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A Correlation of the Low and High Temperature Water-Oil Relative Permeability Characteristics of Typical Western Canadian Unconsolidated Bitumen Producing Formations

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Abstract

Large reserves of heavy bitumen (<10 deg API) exist in shallow, unconsolidated sandstone formations in central and western Alberta. The McMurray, Grand Rapids, Clearwater and Wabiskaw Cretaceous Manville sands comprise the majority of the heavy oil producing zones of this type. Cyclic steam injection, steam drive and steam assisted gravity drainage (SAGD) are used extensively in this area to produce heavy bitumen at depths where surface mining is impractical. The water-oil relative permeability characteristics of these formations strongly control the ability to inject hot water and/or steam, and the overall conformance and recovery of bitumen from the formations. This paper reviews an extensive database of reservoir condition water oil relative permeability data conducted at temperatures from 10 to 275 °C and presents correlations to estimate water-oil relative permeability character and residual oil saturations for preliminary evaluation purposes to aid in the high level screening of potential future projects in these formations.

Introduction

The worlds largest remaining known reserves of liquid hydrocarbons are contained in the shallow, unconsolidated Cretaceous period Manville sands in central and eastern Alberta. Some of these deposits exist at shallow depths that allow the recovery of the sand using direct surface mining and the subsequent extraction of the bitumen from the mined sand. However, large portions of the bitumen are buried at depths too great for economic mining operations. To extract the heavy bitumen from these zones, a number of in-situ thermal techniques, such as cyclic steam injection, steam drive and steam assisted gravity drainage (SAGD) have been successfully used. The multiphase flow interference effects associated with steam, steam condensate and bitumen moving concurrently through the pore system is represented by relative permeability curves. As such, these curves play a very large role in determining the speed, efficiency and ultimate economics of a thermal recovery process.

Very little regressed relative permeability data on unconsolidated sands, with the exception of a study by Frizzell(1), have been presented in the literature. A number of authors (2-6) have described and discussed high temperature relative permeability measurements for unconsolidated heavy oil sand systems. However, considerable controversy exists with some authors (7-12) suggesting that temperature does not play a role in the relative permeability of heavy oil systems, while others (13-18) claiming that there are strong temperature effects.

This Study

This study examined a specific subset of low and high temperature waterflood and steamflood tests that were conducted on unconsolidated cores over a 15 year period. A total of 43 different studies were analyzed, all of which were conducted on samples taken from the heavy oil producing regions in central and eastern Alberta and western Saskatchewan in the western Canadian sedimentary basin. All of the samples tested had the following common characteristics;

1. All samples were preserved state core that had been frozen on site immediately after coring to prevent oxidation and core disturbance.
2. Over 90% of the samples tested were sourced from the McMurray sandstone formation, hence the correlations resulting from this work have specific application to McMurray sandstone formation production zones.
3. Actual reservoir bitumen was used in all tests. Bitumen gravity varied from 7.5 to 12 deg API over the 43 sample sets which were evaluated, with reservoir condition viscosity ranging from over 1,000,000 mPa.s to approx. 8000 mPa.s.
4. Displacement rates were kept low in all tests to minimize the potential for alterations in relative permeability due to fines migration effects.
5. Samples were relatively homogenous 'massive' sands (although varying grain size and clay/shale content was present over the sample set).
6. Water-Oil relative permeability was determined using the unsteady state method on 41 of the 43 tests, and steady state method on the remaining two tests.
7. Relative permeability curves for the unsteady state data were regressed using a history matching method(19).

Table 1 provides a composite summary of the average properties of the 43 samples evaluated in the study. Average oil permeability was approx 4600 mD at an initial water saturation value of 17.5%. These values, in the authors' experience, are typical for the McMurray region sand deposits in the producing area under consideration.

A number of differing types of information were extracted from the available dataset and are presented in the following sections, along with correlations where appropriate. It should be noted that in many cases considerable variance in the data sets was observed, although general trends were still able to be derived. The correlations presented in this paper should be used for preliminary evaluation purposes only, and are not meant to replace specific lab measurements for a given reservoir situation.

