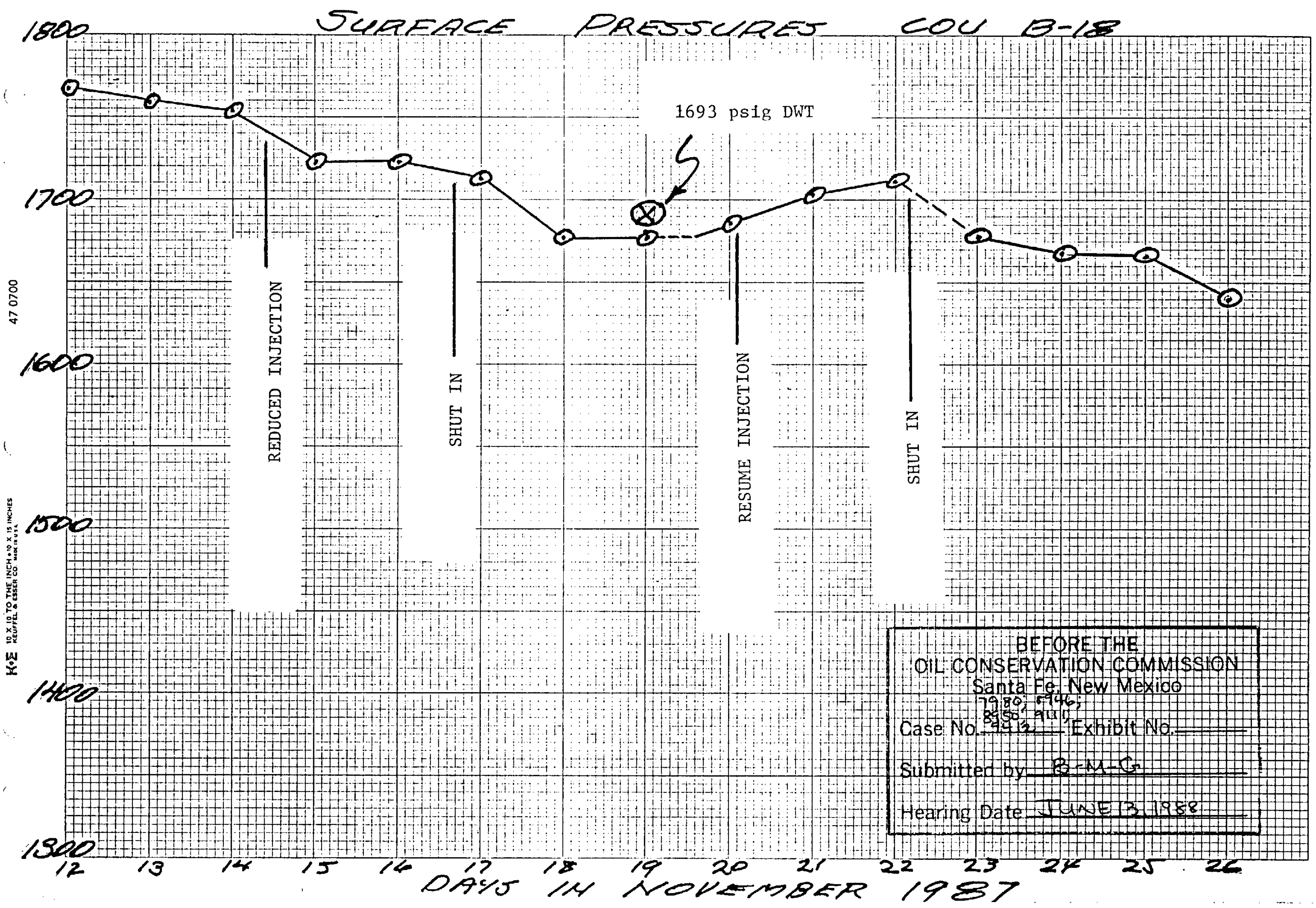
MK. LEMAY

SURFACE PRESSURES
C.O.U B-18
Part of November, 1987

DATE	STATUS	METER PRESSURES* STATIC	PSIA	PSIG	DEAD WEIGHT PRESSURE
Nov. 12	Injecting	7.70	1779	1768	
Nov. 13	Injecting	7.68	1770	1759	
Nov. 14	Injecting	7.67	1765	1754	
Nov. 15	Injecting (Small Vol.)	7.60	1733	1722	
Nov. 16	Shut in	7.60	1733	1722	
Nov. 17	Shut in	7.58	1724	1713	
Nov. 18	Shut in	7.50	1688	1677	
Nov. 19	Shut in	7.50	1688	1677	1693
Nov. 19	9:00 AM Start Inj.				
Nov. 20	Injection (Small Vol.)	7.52	1697	1686	
Nov. 21	Injection (Small Vol.)	7.52	1715	1704	
Nov. 22	Injection (Small Vol.)	7.58	1724	1713	
Nov. 22	12:00 N (Shut in)				
Nov. 23	Shut in	7.50	1688	1677	
Nov. 24	Shut in	7.48	1678	1667	
Nov. 25	Shut in	7.48	1678	1667	
Nov. 26	Shut in	7.42	1652	1641	
Nov. 27	Shut in	7.43	1656	1645	
Nov. 28	Shut in	7.43	1656	1645	

* 3000# spring: PSIA = $(\text{static})^2 \times 30$

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7980, 8946; 8950; 9111; 9412 Exhibit No. 4
Submitted by B-M-G
Hearing Date June 13, 1988



BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 7980, 6946, 8950, 9411, 9412 Exhibit No. ______

Submitted by B-M-G

Hearing Date JUNE 13, 1988

Effective Displacement of Oil by Gas Injection in a Preferentially Oil-Wet, Low-Dip Reservoir

Jaffar A.N. Shehabi, SPE-AIME, The Bahrain National Oil Co.

Introduction

Gas injection as a means of maintaining pressure and improving oil recovery has been employed in the Bahrain field Second Pay Limestone B reservoir for the last 39 years. This reservoir is oil-wet. Maintaining reservoir pressure was the primary objective in the beginning. The pressure response was almost immediate and probably conformed very closely to a simple material balance, because all producing zones on the highly faulted Bahrain structure were still close to virgin conditions.

Early gas breakthrough became a matter of concern with respect to total field productivity and ultimate recovery. However, wells in the gas area were kept on production, at an optimum rate governed by tubing submergence. It gradually was realized that even with early breakthrough, a satisfactory oil recovery factor was being obtained. Attention then focused on determining actual recovery and explaining the mechanism involved.

The most recent reservoir study showed a 50% recovery factor in the gas-invaded volume, as compared to 20 to 25% in the water-invaded volume. It also was found that because of fluid transfer to other zones, the required injection rate for the Limestone B is 70,000 Mcf/D (1.98×10^6 m^3/d) instead of the 40,000 Mcf/D (1.13×10^6 m^3/d) calculated for the Limestone B alone.

