. As gas from an expanding gas cap or from gas injection wells expands into an oil zone and displaces oil toward producing wells, it leaves behind a oil saturation which is initially fairly high. Under the influence of gravity, this oil drains downward to the oil zone, leaving a much lower oil saturation. Simultaneously, the gas saturation formed in the oil zone rises to the top of the oil zone under the influence of gravity and rejoins the gas cap. The gas saturation can be reduced to a small value if this gravitational segregation of gas and oil has time to occur.

b. Gravitational segregation (or gravity drainage) does not occur rapidly. In general, the higher the formation permeability, the higher the rate of gravity drainage. Gravity drainage can always improve recovery efficiently slightly (because of reduced residual oil saturation), but it can play a major role only when the oil withdrawal rate from the reservoir is comparable to the rate at which oil drains naturally from the gas-invaded region. This is why only a relatively few, high-permeability reservoirs can take advantage of gravity drainage and still produce at economic rates.

c. Oil recovery from gravity drainage reservoirs is rate sensitive. At high oil withdrawal rates, gravity drainage cannot occur rapidly enough for the oil drained to rejoin the oil column; gas overrides the oil column, moves down, and may break through prematurely into producing wells; and reservoir pressure drops more rapidly than at lower withdrawal rates, causing increased gas saturations and consequent increased producing gas-oil ratios. Alternatively, at low withdrawal rates, gravity drainage can occur rapidly enough for the oil drained to rejoin the oil column; gas moves upstructure the oil column; and gas saturation does not build up in the oil column (because the gas migrates upward and away from the oil column under the influence of gravity).

d. Pressure maintenance is also important in many gravity drainage reservoirs. Maintaining pressure minimizes the amount of gas which comes out of solution and minimizes the contribution of solution gas drive as a source of energy and thus maximizes the contribution of gravity drainage.

e. Computer reservoir simulators provide a means of quantifying the withdrawal rates at which gravity drainage can be effective in a given reservoir. Of course, the best quantification is observed field performance at different withdrawal rates. Gravity drainage can be inferred to be effective if production is sustained at low GOR's even though reservoir pressure has dropped substantially below the bubble point, and increased contribution from solution gas drive can be inferred from increasing GOR as reservoir pressure declines.

2. Evidence that gravity drainage is occurring is provided by the production of oil at low GOR from the expansion area, as cited in Mr. A. R. Greer's Brown Exhibit Book, Section I. The pressure in this area is several hundred psi below saturation pressure, yet production is typically at GOR's approaching solution GOR (see attached Figures IR-2, IR-3, and IR-4). If gas were not migrating upstructure from this area and oil were not migrating to the area from upstructure, free gas saturation and, thus, producing GOR would be increasing. The fact that producing GOR is <u>not</u> increasing also implies that solution gas drive is not the dominant drive mechanism.

3. Comparison of Simulated Recovery With and Without Pressure Maintenance

   a. A computer simulation of one zone in the COU compared recoveries at several rates for the reservoir operated with and without pressure maintenance. Properties of the simulated reservoir and of the simulator used are summarized in Figures IR-5 and IR-6. It is especially important to note that only a one-mile wide slice of one zone was simulated. As a point of reference, withdrawal rates from a one-mile slice of COU parallel to the dip have historically been less than 1000 BOPD, with rare exceptions.

b. The attached Figure IR-7 shows ultimate recovery vs, rate for cases with pressure maintained and not maintained. The graph clearly illustrates that recovery is greater when pressure is maintained by gas injection at all but very high withdrawal rates. The main reason for this improved recovery with pressure maintenance is that gas is kept in solution, maintaining reservoir energy.

4. Evaluation of the Effect of Rate on Recovery

a. A computer simulation of COU performance compared recoveries at various rates in a pressure maintenance project in a one-mile wide slice of one zone in the reservoir.

b. At rates below 1100 STB/D (total withdrawals from the one zone in the mile-wide section), the rate at which oil drains down from the gas invaded region equals or exceeds the oil withdrawal rate, so recovery is maximized, as is characteristic of gravity-drainage assisted recoveries (Figure IR-7). At higher rates, oil withdrawal rates exceed the rate at which the oil can drain down under the influence of gravity, and recovery decreases. When withdrawal rates exceed gravity drainage rates, more oil is left behind as an unrecovered saturation. At the same time, higher free gas saturations develop in the oil column, resulting in higher producing GOR and reduced recovery.

c. As the withdrawal rate increases above approximately 1100 BOPD from the one zone modeled in the mile-wide section, the simulator predicts that GOR will increase more rapidly and that the reservoir will reach an economic limit GOR when less oil has been recovered. This result, shown in the attached Figures IR-8 and IR-9 and also tabulated Figure IR-10 for both pressure maintenance and non-pressure maintenance cases, is a quantitative verification of the intuitive ideas expressed in 3b above. Another way of interpreting these results is to observe that, as withdrawal rate increases, solution gas drive becomes more dominant and gravity drainage becomes less dominant.

