

ENHANCED OIL RECOVERY BY DILUTION OF INJECTION BRINE: FURTHER INTERPRETATION OF EXPERIMENTAL RESULTS

Jos G. Maas (Shell Oil Company), Krijn Wit (Shell Intl E&P) and Norman R. Morrow (University of Wyoming)

ABSTRACT

Recently, laboratory experiments on core plugs demonstrated that oil recovery by both waterflooding and spontaneous imbibition could increase significantly when the brine was diluted and other conditions were held constant. A rock/fluids interaction was indicated which increased microscopic displacement efficiency. To assess the impact of such an effect at the scale of an oil reservoir by numerical simulation, the experiments need to be interpreted in terms of changes in relative permeability and/or capillary pressure.

We have conducted a study with MoReS, Shell's reservoir simulator, to further analyse the imbibition experiments. History matching of the experimental results indicated that dilution primarily affected the water relative permeability. In addition, we found that the imbibition capillary pressure is probably close to zero over an extended saturation range. The possible impact of injecting diluted brine on reservoir performance is assessed.

INTRODUCTION

It is now well established that wettability has significant impact on flow parameters such as relative permeability and capillary pressure. Measurements in the laboratory need to be representative of the field. Correct data are essential in establishing the recovery factor (RF) for the field. Wettability is dependent on crude oil/brine/rock (COBR) interactions. Extensive studies have been published on how variation of the parameters of COBR interactions impacts wettability and oil recovery [e.g. 1, 2]. One objective of these studies was to assess the possibility of obtaining improved recovery factors through manipulation of COBR interactions in the reservoir.

A series of papers have been presented which show that COBR interactions and oil recovery depend on brine composition but the mechanisms by which oil recovery is changed are not well understood [2-6]. Tang and Morrow [5] investigated the effect of salinity on oil recovery. Base-case results were obtained using synthetic reservoir brine. Tests at tenfold or hundred-fold dilution increased both breakthrough and final recovery. The impact was significant: increases in recovery of over 20% were observed in some cases. Recoveries were measured for both spontaneous and forced imbibition. For the examples considered in this paper, two scenarios were compared: 1) the initial water saturation and the invading (injected or imbibed) brine were of the same dilution, 2) the initial water saturation was reservoir brine and the invading brine was dilute. Comparison with the base case showed the increase in RF was largest if the diluted brine was used as both the connate and invading brine. However, significant increases have been observed for the second scenario, this being obviously more relevant to application at the outset of waterflooding a reservoir.

Experimental studies were conducted on a variety of COBR combinations. Results consistently pointed towards increased recovery with dilution. However, translation of these results to the field is not straightforward. For this, one needs to characterize the experiments in terms of relative permeabilities and capillary pressures, since wettability is not a direct input parameter for reservoir simulators.

The exploratory data examined in this investigation did not include pressure measurements because the experiments were not designed to generate special core analysis (SCAL) data such as capillary pressure and relative permeabilities. However, it is still feasible to obtain some indications about these SCAL data. This paper addresses such an interpretation, using both analytical work and numerical simulation. The possible impact of the observed phenomena on field performance is discussed.

MAIN CHARACTERISTICS OF THE EXPERIMENTS

In this paper, we will discuss the analysis of experiments on Berea, with Dagang crude and Dagang brine (see Table 1) as detailed in Ref. 5. Cores were initially saturated with brine and equilibrated for 10 days. Initial water saturations of around 22% were established by flow of crude oil. The cores were then aged at reservoir temperature, T_a , for 3 days. The core was then mounted horizontally in a core holder and the crude oil used in aging was flushed from the core by further flow of crude oil. Duplicate core plugs were prepared to obtain pairs of spontaneous imbibition and waterflood tests. Values of ageing time and temperature and temperature of measurement, T_d , are provided with the results in Figs. 1 and 2. Details of the test procedure are available in Refs. 4, 5 and 7.

Table 1 Composition (ppm) of synthetic Dagang brine in the experiments of Ref. 5

Brine	Na ⁺	K ⁺	Ca ²⁺	Mg ²⁺	Cl ⁻	pH	TDS
DG	4,267	7,237	218	32	13,414	6.9	24,168

Spontaneous imbibition

Figs.1a and b show typical production profiles for spontaneous imbibition. Although differences in early-time recoveries are small, dilution clearly brings about a large increase in oil recovery. The effect is largest when both connate brine and imbibing brine are dilute: recovery increases from some 40% OOIP to 60 or 70% OOIP.