0149-2136/79/0012-7652$00.25

This paper describes some pertinent aspects of the reservoir, the gas injection program, and the methods used to calculate the recovery factor.

Reservoir Description

The Bahrain field structure is a highly faulted, elongated anticline (Fig. 1). Structural dips in the oil-producing horizons are in the order of 5°. The Bahrain zones, of middle Cretaceous age, are the most important oil-producing group found in this field. They are divided into eight separate zones, with zonal separation varying from 7 to 50 ft (2.13 to 15.24 m). Three types of lithology are present: limestone, siltstone, and sandstone. At the crest of the structure, the gross productive interval was 525 ft (160 m) and original net oil pay thickness was 325 ft (99 m).

The most important zone within this group, and the subject of this paper, is the Second Pay Limestone B. The reservoir rock is a soft, porous, sugary limestone with limited fractures and vugs. Gross thickness varies slightly from 102 to 116 ft (31 to 35.4 m), all of which is considered net pay. Average porosity and permeability are 25% and 62.8 md, respectively. There are no impermeable streaks to affect vertical permeability. The middle 50 ft (15.24 m) has the highest porosity and permeability. The basal 30 to 40 ft (9.14 to 12.19 m) is slightly different in character and appears to have a lower specific productivity index. Fig. 2 shows the porosity

109' x 62.8 md → 6.8 darcy feet

Gas injection as a means of pressure maintenance has been employed in the Bahrain field Second Pay Limestone B reservoir for the last 39 years. This paper describes aspects of the gas injection program and the method used to calculate recovery of oil by gas, which has been found to be much greater than that by water drive.

profile, and Fig. 3 shows type log. Average initial water saturation was 6% in the upper section and 11% in the basal section. Previous laboratory work led to the conclusion that the reservoir rock was preferentially oil-wet. For wettability determination, two plugs were cut from preserved core samples: one sample was flooded with brine until a minimum oil saturation was obtained; the other sample was flooded with oil until a minimum water saturation was obtained. The sample with minimum oil content was allowed to imbibe oil spontaneously; the sample with minimum water content was allowed to imbibe water spontaneously. The two volumes of imbibed fluids were measured periodically.

The reservoir oil was highly undersaturated, having a saturation pressure of 358 psig (2468 kPa) as compared to the original reservoir pressure of 1,236 psig (8522 kPa) at 1,900 ft (579 m) subsea. The oil has a solution gas/oil ratio (GOR) of 128 scf/STB (22.8 std m^3/stock-tank m^3) and a density of 0.8556 g/cm^3. Since this is an old reservoir, very limited information is available on virgin parameters, such as viscosity.

The productive limits of the Limestone B reservoir, approximately 8.5 miles (13.7 km) long $\times$ 3 miles (4.8 km) wide, encompassed 13,750 acres ($55.640 \times 10^6 m^2$) and contained almost 2 billion STB (318×10^6 stock-tank m^3) original oil in place (OOIP). Cumulative production as of Jan. 1, 1972, was 283 million STB (45×10^6 stock-tank m^3) oil and 79 million STB (12.6×10^6 stock-tank m^3) water. Cumulative gas injected up to Jan. 1, 1972, was 206,433 MMcf (5.8×10^9 m^3).

Gas-Injection History

The first well tapped oil from this zone at 1,236 psig (8522 kPa) in 1932. By Feb. 1938, after only 14 million STB (2.22×10^6 stock-tank m^3) or 0.7% OOIP had been produced, reservoir pressure had declined by 118 psig (813 kPa). High-pressure nonassociated Arab zone gas was readily available for injection into the Limestone B without requiring compression. Thus, the gas injection program to maintain pressure was initiated in April 1938. The Arab gas was relatively rich and was injected without prior processing for liquid recovery. A total of 189,000 MMcf (5.4×10^9 m^3) Arab gas had been injected by April 1974, at which time it was totally replaced by the much leaner and more abundant Khuff zone gas. Up until the discontinuation of Arab gas injection, some 74,383 MMcf (2.1×10^9 m^3) Khuff gas also had been injected.

Limestone B injection was suspended temporarily from May 1962 to Jan. 1965 while continuing to inject the lower siltstone zones. The purpose was to observe reservoir pressure behavior of the lower zones in the absence of injection into the Limestone B. The reservoir pressure of both the siltstone zones and the Limestone B declined rapidly at about the same rate, proving fairly conclusively that reservoir communication existed. As a result, continued gas injection into the Bahrain zones was solely into the Limestone B.

Transfer of fluids from the Limestone B to the underlying and overlying formations prior to 1962 is believed to have been minimal or nonexistent,

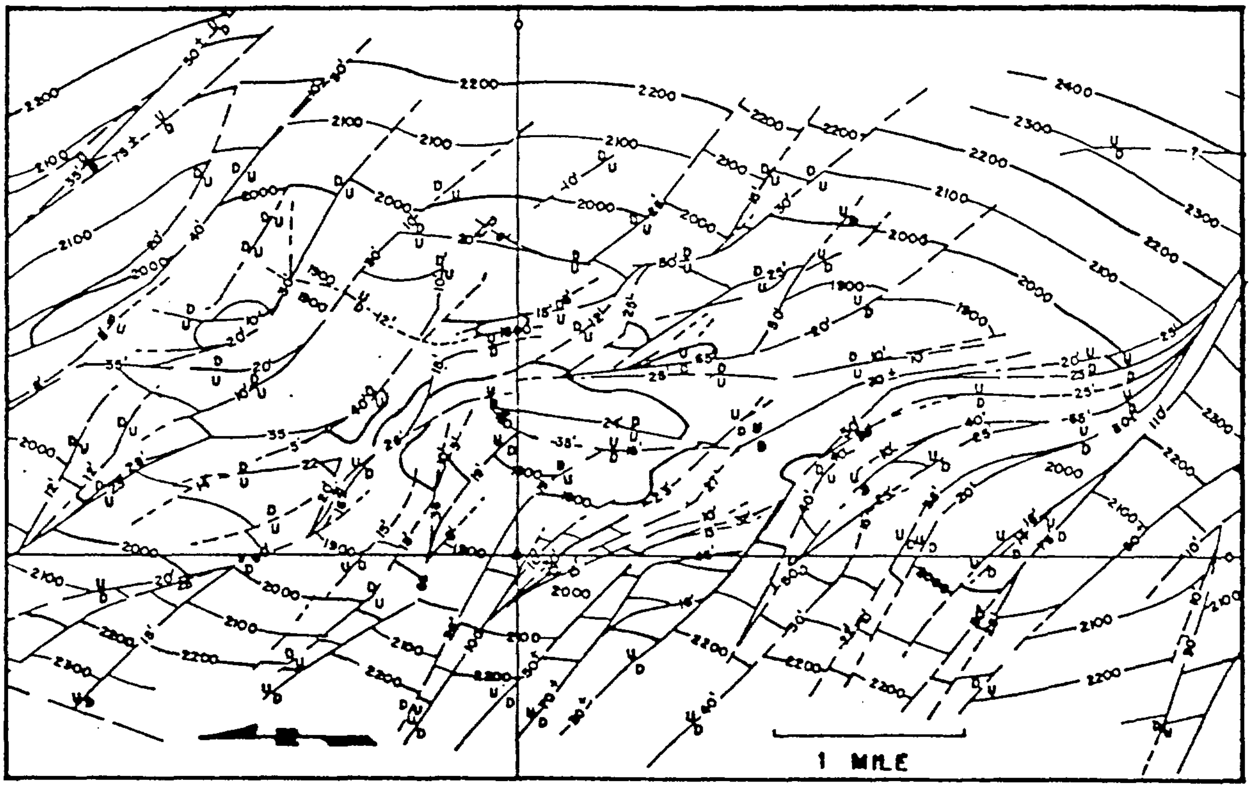


Fig. 1 – Structure map of Second Pay Limestone B.

