February 21, 1986 - meeting with Richard Brekke (B. Dubreuil, M. Arbez)

· Study "Reservoir Model Study Review and Waskada Waterflood Predictions.

Conclusions/Results:

· cummulative voidage replacements are <1, but current voidage replacements are ≅1 / will continue to maintain voidage replacement through waterflooding @ maximum injection pressure and rate.

· PVT - obtained surface sample 13-32-26 / final report now available; P_b=4570 psi

· operating cost/well in Waskada: $1200/month/well for producers → abandonment @ ±0.5 m³ oil/day.

plan to build up pressure

- see Figure No. 1 - definite change in oil viscosity in L. Amaranth Fm. / production rates are severely affected by viscosity changes - high viscosity areas tend to produce less oil as explained in attached memo date ~~Feb~~ Sept. 27/85.

- additional reservoir work:
  - an oil-based core was cut in 11-33 (now 2 oil-based cores in Waskada), but it appears that 11-33 is not a representative (core) well / Future oil-based cores will be cut / the core @ 11-33 shows very low permeability (abnormally low)
  - Brekke will try to get AFE approved for another oil-based core.

- layering described in reservoir model (Sept/85) as based on indentifiable sands (4) on logs

- OW contact based on capillary pressure data + completion experience and is not highly reliable.

- Brekke figures that Swirr ranges from 37 to 60%, and I agree with this, based on oil cores, cappillary tests, etc. / Table 2 of Sept/85 report: history-matched Sw indicates 6-9% mobile water.

- 5-25 pressure screened out

- next step: redo model in low K area.

OIL BASED CORE @ 11-33-1-26.

M E M O

DATE: September 27, 1985

TO: George Patey

FROM: Bob Beamish

RE: Waskada Spearfish - Oil Properties

cc: T. J. Hall
Joe Irwin
Warren Sharpe
Richard Brekke
Mark Mawdsley

Enclosed is a copy of a preliminary map of oil properties (viscosity and density) for the Spearfish zone at Waskada.

In this relatively tight zone there is a serious affect on production rate with oil viscosities in excess of 5 or 6 centipoise. A preliminary model run using a higher than average viscosity shows dramatically reduced rates under water flood.

Because of the economic impact from such lower rates it is recommended that we further define:

a) the area of known higher viscosity,

b) a possible anomaly at well 8-17-1-25 WPM, and

c) new areas by obtaining samples for each new well.

The cost of an oil sample analysis to obtain this data is $70.00.

I suggest that Mark continue with the development of this information and periodic up-dates of mapped data.

R. A. Beamish

BB/cw

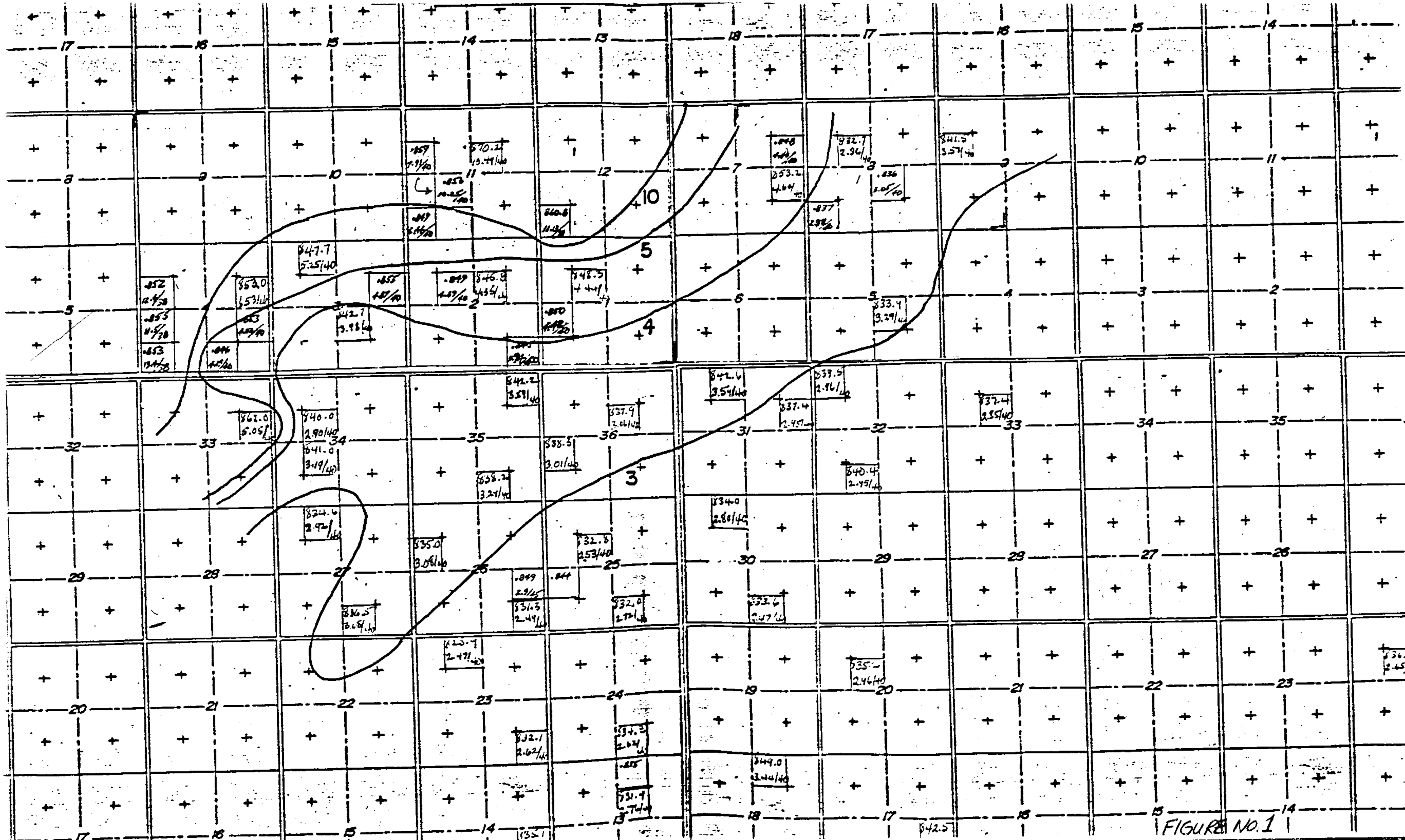


FIGURE NO. 1

AGENDA

Date: February 21, 1986
Time: 1 PM
Place: Manitoba Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba

Purpose: Reservoir Model Study Review and
Waskada Waterflood Predictions

1) Review Reservoir Model Study Report
   - Questions and Answers

2) Describe The Waterflood Prediction Scaling Technique
   - Model Predictions and What They Mean
   - OOIP Calculations For The Prediction Area
   - Selection Criteria Used To Select The Type Of Waterflood Performance
   - Production Forecast Calculations
   - Comparison With Actual Production And Other Prediction Techniques

3) Submission Of Outstanding Waterflood Predictions
   - Timing

4) Other Topics Of Business

Waskada Lower Amaranth Pool
Waterflood Prediction
Scaling Technique

- The model study predictions were run using a history matched portion of the Lower Amaranth Pool. The history matched portion of the reservoir was selected based on two criteria; i) the area had to be "representative" with respect to average reservoir properties (ie. ϕ, k, S_w, reservoir layers, reservoir dip, average reservoir pressure, no communication with other formations) ii) the area had to have as long a production history as possible.

