HISTORY MATCHING OF MULTIPHASE-FLOW FORMATION-TESTER MEASUREMENTS ACQUIRED WITH FOCUSED-SAMPLING PROBES IN DEVIATED WELLS

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ABSTRACT

Complex tool and rock-formation properties are becoming prevalent in formation-testing operations. As hydrocarbon exploration shifts toward high-cost and high-risk frontiers, it is now common to measure pressures and to acquire fluid samples in deviated and sidetrack wellbores. At the same time, standard analytical and numerical methods used for the interpretation of formation-tester measurements continue to be based on restricting physical assumptions, such as single-phase flow, over-simplistic mud-filtrate invasion radial profiles, and vertical wellbores. Interpretation of transient focused-sampling measurements acquired in wells drilled with oil-based mud (OBM) is particularly challenging. The combination of miscibility (between mud-filtrate and in-situ oil) and non-standard probe geometry requires more petrophysically reliable interpretation methods than currently available with single-phase analytical techniques.

We describe the successful application of a three-dimensional (3D) multiphase-flow method to interpret two field data sets acquired with focused-sampling probes in a deviated well. The interpretation method includes the dynamic effects of OBM mud-filtrate invasion and their corresponding impact on fluid properties, such as viscosity and density, in the near-wellbore region. Numerical simulations verify the consistency of the measurements and quantify the role played by petrophysical, fluid, and geometrical properties on the time evolution of the measurements. We adjust key petrophysical properties involved in the simulations to reproduce transient measurements of pressure and GOR acquired with a commercial focused fluid-sampling probe. In addition, we numerically simulate resistivity logs to infer the spatial distribution of fluids in the near-borehole region prior to the onset of fluid sampling. Sensitivity studies further appraise the uncertainty of permeability estimates due to wellbore deviation, OBM filtrate viscosity, and radius of invasion.

The excellent agreement obtained between measured and simulated transient formation-tester measurements reveals key factors for the improved interpretation of focused-sampling probes in OBM environments: We found that irreducible water saturation was influential to determining the spatial distribution of fluids around the wellbore as it affected both the separation of apparent resistivity curves and the early-time portion of pressure transient measurements. Simulation results also indicate that the angle of wellbore deviation can bias permeability estimates especially for cases of high-permeability formations as well as for the case of large viscosity contrasts of the fluids involved during invasion. We confirm that numerical simulation and history matching of formation-tester measurements acquired under complex environmental conditions is a reliable procedure to diagnose noise, biases, and inconsistencies in transient measurements otherwise undetectable with standard interpretation methods.

INTRODUCTION

The increasing use of OBM in drilling operations poses challenges to the interpretation of pressure-transient measurements acquired with formation testers. Because mud filtrate is partially to fully miscible with in-situ hydrocarbon, space and time variations of fluid viscosity, fluid compressibility, fluid density, and gas-oil ratio (GOR) arise which are explicitly neglected by standard analytical (single-phase) methods. At the same time, miscibility between oil and OBM complicates the monitoring of filtrate contamination during fluid sampling. Acquiring clean fluid samples with minimum contamination is crucial to the reliable characterization of fluids via PVT laboratory measurements. Even though occasionally mud-filtrate can be physically separated from virgin fluids, it is not the case for OBM filtrate, whose miscibility with in-situ hydrocarbon also affects the inference of PVT fluid properties from contaminated fluid samples (Gozalpour et al., 1999).

Recently, there have been considerable improvements in the downhole monitoring and quantification of filtrate contamination via GOR and optical density...
(OD) measurements (Hashem et al., 1999; Mullins and Schroer, 2000; Akkurt et al., 2006). By operating within the light spectrum between 400 nm to 2200 nm, OD measurements make use of oil coloration (below 1500 nm) and high-resolution methane-detection channels (around 1600 nm to 1800 nm) to assess whether the fluid in the tool flowline has reached an acceptable level of contamination for sample acquisition. In addition, based on both amount of dissolved methane in the live fluid and color content, it is possible to calculate the corresponding GOR and identify three groups of hydrocarbon components: methane (C1), ethane to pentane (C2 to C5), and hexane (C6+) as well as heavier components (Schlumberger, 2006).

