The Impact of Injection Water Temperature on Recovery from Viscous Oil Reservoirs

**Woods C.I., Goodyear S. G., Jones P. I. R.,
Reynolds C. J., Townsley P. H.**

AEA Technology, Winfrith, U. K.

Copyright 1995, Steering Committee of the European IOR - Symposium.

This paper was presented at the 8th. European IOR - Symposium in Vienna, Austria, May 15 - 17, 1995

This paper was selected for presentation by the Steering Committee, following review of information contained in an abstract submitted by the author(s). The paper, as presented has not been reviewed by the Steering Committee.

ABSTRACT

A number of North Sea reservoirs contain viscous oils in high permeability sandstones. One possible IOR technique is the injection of hot water. Even if specific hot water injection facilities are not provided on the platform, hot water (in contrast to cold sea water) may be available as a by-product of the separators or because the injected water is sourced from an aquifer.

Hot water injection can improve recovery by reducing the oil viscosity and by thermal expansion of the oil. Some authors suggest that it could also lower the absolute value of the residual oil saturation defined by the relative permeabilities. An analytical model is used to explore the influence on oil recovery of different assumptions about the temperature dependence of the relative permeabilities. A literature review of published data is reported. This shows that in many cases the apparent reduction in S_{orw} can be attributed to experimental artefacts arising from inappropriate core conditioning procedures compared to the reservoir flooding sequence. Improved laboratory procedures are proposed.

Simulation studies using models representative of a range of North Sea viscous oil fields are reported. The effect of injecting hot water compared to cold sea water is studied. It is shown that the results of hot water injection are strongly dependent on the reservoir parameters. Cases in which hot water injection can worsen recovery compared to cold water injection are highlighted. This shows the need to use full

temperature modelling when devising optimal reservoir management strategies in North Sea viscous oil fields.

INTRODUCTION

The development of off-shore viscous oil fields in the North Sea represents a new challenge to the industry. These fields comprise relatively clean sands, with high horizontal and vertical permeabilities of several Darcies. The oil viscosities are in the range 5-1000 cp and oil columns are typically less than 300 ft thick, often partially underlain by an aquifer. Water flooding is dominated by gravity in the inter-well region, with water slumping to the bottom of the reservoir around the injectors and coning up to the producers. Development is dependent on the use of horizontal wells to reduce the effects of coning.

A number of these fields are currently at the appraisal or development stage. The viscous nature of the oil makes the reservoirs potential candidates for the application of further IOR techniques, in particular polymer flooding or hot water flooding. Even if specific hot water injection facilities are not provided on the platform, hot water (in contrast to cold sea water) may be available as a by-product of the separators or because the injected water is sourced from an aquifer.

This paper assesses the impact of injection water temperature on recovery from viscous oil reservoirs representative of fields in the North Sea. Increasing the water injection temperature can improve recovery by reducing the oil viscosity and by thermal expansion of

the oil. Some authors suggest that it could also lower the absolute value of the residual oil saturation defined by the relative permeabilities. In the first section, an analytical model for hot water flooding in one dimension is used to investigate under what circumstances reductions in the residual oil saturation due to the increased flooding temperature give increases in the oil recovery. The second section presents a literature review of relative permeability data. Published measurements are assessed critically, to determine whether there is evidence for any temperature dependence of the relative permeabilities that would affect recovery in practice.

The third section considers the influence of water injection temperature over a range of oil viscosities representative of viscous oil reservoirs currently being assessed or developed in the North Sea. The reservoirs are divided into three broad categories, based on their temperature and oil viscosity. Earlier studies are reviewed and new simulations are presented, to judge whether increased water injection temperatures are likely to improve oil recovery in each category.

ANALYTICAL HOT WATER FLOODING MODEL

This section describes an analytical solution in one dimension for hot water flooding. This allows preliminary investigation of the relative importance of changes in viscosity, compared to any changes in the relative permeabilities. For the purposes of the model the fluids are considered to be incompressible and not to change volume on heating. The flow behaviour is modelled in three distinct regions separated by saturation shocks. The regions are: unswept oil, a cold water region and a hot water region.

