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Research Note

Effects of Rock Permeability on Capillary Imbibition Oil Recovery from Carbonate Cores

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Abstract. *In order to investigate the feasibility and effects of core permeability on capillary imbibition recoverable oil from carbonate cores, some laboratory tests were carried out at the EOR research laboratories of Sharif University, Iran. Outcrop rocks with different permeabilities were taken away from a recognized outcrop and used in these experiments. Special core analysis tests were run on two core samples to find out relative permeability and end point saturations. Wellhead separator oil and gas samples were collected and recombined to a reservoir gas - oil ratio. A core flooding system with a capability of free and forced imbibition testing was designed and installed. A number of free and forced imbibition tests with different cores under reservoir conditions were conducted. The results of the tests revealed that capillary imbibition is an almost fast process at laboratory scale and the higher permeable cores will imbibe more easily. A good correlation could be obtained when the ratio of recovery factor to ultimate recovery factor versus a definite function of time was plotted. From these experiments, it concluded that an up scaled relation can be perceived for very low permeable cores, the testing of which may take too long.*

Keywords: *Carbonate cores; Gravity drainage; Imbibition; Capillary pressure; Wettability.*

INTRODUCTION

Fractured reservoirs, although less common and poorly understood than conventional sandstone and carbonate reservoirs, are important contributors to world oil and gas reserves and production. Most Iranian oil and gas reserves are in naturally fractured carbonate reservoirs. Some huge oil fields such as Agha Jari, Gachsaran, Bibihakimeh, Karanj, Parsi, Rag-e-Safid and HaftKel are among the oldest ones. Although the oil recovery factor may be higher than 20 percent for such big fields, it goes below 15 percent or even less for smaller or undeveloped fractured carbonate reservoirs. Most of these reservoirs have weak aquifers, and lack of pressure support can be considered as the main reason for the rapid pressure drop and low recovery factor. The main oil production mechanism for these reservoirs is the expansion of reservoir fluids and rock compaction resulting from this pressure drop. To prevent rapid pressure drop, and by bringing other mechanisms to improve oil production, some fluid (mainly water or gas) should be injected into the reservoir. At present, there are gas injection projects for some major fields such as Marun, HaftKel, Agha Jari etc. While water injection is a more feasible scenario in comparison with gas injection, and requires lower initial investment, there is still no definite water injection plan for any on-shore field [1].

In 1952, Brownscombe and Dyes [2] introduced the concept of a process for imbibition flooding. The process was visualized in terms of a single fracture into which water is injected at one end, production occurring at the other end. As the injected water flows toward the producing end, it is imbibed into the matrix and oil flows out into the fracture flow stream. If the rate of natural imbibition into the matrix is greater than the injection rate, all the water will imbibe into the matrix and only oil will reach the producing end of the fractures. Any water injected above the rate of natural imbibition will increase the water-oil ratio. The water-oil ratio is a function both of the injection rate and the imbibition rate. Several laboratory and

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numerical studies have been conducted regarding this subject.

Kleppe and Morse [3,4] investigated imbibition from a single matrix block surrounded by fractures. They studied the effects of the injection rate on the recovery performances using Berea sand core, and numerically verified the results. They found that matrix oil recovery by imbibition of water from the fracture system was sensitive to oil production. In addition, they measured the relative permeability and capillary pressure of the core. Mattax and Kyte [5] evaluated the importance of imbibition oil recovery from fractured water drive reservoirs by observing the data from real reservoirs. Reis and Cil [6,7] prepared one-dimensional models for oil expulsion by counter-current water imbibition in rocks. They then created a multi-dimensional analytical model for counter-current water imbibition into gas-saturated matrix blocks. Garg, Zwahlen and Patzek [8] carried out some experimental and numerical studies of one-dimensional imbibition on Berea sandstone cores.

