

IOR-06 THE USE OF DISTRIBUTED WELL TEMPERATURE MEASUREMENTS IN WATERFLOOD MANAGEMENT

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Abstract

Fibre optic sensor technology is being increasingly used by the oil industry. Optical fibres can be permanently installed in a well, providing distributed real time temperature data at a one-metre resolution. This paper investigates the link between the temperature distribution in the well and the reservoir performance. A range of fine grid reservoir simulations have been examined to study the temperature changes in a production well over the course of field history, aiming to assess the potential value of accurate distributed well temperature data for management of reservoir waterfloods.

The paper examines the influence of heat conduction, friction and Joule-Thompson cooling on well temperatures. In many instances the temperature profile along the production interval is not sensitive to these terms, being dominated by heat convection as fluids entering the well at the local near-wellbore formation temperature mix with fluids already in the well.

Analytic calculations and fine grid simulations both indicate that the temperature changes associated with injected water travel some 3 times slower than saturation profiles in the formation. Well temperature sensors installed in fields at the start of waterflooding may not provide useful data until several years after water breakthrough. For cold water floods, a re-normalised "cooling curve" plotted along the production interval of a well has a shape which is essentially constant with time, and can be considered as a "fingerprint" which reflects reservoir characteristics. A simple model has been developed to assess the potential for deriving reservoir inflow profiles from such temperature fingerprints. Examples are presented where it is only possible to derive qualitative information from the temperature profiles, largely due to the uncertainty in estimating the local temperature of fluids flowing into the well.

The results of the simulation work are used to identify reservoir scenarios where temperature monitoring is likely to be of most value.

INTRODUCTION

Fibre optic sensor technology is being increasingly used by the oil industry. Optical fibres can be permanently installed in a well, providing distributed real time temperature data at a one-metre resolution. A number of benefits and successes have been reported from monitoring of wells with fibre optic temperature sensors. Examples of anomalies detected by distributed sensors include [1,2,3]: crossflow between adjacent sets of perforations, unexpected seawater breakthrough from a nearby water injector well, flow behind the casing, localised heating around the ESP (backing up the measurements made by the temperature/pressure monitor on the pump itself).

Clearly, distributed temperature data can be used to spot anomalies in well performance – in the same way as in conventional well logging. This study has addressed the question of whether distributed temperature data could be used to look beyond the well. The link between the temperature distribution in the well and the reservoir performance has been investigated, in order to assess how reservoir management could be improved on the basis of distributed well data. Extra knowledge based on well

data is only of value if the information gives an early indication of a well problem, and if it is possible to change the reservoir management strategy in response to the information (such as selectively shutting off high water cut zones).

A number of fine grid reservoir simulations have been run to study temperature changes in a production well over the course of field life. This study focuses on oil reservoirs, under waterflood production (assuming that field pressures remain above the bubble point throughout). In gas reservoirs, well temperature variations could be significantly higher than those anticipated in oil fields. Most of the simulations have modelled a cold water injection scenario, with vertical wells – although distributed temperatures in a simple horizontal well are also discussed.

It will be shown that the distributed well temperature curve will adopt a shape that is dependent on reservoir characteristics, and could be used to infer qualitative information about reservoir layering. It is not possible to use the temperature profiles directly to determine local oil and water flows, unless reservoir modelling is used to “history match” the data.

The paper only addresses temperature distributions in production wells, although it is noted that temperature data *may* assist in assessing injectivity profiles for an injection well. Analysis of temperature data for an injection well would require shutting in the well, meaning that detailed, transient, heat transfer effects near the well would need to be modelled in any calculations. Furthermore, careful planning would be required before commencing injection. Useful data is only available after short periods of injecting of fluid at a temperature different to the surrounding formation – otherwise the formation around the well will be uniformly cooled (or heated) to be in equilibrium with the injection fluids.

DISTRIBUTED WELL SENSORS

Distributed temperature sensors are already being used in oil wells, and developments are underway to develop distributed sensors capable of measuring other wellbore parameters – such as pressure, and multi-phase flow rates. Examples of ways in which such distributed measurements might be expected to help reservoir management are:

- indicating that the well has stopped flowing at a particular depth,
- highlighting any unexpected flows,
- calculating well flow parameters, such as the local water cut.

Fibre optics are used in many distributed sensor applications. Fibre optic cables are reliable at high temperatures, immune to shocks and vibration, and do not suffer from electromagnetic interference.

One way of utilising fibre optic cable to measure distributed temperatures makes use of inherent back-scattering of light within the cable, as light interacts with the molecular structure of the fibre. Light is scattered in two components, one shifted-up and one shifted-down in wavelength relative to the launch wavelength. One of these scattered wavelengths is temperature sensitive. The time delay between sending the light signal and detecting the reflected signal serves to define the position along the fibre at which back-scattering occurred, and the ratio of (up-shifted light):(down-shifted light) can be used to infer the temperature at that position.

Such fibre optic temperature sensors are typically installed in a control line placed along the tubing. Temperatures may be measured at an accuracy of $\pm 0.1^\circ\text{C}$, at a one-metre resolution. Such sensors can be installed in lengths up to 10 km, and have proved to be highly reliable even above 200°C [1].

Distributed sensor technology continues to be developed [4]. Not all fibre optic sensor technology makes use of inherent cable properties to measure well data. Another fibre optic measurement technique uses “Fibre Bragg Gratings”, which are small patterns of lines photographically printed onto the cable. When white light is transmitted down a cable, a specific wavelength will be reflected from each “Fibre Bragg Grating” – the spacing of the gratings dictating the wavelength of the reflected signal. A series of discrete measurements can be made if a number of individual gratings (with different line-spacings) are printed along the length of the cable, each coupled to a suitable sensor which locally strains the cable to change the Fibre Bragg Grating characteristics.

Fibre optic technology offers the promise of a complete reservoir monitoring capability, measuring pressures, temperatures, flow rates, phase fractions, water-cut etc – see, for example, reference [5].

In this project the reservoir simulations and analyses have focussed on the potential uses of well temperature data.

