Environmental and Transport Effects on Core Measurements of Water Saturation, Salinity, Wettability, and Hydrocarbon Composition
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Abstract
Unaltered portions of whole core provide the most reliable measurement of rock properties for hydrocarbon-in-place, reserves, and reservoir-development calculations. However, core cutting and core surfacing operations can significantly alter the water saturation, salinity, hydrocarbon composition, and wettability of the whole core, among other rock core properties. It is necessary to correct laboratory measurements of rock core properties to their in-situ values, and to identify the unaltered volume of whole core that is representative of in-situ reservoir properties. To that end, we have developed a numerical simulator based on an equation-of-state compositional method that models three-dimensional time lapse variations of multiphase fluid saturation, water salinity, phase composition, and wettability of a whole core during core cutting and subsequent core surfacing operations in a vertical wellbore. The UT Coring Simulator (UT-CS) quantifies mudcake growth, mud-filtrate invasion, miscibility of invading filtrate with connate fluid, wettability alteration due to surfactants in invading mud filtrate, phase transition, and fluid expulsion during core surfacing. UT-CS delineates four distinct fluid flow mechanisms that occur within whole core during coring, namely, compressibility-driven concurrent flow, capillary pressure-driven countercurrent imbibition, axial flow, and surfacing-induced fluid phase expulsion. The time of occurrence and the magnitude of these fluid-flow mechanisms govern the alteration of fluid and petrophysical properties. During core cutting, we observed that, at the center of a whole core, water-base coring mud could cause relative changes in fluid saturations, up to +/-100%, and in salinity, and up to +/-15%. More importantly, these measurable changes in in-situ core properties can also occur during oil-base mud (OBM) coring owing to countercurrent imbibition flow. We show that mudcake quality is critical toward preserving core properties during core cutting. On the other hand, during core surfacing (when mudcake is nonexistent), the alteration of core properties is minimized by identifying the depth at which the gas volume fraction in the whole core exhibits an abnormally large increase.

Introduction
Core measurements of water saturation, salinity, hydrocarbon composition, and wettability are critical for accurate estimation of hydrocarbon pore volume and for improved oil recovery. However, laboratory measurements of such properties can significantly differ from their in-situ values due to environmental and transport effects of coring. The coring process involves core cutting, core recovery/surfacing, core shipping, and core storage. During each of these stages, the whole core is in constant contact with coring mud, and is often subjected to significant pressure and temperature changes. In this paper, we discuss the capability of UT-CS to quantify the environmental and transport effects of coring on connate fluid and petrophysical properties of whole core. UT-CS models spatio-temporal variations of fluid phase saturation and fluid phase composition during the entire coring process; it is based on the research work of Abdollah-Pour (2011), wherein a three-dimensional cylindrical compositional simulator was developed to model fluid flow in the near-wellbore region. In addition, extensive synthetic modeling has been performed to attain a conceptual understanding of fluid-flow phenomena in whole core during the coring process and the resulting alteration of core properties. It is essential to correct core measurements because the quality of well-log interpretation strongly relies on the accuracy of core measurements. This paper is an introduction to the capabilities of UT-CS to assist core analysts and petrophysicists in determining in-situ reservoir properties.
Simulation Method

UT-CS models both the core cutting and core surfacing processes. During the core cutting process, the formation is cut to obtain a whole core, which is then stored in a core barrel. Core cutting is performed at an optimum rate of coring-bit penetration to minimize mud-filtrate invasion ahead of the coring bit, dynamic mud-filtrate invasion into whole core, and damage to coring-bit teeth. When whole core is cut out of the formation, its outer surface is exposed to coring mud at higher pressures and dissimilar temperatures to those of the original environment. This process results in connate fluid compression, mud-filtrate invasion, mudcake growth, fluid phase transition, fluid phase miscibility, axial flow, and countercurrent imbibition. Meanwhile, the section of whole core inside the core barrel is subjected to static mud-filtrate invasion, axial flow, and countercurrent imbibition. When the coring bit reaches its final depth of core cutting, the whole core is safely latched inside the core barrel, and then raised to the surface along the wellbore. During the core surfacing process, whole core experiences a continuous decrease in surrounding mud pressure and mud temperature. This situation results in a continuous change of fluid phase saturation and composition. Such changes are modeled using a modified version of Peng-Robinson’s equation of state. The fluid expulsion phase begins once whole core reaches a certain depth, wherein the pressure of a particular fluid phase inside the whole core exceeds the surrounding mud pressure.