FIGURE IR-1

SCHEMATIC OF GRAVITY DRAINAGE
AND PRESSURE MAINTENANCE
IN A DIPPING OIL RESERVOIR

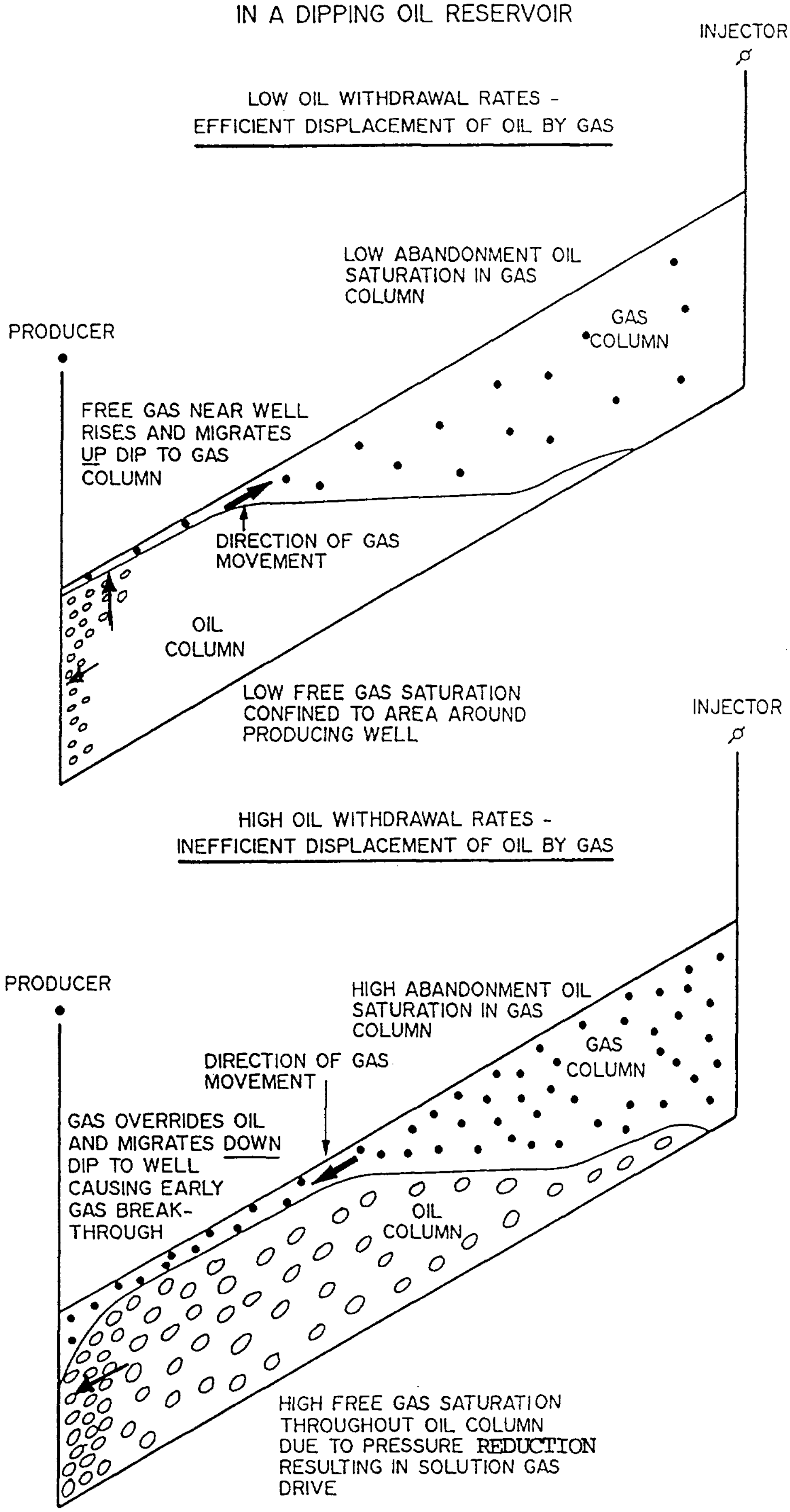


FIGURE IR-2

LOW GOR PRODUCERS IN EXPANSION AREA

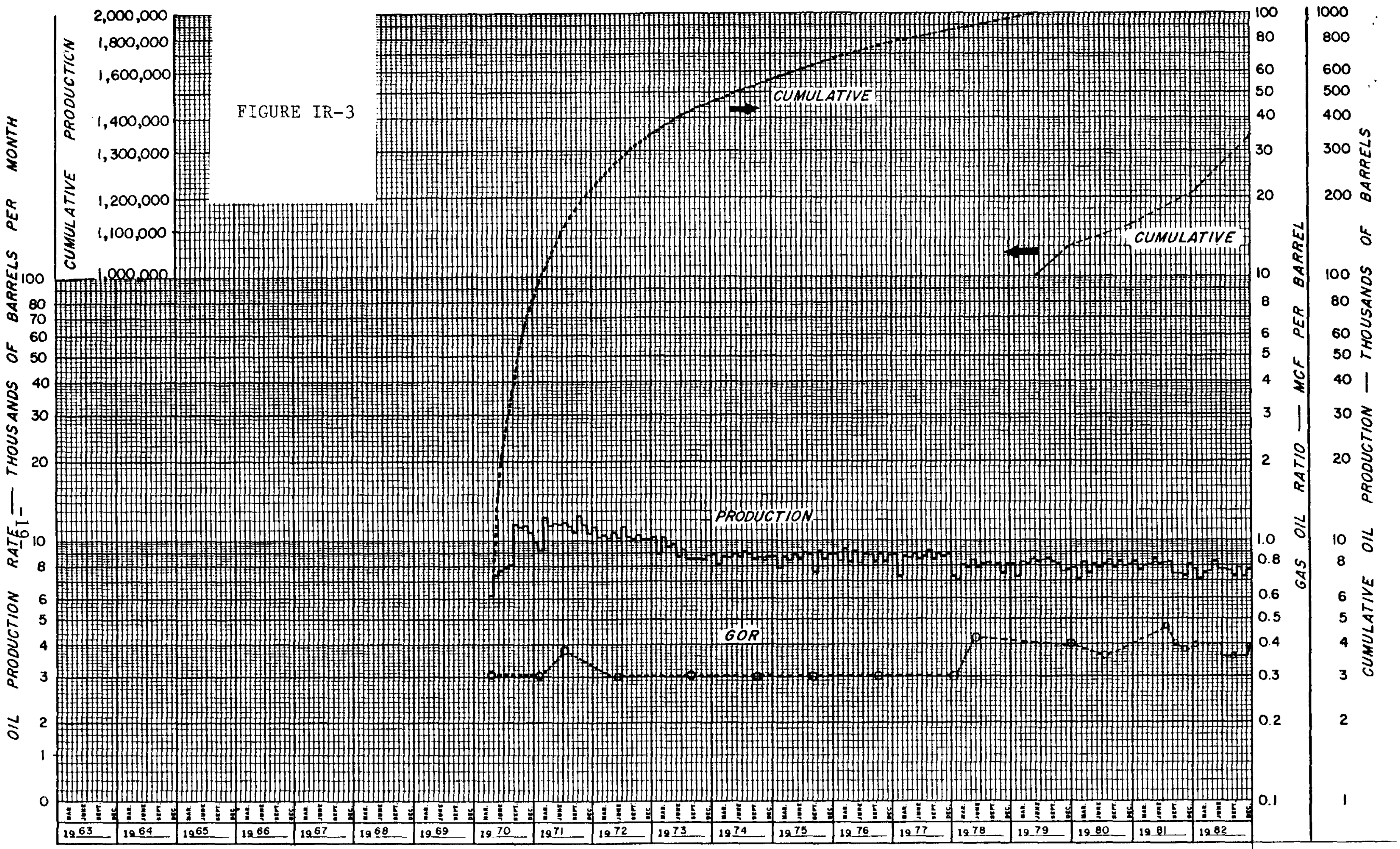
1. The A and B zones have been invaded by injected gas, as production logs from the COU L-27 and B-32 indicate (see A. R. Greer's Brown Exhibit Book, Sections C and D). Production logs in COU F-30 and B-32 indicated that in the C-zone, which has not yet been invaded by the injected gas in downstructure wells, production is still at low GOR. Wells F-18 and B-29 have not had production logs run, but, by analogy, we can infer that they are also producing modest amounts of free gas from upper zones and oil at near solution GOR from the C zone. These four wells have two-thirds of the oil productivity in the expansion area.

Well	Approximate Productivity (BOPD)	Producing GOR (scf/STB)	C-Zone GOR (scf/STB)	Comment
F-18	300	700	600-700	Analogy w/F-30
F-30	350	1200	600-700	Production Log
B-32	700	1200	600-700	Production Log
B-29	1000	1600	600-700	Analogy w/B-32

2. Other wells in the COU have produced at low GOR for long times (at which cumulative production volumes were substantial) and then have had rapidly increasing GOR's. This behavior is characteristic of gravity drainage reservoirs; production histories from COU L-27 (Figure

IR-3), and L-11 (Figure IR-4) illustrate these producing characteristics. The important feature in these figures is the rapid increase in GOR, indicating arrival of a sharp contact, instead of a slower, continuous increase in GOR over several years which is characteristic of solution gas drive.