FACTORS INFLUENCING WELL TEMPERATURES

This section will first consider the transport of heat within the formation, and then address the question of how various heat transfer processes near to the production well will influence the temperature distribution within the well.

Thermal fronts travel through formation at a rate significantly slower than saturation fronts. Cold water injected into a reservoir will initially be heated by the rock through which it flows. Once the water front has moved a significant distance from the injection well, its temperature will be equal to that of the undisturbed formation – with the thermal front a considerable distance behind the advancing water front. In a radial flow geometry, it is possible to derive a simple analytic expression relating the thermal front speed, V_{th} , to the total Darcy velocity of the fluids ($Q/2\pi rh$):

$$V_{th} = \frac{Q}{2\pi rh \cdot \phi} \frac{1 + \alpha}{(1 - S_{or} + \alpha + \beta)} \dots\dots\dots (1)$$

$$\alpha = \frac{\rho_o C_o}{\rho_w C_w - \rho_o C_o}, \quad \beta = \frac{1 - \phi}{\phi} \frac{\rho_R C_R}{\rho_w C_w - \rho_o C_o} \dots\dots\dots (2)$$

The derivation assumes radial flooding, with no heat conduction losses normal to the direction of flow. In practice such conduction losses will further reduce the speed at which the thermal front advances. With typical formation, oil and water properties, the simple analytical model indicates that the thermal front will take 3-4 times longer to reach the production well than the water saturation front.

Although a number of simplifying equations are made in deriving equations (1) and (2), temperature fronts modelled with fine grid reservoir simulations are found to be broadly consistent with the predictions of the simple model. The reservoir simulations include the effects of heat conduction and convection throughout the fluid/rock system (including heat losses at the upper and lower boundaries of the reservoir), giving a realistic estimate of temperature distributions in the formation. For this study, it is necessary to calculate the temperature profile that would be measured by a distributed sensor – i.e. the temperature profile inside the production well. The well temperature profile is not the same as the profile of temperatures in the formation temperature near the wellbore (the “near-wellbore formation”) – although the two are closely linked. In fact, a number of heat transfer mechanisms apply in-and-around the production well:

1. Heat convection.
2. Axial heat conduction within the fluids and the tubing walls.
3. Radial heat conduction between the well bore fluids and the tubing, the cement and the surrounding formation.
4. Heat generated/absorbed by friction and fluid expansion within the well (Joule-Thompson cooling).
5. Cooling caused by fluid expansion close to the well (Joule-Thompson cooling).

Heat convection. This is the dominant heat transfer term, for fluids produced at typical North Sea well rates. Convected heat is the energy carried by formation fluids as they enter the well, and may be calculated from the heat capacity and temperature of fluids entering the well.

Axial Heat Conduction. According to Fourier’s Law, the rate at which heat is conducted along the well is proportional to the thermal conductivity, cross sectional area and temperature gradient.

Radial Heat Conduction. The wellbore fluids, tubing walls, cement and surrounding formation represent concentric layers of material – see Figure 1. Radial heat transfer from the fluids to the formation can be determined using the standard expression [6]:

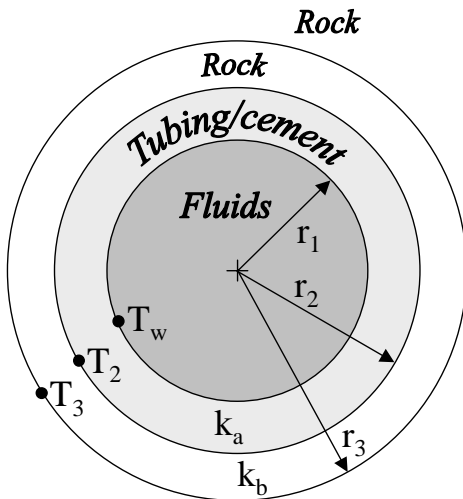


Figure 1 – Radial Heat Transfer

$$q_{radial} = \frac{2\pi L(T_w - T_3)}{\frac{1}{h_c \cdot r_1} + \frac{1}{k_a} \ln\left(\frac{r_2}{r_1}\right) + \frac{1}{k_b} \ln\left(\frac{r_3}{r_2}\right)}, \quad \dots\dots (3)$$

For production wells, layer “a” is the tubing (steel/cement), and layer “b” is the first layer of formation modelled in the reservoir simulator. Parameter h_c is the convection coefficient (convective heat transfer coefficient), which can be estimated using standard correlations [7].

Joule-Thompson Cooling (in wellbore). Thermodynamics textbooks derive the Joule-Thompson equation for adiabatic conditions (i.e. at constant enthalpy):

$$\left(\frac{\partial T}{\partial p}\right)_H = \left(\frac{1}{\rho \cdot C_p}\right)(T \cdot \beta_t - 1) \quad \dots\dots\dots (4)$$

The quantity, $\beta_t = \frac{1}{V} \left(\frac{\partial V}{\partial T}\right)_p$ is the coefficient of thermal expansion. Adiabatic conditions will apply if

the flowing fluids do no work (such as heating/cooling the formation rock) – as is the case when temperature equilibrium has been reached. Once the thermal front has reached the production well in a reservoir developed with cold water flooding, temperatures will continue to cool, albeit slowly, near the well. Conditions are close to adiabatic under these conditions.

The Joule-Thompson equation dictates that any reduction in fluid pressure (fluid expansion) will give rise to a cooling effect. The two terms in the right-hand side of equation (4) indicate that the temperature gradient results partly from the heat energy generated by friction ($dT/dp = -1/\rho \cdot C_p$), and partly from thermal expansion of the fluids.

In a vertical well, the potential energy of fluids rise as they flow up the well – i.e. work is done to lift the fluids. That work in itself will not cause a temperature change, but there will be a Joule-Thompson effect due to expansion of floods and the heat generated by friction.

Joule-Thompson Cooling (in formation).