- The area chosen for the model study was the injection pattern centered around injector 13A-24-1-26 WPM. Important assumptions incorporated into the reservoir model were; i) log determined ϕ and h values for each well in the area ii) k_H values derived from a field average ϕ/k crossplot iii) initial S_w values determined from capillary pressure data

- While reviewing the total pool in search of a "representative" pattern it became apparent that there were two reservoir parameters which varied enough to effect production performance and ultimate oil recovery. The two parameters were permeability and oil viscosity. Therefore, to predict the performance in any given portion of the reservoir at least three (3) different predictions were required (Average k, Low k, High μ).

- Based on history match results, well performance and oil base core tests (well 11-33-1-26 WPM) Omega now believes that although S_{WIRR} may be in the order of 45% initial water saturations are higher and that some mobile water exists. Since, there are concerns surrounding the current method used to determine S_w values, 55% has been chosen as an estimate of average initial water saturation for the OOIP calculations used in the scale up procedure.

- In brief the scaling procedure involves three (3) steps; i) COIP calculations on a well by well basis and a total Unit basis ii) a determination of which portions of the Unit can be represented by each of the different waterflood predictions iii) after the composite oil recovery algorithm is obtained the waterflood prediction for the total Unit is obtained by multiplying the total Unit OOIP by the yearly oil recovery algorithm.

- The criteria to be used for differentiating between average permeability, low permeability and high viscosity areas must distinguish between extremes due to the significantly different production forecasts. After reviewing well performance within Unit No. 1 it was found that wells which produced less than 2% recovery during their first year of production (primary) exhibited very different production characteristics compared to those wells which produced greater than 2% recovery. Thus this criteria was used to select average and low permeability areas. Although a complete review of viscosity trends has not been completed the criteria for selecting high viscosity areas will likely be those areas with oil viscosities greater than 5 cp at standard conditions.

- Once the oil, water and gas forecasts for a given area have been generated the next step is to the align the forecast on a real time basis for comparisons with actual production. The point in time which should be focused on is the date that full injection begins. Differences in the early time production profiles between actual and predicted production may exist due to the sequence of events that actually occur prior to full injection startup. After the optimum injection strategy has been implemented in the Field the actual production can be represented by the predicted production and the ultimate oil recoveries will be similar to those shown in the model study.

- Due to the time frame required to properly compare actual performance to predicted performance it is recommended that the predictions only be updated every 2 to 3 years unless there is a major waterflood expansion. If a new Unit is formed a production forecast will be generated either at the time the waterflood application is made or when the annual pressure maintenance progress report is submitted. If a major waterflood expansion occurs an updated production forecast will be included with the annual pressure maintenance progress report.

[signature]

R.A. Brekke
Petroleum Engineer
Omega Hydrocarbons Ltd.

Waskada (LAm) Unit No. 1

øh + OOIP Determination

	Well	øh	OOIP*		Well	øh	OOIP*		
From Logs	9-23	1.97	122805	2.72	5-25	1.86	115948	2.48	
	10-23	0.89	55480	5.53	6-25	1.61	100364	3.99	
	15-23	1.88	117195	2.23	7-25	1.78	110961	2.30	
	16-23	1.92	119688	2.42	8-25	1.94	120935	1.71	←
	9-24	1.07	66701	3.03	9-25	1.83	114078	1.52	←
	10-24	1.02	63584	2.11	10-25	1.62	100987	3.35	
	11-24	1.21	75428	2.04	11-25	1.28	79792	3.80	
	12-24	1.22	76052	5.77	12-25	1.34	83532	2.89	
	13-24	1.62	100987	No Prod	13-25	0.95	59221	0.57	←
	14-24	1.00	62338	3.78	14-25	0.67	41766	0.48	←
	15-24	0.98	61091	6.07	15-25	0.44	27429	1.80	←
	16-24	1.47	91636	2.27	16-25	1.01	62961	0.93	←
	1-25	1.03	64208	2.73	1-26	1.78	110961	2.63	
	2-25	1.53	95377	4.43	2-26	2.40	149610	2.19	
	3-25	1.60	99740	6.14	7-26	1.28	79792	2.89	
	4-25	1.90	118441	3.44	8-26	1.87	116571	2.65	
		22.31	1390751			23.66	1474908		

Total OOIP for Waskada (LAm) Unit No. 1 = $2865.6 \times 10^3 m^3$

Using 2% oil recovery during the first year of primary depletion as the criteria for differentiating between average and low permeability areas you obtain the following factors for the Unit area;

Average "k" Portion = 0.8512   Low "k" Portion = 0.1488

$$* \quad OOIP = \frac{10000 A \phi h (1 - S_w)}{B_{oi}} = \frac{10000 (16)(\phi h)(1 - .55)}{1.155}$$

WF Prediction

	Year	Predicted * Recovery (%/yr)	Model Predicted Oil Production (m³)	Actual Oil Production (m³)	Decline Curve Predicted Oil Production (m³)
	1981			1326	
	1982			34996	
	1983	4.26	122074	63455	
Jan 1/84 → Full Inj Startup	1984	1.48 (5.74% OOIP)	42411	55295 (5.41% OOIP)	
	1985	1.50	42984	41787	
	1986	1.60	45850	45850 (P)	36882
	1987	1.41	40405	40405 (P)	31994
	1988	1.29	36966	36966 (P)	27753
	1989	1.31	37539	37539 (P)	24074
	1990	1.28	36680	36680 (P)	20883
	1991	1.27	36393	36393 (P)	18115
	1992	1.23	35247	35247 (P)	15714
	1993	1.23	35247	35247 (P)	13631
	1994	1.16	33240	33240 (P)	11824
	1995	1.04	29802	29802 (P)	10258
	1996	0.95	27223	27223 (P)	8897
	1997	0.91	26077	26077 (P)	7718
	1998	0.84	24071	24071 (P)	6695
	1999	0.80	22925	22925 (P)	5807
	2000	0.74	21205	21205 (P)	5038
	2001	0.71	20346	20346 (R)	4370
	2002	0.67	19200	19200 (P)	
		25.68	735885 (25.68% OOIP)	725275 (25.31% OOIP)	446512 (15.6% OOIP

(P) - predicted

* This recovery algorithm was obtained by weighting the model study waterflood predictions by the approriate areal "k" factor.

† The predicted oil production equals predicted recovery × Unit OOIP.

Recovery Determination (using the decline curve technique)

q_i = 3804.3 m^3/month
q_t = 3300.0 m^3/month
q_e = 345.0 m^3/month
Q_i = 155072 m^3
Q_t = 41787 m^3
t = 12 months

Assume exponential decline (n=0)

