COMPARISON OF HIGH/LOW SALINITY WATER/OIL RELATIVE PERMEABILITY

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ABSTRACT
There is much published data in the literature showing that waterflood recovery is dependent on the composition, especially the salinity, of the injection brine. Some of this published data have shown the characteristics of coreflood tests at reduced conditions with dead crude and brines. Relatively few have discussed tests performed at reservoir conditions with live fluids.

This paper describes characteristics of full reservoir condition waterfloods with live crude oil and brines (both high and low salinity) on reservoir plug samples from many global oil producing basins. Experimental procedures and reservoir condition waterflood characteristics are presented in this paper from both secondary (low salinity injection into a plug sample at initial water saturation (Swi)) and tertiary injection (low salinity injection into samples which have already seen high salinity injection). This simulates both low salinity injections in new waterfloods and also in mature waterfloods.

Fully interpreted reservoir condition water/oil relative permeability are also presented. High and low salinity relative permeability data measured on the same reservoir rock types are compared from similar Swi values. The characteristics of injecting low salinity brines after high salinity waterfloods are also discussed.

INTRODUCTION
Waterflooding is one of the most used enhanced oil recovery technique. Until recently it has been viewed exclusively as a physical process for maintaining pressure and sweeping oil to producing wells unless scaling or souring potential was present.

In the 90's, Jadhunandan and Morrow [1995] and Yildiz and Morrow [1996] published papers on the influence of brine composition on oil recovery which started to change the industry's view on how waterflooding works and how it could be optimised. Since then a number of papers have been published investigating this phenomena and growing evidence from the laboratory [Lager et al 2006, Webb et al 2005], field single well tests [McGuire et al 2005, Webb et al 2004, Seccombe et al 2008], and through to reservoir scale evidence [Lager et al 2008], are supporting the technology. Reservoir simulation of the process has also been published by Jerauld et al [2006]. Generally oil recovery is increased significantly, up to 50%, by injecting brines of salinity <4000 ppm opposed to sea water or higher salinity produced waters.

Most of the published corefloods have been performed at reduced conditions, mainly with dead oils and brines, with the objective of improving mechanistic understanding behind the measured increased recovery(for instance Yildiz et al, [1996], Tang et al, [1999]). Webb et al [2005] published reservoir condition oil production data but did not discuss relative permeability. Therefore no data has been reported that could be used for reservoir simulation. This paper therefore presents fully interpreted water/oil relative permeability derived at reservoir conditions.

The success of any EOR technique is the ability to release significant volumes of oil, after secondary recovery scheme, rapidly and at low cost. Most of the reduced condition waterfloods in the literature have suggested that the oil produced by low salinity waterflooding would not develop into an oil bank but would be produced as a long drainage process at high fractional flow of water. This could result in the technology being uneconomical due to the long period of time and the large amount of water which would be required. This paper will show characteristics of oil production for many different reservoirs, at different initial water saturations, measured at full reservoir conditions which suggest very different characteristics, making low salinity waterflood a potential economical EOR technique.

This paper describes the design, execution, analyses and interpretation of full reservoir condition tests on reservoir rock/oil, comparing high and low salinity waterflood tests with live oil and brine. Water/oil relative permeability data obtained on a number of reservoirs from around the world, from different Swi values (Figure 1), are compared to show the speed of response of tertiary production that is achieved during the LoSal ™ EOR technology process.

EXPERIMENTAL PROCEDURES

Description of Equipment

These studies utilised coreflood facilities which operate at full reservoir conditions, up to 150°C and 10000 psi, (Figure 2). Equipment utilises in-situ saturation monitoring by gamma ray and uses live fluids both for ageing and fluid flow (Figure 3). Volumetric production is measured at full reservoir conditions with an in-line separator, and saturations at the end of the flood are confirmed by performing aqueous dispersions with a doped phase.

Reservoir Systems

The relative permeability studies presented have been selected on the basis of showing the impact of low salinity on many of the producing basins across the world (Figure 1). The characteristics of rocks are therefore very different, ranging from relatively clean (low clay content) rocks, to rocks which have many minerals other than quartz. Crude oils also have very different characteristics (acid/base numbers, SARA analyses etc). Connate brine salinities vary from~15,000ppm to ~200,000 ppm. Likewise temperature and pressure of the tested reservoirs vary considerably from ~60^{o}C to ~130^{o}C and ~2500psi to ~7500 psi.