Initial Low Temperature Permeability to Oil vs. Measured Initial Oil Saturation

Figure 1 provides a plot of the measured values of initial permeability to oil in mD vs. the initial oil saturation present in the matrix. It can be observed that sample permeability varied widely, ranging from approx. 1,000 to over 13,000 mD with initial oil saturations ranging from 77 to 88%. A large portion of this variation in oil permeability is related to grain size variations and clay contents within the various McMurray formation facies that were evaluated. However a slight increasing trend of permeability with increasing initial oil saturation is present, as would be expected from classically theories. The form of the regression equation for initial oil permeability as a function of initial oil saturation is given by;

$$K_o = (18591.76)\ln(S_{oi}) + 8160.43$$

Where:
K_o= Initial oil permeability in mD at S_{wi}
S_{oi} = Initial oil saturation – fraction
(Range of Validity $0.75<S_{oi}<0.95$)

Residual Oil Saturation to Hot Waterflooding vs. Temperature

Viscosity of most heavy oils and bitumens decreases dramatically as temperature is increased (much more rapidly than water) which improves the overall mobility ratio of the hot water displacement process. Figure 2 provides a summary of the measured endpoint residual oil saturations to water flood as a function of temperature for the dataset evaluated. From this, a cubic correlation can be derived. This correlation has one of the better regression coefficients in the study. The residual oil saturation vs. hot waterflood temperature regression equation is given by;

$$S_{or} = -0.00000005(T)^3 + 0.00002612(T)^2 - 0.00516927(T) + 0.66975190$$

Where :
S_{or} – residual oil saturation to waterflood (fraction)
T = Temperature – ^{o}C
(Range of validity, $10<T<280\ ^{o}C$)

From this it can be seen that residual oil saturation decreases with increasing temperature (most of the oils were immobile at average McMurray formation temperatures of 6-9^{o}C and had to be heated to 50 to 80 ^{o}C to reduce bitumen viscosity to the point where water injectivity could be created). The most rapid reductions in residual oil saturation to hot water occur at lower temperatures (<100 ^{o}C) and at high temperature (>200 ^{o}C). The lower temperature region is likely motivated by the very sharp reduction in oil viscosity and improvement in water-oil mobility ratio as temperature increases in this less than 100 ^{o}C region. Over 200 ^{o}C, oil viscosity reductions are relatively minor as temperature increases. The reduction in the residual oil saturation in this temperature range may be more related to changes in the wettability of the matrix towards a stronger water wetting condition which reduces the effective permeability to water and thus improving the water-oil mobility ratio.

Reduction in Residual Oil Saturation by Steamflooding vs. Steamflood Temperature

It is well documented that residual oil saturation tends to reduce at constant temperature by steamflooding in comparison to conventional waterflooding at the same temperature condition. This is believed to be due to turbulence effects associated with the vaporization of pellicular films of water underlying trapped bitumen as well as possible changes in interfacial tension (IFT) and wettability during the steam displacement process. Figure 3 illustrates the trend of pre and post steamflood residual oil saturation as a function of steamflood temperature. Figure 4 plots the changes in S_{or} associated with steamflooding at a given temperature condition from which the following correlation can be derived;

$$\Delta S_{ors} = -0.2454 \mathrm{Ln}(T_s) + 1.3912$$

Where:
ΔS_{ors} = Change in residual oil saturation during steamflooding (fraction of total PV)
T_s = Steamflood temperature (^{o}C)
Range of Validity ($200<T_s<280\ ^{o}C$)

Examination of this data suggests that there is considerable scatter in the available dataset, but that a decreasing incremental reduction in Sor with increasing temperature appears to be apparent. At 200 ^{o}C, delta Sor appears to be in the range of 10%, but drops to around 2-3% at 275 ^{o}C. Certainly, the lower values of the original residual oil saturations before the steamflood commences plays a large part; as previously discussed, the S_{or} value is approx. 12% greater at 200 ^{o}C than at 275 ^{o}C.