Figure 1: Schematic Diagram of Solution Types for One Dimensional Hot Water Flooding

The unswept region is considered to be at the lower temperature and an oil saturation of $1-S_{wcl}$. The cold water region can exist in one of two forms, either a conventional Buckley Leverett solution for cold water flooding immediately upstream of the leading shock followed by a constant saturation region (Type I), or a

constant saturation region directly upstream of the leading shock (Type II). Figure 1 shows the possible form of the saturation profiles.

Fluid viscosities and water fractional flow curves are defined at the original reservoir temperature and the injected temperature. It is further assumed that there is instant temperature equilibrium at each position along the system but no heat conduction along the system and that water injection is at the down dip end of the system.

Trailing Shock

At the trailing shock there are three unknown variables, the water saturation upstream of the shock (S_{w3}), the water saturation downstream of the shock (S_{w2}) and the shock velocity (V_2). Correspondingly there are three equations describing the shock: conservation of energy, conservation of mass and characteristic velocity matching upstream of the shock.

Combining and rearranging the equations for the conservation of energy and mass, to eliminate S_{w2} , gives the following expression for the shock velocity as a function of S_{w3} alone:

$$V_2 = \frac{Q}{A\phi} \frac{f_{wH}(S_{w3})(\rho_w C_w - \rho_o C_o) + \rho_o C_o}{S_{w3}(\rho_w C_w - \rho_o C_o) + \rho_o C_o + (1-\phi)(\rho_R C_R / \phi)} \quad (1)$$

The characteristic velocity matching condition behind the shock,

$$V_2 = \frac{Q}{A\phi} \left. \frac{\partial f_{wH}}{\partial S_w} \right|_{S_w=S_{w3}} \quad (2)$$

can now be used in combination with Equation 1 to calculate the saturation upstream of the shock (S_{w3}). The shock velocity can then be calculated by substitution into Equation 2 and the saturation downstream of the shock (S_{w2}) found implicitly from the equation for conservation of mass.

It is interesting to note that the explicit temperature terms have been eliminated from the calculations, the only properties of importance being the fluid viscosities and the water fractional flow curve at the two temperatures

Leading Shock

In order to determine which form the saturation shock takes, (Type I or II), the standard cold waterflood shock is calculated first, given by the solution of the shock condition,

$$V\phi = \frac{Q}{A} \frac{f_{wL}(S_{w1})}{S_{w1} - S_{wcl}} \quad (3)$$

matched with the characteristic velocity behind the shock, given by Equation 2 with $S_w = S_{w1}$. The saturation upstream of this shock (S_{w1}) is then compared with the saturation downstream of the trailing shock (S_{w2}). If S_{w1} is less than S_{w2} then the shock just calculated is valid for the hotwater case (Type I). Otherwise the saturation between the two shocks is constant and S_{w1} is set equal to S_{w2} (Type II) and the velocity of the leading shock is calculated using Equation 3.

Example Calculations

The cumulative oil production is calculated by applying standard fractional flow theory methods to each section of the flood in turn. The examples presented in this section are based upon the properties of typical viscous oil reservoirs in the North Sea (Table 1). The calculations consist of two base cases and two sets of sensitivities.

The first base case represents a viscous dominated flood, and is thus independent of gravity effects. The base case waterflood at the original reservoir temperature only recovers 39.5% of STOIP after 2.5 pore volumes injection. The base hot water flood is an improvement giving an incremental recovery of 13.6% of STOIP after 2.5 pore volumes. However, the total recovery is still low.

Table 1: Parameters Used in Analytical Hot Water Flooding Calculations

Property	Value
Water/oil density difference (kg/m^3)	72.5
Oil viscosity at low/high temp(cp)	190/19
Water viscosity at low/high temp(cp)	0.80/0.43
Porosity	0.35
Permeability (Darcy)	2.0
Residual oil saturation	25%
Connate water saturation	15%

The first set of sensitivities varies the residual oil saturation to hot water from the original value of 25% to 15%, keeping the end point relative permeability and all other parameters the same. This 10% range in the residual saturation gives a corresponding 7.5% range in the cumulative incremental oil at 2.5 pore volumes injection, as illustrated in Figure 2.