Description of Procedures

Core Preparation**.**
Plug samples, nominally 3" long by 1.1/2" in diameter were used for these studies.

All samples used for this study were restored i.e. samples were cleaned to as water wet condition as possible by miscible solvents. After cleaning, samples were saturated with the simulated formation water (both samples for high and low salinity corefloods) by flowing under a back pressure. After ca. 10 pore volumes of brine throughput, samples were removed from the hydrostatic coreholders and initial water saturations set up using the procedures described below.

Acquisition of Initial Water Saturations**.**
It was essential that plug samples had representative Swi values which were matched to the height above the oil water contact in the reservoir. For these cleaned plug samples, initial water saturations were achieved by porous plate de-saturation, using strongly non wetting gas (nitrogen). Once these initial water saturations were acquired, the samples were loaded into hydrostatic coreholders and saturated by flowing refined oil under back pressure.

In-situ saturation monitoring was used to provide distributed saturation data to aid interpretation of experimental results. This technique was based on the linear attenuation of γ-rays. Each source/detector pair viewed a slice of core 4 mm wide. A linear relationship between the log of counts (transmitted flux) and water saturation existed. Therefore, by employing careful calibration procedures for each source/detector assembly, fluid saturations were calculated. A number of these assemblies were mounted along the core plug samples so that water saturation was monitored at fixed positions versus time/throughput during the waterfloods.

Two sets of calibration data were collected for each source/detector pair at the end of each waterflood. 100% brine saturation calibrations were recorded at the end of the cleaning stage. 100% oil saturation calibrations were measured with the core 100% saturated with live crude oil.

In these experiments it was necessary to replace chloride ions in the simulated formation brine with iodide ions so that the contrast between the aqueous and oleic phases was increased. This reduced the noise to signal ratio, and improved the accuracy of the calculated in-situ saturations. The molarity of the doped brine was kept the same as the un-doped brine to ensure that no adverse rock/fluid interactions occurred, although a maximum of 50 g/l of sodium iodide was not exceeded in any test.

Ageing Process.

Samples were loaded into reservoir condition coreholders and slowly raised in pressure and temperature to reservoir conditions. Reservoir temperatures varied from 60^{o}C to 125^{o}C.

The refined oil was miscibly displaced at full reservoir conditions by live crude oil to constant gas/oil ratio via a slug of toluene to ensure that no asphaltene was precipitated due to an incompatibility between the live oil and the refined oil. When the differential pressure was stable, the live crude oil viscosity and effective permeability to live crude oil were measured. All samples were aged in live crude oil for two to three weeks. During the ageing period the crude oil was replaced every few days. A minimum of 3 pore volumes were injected and a sufficient amount was used to achieve a constant pressure drop across the sample and a constant gas oil ratio.

Waterflooding Procedures.

Unsteady state waterfloods were carried out on the sample at full reservoir conditions using in-situ saturation monitoring (Figure 3). In-situ saturations were used to provide data on the oil distributions which developed during the course of the waterflood. Swi for both high and low salinity samples was initiated following on from saturating with the simulated formation brine. Injection brines were simulated formation brine for high salinity waterfloods (salinity 15,000 ppm to >200,000 ppm), and low salinity brine (<5000 ppm) for the low salinity corefloods. All brines, both high and low salinity, used for the waterflood tests, were pre-equilibrated with separator gas at the reservoir pore pressure to ensure no gas transfer from oil to water phases

Low rate waterfloods were carried out on the restored state samples at a typical reservoir advancement rate (1 foot per day, typically corresponding to 4 cm^3/hour in the laboratory). During the injection of the brine, oil production, pressure drop and in-situ saturation data were continuously monitored. Oil production was recorded at full reservoir conditions in an ultrasonic separator. This had the advantage of directly measuring oil production at reservoir conditions. Errors associated with using formation volume factors to correct oil production data were therefore avoided.

For the high salinity secondary waterfloods, tertiary injection of low salinity brine was injected after >10 pore volumes throughput of the high salinity brine.