To further decrease fluid cleanup times and improve the efficiency of real-time separation of mud-filtrate and virgin fluids, a new generation of sampling probes known as “focused-sampling” probes were introduced in the last decade (Dong et al., 2005; Sherwood, 2005; Del Campo et al., 2006). Figure 1 describes the configuration of focused-sampling probes. Compared to conventional sampling probes, focused-sampling probes include two independent probe assemblies connected to independent flowlines with individual pressure gauges, optical sensors, and pumps (O'Keefe et al., 2008). During fluid withdrawal, the central probe assembly (“sample probe”) acquires the fluid sample while the surrounding probe assembly (“guard probe”) diverts mud filtrate.

Despite the various works published on focused-sampling probes, there are only a few papers devoted to the estimation of formation properties, such as permeability, from measurements acquired with this type of probe assemblies. Sherwood (2005) used asymptotic single-phase flow equations to quantify fluid cleanup times as well as to analytically determine the optimal configuration for both guard and sample probes. Based on numerical simulations, Malik et al. (2008) compared the performance of conventional and focused-sampling probes with a compositional equation-of-state (EOS) method. Using joint inversion of transient measurements of GOR and probe pressures, the same authors estimated formation permeability, anisotropy, and rate of mud-filtrate invasion. To date, all pertinent publications have focused their attention exclusively to the case of vertical wellbores and/or single-layer homogeneous rock formations.

The objective of this paper is to history match measurements of pressure and GOR acquired with a commercial focused fluid-sampling probe to verify the consistency of the measurements and to quantify the role played by petrophysical, fluid, and geometrical properties on the time evolution of the measurements. Because the well is deviated 27 degrees with respect to the vertical, the work presented here is (to the authors’ knowledge) one of the first publications to assess the effects of gravity and fluid compositional variations in focused-sampling probes often overlooked by standard interpretation methods. Likewise, we validate the applicability of the 3D fluid compositional method to interpret formation-tester measurements with realistic multi-layered rock-formations. Numerical simulation of resistivity logs is also used to reduce uncertainty in the spatial distribution of fluids before the onset of formation testing, specifically irreducible water saturation and radius of mud-filtrate invasion.

![Fig. 1. Configuration of the focused-sampling probe (O'Keefe et al., 2008).](image)

While the guard flowline acquires most of the surrounding mud-filtrate, the sample flowline supplies low levels of contaminated fluid to the corresponding sample chamber. Independent optical analyzers and pressure gauges are located within each flowline.
METHOD

Iterative Workflow. The method used for analysis is similar to that introduced by Angeles et al. (2008), who estimated permeability jointly from resistivity and formation-tester field measurements acquired in vertical wellbores drilled with water-based mud (WBM). The present application, however, requires that the simulator reproduce the physics of miscibility between oil-based mud (OBM) and in-situ oil as well as the specific geometry of the focused-sampling probe in a deviated wellbore. To that end, we combined the methods introduced by Malik et al. (2008) for the simulation of focused-sampling probes in OBM environments and the method proposed by Angeles et al. (2009) for the simulation of formation-tester measurements acquired in deviated wellbores. Figure 2 shows the iterative workflow adopted in this paper for analysis and interpretation of measurements.

Mud-Filtrate Invasion. We simulate the process of mud-filtrate invasion using the method described by Wu et al. (2005) and modified by Salazar and Torres-Verdín (2009), which takes into account dynamic mudcake growth and time evolution of mud-filtrate due to both OBM and rock-formation properties. Subsequently, we calculate volume-averaged flow-rates and input them to the fluid-flow simulator to describe the spatial distributions of mud filtrate, pressure, water saturation, and salt concentration before the onset of fluid sampling.

