PREDICTION OF FORMATION-TESTER FLUID-SAMPLE QUALITY IN HIGHLY-DEVIATED WELLS

Renzo Angeles, Carlos Torres-Verdin, and Mayank Malik, The University of Texas at Austin

ABSTRACT
Fluid samples acquired with formation testers are often contaminated with mud filtrate. In some cases, it may take hours or even days to achieve acceptable levels of mud-filtrate contamination, thereby rendering the fluid-sampling operation undesirable for either economical or safety considerations. Several analytical and numerical procedures have been proposed to predict fluid cleanup times. However, none of these procedures is suitable for the case of highly-deviated wells, increasingly used in hydrocarbon recovery operations. To further complicate matters, numerical predictions cannot be approximated with analytical solutions because of both the high spatial asymmetry of the mud-filtrate invaded zone (especially for the case of point probes) and non-negligible multiphase rock/fluid interactions. Likewise, it becomes important to appraise the performance of recently-introduced focused fluid-sampling probes for the rapid acquisition of low-contamination fluid samples in highly-deviated wells.

We implement 3D numerical algorithms to simulate formation-tester measurements acquired in highly-deviated wells using point and finite line sources. Because the analysis is not restricted to the assumption of single-phase flow nor it neglects presence of mud-filtrate invasion, numerical simulation enables the quantitative appraisal of realistic tool and formation properties under a wide range of deviation angles. The analysis is centered about four synthetic rock formations (low- to high-permeability rocks) to investigate the effect of rock and fluid properties on the time required to collect fluid samples at 10% and 2% contamination levels as well as on the time to achieve oil breakthrough. Sensitivity studies consider the effects of permeability anisotropy, capillary pressure, gravity segregation, radius of mud-filtrate invasion, fluid viscosity, fluid density, probe diameter, and pumpout rate for oil- and dry-gas-bearing rock formations. Moreover, comparisons are made between sampling operations performed in wells drilled with water-based (WBM) and oil-based (OBM) mud.

We show that, in general, gravity is detrimental to fluid cleanup times. The larger the angle of deviation (with respect to the vertical axis), the longer it takes to achieve oil breakthrough. For instance, one case example indicates that fluid samples with 10% contamination could be achieved 4 hours later in a horizontal well than in an equivalent vertical wellbore for a 100-mD formation invaded 0.5 ft. We also found that gravity-segregated invaded formations strongly affect fluid sampling predictions enforcing our notion that a numerical technique, such as the one suggested in this paper, is necessary to accurately predict fluid-cleanup times in high-angle wells.

INTRODUCTION
One of the major technical challenges in collecting fluid samples for PVT and chemical characterization is to achieve minimum contamination and, perhaps more importantly, to reliably predict tool performance during the sampling operation under a variety of hostile environments. Thus, prompt and thorough decisions can be made regarding tool operational parameters (e.g., probe orientation, flow rate schedule, etc.) or even about the technical feasibility of the test. General guidelines have been published in the past to predict formation-tester sample contamination. However, most efforts have been focused to vertical wellbores, disregarding in large part, the ever more common case of highly-deviated and horizontal wellbores. In addition, complex fluid-flow behavior around formation-tester probes coupled with the asymmetric spatial distribution of mud filtrate requires non-trivial analytical solutions of pressure and fractional flow. The latter solutions are not possible to solve unless one substantially simplifies the assumptions of two-phase flow properties (e.g. constant fluid saturation fronts, negligible capillary pressure and gravity effects) or disregard the mud-filtrate invaded zone. Although practical, these approximate solutions are not accurate to assess either complex formation properties or general tool configurations.

In an earlier work, Hammond (1991) introduced analytical equations for fluid sampling assuming spherically-symmetric fluid flow and a cylindrical invasion distribution around the wellbore. Akram et al. (1999) used numerical simulations and field data to empirically revise Hammond’s equation; they modified the exponent of contamination decay from 2/3 to a function of both radius of invasion and end-point mobility ratio. Similar empirical exponents were proposed based on additional field observations.
Alternatively, the use of numerical algorithms for fluid sampling prediction has proved advantageous in the last decade (Proett et al., 2002; Liu et al., 2004). Alpak et al. (2006) implemented a rigorous numerical method to simulate OBM filtrate cleanup using an equation-of-state compositional fluid-flow simulator. Zazovsky (2008) used finite elements and assumed single-phase flow and piston-like displacement to monitor fluid cleanup based on two major events, namely, the breakthrough of formation fluid at the probe and the transition between fluid-flow regimes (circular to vertical). Predictions of fluid sampling for newly-introduced focused-sampling probes have also been advanced using analytical techniques (Sherwood, 2005) and numerical methods (Hrametz et al., 2001; Malik et al., 2008) for the case of vertical wellbores that penetrate horizontal layers.

To our knowledge, there are no published analytical or numerical solutions that can model fluid sampling with probe-type formation testers for different values of azimuth and well-deviation angle. Recently, Onur et al. (2004) described analytical solutions for pressure measurements acquired with dual-packer formation testers in slanted wells. Using a variant of the uniform flux line-source solution previously advanced by Cinco-Ley et al. (1975), the authors introduced a set of single-phase fluid-flow equations to determine formation properties, such as horizontal permeability ($k_h$), vertical permeability ($k_v$), skin factor ($S$), and tool-storage coefficient ($C$) using nonlinear regression. Sampling prediction was not considered in Onur et al. (2004)’s work.

