Predicting Downhole Fluid Analysis Logs to Investigate Reservoir Connectivity

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Abstract

Compartmentalization is perhaps the single biggest risk factor in deepwater petroleum production. Downhole fluid analysis (DFA) is a new tool to reduce uncertainty associated with reservoir connectivity. Fluid data from DFA logs and various laboratory analyses are studied to elucidate hydrocarbon composition variations in large reservoir sand bodies. This procedure was applied in the Deepwater Tahiti field in the Gulf of Mexico uncovering a large concentration variation of asphaltenes. These asphaltene nanoparticles are shown to be colloidally suspended in the crude oil in agreement with recent laboratory results, and settle preferentially lower in the oil column in accord with the Boltzmann distribution. Relevant fluid features, in this case the asphaltene concentration gradient, are then integrated in a geologic model and used to predict crude oil properties and DFA logs for all hydraulically connected sections of the reservoir. Predicted and newly acquired DFA log data matched for the first production well, establishing that the penetrated sands are likely connected, mitigating compartmentalization risk. This DFA log prediction protocol offers a new method to optimize wireline logging.

Introduction

Knowledge of reservoir architecture is critical to successful development planning.¹ Indeed, history matching of production data is extremely useful for understanding the reservoir.² However, in high-cost arenas where expensive production facilities must be in place prior to production of first oil, history matching for facilities design is precluded. The connectivity of the producing units throughout the field is a major uncertainty and risk factor that behooves conventional as well as novel analytic approaches. Reservoir compartmentalization (the inverse of connectivity) impacts all production strategies, and therefore mandates the use of all sources of information that may help unravel reservoir complexities. One key and relatively new technology that is increasingly exploited for reservoir characterization is Downhole Fluid Analysis (DFA). DFA enables characterization of the fluid in the oil column, creating in essence a continuous downhole fluid log. With a multi-well approach DFA can address the fluid distribution throughout the reservoir. Because reservoir fluids are typically compositionally graded,³ different compartments are often filled with different fluids. Thus DFA can identify compartments.⁴

Acquisition of representative reservoir fluid samples is essential at the early stages of exploration. Ideally, fluids would be analyzed in their existing conditions, i.e. in the formation; however a detailed analysis of the fluid in the rock is not possible today. The closest alternative is the acquisition of downhole fluid samples accompanied by a real time fluid analysis (DFA) while sampling. One of the methods available for downhole fluid sampling is via a wireline formation testing and sampling tool (WFT). With current technology it is possible to obtain contamination-free samples in a very short time.⁵ Furthermore, this technique enables the acquisition of samples at different depths with unmatchable vertical resolution. Proper sampling practices are essential to preserve the composition of the extracted fluid as close as possible to that in the formation, minimizing as much as possible the risk of undesirable phase transitions.

Wireline-conveyed formation testing and sampling tools are described in detail elsewhere.⁶ Figure 1 is a schematic representation of one possible configuration of WFT tool with two DFA modules, a pumpout model, sample modules containing the sampling bottles and two single-probe modules. On the right side of this figure is a picture of the sampling probe. The probe is set in the wellbore against the reservoir rock and fluids are extracted from the formation into the tool flowline by creating a controlled differential pressure with a pump. The contents of the flowline are analyzed in any of the DFA modules, which are based primarily on Visible-Near-Infrared (Vis-NIR) absorption spectroscopy. The light-absorption characteristics of crude oils differ from those of gas, water and oil-based mud filtrate, enabling a quantitative analysis of the fluids flowing through the downhole fluid analyzer.
In this study we report to our knowledge the first field-scale study integrating multi-well Downhole Fluid Analysis data with pressure gradients, geology and geochemistry for the development of a deepwater field. This resulted in the creation of an integrated geology-fluid model that captures the main characteristic in this fluid, i.e. the natural gradient in the asphaltene concentration. This model incorporating the asphaltene gradient has been used here in the field development stage to predict DFA logs at any location in the field with a forward model that uses as input the fluid composition. This synthetic log is used in real time during the DFA job for comparison with the actual DFA log data. This comparison provides a measurement of the degree of lateral and vertical communication throughout the reservoir.

