RELATIVE PERMEABILITY CURVES FOR HIGH PRESSURE, HIGH TEMPERATURE RESERVOIR CONDITIONS

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The Objective of this paper is to clearly investigate the effect of some factors on oil-water relative permeability curves under certain reservoir pressure and temperature. In litreture, the effect of different factors on relative permeability of oil-water systems have been studied under ambient room conditions. However, treatments studies dealing with the effect of factores under reservoir conditions are few. Therefore, in this study, wettability alterations, brine chemistry, clay content, and their impacts on relative permeability curves under particular reservoir pressure and temperature were studied. Pore pressure, pore pressure drawdown and their combined effect with overburden stress and brine chemistry on relative permeability curves were also investigated at reservoir conditions. The relative permeability was calculated using JBN method.

In conclusions, the change of wettability from water wet to mixed wet gives relatively higher relative permeability to oil at high and medium oil saturation in the core samples. But at low oil saturation the relative permeability to oil becomes lower in mixed wet than in water wet.

At reservoir temperature, the oil relative permeability increases at all oil saturations compare with room conditions. This effect may be not due to the change in wettability but due to the change in viscosity ratio.

The effect of clay content on all permeability types (absolute, effective, relative permeability, relative permeability ratio, and fractional water flow) was bad due its damaging effect.

The increase of net overburden pressure cause decrease in the relative permeability of oil, however, its effect on relative permeability of water was negligible.

INTRODUCTION

Relative permeability is a critical parameter for evaluation of reservoir performances. Relative permeability is a direct measure of the ability of the porous medium to conduct one fluid when two or more fluids are present. This flow property is the composite effect of pore geometry, wettability, fluid saturation, saturation history, reservoir temperature, reservoir pressure, overburden pressure, rock types, porosity and permeability types. The relative permeability curves are very important in reservoir studies. The are used in predicting production rate and recovery from the reservoirs during all recovery stages (primary, secondary, and tertiary).

Some of the aforementioned factors were studied at room conditions only and some at reservoirs condition and others are not studied yet like pore pressure (reservoir pressure and pore pressure depletion.

This study is concerned to measure and calculate of relative permeability curves under reservoir conditions by including all involved factors.

The determination of relative permeability curves was carried out by using two kinds of cores, artificial consolidated core and Berea sand stone cores which is strongly water-wet sandstone and consisting typically of 90-95% quartz.

Relative permeability data are necessary for reservoir simulation involving multiphase flow of fluids in porous media. The relative permeability saturation data are usually obtained from displacement experiments with core flooding in the lab. The unsteady-state method can be carried out in a relatively short time, but the interpretation of the data is more complex. Therefore, unsteady state method was used in this study.

LITERATURE REVIEW

Factors affecting the relative permeability Curves

Wettability affects relative permeability because it is a major factor in the control of the location, flow, and spatial distributions of the fluids in the core. Wettability determines the relative locations of oil and water with in the reservoir porous medium. Because of its effect on the oil/water distribution, wettability influences the relative permeabilities of the flowing fluids [2-6].

Temperature is the one of the early studies of temperature on relative permeability was presented by Edmondson [9], Weinbrandt *et al*. [10], Casse and Ramey [11], Ref. [12], Miller M.A. and Ramey H.J. [13] measured dynamic-displacement relative. The study proves that temperature has no effects. Also the references [14]-[18] shown consolidated sands water/oil relative permeabilities at temperature ranging from 22 ºC to 175 ºC. They found that water/oil relative permeability curves are affected by temperature especially at low interfacial tensions (IFT).

The change in wettability of the rock and reduction of the interfacial tension with increasing temperature were important factors in causing the observed changes in the relative permeability curves. The above results from experimental were conducted on fired Berea sandstone cores using n-dodecane and 1% NaCl. Aqueous low-concentration surfactant solutions were used to change interfacial tension levels. For the experiments reported, the fluid pressure was kept constant at 300 psig and the overburden pressure at 650 psig.

Overburden Pressure

The dynamic displacement experiments studied the effect of the confining pressure on porosity, absolute and relative permeability [19]. These experiments were conducted on small, consolidated rock samples under overburden pressure up to 6000 psig and room temperature of 23 ºC. The pore pressure was maintained atmospheric. The examination of experimental results shows a decrease in porosity and permeability with increase in overburden pressure. The explanation for this phenomenon is as the overburden increased, the sand grains are brought close together causing a general shift in the pore throat diameter distribution towards smaller values. For a given water saturation, this leads to redistribution of the wetting phase to occupy more pore throats, while this should not cause any significant change in K_w, it leads to more blockage of the oil flow and hence reduces k_{ro}.

Reservoir Pressure

The effect of confining pressure changes at a fixed temperature and reservoir pressure on the absolute permeability of unconsolidated and consolidated sands was studied. The results show a linear decrease in permeability when the confining pressure is applied. Due to the fact that, the initial pressurization of the system compacts the grains into a tighter structure, after which it responds elastically to changes in confining pressure.

