NUMERIC STUDY OF A DRILLING FLUID LEAK IN A ROCK FORMATION: PERMEABILITY ASPECTS

Gomes, A. F. C.; Marinho, J. L. G.; Oliveira, L. M. T. M.

Centro de Tecnologia, Universidade Federal de Alagoas - UFAL, Maceió-AL, Brasil

Received: 14.09.2016 / Revised: 06.11.2016 / Accepted: 07.11.2016 / Published on line: 29.12.2016

ABSTRACT

The drilling of oil wells is one of the most expensive steps in oil exploration. It requires a high initial investment and it offers an uncertain economic viability. Thus, laboratory tests seek to optimize the process and reduce costs, accidents, and damage to the reservoir. Furthermore, computational calculations and simulations offer more precision and agility in data evaluation, reducing even more the costs and duration of the tests. In this study, a computational model was created to evaluate the drill fluid leak in a permeable rock formation. A fluid was inserted into the reservoir during the well drilling to load debris from the porous domain helping the drill bit. The porosity of the rock formation allows the entry of drill fluid, which can cause environmental damage, can lead to additional expenses, and can derail the well. The objective was to create a model with time-based parameters to conduct the evaluation of the influence of flow parameters. Thenceforth, the simulations allowed observing the high influence of permeability gradients to the profiles of invasion.

KEYWORDS

CFX; permeability; rock formation; simulation; water-based mud

1 To whom all correspondence should be addressed.

Address: Universidade Federal de Alagoas, Av. Lourival Melo Mota – Cidade Universitária – Centro de Tecnologia, Maceió – AL Brasil | ZIP Code: 57000-000 | Telephone: +55 (82) 3214-1292 | e-mail: andersonfgomes93@gmail.com; jlimarinho@ctec.ufal.br; leonardo.oliveira@ctec.ufal.br
doi:10.5419/bjpg2016-0018
1. INTRODUCTION

Petroleum is a natural resource that is an important source of energy and serves as feedstock in the manufacture of various materials such as oils, solvents, fuels, polymers, and drugs. The drilling of oil wells is usually the most expensive stage of its operation. During the drilling stage, one applies a weight on the drilling rig composed of a metal tower, which maintains the drill string with a drill bit at the end (Vieira, 2009). During the drilling, special fluids called mud or drilling fluids are injected. This mud is often a liquid composition that is intended to assist this process. It should marshal the cuttings generated at the surface, cool and lubricate the drill bit, reduce friction between column drilling and rock formation, maintain the well stable, avoiding landslides, and control the process pressure without harming the rock formation, the environment or expose persons (Calabrez, 2013). Even if cost is the primary variable used in deciding between drilling fluids, it is important to use the best formulation of the material to reduce excessive load losses in the circulation, to optimize the well cleaning, to avoid environmental problems caused by invasion of the mud in rock formation or the formation of hydrates (Sorgard et al., 2001).

The output of a lower drilling fluid volume instead of the fluid injected by column denotes the loss of this material to the rock formation. The loss of mud leads to environmental problems and can decrease the relative permeability and generate low productivity, collapsing hydratable formations, leading to erroneous evaluations, trapping the drill string (with overgrowth of the filter cake) and destabilizing the annular region, important for the drag of solid to surface (Al-Yami et al., 2008; Bailey et al., 2000; Farias et al., 2006; Lomba et al., 2002). Numerical simulations are strong allies in the minimization of costs or risks, and offer the possibility to test several variables such as speed, viscosity, density, operating pressure, porosity, and permeability. These numerical simulations establish the best options for the given environment being studied.

Since the return on investment in well drilling is very uncertain and sensitive (due to the high initial investment), the decision to drill a well and how to do it must take into account numerous variables such as its type, volume, drilling speed, technology, hand labor used, and other problems that may arise during the process (Cortez and Pessoa, 2010).