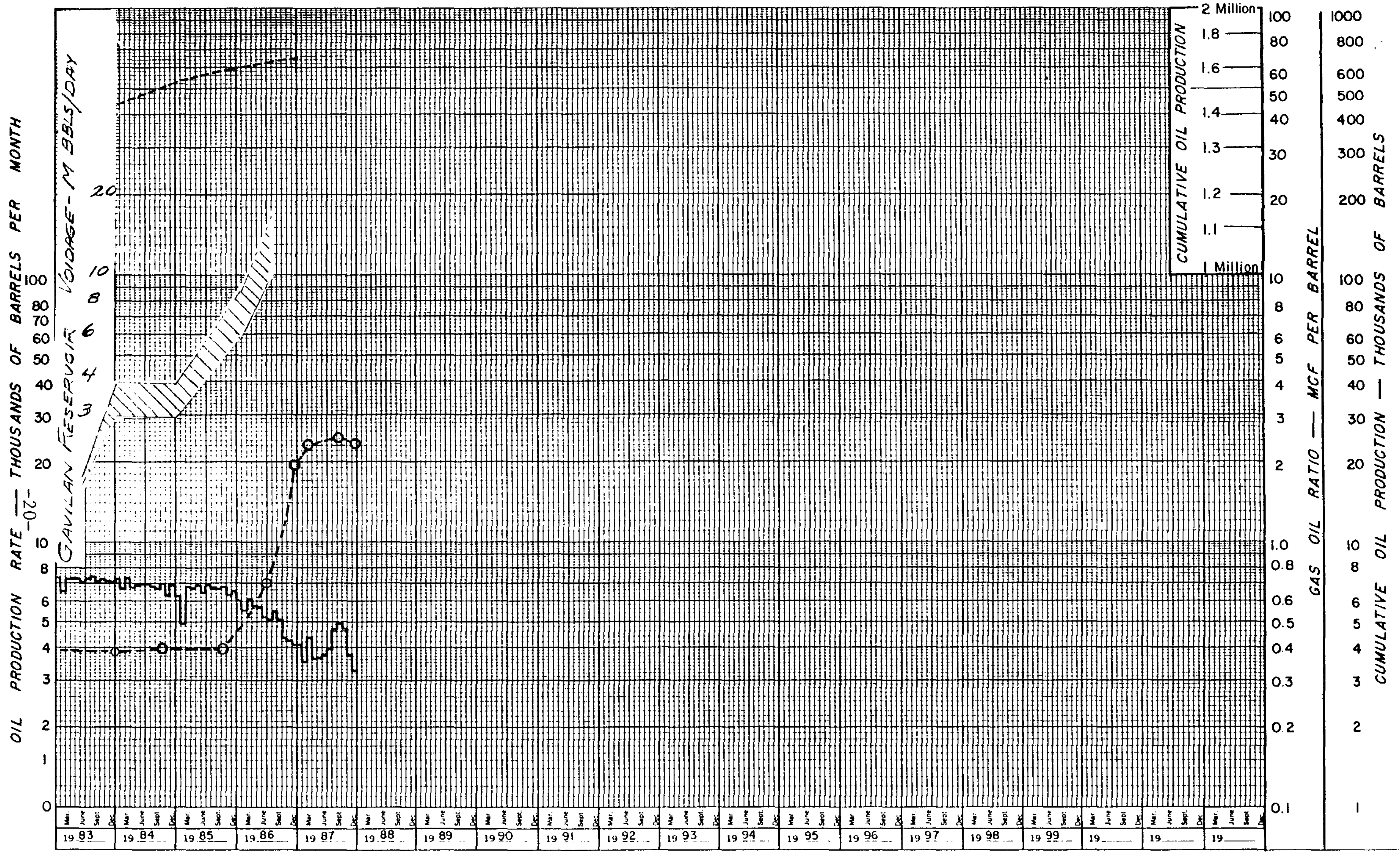
FIGURE IR-3



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL L-27

S.27-26N-1W

C.O.U. L-27
PRODUCTION
HISTORY



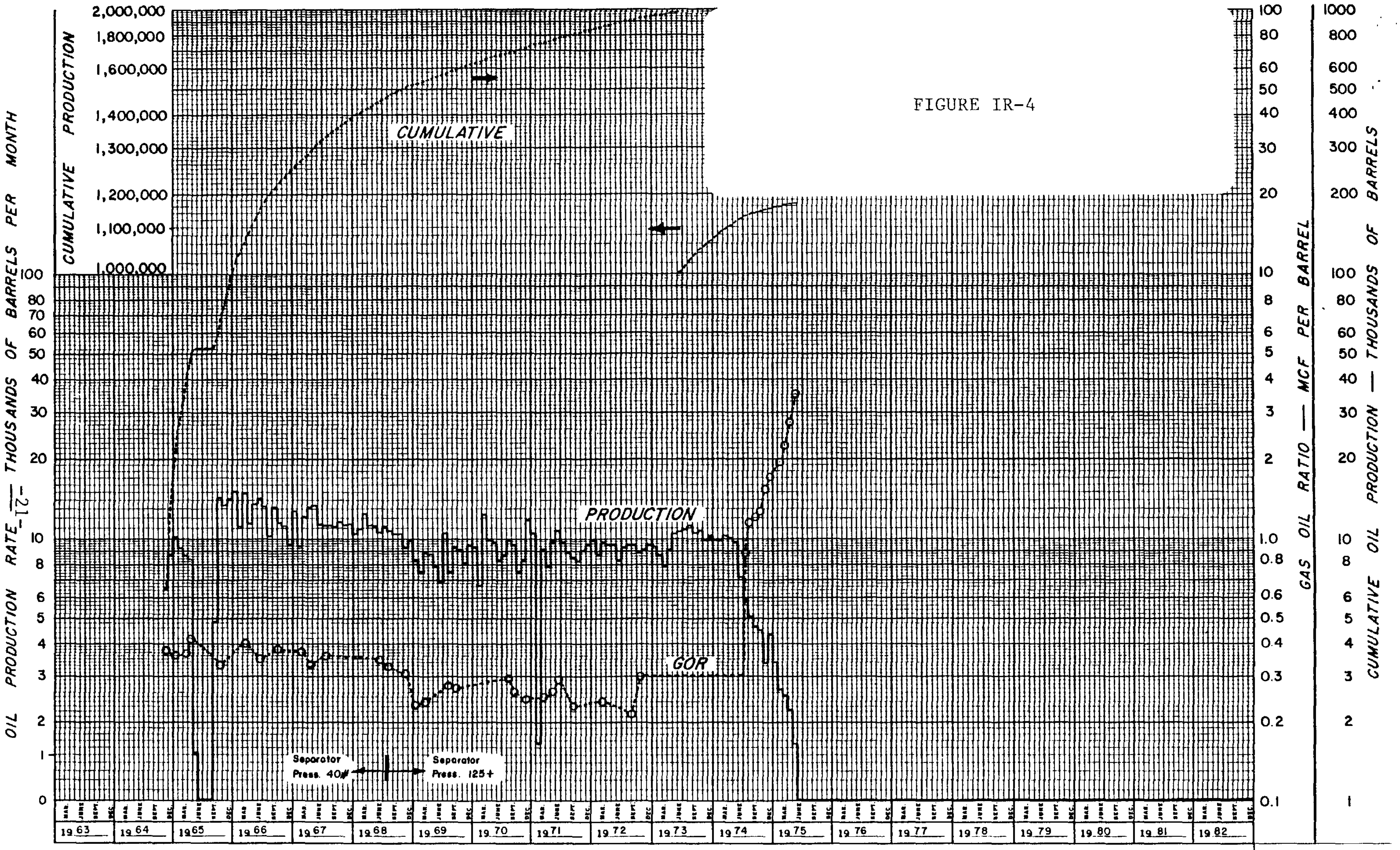
-20-

PRODUCTION HISTORY

CANADA OJITOS UNIT WELL L-27

C.O.U. L-27
PRODUCTION
HISTORY

FIGURE IR-4



PRODUCTION HISTORY
CANADA OJITOS UNIT WELL L-11

FIGURE IR-5

DESCRIPTION OF GRAVITY DRAINAGE MODEL

Reservoir Properties

Model Dimensions:	2-Dimensional Cross Section 5,280 ft Wide (along strike) 42,240 ft Long (dip direction) 40 ft Thick (Net Pay 1 Zone)
Initial Pressure:	1534 psia @ +2775 ft ASL
Saturation Pressure:	1534 psia
Solution Gas-Oil Ratio:	410 scf/STB (for 160 psi separator pressure)
Hydrocarbon Porosity:	0.27% (total porosity 0.3%)
Rock Compressibility:	10×10^{-6} 1/psi
Absolute Permeability:	100 md
Average Dip:	335 ft/mi

Relative Permeability Relationship:

Sg	Krg	Kro
0.00	0.0000	1.0000
0.10	0.103	0.38
0.30	0.33	0.0257
0.50	0.558	0.0004
0.80	0.9000	0.0000

Capillary Pressure: Zero

FIGURE IR-5 (Continued)

Producing Well Conditions

Production Well located near bottom of structure, 1/2 mile east of the western edge of the unit.

Well produced at constant rate until flowing bottomhole pressure reaches 500 psia. Well then produces at a constant bottomhole pressure of 500 psia. Production is terminated when the producing gas-oil ratio reaches 2000 scf/stb or the flow rate falls below 10 STB/day.

Pressure Maintenance Conditions

Injection well located near top of structure, 1/2 mile west of the eastern edge of the unit.

Gas is injected at a constant bottomhole pressure of 1600 psia. Injection rate increases as gas saturation (and, hence, permeability to gas) increases around the injection well.