This extends the traditional applications of DFA by integrating the geologic and fluid models of the field to create a fluids map of the reservoir. This fluids map is then used to predict all upcoming DFA log data before a new well is drilled. Thus, predicted and newly acquired DFA log data can be compared in real time while the Wireline Formation Sampling Tool (WFT) is in the well. If predictions match observations, the reservoir and fluid models are corroborated. If predictions differ from observations, the WFT operation can be modified in real time to ascertain the origin of the observed discrepancies. The primary objective is to analyze and compare hydrocarbon fingerprints throughout the field with the purpose of identifying reservoir connectivity vs. compartmentalization and compositional variations.

This methodology was applied in the offshore Tahiti field in the Gulf of Mexico, unveiling very interesting and useful fluid features. The integration of DFA into the reservoir description revealed an equilibrium concentration gradient of collooidally suspended asphaltene vs. the top of the main sand ranging from 24,000 to 27,000ft TVD. As a consequence, the sands exhibit a high tilt angle, with the top of the main sand ranging from 24000 to 27000ft TVD. Figure 2 shows an image of the 3D geological model depicting the facies distribution at the top of the M21A sand. Reservoir pressure and temperature at 27000ft are 20000psia and 200F. The exploration program included extensive formation evaluation, coring and an extended production test in one well. The reservoir parameters measured indicated a high quality reservoir for this depth, and apparently good lateral communication throughout the field.

Figure 2 3D Geological model showing the different geological facies at the top of the M21A sand and the location of the wells and the water-oil contact. (Yellow=sand, orange=fine sand, tan=coarse sand, gray=shale)

A cross-section of the field normalized to the base of the M21B sand is shown in figure 3. As in all high-cost developments, the connectivity of the sands is the chief risk factor. The extensive formation pressure data available in the M21A and M21B sands indicate that the two sands are in different pressure regimes, but give no indication of pressure discontinuities that would imply reservoir compartments.

The Tahiti Reservoir

The deepwater (4100ft water column) Tahiti Field in the Gulf of Mexico is expected to start production in 2008. The reservoir consists of several stacked Miocene turbidite sands stratigraphically delineated by a ‘three way anticlinal closure truncated against a salt feeder/weld system buried beneath an 11000’ thick salt canopy’. As a consequence, the sands exhibit a high tilt angle, with the top of the main sand ranging from 24,000 to 27,000ft TVD.
within each sand (Figure 4). Pressure communication is a necessary but insufficient condition to establish flow connectivity on production time scales.

In a field where the geology makes seismic interpretation a challenge, efforts to delineate the architecture of the reservoir have focused on fluids acquired and analyzed early in the exploration stage. Three exploration wells, each with a sidetrack, targeting the oil zone were drilled with oil based mud. A total of 14 DFA and sampling stations in the M21 sands provide the fluid samples for this study. Most of the samples have the low levels of contamination required for geochemistry and PVT work. All the DFA data acquired during sampling is of very good quality (high signal-noise ratio), and the computed levels of contamination from downhole data agree very well with those reported in the laboratory. DFA and lab analyses indicated that the hydrocarbons are undersaturated black oil with GORs ranging between 550 and 650scf/stb with a slight decrease with depth.

DFA, Geochemistry fingerprinting of crude oil samples, gas analysis during mud logging and solution gas isotope analysis were the primary fluid analysis techniques initially employed to study the variations in the samples with one of the objectives being identifying reservoir architecture. Geochemistry fingerprinting performed with gas chromatography indicates that all M21A samples are similar among them but distinct from M21B (Figure 5). The minor variations observed in the M21A and M21B sample groups are a result of expected experimental scatter. Fluid composition data from the M-21A updip in the North part of the field exhibits a different trend that may be due to 'baffling' within this sand. Geochemistry fingerprinting has to be done in the laboratory in samples with low levels of contamination by oil-based mud filtrate.

**Starplot of Peak Height Ratios**

![Starplot of Peak Height Ratios](image_url)

**Figure 5** The starplot diagram contains the ratios of the GC component peak heights that were selected as most informative. Geochemistry fingerprinting of crude oil indicates similarities in all M21A samples that distinguish them from M21B samples. This technique cannot analyze the asphaltenes in crude oil.