As the pore pressure increases, the permeability increases. However, when reservoir pressure was released, the permeability did not return to its initial value, but it returns to a higher value. And this was attributed to migration of fines that settle into pore throats.

In conclusion, absolute permeability of a porous medium can only be expressed as a function of the difference between the confining pressure (overburden pressure) and the reservoir pressure.

The Displacement Rate and Contact Angle

The displacement rate and contact angle are affect the shape of imbibition relative permeability curves. Increasing contact angle and rate, will be effect the relative permeability. It increases and the residual saturation decreases [22].

Experimental work

A Berea sand stone cores and artificial highly consolidated sandstone with 12 inches length and 2 inches diameter were used in the flooding test.

In the core flooding test procedure, pressure responses to flow changes through porous media was monitored according (in-compressible, and linear flow conditions) see Fig. 1. The Darcy Equation is used to calculate permeability:

$$q = \frac{kA\,\Delta p}{\mu L} \quad .$$

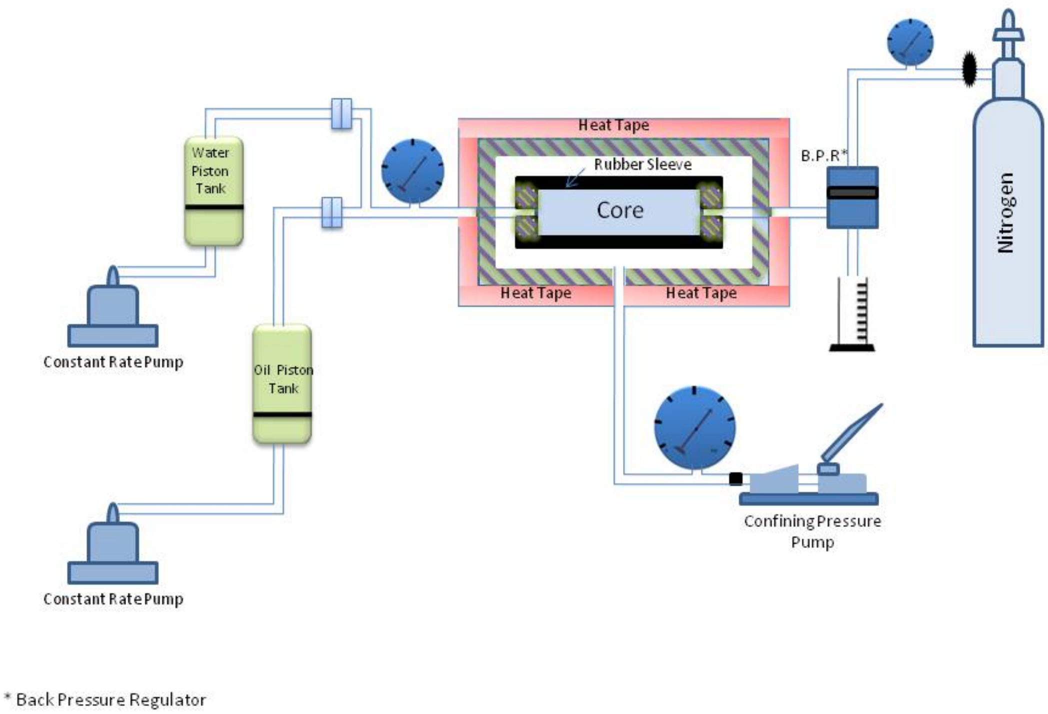


Figure 1. Core flooding station under high pressure and temperature

System operation

- The core was evacuated using a vacuum pump and saturated with known salinity brine.
- Core holder was connected to the main core flooding apparatus.
- 10 % methyl alcohol (methanol) (*Me-OH*) was added to avoid emulation solution between brine and hydrocarbons.
- Four hours should be sufficient to stabilize core temperature.
- Allow the brine to flow through the cores for 30 minutes (minimum) at 10 ml/ min. Some silica fines will be eluted during this period of time.
- After differential pressures have stabilized (minimum of 3 PV eluted through the core flooding) pressures at three different flow rates were recorded and calculate k_{w1}.
- The 100 % brine saturated core was then displaced by the oil phase. The displacement continued until water production from the core becomes zero. After this stage the core was saturated with oil at irreducible water saturation. The relative volumes of the effluents were measured. Continue recording all pressures and periodically measure flow rate.
- After differential pressures have been stabilized (minimum of 3 PV eluted through the core flooding) k_{o1} *was* calculated.
- At this stage, the core should be left under reservoir condition for a period of time (5-7 days) for agitation processes.
- Injecting brine into the core was started and. The water volume and time at breakthrough was recorded. After breakthrough, the produced oil and brine volumes as well as the pressure drop across the core were recorded with time. Oil and water relative permeability was calculated using the JBN method.
- After 100 % water cut, pressures and flow rate recording and k_{w2} calculation continous.