Kazemi et al. [9] used a two-dimensional, two-phase, semi-implicit, numerical simulator to simulate water imbibition and oil recovery in artificially fractured cores. Straight-line permeabilities and low capillary pressure were used for the fracture. The main matching parameter was the matrix capillary pressure. The final matrix capillary pressure after history matching was very close to that measured in the same matrix using a centrifuge.

Babadagli and Ershaghi [10,11] performed laboratory experiments to examine the influences of the injection rate on the capillary imbibition behavior and saturation distribution in the matrix. The system was fully saturated by the oil phase, and the water phase was injected through the fracture displacing the oil in the fracture by viscous forces and the oil in the matrix by capillary imbibition. The experimental model was then matched by a numerical model and used to qualitatively evaluate the configuration effect on capillary imbibition transfer. They observed that the limiting value of the injection rate (critical rate) was defined as a function of maximum matrix capillary pressure and matrix permeability.

IMBIBITION MODELING

Capillary forces are the main drive potential causing imbibition of water into the matrix in the absence of other forces such as gravity. This is similar to putting a capillary tube into a bottle of water. Water will imbibe into the core due to positive capillary forces. As there is positive capillary pressure at the lower water saturation, the water can imbibe into both oil-wet and water-wet cores. Mobility ratio, shape factor and the amount of capillary pressure are major factors influencing the imbibition oil recovery factor. Regarding the modeling of fluid flow from matrix to fractures, Gilman and Kazemi [12] have developed a basic equation to model the fluid flow through the matrix and fracture. Different further experiments were performed by Gilman [13] to investigate the accuracy of the proposed equations.

LABORATORY TESTS

Experimental Setup

Figure 1 shows a schematic flow diagram of the core holder apparatus designed and installed at Sharif University of Technology.

This system consists of different parts as follows:

- Motorized positive displacement pump,
- Heise pressure gauge,
- Differential pressure transducer,
- Temperature transducer,
- Vinci back pressure regulator,
- Vacuum pump,
- Oven with heat controller,
- Temperature controller,
- JEFRI gas flow meter,
- Hydraulic overburden pump,
- High pressure core holder,
- Gas pressure amplifier,
- Visible glass separator,
- Recording computer and software.

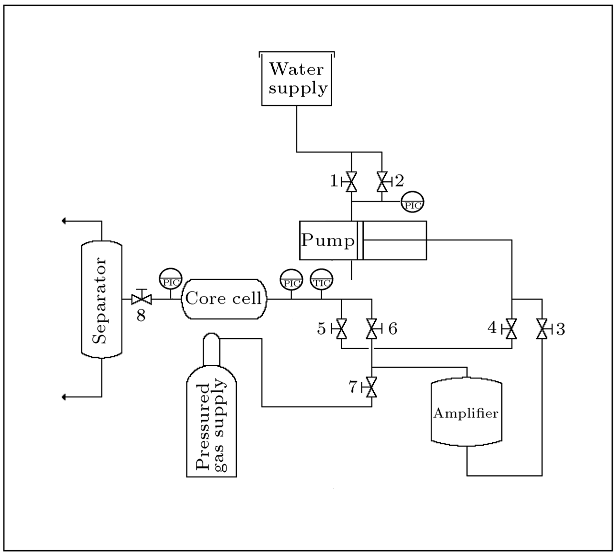

Figure 1. Core holder flow diagram.

The whole system was hydraulically tested up to 6000 psi, and temperature, pressure and flow rate measuring systems were calibrated. In these experiments, a high pressure recombination apparatus was also used. The apparatus was equipped with a temperature controlled air bath and rocking mechanism, specifically for re-combining reservoir oil with solution gas to attain the original fluid composition under reservoir conditions.

Core and Reservoir Fluid Sampling

The Asmari formation has a clear and distinguished outcrop (known as the Asmari Mountain) near the city of Masjed-Soleiman in the southwest of Iran. Carbonate cores were taken from this mountain and reshaped into cylindrical bars to fit the core holder. The diameter and length of the reshaped cores were 1.5 in. and 1 ft., respectively.