Fluid-Flow Simulations. There are two numerical methods used for fluid-flow simulation: (1) Array-induction resistivity measurements are simulated with the UTFET (Ramirez et al., 2006; Lee, 2008; Malik et al., 2008), which includes a two-dimensional (2D) axial-symmetric compositional simulator developed by the Formation Evaluation Research Program of The University of Texas at Austin; (2) formation-tester measurements are simulated with the commercial compositional EOS simulator GEM® developed by the Computer Modeling Group Ltd (CMG).

Upon calculating spatial distributions of pressure, water saturation, and salt concentration, UTFET calculates the corresponding apparent resistivity curves to be compared to field measurements. The purpose of simulating resistivity measurements is twofold: (1) to independently estimate both radius of mud-filtrate invasion and formation permeability, and (2) to cross-validate the values of water saturation, irreducible water saturation, and porosity input to formation-tester simulations.

Another key element in the simulation framework is the numerical grid based on corner-point geometry. This grid enables the inclusion of a synthetic wellbore that consists of void cells, necessary to enforce no-flow inner boundary conditions when simulating pressure-transient measurements. Figure 3 describes the 3D grid with corner-point geometry used to simulate numerically formation-tester measurements. Whereas the wellbore is assumed deviated at a constant angle, rock formation layers are assumed horizontal and laterally infinite.

Multi-Layer Rock Formations. Following the method described by Angeles et al. (2008), we adopt the following porosity-permeability correlation formula to calculate layer permeabilities:

\[
\log k_i = b_k \phi_i + a_k ,
\]

where \( k_i \) is layer permeability, \( \phi_i \) is layer porosity, and \( a_k \) and \( b_k \) are correlation parameters. Using the Schlumberger-Doll Research (SDR) correlation formula that uses the geometric mean of the T2 distribution inferred from NMR measurements, we applied regression analysis to measurements of permeability and porosity to calculate initial values of \( a_k \) and \( b_k \), set to -4.491 and 26.749, respectively. The transformation of variables implicit in equation (1) reduces the number of unknown parameters used in the inversion of permeability. For instance, Field Example B originally included 11 unknown parameters (11 numerical layers) which were then reduced to 2 correlation parameters (\( a_k \) and \( b_k \)).
There are other modifications to rock/fluid properties such as relative permeability, capillary pressure, and residual oil saturation that are updated in the estimation process depending on the specific values of permeability and irreducible water saturation assumed for a given numerical layer. We describe saturation-dependent relative permeability and capillary pressure using drainage equations for the Brooks-Corey model, given by

\[ S_{\text{nw}} = \frac{S_w - S_{\text{irr}}}{1 - S_{\text{irr}} - S_{\text{or}}} \]  

\[ k_{\text{rw}} = k_{\text{ro}}^0 (S_{\text{nw}})^{e_w} \]  

\[ k_{\text{ro}} = k_{\text{ro}}^0 (1 - S_{\text{nw}})^{e_o} \]  

where \( S_w \) is water saturation, \( S_{\text{irr}} \) is irreducible water saturation, \( S_{\text{or}} \) is residual oil saturation, \( S_{\text{nw}} \) is normalized water saturation, \( P_c \) is capillary pressure, \( P_{\text{ce}} \) is capillary entry pressure, \( \phi \) is porosity, \( k \) is permeability, and \( k_{\text{ro}} \) and \( k_{\text{rw}} \) are saturation-dependent relative permeability to water and oil, respectively. The superscript ‘\( \text{ro} \)’ identifies end-point values of the corresponding relative permeability. Exponents \( e_w \), \( e_{\text{rw}} \), and \( e_{\text{ro}} \) are assumed equal to 2, 2.48, and 1.5, respectively. Likewise, end points of water and oil relative permeability were arbitrarily chosen between the range of \([0.18, 0.35]\) and \([0.44, 0.98]\), respectively, based on the assumption that rocks with low permeability would also exhibit low relative permeability. Residual oil saturation was also arbitrarily chosen in the range of \([0.08, 0.13]\) following the linear relationship \( S_{\text{or}} = -3.39 k_{\text{rw}}^{0.63} + 0.63 \).

\[ P_c = P_{\text{ce}} \sqrt{\frac{\phi}{k}} \left( S_{\text{nw}} \right)^{1/e_p} \]  

Figure 4 describes the relative permeability and capillary pressure curves assumed for three of the eleven rock types considered in the same field example.