In this paper, we make use of rigorous 3D multiphase numerical simulation to predict the time evolution of fluid-sample quality in highly-deviated wellbores. The analysis includes cases for vertical and horizontal wellbores ($0^\circ$ and $90^\circ$ deviation, respectively) as well as the quantitative appraisal of focused-sampling probes. Because the numerical method is based on a general-purpose commercial reservoir simulator, it can be applied to a variety of reservoir types, including those that include black oil, gas, and condensate. In addition, gravity and capillary pressures are no longer assumed negligible as in most analytical solutions. A central part of our work quantifies the impact of gravity on fractional-flow measurements acquired for different angles of wellbore deviation and different azimuthal positions of the sample probe around the perimeter of the wellbore.

METHOD

Numerical Simulation. Simulation cases described in this paper were performed with the commercial suite of three-phase, multi-component numerical simulators supported by CMG*. However, the same strategy could be applied with any numerical method that implements corner-point-geometry grids. While cases of water-base mud-filtrate invasion were modeled with a black-oil reservoir simulator, cases of oil-base mud-filtrate invasion used the compositional equation-of-state method. In both cases, rock-fluid properties such as saturation-dependent capillary pressure and relative permeability were explicitly included in the simulations and we rigorously accounted for the effects of gravity.

Of special significance to the simulations of fluid sampling in deviated wells is the design of the numerical grid. Given the specific geometrical and petrophysical constraints of this problem, coupled with the need to properly account for wellbore effects and well orientation (Figure 1), the numerical grid was constructed using corner-point geometry. In so doing, we use a technique similar to that described by Alpak et al. (2003) where, instead of including a true cylindrical wellbore, the wellbore was spatially discretized using a sequence of finite-square grid blocks. Such grid blocks were made inactive to enforce no-flow boundary conditions around the surface of the wellbore as illustrated by the cross-sections of Figures 2 and 3. Due to this spatial discretization strategy, the wellbore can be tilted at any deviation angle while formation beds remain horizontal. The same approach facilitates the simulation of multi-layer models, including the case of finely-laminated rock formations penetrated by a deviated wellbore.

Two additional geometrical properties have to be taken into account to perform the numerical simulations:

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* CMG: Computer Modeling Group Ltd.
First, the dimensions of the wellbore change according to the angle of wellbore deviation ($\theta$) because horizontal “slices” of the wellbore become ellipses, whereby the length of the major axis is scaled by $\cos(\theta)$. Second, the numerical dimensions of the probe (in the case of probe-type formation testers) also change according to deviation angle by a similar factor, which causes the vertical size of the grids to change when used to discretize probe dimensions. The latter situation also arises when simulating fluid-sample acquisition with focused-sampling probes.

Fig. 2. Horizontal cross-section of water saturation intersecting the location of the probe. The cross-section shows the synthetic wellbore shape, well injectors, and the numerical grid used for simulations with a deviation angle of 45º at time $t = 28.8$ min after the onset of drawdown.

Fig. 3. Vertical cross-section of water saturation intersecting the location of the probe. The cross-section shows the synthetic wellbore shape, well injectors, and the numerical grid used for simulations with a deviation angle of 45º at time $t = 28.8$ min after the onset of drawdown.

To simulate the process of mud-filtrate invasion, we place injectors around the surface of the wellbore and enforce fluid injection for a time interval of 0.5 days at specific rates of injection, namely: 17.3, 40.4, and 80.9 $\times 10^{-5}$ cm/s for the base-case model. Both injection rates and time of invasion are arbitrary and are intended solely for the initialization of fluid-saturation and pressure conditions prior to the onset of formation testing. Lower injection rates in the order of $12 \times 10^{-5}$ cm/s are used in our examples of gravity segregation. We do not account for possible variations of injection rate around the perimeter of the wellbore due to gravity. As in the case of numerical simulations of fluid sampling, simulations of mud-filtrate invasion enforce explicit assumptions about capillary pressure and relative permeability. These assumptions prove critical for the cases of gravity segregation and horizontal wells. In addition, because of simplicity, we make no distinction between imbibition and drainage cycles of capillary-pressure and relative-permeability curves. Immediately after the simulation of mud-filtrate invasion, fluids are withdrawn through the probe region to simulate the time evolution of fractional flow rates. We assume that invasion stops during formation testing.

Fig. 4. Results from numerical grid-refinement studies for the simulation of pressure and fractional flow measurements at the end of a 30-min drawdown schedule.

Fig. 5. Simulated radial profiles of water saturation resulting from the process of water-base mud-filtrate invasion. Red and blue curves describe radial profiles of water saturation simulated with a 3D Cartesian grid and a 2D cylindrical grid, respectively. The formation under consideration is the base-case model for Rock Type No. 3 penetrated with a vertical well.
Validation. Figure 4 summarizes the grid refinement studies performed with the base-case model. A total of 227,520 finite-difference grids are necessary to decrease the relative error of the simulated fractional flow rates below 0.05%. The associated CPU time is 38.3 minutes for a 15-hour fluid-sampling simulation (well with a deviation angle of 45º) on a 2.4 Ghz PC (Dell Optiplex 745 computer) with 4GB memory. By comparison, the simulation of a 0.5-hour fluid-sampling operation requires 26.1 minutes of CPU time for the same example. In addition, the base-case model was compared to a vertical well model specified with cylindrical coordinates to evaluate the effects of discretizing the synthetic wellbore with a non-conforming grid. Figure 5 shows the corresponding radial profiles of water saturation simulated at the end of mud-filtrate invasion (WBM example). Both radial profiles compare satisfactorily. For the numerical grid used in this paper, the effects associated with numerical dispersion and borehole shape are negligible when the radius of invasion is shorter than 1.2 ft.

