CANADIAN THESES

THÈSES CANADIENNES

THE UNIVERSITY OF ALBERTA

DISPLACEMENT OF A HEAVY OIL BY CARBON DIOXIDE AND NITROGEN IN A SCALED MODEL

by

TAO ZHU

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE OF

MASTER OF SCIENCE

IN

PETROLEUM ENGINEERING

DEPARTMENT OF MINERAL ENGINEERING

EDMONTON, ALBERTA

SPRING 1986

ISBN 0-315-30226-7

THE UNIVERSITY OF ALBERTA

RELEASE FORM

NAME OF AUTHOR: TAO ZHU

TITLE OF THESIS: DISPLACEMENT OF A HEAVY OIL BY CARBON DIOXIDE AND NITROGEN IN A SCALED MODEL

DEGREE: MASTER OF SCIENCE

YEAR THIS DEGREE GRANTED: SPRING 1986

(SIGNED) Tao Zhu

PERMANENT ADDRESS:

Petroleum Geological Institute, Shao-bei Town

Jiang-do County, Jiang-Su Province

The People's Republic of China

DATED January 15 1986

THE UNIVERSITY OF ALBERTA

FACULTY OF GRADUATE STUDIES AND RESEARCH

The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled DISPLACEMENT OF A HEAVY OIL BY CARBON DIOXIDE AND NITROGEN IN A SCALED MODEL submitted by TAO ZHU in partial fulfilment of the requirements for the degree of Master of Science in Petroleum Engineering.

Supervisor

Date Dec. 29 1985

To My Family

and

My Motherland

Abstract

Heavy oil displacement, using carbon dioxide, was studied in a high pressure scaled model. Several experiments were repeated substituting nitrogen for carbon dioxide, in order to compare the two. It was found that the basic mechanisms postulated for carbon dioxide were absent in the case of nitrogen, which gave oil recoveries similar to those obtained for a waterflood.

In three experiments, there was an initial gas saturation of about 5% in the model. However, it did not affect the oil recovery by WAG(water-alternating-gas) displacement.

Carbon dioxide slug sizes of 10, 20, and 40% HCPV (hydrocarbon pore volume) were employed. Oil recovery dropped to 35.4% for the smallest slug, compared with 43.0% for the 20% slug, and 43.7% for the 40% slug. Results showed that in the case of the 40% slug, much of the injected carbon dioxide was produced, and less efficiently utilized.

Four experiments utilized two different types of model heterogeneities, consisting of a parallel high permeability channel, and a high permeability streak. Oil recovery dropped in both cases, the decrease being 10 to 15 percent.

Two runs employing lower pressures showed that a reduction in the carbon dioxide pressure from 5.5 to 2.5 MPa, resulted in an 8% drop in recovery in the case of the 20% carbon dioxide slug.

The carbon dioxide requirement was less than 100 sm^3/sm^3 in all but the continuous injection runs. This is far below the requirement for miscible carbon dioxide displacement, as well as the air requirement in in situ combustion.

Acknowledgements

The author gratefully acknowledges the guidance and encouragement provided by Dr. S. M. Farouq Ali during this investigation. The author is very proud of this association with Dr. Farouq Ali.

The author also thanks Dr. G.A. Rojas for his guidance during the early stages of this work.

Appreciation is expressed to Dr. W.T. Strickland, Jr., and Husky Oil Operations Ltd. for supplying the oil and materials, and for discussion of experimental results.

The financial support for this research provided by the Alberta Oil Sands Technology and Research Authority (AOSTRA) is gratefully acknowledged. Special thanks are expressed to Dr. C. Hsi and Dr. Ted Cyr of AOSTRA for their encouragement and input to this research.

Tables of Contents

List of Tables

List of Figures

Figure	Caption	Page

1. Introduction

In Alberta and Saskatchewan, large heavy oil deposits occur in formations that are unsuitable for thermal recovery techniques, because they are too thin (less than 10m), heterogeneous, or otherwise marginal. The search for a non-thermal recovery method for such formations has led to the immiscible carbon dioxide flooding process. This process, when optimized for a given reservoir and fluid system, can yield considerable incremental oil recovery beyond that for a waterflood.

The immiscible carbon dioxide flooding process involves injection of a relatively small slug of carbon dioxide followed by water. The process gives highest oil recovery when the carbon dioxide slug is broken into a number of smaller slugs, and alternated with water slugs, with a given WAG (water-to-gas) ratio. In the previous investigation[52], the optimal WAG ratio was found to be 4:1.

The previous research on the immiscible carbon dioxide flooding process was carried out by Rojas and Farouq Ali[52], who developed the scaling criteria for this process, and who used a scaled model. The experimental runs were carried out under a narrow range of conditions. The greater emphasis was placed on the WAG ratio.

The present study is devoted to a broader examination of the carbon dioxide flooding process, in order to determine the effects of several variables not studied in the previous work on oil recovery, and the sensitivity of the process to heterogeneity. In particular, a series of runs were carried out using nitrogen in place of carbon dioxide to determine if the mechanisms postulated for carbon dioxide are indeed valid. Other than that, the effects of an initial gas saturation, slug size, heterogeneities, and operating pressure were investigated. The results of this work further demonstrate the value of the carbon dioxide flooding process, and point to directions for future studies. These will include : operation at low pressures, use of foam for mobility control, and use of other materials in place of carbon dioxide.

2. Literature Review

Work in the early 1960's by Beeson and Ortloff[1], Holm[2], and Welker and Dunlop[3] identified the potential for using carbon dioxide as an enhanced oil recovery agent. In the laboratory[3], using carbon dioxide to displace oil under miscible conditions, oil recovery as high as 95 percent was obtained. However, during those early years, there was little interest in exploiting the heavy oil, and the cost of carbon dioxide usually was greater than the price of crude oil. Hence, most of the developmental work in the past years was focussed on other miscible displacement processes.

There are many reservoirs, mostly those containing viscous oil, which are not amenable to the miscible displacement processes because of unfavourable crude oil properties and reservoir depth. The laboratory results of carbon dioxide displacing heavy oil under immiscible conditions by Welker and Dunlop[3], and Dickerson and Crawford[4] have been enlighting. Beeson and Ortloff[1] found that the additional heavy oil recovery per unit of carbon dioxide injected (on a mass basis) was higher when a slug of carbon dioxide driven by water was injected as a gas phase rather than as a liquid phase. Recent laboratory experiments[12] seem to confirm these earlier results. The field projects involving immiscible carbon dioxide floods conducted by the U.S. Oil Refining Co. in Arkansas in 1969[5] and by Champlin Petroleum Co. in the Wilmington Field in Calfornia in 1983[6] are dramatic proof that immiscible carbon dioxide flooding offers an opportunity to enhance the production of viscous crudes.

Nitrogen, much cheaper than carbon dioxide and natural gas and more readily available, is becoming an increasingly attractive material for economically enhancing oil recovery. In the laboratory[7], the light oil and condensate recovery has exceeded 90 percent of the oil in place when high pressure nitrogen was used. Nothing has been published on the use of nitrogen for heavy oil recovery.

2.1. Mechanisms of Oil Displacement by CO_2 and N_2

2.1.1. Mechanisms of Oil Displacement by CO_2

Two types of displacements are involved in carbon dioxide displacing oil : miscible carbon dioxide floods and immiscible carbon dioxide floods. Holm and Josendal[8,9] have given a comprehensive discussion of the mechanism of oil displacement by carbon dioxide in the miscible displacement process. In carbon dioxide miscible displacement, miscibility develops with two types of mass transfer : extraction of hydrocarbon from the in-place oil to the displacing carbon dioxide, and condensation of carbon dioxide into the in-place oil. Miscible displacement takes place only above a certain pressure. The pressure range for this type of displacement is 7.5 MPa to 20.5 MPa. However, the conditions existing in most heavy oil reservoirs, such as reservoir depth and high miscibility pressure for heavy oils, would make this process impractical.

For the immiscible displacement process, there are five types of forces which control the displacement of heavy oil by carbon dioxide, viz. viscous, capillary, gravitational, diffusive, and inertial forces. In unconsolidated sand reservoirs, laminar flow of carbon dioxide is likely to occur at low or moderate superficial velocities. Therefore, the influence of inertial forces is not significant. Also, in dealing with highly viscous oil displacement from unconsolidated sands, Flock and Peters[10] pointed out that the oil recovery is only a weak function of the capillary forces. Thus, the capillary forces may be neglected. Therefore, the immiscible displacement of heavy oil by carbon dioxide is mainly controlled by viscous, gravitational, and diffusive forces.

Although, it is well known that gravitational segregation occurs in a horizontal reservoir, it has been shown by Craig, Sanderlin, Moore, and Geffen[11] that for high mobility ratios the volumetric sweep efficiency is low and varies very little with the ratio of gravitational to viscous forces. Recently, Rojas and Farouq Ali[12] found that while molecular diffusion of carbon dioxide in oil was high, it was not high enough to mobilize appreciable amounts of oil from uninvaded zones. So, it seems that the viscous forces completely dominate carbon dioxide injection. For immiscible carbon dioxide flooding, four mechanisms have been recently documented by Rojas and Farouq Ali[12] which contributed to increased Aberfeldy oil recovery from unconsolidated sands. They are : viscosity reduction, oil expansion, interfacial tension reduction leading to the formation of water-in-oil emulsions, and blowdown recovery.

2.1.2. Mechanisms of Oil Displacement by N_2

For nitrogen floods, miscible displacement can be obtained by displacing light crude at high pressure. Upon injection, pure high pressure nitrogen gas will become sufficiently enriched with light and intermediate hydrocarbons for miscibility to occur. In the laboratory[7], recoveries as high as 90 percent were obtained by the nitrogen miscible displacement process. However, oil recovery by nitrogen injection is a different type of process than that by carbon dioxide injection. In nitrogen miscible displacement, pure nitrogen is injected into the reservoir to strip the reservoir oil of its light ends[13]. As the light hydrocarbons are absorbed, a two-phase equilibrium point is established between the reservoir oil and nitrogen at a location near the injection well. The liquid phase is composed initially of significant quantities of light and heavy residual hydrocarbons, whereas the gas phase is comprised primarily of nitrogen and light hydrocarbons. Because the gas phase has a higher mobility within the reservoir, it moves ahead of the liquid phase to contact additional reservoir oil. As nitrogen injection continues, the liquid phase is contacted with additional nitrogen with an accompanying decrease in the concentration of light hydrocarbons in the liquid phase until ultimately the liquid phase is reduced to the heavy residual hydrocarbons.

Usually, nitrogen will not develop miscibility with crude oils except at very high pressures or with very high API gravity oils. However, even when nitrogen and reservoir fluid are entirely immiscible, i.e. when no component transfer between oil and gas phase is allowed, good recovery efficiencies are still possible. Slack and Ehrlich[21] indicated that at less than miscibility pressure, one would expect that some of the mechanisms reported for immiscible carbon dioxide flooding - swelling, viscosity reduction, and extraction of intermediates - would still be operative. At still lower pressures, one would expect at least a benefit from the immiscible displacement of oil by gas.

Mobilization of waterflood residual oil by simultaneous injection of water and nitrogen is another possibility in some cases even where nitrogen and oil are immiscible and no swelling, viscosity reduction or vaporization of oil occurs. It has long been recognized that waterflood residual oil saturation can be reduced by the presence of a gas saturation. Slack and Ehrlich[21] found that residual oil saturation reduction is strongly dependent on three-phase relative permeability characteristics. In the laboratory[21], residual oil saturation reduction of up to 18 percent pore volume was measured.

2.2. Solubility of CO_2 in Reservoir Fluids and Fluids Expansion

2.2.1. Solubility of CO_2 in Oil and Oil Expansion

Carbon dioxide is highly soluble in hydrocarbon oils. In 1926, Beecher and Parkhurst[14] found that the solubility of carbon dioxide in crude oil was higher than that of natural gas. For a particular crude oil of 30.2°API, a natural gas (82.5% CH_4) was found to be approximately four times as soluble as air, but only one-third as soluble as carbon dioxide on a molar basis.

The solubility of carbon dioxide in crude oil is governed by the saturation pressure, reservoir temperature, composition of the crude oil and contamination of gases. Up to 125 cubic meters of carbon dioxide will dissolve in one cubic meter of oil[15]. Miller and Jones[14] found that the solubility of carbon dioxide gas increased with pressure and decreased as the temperature and density of the oil increased, with a sharp break in solubility at approximately the condensation pressure of carbon dioxide. Holm[2] also found this sharp break in solubility. The carbon dioxide solubility increased sharply with pressure up to about 1600 psi (10.9 MPa) and then remained at a constant value as pressure was increased above 1600 psi (10.9 MPa). Holm explained that at this point the crude-oil-rich liquid phase, which increased in volume as carbon dioxide dissolved into oil, began to shrink due to the extraction or retrograde vaporization of lighter hydrocarbons into the carbon dioxide-rich gaseous phase.

The swelling of the oil accompanying dissolution of carbon dioxide in the crude depends on the pressure, temperature, crude oil composition, and the mole fraction of carbon dioxide in the oil. This swelling effect is very important because the stock tank volume of residual oil left in the reservoir after flooding is inversely proportional to the swelling factor; i.e. the greater the swelling, the smaller the amount of stock tank oil left in the reservoir.

A number of researchers[3,6,12,16] have shown that the solubility of carbon dioxide gas in conventional heavy oil (14 - 17°API) at moderate pressures (4 - 6 MPa) and temperatures (20 - 25°C) is of the order of 50 - 100 sm³ per cubic metre of oil, yielding a 10 to 20 percent increase in volume. Rojas and Farouq Ali[12] obtained solubilities of 86 and 76 sm³ carbon dioxide per cubic metre of oil for Aberfeldy oil samples at 5.5 MPa and 21 - 21.5°C, with the corresponding swelling factors of 1.17 and 1.14, respectively.

2.2.2. Solubility of CO_2 in Brine and Brine Expansion

Carbon dioxide also has a swelling effect on the water or brine that is present in the reservoir during displacement. Holm and Josendal[9] indicated that there is some expansion of water when carbon dioxide goes into solution (2 to 7 percent) and the water density decreases. Consquently, when carbon dioxide is injected, the densities of the oil and water become closer to each other which lessens the chances for gravity segregation of these fluids and the resultant overriding of the carbon dioxide-water mixtures.

The solubility of carbon dioxide in water depends on salinity, temperature, and pressure. Several researchers[17,18,19] have given extensive data for the solubility of carbon dioxide in water, e.g. the data of Dodds et al[17] shows that in the temperature range of 20 - 70°C and for pressures below 100 atmospheres, the solubility of carbon dioxide in fresh water is less than 6 percent by weight. Mungan[20] indicated that the change in viscosity, density, and formation volume factor of water at these low solubilities can be shown to be less than one percent, and therefore these changes are not significant and may be ignored.

2.3. Viscosity Reduction of Oil Due to CO_2 Solution

The large reduction in viscosity of heavy oils saturated with carbon dioxide is the main mechanism of the immiscible carbon dioxide - flooding process. Viscosity reductions greater than 90 percent can be obtained by saturating heavy oil with carbon dioxide at 5.5 MPag and reservoir temperature[3,22].

The viscosity of oil saturated with carbon dioxide is governed by temperature, pressure, and the concentration of dissolved carbon dioxide. Jacobs et al[23] measured the viscosity of bitumen saturated with carbon dioxide. Their results demonstrate a dramatic decrease in viscosity of bitumen as the saturation pressure is increased. Also it was found that the effect of dissolved carbon dioxide gas on viscosity is less significant as temperature increases. Dickerson and Crawford[4] also reported that a greater percentage reduction in viscosity occurs at a lower operating temperature than at a higher temperature. Generally speaking, a large percentage of the total viscosity reduction by carbonation is obtained in the low pressure range (below 2 MPag) and at low operating temperatures (below 100°C).

Several researchers[16,20,24] have indicated that the higher the initial oil viscosity the greater is the percentage reduction in viscosity upon carbonation of the oil. Thus, viscosity reduction is greater and more significant with medium and heavy oils and not as large with light oils. The recent work by Rojas and Farouq Ali[12] confirmed the above result. They found that when two Aberfeldy heavy oil samples were saturated by carbon dioxide the viscosity decreased considerably from 1080 and 4900 mPa.s for the gas-free oil samples at 21 - 21.5°C to 47 and 82 mPa.s respectively when these two heavy oils were saturated at the same temperature with subcritical carbon dioxide at 5.5 MPa, which represents a 95.6 and a 98.3 percent reduction in viscosity, respectively.

Another factor that affects the viscosity of heavy oil - carbon dioxide mixtures is the time to achieve equilibrium (meaning no change of viscosity with time) between the two fluids. At times lower than the equilibrium time, the viscosity of the mixture decreases with time. Goss and Exall[25] showed an example of the viscosity behaviour of a bitumen sample exposed to a 6.8 MPag carbon dioxide pressure at 50°C. Equilibrium was achieved in 12.5 days and the bitumen viscosity decreased from 18000 mPa.s to 8000 mPa.s during that period of time.

2.4. Diffusion of CO_2 into Heavy Oil and Water

Diffusion is the process by which matter is transported from one part of a system to another as a result of random molecular motion[26]. Diffusion helps carbon dioxide to penetrate into heavy oil and may slightly reduce viscous and gravitational instabilities. The process of diffusion is different from that of solution because diffusion is not related to attractive forces as measured by solubility[27]. The effect of temperature on solution and diffusion of gases into liquids is different. Diffusion increases with increasing temperature, while solubility decreases with temperature.

In the literature[28, 29] many experiments have been performed at atmospheric pressure. Davies et al[28] found that hydrodynamic theories and absolute rate theories which predict that the diffusivity is an inverse function of the solvent viscosity did not fit their experimental data. The diffusion coefficients reported by Davies et al[28] range from 6.03 E-5 cm^2/s to 0.728 E-5 cm^2/s at 25°C and 0 MPag for solvent viscosities ranging from 0.411 mPa.s to 26.5 mPa.s. Rajan and Goren[29] found diffusion coefficients lower than 1.0 E-5 cm^2/s at atmospheric pressure for hydrocarbon oils with viscosities greater than 50 mPa.s.

In 1973, McManamey and Woolen[30] proposed the following equation for the diffusion coefficient of carbon dioxide in organic liquids at atmospheric pressure.

$$D = 1.41 \times 10^{-10} \mu^{-0.47} \qquad (1)$$

where :

D = diffusivity, cm^2/s

μ = dynamic viscosity, mPa.s

Dennoyelle and Bardon[31] recently found that the diffusivity of carbon dioxide increases with increasing pressure. At 15 MPa, diffusion coefficients were found to be more than five times higher than those calculated from Equation (1) for a 570 mPa.s viscous oil. Rojas and Farouq Ali[12] also found high values of carbon dioxide diffusivity in Aberfeldy heavy oils. They found that molecular diffusion coefficients for Samples 1 and 2 were 3.59 E-5 and 2.56 E-5 cm^2/s, respectively. These results are of the same order of magnitude as the molecular diffusion coefficient of carbon dioxide in heavy oils at high pressure reported by Dennoyelle and Bardon[31]. However, Rojas and Farouq Ali[12] concluded that although the diffusion of carbon dioxide in heavy oils at reservoir conditions is high, the amount of diffused carbon dioxide is not enough to produce a large reduction in oil viscosity because the mole fraction of carbon dioxide in Aberfeldy oil samples obtained by diffusion represented less than 20 percent of that obtained by solution with mechanical agitation under the same subcritical carbon dioxide conditions.

Water is not as good a solvent as oil for carbon dioxide. Mungan[20] indicated that the solubility of carbon dioxide in water at a pressure of 150 atmospheres and in the temperature range of 40 - 70°C is approximately 5 percent by weight. At these low solubilities, the change in viscosity, density and formation volume factor of water can be shown to be less than one percent and therefore these changes are not significant at reservoir conditions. However, literature data[30] indicate that diffusion of carbon dioxide in water at 75°C is faster than diffusion of carbon dioxide in oil if the oil viscosity is above 0.5 mPa.s, but still the molecular diffusion coefficient of carbon dioxide in both liquids is of the same magnitude.

2.5. Solubility of Oils in Compressed CO_2 and N_2

The solubility of oil in compressed carbon dioxide or nitrogen is an important mechanism for miscible displacement of oil by carbon dioxide or nitrogen. In 1959, Prausnitz and Benson[32] reported data on the solubility of liquid hydrocarbons in compressed hydrogen, nitrogen, and carbon dioxide. They found that at the same temperature and total pressure, a liquid hydrocarbon is more soluble in nitrogen than in hydrogen and more soluble in carbon dioxide than in nitrogen. They concluded that this result is caused by the differences in physical properties. Such differences between hydrogen (Tc = 33°K) and a typical liquid hydrocarbon (Tc = 500°K) are certainly larger than those between the physical properties of nitrogen (Tc = 126°K) or carbon dioxide (Tc = 304°K) and a typical liquid hydrocarbon. The literature data[7,33] indicated that nitrogen preferentially extracts light hydrocarbon and intermediates (C_1 - C_6) while carbon dioxide extracts the mid-range (C_7 - C_{30}) fractions. The solvent power of carbon dioxide or nitrogen increases with pressure, which is associated with increased carbon dioxide density or nitrogen density. For heavy oils with very small amounts of gasoline and gas-oil range hydrocarbons, very high pressure is required to compress carbon dioxide or nitrogen to a more dense liquid and to promote greater solubility.

2.6. Oil Property Changes Due to N_2

Very little information is available on the solubility, swelling, and viscosity changes in nitrogen-saturated heavy oil. In 1957, Jolley and Hildebrand[34] found that for a given gas at 1 atmosphere and 25°C, dissolving in a series of solvents, log x_2 (x_2 = mole fraction of gas) decreased with the increasing solubility parameter of the solvent; and for different gases in the same solvent, log x_2 increased linearly with increasing Lennard - Jones force constant of the gas. Their data shows that the solubility of nitrogen in solvent is much lower than that of carbon dioxide, being approximately 10 percent of that of carbon dioxide.

Recently, Svrcek and Mehrotra[35] reported data for the solubility of nitrogen in bitumen. They found that the volumetric solubility of nitrogen in bitumen is only 3.38 cm^3/cm^3 at 6.02 MPa and 33.9°C. This could be attributed to the non-polar nature of nitrogen, which yields a much lower solubility of nitrogen in bitumen compared with carbon dioxide. They also found that at each temperature level, the solubility of nitrogen increased almost linearly with pressure to about four to five MPag. Beyond this pressure the curves appear to approach asymptotic values. Although there was a reduction in nitrogen solubility with temperature, the change was quite small, i.e. the effect of temperature on the solubility of nitrogen is minimal.

No viscosity data on nitrogen saturated heavy oil is available in the literature. In 1980, Jacobs et al[23] measured the viscosity of nitrogen-saturated bitumen. They found that the effect of dissolved nitrogen on bitumen viscosity is very small. Later, Svrcek and Mehrotra[35] also reported that nitrogen has a minimal effect on bitumen viscosity and the reduction in viscosity for nitrogen-saturated bitumen with increasing pressure is much smaller than for the case of carbon dioxide. As mentioned before, the larger reduction in viscosity by saturating nitrogen or carbon dioxide is obtained for the heavier crudes with higher initial viscosities. The effect of dissolved nitrogen on heavy oil viscosity, with lower initial viscosity than that of bitumen, is negligible.

The swelling factor of heavy oil saturated by nitrogen under reservoir conditions is also negligible. Peterson[36] indicated that swelling of oil with nitrogen varies from near zero to two percent and probably would not play a role in reservoir performance.

2.7. Interfacial Tension Reduction

Several researchers[12,37] have reported that the reduction in interfacial tension between displacing and displaced phases by carbon dioxide is an effective recovery mechanism because this reduction causes a decrease in capillary pressure so that a significant reduction in the residual oil saturation may be achieved. In 1956, Moore and Slobod[38] discussed the role of capillary forces and the oil trapping mechanism. They concluded that the capillary pressure difference between the two arms of the "doublet" was the dominant factor in the trapping mechanism, and that the efficiency of the trapping mechanism decreased as the viscous to capillary force ratio increased. In other words, the displacement efficiency would be expected to increase as interfacial tension decreases.

Rosman and Zana[37] examined the relationship between interfacial tension and oil recovery by carbon dioxide. They reported that the interfacial tensions (0.1 - 0.03 mN/m) between carbon dioxide (displacing phase in gaseous state) and a mixture of carbon dioxide and crude oil (displaced phase in liquid state) in a carbon dioxide flood is lower than that between water and oil (24.8 mN/m) in a waterflood, and a reduction of 34 - 39% in waterflood residual oil saturation was achieved by low interfacial tension carbon dioxide flooding at 15 - 16 MPa and 54.4°C.

Recently, Rojas and Farouq Ali[12] measured the interfacial tension between Aberfeldy heavy oil and carbonated brine with increasing carbonation pressure of brine. They found that the interfacial tension reduces from 25 mN/m to 16 mN/m when the pressure increases from 0.1 MPa to 5.5 MPa. They indicated that the positively charged nitrogen compounds resulting from the action of carbonic acid on the nitrogen bases of Aberfeldy heavy oil may cause formation of surfactants which concentrate at the oil-water interface and produce the reduction in interfacial tension. This reduction in interfacial tension may lead to the in-situ formation of brine-in-oil emulsions, which enhance oil recovery by carbon dioxide/brine injection.

Several researchers have noticed the reduction in interfacial tension between crude oil and water under acidic conditions. Scott et al[39] reported that the interfacial tension test results show that any change in pH from neutral decreases interfacial tension for the tested crudes. Farouq Ali et al[40] presented curves of interfacial tension of Lloydminster crude oils as a function of pH, showing reductions of interfacial tension at both low and high pH values. Breston and Macfarlane[41] also showed that the interfacial tension between Bradford crude and water can be reduced from 28.8 to 18.1 mN/m by carbonation at 5.2 MPag.

2.8. Permeability Changes Caused by Carbon Dioxide

2.8.1. Rock Dissolution and Precipitation by Carbonic Acid

The acidic effect of carbon dioxide on the rock matrix has been shown to increase injectivity by direct action on the carbonate portions of the rock[7] and by a stabilizing action on clays in the rock[42]. In 1959, Holm[2] reported a study in which the permeability of a dolomite core increased three fold after about nine pore volumes of carbon dioxide slug and carbonated water had been injected through the core. It was concluded that in field applications of carbon dioxide, the increase in permeability would occur primarily in the immediate vicinity of injection well.

Carbon dioxide dissolves in water to form carbonic acid according to the following reversible reaction :

$$H_2O + CO_2 = H_2CO_3 \tag{2}$$

Dolomitic rocks or carbonate rocks contain mainly $CaCO_3$ and $MgCO_3$. The metal carbonates will react with carbon dioxide in the presence of water to form water soluble bicarbonates. The stoichiometric equations of the reactions are as follows[43] :

$$
\begin{aligned}
H_2O + CO_2 + CaCO_3 &= Ca(HCO_3)_2 \\
H_2O + CO_2 + MgCO_3 &= Mg(HCO_3)_2
\end{aligned}
\qquad (3)
$$

The factors that affect the equilibrium in the above reactions are changes in the concentrations of the reactants and the products, pressure, and temperature[44]. The solubility of carbon dioxide in water and hence its concentration increases with an increase in pressure[42], and decreases with an increase in temperature[45].

The results of the laboratory study by Omole and Osoba[43] showed that carbon dioxide would dissolve some of the rock around an injection well in a field application, and dissolved carbonate was found to be precipitated along the flow path as the pressure dropped in the laboratory experiments. It was concluded that the higher the injection pressure, the more pronounced would be such dissolution of rock. It was also found that the precipitate reduced permeability. The amount of carbonate precipitated was dependent on the magnitude of the pressure drop. The larger the pressure drop, the greater was the carbonate precipitation and the reduction in permeability.

In 1952, Breston and Macfarlane[41] reported that in the experiments for determining the effective permeability of the fresh sand samples to carbonated water, when switching from brine to carbonated water, there was no significant change in effective permeability. However, Graue and Blevins[46] later reported that small channels of high permeability produced by rock dissolution in a tertiary carbon dioxide - waterflood pilot in the Sacroc unit caused early breakthrough of carbon dioxide (7 days) in one of the producers. Because of carbon dioxide channeling, the volumetric sweep efficiency was estimated to be as low as 33%.

2.8.2. Asphaltene Deposition by CO_2

It is a well known fact that some acids when in contact with crude oil may precipitate asphaltenes, thus plugging the pore space[47]. Strausz[48] describes asphaltenes as high molecular weight materials which, on solvent fractionation, appear as a dark coloured amorphous solids which are kept in colloidal suspension in the bitumen by the lower molecular weight polar materials. Asphaltene precipitation occurs when the hydrocarbons and polar oil fraction lose their ability to disperse colloidally the asphaltene fraction. When carbon dioxide and light oil mix at high pressure, multiple liquid phases may occur in mutual equilibrium. The heavy ends of a light oil precipitate out with the addition of carbon dioxide.

Holm[2] indicated that phase behaviour studies of carbon dioxide and crudes containing asphalt showed that an asphalt-rich phase was formed at high pressures and at temperatures above 100°F, but there was no evidence of asphalt precipitation in the experiments. Graue and Zana[49] also observed a dark solid precipitation at carbon dioxide concentrations of 44% mole, or higher, in carbon dioxide-light oil systems. The solid precipitation was estimated to be 2 - 5% volume of the original reservoir oil. They concluded that it is possible that such precipitation in the reservoir would cause a reduction in rock permeability. However, some researchers[50,51] indicated that the precipitation of solid phases in the carbon dioxide-oil transition zone might reduce carbon dioxide mobility below the level anticipated from normal viscosity and relative permeability relations, which could increase recovery.

2.9. Laboratory Investigations on Heavy Oil Recovery by CO_2

Basically four different immissible carbon dioxide/water displacement processes can be used for recovering heavy oil. They are: straight or continuous carbon dioxide injection, carbon dioxide slug process, injection of alternate slugs of carbon dioxide and water (WAG process), and simultaneous injection of carbon dioxide and water.

2.9.1. Continuous CO_2 Injection

In this process, carbon dioxide is injected continuously up to a high producing GOR (gas/oil ratio) of the order of 4500 sm³/m³. Several researchers[52, 53] have reported that the continuous carbon dioxide process is an inefficient strategy for heavy oil recovery.

In 1983, Sayegh et al[53] reported that the recovery of aged Lloydminster crude oil (23700 mPa.s at 20°C) by carbon dioxide continuous injection at 3.45 MPa and 20°C up to gas breakthrough was less than three percent of pore volume in all runs. The tests were carried out in a core of 0.44 m length and 2.8 cm diameter. Very high oil viscosity, low back pressure, and rapid injection rate of the carbon dioxide may be the reasons for that low recovery efficiency.

Recently, Rojas and Farouq Ali[12] reported that upon the injection of 20% HCPV (hydrocarbon pore volume) of carbon dioxide, only 3% of the original oil (1032 mPa.s at 23°C) in place was recovered. They found that high production of carbon dioxide occurred after carbon dioxide breakthrough, and the oil produced-fluid injection ratio (OPFIR) was less than 0.25. The same authors[12] indicated that results of tests showed that the continuous carbon dioxide injection process under subcritical conditions was not applicable to heavy oils of the Aberfeldy Lloydminster type because the immiscible displacement of these viscous oils by carbon dioxide is completely dominated by viscous forces, and mass transfer between carbon dioxide and crude oil does not appear to enhance appreciably the recovery.

2.9.2. CO_2 Slug Process

In this case, carbon dioxide is injected from the start of the process until the desired carbon dioxide slug has been injected. Then water is injected continuously until the process is terminated at a producing WOR (water/oil ratio) higher than 20 m^3/m^3.

In 1959, Beeson and Ortloff[1] investigated the use of water-driven carbon dioxide slugs to recover viscous crude oil (20°API, 400 mPa.s at 21.1°C) from small diameter models at low flow rates with the carbon dioxide slugs in the liquid (at 6.9 MPa and 21.1°C) and gas (at 6.9 MPa and 54.4°C) states. In both cases, the oil recovery was approximately 50% of the original oil in place, much higher than that obtained by waterflood (29%). The authors reported that the additional oil recovery per unit mass of carbon dioxide injected was higher in the carbon dioxide gas slug floods than in the carbon dioxide liquid slug floods.

Holm[51] reported the results of laboratory studies on a viscous oil (90 mPa.s at 21.1°C), displaced by a carbon dioxide slug (44.5 sm^3/m^3 of oil in place), followed by water. An 80% increase in oil recovery over a conventional waterflood was achieved by Holm[51]. However, Farouq Ali and Rojas[52] recently pointed out that the subcritical carbon dioxide slug (20% HCPV) process for secondary heavy oil recovery had three disadvantages with respect to the WAG process. They are :

1. Undue oil production delay and high production of free carbon dioxide during slug injection.
2. Lower overall recovery.
3. Higher carbon dioxide requirement.

2.9.3. Simultaneous Injection of CO_2 and Water

In this process, carbon dioxide and water are injected simultaneously until the total desired amount of carbon dioxide has been injected. Then, water is injected continuously until the process is terminated at a producing WOR higher than 20 m^3/m^3. The main difference between simultaneous injection of carbon dioxide and water and the carbon dioxide slug process is the accessibility of oil to carbon dioxide. As a slug, carbon dioxide directly contacts the oil. For simultaneous carbon dioxide and water injection, CO_2 is largely dissolved in the water and must transfer from the water to the oil.

In 1969, Holm[55] indicated that a much lower residual oil saturation was obtained with a carbon dioxide slug flood than with a carbonated waterflood. Holm[51] also pointed out the three disadvantages of using carbonated water :

1. Carbonated water is not as effective as carbon dioxide in reducing oil saturation ;
2. For the same amount of carbon dioxide, a carbonated waterflood recovers less oil than the slug process ;
3. The additional oil recovered by a carbon dioxide slug flood is produced more rapidly than the oil recovered by a carbonated waterflood.

Recently, Farouq Ali and Rojas[52] reported that the simultaneous injection of carbon dioxide and water process had not been used in field applications because of two potential problems :

1. Severe corrosion of injection wells by the mixture of carbon dioxide and water at high pressure.
2. Injectivity reduction when injecting two phases simultaneously.

2.9.4. Injection of Alternate Slugs of CO_2 and Water (WAG)

In this case, small slugs of carbon dioxide and water are injected alternately until the total desired amount of carbon dioxide has been injected. Then, water is injected continuously until the process is terminated at a producing WOR higher than 20 m^3/m^3.

As several researchers[52,53] have indicated, the injection of subcritical carbon dioxide alone without water is unable to displace efficiently a viscous oil, and thus immiscible carbon dioxide displacement needs to be supplemented with carbon dioxide mobility control. Holm[54] recently indicated that alternate injection of water with carbon dioxide (the WAG process) has been the most widely used mobility control method.

In 1958, Caudle and Dyes[54] proposed the control of gas mobility in a gas-driven displacement by injecting water along with the gas, thus visualizing the main mechanism of the WAG process. The authors[54] explained the carbon dioxide/brine injection process as follows. The presence of brine in the carbon dioxide invaded zone lowers the relative permeability to carbon dioxide, decreasing its mobility. In this way, the injected brine interferes with the flow of carbon dioxide to decrease its rapid production.

Carbon dioxide mobility depends on the brine slug volumes and carbon dioxide slug volumes. Caudle and Dyes[54] pointed out that if too much gas is injected the process can only approach the mechanism of the gas-driven displacement, and if too little gas is injected the worst that can happen is that the reservoir will be subjected to a water drive.

Recently, Ko and Stanton[57] indicated that in the presence of trapped light oil saturation (i.e. in tertiary recovery), larger carbon dioxide slugs are required in a WAG process for more efficient displacement. Conversely, in the absence of light oil trapping (i.e. in secondary recovery), smaller carbon dioxide slugs are required to maintain good mobility control.

Very little information on laboratory studies of injection of alternate slugs of carbon dioxide and water for heavy oil recovery has been published. Farouq Ali and Rojas[52] recently indicated that the WAG ratio had a considerable effect on the secondary recovery for moderate viscosity oils. They reported that if the brine slugs are of equal or less volume than the carbon dioxide slugs, brine is unable to control effectively carbon dioxide mobility in heavy oil reservoirs with concomitant excessive production of carbon dioxide. Thus, they concluded that a WAG ratio of 4:1 was the best among the five tested for recovering the heavy oil of Aberfeldy reservoirs in Lloydminster.

In field applications, the WAG process as a secondary recovery process is being used with encouraging results in the third phase of the Lick Creek Meakin Sand Unit immiscible carbon dioxide/waterflood project, which is the largest field application of carbon dioxide in recovering heavy oil (17°API, 160 mPa.s at 48°C)[58].

2.10. Heavy Oil Recovery by N_2

Very little information is available in the literature on the use of nitrogen for heavy oil recovery. However, because nitrogen is much cheaper and more readily available, it is becoming an increasingly attractive material for economically enhancing oil recovery.

It has long been recognized that waterflood residual oil saturation can be reduced by the presence of a gas saturation. Craig[59] reviewed literature on the effect of an initial free gas saturation formed by primary depletion below the bubble point pressure on waterflood residual oil. Depending on the magnitude of the gas saturation also trapped by the waterflood, residual oil saturation in water-wet consolidated rocks was generally lowered by up to 10% PV.

In 1981, Slack et al[21] proposed a method of immiscible displacement of oil by simultaneous injection of water and nitrogen. They found that residual oil saturation reduction strongly depends on three-phase relative permeability characteristics. Reductions of up to 18% PV were measured for a mineral oil at 50 psig by Slack et al[21], using simultaneous injection of water and nitrogen in Berea sandstone. They concluded that despite gravity segregation, immiscible water-nitrogen flooding is capable of recovering an appreciable fraction of waterflood residual oil at reasonable nitrogen-oil ratios and in reasonable times. But the experiments[21] with high permeability unconsolidated sands showed only a very small residual oil saturation reduction with simultaneous water-nitrogen flow. Slack et al[21] pointed out that the gas-water immiscible displacement would be most effective in consolidated rocks.

However, the effect of gas or simultaneous gas-water injection on a waterflood residual oil saturation established with no gas present is potentionally different than the effect of an initial gas saturation because of the different saturation histories involved (gas displacing water displacing oil in the former case and water displacing gas displacing oil in the latter)[21]. Several researchers[60,61] suggest that the effect of gas-water injection will increase production ranging upward from two percent of waterflood recovery.

In 1983, Sayegh and Maini[53] conducted experiments using nitrogen to continuously displace a heavy oil (10531 mPa.s at 0 MPag and 21.0°C) at 3.45 MPa and 20°C. As expected, they found that the recovery by nitrogen injection was very inefficient and only resulted in 4.5% PV oil production.

Several researchers[62,63] have indicated that a slug of carbon dioxide pushed by nitrogen can reduce the amount of carbon dioxide required and hence reduce the cost. In 1979, O'Leary et al[62] injected a slug of pure carbon dioxide pushed by nitrogen to displace a West Texas crude oil of approximately 34°API gravity at 1250 psi (8.5 MPa) and 107°F (41.7°C) in 100 feet long cores. The oil recovery varied from 90 to 98 percent when the carbon dioxide slug size varied from 5 to 25 percent of hydrocarbon pore volume (HCPV). Without carbon dioxide, an oil recovery close to 60 percent of the oil in place was obtained. No information is available in the literatures for heavy oil recovered by a nitrogen-driven carbon dioxide slug process.

In oil field applications, nitrogen injection has been used in at least 7 field tests that include : pressure maintenance, enhanced gravity drainage, attic oil recovery, gas cap displacement, driving a miscible carbon dioxide slug, miscible displacement, and cycling of condensate reservoirs[64].

Another nitrogen injection field application is exhaust gas (consisting of about 87% nitrogen, 11% to 13% carbon dioxide, and inert gas[22]) stimulation. In this case, the mixture of carbon dioxide, and nitrogen is injected into viscous crude reservoirs[0]. The carbon dioxide dissolves readily in the crude, increasing its volume and reducing its viscosity[24]. The nitrogen is displaced back into the formation as a gas under pressure. When a well is opened, energy from the compressed nitrogen charge helps move the thinned, expanded oil to the wellbore. This type of process has been applied in several oil fields to stimulate heavy oils[45].

3. Statement of the Problem

The previous research[52] on the immiscible carbon dioxide flooding process employed a constant slug size, and a constant pressure, with emphasis on the WAG ratio. This investigation attempts to extend the previous work, and also to examine several new areas, with the following objectives:

1. To repeat a series of runs using nitrogen in place of carbon dioxide, to determine if the mechanisms postulated for carbon dioxide are indeed valid.

2. To evaluate the effect of an initial gas saturation, using nitrogen or carbon dioxide as the gas, followed by a WAG displacement.

3. To investigate the effect of slug size.

4. To evaluate the effect of two types of sand pack heterogeneities on the process efficiency.

5. To investigate the effect of the operating pressure.

4. Experimental Apparatus, Procedure, and Materials

4.1. High Pressure Physical Model

The high pressure physical model is designed to simulate a shallow, thin, horizontal, unconsolidated sandstone reservoir rock containing fluid with properties similar to the average properties of the Aberfeldy field in the Lloydminster area. A schematic diagram of the physical model is shown in Figure 1. The main components of the model are the pressure vessel, the fluid injection and production systems, and the data collection system.

4.1.1. Pressure Vessel

The basic structural element of the physical model is a steel flanged rectangular pressure vessel. The vessel can withstand pressures up to 10 MPa at 100°C with the maximum deflection of the walls being less than 0.01 mm. Figure 2 shows cross-sections of the vessel. Table 1 shows the main characteristics of the high pressure vessel.

The model is operated to simulate a horizontal five-spot pattern. The fluid is injected at one well in the corner of the vessel and produced from another well in the opposite corner. Figure 3 shows the location of the wells in the pattern. The wells were made of 1/8 inch (3 mm) stainless steel tubing with small holes (0.055 mm in diameter) perforated along a length of approximately one inch from the bottom.

The model is provided with another well with a thermistor inserted to measure the temperature of the porous medium. A thermistor is basically a semiconductor, which exhibits rapid, extremely large changes in resistance as a result of relatively small changes in temperature. Thermistors are more accurate than thermocouples for temperatures below 100°C. The position of the thermistor is shown in Figure 3.