At the end of the waterflood test sequence and after the plugs were cleaned to Sw=1, miscible dispersions using doped and undoped brine were performed at relatively low rates to determine the aqueous pore volumes at the end of the waterflood process and fully brine saturated, by two independent means, (density and concentration profile from the measured gamma attenuation). In this way a number of independent means of measuring low salinity benefit were performed (mass balance, in-situ saturation during waterflood, dispersion tests).

Coreflood Analyses and Interpretation.

Laboratory production and differential pressure were initially analysed using the Johnson Bossler Naumann technique [1959]. This however assumes that there are no impacts of capillary pressure on waterflood characteristics. This rarely is the case. Therefore further interpretation is required to remove the impact of capillary pressure on the relative permeability data. In the corefloods discussed here, imbibition capillary pressure was derived from the dynamic waterflood in-situ saturation and differential pressure data measured during the waterflood.

The starting point for the data interpretation was to confirm that the JBN data sets were consistent with the pressure and production data measured in the laboratory. This was performed by including the laboratory measured data and the JBN relative permeability data into an input file which was run through the 1D coreflood simulator 'PAWS' [Carr et al 1983]. The next stage in the interpretation process was to include imbibition capillary pressure data, and modify the relative permeability data in the PAWS input file. Imbibition capillary pressure was derived from waterflood displacement data and the measured in-situ saturation data.

The PAWS simulator was run, and the simulated production and pressure profiles compared against those generated during the experiment. If poor agreement was obtained then the relative permeability to oil and water were modified until good agreement was observed. Once good agreement was obtained, simulated in-saturation profiles at the end of the waterflood were checked against the in-situ saturation profiles which developed in the laboratory.

SECONDARY WATERFLOOD CHARACTERISTICS

Many reservoir condition secondary recovery injections of low salinity brine, performed in BP's laboratories, have now been completed. All reservoir condition waterfloods, when a comparison has been able to be made, have shown incremental recovery, both in dry oil and reduction in remaining oil saturation, after waterflood. An example of oil production vs. throughput for a high salinity and low salinity secondary displacements, are given in **Figure 4** for a 200,000 ppm salinity reservoir system. These characteristics are similar to those that are seen in any salinity, whether lower or higher.

Many waterfloods have been performed comparing high and low salinity injection waters. Swi values ranged from 0.05 to >0.25 (Figure 5); A range of wettabilities are therefore likely to have been investigated (although these were not measured explicitly). All have shown similar characteristics. When compared with the high salinity curves, the low salinity curves can be seen to have similar mobilities, but are shifted in saturation, generally by the change in saturation observed for the low salinity benefit. This indicates that dry oil production is increased (the first point reported in unsteady state waterfloods is the shock front saturation). This shift in the dry oil production appears to be similar to the reduction in residual oil saturation between the high and low salinity waterfloods. The low salinity benefit is therefore seen as a shift in fractional flow behaviour, manifest by a shift in relative permeability behaviour.

Incremental dry oil recovery shows the mechanism to be kinetically quick (consistent with the double layer/multiple ion exchange theory [Lager et al, 2006], and importantly from a reservoir perspective, increasing the amount of oil produced during the phase of production plateau. Ranges in incremental oil were measured from 5% to 40% based on high salinity recoveries (Table 1).

One of the concerns with low salinity waterflooding is one of detrimental rock/fluid interactions, causing reduction in permeability and therefore reducing injectivity into a reservoir. In all cases, the end point relative permeability to water appears to be similar after high and low salinity (Figure 5). Also the shape of the water relative permeability (increasing) curve indicates that there is no material damage to the sample due to fines migration or clay swelling for these samples.

TERTIARY WATERFLOOD CHARACTERISTICS

The majority of the reservoir condition waterfloods performed by BP's laboratory, comparing high and low salinity in secondary injection, have also been compared after tertiary (low salinity brine has been injected after multiple pore volumes of high salinity brine). Example oil production profiles are given in Figure 10 and Figure 11 and show that the increased production does not appear to be dependent on salinity of the resident phase prior to low salinity injection. Once again low salinity injection was seen to improve oil recovery in all cases where the comparison was made.

For most EOR processes to be economical in the field, it is essential that oil is produced quickly. The characteristics of these reservoir condition corefloods, performed by BP, are very different to some of the previously reported tests performed at reduced conditions by non BP laboratories.