FIGURE IR-6

STRUCTURAL CROSS-SECTION OF
CANADA OJITOS UNIT
USED IN GRAVITY DRAINAGE
AND PRESSURE MAINTENANCE SIMULATION

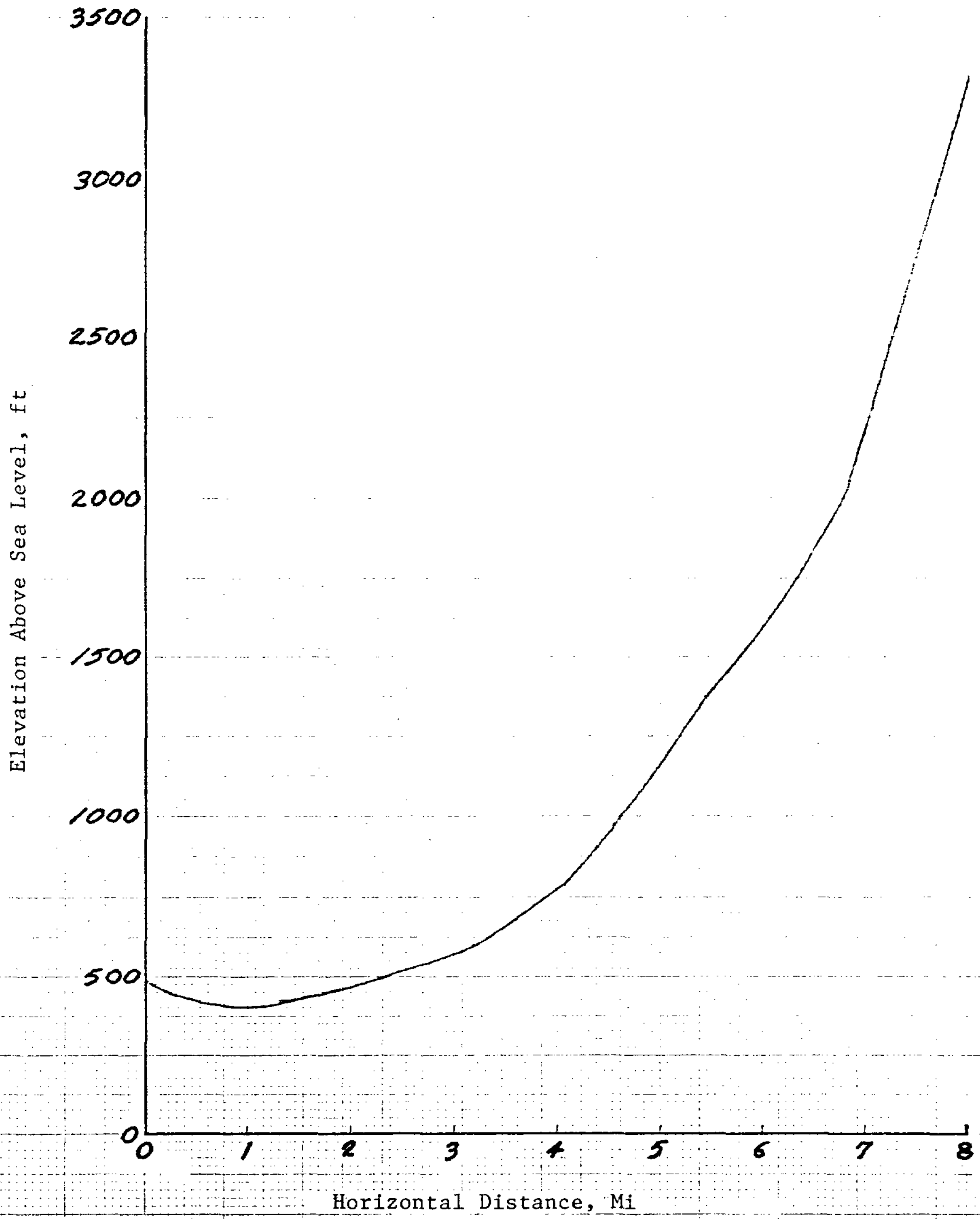


FIGURE IR-7

EFFECT OF PRODUCTION RATE & PRESSURE MAINTENANCE

ON RECOVERY - CANADA OJITOS UNIT

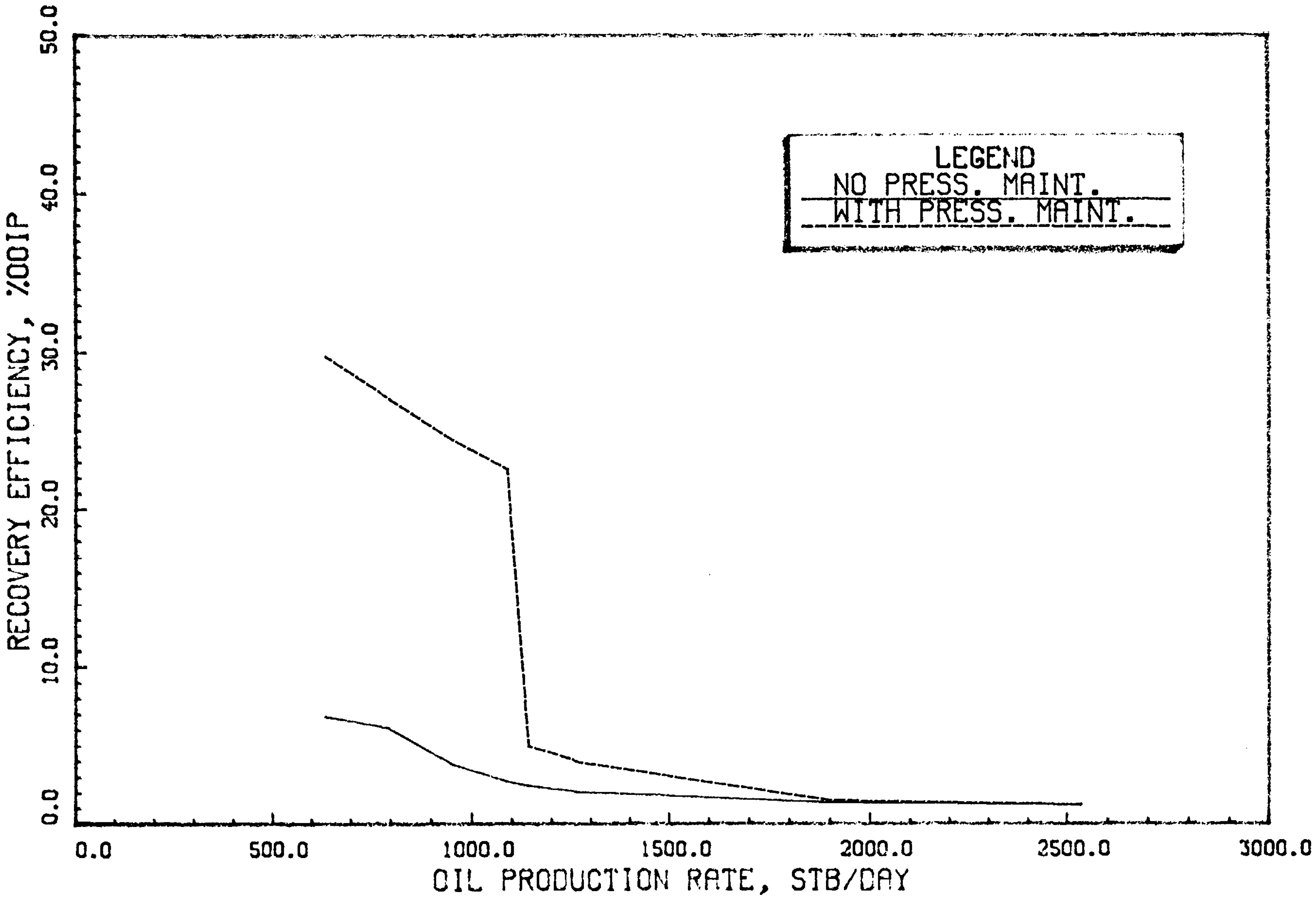


FIGURE IR-8

Canada Ojitos Unit - With Pressure Maintenance

Effect of Rate on G-O-R Performance

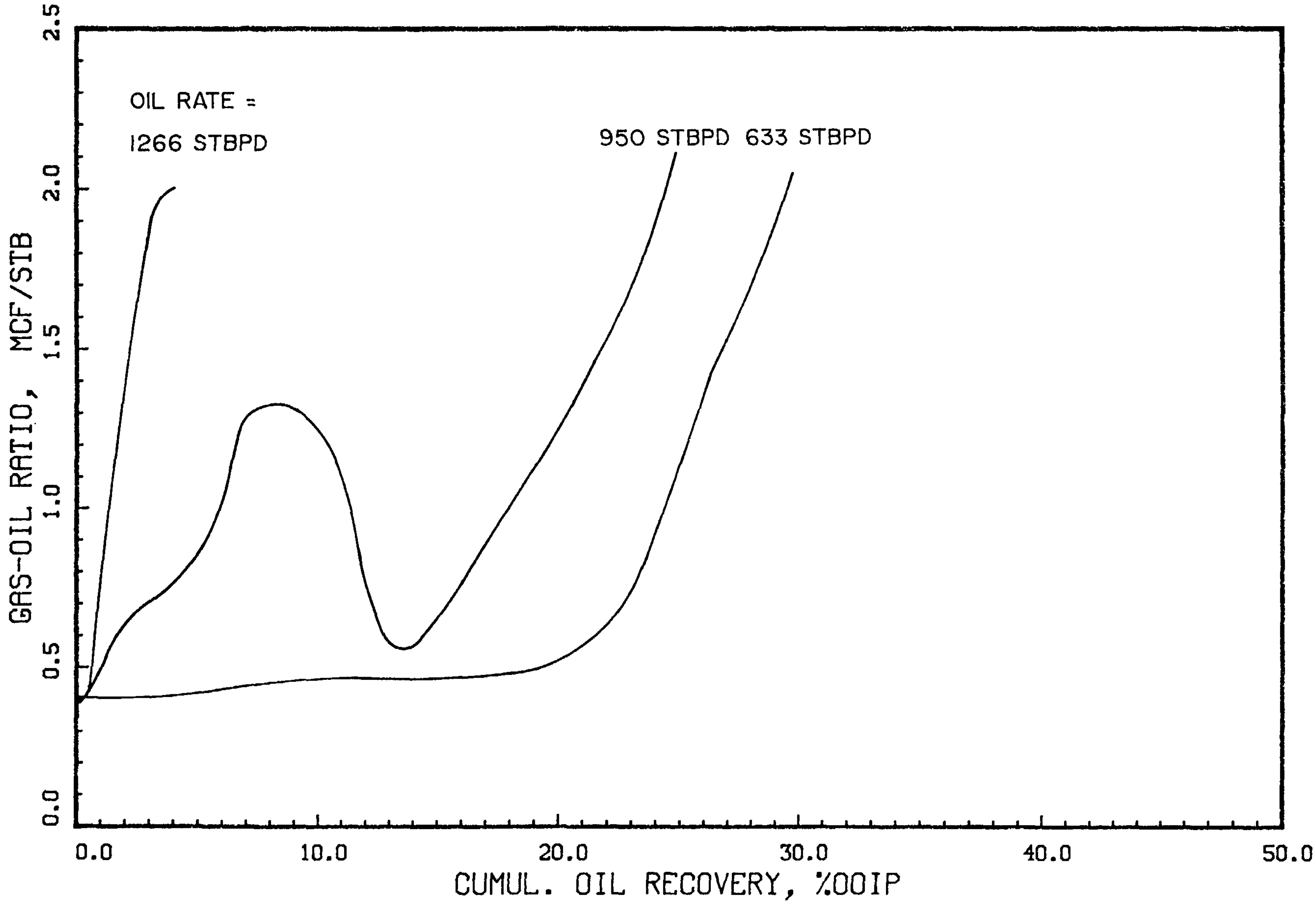


FIGURE IR-9

Canada Ojitos Unit - No Pressure Maintenance

Effect of Rate on G-O-R Performance

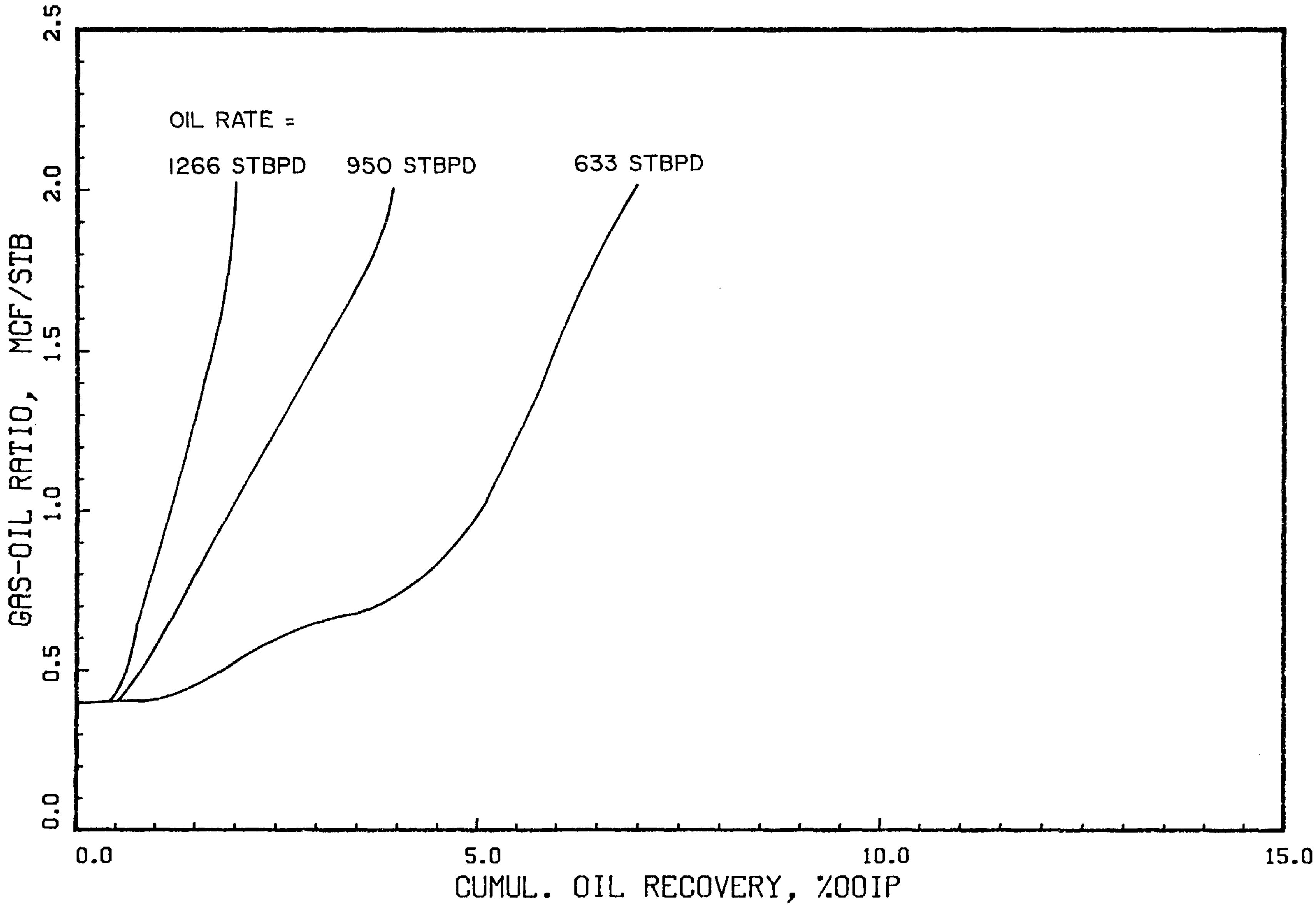


FIGURE IR-10

CANADA OJITOS UNIT - WEST PUERTO CHIQUITO FIELD

EFFECT OF RATE AND PRESSURE MAINTENANCE ON OIL RECOVERY*

CASE WITH NO PRESSURE MAINTENANCE

OIL RATE (STBPD)	RECOVERY EFFICIENCY (%OOIP)
2532	1.19
1899	1.34
1266	2.03
1139	2.43
1085	2.71
950	3.78
791	6.13
633	6.84

CASE WITH PARTIAL PRESSURE MAINTENANCE
(GAS INJECTION AT CONSTANT 1600 PSIA BHP)

OIL RATE (STBPD)	RECOVERY EFFICIENCY (%OOIP)
2532	1.17
1899	1.47
1266	3.93
1203	4.47
1139	4.93
1085	22.53
950	24.39
633	29.71

* Production forecasts based on limiting gas-oil ratio of 2000 scf/stb.