Endpoint Permeability to Brine at Residual Oil Saturation to Waterflood vs. Temperature

Figure 5 provides a comparative plot of the endpoint permeability to brine (in mD) as a function of hot waterflood temperature. There is a large degree of variation in this dataset due to the considerable variability in overall sample permeability amongst the 43 different reservoir samples in the study. A general increasing trend of the brine permeability with increasing temperature is noted, with the largest increases in brine permeability being observed at the lower (<100 ^{o}C) temperature levels. The form of the regression expression for brine permeability as a function of temperature is given by;

$$K_b = 0.1729678(T)^{1.2119608}$$

Where:
K_b = Endpoint Brine Permeability – mD
T = Waterflood Temperature – ^{o}C
(Range of validity, $50<T<280\ ^{o}C$)

The results suggest that at high temperature, wettability changes towards a more water wet condition may suppress the effective brine permeability. Since it is known from the preceding discussion that residual oil saturation decreases above 200 ^{o}C, one would expect a corresponding increase in water permeability. Although an increase is observed in the trend line, it is relatively minor and this suggests that the high temperature wettability or pore damage effects in this temperature range may be suppressing the effective water phase permeability.

Endpoint Relative Permeability to Brine at Residual Oil Saturation to Waterflood vs. Temperature

Figure 6 provides a plot of endpoint relative permeability to brine vs. temperature. Since relative permeability is referenced to the absolute permeability, this should remove some of the variance observed in the previous sample set, and this appears to be the case with a much tighter data cluster and better regression coefficient for the composite trend line which is given by;

$K_{rw} = 0.0005567(T)^{0.8267637}$

Where:
K_{rw} = Endpoint relative permeability to water (fraction)
T = Waterflood temperature (^{o}C)
(Range of Validity 10<T<280 ^{o}C)

Once again, it can be observed that water phase relative permeability increases with temperature, with the most pronounced increases being observed at the lower temperature levels. The comments of the preceding section regarding high temperature damage and wettability effects suppressing the high temperature water relative permeability should also be noted here as well.

Percentage Change in Brine Permeability Pre vs. Post Steamflood vs. Temperature

On a limited subset of the available data, pre and post steamflood water permeability was obtained in a single phase (100% water flow) region. This data is plotted as Figure 7, and although considerably scatter is apparent, it can be seen that the best fit to the available data is given by the equation;

$\Delta K_B = -20.258755 Ln(K_{ps}) + 127.426317$

Where:
ΔK_B = Percentage increase/reduction in brine Permeability (in mD) due to steamflooding
K_{ps} = Pre steamflood brine permeability (mD)
(Range of Validity $100<K_{ps}<5000$ mD)

This data indicates that the higher the effective-water-permeability prior to the steamflood, the greater the potential for damage, and subsequent reduction in the post-steam exposure permeability. The reason for this trend is not immediately apparent. The authors speculate that it may be related to higher degrees of mobility of clays and/or fines that can be dislodged and transported to pore-throat blocking locations that are associated with higher permeability, less consolidated samples.

Initial Water Saturation vs. Temperature

On a limited subset of samples, high temperature oilfloods were conducted after waterflooding the samples at lower temperatures. From these tests it was possible to measure the irreducible water saturation to oil as a function of temperature. This data is of particular importance when examining hysteresis effects in cyclic steam projects where oil is flooding back into previously highly water saturation zones surrounding the wellbore. This data is plotted as Figure 8 and resulted in a relatively good linear correlation of initial water saturation vs. oilflood temperature as given by;

$S_{wi} = 0.000830(T) + 0.135533$

Where:
S_{wi} = Initial water saturation under dynamic oilflood
T = Oilflood temperature (^{o}C)
(Range of Validity 10<T<280 ^{o}C)

This data indicates significant increases in 'trapped' water saturation as temperature increases. This phenomena has been documented by other authors, and is believed to be related to a combination of poorer mobility effects (viscosity ratio of oil displacing water is much reduced as temperature increases) and the water relative permeability is reduced as the rock matrix becomes more water wet at higher temperatures due to temperature induced desorption issues.