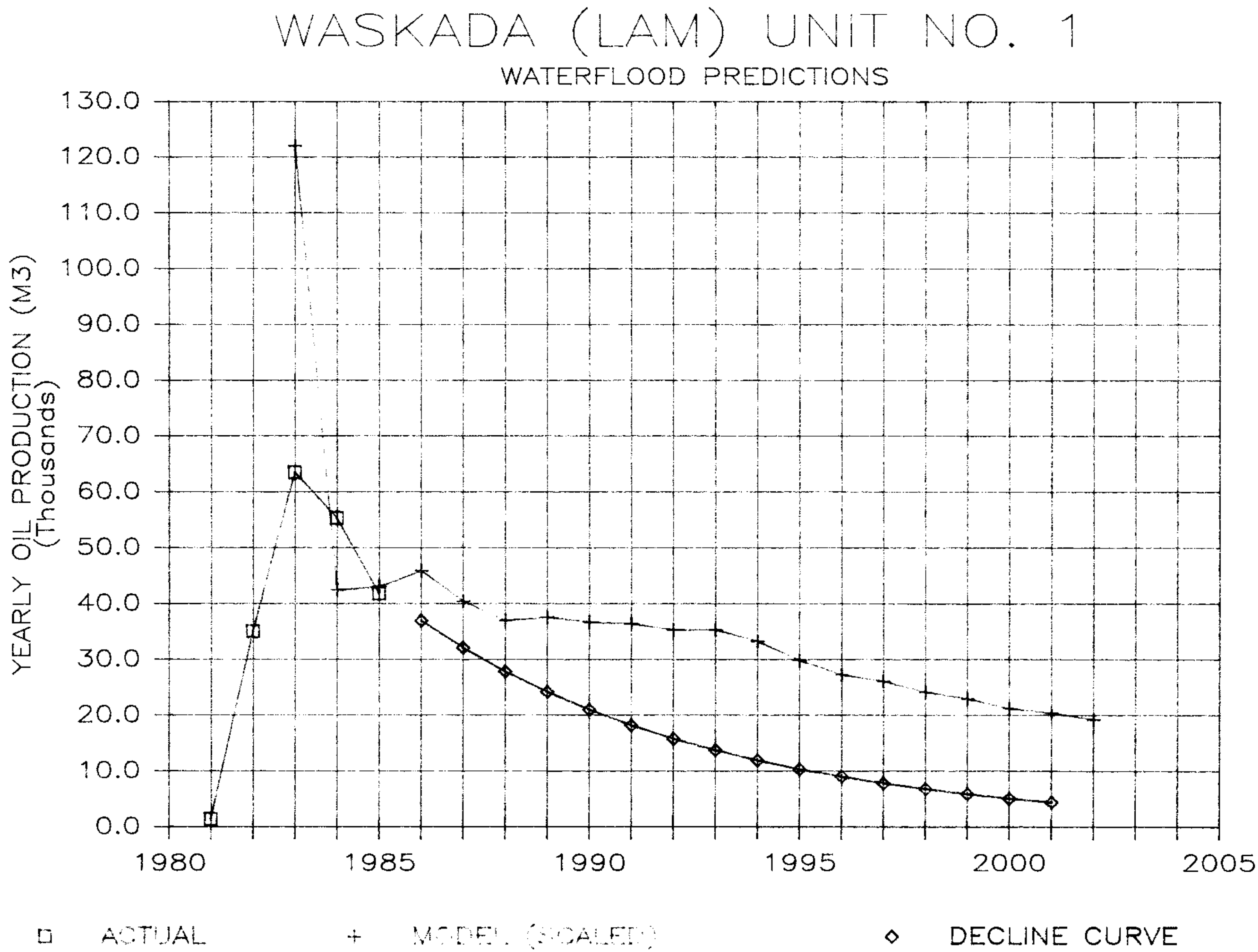
$$D = \frac{\ln(q_i/q_t)}{t} = \frac{\ln(3804.3/3300)}{12} = .01185 \text{ month}^{-1}$$

$$t_e = \frac{\ln(q_i/q_e)}{D} = \frac{\ln(3804.3/345)}{.01185} = 202.56 \text{ months}$$

$$Q_e = q_i(t_e)\left(\frac{1-(q_i/q_e)^{-1}}{\ln(q_i/q_e)}\right) = 291{,}923.2 \text{ m}^3$$

$$Q_{Total} = Q_i + Q_e = 446995.2 \text{ m}^3$$

$$\% \text{ Recovery} = \frac{Q_{Total}}{OOIP} = \frac{446995.2}{2865600} = 15.6\%$$


WASKADA (LAM) UNIT NO. 1
WATERFLOOD PREDICTIONS
YEARLY OIL PRODUCTION (M3)
(Thousands)
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
1980
1985
1990
1995
2000
2005
ACTUAL
MODEL (SCALED)
DECLINE CURVE

WASKADA Unit No.1 Reserves Estimates.

planimetering Unit #1: $OOIP = \left[(0.5 \times 1519128) + (0.7 \times 2141721) + (0.9 \times 1021053) + (1.1 \times 846727) \right] \times 0.50 \times 0.8$

(0.50 = $1 - S_w$; 0.8 = $1/B_{oi}$)

$= 1.75 \times 10^6 \, m^3$ oil.

Pre-unit production: 52 658.5 m^3 oil
14 924.2 m^3 water

current depletion
11% of OOIP

Unit production (excludes pre-unit): 143 759.9 m^3 oil (Jan. 1/86)
77 259.7 m^3 water "

Rec. Reserve Calculations:

A) $q_i = 140 \, m^3/d$ (July 1/84)
$q_t = 107 \, m^3/d$ (Jan. 1/86)
$t = 1.5$ years.
↓
$A_i = 16.41\%$ decline

B) $q_i = 107 \, m^3/d$
$q_t = 11.5 \, m^3/d$ (23 producers @ $0.5 \, m^3/d$)
$A_i = 16.41\%$
↓
$t = 12.4$ yrs.
$N_p = 194\ 467 \, m^3$ oil

total oil produced to abandonment (including pre-unit) = 390 885.4 m^3 oil

estimated recovery = $390885.4 / 1.75 \times 10^6 = 0.22$ or <u>22%</u>.

Waskada Model Study - Feb 21/86

1 - STUDY AREA REPRESENTATIVE OF THE AREA - ON WHAT BASIS

2 - HISTORY MATCH PARAMETERS

(VARIABLE)	(OUTPUT)
ROCK COMPRESSIBILITY	RESERVOIR PRESS.
WELL FRACTIONS	FBHP
TRANSMISSIBILITIES	WOR'S
RELATIVE PERM.	GOR'S

3. PREDICTIONS

1 -	EXTENSION OF HISTORY	% Rec 20yrs	25.3%	
		ECON. LIMIT	39.7%	-42yr
2 -	PRIMARY	20yr	9.1	
		EL	9.1	
3 -	WATERFLOOD (TIMING)	20yr	26.7	
		EL	38.2	41 yr
4 -	WATERFLOOD (LOW PERM)	20yr	19.6	
		EL	36.5	58yr
5	PVT CASE			

1. HOW DOES WATERFLOOD TIMING CASE DIFFER FROM HISTORY EXTENSION CASE?

2 STATUS OF PVT DATA COLLECTION

3 ECONOMIC LIMIT - ~~WHAT IS~~ HOW DO you calculate your economic limit \$ /m /well? WOR based.

4. CURRENT pressure 780 kPa above P_b. Is this enough having regard for very rapid drawdowns.

5. Additional reservoir work - rock compressibility
ϕ S_w oil base core
S_{or} S_{gc} S_{wi}

6. Basis of Layer definition?

7. Basis of oil water contact estimation (-465 m)

8 Can we get references (1) & (3)

9. $k\phi$ relationship - more questions

10. Table 2 shows S_w of 56-72% whereas irreducible water saturations of 37% to 60% are listed on p 3 - How do the two ranges relate?

11 Initial reservoir pressure 8900 kPa - at what depth? Pressure on 5-25 from Nov 81 indicates a higher pressure. Effect on study results?

12. Salt water density shouldn't it be higher than 1000kg/m³?

~~13. Par 5~~

13. Decline rate. 44% /yr now 16%/yr is this the true decline?

14. P.7 injection at 18000 BHP - effect of injection at less than maximum?

15. Mississippian communication - is it assumed this doesn't exist. How might it affect result if it does exist

~~16. History match period~~

16. Reasons for peak oil bank so late in continuation run.

17. High recoveries. Do you think that we're actually going to see 40% recovery in this Pool?
Marc's review

18. Use of model in other areas

19. Predictions - area / time

20 Well prod. data

21. Annual progress report

22 Unit 5 enlargement.

File
Waskada L.Am. Unit No 1
General Corres.

H. Clare Moster

I've made a brief review of Omega's pilot waterflood shheme and have made the following observations regarding response to injection.