**FIELD EXAMPLE A**

**General Description.** Field Example A targeted offshore, upper Paleocene to lower Eocene turbidite fan lobes located at a total well depth of more than 18500 ft, under approximately 6500 ft of water. Exploration challenges included poor sub-salt imaging, unknown sand distribution, and limited flow capacity. Formation testing objectives were the following (in order of priority):

- Acquire PVT-quality hydrocarbon samples from the main reservoir units.
- Measure representative formation pressures and temperatures in the main reservoir units to infer pore pressure and temperature profiles for the well and to infer hydrocarbon gradients.
- Acquire high-quality build-up and drawdown data for pressure transient analysis to quantify mobility of the main reservoir units.
- Acquire a representative water sample from one of the target sections for petrophysical evaluation and scale potential.

**Figure 5** describes the location of the formation tester at the onset of fluid withdrawal and the corresponding well logs used for petrophysical assessment within the depth interval of inspection. High gamma-ray values and large separation between density and neutron porosity indicate relatively high values of volumetric shale concentration in the formation. Because of this observation, we used the dual-water model (Clavier et
al., 1984) to calculate water saturation and clay-bound water fraction. Table 1 summarizes the geometrical and numerical simulation properties assumed for the field example considered in this paper. Table 2 summarizes the corresponding petrophysical and fluid properties, and Table 3 summarizes the mud and mudcake properties assumed for the simulations of mud-filtrate invasion.

The temperature gradient is equal to 1.2 °F/100 ft whereas the reference temperature is 254 °F at 17192 ft MD (equal to 15696.5 ft TVD). Likewise, salinity of formation water is equal to 105,000 ppm as estimated from a Picket plot of porosity and resistivity in a clean-sand water zone. The latter value of salinity was further validated with the resistivity simulations described in the next section. Archie’s parameters $a$, $m$, and $n$ are equal to 1, 1.9, and 2.1, respectively.

For this field example, a total of 90,262 fundamental (unrefined) grid blocks were used to perform the numerical simulations in addition to locally-refined grids included around the focused-sampling probe. The associated CPU time for a 2.4 Ghz PC (Dell Optiplex 745 computer) is 1.2 hours for a 1-day simulation of mud-filtrate invasion and 13.7 hours for a 4.4-hour simulation of fluid-sampling with a compositional simulation that invoked 8 pseudo-components.

As emphasized earlier, miscibility between OBM and in-situ oil makes it necessary to use a compositional EOS simulator. For this field example, we lumped the existing hydrocarbon components reported by a PVT laboratory study into 8 pseudo-components. While five pseudo-components ($N_2C_1$, $CO_2C_3$, $C_4C_6$, $C_7C_18$, and $C_{19+}$) were used to specify the in-situ hydrocarbon, three additional pseudo-components described the oil-based mud ($MC_{14}$, $MC_{16}$, and $MC_{18}$). Table 4 and Table 5 summarize the EOS parameters and mol fractions assumed for OBM and in-situ hydrocarbon, respectively.
Following a similar approach to that of Malik et al.’s (2008), the fluid compositional model assumes that phase compositions change according to Peng–Robinson’s EOS (Peng and Robinson, 1976) and fluid density is dynamically modified with the variations of pressure and fluid composition. In both field examples, in-situ oil has a viscosity of approximately 5.5 cp whereas OBM filtrate has a viscosity of 2 cp.

**Simulation of Resistivity Measurements.** Figure 6 shows the final values of porosity, permeability, and water saturation calculated for Field Example A. Preliminary results obtained from the dual-water model were segmented into numerical layers for input into the fluid-flow compositional simulator. Subsequently, we simulated resistivity and formation-tester measurements in an iterative way until achieving an acceptable agreement between simulations and measurements. The values indicated in Figure 6 are the final estimates obtained from several iterations. Figure 7 displays the layered model with the successful match between measured and simulated array-induction measurements. Even though simulated resistivity curves do not exhibit the various rapid and local variations observed in the measured curves, magnitude and separation between simulated resistivity curves are in very good agreement with those of measured apparent resistivities.