The change in flow behaviour due to the modification of the residual oil saturation allows higher water saturations to occur in the system. In the original set of sensitivities the water relative permeability at residual oil remained at 0.3. In reality, the lower oil saturations are likely to increase the water relative permeability. The second set of sensitivities modifies the hot water endpoint relative linearly as a function of the residual oil to hot water, assuming that the endpoint would be equal to 1 in the limiting case of $S_{orU} = 0$. This

significantly reduces the incremental oil produced for the lower values of S_{orU} . In these cases, the advantage observed by altering the residual oil saturation is almost eliminated by the modification of the endpoint relative permeability, as illustrated in Figure 2.

Figure 2: Hot Water Flooding Incremental Recovery as a Function of Residual Oil Saturation

The second base case is the vertical equivalent of the first, introducing the effect of gravity into the system. In this case the waterflood cumulative production at 2.5 pore volumes is 51.2%. Hot water flooding gives an incremental recovery of 16.8%. This case is significantly more efficient than the horizontal case, and even has a slightly improved incremental production. The same sets of sensitivity cases were performed as for the viscous dominated model. Both sets of sensitivity cases present almost identical results (Figure 2) giving just over 10% of STOIP additional incremental recovery for a reduction in residual oil saturation from 25% to 15% for hot water, because little mobile oil is left behind the temperature front in all the hot water cases.

These illustrative examples show the importance of gravity forces in one dimensional displacements. If relative permeabilities have a temperature dependence, an increasing water end point relative permeability can remove any benefit that might have been expected from a lowered residual oil saturation in viscous dominated displacements. It should be noted that these results cannot be applied directly to field cases, because the displacement mechanisms operating in 2 and 3 dimensions are much more complicated than those in 1 dimension.

LITERATURE REVIEW OF HOT WATER RELATIVE PERMEABILITY DATA

Relative permeabilities for oil and water are commonly determined by one of three different methods [3] - steady state, Johnson-Bossler-Naumann (JBN) or history matching. In principle, the steady state method is the most reliable. However, it assumes that the phase saturation is constant along the length of the core,

which may take a considerable time to attain, therefore such experiments are time consuming to perform.

The JBN method [4], which is applicable to immiscible displacements, assumes that the phase saturations are uniform across the core. This assumption is frequently violated in core floods with viscous oils due to viscous fingering. A comparison of the two methods for a single experiment [5] shows that the JBN method predicts relative permeability curves shifted to higher water saturations.

A review of the available reports has shown relative permeabilities measured in the laboratory may be affected by temperature as a result of underlying physico-chemical factors (relevant to the reservoir), including changes to the wettability, mineral dissolution and clay activation [6-11]. However, the review highlighted that many experiments might have been more strongly influenced by experimental artefacts (not relevant to the reservoir). These are discussed in the following section. In general, reported experiments with the most detailed descriptions and least possible number of experimental artefacts conclude that relative permeabilities are independent of temperature.

Laboratory Artefacts Affecting Relative Permeabilities

Viscosity Ratio

Standard fractional flow theory shows that the throughput required to attain a given saturation increases with the displacement mobility ratio. Reference [12] shows how the mobility ratio changes with water saturation for a typical oil-water system at three temperatures, and demonstrates that at higher temperatures significantly less throughput is required. Reference [13] provides a rule of thumb, suggesting that the throughput in terms of pore volumes should be at least the oil-water viscosity ratio to attain the true residual oil saturation.

The viscosity ratio also has an important influence on viscous fingering. The Peters and Flock criterion for onset of viscous instability in cylindrical core floods [14] shows instability increases with flow rate and oil-water viscosity ratio for adverse mobility ratios. Usually, an adverse viscosity ratio will fall as temperature rises, so that viscous fingering becomes less prevalent, and less oil is bypassed. This may lead to an apparent fall in residual oil saturation with temperature increase.