### Nanocolloidal Asphaltene Suspension in Crude Oil

The primary objective of this study was to integrate DFA with other sources of data such as formation pressure and geology to discriminate fluids throughout the field with the purpose of identifying reservoir architecture and fluid compositional variations. In particular, the natural composition gradient of the fluids must be taken into account in order to predict DFA spectra in upcoming DFA stations and to facilitate pressure data.
comparisons with other samples from the putatively same sand. It is notable that in this reservoir other fluid parameters that could be used for discriminating samples, such as concentration of lighter hydrocarbon components or gas/oil ratio (GOR), have minimum variation. This is expected for highly undersaturated black oils. That is, a highly undersaturated black oil in equilibrium is not expected to exhibit a GOR gradient. In particular, if the formation pressure is much higher than the saturation pressure, and if the saturation pressure is quite different from the critical pressure, then significant GOR gradients are not expected. This prompted us to look at other fluid features that could be used to better compare the fluids to identify reservoir architecture.

The analysis of the Tahiti DFA data reveals a concentration gradient in the heaviest organic components of the fluids in the two main sands, the ‘asphaltenes’. Composition variations in other hydrocarbon components were negligible, and without taking into account the asphaltenes the fluids would have been considered homogeneous. The asphaltene concentration gradient of the fluids in this field was revealed by DFA data as an increase of the color of the fluid with depth, and was confirmed by the excellent correlation between downhole absorption spectroscopy and laboratory SARA analyses on all the fluid samples.

Asphaltenes are defined as the n-heptane insoluble, toluene soluble fraction of crude oil. The compositional description known as SARA is used to determine the concentration of Saturates, Aromatics, Resins and Asphaltenes in a crude oil sample. Asphaltenes are well known for their tendency to aggregate and even flocculate yielding deposits in tubulars and elsewhere. Asphaltene onset pressures measured in the PVT lab for some of the samples in these sands are between 2500 and 8500psi, and though the data is limited, it appears that the fluids with the highest asphaltene content have the highest onset pressure; with the caveat that this measurement is sensitive to sample contamination by OBM filtrate. Asphaltene onset pressures are relevant for flow assurance and may impose production constraints.

Several features contribute to the possible existence of an equilibrium fluid gradient in asphaltene concentration in the Tahiti field. First the high quality of the reservoir sands –high horizontal and vertical permeability– facilitates fluid equilibrium conditions. Second, the reservoir consists of tilted sheet sands of high dip angle, a condition that facilitates the mixing and equilibrium in contrast to an anticlinal structure. Despite the large depth variation to the top of the sand throughout the field, the temperature variation is only 10°F, and this temperature gradient is not expected to perturb fluid equilibrium.

The asphaltene concentration gradient in the Tahiti field has been represented by an equilibrium thermodynamic model based on a Boltzmann’s distribution of the asphaltene nanoparticles collooidally suspended in the homogeneous liquid phase. The asphaltene concentration at any depth in the reservoir is given as an equilibrium suspension of a colloidal asphaltene phase in a homogeneous liquid phase. This is very distinct from the common occurrence where there is a large GOR variation; since the asphaltenepartition dominantly into the liquid phase, a large GOR variation will produce a large asphaltene variation. This is also distinct from nonequilibrium distributions of asphaltenes which can arise from a variety of circumstances such as biodegradation and charge history.

With the equilibrium colloidal suspension of asphaltene, the governing equation is:

\[ c_A(h) = c_A(h_0) e^{\frac{-\Delta p V g h}{k T}} \]  

where \( c_A(h) \) is the asphaltene concentration in %w/w at height \( h \) in the reservoir above the reference height \( h_0 \), \( c_A(0) \) is the asphaltene concentration in %w/w at \( h_0 \), \( \Delta p \) is the density difference between the two components (\( \rho_{asphaltene}=1.2g/cc \) and \( \rho_{oil}=0.8g/cc \)), \( V \) is the volume of the asphaltene ‘sphere’, \( g \) is the earth’s gravitational constant 981 cm/s², \( T \) is the reservoir temperature in °K, and \( k \) is the Boltzmann constant 1.38×10^-16 g cm²/(s²K).

