OMEGA HYDROCARBONS LTD.
1300 SUN LIFE PLAZA III
112 - 4th AVENUE S.W.
CALGARY, ALBERTA, CANADA T2P 0H3
TELEPHONE (403) 261-0743
FAX (403) 264-5691

PETROLEUM BRANCH
DEPARTMENT OF ENERGY AND MINES
JUL 7 1992

July 2, 1992

Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Attention: Mr. John Fox
Chief Petroleum Engineer

Dear Sir:

RE: Waskada Reduced Spacing Pilot Project
Current Status and Future Strategies

The purpose of this letter is to respond to the Board's questions concerning the Waskada reduced spacing pilot project contained in the approval for concurrent MC3a production from well 8A-23-1-26 WPM. The following is a review of production performance to date and a comparison to predicted performance for the infill pilot project area.

1) Base Case Prediction

The base case prediction used in the infill pilot project application was based on production history data to June 1990. Production decline curve analysis resulted in a 1991 predicted average rate of 318 m^3/month and an annual decline rate of 10 percent. During the 4th quarter of 1990 the production from the original producing wells increased to an average rate of 470 m^3/month. This increase in production is attributed to restarting water injection at well 5-24-1-26 WPM as illustrated in Attachment 1. The impact of this change in performance does not effect the infill well forecast, however, a revision to the base case production forecast is necessary. Assuming a 1991 average oil production rate of 450 m^3/month, an abandonment rate of 95 m^3/month and an exponential decline rate of 10%/yr results in a revised ultimate recovery factor of 27.1 percent for the base case.

2) Infill Well Prediction

The sonic logs obtained from the four infill wells were found to have the same reservoir characteristics as the offset wells. While the resistivity logs contained no zones of abnormally high water saturations indicating unswept portions of the reservoir had been contacted. These findings were confirmed by initial oil production rates and producing water cuts which ranged from 2.1 m^3/d to 4.1 m^3/d and 10% to 47%, respectively. The incremental oil production forecast used in the infill pilot project application assumed a composite initial rate of 8.0 m^3/d and an annual decline rate of 15%. Due to a delay in the pilot project start up date from January 1991 to March 1991 a time shift in the incremental production forecast is required for future comparisons but the predicted 3.3 percent incremental recovery remains unchanged.

3) Pilot Project Performance and Future Strategies

Attachment 2 contains a historical production plot for the pilot project area and illustrates the incremental oil production produced to date from the infill wells. Attachment 3 contains a comparison of 1991 actual production to predicted production incorporating the previously mentioned adjustments. Both the base case and infill well forecasts compare favourably with actual production. Factors which are adversely affecting the oil production from the pilot project area are; i) a lower than anticipated reservoir pattern pressure ii) production well downtime and iii) increased water production from some of the original oil wells. The declining infill well production rates are related to the low reservoir pattern pressure and an increase in back pressure caused by flowlining the wells. Production downtime is occurring within the pilot project area each month due to common flowline testing procedures and routine well maintenance. To this point in time no significant interference has been identified between any of the wells.

Omega Hydrocarbons Ltd. remains confident that increased oil recovery from the Lower Amaranth formation is possible through infill drilling. To date the only project disappointment encountered has been the low reservoir pressure. Serious efforts are being made to overinject water into the pilot project area in order to increase reservoir pressures and improve the pilot project performance. Overinjection will continue until the reservoir pressure has returned back to the initial reservoir pressure of 9000 kPa. Monthly monitoring of production and injection has been implemented to ensure the early detection of any problems created by this strategy.

If there are any questions or comments related to this information, please contact the undersigned at (403) 261-0743.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Senior Exploitation Engineer

c.c.: J. Beardsworth
Waskada Reduced Spacing Unit Application File

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Forecast Versus Actual Production Comparison

Pattern 5-24-1-26 WPM

Year	**Revised Base Case Forecast (m^3)**	**Revised Infill Well Forecast* (m^3)**	**Actual Base Case Production (m^3)**	**Actual Infill Well Production (m^3)**
1991	5400	2073	4835	1876
1992	4886	2422		
1993	4421	2084		
1994	4000	1794		
1995	3620	1544		
1996	3275	1329		
1997	2963	1144		
1998	2681	985		
1999	2426	847		
2000	2195	729		
2001	1987	627		
2002	1798	540		
2003	1626	-		
2004	1472	-		
2005	1332	-		
2006	1205	-		
Total	45287	16118		

Pattern 5-24 OOIP = 438,708 m^3
Cumulative Pattern Production (31/12/90) = 85756 m^3
Base Case Recovery Factor = 27.1%
Infill Case Recovery Factor = 30.4%

Base Case Parameters - Initial rate = 15.5 m^3/d, Final rate = 3.1 m^3/d
Decline rate = 10%/yr, Producing wells = 8

Incremental Parameters - Initial rate = 8.0 m^3/d, Final rate = 1.5 m^3/d
Decline rate = 15%/yr, Producing wells = 4

*In the infill well forecast for 1991 nine production months were used.

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January 7, 1991

THE OIL AND NATURAL GAS
CONSERVATION BOARD
Room 309 Legislative Building
Winnipeg, Manitoba
R3C 0V8

Attention: Dr. Ian Haugh
Chairman

Dear Sir:

Re: Waskada Lower Amaranth A Pool
Application for Drilling Spacing Unit Reduction

Omega Hydrocarbons Ltd. acknowledges the Board's letter dated 1990/12/21 and submits the following supplementary information regarding the infill well pilot project evaluation program.

Throughout the development of the Waskada Lower Amaranth A Pool Omega has collected the necessary data to obtain a comprehensive reservoir description. A summary of the information gathered to date includes two reservoir fluid studies, numerous full diameter cores, capillary pressure tests, rock compressibility tests, relative permeability tests, petrology studies, a reservoir simulation study, a fieldwide computerized log interpretation study, annual reservoir pressure surveys and continuous well performance monitoring. It is felt that gathering additional routine type data on the infill wells will not add to the current knowledge base. However, by drilling and production testing the infill wells as Omega has previously proposed it is possible to evaluate reservoir continuity under reduced well spacing and identify trapped oil saturation areas on a pattern basis.

Specifically addressing the items which have been proposed by the Board to enhance the infill well pilot project evaluation Omega offers the following comments;

1) Obtaining interzone data such as TDT logs, EPT logs, GST logs and RFT measurements at the infill wells would have limited practical use. Based on workover experience to date attempts to segregate the various Lower Amaranth sands after the required fracture stimulation have been ineffective. None of the previously mentioned measurements have been performed at

existing wells due to the questionable ability of these tools obtaining meaningful data within an induced fracture system.

2) Interwell communication testing becomes increasingly important as a waterflood matures. To date the producing water cuts on a fieldwide basis remain relatively low and Lower Amaranth waterflood breakthrough is suspected at only a small number of wells. Omega has evaluated the various techniques to obtain interwell communication data and believes that [redacted] is the most reliable method. Due to the high cost of such testing Omega recommends that this type of testing be delayed to such time as significant waterflood breakthrough has occurred within the infill well pilot area. (Estimated cost $30,000)

3) Determining the stress regime and in turn the induced fracture orientation within Waskada are important for future waterflood optimization and infill well expansion. Given that this information can be collected at any newly drilled well Omega is not willing to commit infill pilot project funds to obtain the data. For the time being Omega plans to pursue an industry wide search for existing fracture orientation studies performed in southeastern Saskatchewan or southwestern Manitoba and to investigate available techniques for determining fracture orientation within existing wells.

4) Waterflood performance can be detrimentally effected by out of zone injection therefore [redacted] WPM to confirm that the injection fluids are confined to the Lower Amaranth zone. This additional information will be used to ensure that the infill well pilot project area is receiving adequate pressure support. (Estimated cost $6500)

5) As stated previously Omega is of the opinion that routine core analysis and special core study work on the infill wells will not enhance the current geological and reservoir description. The proposed logging program allows the evaluation of reservoir continuity under reduced well spacing through a direct comparison with the offsetting well logs. Regular production testing of the infill wells will be used to evaluate trapped oil saturation areas within the existing injection pattern and their impact on existing production well performance.

We trust that the information contained herein meets your requirements. We also ask that the subject application be given written approval as soon as possible in order to complete the infill drilling prior to spring breakup.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Engineering Supervisor - Manitoba

/jlb

c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Waskada Reduced Spacing Unit Application File

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December 6, 1990

MANITOBA ENERGY & MINES
PETROLEUM BRANCH
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Attention: Mr. John Fox
Chief Petroleum Engineer

Dear Sir:

Re: Waskada Lower Amaranth A Pool
Application for Drilling Spacing Unit Reduction

Enclosed are the oil in place calculations for the offsetting injection patterns which were requested during our telephone conversation of 1990-12-03. It should be noted that all the injection pattern oil in place calculations assume an area of one full legal subdivision for each well location.

If there are any questions pertaining to this information please contact the undersigned.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke
Engineering Supervisor - Manitoba

RAB:jlb

c.c.: Waskada Special Spacing Unit Application File

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Offset Pattern Oil In Place Calculation

Pattern 13-13-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)
11-13-1-26 WPM	0.373	30985
12-13-1-26 WPM	0.328	27296
13-13-1-26 WPM	0.361	30001
14-13-1-26 WPM	0.361	30001
9-14-1-26 WPM	0.385	31969
16-14-1-26 WPM	0.361	30001
1-23-1-26 WPM	0.675	56068
3-24-1-26 WPM	0.749	62216
4-24-1-26 WPM	0.704	58527
Total:	4.297	357064

$$OOIP = \frac{10000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A=16ha, Sw=0.40, Boi=1.155 Rm^3/m^3

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Offset Pattern Oil In Place Calculation
Pattern 15-13-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)
9-13-1-26 WPM	0.246	20411
10-13-1-26 WPM	0.391	32460
11-13-1-26 WPM	0.373	30985
14-13-1-26 WPM	0.361	30001
15-13-1-26 WPM	0.411	34182
1-24-1-26 WPM	0.373	30985
2-24-1-26 WPM	0.536	44510
3-24-1-26 WPM	0.749	62216
Total:	3.440	285750

$$OOIP = \frac{10000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A=16ha, Sw=0.40, Boi=1.155 Rm^3/m^3

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Offset Pattern Oil In Place Calculation

Pattern 15-14-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)
9-14-1-26 WPM	0.385	31969
10-14-1-26 WPM	0.204	16968
15-14-1-26 WPM	0.331	27542
16-14-1-26 WPM	0.361	30001
1-23-1-26 WPM	0.675	56068
2-23-1-26 WPM	0.340	28280
Total:	2.296	190828

$$OOIP = \frac{10000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A=16ha, Sw=0.40, Boi=1.155 Rm^3/m^3

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Offset Pattern Oil In Place Calculation

Pattern 7-23-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)
1-23-1-26 WPM	0.675	56068
2-23-1-26 WPM	0.340	28280
7-23-1-26 WPM	0.320	26558
8-23-1-26 WPM	0.518	43034
9-23-1-26 WPM	0.840	69839
10-23-1-26 WPM	0.577	47953
Total:	3.270	271732

$$OOIP = \frac{10000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A=16ha, Sw=0.40, Boi=1.155 Rm^3/m^3

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Offset Pattern Oil In Place Calculation

Pattern 15-23-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)
9-23-1-26 WPM	0.840	69839
10-23-1-26 WPM	0.577	47953
14-23-1-26 WPM	0.462	38362
15-23-1-26 WPM	0.589	48936
16-23-1-26 WPM	1.234	102545
1-26-1-26 WPM	1.222	101561
2-26-1-26 WPM	1.041	86561
3-26-1-26 WPM	0.598	49674
Total:	6.563	545431

$$OOIP = \frac{10000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A=16ha, Sw=0.40, Boi=1.155 Rm^3/m^3

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Offset Pattern Oil In Place Calculation

Pattern 7-24-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)
1-24-1-26 WPM	0.373	30985
2-24-1-26 WPM	0.536	44510
3-24-1-26 WPM	0.749	62216
6-24-1-26 WPM	0.618	51396
7-24-1-26 WPM	0.695	57789
8-24-1-26 WPM	0.541	45002
9-24-1-26 WPM	0.524	43526
10-24-1-26 WPM	0.450	37379
11-24-1-26 WPM	0.663	55084
Total:	5.149	427887

$$OOIP = \frac{10000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A=16ha, Sw=0.40, Boi=1.155 Rm^3/m^3

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Offset Pattern Oil In Place Calculation

Pattern 13A-24-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)
9-23-1-26 WPM	0.840	69839
16-23-1-26 WPM	1.234	102545
11-24-1-26 WPM	0.426	35411
12-24-1-26 WPM	0.663	55084
13-24-1-26 WPM	1.231	102299
14-24-1-26 WPM	0.595	49428
3-25-1-26 WPM	0.917	76233
4-25-1-26 WPM	0.843	70085
1-26-1-26 WPM	1.222	101561
Total:	7.971	662485

$$OOIP = \frac{10000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A=16ha, Sw=0.40, Boi=1.155 Rm^3/m^3

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Offset Pattern Oil In Place Calculation

Pattern 15-24-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)
9-24-1-26 WPM	0.524	43526
10-24-1-26 WPM	0.450	37379
11-24-1-26 WPM	0.426	35411
14-24-1-26 WPM	0.595	49428
15-24-1-26 WPM	0.784	65167
16-24-1-26 WPM	0.589	48936
1-25-1-26 WPM	0.728	60494
2-25-1-26 WPM	1.743	144842
3-25-1-26 WPM	0.917	76233
Total:	6.756	561416

$$OOIP = \frac{10000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A=16ha, Sw=0.40, Boi=1.155 Rm^3/m^3

November 15, 1990

The Oil and Natural Gas Conservation Board
Ian Haugh, Chairman
H. Clare Moster, Deputy Chairman
Wm. McDonald, Member

John N. Fox
Chief Petroleum Engineer
Petroleum Branch

RE: Waskada Unit No. 4
Application for Special Drilling Spacing Units

Omega Hydrocarbons Ltd. has addressed all the questions listed in the Board's deficiency letter regarding the application (October 25, 1990). Before the Petroleum Branch begins its detailed technical review of the application, it is recommended that notice of the application be published. Attached is a copy of the proposed Board notice.

It is recommended that the notice be,

(1) published in the Melita New Era, Deloraine Times and Star and the Manitoba Gazette, and

(2) sent directly to

  (a) the surface owners in the project area,
  (b) the working interest and royalty owners in Waskada Unit No. 4,
  (c) the working interest and royalty owners adjacent to the project area,
  (d) major operators in the Waskada Field - Enron, Chevron and Tundra, and
  (e) The Surface Rights Association.

ORIGINAL SIGNED BY
JOHN N. FOX

John N. Fox

Att'd.

Approved: ______________________________
L.R. Dubreuil, Director

Manitoba

The Oil and Natural Gas
Conservation Board

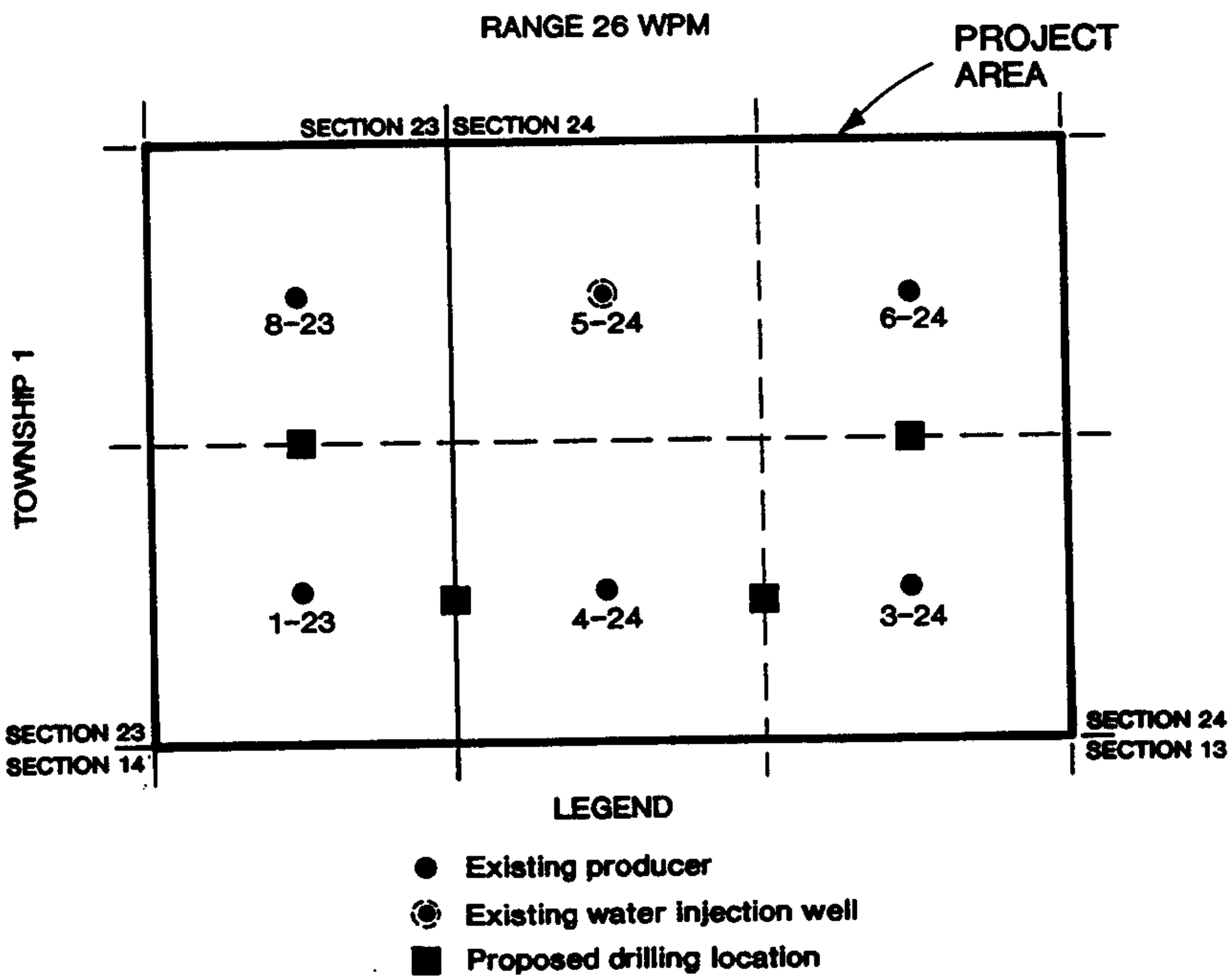
Room 309
Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

(204) 945-3130

NOTICE

UNDER THE MINES ACT

Omega Hydrocarbons Ltd., Operator of Waskada Unit No. 4 ("the unit"), has made application under Section 20 of The Petroleum Drilling and Production Regulation for approval of special drilling spacing units in a portion of the unit ("the project area") outlined below. If the application is approved, it is proposed to drill four (4) wells at the approximate locations shown.



If no intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C 0V8 on or before December 14, 1990, the Board may approve the application.

Copies of the application may be obtained from:

Omega Hydrocarbons Ltd.
1300 Sun Life Plaza III
112-4th Avenue S.W.
Calgary, Alberta
T2P 0H3
1-800-661-9257

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue
Winnipeg, Manitoba
(204) 945-6577

Waskada, Manitoba
(204) 673-2472

Dated at Winnipeg, this 15th day of November, 1990.

H. Clare Moster
Deputy Chairman

OMEGA
HYDROCARBONS LTD

1300 SUN LIFE PLAZA III
112 - 4th AVENUE S W
CALGARY, ALBERTA, CANADA T2P 0H3

TELEPHONE (403) 261-0743
FAX (403) 264-5691

November 7, 1990

The Oil and Natural Gas
Conservation Board
Room 309 Legislative Building
Winnipeg, Manitoba
R3C 0V8

Attention: Dr. Ian Haugh
Chairman

Dear Sir:

Re: Waskada Lower Amaranth A Pool
Application for Drilling Spacing Unit Reduction

Omega Hydrocarbons Ltd., as operator of Waskada Unit No. 4, submits the following supplementary information to our application of 1990-09-28 for a reduced spacing pilot project. This information is in response to the Board's letter of 1990-10-25 outlining concerns and questions regarding the subject application.

The Board's concern with respect to the use of 4 ha spacing is acknowledged. It is not our company's intent to fully develop the project area on 4 ha spacing but to only drill between existing producers to contact unswept oil. Within the pilot project area this infill drilling strategy results in four (4) well locations. For the purpose of clarification Omega requests that is previous application be revised to read "special reduced drilling spacing units with a drilling target area centered on a point equivalent from the existing production wells". Enclosed is a revised diagram of the proposed drilling spacing units.

Waterflood Performance

a) Water injection into well 5-24-1-26 WPM was temporarily terminated during the periods August 1986 to March 1987 and November 1988 to February 1990 to prevent premature water breakthrough from detrimentally effecting ultimate oil recovery. The net result of suspending injection has been to lengthen the time required to achieve ultimate waterflood recovery within the pattern. As can be seen from the production/injection plots enclosed, only well 8-23LAm-1-26 WPM shows a decrease in total fluid production during the periods in question. Erratic production at the other pilot project area wells is a result of production equipment problems rather than a lack of pressure maintenance.

b) During 1988 and 1989 Omega's geological and reservoir engineering staff conducted a complete review of all its Waskada operated wells using computer assisted log interpretation software. The purpose of this review was to investigate why discrepancies between ϕh values calculated using the log overlay technique and well productivity existed. Our findings showed that the original method of determining ϕh values used total porosity rather than an effective porosity corrected for shale content. On a field average basis the revised ϕh values are approximately half the original ϕh values. These modifications do not effect the recoverable oil reserves determined by decline curve analysis, however, they do reduce previously determined oil in place volumes.

c) Enclosed is a technical reference titled, "The Stress Regime of the Western Canadian Basin and Implications for Hydrocarbon Production", which indicates that a predominant NE-SW fracture orientation exists throughout Western Canada. No fracture orientation or insitu fracture studies have been conducted in Waskada, however, all Lower Amaranth wells have been fracture stimulated. As illustrated in Figure 10 of this reference an induced fracture system within a waterflood can detrimentally effect areal sweep efficiency. The infill wells for the pilot project area have been located between suspected fracture planes.

d) In the 1985 reservoir model study the northern half of Section 25-1-26 WPM was included in a one half LSD border surrounding injection pattern 13-24LAm-1-26 WPM. The border area in the simulation study was used to mitigate edge effects and to establish a no flow boundary around the main pattern area being modeled, for these reasons performance at the wells in border areas must reviewed cautiously. Model study performance at wells 9-23-1-26, 11-24-1-26 and 12-24-1-26 WPM is considered reliable since they are included in both injection patterns 5-24-1-26 and 13-24LAm-1-26 WPM. A comparison of cumulative oil recovery to date and final predicted oil saturations at these wells are in good agreement; both indicators show higher cumulative oil recoveries from wells 9-23-1-26 and 12-24-1-26 WPM than well 11-24-1-26 WPM.

Technical Justification

a) The recovery mechanism which accounts for an estimated incremental recovery of 3.3% for the pilot project area is the drainage of unswept portions of the reservoir. Omega is of the opinion that adverse reservoir hetrogeneities exist within the pilot project area and that infill drilling is the optimum method of recovering oil from the unswept areas.

b) The conversion of the existing 16 ha nine-spot patterns to 16 ha five-spot patterns could be accomplished by converting the 4 existing corner producers to injectors. Economically this alternative would have the least capital cost ($25,000/well) given the existing facilities, however, it has the detrimental impact of instanteously reducing pattern productivity. Technically this alternative is risky based on the fact that no significant increase in oil productivity has been observed within the existing pressure maintenance project areas on 16 ha spacing.

Converting the existing 16 ha nine-spot patterns to 8 ha nine-spot patterns is accomplished by drilling 4 infill producers and converting the 4 existing corner producers to injectors. Assuming the same pilot project area size this alternative would cost approximately $365,000 versus the proposed pilot project cost of $624,000. Again the capital cost savings do not offset the technical risks involved with drilling inside the theoretical production streamlines for the existing 16 ha nine-spot pattern. Field experience, as in the case of the North Virden Scallion Unit No. 1, has shown that infill producers drilled between existing injector-producer pairs are poor infill well locations.

Modifying the existing 16 ha nine-spot patterns to 8 ha five-spot patterns combines the previously discussed technical risks of the first two alternatives. Specifically, it assumes the conversion of all existing producers to injectors and positions the 4 infill wells between existing injector-producer pairs. Economically and technically this alternative is unacceptable.

All three of the waterflood modification alternatives suggested by the Board assume that the trapped oil saturation areas can be mobilized by reversing the original production streamlines. Theoretical calculations and field experience have shown that this method of improving oil recovery is most successful in homogeneous type reservoirs. Based on historical pressure data and watercut performance to date in the Waskada Lower Amaranth reservoir the movement of the injected water bank is being influenced both by low reservoir permeability (slow flood front advance) and an induced fracture system (rapid flood front advance). Given these reservoir complexities Omega contends that the Lower Amaranth reservoir is heterogeneous in nature and that an irregular injection scheme is more appropriate. In support of its strategy refer to the technical papers titled, "A Modelling Approach for Optimizing Waterflood Performance, Slaughter Field Chickenwire Pattern" and "Revitalization of the Pembina Field".

c) The proposed pilot project area was selected primarily due to its above average reservoir quality, if this criteria were expanded fieldwide it would encompass approximately one quarter of the Waskada field. Based on a preliminary evaluation Omega considers the following areas amenable to infill drilling; Waskada Lower Amaranth Unit No.1 , Waskada Unit No. 4 and Waskada Unit No. 8.

If full development on reduced spacing were to occur the correlative rights of those locations on or adjacent to existing Unit boundaries would need to be protected. This could be accomplished by either combining existing Units or by an equitable sharing of the production from such wells between the Units effected. No infill wells in this situation would be drilled prior to resolving the correlative rights issue.

d) If the proposed pilot project is successful and the area of reduced spacing was expanded, Omega's primary initiative would be to continue drilling infill producers. In certain portions of the reservoir this strategy could result in a maximum of eight (8) infill well locations per existing injection pattern. Based on the predicted production rates for the infill wells Omega does not anticipate the need for additional injection wells to maintain reservoir voidage. If supplemental pressure support were to be required a line drive type waterflood could be implemented.

e) The existing pressure maintenance strategy within the above average reservoir quality areas consists of maintaining a reservoir pressure equal to 9000 kPa and a cumulative voidage replacement ratio of approximately 1.0; this strategy will remain the same after the completion of the infill wells. Due to the previously discussed suspension of water injection in pattern 5-24-1-26 WPM the current target injection rates have been increased to achieve the desired reservoir pressure and cumulative voidage replacement ratio. Following the implementation of the pilot project production from the infill wells will be added into the monthly voidage calculations and compensated for in the injection target rates at wells 13-13-1-26, 7-23-1-26, 5-24-1-26 and 7-24-1-26 WPM.

f) The incremental production forecast for the proposed infill wells assumes no production acceleration or production interference. Omega has based this production forecast on the performance of other infill well projects which are discussed in the technical literature. Actual performance of the Waskada infill well pilot project will confirm or deny these forecast assumptions.

Project Evaluation Program

a) In order to correlate with existing wells Omega plans to conduct the following logging program at the infill wells;

	Scale (SI)	Interval
Dual Induction Log (DIL-SFL)	1:600	TD to surface casing
	1:240	TD to 750 m
Sonic Log (BHCS-GR)	1:240	TD to 750m 300-100us/m
	1:240	TD to 750m 500-100us/m

No special cores or drill stem tests are planned during the drilling operations.

b) Following the implementation of the pilot project the infill wells will be produced to lease tanks to obtain accurate daily fluid production and watercuts. The existing wells within injection pattern 5-24-1-26 WPM are currently tied in and will continue to be satellite tested on average twice per month. Surface injection pressures and injection volumes will be measured on a daily basis at well 5-24-1-26 WPM. The annual injection well fall off testing program will continue to be performed in and surrounding the pilot project area.

c) Omega intends to conduct additional reservoir pressure measurements at the existing production wells and the infill wells within the pilot project area to assess reservoir pressure support. A regular fluid level monitoring program is also planned for the pilot project area to ensure that total fluid productivity is maximized.

General

a) The holiday oil volume incentives for the infill wells were omitted in the previously submitted pilot project economics. Based on an estimated oil price of $\$135.67/m^3$ at spud date the holiday oil volume per infill well is approximately 1375 m^3 which would be equivalent to a $28,500 reduction in Crown royalties and freehold production taxes. Enclosed is a revised copy of the pilot project economics including the holiday oil volume incentives.

Omega does not use an economic hurdle rate to assess project viability instead discounted net present value, rate of return, payout and risk are all considered. Based on these economic parameters the infill well pilot project is economically viable, however, any negative sensitivity to the production forecast or capital cost assumptions would result in an uneconomic project.

b) The Waskada Lower Amaranth reservoir is considered an inappropriate candidate for horizontal drilling by Omega due to its vertical stratification and thin pay intervals. Directional drilling is technically feasible in the Waskada field and would have the advantage of reducing the impact to surface lands. But as presented in our application this alternative has the disadvantage of increasing capital and operating costs for the pilot project, which as yet is unproven in its ability to recovery incremental oil.

c) Omega has the understanding that the Board will be publically advertising its application for special reduced drilling spacing units. Subject to the inquiries received during the advertisement period Omega would consider holding a public meeting if in the opinion of the Board it could avoid a public hearing.

d) Enclosed is a list of names and addresses for the working interest owners and royalty owners in Waskada Unit No. 4 and within one kilometre of the pilot project area. It should be noted that Omega has purchased Sabre Energy Ltd.'s working interest in Waskada Unit No. 4 and that amendments to the Unit documents will be forthcoming.

We trust that the information contained herein meets your requirements.

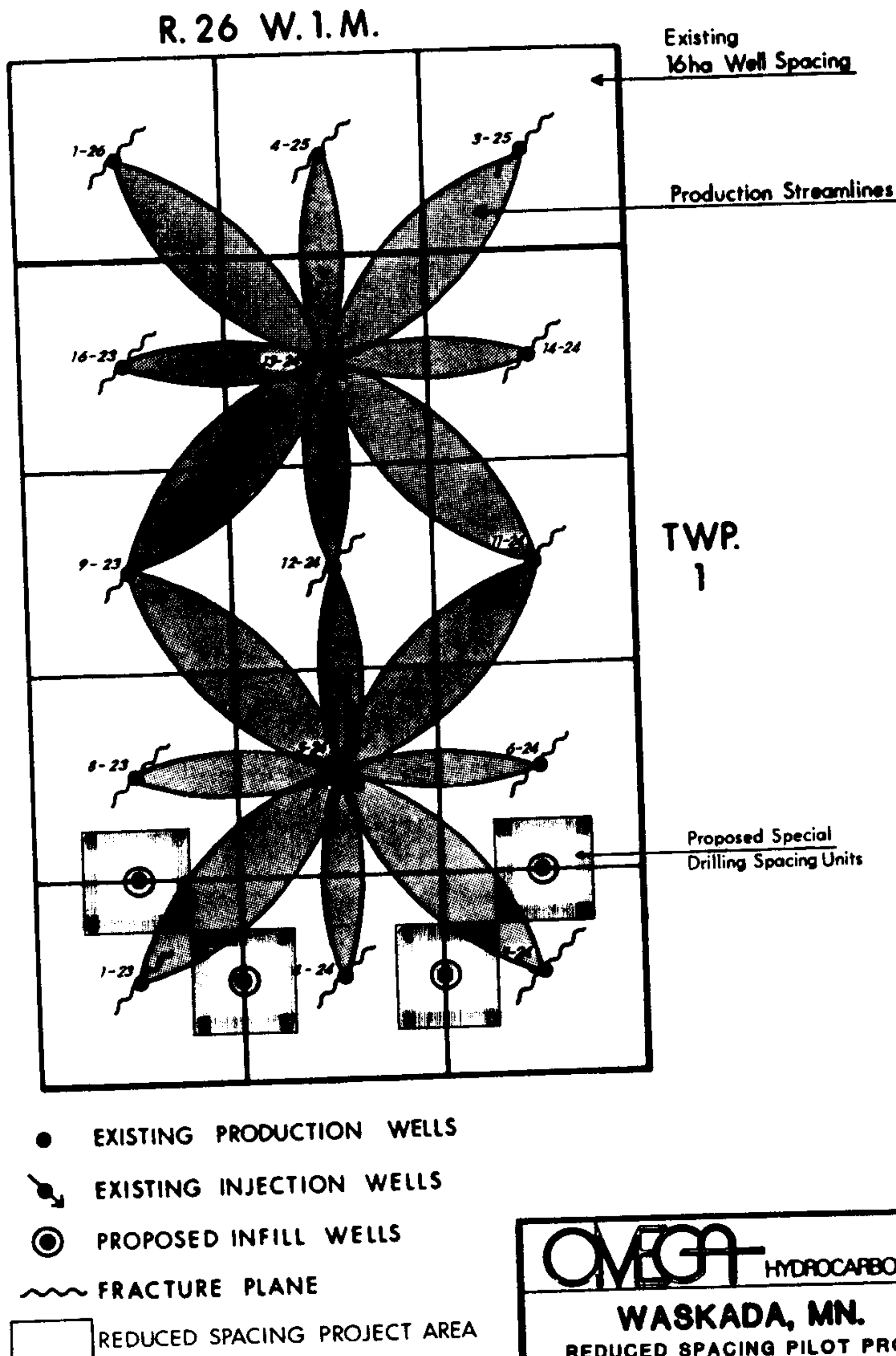
Yours truly,

OMEGA HYDROCARBONS LTD.

G.A. Cormack
Manager, Production Operations

RAB/jb
c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Waskada Reduced Spacing Unit Application File

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
PROPOSED DRILLING SPACING UNITS



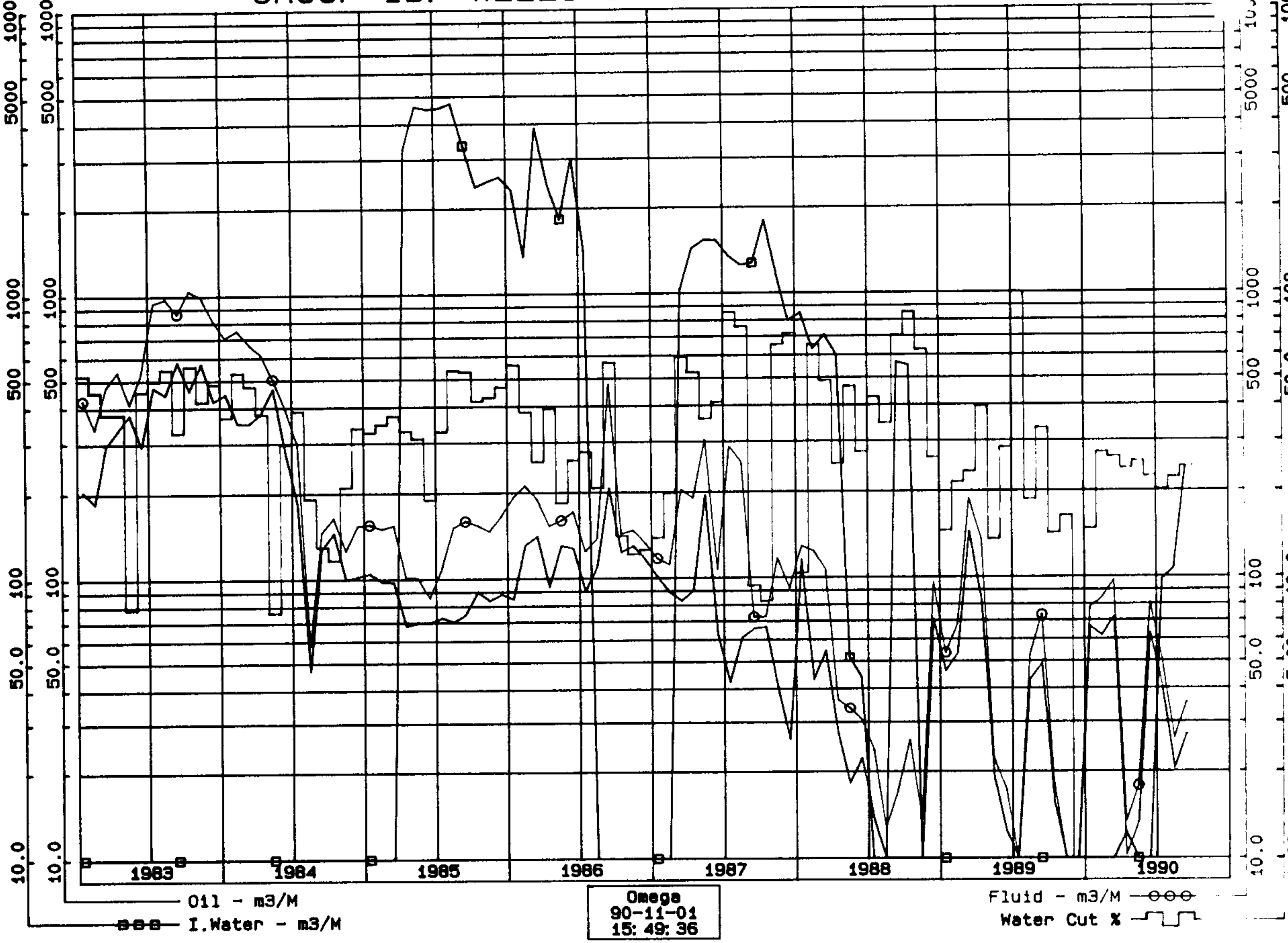
OMEGA HYDROCARBONS LTD.

WASKADA, MN.

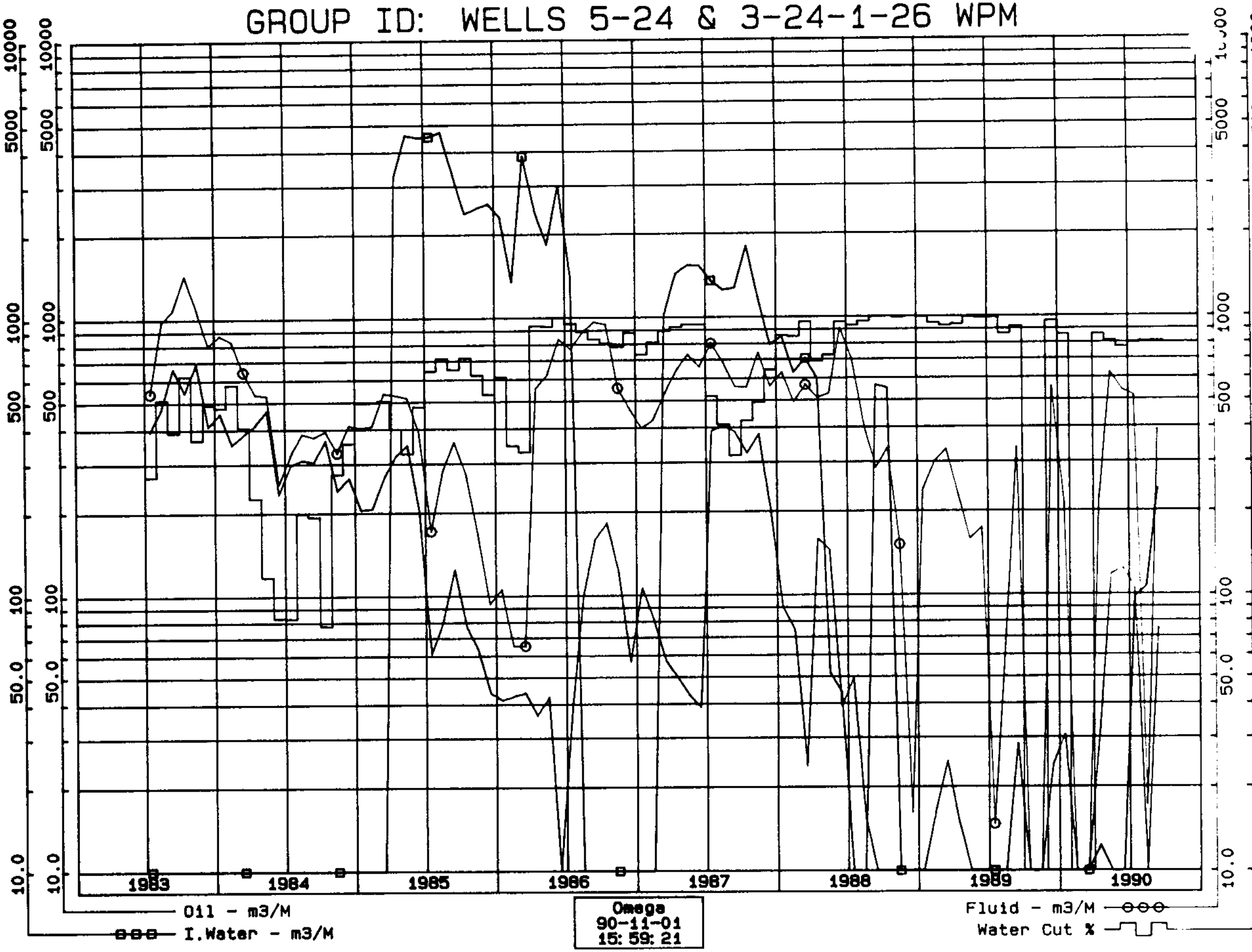
REDUCED SPACING PILOT PROJECT

Scale: Not to Scale	Date: AUG. '90
Geology: R. B.	Contour Interval:
Revised:	File: Drafting:

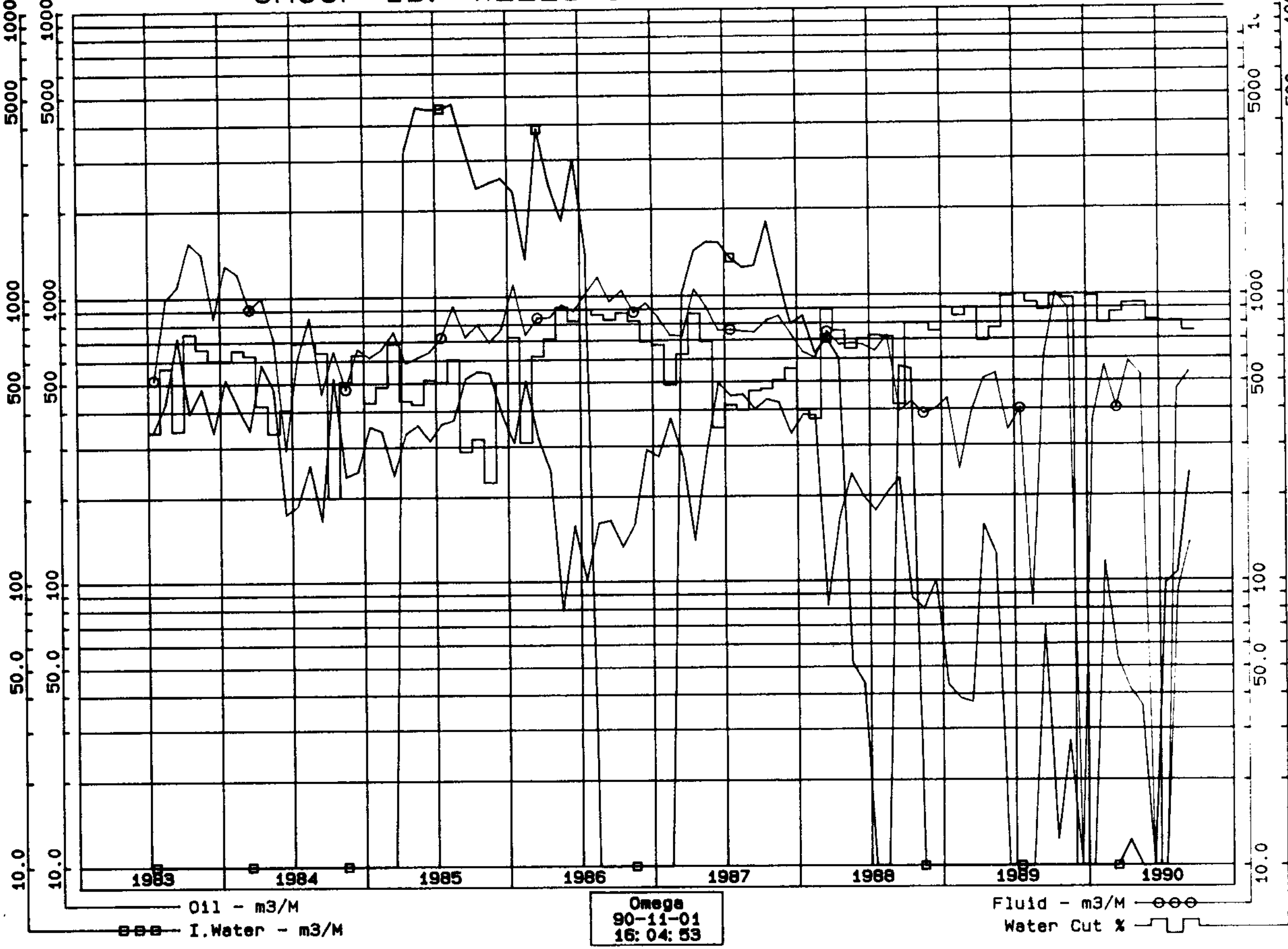
GROUP ID: WELLS 5-24 & 1-23-1-26 WPM

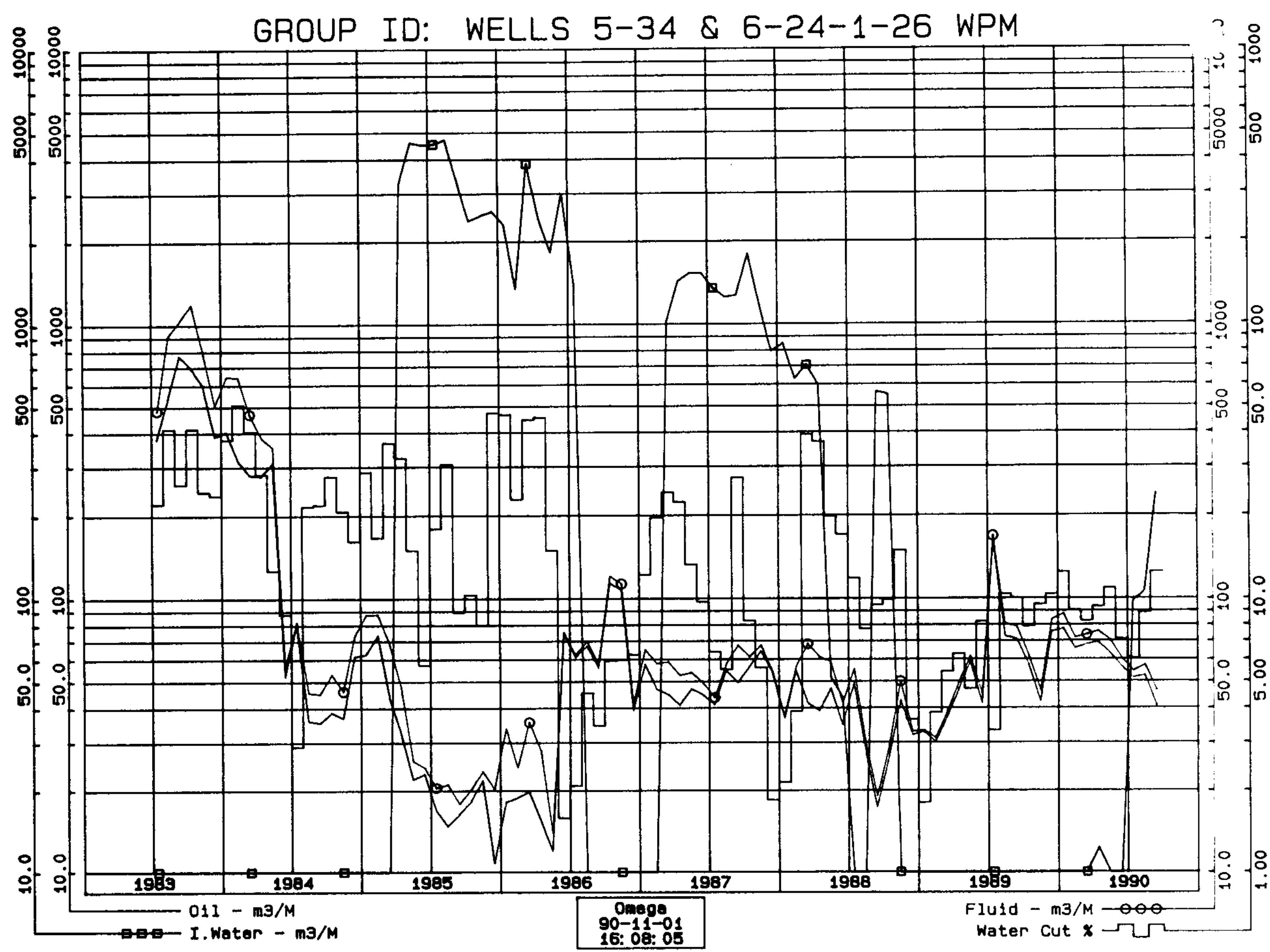


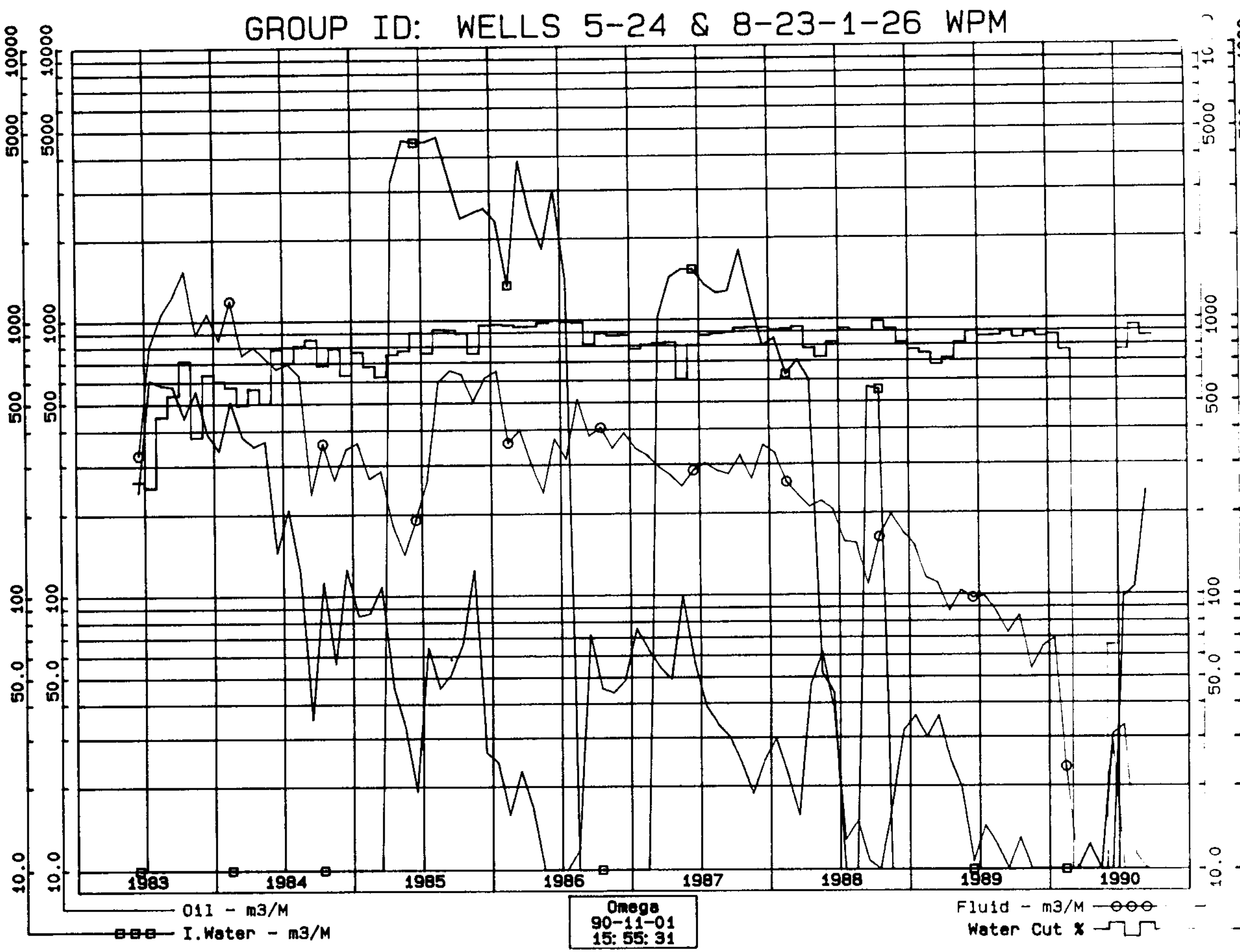
GROUP ID: WELLS 5-24 & 3-24-1-26 WPM



GROUP ID: WELLS 5-24 & 4-24-1-26 WPM




GROUP ID: WELLS 5-34 & 6-24-1-26 WPM
10000
5000
1000
500
100
50.0
10.0
1000
500
100
50.0
10.0
1.00
1983
1984
1985
1986
1987
1988
1989
1990
Oil - m3/M
I.Water - m3/M
Omega
90-11-01
16:08:05
Fluid - m3/M
Water Cut %


GROUP ID: WELLS 5-24 & 8-23-1-26 WPM
10000
5000
1000
500
100
50.0
10.0
1983
1984
1985
1986
1987
1988
1989
1990
Oil - m3/M
I.Water - m3/M
Omega
90-11-01
15:55:31
Fluid - m3/M
Water Cut %

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
Time: 90/11/06 21:26:12
File:

----- --------- CASE DESCRIPTION ----------------------

WASKADA INFILL DRILLING EVALUATION (PATTERN 5-24)
DRILL 4 WELL PILOT, ASSUMES 1990 D&S PRICE FORECST
1990 OPCOSTS:$1250/M,TREAT:$1.75/M3,TRUCK:$3.73/M3,ESC@5%/YR
(INCLUDES HOLIDAY OIL VOLUME INCENTIVES)

Royalty Regime:	MANITOBA	Gas Holiday:	NO
Reserve type:	Prov Devel	Oil Holiday:	NO
Royalty Type:Crwn	Frhd	Eval/Prod Start:	91- 1/91- 1
Sensitivity:	NO	Proj/Econ Life:	12.0/12.0 yrs

-------------- NET PRESENT VALUES (M$) ---------------

DISC RATE (%)	0.0	10.0	15.0	20.0	25.0	30.0
B.T. OPER INC	1526	1075	933	824	738	669
B.T. CAP INV.	624	624	624	624	624	624
B.T. CASH FLOW	902	451	309	200	114	45
A.T. OPER INC	1274	921	808	721	651	595
A.T. CAP INV.	624	624	624	624	624	624
A.T. CASH FLOW	650	297	184	97	27	-29

--------- ECONOMIC INDICATORS ---------

		B.TAX	A.TAX
ROR	- PCNT	33.9	27.3
PAYOUT PERIOD	- EVAL	2.8	3.1
	- CAPTL	2.8	3.1
UNDISC PIR	- $/$	1.45	1.04
15.0 PCT PIR	- $/$	0.50	0.30
30.0 PCT PIR	- $/$	0.07	-0.05
NPV @ 15.0	- $/m3	18.99	11.31
NPV @ 30.0	- $/m3	2.77	-1.78

----------- PRODUCTS RECOVERY -------------

		GROSS	WI	ROY	NET
OIL	E3m3	16	16	2	14
GAS-RAW	E3m3	0	0		
GAS-SALES	E3m3	0	0	0	0
ETHANE	m3	0	0	0	0
PROPANE	m3	0	0	0	0
BUTANE	m3	0	0	0	0
CONDENS.	m3	0	0	0	0
SULPHUR	t	0	0	0	0
OTHER	m3	0	0	0	0

--------- COMPANY W.I. --------

	Init%	Avr%	Rev%
REVENUE	100.0	100.0	
FIELD CAP	100.0	0.0	
PLANT CAP			
GATH CAP			
ORR-GAS			
ORR-OIL			
ROYALTY	12.8	13.1	

-- WI CASH FLOW SUMMARY --

YEAR	-----OIL	PRODUCTION---		TOTAL	--ROYALTY--		--OPERATING--		CASH	NETBACK	CAPTL	B.TAX	TOTAL	-----AFTER	TAX------	
	RATE	VOL.	PRICE	REV.	&MINTAX		EXPENSE		FLOW	B.TAX	INV.	CASH	TAX	CASH	15.0%	CUM
	m3/d	E3m3	$/m3	M$	M$	%	M$	$/m3	M$	$/m3	M$	M$	M$	M$	M$	M$
ZERO											624	-624	0	-624	-624	-624
1991	7	3	135.67	370	47	13	79	28.86	244	89.48	0	244	3	241	224	-400
1992	6	2	148.01	347	44	13	80	34.26	222	94.81	0	222	17	205	166	-234
1993	6	2	161.48	325	46	14	82	40.80	197	97.92	0	197	28	169	119	-114
1994	5	2	176.14	305	41	13	84	48.73	180	104.00	0	180	33	147	90	-24
1995	4	1	192.18	286	38	13	87	58.37	162	108.64	0	162	35	126	67	43
1996	4	1	203.70	261	34	13	90	70.09	137	107.00	0	137	33	104	48	92
1997	3	1	215.97	238	31	13	93	84.29	114	103.53	0	114	29	85	34	126
1998	3	1	228.93	217	28	13	96	101.57	93	97.58	0	93	25	68	24	150
1999	2	1	242.65	198	26	13	100	122.67	72	88.47	0	72	20	52	16	165
2000	2	1	257.19	180	23	13	104	148.29	53	75.54	0	53	15	38	10	176
2001	2	1	272.61	164	21	13	108	179.49	35	57.80	0	35	10	25	6	181
2002	1	1	288.97	150	19	13	113	217.78	18	33.79	0	18	4	13	3	184
SUBT		16		3042	399		1116		1526		624	902	252	650	184	
REM.		0		0	0		0		0		0	0	0	0	0	
TOTL		16		3042	399		1116		1526		624	902	252	650	184	
15.0% DISC				1664	218		513		933		624	309	125	184		
% OF REV.				100	13		31		56		37	19	8	11		

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
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File:

Comment: FAS INFILL DRILLING EVALUATION (PATTERN 5-24)

- ECONOMIC INDICATORS AT POS = 0.0 -----			
ROR	- PCNT	0.0	0.0
PAYOUT PERIOD	- YEARS	0.0	0.0
	- CAL.YEAR	1991.0	1991.0
UNDISC PIR	- $/$	-100.00	-54.16
15.0 PCT PIR	- $/$	-100.00	-57.25
30.0 PCT PIR	- $/$	-100.00	-59.80

Net capital exposure = 424 M$

BREAK EVEN PROBABILITY OF SUCCESS

Disc Rate [%]	15.0	30.0
B.Tax BECOS [%]	57.8	90.4
A.Tax BECOS [%]	56.9	112.9

===================================== RISK ANALYSIS =====================================

	BEFORE TAX						AFTER TAX					
Prob of Success %	ROR %	15% DCF M$	30% DCF M$	Payout Yrs	15% Payout Yrs	15% PIR %	ROR %	15% DCF M$	30% DCF M$	Payout Yrs	15% Payout Yrs	15% PIR %
0	0.0	-424	-424	0.00	0.00	-100	0.0	-243	-254	0.00	0.00	-57
0	0.0	-424	-424	0.00	0.00	-100	0.0	-243	-254	0.00	0.00	-57
10	0.0	-351	-377	0.00	0.00	-79	0.0	-200	-231	0.00	0.00	-45
20	0.0	-277	-330	0.00	0.00	-60	0.0	-157	-209	0.00	0.00	-34
30	0.0	-204	-283	0.00	0.00	-42	2.5	-115	-186	8.28	0.00	-24
40	5.1	-131	-236	7.04	0.00	-26	7.9	-72	-164	5.77	0.00	-14
50	10.8	-58	-189	5.31	0.00	-11	12.3	-29	-141	4.73	0.00	-6
60	16.1	16	-143	4.39	8.97	3	16.1	13	-119	4.12	8.77	2
70	21.0	89	-96	3.79	5.98	16	19.4	56	-96	3.73	6.36	10
80	25.5	162	-49	3.37	4.84	28	22.4	99	-74	3.45	5.36	17
90	29.8	236	-2	3.04	4.16	39	25.0	141	-51	3.24	4.76	23
100	33.9	309	45	2.80	3.70	50	27.3	184	-29	3.06	4.36	30

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
Time: 90/11/06 21:27:23
File:
Report: peeproy

Comment: WAS : INFILL DRILLING EVALUATION (PATTERN 5-24)

WORKING INTEREST CROWN ROYALTIES, MINERAL TAX AND OTHER ROYALTIES

	CROWN ROYALTIES AND MINERAL TAX										OTHER ROYALTIES			
Year	Oil Crown Royalty M$	Gas Crown Royalty M$	Cond Crown Royalty M$	Propane Crown Royalty M$	Butane Crown Royalty M$	Sulphur Crown Roylaty M$	Ethane Crown Royalty M$	Other Prod. Crown Royalty M$	Man Sched Crown Royalty M$	Frhld Mineral Tax M$	Frhld Royalty M$	Oil Over-Riding Royalty M$	Gas Over-Riding Royalty M$	Net Profit Inter. M$
1991	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47.2	0.0	0.0	0.0
1992	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.4	0.0	0.0	0.0
1993	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	41.7	0.0	0.0	0.0
1994	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	39.1	0.0	0.0	0.0
1995	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.7	0.0	0.0	0.0
1996	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.5	0.0	0.0	0.0
1997	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.6	0.0	0.0	0.0
1998	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.9	0.0	0.0	0.0
1999	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.4	0.0	0.0	0.0
2000	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.2	0.0	0.0	0.0
2001	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.1	0.0	0.0	0.0
2002	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.2	0.0	0.0	0.0
12.0	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	389.9	0.0	0.0	0.0
[illegible]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.0	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	389.9	0.0	0.0	0.0

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
Time: 90/11/06 21:39:04
File:
Report: newbtax

Comment: WA \ INFILL DRILLING EVALUATION (PATTERN 5-24)

WORKING INTEREST BEFORE TAX REPORT

Year	Total Revenue M$	Initial Crown/ Manual Royalty M$	Final Crown/ Manual Royalty M$	ORR/ Frhld Royalty M$	Mineral Tax M$	Revenue After Royalty M$	Other Inc & ARTC M$	Total Oper Cost M$	Other Exp & NPI M$	Oper Income M$	Total Intang Capital M$	Total Tang. Capital M$	Total Capital M$	Cash Flow Before Tax M$
											568	56	624	
1991	370	2	0	47	0	322	0	79	0	244	0	0	0	-380
1992	347	1	0	44	0	302	0	80	0	222	0	0	0	222
1993	325	1	1	42	3	280	0	82	0	194	0	0	0	197
1994	305	1	1	39	0	265	0	84	0	180	0	0	0	180
1995	286	1	1	37	0	249	0	87	0	162	0	0	0	162
1996	261	1	1	33	0	227	0	90	0	137	0	0	0	137
1997	238	0	0	31	0	207	0	93	0	114	0	0	0	114
1998	217	0	0	28	0	189	0	96	0	93	0	0	0	93
1999	198	0	0	25	0	172	0	100	0	72	0	0	0	72
2000	180	0	0	23	0	157	0	104	0	53	0	0	0	53
2001	164	0	0	21	0	143	0	108	0	35	0	0	0	35
2002	150	0	0	19	0	130	0	113	0	18	0	0	0	18
12.0	3042	9	5	390	4	2643	0	1116	0	1523	568	56	624	902
[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12.0	3042	9	5	390	4	2643	0	1116	0	1523	568	56	624	902

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
Time: 90/11/06 21:39:24
File:
Report: peepat

Comment: WA' , INFILL DRILLING EVALUATION (PATTERN 5-24)

WORKING INTEREST AFTER TAX DATA

Year	Resorc Income M$	Resorc Allow M$	Land& Dev Bal M$	Land& Dev Depr M$	Expl Bal M$	Expl Depr M$	Tang Bal M$	Tang Depr M$	Plant &Gath Bal M$	Plant &Gath Depr M$	Fed Taxbl Income M$	Fed Tax M$	Prov Taxbl Income M$	Prov Tax M$	Inv Credit M$	Total Tax M$	Cash Flow M$
1991	237	59	568	170	0	0	56	7	0	0	7	2	7	1	0	3	-383
1992	210	52	398	119	0	0	49	12	0	0	38	11	38	6	0	17	205
1993	192	48	278	83	0	0	37	9	0	0	61	18	61	10	0	28	169
1994	175	44	195	58	0	0	28	7	0	0	73	21	73	12	0	33	147
1995	157	39	136	41	0	0	21	5	0	0	77	22	77	13	0	35	126
1996	134	33	95	29	0	0	16	4	0	0	72	21	72	12	0	33	104
1997	112	28	67	20	0	0	12	3	0	0	64	18	64	11	0	29	85
1998	91	23	47	14	0	0	9	2	0	0	54	16	54	9	0	25	68
1999	71	18	33	10	0	0	7	2	0	0	43	12	43	7	0	20	52
2000	52	13	23	7	0	0	5	1	0	0	32	9	32	5	0	15	38
2001	34	9	16	5	0	0	4	1	0	0	21	6	21	4	0	10	25
2002	17	4	11	3	0	0	3	1	0	0	9	3	9	2	0	4	13
12.0	1481	370		560		0		54		0	551	159	551	94	0	252	650
0.0	0	0		0		0		0		0	0	0	0	0	0	0	0
)	1481	370		560		0		54		0	551	159	551	94	0	252	650

Working Interest Owners
Within One Kilometer of the Pilot Project Area

Waskada Unit No. 4

Omega Hydrocarbons Ltd.
1300, 112-4th Ave. S.W.
Calgary, Alberta
T2P 0H3

Sabre Energy Ltd.
800, 1122-4th St. S.W.
Calgary, Alberta
T2R 1M1

Other

Amoco Canada Resources Ltd.
240 - 4th Avenue S.W.
Calgary, Alberta
T2P 4H4

Tundra Oil & Gas Ltd.
1313 One Lombard Place
Winnipeg, Manitoba
R3B 0X3

Enron Oil Canada Ltd.
1300, 700 - 9th Avenue S.W.
Calgary, Alberta
T2P 3V4

Royalty Interest Onwers
Within One Kilometer of the Pilot Project Area

Waskada Unit No. 1

The Canada Trust Company
230 Portage Avenue
Winnipeg, Manitoba
R3C 2S6

Dept. of Energy & Mines
Mineral Resource Division
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Que West Resources Ltd.
1110, 910 - 7th Avenue S.W.
Calgary, Alberta
T2P 3N8

PanCanadian Petroleum Limited
150 - 9th Avenue S.W.
P.O. Box 2850
Calgary, Alberta
T2P 2S5

Triton Canada Resources Ltd.
c/o Canadian Worldwide Energy Ltd.
4th Floor, 255 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

Waskada Unit No. 4

M.D. Allison
3720 Garland Street
Wheat Ridge, Colorado
U.S.A. 80033

The Canada Trust Company
230 Portage Avenue
Box 881
Winnipeg, Manitoba
R3C 2S6

Dept. of Energy & Mines
Mineral Resources Division
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

E.A. McGregor
Box 164
Waskada, Manitoba
ROM 2E0

John H. Spelliscy
14 Taggart Street
Regina, Saskatchewan
S4S 4G4

M.E. McGregor
Box 164
Waskada, Manitoba
ROM 2E0

Reston Resources Ltd.
2311 - 12th Street S.W.
Calgary, Alberta
T2T 3N7

A.I. Hainsworth
11633 - 203rd Street
Maple Ridge, B.C.
V4X 4T8

`hell Canada Resources Limited
J0 - 4th Avenue S.W.
Calgary, Alberta
T2P 2H5

Page Petroleum Ltd.
10th Floor
635 - 8th Avenue S.W.
Calgary, Alberta
T2P 3M3

Bran Van Enterprises Ltd.
240 - 1st Street
Brandon, Manitoba
R7A 5Z9

Amoco Canada Ltd.
240 - 4th Avenue S.W.
Calgary, Alberta
T2P 4H4

J.W. Hainsworth
P.O. Box 433
Deloraine, Manitoba
R0M 0M0

Petroventures Resources Ltd.
1400, 630 - 6th Avenue S.W.
Calgary, Alberta
T2P 0S8

Sceptre Resources Ltd.
2000, 400 - 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Consolidated Trans-Canada
Resources Ltd.
350, 708 - 11th Avenue S.W.
Calgary, Alberta
T2R 0E4

Other

Brosco Fund Limited
c/o Tundra Oil & Gas Ltd.
1313 One Lombard Place
Winnipeg, Manitoba
R3B 0X3

Canada Permanent Trust Co.
1778 Scarth Street
Regina, Saskatchewan

Canadian Gridoil Limited
330 - 9th Avenue S.W.
Calgary, Alberta

J.E. Hainsworth
Box 99
Waskada, Manitoba
R0M 2E0

J.W. Hainsworth
Box 433
Deloraine, Manitoba
R0M 0M0

Olive Hainsworth
Box 433
Deloraine, Manitoba
R0M 0M0

K.A. Little/A.F. Ramseyer
Box 4100
Georgetown, Ontario
L7G 4Y4

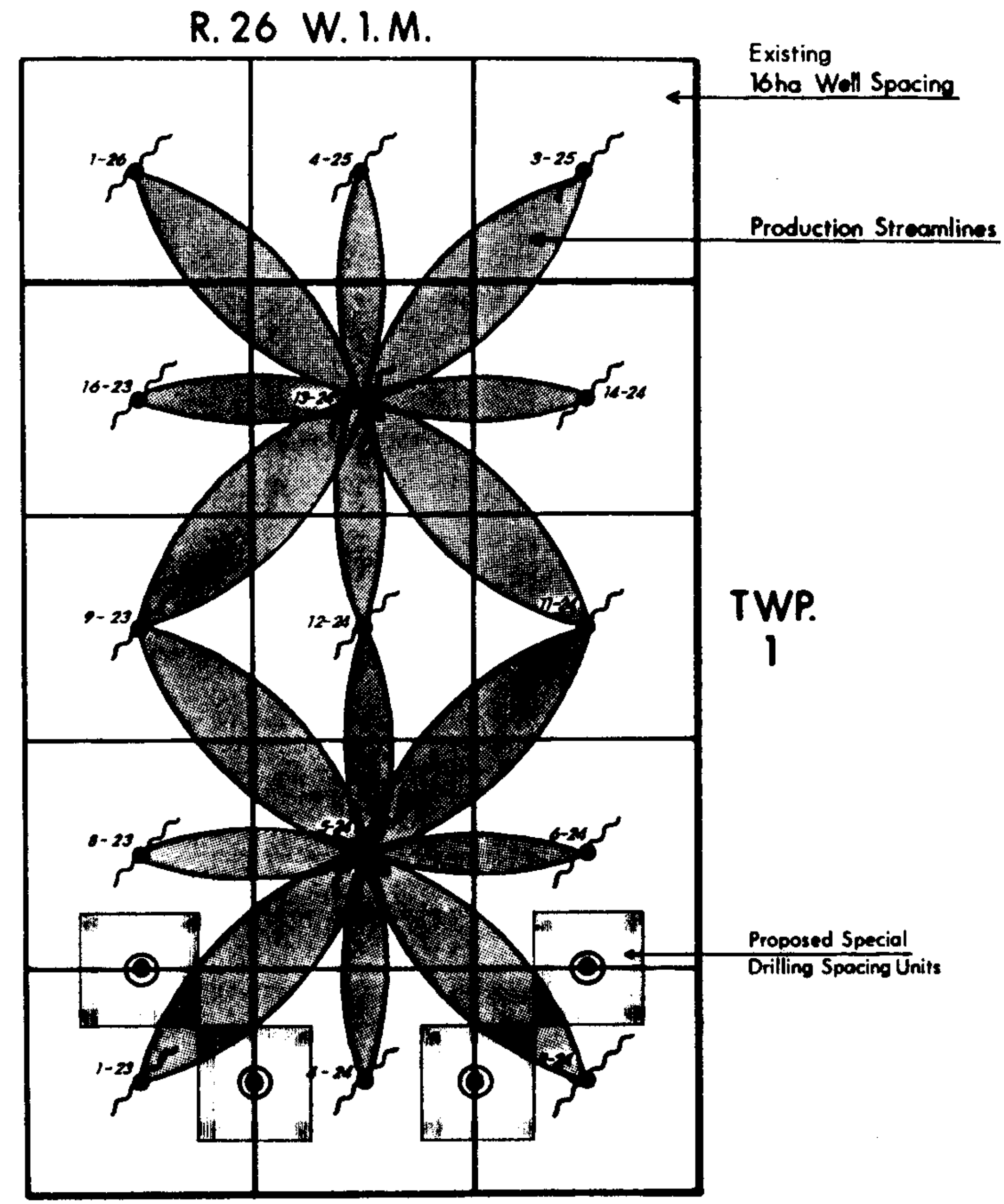
D.E. McGregor
Box 33
Waskada, Manitoba
R0M 2E0

R.J. Hainsworth
Box 99
Waskada, Manitoba
R0M 2E0

C.M. Thomas
Hartney, Manitoba
R0M 0X0

H.D. Meggison
Goodlands, Manitoba
R0M 0R0

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
PROPOSED DRILLING SPACING UNITS



- ● EXISTING PRODUCTION WELLS
- EXISTING INJECTION WELLS
- ◉ PROPOSED INFILL WELLS
- FRACTURE PLANE
- ▭ REDUCED SPACING PROJECT AREA

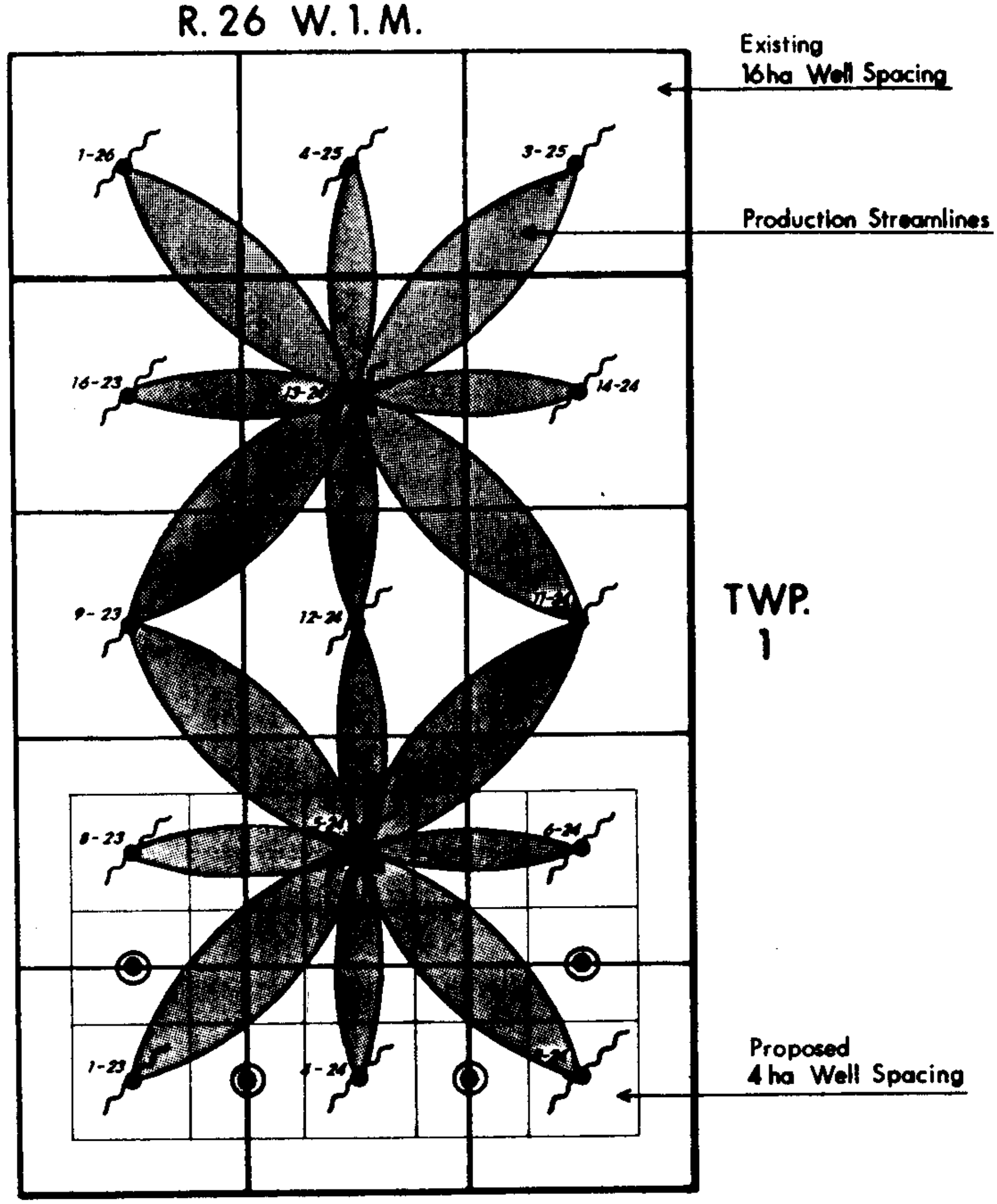
OMEGA HYDROCARBONS LTD.

WASKADA, MN.

REDUCED SPACING PILOT PROJECT

Scale: Not to Scale	Date: AUG. '90
Geology: R. B.	Contour Interval:
Revised:	File: / Drafting:

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
PROPOSED DRILLING SPACING UNITS



● EXISTING PRODUCTION WELLS

EXISTING INJECTION WELLS

PROPOSED INFILL WELLS

FRACTURE PLANE

REDUCED SPACING PROJECT AREA

OMEGA HYDROCARBONS LTD.

WASKADA, MN.

REDUCED SPACING PILOT PROJECT

Not to Scale

AUG. '90

Royalty Interest Onwers
Within One Kilometer of the Pilot Project Area

Waskada Unit No. 1

The Canada Trust Company
230 Portage Avenue
Winnipeg, Manitoba
R3C 2S6

Dept. of Energy & Mines
Mineral Resource Division
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Que West Resources Ltd.
1110, 910 - 7th Avenue S.W.
Calgary, Alberta
T2P 3N8

PanCanadian Petroleum Limited
150 - 9th Avenue S.W.
P.O. Box 2850
Calgary, Alberta
T2P 2S5

Triton Canada Resources Ltd.
c/o Canadian Worldwide Energy Ltd.
4th Floor, 255 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

Waskada Unit No. 4

M.D. Allison
3720 Garland Street
Wheat Ridge, Colorado
U.S.A. 80033

The Canada Trust Company
230 Portage Avenue
Box 881
Winnipeg, Manitoba
R3C 2S6

Dept. of Energy & Mines
Mineral Resources Division
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

E.A. McGregor
Box 164
Waskada, Manitoba
R0M 2E0

John H. Spelliscy
14 Taggart Street
Regina, Saskatchewan
S4S 4G4

M.E. McGregor
Box 164
Waskada, Manitoba
R0M 2E0

Reston Resources Ltd.
2311 - 12th Street S.W.
Calgary, Alberta
T2T 3N7

A.I. Hainsworth
11633 - 203rd Street
Maple Ridge, B.C.
V4X 4T8

ıell Canada Resources Limited
400 - 4th Avenue S.W.
Calgary, Alberta
T2P 2H5

Page Petroleum Ltd.
10th Floor
635 - 8th Avenue S.W.
Calgary, Alberta
T2P 3M3

Bran Van Enterprises Ltd.
240 - 1st Street
Brandon, Manitoba
R7A 5Z9

Amoco Canada Ltd.
240 - 4th Avenue S.W.
Calgary, Alberta
T2P 4H4

J.W. Hainsworth
P.O. Box 433
Deloraine, Manitoba
R0M 0M0

Petroventures Resources Ltd.
1400, 630 - 6th Avenue S.W.
Calgary, Alberta
T2P 0S8

Sceptre Resources Ltd.
2000, 400 - 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Consolidated Trans-Canada
Resources Ltd.
350, 708 - 11th Avenue S.W.
Calgary, Alberta
T2R 0E4

Other

Brosco Fund Limited
c/o Tundra Oil & Gas Ltd.
1313 One Lombard Place
Winnipeg, Manitoba
R3B 0X3

Canada Permanent Trust Co.
1778 Scarth Street
Regina, Saskatchewan

Canadian Gridoil Limited
330 - 9th Avenue S.W.
Calgary, Alberta

J.E. Hainsworth
Box 99
Waskada, Manitoba
R0M 2E0

J.W. Hainsworth
Box 433
Deloraine, Manitoba
R0M 0M0

Olive Hainsworth
Box 433
Deloraine, Manitoba
R0M 0M0

K.A. Little/A.F. Ramseyer
Box 4100
Georgetown, Ontario
L7G 4Y4

D.E. McGregor
Box 33
Waskada, Manitoba
R0M 2E0

R.J. Hainsworth
Box 99
Waskada, Manitoba
R0M 2E0

C.M. Thomas
Hartney, Manitoba
R0M 0X0

H.D. Meggison
Goodlands, Manitoba
R0M 0R0

WASKADA UNIT NO. 4
ROYALTY INTEREST OWNERS

ADDRESSEE LIST

M.D. Allison
3720 Garland Street
Wheat Ridge, Colorado
U.S.A. 80033

Department of Energy and Mines
Mineral Resources Division
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

John H. Spelliscy
14 Taggart Street
Regina, Saskatchewan
S4S 4G4

Reston Resources Ltd.
2311 - 12th Street S.W.
Calgary, Alberta
T2T 3N7

Shell Canada Resources Limited
400 - 4th Avenue S.W.
Calgary, Alberta
T2P 2H5

Page Petroleum Ltd.
10th Floor
635 - 8th Avenue S.W.
Calgary, Alberta
T2P 3M3

Consolidated Trans-Canada Resources Ltd.
350, 708 - 11th Avenue S.W.
Calgary, Alberta
T2R 0E4

Amoco Canada Resources Ltd.
3300, 333 - 7th Avenue S.W.
Calgary, Alberta
T2P 2H8

The Canada Trust Company
230 Portage Avenue
Box 881
Winnipeg, Manitoba
R3C 2S6

E.A. McGregor
Box 164
Waskada, Manitoba
ROM 2E0

M.E. McGregor
Box 164
Waskada, Manitoba
ROM 2E0

A.I. Hainsworth
11633 - 203rd Street
Maple Ridge, B.C.
V4X 4T8

J.W. Hainsworth
P.O. Box 433
Deloraine, Manitoba
ROM 0M0

Petroventures Resources Ltd.
1400, 630 - 6th Avenue S.W.
Calgary, Alberta
T2P 0S8

Bran Van Enterprises Ltd.
240 - 1st Street
Brandon, Manitoba
R7A 5Z9

Sceptre Resources Ltd.
2600, 250 - 6th Avenue S.W.
Calgary, Alberta
T2P 3H7

Working Interest Owners
Within One Kilometer of the Pilot Project Area

Waskada Unit No. 4

Omega Hydrocarbons Ltd.
1300, 112-4th Ave. S.W.
Calgary, Alberta
T2P 0H3

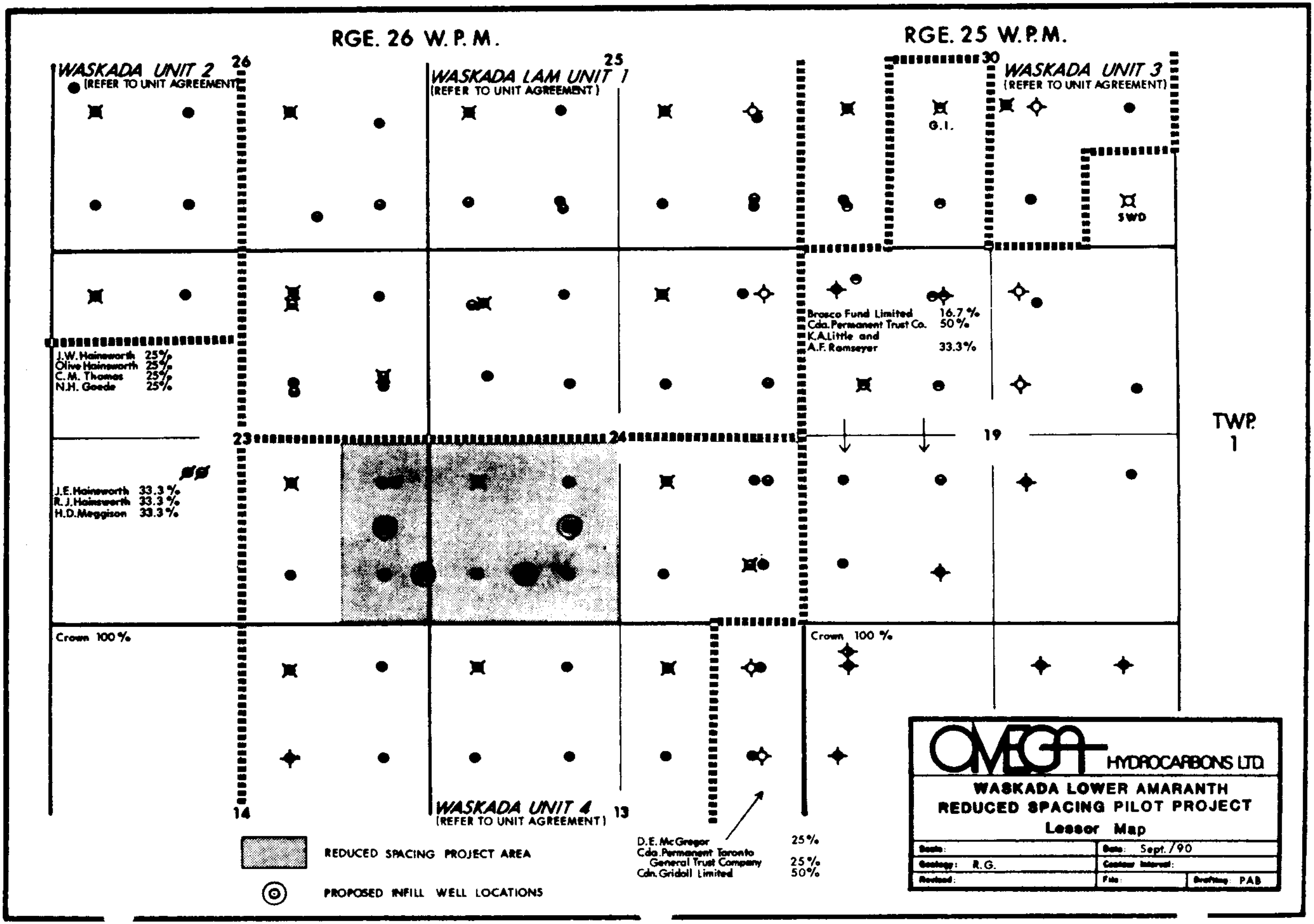
Sabre Energy Ltd.
800, 1122-4th St. S.W.
Calgary, Alberta
T2R 1M1

Other

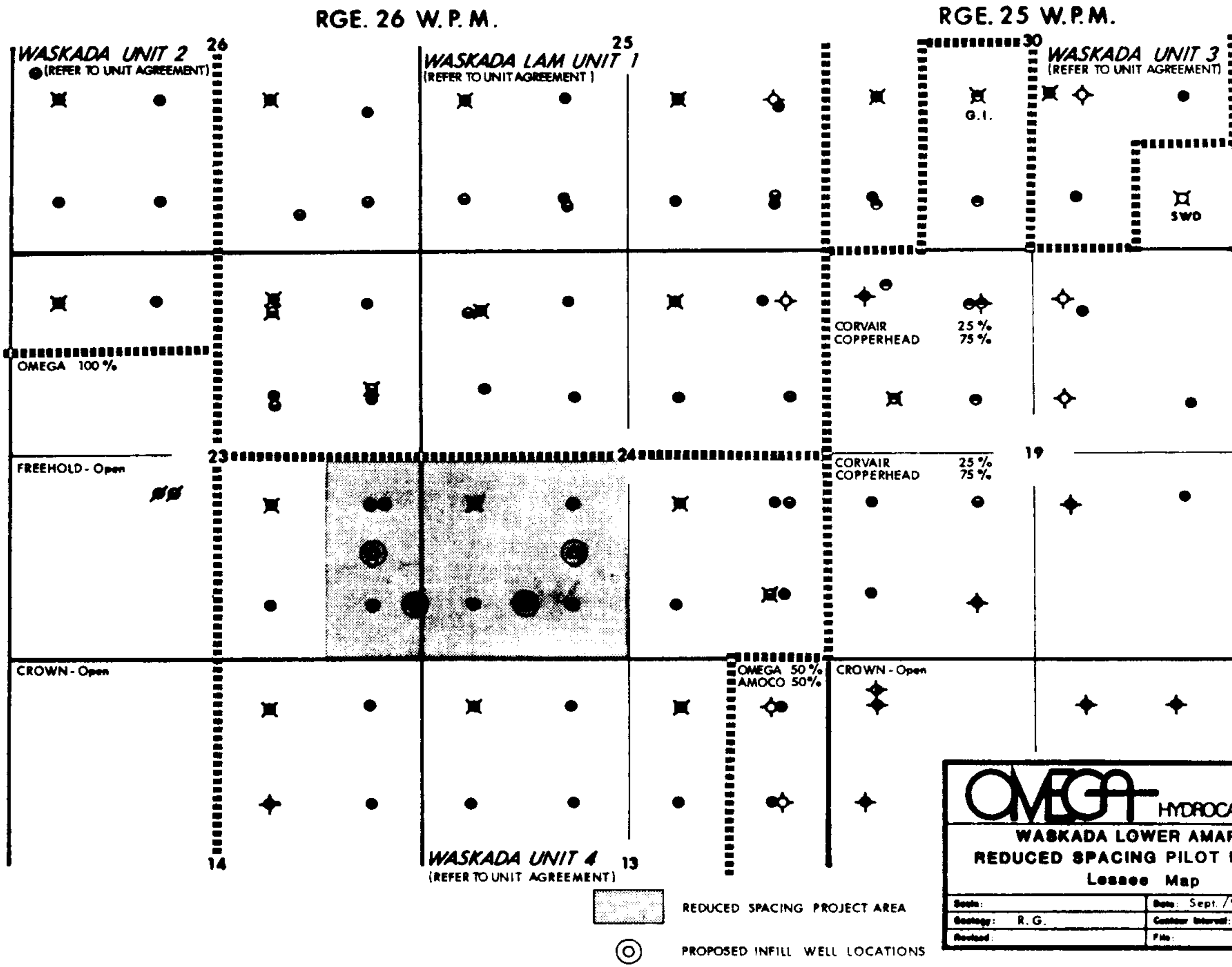
Amoco Canada Resources Ltd.
240 - 4th Avenue S.W.
Calgary, Alberta
T2P 4H4

Tundra Oil & Gas Ltd.
1313 One Lombard Place
Winnipeg, Manitoba
R3B 0X3

Enron Oil Canada Ltd.
1300, 700 - 9th Avenue S.W.
Calgary, Alberta
T2P 3V4



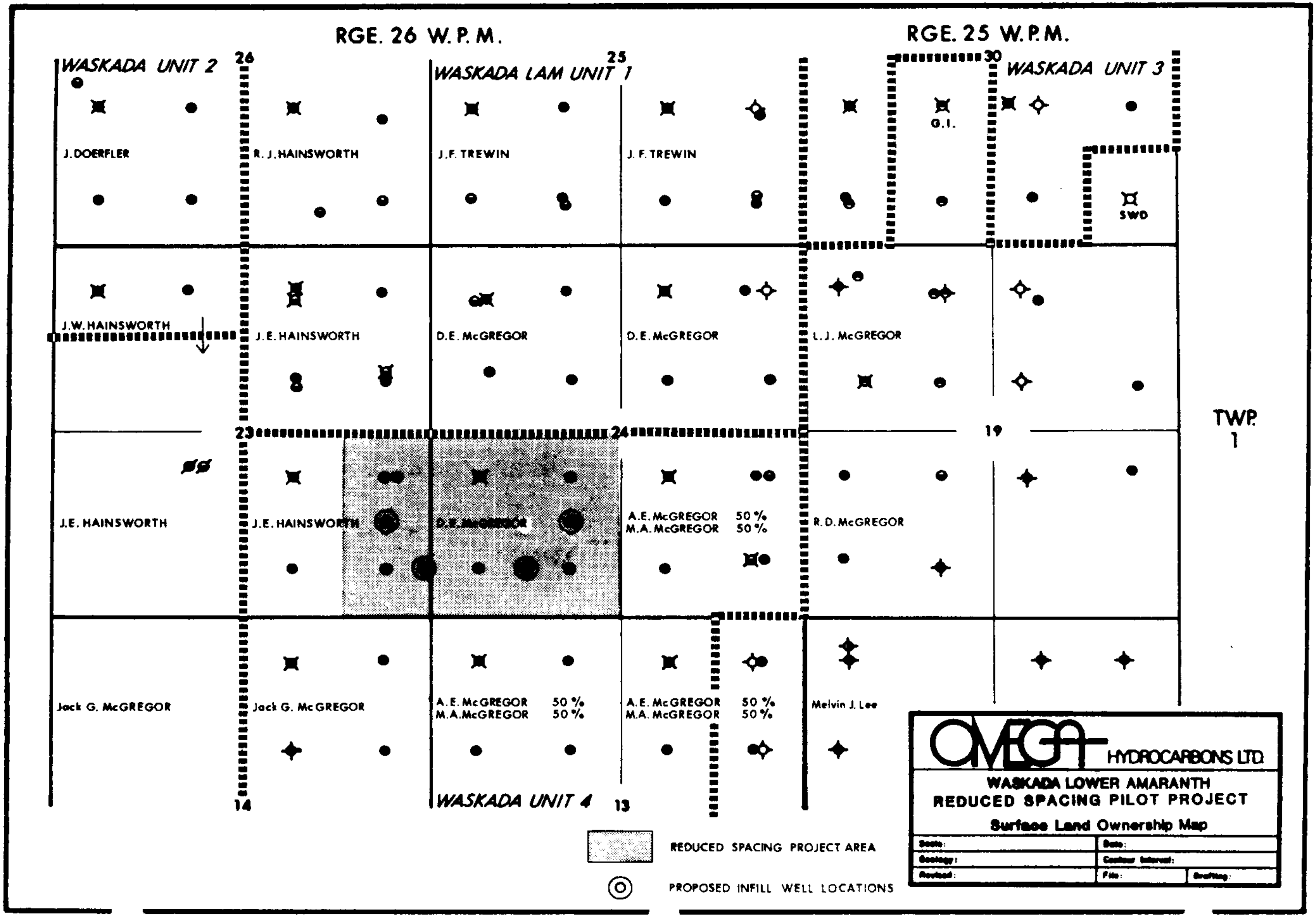
RGE. 26 W.P.M.
RGE. 25 W.P.M.
TWP. 1
WASKADA UNIT 2
(REFER TO UNIT AGREEMENT)
WASKADA LAM UNIT 1
(REFER TO UNIT AGREEMENT)
WASKADA UNIT 3
(REFER TO UNIT AGREEMENT)
WASKADA UNIT 4
(REFER TO UNIT AGREEMENT)
26
25
30
23
24
19
14
13
G.I.
SWD
J.W. Hainsworth 25%
Olive Hainsworth 25%
C.M. Thomas 25%
N.H. Goede 25%
J.E. Hainsworth 33.3%
R.J. Hainsworth 33.3%
H.D. Meggison 33.3%
Brosco Fund Limited 16.7%
Cda. Permanent Trust Co. 50%
K.A. Little and
A.F. Ramseyer 33.3%
Crown 100%
Crown 100%
D.E. McGregor 25%
Cda. Permanent Toronto General Trust Company 25%
Cdn. Gridoil Limited 50%
REDUCED SPACING PROJECT AREA
PROPOSED INFILL WELL LOCATIONS
OMEGA HYDROCARBONS LTD.
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lessor Map
Scale:
Date: Sept./90
Geology: R.G.
Contour Interval:
Revised:
File:
Drafting: PAB



OMEGA HYDROCARBONS LTD.

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lessee Map

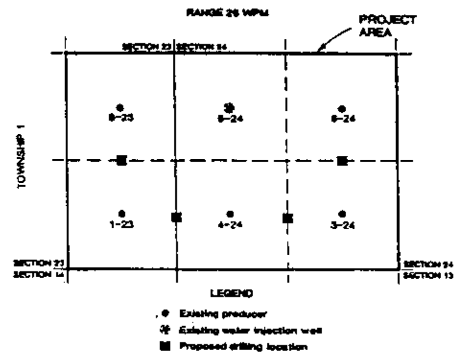
Scale:	Date: Sept. /90
Geology: R. G.	Contour Interval:
Revised:	File: / Drafting: P.A.B.



RGE. 26 W.P.M.
RGE. 25 W.P.M.
WASKADA UNIT 2
WASKADA LAM UNIT 1
WASKADA UNIT 3
WASKADA UNIT 4
26
25
30
23
24
19
14
13
TWP. 1
J. DOERFLER
R. J. HAINSWORTH
J.F. TREWIN
J. F. TREWIN
G.I.
SWD
J.W. HAINSWORTH
J.E. HAINSWORTH
D.E. McGREGOR
D.E. McGREGOR
L.J. McGREGOR
J.E. HAINSWORTH
J.E. HAINSWORTH
D.E. McGREGOR
A.E. McGREGOR 50 %
M.A. McGREGOR 50 %
R.D. McGREGOR
Jack G. McGREGOR
Jack G. McGREGOR
A.E. McGREGOR 50 %
M.A. McGREGOR 50 %
A.E. McGREGOR 50 %
M.A. McGREGOR 50 %
Melvin J. Lee
REDUCED SPACING PROJECT AREA
PROPOSED INFILL WELL LOCATIONS
OMEGA HYDROCARBONS LTD.
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Surface Land Ownership Map
Scale:
Date:
Geology:
Contour Interval:
Revised:
File:
Drafting:

NOTICE—UNDER THE MINES ACT

Omega Hvdrocarbons Ltd., Operator of Waskada Unit No. 4 (" unit") has made application under Section 20 of The Petroleum Drilling and Production Regulation for approval of special drilling spacing units in a portion of the unit ("the project area") outlined below. If the application is approved, it is proposed to drill (4) wells at the approximate locations shown.



If no intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C 0V8 on or before December 14, 1990, the Board may approve the application.

Copies of the application may be obtained from:

Omega Hydrocarbons Ltd.
1300 Sun Life Plaza III
112-4th Avenue S.W.
Calgary, Alberta T2P 0H3
1-800-661-9257

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue	
Winnipeg, Manitoba	**Waskada, Manitoba**
(204) 945-6577	**(204) 673-2472**

Dated at Winnipeg, this 15th day of November, 1990.

H. Clare Moster
Deputy Chairman

UNDER THE HIGHWAYS PROTECTION ACT AND THE HIGHWAY TRAFFIC ACT

THE HIGHWAY TRAFFIC BOARD

Noticeis hereby given that a hearing of the Highway Traffic Board will be held on Tuesday, December 4, 1990 at 10:00 hours in Room 204-301 Weston Street, Entrance "D", Winnipeg, Manitoba R3E 3H4. Phone: 945-8912.

Permits — Part I — Section 9 H.P.A. and Part III — Section 17 H.P.A.

06/001/187/B/90 — David Breland

An application for a permit for a Dwelling (Residential) adjacent to P.T.H. No. 1 (Service Road), R.L. 37, Parish of St. Francois Xavier, R.M. of Cartier.

01/044/193/A/90 — Brokenhead River Park Inc.

An application for a permit for an Access Driveway (Residential) and a Public Street Access (Subdivision) onto P.T.H. No. 44 (Service Road), S.W. ¼, Section 5-13-8 East, R.M. of Brokenhead.

07/016/194/A/90 — Silver Creek Cattle Co. Ltd.

An application for a permit to Relocate an Existing Access Driveway (Residential) onto P.T.H. No. 16, N.E. ¼, Section 34-19-28 West, R.M. of Russell.

01/011/196/BC/90 — Winnipeg River Lions Club

An application for a permit for a Change in Land Use (Residential to Commercial) and a Picnic Area adjacent to P.T.H. No. 11, R.L. 21, Township 18-10 East, L.G.D. of Alexander (Powerview).

03/032/197/A/90 — Suderman Bros. (1981) Ltd.

An application for a permit for an Irrigation Reservoir adjacent to and an Access Driveway (Agricultural) onto P.T.H. No. 32, S.W. ¼, Section 10-1-4 West, R.M. of Stanley.

12/001/099/S/90 — Anglican Church of Canada

An application for a permit for an Off-Premise Sign (Historical) adjacent to P.T.H. No. 1 West, R.L. 54, Parish of Headingley, City of Winnipeg.

Speed Zones Sections 97 & 98 H.T.A.

067-S-H — Mr. Duchek (Reeve) R.M. of St. Andrews

Consideration to be given to a speed reduction on P.T.H. No. 67 between P.T.H. No. 9 & P.R. No. 230, R.M. of St. Andrews.

002-S — Provincial Traffic Engineer

Consideration to be given to extend the modified speed zone of 70 Km/h on P.T.H. No. 3 southwest of its intersection with P.T.H. No. 2 a distance of 200 metres, R.M. of MacDonald.

502-S — Mr. Paul McIntosh

Consideration to be given to extend the restricted speed zone of 50 Km/h northeasterly on P.R. No. 502 for 200 metres beyond the Village of Lac du Bonnet boundary, R.M. of Lac du Bonnet.

19000-S — R.M. of Swan River

Consideration to be given to a restricted speed area of 50 Km/h on portions of the municipal road lying within the S.E. ¼, Section 17-34-29 West, R.M. of Swan River (Benito).

19000-S — R.M. of Swan River

Consideration to be given to a restricted speed area of 50 Km/h on portions of the municipal road lying adjacent to the Northern boundary of the N.E. ¼, Section 7-34-29 West between the C.N.R. right-of-way and P.T.H. No. 83, R.M. of Swan River (Benito).

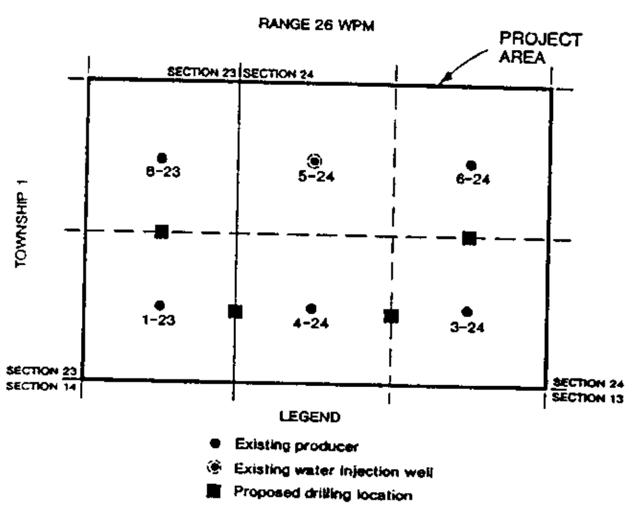
The Highway Traffic Board will be prepared to consider all submissions written or oral on the above applications by contacting the Secretary prior to or at the hearing.

A. POLTARUK, MMM CD
Secretary,
THE HIGHWAY TRAFFIC BOARD.

15930—47

UNDER THE MINES ACT

Omega Hydrocarbons Ltd., Operator of Waskada Unit No. 4 ("the unit"), had made application under Section 20 of The Petroleum Drilling and Production Regulation for approval of special drilling spacing units in a portion of the unit ("the project area") outlined below. If the application is approved, it is proposed to drill four (4) wells at the approximate locations shown.



If no intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C 0V8 on or before December 14, 1990, the Board may approve the application.

Copies of the application may be obtained from:
Omega Hydrocarbons Ltd.
1300 Sun Life Plaza III
112-4th Avenue S.W.
Calgary, Alberta
T2P 0H3
1-800-661-9257

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue
Winnipeg, Manitoba
(204) 945-6577

Waskada, Manitoba
(204) 673-2472

Dated at Winnipeg, this 15th day of November, 1990.

H. CLARE MOSTER,
Deputy Chairman.

15961—47

Waskada W.I.

The meeting was opened with O'Canada, the Creed and a Remembrance Day poem as well as Premier Filmon's Remembrance Day Message were read.

FWIC Mildred Millard on "Dreams". The minutes and the Treasurer's report were given and accepted.

$37.00 was given to the Peace Garden Foundation Fund from Fall Seminar.

The Correspondence was read.

Moved by Dorothy Howden, seconded by Paulette Trewin that we change our meeting day beginning January 1991 to the 3rd Thursday of every month in the Church at two o'clock on a trial basis for 1 year. If members wish to have a meeting in their home, they contact the program committee. Lions will be contacted for a change on the Community Calendar.

Dues remain at $5.00 for the 1990-91 year.

Brandon Hospital's new phone number is 726-1122.

The 4-H Supper for us is December 5th at six o'clock in the United Church.

We will send $25.00 to the Christmas Cheer Board in Brandon.

November 15th we will go to Brandon to view Judy Morningstar's quilts which are on display at the Arts Centre and return via Boissevain to have lunch at Wild Rose Emporium.

The following are our officers and Committee Representatives for 1990-91:

President: Fran Dickinson
Vice: Muriel Radcliffe
Secretary: Lorna Temple
Treasurer: Paulette Trewin (Nell Dow to help)
Board Member: Fran Dickinson
Sunshine Committee: Vera Brown
Cancer and Auditor: Grace Trewin
Program: Grace Trewin, Grace Hooper, Muriel Radcliffe, Pat Temple, Fran Dickinson.
Agriculture: Mildred Millard
Education and Culture: Paulette Trewin
Unity: Nell Dow
Canadian Industry: Mona Gaudin
Home Economics and Health: Muriel Radcliffe
International Affairs: Dorothy Howden
Environment: Diane Kontzie
Citizenship: Vera Brown
Nominating: Melba Stewart, Grace Hooper.

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Waskada WI
President's Annual Report
by Fran Dickinson

Waskada WI has been contributing to the life of our community and country now for 70 years. A special program and birthday cake was presented in conjunction with the Southwest B Seminar that we hosted in October this year.

Our year 1990 has been one of learning and serving. Program topics have be: Discussion of a present issue, celebrating Manitoba's 80 years of WI, Creating Healthy Rural Communities, Farm Land Ownership Board, Horticulture, Health Care Alternatives, Financial Management, Recycling and Exploring Land Industries (realizing we have a great many in our own small community).

Roll Call topics: One of my duties as a Canadian Citizen, My favorite personal or family tradition, Health Care Suggestions, What do you see in the future for farmers?, My favorite plant, A Manitoba Product, Holiday Highlights. Most interesting WI Program and What do you do to keep yourself healthy. All these topics produced lively and interesting discussions.

At each meeting a 2-3 minute brief was given on one of the eight Educational Committee topics which were: Canadian Industry, Citizenship, International Affairs, Home Ec. and Health, Education and Cultural Affairs, Canadian Unity, Agriculture, Environment.

We continue to support the 4-H Program by donating trophies, serving lunch at their Achievement and holding a special entertainment time for the members and leaders. As well our group sponsored an annual Cancer Tea, contributed to the Family Services Tea and Bake Sale, donated books to the Book Mart, collected old eye glasses, sent gifts at Christmas to the Mental Hospital, donated toiletry items and food to the Women's Shelter, remembered former Waskada residents living in the Lodge and Care Wing with fruit parcels at Christmas, cooked for a wedding, served lunch at a member's sale, provided noon lunch at the Spring Board Meeting and made donations to the Peace Garden, Lennox Bell and Pennies for Friendship. To celebrate WI Day in February, we held a supper for members, spouses and senior guests.

We contributed a quilt block and sold tickets on this Regional Quilt. Our WI was represented at the two Board Meetings, the Regional and Provincial Conventions and both fall seminars, one at Waskada and one at Douglas.

We welcomed one more member to our group this year. It has been a full year again but very educational with the varied topics we touched on. We look forward to a new year of working for Home and Country and invite anyone interested to come join with us.

In memoriam

Alexander Gordon;
Gone from us
But not forgotten,
Never shall thy memory fade.
'Round the spot
Where thou art laid.
—Loved and remembered, Daryl, Deb, Jason.

MURRAY— R. E. In loving memory of Bobby, dear husband and father who passed away November 22, 1988.
When thoughts go back
As they often do,
We treasure the memory,
We have of you.
This day is remembered
And quietly kept,
No words are needed,
We'll never forget.
—Always missed and loved by wife Louise and family, Lexie, Barry, Lyle and Christine.

NOTICE OF TENDER

Sealed, written tenders will be received by the Royal Bank, Box 548, Deloraine, Manitoba, ROM 0M0 for the following described farmland:

The S½ 1-2-25, WPM, Excepting all mines and minerals within, upon, or under the said lands and 10.2 acres representing yard site and grain storage.

CONDITIONS OF TENDER:

1. Interested parties must rely on their own inspection and knowledge of the farm property.
2. Tenders must be received at the above office before 5:00 p.m., December 7, 1990.
3. Envelopes containing tender must be marked "Tender" and show the parcel on which the tender is being made.
4. The party submitting the accepted tender will be required to pay an amount equal to 10% of the purchase price and execute an agreement for sale covering all the terms and closing within 10 days from the date the tender is accepted.
5. Highest or any tender not necessarily accepted.

For further information, please contact Keith Wooldridge at 747-3012.

With 1990 being the International Year of Literacy, Manitoba Young Reader's Choice Award has been developed by the Manitoba School Library Audio-Visual Association along with other organizations.

The goals and objectives of this award are to encourage independent reading and to promote an awareness of our Canadian authors. It represents quality and popularity in literature.

Fifteen books have been chosen for the nomination list based on their quality and reading appeal. These titles range from comic novels, full of wit and surprises to perceptive tales of adolescence.

When you read at least 3 titles from the list of 15, you are then eligible to vote for your favourite book!

The voting process is an exciting way to involve readers and have their personal reading preferences acknowledged. So check these titles out at the library—take part—"READ"—and cast a ballot!

Thank You

The Melita and District Chamber of Commerce Fall Promotion Committee would like to thank the Melita Merchants for their support in making our "Bonus Buck" Promotion such a success. We wish to acknowledge their support and, that of their suppliers, in providing many items for the auction and the draws.

All the helping hands at the casino and auction were greatly appreciated and thanks to everyone for supplying lunch and helping to raise some much-needed funds towards the many chamber projects that are taking place at this time.

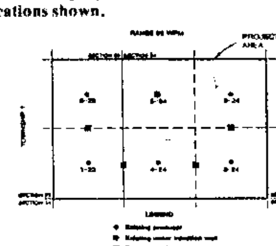
We also wish to thank Thompson's Plastics for the donation of additional blackjack table tops, Dick Harmon for making such a super job of the crown and anchor wheels and to Allan Breemersch for the great job he did as our auctioneer.

***

The biggest "thanks" must go to the general public for your support in making this a successful promotion for without your participation we could not have made any of this happen

NOTICE—UNDER THE MINES ACT

Omega Hydrocarbons Ltd., Operator of Waskada Unit No. 4 ("the unit") has made application under Section 20 of The Petroleum Drilling and Production Regulation for approval of special drilling spacing units in a portion of the unit ("the project area") outlined below. If the application is approved, it is proposed to drill (4) wells at the approximate locations shown.



If no intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C 0V8 on or before December 14, 1990, the Board may approve the application.

Copies of the application may be obtained from:
Omega Hydrocarbons Ltd.
1300 Sun Life Plaza III
112-4th Avenue S.W.
Calgary, Alberta T2P 0H3
1-800-661-9257

The application may be viewed at the offices of the Petroleum Branch:
555-330 Graham Avenue, Winnipeg, Manitoba (204) 945-6577
Waskada, Manitoba (204) 673-2472

Dated at Winnipeg, this 15th day of November, 1990.

H. Clare Moster
Deputy Chairman

ɔme Ec. news

by MARLENE BASKERVILLE

Rebuilding self-esteem

Feeling good about yourself, or having high self-esteem, is one of the most valuable assets a person can have. Self-esteem is developed over time as we move through childhood into adulthood. Love and acceptance from parents, family members and friends help us feel good about ourselves. In additon, the skills and abilities we develop help us value the contributions we can make.

Farming gives a person numerous opportunities to develop and practice skills and abilities that help to build a positive self image. In many ways, however, if the farm is tied too closely to the person's self-image it can also have a negative effect. If the farm income is decreasing, which is a fact of life for some farm families, feelings of inadequacy are visible in lots of invisible ways:

-negative self talk or imagining what others are thinking or saying about you can cause loss of sleep and generally wear you down.

-losing confidence in everything you used to be capable of causes other parts of your life to pull apart.

-concentrating on only the negative, paints a reality that is bleak and dark and creates a feeling of hopelessness.

You can take some steps to raise a damaged sense of self-esteem. By spending some time with others who are" in the same boat" you may come to realize you are not necesssarily to blame for the problems. Many of your negative feelings and reactions are normal during this difficult transition. Being with others who see you as a valuable person can give you a real boost.

You can learn to give yourself the compliments you would like to hear from others. You can put the day's tasks on a list and enjoy checking off one after another. You can learn to take pride in the small things. And most of all, you can learn to separate your own value from the profitability of the farm operation.

If you wait for economic success to give you self-esteem, you can be easily disappointed. Real self-esteem comes from inside. Nothing and no one can take it away except you. The choice is yours.

New publication lists rental and custom charges

At some time in every farmer's life, machinery leasing or custom operation becomes a necessity.

To help farmers and custom operators calculate the cost of these services, Manitoba Agriculture has just released the 1990 edition of *Rental and Custom Charges for Farm Machinery.*

The 12-page guide and work sheet contains approximately hourly rental rates and custom charges for more than 40 kinds of production equipment including tractors, combines, harvesters, tillage tools and seeding equipment.

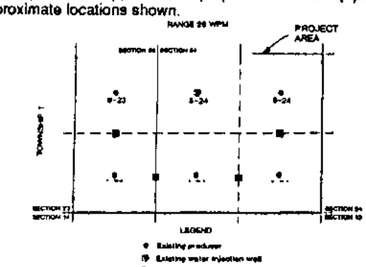
Orly Friesen, chief of Manitoba Agriculture's Engineering Services Section, says the rates are based on the retail list price of the machine and allow for depreciation, interest on investment, maintenance, repairs and a 20 per cent mark up.

With the work sheet included in the guide, farmers can calculate hourly charges for a wide range of equipment sizes.

Copies of *Rental and Custom Charges for Farm Machinery* are available from local ag rep offices.

NOTICE
UNDER THE MINES ACT

Omega Hydrocarbons Ltd., Operator of Waskada Unit No. 4 ("The unit"), has made application under Section 20 of The Petroleum Drilling and Production Regulation for approval of special drilling spacing units in a portion of the unit/the project area, outlined below. If the application is approved, it is proposed to drill four (4) wells at the approximate locations shown.



If no intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3G 0V8 on or before December 14, 1990, the Board may approve the application.

Copies of the application may be obtained from

Omega Hydrocarbons Ltd.
1300 Sun Life Plaza III
112-4th Avenue S.W.
Calgary, Alberta
T2P 0H3
1-800-661-9257

The application may be viewed at the offices of the Petroleum Branch
555-330 Graham Avenue
Winnipeg, Manitoba
(204)945-6577
Waskada, Manitoba
(204) 673-2472

Dated at Winnipeg, this 15th day of November, 1990

H. Clare Moster
Deputy Chairman

NOTICE OF TENDER

Sealed, written tenders for the properties described below will be received by:

Meighen, Haddad & Co.
Barristers & Solicitors
P.O. Box 485
Deloraine, Manitoba
R0M 0M0

PROPERTIES FOR SALE:
All 11-1-26
E-1/2 29-1-27 exc. Road Plan 332
NE-1/4 19-1-27
NE-1/4 35-1-28

CONDITIONS OF TENDER:
1. Tenders must be received on or before 3:00 p.m., December 17, 1990.
2. Tenders may be made on individual parcels or the property as a whole.
3. Each tender must be accompanied by a $1,000.00 cheque deposit payable to Meighen, Haddad & Co. Deposits accompanying unacceptable tenders will be refunded.
4. Highest or any tender not necessarily accepted.
5. Any or all of the above parcels may be withdrawn from tender by the Vendor.
6. All mines and minerals excepted.

TERMS AND CONDITIONS OF SALE:
1. The bidder whose tender is accepted will be required to complete an agreement covering the terms and conditions of sale.
2. In addition to the deposit, the balance of the accepted tender must be paid within 60 days from the date of notification of tender acceptance, or evidence provided that the purchase funds will be available under conditions acceptable to the Vendor. If the balance of the accepted tender is not paid within the set time limit, the deposit made may be forfeited as liquidated damages and not as a penalty.
3. Possession is not authorized until acceptable arrangements for full payment are made following acceptance of tender.

For further details or an appointment to view, contact:
Bill McKinney
Box 70
Waskada, Manitoba
R0M 2E0
Phone: 673-2424

Copy of notice for All 3 Board members!

Manitoba

Action / Route Slip

Date: November 15, 1990

To: H. Clare Moster
Deputy Chairman

From: John N. Fox
Chief Petroleum Engineer

RE: Omega's Reduced Spacing Application

Telephone:

- [ ] Take Action
- [ ] Per Your Request
- [ ] Circulate, Initial and Return
- [ ] For Approval and Signature
- [ ] Make ____ Copies
- [ ] May We Discuss
- [ ] For Your Information
- [ ] Return With Comments or Revisions
- [ ] Draft Reply for Signature
- [ ] Please File

(copy please)

Comments: Omega has responded satisfactorily to the Board's deficiency letter. Attached is the proposed notice of Omega's application. The notice will be

(1) published in the Melita and Deloraine papers

(2) sent directly to the (a) surface owners in the project area

Does this cover all WIO's & RO's immediately offsetting project area? *(b) working interest owners and royalty owners in Waskada Unit No.4

(c) Enron, Chevron and Tundra

(d) Surface Rights Association ?

HRD

What are Omega's public consultation plans?

MG-1298 PS-f-182 8940100671

Manitoba

Action / Route Slip

Date: November 15, 1990

To: H. Clare Moster
Deputy Chairman

From: John N. Fox
Chief Petroleum Engineer

RE: Omega's Reduced Spacing Application

Telephone:

- ☐ Take Action
- ☐ Per Your Request
- ☐ Circulate, Initial and Return
- ☐ For Approval and Signature
- ☐ Make ______ Copies
- ☐ May We Discuss
- ☐ For Your Information
- ☐ Return With Comments or Revisions
- ☐ Draft Reply for Signature
- ☐ Please File

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(1) published in the Melita and Deloraine papers

(2) sent directly to the (a) surface owners in the project area

(b) working interest owners and royalty owners in Waskada Unit No.

(c) Enron, Chevron and Tundra

(d) Surface Rights Association

MG-1298 PS-I-182 8940100671

Royalty Interest Onwers
Within One Kilometer of the Pilot Project Area

Waskada Unit No. 1

The Canada Trust Company
230 Portage Avenue
Winnipeg, Manitoba
R3C 2S6

Ingrid
Send to * addresses. Please check with Melita & Deloraine papers re: notice &

gy & Mines
rce Division
nch
ham Avenue
toba
R3C 4E3

Que West Resources Ltd.
1110, 910 - 7th Avenue S.W.
Calgary, Alberta
T2P 3N8

PanCanadian Petroleum Limited *
150 - 9th Avenue S.W.
P.O. Box 2850
Calgary, Alberta
T2P 2S5

Triton Canada Resources Ltd. *
c/o Canadian Worldwide Energy Ltd.
4th Floor, 255 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

Waskada Unit No. 4

M.D. Allison
3720 Garland Street
Wheat Ridge, Colorado
U.S.A. 80033

The Canada Trust Company
230 Portage Avenue
Box 881
Winnipeg, Manitoba
R3C 2S6

Dept. of Energy & Mines
Mineral Resources Division
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

E.A. McGregor
Box 164
Waskada, Manitoba
R0M 2E0

John H. Spelliscy
14 Taggart Street
Regina, Saskatchewan
S4S 4G4

M.E. McGregor
Box 164
Waskada, Manitoba
R0M 2E0

Reston Resources Ltd.
2311 - 12th Street S.W.
Calgary, Alberta
T2T 3N7

A.I. Hainsworth
11633 - 203rd Street
Maple Ridge, B.C.
V4X 4T8

Shell Canada Resources Limited
400 - 4th Avenue S.W.
Calgary, Alberta
T2P 2H5

Page Petroleum Ltd.
10th Floor
635 - 8th Avenue S.W.
Calgary, Alberta
T2P 3M3

Bran Van Enterprises Ltd.
240 - 1st Street
Brandon, Manitoba
R7A 5Z9

Amoco Canada Ltd.
240 - 4th Avenue S.W.
Calgary, Alberta
T2P 4H4

J.W. Hainsworth
P.O. Box 433
Deloraine, Manitoba
R0M 0M0

Petroventures Resources Ltd.
1400, 630 - 6th Avenue S.W.
Calgary, Alberta
T2P 0S8

Sceptre Resources Ltd.
2000, 400 - 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Consolidated Trans-Canada
Resources Ltd.
350, 708 - 11th Avenue S.W.
Calgary, Alberta
T2R 0E4

Other

Brosco Fund Limited
c/o Tundra Oil & Gas Ltd.
1313 One Lombard Place
Winnipeg, Manitoba
R3B 0X3

NO

Canada Permanent Trust Co.
1778 Scarth Street
Regina, Saskatchewan

Canadian Gridoil Limited
330 - 9th Avenue S.W.
Calgary, Alberta

J.E. Hainsworth
Box 99
Waskada, Manitoba
R0M 2E0

J.W. Hainsworth
Box 433
Deloraine, Manitoba
R0M 0M0

Olive Hainsworth
Box 433
Deloraine, Manitoba
R0M 0M0

K.A. Little/A.F. Ramseyer
Box 4100
Georgetown, Ontario
L7G 4Y4

D.E. McGregor
Box 33
Waskada, Manitoba
R0M 2E0

R.J. Hainsworth
Box 99
Waskada, Manitoba
R0M 2E0

C.M. Thomas
Hartney, Manitoba
R0M 0X0

H.D. Meggison
Goodlands, Manitoba
R0M 0R0

Working Interest Owners
Within One Kilometer of the Pilot Project Area

Waskada Unit No. 4

Omega Hydrocarbons Ltd.
1300, 112-4th Ave. S.W.
Calgary, Alberta
T2P 0H3

Sabre Energy Ltd.
800, 1122-4th St. S.W.
Calgary, Alberta
T2R 1M1

Other

Amoco Canada Resources Ltd.
240 - 4th Avenue S.W.
Calgary, Alberta
T2P 4H4

Tundra Oil & Gas Ltd.
1313 One Lombard Place
Winnipeg, Manitoba
R3B 0X3

Enron Oil Canada Ltd.
1300, 700 - 9th Avenue S.W.
Calgary, Alberta
T2P 3V4

* CHEVRON CANADA RESOURCES
VARDEN

VOL. 34 NO. 3 (SEPT. 1986), P. 364-378

THE STRESS REGIME OF THE WESTERN CANADIAN BASIN AND IMPLICATIONS FOR HYDROCARBON PRODUCTION

J.S. BELL[1] AND E.A. BABCOCK[2]

ABSTRACT

In the Western Canadian Basin, overcoring measurements, hydraulic fractures, bed-slip movements and wellbore breakouts suggest a contemporary stress regime where from surface to about 350 m depth $S_{Hmax}>S_{Hmin}>S_v$, from about 350 m to about 2500 m depth $S_{Hmax}>S_v>S_{Hmin}$, and below about 2500 m $S_v>S_{Hmax}>S_{Hmin}$. S_{Hmax} appears to be oriented NE-SW, approximately perpendicular to the strike of Rocky Mountain thrust faults, except over the Peace River Arch and other basement uplifts that appear to refract the stress trajectories.

