A new numerical model of electrokinetic potential response during hydrocarbon recovery

J. H. Saunders, M. D. Jackson, and C. C. Pain

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We present results from a new numerical model capable of simulating two-phase flow in a porous medium and the electrical potentials arising due to electrokinetic phenomena. We suggest that, during water-flood of an initially oil-filled reservoir, encroaching water causes changes in the electrokinetic potential at the production well which could be resolved above background electrical noise; indeed, water approaching the well could be detected several 10’s to 100’s of meters away. The magnitude of the measured potential depends upon the production rate, the coupling between fluid and electrical potentials, and the nature of the front between the displaced oil and the displacing water. Citation: Saunders, J. H., M. D. Jackson, and C. C. Pain (2006), A new numerical model of electrokinetic potential response during hydrocarbon recovery, Geophys. Res. Lett., 33, L15316, doi:10.1029/2006GL026835.

1. Introduction

Permanently installed downhole sensors are increasingly being deployed to provide ‘real-time’ reservoir data during hydrocarbon production. This data helps to reduce uncertainty in the reservoir description and contributes to reservoir management decisions. In this paper, we suggest that measurements of electrokinetic (EK) potential during production, using permanently installed downhole electrodes, could be used to detect water encroachment toward a production well. Electrokinetic potentials are generated when ionic fluid moves through a porous rock [Ishido and Mizutani, 1981; Revil et al., 1999]. Their application in oilfield monitoring was first suggested by Wurmstich and Morgan [1994], who concluded that the measured signals were likely to be too small to resolve. However, they used a simple single-phase model to predict the measured potential at the surface, and at a monitoring well some distance away from the production well, for a production rate of 500 bbl/day. Worthington et al. [2002] presented more encouraging results, assuming that monitoring occurred at the production well.

Since this work was published, downhole electrodes in cemented arrays, mounted at the production well on the outside of insulated casing, have been successfully applied in subsurface resistivity surveys during oil production [e.g., Bryant et al., 2001]. Similar technology could be used to measure electrokinetic potential. Moreover, recent and ongoing work has changed our understanding of the electrokinetic coupling under two-phase conditions [Guichet et al., 2003; Revil and Cerepi, 2004]. Production rates much higher than the 500 bbl/day simulated by Wurmstich and Morgan [1994] are also routinely obtained.

2. Governing Equations

The equations governing two-phase flow in a porous medium with electrokinetic coupling consist of a constitutive equation (Darcy’s Law) for each fluid phase $i$, and for the charge density (Ohm’s Law) [Wurmstich and Morgan, 1994; Haartsen and Pride, 1997]:

$$
\nu_i = -\frac{kk_i}{\eta_i} \left[ \nabla P_i - \rho_i \mathbf{g} \right] - L_s \nabla \Psi,
$$

$$
\mathbf{j} = -L_s \left[ \nabla P_w - \rho_w \mathbf{g} \right] - \sigma_r \nabla \Psi,
$$

in which $\nu$ is velocity, $k$ is permeability, $k_r$ is relative permeability dependent on the phase saturation, $\eta$ is viscosity, $P$ is pressure, $\rho_i$ is density and $\mathbf{g}$ is the gravitational term, $\Psi$ is electric (streaming) potential, $\mathbf{j}$ is electric current, $\sigma_r$ is the saturated rock conductivity and $L_s$ is the electrokinetic coupling term, an equation for conservation of mass:

$$
\phi \frac{\partial S_w}{\partial t} + \nabla \cdot \mathbf{j} = Q_t,
$$

where $\phi$ is the porosity and $Q_t$ is a source/sink term, and a capillary pressure relationship between the fluid phases:

$$
P_w = P_o + P_c.
$$

If there are no external current sources, then $\nabla \cdot \mathbf{j} = 0$, and thus equation (2) may be rewritten:

$$
\nabla \cdot [\sigma_r \nabla \Psi] = -\nabla \cdot \left[ L_s \left( \nabla P_w - \rho_w \mathbf{g} \right) \right].
$$