It is complex to represent empirically all the conditions of an oil well. Numerical simulations can make the difference between a good and a bad investment. Among the advantages of using computer simulations are its lower cost, higher response speed, better reproducibility, and high dynamism. Moreover, the possibility of testing empirical extreme situations may be too expensive or impossible. Thus, computational evaluations and simulations can provide more data with greater precision about the economic viability of the well, and also the technology to be used with higher aggregate income.

For the study of fluid invasion, it is necessary to consider some parameters such as permeability, porosity, pressure gradient, viscosity, and density of the fluid, among others. Permeability is a property that measures the ability of a fluid to flow through a particulate material. In literature, there are works, such the one done by Semmelbeck and Holditch (1988), which investigate the effects of flow properties in the invasive process with a numerical simulator. The simulator radially checks for saturation answers to permeabilities, porosities, pressures, and different contact times. It also finds piston-like profiles saturation for high permeabilities, for low permeabilities capillary forces causes scattered saturation profile. Won et al. (2008) used computational fluid dynamics to simulate radial invasion profiles for different values of porosity, permeability, contact time, mud density, type of formation, fluid pressure, and models of fluid. The authors found a directly proportional relationship between the increase in permeability and the intensity of invasion. Wu et al. (2004) numerically studied mud invasion results with two days of run for deviated wells (45°) finding characteristic saturation profiles for permeabilities between 100 to 800 md. Ling et al. (2015) calculated invasion limits of water-based drilling fluids during a period of 10 hours with pie permeabilities between 0.001 to 0.01 md and a rock with 5 md. Waldmann et al. (2007) developed a model and studied the impact of pressure gradient, variations of permeability and porosity to pie and rock formation, and compared it with experimental data calculations, finding R = 99.8%, confirming model effectiveness.
To Ghori and Heller (1998), the variation of permeability is the formation heterogeneous aspect more important to oil extraction. A variety of materials from different ages cause this heterogeneity. Many studies seek to predict or relate permeability with other properties (Khalid et al. 2010; Lake and Jensen, 1989; Mohaghegh et al. 1997; Shokir et al. 2005).

Thus, this work aims to develop a computational model for the simulation of a drilling process with a water-based fluid into a rock formation region saturated with oil. It provides the numerical analysis of the magnitude and the profile of invasion of mud in the porous region and explains how its permeability can influence the invasive process.

2. METHODOLOGY

2.1 Catalyst preparation Geometric model, mesh, and domains

In this work, it was considered a rocky region where a drilling well was generated. Since the average depth of the oil wells is about 5000 to 6500 m in pre-salt reservoirs (Johann et al., 2012), the computational fluid dynamic modeling of the entire process from the well to the surface would become disproportional. This disproportion would not favor the meshing, and would not be viable for understanding the variables, in addition to requiring a very high computational effort. Based on the above, a limited volume of reference was taken for simplification of the form template to only cover a significant region of the process allowing a macroscopic vision of the problem according to Figure 1.

The modeled process is the drilling of an oil well. The drilling fluid is pumped through the inside of the column and is ejected by the drill. It drains to the annular region, between the drill string and the formation, and drags the gravels formed by breaking the rock to the surface. That way, the mud moves downward inside the column and ascendant in the region between the column and the rock formation according to Figure 2.

Figure 1. Overall scheme. (a) Illustration of the pre-salt environment. (b) Expansion of the studied area.

Figure 2. Flow scheme of drilling fluids.
The drill has a diameter of 20 centimeters (about 8 inches) and the column where it is allocated has 16 cm of diameter (approximately 6.3 inches). For the geometry of the rock formation were considered dimensions of 60 cm x 60 cm x 300 cm. To reduce computational effort, a cut along one of the perpendicular axes was made, according to Figures 3 and 4, with dimensions mentioned in Table 1.