Hydraulic fractures will propagate along planes normal to the least principal stress. Thus, above about 350 m such fractures will be horizontal, and below that depth they will be vertical and oriented parallel to S_{Hmax}. Knowledge of the stress configuration will assist directional drilling and planning of waterflood well configurations. This knowledge is also essential for planning multifractured inclined wells, such as might economically drain Deep Basin tight gas sands. Anisotropic horizontal principal stresses may have affected the Western Canadian Basin since the onset of the Laramide orogeny and induced non-uniform horizontal permeability fabrics in Mesozoic sandstones.

The Western Canadian Basin is part of a widespread North American midcontinent stress province that exhibits a common orientation of compressive stresses. It is speculated that this stress regime is largely caused by NE-directed drag exerted on the base of the lithosphere by a mantle convection cell which upwells beneath western North America.

RÉGIME DE TENSION DU BASSIN SÉDIMENTAIRE DE L'OUEST CANADIEN. APPLICATION À LA PRODUCTION D'HYDROCARBURES

RÉSUMÉ

Dans le bassin sédimentaire de l'ouest canadien, des mesures de surcarottages de forages, des fractures hydrauliques, des plans de glissement et des fracturations/écroulements de puits suggèrent un régime de tension où $S_{Hmax}>S_{Hmin}>S_v$ de la surface à 350 m de profondeur, $S_{Hmax}>S_v>S_{Hmin}$ de 350 m à 2500 m de profondeur et $S_v>S_{Hmax}>S_{Hmin}$ en-dessous de 2500 m de profondeur. S_{Hmax} aurait une orientation nord-est/sud-ouest, à peu près perpendiculaire à la trace des chevauchements des Montagnes Rocheuses, sauf au-dessus du Peace River Arch et d'autres soulèvements de socle qui semblent réfracter les trajectoires de tension.

Les fractures hydrauliques se propagent le long des plans perpendiculaires à la composante minimale de tension. De telles fractures seront ainsi horizontales au-dessus de 350 m de profondeur, et verticales parallèles à S_{Hmax} en-dessous. La connaissance des configurations de régimes de tension faciliterait les forages orientés ainsi que la planification des forages d'injection. Ces données sont aussi essentielles pour planifier les puits inclinés avec fractures à orientations multiples tels qu'ils puissent drainer économiquement les grès peu perméables du Deep Basin. Le bassin sédimentaire de l'ouest canadien aurait été soumis à des tensions à composante principale horizontale et anisotropique depuis le début de l'orogénèse laramienne: ceci aurait produit un régime à perméabilité horizontale très peu uniforme au sein des grès mésozoïques.

Le bassin sédimentaire de l'ouest canadien fait partie d'une province au centre du continent nord-américain ayant une composante de compression commune. Le régime de tension serait causé, en majeure partie, par une cellule de convection du manteau remontant en-dessous de l'Amérique du Nord et trainant la base de la lithosphère vers le nord-est.

Traduction: André Zolnai et Jean Pelletier

INTRODUCTION

The purpose of this paper is to summarize and interpret all available information on the present-day state of stress in the Western Canadian Basin, and to interpret the implications of the stress regime for hydrocarbon production.

Stress magnitudes have been measured by overcoring and hydraulic fracturing. Principal stress directions have been determined from overcoring, induced-fracture orientations, wellbore breakouts, stress and strain gauge grid and bed slips in recent excavations. Horizontal stres anisotropy is inferred from the presence of breakouts.

By far the largest body of data is provided by wellbor breakouts, and this paper reports analyses from 154 well Mean breakout azimuths from 94 of these wells have bee

[1]Atlantic Geoscience Centre, Geological Survey of Canada, P.O. Box 1006, Dartmouth, Nova Scotia B2Y 4A2

[2]Alberta Research Council, P.O. Box 8330, Postal Station F, Edmonton, Alberta T6H 5X2

During the some eight years of their research, the authors have received prints of uncomputed dipmeter logs from many oil companies and had invaluable discussions with J.W. Cox, M.B. Dusseault, C.K. Fordjor, D.I. Gough, J.M. Gronseth, K.Y. Lo, and R.E. Wyman. A.J. Deal, C. Lambert, S. Leung and A. Podrouzek assisted in data collection and reduction. J.S. Bell is grateful for encouragement and support from B.P. Canada Resources Ltd. and the Geological Survey of Canada. E.A. Babcock's research has been supported by the Natural Science and Engineering Research Council of Canada. The manuscript was typed by Nelly Koziel; G.L. Cook drafted the figures; and the text has benefited considerably from the suggestions of J.M. Dixon, D.I. Gough, A.C. Grant, J. Kramers and G. Stockmal.

published previously (Babcock, 1978; Gough and Bell, 1981; Fordjor and others, 1983), but logs for each of these wells have been reviewed for this study and, in some cas the results have been revised (see Appendix).

Analyses of 60 additional wells are also included, extending coverage into the Rocky Mountain Foothills, southeastern Alberta, and Saskatchewan.

Stress Magnitude

The stress field at a point can be represented by three principal stresses (Jaeger and Cook, 1976), which are identified in this paper as σ_1, σ_2, and σ_3 for the maximum, intermediate, and minimum principal compressive stresses, respectively. One of the principal stresses is approximately vertical and is designated here S_v. The greater and lesser horizontal principal stresses are labelled S_{Hmax} and S_{Hmin}.

At the present time, there is not a large amount of published information on *in situ* stress magnitudes in western Canada. Most of the measurements have been made either at shallow depths in tar-sand units or at depths of 2 km to 3 km in Mesozoic sandstones and shales of the Deep Basin. No measurements in carbonate sequences have been reported.

Table 1 lists published stress magnitude measurements; their locations are shown in Figure 1. In Figure 2, the inferred principal stress magnitudes are plotted against depth. This is a somewhat arbitrary approach because it groups data from several widely separated areas where the stress profiles may differ. However, it does argue for an anistropic stress regime in the Western Canadian Basin.

The ratio of the greater horizontal principal stress to the lesser appears to be of the order of 1.3 to 1.6 (Table 1). Except at shallow depths, as at Wabasca in north central Alberta (Fig. 1), S_{Hmin} appears to be the least principal stress, provided the vertical stress is lithostatic.

The stress magnitudes reported by Kaiser and others (1982) for the Kipp Mine in southern Alberta are based on direct measurements by means of multipoint extensometers and borehole stress-change gauges, so that S_{Hmax} and S_{Hmin} were measured independently. The principal stress values reported by Holzhausen and others (1980), Imperial Oil (1978), Settari and Raisbeck (1978), Wyman and others (1980), Kry and Gronseth (1982) and McLennan and others (1982) are derived from hydraulic-fracturing results. With appropriate interpretation, the instantaneous shut-in pressure will be equal to the lesser horizontal principal stress (Gronseth and Kry, 1983). The greater horizontal principal stress can be estimated from the relationship:

$$S_{Hmax} = 3S_{Hmin} - P_r - P_o \quad (1)$$

where P_r is the reopening pressure and P_o is the pore pressure in the rock (Bredehoeft and others, 1976). Wyman and others (1980) described massive hydraulic fracturing of the Cretaceous Fahler sandstone between depths of 2021 m and 2066 m in the Canhunter Texcan 11-12-71-13W6 well. They stated that the mean gradient of fracture propagation was 19.7 KPa/m, which is equivalent to between 39.7 and 40.7 MPa over the fractured interval. Reopening of fractures occurred at pressures exceeding 42.1 MPa, and the pore pressure in the sandstone was 15.2 MPa. If the fracture propagation pressure is equated to the lesser horizontal principal stress S_{Hmin}, equation (1) yields S_{Hmax} values in the 61.8 to 64.8 MPa range. These values are listed in Table 1, together with a vertical stress estimate based on the lithostatic stress (the load exerted by a column of rock plus pore fluids of mean density 2500 kg/m^3).

As can be seen, the picture of stress magnitudes in the Western Canadian Basin is far from complete at the present time. The capability of different rocks to transmit stress laterally is known to vary, and this is vividly illustrated by Kry and Gronseth's (1982) S_{Hmin} measurements of 30 MPa and 36 MPa in, respectively, shale and sandstone sequences that were separated vertically by only 28 m at locality 8 (Table 1, Fig. 2). True stress profiles are not likely to exhibit uniform increases with depth (Rosepiler, 1979), although the widespread reference to "fracture gradients" by petroleum engineers might suggest otherwise. In practice, fracture gradients give a useful indication of the average change of S_{Hmin} with depth in a basin, and information of this type for many oil and gas fields in the Western Canadian Basin is known to company production engineers. Figures ranging between 0.7 psi/ft (15.8 KPa/m) and 0.9 psi/ft (20.4 KPa/m) are used; Wyman and others (1980) report a fracture gradient of 0.87 psi/ft (19.7 KPa/m) for the Deep Basin area.

Indications of relative principal stress magnitudes at shallow depths in central and eastern Alberta are given by induced-fracture orientations at heavy oil and pilot plants (Table 2). Above approximately 350 m, induced fractures are horizontal, which implies that σ_3, the least principal stress, is vertical. Below that depth, the vertical induced fractures imply that σ_3 is horizontal.

This information suggests the following stress magnitude model. From the surface to depths of the order of 350 m, σ_1 and σ_2 are probably horizontal and σ_3 vertical. Below this, to depths of approximately 2500 m, σ_1 and σ_3 are horizontal and σ_2 vertical. At greater depths, σ_1 may become vertical; but it should be noted that this interpretation is based on S_{Hmax} values which are inferred, not measured, and on the assumption that the vertical stress, S_v, is equivalent to the lithostatic load. Hence, the stress field appears to be that associated with strike-slip faulting in the top 2500 m, but may be of normal faulting type at greater depths.

Principal Stress Directions

In this paper it is assumed that one principal stress is vertical, or nearly vertical, and oriented normal to the

Loc. No.	Depth	Location	Rock Type	S_{Hmax}	S_{Hmin} (in MPa)	S_v	S_{Hmax}/S_{Hmin}	Method	Source
	152 m	Kipp Mine	Shale/siltstone	4.25±0.6	~3.0	3.6	1.4	Overcoring	Kaiser and others, 1982
	180 m	Kipp Mine	Shale/siltstone	5.0	3.3	4.2	1.5	Overcoring	Kaiser and others, 1982
2	240 m	Wabasca	Poorly consolidated sandstone		6.4-7.7	5.8-6.1		Hydraulic fracture	Settari and Raisbeck, 1978
	317 m	Gregoire Lake	Poorly consolidated sandstone		5.6	7.0		Hydraulic fracture	Holzhausen and others, 1980
4	417 m	Cold Lake	Poorly consolidated sandstone		9.8	10.4		Hydraulic fracture	Settari and Raisbeck, 1978
	420 m	Cold Lake	Poorly consolidated sandstone		7.9-9.1	11.1-12.1			
5	457 m	Cold Lake	Poorly consolidated sandstone		9.0	11.25		Hydraulic fracture	Imperial Oil, 1978
6	2021-2066 m	11-12-71-13W6 well	Deep Basin sandstone	61.8-64.8	39.7-40.7	50.4-51.7	1.6	Hydraulic fracture	Inferred from Wyman, Holditch and Randolph, 1980
7	2073 m	c-16-I 93-P-1 well	Sandstone	63-71	40.7	50.2	1.6	Hydraulic fracture	Kry and Gronseth, 1982
	2095 m	c-16-I 93-P-1 well	Sandstone	51-57	34.5	52.7	1.6		
	2128 m	c-16-I 93-P-1 well	Sandstone	61-63	38.6	53.3	1.6		
	2149 m	c-16-I 93-P-1 well	Sandstone	65-72	42.3	53.8	1.6		
	2165 m	c-16-I 93-P-1 well	Sandstone/shale	62-65	39.0	54.3	1.6		
8	2213 m	10-16-69-11W6 well	Shale	40	30		1.3	Hydraulic fracture	Kry and Gronseth, 1982
	2241 m	10-16-69-11W6 well	Sandstone	51	36		1.4		
7	2269 m	c-16-I 93-P-1 well	Sandstone/shale	62-63	45.1	66.7	1.4	Hydraulic fracture	Kry and Gronseth, 1982
	2679 m	c-16-I 93-P-1 well	Sandstone/shale	60-77	44.3	67.0	1.5		
	2699 m	c-16-I 93-P-1 well	Sandstone		45.2	67.5			
	2717 m	c-16-I 93-P-1 well	Shale	59-71	44.0	68.0	1.5		
	2740 m	c-16-I 93-P-1 well	Shale		46.2	68.5			
	2750 m	c-16-I 93-P-1 well	Shale		45.1	68.8			
	2765 m	c-16-I 93-P-1 well	Sandstone/shale		46.6	69.1			
9	2992 m	1-12-35-7W5 well	Calcareous siltstone		60.0	74.8		Hydraulic fracture	McLennan and others, 1982
	2996-3009 m	1-12-35-7W5 well	Sandstone/ siltstone		61.0	75.1			

Table 1. Stress-magnitude measurements in the Western Canadian Basin.

mean topographic surface. Stress measurements from various parts of the world support this assumption (McGarr and Gay, 1978).

In contrast to the limited availability of stress magnitude measurements, there are numerous indications of the orientations of the principal horizontal stresses in the Western Canadian Basin. Table 3 lists S_{Hmax} asimuths derived from overcoring measurements, induced fractures and surficial stress-relief phenomena. The locations of these stress-oriented indications and their azimuths are shown in Figure 1.

Overcoring, Induced Fractures and Stress-Relief Features

Around Exshaw and in the Kananaskis Valley, Bell (1985) reported updip bed slip in recently excavated road cuts and concluded that this movement represented surficial stress relief in the S_{Hmax} direction. Nearby, in the Wilson Mine at Canmore, Grant (1970) reported S_{Hmax} determinations from two overcovered boreholes drilled in the mine roof. The more reliable readings suggest an approximately ENE orientation for S_{Hmax}. Overcoring measurements at the Kipp Mine gave similar S_{Hmax} azimuths (Kaiser and others, 1982).

McLeod (1977) reported fluid communication between NE-SW-aligned wells during water flooding of "J" lease in the Pembina oil field (Location 13, Figs. 1 and 7). Gough and Bell (1981) interpreted this behaviour as resulting from induced vertical hydraulic fracturing of the Cardium sandstone normal to S_{Hmin} and they therefore inferred that S_{Hmax} was oriented NE-SW.

Hassan (1982) analyzed the results of fracture stimulation in Amoco's "F" lease in the same field and noted that where injection and production wells lay on a NE-SW trend, fracturing caused a 135 percent increase in the water-to-oil ratio (Location 14, Figs. 1 and 7). In the

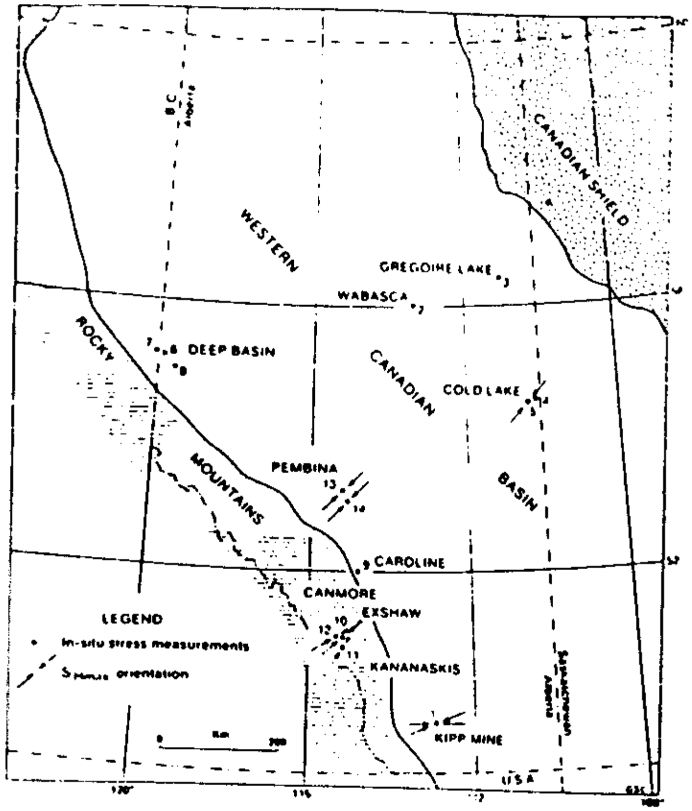


Fig. 1. Locations of *in situ* stress magnitude measurements and orientations in the Western Canadian Basin and Rocky Mountains. Depths, rock types and stress-magnitude values for numbered locations are listed in Table 1.

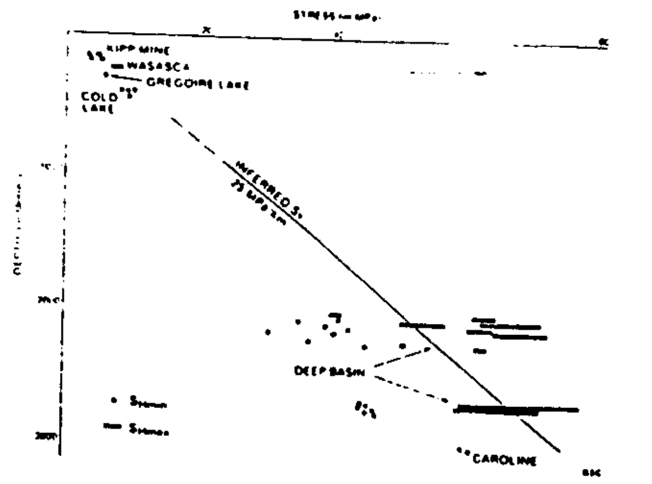


Fig. 2. Stress-magnitude measurements made in the Western Canadian Basin plotted against burial depth. The values are listed in Table 1.

nearby Violet Grove "AB" lease, where injection and production wells are offset along a N-S axis, post-fracture increases in the water-to-oil ratio averaged only 19 percent. Again, this flow pattern is consistent with NE-SW-oriented vertical hydraulic fractures being induced along the S_{Hmax} azimuth (Hubbert and Willis, 1957).

A similar stress configuration appears to exist at Cold Lake, where Imperial Oil (1978) report propagating fractures between wells at depths of approximately 450 m. Imperial Oil noted that the observed fluid movement at Cold Lake during steam injection was mainly in a preferred NE-SW direction, and their planned well configurations in several proposed pilot plants suggest that the induced fractures were expected to be oriented between 030° and 045°. This implies that, in the Cold Lake area, S_{Hmax} is also oriented approximately NE-SW.

These measurements and observations favour a generally NE-SW orientation for S_{Hmax} over much of the Western Canadian Basin, but they do not provide a focussed picture of the principal stress configuration. Fortunately, some details can be filled in by breakout azimuths.

Breakouts

The walls of boreholes spall so as to produce intervals with noncircular cross sections which have long axes that share a common mean orientation (Cox, 1970; Babcock, 1978). Such spalled intervals are defined as breakouts in cases where the shorter diameter of the borehole corresponds to the drill-bit diameter. Breakouts exhibiting well-grouped azimuths have been reported in the Yukon and Northwest Territories, the Canadian Arctic, Western Canada, Quebec and the Maritimes, various areas in the United States, Europe, Africa, Asia, Australia and the East Pacific Ocean (Cox, 1983; Bell and Gough, 1983; Newmark and others, 1984). In all areas where reliable *in situ* stress measurements are available, the mean breakout axes can be shown to be parallel to S_{Hmin} and therefore perpendicular to S_{Hmax}. This relationship is well established empirically and strongly supported by theory (Bell and Gough, 1979; Gough and Bell, 1982; Zoback and

Company — Location	Depth	Fracture Type	Fracture Pressure	Data Source
Shell Canada — Athabasca	45.7 m	Horizontal	Not reported	Nicholls and Luhning, 1977
Mobil Canada — Athabasca	115.8 m	Horizontal	Not reported	Nicholls and Luhning, 1977
AOSTRA-Numac — Athabasca	above 152.4 m	Horizontal	Not reported	Nicholls and Luhning, 1977
Amoco Canada — Athabasca	183-274 m	Horizontal	Not reported	Nicholls and Luhning, 1977
Gulf Canada — Wabasca	243.8 m	Horizontal	6.4 - 7.7 MPa	Nicholls and Luhning, 1977
Gulf Canada — Gregoire Lake	317 m	Vertical/ horizontal	5.6 - 9.3 MPa	Settari and Raisbeck, 1978; Holzhausen and others, 1980
Shell Canada — Athabasca	330 m	Horizontal	Not reported	Doscher and others, 1963
Atlantic Richfield — Athabasca	365.8 m	Vertical	Not reported	Nicholls and Luhning, 1977
Esso Resources — Cold Lake	457.2 m	Vertical NE/SW	9.0 MPa	Imperial Oil Ltd., 1978
AOSTRA/Shell — Peace River	548.6 m	Not reported	above 7.6 MPa	Nicholls and Luhning, 1977

Table 2. Reported fractures in heavy oil sand *in situ* pilot plants.

Loc No.	Depth	Location	S_{Hmax}	Indicator	Data Source
10	Surface	Exshaw	049°	Updip bed slip	Bell (in press)
11	Surface	Kananaskis Valley	032°	Updip bed slip	Bell (in press)
1	152 m	Kipp Mine	~ 090°	Overcoring	Kaiser and others, 1982
1	180 m	Kipp Mine	070° ± 20°	Overcoring	Kaiser and others, 1982
12	240 m	Canmore	055° - 066°	Overcoring	Grant, 1970
5	457 m	Cold Lake	030° - 045°	Induced fracture	Grant, 1970
13	1615 m	Pembina Oil Field "J" lease	~ 045°	Inferred induced fractures	McLeod, 1977
14	1675 m	Pembina Oil Field "F" lease	~ 045°	Inferred induced fractures	Hassan, 1982

Table 3. Principal horizontal stress orientations indicated by overcoring, induced fractures, and surficial stress-relief phenomena.

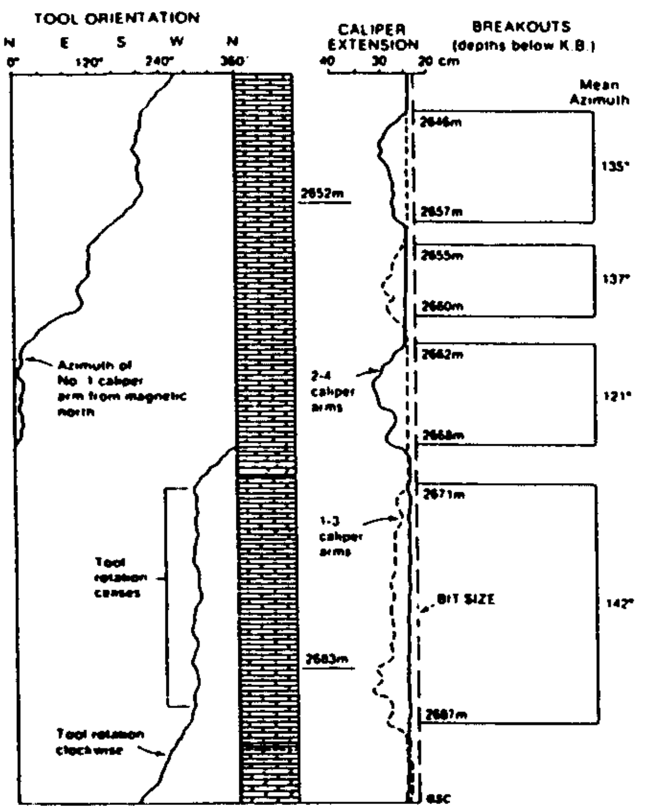


Fig. 3. Dipmeter record of four breakouts in the Nairb Petroleums Pembina 1-9-50-12W5 well as documented on the unprocessed log. The breakouts are characterized by differential extension of the two pairs of caliper arms and concurrent nonrotation of the dipmeter tool while two caliper arms are locked into the elongated, pseudo-elliptical breakout zone. The azimuths of the long axes of breakouts are calculated from the tool-orientation record after correcting for the magnetic declination at the well site.

others, 1985). It is now clear that breakouts will reliably indicate the orientations of the principal horizontal stresses affecting the borehole in which they have been measured.

Breakouts in the Western Canadian Basin

Because of the width of the spalled sections of borehole walls that have broken out, breakouts can be felt by the hydraulically extendible pads of four-arm dipmeter tools. These tools are generally raised up wells at approximately 10 m/minute, and the cable is torqued so as to cause the tool to rotate clockwise. This rotation ceases if one or both pads of a pair are trapped in a breakout. Breakouts are recognized on the uncomputed dipmeter log from the records of the azimuth of the No. 1 caliper and the extensions of calipers 1-3 and 2-4, as described below and, in more detail, by Babcock (1978), Bell and Gough (1981, 1983), and Cox (1983).

Figure 3 illustrates an uncomputed four-arm dipmeter record. The curves on the far right of the log record the diameters measured by the two pairs of opposed calipers, with diameter increasing to the left. Tool orientation is indicated on the left side of the log, where the solid curve records the azimuth of caliper 1 with respect to magnetic north. A typical breakout zone is present from 2687 m to 2671 m. Over this interval, opposed calipers 2 and 4 record a hole width of approximately 24 cm, equivalent to the diameter of the drill bit (22.7 cm). Calipers 1 and 2 record a varying borehole diameter which generally ranges between 28.5 cm and 31 cm. The curve recording the compass azimuth of caliper 1 near the base of the figure shows that the tool had been rotating clockwise as it was drawn up the well. At 2687 m, tool rotation ceased, calipers 1 and 3 became fixed within the elongated breakout, and the dipmeter was drawn up the borehole with caliper 1 oriented at an average azimuth of 299°. Adding the magnetic declination (23°) we obtain an azimuth of 322°, or 142°, for the breakout. Like other breakouts of any length, this one shows variations of azimuth of 10 to 20 degrees. Some of this is presumably a result of variation in the fit of the dipmeter pads into the fractured borehole wall, but some probably reflects true variation in the azimuth of the long diameter. Borehole televiewer records of breakouts document a similar vertical variation in azimuth over breakout zones (Plumb and Hickman, 1985).

All the breakouts referred to in this paper were identified and oriented in this manner using the following criteria:

1. The log must indicate tool rotation above and below the breakout.
2. Rotation must cease over the breakout interval (No. 1 Caliper arm must record a roughly constant azimuth).
3. One pair of calipers must record the original, or slightly enlarged, drilled diameter of the borehole, and the other a larger diameter. Within each breakout, the azimuth of the larger diameter of the hole was measured at depth intervals of 61 cm (2 ft) or 1 m. These azimuths were combined with equal weights to give a mean azimuth with standard deviation for each well by means of the statistical

methods described by Mardia (1972) for nonpolar directional data.

Many of the wells studied were logged only in their deeper p by four-arm dipmeter tools, but a large number were logged over all but the shallowest sections. Breakouts were identified in all lithologies; however, they were least abundant in Mesozoic sandstones and particularly well-developed in Paleozoic carbonates. The total thickness of all the breakouts recognized in a single well ranged from 2 m to 2086.9 m (Appendix). The shallowest breakout measured extended upward to a level of 112.5 m KB, whereas the base of the deepest breakout was at a depth of 5485.2 m KB. (Appendix). Forty-four wells exhibited significantly consistent breakout orientations. In these wells, the total thickness of breakouts exceeded 100 m, and their mean azimuths exhibited standard deviations of less than 10°.

Fordjor and others (1983) found no evidence of any significant vertical variation of breakout azimuth in wells in which breakout azimuths were measured over depth ranges of 600 m or more. We have not observed this either, although, if basement topography influences stress trajectories (Lloyd and Bell, 1985), denser data grids may enable us ultimately to recognize subtle systematic azimuth changes with depth around areas of significant basement relief. At our resolution, it is reasonable to interpret the breakout azimuths as indicating essentially constant stress geometry at all depths of a well.

Mean breakout azimuths of 154 wells are plotted in Figure 4. Seventeen wells contain a minor population of breakouts with mean azimuths which vary significantly from their major population. In 13 wells this variation is between 70° and 90°, whereas in four wells the minor population azimuth differs from the major by only approximately 30°. As can be seen from Figure 4, the minor population azimuths do not conform to the regional trends established by the major azimuths. It is not obvious what these anomalous breakout orientations mean. They meet the three recognition criteria described above, yet they still may not represent true breakouts. There are hints in some wells that the discordant borehole ellipticity has resulted from mudcake adhering preferentially to an extended broken-out zone (Fig. 5C) and in some cases in intervals where the entire borehole circumference has caved (Fig. 5D). In other words, washouts (Cox, 1983) have been "padded" so as to reduce the borehole diameter along their larger

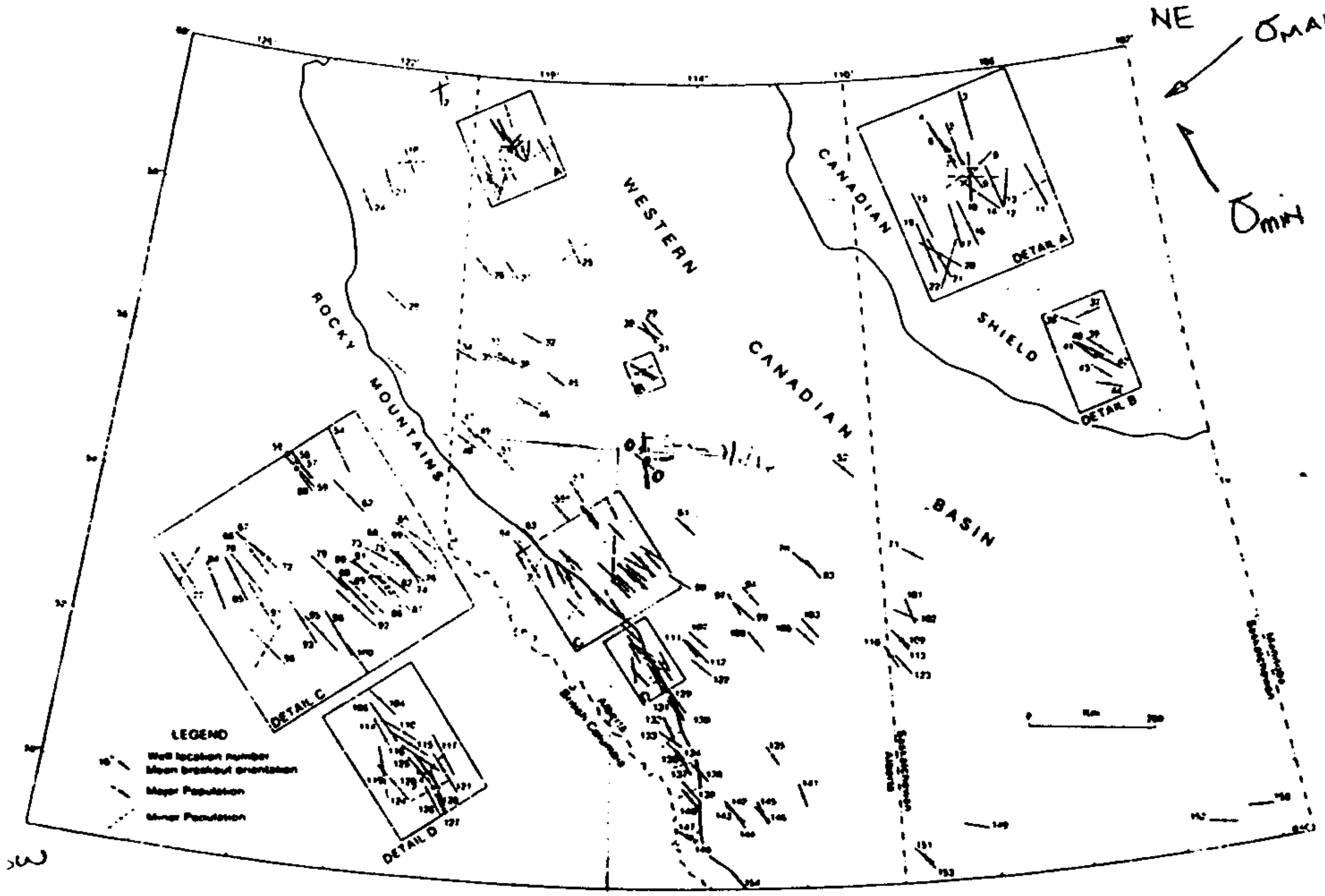


Fig. 4. Mean azimuths of major and minor breakout populations for 154 wells in the Western Canadian Basin and Rocky Mountains. The well-location numbers correspond with the listing in the Appendix containing location data and details of breakout abundance, depth and orientation statistics. Azimuths from wells 149, 150 and 152, which depart from the regional orientation, are based on limited data and may not be reliable.

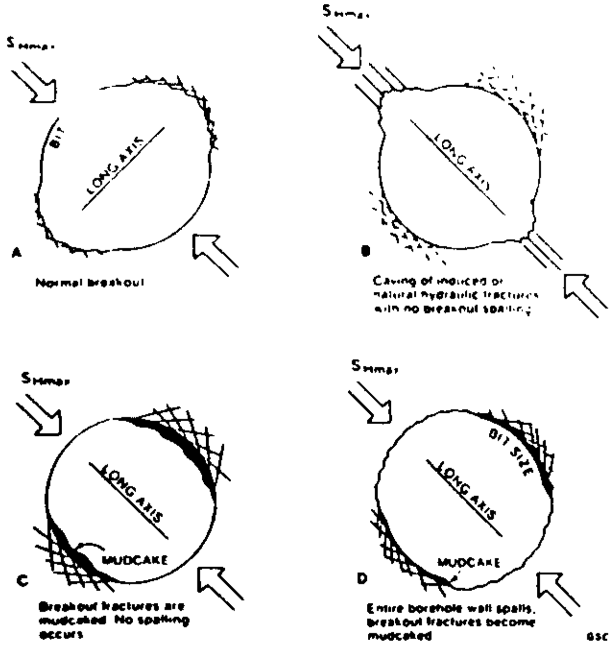


Fig. 5. Possible causes of anomalous breakout orientations discussed in the text.

axis, and so produce wellbore ellipticity normal to the natural breakout direction. An alternative possibility is that high mud pressures during drilling initiated hydraulic fractures locally, which have subsequently caved and extended the borehole because of contributory rock-fabric weaknesses (Fig. 5B).

The majority of the wells analyzed, however, contain nly breakouts with common azimuths which delineate a coherent and consistent picture of principal stress axes across the Western Canada Basin in British Columbia, Alberta and Saskatchewan (Fig. 4). The picture that emerges is one in which S_{Hmin} is oriented more or less parallel to the Rocky Mountains, but there are also areas which exhibit departures from this trend. This is brought out more clearly in Figure 6 where the breakout azimuths have been used to construct a horizontal stress trajectory map of the basin. Between latitudes 55° and 57°N, the breakout azimuths, and inferred stress trajectories, show a significant clockwise rotation relative to those south and north of this region. Fordjor and others (1983) suggest that this rotation of the stress tensor could be related to the Peace River Arch. The area of rotated horizontal principal stresses coincides areally with this subsurface basement peninsula (Fig. 6), and the sense of stress rotation is consistent with the stress tensor refraction such a configuration would produce (Lloyd and Bell, 1985). A similar effect may be present in southern Alberta and Saskatchewan, over the Sweetgrass Arch (Fig. 6). There are also a number of local anomalies in the mean breakout azimuths in the cluster of northwestern Alberta wells (Fig. 4, detail A). These may also be related to an unnamed basement high (Porter and others, 1982) in that area, which is outlined in Figure 6. In regional terms, what the mean breakout azimuths appear to be documenting is a stress province in which S_{Hmax} is oriented approximately NE-SW except where this signature is modified by basement topography. This picture is fully compatible with the stress tensor geometry inferred from the overcoring measurements, induced-fracture orientations and stress-relief features discussed previously.

It is valid to ask how accurate the stress trajectory map of the Western Canadian Basis is likely to be. Control points are somewhat spottily distributed, but there is a consistency to the data which is noteworthy. For example, fifteen closely spaced wells in the West Pembina area exhibit very similar mean breakout azimuths in the Devonian carbonate section. They are all oriented approximately NW-SE (Fig. 7). This implies a similar direction for S_{Hmin}; and if this is also the orientation of the least principal stress in the Cardium Formation at depths of 1600 m to 1700 m, the induced-fracture orientations are well accounted for. Another approach to evaluating the reliability of directional data is to plot only the best. Figure 8 portrays only those wells where the breakout intervals total more than 100 m and the mean azimuths exhibit standard deviations of less than 10°. These forty-four wells constitute a coherent data set compatible with the stress trajectory map (Fig. 6) compiled from all the breakout azimuths.

Implications for Hydrocarbon Recovery

A valuable application of knowing the directions and relative magnitudes of the principal stresses at a point in the Earth's crust is that it permits one to predict the orientation of hydraulically induced fractures. These will open in the plane perpendicular to σ_3, the least principal stress (Hubbert and Willis, 1957). At depths below approximately 350 m in the Western Canadian Basin σ_3 = S_{Hmin}. Hydraulic fractures will, therefore, be vertical and oriented parallel to S_{Hmax}. The stress trajectory map (Fig. 6) is thus a tool for predicting induced-fracture orientations within the area it covers.

Predicting fracture propagation directions can be advantageous in a number of situations. If a well has missed a target such as a pinnacle reef, and the target's location is known, it may prove possible to connect the well to the reservoir by hydraulic fracturing (Fig. 9). This is likely to be a much cheaper option that additional directional drilling. Another possible application, suggested by Hassan (1982), is blowout-well control. Where blowout control involves pumping a heavy slurry down a relief well — if the relief well is so located that predicted hydraulic fractures would intersect the blowout well — there will be a higher chance of establishing communication between the two wellbores.

If the preferred hydraulic-fracture azimuths in an oil or gas field are known, this knowledge can be used to help design the optimum well configuration for development. Negative experience with waterflood-induced fractures within the Cardium Sandstone in the Pembina oil field has shown that oil recovery can be reduced by inappropriate

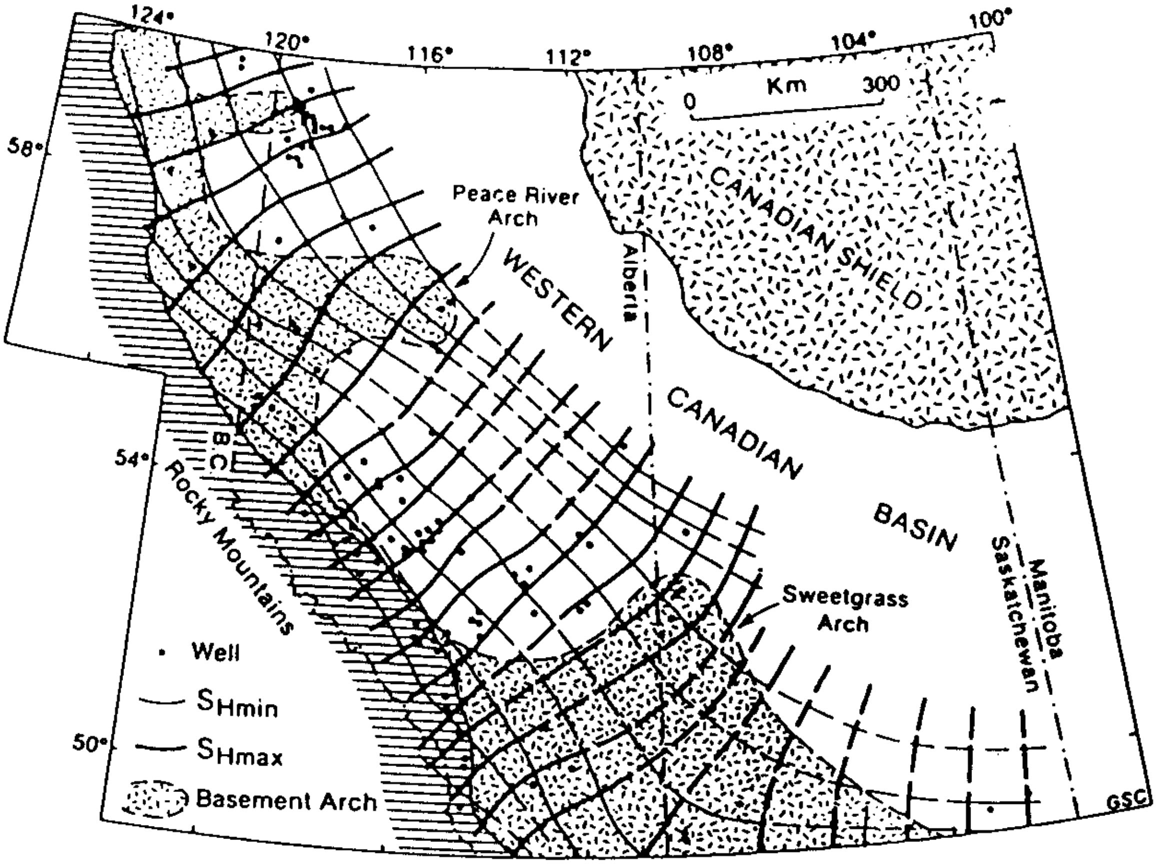


Fig. 6. Possible stress trajectories inferred from breakout orientations in the Western Canadian Basin. Note the deflections of principal horizontal stress directions around basement arches.

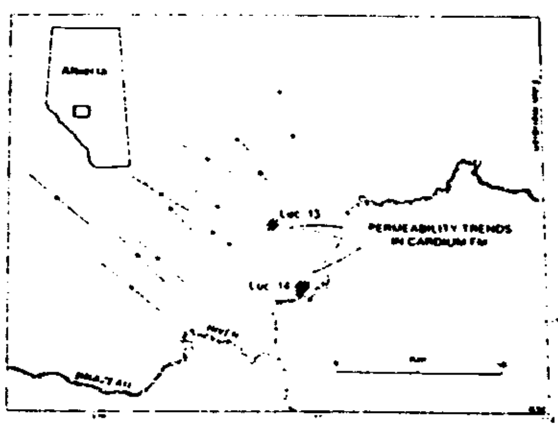


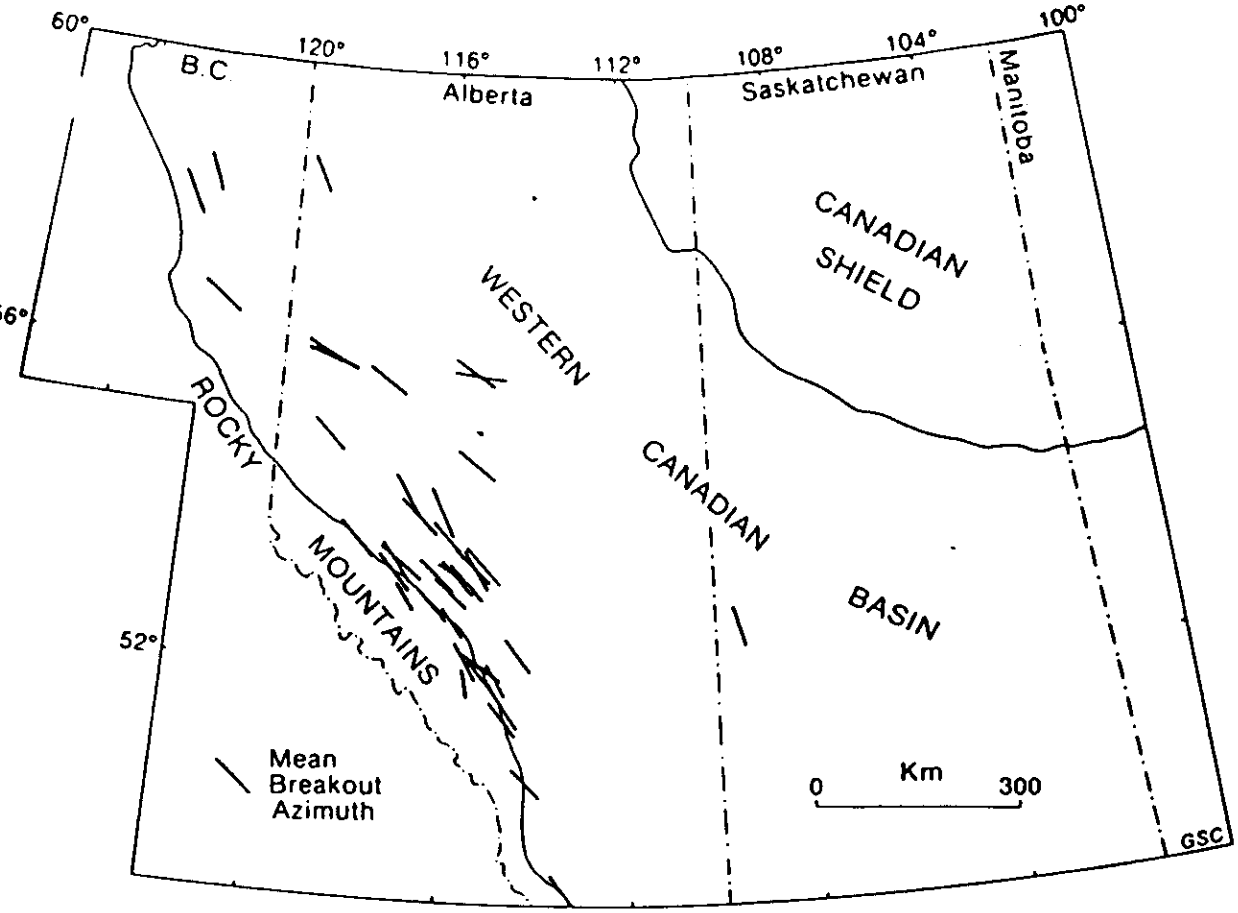
Fig. 7. Consistent NW-SE orientations of the mean breakout azimuths from 15 closely spaced wells in the West Pembina area implying that S_{Hmax} is oriented NE-SW in this area. Inferred hydraulic fractures, expressed as permeability trends in the Cardium Formation sandstone reservoirs, agree with these principal stress directions.

placement of injection and production wells (McLeod. 1977; Hassan, 1982). Figure 10 illustrates an idealized oil field in a reservoir stressed so that hydraulic fractures will be vertical and propagate northeastward and southwestward away from injection wells. Two well configurations are shown. In the "bad" array, injection and production wells along the fracture trend become linked by hydraulic fractures with the result that most of the water flows in one well and out another without sweeping much oil towards other production wells. In the "good" array, injection and production wells are spaced so that hydraulic fractures do not connect wells but distribute the injected water so that it can effectively sweep oil towards many production wells.

The Wattenberg field in the Denver Basin produces from Muddy "J" Formation, tight gas sands requiring massive hydraulic fracturing. The fractures exhibit a preferred orientation of 340° (Smith and others, 1978), and simulation studies suggest that an optimum fracture length is approximately 1200 m (Roberts, 1981). Field monitoring documents gas drainage into the fractures from axially aligned ellipsoidal zones around them, and the most profitable gas wells are those which are spaced so as to exploit the optimum fracture length and preferred orientation (Smith, 1979).

In areas where induced fractures are consistently oriented and thick pay sections are present, drilling inclined wells and spacing a series of fractures along them (Fig. 11) may prove commercially advantageous. For good results, the inclined well should be directed at a high angle to the preferred fracture plane.

Strubhar and others (1975) describe an experimental well drilled through low-permeability chalk in the Caddo-Pine Island oil field of northwestern Louisiana. The well



'g. 8. Mean breakout azimuths of 44 wells containing a large number of consistently oriented breakouts. The total vertical thickness of all .akouts exceeds 100 m per well, and orientation standard deviations are less than 10°. The figure portrays the "best data."

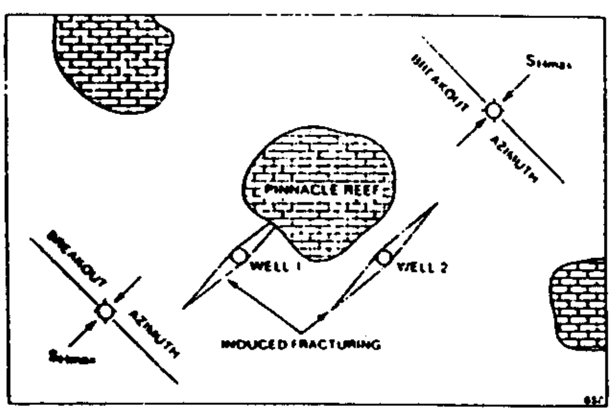


Fig. 9. Prediction of hydraulic-fracture orientation. Horizontal principal stress directions derived from breakouts in nearby wells show that hydraulic fractures propagated from Well 1 could intersect the pinnacle reef target, whereas fractures from Well 2 are likely to miss the reef.

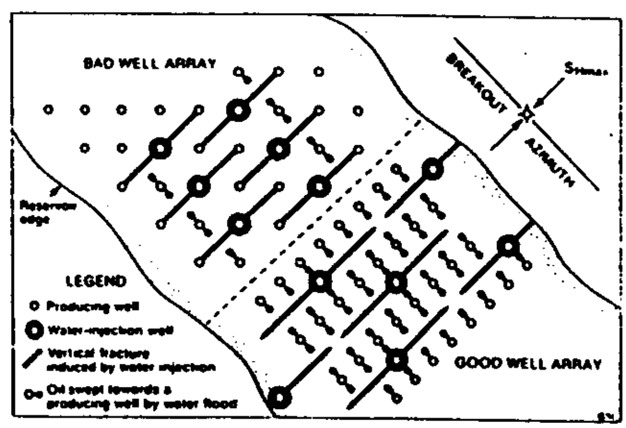


Fig. 10. Well arrays in an idealized oil field where waterfloodin promotes hydraulic fracturing. In the "bad" array, little oil is recovere because induced fractures connect water injection wells with intende production wells. In the "good" array, the induced fractures do not connect wells but distribute the injected water so that it drives oil towar many production wells. Breakouts predict fracture orientations.

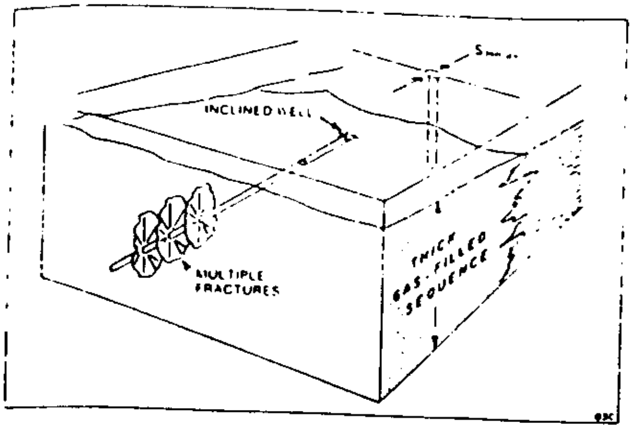


Fig. 11. Schematic diagram showing an inclined well drilled at approximately right angles to S_{Hmax}, from which several spaced fractures have been propagated. This configuration would provide greater reservoir drainage and higher flow rates than could be obtained from a vertical well with a single fracture feeding it. Knowledge of principal stress directions, provided by breakouts, is needed to align such a multifractured inclined well.

was drilled normal to the induced-fracture azimuth at an angle of 52° from the vertical. Four hydraulic fractures were propagated at measured depths of 1540 ft, 1595 ft, 1650 ft and 1700 ft (469 m to 518 m). This multifractured well produced between two and three times as much oil as a conventionally fractured well in the field. The experimental well cost approximately four times as much to drill and complete, but Strubhar and others (1975) believed cost reductions were feasible and that deeper wells could be very cost-effective. In western Canada, much of the 5000-m-thick Mesozoic section of tight, gas-bearing sandstones in the Deep Basin (Masters, 1979) may be profitably produced from multifractured inclined wells.

There are several other implications arising from the anisotropic stress regime in the Western Canadian Basin (Fig. 6). The principal horizontal stress configuration appears to be geometrically related to the overthrust faulting in the Foothills and Rocky Mountains. It is likely that similarly oriented lateral compression was imposed on the basin in early Mesozoic time as the Laramide orogeny evolved. In other words, S_{Hmax} probably has had a generally NE-SW orientation for at least the last 100 million years and maybe longer. Therefore, the sediments in the Western Canadian Basin (of Paleocene age and older) most likely have been subjected to anisotropic horizontal compression for a considerable period: in the case of the Upper Mesozoic sediments this could amount to nearly their entire burial life. One has to ask whether some of these rocks have developed a diagenetic fabric in consequence. To the authors' knowledge, this possibility has not been investigated systematically: however, directional permeability is widely recognized and documented in core analyses performed for company production departments. Uneven solution by pressure cementation of quartz grains could produce anisotropic permeability fabrics in sandstones subjected to unequal lateral compression. In addition, overpressuring in deeply buried sequences could cause natural hydraulic fracturing oriented parallel to S_{Hmax}, which would lead to preferred direction of fluid flow through the affected section. Stylolites, which exhibit preferred orientations in limestones, may also represent a response to anisotropic subsurface stress regimes (Nelson, 1981). From a diagenetic standpoint, mineral transformations that are strongly pressure-dependent may be promoted by S_{Hmax} levels rather than be depth-dependent as heretofore assumed. Clearly, there is much to investigate in documenting how sediments respond over time to high and unequal horizontal stresses.

It is well known that cores recovered from deeply buried rocks expand and fracture on being raised to the surface (Teufel, 1981; Montgomery and Ren, 1983). If these cores have been subjected to unequal horizontal *in situ* stresses, expansion fractures which form will tend to open along vertical planes normal to S_{Hmax}. This possibility should be borne in mind when examining cores, and assessing measurements which apparently diagnose permeability anisotropy in rocks tested under atmospheric conditions.

Implications for Crustal Kinematics

As Fordjor and others (1983) have demonstrated, the stress regime in the Western Canadian Basin is not a local phenomenon. The area lies on the northwestern edge of the Mid-Continent Stress Province (Zoback and Zoback, 1980) in which NE-SW S_{Hmax} azimuths occur in an area bounded by the plains of the United States Mid West, Arkansas, Tennessee, New York State (Zoback and Zoback, 1980), the Canadian Maritimes, the Arctic Islands (Cox, 1983) and the Northwest Territories (Gough and others, 1983). Consistent stress orientation over the whole mid-continent of North America is difficult to ascribe to any cause other than contemporary northeastward traction on the underside of the lithosphere. Other mechanisms are not likely to have imprinted so widespread a stress signature. For example, in the Western Canadian Basin, postglacial uplift might have produced a NE-SW orientation of S_{Hmax} but would have produced a very different orientation in New York State and Ontario. Similarly, pressure exerted on the western Canadian lithosphere by the subducting Juan de Fuca plate might produce the observed compression of the Western Canadian Basin but would not cause the same stress orientation in Arkansas and Missouri (Zoback and Zoback, 1980).

Northeastward traction would arise (1) if the lithospheric plate containing the mid-continent of North America is sliding SW and is experiencing viscous drag from a passive asthenosphere, as suggested by Zoback and Zoback (1980), or (2) if northeastward flow in the underlying mantle is pushing the plate, again by viscous drag (Fordjor and others, 1983). The stress orientations in the Mid-Continent Stress Province alone cannot be used to discriminate between these two possibilities.

To the west of the Mid-Continent Stress Province in the United States of America, Zoback and Zoback (1980) have identified a series of extensional stress provinces in the region between the east front of the United States Rocky Mountains and the Sierra Nevada (Fig. 12). These extensional stress provinces include the Basin and Range, Colorado Plateau, and Rio Grande Rift, and are characterized by contemporary normal faulting in stress regimes where is vertical. Dixon and Farrar (1980), Farrar and Dixon (1980), and Gough (1984) have pointed out that this region is one of current basaltic vulcanism and high heat flow. In addition, they noted that seismological studies indicate that elastic body-wave velocities are reduced and their amplitudes attenuated in the underlying upper mantle. In the same region, magnetometer arrays have recorded anomalous electrical conductivity so distributed that it correlates positively with heat flow and the seismic low-velocity high-attenuation layer (Gough, 1974). As Farrar and Dixon (1980) and Gough (1984) emphasized, this close association of vulcanism, high heat flow, low seismic velocity and electrical conductivity is most logically accounted for in terms of partial melting in the uppermost mantle and a concurrent upflow of mantle material. The area involved is undergoing extension, as would be expected above an upcurrent in the mantle. Now an extensional stress province of these dimensions (Fig. 12), between the Great Plains and the Sierra Nevada, could not exist in this location if the North American plate were sliding over a passive asthenosphere towards the southwest. Such kinematics would require NE-SW compression to continue westward as far as the Sierra Nevada or even to the San Andreas fault zone. The observed extensional stress regime, with σ_1 vertical, implies vertical pressure from below and points to a mantle upcurrent which bends over towards the northeast to push the North American plate northeastward by viscous drag (Fig. 13). As Houseman (1983) has shown, such viscous drag could be provided by a large aspect ratio convection cell driven by lateral, rather than vertical, temperature differences in the mantle.

In that the postulated region of mantle upflow is likely to have originally formed part of the East Pacific Rise (Dixon and Farrar, 1980; Gough, 1984), the proposed mechanism for plate dynamics is analagous to "ridge-push." Solomon and others (1980) found that much of the reliable intraplate stress orientation data obtained from earthquake mechanisms agreed well with predictions from a model that included ridge push as one of the driving forces of plate tectonics. Recently, Newmark and others (1984) have measured breakout azimuths in the Deep Sea Drilling Program holes drilled in the East Pacific Ocean and obtained principal stress orientations which are also consistent with ridge push by the East Pacific Rise and the Costa Rica Rift.

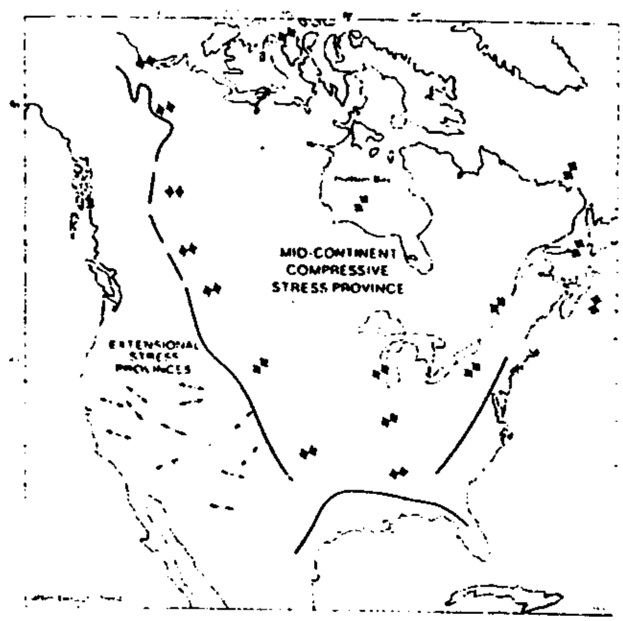


Fig. 12. North American stress provinces. Pairs of broad arrows show the directions of the greater horizontal stress within the North American Mid-Continent Stress Province. The two-headed thin arrows indicate the directions of the lesser horizontal principal stress in the extensional stress provinces recognized in the western United States. Stress orientation data are summarized from Zoback and Zoback (1980), Cox (1983) and Gough (1984). The Hudson Bay orientation comes from studies in progress by Bell.

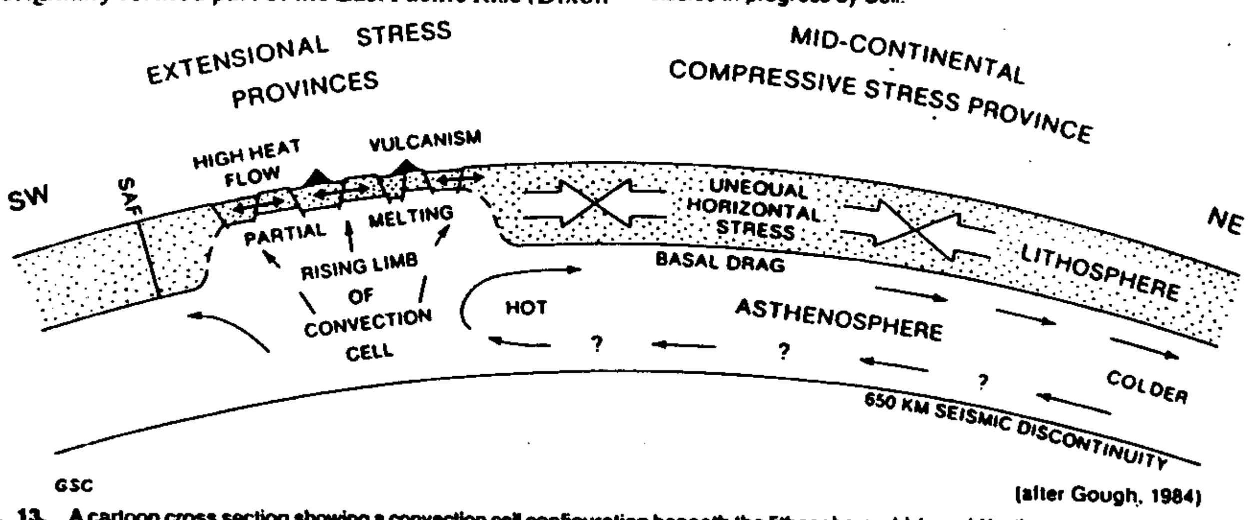


Fig. 13. A cartoon cross section showing a convection cell configuration beneath the lithosphere which could be the cause of the stress regime the Mid-Continent Stress Province. Stress arrow symbols correspond to those of Figure 12. SAF — San Andreas Fault; lithosphere is stippled.

In summary, it appears probable that the anisotropy in the stress regime of the Western Canadian Basin is largely caused by the mid-American lithosphere's being pushed northeastward by a mantle convection cell which rises beneath western North America.

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Appendix

						S_{Hmin}		S_{Hmax}	
						Mean Breakout Azimuth			
Well Number	Well	Number of Breakouts	Total Breakout Thickness Logged in Metres	Shallowest Breakout (m below KB)	Deepest Breakout (m below KB)	Major Population (Standard Deviation)	Minor Population (Standard Deviation)	Predicted Hydraulic Fracture Azimuth	Data Source
1	b-45-A-94-P-14	6	9.7	1745.5	1815.6	060.9 (17.1)		—	3
2	b-45-1-94-P-11	11	219.4	280.4	1755.6	168.2 (10.8)		078 (±11)	2*
3	03-11-121-7W6	2	9.1	1481.3	1622.1	159.2 (2.8)		069 (±3)	3*
4	03-01-119-9W6	4	48.5	469.4	1751.2	140.4 (15.2)		050 (±15)	3
5	02-36-118-8W6	4	42.4	1488.5	1666.6	153.0 (9.6)		063 (±10)	3, 1
6	09-15-118-8W6	3	39.4	1578.1	1665.9	128.7 (0.8)		039 (±1)	3
7	14-09-118-8W6	4	42.4	299.9	794.9	141.3 (11.9)		051 (±12)	3
8	14-36-116-6W6	3	24.2	1343.5	1479.4	037.1 (13.0)		—	3
9	12-33-116-6W6	8	54.5	274.9	1517.2	139.7 (6.0)	48.9 (12.9)	050 (±6)	3*
10	15-09-116-6W6	2	12.2	1315.4	1352.7	172.2	86.2	082	4
11	03-01-116-1W6	2	6.1	1512.3	1565.9	146.4	55.3	056	4
12	05-28-115-4W6	2	18.2	1350.2	1420.9	153.3 (3.6)		063 (±4)	3
13	15-29-115-3W6	12	209.1	488.9	1288.0	178.1 (21.0)		088 (±21)	3*
14	12-33-114-5W6	1	36.6	1456.0	1494.9	119.8		030	4
15	13-35-112-10W6	13	109.1	1378.3	1799.5	150.8 (11.4)		061 (±11)	3
16	03-21-112-6W6	2	12.1	1336.8	1420.9	159.0 (0.9)		069 (±1)	3
17	09-09-112-7W6	3	43.3	1440.4	1631.8	149.9 (3.8)		060 (±4)	1*
18	d-35-J-94-I-12	6	579.1	1135.0	2135.3	152.7 (13.6)	80.5 (2.6)	063 (±14)	2
19	10-17-110-9W6	5	223.1	1416.6	1732.4	155.3 (9.7)		065 (±10)	3, 5
20	05-33-109-8W6	3	48.5	1589.2	1695.8	113.3 (29.1)		—	3*
21	15-29-109-8W6	3	73.8	1523.9	1644.0	142.5 (7.2)		053 (±7)	5
22	07-18-109-7W6	9	42.4	1497.1	1789.7	13.0 (6.4)		—	3
23	d-84-G-94-J-8	9	333.4	1507.5	2134.7	156.7 (8.8)		067 (±9)	2*
24	b-14-G-94-J-2	6	168.9	2332.8	2598.6	152.2 (4.8)		062 (±5)	2
25	11-1-100-20W5	2	31.1	112.5	1438.6	154.6 (5.5)	53.5 (4.6)	065 (±6)	2*
26	10-25-96-10W6	3	65.2	2240.2	2344.4	136.3 (9.9)		046 (±10)	2*
27	01-28-96-5W6	9	81.7	1809.8	2295.6	143.0 (11.4)	173.0 (3.8)	053 (±11)	2*
28	d-53-B-94-A-13	3	156.0	1030.1	1240.4	126.0 (3.6)		036 (±4)	2
29	06-29-88-7W5	6	55.5	1214.3	1328.9	133.9 (20.4)		044 (±20)	2*
30	4-30-87-8W5	4	75.9	1055.8	1352.6	118.0 (10.0)		028 (±10)	5
31	10-29-87-8W5	4	2.4	1356.9	1360.0	145.5 (0)		056	5
32	07-07-86-1W6	4	52.4	1700.4	2024.1	116.2 (9.8)		026 (±10)	3*
33	09-18-83-6W6	10	213.3	1563.0	2306.6	115.4 (4.5)		025 (±5)	3
34	16-24-82-12W6	17	408.0	320.0	1257.8	117.2 (13.8)		027 (±14)	6
35	12-24-82-6W6	10	277.4	1482.4	1964.6	105.8 (6.4)		016 (±6)	3
36	11-29-82-5W6	12	163.9	1426.4	2106.1	109.7 (5.7)	80.2 (5.5)	020 (±6)	2*

37	09-05-82-9W5	3	12.2	1569.0	1609.3	067.1 (5.0)		[illegible]	3
38	11-36-81-10W5	7	21.3	1514.8	1564.5	109.3 (5.8)		[illegible] (±6)	1
39	14-21-81-9W5	1	24.4	1731.1	1762.3	120.9		[illegible]	4
40	14-20-81-9W5	17	301.7	239.6	1544.0	123.1 (8.7)		[illegible] (±9)	3
41	02-20-81-9W5	5	97.5	1244.7	1387.4	115.3 (0.8)		025 (±1)	3
42	04-15-81-9W5	3	21.3	1497.1	1575.7	116.6 (2.5)		027 (±3)	3
43	10-09-81-9W5	1	12.2	1694.6	1706.8	123.4		033	4
44	05-03-81-9W5	9	188.9	1011.9	1720.8	97.8 (4.9)		008 (±5)	3
45	14-35-79-23W6	10	370.6	1234.3	2550.4	124.1 (8.7)		034 (±9)	2*
46	11-01-76-2W6	6	66.4	2073.8	2388.3	114.8 (7.6)	86.8 (5.3)	025 (±8)	2*
47	10-11-71-11W6	55	910.0	239.6	1857.9	133.8 (6.2)		044 (±6)	6
48	10-16-69-11W6	2	17.0	2215.0	2235.0	120.5 (8.2)		031 (±8)	6
49	13-19-69-8W6	29	328.8	2975.9	3990.8	131.5 (14.5)		042 (±14)	1
50	13-20-67-9W5	11	134.1	2025.0	2249.9	127.2 (5.8)		037 (±6)	1
51	10-26-66-5W6	17	74.7	1828.1	2254.8	131.2 (9.4)		041 (±9)	1
52	12-08-66-5W4	1	2.0	477.0	479.0	131.0 (3.0)		041 (±3)	2
53	16-23-62-20W5	15	256.9	1209.4	2062.1	147.1 (6.5)		057 (±7)	1
54	10-07-60-14W5	11	103.6	2271.9	2638.8	154.3 (8.8)		064 (±9)	3
55	12-13-59-18W5	4	48.8	3043.6	3342.2	136.5 (9.3)		047 (±9)	5
56	02-29-59-22W5	41	573.0	2346.8	3920.1	135.0 (10.4)		045 (±10)	3
57	02-01-59-18W5	20	132.6	3129.5	3444.0	133.6 (9.8)		044 (±10)	5
58	06-06-59-17W5	16	198.7	3091.7	3467.2	138.9 (11.9)		049 (±12)	5
59	01-26-58-18W5	8	37.2	3229.5	3541.6	135.5 (8.7)		046 (±9)	5
60	12-23-58-18W5	10	39.6	3259.9	3482.4	137.9 (3.6)		048 (±4)	5
61	04-29-57-3W5	2	12.2	1336.1	1697.0	135.0 (4.8)		045 (±5)	2*
62	11-24-56-14W5	8	118.6	2791.8	3027.1	136.2 (7.2)		046 (±7)	5
63	1-16-55-27W5	48	1217.3	3545.8	5263.6	132.9 (6.8)		043 (±7)	5
64	11-23-53-2W6	32	545.9	1573.9	2462.7	134.7 (14.2)	175.0 (6.0)	045 (±14)	5
65	12-19-53-8W5	4	79.9	1983.5	2376.1	123.8 (2.4)		034 (±2)	3
66	16-16-52-21W5	13	89.0	3699.2	4078.3	124.9 (4.6)		035 (±5)	3
67	03-05-52-21W5	16	125.0	3830.5	4381.0	142.3 (7.2)		052 (±7)	2*
68	07-10-52-10W5	10	101.2	2188.4	2530.3	132.2 (6.1)		042 (±6)	2
69	13-09-52-8W5	20	443.0	469.4	2192.6	137.4 (7.5)		047 (±8)	3
70	06-01-52-13W4	3	153.0	1362.0	1924.0	131.8 (10.5)		042 (±11)	6
71	2D1-10-52-23W	4	51.0	364.0	532.0	120.7 (4.0)		031 (±4)	6
72	6-30-51-20W5	17	322.8	3544.0	4152.0	129.4 (8.6)		039 (±9)	5
73	04-26-51-11W5	2	15.8	2616.6	2640.4	119.8 (3.3)		030 (±3)	3
74	05-09-51-9W5	2	103.0	2062.5	2409.6	147.8 (2.1)		058 (±2)	3
75	08-08-51-9W5	8	30.0	684.9	747.0	134.7 (3.8)		045 (±4)	3
76	10-004-51-9W5	1	20.1	2437.1	2457.2	131.8 (2.6)		042 (±3)	2
77	10-12-50-27W5	30	1200.0	303.0	2570.5	145.6 (14.4)	27.2 (18.3)	056 (±14)	5
78	2-14-50-22W5	53	788.2	3322.2	4858.3	138.7 (9.3)		049 (±9)	5
79	06-20-50-15W5	41	295.8	2789.1	3682.1	132.5 (9.1)		043 (±9)	3
80	14-20-50-12W5	24	126.7	2263.0	2894.8	122.4 (4.7)		032 (±5)	3
81	01-09-50-12W5	27	118.0	2645.3	3172.2	137.3 (8.6)		047 (±9)	2
82	06-12-50-11W5	12	87.0	756.2	833.6	126.3 (2.9)		037 (±3)	3
83	11-22-50-11W4	3	38.4	513.8	573.6	146.0 (2.3)		056 (±2)	1
84	07-09-49-24W5	71	707.9	453.2	4228.3	156.7 (21.3)		067 (±21)	3
85	03-36-49-23W5	84	1013.3	477.6	5485.2	151.2 (10.6)		061 (±11)	3
86	15-15-49-11W5	15	157.0	2409.0	2916.0	138.6 (8.9)		049 (±9)	6
87	13-05-49-10W5	6	412.7	2340.7	2897.3	136.8 (7.5)		047 (±8)	2*
88	15-28-48-13W5	2	28.9	3167.3	3250.5	137.0 (3.2)		047 (±3)	2*
89	06-30-48-12W5	12	73.3	3064.6	3472.4	133.9 (4.1)		044 (±4)	2.3
90	10-32-48-4W5	4	42.4	1525.8	1717.8	124.1 (5.2)		034 (±5)	1*
91	16-25-47-21W5	17	175.3	4801.6	5219.7	146.6 (9.7)		057 (±10)	5
92	03-32-47-13W5	23	159.4	2919.5	3405.9	131.3 (7.6)		041 (±8)	3
93	06-30-46-17W5	51	933.3	991.8	3650.1	145.9 (10.8)		056 (±11)	3
94	11-27-46-21W4	6	65.8	976.5	1322.8	138.8 (7.1)		049 (±7)	5
95	10-27-45-16W5	14	406.7	3728.4	4693.4	135.3 (2.3)		045 (±2)	3
96	10-25-45-15W5	11	61.8	3192.6	3480.0	148.3 (3.8)		058 (±4)	3
97	10-24-45-24W4	3	70.7	1119.1	1228.2	149.2 (4.3)		059 (±4)	1*
98	11-21-44-20W5	27	696.1	2687.0	4230.4	134.1 (20.1)	29.0 (9.8)	044 (±20)	5
99	14-10-44-22W4	3	9.1	1319.1	1420.3	133.7 (8.2)		044 (±8)	5
100	11-22-43-13W5	6	251.1	3433.4	3889.1	143.5 (7.6)		054 (±8)	5
101	06-07-43-24W3		125.0	440.0	713.0	162.9 (9.7)		073 (±10)	6
102	09-29-42-25W3	1	14.0	514.0	528.0	117.7 (3.8)		028 (±4)	6
103	16-10-41-12W4	9	171.9	210.3	838.2	142.2 (11.5)		052 (±12)	1*
104	07-25-40-12W5	4	20.7	4329.8	4413.3	132.3 (8.7)		042 (±9)	5
105	15-10-40-13W4	4	33.5	798.5	975.3	128.9 (12.4)		039 (±12)	1*
106	04-04-39-11W5	9	81.1	4299.9	4647.9	144.4 (8.9)		054 (±9)	5
107	10-35-39-2W5	5	72.2	1820.1	2093.8	131.6 (11.4)		042 (±11)	5
108	16-24-39-21W4	8	14.3	1222.2	1520.0	140.8 (4.8)		051 (±5)	1*
109	12-5-39-26W3	1	8.0	644.0	652.0	136.8 (1.4)		047 (±1)	6
110	06-01-38-10W5	7	46.0	640.7	3992.7	120.2 (7.1)		030 (±7)	5
111	10-23-38-3W5	9	109.4	2182.8	2957.6	141.7 (8.8)		052 (±9)	1

-	07-10-38-2W5	8	60.3	1892.7	2196.3	136.7 (13.9)		047 (±14)	1*
13	11-36-38-27W3	1	35.0	533.6	599.0	143.7 (5.7)		054 (±6)	6
14	14-21-37-11W5	30	927.3	2218.8	5149.0	151.0 (4.7)		061 (±5)	3
1	06-17-37-9W5	39	527.3	2165.8	3124.0	121.9 (2.9)		032 (±3)	3
	06-08-36-8W5	3	265.2	2435.8	2718.0	122.7 (3.0)		033 (±3)	5
	11-[illegible]-7W5	8	49.7	3381.3	3351.9	153.1 (4.7)		063 (±5)	5
18	02-[illegible]-28W3	1	16.0	749.0	765.0	150.5 (2.8)		061 (±3)	6
119	05-05-35-11W5	12	284.8	4401.4	5129.2	170.7 (8.5)		081 (±9)	3
1	07-03-35-8W5	77	1685.5	283.5	2800.9	142.2 (12.6)	41.2 (15.2)	052 (±13)	5
1	01-12-35-7W5	9	259.0	2400.0	3078.0	148.7 (7.5)		059 (±8)	6
122	11-20-35-1W5	20	38.7	2357.8	2854.0	133.0 (5.4)		043 (±5)	1
123	09-06-35-26W3	1	2.0	833.0	835.0	142.5 (1.2)		053 (±1)	6
124	02-13-34-11W5	7	39.0	3943.9	4680.3	138.3 (5.8)		048 (±6)	3
125	03-32-34-8W5	9	618.1	1389.8	2743.6	139.3 (7.2)		049 (±7)	3
126	07-22-33-8W5	31	2086.9	493.8	3719.3	151.8 (26.9)	61.0 (27.5)	061 (±27)	5
127	07-17-33-7W5	17	655.3	483.4	2459.6	136.3 (13.1)		036 (±13)	3
128	06-16-33-7W5	72	956.7	298.1	2693.7	154.4 (16.5)		064 (±17)	5
129	12-2-30-5W5	25	535.8	3372.2	4108.5	145.6 (7.0)		057 (±7)	5
130	10-21-29-5W5	14	624.5	3523.3	4293.8	145.4 (12.1)		055 (±12)	5
131	06-33-28-5W5	28	514.8	1833.3	2569.3	141.9 (2.7)		052 (±3)	5
132	12-33-25-6W5	60	1291.3	618.7	2762.5	155.2 (27.7)		065 (±30)	5
133	15-15-24-6W5	21	312.4	1733.0	2602.9	126.5 (14.0)	48.0 (6.3)	037 (±14)	5
134	05-15-22-5W5	23	205.4	1569.6	2031.1	134.7 (15.3)		045 (±15)	5
135	10-29-21-19W4	3	3.7	1204.5	1313.0	143.2 (17.2)		053 (±17)	1
136	06-07-21-4W5	21	150.3	1482.4	1897.6	147.6 (15.1)		058 (±15)	5
137	5-27-20-4W5	46	163.0	1063.7	1984.8	153.9 (14.9)	74.7 (4.7)	064 (±15)	5
138	11-12-19-2W5	26	209.7	2505.9	2972.3	136.7 (5.8)		047 (±6)	1
139	10-16-16-3W5	34	827.2	298.7	2744.3	140.3 (23.8)	63.4 (17.2)	050 (±24)	5
140	10-04-15-3W5	49	204.8	1221.5	2923.5	141.9 (13.4)		052 (±13)	5
141	10-21-15-15W4	6	142.0	114.6	636.4	163.2 (18.4)		073 (±18)	6
142	10-16-13-26W4	15	34.4	1825.7	2141.4	138.0 (5.7)		048 (±6)	1
143	10-25-12-26W4	15	39.6	1982.0	2191.4	143.3 (7.3)		053 (±7)	1
144	11-19-12-25W4	7	25.0	1825.7	1953.1	129.1 (6.9)		039 (±7)	1
145	14-30-12-21W4	3	26.8	1082.6	1274.9	136.0 (1.6)		046 (±2)	1
146	10-30-12-21W4	11	19.2	1279.5	1368.5	151.2 (8.8)		061 (±9)	1
147	04-23-09-4W5	5	17.1	2724.7	2789.4	121.0 (8.4)		031 (±8)	1*
148	06-11-09-4W5	11	614.1	1808.6	3028.3	127.2 (25.2)	57.2 (15.5)	037 (±25)	5
149	16-07-09-18W3	2	9.0	1303.0	1380.0	102.7 (12.3)		013 (±12)	6
150	16-22-06-3W2	2	13.0	1151.0	1191.0	095.7 (4.0)		006 (±4)	6
1	11-05-05-27W3	2	25.0	1270.0	1360.0	132.8 (10.0)		043 (±10)	6
2	16-33-04-9W2	2	118.9	2279.8	2398.6	100.1 (32.4)		010 (±32)	6
153	06-28-04-27W3	2	48.0	1272.0	1362.0	139.5 (3.9)		049 (±4)	6
1	03-02-02-26W4	4	158.0	2897.0	3086.0	142.8 (2.4)		053 (±2)	6

Data Sources:
1. Babcock, 1978
2. Gough and Bell, 1981
3. Fordjor, Bell and Gough, 1983
4. Fordjor, M.Sc. Thesis, 1982
5. Babcock, this study
6. Bell, this study

*Mean Breakout Azimuth recalculated for this study

A Modeling Approach for Optimizing Waterflood Performance, Slaughter Field Chickenwire Pattern

James E. Thomas, SPE-AIME, Amoco Production Co.
Vance J. Driscoll, SPE-AIME, Amoco Production Co.

Introduction

The 3,200-well Slaughter field is one of Texas' major fields. It is on the North Basin Platform in West Texas, approximately 35 miles west-southwest of Lubbock. The field was discovered in April, 1937, and most drilling took place in the late 1940's. It produces 32°API sour crude from the San Andres dolomite formation of Permian age at an average depth of 5,000 ft. The formation is relatively heterogeneous; its structure is a monocline, dipping at less than 1° to the south-southeast. The field covers an area of approximately 100,000 acres and currently has 2,311 producing wells and an estimated 903 water injection wells. The producing rate of 113,000 BOPD (July, 1972) ranks fourth in Texas. Cumulative production to Jan. 1, 1972, was 464 million bbl.

Field discovery and bubble-point pressure was 1,710 psia at 1,250 ft (subsea). Except for several minor gas injection projects, the field produced by a solution gas drive until waterflooding operations commenced during the mid 1960's on many leases. The field is not being produced as one fieldwide secondary recovery unit but consists of a group of smaller units and cooperating lease floods. Water injection operations are currently being conducted on practically every major lease or unit.

A unique spacing exists in much of the field since that part of West Texas was originally surveyed in the Spanish land measurements of hectares, labors, and leagues. A large portion of the field was developed with a density of five wells per labor (35.4 acres per well). Four wells usually were drilled at locations 440 to 500 ft from the respective labor lines and a fifth well was drilled in the center of the labor. Many of the early Slaughter Field waterflood projects started as cooperative lease-line injection projects or peripheral waterfloods. These were later converted to a unique pattern when it was determined that an increased injection-to-producing-well ratio was necessary for more effective flooding in this low-permeability reservoir.

Fig. 1 shows the two-injector, three-producer pattern that Slaughter Field operators call the "chickenwire" pattern. The pattern results in six injectors enclosing three producing wells. A repeating developed chickenwire pattern results in a net injector: producer ratio of 2:3 during secondary operations as opposed to a ratio of 1:1 for the conventional five-spot pattern.

The chickenwire pattern resulted in an intensification of flooding. However, it was not obvious whether or not this was the optimum pattern or to what degree waterflood recovery might be influenced by previous unbalanced injection. Even with this intensified injection pattern, most flood rates would be relatively low and the projects long-lived. Thus, it was decided several years ago to do a model study of a typical area of the field. This study would investigate the effects of imbalance and additional drilling or well conversions on rates and ultimate recovery.

A two-dimensional areal simulation indicated significant trapping of oil between center and off-center producers in this unique waterflooding pattern. For typical conditions, the predicted ultimate recovery of 41 percent of original oil in place was increased to 44.6 percent by drilling additional producers between center and off-center producing wells.

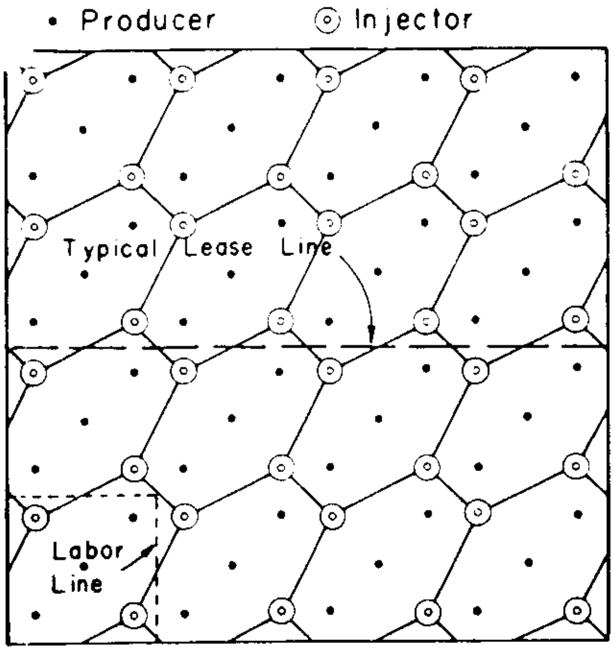

Fig. 1—Typical chickenwire patterns.

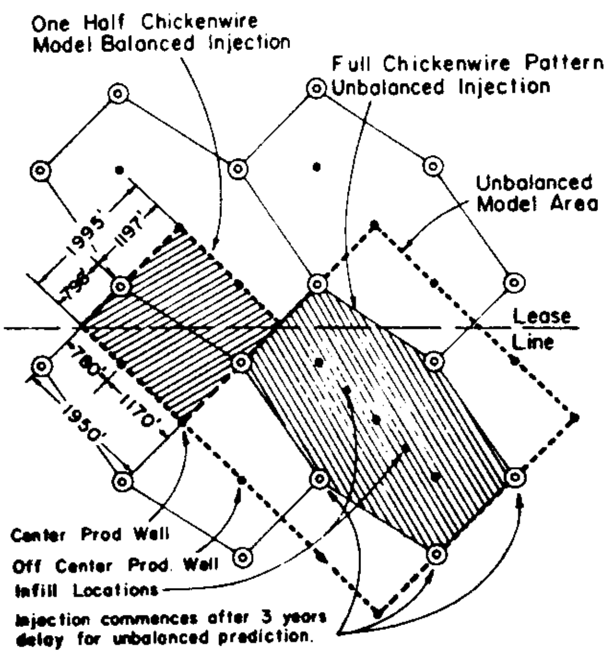

Fig. 2—Area of one-half chickenwire model (balanced injection case) and area of larger model (unbalanced case).

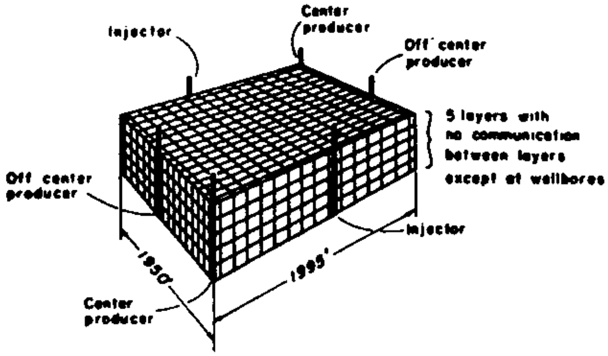

Fig. 3—Three-dimensional view of two-dimensional multilayered areal balanced model (one-half chickenwire pattern).

Various sensitivity runs and allowances for variations in formation capacity and oil in place would then permit scaling and application to a number of other areas of the field not specifically investigated.

Model Description

A two-dimensional, three-phase multilayer "black oil" mathematical reservoir simulator[4] was used to investigate waterflood performance. Fig. 2 presents a diagram of the 16 × 16 mesh configuration used to stimulate one half of a chickenwire pattern. It contains a net of one injector and one and one-half producers. This one-half-chickenwire area is the smallest repeatable element of the pattern using rectangular grid blocks that can be used to simulate the interactions between injectors and producing wells in the pattern with balanced injection. Fig. 3 presents a three-dimensional view of the two-dimensional multilayer areal model used.

The advantage of modeling a portion of a pattern or a segment of a reservoir, instead of an enlarged reservoir area, is that the grid pattern can be fine enough for interfaces between the injected water and oil to be mapped without incurring the computing costs of a larger area using the same grid density. A fairly fine grid, along with a multilayer model, eliminates the need to modify laboratory-derived relative permeability data for pseudo stratification effects. It also enhances the resolution of areal and vertical sweep displacement efficiencies, which were critical parameters in this investigation. The effect of grid size on calculated rate forecasts has been discussed in other papers.[1,2]

The particular model configuration used for this study (Fig. 3) resulted in individual cell dimensions of 130 × 133 ft (0.397 acres), with a reservoir pore volume of 4,434 bbl. Corner blocks had one-fourth this pore volume, and edge blocks had one-half. Figs. 2 and 3 show that the chickenwire center producing wells are quarter wells in the model element and the other wells are half wells.

Reservoir Parameters

Table 1 gives parameters used for the particular model runs being discussed. Some predictions were made with other parameters, but those listed are considered typical.

All the model predictions were run with the assumption that injection remained in the matrix pay. Amoco has run step-rate tests on its Slaughter Field injection wells and follows a policy of injecting water at pressures below reservoir parting pressures. The areas being studied were at less than top allowable and production would be at capacity conditions even with waterflood response. Thus, the only rate restraint on the model was a minor restraint on the initial water injection rate to correspond with field practices as to actual maximum injection rates.

A plot of the oil-water relative permeability used is given in Fig. 4. Fig. 5 presents the linear fractional flow curve calculated from these relative permeability data and the oil and water viscosities.

Where injection rates are critical and at capacity, it is important to calibrate the model by comparing

TABLE 1—DATA USED IN BASE-CASE, ONE-HALF CHICKENWIRE PREDICTION MODEL, SLAUGHTER FIELD

Average permeability, md	10.0
Porosity, percent	12
Net pay thickness, ft	60
kh, md-ft	600
φh, percent-ft	720
Number of layers	5
Number of grid blocks per layer	256
Number of total grid blocks	1,280
Bottom-hole injection pressure limit, psig (SP = 1,200 psig)	3,170
Reservoir pressure at start of waterflood, psig	400
Geometric condition ratio—injectors (effective wellbore radius: 11.8 ft vs 0.198 ft nominal)	2.0
Geometric condition ratio—producers (effective wellbore radius: 3.36 ft vs 0.198 ft nominal)	1.5
Stratification factor for layers	20
Initial gas saturation, percent	18
Initial water saturation, percent	13
Oil viscosity at 400 psig, cp	2.27
Water viscosity, cp	0.65
Mobility ratio at breakthrough	0.23
Initial oil formation volume factor	1.228
Oil formation volume factor at 400 psig	1.113
Pore volume, bbl	4,988,000
Original oil in place at bubble point, STB	3,534,000
Estimated ultimate primary recovery at 100 psig abandonment pressure (5,700 bbl/acre, or 14.4 percent of original oil in place), STB	509,000

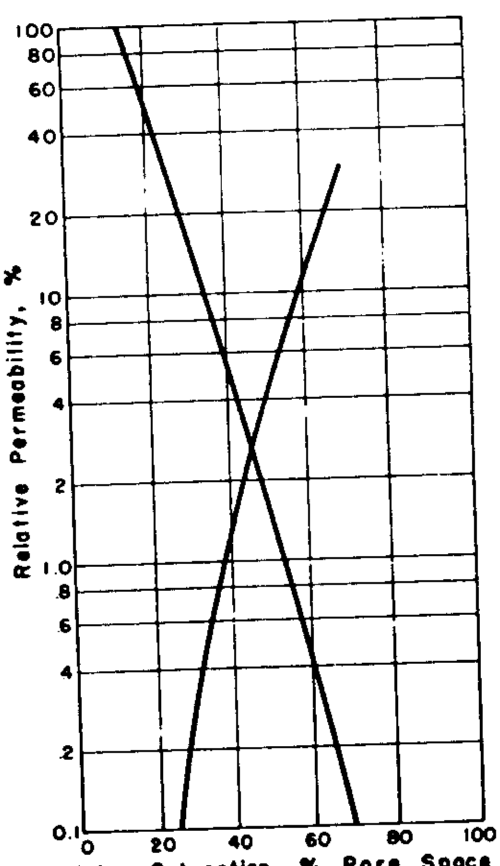

Fig. 4—Oil-water relative permeability relationship used in model runs.

the actual injection rates (Injectivity Index) on a number of injection wells (before interference) with injectivities predicted by the model for the same cumulative injection divided by ϕh. This approach was used in calibrating the parameters used in the model and in applying the results to other areas of the field.

The average permeability per foot of net pay appears to vary from about twice to about one-half the particular value modeled. Lower values are indicated in certain extreme edge areas. All these indicated values of permeability are in turn interrelated to the relative permeability curve and effective wellbore sizes used. Although a typical ultimate primary recovery is 5,700 bbl/acre, values range from less than 1,000 to as high as 12,000 bbl/acre.

Stratification

An attempt to predict waterflood performance in a West Texas dolomitic reservoir like the Slaughter field must consider stratification to account for reservoir heterogeneity. The model used in this particular study predicts the movement of oil, gas, and water through a reservoir composed of horizontal layers that are in communication only at the wellbore. Five layers of equal ϕh were used to describe stratification effects.

A logarithmic permeability distribution method[3,4] was used in describing the permeabilities for the five layers with a permeability stratification factor (k_{max}/k_{min}) of 20. This stratification factor was determined by averaging the permeability and porosity from core samples above a cutoff limit into successive 5-ft groupings, determining average permeability, porosity, and k/ϕ values for these 5-ft groupings, and then sorting the k/ϕ values in ascending k/ϕ order. The resulting relationship was plotted on semilogarithmic paper vs percentage of cumulative porosity feet.

The best straight line was drawn through these data points. Intercepts at 0 and 100 percent of cumulative porosity feet had a k_{max}/k_{min} relationship of about 20 to 1. A percentage of permeability feet for each

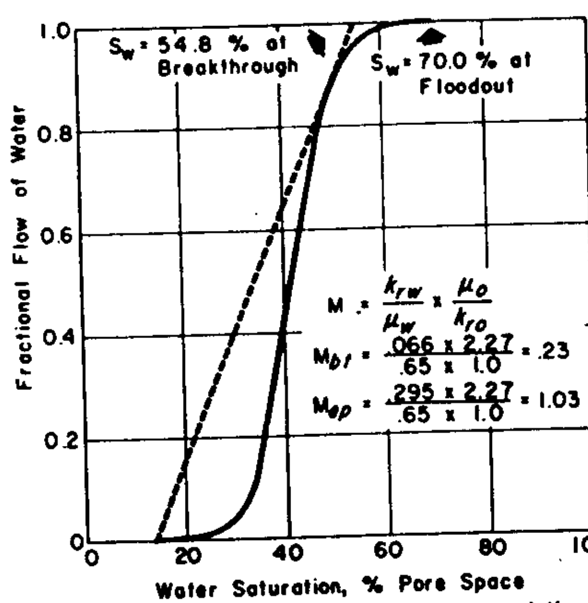

Fig. 5—Fractional flow curve. Calculated from relative permeability and fluid viscosities used.

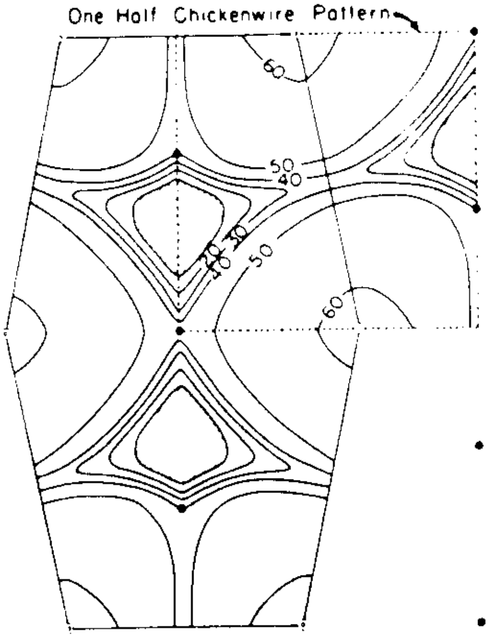

Fig. 6—Water saturation map from results of balanced one-half chickenwire model. Saturations are for Layer 2 after injection of water volume equal to 145 percent of gas-phase volume (10.5 years). Cross-hatched area is model area with original water saturation.

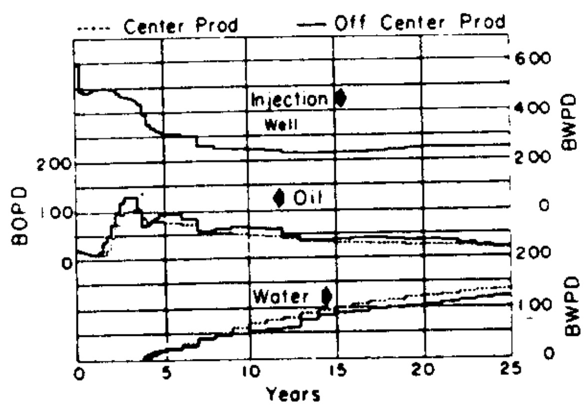

Fig. 7—Individual well performance vs time; balanced model, base case.

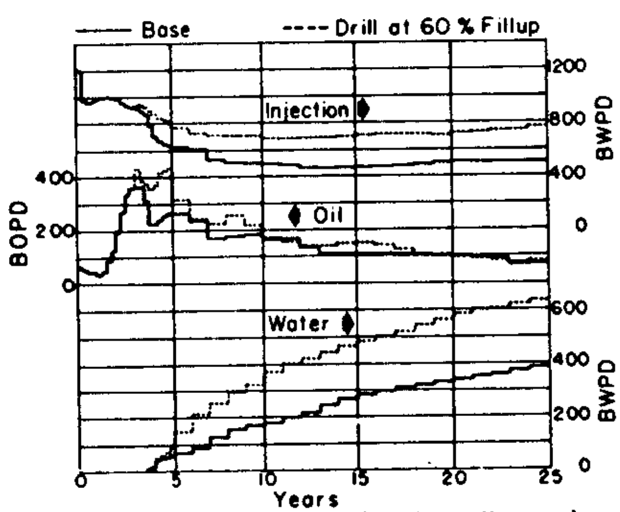

Fig. 8—Predictions for full chickenwire pattern — base case and "drill at 60 percent of gas-phase fillup" case, two injectors and three or five producers.

of the five layers was then determined from this logarithmic distribution. It has been found in a number of West Texas waterflood studies that this procedure for assigning a permeability variation permits an approximate matching of performance with this type of model where some crossflow plus limited numerical model dispersion exists.

The permeability used for the five equal porosity-foot layers for the particular prediction reported here are listed below:

Layer	Permeability (md)
1	23.95
2	12.94
3	7.10
4	3.90
5	2.11
Average of all layers	10.00

This permeability distribution is equivalent to a Lorenz coefficient[4] of 0.49. It is also roughly equivalent to a log-normal variation factor of 0.63 as used by Dykstra-Parsons.[5,7]

Base Prediction

The primary reasons for modeling the Slaughter Field chickenwire pattern were (1) to determine whether oil would tend to be trapped at the economic limit between the center and off-center producers, and (2) to evaluate possible acceleration of flooding in these long-life floods (40 to 60 or more years). The base case, which called for operations to continue, with the water injectors placed on injection at the same time and with injection equally balanced, was first run to determine if the reservoir parameters used would cause the prediction to match actual early flood performance and to determine how much oil would tend to be trapped between the center and off-center producers.

A preliminary check against the performance data of the base-case prediction indicated that it matched reasonably when scaled for individual pattern variations in permeability, porosity, and net pay, and that potentially recoverable oil reserves would be trapped between the center and off-center producers. Fig. 6, a contour map of water saturation, shows that a "trapped" oil area does exist between the two producers.

Fig. 7 shows individual well performance for the base-case prediction. The center and off-center producing wells respond at about the same time, and later they experience water breakthrough almost simultaneously, thus tending to trap oil between them. A layer with higher permeability has a higher areal sweep efficiency at any stage of flooding than a layer with lower permeability. The map of water saturation shown in Fig. 6 is for Layer 2, the second-highest permeability layer. It reflects conditions after 10.5 years of the waterflood prediction, with cumulative injection into all five layers equal to 145 percent of the original gas fillup volume, or 26 percent of total pore volume. The producing percent water cut for the model at the time was 50 percent.

Fig. 8 compares the predictions for the base case with those for the drill case (to be discussed later). The curves reflect a full chickenwire pattern (three net producers and two net producers), or twice the rates from the half-chickenwire model. Base-case ultimate recovery was a favorable 41.0 percent of the original oil in place. For one half of a chickenwire pattern (one and one-half producers and one injector) as investigated by this particular model, this secondary-plus-primary recovery was 1,447,600 bbl, or 938,600 bbl of waterflood recovery over estimated ultimate primary recovery. The life of the prediction under the base case was 57 years to a half-pattern economic limit of 8 BOPD. Total water injection to this economic limit was indicated to be 6.0 million bbl, or 1.2 total pore volumes.

The model predictions showed a greater drop in productivity than is normally experienced during the short production period after waterflooding commences but before the oil bank reaches the producing wells. This more pronounced oil production decline was, in part, a reflection of the fact that at the start of the waterflood the actual reservoir would not be at a constant pressure throughout as reflected by the model input pressures, but would have lower semisteady-state pressure gradients around the individual producing wells. No attempt was made to run the model from the initial Slaughter Field discovery conditions. The combination laboratory- and field-derived gas-oil relative permeability data used gave a reasonable check on early well GOR performance prior to response.

Infill Drilling

As illustrated by Fig. 6, an obvious method for recovering the trapped oil was to drill a well between the center and off-center producers. A model prediction was run in which a new producer was drilled between these two producers (see Fig. 2). This results in two newly drilled producing wells per full chickenwire pattern. The model was run several times, with the new producing well drilled at a cumulative water injection equal to 31, 60, and 85 percent of the total-pattern initial gas fillup volume.

The prediction obtained for the case in which the infill drilling occurs at the time the peak producing rate is reached was the better one as far as discounted return on investment was concerned. In this case, the water injection was equal to 60 percent of the gas-phase fillup volume (541,000 bbl in one half of a chickenwire pattern).

Fig. 8 compares the base case of the chickenwire pattern with the case where two additional producers were drilled between the center and off-center producers at this 60 percent of fillup volume. The model showed an incremental oil recovery of 130,000 bbl per infill well as a result of the infill drilling. This was a 13.8-percent increase over the 938,600 bbl of waterflood recovery per half chickenwire pattern under the base case. Cases run with different timing as far as drilling is concerned resulted in an incremental increase of 130,000 bbl (± 5,000 bbl) over the base case. The present-worth economics was also good, although slightly less favorable than for the case of 60 percent of fillup volume.

Comparison of Base Case and Drill Case

For the case that called for drilling at 60 percent of fillup volume, the ultimate recovery to the economic limit of 10 BOPD (two and one-half producers and one injector) was 1,577,600 bbl, or 44.6 percent of the original oil in place per one-half chickenwire pattern. This was an increase over the base case of 3.6 percent of the original oil in place. The predicted economic life for this pattern configuration was 55 years.

An approximate evaluation of indicated volumetric recovery efficiencies to an economic limit was made for the two cases. According to the linear fractional flow curve derived from the oil-water relative permeability curve, the average water saturation for 100-percent areal sweep was 61 percent at 97.1-percent water cut (economic limit). Calculations using oil formation volume factors at discovery and 400 psi give a recovery of 50.5 percent of oil originally in place, assuming 100-percent volumetric sweep. Thus, the base-case recovery factor of 41.0 percent (14.4 percent indicated ultimate primary plus 26.6 percent from waterflood) reflects a volumetric recovery efficiency of about 82.2 percent, compared with a volumetric recovery efficiency of 88.3 percent for the 44.6 percent ultimate recovery of the case that calls for drilling at 60 percent of pore volume fillup.

Alternative Patterns

Other possibilities for recovering this trapped oil were investigated. Several predictions were run using the balanced half chickenwire 16 × 16 model where the center producing well was converted to water injection status rather than the two infill wells' being drilled. To more fully evaluate the range of possibilities, the center well was converted to water injection at cumulative water injection volumes ranging from 0 to 153 percent of the original gas fillup volume.

Fig. 9 shows cumulative oil recovery vs time for

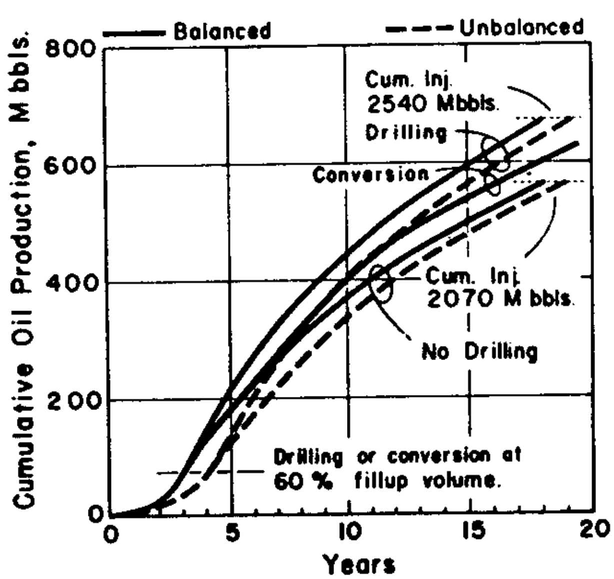

Fig. 9—Performance predictions from start of waterflood for one-half chickenwire pattern, balanced and unbalanced injection.

base, drill, and conversion cases for a period of about 18 years. Conversion and drilling cases shown are at a cumulative water injection equal to 60 percent of the original gas fillup volume. Under conversion, early rate increases from the remaining producers more than offset the production loss due to conversion of the center producer. However, ultimate recovery at 50- to 60-year economic limits converged on the base case. This indicated that increased recovery in the trapped-oil areas was offset by poorer ultimate sweep in other portions of the pattern. Except for certain areas where the amount of oil in place was small, the results were not so attractive economically as they would have been by drilling two additional wells per pattern. In a certain relatively low range of oil in place, a low-cost conversion of the center well was marginally attractive over the base case. Converting the center well to injection also resulted in less oil recovery to an economic limit than would have been obtained by drilling new producers.

Imbalance Due to Timing of Injection

The most common cause of injection imbalance in the Slaughter field was early injection into wells along lease or unit lines. In this case, three wells on one corner of a chickenwire pattern would be placed on injection approximately 3 years before the other three wells were converted to injectors. (See Fig. 2.) This unbalanced situation was studied by constructing a 31 × 31 grid-block model with the same mesh size as the smaller balanced model to simulate two complete chickenwire patterns. In this simulation, 23 percent of total pattern fillup volume was injected into the three early injectors of the six injectors directly associated with a given pattern before the later injectors were converted. Considering the "mirror image" characteristic of modeling, this model does not fully reflect the unbalanced situation described, but it does approximate it. The case in which there was no additional infill drilling, and the case in which drilling took place at 60 percent of fillup were run using this unbalanced injection model.

Fig. 9 also gives plots of cumulative oil recovery vs time for these runs as compared with the balanced model predictions. The unbalanced injection cases were delayed in time, but after a catch-up period, the cumulative oil recovery to a common cumulative injection volume was essentially the same. Ultimate recoveries at 55- and 60-year economic limits were virtually identical. Saturation maps indicated only a minor effect on the selection of the optimum infill location with this degree of imbalance.

The unbalanced injection cases did not reflect imbalance due to such things as areal permeability or net pay variations. However, they did indicate that ultimate recoveries are relatively insensitive to moderate degrees of injection well imbalance. While not directly analogous, results appear compatible with those indicated by Prats *et al.*[8] as to the effects of off-pattern wells on five-spot waterflood performance.

Application of Results

Present-worth drilling economics were calculated to give weight to both increased oil recovery and increased oil production rates early in the life of the waterflood. For the typical 130,000-bbl incremental recovery case presented for infill drilling, a net return on discounted investment (10-percent discount) of 1.7 was calculated before federal income taxes on the basis of a total investment of $59,300 per infill well.

Performance predictions were scaled for areas with different values of oil in place and formation capacity. The application of appropriate economic factors, including risk and federal income taxes, permitted an evaluation of the ranges of oil in place and type of pay necessary to meet economic criteria for the drilling of infill wells in other Slaughter Field chickenwire areas. Scaling and synthesis of various base predictions also made it possible to make reasonable over-all predictions for various units or leases.

Results of Drilling

This study resulted in a substantial infill drilling program by Amoco Production Co. Other operators of Slaughter Field chickenwire floods also have drilled infill wells between center and off-center producing wells. In certain areas where there is abundant oil in place and permeabilities are better, certain other well arrangements appear economically attractive. These include drilling four injection or producing wells midway between injectors on the long sides of the pattern (net of two per pattern), as well as drilling the two infill producers. In areas where the amount of oil in place is small or the permeability is very low, infill drilling cannot be economically justified.

At a recent count, 215 infill locations have been drilled in the Slaughter field. A great majority of these were infill producing wells in the chickenwire pattern located between the center and off-center producers. The first 110 wells drilled on Amoco-operated flood projects had an average initial potential of 88 BOPD/well. The two infill wells per pattern were completed

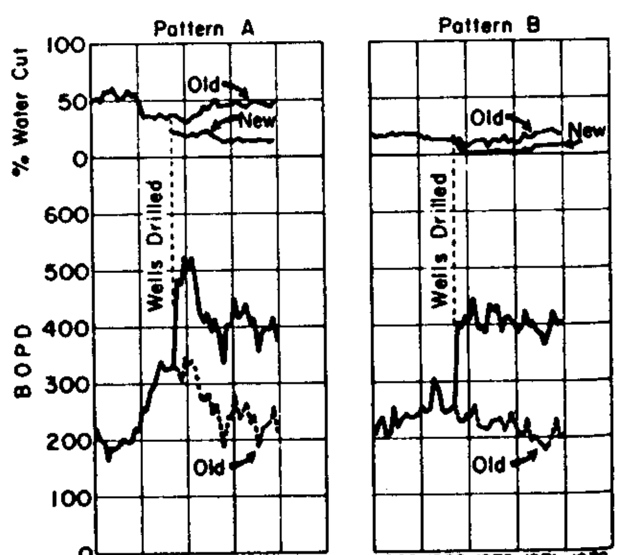

Fig. 10—Performance of two representative chickenwire patterns in Slaughter field where infill wells were drilled between center and off-center producing wells. Total producing rate for each pattern was about 40 BOPD before initial response.

as was anticipated from the model work with water cuts considerably less than the water cuts being experienced by the three original producers in the chickenwire pattern.

Fig. 10, a graph of the performance of two representative chickenwire patterns, shows that the newly drilled wells are producing with significantly lower water cuts. Both of these are older patterns where new wells were drilled a number of years after response had been experienced at the old producers. Cumulative injection on a pattern basis at the time of infill drilling was about 160 percent of the original pattern fillup volumes. Individual well producing rates before initial waterflood response had been about 8 to 13 BOPD. An initial decline in water cut on newly-drilled wells is typical in this field and is primarily attributable to stimulation effects. As indicated by the model and subsequently demonstrated in the field, the net increase in pattern withdrawals is somewhat less than the sum of producing rates obtained from the new producers. This is a result of interaction between the new and old producers.

Conclusions

1. Significant amounts of oil would be trapped in a poorly swept area between the center and off-center producers of Slaughter Field chickenwire waterflood patterns if no change were made in the producer-injector configuration.

2. The drilling of two producers per pattern, one each between the center and off-center producers, increased oil recovery typically from 41.0 to 44.6 percent of the original oil in place. This was economically attractive where sufficient oil in place and formation capacity were available.

3. The most common injection imbalance in chickenwire patterns, caused by earlier initial injection at three of the six injectors directly associated with a given pattern, was not enough to make the ultimate recovery significantly different from that in the balanced injection cases, provided future injection was approximately in balance.

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JPT

Paper (SPE 4070) was presented at SPE-AIME 47th Annual Fall Meeting, held in San Antonio, Tex., Oct. 8-11, 1972.

October 25, 1990

Mr. G.A. Cormack
Manager, Production Operations
Omega Hydrocarbons Ltd.
1300, 112 - 4th Avenue S.W.
Calgary, Alberta
T2P 0H3

Dear Sir:

RE: Waskada Unit No. 4
Application for Drilling Spacing Unit Reduction

Your application dated September 28, 1990 for approval of special drilling spacing units for a portion of Waskada Unit No. 4 is acknowledged.

The application has been reviewed in detail. There are a number of areas which require further clarification, information or comment. These are outlined below.

Notice of the application will be published as soon as the Board has received a satisfactory response to this letter.

In the application, Omega refers to reducing the size of drilling spacing units from 16 ha to 4 ha within the project area. Use of the term "4 ha" spacing implies plans for 64 wells per section, or in the case of Omega's half section project area, a total of 26 additional wells. If it is not Omega's intent to fully develop the project area on 4 ha spacing and to avoid any misunderstanding, a more appropriate description of the application would be for special reduced drilling spacing units.

Waterflood Performance

(a) Injection into the 5-24-1-26 has been suspended for long periods, August 1986 to March 1987 and November 1988 to February 1990. Why was injection suspended and what effect has the suspension of injection had on waterflood performance within the project area? In your discussion, please comment on individual well production performance.

(b) A review of the porosity-metre values for the wells within the project area indicates a significant reduction in oil-in-place from previous information filed with the Board. Comment on the reasons for this reduction in oil-in-place.

(c) Omega suggests there may be a NE-SW fracture system in the Lower Amaranth Formation in the Waskada Field. What is the basis for this interpretation? Is the fracture system natural or induced or a combination of both? Discuss the effect of the fracture system on the waterflood performance and on the location of the proposed infill wells.

(d) The 1985 Waskada Reservoir Model Study included the project area. How does the actual waterflood performance within the 5-24-1-26 injection pattern compare to the model study results? Please discuss any major deviations between actual and predicted performance.

Technical Justification

(a) Omega has estimated the incremental recovery from the four infill wells will equal 3.3% of the original oil-in-place. The incremental recovery appears to be based on assumptions regarding the initial productivity and decline rate of the infill wells. Please quantify the factors Omega believes are contributing to the incremental recovery (for example, drainage of unswept portions of the reservoir, improved areal sweep efficiency, improved continuity, pattern realignment or improved completion techniques).

(b) Omega proposes to increase the well density in the project area by drilling four infill wells between existing producers. The proposed location of the infill wells precludes the use of a number of infill drilling and waterflood modification alternatives that may be feasible for the Lower Amaranth Formation in the Waskada Field. In order to demonstrate that Omega has selected the optimum strategy for reduced spacing, please review the technical and economic feasibility of the following infill drilling and waterflood modification alternatives.

(1) No infill drilling and conversion of producers to injectors to modify the existing 16 ha nine-spot injection patterns to 16 ha five-spot injection patterns.

(2) Infill drilling on 8 ha spacing and injector conversions to develop 8 ha nine-spot injection patterns.

(3) Infill drilling on 8 ha spacing and injector conversions to develop 8 ha five-spot injection patterns.

Schematics of the above-noted infill drilling and waterflood modification alternatives are shown in Figures 1 and 2.

(c) Omega indicated in its application that if the pilot project is successful, infill drilling may be considered in other parts of the

Waskada Field. Please submit a map outlining those parts of the Waskada Field Omega considers amenable to infill drilling, including the locations of possible infill wells. If full development on reduced spacing were to occur, some locations would be on or adjacent to unit boundaries. How will Omega address correlative rights in this situation?

(d) If the project is successful, what is Omega's ultimate strategy as it pertains to infill drilling and waterflood modifications? Will the 5-24-1-26 injection pattern eventually be expanded to a seventeen-spot injection pattern or will some wells be converted and in what injection configuration?

(e) How does Omega intend to operate the waterflood in and surrounding the project area after completion of the infill wells? Please comment on the target injection rates, the proposed monthly and cumulative voidage-replacement targets and the predicted reservoir pressure for the injection patterns in and surrounding the project area.

Note: the cumulative voidage-replacement ratio in the 5-24-1-26 injection pattern is only 0.47 and the estimated reservoir pressure is only 5161 kPa.

(f) Does Omega expect to see any acceleration of production or production interference as a result of the infill wells?

Project Evaluation Program

(a) Please provide a summary of the well data that will be obtained during the drilling of the infill wells.

(b) What is Omega's proposed program for monitoring production rates and reservoir pressure in the project area?

(c) List any additional surveys, tests or analyses Omega intends to carry out to evaluate the project.

General

(a) Do the infill drilling economics include a holiday volume for the infill wells? If no, what effect will a holiday volume have on the project economics? What are Omega's economic hurdle rates?

(b) Discuss the advantages and disadvantages of using directional drilling or horizontal drilling as an alternative to conventional infill drilling in the Lower Amaranth Formation in the Waskada Field?

(c) What are Omega's public consultation plans in respect of the application?

(d) Please provide a list of names and addresses for:

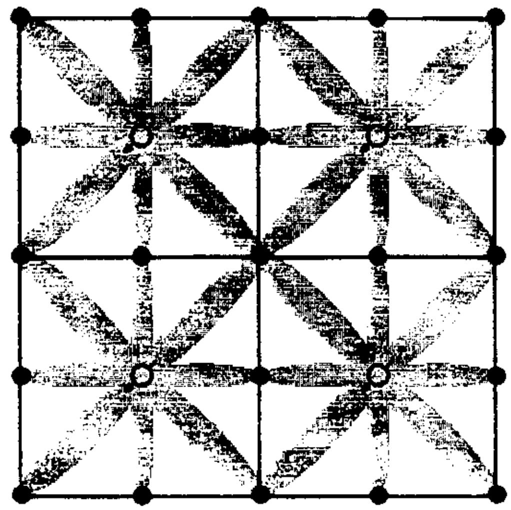
(1) the working interest owners in Waskada Unit No. 4 and within 1 km of the project area, and
(2) the royalty owners in Waskada Unit No. 4 and within 1 km of the project area.

If you have any questions or require further clarification, please contact L.R. Dubreuil, Director of Petroleum, or John Fox, Chief Petroleum Engineer, at 945-6573 or 945-6574 respectively.