1. Although no clearcut response is indicated in any well, a number of wells, mostly in the S½ Section 25-1-26 have shown stable oil rates. One well, 4-25-1-26 has actually shown an increase in oil rate although this may not be entirely due to the waterflood.

2. Wells in the N½ Section 24-1-26 do not appear to have responded as well to injection. As an example 11-24 and 10-24 have shown a continued decline at a rate of 70 - 80%/year.

3. Other areas of the pool were reviewed and demonstrate decline rates of 60 - 80%/year.

4. Water production appears to be a problem only at 1-25 LAm (where it may be associated with Mississippian injection at 6-30) and to a lesser extent at 12-24.

5. While response is certainly not overwhelming, performance of wells in the pilot area appears to be holding up better than wells in other areas. This would translate to incremental recovery although this is difficult to quantify at this time. Performance also indicates that positive effects of water injection may not be felt in all patterns.

Bob Dubreuil

HYDROCARBONS Ltd.
TELEPHONE: (403) 261-0743 630-330 FIFTH AVENUE S.W., CALGARY, ALBERTA T2P 0L4

March 30, 1983

Manitoba Petroleum Branch
975 Century Street
Winnipeg, Manitoba
R3H 0W4

DEPARTMENT OF ENERGY AND MINES
APR 5 1983
PETROLEUM BRANCH

Attention: Mr. Bob Dubreuil

Dear Bob:

Re: Waskada Lower Amaranth Unit No. 1

In response to your letter of March 16 and our telephone discussion of March 28 attached herewith are:

1) A copy of C & M Engineering Ltd.'s report Waskada Water Injection System on the results of their investigation. Specifically addressing water compatibility refer to page 23 which indicates that all formation brines were compatible however there is an indication of possible problems with respect to the Blairmore water. While these compatibility problems could probably be alleviated with scale preventatives this is currently not a concern because we are only injecting produced water in the pilot. Waskada 11-29 water well has been disconnected and suspended until there is a change in the situation. Further testing of possible solutions will be undertaken as the need arises.

2) A copy of Corelab's Special Core Study of the Lower Amaranth rock.

3) The February, 1983 Water Report for the pilot. You will notice that water injection pressures were not available for this report. The wells went on injection on February 25 and operated only intermittently because of a few start up problems. This situation will be rectified in the March report.

   As stated above, all injected water was derived from separation of produced brine and therefore is a blend of waters from all formation according to the proportions produced to the battery.

Omega will shortly be obtaining the necessary samples to do flash liberation tests from a recombined sample and these results will be forwarded as they become available.

We intend to run the spinner survey on an injection well (probably 13A-24) as soon as the injection system appears to have stabalized; probably in about 2-4 months from now.

I hope that this will fulfill your requirements.

Yours truly,

OMEGA HYDROCARBONS LTD.

E. Wyse

EW/cn
Encl.

C & M Engineering Ltd.

OMEGA HYDROCARBON LTD.

WASKEDA WATER INJECTION SYSTEM

C & M Engineering Ltd.

March 4th, 1983
Job No. 0080

Omega Hydrocarbon Ltd.
#630, 330 5th Avenue S.W.
CALGARY, Alberta

ATTENTION: Mr. George Padey, V.P. Productions

RE: WASKEDA WATER INJECTION SYSTEM

Dear Sir:

We are attaching the completed report concerning this subject.

A draft copy of this report was previously issued. All laboratory charges were issued directly from Bio-Chem Consulting Services Ltd. The attached invoice covers only the consulting services performed.

Trusting this is satisfactory, and should you have any questions, please do not hesitate in calling our office at your convenience.

Yours very truly,

Roger H. Giovanetto, P. Eng.

RHG:ck
attach.

C & M Engineering Ltd.

OMEGA HYDROCARBON LTD.

WASKEDA WATER INJECTION SYSTEM

PREPARED BY: Roger H. Giovanetto, P. Eng.

DATED: March 3rd, 1983

C & M Engineering Ltd.

TABLE OF CONTENTS

C & M Engineering Ltd.

OMEGA HYDROCARBON LTD.

WASKEDA WATER INJECTION SYSTEM

1.0 SUMMARY OF CONCLUSIONS

1. Blairmore source water exhibits a slight scaling tendency and is severely contaminated with high populations of sulfate reducing bacteria.

   The source water is further considered to be highly corrosive if oxygen gains access to the system.

2. Water produced from the Alida Formations exhibit some potential for deposition of calcium sulfate and calcium carbonate. H_2S naturally associated with this water makes the water corrosive. Corrosion failures have occurred in the tubing and pitting has been noted on the downhole pumps.

3. Water produced from the Tilston Formation is considered a high brine exhibiting a slight tendency to precipitate calcium carbonate scale. This water is also corrosive. The corrosivity of the water reflects the presence of H_2S, CO_2 and acid pH. No scaling or corrosion has been noted on equipment

.../2

SUMMARY OF CONCLUSIONS (cont'd)

handling this produced fluid.

4. Water produced from the Spearfish Formation is considered a moderate sweet brine which exhibits some tendency to precipitate calcium carbonate. Scale deposition has been noted on the bottom hole pump screen.

5. All waters from the Spearfish, Tilston and Alida production zones exhibit slight contamination with sulfate reducing bacteria. It is likely that this contamination was introduced by waters used to service or drill these wells.

6. The suspended solids associated with waters from the Spearfish, Tilston and Blairmore formations comprised sand, salt crystals, iron sulfide and iron oxide particles and exhibit good filtration characteristics. The suspended solids content of the water collected from the Alida formation are considered high and comprised large black particles which concentrated at the oil/water interface. Water samples collected from the disposal wellhead contained a high concentration of suspended solids and the fluid exhibits a significantly lower filterability. It is likely that oil associated with this sample caused reduction in the filterability of this sample.

2.0 RECOMMENDATIONS

1. The Blairmore Formation water is highly contaminated with sulfate reducing bacteria. This well should be slug treated with 20 U.S. gals. of a biocide designed to destroy sulfate reducing bacteria (X-Cide 320 or equal). The chemical should be slugged into the annulus of the well, the well fluid circulated down the annulus and up the tubing, then the well shut in until required.

2. Blairmore Formation water has, historically proven to be corrosive when oxygen gains access to the water. We suggest that a gas blanket (natural gas, propane, nitrogen, etc.) be placed in the annulus to prevent ingress of oxygen during pumping. All wellhead fittings should also be maintained in a tight condition.

3. Production from the 3 producing zones shall be comingled in the treater. The separated clean water shall be stored in 2 fibreglass tanks connected by an equilizing line at the 10 ft. level. Water shall enter the first vessel near the bottom of the tank and discharge through a riser equipped with a deflector plate. The top of the riser shall always be below the low water level in the tank.

RECOMMENDATIONS (cont'd)

Water discharging from the second tank shall be taken from near the bottom of the tank through a vertical riser located below the minimum fluid level in the tank.

Each tank shall be sized to provide a minimum of one hours retention to allow solids to settle. All tanks used shall be gas blanketed to prevent ingress of oxygen into the system.

4. The internal shell of the treater should be coated with an epoxy based coal tar selected and cured in such a manner to withstand the operating conditions.

5. Produced fluids trucked into the treatment plant shall be discharged into a separate coated or fibre-glass receiving tank. The fluids from this tank shall be pumped to a treater. The piping shall be equipped with 3 X 1/4" injection valves to allow injection of an oxygen scavenger, scale preventative and biocides if required. All injection points should be located upstream of the recirculation pump. The chemical injection pumps should be tied in electrically such that the chemical pumps operate whenever the recirculation pumps start. This will ensure that the requisite chemicals are added whenever fluid is transferred to the treater.