This model has been shown to be consistent with laboratory determinations of the colloidal suspension of asphaltenes in toluene, lending credence to the analysis herein. In our model all variables are known except the volume of the asphaltene nanoaggregate. From a calculation using a concentration variation of 2 over a 2000 feet column, the diameter of the asphaltene ‘sphere’ is derived from this model to be 16Å. This number is comparable with recent rotational and translational diffusion measurements of asphaltene molecules in toluene. In addition, this number is consistent with the ultrasonic determination of asphaltene nanoaggregate parameters by high-Q ultrasonics and NMR. Modeling the asphaltene gradient, necessary for DFA log prediction, utilizes the latest thinking in asphaltene science.

**Downhole Reservoir Fluid Analysis**

DFA consists in part of measuring the visible-near-infrared (Vis-NIR) spectrum of the formation fluids passing through the flowline of the WFT tool as a function of time. The Vis-NIR absorption spectrum of a substance is determined by the concentration of molecular components that respond to energy changes induced by absorption of photons within the wavelength range of analysis. In the case of crude oil, the methane CH4, the -CH3 and -CH2- groups have characteristic peaks in the NIR region that can be treated to give information on fluid composition, such as the proportion of methane, other hydrocarbon gases and hydrocarbon liquids (hexanes plus). More detailed analysis of the absorption band enables determination of the concentration of ethane. The gas-oil ratio of the crude oil can be derived from the composition.

The visible and near infrared region also contains information on the electronic absorption edge of the crude oil, the “color”, which is dictated by the concentration of the larger molecules.

\[ *1 \text{ Å} = 1\times10^{-8} \text{cm} \]
i.e. asphaltenes and to a lesser extent resins. The color is due to light absorption by polycyclic aromatic hydrocarbons. Figure 6 shows the Vis-NIR absorption spectra of several common reservoir fluids. Large variations in the absorption response are observed for different types of hydrocarbons, with a graded transition from the ‘colorless’ gases and condensates to the much darker heavy oils.

Figure 6 Vis-NIR absorption spectra of different reservoir and well fluids.

For measuring the strength of the color, we use interchangeably the terms ‘Absorption’ (A) and ‘Optical Density’ (OD) of the crude oil samples. However, rigorously OD equals absorption plus scattering, thus if there is no light scattering, such as with a pure crude oil, then OD=A. Asphaltenes in their native state in crude oil (as nanoaggregates) are absorbers, not scatterers, of visible and near-infrared light. At any wavelength (λ) the absorption (A_λ) of a sample is defined as the logarithm of the transmittance, i.e. the log of the intensity ratio of the incident light (I_0) and the light received by the detector on the other side of the sample (I). The optical density (OD_λ) is given by Equation 2:

\[
OD_\lambda = A_\lambda = \log_{10}\left(\frac{I_0}{I}\right)
\]  

Figure 7 DFA log data from all the sampling stations in the M21A sand show a large color variation.

Figure 8 DFA log data from all the sampling stations in the M21B sand showing a large color variation.

Results and Discussion

DFA is performed by continuously measuring the fluid properties while the WFT tool remains at one sampling station extracting fluids from the formation. The measured fluid properties in the downhole vary with time as fluids from the non-invaded zone reach the tool. DFA absorption data for all the DFA and sampling stations in the M21A and M21B sand at the time that the contamination levels were the lowest are shown in Figure 7 and Figure 8 respectively. The large color variation correlates with the variation of the asphaltene content of the samples as measured by laboratory SARA analyses. The optically darker fluids are those with the higher asphaltene concentration and are also deeper in the structure. This large color-asphaltene variation can be used to investigate the continuity of the reservoir.

The correlation between asphaltene content and color in the Tahiti oils (Figure 9) is clear once the effects of contamination by oil-based mud (OBM) have been accounted for. The base
oil (the filtrate) used for the preparation of the OBM is basically colorless and acts as a diluting agent to the crude oil. The excellent agreement between downhole and laboratory data supports our initial observation on the variations in the light absorption characteristics of the fluids in this reservoir; a contributing factor that made this observation possible is the high quality of the downhole measurements and the low error introduced by the use of several DFA tools to acquire this data over a period of two years. The color variation successfully captured by the downhole analysis is due primarily to the varying asphaltene content of the fluid.