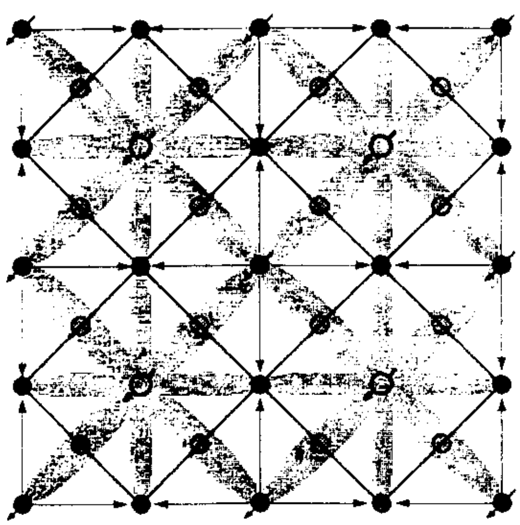
Yours respectfully,

H. Clare Moster
Deputy Chairman

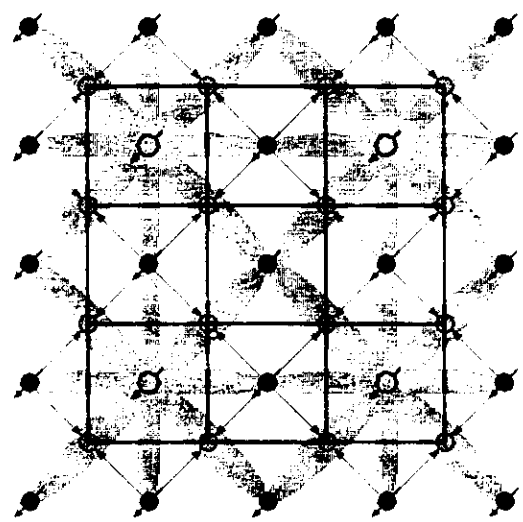
FIVE-SPOT VERSUS NINE-SPOT INFILL DEVELOPMENT



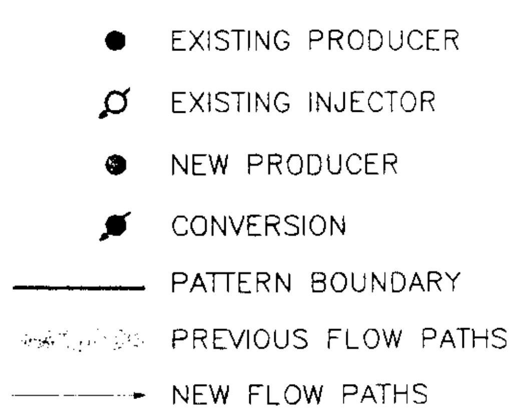
EXISTING 16 HECTARE 9-SPOT



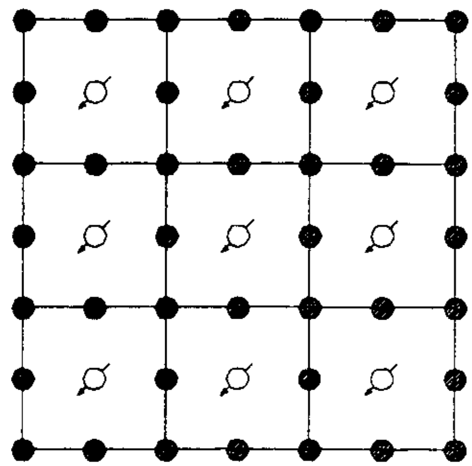
8 HECTARE 9-SPOT



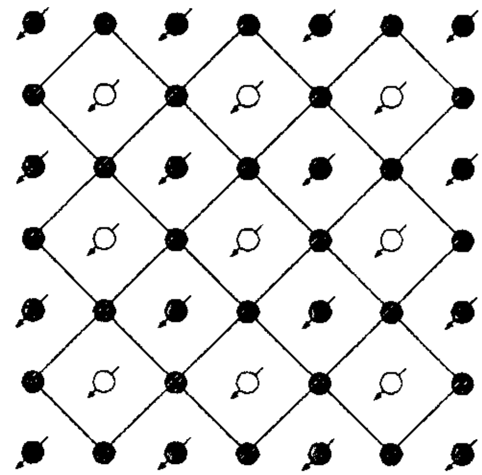
8 HECTARE 5-SPOT



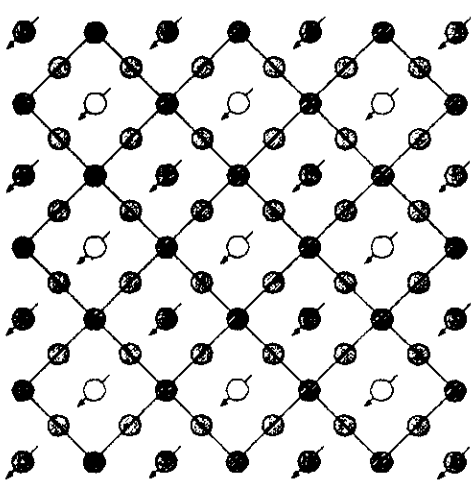
PATTERN CONFIGURATION OPTIONS



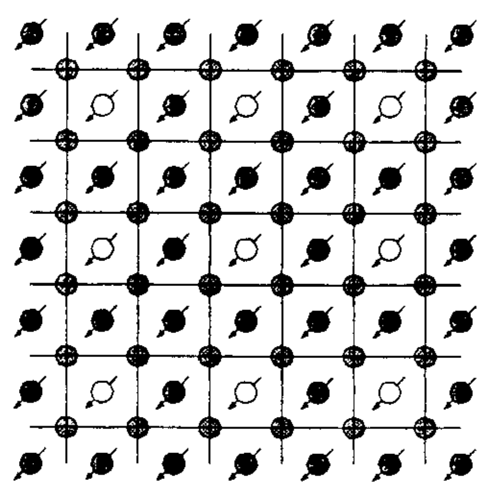
CURRENT NINE-SPOT
16 HECTARE (40 ACRE)



FIVE-SPOT
16 HECTARE (40 ACRE)



NINE-SPOT
8 HECTARE (20 ACRE)

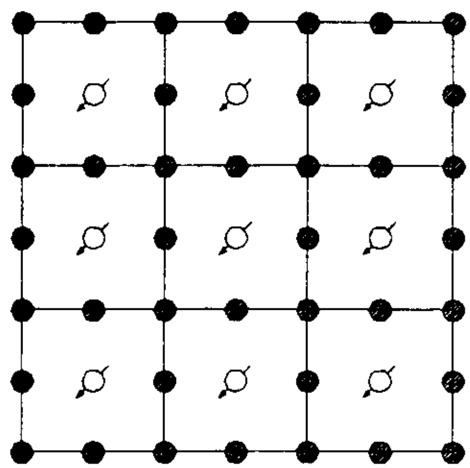


FIVE-SPOT
8 HECTARE (20 ACRE)

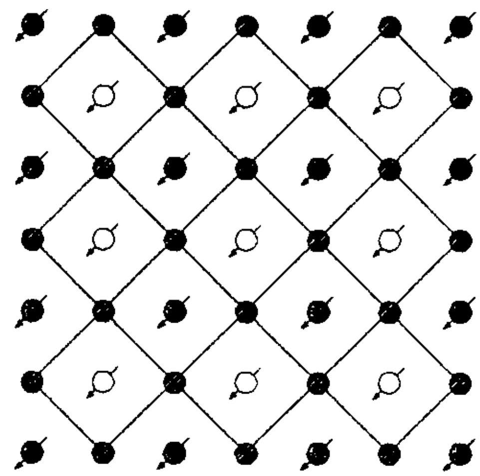
NEW PRODUCER

CONVERSION TO INJECTION

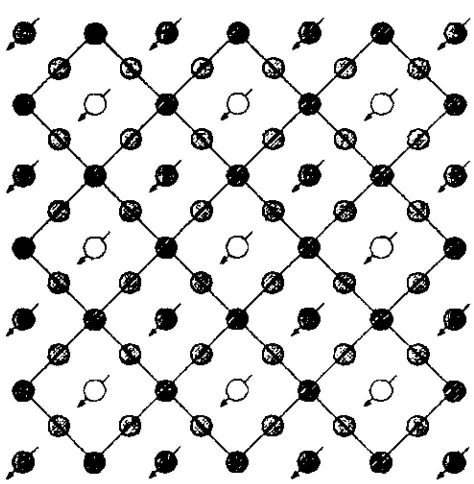
PATTERN CONFIGURATION OPTIONS



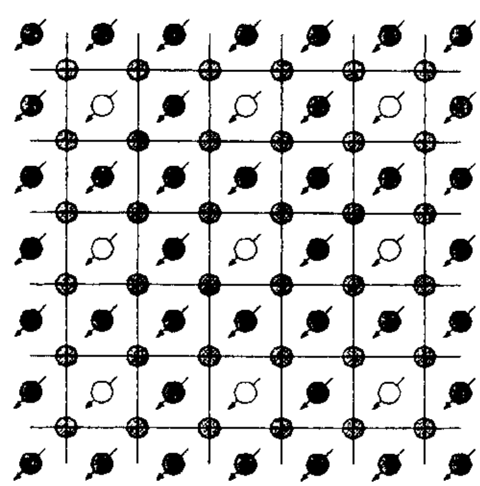
CURRENT NINE-SPOT
16 HECTARE (40 ACRE)



FIVE-SPOT
16 HECTARE (40 ACRE)



NINE-SPOT
8 HECTARE (20 ACRE)

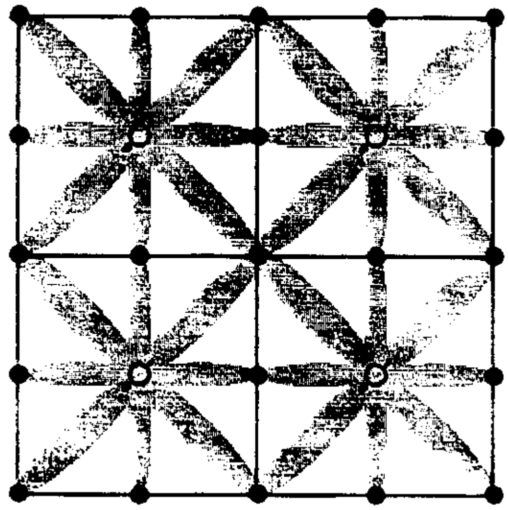


FIVE-SPOT
8 HECTARE (20 ACRE)

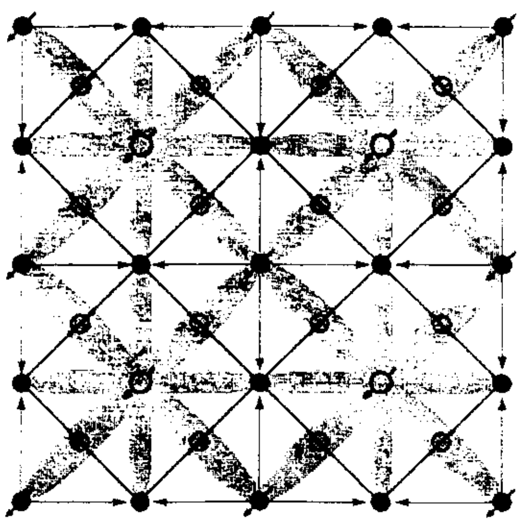
NEW PRODUCER

CONVERSION TO INJECTION

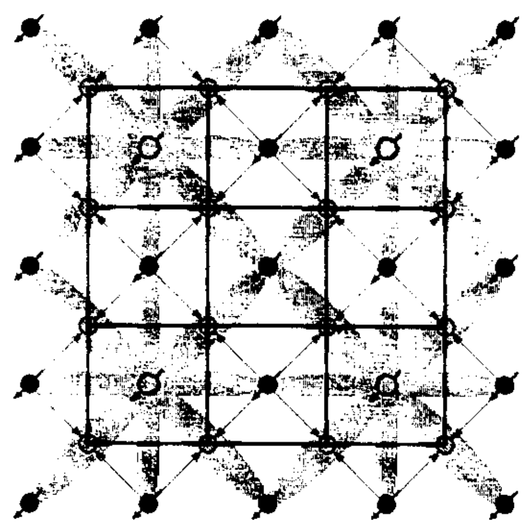
FIVE-SPOT VERSUS NINE-SPOT INFILL DEVELOPMENT



EXISTING 16 HECTARE 9-SPOT



8 HECTARE 9-SPOT



8 HECTARE 5-SPOT

EXISTING PRODUCER

EXISTING INJECTOR

NEW PRODUCER

CONVERSION

PATTERN BOUNDARY

PREVIOUS FLOW PATHS

NEW FLOW PATHS

OMEGA
HYDROCARBONS LTD

1300 SUN LIFE PLAZA III
112 - 4th AVENUE S.W.
CALGARY ALBERTA CANADA T2P 0H3

TELEPHONE (403) 261 0743
FAX (403) 264 5691

October 19, 1990

Enron Oil Canada Ltd.
1300, 700 - 9th Avenue S.W.
Calgary, Alberta
T2P 3V4

Dear Sir:

Re: Waskada Lower Amaranth A Pool
<u>Proposed Drilling Spacing Unit Reduction</u>

Enclosed for your information is a copy of an application submitted to the Manitoba government on September 28, 1990. The intent of the application is to obtain approval to implement of an infill well pilot project within Waskada Unit No. 4 or more specifically the southern half of injection pattern 5-24-1-26 WPM.

Should you have any questions regarding this application please contact the undersigned at your convenience.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Engineering Supervisor - Manitoba

DEPARTMENT OF ENERGY AND MINES
OCT 26 1990
PETROLEUM BRANCH

RAB:jb

c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Reduced Spacing Application File

OMEGA
HYDROCARBONS LTD

1300 SUN LIFE PLAZA III
112 - 4th AVENUE S.W.
CALGARY ALBERTA CANADA T2P 0H3
TELEPHONE (403) 261-0743
FAX (403) 264-5691

October 19, 1990

Chevron Canada Resources Ltd.
500 - 5th Avenue S.W.
Calgary, Alberta
T2P 4L5

Attention: Mr. Stan Borowski

Dear Sir:

Re: Waskada Lower Amaranth A Pool
Proposed Drilling Spacing Unit Reduction

Enclosed for your information is a copy of an application submitted to the Manitoba government on September 28, 1990. The intent of the application is to obtain approval to implement of an infill well pilot project within Waskada Unit No. 4 or more specifically the southern half of injection pattern 5-24-1-26 WPM.

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Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Engineering Supervisor - Manitoba

RAB:jb

c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Reduced Spacing Application File

OMEGA
HYDROCARBONS LTD

1300 SUN LIFE PLAZA III
112 4th AVENUE S W
CALGARY, ALBERTA, CANADA T2P 0H3
TELEPHONE (403) 261 0743
FAX (403) 264-5691

October 19, 1990

Baxter Lake Holding Company Limited
#214, 11803 - 125th Street
Edmonton, Alberta
T5L 0S1

Dear Sir:

Re: Waskada Lower Amaranth A Pool
Proposed Drilling Spacing Unit Reduction

Enclosed for your information is a copy of an application submitted to the Manitoba government on September 28, 1990. The intent of the application is to obtain approval to implement of an infill well pilot project within Waskada Unit No. 4 or more specifically the southern half of injection pattern 5-24-1-26 WPM.

Should you have any questions regarding this application please contact the undersigned at your convenience.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Engineering Supervisor - Manitoba

RAB:jb

c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Reduced Spacing Application File

OMEGA
HYDROCARBONS LTD

1300 SUN LIFE PLAZA III
112 4th AVENUE S W
CALGARY ALBERTA, CANADA T2P 0H3

TELEPHONE (403) 261 0743
FAX (403) 264 5691

October 19, 1990

Tundra Oil and Gas Ltd.
1313 One Lombard Place
Winnipeg, Manitoba
R3B 0X3

Dear Sir:

Re: Waskada Lower Amaranth A Pool
Proposed Drilling Spacing Unit Reduction

Enclosed for your information is a copy of an application submitted to the Manitoba government on September 28, 1990. The intent of the application is to obtain approval to implement of an infill well pilot project within Waskada Unit No. 4 or more specifically the southern half of injection pattern 5-24-1-26 WPM.

Should you have any questions regarding this application please contact the undersigned at your convenience.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Engineering Supervisor - Manitoba

RAB:jb

c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Reduced Spacing Application File

OMEGA
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112 4th AVENUE S.W.
CALGARY ALBERTA CANADA T2P 0H3
TELEPHONE (403) 261-0743
FAX (403) 264-5691

October 19, 1990

Chauvco Resources Ltd.
2900, 255 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

Attention: Mr. Dennis Robertson

Dear Sir:

Re: Waskada Lower Amaranth A Pool
Proposed Drilling Spacing Unit Reduction

Enclosed for your information is a copy of an application submitted to the Manitoba government on September 28, 1990. The intent of the application is to obtain approval to implement of an infill well pilot project within Waskada Unit No. 4 or more specifically the southern half of injection pattern 5-24-1-26 WPM.

Should you have any questions regarding this application please contact the undersigned at your convenience.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Engineering Supervisor - Manitoba

RAB:jb

c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Reduced Spacing Application File

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CALGARY ALBERTA CANADA T2P 0H3
TELEPHONE (403) 261-0743
FAX (403) 264-5691

October 19, 1990

Working Interest Owners
Waskada Unit No. 4
(Addressee List Attached)

Dear Sirs:

Re: Waskada Unit No. 4
Proposed Drilling Spacing Unit Reduction

Under the terms of the Unit Operating Agreement for Waskada Unit No. 4 please be advised that Omega Hydrocarbons Ltd. submitted an application to the Manitoba government on September 28, 1990 requesting a drilling spacing unit reduction. The intent of the application is to obtain approval to implement an infill well pilot project in the southern half of injection pattern 5-24-1-26 WPM. If successful, it is predicted that the pilot project will recover an incremental 16274 m^3 of oil from the pilot project area.

Should you have any questions regarding this application please contact the undersigned at your convenience.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Chairman, Operating Committee

RAB:jb

c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Reduced Spacing Application File
Unit No. 4 File

WASKADA UNIT NO. 4
WORKING INTEREST OWNERS
<u>Addressee List</u>

Sabre Petroleums Ltd.
8th Floor, 1122 - 4th Street S.W.
Calgary, Alberta
T2R 1M1

Attention: Mr. Philip Miu

Waskada Lower Amaranth
Reducing Spacing Pilot Project
Technical Presentation
(90/10/11)

<u>Reservoir Characteristics</u>

- the Waskada Lower Amaranth reservoir is vertically stratified with thin interbedded shale stringers thus the oil producing sands are usually poorly developed with uniformly low effective porosities and permeabilities. B + C sands

- low reservoir permeability commonly translates into poor wellbore drainage.

- fracture stimulations have been performed on most Lower Amaranth wells to achieve economic levels of production, however, fractures tend to skew production streamlines within a waterflood pattern and reduce areal sweep. - induced fracture orientation

- historical data indicates that water injectivity and pressure maintenance have been achieved with the existing inverted nine spot pattern injection scheme.

- since waterflooding was initiated the average oil production decline rate within the pressure maintenance areas has been approximately 15%/year.

- various injection strategies and well workovers have been attempted within the pressure maintenance areas but have not been able to significantly alter the production decline rate.

- the estimated field wide oil recovery factor is only 15% OOIP, current individual injection pattern recoveries vary between 2.4% and 18.3% OOIP.

- given the preceding reservoir characteristics the Lower Amaranth formation appears to be an ideal candidate for infill drilling.

effective $\phi_e < \phi_{TOTAL\ CORE}$

o FIELD WIDE WOR DROP FROM 2 to 1 OVER LAST YEAR
FN 48D - WET STRINGER WELLS b SEC 31-1-25

- frac orientation based regional studies Alta & Sask. (assumed) - not entirely conclusive - not major part of project

- trapped oil within B sand pinch outs in south part of project area

Waskada Lower Amaranth
Reducing Spacing Pilot Project
Technical Presentation
(90/10/11)

Pilot Project Design

- the 1985 reservoir simulation study indicates that trapped oil saturations exist inside the 256 ha study area after being waterflooded for 35 years.

- identification of the trapped oil saturations areas have been achieved by using cumulative production maps and geological fence diagrams.

- Omega has chosen to implement a pilot project with the intent of confirming and quantifying the incremental reserves associated with infill drilling at Waskada.

- the factors used to select the pilot project area were; above average reservoir quality, good reservoir continuity, a proven oil producing area, a low producing water/oil ratio, a single injection pattern area, common working interest/royalty owners, consenting surface landowners.

- a thorough review of the pool resulted in selecting the southern half of injection pattern 5-24-1-26 WPM for the pilot project area.

- the proposed infill wells have been located between existing producers which positions them outside the theoretical production streamlines and between suspected northeast-southwest fracture planes.

- modifications to the existing injection system will not be necessary, plans are to use the existing injection wells to maintain pressure and replace voidage taken from the infill wells.

Waskada Lower Amaranth
Reducing Spacing Pilot Project
Technical Presentation
(90/10/11)

Production Forecast/Pilot Project Economics

- a base case forecast was developed for the pilot project area using a current production rate of 11 m^3/d, an economic limit of 0.4 m^3/d per well and an annual decline rate of 10%/year.

- assuming an OOIP of 483708 m^3 for the 5-24-1-26 WPM pattern area current oil recovery is 16.8%, base case ultimate oil recovery is predicted to be 23.3% (112650m^3) with average recoverable reserves/well of 14,000 m^3.

- the incremental production forecast for the proposed infill wells has been derived by assuming initial production rates of 2 m^3/d per well, an economic limit of 0.4 m^3/d per well and incremental recoverable reserves of 4000 m^3 per well.

- the infill well forecast increases the ultimate oil recovery from the 5-24-1-26 WPM pattern area to 26.6% (128924 m^3) which is equivalent to an incremental oil recovery of 3.3% or 16274 m^3.

- initial capital requirements are $624,000 ($156,000/well) to drill and complete four infill wells; these costs have been reduced by $30,000/well by using surplus equipment.

- it has been assumed that the four proposed infill wells will each qualify for an initial holiday oil volume and will be classified as new oil production following the depletion of the initial holiday oil volumes.

- the pilot project economic parameters are; after tax NPV @ 15% DCF = $159,000, after tax rate of return = 25.3%, after tax payout = 3.3 years.

Waskada Lower Amaranth
Reducing Spacing Pilot Project
Technical Presentation
(90/10/11)

Impact On Royalty/Working Interest Owners and Surface Landowners

- the proposed pilot project area is contained entirely within the Waskada Unit No. 4 unit boundary and therefore will have no detrimental effect on the correlative rights of offset owners.

- all lessees and lessors in Waskada Unit No. 4 will benefit through increased revenues generated by the incremental oil production.

- incremental freehold royalty payments are estimated to be $389,900, incremental Crown royalty and production taxes are estimated to be $37,200

- due to economic considerations the four proposed infill wells are planned to be drilled vertically and will require separate surface leases for production.

- to minimize the impact of reduced well spacing on surface landowners Omega will position two infill wells on existing road allowances.

- surface obstructions will be minimized at the other two infill well locations by using non built up trails and production flowlines.

- all parties effected by the proposed infill drilling pilot project have or will be contacted by Omega prior to the implementation of the project.

SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE 4977

Recovery Optimization Through Infill Drilling - Concepts, Analysis, and Field Results

By

Vance J. Driscoll, Member SPE-AIME, Amoco Production Co.

This paper was prepared for the 49th Annual Fall Meeting of the Society of Petroleum Engineers of AIME, to be held in Houston, Texas, Oct. 6-9, 1974. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Publication elsewhere after publication in the JOURNAL OF PETROLEUM TECHNOLOGY or the SOCIETY OF PETROLEUM ENGINEERS JOURNAL is usually granted upon request to the Editor of the appropriate journal provided agreement to give proper credit is made.

Discussion of this paper is invited. Three copies of any discussion should be sent to the Society of Petroleum Engineers office. Such discussions may be presented at the above meeting and, with the paper, may be considered for publication in one of the two SPE magazines.

ABSTRACT

This paper gives theoretical concepts and some supporting mathematical model and field performance data which demonstrate factors that can be involved in recovery increases by infill drilling. Many of these factors relate to various reservoir heterogeneities and are quantitatively more important in fluid injection projects. Recovery increase by infill drilling projects of low-permeability waterflood projects can be due to as many as nine different factors with varying degrees of technical difficulty to specifically quantitize. However, based on performance and certain theoretical knowledge and concepts, reasonable factors involving judgment can be developed as to percent of original oil-in-place recovery increase.

Attractive conventional growth economics based on increased ultimate waterflood recovery are indicated for areas of low-permeability, slowly depleting reservoirs with relatively large amounts of oil in place. This is in addition to substantial increases in current rates of production and present worth. Typically, an increase on the order of 4 percent of the original oil in place will be gained by infill drilling from 40- to 20-acre spacing. However, this can vary by a factor of two or more depending upon the specific situation.

References and illustrations at end of paper.

INTRODUCTION

There is probably no place more than reservoir engineering where a spirit of Hegelian dialecticism applies. That is, there is "truth" and "error." However, in the truth there still exists some error. Consequently, with time a new truth evolves that is purged of some previous imperfections. In the 1940's, Uren,[1] Muskat,[2] and predecessor companies of Exxon,[3] among others, published thinking and results properly decrying misapplications of Cutler's rule. This had been a previous empirical observation which indicated that primary recovery in densely drilled portions of fields was greater and proportional to the square root of well density. It was generally shown that this was due to migration from less densely drilled areas of the same fields rather than an increase in over-all recovery.

The tendency since about the 1950's has been to consider increased recovery by infill drilling as negligible or only to consider it where some one factor in a particular reservoir had a dramatic effect upon recovery. This has been partly due to past limitations on ability to realistically describe and simulate actual reservoir heterogeneity and displacement. The advent of numerical simulation and various improvements in quantitative reservoir description and information evaluation techniques over the past 20 years, while still subject to limitations, currently permit a more quantitative evaluation of these factors. For fluid injection projects, the added aspects of point injection, resaturation, and greater distance of fluid travel due to division into injection and withdrawal points, inherently tends to magnify the quantitative effects of well spacing, arrangements, lateral discontinuities, etc., on recovery.

The purpose of this paper is to set forth more explicitly these factors and their quantitative effects in the petroleum literature. Due to the broadness of scope, it will be possible only to highlight these factors. A detailed evaluation of each one could well be the subject of one or more papers in themselves.

CONCEPTS

The nine factors to be presented here as having an effect on recovery increase by infill drilling are (1) taking advantage of areal heterogeneity by giving favorable flooding orientation (turn 5-spots 45°, etc.), (2) minimization of lateral-type pay discontinuities, (3) recovery of "wedge edge" oil, (4) improved areal sweep (minimizing poor geometry effects caused by the original well arrangement and/or initial injection-production well selection), (5) better confinement of injection fluids to pay zones, (6) better control of injection profiles where zones exist that are not generally in direct vertical communication, (7) increased conductivity (rates) and reduced per well economic limits, (8) reduced oil shrinkage and improved displacement efficiency by accelerating injection and effectively waterflooding at a lesser stage of primary depletion, and (9) possible adverse effects of prior injection imbalance.

This paper discusses low permeability reservoirs in West Texas. However, most of these concepts apply equally as well in higher permeability reservoirs. In addition, other factors such as gravity and trapped gas saturation can be involved in higher permeability reservoirs.

ANALYSIS

Favorable Flooding Orientation

The need for inclusion of layering, areal sweep efficiency, and mobility ratio effects in determining waterflood performance has been well recognized for a number of years. These and relative permeability, saturation, and fluid property data are generally employed in some manner in all current waterflood prediction calculations. One factor that can make a large difference in waterflood recovery in practical field applications over and above the factors cited is the presence of adverse areal heterogeneity. While this can be due to anisotropic permeability, poor flood performance often appears to be due to natural or induced vertical (high angle) fractures.

Fig. 1 schematically illustrates the effects of an east-west type fracture orientation on resulting waterflood performance. This is for an 80-acre five-spot waterflood where intervening producing wells are on an east-west line to injection wells. In many of our West Texas waterflood projects injected fluids often have a preferential direction of movement due to directional areal permeability or pre-existing or induced fractures. As indicated visually, injection water has preferentially moved in an east-west direction resulting in early water breakthrough at the existing producing wells. Considerable oil is therefore "trapped" in the area between the watered-out producers at economic limits of production. Infill drilling between the existing wells on a path diagonal or perpendicular to the direction of preferential water movement will result in additional oil recovery.

While attributable to highly directional areal permeability by Hutchinson,[4] an early case of flooding performance of this type was reported by Hunter[5] in 1956 for the North Burbank Unit in Oklahoma. Reported fracturing of the formation at a pressure gradient of 0.265 psi/ft plus the highly directional nature of water breakthrough indicates vertical-type fracturing in light of current knowledge. Similar type occurrences on either a limited or broad scale in a number of Amoco West Texas waterfloods have led to a general policy of controlling injection to below formation parting pressures.

Model results from various Amoco studies to be cited were conducted with a two-dimensional, three-phase multilayer "black oil" mathematical reservoir simulator.[6] A five-layer model with 11 x 11 grid blocks per layer, with interconnection only at wellbores, was employed to represent a 40-acre symmetrical element of an 80-acre five-spot. Corner blocks had one-fourth the area and edge blocks one-half the area of other blocks. All waterflood model results to be discussed are for low-mobility waterfloods. Fields were in various stages of primary depletion ranging from intermediate to advanced with gas saturations on the order of 9 to 18 percent at start of flooding. Approximately logarithmic permeability distribution was employed with a permeability distribution factor (K_{max}/K_{min}) ranging from 20 to 53. This is roughly equivalent to a log-normal permeability variation factor as used by Dykstra-Parsons[9,10] of about 0.63 to 0.75.

Figs. 2 and 3 show some model sensitivity analysis results obtained during our 1970 Anton-Irish Clearfork Unit Study. This is a ,,900-ft Clearfork field located in Lamb, Hale, and Hockley Counties of West Texas. An 80-acre five-spot pattern in Anton-Irish Clearfork results in most producers being on a due east-west line to injectors. Practically all wells in this unit were given large volume, high rate fracture stimulation treatments at one time or another. From well performance, it is not always possible to distinguish between the effects of directional permeability or natural and/or induced fracturing, particularly where the fracturing may be 10^{0} to 20^{0} off of a direct line with the producing well. These particular model runs were made to give a quantitative "feel" as to the effect on well and field performance of moderate directional permeability or a set of induced fractures.

To simulate a fracture, model blocks one-tenth the width of the distance between well rows had their east-west conductance increased to 11 times their nörmal value on a line between injectors and producers. This in effect doubled the east-west to the north-south conductance, with this extra 100 percent conductance being confined to a narrow set of blocks. This would be somewhat analogous to operating an injection well so that amount of injection was approaching twice the formation parting pressure rate.

As shown on Fig. 2, recovery to a 95 percent watercut was reduced from 35.3 to 25.8 percent, or some 9.5 percent of the original oil-in-place over the 80-acre vertically stratified, but areally homogeneous, permeability case. With a 2.25:1 uniformly higher east-west over north-south directional permeability orientation, recovery of the original oil in place was indicated to be reduced by 1.4 percent from 35.3 to 33.9 to the same 95 percent watercut. Geometric mean permeability was the same as the homogeneous case.

Infill drilling, which turned the orientation so that flooding tended to proceed at an angle to any moderate uniform directional permeability, resulted in essentially the same 36.0 percent ultimate recovery for a homogeneous or a 2.25:1 east-west to north-south permeability orientation. For the infill five-spot, recovery was not only accelerated, but also was increased from 35.3 to 36.0 percent of the original oil-in-place to the same watercut. This is primarily attributed to effectively "catching" the flood at a lesser stage of primary depletion resulting in less shrinkage and slightly better displacement and sweep efficiencies. Actually, due to (1) lower geometric resistance with a closer pattern and (2) the fact that over-all unit operating cost would not be fully doubled with infill development, additional recovery over the 0.7 percent of original oil in place shown here to a common watercut should be obtainable. However, effects of flooding at a lesser stage of primary depletion and the effects of increased geometric conductance and lowered BOPD per well economic limits will be quantitatively discussed elsewhere.

Fig. 3 shows oil and water producing rates vs time for the 80-acre five-spot with and without the 11:1 east-west fracture. While certain well performance, formation packer, and borehole televiewer data indicate that some limited east-west type fracturing exists at Anton Irish Clearfork, the finite fracture runs actually seem to resemble quite closely certain performance that has been observed in the Fullerton Clearfork Unit of Andrews County, West Texas.

In the Fullerton Unit the basic pattern is a repeating three-to-one direct line drive. This consists of three north-south producing rows between north-south rows of injectors. In an east-west direction the three intervening producers are on a direct line with offsetting injectors. Characteristically, limited oil response has been obtained with premature water breakthrough and high watercuts at the producing wells. On the other hand, high oil rates and lower watercuts generally have been obtained on certain initial infill wells drilled off the east-west line between injectors.

Minimize Lateral-Type Pay Discontinuities

A factor usually ignored in a quantitative sense until the last few years has been the effect of lateral-type pay discontinuities on calculated recovery with different depletion mechanisms. With 40-acre development, typically, oil must move up to 660 ft (745 ft radially) to reach a wellbore. Additionally, providing a small lense had been penetrated by at least one well, it should be fairly well depleted under primary operations. On the other hand, with conversion even to the most densely spaced waterflood pattern of an 80-acre five-spot with the same number of wells, average travel distance of injected fluids from an injector to a producer would become in excess of 1,320 ft and waterflood recovery would be obtainable only if penetrated by both a production and injection well. Poor sweep efficiency also will be obtained from small lenses only moderately greater than well spacing.

In support of a capacity allowable request to the Texas Railroad Commission, Shell Oil Co. as unit operator of the Denver Unit, Wasson (San Andres) field, presented data[11] in March 1972 to show that infill drilling would result in an increase in ultimate recovery from this unit. Shell concluded that ultimate recovery from the unit could be increased by the infill-drilling programs in three different ways. These were (1) a more uniform injection pattern, (2) better control of injection profiles, and (3) closer spacing in this heterogeneous reservoir.

While recovery increases were attributable to several different factors such as improved injection profiles and more uniform patterns, it also was estimated that some 18 million bbl of incremental recovery would be obtained from a designated 8,200-acre pre-1973 drilling area as a result of minimizing lateral-type pay discontinuities. Schematic cross-sections are included in a recent Society of Petroleum Engineers paper,[12] while a sample detailed cross-section is given in hearing testimony.[11] In essence, a detailed study by Shell geologists indicated that the pay section was broken into a number of vertically separate pay zones. It was further concluded that these zones were not uniformally continuous in a lateral direction and that portions either died out or became ineffective as net pay as a function of horizontal distance.

Fig. 4 shows percent continuous pay as a function of distance for the Wasson (San Andres) field as arrived at by Shell.[11] Differences in laterally continuous pay of some 4 percent are indicated between 20- and 40-acre spacing. On the average, 90 percent was indicated to be continuous at a distance of 933 ft and 86 percent continuous at a distance of 1,320 ft. As may be noted at distances slightly in excess of 1 mile, the percent continuous pay decreased to 50 percent.

Since there were some 930 million bbl of original oil in place in the initial infill area of this unit, an 18-million-bbl increase would represent a recovery increase due to this factor of on the order of 2 percent of the original oil in place. Certain studies in another West Texas San Andres reservoir and a West Texas Clearfork reservoir indicate the Wasson results are realistic.

Since there usually is substantial continuity, pressure interference testing normally will have insufficient resolution to prove or disprove limited lateral pay discontinuities. Kunkel and Bagley[13] present pressure and other data in a 1965 article on the Means Queen Sand waterflood of Andrews County, West Texas, which tend to support some gross lateral pay discontinuities in this reservoir.

Recovery of "Wedge-Edge" Oil

Situations exist in a number of fields where "wedge-edge" oil occurs due to (1) the dipping of the various porous zones and the presence of oil-water or gas-oil contacts, (2) the uneven lateral extent of pay zones, or (3) simply inadequate edge development. Thus, additional drilling is required to recover this wedge-edge oil. Fig. 5 is a schematic cross-section of San Andres porous zones that dip below the oil-water contact in the eastern portion of an Amoco-operated unit in the Wasson Field. As indicated on the schematic cross-section, only Wells 116, 128, and 150 existed prior to the infill-drilling program. Outlined on the figure is the amount of wedge-edge oil that would not have been recovered if Wells 227 and 242 had not been drilled. It has been estimated that drilling additional wells in this unit for this type oil will result in an additional recovery of about 5.5 million bbl at a total investment cost of $1.26 million. This is one of several examples that could be cited of how additional drilling can be used in situations of this type to recover additional reserves.

Improved Areal Sweep (Minimize Poor Geometry Effects)

Even without areal anisotropy, additional wells can be used to minimize poor geometry effects caused by the original well arrangement and/or initial injection-production well selection. In a previously published Amoco paper[14] it was shown that infill drilling two wells between the existing three producers in a West Texas Slaughter field "chickenwire" pattern would typically result in an increase in recovery of on the order of 3.6 percent of the original oil in place. Fig. 6 conceptually shows the improved areal sweep indicated by drilling the two infill wells plus additional production wells between the injectors on the long diagonals of this pattern.

Shell, in testimony[11] before the Railroad Commission, estimated that some 14,000,000 bbl of additional recovery, or some 1½ percent of the oil in place, should be obtainable through improved areal sweep in the initial Wasson Denver Unit infill-drilling area. This was by infilling to a more uniform nine spot-type pattern. In other situations it can be shown that infill drilling and conversion of a five-spot flood to an infill nine-spot will result in increases in areal sweep efficiency since new producers will tend to be in "trapped" oil areas.

Confine Injection Fluids to Pay Zones

Another problem that can sometimes be fully overcome only by infill drilling is the one of confining injection fluids to the pay zone. Fig. 7 is a sketch that illustrates a problem which has occurred in several of our West Texas waterfloods. Primarily due to heavy stimulation in the past to obtain maximum fluid producing rates, various wells, when converted to injection, were found to be losing water in significant quantities below the total depth of the well.

There is a certain tendency for vertical fractures to be confined within a porous zone, particularly if pay zone pressures are low. However, high-rate large-volume fracture treatments have been found to sometimes result in fractures that penetrate dense zones to underlying or overlying porous water-bearing zones. Selective plugging, squeeze cementing, or other remedial techniques are often only partially successful in eliminating this problem. Further, with high angle fracturing there is no certainty except by prolonged observance of offset well performance, repeated pressure pulse testing, etc., that apparent elimination in the wellbore has really resulted in effective elimination of communication to an underlying or overlying water-bearing zone.

Certain performance data gives quite conclusive evidence that extensive fracturing to underlying water zones in both injection and producing wells has occurred in one of Amoco's major West Texas floods. In another flood, isolated occurrences of this type were initially detected by major pressure responses at wells two rows away from injection wells in a direction perpendicular to the known fracture orientation. Intervening wells had low pressures in the pay zone since fillup had not yet occurred. While various measures can be taken with existing wellbores, infill drilling usually provides for more effective alleviation of these problems.

Better Control of Injection Profiles

Where various pay zones exist not in direct vertical communication, it would ideally be desirable to inject into each zone in accordance with its porosity feet or, more precisely, its displacable oil saturation. This would result in the highest amount of oil recovery for a given amount of water production. This is schematically illustrated in a highly simplified manner by Fig. 8. Based on its model study results, Shell has estimated[11] that another 14 million bbl, or 1½ percent of the original oil in place, could be recovered for the initial infill drill area of the Wasson Denver Unit by increasing the vertical conformance from the upper pay by one-half of that between existing profiles and that obtainable with uniform injection. They also discuss various completion techniques most effectively employable on new wells and show results indicating improved profiles on new injection wells. Another operator[15] has discussed various techniques that have been employed in another unit in the same field to obtain improved injection-well conformance in existing wellbores.

Due to permeability variations, a completely ideal injection profile is unattainable except by mechanical separation and selective injection. This implies an absence of natural fractures, good cement jobs, and light selective stimulations. With on the order of 30 to 40 ft of separation being required to eliminate most "behind-the-pipe" communication, this is often not feasible without nonperforation of some vertically separated thin pay zones plus mechanically separated "restricted rate" flooding of some of the naturally more permeable intervals.

Another approach that has been employed in the same field has been a modified open-hole program. Pipe is set at the top of the pay, the well drilled through the lower permeability first porosity, and given a staged fracture treatment. The main pay is then drilled and given a low-pressure staged acid stimulation below a packer. As opposed to older wells with casing set high, this has eliminated most problems with water loss above the pay section and/or out the bottom of the hole. More effective stimulation of the lower permeability upper zones also tends to result in more uniform injection profiles.

A key improvement in waterflooding operations is believed to be to insure that all pay is taking water. In addition to techniques mentioned by others, the acid interface technique has been used to successfully establish injection in porous sections not previously taking water or production from porous sections, not previously giving up producing fluids. While the optimum means of accomplishing profile improvement may be subject to debate, there is no question that improving injection and producing well profiles and confinement of injection to and production from pay zones should lead to increased waterflood recovery.

Increased Conductivity (Rate) and Reduced Well BOPD Limits By Infill Drilling

Another conceptual reason for increased recovery with closer spacing is that the resistance to flow is somewhat reduced. Typically, this will increase per-well injectivity or productivity by some 12½ percent. The above number is based on an average geometric condition ratio of 2.5 on 40-acre spacing, giving an effective wellbore radius for flow purposes of about 33.8 ft as opposed to a nominal 0.32 ft (7-7/8-in. wellbore).

For geometric conductance purposes, the

40-acre five-spot resistance is very closely proportional to two times ln (526.5/33.8) as opposed to twice the ln (744.5/33.8) for an 80-acre five-spot. Consequently, the geometric conductance ratio of an 80-acre five-spot over a 40-acre five-spot for the same 33.8 ft effective wellbore is approximately in the ratio of 6.182/5.486 = 1.125. Thus with doubled density, injection and producing rates after fillup are on the order of 2¼ times the 80-acre flood rate for the same stage of depletion, same pressure differentials, etc.

A 33.8-ft effective wellbore size also is equivalent to a symmetrical vertical fracture of infinite conductivity and of height equal to the pay section and extending about 67.6 ft in both directions from the wellbore for an overall length of about 135 ft as opposed to a nominal wellbore diameter. Injection-well pressure falloff testing indicates this is a fairly representative value.

A further factor for West Texas floods is that these are low-mobility ratio floods of an intermediate to oil-wet character. Injectivity declines until sometime after initial water breakthrough and then increases as residual oil saturations are gradually further reduced. Thus, total system mobility tends to increase in the later stages of depletion. Consequently, for any given pattern spacing, producing a well to a higher watercut also results in some additional increase in total system injectivity and total fluid producing rates due to improved mobility.

Fig. 9 shows the results of a systematic investigation of these factors from our Levelland (San Andres) Unit, Hockley County, Texas, Feb. 1970 Model Study. A value of formation flow capacity of 320 md-ft is high for the Levelland Unit. However, for this value an equivalent 10 BOPD per producing well economic limit on the 42.5-acre infill five-spot gave 49.2 percent ultimate recovery as opposed to 48.4 percent ultimate recovery on the 85-acre five-spot pattern. This is a recovery difference of some 0.8 percent of the original oil in place. Corresponding watercuts were 98 percent and 97.5 percent. However, a more reasonable economic limit for the infill drill case could be 9 BOPD or 98.2 percent watercut (80 percent increase in total unit operating cost). This would result in a recovery of 49.4 percent or a total spread of 1.0 percent of the original oil in place in ultimate recovery.

At lower formation capacity (less than 320 md-ft), ultimate waterflood recovery to an economic limit under both patterns decreases. However, the spread between the two cases continues to increase. For 53.3 md-ft, which would be typical of the Northern Levelland Unit - May Montgomery Unit area, there is a total spread of 3.8 percent in ultimate recovery. This is between 10 BOPD economic limits for the 85-acre five-spot and 9 BOPD for the 42.5-acre five-spot. Ultimate recoveries were 35.5 and 39.3 percent of the original oil in place, respectively.

On the other hand, for high formation capacity wells on a five-spot pattern, economic limits may be controlled by the mechanical lift capacity of the producing wells and the part of the spread due to increased conductivity as opposed to reduced average per-well operating cost will be eliminated. For West Texas conditions, it appears that there often will be something on the order of a 1 to 2 percent increase in recovery of the original oil in place due to increased conductivity (permissible rates) and lower per-well operating costs at economic limits.

Reduced Shrinkage and Improved Displacement by Accelerated Flooding

Minor increases in ultimate recovery will occur when less primary depletion has occurred prior to repressuring by accelerated water injection. Due to less shrinkage, less stock tank oil is left behind for a given residual oil saturation. In addition, due to slightly lower oil viscosity where more gas is retained or put back into solution, there are also minor improvements in mobility ratio and thus displacement, vertical, and areal sweep efficiency. The West Texas Grayburg, San Andres, Clearfork, and Yates formations in question are relatively low shrinkage crudes. However, some typical calculations for the Levelland (San Andres) Unit indicated on the order of an additional 0.44 percent of original oil in place would be recovered for each 100 psi higher pressure at which flooding occurred in the intermediate primary depletion range. Typically, there might be 50 psi less depletion by initially going to an infill five-spot prior to fillup. This would amount to about a 0.2 percent increase in recovery of the original oil in place.

Amount of Prior Injection Imbalance

In considering infill drilling, the possible adverse factor of amount of prior injection balance must be considered. In some cases, for an infill nine-spot pattern, for example, it can be shown that a certain amount of prior injection imbalance can sometimes result in increased areal sweep. In others there is no question that there will be a tendency for poorer areal sweep. While we have made no generalized study of the effects of injection imbalance, results in several specific model studies indicate that its effect on ultimate recovery is less than would usually be anticipated.

In a recent modeling study of a San Andres reservoir, complex modeling elements were ployed to include the effects of substantial injection imbalance. One of these modeling elements is shown by Fig. 10, along with the optimum conversion and infill program arrived at. As shown, a northern seven-well tier element was involved with six potential 20-acre infill locations. Wells immediately north of the centerline had water cuts of 70 to 80 percent even though perpendicular to indicated limited directional permeability. Over-all, the model included effects of prolonged center and substantial edge injection with somewhat later intensified 160-acre inverted nine-spot waterflooding in intervening areas.

Due to prolonged centerline injection, it did not appear feasible to convert the first offsetting row of wells and infill a five-spot producer. Leaving this first offsetting row of wells on production and infill drilling between it and the next row also was not indicated to be the optimum case as this tended to create a trapped-oil area between existing and new producers. Runs also were made eliminating this second infill well entirely. The best case, as shown by Fig. 10, was an infill five-spot for the four northern locations and an additional well nearly on line with existing Row 6 producers.

Allowances were included for lateral discontinuity effects as well as areal sweep efficiency and normal vertical-type stratification. Appropriate minor differences in economic limits were accounted for. Over-all recovery increase, indicated for the optimum infill flood pattern, was about 2.2 percent of the oil in place. Increases in excess of 3 percent of the original oil in place were indicated by pattern changes and infill drilling in another major area of the field.

Other Benefits From Infill Drilling

Most major waterflood fields were originally drilled in the 1930's to the 1950's. Consequently, there is only limited core data and less reliable, older radioactive and electric logs of that day available on most wells for quantitative determination of amount and detailed distribution of oil in place. Similarly, more reliable native-state relative permeability tests, etc., have only been obtainable via deepenings or infill drilling. Thus infill drilling generally permits more accurate reservoir engineering analysis. This will result in more effective field operation of these floods and more accurate assessment of tertiary recovery possibilities.

FIELD RESULTS

While it is possible to show various individual-well performance curves showing low watercuts at infill locations or other factors tending to support recovery increases, it was thought that it would be more effective to show some over-all results before and after infill drilling. For this approach to have validity, it is necessary for a major amount of waterflood production to have occurred under one pattern followed by a significant performance period after infill drilling. Obscuring effects of many progressive changes in waterflood pattern throughout a flood's life would have to be avoided. This significantly limits the number of examples obtainable for a quantitative analysis from a decline-curve performance approach.

It is recognized that a decline-curve analysis is not rigorous nor is it the normally preferred method to analyze waterflood performance. However, its use was dictated by the limitations on basic data available on floods meeting requirements of a major waterflood performance period before and after infill drilling. In spite of the limitations on the method of analysis, there appears to be no question that recovery increases have occurred in the two examples to be cited in view of the well established declines before and after infill drilling.

Infill Waterflood A

Fig. 11 presents decline-curve performance indicating ultimate waterflood recovery before and after a large-scale infill drilling program for a large non-Amoco-interest West Texas lease. Production is from a 2,600 ft to 3,200 ft Yates Sand-Queen Sand section discovered in 1929. The over-all gross section consists of sand and shaley sand alternating with dense dolomite. As of Dec. 31, 1955, the tract had some 410 wells with a cumulative production of 25,849,000 bbl and a decline curve indicated ultimate primary of 32,299,000 bbl. Producing mechanism was by solution gas drive. The crude was considered to be initially saturated at the 1,400-psig discovery pressure. Initial reservoir oil viscosity was estimated to be 1.39 cp with stock-tank gravity of the oil being 32° API.

While 10-acre spacing was permitted, predominate development density was 40 acres. During the period 1955 to 1958, the lease was converted to waterflooding by infill and some edge drilling. Predominate pattern was 40-acre five-spot with injection wells lined up in an east-west direction and most producing wells on a 45° diagonal. Total well count was 820 wells, including some 330 injection wells as of Dec. 31, 1958. The flood peaked at about 24,500 BOPD during 1962 at a total well count of 860 including 350 injection wells. As of Aug. 31, 1967, production had declined to 11,000 BOPD.

While the over-all flood could be characterized as a 40-acre five-spot there was [illegible]ally some 10-acre development to a 20-acre five-spot or partial inverted nine-spot pattern in certain areas. Cumulative recovery as of Aug. 31, 1967, was 80,516,179 bbl with an indicated ultimate recovery of 100,358,000 bbl based on the established 15.5 percent per year decline and the economic limit as shown by Table 1. An additional 247 infill producing wells were drilled primarily over the next 2-year period, reducing density for the over-all 15,320-acre developed area from 17.4 to 13.63 acres per well. Ratio of producers to injectors was increased from 1.31 to 1.97. Most of these wells were infill drilled between the injection wells on an east-west direction. As a result of this drilling, the flood reached a new peak of some 19,000 B/D, and it is currently on an established decline of 16.7 percent per year. Cumulative production as of Dec. 31, 1973 was 107,107,877 bbl, or about 7 million bbl greater than the previously indicated ultimate waterflood recovery. Current extrapolated ultimate recovery is indicated to be 115 million bbl. Current active well count is some 813 wells, consisting of 512 active producers and 301 active injectors or a producer-to-injection ratio of about 1.7 to 1.

A reliable pore volume number for oil in place was not available to us; however, dividing the decline-curve indicated ultimate primary recovery of 32.3 million by a 12-percent recovery factor would indicate an initial oil in place on the order of 269 million bbl. Dividing the 14.6 million bbl of increased waterflood recovery by this number indicates an increased recovery of some 5.4 percent of the original oil in place. A detailed analysis of reasons for the increased recovery is not possible. However, it appears to be primarily due to minimization of lateral pay discontinuities and increased sweep by drilling in potential trapped-oil areas. Better mechanical completion efficiencies, etc., could be involved, but detailed information regarding these aspects is not available.

Infill Waterflood B

A second example of performance-indicated increases in ultimate recovery by infill drilling is given by Fig. 12. This is an 800-acre developed Amoco-operated tract in a 4,100-ft West Texas Grayburg Field discovered in 1934. Pay is scattered over a gross dolomitic section of on the order of 230 ft. Average permeability of the net pay ranges from 1 to 5 md. The field was under a solution gas drive mechanism with an original and bubble-point pressure of 1,740 psi. Initial crude viscosity was 1.5 cp.

The lease was initially developed with 20-acre density on its east edge and 40-acre density over the western lower pay quality area. An infill 20-acre double five-spot pilot was initiated in the best part of this lease in early 1956 by infill-drilling two producers on 10-acre density. The lease was in an advanced stage of primary depletion at this time, with a recovery of about 12 percent of the original oil in place. Due to the infill, the pilot injection wells were lined up east-west and north-south with the infill producers at a 45° angle. Based on satisfactory pilot performance, the lease was converted to a full-scale five-spot flood by converting certain existing wells to injection in 1959 through 1960. This gave an 80-acre five-spot pattern over most of the lease. Over-all development consisted of 16 injectors and 15 producers. The full-scale pattern was such that most producing wells were on an east-west line to injection wells.

The full-scale flood was characterized by early water breakthroughs, poor oil response, and excessive injection to withdrawal ratios. Subsequent pressure and production interference tests, wellbore televiewer logs, etc., have indicated a natural and/or induced fracture system having an orientation of 90° to 110°E of N throughout this area. Infill drilling of 17 wells including one replacement, primarily in 1969 through 1970 changed the orientation and density from an 80-acre five-spot to a 40-acre five-spot over the western portion of the lease. Total wells increased from 31 to 47, consisting of 25 injectors and 22 producers. Production increased from about 250 to a peak of over 2,000 BOPD. A number of infill wells were initially completed essentially water free. Over-all lease water cut dropped from 85 to 50 percent. Decline curve indicated ultimate waterflood recovery was increased from 4,565,800 to 7,008,200 bbl. This is from 18.6 to 28.5 percent of pore volume-indicated original oil in place of 24.6 million bbl. The 2.44-million-bbl increase amounts to some 9.9 percent of the original oil-in-place. While various factors are involved, it appears that the primary reason for an increased recovery of this magnitude is providing flooding across the existing fracture orientation. In the original pilot area, which was drilled to 10-acre spacing, double 20-acre five-spot physical cumulative recovery is approaching 31 percent of the original oil in place.

SUMMARY

Various theoretical concepts have been presented demonstrating reasons for increased recovery through infill drilling. While these were oriented toward formations of lower permeability being subjected to waterflooding, most have general applicability. Certain model results have been presented or referenced which

support these concepts. Indicated recovery increases from several field case histories as ported by well-established waterflood decline curves before and after infill drilling are presented. In addition, an extensive study by Shell Oil Co. for the Wasson (San Andres) Field-Denver Unit indicated a recovery increase for the area infill drilled of up to 5 percent of the original oil in place. This consisted of 1½-percent improved areal sweep efficiency, 1½-percent improved vertical sweep efficiency, and 2-percent improved recovery due to reduced lateral discontinuity effects. Another Amoco study is cited, which without benefit of improved areal heterogeneity effects and considerable injection balance, indicates an increased recovery of about 2.2 percent due primarily to minimization of lateral discontinuities and economic limit effects.

CONCLUSIONS

1. Infill drilling can indeed increase recovery.

2. For low permeability waterfloods, increasing well density from 40 to 20 acres will typically result in a recovery increase on the order of 4 percent of the original oil in place.

3. Amount of waterflood recovery increase will normally range from about 2 to 8 percent of the oil in place; however, higher values such as 8 percent will be obtained only where marked areal heterogeneity effects exist that will be overcome by the infill drilling.

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TABLE 1 - PERFORMANCE ANALYSIS OF ULTIMATE WATERFLOOD RECOVERIES BEFORE AND AFTER INFILL DRILLING - CASES A AND B

	Case A	Case B
Before Infill		
Date	8-31-67	12-31-68
Producers	500	15
Injectors	380	16
Total Wells	880	31
Rate	11,000 BOPD	242 BOPD
Annual Decline Rate	15.5 %/Yr.	15.8 %/Yr.
Economic Limit	1,928 BOPD	93 BOPD
	2.2 BOPD/TW	3.0 BOPD/TW
Future	19,841,821 bbls.	319,000 bbls.
Cumulative Prod.	80,516,179 bbls.	4,246,800 bbls.
Ultimate Waterflood	100,358,000 bbls. (37.3%)	4,565,800 bbls. (18.6%)
After Infill		
Date	12-31-73	12-31-73
Producers	747	22
Injectors	380	25
Total Wells	1,127	47
Rate	6,400 BOPD	680 BOPD
Annual Decline Rate	16.7 %/Yr.	17.2 %/Yr.
Economic Limit	2,480 BOPD	141 BOPD
	2.2 BOPD/TW	3.0 BOPD/TW
Future	7,892,123 bbls.	1,050,400 bbls.
Cumulative Prod.	107,107,877 bbls.	5,957,800 bbls.
Ultimate Waterflood	115,000,000 bbls. (42.7%)	7,008,200 bbls. (28.5%)
OOIP	269,000,000 bbls.?	24,612,000 bbls.
Increased Recovery	14,642,000 bbls.	2,442,400 bbls.
Approx. % OOIP	5.4 %	9.9 %
Bbls./Infill Well	59,300 bbls.	152,700 bbls.

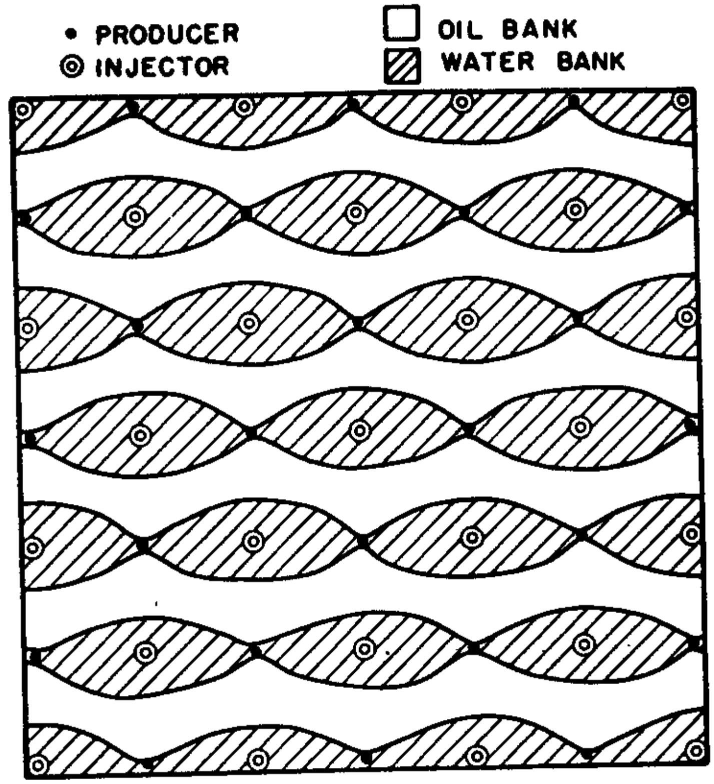

Fig. 1 East-west breakthrough 80-acre 5-spot waterflood

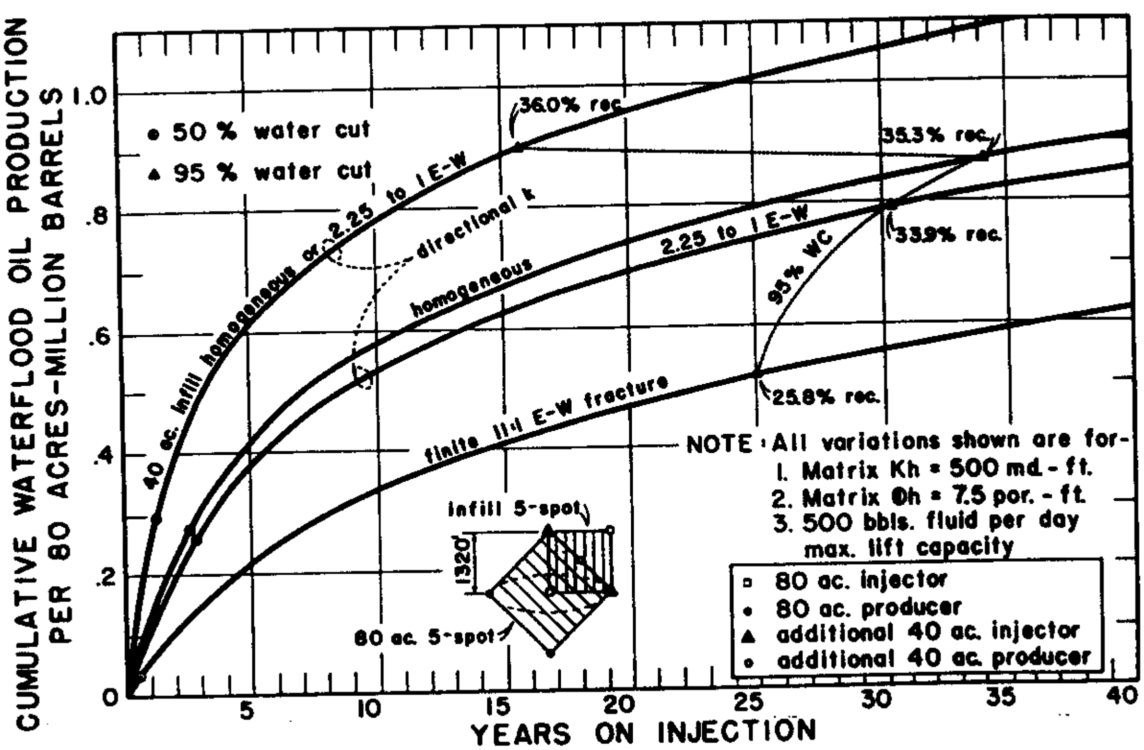

Fig. 2 - Recovery sensitivity to pattern orientation with directional permeability or finite capacity fractures (AICFU-1970 model study data).

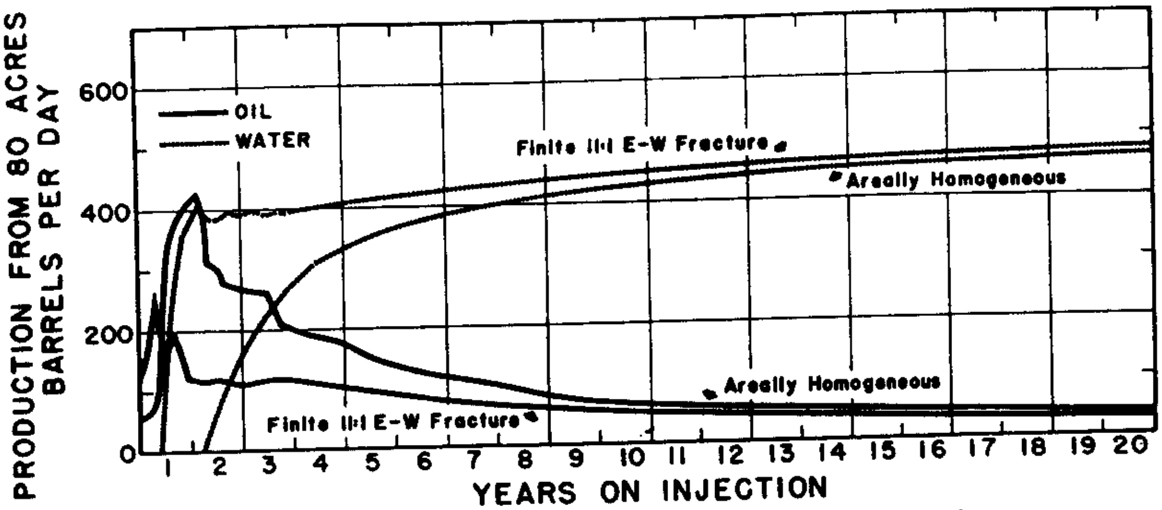

Fig. 3 - Rate vs. time - 80-acre 5-spot, homogeneous and finite fracture cases (AICFU-1970 model study data).

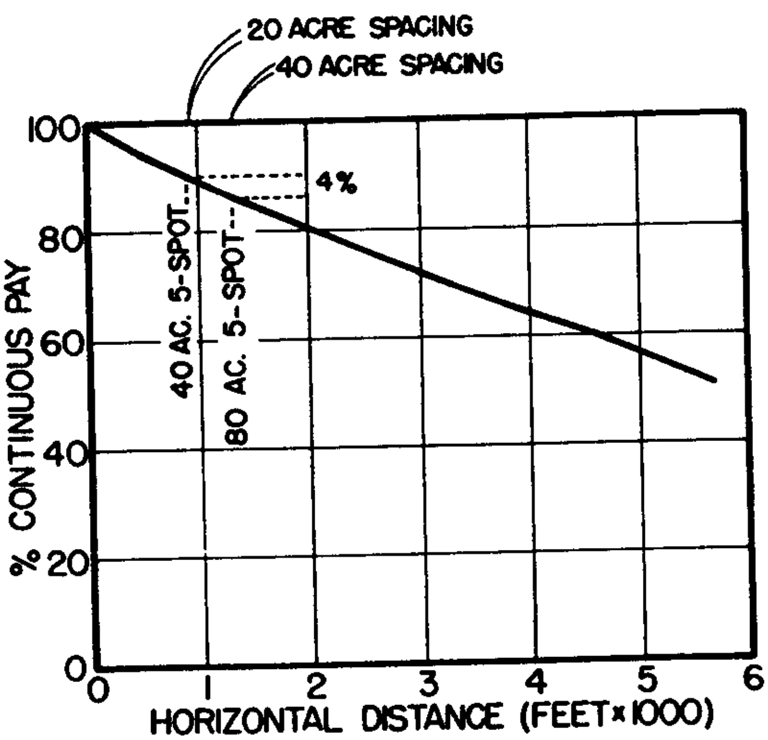

Fig. 4 - Pay continuity vs. horizontal distance - Wasson San Andres field.

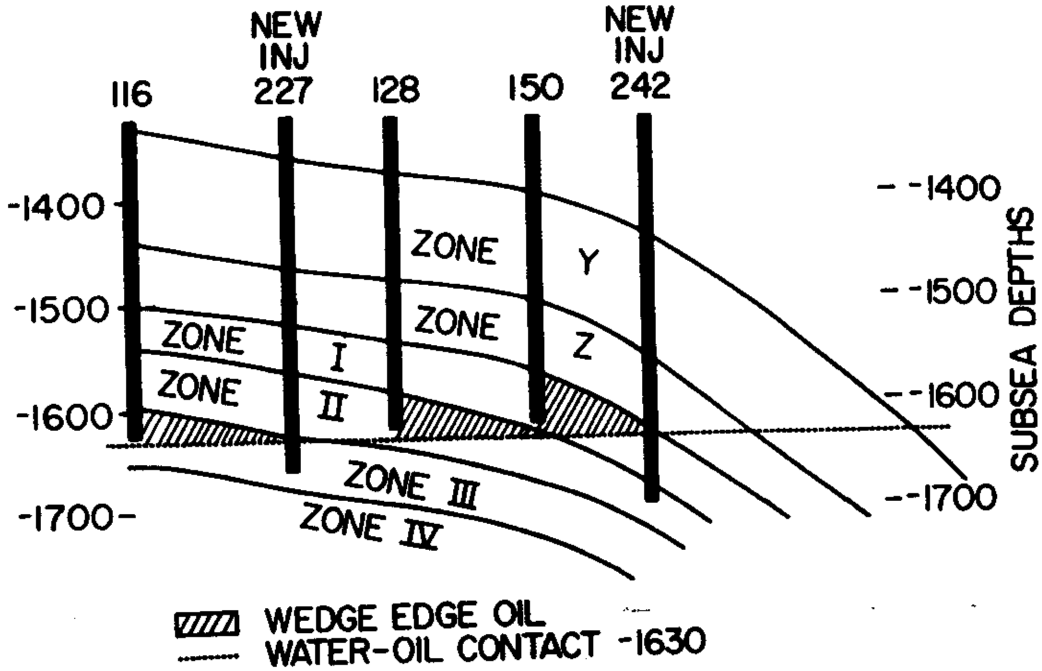

Fig. 5 - Wedge edge oil recovery by infill and edge drilling.

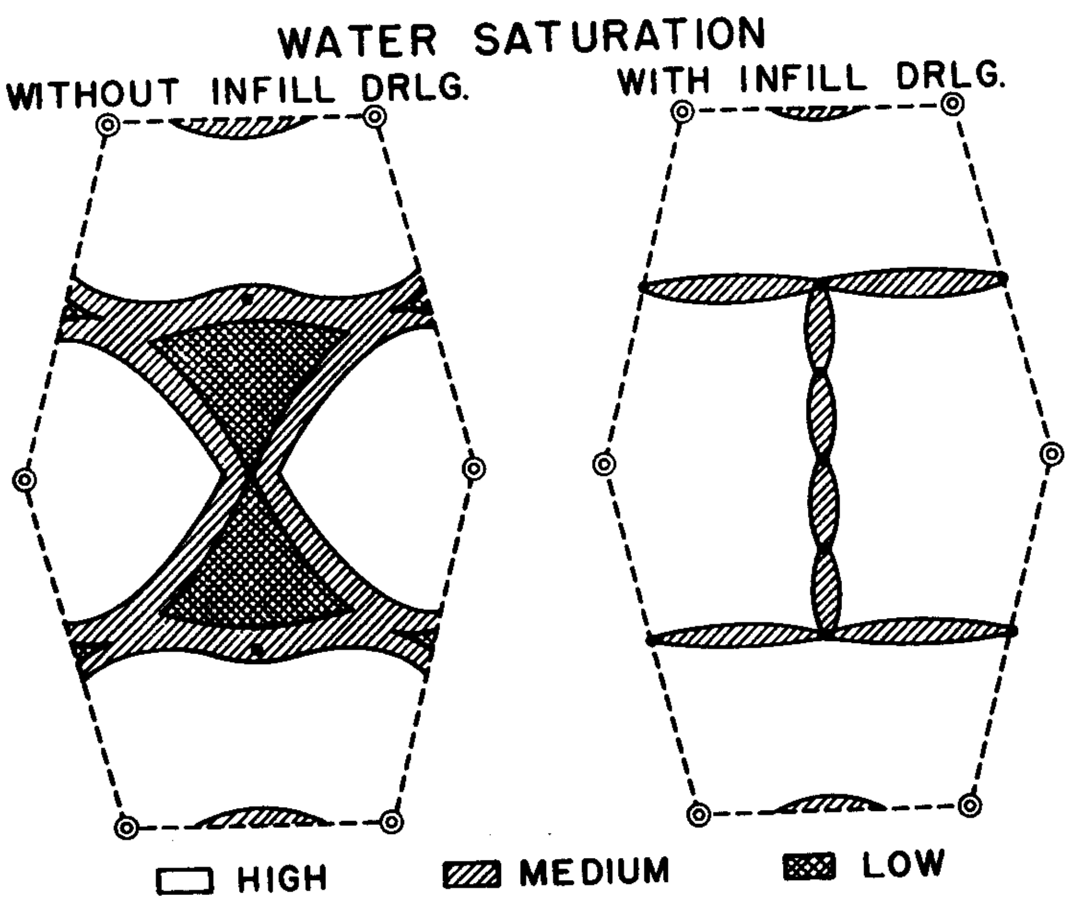

Fig. 6 - Improved areal sweep by minimizing poor geometry effects - Slaugher field "chickenwire pattern."

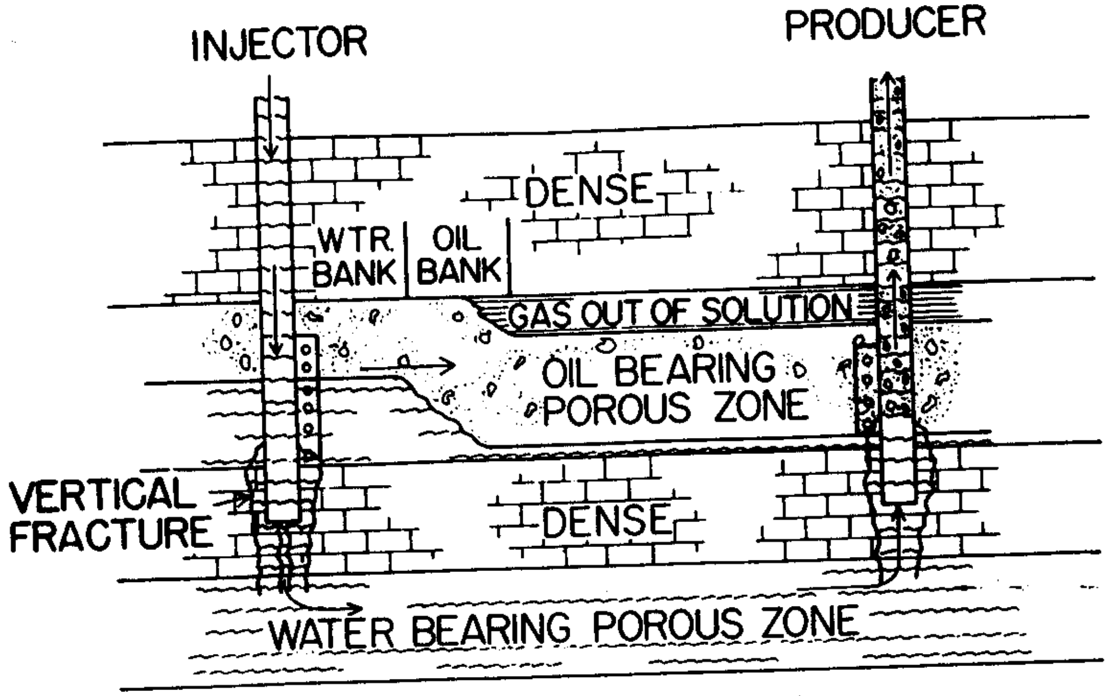

Fig. 7 - Confine injection fluids to pay zones.

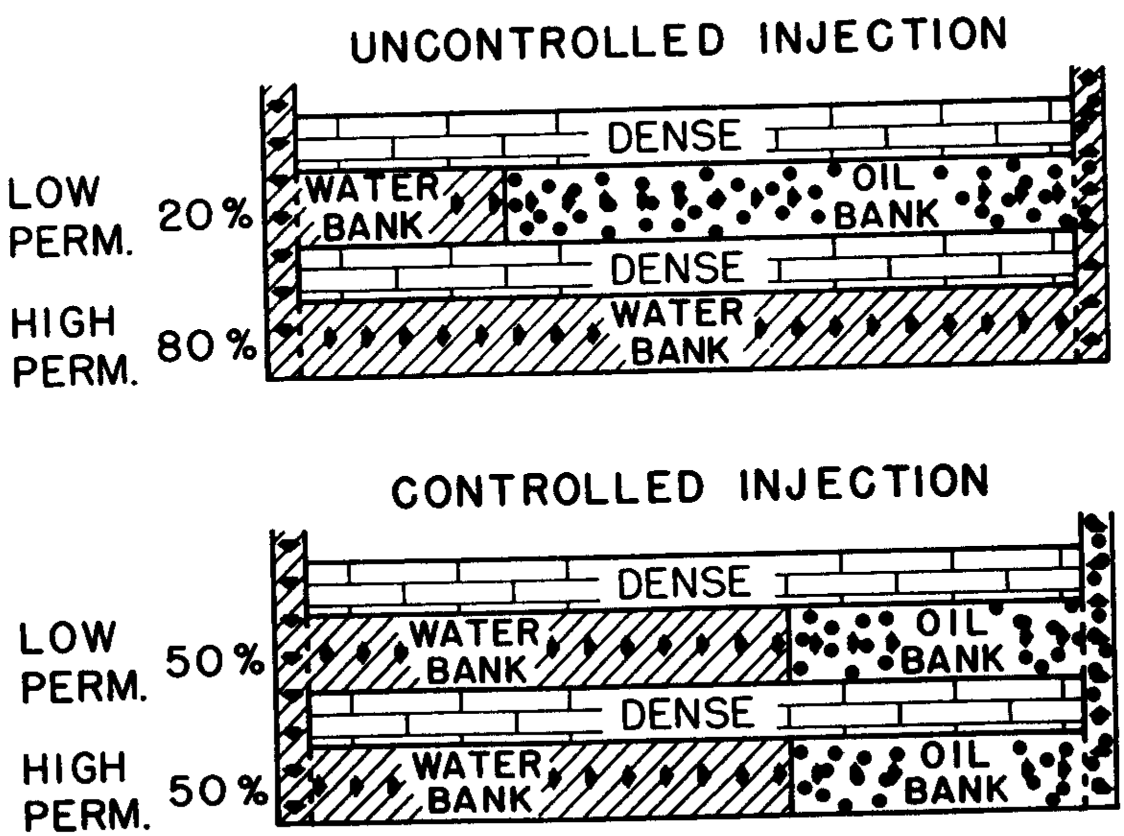

Fig. 8 - Better control of injection profiles where vertically separate pay zones exist.

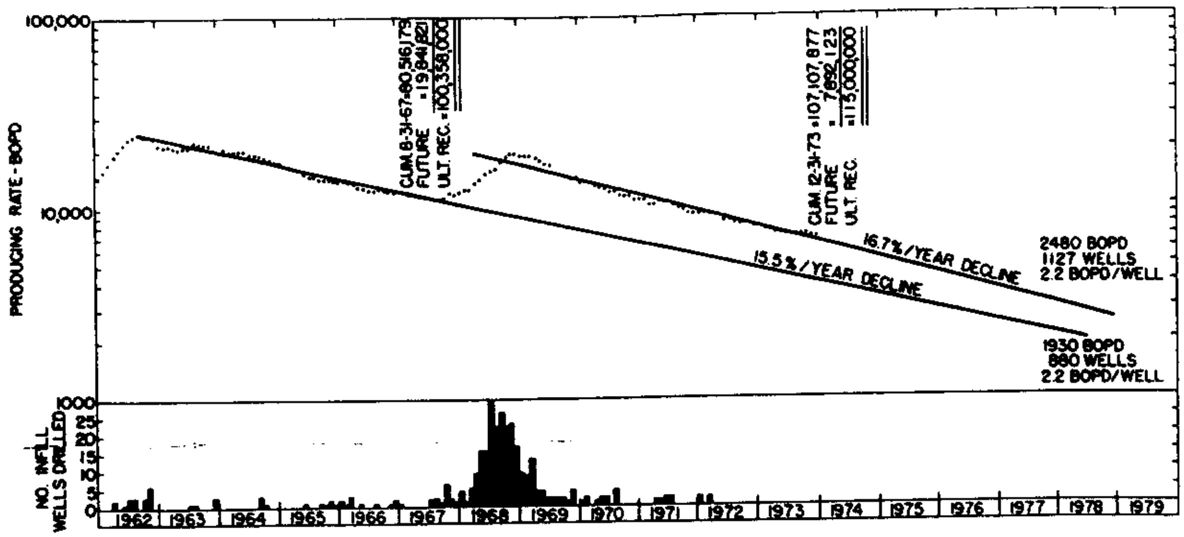

Fig. 11 - Infill Case A - 2600-ft West Texas Yates production.

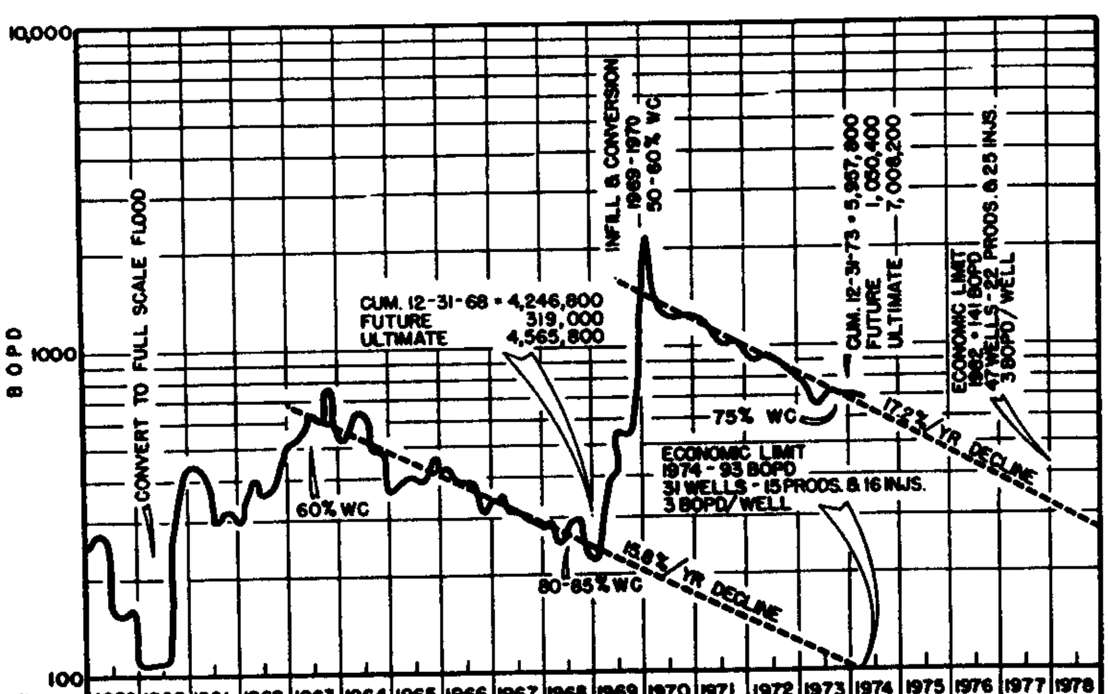

Fig. 12 - Infill Case B - 4100-ft West Texas Yates production.

Gould

Sarem

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Infill Drilling for Incremental Recovery

T.L. Gould, SPE, Scientific Software Intercomp, and **A.M. Sam Sarem**, SPE, Unocal Science & Technology Div.

Summary. The purpose of this paper is to summarize what has been learned over the last several years about infill drilling and to recommend when it should and should not be considered. In general, the more a reservoir deviates from ideal behavior, the greater the opportunity for incremental recovery by infill drilling.

Introduction

Infill drilling of pattern waterfloods has received remarkably little attention from both the public and professional communities. Given the right circumstances, this process can compete favorably with EOR processes on a recovery basis for much less investment and operating cost. And yet, to the best of our knowledge, there are no research institutes, university projects, government programs, or tax incentives to encourage the development and application of infill drilling. There is virtually no technical literature on the subject, compared with EOR, and until recently very little field data supported or denied any claim concerning the benefits of infill drilling.

In 1980, van Everdingen and Kriss[1] provided our industry yet another service by raising a controversy around infill drilling. Their statement that "infill drilling, if done properly, can be used to recover at least as much oil as the U.S. already has produced" (120 billion bbl [19×10^9 m^3]) created a controversy that still goes on today. Although we believe this statement to be exaggerated for the U.S. as a whole, it is interesting to note that there are no projects under way to determine just how much could be recovered. As a result of his original position papers, van Everdingen was asked by the U.S. DOE to investigate the subject further. His resulting proof was inconclusive, primarily because of a lack of good field data and reservoir description.

In 1980, Holm[2] provided a thought-provoking discussion of van Everdingen and Kriss' work, but his analysis was limited by the same lack of field data. At that time, very little technical analysis existed of infill drilling as an incremental recovery process and the mechanisms involved. Holm's estimate of the potential of infill drilling is much more conservative: "with our best efforts we could add to U.S. reserves about 1 to 1.5 billion bbl/yr for about 10 years." In our current times of reduced reserve additions from exploration, such additions would be most welcome. Holm's estimated national average was 34×10^3 to 47×10^3 bbl [5406 to 7472 m^3] per infill well.

In 1983, a very significant paper by Barber *et al.*[3] confirmed Driscoll's[4] 1974 observations of 2 to 8% incremental recovery from infill drilling. Barber *et al.* analyzed nine sets of field data showing very positive incremental recovery from infill drilling. Two of the reservoirs, Dorward and Sand Hills, were primary projects and cannot be used for comparison with secondary pattern floods. The Howard-Glassock reservoir is a peripheral flood and as such is also not directly comparable. Data from Barber *et al.*,[3] Driscoll,[4] and Ghauri *et al.*[5] are summarized in Table 1 for a total of 1,323 wells with an average incremental recovery of 107.1×10^3 bbl [17×10^3 m^3] per infill well. This average is greater than Holm's by a factor of two to three but is weighted specifically for west Texas carbonates.

If Holm's more conservative estimate is correct, 10 to 15 billion bbl [1.6×10^9 to 2.4×10^9 m^3] is still a very large number for a virtually unstudied incremental recovery process. This represents 2 to 3% of the national original oil in place (OOIP) of 460 billion bbl [73×10^9 m^3]. Current field data for a limited number of projects show estimated infill recoveries of about 5% OOIP. Although the true benefit of infill drilling is unknown, its potential is well established.

The Natl. Petroleum Council (NPC) published a study on EOR potential in the U.S.[6] in 1984 that concluded that "as much as 14.5 billion bbl of additional oil could ultimately be recovered with the successful application of existing EOR technology, under current economic conditions." NPC's

TABLE 1—SUMMARY OF INFILL-DRILLING INCREMENTAL RECOVERIES

Project	Number of Wells	Project Volume (10^6 bbl)	Volume per Well (10^3 bbl)	Infill Spacing (acres)	Volume (bbl/acre)
Means San Andres					
20-acre infills	141	15.4	109	20	5,450
10-acre infills	16	1.2	75	10	7,500
Fullerton Clearfork	254	24.6	97	20	4,850
Robertson Clearfork	138	10.7	78	18	4,330
IAB (Menielle Penn)	17	1.7	100	40	2,500
Hewitt	15	0.4	27	5	5,400
Loudon	50	0.97	19	10	1,900
Yates Sand	247	14.6	59	10	5,900
Grayburg	17	2.44	144	20	7,200
Wasson San Andres (Denver Unit)	293	51.0	174	20	8,700
North Riley Clearfork Unit	91	13.2	145	20	7,250
Dollarhide Clearfork "AB" Unit	44	5.52	125	20	6,250
Total (or well average)	1,323	141.7	107.1	17.5	6,120

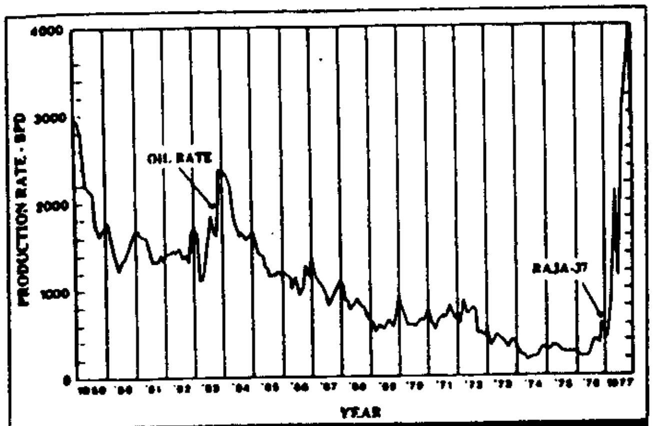

Fig. 1—Raja production after infill.

conclusion implies \$30/bbl [\$189/m³] nominal crude price and 10% minimum discounted-cash-flow rate of return (ROR). At \$20/bbl [\$126/m³], the projection by EOR process is 4.4 billion bbl [700×10^6 m³] for thermal processes, 2.0 billion bbl [318×10^6 m³] for miscible processes, and 1.0 billion bbl [159×10^6 m³] for chemical processes, for a total of 7.4 billion bbl [1.2×10^9 m³].

There is significant upside potential because of technology improvements, but at \$20/bbl [\$126/m³], there is insufficient incentive to develop it. With crude prices at \$20/bbl [\$126/m³] and below, infill drilling would appear to have potential equal to or greater than EOR processes. We must stress "potential" here; the number and quality of infill locations have never been determined nationally.

The combination of infill drilling and EOR in the same project can be every effective. Restine *et al.*[7] described an infill drilling project after a tertiary steamflood was completed and reported incremental oil recoveries of 4 to 7% OOIP after infilling from 1.25 to 0.625 acres/well [0.5 to 0.25 ha/well]. Alternatively, infill drilling before a tertiary miscible or chemical process has the benefits of better pattern control, shorter project life (better ROR), and improved areal/vertical sweep. The incremental recovery generated by the infill wells may be more than sufficient to pay out these wells before the tertiary project.

Field Experience

Why is infill drilling suddenly surfacing as an incremental recovery process after so many years of waterflooding experience? One answer is that infilling has always been a part of good waterflood management. It has not been recognized, however, as an incremental recovery process until recently, and it had not been reported separately from total waterflood performance until the early 1980's.

Although field experience with infill drilling is extensive, relatively little has actually been published. When knowledgeable engineers are asked why, the answer usually comes back in the form of "we're too busy making money to analyze the process." This leads one to believe that infilling may already be extensive and, as such, might not have as big a potential as theoretically possible because it is already included in current reserves to an unknown extent.

Project Reviews. Infill drilling results are sketchy but cover the full range of projects from primary to tertiary. Here we highlight some field case studies.

Primary. The Raja field,[8] located in South Sumatra, was produced from 1940 to 1976 from 36 wells on 80-acre [32-ha] spacing. Between 1976 and 1978, six wells were drilled, which increased production from 300 to 3,500 BOPD [47.7 to 556 m³/d oil].

The geologic setting of this field is complex, with production from many limestone and sand zones over a gross interval of 1,500 ft [457 m]. The channel-type sands meander and drape across the structure.

The Raja field primary infill project showed more than a 10-fold increase in production caused primarily by lateral continuity effects. Fig. 1 shows the performance of this infill project.

Secondary. Fig. 2A shows the performance of infill waterflood projects in the North Riley (Clearfork) Unit. Since 1984, 91 infill wells have been drilled in the North Riley Unit, producing more than 3.2 million bbl [509×10^3 m³] of oil. Infill wells currently average 29 BOPD/well [4.6 m³/d oil/well], accounting for 70% of unit production. Ultimate production from infill wells is forecast to average 145,000 bbl [23×10^3 m³] of oil per well on the basis of decline-curve analysis. To date, no evidence of interference has been observed.

With the drilling of these infill wells, the unit has evolved from an 80-acre [32-ha] five-spot to an 80-acre [32-ha] inverted-nine-spot waterflood. Therefore, the current thrust of activity in the North Riley Unit is a major conversion project. However, another possible thirty-four 20-acre [8-ha] locations remain to be developed.

Fig. 2B shows the performance of infill waterflood projects in the Dollarhide (Clearfork "AB") Unit. Since 1980, 44 infill wells have been drilled in the Dollarhide Unit, producing more than 2.65 million bbl [421×10^3 m³] of oil. Infill wells currently produce more than 80% of the 2,000-BOPD [318-m³/d-oil] unit production. The unit production curve shows total oil production and oil production allocated to 40-acre [16-ha] producers. This graph indicates that virtually no interference has resulted from the increased well density. Ultimate production from the infill wells is forecast to average 125,000 bbl [20×10^3 m³] of oil per well on the basis of decline-curve analysis. Infill drilling on 20-acre [8-ha] spacing

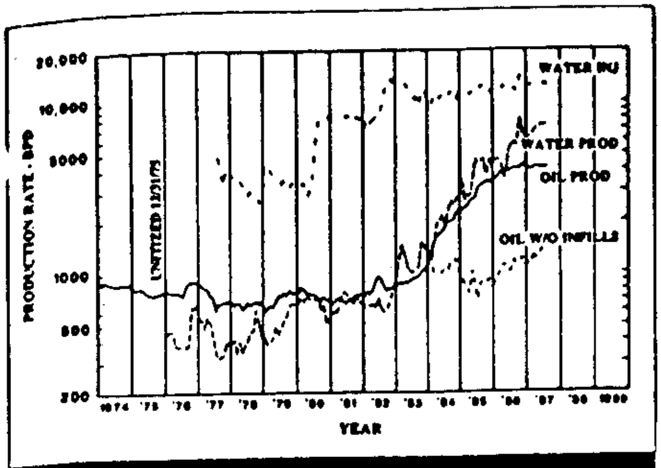

Fig. 2A—Production datagraph—North Riley (Clearfork) Unit.

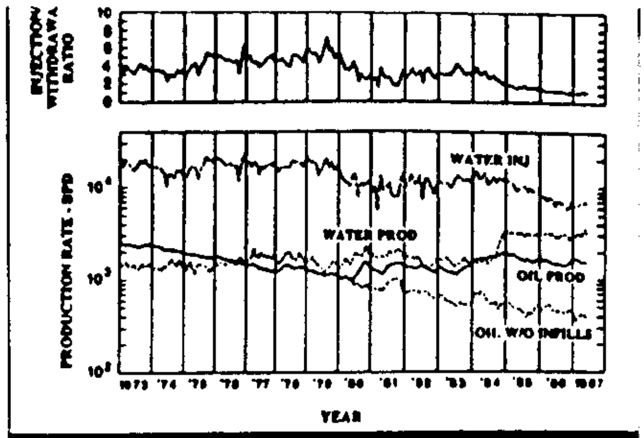

Fig. 2B—Production datagraph—Dollarhide (Clearfork "AB") Unit.

in the unit should be finished in 1989 when the few remaining locations have been exhausted.

Tertiary. Restine *et al.*[7] showed results for three infill projects that occurred after the initial steamflood. Fig. 3 shows the production from the Canfield R1 and R sands that resulted from infills after the original steamfloods were completed. Incremental recovery was about 1.76×10^6 bbl [280×10^3 m^3] for 80 wells on 0.625-acre [0.25-ha] spacing, or about 35,200 bbl/infill acre [13.8×10^3 m^3/infill ha]. The total net pay was about 148 ft [45 m] with a porosity of 31%. The incremental recovery of infill as a quaternary process resulted in 238 bbl/infill acre-ft [0.03 m^3/infill m^3].

Summary of Results. Results have been reported for only 11 secondary infill projects to date, covering 1,323 wells, as shown in Table 1. The total incremental recovery of these projects is 142 million bbl [22.6×10^6 m^3] for an average of 107,100 bbl/well [17×10^3 m^3/well]. Table 2 provides a detailed summary of these 11 projects. Intuitively, we might have expected to see a trend of recovery with viscosity ratio. Unfortunately, there is no obvious trend, but the average of 6,120 bbl/infill acre [973 m^3/infill ha] can be compared with Holm's national average. If we use a well spacing of 17.5 acres [7.1 ha], which is the average of reported projects, and we use Holm's estimates of 34×10^3 to 47×10^3 bbl/well [5.4×10^3 to 7.5×10^3 m^3/well], then his estimate corresponds to 1,940 to 2,680 bbl/infill acre [762 to 1053 m^3/infill ha], with an average of 2,310 bbl/infill acre [907 m^3/infill ha].

It is interesting to note that the fields reported to date show an average of nearly three times Holm's estimate. This tends to confirm Holm's estimate, because the field data are mostly west Texas carbonates with the benefit of improved continuity. The continuity effect in these fields would tend to put them well above a national average.

Such estimates should be refined to a recovery basis and related to infill water cut and areal and vertical permeability variations. This would reduce some of the scatter, but probably would require a pattern-by-pattern analysis.

Evaluating the Opportunity

Several factors must be considered during the planning of an infill project: (1) production/injection performance, (2) reservoir description, (3) infill drilling project design, and (4) economic evaluation. If any one of these factors is analyzed insufficiently, the project could fail.

Production/Injection Performance. In an ideal waterflood with a known mobility ratio, we know that the oil volume produced before water breakthrough follows a well-defined relationship. Each pattern needs to be analyzed relative to its theoretical performance to determine the actual sweep efficiency. In general, the worse the original waterflood

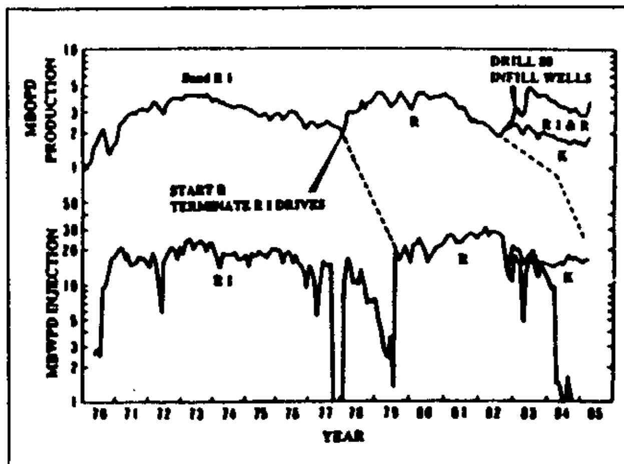

Fig. 3—1970 Canfield oil production and steam injection history.

efficiency, the better the infill opportunity. The infill project can suffer the same inefficiency, however, unless careful analysis is performed to determine the cause. The infill project design must properly account for this.

Injection performance is another valuable clue that is often overlooked. In an ideal flood, all injectors should be balanced, and the injection/production ratio should also be balanced. In reality, these two values never are balanced on a pattern-by-pattern basis. Setting up streamline models and looking for trends and anomalies provides information for the infill project design. Streamline models that do not account for reservoir heterogeneity, however, can do more harm than good.

Reservoir Description. Without a good reservoir description, the risk that an infill project may not succeed is very high, particularly if the original project efficiency was poor. Although the infill opportunity may be high, if you do not know the reason for the original behavior, you cannot design an appropriate infill strategy.

Geologic Studies. Geologic studies are the first step in preparing a good reservoir description. Lithologies need to be mapped and reliable models of the depositional environment developed.

Log Data. Petrophysical analysis and interwell zone correlations are very useful in determining continuity and average pattern properties. Of particular interest are net pay, porosity, and OOIP or current oil in place.

Seismic Data. Both two-dimensional and three-dimensional seismic data can be very useful after the initial waterflood but before the infill project is designed. In many cases, the

TABLE 2—SUMMARY OF INFILL DRILLING PROJECTS

	Means San Andres		Fullerton Clearfork	Robertson Clearfork	IAB Menlelle Penn	Hewitt Hoxber
Rock	Dolomite		Dolomite	Dolomite	Limestone	Sandstone
Depth, ft	4,400		7,000	6,500	5,800	2,000 to 3,400
Gross thickness, ft	300		600	1,400	—	1,500
Net thickness, ft	92		92	200 to 300	45	100 to 170
Porosity, percent	9		10	6.3	7	21
Permeability, md	20		3	0.65	27	184
Interstitial water, percent	29		22	30	—	21
Residual oil, percent	36		28	24	—	—
Temperature, °F	100		117	117	134	96
Dykstra-Parsons coefficient	—		0.83	—	—	0.73
Fluids						
Gravity, °API	29		42	32	44	35
FVF	1.04		1.62	1.25	1.86	1.13
Saturation pressure, psi	310		2,370	1,700	2,525	905
Oil viscosity, cp	6		0.75	1.2	0.2	8.7
Water viscosity, cp	0.8*		0.6	0.6	0.5*	0.95*
Viscosity ratio	7.5		1.25	2.0	0.4	9.2
Infill Projects	A	B				
Number of wells	141	16	254	138	17	15
Acres per well	20	10	20	18	40	5
Infill water cut	—	—	—	—	—	96 to 97
Incremental oil, 10^6 bbl	15.4	1.2	24.6	10.7	1.7	0.4
Incremental per well, 10^3 bbl	109	75	97	78	100	27
Incremental per well per infill acre, bbl/acre	5,450	7,500	4,850	4,330	2,500	5,400
Estimated incremental recovery, % OOIP	5 to 8	2 to 5	3 to 4	—	4	—

*Estimated value.

TABLE 2—SUMMARY OF INFILL DRILLING PROJECTS (continued)

	Loudon Penn	Yates Sand	Grayburg	Wasson San Andres	North Riley	Dollarhide "AB" Unit
Rock	Sandstone	Sandstone	Dolomite	Dolomite	Dolomite	Dolomite
Depth, ft	1,500	2,600 to 3,200	4,100	5,200	6,300 to 7,300	5,800
Gross thickness, ft	—	—	230	300 to 500	1,000	1,800
Net thickness, ft	16	—	—	137	100 to 400	100 to 150
Porosity, percent	20	—	—	12	8	10
Permeability, md	100	—	1 to 5	5	12	11
Interstitial water, percent	—	—	—	24	36	18
Residual oil, percent	29	—	—	40	25	33
Temperature, °F	78	86*	101*	105	107	112
Dykstra-Parsons coefficient	0.42	—	—	—	—	—
Fluids						
Gravity, °API	38	32	—	33	35	38
FVF	—	—	—	1.31	1.12	1.20
Saturation pressure, psi	—	—	—	1,805	1,280	2,190
Oil viscosity, cp	5	1.39	1.5	1.3	2.25	1.9
Water viscosity, cp	1.05*	0.95*	0.8*	0.7	0.75	0.6
Viscosity ratio	4.8	1.46	1.9	1.85	3.4	3.17
Infill Projects						
Number of wells	50	247	17	293	91	44
Acres per well	10	10	20	20	20	20
Infill water cut	98	—	85	—	—	—
Incremental oil, 10^6 bbl	0.97	14.6	2.44	51.0	13.2	5.52
Incremental per well, 10^3 bbl	19	59	144	174	145	125
Incremental per well per infill acre, bbl/acre	1,900	5,900	7,200	8,700	7,250	6,250
Estimated incremental recovery, % OOIP	—	5.4	9.9	5	6	3 to 5

*Estimated value.

original seismic data are unavailable or were not used to develop a structure with faults with detail at the pattern level. Three-dimensional seismic, vertical seismic profile, and well-to-well tomography can be used to estimate interwell areal heterogeneity.[9]

Well Tests. Individual well tests can provide an estimate of average properties in the vicinity of the well and the type of reservoir (single or dual porosity, radial or bounded flow). In general, selected interference well testing should also be performed on existing injectors and producers before an infill

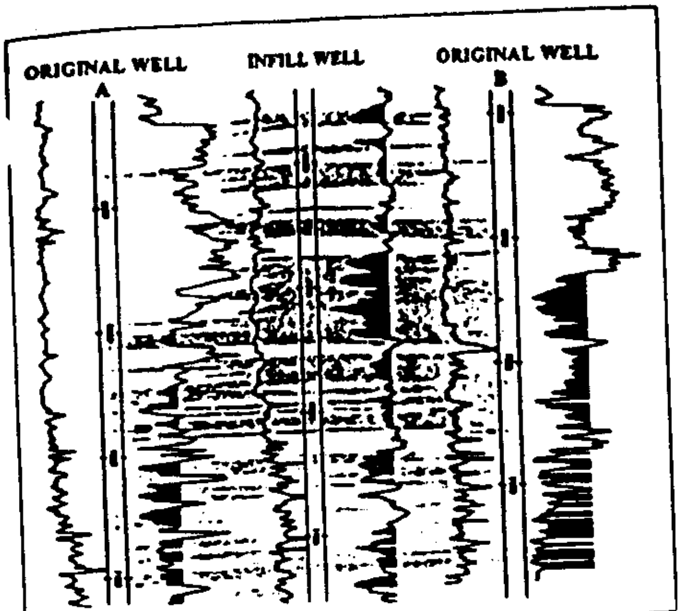

Fig. 4—Type cross sections—Fullerton Clearfork reservoir.

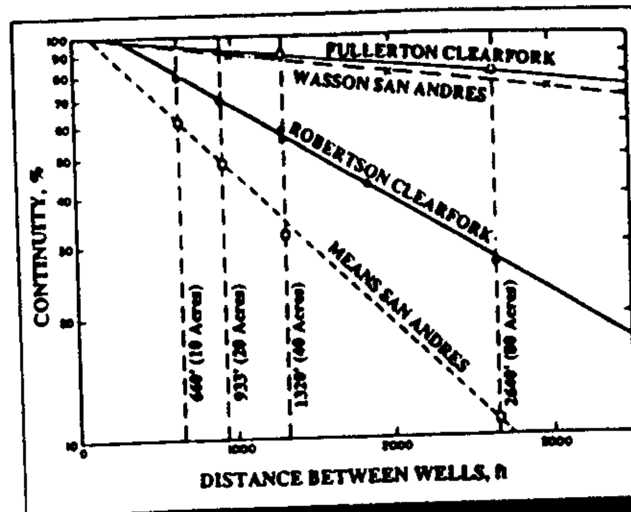

Fig. 5—Continuity vs. distance between wells.

design to provide information on directional permeability. Use of modern well test analysis methods to determine whether dual-porosity behavior exists can yield some surprises.

Tracer Tests. Tracer tests can give information that is unavailable by any of the previously discussed methods. Wagner[10] provides excellent examples of what can be learned from tracer tests.

Tracer tests are the only practical method of determining net areal/vertical sweep efficiency within a pattern. Brigham and Abbaszadeh-Dehghani[11] showed that these measurements can also be used to determine the relative layer response and estimates of effective vertical heterogeneity. These tests can be critical in determining whether permeability barriers or anisotropy exist and to what degree.

Infill Drilling Project Design. A project design phase should be performed with the results of the reservoir-description step to determine the expected infill performance for each pattern and to develop total project revenue and cost forecasts for the economic evaluation. Considerations include the following, but will vary by project.

1. The need for a pilot project to obtain good log and core data. If a pilot is called for, then a tracer test should be included to explore for areal and vertical heterogeneity.
2. Infill pattern alternatives (line drive to five-spot, five-spot to nine-spot) and location selection. In highly heterogeneous reservoirs, optimum pattern spacing may require a side study.
3. Selective isolation or polymer plugging of the most productive (thief) zones.
4. Stimulation or fracturing requirements.
5. Estimated drilling and conversion costs.
6. Production facility changes to account for reduced water cut and increased injection-facility requirements.
7. Improvements in project monitoring and control.
8. Forecast of production performance of each pattern after infill.
9. Forecast of total project performance and estimates of upside and downside volumes.

Economic Evaluation. A clear understanding of the current economic limit and the impact of infill drilling on the new economic limit is essential in evaluating a project. Because the infill process is a combination of incremental recovery and acceleration, the economic analysis must be performed carefully on a discounted basis.

Determining the expected revenues from decline curves is very risky. Gould and Munoz[12] showed that both continued waterflood and infill do not behave as classic declines would predict near the economic limit, which is where this analysis must be performed. The only realistic way to estimate volumes is through some form of modeling, either numerical or analytical.

Recovery Mechanisms

The key question is whether infill drilling of a secondary pattern flood provides true incremental oil recovery, simple acceleration, or both. In an ideal, homogeneous system, infill drilling can only accelerate production. No real reservoirs are ideal or homogeneous; hence, infill drilling can also play a major role in incremental recovery. The mechanisms that provide incremental recovery are easily defined but very difficult to evaluate in a real field situation. Driscoll[4] presented the first clear discussion of the factors causing increased recovery when secondary pattern floods are infill-drilled. The recovery mechanisms involved can be classified, in order of importance, as (1) improved reservoir continuity, (2) improved areal sweep, (3) improved vertical sweep, (4) recovery of wedge-edge oil, and (5) improved economic limit. Each of these factors can contribute to incremental recovery independently and therefore may be additive for a specific project.

Improved Continuity. Because most currently available field data are from west Texas carbonates, many engineers consider improved lateral pay continuity to be the only mechanism of importance to infill drilling. Fig. 4 illustrates this concept.[3] The infill well, between original Wells A and B, opens up new pay that was not shown in Well A or B, and it provides a different correlation of continuous zones than would have been derived from Wells A and B alone. For example, the upper part of the logs between Well B and the infill show floodable zones that did not exist between Wells A and B.

Fig. 5 shows another way to analyze the improvement in continuity that results from infill drilling. This figure shows the fraction of gross pay that is continuous between wells at various spacings for several major projects: Means San Andres,[3] Robertson Clearfork,[13] Fullerton Clearfork,[14] and Wasson San Andres (Denver Unit).[4] Barbe and Schnoebelen[13] added another distinction between continuous and floodable zones: the floodable pay is even less than the continuity analysis would show owing to heterogeneity.

The Means and Robertson curves are the result of recent analysis. Barber *et al.*[3] showed how such curves tend to show less continuity as more data become available at smaller

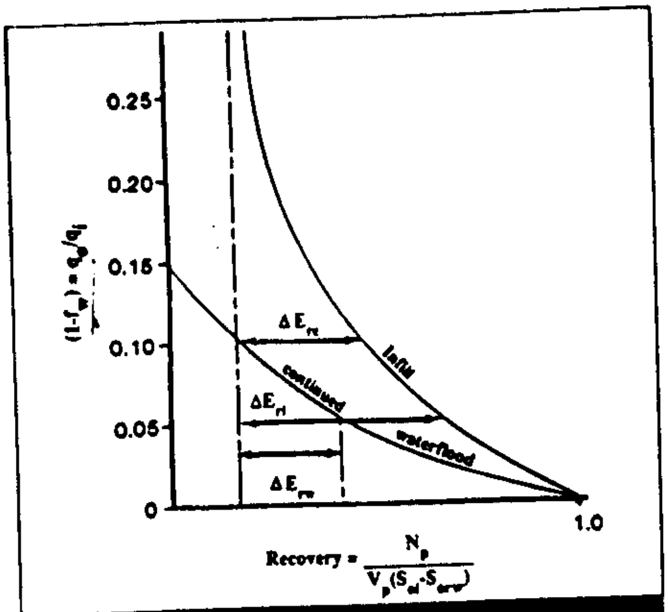

Fig. 6—Schematic of typical infill simulation results.

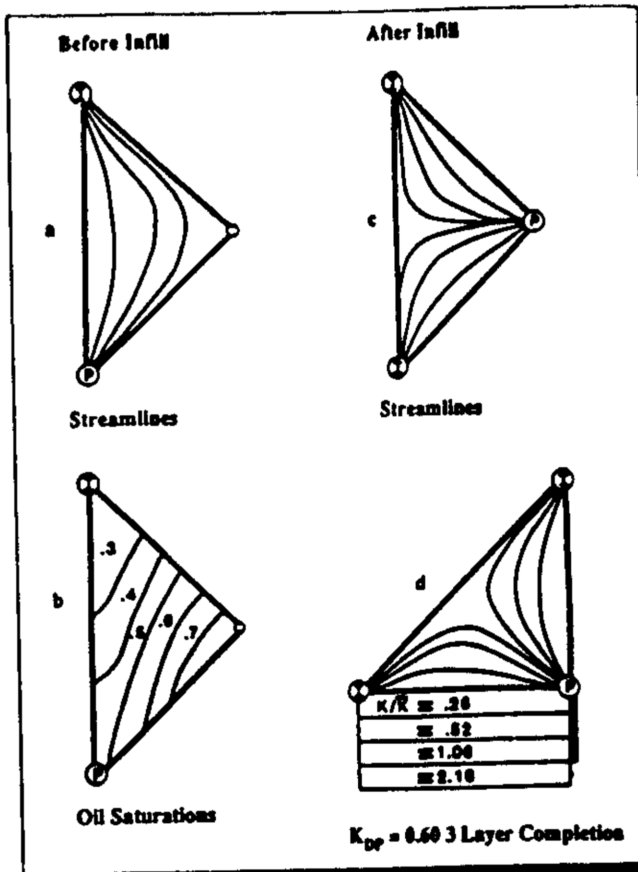

Fig. 7—Schematic of infill cases.

spacing. Because the Fullerton and Wasson curves are based on relatively large spacing, they might also move down with more infill data.

Now consider infill drilling from 40- to 20-acre [16- to 8-ha] spacing on the Means curve. We would expect to see a 14% increase in continuity with most of the new oil at virgin conditions. Data[3-5,13] confirm this effect. Although this effect is dominant in west Texas carbonates, other types of reservoirs can benefit from other mechanisms.

Improved Areal Sweep. If a reservoir is truly homogeneous, then infill drilling will have only a small impact on incremental recovery. The primary effect of infilling in this case is acceleration. In the extreme ideal case, infilling does not occur until 100% water cut, which implies 100% recovery of mobile oil. In reality, infilling would occur before the economic limit, and the amount of incremental recovery depends on the degree of areal heterogeneity or anisotropy, the water cut at the economic limit, the water cut at which infilling occurs, and the flood mobility ratio. This effect is shown schematically in Fig. 6,[12] which plots oil cut $(1-f_w)$ vs. recovery. At 100% water cut, the continued waterflood recovers all movable oil. If the economic limit were 95% water cut and the infill occurred at 90%, however, then the infill process delivers an incremental recovery of $\Delta E_{ri}-\Delta E_{rw}$ at the same economic limit. The acceleration effect is shown by the increase in oil cut during this whole process.

Areal sweep is improved by reversing the original streamlines and sweeping across the previously unswept areas (sweet spots), as shown schematically in Fig. 7 for a five-spot pattern. Fig. 7a shows the streamlines before infill drilling; Fig. 7b shows the corresponding oil saturations. In Fig. 7c, the original producer is converted to an injector after the completion of a new producer at the infill location. The new streamlines sweep across the area of highest oil saturation.

Fig. 8 shows the effect of water cut at infill for the homogeneous case as a function of oil/water viscosity ratio for an assumed set of relative permeabilities. These results are based on simulation studies with a built-in error of 1 to 2% incremental recovery. Recoveries tend to increase as viscosity ratios increase, but only to a point. This portion of the figure is intuitive; the higher the viscosity ratio, the lower the areal sweep efficiency. Hence, the infill opportunity is greater. At higher viscosity ratios, water tends to break through into the new producer before equivalent improvements in sweep can occur. Overall, for the homogeneous case, it could be argued that the incremental recovery is too close to the error threshold to be significant.

Fortunately for this analysis, no fields are homogeneous. Now consider a simulation case based roughly on the Grayburg field[4] experience. In this field, the original waterflood pattern appears to have been aligned with a directional permeability effect, as evidenced by early water breakthrough and poor oil response (sweep efficiency). After infill at 85% water cut, the water cut drops to 50% and incremental recovery is estimated to be 10% of OOIP. The viscosity ratio is about two.

Fig. 9 shows the effect of directional permeability and viscosity ratio on recovery. The higher the ratio of x-direction to y-direction permeability, the greater the infill recovery. The reason for this is the creation of a "water wall" or line source by the original flood. After infill, the injection is effectively distributed along the line between the original injector and producer. This greatly improves sweep efficiency, as shown by the simulation and confirmed by field data.

Anisotropy is an extreme form of areal heterogeneity that provides the maximum infill recovery. Areal variations of permeability and porosity will also leave undetected pockets of high oil saturation that will be swept when the streamlines are reversed after infill drilling. The degree of incremental recovery depends totally on the reservoir's geologic description.

Determining the areal variation of oil saturation or permeability is very difficult but necessary if a proper infill design is to be made. In fact, in some cases, infill drilling could result in reduction of ultimate recovery if directional permeability favors the original pattern. In this case, infill drilling would shift the pattern 45° and align the direction of maximum permeability along a line connecting the injector and producer, causing severe water channeling.

Improved Vertical Sweep. In the past, vertical sweep has been tied to permeability variation in a single- or multilayer system. Some idea of crossflow between layers is usually an additional consideration. During an infill drilling project, new wells are completed and existing producers are converted to injectors. An opportunity exists at this point to isolate

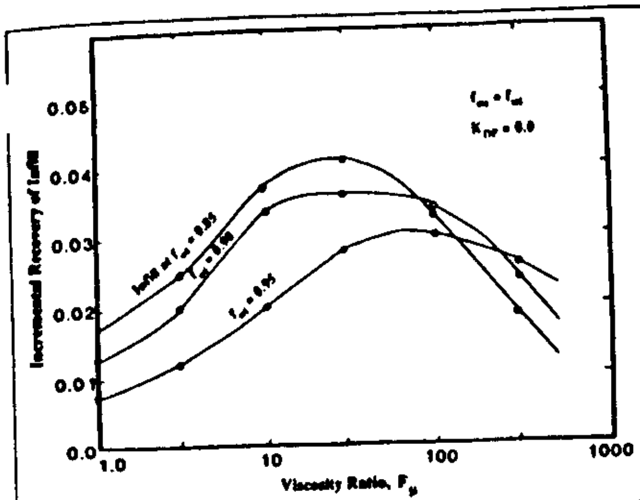

Fig. 8—Effect of water cut at infill on incremental recovery—homogeneous case.

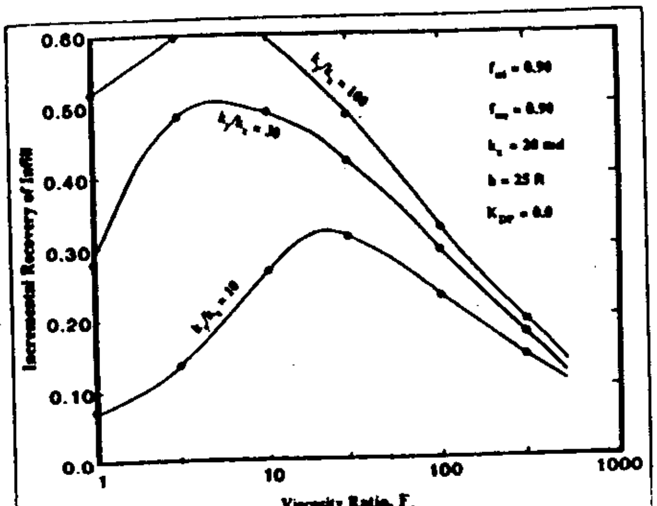

Fig. 9—Effect of areal heterogeneity on incremental recovery.

TABLE 3—PERMEABILITY RATIOS IN A FOUR-LAYER SYSTEM

	K_{DP}		
Layer	0.4	0.6	0.85
1	0.50	0.26	0.036
2	0.75	0.52	0.16
3	1.11	1.06	0.74
4	1.65	2.16	3.09

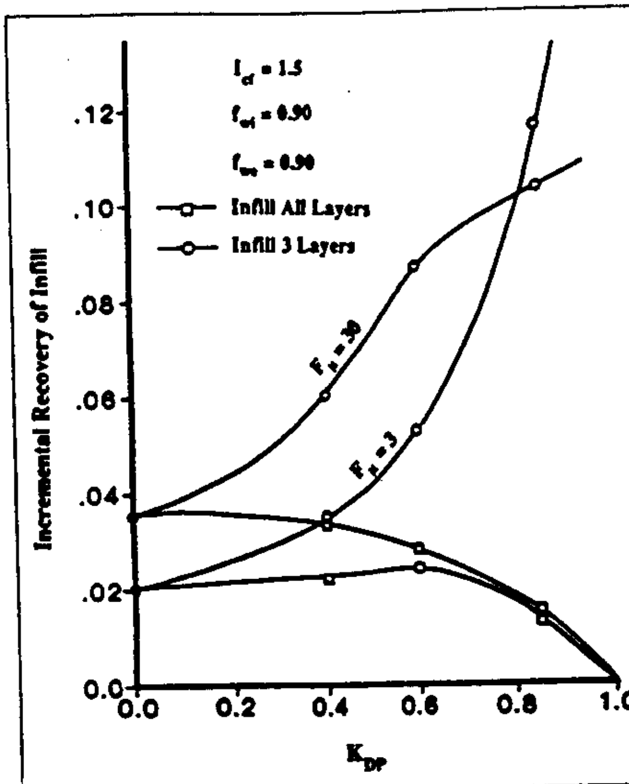

Fig. 10—Effect of selective perforation of infill incremental recovery.

previously swept zones mechanically to maximize vertical sweep. The efficiency of these recompletions, however, depends on the degree of crossflow between the new active zones and the isolated (thief) zones.

With the Dykstra-Parsons coefficient, K_{DP}, the permeability ratio of $k/\bar{k}$ can be distributed over a four-layer system as shown in Table 3. In this table, the highest ratio is at the bottom, but a thief zone could be anywhere vertically without affecting the coefficient K_{DP}. In this case, Layer 4 is swept nearly clean before infill. Obviously, more layers should be used if accuracy is required, but our purpose here is to explore trends only.

Consider the case shown schematically in Fig. 7d. The infill producer has been completed in three of the four layers, isolating the thief zone except for crossflow. Fig. 10 shows the incremental infill recovery as a function of vertical heterogeneity (K_{DP}) for two different viscosity ratios. As the K_{DP} coefficient increases, the incremental recovery also increases for the three-layer completion case. Completing all four layers shows declining incremental recovery with increased heterogeneity. This clearly shows the justification for selective isolation or plugging of thief zones after infill.

Crossflow between layers is very difficult to determine from field data, but it can have a significant effect on incremental recovery. Fig. 11 shows the effect of crossflow using the index I_{cf} defined by Zapata and Lake.[15] At I_{cf}=0.0, a "layer-cake" model exists, while at $I_{cf}=\infty$, the results should approach the four-layer completion results. For the cases shown here, a medium crossflow of 1.5 was used. It is clear from Fig. 11 that layer-cake models will tend to overpredict the incremental recovery, unless each zone is truly isolated.

Fig. 12 shows the incremental infill recovery as a function of viscosity ratio, F_μ, and K_{DP} at an infill water cut of 90% for a three-layer completion. As expected, the incremental recovery increases with increasing K_{DP}. With increasing vertical heterogeneity, the most permeable zones are preferentially swept, leaving higher oil saturations in the remaining zones. If crossflow does not exist and the zones can be selectively completed, the results in this figure could be very conservative. If crossflow is high, the results shown here are optimistic.

Care must be used in taking absolute values from Figs. 8 through 12 because they represent incremental recoveries of movable oil (not OOIP) and they are reported at the point of infill water cut equal to economic limit ($f_{wi}=f_{we}$). Fig. 6 shows that at the extreme economic limit equal to 100% water cut (zero oil cut), there can be no incremental infill recovery because of areal or vertical sweep effects. If, however, the economic limit were 95% with infill performed at 90% as shown in Fig. 12, the incremental recoveries would be as shown in Table 4 for two viscosity ratios, F_μ. These results use one set of relative permeabilities. Oil/water viscosity ratios in the range of 1 to 300 correspond to mobility ratios of about 0.3 to 3.0, depending on the relative permeabilities at breakthrough. Viscosity ratios less than 4.5 are "favorable mobility" waterfloods for these examples.

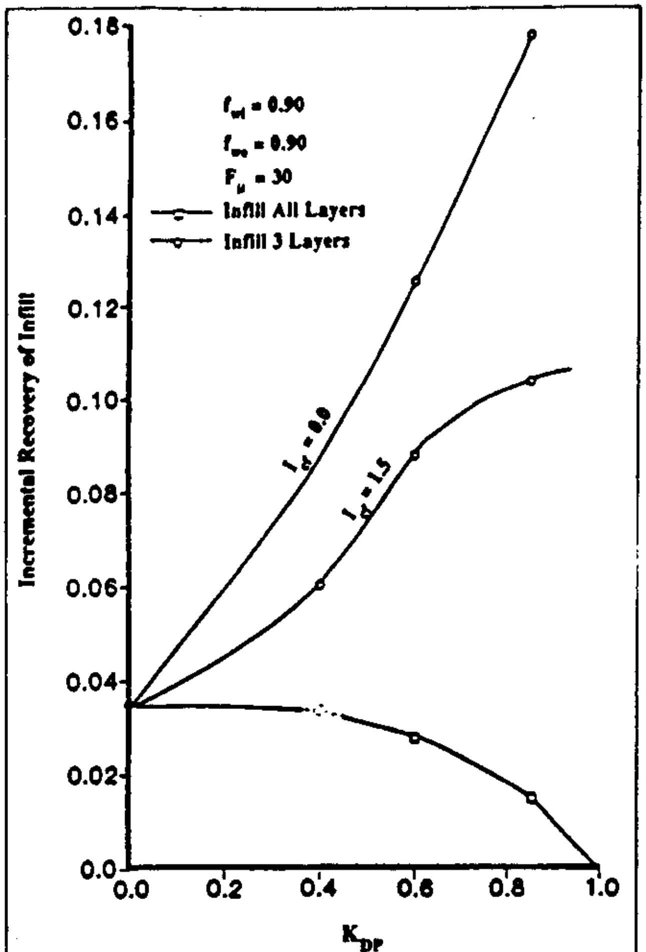

Fig. 11—Effect of crossflow incremental infill recovery.

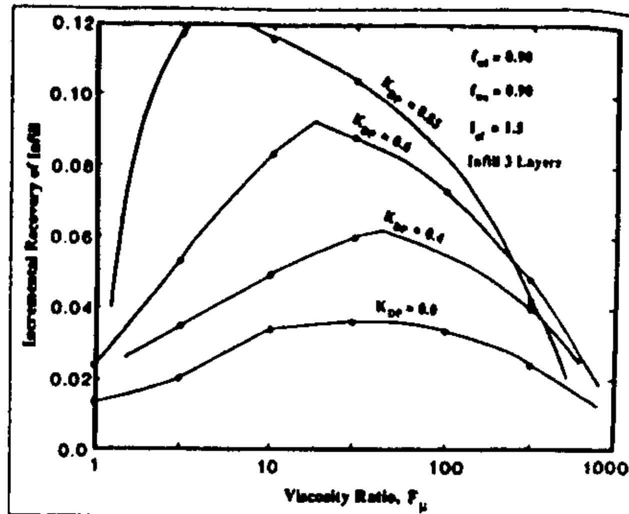

Fig. 12—Effect of vertical heterogeneity on incremental recovery.

TABLE 4—INCREMENTAL RECOVERY VS. HETEROGENEITY

	F_μ	
K_{DP}	3	30
0.0	0.5	1.0
0.4	1.8	3.9
0.6	3.3	7.5
0.85	10.1	11.4

Another way to analyze these results is to compare infill with remaining reserves, as shown in Fig. 13. The vertical bars represent the full range of viscosity ratios of 1 to 300, so we can see that the results are much more sensitive to vertical heterogeneity. This figure shows that if infilling occurred at 90% water cut and K_{DP} were 0.6, then the remaining reserves would be doubled if the economic limit were 94%. At higher heterogeneity, the reserve addition ratio would be higher. At higher economic limits, the reserve addition ratio would be less. A similar set of plots should be prepared before each infill project because each pattern would have different values of K_{DP} and infill water cut.

Recovery of Wedge-Edge Oil. As pattern size is decreased, more oil can be swept near the oil/water contact or stratigraphic features. This is strictly a geometry effect but can result in flooding of virtually unswept zones. In some fields originally developed on wide spacing, this can result in significant volumes.

Improved Economic Limit. One of the very significant economic benefits of infill drilling is the acceleration of recovery. In addition to increasing the number of producers, the field injection rate is increased by more than the well ratio might indicate because the pressure drop between injector and producer occurs over a shorter distance. Because the water cut is significantly decreased, operating costs are also reduced. As a result of these operating changes, the economic limit for a project will be improved.

Future Work

The U.S. DOE, in association with API or NPC, should form another task force similar to that created for the 1984 EOR evaluation.[6] The charter of this task force would be to determine the potential incremental recovery that could be achieved in the U.S. by infill drilling of primary production, of waterflood projects, and in association with tertiary EOR projects. As a part of this work, the task force would identify how much of our current national reserve was a result of waterflooding in peripheral floods, original pattern floods, and infill pattern floods.

One or more predictive models, similar to those created by DOE/NPC for EOR processes,[16] should be constructed to evaluate both the technical and economic potential of the infill drilling process.

SPE should consider adding infill drilling to its *Enhanced Oil Recovery Field Reports* series to encourage more reporting of project results. SPE should also consider special forums or dedicate a program to this subject at one or more annual meetings.

University research programs should begin to include thesis-level projects in this area. The DOE should be encouraged to provide funds for new research programs.

Conclusions

1. Infill drilling provides incremental recovery in addition to acceleration, as shown by both simulation and field results.
2. Incremental recovery is achieved primarily by sweeping unswept areas/zones and by improving areal/vertical sweep.
3. Infill drilling can improve the economic limit and thereby allow incremental production that would not otherwise occur economically.
4. Infill projects are not without risk and require detailed reservoir description and infill project design to improve the chances for success.
5. Results of simulation and field projects show that infill drilling can potentially provide incremental recoveries equal to or greater than EOR processes on an individual field basis.
6. Because infill drilling is standard waterflood practice, some incremental recovery from infill is already incorporated in U.S. national reserve estimates.

7. The true magnitude of national reserve additions through infill drilling is unknown and difficult to determine, although its potential could be high.

8. Combining infill drilling with EOR projects as either a pre- or postphase offers great potential.

9. Reservoirs that exhibit relatively poor initial waterflood efficiency on large spacings should be analyzed as candidates for incremental recovery by infill drilling.