Petrophysical and Geometrical Assumptions. The most restricting assumption of the simulation approach described in this paper is that the off-diagonal entries of the permeability tensor are negligible. Such a condition is only true when the computational grid is aligned with the principal axes of the permeability tensor. For the numerical grid suggested here, the condition does not hold true in general and, consequently, the corresponding simulation error will increase for the case of highly-anisotropic formations. Further confirmation of the validity of our assumption was obtained with cases of 0º, 15º and 90º of wellbore deviation (described later in Figure 10). In general, the numerical error due to our permeability-tensor approximation is most noticeable for the 60º cases but still deemed satisfactory for the objectives pursued in this paper. For Rock Type No. 3 with 0.4 ft of mud-filtrate invasion and 60º of wellbore deviation, the numerical error is ±0.3 hours for a 3.5-hour prediction of 10% fluid contamination.

Table 1. Summary of porosity and permeability values assumed for the four synthetic rock types considered in this paper.

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>k (mD)</th>
<th>φ (fraction)</th>
<th>S_{swr} (fraction)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>0.10</td>
<td>0.21</td>
</tr>
<tr>
<td>2</td>
<td>10</td>
<td>0.16</td>
<td>0.16</td>
</tr>
<tr>
<td>3</td>
<td>100</td>
<td>0.25</td>
<td>0.11</td>
</tr>
<tr>
<td>4</td>
<td>500</td>
<td>0.32</td>
<td>0.07</td>
</tr>
</tbody>
</table>

Synthetic Rock Types. In order to quantify the relationship between fluid cleanup times and wellbore deviation and other influential rock-fluid properties, we introduce four synthetic rock types. These synthetic rock types span a wide range of petrophysical properties that enable a realistic analysis of fluid cleanup times. Table 1 summarizes the permeability and porosity values assumed for each of the four synthetic rock types. Figure 6 shows the corresponding capillary-pressure and relative-permeability curves, and Tables 2 and 3 describe the numerical grid dimensions and rock/fluid properties assumed in the simulations of fluid cleanup.

In what follows, we refer to as “base-case model” the set of standard formation properties and numerical discretization assumed for most of the simulation examples considered in this paper. Although arbitrary, the petrophysical properties assumed for the base-case model are consistent with realistic field observations. For instance, the probe diameter for the base-case model is equal to 0.56 in and the wellbore diameter is equal to 8.5 in. The probe cross-sectional area is discretized using 9 grid blocks (each 0.17 in length). An additional set of 451 null grid blocks is used to specify the synthetic wellbore. The top of the formation is located at 9,100 ft and the reference pressure at the depth of 9,175 ft is assumed equal to 4,000 psi. For oil-reservoir cases, the location of the water/oil contact (WOC) is assumed equal to 10,000 ft. The production...
NUMERICAL SENSITIVITY STUDIES

This section analyzes the effects of rock/fluid properties on fluid-cleanup times as well as their dependence on angle of wellbore deviation. To that end, a total of 180 simulations were performed at various radii of invasion with fluid contamination measurements being sampled as described in Figure 8: at 2%, 10%, and 80% contamination levels. We consider the 80% level of contamination as an indicator of oil-breakthrough time because, in practice, measurements are noisy and any prediction above that level would be difficult to differentiate in field applications. We note that fractional flow ($f_w$) measurements are used as contamination functions for the case of WBM muds. On the other hand, OBM muds require different contamination functions discussed later in this paper.

flow rate enforced at the probe is assumed equal to 10 cc/s for the base-case model. Figure 7 describes the time evolution of oil-flux vectors superimposed to spatial cross-sections simulated for the base-case model for Rock Type No. 3 with a deviation angle of 45°. The direction and number of arrows in the figure clearly indicate changes of flow regimes as well as the increasing influence of spatial regions located far away from the sink probe as fluid sampling progresses with time. As emphasized later with log-log contamination plots, changes in flow regimes are important for real-time predictions of fluid-cleanup times, even for cases of mud-filtrate invasion affected by gravity segregation.

Table 2 Summary of geometrical and numerical simulation properties assumed for the base-case model.

<table>
<thead>
<tr>
<th>Property</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellbore radius, $r_w$</td>
<td>ft</td>
<td>0.354</td>
</tr>
<tr>
<td>External radius, $r_e$</td>
<td>ft</td>
<td>160.0</td>
</tr>
<tr>
<td>Reservoir thickness</td>
<td>ft</td>
<td>150.0</td>
</tr>
<tr>
<td>Water/oil contact depth</td>
<td>ft</td>
<td>10,000</td>
</tr>
<tr>
<td>Number of grid blocks – x direction</td>
<td>–</td>
<td>64</td>
</tr>
<tr>
<td>Number of grid blocks – y direction</td>
<td>–</td>
<td>79</td>
</tr>
<tr>
<td>Number of grid blocks – z direction</td>
<td>–</td>
<td>45</td>
</tr>
</tbody>
</table>

Table 3 Summary of rock and fluid properties assumed for the base-case model.

<table>
<thead>
<tr>
<th>Property</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil density</td>
<td>g/cc</td>
<td>0.84</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>cp</td>
<td>0.5</td>
</tr>
<tr>
<td>Oil compressibility</td>
<td>1/psi</td>
<td>2.7e-5</td>
</tr>
<tr>
<td>Oil bubble point pressure, $P_{bo}$</td>
<td>psi</td>
<td>500</td>
</tr>
<tr>
<td>Oil formation volume factor @ $P_{bo}$</td>
<td>RB/STB</td>
<td>1.2</td>
</tr>
<tr>
<td>Water density</td>
<td>g/cc</td>
<td>1.0</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>cp</td>
<td>0.5</td>
</tr>
</tbody>
</table>

Fig. 7. Time evolution of oil-flux vectors superimposed on spatial cross-sections of water saturation for the base-case model. The simulated were performed at fluid-sampling times equal to 14.4, 28.8, 72, and 144 min after the onset of drawdown.

Fig. 8. Simulated time evolution of fractional flow (water). Arrows indicate specific fluid-sampling times considered in this paper to appraise fluid contamination.