because pressures were compatible. In subsequent material balance studies, it was found that recovery efficiency by gas was more than 50%. This indicates fluid transfer due to the decline in pressure in the underlying and overlying formations.

Subsequent production behavior of the individual zones has conclusively proved that the Limestone B is only one part of a unit that also includes the overlying sandstone and the underlying siltstones. This conclusion is important from the standpoint of determining injection rate requirements and explaining anomalously high recovery factors that could be calculated for any of these zones if they were treated as an entity. Examples are given later in the text. Overall recovery factor on a unit basis is probably in line with industry published data.

Another interesting aspect of the injection suspension period is the appearance of water cuts in the higher structural row of Limestone B wells and the regression of this water shortly after gas injection was resumed. Fig. 4 shows the fieldwide extent of this occurrence. Fig. 5 shows the recent pressure and production history of the Limestone B. In this figure as well as in subsequent figures, early history was not included, because very few recovery calculations were made before 1960.

Recovery Mechanism

In order to analyze the recovery mechanism and calculate reserves, the Limestone B was subdivided into north, central, and south areas. Major faults that would prevent further expansion of the gas cap in a north-south direction helped to define the individual areas (Fig. 4). The north and south areas have been under the influence of an active water drive, whereas the central area has a combination of gas-cap drive, gravity drainage, and water drive.

The material balance calculations made in 1954 and 1959 following neutron surveys indicated a 50% recovery efficiency. In 1972, Laterolog surveys behind the water front indicated a 20% displacement efficiency by water.

In the 1972 study, a cutoff had to be chosen in order to calculate the fluid transfer to other zones. Thus, 50% and 20% recovery efficiencies by gas and water, respectively, were chosen. Gravity drainage was not quantified and was assumed to be an integral part of the 50% recovery factor.

Central Area

Ultimate recovery in the central area is estimated to be 29.7%, resulting from a combination of gas displacement, gravity drainage, and displacement by water. Recovery efficiency in the gas-invaded volume is 50% as compared to 20 to 25% in the water-invaded volume. Therefore, the objective is to continue gas injection at an optimum rate until a practical maximum growth of the gas cap is reached. The optimum rate is defined as the rate that will maintain reservoir pressure with zero net water influx. Because of fluid transfer from the Limestone B to other zones, the current optimum injection rate actually required is much higher than theoretically required – 66,000 to 70,000 Mcf/d (1.87 to 1.98 ×

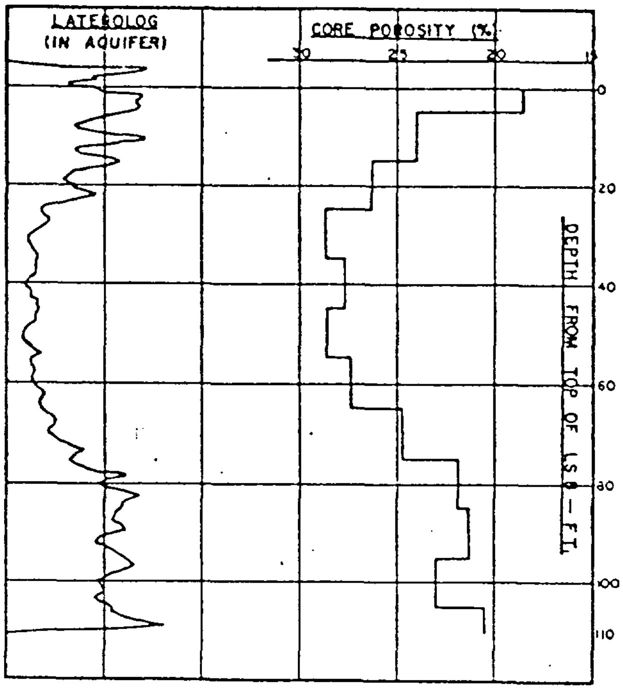


Fig. 2 – Porosity distribution in Second Pay Limestone B.

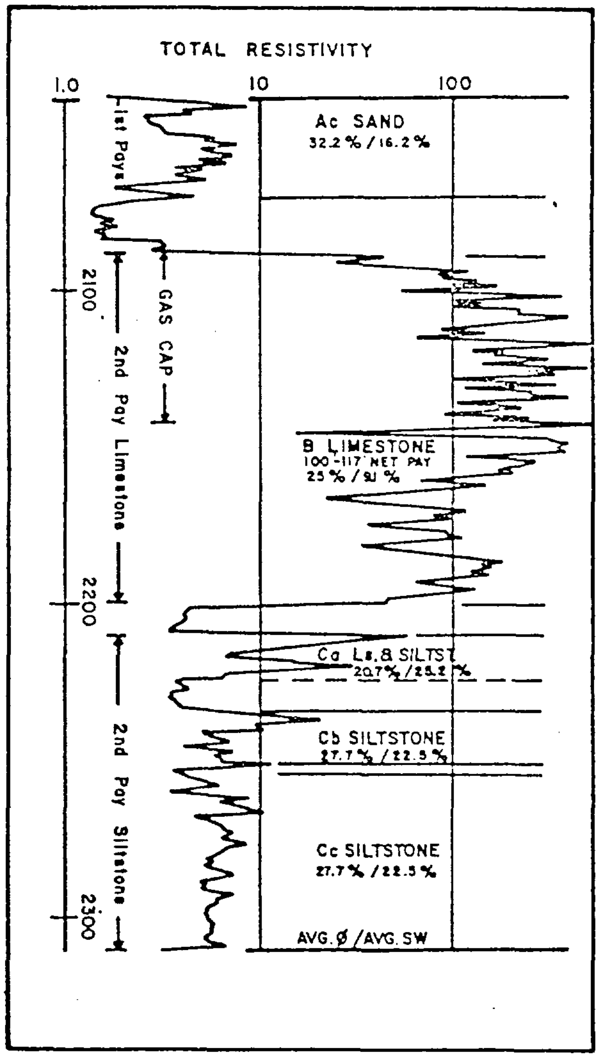


Fig. 3 – Type log showing Second Pay Limestone B with the overlying and underlying zones.