Capillary Pressure End Effect

At the core outlet, there may be additional oil held up by capillary pressure. Rapoport and Leas [15] showed that capillary pressure end effects could be ignored at

high flow rates, in long cores or with a viscous displacing phase, when viscous forces start to overcome the capillary forces reducing the quantity of oil held up. In experiments with viscous oils there is usually a choice between viscous fingering, present at higher flow rates, or a significant capillary end effect.

Initial Saturation

In some hot water flooding relative permeability measurements the cores are initially conditioned at a low temperature, whereas in others the cores are conditioned at the temperature of the hot water flood. This difference in conditioning procedure may affect the initial oil saturation, which may in turn influence the effective residual oil saturation. Data from steady state relative permeability measurements reported in the literature [12,16,17] are illustrated in Figure 3. The end point saturations have been normalised with respect to their values at the minimum test temperature in each experiment. As temperature increases, the initial water saturation increases and the residual oil saturation decreases, suggesting that there is a correlation between the core conditioning procedure and effective residual oil saturation.

Figure 3: Steady State Hot Water Floods - Normalised Initial Water and Residual Oil Saturations

The same procedure was followed for the unsteady state experiments reported in the literature [18-21] and Figure 4 shows the normalised data from these studies. The data derived from cores conditioned at a constant temperature [21] show no correlation, but the data derived from cores conditioned at the hot water flooding temperature [18-20] show the same trend as the steady state results. This shows that core conditioning at the hot water flooding temperature appears to lead to a negative correlation between residual oil saturation and initial water saturation.

Increasing initial water saturations with temperature could arise because the smaller contrast between the oil and water viscosities would require a significantly larger throughput of oil to obtain a given water saturation. If cores are conditioned using a broadly similar oil throughput irrespective of the temperature,

the initial water saturation would appear to decrease with temperature.

Figure 4: Unsteady State Hot Water Floods - Normalised Initial Water and Residual Oil Saturations

Recommended Laboratory Procedures

In view of the scope for possible experimental artefacts, it is important that laboratory studies are performed in a way that is representative of how hot water flooding would progress in the reservoir. The analytical model shows that the temperature front moves through the reservoir much more slowly than the cold water front. Thus, the reservoir will have experienced a degree of cold water flooding at the original reservoir temperature before the temperature front arrives. In view of this, it is recommended that cores are conditioned at the initial reservoir temperature and to the same initial water saturation, prior to any hot water flooding. Hot water relative permeabilities should then be measured by raising the core temperature (with no fluid injection) to the target injection temperature prior to hot water flooding. As a variation on this procedure, a period of cold water injection might be included before raising the temperature to represent the sequence of saturation and temperature changes experienced in the field.

These procedures were followed in a study recently reported by Lach [1]. Unsteady-state water floods were performed in cores at 87, 150 and 200°F, with the cores being conditioned at the same temperature prior to raising the temperature. Within experimental scatter, the value of S_{wi} was independent of temperature, Table 2.

Table 2: S_{or} for Different Temperatures [1]

Temperature (°F)	S_{wi}	Effective S_{or}
87	0.20	0.35
150	0.19	0.29
150	0.23	0.27
200	0.19	0.28
200	0.22	0.27

Hot water flooding gave some reduction in the effective residual oil saturation at a given throughput (Table 2). However, this could be explained simply as a result of changes in viscosity ratio. A good match to the core flooding production profiles at 87 and 150°F could be obtained with the same set of relative permeability curves, using the residual oil saturation of 25%.

It is clear that core conditioning can have an important effect on the result of an experiment and, to simulate a field project more closely, core floods should be conducted on cores conditioned to the relevant initial water saturation at field temperature.