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3. Description of the Model

3.1. Geology and Dimensions

The three-dimensional reservoir model (Figure 1) is similar to that used by Wurmstich and Morgan [1994], and consists of six layers. The reservoir sandstone is confined above and below by low-porosity limestone or shale layers, which in turn are bounded by thick brine-saturated sandstone deposits. Above the upper sandstone layer, and reaching the surface is a resistive weathered layer. For the purposes of setting the potential to zero at infinity, the model extends 2000 m below the Earth surface, and the total horizontal extent is 2000 × 2000 m. Flow occurs in a channel extending 250 m to either side of the borehole perpendicular to the principle flow direction (see section 3.4). The production well is positioned at the center of this domain, with inflow over an interval of 80 m at the center of the reservoir layer. We assume that the well is equipped with electrodes mounted on the outside of insulated casing. We simulate four production scenarios based on this model, designed to explore the effect of varying the properties of the reservoir (Table 1).

![Figure 1. Stratigraphy of the 3D reservoir model (top to bottom): a highly-resistive weathered layer (100 m), a brine-saturated sandstone layer (300 m), a low-permeability confining layer (100 m), the reservoir sandstone layer (100 m), a second low-permeability confining layer (100 m) and another sandstone layer which extends a further 1000 m below the region shown. The position of the borehole is indicated by the dashed line. Total horizontal extent 2000 m (left-to-right and into-page), with a 500 m-wide channel constituting the flowing part of the reservoir.](image)

3.2. Rock and Fluid Properties

The fluid properties are based on those of Wurmstich and Morgan [1994] (Table 1). Flow is assumed to be viscous dominated; gravity and capillary forces are neglected, so fluid densities are the same and the oil-water capillary pressure is zero. This is a reasonable assumption in many oil reservoirs, particularly in the vicinity of a production well where fluid pressure gradients are large [Dake, 1978; Yortsos and Athanassios, 1980; Shook et al., 1999]. For partial saturations, the bulk rock conductivity is given by [Wurmstich and Morgan, 1994]:

\[
\sigma_r = \left[ \sigma_o + (S_w + S_{wc})^2(\sigma_w - \sigma_o) \right] \phi^{1.8},
\]

where \(\sigma_o\) and \(\sigma_w\) are the oil and brine conductivities, respectively. The relative permeabilities \(k_{rw}\) and \(k_{ro}\) are given by:

\[
k_{rw} = 0.3 \left( \frac{S_w}{1 - S_o - S_{wc}} \right)^2,
\]

\[
k_{ro} = 0.8 \left( \frac{S_o}{1 - S_{wc} - S_w} \right)^2.
\]

3.3. Electrokinetic Coupling

The electrokinetic coupling coefficient \(C_e\) plays a key role in controlling the magnitude of the electrokinetic potential. Its value depends upon the electrolyte concentration (salinity), electrolyte pH, ionic species within the electrolyte, temperature, rock mineralogy, and rock texture at a given pressure. There are few measured values of the coupling coefficient in brine-saturated sandstone cores over the range of brine conductivities typical of oil reservoirs (<0.01 Sm\(^{-1}\)). The values available range from c. 10\(^{-6}\) VPa\(^{-1}\) to c. 10\(^{-8}\) VPa\(^{-1}\) [Morgan et al., 1989; Lorne et al., 1999; Sprunt et al., 1994]. Wurmstich and Morgan [1994] used a value of 10\(^{-7}\) VPa\(^{-1}\), corresponding to a brine conductivity \(\sigma_w\) of 0.29 Sm\(^{-1}\). We begin by using the same value of \(C_e\) in this study, with \(\sigma_w = 0.31\) Sm\(^{-1}\) and \(\sigma_o = 1 \times 10^{-5}\) Sm\(^{-1}\).