As mentioned earlier, the coring process involves several distinct stages with their own defining fluid flow mechanisms and phase behavior. Each of these stages is quantified with specific physical models. The following assumptions are incorporated in the physical models: (1) the core cutting process is isothermal, (2) there is a no-flow boundary at the center of the core, (3) there is no chemical reaction or solid-phase precipitation, (4) Darcy’s law for multiphase fluid is valid, (5) the whole core is slightly compressible, (6) petrophysical layers in the whole core have 0º-dip, (7) no energy transfer takes place during core cutting and core surfacing processes, (8) there is no mass transfer from hydrocarbon components into the aqueous phase, (9) there can be a maximum of three coexisting fluid phases – aqueous, oil, and gas phase, and (10) phase behavior is not affected by the aqueous phase. UT-CS integrates the following physical models when simulating the entire coring process:

Reservoir model. This model describes a vertically-connected, zero-dip, multiphase, and multicomponent reservoir that can accommodate spatial variation of in-situ petrophysical, rock, and fluid properties.

Core-cutting model. This model simulates the extraction of whole core from the parent reservoir, and involves exposure of reservoir and whole core to coring mud as conditioned by whole core diameter, rate of coring-bit penetration, and coring interval.

Mud-filtrate invasion model. This model describes the interaction between the core-cutting and reservoir models. Mud-filtrate invasion takes place because of the overbalance pressure originating from the differences between hydrostatic pressure in the whole core and coring mud pressure. As a result, there are spatio-temporal variations of rock, fluid, and petrophysical properties. For modeling purposes, we have modified the productivity index method (Pour et al., 2011) to calculate flow rate during mud-filtrate invasion. This model is reliable for both immiscible and partially to fully miscible mud-filtrate invasion.

Mudcake growth model. This model describes the petrophysical properties of mudcake, which is a petrophysical layer on the core surface formed because of the accumulation of mud solid fraction. It is assumed that, at the beginning of invasion, mud particles instantaneously form an internal mudcake of limited thickness inside the whole core. Further, we use Dewan and Chenevert’s (2001) formulation for expressing external mudcake permeability and porosity as a function of differential pressure across mudcake that varies continuously with time of invasion. We also implemented Chen et al.’s (2004) equation of time evolution of external mudcake thickness.

Salinity model. This model quantifies physical dispersion effects on the spatial distribution of aqueous phase salt concentration during exposure of the whole core to coring mud filtrate of dissimilar salt concentration. Physical dispersion leads to radial spreading of aqueous salt concentration, thereby altering core measurements of water salinity. George et al. (2004) described the salt mixing phenomenon that takes place in the near-wellbore region due to differences in salt concentration between mud filtrate and connate water.

Wettability-alteration model. This model quantifies the effects of emulsifiers/surfactants contained in mud filtrate on the wettability of invaded whole core. The magnitude, extent, and type of wettability alteration are governed by pore-volume concentration, and time of contact between grain surfaces and the surfactant included in mud filtrate. The effect of wettability alteration on relative permeability and capillary pressure of whole core is described as surfactant concentration-based linear interpolation between the initial condition and the completely altered wettability state.
Core-barrel model. This model quantifies static invasion and countercurrent imbibition of coring mud filtrate into the portion of whole core that is inside the core barrel before the core surfacing process takes place. Retrieved whole core moves upward into core barrel as the coring bit penetrates deeper, along with the coring mud that fills the gap between the whole core surface and the inner diameter of the core barrel.