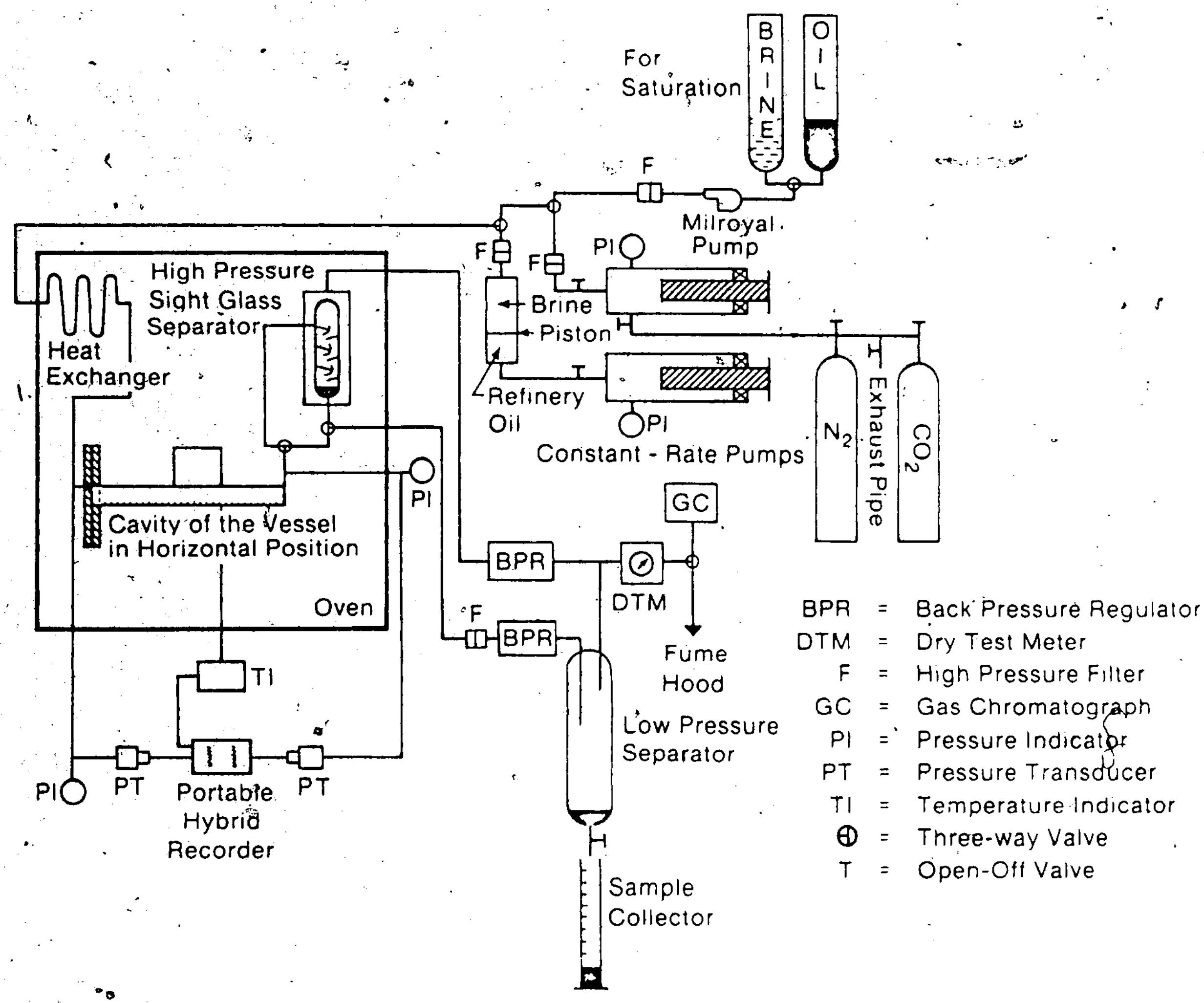


Figure 1 Schematic Diagram of the Physical Model

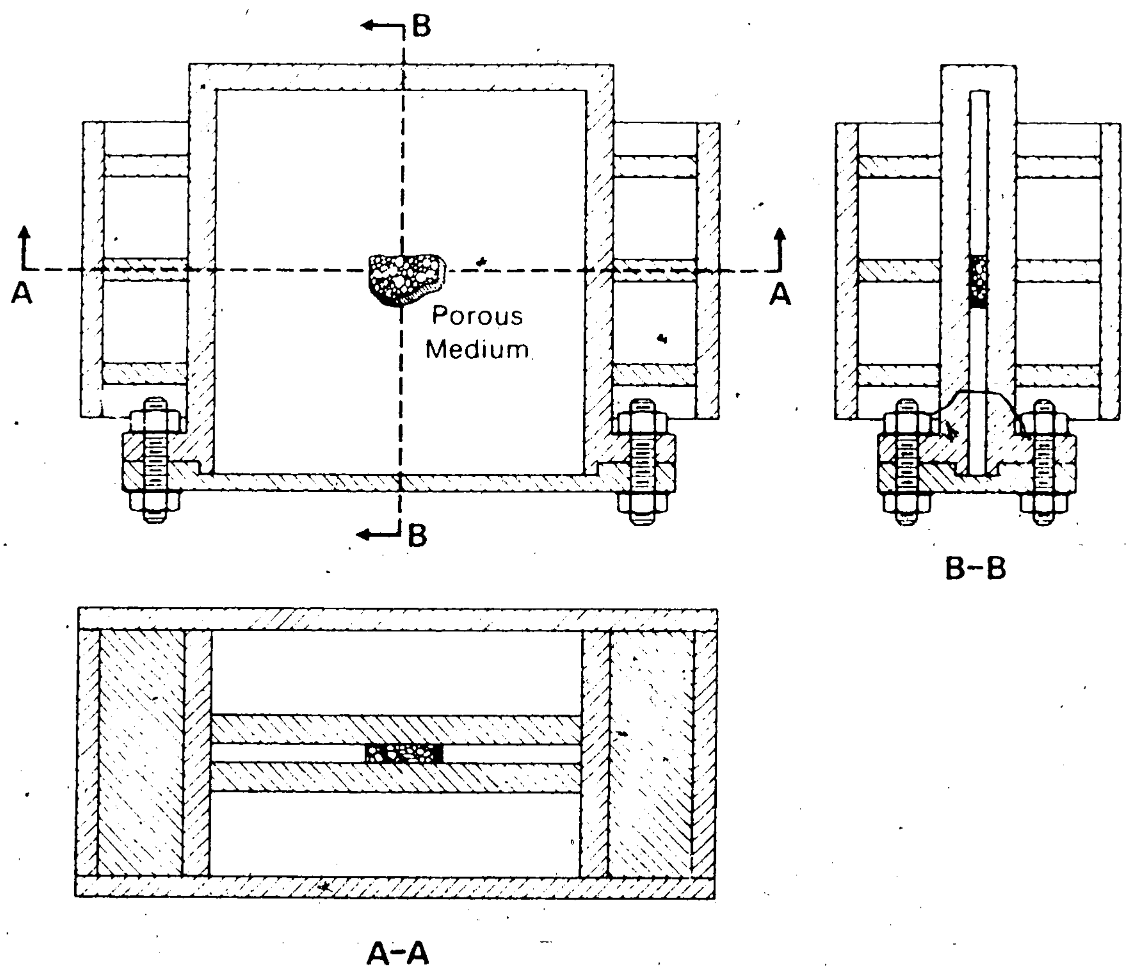


Figure 2 Cross Sections of the High Pressure Vessel

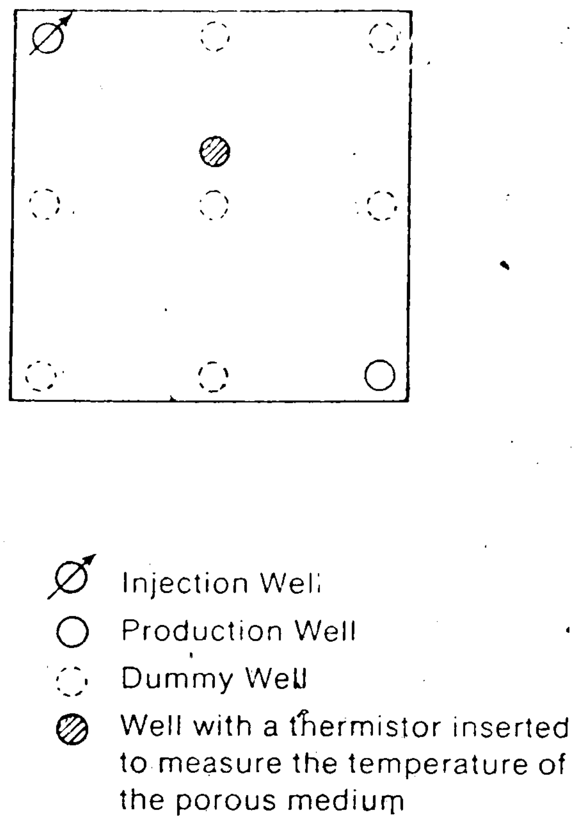


Figure 3   5—spot pattern for horizontal floods.

Table 1

Characteristics of the High Pressure Vessel

- Rectangular shape 45.7 cm x 45.7 cm x 2.2 cm
- Three reinforcing members
- Maximum internal pressure : 10 MPa
- Maximum deflections of walls at 10 MPa less than 0.01mm
- Weight about 1 Tonne
- Number of wells available : 9
- Possible patterns to simulate : 5-spot, 9-spot, line drive
- The central well permits the simulation of cyclic injection
- The model can be rotated for horizontal, inclined, or vertical floods

4.1.2. Fluid Injection and Production Systems

The brine and oil were injected by a Milroyal postive displacement pump for saturating the porous medium. A filter block located upstream of the model was used to filter the brine and oil.

Two dual, constant rate, screw-type, high pressure piston pumps were used to inject the carbon dioxide, nitrogen, and brine into the porous meduim, according to the type of run. The injection rate could be controlled by varying the pump speed. Carbon dioxide was injected directly by the constant rate piston pump into the model because dry carbon dioxide is not corrosive. However, as brine is very corrosive, it was injected into the model from a high pressure steel cylinder with a floating piston, which was actuated by the constant rate pump.

The effluents from the model were separated in a glass separator operating at atmospheric pressure. The top of the separator was connected to a dry test meter (DTM) to measure the amount of gas produced. Liquids were collected in graduated cylinders from the separator.

4.1.3. Data Collection System

The production pressure was controlled by an automatic back pressure regulator (BPR), which was located upstream from the separator. Two Heise pressure gauges were used to measure the production and injection pressures, and two pressure transducers, connected to a portable hybrid recorder, recorded the injection and production pressure histories every five seconds for each run.

The temperature of the porous medium was measured with a thermistor. It was both displaced by an Omega temperature controller and recorded every five seconds by a portable recorder.

The cumulative volume of the gas produced was measured by a dry test meter (DTM) with an accuracy of 10 cm^3 at room conditions.

4.2. Materials

4.2.1. Fluids

Commercial grade carbon dioxide (99.5% purity) and nitrogen (99.95% purity) were used in all displacement experiments. The displacement experiments employed reservoir water to create an irreducible water saturation. Five different viscosity crude oil samples from the

Aberfeldy field in the Lloydminster area were used in the displacement tests. Reservoir water (jointly with carbon dioxide and/or nitrogen) was used to recover oil from the porous medium.

In order to compare the heterogeneous pack runs and low pressure (2.5 MPag) runs with the homogeneous pack high pressure (5.5 MPag) runs, it was necessary to have similar viscosities for crude oils in those different runs. Crude oil sample No. 10, with a viscosity of 1101 mPa.s which was close to the viscosity of oil sample No. 8 (1116 mPa.s), was a mixture of oil sample No. 9 (2107 mPa.s at 0 MPag and 23°C) and a refined oil (198 mPa.s at 23°C). The mixture, oil sample No. 10, was composed of 77.8 percent of crude oil sample No. 9 and 22.2 percent of refined oil. The properties of this oil sample are shown in Table 2.

It was necessary to dehydrate the oil received from the field because it contained more than 10% by volume of water. A demulsifier (used by Husky Oil Company in the Lloydminster area) was added to the oil sample in a concentration of 0.01% of sample volume. Then the water was separated from the oil in an oil dryer by gravity at a constant temperature (40°C) for nearly six months. The water was drained from the oil dryer daily at the beginning and weekly near the end until no more free water was produced. At this point, a sample of the oil was analyzed

Table 2

Properties of Oil and Water in the Experiment

Reservoir Water:

Density, kg/m³ at 23°C	1047
Viscosity, mPa.s at 23°C	1.14
pH at 23°C	7.5 - 8.1

Water Analysis:

Total solids, ppm	77200
Hardness, ppm	8997
Sulphates, ppm	41122
Alkalinity, ppm	60
Iron, ppm	67.5
Calcium, ppm	1971
Magnesium, ppm	990
Sodium, ppm	19850
Potassium, ppm	3610
Salt, ppm	67851

Nature of Alkalinity: Bicarbonate of Calcium and Magnesium

Table 2 (Continued)

PROPERTIES	Sample 2	Sample 7	Sample 8	Sample 9	Sample 10
Density, kg/m³ at 0 MPag and 23°C	970.2	952.8	960.6	966	946
Viscosity, mPa.s at 0 MPag and 23°C	3897	1032	1116	2107	1101
Water Content, % Weight	0.0	below 0.1	below 0.1	2.5	2.0
Sand Content, % Weight	1.0	1.0	2.0	0.5	below 0.1
Molecular Weight, g/gmol	460	425	---	--	--

for water and sand content. A summary of the average properties of the dried oil and brine samples is given in Table 2.

4.2.2. Unconsolidated Sand

The sand used for the experiments was Ottawa Silica Sand, from Ottawa, Michigan. It was analyzed by x-ray analysis to determine the bulk mineralogy. Table 3 shows the bulk mineralogy of this sand.

4.3. Packing, Saturation, and Model Cleaning Procedures

Two packing techniques, wet packing and dry packing, were used for the experiments. The wet packing technique was used to obtain consistent properties in the homogeneous displacement tests, while the dry packing technique was used to obtain heterogeneous properties in the heterogeneous displacement runs. For wet packing (Figure 4), the model box was filled with distilled water to a height of 10 cm with the model in the vertical position. Then the model was filled by sand, and was vibrated with an air vibrator. During the packing process, a constant 10 cm head of distilled water was kept above the sand. A 10 cm tall filling lid was used to maintain the same head of distilled water at the end of the packing process after the

Table 3

*Bulk Minerology of Ottawa Silica Sand **

QZ	OR	C	Type of Clay
M	---	t	Possibly Illite/Smectite

Note : QZ = Quartz

OR = Orthoclase

C = Clays

M = Major

t = trace

Where M is greater than t

* Determined by the Department of Geology, University of Alberta.

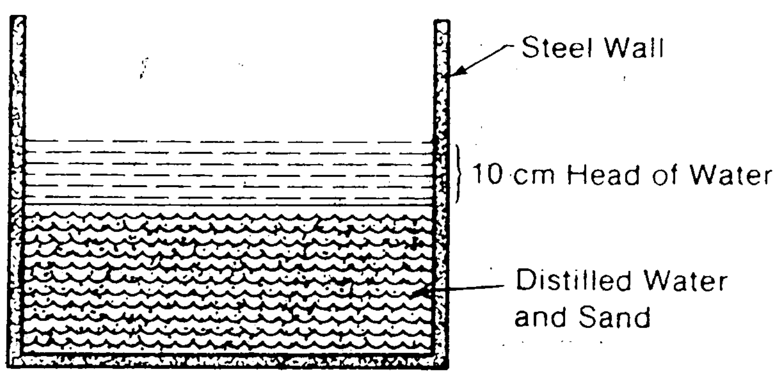


Figure 4 Wet packing method

model had been filled with sand. The model was vibrated for about 20 - 30 minutes after it was filled with sand. Following this, the packing lid was replaced by the flange plate and the model was ready for the next step. The wet packing process took approximately three hours. The model vibration during and after packing eliminated the trapping of air by sand.

For dry packing (Figure 5), the model was filled with the Ottawa Silica Sand and glass beads as well as being vibrated with an air vibrator. After the model had been filled with the sand and glass beads, the distilled water was added to the model cavity and the model was vibrated for several hours. Then the flange plate was put in place. After this, the model was evacuated with a vacuum pump and vibrated with an air vibrator for about 72 hours. The purpose of the vacuum and vibration was to eliminate the trapped air during the packing process. The dry packing process took approximately four days.

After packing the model with sand, or sand and glass beads, the model was tested for leaks at a pressure of 7 Mpa. Then the distilled water was displaced miscibly by reservoir water from the bottom to the top in order to determine the pore volume (as shown in Figure 6). After the absolute permeability was determined, oil was injected using the three wells at top of the vertically positioned

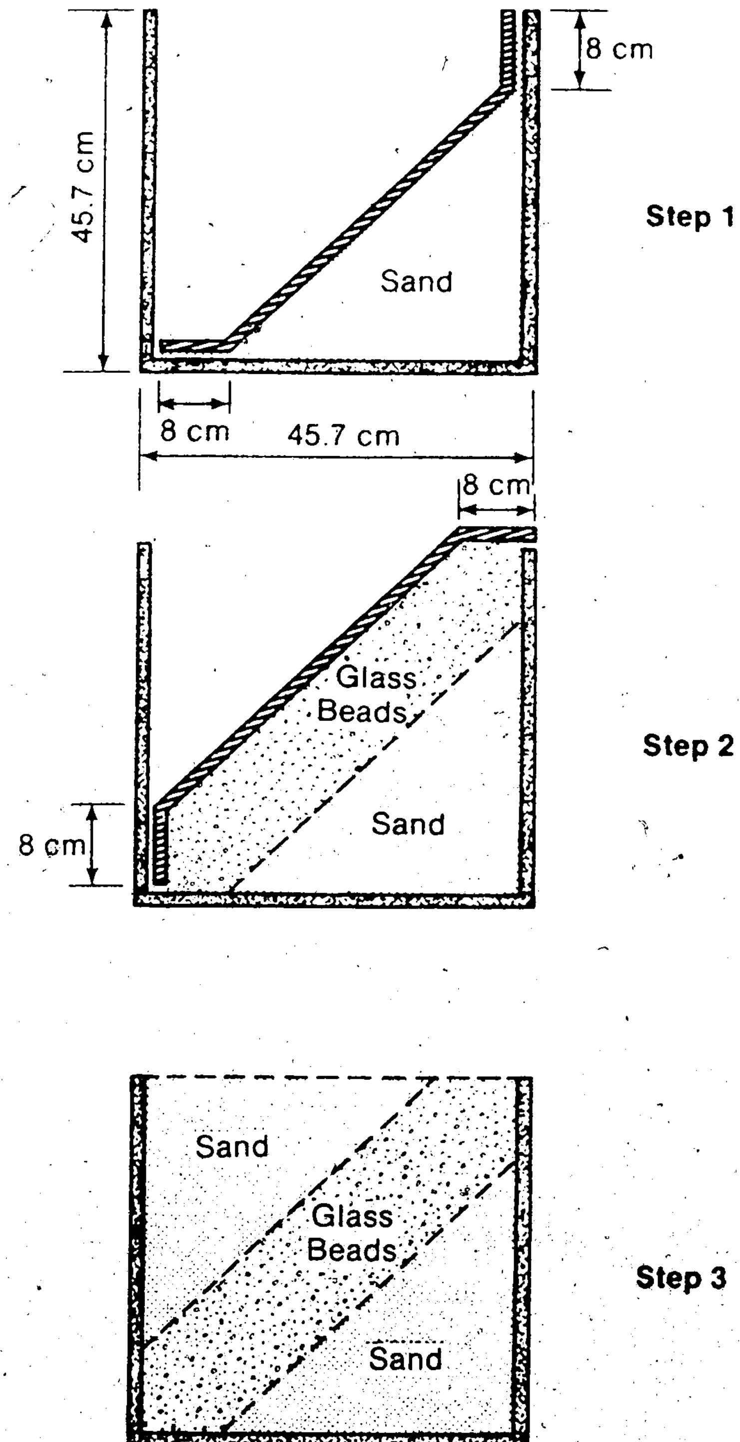


Figure 5 Dry packing method.

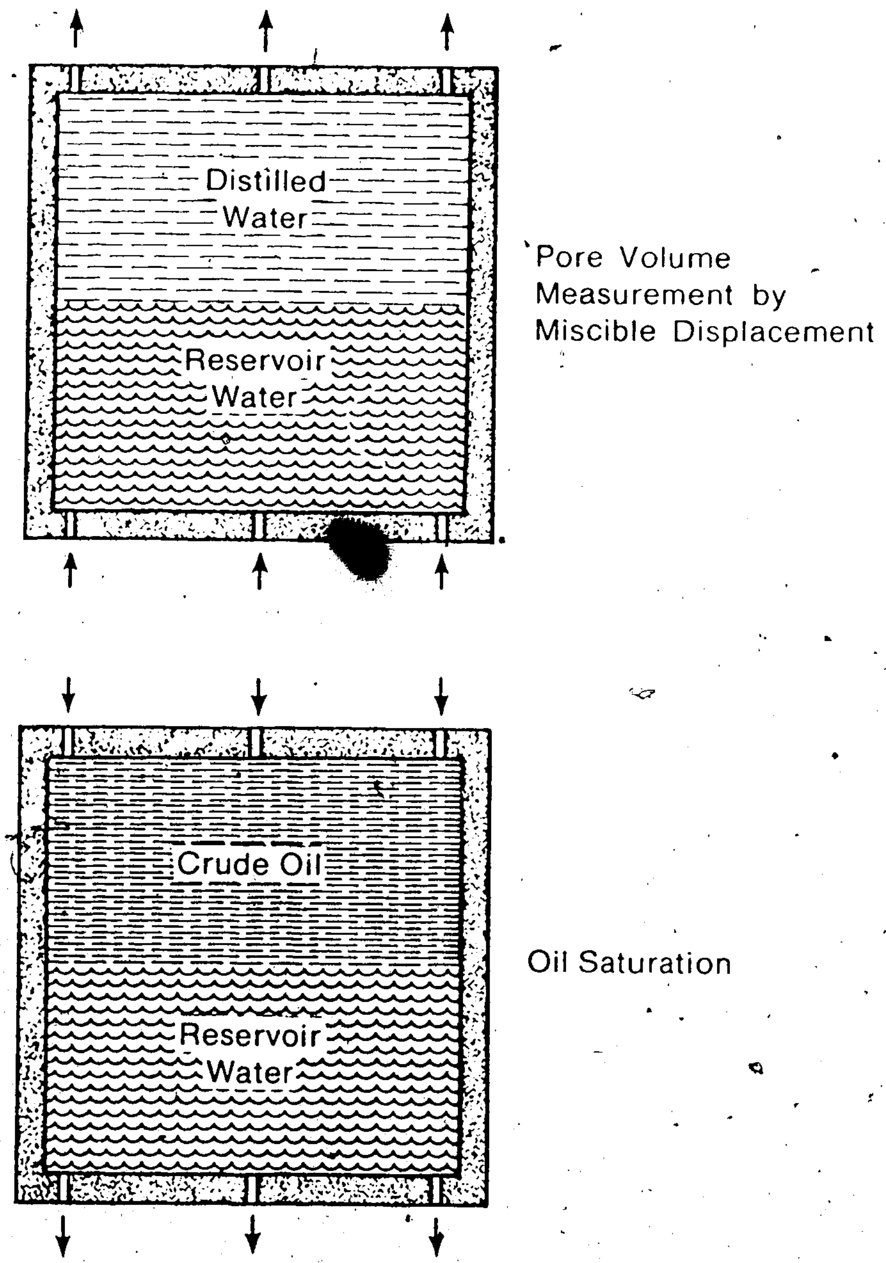


Figure 6 Pore volume determination and oil saturation

model to create an irreducible water saturation in the porous medium (Figure 6). Following this, the model was repressurized at 3.45 MPag with oil to simulate the initial reservoir pressure of the Aberfeldy reservoirs in the Lloydminster area and up to 2.5 MPag to simulate the declined pressure of the same reservoir. At this point the model was ready for brine injection with either carbon dioxide or nitrogen.

The following cleaning procedure was employed at the end of each run. The oil, brine, and sand in the vessel's cavity were removed with a metal scraper. The interior walls of the cavity were cleaned with Varsol. The vessel's cavity was then dried using compressed air. All the wells and the flange plate were cleaned with Varsol and toluene. Great care was taken to ensure the cleanliness of the wells so that the well perforations would not become plugged.

4.4. Porosity and Permeability Measurements

The miscible displacement method was employed to determine the pore volume and porosity of the porous medium. In this method, the distilled water used for packing was displaced vertically by reservoir water flowing from the bottom to the top. The samples of all effluents were collected and their refractive indices were measured using a refractometer. The refractive indices of pure distilled water and pure reservoir water were measured for each run and a plot of refractive index versus percentage of reservoir water in the mixture was also constructed (shown in Figure 7). Using this plot of refractive index versus percentage of reservoir water, the percentage of reservoir water in each sample was determined and a graph of percent displacing fluid in the effluent versus cumulative volume produced was then plotted (Figure 8). The areas above and below the S-shaped curve were balanced and the pore volume was determined. The porosity was calculated by dividing the pore volume by the volume of the vessel's cavity. For reliable results of porosity calculation, it was necessary to measure the volume of the cavity rather than calculating its volume according to its dimensions. The measured volume of the cavity was 4871 cc, while the calculated volume was 4594.7 cc. In this displacement method, viscous and gravitational instabilities do not occur during the displacement because the heavier reservoir water was injected from the bottom to the top and the mobility ratio of distilled water to reservoir water was slightly less than one.

The absolute permeability of the porous medium was determined by placing the model in a horizontal position and flowing reservoir water at various flow rates. The pressure drop between injection well and production well was kept constant and recorded with a Heise pressure gauge.

FIGURE 7, Refractive Index Versus Percent of Reservoir Water in the Mixture

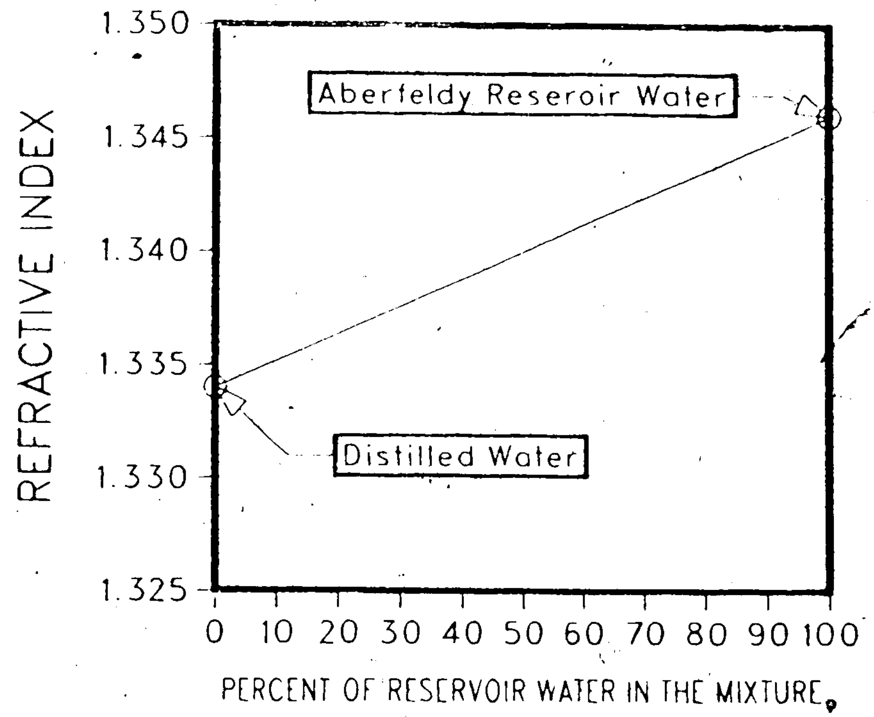
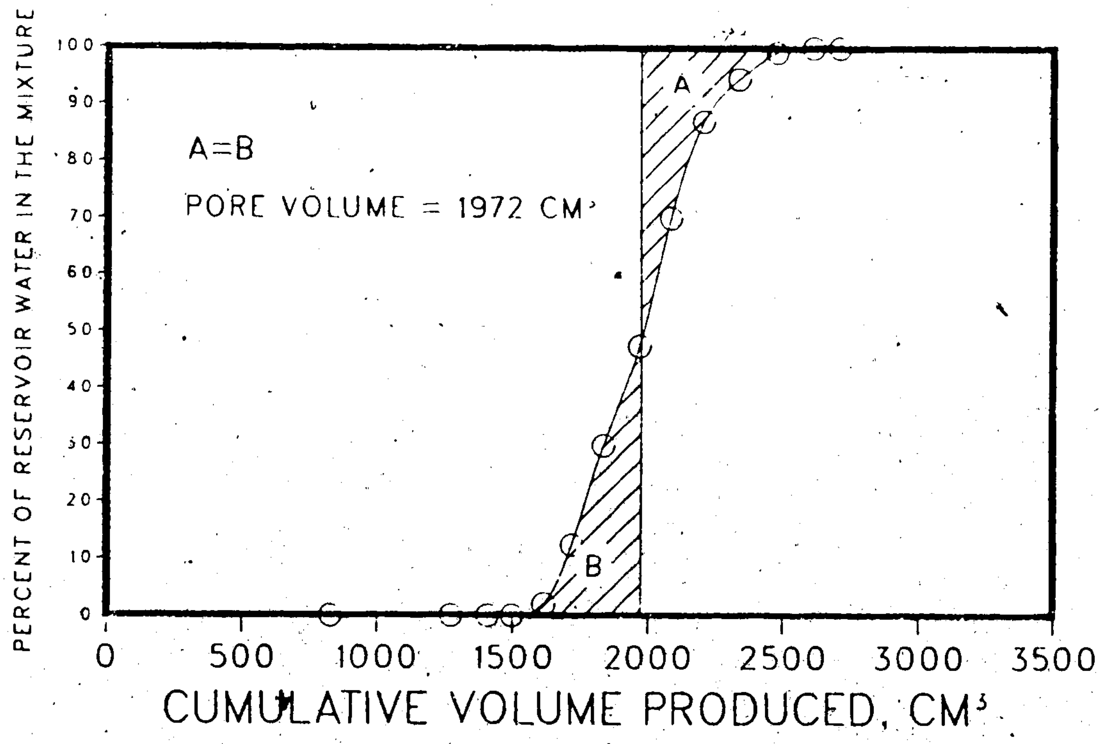


FIGURE 8. Determination of pore volume by Miscible Displacement (run 12)



A flow equation derived for a five-spot pattern according to the conductivity theory was used to calculate the absolute permeability. After that, the model was placed in a vertical position and oil was injected into the model from top to bottom to create an irreducible water saturation in the porous medium. More oil was then injected to pressurize the model to 3.45 MPag to simulate the actual pressure of the Aberfeldy reservoirs of the Lloydminster area in the first 21 runs and up to 2.5 Mpag to simulate the declined pressure of the same reservoir in the last two runs.

4.5. Experimental Procedure

To start a run, the model pressure was increased to the test pressure by injecting carbon dioxide or nitrogen with the production well closed. Once the run pressure was reached in the model, carbon dioxide (or nitrogen) and brine were injected into the model at a constant flow rate from the screw-driven pumps and the pressure of the production well was controlled by the back pressure regulator. The pressure was controlled at 5.5 MPag for the first 21 runs and at 2.5 MPag for the last 2 runs. The run temperature was 21 - 22°C. In all runs, the produced fluids went directly to the low pressure separator because at low production rates it was not necessary to use the high pressure separator and the production fluids were bypassed to the atmospheric separator.''

Carbon dioxide breakthrough was detected by observing the first production of carbon dioxide in the separator and the initial movement of the gas meter needle. Brine breakthrough was detected by analyzing emulsion effluent samples for brine content because free brine did not breakthrough at the beginning. The brine content of the emulsion was determined by adding an equal volume of toluene, and shaking the sample. Then the free water was separated from the mixture by centrifuging it at 3000 rpm for 20 minutes.

During the runs, the produced liquids were collected from the separator and the volume of gas produced was measured by a dry test meter. The pressures of injection and production as well as the temperature of the model were recorded by a hybrid recorder.

4.5.1. Brine - Alternating - Gas (Carbon Dioxide or Nitrogen) Slugs (WAG Process)

In this process, small slugs of gas (carbon dioxide or nitrogen) and brine were injected alternately until a total amount of 20% HCPV (Hydrocarbon Pore Volume) of gas was injected. Brine was then injected continuously until the process was terminated at a producing WOR of approximately 20 m^3/m^3. The amount of gas injected was calculated at 5.5

MPag and 21°C. The WAG ratios (brine slug volume to carbon dioxide slug volume) for secondary and tertiary recovery of Aberfeldy - Lloydminster heavy oil were fixed at 4 : 1, the 4 : 1 WAG ratio was the best one among five tested[44]. Runs 4,5,6,7,8, and 16 were conducted using this procedure.

4.5.2. Carbon Dioxide Slug Process

In this case, a carbon dioxide slug of 20% HCPV was injected at a constant flow rate. Following the carbon dioxide slug, brine was injected continuously until a water - oil ratio of approximately 20 m^3/m^3 was attained. One of the runs (Run 12) using this process was conducted with the porous medium at irreducible water saturation. Another run (Run 2) was carried out by injecting the slug of carbon dioxide after a brineflood.

4.5.3. Brineflood

Three brinefloods (Runs 2, 3, and 8) were conducted in order to determine whether the carbon dioxide - brine injection processes or nitrogen - brine injection processes were able to recover additional oil with respect to that recovered by the brine alone. In this process, brine was injected continuously at the beginning, and at a constant flow rate until a WOR of approximately 20 m^3/m^3 was attained. Breakthrough was detected by analyzing samples as explained above.

4.5.4. Special Processes

Beside the above processes, several other processes were investigated. These were : gas flooding prior to carbon dioxide WAG process, continuous carbon dioxide flood prior to carbon dioxide WAG process, composite carbon dioxide and nitrogen slugs driven by brine, heterogeneous packs and carbon dioxide WAG runs at low pressures. The objective of these experiments was to investigate the effect of initial gas saturation, carbon dioxide slug size, heterogeneous reservoirs, and reservoir pressure.

4.5.4.1. Gas Flood Prior to Carbon Dioxide WAG Process

In this process nitrogen was injected continuously until the process was terminated at a producing GOR (gas - oil ratio) o approximately 10000 sm^3/m^3. Then the WAG process with a ratio of 4 : 1 was carried out, until a total amount of 20% HCPV of carbon dioxide was injected. After this, brine was injected continuously until a WOR of approximately 20 m^3/m^3 was obtained. One gas flood before the carbon dioxide WAG process (Run 9) investigated the effect on recovery due to initial gas saturation prior to the carbon dioxide WAG process.

4.5.4.2. Continuous Carbon Dioxide Flood Prior to Carbon Dioxide WAG Process

This process was similar to the gas flood prior to carbon dioxide WAG process. Instead of injecting nitrogen in the aforementioned process, carbon dioxide was injected until a GOR of approximately 10000 sm^3/m^3 was achieved. After this, the WAG process, using a (20% HCPV) total slug of carbon dioxide, was carried out. Then brine was injected continuously until the process was terminated at a producing WOR of approximately 20 m^3/m^3. Runs 10 and 11 were carried out using this process.

4.5.4.3. Composite Carbon Dioxide and Nitrogen Slugs Driven by Brine

This process was similar to the carbon dioxide slug process except that a carbon dioxide slug of 10% HCPV, followed by a nitrogen slug of 10% HCPV, was injected, rather than a 20% HCPV slug of carbon dioxide. The composite carbon dioxide - nitrogen slugs were then driven by brine to a WOR of approximately 20 m^3/m^3. One run (Run 15) using this process was conducted with the porous medium at irreducible water saturation.

4.5.4.4. Heterogeneous Packs

Four runs (Runs 18, 19, 20, and 21) were carried out to examine the effect of heterogeneity on the carbon dioxide flood process.

A heterogeneous packing technique was used to obtain packs with heterogeneous properties in one or two dimensions, but still with homogeneous properties in the other dimensions. Two types of heterogeneous packs were obtained by using this packing technique (i.e. two parallel layers, which consisted of an Ottawa Silica Sand layer on the top and a glass beads layer on the bottom, when the model was in the horizontal position; and diagonal glass bead layers which consisted of one diagonal glass bead layer and two triangular Ottawa Silica Sand layers on each side of a glass bead layer). These heterogeneous packs are shown in Figures 9 and 10, respectively.

To obtain two parallel layers, with the model in the vertical position, a thin steel plate was inserted into the vessel's cavity and kept in the middle of the cavity during the packing process. Then the model was filled with distilled water to a height of 10 cm. The distilled water was followed by sand on one side of the thin steel plate and by glass beads on the other side. During the packing process, the model was vibrated with an air vibrator and a 10 cm head of distilled water was kept above the sand and

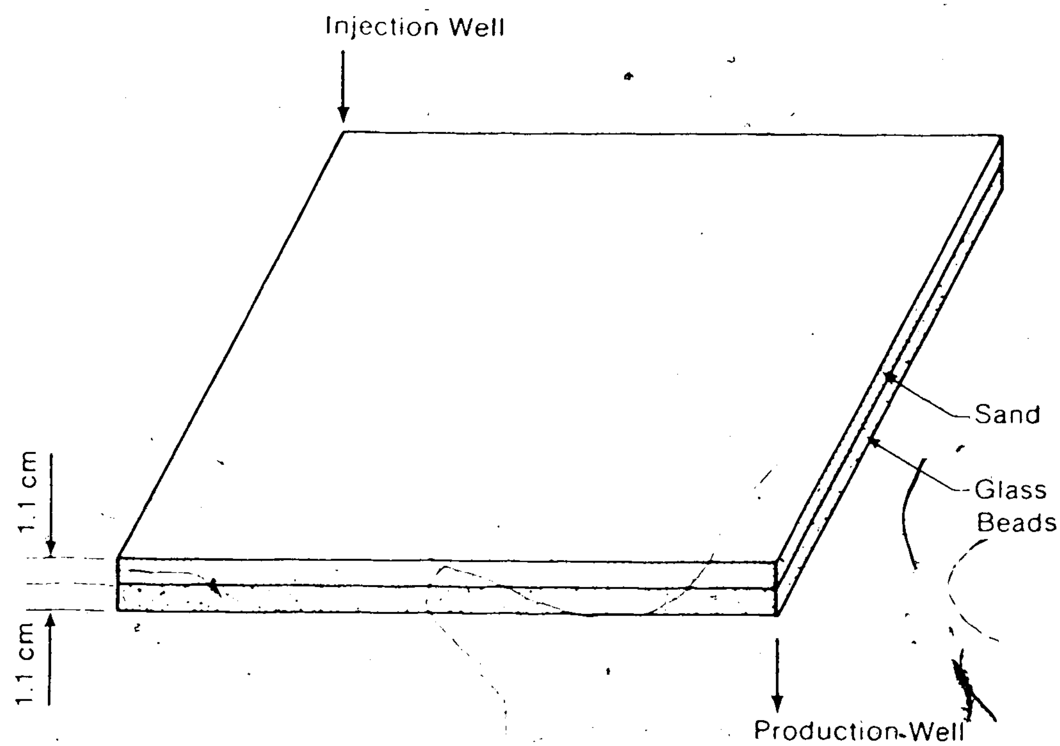


Figure 9 Heterogeneous model consisting of two parallel layers.

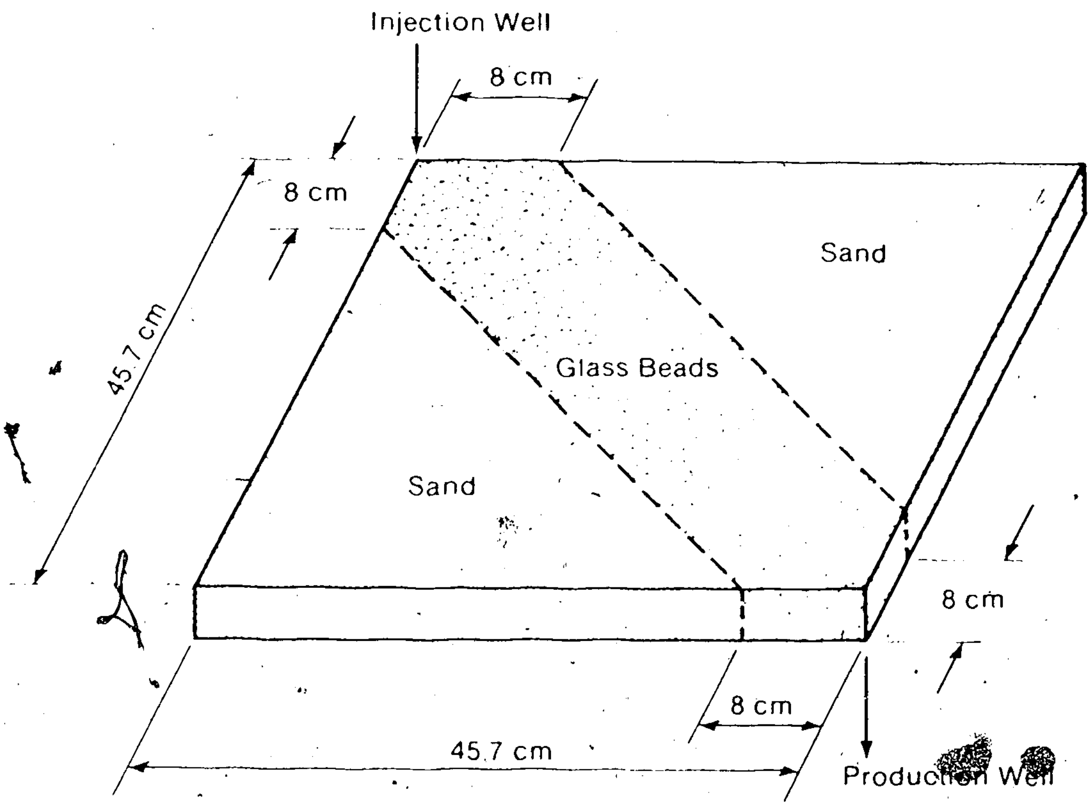


Figure 10 Heterogeneous Model consisting of a diagonal high permeability streak.

glass beads, while the thin steel plate was moved up gradually. In order to maintain the same head of distilled water at the end of the packing process, a 10 cm tall filling lid with a shape similar to that of the cavity was placed on top of the model after it had been filled with sand and glass beads. Then the model was vibrated for several hours. Following this, the packing lid was replaced by the flange plate, and the model was evacuated and vibrated for about 72 hours. The evacuation and vibration of the model after packing eliminated the air trapped by the sand and glass beads. After evacuation, more distilled water was drawn into the model.

For the diagonal glass beads layer packing process, the model was placed in a vertical position and a plate, with bent edges, shown in Figure 5, was inserted into the vessel's cavity. The lower triangle was then filled with Ottawa Silica Sand and the model was vibrated (as shown in Figure 5, step 1). After filling the lower triangle with sand, the distilled water was added to the model and the model was vibrated for about one hour. Then the distilled water in the model was drawn out. The plate was placed in another position and the model was filled with glass beads diagonally (as shown in Figure 5, step 2). Then the model was filled with distilled water again and vibrated for an hour. Following this, the distilled water was drawn out again and the plate was removed from the model. In the third step, the upper triangle was filled with sand and the packing lid was placed on top of the model. The model was again filled with distilled water and vibrated with an air vibrator for several hours. During the vibration, the 10 cm head of distilled water was maintained. After this, the packing lid was removed and the flange plate was placed on top of the model. The model was evacuated with a vacuum pump and vibrated for 72 hours. After evacuation, additional distilled water was drawn into the model to replace the evacuated space.

