Abstract

Today’s climate of a general lack of resources and people, high prices and limited rig availability forces the oil industry to plan for efficient production and secondary recovery. This puts more weight on understanding reservoir architecture and fluid complexities, the main drivers of recovery. Improving confidence in reservoir architecture has taken center stage in risk management especially in high cost environments. Data availability to increase this confidence will always be limited by budget and/or operational constraints. This puts the strike on maximizing the value of acquired data and integrating all available data to help this cause.

Recent advances in sensor technology and petroleum science allows using downhole fluid analysis data to improve confidence in reservoir architecture. Mapping composition, gas oil ratio (GOR) and density across the field is common practice. These properties are based on the amount of solution gas in the liquid phase and their equilibrium distribution can be predicted by (typically) cubic equations of state (EOS). Evaluating the relative asphaltene distribution is based on different physics: the suspension of solids in the liquid phase. It is robustly assessed by the latest generation of downhole fluid analysis (DFA) tools and recent breakthroughs in science now also allow predicting equilibrium distributions by EOS. Consequently, two equations of state are used to analyze two separate fluid gradients, GOR and asphaltenes, yielding a robust method of reservoir evaluation. This new independent workflow is especially valuable when used in concert with PVT reports, well test data, static pressure gradients and other common techniques to assess reservoir architecture.

This paper presents two real-life case studies from the Norwegian continental shelf that use available DFA data to support the assumptions made from other data on reservoir architecture between wells. It shows the validity of the concept, but also highlights the limits and constraints of such a data set. These case studies lead the way to planning the data acquisition to include a more comprehensive DFA data set to address connectivity and other reservoir concerns.

Introduction

A valuable plan to manage subsurface uncertainty assesses the impact of the fluid properties on the project execution. Understanding the fluid properties and their vertical and lateral distribution will elucidate quality and continuity of the discovery during the exploration and appraisal phase and extend into deciding development options. The fluid distribution in the reservoir is a function of source rock material, migration path, charge history, charge mechanisms, processes working towards fluid equilibration, processes working towards fluid dis-equilibrium, geologic setting, burial history, reservoir architecture, timing, etc. Hence an interdisciplinary approach is necessary to make use of the information contained in the fluid distribution to constrain the understanding of processes that impact production. The level of confidence rises with the data quality and data availability. Acquiring high quality data to map spatial variations of fluid properties across the field is an integral part of this methodology.
Stratigraphy and structure analysis, static formation pressure surveys, mud gas analysis, isotope analysis, oil geochemistry and solution gas geochemistry are routinely used to assess compartmentalization. However, in spite of this array of methods, unrecognized compartmentalization remains one of the leading causes of production underperformance in the industry. New methods are required to address the bad news of compartmentalization or to reveal the good news of connectivity. A new method that has had much success is to assess if reservoirs fluids are equilibrated, if so, then reservoir connectivity is indicated. (Mullins 2008). In particular, fluid compositional equilibrium is orders of magnitude more stringent than pressure equilibration to reveal reservoir connectivity (Muggeridge and Smalley 2008, Pfeiffer et al. 2011). Moreover, it is now possible to determine independently whether GOR gradients and asphaltenes gradients are equilibrated (Freed et al. 2010). Specifically the application of new asphaltene science in new wireline workflows allows to assess fluid equilibrium based on the suspended solids in the oil; the asphaltenes (Mullins 2010). This new approach is based on different physics than the industry standard of assessing the solution gases in oil. Frequently, it is the asphaltenes that provide the best method of analysis of reservoir connectivity. The case studies in this paper show the application of this new methodology in real life examples.

Case One shows how the existing formation evaluation data is used to support the hypothesis of dis-connectivity or compartmentalization. This case is representative of a situation where connectivity was not part of the focus during the data acquisition and the question needs to be answered with the data available at hand. It validates the concept of the proposed workflow, but clearly shows its limitation if the data acquisition plan and operational constraints do not give the flexibility to react upon the interpretation done in real time.

Case Two summarizes advanced data interpretation and workflows from a well and its sidetrack to reduce subsurface uncertainty with regards to connectivity. Advanced interpretation of Downhole Fluid Analysis strongly indicates that three of the four oil bearing sands are vertically in communication whereas the asphaltenes content in the fourth sand is five times as high as compared to the other sands plausibly indicating disconnectivity. Other fluid properties, governed under the laws of vapor-liquid equilibrium, like solution gas ratio, density, light end ratios saturation pressure and CO2 content lack the dynamic range to make a clear cut assessment.

**Statement of Theory**

Asphaltenes in crude oil are colloidally suspended solids. Cubic equations of state fail to model asphaltene gradients. (Lyn Orr 2012). The understanding of asphaltene gradients and dynamics of fluids in reservoirs had been hindered in the past by the lack of knowledge of asphaltene nanoscience (Mullins et al. 2013). Recently, the Yen-Mullins model, has been proposed consisting of the dominant forms of asphaltenes in crude oils; molecules, nanoaggregates and clusters (Mullins 2010). It enables the development of the first predictive equation of state for asphaltene gradients in reservoirs, the Flory-Huggins-Zuo (FHZ) EOS (Freed et al. 2010). This new asphaltene EOS is readily exploited with the latest updates in downhole fluid analysis on wireline formation testers thereby elucidating important fluid properties and complex reservoir structures (Zou et al. 2011).