Figure 9 Correlation between optical density of live fluid samples in M21A and M2B from DFA and asphaltene content from SARA analysis.

Tahiti Asphaltene Concentration Gradient

The optical data measured downhole was corrected for contamination and plotted against depth. Figure 10 and Figure 11 show the optical data for each zone. In the M21A sand (Figure 10) two very distinctive groups were observed: a group with samples from the central and south part of the field (red circles) and a group with the samples from the north part of the field (green circles). The two data groups can be modeled with the same size of the asphaltene nanoaggregate (16Å). Therefore the whole field has the same gradient, but the north part has a much lower concentration of asphaltenes. The review of the seismic which indicated the possibility of additional faulting in the north part of the field was conducted when modifying the earth model after reprocessing the seismic and including the development well data. This observation corroborated results of the advanced fault detection method used to interpret the new Multi-Azimuth PSDM seismic dataset.

The points from M21A South in figure 11 that appear to be separated from the trend were acquired in the same well at the top and bottom of M21A and the two stations have a vertical offset of 35ft. Both samples have a relatively low asphaltene concentration for their depth in the reservoir. There are two other cases of samples acquired at the top and bottom of the M21A sand in two separate wells, and the deepest sample has always more ‘color’. This could be pointing to some minor fluid variations across the bedding of M21A. The petrophysical interpretation in M21A does show some degree of variation in the quality of the sand in the vertical direction due to some interspersed shales. A drill-stem test in the discovery well detected a flow barrier; however in this test M21A and M21B were commingled. With the information available at this time it is difficult to determine conclusively what could be the reason for the different color in these two points. It is possible that the samples taken in the very upper portion of the sand may represent an upper member that is baffled from the rest of the reservoir and that may contain a slightly lighter fluid (one with a larger component of later, more mature oil). In these turbidite floods there are frequently very clean events at the beginning and end of the depositional cycle that would support such a model. In practice, it is preferred to sample at the top of a sand so that the majority of the length of the WFT tool is in the shale section and not exposed to the overbalance, so there is always the risk of sampling in a member that might be not representative of the entire interval. Multiple DFA stations would have added value in this case, even though it was considered that k_v/k_h is high and there are no obvious pressure barriers between sand members.

Figure 10 Variation of DFA optical density with depth in the M21A sand. Two main trends were observed in the data, one for the center and south of the field and the other for samples from the north part of the field. The solid lines are the computed optical densities from the Boltzmann distribution model with an asphaltene nanoaggregate diameter of 16Å.

We do have to acknowledge, however, that the pressure gradient data within each sand in each well doesn’t lend support to the concept of stratigraphic baffling. A careful examination of the pressure data was undertaken to address why the cleaned fluid densities do not match WFT gradients to a higher degree, though it is wise to keep in mind the present limitations of laboratory measurements of density and viscosity at very high pressures (~20kpsi in this case). From such an analysis, no indication was found of vertical separation that would have been previously unnoticed and it
was not possible to differentiate any density gradients across sands in individual wells.

From the petrophysical analysis, M21B appears more homogeneous than M21A; however, fewer fluid sampling stations were performed in this sand. All the DFA measurements in M21B are in very good agreement with the model for the same asphaltene particle diameter of 16Å (Figure 11). Only one sample was acquired in the north part of the field and it has color and asphaltene concentration similar to two other samples that are at about the same depth but in the south and center part of the field.

![Figure 11 Variation of DFA optical density with depth in the M21B sand for the whole field. The solid lines are the predicted optical densities from the Boltzmann model with an asphaltene nanoaggregate diameter of 16Å.](image)

**Chain of Custody**

A long standing problem in the oil business is the inability to prove that laboratory analyses performed on samples up to a year or more after sample acquisition do in fact relate to the virgin reservoir fluid. Indeed, discrepancies between openhole wireline samples and ultimate production samples are often attributed in part to invalid samples in the lab. To address this we have implemented a new Chain of Custody procedure, a concept borrowed from forensic science. This process consist of a Vis-Nir spectrum of the sample downhole at the point of sample acquisition (DFA), and then performing the same spectral measurements under reservoir conditions in the laboratory before any other fluid analyses.