Another important result from resistivity matching is observed at XX345 ft TVD: the relatively large separation between resistivity curves is caused predominantly by the presence of mobile water. We could not match this portion of the resistivity data without invoking such petrophysical condition. If the water were irreducible (residual), we would experience single-phase flow; hence, OBM filtrate would only displace the existing oil, which would not cause separation between resistivity curves. Therefore, we conclude that the existing separation between deep and shallow apparent resistivity curves originates from the presence of mobile water in the formation (in a previous stage of analysis we verified that the separation between resistivity curves was not due to post-processing effects implicit in the calculation of apparent resistivities). In the simulations, we adjusted the value of irreducible water saturation in addition to the radius of invasion until we secured a good match between simulated and measured curves. For this field
Fig. 6. Discretization of the logs into petrophysical layers describing the final estimated values of porosity (left-hand track), permeability (center track), and water saturation (right-hand track) for Field Example A. Discretized log values are used as input to the simulations of mud-filtrate invasion and formation-tester measurements. The formation-tester probe is located at XX338 ft TVD.

Fig. 7. Comparison of measured and numerically simulated AIT apparent resistivity curves. Numerically simulated apparent resistivity curves were obtained from layer-by-layer estimated values of permeability and radius of mud-filtrate invasion for Field Example A. The formation-tester probe is located at XX338 ft TVD.

example, final values of $a_i$ and $b_i$ were -4.491 and 26.63, respectively. Table 6 summarizes the final estimated values of porosity, permeability, water saturation, and irreducible water saturation.

Simulation of Formation-Tester Measurements.
Upon cross-validating the petrophysical properties and the radius of mud-filtrate invasion (approximately 0.6 ft) with resistivity measurements, we performed 3D compositional simulations with CMG-GEM® adopting a corner-point geometry. Figure 8 describes the vertical and horizontal cross-sections of oil-mass density at 28.8 min after the onset of fluid sampling. Locally refined grids are included in front of the focused-sampling probe to increase the accuracy of the simulations due to rapid space-time variations of fluid saturation taking place in that region.

Figure 9 shows the measured pressure as well as the fluid-flow rates imposed on guard and probe samples. We note that the early- and late-time portions of the flow rates are in “commingled” mode. That is, the two flowlines associated with guard and sample probes were hydraulically connected during fluid pumpout, hence only one flow rate is observed at a given time. The sample pump works alone until 2500 seconds when it stops and the guard pump begins its operation. This is a calibration stage where the same liquid is purposely flowed through one optical analyzer and then the other. In our simulations, whenever in commingled mode, we
portion of pressure measurements with numerical simulations. More importantly, this behavior follows from nonlinear time-space variations of fluid viscosity during sampling and is not related to manipulation of fluid flow rates. The formation-tester pressure initially reflects the low viscosity of mud filtrate, which results in high fluid mobility and low pressure drawdown. As fluid sampling progresses, in-situ oil (with larger values of viscosity) decreases the mobility of the fluid entering the focused-sampling probe, thereby explaining the high values of pressure drawdown at the end of the test.

To validate the numerical gridding adopted in this work, we first compare the simulated pressures against single-phase flow simulations. Figure 10 shows the final match between measured and simulated pressures. We observe that even though the match is good for the late-time portion of pressure measurements, the early-time portion before 12500 seconds is not adequately matched with the reported flow rates. As emphasized in a subsequent section of this paper, the difficulty in matching such time portion of the data is due to invalid assumptions in the single-phase interpretation model. Figure 12 compares the simulated and measured GOR measurements at sample and guard probes. Even though the match is satisfactory, it was not possible to match the entire time record, especially at the sample probe immediately after the first 5000 seconds of fluid withdrawal.