Wellhead separator oil and gas samples were also collected and recombined to reservoir conditions with a proper proportion of oil and gas. The reservoir fluid properties are shown in Table 1.

Core Porosity and Permeability Measurements

The properties of five core samples provided for this study are shown in Figure 2.

The cores were put in an oven at 95°C and 50 millibara vacuum pressure for about 48 hours. The dried cores were weighed with an electronic scale with an accuracy of 1.0 mgr. Then, the cores were saturated with pure water and weighed. The porosity was calculated from the differences in core weight and volume, by accurately measuring core dimensions, and confirmed by insertion into water. The initially special analyzed cores were checked for absolute permeability by injection of pure water at different flow rates and by recording the inlet and outlet pressures. Table 2 summarizes the results obtained for permeability tests on core samples C1 to C5.

Table 1. Reservoir fluid properties at bottomhole conditions.

Reservoir temperature	210 F
RS	325 Scf/stb
Formation factor, BO	1.2686 Res. Vol./ Std Vol.
Bubble point pressure	1545 PSIG
Fluid viscosity	0.35 cp
Fluid density	0.7786 Gr/cc

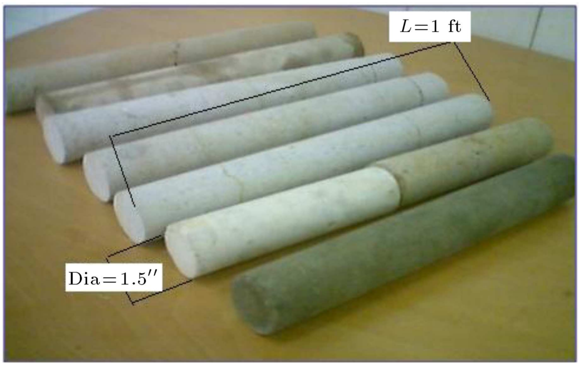

Figure 2. Cores used in these experiments.

These cores were selected from among more than 10 cores to cover a wide range of permeability and porosity. The relationship between core permeability and porosity is illustrated in Figure 3.

Imbibition Tests

After first drainage, the core will be at irreducible water saturation. From Figure 4, it is understood that there is a potential for water to imbibe into the core, even if it is highly oil wet. Water can spontaneously imbibe into the core until its saturation increases to SWSP.

In these experiments, the imbibition process was

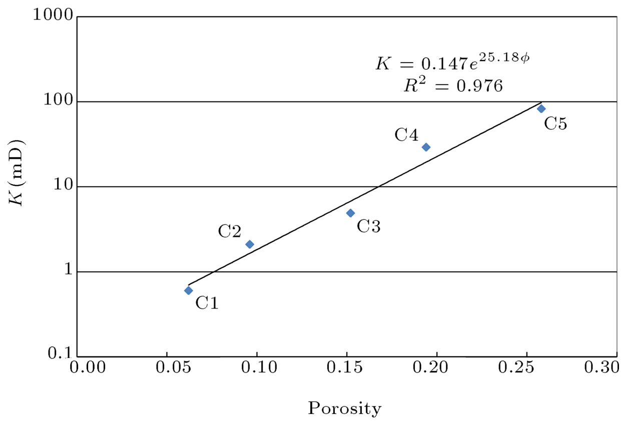

Figure 3. Relationship between core permeability and porosity.

Table 2. Core specifications.

Core	K, mD	ϕ	PV	Oil-in-Place, Scc	Recovery Oil, cc	RF
C1	0.6	0.062	22.0	13.9	3.2	0.23
C2	2.1	0.096	34.1	21.5	4.3	0.20
C3	4.9	0.152	54.0	34.0	5.9	0.17
C4	29.2	0.194	68.9	43.4	6.5	0.15
C5	82.7	0.258	91.6	57.8	6.9	0.12

