ADVANTAGES IN JOINT-INVERSIONS OF RESISTIVITY AND FORMATION-TESTER MEASUREMENTS: EXAMPLES FROM A NORWEGIAN FIELD

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ABSTRACT

Past studies have reported the strong benefits from the joint-integration of resistivity and formation-tester measurements in conventional petrophysical evaluation. However, the practical aspects of such integration are still unclear for many experienced log analysts. This paper illustrates the successful application of this multi-physics approach by using data acquired in a Norwegian field.

Unlike previous approaches, we use a reservoir simulator dynamically-coupled to a mud-filtrate invasion model to enforce two-phase fluid flow in a multilayered rock formation model. The simulated resistivity and formation-tester measurements explicitly take into account specific two-phase flow and mud-filtrate invasion properties, such as capillary pressure and relative permeability. The integration of resistivity and formation-tester measurements involves an iterative process with the following steps: 1) Simulation of mud-filtrate invasion and resistivity tool responses based on an initial multilayered rock formation model. 2) Update the rock formation model by using pressure transient data. 3) Iterate between 1) and 2) until a match is obtained with both pressure transient measurements and resistivity measurements. The formation tester measurements were acquired with a dual-packer module and resistivity measurements were acquired with laterolog tools.

Generally, the examples from different wells shown in this work exhibited promising results into constraining the multiple solutions inherent to multilayered rock formation models. The nuclear magnetic resonance (NMR) log was applied to divide the formation into different layers by ordering the T2-distributions into a limited number of electrofacies. In another well, where NMR data was not available, we suggest that a permeability correlation formula derived from core data be used instead. Several sensitivity studies were performed on the final inverted values in an effort to quantify the level of uncertainty present in the estimation process. The final result is a constrained multilayered rock formation model where the complexities of multiphase flow have been taken into account, which is more representative of the existing rock formation than models obtained through stand-alone well-log correlations.

INTRODUCTION

It is common practice in the industry that both resistivity and formation-tester measurements are analyzed separately one from the other. While formation-tester measurements are mostly studied with a single-layer single-phase flow model to determine rock formation properties, such as permeability and skin; resistivity measurements are used along with petrophysical models, core laboratory results, and correlations to assess other formation properties, such as fluid saturations and permeability. This poses a problem for the petrophysicist because the permeability log estimate is only checked against Klinkenberg-corrected core values, whenever available, and it does not take full advantage of the in-situ dynamic information provided by the formation-tester measurements. To further complicate matters, the single-layer single-phase model conventionally used to interpret formation-tester measurements can sometimes be over-simplistic when it disregards the effect of the mud-filtrate invaded zone or the non-uniform distribution of fluids (not necessarily at irreducible saturations) over the pay zone of interest. Last but not least, there is also the high level of uncertainty associated to multilayered models. If we were to use them (e.g., to assess finely-laminated formations or to validate electrofacies from NMR and formation imager logs), significant non-uniqueness in the estimates would prevent any of the aforementioned measurements to independently assess each numerical layer, not without committing to a large uncertainty bracket.

Several authors have already published similar approaches. Zeybek et al. (2001) used two-phase flow simulations of formation-tester sampling operations to refine relative permeability curves originally estimated from openhole resistivity logs. Alpak et al. (2004, 2004) applied synthetic models to study the joint
inversion of pressure and both time-lapse electromagnetic and dc resistivity measurements. Their paper reported beneficial reduction of non-uniqueness in the estimation process suggesting that more accurate inversions of formation properties could be obtained with this multi-physics approach. Salazar et al. (2005) conducted the estimation of permeability based on the simulation of mud-filtrate invasion. Later on, the same author estimated permeability from borehole array induction measurements (Salazar et al., 2006) in a North Louisiana tight gas sand formation. On a different perspective, Angeles et al. (2007) found through the use of sensitivity-coefficient maps that the integration of various formation-tester measurements, such as pressure and fractional flow rate, could increase the spatial region of investigation at a given time thereby reducing the non-uniqueness in a given estimate if several measurements were combined during the estimation process.

This paper illustrates how a multi-physics approach can be effectively used to integrate resistivity and formation-tester measurements with data acquired from a field in the Norwegian Sea. Unlike the previous approaches, this work applies rigorous multiphase-flow modeling to both formation-tester (pressure and fractional flow rate) and resistivity measurements and it is dynamically-coupled with the physics of mud-filtrate invasion. In addition, we employ a multilayered model and an iterative process to obtain the final estimates which reconcile the measured values with the common earth rock model.

METHODOLOGY

Process Workflow. The field examples in this study follow the flow diagram described in Fig. 1. We use a numerical reservoir simulator to model two-phase fluid flow in the rock formation. The simulator is dynamically coupled to a mud-filtrate invasion algorithm where it enforces explicit assumptions on capillary pressure and relative permeability properties. Once the process of mud-filtrate invasion is simulated, the spatial resistivity values are used to simulate tool resistivity measurements and compared against the field measured data. At the same time, the same layer properties (porosity, permeability, connate water saturation) are input to an equivalent two-phase flow simulator to simulate the process of mud-filtrate invasion (in general, times of invasion for resistivity and formation-tester measurements are not equal). The formation tester simulations assume those resulting fluid and rock properties distributions to be those present at the onset of the packer fluid withdrawal. This is an iterative process that finishes once the earth model honors both resistivity and formation-tester measurements.