Low Temperature Water-Oil Relative Permeability Curves (60<T<100 ^{o}C)

Figure 9 provides a plot of all of the lower temperature (less than 100 ^{o}C) water oil relative permeability curves that were evaluated during the study. Considerable variance is present in the data (particularly on the water side). Using simple exponential fit regression formulations, the following 'average' low temperature water-oil relative permeability curves can be derived as a composite of the available data. Due to the wide variance in the rel perm curve character, it can be seen that this correlations do not replace the need for actual lab measurements, but do provide preliminary estimates of the range of relative permeability character that would be expected at lower temperatures in a typical McMurray sandstone producing formation.

$$S_N = {(0.60 - S_w)}\big/{(0.45)}$$

$$K_{rw} = 0.021(1 - S_N)^5$$
$$K_{ro} = (S_N)^{2.2}$$

Where:
S_n = normalized water saturation function
S_w = actual water saturation at which relative permeability evaluation is required (fraction)
K_{rw}= Relative permeability to water (fraction)
K_{ro}= Relative Permeability to oil (fraction)
Range of Validity – Temperatures between 60 to 100 ^{o}C, water saturation range between 15 to 60%.

High Temperature Water-Oil Relative Permeability Curves (150<T<275 ºC)

Figure 10 provides a plot of all of the higher temperature (greater than 150^{o}C) water oil relative permeability curves that were evaluated during the study. Considerable variance is present in the data, and is much more pronounced on the water side than noted in the previous low temperature data, suggesting that individual rock character and lithology plays a very strong role at high temperature in determining water phase relative permeability character. Using simple exponential fit regression formulations, the following 'average' low temperature water-oil relative permeability curves can be derived as a composite of the available data. Once again the authors emphasize that due to the wide variance in the rel perm curve character it can be seen that this correlations do not replace the need for actual lab measurements.

$$S_N = {(0.85 - S_w)}\big/{(0.70)}$$

$$K_{rw} = 0.055(1 - S_N)^{2.5}$$

$$K_{ro} = (S_N)^3$$

Where:

S_n = normalized water saturation function
S_w = actual water saturation at which relative permeability evaluation is required (fraction)
K_{rw}= Relative permeability to water (fraction)
K_{ro}= Relative Permeability to oil (fraction)
Range of Validity – Temperatures between 150 to 275 °C, water saturation range between 15 to 85%.

It can be observed that as temperature increases the water phase relative permeability curves appear to become less concave (less affected by multiphase flow interference effects) while the oil phase curves become slight more concave.

Conclusions

A statistical analysis was conducted of 43 core displacement tests in preserved state cores taken from predominantly McMurray unconsolidated sandstones in Western Canada saturated with 7.5 to 12 deg API oil. The study determined that;

1. Average initial water saturation in the reservoir zones was approx 17.5% (Soi = 82.5%)
2. Average permeability to oil at the initial water saturation at the mobilization temperature of the in-situ bitumen (50-80 °C) was 4567 mD.
3. Regression equations were developed based on the available data that indicated that;
    a. Residual oil saturation decreased in a non linear fashion as temperature increased.
    b. Incremental oil saturation reductions at a given temperature due to steamflooding were observed, and the value of the incremental reduction in residual oil saturation appeared to be directly related to the steamflood temperature and initial pre steamflood Sor, with greater reductions in Sor being observed at lower steamflood temperatures.
    c. Permeability to brine increased in a non linear fashion with waterflood temperature, with the most rapid increases being observed at temperatures of less than 100 °C.
    d. Relative permeability to brine increased in a non linear fashion with waterflood temperature, with the most rapid increases being observed at temperature of less than 100 °C.
    e. Higher quality rock was found to be more susceptible to permeability reductions due to steamflooding.
    f. Initial water saturation was found to be a strong increasing function of temperature.
4. 'Average' relative permeability curve correlations for water and oil phase relative permeability were generated for both low (<100 °C) and high (>150 °C) temperatures for the sample dataset.
5. Considerable variation was observed in the sample dataset due to wide variations in reservoir quality and lithology over the suite of samples evaluated. These correlations should be used for preliminary evaluation purposes only and are not intended to replace actual laboratory data measurements on specific reservoir samples for a given project application.