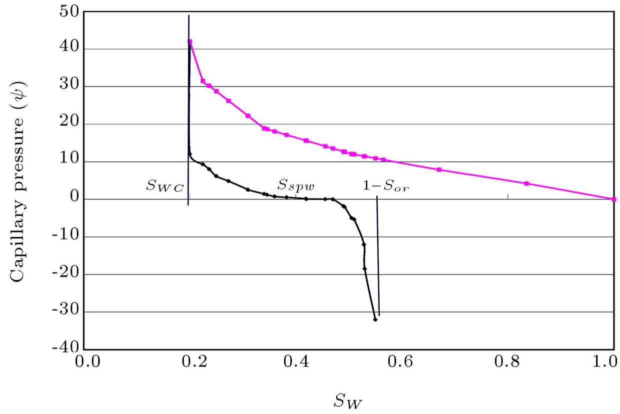

Figure 4. Drainage-Imbibition capillary pressure curve for a typical core sample.

performed in the laboratory by first saturating the core with water, then displacing the water to its irreducible (connate) saturation by the injection of oil through the core holder; holding an overburden pressure of 200-300 psi during this process. This procedure was designed to establish the original fluid saturations that are found when the reservoir was discovered. Then, the overburden pressure was removed by losing the appropriate screws to allow an interconnection between the core and the annulus space. The wetting phase (water) was reintroduced into the core while the water (wetting phase) was continuously increasing. Water was injected through the free gap (representative of fractures) at relatively high rates and the collected oil was accurately measured and recorded. The tests were performed at reservoir conditions of 210 F and 3950-4000 psig average pressure.

RESULTS AND DISCUSSIONS

The only driving force in imbibition is the existing capillary pressure between oil and water, and hence the oil recovery for each core depends on these capillary pressures. Figure 4 shows a typical capillary pressure for a sample core.

The first drainage curves occur when oil is replacing the initially water saturated cores. For a reservoir rock, far from the transition zone, the reservoir rocks are at connate water saturation, SWC. There is a positive capillary pressure at this saturation indicating a potential for spontaneous water imbibition into the reservoir rock. The spontaneous water imbibition will continue until the water saturation increases to SWSP where $P_o = P_w$, i.e. there is no driving force. So, for the ultimate imbibition oil recovery factor it can be concluded that:

$$R_U = \frac{S_{SPW} - S_{WC}}{1 - S_{WC}}. \tag{1}$$

From the above relationship, one can calculate the ultimate recovery factor, knowing the endpoint saturations. In the experiments undertaken, as we did not know the endpoint saturations, we found the ultimate recovery factor experimentally, and then compared it with the endpoint saturations derived from capillary pressures we had for the sample cores. Figure 5 shows the cumulative recovered oil versus time, and Figure 6 shows the calculated oil flow rate at different times derived from cumulative oil.

Figure 7 illustrates the oil recovery factors versus time. There is no unique relation between oil recovery factor and elapsed time for all the cores.

To find a proper relationship, we focused on the J-Leveret definition of rock typing. As the cores were prepared from one rock, we assumed that there is only one rock type with different K and ϕ. So, the IFT and wettability angle were assumed to be the same. Based on the J-Leverrett definition, we have:

$$J = \frac{P_C}{\sigma \cos\theta}\sqrt{\frac{K}{\phi}}. \tag{2}$$

From this definition, and for a specific reservoir, one can conclude that the rocks with the same (K/ϕ) have

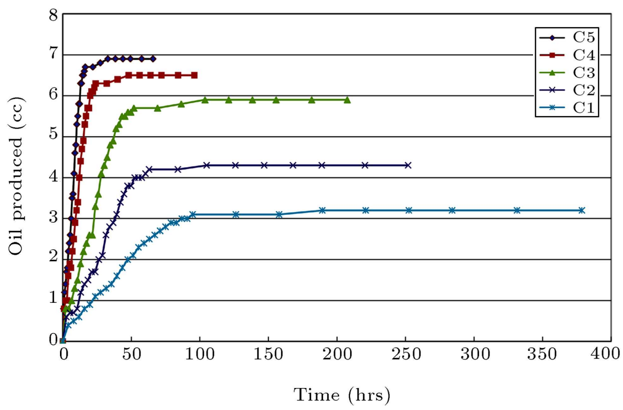

Figure 5. Free imbibition recovered oil for different core samples.