Another important remark is that GOR measured with the optical module of the formation tester will generally not closely agree with the GOR measured in the PVT laboratory. To circumvent this problem, we first normalized the measured GOR and then scaled it with a multiplier so that it could be compared to simulations.

We implemented the same numerical grid with the compositional simulator using the EOS parameters reported in Tables 4 and 5. Based on PVT reports from laboratory analysis of fluid samples, in-situ oil includes 20.2% C1-C4 molar content which accounts for a sufficiently high content of solution gas to justify the use of GOR measurements as discriminators of OBM filtrate and in-situ oil. Moreover, we assume OBM filtrate to be gas free. Figure 11 shows good agreement between simulated and measured pressures obtained with compositional simulations. Notice that, unlike results obtained with single-phase flow assumptions, the figure also indicates a good match of the early-time

Table 6 Summary of final estimated values of porosity, permeability, water saturation, and radius of invasion for Field Example A. The number between brackets corresponds to irreducible water saturation.

<table>
<thead>
<tr>
<th>Layer</th>
<th>φ [fraction]</th>
<th>k [md]</th>
<th>S_w [Swirr]</th>
<th>r_{inv} [ft]</th>
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Sensitivity Studies. We performed several sensitivity studies to assess the effects of angle of wellbore deviation, radius of invasion, and mud-filtrate viscosity on the estimated permeability. Figure 13 describes the simulated pressure measurements as permeability increases from 30.8 mD to 52.4 mD in the numerical layer located directly across the formation-tester probe. As expected, the larger the formation permeability the lower the magnitude of pressure drawdown. We also observe that because the variations of pressure are significantly large for such a range of permeability, uncertainty in our final estimate of layer permeability is relatively low.

Figure 14 quantifies the effect of angle of wellbore deviation in the simulated pressure measurements. Results confirm that the magnitude of pressure drawdown increases as the angle of wellbore deviation increases. In other words, we could introduce a bias in the estimation of permeability when the angle of wellbore deviation was not accounted for in the interpretation. The erroneous assumption of a vertical wellbore would bias the permeability estimates toward lower values than actual because an additional drawdown would be necessary to match the pressure measurements with numerical simulations.

Furthermore, we observe that variations of pressure are relatively smaller than those observed in the sensitivity studies of permeability. This behavior suggests that if we estimated the angle of deviation with the remaining properties assumed known, the uncertainty of the estimated value would be high compared to that of permeability.

Figure 15 quantifies the effect of radius of mud-filtrate invasion on simulated pressure measurements. We observe that the larger the radius of invasion the larger the concentration of low-viscosity filtrate between the sampling probe and the virgin fluids. This behavior increases the mobility of the produced fluid and explains the observed lower pressure differentials.

Furthermore, we observe that variations of pressure are relatively smaller than those observed in the sensitivity studies of permeability. This behavior suggests that if we estimated the angle of deviation with the remaining properties assumed known, the uncertainty of the estimated value would be high compared to that of permeability.
Fig. 11. Comparison of simulated and measured pressures for Field Example A. Simulations were performed using compositional simulations. Both OBM filtrate and in-situ oil are assumed with viscosities of 2.0 cp and 5.5 cp, respectively. Initially, the formation tester pressure is largely affected by the low mud-filtrate viscosity which results in high fluid mobility and low pressure drawdown. As fluid sampling progresses, in-situ oil with larger values of viscosity decreases the mobility of the fluid entering the focused-sampling probe, thereby explaining the high values of pressure drawdown at the end of the test.

Fig. 12. Measured and numerically-simulated time records of gas-oil ratio (GOR) for sample and guard probes. Numerical simulations were obtained with the final estimates of permeability considered for Field Example A.

The figure also emphasizes the importance of history-matching resistivity measurements in addition to pressure measurements as an independent means to constrain the assumed radius of invasion.

**Figure 16** describes the effect of mud-filtrate viscosity on the simulated pressure measurements: the larger the OBM filtrate viscosity the larger the pressure differential.