As shown in Figure 12, six live fluid samples from the exploration campaign were validated by doing a Chain of Custody study, the pressure and temperature of the downhole and laboratory measurements were ~20000psi and 200ºF. Even though five different DFA tools were used to acquire the downhole fluid data during exploration there was in general an excellent agreement between downhole and laboratory spectroscopy; thus, DFA tool to tool error is small. The results indicated that all samples but one had been well preserved with respect to their original concentration of heavy components. One sample appeared to have lost some asphaltene content in the laboratory analysis compared to DFA. Indeed this sample had a lower asphaltene content measurement from SARA, and was the only outlier on the depth vs. asphaltene content plot (sample 3.04 in Figure 12). Fortunately a second sample bottle in the same sand was available with the original concentration of asphaltenes. Another observation from the Chain of Custody analysis was that a couple of sample bottles had lost some gas during the three-year storage period. Fortunately for this study, the amount of gas that leaked out of the sample bottle was small and had no impact on the asphaltene content, which is the primary concern here. Loss of components from expensive and irreplaceable downhole fluid samples is unfortunately very common, hence the paramount importance of acquiring as much information as possible in the wellbore and validating the live fluid samples with absorption spectroscopy in the laboratory to ensure Chain of Custody.

![Figure 12 DFA (red open circle) and Laboratory (blue line) NIR absorption spectra of six live-oil samples measured at downhole P&T. Only sample 3.04 had OD_{DFA}>OD_{lab} for λ<1400nm, indicating some loss of asphaltenes. DFA data come from different instruments and were acquired over the two-year exploration campaign. Laboratory measurements on live fluid samples were done after 2-3 years of sample storage.](image)

Fluorescence methods are less sensitive to artifacts from light scattering than absorption and can be very useful in their own right. The absorption and fluorescence spectra of 11 dead oil samples at atmospheric conditions were measured in the laboratory. The results confirmed that same trends observed in the downhole live fluid data were duplicated in the dead oil samples, i.e. samples with higher concentration of asphaltenes have a higher absorption and lower fluorescence.

In order to assess the contribution of the asphaltenes to the color of the crude oil, given the fact that both resins and asphaltenes determine the color, the dead oil samples were diluted in n-heptane (50cc/g) and the absorption spectrum of the maltenes, i.e. the oil without the asphaltene, was measured.
It was observed that in general around 80% of the color of the Tahiti crude oils is due to the asphaltenes. It is also very interesting that the resin concentrations measured in the SARA analyses, between 12 and 19% for these oils, do not vary as widely as the asphaltene does, nor do they have any apparent correlation with asphaltene content or depth in the reservoir. This has been interpreted as a lack of resin-asphaltene association.

**Integrating the Geological and Fluids Model of the Reservoir**

Generally, reservoir models do not incorporate any asphaltene gradients because there is some uncertainty regarding the corresponding asphaltene science, and because such complexity would slow dynamic reservoir simulations to unacceptable levels. Nevertheless, the asphaltene gradient can impact important production parameters such as viscosity, asphaltene onset pressure and compositional variation with production time. More importantly, fluid gradients of all kinds can be very revealing about the reservoir architecture. From a DFA perspective, it is very important to keep in mind that the model is not truth but an approximation. It is important to test this approximation with DFA in real time during the job because if the model is found to be in error, the WFT is in the well and new DFA measurements can be made to uncover the source of discrepancy.

**Prediction of DFA Logs from Fluids+Geologic Model**

From an operational point of view it is very important to have a real-time procedure for comparing fluid samples to evaluate reservoir continuity. When unexpected reservoir or fluid features are found in DFA log data, real-time analysis enables modifying the WFT program to analyze the origins of discrepancies. In addition, traditional techniques involving laboratory analyses and geochemistry studies have a long turnaround time and are not suitable for the fast pace of a development program, nor a wireline job. Pressure gradients, though invaluable, do not provide a complete picture of the reservoir, especially in the necessary time frame. In fact, in deep offshore developments such as this, the completion of the wellbore needs to be decided within a few hours after openhole formation evaluation. Reservoir compartments that are deemed incapable of sustaining commercial production beyond the economic horizon are considered of no interest, and if a wrong decision is made, it is followed by costly workover operations and delayed production.