Assumptions. For the cases shown in this paper, the main assumptions are that the wellbore is vertical and the formation beds do not have any dip. It is also assumed that there are no lateral variations in the rock formation and that no gas comes out of formation oil due to pressure changes during the tests. Other specific assumptions are described in the next paragraphs.

Resistivity Model. Numerical simulations of laterolog measurements, such as the ones studied in this report, were performed with UTFET, a two-dimensional cylindrical, two-phase (oil and water) simulator developed by the University of Texas at Austin (Chew et al., 1984; Zhang et al., 1999; Ramirez et al., 2006). It allows numerical simulations of water-base and oil-base mud-filtrate invasion, salt mixing, temperature, and well logging tool responses for single and multi-layer rock formations penetrated by a vertical well. In this work, once the process of water-based mud-filtrate invasion is simulated, the spatial distributions of electrical resistivity become the input for the simulation of well-logging measurements.

Indonesia Equation. The lithology in the rock formations evaluated in this work resembles that of non-Archie shaly rocks for dispersed shale and laminated sand/shale formations. Therefore, a shaly sand model was needed to compensate for the shale concentration when estimating water saturation. We used the Indonesia equation similar to that used by the operator in the petrophysical assessment of wells from the Norwegian continental shelf in the North Sea. The equation is shown next:

\[
S_w = \frac{1}{R_t} \left( \frac{V_{sh}}{R_{sh}} \right)^{2/n} + \frac{a \phi_w^{2/m}}{(a R_w^{1/2})^2},
\]

where \(S_w\) is water saturation, \(R_t\) is total resistivity, \(R_w\) is water resistivity, \(V_{sh}\) is shale concentration, \(\phi_e\) is effective porosity, \(R_{sh}\) is shale resistivity, \(a\) is the tortuosity factor, \(m\) is the cementation exponent, and \(n\) is the saturation exponent. As expected, the Indonesia equation reduces to Archie’s equation in clean sands while it compensates for shale concentration in shaly sands.

Mud-filtrate Invasion. For water-based muds (WBM), we use an adaptation of INVADE, developed by Wu et al. (2002). Hence, the simulations include the dynamically coupled effects of mudcake growth and two-phase, immiscible mud-filtrate invasion. In other
words, the flowrate of mud-filtrate invasion depends on both mud and rock properties.

Two-Phase Flow Model. A similar simulator to the one described in the “Resistivity Model” section is encoded within UTFTT. The difference is that UTFTT is especially designed to simulate, design, and diagnose formation-tester measurements acquired in a vertical well with a dual-packer and additional monitoring probes configuration. Both UTFTT and UTFET accept inputs of relative permeability and capillary pressures for the consistent simulation of mud-filtrate invasion and subsequent fluid withdrawal through the packer section.

Upscaling Criteria. The final model is a high-resolution multilayered rock model that is not suitable for coarse-scale full-field reservoir simulations neither convenient for result comparisons with analogous estimation methods, such as the analytical solution conventionally reported with formation tester data. Thus, we used the following upscaling criteria to determine the effective formation properties that can best represent the final multilayered model into an equivalent single-layer model. Accordingly, porosity is calculated with a simple average of the layer porosities, average horizontal permeability ($k_h$) is calculated assuming the beds are in parallel, and average vertical permeability ($k_v$) is calculated assuming the beds are in series:

$$k_h = \frac{\sum_{i=1}^{n} k_i h_i}{\sum_{i=1}^{n} h_i} \quad \text{and} \quad k_v = \frac{\sum_{i=1}^{n} k_i h_i}{\sum_{i=1}^{n} k_i}$$

(2)

where $h_i$ and $k_i$ are thickness and permeability of layer $i$, respectively, and $n$ is the number of layers.

Skin and Tool Storage. The two-phase flow simulators used here do not explicitly consider damage skin or tool flowline storage. The latter is partially taken into account with the presence of compressible fluids in the near-wellbore region. However, the effect of skin on the pressure measurements needs to be addressed because some wells studied in this report have skin values as high as 4.5. We assume that the skin found from the single-phase flow analysis is due only to damage and that the same pressure drop due to skin ($\Delta P_{skin}$) will be present when two-phase flow occurs during the formation test. The additional pressure drop due to skin was approximated with the following equation, in practical metric units:

$$\Delta P_{skin} = 18.61 \left( \frac{q \mu B}{kh} \right) S ,$$

(3)

where $S$ is skin factor, $k$ is permeability, $h$ is formation thickness, $\mu$ is viscosity, $B$ is formation volume factor, and $q$ is production flowrate. This additional pressure
drop is first added to the simulator under single-phase flow conditions and validated against an in-house analytical limited-entry flow model. Once this pressure drop is verified with the analytical solution, we use it as an additional pressure drop for the two-phase flow simulator response. In general, this resulted in a good approximation.

FIELD APPLICATIONS

The previous procedure was successfully applied to several wells in the Norwegian Sea. We present three field examples:

- Field Example A
- Field Example B
- Field Example C

Each example shows distinct approaches evaluated in this work. Field Example A takes advantage of NMR electrofacies (determined from a previous analysis) to choose the location of the numerical layers as well as to update the values of the numerical layers identified with a specific electrofacies number. Field Example B did not have NMR electrofacies; however, we arbitrarily defined the numerical layers from the existing permeability log curve. In this well, we also used a permeability correlation to reduce the number of unknowns from 18 layers to a few parameters. Field Example C applies a similar method as the one used in Field Example B; however, the large content of clay in the layers makes it necessary to use an anisotropy ratio different than 1 in each numerical layer. All the examples gave important insight on the nature of the non-uniqueness present in these multilayered models.