.../5

RECOMMENDATIONS (cont'd)

6. The injection water should be filtered through a 10 micron backwashable cartridge filter before injection into the system. Filtration studies indicate that this filtration system should easily handle solids removal economically if NO oil is present in the system. If oil is present in the system (free oil or solids saturated with oil), surface matting will result in short filter runs. If oil cannot be effectively removed, a backwashable anthrafilt filter should be used.

7. All water injection lines will comprise epoxy coated pipe joined using the Zap lock technique. The production system and downhole equipment however, comprised bare steel. In order to monitor the corrosivity of the fluid, flush mounted corrosion probes (1" D bull plugs) should be located on the bottom of the line as follows:

   1. Production wellhead - one well producing from each zone.
   2. Production well 4-30
   3. Emulsion line - treater inlet

RECOMMENDATIONS (cont'd)

Standard coupons should be placed at the following locations:

1. Source Wellhead
2. Water Dump - Treater Outlet
3. Injection Pump Suction
4. Injection Wellhead

8. A catalyzed oxygen scavenger should be continuously added to the trucked fluid entering the treater. An initial dosage of 1 qt. catalyzed ammonium bisulfite is required to treat 100 bbls of water assuming fully saturated water. Tests should be run to assess actual requirements. A pump and tank is required to continuously add this product to the system.

9. All water used to drill or service producing wells should contain a biocide to prevent contamination of the producing well. One quart of 10% active bleach can be slugged into the truck carrying the water <u>or</u> 100 ppm of a organic biocide can be used.

10. Initially, a phosphonate based scale preventative should be added to the treater inlet to control scale throughout the treater and injection system. An

RECOMMENDATIONS (cont'd)

initial dosage of 25 ppm is recommended based upon water volumes (i.e., 1 lb. chemical/100 bbls water). A pump and tank is required to continously add the product to the system.

11. When source water is used for injection, an organic biocide should be continuously added at the wellhead if possible, at a dosage of 50 ppm.

12. One month after the system start up, a field survey should be undertaken to assess actual operating conditions, chemical effectiveness and water quality control. Chemical usage will be upgraded at that time.

13. The corrosion inhibitor presently slugged into producing well 4-30 should be continued. This program should not be expanded at this time.

Bio-Chem Consulting SERVICES LTD

WATER QUALITY REPORT

Date Sept. 15/82
Project No BC 960
Report No

Date Sampled Sept. 13, 1982 Date Recieved Sept. 15, 1982
Company Omega Hydrocarbon
Address Waskada
Sample Point 7-25-1-25 Produced Water
Appearance

	Reading	mg/l	meq/l	Remarks
pH	7.0			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		200	3.3	
Chloride Cl^-		47000	1324	
Sulfate SO_4^{--}		3900	488	
Total Hardness		4040		
Calcium Ca^{++}		1000	50	
Magnesium Mg^{++}		370	30.8	
Sodium Na^{++} +k+		39894	1735	
Barium		0.08		
Strontium		10.0		
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		29		
Manganese Mn		1.4		
Dissolved Solids		92410		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with A.P.H.A. and A.P.I. Recommendations

Glo-Chem Consulting
SERVICES LTD

WATER QUALITY REPORT

Date Sept. 15, 8
Project No BC 960
Report No 960-2

Date Sampled Sept. 13, 1982 Date Recieved Sept. 15, 1982

Company Omega Hydrocarbon

Address Waskada

Sample Point Source Well Water (Blairemore)

Appearance

	Reading	mg/l	meq/l	Remarks
pH	8.1			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		730	11.9	
Chloride Cl^-		2400	67.6	
Sulfate SO_4^{--}		300	6.3	
Total Hardness		36		
Calcium Ca^{++}		6.7	0.33	
Magnesium Mg^{++}		4.7	0.39	
Sodium Na^{++} +k+		1973	85.8	
Barium		0.03		
Strontium		3.25		
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		0		
Manganese		0		
Dissolved Solids		5418		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with A P H A and A P I Recommendations

Bio-Chem Consulting SERVICES LTD

WATER QUALITY REPORT

Date Sept. 15/82
Project No BC 960
Report No 960-3

Date Sampled Sept. 13/82 Date Recieved Sep. 15/82

Company Omega Hydrocarbon

Address Waskada

Sample Point 4-30-1-25 Produced Water

Appearance

	Reading	mg/l	meq/l	Remarks
pH	7.2			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		230	3.8	
Chloride Cl^-		44000	1239	
Sulfate SO_4^{--}		3900	81.3	
Total Hardness		4635		
Calcium Ca^{++}		920	46	
Magnesium Mg^{++}		560	46.7	
Sodium Na^{+} +k+		28322	1231	
Barium		0.01		
Strontium		20.0		
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		0.6		
Manganese		0.6		
Dissolved Solids		77980		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with A P H A and A P I Recommendations

WASKEDA WATER INJECTION SYSTEM

a) MICROBIOLOGICAL SURVEY

SAMPLE LOCATION	ZONE	TOTAL BACTERIA POPULATION		SULFATE REDUCING BACTERIA POPULATION	
		SESSILE BACTERIA	PLANKTONIC BACTERIA	SESSILE BACTERIA	PLANKTONIC BACTERIA
SW 11-29-1-25.W1	Blairmore	$4.0 \times 10^7/cm^2$	$8.8 \times 10^5/ml$	$4.5 \times 10^5/cm^2$	$4.5 \times 10^3/ml$
4-30-1-25.W1	Alida		$1.4 \times 10^5/ml$		10/ml
13-24-1-25.W1	Alida	$6.8 \times 10^6/cm^2$			25/ml
16-13-1-26.W1	Tilston		$3.2 \times 10^4/ml$		5/ml
16-11-1-26.W1	Spearfish	$2.1 \times 10^7/cm^2$	$1.9 \times 10^5/ml$	$30/cm^2$	25/ml
Treater B			$1.9 \times 10^6/ml$		3/ml
11-30-1-25.W1	Disposal Well	$7.5 \times 10^5/cm^2$	$1.9 \times 10^6/ml$	$40/cm^2$	45/ml
4-30-1-25.W1	Tubing Sample		$3.8 \times 10^5/ml$		

3.0 FLUID CHARACTERISTICS

Water from the Blairmore Source Well exhibits the following characteristics.

1. Alkaline in reaction, pH = 8.5

2. High alkalinity due to the presence of sodium bicarbonate with trace quantities of calcium in magnesium bicarbonate.

3. The sulfate and chloride contents are considered low. No calcium sulfate precipitatation is expected from the water.

4. The total hardness is considered low. No calcium carbonate precipitation is expected from this water due to the low calcium content of the water.

5. Total bacteria populations (sessile and planktonic) are considered high and large numbers of sulfate reducing bacteria are present.

.../13

FLUID CHARACTERISTICS (cont'd)

The sample of water collected from the Alida Production Zone are as follows:

1. Slightly alkaline in reaction, pH = 7.6

2. Moderate alkalinity due to the presence of calcium bicarbonate.

3. Moderate chloride content primarily present as the sodium salt.

4. High sulfate content present as calcium and magnesium salt. This water exhibits a moderate potential for deposition of calcium sulfate.

5. The total hardness is considered high. Calculation of the Rheizner Stability Index indicates scale forming tendencies at temperatures exceeding 50°F. A corrosive tendency is indicated at lower temperatures.

6. Total iron and manganese contents are considered low.

7. The microbiological analysis shows moderate populations of sulfate reducing bacteria in this water.

FLUID CHARACTERISTICS (cont'd)

The water samples collected from the Tilston Formation exhibits the following characteristics.