4.5.4.5. Carbon Dioxide Slug WAG Runs at Low Pressure

This process was similar to the brine-alternating gas slugs (WAG) process except that the runs were carried out at 2.5 MPag in this case rather than at the 5.5 MPag used in all the other runs. A total amount equivalent to a 20% HCPV of carbon dioxide slug at 5.5 MPag and 21°C was injected for the purpose of comparing the results of runs at 2.5 MPag with those at 5.5 MPag. The Starling equation of state was employed to calculate the amount of carbon dioxide injected. When the number of moles of 20% HCPV carbon dioxide at 5.5 MPag and 21°C were calculated, the volume of the same number of moles at 2.5 MPag and 21°C could then be obtained using the Starling equation. Two runs (Runs 22 and 23) were carried out using this process.

4.6. Oil - Water Separation

The emulsions produced during the displacement test were broken by adding one drop of demulsifier (used by Husky Oil Company in Lloydminster) per 100 cm^3 (about 0.01%) of sample and leaving the mixture in a thermostatic bath at 70°C for 24 hours. The pure water was removed from sample. Then 30 - 50 cm^3 of toluene was added to the remaining sample, which still contained a small amount of water in oil, and the mixture was centrifuged at 3000 rpm for 20 minutes.

4.7. Data Processing

The experimental data was processed using a computer program. This program was based on the material balance of oil, water, and carbon dioxide or nitrogen. The amount of fluids injected was calculated from this program. It also calculated the water - oil ratios (WOR), gas - oil ratios (GOR), oil recovery (R), the total volume of oil produced (NP), oil produced - fluid injected ratio (OPFIR), carbon dioxide retention and carbon dioxide required to produce a unit volume of oil.

The Starling equation of state[67] for carbon dioxide and nitrogen was used for material balance to calculate the moles of carbon dioxide injected and produced as well as the moles of nitrogen injected and produced. This equation of state has the following general form.

$$P = \rho RT + (B_0RT + A_0 - C_0/T^2 + D_0/T^3 - E_0/T^4)\rho^2 + (bRT - a - d/T)\rho^3 + \beta(a + d/T)\rho^4 + (c\rho^3/T^2)(1 + \gamma\rho^2)\exp(-\gamma\rho^2)$$

Where : P - pressure

T - temperature

ρ - density

Two new sets of the constants were derived to use the equation in SI units because the constants in the original paper were in British units. For pressure (P) in MPa, temperature (T) in K and density (ρ) in kg-mole/m³, the constants for carbon dioxide are:

$B_0 = 0.024588$

$A_0 = 0.176976$

$C_0 = 2.451876 \times 10^4$

$D_0 = 1.883482 \times 10^6$

$E_0 = 2.631556 \times 10^4$

$b = 0.003781$

$a = 0.009434$

$d = 0.055761$

$\beta = 0.0000961229$

$c = 1.4197888 \times 10^3$

$\gamma = 0.006421$

$R = 0.008314$

The constants for nitrogen are:

$B_o = 0.0422649$

$A_o = 0.112428$

$C_o = 1143.6859$

$D_o = 8.9909 \times 10^4$

$E_o = 3.11307 \times 10^6$

$b = 0.00324822$

$a = 0.00235560$

$d = 0.0290594$

$\beta = 0.0000736446$

$c = 43.703149$

$\gamma = 0.00428738$

$R = 0.008314$

A trial and error procedure with an acceleration approach was used for the above equation to determine the molar densities of carbon dioxide and nitrogen. According to Starling[67], the above equation predicts experimental density data with an average uncertainty of 1% for carbon dioxide and less than 0.5% for nitrogen.

The calculations of the carbon dioxide and nitrogen retention in the composite carbon dioxide - nitrogen slugs (driven by water) process were different from those calculations in other processes. First, a retention of 20% total nitrogen injected was estimated according to the previous experiments. Then the volume of carbon dioxide produced and the volume of nitrogen produced was determined. Thus, the retention of carbon dioxide was calculated by subtracting carbon dioxide produced from the carbon dioxide injected.

In order to determine the permeability for the glass bead layer and the sand layer in the heterogeneous packing, individual permeabilities for glass beads and sand were measured in a tube that was 61 cm in length and 4.8 cm in diameter. The permeabilities are 28.4 darcies for glass beads and 11.2 darcies for sand, respectively. Then the ratio of permeability for glass beads to sand was calculated. The following equation then is used to calculate the individual layer permeability :

$$K_t A_t = K_1 A_1 + K_2 A_2$$

Where: K_t - Total permeability for two parallel layers

A_t - Total cross-sectional area

K_1 - Glass bead layer permeability

A_1 - Glass bead layer cross-sectional area

K_2 - Sand layer permeability

A_2 - Sand layer cross-sectional area

and, $A_1 = A_2 = A_t/2$

$$K_1 = (28.4/11.2)\ K_2 = 2.53\ K_2$$

Flow velocities in a five-spot pattern vary significantly from near the wellbore to midway between wells. The following formula suggested by Stalkup[48] is used for calculating the appropriate superficial velocity:

$$V = (5\ Q)/(1.4142\ H\ L)$$

Where: V - Superficial velocity (cm/s)

Q - Injection rate (cm_3/s)

H - Thickness (cm)

L - Length of the model (cm)

5. Discussion of Results

5.1. Presentation of the Experimental Results

In this study, a total of 23 experimental runs were carried out. Results of Runs 2 to 23 are presented in Table 4, which summarizes the basic data. Detailed injection/production data are given in Tables A1 to A22 for Runs 2 to 23, respectively. The run histories are plotted in Figs. 11 to 37, respectively. All of the important run parameters are indicated in the figures for convenience.

5.2. Types of Runs Conducted

As noted in the chapter on experimental results, several types of runs were carried out, in order to test the hypotheses regarding the process mechanism, and also to examine a wide range of operating conditions. The run types are indicated in Table 4, and are also summarized below for reference:

Nitrogen in place of CO_2 : Runs 4 to 8

Effect of an Initial Gas Saturation, Using Nitrogen : Run 9

Effect of an Initial Gas Saturation, Using Carbon Dioxide : Run 10 and 11

Effect of Slug Size : Runs 14, 16, and 17

TABLE 4

SUMMARY OF DISPLACEMENT TESTS

AVERAGE EXPERIMENTAL CONDITIONS: P=5.5 MPAG & T=21 C

RUN NO.	GAS TYPE	EXPERIMENT DESCRIPTION	WAG RATIO	TOTAL SLUG NO.	GAS REQUIREMENT SM3/M3	SUPERFICIAL VELOCITY (M/D) GAS	BRINE	Soi (%)	OIL RECOVERY (% OF HCPV) BY BRINE-FLOOD	BY GAS & BRINE	BY BLOW-DOWN	TOTAL
2***	CO2	GAS SLUG DRIVE BY BRINE AFTER BRINEFLOOD		1	180.3(CO2)	0.776	0.776	89.7	32.46	8.04	2.73	43.2
3***	CO2	20.3% WAG PROCESS AFTER BRINEFLOOD	4:1	10	290.9(CO2)	0.776	0.776	89.8	29.57	4.91	1.87	36.4
4	N2	20.1% WAG PROCESS	4:1	10	33.9(N2)	1.035	1.035	81.5		28.97	4.06	33.0
5*	N2	20.0% WAG PROCESS	4:1	10	34.3(N2)	1.035	1.035	93.0		29.45	3.01	32.5
6*	N2	20.0% WAG PROCESS	4:1	18	35.3(N2)	1.293	1.293	82.9		29.21	2.40	31.6
7*	N2	20.0% WAG PROCESS	3:1	10	34.1(N2)	1.552	1.552	91.0		30.11	2.61	32.7
8*	N2	20.0% WAG PROCESS AFTER BRINEFLOOD	4:1	10	178.5(N2)	0.776	0.776	91.6	25.32	4.02	2.24	31.6
9*	CO2	20.0% WAG PROCESS AFTER N2 GASFLOOD	4:1	10	1298.2(N2) 59.0(CO2)	0.323	1.552	92.1		41.71	1.96	43.7
10*	CO2	20.0% WAG PROCESS AFTER CO2 GASFLOOD	4:1	10	758.9(CO2)	0.323	1.293	92.5		57.55	0.64	58.2
11*	CO2	20.0% WAG PROCESS AFTER CO2 GASFLOOD	4:1	10	710.1(CO2)	0.388	0.323	91.1		60.46	0.75	61.2
12*	CO2	20% GAS SLUG DRIVEN BY BRINE		1	60.3(CO2)	2.069	2.069	92.4		32.52	0.44	33.0
13*	CO2	20.2% WAG PROCESS	4:1	10	54.9(CO2)	2.586	2.586	90.3		34.46	1.44	35.9
14*	CO2	40.3% WAG PROCESS	4:1	10	89.2(CO2)	1.552	1.552	89.9		42.31	1.38	43.7

TABLE 4 (Continued)

SUMMARY OF DISPLACEMENT TESTS

AVERAGE EXPERIMENTAL CONDITIONS: P=5.5 MPAG & T=21 C

RUN NO.	GAS TYPE	EXPERIMENT DESCRIPTION	WAG RATIO	TOTAL SLUG NO.	GAS REQUIREMENT NO.	SUPERFICIAL VELOCITY (M/D) GAS	SUPERFICIAL VELOCITY (M/D) BRINE	Sio	OIL RECOVERY (% OF HCPV) BY BRINE-FLOOD	BY GAS & BRINE	BY BLOW-DOWN	TOTAL
15*	CO2 & N2	10% CO2 SLUG THEN 10% N2 GAS SLUG DRIVEN BY BRINE		1	27.5(CO2) 15.8(N2)	1.552	1.552	90.6		33.81	1.60	35.4
16*	CO2	20.0% WAG PROCESS (Lower rate)	4:1	10	45.1(CO2)	1.552	1.552	90.5		40.92	2.08	43.0
17*	CO2	10.1% WAG PROCESS	4:1	9	27.9(CO2)	1.552	1.552	89.9		34.13	1.27	35.4
18****	CO2	20.0% WAG PROCESS (Heterogeneous)	4:1	10	64.4(CO2)	1.552	1.552	88.5		28.17	2.09	30.3
19*****	CO2	20.0% WAG PROCESS (Heterogeneous)	4:1	10	85.2(CO2)	1.552	1.552	92.5		21.51	1.25	22.8
20**	CO2	20.0% WAG PROCESS (Heterogeneous)	4:1	10	63.9(CO2)	1.552	1.552	88.8		28.90	1.39	30.3
21**	CO2	20.0% WAG PROCESS (Heterogeneous)	4:1	10	67.7(CO2)	1.552	1.552	89.7		27.81	0.38	28.8
22**	CO2	9.8% WAG PROCESS (Low pressure)	4:1	9	36.9(CO2)	1.293	1.293	92.9		25.12	0.60	25.7
23**	CO2	20.0% WAG PROCESS (Low pressure)	4:1	10	55.8(CO2)	1.552	1.552	90.4		33.58	1.32	34.9

NOTE: 1. AVERAGE EXPERIMENTAL CONDITIONS FOR RUN NO. 22 & 23: P=2.5 MPAG & T=21°C

2. RUNS 19 & 20 ARE TWO PARALLEL LAYERS PACKING, WHILE RUNS 18 & 21 ARE DIAGONAL GLASS BEADS LAYER PACKING.

3. CO2 IN RUNS 10 & 11 MAY BE IN A LIQUID STATE BECAUSE A SIPHON IS IN THE CONTAINER

4. *---sample NO. 8 (1116 mPa s), **---sample NO. 10 (1101 mPa s), ***---sample NO. 7 (1032mPa s)

*****---sample NO. 9(2107 mPa.s), Run 4 is sample NO. 2 (3897 mPa s)

5. Sio---Initial oil saturation

Composite Carbon Dioxide and Nitrogen Slugs : Run 15

Heterogeneous Sand Packs : Runs 18 to 21

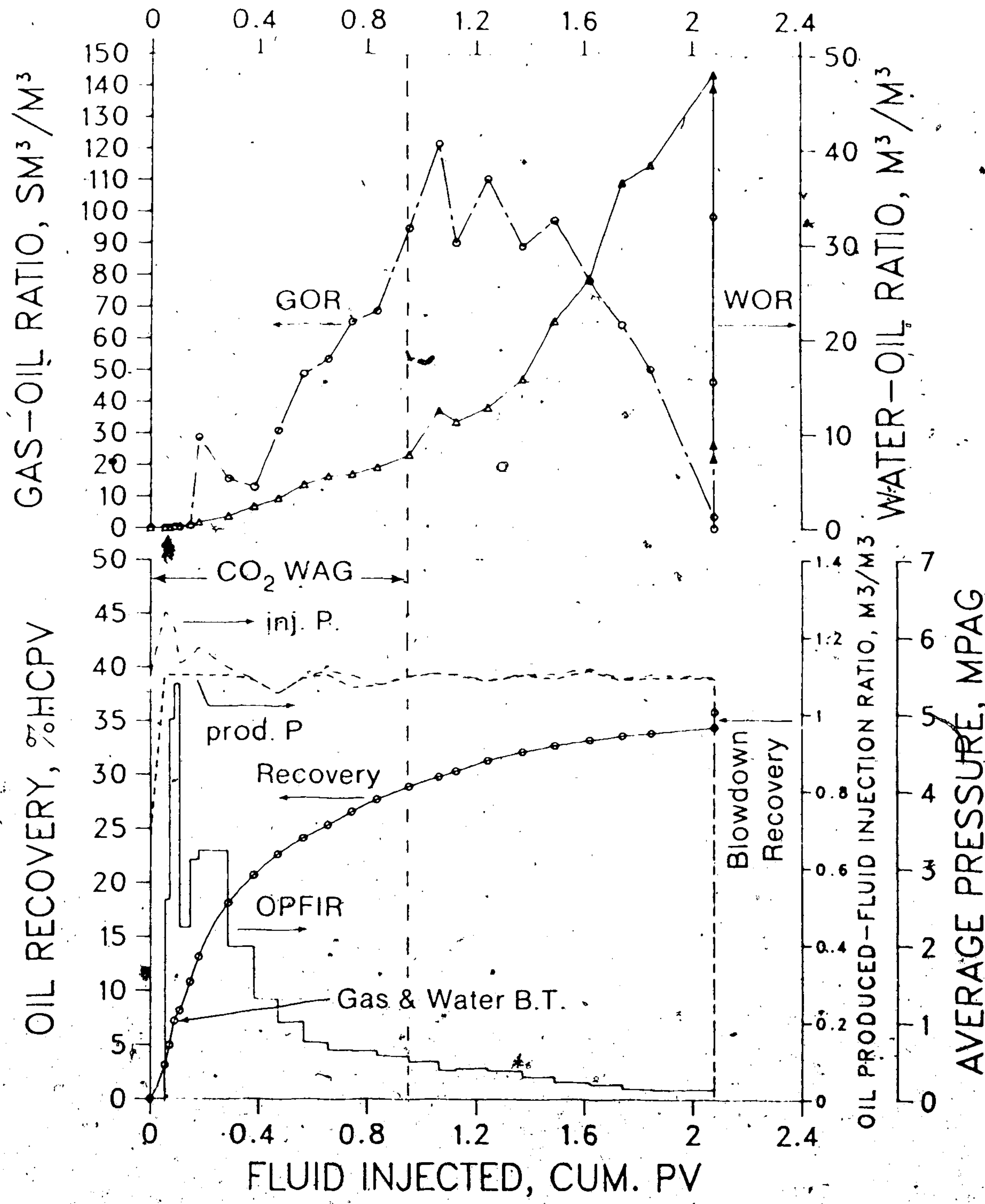
Low Pressure Runs : Runs 22 and 23

In addition, Runs 2, 3, and 8 were carried out with the sand pack initially waterflooded. In all other runs, the sand pack was initially saturated with oil and irreducible water saturation. Run 13, for which the production history is shown in Figure 11, was primarily conducted to reproduce the results of the previous work by Rojas and Farouq Ali[52]. The average velocity in the model in most runs was 1.552 m/day; in several runs it was varied to assess the effect of velocity (Please refer to the Chapter 4 Section 4.7. "Data Processing" for calculation of the average superficial velocity). In Runs 2 and 12, a single slug of carbon dioxide was driven by brine, and in Run 15 a composite carbon dioxide and nitrogen slug was driven by brine. In all other runs, a WAG-type displacement was employed. In all runs (except Runs 22 and 23), as was the case in the previous work by Rojas and Farouq Ali[52], a constant operation pressure of 5.5 MPa was employed.

5.3. Comments on Table and Graph Entries

Tables 4 and A1 to A22 list the type of run, the WAG ratio (ratio of the total volume of water injected to the

FIGURE 11 , Production History of Run 13



NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=2.586 m/d, 20% CO_2 WAG process, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =38.71%, So=90.3%, k=5.273 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

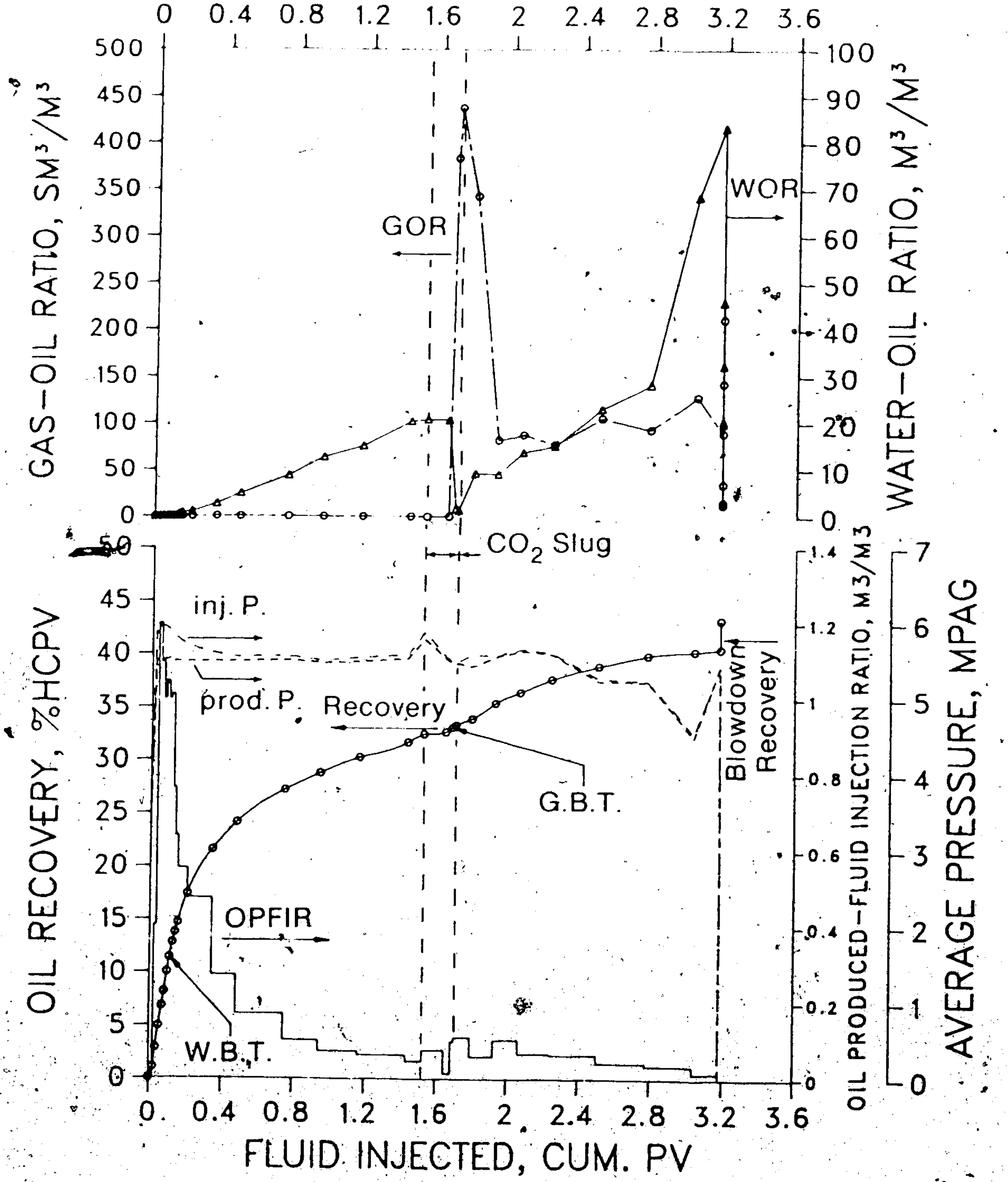
total volume of carbon dioxide injected), the total number of slugs (the number of slugs into which the total volume of carbon dioxide or water is split for the WAG displacement); the superficial velocities for the carbon dioxide slug (gas) injection and brine injection, and oil recovery. The total oil recovery is made up of oil recovery by waterflood (using brine), where applicable, by the injected gas (carbon dioxide and/or nitrogen) and brine (single slug or WAG), and by blowdown at the end of a run. These recovery figures are indicated separately. Also shown is the carbon dioxide requirement, defined as the volume of carbon dioxide required to produce a unit volume of oil, in sm^3/sm^3. Note that the volume of carbon dioxide recovered at the end of a run is not subtracted from the carbon dioxide injected in calculating the requirement.

Figures 11 to 37 show run histories by means of six plots, each on the basis of cumulative fluid injected, which is the abscissa. The top two plots in each figure are the producing gas-oil ratio (GOR) and water-oil ratio (WOR) graphs, in sm^3/sm^3. The two plots immediately below are for the injection pressure, and the back pressure at the production end, respectively. The bottom two plots are for cumulative oil recovery, as percent of the hydrocarbon pore volume, and the instantaneous oil produced-to-fluid injected ratio, in m^3/m^3. This ratio reflects the relative oil production rates, if one considers that the fluid injected will have approximately the same incremental volume. Points of carbon dioxide and water breakthrough are indicated (Please refer to the chapter on Experimental Details for determination of the point of carbon dioxide breakthrough).

5.4. Waterflood Recovery

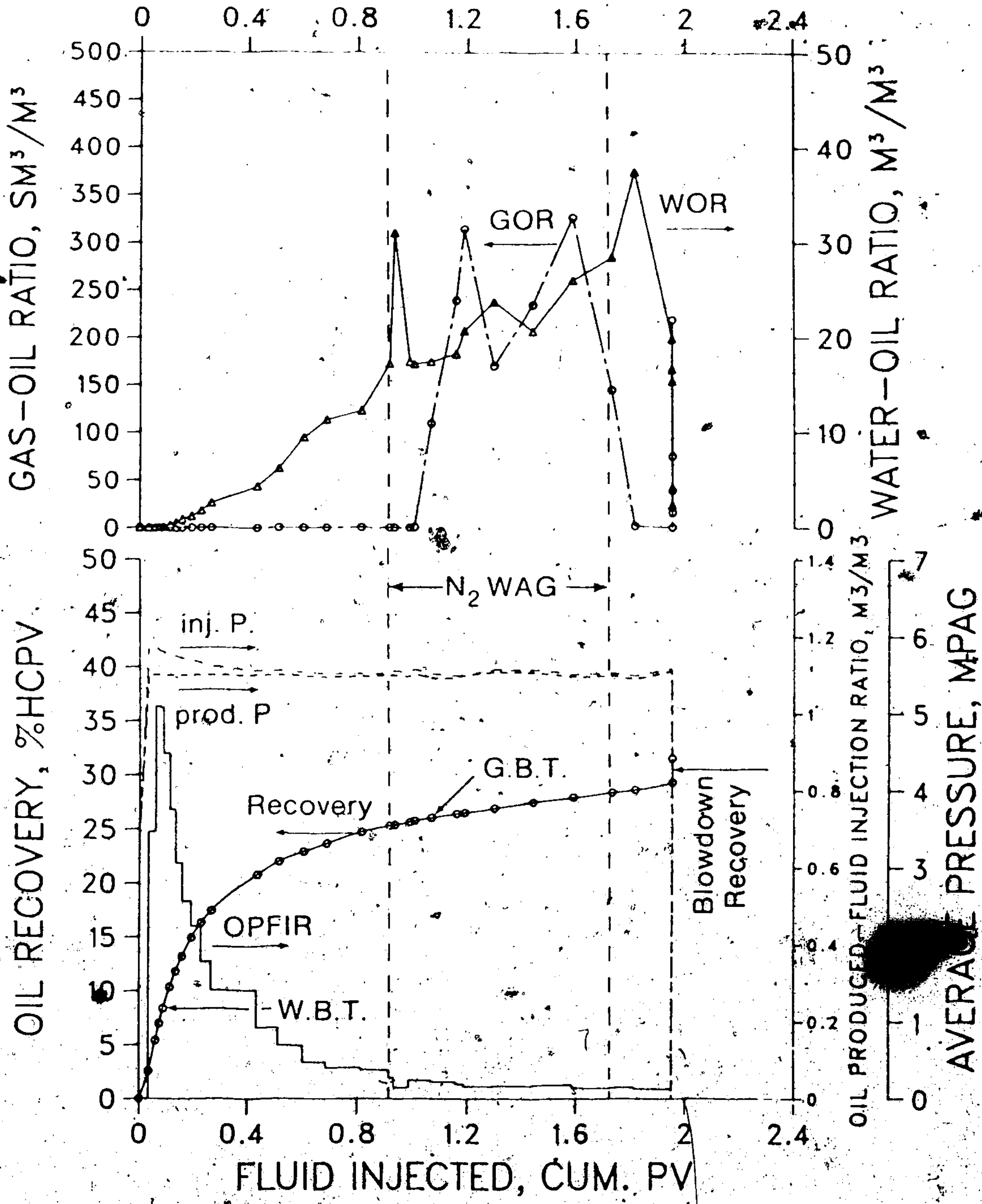
As noted above, in three out of the 23 runs conducted, the sand pack was first waterflooded. In other runs, the initial oil saturation corresponded to irreducible water saturation. It is important to examine waterflood recovery in order to show the effectiveness of a carbon dioxide flood. Runs 2, 3, and 8 employed a waterflood prior to the carbon dioxide flood. Oil recovery in these was 32.5, 29.6, and 25.3% of the original oil in place, respectively, for an initial oil saturation of approximately 90% pore volume (as shown in Figures 12, 13, and 14). These figures are for Oil Sample Nos. 7 and 8, with viscosities of 1032 and 1116 mPa.s, respectively. Previously, Rojas and Farouq Ali[52] found waterflood recoveries of 32 to 36% for a similar oil and sand. This waterflood recovery is clearly higher than recoveries normally observed in Saskatchewan oil reservoirs, which are approximately one-half of these values. The main reason for the higher model recoveries is the homogeneity of the sand pack. In contrast, heavy oil reservoirs in Saskatchewan are rather heterogeneous, with

FIGURE 12 ; Production History of Run 2



NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=0.776 m/d, 20% CO_2 SLUG drive by brine after brineflood, Homogeneous Pack, μ_o = 1032 mpa.s @ 23°C & 0 Mpag, ϕ =37.55%, So=89.7%, k=8.5 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

Figure 13. Production History of Run 8



NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=0.776 m/d, 20% N_2 WAG process after brineflood, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =38.55%, So=91.6%, k=9.654 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

Composite Carbon Dioxide and Nitrogen Slugs : Run 15

Heterogeneous Sand Packs : Runs 18 to 21

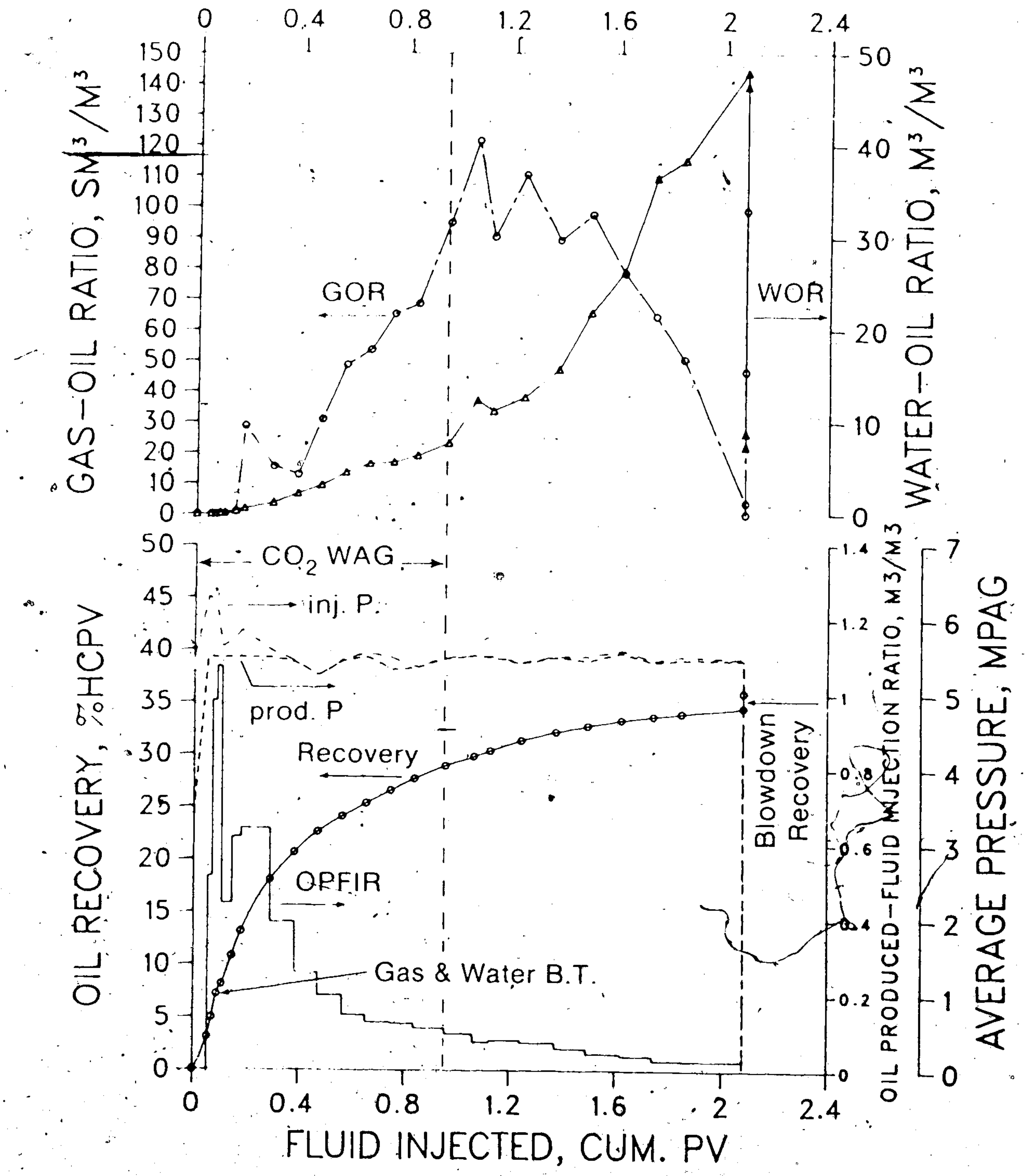
Low Pressure Runs : Runs 22 and 23

In addition, Runs 2, 3, and 8 were carried out with the sand pack initially waterflooded. In all other runs, the sand pack was initially saturated with oil and irreducible water saturation. Run 13, for which the production history is shown in Figure 11, was primarily conducted to reproduce the results of the previous work by Rojas and Farouq Ali[52]. The average velocity in the model in most runs was 1.552 m/day; in several runs it was varied to assess the effect of velocity (Please refer to the Chapter 4 Section 4.7. "Data Processing" for calculation of the average superficial velocity). In Runs 2 and 12, a single slug of carbon dioxide was driven by brine, and in Run 15 a composite carbon dioxide and nitrogen slug was driven by brine. In all other runs, a WAG-type displacement was employed. In all runs (except Runs 22 and 23), as was the case in the previous work by Rojas and Farouq Ali[52], a constant operation pressure of 5.5 MPa was employed.

5.3. Comments on Table and Graph Entries

Tables 4 and A1 to A22 list the type of run, the WAG ratio (ratio of the total volume of water injected to the

FIGURE 11, Production History of Run 13



NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=2.586 m/d, 20% CO_2 WAG process, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =38.71%, So=90.3%, k=5.273 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

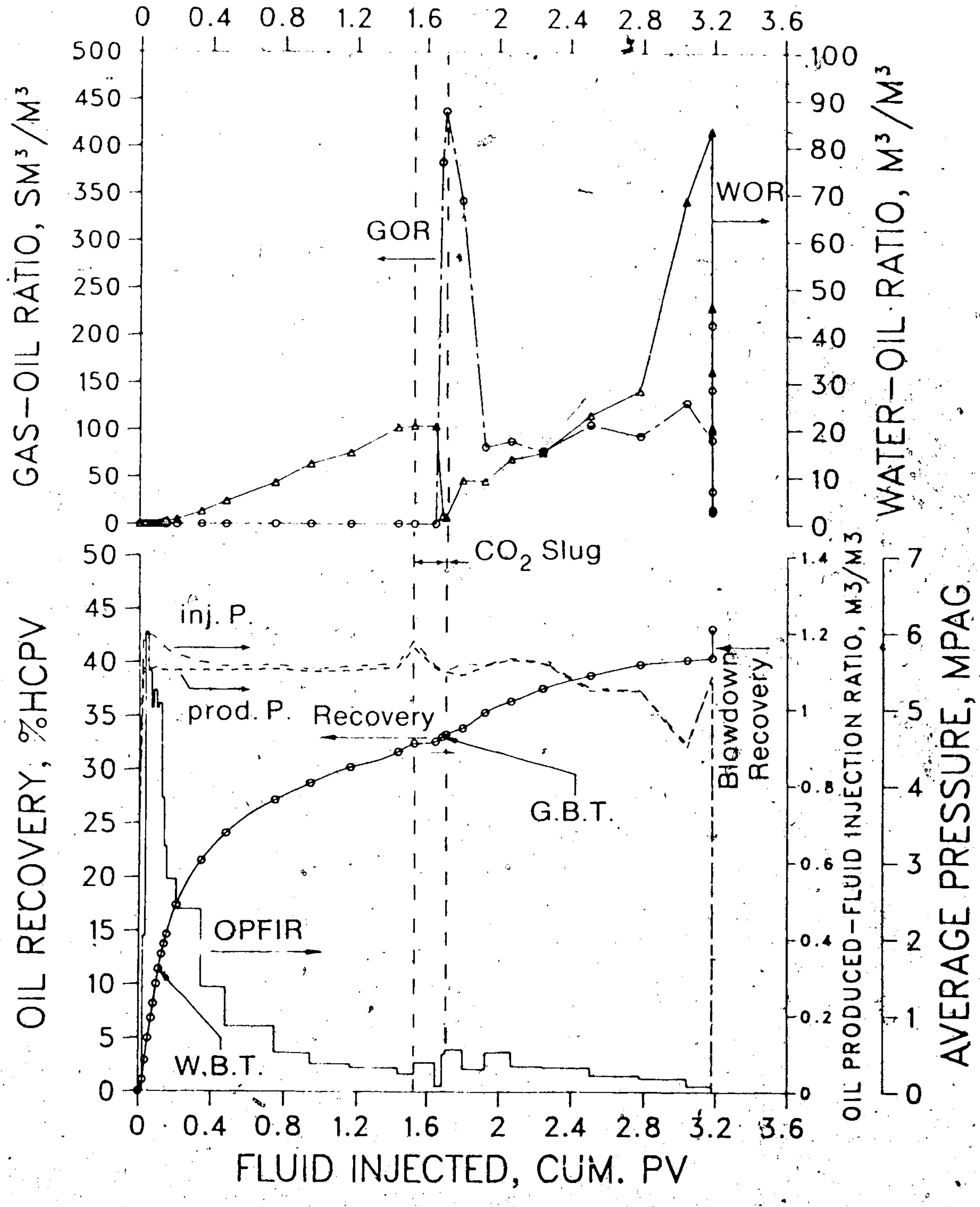
total volume of carbon dioxide injected), the total number of slugs (the number of slugs into which the total volume of carbon dioxide or water is split for the WAG displacement), the superficial velocities for the carbon dioxide slug (gas) injection and brine injection, and oil recovery. The total oil recovery is made up of oil recovery by waterflood (using brine), where applicable, by the injected gas (carbon dioxide and/or nitrogen) and brine (single slug or WAG), and by blowdown at the end of a run. These recovery figures are indicated separately. Also shown is the carbon dioxide requirement, defined as the volume of carbon dioxide required to produce a unit volume of oil, in sm^3/sm^3. Note that the volume of carbon dioxide recovered at the end of a run is not subtracted from the carbon dioxide injected in calculating the requirement.

Figures 11 to 37 show run histories by means of six plots, each on the basis of cumulative fluid injected, which is the abscissa. The top two plots in each figure are the producing gas-oil ratio (GOR) and water-oil ratio (WOR) graphs, in sm^3/sm^3. The two plots immediately below are for the injection pressure, and the back pressure at the production end, respectively. The bottom two plots are for cumulative oil recovery, as percent of the hydrocarbon pore volume, and the instantaneous oil produced-to-fluid injected ratio, in m^3/m^3. This ratio reflects the relative oil production rates, if one considers that the fluid injected will have approximately the same incremental volume. Points of carbon dioxide and water breakthrough are indicated (Please refer to the chapter on Experimental Details for determination of the point of carbon dioxide breakthrough).

5.4. Waterflood Recovery

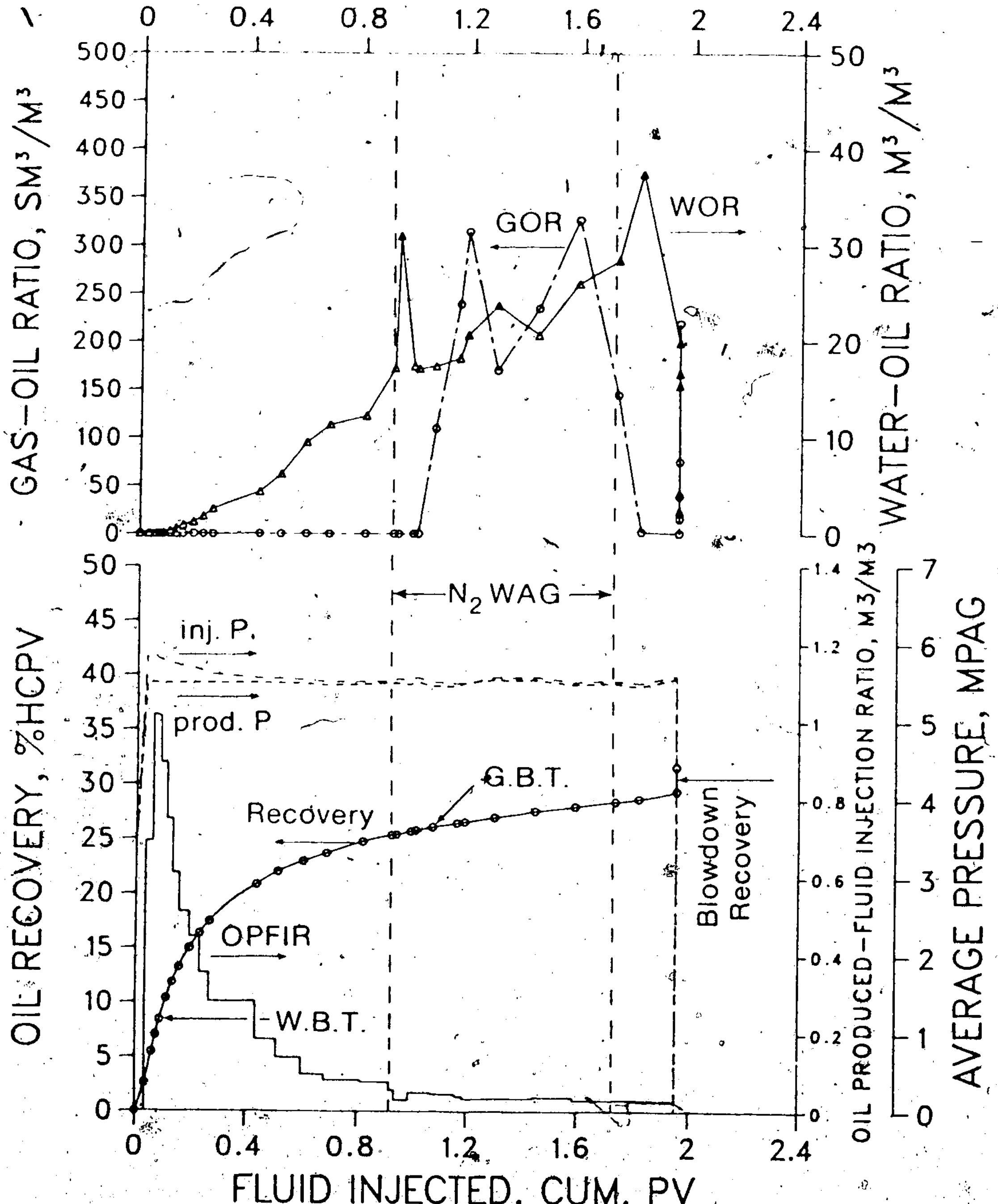
As noted above, in three out of the 23 runs conducted, the sand pack was first waterflooded. In other runs, the initial oil saturation corresponded to irreducible water saturation. It is important to examine waterflood recovery in order to show the effectiveness of a carbon dioxide flood. Runs 2, 3, and 8 employed a waterflood prior to the carbon dioxide flood. Oil recovery in these was 32.5, 29.6, and 25.3% of the original oil in place, respectively, for an initial oil saturation of approximately 90% pore volume (as shown in Figures 12, 13, and 14). These figures are for Oil Sample Nos. 7 and 8, with viscosities of 1032 and 1116 mPa.s, respectively. Previously, Rojas and Farouq Ali[52] found waterflood recoveries of 32 to 36% for a similar oil and sand. This waterflood recovery is clearly higher than recoveries normally observed in Saskatchewan oil reservoirs, which are approximately one-half of these values. The main reason for the higher model recoveries is the homogeneity of the sand pack. In contrast, heavy oil reservoirs in Saskatchewan are rather heterogeneous, with

FIGURE 12, Production History of Run 2



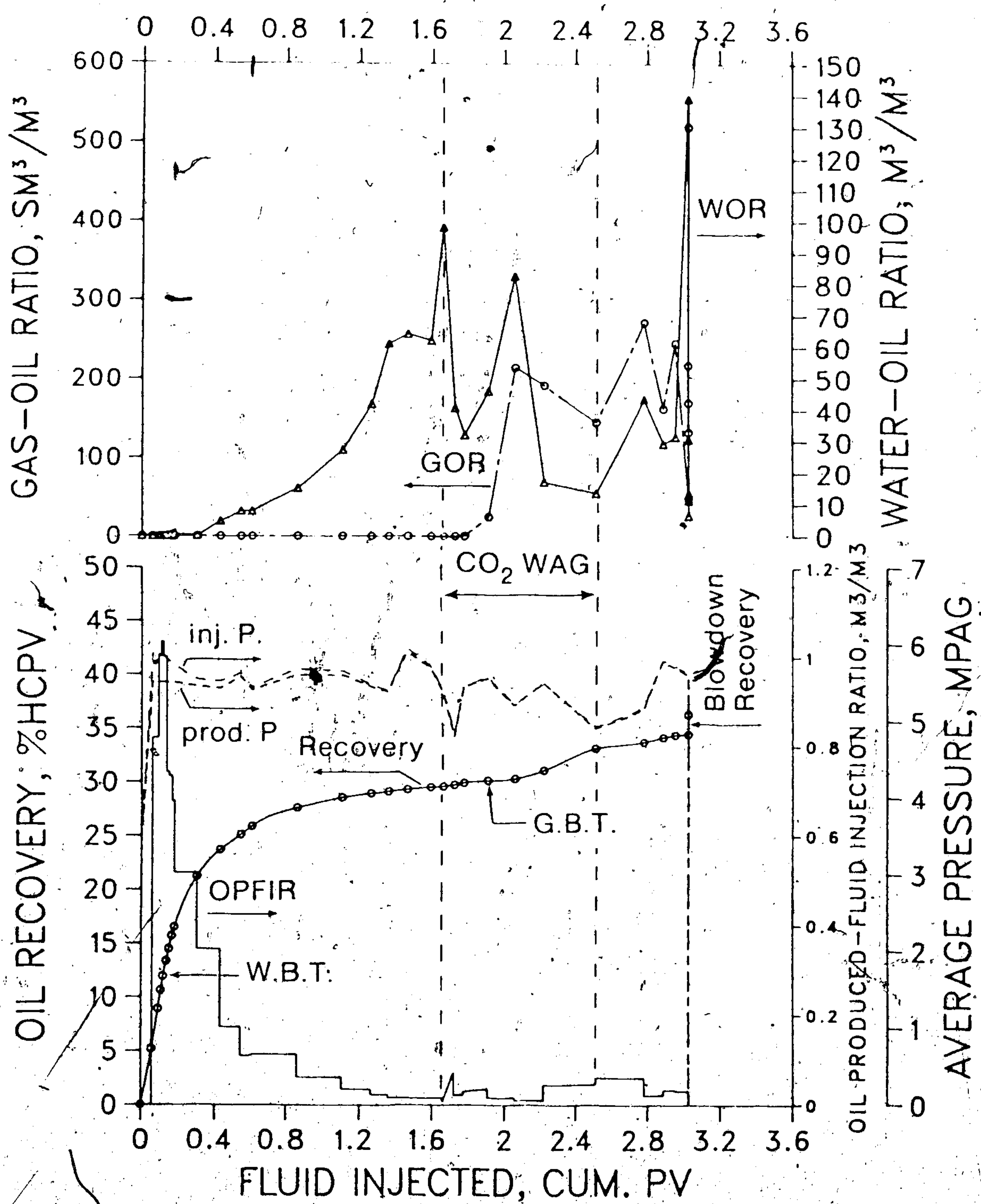
NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=0.776 m/d, 20% CO_2 SLUG drive by brine after brineflood, Homogeneous Pack, μ_o = 1032 mpa.s @ 23°C & 0 Mpag, ϕ =37.55%, So=89.7%, k=8.5 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

Figure 13 Production History of Run 8



NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=0.776 m/d, 20% N_2 WAG process after brineflood, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =38.55%, So=91.6%, k=9.654 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 14 , Production History of Run 3



NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=0.776 m/d, 20.3% CO_2 WAG process after brineflood, Homogeneous Pack, μ_o = 1032 mpa.s @ 23°C & 0 Mpag, ϕ =39.81%, So=89.8%, k=9.959 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

considerable sand production, which causes formation of microchannels ("wormholes") and leads to a low waterflood efficiency. Additionally, the model was confined, and the flooding rates were relatively high, so that the effect of gravity was less than that in the field. One may ask how far the field oil recoveries would be lower than the model values for the carbon dioxide flooding process, because of formation heterogeneities. Runs 18 to 21 were designed to answer this question for two types of heterogeneities, and will be discussed later. Oil recovery was found to be relatively insensitive to heterogeneity.