FIELD EXAMPLE A

General Description. Oil sampling occurred at XX67.8 mMD using the dual packer module. Fig. 2 shows the location of the formation test and the corresponding petrophysical evaluation. The formation corresponds to a marine, inner shelf depositional environment of Jurassic age. The analyzed section is comprised of sandstone with thin siltstone beds and dolomite stringers. The sandstone is silty to fine grained, though predominantly very fine. It is also non calcareous, loose, friable, and it contains mica and pyrite. The siltstone varies from soft and crumbly to hard and brittle, has sandy laminae in parts and locally grades to claystone.

Numerical Layering. There are several alternatives at this point. One could use a log (e.g., $V_{Sh}$, permeability) or, if available, a more advanced option such as the case of electrofacies derived from NMR and formation imager logs. Because of their sensitivity to pore size distributions and visual texture (respectively), electrofacies can be used to both locate the boundaries of the numerical layers and associate the permeability of each layer to a corresponding electrofacies, reducing the number of unknown parameters in the estimation process. In this field example, we used the NMR log to select an initial number of 23 electrofacies from the studied interval. Fig. 3 and Fig. 4 describe the electrofacies processing. This number was then reduced to 6 groups and a total of 18 numerical layers. Hence, not only we obtained faster simulation runs but reduced the number of unknowns from 18 to merely 6 unknowns. In Fig. 5, facies groups with high number are associated to low-permeability and laterally-extensive barriers.

Rock/Fluid Properties. Rock, fluid, and petrophysical properties assumed in the numerical simulations are summarized in Table 1. Relative permeability and capillary pressure curves were input to the simulator via Brooks-Corey coefficients, obtained from a match with core laboratory results from a nearby well.
Whereas values of bubble point pressure and formation oil volume factor were obtained from the PVT report, values of oil viscosity and oil compressibility were obtained from the single-phase flow analysis on the same well. Oil density was derived from pressure gradients and in agreement with the PVT analysis made on the oil sample collected at XX67.8 mMD. Water PVT properties were arbitrarily assumed except for the water density, obtained from the log header. The water-based mud used during drilling was 1.3 g/cc CaCO3 Aquadrill. Formation water salinity was assumed equal to 47,700 ppm and obtained from the well evaluation report. The latter was verified by performing a sensitivity analysis varying formation resistivity to match computed water saturation and comparing simulated deep and shallow resistivity to log resistivity curves. Mud-filtrate salinity was assumed equal to 145,000 ppm and derived from the resistivity of mud filtrate in the log header.

**Table 1** Summary of rock, fluid, and petrophysical properties for Field Example A

<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>0.82</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>cp</td>
<td>2.5</td>
</tr>
<tr>
<td>Oil compressibility</td>
<td>1/bar</td>
<td>2.0e-4</td>
</tr>
<tr>
<td>Oil bubble point pressure, $P_{bo}$</td>
<td>bar</td>
<td>147.5</td>
</tr>
<tr>
<td>Oil formation volume factor @ $P_{bo}$</td>
<td>Rm$^3$/Sm$^3$</td>
<td>1.169</td>
</tr>
<tr>
<td>Water density</td>
<td>g/cc</td>
<td>1.3</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>cp</td>
<td>1.0</td>
</tr>
<tr>
<td>Water salt concentration</td>
<td>ppm</td>
<td>47,700</td>
</tr>
</tbody>
</table>

**Table 2** Summary of mud properties for Field Example A

<table>
<thead>
<tr>
<th>Property</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mudcake permeability</td>
<td>md</td>
<td>0.03</td>
</tr>
<tr>
<td>Mudcake porosity</td>
<td>fraction</td>
<td>0.30</td>
</tr>
<tr>
<td>Mud solid fraction</td>
<td>fraction</td>
<td>0.06</td>
</tr>
<tr>
<td>Mudcake maximum thickness</td>
<td>cm</td>
<td>1.02</td>
</tr>
<tr>
<td>Mudcake compressibility exponent</td>
<td>fraction</td>
<td>0.40</td>
</tr>
<tr>
<td>Mudcake exponent multiplier</td>
<td>fraction</td>
<td>0.10</td>
</tr>
<tr>
<td>Mud hydrostatic pressure</td>
<td>bar</td>
<td>253</td>
</tr>
<tr>
<td>Initial formation pressure</td>
<td>bar</td>
<td>204</td>
</tr>
<tr>
<td>Overbalance pressure</td>
<td>bar</td>
<td>49</td>
</tr>
<tr>
<td>Mud filtrate salt concentration</td>
<td>ppm</td>
<td>145,000</td>
</tr>
</tbody>
</table>

Mud properties assumed for the modeling of mud-filtrate invasion in both simulators are summarized in **Table 2**. For resistivity simulations, the time of invasion was assumed 0.63 days. For formation tester simulations, the time of invasion was assumed equal to 1.0 day. It is necessary to clarify that the “time of invasion” used here is not the actual time of invasion but an average value obtained from the fractional flow and resistivity measurements after multiple iterations. To estimate the true time of invasion one would require knowledge of mudcake buildup and removal, number of wiper trips, circulation time, and whether the mudcake was removed during certain stages of the drilling process. Instead, the estimate given above is the value that creates a specific fluid and pressure distribution.
around the wellbore such that the responses in the fractional flow and resistivity measurements (in particular, the separation between the deep and shallow curves) can match the observed data.