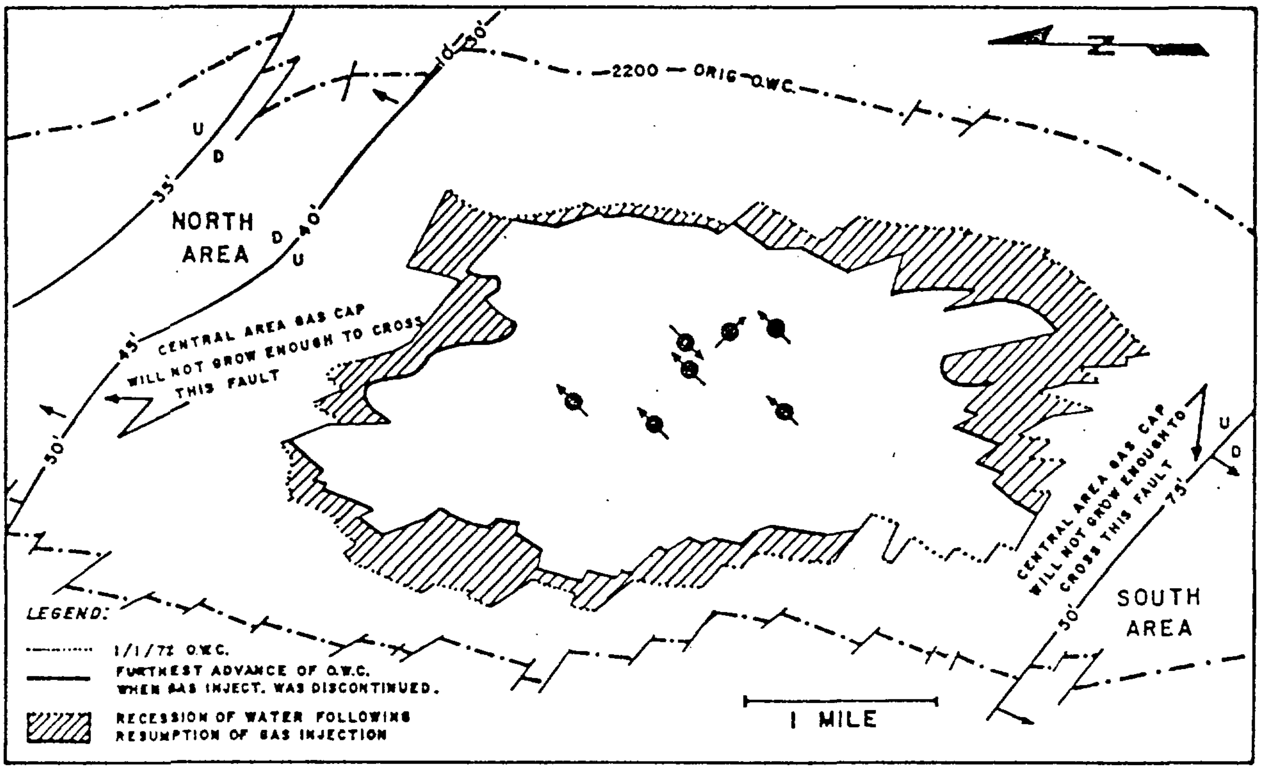


Fig. 4 – Effect of resumption of gas injection.

10^6 m^3/d) vs approximately 37,000 to 40,000 Mcf/D (1.05 to 1.13 × 10^6 m^3/d).

A study of actual experience shows that excessive gas injection rates into this particular pore geometry and rock wettability can displace encroached water back toward the aquifer, thus reducing water cuts to some extent. This unique effect was used to temporarily increase Limestone B oil production rates.

A strong gravity override influence, mainly in the direction of the east and west flanks, will limit the ultimate volume contacted by gas. After 33 years of injection, 63% of original HCPV actually had been "contacted" by gas. Gravity underride also is evident in the water-encroached volume. Approximately 25% of original HCPV has been contacted by water.

Qualitatively speaking, production data suggest that the critical rate with gas displacement is very low compared with that in the case of water displacement. This is because of the higher mobility of the gas. Because of the low dip and high vertical permeability, even with water the critical rate is low.

Fig. 6 may be useful in the case of gas displacement. However, note that very little theoretical work was done to predict such rates; the performance of the reservoir was relied upon greatly.

The water influx into the Limestone B central area has been greatest at the north and south ends because of long distances from gas injection wells at the crest of the formation. It seems overall effectiveness of gas injection can be improved by providing gas injection points closer to the north and south ends of the central area. Dispersion of the gas injection has been started in a southerly and northerly direction.

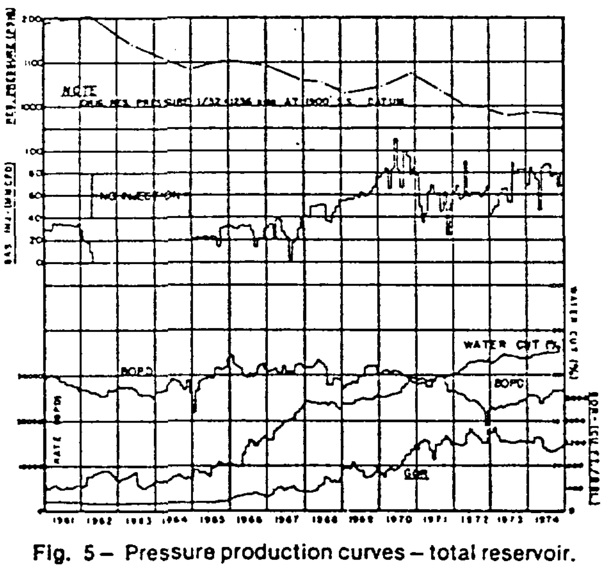


Fig. 5 – Pressure production curves – total reservoir.

Areal Pressure Distribution

Gas injection for pressure maintenance in this anticlinal reservoir has been used successfully, and the rates of injection have been increased from time to time with planned increments of oil withdrawal (Fig. 5). As the injected gas front receded from the crest, the off-take points gradually concentrated downstructure between the gas- and water-drive influences. As the gas-injection program progressed, completions in the Limestone B either were shut in or abandoned to prevent excessive production of gas. Such completions had been produced as long as possible by submerging the tubing below the liquid level in the wells and reducing the production rates.