RESULTS AND DISCUSSION

The following sections present and discuss the effect of clay, wettability alteration, temperature, chemical, pore pressure, and overburden pressure on oil-water relative permeability, fractional flow curves, and relative permeability ratio.

Effect of Brine Chemistry

Sodium hydroxide (NaOH) with low concentration (0.2 %) is used to change the wettability. The contact angle between oil and brine with 20 % NaCl, 20 % NaCl , and 0.2 % NaOH was measured at room of 23 ºC and reservoir temperature of 70 ºC as a function with time for Berea sand stone . The results are shown in Table (1).

Table 1

The pH, viscosity, and contact angle between brine and crude oil at room and reservoir temperature

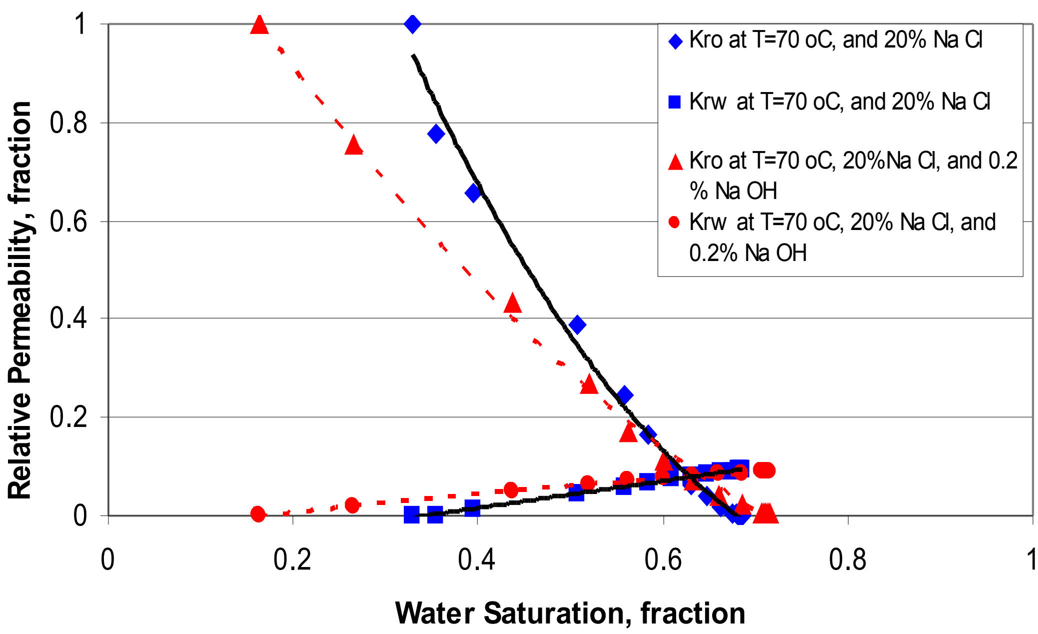
	Brine	pH	Viscosity, cp	Contact angle, º
1	20 % NaCl @ 23 ºC	7.2	1.06	43
2	20 % NaCl + 0.2 % NaOH @ 23 ºC	10.54	1.50	130
3	20 % NaCl @ 70 ºC	7.2	0.8	42
4	20 % NaCl + 0.2 % NaOH @ 70 ºC	10.54	0.8	129
5	20 % NaCl @ 23 ºC Sample eluted from the core	7.2	0.8	43

To investigate the results from the above Table (1), the oil used in this study has no effect on the pH and the contact angle, when the ageing process is completed (4-7 days) under reservoir condition at connate water saturation. The pH and contact angle are the same for the brine used in the core flooding under reservoir condition for ageing process period, and for the other brine that is not used for flooding see Table (1) Samples 1, 3, and 5 also samples 2, and 4.

The Effect of Wettability

The core wettability is changed from water-wet to mixed or oil-wet by adding 0.2 % NaOH. The pore space progressively becomes more oil-wet due to film rupture as the capillary pressure is raised. The brine during imbibition and the oil sees a different porous medium, which is now mixed wet or partially oil wet. The brine during imbibition would tend to go into largest pores of the oil wet and of course continue to flow through the smallest pores which have not been contacted by oil during drainage and hence are still water-wet. This may create a very different fluid distribution than would have been achieved if the core were oil-wet to begin with. Figs (2 - 4) shown that:

- Oil recovery increases if the core becomes oil-wet, the ultimate oil recovery for water-wet core equals to 53 %, and the ultimate oil recover for oil-wet core was 67 %.
- Oil relative permeability increases for medium and low oil saturations if the core was strongly oil-wet, and decreases for high oil saturation.



Figгку 2. Effect of wettability on relative permeability curves at reservoir conditions

- Fractional water curve for oil-wet core is better than water-wet core for low oil saturation, but the opposite is true for high and medium oil saturation, see Fig. 3.
- Relative permeability ratio is lower in oil-wet than water-wet core for low oil saturation, but the opposite is true for higher oil saturation and medium, see Fig. 4.