Nomenclature

E_r = recovery efficiency of movable oil, fraction
E_{re} = infill recovery efficiency at economic limit ($f_{wi} = f_{we}$)
E_{ri} = infill recovery efficiency
E_{rw} = recovery efficiency for continued waterflood
f_w = water cut
f_{we} = water cut at economic limit
f_{wi} = infill water cut
F_μ = viscosity ratio (oil/water at reservoir conditions)
h_n = net thickness
h_t = gross thickness
I_{cf} = crossflow index $= (L/h_t)(k_y/k_x)^{0.5}$
k = permeability
k_x = x-direction permeability
k_y = y-direction permeability
K_{DP} = Dykstra-Parsons coefficient
N_p = cumulative oil production
q_i = initial flow rate = total rate
q_o = oil rate
S_{oi} = initial oil saturation
S_{orw} = residual oil saturation
V_p = PV

Superscript

$\bar{}$ = average

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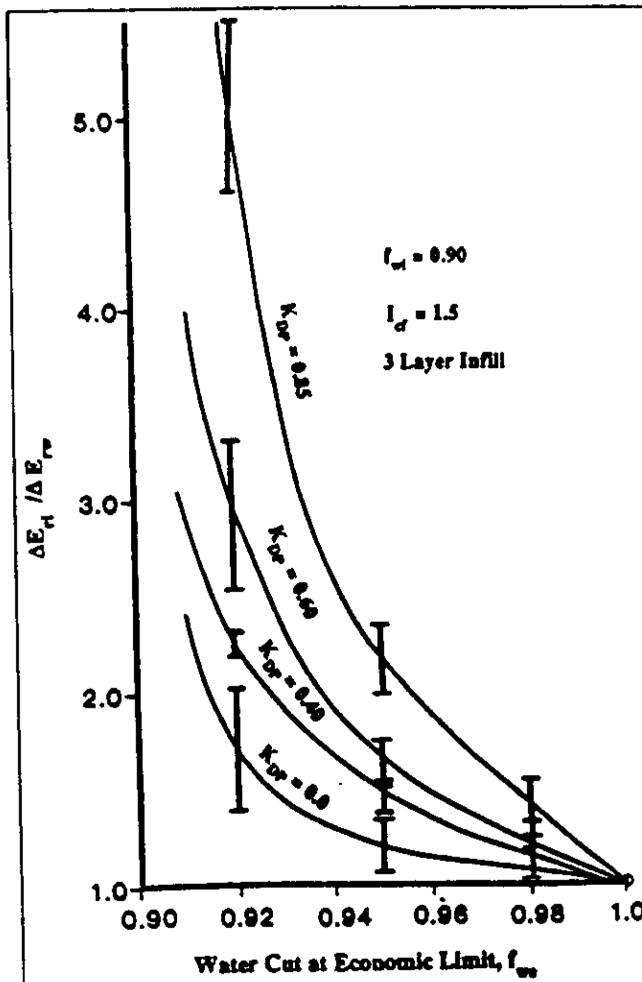

Fig. 13—Effect of vertical heterogeneity and economic limit on incremental reserve additions.

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SI Metric Conversion Factors

acres	× 4.046 873	E−01	=	ha
°API	141.5/(131.5+°API)		=	g/cm³
bbl	× 1.589 873	E−01	=	m³
cp	× 1.0*	E−03	=	Pa·s
ft	× 3.048*	E−01	=	m
°F	(°F−32)/1.8		=	°C
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

JPT

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Infill Drilling Enhances Waterflood Recovery

Ching H. Wu, SPE, **B.A. Laughlin,*** SPE, and **Michel Jardon,** Texas A&M U.

Summary. Two sets of west Texas carbonate reservoir and waterflood data were studied to evaluate the impact of infill drilling on waterflood recovery. Results showed that infill drilling enhanced the current and projected waterflood recovery from most of the reservoirs. The estimated ultimate and incremental infill-drilling waterflood recovery was correlated with well spacing and other reservoir and process parameters. Results of the correlation indicated that reducing well spacing from 40 to 20 acres [16 to 8 ha] per well would increase the oil recovery by 8 to 9% of the original oil in place (OOIP). Because of the limited data base and regressional nature of the correlation models, the infill-drilling recovery estimate must be used with caution.

Introduction

The concept of optimal well spacing for oil recovery has been an important and controversial subject[1-8] for more than 50 years. Before 1960, ultimate recovery by primary mechanisms was considered to be independent of well spacing.[2-6] In 1969, Davis and Shepler[9] reported that by reducing well spacing from 40 to 20 acres [16 to 8 ha], primary oil recovery from the San Miguel Unit of the Sacatosa field in southwest Texas was increased by at least 14% OOIP. The relationship between primary ultimate recovery and well spacing was not well established, possibly because reservoir heterogeneity was not considered.[10]

Waterflood technology began developing in the early 1920's and became popular in the 1950's. Mainly for economic reasons, the use of existing wells with some additional infill wells was common for waterflood projects, but the impact of well spacing on optimal waterflood recovery was not seriously considered. In 1971, Emmett *et al.*[11] reported that reducing well spacing from 40 to 20 acres [16 to 8 ha] economically accelerated the producing rate and increased ultimate recovery by gas/water injection in Wyoming's Tensleep reservoir. In 1973, Thomas and Driscoll[12] reported that infill drilling in chickenwire patterns in the Slaughter field, TX, increased oil recovery by an average of 3.6% OOIP and was profitable.

Infill drilling for improving waterflood recovery was initiated in the early 1970's in the carbonate reservoirs in the Permian Basin of west Texas. Results in the literature[13-21] indicated that infill drilling can improve ultimate recovery from heterogeneous reservoirs; however, a consistent set of field data was not available for developing a correlation between waterflood recovery and well spacing.

The objective of this study was to acquire a set of consistently evaluated field data from west Texas carbonate reservoirs to determine the impact of infill drilling on waterflood recovery and to develop linear regression models correlating waterflood recovery with respect to well spacing and other reservoir/process parameters.

*Now at Union Pacific Research Co.

Effect of Well Spacing on Waterflood Recovery

Reservoirs Studied. For this Phase 1 study, 24 reservoirs were selected from Railroad Commission of Texas *Bulletin 82.*[22] The purpose of this study was to use a publicly available data base to evaluate statistically the effect of well spacing on waterflood recovery. **Table 1** lists the reservoir units and properties. Reservoirs developed on a five-spot pattern only were selected, to avoid the effect of different flood patterns on oil recovery efficiency and on the correlation. In this study, the well spacing was of primary concern; the effect of infill drilling on incremental recovery was not considered. The reservoir and process data were obtained mainly from *Bulletin 82*. The data were adjusted and updated with additional data gathered from Railroad Commission of Texas dockets and from the literature.[12,15,16,19,23,24]

The reservoirs studied are located in the region on the north end of the central basin platform and Midland basin and south of the Matador Arch, as shown in **Fig. 1**. The pays of these reservoirs are in the lower part of the San Andres formation. The lithology is composed of dolomite, anhydrite, siltstone, and salts. The depositional sequences are cyclic in nature. The component facies of each cycle are thin and laterally discontinuous.[23,24] The heterogeneity of the reservoir rocks and the discontinuity of the pay sections are very favorable for infill-drilling operations to improve waterflood recovery.

Correlation of Waterflood Recovery With Well Spacing. **Table 2** shows the oil recovery and the well spacing of the 24 units studied. A series of least-squares fittings was made to correlate waterflood recovery with each reservoir and process parameter, which included productive area, net pay, porosity, permeability, gravity, flow capacity, and well spacing. Results showed that the correlation with all parameters except well spacings was very poor.

The waterflood recovery showed a correlation trend with well spacing. Two correlation equations were developed with a least-squares fitting program.

The first-degree polynomial correlation equation was

$$E_w = 41.486 - 0.41924 s_w, \quad \text{........} (1)$$

and the third-degree polynomial correlation equation was

$$E_w = 54.472 - 1.5392 s_w + 0.02598 s_w^2 - 0.00016385 s_w^3, \quad \text{............} (2)$$

where E_w = waterflood recovery and s_w = well spacing.

Fig. 2 shows the trend of waterflood recovery vs. well spacing and the calculated waterflood recovery from Eqs. 1 and 2. The correlation equations indicated that reducing well spacing from 40 to 20 acres [16 to 8 ha] per well would increase oil recovery by about 8 to 9% OOIP. A multiple-variable regression analysis was used to develop the following correlation equation to estimate waterflood recovery from the reservoir and process parameters:

$$E_{wE} = -36.5204 + 1.087629 E_{Pd} + 1.416565\,\gamma_{API} + 1.274887\phi - 0.167495 s_w. \quad \text{..............} (3)$$

Because of the significant data scattering, any waterflood-project recovery estimated from Eq. 3 must be confirmed by a sound reservoir engineering evaluation.

Effect of Infill Drilling on Waterflood Recovery

Reservoirs Studied. Fig. 3 shows the locations of the 16 units for the Phase 2 study. The unit information[25-50] is given in **Table** 3. The reservoirs were selected from differ-

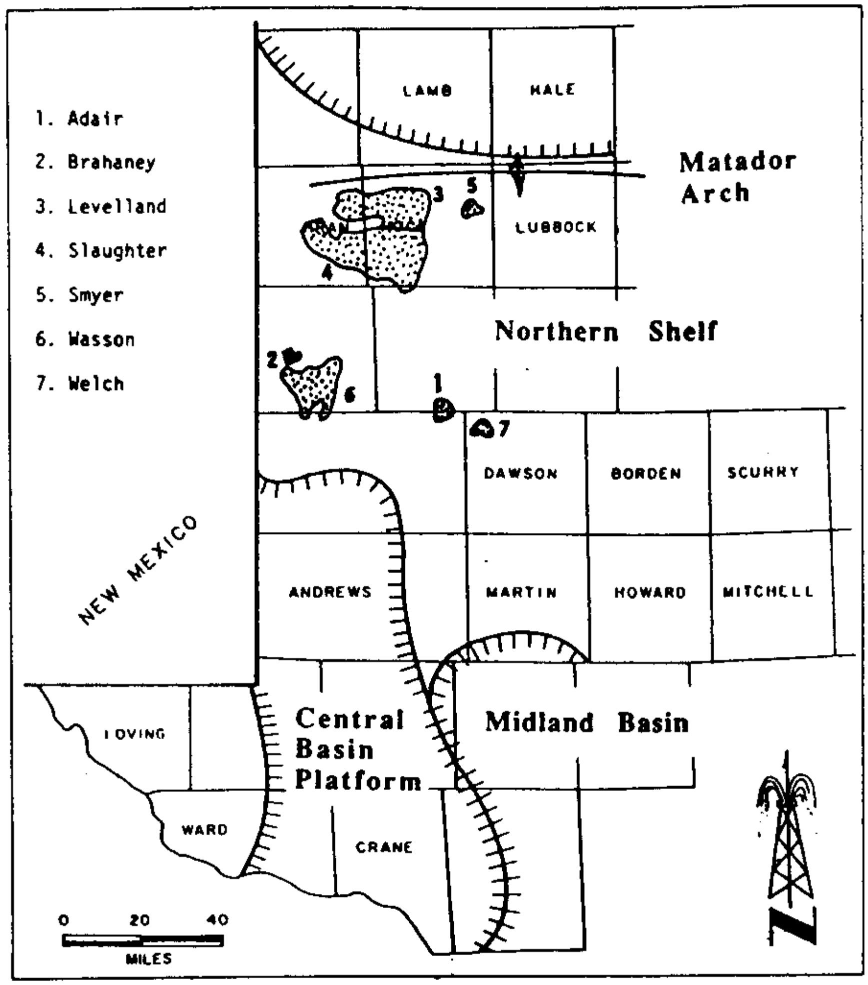

Fig. 1—Location map for Phase 1 study.

TABLE 1—RESERVOIR PROPERTIES FOR PHASE 1 STUDY

Field/Unit	OOIP (MMSTB)	Area (acres)	Net Pay (ft)	Original Pressure (psi)	Porosity (%)	Permeability (md)	Depth (ft)	Gravity (°API)
Adair/San Andres	168.000	5,338.0	50.0	1,875	14.1	4.0	4,789	33.5
Brahaney/Plains	43.500	3,731.0	25.0	1,940	10.2	1.0	5,300	32.0
Brahaney/West	64.300	4,240.0	50.0	2,200	9.9	2.0	5,000	31.4
Brahaney/Brahaney	48.000	4,200.0	27.0	1,800	8.7	2.0	5,301	32.0
Levelland/Southwest	50.000	4,508.0	25.0	1,500	9.0	2.0	4,865	29.0
Levelland/XIT	55.000	7,038.0	28.0	1,350	8.5	3.0	4,927	29.0
Levelland/Jennings	3.300	134.0	31.0	1,690	12.0	5.0	5,000	26.0
Levelland/Starnes	23.195	4,140.0	15.0	1,700	12.0	5.0	5,050	26.0
Levelland/Masten	19.600	1,785.0	45.0	1,200	6.0	3.0	4,960	29.0
Levelland/West	61.500	7,720.0	20.0	1,690	9.0	1.0	4,850	29.0
Levelland/Northeast	28.524	679.0	20.0	1,710	10.0	2.0	4,675	30.9
Levelland/Southeast	143.680	5,800.0	59.0	1,710	9.0	2.0	4,800	32.0
Levelland/Coble A	10.750	267.0	109.0	1,710	9.1	3.0	4,850	29.0
Levelland/Coble C	5.375	133.0	76.0	1,690	8.5	3.0	4,850	30.4
Levelland/Gann	10.000	268.0	85.0	1,690	7.8	3.0	4,850	29.0
Levelland/Roberts	5.375	134.0	94.0	1,690	9.3	3.0	4,850	29.0
Levelland/Coble B	8.000	500.0	35.0	1,500	10.0	1.0	4,850	29.0
Levelland/Veal	15.508	1,036.0	22.0	1,690	11.4	3.0	4,900	29.0
Slaughter/Lincoln A	118.000	6,268.0	60.0	1,710	9.6	6.0	4,915	30.6
Slaughter/Estate Pilot	0.622	12.3	77.5	1,710	11.4	5.8	4,985	30.0
Smyer/East Clearfork	32.000	1,920.0	75.0	2,100	8.3	3.0	5,880	27.0
Wasson/Willard	624.000	1,310.0	180.0	1,805	7.0	1.0	5,100	33.0
Wasson/Cornell	195.000	1,923.0	122.0	1,800	8.4	4.0	4,900	34.0
Welch/West Welch	229.074	9,415.0	64.0	2,200	9.3	4.0	4,900	34.0
Welch/South Welch	131.090	2,833.0	79.0	2,100	9.3	9.0	4,950	34.0

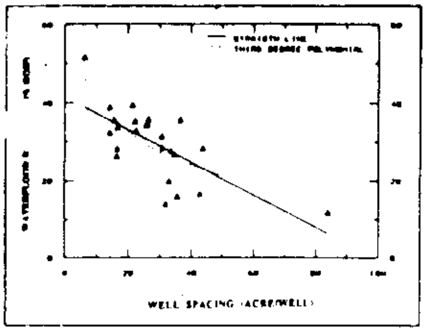

Fig. 2—Correlation between waterflood recovery and well spacing.

ent regions in the central basin platform and the northern shelf of west Texas. The purpose of this study was to develop a consistently evaluated data base for determining the impact of infill drilling on waterflood recovery. Most of the reservoirs chosen have a large amount of reservoir and production performance data in the public domain. **Table 4** lists the reservoir properties of these units.

Projection of Oil Recoveries. Decline-curve analysis was used to project and to estimate the ultimate recovery for primary depletion, waterflooding, and infill drilling. Both exponential and hyperbolic decline-curve analyses were performed for each unit. The ultimate recovery was estimated with an economic production rate of 3 STB/D [0.476 stock-tank m^3/d] per well. Most of the decline-curve analyses showed that infill drilling accelerated the producing rate and increased the ultimate waterflood recovery. When the decline data were not sufficient or the decline trend was not fully developed for meaningful decline-curve analysis, an average decline rate from the adjacent units or the most probable decline rate from the production curve was used to estimate the recovery. Where necessary, the oil-cut decline curve was also used to help estimate the production rate and recovery.

Table 5 shows the estimated ultimate oil recoveries. The ultimate primary recovery ranged from 5.5 to 25% OOIP; the ultimate initial waterflood recovery ranged from 7.3 to 31.8% OOIP; and the ultimate infill-drilling waterflood recovery ranged from 8.5 to 43% OOIP. Table 5 also shows the average incremental infill well recovery. The incremental infill drilling recovery per infill well ranged from 26 to 990 MSTB [4.13×10^3 to 157.4×10^3 stock-tank m^3].

Infill-Drilling Recovery vs. Well Spacing. **Fig. 4** shows the plot of ultimate infill-drilling waterflood recovery vs. well spacing. The solid line shows the average trend for all data points except for the Fuhrman-Mascho and West Goldsmith Units, which had exceptionally low recovery efficiencies. An estimate from the average trend indicated that decreasing well spacing from 40 to 20 acres [16 to 8 ha] per well would increase oil recovery by about 9% OOIP.

Fig. 5 shows the plot of incremental infill-drilling waterflood recovery vs. well spacing after infill drilling. Most of the units studied had the well spacing halved from the initial waterflood well spacing (e.g., from 40-acre [16-ha] initial waterflood well spacing to 20-acre [8-ha] infill-drilling well spacing). The solid line shows the average trend for all data points except for the Fuhrman-Mascho and West Goldsmith Units and for the Wasson/Denver Unit, which had an exceptionally high infill-drilling recovery. The average trend indicated that infill drilling to reduce well spacing to 50 acres [20 ha] would result in a negligible incremental waterflood recovery. However, reducing well spacing from 40 to 20 acres [16 to 8 ha] would result in an incremental infill drilling recovery of 9% OOIP.

A plot of incremental infill-drilling recovery per infill well vs. well spacing showed no consistent correlation trend. This means that although infill drilling can enhance waterflood recovery, other reservoir and process parameters may also play an important role in determining ultimate waterflood recovery.

TABLE 2—OIL RECOVERY AND WELL SPACING FOR PHASE 1 STUDY (from Texas Railroad Commission data[22])

Field/Unit	Primary Recovery (% OOIP)	Waterflood Recovery (% OOIP)	Well Spacing (acres/well)
Adair/San Andres	4.3	31.1	30.7
Brahaney/Plains	19.2	35.5	36.6
Brahaney/West	8.6	16.4	42.8
Brahaney/Brahaney	0.0	11.5	84.0
Levelland/Southwest	9.0	15.7	35.5
Levelland/XIT	17.4	28.1	43.7
Levelland/Jennings	20.0	35.0	22.3
Levelland/Starnes	18.0	26.6	34.8
Levelland/Masten	8.2	13.8	31.9
Levelland/West	18.9	27.4	33.6
Levelland/Northeast	15.0	28.3	30.9
Levelland/Southeast	17.9	39.2	21.4
Levelland/Coble A	16.7	35.2	15.7
Levelland/Coble C	14.9	26.0	16.6
Levelland/Gann	16.7	33.4	16.7
Levelland/Roberts	14.9	27.9	16.7
Levelland/Coble B	15.5	38.6	14.3
Levelland/Veal	19.3	35.6	26.6
Slaughter/Lincoln A	11.3	19.7	32.9
Slaughter/Estate Pilot	—	51.3	6.2
Smyer/East Clearfork	18.6	33.9	25.9
Wasson/Willard	16.7	34.5	26.0
Wasson/Cornell	13.8	32.1	14.0
Welch/West Welch	8.6	32.6	22.7

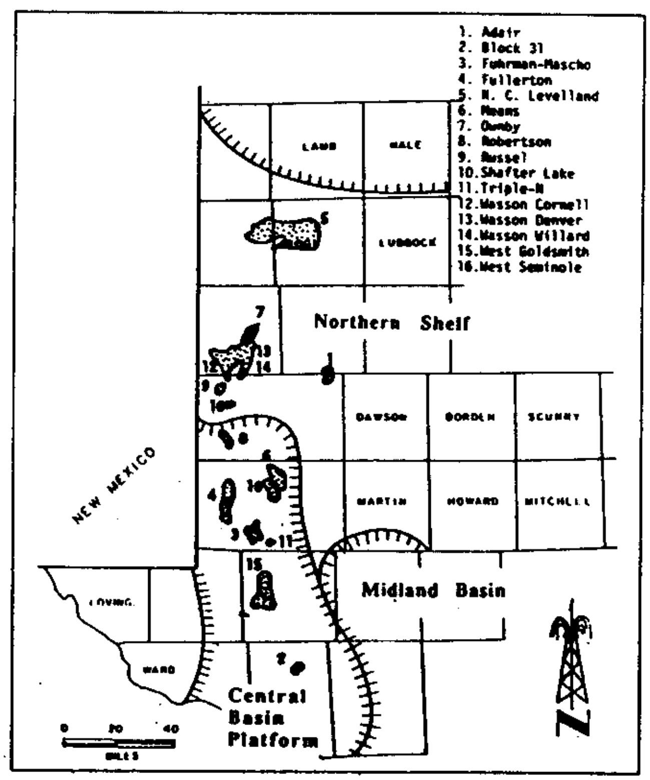

Fig. 3—Location map for Phase 2 study.

TABLE 3—UNITS FOR PHASE 2 STUDY

Field/Unit	Refs.	Formation	Major Rock Type	Primary Recovery: Discovery	Primary Recovery: Well Spacing (acres/well)	Primary Recovery: Mechanism
Adair/San Andres	25	San Andres	Dolomite	1947	54	Solution gas
Block 31/Block 31	26	Grayburg	Dolomite	1956	80	Waterdrive
Fuhrman-Mascho/Block 9	22, 27	Grayburg	Dolomite	1930	160	Solution gas
Fullerton/Clearfork	28, 29, 30	Clearfork	Dolomite	1942	40	Solution gas
Levelland/N.C. Levelland	31	San Andres	Dolomite	1945	42	Solution gas
Means/San Andres	32, 33, 34	San Andres	Dolomite	1934	40	Solution gas
Ownby/San Andres	35, 36, 37	San Andres	Dolomite	1941	40	Solution gas
Robertson/Clearfork	38, 39	Clearfork	Dolomite	1942	80	Solution gas
Russell/Clearfork (7,000 ft)	40	Clearfork	Dolomite	1941	50	Solution gas
Shafter Lake/Grayburg	41	San Andres	Dolomite	1929	160	Solution gas
Triple-N/Grayburg	42, 43	Grayburg	Sandstone/dolomite	1964	80	Solution gas
Wasson/Cornell	44	San Andres	Limestone	1936	44	Solution gas
Wasson/Denver	45, 46	San Andres	Dolomite	1936	36	Solution gas/cap
Wasson/Willard	47	San Andres	Dolomite	1936	86	Solution gas/cap
West Goldsmith/West Goldsmith	48	San Andres	Dolomite	1956	40	Solution gas
West Seminole/San Andres	49, 50	San Andres	Dolomite	1948	40	Solution gas

TABLE 4—RESERVOIR PROPERTIES FOR PHASE 2 STUDY

Field/Unit	Area (acres)	Depth (ft)	Thickness (ft)	Porosity (%)	Permeability (md)	Oil FVF (RB/STB)	Gravity (°API)	S_{wi} (%)	OOIP (MMSTB)
Adair/San Andres	5,338	4,900	50	14.1	3.7	1.12	33.5	35.0	168
Block 31/Block 31	1,104	3,180	20	18.0	96.0	1.08	29.6	30.0	9
Fuhrman-Mascho/Block 9	3,948	4,450	80	7.0	4.0	1.12	29.0	30.0	79
Fullerton/Clearfork	29,542	6,700	85	10.0	3.0	1.62	42.0	23.6	1,029
Levelland/N.C. Levelland	11,250	4,750	30	8.0	1.8	1.23	31.0	25.0	133
Means/San Andres	14,328	4,300	200	9.0	29.0	1.04	29.3	28.8	382
Ownby/San Andres	2,960	5,200	32	14.1	4.5	1.35	32.0	38.1	52
Robertson/Clearfork	4,696	5,800	247	6.0	0.9	1.38	34.6	29.0	275
Russell/Clearfork (7,000 ft)	8,510	7,350	95	5.3	1.5	1.28	34.7	24.0	210
Shafter Lake/Grayburg	11,082	4,300	49	6.5	5.0	1.24	32.0	25.0	165
Triple-N/Grayburg	2,192	4,325	20	12.1	6.6	1.23	31.9	40.0	20
Wasson/Cornell	1,923	4,900	200	8.5	3.7	1.30	33.0	15.0	195
Wasson/Denver	25,505	4,800	200	10.0	5.0	1.31	33.0	15.0	2,108
Wasson/Willard	13,360	5,100	111	8.5	1.5	1.31	32.0	20.0	624
West Goldsmith/West Goldsmith	4,640	4,273	57	6.4	3.7	1.36	35.5	36.0	47
West Seminole/San Andres	3,720	5,112	118	9.9	20.7	1.38	32.4	18.0	174

TABLE 5—ESTIMATED ULTIMATE RECOVERIES FOR PHASE 2 STUDY
(from decline-curve analysis)

Field/Unit	Primary (% OOIP)	Initial Waterflood (% OOIP)	Infill Drilling (% OOIP)	Incremental Oil Recovery per Infill Well (MSTB/well)	Well Spacing* (acres/well)
Adair/San Andres	12.5	31.8	36.2	67	20.0
Block 31/Block 31	25.0	31.0	43.0	85	10.0
Fuhrman-Mascho/Block 9	9.3	10.9	12.9	39	20.0
Fullerton/Clearfork	11.0	17.0	23.6	377	36.0
Levelland/N.C. Levelland	14.8	19.1	27.8	137	21.3
Means/San Andres	14.1	30.0	39.8	192	20.0
Ownby/San Andres	13.9	24.5	31.0	170	20.0
Robertson/Clearfork	11.8	15.5	21.3	73	40.0
Russell/Clearfork (7,000 ft)	16.8	23.0	27.1	205	40.0
Shafter Lake/San	14.5	20.0	20.7	26	40.0
Andres	10.0	25.3	35.0	33	20.0
Triple-N/Grayburg	10.7	27.4	35.7	337	14.0
Wasson/Cornell	10.0	19.0	43.0	990	20.0
Wasson/Denver	13.4	22.0	29.0	128	20.0
Wasson/Willard					
West Goldsmith/West Goldsmith	5.5	7.3	8.5	40	33.0
West Seminole/San Andres	5.5	14.4	22.3	259	31.2

*After infill drilling.

"The correlation equations indicated that reducing well spacing from 40 to 20 acres [16 to 8 ha] per well would increase oil recovery by about 8 to 9% OOIP."

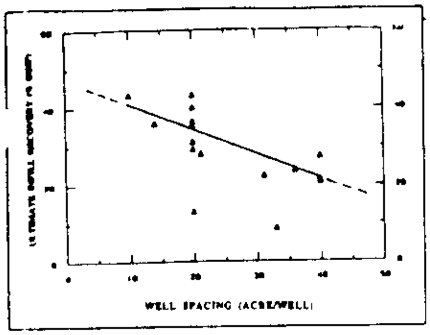

Fig. 4—Correlation trend between ultimate infill-drilling waterflood recovery and well spacing.

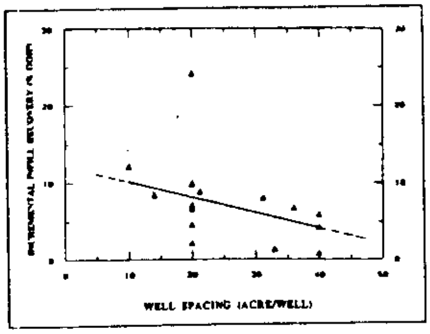

Fig. 5—Correlation trend between incremental infill-drilling waterflood recovery and well spacing.

TABLE 6—STATISTICS FOR THE INFILL-DRILLING WATERFLOOD RECOVERY CORRELATION

Analysis of Variance

R^2	F Value	Prob > F
0.9584	34.592	0.0001

Parameter Estimates

Variable	Parameter Estimate	Standard Error	t for HO: Parameter = 0	Prob > |t|
Intercept	−0.30972	10.13984	−0.031	0.9763
X_1	0.18923	0.03231	5.855	0.0002
E_{wi}	1.21112	0.12108	10.002	0.0001
B_{oi}	19.42119	11.15698	1.741	0.1157
k	0.07361	0.03370	2.184	0.0568
γ_{API}	−0.84185	0.45212	−1.862	0.0955
S_{wi}	0.09057	0.11165	0.811	0.4382

Oil Recovery Correlations. As discussed previously, infill-drilling waterflood recovery is not a function of well spacing alone. Other reservoir and process parameters, such as OOIP, primary recovery, and initial waterflood recovery, may also affect ultimate infill-drilling waterflood recovery. Therefore, there is a need to develop correlation models using a multiple-variable regression analysis.

The SAS Inst.'s statistical analysis program was used to develop the correlation models. The program uses multiple-variable linear regression analysis to find the best fit for the data. The correlation models developed were for (1) ultimate infill-drilling waterflood recovery, (2) incremental infill-drilling waterflood recovery, and (3) incremental infill-drilling recovery per infill well.

Ultimate Infill-Drilling Waterflood Recovery Correlation. The independent variables used to develop the best correlation for ultimate infill-drilling waterflood recovery included the ratio of OOIP to well spacing, productive area, depth, pay thickness, porosity, permeability, oil FVF, API gravity, initial water saturation, OOIP, primary recovery, initial waterflood recovery, and well spacing. Table 6 shows the statistics for the ultimate infill-drilling waterflood recovery correlation. The SAS program uses the R^2 value, the F value, and the Probability > F for variance analysis. The R^2 value is the ratio of the sum of squares of difference between the regression value and the sample mean to the sum of squares of difference between the sample values and the sample mean. It represents the fraction of the samples accountable by the regression model. The closer this value approaches 1.0, the better the regression model fits the samples. The R^2 value, however, will approach 1.0 as the number of independent variables increases, even though the correlation is inadequate for predicting the dependent variable. Therefore, this R^2 value needs to be evaluated with the F-value analysis. For the variance analysis, the F value should be greater than the given $F_{rejection}$ criterion corresponding to the rejection value of 0.05. This $F_{rejection}$ value also varies with the number of samples and variables in the correlation model. The value of F needs to fall in the rejection interval to accept the alternative hypothesis that at least one of the regression coefficients is nonzero. The variance analysis provides the probability value that the regression coefficients are zeroes. The lower the probability value, the better the correlation. The value for Probability > F should be less than the set rejection region of 0.05.

The standard error of the parameter estimates represents the deviation of the regression coefficient from the mean that might be expected. It can be used to construct the confidence intervals of the regression coefficients. In assessing the contribution of the regression coefficient, the value should be as small as possible. The Student's t test is used to determine the contribution of each independent variable to the regression equation. The absolute value of the estimated t value for testing the hypothesis (t FOR HO: PARAMETER = 0, Table 6) must be greater than the critical t value representing the lower limit of the rejection region to conclude that the parameter can be used to determine the dependent variable. The Prob > |t| value corresponding to the t value either confirms or rejects the hypothesis that the independent variable contributes to the prediction of the dependent variable. A small value implies that the estimate is strongly dependent on the independent variable. The parameter estimates provide the coefficients of the independent variables in the correlation equation, and the standard errors are used to construct confidence intervals for the parameter estimates at a confidence level chosen by the user.

As can be seen from Table 6, the R^2 value is 0.95, which is good, and the F value is 34.59, which is much greater than the $F_{rejection}$ value of 3.37. The $F_{rejection}$ value can be found from the F-value table in most statistics textbooks. The conclusion is that this correlation is good for estimating ultimate infill-drilling waterflood recovery, E_{lc}. The regression equation is

$$E_{lc} = -0.3097 + 0.1892 N/s_w + 1.2111 E_{wid} + 19.421 B_{oi} + 0.0736 k - 0.8418 \gamma_{API} + 0.0906 S_{wi} \quad \ldots\ldots (4)$$

". . . although infill drilling can enhance waterflood recovery, other reservoir and process parameters may also play an important role in determining ultimate waterflood recovery."

TABLE 7—STATISTICS FOR THE CORRELATION FOR INCREMENTAL INFILL-DRILLING WATERFLOOD RECOVERY

Analysis of Variance

R^2	F Value	Prob>F
0.8156	17.698	0.0001

Parameter Estimates

Variable	Parameter Estimate	Standard Error	t for HO: Parameter = 0	Prob>|t|
Intercept	7.262094	2.444357	2.971	0.0117
X_1	0.169558	0.027238	6.225	0.0001
k	0.065631	0.032712	2.006	0.0679
s_w	−0.126929	0.079201	−1.603	0.1350

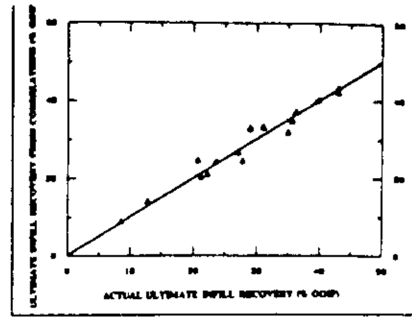

Fig. 6—Comparison of estimated and actual ultimate infill-drilling waterflood recovery.

Fig. 6 plots the actual infill-drilling recovery estimated from the decline-curve analysis vs. that calculated from the regression equation. The 45° line represents a perfect correlation estimate for the infill-drilling recovery. The cluster of data points along the 45° line indicates the validity of the correlation equation. The correlation model requires such readily available reservoir and process parameters as N/s_w, E_{wid}, B_{oi}, k, γ_{API}, and S_{wi} to estimate infill-drilling recovery.

Incremental Infill-Drilling Waterflood Recovery Correlation. Table 7 shows the statistics for the incremental infill-drilling waterflood recovery correlation. As can be seen, the R^2 value is 0.81, which is low. The low R^2 value may be attributed to the scattering of data and to the fact that the equation includes three rather than six variables for the ultimate infill-drilling recovery correlation. However, the F value for the correlation is 17.69, which is much greater than the $F_{rejection}$ value of 3.49. This indicates that this correlation is adequate for estimating the dependent variable ΔE_{Ic}. The regression equation is

$$\Delta E_{Ic} = +7.3179 + 0.1720 N/s_w + 0.0656 k - 0.1311 s_w . \quad \text{.......(5)}$$

Fig. 7 plots the actual incremental infill-drilling recovery estimated from the decline-curve analysis vs. that calculated from the regression equation. The 45° line represents a perfect correlation estimate for the incremental infill-drilling recovery. The scattering of data points along the 45° line indicates the correlation equation can provide a reasonable recovery estimate when the incremental infill recovery is above 5% OOIP. The correlation model requires such readily available reservoir and process parameters as N/s_w, k, and s_w to estimate incremental infill-drilling recovery.

Incremental Infill-Drilling Recovery per Infill Well. Table 8 shows the statistics for the correlation for incremental infill-drilling recovery per infill well. Because the R^2 value is 0.98, which is high, and the F value for the correlation is 71.42, which is much greater than the rejection F value of 3.37, the quality of the correlation is acceptable. The regression equation is

$$\Delta N_{pI} = -149{,}560 + 12{,}913 N/s_w + 654.91 h + 42.110 D + 11{,}524 \phi - 3{,}014 S_{wi} - 1{,}240 n . \quad \text{.........(6)}$$

Fig. 8 plots the actual incremental infill-drilling recovery per infill well estimated from the decline-curve analysis vs. that calculated from the regression equation. The cluster of data points along the 45° line indicates the validity of the correlation equation. The correlation model requires such readily available reservoir and process parameters as N/s_w, h, D, ϕ, S_{wi}, and n to estimate the incremental infill-drilling recovery per infill well.

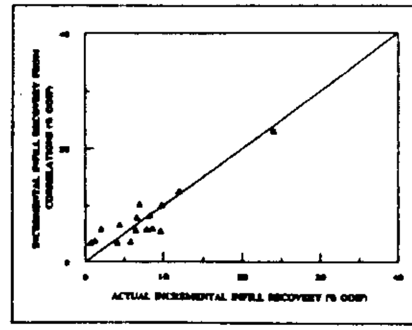

Fig. 7—Comparison of estimated and actual incremental infill-drilling waterflood recovery.

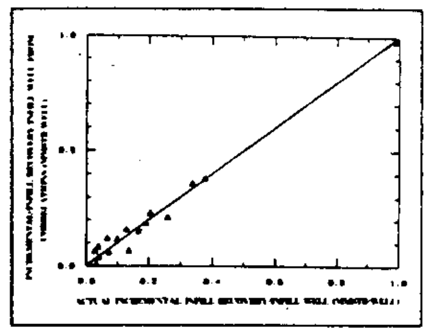

Fig. 8—Comparison of estimated and actual incremental infill-drilling recovery per infill well.

TABLE 8—STATISTICS FOR THE CORRELATION FOR INCREMENTAL INFILL-DRILLING RECOVERY PER INFILL WELL

Analysis of Variance

R^2	F Value	Prob>F
0.9794	71.427	0.0001

Parameter Estimates

Variable	Parameter Estimate	Standard Error	t for HO: Parameter = 0	Prob>|t|
Intercept	−149,560.00	108,705.300	−1.376	0.2021
X_1	12,913.36	1,117.718	11.553	0.0001
h	654.93	221.026	2.963	0.0159
D	42.11	12.779	3.295	0.0093
ϕ	11,524.45	4,028.574	2.861	0.0188
S_{wi}	−3,014.42	2,030.652	−1.484	0.1718
n	−1,240.03	208.683	−5.942	0.0002

Waskada Lower Amaranth

N/Sw (Trend Area) = 2.7966

K = 1.0 md

Sw = 20 acre

Ewid = 15%

Boi = 1.155

γAPI = 36

Swi = 40%

ΔEIc = 5.8%

Incremental Infill WF Recovery

Discussion

There are many uncertainties in the use of decline-curve analysis for assessing the incremental oil recovery by waterflooding and by infill-drilling waterflooding. For example, the timing and extent of infill drilling would affect infill-drilling waterflood performance. The result of decline-curve analysis would also be dependent on the operational strategy and on state regulations. A more detailed study using a larger data base may eliminate the uncertainties involved in allocating the waterflood recovery resulting from infill drilling.

The assumption that the production decline started at the time the initial waterflood or the infill drilling was initiated tends to underestimate the magnitude of the primary recovery and the initial waterflood recovery. Estimating primary recovery was especially difficult when the early production data were either uncertain or not available.

We encountered some difficulties in defining the well spacing, especially when the flood pattern was changed during infill drilling over an extended period of time and when irregular flood patterns were used. A better data base with detailed infill-drilling schedules will provide a more consistent well-spacing value, which may eliminate some uncertainties in the correlation.

Infill drilling is an integral part of the improved oil recovery process. It is very important that the impact of infill drilling on the profitability of waterflood and other EOR projects be further investigated.

Most of the technical data used in this study were from the Railroad Commission of Texas and Dwight's Energy Resources. The purpose of this work will have been served if a general interest is stimulated in infill drilling for waterflooding.

Conclusions

1. A correlation of waterflood recovery and well spacing using the data base from the Railroad Commission of Texas showed that as well spacing decreased, waterflood recovery increased.

2. The impact of infill drilling on waterflood recovery from the carbonate reservoirs studied was substantial. As the well spacing was decreased from 40 to 20 acres [16 to 8 ha], the average incremental infill-drilling waterflood recovery was about 8 to 9% OOIP. It should be remembered that there are always exceptional cases.

3. Regression correlation models were developed for estimating ultimate infill-drilling waterflood recovery, incremental infill-drilling waterflood recovery, and incremental infill-drilling recovery per infill well for the carbonate reservoirs in the Permian Basin. The regression models can provide estimates of infill-drilling recovery from readily available basic reservoir and process parameters. Because of the limited data base and regressional nature of the correlation models, the infill-drilling recovery estimate must not be used indiscriminately; it must be substantiated by a sound reservoir engineering study on a particular reservoir in the region.

Nomenclature

B_{oi} = initial oil FVF, RB/STB [res m^3/stock-tank m^3]
D = producing-zone depth, ft [m]
E_{Ic} = ultimate infill-drilling waterflood recovery estimated from correlation equation, % OOIP
E_{Pd} = ultimate primary recovery estimated from decline-curve analysis, % OOIP
E_w = waterflood recovery, % OOIP
E_{wE} = estimated waterflood recovery, % OOIP
E_{wic} = ultimate initial waterflood recovery estimated from correlation equation, % OOIP
E_{wid} = ultimate initial waterflood recovery estimated from decline-curve analysis, % OOIP
ΔE_{Ic} = incremental infill-drilling waterflood recovery estimated from correlation equation, % OOIP
F = Fisher's F distribution
h = pay thickness, ft [m]
k = permeability, md
n = number of infill wells drilled after initial waterflood
N = OOIP, MMSTB [10^6 stock-tank m^3]
ΔN_{pI} = incremental infill-drilling waterflood recovery per infill well estimated from correlation equation, STB [m^3]
R^2 = square of sample correlation coefficient
s_w = well spacing, acres/well [ha/well]
S_{wi} = initial water saturation, %
t = Student's t distribution
X_1 = N/s_w
γ_{API} = gravity, °API [g/cm^3]
ϕ = porosity, %

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SI Metric Conversion Factors

acre	× 4.046 873	E−01	=	ha
°API	141.5/(131.5+°API)		=	g/cm³
bbl	× 1.589 873	E−01	=	m³
ft	× 3.048*	E−01	=	m
md	× 9.869 233	E−04	=	μm²
miles	× 1.609 344*	E+00	=	km
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

Provenance

Original SPE manuscript, **Impact of Infill Drilling on Waterflood Recovery: West Texas Carbonate Reservoirs**, received for review March 10, 1988. Paper accepted for publication July 21, 1989. Revised manuscript received April 7, 1989. Paper (SPE 17286) first presented at the 1988 SPE Permian Basin Oil and Gas Recovery Conference held in Midland, March 10–11.

JPT

Wu

Jardon

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REVITALIZATION OF THE PEMBINA FIELD

BY
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__Abstract__: Over the past eight years, 1981 to mid 1989, Canadian Occidental has invested $16,300,000 in the revitalization of the company's Pembina properties. A total of $3,800,000 was invested in 83 fracture stimulations yielding an average payout period of just over one year and incremental reserves per job of 2130 m^3. The stimulated wells are currently producing 45 m^3/day of incremental oil yielding $1,650,000/year of additional revenue for the Pembina operation. A total of $12,500,000 was invested in 33 infill wells and their associated facilities. The infill wells have an average payout period of 2.5 years and the estimated incremental reserves per well of 10,930 m^3. The infill wells are currently producing 80 m^3/day of incremental oil yielding $2,000,000/year of additional revenue. Canadian Occidental's program has increased the current annual revenue to $5,550,000 from an estimated $1,900,000 if none of the work had been carried out. The increase is significant considering the majority of the work has achieved payout. The work carried out by Canadian Occidental ensures continued profitability and life from the field in the future.

__Introduction__ - The main purpose in writing this paper is to prove to the industry that the Pembina Oilfield can be a source of significant reserves and revenue in the future. Huge gains in productivity cannot be expected but sustained economic development can take advantage of the already existing infrastructure with excellent returns in both production and profit.

Cities-Service/Canadian Occidental has been active in the Pembina Oilfield since 1956 and was instrumental in setting up many of the Units in the field. The Company's first waterfloods were initiated in 1961. The Company also experimented with gas/LPG injection in both Bear Lake and Keystone. By 1965, the entire field has been unitized and the majority was under waterflood, see Figure 1.

Canadian Occidental currently operates 412 wells in the field with 15 batteries and 76 satellites and one gas plant located in Keystone. Of the 412 wells, 282 are producing, 65 are injectors and 65 wells are shut-in. Production from the field, on a Lease Gross Basis, currently averages 420 m^3/day of oil, 112 10^3m^3/day of gas, and 1850 m^3/day of water as of November 30, 1989. Production on a per producing well basis averages on 1.5 m^3/day of oil, 0.4 10^3m^3/day of gas, and 6.6 m^3/day of water.

The average producing well operating cost, including battery, shut-in well and injector costs, currently averages $28,800/year. Using a price of $120/$m^3$, the break even production rate for a Pembina well is 0.7 m^3/day. Overall, the field is still profitable, but every means has to be taken to increase production. Since the operating cost is not directly proportional to production rates, a 50% increase in production may only equate to a 10% increase in operating costs. Any incremental oil production adds significantly to the bottom line for the District.

Background - Cities-Service/Canadian Occidental has always maintained a physical presence in the Pembina oilfield. That presence proved to be an invaluable training ground for both Production Operations and Production Engineering. There are several reasons why an aggressive fracing and infill drilling program were pursued in Pembina; they are:

- The production infrastructure was already in place, any new production would have a low incremental cost.
- An aggressive development oriented team of Production and Engineering personnel worked closely together initiating projects.
- Solid management commitment for development of the Pembina oilfield.
- Good economic returns.

The above factors resulted in 83 fracs from 1985 to mid 1989 and 33 infill wells being drilled from 1981 to 1989

Fracture Stimulation Post Audit

Introduction - The following post audit on Canadian Occidental's fracture stimulation program was carried out to determine the answers to the following questions:

- what is the success rate, incremental production and economics for the 83 frac's performed by Canadian Occidental in the Pembina area from 1984-89, see Figure 2.
- what is the frac life of the stimulations. Frac life is defined by the initially frac date to the date in the future when the frac decline rate would cross the base decline rate.
- what effects do frac's have on WOR.
- do frac's just accelerate production or are new reserves being produced.

Canadian Occidental's Engineering staff in Drayton Valley used the following criteria when choosing fracture stimulation candidates. Explanations into what was looked for in each criteria are also included.

- Build Up Analysis: A high skin factor from build ups are used when available.
- Fluid Capacity Ratio: The ratio of present fluid production rate over peak fluid production rate. The lower the ratio, the better the stimulation potential.
- Present Fluid Production: Used in conjunction with Fluid Capacity Ratio in order to determine the potential increase in well productivity.
- WOR: The lower the water oil ratio, the better the candidate.
- Well Recovery: The recovery from wells is also used. If the well's total recovery is very low, it usually indicates poor reservoir. If the recovery is very high, the well likely does not need stimulation. Wells with average area recoveries were found to be the best candidates.
- Open Hole Log Profiles: The logs from each well were reviewed to determine if there was any new perforation potential.
- Fracture Stimulation History: Wells that had never been refractured were considered good candidates. Wells that had been stimulated within the past five years were considered poor.

All of the above criteria were used in screening fracture stimulation candidates.

Historically, the sizes of the treatments have increased with time. Many of the wells were originally stimulated with gelled crude jobs ranging in size from 25 to 30 tons of sand. The most recent polyemulsion fracs carried out by Canadian Occidental in Pembina are in the range from 50 to 70 tonnes of 20/40 sand.

Economic Results - Of the 83 fracture stimulations carried out by Canadian Occidental from 1984 to mid 1989, 19 were considered failures. A failure was defined as a frac which had no long term positive effect on the well's productivity. The average oil production increase, after one year, has averaged 1.6 m^3/day/well. The largest single increase after one year was 9.6 m^3/day in PECU #1.

The analysis of the frac's has been broken down into five main Canadian Occidental operated areas. They are:

- Pembina Easyford Cardium Unit #1 (PECU #1)
- 100% Leases (A,D,EFG,MKO, Modeste)
- Northwest Pembina Cardium Unit #1 (NWPCU #1)
- Pembina Bear Lake Cardium Unit #1 (PBLCU #1)
- Pembina Keystone Cardium Unit #2 (PKCU #2)

The production results from all 83 frac's are contained in Figures 3, 4 and 5. The results show a significant increase in production from an average 1.2 m^3/day/well prior to the frac to 2.8 m^3/day/well one year after the frac. The current production per well averages 2.0 m^3/day.

POGO™, a registered trademark of PSI Energy Software, Inc., economics were run on a year by year basis to determine the economic indicators for Canadian Occidental's fracture stimulation program. The economics indicated an average frac life of 6.45 years, an average capital cost of \$45,500, with a corresponding Net Present Value, discounted at 18%, of \$60,500. The payout period was calculated to be 1.06 years and the incremental reserves per job averaged 2130 m^3, see Figure 6.

Over the past five years Canadian Occidental spent nearly \$3,800,000 on fracture stimulations in Pembina resulting in an additional 177,000 m^3 of oil being recovered. The average finding and development cost for those additional reserves was only \$21.33/m^3.

Frac Life - Decline curve analysis was used to determine frac life. A typical Pembina Cardium well's production declines at 7-12%/year. After a frac the oil rate is increased by an average of 130% but the decline rate for the oil increases to 17 to 25%/year. The Frac Life, as previously defined in the Introduction, ranges from 5.4 to 7.5 years, see Figure 7. Since the stimulated wells production rate returns to previous decline rate levels after 6.5 years, there must be degradation of the frac. Fines movement in the new frac is thought to be the main contributor in the decrease in frac conductivity. With time the frac continues to fill up with fines until such a time that its permeability returns to near matrix rock permeability. Fill up of the frac with fines can be used to explain why, after 6.5 years, the decline rate returns to the normal non-stimulated rate of 7-12%/year.

Effective on WOR - Decline curve analysis was used to determine the effect on Water Oil Ratios by fracture simulation in the Pembina Cardium, see Figure 8. Even though total fluid inflow was enhanced significantly, there was no noticeable increase in WOR by fracture stimulation. This is believed to occur since the frac's are penetrating lower permeability non waterflood swept portions of the reservoir.

Accelerated Production of New Reserves - If fracture stimulations were found to only accelerate reserve recovery rather than enhance recovery, the value of the entire program would be in doubt. In order to substantiate the theory on frac life and the continuous fill up of the frac with fines resulting in the frac conductivity returning to near matrix levels within 6 to 7 years, decline curve analysis was again used. The 12 frac's which were conducted in PECU #1 in 1979 were reviewed to see if their production behavior matched the frac life theory. The average oil production per well prior to the frac's was 2.2 m^3/day. After the frac the oil production increased to 3.8 m^3/day. The prefrac decline rate averaged 7.5%/year while the post frac decline rate averaged 14.5%/year for 7 years when the decline rate again returned to the prefrac decline rate of 7.5%/year, see Figure 9. By extrapolating the prefrac decline rate seven years into the future the wells productivity returned to what the production would have declined to if the wells had not been stimulated. Therefore, the temporary production gain for the seven years of the frac's life was incremental production which would not have been produced if the well had not been stimulated. The estimated incremental production per 1979 frac averaged 1920 m^3. The results from the twelve 1979 frac's in PECU #1 compare favorably with the expected results from the 1984-mid 1989 frac's,

Conclusions - The 83 fracture stimulations carried out in Pembina by Canadian Occidental have had a very positive effect on the areas profitability. The fracture stimulated wells are currently producing 45 m^3/day of incremental oil production which, at a 100 $/$m^3$ netback, results in $1,650,000/year in additional revenue for the District. It has been estimated that by stimulating 26 wells a year with a 75% success rate and an average incremental production increase, per successful job, of 1.6 m^3/day the decline in the field's productivity could be reduced to zero.

Infill Drilling Post Audit

Introduction: This post audit on the Infill Drilling Program, which was carried out by Canadian Occidental Petroleum Ltd. from 1981 to mid 1989, and resulted in 33 wells being drilled, was done in order to answer the following main questions.

- What is the success rate, production and economic results for the 33 wells which were drilled.
- What is the incremental reserves expected from the infill wells.
- What is the typical production profile for an infill well.
- What effect do infill wells have on the surrounding original wells, is there interference.
- What positive effect has the infill drilling had on the Pembina Operations in terms of revenue and production.

A review of Historical Pembina drilling and the method for evaluating the infill drilling locations will be discussed next.

Historical Infill Drilling: The Pembina field was initially drilled down to 160 acre spacing in the mid to late 1950's. By the mid 1960's, the pool had been drilled down to 80 acre spacing and the pool placed on waterflood. Continued infill drilling was not actively pursued until 1970 when Texaco drilled 8 wells on the modified infill drilling pattern. The Texaco wells served as a guide for CanadianOxy's infill program. Infill drilling was virtually ceased in the 1970's.

In late 1980, Canada Cities-Service proposed a conventional infill drilling program in Pembina Easyford Cardium Unit #1. A total of 20 wells were proposed, but only one was approved. The original producers in Easyford were drilled on LSD's 6, 8 and 16, with an injector at LSD 14, see Figure 10. Infill wells were proposed on LSD's 2, 4, 10 and 12. The first infill well 04-18-50-08 W5M was not considered a great success. Open hole logs indicated that the top portion of the reservoir, the most permeable section, had already been swept by the waterflood. The results from 04-18 required a re-evaluation of infill well locations.

Re-Evaluation of Infill Locations: The accepted method for infill drilling in the Pembina prior to 1970 was to drill on all even numbered LSD's in a section. That was fine prior to the waterfloods being initiated, but not acceptable on mature waterfloods. By drilling on even numbered LSD's, infill wells were placed directly between producers and injectors, see Figure 11. Classical waterflood theory and common sense would indicate that drilling between an injector and a producer would place a well in a swept portion of the reservoir. The logical placement for infill wells would then be between producing wells on odd number LSD's in order to fully exploit the unswept portions of the reservoir. A method had to be developed for choosing the best candidates for infill drilling. A waterflood equation, based on Darcy's Law, see Figure 12, was developed by CanadianOxy's Reservoir Engineering Group. The equation is:

$$f = \frac{(P_i - P_p)M}{r_k \times r}$$

Where
f = Injector - Flood Front Advance (m)
M = Time to Breakthrough (months)
r_k = Waterflood Coefficient (months x kPa/m^2)
P_i = Injection Pressure (kPa)
P_p = Production Pressure (kPa)
r = Injector - Producer Distance (m)
f/m = Apparent Velocity of the Flood Front (m/month)
$\frac{P_i - P_p}{r}$ = Interwell Pressure Gradient kPa/m

The analysis method uses actual field data and follows the following course, see Figure 13.

- Using known variables at the time of breakthrough the reservoir coefficient r_k is determined for the pool and plotted on a map at the midpoint between an injector and producer. The procedure is repeated for the entire area so an r_s map can be developed.

- A determination of the flood front advance along the line between the producing wells is done by using r_s and substituting Pr, at the time of breakthrough, in the place of Pp. M is defined as the average of the time to breakthrough at the two nearby producers. All other variables remain constant. In this way the unknown flood front distance f can be estimated.

The process is then repeated for all of the producer midpoints surrounding an injector until the waterflood star at breakthrough is determined. The volume of the star is then calculated and taking into account Displacement and Vertical sweep efficiencies and the areal extent of the star. The volume of the star is then compared to the actual volume of water injected from the start of the waterflood to breakthrough.

Now that the size of the waterflood star at breakthrough is determined, an estimate of the size of the waterflood star at the present time can be done, see Figure 14. Since the geometry of different stars can be very complex, a nomograph was developed for relating the cumulative oil at the present time/cumulative oil at breakthrough, the volume factor, to the Present f/Breakthrough f, the length factor. The breakthrough f line on the nomograph for the particular midpoint are used to determine the length factor. The displayed nomograph is for a 160 acre 9 spot pattern, see Figure 15.

The procedure for determining the waterflood stars is repeated over the entire area and drawn on a map. An estimate of the size of the unswept pods between producers is now evident and infill location can be chosen on that basis. Other factors which came into play in choosing final candidates are:

- Expected fluid production rates
- Well recoveries
- Area permeability and pay thickness

A total of 20 infill wells at PECU #1 were chosen using this method, see Figure 16 for modified drilling patterns.

The four infill wells at PBLCU#1 were chosen based on Geology and Reservoir Engineering. Bear Lake has a thick conglomerate section in the middle portion of the reservoir.

The three wells drilled at D Battery and the well at NWPCU#1 were done to complete the 32 hectare spacing. Finally, the three wells at "K" Battery were drilled on a true 16 hectare spacing, see Figure 17 for all infill locations.

Economics: The results from the 33 infill wells have been attached see Figure 18. Canadian Occidental invested a total of $12,500,000 from 1981 to 1989. Included in the costs are the necessary flowlines and facilities modifications. A total of five satellites were built to accommodate the new wells and "K" Battery was rebuilt as part of the three well drilling program conducted in 1989. The average cost per well was $377,500. Operating costs were set initially at $24,000/year/well inflated at 4%/year. The average economic life is estimated at 15 years. The Net Present Value, per well, averaged $389,700 discounted at 12% and $329,200 discounted at 18%. The payout period per well is estimated at 2.5 years with a corresponding Rate of Return of 38%.

Incremental Reserves: The total incremental recovery per well is estimated to be 10,930 m^3. The finding and development cost averages $34.5/$m^3$. The infill drilling program increased the Net Present Value of the Pembina by nearly $11,000,000 discounted at 18%, and added over 360,000 m^3 to the recoverable reserves of the Pembina field. All of the reserves from the infill wells was considered incremental.

Production Profile: Infill wells in Pembina are characterized by high initial production rates; 9.9 m^3/day/well, and a moderate WOR, averaging 1.0 m^3/m^3 initially, declining rapidly to approximately 50% of the initial rate after one year, 4.8 m^3/day/well with the WOR increasing to 1.6 m^3/m^3. The production decline rate then stabilizes at 10 to 15% per year and the WOR stabilizes at the field average of 2.0 m^3/m^3. After about three years time, the production from the infill wells is comparable to the nearby original wells, see Figure 19. See Figures 20 and 21 for well by well details. Overall payout on the wells have been achieved during the initial high production rate phase.

Interference Effects: Production rates from the original wells surrounding the infill wells was monitored in order to determine if there is interference between the infill and original wells. If production from the original wells declined more rapidly when infill wells were drilled, a portion of the production from the infill wells would have to be classified as acceleration of reserves instead of incremental. Production rates from the PECU#1 wells have been monitored closely for interference effects. To date, four and a half years, there has been no noticeable interference between infill and original wells. This is the case because the permeability in the Cardium, in most areas, is limited and the drainage area per well is also small. Therefore, all of the reserves from the infill wells were classified as incremental.

Overall Effects: The drilling of the 33 infill wells has had a very positive effect on Canadian Occidental's Pembina operation. For ease of review, some of the effects are listed in point form.

- The infill wells are currently contributing 80 m^3/day of oil production, on a Lease Gross basis to the Canadian Occidental operated areas.
- The annual revenue, using operating costs of $28,800/year/well and a netback of $100/$m^3$ after royalties from the infill wells is estimated to be $2,000,000/year currently.
- The majority of the wells have reached payout and are currently generating positive revenue.
- The infill drilling program allowed for the construction of new facilities and was also indirectly responsible for the upgrading of three of the company's main batteries.
- The economic life of the field has been extended by increasing the area's productivity.
- The intangible benefits in morale for the Operations and Engineering staff in Drayton Valley has been very positive. The commitment of the company to Pembina Field Development ensures a long and prosperous stay in Pembina.

Conclusions: The infill drilling program has an 82% success rate based on 27 of the 33 wells being considered good successes. The very first infill well 4-18-50-8 W5M was a failure due mainly to its location between an injector and a producer and the poor quality of the reservoir it was drilled in. The 2-1-49-9 W5M well in NWPCU#1, drilled in 1986, has experienced damage from workovers and production has not maintained its initial high levels. The 9-14-50-9 W5M in PECU#1 also drilled in 1986, has remained shut-in due to a very high watercut. The well encountered the edge of the PBLCU#1 conglomerate which was watered out. The three wells in K Battery, drilled in 1989, have a Rate of Return of 11%, based on the drilling and tie-in costs, and are hampered by inadequate water injection. Injection is being increased to solve the voidage problems.

The minimum initial production rate for an infill well was calculated using the following criteria:

Capital Expenditure:	$350,000
Operating Cost:	$28,800/year
Decline Rate:	10%/year
Discount Rate:	18%

The minimum required initial production rate is only 3.0 m^3/day using Canadian Occidental's current price forecast. The production forecast does not include the characteristic peak production rate for one year which would enhance any drilling economics significantly.

Infill drilling in the Pembina has proved to be an economic means to increase production, reserves and revenue from the field. The relatively low drilling and tie-in costs, along with the existing infrastructure, make the investment low risk with reasonable Rates of Return. By using some of the previously outlined criteria and common sense, dozens of infill drilling locations become obvious within Canadian Occidental's operated properties. Throughout the entire Pembina there are probably hundreds of likely infill drilling locations ready to be developed.

REVITALIZATION RESULTS

Conclusions: The Pembina Operation of Canadian Occidental in the 70's can be characterized by good production rates, slowly rising WOR's, and a steady slow decline in oil productivity. There was little capital investment in the area and the company was harvesting the results of all of the work done in the 1960's.

The 1980's brought a renewed commitment by the company to the Pembina field in the areas of Fracture Stimulation and Infill Drilling, as well as the upgrading of Production Facilities. By using Decline Curve Analysis, the estimated production from the field would now be at 295 m^3/day assuming no fracture stimulations and infill drilling, see Figure 22. Based on previously outlined operating costs of $28,800/producing well, the original 249 producing wells would cost $7,200,000/year to operate. The oil revenue, based on a netback of $100/$m^3$, would be $9,100,000/year, leaving a net revenue of only $1,900,000/year from Canadian Occidental's Pembina operated areas if the revitalization program had not been carried out. As previously outlined, the fracture stimulation program is currently adding $1,650,000/year to the Pembina, and the infill drilling program is currently adding $2,000,000/year.

By investing $16,300,000, most of which has already reached payout from 1981 to mid 1989, Canadian Occidental has been able to increase the net revenue from the field to $5,550,000/year currently from an estimated $1,900,000/year if none of the work had been carried out. The excellent results Canadian Occidental has seen from the revitalization of the Pembina will ensure that future development will continue to extend the life and profitability of the field.

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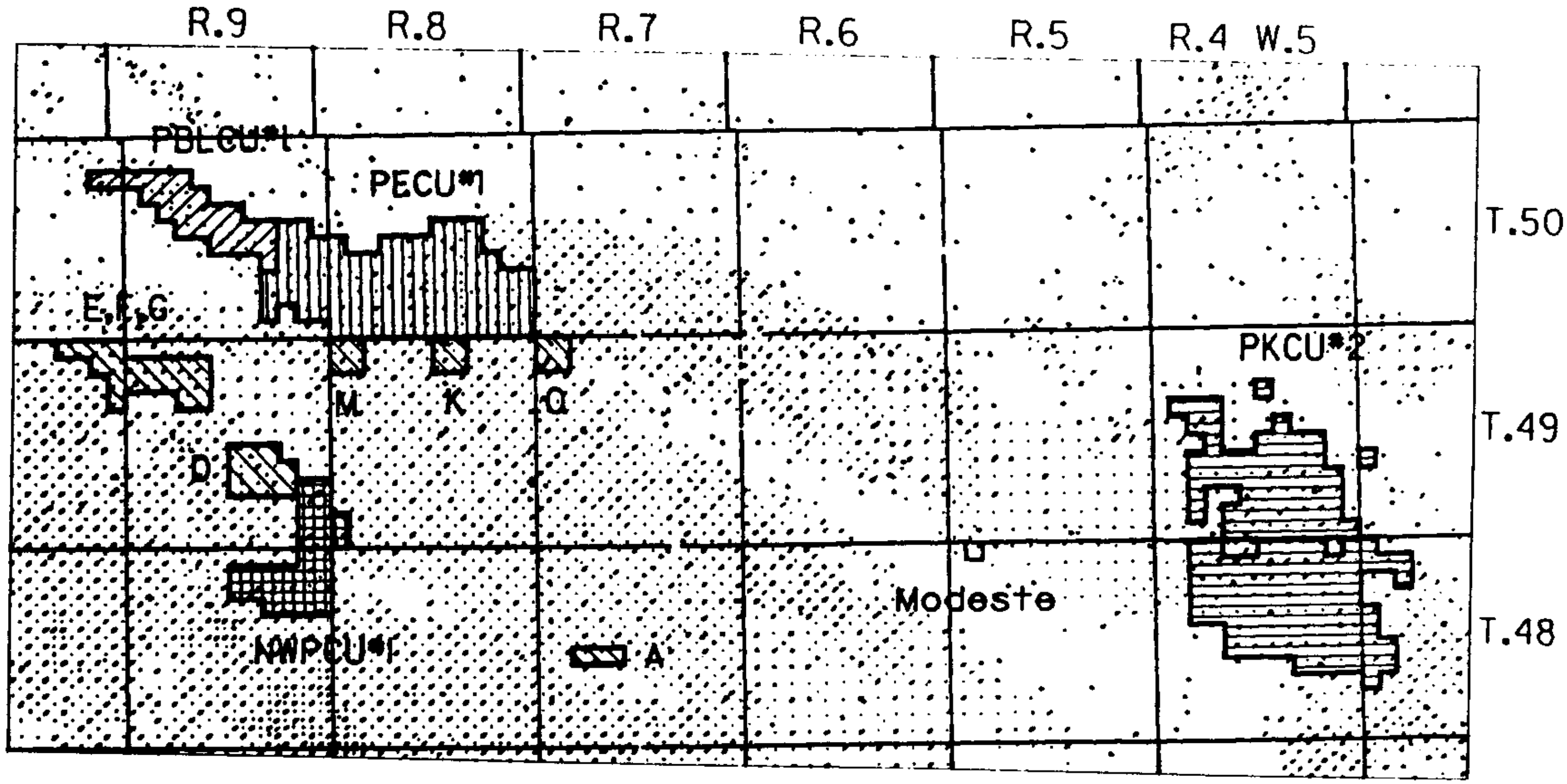
Figure I



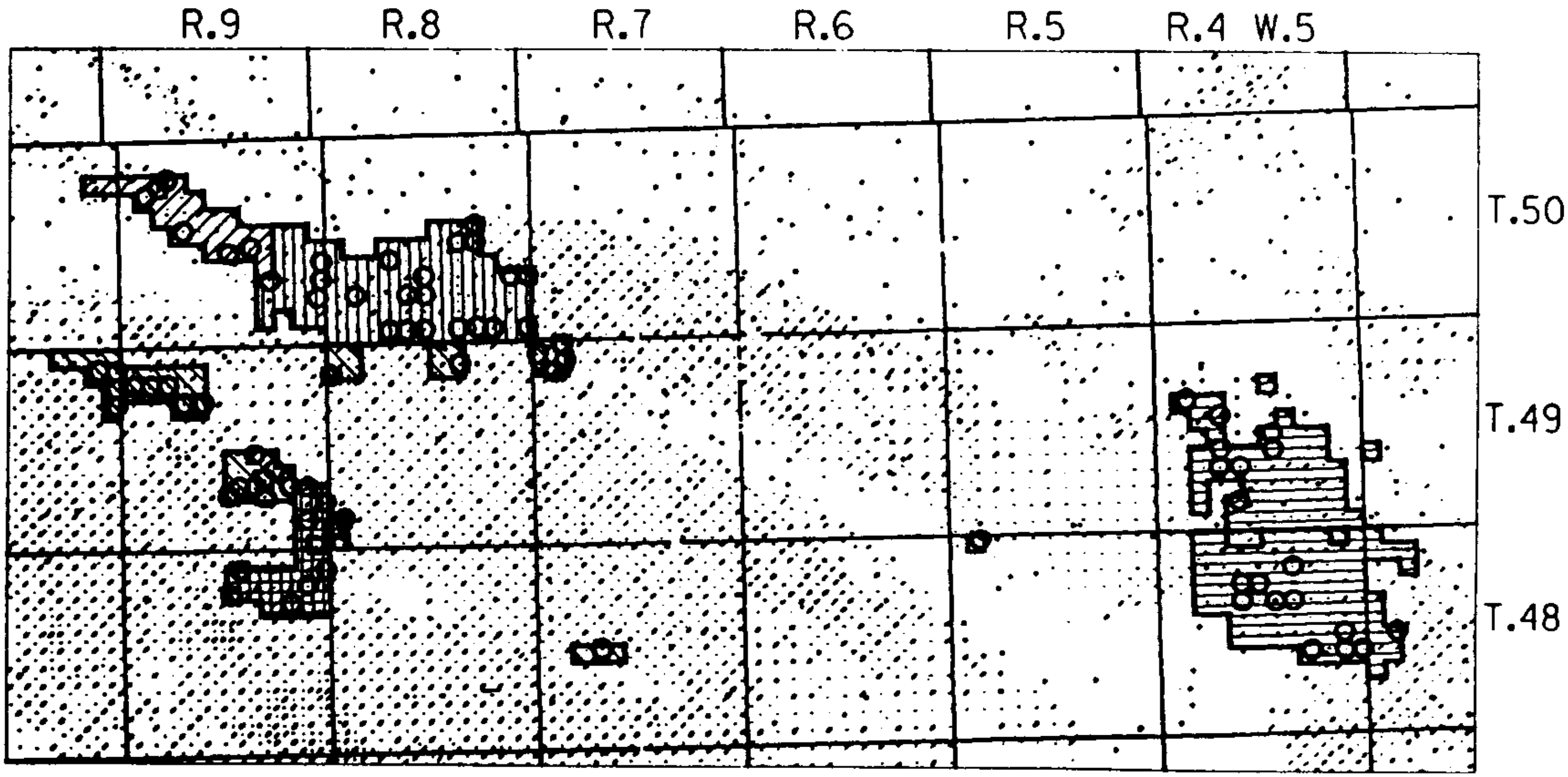
Canadian Occidental Petroleum Ltd

PEMBINA

UNIT & NON-UNIT PROPERTIES

REVISED :	PLAT No.: CXI:[300,]]C782A.BOR

Figure 2



Canadian Occidental Petroleum Ltd

PEMBINA

FRAC'S WELLS 1985-1989

REVISED :

PLAT No. : CXI:[300,1]C785A.BOR

FIGURE 3

COPL 5 YEAR FRAC HISTORY - PEMBINA (AS OF 1988-05)

AREA	LOCATION	DATE	SIZE	PREFRAC OIL	PREFRAC WATER	PREFRAC WOR	POSTFRAC* OIL	POSTFRAC* WATER	POSTFRAC* WOR	PRESENT OIL	PRESENT WATER	PRESENT WOR	COMMENTS
PCCU #1	08-01-50-08	1986-06	67t of 20/40 sand	1.3	2.0	1.5	1.1	1.7	1.5	1.0	1.1	1.1	FAILURE
	06-02-50-08	1985-08	35t of 20/40 sand	4.8	14.3	3.0	7.7	23.9	3.1	2.5	18.0	7.2	SUCCESS
	08-02-50-08	1985-08	35t of 20/40 sand	1.4	5.1	3.6	2.3	7.1	3.1	1.0	5.5	5.5	SUCCESS
	08-03-50-08	1988-09	50t of 20/40 sand	2.2	2.9	1.3	10.0	5.0	0.5	10.0	5.0	0.5	SUCCESS
	06-04-50-08	1988-09	7.9t of 20/40 sand	0.4	3.8	9.5	1.9	6.0	3.2	1.9	6.0	3.2	SUCCESS
	08-04-50-08	1985-08	35t of 20/40 sand	2.5	8.1	3.2	12.1	16.6	1.4	3.1	14.0	4.5	SUCCESS
	08-05-50-08	1988-09	12.6t 20/40 sand	1.5	3.1	2.1	1.1	1.1	1.0	1.1	1.1	1.0	FAILURE
	08-07-50-08	1987-06	50t of 20/40 sand	3.6	5.6	1.6	2.6	4.2	1.0	2.5	3.2	1.3	FAILURE
	06-09-50-08	1987-05	50t of 20/40 sand	2.4	5.6	2.3	3.2	21.1	6.6	3.5	17.5	5.0	SUCCESS
	08-09-50-08	1985-08	35t of 20/40 sand	2.1	5.0	2.4	4.0	6.0	1.5	2.4	4.5	1.9	SUCCESS
	16-09-50-08	1986-12	50t of 20/40 sand	2.4	5.2	2.2	2.0	3.5	1.8	3.4	2.4	0.7	FAILURE
	14-12-50-08	1987-06	40.8t 20/40 sand	1.3	1.6	1.2	1.5	3.3	2.2	S.I.	S.I.	-	FAILURE
	16-12-50-08	1985-09	35t of 20/40 sand	1.2	4.3	3.6	6.6	10.3	1.6	S.I.	S.I.	-	SUCCESS, S.I. 1987
	14-14-50-08	1987-06	35t of 20/40 sand	3.0	0.3	0.1	2.2	0.1	0.0	1.8	0.2	0.1	FAILURE
	16-15-50-08	1987-06	50t of 20/40 sand	1.0	1.7	1.7	0.8	2.8	3.5	0.8	0.3	0.4	FAILURE
	08-17-50-08	1987-06	50t of 20/40 sand	2.1	1.0	0.5	1.2	1.5	1.3	0.6	2.0	3.3	FAILURE
	06-23-50-08	1986-08	50t of 20/40 sand	0.4	0.7	1.7	5.0	3.5	0.7	1.2	3.1	2.6	SUCCESS
	14-11-50-09	1987-07	25t of 20/40 sand	0.6	2.7	4.5	0.2	1.5	7.5	1.0	5.4	5.4	MINOR SUCCESS**
	08-12-50-09	1986-06	50t of 20/40 sand	2.1	2.3	1.1	3.1	2.5	0.8	3.0	2.2	0.7	SUCCESS
	16-12-50-09	1986-11	50t of 20/40 sand	1.2	1.0	0.8	1.1	0.5	0.5	0.5	1.0	2.0	FAILURE
	08-13-50-09	1987-01	50t of 20/40 sand	3.7	3.0	1.0	2.0	3.2	1.6	3.0	7.0	2.3	FAILURE
			TOTAL	42.0	80.1	1.9	71.5	125.4	1.8	44.3	99.5	2.2	
			WELL AVERAGE	2.0	3.8	1.9	3.4	6.0	1.8	2.1	4.7	2.2	
100 % (A)	16-17-48-07	1986-10	50t of 20/40 sand	1.3	1.0	0.8	2.0	1.3	0.7	1.3	0.5	0.4	MINOR SUCCESS
(E,F,G)	06-20-49-09	1986-08	70t of 20/40 sand	1.0	0.8	0.8	7.0	2.0	0.3	1.4	1.2	0.9	SUCCESS
	08-20-49-09	1986-10	80t of 20/40 sand	0.2	0.5	2.5	0.4	1.5	3.8	0.2	1.5	7.5	MINOR SUCCESS**
	14-29-49-09	1988-01	32.7t 20/40 sand	0.4	1.0	2.5	1.2	1.5	1.3	1.2	1.5	1.3	SUCCESS TO PRESENT
	14-30-49-09	1988-08	14t of 20/40 sand	0.3	0.8	2.7	0.6	0.8	1.3	0.6	0.8	1.3	FAILURE TO PRESENT
	16-30-49-09	1986-10	5.7t of 20/40 sand	0.4	1.3	3.3	0.8	1.3	1.6	0.2	1.5	7.5	MINOR SUCCESS
	08-25-49-10	1986-10	2.6t of 20/40 sand	0.5	0.8	1.6	2.0	2.5	1.3	0.5	0.6	1.2	SUCCESS
	14-25-49-10	1988-08	42t of 20/40 sand	0.3	0.6	2.0	0.6	0.4	0.7	0.6	0.4	0.7	N.S. TO PRESENT
	06-36-49-10	1986-10	44t of 20/40 sand	0.4	0.3	0.7	0.8	1.0	1.3	0.5	1.4	2.8	MINOR SUCCESS
	08-36-49-10	1985-09	50t of 20/40 sand	0.6	0.6	1.0	3.0	1.5	0.5	0.8	0.8	1.0	SUCCESS
(H,I,J)	02-31-49-07	1988-03	54t of 20/40 sand	0.2	0.2	1.0	0.7	0.4	0.6	0.9	0.4	0.4	SUCCESS
	08-31-49-07	1988-03	65t of 20/40 sand	0.3	0.2	0.7	1.2	0.7	0.6	1.2	0.5	0.4	SUCCESS
	12-31-48-07	1987-09	65t of 20/40 sand	0.6	0.7	1.2	5.6	2.7	0.5	1.3	0.8	0.5	SUCCESS
	14-31-49-07	1987-07	65t of 20/40 sand	0.6	0.0	0.0	2.2	0.0	0.0	0.9	0.2	0.2	SUCCESS
	06-31-49-08	1988-11	22.2t 20/40 sand	0.4	4.0	10.0	0.8	14.0	17.5	0.8	14.0	17.5	N.S. TO PRESENT
	08-36-49-08	1987-06	30t of 20/40 sand	2.5	8.0	3.2	8.4	10.6	1.3	3.6	7.3	2.0	SUCCESS
(MODESTE)	16-31-48-05	1985-02	35t of 20/40 sand	1.3	0.0	0.0	3.1	0.1	0.0	2.0	0.1	0.1	SUCCESS
(D)	12-10-49-09	1987-03	50t of 20/40 sand	3.0	0.3	0.1	6.5	0.8	0.1	3.0	0.7	0.2	SUCCESS
	14-10-49-09	1988-06	50t of 20/40 sand	0.9	0.9	1.0	1.0	3.0	3.0	1.0	3.0	3.0	FAILURE TO PRESENT
	16-10-49-09	1986-11	50t of 20/40 sand	1.5	0.1	0.1	6.5	0.3	0.0	3.2	0.4	0.1	SUCCESS
	12-11-49-09	1988-06	50t of 20/40 sand	1.3	1.1	0.8	1.6	1.6	1.0	1.6	1.6	1.0	N.S. TO PRESENT
	16-11-49-09	1987-03	80t of 20/40 sand	0.7	0.0	0.0	2.2	0.2	0.1	1.9	0.3	0.2	SUCCESS
	06-14-49-09	1987-03	60t of 20/40 sand	1.6	0.0	0.0	2.7	0.0	0.0	1.3	0.1	0.1	SUCCESS
	06-16-49-09	1987-03	60t of 20/40 sand	1.5	0.9	0.6	4.2	0.4	0.1	4.3	0.5	0.1	SUCCESS
	16-15-49-09	1986-11	45.0t 20/40 sand	2.5	0.0	0.0	6.2	0.2	0.0	4.2	0.2	0.0	SUCCESS
			TOTAL	26.3	26.1	1.0	71.3	40.0	0.7	39.7	40.3	1.0	
			WELL AVERAGE	1.0	1.0	1.0	2.9	2.0	0.7	1.6	1.6	1.0	

* BASED ON PRODUCTION ONE YEAR LATER   ** POSSIBLE EMULSION BLOCK

ALL RATES ARE IN CUBIC METRES PER DAY

FIGURE 4

CDPL 5 YEAR FRAC HISTORY CONTINUED

AREA	LOCATION	DATE	SIZE	PRETRAC OIL	PRETRAC WATER	PRETRAC WOR	POSTFRAC* OIL	POSTFRAC* WATER	POSTFRAC* WOR	PRESENT OIL	PRESENT WATER	PRESENT WOR	COMMENTS
MPCU #1	12-06-49-08	1988-01	50t of 20/40 sand	0.5	0.3	0.6	4.0	2.0	0.5	3.2	0.8	0.3	SUCCESS
	14-06-49-08	1987-07	50t of 20/40 sand	2.0	0.5	0.3	6.0	2.0	0.3	4.4	1.5	0.3	SUCCESS
	14-25-48-09	1986-08	50t of 20/40 sand	4.0	0.8	0.2	5.3	1.5	0.3	1.6	2.3	1.4	SUCCESS
	08-26-48-09	1987-08	50t of 20/40 sand	1.0	0.1	0.1	2.6	0.0	0.0	1.9	0.0	0.0	SUCCESS
	12-27-48-09	1988-08	44t of 20/40 sand	0.8	0.7	0.9	3.0	3.3	1.1	1.4	2.4	1.7	SUCCESS TO PRESENT
	06-34-48-09	1987-07	50t of 20/40 sand	0.8	0.6	0.7	2.3	0.3	0.1	1.6	1.0	0.6	SUCCESS
	08-36-48-09	1985-08	35t of 20/40 sand	0.6	0.3	0.5	0.9	0.5	0.6	0.7	0.8	1.1	MINOR SUCCESS
	02-01-49-09	1988-10	50t of 20/40 sand	1.5	0.2	0.1	1.6	0.2	0.1	1.6	0.2	0.1	FAILURE TO PRESENT
	14-01-49-09	1985-12	35t of 20/40 sand	0.0	0.0	-	0.1	5.5	55.0	0.1	6.5	65.0	FAILURE, S.I. 1986
	08-12-49-09	1985-10	35t of 20/40 sand	0.6	4.0	6.7	4.0	2.5	0.6	2.0	2.0	1.0	SUCCESS**
	14-12-49-09	1987-07	50t of 20/40 sand	3.4	0.1	0.0	3.1	0.0	0.0	3.0	0.0	0.0	FAILURE
			TOTAL	15.2	7.6	0.5	32.9	17.0	0.5	21.5	17.5	0.8	
			WELL AVERAGE	1.4	0.7	0.5	3.0	1.6	0.5	2.0	1.6	0.8	
PBLCU #1	12-15-50-09	1988-11	50t of 20/40 sand	1.1	0.8	0.7	3.0	1.3	0.4	3.0	1.3	0.4	SUCCESS TO PRESENT
	16-15-50-09	1988-12	50t of 20/40 sand	2.9	30.0	10.6	5.7	40.0	7.0	5.7	40.0	7.0	SUCCESS TO PRESENT
	08-20-50-09	1986-09	31.9t 20/40 sand	0.0	0.0	-	1.0	0.0	0.0	1.3	0.0	0.0	SUCCESS
	08-20-50-09	1989-04	31.9t 20/40 sand	1.0	0.0	0.0	ROD REPAIR, STILL RECOVERING			-	-	-	
	12-29-50-09	1989-03	50t of 20/40 sand	8.0	100.0	12.5	20.0	190.0	9.5	20.0	190.0	9.5	SUCCESS TO PRESENT
	14-29-50-09	1984-05	5t of 20/40 sand	0.9	12.6	14.0	0.3	2.6	8.7	0.6	3.5	5.8	FAILURE
	08-30-50-09	1988-04	50t of 20/40 sand	0.0	0.0	-	4.5	0.9	0.2	4.5	0.9	0.2	SUCCESS TO PRESENT
			TOTAL	13.9	143.4	10.3	34.5	234.0	6.8	35.1	235.7	6.7	
			WELL AVERAGE	2.0	20.5	10.3	4.9	39.1	7.9	5.0	33.7	6.7	

AREA	LOCATION	DATE	SIZE	PRETRAC OIL	PRETRAC GAS(E3)	PRETRAC GOR	POSTFRAC* OIL	POSTFRAC* GAS(E3)	POSTFRAC* GOR	PRESENT OIL	PRESENT GAS(E3)	PRESENT GOR	COMMENTS
PECU #2	16-10-48-03	1985-09	35t of 20/40 sand	0.0	0.0	-	1.0	4.0	4.0	0.7	2.8	4.0	SUCCESS**
	06-13-48-04	1985-08	35t of 20/40 sand	0.1	0.1	1.0	1.2	0.5	0.4	0.6	0.4	0.7	SUCCESS
	08-13-48-04	1985-08	35t of 20/40 sand	0.2	0.1	0.5	1.8	1.3	0.7	2.0	0.8	0.4	SUCCESS**
	14-13-48-04	1985-08	35t of 20/40 sand	0.1	0.2	2.0	2.0	3.5	1.8	0.7	3.1	4.4	SUCCESS
	06-14-48-04	1987-08	35t of 20/40 sand	0.2	0.3	1.5	1.3	0.8	0.6	2.0	0.6	0.3	SUCCESS
	14-21-48-04	1985-02	35t of 20/40 sand	0.2	0.1	0.5	1.0	0.6	0.6	0.8	0.3	0.4	SUCCESS
	16-22-48-04	1986-08	35t of 20/40 sand	0.4	0.1	0.3	1.6	1.4	0.9	1.3	1.4	1.1	SUCCESS
	14-22-48-04	1987-08	21.7t 20/40 sand	0.1	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	FAILURE
	14-27-48-04	1985-08	35t of 20/40 sand	0.3	0.5	1.7	1.0	1.0	1.0	1.0	0.8	0.8	SUCCESS**
	06-28-48-04	1986-06	50t of 20/40 sand	0.1	0.1	1.0	1.4	0.9	0.6	1.7	1.3	0.8	SUCCESS**
	08-28-48-04	1986-08	35t of 20/40 sand	0.1	0.1	1.0	1.0	1.0	1.0	1.3	2.0	1.5	SUCCESS**
	14-04-49-04	1985-03	35t of 20/40 sand	0.0	0.0	-	1.0	0.7	0.7	1.4	0.3	0.2	SUCCESS**
	16-08-49-04	1987-09	50t of 20/40 sand	0.1	0.1	1.0	1.0	1.1	1.1	1.1	1.3	1.2	SUCCESS**
	14-09-49-04	1987-08	50t of 20/40 sand	0.2	0.2	1.0	1.5	1.5	1.0	2.5	1.5	0.6	SUCCESS**
	06-15-49-04	1987-07	50t of 20/40 sand	0.3	0.1	0.3	0.7	0.7	1.0	2.0	0.9	0.3	SUCCESS
	14-15-49-04	1987-08	22.7t 20/40 sand	0.2	0.1	0.5	2.0	0.7	0.4	2.0	0.6	0.3	SUCCESS**
	08-17-49-04	1987-09	22.7t 20/40 sand	0.1	0.1	1.0	0.6	0.4	0.7	0.5	0.3	0.6	FAILURE
	16-19-49-04	1985-03	35t of 20/40 sand	0.3	0.3	1.0	3.1	1.2	0.4	1.9	0.8	0.4	SUCCESS**
	08-20-49-04	1986-06	50t of 20/40 sand	0.1	0.1	1.0	0.1	0.1	1.0	0.1	0.1	1.0	FAILURE
			TOTAL	3.1	2.6	0.8	24.2	22.2	0.9	23.7	19.3	0.8	
			WELL AVERAGE	0.2	0.1	0.8	1.3	1.2	0.9	1.2	1.0	0.8	

* BASED ON PRODUCTION ONE YEAR LATER

** WITH WELLHEAD COMPRESSION

ALL RATES ARE IN CUBIC METRES PER DAY

FIGURE 5

PRODUCTION AREA SUMMARY

AREA	# FRACS	PREFRAC OIL	PREFRAC WATER	PREFRAC WOR	POSTFRAC* OIL	POSTFRAC* WATER	POSTFRAC* WOR	PRESENT OIL	PRESENT WATER	PRESENT WOR
PECU #1	21.0	42.0	80.1	1.9	71.5	125.4	1.8	44.3	99.5	2.2
PECU #2	19.0	3.1	0.0	0.0	24.2	0.0	0.0	23.7	0.0	0.0
MAPCU #1	11.0	15.2	7.6	0.5	32.9	17.0	0.5	21.5	17.5	0.8
PULCU #1	7.0	13.9	143.4	10.3	34.5	234.0	6.8	35.1	235.7	6.7
100%	25.0	24.3	24.1	1.0	71.3	48.0	0.7	39.7	40.3	1.0
TOTAL	83.0	98.5	255.2	2.6	234.4	426.8	1.8	164.3	393.0	2.4

*BASED ON PRODUCTION ONE YEAR LATER

FIGURE 6
ECONOMIC CONSOLIDATION SUMMARY OF FRACTURE STIMULATIONS*
AFTER INCOME TAX

YEAR	# FRACS	LIFE (YEARS)	CAPITAL (E3 $)	NPV @ 12% (E3 $)	NPV @ 18% (E3 $)	PAYOUT (YRS)	DISC PO (YRS)	R OF R (PCT)	INCREMENTAL PROD. (00 M3)
1985	20	5.50	854.7	1757.0	1567.2	0.63	0.68	253.9	36000
1986	18	5.42	800.0	1841.9	1628.5	0.79	0.86	211.09	50600
1987	26	7.50	1202.0	1468.2	1215.2	1.21	1.42	93.37	50000
1988	19	7.00	919.0	772.6	614.6	1.58	1.84	64.08	40400
TOTAL	83	-	3775.7	5839.7	5025.5	-	-	-	177000
AVE.	-	6.45	45.5	70.36	60.5	1.06	1.22	150.89	2130

* SINCE THERE WERE ONLY 2 FRACS DONE IN 1984 & 3 FRACS DONE IN 1989, THEIR ECONOMICS WERE CONSOLIDATED WITH 1985 & 1988 RESPECTIVELY.

PEMBINA FIELD (1984-89)

Figure 7

FRAC LIFE DETERMINATION
30 1984 STIMULATION

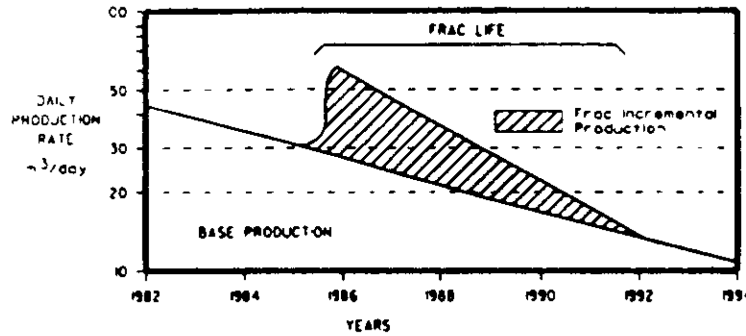


Figure 8

EFFECT on WOR
30 1984 STIMULATION

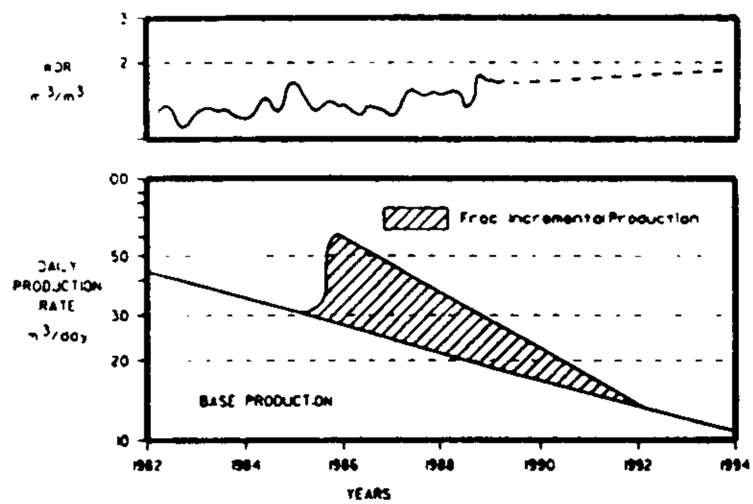


Figure 9

LONG TERM DECLINE EFFECTS
12 1979 STIMULATION

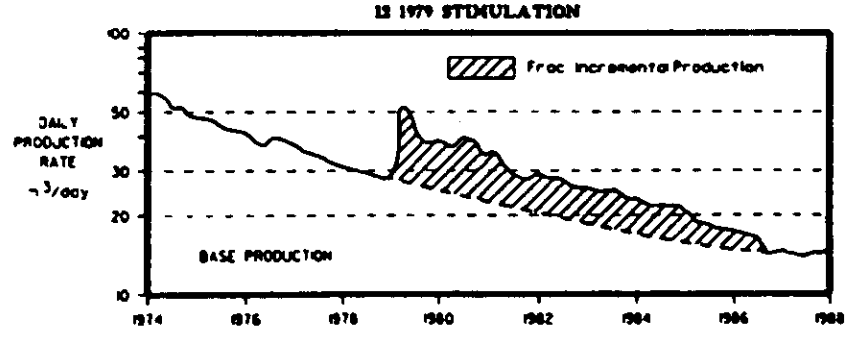


Figure 10

ORIGINAL PEMBINA
DEVELOPMENT

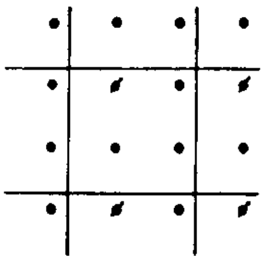


Figure 11

NORMAL PEMBINA
INFILL DEVELOPMENT

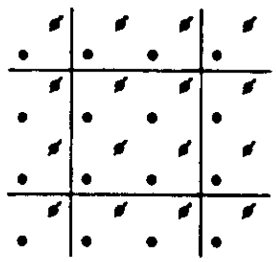


Figure 12

Equation 1 DARCY'S LAW

$$\frac{q}{a} = \frac{-k}{\mu}\frac{dp}{dx}$$

where

- q : volumetric flow rate cm^3/sec.
- a : cross sectional area cm^2
- k : permeability darcies
- μ : viscosity centipoises
- $\frac{dp}{dx}$: pressure gradient atmospheres/centimetre
- $\frac{q}{a}$: apparent velocity cm/sec.

Equation 2 WATERFLOOD

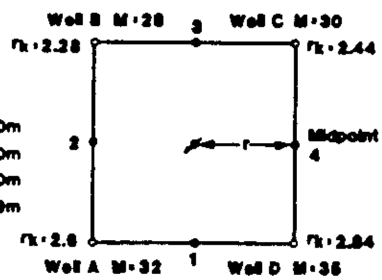
$$\frac{f}{M} = \frac{1}{r_k} \times \frac{P_I - P_p}{r}$$

where

- f : injector - flood front advance m
- r : injector - producer distance m
- M : time to breakthrough months
- P_I : injection pressure kPa
- P_p : production pressure kPa
- $\frac{f}{M}$: apparent velocity of flood front m/month
- $\frac{P_I - P_p}{r}$: interwell pressure gradient kPa/m
- r_k : reservoir coefficient (month x kPa)/m²

Figure 13 DETERMINATION OF MIDPOINT FLOOD FRONT ADVANCE

FIVE SPOT PATTERN



Midpoint
- 1 : 290m
- 2 : 290m
- 3 : 290m
- 4 : 288m

Let
- r : 424 m
- M : varies
- P_I : 30,000
- P_r : 20,000
- r_k : varies

$$f = \frac{(P_I - P_r)\,M}{r_k \times r}$$

For Midpoint 1

$$f = \frac{(30{,}000 - 20{,}000)\ 33.5}{2.72 \times 474} = 290$$

Figure 15 FLOOD FRONT ADVANCE MULTIPLIERS (9 SPOT 160 ACRES)

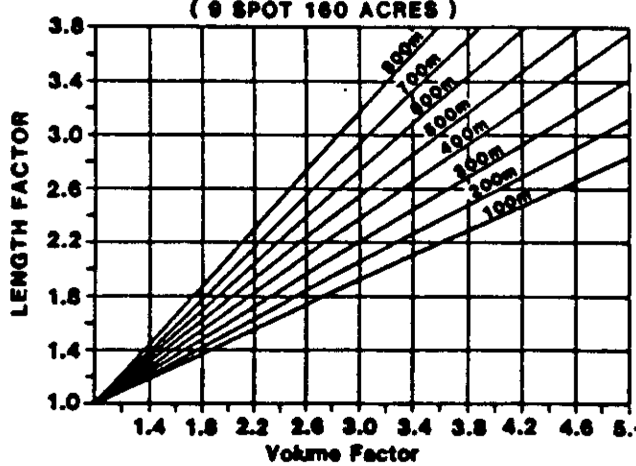
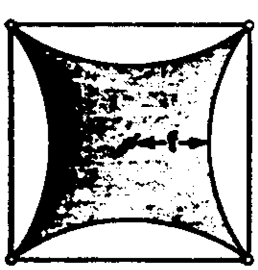


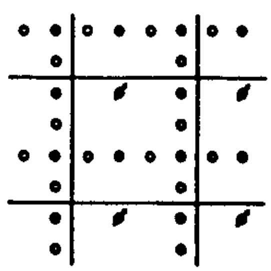
Figure 14 WATERFLOOD "STAR" FOR THE 5 SPOT EXAMPLE



Waterflood "STAR" Limit of the Reservoir Effected by water.

Figure 16

MODIFIED PEMBINA
INFILL DEVELOPMENT
FOR A 160 ACRE 9 SPOT



MODIFIED PEMBINA
INFILL DEVELOPMENT
FOR AN 80 ACRE 5 SPOT

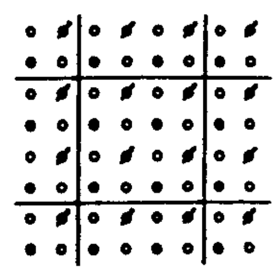


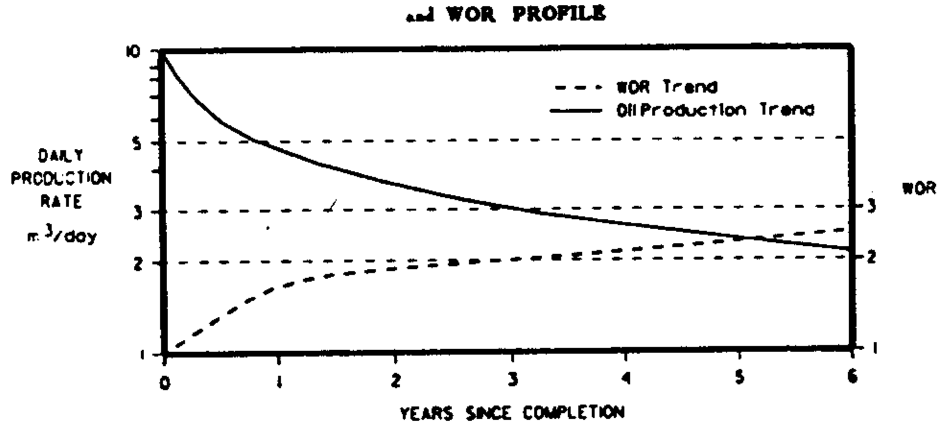
FIGURE 18

ECONOMIC CONSOLIDATION SUMMARY OF INFILL DRILLED WELLS AFTER INCOME TAX

YEAR	# INF.W.	LIFE (YEARS)	CAPITAL (E3 $)	NPV @ 12% (E3 $)	NPV@ 18% (E3 $)	PAYOUT (YRS)	DISC. C. FLOW/ DISC.INV.	R OF R (PCT)	TOTAL RES. (E3M3)	$/M3
1981	1	6.83	401.3	-78.2	-246.8	4.16	-0.18	7.62	3.8	105.6
1983	1	13.92	150.0	1057.6	1248.8	0.54	3.08	369.35	10.5	14.3
1984	6	11.75	2240.8	1322.8	1097.6	2.2	0.29	36.16	41.8	53.6
1985	12	15.25	4816.0	6091.2	5602.0	1.31	0.68	72.07	147.6	32.6
1986	5	13.75	2055.7	-269.6	-567.2	4.62	-0.11	10.10	27.6	74.5
1987	4	19.56	1220.8	4486.0	3801.0	0.75	3.2	250.0	91.1	13.4
1989	4	16.19	1572.1	249.2	-71.1	5.8	0.26	16.5	38.2	41.2
TOTAL	33	-	12456.7	12859.0	10864.3	-	-	-	360.6	34.5
AVE.	-	14.97	377.5	389.7	329.2	2.51	1.6	38.00	10.93	34.5

Figure 19

TYPICAL INFILL WELL PRODUCTION and WOR PROFILE



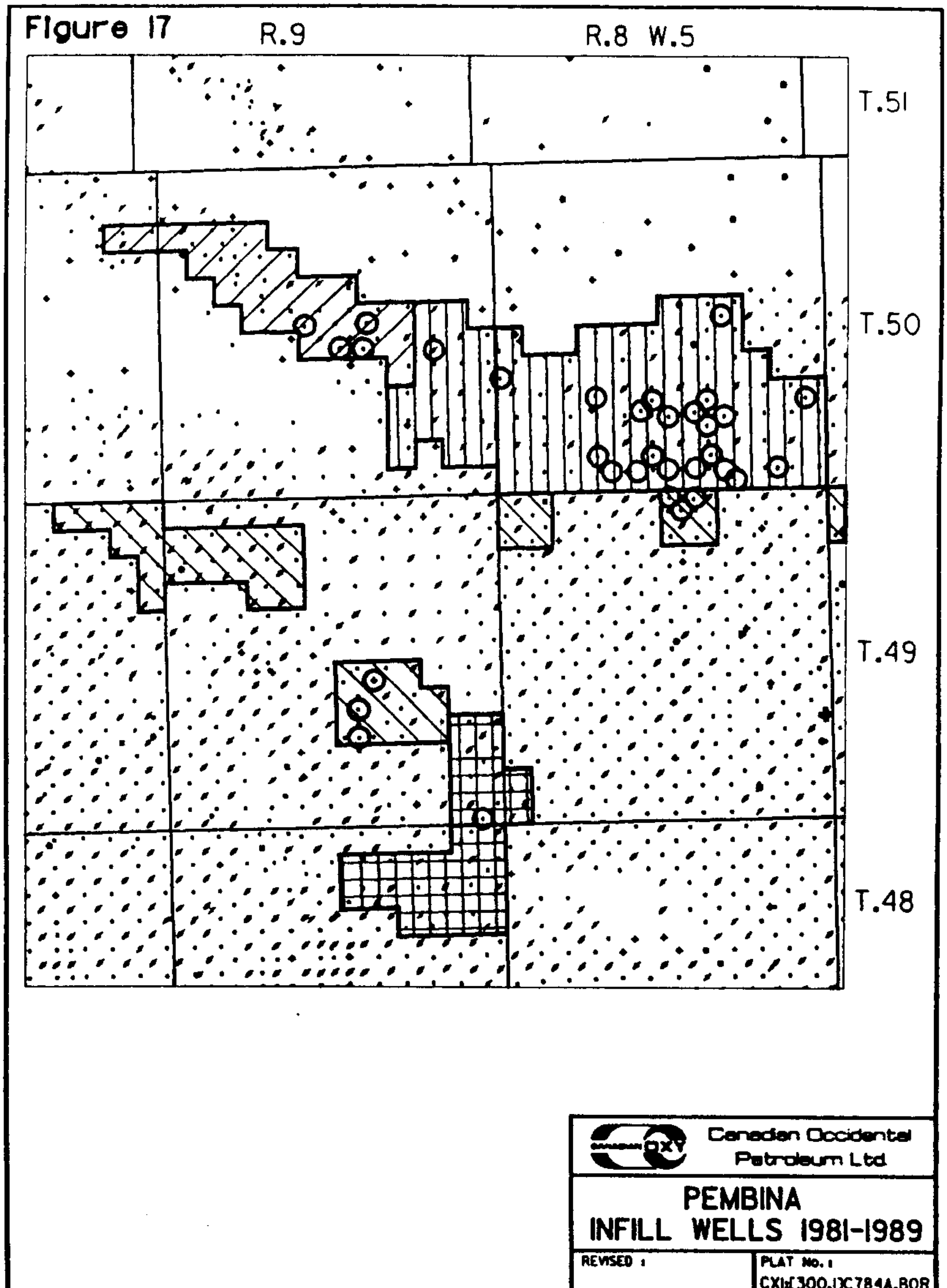


Figure 17
R.9
R.8 W.5
T.51
T.50
T.49
T.48
Canadian Occidental
Petroleum Ltd
PEMBINA
INFILL WELLS 1981-1989
REVISED :
PLAT No. :
CXI:[300,1]C784A.BOR

FIGURE 20

COPL INFILL DRILLING POST AUDIT - PEMBINA (AS OF 1988-08)

AREA	LOCATION	O.C DATE	STATUS	INITIAL OIL	INITIAL WATER	INITIAL WOR	POST* OIL	POST* WATER	POST* WOR	PRESENT OIL	PRESENT WATER	PRESENT WOR
PECU #1	05-01-50-08	1986-11	OIL PRODUCER	4.0	6.1	1.5	2.1	3.1	1.5	0.0	0.0	1.0
	03-02-50-08	1985-12	OIL PRODUCER	22.8	3.8	0.2	13.3	4.5	0.3	8.6	4.8	0.6
	05-02-50-08	1985-12	OIL PRODUCER	17.7	9.2	0.5	10.6	4.8	0.5	2.8	7.6	2.7
	05-03-50-08	1985-12	OIL PRODUCER	9.1	15.1	1.7	3.2	7.6	2.4	1.1	5.2	4.7
	07-03-50-08	1985-12	OIL PRODUCER	20.7	2.4	0.1	9.0	2.5	0.3	6.0	2.6	0.5
	09-03-50-08	1985-12	OIL PRODUCER	8.2	23.8	2.9	3.7	16.8	4.5	2.4	16.1	6.7
	05-04-50-08	1985-12	OIL PRODUCER	14.8	6.4	0.4	3.6	3.0	0.8	2.5	4.0	1.6
	07-04-50-08	1985-12	OIL PRODUCER	12.5	10.3	0.8	4.6	7.2	1.6	2.6	8.5	3.3
	09-04-50-08	1985-12	OIL PRODUCER	8.9	14.4	1.6	1.7	8.1	4.8	1.1	8.2	7.5
	09-05-50-08	1985-12	OIL PRODUCER	9.2	15.2	1.7	2.4	6.2	2.6	1.5	6.3	4.2
	09-08-50-08	1983-01	OIL PRODUCER	9.1	5.0	0.5	3.5	7.0	2.0	2.4	9.0	3.8
	07-09-50-08	1986-11	OIL PRODUCER	6.2	15.5	2.5	1.2	4.9	4.1	1.8	9.6	5.3
	09-09-50-08	1985-12	OIL PRODUCER	12.4	13.1	1.1	5.2	8.2	1.6	2.5	7.2	2.9
	01-10-50-08	1985-12	OIL PRODUCER	12.6	11.6	0.9	4.4	10.7	2.4	2.1	9.6	4.6
	05-10-50-08	1986-11	OIL PRODUCER	8.6	7.0	0.9	3.4	6.1	1.8	2.1	4.5	2.1
	07-10-50-08	1986-11	OIL PRODUCER	10.5	7.8	0.7	7.0	6.3	0.9	2.6	8.8	3.4
	09-10-50-08	1985-12	OIL PRODUCER	5.2	8.1	1.6	1.0	2.1	2.1	0.8	1.7	2.1
	05-11-50-08	1986-11	OIL PRODUCER	5.9	5.1	0.9	1.6	5.4	3.4	1.7	3.6	2.1
	10-12-50-08	1986-11	SHUT IN	8.8	6.0	0.7	3.4	1.1	0.3	-	-	-
	06-18-50-08	1981-06	OIL PRODUCER	6.5	4.8	1.1	2.8	4.1	1.5	0.6	6.1	10.2
	04-23-50-08	1986-12	OIL PRODUCER	7.2	10.1	1.4	3.0	2.8	0.9	2.1	0.8	0.4
	09-14-50-09	1986-12	SHUT IN	3.0	29.6	9.9	-	-	-	-	-	-
			TOTAL	221.7	231.2	1.0	90.5	122.5	1.4	46.9	125.0	2.7
			WELL AVERAGE	10.1	10.5	1.0	4.1	5.6	1.4	2.1	5.7	2.7
100 S (D)	11-10-49-09	1987-06	OIL PRODUCER	19.1	0.0	0.0	7.1	0.0	0.0	5.7	0.0	0.0
	03-15-49-09	1987-06	OIL PRODUCER	8.2	6.1	0.7	2.9	1.5	0.5	1.5	0.7	0.5
	10-15-49-09	1987-01	OIL PRODUCER	13.1	0.0	0.0	6.3	0.0	0.0	5.5	0.2	0.0
(E)	11-34-49-08	1989-01	OIL PRODUCER	5.2	15.6	3.0	2.4	6.8	2.8	2.4	0.2	0.1
	13-34-49-08	1989-01	OIL PRODUCER	6.8	10.6	2.7	3.6	8.2	2.3	3.6	0.2	2.3
	15-34-49-08	1989-01	OIL PRODUCER	7.3	12.4	1.7	6.2	9.6	2.3	4.2	9.6	2.3
			TOTAL	55.7	52.7	0.9	26.5	26.1	1.0	22.9	18.9	0.8
			WELL AVERAGE	9.3	8.8	0.9	4.4	4.4	1.0	3.8	3.2	0.8
MAPCU #1	02-01-49-09	1986-02	OIL PRODUCER	12.5	0.0	0.0	2.7	0.1	0.0	1.6	0.2	0.1
PELCU #1	10-15-50-09	1986-11	OIL PRODUCER	6.6	0.0	1.2	4.8	7.2	1.5	1.9	9.7	5.1
	12-15-50-09	1986-11	OIL PRODUCER	6.1	0.5	0.1	1.9	0.5	0.3	3.0	1.6	0.5
	02-21-50-09	1987-01	OIL PRODUCER	20.6	0.1	0.0	16.8	0.2	0.0	7.2	1.0	0.1
	02-22-50-09	1989-04	OIL PRODUCER	15.8	19.1	1.2	15.8	19.1	1.2	15.8	19.1	1.2
			TOTAL	49.1	27.7	0.6	39.3	27.0	0.7	27.9	31.4	1.1
			WELL AVERAGE	12.3	6.9	0.6	9.8	6.8	0.7	7.0	7.9	1.1

* BASED ON PRODUCTION ONE YEAR LATER

ALL RATES ARE IN CUBIC METRES PER DAY

FIGURE 21

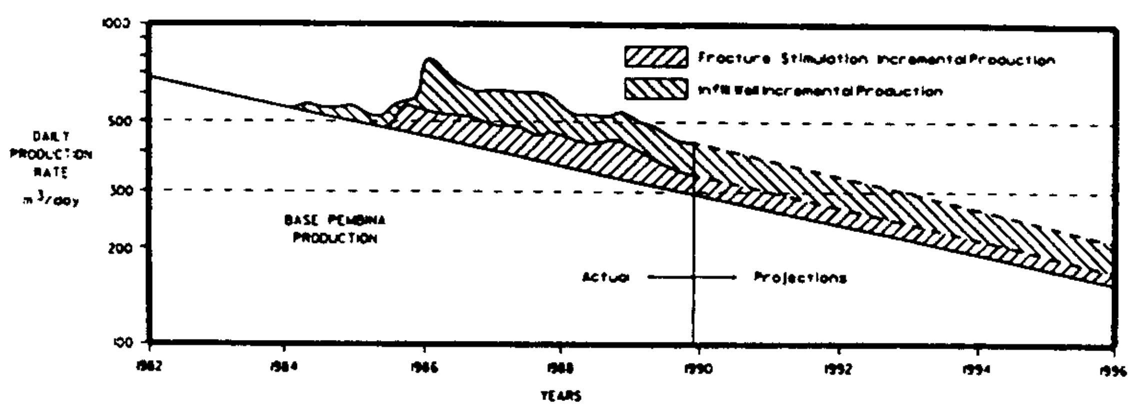
PRODUCTION AREA SUMMARY

AREA	# INF.W.	INITIAL OIL	INITIAL WATER	INITIAL WOR	POST* OIL	POST* WATER	POST* WOR	PRESENT OIL	PRESENT WATER	PRESENT WOR
PECU #1	22.0	221.7	231.2	1.0	90.5	122.5	1.4	46.9	125.0	2.7
TODL	6.0	55.7	52.7	0.9	26.5	26.1	1.0	22.9	18.9	0.8
BMPCU #1	1.0	12.5	0.0	0.0	2.7	0.1	0.0	1.6	0.2	0.1
PBLCU #1	4.0	49.1	27.7	0.6	30.3	27.0	0.7	27.9	31.4	1.1
TOTAL	33.0	339.0	311.6	0.9	159.0	175.7	1.1	99.3	175.5	1.8

*BASED ON PRODUCTION ONE YEAR LATER

Figure 22

PEMBINA REVITALIZATION RESULTS



OMEGA

September 18, 1990

Manitoba Energy and Mines
Mineral Resources Division
975 Century Street
Winnipeg, Manitoba
R3H 0W4

Gentleman:

Re: Proposed Reduced Spacing Application
Waskada Area, Manitoba
OHL File: T-49-90

Please be advised that I have no objection to Omega Hydrocarbons Ltd. making application for the use of reduced drilling spacing units on my land as indicated below.

Land: SW 24-1-26 WPM

My consent to this application is subject to Omega Hydrocarbons Ltd., providing a satisfactory well development plan to me.

Witness

D. E. McGregor
Donald E. McGregor

~~Edmund A. McGregor~~

~~Mary Elizabeth McGregor~~

Box [redacted] 33
Waskada, Manitoba
R0M 2E0
Telephone: 673-2578

OMEGA

September 18, 1990

Manitoba Energy and Mines
Mineral Resources Division
975 Century Street
Winnipeg, Manitoba
R3H 0W4

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Land: SE 23-1-26 WPM

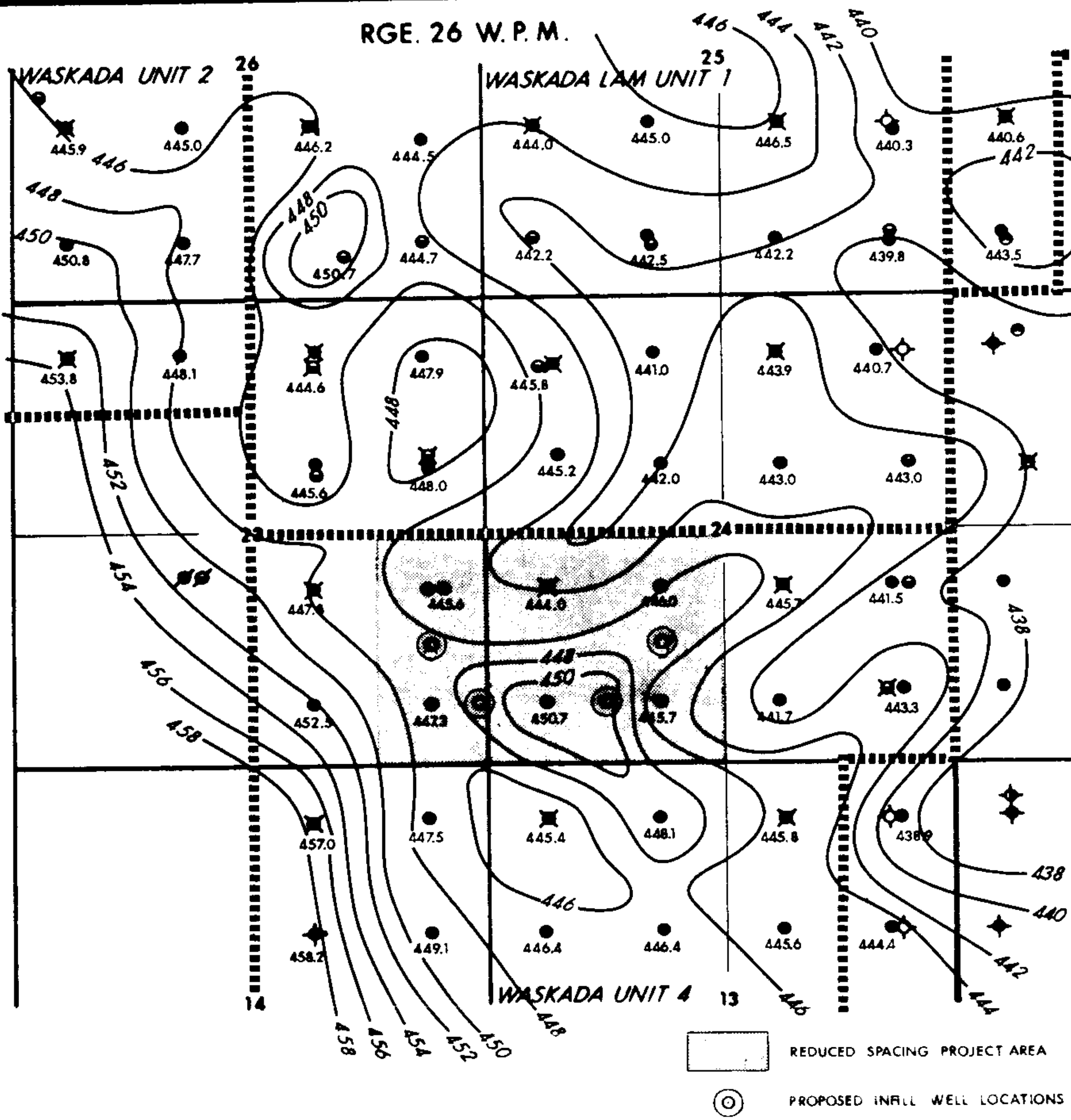
My consent to this application is subject to Omega Hydrocarbons Ltd., providing a satisfactory well development plan to me.