With the application of ICEM CFD™, unstructured meshes were generated for the two geometries. Three options of elements allocation were tested (Octree, Delaunay, and Smooth). More favorable results were reached with the Smooth model. Limit dimensions and refinement tools were used for the elements and tetrahedral meshes was generated according to Table 2 for the Mesh Test quoted ahead.

![Figure 3. Geometric representation before (a) and after the central cut (b).](image)

![Figure 4. Geometric representation with the dimensions of the domains.](image)

<table>
<thead>
<tr>
<th>Table 1. Geometry Dimensions.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>-</strong></td>
</tr>
<tr>
<td>---</td>
</tr>
<tr>
<td>A</td>
</tr>
<tr>
<td>B</td>
</tr>
<tr>
<td>C</td>
</tr>
<tr>
<td>D</td>
</tr>
<tr>
<td>E</td>
</tr>
<tr>
<td>F</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 2. Number of elements in each mesh.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Mesh</strong></td>
</tr>
<tr>
<td>---</td>
</tr>
<tr>
<td>1</td>
</tr>
<tr>
<td>2</td>
</tr>
<tr>
<td>3</td>
</tr>
<tr>
<td>4</td>
</tr>
</tbody>
</table>
2.2 Mathematical Model

The model developed for the study aimed at reducing computational effort and was governed by fundamental equations of mass, energy, and momentum conservation. Besides, a few considerations were made:

- Constant reservoir properties;
- Absence of chemical reactions;
- Neglect of thermal effects;
- Newtonian and incompressible fluids;
- Darcy Flow;
- Negligible gravity effects;
- 2 hours of simulation in transient state;
- Null solid transportation.

Traditionally, the equations of mass, momentum, and energy conservation are drawn up to represent fluid-based systems since their conditions are respected (Bird et al., 2002). In fluid mechanics the continuity equation is a consequence of mass conservation in a fluid-flow.

The first parcel refers to mass buildup in domain pores and the second parcel refers to its flow:

\[
\frac{\partial(\Phi \cdot \rho)}{\partial t} + \nabla \cdot \left( \bar{u} \cdot \rho \right) = 0
\]  

(1)

Where \(\Phi\) represents domain porosity, \(\frac{\partial(\Phi \cdot \rho)}{\partial t}\) is the mass accumulation in the domain pores and the second parcel refers to mass transfer, such \(\bar{u}\) is the velocity vector, and \(\rho\) the density.

Darcy’s law is used to represent the porous flow and flow potential coupling to the equation of continuity. The equation relates the apparent fluid velocity in one direction with the potential gradient (pressure differential) in a specific way, as in Equation 2:

\[
u_s = - \frac{k_s \rho}{\mu} \frac{\partial \rho}{\partial s}
\]  

(2)

Where \(\nu_s\) is the fluid-flow velocity in \(s\)-direction (x, y, or z). \(k_s\) is the permeability of the porous medium in the \(s\)-direction, being \(\mu\) the fluid viscosity.

The system used is applied in a two-phase flow. The model requires the inclusion of saturation, which is the property that represents the ratio of volume occupied by such fluid by the total volume of evaluated pores. Therefore, when the volume of pores is evaluated under the flow of a particular fluid, the plots of pores occupied by such material must be selected. That way, the Darcy’s law associates values of pressure gradients to fluid-flow speed values:

\[
\frac{\partial(\Phi \cdot \rho \cdot S_i)}{\partial t} + \nabla \cdot \left( \bar{u} \cdot \rho \cdot S_i \right) = 0
\]  

(3)

Ansyl CFX™ understands the mass and momentum conservation equations under another aspect. The general equation of continuity, mathematically exposed earlier in Equation 1, has an increase of an area porosity tensor, a second order symmetric tensor (\(F\)),

\[
\frac{\partial(\Phi \rho)}{\partial t} + \nabla \cdot (\rho \cdot \bar{u}) = 0
\]  

(4)