5.5. Reproducing the Previous Work

Runs 3 and 12 closely reproduced the conditions of Runs 19 and 8, respectively, reported by Rojas and Farouq Ali[52].

Run 3 employed a 4:1 WAG ratio, with a 20.3% carbon dioxide slug, with the model initially waterflooded. In this run the recovery was 36.3%, while the recovery reported previously was 48.7%. One difference between Run 3 and the previous work was the superficial velocity, which was 0.776 m/day for both the slug and water injection phases. In the previous work, the velocity was 1.44 m/day. Figure 14 gives the production history for Run 3, while Fig. 15 gives a similar plot for Run 19 in the previous work. Although the recovery figures differ substantially, the production curves are remarkably similar. For example, the points of carbon dioxide breakthrough are almost identical. The GOR and WOR curves have very similar variations. Notice that the oil production curve (OPFIR) in the previous work shows a continuing high oil rate, possibly because of the higher injection rate. It was shown in the previous work that a high water injection rate is crucial for a high displacement efficiency in the carbon dioxide process.

Run 12 in the present work purports to reproduce the conditions of Rojas and Farouq Ali's Run 8. In both cases,

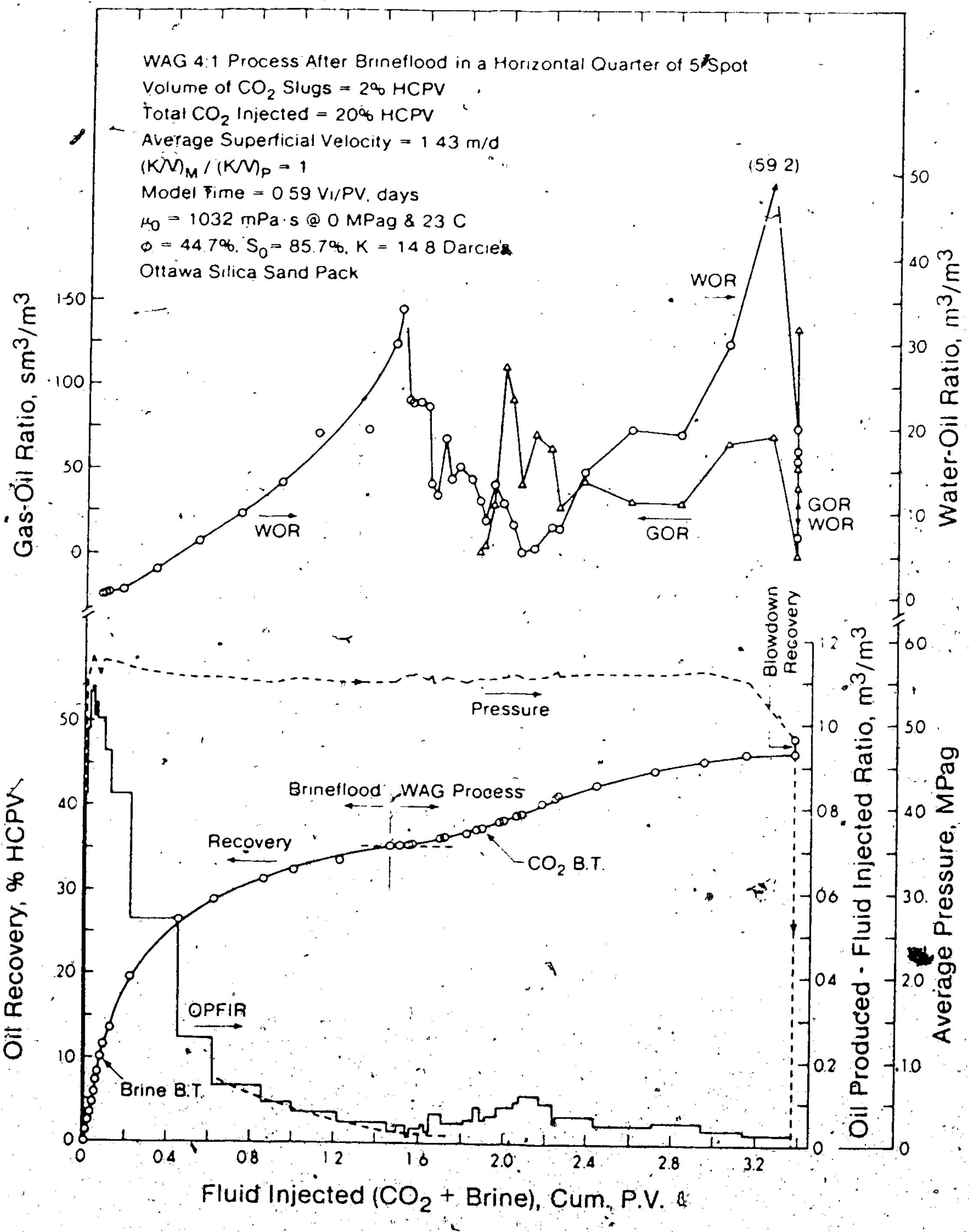
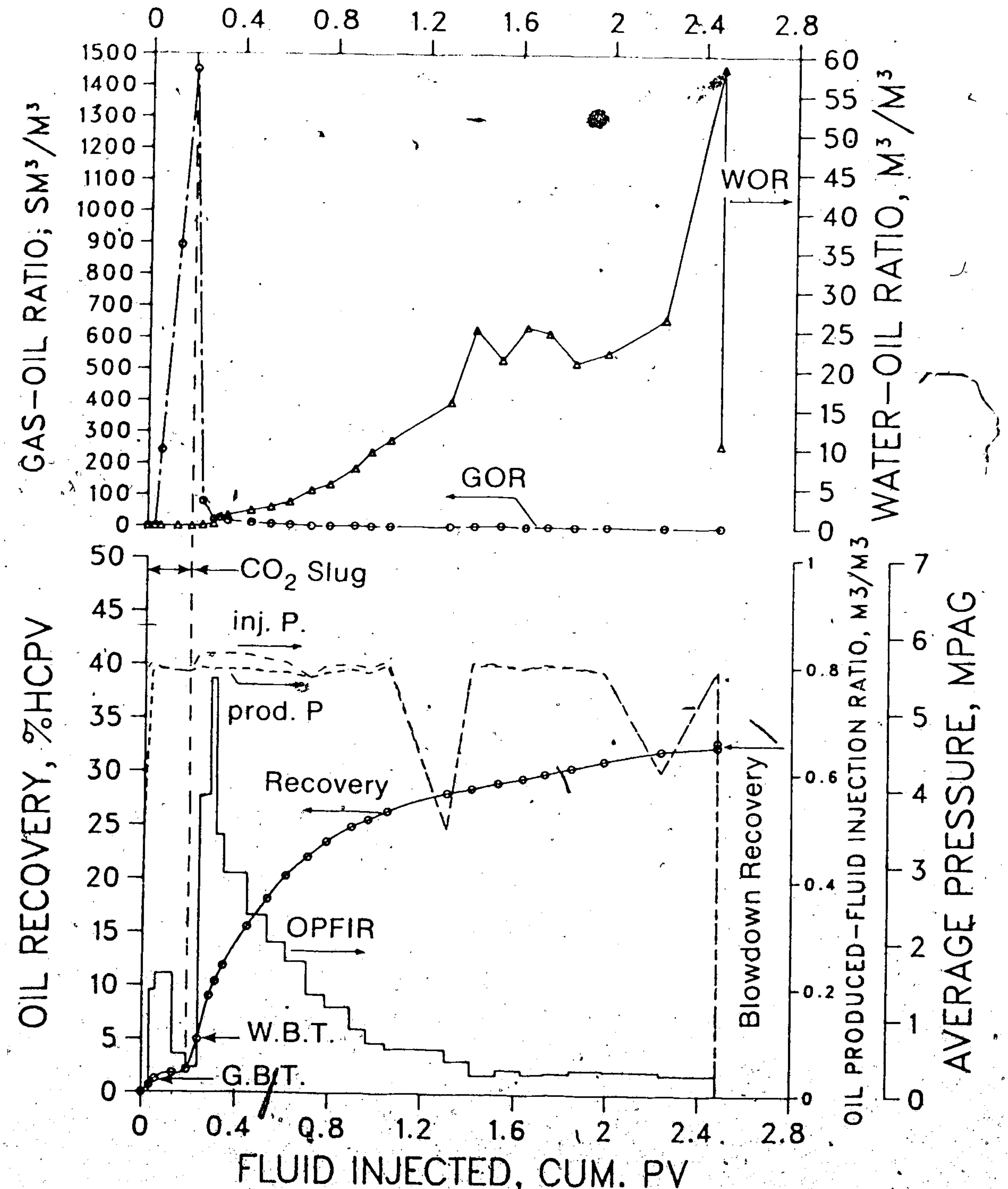


Figure 15 Production History of Run 19 (by Rojas and Farouq Ali)

a single slug of carbon dioxide was driven by a brine flood.

The total oil recovery in the two cases was 33.0% and 38.3%, respectively. Figures 16 and 17 show the production histories of the two runs, respectively. Again, very close agreement is evident. The blowdown recoveries in the two runs were considerably different, leading to somewhat different total recoveries. On the whole, it can be concluded that the present experimental results appear to be close to those obtained previously, and the observed differences can be attributed to somewhat different operating conditions, such as velocities.

FIGURE 16, Production History of Run 12



NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=2.069 m/d, 20% CO_2 SLUG drive then by brine, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =40.48%, So=92.4%, k=12.383 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

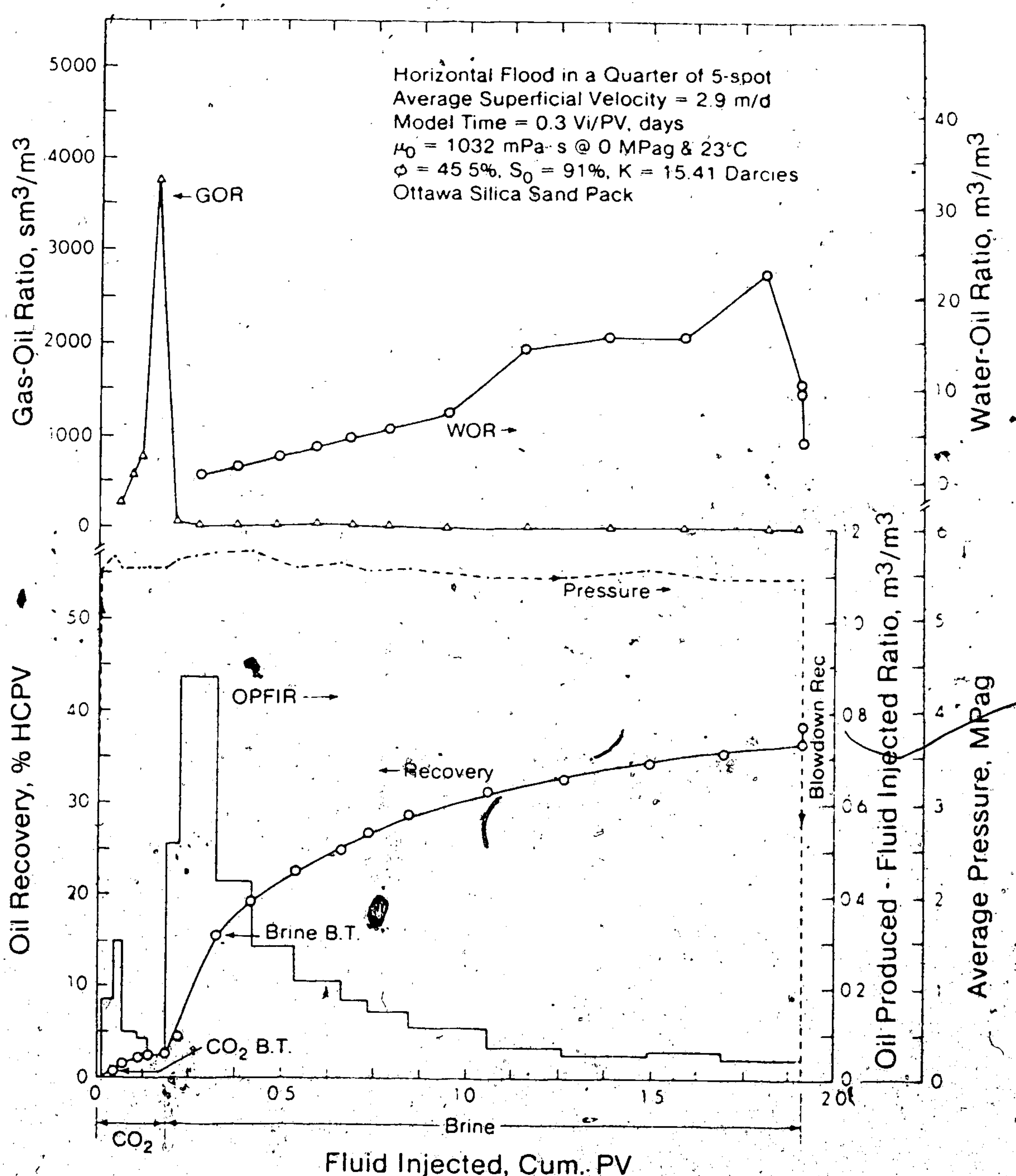
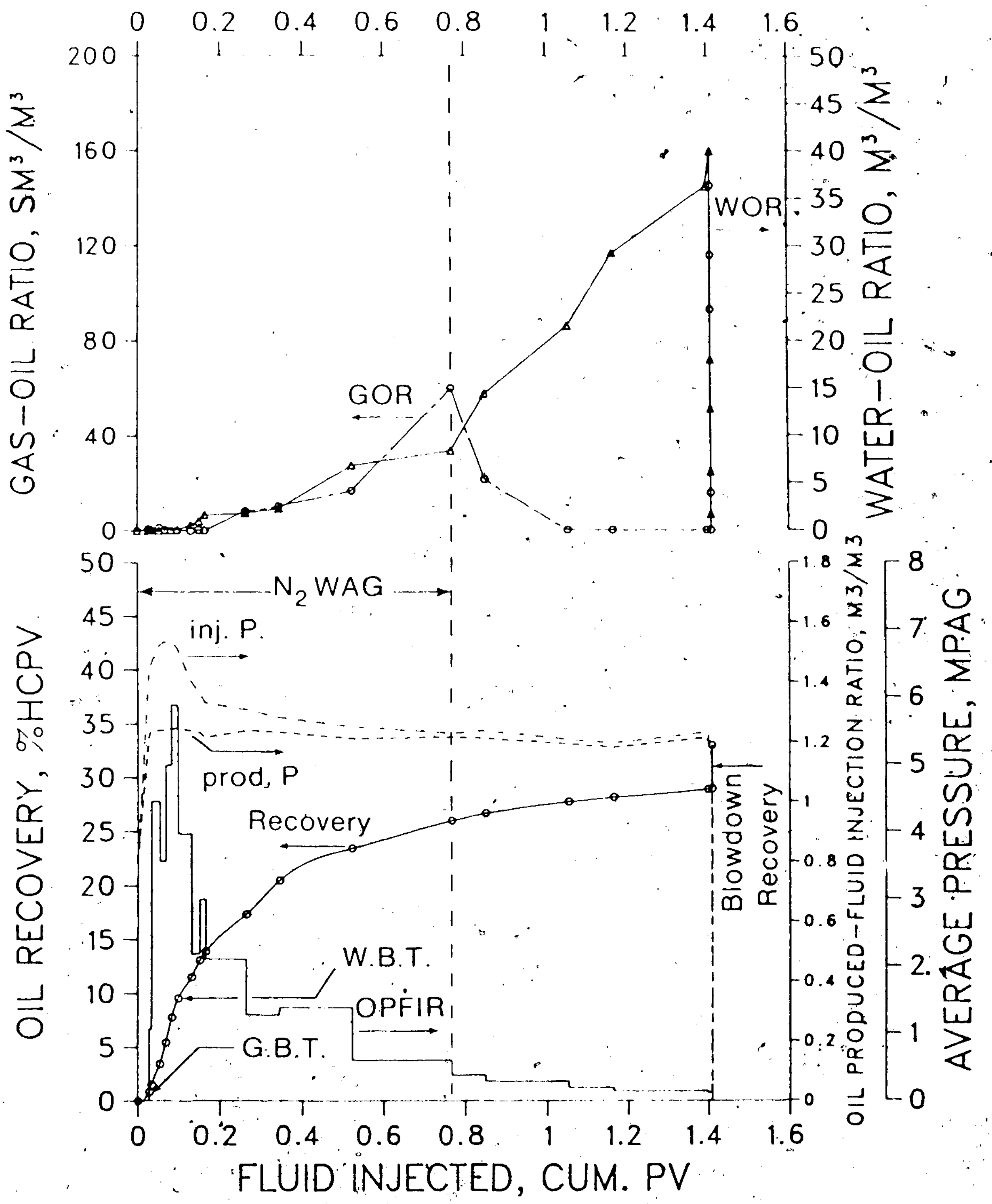


Figure 17 Production History of Run 8 (by Rojas and Farouq Ali)

5.6. *Nitrogen Floods*

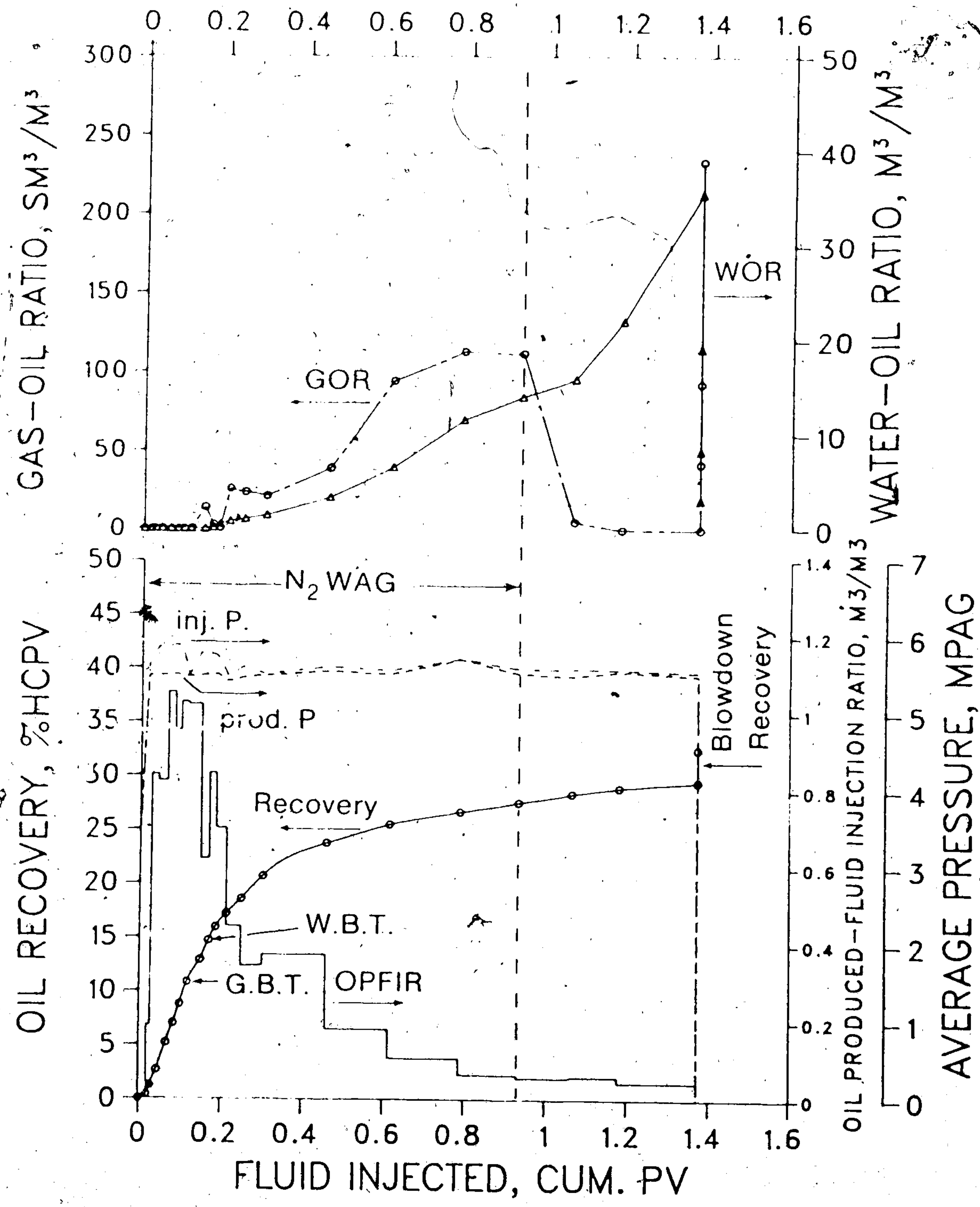
Runs 4 through 8 were carried out to assess the mechanisms attributed to carbon dioxide as the displacing agent. This was accomplished by substituting nitrogen in place of carbon dioxide in WAG type runs. All five runs employed a nitrogen slug of 20% HCPV (hydrocarbon pore volume); in Run 8, the model was previously waterflooded. Run 4 utilized a 3897 mPa.s oil, while in the remaining runs, a 1116 mPa.s oil was employed. The production histories of these runs are shown in Figs. 18 to 22. It is clear that in all cases nitrogen breakthrough occurred almost immediately upon injection. Water breakthrough occurred at approximately 0.2 pore volumes, except in Run 8, where there was mobile water to begin with. Water breakthrough occurred at almost the same point in the waterfloods also (Runs 2, 3, and 8). Recoveries in Runs 4 to 7 were 33.0, 32.4, 31.6, and 32.7%, respectively. The waterflood recoveries, discussed in the previous section, averaged about 29%. Also Table 4 shows that the blowdown recoveries for these four runs were 4.1, 3.0, 2.4, and 2.6%, respectively. Thus, if we do not consider blowdown, the recoveries average at 29.4%, almost the same as the waterflood recovery. It can therefore be concluded that nitrogen accomplished little more than water as a flooding agent. The additional recovery during gas blowdown essentially provided the incremental recovery. Run 8, in

FIGURE 18 , Production History of Run 4



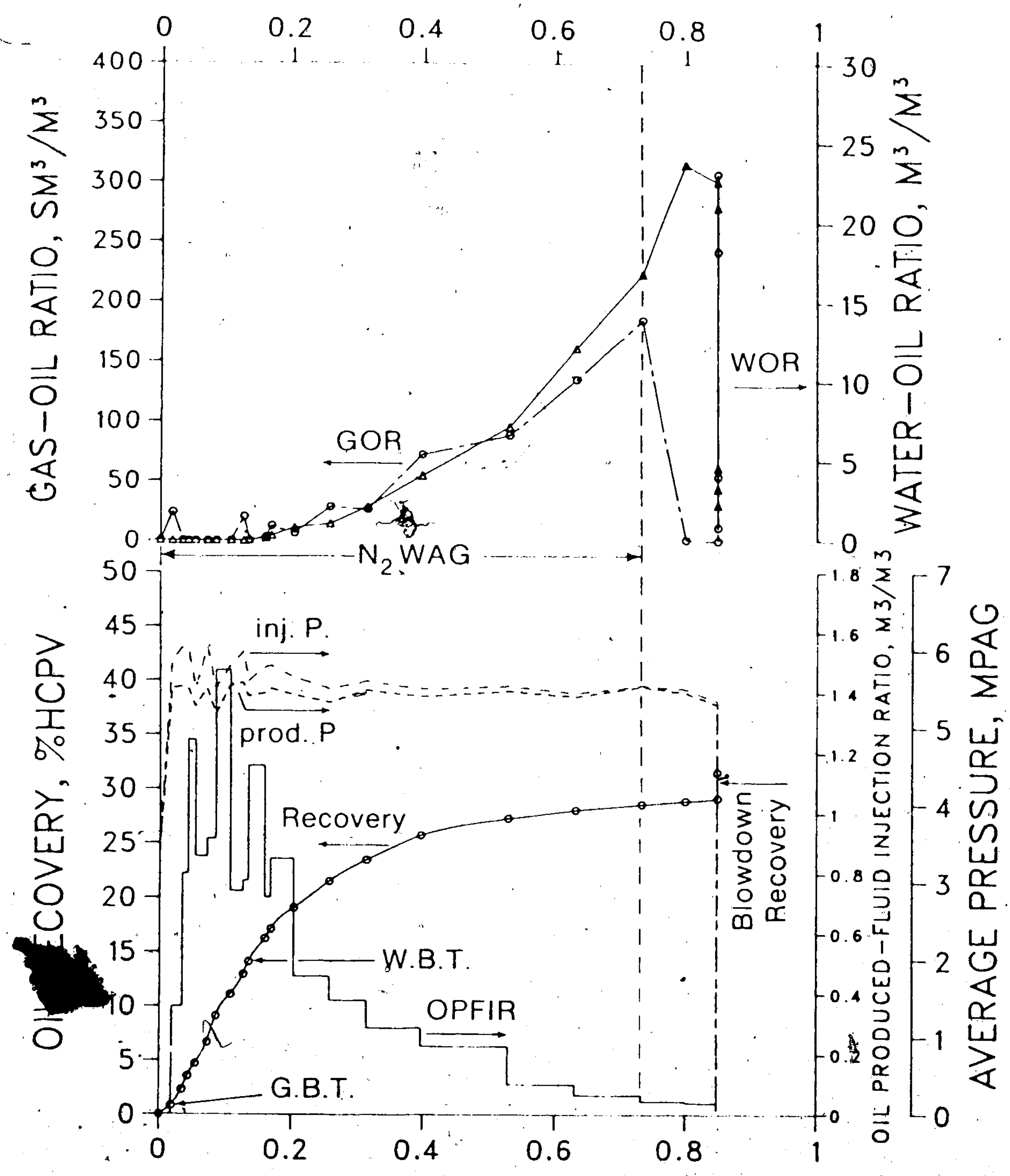
NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.035 m/d, 20.1% N_2 WAG process, Homogeneous Pack, μ_o = 3896.75 mpa.s @ 23°C & 0 Mpag, ϕ =46.51%, So=81.52, k=11.179 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 19, Production History of Run 5



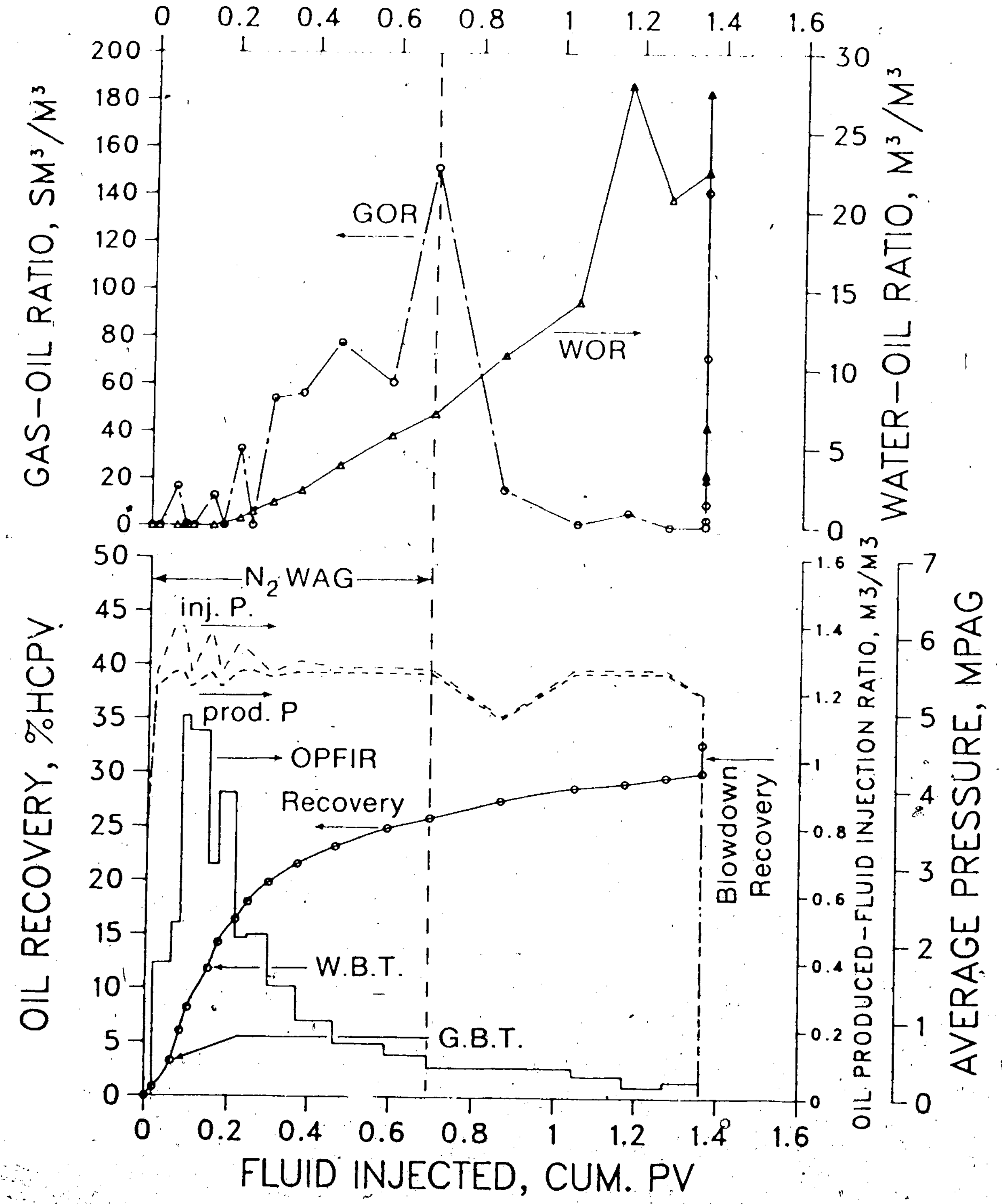
NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.035 m/d, 20% N_2 WAG process, Homogeneous Pack;
μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =40.40%, So=92.98%, K=11.988 Darcies,
Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 20, Production History of Run 6



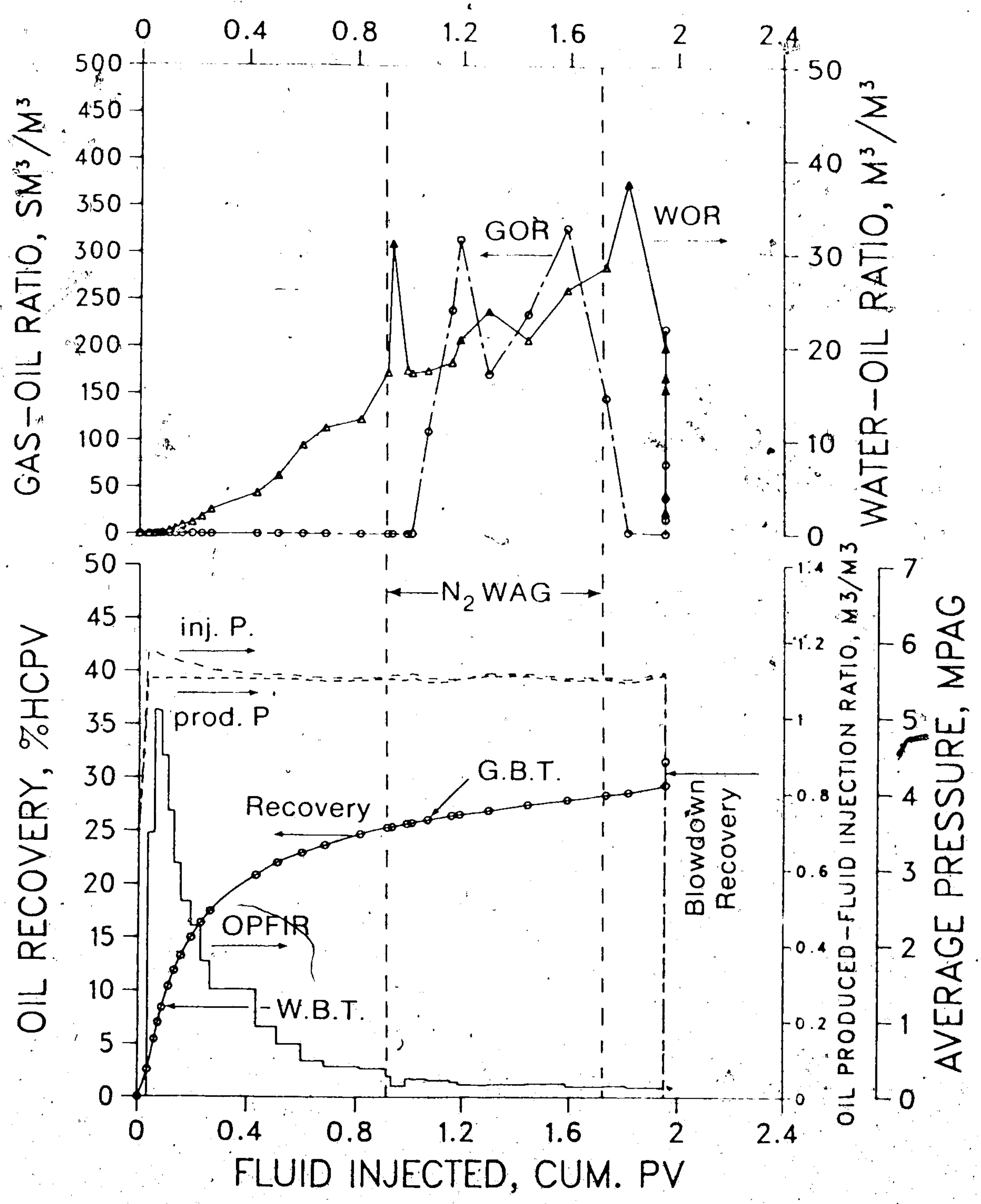
NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.293 m/d, 20% N_2 WAG process, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =47.04%, So=82.85%, K=15.786 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 21, Production History of Run 7



NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=1.552 m/d, 20% N_2 WAG process, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =41.85%, So=91.0%, K=16.807 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 22, Production History of Run 8



NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=0.776 m/d, 20% N_2 WAG process after brineflood, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =38.55%, So=91.6%, k=9.654 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

which the nitrogen displacement was conducted following a waterflood, shows a total recovery of 31.6%, although the waterflood recovery in this case was lower. However, this was compensated by the subsequent gas drive effects. Again, it is clear that no gain was made by nitrogen, except for the blowdown. It should be noted that unlike blowdown in the case of carbon dioxide, which is a solution gas drive effect, blowdown in the case of nitrogen is essentially a gas drive by included, rather than dissolved nitrogen. An examination of Fig. 22 shows the interesting feature that gas breakthrough did not occur immediately as would be expected because the model was initially waterflooded. Rather the injection of the first small slug of nitrogen delayed the breakthrough to about 0.1 pore volume, probably due to gas permeability hysteresis effects.

It should be noted that neither oil viscosity (Run 4 versus Run 5), nor the WAG ratio (4:1 in Run 5 versus 3:1 in Run 7), nor the number of slugs into which the main slug was split (10 in Run 5 versus 18 in Run 6) made much difference to oil recovery. It is particularly remarkable for Run 4, in which the oil viscosity was four times higher than that in Run 5, and yet the oil recoveries for the two runs were almost the same. This reflects the effectiveness of the WAG process, even in the case of an insoluble gas such as nitrogen.

lowdown. It should be noted that unlike blowdown in
ase of carbon dioxide, which is a solution gas drive
t, blowdown in the case of nitrogen is essentially a
rive by included, rather than dissolved nitrogen. An
nation of Fig. 22 shows the interesting feature that
reakthrough did not occur immediately as would be
ted because the model was initially waterflooded.
r the injection of the first small slug of nitrogen
ed the breakthrough to about 0.1 pore volume, probably
o gas permeability hysteresis effects.

It should be noted that neither oil viscosity (Run 4
s Run 5), nor the WAG ratio (4:1 in Run 5 versus 3:1
n 7), nor the number of slugs into which the main slug
plit (10 in Run 5 versus 18 in Run 6) made much
rence to oil recovery. It is particularly remarkable
in 4, in which the oil viscosity was four times higher
that in Run 5, and yet the oil recoveries for the two
were almost the same. This reflects the effectiveness
e WAG process, even in the case of an insoluble gas
is nitrogen.

lowdown. It should be noted that unlike blow

ase of carbon dioxide, which is a solution g

t, blowdown in the case of nitrogen is essen

rive by included, rather than dissolved nitr

nation of Fig. 22 shows the interesting feat

reakthrough did not occur immediately as wou

ted because the model was initially waterflo

r the injection of the first small slug of n

ed the breakthrough to about 0.1 pore volume

o gas permeability hysteresis effects.