GAS CYCLING

Conclusion

Expansion of the COU would provide the opportunity to build a gas plant with attractive economics. This plant would permit the unit operator to replace the COU reservoir gas-gas cap with residue gas from the gas plant. Simulation indicates hydrocarbon liquid recovery could be increased by over 700,000 barrels with this process.

Evidence and Discussion

1. A compositional reservoir simulator was used to analyze the gas cycling project and to analyze a prospective gas plant. Simulation results are summarized on the attached Figure GC-1, which shows hydrocarbon liquids recovery as a function of time for two cases: (1) continued reinjection of reservoir gas (no cycling) and (2) recovery of high percentages of ethanes and heavier hydrocarbons from produced gas and injection of plant residue gas (cycling). In addition, the incremental increase in liquid recovery is shown. The final results are brought into sharper focus on the following bar graph (Figure GC-2) and table (Figure GC-3) which summarize the components of the increased recovery.

2. Details of the Simulation:

   a. Details of the reservoir model are given in the attached Figure GC-4 and schematic (Figure GC-5) showing model elevation.

   b. Gas composition and "pseudo components" derived from this composition to use in the simulator are given in Figure GC-6.

   c. Model validation (matches of historical producing GOR's) is presented in Figure GC-7. The observed and predicted data agree well, which establishes that the reservoir description provides an adequate basis for projecting future performance with the two operating alternatives: reinjection of reservoir gas and injection of gas plant residue gas.

   d. A description of the two alternative cases for forecasting (reinjection of reservoir gas and injection of plant residue gas (cycling)) is given in the Figure GC-8.

   e. Graphs and tabulations of recoveries and production schedules also follow (Figures GC-9 through GC-12).

FIGURE GC-1

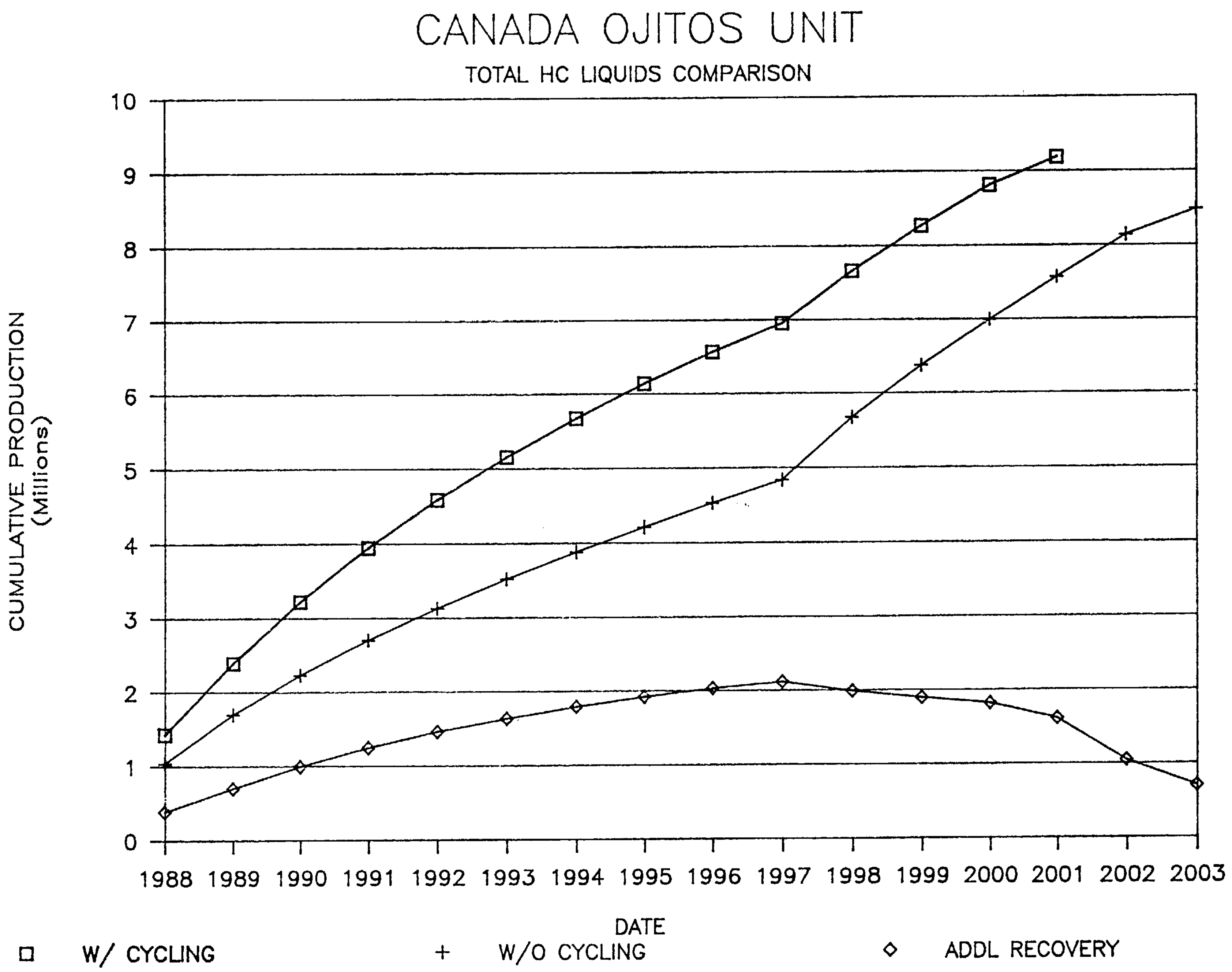
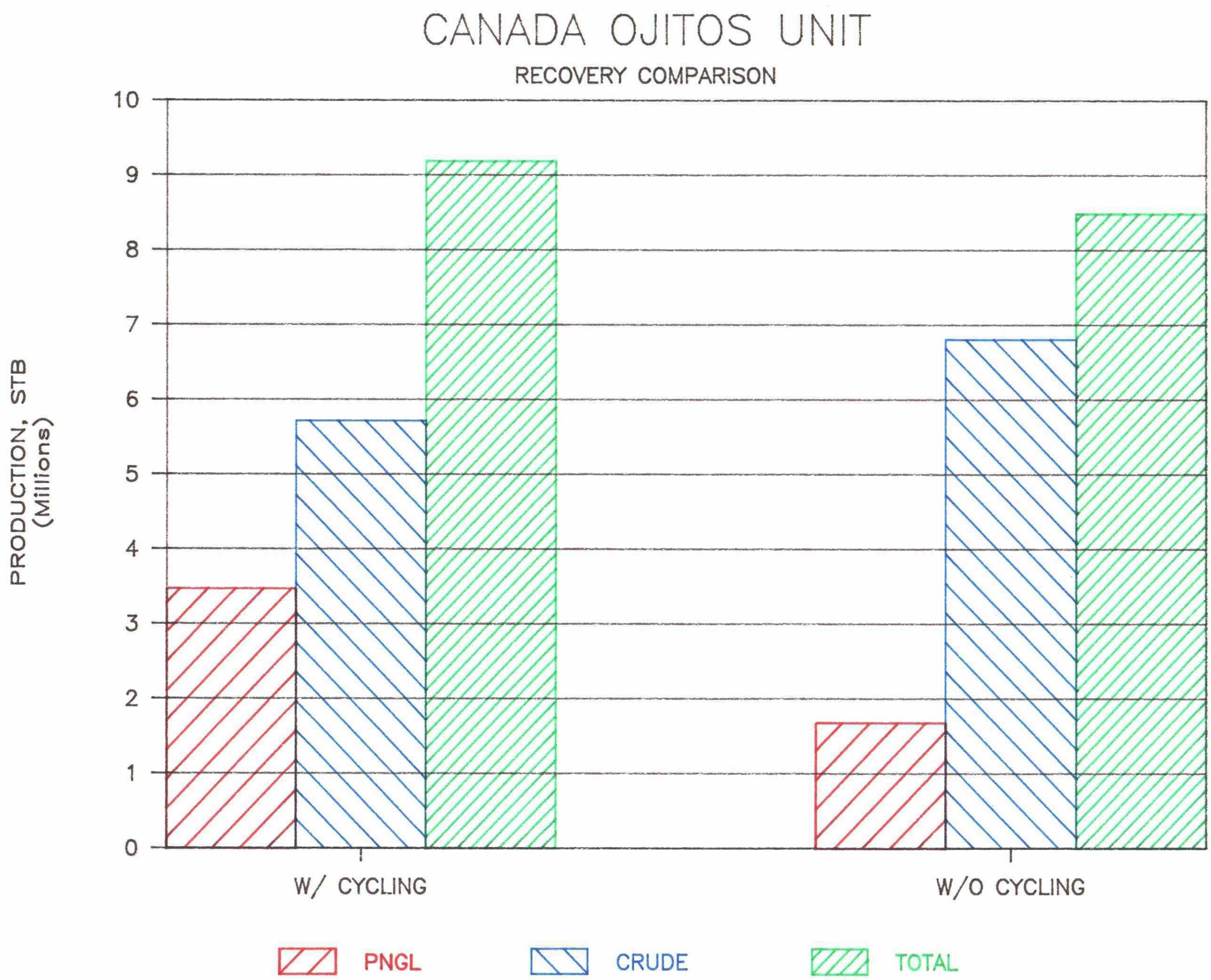