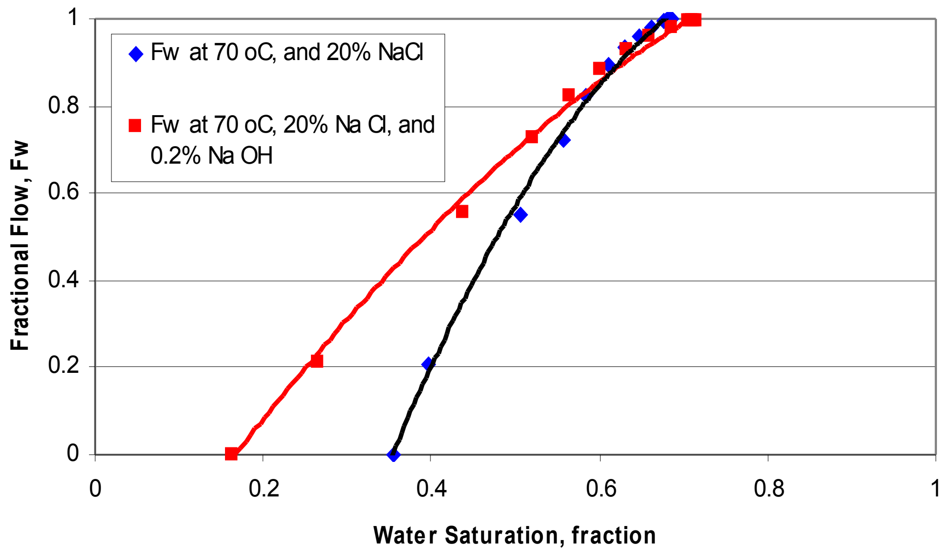


Figure 3. Effect of wettability on fraction flow curves at reservoir conditions

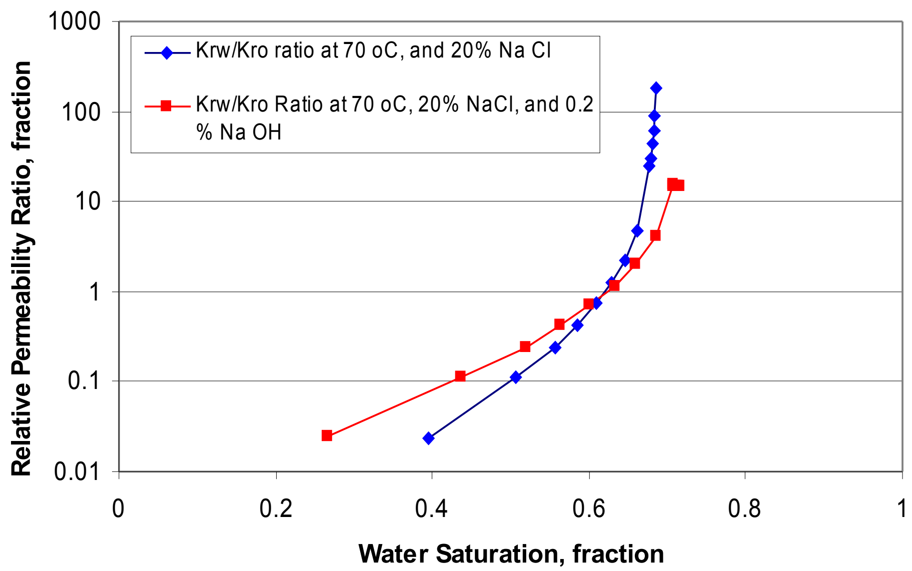


Figure 4. Effect of wettability on relative permeability ratio curves at reservoir conditions

The Effect of Clay Content

Residual oil saturation was lower in the relatively clay free cores.

Oil relative permeability was higher in the clean cores compares with cores contains some percentage of clay. And we get the opposite results for the water relative permeability, see Fig. 5.