Waterfloods (forced imbibition)

Figs. 2a and b show typical waterflood production profiles. Dilution of the brine brings about a delay in water breakthrough from about 0.3 PV towards 0.4 to 0.5 PV and a marked increase in final recovery at some 10 PV brine injected: from about 50% OOIP towards 70% or more OOIP. As for spontaneous imbibition, the increases in recovery are larger when both the connate brine and the injected brine are diluted. The final oil saturations in the displacement experiments were lower than in the spontaneous imbibition experiments

INTERPRETATION OF THE EXPERIMENTS IN TERMS OF RELATIVE PERMEABILITIES AND CAPILLARY PRESSURES

Spontaneous imbibition experiments

Shell's simulator MoReS [8] was used to simulate spontaneous imbibition. Typical input parameters are listed in Table 2. The simulations were carried out in 1-D, with 50 and 500 grid blocks to describe the core plug. At both ends of the core plug, grid blocks were added to mimic the bath, and by way of boundary conditions. The properties of these grid blocks were: absolute permeability set to 10,000 times the permeability in the plug; capillary pressure set to zero and relative permeability set to straight lines with end-point of unity. These settings and others used are identical to the ones detailed in Ref. 8.

Table 2 Experimental parameters used in the simulations

h	3.8	cm
w	2.5	cm
L	5	cm
K_{abs}	550	mD
ϕ	0.23	Fraction
μ_w	0.5	mPa.s
μ_o	55	mPa.s
σ	30	mN/m

From the measured imbibition rates, as compared with results for very strongly water wet conditions, it was clear that the effective capillary pressures were extremely low and sometimes of the same order as buoyancy forces. As a base case, we simulated spontaneous imbibition with P_c set at zero. This allowed us to estimate an imbibition rate due to gravity forces alone as given by the hydrostatic head $\Delta\rho gh$ within the core (nomenclature is listed at the end of this paper). In Fig. 3 we compare this base case with the results of the base experiment (no dilution). Clearly, imbibition in the experiments is much faster than in the simulation of production by gravity forces alone. A variety of different shapes of relative permeabilities given by variation of Corey parameters were tested. We were unable to obtain sufficient production with the proper time dependency by varying Corey exponents of water between 3 and 5 and/or Corey exponents of oil between 1 and 3. In our experience, such a range of Corey exponents certainly spans most examples of wettability arising from COBR interactions.

This means that imbibition must involve a positive capillary pressure within the sample. A detailed comparison revealed that such a positive P_c must exist over a wide saturation range (from S_{wi} to close to the ultimate $1-S_o$ established by spontaneous imbibition). Application of Darcy's law at early times and equating ΔP to $\Delta p_{gh} + P_c$, provided an estimate of P_c of around 0.3 kPa, a small, but apparently significant capillary pressure. Given the sensitivity of our simulation results to this very small but positive P_c , we are confident that the actual positive P_c is between 0.2 and 0.4 kPa, for saturations between S_{wi} and 0.5. This means that in terms of effective imbibition capillary pressure the plug is only slightly water wet.

The ultimate oil recovery for spontaneous imbibition is determined by the water saturation at which the capillary pressure drops to zero. The experiments showed that by diluting the brine the ultimate recovery for spontaneous imbibition increased, indicating a shift of the zero crossing point to higher water saturation. In terms of the Amott wettability index to water, such a shift relates to more water-wet conditions.

Waterfloods (forced imbibition)

The ultimate recovery by waterflooding is larger than the ultimate recovery by spontaneous imbibition. This indicates that the capillary pressure relation has a negative branch, and that oil which is still connected and potentially mobile could be produced by applying viscous pressure gradients that overcome this (negative) capillary pressure.

The data on oil recovery versus PV of water injected provides the water breakthrough recovery; and the recovery at 10 PV injected provides an indication of the residual oil saturation for a water flood. The remaining oil saturation at 10 PV dropped by almost one third (from some 35% to 25% PV) for a 100-fold dilution. It is likely that such a large reduction in remaining oil saturation is caused by both a change in capillary pressure function and by a reduction of the residual oil saturation. In many circumstances a reduction in the residual oil saturation indicates a change towards reduced water wetness. Thus the increase in recovery with dilution for water flooding was unexpected when first observed, as the spontaneous imbibition indicated a more water-wet behaviour.