Witness

Joyce Hainsworth
Joyce E. Hainsworth

R.J. Hainsworth
Roland Hainsworth

Box 99
Waskada, Manitoba
ROM 2E0
Telephone: 673-2638

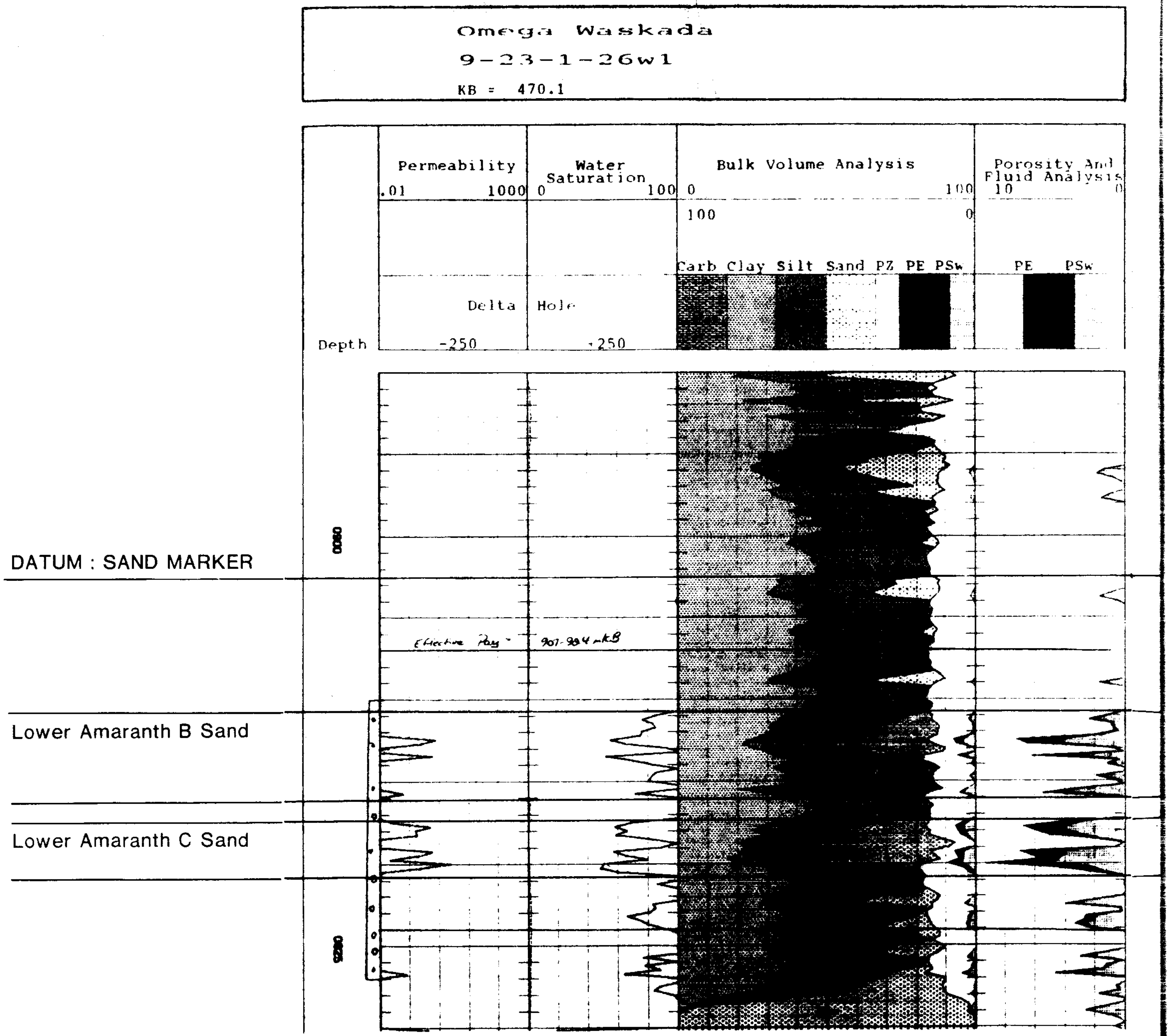


OMEGA HYDROCARBONS LTD

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT

Lower Amaranth Structure Map

Scale:		Date: Sept /90	
Geology: DAC		Contour Interval: 2 m	
Revised:		File:	Drafting: PAB

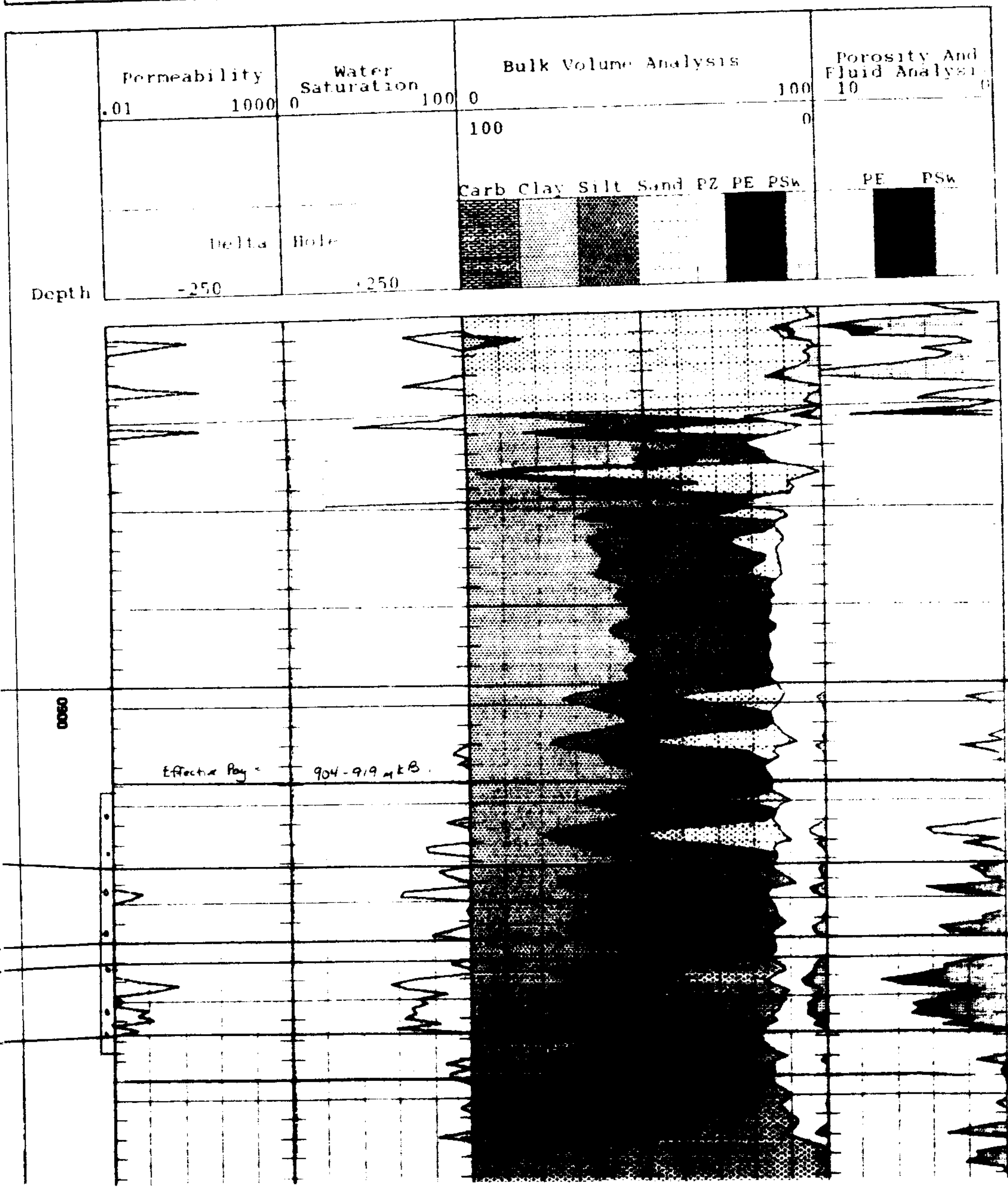


ø h - 0.840 Cum. Oil. - 10,673 m3 Cum. Wtr. - 32,548 m3 On Prod'n. - Aug. 1982

Omega Waskada

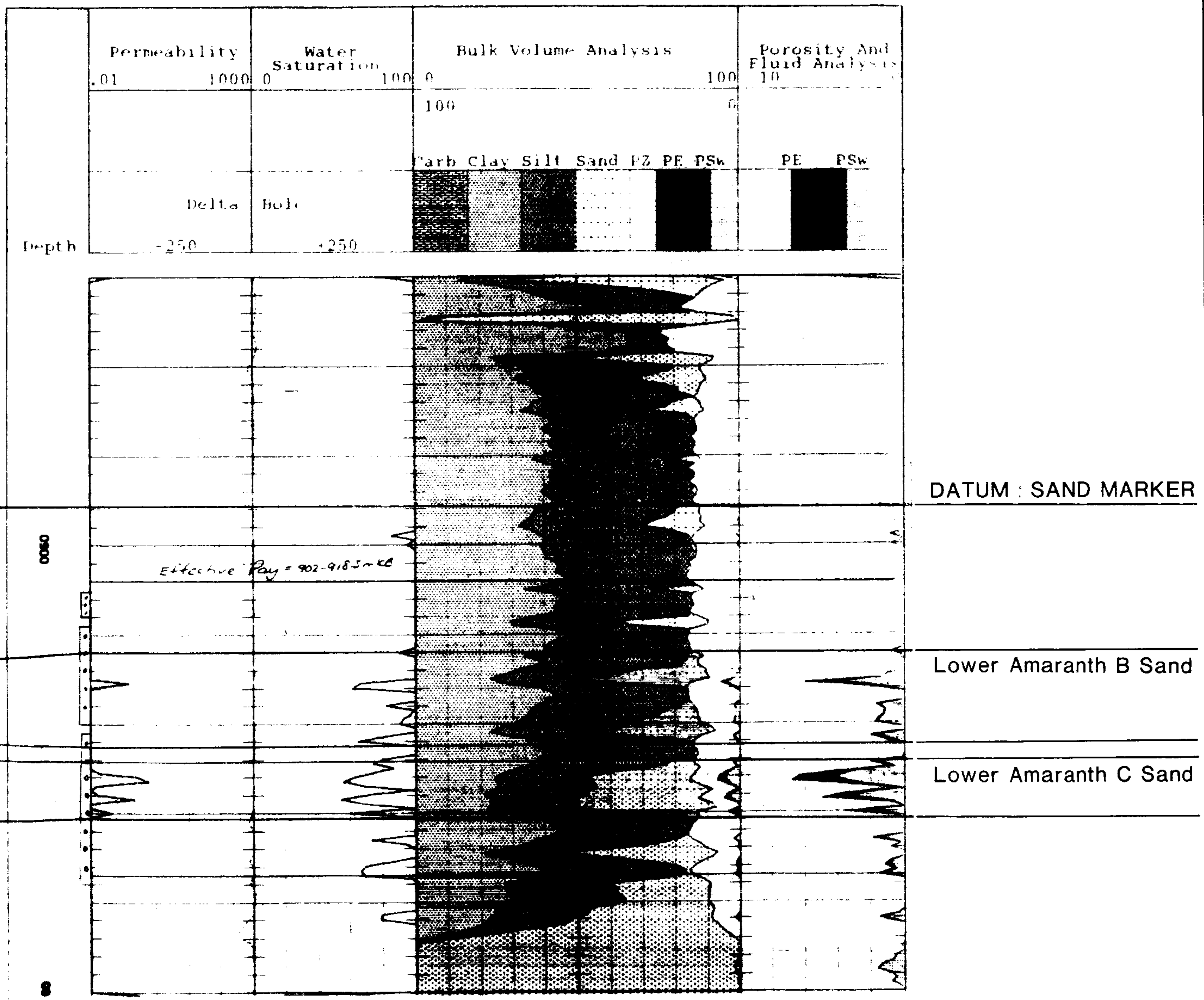
12-24-1-26w1

KB = 468.1



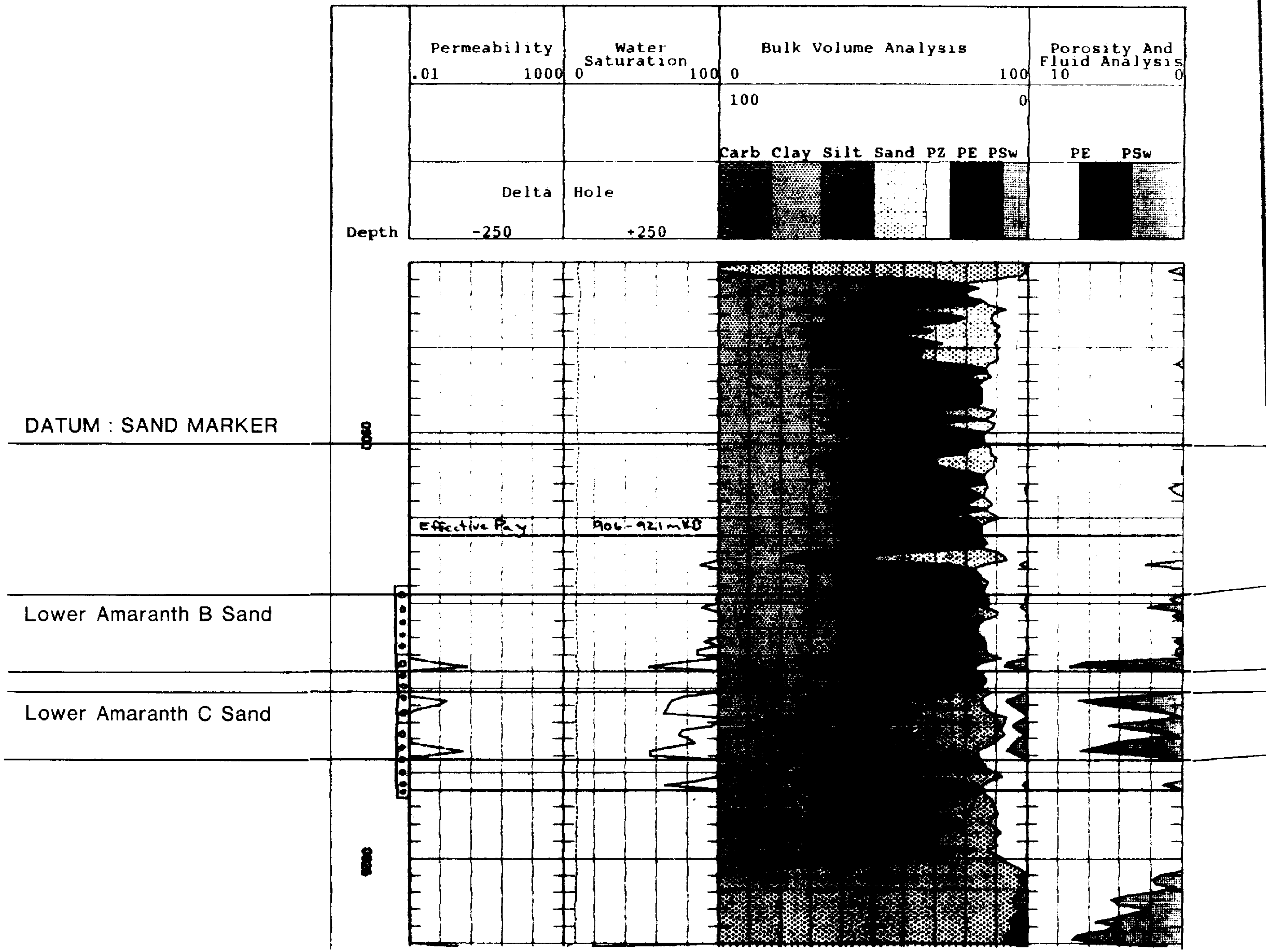
ø h = 0.663 Cum. Oil = 13,954 m3 Cum. Wtr. = 6709 m3 On Prod'n. = Dec. 1982

Omega Waskada
11-24-1-26w1
KB = 470.3

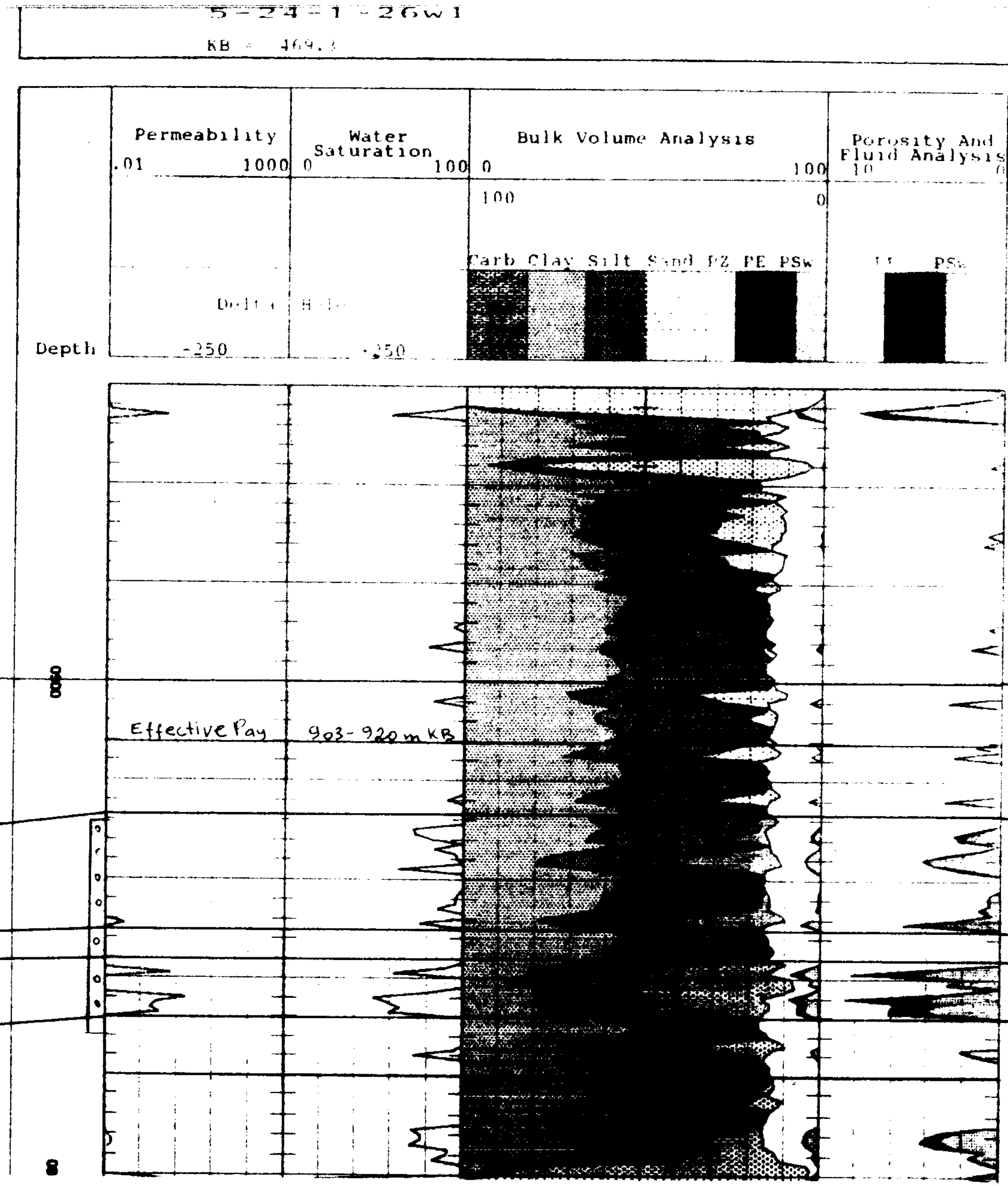


ø h - 0.426 Cum Oil - 4096 m3 Cum. Wtr - 354 m3 On Prod'n. - March 1982

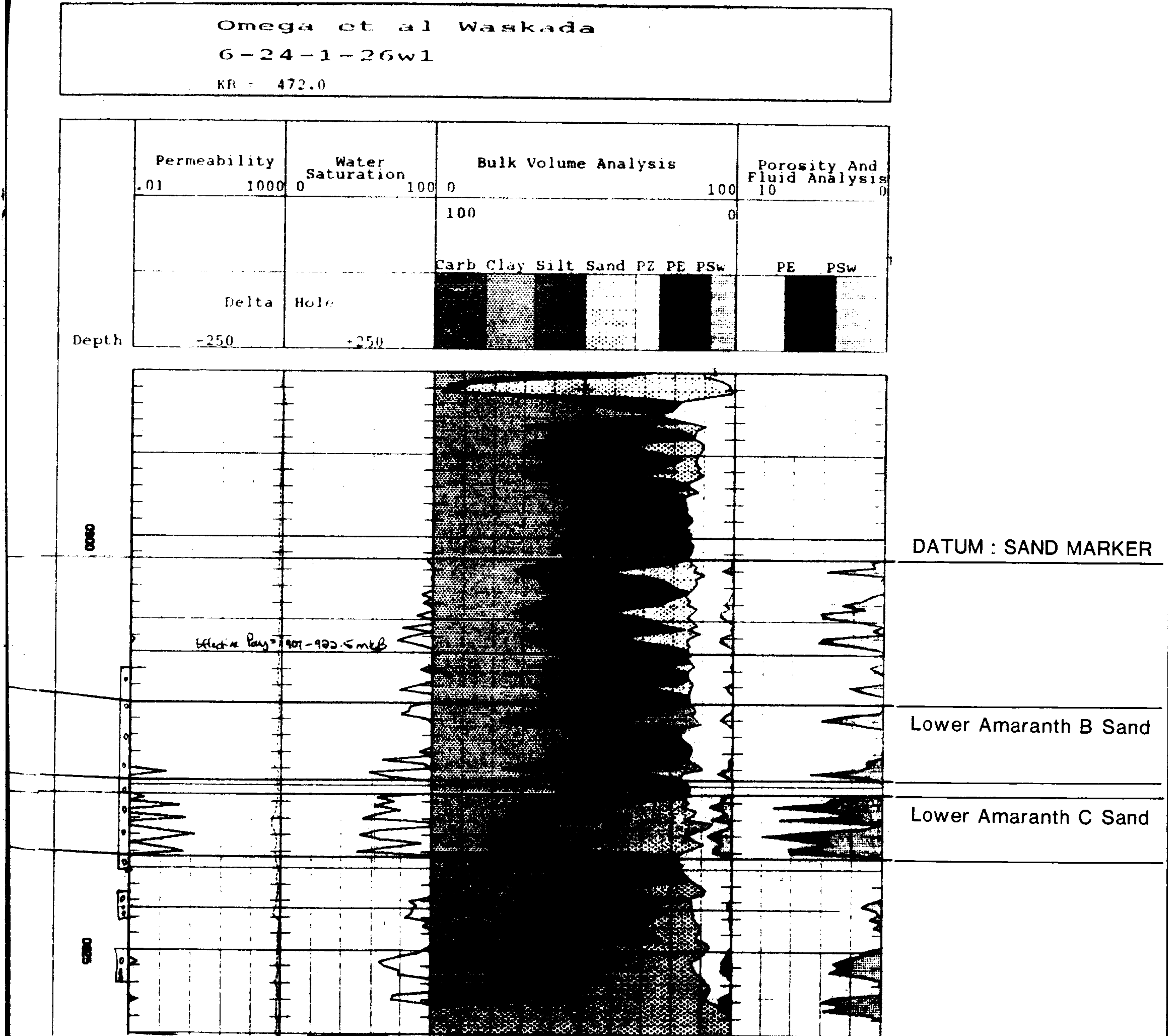
Omega WAskada
8A-23-1-26w1
KB = 470.4



ø h - 0.518 Cum. Oil 5743 m3 Cum. Wtr. 20,685 m3 On Prod'n. - June 1983



ø h – 0.627 Cum. Oil – 2593 m3 Cum. Wtr – 2027 m3 Cum. Inj. – 65,874 m3 On Prod'n – July 1983 On Inj. – Apr. 1985

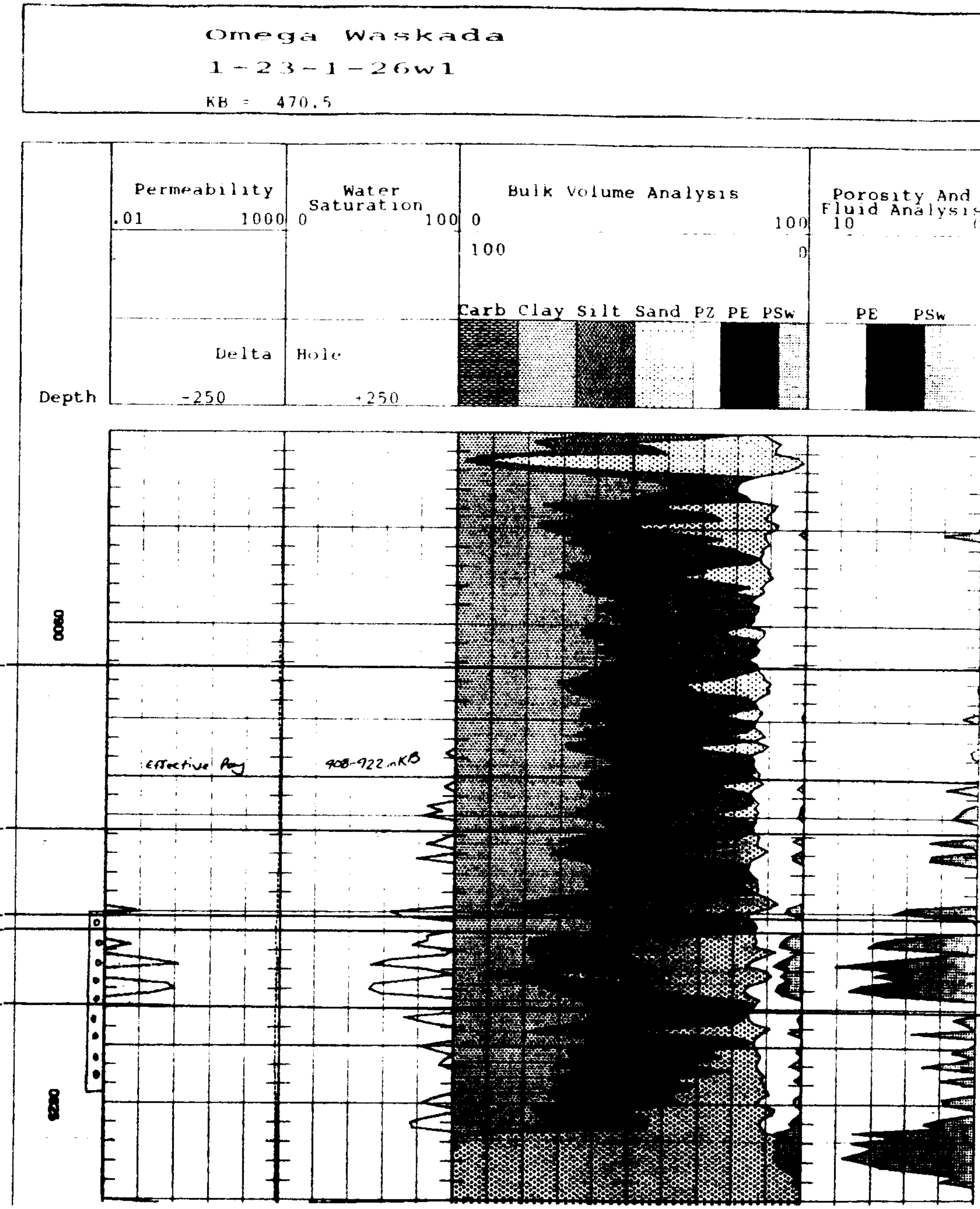


ϕh - 0.618 Cum. Oil - 5824 m3 Cum. Wtr.- 986 m3 On Prod'n. - July 1983

DATUM : SAND MARKER

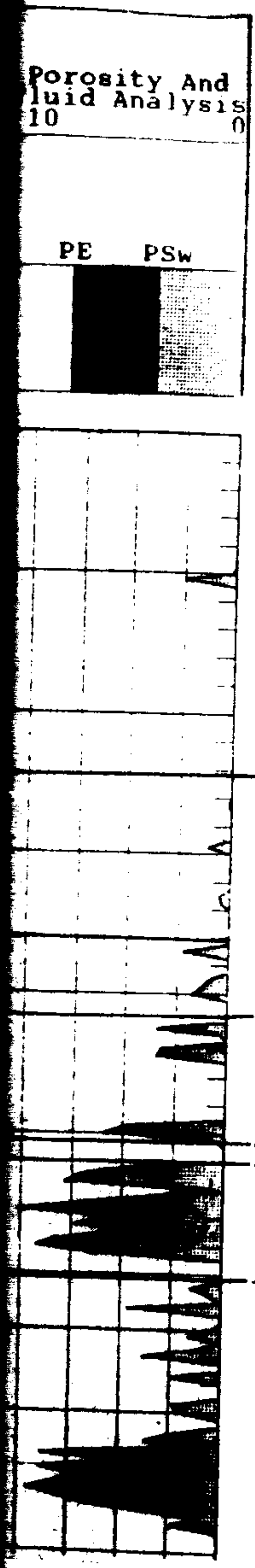
Lower Amaranth B Sand

Lower Amaranth C Sand

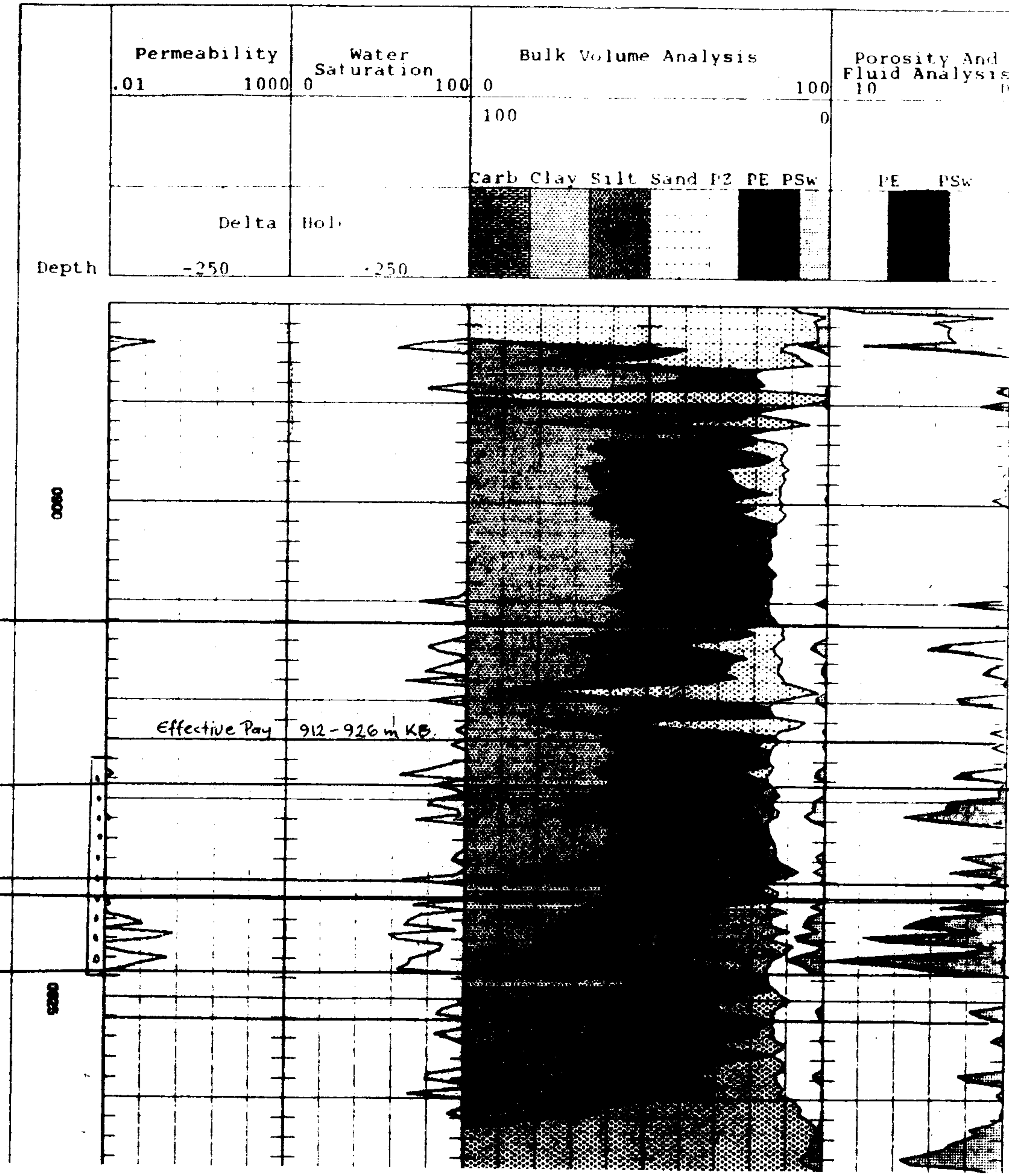


ø h - 0.675 Cum. Oil - 10,420 m3 Cum. Wtr. - 6813 m3 On Prod'n. - Aug. 1982

Omega Waskada
4-24-1-26w1
KB - 469.1



982

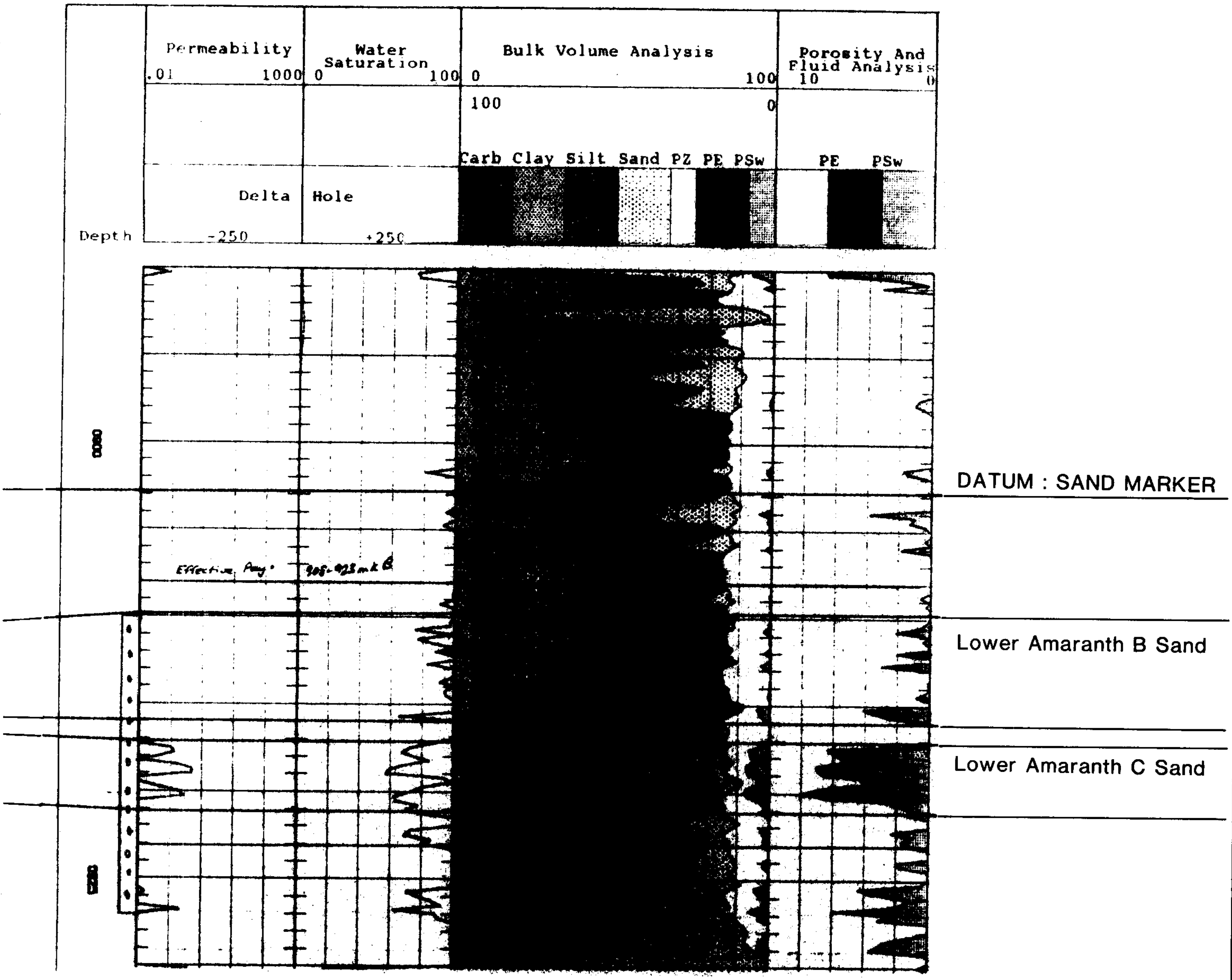


ø h - 0.704 Cum. Oil - 18,420 m3 Cum. Wtr. - 36,590 m3 On Prod'n. - July 1983

Omega et al Waskada

3-24-1-26w1

KB = 471.3



ø h – 0.749 Cum. Oil 10,975 m3 Cum. Wtr. – 24,047 m3

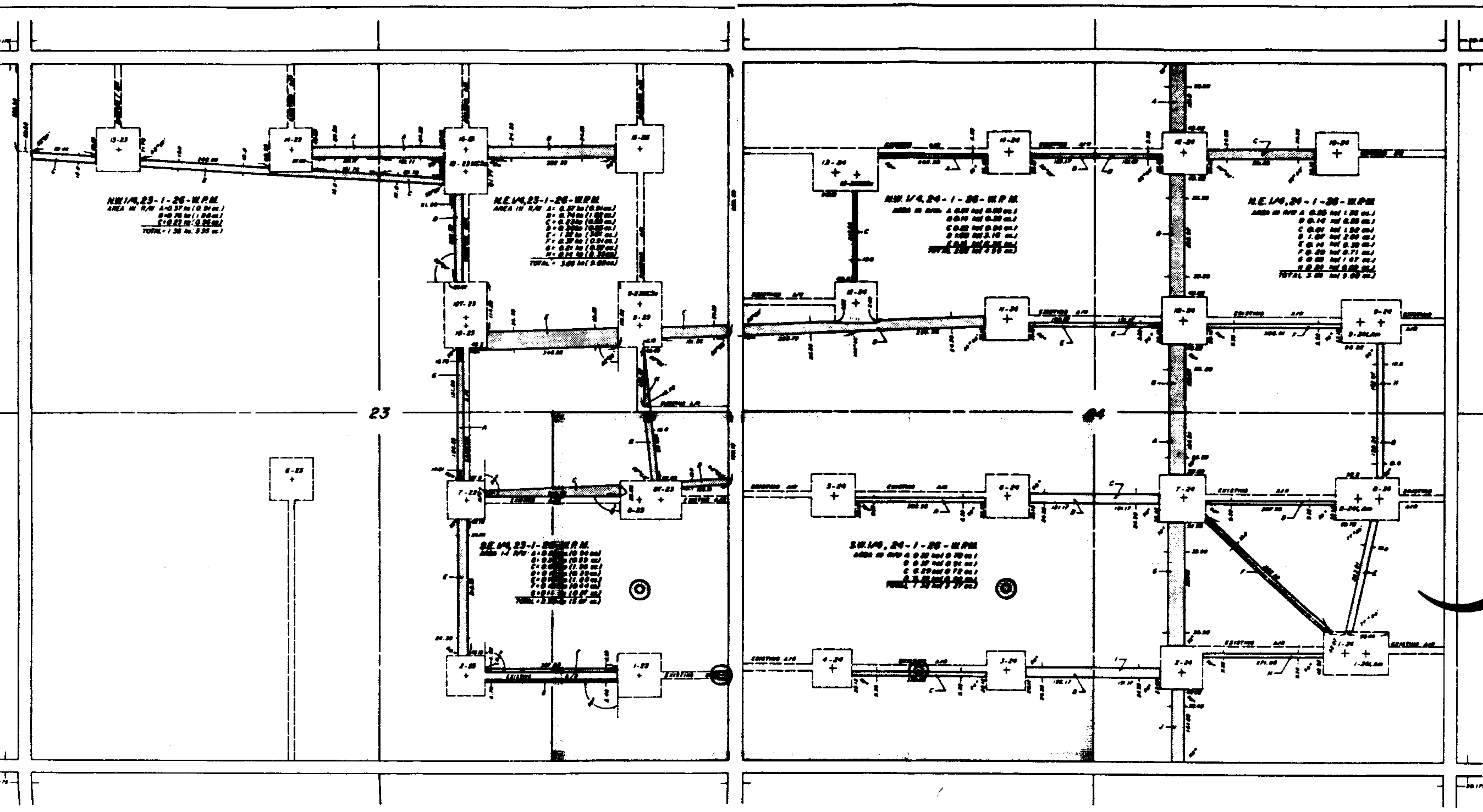
On Prod'n.-July 1983

OMEGA HYDROCARBONS LTD.

WASKADA LOWER AMARANTH
REDUCED SPACING PROJECT

PILOT AREA FENCE DIAGRAM

Scale: Not To Scale	Date: SEPTEMBER 1990
Geology:	Contour Interval:
Revised:	File: / Drafting:



OMEGA HYDROCARBONS LT

Flowline Composite Plan

Sec. 23 & 24, Twp. 1, Rge. 26, W.P.M

Scale: 1:10,000

OMEGA HYDROCARBONS LTD.

PROPOSED INFILL WELL LOCATIONS

REDUCED SPACING PROJECT AREA

OMEGA HYDROCARBONS LTD.			
WASKADA LOWER AMARANTH			
REDUCED SPACING PILOT PROJECT AREA MAP			
Scale: 1:10,000		Date: Sept./90	
Geology: R.B.		Contour Interval:	
Revised:		File:	Drafting: PAB.

OMEGA
[illegible]DROCARBONS [illegible]

[illegible] S[illegible]N[illegible] PLAZA III
[illegible] 4th AVENUE S.W.
[illegible]ALGARY ALBERTA CANADA [illegible]

TELEPHONE (403) 26[illegible]
FAX (403) 264-[illegible]

September 28, 1990

The Oil and Natural Gas
Conservation Board
Room 309 Legislative Building
450 Broadway Avenue
Winnipeg, Manitoba
R3C 0V8

Attention: Mr. Charles S. Kang
Chairman

Dear Sir:

Re: Waskada Lower Amaranth A Pool
Application for Drilling Spacing Unit Reduction

Pursuant to Section 20 of the Manitoba Petroleum Drilling and Production Regulations, Omega Hydrocarbons Ltd. hereby makes application to reduce the size of the existing drilling spacing units from 16 ha to 4 ha within the prescribed pilot project area and that the drilling target areas remain centrally located. Omega plans to drill four infill wells inside a pilot project area surrounding injection well 5-24-1-26 WPM. Engineering estimates indicate that the proposed drilling spacing unit reduction will increase the ultimate oil recovery within the injection pattern area from 23.3% OOIP (112,650 m^3) to 26.6% OOIP (128,924 m^3). Should this infill drilling pilot project prove economically successful, similar drilling spacing unit modifications may be considered in other parts of the Waskada field.

In accordance with the general content requirements of Section 115 of the Petroleum Drilling and Production Regulations, the following information is submitted in support of this application.

Reservoir Characteristics

The Waskada Lower Amaranth A pool is an undersaturated hydrocarbon system located at a depth of 900 mKB. The reservoir is vertically stratified as a result of thin interbedded shale stringers. Thus the oil producing sands are usually poorly developed with uniformly low porosities and permeabilities. Due to these reservoir characteristics it is necessary to fracture stimulate all Lower

Amaranth wells in order to achieve economic levels of production. The reservoir dips in a southwesterly direction with the initial oil-water contact estimated at 465 m subsea. The initial reservoir fluid has a bubble point pressure of 4220 kPa at a reservoir temperature of 45°C.

Currently most of the Lower Amaranth A pool is under pressure maintenance by water injection and the average reservoir pressure is 9000 kPa. The pressure maintenance projects operated by Omega were developed using an inverted nine spot injection pattern on 16 ha spacing. Since waterflooding was initiated the average oil production decline rate within the pressure maintenance areas has remained relatively constant at 15%/year. Current oil recovery factors calculated on an individual injection pattern basis vary between 2.4% and 18.3% of original oil in place. The large variance in recovery factors is directly related to reservoir quality and volumetric sweep efficiency. Using decline curve analysis the oil recovery factor for the Waskada field is estimated to be approximately 15 percent of the original oil in place.

Project Design

Upon review of the 1985 Waskada Reservoir Model Study it has been observed that there are trapped oil saturations which are not be recovered by waterflooding in the final predicted oil saturation maps. If this observation is extrapolated to the entire pool it becomes apparent that ultimate oil recoveries may be improved in the Waskada field by infill drilling.

An infill drilling pilot project area has been selected based on the following technical factors, i) above average reservoir quality ii) good reservoir continuity iii) a proven oil producing area iv) a low producing water/oil ratio and v) a single injection pattern area. A thorough review of the pool resulted in selecting the southern half of injection pattern 5-24-1-26 WPM for the reduced drilling spacing unit pilot project area. The locations for the four proposed infill wells were chosen between existing producers. This reduces the drilling risk by drilling outside the theoretical production streamlines for an inverted nine spot pattern and between suspected northeast-southwest fracture planes. Modifications to the existing injection system are not considered necessary at this time, plans are to use the existing injection wells to maintain reservoir pressure and replace voidage taken from the infill wells.

Production Forecasts

A base case forecast has been developed by using the production history for all wells contained in injection pattern 5-24-1-26 WPM. Oil production within the injection pattern is currently declining at 10%/year. Assuming an economic limit of 0.4 m^3/d per well and an original oil in place of 483708 m^3 for the total injection pattern area, current oil recovery is 16.8% OOIP and ultimate oil recovery is predicted to be 23.3 % OOIP.

The incremental production forecast for the proposed infill wells has been determined by using current production rates from offsetting wells and average incremental oil recovery estimates from the technical literature. Assuming an initial rate of 2.0 m^3/d per well, an economic limit of 0.4 m^3/d per well and incremental recoverable reserves per well of 4000 m^3 results in a 3.3% incremental pattern recovery and a 14%/year production decline for the infill wells. The assumptions used in this forecast may be conservative given that the average recoverable reserves per producing well under the base case forecast is 14,000 m^3 and that flush production is not taken into consideration.

Impact On Lessees, Lessors and Working Interest Owners

The proposed pilot project area is contained entirely within Waskada Unit No. 4 and does not encroach upon the unit boundary. Thus the proposed pilot project will have no detrimental effect on the correlative rights of offsetting royalty and working interest owners. Incremental oil production will be shared in an equitable fashion by all lessees and lessors in Waskada Unit No. 4 as per the Unit agreement. Benefits to the Crown will take the form of incremental Crown royalties and Freehold production taxes from the proposed infill wells.

Impact On Surface Landowners

It is Omega Hydrocarbons Ltd.'s intent to minimize agricultural impact and simultaneously maximize oil recovery. To maintain project viability the proposed infill wells will be drilled vertically and will be positioned on existing lease road allowances if applicable. Where an infill well location can not be drilled on an existing road allowance a new surface lease will be constructed and surface obstructions will be minimized through the use of non built up trails and production flowlines. Those surface lease owners effected by the pilot project were consulted and are in agreement that the previously mentioned considerations will have the least impact on existing farming operations.

Cost estimates indicate that directional drilling will increase the drilling and completion cost of a well by 20% or $30000/well compared to a conventional vertical well. Based on industry experience it is also known that higher production operating costs are associated with directionally drilled wells. The proposed infill well pilot project has an after tax rate of return of 25.3%

which is marginally economic considering the incremental oil recovery uncertainties. The increased capital and operating costs related to directional drilling further increase the economic risk associated with the project and therefore can not be economically justified at this time.

Infill Well Royalty/Production Tax Treatment

Based on our company's interpretation of the Manitoba Mines Act the four proposed infill wells will each qualify for an initial holiday oil volume. Following the depletion of the holiday oil volumes oil production from the subject wells shall be classified as new oil for the purpose of royalty and production tax calculations. This interpretation assumes that once the application for reduced spacing is approved each proposed infill well will become the only well in the drilling spacing unit in which the well is located.

Production Operations and Monitoring

The proposed infill wells will be operated in accordance with the Manitoba Petroleum Drilling and Production Regulations. Given that no injection well modifications are contemplated at this time, pressure maintenance operations will continue to be governed by Board Order No. PM58.

In further support of this application find attached the following information:

1) Pilot Project Area Map
2) Proposed Drilling Spacing Unit Diagram
3) Lessor Map of the Pilot Project Area
4) Lessee Map of the Pilot Project Area
5) Surface Landowners Map of the Pilot Project Area
6) Correspondence with Surface Landowners
7) Lower Amaranth Structure Map
8) Lower Amaranth Øh Map
9) Lower Amaranth Cumulative Oil Production Map
10) Lower Amaranth Cumulative Water Production Map
11) Pilot Project Area Fence Diagram
12) Injection Pattern 5-24-1-26 WPM OOIP Calculation
13) Injection Pattern 5-24-1-26 WPM Production History
14) Individual Well Production Histories (1-23, 8-23, 3-24, 4-24, 6-24)
15) Base Case and Infill Case Production Forecasts
16) Pilot Project Economics
17) Technical References

Should you have any comments or questions related to this application, please contact Mr. Richard Brekke at (403) 261-0743. We would appreciate your earliest attention to this matter.

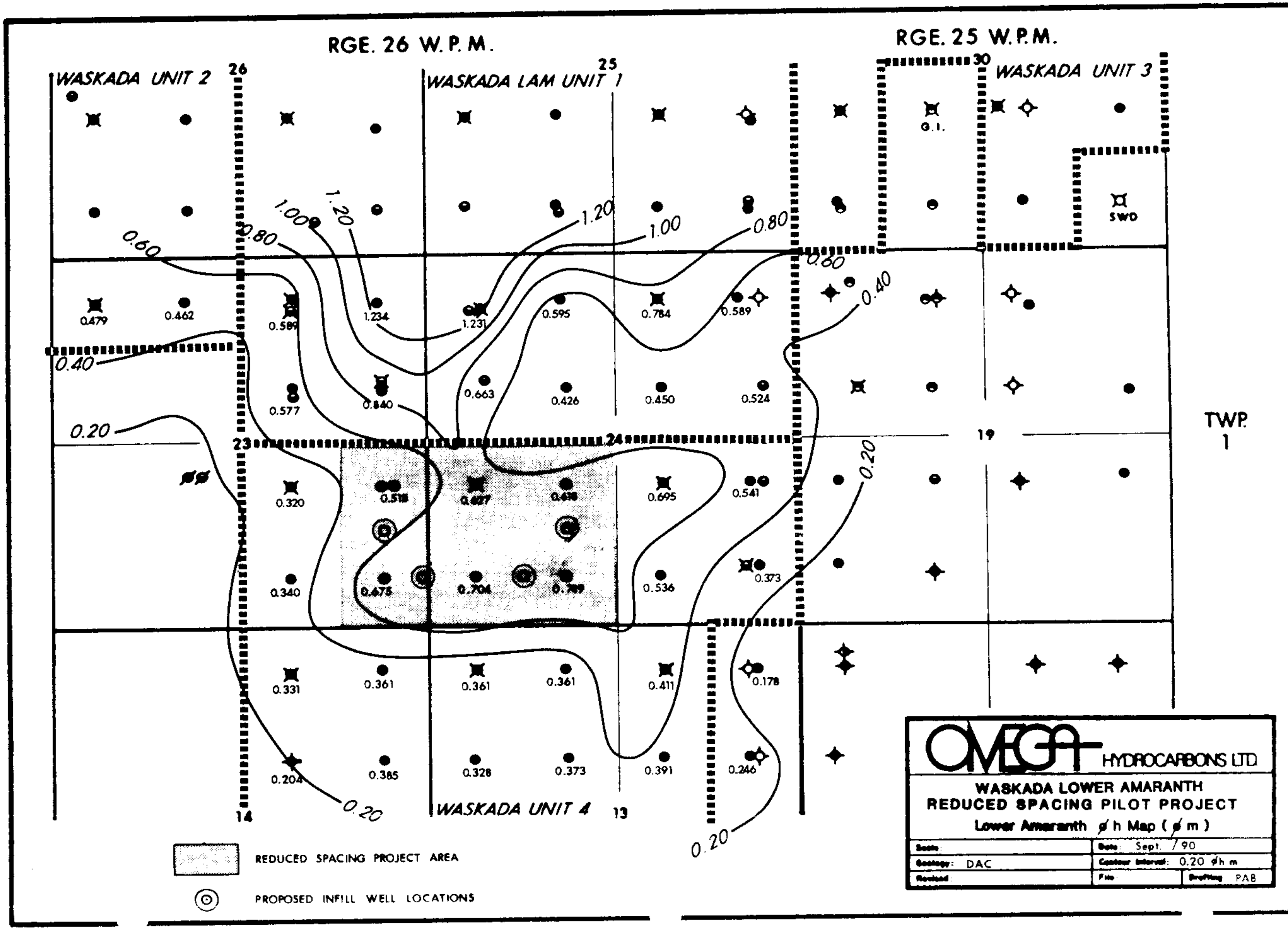
Yours truly,

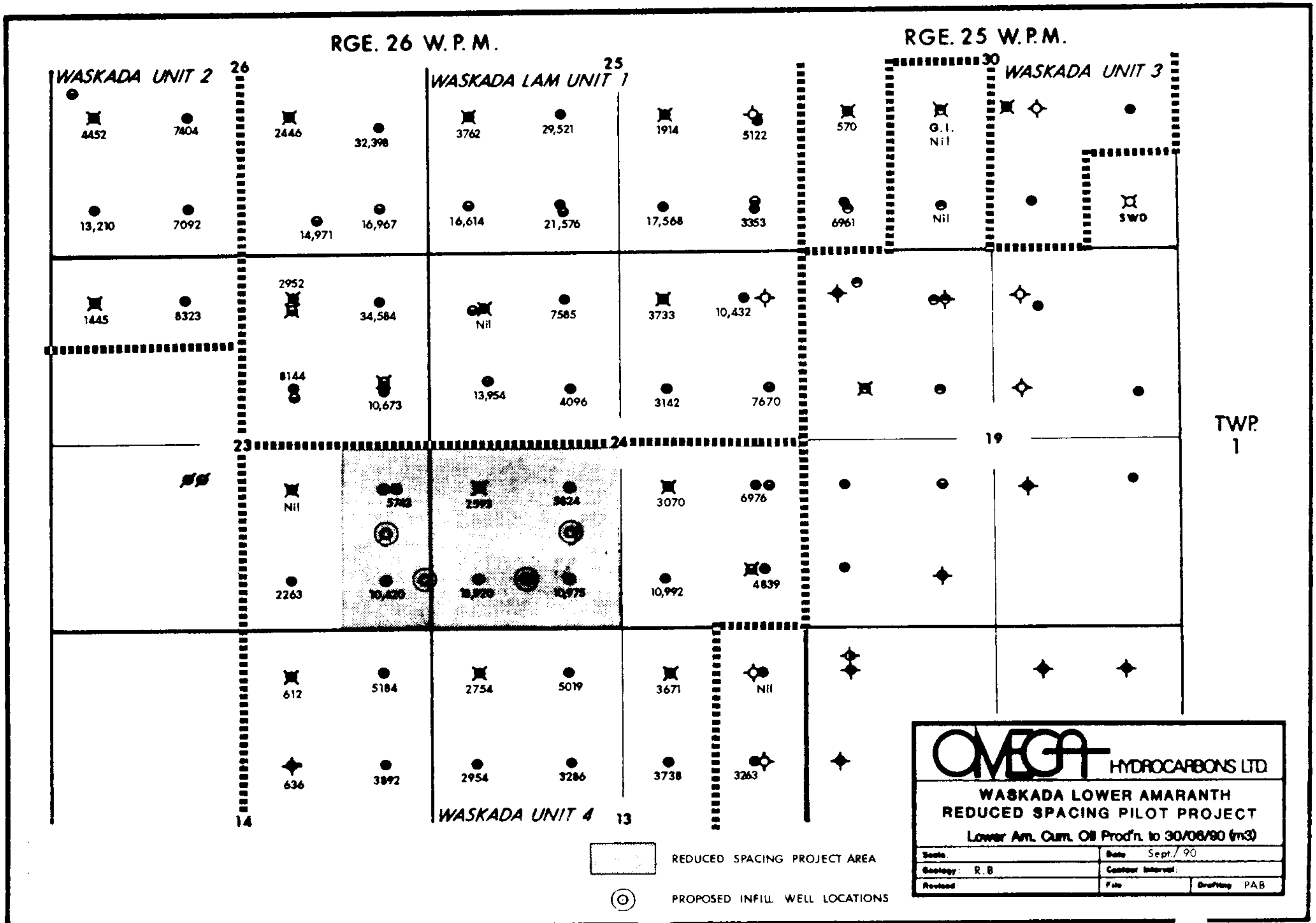
OMEGA HYDROCARBONS LTD.

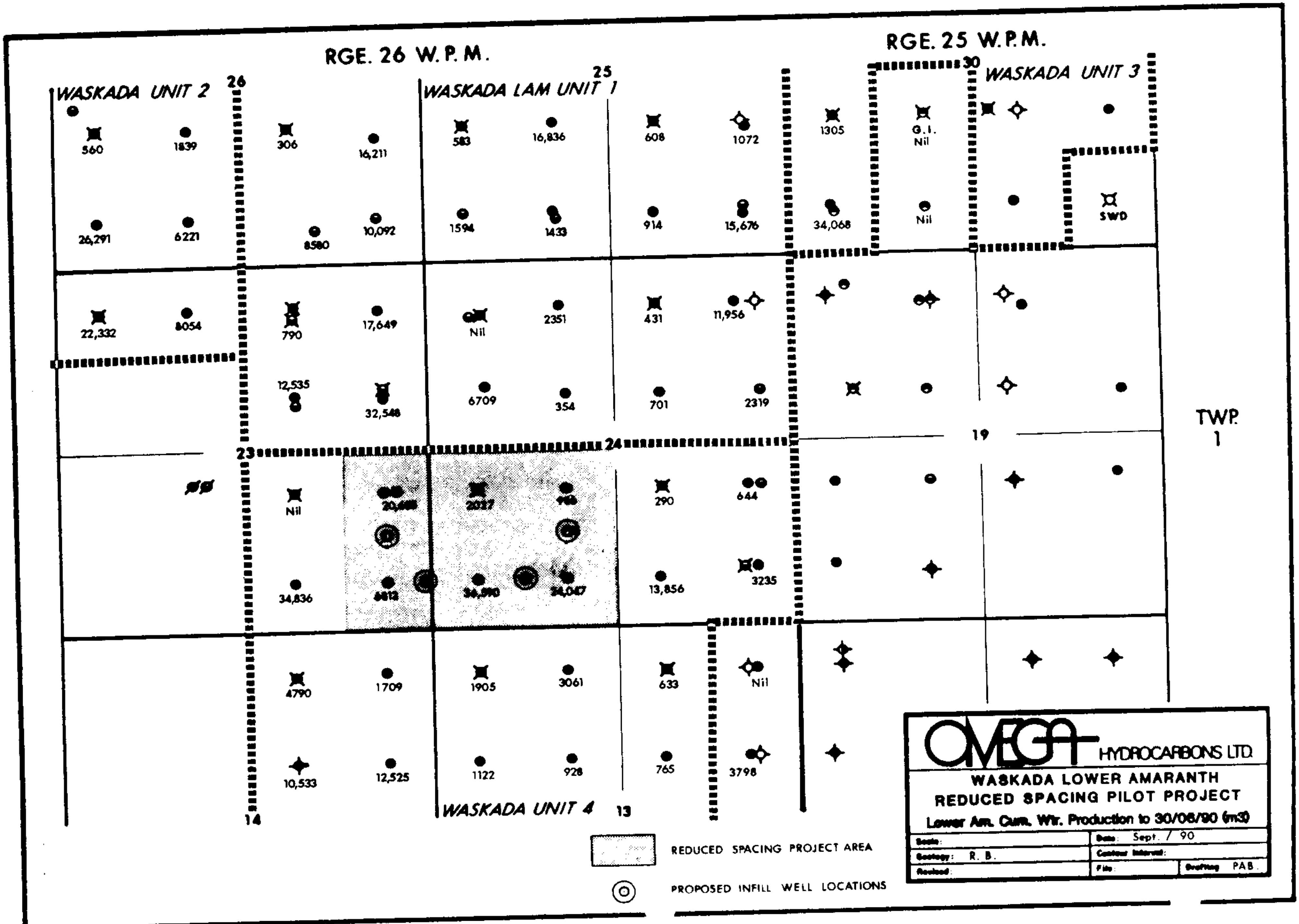
G.A. Cormack
Manager, Production Operations

/jb

c.c.: L.R. Dubreuil - Manitoba Petroleum Branch
Waskada Reduced Drilling Spacing Unit Application File

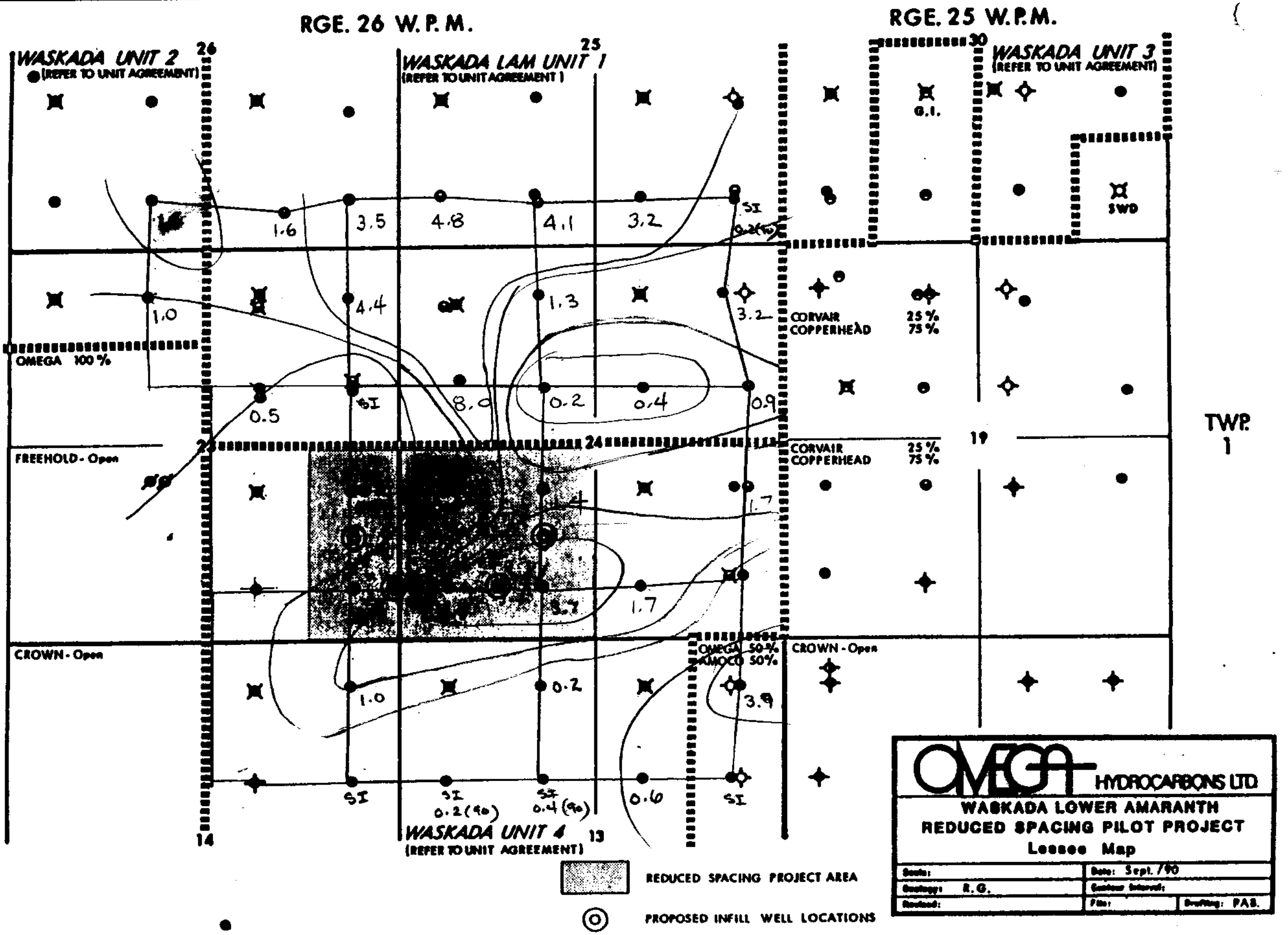

RGE. 26 W.P.M.
RGE. 25 W.P.M.
TWP. 1
WASKADA UNIT 2
WASKADA LAM UNIT 1
WASKADA UNIT 3
WASKADA UNIT 4
G.I.
SWD
26
25
30
23
24
19
14
13
0.20
0.40
0.60
0.80
1.00
1.20
0.479
0.462
0.589
1.234
1.231
0.595
0.784
0.577
0.840
0.663
0.426
0.450
0.524
0.320
0.518
0.627
0.618
0.695
0.541
0.340
0.675
0.704
0.789
0.536
0.373
0.331
0.361
0.411
0.178
0.204
0.385
0.328
0.391
0.246
REDUCED SPACING PROJECT AREA
PROPOSED INFILL WELL LOCATIONS
OMEGA HYDROCARBONS LTD
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lower Amaranth ø h Map (ø m)
Scale:
Date: Sept. /90
Geology: DAC
Contour Interval: 0.20 ø h m
Revised:
File:
Drafting: PAB


RGE. 26 W.P.M.
RGE. 25 W.P.M.
WASKADA UNIT 2
WASKADA LAM UNIT 1
WASKADA UNIT 3
WASKADA UNIT 4
26
25
30
23
24
19
14
13
TWP. 1
4452
7404
2446
32,398
3762
29,521
1914
5122
570
G.I. Nil
13,210
7092
14,971
16,967
16,614
21,576
17,568
3353
6961
Nil
SWD
1445
8323
2952
34,584
Nil
7585
3733
10,432
8144
10,673
13,954
4096
3142
7670
Nil
3070
6976
2263
10,992
4839
612
5184
2754
5019
3671
Nil
636
3892
2954
3286
3738
3263
REDUCED SPACING PROJECT AREA
PROPOSED INFILL WELL LOCATIONS
OMEGA HYDROCARBONS LTD
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lower Am. Cum. Oil Prod'n. to 30/06/90 (m3)
Scale:
Date: Sept./90
Geology: R.B
Contour Interval:
Revised:
File:
Drafting: PAB



RGE. 26 W.P.M.
RGE. 25 W.P.M.
WASKADA UNIT 2
WASKADA LAM UNIT 1
WASKADA UNIT 3
WASKADA UNIT 4
TWP. 1
26
25
30
23
24
19
14
13
560
1839
26,291
6221
22,332
8054
306
16,211
8580
10,092
790
17,649
12,535
32,548
583
16,836
1594
1433
Nil
2351
6709
354
608
1072
914
15,676
431
11,956
701
2319
1305
34,068
G.I.
Nil
Nil
SWD
Nil
34,836
2027
290
644
13,856
3235
4790
1709
10,533
12,525
1905
3061
1122
928
633
765
Nil
3798
REDUCED SPACING PROJECT AREA
PROPOSED INFILL WELL LOCATIONS
OMEGA HYDROCARBONS LTD.
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lower Am. Cum. Wtr. Production to 30/06/90 (m3)
Scale:
Date: Sept. / 90
Geology: R. B.
Contour Interval:
Revised:
File:
Drafting: PAB.

DAILY OIL (m3/d) SEP/90

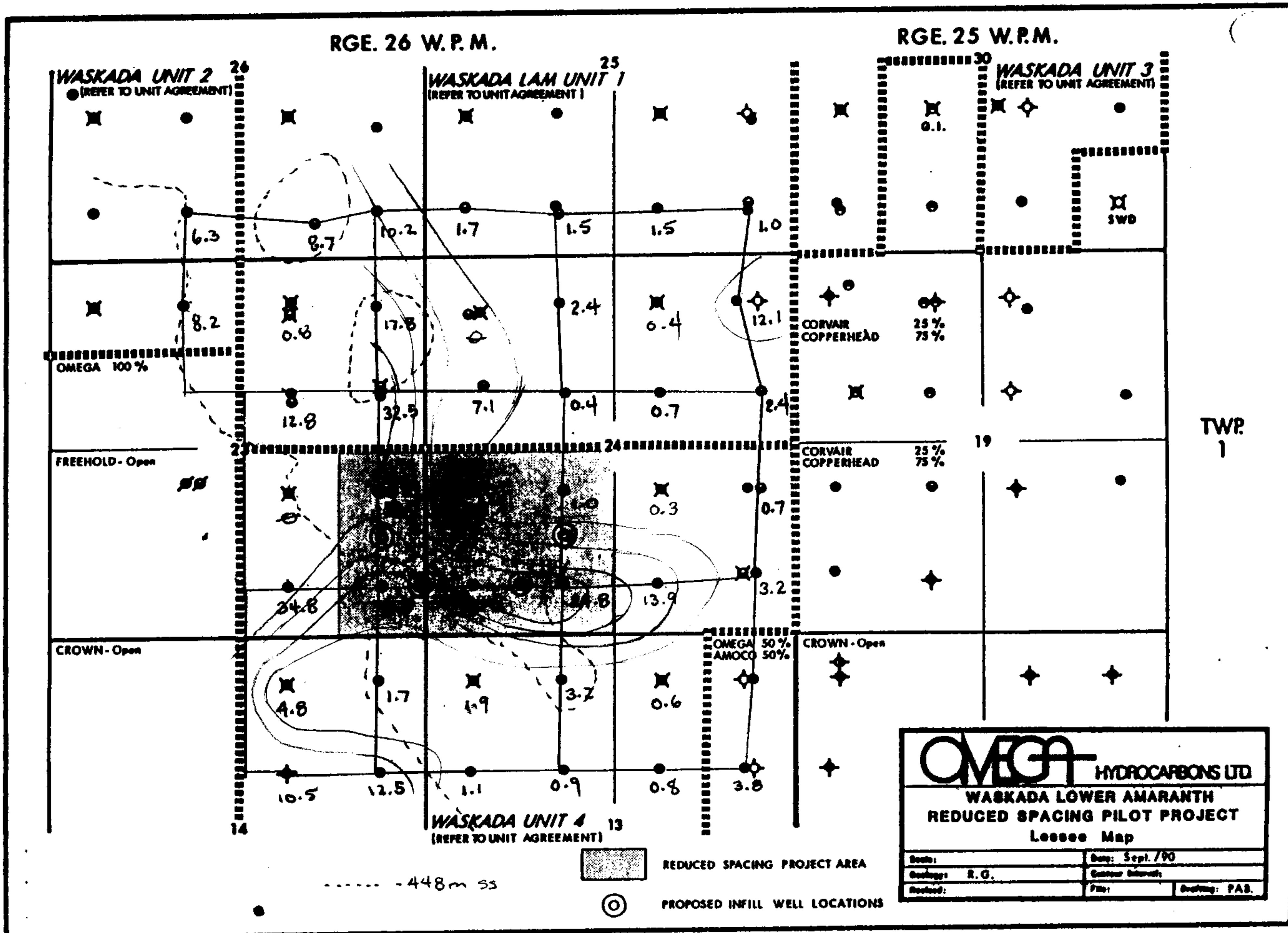


OMEGA HYDROCARBONS LTD

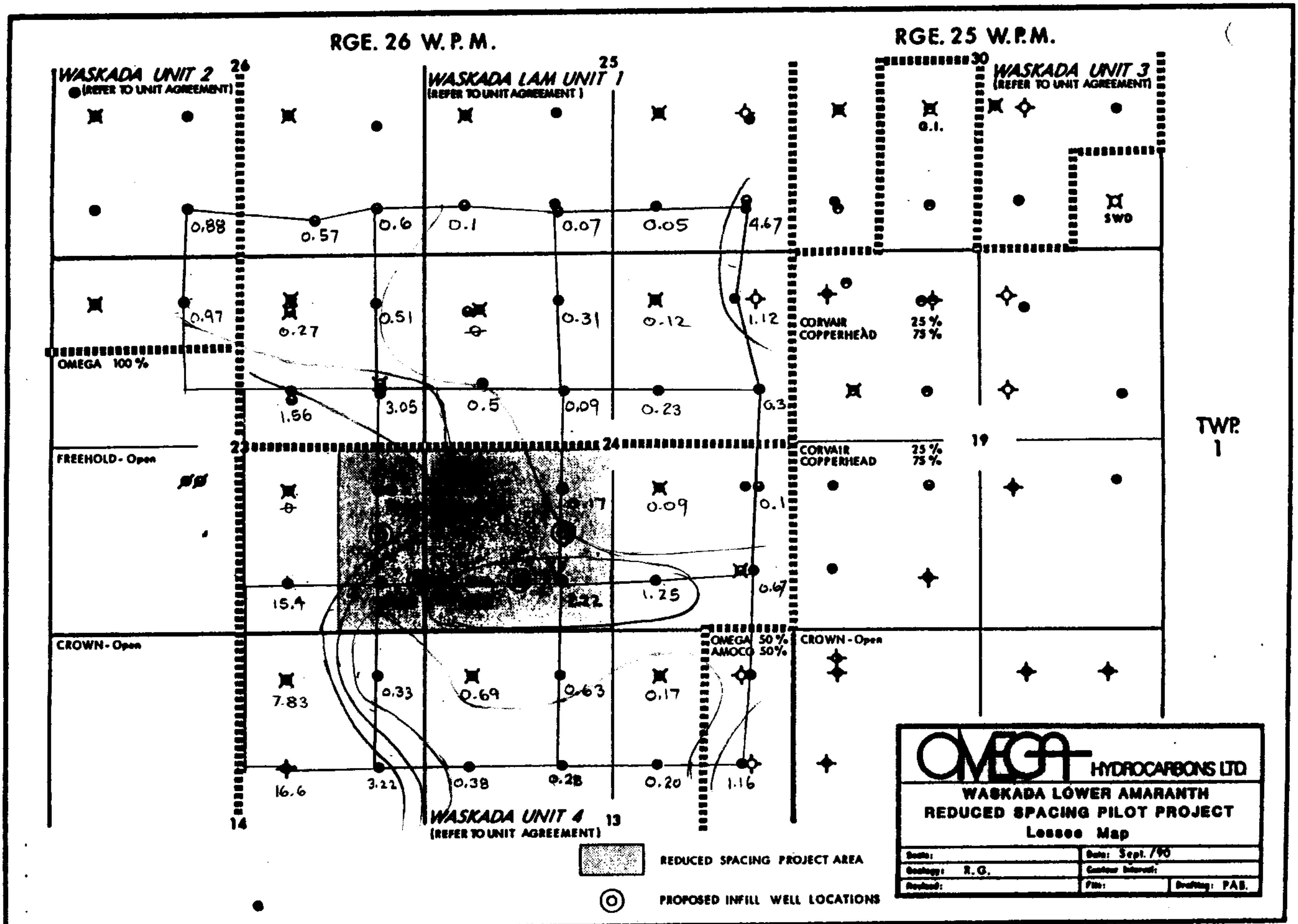
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lessee Map

Scale:	Date: Sept. /90
Geology: R.G.	Contour Interval:
Revised:	File: / Drafting: PAS.

CUMULATIVE WATER



CUMULATIVE WOR

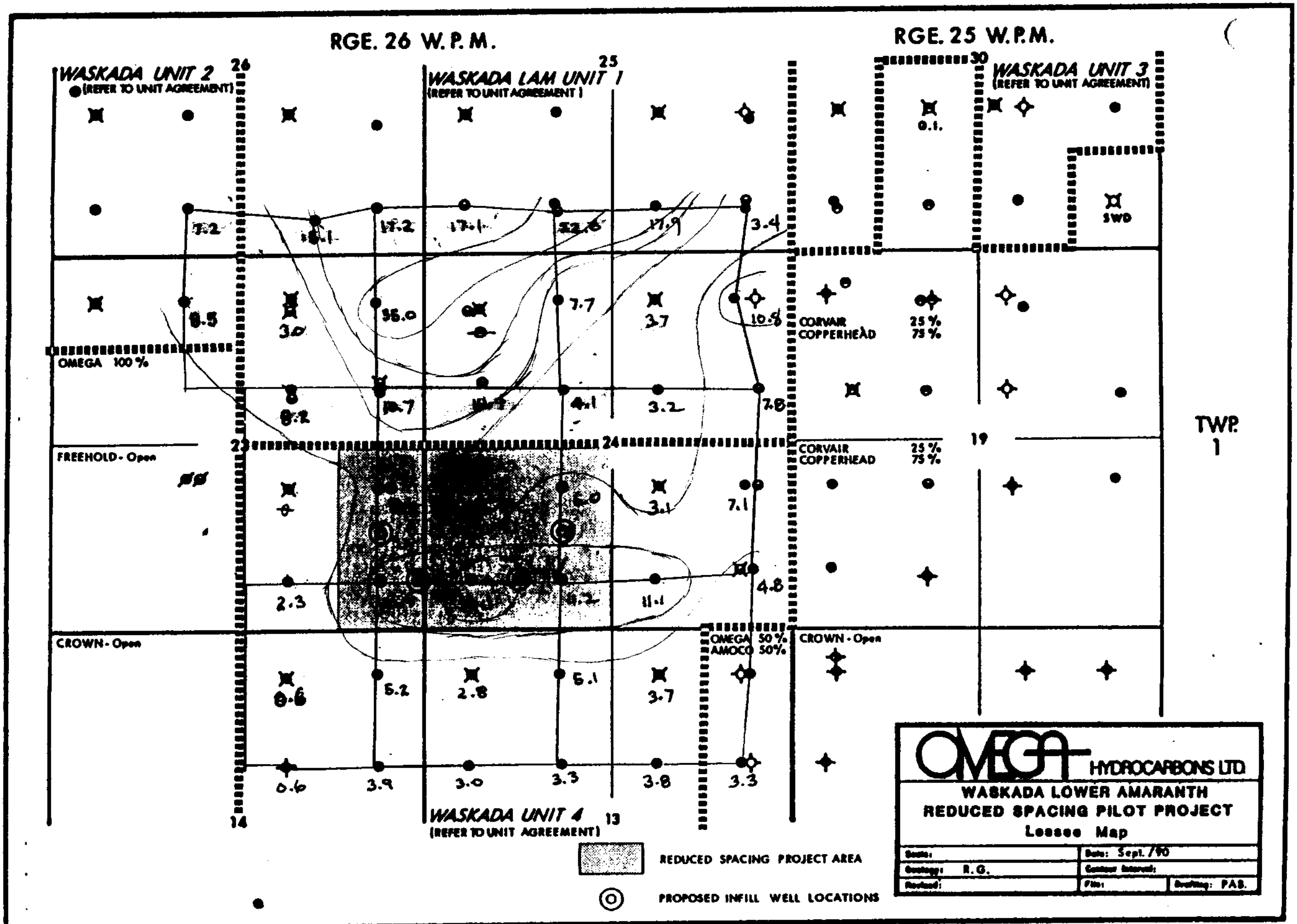


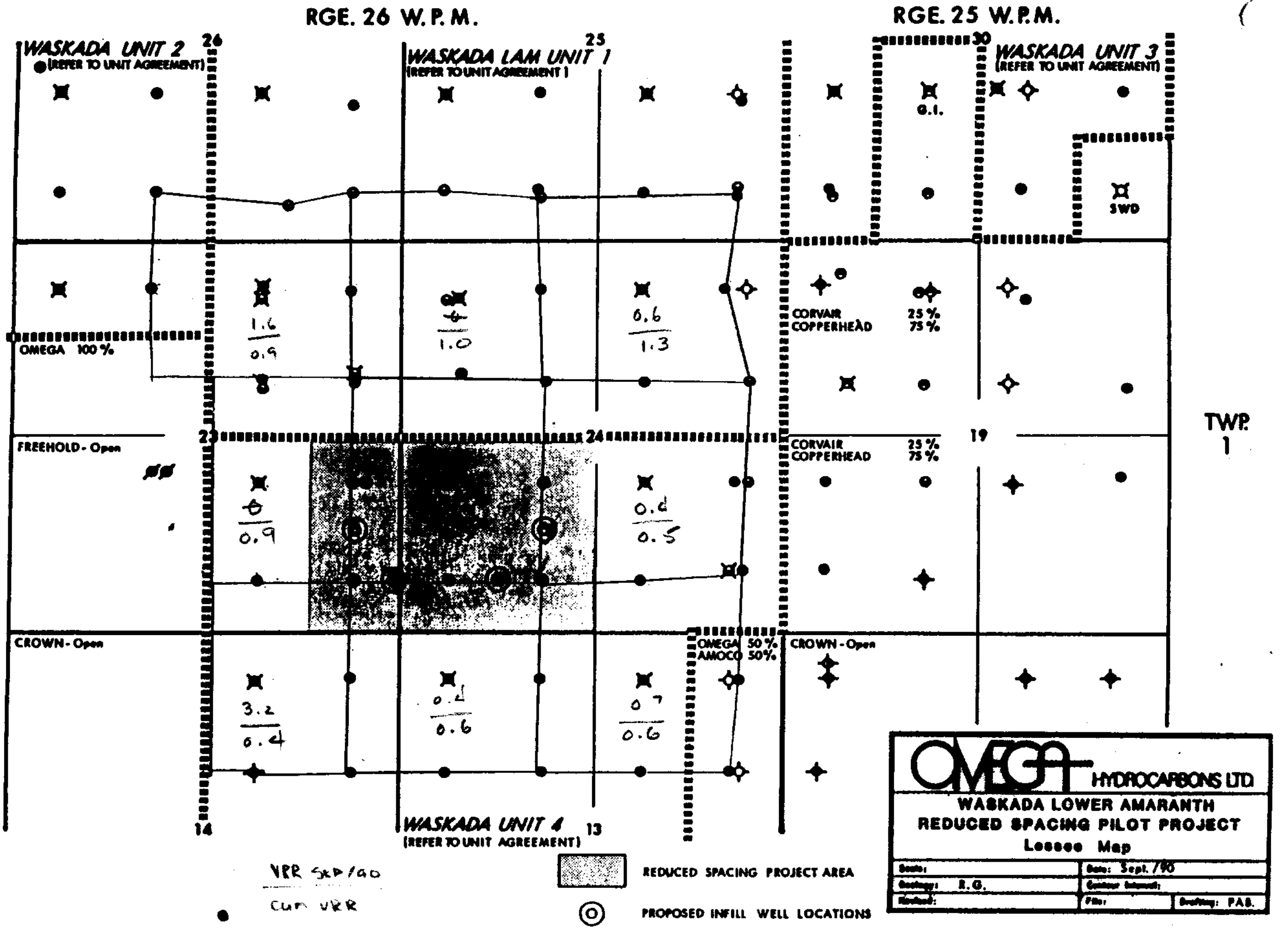
OMEGA HYDROCARBONS LTD

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lessee Map

Scale:
Date: Sept. /90
Geology: R.G.
Contour Interval:
Revised:
File:
Drafting: PAB.

CUMULATIVE OIL ($10^3 m^3$)





OMEGA HYDROCARBONS LTD.

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lessee Map

Scale:	Date: Sept. /90
Geology: R.G.	Contour Interval:
Revised:	File: / Drafting: P.A.B.

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Oil In Place Calculation

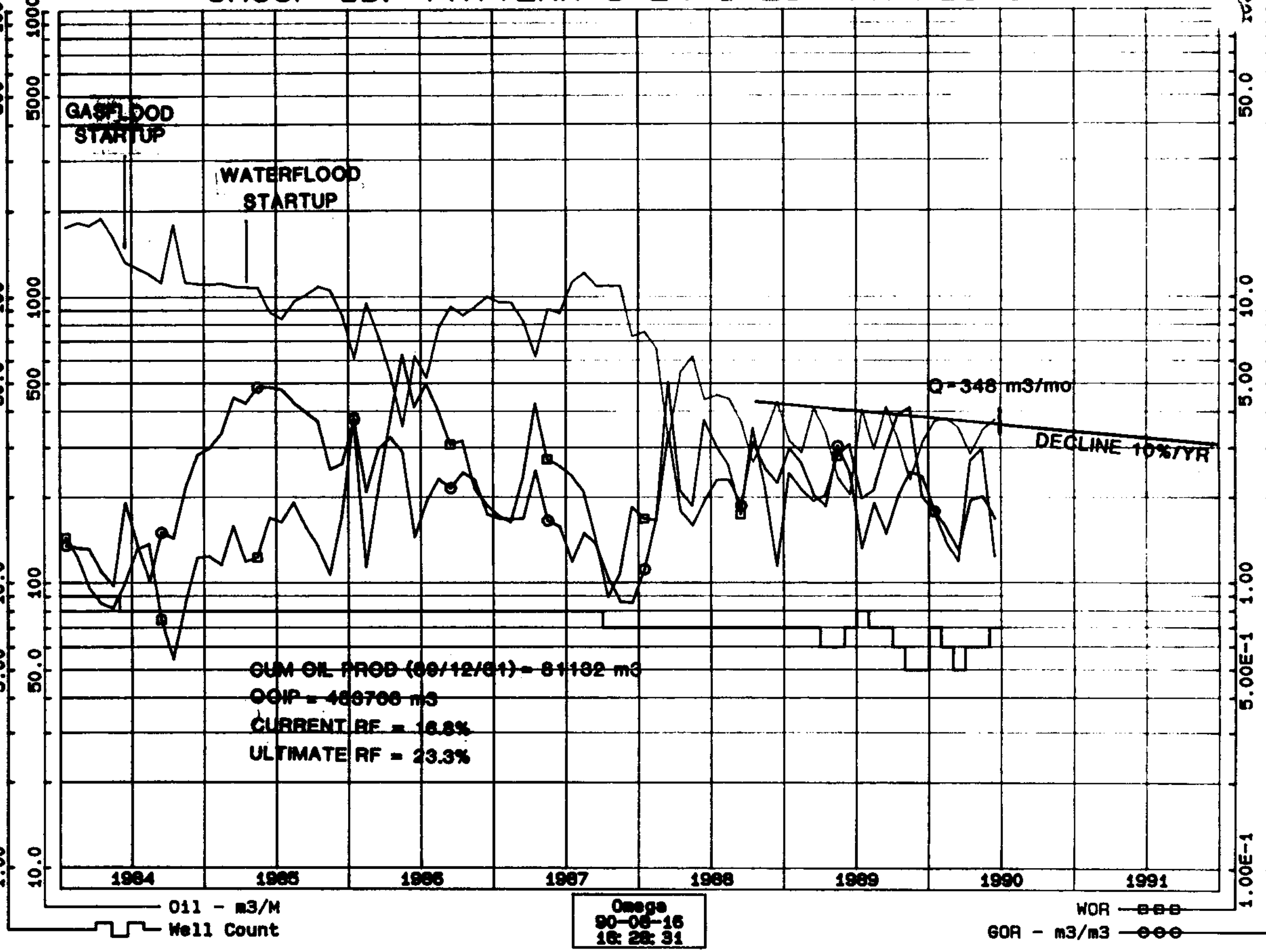
Pattern 5-24-1-26 WPM

Well	ϕh (ϕ.m)	Original Oil In Place (m^3)	CUM. PROD	REC TO DATE
1-23-1-26	0.675	56068	10420	18.6
8-23-1-26	0.518	43034	5743	13.3
9-23-1-26	0.840	69839	10673	15.3
3-24-1-26	0.749	62216	10975	17.6
4-24-1-26	0.704	58527	18920	32.3
5-24-1-26	0.627	52133	2593	5.0
6-24-1-26	0.618	51396	5824	11.3
11-24-1-26	0.426	35411	4096	11.6
12-24-1-26	0.663	55084	954	25.3
			83[illegible]49	17.2
Total:	5.820	483708		

$$OOIP = \frac{10,000\ (A)\ (\phi)\ (h)\ (1-Sw)}{Boi}$$

OOIP Parameters - A = 16 ha, Sw = 0.40, Boi = 1.155Rm^3/m^3

GROUP ID: PATTERN 5-24-1-26 WPM HISTORY



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*** STORE ***
OMEGA PRODUCTION DATA BASE
GROUP ID: PATTERN 5-24-1-26 WPW HISTORY

Month	Well Count Prdn	Well Count Inje	Well Count P/In	Well Count S/Ab	Hours	Oil m3/D	Water m3/D	Gas km3/D	Oil m3/M	Fluid m3/M	Water m3/M	Gas km3/M	Water Cut %	WOR	GOR m3/m3	Cum Oil m3	Cum Wtr m3	Cum Gas km3	I.Water m3/M	Cum I.W m3	I.Gas km3/M	Cum I.G km3
1982-03	1.0	0.0	0.0	0.0	408	2.6	0.1	0.0	79.6	82.6	3.0	0.0	3.6	0.04	0	79.6	3.0	0.0	0.0	0.0	0.0	0.0
1982-04	1.0	0.0	0.0	0.0	648	4.6	0.1	0.0	139.0	143.4	4.4	0.0	3.1	0.03	0	218.6	7.4	0.0	0.0	0.0	0.0	0.0
1982-05	1.0	0.0	0.0	0.0	360	4.6	0.2	0.0	141.2	146.9	5.7	0.0	3.9	0.04	0	359.8	13.1	0.0	0.0	0.0	0.0	0.0
1982-06	1.0	0.0	0.0	0.0	720	7.2	0.0	0.0	215.8	216.9	1.1	0.0	0.5	0.01	0	575.6	14.2	0.0	0.0	0.0	0.0	0.0
1982-07	1.0	0.0	0.0	0.0	744	5.5	0.0	0.0	171.8	171.8	0.0	0.0	0.0	0.00	0	747.4	14.2	0.0	0.0	0.0	0.0	0.0
1982-08	3.0	0.0	0.0	0.0	1608	14.1	5.5	0.0	437.8	607.5	169.7	0.0	27.9	0.39	0	1185.2	183.9	0.0	0.0	0.0	0.0	0.0
1982-09	3.0	0.0	0.0	0.0	2064	21.1	9.3	0.0	632.3	910.5	278.2	0.0	30.6	0.44	0	1817.5	462.1	0.0	0.0	0.0	0.0	0.0
1982-10	3.0	0.0	0.0	0.0	1527	11.7	4.3	0.0	363.7	495.8	132.1	0.0	26.6	0.36	0	2181.2	594.2	0.0	0.0	0.0	0.0	0.0
1982-11	3.0	0.0	0.0	0.0	2145	15.3	7.2	0.0	458.4	674.9	216.5	0.0	32.1	0.47	0	2639.6	810.7	0.0	0.0	0.0	0.0	0.0
1982-12	4.0	0.0	0.0	0.0	2184	14.8	6.8	0.8	459.6	671.1	211.5	23.9	31.5	0.46	52	3099.2	1022.2	23.9	0.0	0.0	0.0	0.0
1983-01	3.0	0.0	0.0	1.0	2220	12.0	10.7	0.9	370.9	701.2	330.3	29.4	47.1	0.89	79	3470.1	1352.5	53.3	0.0	0.0	0.0	0.0
1983-02	4.0	0.0	0.0	0.0	2216	19.8	13.2	1.0	553.7	924.2	370.5	28.1	40.1	0.67	51	4023.8	1723.0	81.4	0.0	0.0	0.0	0.0
1983-03	4.0	0.0	0.0	0.0	2504	29.2	21.2	1.1	904.2	1560.9	656.7	32.8	42.1	0.73	36	4928.0	2379.7	114.2	0.0	0.0	0.0	0.0
1983-04	4.0	0.0	0.0	0.0	2796	38.3	20.4	2.3	1147.7	1760.9	613.2	68.0	34.8	0.53	59	6075.7	2992.9	182.2	0.0	0.0	0.0	0.0
1983-05	4.0	0.0	0.0	0.0	2359	31.3	19.1	1.8	971.8	1563.9	592.1	56.5	37.9	0.61	58	7047.5	3585.0	238.7	0.0	0.0	0.0	0.0
1983-06	5.0	0.0	0.0	0.0	3260	47.2	25.5	3.3	1415.7	2181.3	765.6	99.8	35.1	0.54	70	8463.2	4350.6	338.5	0.0	0.0	0.0	0.0
1983-07	9.0	0.0	0.0	0.0	5235	71.5	55.1	6.1	2217.7	3924.8	1707.1	188.6	43.5	0.77	85	10680.9	6057.7	527.1	0.0	0.0	0.0	0.0
1983-08	9.0	0.0	0.0	0.0	6415	69.8	64.9	4.3	2164.6	4175.8	2011.2	132.6	48.2	0.93	61	12845.5	8068.9	659.7	0.0	0.0	0.0	0.0
1983-09	9.0	0.0	0.0	0.0	6297	75.3	71.2	6.3	2259.7	4395.6	2135.9	188.1	48.6	0.95	83	15105.2	10204.8	847.8	0.0	0.0	0.0	0.0
1983-10	9.0	0.0	0.0	0.0	6644	66.7	106.8	8.4	2067.4	5377.8	3310.4	259.5	61.6	1.60	126	17172.6	13515.2	1107.3	0.0	0.0	0.0	0.0
1983-11	9.0	0.0	0.0	0.0	6192	75.4	75.4	8.2	2262.0	4524.6	2262.6	246.4	50.0	1.00	109	19434.6	15777.8	1353.7	0.0	0.0	0.0	0.0
1983-12	9.0	0.0	0.0	0.0	5696	60.0	85.2	9.3	1860.5	4500.8	2640.3	287.4	58.7	1.42	154	21295.1	18418.1	1641.1	0.0	0.0	0.0	0.0
1984-01	9.0	0.0	0.0	0.0	5187	56.8	81.7	7.7	1761.9	4294.0	2532.1	238.5	59.0	1.44	135	23057.0	20950.2	1879.6	0.0	0.0	0.0	0.0
1984-02	9.0	0.0	0.0	0.0	5161	63.2	77.7	8.4	1831.8	4086.3	2254.5	242.8	55.2	1.23	133	24888.8	23204.7	2122.4	0.0	0.0	0.0	0.0
1984-03	9.0	0.0	0.0	0.0	5034	57.5	55.5	7.5	1782.8	3502.2	1719.4	233.9	49.1	0.96	131	26671.6	24924.1	2356.3	0.0	0.0	0.0	0.0
1984-04	9.0	0.0	0.0	0.0	5400	63.1	53.7	6.9	1893.5	3504.8	1611.3	206.8	46.0	0.85	109	28565.1	26535.4	2563.1	0.0	0.0	0.0	0.0
1984-05	9.0	0.0	0.0	0.0	5356	52.3	42.8	5.1	1621.6	2949.1	1327.5	158.7	45.0	0.82	98	30186.7	27862.9	2721.8	0.0	0.0	59.3	59.3
1984-06	8.0	1.0	0.0	0.0	4947	44.3	44.3	8.5	1328.0	2657.4	1329.4	254.6	50.0	1.00	192	31514.7	29192.3	2976.4	0.0	0.0	133.1	192.4
1984-07	8.0	1.0	0.0	0.0	5628	40.9	53.7	5.6	1268.2	2933.9	1665.7	172.6	56.8	1.31	136	32782.9	30858.0	3149.0	0.0	0.0	90.5	282.9
1984-08	8.0	1.0	0.0	0.0	5891	39.0	53.3	3.9	1207.8	2859.6	1651.8	121.9	57.8	1.37	101	33990.7	32509.8	3270.9	0.0	0.0	45.5	328.4
1984-09	8.0	1.0	0.0	0.0	5236	37.4	28.0	5.6	1122.3	1961.7	839.4	168.6	42.8	0.75	150	35113.0	33349.2	3439.5	0.0	0.0	162.8	491.2
1984-10	8.0	1.0	0.0	0.0	5890	58.1	31.6	8.3	1800.9	2701.1	900.2	258.3	33.2	0.54	143	36913.9	34329.4	3697.8	0.0	0.0	157.7	648.9
1984-11	8.0	1.0	0.0	0.0	5661	37.6	31.8	8.1	1127.8	2083.2	955.4	242.6	45.9	0.85	215	38041.7	35204.8	3940.4	0.0	0.0	88.7	737.6
1984-12	8.0	1.0	0.0	0.0	5920	36.0	44.0	10.2	1114.8	2480.3	1365.5	315.1	55.1	1.22	203	39156.5	36650.3	4255.5	0.0	0.0	56.9	794.5
1985-01	8.0	1.0	0.0	0.0	5729	35.8	44.4	10.7	1109.7	2486.7	1377.0	332.1	55.4	1.24	299	40266.2	38027.3	4587.6	0.0	0.0	57.5	852.0
1985-02	8.0	1.0	0.0	0.0	5376	39.9	46.1	13.4	1117.8	2408.7	1290.9	376.4	53.6	1.15	337	41384.0	39318.2	4964.0	0.0	0.0	0.0	852.0
1985-03	8.0	0.0	0.0	1.0	5880	35.2	55.9	15.7	1090.4	2822.2	1731.8	487.0	61.4	1.59	447	42474.4	41050.0	5451.0	0.0	0.0	0.0	852.0
1985-04	8.0	1.0	0.0	0.0	5457	36.2	43.0	15.4	1084.5	2373.7	1289.2	462.6	54.3	1.19	427	43558.9	42339.2	5913.6	3241.0	3241.0	0.0	852.0
1985-05	8.0	1.0	0.0	0.0	5838	34.8	42.8	16.9	1079.4	2406.9	1327.5	523.7	55.2	1.23	485	44638.3	43666.7	6437.3	4613.4	7854.4	0.0	852.0
1985-06	8.0	1.0	0.0	0.0	5788	29.6	50.1	14.4	886.8	2390.7	1503.9	430.6	62.9	1.70	486	45525.1	45170.6	6867.9	4521.9	12376.3	0.0	852.0
1985-07	8.0	1.0	0.0	0.0	5544	27.1	44.2	12.9	839.4	2210.0	1370.6	400.1	62.0	1.63	477	46364.5	46541.2	7268.0	4553.6	16929.9	0.0	852.0
1985-08	8.0	1.0	0.0	0.0	5910	31.2	59.9	13.4	968.6	2825.8	1857.2	414.8	65.7	1.92	428	47333.1	48398.4	7682.8	4727.4	21657.3	0.0	852.0
1985-09	8.0	1.0	0.0	0.0	5658	33.9	53.5	13.5	1017.6	2622.5	1604.9	404.4	61.2	1.58	397	48350.7	50003.3	8087.2	3359.6	25016.9	0.0	852.0
1985-10	8.0	1.0	0.0	0.0	5952	35.2	47.4	13.0	1090.9	2561.5	1470.6	402.7	57.4	1.35	369	49441.6	51473.9	8489.9	2383.0	27399.9	0.0	852.0
1985-11	8.0	1.0	0.0	0.0	5760	35.2	37.6	8.8	1055.8	2183.0	1127.2	265.0	51.6	1.07	251	50497.4	52601.1	8754.9	2496.3	29896.2	0.0	852.0
1985-12	8.0	1.0	0.0	0.0	5826	27.9	47.6	7.3	864.5	2339.8	1475.3	227.4	63.1	1.71	263	51361.9	54076.4	8982.3	2509.2	32405.4	0.0	852.0
1986-01	8.0	1.0	0.0	0.0	5952	19.7	74.7	7.4	610.6	2927.0	2316.4	229.6	79.1	3.79	376	51972.5	56392.8	9211.9	2317.7	34803.1	0.0	852.0
1986-02	8.0	1.0	0.0	0.0	5193	34.1	38.6	7.1	954.4	2034.1	1079.7	199.4	53.1	1.13	209	52926.9	57472.5	9411.3	1346.0	36149.1	0.0	852.0
1986-03	8.0	1.0	0.0	0.0	5580	23.5	49.5	7.0	728.4	2264.3	1535.9	216.6	67.8	2.11	297	53655.3	59008.4	9627.9	3854.5	40003.6	0.0	852.0
1986-04	8.0	1.0	0.0	0.0	5732	18.0	66.9	5.9	539.3	2546.4	2007.1	175.8	78.8	3.72	326	54194.6	61015.5	9803.7	2434.1	42437.7	0.0	852.0

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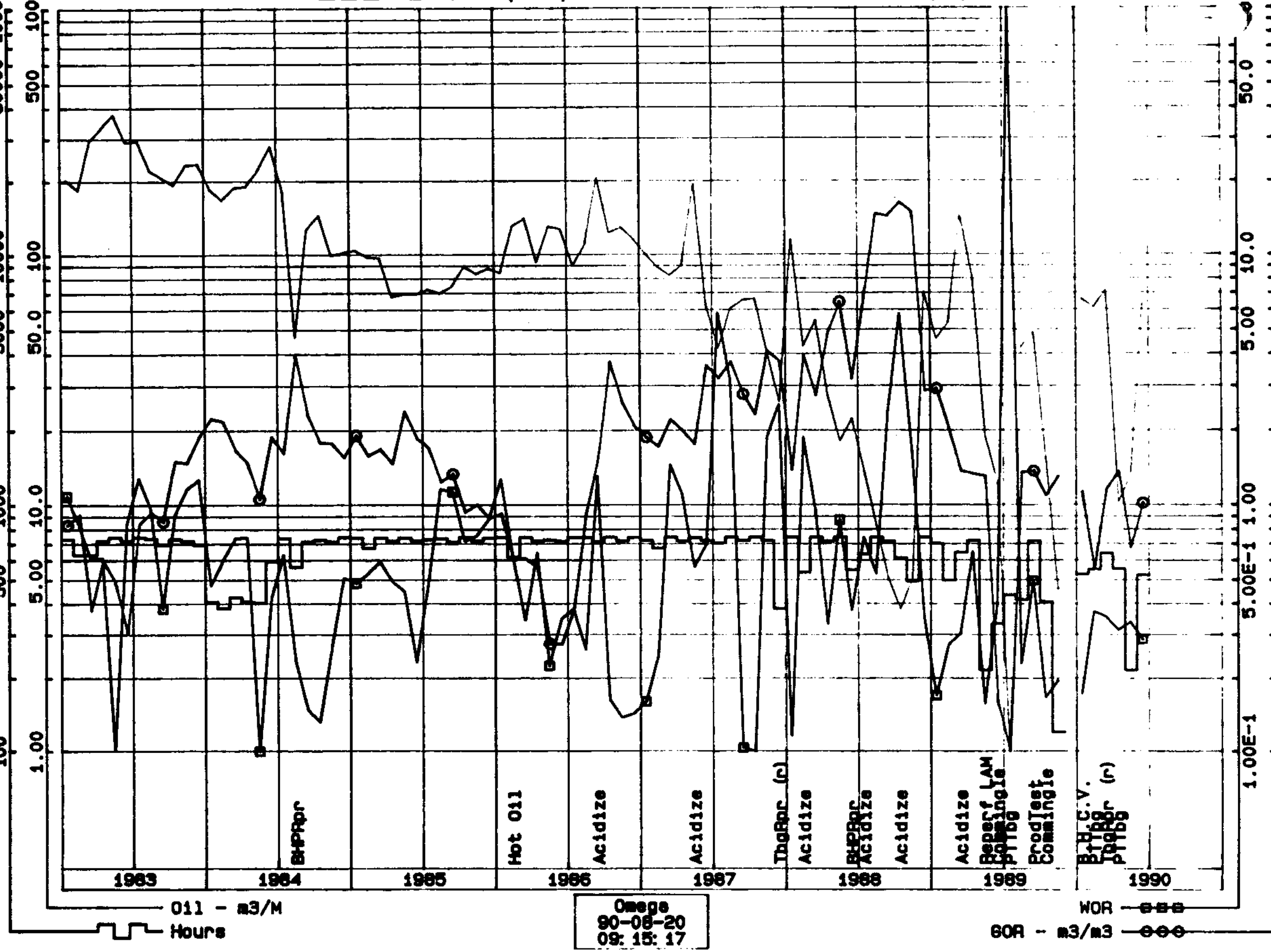
*** STORE ***
OMEGA PRODUCTION DATA BASE
GROUP ID: PATTERN 5-24-1-26 WPM HISTORY

Month	Well Count Prdn	Injn	P/In	S/Ab	Hours	Oil m3/D	Water m3/D	Gas km3/D	Oil m3/M	Fluid m3/M	Water m3/M	Gas km3/M	Water Cut %	WOR	GOR m3/m3	Cum Oil m3	Cum Wtr m3	Cum Gas km3	I.Water m3/M	Cum I.W m3	I.Gas km3/M	Cum I.G km3
1986-05	8.0	1.0	0.0	0.0	5810	11.4	72.2	3.3	354.8	2593.9	2239.1	102.5	86.3	6.31	289	54549.4	63254.6	9906.2	1031.3	44269.0	0.0	852.0
1986-06	8.0	1.0	0.0	0.0	5744	20.7	85.7	3.0	622.4	3193.7	2571.3	90.0	80.5	4.13	145	55171.8	65825.9	9996.2	3005.5	47274.5	0.0	852.0
1986-07	8.0	1.0	0.0	0.0	5770	16.9	84.5	3.3	524.7	3144.2	2619.5	101.3	83.3	4.99	193	55696.5	68445.4	10097.5	1402.7	48677.2	0.0	852.0
1986-08	8.0	0.0	0.0	1.0	5569	25.1	101.2	5.8	778.7	3916.8	3138.1	181.3	80.1	4.03	233	56475.2	71583.5	10278.8	0.0	48677.2	0.0	852.0
1986-09	8.0	0.0	0.0	1.0	5753	31.0	95.5	6.7	930.1	3795.2	2865.1	200.6	75.5	3.08	216	57405.3	74448.6	10479.4	0.0	48677.2	0.0	852.0
1986-10	8.0	0.0	0.0	1.0	5681	27.8	88.3	6.8	862.2	3600.1	2737.9	211.3	76.1	3.18	245	58267.5	77186.5	10690.7	0.0	48677.2	0.0	852.0
1986-11	8.0	0.0	0.0	1.0	5760	30.9	66.1	7.1	925.7	2909.1	1983.4	213.2	68.2	2.14	230	59193.2	79169.9	10903.9	0.0	48677.2	0.0	852.0
1986-12	8.0	0.0	0.0	1.0	5905	32.4	60.9	5.6	1003.2	2890.5	1887.3	174.9	65.3	1.88	174	60196.4	81057.2	11078.8	0.0	48677.2	0.0	852.0
1987-01	8.0	0.0	0.0	1.0	5812	31.0	53.2	5.2	960.0	2610.1	1650.1	161.6	63.2	1.72	168	61156.4	82707.3	11240.4	0.0	48677.2	0.0	852.0
1987-02	8.0	0.0	0.0	1.0	5376	34.2	55.7	5.7	957.1	2518.0	1560.9	160.4	62.0	1.63	168	62113.5	84268.2	11400.8	0.0	48677.2	0.0	852.0
1987-03	8.0	1.0	0.0	0.0	5705	26.5	62.6	4.5	821.8	2760.9	1939.1	138.3	70.2	2.36	168	62935.3	86207.3	11539.1	1020.2	49697.4	0.0	852.0
1987-04	8.0	1.0	0.0	0.0	5634	20.7	87.9	5.1	619.7	3256.5	2636.8	154.3	81.0	4.25	249	63555.0	88844.1	11693.4	1432.8	51130.2	0.0	852.0
1987-05	8.0	1.0	0.0	0.0	5718	29.3	80.1	4.9	909.8	3391.4	2481.6	150.7	73.2	2.73	166	64464.8	91325.7	11844.1	1536.5	52666.7	0.0	852.0
1987-06	8.0	1.0	0.0	0.0	5596	29.3	75.7	4.6	879.7	3150.1	2270.4	138.6	72.1	2.58	158	65344.5	93596.1	11982.7	1536.1	54202.8	0.0	852.0
1987-07	8.0	1.0	0.0	0.0	5810	36.3	86.9	4.3	1126.3	3821.1	2694.8	133.7	70.5	2.39	119	66470.8	96290.9	12116.4	1352.6	55555.4	0.0	852.0
1987-08	8.0	1.0	0.0	0.0	5940	39.2	82.1	5.9	1216.4	3762.2	2545.8	181.9	67.7	2.09	150	67687.2	98836.7	12298.3	1252.5	56807.9	0.0	852.0
1987-09	8.0	1.0	0.0	0.0	5548	36.4	51.8	5.0	1093.3	2647.7	1554.4	149.2	58.7	1.42	136	68780.5	100391	12447.5	1273.0	58080.9	0.0	852.0
1987-10	7.0	1.0	0.0	1.0	5200	35.3	31.5	3.7	1093.8	2069.1	975.3	113.4	47.1	0.89	104	69874.3	101366	12560.9	1804.6	59885.5	0.0	852.0
1987-11	7.0	1.0	0.0	1.0	4890	36.4	39.3	3.1	1091.6	2269.5	1177.9	94.0	51.9	1.08	86	70965.9	102544	12654.9	1176.2	61061.7	0.0	852.0
1987-12	7.0	1.0	0.0	1.0	4004	23.5	43.6	2.0	729.4	2080.4	1351.0	62.5	64.9	1.85	86	71695.3	103895	12717.4	794.9	61856.6	0.0	852.0
1988-01	7.0	1.0	0.0	1.0	5010	24.4	41.1	2.7	757.9	2031.8	1273.9	84.7	62.7	1.68	112	72453.2	105169	12802.1	851.9	62708.5	0.0	852.0
1988-02	7.0	1.0	0.0	1.0	4601	22.8	37.9	3.9	660.8	1759.4	1098.6	112.2	62.4	1.66	170	73114.0	106268	12914.3	628.3	63336.8	0.0	852.0
1988-03	7.0	1.0	0.0	1.0	4954	10.3	52.3	3.5	319.3	1939.2	1619.9	108.4	83.5	5.07	339	73433.3	107888	13022.7	707.1	64043.9	0.0	852.0
1988-04	7.0	1.0	0.0	1.0	5018	18.3	38.7	3.3	547.9	1710.3	1162.4	98.6	68.0	2.12	180	73981.2	109050	13121.3	598.8	64642.7	0.0	852.0
1988-05	7.0	1.0	0.0	1.0	5112	20.1	37.4	3.2	623.1	1783.5	1160.4	99.0	65.1	1.86	159	74604.3	110211	13220.3	51.7	64694.4	0.0	852.0
1988-06	7.0	1.0	0.0	1.0	4669	14.7	54.9	2.9	440.3	2088.3	1648.0	86.0	78.9	3.74	195	75044.6	111859	13306.3	43.7	64738.1	0.0	852.0
1988-07	7.0	0.0	0.0	2.0	4939	14.7	44.8	3.4	456.6	1845.0	1388.4	105.4	75.3	3.04	231	75501.2	113247	13411.7	0.0	64738.1	0.0	852.0
1988-08	7.0	0.0	0.0	2.0	4809	14.3	37.1	3.3	443.6	1595.0	1151.4	102.5	72.2	2.60	231	75944.8	114398	13514.2	0.0	64738.1	0.0	852.0
1988-09	7.0	1.0	0.0	1.0	4209	12.4	21.6	2.3	370.8	1017.7	646.9	69.5	63.6	1.74	187	76315.6	115045	13583.7	565.2	65303.3	0.0	852.0
1988-10	7.0	1.0	0.0	1.0	4709	8.5	30.2	2.7	265.0	1200.1	935.1	83.2	77.9	3.53	314	76580.6	115980	13666.9	552.4	65855.7	0.0	852.0
1988-11	7.0	0.0	0.0	2.0	4169	11.2	24.3	2.8	335.5	1064.7	729.2	85.0	68.5	2.17	253	76916.1	116710	13751.9	0.0	65855.7	0.0	852.0
1988-12	7.0	0.0	0.0	2.0	4449	14.0	15.9	3.1	432.9	927.3	494.4	97.4	53.3	1.14	225	77349.0	117204	13849.3	0.0	65855.7	0.0	852.0
1989-01	7.0	0.0	0.0	2.0	5165	10.2	25.0	3.1	317.3	1092.5	775.2	94.9	71.0	2.44	299	77666.3	117979	13944.2	0.0	65855.7	0.0	852.0
1989-02	7.0	0.0	0.0	2.0	4187	10.3	22.0	2.7	288.4	904.4	616.0	75.9	68.1	2.14	263	77954.7	118595	14020.1	0.0	65855.7	0.0	852.0
1989-03	7.0	0.0	0.0	2.0	4416	13.3	25.9	2.7	413.7	1216.4	802.7	84.7	66.0	1.94	205	78368.4	119398	14104.8	0.0	65855.7	0.0	852.0
1989-04	6.0	0.0	0.0	3.0	4045	11.3	23.0	2.1	339.0	1029.8	690.8	63.1	67.1	2.04	186	78707.4	120089	14167.9	0.0	65855.7	0.0	852.0
1989-05	6.0	0.0	0.0	3.0	3936	7.6	21.3	2.3	235.3	894.1	658.8	71.6	73.7	2.80	304	78942.7	120747	14239.5	0.0	65855.7	0.0	852.0
1989-06	7.0	0.0	0.0	2.0	3781	6.8	21.1	1.7	204.7	836.7	632.0	50.1	75.5	3.09	245	79147.4	121379	14289.6	0.0	65855.7	0.0	852.0
1989-07	8.0	0.0	0.0	1.0	3927	13.2	26.0	1.7	407.9	1215.3	807.4	53.8	66.4	1.98	132	79555.3	122187	14343.4	0.0	65855.7	0.0	852.0
1989-08	7.0	0.0	0.0	2.0	3903	9.6	20.4	1.8	296.6	927.8	631.2	56.7	68.0	2.13	191	79851.9	122818	14400.1	0.0	65855.7	0.0	852.0
1989-09	7.0	0.0	0.0	2.0	4798	13.9	41.2	2.1	415.9	1651.6	1235.7	61.8	74.8	2.97	149	80267.8	124054	14461.9	0.0	65855.7	0.0	852.0
1989-10	6.0	0.0	0.0	3.0	3492	10.3	40.3	2.1	319.9	1569.7	1249.8	64.9	79.6	3.91	203	80587.7	125304	14526.8	0.0	65855.7	0.0	852.0
1989-11	5.0	0.0	0.0	4.0	2347	7.7	31.8	1.9	230.5	1184.7	954.2	56.9	80.5	4.14	247	80818.2	126258	14583.7	0.0	65855.7	0.0	852.0
1989-12	5.0	0.0	0.0	4.0	3363	10.1	20.4	2.4	313.4	944.7	631.3	74.4	66.8	2.01	237	81131.6	126889	14658.1	0.0	65855.7	0.0	852.0
1990-01	7.0	0.0	0.0	2.0	3947	12.0	21.3	2.1	371.5	1033.1	661.6	66.4	64.0	1.78	179	81503.1	127551	14724.5	0.0	65855.7	0.0	852.0
1990-02	6.0	0.0	0.0	3.0	3591	13.6	18.9	2.1	380.4	908.6	528.2	59.1	58.1	1.39	155	81883.5	128079	14783.6	0.0	65855.7	0.0	852.0
1990-03	5.0	1.0	0.0	3.0	3323	11.4	13.5	1.5	352.5	772.1	419.6	45.8	54.3	1.19	130	82236.0	128498	14829.4	4.8	65860.5	0.0	852.0
1990-04	6.0	1.0	0.0	2.0	3593	9.5	25.7	1.9	285.5	1055.1	769.6	55.9	72.9	2.70	196	82521.5	129268	14885.3	12.3	65872.8	0.0	852.0
1990-05	6.0	1.0	0.0	2.0	3454	11.2	33.4	2.3	346.7	1383.3	1036.6	70.1	74.9	2.99	202	82868.2	130305	14955.4	0.9	65873.7	0.0	852.0
1990-06	7.0	1.0	0.0	1.0	3798	12.5	15.6	2.1	376.1	844.2	468.1	63.3	55.4	1.24	168	83244.3	130773	15018.7	0.9	65874.6	0.0	852.0

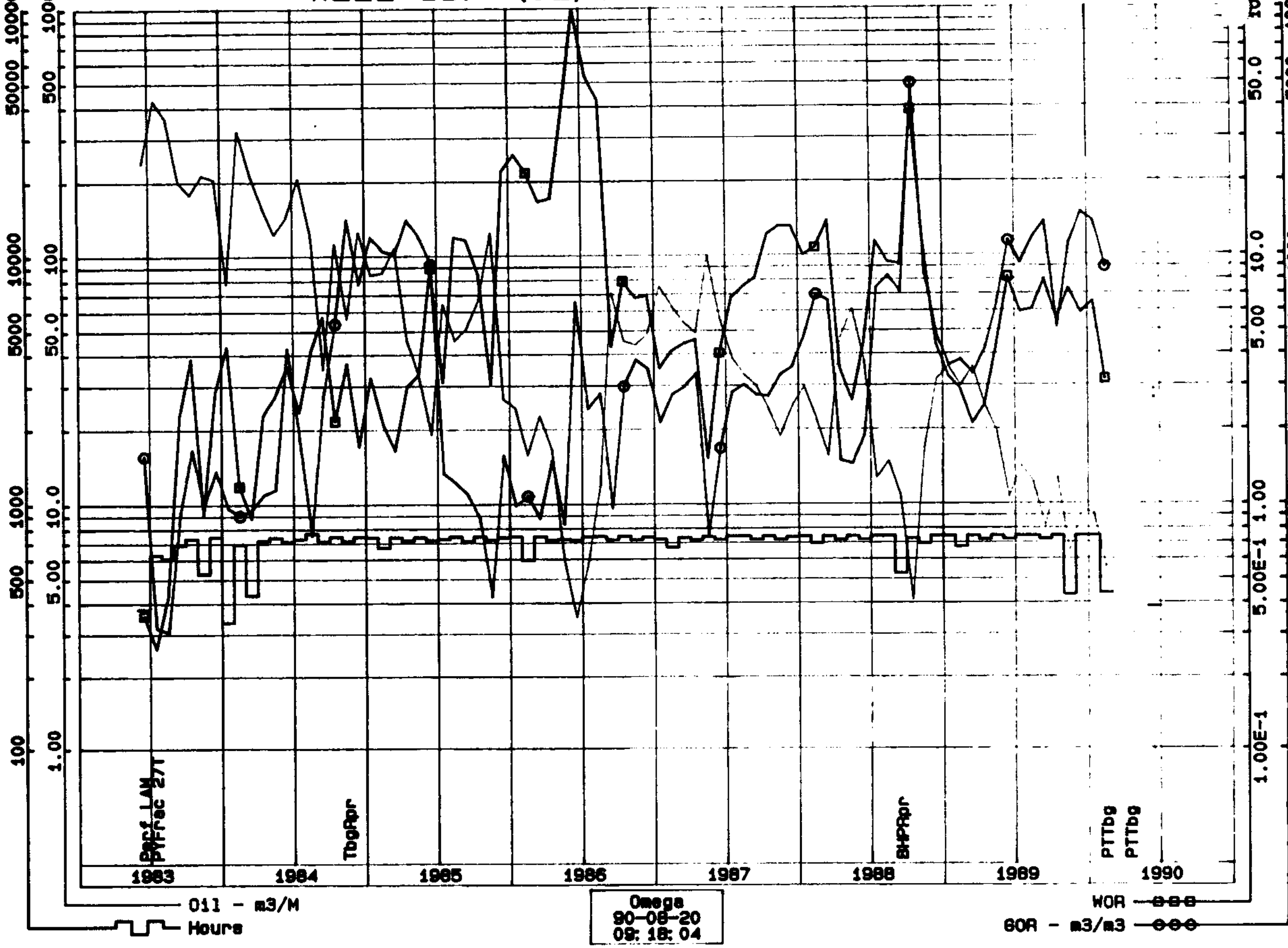
GROUP ID: PATTERN 5-24-1-26 WPM HISTORY
List of Wells

(00)01-23-001-26W1M(0)   (02)08-23-001-26W1M(0)   (00)09-23-001-26W1M(0)   (00)03-24-001-26W1M(0)   (00)04-24-001-26W1M(0)   (00)05-24-001-26W1M(0)   (00)06-24-001-26W1M(0)

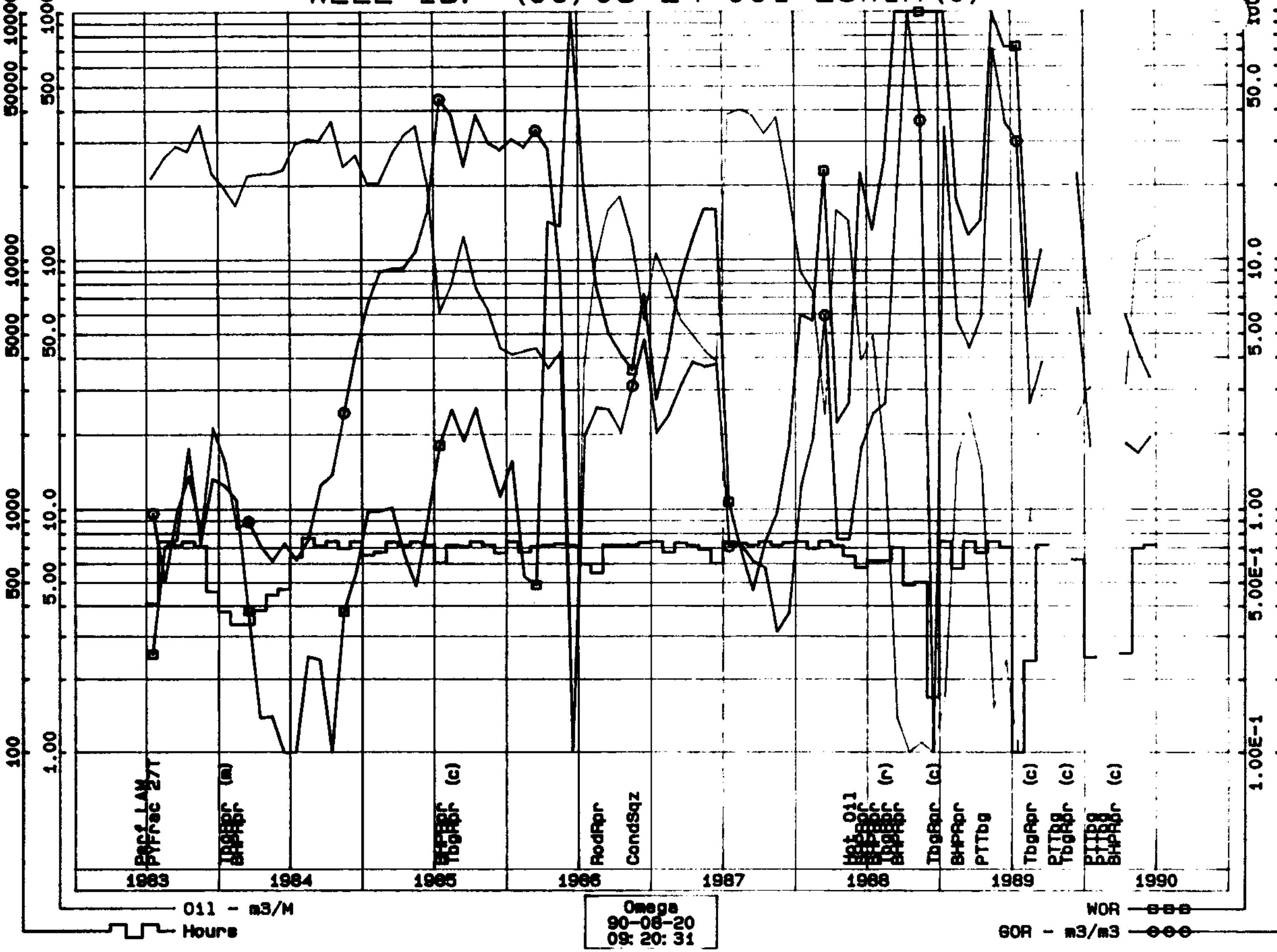
WELL ID: (00) 01-23-001-26W1M (0)



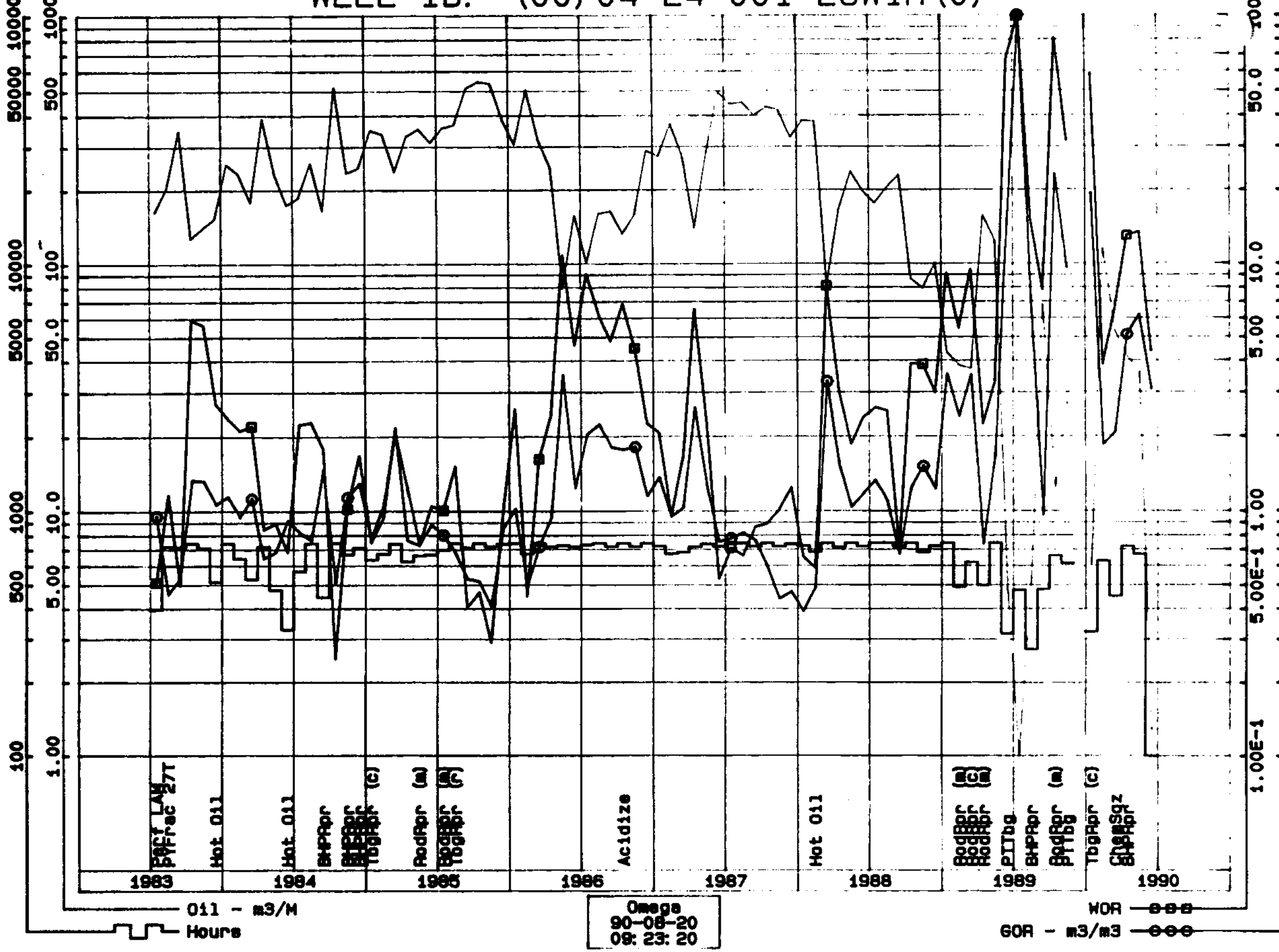
WELL ID: (02) 08-23-001-26W1M (0)

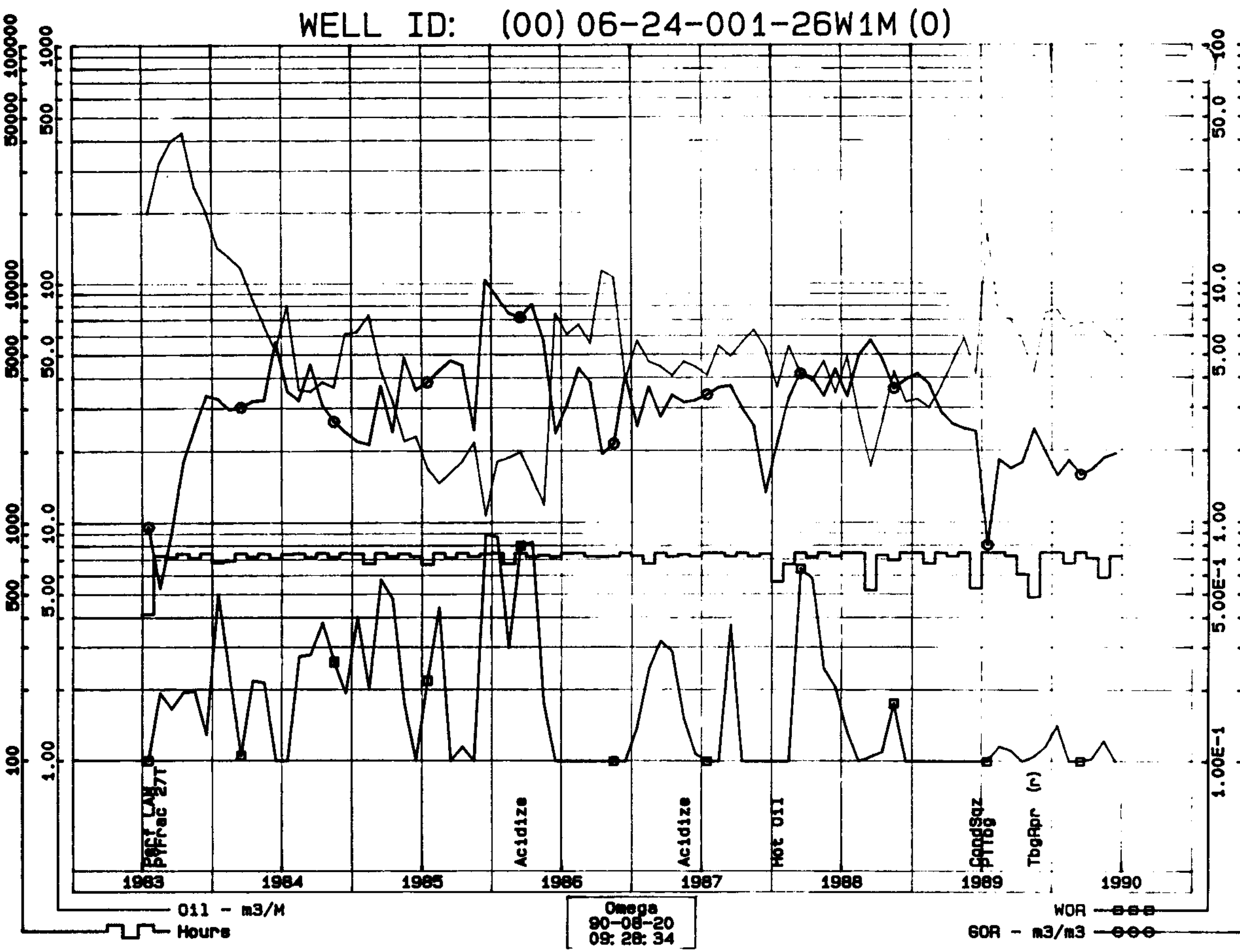


WELL ID: (00) 03-24-001-26W1M (0)



WELL ID: (00) 04-24-001-26W1M (0)





WELL ID: (00) 06-24-001-26W1M (0)
100000
50000
10000
5000
1000
500
100
10000
1000
500
100
50.0
10.0
5.00
1.00
100
50.0
10.0
5.00
1.00
5.00E-1
1.00E-1
10000
5000
1000
500
100
50.0
10.0
Perf LAM
PTfrac 27T
Acidize
Acidize
Hot Oil
CondSqz
PTTbg
TbgRpr (r)
1983
1984
1985
1986
1987
1988
1989
1990
Oil - m3/M
Hours
Omega
90-08-20
09:28:34
WOR
GOR - m3/m3

Waskada Lower Amaranth
Reduced Spacing Pilot Project
Oil Production Forecasts

Pattern 5-24-1-26 WPM

Year	Base Case Production (m^3)	Incremental Production (m^3)	Infill Case Production (m^3)
1990	4100	-	4100
1991	3821	2725	6546
1992	3439	2343	5782
1993	3095	2015	5110
1994	2786	1733	4519
1995	2507	1490	3997
1996	2256	1281	3537
1997	2031	1102	3133
1998	1828	948	2776
1999	1645	815	2460
2000	1480	701	2181
2001	1332	603	1935
2002	1198	518	1716
Total:	31518	16274	47792

Pattern 5-24 OOIP = 483,708 m^3
Cumulative Pattern Production (31/12/89) = 81132 m^3
Current Recovery Factor = 16.8%
Base Case Recovery Factor = 23.3%
Infill Case Recovery Factor = 26.6%

Base Case Parameters - Initial rate = 11.0m^3/d, Final rate = 3.2m^3/d
Decline rate = 10%/yr., Producing wells = 8

Incremental Parameters - Initial rate = 8.0m^3/d, Final rate=1.6m^3/d
Decline rate = 14%/yr, Producing wells= 4

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
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File: WINFILL

-------------------- CASE DESCRIPTION ----------------------

WASKADA INFILL DRILLING EVALUATION (PATTERN 5-24)
DRILL 4 WELL PILOT, ASSUMES 1990 D&S PRICE FORECST
1990 OPCOSTS:$1250/M,TREAT:$1.75/M3,TRUCK:$3.73/M3,ESC@5%/YR

Royalty Regime:	MANITOBA	Gas Holiday:	NO
Reserve type:	Prov Devel	Oil Holiday:	NO
Royalty Type:Crwn	Frhd	Eval/Prod Start:	91- 1/91- 1
Sensitivity:	NO	Proj/Econ Life:	12.0/12.0 yrs

-------------- NET PRESENT VALUES (M$) ----------------

DISC RATE (%)	0.0	10.0	15.0	20.0	25.0	30.0
B.T. OPER INC	1498	1049	908	800	715	647
B.T. CAP INV.	624	624	624	624	624	624
B.T. CASH FLOW	874	425	284	176	91	23
A.T. OPER INC	1246	895	783	697	628	573
A.T. CAP INV.	624	624	624	624	624	624
A.T. CASH FLOW	622	271	159	73	4	-51

--------- ECONOMIC INDICATORS ---------

		B.TAX	A.TAX
ROR	- PCNT	31.9	25.3
PAYOUT PERIOD	- EVAL	2.9	3.3
	- CAPTL	2.9	3.3
UNDISC PIR	- $/$	1.40	1.00
15.0 PCT PIR	- $/$	0.46	0.25
30.0 PCT PIR	- $/$	0.04	-0.08
NPV @ 15.0	- $/m3	17.45	9.78
NPV @ 30.0	- $/m3	1.39	-3.16

----------- PRODUCTS RECOVERY ------------

		GROSS	WI	ROY	NET
OIL	E3m3	16	16	2	14
GAS-RAW	E3m3	0	0		
GAS-SALES	E3m3	0	0	0	0
ETHANE	m3	0	0	0	0
PROPANE	m3	0	0	0	0
BUTANE	m3	0	0	0	0
CONDENS.	m3	0	0	0	0
SULPHUR	t	0	0	0	0
OTHER	m3	0	0	0	0

--------- COMPANY W.I. --------

	Init%	Avr%	Rev%
REVENUE	100.0	100.0	
FIELD CAP	100.0	0.0	
PLANT CAP			
GATH CAP			
ORR-GAS			
ORR-OIL			
ROYALTY	17.4	14.0	

--- WI CASH FLOW SUMMARY ---

YEAR	-----OIL PRODUCTION--- RATE m3/d	VOL. E3m3	PRICE $/m3	TOTAL REV. M$	--ROYALTY-- &MINTAX M$	%	--OPERATING-- EXPENSE M$	$/m3	CASH FLOW M$	NETBACK B.TAX $/m3	CAPTL INV. M$	B.TAX CASH M$	TOTAL TAX M$	-----AFTER TAX------ CASH M$	15.0% M$	CUM M$
ZERO											624	-624	0	-624	-624	-624
1991	7	3	135.67	370	64	17	79	28.86	227	83.25	0	227	3	224	208	-416
1992	6	2	148.01	347	55	16	80	34.26	212	90.38	0	212	17	194	158	-258
1993	6	2	161.48	325	47	14	82	40.80	196	97.36	0	196	28	168	119	-139
1994	5	2	176.14	305	41	13	84	48.73	180	104.00	0	180	33	147	90	-49
1995	4	1	192.18	286	38	13	87	58.37	162	108.64	0	162	35	126	67	18
1996	4	1	203.70	261	34	13	90	70.09	137	107.00	0	137	33	104	48	67
1997	3	1	215.97	238	31	13	93	84.29	114	103.53	0	114	29	85	34	101
1998	3	1	228.93	217	28	13	96	101.57	93	97.58	0	93	25	68	24	125
1999	2	1	242.65	198	26	13	100	122.67	72	88.47	0	72	20	52	16	140
2000	2	1	257.19	180	23	13	104	148.29	53	75.54	0	53	15	38	10	151
2001	2	1	272.61	164	21	13	108	179.49	35	57.80	0	35	10	25	6	156
2002	1	1	288.97	150	19	13	113	217.78	18	33.79	0	18	4	13	3	159
SUBT		16		3042	427		1116		1498		624	874	252	622	159	
REM.		0		0	-0		0		0		0	0	0	0	0	
TOTL		16		3042	427		1116		1498		624	874	252	622	159	
15.0% DISC				1664	243		513		908		624	284	125	159		
% OF REV.				100	15		31		55		37	17	8	10		

'ETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
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Comment: WASKADA INFILL DRILLING EVALUATION (PATTERN 5-24)

----- ECONOMIC INDICATORS AT POS = 0.0 -----

ROR	- PCNT	0.0	0.0
PAYOUT PERIOD	- YEARS	0.0	0.0
	- CAL.YEAR	1991.0	1991.0
UNDISC PIR	- $/$	-100.00	-54.16
15.0 PCT PIR	- $/$	-100.00	-57.25
30.0 PCT PIR	- $/$	-100.00	-59.80

Net capital exposure = 424 M$

BREAK EVEN PROBABILITY OF SUCCESS

Disc Rate [%]	15.0	30.0
B.Tax BECOS [%]	59.9	94.9
A.Tax BECOS [%]	60.4	125.4

RISK ANALYSIS

	BEFORE TAX						AFTER TAX					
Prob of Success %	ROR %	15% DCF M$	30% DCF M$	Payout Yrs	15% Payout Yrs	15% PIR %	ROR %	15% DCF M$	30% DCF M$	Payout Yrs	15% Payout Yrs	15% PIR %
0	0.0	-424	-424	0.00	0.00	-100	0.0	-243	-254	0.00	0.00	-57
0	0.0	-424	-424	0.00	0.00	-100	0.0	-243	-254	0.00	0.00	-57
10	0.0	-353	-379	0.00	0.00	-80	0.0	-203	-233	0.00	0.00	-46
20	0.0	-282	-335	0.00	0.00	-61	0.0	-162	-213	0.00	0.00	-35
30	0.0	-212	-290	0.00	0.00	-44	1.8	-122	-193	8.83	0.00	-25
40	4.5	-141	-245	7.34	0.00	-28	7.0	-82	-173	6.05	0.00	-16
50	10.0	-70	-201	5.52	0.00	-13	11.3	-42	-152	4.95	0.00	-8
60	15.1	1	-156	4.57	11.64	0	14.9	-2	-132	4.35	0.00	-0
70	19.7	72	-111	3.95	6.52	13	18.0	39	-112	3.93	7.14	7
80	24.0	142	-67	3.53	5.18	24	20.7	79	-92	3.65	5.88	13
90	28.1	213	-22	3.20	4.45	35	23.1	119	-72	3.43	5.18	20
100	31.9	284	23	2.94	3.93	46	25.3	159	-51	3.26	4.73	25

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
Time: 90/09/28 16:15:07
File: WINFILL
Report: peeproy

Comment: WASKADA INFILL DRILLING EVALUATION (PATTERN 5-24)

================================ WORKING INTEREST CROWN ROYALTIES, MINERAL TAX AND OTHER ROYALTIES ================================

	[---------- CROWN ROYALTIES AND MINERAL TAX								----------]	[-------- OTHER ROYALTIES			-------]
Year	Oil Crown Royalty M$	Gas Crown Royalty M$	Cond Crown Royalty M$	Propane Crown Royalty M$	Butane Crown Royalty M$	Sulphur Crown Roylaty M$	Ethane Crown Royalty M$	Other Prod. Crown Royalty M$	Man Sched Crown Royalty M$	Frhld Mineral Tax M$	Frhld Royalty M$	Oil Over-Riding Royalty M$	Gas Over-Riding Royalty M$	Net Profit Inter. M$
1991	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.1	47.2	0.0	0.0	0.0
1992	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.9	44.4	0.0	0.0	0.0
1993	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.2	41.7	0.0	0.0	0.0
1994	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	39.1	0.0	0.0	0.0
1995	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.7	0.0	0.0	0.0
1996	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.5	0.0	0.0	0.0
1997	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.6	0.0	0.0	0.0
1998	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.9	0.0	0.0	0.0
1999	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.4	0.0	0.0	0.0
2000	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.2	0.0	0.0	0.0
2001	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.1	0.0	0.0	0.0
2002	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.2	0.0	0.0	0.0
12.0	8.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.7	389.9	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.0	8.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.7	389.9	0.0	0.0	0.0

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
Time: 90/09/28 16:13:41
File: WINFILL
Report: newbtax

Comment: WASKADA INFILL DRILLING EVALUATION (PATTERN 5-24)

==================== WORKING INTEREST BEFORE TAX REPORT ====================

Year	Total Revenue M$	Initial Crown/ Manual Royalty M$	Final Crown/ Manual Royalty M$	ORR/ Frhld Royalty M$	Mineral Tax M$	Revenue After Royalty M$	Other Inc & ARTC M$	Total Oper Cost M$	Other Exp & NPI M$	Oper Income M$	Total Intang Capital M$	Total Tang. Capital M$	Total Capital M$	Cash Flow Before Tax M$
											568	56	624	
1991	370	2	2	47	15	306	0	79	0	212	0	0	0	-397
1992	347	1	1	44	9	292	0	80	0	203	0	0	0	212
1993	325	1	1	42	4	278	0	82	0	192	0	0	0	196
1994	305	1	1	39	0	265	0	84	0	180	0	0	0	180
1995	286	1	1	37	0	249	0	87	0	162	0	0	0	162
1996	261	1	1	33	0	227	0	90	0	137	0	0	0	137
1997	238	0	0	31	0	207	0	93	0	114	0	0	0	114
1998	217	0	0	28	0	189	0	96	0	93	0	0	0	93
1999	198	0	0	25	0	172	0	100	0	72	0	0	0	72
2000	180	0	0	23	0	157	0	104	0	53	0	0	0	53
2001	164	0	0	21	0	143	0	108	0	35	0	0	0	35
2002	150	0	0	19	0	130	0	113	0	18	0	0	0	18
12.0	3042	9	8	390	29	2614	0	1116	0	1469	568	56	624	874
0.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12.0	3042	9	8	390	29	2614	0	1116	0	1469	568	56	624	874

PETROLEUM ECONOMICS EVALUATION PROGRAM
OMEGA HYDROCARBONS LTD.