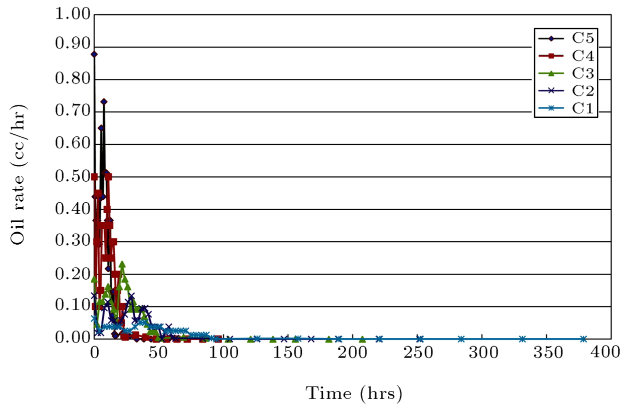

Figure 6. Calculated oil rate at different time.

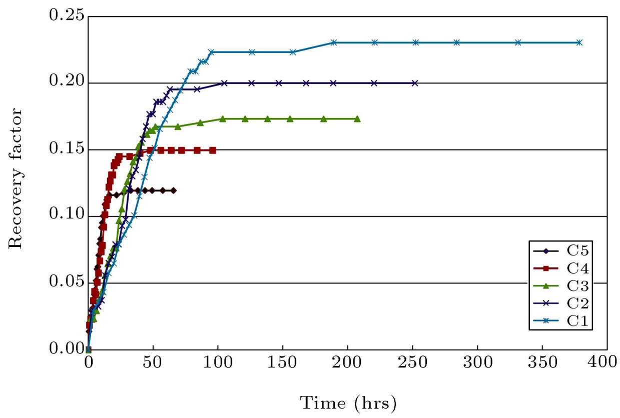

Figure 7. Oil recovery factor versus time.

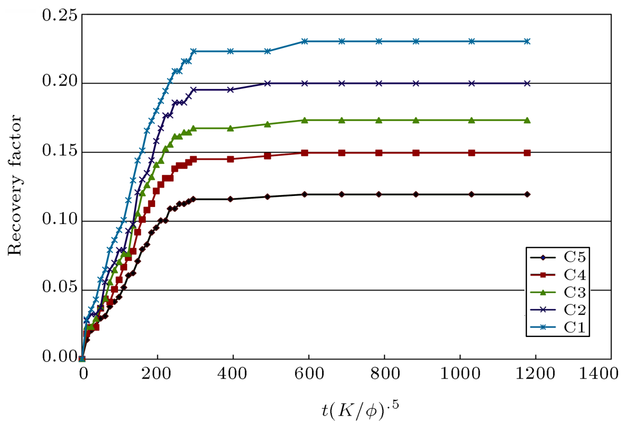

Figure 8. Recovery factor with respect to modified time.

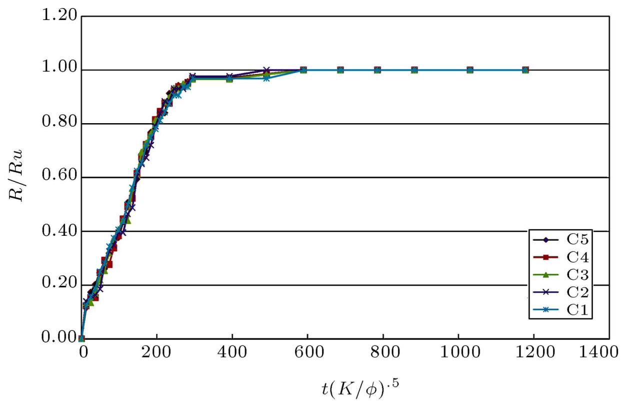

Figure 9. Ratio of RF to ultimate recovery factor.

close behavior. Considering this definition, a modified function of time was introduced as:

$$t^* = t\sqrt{\frac{K}{\phi}}. \tag{3}$$

Figures 8 and 9 show the recovery factor and the ratio of recovery factor to ultimate recovery factor versus t^*. From Figure 9 it can be understood that a unique relationship could be found to represent the imbibition oil recovery for the same rock types.