Core surfacing model. This model quantifies the effects of reduction in surrounding mud pressure and mud temperature on fluid phase saturation and fluid phase composition during the core surfacing process. We assume that the external mudcake disintegrates due to a reduction in pressure difference across the mudcake. It is observed the fluid phase pressure inside whole core is lower than surrounding mud pressure during the initial stage of surfacing, resulting in countercurrent imbibition and static invasion. On the other hand, fluid phase pressure in the whole core can exceed the surrounding pressure during the final stage of core surfacing when the whole core has reached near to the surface, thereby resulting in the expulsion of fluid phases.

Verification of the Simulator
UT-CS is based on an equation-of-state compositional algorithm we use CMG’s Generalized Equation-of-State Model (CMG-GEM) compositional reservoir simulator for verification purposes. At first, UT-CS’s mudcake-growth model was deactivated to simulate mud-filtrate injection rather than mud-filtrate invasion. This allowed us to compare UT-CS simulation results to those obtained with CMG-GEM for injection of oil-base mud filtrate (OBMF) and water-base mud filtrate (WBMF) into whole core containing oil, gas, and aqueous phases. Figures 1(a) and 1(b) show agreement between UT-CS and CMG-GEM for radial distribution of fluid phase saturation along the diameter of whole core for five different cases of mud-filtrate injection. Furthermore, we verified the simulation of physical dispersion of aqueous phase salt concentration that occurs when water-base mud (WBM) of dissimilar salinity is injected into whole core. Figure 1(c) describes the distribution of salt concentration along the radius of a whole core, and indicates agreement between CMG-GEM and UT-CS. Further, we used CMG’s phase behavior and fluid property program, WINPROP, to verify the phase behavior modeling method that we implemented into UT-CS’s core-surfacing and reservoir model.

In addition to using CMG-GEM and WINPROP for verification purposes, we compared UT-CS’s simulation of countercurrent water imbibition with that documented in the publications by Blair (1960) and Pooladi-Darvish et al. (2000). This comparison is necessary because, at core-scale dimension, capillary pressure-driven countercurrent imbibition may give rise to significant alteration of fluid phase saturation. Figures 2(a) and 2(b) indicate agreement between UT-CS’s simulations -and published results.

Applications
UT-CS was used to verify fluid-flow phenomena and fluid phase behavior in whole core which takes place during the entire coring process. First, we illustrate the four distinct fluid-flow mechanisms in whole core. Then, we quantify the influence of key petrophysical properties on the alteration of in-situ conditions of whole core. Finally, we apply UT-CS for modeling mud-filtrate invasion ahead of the coring bit, core cutting process, and core surfacing process.

Fluid-flow Mechanism.

Concurrent Flow. Fluid flow in whole core begins with concurrent flow, wherein mud filtrate invades by compressing and concurrently displacing the slightly compressible connate fluid. This flow gradually dissipates as the pressure of the fluid phase inside the whole core attains a pseudo-steady state value.

Countercurrent Imbibition. Countercurrent imbibition develops after connate fluid reaches its compressibility limit. In this flow mechanism, the capillary pressure gradient forces mud filtrate to flow radially inward into the confined cylindrical geometry of the whole core. This behavior results in the simultaneous egress of connate fluids from the outer exposed cylindrical surface of the whole core. During countercurrent imbibition, the injecting fluid phase has a pressure gradient that drives the fluid phase toward the center of the whole core, while the remaining fluid phases develop pressure gradients that flush them out of the core. Figure 3(a) shows an example of imbibition of the water phase, while Figure 3(b) indicates that the oil phase is being flushed out of the whole core.