1. Nearly neutral in reaction, pH = 7.3

2. Low alkalinity present as calcium bicarbonate.

3. Very high chloride content chiefly present as sodium chloride but with appreciable quantities of calcium and magnesium salt.

4. High sulfate content present as the calcium salt. Calculation of the sulfate scale forming index indicates that no calcium sulfate precipitation would occur from this water.

5. High total hardness. Calculation of the carbonate stability index indicates scale forming tendencies at temperatures exceeding 70°F. The quantity of scale deposit would be limited by the low alkalinity in this water. This water is also considered corrosive at lower temperatures due to the presence of H_2S and CO_2 in the water.

6. The aerobic and anaerobic bacteria populations of this water are considered low to moderate and only a few sulfate reducing bacteria are noted.

FLUID CHARACTERISTICS (cont'd)

The sample of water collected from the Spearfish Formation exhibits the following characteristics:

1. Nearly neutral in reaction, pH = 7.4

2. Low alkalinity present as calcium bicarbonate.

3. Moderate Chloride level.

4. High sulfate content present as the calcium and magnesium salt. No significant sulfate precipitation is expected from this water.

5. High total hardness. Calculation of the Rheizner Stability Index indicates scale forming tendencies at all practical operating conditions. The quantity of scale deposited would be limited by the low alkalinity of the water.

6. Total bacteria counts are considered high but only a few sulfate reducing bacteria are noted.

FLUID CHARACTERISTICS (cont'd)

The produced waters are comingled in the treater and disposed of into one disposal well at this time. The analysis indicates that at the time of sampling, the treater water comprised primarily Alida Formation water comingled with lesser quantities of Spearfish Formation water. The water exhibits the following characteristics.

1. Slightly alkaline in reaction, pH - 7.6

2. Moderate/low alkalinity present as calcium bicarbonate.

3. Moderate chloride content.

4. High sulfate content present as calcium and magnesium salts.

5. High total hardness. Calculation of the Rheizner Stability Index indicates scale forming tendencies at all practical operating temperatures. Scale deposition would reflect a calcium carbonate precipitate.

6. The total bacteria populations are considered high and only a few sulfate reducing bacteria are noted.

.../17

4.0 FILTERABILITY

The suspended solids associated with the waters collected from the Spearfish, Tilston and Blairmore Formations comprised a mixture of sand, salt crystals, iron sulfide and iron oxide particles. Microscopic examination showed that the particles were free of oil and exhibited good filtration characteristics. Filtration of this water through a 10µ filter would remove >90% of the solids.

Examination of the suspended solids associated with the water from the Alida Formation comprised large, black particles concentrated at the oil/water interface. The large black clumps are made up of separate particles of iron sulfide and clays, bonded together with a heavy hydrocarbon. This water exhibits a low filterability due to the presence of oil.

The water collected from the disposal wellhead also exhibits a low filterability due to the presence of oil and oil wetted solids. The particles comprised a mixture of sand, clay, iron oxides and iron sulfides. The quantity of suspended solids in the water were significantly higher than previous samples. It is likely that this represents particles settled in the line and sample point during normal operations.

.../

FILTERABILITY (cont'd)

All waters examined, with the exception of that collected from the Alida Zone, exhibit good filterability characteristics. The presence of heavy ends coating the particles, associated with the Alida water, dramatically reduce the filterability of the mixed waters.

A standard cartridge filter can be used to remove suspended solids from the disposal water if the oil content of the water can be minimized. If oil enters the disposal water system, solids matting will occur on the surface of the filter, resulting in premature plugging and short filter runs.

If oil carryover into the injection water occurs, a backwashable antrafilt or sand filter is recommended. If a sand filter is selected, the top one foot of medium should comprise treated antrafilt.

FILTERABILITY (cont'd)

We therefore recommend the following:

1. The building shall be designed to accomodate a backwashable sand or anthrafilt filter and backwash tank.

2. A 10μ cartridge filter shall be installed for solids content and economics of filtration evaluated.

3. If cartridge filters prove economically ineffective, a backwashable sand or anthrafilt filter should be installed.

5.0 BACTERIA CONTROL

Analysis show that the Blairmore Source Well is highly contaminated with large populations of general bacteria including sulfate reducing bacteria. The producing wells exhibit moderate degree of contamination. It is likely that the producing zones have been contaminated by using untreated waters for drilling or servicing. In order to control bacteria contamination throughout the system, the following steps should be taken.

1. Add 20 U.S. gallons of a water soluble biocide (Tretolite X-Cide 320 or equal) to the annulus of the Blairmore Source Well. Circulate the treated fluid to the bottom of the well then shut in the well until required.

2. All water used to drill or service new or existing producing wells shall be treated with a biocide prior to use. One quart of 10% sodium hyprchlorite (bleach) or 100 ppm of an organic biocide (Tretolite X-Cide 320 or equal) should be added to each truck-load of water as it is collected. No separate treatment is recommended at this time for clean up of existing producing wells.

BACTERIA CONTROL (cont'd)

3. If trucked water is to be added to the system, all produced water shall be treated with 100 ppm of an organic biocide to elimate bacterial contamination introduced during trucking.

4. The outlet piping at the following locations shall be equipped with a 1/4 inch injection valve to allow biocide addition if required.

   a) Source Wellhead
   b) Treater Inlet or Outlet
   c) Trucked Water Tank Outlet Piping

5. Sessile and planktonic bacteria populations shall be monitored by installing flush mounted probes and/or fluid sampling points at the following locations.

   a) Source Wellhead
   b) One Producing Well from each Producing Zone
   c) Water Dump Line from the Treater
   d) Injection Pump Suction
   e) Injection Wellhead

6.0 SCALE CONTENT

All waters tested exhibit some potential for deposition of calcium carbonate scale. Scale deposition however has only been noted on dowhole pumps handling Spearfish Producing Wells.

Waters from the Alida Formation also exhibit some theoretical tendency to precipitate calcium sulfate scale (gyp). No calcium sulfate deposits have, to date, been found in the system.

Evaluation of the water compatibility study show the following results.

1. Formation waters were compatible at all maximum concentrations under test conditions.

2. Addition of Blairmore Formation water to the various produced water mixtures results in deposition of both calcium carbonate and calcium sulfate scale. The quantity of calcium carbonate scale deposition increased as the percent of source water increased up to 65% source water. The quantity of calcium sulfate noted during the test was limited to less than 20% of the total deposit.

SCALE CONTENT (cont'd)

It is our understanding that scale deposits have only been found in one downhole pump handling Spearfish produced water. No source water is, as yet, added to the disposal system. We do not suggest the use of a scale preventative at this time, however, the following steps should be taken.

1. Locate 1/4 inch injection valves to allow for chemical (scale preventative) addition at the following locations.

   a) Emulsion Inlet to the Treater
   b) Recirculation Pump from trucked Water Tank
   c) Injection Pump Suction

2. Closely monitor all pumps pulled from producing wells with respect to the quantity and chemical composition of deposits found in the pump. Recommendations for dowhole scale control shall be made when the problem is determined to be significant.

3. Examine the fire tube in the treaters ~~closely~~ and water tank bottoms to ascertain the quantity and composition of deposited materials whenever possible. It may be desirable to continuously

SCALE CONTENT (cont'd)

add a scale preventative to the emulsion inlet and the treater as a safety precaution against fire tube failure.

4. Conduct water hardness surveys across the water handling system. Plot changes in hardness, calcium and magnesium content.

5. When source water is added to the mixed produced waters, commence addition of a scale preventative to the source water.