INFLUENCE OF INJECTION TEMPERATURE ON PRODUCTION FROM NORTH SEA VISCOUS OIL RESERVOIRS

The North Sea reservoirs currently being assessed or developed have been divided into three broad categories and each is considered separately in this section. Clearly it would be unrealistic to attempt to provide a comprehensive set of guidelines from which the impact of injection temperature could be calculated for any North Sea field. The aim of this section is, therefore, to present illustrative examples that highlight the issues associated with injection temperature in each reservoir category. There is still a need for detailed studies on specific reservoir applications, addressing issues such as:

- the effect of heterogeneity, since hot water injection could exacerbate any tendency for fingering or channelling
- the impact of temperature on thermal fracturing.

Moderate Temperature Fields with Oil. Viscosities Around 10 cp

A number of North Sea fields in this category have recently commenced production. A study of polymer and hot water flooding in a generic model with properties representative of this class of reservoirs was published recently [22].

A three-dimensional, rectangular reservoir model was employed, comprising half an injector-producer pair in a line-drive pattern, with a spacing of 3300 ft. The oil column height was 200 ft and the STOIP for a complete unit of the pattern was 56.6 MMSTB. Aquifer thicknesses of 0, 50 and 100 ft were studied. The producer was rate constrained at 30000 bbl/D for a complete pattern element, and the injector provided voidage replacement. The reservoir temperature was 170°F and the oil viscosity was 10 cp at reservoir conditions. The horizontal permeability was 3 Darcies and the k_v/k_h ratio was 0.9.

The injection of cold water at 70°F and hot water at the reservoir temperature of 170°F was compared. In both cases the flood was dominated by gravity in the inter-well region, with water slumping to the bottom of the reservoir and coning up to the producers. The recoveries at 15 years are given in Table 3 below, taken from [22]

Table 3: Cold and Hot Water Flooding Recoveries in Reservoir Containing 10 cp Oil

Aquifer thickness (ft)	Cold Water Recovery (% STOIP)	Hot Water Recovery (% STOIP)
0	61.4	60.5
50	47.3	39.5
100	33.0	27.8

The recoveries are similar in the absence of underlying water, but hot water flooding is 16% less efficient when an aquifer is present. The oil production profiles for the cases with a 50 ft aquifer are illustrated in Figure 5, taken from [22].

Figure 5: Effect of Injection Temperature on Oil Production Rates for 50 ft Aquifer

The difference in production is caused by the impact of temperature in the water leg. The injected water slumps around the injector and channels along the base of the sand. Thus, the temperature front advances rapidly through the aquifer, compared to the oil column and the base of the reservoir is cooler than the upper layers in the inter-well region. If the injected water is cool, it is more viscous than the formation water. This decreases the mobility of the fluids in the aquifer,

reducing channeling along this path. Thus hot water flooding is detrimental in this class of reservoirs.

Low Temperature Fields With Oil Viscosities Around 100 cp

The efficiencies of cold water, hot water and polymer flooding were compared for the Captain field in the paper by Lach [1]. This field has a STOIP of approximately 1500 MMSTB, with an oil viscosity of 88 cp at reservoir conditions. The reservoir dip is approximately 2°, with water underlying 60% of the field. The field is heterogeneous with permeabilities ranging from 5 to 12 Darcies and the k_v/k_h ratio is estimated at 0.45, therefore waterflooding is expected to be gravity dominated. The waterflood mobility ratio is estimated at 26. These adverse conditions necessitate development using long horizontal wells and result in an estimated recovery factor of 25% for cold water flooding.

Preliminary simulations showed that the best recoveries were obtained from regions with no underlying water and the improved recovery methods (polymer and hot water flooding) were compared in these conditions. The model comprised a sector containing one horizontal injector and one horizontal producer. Both wells were 6000 ft in length and completed near the top of the structure. Injection was at voidage replacement and recovery factors were quoted at 90% watercut for all cases. The hot water injection temperature was 150°F, and the oil viscosity at this temperature was 35 cp. The results for some of the cases presented in [1] are reproduced in Table 4 below.