Pressure falls as fluids flow towards the production well, with the pressure drawdown curve being steeper nearer to the well. This pressure change will cause a Joule-Thompson cooling effect, according to equation (4). If such Joule-Thompson cooling could be detected and measured, then reservoir characteristics could be inferred from the temperatures. For example:

- a) At the start of production, well temperatures will cool from the undisturbed profile, approaching an equilibrium profile that reflects the Joule-Thompson cooling. The higher the local flow rate, the faster the flowing fluids will cool the formation (and influence the well temperatures). If the Joule-Thompson effect is significant, then permeability layering will therefore affect well temperatures from the start of production.
- b) At water breakthrough, the change in fluid properties will give rise to a *change* in Joule-Thompson cooling around the wellbore, which could be quantified if the Joule-Thompson effect is large enough to be measured. That change may, potentially, be detected in temperature measurements. Since this cooling effect is *not* related to the thermal front associated with cold water injection, the well’s temperature change will not lag considerably behind the saturation front.

Conventional reservoir simulators do not model Joule-Thompson cooling of fluids within the formation.

Assessing Heat Transfer Terms Near Production Wells.

This project has used a conventional reservoir simulator, with a full thermal convective well model. Fluids are assumed to enter the well at a temperature equal to the formation temperature (immediately adjacent to well). At the toe of the well, the well temperature equals formation temperature. At each

modelled well block above this, the well temperature is determined by mixing the inflowing fluids with the fluids from deeper in the well. Heat convection is the only one of the five listed heat transfer mechanisms which is included in the simulations. Careful checks have confirmed that the neglect of the heat conduction and Joule-Thompson terms has only minimal impact on calculated temperature profiles.

The magnitude of axial heat conduction has been estimated from simulated data:

- the temperature gradient inside the well was used to estimate *axial heat conduction through the fluids* (using an effective fluid thermal conductivity), and
- the temperature gradient in the formation was used to estimate *axial heat conduction in the tubing* (using steel thermal conductivity).

All of the reported simulations represent high rate wells, and the axial heat conduction is found to be negligible compared to heat convection.

Radial heat conduction rates have been estimated using well temperature (T_w) and formation temperature (T_f) values from the reservoir models. For the 15,000 stb/day well rates modelled here, the radial heat flow is:

- a. significantly higher than axial heat flow,
- b. equivalent to a temperature change in the flowing fluids of the order of just 0.02°C.

Joule-Thompson expansion will also have only a slight impact on well temperatures. Typical values for the coefficient of thermal expansion are:

- water: $\beta_t = 0.0004 \text{ (}^\circ\text{C)}^{-1}$
- oil: $\beta_t = 0.0011 \text{ (}^\circ\text{C)}^{-1}$.

Consider oil and water at, for example, 50% watercut flowing in a horizontal pipe with a frictional pressure gradient of ~0.02 psi/ft. Using the Joule-Thompson equation (4), this equates to a *very small* temperature gradient of 0.035°C/1000 ft (temperatures increase as fluids flow downstream).

At a typical temperature of 160°C, the Joule-Thompson cooling will be:

- oil: $(\partial T/\partial p)_H = 0.0024 \text{ }^\circ\text{C/psi}$
- water: $(\partial T/\partial p)_H = 0.0014 \text{ }^\circ\text{C/psi}$.

In a reservoir with drawdown of, say, 500 psi, Joule-Thompson cooling in the formation could amount to 1.2°C for oil, and 0.7°C for water. However, only some 30% of this drawdown would occur within 10ft of the well, giving a Joule-Thompson temperature effect near the well whose magnitude is close to the resolution of distributed sensors. Since distributed sensors do not measure formation temperatures directly, but rather the temperatures inside the wellbore, omitting Joule-Thompson cooling due to pressure drawdown from calculations has only a slight impact on the distributed profiles.

The Joule-Thompson cooling effect for gas could be some 30 times larger than for an oil field – assuming a similar pressure drawdown. Clearly Joule-Thompson cooling can have a significant effect on well temperatures in a gas field.

It is concluded from heat transfer calculations that although the reservoir simulations do not model all of the transfer terms in-and-around production wells, this will not impact on the computed well temperatures, as long as wells are flowing at a moderate to high rate (1,500 to 15,000stb/day). Even if temperature changes due to the neglected heat transfer terms were not negligible, that would not affect the conclusions drawn regarding the use of distributed well temperature data in oil reservoir management – although it would increase the complexity of analysis of the temperature data. During shut-in periods, convection of heat from inflowing fluids will cease. Then conductive heat transfer effects will become significant, smoothing out local interruptions in temperature gradients both axially and radially.

CALCULATIONS OF WELL TEMPERATURES DURING WATERFLOOD

Fine grid reservoir simulations of waterflooded reservoirs have been used to examine the link between distributed well temperatures and reservoir performance. The models have shown that the well temperature profile can be viewed as a “fingerprint” characteristic of the particular reservoir. However,

the cooling impact of injected cold water may not be measured until a considerable time after water breakthrough. Furthermore, the distributed temperature data is unlikely to be of sufficient accuracy to enable reservoir layering to be characterised.

A series of simulations was run for a reservoir with drainage area of 110 acres. The reservoir height is 140 ft. Radial symmetry is assumed: water is injected all around the circumference of the model, with a vertical production well at the centre. Initially the fluids and rock are assumed to be at 70°C. Injection and production rates are 15,000 stb/day, with a water injection temperature of 10°C. The oil viscosity is temperature-dependent, ranging from 1 cp at 70°C to 12.6 cp at 10°C.

A number of different reservoir scenarios have been explored, modifying various model parameters:

- different permeability layering patterns
- flow rates
- porosity, net-to-gross ratio and rock thermal properties.
- geothermal gradient.
- reservoir drainage area

Model results will be presented to illustrate the general findings of these simulations. It is beyond the scope of this paper to present temperature profiles calculated for all of the reservoir scenarios modelled. To assist in the discussion of results, a geothermal gradient of zero has been assumed unless otherwise stated.

Multi-Layered Formation

A layered formation has been defined, with four 1000 md layers and four 100 md layers. Water breakthrough time is found to be about 1,260 days. At around this time the saturation distribution in the reservoir is plotted in Figure 2.

