A SUMMARY OF EXPERIMENTALLY DERIVED RELATIVE PERMEABILITY AND RESIDUAL SATURATION ON NORTH SEA RESERVOIR CORES

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ABSTRACT

In an early stage of field evaluation there is a need to predict SCAL properties of the reservoir. Particular consideration should be given to residual saturation and end-point relative permeability. However, very limited amounts of experimental data are available at the initial stage. Hence, the objective of this work was to provide a summary of a number of laboratory measurements performed on North Sea material, which can serve as a database for initial evaluation. General trends with respect to variation of SCAL properties have been investigated with for instance, depositional environment, permeability, or wettability.

We have summarised waterflooding, gas injection and trapped gas measurements and tried to find relations to reservoir characteristics.

Examples of such relations are; End-point relative permeability as a function of permeability, rock type, depositional environment and wettability. Residual oil saturation was studied as function of; initial water saturation, permeability, and wettability. Finally, trapped gas as a function of; initial gas saturation, permeability, rock type, and depositional environment, have also been investigated.

Gas trapping is found to be lower in three-phase flow than two-phase flow. The results from waterflooding, and wettability indices (USBM and Amott-Harvey) have identified three different types of intermediate wetting state.

INTRODUCTION

In our literature survey we have only found a few summaries of large experimental special core analysis (SCAL) programs[1-7]. The SCAL summaries are usually from one specific oilfield[3-7] and only a few papers[1,2] compare core data from several oil fields. In this summary we have selected more than 500 SCAL experiments from different reservoirs. This summary has avoided data from heterogeneous material such as all the data reported by Tjolsen et al.[3] In that study the statistical variation was a main target, and hence, many of these cores had strong laminations that prevented flow in parts of the core pore volume. Thus, many cores would never have been selected in a high-quality core flood program, but as mentioned that was not the aim of that study. The core floods that are included here are based on selected SCAL studies from 30 fields in the North Sea area.

Several reservoirs consist of depositional environments that are different part of deltas. Examples are Brent reservoirs like the Oseberg, and Gullfaks fields, and fluvial deposits (Snorre), but also shoreface environment (Brage) often influenced by tidal movement (Smørbukk). The most complex of these reservoirs includes channel sands, highly faulted and sometimes also fractured reservoirs. In addition we have added data for chalk reservoirs found in the southern part of the North Sea basin, consisting of marine pelagic chalk. More description of the geology is found in references 8 and 9.

Gas injection data originate from different experiments, and the experimental conditions may vary from near ambient condition to full reservoir pressure and temperature. Thus, the interfacial tensions will be altered considerably. The gas injection is generally a drainage process, and the end-point saturation may be strongly influenced by the viscous-gravity-capillary force balances[12]. The derived relative permeability in the literature is usually not analysed for capillary influence on the phase mobility, and this adds uncertainty to the reported results. Felsenthal[2] has reported a large summary of gas-oil displacements. That study involved more than 300 experiments from 19 fields. Jerauld[11] has reported an extensive analysis of gas-oil data from one field (Prudhoe Bay). Several papers have summarised the effect of connate water on gas-oil displacement[10,11]. The main effect has been a decrease in oil recovery with decreasing connate water saturation. In this paper the effect of water saturation on recovery efficiency is investigated, together with effect of permeability, rock type, reservoir quality, and depositional environment.

Trapped gas has been studied both from gas injection studies and as part of gas field development. In this summary we have included both two-phase and three-phase gas trapping. Two-phase gas trapping means two mobile phases the experiment could still have a third immobile phase, as an example, connate water. In the literature trapped gas have been extensively studied[11,13-23]. The major relationship identified in published literature is that the trapped gas is a function of the initial gas saturation.

Wettability will influence most fluid flow processes in porous media. Thereby analysis of the wetting state of the porous media is regarded as a key factor for gas injection, trapped gas and more obviously waterflooding. Most reservoirs fall into the large group of intermediate wet state. Usually there is not enough data to resolve this lumped group of intermediate wet reservoirs. In this study, different intermediate wet states are resolved into fractional wet, and two groups of mixed wet, analogous to the network modelling approach by Dixit et al.[26].