Table 4: Comparison of Cold and Hot Water Flooding Recoveries in Captain

Production rate (bbl/D)	k_v/k_h	Cold water recovery (%STOIP)	Hot water recovery (%STOIP)
10000	0.45	40.2	40.9
10000	0.75	39.0	38.4
5000	0.45	39.6	37.0

These results show that hot water flooding was of marginal benefit for the base case sector model and actually reduced the recovery compared to conventional cold water flooding in some scenarios. In cases where an increment was obtained from hot water flooding, there was a long delay between the start of the project and incremental oil production. The thermal front lagged behind the saturation front severely, because of the thermal capacity of the rock and resident fluids.

Low Temperature Fields With Oil Viscosities Around 400 cp

Some North Sea discoveries have low temperatures and viscosities of several hundred centipoise. Advances in horizontal well technology may make these prospects commercially attractive. However, recovery efficiencies from conventional water flooding are likely to be low. A comparative study of cold and hot water flooding was performed for a generic field in this category and the main results are reported in this section.

The rectangular, two-dimensional reservoir model used for these simulations is illustrated in Figure 6. The basic reservoir and fluid properties are given in Table 5.

Figure 6: Diagram of Grid Used in Simulations of Hot Water Injection for 400 cp Oil

Table 5: Basic Model Parameters

Property	Value
Water/Oil density difference (kg/m ³)	98
Temperature (°C)	30.6
Oil viscosity (cp)	400
Water viscosity (cp)	0.79
Porosity	0.33
Permeability (Darcy)	5.0
k_w/k_h	0.5
Residual oil saturation	25%
Connate water saturation	10%

at initial reservoir temperature

The dependence of the oil viscosity on temperature was based on the correlation in [23], normalised to the initial reservoir conditions. The model width was 6000 ft and the STOIP was 37.6 MMSTB. Both the injector and producer were horizontal and completed over the entire width of the model, which comprised half a pattern element. The production rate was 7500 bbl/D, corresponding to a rate of 15000 bbl/D for a complete pattern element. Results are quoted at 25 years unless otherwise stated.

The cold water injection temperature was fixed at the reservoir temperature, therefore the cold water flooding cases were isothermal. In the hot water cases, hot water was injected throughout field life.

Simulation Results

The injection temperature in the hot water base case was 100°C above the initial reservoir temperature. The base case cold and hot water flood results (CB1 and HB1, respectively) are summarized in Table 6.

Table 6: Results at 25 Years

Case	Cum. Oil Production		Final Watercut
	(MMSTB)	(% STOIP)	
CB1	10.60	28.20	0.955
HB1	13.53	35.99	0.883
HX1	12.17	32.37	0.903

Hot water flooding produces an additional 2.93 MMSTB of oil, or 7.79% of STOIP. The oil production profiles for these cases are illustrated in Figure 7. There is a clear IOR signal in the production rate at approximately 8 years.

Figure 7: Oil Production Profiles for Hot and Cold Water Injection

Alternative termination criteria might be adopted. If, for example, the well became uneconomic when the watercut increased above 90%, then it would be shut in after approximately 8.5 years in the cold water flood, recovering only 8.01 MMSTB. In contrast, the watercut for hot water flooding increases briefly to 90.5% at 13.5 years, but then decreases again, therefore the well would remain economic throughout the 25 year field life.

Incremental Recovery Mechanism

The water saturations at 5, 10 and 25 years are shown in Figure 8. The saturation plots show that the basic sweep patterns are broadly similar, with extensive coning of water at the producer.

Figure 8: Water Saturation Distributions During Hot and Cold Water Injection

Figure 9: Temperature Distribution During Hot Water Flooding

The temperature profiles in the reservoir at 5, 10 and 25 years are illustrated in Figure 9, which shows that the injected water does not mix fully with the aquifer, but appears to ride along the top of the water leg. The top of the oil column remains near the original reservoir temperature throughout the 25 years. Hot water injection produces local heating in the region of the original OWC. In the heated regions, the lowered

oil viscosity enhances gravity segregation, with oil initially migrating upwards, rather than being produced directly. This leaves the majority of the heated zone at close to the residual oil saturation defined by the relative permeabilities. The onset of incremental production coincides with the arrival of heated water at the producer, Figure 10.