In view of the large, unfavourable viscosity contrast between oil and water (ratio 50) the increase in breakthrough recovery given by flooding with dilute brine was remarkably large⁹⁾. Simulations with the MoReS reservoir simulator could not reproduce these results when applying oil and water relative permeabilities with Corey exponents in the normally observed range as above and endpoint relative permeabilities in the order of about 0.2 (water) and 0.7 (oil). Through lowering the residual oil saturation we could history match the late time behaviour, but the breakthrough behaviour was not significantly affected. Only by significantly reducing the water mobility (by reducing the end point of the water relative permeability relation to some 0.05) could a reasonable match be obtained. This is a most unusual but very clear outcome of the comparison between simulations and experimental results. This significant reduction in the water mobility not only increases the breakthrough recovery, but it also brings the remaining oil saturation at 10 PV injected

⁹⁾ Despite the large viscosity ratio, the risk for viscous fingering is deemed minimal, since the Hagoort [9] number calculates at 0.4 or smaller (with a critical number at unity).

much closer to the residual value. Consequently, a large part of the 10% increased oil recovery appears to be due to the improved oil/water mobility ratio.

We cannot rule out that the residual oil saturation still was lowered also by the dilution. However, the effect can only be small since the breakthrough behaviour governs already the bulk of the effect in the water relative permeability. Within the uncertainties of our history matching, we found that the effect on S_{or} is less than some 5% PV. In the same way, we have studied the impact of dilution on kro. From the combined spontaneous and forced imbibition history matches, we estimate the effect of dilution on kro to be not more than a factor of 2.

The mechanism of improved recovery with dilution is not well understood. Necessary conditions are the presence of connate water, the presence of clay, and adsorption of polar components from crude oil. A hypothetical mechanism for the recovery behaviour has been suggested [6] that depends on limited release of clay particles from pore walls. The clays within a rock sample are mainly associated with connate water. However, in regions where the clay particles are contacted by crude oil, adsorption of polar components from crude may result in mixed-wet clay particles. Waterflooding with brine of decreased salinity will tend to decrease clay-clay interactions and promote release of oil and associated clay from pore surfaces. Permeability loss related to this process is minor. Much remains to be learned about such complex crude oil/brine/rock interactions, and how their effect on waterflood recovery should be modeled.

IMPACT ON RESERVOIR PERFORMANCE

The estimates of how dilution of injection brine impacts relative permeability and capillary pressure can be used to predict, qualitatively, reservoir performance. We will consider two scenarios: injection of diluted brine into virgin reservoirs and into well-developed (“brown fields”) water-drive reservoirs.

Virgin reservoirs

Fig. 4 shows how a typical fractional flow f_w curve changes from a base case to the diluted case. At this stage, we will neglect the miscible displacement of the connate brine by the injection brine; we will touch upon this later. Fig. 5 has the corresponding 1-D Buckley-Leverett saturation profiles, as derived from df_w/dS_w [10]. Since the water saturation at the shockfront (breakthrough saturation) increases significantly by dilution, the velocity of the shock front will decrease significantly, if the injection rate is kept constant. Water breakthrough (WBT) on the field scale should be delayed similar to the experimental results. At dilution, less oil production will be generated after WBT, since S_{sh} has increased. Effectively, oil production is accelerated when compared to the base case. In turn, this will bring about a lowering of the economic “residual” oil saturation (remaining oil saturation). Note that for a field to have 1-D displacement characteristics, the field must have negligible dip and the displacement must be governed by diffuse flow, dominating the effect of gravity.

Dipping reservoirs may demonstrate a less pronounced effect under dilution of injection brine. Firstly, gravity will impact on the fractional flow curve (see e.g. Ref. 10) and the shockfront saturation will be significantly enlarged in the base case already, with respect

to the shockfront saturation under diffuse flow (1-D in a horizontal reservoir). Dilution may still increase the shock front saturation further and WBT may still be delayed, but there is just less room for improvement. Secondly, the movable oil behind the shock front will move vertically upwards under water-oil gravity drainage (see Fig. 6) until it reaches the caprock, building-up higher oil saturations locally, and be produced at a fairly favourable oil relative permeability. Since we have not detected a significant effect on the oil relative permeability by dilution of brine, we expect that the gravity drainage process will be hardly affected. Consequently, the oil production after WBT may not be accelerated and the economic residual oil saturation may be unchanged with respect to the base case of the dipping reservoir.