Water flooding results were available for all the 30 reservoirs. This large amount of data have been used to analyse effects of; wettability, initial saturation, permeability, rock type, reservoir quality, on residual oil saturation and relative permeability. However, we have limited the discussion to the most significant trends in the data. The results are compared to other summaries of waterflooding results[1,4,5,7].

As this study compare data with different petrophysical properties, depositional environment, and experimental conditions. Only very strong relations are expected to be detected through the scatter of the data, that is representing different properties and conditions, due to the factors mentioned above.

RESULTS AND DISCUSSION
Gas Injection
Gas injection data discussed are from measurements by long core gas injection at reservoir condition or centrifuge gas-oil drainage experiments. The variation in gas-oil interfacial tension makes comparison of a large number of gas injection experiments difficult. However, centrifuge experiments for different fields should be a better basis for discussion. The direct measurements from a core flood reveal the average remaining oil saturation in the core, and further determination of residual oil relays of an interpretation of the experimental results. We refer the reader to further discussion about remaining and residual oil saturation to gas in ref.4. The remaining oil saturation for all the gas injection experiments is compared. We found an average remaining oil saturation Sorg of 0.16, while the average remaining oil saturation from all the waterfloods was 0.20. This shows that the relation from individual fields, where Sorg<Sorw is also reflected in this large amount of data from 30 oil fields.

The remaining oil saturation is correlated to Swi, and showed a trend of higher Sorg for higher initial oil saturation. An earlier study[10] has shown that oil recovery increased with connate water present compared to no water present. The influence of water-oil capillary pressure was found to change (reduce) the drainage rate, and also reduced oil relative permeability. If the displacement efficiency is compared to the initial water saturation a more complex relation is seen, Figure 1. At low Swi the oil recovery is increasing, but for Swi > 0.2 the oil recovery is reduced with increasing initial water saturation. These results are different from relations seen in Prudhoe Bay data[11], where displacement efficiency increased for a wide range of water saturations. Review of the literature indicates that the presence of connate water is generally an increase in oil recovery with water saturation up to a saturation range where water becomes mobile. This argument may suggest that water becomes mobile at water saturation above 20 per cent. However, all the cores are drained to irreducible water saturation, either by viscous displacement or in a centrifuge, and should represent a high capillary pressure range. The cores are driven down to irreducible whatever the location of the sample with respect to the initial WOC. A drainage process may leave a very low but still a non-zero water mobility, with water moving through films and micropores.

The Sorg is reduced with increasing rock permeability, but the variation is only a average reduction in Sorg from 0.15 to 0.1 for a permeability range of 1 mD to 10000 mD. Sorg seems to be positive correlated to "reservoir quality" as described by the square-root ratio of permeability to porosity. A correlation including porosity, permeability and initial oil saturation, analogous to Jerauld[11] could not explain the variation in Sorg. Due to the large scatter in the gas injection results and the influence of variation in interfacial tensions,

further grouping of gas injection data with wettability and depositional environment did not display any strong trends in the results. The end-point gas relative permeability is analysed but show poor correlation to other rock properties. Under a drainage process strong rate effects may obscure the interpretation[12].

Trapped Gas
In all gas reservoirs and also gas condensates, the trapped gas is an important factor for gas recovery. During depressurisation the water contact may move upwards and trap considerable amount of the gas present. Several papers have investigated and/or reviewed gas trapping[11,13-18].

Our sources of trapped gas data are from delta front, shorefront marine and turbudite sandstones. Two-phase data is plotted in a relation of initial gas saturation and trapped gas. The selected data represent very high initial gas saturation (1-Swc-Sor). A large scatter in the trapped gas saturation data is seen in Figure 2. However, a Land-type relation still represents a reasonable average behaviour. A Land-type function [19] gives a Land constant of 1.75, corresponding to a maximum-trapped gas saturation of 0.36. Figure 2 also includes the logarithmic trend-line through the data. The relation of trapping of non-wetting phase (like Land function) may not be valid at low initial, non-wetting phase saturation[20]. This is indicated by the trend-lines compared to Land function, in Figures 2 and 3.