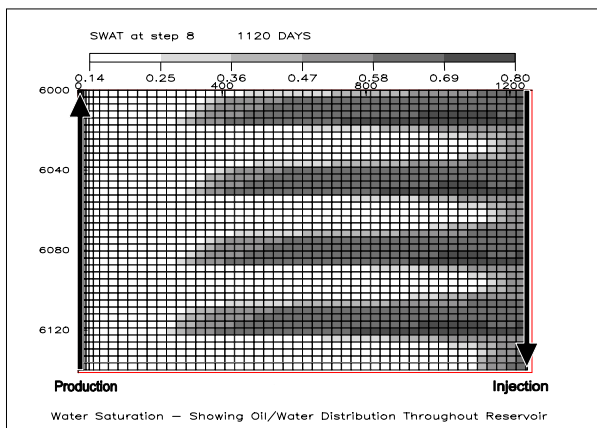


Figure 2 – Water Saturation (1,120 days)

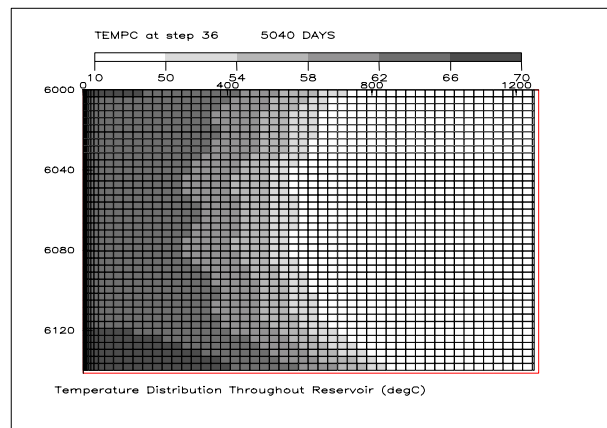


Figure 3 – Temperature Distribution (5,040 days)

Figure 3 illustrates the temperature distribution in the reservoir at the later time of 5,040 days – confirming that the thermal front advances much slower than the saturation front.

Well temperatures drop 1°C below initial temperatures after around 4,200 days. With a sensor accuracy of $\pm 0.1^\circ\text{C}$, it would not be possible to resolve an accurate well temperature profile unless the well temperature changes by *at least* 1°C from initial conditions. The temperature profile in the well at 4,200 days is plotted in Figure 4, overlaid with plots of the formation temperature (adjacent to the wellbore) and the water flow rates along the production interval. The water rates are negligible in the low permeability layers, giving rise to a formation temperature profile that oscillates between low permeability and high permeability layers. At the base of the well (which is in a low permeability region of the reservoir), fluids enter the well at a temperature equal to the formation temperature. Fluids from the high permeability layers typically enter the well at a temperature *cooler* than the fluids in the well, so the well temperature tends to decrease as we move upwards within a high permeability layer. With little inflow from the low permeability layers, the well temperature tends to be quite flat across those layers. The well temperature profile in Figure 4 can be viewed as a “fingerprint” for this well. The shape of the fingerprint is dictated by the flow velocities and temperatures within the formation, which are in turn dependent on formation heterogeneities (such as layering).

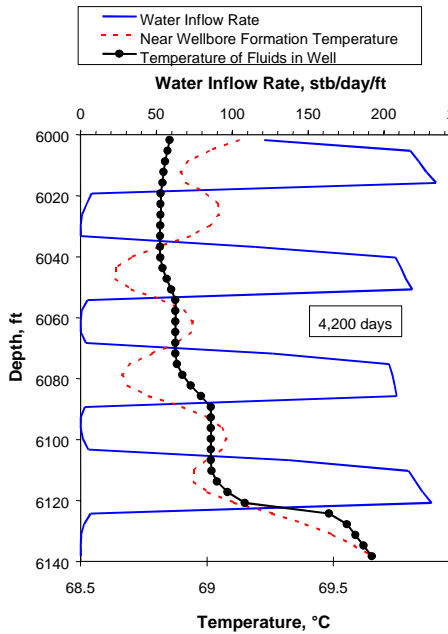


Figure 4 – Well Temperature Profile

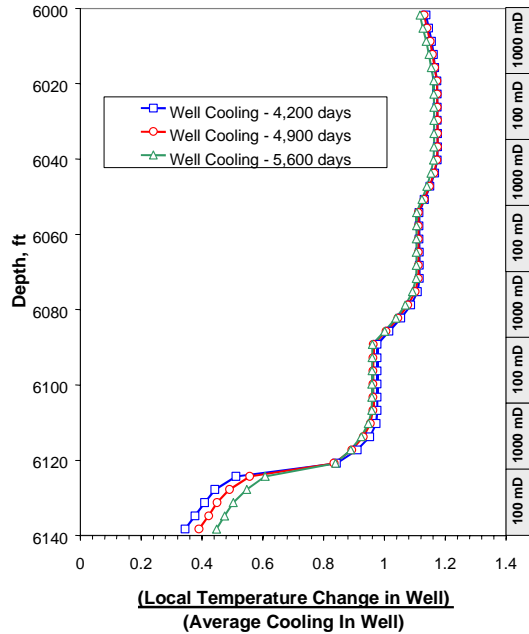


Figure 5 - Re-Normalised Well Cooling Curve

The well temperature profile changes with time, but its shape is found to be reasonably constant. This is demonstrated in Figure 5 where a re-normalised “cooling factor” has been plotted at three different times covering a period of 4 years. The re-normalisation formula is:

$$"cooling\ factor\ at\ depth\ z" = \frac{T(z) - T_{init}(z)}{\bar{T} - T_{init}} \dots\dots\dots(5)$$

where \bar{T} represents the depth-average temperature, accounting for the whole of the reservoir’s production interval. This form of equation has been selected because similar “cooling factor” plots were generated for simulations which include a geothermal gradient – in which case the re-normalisation needs to account for the non-uniform T_{init} profile. Like the well temperature curve in Figure 4, the “cooling factor” curve of Figure 5 is also a “fingerprint” for the reservoir

Two-Layer Formation

The dependence of the well temperature profile on heterogeneity is illustrated by considering a reservoir with a simpler layering pattern – e.g. a high permeability layer (1000 md) above a low permeability layer (100 md). Water breakthrough again occurs at ~1,260 days. In Figure 6, the well temperature profile is plotted after 2,940 days – this being the earliest time at which temperatures are 1°C below initial temperatures. Once again, the time delay between breakthrough and the accurate measurement of well temperature profiles is considerable: over 4 years in this example.