To the fluid flow, Araújo and Farias Neto (2009) worked with the presence of another second-order symmetric tensor (\(W\)), responsible for controlling anisotropies on flow resistance in the porous medium in the form:

\[
\frac{\partial(\Phi \rho \bar{u})}{\partial t} + \nabla \cdot \left( \rho \cdot (F \cdot \bar{u}) \times \bar{u} \right) -
\]

\[
- \nabla \cdot \left( \mu F \cdot (\nabla \bar{u} + (\nabla \bar{u})^T) \right)
\]  

(5)

\[
= - \Phi W \cdot \bar{u} - \Phi \nabla \rho
\]

(5)

If the flow resistance \((W)\) is very high, a pressure gradient too high is needed to maintain the balance of the right side of equation. That way, both offer very high values, making the convective and diffusive terms, on left side, meaningless to the application, turning the Equation 5 into a simplified version of Darcy’s law (Equation 2):

\[
\bar{u} = - \nabla \rho / W
\]  

(6)

Considering a multiphase flow with high
viscosity in porous domain and incompressible Newtonian fluid with constant physicochemical properties, static walls, and transient and isothermal flow, the continuity and motion equations become:

\[
\frac{\partial (\rho \phi S_i)}{\partial t} + \nabla \cdot (\rho S_i \mathbf{F} \cdot \mathbf{u}) = 0
\]  

(7)

\[
\frac{\partial (\phi \rho \phi S_i \mathbf{u})}{\partial t} + \nabla \cdot (\phi S_i (\rho \mathbf{F} \cdot \mathbf{u}) \times \mathbf{u}) = \nabla \cdot (\mu \phi S_i \cdot (\nabla \mathbf{u} + (\nabla \mathbf{u})^T)) - \phi S_i \nabla p
\]  

(8)

For which \(\rho\) is the density, \(\phi\) the porosity, \(\mu\) is viscosity, \(S_i\) the saturation of component \(i\), \(\mathbf{u}\) is the vector speed, and \(S_M\) the source of moment due to external forces.

Finally, at the curve fitting by tendency lines, one can calculate the Determination Coefficient value (R²), which is a percentage indication of how a mathematical model can represent observed values empirically. The highest value of R² indicates best model representation. This value is defined by Linear Regression, calculated by:

\[
R^2 = 1 - \sum_{i=1}^{n} (x_i - \hat{x}_i)^2
\]  

(9)

Where \(x_i\) is the real value of \(x\) in each \(i\)-moment, and \(\hat{x}_i\) is the calculated value of \(x\) in \(i\)-moment.

### 2.3 Tests

Initially, a test was conducted to set the mesh to be used in the permeability study. For drilling fluid variables were considered the works of Amorim et al. (2008) and Menezes et al. (2009) with bentonite clay from Cubati (PB) and Boa Vista (PB), respecting the conditions for water-based drilling fluid or bentonite clay listed in the standards N-2604 and N-2605. The case studies with their properties are listed in Table 3.

It was stipulated the presence of an oily fluid in the porous domain with the properties taken as viscosity = 0.17 Pa.s and API degree of 30.9 (868.7 kg/m³) (Oliveira, 2015) to simulate the presence of petroleum, as shown in Table 4. In addition, the flow pressure in the fluid entrance was set to 10 atm and the porous domain pressure in 1 atm. Figure 5 shows the rock formation (porous domain) in green and the annular region (fluid domain) in a shade of gray. Table 5 shows the operational settings of the model.