We also require knowledge of the way in which the coupling coefficient varies with water saturation. Both Wurmstich and Morgan [1994] and Worthington et al. [2002] assumed an enhanced coupling in partially saturated conditions. However, recent work suggests that the coupling coefficient decreases with decreasing water saturation,
because the volumetric counter-ion density which can be transported by the flow scales with water saturation, so the electrokinetic coupling scales in the same way [Guichet et al., 2003; Revil and Cerepi, 2004]. The coupling coefficient at saturation is given by the single-phase value; at connate water saturation the water phase becomes immobile so the electrokinetic coupling ceases. The nature of the relationship at intermediate saturations depends upon the excess of counter-ions in the electrical boundary layer relative to the concentration of ions in the neutral electrolyte. The simplest relationship is linear, valid when the excess of counter-ions is small [Revil and Cerepi, 2004].

Based on this, we scale the electrokinetic coupling coefficient $C_v$ linearly with water saturation, from zero at connate water to a maximum (initially of $10^{-7} \text{ VPa}^{-1}$) at residual oil saturation. This relationship may not apply if the pores are oil-wet, if the oil phase contributes to the electrical potential, if there is a charge separation (and therefore an electrokinetic effect) between the oil and water phases, or if there is significant hysteresis between drainage and water-flooding. However, it is a reasonable first assumption.

3.4. Flow and Boundary Conditions

Pressure support by water injection or aquifer influx is simulated at one end of the domain by setting the water saturation to occupy the whole mobile pore space. Zero normal flow boundary conditions are applied on all other boundaries. Zero electrical potential is specified on all boundaries except at the Earth surface and on the boundary where fluid enters the reservoir. The natural boundary condition is applied at the Earth surface, which represents zero normal current flow.

4. Results

We begin by simulating a typical offshore production rate of 10,000 bbl/day (0.0138 m$^3$/s) in model 1 (Table 1). We find that large electrical signals are generated by water flowing toward the well. The electrical potential (with respect to a distant reference electrode) measured at the well increases as the water front approaches, reaching a maximum of nearly 200 mV just before breakthrough (Figure 2). The potential increases sharply as the water front approaches the well, reaching a maximum of nearly 200 mV just before breakthrough (Figure 2).

![Figure 2](https://example.com/figure2.png)

**Figure 2.** Electrical potential measured at the borehole plotted against the distance of the water front from the borehole, for each of the four models. The position of the water front is defined by an increase in water saturation equal to 10% of the mobile pore space. The potentials increase significantly while the water front is still many tens of meters from the borehole. Signal amplitudes are well above the expected noise level (0.1–1 mV).

<table>
<thead>
<tr>
<th>Model Number</th>
<th>Model Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Model as described by Wurmstich and Morgan [1994] and shown in Figure 1. Production occurs over 80 m interval (510–590 m depth) in borehole at a rate of 10,000 bbl/day.</td>
</tr>
<tr>
<td>2</td>
<td>Limestone confining layers ($\rho_L = 763 \Omega \text{ m}$) replaced by shale ($\rho_S = 30 \Omega \text{ m}$) to investigate the effect of higher conductivity on EK potentials.</td>
</tr>
<tr>
<td>3</td>
<td>High permeability region (500 mD) between 525 and 550 m depth to investigate the effect of fingering of the water front.</td>
</tr>
<tr>
<td>4</td>
<td>Oil viscosity raised to 0.01 Pa.s to investigate the effect of a less well-defined water front.</td>
</tr>
</tbody>
</table>

*The first is based on that of Wurmstich and Morgan [1994], while the remaining three are used to explore the effect of changing the reservoir or fluid properties.*
front approaches, showing a distinct change in slope while the water front is as much as 50 m away. (For this production rate, 50 m of movement of the water front represents approximately 100 days of production). The measured potential is well above the expected noise level of 0.1–1 mV [Bryant et al., 2001], even when the water front is more than 200 m from the borehole. These values compare with maximum streaming potentials calculated by Wurmstich and Morgan [1994] of 32.8 mV for one-phase flow and 63.4 mV for two-phase flow.