Axial Flow. Axial flow occurs when there is a vertical pressure gradient. Crossflow and mud-filtrate invasion ahead of the coring bit are examples of axial flow in whole core. Axial flow can be in the form of either concurrent or countercurrent flow. Figure 4(a) shows the magnitude of relative change in whole-core water saturation due to crossflow of WBMF into a 3.5 foot long core having three petrophysical layers: (layer 1) good rock quality from 0 to 1 foot, (layer 2) excellent rock quality from 1 to 2.5 feet, and (layer 3) poor rock quality from 2.5 to 3.5 feet. This figure clearly indicates that the original oil phase from layers 1 and 3 has been displaced into layer 2, thereby producing a greater relative change in water saturation in the regions adjoining layer 2.

Role of Petrophysical Properties.

Mudcake Quality. The quality of a mudcake is defined in terms of its resistance to fluid flow into whole core. An excellent quality mudcake can bear a high-pressure differential. We identified the following parameters to be critical in
quantifying mudcake quality: entry pressure, permeability of external mudcake, thickness of internal mudcake, mud solid fraction, and permeability of the damaged zone due to internal mudcake. Figure 5(a) shows negligible change in water saturation at the center of the core in the presence of excellent and good quality mudcake. Figure 5(b) shows that poor-quality mudcake grows slower; as a result, such a mudcake is not able to withstand the high-pressure differential, and consequently exhibits a higher permeability to mud filtrate.

**Composition of Coring Mud-Filtrate.** Figure 6(a) shows that OBMF with lighter hydrocarbon components (for example, C10 and mixture of 70% C18 with 30% C2) produces greater displacement of connate water. It is also observed that presence of 30% water saturation as emulsifier in OBM (C22) gives rise to higher water saturation in whole core.

**Overbalance Pressure.** During the core cutting process, connate fluid in whole core is exposed to an overbalance pressure that can cause a phase transition depending on the phase behavior of connate fluids. Figure 7(a) describes a case of OBMF invasion into whole core wherein the overbalance pressure does not transforms the in-situ gas phase into oil phase during core cutting. This behavior results in unaltered oil saturation at the center of the core when oil phase pressure becomes equal to the outside mud pressure. On the contrary, Figure 7(b) shows OBMF invasion at two different mud pressures: the connate gas phase is transformed into oil phase, resulting in a dissimilar decrease in gas saturation when the oil phase pressure at the center becomes equal to the outside mud pressure.

**Formation Rock Quality.** A formation with excellent rock quality exhibits high permeability, high porosity, uniform grain sizes, large pore throats, low residual saturations, and high relative permeability. Figures 8(a) and 8(b) show that reservoir rocks with excellent quality are susceptible to deeper mud-filtrate invasion, thereby undergoing significant alteration of fluid saturation and other fluid properties.

**Saturation-Height Function.** Original fluid phase pressure and temperature gradually increase with reservoir depth, whereas oil-water and gas-oil capillary pressure decrease with reservoir depth. These variations govern the vertical distribution of fluid phase saturation in the reservoir. Consequently, entry pressure and relative permeability to the flow of mud filtrate vary with reservoir depth. Woodhouse (1998) described the effects of the saturation-height function on whole core by measuring water saturation obtained from OBM coring. Figure 9(a) shows deeper OBMF invasion into the whole core section lying in the lower transition zone. Similarly, Figure 9(b) indicates deeper OBMF invasion in whole core section within the upper transition zone. The saturation-height function results in variations in the magnitude of alteration of core properties along the length of whole core.

**Formation Wettability and Wettability Alteration.** Mud-filtrate invasion is deeper when the invading fluid is the wetting phase, whereby OBMF entails shallower invasion in a water-wet core. However, presence of oil-wetting surfactants in OBMF increases the radial length of invasion in a water-wet core. We observed deep OBMF invasion when an oil-wet core was exposed to oil-base coring mud. Figure 10 illustrates the above-mentioned effects.