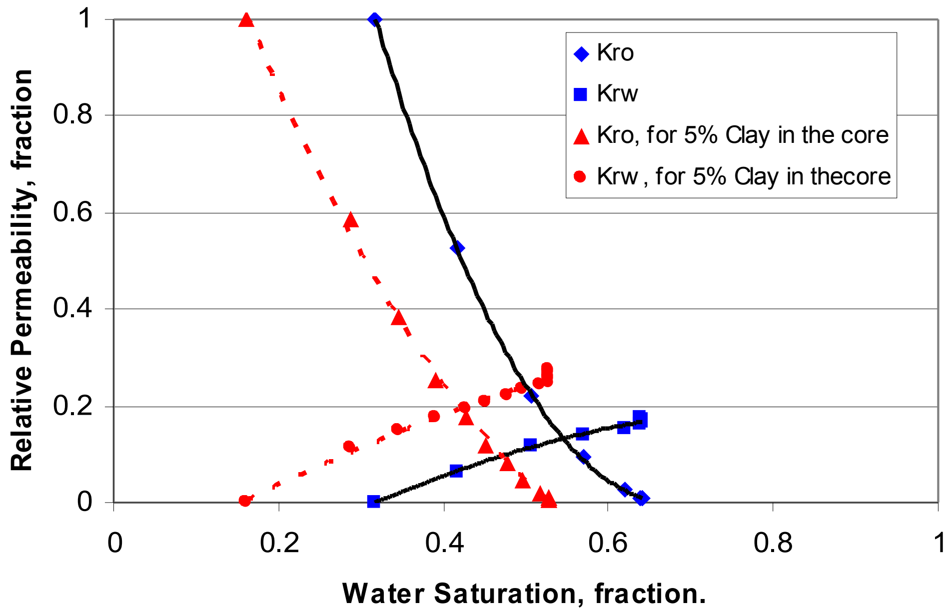


Figure 5. Effect of clay on relative permeability curves at reservoir conditions

- Fractional water curve for clean core was better than dirty cores for all oil saturations, see Fig. 6.
- Relative permeability ratio is lower in clean core than dirty cores for all oil saturations, see Fig. 7.

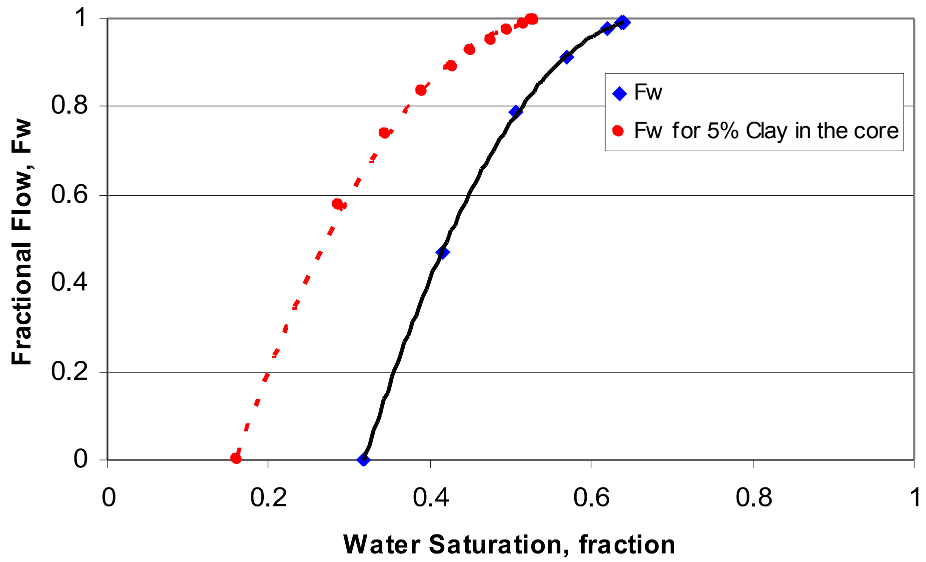


Figure 6. Effect of clay content on fraction flow curves at reservoir conditions

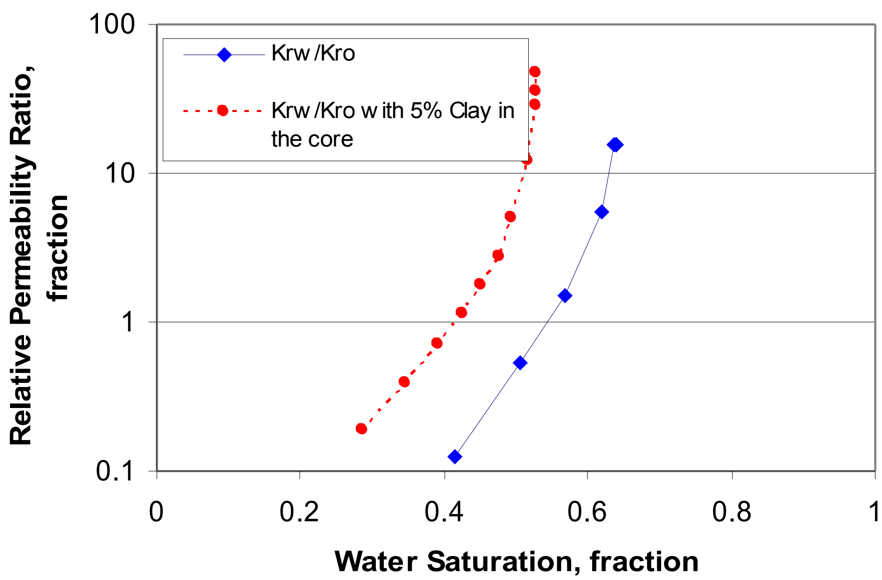


Figure 7. Effect of clay content on relative permeability ratio curves at reservoir conditions

The Effect of Temperature

The water wet cores were studied at 23 ºC and 70 ºC. The wettability did not change with temperature for a test of 72 hours. Water pH before and after test are equals 7.2 and 7.3 almost the same. The improvement in the oil relative permeability may be due to decease in oil-to-water viscosity ratio.