The trapped gas is correlated to initial gas saturation both for two- and three-phase gas trapping, Figure 2 and 3. The three-phase data show less gas trapping, similar to earlier observations[21-22]. The Land constant was increased to 2.05 for the three phase data, corresponding to a maximum-trapped gas saturation of 0.33. The three-phase gas trapping is important in WAG processes because it influences both mobility of the phases, and the residual oil saturation. The Land constant for three-phase gas trapping is earlier found to vary with wettability[23].

Some papers[11,18] have tried to correlate trapped gas to other petrophysical measurements like porosity, permeability, reservoir quality, formation factors, etc. We found Sgt to give trend of both increasing and decreasing Sgt as a function of porosity similar to the data reported by Hamon et al.[18], but opposite to the consistent trend observed by Jerauld[11]. The overall trend (all data included) showed no relationship between Sgt and porosity. We found trapped gas not to be correlated to other petrophysical properties like permeability, reservoir quality / flow zone indicator. A minor improvement in the correlation was seen for specific field data with Sgt as a function of the product of reservoir quality and initial gas saturation, but the main factor influencing trapped gas is found to be the initial gas saturation.

Waterflooding
The waterflood data show a wide variation in remaining oil saturation, Figure 4. The remaining oil saturation ranges from 0.04 to 0.45 saturation units. The average remaining oil saturation by waterflooding was 0.20.

Measurements of remaining oil saturation as a function of wettability have detected a minimum in remaining oil saturation at intermediate wettability. Usually, these trends are found in a series of core flood from a specific rock type. In our comparison all the waterflood data from 30 reservoirs are included, but still the same type of relation is clear from the trend curve, Figure 5. The data used include both fresh and restored core if the wettability tests confirmed that fresh and restored cores were equal. If restored cores deviated from fresh only the fresh core results are used. Further analysis of why for some reservoirs wettability is restored, while other cases wettability cannot be restored it a topic for later studies.

The waterflood data is grouped by Amott-Harvey[24] wettability index, I_{AH}. Oilwet cores with $I_{AH} < -0.3$, intermediate wet cores where $-0.3 < I_{AH} < 0.3$, and waterwet cores where $I_{AH} > 0.3$. Figure 6 shows that the average remaining oil saturation is lower for the more intermediate wet cores. However, this is the average oil saturation at the end of the experiments, and not necessarily the true relation for the residual oil saturations.

The end-point water relative permeability is higher for the intermediate cores than the oil-wet cores. This result may be influenced by the lower remaining oil saturation for intermediate wet cores. If the end-point water relative permeability is multiplied by the end-point water saturation, a linear decrease is seen as a function of more oil wet core property, Figure 7.

For several reservoirs a relation of more oil-wet behaviour is seen at low water saturation. If the reservoir is initialised through a primary drainage, low water saturation is consistent with high capillary pressure. Basu and Sharma[25] have concluded that the proportion of oil-wet patches on the rock surfaces increases with increasing capillary pressure as the effect of surface curvature are overcome by the applied capillary pressure. This data summary reflects a trend that is consisted with these arguments, Figure 8. The overall trend is more waterwet at high initial water saturation. A similar trend is seen in summaries of field variations of wettability[4,7].

Most of the sandstone reservoirs included in summary are in the range of intermediate wettability. Intermediate wetting can be divided into three sub-classes. Fractionally-wet (FW) where oil and water wet sites are random with respect to pore size, and mixed wet defined by water and oil wet pores that are sorted by pore size. There are two classes of mixed wet state. MWL (mixed-wet large) is defined by oil wet large pores, while MWS (mixed-wet small) refers to the smaller pores are oil wet. Usually we regard the reservoir to initially be waterwet, and oil is migrating through a primary drainage process. Using this argument oil wet fraction should be in the larger pores that are invaded by primary

drainage. Though, the opposite MWS can also be theoretically explained to occur, and indeed this study shows that several of the reservoirs may have a MWS type of wettability.

Dixit et al[26] have used network modelling to analyse expected wettability measurements that should be observed for different classes of intermediate wettability. They have found that the relation between two conventional wettability measurements, USBM[27] and Amott-Harvey[24] wettability indices, can distinguish between the different classes of intermediate wet cores.

