Abstract

Downhole fluid analysis in a vertical and areal reservoir scale prior to oil or gas production is essential in order to design production strategies and production facilities. In addition, reservoir compartmentalization and hydrocarbon compositional grading magnify the necessity to map fluid properties vertically and laterally in the reservoir prior to production.

This paper describes the Downhole Fluid Analysis (DFA) process with the latest fluid sensors for improved reservoir management. DFA is a unique process that combines fluid identification sensors, which allow real time monitoring of a wide range of parameters as GOR, fluid density, viscosity, fluorescence and composition (CH4, C2, C3-C5 and C6+, CO2), free gas and liquid phases detection, saturation pressure, as well WBM & OBM filtrate differentiation and pH.

We examine two field cases in which compartmentalization and fluid variations were observed with both downhole fluid analysis measurements and pressure gradients. Fluid modeling is used to describe the fluid column according to a fluid equilibrium model and then compared to field pressure gradient to check the appropriateness of the pressure gradient models that accounts for the fluid density changes observed. The results of the modeled fluid and pressure analysis are compared to actual downhole measurements of the pressure profile and in-situ fluid logs. In particular, pressures and densities calculated from the multiple sources of information, pressure, and fluids are compared to direct actual measurements and integrated with the petrophysical model to support the vertical and areal reservoir modeling.

The combination of Downhole Fluid Analysis mapping together with pressure measurements and petrophysical data shows to be very effective for compartmentalization and reservoir characterization.

Using this method we present field DFA and pressure gradient data and its integration into numerical simulation modeling to conceptually evaluate the impact of fluid composition / properties gradation and compartmentalization in the productivity of some reservoirs.

1. Introduction

Reservoir connectivity impacts fundamental issues such as reserves estimation and well placement, and it is considered among the most important risk factors in offshore environments. Hence, it is desirable to assess connectivity with as much confidence as possible and as early in the development plan as possible. Reservoir connectivity can typically be proven during production, but at that point the information carries little value. Prior to production, connectivity is often assessed using techniques such as pressure gradients, petrophysical logs, and geochemical fingerprints. However, these methods cannot guarantee connectivity.
Interpretation of fluid compositional gradients represents a critical alternative method for assessing connectivity. Compositional gradients occur commonly and can result from a variety of factors including gravitational segregation, biodegradation, and charge history.

Analysis of compositional gradients is an attractive method to evaluate connectivity because it is based on a different physics from traditional methods (hence it represents an independent analysis) and because compositional grading can be delineated accurately during the exploration phase by wireline logging tools such as the Downhole Fluid Analysis family of tools (Figure 1).

The Downhole Fluid Analysis (DFA) process has been successfully used to delineate reservoir attributes such as vertical and lateral connectivity and properties of the fluids produced (Betancourt et al. 2009; Dubost et al. 2007; Elshahawi et al. 2005; Mullins et al. 2005, 2007a; Gisolf et al. 2009). The new generation DFA tools not only measure bulk fluid properties such as GOR, density and light-end composition of CO₂, C₁, C₂, C₃-C₅ and C₆⁺ more accurately but also color (optical fluid density, OD) that is related to the heavy ends (asphaltenes and resins) in real time at downhole conditions. In addition, the color measurement is one of the most robust measurements in DFA. Therefore, analysis of color gradients in oil columns becomes vital to discern reservoir complexities by means of integrating advance asphaltene science with DFA Fluid Profiling.

Asphaltenes are defined by a solubility classification, for example, soluble in toluene, insoluble in n-heptane. Asphaltenes are heavy polycyclic aromatic compounds that form nanocolloidal particles dispersed and/or suspended in oil. These nanocolloidal aggregates are the heaviest components in crude oil with by far the lowest diffusivity (Mullins et al. 2007b). Gravitational segregation tends to drive heavy asphaltenes down in an oil column whereas light hydrocarbons such as methane and other dissolved gas tend to rise in the column. In addition, because light hydrocarbons also make poor solvents for asphaltenes, high-GOR oils are poor solvents for asphaltenes, and asphaltenes are expelled from the high-GOR top of the oil column. That is both gravity and solubility tend to make asphaltene concentration low at the top of the oil column. The fluids necessarily enter the reservoir out of their ultimate equilibrium, so to establish fluid equilibrium in the reservoir requires considerable fluid flow. Thus fluids that are determined to be in equilibrium in regions of the reservoir suggest that those reservoir regions are connected. In particular, if asphaltenes are equilibrated in spite of their small transport coefficients, the connectivity is implied because flow barriers would greatly impede asphaltene equilibration in the reservoir. Any sealing barrier or flow restriction interrupts the movement and migration of asphaltenes. In contrast the presence of a discontinuous asphaltene concentration vertically or laterally within the reservoir explicitly indicates a boundary for fluid flow. Although asphaltene gradients do not explicitly prove reservoir connectivity, the lack of an asphaltene gradient demonstrably indicates the lack of connectivity.