The temperature profile plotted in Figure 4 is very different in character to that shown in Figure 6 – supporting the idea that measured distributed temperature profiles represent fingerprints which vary from well to well, being influenced by reservoir heterogeneity.

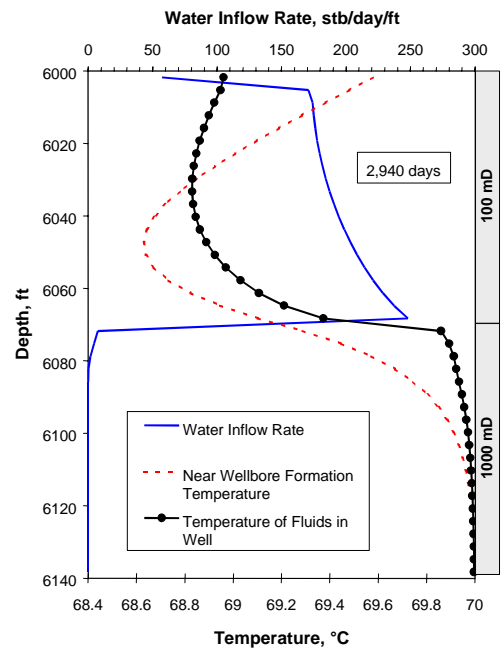


Figure 6 - Well Temperature Profile

High Permeability Streak

The time-scales for water to breakthrough and for thermal fronts to reach the production well will be smaller than discussed in previous sections if a very high permeability streak connects the injection and production wells. An illustrative simulation has been developed which has a single high permeability layer (“permeability-thickness” product of 37.5 D.ft), within an otherwise homogeneous formation (permeability 50 md).

The water breakthrough time is modelled to be about 200 days. The well temperature is simulated to drop 1°C below the initial temperature after 650 days – indicating that useful temperatures are not observed at the well until 3.3 times later than the breakthrough time. With a very thin high permeability layer, the heat conduction within the formation is greater than in previous models, enhancing the rate at which the advancing cold water front is heated by the surrounded formation.

Figure 7 illustrates the distributed temperature profile at 650 days (once again overlaid with plots of the near-wellbore formation temperature and the water flow rates along the production interval). The well temperature plot includes a sharp discontinuity at well depth 6,108 ft, indicating the bottom of the high permeability streak. It would be difficult to estimate the thickness of the streak, the “permeability-thickness” product or any other properties from examination of the well temperature profile alone, since there is very little “shape” to the temperature profile at depths above 6,108 ft.

Temperature Changes Due to Geothermal Gradient

All of the temperature profiles plotted above were derived from models that did not include a geothermal gradient – in order to simplify the plots and description of temperature profiles. The magnitude of geothermal gradient does not affect the time taken for a cold thermal front to move from an injection to a production well. Furthermore, the presence of a geothermal gradient does not damage the principle that measured well temperature profiles (or “cooling curves”) are fingerprints which reflect reservoir characteristics (especially layering).

A field was simulated with significant water coning around a vertical production well. Cold water (10°C) is injected at 15,000 bbl/day into a 100 ft aquifer below a 200 ft thick oil column. Fluids are produced from a well that penetrates just 45 ft into the top of the reservoir. At the start of production, the well temperatures increase as warmer fluids from deeper in the reservoir are pulled up towards the surface – but the temperature profile is rather flat and could not be used to deduce any information about reservoir performance. The slight increase in temperatures continues until the cold thermal front from the injected fluids reaches the well which, due to the slow advance speed of thermal fronts, is late in the simulation. Only then do the temperature profiles to adopt a shape which is “characteristic” of reservoir properties such as layering.

In general, geothermal gradients will give rise to well temperature profiles with only small and gradual fluctuations - giving little scope for extracting detailed information about flow from specific layers. However, in the case of commingled production from reservoirs with significant depth separation, the different inflowing temperatures from the two layers may make it possible to detect well problems (such as plugged perforations) from a well temperature profile.

Horizontal & Near-Horizontal Wells

When a reservoir is developed using horizontal wells, the physical rules governing the relative speeds of saturation fronts and thermal fronts will be the same as for vertical wells. The thermal front from the

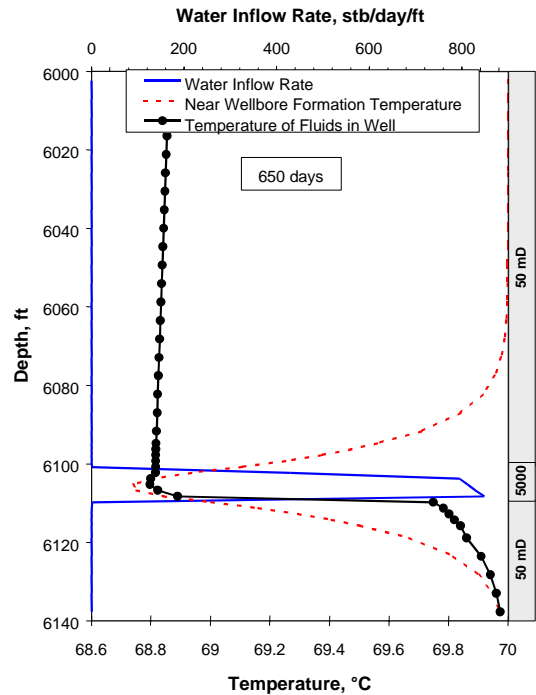


Figure 7 - Well Temperature Profile – Formation with High Permeability Streak

injection fluid would not be expected to have a measurable impact on horizontal production well temperatures until long after water breakthrough. A simulation of a reservoir produced under water injection using a horizontal producer would not therefore add any knowledge to that described in previous paragraphs. Instead, a study has been made of a horizontal well positioned a short distance above an aquifer, to investigate whether the geothermal gradient in the reservoir could give rise to changes in the production well temperature which could be used to analyse the water breakthrough characteristics in the horizontal well.