During tertiary core flood tests, differential pressure during the high salinity and low salinity injections were continuously monitored. Summary end point relative permeability data for example data sets are given in Table 2. These data represent data sets that are near the extremes of initial water saturations seen. The permeability after low salinity is similar to that measured after high salinity injection. It should be pointed out that although only three corefloods are reported here, similar characteristics have been seen in all reservoir condition corefloods performed by BP, where tertiary low salinity benefits have been measured. This indicates, at least for the reservoir systems tested, that no adverse rock/fluid interaction is observed with the low salinity brine. Also several systems had high salinity injected after the low salinity injection. Again the effective permeabilities were similar to the low salinity values.

CONCLUSION

1. Reservoir condition waterfloods have proven that low salinity waterfloods improve waterflood characteristics previously seen in reduced condition experiments- Incremental benefits range from ~5-40% over a wide range of reservoir systems (rock, fluid, saturation, temperature and pressure).
2. The additional low salinity recovery is produced as dry oil for secondary floods and results in a reduction in residual oil saturation.
3. Generally end point water relative permeability data do not vary significantly between high and low salinity waterfloods, in secondary or tertiary modes.
4. Tertiary waterflood characteristics observed at reservoir conditions are materially different to those measured at reduced conditions.

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Table 1: Summary of Coreflood Results

Field	Sor High	Sor Low	% WF Meas
A	0.33	0.25	16
B	0.32	0.24	14
B	0.21	0.13	11
C	0.23	0.19	8
C	0.23	0.19	8
D	0.25	0.13	21
E	0.33	0.12	39
F	0.2	0.1	20
G	0.26	0.23	7
G	0.18	0.13	9
G	0.19	0.12	11
G	0.23	0.2	5
A			9
A			8
B	0.28	0.2	13
B	0.28	0.15	22
C	0.27	0.23	7
C		0.2	11
A	0.125	0.077	6
A	0.33	0.3	5
A	0.2	0.1	13
A	0.2	0.18	~5
B	0.27	0.2	10
B	0.27	0.22	8
A	0.47	0.43	8
C	0.31	0.26	8
C	0.31	0.28	4
A	0.26	0.18	12
A	0.26	0.22	7

Table 2: Examples of Summary Relative Permeability after high and low salinity

Reservoir	Keo @ Swi	Swi	Sor high Sal	krw high Sal	Sor low Sal	krw low Sal
A	1140	0.05	0.351	0.14	0.3	0.153
B	650	0.145	0.289	0.23	0.214	0.32
C	325	0.212	0.21	0.128	0.15	0.19

Figure 1: Global reach of LoSal^{TM} EOR Technology Relative Permeability Evaluations

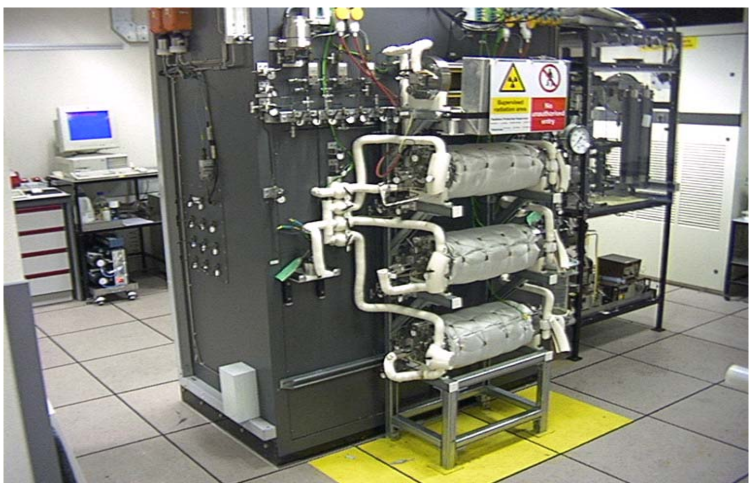
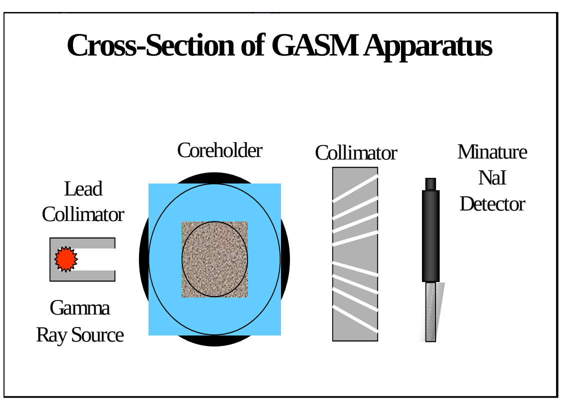