- Oil recovery increases at higher temperature, the ultimate oil recovery for low temperature core equal to 49.7 %, and the ultimate oil recover for high temperature core increase to 53 %, see Fig. 8.
- Fractional water flow curve was better for core is tested at higher temperature at all oil saturations, see Fig. 9.
- Increasing temperature causes lower reservoir relative permeability ratio, see Fig. 10.

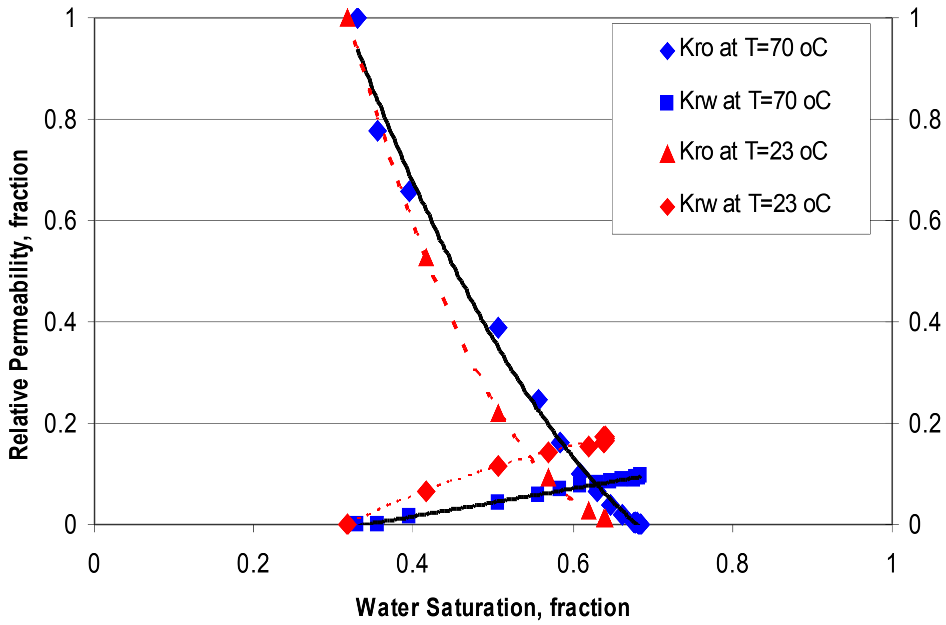


Figure 8. Effect of temperature on relative permeability curves at reservoir conditions

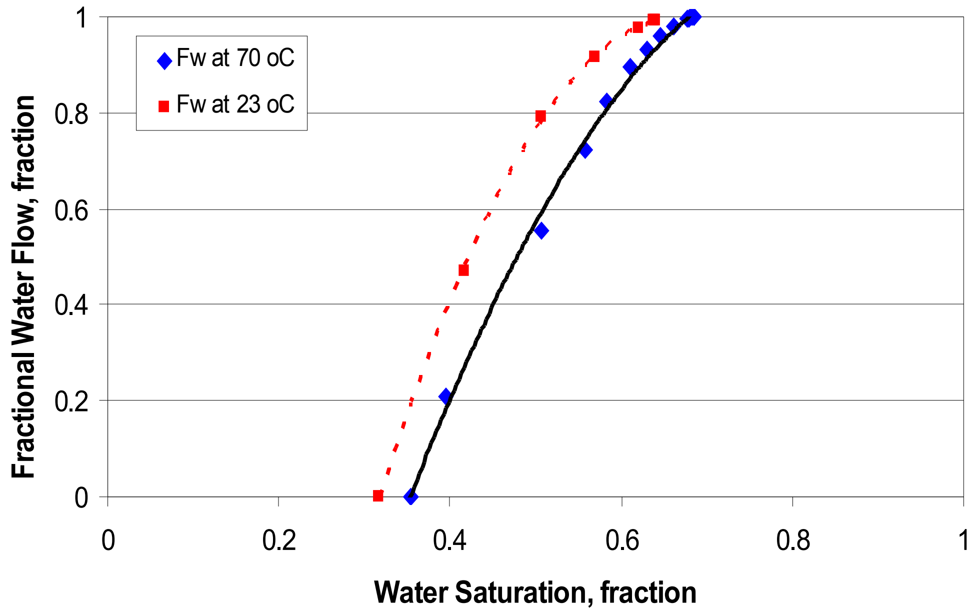


Figure 9. Effect of temperature on fractional flow curves at reservoir conditions