The formation temperature gradient was assumed equal to 3.5 degC/100 meter (obtained from the final well report) and the reference temperature at XX68 mTVD MSL is 80 degC. Archie and Indonesia equation parameters are \( a=1, \ m=2.1, \ n=2 \) (obtained from the petrophysical analysis) and \( R_{Sd} \) is 5.5 ohmm.

Results. Simulations of mud-filtrate invasion after several iterations are shown in Fig. 6 and Fig. 7. The final invaded distance depends not only on the mud properties but on the rock formation dynamic properties at a given layer. This is clearly observed in Fig. 6 where different layers with different permeabilities show distinct invaded zones at the onset of the resistivity simulations. As mentioned before, formation resistivity is obtained from the distribution of water saturation and salt concentration. Fig. 7 describes the radial distribution of water saturation at the packer depth.

Final estimates of porosity, permeability, water saturation and resistivity are shown in Fig. 8 and Fig. 9. Notice that porosity and water saturation estimates compare well with the interpreted log values; however, permeability seems overestimated by the interpretation (KLOGH curve) at the sampling depth.

Fig. 6 2D Cross-sections of water saturation (upper panel) and total resistivity (lower panel) at the onset of the resistivity tool simulations for Field Example A.

Fig. 7 Radial distribution of water saturation at the packer depth for several times of invasion (Field Example A).

Fig. 9 indicates a satisfactory match between measured (RLA) and simulated resistivities (RLL). There is an additional explanation needed for this figure. The tool used in the logging program was an HRLA \(^*\), which delivers 5 resistivity curves. The simulator outputs dual laterolog tool DLT \(^*\) curves. We use a geometric average between RLA2 and RLA3 to be able to evaluate the shallow resistivity simulated curve (RLLS). In turn, RLA5 is directly compared to the deep resistivity simulated curve (RLLD). In the same figure, the third track (RLLD-RLLS) indicates the differentials of deep and shallow curves (related to mud invasion and formation permeability) for simulated and measured data, respectively. The fourth track (DIFF) shows the difference between the two deep curves (DIFF_D) and the two shallow (DIFF_S) curves.

As it can be observed, the only noticeable differences between measured and simulated resistivities are mostly due to either numerical boundary effects or coarse averaging of layer properties, which can be corrected by increasing the number of layers.

\(^*\) HRLA and DLT are trademarks of Schlumberger
Pressure measurements from the formation tester tool are analyzed next. We start by matching measured and simulated pressures under single-phase flow assumptions and the parameters derived from the single-phase flow model. Our purpose is to:

1) Validate the simulator against a known model and also test the numerical grid configuration.
2) Confirm the calculated pressure drop due to skin.

The same pressure drop is later added to the two-phase flow simulations to account for damage skin.

Fig. 10 shows an excellent agreement between the pressure responses. Notice that neither the single- nor the two-phase flow simulations match the initial part of the pressure measurements. This is due to other near-wellbore and tool mechanisms (tool storage, fines migration) that are not taken into account in the simulations. Table 3 summarizes the input parameters enforced by the simulator.

Table 3: Input parameters used in the simulations to match the analytical single-phase flow model – Field Example A

<table>
<thead>
<tr>
<th>Property</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal permeability</td>
<td>md</td>
<td>30</td>
</tr>
<tr>
<td>Vertical permeability</td>
<td>md</td>
<td>20</td>
</tr>
<tr>
<td>Total thickness</td>
<td>m</td>
<td>4.3</td>
</tr>
<tr>
<td>Packer interval</td>
<td>m</td>
<td>1</td>
</tr>
<tr>
<td>Location of interval (from top)</td>
<td>m</td>
<td>2.3</td>
</tr>
<tr>
<td>Skin factor</td>
<td>--</td>
<td>0.45</td>
</tr>
<tr>
<td>Porosity</td>
<td>--</td>
<td>0.25</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>cp</td>
<td>2.5</td>
</tr>
<tr>
<td>Oil formation volume factor</td>
<td>Rm³/Sm³</td>
<td>1.5</td>
</tr>
<tr>
<td>Total compressibility</td>
<td>1/bar</td>
<td>2.0e-4</td>
</tr>
<tr>
<td>Initial pressure</td>
<td>bar</td>
<td>205.4</td>
</tr>
</tbody>
</table>

Once the single-phase single-layer model was validated, simulations for single- and two-phase flow were performed in the multilayered model. For the two-phase flow simulations, the time of invasion was estimated to be 1 day, in agreement with the fractional flow curve shown in Fig. 11. In particular, we matched the time of oil breakthrough during fluid cleanup, choosing the 80% contamination value as indication of such event. Fig. 12 illustrates the fluid cleanup process during the formation testing operation. The figure also explains the apparent buildup of pressure during the initial drawdown in the two-phase flow simulations. Originally, the tool ‘observes’ a mud-filtrate invaded zone, with high water saturation and low effective oil permeability. As fluid is withdrawn from the formation, a channel is created through the mud-filtrate invaded zone, decreasing the water saturation and increasing the effective oil permeability in the rock. Thus, the tool needs a smaller drawdown for the same production rate causing the pressure to ‘buildup’. Single-phase flow simulations presented here do not consider the presence of any invaded zone.