This paper presents a case study where reservoir connectivity is evaluated by a combination of tools; compositional gradient analysis together with modern Downhole Fluid Analysis (DFA) techniques. The results provide an improved assessment of reservoir connectivity when compared to using only traditional techniques. In order to understand production potential and drainage patterns predictive modeling is applied through reservoir simulation integrating petrophysical analysis, formation tester data and DFA analysis.
In this work, we show an asphaltene gradient in well A as defined by DFA coloration. The same reservoir observed at well B appears to be exposed to the same gradient. A simple Boltzmann distribution is presumed to apply yielding the size of the (colloidal) asphaltene aggregate in the oil. This aggregate is shown to be consistent with existing knowledge of petroleum science. The importance of understanding this gradient is discussed in terms of reservoir compartmentalization and reservoir management. Identification of compositional gradients and reservoir compartmentalization early in the life of a high cost offshore development can have significant financial impact to field Appraisal and Development decisions.

2. Case Study

Single Well Analysis (Well A)

The studied reservoirs are turbidities sands with reservoir quality ranging from excellent to moderate. Lithology can vary from simple to complex, and heterogeneity with vertical permeability barriers and baffles in the reservoir interval is common. The petrophysical evaluation consisted of well log data preparation, cross plot analysis for parameter determination and qualitative/quantitative formation analysis. Integration of resistivity and nuclear magnetic resonance in the saturation analysis helped to validate the bound fluid volume that is used as input to the permeability equation. This comparison also proved useful in determining intervals where viscous oil made the estimation of bound water from magnetic resonance unreliable.

As part of the petrophysical evaluation the continuous permeability indicator was calibrated using FT mobility and Mini-Test data.

The final model provides continuous profiles of effective porosity ($\phi_{\text{eff}}$), initial water and oil saturations ($S_w$, $S_o$, irreducible water ($S_{wi}$)) and intrinsic permeability ($K$).

Direct fluids measurements for the reservoir under study are shown in Figures 2 and 3. This reservoir presents pronounced compositional grading, with fluid density, color and viscosity (determined by pressure tests and the use of Downhole Fluid Analysis techniques - DFA) varying significantly across the about 250 m gross pay zone; such compositional grading is often associated with reservoir compartmentalization. Independently, variable pressure gradient and open hole logs identify possible sealing barriers across this well, suggesting compartmentalization.

It is becoming increasingly clear that compositional grading is to be expected, mainly in viscous oils, whereas in the past compositional grading was viewed as an aberration (C. Hoier, L. Whitson, C.H., 2000).

In order to confirm the fluid variations defined by the pressure pretests analysis, several fluid sampling stations were recorded using formation tester pump out and Downhole Fluid Analysis modules. These consisted of Optical Fluid Analyzers, InSitu Fluid density and viscosity sensors for a continuous monitoring of fluid clean out and fluid characterization. Figure 4 presents the Optical Fluid stations response for stations A to D m and the in situ fluid density and viscosity for stations A and C. The surveys in Figures 5 & 6 confirm the nature of the fluid columns identified by pressure gradient and allow more representative fluid sample collection while monitoring potential risk due to excessive flow rate in these unconsolidated sandstones.

The fluid color obtained in the near-infrared spectra by the Downhole Fluid Analysis sensors are presented together with other DFA parameters in Figure 4 and can be correlated with the asphaltene content of the fluids (Betancourt, et al. 2007; Zuo et al. 2009). The higher Fluid Coloration indicates higher asphaltene concentration. In the present case the oil stations with optical fluid densities in the channel 1750 v. represent nearly 15% weight in asphaltenes.

Lab Analysis also confirms the downhole readings presented in Figure 4 to 6.
Figure 2: Wireline logs and formation tester pressure gradient; Illustrate the system compartments and density gradient for well A.
Figure 3: Compositional grading in the intermediate zone inferred from pressure pretests in well A.
Figure 4: Compositional fluid grading in well A illustrated by the increase in hydrocarbon density from pressure pretests, fluid optical density and in situ viscosity from Downhole Fluid Analysis.