It is of interest to note that injection of diluted brine is likely to create a bank of connate water at initial salinity, behind which the drive process will be similar to the diluted-diluted case of Ref 5. The production behaviour of a virgin reservoir under injection of diluted brine will resemble the superposition of a normal drive and of a drive governed by the fractional flow curve modified by dilution. When simulating the field, the miscible displacement of the virgin connate brine by the diluted injection brine must be modelled correctly. Heterogeneities and layering in general will tend to smear-out WBT behaviour, but the characteristics should still be maintained: delay of WBT and acceleration of oil production.

Brown fields

We expect that injection of diluted brine into a field with a waterdrive already underway will bring about production behaviour that is a superposition of the base-case profile and the diluted case profile. Such a superposition is demonstrated in Fig. 7 for the 1-D Buckley-Leverett saturation profile and in Fig. 8 for the cumulative oil production. So, still acceleration is expected with respect to continuing the injection with compatible brine, but the effect is likely to be smaller than in virgin reservoirs. Clearly, for brown fields, it is preferable, even more so than for virgin reservoirs, to predict reservoir performance from actual SCAL data in order to assess the compounded effects of dilution and the economics of the process. The SCAL measurements may also serve to study the effect of formation damage through dilution of injection brine. However, from the analysis presented here, we expect that the “damage” is primarily a symptom of the reduction of the endpoint of the water relative permeability.

It is of interest to note that, depending on the salinity of the available injection brine, use of diluted brine in itself may not always require increased capital expenditures.

CONCLUSIONS

A detailed analysis has been carried out on imbibition and waterflood experiments reported by Tang et al. on the impact of injection of dilute brine on oil recovery with the working assumption that the recovery mechanism can be modelled by SCAL analysis. Use of simulation to match experimental results provided information on how relative permeability and capillary pressure changed as a result of dilution. The primary impact of dilution of injected brine was on the water relative permeability: it was lowered by a factor of 5 or so. The capillary pressure function was close to zero over an extended saturation range and the zero crossing point moved to higher water saturations with dilution. Residual oil saturation may be somewhat decreased by dilution, but no significant effect could be determined.

With the impact on relative permeability and capillary pressure analysed, we are able to transfer the laboratory results to the field. The effect can be as significant as in the laboratory, i.e. a decrease in economic remaining oil saturation from 35 to 25% PV. However, results vary significantly depending on the actual situation: virgin vs. brown field, predominant diffuse flow vs. gravity determined flow.

Simulations are required to assess the merit of injection of diluted brine for each individual case. We recommend scouting simulations to be performed in 2-D models, assuming a reduction in water end-point relative permeability by a factor 5 to 10. In case significant enhanced production performance is found, appropriate SCAL measurements are needed to determine the best estimate of the parameter settings. The model results may be sensitive to proper modelling of the miscible displacement of the connate water by the diluted brine.

ACKNOWLEDGEMENT

The authors thank the management of Shell International Exploration and Production B.V. (SIEP) for permission to publish this work.

REFERENCES

- [1] Cuiec, L.E., "Evaluation of reservoir wettability and its effect on oil recovery", *Interfacial Phenomena in Petroleum Recovery*, N.R. Morrow (ed.), Surfactant Science Series, 36, Marcel Dekker, Inc., New York, (1991), 257.
- [2] Jadhunandan, P. and Morrow, N.R.: "Effect of Wettability on Waterflood Recovery for Crude Oil/Brine/Rock Systems," *SPE Reservoir Engineering*, (Feb. 1995), 40-46.
- [3] Yildiz, H.O., Valat, M., and Morrow, N.R.: "Effect of Brine Composition on Wettability and Oil Recovery of a Prudhoe Bay Crude Oil," *J. Can. Pet. Tech.*, (Jan. 1999), **38** (1) 26-31.
- [4] Morrow, N.R., Tang, G., Valat, M. and Xie, X.: "Prospects of improved oil recovery related to Wettability and Brine Composition" *J. Pet. Sci. Eng.*, (June 1998), **20**, 267-276.
- [5] Tang, G.Q. and Morrow, N.R.: "Salinity Temperature, Oil Composition and Oil Recovery by Waterflooding," *SPE Reservoir Engineering*, (November 1997), 269-276.