Based on the final iterations and the sensitivity analyses shown in the Appendix, inverted values are reported in Table 4 accompanied by their corresponding uncertainty bounds. Since Group 1 was not present in the studied interval, there are no inverted values shown in the table (‘N/A’). Facies Group 6 could not be determined either because the only layer that belongs to this group is located far away from the packer and at the border of the numerical model. The latter heavily affects the same layer due upper shoulder resistivities. On the other hand, Groups 2 and 3 are the groups with the smallest uncertainty associated to the estimates. It
can be shown from the sensitivity studies that each measurement (resistivity or formation tester) contributes to the reduction of uncertainty in a given group and, particularly for this example; the estimates in Group 2 and 3 are small simply because the layers associated to these facies groups are within the area of investigation of the formation tester.

For Field Example A, single-phase flow permeability estimates are relatively lower than their two-phase flow analogs. In addition, notice that upscaled single-phase layer values do not exactly agree with the single-phase flow model even though the single-phase single-layer model was validated against the same parameters. This is because our upscaling operation assumes that flow occurs in all the layers being considered (flow in parallel for the horizontal permeability, flow in series for the vertical permeability) whereas the single-phase analytical model assumes a limited flow entry model. Therefore, the upscaled values should be more representative if the entire upscaled interval was put on production and not only the interval straddled by the packers.

FIELD EXAMPLE B

General Description. The sandy section of Field Example B extends from XX33 mMD to XX88 mMD. It comprises sandstone with thin claystone beds grading into siltstone. The sandstone is silty to fine grained, contains mica, pyrite, and occasionally glauconite. The claystone is very sandy and silty grading into silty sandstones. Fig. 13 shows the location of the formation test along with the corresponding petrophysical evaluation for the studied interval.

Field Example B contains data from an interval pressure-transient test (IPTT) with dual-packer module and one vertical probe. Accordingly, shut-in periods were added at the end of the sampling operation in addition to the standard acquisition of formation pressure and hydrocarbon sampling. This offers the
advantage of considerably larger depth of investigation (reported here as approximately 28 m) in addition to a clean longer build-up that could exhibit both spherical and radial flow regimes; hence, more robust estimates of horizontal and vertical permeability than when dealing only with sampling data. The dual packer module was set at XX69.5 m. Additional final buildups lasted up to 1.5 hours and contained a monitor probe located 2 m above the center of the packer interval (0.9 m).

For this analysis, there were no NMR electrofacies available, hence, the numerical layering was chosen arbitrarily from the permeability log curve, previously correlated to core permeability results. The earth model consisted of a total of 21 numerical layers.

**Results.** The simulation of mud-filtrate invasion is described by the water saturation profile in Fig. 14.

For resistivity simulations, the average time of invasion was assumed equal to 0.4 days. For formation tester simulations, the average time of invasion was assumed equal to 1.3 days. Archie and Indonesia equation parameters are $a=1$, $m=2.1$, $n=2$, and $R_{Sh}$ is 15 ohmm.

**Fig. 13** Depth interval studied for Field Example B indicating the location of the formation test at XX69.5 m.

**Fig. 14** 2D Cross-section of water saturation indicating the mud-filtrate invaded zones at the onset of resistivity simulations (Field Example B).

**Fig. 15** Final estimates of porosity, permeability, and water saturation for Field Example B.

**Fig. 16** Final estimates of resistivity curves for Field Example B. The shaded region indicates the position of the formation tester.
Table 6  Summary of rock, fluid, and petrophysical properties for Field Example B

<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>0.774</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>cp</td>
<td>1.03</td>
</tr>
<tr>
<td>Oil compressibility</td>
<td>1/bar</td>
<td>1.53e-4</td>
</tr>
<tr>
<td>Oil bubble point pressure, $P_{bo}$</td>
<td>bar</td>
<td>147.5</td>
</tr>
<tr>
<td>Oil formation volume factor @ $P_{bo}$</td>
<td>Rm$^{-3}$/Sm$^{-3}$</td>
<td>1.169</td>
</tr>
<tr>
<td>Water density</td>
<td>g/cc</td>
<td>1.34</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>cp</td>
<td>1.0</td>
</tr>
<tr>
<td>Water salt concentration</td>
<td>ppm</td>
<td>47,700</td>
</tr>
</tbody>
</table>

Final estimates of porosity, permeability, water saturation and resistivity after several iterations are shown in [Fig. 15](#) and [Fig. 16](#). Porosity and water saturation estimates compare well with the interpreted log values; however, permeability seems overestimated by the interpretation (KLOGH curve) at the sampling depth. On the other hand, there is a satisfactory match between measured (HLL$i$) and simulated (RLL$i$) laterolog resistivities.

Pressure measurements are also analyzed like the previous example. We first match the simulated pressures with the parameters found from the analytical single-phase flow model, obtaining an excellent match using a skin value of 3.1. Compared to 2.9 from the analytical solution, it can be seen that the approximation given by equation (3) deviates as the skin factor becomes significantly larger. Nonetheless, this does not affect the method proposed here and this is the value of the validation. We use the same pressure drop used in the single-phase pressure match and add it to the two-phase flow simulations to account for skin. This is valid if we assume that the drop of pressure due to damage stays equal regardless the number of phases flowing in the rock formation. [Fig. 17](#) and [Fig. 18](#) describe the two-phase flow simulations performed in the multilayered model.

