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Quantitative mixing rules for downhole oil-based mud contamination monitoring in real time using multiple sensors

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A B S T R A C T

Accurate quantification of oil-based drilling mud (OBM) filtrate contamination of hydrocarbon samples is still one of the biggest challenges in formation fluid sampling with formation testers. There exist contamination quantification techniques, but they can be technique sensitive, lack a confident level of quality control and apply only to a limited combination of probe types and formation fluid types. In particular, current techniques rely on an assumed absence of mud filtrate coloration at relevant optical channels and on sufficient optical density contrast between mud filtrate and virgin fluids. Such assumed fluid properties may not materialize when, for example, drilling muds are reused in multiple wells or when virgin fluids exhibit little color due to the absence of asphaltenes.

In this paper, new mixing rules have been developed for mass density and shrinkage factor and for the newly defined "*f*-function" and "*q*-function". The *f*-function, also referred to as the modified gas/oil ratio, is essentially a combination of gas/oil ratio with shrinkage factor. Similarly, the *q*-function is referred to as modified composition and is a combination of composition with mass density. OBM filtrate contamination in volume fraction, optical density, *f*-function, mass density, shrinkage factor, and *q*-function at a specified downhole sampling station have been found to be mutually linearly related as predicted by the mixing rules. The mutually linear relations are further confirmed by laboratory data for different mixtures of mud filtrate and formation fluids. Application of these mixing rules enables accurate OBM filtrate contamination in hydrocarbon samples if the filtrate properties and virgin fluid properties can be determined. A new methodology has been developed to determine the properties of the virgin formation fluid and mud filtrate, which are referred to as endpoints. The mud filtrate properties are obtained by extrapolating the mutually linear relations established from the cleanup data to zero gas/oil ratio or other known filtrate values such as zero methane composition, and/or zero optical density at specified wavelengths. The virgin fluid properties are determined by the power-law fitting of cleanup data coupled with the flow regime identification which is confirmed by large number of downhole fluid analysis datasets from wireline formation testers and numerical simulation.

This novel methodology enables accurate quantification of the OBM filtrate and pure virgin formation fluid. Furthermore, the self-consistency of using multiple independent sensors provides confidence and greatly improves the robustness and quality control of OBM filtrate contamination monitoring downhole. Finally, contamination results can be expressed in volume or weight percent and as live fluid or stock-tank liquid fraction for easy comparison to laboratory results.

A latest generation downhole fluid analysis (DFA) tool was employed to measure fluid properties downhole in real time on more than 30 DFA stations acquired with either conventional probes or 3D radial probes. The new methodology was applied to each of the acquired datasets. All the results from the new method are in good agreement with the results of the laboratory analysis.

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1. Introduction

Acquisition and analysis of representative formation fluid samples downhole in real time is of great importance in determining the economic value of reserves and field development plans. Accurate native fluid characterization with formation testers is the gateway not only to clean samples, but also to understanding fluid property distributions with confidence in a single well and across the entire reservoir. It is also an enabler for the emerging workflow that uses downhole fluid analysis (DFA) data to characterize the reservoir and the dynamic processes that give rise to its fluid distribution (Zuo et al., 2013a). During the drilling process, overbalance (positive pressure differential) between the mud column and the formation, results in drilling mud filtrate invasion into the formation in the near borehole region. Therefore, fluid samples acquired with formation testers are inevitably composed of a mixture of the mud filtrate and virgin formation fluid. If the filtrate is fully miscible with the formation fluid, such as gas and oil sampling in a well drilled with oil-based mud (OBM), the filtrate contamination can significantly affect the sample quality and all subsequent analysis.

Oil-based mud contamination monitoring (OCM) is used to continuously quantify the contamination of the fluid in the flowline of the downhole acquisition tool and combines DFA measurements with the expected time evolution of the flowline contents during cleanup (Mullins and Schroer, 2000; Mullins et al., 2000). The requisite utility is to alert technologists monitoring the job when low mud filtrate contamination is achieved. Subsequently, the low filtrate contaminated formation fluid can be collected into sample chambers in the tool or measured directly and continuously to provide fluid properties downhole without the need of bringing samples to surface or laboratory for analysis. Formation testers with DFA are often used to acquire formation fluid samples downhole. The difference in optical absorption spectrum between the reservoir fluid and drilling mud filtrate is key to making the task of contamination monitoring viable with optical measurements (Mullins and Schroer, 2000; Mullins et al., 2000). In particular, since OBM drilling fluids lack appreciable dissolved gas and/or asphaltenes, while most crude oils contain at least one of the two components, OCM methods can be based on this compositional difference (Mullins and Schroer, 2000; Mullins et al., 2000).