**FIELD EXAMPLE B**

**Simulations of Resistivity Measurements.** The second field example is located in the same well as that of Field Example A and includes a similar formation-tester configuration. **Figure 17** describes the studied depth interval with the corresponding location of the formation test. The rock formation is a massive, approximately 100 ft-thick sand that causes predominantly spherical flow in the measured pressure
Simulations of Formation-Tester Measurements. Figure 20 describes the measured pressure as well as the fluid-flow rates imposed on guard and probe samples. The formation test lasted approximately 9 hours and included several short intervals when the seal was lost, particularly at 9000 and 22000 seconds. This behavior caused significant noise in both flow rates and GOR. Figure 21 shows the final match between measured and simulated pressures using compositional simulations. By explicitly accounting for mud-filtrate invasion in the analysis of formation-tester measurements we secured an excellent match between numerical simulations and measurements. Low-viscosity OBM filtrate causes a gradual transition in time from high-mobility to low-mobility pressure responses while fluid is withdrawn from the formation.
Fig. 17. Well logs considered for the petrophysical description of Field Example B indicating the location of the formation-tester focused-sampling probe at XX105 ft MD (XX509 ft TVD). The left-hand track includes the gamma-ray and caliper logs, the center tracks show array-induction (AIT) apparent resistivity measurements (AT10 to AT90), neutron porosity (NPHI), bulk density (RHOM), NMR porosity (TCMR), and the right-hand track displays interpreted free fluid (CMFF) with light shading and bound fluid with dark shading.

Fig. 18. Discretization of the logs into petrophysical layers describing the final estimated values of porosity (left-hand track), permeability (center track), and water saturation (right-hand track) for Field Example B. The formation-tester probe is located at XX509 ft TVD.
Fig. 19. Comparison of measured and numerically-simulated AIT apparent resistivity curves. Numerically simulated apparent resistivities were obtained from layer-by-layer inverted values of permeability and radius of mud-filtrate invasion for Field Example B. The formation-tester probe is located at XX509 ft TVD.

Fig. 20. Time records of pressure measurements (blue curve) and fluid production rates acquired through the sample (green curve) and guard (red curve) probes for Field Example B. Flow rates enforced by the simulator are also shown as discrete rates. For this field example, except the time interval around 18000 seconds, flow rates are in commingled mode, i.e., the sample and guard probes are hydraulically connected to the same flowline. During those intervals, flow rates assumed in the simulations are divided according to the ratio of sample- and guard-probe areas.
Fig. 21. Comparison of simulated and measured pressures for Field Example B. Simulations were performed using compositional simulations. Both OBM filtrate and in-situ oil are assumed to have viscosities of 2.0 cp and 5.5 cp, respectively. Initially, the formation tester pressure is largely affected by the low mud-filtrate viscosity which results in high fluid mobility and low pressure drawdown. As fluid sampling progresses, in-situ oil with larger values of viscosity decreases the mobility of the fluid entering the focused-sampling probe, thereby explaining the high values of pressure drawdown at the end of the test.

Table 7

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<td>0.34 [0.30]</td>
<td>1.5</td>
</tr>
<tr>
<td>6</td>
<td>0.19</td>
<td>2.47</td>
<td>0.45 [0.43]</td>
<td>1.7</td>
</tr>
<tr>
<td>7</td>
<td>0.22</td>
<td>15.3</td>
<td>0.36 [0.34]</td>
<td>1.5</td>
</tr>
<tr>
<td>8</td>
<td>0.20</td>
<td>6.15</td>
<td>0.42 [0.38]</td>
<td>1.3</td>
</tr>
<tr>
<td>9</td>
<td>0.20</td>
<td>6.15</td>
<td>0.44 [0.38]</td>
<td>1.6</td>
</tr>
<tr>
<td>10</td>
<td>0.19</td>
<td>4.54</td>
<td>0.50 [0.49]</td>
<td>1.6</td>
</tr>
<tr>
<td>11</td>
<td>0.23</td>
<td>38.1</td>
<td>0.38 [0.37]</td>
<td>1.3</td>
</tr>
</tbody>
</table>

Figure 22 compares the simulated and measured GOR measurements at both sample and guard probes. Despite substantial noise in the measurements, we achieved a satisfactory match with numerical simulations of the commingled probes. Table 7 summarizes the final estimated values of porosity, permeability, water saturation, and irreducible water saturation.