Fig. 9. Effect of radius of mud-filtrate invasion on simulated fractional-flow measurements for synthetic Rock Type No. 3.
Fig. 10. Relationship between fluid-cleanup time (fw = 10%) and radius of mud-filtrate invasion for various angles of wellbore deviation. The curves were constructed with numerical simulation results for synthetic Rock Type No. 3.

In the following examples, and unless otherwise stated, the probed rock formation is assumed homogeneous and isotropic, whereas the in-situ hydrocarbon is assumed black-oil invaded with WBM.

**Effect of Wellbore Deviation.** Simulations were performed for wellbore deviation angles of 0º, 15º, 30º, 45º, 60º, and 90º. Figures 9 and 10 describe the relationship between fluid-cleanup time and radius of mud-filtrate invasion ($r_{inv}$) for Rock Type No. 3. We observe that fluid-cleanup time increases exponentially with radius of invasion. More importantly, the curves in Figure 10 shift from right to left as the angle of wellbore deviation increases, implying that gravity is detrimental to sampling operations. Specifically, for Rock Type No. 3 and a radius of invasion of 0.5 ft, simulations indicate that 1.4 hours are necessary to achieve 10% contamination when the wellbore is vertical. By contrast, it takes 5.4 hours to achieve the same level of fluid contamination when the wellbore is tilted to 90º.

Another observation concerns the way in which the curves are distributed between the “envelope” of 0º and 90º angles of deviation. These two limiting cases contain orthogonal grids that are aligned with the main axes of the permeability tensor and, hence imply zero off-diagonal elements. As observed in Figure 10, remaining curves evolve monotonically between the two limiting cases, thereby suggesting that our numerical approach and assumptions thereof are satisfactory for this application.

Figure 11 and Figure 12 describe the effects of wellbore deviation for Rock Types Nos. 1 and 4 at contamination levels of 10% and 80%. As expected, the curves for Rock Type No. 1 are shifted toward the left.

Fig. 11. Relationship between time of oil-breakthrough (fw = 80%) and radius of mud-filtrate invasion for various angles of wellbore deviation. The curves were constructed with numerical simulation results for synthetic Rock Types No. 1 (upper panel) and 4 (lower panel).

Fig. 12. Relationship between time to achieve fw = 10% and radius of mud-filtrate invasion for various angles of wellbore deviation. The curves were constructed with numerical simulations for synthetic Rock Types No. 1 (upper panel) and 4 (lower panel).
Fig. 13. Effect of permeability anisotropy on fluid-cleanup time (fw = 80%) for various angles of wellbore deviation. The curves were constructed with numerical simulations of synthetic Rock Type No. 3 and are compared against those of the isotropic base-case model.

Fig. 14. Effect of production flow rate (q) on fluid-cleanup time (fw = 80%) for various angles of wellbore deviation. The curves were constructed with numerical simulations for synthetic Rock Type No. 3 and are compared against those of the base-case model with q = 10 cc/s.

Thus, it takes longer to achieve the same level of fluid cleanup for an equal value of radius of invasion than for Rock Type No. 4. Such behavior is due to the fact that Rock Type No. 1 represents a tight formation which entails relatively deep invasion and large capillary-pressure effects during both invasion and fluid sampling. Hence, it takes longer to achieve similar values of fluid cleanup than for Rock Type No. 4 (a highly permeable rock which exhibits relatively low values of capillary pressure).

Fig. 15. Effect of oil viscosity (viso) on fluid-cleanup time (fw = 80%) for various angles of wellbore deviation. The curves were constructed with numerical simulations of synthetic Rock Type No. 3 and are compared against those of the base-case model assuming viso=0.5 cp.

Fig. 16. Effect of water viscosity (visw) on fluid-cleanup time (fw = 80%) for various angles of wellbore deviation. The curves were constructed with numerical simulations for synthetic Rock Type No. 3 and are compared against those of the base case model assuming visw=0.5 cp.

Effect of Permeability Anisotropy. The base-case model was modified with an anisotropy ratio ($k_h/k_v$) of 10. Figure 13 shows that regardless of angle of deviation, fluid cleanup improves as a consequence of the increase of anisotropy.

Effect of Production Rate. Two production flow rates (q) at the sampling probe were simulated and compared against the base-case model (q = 10 cc/s): q = 1 and 30 cc/s. Figure 14 confirms that fluid-cleanup times improve with an increase of rate of probe production. For example, the oil breakthrough time simulated for Rock Type No. 3 in a 60° deviated wellbore with 0.9 ft of mud-filtrate invasion decreases from 0.31 to 0.1 hours when the production rate increases from 10 to 30 cc/s, respectively.

Effect of Fluid Viscosity. We considered variations of fluid viscosity to assess the corresponding impact on fluid-cleanup times at various angles of wellbore deviation. Accordingly, numerical simulations were performed for values of oil viscosity (viso) of 10 and
100 cp. **Figure 15** compares numerical simulations for the 10-cp case against those of the base-case model (with \( v_{iso} = 0.5 \) cp). It is observed that fluid-cleanup time increases as oil viscosity increases. As shown in **Figure 16**, simulations performed with different values of water viscosity \( v_{isw} = 0.5 \) and 1 cp were also considered, indicating that the more viscous the water the shorter the time required to retrieve clean fluid samples.

**Effect of Fluid Density.** Fluid-cleanup times for the base-case model did not appreciable change with an increase of oil density from 0.88 to 0.93 g/cc (equivalent to changing the API gravity from 30º to 20º). This behavior is attributed to negligible gravity segregation effects. A subsequent section of this paper quantifies in detail the effects of gravity segregation on fluid cleanup times.