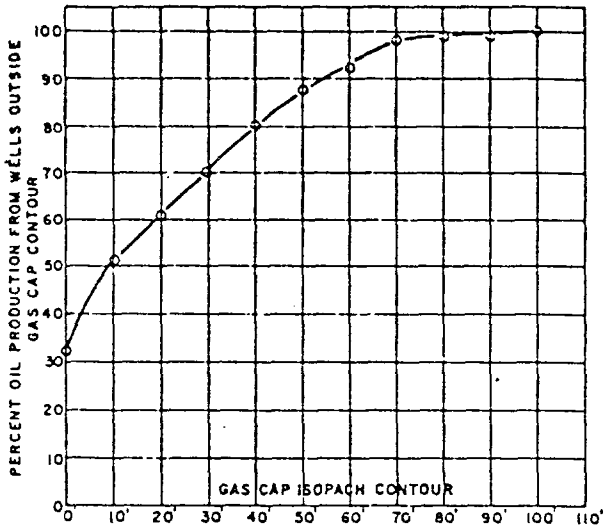


Fig. 6 – Distribution of oil production with respect to gas-cap thickness.

By the end of 1956, as a result of this action, very little oil was being produced from below the gas cap, the main withdrawal having been established around the lateral perimeter of the cap. As of Jan. 1, 1973, over 60% of the central area production came from the area having 20 ft (6 m) or less gas-cap thickness (Fig. 6). A further consequence of this change in oil-withdrawal pattern was a change in the pressure pattern of the reservoir. Before the commencement of gas injection, the lowest pressures were found in the central portion of the reservoir, but as withdrawal moved out with the expansion of the gas cap, the lowest pressures were transferred to the line of greatest production. This resulted in the formation of a "pressure trough" between the gas-invaded area and the aquifer perimeter (Fig. 7). The circumference of the pressure trough increased with the expansion of the gas cap and the resultant outer movement of oil withdrawal from the center of the reservoir. The effect of this low-pressure ring on the gas-cap shape will be considered at a later stage.

North and South Areas

With the present gas injection pattern, there is no chance of creating gas caps in the north and south areas. Water drive, with low recovery efficiency, is the predominant displacement mechanism in these areas. As of Jan. 1, 1972, there were 69 million STB (11×10^6 stock-tank m^3) in place above the oil/water contacts in these areas.

Recent production history is shown in Fig. 8 (north area) and in Fig. 9 (south area). Current production in the north area is 2,950 BOPD (469 m^3/d oil) with 87% water cut. Current production in the south area is 3,050 BOPD (485 m^3/d oil) with 81% water cut.

Plots of water cut vs cumulative oil production were used to determine ultimate oil recovery in each area. The ultimate recovery factors were determined to be 7% in the north area and 9.4% in the south area. These appeared reasonable when compared with breakthrough recovery factors determined by volumetric balance.

The low recovery factors result from a combination of inherently low recovery efficiency by water displacement (20%) and movement of oil from these downstructure to upstructure areas. Movement

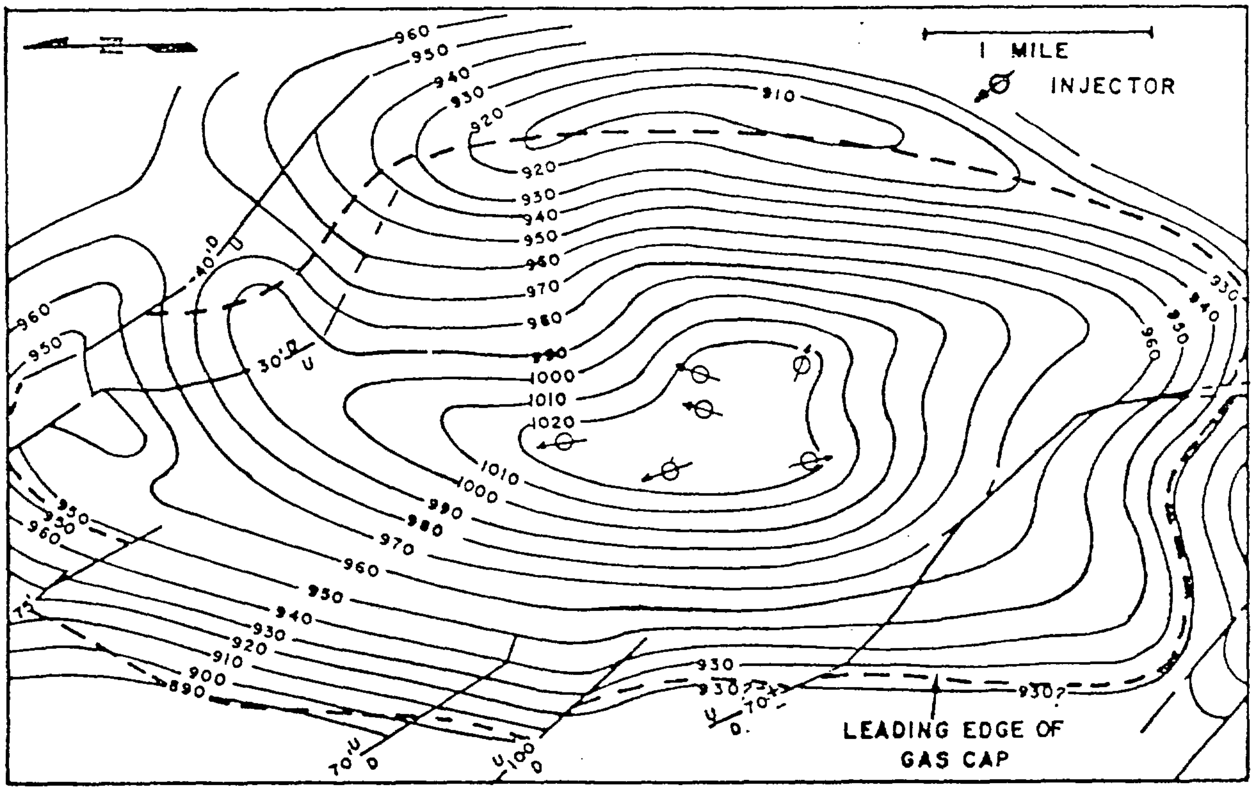


Fig. 7 – Isobaric map (psi).

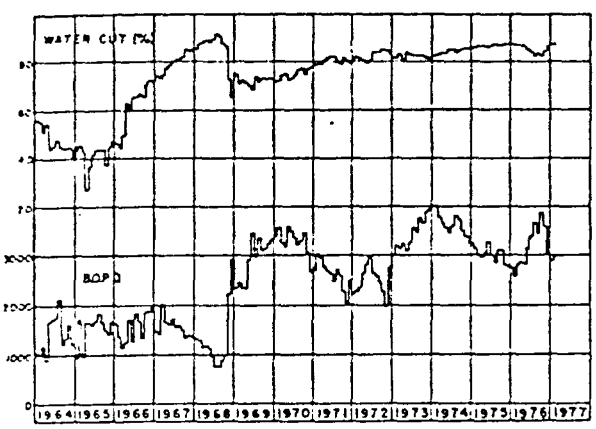


Fig. 8 – Production history of north area.