Asphaltene gradients enable assessing reservoir connectivity in black oil, where most other fluid properties appear homogeneous or lack dynamic range to make the assessment. The variation in asphaltene content is barely registered in the oil density due to the small concentration of asphaltenes in the black oils of the presented cases. A typical asphaltene gradient of black oil is in the range of a 1%wt-3%wt. Therefore asphaltene gradients often remain undetected in the absence of downhole fluid analysis. The potential to use asphaltene gradients to assess reservoir connectivity has been successfully worked in several cases (Dong et al. 2013, Mullins et al. 2013, Seifert et al. 2012, Mullins et al. 2011, Mullins et al. 2010, Betancourt et al. 2007, Elshahawi and Mullins 2005). Asphaltene gradients in oil columns can be very large yet still be amenable to the FHZ EOS (Zuo et al. 2011).

Advanced DFA robustly measures relative asphaltene variations through fluid coloration changes. Additional answer products include Gas oil ratio (GOR), light end composition (C1, C2, C3-C5, C6+ and CO2), density, viscosity and fluorescence (Dong et al. 2008). DFA measurements are station measurements at in situ conditions that are conveyed as part of a wireline formation tester and thus can be interpreted in real time. The proposed workflow consists of acquiring sufficient DFA measurement stations in the well to establish vertical gradients that are benchmarked against the predicted equilibrium distribution. In addition, the latest technology has advanced the accuracy to a level that enables well to well comparison of these gradients. The number of DFA stations ideally differentiates continuous distributions from stair step changes in the gradients. An interdisciplinary approach integrates the data to support one of the different possible reservoir architecture models.
Case One

BG drilled an Exploration and an Appraisal well on the Norwegian continental shelf within a distance of ca. 2km of each other. Figure 1 shows a model of the reservoir setting. One sample and DFA station was acquired per sand, giving us 3 data points in two wells. Samples were acquired in focused sampling technique. Oil based mud filtrate contamination varies from 3%-6% vol. The discovery well encountered oil-down-to in the upper sand. The lower sand was water bearing under a slightly higher aquifer pressure compared to the appraisal well. The appraisal well encountered oil-down-to in the upper sand and an oil water contact in the lower sand.

Static formation pressure finds the upper sand in the appraisal well 1.2bars lower than the upper sand in the discovery well. Figure 2 shows the static formation pressure surveys in the two wells. The aquifer pressure in the lower sand south seems to be slightly elevated. The 1.2bar difference between the top two sands is unlikely to be depletion due to the Drill Stem Test (DST) in the discovery well. Sub-seismic faults are suspected to be the cause for the DST to indicate boundaries close to the well.

Figure 1 - Discovery Well (south) and Appraisal Well (north) with suspected reservoir model

Figure 2 - Pressure gradients: lower pressure regime in the upper sand north and higher aquifer pressure in the lower sand south

Figure 3 shows the light end ratios represented in a spider plot (based on laboratory data). All samples plot on top of each other and indicate that the light end comparison does not yield information to differentiate between the oils in the different parts of the reservoir.

The DST sample comeles fluid from a 16m interval. SARA analysis shows 72% wt of saturates (Figure 4). Saturates are not good solvents of asphaltenes, which could explain the relatively low asphaltene content of 0.69% wt. The low level of asphaltenes is confirmed by the low level of fluid coloration.

Figure 3 - Light end comparison (from lab composition) does not yield information to differentiate between the oils in the different parts of the reservoir

Figure 4 – SARA analysis of the DST sample. Saturates are not good solvents for asphaltenes. Saturates content of 72% wt could cause the relatively low asphaltene content of 0.68% wt. In such conditions it would take little fluid variation to see asphaltene disequilibrium.

Figure 5 shows the spectroscopy data of the three DFA/sample stations. The fluid coloration can be corrected for up to 10% of filtrate contamination with confidence. The mud filtrate is assumed to be colorless in the optical wavelength channels used here. After contamination correction and baseline correction the data can be compared between stations. The optical density (after correction) is linearly related to the asphaltene content of the oil. Results are shown in the DFA prediction plot in Figure 6 together with the equilibrium prediction lines. The data indicates twice the asphaltene content in the upper sand.
south compared to the upper sand North and four times the amount of asphaltenes in the lower sand North. It is not common to see such a huge increase in asphaltenes content in connected reservoirs except possibly at the base of the column (Seifert et al. 2012) and that usually involves identified asphaltenes instability.