A fine grid 3D reservoir model was developed, representative of a field developed with horizontal wells some 3,000 ft apart.

The homogeneous reservoir is assumed to be at a depth of 3,500 ft, with the oil-water-contact at ~3,690 ft. The well is completed over a 1,800 ft length, with a dip of 2.5° to the horizontal. The stand-off varies from 62 to 142 ft. The undisturbed temperature is 40°C at the top of the reservoir, with a geothermal gradient of 0.01°C/ft. The oil viscosity is ~3.3 cp at these temperatures.

Well friction has been modelled, so the pressure at the heel of the well is significantly lower than at the toe. Even so, breakthrough occurs first at the toe of the well. As time advances water breakthrough is

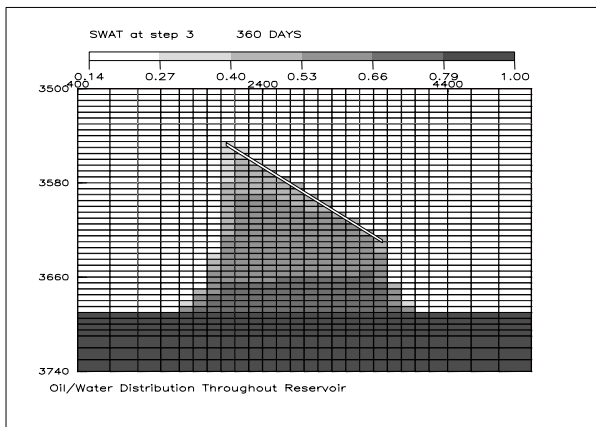


Figure 8 – Water Saturation (Near-Horizontal Well)

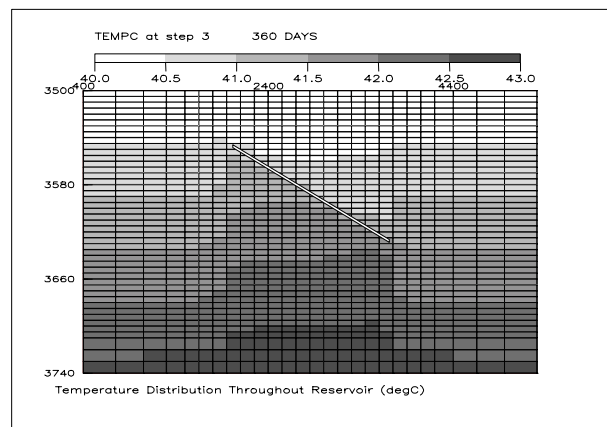


Figure 9 – Temperature Distribution (Near-Horizontal Well)

observed at points further up the well. Figures 8 and 9 show water saturations and temperatures in the formation after producing for 360 days at 15,000 stb/day. By that time water has broken through all along the well. At the heel of the well water represents 6% of the inflowing volume. The overall well watercut is 26.2%.

The well temperature profile at 120, 240 and 360 days is shown in Figure 10. The near wellbore formation temperatures generally follow the same trend as the undisturbed, geothermal profile, but are slightly warmer. The well temperature profile is shallower than the geothermal – which would be expected on the basis that inflowing fluids mix in the well (so that well temperatures are equivalent to running average of formation temperatures, commencing at the toe of the well). Inflow occurred initially at the toe of the well after ~120 days. By ~240 days, water had broken through in the bottom two-thirds of the well. It is unlikely that these breakthrough facts could be inferred from analysis of the well temperature data.

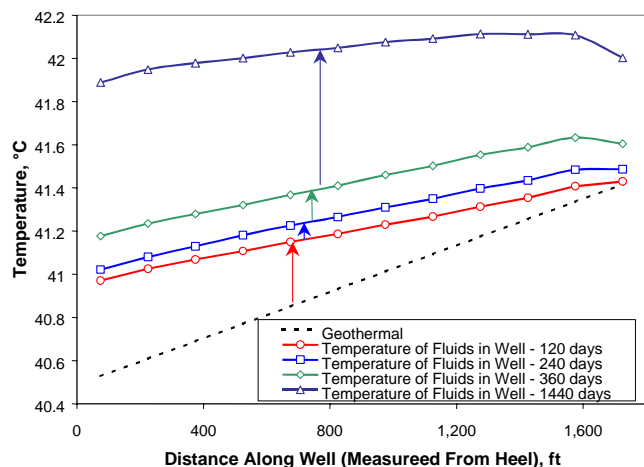


Figure 10 - Well Temperature Profiles (Near-Horizontal Well)

Even at later times measurement of the temperature of fluids in the well is unlikely to yield data which could lead to an accurate estimation of reservoir characteristics. Figure 10 also shows the well

temperature profile after 1,440 days (4 years). Well temperatures are now some 0.6-1.4°C higher than undisturbed temperatures, but the well temperature profile is still essentially flat – ranging from 41.9-42.1°C. It would be beyond the sensitivity of distributed temperature sensors to resolve any detailed features within the distributed temperature profile when the range of temperatures is so narrow.

This reservoir model with a horizontal production well indicates that distributed temperature data would not provide data suitable for quantifying any reservoir flow parameters (local permeabilities, oil and water phase ratios), unless there is any anomalous well flow behaviour (such as blocked perforations). The cold thermal front associated with water from the injection well would only influence measured production well temperature profiles late in field life.