- [6] Tang, G. and Morrow, N.R.: "Influence of Brine Composition and Fines Migration on Crude Oil/Brine/Rock Interactions and Oil Recovery" *J. Pet. Sci. Eng.*, (Dec. 1999), **24**, 99-111.
- [7] Tang, G., "Improved Waterflood Recovery: Temperature and Brine and Crude Oil Composition" PhD Thesis, University of Wyoming, (May 1998).
- [8] Maas, J.G., and Schulte, A.M., "Computer simulation of Special Core Analysis (SCAL) flow experiments shared on the Internet", SCA-9719 presented at the Intl. SCA Symp., Calgary, September 1997. This restricted version of MoReS to simulate SCAL experiments is available on the public Internet at [//scores.sieppartners.com/scores/](http://scores.sieppartners.com/scores/). Usage is free of charge.
- [9] Hagoort, J., "Displacement Stability of Water Drives in Water Wet Connate Water Bearing Reservoirs", *Soc. Pet. Eng. J.*, February 1974, pp 63-74, Trans. AIME.
- [10] Dake, L.P., *Reservoir Engineering*, Elsevier, Amsterdam, (1978)

NOMENCLATURE

f	fractional flow		<i>Subscripts</i>
g	gravity (m/s^2)	a	ageing
h	sample height (m)	abs	absolute
K	permeability (m^2)	c	characteristic
L	sample length (m)	d	displacement
PV	pore volume	i	initial
S	saturation	o	oil
t	time (s)	r	residual
T	temperature (deg. C)	sh	shock
w	sample width (m)	w	water

Greek

μ	viscosity (mPa.s)
ρ	density (kg/m^3)
σ	interfacial tension (mN/m)
ϕ	porosity (fraction)

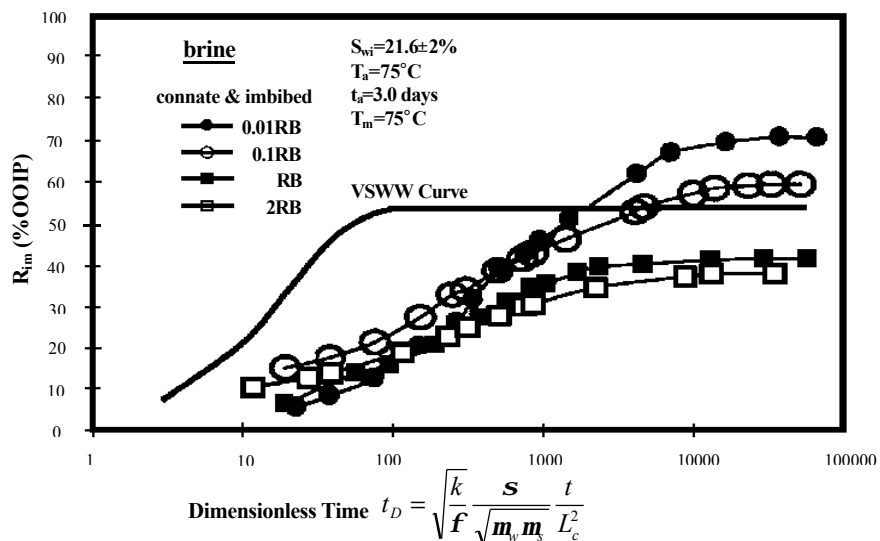


Fig. 1a Connate brine and imbibing brine of the same composition.

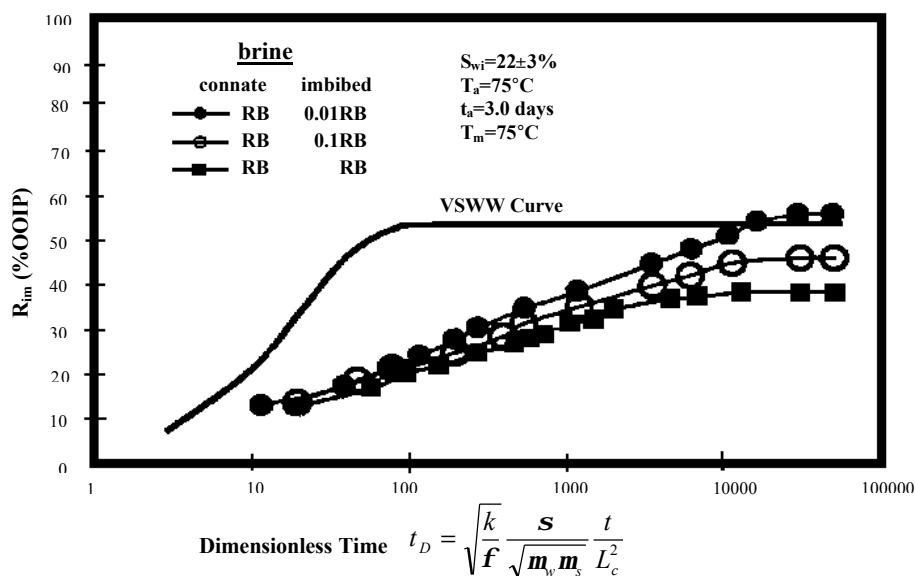


Fig. 1b Reservoir brine as connate brine.