**GAS-BEARING FORMATIONS**
The numerical grid remains unchanged when performing simulations of invasion and fluid withdrawal in dry-gas reservoirs. However, in the simulations we consider a gas-water model and assume that WBM invades the formation. **Figure 17** reveals interesting properties of mud-filtrate invaded gas- and oil-bearing reservoirs. Gas mobility is usually higher than oil mobility because of typically low values of gas viscosity. This translates into relatively low mobility ratios and, in turn, into relatively sharp fluid saturation/concentration fronts. Consequently, as shown in **Figure 18**, the fractional flow curve quickly reaches a constant-value asymptote, indicating that relatively short fluid cleanup-times are necessary to achieve acceptable levels of fluid contamination regardless of radius of invasion. We also observe that gravity forces increase their detrimental effects on fluid-cleanup time as the angle of wellbore deviation increases. The above observation is conspicuous for rock formations similar to Rock Type No. 1.

**OBM INVASION**
We use the same numerical strategy to simulate the process of OBM-filtrate invasion in oil- and gas-bearing reservoirs. The numerical grid remains unaltered but the reservoir model changes from black-oil to a compositional equation-of-state (EOS) model. In the simulations described in this section, oleic phase compositions in both OBM-filtrate and in-situ hydrocarbon are tracked using the Peng-Robinson EOS (Peng and Robinson, 1978). In addition, fluid viscosities are calculated using the Lohrenz-Bray-Clark (LBC) correlation (Lohrenz et al., 1964), and phase densities are calculated from the EOS to account for compositional and pressure variations in the vicinity of the formation-tester probe during fluid sampling.

**Tables 4 and 5** summarize the fluid and formation properties assumed in the compositional simulations for both in-situ fluid and mud-filtrate. These properties are based on field measurements reported by Malik et al. (2007). The reservoir model consists of 8 pseudo-components: 5 pseudo-components included in formation oil (\( C_1 \) to \( C_{19} \)) and 3 pseudo-components included in OBM-filtrate (\( C_{14} \) to \( C_{18} \)). Likewise, in-situ fluid consists of \( C_1-C_4 \) components of 70 mol %, that is,
light oil with significant gas content that enables discrimination of mud-filtrate from virgin fluid with an optical fluid analyzer using gas/oil ratio (GOR) measurements.

Even though in this paper we use GOR to discriminate native from invading fluid, we note that other measurements acquired with formation testers could be used for discrimination, including density, optical density, pH, and viscosity. We use GOR in connection with the contamination function \( C(t) \) introduced by Austad \( et \) \( al. \) (2001), namely,

\[
C(t) = 1 - \frac{1}{\rho_m \left( \frac{\text{GOR}_o}{\text{GOR}(t)} - 1 \right) + 1}
\]

where \( t \) is elapsed time measured from the onset of fluid withdrawal, \( \rho_m \) is mud density, \( \rho_o \) is formation oil or gas density, \( \text{GOR}_o \) is uncontaminated formation GOR, and \( \text{GOR}(t) \) is the measured GOR. Hence, the contamination function becomes 0 in the absence of mud-filtrate invasion (where densities and GOR remain equal) and 1 in a fully-invaded sample (where \( \text{GOR}(t) \) is close to 0 due to negligible gas content).

There is an additional technical point to be considered.

**Table 4** Equation-of-state parameters and mol fractions of the in-situ pseudo-components assumed in this paper for the simulation of OBM invasion.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>N(_2)</th>
<th>C(_1)</th>
<th>C(_2)</th>
<th>C(_3)</th>
<th>C(_4)</th>
<th>C(_6)</th>
<th>C(<em>7) - C(</em>{18})</th>
<th>C(_{19}) +</th>
</tr>
</thead>
<tbody>
<tr>
<td>Molar Concentration</td>
<td>0.618</td>
<td>0.079</td>
<td>0.0875</td>
<td>0.179</td>
<td>0.036</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Critical Temp. (ºF)</td>
<td>-126</td>
<td>125.9</td>
<td>359.8</td>
<td>656.2</td>
<td>1060</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Critical Press. (psi)</td>
<td>653.3</td>
<td>839.4</td>
<td>498.2</td>
<td>322.3</td>
<td>184.4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Acentric Factor</td>
<td>0.011</td>
<td>0.146</td>
<td>0.230</td>
<td>0.490</td>
<td>0.919</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Molar Weight (lbs/mol)</td>
<td>16.6</td>
<td>36.23</td>
<td>67.73</td>
<td>132.8</td>
<td>303.2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volume Shift Parameter</td>
<td>-0.19</td>
<td>-0.131</td>
<td>-0.056</td>
<td>0.171</td>
<td>0.231</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 5** Equation-of-state parameters and mol fractions of the mud-filtrate pseudo-components assumed in this paper to simulate cases of OBM invasion.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MC(_{14})</th>
<th>MC(_{16})</th>
<th>MC(_{18})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Molar Concentration</td>
<td>0.6489</td>
<td>0.2145</td>
<td>0.1364</td>
</tr>
<tr>
<td>Critical Temp. (ºF)</td>
<td>755.1</td>
<td>822.5</td>
<td>878.1</td>
</tr>
<tr>
<td>Critical Press. (psi)</td>
<td>261.8</td>
<td>240.2</td>
<td>224.4</td>
</tr>
<tr>
<td>Acentric Factor</td>
<td>0.6257</td>
<td>0.7118</td>
<td>0.7842</td>
</tr>
<tr>
<td>Molar Weight (lbs/mol)</td>
<td>190</td>
<td>222</td>
<td>251</td>
</tr>
<tr>
<td>Volume Shift Parameter</td>
<td>0.0792</td>
<td>0.0666</td>
<td>0.0439</td>
</tr>
</tbody>
</table>

**Fig. 19.** Horizontal cross-section of the simulated oil mass density during fluid sampling in Rock Type No. 3 at time \( t = 1.44 \) min after the onset of drawdown. Locally-refined grids shown here are included in the simulation of OBM-filtrate invasion.