INTERPRETING WELL TEMPERATURE PROFILES

Reservoir models have shown that the well temperature profile is like a “fingerprint” characteristic of the reservoir, provided that thermal fronts from injection wells have reached the producer. Such profiles could provide the reservoir engineer with a means of *qualitatively* assessing the effect of layering and other heterogeneities in the reservoir. In particular, it may be possible to use distributed well temperatures to detect anomalies in the flow, for example:

- blocked perforations,
- breakthrough from a nearby well,
- flow behind casing.

Since temperature sensors are capable of collecting large quantities of data (versus depth and time), it is attractive to consider whether that data may be used in a quantitative manner to enhance the reservoir description and therefore improve reservoir management.

Analyses based on the simulated data have shown that it would not be practical to use temperature data to quantify reservoir parameters (such as inflow profiles) along the completion interval, without running reservoir simulations. Inflow profiles can only be derived from well temperatures if highly accurate distributed data is available, in addition to accurate estimates of formation temperatures adjacent to the production well. In a heterogeneous reservoir such detailed information will not be available.

To explore the potential for interpreting distributed well data without the need for detailed reservoir modelling, a simple set of equations was derived - calculating reservoir flow rates at discrete intervals along the well, making use of distributed well temperature data. The derivation neglects axial and radial heat transfer, and Joule-Thompson cooling, but the resultant equations are valid for high rate wells.

The production interval is divided into a series of lengths. At any chosen position, n , the temperature in the well (T_n^w) can be expressed in terms of:

- Temperature in the well below that position (T_{n-1}^w)
- Temperature at which oil and water enters the well (i.e. the formation temperature, T_n^f)
- Oil and water flow rates (q_n is the flow rate from the formation to the well at position n , Q_n is the flow rate in the well at position n)
- Oil and water thermal properties.

This leads to:

$$\left[Q_{n-1}^o C_o + Q_{n-1}^w C_w \right] T_{n-1}^w + \left[q_n^{tot} (1 - \lambda_n) C_o + q_n^{tot} \lambda_n C_w \right] T_n^f = \dots \dots \dots (6)$$

$$\left[(Q_{n-1}^o + q_n^{tot} (1 - \lambda_n)) C_o + (Q_{n-1}^w + q_n^{tot} \lambda_n) C_w \right] T_n^w$$

Clearly, estimates of formation temperature and local oil/water ratios are necessary to solve such equations. Although the formation temperature cannot be measured directly, it may be possible to estimate approximate values from reservoir modelling. Some service companies have discussed the idea of inserting fibre cables directly into the formation in order to provide a direct measure of formation temperature values, but this concept has not been proven.

A spreadsheet tool was set up to solve a system of equations based on (6), attempting to use available well temperature data to estimate oil/water inflow profiles. Commercially available software for thermodynamic well modelling could have been used instead (such as production logging interpretation software). Tests with the spreadsheet (and consideration of the heat transfer terms reported on pages 4 and 5) showed that such commercial packages are not necessary for analysing temperature data from high-rate production wells.

Calculations were performed using well temperature data derived for a number of alternative reservoir scenarios. The results of such calculations have been shown to be *very* sensitive to:

- Noise/uncertainty/errors in the measured temperature data,
- Uncertainty in the estimated temperature of the formation adjacent to the well (the temperature at which fluids flow into the well),
- Uncertainty in the estimated local watercut.

The source of this sensitivity is readily seen when equation (6) is re-arranged:

$$q_n^{tot} = \frac{[Q_{n-1}^o C_o + Q_{n-1}^w C_w](T_n^w - T_{n-1}^w)}{[(1 - \lambda_n) C_o + \lambda_n C_w](T_n^f - T_n^w)} \dots \dots \dots (7)$$

Any computation of the local inflow rate will be limited by the accuracy at which the well temperature gradient $(T_n^w - T_{n-1}^w)$ can be measured, and will be strongly dependent on the estimated difference between the *measured* well temperature and the *estimated* formation temperature $(T_n^f - T_n^w)$ - which is often a small quantity.

In spite of the sensitivity to errors and uncertainty in the data, attempts were made to calculate the inflow rate as a function of depth for a vertical well, without reservoir modelling. The *only* accurate data available for the calculation are the distributed well temperature profile and the oil/water flow rates measured at surface. Algorithms were developed to construct formation temperature profiles consistent with the measured data. These algorithms made as much use of the data as possible. For instance, in regions where the well temperature profile is flat, equation (7) dictates that the formation temperature equals the well temperature. The same equation can also be used to determine whether the formation temperature is higher or lower than the measured well temperature at each position. The spreadsheet tool was used to construct a range of plausible formation temperature profiles, and also to estimate local watercut distributions (ensuring consistency within the dataset, so that those regions with the coolest formation temperature also have the highest inflowing watercut). In this manner a number of valid estimates of local water and oil inflow rates was derived. Figure 11 illustrates one set of results, comparing the calculated water inflow profile with the “true” profile. From the whole range of calculations run with the spreadsheet tool, Figure 11 shows one of the best sets of results, since it is based on an assumed formation temperature profile which is quite similar to the true one. Had real well data been used in the analysis, there would be no way of knowing that the “best” solution has been obtained, since the formation temperature cannot be measured directly.

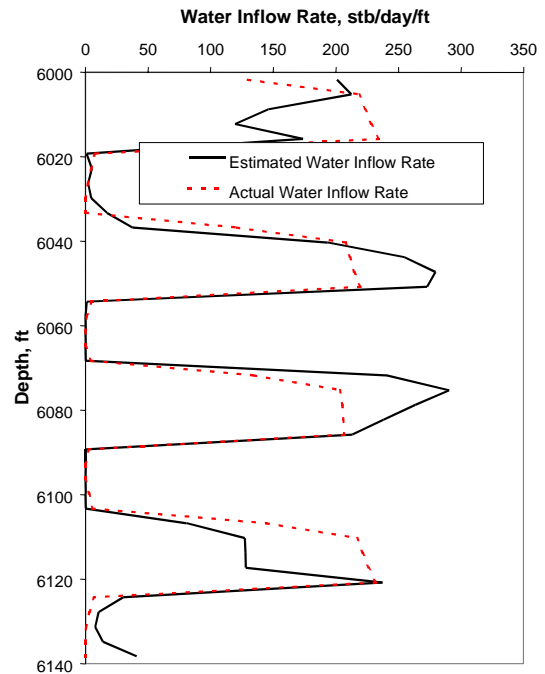


Figure 11 - Computing Inflow Rates from Well Temperature Data

The solution shown in Figure 11 captures the general features of the inflow profile, but has a mean water inflow rate error of 48 stb/day/ft - representing an error of $\sim \pm 25\%$ with respect to water flow rates in the high permeability layers (200 stb/day/ft). Similar results were obtained when analysing a range of