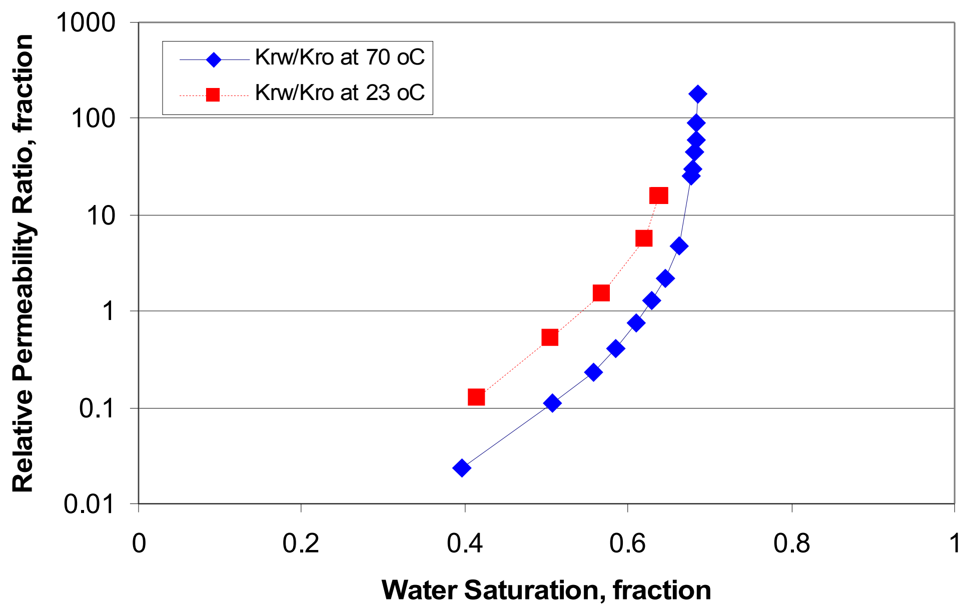


Figure 10. Effect of temperature on relative permeability ratio curves at reservoir conditions

The Effect of Net Overburden Pressure

Figure 11 indicates the effect of the net overburden pressure on the oil-water relative permeability curves at the end point (S_{wi}, and S_{or}). The test was performed under reservoir pressure and temperature equal to 1000 psi and at 70 °C respectively. This figure shows that the net overburden pressure affects oil relative permeability. The oil relative permeability decreases with increasing the net overburden pressure due to compaction. The larger pores that are filled by oil become smaller due to increasing net overburden pressure. Then the space for oil phase path become smaller, therefore the oil relative permeability decreases. This means that the increase in the net overburden pressure may let to changes in the pore geometry that leads to changes in fluid distribution in pores.

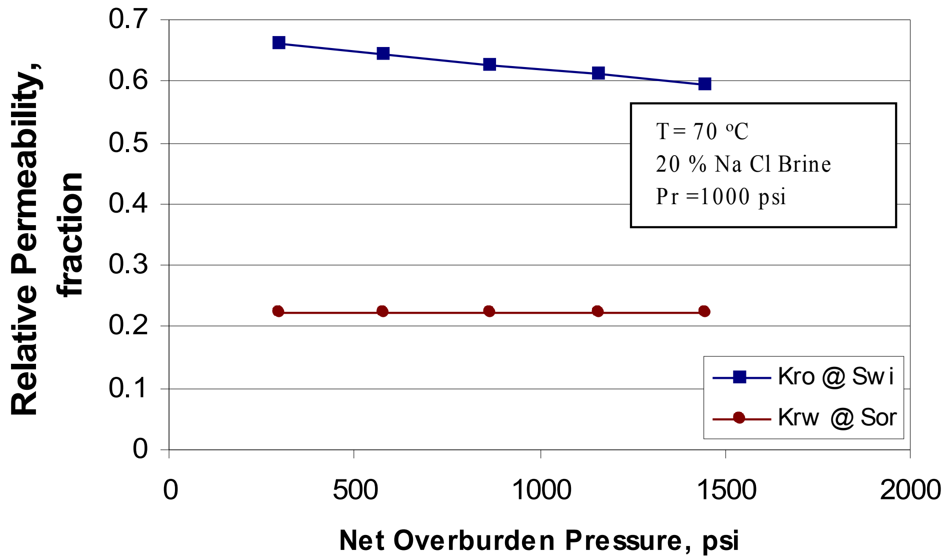


Figure 11. The effect of net overburden pressure
on oil and water relative permeability at the end points

CONCLUSIONS

1. The change of wettability from water wet to mixed wet gives higher oil relative permeability at high and medium oil saturation. But at low oil saturation the opposite was noticed.

2. At higher temperature, oil relative permeability increases not due to the change in wettability but due to the change in oil viscosity.

3. Fractional water flow and relative permeability ratios become lower at higher temperature.

4. Clay content in the core sample has a clear affect on all permeability (absolute, effective, relative permeability, relative permeability ratio, and fractional water flow).

5. Fractional water curve and relative permeability ratio are lower in clean cores than that contain some clay.

6. The net overburden pressure effects oil relative permeability. Oil relative permeability decreases due to increase of net overburden pressure, but the water relative permeability dose not change (negligible).