**Fig. 20.** Vertical cross-section of the simulated MC\(_{14}\) mole fraction during fluid sampling on Rock Type No. 3 at time \( t = 1.44 \) min after the onset of drawdown. Locally-refined grids shown here are constructed to simulate cases OBM-filtrate invasion.

**Fig. 21.** Relationship between fluid-cleanup time (\( f_w = 80\% \)) and radius of OBM mud-filtrate invasion for various angles of wellbore deviation. The curves were constructed with numerical simulation results for synthetic Rock Type No. 3.
when simulating cases of fluid contamination with OBM: As the number of pseudo-components increases, the requirements for computation time and memory increase. An alternative to the numerical grid structure described earlier is to use the locally-refined grids described in Figure 19 and Figure 20. By doing so, the number of grid blocks dramatically decreases from 227,520 to 91,905 (of which 74,359 are fundamental). Nonetheless, the CPU time increases to 1.48 hours for a 0.5-hour sampling simulation. We also emphasize that locally-refined grids are not straightforward to specify as in the numerical grid structure used in simulation cases involving WBM.

Figure 19 is a horizontal slice of the synthetic wellbore that intersects the probe depth. Instead of water saturation (used in cross-sections for WBM cases), we use oil mass density to distinguish OBM from formation oil, both fully miscible and thereby constituting a single-phase system. We note that the choice of oil mass density was arbitrary; other fluid properties could have been plotted to describe invasion in the figure, such as oil viscosity, for instance. Similarly, Figure 20 is a vertical slice of the same simulation case for a representative mole fraction ($MC_{14}$) in the OBM-filtrate composition. Figure 21 indicates that one can also plot cleanup time vs. radius of mud-filtrate invasion as in the cases of WBM for different angles of wellbore deviation. We observe that gravity has comparable deleterious effects on fluid-cleanup times to those of WBM-invasion case examples: the larger the wellbore deviation, the longer it takes to secure a clean fluid sample.

FOCUSED FLUID-SAMPLING PROBES

Recently, focused fluid-sampling probes have received significant attention in the formation-tester literature. They are based on the concept of a “sample” probe surrounded by a number of “guard” probes. As shown by Hrametz et al. (2001) and others, such probe configuration is used to reduce the level of sample contamination further than with a conventional probe. In this paper, we show that fluid sampling with focused probes can be analyzed with the same numerical approach described earlier to predict fluid-cleanup times for specific geometrical and petrophysical formation properties and as a function of the angle of wellbore deviation.

Figure 22 describes both the numerical discretization used to simulate fluid-sampling with focused-sampling probes and the geometrical dimensions of the probe itself. The same probe configuration was invoked by Malik et al. (2008), who implemented a similar numerical simulation approach for the case of vertical wellbores. Remaining rock formation properties are equal to those of the base-case model including the total production flow rates enforced at the probe (10 cc/s). Flow rates are proportionally divided using a 1:3 ratio for sample and guard probes, respectively. Figure 23 shows the fractional-flow rates simulated with the focused-sampling probe-type formation tester for Rock Type No. 3 invaded with WBM at 45º of wellbore deviation. Clearly, the sample probe achieves lower levels of sample contamination compared to the conventional probe while the mud-filtrate content sampled with guard probes is relatively high. This behaviour is confirmed by Figure 24 and Figure 25, where the observe that the sample probe dramatically improves the fluid-cleanup time regardless of radius of mud-filtrate invasion, when compared to fluid-cleanup times of a conventional probe (described earlier).
Effect of Wellbore Deviation. Gravity has the same effect on focused-sampling probes as in conventional probes. The larger the angle of wellbore deviation, the longer it takes to achieve clean samples. However, Figure 25 also indicates an interesting feature of the simulated curves for $f_w=10\%$: The sample probe seems unaffected by the wellbore deviation for radii of invasion shorter than 0.5 ft (for the case of Rock Type No. 3). In this case, there is an additional benefit stemming from using focused-sampling probes: Not only can one achieve shorter fluid-cleanup times (at 10% contamination, compared to a conventional probe) but the effect of gravity is further reduced for the case of rock formations exhibiting negligible mud-filtrate invasion. A similar behaviour was observed in the simulated curves for $f_w=2\%$.

Effect of Probe Orientation. The previous simulation examples assumed that the sampling probe was facing the upper side of the deviated wellbore. Figure 26 shows the numerical grid to simulate the corresponding fractional-flow curves when assuming a horizontal well analogous to that shown in Figure 22 except that the sampling probe is positioned to test the lower side of the wellbore. Figure 27 indicates that there is a small increase in the times necessary to achieve fluid cleanup when the sampling probe is facing the lower side of the wellbore. The corresponding time increase, however, increases with larger values of radii of mud-filtrate invasion.

Fig. 24. Relationship between fluid-cleanup time ($f_w = 80\%$) and radius of mud-filtrate invasion for focused-sampling probes at various angles of wellbore deviation. The curves were constructed with simulations for Rock Type No. 3. In this case, fluid-cleanup time is considerably shorter for the sample probe (upper panel) than for the guard probe (lower panel).

Fig. 25. Relationship between fluid-cleanup time ($f_w = 10\%$) and radius of mud-filtrate invasion for focused-sampling probes at various angles of wellbore deviation. The curves were constructed with numerical simulations at the sample (upper panel) and guard probes (lower panel) for synthetic Rock Type No. 3.

Gravity Segregation. Previous observations concerning the effect of probe orientation were based on invasion rates associated with the base-case model. The latter model assumes a relatively fast rate of mud-filtrate invasion, thereby limiting the time available for gravity segregation to take place. This situation causes an invasion profile that is almost spatially symmetric around the wellbore, hence explaining the small difference in fluid-cleanup times for the examples of upward probe orientation described above. To verify
whether the same situation arises in cases with presence of gravity segregation, we reduced the rate of mud-filtrate invasion to $12 \times 10^{-5} \text{ cm/s}$ and extended the invasion time to 7 days with Rock Type No. 4 (the synthetic rock formation that exhibits the highest permeability and the lowest capillary-pressure effects).