CANADA OJITOS UNIT
TOTAL HC LIQUIDS COMPARISON
CUMULATIVE PRODUCTION
(Millions)
0
1
2
3
4
5
6
7
8
9
10
1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003
DATE
W/ CYCLING
W/O CYCLING
ADDL RECOVERY

FIGURE GC-2



CANADA OJITOS UNIT
RECOVERY COMPARISON
PRODUCTION, STB (Millions)
10
9
8
7
6
5
4
3
2
1
0
W/ CYCLING
W/O CYCLING
PNGL
CRUDE
TOTAL

FIGURE GC-3

RECOVERY COMPARISON
CANADA OJITOS UNIT
GAS PLANT MODEL STUDY

	With Cycling	Without Cycling	Difference
PNGL	3470 MB	1681 MB	+1789 MB
Crude	5713 MB	6801 MB	-1088 MB
Total	9183 MB	8482 MB	+701 MB

FIGURE GC-4

MODEL DESCRIPTION
CANADA OJITOS UNIT
GAS PLANT MODEL STUDY

Model Dimensions:	2-Dimensional Cross-Section 42,240 ft wide (8 mi) 36,960 ft long (7 cells @ 5280 ft each) 3 layers (30 ft, 30 ft, and 40 ft thickness)
Initial Pressure:	1534 psia @ datum (+1850 ft ASL)
Saturation Pressure:	1534 psia
Solution Gas-Oil Ratio:	428 scf/STB (for model separator conditions)
Total Porosity:	0.3%
Rock Compressibility:	10×10^{-6} 1/psi
Absolute Permeability:	100 md - Horizontal 0.00005 md - Vertical (between zones)
Capillary Pressure:	Zero
Original Oil In Place:	47 MMSTB

Plant Recovery Factors:

Component	Recovery
C_2	70%
C_3	90%
C_{4+}	100%

FIGURE GC-4 (Continued)

MODEL DESCRIPTION
CANADA OJITOS UNIT
GAS PLANT MODEL STUDY

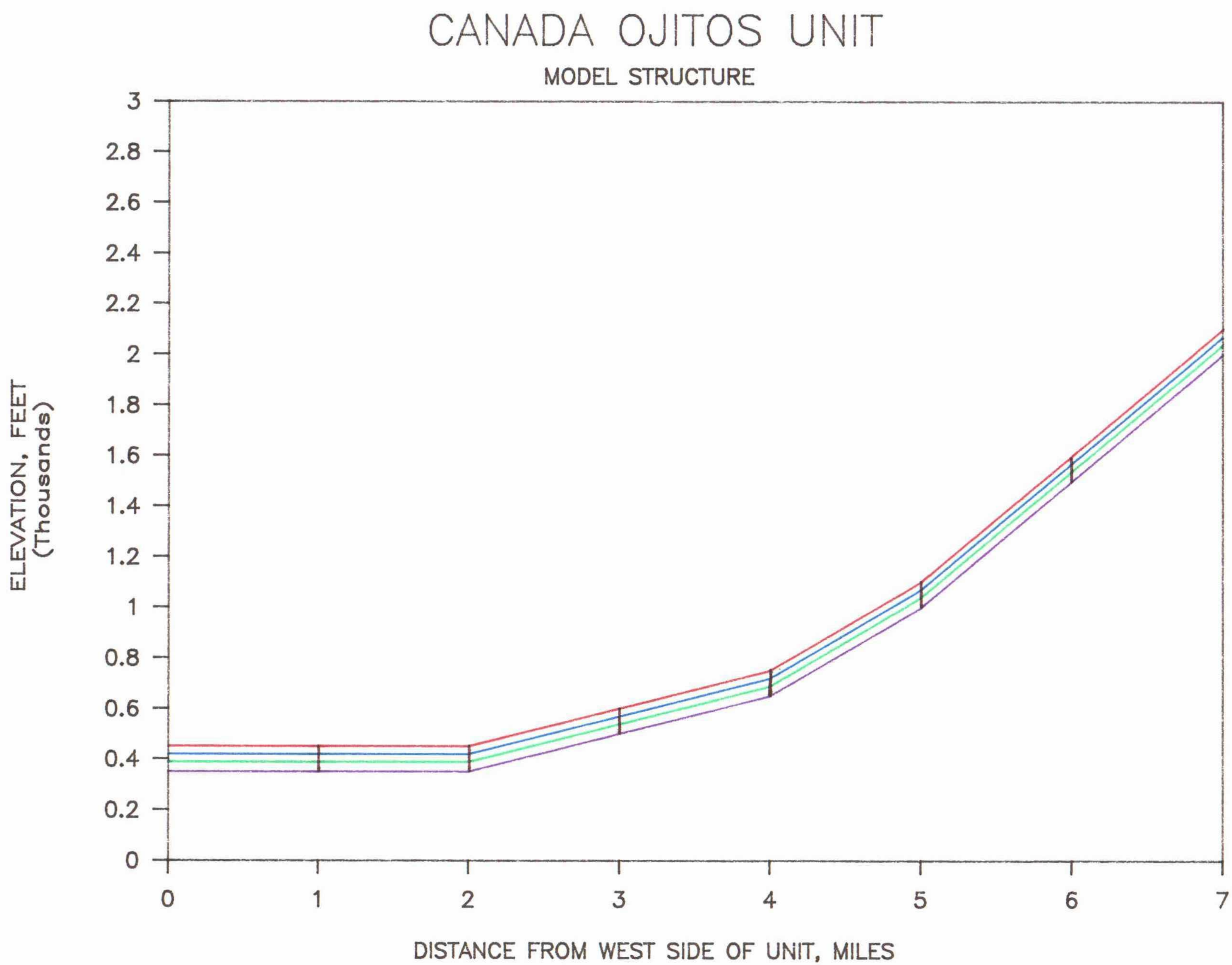
- Unit production is from four wells located in alternate cells in model.

- Furthest updip well converted to gas injection at proper time historically.

- Historical field oil and gas production allocated to model wells nearest actual wells.

- Model ends at Canada Ojitos Unit/Gavilan Mancos pool boundary on west. However, it was necessary to withdraw additional volumes of oil from western area during later years of history to match historical GOR and pressure performance in this area. This was done with an additional well in the most western cell. The "Gavilan Migration" was represented by the production from this well.

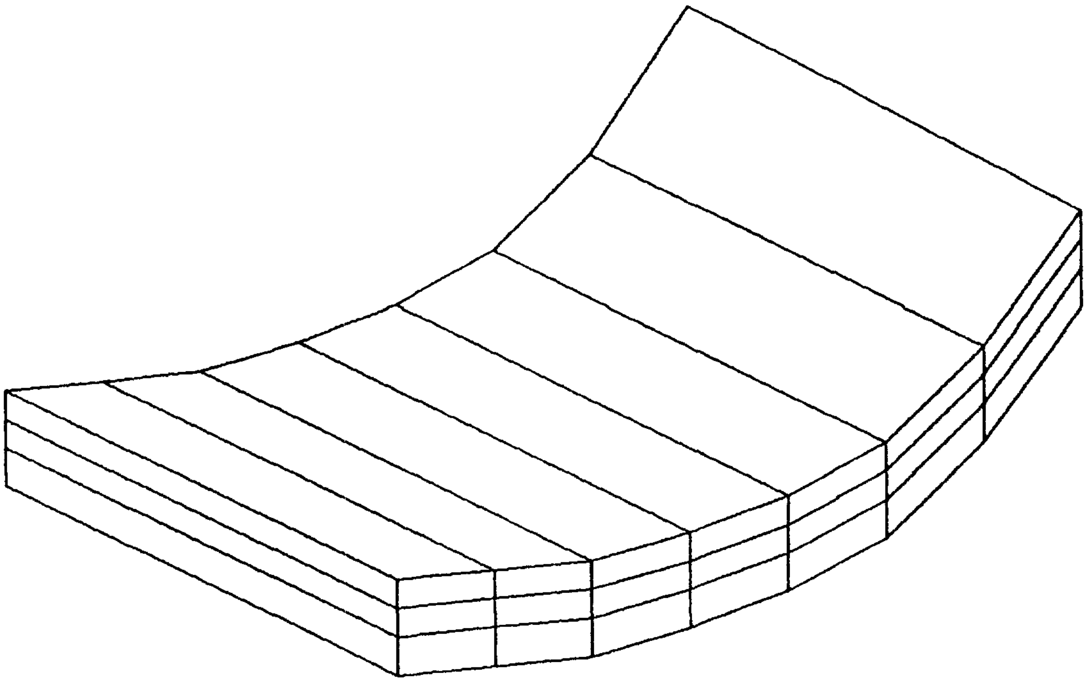
FIGURE GC-5


CANADA OJITOS UNIT
MODEL STRUCTURE
ELEVATION, FEET
(Thousands)
3
2.8
2.6
2.4
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
1
2
3
4
5
6
7
DISTANCE FROM WEST SIDE OF UNIT, MILES

CANADA OJITOS UNIT

GAS PLANT STUDY MODEL

PERSPECTIVE VIEW



AREAL VIEW

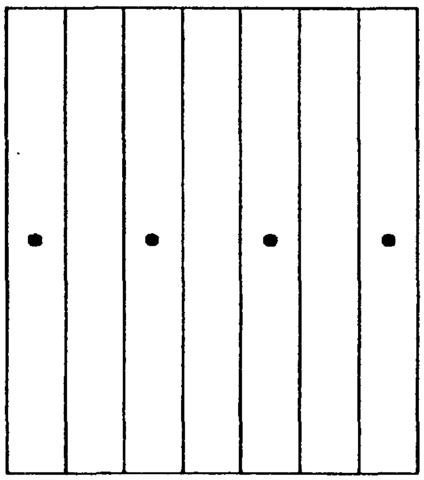


FIGURE GC-6

RESERVOIR GAS COMPOSITION

CANADA OJITOS UNIT
GAS PLANT MODEL STUDY

Component	Pseudo Component	Mol %	GPM
C_1	P_1	83.584	
N_2	P_1	0.270	
C_2	P_2	9.572	2.556
C_3	P_3	4.010	1.099
iC_4	P_3	0.473	0.154
nC_4	P_3	0.864	0.271
CO_2	P_3	0.671	
iC_5	P_4	0.221	0.080
nC_5	P_4	0.218	0.079
C_6+	P_4	0.117	0.050
		100.000	4.289

Heat Content = 1181 Btu/Scf

Based on processing the Canada Ojitos Unit gas at the discharge of the second stage of compression (approximately 1000 psig).