Version: 89-11-01
Time: 90/09/28 16:14:26
File: WINFILL
Report: peepat

Comment: WASKADA INFILL DRILLING EVALUATION (PATTERN 5-24)

==================== WORKING INTEREST AFTER TAX DATA ====================

Year	Resorc Income M$	Resorc Allow M$	Land& Dev Bal M$	Land& Dev Depr M$	Expl Bal M$	Expl Depr M$	Tang Bal M$	Tang Depr M$	Plant &Gath Bal M$	Plant &Gath Depr M$	Fed Taxbl Income M$	Fed Tax M$	Prov Taxbl Income M$	Prov Tax M$	Inv Credit M$	Total Tax M$	Cash Flow M$
1991	237	59	568	170	0	0	56	7	0	0	7	2	7	1	0	3	-400
1992	210	52	398	119	0	0	49	12	0	0	38	11	38	6	0	17	194
1993	192	48	278	83	0	0	37	9	0	0	61	18	61	10	0	28	168
1994	175	44	195	58	0	0	28	7	0	0	73	21	73	12	0	33	147
1995	157	39	136	41	0	0	21	5	0	0	77	22	77	13	0	35	126
1996	134	33	95	29	0	0	16	4	0	0	72	21	72	12	0	33	104
1997	112	28	67	20	0	0	12	3	0	0	64	18	64	11	0	29	85
1998	91	23	47	14	0	0	9	2	0	0	54	16	54	9	0	25	68
1999	71	18	33	10	0	0	7	2	0	0	43	12	43	7	0	20	52
2000	52	13	23	7	0	0	5	1	0	0	32	9	32	5	0	15	38
2001	34	9	16	5	0	0	4	1	0	0	21	6	21	4	0	10	25
2002	17	4	11	3	0	0	3	1	0	0	9	3	9	2	0	4	13
12.0	1481	370		560		0		54		0	551	159	551	94	0	252	622
0.0	0	0		0		0		0		0	0	0	0	0	0	0	0
12.0	1481	370		560		0		54		0	551	159	551	94	0	252	622

Figure 19

OIL-WATER RELATIVE PERMEABILITY

Waskada Lower Amaranth Pool

Irreducible Water Saturation = 0.37

Rock Type 2

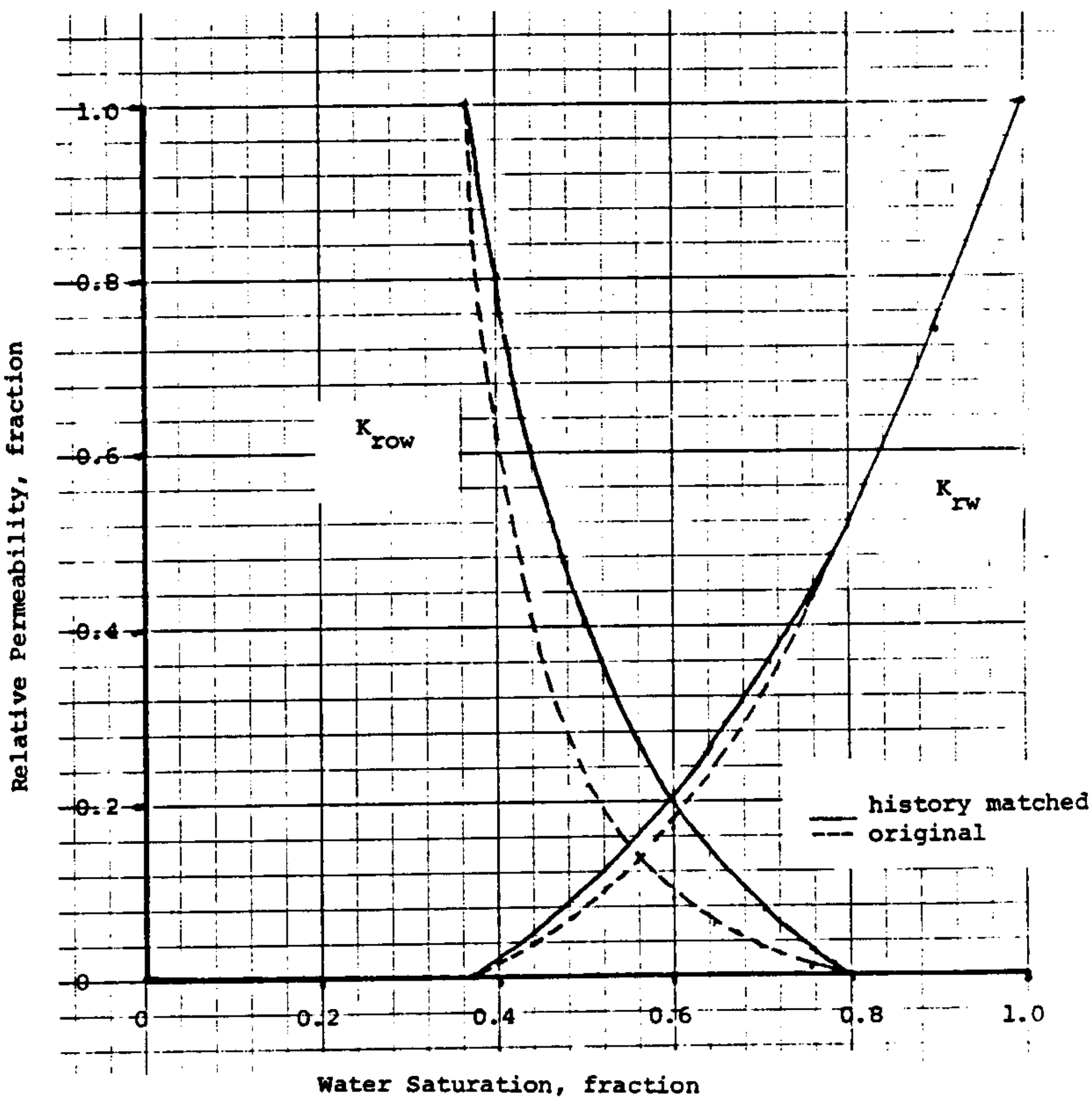


Figure 23

OIL-WATER RELATIVE PERMEABILITY

Waskada Lower Amaranth Pool

Irreducible Water Saturation = 0.63

Rock Type 3

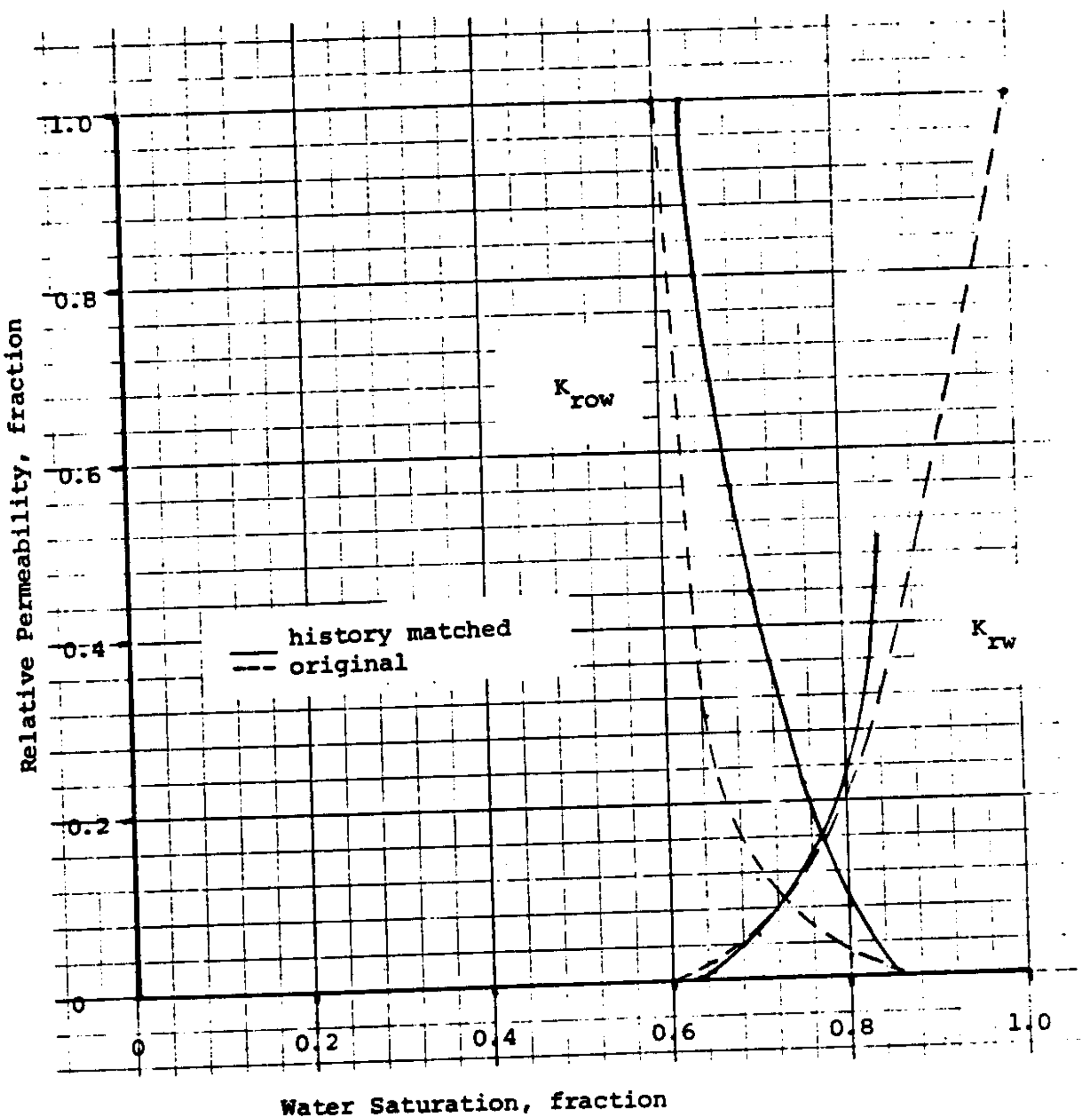


Figure 18

AVERAGE WATER-OIL RELATIVE PERMEABILITY RATIO

Waskada Lower Amaranth Pool

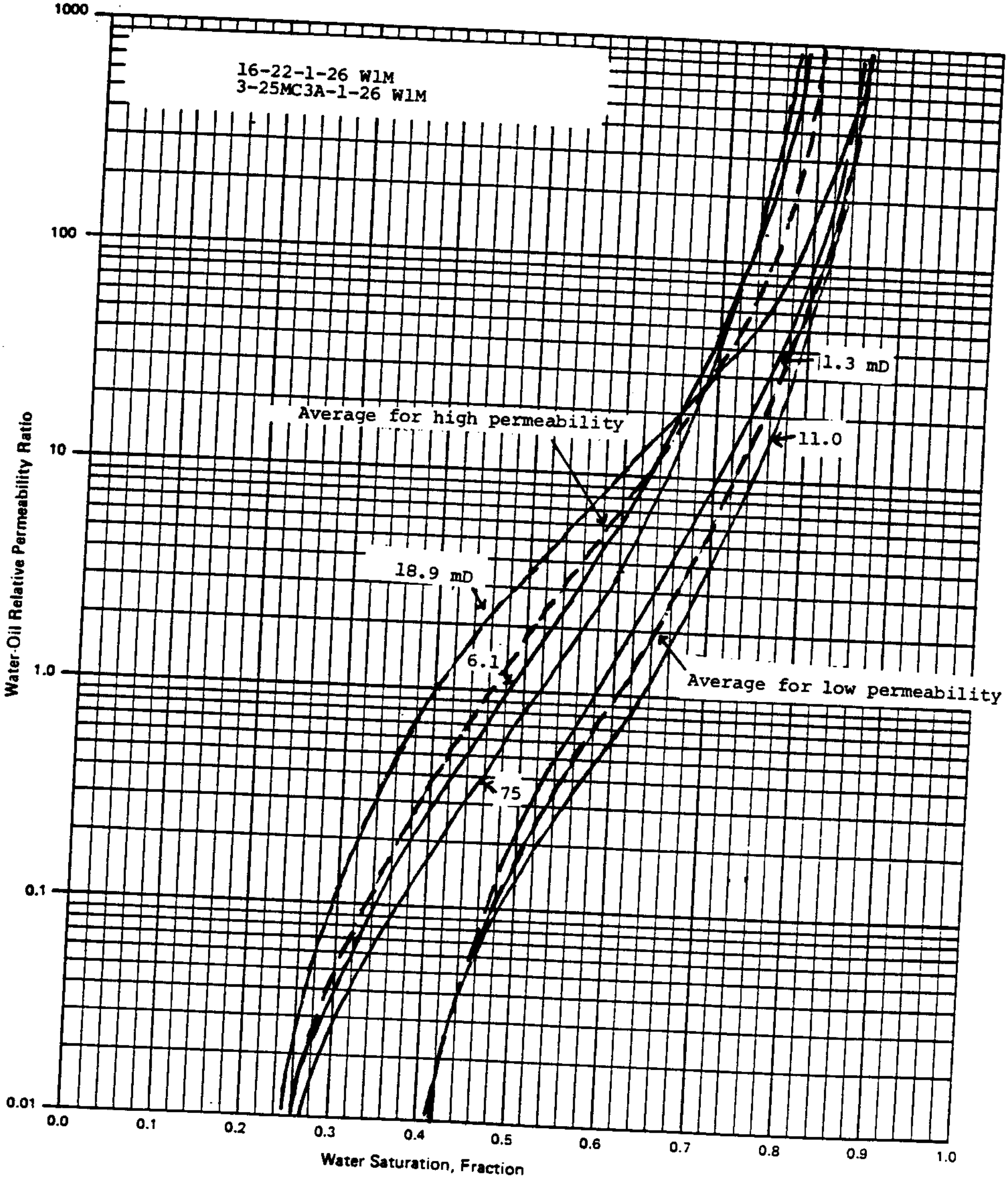


Figure 17

POROSITY-WATER SATURATION RELATIONSHIP

Waskada Lower Amaranth Pool

3-25-1-26 W1M

Oil Base Core

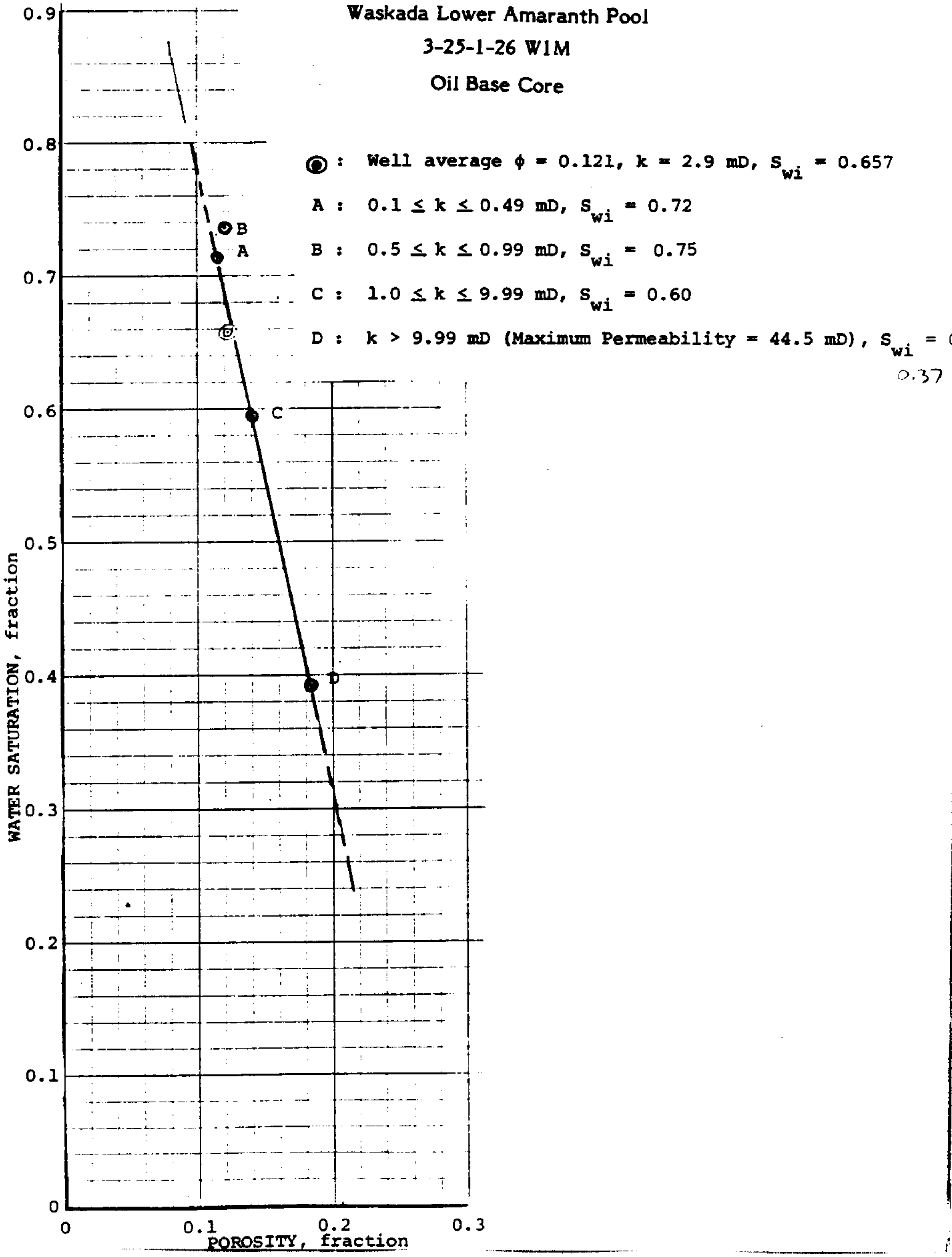


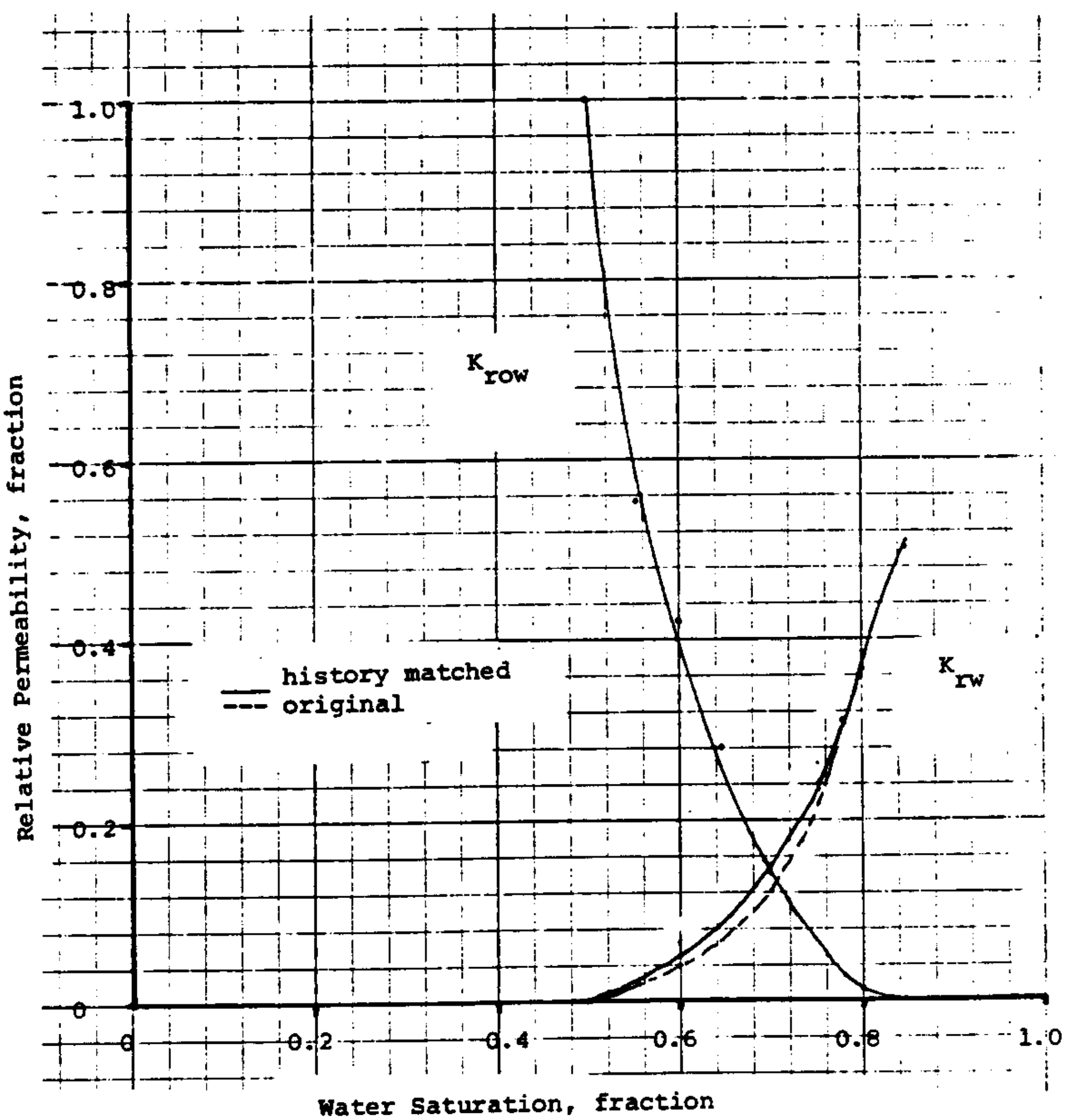
Figure 21

OIL-WATER RELATIVE PERMEABILITY

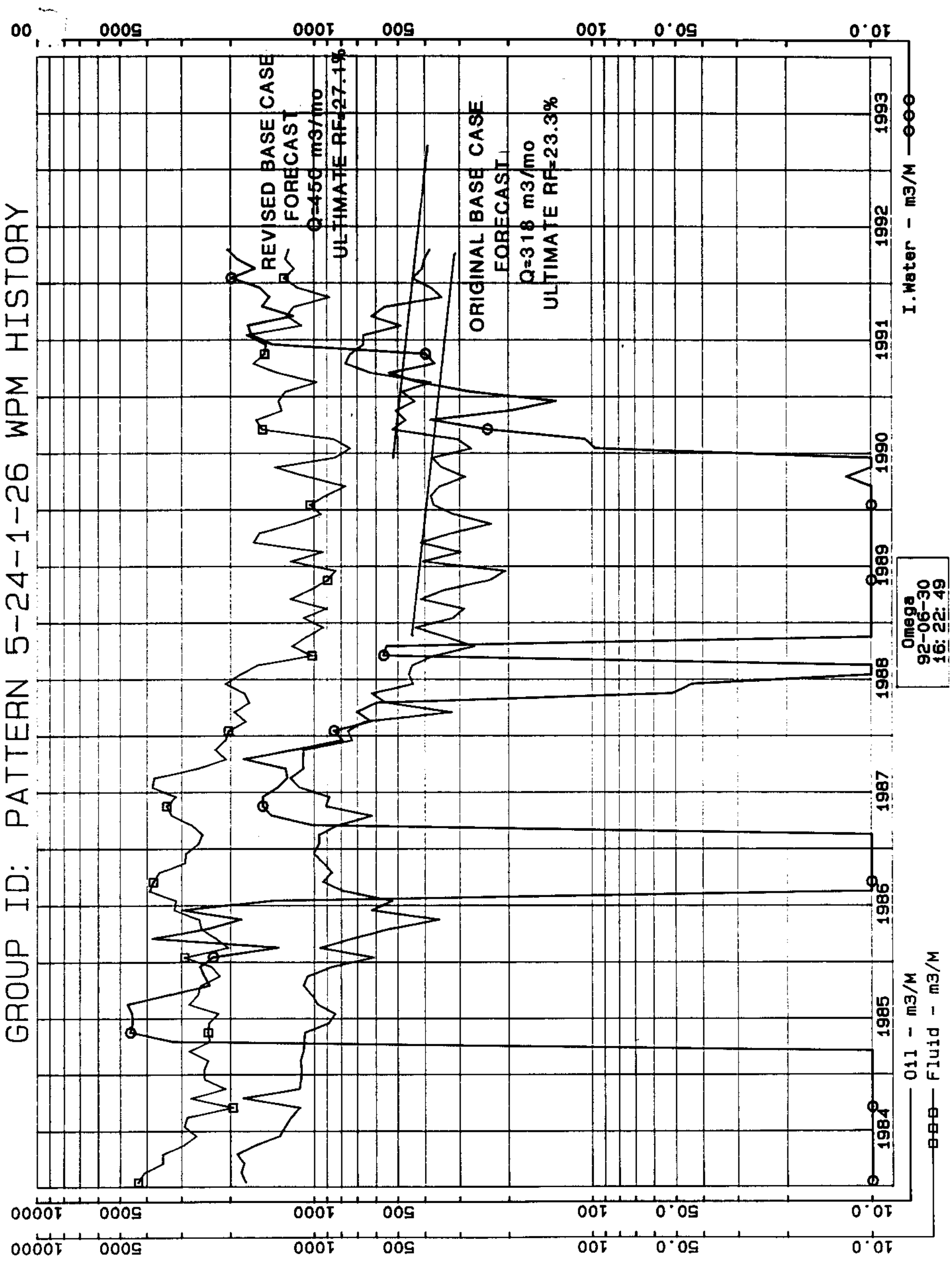
Waskada Lower Amaranth Pool

Irreducible Water Saturation = 0.5

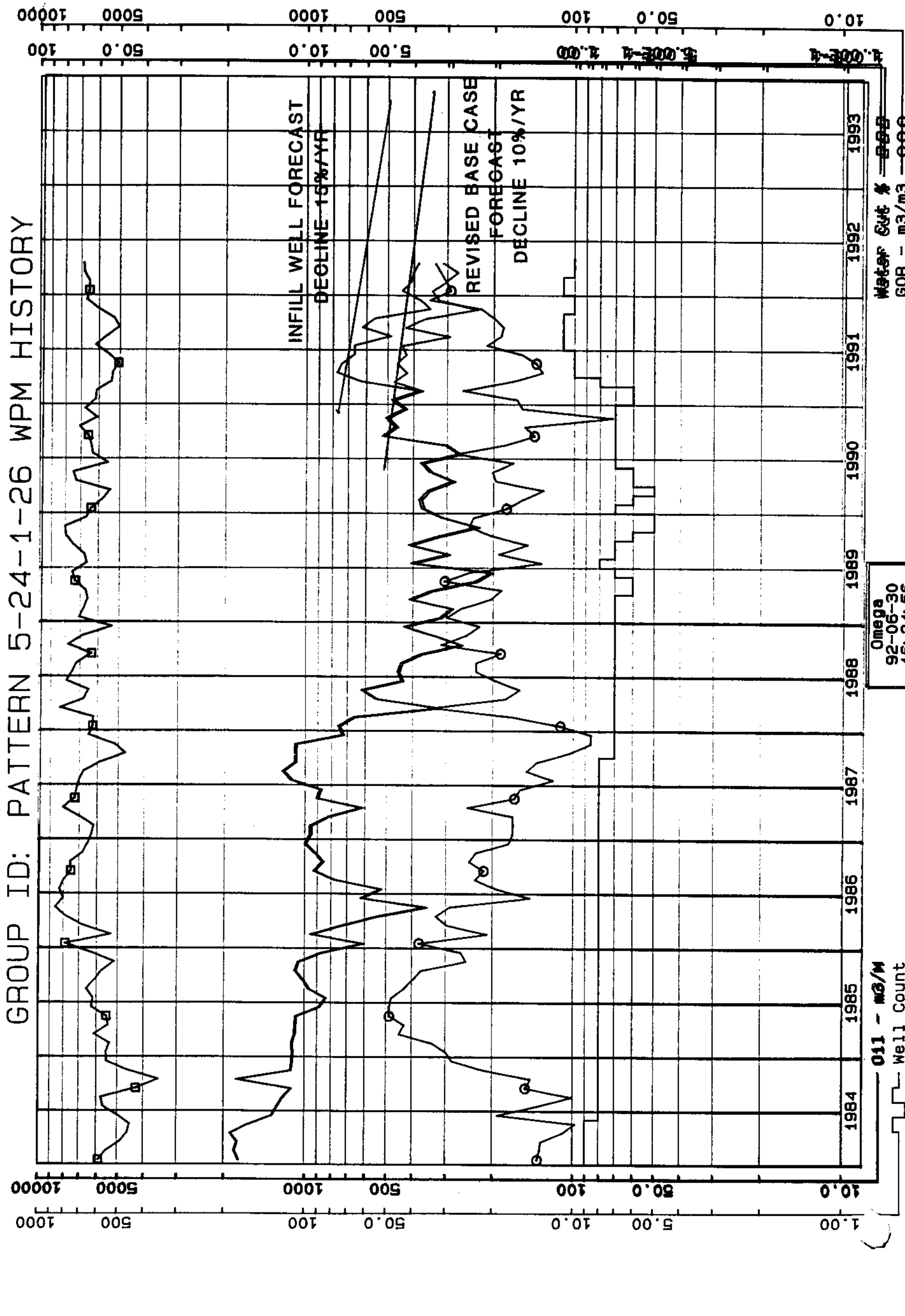
Rock Type 1



Attachment 1



Attachment 2



WASKADA UNIT No. 4

5-24-1-26 INJECTION PATTERN

1992 PRODUCTION (m^3)

1992	ALL WELLS	INFILL WELLS	EXISTING WELL
JAN	441.0	88.7	352.3
FEB	408.0	96	312.0
MAR	386.5	59.6	326.9
APR.	382.8	40	342.8

INITIAL INFILL WELL DECLINE RATE

$q_i = 337.1$ m^3/month (APR/91)

$q_t = 40$ m^3/month (APR/92)

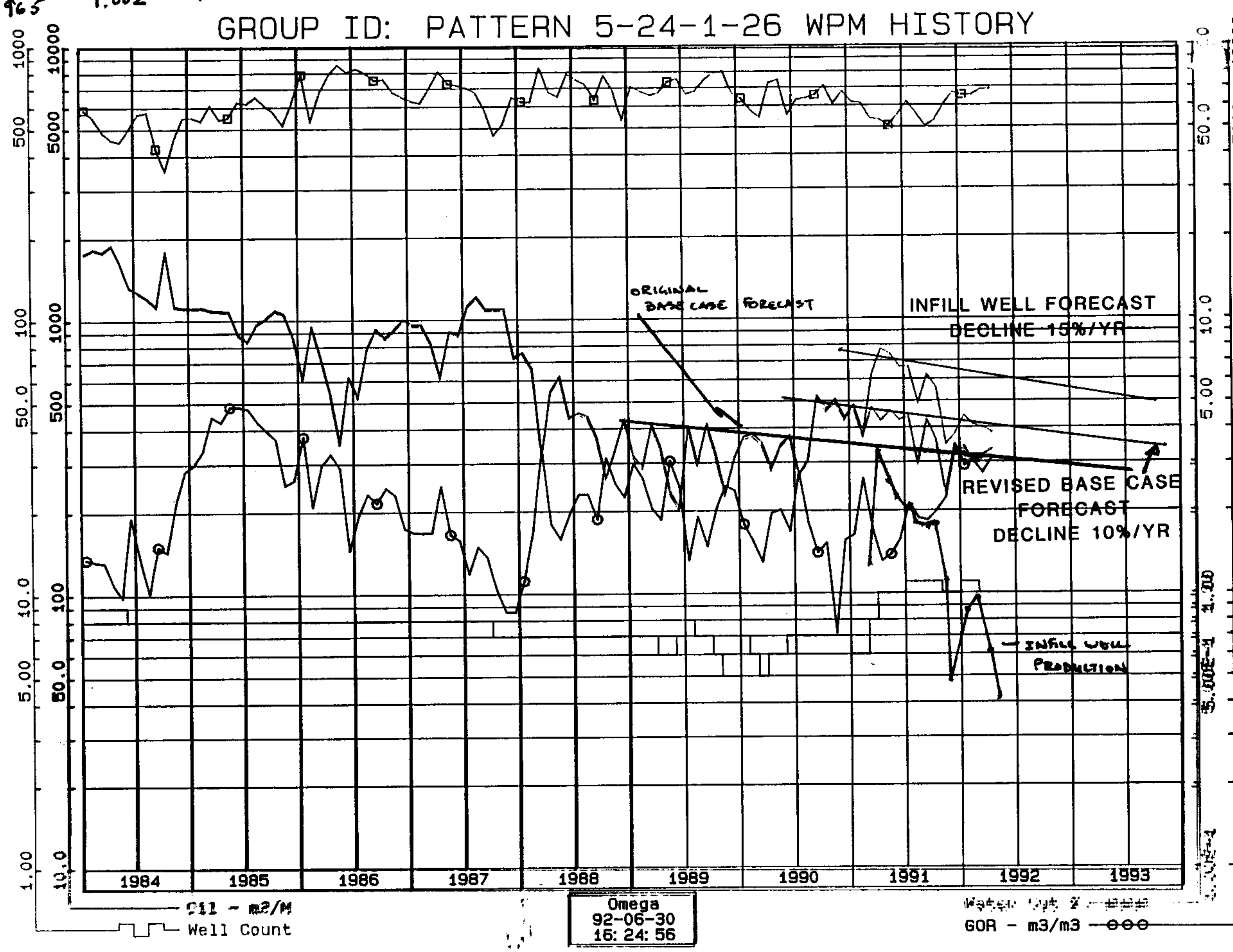
$t = 1$ yr

DECLINE RATE = 200 % / yr.

Attachment 2

PRORATION FACTORS OIL

JAN .965 FEB 1.002 MAR 1.072 APR 1.119



5-24 INJECTION PATTERN PRODUCTION EXCLUDING INFILL WELLS

June 20, 1991

Mr. Warren Sharp
District Manager
Omega Hydrocarbons Ltd.
P.O. Box 130
Waskada, Manitoba
ROM 2E0

Dear Warren:

RE: **Waskada Unit No. 4**
Reduced Spacing Project

Your request to continue to produce the infill wells to lease tank or run common flowlines has been reviewed by the Petroleum Branch.

Omega in its application for reduced spacing indicated the company would minimize the actively used lease area. This condition is regarded by The Oil and Natural Gas Conservation Board as fundamental to the approval of such projects. Therefore your request to permanently produce the infill wells to lease tank is denied. The infill wells may continue to be produced to lease tank until Omega is otherwise advised by the Branch.

The Branch is prepared to entertain an application for use of common flowlines for the infill wells. The application should be filed in accordance with the requirements of Section 127 of the Petroleum Drilling and Production Regulation. In particular, Omega is requested to file,

(1) plans for production testing the wells on the common flowline to ensure accurate data is obtained to evaluate the reduced spacing project, and

(2) detailed economics comparing the installation of separate and common flowlines for the infill wells.

If you have any questions in respect of this matter please contact the undersigned at 945-6574.

Yours truly,

John N. Fox, P. Eng.
Chief Petroleum Engineer

cc: Waskada

HYDROCARBONS Ltd.
TELEPHONE: (204) 673-2528
P.O. BOX 130, WASKADA, MANITOBA R0M 2E0

May 28, 1991.

Mr. John Fox,
Chief Petroleum Engineer,
Petroleum Branch,
555 - 330 Graham Avenue,
Winnipeg, Manitoba,
R3C 4E3.

Dear Sir:

Re: Producing Infill Pilot Project Wells

At the present time we are continuing to monitor the production out of each well on a daily basis. To do this we have to produce each well into a lease tank. If these wells were tied into a satellite we would not be able to leave them on test.

To accommodate our committment to minimize the activity on our lease areas we put in buried flowlines from 8A-23-1-26 to 6A-24-1-26 back to the built up road areas and placed our field tanks on these road areas. This causes very little extra inconvenience to the farming operations. As well we set these jacks east west rather than north south to minimize the obstruction for the farming patterns.

As of this time we are not sure the production has levelled off to the rate we can expect so we do not want to spend anymore than necessary to keep this an economically viable project.

We feel due to the capabilities of our existing production facilities the most economical way to produce these wells would be to common flowline one infill well with one existing well and use the usual testing procedure for common flowlines. This of course would be done after the initial testing period to lease tanks.

.../2

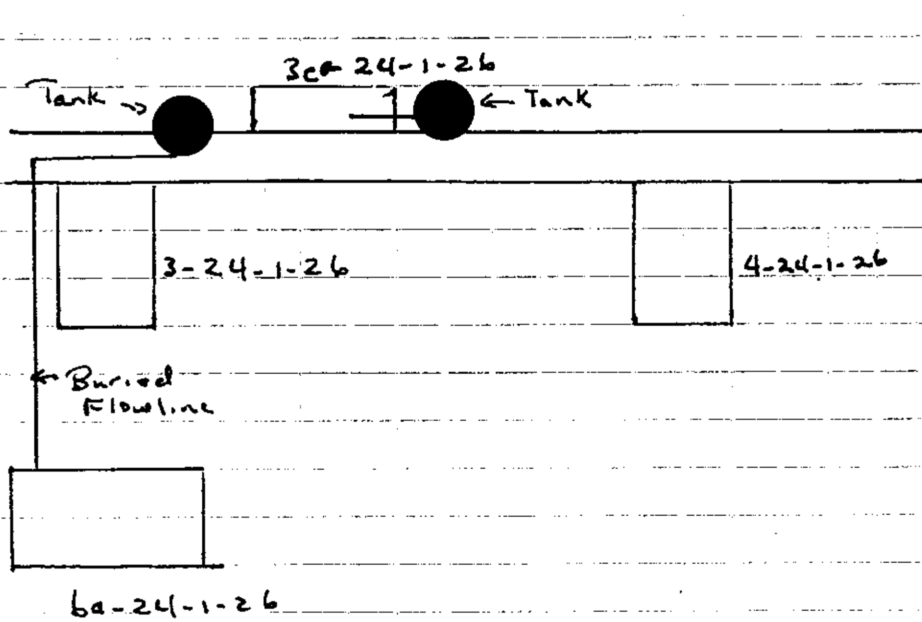
By doing this we would not have the cost of installing extra flowlines plus the disturbance to the farm land for flowline installation. If common flowlines are not acceptable our proposal would be to produce to the field tanks as we are now set up.

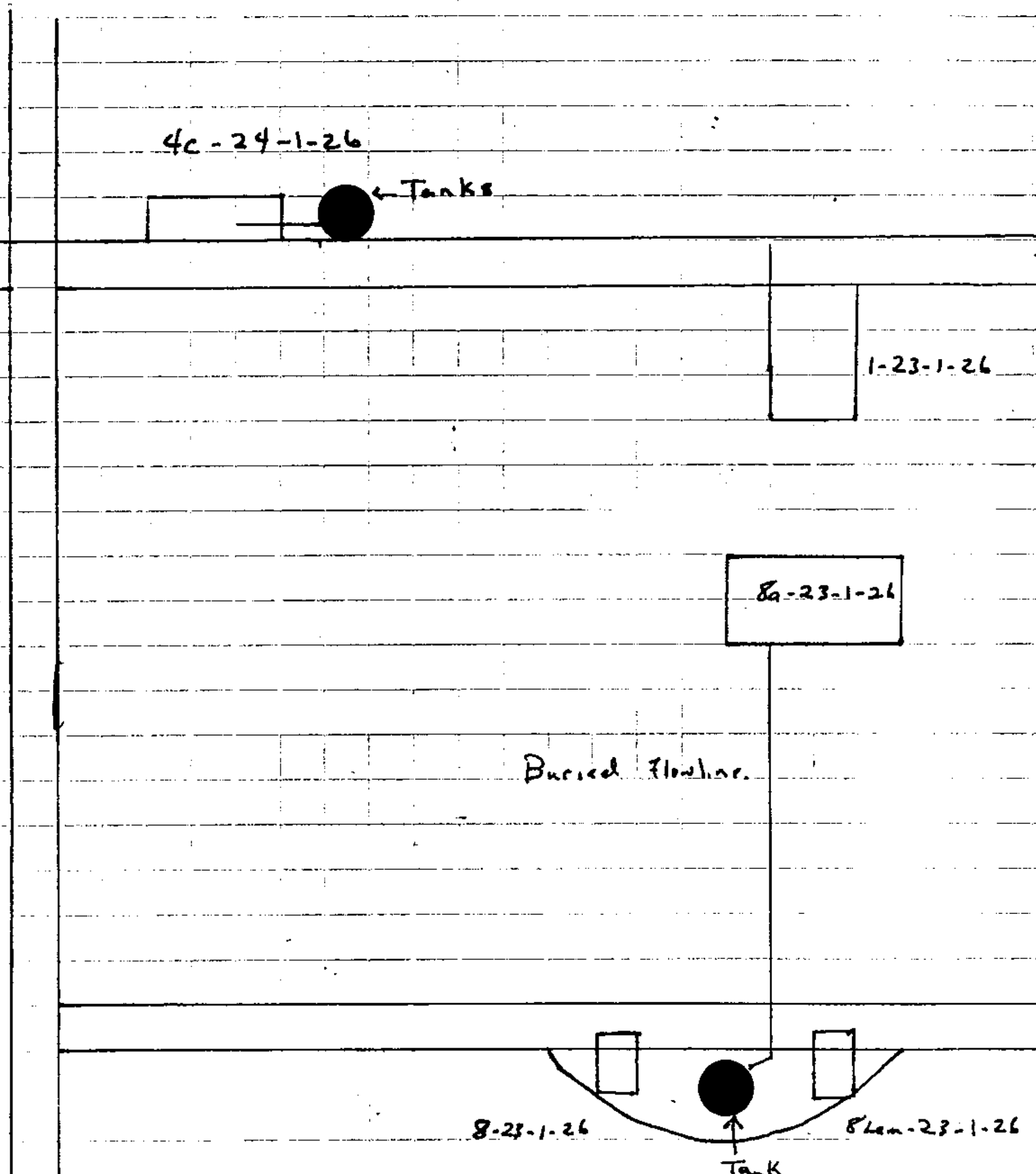
I hope you find this acceptable to enable us our continued operation of this project.

Yours truly,

Warren Sharp,
District Manager.

WS/sw





After test period.

Common Flowline

6a-24-1-26 → 3-24-1-26

3c-24-1-26 → 4-24-1-26

4c-24-1-26 → 1-23-1-26

8a-23-1-26 → 8-23-1-26

June 10, 1991

Mr. R.A. Brekke, P. Eng.
Senior Exploitation Engineer
Omega Hydrocarbons Ltd.
1300, 112 - 4th Avenue S.W.
Calgary, Alberta
T2P 0H3

Dear Richard:

RE: Waskada Reduced Spacing Pilot Project
Water Injection Targets

Your plans as outlined in your letter dated May 31, 1991, to over-inject at a voidage-replacement ratio of approximately 1.3 in the injection patterns in and surrounding the reduced spacing project area is acceptable.

The Branch is concerned that a continued drop in reservoir pressure may result in a loss in ultimate recovery. Therefore, failure to meet a voidage-replacement target of 1.0 may result in the Branch recommending to the Oil and Natural Gas Conservation Board that some of the producing wells in the reduced spacing project be shut in.

If you have any questions in respect of this matter, please contact the undersigned at (204) 945-6574.

Yours truly,

For

John N. Fox
Chief Petroleum Engineer

INJECTION PATTERN		MARCH, 1991 MONTHLY INJ. VOLUME (m^3)	MARCH, 1991 VRR	APRIL, 1991 MONTHLY INJ. VOLUME	APRIL, 1991 VRR
13-13		1.2	0	387.2	0.50
15-13		546.5	0.89	396.3	0.85
15-14		13.5	0.38	11.4	1.46
7-23		306.3	1.41	204.8	1.22
15-23		48.7	0.14	274	0.98
5-24		540.4	0.38	368.9	0.25
7-24		467.5	0.69	346.1	0.58
13A-24		180.1	0.40	138.4	0.39
15-24		123.0	0.32	122.4	0.31
	TOTAL	2227.2	0.46	2249.5	0.50

May 29, 1991

Mr. R.A. Brekke, P. Eng.
Senior Exploitation Engineer
Omega Hydrocarbons Ltd.
1300, 112 - 4th Avenue S.W.
Calgary, Alberta
T2P OH3

Dear Richard:

RE: Waskada Reduced Spacing Pilot Project
Water Injection Targets

The Branch has received your letter listing the results of pressure surveys conducted on the recently drilled infill wells. The Branch is very concerned that the average reservoir pressure in most of the infill wells is below the estimated bubble point pressure of 4220 kPa.

You are requested to provide the Branch with Omega's water injection targets for the 5-24-1-26 well and the surrounding injectors; 13-13-1-26, 15-13-1-26, 15-14-1-26, 7-23-1-26, 15-23-1-26, 7-24-1-26, 13-24-1-26 and 15-24-1-26. In support of the injection targets please provide an estimate of the time needed to repressure the project area to an average reservoir pressure (datum -440 m subsea) of 4500 - 5000 kpa.

If you have any questions please contact the undersigned at (204) 945-6574.

Yours truly,

John N. Fox, P. Eng.
Chief Petroleum Engineer

OMEGA
HYDROCARBONS LTD.

1300 SUN LIFE PLAZA III
112 - 4th AVENUE S.W.
CALGARY, ALBERTA, CANADA T2P 0H3
TELEPHONE (403) 261-0743
FAX (403) 264-5691

May 31, 1991

Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Attention: Mr. John Fox
Chief Petroleum Engineer

Dear Sir:

**RE: Waskada Reduced Spacing Pilot Project
Water Injection Targets**

Omega Hydrocarbons Ltd. concurs with your concern surrounding the low reservoir pressures found at the four infill wells and has taken steps to correct the situation starting June 1, 1991. The previously submitted isobaric map shows a localized low pressure area surrounding injection well 5-24-1-26 WPM and average reservoir pressures greater than the bubble point pressure at the surrounding injectors. Thus, Omega plans to overinject into injector 5-24-1-26 WPM while continuing to at least replace voidage at the offset injectors.

Attachment 1 summarizes the recent production withdrawl rates for the injection patterns of concern and the proposed injection targets for June 1991. It should be noted that the voidage replacement calculations presented herein incorporates the infill well production. Based on previous experience in Waskada and constant injection rates repressuring injection pattern 5-24-1-26 WPM to above 4500 kPa should be accomplished in approximately 4 months.

If there are any further questions related to this matter please contact the undersigned at (403) 261-0743.

Yours truly,

OMEGA HYDROCARBONS LTD.

R.A. Brekke, P. Eng.
Senior Exploitation Engineer

RB/ns
c.c.: J. Beardsworth
Waskada Reduced Spacing Application File

Waskada Reduced Spacing Pilot Project
Water Injection Targets

Injection Pattern	February 1991 Production Withdrawl (Rm^3)	March 1991 Production Withdrawl (Rm^3)	April 1991 Production Withdrawl (Rm^3)	Proposed June 1991 Water Injection Target (m^3/month)
13-13-1-26 WPM	677.3	746.0	771.9	750.0
15-13-1-26 WPM	610.6	612.5	464.9	450.0
15-14-1-26 WPM	0.0	35.8	7.8	150.0
7-23-1-26 WPM	74.5	216.7	167.5	210.0
15-23-1-26 WPM	346.2	343.3	279.4	750.0
5-24-1-26 WPM	1,244.7	1,405.0	1,472.0	1,800.0
7-24-1-26 WPM	670.9	675.8	601.9	600.0
13A-24-1-26 WPM	396.2	446.4	357.7	900.0
15-24-1-26 WPM	327.6	386.6	397.3	480.0
	4868.1		4520.4	6090

Note: Bw (injection water) = 1.007 Rm^3/m^3

AVER. 4700 m^3

VRR=1.30

May 1, 1991

Mr. Warren Sharp
Omega Hydrocarbons Ltd.
1300, 112 - 4th Avenue S.W.
Calgary, Alberta
T2P OH3

Dear Warren:

RE: Flowline Construction - Waskada Unit No. 4
Reduced Spacing Project

As a result of our discussion April 30, 1991, I reviewed the conditions of the Board's approval and the commitments Omega made in its application with respect to flowlines, production measurement and land use.

In its application Omega committed to flowlining the wells and minimizing the actively used lease area. The Petroleum Branch because it's a pilot project expects Omega to collect as accurate production data as possible. For these reasons I don't think it is feasible to use test tanks (except on a temporary basis) or common flowlines in the project area. The Petroleum Branch will however, review any proposal you have that accomplishes the above objectives.

If you want to discuss this further, please call me.

Yours truly,

John N. Fox
Chief Petroleum Engineer

cc: Waskada

Manitoba

The Oil and Natural Gas
Conservation Board

Room 309
Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

(204) 945-3130

January 25, 1991

Mr. R.A. Brekke, P. Eng.
Sr. Exploitation Engineer
Omega Hydrocarbons Ltd.
1300, 112-4th Avenue S.W.
Calgary, Alberta
T2P 0H3

Dear Sir:

RE: Waskada Unit No. 4 Reduced Spacing
Board Order No. SU 7

A copy of Board Order No. SU 7 establishing four (4) 200 x 200 m square spacing units in a portion of Waskada Unit No. 4 ("the project area") is attached.

The Board believes Omega's reduced spacing pilot project will provide valuable information on the potential for incremental recovery by infill drilling in the Waskada Lower Amaranth A Pool. The Board is not convinced however, that Omega's proposal of drilling only infill producers will maximize ultimate recovery.

The Board does not want to discourage operators from infill drilling but rather wants to encourage operators to thoroughly analyze infill drilling and waterflood modification alternatives and select the alternative that maximizes ultimate economic recovery. The Board believes that it would be beneficial for Omega to use the reservoir and performance data it has collected and the additional data that becomes available from the reduced spacing pilot project to update and fine-tune its 1985 Waskada Reservoir Model Study. The updated model study could then be utilized to evaluate infill drilling and waterflood modification alternatives for future reduced spacing applications.

The Board acknowledges Omega's plans to run an injection profile log at 5-24-1-26 to evaluate the vertical conformance of the waterflood. The Board is also pleased to see that Omega is considering the possibility of running fracture orientation logs and a tracer program. The information obtained from such surveys provides a better understanding of reservoir performance and would contribute significantly to the improvement of the model study.

Pressure maintenance operations in the project area will continue to be governed by Board Order No. PM 58 ("the Order"). Omega is reminded that in accordance with Section 1 of the Order, the company is required to either maintain continuous water injection or apply to the Board for approval to suspend water injection. The annual pressure maintenance project report required under Section 7 of the Order should be expanded to include a separate section discussing the performance of the reduced spacing project.

In order to minimize land use conflicts, it is the Board's understanding that Omega has committed to locating two of the infill wells on existing access roads, running underground hydro, using non built up roads, flowlining the wells and minimizing the actively used lease area.

The four proposed infill wells will be classified as new oil wells, entitled to a holiday oil volume calculated in accordance with the regulations. For further information on royalty and production tax matters, please contact Brad Thiessen, Manager of Petroleum Administration, at (204) 945-6571.

Omega in its application for well licences for the infill wells is requested to:

(1) submit for approval of the Director of Petroleum its drilling program including its contingency plan in the event of a well kick, blowout or other loss of control situation, and

(2) obtain the approval of the Rural Municipality of Arthur for any well to be located less then 50 m from the municipal road allowance.

If you have any questions in respect of this matter, please contact L.R. Dubreuil, Director of Petroleum, at (204) 945-6573 or John Fox, Chief Petroleum Engineer, at (204) 945-6574.

Yours respectfully,

HCMoster

H. Clare Moster
Deputy Chairman

Manitoba

The Oil and Natural Gas Conservation Board

Room 309
Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

(204) 945-3130

Order No. SU 7

An Order Pertaining to Drilling Spacing Units
Waskada Lower Amaranth A Pool
Waskada Unit No. 4

WHEREAS, subsection (9)(b) of section 62 of "The Mines Act", being Chapter M160 of the Continuing Consolidation of the Statutes of Manitoba, provides as follows:

"62(9) Without restricting the generality of subsection (8) the board, with the approval of the minister, may make orders

(b) respecting the designation of the area that shall be allocated to a well in connection with fixing allowable production;"

AND WHEREAS, clause (1)(f) of section 63 of "The Mines Act" being Chapter M160 of the Continuing Consolidation of the Statutes of Manitoba, provides in part as follows:

"63(1) For the purpose of carrying out the provisions of this Part and Part III according to their intent, the Lieutenant Governor in Council may make such regulations and orders as are ancillary thereto, and are not inconsistent therewith; and every such regulation or order made under, and in accordance with the authority granted by, this section has the force of law; and, without restricting the generality of the foregoing, the Lieutenant Governor in Council may make regulations and orders,

(f) prescribing spacing units and the size and shape of spacing units;"

AND WHEREAS, subsection (1) of section 20 of Manitoba Regulation 430/87R under The Mines Act ("the Petroleum Drilling and Production Regulation") provides as follows:

> "20(1) Notwithstanding section 19, the board may, after a public hearing or after publication of notice, prescribe by order special drilling spacing units which may differ from normal drilling spacing units in size, shape or target area."

AND WHEREAS, subsection (3) of Section 21 of the Petroleum Drilling and Production Regulation provides as follows:

> "21(3) Where a special drilling spacing unit is prescribed under section 20, the board may prescribe the target area within which a well shall be completed in order to qualify for a maximum permissible production rate based on the area of the special drilling spacing unit."

AND WHEREAS, the Board received an application dated September 28, 1990 from Omega Hydrocarbons Ltd. as unit operator of Waskada Unit No. 4 ("the unit area") for approval to reduce the size of drilling spacing units in a portion of the unit area outlined in Schedule A ("the project area").

AND WHEREAS, upon publication of notice of the application, the Board received no objections to or interventions in the application.

AND WHEREAS, the Board upon review of the application considers that establishment of smaller drilling spacing units within the project area may result in an increase in recovery of crude oil from the project area.

NOW THEREFORE, the Board orders:

1. The establishment of four (4) special drilling spacing units for the drilling of wells within the project area, for the purpose of producing oil from or injecting salt water into the Lower Amaranth Formation. Each spacing unit shall be a square having sides 200 metres in length, centered on the midpoint of the boundary of the legal subdivisions. The resulting configuration of special drilling spacing units is shown on Schedule A.

2. The target area of each special drilling spacing unit shall be a square area having sides fifty metres from the sides of the special drilling spacing unit and parallel to them.

3. The location of any new wells in the project area shall conform to the requirements of Section 17 of the Petroleum Drilling and Production Regulation and shall not be drilled within 130 metres of any other well in the pool.

H. Clare Moster
Deputy Chairman

Ian Haugh
Chairman

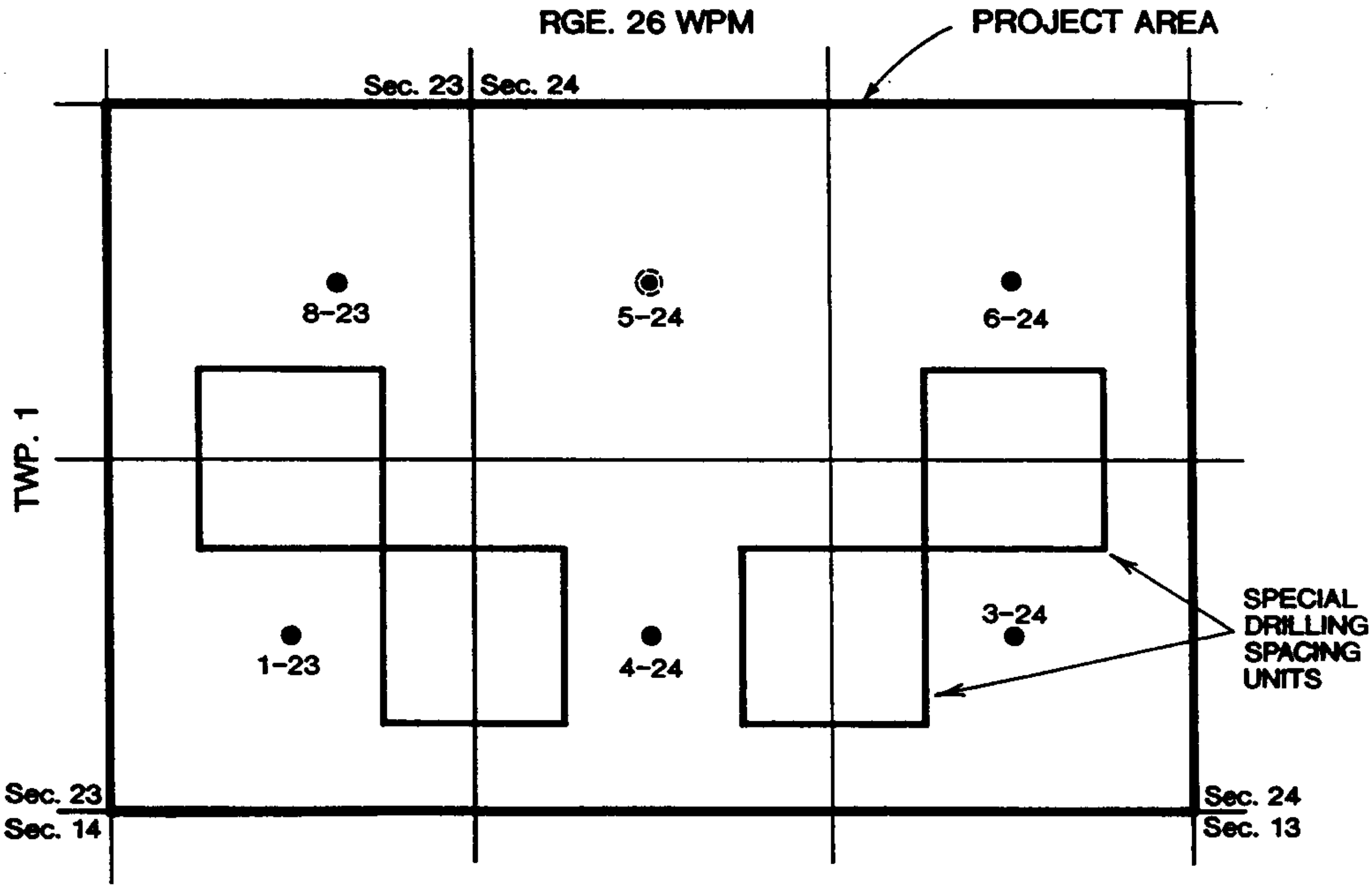
OIL AND NATURAL GAS CONSERVATION BOARD ORDER NO. SU 7 APPROVED THIS 23rd DAY OF January A.D., 1991 AT THE CITY OF WINNIPEG.

APPROVED:

Harold Neufeld
Minister of Energy and Mines

BOARD ORDER NO. SU 7
SCHEDULE A

WASKADA UNIT NO. 4
SPECIAL DRILLING SPACING UNITS
LOWER AMARANTH FORMATION



LEGEND

- Existing water injection well
- Existing producer

Manitoba

Action / Route Slip

Date: January ~~21~~ 23, 1991

To: Ian Haugh

From: H. Clare Moster

Telephone:

ASSISTANT DEPUTY MINISTER ENERGY JAN 24 1991 DEPARTMENT OF ENERGY and MINES

DEPARTMENT OF ENERGY AND MINES Deputy Minister's Office JAN 22 1991

- [ ] Take Action
- [ ] Per Your Request
- [ ] Circulate, Initial and Return
- [x] For Approval and Signature
- [ ] Make ___ Copies
- [ ] May We Discuss
- [ ] For Your Information
- [ ] Return With Comments or Revisions
- [ ] Draft Reply for Signature
- [x] Please File

Comments: RE: SPECIAL REDUCED SPACING APPLICATION (OMEGA - WASKADA UNIT NO. 4)

The attached Board Order No. SU 7 is recommended for your signature and the Minister's approval.

The proposed covering letter will be the Board's response to Omega's January 7, 1991 deficiency letter.

Please return signed and approved Order at your earliest convenience.

MG-1298 PS-f-182 8940100671

JOHN
FORWARDED TO MOSTER
JAN 16/91

Manitoba

Memorandum

Date January 16, 1991

To
The Oil and Natural Gas
Conservation Board
- Ian Haugh, Chairman
- H. Clare Moster, Deputy Chairman
- Wm. McDonald, Member

From
John N. Fox
Chief Petroleum Engineer
Petroleum Branch

Telephone

Subject

First | Fold

RE: Waskada Unit No. 4
Application for Reduced Spacing

Notice of Omega's application to reduce spacing in a portion of Waskada Unit No. 4 was advertised in the Melita New Era, the Deloraine Times and Star and the Manitoba Gazette. Notices were also sent directly to,

(1) the working interest and royalty owners within and adjacent to the project area,
(2) the surface owners in the project area,
(3) major operators in the Waskada Field,
(4) the Surface Rights Association, and
(5) Rural Development, Agriculture and Environment (including a copy of the application).

No objections to or interventions in the application were received. None of the Departments notified had any major concerns with the application (Attachments 1 - 3).

RECOMMENDATIONS

It is recommended that the Board approve the reduced spacing application. Proposed Board Order No. SU 7 establishing four (4) 200 m x 200 m square spacing units within the project area is attached.

The proposed Board letter of approval to accompany Board Order No. SU 7 is attached and requires Omega to,

(1) consider updating and fine-tuning its 1985 Reservoir Model Study to evaluate infill drilling and waterflood modification alternatives for future reduced spacing applications,

(2) submit a review of the reduced spacing project with its annual pressure maintenance project report,

(3) submit for approval of the Director of Petroleum its drilling program including Omega's contingency plan in the event of a well kick, blowout or other loss of well control situation, and

(4) obtain the approval of the Rural Municipality of Arthur for any well to be located less the 50 m from the municipal road allowance.

DISCUSSION

The proposed 96 ha reduced spacing pilot project is in the 5-24-1-26 (WPM) 9-spot injection pattern in Waskada Unit No. 4 (Figure 1). Omega selected the project area based on the following technical considerations,

(1) above average reservoir quality - average recovery 10386 m^3 /well in the project area vs. 4476 m^3 /well for the Waskada Field,

(2) good reservoir continuity,

(3) a proven oil producing area - current average productivity 2.1 m^3 /d/well in the project area vs. 1.3 m^3 /d/well for the Waskada Field,

(4) a low producing WOR - average WOR 2.6 m^3 /m^3 in the project area vs 1.3 m^3/m^3 for the Waskada Field, and

(5) a single injection pattern.

Pressure maintenance in the 5-24-1-26 injection pattern has included both gas and water injection. Gas was initially injected into 5-24-1-26 commencing in June, 1984. Premature gas breakthrough occurred in November, 1984 at the 8-23, 3-24 and 4-24 wells (Figure 2). Gas injection at 5-24 was terminated in March, 1985 after 852 x 10^3 m^3 gas (1.7% PV) was injected.

Water injection commenced in April, 1985 and to date a total of 66 319 m^3 (7.2% PV) has been injected.

A plot of the production history for the 5-24-1-26 injection pattern is shown in Figure 3 (the plot includes the 9-23, 11-24 and 12-24 wells outside the reduced spacing project area). From decline curve analysis, the estimated primary and secondary oil recovery for the 5-24 injection pattern is 12% OOIP and 23.3% OOIP, respectively. Individual well recoveries within the project area to date range from 5 - 25% OOIP and average 17.2% OOIP.

Omega's 1985 Waskada Reservoir Model Study of the Lower Amaranth Formation was conducted on the area just north of the proposed reduced spacing project area (Figure 1). The predicted primary and ultimate waterflood recovery from the model study were 9.1% and 36.5% - 38.2%, respectively (the variation in ultimate waterflood recovery was a function of the average permeability used).

Figure 4 shows the waterflood production forecast from the model study. The waterflood model performance is characterized by a lessening of the production decline and a steady increase in WOR over the first 10 years. No oil bank is formed as a result of the initial mobile water saturation.

The waterflood performance of the 5-24 injection pattern has been poorer than predicted, characterized by a more rapid decline in oil production and a higher than predicted and very erratic WOR.

By comparing the mobile oil saturation (initial oil saturation - residual oil saturation to waterflooding) to the estimated ultimate waterflood recovery for the 5-24 injection pattern, it is possible to estimate a volumetric sweep efficiency. Based on an initial oil saturation of 40% - 64% and a residual oil saturation after waterflooding of 15% - 20%, the estimated volumetric sweep efficiency for the 5-24 injection pattern is between 31% - 47%, compared with a predicted volumetric sweep from the model study of between 48% - 76%. Table 1 shows a comparison between actual performance of the 5-24 injection pattern and the waterflood performance predicted by the model study.

The reasons for the poor volumetric sweep efficiency in the 5-24 injection pattern are unclear but in all probability are a combination of the following:

(1) initial mobile water saturation - the 5-24 injection pattern had a WOR = 0.5 m^3/m^3 prior to waterflood start-up,

(2) permeability variations within the Lower Amaranth - only 12-24-1-26 in the 5-24 injection pattern has been cored but Chevron in its Waskada Unit No. 6 pressure maintenance application calculated a Dystra-Parsons permeability variation of 0.8 (range 0 - 1.0, with zero equivalent to a homogeneous system),

(3) injected fluid channelling between the injection/producer,

(4) preferential flow paths created by fractures induced during stimulation of the wells, and

(5) poor vertical distribution of injected water.

Since water injection commenced in the 5-24 injection pattern, injection has twice been suspended for significant periods of time, August /86 to March /87 and November /88 to February /90. During temporary suspension of water injection, which Omega indicated was to prevent premature water breakthrough from detrimentally affecting ultimate recovery, there was a steady decline in WOR and a corresponding moderation or reversal of the decline in oil production (Figure 3).

The premature breakthrough of gas injection and the production performance during the temporary suspension of water injection suggests that there is channelling between the 5-24 injector and some of the producing wells and overall poor areal sweep in the 5-24 injection pattern. Omega also contends that fractures induced during well stimulation have created a preferential flow path in a NE - SW direction which has had an adverse effect on waterflood performance. A review of the production of on-trend wells (1-23, 9-23, 3-24, and 11-24) and off-trend wells (8-23, 4-24, 6-24 and 12-24) shows little difference in performance until mid-1988 through 1989 when an erratic increase in water production at the on-trend wells 1-23 and 3-24 resulted in a significant drop in oil productivity, as shown in Figure 5. Presently, however, oil production and WOR for on and off-trend wells are comparable casting some doubt on Omega's conclusion that preferential movement of injected fluids along induced fractures has had a detrimental impact on waterflood preformance in the 5-24 injection pattern.

Waterflood performance in the 5-24 injection pattern has been poorer than predicted due to premature injection fluid breakthrough and poor volumetric sweep efficiency. It is suggested that because of the poor initial waterflood performance, the 5-24 injection pattern is a good infill drilling candidate.

REDUCED SPACING PILOT PROJECT DESIGN

Omega has applied for special reduced drilling spacing units within the project area to permit the drilling of 4 infill wells on 4 ha spacing units between existing producers as shown in Figure 1.

Omega's rationale for choosing the infill locations midway between existing producers is to place the wells outside theoretical production streamlines and the suspected NE - SW induced fracture plane, in a portion of the reservoir least likely to have been swept by the waterflood.

Omega estimates the improved areal sweep achieved by locating the infill wells in potentially unswept portions of the reservoir will result in an incremental recovery of 3.3% OOIP in the project area or approximately 4000 m^3 /well. The 3.3% increase in recovery represents a 4-6% increase in volumetric sweep efficiency as a result of the infill wells.

Reserve additions through infill drilling are difficult to quantify. Omega's estimated incremental recovery of 3.3% OOIP, is less than the incremental recovery of 4% OOIP commonly quoted in the literature for infill drilling from 16 ha to 8 ha spacing in low permeability reservoirs under waterflood.

Omega's infill well production forecast assumes an initial productivity of 2 m^3/d/well declining at 14% /yr with no interference between the infill and existing wells. This forecast is probably conservative given the average initial well productivity in the 5-24 injection pattern was 11.1 m^3/d/well and the current average productivity is 2.1 m^3/d/well.

Omega's injection strategy is to replace voidage and maintain reservoir pressure in the project area and surrounding injection patterns. The 5-24 injector and surrounding injection wells should have no problem meeting the additional voidage from the infill wells (estimated at 42 rm^3/d).

As a result of the temporary suspension of injection at 5-24-1-26, the cumulative voidage-replacement ratio in the 5-24 injection pattern is only 0.46 and the reservoir pressure at 5-24 is only 4545 kPa (static gradient run 90/12/19) less than 400 kPa above the bubble point. The Board should remind Omega that in accordance with Section 1 of Board Order No. PM 58 covering Omega's Lower Amaranth pressure maintenance projects, the operator is to either maintain continuous injection or apply to the Board for approval to suspend injection.

Omega indicated that should the reduced spacing project prove economically successful, it may apply to reduce spacing in Unit No.'s 1, 4 and 8 (Figure 6) which cover approximately 1/4 of the Waskada Field. Omega's tentative plans would be to continue drilling infill producers, 8 per 9-spot injection pattern thereby creating 17-spot injection patterns. Then, if required for pressure support, Omega may eventually modify injection to implement a line-drive scheme.

The Board in its deficiency letter (October 25, 1990) requested Omega review a number of infill drilling and waterflood modification alternatives.

(1) No infill drilling and conversion of producers to injectors to modify the existing 16 ha nine-spot injection pattern to 16 ha five-spot injection patterns (Figure 7).

(2) Infill drilling on 8 ha spacing and injector conversions to develop 8 ha nine-spot injection patterns (Figure 8).

(3) Infill drilling on 8 ha spacing and injection conversions to develop 8 ha five-spot injection patterns (Figure 9).

All the above infill drilling and waterflood modification alternatives improve areal sweep efficiency by altering flow streamlines, reducing interwell distances, realigning injection patterns, and increasing the injector/producer ratio. The location of the infill wells in Omega's proposed reduced spacing project effectively eliminates the above alternatives.

Omega's major concerns with the above alternatives are;

(1) the loss of productivity from conversion of existing producers to injectors,

(2) the additional capital costs for injector conversions, and

(3) the location of infill wells between existing producer/injector pairs in a swept portion of the reservoir.

In Omega's view, the above technical and economic concerns are magnified by the poor performance of the waterflood especially its failure to significantly increase productivity. The Petroleum Branch does not disagree with Omega's cursory assessment of the infill drilling and waterflood modification alternatives but believes future reduced spacing applications for the Waskada Lower Amaranth A Pool should include a more technically rigorous analysis of these alternatives.

In order to conduct a more detailed evaluation of infill drilling and water modification alternatives, Omega will require additional geological, reservoir and production data. The Petroleum Branch is concerned Omega's proposed pilot project evaluation program consisting of a dual induction and sonic log, additional pressure surveys and regular production testing will not provide this information.

The Board (December 21, 1990) requested Omega review the feasibility of running additional logs, tests, surveys and analyses designed to provide additional geological and reservoir information. Omega's position is that it has already collected the necessary data to obtain a comprehensive reservoir description. The company believes saturation logs and other zonal data has limited practical use because the wells have to be fractured. Omega did agree however to run an injection profile log at 5-24-1-26 and in the future consider conducting a tracer survey and running fracture orientation logs.

At this time, the Branch is prepared to recommend approval of the application without additional logs, tests, surveys and analyses. It is suggested however, that the Board indicate to Omega that it would be beneficial in the review of future reduced spacing applications, if the company used the reservoir data it has collected and the additional data from the reduced spacing project to fine-tune and update its 1985 Waskada Reservoir Model Study. The updated model study could then be utilized to evaluate infill drilling and waterflood modification alternatives.

LAND USE IMPACTS

The reduced spacing project area is totally in crop land. The location of the infill wells minimizes land use conflicts as 2 locations are on existing access roads as shown in Figure 10 (one adjacent to a municipal road allowance). The 4 infill locations including the access roads will require an additional 4 ha surface area. To further minimize the impact on agricultural activities, Omega plans to run underground hydro, use non built up trails, flow line the wells and minimize the actively used lease area.

When questioned as to whether horizontal drilling could be utilized to further reduce land use impacts, Omega indicated the Lower Amaranth Formation is not an ideal horizontal well target because of its lenticular nature. Other operators have also expressed concerns with the Lower Amaranth as a horizontal well target.

Omega has indicated, however, that in circumstances where land use impacts were severe, it would consider directional drilling. However, because of the added costs and the pilot nature of this project, Omega is not prepared to utilize directional drilling at this time.

PROPOSED BOARD ORDER NO. SU 7

The Petroleum Branch believes the proposed reduced spacing pilot project will yield information regarding the areal conformance of the waterflood and the potential for increasing recovery in the Waskada Lower Amaranth A Pool by infill drilling. It is therefore recommended that the application be approved. Proposed Board Order No. SU 7 establishes four

(4) 4 ha spacing units for the drilling of the infill wells. The 200 m x 200 m square spacing units which overlie the original 16 ha spacing units are centered on the midpoint of the boundaries of the LSD's. No attempt has been made to modify the original 16 ha spacing units.

ORIGINAL SIGNED BY
JOHN N. FOX

John N. Fox

Encl.

Original signed by
L. R. DUBREUIL

Approved: ______________________________

L.R. Dubreuil, Director

<u>**Order No. SU 7**</u>

An Order Pertaining to Drilling Spacing Units
Waskada Lower Amaranth A Pool
Waskada Unit No. 4

WHEREAS, subsection (9)(b) of section 62 of "The Mines Act", being Chapter M160 of the Continuing Consolidation of the Statutes of Manitoba, provides as follows:

> "62(9) Without restricting the generality of subsection (8) the board, with the approval of the minister, may make orders
>
> (b) respecting the designation of the area that shall be allocated to a well in connection with fixing allowable production;"

AND WHEREAS, clause (1)(f) of section 63 of "The Mines Act" being Chapter M160 of the Continuing Consolidation of the Statutes of Manitoba, provides in part as follows:

> "63(1) For the purpose of carrying out the provisions of this Part and Part III according to their intent, the Lieutenant Governor in Council may make such regulations and orders as are ancillary thereto, and are not inconsistent therewith; and every such regulation or order made under, and in accordance with the authority granted by, this section has the force of law; and, without restricting the generality of the foregoing, the Lieutenant Governor in Council may make regulations and orders,
>
> (f) prescribing spacing units and the size and shape of spacing units;"

AND WHEREAS, subsection (1) of section 20 of Manitoba Regulation 430/87R under The Mines Act ("the Petroleum Drilling and Production Regulation") provides as follows:

> "20(1) Notwithstanding section 19, the board may, after a public hearing or after publication of notice, prescribe by order special drilling spacing units which may differ from normal drilling spacing units in size, shape or target area."

AND WHEREAS, subsection (3) of Section 21 of the Petroleum Drilling and Production Regulation provides as follows:

> "21(3) Where a special drilling spacing unit is prescribed under section 20, the board may prescribe the target area within which a well shall be completed in order to qualify for a maximum permissible production rate based on the area of the special drilling spacing unit."

AND WHEREAS, the Board received an application dated September 28, 1990 from Omega Hydrocarbons Ltd. as unit operator of Waskada Unit No. 4 ("the unit area") for approval to reduce the size of drilling spacing units in a portion of the unit area outlined in Schedule A ("the project area").

AND WHEREAS, upon publication of notice of the application, the Board received no objections to or interventions in the application.

AND WHEREAS, the Board upon review of the application considers that establishment of smaller drilling spacing units within the project area may result in an increase in recovery of crude oil from the project area.

NOW THEREFORE, the Board orders:

1. The establishment of four (4) special drilling spacing units for the drilling of wells within the project area, for the purpose of producing oil from or injecting salt water into the Lower Amaranth Formation. Each spacing unit shall be a square having sides 200 metres in length, centered on the midpoint of the boundary of the legal subdivisions. The resulting configuration of special drilling spacing units is shown on Schedule A.

2. The target area of each special drilling spacing unit shall be a square area having sides fifty metres from the sides of the special drilling spacing unit and parallel to them.

3. The location of any new wells in the project area shall conform to the requirements of Section 17 of the Petroleum Drilling and Production Regulation and shall not be drilled within 130 metres of any other well in the pool.

H. Clare Moster
Deputy Chairman

Ian Haugh
Chairman

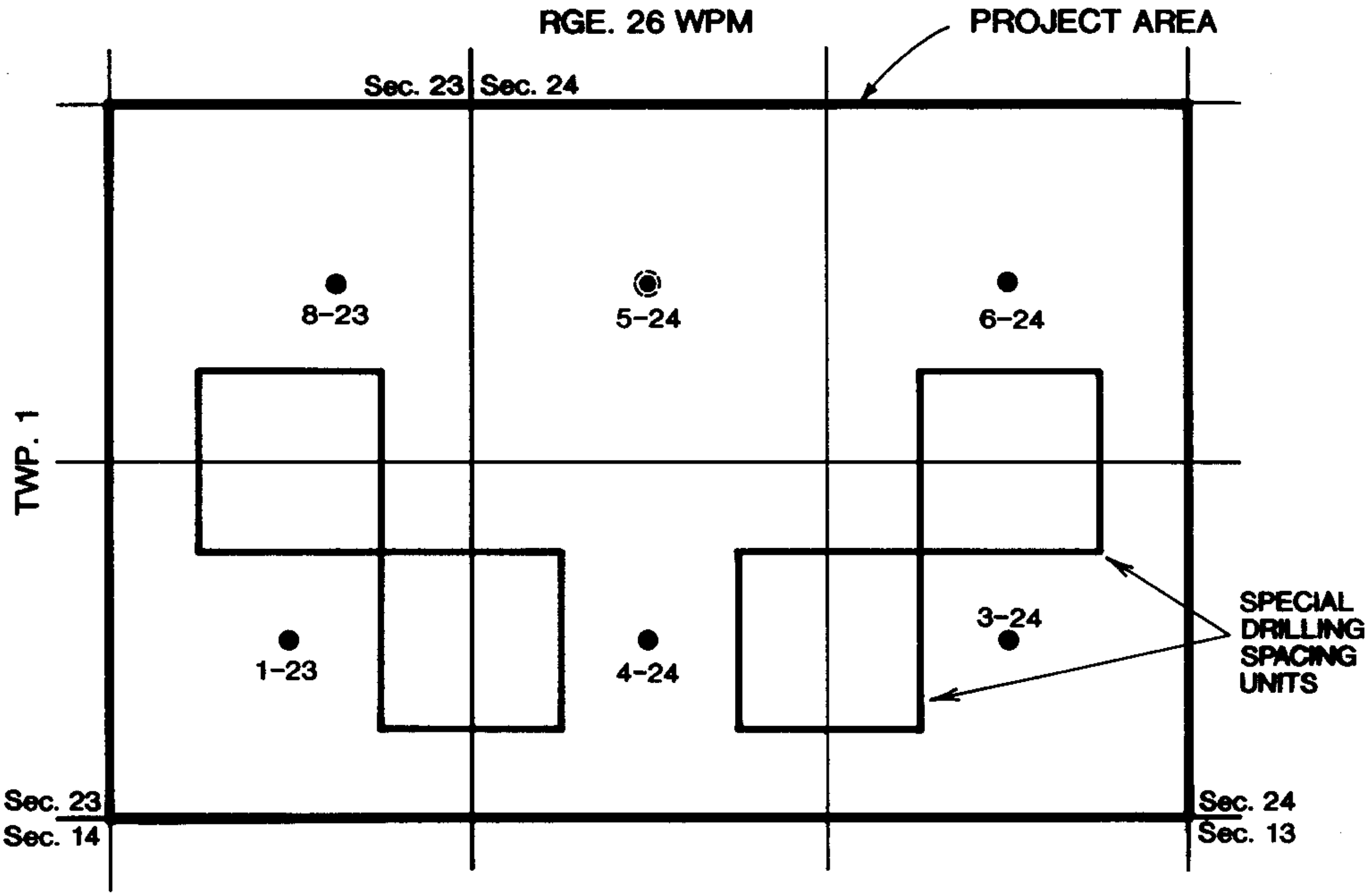
OIL AND NATURAL GAS CONSERVATION
BOARD ORDER NO. SU 7 APPROVED THIS
DAY OF A.D., 1991
AT THE CITY OF WINNIPEG.

APPROVED:

Harold Neufeld
Minister of Energy and Mines

BOARD ORDER NO. SU 7
SCHEDULE A

WASKADA UNIT NO. 4
SPECIAL DRILLING SPACING UNITS
LOWER AMARANTH FORMATION



LEGEND

◉ Existing water injection well

● Existing producer

ATTACHMENT 1

Man'toba

Memorandum

Date: January 15, 1991

To: Mr. John N. Fox
Chief Petroleum Engineer
Petroleum Branch
555 - 330 Graham Ave.

From: Serge Scrafield
Acting Director
Provincial Planning
Rural Development

Telephone: 405 - 800 Portage

Subject: **WASKADA UNIT NO. 4**
~~REDUCED SPACING PILOT PROJECT~~

Thank you for sending to us a copy of Omega's application and additional information filed in support of their application.

Our Department's Field Office in Deloraine has reviewed the material and discussed the project proposal with the Reeve of the R.M. of Arthur and with your Department's inspector in Waskada.

The following concerns were raised:

- That there be proper set backs from municipal roads;
- That the results of the Pilot Project be made available to the municipality;
- That the company make every effort to reach satisfactory lease arrangements with the landowners involved; and
- That the company undertake effective and prompt remedial actions should there be any spills.

Should you receive, at anytime, a report on the Pilot Project from the company, we and the municipality would appreciate a copy.

Thank you very much for your attention.

Shelby Prod
for Serge Scrafield

SS\SP

c.c. Mr. G. D. Forrest
Mr. D. Johns
Mr. N. Carroll
Mr. T. Brown
Mr. D. Partridge

ATTACHMENT 2

Manitoba

Memorandum

Date December 21, 1990

To John Fox
Chief Petroleum Eng.
Petroleum Branch
555-330 Graham Ave.

From J.R.D. Partridge, Chief
Land Utilization Section
Manitoba Agriculture
908 - 401 York Ave.
Winnipeg, MB.

Subject Reduced Spacing Pilot
Waskada Unit 4

Telephone 945-3837

First | Fold

We have reviewed the proposed reduced spacing project for four pilot wells on SE23 & SW24-1-26W, and in view of the proposed alignment of the new wells with existing wells, feel they will have much less adverse impact on farming operations than if they were sited on the L.S.D. corners as some previous proposals have been.

J.R.D. Partridge

PS f 25 894-01-00271

ATTACHMENT 3

PS-f-25

Manitoba

Memorandum

Date: December 21, 1990

To: John N. Fox
Chief Petroleum Engineer
Petroleum Branch
555- 330 Graham Avenue

From: Floyd Phillips
Chief, Terrestrial
Quality Management

Subject: Omega Hydrocarbons Reduced Spacing Pilot Project

Telephone: 945-7003

First | Fold

The Terrestrial Quality Section of Manitoba Environment is not concerned about the impacts of this reduced spacing pilot project.

Manitoba Environment is concerned about the potential loss of agricultural land and natural habitat which could result if reduced spacing proves to be viable and is expanded in the future. We realize that it is really up to the land owner to decide whether economic benefits adequately compensate for the loss of productive land and the inconvenience of more obstructions in the fields. Nevertheless we would want the proponent to make every effort to avoid positioning wells in agricultural fields or within the high water zone of potholes or creeks. The company should also avoid locations within natural bush or grassland habitat as much as possible. Wells should be located at the edge of fields, preferably along property boundaries and fence lines or at the edge of natural grassland or bush areas.

Thank you for giving us the opportunity of commenting on this proposal.

S. Floyd Phillips.

S. Floyd Phillips

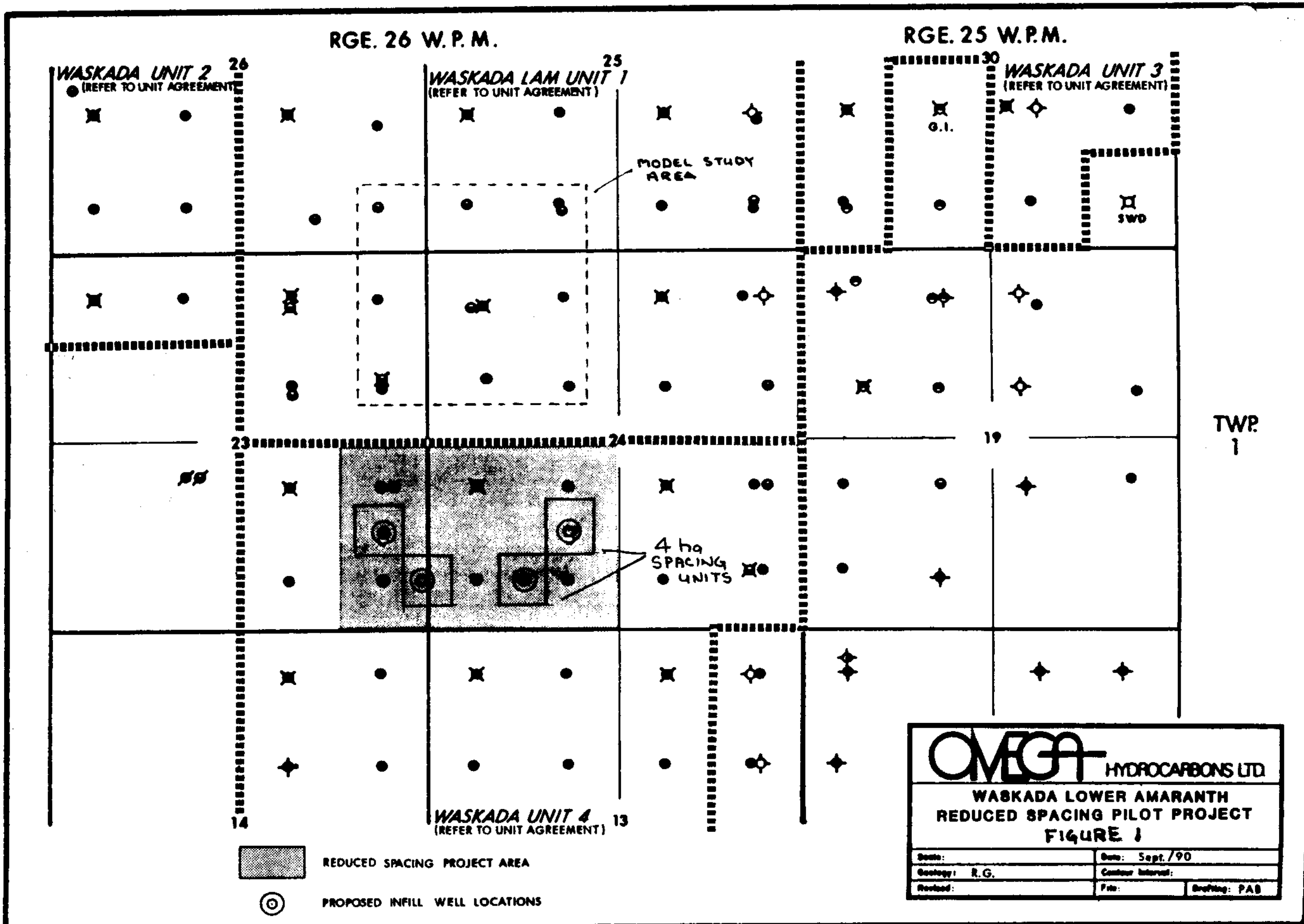
TABLE 1

COMPARISON OF ACTUAL VS PREDICTED
WATERFLOOD PERFORMANCE

	5-24 Injection Pattern	1985 Waskada Reservoir Model Study
Primary Recovery	12.0%	9.1%
Secondary Recovery	23.3%	36.5% - 38.2%
Initial Oil Saturation (Soi)	40 - 64%	40 - 64%
Residual Oil Saturation to Waterflooding (Sorw)	15 - 20%	15 - 20 %
Volumetric Sweep Efficiency* (E_V)	31 - 47%	48 - 76%

* $Np = N \cdot E_D \cdot E_V$

Where Np = oil recovery
N = original oil in place
E_D = displacement efficiency = $\frac{(Soi - Sorw)}{Soi}$
E_V = volumetric sweep efficiency = $E_{AS} * E_{VS}$
Where E_{AS} = areal sweep efficiency
E_{VS} = vertical sweep efficiency


RGE. 26 W. P. M.
RGE. 25 W.P.M.
WASKADA UNIT 2
(REFER TO UNIT AGREEMENT)
WASKADA LAM UNIT 1
(REFER TO UNIT AGREEMENT)
WASKADA UNIT 3
(REFER TO UNIT AGREEMENT)
WASKADA UNIT 4
(REFER TO UNIT AGREEMENT)
26
25
30
23
24
19
14
13
G.I.
SWD
MODEL STUDY AREA
4 ha SPACING UNITS
TWP. 1
REDUCED SPACING PROJECT AREA
PROPOSED INFILL WELL LOCATIONS
OMEGA HYDROCARBONS LTD.
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
FIGURE 1
Scale:
Date: Sept./90
Geology: R.G.
Contour Interval:
Revised:
File:
Drafting: PAB

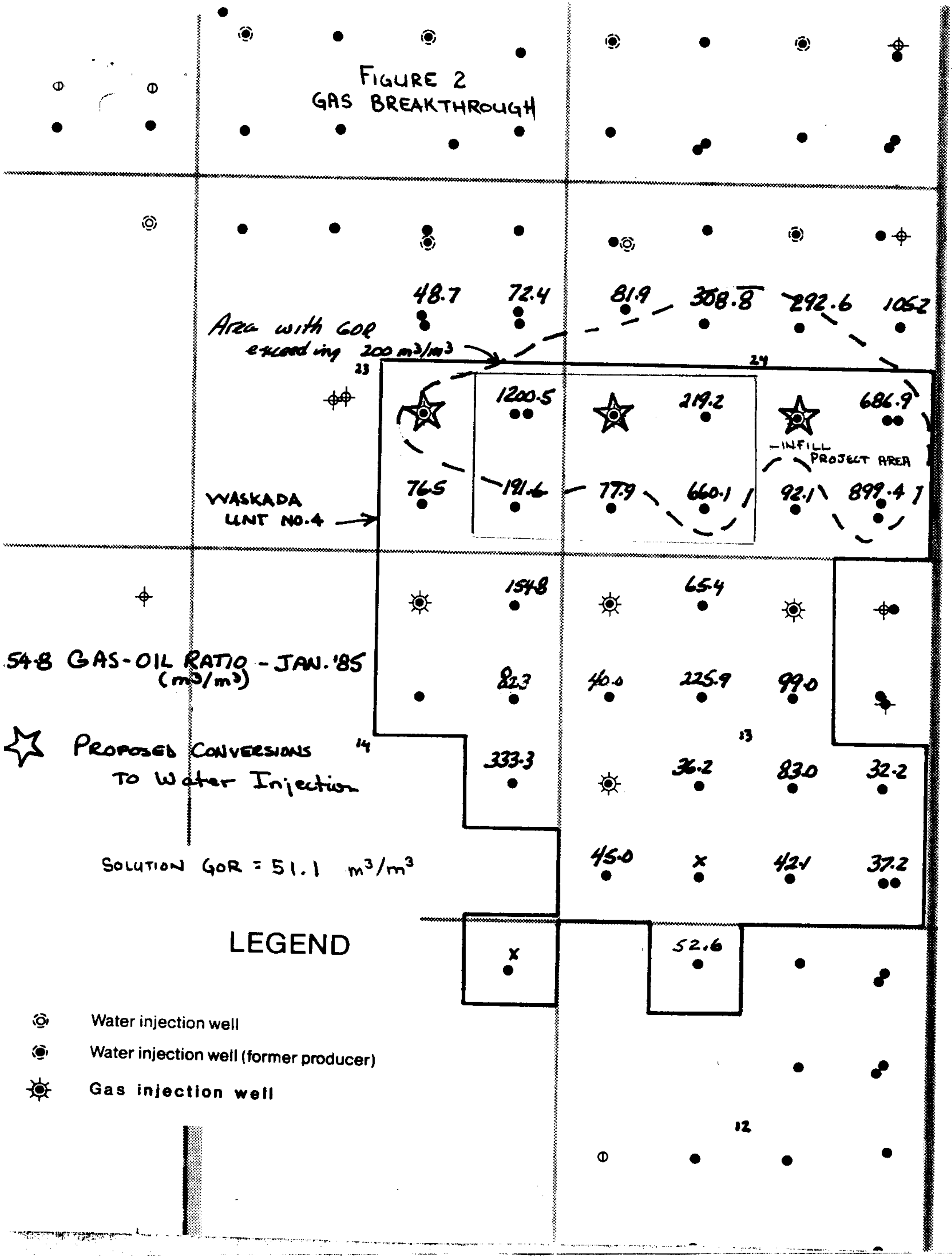


FIGURE 2
GAS BREAKTHROUGH
48.7
72.4
81.9
308.8
292.6
106.2
Area with GOR exceeding 200 m3/m3
23
24
1200.5
219.2
686.9
INFILL PROJECT AREA
76.5
191.6
77.9
660.1
92.1
899.4
WASKADA UNIT NO. 4
154.8
65.4
54.8 GAS-OIL RATIO - JAN. '85 (m3/m3)
82.3
40.0
225.9
99.0
Proposed Conversions To Water Injection
14
13
333.3
36.2
83.0
32.2
SOLUTION GOR = 51.1 m3/m3
45.0
42.1
37.2
LEGEND
52.6
Water injection well
Water injection well (former producer)
Gas injection well
12

PRODUCTION HISTORY 5-24-1-26 INJECTION PATTERN

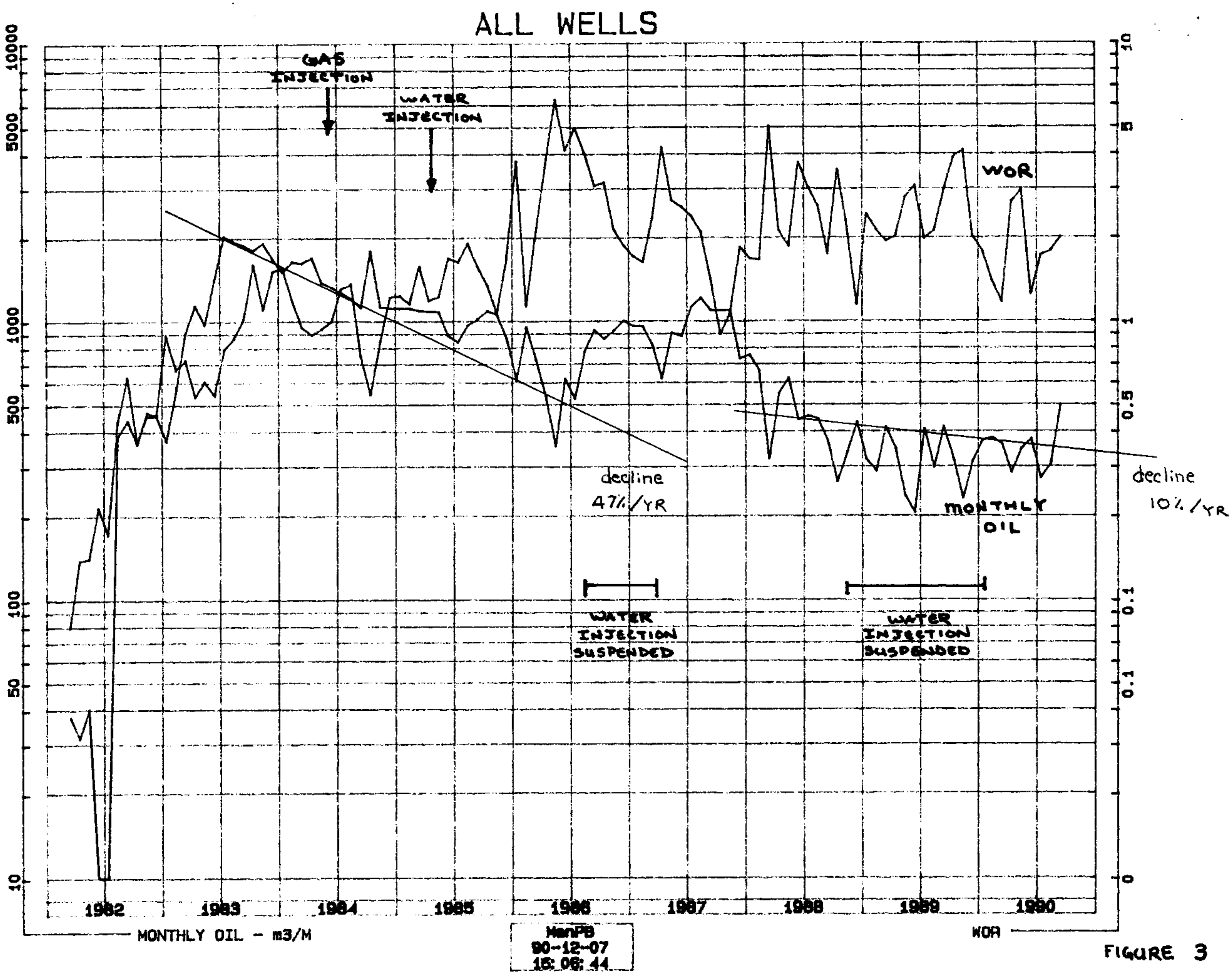
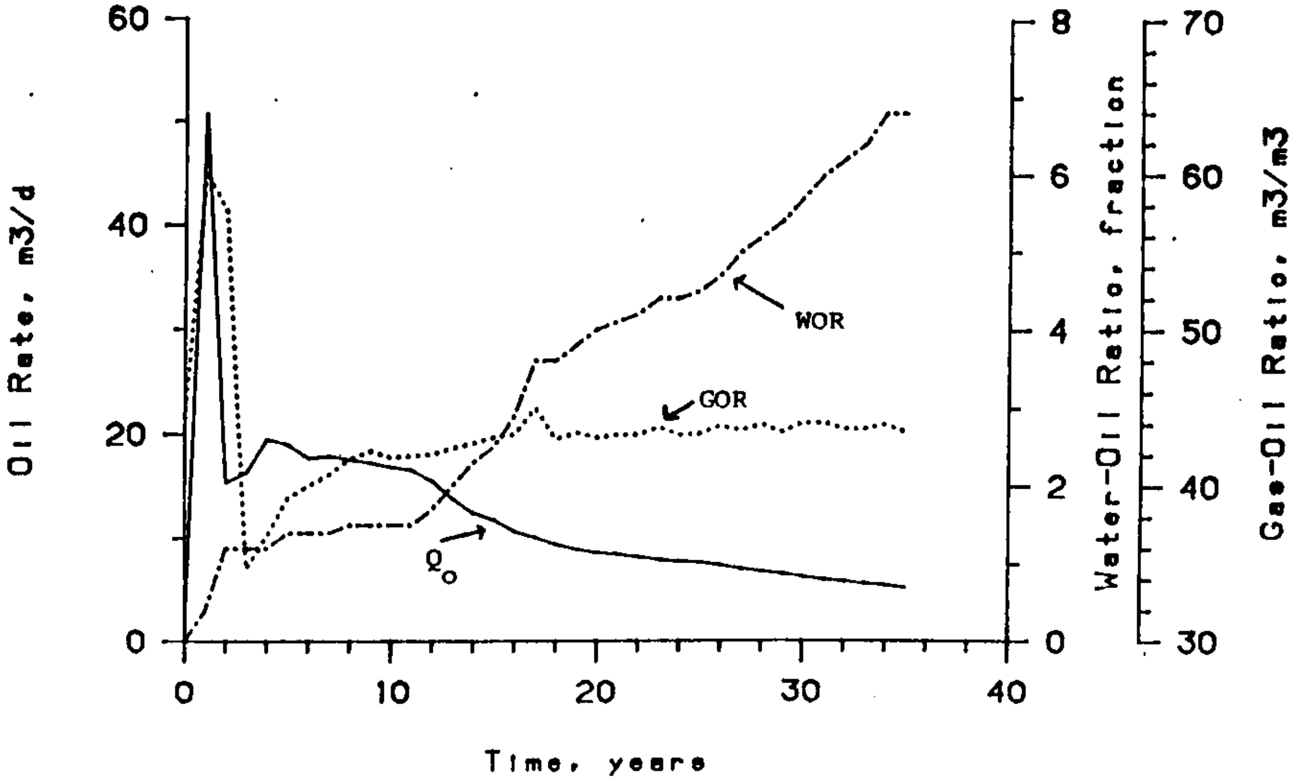


FIGURE 3

FIGURE 4

MODEL STUDY

WATERFLOOD PRODUCTION FORECAST



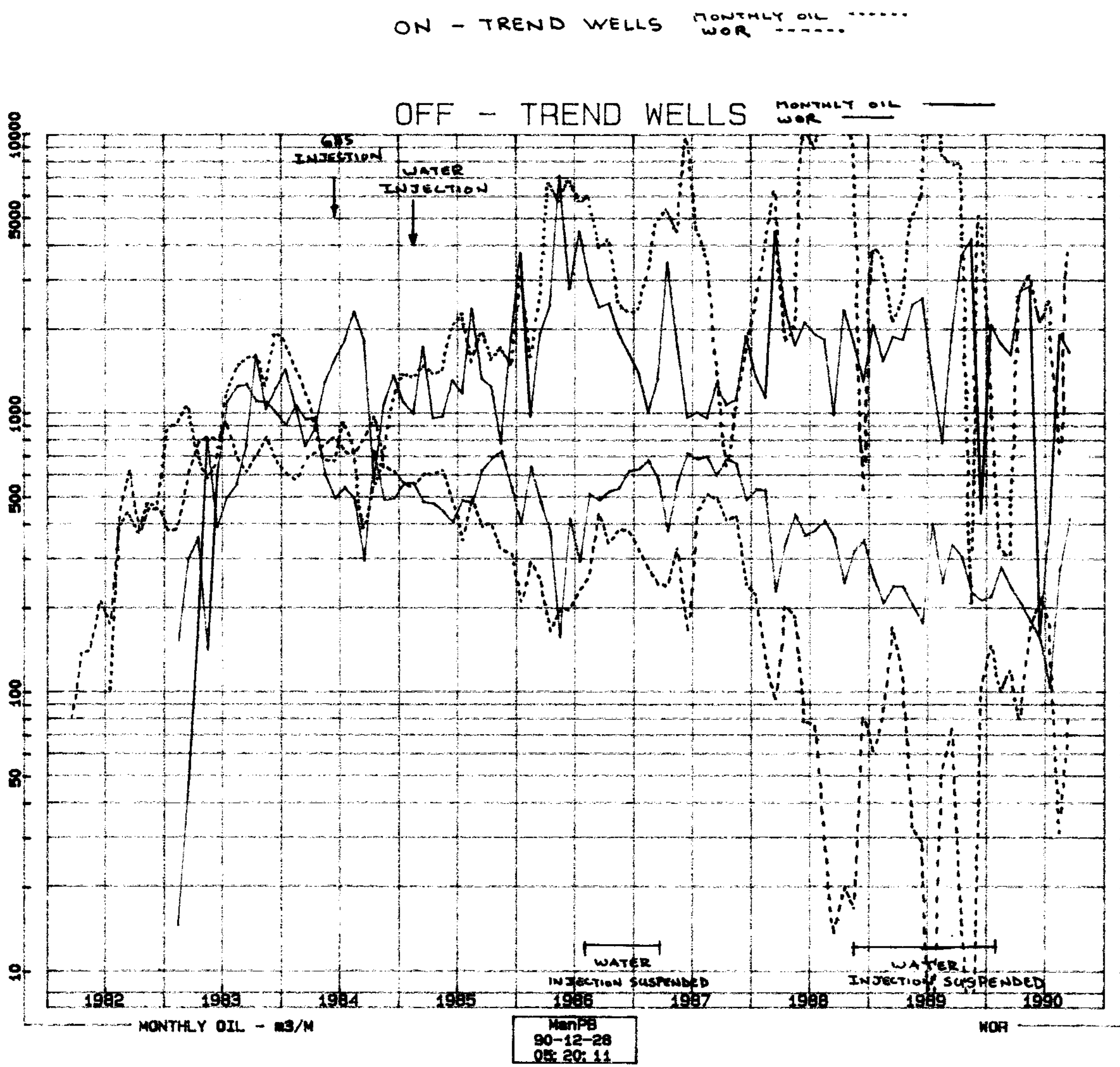

ON - TREND WELLS
MONTHLY OIL
WOR
OFF - TREND WELLS
MONTHLY OIL
WOR
GAS INJECTION
WATER INJECTION
WATER INJECTION SUSPENDED
WATER INJECTION SUSPENDED
10000
5000
1000
500
100
50
10
5
1
0.5
0.1
0.1
0
1982
1983
1984
1985
1986
1987
1988
1989
1990
MONTHLY OIL - m3/M
WOR
ManPB
90-12-28
05:20:11

FIG. 5

FIGURE 6

POTENTIAL REDUCED SPACING EXPANSION

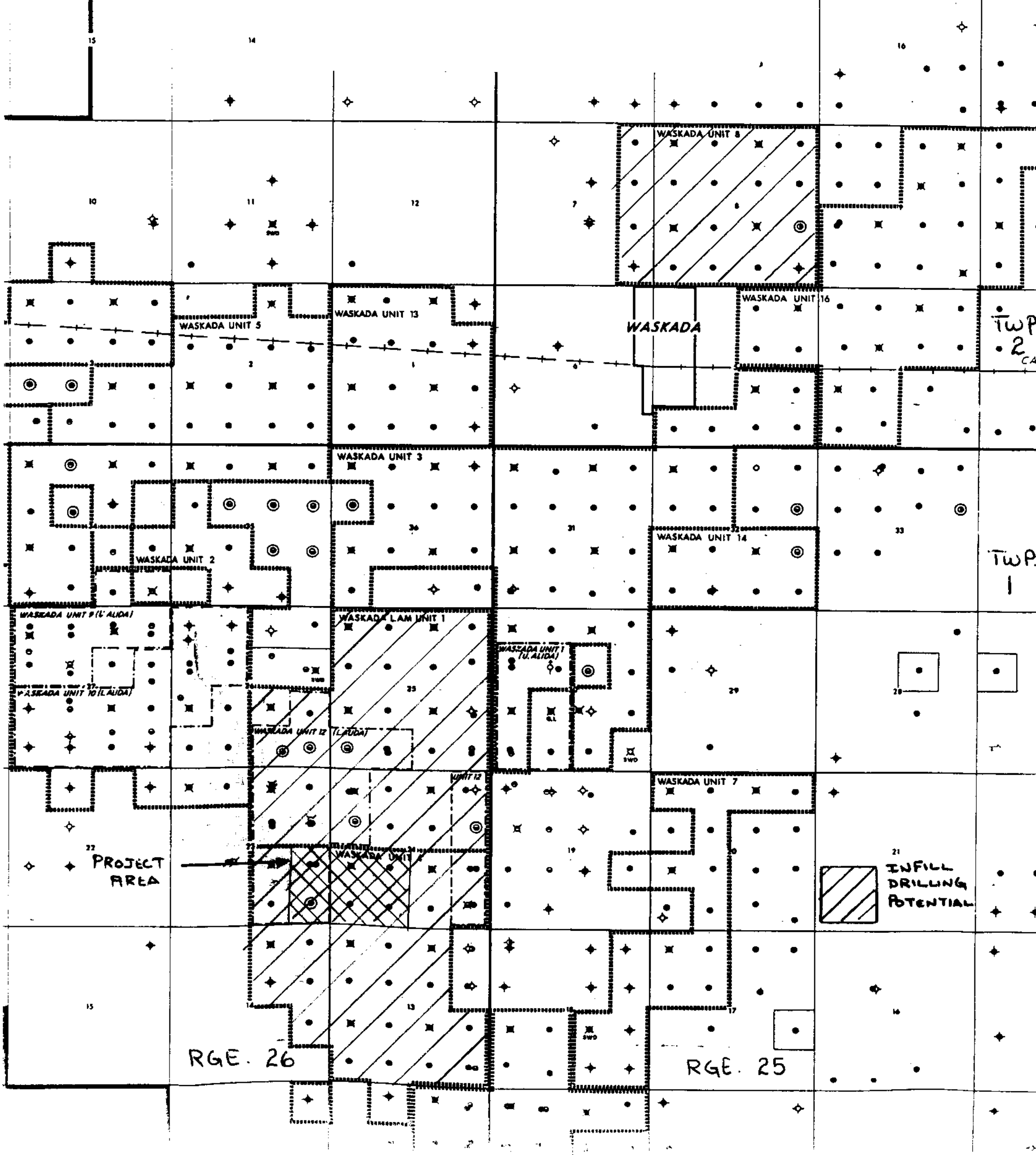


FIGURE 7

16 ha 5-SPOT INJECTION PATTERN

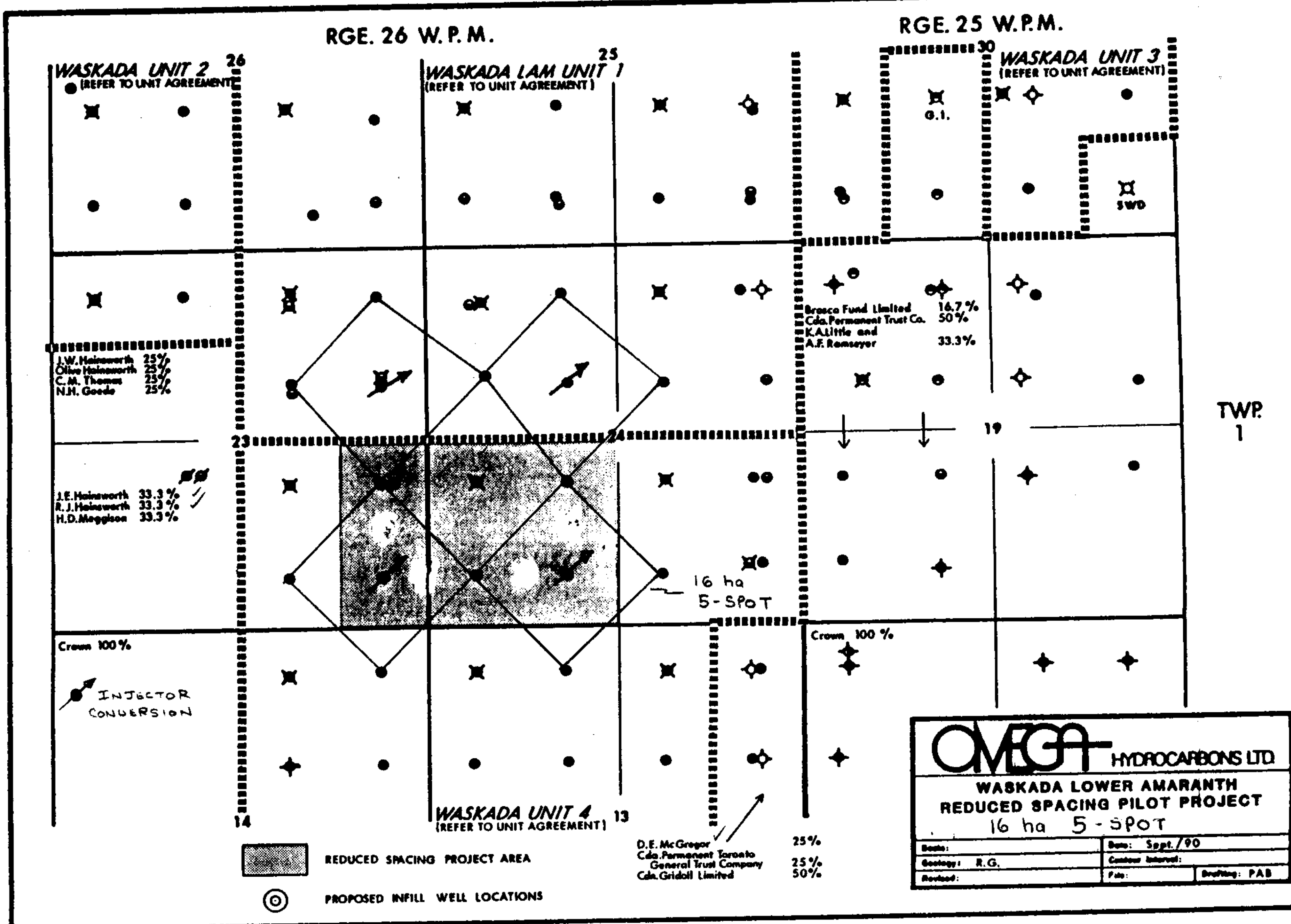


FIGURE 8

8 ha 9-SPOT INJECTION PATTERN

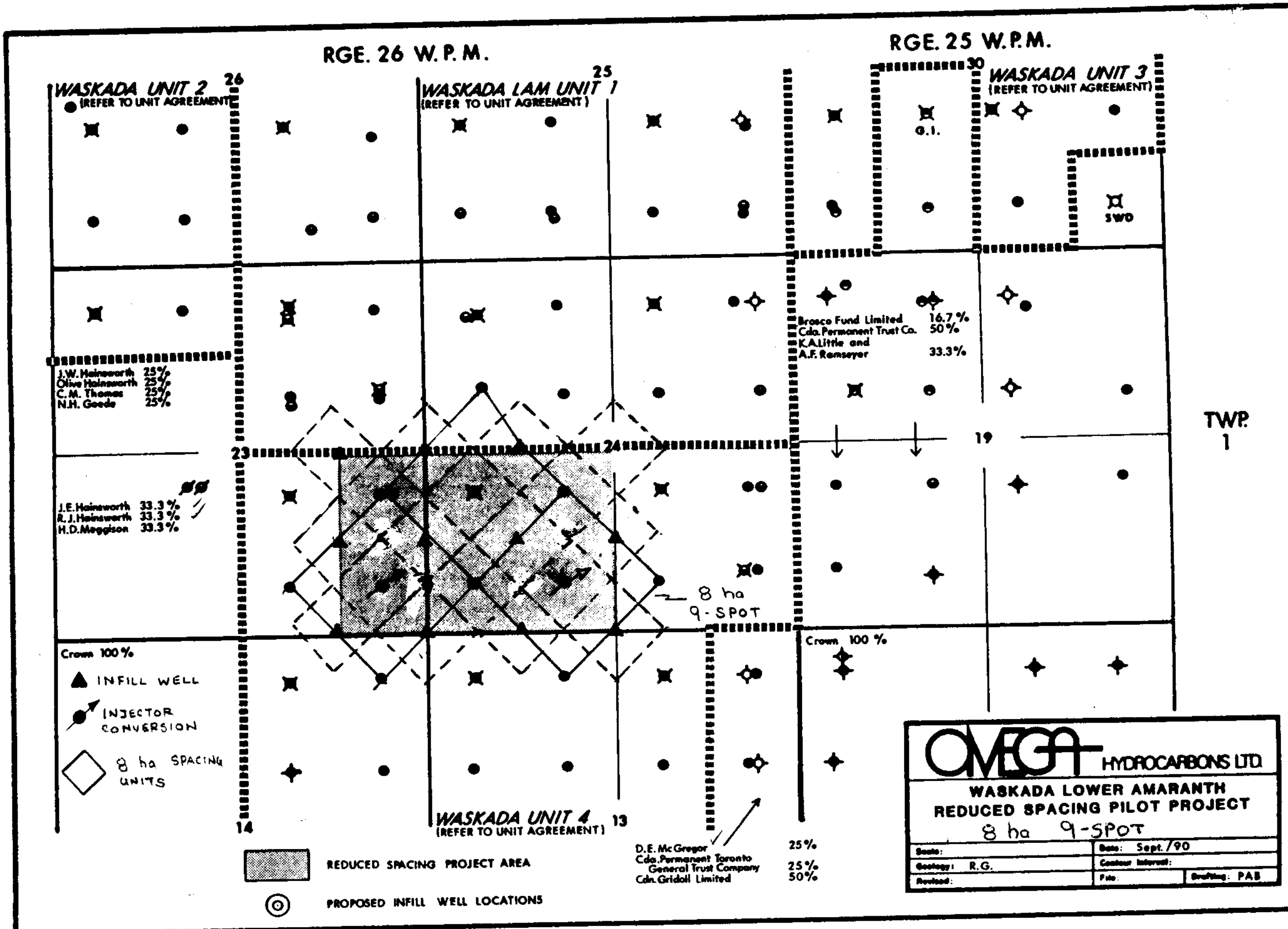


FIGURE 9

8 ha 5-SPOT INJECTION PATTERN

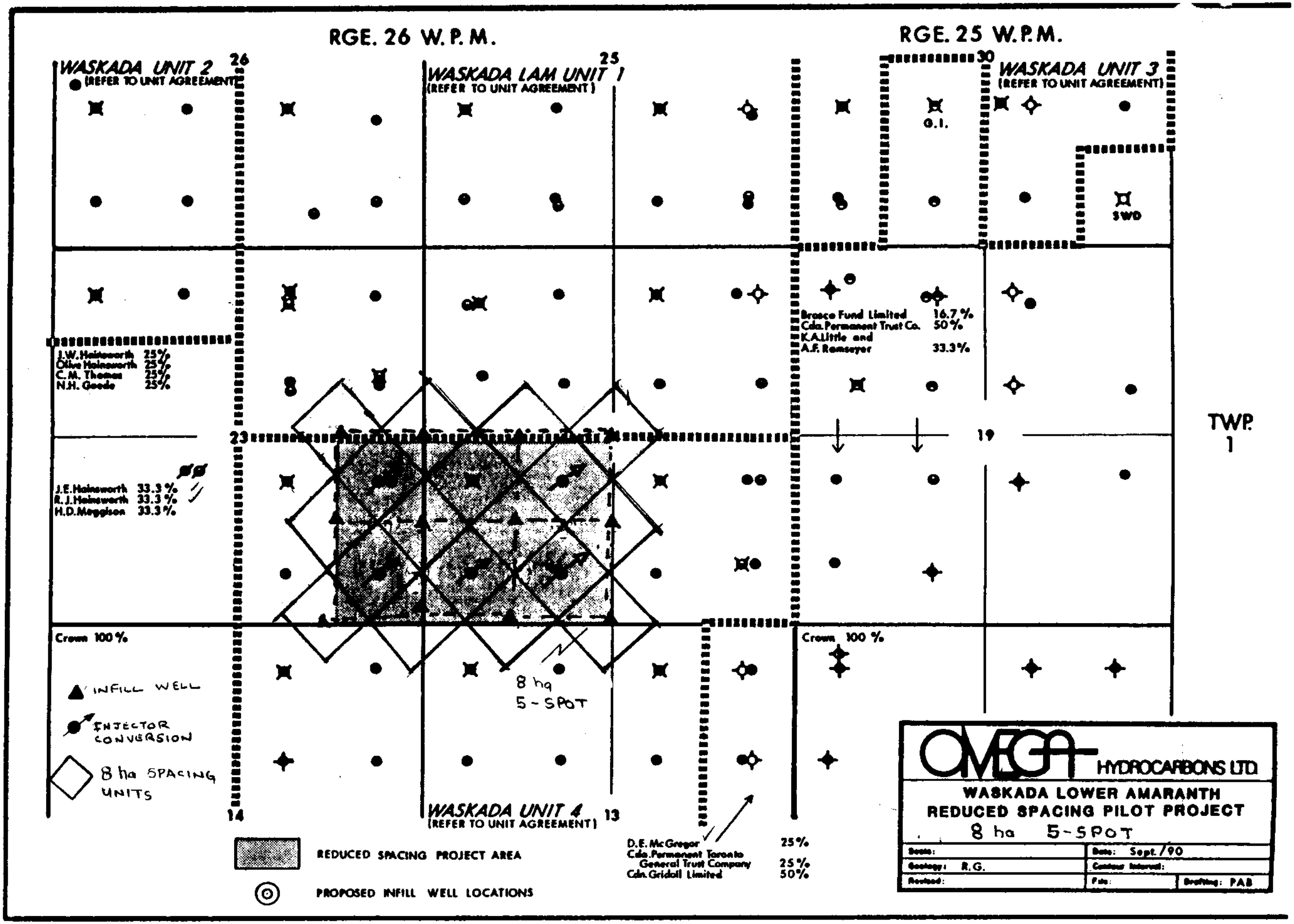
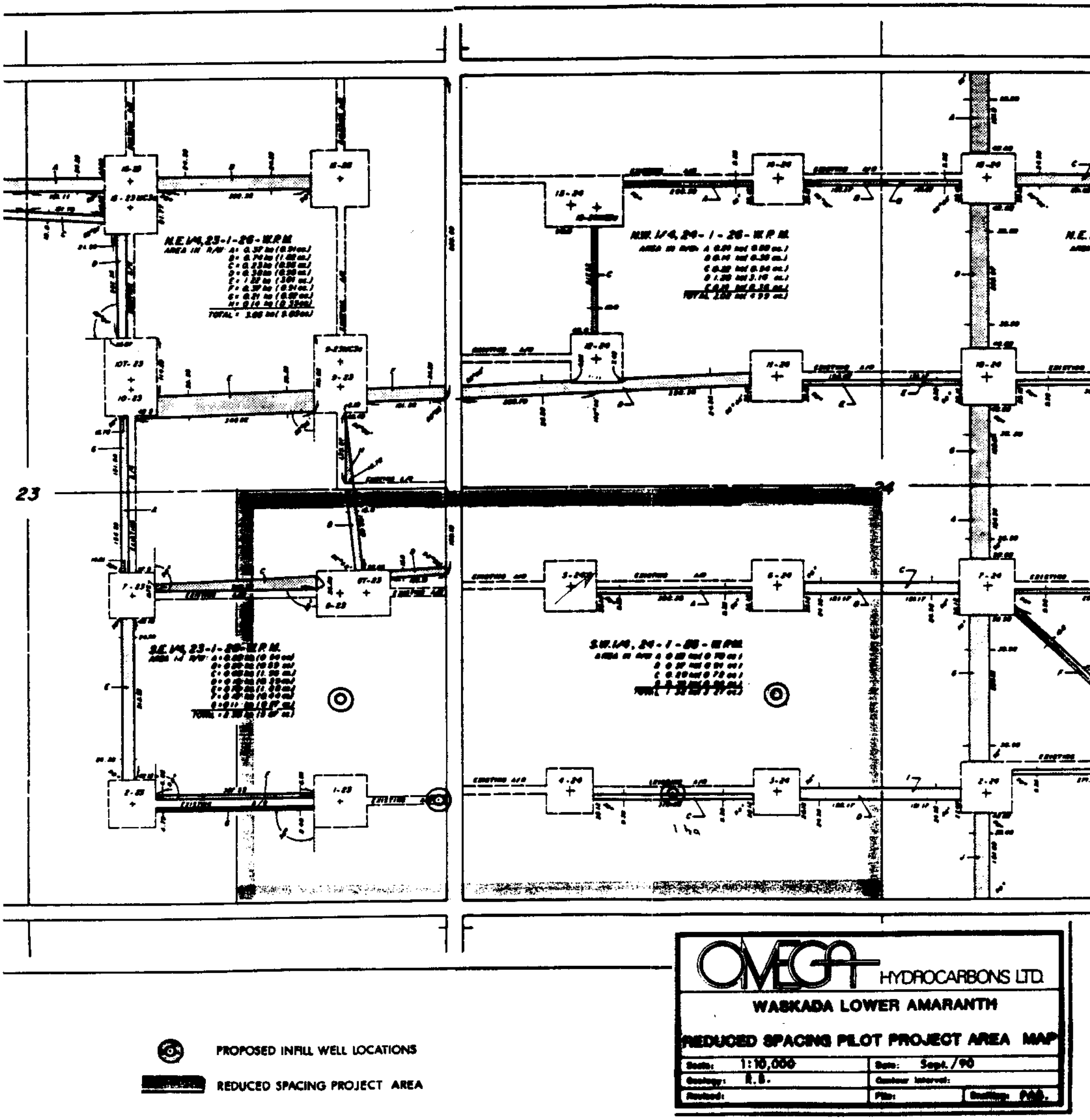


FIGURE 10

SURFACE LAND USE



JOHN.