The incremental recovery mechanism is a complex interaction between gravity forces and temperature induced changes in viscosity and density. Improved sweep in some regions is offset to some extent by oil resaturation of previously swept regions.

Figure 10: Producer Bottom Hole Temperature and Oil Rate, Case HB1.

Thermal expansion of the oil is known to contribute to improved recovery. It is interesting to note that in this model thermal expansion of the water plays an important role. The lower density of the heated water reduces thermal losses to the aquifer and speeds up the propagation of the temperature front through the reservoir. This is illustrated by results from Case HX1 in which thermal expansion of the water was switched off. The corresponding oil production profile is shown in Figure 7, with the response to hot water injection being delayed to 15 years. The incremental recovery at 25 years is reduced by nearly a factor of two.

CONCLUSIONS

1. An analytical model of hot water flooding has been used to assess the impact of temperature dependent relative permeabilities on hot water flooding. If the absolute residual oil saturation is reduced by hot water, corresponding increases in water relative permeabilities can offset any anticipated benefits.
2. There is a negative correlation between S_{wi} and S_{or} for cores conditioned at the hot water flood temperature, but no correlation for cores conditioned at a fixed temperature. Recommendations for consistent conditioning procedures have been made.
3. The most detailed and careful experiments show relative permeabilities that are independent of temperature.
4. Hot water flooding can be detrimental in moderate - high temperature reservoirs with oil viscosities around 10 cp.

5. Hot water flooding can have marginal benefits in low temperature reservoirs with oil viscosities around 100 cp.
6. Hot water flooding may be attractive in low temperature fields with oil viscosities around 400 cp. In a simple, generic model, it produced 10% more oil than cold water flooding over the same period and also significantly extended the economic life of the well.

ACKNOWLEDGEMENTS

This work was funded by the UK Department of Trade and Industry, as part of its IOR programme, whose permission to publish is gratefully acknowledged.

NOMENCLATURE

A	Cross sectional area [m^2]
C	Heat capacity [$J/(kg.K)$]
f	Fractional flow
Q	Flow rate [m^3/s]
S_{or}	Residual oil saturation
S_{wi}	Initial water saturation
S_{w1}	Saturation upstream of leading shock
S_{w2}	Saturation downstream of trailing shock
S_{w3}	Saturation upstream of trailing shock
t	Time [s]
T	Temperature [K]
V_1	Velocity of the leading shock [m/s]
V_2	Velocity of the trailing shock [m/s]
$V_{sat}(S_w)$	Characteristic velocity of saturation S_w [m/s]
ϕ	Porosity
ρ	Density [kg/m^3]

Subscripts

H	Higher temperature (injection fluid)
L	Lower temperature (Original reservoir temperature)
w	Water
o	Oil
R	Rock

REFERENCES

- [1] Lach, J, "Evaluation of Cold Water, Hot Water and Polymer Injection Schemes with Long Horizontal Well Application - Captain Field, UKCS", DTI IOR Conference "Best Practices for Improved Oil Recovery", 10 November 1993, Cafe Royal, London.
- [2] King, GR, "Alba Field - Polymer Flood Potential Considering Risk", DTI IOR Conference "Best Practices for Improved Oil Recovery", 10 November 1993, Cafe Royal, London.