The small spread in the different prediction lines shows how variations in asphaltene size the impact the equilibrium. The size of the asphaltenes is tightly constrained by the Yen Mullins Model. With only three data points in two wells it is not possible to establish a meaningful vertical asphaltene gradient that can be compared laterally. Nevertheless, the magnitude of the difference in asphaltenes supports the hypothesis of dis-connectivity; it also discharges the DST-depletion theory.

Case One shows the value of information of the DFA data beyond its sample quality assurance purpose. It validates the concept. It also highlights that the data acquisition plan needs to target compartmentalization to acquire a more comprehensive data set in future applications.

Case Two

Wintershall drilled an exploration well with several targets, where the secondary target was found to be oil bearing. The well encountered two pressure regimes. Other wells had been drilled in the same structure, and similar properties were expected. But this was not observed. The main pressure regime was slightly lower than in the offset wells, the PVT properties were different, including a different bubble point pressure. There was no gas cap encountered in this well. Vertical and horizontal connectivity is one of the major uncertainties. The subsurface uncertainty revolves around sub-seismic faults and barriers (Figure 7).

In Well A, oil was sampled at 4 different depths over a vertical extent of approximately 70mTVD. The static formation pressure (Figure 8) fails to identify compartmentalization with confidence. The formation pressure measurements fall on a single gradient with the exception of the 4th sand, which is at 0.5bar higher pressure. This puts the 4th sand on the same
pressure regime as the offset wells. Nevertheless, such a small pressure difference is too small to make a confident assessment on discontinuity.

Figure 8 - Formation Pressures & gradients. Note that the bottom sand of Well A has a slightly elevated pressure.

PVT analyses compare methane content, GOR, CO2 content of the different sample locations amongst each other and with the offset wells. It is difficult to identify clear trends or confidently discern differences. All of these assessments are based on vapor liquid equilibrium. DFA helps to resolve ambiguity as it adds data that is based on different physics: the suspension of solids (asphaltenes) in liquid (oil). Three out of four measure points exhibit equilibrated asphaltene content that implies good vertical connectivity (Pfeiffer et al. 2011).

The 4th measure point exhibits a 3 fold increase in asphaltene content. Its GOR is slightly less and the fluorescence signal is suppressed by the higher fluid coloration corroborating the large color value. These measurements imply dis-equilibrium in the 4th sand. Together with all other log and pressure data this implies discontinuity between this sand and the rest of the reservoir.

Figure 9 summarizes the DFA and pressure measurements in Well A and its sidetrack. The sidetrack penetrated the top two hydrocarbon bearing sands down dip in approximately 200m lateral distance. The Pressure measurements in the sidetrack line up with the gradient in the main well.
The asphaltene content (3rd track) matches the one encountered in the top sand of the main well. This implies lateral connectivity in the top sands between the main bore and the sidetrack. The 4th track shows GOR in green hexagons, fluorescence in pink squares and density in blue pentagons.

The comparison of the asphaltene content in concert with other pvt and pressure data helped to delineate the most plausible of five reservoir models. Figure 10 shows a schematic representation of the cross section through the structure. The sequence of formations were thought to be different between Field A and Field B, but it was thought that Field B would contain the same fluids as in Field A. The limited resolution of the seismic data does not resolve geologic features to assess connectivity. The Static Formation pressure survey followed by the DFA stations indicates the absence of the gas cap in Field B. This was not expected and at this point, the depositional environment and geologic setting had to be rethought. Diligent vertical fluid scanning and assessing of the relative asphaltene content through DFA provides the pivoting evidence in this process. After integrating all formation testing data, including the relative asphaltenes content, it becomes clear that field A and B are separated. Also the presence of a vertical barrier between the top three sands and the bottom sand is a prudent assumption.
Figure 10 – New Reservoir model after integrating all formation testing data, including the relative asphaltene content. Field A and B are separated. The presence of a vertical barrier between the top three sands and the bottom sand in Field B is a prudent assumption.

Conclusions

Downhole fluid analysis has evolved beyond a tool made purely for sample quality assurance to provide fluid properties. The aim is not to replace sampling by adding a growing list of downhole measurements, but to map key fluid properties vertically and laterally. The latest technology allows well to well comparison of data. This enables field wide studies to reduce subsurface uncertainty that starts in the exploration and appraisal stage and extend into the development phase where the additional data keeps increasing the understanding of the reservoir architecture. The application of new asphaltene science in new wireline workflows allows to assess fluid equilibrium based on the suspended solids in the oil; the asphaltenes. This new approach is based on different physics than the industry standard of assessing the solution gases in oil. The case studies in this paper show the application of the latest technology and validate the methodology.

The acquisition of enough measurements is optimized by benchmarking the measured fluid properties against the thermodynamic equilibrium distribution, established by the FHZ EOS for asphaltenes. This assessment of fluid gradients is best done in real time by skilled practitioners, as it allows optimizing the acquisition program while the tool is still in the well. The presented methodology is increasingly being used in the Middel East, offshore West Africa, South America, Gulf of Mexico and in the North Sea.

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