Prior to selection of a scale preventative, evaluate various scale preventatives to ascertain critical dosages required for control. The products selected for testing should include the following general type of scale control compounds.

a) Phosphonate
b) Phosphated Esters
c) Polymeric Materials

The products selected must also be compatible with other products used in the system.

7.0 CORROSION CONTROL

Evaluation of the chemical analysis indicates that the Tilston and Spearfish Formation waters exhibit a moderate corrosivity. No or insignificant corrosion has been noted in the equipment handling these fluids.

Water from the Alida Formation exhibits a corrosive tendency due to the presence of acid gases in the water. Corrosion failures have been experienced on the tubing and pitting noted on the downhole pump of one producing well handling this water. The corrosion attack was not evaluated.

The Blairmore source water exhibits a moderate corrosive tendency. No corrosion has been noted on the equipment handling this water, however, the well has operated only periodically since completion.

Oxygen ingress into the various waters will cause a dramatic increase in their corrosivity. Corrosion will reveal itself as localized pits at the most active metal surfaces. Historically, Blairmore source water becomes excessively corrosive after oxygen contamination. It is likely that mixed water contaminated with oxygen will also be corrosive. It is the writers' opinion that no known organic corrosion

CORRODSION CONTROL (cont'd)

inhibitor marketed today will function effectively in the presence of oxygen and a slightly sour environment.

In order to minimize oxygen ingress into the system, the following steps should be taken.

1. Gas blankets (approximately 1 lb. pressure) should be placed on the annulus of the source well, and on all storage vessels. The slight positive pressure will minimize the quantity of air drawn into the system when the level of the reservoir is rapidly drawn down.

2. All fittings shall be maintained in tightened conditions. Particular attention should be paid to the packing hold down assembly on valves.

3. All trucked waters should be stored in a separate receiver vessel and de-oxygenated with a catalyzed oxygen scavenger before mixing with the remaining injection water. A pump and tank should be purchased to continuously add this product to the system at a dosage of 10 ppm oxygen scavenger per one (1) ppm dissolved oxygen in the water.

CORROSION CONTROL (cont'd)

We do not suggest that corrosion inhibitors be added to the system at this time with the exception of that producing well where corrosion has been noted in the past (Alida Formation). The downhole equipment, surface lines, vessels, etc. should however be evaluated at each opportunity and the results of the evaluation recorded. We further suggest that flush mounted coupons be placed at the following minimum location:

a) Bottom of the lines at one producing wellhead handling fluid from each zone.

b) Bottom of the line at producing wellhead 4-30.

c) Bottom of the line at the emulsion inlet to the treater.

Conventional coupons should be located at the following locations:

a) Source Wellhead
b) Water Dump Line from the Treater Outlet
c) Trucked Water Line at the Recirculation Pump suction
d) Injection Pump Suction
e) Injection Wellheads

CORRORSION CONTROL (cont'd)

All coupons should be evaluated after 60 days relative to weight loss, nature of the attack and nature of deposit build up on the coupon surface. If these coupons are handled properly and stored in a clean plastic bag, they may also be used to assess sessile (adherent) bacteria populations.

We further suggest that fluid samples be collected from all producing wells and monitored for total iron and manganese contents. These readings should be plotted graphically and used to establish trends. Evaluation of trends will assist in determining the occurance of downhole corrosion.

8.0 GENERAL

The water injection system shall comprise internally plastic coated materials joined using the Zap Lock technique. Water tank and treaters shall be coated with an epoxy resin or be constructed of fibreglass epoxy material. All storage tanks shall be subjected to a gas blanket. (Pressure up to 1 lb.).

All production from the field shall be comingled in a header system and dehyrated in a horizontal treater. The produced water shall discharge into two fibreglass tanks connected by equilizer lines. The water shall enter the bottom of the first tank and discharge into the tank through a diffuser capped with a deflection plate. Equilizer lines shall be located at the minimum tank levels. Water from the second tank (feed to the filter) shall also be taken through a vertical riser. The water discharge into tanks or suction lines from the tanks shall always be located below the minimum liquid level to prevent splashing or vortexing.

A third tank may be added to the system to provide extra retention for solids settling and oil skimming. This tank should comprise a coated metal tank. This vessel should also be gas blanketed. Removal of oil and minimizing solids will allow for efficient filtration of the water.

GENERAL (cont'd)

Produced fluids trucked into the treatment plant should be received in a separate tank.

Geo-Chem Consulting SERVICES LTD

WATER QUALITY REPORT

Date Sept. 28/8
Project No 960
Report No 960-4

Sampled Sept. 22/82 Date Recieved Sept. 23,/82

Company Omega Hydrocarbon
Address Waskeda
Sample Point 11-29 Blairmore Source Well
Appearance

	Reading	mg/l	meq/l	Remarks
pH	8.5			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		730	11.9	
Chloride Cl^-		2200	61.9	
Sulfate SO_4^{--}		330	6.9	
Total Hardness		44.5		
Calcium Ca^{++}		9.0	0.45	
Magnesium Mg^{++}		5.3	0.44	
Sodium Na^{++} +k+		1836	79.8	
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		0.4		
Manganese, Mn		0.0		
Dissolved Solids		5110		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with APHA and API Recommendations

Bio-Chem Consulting
SERVICES LTD

WATER QUALITY REPORT

Date Sept. 28/8
Project No. 960
Report No. 960-5

Sampled Sept. 22/82 Date Recieved Sept. 23/82

Company Omega Hydrocarbon
Address Waskeda
Sample Point Alida 4-30-1-25
Appearance

	Reading	mg/l	meq/l	Remarks
pH	7.6			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		280	4.6	
Chloride Cl^-		44000	1239	
Sulfate SO_4^{--}		4200	87.5	
Total Hardness		4750		
Calcium Ca^{++}		950	47.5	
Magnesium Mg^{++}		570	47.5	
Sodium Na^{++} +k+		28430	1236	
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		1.2		
Manganese, Mn		0.2		
Dissolved Solids		78410		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with A P H A and A P I Recommendations.

Bio-Chem Consulting SERVICES LTD

WATER QUALITY REPORT

Date Sept. 28/8
Project No. 960
Report No. 960-6

Date Sampled Sept. 22/82 Date Recieved Sept. 23/82
Company Omega Hydrocarbon
Address Waskeda
Sample Point Tilston 16-13-1-26 Produced Water
Appearance

	Reading	mg/l	meq/l	Remarks
pH	7.3			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		170	2.79	
Chloride Cl^-		130000	3662	
Sulfate SO_4^{--}		2600	54.2	
Total Hardness		9500		
Calcium Ca^{++}		1800	90	
Magnesium Mg^{++}		1200	100	
Sodium Na^{+} +k+		81167	3529	
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		3.2		
Manganese, Mn		0.35		
Dissolved Solids		215838		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with APHA and API Recommendations

Bio-Chem Consulting
SERVICES LTD

WATER QUALITY REPORT

Date Sept.28/82
Project No 960
Report No 960-7

Sampled Sept. 22/82 Date Recieved Sept. 23/82
Company Omega Hydrocarbon
Address Waskeda
Sample Point Spearfish 16-11-1-26 Produced Water
Appearance

	Reading	mg/l	meq/l	Remarks
pH	7.4			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		140	2.3	
Chloride Cl^-		64000	1803	
Sulfate SO_4^{--}		3900	81.3	
Total Hardness		6290		
Calcium Ca^{++}		1400	70	
Magnesium Mg^{++}		670	55.8	
Sodium Na^{++} +k+		40498	1761	
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		5.0		
Manganese, Mn		0.95		
Dissolved Solids		110486		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with A P H A and A P I Recommendations

Geo-Chem Consulting

SERVICES LTD

WATER QUALITY REPORT

Date Sept.28/82

Project No 960

Report No 960-8

Date Sampled Sept. 22/82 Date Recieved Sept.23/82

Company Omega Hydrocarbon

Address Waskeda

Sample Point 11-30-1-25 Disposal Well Pump to Disposal Well.