In Field Example B there were no available NMR or formation imager electrofacies. Yet, to avoid dealing with 21 parameters (one permeability value per numerical layer), we used the following permeability correlation to reduce the number of inversion parameters to 2:

$$\log k = b_{k} \phi + a_{k} ,$$  \hspace{1cm} (4)

where $k$ is permeability, $\phi$ is porosity, and $a_{k}$ and $b_{k}$ are correlation parameters. The same permeability transform had already been applied in several petrophysical assessments in nearby wells. For those wells, the correlation parameters were: $a_{k} = -4.07$ and $b_{k} = 20.932$. We used these parameters to build an initial guess on the permeability values corresponding to each of the 21 numerical layers.

Results in Table 7 were obtained with $a_{k} = -4.56$ and $b_{k} = 20.932$. In addition, the permeability of layer No. 12 located approximately at XX68 m in [Fig. 15](#) was set to 135 md (see more details in the Appendix). The table contains upscaled values for two values of formation thickness. The thickness of 3.1 m corresponds to the interval between the numerical layers directly affected (adjacent to) packer and monitor probe. The thickness of 7.31 m corresponds to the interval between numerical layers with very low permeability values (<0.1 md). Notice that, at some value of formation thickness between 3.1 and 7.31 m, the values between...
the analytical single-phase analysis and our two-phase estimates should be very close. However, for the same formation thickness, the two-phase flow simulations yield relatively smaller magnitudes of horizontal and vertical permeability.

<table>
<thead>
<tr>
<th>Property</th>
<th>Units</th>
<th>Single</th>
<th>Two-Phase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td></td>
<td>0.231</td>
<td>0.278</td>
</tr>
<tr>
<td>Horiz. permeability, (k_h)</td>
<td>md</td>
<td>24.5</td>
<td>37.4</td>
</tr>
<tr>
<td>Vertical permeability, (k_v)</td>
<td>md</td>
<td>9.4</td>
<td>16.3</td>
</tr>
<tr>
<td>(k_v/k_h)</td>
<td></td>
<td>0.38</td>
<td>0.44</td>
</tr>
<tr>
<td>Thickness</td>
<td>m</td>
<td>7</td>
<td>3.1</td>
</tr>
</tbody>
</table>

Another important observation is related to the high permeability value set to layer No. 12, determined by means of the additional monitor probe included in the toolstring. There was no other way to determine such high value of permeability because layer No. 12 did not contribute much to the packer pressure. This is a good example of the contribution of additional monitor probes to formation-tester toolstrings.

FIELD EXAMPLE C

**General Description.** Field Example C also contains data from an IPTT configuration with dual-packer module and one vertical probe. The dual packer module was set at XX52.5 m. Additional final buildups lasted up to 1.5 hours and contained a monitor probe located 2 m above the center of the packer interval (0.9 m). The sandy section of Field Example C comprises sandstone with thin claystone beds grading into siltstone; however, unlike Field Examples A and B, the volume of clay present in the sand is relatively high.

The packer and monitor probe were set at XX52.5 mMD and XX50.5 mMD, respectively. Their location is shown in Fig. 19 along with the corresponding petrophysical evaluation. Final estimates of porosity, permeability, water saturation and resistivity after several iterations are shown in Fig. 20 and Fig. 21.

Likewise, pressure simulations in the multilayered model are shown in Fig. 22. In agreement with the fractional flow curve and the time of oil breakthrough during fluid cleanup, the time of invasion was assumed equal to 0.9 days. As it can be observed, the match is satisfactory for packer and monitor-probe pressures.
Matched packer and probe pressures using two-phase flow simulations on the multilayered model (Field Example C).

Fig. 22

Results. In this example, a permeability correlation similar to equation (4) was used to avoid dealing with 18 parameters (one permeability value per numerical layer) and reduce this number to 2. Table 8 shows the results obtained with $a_k=-4.28$ and $b_k=20.932$. However, unlike the previous cases where we assumed isotropic layers, a layer anisotropy ratio ($k_v/k_h$) of 0.5 was needed to match the measurements. Several other options were explored with the sensitivity studies but they were far from achieving a satisfactory match (see Appendix). One explanation for the need of anisotropic layers is the high content of clay in the sand. This was also found in the analytical single-phase analysis which reported an anisotropy ratio as high as 0.04.

Table 8

<table>
<thead>
<tr>
<th>Property</th>
<th>Units</th>
<th>Single</th>
<th>Two-Phase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>--</td>
<td>0.236</td>
<td>0.268</td>
</tr>
<tr>
<td>Horiz. permeability, $k_h$</td>
<td>md</td>
<td>22.8</td>
<td>22.8</td>
</tr>
<tr>
<td>Vertical permeability, $k_v$</td>
<td>md</td>
<td>0.8</td>
<td>3.8</td>
</tr>
<tr>
<td>$k_v/k_h$</td>
<td>--</td>
<td>0.04</td>
<td>0.17</td>
</tr>
<tr>
<td>Thickness</td>
<td>m</td>
<td>5</td>
<td>4.3</td>
</tr>
</tbody>
</table>

As in Field Example B, there was an important contribution from the additional monitor probe included in the toolstring. Without it, the packer pressures alone could have led us to erroneous values of rock formation permeability and permeability anisotropy ratio. Table 8 contains upscaled values for two values of formation thickness. The thickness of 4.3 m corresponds to the interval between the numerical layers directly affected by (adjacent to) packer and monitor probe. The thickness of 6.0 m corresponds to the interval between numerical layers with very low permeability values (<0.4 md). In general, the inverted results confirm the presence of high anisotropy ratio in this formation, similarly to what was reported in the single-phase analytical analysis.