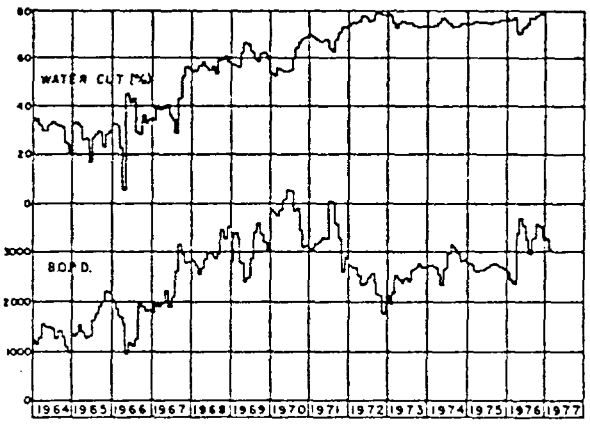


Fig. 9 – Production history of south area.

of oil from the south area is more restricted because of the larger faults present in the south. This is reflected in the slightly higher recovery factor.

With increased gas injection rates, it appears that flow across the faults separating north and south areas from the central area has been reversed. The right-hand portion of Fig. 10 indicates that oil is being transferred to the north and south areas.

Recovery Factor Calculation in the Central Area

The neutron log proved a very useful tool in the recovery factor calculations, with the complex structure and production history of the Limestone B and with the attendant gas override and water underride. A horizontal oil/gas interface need not be assumed, because a carefully designed neutron survey of selected wells would make it possible to generate a gas-cap isopach map (Fig. 11). A volumetric material balance approach then is used to compute the recovery factor in the gas cap. A sample recovery calculation appears as Table 1.

Several neutron surveys were run in the gas-cap area, and each time a recovery factor in the gas cap was calculated. The average recovery for these surveys was 50% (Fig. 12). These calculations proved beyond any doubt that oil recovery by gas is much better than by water in the Limestone B reservoir. This is thought to result from a combination of more than one of the following:

1. Recovery by gas was enhanced by the miscible action of liquids entrained in the injected gas.
2. Arab gas going into solution enhanced the oil mobility.
3. The Limestone B reservoir rock may be oil wet because: (1) laboratory analysis showed a high degree of oil wettability in cores taken from the reservoir;[1] (2) the Laterolog shows the upper portion of the section to have extremely high resistivity, which indicates calculated water saturations of less than 6% (Fig. 13); and (3) excessive gas injection rates can displace encroached water back toward the aquifer

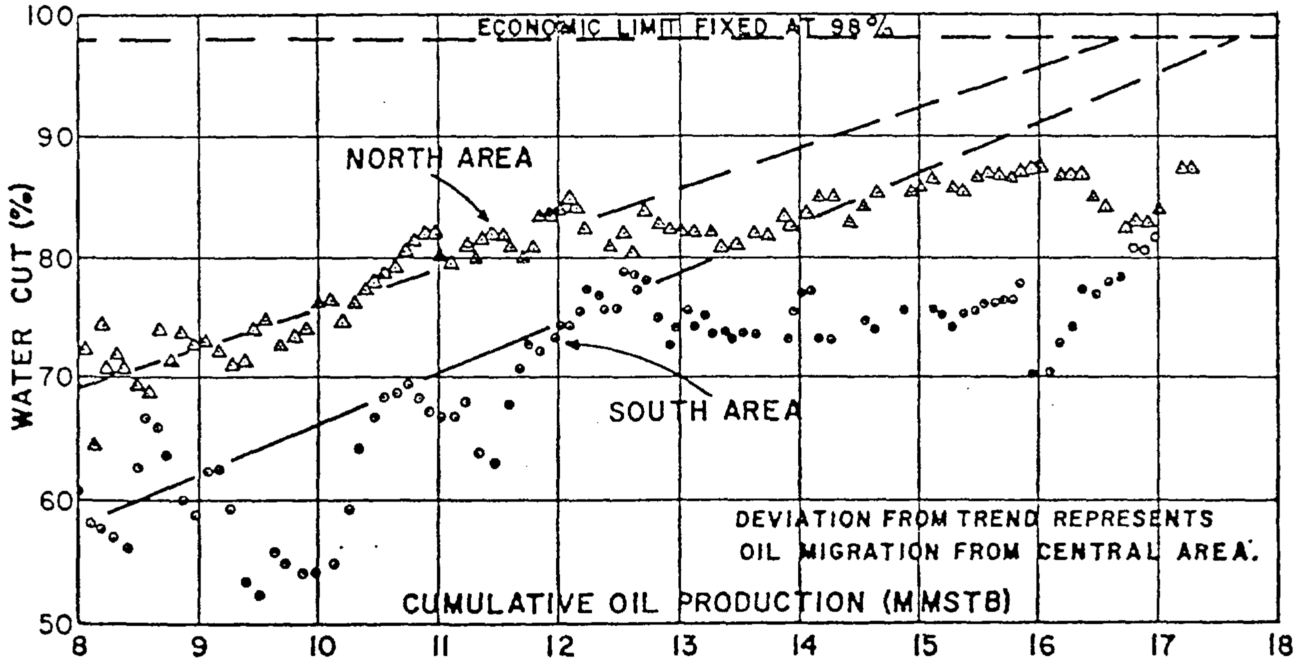


Fig. 10 – Cumulative oil production vs water cut.

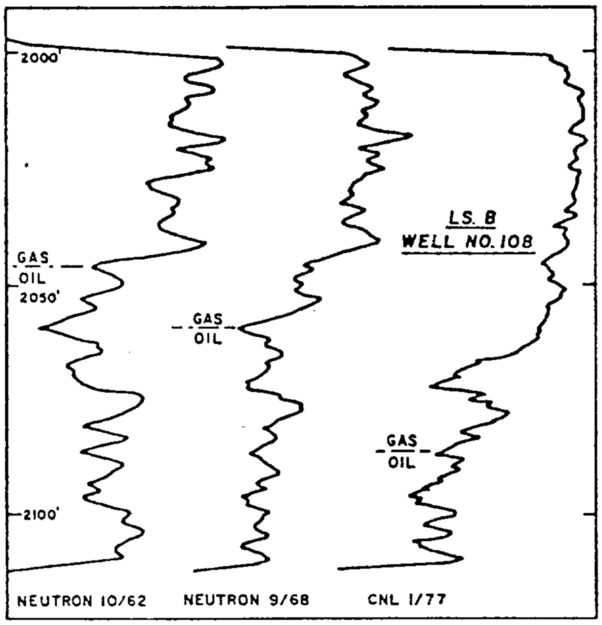


Fig. 11 – Monitoring gas-cap advance by neutron logs.

and reduce or even eliminate water cuts (a case in point is Well 253 where the water cut was as high as 50% and is now zero).

4. Gravity drainage also enhanced the recovery in spite of the low dips in the reservoir rock. The structure is highly faulted and allows Limestone B oil to drain further into underlying pay zones, especially because the pressure in these zones is lower.

Hence, the homogeneous characteristics of the zone, the pressure differential that exists between this zone and the underlying zones, and the communication between these zones by virtue of juxtaposition all contribute to a very effective gravity drainage from the Limestone B (Fig. 14).