Appearance

	Reading	mg/l	meq/l	Remarks
pH	7.2			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		200	3.3	
Chloride Cl^-		54000	1521	
Sulfate SO_4^{--}		4400	91.7	
Total Hardness		4415		
Calcium Ca^{++}		1000	50	
Magnesium Mg^{++}		460	38.3	
Sodium Na^{++} +k+		35137	1528	
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		9.1		
Manganese, Mn		0.75		
Dissolved Solids		95190		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with A.P.H.A. and A.P.I. Recommendations

uic-chem consulting
SERVICES LTD

WATER QUALITY REPORT

Date Sept. 28/8

Project No 960

Report No 960-9

e Sampled Sept. 22/82 Date Recieved Sept. 23/82

Company Omega Hydrocarbon

Address Waskeda

Sample Point Treater B (Prod. Water from the Three Producing Zones)

Appearance

	Reading	mg/l	meq/l	Remarks
pH	7.6			
Specific Conductance				
Turbidity				
Hydroxide OH^-		0	0	
Carbonate CO_3^{--}		0	0	
Bicarbonate HCO_3^-		260	4.3	
Chloride Cl^-		62000	1746	
Sulfate SO_4^{--}		4200	87.5	
Total Hardness		5875		
Calcium Ca^{++}		1200	60	
Magnesium Mg^{++}		690	57.5	
Sodium Na^{++} +k+		39567	1720	
Hydrogen Sulfide H_2S				
Total Sulfides				
Total Iron Fe		1.9		
Manganese, Mn		0.5		
Dissolved Solids		107183		
Total Solids				
Suspended Solids				
Oils and Greases				
Ammonia NH_4				
Phenols				
Dissolved Carbon Dioxide CO_2				
Dissolved Oxygen O_2				
COD				
BOD 5 day				
TON				

Comments

Methods in Conformance with A P H A and A P I Recommendations

9.0 FILTERABILITY TEST

a) Spearfish Producing Zone Water

time (sec.)	Filtered Volume
3	20 ml
6	40 ml
10	60 ml
13	80 ml
15	100 ml
18	120 ml
22	140 ml
24	160 ml
28	180 ml
31	200 ml
↓	
12 min.	

Suspended Solids 14 mg/l

- iron sulfide + sand + salt + salt crystals

b) Tilston Producing Zone Water

time (sec.)	Filtered Volume
6	20 ml
12	40 ml
18	60 ml
24	80 ml
30	100 ml
36	120 ml
42	140 ml
48	160 ml
54	180 ml
60	200 ml
↓	
10 min.	

Suspended Solids 21 mg/l

- iron sulfide + sand + salt + salt crystals

FILTERABILITY TEST (cont'd)

c) Blairmore Zone Water

time (sec.)	Filtered Volume	
6	20 ml	Suspended Solids 1.3 ml/1
12	40 ml	
19	60 ml	- rust brown deposit, granular in nature
26	80 ml	
34	100 ml	
42	120 ml	- O_2 content = 0.5 ppm
49	140 ml	

d) Alida Zone Water

Millipore filter studies could not be undertaken due to quantity of oil in system.

Suspended Solids = 510 ppm

Deposit = coal like appearance (large chunks) + sand and salt crystals. Solids concentrate at interface of oil/water.

e) Disposal System (1-30-1-25)

time (sec.)	Filtered Volume	
20	20 ml	Suspended Solids 330 mg/1
48	40 ml	
116	60 ml	- sand + silt + salt crystals
257	80 ml	
310	100 ml	- O_2 = 0.7 ppm
		- H_2S < 1%
		- CO_2 = 150 ppm

FILTERABILITY TEST (cont'd)

e) Treater Water

Suspended solids content = 61.4 mg/l

Deposit = dark grey/black color, uniform,
iron sulfide + sand + silt + salt crystals.

File "General Correspondence
Waskada Lower Amaranth Unit
No. 1

March 16, 1983

Omega Hydrocarbons Ltd.
630 - 330 - 5th Ave. S.W.
Calgary, Alberta
T2P 0L4

Attention: Mr. Ed Wyse

Dear Ed:

Waskada Lower Amaranth Unit No. 1

With reference to correspondence between Omega and the Branch, regarding the subject Unit and pilot waterflood scheme, we note that the following items remain outstanding:

1) Results of compatability tests on Lower Amaranth and Swan River waters (reference - Point 2d of your letter of June 28, 1983).

2) Report on special core studies to be performed by Core Laboratories on the oil base core from the well Omega Waskada 3-25MCa-1-25 (WPM) (reference - Point 3d of your letter of June 28, 1983).

3) Plans to obtain flash liberation data from a recombined sample of reservoir fluids (reference - Point 4 of your letter of August 9, 1983).

We request that you inform us as to the status of these items at your earliest convenience.

In addition, we request that you submit your plans to obtain at least one spinner survey on an injection well within the first year of the pilot operation (reference - Point 1e of your letter of August 9, 1982).

Also, I would like to draw your attention to a typographic error in Board Order No. PM39 Clause 6(1) should read " - - a report of the quantity, source and pressure - -".

Yours sincerely,

Original Signed By
L. R. DUBREUIL

L. R. Dubreuil
Chief Petroleum Engineer
Petroleum Branch

LRD/sb

HYDROCARBONS Ltd.
TELEPHONE: (403) 261-0743 630 - 330 FIFTH AVENUE S.W., CALGARY, ALBERTA T2P 0L4

February 22, 1983

DEPT. OF ENERGY AND MINES
FEB 24 1983
PETROLEUM BRANCH

Petroleum Branch
Department of Energy & Mines
975 Century Street
Winnipeg, Manitoba
R3H 0W4

Attention: Mr. Bob Dubreiul

Dear Sir:

RE: Waskada Pressure Surveys
15-24, 2-25 and 3-25-1-26 WPM

Enclosed herewith are the pressure survey reports recently completed at Waskada and promised in my January 24 letter.

In addition the following additional production testing on unit wells has been done:

1) 9-24-1-26 WPM

Jan. 17, 1983	Hrs: 24	Oil: 4.80 m^3	Water: 1.00 m^3
Jan. 18, 1983	Hrs: 24	Oil: 1.20 m^3	Water: 0.10 m^3
Jan. 19, 1983	Hrs: 24	Oil: 2.70 m^3	Water: 0.10 m^3
Jan. 30, 1983	Hrs: 24	Oil: 0.80 m^3	Water: 0.10 m^3
Jan. 31, 1982	Hrs: 24	Oil: 1.50 m^3	Water: 0.10 m^3

2) 12-24-1-26 WPM

Feb. 3, 1983	Hrs: 24	Oil: 10.30 m^3	Water: 0.10 m^3
Feb. 4, 1982	Hrs: 24	Oil: 10.30 m^3	Water: 0.10 m^3

3) 1A-25-1-26 WPM

Jan. 20, 1982	Hrs: 24	Oil: 42.34 m^3	Water: 1.76 m^3
Jan. 29, 1983	Hrs: 24	Oil: 22.32 m^3	Water: 0.50 m^3
Feb. 11, 1983	Hrs: 24	Oil: 18.79 m^3	Water: 0.38 m^3

The only unit oil wells that have as yet not been tested are

2-25 and 3-25-1-26 WPM. These tests will be forwarded as soon as they become available.

Yours truly,

OMEGA HYDROCARBONS LTD.

Ed Wyse
Petroleum Engineer

EW/sp

Encl.