Figure 2: Typical Reservoir Condition



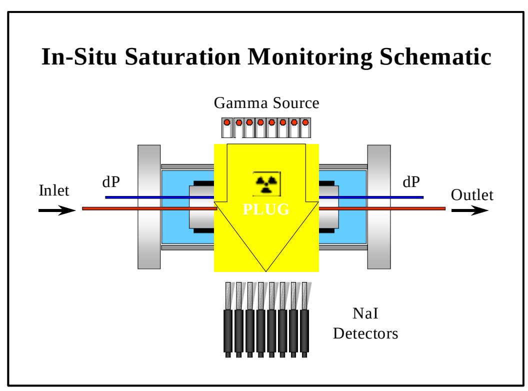


Figure 3: Schematic of In-situ Saturation Monitoring Equipment

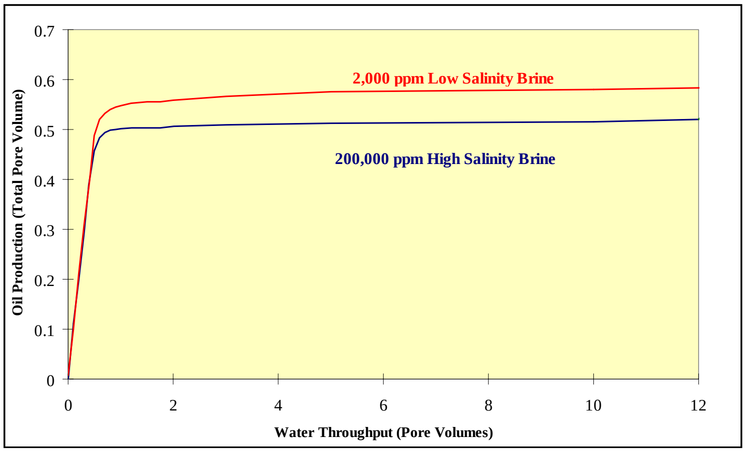


Figure 4: Secondary Production Profiles

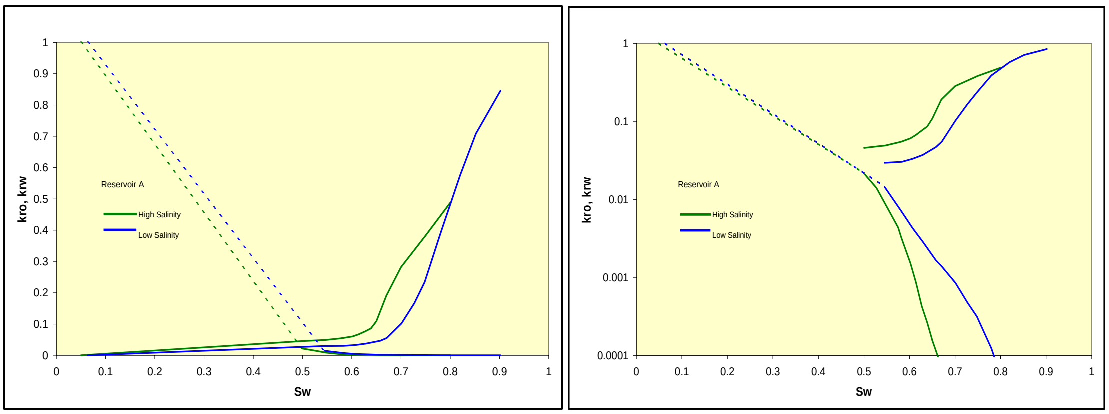


Figure 5: Water/Oil Relative Permeability – Swi<0.1