For $I_{AH} = 0$, and $I_{USBM} = 0$ indicates FW
For $I_{AH} = 0$, and $I_{USBM} > 0$ indicates MWL
For $I_{AH} = 0$, and $I_{USBM} < 0$ indicates MWS

If the larger pores are more oil-wet (MWL), the USBM index indicates more water wet conditions than does the I_{AH}. Snap-off in the water-wet pores also shifts USBM calculations to more water-wet values without affecting the Amott-Harvey results. Fractional wet core should have equal I_{USBM} and I_{AH}. For MWS cores snap-off is suppressed and smaller pores are the more oil-wet, $I_{USBM} < I_{AH}$

In our data set 13 different reservoirs had enough USBM and Amott-Harvey wettability data to check this dependency. Of the 13 reservoirs, five could be grouped as MWL, four as FW, and four as MWS. There is no correlation of the different intermediate wet classes to depositional environment. The rock types that are showing a fractional-wet behaviour are characterised by a more robust wettability. Cleaned cores maintain a non-water-wet state, indicating that the wetting sites may be coupled to mineralogy in addition to adsorption/deposition of oil components changing the surface properties of the rock. Also MWS maintains wettability after cleaning, while the mixed wet (MWL) cores become water wet after solvent cleaning.

Figure 9 shows all data available with both USBM and Amott-Harvey indices. The trend-line goes through the origin of the co-ordinates, thus, indicating fraction wet behaviour. Plotting individual reservoirs the mentioned split in FW, MWL and MWS should be detected. The wettability data for each of these groups are shown in Figure 10. The average waterflood remaining oil saturation is lowest for MWL cores (0.165), followed by fraction wet with average Sorw of 0.178, and MWS with 0.217.

The remaining oil saturation for the MWL rocks show a reduced Sorw with increasing permeability, but the FW and MWS reservoirs indicate a constant Sorw independent of permeability.

Similar grouping may be seen for remaining oil saturation as a function of initial water saturation. The MWL rocks show an increase in Sorw with increase in Swi, while both

FW and MWS rocks show little variations of Sorw with Swi and a weak trend of reduced Sorw at higher Swi.

Further studies of this large SCAL data-summary should also include shape of relative permeability curves and capillary pressure relations for different classes of intermediate wettability.

CONCLUSIONS

The recovery efficiency by gas injection increases with initial water saturation at low water saturation, but an opposite trend is seen at high water saturation.

Gas trapping is lower in three-phase flow than two-phase flow.

Even in this large set of data from 30 different reservoirs a trend of lower remaining oil saturation is seen for intermediate wet cores.

The end-point water relative permeability is highest for intermediate wet cores, but the effect of variation in remaining oil saturation influence this trend. A better measure for the variation in end-point properties is the product of end-point relative permeability and the corresponding phase saturation.

Three different type of intermediate wetting state is observed from USBM and Amott-Harvey wettability indices.

Experimental wettability indices indicate that both fractional wet and mixed wet with either the large or the small pores being oil wet may exist in North Sea sandstone reservoirs.

The properties of the cores, identified as having oil wet large pores, are different from the fractional wet or mixed wet cores where the oil wet sites are located in the smaller pores.

ACKNOWLEDGEMENTS

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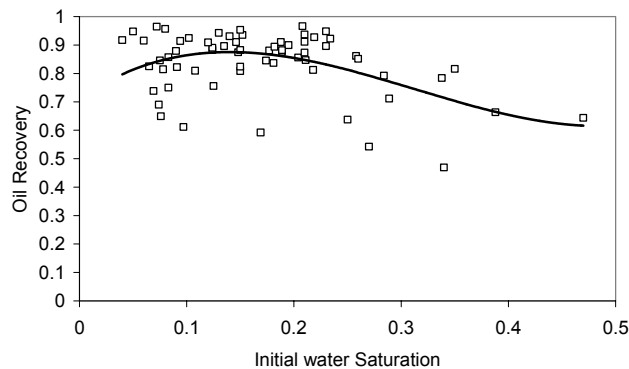
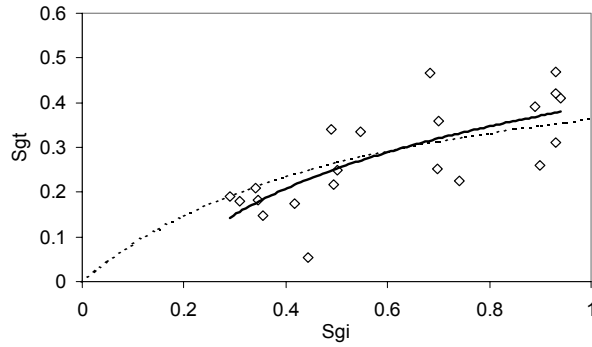Figure 1. Oil recovery by gas injection as a function of initial water saturation.