FIGURE GC-7

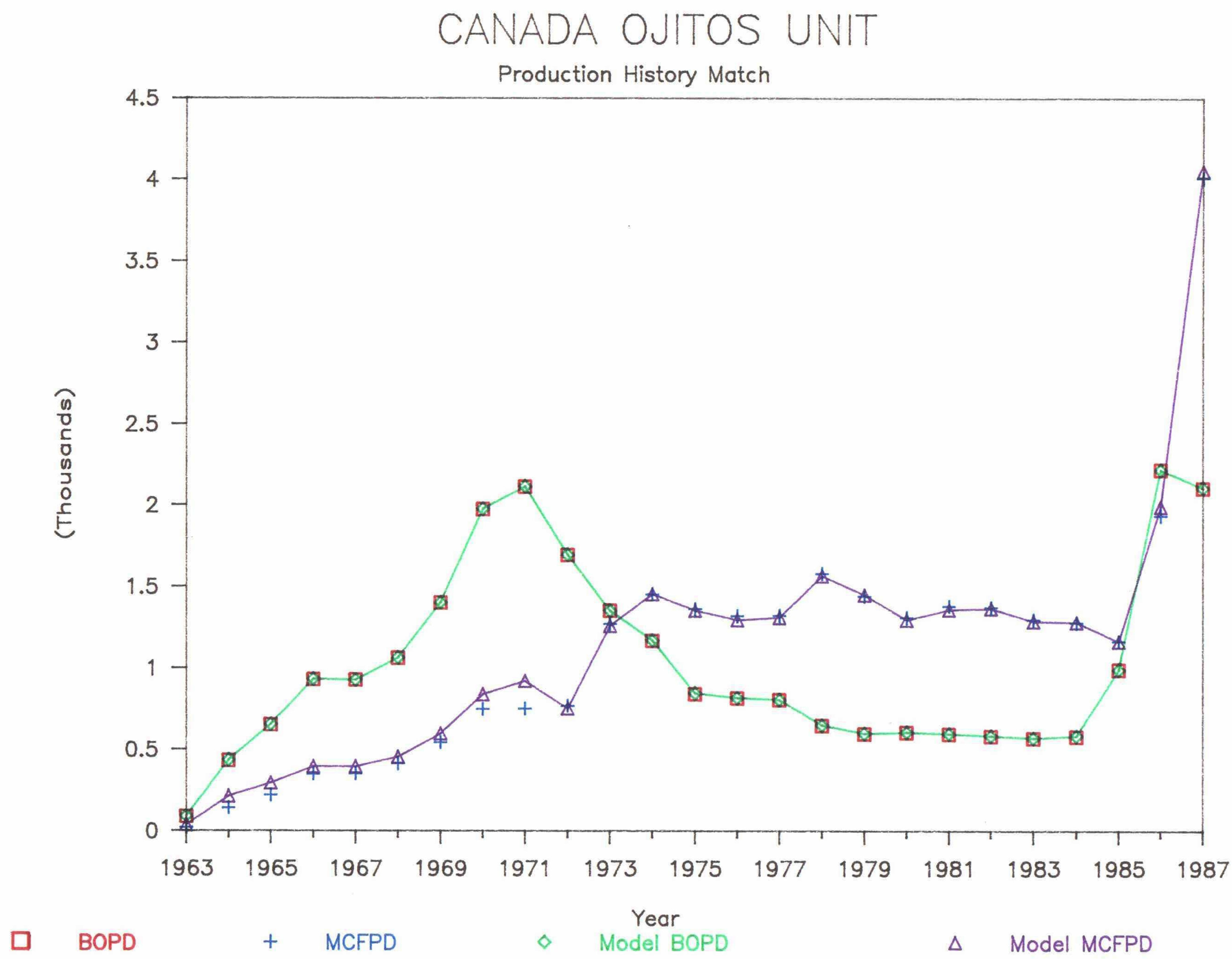

CANADA OJITOS UNIT
Production History Match
(Thousands)
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
Year
BOPD
MCFPD
Model BOPD
Model MCFPD

FIGURE GC-8

DESCRIPTIONS OF FORECAST CASES
CANADA OJITOS UNIT
GAS PLANT MODEL STUDY

Without Cycling (No Gas Plant):

- Continue operations for 10 years, then cease injection and blow down to 500 psi pressure.

- Gas "processed" during blow down to determine possible liquid recovery.

- Initial field production rate = 8.4 MMscf/D (limited by gas available for injection of 7.7 MMscf/D).

- All of produced gas injected.

- Only two most downdip wells produced.

- "Gavilan Migration" assumed equal to zero after 1/1/89.

With Cycling (Produced Gas Processed):

- Processing to begin at model time 1/1/88 and continue for 10 years; then, cease injection and blow down to 500 psi reservoir pressure.

- Processing continued to end of blow down.

- Field production rate = 10 MMscf/D (limited by injection of 7.7 MMscf/D).

- Only two most downdip wells produced.

- "Gavilan Migration" assumed equal to zero after 1/1/89.

- All of produced gas injected (after fuel and shrinkage).

- Efficiency of plant liquids recovery shown in Figure GC-4.

FIGURE GC-9

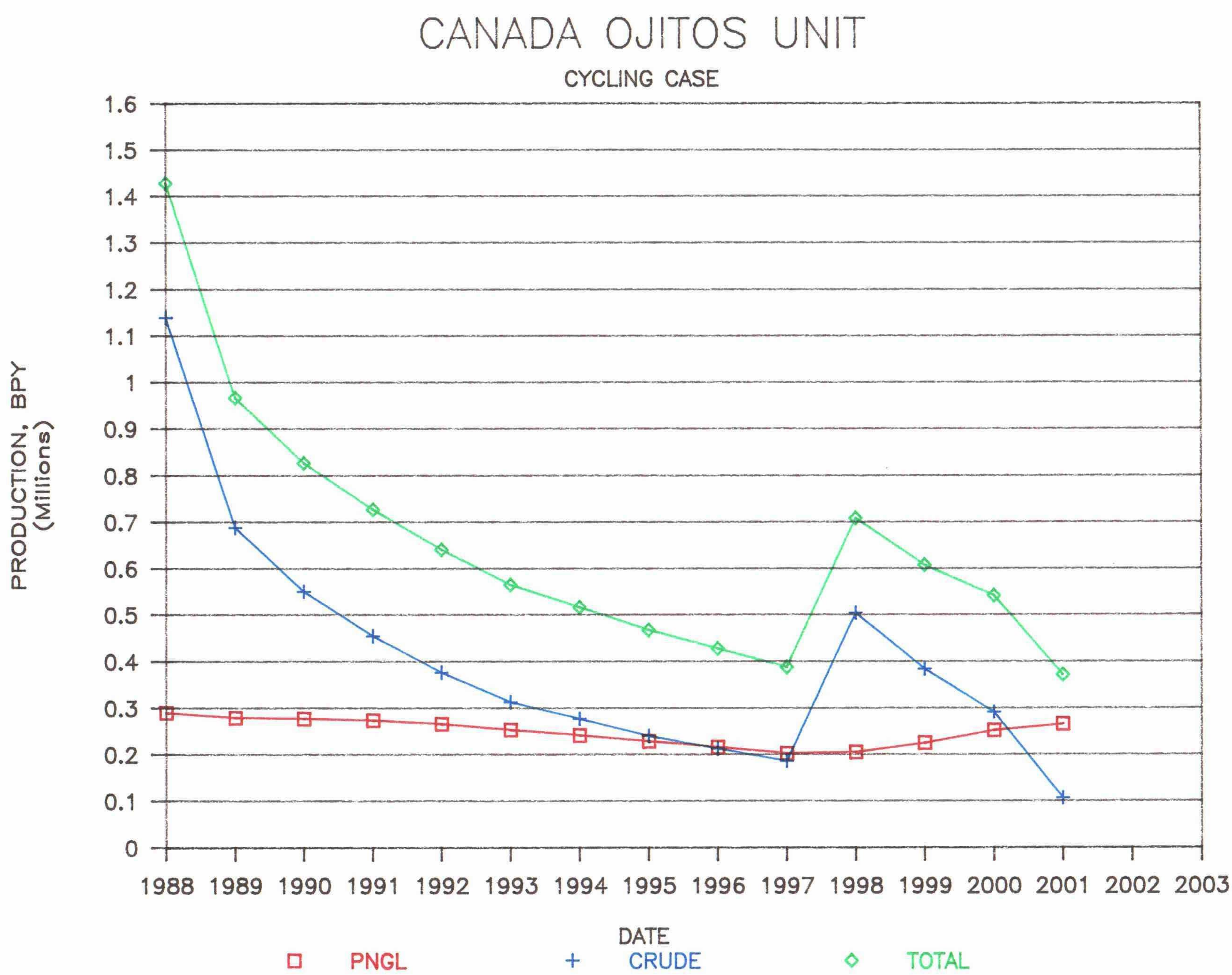
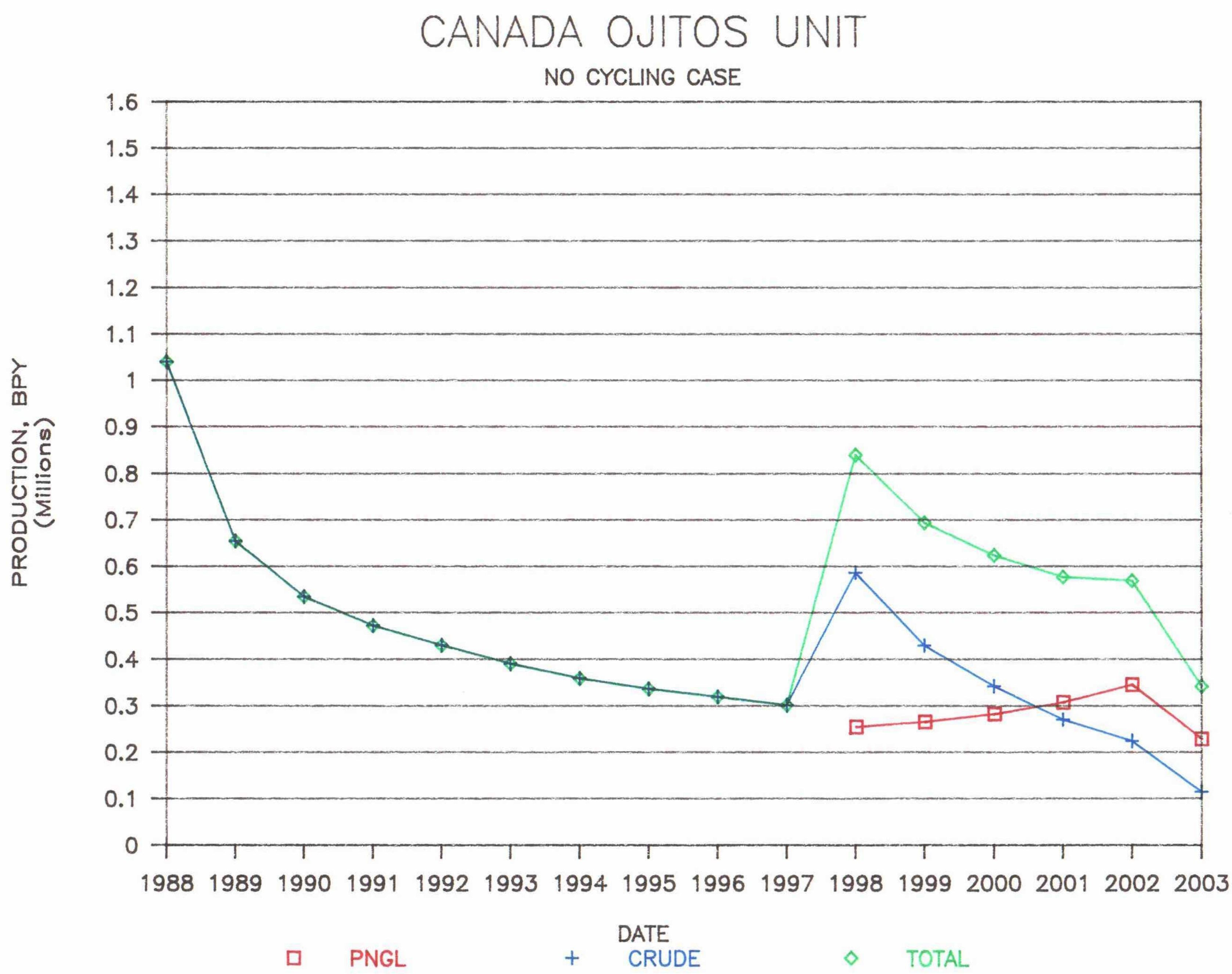