Figures 28 and 29 show the resulting spatially asymmetric mud-filtrate distribution around the wellbore at the end of the invasion. This time we observe a large difference in the flow regimes developed at the sampling probe because of the relative orientation of the probe with respect to the wellbore. As suspected, Figure 30 confirms that a probe facing the lower side of the wellbore will take longer to achieve clean fluid samples. For instance, when Rock Type No. 4 is radially invaded by approximately 0.6 ft, it will take either 1.5 or 11.4 minutes to observe oil breakthrough at the sampling probe depending on whether the probe is facing the upper or lower side of the wellbore, respectively. Likewise, it will take 75 extra minutes to achieve fluid-contamination levels of 10% for the same sampling operation.

Figure 30 also reveals a feature not observed before in previous simulation examples: there is a specific radius of mud-filtrate invasion at which the guard probe is no longer useful for fluid sampling because it begins to achieve cleaner fluid samples faster than the sample probe! Although this behavior is related to the 1:3 ratio assumed fixed of flow rates for the focused-sampling probe configuration, simulation results stress the need of adjusting the flow rate ratio in response to specific tool configurations and petrophysical properties of the probed formation. Furthermore, this simulation example makes illustrates the complexity of fluid-sampling prediction for the case of spatially asymmetric invasion around the wellbore.
Fig. 29. Vertical cross-section of the simulated spatial distribution water saturation at times $t = 0$ min (upper panel) and 28.8 min (lower panel) after the onset of drawdown, intersecting the location of a focused-sampling probe. The cross-sections show both the synthetic wellbore shape and the location of the probe facing the upper side of a horizontal well.

CONTAMINATION REGIMES

It is important to compare the previous case examples affected by gravity segregation with the asymptotic behaviour expected from analytical solutions. Most of the proposed analytical solutions in the open technical literature follow a model similar to that suggested by Hammond (1991), where the contamination function $C(t)$ is given (in consistent units) by

$$C(t) = \begin{cases} 1, & t \leq t_D \\ 1 - \sqrt{1 - \left(\frac{t_D}{t}\right)^{2/3}}, & t > t_D \end{cases}, \quad (2)$$

with the dimensionless time scale $t_D$ expressed as

$$t_D = \frac{4\pi\phi r_{inv}^3}{3q} \sqrt{\frac{k_v}{k_h}}, \quad (3)$$

where $\phi$ is porosity, $r_{inv}$ is radius of mud-filtrate invasion, $q$ is production flow rate, $k_v$ is vertical permeability, and $k_h$ is horizontal permeability. Thus, at late times, the contamination function $C(t)$ decays as $(t_D / t)^{2/3}$. Following a similar strategy as the one used in pressure-transient testing analysis to identify flow regimes (e.g., spherical, radial), we plot the contamination function versus time using log-log scales. The data should then reveal a slope of -2/3 for the case of spherical sampling draining a cylindrically-invaded region with negligible viscosity-contrast and capillary-pressure effects. Other slope values, such as -5/12 have been proposed to interpret field observations (Mullins, 2000).

Figures 31 and 32 show log-log contamination plots for the cases where the focused-sampling probe faces the upper and lower side of the wellbore, respectively. Although the slope observed in both cases is close to the values of -2/3 and -5/12, the fact is that there is not one single asymptotic line that can predict the shown examples. Nonetheless, we can distinguish a set of contamination regimes evolving with time. First, there is only production of mud filtrate which finishes at the time of oil-breakthrough. Second, slopes in the range of -2/3 and -5/12 develop as sampling continues. Zazovsky (2008) suggests that the change of slope from -5/12 to -2/3 takes place because the contamination regimes are switched from early-time radial to spherical flow. This change in fluid-cleanup regime is no longer
evident for the case of gravity-segregated mud-filtrate invasion as radial flow takes place concomitantly with spherical cleanup. Finally, the slopes associated with measurements acquired with all probes (sample and guard) tend to a value close to \( \sim 1.5 \), which we attribute to the effect of capillary pressure, generally not seen in OBM-filtrate invaded formations but noticeable in cases of WBM-filtrate invasion.

**SUMMARY AND DISCUSSION**

The simulation framework introduced in this paper is rigorous and general: it only requires specifying a synthetic wellbore and numerical grids using corner-point geometry. Hence, for the study it is possible to include full capabilities of modern reservoir simulators, i.e. no restriction exists on the use of black-oil or compositional multiphase flow. Likewise, simulation examples showed that the process of mud-filtrate invasion could be readily incorporated in the simulations regardless of the mud system (WBM or OBM) used with drilling. Although compositional simulations, such as those necessary in the presence of OBM-filtrate invasion, involve additional computational expense compared to black-oil models (in one example the CPU time increased from 26.1 to 1.48 hours when simulating a 0.5-hour sampling operation), they enable the analysis of cases wherein phase behavior is relevant, such as those arising with volatile oil and gas condensate.

The examples described in this paper indicate that neglecting gravity and capillary-pressure effects in the prediction of fluid-sampling times can lead to substantial errors when the wellbore is not vertical. Specifically, for our base-case model with Rock Type No. 3, a rock formation invaded at 0.5 ft radial distance requires 1.1 and 4.0 hours of extra time to achieve 10% contamination levels when the angle of wellbore deviation is 45° and 90° (respectively) compared to that of a vertical well. On the other hand, capillary forces spatially smooth the invasion profile, especially in oil-bearing formations invaded with water-based mud. Likewise, capillary forces cause an increase of slope (faster decay) in the late-time fractional flow curves, when in-situ hydrocarbons flow at irreducible values of mud-filtrate saturation.