Acknowledgement

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Table 1 - Summary of Average Properties of the 43 Datasets Used in the Regression Analysis

Average Initial Oil Saturation (fraction)	0.825
Average Initial Water Saturation (fraction)	0.175
Average Initial Permeability to Oil at Swi – mD	4567

Figure 1 - Measured Initial Oil Permeability vs. Measured Original Oil Saturation in Sample

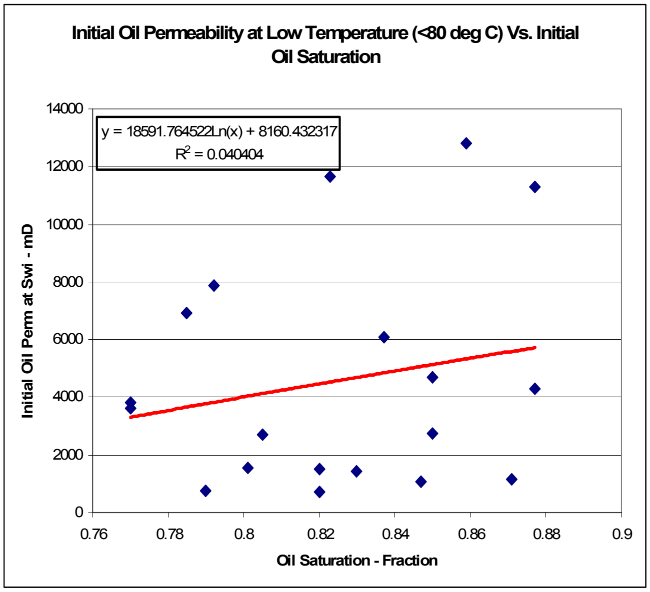

Figure 2 - Residual Oil Saturation to Waterflood vs. Temperature

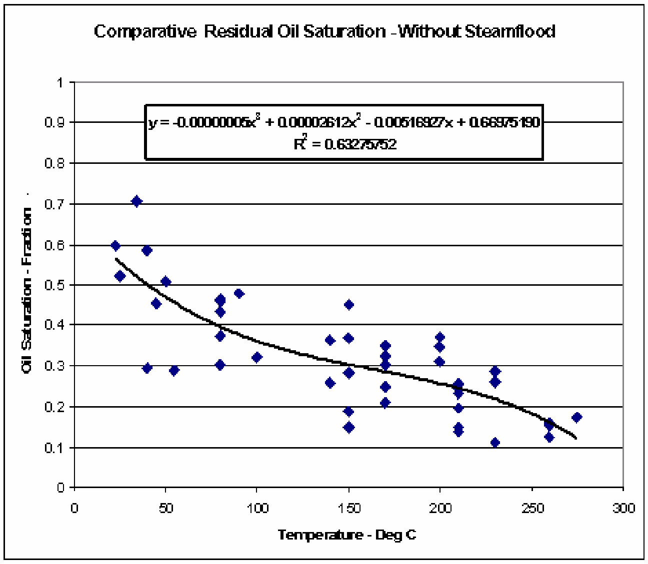

Figure 3 - Pre and Post Steamflood Residual Oil Saturation vs. Steamflood Temperature