CANADA OJITOS UNIT
CYCLING CASE
PRODUCTION, BPY (Millions)
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003
DATE
PNGL
CRUDE
TOTAL

FIGURE GC-10

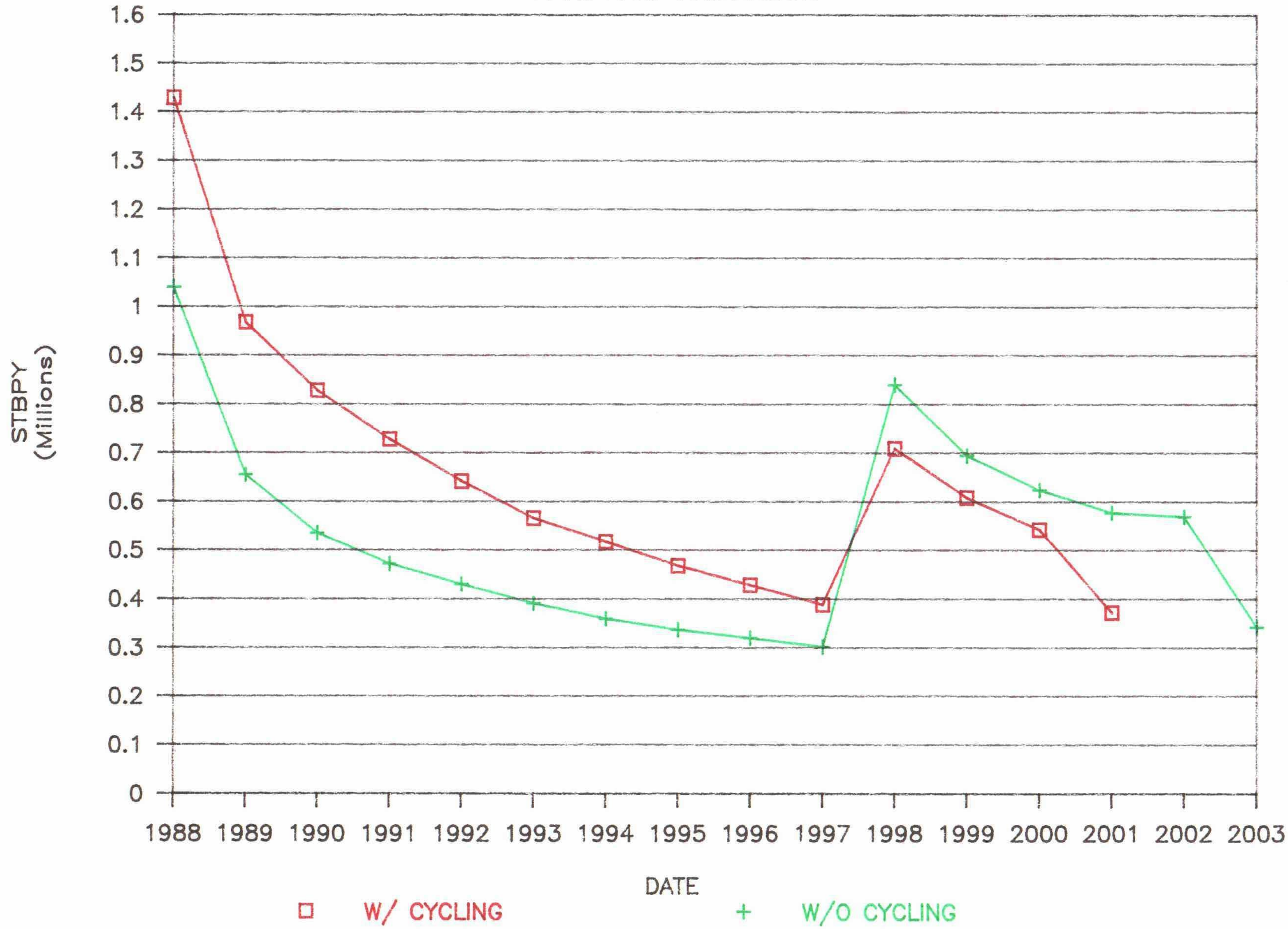


CANADA OJITOS UNIT
NO CYCLING CASE
PRODUCTION, BPY
(Millions)
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
DATE
PNGL
CRUDE
TOTAL

FIGURE GC-11

CANADA OJITOS UNIT

TOTAL RATE COMPARISON



[redacted]

FIGURE GC-12

PRODUCTION SCHEDULES
CANADA OJITOS UNIT
GAS PLANT MODEL STUDY

Cycling Case

Year	PNGL (MSTBPY)	Gas Prod (MMCFPY)	Oil Prod (MSTBPY)	Avg Press (psia)	Cum PNGL (MSTB)	Cum Oil (MSTB)	Total Liq Prod (MSTBPY)	Cum Tot Liq (MSTB)
1988	289	3660	1139	1418	289	1139	1428	1428
1989	279	3650	688	1315	568	1827	967	2395
1990	277	3650	550	1315	845	2377	827	3222
1991	273	3650	454	1317	1118	2831	727	3949
1992	265	3660	376	1301	1383	3207	641	4590
1993	253	3650	312	1216	1636	3519	565	5155
1994	241	3650	276	1253	1877	3795	517	5672
1995	228	3650	239	1210	2105	4034	467	6139
1996	216	3660	212	1208	2321	4246	428	6567
1997	202	3650	185	1106	2523	4431	387	6954
1998	205	3650	503	1004	2728	4934	708	7662
1999	225	3650	383	826	2953	5317	608	8270
2000	252	3660	290	652	3205	5607	542	8812
2001*	265	3226	106	500	3470	5713	371	9183

No Cycling Case

Year	PNGL (MSTBPY)	Gas Prod (MMCFPY)	Oil Prod (MSTBPY)	Avg Press (psia)	Cum PNGL (MSTB)	Cum Oil (MSTB)	Tot Liq Prod (MSTBPY)	Cum Tot Liq (MSTB)
1988	-	-	1040	1435	0	1040	1040	1040
1989	-	-	654	1418	0	1694	654	1694
1990	-	-	535	1400	0	2229	535	2229
1991	-	-	472	1385	0	2701	472	2701
1992	-	-	430	1371	0	3131	430	3131
1993	-	-	390	1357	0	3521	390	3521
1994	-	-	359	1344	0	3880	359	3880
1995	-	-	336	1331	0	4216	336	4216
1996	-	-	319	1319	0	4535	319	4535
1997	-	-	301	1307	0	4836	301	4836
1998	254	3150	586	1152	254	5422	840	5676
1999	265	3150	429	1001	519	5851	694	6370
2000	282	3159	342	855	801	6193	624	6994
2001	307	3150	270	712	1108	6463	577	7571
2002	345	3150	224	574	1453	6687	569	8140
2003*	228	1753	114	500	1681	6801	342	8482

*Partial year