Given the linear relationship between color and asphaltene content (Figure 9), once the latter is known at any depth in the reservoir, it is possible to predict what the OD should be at the correlating wavelength, in our case 1000nm. The fluids in the M21 sands are black undersaturated oils with API around 30° and GOR around 600scf/stb at reservoir pressures around 20000psia. The visible light range of the spectrum in this crude oil is off scale due to the high concentration of chromophores (color yielding molecular constituents), and the color features in the NIR region are captured with channels that have wavelengths longer than 1000nm. The oil/water contact is much deeper in the structure and all the crude oil samples were water free.

As mentioned above, the effects of OBM contamination have to be considered in the data processing. The OBM fraction is treated as a colorless fluid volume linearly affecting the absorption amplitude at wavelengths less than or equal to 1600nm. For instance, if at 1000nm the OD is 1.0 with OBM contamination of 5% by volume, the corrected OD is 1/(1-0.5)=1.05. Light absorption at 1000nm has been used in this study as the color indicator because it is the shortest, non-saturated wavelength and thereby exhibits the largest linear variation.
among samples. The effects of OBM cannot be decoupled from the fluid spectra in the hydrocarbon peak region.

Crude oils and asphaltenes exhibit an exponential decay in the color-dominated region of the Vis-NIR spectrum with a constant decay width related to the Urbach tail observed in solid state physics. This is the base of the de-coloration algorithm for GOR correction. In a plot of wavenumber vs. log(OD) the absorption edge of crude oils show as lines with the same slope. The computation of the light absorption at other Vis-NIR wavelengths is straightforward once the OD at a reference wavelength, in our case 1000nm, and the slope are determined (Figure 14). The baseline, 1600nm, cannot be extrapolated from this relationship due to a small absorption caused by vibration of molecular bonds in alkanes. Light scattering problems that could also affect the fluid spectrum were not significant in this dataset, but should be accounted for by doing proper baseline subtraction. Equation 3 describes the absorption behavior in the spectral region dominated by electronic absorption from various large polycyclic aromatic hydrocarbons:

\[ \text{OD} = C e^{\frac{1}{\lambda_{1650}}} \]  

where C is the pre-exponential factor (the intercept in the plot), 1/\(\lambda\) is the wavenumber in cm\(^{-1}\) and 1650cm\(^{-1}\) is the exponential decay width calculated for the M21A oils (the slope in Figure 14), which for this dataset is within two standard deviations of the mean exponential decay for crude oils (2162±260cm\(^{-1}\)) given in reference 27.

\[ \text{ln}(\text{OD}_\lambda) = \text{ln}(\text{OD}_\lambda^{\text{ref}}) + \frac{10^7}{\lambda_{\text{ref}}} - \frac{10^7}{\lambda_{1650}} \]  

What we have obtained so far is a contamination-free NIR spectrum of the fluid at any depth in the reservoir. In practice, when a new sample is acquired, the contamination level of the fluid has to be taken into account in order to compare the measured and predicted spectra.

Example

The procedure described above is implemented here in one of the development wells in the Tahiti field. The PS002 well targeted the south part of the field toward the top of the structure, and the petrophysical logs indicated a very close agreement between the depths of the intersected M21 sands and the geological model. DFA logs were predicted for the M21A and M21B sands (Figure 15), computing first the expected concentration of asphaltene in each zone and generating the complete fluid spectrum from the respective color at 1000nm. There was one sampling station on each M21A and M21B, and samples were acquired with a WFT and analyzed with DFA. Pressure gradients and downhole measurement of GOR in the two sands are in agreement with the observations in neighboring wells.