It should be noted that neither oil viscosit

s Run 5), nor the WAG ratio (4:1 in Run 5 ve

n 7), nor the number of slugs into which the

plit (10 in Run 5 versus 18 in Run 6) made n

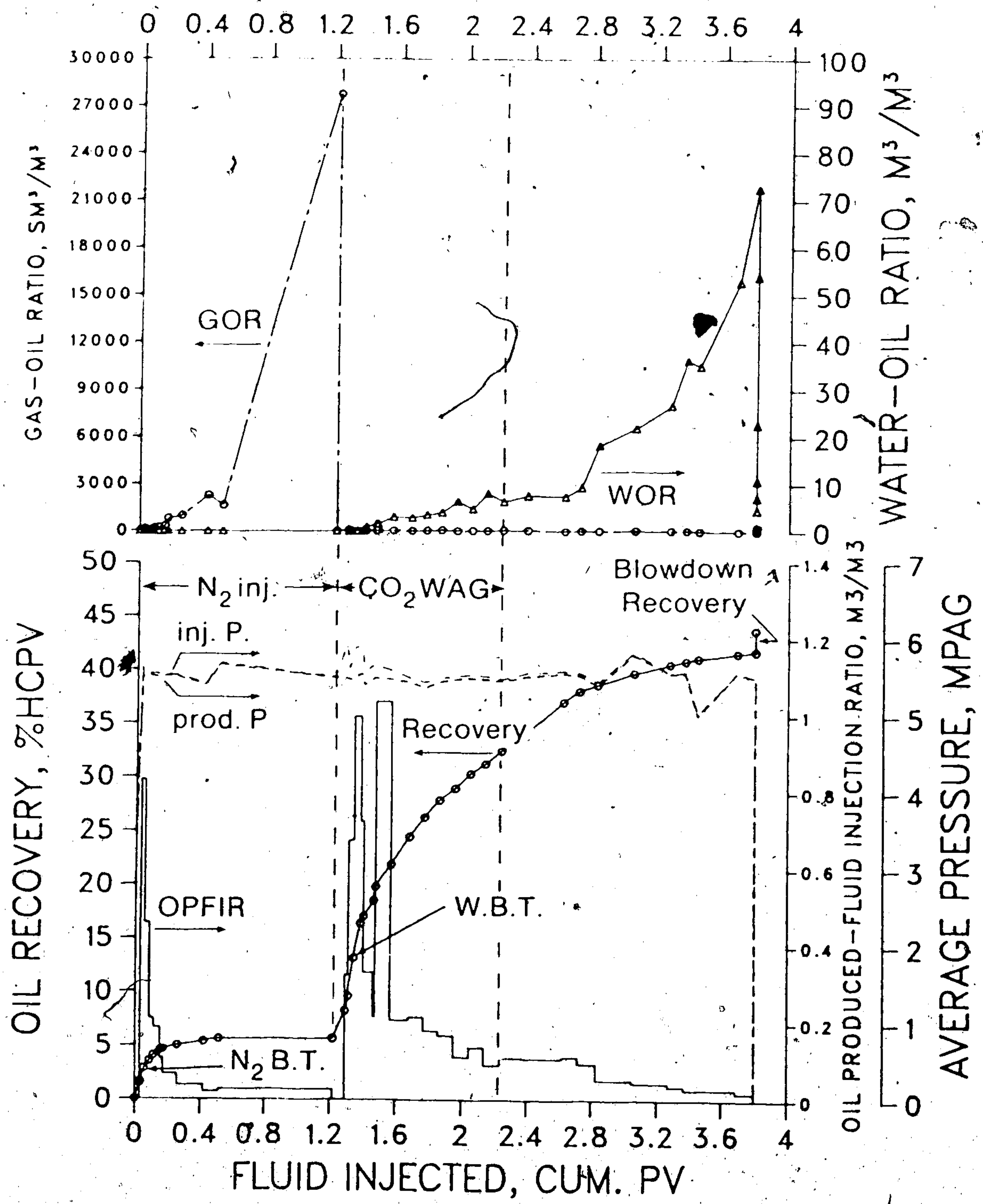
rence to oil recovery. It is particularly re

un 4, in which the oil viscosity was four ti liquid state in Runs 10 and 11). It is to be noted that in these runs, over one pore volume of either gas was injected.

Table A8 shows that prior to carbon dioxide slug injection, 5.67% of the oil was produced by the nitrogen preflush. Similarly, Tables A9 and A10 show that the carbon dioxide preflush produced 32.0 and 27.6% of the oil in place. Thus the high recoveries obtained are due to the large volume of the preflush gas. Even so, it is interesting that the presence of a gas saturation had only a very small effect on the subsequent carbon dioxide WAG process.

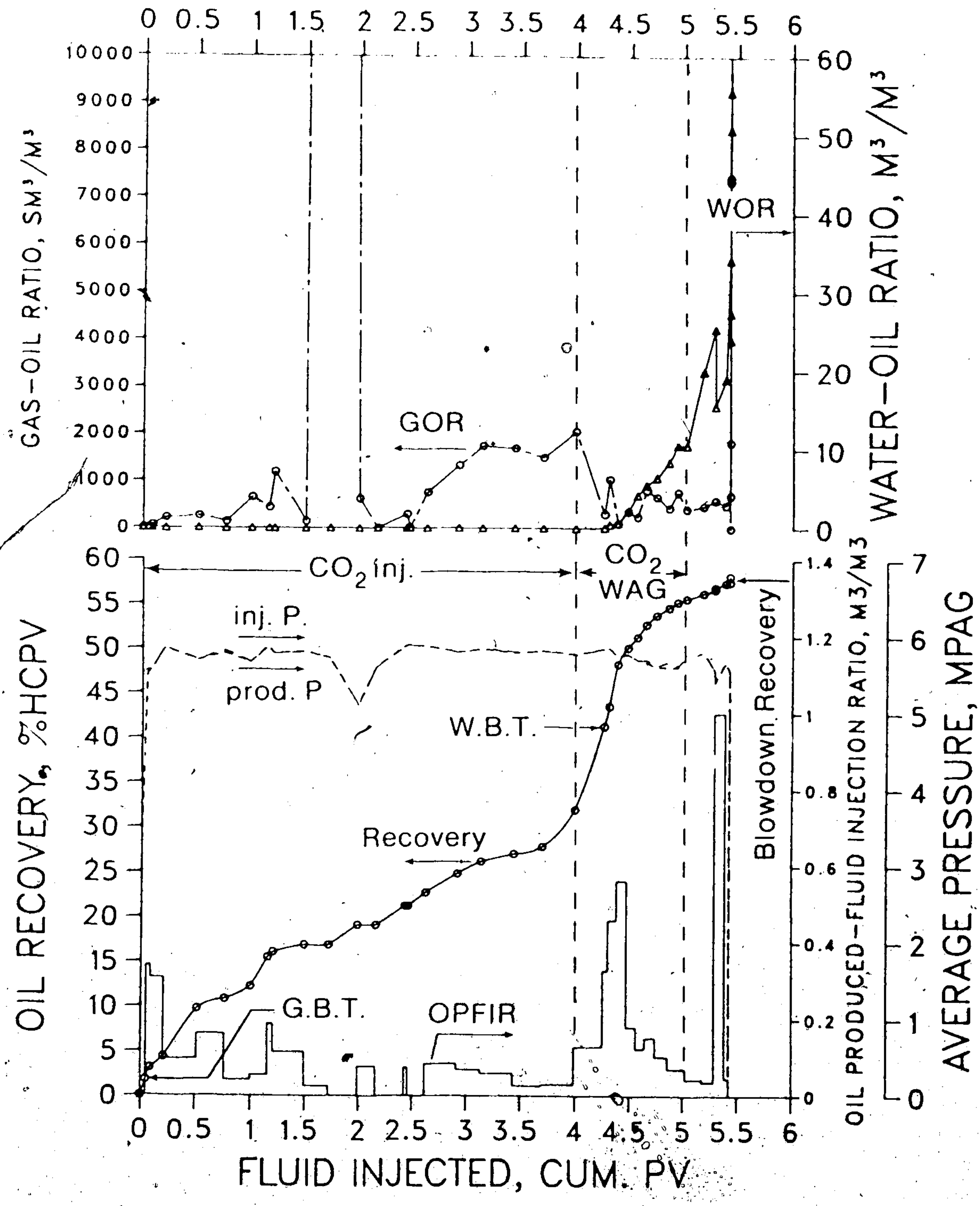
Referring to Figs. 23, 24, and 25, for the aforesaid runs, it is evident that the oil production behaviour was very different in the case of the nitrogen and carbon dioxide preflushes. In the case of nitrogen (Fig. 23), there is an initial period of very low oil production rates to about 0.2 pore volume, following which there is essentially zero oil production. This behaviour is typical of a gas drive under a very unfavourable mobility ratio of the order of 30000. At approximately 1.2 pore volumes, the carbon dioxide WAG process is started, and the subsequent production behaviour is typical of a carbon dioxide WAG displacement. Oil recovery in this portion of the displacement was 43.67 - 5.67 = 38%.

FIGURE 23 , Production History of Run 9



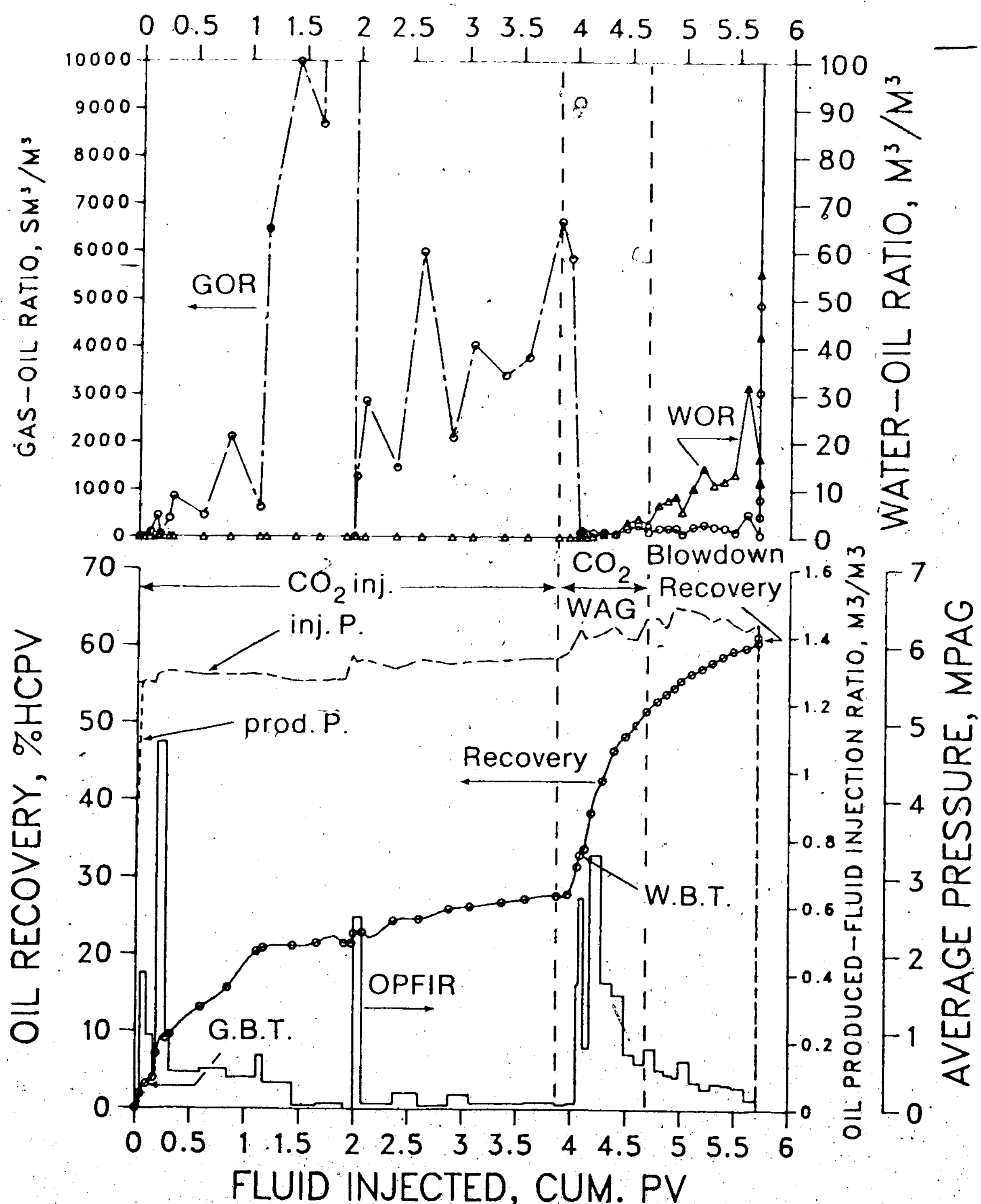
NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=0.323 m/d(gas), 1.552 m/d(brine), N_2 GAS FLOODING, THEN 20% CO_2 WAG Process, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =42.08%, So=92.1%, k=17.576 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 24 , Production History of Run 10



NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=0.323 m/d(gas), 1.293 m/d(brine), 20% CO_2 WAG process after CO_2 Flooding, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =39.87%, So=92.5%, k=15.54 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 25 , Production History of Run 11



NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=0.388 m/d(gas), 0.323 m/d(brine), 20% CO_2 WAG process after CO_2 Flooding, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =40.85%, So=91.1%, k=17.399 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

In the case of carbon dioxide, the production behaviour is quite different, as Figs. 24 and 25 show. It is seen that oil was produced throughout the injection of carbon dioxide. The additional recovery due to the WAG displacement after the preflush was 58.2 - 32.0 = 26.2% in Run 10, and 61.2 - 27.6 = 33.6% in Run 11. The most important difference in this case is that the carbon dioxide used for the preflush lowered the model oil viscosity to approximately 47 mPa.s, as a result of which the gas drive by carbon dioxide was rather effective. In both cases, a sharp increase in the oil production rate is evident at approximately 4 pore volumes, which is the point at which the carbon dioxide WAG process was started. In all cases the produced GOR is very high, indicating inefficient utilization of carbon dioxide or nitrogen. The high values of gas requirement in Table 4 support this. Summarizing, it can be said that an initial gas saturation in the range of 5% does not appear to have an appreciable effect on the carbon dioxide WAG process. The carbon dioxide preflush runs further show the interesting effect of saturating the crude oil with carbon dioxide prior to WAG displacement.

5.8. Effect of Carbon Dioxide Slug Size

In all runs carried out in this investigation, the carbon dioxide slug size was kept constant at 20% HCPV. In two runs, Runs 14 and 17, slug sizes of 40 and 10% were employed to determine the sensitivity of oil recovery to the slug size. The total oil recoveries for the three slugs used are plotted in Fig. 26. It is evident that the oil recovery for a 20% slug (43.0% in Run 16) was close to that for the 40% slug (43.7% in Run 14), but appreciably higher than for the 10% slug (35.4% in Run 17). It appears that a larger carbon dioxide slug is less efficiently utilized, and the oil recovery is only slightly higher. Figures 27, 28, and 29 show the production histories for the 10, 20, and 40% carbon dioxide slugs, respectively. The initial OPFIR in the case of the 40 and 20% slugs is approximately 90% in the oil bank. In contrast, it is about 100% for the 10% slug. The oil production in the declining OPFIR period is higher in the case of the 40% slug than in the other two. The blowdown recoveries are nearly the same in all cases. These results have an important practical implication, viz. a relatively small slug (20% HCPV in this work) is adequate for oil recovery by the immiscible carbon dioxide WAG process, and a larger slug provides only a small improvement. The optimal nature of the 20% slug is further indicated by the GOR curves in Figs. 27, 28, and 29. In the case of both the 10 and 40% slugs, the GOR rises rapidly, while in the case of the 20% slug it is considerably lower. The effect of slug size on gas-oil ratio is also plotted in Figure 30.

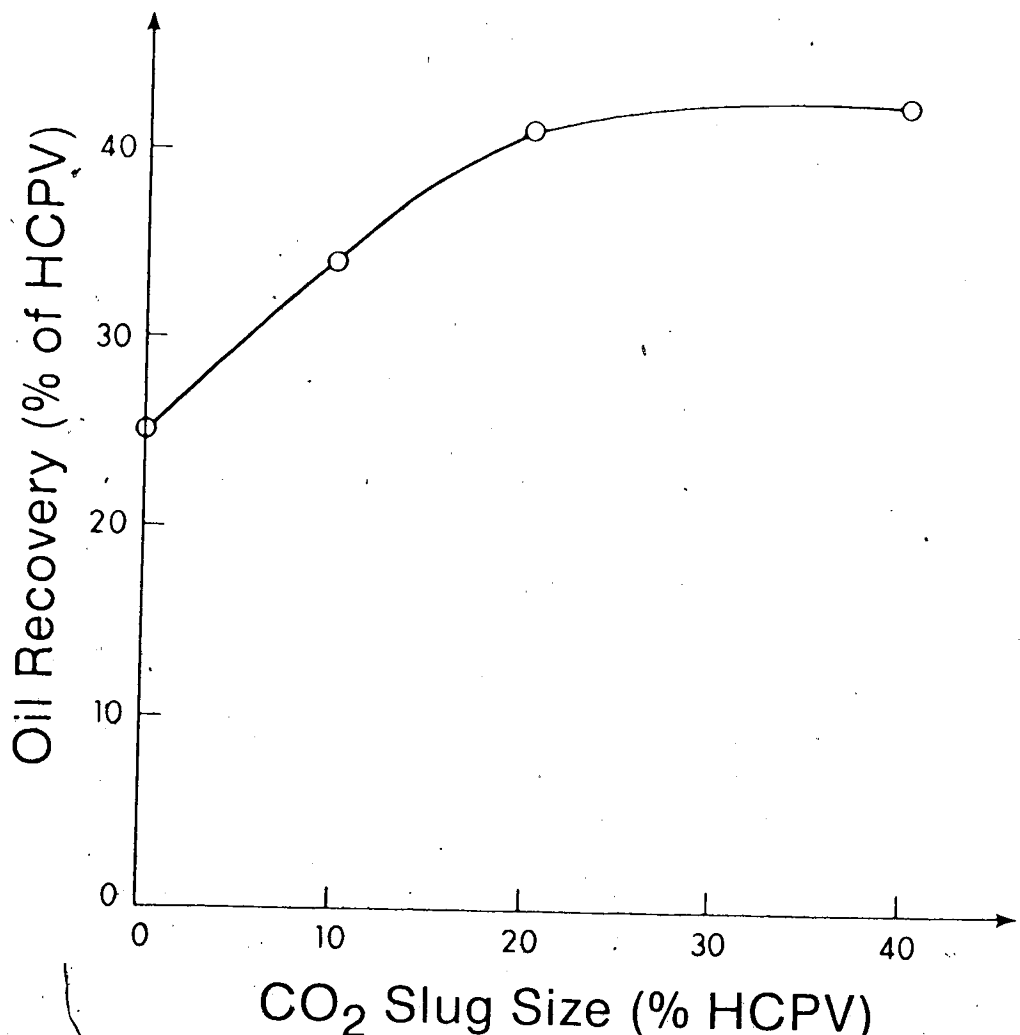
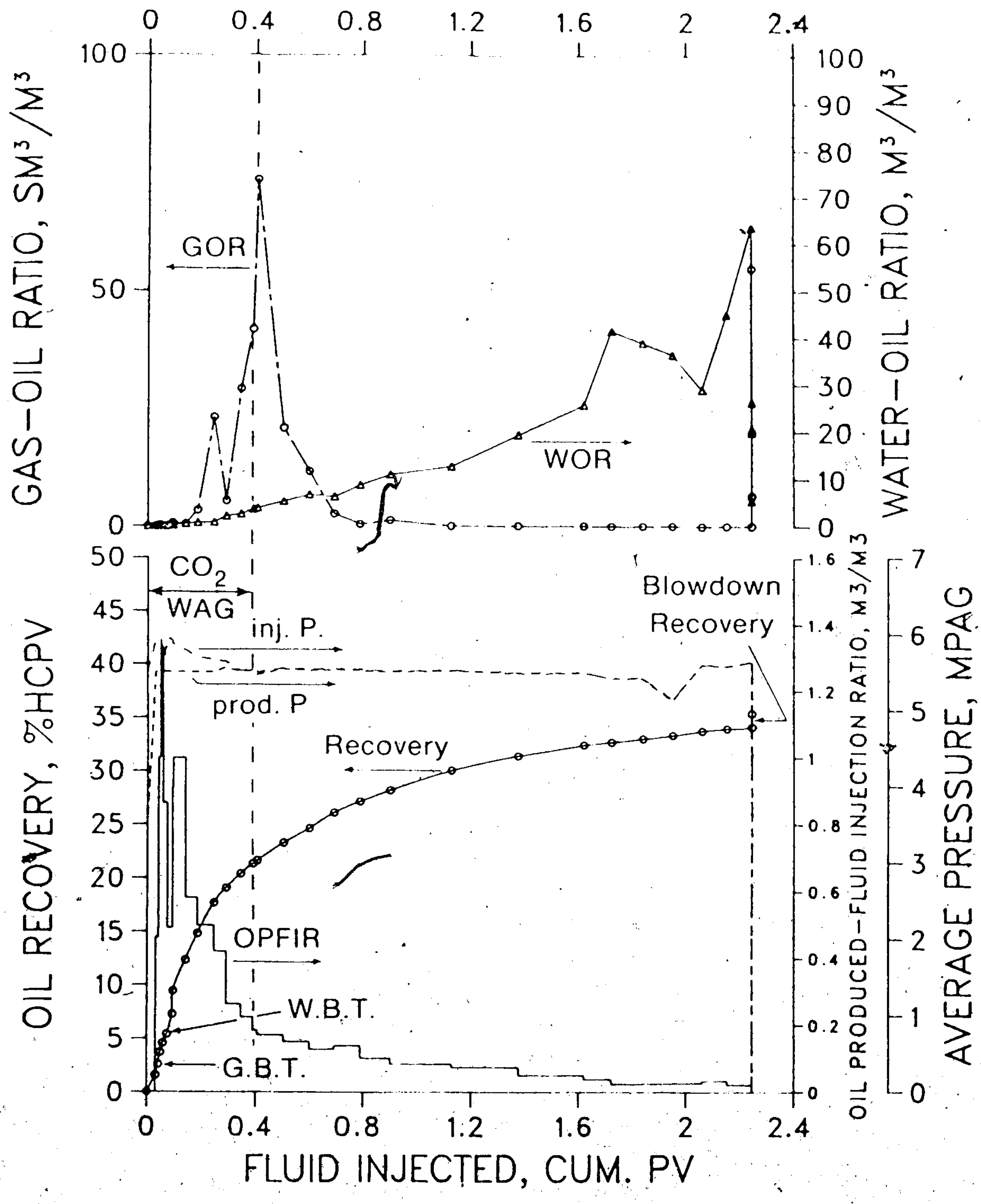


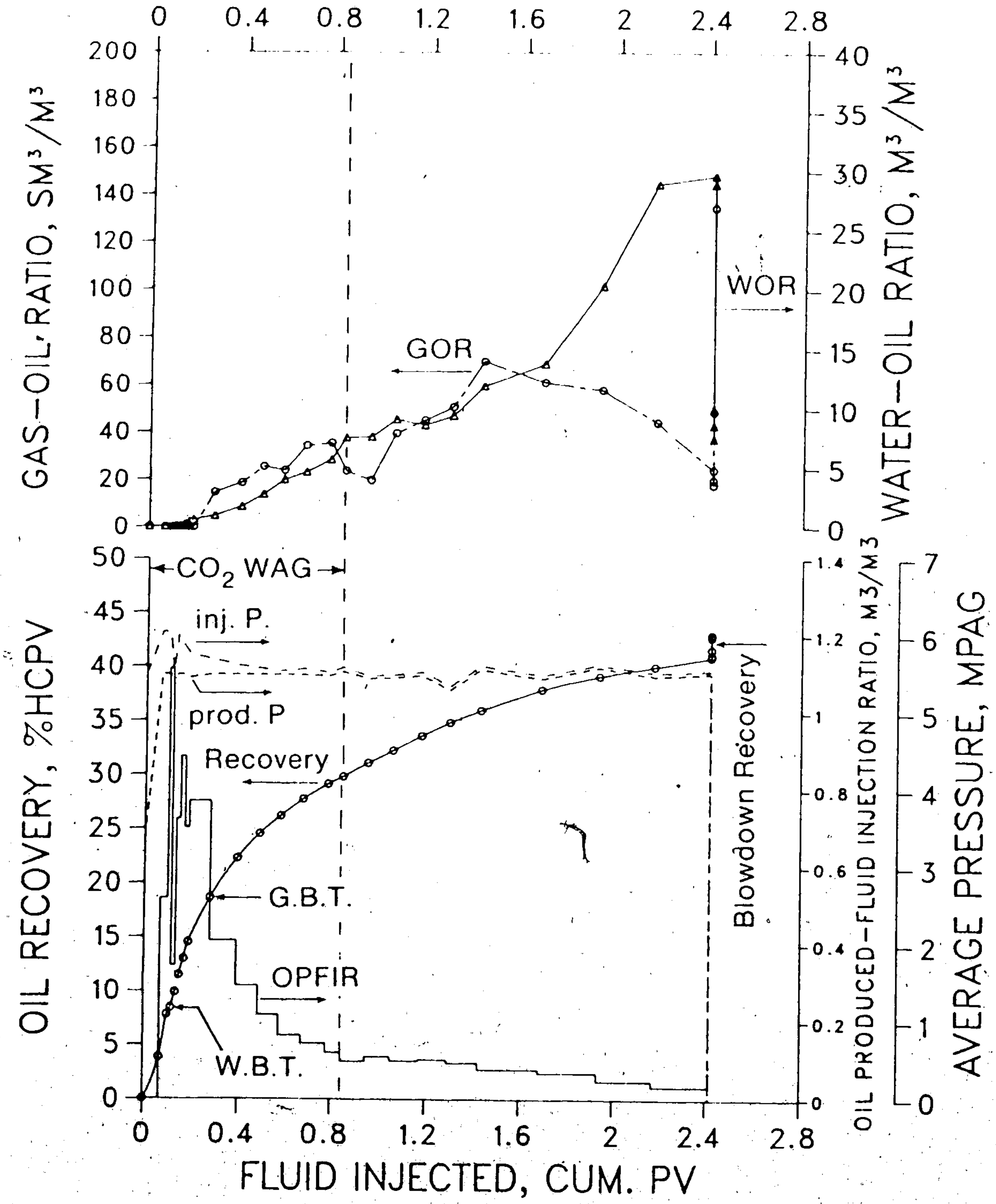
Figure 26. Effect of CO_2 slug size

FIGURE 27, Production History of Run 17



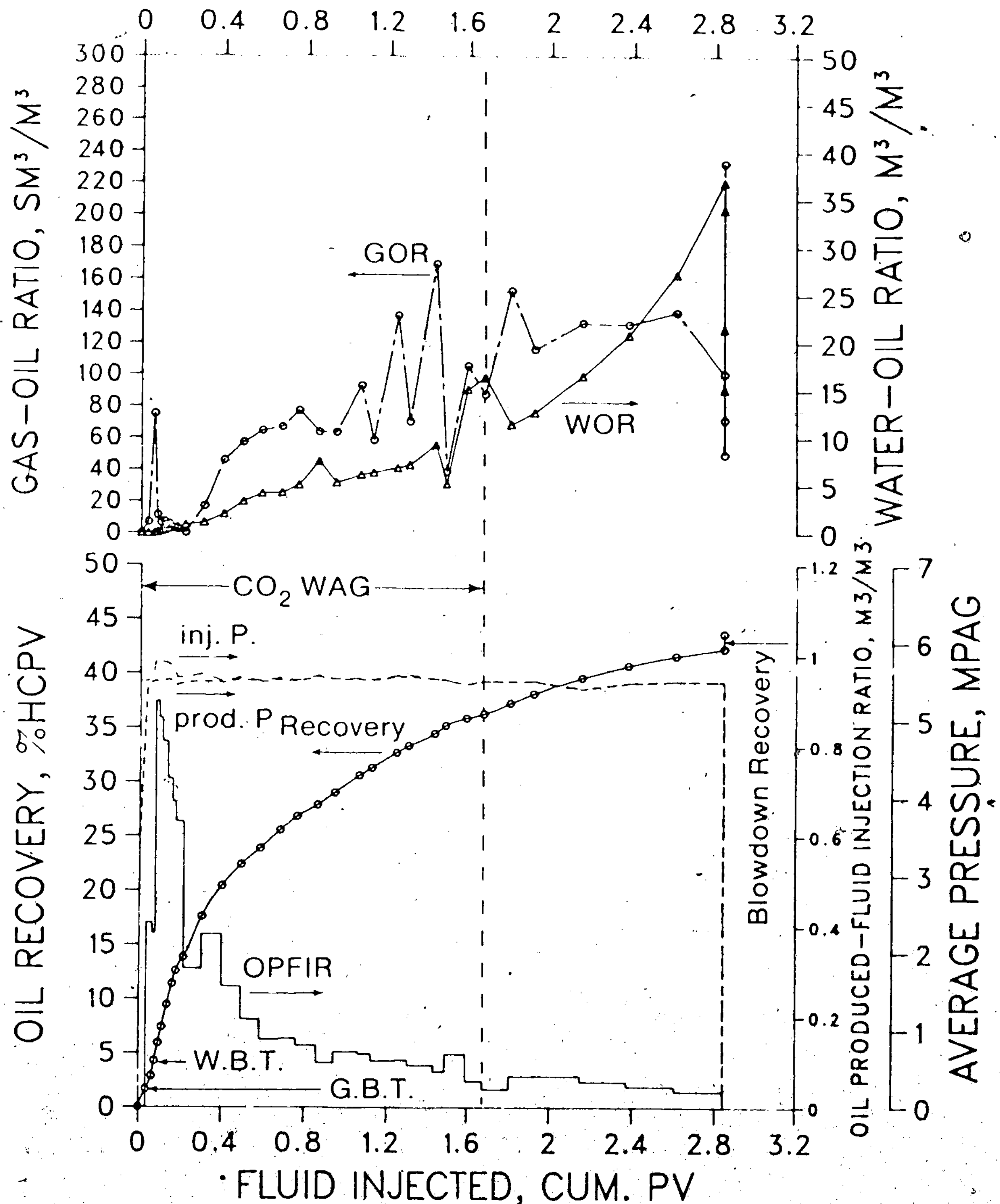
NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.552 m/d, 10.1% CO_2 WAG process, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ=42.31%, So=89.87%, k=18.357 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 28 , Production History of Run 16



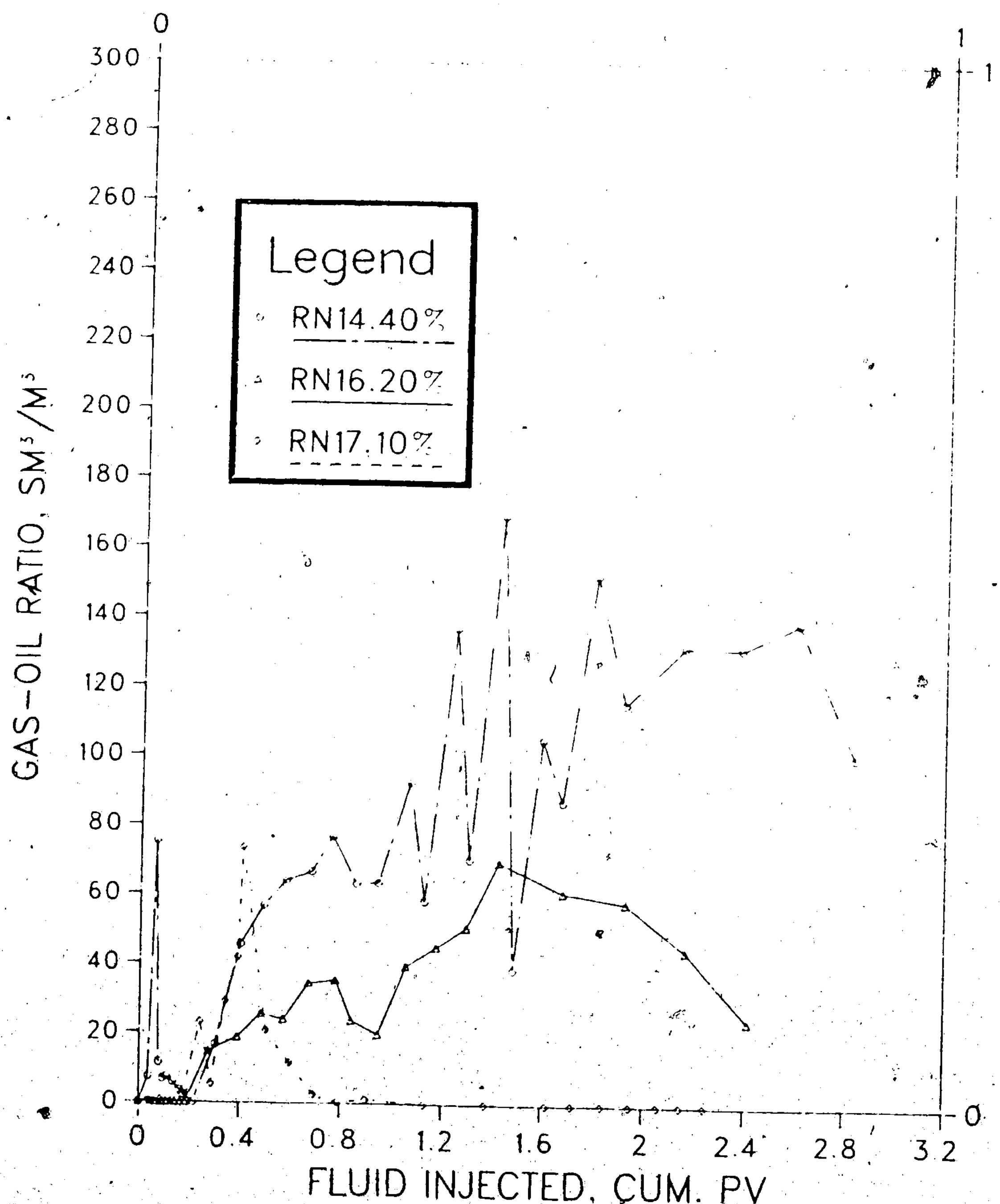
NOTE: Horizontal Flood in a Quarter of 5—spot, Average Flow Velocity=1.552 m/d, 20% CO_2 WAG process, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =39.26%, So=90.5%, k=14.285 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 29, Production History of Run 14



NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.552 m/d, 40.3% CO_2 WAG process, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =43.15%, So=89.87%, k=16.20 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

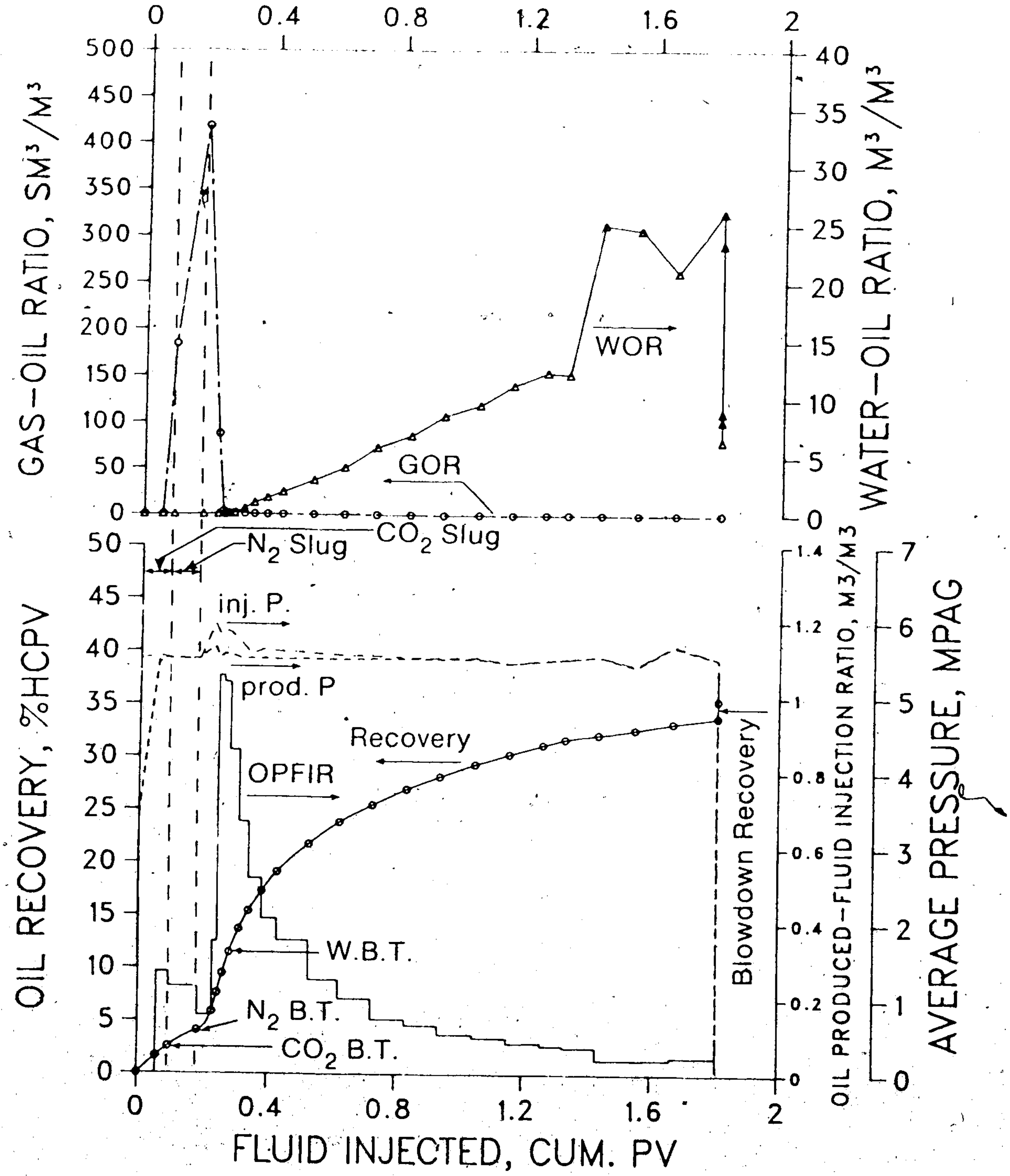
FIGURE 30 – Effect of Slug Size on Gas-Oil Ratio



5.9. Composite Carbon Dioxide - Nitrogen Slugs

The nitrogen WAG runs discussed proviously showed that nitrogen provides little improvement over a waterflood. This concept was further tested in an interesting composite slug run (Run 15), in which a single 10% slug of carbon dioxide was followed by a 10% slug of nitrogen , which was driven by brine. The recovery in this run was 35.4%, which is identical to the 35.4% recovery obtained in Run 17, employing a 10% carbon dioxide slug. In other words, the additional slug of nitrogen did not improve oil recovery at all. The run histories for these two runs are shown in Figs. 31 and 27, respectively. The two production histories for these runs are remarkably similar; the oil production in the composite slug case (Run 15) is essentially delayed by approximately 0.2 pore volume. Thus the effect of nitrogen was to delay oil production. Notice that carbon dioxide was injected first. Also, Run 17 was a WAG run, which explains oil production from the start.

FIGURE 31 , Production History of Run 15



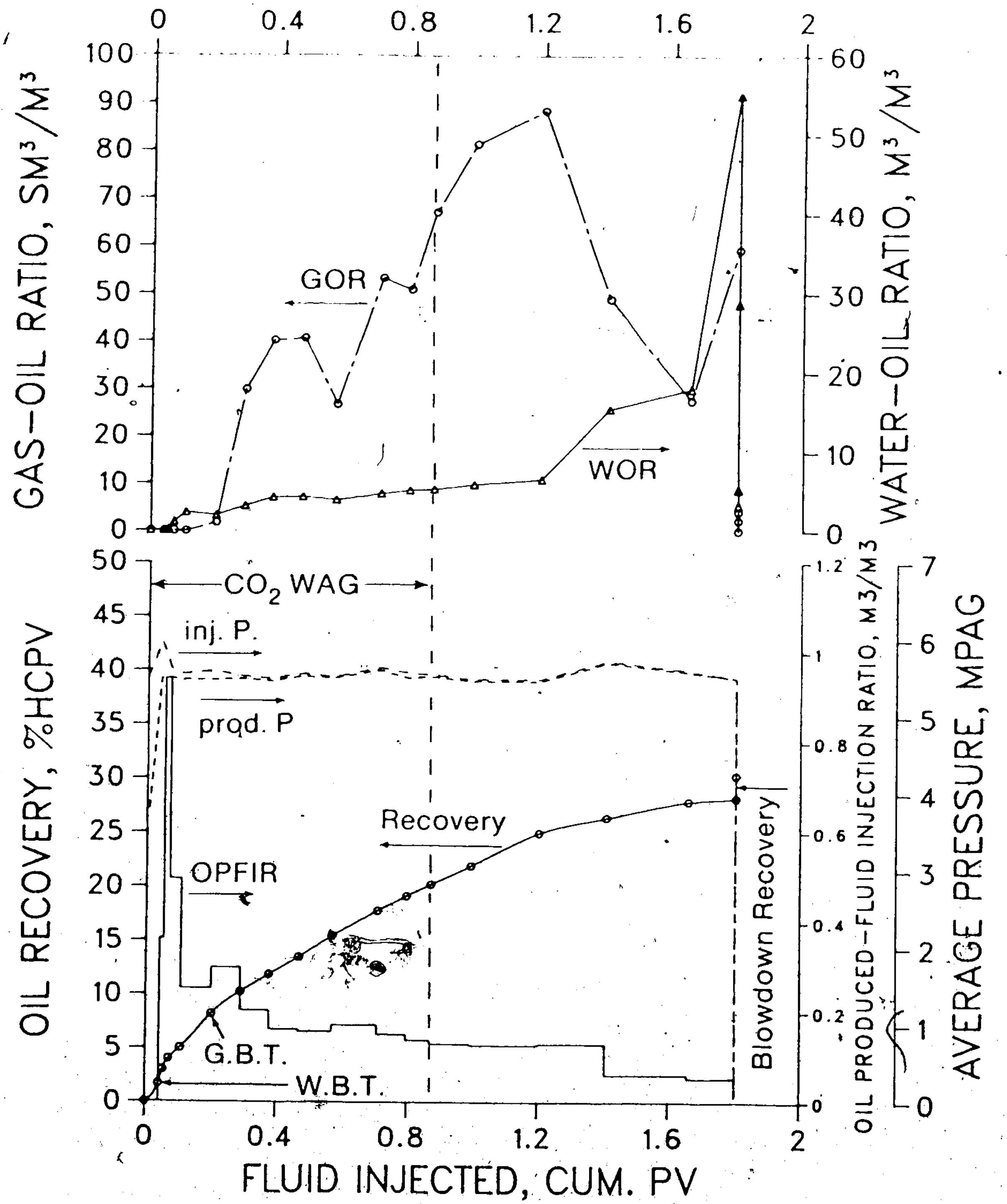
NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.552 m/d, 10% CO_2 + 10% N_2 SLUG drived by brine, Homogeneous Pack, μ_o = 1116 mpa.s @ 23°C & 0 Mpag, ϕ =41.12%, So=90.6%, k=14.901 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

5.10. Heterogeneous Sand Packs

An important question that may be asked is : what is the sensitivity of the carbon dioxide WAG process to formation heterogeneities? It was decided to examine this problem for two types of heterogeneities, employing a 20% carbon dioxide slug and a 4:1 WAG ratio. Oils with viscosities of 1101 and 2107 mPa.s were employed for each type of heterogeneity.