Manitoba

Memorandum

Date: January 15, 1991

To: Mr. John N. Fox
Chief Petroleum Engineer
Petroleum Branch
555 - 330 Graham Ave.

From: Serge Scrafield
Acting Director
Provincial Planning
Rural Development
Telephone: 405 - 800 Portage

Subject: **WASKADA UNIT NO. 4**
~~REDUCED SPACING PILOT PROJECT~~

Thank you for sending to us a copy of Omega's application and additional information filed in support of their application.

Our Department's Field Office in Deloraine has reviewed the material and discussed the project proposal with the Reeve of the R.M. of Arthur and with your Department's inspector in Waskada.

The following concerns were raised:

- That there be proper set backs from municipal roads;
- That the results of the Pilot Project be made available to the municipality;
- That the company make every effort to reach satisfactory lease arrangements with the landowners involved; and
- That the company undertake effective and prompt remedial actions should there be any spills.

Should you receive, at anytime, a report on the Pilot Project from the company, we and the municipality would appreciate a copy.

Thank you very much for your attention.

Shelley Prod
for Serge Scrafield

SS\SP

c.c. Mr. G. D. Forrest
Mr. D. Johns
Mr. N. Carroll
Mr. T. Brown
Mr. D. Partridge

PS F-25 894 01-00930

December 21, 1990

Mr. R. Brekke, P. Eng.
Omega Hydrocarbons Ltd.
1300, 112 - 4th Avenue S.W.
Calgary, Alberta
T2P OH3

Dear Sir:

RE: Waskada Unit No. 4
Application for Reduced Spacing

The Board received no objections to or interventions in Omega's reduced spacing application. The Board is awaiting comment on the application from other interested government departments.

The Board has reviewed Omega's application and the information filed in support of the application. The Board believes the proposed reduced spacing pilot project will yield information regarding the areal conformance of the waterflood and the potential for increasing recovery by infill drilling.

The Board is concerned however, that Omega's proposed pilot project evaluation program consisting of a dual induction and sonic log, additional pressure surveys and regular production testing may not provide the geological and reservoir information necessary to;

(1) enhance the understanding of waterflood performance in the pilot project area and fine-tune the 1985 Waskada Reservoir Model Study,

(2) evaluate the impact of the induced fracture system on waterflood performance,

(3) optimize the placement of future infill wells, and

(4) optimize the placement of injection wells and select the appropriate injection pattern.

In respect of this concern, the Petroleum Branch has developed a list of reservoir logs, tests, surveys and analyses designed to provide an improved understanding of these factors. Prior to final disposition of the application, the Board requests that Omega comment on the feasibility (technical merit and costs) of each item and indicate any that it would be prepared to pursue as part of the reduced spacing pilot project.

(1) Open hole or cased hole water saturation determination logs [e.g. Thermal Decay Time Log (TDT), Electromagnetic Propagation Log (EPT), Gamma Spectrometry Log (GST)].

(2) Tests or surveys to evaluate interwell communication, reservoir heterogenity/continuity and reservoir flowpaths (e.g. tracer injection or well interference tests).

(3) Determination of stress regime for prediction of induced fracture orientation (e.g. Formation Microscanner, dipmeter or multi-armed caliper log .

(4) Tests or surveys to evaluate vertical conformance of the waterflood (e.g. zonal pressure profile and fluid sampling using a Repeat Formation Tester (RFT) or injection profile logs).

(5) Core and special core analysis to enhance geological and reservoir understanding of the Waskada Lower Amaranth A Pool, and help fine-tune the 1985 Waskada Reservoir Model Study.

The Board expects the reduced spacing pilot project to yield the additional geological and reservoir information necessary for Omega to more thoroughly evaluate the infill drilling and waterflood modification alternatives outlined in the Board's letter of October 25, 1990.

If you have any questions in respect of this matter, please contact L.R. Dubreuil, Director of Petroleum, at (204) 945-6573 or John N. Fox, Chief Petroleum Engineer, at (204) 945-6574.

Yours respectfully,

ORIGINAL SIGNED BY
H. CLARE MOSTER

H. Clare Moster
Deputy Chairman

November 16, 1990

Serge Scrafield
Senior Planner
Provincial Planning Branch
4th floor - 800 Portage Avenue

John N. Fox
Chief Petroleum Engineer
Petroleum Branch
555-330 Graham Avenue

RE: Waskada Unit No. 4
<u>Reduced Spacing Pilot Project</u>

Omega Hydrocarbons Ltd. has made application to reduce well spacing in a portion of Waskada Unit No. 4. The area of interest is outlined in Figure 1. The proposal involves the drilling of four infill wells within the 130 ha project area.

The pilot project, which requires the approval of The Oil and Natural Gas Conservation Board, is designed to evaluate the incremental oil recoverable by drilling between existing producing wells.

If the project proves technically and economically successful, Omega has indicated it may apply for reduced spacing in other parts of the Waskada Field.

Attached is a copy of Omega's application and additional information filed in support of the application. I ask that you review the application and provide me with your comments before December 14, 1990. If you have any questions regarding the application, please contact me at 945-6574.

ORIGINAL SIGNED BY
JOHN N. FOX

John N. Fox

cc: Dale Partridge
Manitoba Agriculture

- 90.12.21 no concerns, minimal impact on agriculture with 4 ha spacing

cc: Floyd Phillips
Manitoba Environment

- 90.12.21 no concerns @ pilot stage
- should have a meeting in future re: WEU #1 infill proposal

Serge Scrafield
Senior Planner
Provincial Planning Br.
Rural Development
800 Portage Ave.

Dale Partridge, Chief
Land Utilization and Soil Survey Section
Manitoba Agriculture
908 - 401 York Avenue

Floyd Phillips
Terrestrial Standards & Studies
Manitoba Environment
Bldg. 2 - 139 Tuxedo

The Manitoba Surface Rights Association
Box 967
Virden, Manitoba
R0M 2C0

LAND USE - ADDITIONAL AREA

TYPICAL LEASE 1 ha 100 m * 100 m

TYPICAL ACCESS ROAD

2 INFILL WELLS ON ACCESS ROAD

$$(2) * \left[1\,ha - \left(\underbrace{100\,m \times 15\,m}_{\text{existing access road allowance}} \right) \right] = 1.7\ ha$$

2 INFILLS NOT ON EXISTING ACCESS ROAD

$(2) * 1\,ha = 2\,ha$

2 ACCESS ROADS

$(2) * (15 * 100\,m) = 0.3$

INFILL PROJECT

- SELECTION CRITERIA
  (1) good reservoir quality (ϕh)
  (2) reservoir continuity
  (3) good productivity
  (4) low WOR

- 4 INFILL WELL - RECOVER APPROXIMATELY 4000 m^3 EACH, INCREMENTAL RECOVERY OF 3.3%

  - INCREMENTAL RECOVERY APPEARS TO BE BASED ON ASSUMPTIONS OF INITIAL PRODUCTIVITY AND ESTIMATED DECLINE FOR THE INFILL WELLS — WHAT FACTORS CONTRIBUTE TO THIS INCREMENTAL RECOVERY — <DRAINAGE OF UNSWEPT PORTIONS OF THE RESERVOIR> IMPROVED WATERFLOOD SWEEP EFFICIENCY, INCREASED CONTINUITY, IMPROVED COMPLETION PRACTICES, IMPROVED PATTERN REALIGNMENT, UTILIZATION OF FRACTURE ORIENTATION — WHAT IS THE SIGNIFICANCE,
  - conservative incremental production forecast - assume no element of acceleration from infill product.

- OPTIONS REVIEWED BY OMEGA
  (1) 16 ha - 5-spot convert on trend wells to injection — recognizes/utilizes advantage of on trend injection vs off trend production
  (2) 8 ha - 9-spot
  3) 8 ha - 5-spot

ALL THE ABOVE CONFIGURATIONS IMPROVE WATERFLOOD AREAL SWEEP BY

ADDITIONAL AREA
S. 30-1-25
UNIT #8
S. 25, 23, 26 - 1-26

EITHER ALTERNATING THE FLOW STREAMLINES, (INCREASING INJECTOR/PRODUCER RATIO) OR REDUCING SPACING / INTERWELL DISTANCES

- 4 ha SPACING CONFIGURATION PROPOSED BY OMEGA EFFECTIVELY ELIMINATES THESE OPTIONS — WHAT IS THE ULTIMATE INJECTION CONFIGURATION ENVISIONED BY OMEGA — WILL OMEGA BE CONVERTING ANY PRODUCERS TO INJECTION - WHAT DOES OMEGA BELIEVE IS THE ACTUAL DRAINAGE AREA OF A LAM WELL
- IF 4 INFILL WELLS ARE SUCCESSFULLY, WHAT ADDITIONAL WELLS WOULD BE DRILLED - want to evaluate interference effects, within a single pattern + within a single unit (common ~~RO's~~)
- FUTURE WATERFLOOD OPERATIONS - VRR = 1.0, 5-24 pattern & SURROUNDING PATTERNS 13-13, 7-23, 7-24
  - MAINTAIN PATTERN PRESSURE AT APPROXIMATELY 9000 kPa

✓ INFILL WELL EVALUATION — PERFORMANCE OF WATERFLOOD

- LOGGING SUITE - fracture identification logs, water saturation logs
- CORE, IN-SITU SATURATION DETERMINATION
- DST, pressure survey - existing wells + new wells
- injection profile logging
- production logging
- wellbore televiewer (to determine natural fracture system orientation
- use of tracer

REVIEW OF TECHNICAL PAPERS

low-k reservoirs infill drilling incremental recoveries ≈ 4%
from reducing spacing from 40 ac to 20%

- quantify reservoir heterogeneity, improved quantitative
reservoir description & info evaluation tech.

NINE FACTORS EFFECTING RECOVERY

(1) areal heterogeneity → evidence of fracture trend
hyd. fracturing orientation
Δrec = 36% infill drill diagonally/perpendicular to fracture trend

(2) minimize lateral discontinuities → review logs
correlate pay continuity Δrec = 4%

(3) recovery of "wedge edge" oil

(4) improved areal sweep → minimize poor geometry
infill wells in underdrainage/sweep portion of reservoir uniform inj. pattern Δrec = 11%

(5) confinement of injection fluid → considered
injection profiling of S-24-1-26, production
testing/logging to evaluate zonal productivity

(6) better control of injection profiles

(7) increased conductivity & reduced eco. limit

(8) reduced oil shrinkage + accelerating injection
minor increases in ult. rec. will occur when less primary depletion
less shrinkage = less STB / residual So, lower μ due ↑ gas in solⁿ
= slight improvement in mobility ratio = slight improvement sweep eff.

CDN OXY
INFILL DRILLING
PEMBINA CARDIUM

- Pembina Cardium infill drilling mature waterflood (Cdn Oxy)
80 to 40 ac - normal infill location even no. LSD
directly between producer - injector - problem in
swept portion of reservoir

- placement of infill wells between producing wells
to fully exploit unswept portion of reservoir

- infill options used in Pembina
  between producers in 160 ac 9 spot
  - convert 80 ac 5 spot to 40 ac 9 spot

- production profile { high I.P. rapid decline
  1st yr { moderate WOR, steady increase
  - stabilized decline of WOR
- no interference effects between infill
wells & original wells

- recovery increase by infill drilling in
low permeability waterflood - 4% of OOIP
by reducing from 40 ac to 20 ac

- factors that may contribute to incremental
recovery - improved areal sweep by
locating infill wells in unswept portion of
reservoir

- evaluation of an infill project
  (1) production / injection performance
  (2) reservoir description
  (3) project design - infill pattern alternatives
  (4) economics

- in general poorer original WF performance the better the infill opportunity

$$\text{Recovery} = \frac{N_p}{V_p\,(S_{oi} - S_{orw})}$$

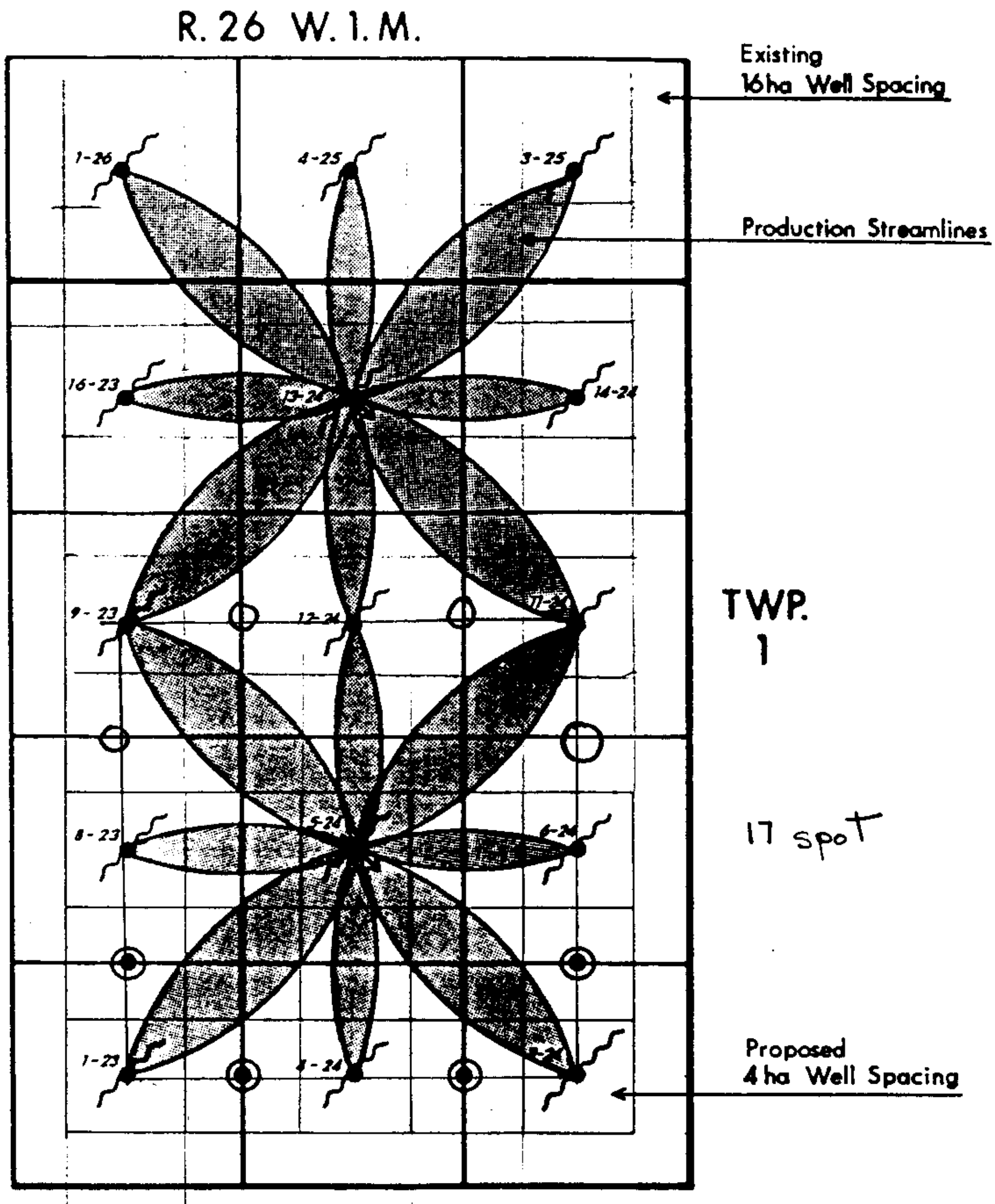
- areal sweep is improved by reversing production streamlines & sweeping across previously unswept areas

- shift pattern alignment

- reservoir has exhibited relatively poor initial waterflood performance

- reserve additions through infill drilling is difficult to determine

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
PROPOSED DRILLING SPACING UNITS



- EXISTING PRODUCTION WELLS
- EXISTING INJECTION WELLS
- PROPOSED INFILL WELLS
- FRACTURE PLANE
- REDUCED SPACING PROJECT AREA

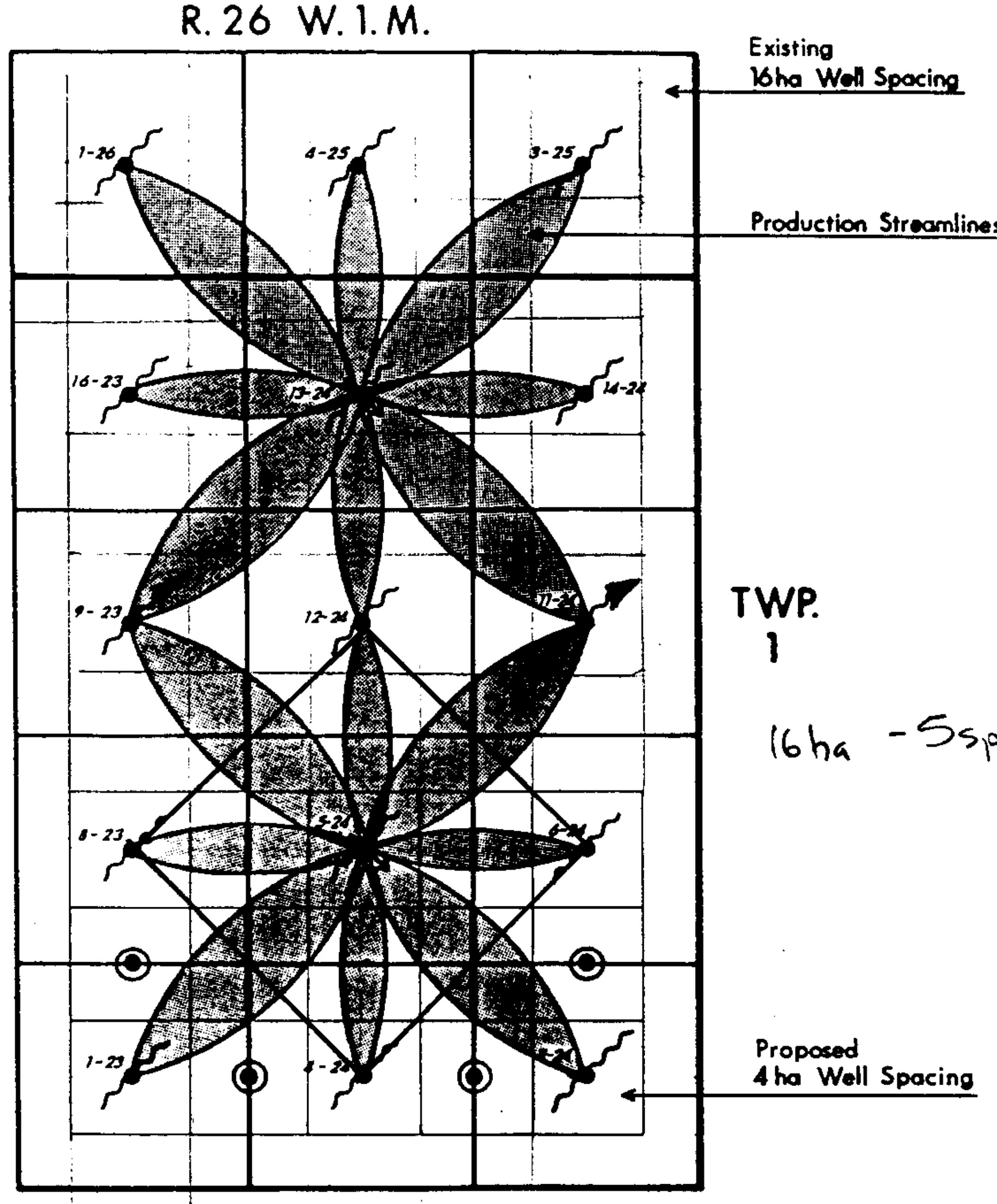
OMEGA HYDROCARBONS LTD.

WASKADA, MN.

REDUCED SPACING PILOT PROJECT

Scale: Not to Scale	Date: AUG. '90
Geology:	Contour Interval:
Revised:	File: Drafting:

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
PROPOSED DRILLING SPACING UNITS



● EXISTING PRODUCTION WELLS

EXISTING INJECTION WELLS

◉ PROPOSED INFILL WELLS

〰 FRACTURE PLANE

REDUCED SPACING PROJECT AREA

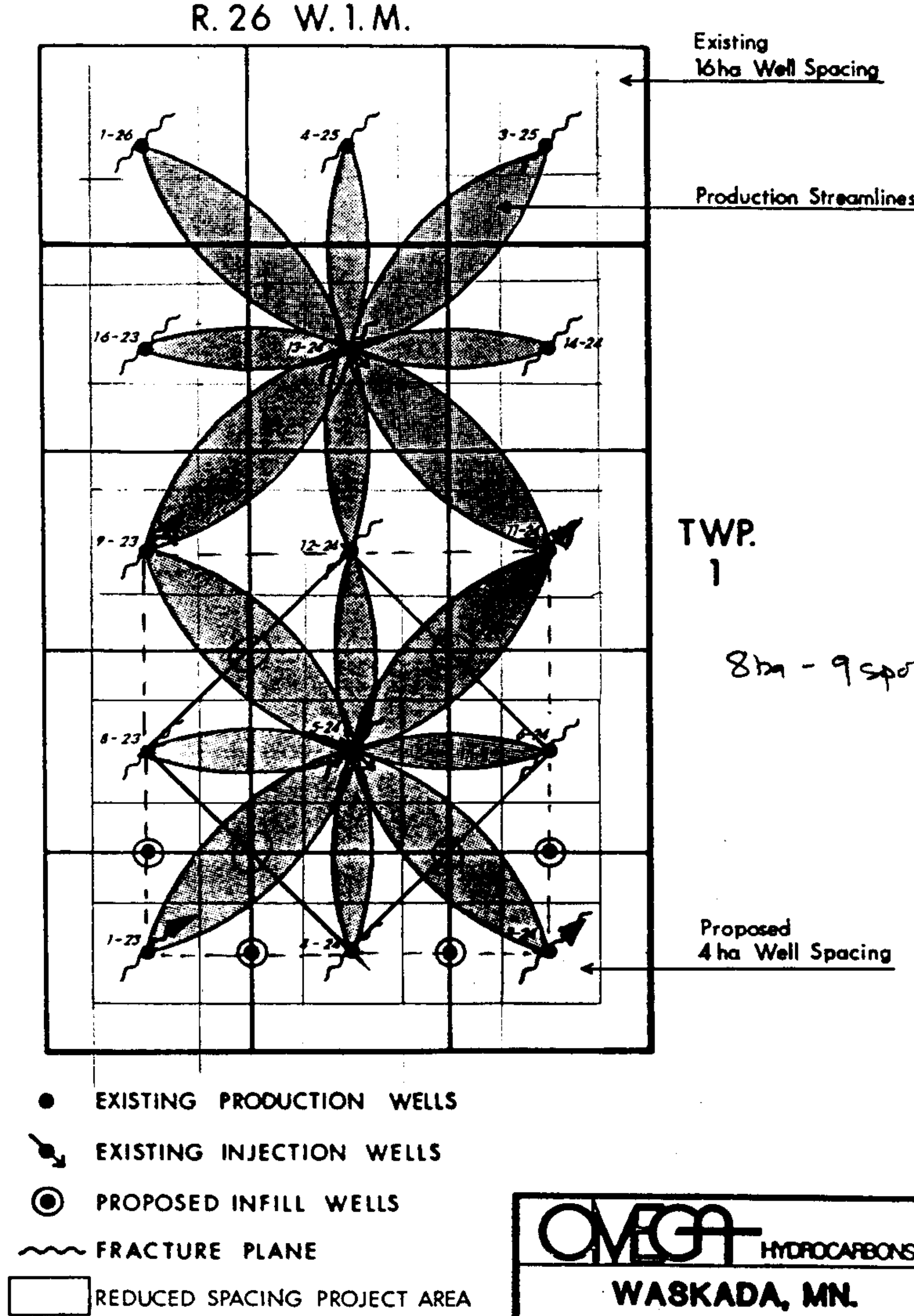
OMEGA HYDROCARBONS LTD.

WASKADA, MN.

REDUCED SPACING PILOT PROJECT

Scale: Not to Scale	Date: AUG. '90
Geology: R. B.	Contour Interval:
Revised:	File: / Drafting:

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
PROPOSED DRILLING SPACING UNITS



OMEGA HYDROCARBONS LTD

WASKADA, MN.

REDUCED SPACING PILOT PROJECT

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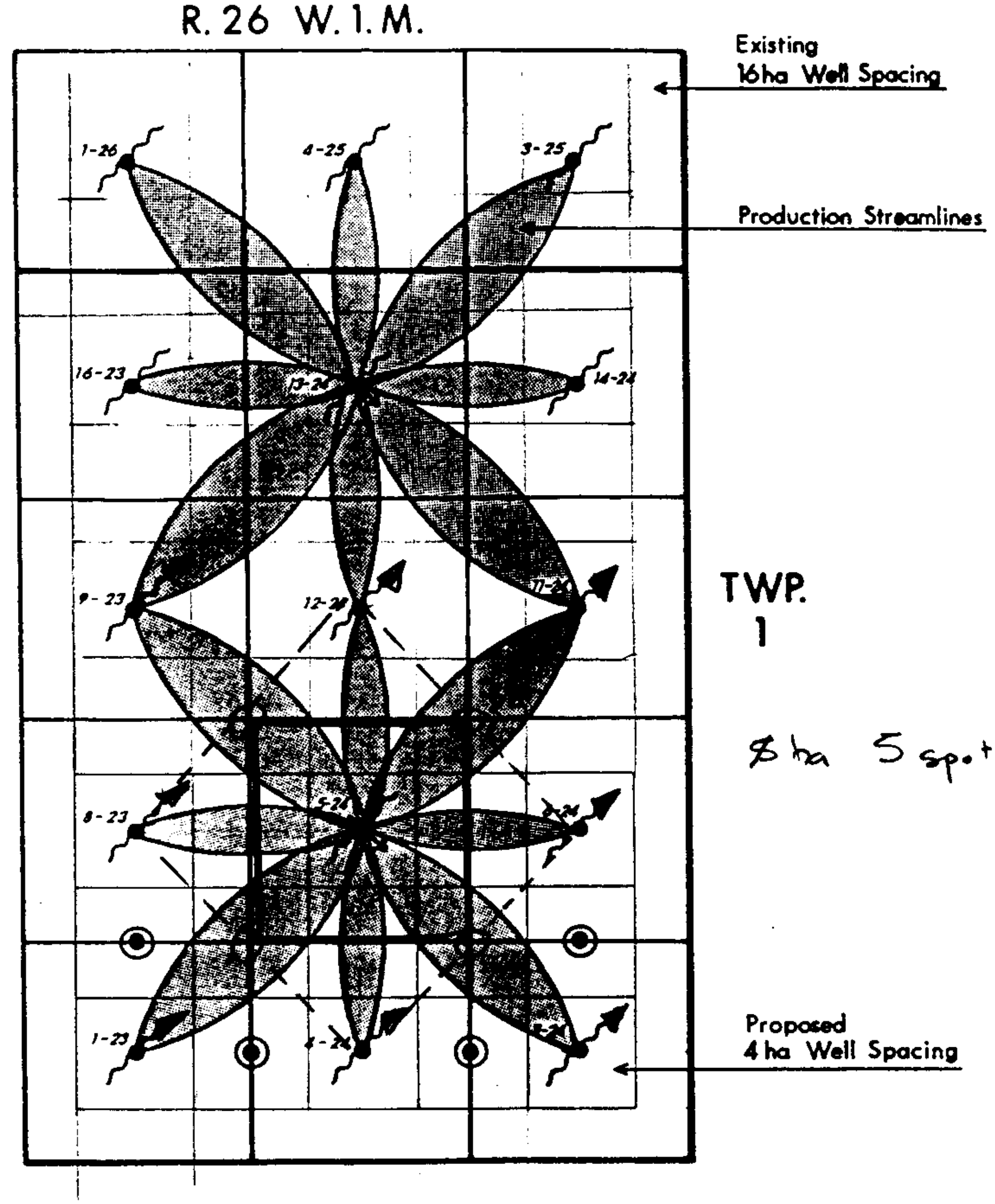
Revised:	File: Drafting:

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
PROPOSED DRILLING SPACING UNITS



● EXISTING PRODUCTION WELLS

EXISTING INJECTION WELLS

◉ PROPOSED INFILL WELLS

FRACTURE PLANE

REDUCED SPACING PROJECT AREA

OMEGA HYDROCARBONS LTD.

WASKADA, MN.

REDUCED SPACING PILOT PROJECT

Scale: Not to Scale		Date: AUG. '90	
Geology: R. B.		Contour Interval:	
Revised:		File:	Drafting:

PRODUCTION FORECAST

· BASE CASE IS A CONTINUATION OF THE OBSERVED PRODUCTION DECLINE IN THE PROJECT AREA WITH NO INTERFERENCE BETWEEN THE EXISTING WELLS & INFILL WELL OR NO PRODUCTION ACCELERATION COMPONENT HAS BEEN INCLUDED

* INFILL PRODUCTION FORECAST CONSERVATIVE (?)

ADDITIONAL QUESTIONS.

1. IS STRUCTURE MAP - top of ∅ or 'C' Sand (?)

2. EXPLAINATION SUCH AS FAULTING FOR THE LOW @ 4-24

SURFACE IMPACTS

- Rural Development, Agriculture, Environment were contact regarding the application

- crop land "wheat" "barley", flax "sunflowers", mustard rape seed - continuously cropped

- land occupied (a) wellsite -
(b) access road -

- concerns - no built-up roads [access road not extended between N/S pairs of wells ie 1-23 & 8-23]
- underground hydro
- minimize activity and lease area
- flowlines

- 1D-23 setback from municipal road allowance approval of RM of Arthur required
- no concerns wrt the Waskada Cr.

LAND USE IMPACT

INFILL WELLSITES - 1 ha

ACCESS ROADS, WHERE NECESSARY - 0.2 ha

- CONSENT OF SURFACE OWNERS WITHIN PROJECT AREA, ANY CONCERNS THAT SURFACE OWNERS OUTSIDE PROJECT AREA WILL OBJECT TO APPLICATION

- PLANS FOR PROJECT EXPANSION

- OMEGA CONSIDERING HOLDING AN OPEN HOUSE IN WASKADA

ECONOMICS

- NO HOLIDAY VOLUME ? FOR PURPOSE OF CALCULATION THE INTERWELL DISTANCE D = 200 m.
- PRICE FORECAST $21.50/bbl - 1991 to $46/bbl - 2002 POSSIBLY CONSERVATIVE IN LIGHT OF PERSIAN GULF CRISIS - OCT/90 WASKADA OIL PRICE +$40/bbl

- PROJECT RISK

1. PROJECT AREA - WATERFLOOD PERFORMANCE

- AREA ORIGINALLY UNDER GAS FLOOD - CHARACTERIZED BY EARLY BREAKTHROUGH (JUN/84 to FEB/85)

- FIG. 1 SHOWS GOR (JAN/85) NO EVIDENCE OF PREFERENTIAL FLOW ALONG SW-NE FRACTURE TREND
  - LOCATION SELECTION
- NOTICE REVIEW OF Øh USED TO DETERMINE TRACT FACTORS FOR WASKADA UNIT NO. 1 AND ØH IN APPLICATION CONSIDERABLY LOWER
  - 59% REDUCTION IN OOIP

WELL	ØH UNIT	ØH INFILL	Δ%
1-23	1.51	0.675	55
8-23	1.58	0.518	67
9-23		0.84	-
3-24	1.4	0.749	46
4-24	2.13	0.704	67
5-24	1.52	0.627	59
6-24	1.26	0.618	51
11-24		0.426	-
12-14		0.663	-

- 5-24 INJECTION PATTERN - INJECTION FOR ALL PRACTICAL PURPOSES HAS BEEN SUSPENDED SINCE APR/88, PRODUCTION FOR THE 6 MONTH PERIOD PRIOR TO APR/88 WAS 685 M3/MONTH OIL & 1965 m3/MONTH FLUID VS. 433 M3/MONTH OIL & 1588 M3/MONTH FLUID FOR THE FOLLOWING 6 MONTHS

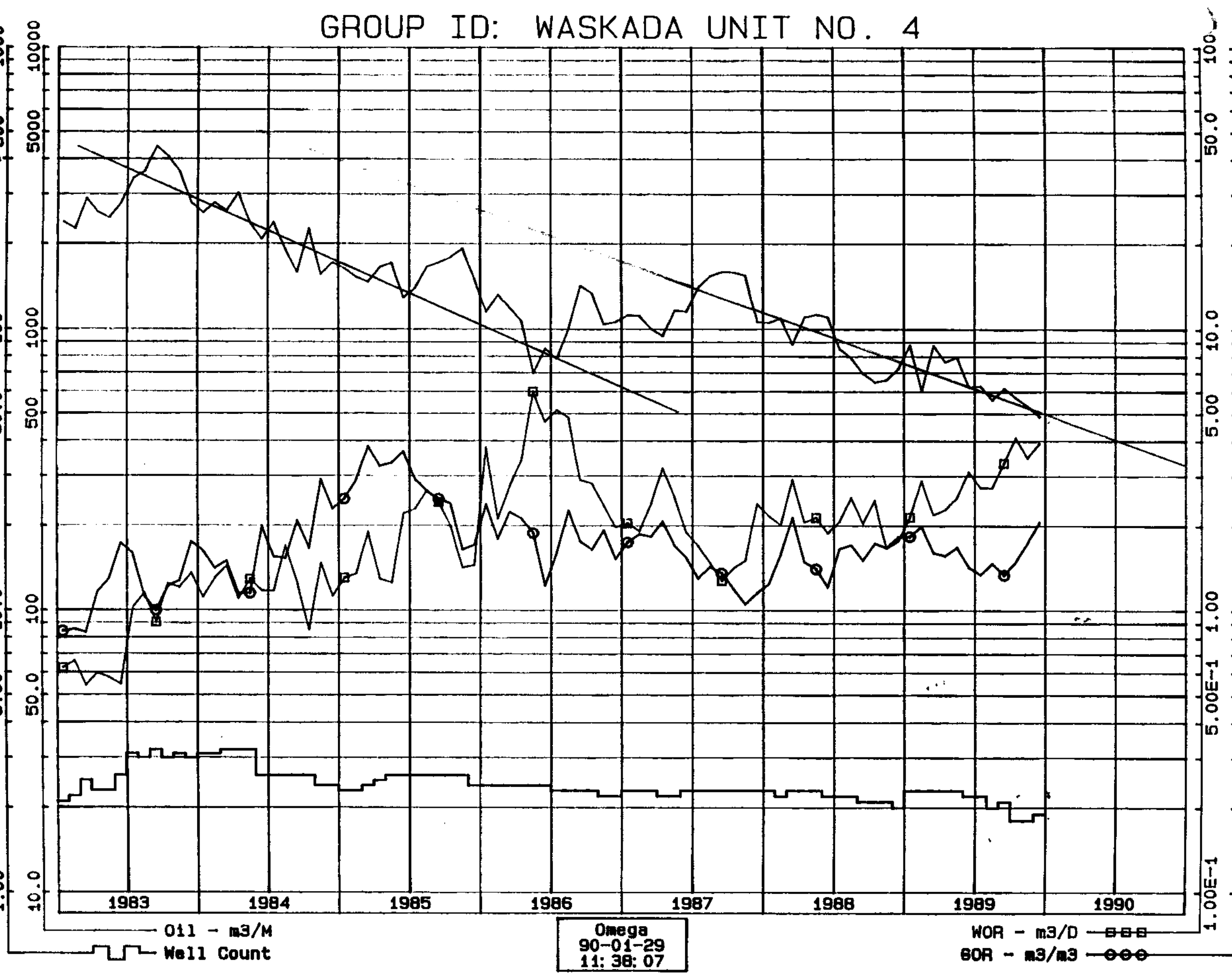
- SINCE APR/88 WHEN INJECTION WAS SUSPENDED OIL PRODUCTION HAS DROPPED 49% TO 352 $\frac{m^3}{MON}$ (JAN TO JUN /90) DO YOU THINK THIS DECLINE WOULD HAVE BEEN LESS SEVERE IF INJECTION HAD CONTINUED IN THE 5-24 INJECTION PATTERN (CONTINUED WATER INJECTION IS NECESSARY TO ACHIEVE FURTHER AREAL SWEEP AFTER WATER BREAKTHROUGH)
- CUMULATIVE VRR = 0.5
- COMMENT ON PRODUCTION PERFORMANCE OF WELLS WITHIN PROJECT AREA

4-24-1-26 18920 m^3 oil, 36390 m^3 water
OFF TREND (ie. not on SW-NE FRACTURE TREND WITH INJECTION WELL)

OFF TREND 8-23-1-26 5743 m^3 oil, 20685 m^3 water

1-23-1-26 ON TREND 10420 m^3 OIL, 6813 m^3 WTR
11-24-1-26 ON TREND 4096 m^3 OIL, 354 m^3 WTR

- LOOKING FOR CONFIRMATION OF FRACTURE SYSTEM EFFECT ON FLOOD PERFORMANCE ie. ON TREND EARLY BREAKTHROUGH

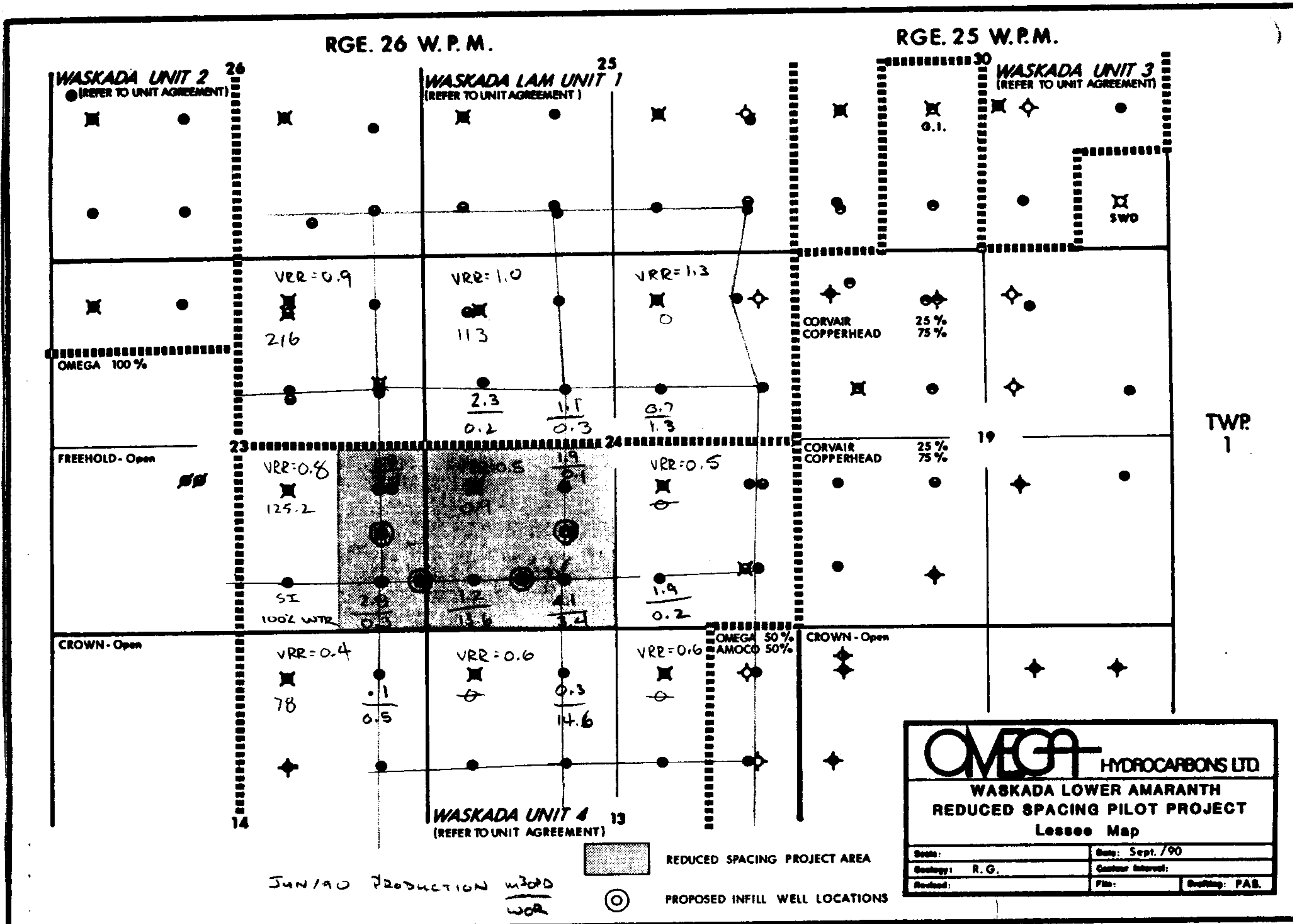


$q_i = 920$

$q_t = $ [illegible]

$d = 1.5$

$D = 21\%$


RGE. 26 W.P.M.
RGE. 25 W.P.M.
WASKADA UNIT 2
(REFER TO UNIT AGREEMENT)
WASKADA LAM UNIT 1
(REFER TO UNIT AGREEMENT)
WASKADA UNIT 3
(REFER TO UNIT AGREEMENT)
WASKADA UNIT 4
(REFER TO UNIT AGREEMENT)
26
25
30
23
24
19
14
13
TWP. 1
G.I.
SWD
OMEGA 100%
FREEHOLD - Open
CROWN - Open
CORVAIR
COPPERHEAD
25%
75%
OMEGA 50%
AMOCO 50%
VRR=0.9
216
VRR=1.0
113
VRR=1.3
0
2.3
0.2
1.1
0.3
0.7
1.3
VRR=0.8
125.2
VRR=0.5
1.9
0.2
SI
100% WTR
VRR=0.4
78
VRR=0.6
VRR=0.6
.1
0.5
0.3
14.6
REDUCED SPACING PROJECT AREA
PROPOSED INFILL WELL LOCATIONS
JUN/90 PRODUCTION m3OPD
WOR
OMEGA HYDROCARBONS LTD.
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lessee Map
Scale:
Date: Sept. /90
Geology: R.G.
Contour Interval:
Revised:
File:
Drafting: PAB.

P_i = 2000 m³/mon   t = 7.5 yrs   D = 47%

P_t = 60 m³/mo

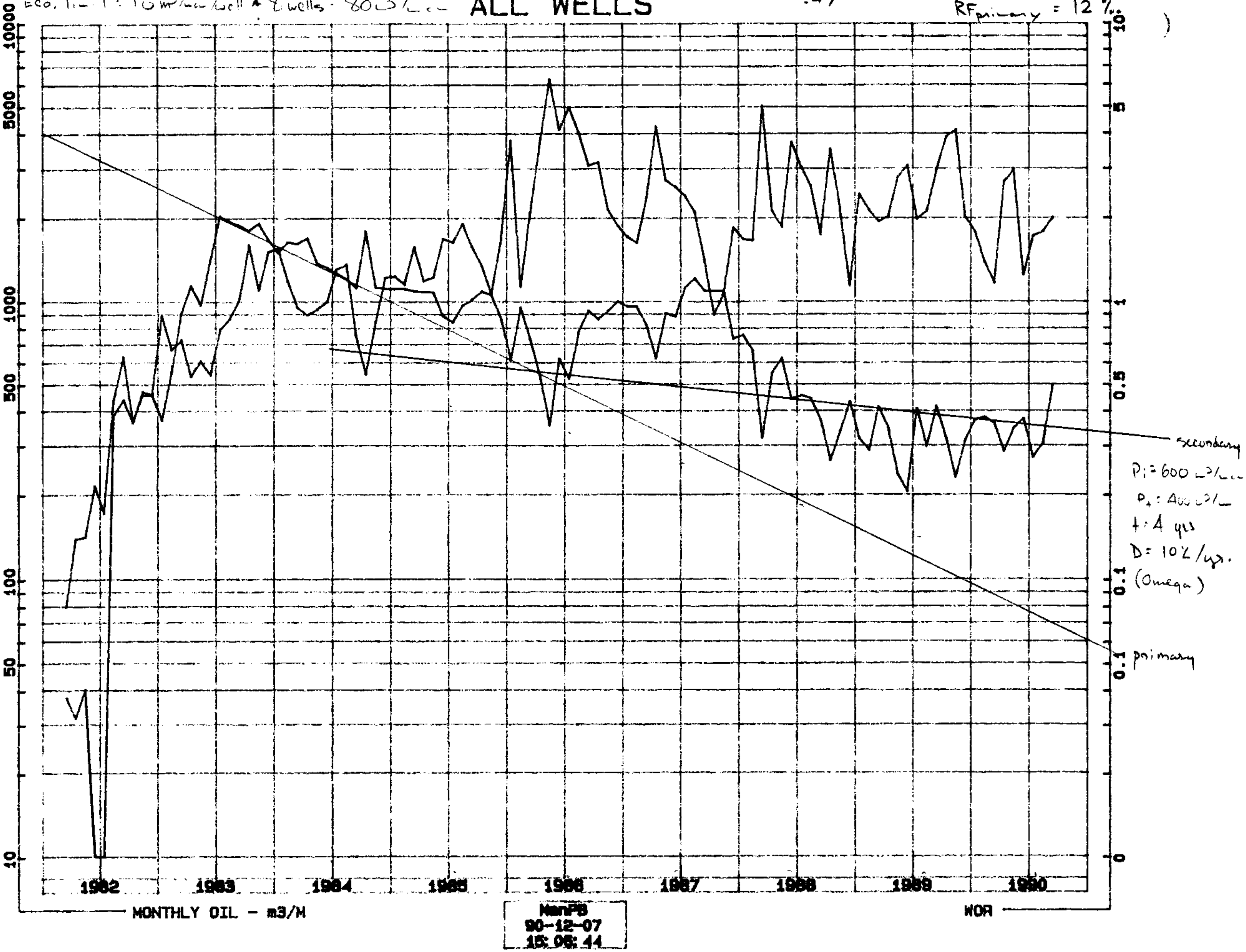
Eco. limit : 10 m³/mo/well × 8 wells = 80 m³/mo

$G_{83-0?}$ 29213

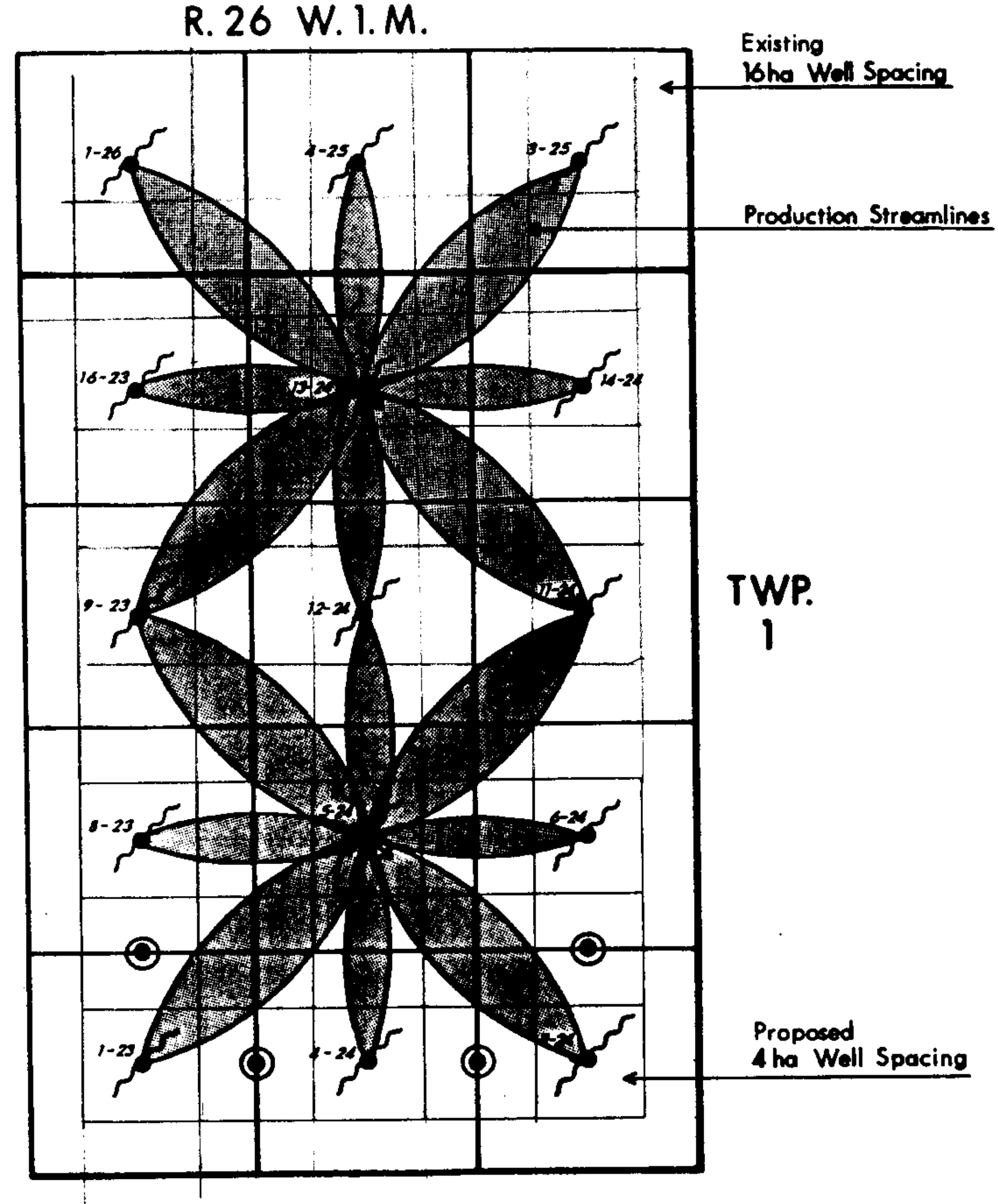
$Q_{p_{PRIMARY}} = \frac{(2000 - 80) \cdot 12}{.47}$ = 49021 m³ + 9213 = 58234 m³

OOIP : 483208 m³

RF primary = 12 %



WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
PROPOSED DRILLING SPACING UNITS



- EXISTING PRODUCTION WELLS
- EXISTING INJECTION WELLS
- PROPOSED INFILL WELLS
- FRACTURE PLANE
- REDUCED SPACING PROJECT AREA

OMEGA HYDROCARBONS LTD.

WASKADA, MN.

REDUCED SPACING PILOT PROJECT

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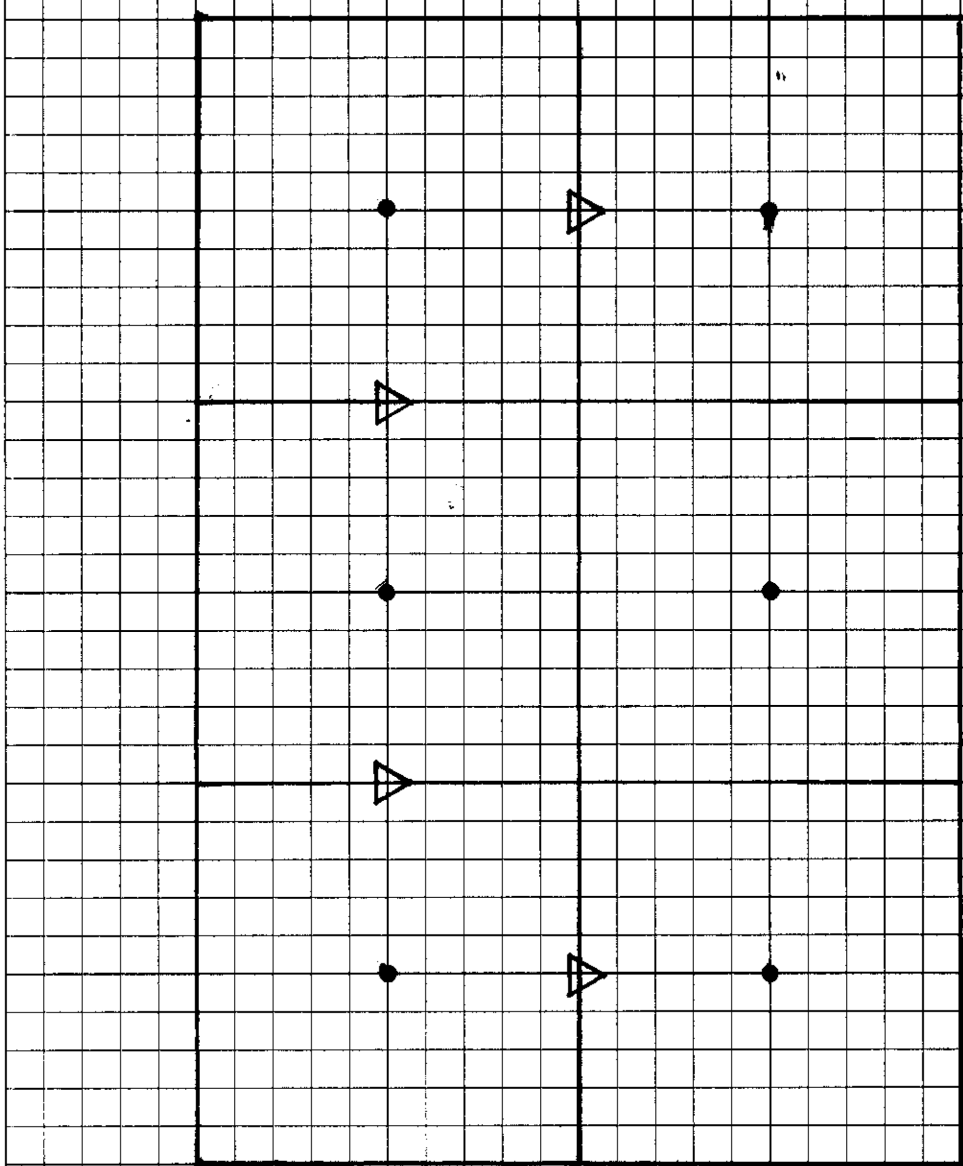
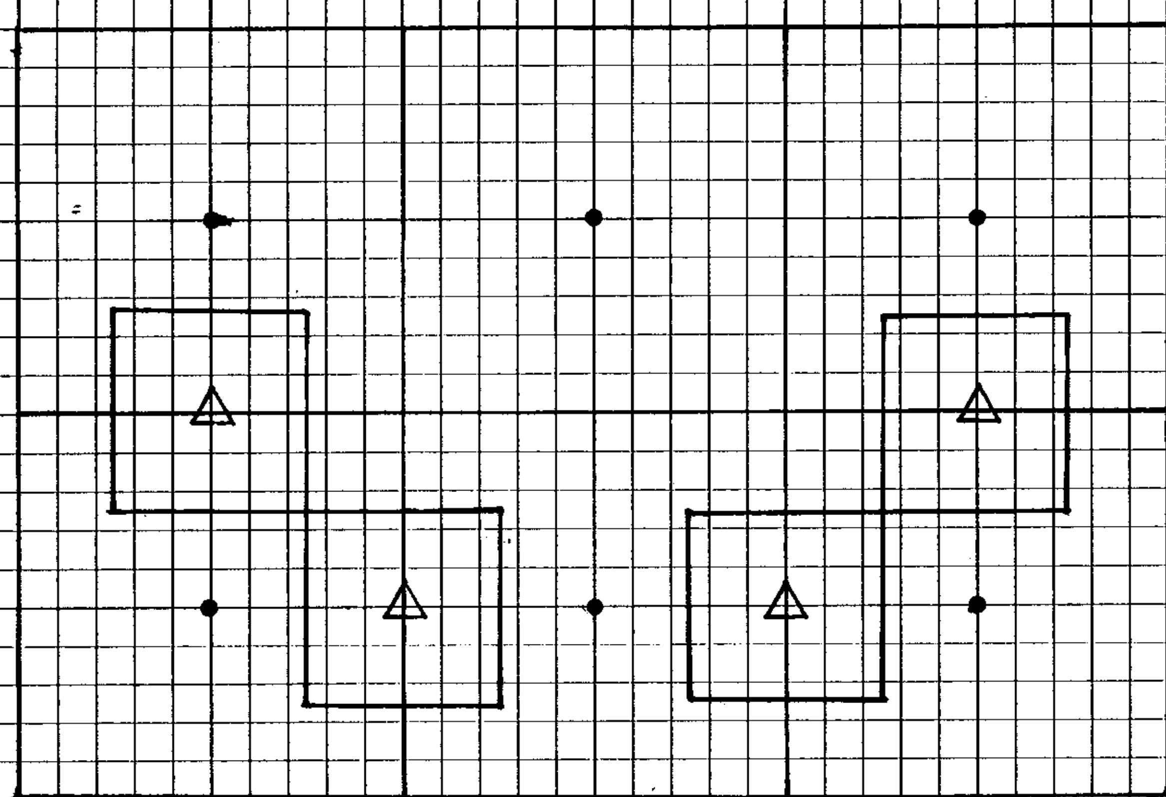
Geology:	Contour Interval:
Revised:	File: Drafting:

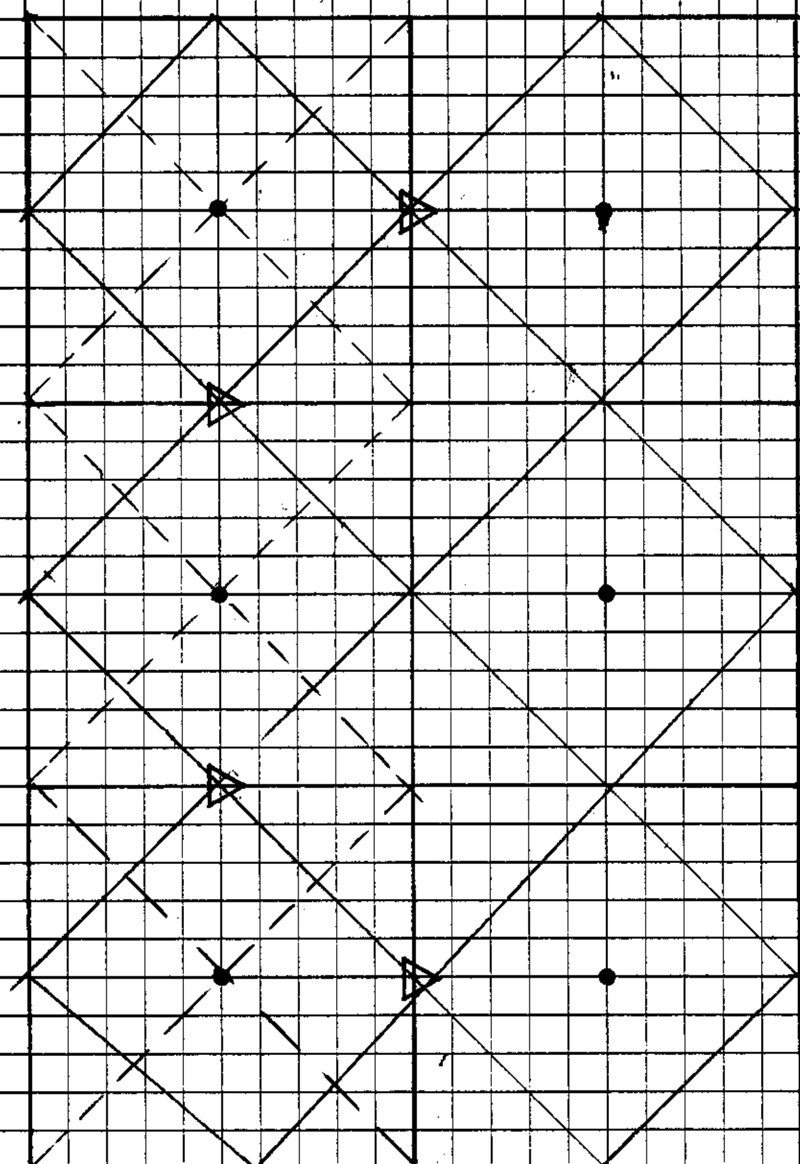


PROPOSED SPACING UNITS. - SUPERIMPOSE 4 x 4 ha SPACING UNITS ON EXISTING 16 ha SPACING UNITS

ADVANTAGES
- only needed SU established
- expandable

DISADVANTAGES
- doesn't address modification to existing SUs
- 4 ha size



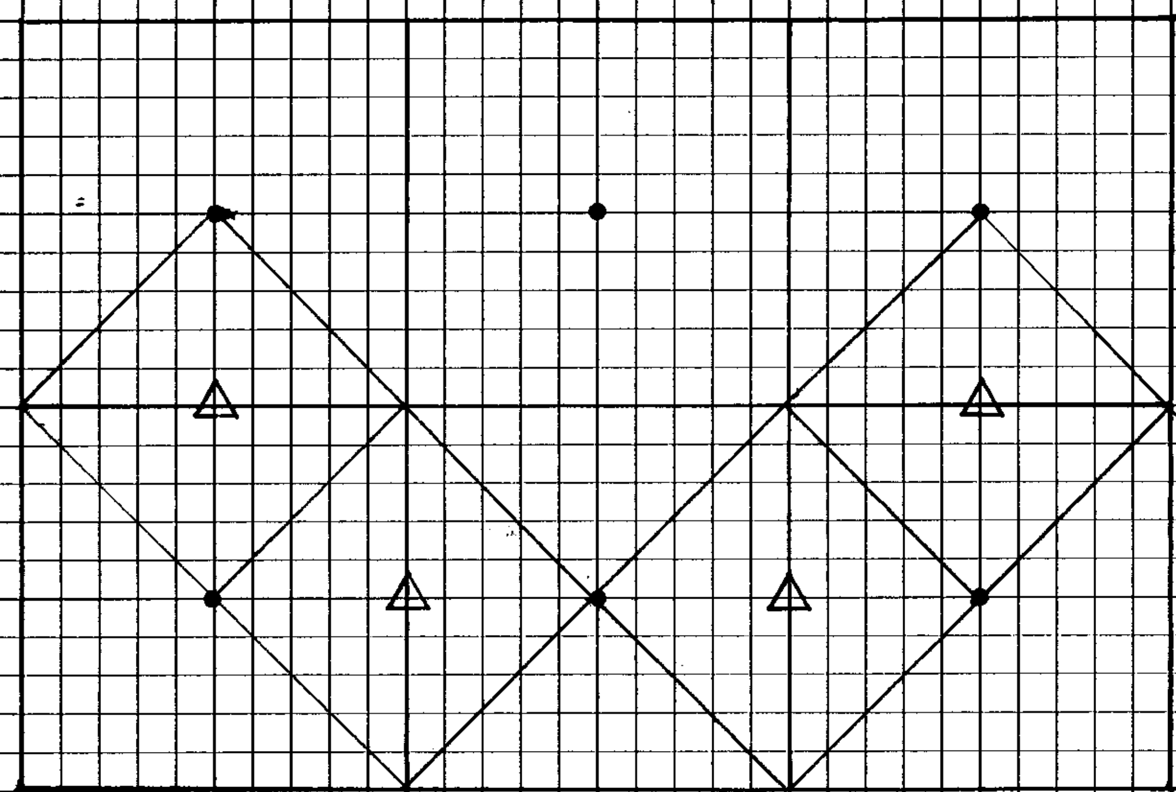


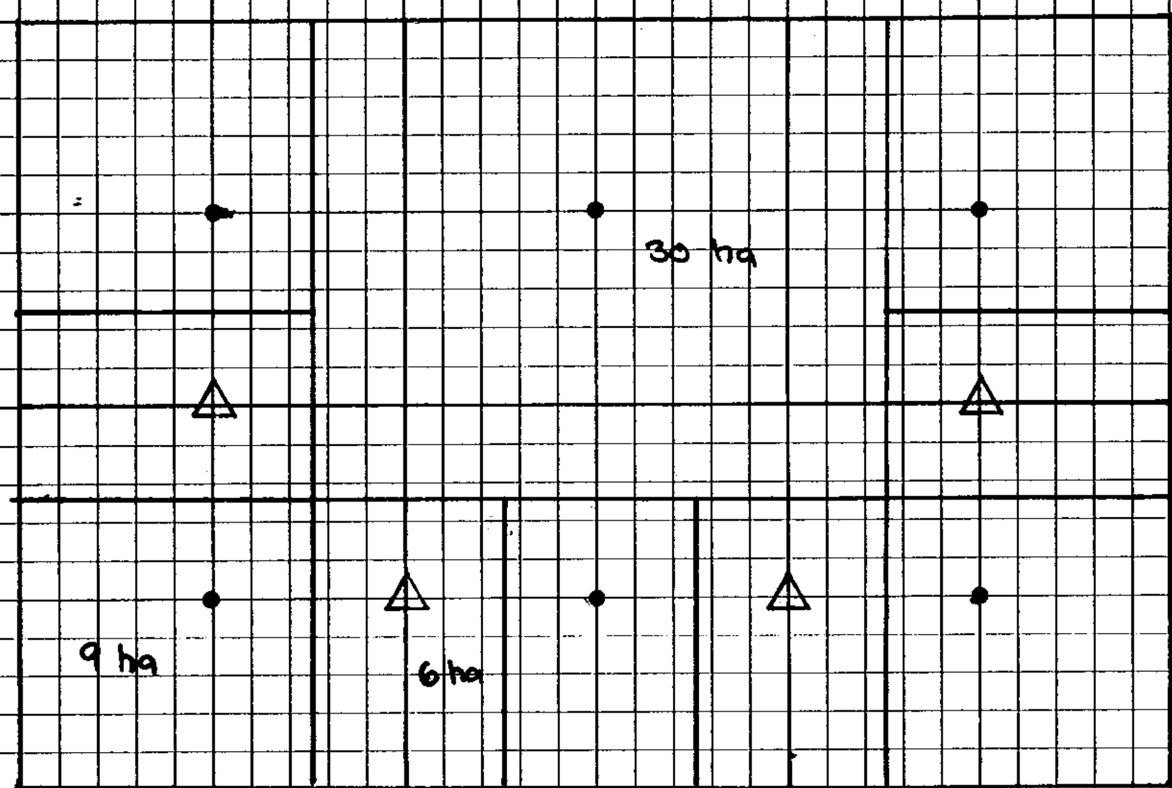
ADVANTAGES

- 80 ha SU.
- expandable

DISADVANTAGE

- don't match with existing well locations
- don't address existing SU.





ADVANTAGE
. no undrilled SU
. Repeatable for expansion
. SU < 4 ha
DISADVANTAGES
. different sized shapes

100m×100m target area centered
on proposed well locations

BACKGROUND - INJECTION PATTERN 5-24-1-26 (W5M)

- Waskada Unit No. 4 became effective June, 1984. Lean gas injection commenced at 5-24 in JUNE/84

- A total of $10^3 m^3$ (m^3) of lean gas was injected into Unit No. 4

- A total of $852 * 10^3 m^3$ (16451.4 m^3) of lean gas was injected into 5-24

- gas injection was suspended in MARCH/85 and water injection commenced APRIL/85

- early gas breakthrough noted at 8-23, 3-24 & 4-24 in OCT/84, NOV/84, AUG/84 respectively - SEE FIG. 1
AREA WITH GOR > 200 m^3/m^3

- gas breakthrough no evidence of preferential flow along SW-NE frac trend

→ Bob

PS-1-25

MANITOBA

Inter-Departmental Memo

Date: March 12, 1985

To: The Oil and Natural Gas Conservation Board

R. B. Chenier - Chairman
Wm. McDonald - Deputy Chairman
J. F. Redgwell - Member

From: H. Clare Moster
Director, Petroleum Branch

Telephone

Subject: Waskada Unit No. 4 - Conversion of Gas Injection to Water Injection

First | Fold

Omega Hydrocarbons Ltd., as operator of Waskada Unit No. 4, has made application to convert the following three wells from gas injection to water injection:

Omega Waskada GIW 7-23-1-26
Omega et al Waskada GIW 5-24-1-26
Omega Waskada Prov. GIW 7-24-1-26

Recommendation:

It is recommended that the application be approved (draft letter of approval attached).

Discussion:

Figure No. 1 is a map of Waskada Unit No. 1 and surrounding area showing the location of current gas and water injectors. Aslo shown are average gas-oil ratios (GOR's) for January 1985. From this map, it is evident in the northern part of the Unit, surrounding the three wells that Omega has requested approval to convert to water injection wells. (Note that the normal solution GOR is about 50 m^3/m^3).

Production history for wells showing the most drastic increases in GOR do not show any signs of production rate response to injection. This suggests that the high mobility gas has bypassed most of the oil and has travelled to producing wells through high permeability streaks. Continued production in this mode would likely result in only limited additional oil recovery.

Conversion of the subject wells to water injection is more likely to result in production response. While water injection will also be controlled by permeability distribution, the water-to-oil mobility ratio is much less than the gas-to-oil mobility ratio, and therefore the effects of high permeability zones will be lessened.

As Omega notes, patterns in the southern part of the Unit have shown response to gas injection, and GOR's are not excessive. In view of this, there is no reason to terminate gas injection in this area. However, performance monitoring will continue. If gas

....2

breakthrough occurs in another area, future conversions to water injection will be considered.

Subclause 1(4) of Board Order No. PM 41 empowers the Board to "approve or require the conversion of any well or wells from gas injection to water injection if the Board is of the opinion that continued gas injection would be detrimental to pressure maintenance operations or to ultimate recovery or if the Board is of the opinion that there is an insufficient supply of gas for injection".

This clause was designed to accommodate the current situation. Attached is a draft of a letter approving Omega's application.

Original Signed by H. C. Moster

H. Clare Moster

LRD/HCM/lk

RESERVOIR PROPERTIES (CMG MODEL STUDY)

ϕ 2-20% ϕ_{ave} = 13%

k 0.5 - 10 md

4 pseudo-layers used

S_{w_c} = 44 %

$S_{w_{ave}}$ = 63 %

$S_{o_{rw}}$ = 15 %

$S_{o_{rg}}$ = 12 %

μ_o = 1.3 mPas @ P_b = 4220 kPa

P_R = 8672 kPa

R_s = 51.1 m^3/m^3

injection commenced OCT/83 MODEL STUDY PV = 3370 $10^3 m^3$

B_{g_i} = .019

~~MODEL STUDY~~

TIME	GAS INJ (m^3)	GAS INJ (rm^3)	(% PV)	GOR
3 MON	7.64×10^5	14516	0.4	97
6 MON	1.68×10^6	31920	0.9	98
9 MON	2.73×10^6	51870	1.5	115
1 YR	3.98×10^6	75620	2.2	137
1.5 YR	8×10^6	152000	4.5	220
2 YR	1.18×10^7	1520000	6.7	302
3 YR	3.16×10^7	600400	17.8	670
4 YR	5.39×10^7	1024100	30	1002

WASKADA UNIT NO. 4 - 5-24 INJ DAT.

PV = 928 × 10³ m³
B_g = .019

DATE	GAS INJ (Mm³)	(% PV)	GOR	
1 MON	1119	0.1	220.7	
2	3630.	0.4	151.4	
3 MON	5337	0.6	101.6	
4	6195	0.7	142.9	
5	9305	1.0	115	
6 MON	12317	1.3	230	
7	14013	1.5	289	
8	15226	1.6	287	
9 MON	16451	1.7	310	
10	16451	1.7	428	
11	16451	"	375	WATER INJ. STARTUP
1 YR	16451	"	398	
1.5 YR	"	"	204	
2 YR	"	"	146	
3 YR	"	"	135	
4 YR	"	"	183	

- a gas sat^n gradient exist between production/injection wells
- with dispersed gas injection - no oil banking will occur

- adverse mobility ratio - immediate gas breakthrough, continuously increasing GOR & no oil bank formation

1985 CMG MODEL STUDY

S_{w_i} = 37% – 60%

S_{oR} = 15 - 20 %

ϕ_{ave} = 15%

k_{ave} : 2.96 md

μ_o = 1.3 mPa·s

μ_w = 0.7 mPa·s

B_w : 1.007 m³/m³

- model study - oil recovery not significantly affected by Timing of WF as long as pressure remains above the BP.

THEORETICAL WATERFLOOD RECOVERY

$$R = \frac{S_{oi} - S_{orw}}{S_{oi}}$$

$15\% \leq S_{oi_w} \leq 20\%$ $\quad$ $40\% \leq S_{oi} \leq 63\%$

$37\% \leq S_{wi} \leq 60\%$

$50\% \leq R \leq 76\%$ of OOIP

ACTUAL WATERFLOOD RECOVERY

$\frac{N_p}{N} = 23.3\%$

CALCULATED VOLUMETRIC SWEEP = $\frac{\text{ACTUAL RECOVERY}}{\text{THEORETICAL RECOVERY}}$

$= \frac{23.3\%}{50\%} = 46.6$

$31\% \leq E_V \leq 46.6\%$ $\quad$ $= \frac{23.3}{76}$

INCREASE IN VOLUMETRIC SWEEP EFFICIENCY
RESULTING FROM INFILL DRILLING

Δ RECOVERY = 3.3% $\quad$ $\frac{N_p}{N} = 26.6$

$\frac{\text{PREDICTED RECOVERY}}{\text{THEORETICAL RECOVERY}} = \frac{26.6}{50} = 53\% \Big/ \frac{26.6}{76} = 35\%$

WATERFLOOD PERFORMANCE

- wtr injection at 5-24 commenced APR/85

- max. inj. rate (May - Aug / 85) 152 m³/d 5-24

- CAN 5-24 & OFFSETTING INJECTION WELLS MEET VRR = 1.0 — NO PROBLEM

$B_{oi} = 1.155$
$B_w = 1.0$

INJ PATTERN	SEPTEMBER 1990 VOIDAGE (rm³/d)	INJ (rm³/d)	VRR	INJECTION CAPABILITY (rm³/d)	ADDITIONAL INFILL WELL VOIDAGE (rm³/d)
5-24	40.4	8	0.2	90 - 150	22
13-13	15.8	5.5	0.4	50	14
15-13	7.0	5.0	0.7	62	—
15-14	0.9	2.9	3.2	<20	—
7-23	2.5	0	0	85	4
15-23	11.4	18.4	1.6	66	—
7-24	14.3	5.2	0.4	80	4
13-24	28.3	0	0	60	—
15-24	11.9	7.6	0.6	71	—

P_R 1990 fall-off tests

13-13	8505
15-13	8871
15-14	10673
7-23	8241
7-24	8946

WATERFLOOD PERFORMANCE PREDICTION

OMEGA WF RECOVERY 112.6 × 10³ m³ — 23.3 % OOIP (See Figure eco limit 0.4m³/d)

CMG 1985 simulation indicated WF recoveries of 19.6 - 26.7 % after 20 yrs. depending on the permeability estimates used

- when WF extended 40-50 yrs recoveries increased to 36.5-38 %

Individual well recoveries to date rge from 5-25 % of OOIP / well

NOTE: reevaluation of OOIP — 50% reduction in OOIP

- injection suspended in Aug/86 until Mar/87 as a result of a sudden increase in WOR from < 2.0 to > 3 in 1st Qu/86
- after inj suspended steady decline in WOR from > 4 to < 2 & a corresponding increase in oil prod.

- similarly in 1988, erratic increase in water prod. led to suspension of injection in Nov/88 through Feb/90

- Fluid production in 1st 8 mth 88 - 1870 m³/mon
- fluid production 88-09 to 90-06 1076 m³/mon (42% decline) though oil production has only declined ≈ 20%

- oil production behavior during suspension of inj @ S-24 suggests water channeling between the inj & producers

- difference in

INFILL PERFORMANCE PREDICTION

- WELL LOCATIONS - ON LSD BOUNDARY & ON 10 AC SPACING BOUNDARY, FOR EXAMPLE THE SAME WELL COULD BE 3B-24 / 3C-24 / 4A-24 / 4D-24

1D-23
8A-23
3C-24
6A-24
} INFORMAL DESIGNATION

WELL	IP		1990		PREDICTED PERFORMANCE	
	OIL	WATER	OIL	WATER	OIL	WATER
1-23	4.7 (9.1)	1.7	1.4	0.4		
1D-23					4.5	6.4
8-23	3.8 (15.3)	11.3	0.3	0.6		
8A-23					2.6	3.5
6-24	1.6 (11.8)	0.3	2.0	0.2		
6A-24					4.0	3.1
3-24	~~10~~.1 (9.8)	2.3	2.3	9.6		
3C-24					6.1	8.8
4-24	10.1 (9.4)	12.5	1.8	10.9		

( ) FIRST 3 MONS ON PROD.

Omega IP 2.0 m³OPD declining @ 14%
incremental reserves 4000 m³/well

ESTIMATED INFILL WELL VOIDAGE 42 Rm³/d

FRACTIONAL FLOW CALCULATIONS $f_w = \frac{1}{1 + \frac{k_{ro}}{\mu_o} \times \frac{\mu_w}{k_{rw}}}$

ROCK TYPE II
$S_{wc} = 0.37$

SW	K_{ro}	K_{rw}	$\frac{k_{ro}}{k_{rw}}$	$1 + \frac{k_{ro}}{\mu_o} \times \frac{\mu_w}{k_{rw}}$	fw
0.37	1.0	0	∞	—	0
0.44	0.6	0.05	12	7.5	.13
0.48	0.48	0.08	6	4.24	.24
0.56	0.27	0.16	1.7	1.918	.52
0.64	.14	.26	0.54	1.292	.77
0.70	.08	.34	0.24	1.13	.89
0.76	.03	.44	.07	1.04	.96
0.8	0	0.52	0	1	1

DATA

$\mu_w = 0.7$ cp (estimated) BHT = 45°C (113°F

$\mu_o = 1.3$ cp

$\frac{\mu_w}{\mu_o} = 0.54$

$q_i = 119$ m3/d (747 b/d) average 1ST 9 months 5-24 on injection

$A_x =$ (5-24 inj - 4-24 prod)

$\phi =$

4-2A prior to commencement of water injection
water cut (f_w) = 0.5

- mobile water result in no oil bank
formation, flood characterized by steadily
increase WOR

Mobility ratio $M = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o}$ k_{rw} @ S_w breakthrough

k_{ro} @ S_{wi}

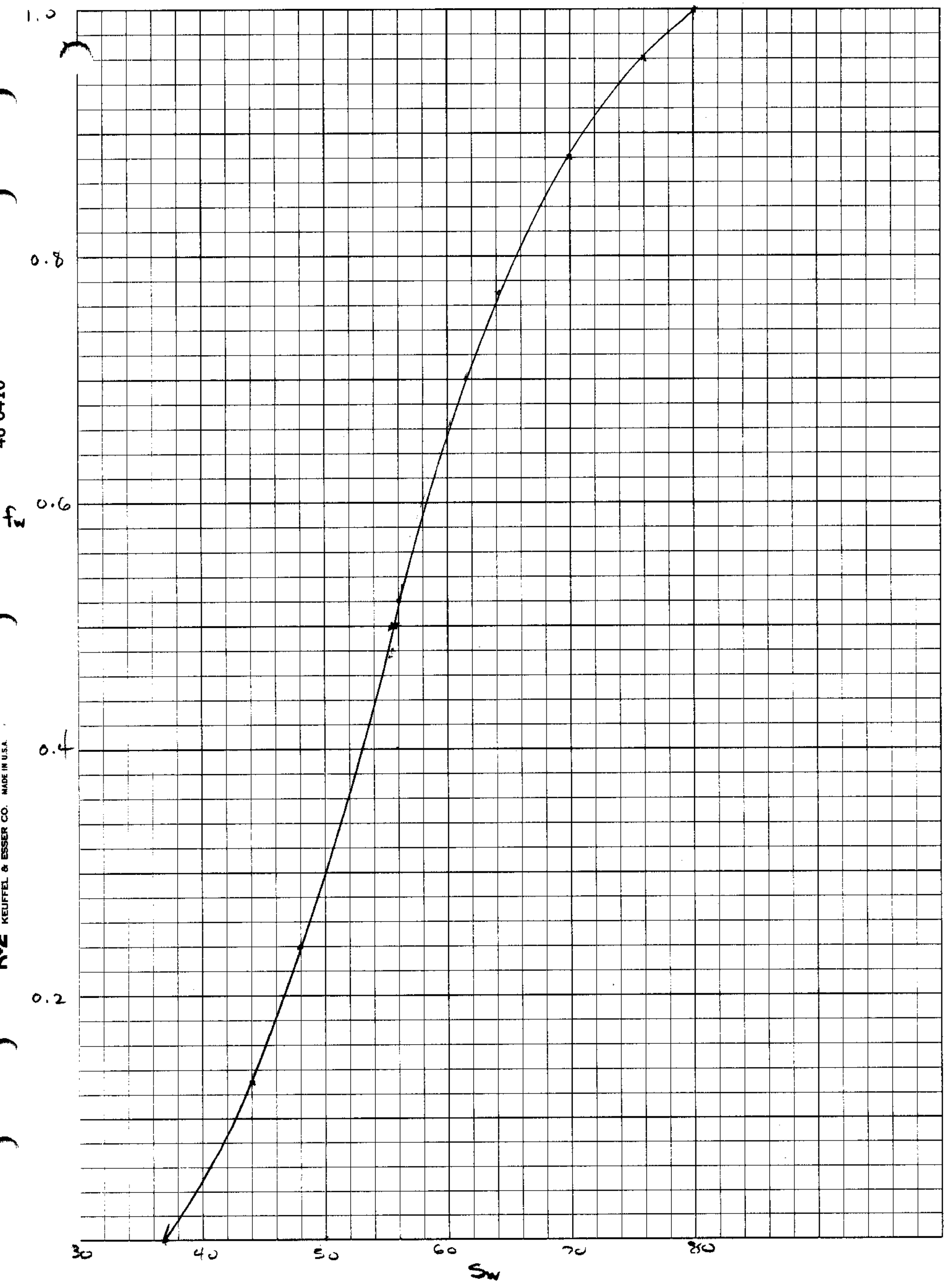
WOR	Sw_c	k_{ro}	μ_o	k_{rw}	μ_w	$\frac{k_{ro}}{\mu_o}$	$\frac{k_{rw}}{\mu_w}$	M
0	0.37	1.0	1.3	.2	0.7	0.77	0.29	0.38
1.0	0.56	0.27	1.3	.2	0.7	0.21	0.29	1.38

- initial mobile water saturation adverse effect on the mobility ratio with result in poorer sweep efficiency

- published areal sweep values

inverted 5 spot 80 + %
inverted 7 spot 73-82 %
inverted 9 spot 49-78 %

- permeability variation within reservoir significant effect on volumetric sweep



1.0
0.8
0.6
0.4
0.2
f_w
30
40
50
60
70
80
S_w

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Waskada Unit No.2 became effective January 1, 1984. Immediately following unitization, an inverted nine spot pattern waterflood was initiated at wells 16-22, 5-26, 13-26, 5-27, 7-27, 13A-27 and 15A-27-1-26 WPM. In September 1985 the Unit was expanded and water injection began at well 5-35-1-26 WPM. In February, 1989 16-22-1-26 WPM was abandoned and replaced by 13-23-1-26 WPM as the pattern injector.

Waskada Unit No. 3 was formed May 1, 1984 and water injection was quickly initiated at wells 5-39, 13-30, 15-30, 5-31 and 7-31-1-25 WPM. In September 1984 the Unit was expanded to include LSD 12-30-1-25 WPM. A second expansion took place during 1985 and involved the addition of five new injection wells located at 13-31, 15-31, 13-32-1-25 and 13-36, 15-36-1-26 WPM. Two separate Unit expansions occurred in 1986 and three new injection wells located at 5-36, 7-36-1-26 and 7-5-2-26 WPM were added.

Waskada Unit No. 4 became effective June 1984. Following unitization an inverted nine spot pattern gas flood was initiated at wells 5-13, 13-13, 15-13, 15-14, 7-23, 5-24 and 7-24-1-26 WPM. Lean gas injection into these wells was continuous up to February 1985. Due to premature gas breakthrough at the production wells surrounding injectors 7-23, 5-24 and 7-24-1-26 WPM gas injection was terminated at these three wells and water injection was started April 1985. Lean gas injection continued at injectors 5-13, 13-13, 15-13 and 15-14-1-26 WPM until September 1985. In December 1985 the remaining gas injectors and two additional wells 16-11 and 7-13-1-26 WPM were converted to water injection.

Waskada Unit No. 5 was formed January 1, 1985 and water injection began at wells 13-35, 15-35-1-26 and 5-2, 7-2-2-26 WPM immediately following unitization. In March 1986 the Unit was expanded and water injection began at wells 5-34, 13-34, 15-34-1-26 WPM and 15-2, 7-3-2-26 WPM.

Waskada Unit No. 4

The cumulative oil, water and gas production to December 31, 1989 for Waskada Unit No. 4 were 146.0 x 10^3 m^3, 227.8 x 10^6 m^3 and 22.2 x 10^6 m^3 respectively. During 1989 the monthly oil production, water production and gas/oil ratios varied from 489 to 880 m^3/month, 1531 to 2355 m^3/month and from 134 to 206 m^3/m^3, respectively. The historical production data for Waskada Unit No. 4 is illustrated in Figure 5. Figure 15 contains an updated plot of actual versus forecasted oil production for the Unit. A summary of workovers performed during 1989 within this Unit is contained in Table 6. Voidage replacement data for the individual injection patterns are contained in Tables 43 through 51.

Pressure tests conducted on wells 5-13-1-25 WPM, 7-13-1-26 WPM, 13-13-1-26 WPM, 15-13-1-26 WPM, 15-14-1-26 WPM, 7-23-1-26 WPM and 7-24-1-26 WPM indicate that pressures in this Unit are at or above the initial reservoir pressure. The gas/oil ratio for this Unit continues to exceed the solution gas/oil ratio due to trapped gas saturations from prior injection.

Individual injection pattern data, including gas/oil ratios versus time, water cut ratios versus time and surface injection pressures versus time are presented in Figure 31 through 33.

Waskada Lower Amaranth
Injection Well Summary

Well	Unit	Type	Injection Startup Date			Cumulative Injection 89/12/31 (Rm^3)	Cumulative VRR 89/12/31
15-23-1-26 WPM	Unit 1	Water	83	10	18	76777.9	0.899
13A-24-1-26 WPM	Unit 1	Water	83	02	25	86676.2	1.086
15-24-1-26 WPM	Unit 1	Water	83	02	25	84585.0	1.364
5-25-1-26 WPM	Unit 1	Water	83	02	25	108815.2	0.997
7-25-1-26 WPM	Unit 1	Water	83	02	25	90912.6	1.203
13-25-1-26 WPM	Unit 1	Water	83	12	24	45892.2	0.804
15-25-1-26 WPM	Unit 1	Water	83	12	01	26435.8	1.199
7-26-1-26 WPM	Unit 1	Water	84	01	17	64616.8	1.060
16-22-1-26 WPM	Unit 2	Water	83	12	21	61790.0	1.030
13-23-1-26 WPM	Unit 2	Water	88	02	29	6848.7	1.067
5-26-1-26 WPM	Unit 2	Water	84	01	28	75028.7	0.881
13-26-1-26 WPM	Unit 2	Water	84	02	08	57700.0	0.950
5-27-1-26 WPM	Unit 2	Water	84	02	10	70884.2	0.863
7-27-1-26 WPM	Unit 2	Water	84	02	10	85931.2	0.951
13A-27-1-26 WPM	Unit 2	Water	84	02	10	65795	1.017
15A-27-1-26 WPM	Unit 2	Water	84	01	26	75780	1.030
5-35-1-26 WPM	Unit 2	Water	85	10	08	20586.1	0.418
5-30-1-25 WPM	Unit 3	Water	84	08	08	68048.1	0.996
7A-30-1-25 WPM	Unit 3	Water	87	12	08	13593.0	0.373
13-30-1-25 WPM	Unit 3	Water	84	06	08	37575.3	1.273
15-30-1-25 WPM	Unit 3	Water	84	06	08	57935.4	1.057
5-31-1-25 WPM	Unit 3	Water	84	06	10	43581.2	1.181
7-31-1-25 WPM	Unit 3	Water	84	06	10	55342.5	0.864
13-31-1-25 WPM	Unit 3	Water	85	10	11	26979.1	1.303
15-31-1-25 WPM	Unit 3	Water	86	01	24	15200.2	.772
13-32-1-25 WPM	Unit 3	Water	85	10	11	32159.0	0.757
5-36-1-26 WPM	Unit 3	Water	86	12	02	12518.7	0.975
7-36-1-26 WPM	Unit 3	Water	86	11	25	18951.6	1.131
13-36-1-26 WPM	Unit 3	Water	85	10	05	23401.6	1.630
15-36-1-26 WPM	Unit 3	Water	85	10	17	24792.2	1.632
7-5-2-25 WPM	Unit 3	Water	86	07	28	16327.8	0.754
16-11-1-26 WPM	Unit 4	Water	85	12	31	15592.8	0.817
5-13-1-26 WPM	Unit 4	Water	85	12	01	24484.7	0.679
7-13-1-26 WPM	Unit 4	Water	85	12	18	42372.6	0.625
13-13-1-26 WPM	Unit 4	Water	85	12	01	32531.3	0.631
15-13-1-26 WPM	Unit 4	Water	85	12	01	28152.3	0.615
15-14-1-26 WPM	Unit 4	Water	85	12	01	17439.3	0.399
7-23-1-26 WPM	Unit 4	Water	85	04	01	62943.3	0.889
5-24-1-26 WPM	Unit 4	Water	85	04	01	65855.7	0.482
7-24-1-26 WPM	Unit 4	Water	85	04	01	53732.6	0.552
5-13-1-26 WPM	Unit 4	*Gas	84	06	18	830000.0	N/A
13-13-1-26 WPM	Unit 4	*Gas	84	06	13	2601000.0	N/A
15-13-1-26 WPM	Unit 4	*Gas	84	06	15	1531000.0	N/A
15-14-1-26 WPM	Unit 4	*Gas	84	06	15	525000.0	N/A
7-23-1-26 WPM	Unit 4	*Gas	84	08	01	365000.0	N/A
5-24-1-26 WPM	Unit 4	*Gas	84	06	15	852000.0	N/A
7-24-1-26 WPM	Unit 4	*Gas	84	06	13	714000.0	N/A

Table 50

INJECTION PATTERN 5-24-1-26 WPM (UNIT4)

HPP = 908.6 mCF

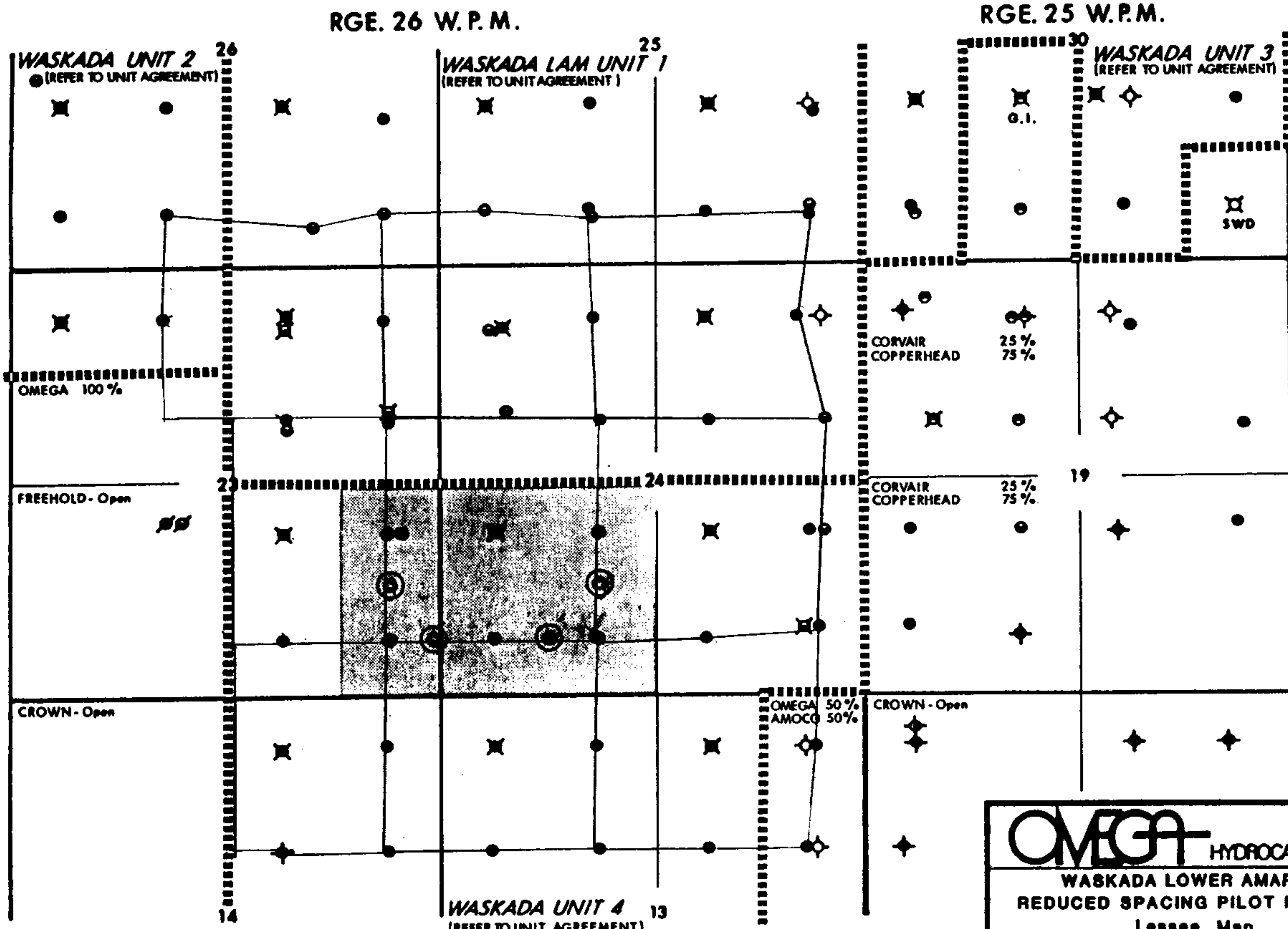
	SURFACE INJ PRESS (KPAG)	TOTAL PROD (RM3)	TOTAL INJ (RM3)	VRR	CUM VRR	AVERAGE PATTERN PRESS (KPAG)	INJ HRS	OIL PROD (M3)	WATER PROD (M3)	GAS PROD (KM3)	GAS INJ (KM3)	INJ RATE (RM3/D)	INJECTIVITY INDEX (RM3/D/KPAG)	CUM INJ (RM3)	CUM PRESSURE TIME (MPA*D)	HALL PLOT SLOPE (MPA*D/M3)	WC RATIO (M3/M3)	GOR (M3/M3)	COMMENTS
JUN	8230	2510.5	1119.2	0.446	0.041	5500	322	454.9	523.5	100.4	59.3	83.42	0.029970	1119.2	110.4	0.099	0.535	220.7	GAS INJECTION STARTUP
JUL	7595	2046.9	2510.6	1.227	0.127	5500	734	452.5	661.5	68.5	133.1	82.09	0.030223	3629.8	342.7	0.093	0.594	151.4	
AUG	9050	1596.3	1706.9	1.069	0.180	5500	768	424.4	695.0	43.1	90.5	53.34	0.014006	5336.7	632.3	0.170	0.621	101.6	
SEPT	8410	1491.0	857.8	0.575	0.203	5500	720	395.9	342.6	56.6	45.5	28.59	0.009651	6194.5	804.6	0.294	0.464	142.9	
OCT	8943	1914.7	3110.1	1.624	0.297	5435	620	633.6	340.1	72.9	162.0	118.86	0.033300	9304.6	1110.6	0.075	0.355	115.0	
NOV	8665	2223.1	3012.7	1.355	0.383	5435	684	403.8	369.4	93.0	157.7	105.71	0.032202	12317.3	1365.6	0.002	0.478	230.2	
DEC	8065	2817.0	1695.2	0.602	0.423	5435	726	402.7	510.2	116.7	80.7	56.04	0.020889	14012.5	1609.5	0.144	0.559	209.7	
JAN 1985	8702	3303.8	1213.1	0.367	0.280	4808	740	416.5	496.3	119.0	56.9	39.34	0.009969	15225.6	1877.8	0.221	0.544	207.6	CALC CHANGE (EXCESS GAS)
FEB	8928	3514.1	1225.8	0.349	0.284	4808	672	420.0	461.7	130.2	57.5	43.78	0.010492	16451.4	2127.8	0.204	0.524	310.0	
MAR		4548.4	0.0	0.000	0.265	4808	0	392.2	639.6	167.9	0.0	ERR	ERR	16451.4	2127.8	ERR	0.620	428.1	
APR	1415	3843.9	3263.7	0.849	0.296	4808	700	389.4	435.1	146.2		111.90	0.018476	19715.1	2169.1	0.013	0.520	375.4	WATER INJECTION STARTUP
MAY	5050	3968.9	4645.7	1.171	0.342	4808	744	380.9	439.2	151.5		149.86	0.015463	24360.8	2325.6	0.034	0.536	397.7	
JUN	6930	3373.6	4553.6	1.350	0.384	4808	720	322.7	508.4	122.8		151.79	0.013117	28914.4	2533.5	0.046	0.612	380.5	
JUL	7147	3119.9	4585.5	1.470	0.425	4808	744	331.7	405.3	112.0		147.92	0.012540	33499.9	2755.1	0.040	0.594	340.1	
AUG	6829	3422.4	4760.5	1.391	0.464	4808	744	360.5	744.7	114.4		153.56	0.013388	38260.4	2966.8	0.044	0.674	317.3	
SEPT	6373	3257.0	3383.1	1.039	0.485	4808	720	410.2	607.2	112.9		112.77	0.010238	41643.5	3158.0	0.057	0.597	275.2	
OCT	4619	3247.7	2399.7	0.739	0.494	4808	744	444.0	580.1	113.5		77.41	0.008359	44043.2	3301.2	0.060	0.566	255.2	
NOV	4783	2267.5	2513.8	1.109	0.508	4808	720	446.0	422.0	76.6		83.79	0.008891	46557.0	3444.7	0.057	0.486	171.4	
DEC	5655	2320.9	2607.0	1.123	0.523	4808	744	352.4	619.7	71.9		84.10	0.008160	49164.0	3620.0	0.067	0.637	204.0	
JAN 1986	4932	2641.3	2333.9	0.884	0.533	4808	744	252.8	956.7	71.7		75.29	0.007864	51497.9	3772.9	0.066	0.791	283.6	
FEB	4557	1896.8	1355.4	0.715	0.536	4808	528	400.3	425.4	61.6		61.61	0.006690	52853.3	3873.1	0.074	0.515	153.9	
MAR	4774	2171.0	3881.5	1.788	0.558	4808	744	302.5	616.6	65.8		125.21	0.013290	56734.8	4021.1	0.030	0.671	217.5	
APR	5960	1927.6	2451.1	1.272	0.584	5503	720	228.6	729.1	55.7		81.70	0.008247	59185.9	4199.9	0.073	0.761	243.7	
MAY	5418	1634.1	1844.1	1.129	0.593	5503	500	127.0	830.0	36.6		88.52	0.009452	61030.0	4312.8	0.061	0.868	206.4	
JUN	5773	1796.4	3026.5	1.685	0.612	5503	720	261.2	935.1	38.2		100.88	0.010380	64056.5	4486.0	0.057	0.782	146.2	
JUL	6811	1874.5	1412.5	0.754	0.615	5503	432	203.8	901.5	40.0		78.47	0.007295	65469.0	4608.6	0.007	0.820	200.2	
AUG		2753.7	0.0	0.000	0.599	5503	0	323.0	1166.5	73.4		ERR	ERR	65469.0	4608.6	ERR	0.783	227.2	
SEPT		2602.1	0.0	0.000	0.585	5503	0	353.9	1005.8	73.6		ERR	ERR	65469.0	4608.6	ERR	0.740	208.0	
OCT		2627.0	0.0	0.000	0.571	5503	0	346.5	1009.0	74.7		ERR	ERR	65469.0	4608.6	ERR	0.744	215.6	
NOV		2407.0	0.0	0.000	0.559	5503	0	366.0	753.8	76.3		ERR	ERR	65469.0	4608.6	ERR	0.673	200.5	
DEC		2161.5	0.0	0.000	0.549	5503	0	405.4	724.1	65.3		ERR	ERR	65469.0	4608.6	ERR	0.641	161.1	
JAN 1987		2003.8	0.0	0.000	0.540	5503	0	397.6	631.0	62.2		ERR	ERR	65469.0	4608.6	ERR	0.614	156.4	
FEB		1947.9	0.0	0.000	0.531	5503	0	400.0	559.8	62.0		ERR	ERR	65469.0	4608.6	ERR	0.570	153.6	
MAR	1840	1845.9	1027.3	0.357	0.532	5503	480	350.1	676.2	52.0		51.37	0.008877	66496.3	4645.4	0.036	0.659	150.0	
APR	1262	2276.5	1442.8	0.634	0.533	5503	695	248.7	907.0	59.8		49.82	0.009566	67939.1	4681.9	0.025	0.799	240.5	
MAY	3458	2107.9	1547.3	0.734	0.537	5503	456	369.1	864.8	56.1		81.44	0.010990	69486.4	4747.6	0.042	0.701	152.0	
JUN	3564	1944.8	1546.9	0.795	0.541	5503	552	399.6	739.4	54.0		67.26	0.008955	71033.3	4829.6	0.053	0.649	135.1	
JUL	2537	2037.8	1362.1	0.668	0.543	5503	456	451.9	845.2	52.6		71.69	0.011057	72395.4	4877.8	0.035	0.652	116.4	
AUG	2153	2329.5	1261.3	0.541	0.543	5503	504	479.1	802.9	68.7		60.06	0.009847	73656.7	4923.0	0.036	0.626	143.4	
SEPT	3214	1849.4	1849.4	1.000	0.545	5503	384	422.0	578.3	57.0		115.59	0.016143	75506.1	4974.4	0.028	0.578	135.1	
OCT	1904	1459.8	1459.8	1.000	0.552	5503	576	444.4	425.9	45.1		60.83	0.010397	76965.9	5020.1	0.031	0.489	101.5	
NOV	4335	1384.8	1384.8	1.000	0.555	5503	552	437.3	478.2	37.7		60.21	0.007270	78350.7	5119.8	0.072	0.522	86.2	
DEC	712	1177.6	800.5	0.680	0.556	5503	720	303.7	540.3	25.6		26.68	0.005720	79151.2	5141.2	0.027	0.652	84.3	
JAN 1988	72	1289.0	857.9	0.666	0.557	5503	696	322.6	497.8	33.7		29.58	0.007362	80009.1	5143.3	0.002	0.607	104.5	
FEB	131	1428.3	632.7	0.443	0.556	5503	576	297.3	424.0	45.4		26.36	0.006465	80641.0	5146.4	0.005	0.580	152.7	
MAR		1620.0	712.0	0.440	0.555	5503	720	136.6	660.7	45.1		23.73	0.006014	81353.8	5146.4	0.000	0.829	330.2	
APR	281	1375.8	603.0	0.438	0.554	5503	624	222.3	490.7	40.5		23.19	0.005486	81956.8	5153.7	0.012	0.680	102.2	
MAY		1380.0	52.1	0.038	0.554	5503	126	264.5	479.5	41.2		9.92	0.002515	82008.9	5153.7	0.000	0.644	155.0	

INJECTION PATTERN 5-24-1-26 WPM (UNIT4)

WPP = 900.6 mCF

	SURFACE INJ PRESS (KPAG)	TOTAL PROD (RM3)	TOTAL INJ (RM3)	VRR	CUM VRR	AVERAGE PATTERN PRESS (KPAG)	INJ HRS	OIL PROD (M3)	WATER PROD (M3)	GAS PROD (KM3)	GAS INJ (KM3)	INJ RATE (RM3/D)	INJECTIVITY INDEX (RM3/D/KPAG)	CUM INJ (RM3)	CUM PRESSURE TIME (MPA*D)	HALL PLOT SLOPE (MPA*D/M3)	WC RATIO (M3/M3)	GOR (M3/M3)	COMMENTS
JUN		1409.8	44.0	0.031	0.544	5503	126	200.6	603.3	36.9		8.38	0.002124	82052.9	5153.7	0.000	0.750	183.9	
JUL		1496.5	0.0	0.000	0.539	5503	0	209.1	528.7	44.7		ERR	ERR	82052.9	5153.7	ERR	0.717	213.8	
AUG		1428.5	0.0	0.000	0.533	5503	0	214.1	476.7	43.9		ERR	ERR	82052.9	5153.7	ERR	ERR	ERR	
SEPT	81	930.8	569.2	0.612	0.534	5503	528	182.0	249.2	31.1		ERR	ERR	82622.1	5153.7	0.000	ERR	ERR	
OCT		1177.7	556.3	0.472	0.533	5503	696	127.5	377.7	37.5		ERR	ERR	83178.4	5153.7	0.000	ERR	ERR	
NOV		1147.1	0.0	0.000	0.529	5503	0	163.6	224.7	38.2		ERR	ERR	83178.4	5153.7	ERR	ERR	ERR	
DEC		1123.6	0.0	0.000	0.526	5503	0	195.6	236.7	41.0		ERR	ERR	83178.4	5153.7	ERR	ERR	ERR	
JAN 1989		1178.0	0.0	0.000	0.522	5503	0	143.3	326.5	39.9		ERR	ERR	83178.4	5153.7	ERR	0.695	0.0	
FEB		899.1	0.0	0.000	0.519	5503	0	123.9	233.1	31.0		ERR	ERR	83178.4	5153.7	ERR	0.653	0.0	
MAR		1042.7	0.0	0.000	0.515	5503	0	163.2	312.8	24.3		ERR	ERR	83178.4	5153.7	ERR	0.657	0.0	
APR		832.3	0.0	0.000	0.505	5503	0	142.0	277.8	24.3		ERR	ERR	83178.4	5153.7	ERR	0.662	0.0	
MAY		957.4	0.0	0.000	0.502	5503	0	109.5	289.0	29.8		ERR	ERR	83178.4	5153.7	ERR	0.725	0.0	
JUN		776.4	0.0	0.000	0.499	5503	0	95.1	271.4	22.3		ERR	ERR	83178.4	5153.7	ERR	0.741	0.0	
JUL		950.8	0.0	0.000	0.497	5503	0	203.0	337.5	26.4		ERR	ERR	83178.4	5153.7	ERR	0.624	0.0	
AUG		781.1	0.0	0.000	0.494	5503	0	135.4	205.1	25.3		ERR	ERR	83178.4	5153.7	ERR	0.602	186.9	
SEPT		1080.7	0.0	0.000	0.491	5503	0	188.6	469.3	26.4		ERR	ERR	83178.4	5153.7	ERR	0.713	140.0	
OCT		1314.8	0.0	0.000	0.487	5503	0	156.1	593.6	31.7		ERR	ERR	83178.4	5153.7	ERR	0.792	203.1	
NOV		115.0	0.0	0.000	0.484	5503	0	114.1	476.9	28.3		ERR	ERR	83178.4	5153.7	ERR	0.807	248.0	
DEC		829.5	0.0	0.000	0.482	5503	0	131.5	180.9	28.7		ERR	ERR	83178.4	5153.7	ERR	0.579	218.3	
JAN /90																			
FEB																			
MAR																			
APR																			
MAY																			
JUN																			
JUL																			
AUG																			

Table 50



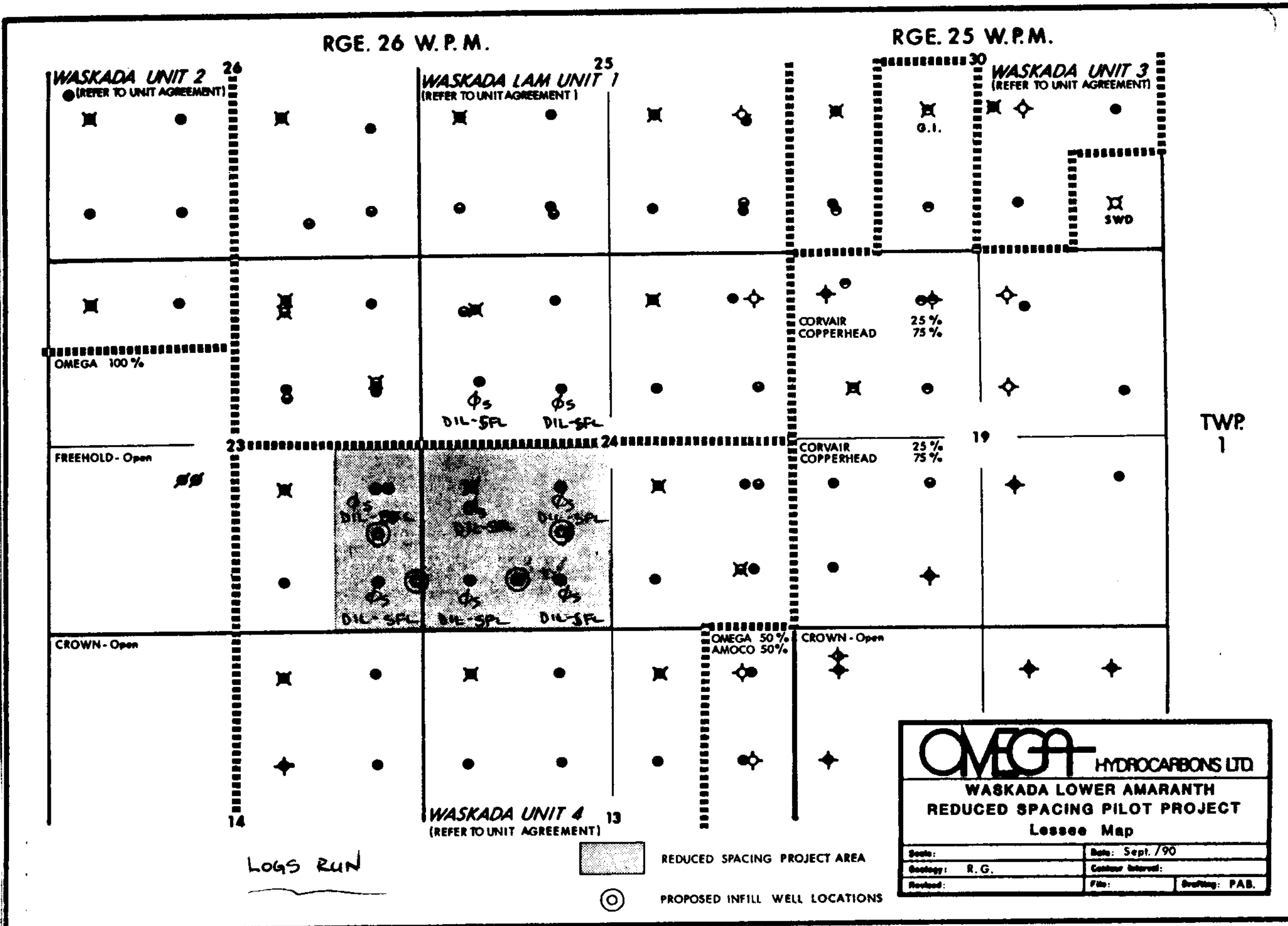
REDUCED SPACING PROJECT AREA

PROPOSED INFILL WELL LOCATIONS

OMEGA HYDROCARBONS LTD

WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lessee Map

Scale:	Date: Sept. /90
Geology: R.G.	Contour Interval:
Revised:	File: / Drafting: PAB.