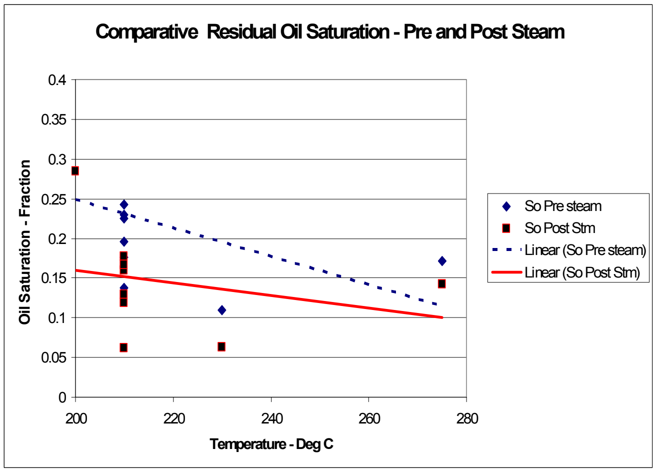

Figure 4 - Reduction in Residual Oil Saturation by Steamflood

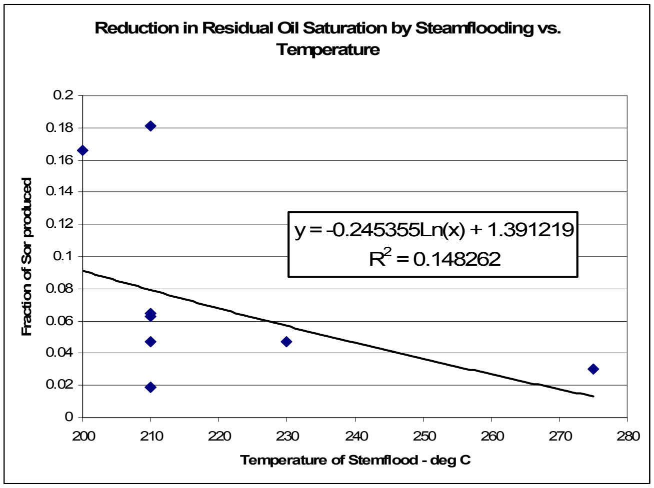

Figure 5 - Endpoint Permeability to Brine vs. Temperature

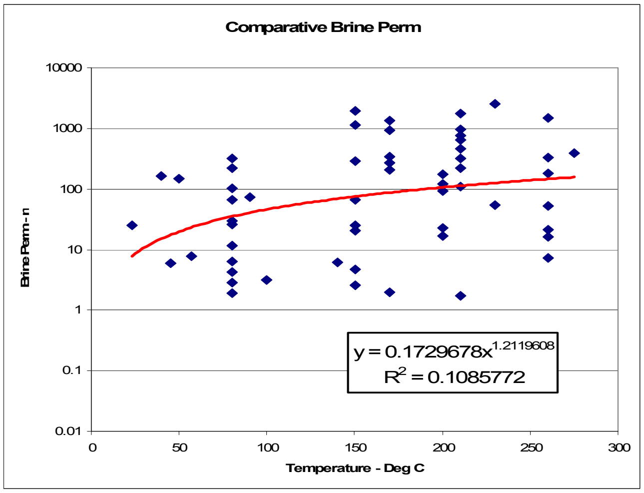

Figure 6 - Endpoint Relative Permeability to Brine vs. Temperature

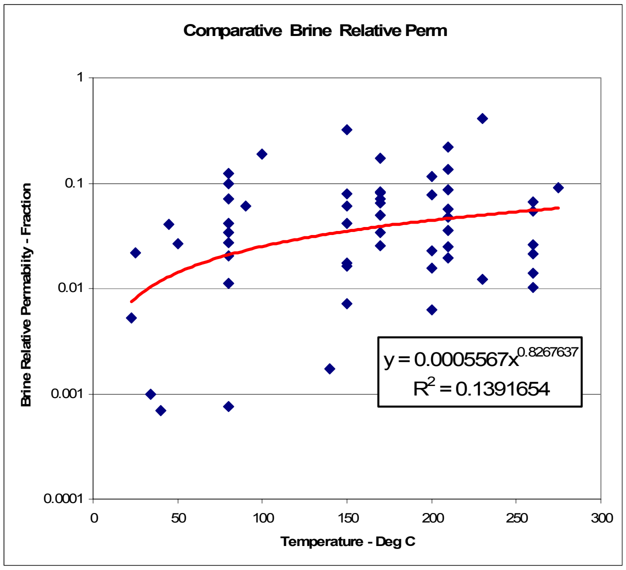

Figure 7 - Percent Change in Brine Perm During the Steamflood Process vs. Temperature