Figure 2. Two-phase gas trapping as a function of initial gas saturation. Solid line best logarithmic fit, dashed line Land correlation with a Land constant of 1.75.
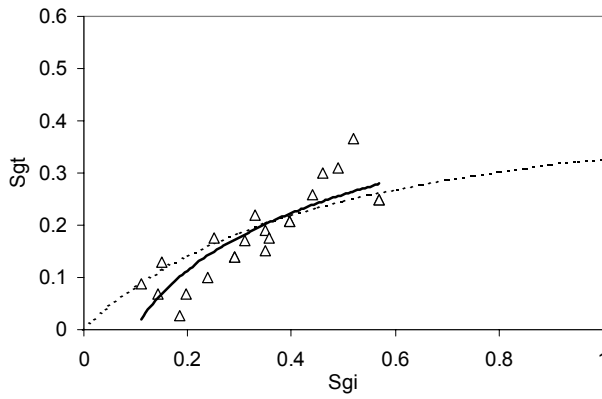

Figure 3. Three-phase gas trapping as a function of initial gas saturation. Solid line best logarithmic fit, dashed line Land correlation with a Land constant of 2.05.
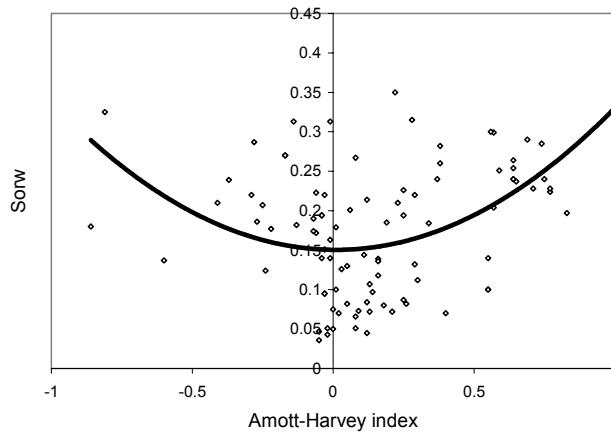

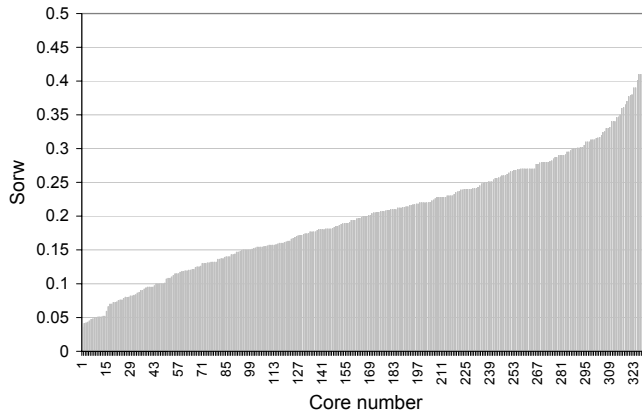Figure 4. Variation in waterflood remaining oil saturation over 350 core floods from 30 different oil reservoirs.