OPTICAL DENSITIES AT OTHER WAVELENGTHS (\(\lambda<1600\text{nm}\)) ARE CALCULATED USING EQUATION 4:

\[ \text{OD} = C e^{\frac{1}{\lambda \text{ (1650cm}^{-1})}} \]

where C is the pre-exponential factor (the intercept in the plot), 1/\(\lambda\) is the wavenumber in cm\(^{-1}\) and 1650cm\(^{-1}\) is the exponential decay width calculated for the M21A oils (the slope in Figure 14), which for this dataset is within two standard deviations of the mean exponential decay for crude oils (2162±260cm\(^{-1}\)) given in reference 27.

\[ \text{ln}(\text{OD}_\lambda) = \text{ln}(\text{OD}_\lambda^{\text{ref}}) + \frac{10^7}{\lambda_{\text{ref}}} - \frac{10^7}{\lambda_{1650}} \]  

Optical densities at other wavelengths (\(\lambda<1600\text{nm}\)) are calculated using equation 4:

1 wavenumber [cm\(^{-1}\)] = 1/ wavelength (\(\lambda\)) = 10\(^7\)/\(\lambda\)[nm]

Figure 14 log(OD) of the Tahiti crude oils scales linearly with wavenumber in the region of the electronic absorption by the largest molecules. The systematic absorption behavior of all crude oils is used to predict DFA logs.

Figure 15 DFA log data. i) Predicted from the geological model (right track) and ii) measured log data from two sampling stations in the new well.

In Figure 15 a snapshot of the synthetic log and the actual measurement is presented next to the petrophysical logs and a cross-section of the geologic model of the field generated by the 3D geological modeling software. The software used runs in PC and can be brought to the wellsite to facilitate the analysis of the data during the WFT run. In the field the fluid spectrum is measured every 0.3seconds and the ten optical channels of the tool are presented with a color code.

Figure 16 shows the optical density of the new samples in the
PS002 well (PS) with the rest of the samples in M21A and M21B and the model used for the prediction of the fluid color. The two sands have the same gradient in the asphaltene concentration, but in general the fluid in the shallower M21A has more ‘color’ (higher asphaltene concentration) than in M21B. The two samples acquired in the PS well have more color than predicted from the model. For M21B the difference between the measurement and the model is 10%, but for M21A it is 30%. The absorption spectra of live samples from each station in the PS well were measured in the laboratory (Figure 17) at the same pressure and temperature as the DFA measurement. In both cases there was an excellent agreement between downhole and lab data.

Figure 16 Fluid model for the Tahiti oils in the M21A and M21B sand showing the newly acquired samples in the PS well.

Figure 17 Live-oil spectra of the PS samples measured in the fluids laboratory at ~20,000psi and 200°F (blue lines) and downhole measurements (red circles) are in good agreement, validating the quality of the samples.

To assess the error of the model we take advantage of the three pairs of data points from the same sand acquired in separate wells. The variation of fluid color between the top and bottom of the sand for these three pairs of measurements is about 20%. We estimate that our model could inherit this 20% error, in which case the two data points from the PS well are in reasonable agreement with the model, with the highest error in the more heterogeneous M21A sand. A color inversion, i.e. M21A having less color than M21B would have been another indication of the existence of a compartment.

Conclusions

Asphaltene colloidal gravity segregation is shown to yield an easily measured color variation in the Tahiti oils. This asphaltene concentration gradient is different from the norm in that here there is little GOR variation and therefore little color variation due to composition changes in the liquid fraction. The denser asphaltene particles are subject to buoyancy forces and are found preferentially lower in the column. The corresponding color variation can be captured by DFA methods and used during the Wireline DFA job to investigate the hydraulic communication between the newly drilled wells and the corresponding sands penetrated by previous wells.

The procedure presented here is:
1. analyze available DFA data,
2. integrate DFA into a geological model of the reservoir,
3. predict DFA logs at any location in the field, and
4. compare the predictions with the DFA measurements in newly drilled wells to validate the fluid and geologic model.

With real time DFA log analysis, a common feature in today’s logging environment, model discrepancies uncovered by a mismatch with DFA measurements can be investigated during the wireline formation evaluation program. This workflow can be implemented during exploration, appraisal and development. Both the geology and the fluids in the model are compared to the real reservoir and fluid properties, and if needed, both models could be updated.

The advantages of this procedure are the real-time aspect, answers are available while DFA measurements are being recorded, and fluids are analyzed in the wellbore, where the risk of deleterious transformations of the fluids is minimum. This is a new way to bring value by taking advantage of DFA to guide not only sample acquisition but fluid data acquisition in general to help unravel reservoir architecture. DFA fluid mapping could be complementary to lab geochemistry studies and analyses of field pressure gradients, or as in the case study, it may tap into more advantageous and previously unnoticed reservoir features.

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