DISCUSSION

The uncertainty in the permeability estimates for the examples presented in this paper was effectively reduced by the integration of resistivity and formation-tester measurements. This was clearly shown in the sensitivity studies provided in the Appendix, where we were able to separate the contribution from different tool measurements to the joint-inversion results in terms of uncertainty bounds. In fact, not only we were able to assess a dynamic property, such as permeability, but we could confirm the existing petrophysical models using rigorous multi-phase flow physics. Herein lies one of the major advantages in this multi-physics approach, we were able to constrain the several non-unique solutions inherent to multilayered models, otherwise difficult to achieve using stand-alone models.

The use of electrofacies (derived from NMR logs in this case) and correlation formulas, such as those used in the last two field examples, helped reducing the number of unknowns in the estimation process from a range of 18 to 20 numerical layers to a range of 2 to 6 parameters. Likewise, the use of electrofacies proved to be extremely useful as they helped both defining the location of the numerical layers and associating a given facies permeability value to a numerical layer with similar pore-size distribution. In our criteria, this gave the analysis more physical consistency and made it easier to invert for 6 unknowns.

On the value of additional monitor probes included in the formation-tester toolstring, it was observed that the extra probe pressure measurements contributed to the reduction of uncertainty in the layers located between the packer and monitor probe. In Field Example B, we were able to assess a thin layer of high permeability which would have been bypassed if only packer pressures were used alone. The monitor probe also played an important role when constraining the values of permeability anisotropy in Field Example C, where the rock formation exhibited high content of clay.

Since the present multi-physics technique can estimate permeability values in layers where the formation-tester measurements cannot investigate, we think it is possible
to achieve a more accurate upscaled rock model than that determined through standard formation-tester interpretation models. This is especially important for cases where the production zone is considerably larger than the area sampled by the formation tester. Likewise, we expect that our upscaled rock model should also be more representative of the formation when dealing with larger-scale full-field reservoir simulations.

CONCLUSIONS

We have used examples from a Norwegian field to illustrate the procedure and advantages of joint-inversions of resistivity and formation-tester measurements, namely: 1) They use two independent measurements of in-situ dynamic and static data for the estimation of formation properties (e.g., permeability); hence, they can drastically reduce the uncertainty in the final estimates, 2) They provide an alternative to validate the existing petrophysical model, and 3) They give valuable feedback on the permeability log estimate, usually obtained through correlations and Klinkenberg-corrected core laboratory results. We also assessed the use of electrofacies (derived from NMR in this paper) and correlation formulas as a means to reduce the number of unknowns in the estimation process. Overall, we obtained excellent results despite the severe non-uniqueness usually associated to finely-laminated rock formation models.

NOMENCLATURE

\[ a \] : Archie’s tortuosity factor, [ ]
\[ B \] : Formation volume factor, [Rm³/Sm³]
\[ C_{mu} \] : Conductivity of mud-filtrate, [mho/m]
\[ C_r \] : Conductivity of connate water, [mho/m]
\[ F_w \] : Fractional flow rate, [fraction]
\[ h \] : Layer/formation thickness, [m]
\[ k \] : Formation permeability, [md]
\[ k_h \] : Horizontal permeability, [md]
\[ k_v \] : Vertical permeability, [md]
\[ k_h/k_v \] : Permeability anisotropy ratio, [ ]
\[ m \] : Archie’s cementation exponent, [ ]
\[ n \] : Archie’s saturation exponent, [ ]
\[ P \] : Pressure, [bar]
\[ P_c \] : Capillary pressure, [bar]
\[ \Delta P_{skin} \] : Pressure drop due to skin, [bar]
\[ q \] : Production flow rate, [m³/day]
\[ R_w \] : Water resistivity, [Ω·m]
\[ R_{sh} \] : Shale resistivity, [Ω·m]
\[ R_f \] : Total resistivity, [Ω·m]
\[ S \] : Skin factor, [ ]
\[ S_w \] : Water saturation, [fraction]
\[ V_{sh} \] : Shale concentration, [fraction]
\[ \phi_e \] : Formation effective porosity, [fraction]
\[ \mu \] : Viscosity, [cp]
\[ \sigma_{ap} \] : Deep apparent conductivity, [mho/m]
\[ \sigma_{shallow} \] : Shallow apparent conductivity, [mho/m]

ACKNOWLEDGEMENTS

We are grateful to StatoilHydro ASA management for the permission to publish the field data examples discussed in this paper and for sponsoring the summer visit of Renzo Angeles to the Rotvoll Research Centre, Trondheim, Norway. We would also like to thank Lars Høier for the support of this work and revision of the manuscript.

Several other people contributed to this work with valuable discussions and feedback: Hee Jae Lee, the main code developer of UTFET and UTFTT simulators, Crystal Duan, Benjamin Voss, Mayank Malik, and Jesus Salazar. This work was also partially funded by the University of Texas at Austin’s Research Consortium on Formation Evaluation.

REFERENCES


**APPENDIX: SENSITIVITY STUDIES**

The Appendix section describes the sensitivity studies performed using resistivity and pressure simulations for selected field examples shown in this paper:

**Sensitivity Analysis for Permeability Estimates in Field Example A.** Sensitivities of pressure simulations to permeability estimates in facies Group 2 are shown in Fig. A1. Permeability was perturbed 10% of its reported value (38 ± 3.8 md). Since the packer is set in front of a layer that belongs to facies Group 2, pressure responses show clear sensitivity to the permeability estimate of this facies group. Hence, there is less uncertainty in our estimate for this group compared to other groups if we use only pressure measurements. On the other hand, Fig. A2 shows the same perturbations on the resistivity model. It can be observed that the difference between the simulations is negligible (curves overlap). In other words, uncertainty would be larger than the ± 3.8 md range if we were to use only resistivity curves in the estimation. In the figure, the word ‘Report’ indicates that the resistivity curve was simulated with the reported value. The word ‘Pert’ indicates that the resistivity curve was simulated with the perturbation of ± 3.8 md.