Figure 5. Waterflood remaining oil saturation as a function of wettability. Trend in data from 30 different reservoirs.
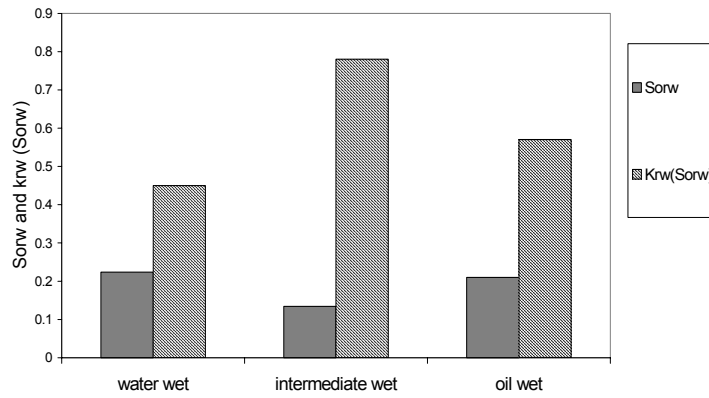
Figure 6. Waterflood remaining oil saturation and end-point water relative permeability for different groups of rock wettability.
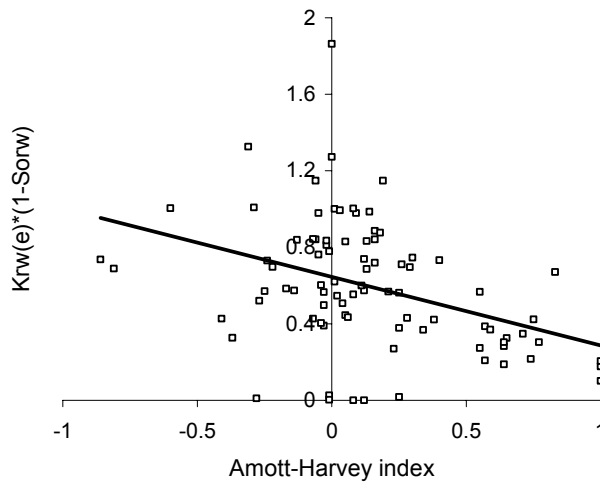

Figure 7. Waterflood end-point water relative permeability scaled by end-point saturation versus wettability.
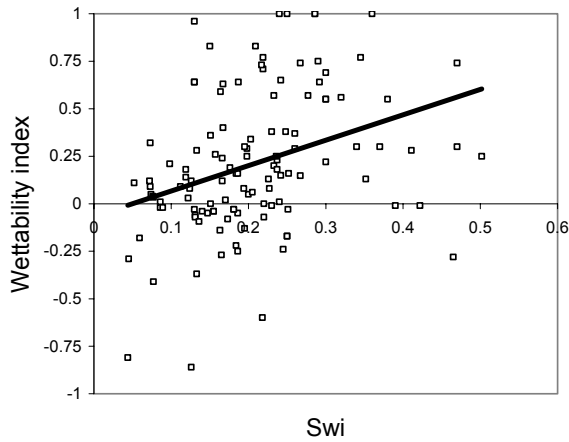
Figure 8. Wettability index as a function of initial water saturation
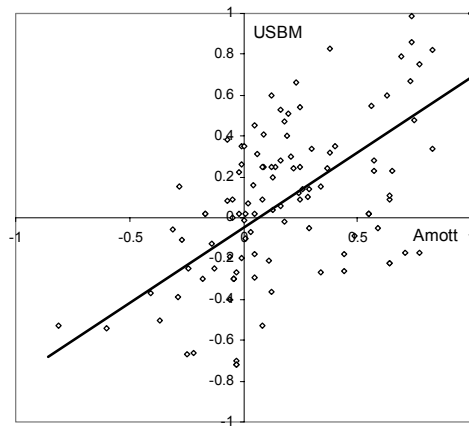

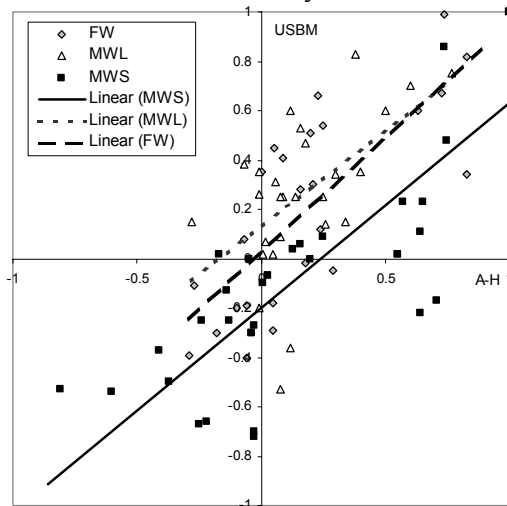Figure 9. Relation between Amott-Harvey and USBM wettability indices. (all cores)

Figure 10. Analysis of 13 fields with different intermediate wet behaviour. The wettability data are grouped in three sub-groups based on relation between USBM and Amott-Harvey indices.