4.1. High Conductivity Confining Layers

[Wurmstich and Morgan 1994] assumed that the reservoir sandstone was confined by low conductivity limestone layers. It is more common for the reservoir to be confined by high conductivity shale layers. We simulate this by increasing the conductivity of the confining layers to 1/30 S/m (model 2 in Table 1). We find that the effect of this is to diminish the potential measured at the borehole, such that the maximum potential measured before breakthrough is just over 100 mV. The curve still shows a marked change at around 50 m from the borehole, so is clearly useful for monitoring the approach of the water front. In real reservoirs, the production interval may cross shale layers, so the influence of non-reservoir conductivity will be important.

4.2. Reservoir Heterogeneity

[17] Sandstone reservoirs typically exhibit spatially correlated permeability heterogeneity which reflects the depositional processes through which they were formed. We simulate the effect of this by introducing a high permeability layer (500 mD) in the upper half of the reservoir which extends over the model domain (model 3; Table 1). This allows us to investigate the effect of instabilities in the otherwise flat displacement front (Figure 3). In this case, the potential measured at the well is diminished by around 50%, but the peak potential is measured in line with the approaching finger of water in the high permeability layer between 525 and 550 m depth (Figure 4). This suggests that the potentials measured at the borehole are sensitive to the variation in saturations across the production interval. It is apparent then, if not surprising, that incorpo-
ration of heterogeneity into the reservoir model will be important in assessing the full capability of this method.

4.3. Shock Front Water Saturation

The fluid and rock properties used in models 1–3 yield a high shock front saturation over which most of the saturation change occurs. In many reservoirs, the rock and fluid properties yield a lower shock front saturation and a 'smoother' displacement front. We simulate this by increasing the oil viscosity by a factor of 10. We record higher potentials at the well (Figure 2), caused by the water flowing more quickly through the pore-space of the rock but at lower saturation, and therefore higher resistivity (Figure 5). In this case, the electrokinetic response will depend strongly on the nature of the coupling at intermediate saturations which is currently poorly understood.

4.4. Coupling Coefficient and Production Rate

The electrokinetic potential measured at a well scales linearly with the magnitude of the coupling coefficient $C_r$, and also, if flow is viscous dominated, with the magnitude of the fluid pressure gradient $\nabla P$ (equation (5)). At high brine salinities, the limited experimental data suggests that the coupling coefficient may decrease by an order of magnitude from the value of $10^{-7}$ VPa$^{-1}$ used in this study, in which case the maximum measured potential we predict would fall to around 16 mV (Figure 2). If the production rate, and hence pressure gradient into the well, was also reduced by an order of magnitude, then the signals may be too small to resolve. However, in reservoirs with relatively low salinity brine, the coupling coefficient may be $>10^{-6}$ VPa$^{-1}$, in which case we would expect to measure large electrical signals. When capillary and gravity forces are also significant, then changing the pressure gradient will also change the balance of forces and hence the flow field [Shook et al., 1999], so the simple linear relationship between electrical signal and pressure gradient will no longer hold.

5. Conclusion

We have developed a new numerical model capable of simulating two-phase flow in porous media and the coupled electrical potential. In contrast to earlier studies, our preliminary results suggest that large potentials may be measured at an oil production well, which increase as water encroaches upon the well. We suggest that the use of electrodes permanently deployed downhole to monitor the movement of fluids during production should be reinvestigated, particularly in reservoirs with relatively low salinity brines, and wells with high pressure drawdown. However, the magnitude of the measured potential depends upon the production rate, the coupling between fluid and electrical potentials, and the nature of the front between the displaced oil and the displacing water. The nature of the electrokinetic coupling, particularly during multi-phase flow, is poorly understood. Further work is required to understand and predict the effects of brine salinity, rock mineralogy and wettability.

References


Shook, M., D. Li, and L. W. Lake (1999), Scaling immiscible flow through permeable media by inspectional analysis, In Situ, 16(4), 311–349.


Figure 5. The effect of increasing the oil viscosity: water saturations plotted along a horizontal line through the borehole for model 1 ($\eta_o = \eta_o = 0.001$ Pa.s) and model 4 ($\eta_o = 0.001$ Pa.s, $\eta_o = 0.01$ Pa.s). Water moving from left to right.


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