### Table 3. Case studies.

<table>
<thead>
<tr>
<th>Test</th>
<th>Mesh</th>
<th>Permeability</th>
<th>Constants</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Porosity</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>0.02 darcy</td>
<td>20%</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>0.02 darcy</td>
<td>20%</td>
</tr>
<tr>
<td>3</td>
<td>3</td>
<td>0.02 darcy</td>
<td>20%</td>
</tr>
<tr>
<td>4</td>
<td>4</td>
<td>0.02 darcy</td>
<td>20%</td>
</tr>
<tr>
<td>5</td>
<td>3</td>
<td>0.01 darcy</td>
<td>20%</td>
</tr>
<tr>
<td>6</td>
<td>3</td>
<td>0.03 darcy</td>
<td>20%</td>
</tr>
<tr>
<td>7</td>
<td>3</td>
<td>0.04 darcy</td>
<td>20%</td>
</tr>
</tbody>
</table>

### Table 4. Settings of involved fluids.

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Viscosity (Pa.s)</th>
<th>Density (kg/m³)</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aqueous Fluid</td>
<td>0.045</td>
<td>1100</td>
<td>Menezes et al., 2009</td>
</tr>
<tr>
<td>Oil</td>
<td>0.17</td>
<td>868.7</td>
<td>Oliveira, 2015</td>
</tr>
</tbody>
</table>
3. RESULTS AND DISCUSSION

In this step the results found are presented and discussed with the proposed model. Initially, the mesh test result is presented. Then, one can view the profiles of the case studies involving water-based mud developed for this study.

3.1 Mesh test

Figure 6 shows plotted mud saturations in Porous Domain as a function of elapsed time for the different meshes. The note section of Figure 6 lists the time (in seconds) that is required for the computer to get each result. Table 3 provides the details of each mesh used for the test.

The first mesh, with fewer elements, can be disposed on basis of the point where $t = 600s$, with a big non-linearity at a local maximum. The results for this same mesh are quite linear with $R^2 = 99.52\%$. In the second mesh it is observed the same problematic point at $t = 600s$, however the character is far more linear, with $R^2 = 99.8\%$. Despite having a curve with a bit higher error ($R^2 = 99.26\%$), the third mesh offers the best results based on set expectations, and without temporal coherence defects. Mesh 4 offered a very high response time and a result well below the expectations, with dispersed characteristics due to under-representation in the volume.

Thus, the following permeability tests used results found with the third mesh in association with defined rocky formation and fluid settings.

3.2 Permeability test

For permeability study were taken values between 0.01 and 0.04 Darcy. Permeability refers to the permission that a porous solid offers to mass transfer. The higher the permeability of a material, the greater must be transfer of fluid and, therefore, in the evaluated case, the greater must be the invasion of the fluid in porous domain, measured by saturation of fluid. While Costa

Table 5. Operational outline settings.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal Speed Flow</td>
<td>Input condition</td>
<td>0.3048 m/s</td>
</tr>
<tr>
<td>Porous domain pressure</td>
<td>Output condition</td>
<td>1 atm</td>
</tr>
<tr>
<td>Running time</td>
<td>Process duration</td>
<td>2 hours</td>
</tr>
<tr>
<td>Fluid Attacker</td>
<td>Aqueous Drill Fluid</td>
<td>Saturation = 0</td>
</tr>
<tr>
<td>Fluid inside the rock</td>
<td>Oil</td>
<td>Saturation = 1</td>
</tr>
</tbody>
</table>

Figure 6. Graph with fluid saturation in porous domain x time for different meshes.
(2009) and Cunha (2010) cited orders of magnitude for permeability between 1 and 100 Darcy, Gomes (2002), Levorsen (1954), and Rosa et al. (2011) used rocks with much smaller values, up to $10^{-7}$ in shales and $10^{-10}$ in limestone. The permeabilities used in this work are within specifications for deep rocks.

To facilitate the understanding of the values, a graph – Figure 7 – comparing saturation results was developed. Comparative montages with invasion profiles created by CFD-Post™ were also compiled in the following figures.

According to Figure 7, there is a considerable difference caused by variation of permeabilities. The values taken as results of each case study are related to invasion of mud – the volume fraction of fluid in relation to total volume of pores (i.e. the total volume occupied by the mud or inherent oil). This means that the permeability of the rocky formation influences the invasion profile of drilling fluid greatly.