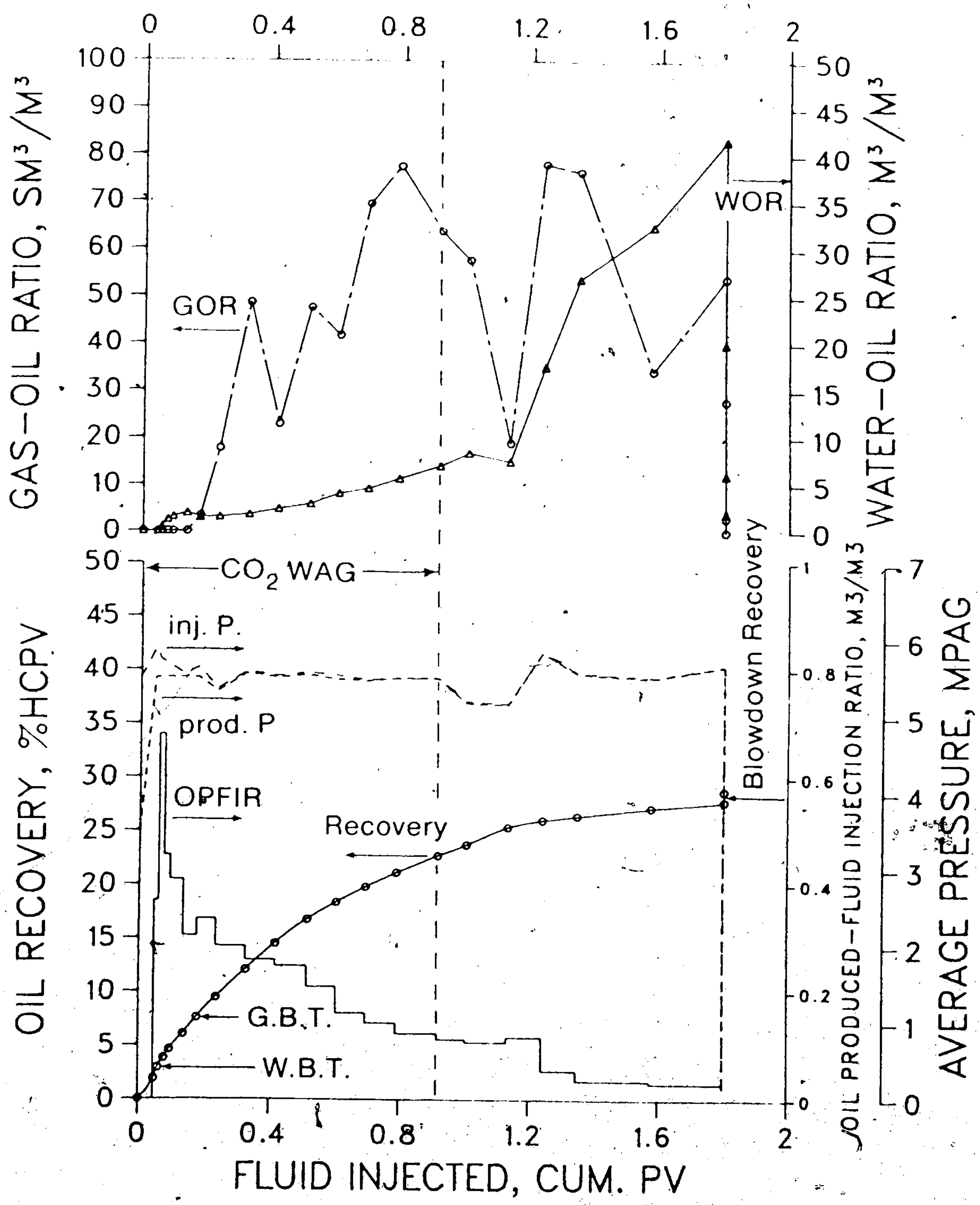
Runs 18 and 21 employed the model with a high permeability channel packed along the diagonal connecting the injection and production wells, as shown in Fig. 10. The approximate permeability of the channel was 25 darcies, as compared to the pack permeability of 16.969 darcies (average)(Please refer to the Chapter 4, Section 4.7. "Data Processing" for calculating the permeability of the glass beads layer). The oil recovery in Run 18 was 30.3% for the more viscous oil, while it was 28.8% in Run 21 for the less viscous oil. This somewhat unexpected recovery might be due to the nonuniformity of the heterogeneous pack. The latter can be compared with the figure of 43%, obtained in Run 16. The run histories for Runs 18 and 21 are shown in Figs. 32 and 33. A comparsion of Runs 21 and 16 (Figs. 33 and 28) clearly shows that in the heterogeneous model, carbon dioxide breakthrough occurred considerably earlier, and most important, the producing gas-oil ratio was much

FIGURE 32 , Production History of Run 18



NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.552 m/d, 20% CO_2 WAG process, Heterogeneous Pack, μ_o = 2107.3 mpa.s @ 23°C & 0 Mpag, ϕ =38.80%, So=88.5%, k=18.098 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 33 , Production History of Run 21



NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.552 m/d, 20% CO_2 WAG process, Heterogeneous Pack, μ_o = 1101 mpa.s @ 23°C & 0 Mpag, ϕ =38.69%, So=89.7%, k=15.840 darcies, Run Condition ; 21~22°C & 5.5 Mpag.

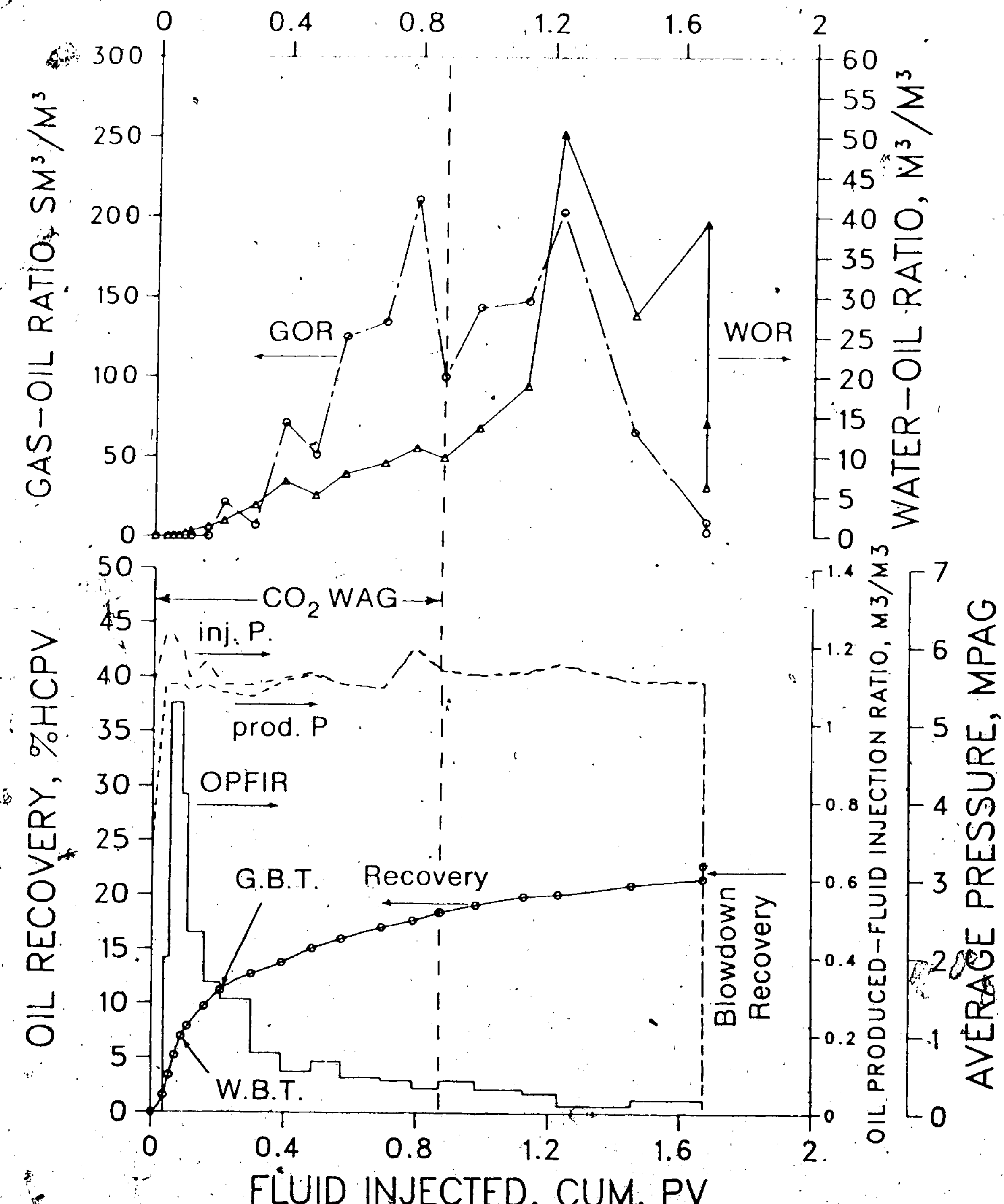
higher. Although the initial OPFIR was relatively lower, a high value was sustained for a much longer time than in the case of the homogeneous model. The high gas-oil ratio is even more apparent in Fig. 32 for Run 18 (2107 mPa.s oil).

In Runs 19 and 20, the model was packed with two communicating, parallel equal thickness layers, as shown in Fig. 9. The approximate permeabilities of the two layers were 25 and 10 darcies, for the glass bead layer and the sand layer, respectively. Run 20, utilizing the 1101 mPa.s oil yielded a recovery of 30.3%, while Run 19, employing the 2107 mPa.s oil gave a recovery of 22.8%. The 30.3% recovery for Run 20 can be compared with 43.0% for Run 16, as before. The production histories for Runs 19 and 20 are shown in Figs. 34 and 35, respectively. In both cases, it is clear that gas-oil ratios were very high as compared to the homogeneous pack (Fig. 28), indicating inefficient utilization of the injected carbon dioxide.

It is interesting to note that in all heterogeneous pack runs, the producing water-oil ratio was close to that obtained for the homogeneous packs, as shown by Figs. 32, 33, 34, 35 compared with Fig. 28.

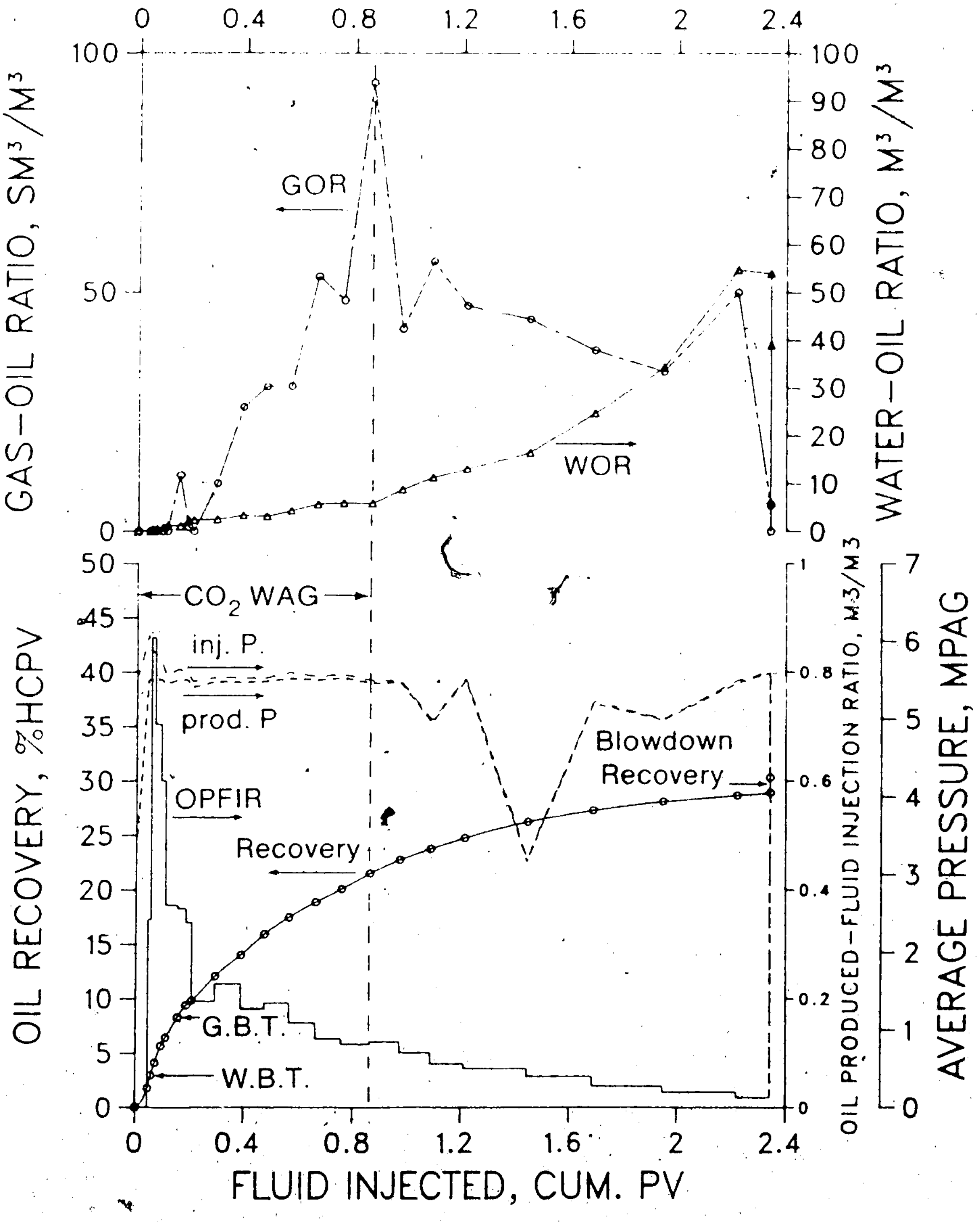
Summarizing, it is clear that the presence of a heterogeneity in the sand pack causes a decrease in oil recovery, early gas breakthrough, high gas-oil ratios, and inefficient utilization of carbon dioxide. At the same time, the decrease in recovery is not as drastic as the permeability contrast would seem to indicate. Only two types of heterogeneities were examined in this work, with a relatively small permeability contrast (about 2 to 1). Other types of more severe heterogeneities will be simulated in the next phase of this research.

FIGURE 34, Production History of Run 19



NOTE: - Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=1.552 m/d, 20% CO_2 WAG process, Heterogeneous Pack, μ_o = 2107.? mpa.s @ 23°C & 0 Mpag, ϕ =37.24%, So=92.5%, k=18.587 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

FIGURE 35, Production History of Run 20

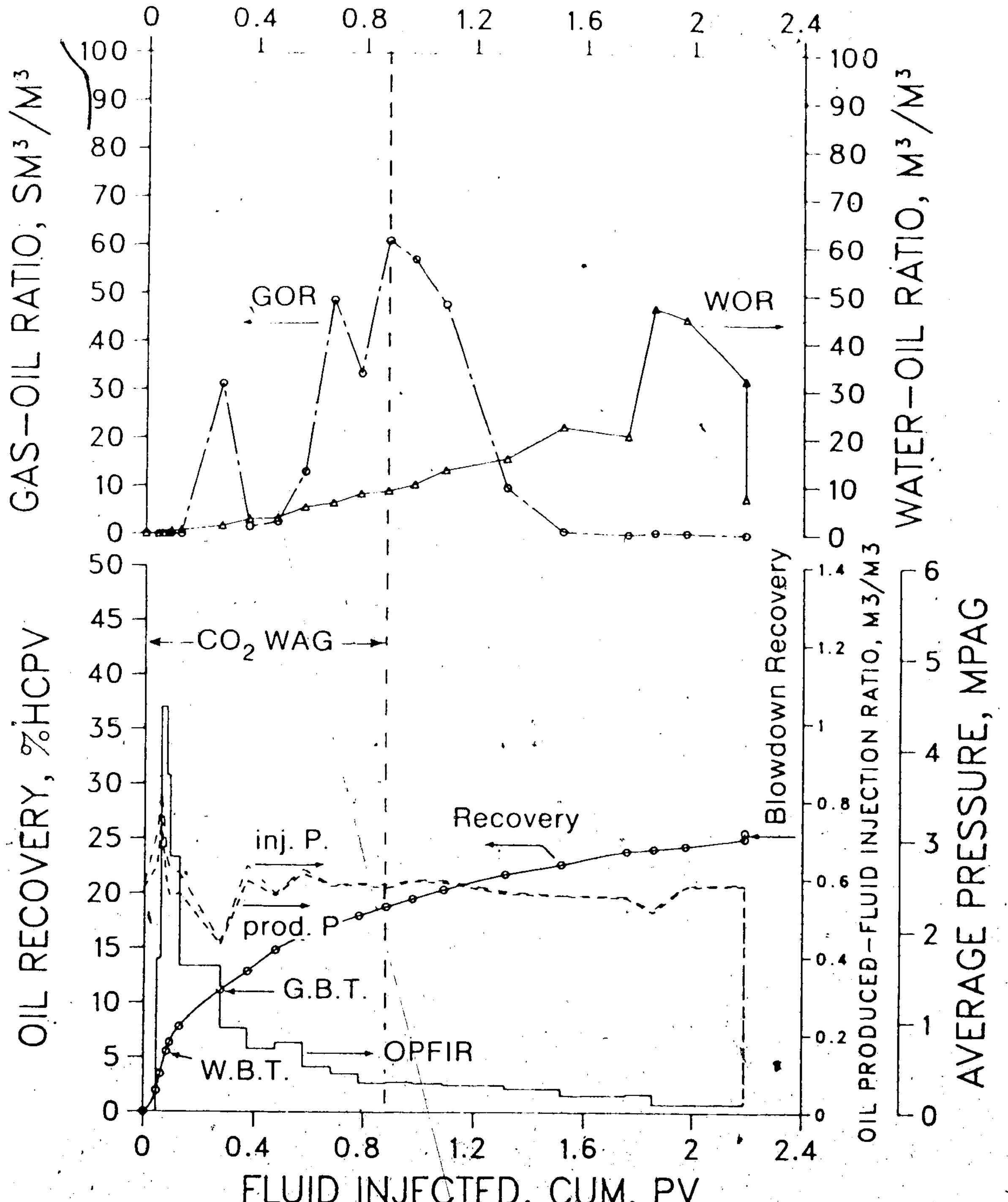


NOTE: Horizontal Flood in a Quarter of 5-spot, Average Flow Velocity=1.552 m/d, 20% CO_2 WAG process, Heterogeneous Pack, μ_o = 1101.0 mpa.s @ 23°C & 0 Mpag, ϕ =37.37%, So=88.77%, k=16.394 Darcies, Run Condition : 21~22°C & 5.5 Mpag.

5.11. Low Pressure Carbon Dioxide WAG Runs

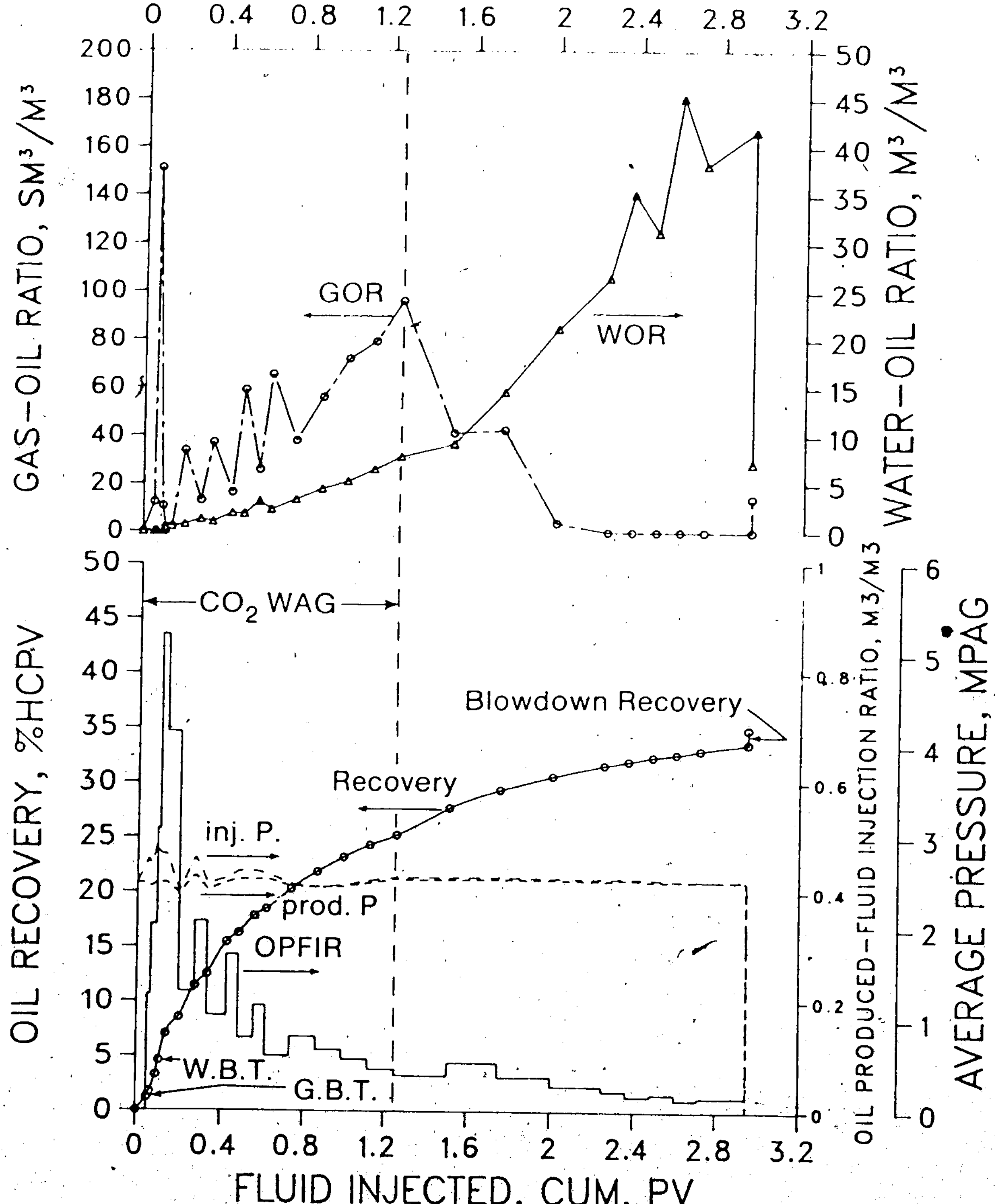
In all of the previous work, the operating pressure was kept constant at 5.5 MPag. In a waterflooded reservoir, the abandonment pressure is often much lower, and it is impractical to pressurize the reservoir to 5.5 MPag. It was, therefore, decided to carry out two runs at an operating pressure of 2.5 MPag, this pressure being representative of a typical watered-out Saskatchewan reservoir. Runs 22 and 23 employed 10 and 20% HCPV slugs (equivalent to those at 5.5 MPag, in terms of total number of moles) of carbon dioxide in a 4:1 WAG process. The oil recoveries for these runs were 25.7 and 34.9%, respectively (as shown in Figures 36 and 37), and can be compared with the recoveries of 35.4 and 43.0%, for similar high pressure runs, Runs 17 and 16, respectively. Clearly, there is a considerable drop in oil recovery in the case of the 10% slug, but the recovery is approximately eight percentiles lower in the case of the 20% slug. This is significant, if one considers the solubility of carbon dioxide in oil at 5.5 MPag (86 sm^3/sm^3) and 2.5 MPag (33 sm^3/sm^3). It can be concluded that a decrease in the operating pressure causes a drop in oil recovery, which was relatively small for some optimal carbon dioxide slug size, which was 20% HCPV (at 5.5 MPag) in this study.

FIGURE 36 , Production History of Run 22



NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.293 m/d, 9.8% CO_2 WAG process, Homogeneous Pack, μ_o = 1101 mpa.s @ 23°C & 0 Mpag, ϕ =40.27%, So=92.9%, k=13.313 Darcies,$#, Run Condition : 21~22°C & 2.5 Mpag.

FIGURE 37, Production History of Run 23



NOTE: Horizontal Flood in a Quarter of 5–spot, Average Flow Velocity=1.552 m/d, 20% CO_2 WAG process, Homogeneous Pack, μ_o = 1101 mpa.s @ 23°C & 0 Mpag, ϕ =41.16%, So=90.4%, k=17.357 Darcies, Run Condition : 21~22°C & 2.5 Mpag.

5.12. Oil Recovery and Carbon Dioxide Requirements

Figure 38 summarizes the oil recovery for selected runs by means of a bar graph. Waterflood recovery is also shown for comparison. The results are for runs in which the oil viscosity was approximately 1000 mPa.s. It is seen that the highest recovery was 61.2% in Run 11, where a carbon dioxide preflush was used prior to the WAG process - clearly a very inefficient use of carbon dioxide. The lowest recovery was obtained in Run 22, which utilized a 10% slug at the lower pressure of 2.5 MPag.

Figure 39 shows the carbon dioxide requirement, which is defined as the sm^3 of carbon dioxide injected to produce one sm^3 of oil. The highest value among the carbon dioxide runs is 759 (Run 10), for a carbon dioxide preflush, while the lowest value is 28 (Run 17) for a 10% slug. Almost all values are below 100, which is very significant, considering that the carbon dioxide requirement in the case of miscible carbon dioxide floods is 1500 to 3000 sm^3/sm^3. Thus the immiscible carbon dioxide WAG process is very efficient. It is ideally suited for moderately viscous oils (1000 to 2000 mPa.s) occurring in oil reservoirs that are unsuitable for the application of thermal methods, or where such methods (especially in situ combustion) have failed. Many other factors, such as oil viscosity, reservoir depth and bottom water, must be considered in the field application of this process.

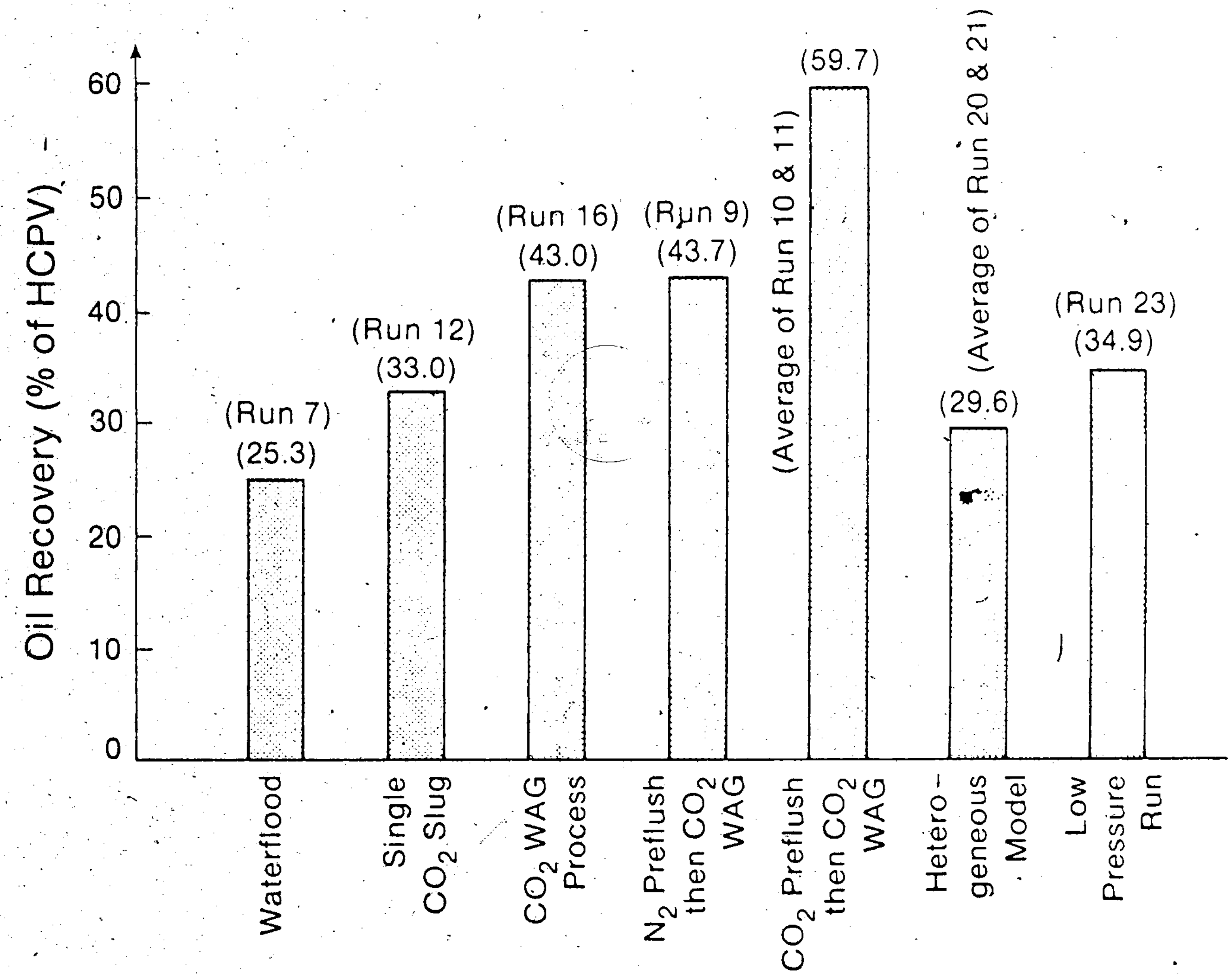


Figure 38. Comparison of total oil recovery obtained in selected displacements for an oil viscosity of approximately 1000 mPa.s

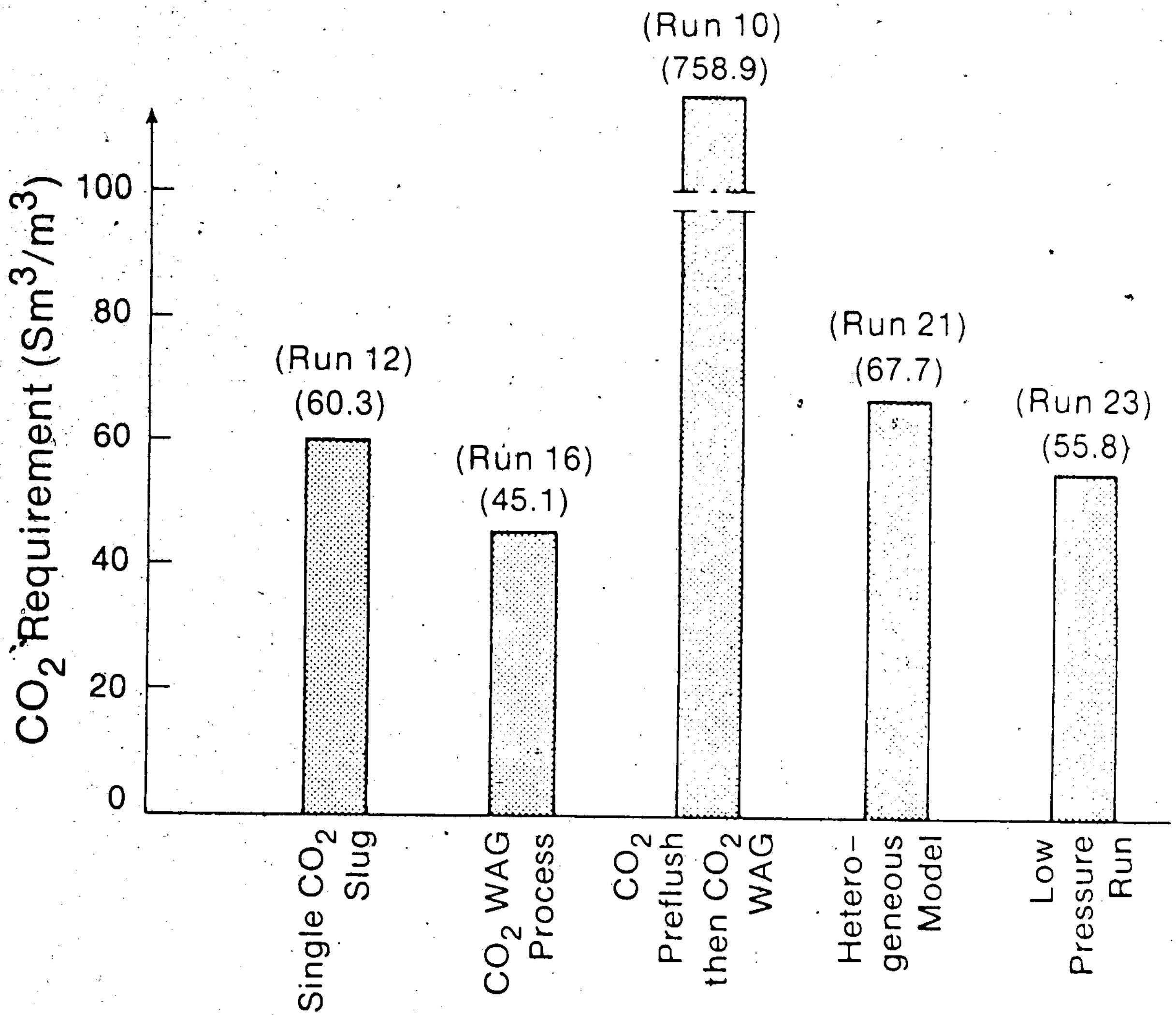


Figure 39. Comparison of CO_2 requirement in selected displacements for an oil viscosity of approximately 1000 mPa.s

6. Conclusions

This investigation was designed to examine a variety of operating conditions for the immiscible carbon dioxide WAG process, in order to judge its sensitivity to some of the field conditions. In addition, it was intended to study the effect of using nitrogen - a noncondensable gas - in place of carbon dioxide. With this end in view, a series of experimental runs were carried out in a scaled high pressure model, the results of which are summarized in Table 4, on page 72. Within the framework of this study, the following conclusions are derived:

1. Substitution of nitrogen for carbon dioxide yields nearly the same oil recovery as a waterflood in a WAG type process. It is therefore concluded that the mechanisms postulated for the carbon dioxide WAG process are valid, i.e. carbon dioxide leads to oil viscosity reduction, volume increase, and lowering of oil-water IFT.

2. A small initial gas saturation, of the order of 5% pore volume, whether it is free nitrogen or carbon dioxide, has an insignificant effect on total oil recovery.

3. The carbon dioxide WAG process depends on the slug size, the oil recovery decreasing considerably over

the 10 to 20% HCPV slug size range, and increasing only slightly over the 20 to 40% HCPV range.

4. Oil recovery decreased by approximately 13 to 15 percentiles when one of the two severe reservoir-scale heterogeneities tested was present. Based upon the comparison with homogeneous pack runs, possibly the process is relatively insensitive to heterogeneities.

5. Oil recovery decreased by approximately 8 percentiles, when a pressure of 2.5 MPag was employed in place of 5.5 MPag, for the 20% slug.

6. The carbon dioxide requirement in the runs conducted was well below 100 sm^3/sm^3, in nearly all runs. This compares favourably with the carbon dioxide or air requirements of 1500 to 3000 sm^3/sm^3 in the miscible carbon dioxide process or in in situ combustion.

Nomenclature

A = Cross-Sectional Area (cm^3)

D = Diffusivity (cm^2/s)

H = Thickness (cm)

K = Permeability (darcy)

L = Length (cm)

P = Pressure (MPa)

Q = Injection Flow Rate (cm^3/s)

S_{oi} = Initial Oil Saturation (%)

T = Temperature (°C or K)

V = Superficial Velocity (cm/s or m/d)

ρ = Molar Density (kg-mole/m^3)

μ = Viscosity (mPa.s)

References

1. Beeson, D.M. and Ortloff, G.D. : "Laboratory Investigation of the Water-Driven Carbon Dioxide Process for Oil Recovery", J. Pet. Tech., April 1959, 63-66.
2. Holm, L.W. : "Carbon Dioxide Solvent Flooding for Increased Oil Recovery", Trans., AIME, 1959, 216, 225-231.
3. Welker, J.R. and Dunlop, D.D. : "Physical Properties of Carbonated Oils", J. Pet. Tech., Aug. 1963, 873-876.
4. Dickerson, L.R. and Crawford, G.W. : "Lab. Tests Show That CO_2 Scores Highest in Reducing Oil Viscosity", Oil and Gas J., Feb. 22, 1960, 96-98.
5. McRee, B.C. : "CO_2 : How It Works Where It Works", Pet. Eng. Intl., Nov. 1977, 52-63.
6. Saner, W.B. and Patton, J.T. : "CO_2 Recovery of Heavy Oil : The Wilmington Field Test", Paper SPE 12082, presented at the 58th Annual Technical Conference and Exhibition, San Francisco, CA., Oct. 5-8, 1983.
7. Rushing, M.D., Thomasson, B.C., Reynolds, B., and Crawford, P.B. : "Miscible Displacement With Nitrogen", Pet. Engineer, Nov. 1977, 26-30.
8. Holm, L.W. : "Status of CO_2 and Hydrocarbon Miscible Oil Recovery Methods", SPE 5560, presented at the

50th Annual Fall Meeting of SPE, Dallas, Sept. 28 - Oct. 1, 1975.

9. Holm, L.W. and Josendal, V.A. : "Mechanisms of Oil Displacement by Carbon Dioxide", J. Pet. Tech., Dec. 1974, 1427-1438.

10. Flock, D.L., Peters, E.J., Baird, H., Wiborg, R., and Kloepfer, J. : "The Influence of Frontal Instabilities During Viscous Oil Displacements", The Oil Sands of Canada - Venezuela, 1977, CIM Special Volume 17, 380-385.

11. Craig, F.F. Jr., Sanderlin, J.L., Moore, D.W., and Geffen, T.M. : "A Laboratory Study of Gravity Segregation in Frontal Drives", Trans. AIME, Vol 210, 1957, 275-282.

12. Rojas, G. and Farouq Ali, S.M. : "Dynamics of Subcritical CO_2/Brine Floods for Heavy Oil Recovery", Paper SPE 13598 presented at the 1985 SPE California Regional Meeting, Bakersfield, CA., March 27-29, 1985.

13. Morel, T.J., Haynes, S. Jr., and Park, J.H. : "Method of Enhanced Oil Recovery Employing Nitrogen Injection", Alberta Oil Sands Information Center, 3042E, Mar. 6, 1984.

14. Beecher, C.E. and Parkhurst, I.P. : "Effect of Dissolved Gas Upon the Viscosity and Surface Tension of Crude Oils", Petroleum Development and Technology in 1926, Pet. Div. AIME, 51-69.

15. Interstate Oil Compact Commission : Secondary and Tertiary Oil Recovery Processes, IOCC, Oklahoma City, 1974.

16. Miller, J.S. and Jones, R.A. : "Physical Characteristics of Heavy Oil After CO_2 Saturation are studied in DOE Tests", Oil and Gas J., July 6, 1981, 135-145.

17. Dodds, W.S., Stutzman, L.F., and Sollami, B.J. : "Carbon Dioxide Solubility in Water", Chem. Eng. Data Series, Vol. 1, No. 1, 1956, 92-94.

18. Holm, L.W. : "CO_2 Slug and Carbonated Water Oil Recovery Process", Prod. Monthly (Sept. 1963), P. 6.

19. Stewart, P.B. and Munjal, P. : "Solubility of CO_2 in Pure Water, Synthetic Sea Water", J. Chem. and Eng. Data, V15, No. 1, 1970, P.76.

20. Mungan, N. : "Carbon Dioxide Flooding - Fundamentals", J. Can. Pet. Tech., Jan. - March 1981, 87-92.

21. Slack, W.W. and Ehrlich, R. : "Immiscible Displacement of Oil by Simultaneous Injection of Water and Nitrogen", SPE/DOE 9807, presented at the 1981 SPE/DOE Second Joint Symposium on Enhanced Oil Recoveery of the Society of Petroleum Engineers held in Tulsa, Oklahoma, April 5-8, 1981.

22. Clark, N.J., Roberts, T.G., and Lindner, J.D. : "Engine Exhaust Gas Boots Heavy Oil Recovery", Pet. Eng., Aug. 1964, 43-47.

23. Jacobs, F.A., Donnelly, J.K., Stanislav, J., and Svrcek, W.Y. : "Viscosity of Gas-Saturated Bitumen", J. Can. Pet. Tech., Oct.-Dec. 1980, 46-50.

24. Davison, K. : "Inert Gas Boots Recovery From Heavy Oil Reservoirs", World Oil, March 1967, 98-105.

25. Goss, M.J. and Exall, D.I. : "Experimental Investigations of the Transport Mechanisms Controlling In Situ Recovery From Heavy Oil Sands", The Oil Sands of Canada-Venezuela 1977, CIM Special Volume 17, 327-333.

26. Crank, J. : The Mathematics of Diffusion, Oxford at the Clarendon Press, 1967.

27. Hildebrand, J.H., Prausnitz, J.M., and Scott, R.L. : Regular and Related Solutions, Van Nostrand Reinhold Co., New York, 1970.

28. Davies, G.A., Ponter, A.B., and Craine, K. : "The Diffusion of Carbon Dioxide in Organic Liquids", Can. J. Chem. Eng., Dec. 1967, 372-376.

29. Rajan, S.M. and Goren, S.L. : "Gas Absorption by Drops Travelling on a Vertical Wire", AIChE J., Jan. 1967, 91-96.

30. McManamey, W.J. and Woollen, J.M. : "The Diffusivity of Carbon Dioxide in Some Organic Liquids at 25°C and 50°C", AIChE J. May 1973, 667-669.

31. Denoyelle, L. and Bardon, C. : "Diffusivity of Carbon Dioxide into Reservoir Fluids", Paper CIM 115-15 : 30

presented at the 86th CIM Annual General Meeting, Ottawa, April 17, 1984.

32. Prausnitz, J.M. and Benson, P.R. : "Solubility of Liquids in Compressed Hydrogen, Nitrogen, and Carbon Dioxide", AIChE J., June 1959, 161-164.

33. Holm, L.W. and Josendal, V.A. : "Effect of Oil Composition on Miscible-Type Displacement by Carbon Dioxide", Soc. Pet. Eng. J. , Feb. 1982, 87-98.

34. Jolley, J.E. and Hildebrand, J.H. : "Solubility, Entropy, and Partial Molal Volumes in Solutions of Gases in Non-Polar Solvents", American Chemical Society J., March 5, 1958, 1050-1054.

35. Svrcek, W.Y. and Mehrotra, A.K. : "Gas Solubility, Viscosity and Density Measurements for Athabasca Bitumen", J. Can. Pet. Tech., July-Aug. 1982, 31-38.

36. Peterson, A.V. : "Optimal Recovery Experiments With N_2 and CO_2", Pet. Eng. International, Nov. 1978, 40-50.

37. Rosman, A. and Zana, E. : "Experimental Studies of Low IFT Displacement by CO_2 Injection", Paper SPE 6723 presented at the 52nd Annual Fall Technical Conference and Exhibition, Denver, Col., Oct. 9-12, 1977.

38. Moore, T.F. and Slobod, R.L. : "The Effect of Viscosity and Capillarity on the Displacement of Oil by Water", Producers Monthly, Aug. 1956, 20-30.

39. Scott, G.R., Collins, H.N., and Flock, D.L. : "Improving Waterflood Recovery of Viscous Crude Oils

by Chemical Control", J. Can. Pet. Tech., Oct.-Dec. 1965, 243-251.

40. Farouq Ali, S.M., Figueroa, J.M., Azuaje, E.A., and Farquharson, R.G. : "Recovery of Lloydminster and Morichal Crudes by Caustic, Acid, and Emulsion Floods", J. Can. Pet. Tech., Jan.-March, 1979, 53-59.

41. Breston, J.N. and Macfarlane, R.M. : "The Effect of a Number of Variables on Oil Recovery From Cores When Flooded With Carbonated Water and Liquid CO_2", Producers Monthly, Nov. 1952, 36-45.