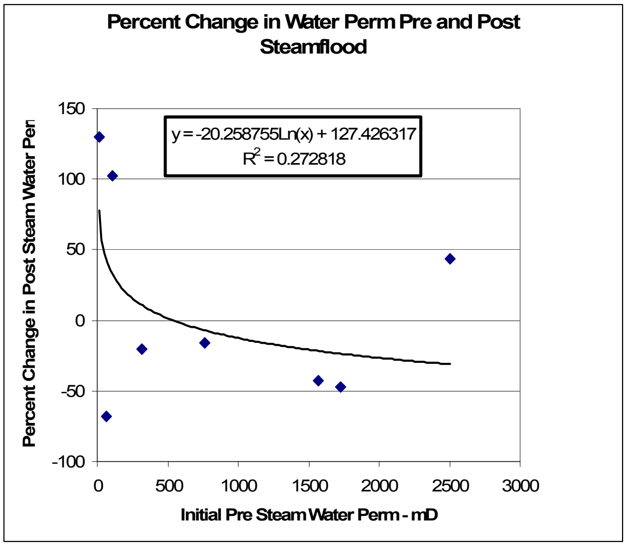

Figure 8 - Initial Water Saturation Generated by Oil Displacement vs. Temperature

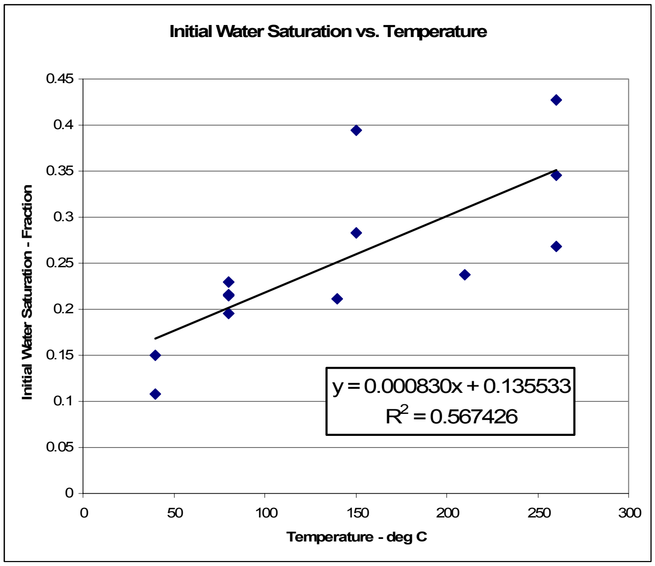

Figure 9 - Summary of Low Temperature Water-Heavy Oil Relative Permeability Data (<100°C)

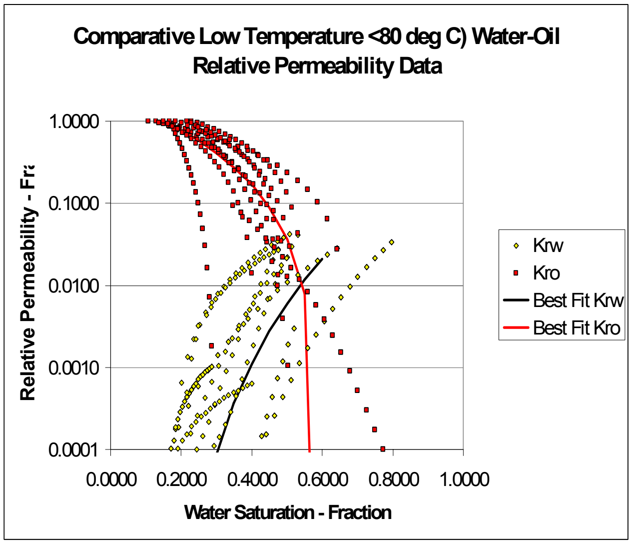

Figure 10 - Summary of High Temperature Water-Oil Relative Permeability Data >150°C