CONCLUSIONS

- A better understanding of capillary imbibition in naturally fractured carbonate reservoirs can lead us to an appropriate decision on water flooding for higher oil recovery.
- Even for oil-wet cores, we can see the displacement of oil by water due to positive capillary pressure at connate water saturation.
- Imbibition is a feasible and almost fast process at laboratory scale.
- The imbibition recovery factor is much higher for low permeable cores due to greater capillary pressure.
- At reservoir scale, the process may not be so fast, because the blocks are very large and the process will be much slower.
- A unique correlation between oil recovery and a function of time could be reached for the same types of carbonate core.

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NOMENCLATURE

K	absolute permeability, md
K_{ro}	oil relative permeability
L	core length, ft
N_{po}	ultimate oil production, ft^3
p	pressure, psi
P_c	capillary pressure, psi
R	recovery factor in units of OOIP
V_p	pore volume, ft^3
ϕ	porosity, fraction
S_{spw}	spontaneous water saturation
S_{spo}	spontaneous oil saturation
S_{WC}	connate water saturation
S_{or}	residual oil saturation
P_W	water pressure, psi
P_O	oil pressure, psi

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BIOGRAPHIES

Hamid Reza Darvishi graduated from the Petroleum University of Technology in 1988 with a B.S. degree in Chemical Engineering and immediately joined the National Iranian Oil Company as a Petroleum Engineer. He received his M.S. degree in Chemical Engineering from Amirkabir University, Tehran, Iran, in 1996, and his M.S. degree in Petroleum Engineering from London University (Imperial College) in 2000. He is also a Ph.D. candidate in Reservoir Engineering at Sharif University of Technology. He has been working in different areas of the oil industry for more than 18 years. He is a member of the Society of Petroleum Engineers (SPE).

Iraj Goodarznia has been a Professor of Chemical Engineering at Sharif University of Technology since 1984. He graduated from Abadan Institute of Technology in 1968 with a BS degree in Refinery Technology and received his Ph.D., DIC and M.S. from Imperial College, London, from 1968-1972, respectively. He has published over 50 papers in International Journals and Congresses. Some other achievements, in brief, are as follows:

- Founder and Chairman of Association of Iranian Engineering Societies, since 1997.
- Founder (and Chairman 1996-1997) of Iranian Society of Instrument and Control Engineers, since 1993.
- Member (Chairman 1991-1998) of Iranian Academy of Science, Chemical Engineering Branch, since 1991.
- Member (Chairman of Relations Committee 1991-1993) of Iranian Association of Chemical Engineers, since 1991.
- Founder and Chairman of Iranian Society of Indigenous Technologies, since 2001.
- Twenty Two Patents.

Fereidoon Esmaeilzadeh was born in 1963 in Abadan, Iran. He has been Associate Professor of Shiraz University, Iran, and Adjunct Professor of Sharif University of Technology since 2002 and 2001, respectively. Between 1994 and 2002 he has been Visiting Professor at the Petroleum University of Technology and Isfahan University of Technology. He has more than 10 years experience in the National Iranian Oil Company (N.I.O.C.) as an administrator of Reservoir Simulation, Production Engineering and Petrophysics in Ahvaz, Tehran and Shiraz, in Iran. He has a B.S. degree from Abadan Institute of Technology, Abadan, Iran (1986), an M.S. degree from Shiraz University, Shiraz, Iran (1990) and a Ph.D. degree from Sharif University of Technology, Tehran, Iran (2001), all in Chemical Engineering. He is a member of the Society of Petroleum Engineers (SPE) and Iranian Association of Chemical Engineering.