Figure 5. Downhole density and viscosity reading for station B in well A.
Multi Well Analysis (wells A & B in same block)

Later the operator drilled a second well in the field (referred to as Well B). On Well B oil samples and water samples were acquired together with detailed open hole logs and pressure tests data. Figure 7 illustrates the detailed analysis of the fluid column inside each compartment and also identifies compositional grading in both of the studied oil columns in well B. Figure 8 complements the analysis for well B illustrating pressure pretests, fluid optical density from DFA and lab viscosity analysis.

Additionally the multi well data analysis for wells A & B is presented in Figure 9. It shows the good match between the pressure data acquired in these wells over the zone of interest. The small absolute pressure difference of less than 5 psi at similar depths seems to be in good agreement. It suggests areal connectivity between wells A & B locations. However, a detailed pressure gradients analysis shows a little denser fluid in Well B.

Additionally, from Figure 10 we can see that the oil sample taken at Well B has a small optical color difference when compared with a sample from the same horizon in Well A (station C). The difference is magnified in the InSitu oil viscosity.

These results suggest partial reservoir connectivity in the lower oil zones of Wells A and B. Discontinuous fluid properties vertically or laterally within the reservoir explicitly indicate fluid flow barriers. In particular the oil viscosity is related to the difference in the asphaltene concentration for this type of oils and abnormalities for a complete vertical segregation of asphaltenes are associated with connectivity limitations.
Figure 7: Wireline logs and formation tester pressure gradient illustrate the system compartments and density gradient for well B.
Figure 8: Compositional fluid grading in well B illustrated by pressure pretests, fluid optical density from DFA and lab viscosity analysis.

Figure 9. Multi Well Analysis: Integration of pressure and DFA Stations data from Well A and Well B.
3. Fluid Profiling and Impact in Reservoir Management

Confident fluid properties and mitigating intervention methods are needed for optimal completions, facilities design and production strategies. Consequently, getting the correct answer in the first attempt is a necessity (O.C. Mullins, H. Elshahawi, et al, 2005).

Among the studied wells in this viscous oil environment, the oil column in Figure 10 is affected by compositional grading. The vertical oil column density varies from 0.89 to 0.95 g/cc and the down-hole oil viscosity changes from 16 to 80+ cps from top to bottom as confirmed by the integration of the selective pressure gradients, DFA stations and PVT analysis of the fluid samples taken along the vertical column.

A detailed petrophysics analysis and commercial reservoir simulator ECLIPSE* in fully implicit, black oil mode is used to simulate well placement and completion configurations strategies (Horizontal / Slanted & MLT wells completion) in order to investigate commercial production rates and efficient drainage process in these heavy oil reservoir.

Figure 11 presents the detailed petrophysics analysis for one of the studied wells. The final model provides continuous profiles of effective porosity ($\phi_{eff}$), initial water, oil saturations ($S_w$, $S_o$), irreducible water ($S_{wi}$) and intrinsic permeability ($K$).

Figure 12 presents the expected irregular drainage with a slanted well configuration due to the reservoir compositional gradient. The irregularity is evident in the vertical drainage, mainly at the heaviest oil levels. This phenomenon affects both the vertical and areal drainage.

The initial Productivity Index sensitivity analysis for this viscous oil reservoir with compositional grading is presented in Fig.13. Horizontal / slanted wells with drainage sections of 500 meters vs. vertical well completions are considered. It shows the advantage of the horizontal / slanted wells, mainly in the top zone of the reservoir with the lowest oil viscosity range. Productivity and drainage in the highest viscous oil interval at the bottom is not efficient for the studied
completion under cold conditions. Therefore, it is suggested to place horizontal / slanted wells in the top levels or multilaterals with control systems.

To reiterate, a rigorous approach should be to constrain the geological model with the fluids model; which ultimately leads to an improved reservoir model. This can be accomplished only through Downhole Fluid Analysis mapping. The Downhole Fluid Analysis has been fundamental in the exploitation optimization by more robust reservoir management approaches.

Fig.11. Petrophysics analysis for productivity modeling, Well B
3. Conclusions

- Advanced Downhole Fluid Analysis (DFA) is a process aimed to enhance reservoir model construction and to change conventional work flows by reducing the uncertainties associated with compositional grading and compartmentalization.
- Downhole Fluid Analysis (DFA) helps to understand asphaltene compositional grading (vertically & areal) for middle to heavy density oils that tend to exhibit heavy end grading.
- Integration of DFA into reservoir development activities by a repetitive process as new wells are drilled in these fields could reduce fluid characterization uncertainties and their impact in reservoir management.
- Downhole Fluid Analysis is a process aimed not only to support fluid sampling operations in real time, but to utilize laboratory studies and down-hole fluid data to build and constrain reservoir models.
5. References


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