DISCUSSION

The two field examples described in this paper revealed key factors in the interpretation of focused-sampling probe measurements acquired in deviated wells drilled with OBM. Important parameters for consideration are the viscosities of both OBM filtrate and in-situ oil. It would be impossible to match the complete time interval of pressure measurements with numerical simulations, especially the early-time portion of the time record, by neglecting time-space variations of viscosity between filtrate and in-situ oil that occur as in-situ fluid is retrieved from the formation. Even with manipulation of the measured flow rates, a constant viscosity solution (such as the one used with single-phase analytical methods) will not reproduce the downward trend in time observed in the measured pressures. Analytical solutions will exhibit a flat, almost-constant pressure drawdown similar to that shown in Figure 10.

Another important parameter in the estimation of formation properties was irreducible water saturation. Initially, we assumed that formations included only irreducible water saturation, which proved correct for several of the layers (irreducible water saturation equal or very close to initial water saturation). We found, however, that the smallest amount of mobile water could also significantly affect the numerical simulations of apparent resistivity, in particular the separation between apparent deep and shallow resistivities. There is another explanation for this behavior and it is attributed to wettability changes due to emulsifiers and oil-wetting agents present in the OBM system. For the purpose of this paper, we discarded such option but we recognize that it is an equally feasible explanation for the separation of apparent resistivity curves.

For Field Example A, this observation was crucial because the formation tester was located immediately above a depth interval containing mobile water that also influenced the numerical simulations of pressure transients. Pressure simulations were equally affected by additional mobile water because it decreased the effective oil mobility, hence increasing the simulated pressure differential and, consequently, increasing the estimated permeability.
Simulation results also suggest that the angle of wellbore deviation could have a significant impact on the performance of focused fluid-sampling probes. Not only does the test require a larger pressure drawdown from the pumpout module to enable the same production flow rate but it also biases permeability estimates toward lower values than actual if the assumption of vertical wellbore is imposed on the interpretation of formation-tester pressures acquired in a deviated wellbore.

CONCLUSIONS

Multiphase compositional simulations were crucial to reproduce the two field sets of pressure and GOR measurements acquired with focused-sampling probes. Time variations of fluid viscosity during OBM filtrate cleanup caused a downward trend in the time evolution of pressure that could not be explained with conventional single-phase analytical solutions.

For the cases studied in this paper, we found that the larger the angle of wellbore deviation the larger the pressure drawdown. If neglected, the angle of wellbore deviation could bias the estimated permeability toward lower values than actual. On the other hand, we found that mud-filtrate viscosity and radius of invasion were the most dominant properties when attempting to reproduce the early-time portion of pressure transients with numerical simulations.

History matching of resistivity measurements helped us to diagnose and quantify mobile water saturation that caused separation between apparent resistivity curves in wells drilled with OBM. In addition, resistivity simulations provided us with a redundant way to determine the radial profile of mud-filtrate invasion, which remained uncertain from the separate history match of GOR measurements. The two field examples considered in this paper indicate that combining resistivity with formation-tester measurements reduces ambiguity in the interpretation, enables more accurate estimations of permeability, and improves the prediction of fluid cleanup times, especially in the case of deviated wells.

Simulation of formation-tester measurements acquired in complex environmental conditions requires information about a multitude of petrophysical, fluid, and rock-fluid properties not usually invoked with standard interpretation methods. In addition, it requires expertise with compositional simulation of fluid flow in porous media, especially grid design and refinement, as well as stability conditions for accurate time marching. However, in field cases such as the ones considered in this paper, numerical simulation and history matching are the only reliable alternatives to appraise the consistency of the petrophysical assumptions and to identify biased, noisy, and inadequate measurements.
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