Fig. 1 Effect of brine 10 and 100 fold dilution in spontaneous imbibition experiments [Ref. 5]. VSWW stands for very strongly water-wet.

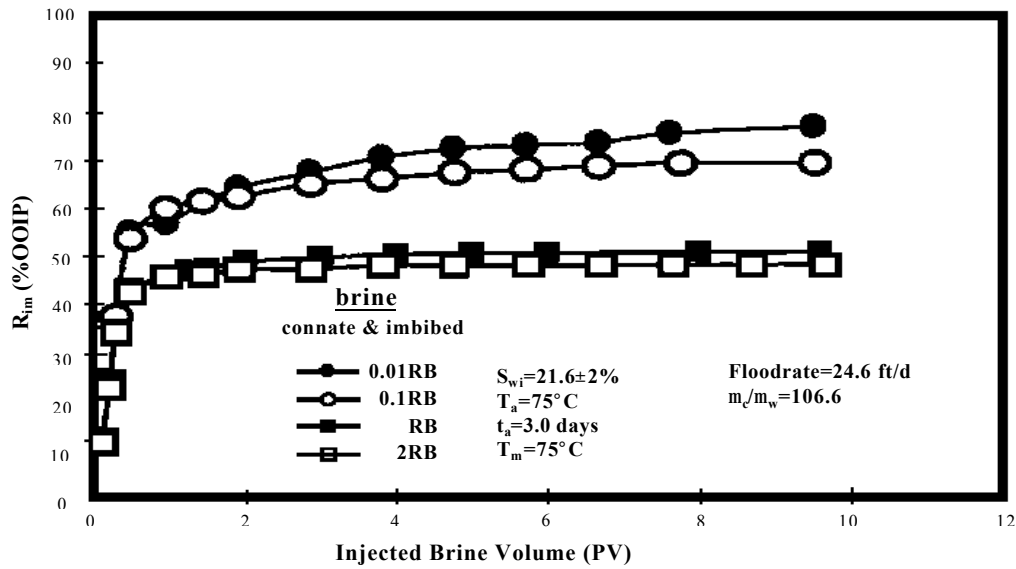


Fig. 2a Connate brine and imbibing brine of same composition.

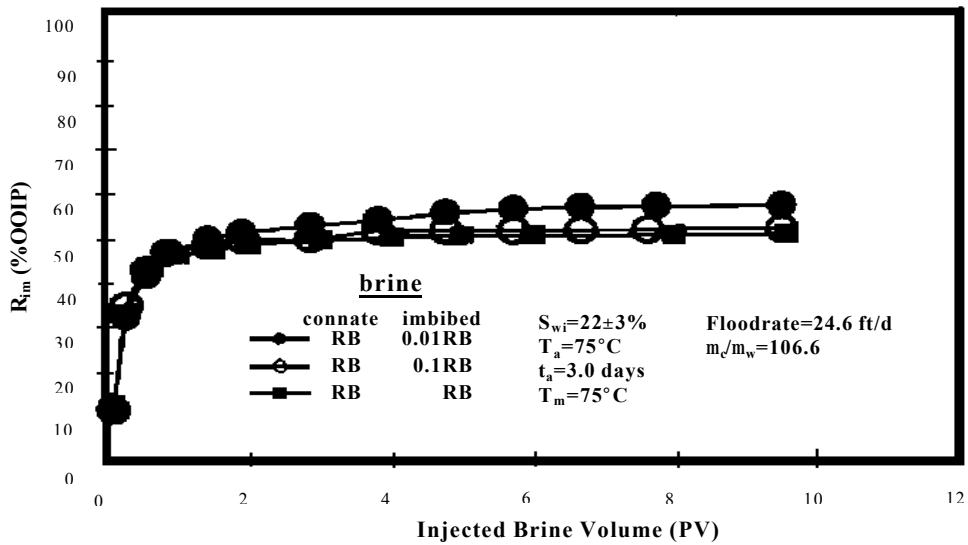


Fig. 2b Reservoir brine as connate brine.