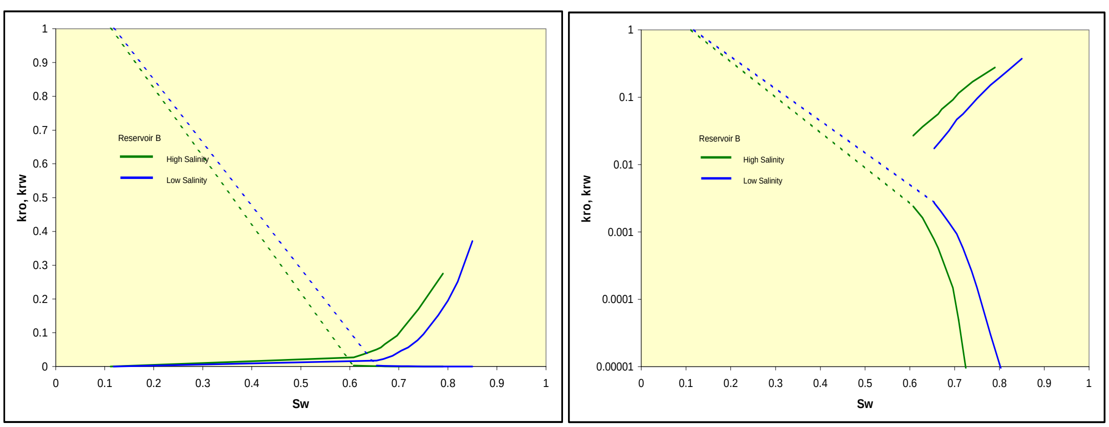


Figure 6: Water/Oil Relative Permeability – Swi 0.1-0.17

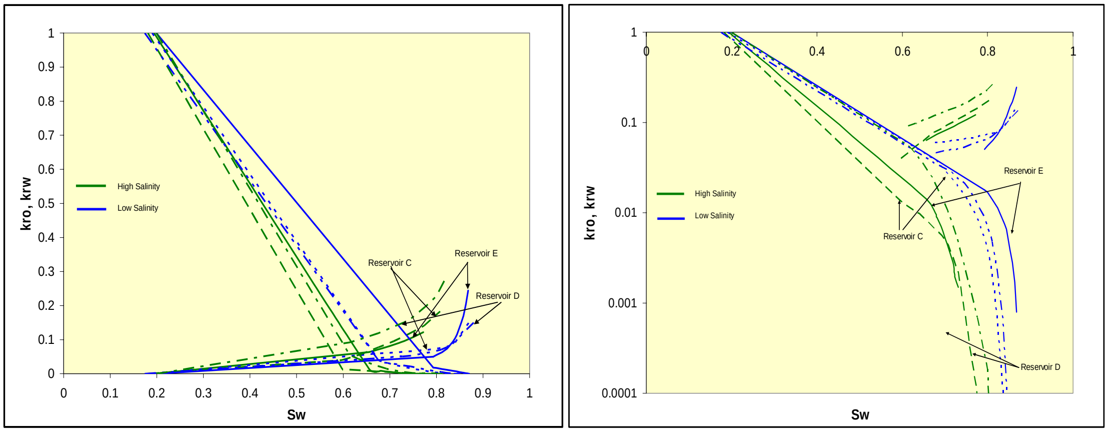


Figure 7: Water/Oil Relative Permeability –Swi 0.18-0.2

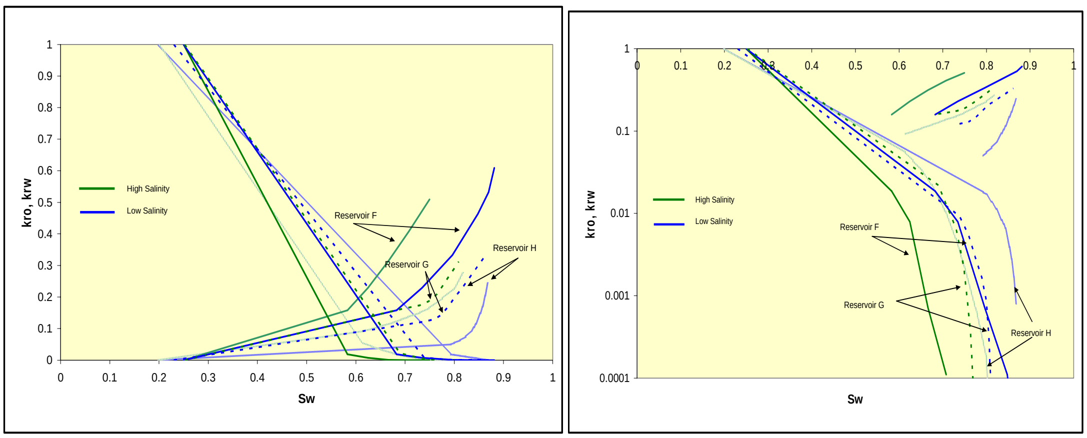


Figure 8: Water/Oil Relative Permeability –Swi 0.2-0.25