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NOMENCLATURE

A = cross-section, cm^2

ϕ = core porosity,

ϕ_i= initial core porosity,

μ_o = oil viscosity,

ρ_o = oil density, g/cc

ΔP = pressure drop

ΔP_s = pressure drop at the start of injection,

μ_w = viscosity of the displacing phase (water viscosity),

ρ_w = water density, g/cc

d = core diameter,

d= derivative operator

f = fractional flow

f_o = oil fractional flow, fraction

f_{o2} = oil fractional flow at the out let end, fraction

f_w = water fractional flow, fraction

f_{w2} = water fractional flow at the out let end, fraction

i_{crit} = critical injection rate, cc/min

IFT = interfacial tension, mN/m

I_r = relative injectivity

i_w = injection rate, cc/min.

K = permeability, md

K_i =initial permeability, md

K_o = effective oil permeability, md

k_{ro} = oil relative permeability, fraction

k_{rw} = water relative permeability, fraction

k_w = effective water permeability, md

L = core length,

N_p = cumulative oil produced, P.V

P_{ov} = overburden pressure, psi

S_{or} = residual oil saturation, fraction

S_{w2} = water saturation at the out let end, fraction

S_{w2avg} = average water saturation at the out let end, fraction

S_{wavg} = average water saturation,

S_{wf} = water saturation at breakthrough (B.T.), fraction

$S_{wf\,avrg.}$ =average water saturation at B.T., fraction

S_{wi} = initial water saturation,

S_{wi} = initial water saturation, fraction

t = time

V= average velocity of flow, $(v = \frac{i_w}{A})$

V_s= average velocity of flow, $(v_s = \frac{i_w}{A})$

W_{inj} = water injected, P.V

W_p= water produced, P.V

JBN : Johnson – Bosller – Naumann approach

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Table 2

JBN calculations for a run example

Time, sec	Δp,psi	Vt, cc	Vop, cc	Vwp, cc	Qwi, cc	Qwi, pv	Qwp,cc	Qwp, pv	Ir	Ln(Qwi)
0	0	0	0	0	0	0	0	0		
3301.2	88	45	45	0	45	0.191489	0	0	1	3.806662
810	90	16	12	4	61	0.259574	4	0.017021	1.416884	4.110874
1600	85	33	5	28	94	0.4	32	0.13617	1.566452	4.543295
1240	80	25	3.5	21.5	119	0.506383	53.5	0.22766	1.626935	4.779123
1270	74	25	2	23	144	0.612766	76.5	0.325532	1.717302	4.969813
1190	75	25	2	23	169	0.719149	99.5	0.423404	1.808314	5.129899
1180	74	25	2	23	194	0.825532	122.5	0.521277	1.848282	5.267858
1150	74	25	1.5	23.5	219	0.931915	146	0.621277	1.896498	5.389072
1125	75	25	1	24	244	1.038298	170	0.723404	1.912794	5.497168
1100	75	25	1	24	269	1.144681	194	0.825532	1.956267	5.594711
1105	74	25	1	24	294	1.251064	218	0.92766	1.973731	5.68358
1110	74	25	1	24	319	1.357447	242	1.029787	1.964841	5.765191
1100	72	25	1	24	344	1.46383	266	1.131915	2.037778	5.840642
1095	72	25	0	25	369	1.570213	291	1.238298	2.047083	5.910797

Qo, cc	fo	Ln(1/Qwi)	Ln(1(/I*Qwi))	slope m	Swav	Sw	Kro	Krw
45	1				0.3617	0.3617	1	0
57	0.391115	-4.11087	-4.45933	0.838476	0.604263	0.50274	0.466459	0.067126
62	0.160179	-4.54329	-4.99211	0.76768	0.62554	0.561468	0.208653	0.101124
65.5	0.101418	-4.77912	-5.26582	0.731622	0.640433	0.589077	0.138621	0.113532
67.5	0.073526	-4.96981	-5.51057	0.703707	0.648944	0.60389	0.104484	0.121699
69.5	0.059113	-5.1299	-5.72229	0.681097	0.657455	0.614944	0.086791	0.127695
71.5	0.051277	-5.26786	-5.88211	0.662196	0.665965	0.623634	0.077435	0.132434
73	0.046903	-5.38907	-6.02908	0.646022	0.672348	0.628639	0.072603	0.136375
74	0.044449	-5.49717	-6.14573	0.631932	0.676604	0.630452	0.070339	0.139775
75	0.043101	-5.59471	-6.26575	0.619482	0.680859	0.631522	0.069576	0.142785
76	0.042403	-5.68358	-6.36351	0.608352	0.685114	0.632065	0.069702	0.145503
77	0.042093	-5.76519	-6.4406	0.598308	0.68937	0.632231	0.070353	0.147994
78	0.042013	-5.84064	-6.5525	0.589169	0.693625	0.632125	0.071309	0.150302
78	0	-5.9108	-6.62721	0.580797	0.693625	0.693625	0	0.155