Fig. 2 Effect of brine 10 and 100 fold dilution in waterflooding experiments [Ref. 5].

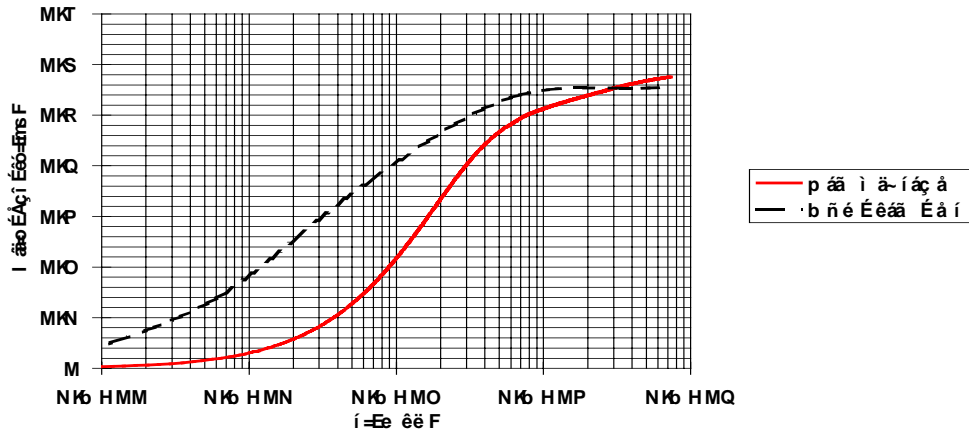


Fig. 3 Comparison of simulation at $P_c=0$ and spontaneous imbibition experimental data.

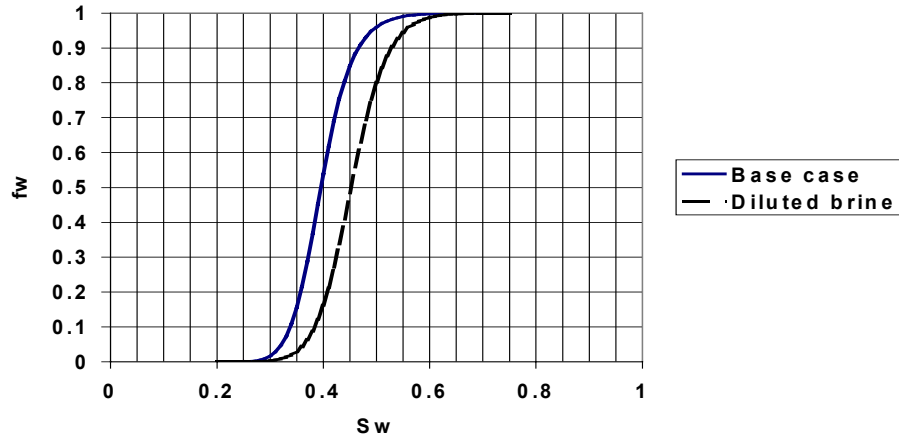


Fig. 4 Comparison of fractional flow curves between base case and diluted brine

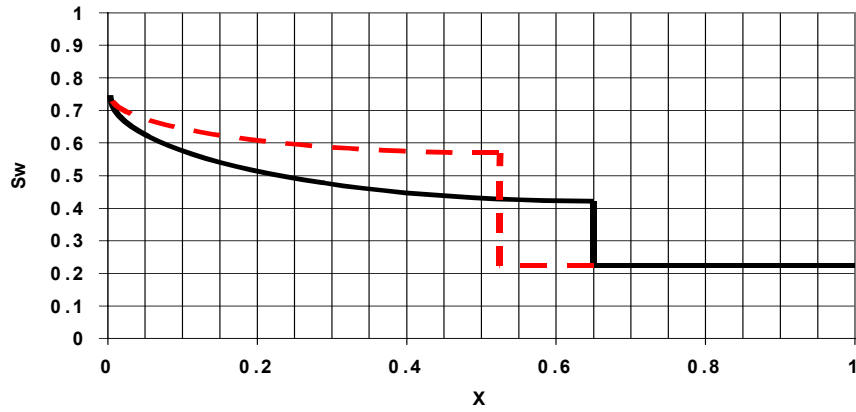


Fig. 5 Comparison of Buckley Leverett saturation profiles for base case (solid) and diluted brine (dashed). X is a dimensionless length.