Fig. A3 and Fig. A4 show a complete different picture for facies Group 5. Even though we use the same perturbation as the one used for Group 2, i.e. the range of 2 ± 3.8 md, the pressure responses remain unaltered. Putting it in terms of relative magnitude, this is indeed an extremely large perturbation (190% of the reported permeability). The plot also shows an even larger value: 100 md. However, the pressure keeps unchanged suggesting a large uncertainty in this group permeability if only pressures are used in the petrophysical assessment. On the contrary, Fig. A4 shows a drastic change in the resistivity curves if the permeability of this group was 0.01 md. In other words, this time it is resistivity measurements that constrain the estimate value for this facies group.

**Fig. A1** Sensitivity of pressure simulations to permeability estimates in Facies Group 2 (Field Example A).

**Fig. A2** Sensitivity of resistivity simulations to permeability estimates in Facies Group 2 (Field Example A).

The previous sensitivity studies are summarized in Fig. A5, where uncertainty bounds are associated to the estimates of facies permeability due to either resistivity or pressure measurements. Most importantly, the figure clearly shows the advantage of using both integrated measurements in the reduction of such uncertainty bounds.

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For instance, the uncertainty range for facies 2 and 3 would be very high if only resistivity measurements were used in the estimation of their permeability values. However, the situation is reversed for facies 4 and 5. In those cases, the resistivity measurements ‘dominate’ the uncertainty bounds simply because the packer is not sensitive to the permeability of these facies groups. Facies 6 could not be determined using the current model, hence its large range of uncertainty.

**Sensitivity Analysis for Permeability Estimates in Field Example B.** We analyze the effects of $a_k$ and $b_k$ values from equation (4): $a_k$ is an offset and $b_k$ is an scaling factor. Several simulations were done to show the effect of increasing values of $b_k$ in the simulated pressure responses.

Accordingly, the value of $a_k$ was modified to match the measured data. It was observed that:

- Although packer pressures matched, probe pressures did not agree.
- Increasing values of $b_k$ could improve the match in the probe pressures but resulted in decreasing values of layer permeability. In particular, if we increased the value of $b_k$ above 30, the corresponding values of permeability became too low that this was an unrealistic choice. Thus, it was not possible to match the pressure measurements without applying an extra modification to the model.

After several sensitivity studies, such a modification was found from the monitor probe pressure response. In addition to the values of $a_k=-4.56$ and $b_k=20.932$, the monitor probe pressure was matched when the permeability of layer No. 12 (located approximately at XX68 m) was increased to 135 md. These are the parameters reported in the results for the analysis of Field Example B. Other alternatives were investigated for this field example but are not reported in this paper for space restrictions.

**Sensitivity Analysis for Permeability Estimates in Field Example C.** Unlike the previous cases, this study required the assumption of anisotropic layers. First, isotropic layers were tested with several combinations of $a_k$ and $b_k$ but the best match could only agree in terms of drawdown magnitude but not in shape,
especially the shape of the last buildup. Subsequently, anisotropic layers with $k_h/k_v=10$ were tested. We obtained a good match in the packer pressures but the probe pressures required a larger drawdown magnitude. Such drawdown did not increase even if we used different permeability values for the layers located between packer and probe (high or low values did not work). The best match for Field Example C was obtained when using anisotropic layers of $k_h/k_v=2$.

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Renzo Angeles is a Graduate Research Assistant and a PhD candidate at the University of Texas at Austin. From 2000–2003, he worked as a field engineer for Schlumberger, receiving training in Peru, Colombia, Ecuador, USA, and Canada. In the past years, he has held two summer internships with Chevron in Houston and one with StatoilHydro in Trondheim, Norway. He is a recipient of the Presidential Endowed Osmar Abib Scholarship and the Chevron Scholarship. His interests involve pressure transient analysis, near-wellbore numerical modeling, petrophysics, and inversion techniques. His PhD research focuses on the quantitative analysis and inversion of formation-tester measurements acquired in highly-deviated wells using multi-phase flow analysis and the effects of mud-filtrate invasion.

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Carlos Torres-Verdín received a Ph.D. degree in Engineering Geoscience from the University of California, Berkeley, in 1991. During 1991–1997 he held the position of Research Scientist with Schlumberger-Doll Research. From 1997–1999, he was Reservoir Specialist and Technology Champion with YPF (Buenos Aires, Argentina). Since 1999, he has been with the Department of Petroleum and Geosystems Engineering of The University of Texas at Austin, where he currently holds the position of Associate Professor. He conducts research on borehole geophysics, well logging, formation evaluation, and integrated reservoir characterization. Torres-Verdín has served as Guest Editor for Radio Science, and is currently a member of the Editorial Board of the Journal of Electromagnetic Waves and Applications, and an associate editor for Petrophysics (SPWLA) and the SPE Journal. He is co-recipient of the 2003, 2004, and 2006 Best Paper Award by Petrophysics, and is recipient of SPWLA’s 2006 Distinguished Technical Achievement Award.