Recent Investigations

Injected Gas Quality

Up to 1974, rich unstripped gas [15 to 20 bbl condensate/MMcf gas (84 to 112 m^3 condensate/10^6 m^3 gas)] had been injected into the Limestone B. Subsequently, leaner Khuff gas has been used for injection.

One may wonder what effect this leaner gas has on recovery. The problem was approached as if phase equilibria were the only factor affecting recovery.

The tool used in this investigation has been a flash computer program. Starting with the analyses of both the Arab gas and the crude oil, the composition of the gaseous and liquid phases in the gas cap was computed. The computation then was repeated using Khuff gas. Then the reservoir pressure was altered to see whether the Khuff gas displacement efficiency could match that of Arab gas. This investigation revealed that: (1) Khuff gas causes 8.5% less initial oil swelling than Arab gas; (2) further injection of 1 PV Khuff gas causes a 2.2% shrinkage whereas 1 PV Arab gas causes an additional 4.9% swelling; (3) the oil phase is stripped of much of its light ends when Khuff gas is used, thus becoming less mobile; and (4) a reservoir pressure increase of some 200 psi (1378 kPa) is necessary to offset the drawbacks resulting from use of a leaner gas.

One asset of Khuff gas is its high CO_2 content (6%), since CO_2 is known to enhance recovery by improving microscopic displacement efficiency of oil. However, this factor was not considered here.

In fact, the results of such investigation will be used only qualitatively, since miscible displacement/phase equilibria is not the sole factor affecting recovery and its relative contribution to recovery is not known.

Most of the PVT data available is for reservoir oil being displaced by Arab gas. No PVT data with Khuff gas is available. However, viscosity was not measured when the reservoir fluid was contacted by Arab gas. Whenever such viscosity is required, Beal's correlation tables are used, the reservoir fluid having these properties: viscosity = 2.08 cp at 136°F (2.08 kPa·s at 58°C), bubble-point pressure = 358 psig (2468 kPa), density = 33.5°API (847 mg/cm^3), and formation volume factor = 1.13. Viscosity of reservoir fluid in contact with Arab gas is computed to be 1.1 cp (1.1 kPa·s). Thus, the lowering of viscosity has been helpful in increasing the rate of gravity drainage.

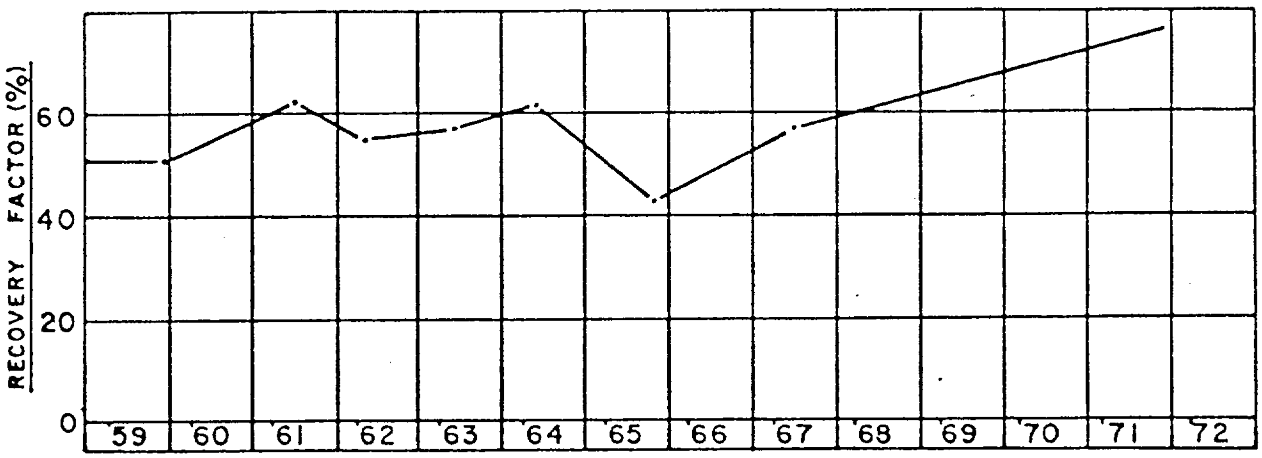


Fig. 12 – Oil recovery factors by gas displacement (based on data obtained from neutron and pressure surveys).

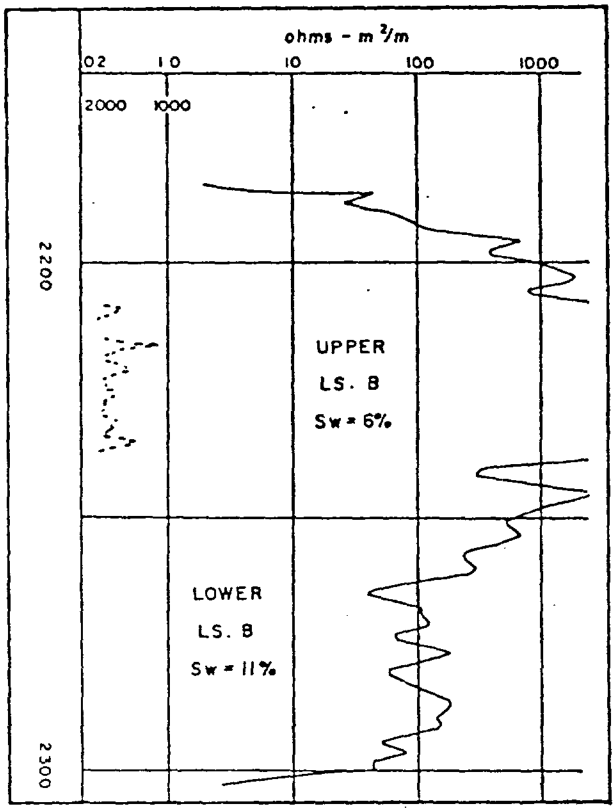


Fig. 13 – Typical Laterolog of Limestone B original oil column.