Mullins et al. (2000) proposed a method to estimate OBM filtrate contamination using optical density (OD) measured by DFA tools. Variations in the DFA measured optical density at color and/or methane channels with time were fitted by $OD(t)=C-Dt^{-5/12}$, where t is the time, C and D are the two adjustable parameters. When a probe is used as a point sink in a homogeneous formation without a borehole, the clean-up should vary with $t^{-2/3}$ at late times (Hammond, 1991). In the presence of a borehole, however, filtrate clean-up was (semi)empirically found to slow, varying with $t^{-5/12}$ (Mullins and Schroer, 2000; Mullins et al., 2000). This slowed behavior was subsequently confirmed in numerical simulations (Alpak et al., 2006). Once a model $OD(t)$ is obtained, t is extrapolated to infinity and the fitting parameter C is left to represent the OD of a virgin fluid (Mullins and Schroer, 2000; Mullins et al., 2000; Dong et al., 2002). In addition, it is assumed that the OD of the mud filtrate with baseline-correction at the specified color and/or methane channels is equal to zero. Then the two OD endpoints, the mud filtrate and virgin fluid, are known and thus OBM filtrate contamination level can be calculated using the OD mixing rules (Mullins and Schroer, 2000; Mullins et al., 2000; Dong et al., 2002, 2003a, b). With the latest generation DFA tools (O'Keefe, 2009), Hsu et al. (2008) developed a multichannel OCM algorithm based on a synchronized optical density at multiple wavelengths. However, the existing techniques are valid for oil with sufficient asphaltene content (sufficient OD) which is linearly related to optical density at color channels (Zuo et al., 2013a) and colorless mud filtrate (set to zero OD) at specified color channels. Moreover, the accuracy of the pure mud filtrate and virgin formation fluid characterization is also limited if there is no or minimal optical density contrast between the formation fluid and filtrate. Such lack of contrast in optical density is frequently observed, when mud systems absorb color from well to well reuse or if the native formation fluid lacks color (asphaltene content).

New formation interface geometries (probes) are continuously introduced into oilfields, which can invalidate assumptions made regarding the time dependence of the cleanup behavior. Several different probes are often used during a given wireline sampling run; it is highly desirable to have a contamination algorithm that is generalized for all probe types and not dependent on the specific probe type. In addition to new probe geometries, there has also been significant development of new and improved DFA sensors introduced on formation testers in recent years. The new DFA tools measure optical density at many color channels, gas/oil ratio (GOR), mass density, compositions, formation volume factor, viscosity, resistivity, fluorescence, etc. Moreover, DFA is increasingly used for reservoir evaluation without capturing fluid samples at every depth. In the absence of laboratory analysis, the importance of accurate contamination quantification cannot be overstated. However, the methods used to predict mud filtrate contamination have not kept up with the change in technology until now. A combination of the utilization of multiple sensors with new methods, new techniques, and new algorithms gives rise to a significant improvement in the prediction accuracy of fluid sample contamination downhole in real time.

Any downhole quantification of hydrocarbon filtrate content requires knowledge of the properties of a virgin reservoir fluid and pure mud filtrate. These properties, here referred to as endpoints, cannot be measured directly in most cases and determining endpoint properties is one of the core challenges of real-time oil contamination monitoring. Once the end points have been determined, a mixing rule is required to compute the filtrate content from the fluid property measured at any time throughout the filtrate cleanup process.

In this paper, first, the mixing rules for different fluid properties are developed and two auxiliary functions are newly defined to keep all the mixing rules similar and consistent. Then mutually linear relations are determined amongst the fluid properties. Next, the mixing rules and linear relations are confirmed by the laboratory data, the latest generation DFA tools are used to measure the variations of fluid properties with the volume pumped from formation to flowline and the new multi-sensor OCM method is applied to the DFA measured data to quantify OBM filtrate contamination in real time. One black oil example at a field DFA station is given to show (1) how to obtain the endpoints of the virgin fluid using the power-law fitting model combined with flow regime identification; (2) how to establish linear relations using cross-plots, thereby attaining the endpoints of the mud filtrate; (3) how to obtain the endpoints of the virgin fluid using the linear relations and then compare them with those from the power-law fitting model for self-consistency check; (4) how to determine OBM filtrate contamination using the mixing rules and the obtained endpoints; and (5) how to convert OBM filtrate contamination from volume fraction to weight fraction and from live fluid fraction to stock tank liquid fraction. Finally, the method is extended to a large number of DFA stations and the obtained OCM results are in good agreement with the laboratory analysis data.