RGE. 26 W.P.M.
RGE. 25 W.P.M.
WASKADA UNIT 2
(REFER TO UNIT AGREEMENT)
WASKADA LAM UNIT 1
(REFER TO UNIT AGREEMENT)
WASKADA UNIT 3
(REFER TO UNIT AGREEMENT)
WASKADA UNIT 4
(REFER TO UNIT AGREEMENT)
26
25
30
23
24
19
14
13
G.I.
SWD
OMEGA 100%
FREEHOLD - Open
CROWN - Open
CORVAIR
COPPERHEAD
25%
75%
OMEGA 50%
AMOCO 50%
TWP. 1
ϕ_s
DIL-SFL
LOGS RUN
REDUCED SPACING PROJECT AREA
PROPOSED INFILL WELL LOCATIONS
OMEGA HYDROCARBONS LTD.
WASKADA LOWER AMARANTH
REDUCED SPACING PILOT PROJECT
Lessee Map
Scale:
Geology: R.G.
Revised:
Date: Sept. /90
Contour Interval:
File:
Drafting: P.A.B.

$.15 < S_{ROW} < 0.20$

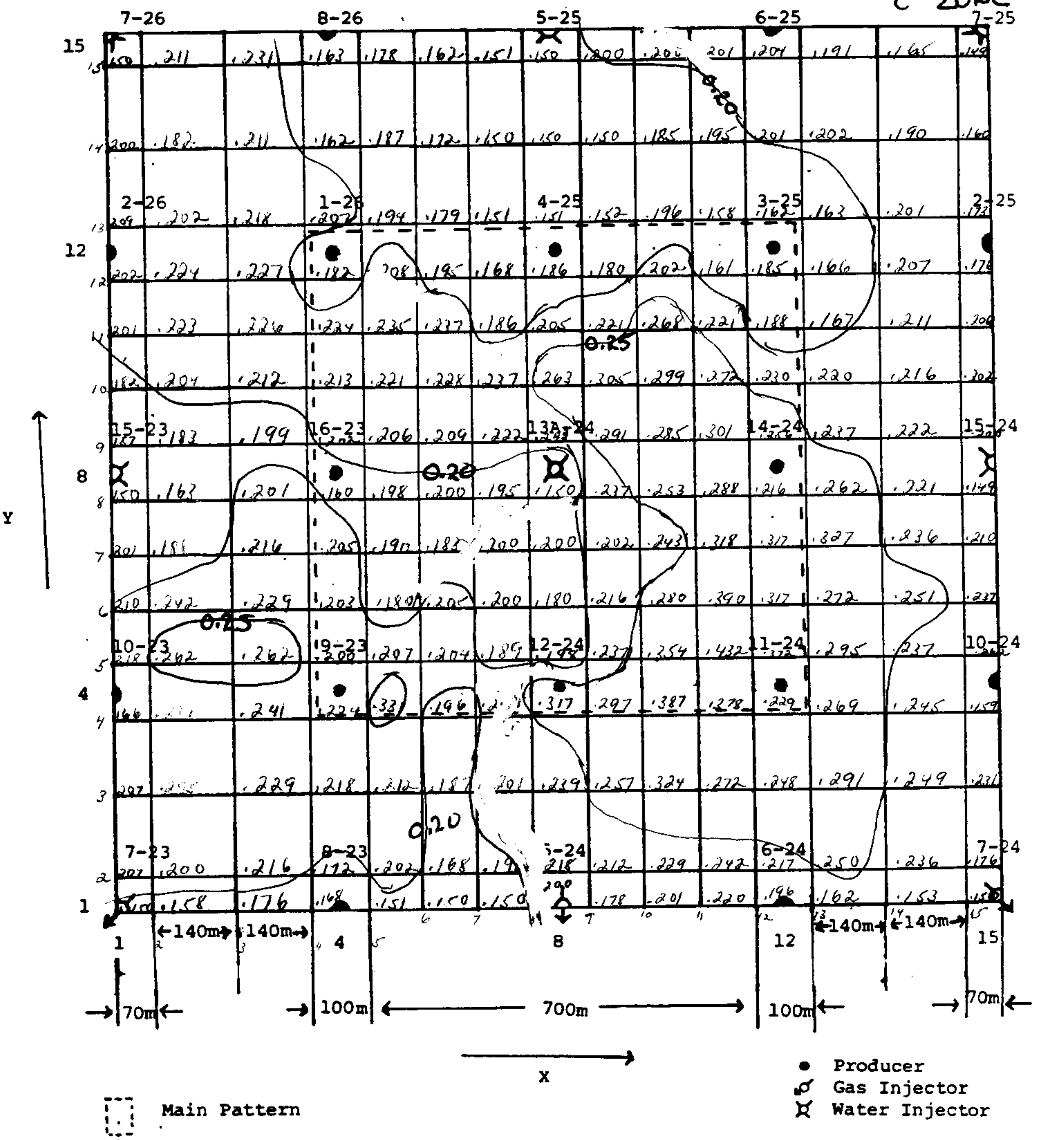
Figure 1

MODEL AREAL GRID AND WELL LOCATION

Waskada Lower Amaranth Pool

TWP.1 R.26 W1M

FINAL OIL SATURATION 'C' ZONE



GEOLOGY

- reservoir facies vfg subarkose
  - fining-upwards sequence
  - best ϕ & k in central portion of field (Weekaska Dome)
  - interbedded sands / siltstone / mudstone ϕ_{ave}=25% k=1-10md

  - log cutoff, non-dimensional GR index

$$NGRI = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} = \%$$

  - elongate, subparallel belts of thick LAm section show an overall trend SW-NE

* - little variation in thickness of LAm member in project area

  - dips gently to SW

* study area interfingering of 4-5 laterally extensive subarkose units

- LAm water-wet
- oil/water contact in Twp 1-26 -450 to -455 in SS
  postulated @ -465

N. Dakota

Production Performance Curves
Well Location Maps

EAST NEWBURG - (pg 139) 160 ac spacing single well pool - NOT PRODUCING
LANDA (pg 243) 80 ac spacing 2 wells c̄ pool
LEONARD pg 245 40 ac spacing 4 wells c̄ pool
Russell (pg 397) 80 ac spacing 6 wells c̄ pool
* SOUTH WESTHOPE (pg 426) 80 ac spacing 71 wells.
WESTHOPE pg 4[illegible] 40 ac spacing 1 well c̄ pool
✓ NEWBURG (pg 313) UNIT 40 ac spacing 123 wells WATERFLOOD

Kelly Carlson
(Oil & Gas Commission)
(701) 224 2969

N. Dakota

Production Performance Curves
Well Location Maps

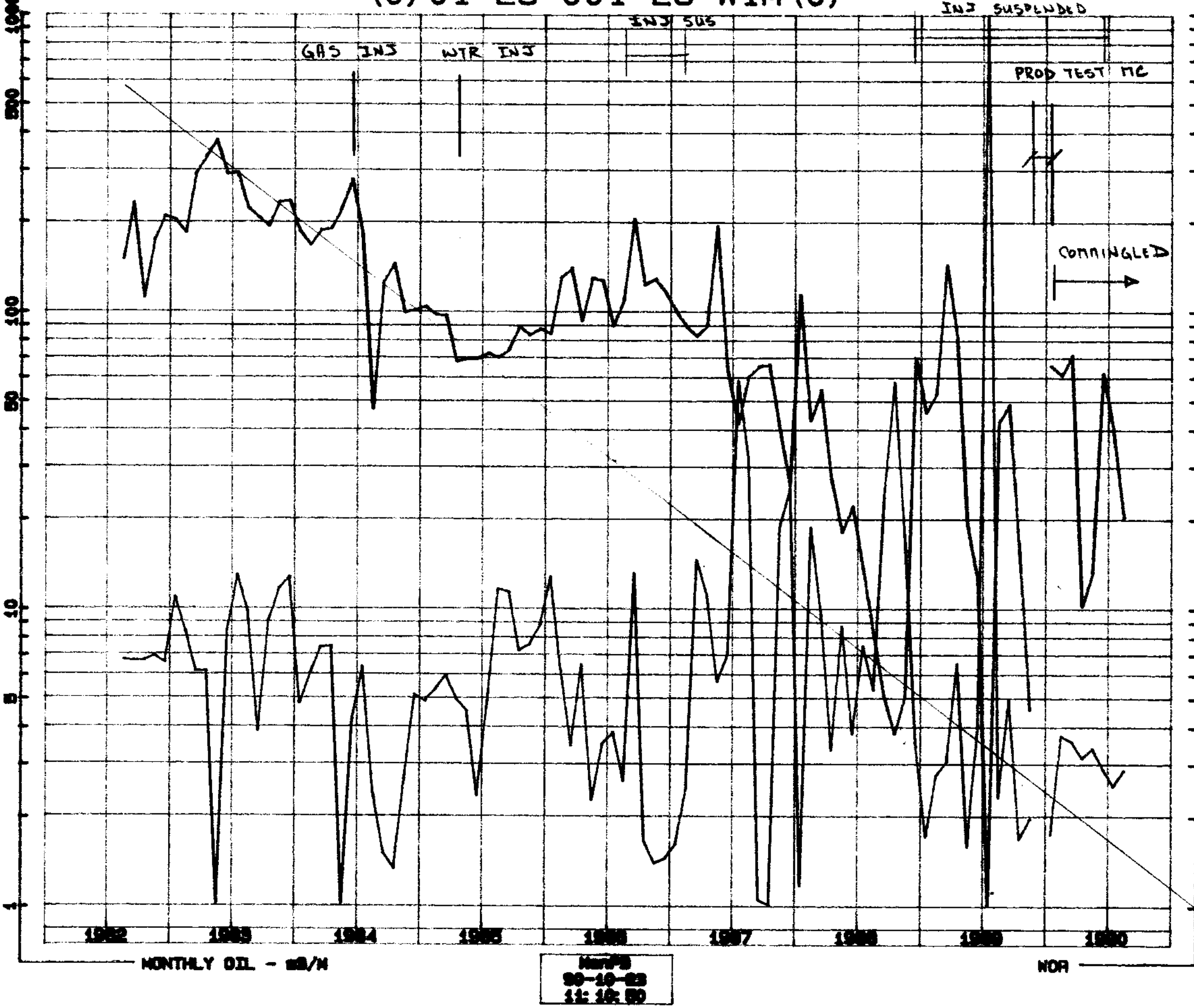
EAST NEWBURG - (pg 139) 160 ac spacing single well pool - NOT PRODUCING
LANDA (pg 243) 80 ac spacing 2 wells in pool
LEONARD (pg 245) 40 ac spacing 4 wells in pool
RUSSELL (pg 397) 80 ac spacing 6 wells in pool
* SOUTH WESTHOPE (pg 426) 80 ac spacing 71 wells.
WESTHOPE (pg 495) 40 ac spacing 1 well in pool
* NEWBURG (pg 313) UNIT 40 ac spacing 123 wells WATERFLOOD

Kelly Carlson
(Oil & Gas Commission)
(701) 224 2969

Q:
$q_i = 70\ m^3/mo$
$q_t = 10\ m^3/mo$
$t = 2.6$ yrs
$D = .748$
$Q_D = 6401 + 962$
$= 7363$

OOIP = 56068
RF_p = 13.1 %
$RF_{to\ date}$ 18.6 %

(0) 01-23-001-26 W1M (0)



PAGE NO. 1 *** S T O R E *** ManPB
WASKADA1 90-12-07
WELL (0)01-23-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1982-08-06 LAND#3 2795
ACCTG 4 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1982-08	264	150.7	100.6	13.7	0.67	150.7	100.6
1982-09	648	233.1	154.3	8.6	0.66	383.8	254.9
1982-10	392	111.4	73.8	6.8	0.66	495.2	328.7
1982-11	715	174.7	120.6	5.9	0.69	669.9	449.3
1982-12	648	210.8	137.4	7.8	0.65	880.7	586.7
1983-01	732	203.6	221.4	6.7	1.09	1084.3	808.1
1983-02	632	184.4	153.1	7.0	0.83	1268.7	961.2
1983-03	632	292.8	178.6	11.1	0.61	1561.5	1139.8
1983-04	720	333.6	204.1	11.1	0.61	1895.1	1343.9
1983-05	744	378.2	32.2	12.2	0.09	2273.3	1376.1
1983-06	720	290.7	244.1	9.7	0.84	2564.0	1620.2
1983-07	744	294.1	378.6	9.5	1.29	2858.1	1998.8
1983-08	736	223.5	215.7	7.3	0.97	3081.6	2214.5
1983-09	696	207.8	79.6	7.2	0.38	3289.4	2294.1
1983-10	732	193.7	175.8	6.4	0.91	3483.1	2469.9
1983-11	720	234.6	272.4	7.8	1.16	3717.7	2742.3
1983-12	696	237.3	301.2	8.2	1.27	3955.0	3043.5
1984-01	408	186.1	88.4	10.9	0.48	4141.1	3131.9
1984-02	384	167.6	100.7	10.5	0.60	4308.7	3232.6
1984-03	426	188.6	139.1	10.6	0.74	4497.3	3371.7
1984-04	408	191.3	142.4	11.3	0.74	4688.6	3514.1
1984-05	404	223.9	7.8	13.3	0.03	4912.5	3521.9
1984-06	593	279.3	117.9	11.3	0.42	5191.8	3639.8
1984-07	738	181.5	114.9	5.9	0.63	5373.3	3754.7
1984-08	564	46.8	11.1	2.0	0.24	5420.1	3765.8
1984-09	716	126.8	18.9	4.3	0.15	5546.9	3784.7
1984-10	726	145.4	19.2	4.8	0.13	5692.3	3803.9
1984-11	716	99.4	26.4	3.3	0.27	5791.7	3830.3
1984-12	744	102.0	52.1	3.3	0.51	5893.7	3882.4
1985-01	740	104.4	50.7	3.4	0.49	5998.1	3933.1
1985-02	672	97.7	52.1	3.5	0.53	6095.8	3985.2
1985-03	740	97.1	57.6	3.1	0.59	6192.9	4042.8
1985-04	719	67.8	33.4	2.3	0.49	6260.7	4076.2
1985-05	740	69.6	31.3	2.3	0.45	6330.3	4107.5
1985-06	720	69.5	16.2	2.3	0.23	6399.8	4123.7
1985-07	728	72.7	35.5	2.4	0.49	6472.5	4159.2
1985-08	736	70.1	81.4	2.3	1.16	6542.6	4240.6
1985-09	713	74.7	84.6	2.5	1.13	6617.3	4325.2
1985-10	744	89.7	64.4	2.9	0.72	6707.0	4389.6
1985-11	720	83.6	63.2	2.8	0.76	6790.6	4452.8
1985-12	737	88.1	77.6	2.9	0.88	6878.7	4530.4
1986-01	744	84.4	107.5	2.7	1.27	6963.1	4637.9
1986-02	618	130.7	80.8	5.1	0.62	7093.8	4718.7

5-24 inj. commenced

*** STORE ***

WASKADA1

WELL (0)01-23-001-26 W1M(0)

ManPB
90-12-07
14:11:00

FIELD 3
POOL 29
BLOCK 1
ACCTG 4

PROVINCE MAN.
WORKING INTEREST 0.00000%
ON PRDN 1982-08-06
ON INJN NOT ON YET

LAND#1 2
LAND#2 0
LAND#3 2795

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1986-03	744	140.8	48.3	4.5	0.34	7234.6	4767.0
1986-04	719	93.1	60.1	3.1	0.65	7327.7	4827.1
1986-05	726	130.4	29.4	4.3	0.23	7458.1	4856.5
1986-06	718	127.1	44.3	4.2	0.35	7585.2	4900.8
1986-07	743	89.7	34.3	2.9	0.38	7674.9	4935.1
1986-08	744	109.9	28.7	3.5	0.26	7784.8	4963.8
1986-09	713	206.5	271.9	7.0	1.32	7991.3	5235.7
1986-10	745	123.0	20.1	4.0	0.16	8114.3	5255.8
1986-11	720	129.7	17.9	4.3	0.14	8244.0	5273.7
1986-12	744	116.0	16.7	3.7	0.14	8360.0	5290.4
1987-01	724	100.9	16.2	3.3	0.16	8460.9	5306.6
1987-02	672	89.2	22.0	3.2	0.25	8550.1	5328.6
1987-03	744	82.8	120.9	2.7	1.46	8632.9	5449.5
1987-04	719	90.3	99.6	3.0	1.10	8723.2	5549.1
1987-05	744	194.8	109.8	6.3	0.56	8918.0	5658.9
1987-06	720	62.9	43.9	2.1	0.70	8980.9	5702.8
1987-07	720	42.0	245.8	1.4	5.85	9022.9	5948.6
1987-08	744	60.9	191.6	2.0	3.15	9083.8	6140.2
1987-09	720	65.7	6.8	2.2	0.10	9149.5	6147.0
1987-10	744	66.6	6.0	2.1	0.09	9216.1	6153.0
1987-11	720	40.6	76.4	1.4	1.88	9256.7	6229.4
1987-12	384	25.9	65.7	1.6	2.54	9282.6	6295.1
1988-01	744	115.7	13.4	3.7	0.12	9398.3	6308.5
1988-02	552	42.9	80.8	1.9	1.88	9441.2	6389.3
1988-03	744	54.7	52.0	1.8	0.95	9495.9	6441.3
1988-04	720	27.4	9.1	0.9	0.33	9523.3	6450.4
1988-05	744	18.1	15.8	0.6	0.87	9541.4	6466.2
1988-06	552	22.3	8.4	1.0	0.38	9563.7	6474.6
1988-07	648	13.7	10.2	0.5	0.74	9577.4	6484.8
1988-08	744	8.3	4.4	0.3	0.53	9585.7	6489.2
1988-09	720	5.1	12.0	0.2	2.35	9590.8	6501.2
1988-10	624	3.8	22.0	0.1	5.79	9594.6	6523.2
1988-11	504	5.1	8.5	0.2	1.67	9599.7	6531.7
1988-12	744	70.8	25.0	2.3	0.35	9670.5	6556.7
1989-01	696	45.8	7.8	1.6	0.17	9716.3	6564.5
1989-02	504	53.4	14.6	2.5	0.27	9769.7	6579.1
1989-03	648	144.3	44.0	5.3	0.30	9914.0	6623.1
1989-04	720	82.1	53.6	2.7	0.65	9996.1	6676.7
1989-05	216	19.1	3.0	2.1	0.16	10015.2	6679.7
1989-06	336	12.4	4.9	0.9	0.40	10027.6	6684.6
1989-07	432	0.0	4.9	0.0	99.99	10027.6	6689.5
1989-08	408	42.7	9.8	2.5	0.23	10070.3	6699.3
1989-09	720	48.9	24.3	1.6	0.50	10119.2	6723.6

*** S T O R E ***
WASKADA1
WELL (0)01-23-001-26 W1M(0)

ManPB
90-12-07
14:11:00

FIELD 3
POOL 29
BLOCK 1
ACCTG 4

PROVINCE MAN.
WORKING INTEREST 0.00000%
ON PRDN 1982-08-06
ON INJN NOT ON YET

LAND#1 2
LAND#2 0
LAND#3 2795

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1989-10	408	15.6	2.6	0.9	0.17	10134.8	6726.2
1989-11	120	4.6	0.9	0.9	0.20	10139.4	6727.1
SHUT IN							
1990-01	528	66.3	11.5	3.0	0.17	10205.7	6738.6
1990-02	552	61.4	22.9	2.7	0.37	10267.1	6761.5
1990-03	648	71.8	25.5	2.7	0.36	10338.9	6787.0
1990-04	552	10.2	3.2	0.4	0.31	10349.1	6790.2
1990-05	216	13.3	4.5	1.5	0.34	10362.4	6794.7
1990-06	528	62.8	18.1	2.9	0.29	10425.2	6812.8
1990-07	696	40.1	10.1	1.4	0.25	10465.3	6822.9
1990-08	648	20.3	5.8	0.8	0.29	10485.6	6828.7

$q_i = 330$ m³/m

$q_t = 10$ m³/m

$t = 3.75$ yrs.

$D = .93$

$Q_p = 4129$ m³

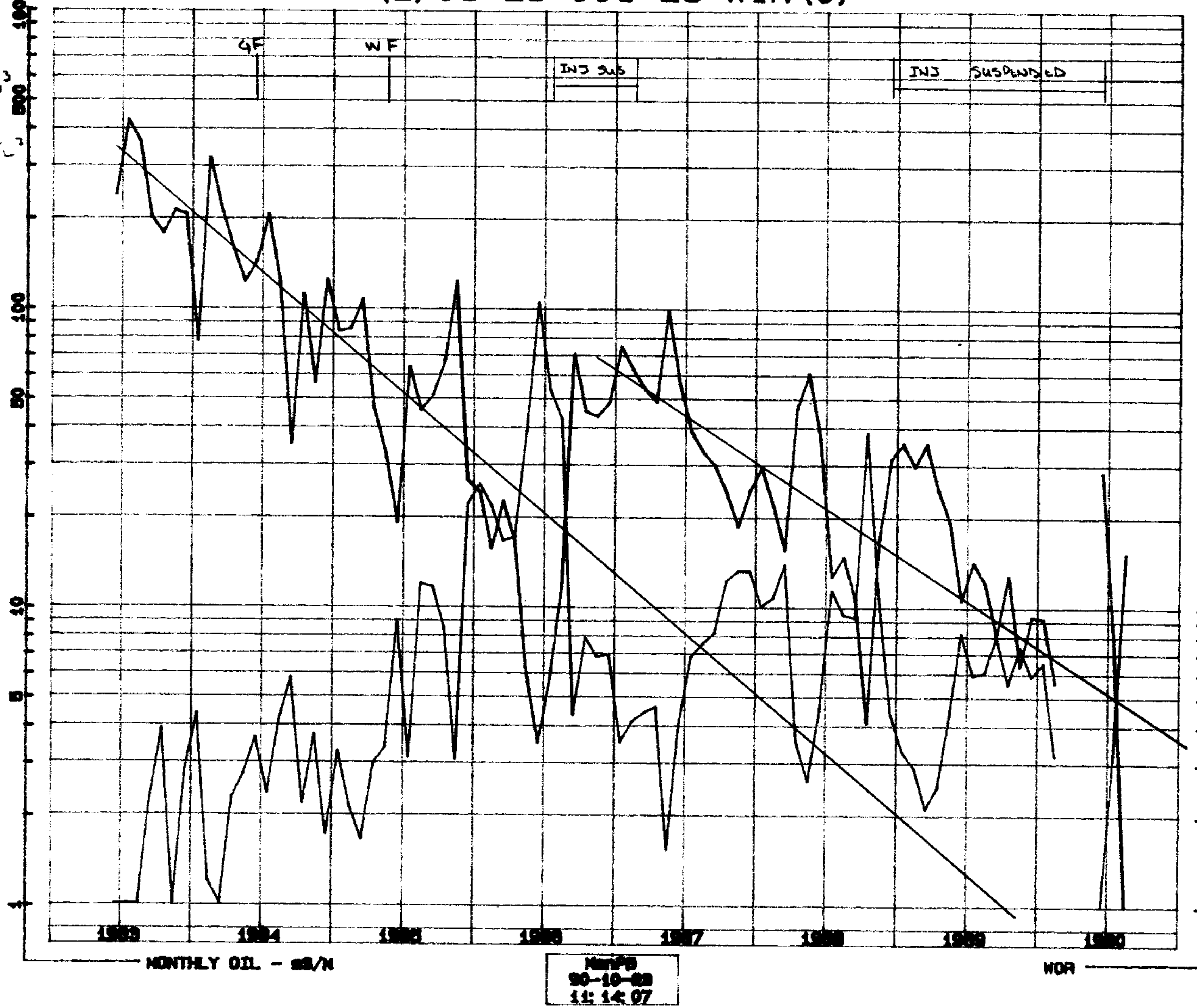
$Q_{ult} = 5754$ m³

OOIP: 43034

RF_{wf}: 13.3%

RF_p = 9.6%

(2) 08-23-001-26 W1M (0)



PA .O. 1 *** STORE *** ManPB
WASKADA1 90-12-07
WELL (2)08-23-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1983-06-25 LAND#3 3017
ACCTG 4 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3	
1983-06	380	240.8	86.2	15.2	0.36	240.8	86.2	
1983-07	629	429.3	112.9	16.4	0.26	670.1	199.1	
1983-08	608	363.3	157.5	14.3	0.43	1033.4	356.6	
1983-09	690	202.8	460.2	7.1	2.27	1236.2	816.8	
1983-10	732	178.5	693.5	5.9	3.89	1414.7	1510.3	
1983-11	528	214.8	195.6	9.8	0.91	1629.5	1705.9	
1983-12	744	206.3	587.2	6.7	2.85	1835.8	2293.1	
1984-01	336	77.8	338.8	5.6	4.35	1913.6	2631.9	
1984-02	696	322.3	383.5	11.1	1.19	2235.9	3015.4	
1984-03	432	216.3	191.1	12.0	0.88	2452.2	3206.5	
1984-04	720	159.0	363.8	5.3	2.29	2611.2	3570.3	
1984-05	740	123.0	336.7	4.0	2.74	2734.2	3907.0	
1984-06	713	144.5	523.4	4.9	3.62	2878.7	4430.4	
1984-07	730	207.7	488.1	6.8	2.35	3086.4	4918.5	
1984-08	768	122.2	507.2	3.8	4.15	3208.6	5425.7	
1984-09	716	35.0	201.5	1.2	5.76	3243.6	5627.2	
1984-10	745	112.7	244.7	3.6	2.17	3356.3	5871.9	
1984-11	716	56.3	209.3	1.9	3.72	3412.6	6081.2	
1984-12	744	125.8	215.7	4.1	1.71	3538.4	6296.9	
1985-01	740	84.3	275.6	2.7	3.27	3622.7	6572.5	
1985-02	672	86.3	182.6	3.1	2.12	3709.0	6755.1	
1985-03	740	108.1	178.3	3.5	1.65	3817.1	6933.4	
1985-04	719	46.0	137.0	1.5	2.98	3863.1	7070.4	5.24 Inj. Started
1985-05	740	32.5	109.6	1.1	3.37	3895.6	7180.0	
1985-06	720	19.1	171.9	0.6	9.00	3914.7	7351.9	
1985-07	728	64.4	199.8	2.1	3.10	3979.1	7551.7	
1985-08	744	45.7	548.2	1.5	12.00	4024.8	8099.9	
1985-09	713	51.8	603.4	1.7	11.65	4076.6	8703.3	
1985-10	744	67.0	566.4	2.2	8.45	4143.6	9269.7	
1985-11	720	124.6	380.4	4.2	3.05	4268.2	9650.1	
1985-12	737	26.6	588.6	0.9	22.13	4294.8	10238.7	WTR BREAKTHROUGH
1986-01	744	24.3	627.2	0.8	25.81	4319.1	10865.9	
1986-02	594	15.7	342.3	0.6	21.80	4334.8	11208.2	
1986-03	744	22.7	376.8	0.7	16.60	4357.5	11585.0	
1986-04	719	16.6	284.6	0.6	17.14	4374.1	11869.6	
1986-05	726	6.0	232.0	0.2	38.67	4380.1	12101.6	
1986-06	718	3.5	367.2	0.1	104.9	4383.6	12468.8	
1986-07	743	5.8	307.1	0.2	52.95	4389.4	12775.9	
1986-08	744	11.8	501.9	0.4	42.53	4401.2	13277.8	
1986-09	720	71.6	307.5	2.4	4.29	4472.8	13585.3	
1986-10	745	45.5	360.4	1.5	7.92	4518.3	13945.7	
1986-11	720	43.8	297.8	1.5	6.80	4562.1	14243.5	
1986-12	739	48.9	339.2	1.6	6.94	4611.0	14582.7	

*** STORE ***

ManPB

WASKADA1

90-12-07

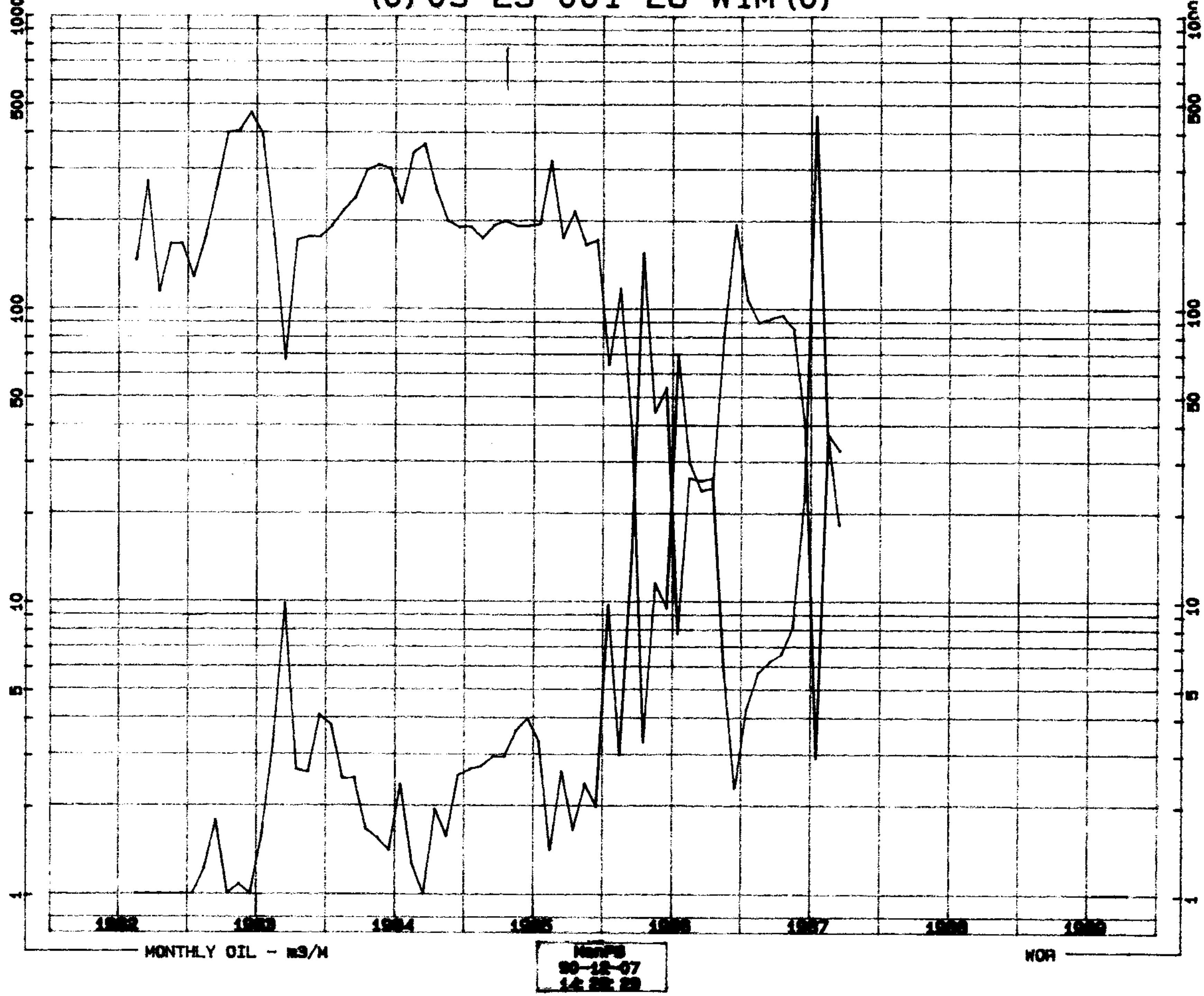
WELL (2)08-23-001-26 W1M(0)

14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1983-06-25 LAND#3 3017
ACCTG 4 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1987-01	724	75.6	265.6	2.5	3.51	4686.6	14848.3
1987-02	672	63.0	260.0	2.3	4.13	4749.6	15108.3
1987-03	736	54.2	239.9	1.8	4.43	4803.8	15348.2
1987-04	719	49.0	226.5	1.6	4.62	4852.8	15574.7
1987-05	744	99.3	151.7	3.2	1.53	4952.1	15726.4
1987-06	720	56.5	229.2	1.9	4.06	5008.6	15955.6
1987-07	744	38.9	264.3	1.3	6.79	5047.5	16219.9
1987-08	744	33.3	251.7	1.1	7.56	5080.8	16471.6
1987-09	720	30.1	246.9	1.0	8.20	5110.9	16718.5
1987-10	744	24.3	297.5	0.8	12.24	5135.2	17016.0
1987-11	720	18.7	247.7	0.6	13.25	5153.9	17263.7
1987-12	744	24.7	325.9	0.8	13.19	5178.6	17589.6
1988-01	744	29.7	297.9	1.0	10.03	5208.3	17887.5
1988-02	696	22.0	237.3	0.8	10.79	5230.3	18124.8
1988-03	744	15.6	216.6	0.5	13.88	5245.9	18341.4
1988-04	720	46.7	164.0	1.6	3.51	5292.6	18505.4
1988-05	744	61.4	160.1	2.0	2.61	5354.0	18665.5
1988-06	720	37.4	168.9	1.2	4.52	5391.4	18834.4
1988-07	744	12.7	144.8	0.4	11.40	5404.1	18979.2
1988-08	744	14.9	140.4	0.5	9.42	5419.0	19119.6
1988-09	528	10.7	98.7	0.5	9.22	5429.7	19218.3
1988-10	720	4.1	159.2	0.1	38.83	5433.8	19377.5
1988-11	696	16.9	181.6	0.6	10.75	5450.7	19559.1
1988-12	744	31.7	138.8	1.0	4.38	5482.4	19697.9
1989-01	744	35.7	116.9	1.2	3.27	5518.1	19814.8
1989-02	672	29.8	86.3	1.1	2.90	5547.9	19901.1
1989-03	744	35.7	75.0	1.2	2.10	5583.6	19976.1
1989-04	720	24.9	62.1	0.8	2.49	5608.5	20038.2
1989-05	744	19.5	84.2	0.6	4.32	5628.0	20122.4
1989-06	720	10.6	86.7	0.4	8.18	5638.6	20209.1
1989-07	744	14.3	84.4	0.5	5.90	5652.9	20293.5
1989-08	744	12.2	74.2	0.4	6.08	5665.1	20367.7
1989-09	720	8.1	64.5	0.3	7.96	5673.2	20432.2
1989-10	744	12.9	71.1	0.4	5.51	5686.1	20503.3
1989-11	432	6.4	47.1	0.4	7.36	5692.5	20550.4
1989-12	744	9.4	55.1	0.3	5.86	5701.9	20605.5
1990-01	744	9.2	60.0	0.3	6.52	5711.1	20665.5
1990-02	432	5.6	17.8	0.3	3.18	5716.7	20683.3
SHUT IN							
1990-06	384	28.7	2.0	1.8	0.07	5745.4	20685.3
1990-07	744	7.9	25.3	0.3	3.20	5753.3	20710.6
1990-08	744	0.7	10.6	0.0	15.14	5754.0	20721.2
1990-09	120	0.2	1.2	0.0	6.00	5754.2	20722.4

(0) 09-23-001-26 W1M (0)



PAL D. 1 *** S T O R E *** ManPB

WASKADA1 90-12-07

WELL (0)09-23-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2

POOL 29 WORKING INTEREST 0.00000% LAND#2 0

BLOCK 1 ON PRDN 1982-08-12 LAND#3 2792

ACCTG 1 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3	
1982-08	600	146.8	63.0	5.9	0.43	146.8	63.0	
1982-09	720	273.3	117.3	9.1	0.43	420.1	180.3	
1982-10	396	114.2	48.4	6.9	0.42	534.3	228.7	
1982-11	715	167.2	76.3	5.6	0.46	701.5	305.0	
1982-12	720	167.0	65.3	5.6	0.39	868.5	370.3	
1983-01	744	128.4	104.8	4.1	0.82	996.9	475.1	
1983-02	504	173.7	211.9	8.3	1.22	1170.6	687.0	
1983-03	632	258.1	460.1	9.8	1.78	1428.7	1147.1	
1983-04	720	401.3	350.1	13.4	0.87	1830.0	1497.2	
1983-05	744	407.6	439.9	13.1	1.08	2237.6	1937.1	
1983-06	720	469.9	275.5	15.7	0.59	2707.5	2212.6	
1983-07	772	395.3	629.5	12.3	1.59	3102.8	2842.1	
1983-08	659	179.9	602.9	6.6	3.35	3282.7	3445.0	
1983-09	615	66.9	660.0	2.6	9.87	3349.6	4105.0	
1983-10	738	172.3	458.5	5.6	2.66	3521.9	4563.5	
1983-11	720	177.2	461.7	5.9	2.61	3699.1	5025.2	
1983-12	744	176.6	723.8	5.7	4.10	3875.7	5749.0	
1984-01	744	193.1	728.2	6.2	3.77	4068.8	6477.2	
1984-02	696	218.0	539.4	7.5	2.47	4286.8	7016.6	
1984-03	744	240.5	600.8	7.8	2.50	4527.3	7617.4	
1984-04	720	297.7	494.8	9.9	1.66	4825.0	8112.2	
1984-05	740	311.7	483.6	10.1	1.55	5136.7	8595.8	
1984-06	713	302.8	425.8	10.2	1.41	5439.5	9021.6	
1984-07	738	229.4	543.7	7.5	2.37	5668.9	9565.3	
1984-08	768	342.1	432.6	10.7	1.26	6011.0	9997.9	
1984-09	716	368.0	216.2	12.3	0.59	6379.0	10214.1	
1984-10	745	256.1	498.8	8.3	1.95	6635.1	10712.9	
1984-11	716	200.1	314.0	6.7	1.57	6835.2	11026.9	
1984-12	744	190.1	483.9	6.1	2.55	7025.3	11510.8	
1985-01	740	191.9	513.4	6.2	2.68	7217.2	12024.2	
1985-02	672	174.0	475.9	6.2	2.74	7391.2	12500.1	
1985-03	704	193.3	571.6	6.6	2.96	7584.5	13071.7	
1985-04	719	200.8	591.6	6.7	2.95	7785.3	13663.3	— WTR INJ @ 5-24
1985-05	737	192.1	692.8	6.3	3.61	7977.4	14356.1	
1985-06	720	192.4	770.1	6.4	4.00	8169.8	15126.2	
1985-07	663	196.4	651.3	7.1	3.32	8366.2	15777.5	
1985-08	744	321.9	453.2	10.4	1.41	8688.1	16230.7	
1985-09	668	174.7	460.3	6.3	2.63	8862.8	16691.0	
1985-10	744	216.4	358.2	7.0	1.66	9079.2	17049.2	
1985-11	720	165.7	395.3	5.5	2.39	9244.9	17444.5	
1985-12	737	172.7	343.4	5.6	1.99	9417.6	17787.9	
1986-01	744	64.5	632.4	2.1	9.80	9482.1	18420.3	— WTR BREAKTHROUGH
1986-02	672	117.8	351.0	4.2	2.98	9599.9	18771.3	

WASKADA1 90-12-07

WELL (0)09-23-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2

POOL 29 WORKING INTEREST 0.00000% LAND#2 0

BLOCK 1 ON PRDN 1982-08-12 LAND#3 2792

ACCTG 1 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1986-03	744	38.3	534.0	1.2	13.94	9638.2	19305.3
1986-04	719	3.3	516.8	0.1	156.6	9641.5	19822.1
1986-05	726	11.6	512.8	0.4	44.21	9653.1	20334.9
1986-06	718	9.5	514.3	0.3	54.14	9662.6	20849.2
1986-07	743	70.2	542.9	2.3	7.73	9732.8	21392.1
1986-08	744	29.7	789.8	1.0	26.59	9762.5	22181.9
1986-09	720	23.9	617.7	0.8	25.85	9786.4	22799.6
1986-10	745	24.5	649.0	0.8	26.49	9810.9	23448.6
1986-11	720	82.4	497.4	2.7	6.04	9893.3	23946.0
1986-12	742	195.4	447.9	6.3	2.29	10088.7	24393.9
1987-01	724	107.7	463.7	3.6	4.31	10196.4	24857.6
1987-02	672	89.8	513.1	3.2	5.71	10286.2	25370.7
1987-03	740	92.9	580.7	3.0	6.25	10379.1	25951.4
1987-04	719	95.6	634.5	3.2	6.64	10474.7	26585.9
1987-05	735	85.4	701.0	2.8	8.21	10560.1	27286.9
1987-06	672	39.8	913.4	1.4	22.95	10599.9	28200.3
1987-07	688	2.9	1341.0	0.1	462.4	10602.8	29541.3
1987-08	744	37.4	1402.4	1.2	37.50	10640.2	30943.7
1987-09	624	32.9	602.4	1.3	18.31	10673.1	31546.1
SHUT IN							
1989-07	288	0.0	245.4	0.0	99.99	10673.1	31791.5
1989-08	744	0.0	373.9	0.0	99.99	10673.1	32165.4
1989-09	720	0.0	259.7	0.0	99.99	10673.1	32425.1
1989-10	336	0.0	122.8	0.0	99.99	10673.1	32547.9

$Q_{86\text{-}01} = 6647$

$q_i = 58\ m^3/mo$

$q_t =$ [illegible]

$t = 1.25$ yrs

$D = 1.41$

$Q_p = 6647 + 409 = 7055\ m^3$

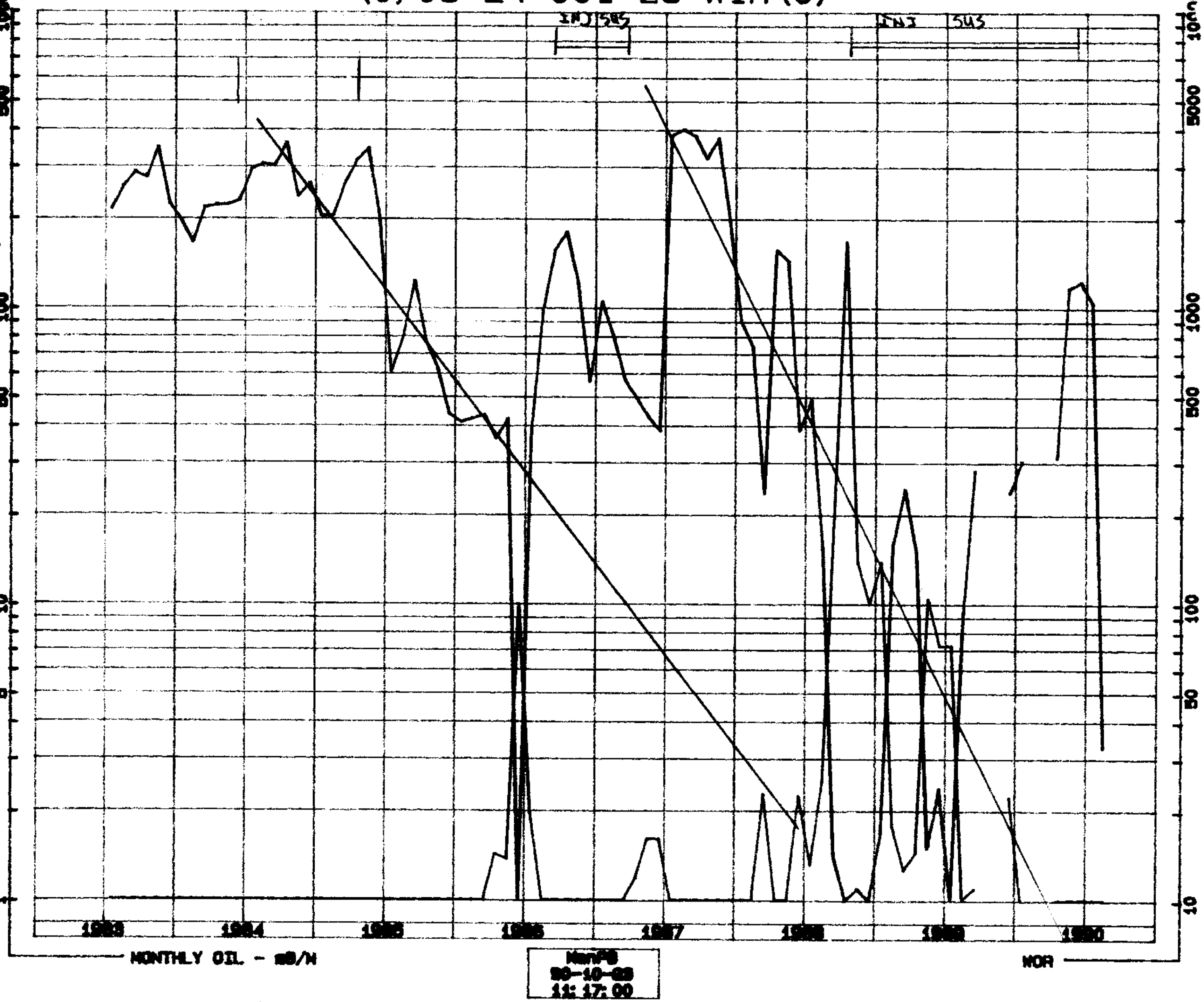
OOIP = 62216

$Rf_p = 11.3$

$Q_{ult} = 10975$

$RF_{WF} = 17.6$

(0) 03-24-001-26 W1M (0)



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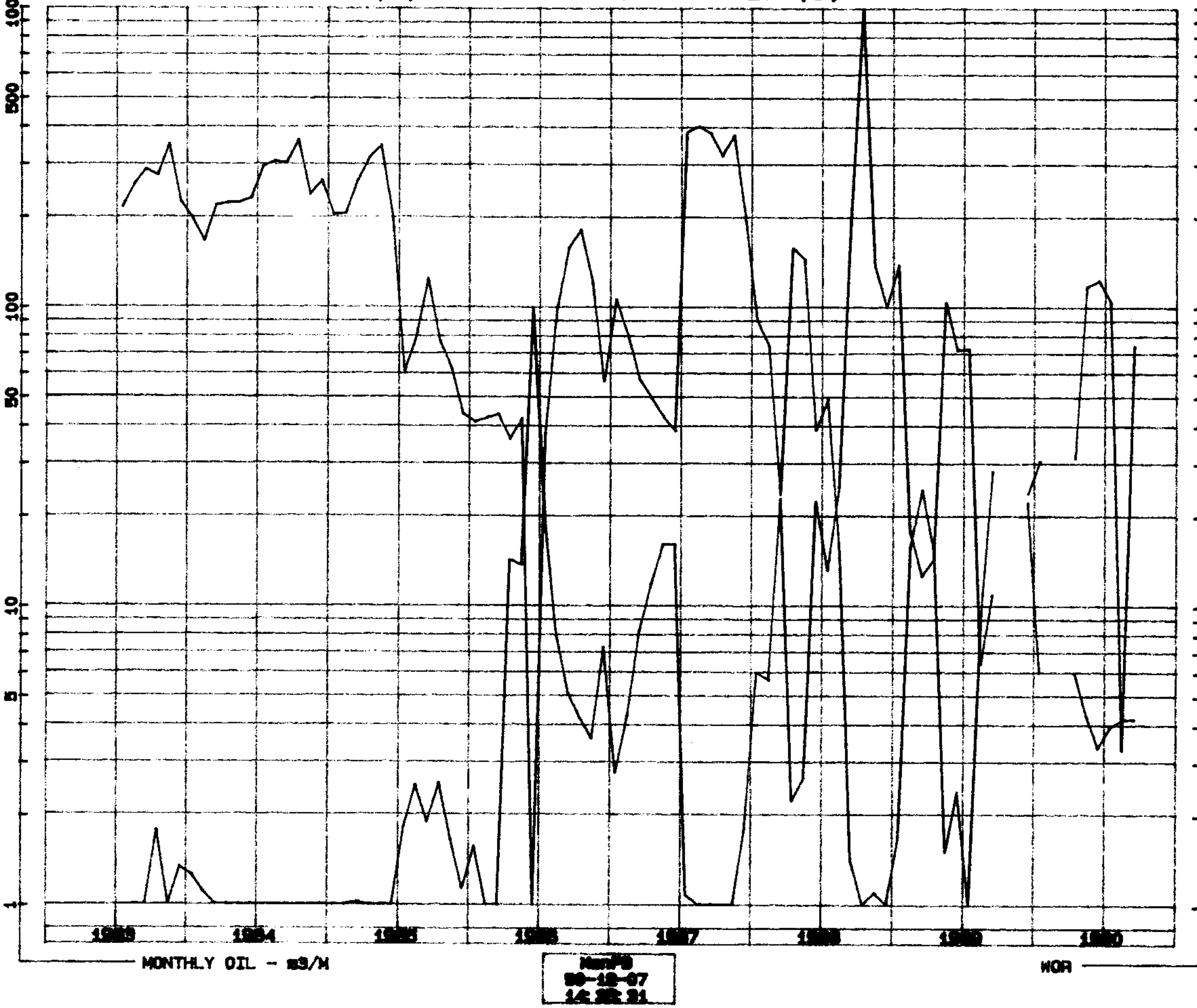


PAGE . 1 *** S T O R E *** ManPB

WASKADA1 90-12-07

WELL (0)03-24-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2

POOL 29 WORKING INTEREST 0.00000% LAND#2 0

BLOCK 1 ON PRDN 1983-07-15 LAND#3 3028

ACCTG 4 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3	
1983-07	408	216.2	54.8	12.7	0.25	216.2	54.8	
1983-08	743	258.0	181.9	8.3	0.71	474.2	236.7	
1983-09	718	289.5	219.1	9.7	0.76	763.7	455.8	
1983-10	742	275.8	487.1	8.9	1.77	1039.5	942.9	
1983-11	712	351.4	257.6	11.8	0.73	1390.9	1200.5	
1983-12	458	225.6	300.8	11.8	1.33	1616.5	1501.3	
1984-01	379	197.0	246.7	12.5	1.25	1813.5	1748.0	
1984-02	336	166.4	182.7	11.9	1.10	1979.9	1930.7	
1984-03	336	219.5	84.1	15.7	0.38	2199.4	2014.8	
1984-04	384	223.9	30.9	14.0	0.14	2423.3	2045.7	
1984-05	444	224.6	31.5	12.1	0.14	2647.9	2077.2	
1984-06	470	232.4	21.1	11.9	0.09	2880.3	2098.3	
1984-07	641	295.5	26.7	11.1	0.09	3175.8	2125.0	
1984-08	768	309.0	76.5	9.7	0.25	3484.8	2201.5	
1984-09	714	302.9	72.7	10.2	0.24	3787.7	2274.2	
1984-10	745	363.3	30.7	11.7	0.08	4151.0	2304.9	
1984-11	696	238.6	90.7	8.2	0.38	4389.6	2395.6	
1984-12	744	266.2	146.6	8.6	0.55	4655.8	2542.2	
1985-01	654	204.2	200.1	7.5	0.98	4860.0	2742.3	
1985-02	672	206.3	204.1	7.4	0.99	5066.3	2946.4	
1985-03	740	265.6	271.6	8.6	1.02	5331.9	3218.0	
1985-04	719	317.5	211.5	10.6	0.67	5649.4	3429.5	- WTR INJ @ 5-24
1985-05	740	348.8	168.7	11.3	0.48	5998.2	3598.2	
1985-06	720	199.9	184.8	6.7	0.92	6198.1	3783.0	
1985-07	606	61.0	110.9	2.4	1.82	6259.1	3893.9	
1985-08	718	79.9	200.7	2.7	2.51	6339.0	4094.6	
1985-09	712	124.9	235.4	4.2	1.88	6463.9	4330.0	
1985-10	744	77.1	196.7	2.5	2.55	6541.0	4526.7	
1985-11	720	62.5	103.0	2.1	1.65	6603.5	4629.7	
1985-12	667	43.9	49.6	1.6	1.13	6647.4	4679.3	
1986-01	744	41.3	64.8	1.3	1.57	6688.7	4744.1	
1986-02	672	42.7	22.7	1.5	0.53	6731.4	4766.8	
1986-03	709	43.9	21.5	1.5	0.49	6775.3	4788.3	
1986-04	719	36.3	520.0	1.2	14.33	6811.6	5308.3	— WTR. BREAKTHROUGH
1986-05	728	42.4	581.7	1.4	13.72	6854.0	5890.0	
1986-06	718	0.0	839.9	0.0	99.99	6854.0	6729.9	
1986-07	600	37.5	732.4	1.5	19.53	6891.5	7462.3	
1986-08	551	99.5	786.6	4.3	7.91	6991.0	8248.9	
1986-09	720	158.4	807.8	5.3	5.10	7149.4	9056.7	
1986-10	718	182.3	765.0	6.1	4.20	7331.7	9821.7	
1986-11	720	121.2	435.2	4.0	3.59	7452.9	10256.9	
1986-12	736	56.6	412.5	1.8	7.29	7509.5	10669.4	
1987-01	744	106.4	292.6	3.4	2.75	7615.9	10962.0	

WASKADA1 90-12-07
WELL (0)03-24-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1983-07-15 LAND#3 3028
ACCTG 4 ON INJN NOT ON YET

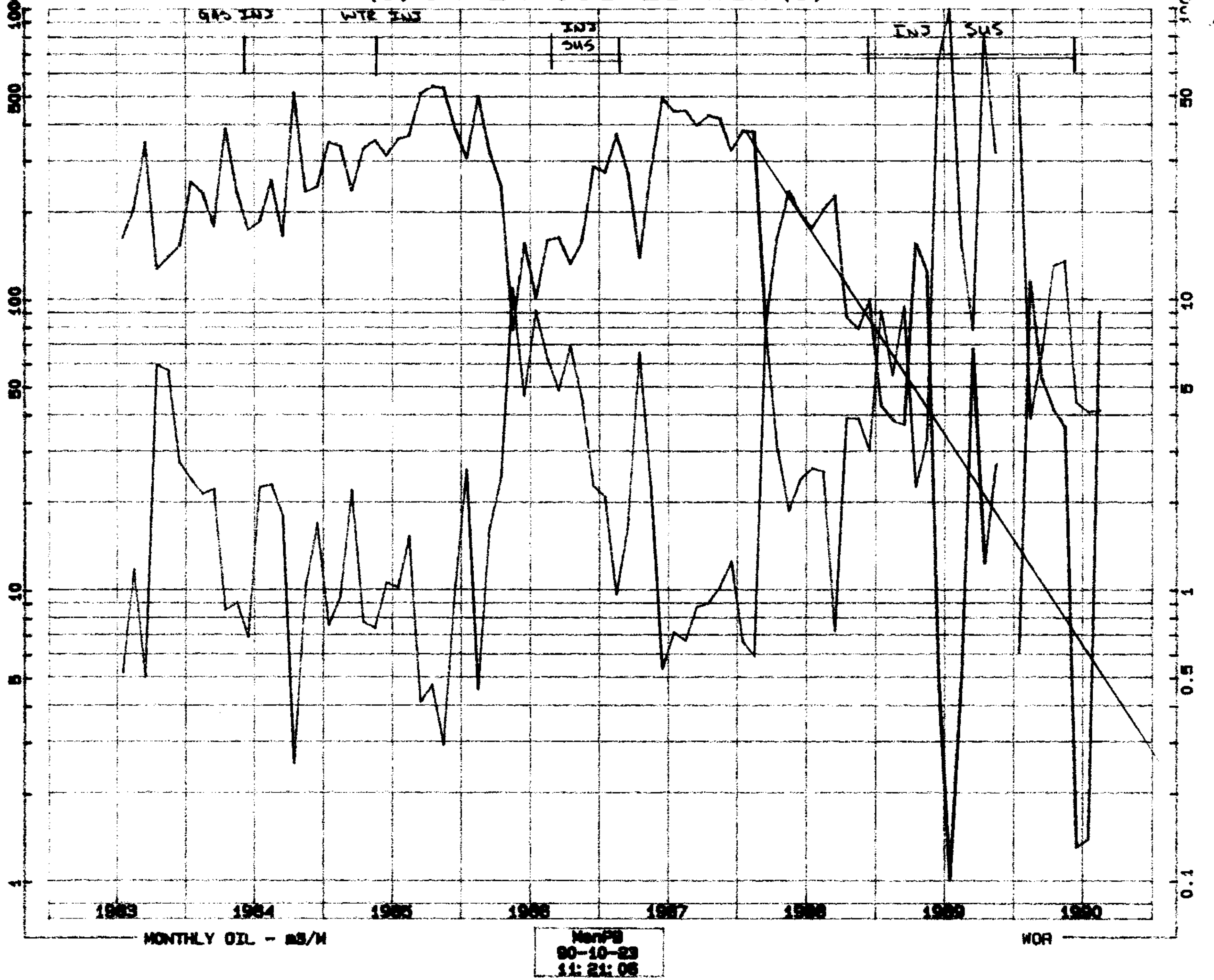
MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1987-02	672	80.8	346.9	2.9	4.29	7696.7	11308.9
1987-03	736	57.3	472.0	1.9	8.24	7754.0	11780.9
1987-04	719	49.8	590.2	1.7	11.85	7803.8	12371.1
1987-05	696	43.0	692.2	1.5	16.10	7846.8	13063.3
1987-06	624	38.6	621.5	1.5	16.10	7885.4	13684.8
1987-07	744	387.7	417.1	12.5	1.08	8273.1	14101.9
1987-08	744	405.2	281.7	13.1	0.70	8678.3	14383.6
1987-09	720	382.9	178.1	12.8	0.47	9061.2	14561.7
1987-10	744	321.7	236.1	10.4	0.73	9382.9	14797.8
1987-11	720	377.9	365.3	12.6	0.97	9760.8	15163.1
1987-12	744	199.6	361.4	6.4	1.81	9960.4	15524.5
1988-01	744	90.1	541.9	2.9	6.01	10050.5	16066.4
1988-02	696	74.2	419.8	2.6	5.66	10124.7	16486.2
1988-03	744	23.7	544.4	0.8	22.97	10148.4	17030.6
1988-04	720	158.9	352.2	5.3	2.22	10307.3	17382.8
1988-05	648	144.6	385.2	5.4	2.66	10451.9	17768.0
1988-06	576	38.7	872.7	1.6	22.55	10490.6	18640.7
1988-07	624	49.4	649.8	1.9	13.15	10540.0	19290.5
1988-08	624	15.5	390.2	0.6	25.17	10555.5	19680.7
1988-09	696	1.4	284.4	0.0	203.1	10556.9	19965.1
1988-10	480	0.2	336.5	0.0	1683	10557.1	20301.6
1988-11	504	1.1	150.8	0.1	137.1	10558.2	20452.4
1988-12	168	0.0	16.1	0.0	99.99	10558.2	20468.5
1989-01	744	1.7	236.0	0.1	138.8	10559.9	20704.5
1989-02	576	16.1	284.5	0.7	17.67	10576.0	20989.0
1989-03	744	24.6	309.1	0.8	12.57	10600.6	21298.1
1989-04	672	14.9	215.5	0.5	14.46	10615.5	21513.6
1989-05	744	1.5	156.9	0.0	104.6	10617.0	21670.5
1989-06	696	2.4	172.8	0.1	72.00	10619.4	21843.3
1989-07	480	0.2	14.5	0.0	72.50	10619.6	21857.8
1989-08	240	9.1	58.1	0.9	6.38	10628.7	21915.9
1989-09	720	28.4	310.2	0.9	10.92	10657.1	22226.1
SHUT IN							
1989-12	624	23.9	534.2	0.9	22.35	10681.0	22760.3
1990-01	240	30.7	184.6	3.1	6.01	10711.7	22944.9
SHUT IN							
1990-04	264	31.5	187.2	2.9	5.94	10743.2	23132.1
1990-05	696	117.9	507.9	4.1	4.31	10861.1	23640.0
1990-06	720	124.0	416.2	4.1	3.36	10985.1	24056.2
1990-07	744	104.5	412.4	3.4	3.95	11089.6	24468.6
1990-08	24	3.3	13.8	3.3	4.18	11092.9	24482.4
1990-09	480	74.6	314.0	3.7	4.21	11167.5	24796.4

NO ESTIM... OF PRIMARY RECOVERY

ULTIMATE RECOVERY (EST) = 19920 m^3

R_{WF} : 32.3 %

(0) 04-24-001-26 W1M (0)



PAGE . 1 *** S T O R E *** ManPB
WASKADA1 90-12-07
WELL (0)04-24-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1983-07-15 LAND#3 3029
ACCTG 4 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3	
1983-07	396	163.8	84.3	9.9	0.51	163.8	84.3	
1983-08	721	207.5	242.9	6.9	1.17	371.3	327.2	
1983-09	718	349.5	174.0	11.7	0.50	720.8	501.2	
1983-10	742	127.3	759.4	4.1	5.97	848.1	1260.6	
1983-11	712	140.8	796.8	4.7	5.66	988.9	2057.4	
1983-12	514	153.8	418.7	7.2	2.72	1142.7	2476.1	
1984-01	744	256.2	610.4	8.3	2.38	1398.9	3086.5	
1984-02	643	232.8	495.0	8.7	2.13	1631.7	3581.5	
1984-03	528	178.6	395.1	8.1	2.21	1810.3	3976.6	
1984-04	720	391.1	331.1	13.0	0.85	2201.4	4307.7	
1984-05	476	234.3	210.8	11.8	0.90	2435.7	4518.5	
1984-06	328	174.0	119.0	12.7	0.68	2609.7	4637.5	
1984-07	569	187.3	421.7	7.9	2.25	2797.0	5059.2	
1984-08	743	258.8	594.5	8.4	2.30	3055.8	5653.7	
1984-09	445	165.2	295.2	8.9	1.79	3221.0	5948.9	
1984-10	745	520.1	129.8	16.8	0.25	3741.1	6078.7	
1984-11	668	235.7	242.3	8.5	1.03	3976.8	6321.0	
1984-12	712	246.5	416.0	8.3	1.69	4223.3	6737.0	
1985-01	635	351.9	264.2	13.3	0.75	4575.2	7001.2	
1985-02	672	338.8	320.3	12.1	0.95	4914.0	7321.5	
1985-03	740	237.5	521.2	7.7	2.19	5151.5	7842.7	
1985-04	624	332.6	255.6	12.8	0.77	5484.1	8098.3	- WTR INJ STARTS @ 5-24
1985-05	661	356.0	260.5	12.9	0.73	5840.1	8358.8	
1985-06	668	313.6	331.0	11.3	1.06	6153.7	8689.8	
1985-07	696	359.1	363.9	12.4	1.01	6512.8	9053.7	
1985-08	744	369.9	563.3	11.9	1.52	6882.7	9617.0	
1985-09	713	515.2	209.4	17.3	0.41	7397.9	9826.4	
1985-10	744	546.8	256.4	17.6	0.47	7944.7	10082.8	
1985-11	720	538.0	156.5	17.9	0.29	8482.7	10239.3	
1985-12	737	388.7	387.9	12.7	1.00	8871.4	10627.2	
1986-01	744	307.1	796.3	9.9	2.59	9178.5	11423.5	
1986-02	672	506.8	228.1	18.1	0.45	9685.3	11651.6	
1986-03	744	321.8	522.9	10.4	1.62	10007.1	12174.5	
1986-04	719	245.6	603.4	8.2	2.46	10252.7	12777.9	
1986-05	728	78.6	859.4	2.6	10.93	10331.3	13637.3	- WATER BREAKTHROUGH
1986-06	718	157.9	731.2	5.3	4.63	10489.2	14368.5	
1986-07	732	100.9	922.9	3.3	9.15	10590.1	15291.4	
1986-08	744	161.0	1006.2	5.2	6.25	10751.1	16297.6	
1986-09	720	164.6	795.2	5.5	4.83	10915.7	17092.8	
1986-10	742	132.7	916.1	4.3	6.90	11048.4	18008.9	
1986-11	720	159.6	722.8	5.3	4.53	11208.0	18731.7	
1986-12	743	290.4	658.2	9.4	2.27	11498.4	19389.9	
1987-01	724	274.6	570.5	9.1	2.08	11773.0	19960.4	

WASKADA1 90-12-07

WELL (0)04-24-001-26 W1M(0) 14:11:00

FIELD 3	PROVINCE MAN.	LAND#1 2
POOL 29	WORKING INTEREST 0.00000%	LAND#2 0
BLOCK 1	ON PRDN 1983-07-15	LAND#3 3029
ACCTG 4	ON INJN NOT ON YET	

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1987-02	672	373.4	358.1	13.3	0.96	12146.4	20318.5
1987-03	682	272.5	453.8	9.6	1.67	12418.9	20772.3
1987-04	719	139.6	918.3	4.7	6.58	12558.5	21690.6
1987-05	744	282.6	635.6	9.1	2.25	12841.1	22326.2
1987-06	720	495.7	263.0	16.5	0.53	13336.8	22589.2
1987-07	744	445.8	317.5	14.4	0.71	13782.6	22906.7
1987-08	744	452.1	300.4	14.6	0.66	14234.7	23207.1
1987-09	720	400.0	348.0	13.3	0.87	14634.7	23555.1
1987-10	744	433.9	389.1	14.0	0.90	15068.6	23944.2
1987-11	720	421.7	430.3	14.1	1.02	15490.3	24374.5
1987-12	744	327.5	409.3	10.6	1.25	15817.8	24783.8
1988-01	744	383.3	252.4	12.4	0.66	16201.1	25036.2
1988-02	696	381.2	224.4	13.1	0.59	16582.3	25260.6
1988-03	744	81.7	666.8	2.6	8.16	16664.0	25927.4
1988-04	720	166.5	507.6	5.6	3.05	16830.5	26435.0
1988-05	744	238.2	442.6	7.7	1.86	17068.7	26877.6
1988-06	720	198.5	474.5	6.6	2.39	17267.2	27352.1
1988-07	744	176.7	462.3	5.7	2.62	17443.9	27814.4
1988-08	744	205.0	520.9	6.6	2.54	17648.9	28335.3
1988-09	720	230.1	164.4	7.7	0.71	17879.0	28499.7
1988-10	744	87.2	340.5	2.8	3.90	17966.2	28840.2
1988-11	672	79.4	308.4	2.8	3.88	18045.6	29148.6
1988-12	720	100.5	300.3	3.4	2.99	18146.1	29448.9
1989-01	744	43.2	395.8	1.4	9.16	18189.3	29844.7
1989-02	480	38.4	209.7	1.9	5.46	18227.7	30054.4
1989-03	624	37.2	353.2	1.4	9.49	18264.9	30407.6
1989-04	504	157.9	355.1	7.5	2.25	18422.8	30762.7
1989-05	744	124.3	410.2	4.0	3.30	18547.1	31172.9
1989-06	312	5.0	333.3	0.4	66.66	18552.1	31506.2
1989-07	480	0.0	402.1	0.0	99.99	18552.1	31908.3
1989-08	264	5.1	76.9	0.5	15.08	18557.2	31985.2
1989-09	480	68.5	534.9	3.4	7.81	18625.7	32520.1
1989-10	672	12.3	1004.5	0.4	81.67	18638.0	33524.6
1989-11	624	27.2	867.7	1.0	31.90	18665.2	34392.3
SHUT IN							
1990-01	312	6.1	358.9	0.5	58.84	18671.3	34751.2
1990-02	624	116.5	449.4	4.5	3.86	18787.8	35200.6
1990-03	456	53.4	350.5	2.8	6.56	18841.2	35551.1
1990-04	720	41.8	544.5	1.4	13.03	18883.0	36095.6
1990-05	672	36.1	489.1	1.3	13.55	18919.1	36584.7
1990-06	24	1.3	5.7	1.3	4.38	18920.4	36590.4
1990-07	24	1.4	5.7	1.4	4.07	18921.8	36596.1
1990-08	744	91.2	377.1	2.9	4.13	19013.0	36973.2

WASKADA1 90-12-07
WELL (0)04-24-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1983-07-15 LAND#3 3029
ACCTG 4 ON INJN NOT ON YET

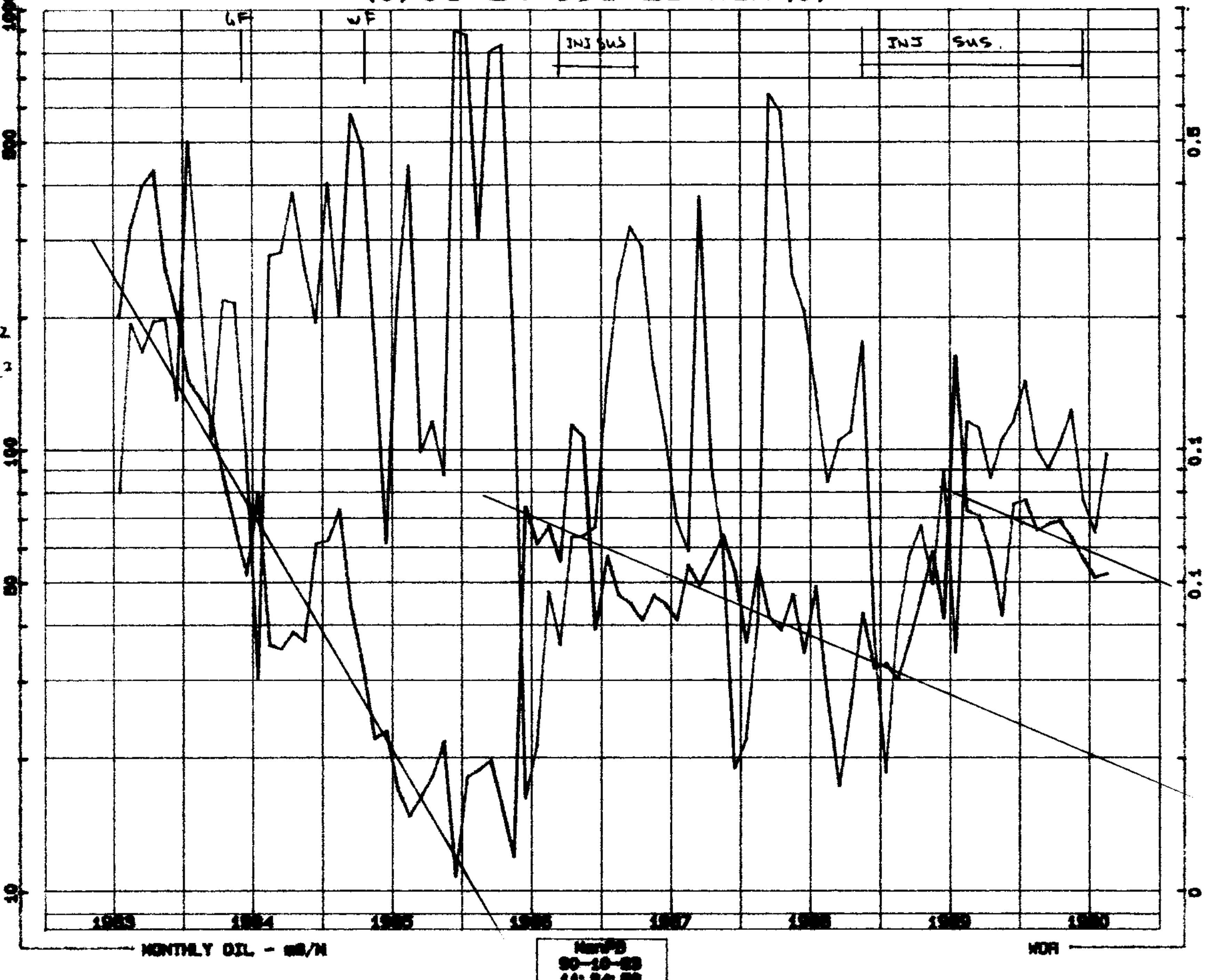
MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1990-09	720	135.8	399.8	4.5	2.94	19148.8	37373.0

OOIP = 51396

Q_p = 3054

RF_p = 5.9%

(0) 06-24-001-26 W1M (0)



q_1 = 700 m³/...

q_2 = 200 m³/...

t = 4 yrs

D = 0.31

Q_{abn} = 5430

Q_{ult} = Q_p + 2322

= 5752 m³

RF_{ult} = 11.2%

PAGE . 1 *** S T O R E *** ManPB
WASKADA1 90-12-07
WELL (0)06-24-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1983-07-14 LAND#3 3031
ACCTG 4 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3	
1983-07	414	199.9	16.0	11.6	0.08	199.9	16.0	
1983-08	727	319.4	61.9	10.5	0.19	519.3	77.9	
1983-09	718	398.1	66.2	13.3	0.17	917.4	144.1	
1983-10	742	431.9	84.3	14.0	0.20	1349.3	228.4	
1983-11	712	259.9	51.2	8.8	0.20	1609.2	279.6	
1983-12	744	203.5	26.3	6.6	0.13	1812.7	305.9	
1984-01	680	143.4	72.0	5.1	0.50	1956.1	377.9	
1984-02	691	131.0	30.2	4.5	0.23	2087.1	408.1	
1984-03	744	117.7	12.4	3.8	0.11	2204.8	420.5	
1984-04	720	86.7	19.0	2.9	0.22	2291.5	439.5	
1984-05	740	67.1	14.4	2.2	0.21	2358.6	453.9	
1984-06	710	52.0	5.0	1.8	0.10	2410.6	458.9	
1984-07	737	80.2	2.4	2.6	0.03	2490.8	461.3	
1984-08	744	35.9	9.9	1.2	0.28	2526.7	471.2	
1984-09	716	35.3	9.9	1.2	0.28	2562.0	481.1	
1984-10	745	38.6	14.8	1.2	0.38	2600.6	495.9	
1984-11	717	36.7	9.6	1.2	0.26	2637.3	505.5	
1984-12	744	61.5	11.9	2.0	0.19	2698.8	517.4	
1985-01	740	62.5	25.2	2.0	0.40	2761.3	542.6	
1985-02	672	73.3	14.7	2.6	0.20	2834.6	557.3	
1985-03	744	43.5	25.2	1.4	0.58	2878.1	582.5	
1985-04	719	32.2	15.4	1.1	0.48	2910.3	597.9	- WTR. INJECTION STARTS
1985-05	740	22.0	3.9	0.7	0.18	2932.3	601.8	
1985-06	720	23.0	1.4	0.8	0.06	2955.3	603.2	
1985-07	667	16.9	3.7	0.6	0.22	2972.2	606.9	
1985-08	744	14.7	6.5	0.5	0.44	2986.9	613.4	
1985-09	713	16.3	1.6	0.5	0.10	3003.2	615.0	
1985-10	744	18.2	2.1	0.6	0.12	3021.4	617.1	
1985-11	720	21.8	1.9	0.7	0.09	3043.2	619.0	
1985-12	737	10.7	9.6	0.3	0.90	3053.9	628.6	
1986-01	744	18.1	15.8	0.6	0.87	3072.0	644.4	
1986-02	672	18.8	5.6	0.7	0.30	3090.8	650.0	
1986-03	744	19.8	15.9	0.6	0.80	3110.6	665.9	
1986-04	719	15.4	12.8	0.5	0.83	3126.0	678.7	
1986-05	728	11.9	2.1	0.4	0.18	3137.9	680.8	
1986-06	718	74.6	1.2	2.5	0.02	3212.5	682.0	
1986-07	743	61.0	1.3	2.0	0.02	3273.5	683.3	
1986-08	744	67.2	3.2	2.2	0.05	3340.7	686.5	
1986-09	720	55.7	2.0	1.9	0.04	3396.4	688.5	
1986-10	719	114.1	7.2	3.8	0.06	3510.5	695.7	
1986-11	720	106.9	6.8	3.6	0.06	3617.4	702.5	
1986-12	744	39.0	2.6	1.3	0.07	3656.4	705.1	
1987-01	724	57.5	8.0	1.9	0.14	3713.9	713.1	- WATER BREAKTHROUGH (2)

WASKADA1 90-12-07

WELL (0)06-24-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2

POOL 29 WORKING INTEREST 0.00000% LAND#2 0

BLOCK 1 ON PRDN 1983-07-14 LAND#3 3031

ACCTG 4 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1987-02	672	46.8	11.4	1.7	0.24	3760.7	724.5
1987-03	744	44.7	14.3	1.4	0.32	3805.4	738.8
1987-04	719	40.9	11.8	1.4	0.29	3846.3	750.6
1987-05	744	46.8	7.2	1.5	0.15	3893.1	757.8
1987-06	720	44.6	4.8	1.5	0.11	3937.7	762.6
1987-07	744	41.0	2.8	1.3	0.07	3978.7	765.4
1987-08	744	54.7	3.2	1.8	0.06	4033.4	768.6
1987-09	720	49.2	18.5	1.6	0.38	4082.6	787.1
1987-10	744	56.3	5.1	1.8	0.09	4138.9	792.2
1987-11	720	64.0	3.8	2.1	0.06	4202.9	796.0
1987-12	744	53.2	1.0	1.7	0.02	4256.1	797.0
1988-01	576	36.5	0.8	1.5	0.02	4292.6	797.8
1988-02	672	54.4	2.2	1.9	0.04	4347.0	800.0
1988-03	744	41.6	26.7	1.3	0.64	4388.6	826.7
1988-04	720	38.8	22.6	1.3	0.58	4427.4	849.3
1988-05	744	47.0	11.6	1.5	0.25	4474.4	860.9
1988-06	720	34.5	7.1	1.2	0.21	4508.9	868.0
1988-07	744	49.0	6.6	1.6	0.13	4557.9	874.6
1988-08	744	27.4	2.3	0.9	0.08	4585.3	876.9
1988-09	528	17.2	1.8	0.8	0.10	4602.5	878.7
1988-10	720	26.4	2.9	0.9	0.11	4628.9	881.6
1988-11	696	42.6	7.5	1.5	0.18	4671.5	889.1
1988-12	744	31.8	1.2	1.0	0.04	4703.3	890.3
1989-01	744	32.7	0.6	1.1	0.02	4736.0	890.9
1989-02	672	30.0	1.2	1.1	0.04	4766.0	892.1
1989-03	744	36.7	2.1	1.2	0.06	4802.7	894.2
1989-04	720	46.3	3.1	1.5	0.07	4849.0	897.3
1989-05	744	58.9	2.9	1.9	0.05	4907.9	900.2
1989-06	528	41.3	3.7	1.9	0.09	4949.2	903.9
1989-07	744	163.2	5.6	5.3	0.03	5112.4	909.5
1989-08	744	72.5	8.4	2.3	0.12	5184.9	917.9
1989-09	720	70.8	7.9	2.4	0.11	5255.7	925.8
1989-10	600	57.2	4.9	2.3	0.09	5312.9	930.7
1989-11	480	41.9	4.4	2.1	0.11	5354.8	935.1
1989-12	744	75.2	8.7	2.4	0.12	5430.0	943.8
1990-01	744	77.2	11.0	2.5	0.14	5507.2	954.8
1990-02	672	65.4	6.5	2.3	0.10	5572.6	961.3
1990-03	744	67.7	6.1	2.2	0.09	5640.3	967.4
1990-04	696	69.0	7.1	2.4	0.10	5709.3	974.5
1990-05	576	62.9	7.7	2.6	0.12	5772.2	982.2
1990-06	720	56.3	4.3	1.9	0.08	5828.5	986.5
1990-07	744	51.2	3.3	1.7	0.06	5879.7	989.8
1990-08	744	52.4	5.1	1.7	0.10	5932.1	994.9

*** STORE ***

WASKADA1

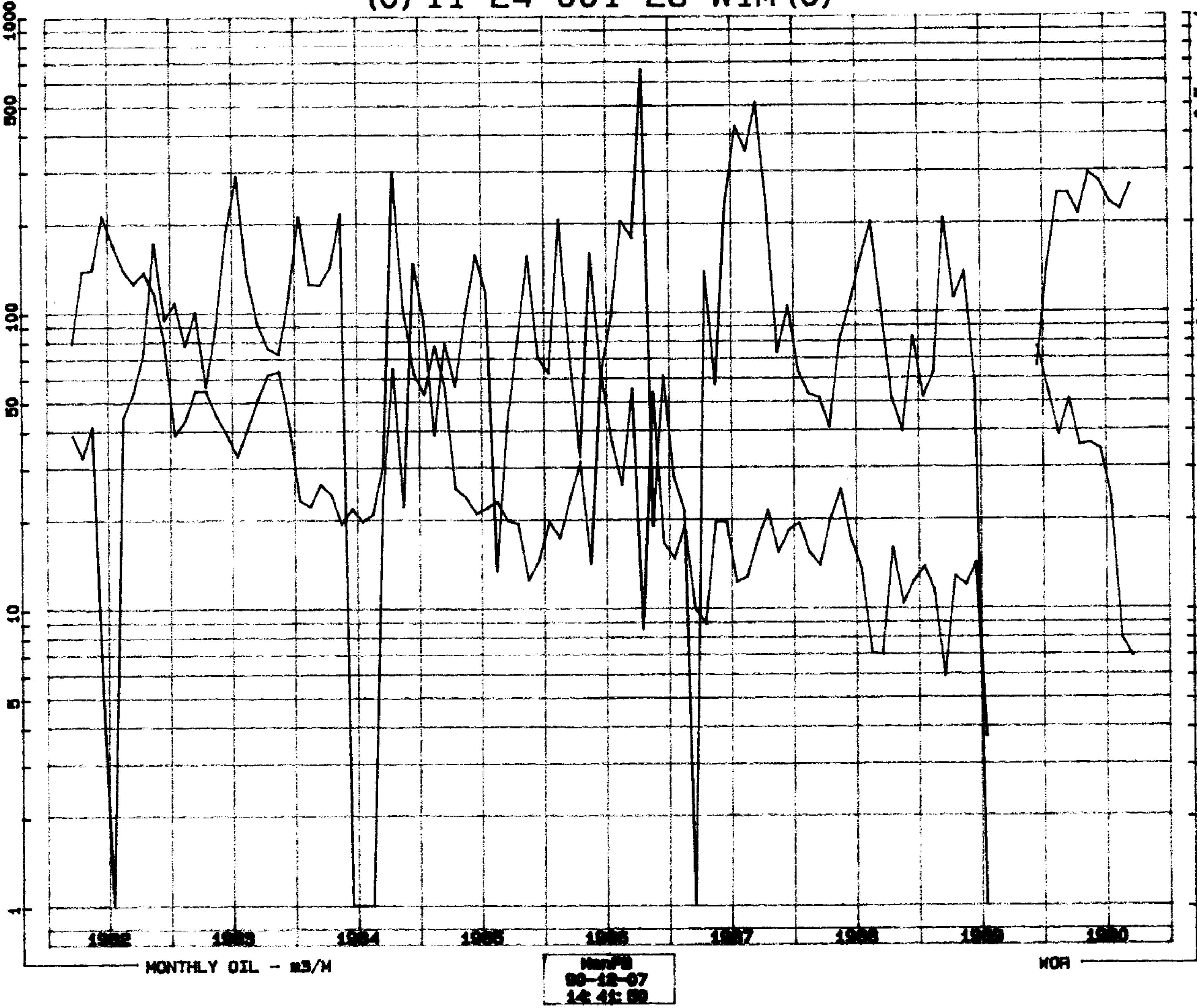
WELL (0)06-24-001-26 W1M(0)

ManPB
90-12-07
14:11:00

FIELD 3	PROVINCE MAN.	LAND#1	2
POOL 29	WORKING INTEREST 0.00000%	LAND#2	0
BLOCK 1	ON PRDN 1983-07-14	LAND#3	3031
ACCTG 4	ON INJN NOT ON YET		

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1990-09	720	40.6	5.8	1.4	0.14	5972.7	1000.7

(0) 11-24-001-26 W1M (0)



PAGE 1 *** S T O R E *** ManPB

WASKADA1 90-12-07

WELL (0)11-24-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2

POOL 29 WORKING INTEREST 0.00000% LAND#2 0

BLOCK 1 ON PRDN 1982-03-12 LAND#3 2745

ACCTG 1 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3	
1982-03	408	79.6	3.0	4.7	0.04	79.6	3.0	
1982-04	648	139.0	4.4	5.1	0.03	218.6	7.4	
1982-05	360	141.2	5.7	9.4	0.04	359.8	13.1	
1982-06	720	215.0	1.1	7.2	0.01	574.8	14.2	
1982-07	744	171.8	0.0	5.5	0.00	746.6	14.2	
1982-08	744	140.3	6.1	4.5	0.04	886.9	20.3	
1982-09	696	125.9	6.6	4.3	0.05	1012.8	26.9	
1982-10	739	138.1	9.9	4.5	0.07	1150.9	36.8	
1982-11	715	116.5	19.6	3.9	0.17	1267.4	56.4	
1982-12	734	79.1	7.3	2.6	0.09	1346.5	63.7	
1983-01	744	38.9	4.1	1.3	0.11	1385.4	67.8	
1983-02	648	43.8	3.3	1.6	0.08	1429.2	71.1	
1983-03	632	55.0	5.4	2.1	0.10	1484.2	76.5	
1983-04	712	54.8	3.0	1.8	0.05	1539.0	79.5	
1983-05	744	45.1	4.0	1.5	0.09	1584.1	83.5	
1983-06	720	38.9	7.2	1.3	0.19	1623.0	90.7	
1983-07	744	32.8	9.3	1.1	0.28	1655.8	100.0	
1983-08	744	40.7	5.3	1.3	0.13	1696.5	105.3	
1983-09	712	51.5	4.6	1.7	0.09	1748.0	109.9	
1983-10	742	62.3	4.6	2.0	0.07	1810.3	114.5	
1983-11	712	63.9	4.5	2.2	0.07	1874.2	119.0	
1983-12	744	42.6	4.7	1.4	0.11	1916.8	123.7	
1984-01	744	23.3	4.8	0.8	0.21	1940.1	128.5	
1984-02	691	22.2	2.7	0.8	0.12	1962.3	131.2	
1984-03	744	26.5	3.2	0.9	0.12	1988.8	134.4	
1984-04	720	24.4	3.4	0.8	0.14	2013.2	137.8	
1984-05	740	19.4	4.1	0.6	0.21	2032.6	141.9	
1984-06	710	21.9	0.0	0.7	0.00	2054.5	141.9	
1984-07	737	19.8	0.0	0.6	0.00	2074.3	141.9	
1984-08	768	21.0	0.0	0.7	0.00	2095.3	141.9	
1984-09	497	30.8	0.7	1.5	0.02	2126.1	142.6	
1984-10	745	302.7	19.2	9.8	0.06	2428.8	161.8	
1984-11	716	102.2	2.2	3.4	0.02	2531.0	164.0	
1984-12	744	62.5	9.0	2.0	0.14	2593.5	173.0	
1985-01	740	53.1	4.8	1.7	0.09	2646.6	177.8	
1985-02	672	77.5	2.9	2.8	0.04	2724.1	180.7	
1985-03	740	55.9	4.3	1.8	0.08	2780.0	185.0	
1985-04	719	25.5	1.4	0.9	0.05	2805.5	186.4	- INJ. COMMENCES 5-24
1985-05	740	23.8	2.3	0.8	0.10	2829.3	188.7	
1985-06	720	21.0	3.2	0.7	0.15	2850.3	191.9	
1985-07	728	22.0	2.5	0.7	0.11	2872.3	194.4	
1985-08	744	23.1	0.3	0.7	0.01	2895.4	194.7	
1985-09	713	19.9	0.8	0.7	0.04	2915.3	195.5	

PAGE . 2 *** STORE *** ManPB
WASKADA1 90-12-07
WELL (0)11-24-001-26 W1M(0) 14:11:00

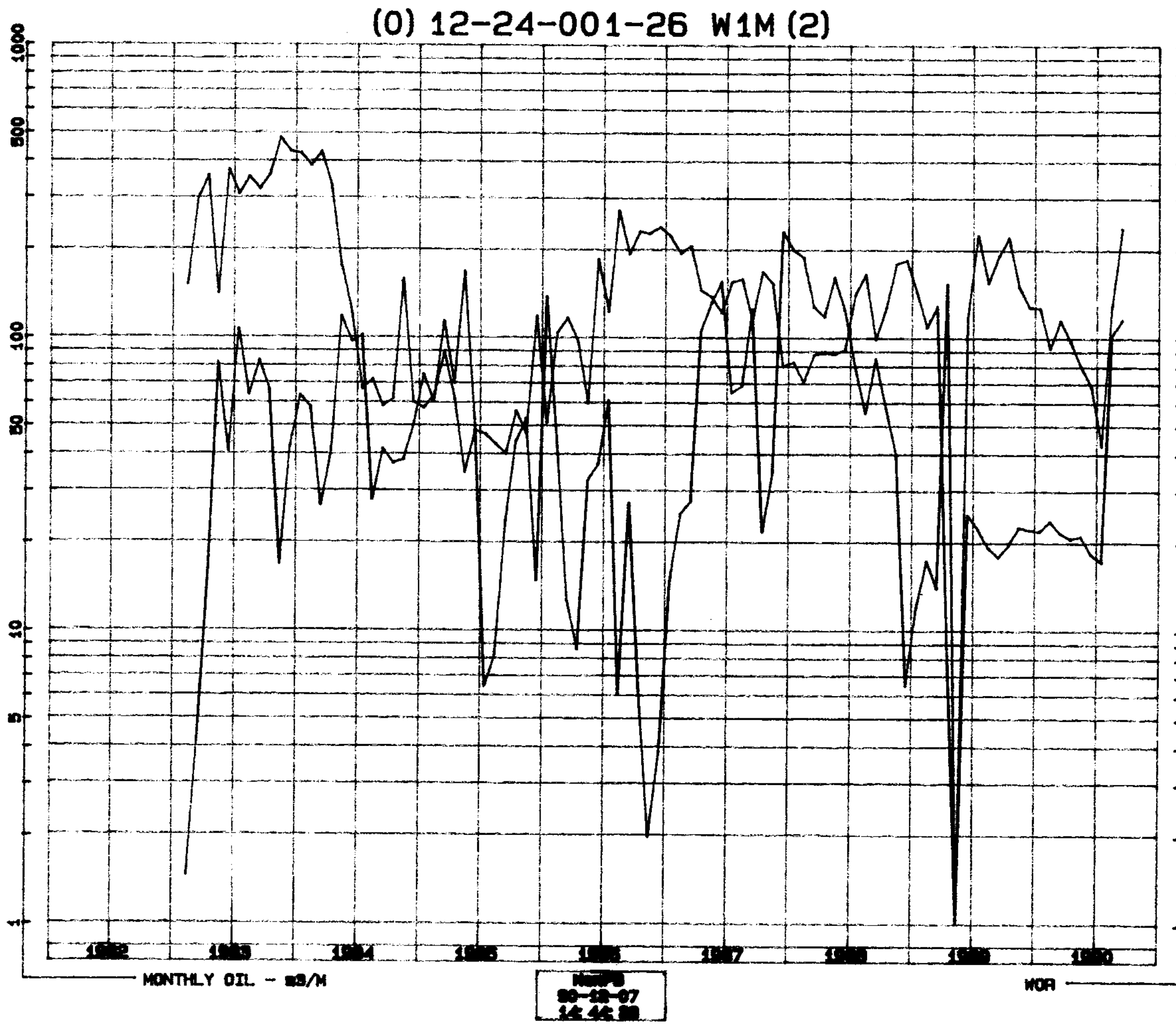
FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1982-03-12 LAND#3 2745
ACCTG 1 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1985-10	744	19.4	1.5	0.6	0.08	2934.7	197.0
1985-11	720	12.5	1.9	0.4	0.15	2947.2	198.9
1985-12	737	14.7	1.0	0.5	0.07	2961.9	199.9
1986-01	744	19.8	1.2	0.6	0.06	2981.7	201.1
1986-02	672	17.4	3.5	0.6	0.20	2999.1	204.6
1986-03	377	23.7	1.7	1.5	0.07	3022.8	206.3
1986-04	719	31.6	1.0	1.1	0.03	3054.4	207.3
1986-05	728	14.2	2.2	0.5	0.15	3068.6	209.5
1986-06	718	63.3	3.8	2.1	0.06	3131.9	213.3
1986-07	733	36.9	3.5	1.2	0.09	3168.8	216.8
1986-08	554	26.2	5.2	1.1	0.20	3195.0	222.0
1986-09	720	55.7	9.7	1.9	0.17	3250.7	231.7
1986-10	522	8.5	5.5	0.4	0.65	3259.2	237.2
1986-11	720	54.2	1.0	1.8	0.02	3313.4	238.2
1986-12	713	16.7	1.0	0.6	0.06	3330.1	239.2
1987-01	724	14.8	0.4	0.5	0.03	3344.9	239.6
1987-02	672	19.3	0.4	0.7	0.02	3364.2	240.0
1987-03	579	10.0	0.0	0.4	0.00	3374.2	240.0
1987-04	601	8.9	1.2	0.4	0.13	3383.1	241.2
1987-05	599	19.8	1.1	0.8	0.06	3402.9	242.3
1987-06	720	19.7	4.5	0.7	0.23	3422.6	246.8 — WATER BREAKTHROUGH
1987-07	703	12.3	5.1	0.4	0.41	3434.9	251.9
1987-08	744	12.9	4.4	0.4	0.34	3447.8	256.3
1987-09	624	17.0	8.5	0.7	0.50	3464.8	264.8
1987-10	744	21.6	4.8	0.7	0.22	3486.4	269.6
1987-11	576	15.5	1.1	0.6	0.07	3501.9	270.7
1987-12	744	18.5	1.9	0.6	0.10	3520.4	272.6
1988-01	744	19.6	1.2	0.6	0.06	3540.0	273.8
1988-02	624	15.5	0.8	0.6	0.05	3555.5	274.6
1988-03	504	14.0	0.7	0.7	0.05	3569.5	275.3
1988-04	720	20.1	0.8	0.7	0.04	3589.6	276.1
1988-05	744	25.4	2.0	0.8	0.08	3615.0	278.1
1988-06	672	17.1	1.8	0.6	0.11	3632.1	279.9
1988-07	744	13.5	2.0	0.4	0.15	3645.6	281.9
1988-08	480	7.1	1.4	0.4	0.20	3652.7	283.3
1988-09	336	7.0	0.7	0.5	0.10	3659.7	284.0
1988-10	672	16.1	0.8	0.6	0.05	3675.8	284.8
1988-11	432	10.4	0.4	0.6	0.04	3686.2	285.2
1988-12	576	12.4	1.0	0.5	0.08	3698.6	286.2
1989-01	744	13.9	0.7	0.4	0.05	3712.5	286.9
1989-02	672	11.5	0.7	0.4	0.06	3724.0	287.6
1989-03	408	5.9	1.2	0.3	0.20	3729.9	288.8
1989-04	720	12.9	1.4	0.4	0.11	3742.8	290.2

PAGE 3 *** STORE *** ManPB
WASKADA1 90-12-07
WELL (0)11-24-001-26 W1M(0) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1982-03-12 LAND#3 2745
ACCTG 1 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1989-05	744	12.0	1.6	0.4	0.13	3754.8	291.8
1989-06	720	14.3	0.8	0.5	0.06	3769.1	292.6
1989-07	456	3.7	0.0	0.2	0.00	3772.8	292.6
SHUT IN							
1989-12	696	76.8	4.9	2.6	0.06	3849.6	297.5
1990-01	624	54.7	7.7	2.1	0.14	3904.3	305.2
1990-02	672	38.7	9.5	1.4	0.25	3943.0	314.7
1990-03	744	51.1	12.5	1.6	0.24	3994.1	327.2
1990-04	648	35.5	7.4	1.3	0.21	4029.6	334.6
1990-05	744	36.3	10.4	1.2	0.29	4065.9	345.0
1990-06	720	34.3	9.2	1.1	0.27	4100.2	354.2
1990-07	744	23.7	5.4	0.8	0.23	4123.9	359.6
1990-08	504	7.9	1.7	0.4	0.22	4131.8	361.3
1990-09	720	6.9	1.8	0.2	0.26	4138.7	363.1



(0) 12-24-001-26 W1M (2)
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MONTHLY OIL - m3/M
WOR

PAGE . 1   *** STORE ***   ManPB
WASKADA1   90-12-07
WELL (0)12-24-001-26 W1M(2)   14:11:00

FIELD 3   PROVINCE MAN.   LAND#1 2
POOL 29   WORKING INTEREST 0.00000%   LAND#2 0
BLOCK 1   ON PRDN 1982-12-17   LAND#3 2718
ACCTG 1   ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1982-12	1	0.0	0.0	0.0	0.00	0.0	0.0
SHUT IN							
1983-02	432	151.8	2.2	8.4	0.01	151.8	2.2
1983-03	608	298.3	12.6	11.8	0.04	450.1	14.8
1983-04	644	358.0	56.0	13.3	0.16	808.1	70.8
1983-05	327	140.9	116.0	10.3	0.82	949.0	186.8
1983-06	720	375.4	152.6	12.5	0.41	1324.4	339.4
1983-07	720	307.9	330.3	10.3	1.07	1632.3	669.7
1983-08	744	353.8	225.0	11.4	0.64	1986.1	894.7
1983-09	712	321.0	267.9	10.8	0.83	2307.1	1162.6
1983-10	732	361.2	238.6	11.8	0.66	2668.3	1401.2
1983-11	712	481.0	80.4	16.2	0.17	3149.3	1481.6
1983-12	744	432.2	183.9	13.9	0.43	3581.5	1665.5
1984-01	744	425.8	270.1	13.7	0.63	4007.3	1935.6
1984-02	691	386.5	222.7	13.4	0.58	4393.8	2158.3
1984-03	744	432.5	115.4	14.0	0.27	4826.3	2273.7
1984-04	720	329.6	136.1	11.0	0.41	5155.9	2409.8
1984-05	740	175.8	208.0	5.7	1.18	5331.7	2617.8
1984-06	710	121.1	117.2	4.1	0.97	5452.8	2735.0
1984-07	738	66.8	68.2	2.2	1.02	5519.6	2803.2
1984-08	768	72.0	20.0	2.3	0.28	5591.6	2823.2
1984-09	716	58.3	24.3	2.0	0.42	5649.9	2847.5
1984-10	702	62.0	23.0	2.1	0.37	5711.9	2870.5
1984-11	716	158.8	60.9	5.3	0.38	5870.7	2931.4
1984-12	744	60.2	30.3	1.9	0.50	5930.9	2961.7
1985-01	740	57.4	43.0	1.9	0.75	5988.3	3004.7
1985-02	672	63.9	38.3	2.3	0.60	6052.2	3043.0
1985-03	740	89.4	102.0	2.9	1.14	6141.6	3145.0
1985-04	719	62.1	43.3	2.1	0.70	6203.7	3188.3 — ON INJ 5-24
1985-05	740	34.6	58.4	1.1	1.69	6238.3	3246.7
1985-06	720	48.3	25.3	1.6	0.52	6286.6	3272.0
1985-07	728	46.9	3.0	1.5	0.06	6333.5	3275.0
1985-08	744	43.3	3.6	1.4	0.08	6376.8	3278.6
1985-09	713	40.1	9.4	1.3	0.23	6416.9	3288.0
1985-10	744	56.3	24.9	1.8	0.44	6473.2	3312.9
1985-11	720	47.1	25.0	1.6	0.53	6520.3	3337.9
1985-12	737	119.1	17.6	3.9	0.15	6639.4	3355.5
1986-01	744	51.1	71.2	1.6	1.39	6690.5	3426.7
1986-02	621	104.5	45.7	4.0	0.44	6795.0	3472.4
1986-03	744	117.4	14.8	3.8	0.13	6912.4	3487.2
1986-04	719	97.4	8.4	3.3	0.09	7009.8	3495.6
1986-05	728	59.7	19.5	2.0	0.33	7069.5	3515.1
1986-06	718	186.5	69.4	6.2	0.37	7256.0	3584.5

PAGE 2 *** STORE *** ManPB
WASKADA1 90-12-07
WELL (0)12-24-001-26 W1M(2) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1982-12-17 LAND#3 2718
ACCTG 1 ON INJN NOT ON YET

MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1986-07	733	122.7	75.1	4.0	0.61	7378.7	3659.6
1986-08	744	273.4	16.5	8.8	0.06	7652.1	3676.1
1986-09	720	193.7	53.3	6.5	0.28	7845.8	3729.4
1986-10	745	231.6	14.6	7.5	0.06	8077.4	3744.0
1986-11	720	227.9	4.5	7.6	0.02	8305.3	3748.5
1986-12	744	240.2	9.2	7.7	0.04	8545.5	3757.7
1987-01	724	222.5	33.1	7.4	0.15	8768.0	3790.8
1987-02	672	194.8	49.0	7.0	0.25	8962.8	3839.8
1987-03	744	207.4	57.5	6.7	0.28	9170.2	3897.3
1987-04	719	145.6	154.7	4.9	1.06	9315.8	4052.0 - WATER BREAKTHROUGH
1987-05	744	138.1	183.0	4.5	1.33	9453.9	4235.0
1987-06	720	121.9	190.1	4.1	1.56	9575.8	4425.1
1987-07	744	155.7	101.2	5.0	0.65	9731.5	4526.3
1987-08	744	159.9	110.4	5.2	0.69	9891.4	4636.7
1987-09	720	115.5	145.2	3.9	1.26	10006.9	4781.9
1987-10	744	169.4	36.7	5.5	0.22	10176.3	4818.6
1987-11	720	153.2	53.3	5.1	0.35	10329.5	4871.9
1987-12	744	80.0	185.8	2.6	2.32	10409.5	5057.7
1988-01	744	83.0	166.3	2.7	2.00	10492.5	5224.0
1988-02	696	70.6	133.3	2.4	1.89	10563.1	5357.3
1988-03	744	88.0	112.7	2.8	1.28	10651.1	5470.0
1988-04	720	89.5	106.1	3.0	1.19	10740.6	5576.1
1988-05	744	88.4	143.1	2.9	1.62	10829.0	5719.2
1988-06	720	91.8	114.6	3.1	1.25	10920.8	5833.8
1988-07	720	141.6	112.7	4.7	0.80	11062.4	5946.5
1988-08	744	165.6	91.7	5.3	0.55	11228.0	6038.2
1988-09	696	99.3	84.9	3.4	0.85	11327.3	6123.1
1988-10	744	127.2	73.2	4.1	0.58	11454.5	6196.3
1988-11	672	180.0	72.0	6.4	0.40	11634.5	6268.3
1988-12	744	185.7	12.0	6.0	0.06	11820.2	6280.3
1989-01	744	144.3	17.4	4.7	0.12	11964.5	6297.7
1989-02	600	109.2	19.0	4.4	0.17	12073.7	6316.7
1989-03	504	129.3	18.1	6.2	0.14	12203.0	6334.8
1989-04	489	9.3	14.4	0.5	1.55	12212.3	6349.2
1989-05	1	0.0	0.0	0.0	0.00	12212.3	6349.2
1989-06	456	118.7	29.8	6.2	0.25	12331.0	6379.0
1989-07	744	226.5	50.5	7.3	0.22	12557.5	6429.5
1989-08	744	155.0	29.9	5.0	0.19	12712.5	6459.4
1989-09	720	191.2	34.2	6.4	0.18	12903.7	6493.6
1989-10	720	221.9	43.9	7.4	0.20	13125.6	6537.5
1989-11	696	150.4	34.1	5.2	0.23	13276.0	6571.6
1989-12	744	128.1	28.4	4.1	0.22	13404.1	6600.0
1990-01	744	127.3	27.9	4.1	0.22	13531.4	6627.9

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WELL (0)12-24-001-26 W1M(2) 14:11:00

FIELD 3 PROVINCE MAN. LAND#1 2

POOL 29 WORKING INTEREST 0.00000% LAND#2 0

BLOCK 1 ON PRDN 1982-12-17 LAND#3 2718

ACCTG 1 ON INJN NOT ON YET

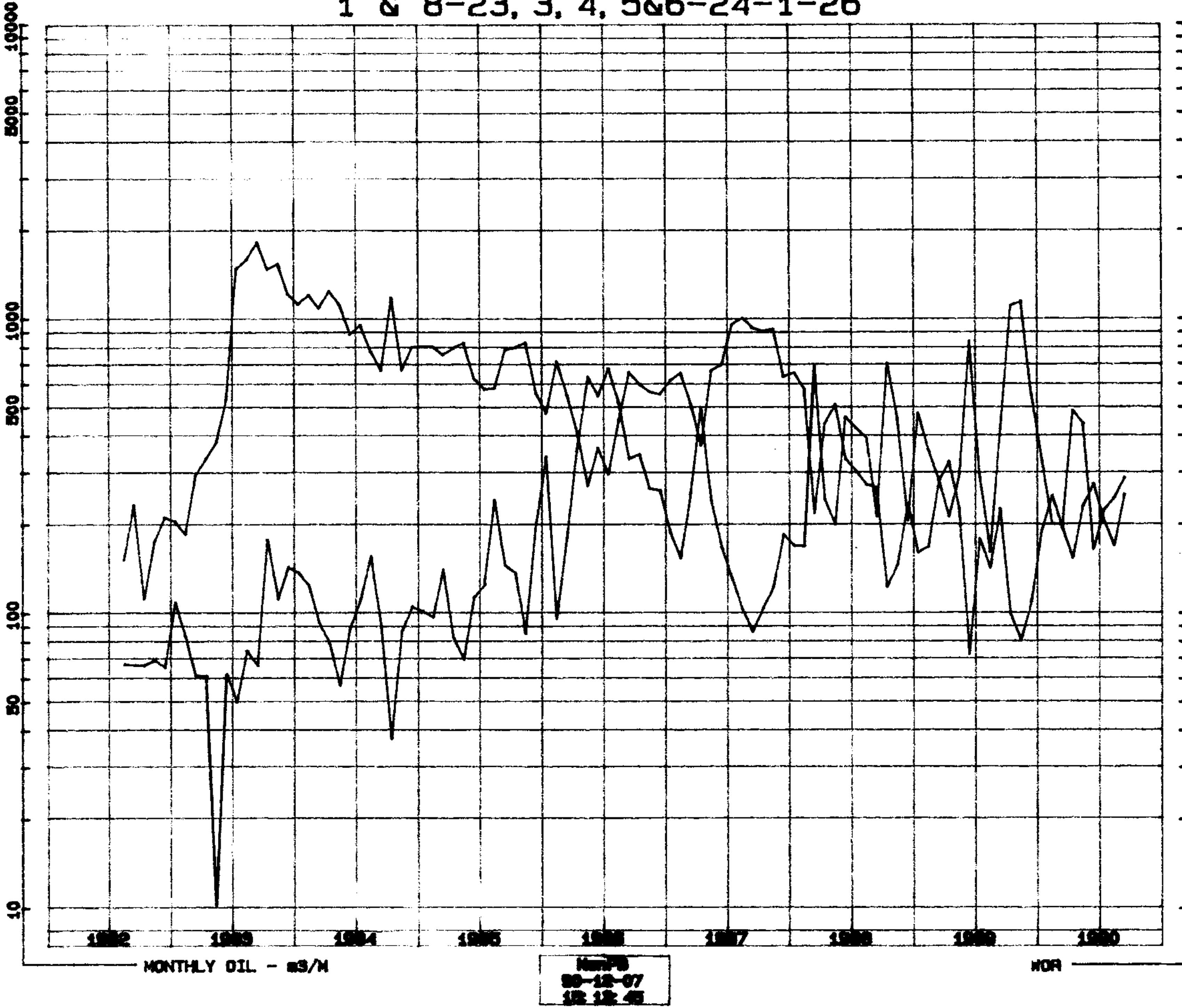
MONTH	HOURS	OIL m3/M	WATER m3/M	OIL m3/d	WOR	CUM.OIL m3	CUM.WAT m3
1990-02	648	92.8	22.1	3.4	0.24	13624.2	6650.0
1990-03	744	115.6	25.0	3.7	0.22	13739.8	6675.0
1990-04	720	97.5	20.2	3.3	0.21	13837.3	6695.2
1990-05	744	80.2	17.0	2.6	0.21	13917.5	6712.2
1990-06	720	68.7	12.6	2.3	0.18	13986.2	6724.8
1990-07	648	43.0	7.4	1.6	0.17	14029.2	6732.2
1990-08	648	129.8	133.7	4.8	1.03	14159.0	6865.9
1990-09	720	239.3	277.5	8.0	1.16	14398.3	7143.4

WASKADA1 90-12-07
WELL (0)05-24-001-26 W1M(0) 14:09:23

FIELD 3 PROVINCE MAN. LAND#1 2
POOL 29 WORKING INTEREST 0.00000% LAND#2 0
BLOCK 1 ON PRDN 1983-07-15 LAND#3 3030
ACCTG 4 ON INJN 1984-06-15

MONTH	HOURS	I.WATER m3/M	C.I.WAT m3
1987-08	504	1252.5	56807.9
1987-09	384	1273.0	58080.9
1987-10	744	1804.6	59885.5
1987-11	720	1176.2	61061.7
1987-12	744	794.9	61856.6
1988-01	696	851.9	62708.5
1988-02	576	629.9	63338.4
1988-03	720	707.1	64045.5
1988-04	624	598.8	64644.3
1988-05	126	51.7	64696.0
1988-06	126	43.7	64739.7
SHUT IN			
1988-09	528	565.2	65304.9
1988-10	696	552.4	65857.3
SHUT IN			
1990-03	24	4.8	65862.1
1990-04	216	12.3	65874.4
1990-05	24	0.9	65875.3
1990-06	24	0.9	65876.2
1990-07	168	97.7	65973.9
1990-08	48	106.8	66080.7
1990-09	48	238.6	66319.3

1 & 8-23, 3, 4, 5&6-24-1-26



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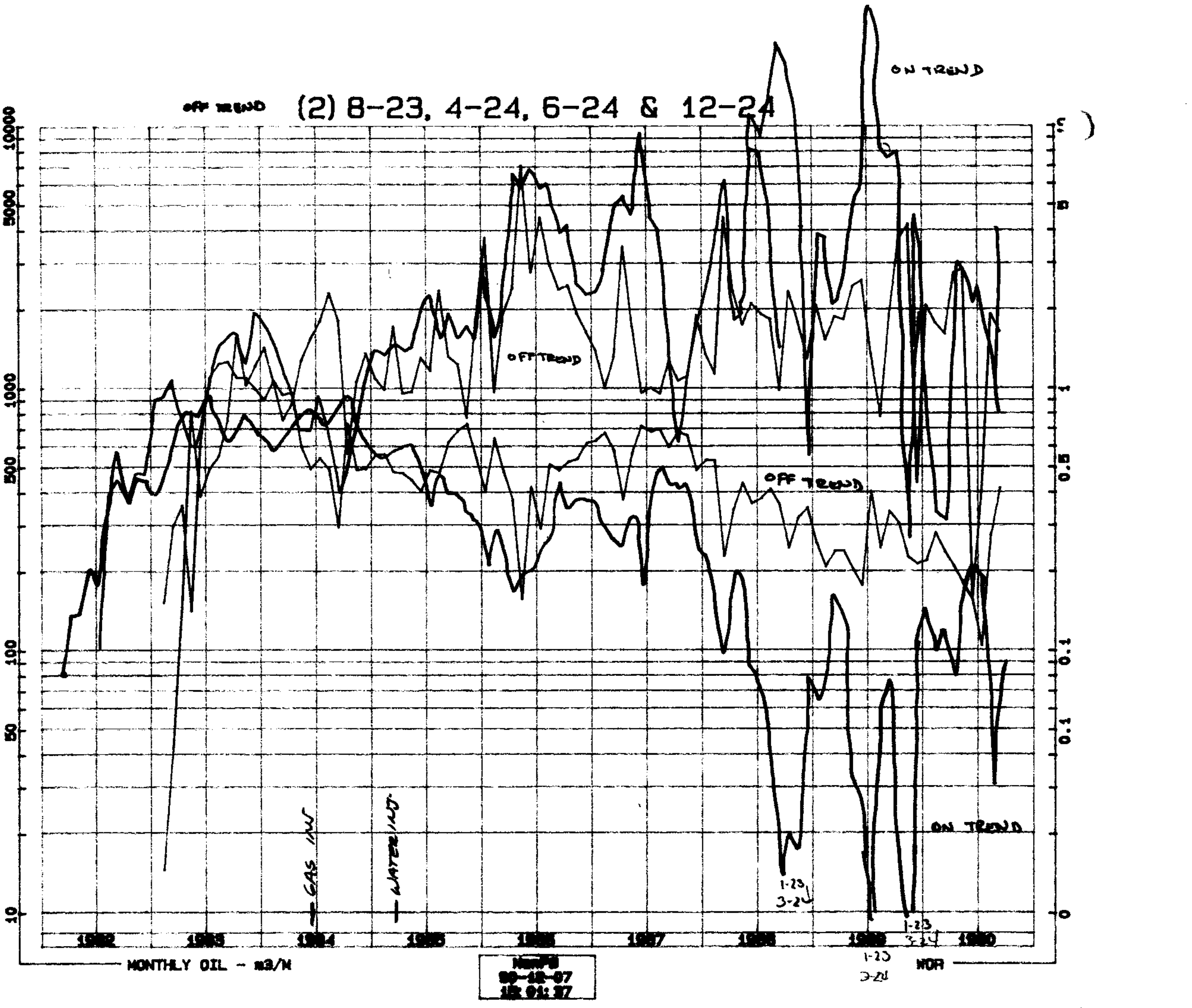

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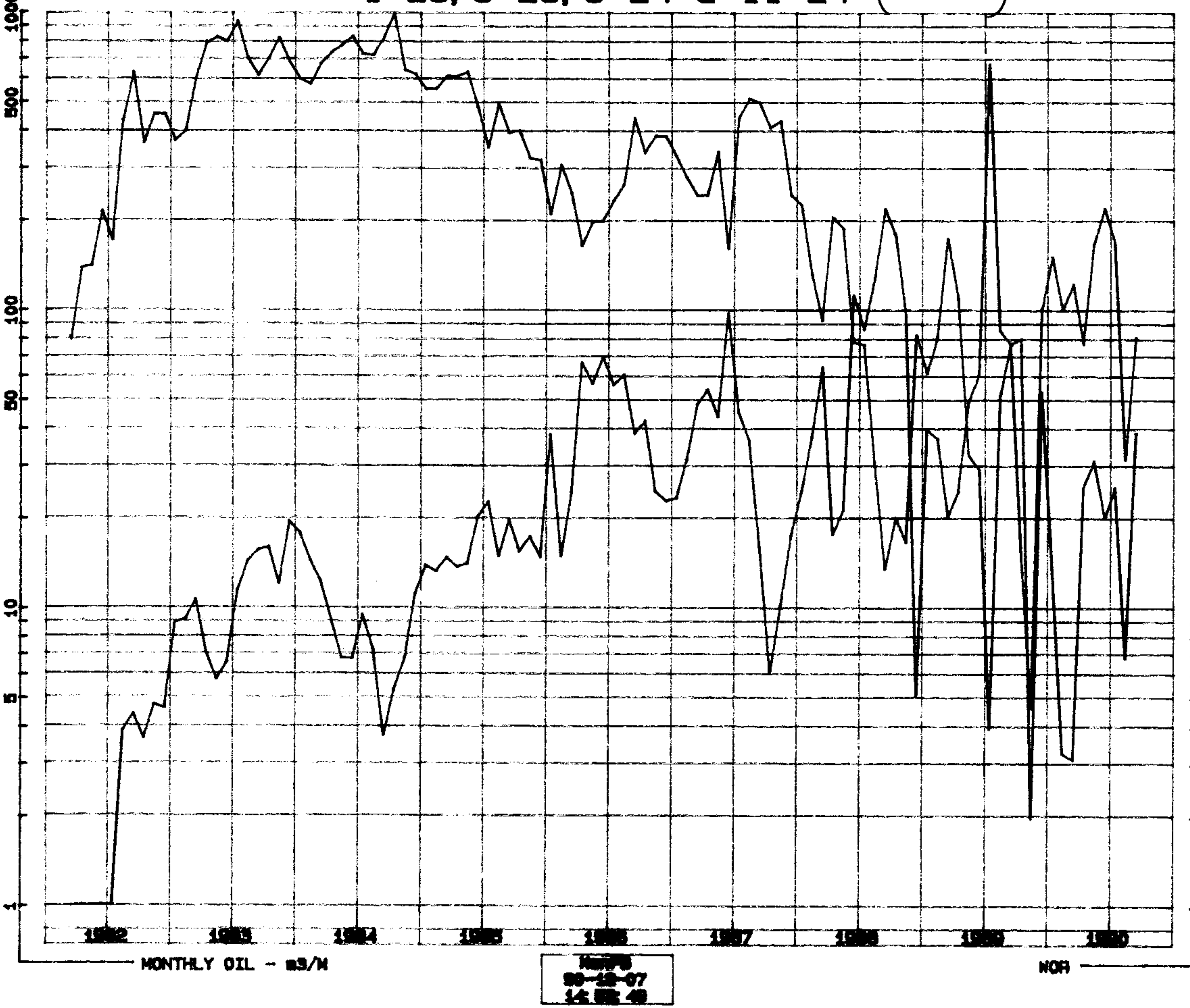

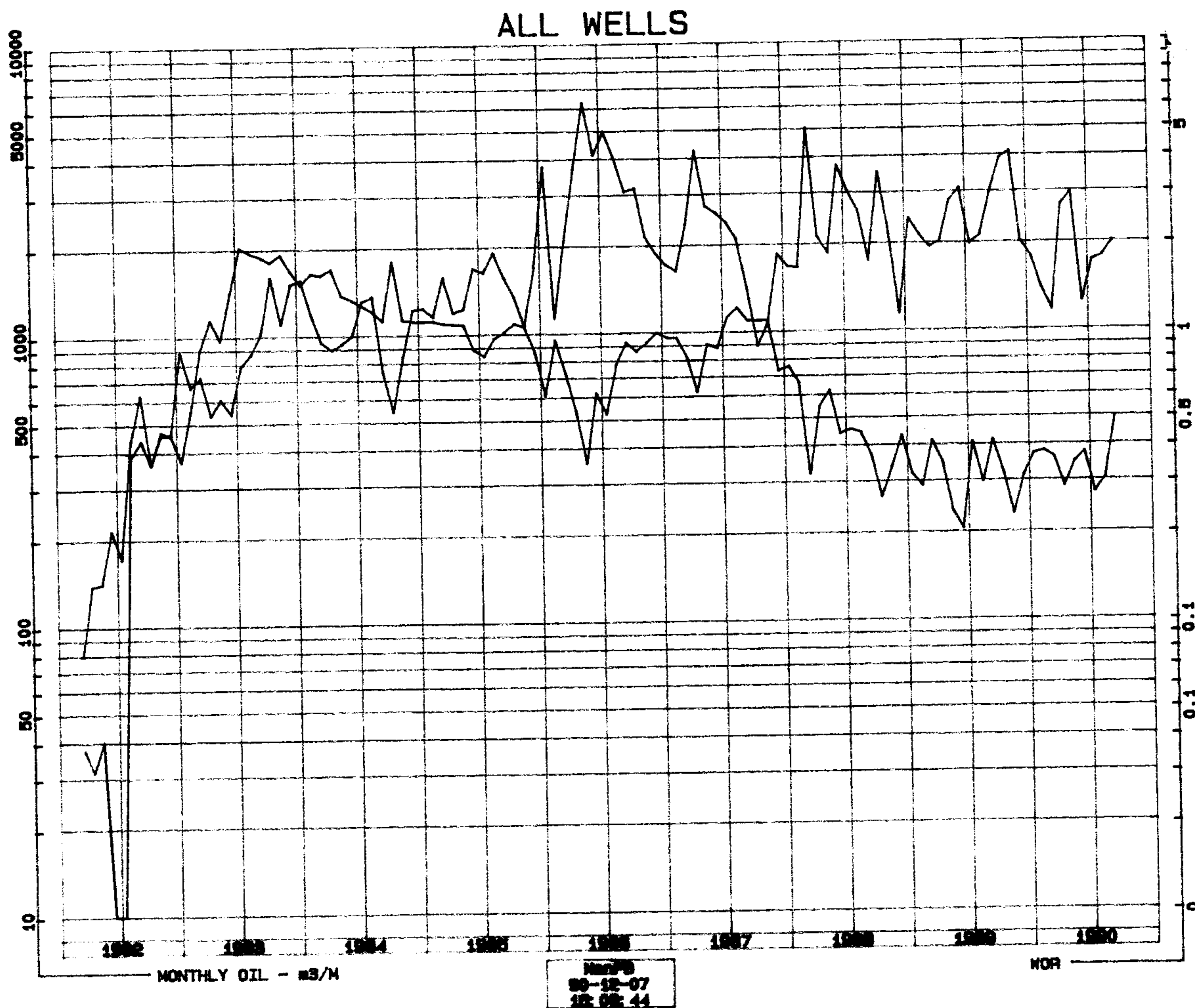
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