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**Fig. 31.** Simulated time evolution of fractional flow (water) for various radii of mud-filtrate invasion \((r_{inv})\) plotted in log-log scales. The simulations were performed with the focused-sampling probe set against the upper part of a horizontal wellbore in the presence of gravity segregation.

**Fig. 32.** Time evolution of the simulated fractional flow (water) for various radii of mud-filtrate invasion \((r_{inv})\) plotted in log-log scales. The simulations were performed with the focused-sampling probe set against the lower part of a horizontal wellbore in the presence of gravity segregation.

Gravity segregation also plays a major role in fluid sampling. We showed that it takes an additional 75 minutes to achieve 10% contamination levels for Rock Type No. 4 depending on whether the sampling is performed with the probe facing the upper or the lower side of the wellbore. In this case, the highly-permeable
Rock Type No. 4 was slowly invaded for a long period of time. There is no rule-of-thumb for diagnosing when such an adverse situation may occur because gravity segregation results from the interplay of many factors, including permeability anisotropy, gravity, capillary pressure, and rate of mud-filtrate invasion. The additional complexity of flow streamlines and invasion radial profiles enforces our notion that a numerical technique, such as the one suggested in this paper, is necessary to accurately predict fluid-cleanup times when formation-tester measurements are acquired in high-angle wells.

To accurately and reliably predict fluid-cleanup times, it is necessary to know the specific transition times between contamination regimes. In cases of considerable spatial asymmetry of mud-filtrate invasion, such as when formation-tester measurements are acquired in the presence of gravity-segregated invasion profiles, analytical asymptotes of single-phase behaviour are no longer accurate for the prediction of fluid-cleanup times. We showed that log-log contamination plots could be used to diagnose such transitions, thereby enabling the monitoring and possible extrapolation of fluid-cleanup times for prediction in real-time operations. Nonetheless, as emphasized throughout this paper, complex tool and rock formations can cause strong non-linear variations in fluid-contamination plots. Accurate and reliable numerical modelling is the only way to predict fluid-cleanup in the most general situation of rock-fluid interactions and spatial heterogeneities of petrophysical properties.

CONCLUSIONS
The following conclusions stem from the work reported in this paper:
1. A new numerical approach was introduced and tested with synthetic examples to predict fluid-cleanup times for sampling operations with probe-type formation testers in highly-deviated wellbores. The method can also be used for formation testing with focused-sampling probes.
2. For the cases studied in this paper, the larger the angle of wellbore deviation, the longer it takes to retrieve uncontaminated fluid samples. Thus, predictions of fluid-cleanup time with analytical solutions in these well configurations can be erroneous. For instance, using Rock Type No. 3 to achieve 10% contamination levels in a 0.5-ft invaded formation, the error between time predictions of 0º and 90º wellbore deviations is approximately 4 hours.
3. Gravity-segregated mud-filtrate invaded profiles are strongly asymmetric and considerably affect fluid-sampling operations. In such situations, sampling probes oriented toward the upper side of the wellbore secure clean fluid samples faster than probes facing the lower side of the wellbore.
4. In cases where setting the sampling probe on the lower side of the wellbore is the only option available, attention should be paid to the ratio of flow rates between sample and guard probes (if using focused-sampling probes). If not optimized and varied with time, a time-constant ratio of flow rates may cause guard probes to acquire lower contamination fluid samples than sample probes.
5. Since there are no rules-of-thumb to diagnose gravity-segregated, invaded formations, it is suggested that our simulation method be used to determine the interplay between viscous, capillary, and gravity forces before predicting sampling times, especially for the case of highly-permeable formations with low anisotropy (\(k_h/k_v\)) and suspect of long invasion time intervals.
6. Even though asymptotic analytical solutions are not accurate for fluid-cleanup time prediction, it is possible to diagnose a change of spatial fluid-cleanup regimes with log-log plots that describe the time evolution of fluid contamination.

NOMENCLATURE

- \(C\) : Tool storage coefficient, [bbl/psi]
- \(C(t)\) : Contamination function, [fraction]
- \(f_o\) : Oil Fractional-flow rate, [fraction]
- \(f_w\) : Water Fractional-flow rate, [fraction]
- \(GOR\) : Gas/oil ratio, [ft³/bbl ]
- \(k\) : Formation permeability, [md]
- \(k_r\) : Relative permeability, [md]
- \(k_h\) : Horizontal permeability, [md]
- \(k_v\) : Vertical permeability, [md]
- \(k_h/k_v\) : Permeability anisotropy, [ ]
- \(P\) : Pressure, [psi]
- \(P_e\) : Capillary pressure, [psi]
- \(\Delta P\) : Pressure drawdown, [psi]
- \(q\) : Production flow rate, [cc/s]
- \(r_w\) : Wellbore radius, [ft]
- \(r_e\) : External radius, [ft]
- \(S\) : Skin factor, [ ]
- \(S_w\) : Water saturation, [fraction]
- \(S_{wirr}\) : Irreducible water saturation, [fraction]
- \(\phi\) : Porosity, [fraction]
- \(\phi_o\) : Oil Fractional-flow rate, [fraction]
- \(\phi_w\) : Water Fractional-flow rate, [fraction]
- \(\phi_{vis}\) : Oil viscosity, [cp]
- \(\phi_{vbw}\) : Water viscosity, [cp]
- \(\rho_o\) : Oil density, [g/cc]
- \(\rho_w\) : Water density, [g/cc]
- \(\rho_m\) : Mud density, [g/cc]
- \(\phi\) : Porosity, [fraction]
- \(\theta\) : Angle of wellbore deviation, [degrees]

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