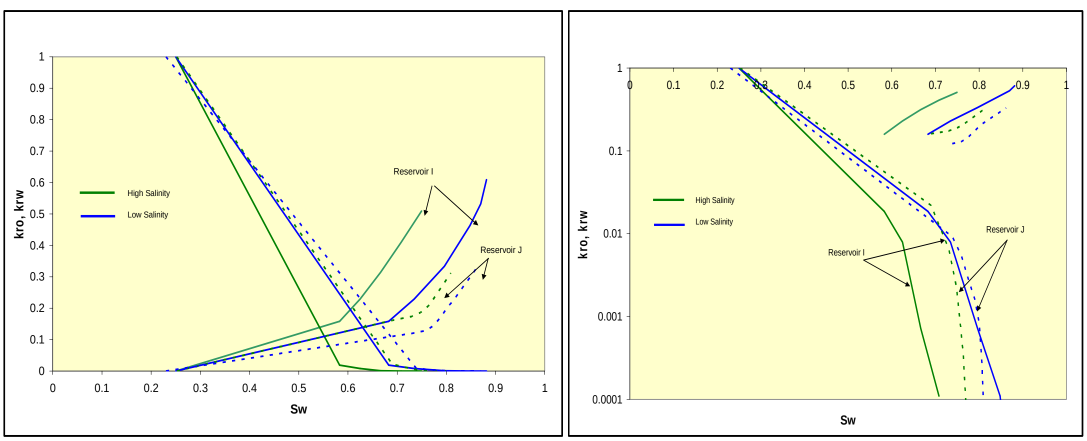


Figure 9: Water/Oil Relative Permeability –Swi >0.25

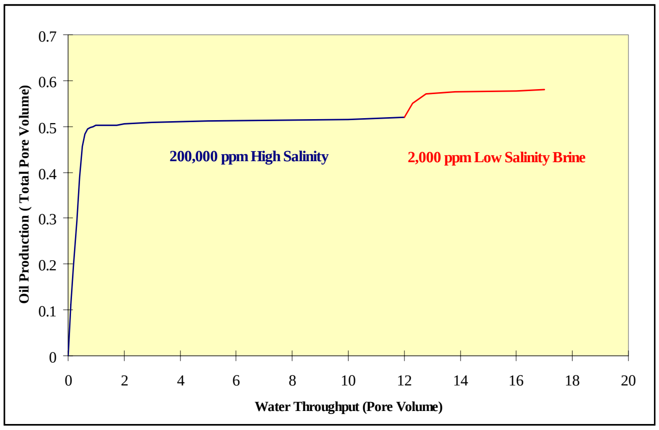


Figure 10: Tertiary Production from High and low Salinity Connate Brines

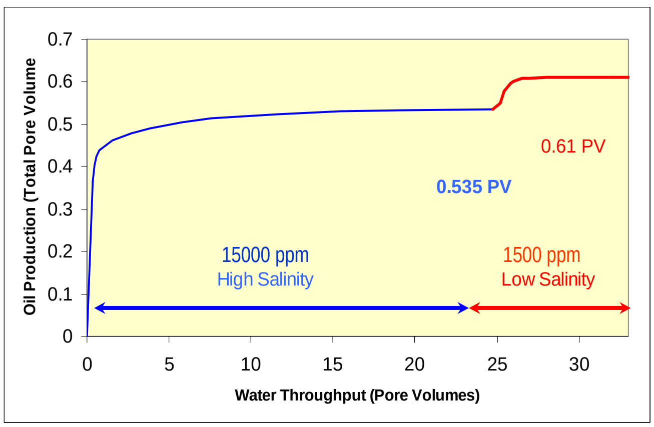


Figure 11: Tertiary Production from High and low Salinity Connate Brines