- [3] Rose, W, "Relative Permeability", Ch 28, SPE Petroleum Engineering Handbook, Ed., Howard B Bradley, SPE 1987.
- [4] Johnson, EF, Bossler, DP, and Naumann, VO, "Calculation of Relative Permeability from Displacement Experiments", Trans. AIME 1959 Vol 316 p370-372.
- [5] Polikar, M, Farouq Ali, SM, and Puttagunta, VR, "High Temperature Relative Permeabilities for Athabasca Oil Sands" SPE 17424 SPE Res Eng. Feb. 1990, p25.
- [6] Black, CJI, Henning, PJ, and Sincock, KJ, "Improved Core Testing to Aid Heavy Oil field Development" 4th Unitar/Undp et al Heavy Crude and Tar Sands Int. Conf., Edmonton, Canada, August 1988, Preprints, Vol. 4 Paper 139.
- [7] Bennion, DB, Thomas, FB, Sheppard, DA, "Formation Damage due to Mineral Alteration and Wettability Changes during Hot Water and Steam Injection in Clay-Bearing Sandstone Reservoirs" SPE 23783, SPE Int. Symp. on Formation Damage Control, Lafayette, Louisiana, Feb 1992.
- [8] Casse, FJ, and Ramey, HJ, Jr. "The Effect of Temperature and Confining Pressure on Single-Phase Flow in Consolidated Rocks", JPT August 1979 p1051.
- [9] Sydansk, RD, "Discussion of the Effect of Temperature and Confining Pressure on Single-Phase Flow in Consolidated Rocks", JPT August 1980 p1329.
- [10] Dahab, AS, Omar, AE, El-Gassier, MM, and El Kariem, HA, "Formation Damage Effects due to Salinity, Temperature and Pressure in Sandstone Reservoirs as indicated by Relative Permeability Measurements", Journal of Petroleum Science and Engineering, 6 (1992) p403-412.
- [11] Gebran, BD, Brigham, WE, and Ramey, HJ, Jr. "Absolute Permeability as a Function of Confining Pressure, Pore Pressure and Temperature", SPE 10156.
- [12] Black, JB, and Dougall, RS, "The Effect of Temperature on Relative Permeabilities in Unconsolidated Sands", 26th AICHE Nat. Heat Transfer Conf. Philadelphia, Penn. August 1989.
- [13] Maini, BB, and Okazawa, T, "Effects of Temperature on Heavy Oil-Water Relative Permeability of Sand", JCPT (Heavy Oil) May-June 1987, Vol. 27, No. 3. p33
- [14] Peters, EJ, and Flock, DL, "The Onset of Instability During Two-phase Immiscible Displacement in Porous Media", SPEJ, April 1981, p249-258.
- [15] Rapoport, LA, and Leas, WJ, "Properties of Linear Waterfloods", Trans AIME, 1953, Vol. 198, p139.
- [16] Lo, HY, and Mungan, N., "Effect of Temperature on Water-Oil Relative Permeabilities in Oil-Wet and Water-Wet Systems", SPE 4505, 48th Ann. Fall Meeting, Las Vegas, NV, September 1973.
- [17] Torabzadeh, SJ, and Handy, LL, "The Effect of Temperature and IFT on Water/Oil Relative Permeabilities of Consolidated Sands", SPE 12689, 4th SPE/DOE Symp. on EOR, Tulsa, OK, April 1984.
- [18] Chengzhu, G, Yuling, K, Zihua, C, Qi, J, and Guanghui, Z, "Laboratory Study of High Temperature Relative Permeability on Unconsolidated Natural Sands", 7th Ann. Alta Oil Sands Technol. Advances in Pet. Rec. and Upgrading Tech. June 1986 Calgary, Alberta, Session 2 Paper 5.
- [19] Miller, MA, and Ramey, HJ, "Effect of Temperature on Oil/Water Relative Permeabilities of Unconsolidated and Consolidated Sands", SPEJ December 1985, p945.
- [20] Poston, SW, Ysrael, S, Hossain, AKMS, Montgomery, EF, and Ramey, HJ, "The Effect of Temperature on Irreducible Water Saturation and Relative Permeability of Unconsolidated Sands", SPEJ June 1980, p171-180.
- [21] Edmondson, TA, "Effects of Temperature on Waterflooding", JCPT August 1965 p236, Heavy Oil Seminar, Petroleum Soc. CIM, Calgary, May 1965.
- [22] Goodyear, SG, Mead, BJ, and Woods, CL, "A Novel Recovery Mechanism for Polymer Flooding in Gravity-Dominated Viscous Oil Reservoirs", SPE/DOE 27772.
- [23] Prats, M.(Ed.) "Thermal Recovery", SPE Henry L Doherty Series Monograph, Volume 7, SPE 1982, p216.