42. Crawford, H.R., Neil, G.H., Bucy, B.J., and Crawford, P.B. : "Carbon Dioxide - A Multipurpose Additive for Effective Well Stimulation", J. Pet. Tech., March 1963, 237-242.

43. Omole, O. and Osoba, J.S. : "Carbon Dioxide - Dolomite Rock Interaction During CO_2 Flooding Process", Paper No. 83-34-17 presented at the 34th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alta., May 10-13, 1983.

44. Berry, R.S., Rice, S.A., and Ross, J. : Physical and Chemical Kinetics, Part 3, John Wiley and Sons, New York, 1980.

45. "Target Reservoir for CO_2 Miscible Flooding", Final Report. U.S. Department of Energy, Oct. 1980, 1-92.

46. Graue, D.J. and Blevins, T.R. : "SACROC Tertiary CO_2 Pilot Project", Paper SPE 7090 presented at the 5th

symposium on Improved Methods for Oil Recovery, SPE - AIME, Tulsa, Okla., April 16-19, 1978.

47. David, A. : "Asphaltene Flocculation During Solvent Stimulation of Heavy Oils", Paper 47 d, presented at the 71st National Meeting of AIChE, Dallas, Texas, Feb. 20-30, 1972.

48. Strausz, O.P. : "Some Recent Advances in the Chemistry of Oil Sand Bitumen", Presented at the UNITAR first International Conference on the Future of Heavy Crude and Tar Sand, Edmonton, Alta., 1979, McGraw-Hill, Inc., 187-194.

49. Graue, D.J. and Zana, E.T. : "Study of a Possible CO_2 Flood in Rangely Field", J. Pet. Tech., July 1981, 1312-1318.

50. Stalkup, F.I. Jr. : "Status of Miscible Displacement", J. Pet. Tech., April 1983, 815-826.

51. Holm, L.W. : "CO_2 Requirements in CO_2 Slug and Carbonated Water Oil Recovery Processes", Producers Monthly, Dec. 1963, 16-28.

52. Farouq Ali, S.M. and Rojas, G. : "Scaled Model Studies of Carbon Dioxide/Brine Injection Strategies for Heavy Oil Recovery From Thin Formations", Paper No. 85-36-47, presented at the 36th Annual Technical Meeting of the Petroleum Society of CIM, Edmonton, Alta., June 2-5, 1985.

53. Sayegh, S.G. and Maini, B.B. : "Laboratory Evaluation

of the CO_2 Huff-n-Puff Process for Heavy Oil Reservoirs", J. Can. Pet. Tech., May-June 1984, 29-36.

54. Caudle, B.H. and Dyes, A.B. : "Improving Miscible Displacement by Gas-Water Injection", Trans. AIME, Vol. 213, 1958, 281-284.

55. Holm, L.W. : "Modified Waterfloods Can Improve Ultimate Recovery", World Oil, Oct. 1969, 126-132.

56. Holm, L.W. : "CO_2 Flooding : Its Time Has Come", Distinguished Author Series, J. Pet. Tech., Dec. 1982, 2739-2745.

57. Ko, S.C.M. and Stanton, P.M. : "Tertiary Recovery Potential of CO_2 Flooding in Joffre Viking Pool, Alberta", Paper No. 83-34-18 presented at the 34th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alta., May 10-13, 1983.

58. Reid, T.B. and Robinson, H.J. : "Lick Creek Meakin Sand Unit Immiscible CO_2/Waterflood Project", J. Pet. Tech., Sept. 1981, 1723-1729.

59. Craig, F.F. Jr. : The Reservoir Engineering Aspects of Waterflooding, SPE Monograph Volume 3, Society of Petroleum Engineers, Dallas, 1971, Chapter 3.

60. Saxon, J. Jr., Breston, J.N., and Macfarlane, R.M. : "Increased Oil Recovery From Long Core Water Floods by Preliminary Gas Injection", Producers Monthly, Jan. 1951, 7-17.

61. Pfister, R.J. : "More Oil From Spent Water Drives by

Intermittent Air or Gas Injection", Producers Monthly, Sept. 1947, 10-12.

62. O'Leary, J.P., Murray, T.H., Guillory, T., Greive, C., Reece, M.C., Nugent, M., Perkins, T., and Crawford, P.B. : "Nitrogen-Driven Carbon Dioxide Slugs For Enhanced Recovery", Interstate Oil Compact Committee Bulletin, Vol. 21, No. 1, June 1979.

63. Crawford, P.B. : "Use of Non-Hydrocarbon Gases for Enhanced Oil Recovery", 4th Geofluids Conference (Piacenza, Italy) Pet. Inf. Int. N. 1589, July 15, 1983, 39-46.

64. Anonymous : "Nitrogen Injection Takes Hold", Compressed Air Magazine, October 1982, 26-30.

65. Clark, N.J. : "Exhaust Gas : Promising Recovery Tool", Oil and Gas J. , July 11, 1966, 60-62.

66. Rojas, Gonzalo A. : "Scaled Model Studies of Immiscible Carbon Dioxide Displacement of Heavy Oil", Ph. D. Thesis, University of Alberta, 1985, P. 85.

67. Starling, K. E. : Fluid Thermodynamic Properties for Light Petroleum Systems, Gulf Publishing Co., 1973.

68. Stalkup, F.I. Jr. : Miscible Displacement, Monograph Volume 8, SPE-AIME, 1983.

Appendix A

Production Histories

of All Runs in Tabulated Form

TABLE A1

RESULTS OF RUN 2
(20% CO2 slug driven by brine after brineflood)

OIL VISCOSITY = 1032 mpa.s
PORE VOLUME= 1829.0 CM3
HYDROCARBON PORE VOLUME= 1640.0 CM3
POROSITY= 37.55%
IRREDUCIBLE WATER SATURATION= 10.33%
INITIAL OIL SATURATION= 89.67%
ABSOLUTE PERMEABILITY= 8.5001 DARCIES
CARBON DIOXIDE RETENTION= 35.70 %
CARBON DIOXIDE REQUIRED= 180.8 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
3.45	3.45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.96	5.50	0.0	41.9	0.023	17.0	1.04	0.0	0.0	0.406
5.97	5.52	0.0	66.9	0.037	47.0	2.87	0.0	0.0	1.200
5.96	5.50	0.0	97.9	0.054	81.0	4.94	0.0	0.0	1.097
5.96	5.52	0.0	128.9	0.070	112.0	6.83	0.0	0.0	1.000
5.94	5.52	0.0	149.9	0.082	134.0	8.17	0.0	0.0	1.048
5.91	5.54	0.0	179.9	0.098	164.0	10.00	0.0	0.0	1.000
5.88	5.56	0.0	201.9	0.110	186.3	11.36	0.0	0.12	1.014
5.83	5.50	0.0	231.9	0.127	209.3	12.76	0.0	0.35	0.767
5.81	5.50	0.0	256.9	0.140	225.3	13.74	0.0	0.56	0.640
5.78	5.50	0.0	283.9	0.155	240.3	14.65	0.0	0.80	0.556
5.70	5.50	0.0	378.5	0.207	285.3	17.40	0.0	1.13	0.476
5.61	5.50	0.0	627.5	0.343	353.3	21.54	0.0	2.68	0.273
5.56	5.50	0.0	873.6	0.478	395.3	24.10	0.0	4.90	0.1[illegible]
5.58	5.52	0.0	1365.9	0.747	445.3	27.15	0.0	8.72	0.102
5.52	5.48	0.0	1723.4	0.942	471.3	28.74	0.0	12.69	0.073

TABLE A1 (CONTINUED)

RESULTS OF RUN 2

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.56	5.50	0.0	2123.4	1.161	496.3	30.26	0.0	15.12	0.063
5.60	5.54	0.0	2618.4	1.432	519.3	31.66	0.0	20.39	0.046
5.90	5.80	0.0*	2788.4	1.525	532.3	32.46	0.0	20.77	0.076
5.57	5.54	222.6	2788.4	1.646	535.3	32.64	0.0	20.67	0.013
5.50	5.48	293.6	2788.4	1.685	542.3	33.07	383.49	1.71	0.099
5.50	5.48	328.1**	2788.4	1.704	546.1	33.30	437.51	1.37	0.110
5.60	5.44	328.1	2958.4	1.797	556.1	33.91	342.24	9.20	0.059
5.58	5.56	328.1	3190.4	1.924	580.1	35.37	81.10	9.00	0.103
5.67	5.64	328.1	3448.4	2.065	597.1	36.41	86.82	13.65	0.066
5.62	5.60	328.1	3768.4	2.240	617.1	37.63	76.44	15.00	0.063
5.28	5.24	328.1	4251.9	2.504	637.1	38.85	104.42	23.00	0.041
5.25	5.24	328.1	4749.9	2.776	654.1	39.88	93.03	28.24	0.034
4.55	4.50	328.1	5225.4	3.036	661.1	40.31	128.60	68.57	0.015
5.44	5.44	328.1	5488.1	3.180	664.1	40.49	89.21	83.33	0.011
2.00	2.00	328.1	5488.1	3.180	665.4	40.57	15.60	20.54	
1.03	1.03	328.1	5488.1	3.180	665.9	40.60	12.98	20.00	
0.20	0.20	328.1	5488.1	3.180	667.9	40.73	142.74	46.00	
0.06	0.06	328.1	5488.1	3.180	674.9	41.15	211.44	32.43	
0.0	0.0	328.1	5488.1	3.180	708.9	43.23	34.83	3.12	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*--Gas inj. start **---Gas inj. stop

TABLE A2

RESULTS OF RUN 3
(20% CO_2 WAG process after brineflood, WAG=4:1)

OIL VISCOSITY = 1032 mpa.s
PORE VOLUME= 1939.1 CM3
HYDROCARBON PORE VOLUME= 1741.0 CM3
POROSITY= 39.81%
IRREDUCIBLE WATER SATURATION= 10.22%
INITIAL OIL SATURATION= 89.78%
ABSOLUTE PERMEABILITY= 9.9590 DARCIES
CARBON DIOXIDE RETENTION= 37.41 %
CARBON DIOXIDE REQUIRED= 290.9 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
3.45	3.45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.88	5.50	0.0	110.0	0.057	90.0	5.17	0.0	0.0	0.818
5.88	5.50	0.0	175.0	0.090	155.0	8.90	0.0	0.0	1.000
5.85	5.50	0.0	204.0	0.105	185.0	10.63	0.0	0.0	1.034
5.84	5.50	0.0	227.0	0.117	208.0	11.95	0.0	0.04	1.000
5.80	5.50	0.0	260.0	0.134	232.5	13.35	0.0	0.14	0.742
5.78	5.50	0.0	287.0	0.148	252.3	14.49	0.0	0.36	0.733
5.76	5.50	0.0	318.0	0.164	273.3	15.70	0.0	0.57	0.677
5.72	5.50	0.0	346.0	0.178	287.8	16.53	0.0	1.00	0.518
5.54	5.45	0.0	582.0	0.300	369.8	21.24	0.0	0.19	0.347
5.52	5.42	0.0	830.0	0.428	412.8	23.71	0.0	4.77	0.173
5.63	5.58	0.0	1055.0	0.544	437.4	25.12	0.0	8.02	0.109
5.44	5.40	0.0	1173.3	0.605	450.8	25.89	0.0	8.03	0.113
5.68	5.60	0.0	1661.3	0.857	480.8	27.62	0.0	15.17	0.061
5.66	5.60	0.0	2145.3	1.106	497.8	28.59	0.0	27.24	0.035
5.48	5.45	0.0	2446.3	1.262	504.8	28.99	0.0	41.86	0.023

TABLE A2 (CONTINUED)

RESULTS OF RUN 3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.40	5.38	0.0	2632.3	1.357	507.8	29.17	0.0	61.00	0.016
5.95	5.90	0.0	2832.3	1.461	510.8	29.34	0.0	64.00	0.015
5.73	5.70	0.0*	3080.3	1.589	514.8	29.57	0.0	62.00	0.016
5.40	5.38	35.0	3184.3	1.660	515.8	29.63	0.0	98.00	0.007
4.84	4.80	70.0	3266.3	1.721	518.3	29.77	0.0	40.60	0.021
5.47	5.45	70.0	3366.4	1.772	521.3	29.94	0.0	32.00	0.030
5.58	5.56	141.6	3548.4	1.903	525.3	30.17	24.33	46.00	0.016
5.22	5.20	211.6	3773.4	2.055	528.3	30.34	213.56	82.33	0.010
5.50	5.50	247.6	4048.7	2.216	542.3	31.15	191.45	17.14	0.045
4.93	4.90	352.6**	4518.7	2.512	577.3	33.16	144.01	13.57	0.061
5.19	5.16	352.6	5037.7	2.780	588.3	33.79	272.05	43.64	0.021
5.80	5.78	352.6	5249.7	2.889	595.3	34.19	161.62	29.29	0.033
5.73	5.70	352.6	5380.7	2.957	599.3	34.42	245.33	31.50	0.031
5.62	5.60	352.6	5518.9	3.028	600.3	34.48	47.85	139.00	0.007
2.12	2.12	352.6	5518.9	3.028	601.8	34.57	216.81	30.67	
1.42	1.40	352.6	5518.9	3.028	605.8	34.80	131.79	13.50	
0.50	0.48	352.6	5518.9	3.028	612.8	35.20	520.20	11.43	
0.03	0.0	352.6	5518.9	3.028	632.8	36.35	169.09	6.50	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery.Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO_2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj start, **---Gas inj stop

TABLE A3

RESULTS OF RUN 4
(20% N2 WAG process, WAG=4:1)

OIL VISCOSITY = 3897 mpa.s
PORE VOLUME= 2265.5 CM3
HYDROCARBON PORE VOLUME= 1847.0 CM3
POROSITY= 46.51%
IRREDUCIBLE WATER SATURATION= 18.47%
INITIAL OIL SATURATION= 81.53%
ABSOLUTE PERMEABILITY= 11.1790 DARCIES
NITROGEN RETENTION= 61.74 %
NITROGEN REQUIRED= 33.9 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
3.54	3.54	0.0*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6.40	5.40	37.0	25.5	0.028	15.0	0.81	0.68	0.0	0.240
6.50	5.50	37.0	37.5	0.033	27.0	1.46	0.0	0.0	1.000
6.78	5.50	37.0	82.5	0.053	63.0	3.41	1.13	0.0	0.800
6.83	5.52	37.0	115.5	0.067	100.0	5.41	0.27	0.0	1.121
6.84	5.52	37.0	148.0	0.082	143.0	7.74	0.0	0.0	1.323
6.72	5.54	74.0	148.0	0.098	176.0	9.53	0.0	0.15	0.892
6.24	5.50	74.0	221.4	0.130	212.0	11.48	0.0	0.61	0.491
6.07	5.48	74.0	264.4	0.149	241.0	13.05	0.18	1.00	0.674
5.92	5.40	74.0	296.0	0.163	256.0	13.86	0.0	1.67	0.474
5.82	5.50	148.7	444.0	0.262	320.0	17.33	8.02	1.81	0.287
5.70	5.48	185.7	592.4	0.343	378.0	20.47	10.17	2.31	0.313
5.56	5.38	296.7	888.9	0.523	433.0	23.44	16.64	6.82	0.135
5.46	5.40	370.7**	1365.6	0.766	480.0	25.99	59.71	8.36	0.085
5.50	5.38	370.7	1551.5	0.848	492.0	26.64	21.18	14.33	0.065
5.37	5.30	370.7	2011.5	1.052	512.0	27.72	0.0	21.50	0.043

TABLE A3 (CONTINUED)

RESULTS OF RUN 4

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.32	5.25	370.7	2266.5	1.164	520.0	28.15	0.0	29.25	0.031
5.48	5.40	370.7	2796.5	1.398	534.0	28.91	0.0	36.29	0.026
5.10	5.10	370.7	2822.5	1.409	535.0	28.97	0.0	40.00	0.038
3.00	3.00	370.7	2822.5	1.409	538.0	29.13	93.21	18.00	
1.20	1.18	370.7	2822.5	1.409	543.0	29.40	145.40	12.80	
0.70	0.10	370.7	2822.5	1.409*	550.0	29.78	116.21	6.14	
0.04	0.0	370.7	2822.5	1.409	610.0	33.03	15.68	1.67	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of N2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas-Oil Ratio
•---Gas inj. start, ••---Gas inj. stop

TABLE A4

RESULTS OF RUN 5
(20% N2 WAG process. WAG=4:1)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 1968.1 CM3
HYDROCARBON PORE VOLUME= 1830.0 CM3
POROSITY= 40.40%
IRREDUCIBLE WATER SATURATION= 7.02%
INITIAL OIL SATURATION= 92.98%
ABSOLUTE PERMEABILITY= 11.9875 DARCIES
NITROGEN RETENTION= 22.97 %
NITROGEN REQUIRED= 34.3 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
3.48	3.48	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.65	5.50	36.6	0.0	0.019	7.0	0.38	0.0	0.0	0.191
5.76	5.50	36.6	17.8	0.028	22.0	1.20	0.0	0.0	0.843
5.88	5.50	36.6	49.3	0.044	48.0	2.62	0.0	0.0	0.825
5.88	5.50	36.6	92.8	0.066	[illegible]4.0	5.14	0.0	0.0	1.057
5.90	5.52	36.6	127.8	0.084	127.5	6.97	0.0	0.0	0.957
5.88	5.50	36.6	159.3	0.100	160.0	8.74	0.0	0.0	1.032
5.50	5.48	73.2	159.3	0.118	197.5	10.79	0.41	0.0	1.025
5.82	5.50	73.2	220.3	0.149	235.5	12.87	13.59	0.0	0.623
5.78	5.50	73.2	259.3	0.169	268.5	14.67	2.56	0.14	0.846
5.76	5.52	73.2	291.3	0.185	291.0	15.90	0.68	0.51	0.703
5.50	5.42	109.8	305.9	0.211	314.0	17.16	25.69	0.87	0.449
5.62	5.48	109.8	381.2	0.249	340.0	18.58	23.50	1.12	0.945
5.53	5.50	146.4	446.1	0.301	378.0	20.66	20.92	1.47	0.374
5.62	5.56	183.0	719.1	0.458	434.0	23.72	38.68	3.36	0.181
5.58	5.52	256.3	948.1	0.612	466.0	25.46	93.83	6.56	0.106

TABLE A4 (CONTINUED)

RESULTS OF RUN 5

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.73	5.72	329.4	1220.1	0.787	488.0	26.67	112.54	11.59	0.064
5.60	5.53	366.0**	1468.5	0.932	504.0	27.54	111.15	14.00	0.056
5.60	5.50	366.0	1724.0	1.062	519.0	28.36	4.88	15.87	0.059
5.59	5.56	366.0	1953.4	1.178	529.0	28.91	0.0	22.00	0.044
5.55	5.50	366.0	2331.4	1.371	539.0	29.45	-0.10	35.50	0.026
2.30	2.24	366.0	2331.4	1.371	542.0	29.62	92.53	19.17	
0.64	0.52	366.0	2331.4	1.371	548.0	29.95	233.53	8.33	
0.0	0.0	366.0	2331.4	1.371	594.0	32.46	41.60	3.13	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio
PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio
GI=Cumulative Volume of N2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas-Oil Ratio
*---Gas inj start.
**---Gas inj stop

TABLE A5

RESULTS OF RUN 6
(20% N2 WAG process, WAG=4:1)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 2291.5 CM3
HYDROCARBON PORE VOLUME= 1898.5 CM3
POROSITY= 47.04%
IRREDUCIBLE WATER SATURATION= 17.15%
INITIAL OIL SATURATION= 82.85%
ABSOLUTE PERMEABILITY= 15.7860 DARCIES
NITROGEN RETENTION= 14.09 %
NITROGEN REQUIRED= 35.3 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
3.38	3.38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.86	5.50	19.0	22.7	0.018	15.0	0.79	23.59	0.0	0.360
6.03	5.52	19.0	57.7	0.033	43.0	2.26	0.29	0.0	0.800
6.02	5.50	19.0	77.0	0.042	67.0	3.53	0.0	0.0	1.244
5.50	5.26	38.0	83.7	0.053	89.0	4.69	0.0	0.0	0.856
6.04	5.50	38.0	124.7	0.071	126.5	6.66	0.0	0.0	0.915
5.50	5.16	38.0	155.6	0.084	172.0	9.06	0.0	0.0	1.475
5.80	5.53	57.0	187.9	0.107	210.0	11.06	0.0	0.0	0.741
5.98	5.58	57.0	232.9	0.127	245.0	12.90	19.87	0.0	0.776
5.60	5.40	76.0	232.9	0.135	267.0	14.06	0.0	0.07	1.158
5.78	5.44	76.0	289.1	0.159	307.5	16.20	3.16	0.16	0.721
5.80	5.50	76.0	309.1	0.168	324.5	17.09	12.38	0.32	0.850
5.65	5.42	100.5	365.4	0.203	361.5	19.04	6.13	0.81	0.458
5.50	5.32	122.0	468.1	0.258	408.5	21.52	28.06	1.04	0.378
5.60	5.48	175.1	544.1	0.314	445.5	23.47	25.70	2.08	0.287
5.50	5.40	213.1	696.4	0.397	488.5	25.73	71.65	4.05	0.226

TABLE A5 (CONTINUED)

RESULTS OF RUN 6

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.54	5.47	272.6	937.6	0.528	518.5	27.31	87.92	7.13	0.100
5.45	5.40	337.1	1109.1	0.631	533.5	28.10	134.90	12.07	0.064
5.55	5.53	380.1**	1296.9	0.732	543.5	28.63	185.16	16.80	0.043
5.50	5.45	380.1	1450.9	0.799	549.5	28.94	0.51	23.67	0.039
5.35	5.30	380.1	1566.4	0.849	554.5	29.21	0.0	22.60	0.043
2.90	2.83	380.1	1566.4	0.849	557.0	29.34	307.89	21.00	
0.50	0.35	380.1	1566.4	0.849	569.0	29.97	243.19	4.58	
0.13	0.07	380.1	1566.4	0.849	585.0	30.81	53.51	2.25	
0.02	0.0	380.1	1566.4	0.849	600.0	31.60	11.18	3.27	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of N2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas-Oil Ratio
*---Gas inj. start. **---Gas inj. stop

TABLE A6

RESULTS OF RUN 7
(20% N2 WAG process, WAG=4 1)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 2038.5 CM3
HYDROCARBON PORE VOLUME= 1855.0 CM3
POROSITY= 41.85%
IRREDUCIBLE WATER SATURATION= 9.00%
INITIAL OIL SATURATION= 91.00%
ABSOLUTE PERMEABILITY= 16.8074 DARCIES
NITROGEN RETENTION= 17.93 %
NITROGEN REQUIRED= 34.1 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
3.40	3.40	0.0*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.50	5.30	38.0	0.0	0.019	15.0	0.81	0.0	0.0	0.395
6.10	5.50	46.0	79.8	0.062	60.0	3.23	16.56	0.0	0.513
6.09	5.50	46.0	125.0	0.084	111.0	5.98	0.60	0.0	1.127
5.50	5.30	83.0	125.0	0.102	151.0	8.14	0.0	0.0	1.081
6.03	5.50	83.0	222.5	0.150	218.0	11.75	12.72	0.01	0.687
5.50	5.30	120.0	236.0	0.175	263.5	14.20	0.11	0.14	0.901
5.86	5.50	120.0	321.4	0.217	303.5	16.36	32.64	0.47	0.468
5.75	5.53	157.0	347.0	0.247	333.5	17.98	0.17	0.90	0.479
5.50	5.44	157.0	451.5	0.299	367.5	19.81	53.89	1.50	0.325
5.65	5.50	194.4	557.5	0.369	399.5	21.54	55.96	2.25	0.223
5.57	5.50	268.4	675.5	0.463	429.5	23.15	77.35	3.83	0.156
5.58	5.50	305.9	897.5	0.590	461.5	24.88	60.53	5.75	0.123
5.55	5.49	371.0**	1043.0	0.694	479.5	25.85	151.28	7.11	0.085
4.94	4.90	371.0	1391.5	0.865	509.5	27.47	15.42	10.83	0.086
5.56	5.50	371.0	1758.0	1.044	532.5	28.71	1.24	14.22	0.063

TABLE A6 (CONTINUED)

RESULTS OF RUN 7

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.56	5.50	371.0	2012.8	1.169	540.5	29.14	5.97	28.00	0.031
5.55	5.50	371.0	2219.3	1.271	550.5	29.68	0.0	20.80	0.048
5.23	5.20	371.0	2402.8	1.361	558.5	30.11	0.25	22.50	0.044
2.88	2.80	371.0	2402.8	1.361	560.5	30.22	3.05	27.50	
0.88	0.85	371.0	2402.8	1.361	570.5	30.75	141.44	6.30	
0.13	0.05	371.0	2402.8	1.361	588.5	31.73	71.40	3.33	
0.03	0.0	371.0	2402.8	1.361	607.0	32.72	9.56	3.00	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio

PP=Production Pressure.
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of N2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas-Oil Ratio
*---Gas inj. start, **---Gas inj. stop

TABLE A7

RESULTS OF RUN 8
(20% N2 WAG process after brineflood)

OIL VISCOSITY = 1116 mpa s
PORE VOLUME= 1877.7 CM3
HYDROCARBON PORE VOLUME= 1720.0 CM3
POROSITY= 38.55%
IRREDUCIBLE WATER SATURATION= 8.40%
INITIAL OIL SATURATION= 91.60%
ABSOLUTE PERMEABILITY= 9.6535 DARCIES
NITROGEN RETENTION= 36.97 %
NITROGEN REQUIRED= 178.5 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
3.40	3.40	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.86	5.50	0.0	63.4	0.034	44.0	2.56	0.0	0.0	0.694
5.86	5.50	0.0	111.5	0.059	93.0	5.41	0.0	0.0	1.019
5.82	5.50	0.0	138.1	0.074	120.0	6.98	0.0	0.0	1.015
5.80	5.50	0.0	164.9	0.088	144.0	8.37	0.0	0.15	0.896
5.78	5.50	0.0	210.2	0.112	178.0	10.35	0.0	0.35	0.751
5.75	5.50	0.0	251.8	0.134	203.5	11.83	0.0	0.63	0.613
5.72	5.50	0.0	297.6	0.158	227.0	13.20	0.0	0.96	0.513
5.70	5.50	0.0	364.5	0.194	257.0	14.94	0.0	1.23	0.448
5.66	5.50	0.0	432.0	0.230	281.0	16.34	0.0	1.83	0.356
5.62	5.50	0.0	499.4	0.266	300.0	17.44	0.0	2.61	0.282
5.56	5.50	0.0	813.8	0.433	358.0	20.81	0.0	4.36	0.184
5.56	5.50	0.0	961.8	0.512	378.5	22.01	0.0	6.17	0.139
5.54	5.49	0.0	1130.1	0.602	394.5	22.94	0.0	9.44	0.095
5.52	5.47	0.0	1285.5	0.685	407.0	23.66	0.0	11.32	0.080
5.52	5.48	0.0	1525.0	0.812	425.0	24.71	0.0	12.22	0.075

TABLE A7 (CONTINUED)

RESULTS OF RUN 8

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.53	5.50	0.0*	1717.6	0.915	435.5	25.32	0.0	17.19	0.055
5.56	5.50	34.5	1717.6	0.933	436.5	25.38	0.0	31.00	0.029
5.54	5.48	34.5	1819.6	0.987	441.5	25.67	0.0	17.40	0.049
5.58	5.52	68.5	1819.6	1.006	443.1	25.76	0.0	17.13	0.047
5.52	5.46	68.5	1933.2	1.066	448.1	26.05	109.21	17.40	0.044
5.50	5.46	136.5	2035.2	1.157	454.6	26.43	238.40	18.23	0.038
5.50	5.50	136.5	2091.8	1.187	456.4	26.53	314.08	20.67	0.032
5.58	5.54	170.5	2261.4	1.295	463.2	26.93	169.57	23.71	0.033
5.58	5.54	238.5	2465.4	1.440	472.9	27.49	233.97	20.65	0.036
5.52	5.48	310.5	2669.8	1.587	480.6	27.94	326.17	26.01	0.028
5.54	5.50	344.5**	2905.1	1.731	488.6	28.41	144.77	28.50	0.030
5.50	5.45	344.5	3062.9	1.815	492.6	28.64	1.78	37.50	0.025
5.60	5.56	344.5	3318.6	1.951	504.6	29.34	0.51	19.92	0.047
1.92	1.88	344.5	3318.6	1.951	509.1	29.60	38.86	15.44	
0.85	0.70	344.5	3318.6	1.951	512.6	29.80	219.05	16.71	
0.20	0.10	344.5	3318.6	1.951	528.1	30.70	74.79	4.23	
0.0	0.0	344.5	3318.6	1.951	543.1	31.58	15.66	2.40	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio
PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery, Percent
OPFIR=Oil Produced-Fluid Injected Ratio
GI=Cumulative Volume of N2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas-Oil Ratio
*---Gas inj. start ; **---Gas inj. stop

TABLE A8

RESULTS OF RUN 9
(N2 gas flooding, then 20% CO2 WAG process)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 2049.6 CM3
HYDROCARBON PORE VOLUME= 1888.0 CM3
POROSITY= 42.08%
IRREDUCIBLE WATER SATURATION= 7.89%
INITIAL OIL SATURATION= 92.11%
ABSOLUTE PERMEABILITY= 17.5763 DARCIES
NITROGEN RETENTION= 51.51 %
NITROGEN REQUIRED=1298.3 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
3.45	3.45	0.0*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.63	5.50	61.0	0.0	0.030	28.5	1.51	0.0	0.0	0.467
5.60	5.50	64.0	0.0	0.031	31.0	1.64	146.42	0.0	0.833
5.55	5.52	113.0	0.0	0.055	53.5	2.83	47.77	0.0	0.459
5.55	5.52	177.0	0.0	0.086	67.0	3.55	173.61	0.0	0.211
5.55	5.50	230.5	0.0	0.112	77.0	4.08	214.85	0.0	0.187
5.52	5.50	310.5	0.0	0.151	85.5	4.53	291.17	0.0	0.106
5.54	5.52	348.5	0.0	0.170	88.0	4.66	786.61	0.0	0.066
5.52	5.50	524.8	0.0	0.256	94.5	5.01	974.73	0.0	0.037
5.42	5.40	857.5	0.0	0.418	101.0	5.35	2263.12	0.0	0.020
5.69	5.67	1044.5	0.0	0.510	106.0	5.61	1636.26	0.0	0.027
5.51	5.50	2492.3**	0.0	1.216	107.0	5.67	27759.04	0.0	0.001

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of N2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas-Oil Ratio
*--- N2 inj. start, **--- N2 inj. stop

TABLE 8 (CONTINUED)

RESULTS OF RUN 9
(20% CO2 WAG process after N2 [illegible] flood)

PORE VOLUME= 2049.6 CM3.
HYDROCARBON PORE VOLUME= 1888.0 CM3
POROSITY= 42.08%
IRREDUCIBLE WATER SATURATION= 7.89%
INITIAL OIL SATURATION= 92.11%
ABSOLUTE PERMEABILITY= 17.5763 DARCIES
CARBON DIOXIDE RETENTION= 26.94 %
CARBON DIOXIDE REQUIRED= 59.0 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	5.50	0.0	0.0	1.216	107.0	5.67	0.0	0.0	0.0
5.94	5.50	0.0	151.4	1.290	156.0	8.26	90.47	0.0	0.324
5.62	5.48	37.7	151.4	1.308	181.5	9.61	0.22	0.0	0.676
5.90	5.50	37.7	218.4	1.341	248.5	13.16	6.25	0.0	1.000
5.92	5.56	37.7	302.6	1.382	309.5	16.39	2.47	0.33	0.725
5.58	5.40	75.5	302.6	1.400	322.0	17.06	1.82	0.88	0.331
5.68	5.50	75.5	430.2	1.463	349.5	18.51	5.57	1.60	0.216
5.66	5.50	75.5	453.8	1.474	374.0	19.81	0.0	1.53	1.038
5.60	5.48	113.3	605.0	1.566	413.0	21.88	24.93	3.00	0.206
5.[illegible]0	5.44	188.9	757.2	1.678	462.0	24.47	33.04	2.90	0.215
5.45	5.37	228.0	908.4	1.770	496.0	26.27	48.85	3.50	0.179
5.50	5.45	265.8	1050.6	1.858	526.0	27.86	68.10	4.00	0.167
5.53	5.48	308.6	1201.8	1.950	547.0	28.97	25.41	6.33	0.111
5.55	5.50	341.4	1353.0	2.043	573.0	30.35	63.60	4.85	0.138
5.53	5.48	379.[illegible]	1504.2	2.135	590.[illegible]	31.25	49.[illegible]	[illegible].06	0.090
5.[illegible]	5.46	428.7	1660.2	2.235	612.5	32.44	79.[illegible]	[illegible]	0.110

TABLE 8 (CONTINUED)

RESULTS OF RUN 9

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.57	5.52	428.7	1963.5	2.383	645.0	34.16	90.28	7.60	0.107
5.60	5.56	428.7	2444.5	2.618	699.0	37.02	33.46	7.46	0.112
5.57	5.53	428.7	2647.5	2.717	718.0	38.03	45.08	9.32	0.094
5.45	5.40	428.7	2872.7	2.827	729.5	38.64	57.97	18.30	0.051
5.84	5.80	428.7	3331.8	3.051	749.5	39.70	68.25	21.90	0.044
5.56	5.56	428.7	3780.9	3.270	765.5	40.55	73.75	26.75	0.036
5.58	5.55	428.7	3986.2	3.370	771.0	40.84	64.59	36.27	0.027
5.03	5.00	428.7	4148.4	3.449	775.5	41.08	27.39	35.00	0.028
5.58	5.57	428.7	4637.8	3.688	784.5	41.55	2.52	52.89	0.018
5.50	5.48	428.7	4862.0	3.797	787.5	41.71	0.0	72.67	0.013
1.90	1.88	428.7	4862.0	3.797	788.5	41.76	4.06	54.00	
1.12	1.10	428.7	4862.0	3.797	791.5	41.92	105.16	22.67	
0.87	0.86	428.7	4862.0	3.797	799.0	42.32	98.94	10.80	
0.18	0.10	428.7	4862.0	3.797	810.5	42.93	267.07	7.17	
0.01	0.0	428.7	4862.0	3.797	824.5	43.67	85.21	4.57	

PI=Ijection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---CO2 inj begin, **---CO2 inj. stop

TABLE A9

RESULTS OF RUN 10
(CO2 gas flooding, then 20% CO2 WAG process)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 1942.0 CM3
HYDROCARBON PORE VOLUME= 1797.0 CM3
POROSITY= 39.87%
IRREDUCIBLE WATER SATURATION= 7.47%
INITIAL OIL SATURATION= 92.53%
ABSOLUTE PERMEABILITY= 15.5369 DARCIES
CARBON DIOXIDE RETENTION= 13.28 %
CARBON DIOXIDE REQUIRED= 758.9 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.55	5.50	92.6	0.0	0.048	31.5	1.75	0.26	0.0	0.340
5.56	5.55	170.6	0.0	0.088	55.5	3.09	59.17	0.0	0.308
5.85	5.84	403.6	0.0	0.208	78.0	4.34	217.02	0.0	0.097
5.69	5.68	999.0	0.0	0.514	174.5	9.71	248.49	0.0	0.162
5.82	5.78	1479.4	0.0	0.762	194.5	10.82	140.55	0.0	0.042
5.66	5.66	1937.3	0.0	0.998	219.5	12.21	649.97	0.0	0.055
5.87	5.87	2247.5	0.0	1.157	278.0	15.47	431.08	0.0	0.189
5.78	5.78	2343.4	0.0	1.207	289.0	16.08	1185.17	0.0	0.115
5.80	5.80	2898.0	0.0	1.492	303.0	16.86	136.65	0.0	0.025
5.72	5.72	3346.0	0.0	1.723	303.0	16.86	162200.00	0.0	0.000
5.10	5.10	3862.9	0.0	1.989	343.0	19.09	615.16	0.0	0.077
5.60	5.60	4201.2	0.0	2.163	343.0	19.09	0.0	0.0	0.000
5.87	5.87	4717.6	[illegible]	2.429	382.0	21.26	289.09	0.0	0.076
5.89	5.89	4773.9	0.0	2.458	382.0	21.26	[illegible]	[illegible]	0.000
5.87	5.87	5094.4	[illegible]	2.623	409.0	22.76	[illegible]	[illegible]	0.084

TABLE A9 (CONTINUED)

RESULTS OF RUN 10

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.79	5.79	5653.8	0.0	2.911	447.0	24.87	1320.24	0.0	0.068
5.84	5.83	6081.2	0.0	3.131	472.0	26.27	1732.39	0.0	0.058
5.80	5.78	6666.1	0.0	3.433	487.0	27.10	1679.80	0.0	0.026
5.81	5.81	7168.3	0.0	3.691	502.0	27.94	1493.16	0.0	0.030
5.77	5.77	7745.2	0.0	3.988	576.0	32.05	2050.32	0.0	0.128
5.84	5.84	7786.7	471.5	4.252	743.5	41.37	297.50	0.09	0.326
5.86	5.85	7834.6	510.8	4.297	783.5	43.60	1039.22	0.52	0.459
5.74	5.74	7880.4	615.8	4.375	868.5	48.33	101.50	0.76	0.563
5.77	5.77	7921.0	759.8	4.470	901.5	50.17	353.99	2.27	0.179
5.70	5.70	7951.6	903.9	4.560	923.0	51.36	249.64	4.26	0.123
5.70	5.66	7972.2	1047.9	4.645	948.0	52.75	805.36	5.56	0.152
5.62	5.60	8010.3	1191.9	4.739	966.5	53.78	662.96	6.46	0.102
5.68	5.60	8066.8	1365.9	4.857	982.5	54.67	434.34	8.44	0.069
5.62	5.60	8101.9	1489.6	4.939	993.7	55.30	768.49	10.61	0.071
5.75	5.73	8135.4	1620.9	5.024	1000.7	55.69	418.13	10.57	0.042
5.80	5.80	8135.4	1917.3	5.176	1011.2	56.27	472.93	19.95	0.035
5.56	5.56	8135.4	2125.3	5.284	1018.7	56.69	587.70	25.40	0.036
5.40	5.40	8135.4	2125.3	5.284	1023.2	56.94	597.26	15.56	450000.025
5.66	5.66	8135.4	2314.3	5.381	1031.7	57.41	488.60	19.00	0.045
5.57	5.56	8135.4**	2394.9	5.422	1034.2	57.55	692.59	34.20	0.031

TABLE A9 (CONTINUED)

RESULTS OF RUN 10

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
4.80	4.78	8135.4	2394.9	5.422	1036.7	57.69	1818.91	27.40	
4.80	4.78	8135.4	2394.9	5.422	1036.7	57.69	1818.91	27.40	
3.58	3.56	8135.4	2394.9	5.422	1038.4	57.79	7448.32	50.76	
2.11	2.08	8135.4	2394.9	5.422	1040.6	57.91	7362.04	39.91	
0.54	0.50	8135.4	2394.9	5.422	1042.6	58.02	15209.90	55.50	
0.02	0.0	8135.4	2394.9	5.422	1045.6	58.19	0.27	24.00	

PI=Ijection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio
PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio
GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start. **---Gas inj stop

TABLE A10

RESULTS OF RUN 11
(20% CO2 WAG process after CO2 gasflood)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 1990.0 CM3
HYDROCARBON PORE VOLUME= 1813.5 CM3
POROSITY= 40.85%
IRREDUCIBLE WATER SATURATION= 8.87%
INITIAL OIL SATURATION= 91.13%
ABSOLUTE PERMEABILITY= 17.3989 DARCIES
CARBON DIOXIDE RETENTION= -8.01 %
CARBON DIOXIDE REQUIRED= 710.1 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.52	5.50	84.6	0.0	0.043	34.0	1.87	0.0	0.0	0.402
5.56	5.54	195.5	0.0	0.098	58.0	3.20	103.03	0.0	0.217
5.50	5.50	326.8	0.0	0.164	72.0	3.97	445.07	0.0	0.107
5.64	5.62	378.5	0.0	0.190	128.0	7.06	51.54	0.0	1.084
5.66	5.66	545.2	0.0	0.274	164.5	9.07	378.68	0.0	0.219
5.66	5.66	620.2	0.0	0.312	172.5	9.51	846.08	0.0	0.107
5.62	5.62	1171.3	0.0	0.589	237.5	13.10	454.45	0.0	0.118
5.62	5.62	1667.1	0.0	0.838	283.0	15.61	2103.63	0.0	0.092
5.64	5.62	2204.8	0.0	1.108	368.0	20.29	614.20	0.0	0.158
5.63	5.62	2322.7	0.0	1.167	377.0	20.79	6472.05	0.0	0.076
5.54	5.54	2859.5	0.0	1.437	382.0	21.06	9990.71	0.0	0.009
5.55	5.54	3297.9	0.0	1.657	389.0	21.45	8676.89	0.0	0.016
5.57	5.56	3793.1	0.0	1.906	389.0	21.45	999999.00	0.0	0.000
5.87	5.87	3932.6	0.0	1.976	389.0	21.45	0.0	0.0	0.000
5.82	5.78	3972.2	0.0	1.996	411.5	22.69	1262.20	0.0	0.568

TABLE A10 (CONTINUED)

RESULTS OF RUN 11

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.82	5.82	4130.4	0.0	2.076	414.0	22.83	2857.96	0.0	0.016
5.70	5.70	4705.7	0.0	2.365	441.5	24.35	1453.78	0.0	0.048
5.82	5.82	5177.8	0.0	2.602	446.0	24.59	5997.62	0.0	0.010
5.76	5.76	5727.0	0.0	2.878	469.5	25.89	2081.13	0.0	0.043
5.80	5.80	6111.4	0.0	3.071	476.0	26.25	4033.91	0.0	0.017
5.82	5.80	6690.3	0.0	3.362	485.5	26.77	3385.37	0.0	0.016
5.84	5.84	7110.2	0.0	3.573	494.0	27.24	3766.09	0.0	0.020
5.84	5.84	7690.7	0.0	3.865	501.5	27.65	6635.06	0.0	0.013
5.92	5.91	7733.1	152.5	3.963	505.0	27.85	5857.27	0.0	0.018
6.16	6.14	7767.1	294.2	4.051	570.0	31.43	88.65	0.0	0.370
6.24	6.23	7767.1	337.3	4.073	597.0	32.92	128.92	0.04	0.626
6.12	6.10	7833.2	354.4	4.114	612.0	33.75	72.07	0.07	0.180
6.12	6.12	7833.2	465.8	4.170	696.0	38.38	95.50	0.26	0.754
6.18	6.17	7877.5	625.9	4.273	772.5	42.60	116.56	0.71	0.374
6.27	6.27	7938.2	772.9	4.377	842.5	46.46	68.70	0.87	0.337
6.11	6.11	7999.1	920.8	4.482	876.5	48.33	186.34	3.18	0.163
6.10	6.10	8055.8	1064.1	4.583	903.5	49.82	252.28	4.04	0.135
6.37	6.37	8097.5	[illegible]	4.675	936.5	51.64	116.91	2.94	0.180
6.38	6.38	8097.5	1402.2	4.774	959.5	52.91	193.23	7.00	0.117
6.24	6.24	8097.5	1566.4	4.856	976.5	53.85	[illegible]	[illegible]	0.104

TABLE A10 (CONTINUED)

RESULTS OF RUN 11

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
6.52	6.52	8097.5	1714.7	4.931	990.8	54.63	203.66	8.72	0.096
6.50	6.50	8097.5	1832.1	4.990	1007.8	55.57	83.06	5.53	0.145
6.48	6.48	8097.5	2034.5	5.091	1024.2	56.48	230.64	10.46	0.081
6.44	6.44	8097.5	2227.2	5.188	1035.9	57.12	279.48	14.64	0.061
6.34	6.33	8097.5	2412.5	5.281	1050.3	57.92	231.14	11.22	0.078
6.41	6.41	8097.5	2610.8	5.381	1064.8	58.72	212.43	11.97	0.073
6.30	6.30	8097.5	2807.6	5.480	1077.8	59.43	125.58	13.46	0.066
6.21	6.20	8097.5	3051.2	5.602	1085.0	59.83	496.06	31.78	0.030
6.30	6.30	8097.5	3265.1	5.710	1096.5	60.46	48.73	16.65	0.054
5.40	5.40	8097.5	3265.1	5.710	1100.5	60.68	801.88	11.50	
4.42	4.42	8097.5	3265.1	5.710	1101.5	60.74	3056.66	55.50	
2.96	2.95	8097.5	3265.1	5.710	1103.0	60.82	4880.60	42.33	
0.94	0.94	8097.5	3265.1	5.710	1103.5	60.85	33984.14	147.00	
0.22	0.22	8097.5	3265.1	5.710	1103.6	60.85	90872.55	834.00	
0.0	0.0	8097.5	3265.1	5.710	1110.1	61.21	437.07	11.92	

PI=Ijection Pressure
WI=Brine Injected
*NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start, **---Gas inj. stop

NOTE: That CO2 retention is -8.0% propably is caused by liquid CO2 being injected rather than dasous CO2.