Moreover, the saturation values provide a good linear effect, and from the 1200s (instant where the invasion profile begins to stabilize) all four corners offer values of determination coefficient equal to 99.9%, indicating a steady growth and consistent results among themselves.

Figure 8 refers to the display of the X-axis in 7200s, the end of run; Figure 8 displays a limited advance in Figure 8A, where there is significant

**Figure 7.** Graph with fluid saturation in porous domain x time for different permeabilities.

**Figure 8.** Comparison of the invasion profiles on the X-axis at 120 minutes for different permeabilities: (a) permeability = 0.01 darcy, saturation = 0.0698796; (b) permeability = 0.02 darcy, saturation = 0.126026; (c) permeability = 0.03 darcy, saturation = 0.176869; (d) permeability = 0.04 darcy, saturation = 0.227248.
invasion of fluid just at the entrance to the bed. Figures 8B and 8C demonstrate an expansionist character, with greater region under invasion, and a breakthrough more complete in Figure 8D, with an average of 22.7% saturation.

As studied by Semmelbeck and Holditch (1988), the profile of mud invasion on rock formation with low permeability reduces the rate of invasion by increasing the amount of saturation in the entry region. It generates the effect of drilling fluid build-up seen to the right of the figures under preview of X-axis and below in figures on the Y-axis. In addition, there was an almost complete invasive fluid expansion in Figure 8D, while it failed to break into the lower permeability rock formation remaining only in adjacent areas to the interfacial region.

Figure 8 shows mud saturation in porous domain on the X-axis, that is, the axis with X = 0 cm. With respect to the Y-axis, it was taken as the reference plane in which Y = 10 cm, located on parallel straight for most of the region between domains, according to Figure 9.

Figure 10 indicates the invasion profiles on the Y-axis. The lower permeability, from the start, limited the expansion of the first run to break into the central region of the entire plan. The lateral symmetry and hue of Figure 10D is already very intense and expansion is well accentuated since Figure 10B, with approximately 50% saturation throughout the central region (projection of the interfacial region at 10 cm). Still in Figure 10D, it is possible realize an invasion on almost any surface with at least 25% saturation.

Finally, with respect to the Z-axis, the central plane was chosen where Z = 150 cm, half of total length (300 cm), to avoid mesh defects and to achieve better results. The results presented in Figure 11A show the great difference found in invasion profiles with different permeabilities. Although, numerically, the saturation values don’t follow a trend of accelerated growth, the visual difference between the expansion of regions with 25% of saturation in the Figures 11C and 11D is more expressive than between Figures 11A and 11B.
Comparatively, it is possible to notice the influence of permeability in the invasion process of the fluid at the same time interval. The Z-axis favors a more ideal and located vision of the geometry, allowing a better understanding of the process. X and Y axis offer a more global view, since the entry of the fluid to the main output.

4. CONCLUSIONS

The mathematical model developed for the present work used conservation equations and represented satisfactorily the influence of permeability on invasion of drilling fluid in rock formation. With the growth of permeability, a considerable increase in invasive process of the fluid in rock was noted with a minimal invasion of approximately 7% after 2 hours of process, and close to 23% with the highest permeability.

NOMENCLATURE

Greek Letters
\( \emptyset \) - Porosity [-]
\( \rho \) – Density [kg/m³]
\( \mu \) – Viscosity [Pa.s]

Symbols
\( F \) – Tensor area porosity [m²]
\( k_s \) – Permeability in direction s [Darcy]
\( p \) – Pressure [Pa]
\( R^2 \) – Determination coefficient
\( S_i \) – Saturation of I [-]
\( t \) – Time [s]
\( \vec{u} \) – Vector velocity [m/s]
\( u_s \) – Velocity in direction s [m/s]
\( x_i \) – Real value of x in the moment i
\( \hat{x}_i \) – Calculated value of x in the moment i

5. REFERENCES