reservoir scenarios – demonstrating that it is *not* possible to employ a measured well temperature profile in isolation to evaluate inflow profiles and reservoir characteristics in a direct, deterministic calculation. In field situations, however, additional data (well logs, core, seismic etc) would be available and should be used to support the interpretation of distributed temperature data. Furthermore, well temperatures may be continually monitored, giving a set of different profiles as temperatures evolve in the reservoir. The whole range of data (temperature profiles and other supporting measurements), may be used to indicate the presence of different layers within the formation in a *qualitative* manner. Any calculations based on distributed temperatures are so sensitive to noise and uncertainties in measured/assumed temperatures that, even with additional data, quantified reservoir and inflow characteristics could only be derived using reservoir modelling.

The potential use of reservoir modelling is seen when a new reservoir simulation is constructed with layer properties defined to give water breakthrough as plotted in Figure 11. The well temperature profile calculated with the new model is shown in the unbroken line in Figure 12. The profile clearly differs to “measured profile” (dotted line). The differences can be used to infer correctly that:

- the inflow rate (and therefore layer permeability) has been under-estimated in the deepest zones, and
- the inflow rate (and layer permeability) has been over-estimated further up the completion interval.

With this information, it would be possible to run a series of simulations in a “history matching” process to determine reservoir properties. This would involve modifying the assumed layer parameters in an iterative manner, in order to develop a reservoir layering model which matches the measured well temperature data, as well as oil and water flow rates measured at surface. The uncertainty in the reservoir description will be reduced as more data is included in any history matching exercise (combining well data with other reservoir information such as core data or seismic data). In this manner, temperature data from production wells in an oil reservoir may contribute to an understanding of reservoir behaviour, even though such temperature data cannot be used alone in any *explicit* calculations to determine reservoir flows.

CONCLUSIONS

Distributed temperature sensors have been successfully deployed in a number of wells. They have been shown to be a useful well monitoring device – particularly suited to detecting flow anomalies such as crossflow between perforations, or unexpected breakthrough from nearby injection well. However, data from such sensors could only provide robust, detailed information related to reservoir behaviour when used in “history matching” with a detailed reservoir simulation model.

When water is injected into a reservoir, a thermal front moves from the injection well towards one of the producers, with an average speed some 3-4 times slower than the speed at which saturation fronts move in the reservoir.

In wells flowing at moderate to high rates, thermal calculations around the production well are dominated by heat convection as fluids flow into the well. Reservoir modelling with conventional simulators provides a legitimate prediction of distributed well temperatures, even though wellbore heat conduction and Joule-Thompson effects are not represented in the calculation.

The shape of a distributed well temperature curve is dependent on reservoir characteristics (especially reservoir layering). The curve can therefore be viewed as a “fingerprint” which depends on the

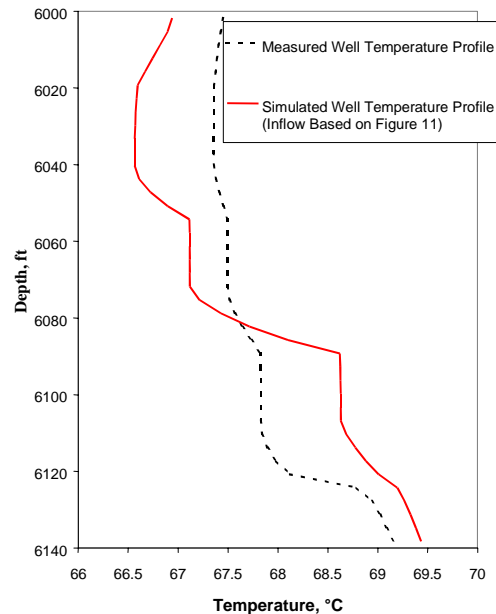


Figure 12 – Comparing Simulated Well Temperature with “Measured” Data

well:reservoir characteristics. For vertical wells it is possible to construct a “degree of cooling” curve whose shape is quite constant with time.

Quantitative interpretation of well temperature profiles is shown to require highly accurate measurements and, critically, an accurate estimate of near wellbore formation temperatures. In a complex, heterogeneous field environment, with “noisy” temperature data, it is not possible to determine local oil and water flows from distributed temperature data, unless reservoir modelling is used to “history match” the data.

Simulations of horizontal wells also indicate that distributed temperature would not provide data suitable for quantifying reservoir flows.

NOMENCLATURE

A	cross sectional area	$z, \Delta z$	distance along well
C	heat capacity per unit volume	α	dimensionless quantity - equation (2)
C_p	heat capacity per unit mass	β	dimensionless quantity - equation (2)
h	height of reservoir section	β_t	coefficient of thermal expansion – see equation (4)
h_c	convection coefficient	ϕ	porosity
k	thermal conductivity	λ	water cut
Q	fluid volumetric flow rate	ρ	density
q_{radial}	radial heat flow	<u>Subscripts/Superscripts</u>	
q^o, q^w	fluid volumetric inflow rate, per unit length of completion	init	initial
r	radius	o	oil
S_{or}	residual oil saturation	R	rock
T	temperature	tot	total (oil + water)
V_{th}	thermal front velocity	w	water

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Acknowledgements: This work was performed as part of the UK Department of Trade and Industry’s Sustainable Hydrocarbon Additional Recovery Programme (SHARP) studies at AEA Technology (www.dti-sharp.co.uk). The DTI’s permission to publish is gratefully acknowledged.