TABLE A11

RESULTS OF RUN 12
(20% CO2 slug driven by brine)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 1972.0 CM3
HYDROCARBON PORE VOLUME= 1822.0 CM3
POROSITY= 40.48%
IRREDUCIBLE WATER SATURATION= 7.61%
INITIAL OIL SATURATION= 92.39%
ABSOLUTE PERMEABILITY= 12.3829 DARCIES
CARBON DIOXIDE RETENTION= 23.76 %
CARBON DIOXIDE REQUIRED= 60.3 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.63	5.50	62.9	0.0	0.032	12.0	0.66	0.0	0.0	0.191
5.56	5.54	112.4	0.0	0.057	23.0	1.26	241.16	0.0	0.222
5.52	5.51	253.1	0.0	0.128	33.0	1.81	892.10	0.0	0.071
5.50	5.50	371.7	0.0	0.188	38.5	2.11	1449.77	0.0	0.046
5.76	5.56	371.7	93.7	0.236	90.5	4.97	78.26	0.13	0.555
5.74	5.54	371.7	188.7	0.284	164.0	9.00	20.96	0.26	0.774
5.75	5.54	371.7	239.7	0.310	188.5	10.35	26.15	1.08	0.480
5.75	5.54	371.7	305.7	0.343	215.5	11.83	16.37	1.37	0.409
5.73	5.54	371.7	507.7	0.446	282.5	15.50	10.47	1.99	0.332
5.67	5.50	371.7	678.6	0.533	330.5	18.14	6.12	2.46	0.281
5.63	5.50	371.7	837.6	0.613	369.5	20.28	4.30	3.05	0.245
5.45	5.43	371.7	1014.6	0.703	402.0	22.06	1.07	4.57	0.184
5.60	5.50	371.7	1176.3	0.785	428.0	23.49	1.19	5.35	0.161
5.61	5.54	[illegible]	1384.8	0.894	453.0	24.86	1.65	7.32	0.120
5.57	5.50	371.7	1522.4	0.960	466.0	25.58	[illegible]	[illegible]	0.094

TABLE A11 (CONTINUED)

RESULTS OF RUN 12

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.66	5.60	371.7	1689.9	1.045	480.0	26.34	0.41	10.93	0.084
3.46	3.46	371.7	2197.6	1.303	511.0	28.05	0.13	15.81	0.061
5.64	5.60	371.7	2411.6	1.411	518.5	28.46	1.41	25.00	0.035
5.63	5.60	371.7	2631.6	1.523	528.5	29.01	3.33	21.20	0.045
5.58	5.56	371.7	2845.6	1.631	536.5	29.45	0.10	25.38	0.037
5.62	5.60	371.7	3037.6	1.729	544.0	29.86	0.0	24.60	0.039
5.60	5.58	371.7	3267.3	1.845	554.5	30.43	0.0	20.90	0.046
5.53	5.52	371.7	3544.6	1.986	566.5	31.09	0.0	22.17	0.043
4.22	4.22	371.7	4029.0	2.232	584.5	32.08	0.0	26.50	0.037
5.56	5.55	371.7	4514.8	2.478	592.5	32.52	0.0	58.50	0.016
0.0	0.0	371.7	4514.8	2.478	600.5	32.96	0.0	10.38	

PI=Ijection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio
PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio
GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start, **---Gas inj. stop

TABLE A12

RESULTS OF RUN 13
(20% CO2 WAG process, WAG=4:1)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 1885.6 CM3
HYDROCARBON PORE VOLUME= 1703.0 CM3
POROSITY= 38.71%
IRREDUCIBLE WATER SATURATION= 9.68%
INITIAL OIL SATURATION= 90.32%
ABSOLUTE PERMEABILITY= 5.2726 DARCIES
CARBON DIOXIDE RETENTION= 37.05 %
CARBON DIOXIDE REQUIRED= 54.9 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.40	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6.32	5.50	34.0	68.8	0.055	53.0	3.11	0.0	0.0	0.516
6.26	5.50	34.0	100.8	0.071	84.5	4.96	0.0	0.0	0.984
6.12	5.50	34.0	136.1	0.090	122.5	7.19	0.21	0.16	1.077
5.64	5.50	71.0	136.1	0.110	138.9	8.16	0.15	0.16	0.443
5.74	5.50	71.0	208.7	0.148	183.9	10.80	0.65	0.31	0.619
5.86	5.50	71.0	270.1	0.181	223.4	13.12	28.54	0.58	0.644
5.60	5.50	105.1	449.6	0.294	307.4	18.05	15.42	1.20	0.393
5.44	5.43	139.2	585.6	0.384	351.4	20.63	12.63	2.18	0.259
5.26	5.26	174.3	721.6	0.475	385.4	22.63	30.70	3.12	0.199
5.47	5.45	208.4	858.6	0.566	410.4	24.10	48.50	4.48	0.146
5.56	5.50	242.4	994.6	0.656	431.9	25.36	53.41	5.42	0.126
5.50	5.34	276.4	1130.6	0.746	452.9	26.59	65.19	5.62	0.124
5.38	5.36	310.4	1267.9	0.837	471.9	27.71	68.51	6.32	0.111
5.50	5.48	344.5	1457.1	0.955	493.4	28.97	94.94	7.70	0.096
5.53	5.52	344.5	1658.[illegible]	1.062	508.[illegible]	29.85	[illegible]	12.33	0.075

TABLE A12 (CONTINUED).

RESULTS OF RUN 13

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.52	5.50	344.5	1777.1	1.125	517.9	30.41	90.23	11.21	0.080
5.44	5.42	344.5	1997.3	1.242	533.9	31.35	110.50	12.69	0.073
5.52	5.50	344.5	2240.5	1.371	547.9	32.17	89.09	15.71	0.058
5.52	5.45	344.5	2471.4	1.493	557.9	32.76	97.32	21.80	0.043
5.60	5.56	344.5	2708.3	1.619	566.9	33.29	78.31	26.33	0.038
5.46	5.43	344.5	2934.6	1.739	572.9	33.64	64.34	36.50	0.027
5.52	5.47	344.5	3133.9	1.845	577.9	33.93	50.44	38.40	0.025
5.48	5.46	344.5	3575.8	2.079	586.9	34.46	3.69	48.00	0.020
0.85	0.85	344.5	3575.8	2.079	587.9	34.52	0.0	46.50	
0.11	0.04	344.5	3575.8	2.079	603.9	35.46	98.89	8.88	
0.01	0.0	344.5	3575.8	2.079	611.4	35.90	46.50	7.40	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start. **---Gas inj. stop

TABLE A13

RESULTS OF RUN 14
(40.3% CO2 WAG process, WAG+4:1)

OIL VISCOSITY = 1.116 mpa.s
PORE VOLUME= 2102.0 CM3
HYDROCARBON PORE VOLUME= 1889.0 CM3
POROSITY= 43.15%
IRREDUCIBLE WATER SATURATION= 10.13%
INITIAL OIL SATURATION= 89.87%
ABSOLUTE PERMEABILITY= 16.2067 DARCIES
CARBON DIOXIDE RETENTION= 30.22 %
CARBON DIOXIDE REQUIRED= 89.2 SM3/M3

PI.MPAG	PP.MPAG	GI.CM3	WI.CM3	VFI/PV	NP.CM3	%R	GOR.SM3/M3	WOR.M3/M3	OPFIR.M3/M3
5.50	3.34	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.50	5.40	75.6	0.0	0.036	31.0	1.64	7.09	0.0	0.410
5.60	5.50	75.6	60.9	0.065	54.5	2.89	75.13	0.0	0.386
5.80	5.50	75.6	90.4	0.079	81.0	4.29	11.29	0.06	0.898
5.75	5.50	75.6	126.4	0.096	112.0	5.93	6.57	0.18	0.861
5.75	5.50	75.6	160.4	0.112	139.5	7.38	7.23	0.25	0.809
5.73	5.52	75.6	213.4	0.137	178.0	9.42	5.69	0.44	0.726
5.69	5.50	75.6	267.4	0.163	214.5	11.36	3.44	0.52	0.676
5.55	5.45	75.6	303.0	0.180	237.0	12.55	2.13	0.67	0.632
5.55	5.48	153.9	303.0	0.217	261.0	13.82	0.0	0.88	0.307
5.60	5.50	153.9	489.5	0.306	332.5	17.60	16.67	1.08	0.383
5.50	5.48	235.9	605.7	0.400	385.5	20.41	45.51	1.94	0.267
5.56	5.53	235.9	798.6	0.492	423.0	22.39	56.79	3.29	0.194
5.51	5.49	312.4	908.1	0.581	451.0	23.85	64.18	4.14	0.151
[illegible]	5.52	312.4	1114.0	0.679	482.5	25.54	[illegible]	[illegible]	0.153
5.52	5.50	388.0	1210.1	0.760	506.0	26.79	[illegible]	[illegible]	0.137

TABLE A13 (CONTINUED)

RESULTS OF RUN 14

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.58	5.56	388.0	1412.2	0.856	526.0	27.85	63.34	7.45	0.099
5.54	5.53	463.6	1514.0	0.941	548.0	29.01	63.52	5.27	0.124
5.55	5.53	463.6	1771.6	1.063	578.5	30.62	92.72	6.11	0.118
5.53	5.51	539.2	1822.0	1.123	591.5	31.31	58.33	6.35	0.103
5.58	5.56	539.2	2071.9	1.242	618.0	32.72	136.95	6.89	0.106
5.59	5.57	614.8	2126.4	1.304	630.2	33.36	70.40	7.20	0.094
5.54	5.53	614.8	2392.1	1.431	651.2	34.47	169.58	9.29	0.079
5.52	5.52	690.5	2430.7	1.485	664.7	35.19	38.81	5.19	0.118
5.47	5.46	690.5*	2655.7	1.592	677.7	35.88	105.06	15.08	0.058
5.51	5.50	761.5**	2760.7	1.676	684.7	36.25	87.12	16.29	0.040
5.51	5.50	761.5	3033.6	1.805	703.7	37.25	152.30	11.42	0.070
5.51	5.50	761.5	3267.6	1.917	720.1	38.12	115.32	12.66	0.070
5.41	5.40	761.5	3757.3	2.150	747.7	39.58	131.88	16.46	0.056
5.49	5.48	761.5	4230.2	2.375	769.2	40.72	131.46	20.77	0.045
5.51	5.50	761.5	4712.7	2.604	786.2	41.62	139.06	27.18	0.035
5.50	5.50	761.5	5209.0	2.840	799.2	42.31	100.56	36.85	0.026
2.06	2.05	761.5	5209.0	2.840	800.7	42.39	49.74	34.00	
0.71	0.70	761.5	5209.0	2.840	804.7	42.60	71.77	21.50	
0.0	0.0	761.5	5209.0	2.840	825.2	43.68	232.97	15.17	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start, **---Gas inj. stop

TABLE A14

RESULTS OF RUN 15
(10% CO2 slug, then 10% N2 slug drived by brine)

OIL VISCOSITY = 11.16 mpa.s
PORE VOLUME= 2003.0 CM3
HYDROCARBON PORE VOLUME= 1815.0 CM3
POROSITY= 41.12%
IRREDUCIBLE WATER SATURATION= 9.39%
INITIAL OIL SATURATION= 90.61%
ABSOLUTE PERMEABILITY= 14.9012 DARCIES
CARBON DIOXIDE RETENTION= 36.78 %
CARBON DIOXIDE REQUIRED = 27.5 SM3/M3
NITROGEN RETENTION = 49.81 %
NITROGEN REQUIRED = 15.8 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.42	0.0*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.54	5.49	110.0	0.0	0.055	29.5	1.63	0.0	0.0	0.268
5.50	5.50	182.0	0.0	0.091	46.0	2.53	184.07	0.0	0.229
5.50	5.50	364.0**	0.0	0.182	74.0	4.08	418.51	0.0	0.154
5.96	5.66	364.0	90.3	0.227	105.5	5.81	86.48	0.0	0.349
5.82	5.51	364.0	120.6	0.242	137.5	7.58	2.92	0.0	1.054
5.88	5.56	364.0	152.9	0.258	171.0	9.42	1.11	0.0	1.037
5.84	5.55	364.0	194.9	0.279	207.0	11.41	1.28	0.04	0.857
5.71	5.50	364.0	254.9	0.309	247.0	13.61	0.30	0.50	0.667
5.56	5.50	364.0	315.9	0.340	278.5	15.34	0.0	0.98	0.516
5.63	5.50	364.0	398.9	0.381	312.5	17.22	0.0	1.41	0.410
5.60	5.49	364.0	494.0	0.428	346.0	19.06	0.0	1.91	0.352
5.58	5.50	364.0	689.6	0.526	394.5	21.74	0.0	2.94	0.248
5.55	5.49	364.0	88[illegible].4	0.622	432.5	23.83	[illegible]	[illegible]	0.198
5.54	5.50	364.0	1086.6	0.724	462.0	25.46	[illegible]	[illegible]	0.144
5.52	5.50	364.0	1297.4	0.830	489.0	26.94	[illegible]	6.82	0.128

TABLE A14 (CONTINUED)

RESULTS OF RUN 15

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.52	5.50	364.0	1511.7	0.937	511.4	28.18	0.0	8.51	0.105
5.52	5.50	364.0	1728.9	1.045	532.2	29.32	0.0	9.43	0.096
5.45	5.44	364.0	1942.3	1.151	549.7	30.29	0.0	11.17	0.082
5.49	5.48	364.0	2155.8	1.258	565.7	31.17	0.0	12.25	0.075
5.50	5.50	364.0	2293.8	1.327	575.4	31.70	0.0	12.09	0.070
5.55	5.54	364.0	2501.1	1.430	583.4	32.14	0.0	25.00	0.039
5.42	5.40	364.0	2731.5	1.545	592.4	32.64	0.0	24.56	0.039
5.69	5.67	364.0	2968.1	1.664	603.2	33.23	0.0	20.94	0.046
5.51	5.50	364.0	3252.5	1.806	613.7	33.81	0.0	26.10	0.037
0.43	0.38	364.0	3252.5	1.806	616.7	33.98	0.0	23.33	
0.22	0.16	364.0	3252.5	1.806	623.7	34.36	0.0	8.86	
0.14	0.02	364.0	3252.5	1.806	631.2	34.78	0.0	8.13	
0.03	0.0	364.0	3252.5	1.806	642.7	35.41	0.0	6.39	

PI=Ijection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start.   **---Gas inj. stop

TABLE A15

RESULTS OF RUN 16
(20% CO_2 WAG process, WAG=4:1)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 1912.4 CM3
HYDROCARBON PORE VOLUME= 1731.0 CM3
POROSITY= 39.26%
IRREDUCIBLE WATER SATURATION= 9.49%
INITIAL OIL SATURATION= 90.51%
ABSOLUTE PERMEABILITY= 14.2848 DARCIES
CARBON DIOXIDE RETENTION= 45.82 %
CARBON DIOXIDE REQUIRED= 45.1 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.38	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6.05	5.50	50.0	76.9	0.066	66.0	3.81	0.0	0.0	0.520
6.04	5.50	50.0	137.9	0.098	134.0	7.74	0.0	0.0	1.115
5.54	5.46	81.9	137.9	0.115	145.0	8.38	0.0	0.09	0.345
6.01	5.50	81.9	172.9	0.133	170.4	9.84	0.0	0.06	0.726
5.92	5.50	81.9	203.9	0.149	197.9	11.43	0.0	0.20	0.887
5.83	5.49	81.9	240.9	0.169	223.9	12.93	0.0	0.48	0.703
5.76	5.46	81.9	275.9	0.187	250.9	14.49	0.0	0.63	0.771
5.70	5.50	116.4	414.4	0.278	321.9	18.60	14.71	0.96	0.410
5.62	5.50	161.1	585.8	0.391	385.4	22.26	18.75	1.74	0.294
5.58	5.50	195.8	730.2	0.484	424.4	24.52	25.52	2.77	0.218
5.55	5.50	230.4	868.7	0.575	452.9	26.16	23.99	4.02	0.165
5.58	5.50	270.6	1016.6	0.673	479.9	27.72	34.51	4.67	0.144
5.53	5.48	33[illegible]	1155.[illegible]	0.778	503.9	29.11	35.52	5.71	0.120
5.60	5.54	336.3	1264.0	0.842	515.9	29.8[illegible]	[illegible]	[illegible].58	0.098
5.49	5.45	346.3	1464.7	0.947	537.9	31.07	[illegible]	[illegible]	0.110

TABLE A15 (CONTINUED)

RESULTS OF RUN 16

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	5.46	346.3	1668.6	1.054	557.9	32.23	39.62	9.10	0.098
5.54	5.49	346.3	1897.6	1.173	581.4	33.59	45.17	8.62	0.103
5.36	5.30	346.3	2131.3	1.296	603.4	34.86	50.80	9.41	0.094
5.62	5.57	346.3	2378.9	1.425	622.4	35.96	69.75	11.89	0.077
5.50	5.45	346.3	2873.9	1.684	655.9	37.89	60.93	13.75	0.068
5.64	5.60	346.3	3344.9	1.930	677.9	39.16	57.95	20.36	0.047
5.53	5.48	346.3	3801.3	2.169	692.9	40.03	44.39	29.00	0.033
5.56	5.52	346.3	4270.3	2.414	708.3	40.92	24.38	29.71	0.033
0.93	0.90	346.3	4270.3	2.414	711.3	41.09	18.11	29.00	
0.54	0.50	346.3	4270.3	2.414	720.3	41.61	20.09	10.00	
0.08	0.03	346.3	4270.3	2.414	740.3	42.77	134.95	8.65	
0.02	0.0	346.3	4270.3	2.414	744.3	43.00	48.86	7.50	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start, **---Gas inj. stop

TABLE A16

RESULTS OF RUN 17
(10% CO2 WAG process; WAG=4:1)

OIL VISCOSITY = 1116 mpa.s
PORE VOLUME= 2060.9 CM3
HYDROCARBON PORE VOLUME= 1852.0 CM3
POROSITY= 42.31%
IRREDUCIBLE WATER SATURATION= 10.13%
INITIAL OIL SATURATION= 89.87%
ABSOLUTE PERMEABILITY= 18.3587 DARCIES
CARBON DIOXIDE RETENTION= 74.11 %
CARBON DIOXIDE REQUIRED= 27.9 SM3/M3

PI.MPAG	PP.MPAG	GI.CM3	WI.CM3	VFI/PV	NP.CM3	%R	GOR.SM3/M3	WOR.M3/M3	OPFIR.M3/M3
5.50	3.45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.92	5.50	18.9	42.8	0.030	28.5	1.54	0.0	0.0	0.462
5.94	5.50	18.9	61.8	0.039	47.5	2.56	0.13	0.0	1.000
5.95	5.50	18.9	77.2	0.047	68.0	3.67	0.24	0.0	1.330
5.57	5.50	37.4	77.2	0.056	84.0	4.54	0.0	0.0	0.863
5.95	5.50	37.4	109.0	0.071	99.6	5.38	0.0	0.09	0.491
5.92	5.50	37.4	147.0	0.089	134.1	7.24	0.66	0.13	0.908
5.86	5.50	37.4	152.6	0.092	174.1	9.40	0.53	0.22	7.042
5.79	5.50	56.2	226.8	0.137	228.1	12.32	0.48	0.46	0.581
5.70	5.50	74.7	300.8	0.182	274.1	14.80	3.33	0.72	0.497
5.66	5.50	110.7	390.9	0.243	327.1	17.66	23.08	0.83	0.421
5.64	5.56	132.5	466.2	0.290	352.6	19.04	5.31	2.12	0.263
5.52	5.50	169.5	540.8	0.345	377.6	20.39	29.10	2.56	0.224
5.54	5.52	188.0	614.8	0.390	394.6	21.31	41.79	3.59	0.184
5.50	5.46	[illegible]	647.1	0.405	400.1	21.6[illegible]	[illegible]	3.82	0.170
5.56	5.54	18[illegible]	852.2	0.505	431.[illegible]	23.28	[illegible]	[illegible]	0.151

TABLE A16 (CONTINUED)

RESULTS OF RUN 17

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M
5.54	5.52	188.0	1047.9	0.600	456.1	24.63	11.55	6.60	0.
5.55	5.53	188.0	1242.4	0.694	483.1	26.09	2.55	6.19	0.
5.54	5.52	188.0	1435.6	0.788	502.6	27.14	0.37	8.74	0.
5.52	5.50	188.0	1668.6	0.901	522.0	28.19	1.21	10.96	0.
5.53	5.52	188.0	2137.3	1.128	556.5	30.05	0.0	12.68	0.
5.50	5.48	188.0	2643.8	1.374	581.5	31.40	0.0	19.32	0
5.50	5.49	188.0	3150.8	1.620	600.5	32.42	0.0	25.63	0
5.42	5.42	188.0	3363.7	1.723	605.5	32.69	0.0	41.40	0.
5.44	5.42	188.0	3604.6	1.840	611.5	33.02	0.0	38.83	0.
5.14	5.12	188.0	3829.2	1.949	617.5	33.34	0.0	36.33	0
5.61	5.60	188.0	4057.8	2.060	625.1	33.75	0.0	29.00	0
5.59	5.58	188.0	4243.5	2.150	629.1	33.97	0.0	45.00	0.
5.65	5.64	188.0	4438.5	2.245	632.1	34.13	0.0	63.67	0.
0.60	0.50	188.0	4438.5	2.245	635.1	34.29	0.0	26.33	
0.35	0.22	188.0	4438.5	2.245	638.6	34.48	6.49	20.71	
0.22	0.15	188.0	4438.5	2.245	641.6	34.64	54.88	20.00	
0.02	0.0	188.0	4438.5	2.245	655.6	35.40	6.20	5.36	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
R=Recovery, Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
...Gas start, *...Gas inj. stop

TABLE A17

RESULTS OF RUN 18
(20% CO2 WAG process, WAG=1:1)
(Diagonal glass beads: layer packing)

OIL VISCOSITY = 2107 mpa.s
PORE VOLUME= 1890.0 CM3
HYDROCARBON PORE VOLUME= 1672.0 CM3
POROSITY= 38.80%
IRREDUCIBLE WATER SATURATION= 11.53%
INITIAL OIL SATURATION= 88.47%
ABSOLUTE PERMEABILITY= 18.0980 DARCIES
CARBON DIOXIDE RETENTION= 45.78 %
CARBON DIOXIDE REQUIRED= 64.4 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.98	5.50	33.4	42.1	0.040	27.5	1.64	0.0	0.02	0.364
5.84	5.50	33.4	65.5	0.052	49.5	2.96	0.0	0.18	0.942
5.62	5.50	33.4	99.7	0.070	66.5	3.98	0.0	1.18	0.497
5.56	5.48	66.8	133.6	0.106	83.5	4.99	0.0	2.35	0.253
5.60	5.48	100.2	277.2	0.200	136.5	8.16	1.70	1.98	0.299
5.53	5.49	133.7	410.8	0.288	170.5	10.20	29.70	3.12	0.203
5.50	5.46	167.3	544.4	0.377	197.5	11.81	40.16	1.22	0.162
5.56	5.52	206.2	677.9	0.468	224.5	13.43	40.55	1.22	0.156
5.52	5.50	242.8	833.8	0.570	257.5	15.40	26.47	3.85	0.172
5.64	5.60	276.2	1060.0	0.707	296.5	17.73	53.23	4.67	0.150
5.57	5.50	309.6	1193.5	0.795	319.5	19.11	50.78	5.13	0.138
5.55	5.52	334.6	1307.5	0.869	337.5	20.19	67.13	5.28	0.129
5.49	5.46	334.6	1537.1	0.990	366.5	21.92	81.52	5.90	0.126
5.49	5.46	334.6	1930.9	1.199	417.5	24.97	88.45	6.57	0.130
5.73	5.70	334.6	2321.7	1.405	441.0	26.38	48.76	15.47	0.060

TABLE A17 (CONTINUED)

RESULTS OF RUN 18

PI, MPAG	PP, MPAG	GI, CM3	WI, CM3	VFI/PV	NP, CM3	%R	GOR, SM3/M3	WOR, M3/M3	OPFIR, M3/M3
5.60	5.58	334.6	2794.6	1.656	466.0	27.87	27.51	18.00	0.053
5.50	5.50	334.6	3073.2	1.803	471.0	28.17	59.20	55.00	0.018
0.60	0.50	334.6	3073.2	1.803	472.5	28.26	0.0	28.67	
0.45	0.35	334.6	3073.2	1.803	478.5	28.62	4.05	5.33	
0.27	0.20	334.6	3073.2	1.803	491.5	29.40	2.18	5.23	
0.10	0.07	334.6	3073.2	1.803	506.0	30.26	0.0	3.31	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO_2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start, **---Gas inj. stop.

TABLE A18

RESULTS OF RUN 19
(20% CO2 WAG process, WAG=4:1)
(Two parallel layers packing)

OIL VISCOAITY = 2107 mpa.s
PORE VOLUME= 1814.0 CM3
HYDROCARBON PORE VOLUME= 1678.0 CM3
POROSITY= 37.24%
IRREDUCIBLE WATER SATURATION= 7.50%
INITIAL OIL SATURATION= 92.50%
ABSOLUTE PERMEABILITY= 18.5869 DARCIES
CARBON DIOXIDE RETENTION= 50.13 %
CARBON DIOXIDE REQUIRED= 85.2 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.40	0.0*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6.16	5.50	24.6	40.9	0.036	26.0	1.55	0.0	0.0	0.397
6.17	5.50	24.6	69.9	0.052	56.5	3.37	0.0	0.0	1.052
6.04	5.50	24.6	98.9	0.068	87.0	5.18	0.0	0.0	1.052
5.94	5.50	24.6	134.4	0.088	116.0	6.91	0.0	0.45	0.817
5.59	5.42	58.2	134.4	0.106	131.5	7.84	0.0	0.71	0.461
5.80	5.50	58.2	227.[illegible]	0.158	162.5	9.68	0.0	1.23	0.333
5.50	5.40	101.8	268.8	0.204	187.0	11.14	21.19	1.96	0.289
5.50	5.34	139.3	402.8	0.299	213.0	12.69	7.02	3.96	0.152
5.59	5.54	172.9	537.2	0.391	230.5	13.74	71.23	6.94	0.104
5.66	5.62	206.5	671.7	0.484	252.5	15.05	51.06	5.14	0.131
5.51	5.50	240.1	806.1	0.577	267.5	15.94	125.11	7.87	0.089
5.46	5.45	286.1	979.2	0.698	285.5	17.01	134.22	9.22	0.082
6.00	5.97	319.7	1113.6	0.790	296.0	17.64	210.63	11.10	0.063
5.70	5.68	336.0**	1248.2	0.873	308.5	18.38	99.59	9.88	0.083
5.64	5.62	336.0	1446.7	0.983	320.5	19.10	143.41	13.67	0.060

TABLE A18 (CONTINUED)

RESULTS OF RUN 19

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.68	5.65	336.0	1708.5	1.127	333.5	19.87	147.10	18.85	0.050
5.78	5.76	336.0	1894.5	1.230	337.0	20.08	202.75	50.43	0.019
5.56	5.54	336.0	2298.4	1.451	351.0	20.92	65.52	27.71	0.035
5.57	5.54	336.0	2700.0	1.674	361.0	21.51	9.08	39.20	0.025
0.29	0.25	336.0	2700.0	1.674	366.0	21.81	2.76	14.20	
0.09	0.07	336.0	2700.0	1.674	382.0	22.77	2.64	6.25	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio
PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio
GI=Cumulative Volume of CO_2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start.
**---Gas inj. stop

TABLE A19

RESULTS OF RUN 20
(20% CO_2 WAG process, WAG=4:1)
(Two parallel layers packing)

OIL VISCOSITY = 1101 mpa.s
PORE VOLUME= 1820.4 CM3
HYDROCARBON PORE VOLUME= 1616.0 CM3
POROSITY= 37.37%
IRREDUCIBLE WATER SATURATION= 11.23%
INITIAL OIL SATURATION= 88.77%
ABSOLUTE PERMEABILITY= 16.3939 DARCIES
CARBON DIOXIDE RETENTION= 58.99 %
CARBON DIOXIDE REQUIRED= 63.9 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.30	0.0*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6.08	5.50	42.5	38.5	0.044	28.0	1.73	0.0	0.0	0.346
5.88	5.50	42.5	60.5	0.057	47.0	2.91	0.0	0.26	0.864
5.84	5.50	42.5	87.5	0.071	66.0	4.08	0.0	0.47	0.704
5.73	5.50	42.5	129.2	0.094	91.0	5.63	0.0	0.86	0.600
5.56	5.44	74.8	129.2	0.112	103.0	6.37	0.0	1.21	0.372
5.64	5.50	74.8	211.3	0.157	133.0	8.23	11.73	1.10	0.365
5.60	5.50	74.8	264.3	0.186	151.0	9.34	0.86	2.33	0.340
5.48	5.40	110.8	264.3	0.206	158.0	9.78	0.0	2.43	0.194
5.54	5.48	143.1	394.8	0.295	195.0	12.07	10.08	2.65	0.227
5.53	5.47	175.4	533.7	0.390	226.0	13.99	25.98	3.42	0.181
5.53	5.48	207.7	662.9	0.478	257.0	15.90	30.24	3.23	0.192
5.60	5.52	240.0	792.1	0.567	282.0	17.45	30.33	4.40	0.155
5.55	5.50	280.8	930.2	0.665	304.5	18.84	53.27	5.67	0.126
5.58	5.53	320.3	1059.4	0.758	324.0	20.05	48.29	5.92	0.116
5.50	5.46	323.4**	1247.1	0.863	347.0	21.47	93.72	5.91	0.120

TABLE A19 (CONTINUED)

RESULTS OF RUN 20

PI, MPAG	PP, MPAG	GI, CM3	WI, CM3	VFI/PV	NP, CM3	%R	GOR, SM3/M3	WOR, M3/M3	OPFIR, M3/M3
5.50	5.47	323.4	1451.3	0.975	367.5	22.74	42.37	8.85	0.100
4.99	4.95	323.4	1658.8	1.089	384.0	23.76	56.43	11.30	0.080
5.54	5.50	323.4	1883.6	1.212	400.0	24.75	47.14	13.13	0.071
3.20	3.16	323.4	2307.4	1.445	424.0	26.24	44.33	16.50	0.057
5.23	5.20	323.4	2747.4	1.687	441.0	27.29	37.88	24.76	0.039
5.00	4.98	323.4	3215.3	1.944	454.0	28.09	33.44	34.38	0.028
5.50	5.46	323.4	3720.4	2.221	463.0	28.65	50.01	54.78	0.018
5.61	5.59	323.4	3944.8	2.345	467.0	28.90	5.68	54.00	0.018
0.68	0.67	323.4	3944.8	2.345	468.0	28.96	0.0	39.00	
0.17	0.16	323.4	3944.8	2.345	489.5	30.29	5.39	6.02	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start. **---Gas inj. stop

TABLE A20

RESULTS OF RUN 21
(20% CO2 WAG process, WAG=4:1)
(Diagonal glass beads layer packing)

IL VISCOSITY = 1101 mpa.s
ORE VOLUME= 1884.7 CM3
YDROCARBON PORE VOLUME= 1690.0 CM3
OROSITY= 38.69%
RREDUCIBLE WATER SATURATION= 10.33%
NITIAL OIL SATURATION= 89.67%
BSOLUTE PERMEABILITY= 15.8398 DARCIES
ARBON DIOXIDE RETENTION= 51.95 %
ARBON DIOXIDE REQUIRED= 67.7 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.50	3.50	0.0*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.88	5.50	44.5	41.9	0.046	32.0	1.89	0.0	0.0	0.370
5.75	5.50	44.5	66.9	0.059	49.0	2.90	0.0	0.53	0.680
5.70	5.50	44.5	99.9	0.077	64.0	3.79	0.0	1.27	0.455
5.65	5.50	44.5	132.9	0.094	77.5	4.59	0.0	1.59	0.409
5.54	5.50	78.3	178.0	0.136	101.5	6.01	0.0	1.96	0.304
5.64	5.50	78.3	255.2	0.177	127.5	7.54	3.40	1.50	0.337
5.36	5.32	132.8	312.8	0.236	159.5	9.44	17.77	1.59	0.285
5.59	5.56	166.6	448.6	0.326	203.5	12.04	48.66	1.86	0.259
5.53	5.50	200.4	583.8	0.416	245.5	14.53	22.88	2.48	0.249
5.58	5.54	234.2	731.5	0.512	283.5	16.78	47.59	3.00	0.209
5.54	5.48	268.0	866.7	0.602	310.5	18.37	41.66	4.15	0.160
5.48	5.46	301.9	1001.9	0.692	334.5	19.79	69.54	4.67	0.142
5.50	5.50	335.9	1151.4	0.789	357.0	21.12	77.60	5.71	0.123
5.50	5.50	338.4**	1386.2	0.915	383.5	22.69	63.78	7.04	0.112
5.20	5.17	338.4	1550.6	1.002	401.0	23.73	57.60	8.37	0.106

TABLE A20 (CONTINUED)

RESULTS OF RUN 21

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
5.17	5.15	338.4	1792.0	1.130	429.0	25.38	18.77	7.46	0.116
5.85	5.83	338.4	1997.0	1.240	440.0	26.04	78.08	17.45	0.053
5.58	5.56	338.4	2197.9	1.346	447.0	26.45	76.47	26.86	0.035
5.52	5.50	338.4	2629.3	1.575	460.0	27.22	34.19	32.46	0.030
5.67	5.66	338.4	3059.1	1.803	470.0	27.81	53.93	41.60	0.023
0.60	0.57	338.4	3059.1	1.803	473.5	28.02	27.81	20.00	
0.28	0.26	338.4	3059.1	1.803	481.5	28.49	2.94	6.00	
0.16	0.15	338.4	3059.1	1.803	486.5	28.79	0.0	2.00	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Ratio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start. **---Gas inj. stop

TABLE A21

RESULTS OF RUN 22
(9.75% CO2 WAG process, WAG=4:1)
(Low pressure run)

OIL VISCOSITY = 1101 mpa.s
PORE VOLUME= 1961.7 CM3
HYDROCARBON PORE VOLUME= 1823.0 CM3
POROSITY= 40.27%
IRREDUCIBLE WATER SATURATION= 7.07%
INITIAL OIL SATURATION= 92.93%
ABSOLUTE PERMEABILITY= 13.3130 DARCIES
CARBON DIOXIDE RETENTION= 62.65 %
CARBON DIOXIDE REQUIRED= 36.9 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
2.50	2.46	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.08	2.70	53.9	35.3	0.045	35.0	1.92	0.0	0.0	0.392
3.52	3.20	53.9	62.3	0.059	63.0	3.46	0.0	0.0	1.037
2.78	2.48	53.9	105.3	0.081	100.0	5.49	0.0	0.08	0.860
2.66	2.36	53.9	128.3	0.093	115.0	6.31	0.0	0.60	0.652
2.62	2.40	107.4	145.8	0.129	141.5	7.76	0.0	0.79	0.373
1.86	1.83	247.4	291.6	0.275	202.5	11.11	31.22	1.70	0.213
2.71	2.54	300.9	433.6	0.374	234.0	12.84	1.49	3.13	0.161
2.40	2.37	353.4	583.6	0.478	270.0	14.81	2.52	3.33	0.178
2.67	2.62	407.0	729.3	0.579	293.0	16.07	12.87	5.61	0.115
2.50	2.48	466.0	875.2	0.684	313.0	17.17	48.66	6.50	0.098
2.52	2.50	516.0	1021.0	0.783	327.5	17.96	33.28	8.45	0.074
2.50	2.46	566.0**	1166.5	0.883	342.5	18.79	60.99	9.07	0.077
2.56	2.54	566.0	1351.4	0.977	356.0	19.53	57.19	10.41	0.073
2.55	2.52	566.0	1570.0	1.089	371.0	20.35	47.74	13.40	0.069
2.43	2.40	566.0	2007.6	1.312	397.0	21.78	9.67	15.81	0.059

TABLE A21 (CONTINUED)

RESULTS OF RUN 22

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
2.39	2.38	566.0	2404.7	1.514	414.0	22.71	0.57	22.35	0.043
2.38	2.36	566.0	2874.7	1.754	436.0	23.92	0.0	20.55	0.047
2.24	2.20	566.0	3071.1	1.854	440.0	24.14	0.41	47.25	0.020
2.50	2.48	566.0	3300.6	1.971	445.0	24.41	0.32	45.00	0.022
2.52	2.50	566.0	3729.9	2.190	458.0	25.12	0.0	32.15	0.030
0.12	0.11	566.0	3729.9	2.190	469.0	25.73	0.0	7.64	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start, **---Gas inj. stop

TABLE A22

RESULTS OF RUN 23
(20% CO2 WAG process, WAG=4:1)
(Low pressure run)

OIL VISCOSITY = 1101 mpa.s
PORE VOLUME= 2004.8 CM3
HYDROCARBON PORE VOLUME= 1812.0 CM3
POROSITY= 41.16%
IRREDUCIBLE WATER SATURATION= 9.61%
INITIAL OIL SATURATION= 90.39%
ABSOLUTE PERMEABILITY= 17.3572 DARCIES
CARBON DIOXIDE RETENTION= 46.22 %
CARBON DIOXIDE REQUIRED= 55.8 SM3/M3

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
2.50	2.49	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.76	2.50	99.2	0.0	0.049	21.0	1.16	12.01	0.0	0.212
2.70	2.45	127.1	0.0	0.068	30.5	1.68	151.02	0.0	0.341
2.92	2.50	127.1	54.4	0.091	58.5	3.23	10.46	0.0	0.515
2.82	2.50	127.1	81.4	0.104	82.0	4.53	1.55	0.17	0.870
2.81	2.50	127.1	145.0	0.136	126.0	6.95	1.90	0.50	0.692
2.41	2.38	251.4	145.0	0.198	153.0	8.44	33.70	0.74	0.217
2.78	2.58	251.4	298.0	0.274	206.0	11.37	12.78	1.26	0.346
2.49	2.42	366.8	298.0	0.332	226.0	12.47	37.02	1.00	0.173
2.55	2.50	366.8	483.6	0.424	279.0	15.40	16.28	1.91	0.285
2.63	2.54	479.8	483.6	0.481	294.0	16.23	58.77	1.80	0.133
2.63	2.53	479.8	629.6	0.553	322.0	17.77	25.66	3.11	0.192
2.60	2.54	595.2	629.6	0.611	333.5	18.41	65.09	2.26	0.100
2.49	2.46	693.7	774.6	0.732	366.5	20.23	37.70	3.30	0.136
2.46	2.45	809.1	919.6	0.862	395.5	21.83	55.57	4.45	0.111
2.48	2.46	917.3	1066.4	0.990	419.5	23.15	71.64	5.25	0.094

TABLE A22 (CONTINUED)

RESULTS OF RUN 23

PI,MPAG	PP,MPAG	GI,CM3	WI,CM3	VFI/PV	NP,CM3	%R	GOR,SM3/M3	WOR,M3/M3	OPFIR,M3/M3
2.53	2.50*	1036.3	1211.4	1.121	439.5	24.25	78.87	6.50	0.076
2.57	2.54	1154.1**	1356.4	1.252	456.5	25.19	95.84	7.82	0.065
2.57	2.54	1154.1	1864.7	1.506	501.5	27.68	41.13	9.18	0.089
2.57	2.54	1154.1	2349.1	1.747	531.5	29.33	42.39	14.53	0.062
2.56	2.54	1154.1	2858.3	2.001	554.5	30.60	3.74	21.13	0.045
2.55	2.52	1154.1	3350.1	2.247	572.5	31.59	0.05	26.39	0.037
2.56	2.54	1154.1	3588.0	2.365	579.0	31.95	0.0	35.15	0.027
2.55	2.52	1154.1	3823.8	2.483	586.5	32.37	0.0	31.13	0.032
2.53	2.52	1154.1	4058.1	2.600	591.5	32.64	0.0	45.20	0.021
2.53	2.52	1154.1	4291.5	2.716	597.5	32.97	0.0	38.17	0.026
2.53	2.52	1154.1	4758.4	2.949	608.5	33.58	0.0	41.73	0.024
0.0	0.0	1154.1	4758.4	2.949	632.5	34.91	14.16	7.17	

PI=Injection Pressure
WI=Brine Injected
NP=Cumulative Volume Oil Produced
WOR=Water-Oil Retio

PP=Production Pressure
VFI=Total Volume of Fluid Injected
%R=Recovery Percent
OPFIR=Oil Produced-Fluid Injected Ratio

GI=Cumulative Volume of CO2 Injected
PV=Pore Volume of Sand Packed
GOR=Gas Ratio
*---Gas inj. start, **---Gas inj. stop