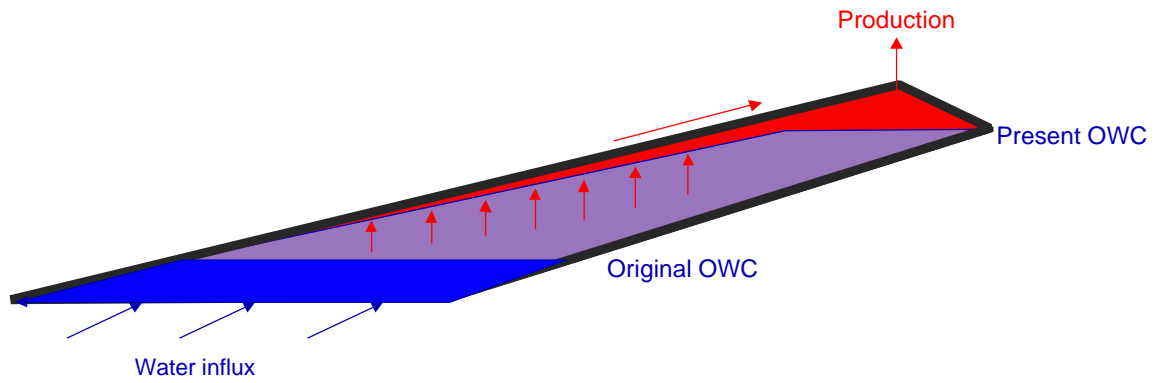


Fig. 6 Gravity drainage of oil behind the shockfront in a dipping reservoir.

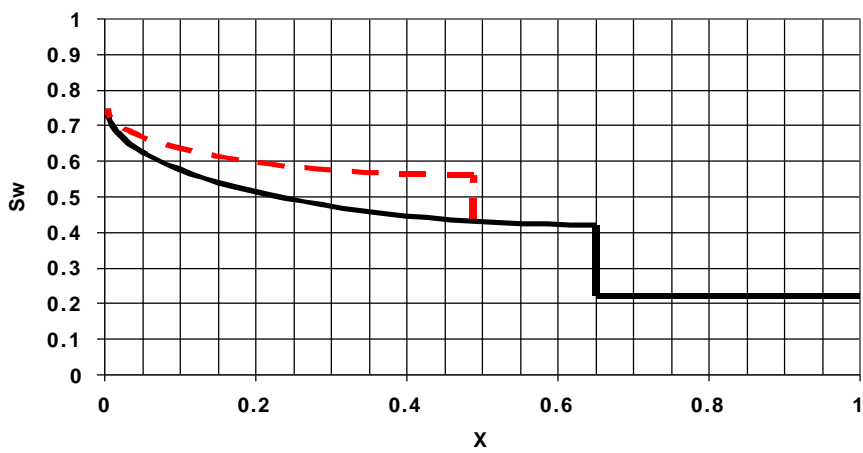


Fig. 7 Development of Buckley Leverett saturation profile in a brown field after injection of diluted brine.

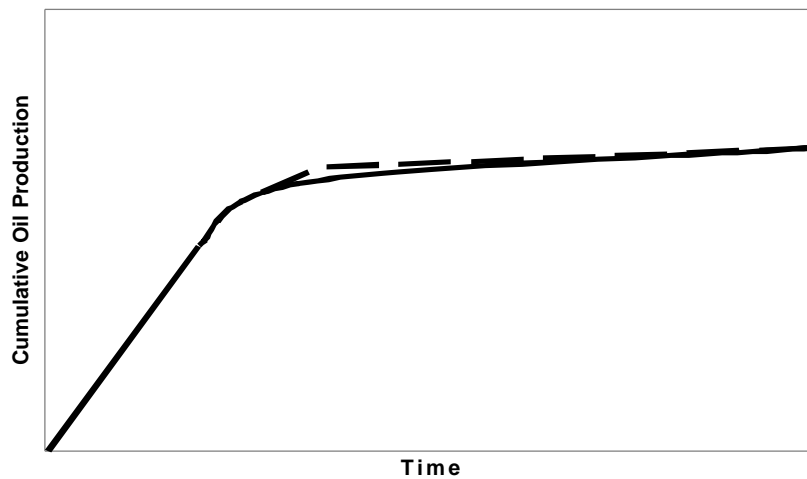


Fig. 8 Production profile for a brown field, base case (solid) and enhancement (dashed) due to dilution of injection brine.