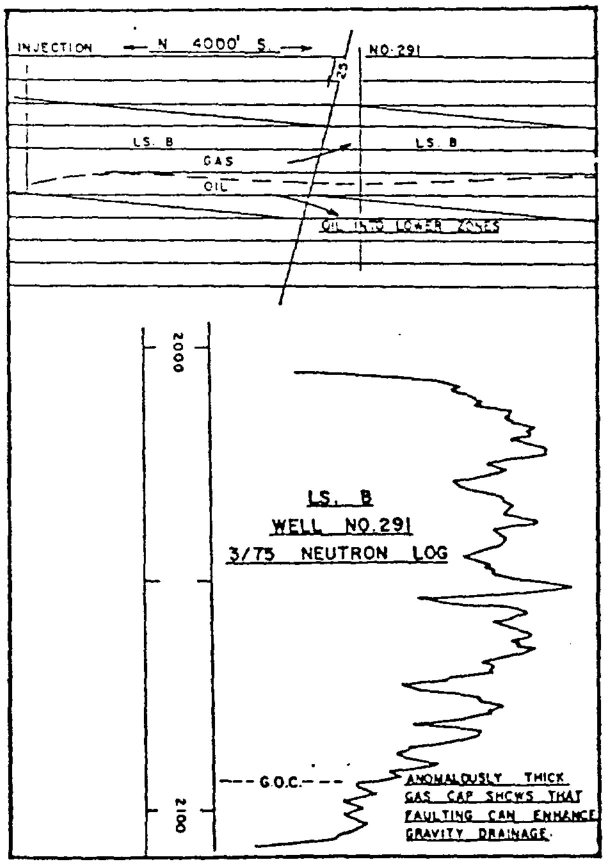


Fig. 14 – Schematic diagram showing enhancement by gravity drainage.

Residual Oil Saturation Profile

It was envisaged that gravity drainage would cause a saturation profile extending from a very low oil saturation at the crest of the structure, where the oil has been contacted by a large number of pore volumes of gas, to a high oil saturation near the gas/oil contact, where the oil has been contacted by only a few pore volumes of gas. Thus, what is calculated as 50% recovery efficiency is merely a reflection of this saturation profile. There is no theoretical reason that, in this highly oil-wet reservoir, residual oil saturation cannot be reduced to a very low figure.

It also appears that gravity drainage may lead to a vertical saturation profile in any well in the gas cap. The logging company has been asked to use its computer program to split the hydrocarbon saturation into gas and oil saturations so that the displacement efficiency can be calculated. To do that, the lithology and gas and oil densities at reservoir conditions had to be provided. It might be possible to extend this analytical approach to older neutron logs if the computer program also was provided with the porosity profile.

So far, the results have been received for only one

TABLE 1 – RECOVERY FACTOR CALCULATION IN THE GAS CAP (May 1, 1962)

Size of Gas Cap: (Based on Neutron Survey 4/62)

Acres	4,663
Acre-ft	133,541
Avg. gas cap thickness, ft	28.6
HCPV, res bbl	239,165,000

Reservoir Parameters for Gas Cap:

Porosity (volume weighted), %	24.56
Water saturation, %	6.01
Gas-cap pressure 5/62, psig	1218
Gas-cap temperature, °F	150
Gas formation volume factor at 1,218 psig, 150°F	2.1723

Net Gas Injected: (May 1, 1962)

Cumulative gas injected, Mcf	88,229,000
Cumulative free gas produced, Mcf	8,203,000
Cumulative net gas injected, Mcf	80,026,000
Cumulative net gas injected, res bbl	173,840,000

Gas Going Into Solution at 1,218 psig: (PVT data)

$$\frac{386-128}{1.103} = 234 \text{ cu ft/RB.}$$

Oil Swelling Factor:

$$\frac{1.226}{1.103} = 1.1115.$$

Recovery Factor Calculation:

G_F = Volume of free gas in gas cap, res bbl;
V_{or} = Volume of residual oil in gas cap, res bbl, of original undersaturated crude;
$\therefore G_F + 1.1115\, V_{or} = 239{,}165{,}000$ res bbl,
and $G_F = 173{,}840{,}000 - V_{or}(0.234)(2.1723)$.

$V_{or} = 108{,}297{,}000$ res bbl;

$$\therefore \text{Recovery factor} = \frac{239{,}165{,}000 - 108{,}297{,}000}{239{,}165{,}000} = 0.547.$$

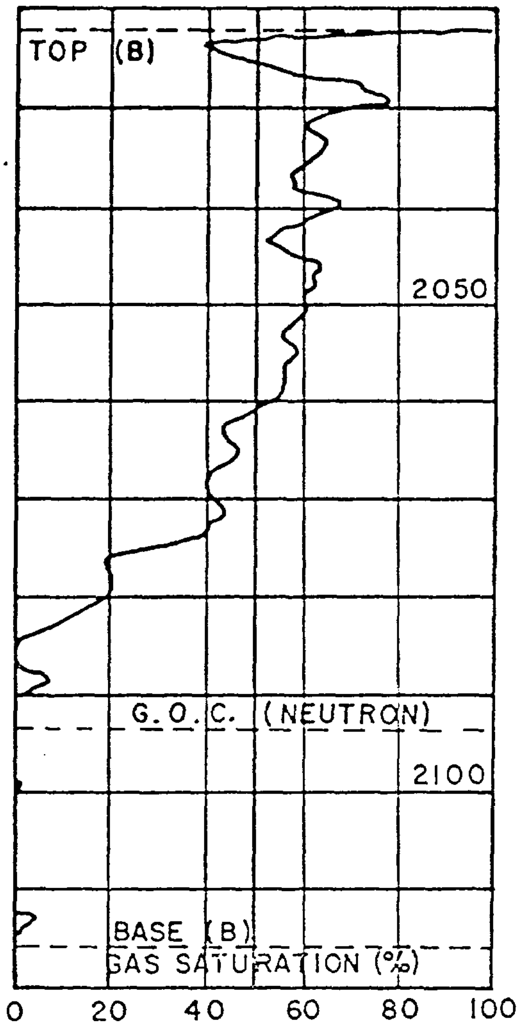


Fig. 15 – Gas saturation.

well (Fig. 15). It is obvious that, as expected, a vertical saturation profile does exist and that the displacement efficiency is in excess of 50%, giving credibility to the calculated 50% recovery efficiency.

The recovery efficiency should not be much less than the displacement efficiency, due to the narrow spacing of the wells.

Conclusions

1. Neutron surveys in conjunction with pressure surveys have been used satisfactorily to determine the percentage of oil recovery by gas displacement.
2. Gravity drainage as well as the oil wettability characteristics of the rock have been conducive to a higher oil recovery by gas than by water.
3. Material balance calculations and log analysis have shown that recovery in the gas cap is 50%.
4. The possibility of reduced recovery because of changing from rich Arab gas to lean Khuff gas is recognized. This potential loss will be offset partially because Khuff gas contains significant CO_2.

Acknowledgments

I acknowledge the assistance rendered by the Bahrain Petroleum Co. Ltd. while compiling this paper.

Reference

1. Cotter, W.T.: "Twenty-Three Years of Gas Injection Into A Highly Undersaturated Crude Reservoir," *J. Pet. Tech.* (April 1962) 361-365.

SI Metric Conversion Factors

acre	×	4.046 873	E+03	=	m^2
bbl	×	1.589 873	E−01	=	m^3
cu ft	×	2.831 685	E−02	=	m^3
°F		(°F−32)/1.8		=	°C
ft	×	3.048*	E−01	=	m
mile	×	1.609 344	E+00	=	km
psi	×	6.894 757	E+00	=	kPa
sq ft	×	9.290 304*	E−02	=	m^2

*Conversion factor is exact.

JPT

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