**Capillary Pressure and Relative Permeability.** Capillary pressure and relative permeability govern the extent of fluid flow in whole core. Figure 11(a) shows that the radial length of mud-filtrate invasion decreases as the capillary entry pressure of mudcake increases. Figure 11(b) describes the sensitivity of mud-filtrate invasion to capillary pressure and relative permeability curves of whole core. We observe that decreasing relative permeability reduces the radial length of mud-filtrate invasion, and that increasing the capillary pressure of a water-wet rock results in deeper mud-filtrate invasion due to the associated increase in countercurrent imbibition.

**Modeling of Coring Stages.**

**Mud-Filtrate Invasion Ahead of the Coring Bit.** Tibbits et al. (1990) tested a coring system to minimize the vertical pressure gradients ahead of the core bit that results in axial flow of mud filtrate and connate fluid into the formation. The extent of this invasion depends on the specific petrophysical properties of the invaded formation, and is controlled by cutting the core at an optimum rate of core-bit penetration. Figure 12(a) shows that there is 0.2 feet of ahead-of-the-bit invasion without alteration at the center of whole core during WBM coring at a coring speed of 30 feet/hour. Figure 12(b) shows 0.4 feet of ahead-of-the-bit invasion with alteration at the center of whole core of the same formation when cored with OBM at a coring speed of 10 feet/hour. This type of modeling can be used for estimating an optimum coring speed that minimizes alteration at the center of whole core during core cutting.

**Core Cutting.** Cutting a whole core is a slow process. The top section of whole core has longer exposure to coring mud compared to the lower section. In addition, due to the effect of the saturation-height function, the extent of mud-filtrate flow varies along the length of whole core. As a result, there can be significant differences in fluid phase saturation and composition between the top and bottom sections of whole core. Figures 13(a) and 13(b) show these differences on a 30-foot long core at the end of the core cutting process under two different rates of coring-bit penetration, 30 feet/hour and 10 feet/hour, respectively.

**Core Surfacing.** During the core surfacing process whole core is subjected to fluid phase transition, fluid expulsion, and countercurrent imbibition due to mud in core barrel. Table 1(a) indicates a drastic change in gas volume fraction in the topmost 400 feet of core surfacing. Also, in the depth range from 1000 feet to 10000 feet, there is a net decrease in gas volume fraction because of the effects of countercurrent imbibition and gas expulsion exceeds the conversion of oil phase to gas phase due to phase transition. Table 1(b) indicates a drastic phase transition in another whole core after it reaches 1000 feet below the surface.
Conclusions
We introduced and validated a new simulator that models multiphase and multicomponent fluid flow in a whole core during the coring process. UT-CS successfully quantified environmental and transport effects on water saturation, salinity, wettability, and phase composition of whole core. It was observed that the alteration of fluid and petrophysical properties during coring operations vary along the length of the whole core depending on the saturation-height function and the rate of core-bit penetration. Simulation results indicate that presence of petrophysical layers of excellent rock quality significantly influences the alteration of core properties in the adjoining petrophysical layers due to axial crossflow. Moreover, we identified that countercurrent imbibition closely followed by surfacing-induced fluid expulsion gives rise to the largest change in core properties. Most importantly, simulation results indicate that a significant alteration of core properties can occur during both oil-base and water-base mud coring, and is governed by rock wettability, rock quality, mudcake quality, presence of lighter hydrocarbon components, capillary pressure, and presence of wettability-altering surfactants in mud filtrate. Nonetheless, rapid growth of mudcake (with a high entry capillary pressure) on the outer surface of the whole core prevents deep mud-filtrate invasion. We encourage coring managers and petrophysicists to use UT-CS to design efficient coring programs, to quantify alterations of in-situ properties, and to identify best locations to retrieve core plugs for subsequent petrophysical laboratory measurements with minimal impact from whole-core operations.

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References
YOU NEED TO LIST ALL PROPERTIES AND ASSUMPTIONS MADE IN THE SIMULATIONS DESCRIBED BELOW, ABSOLUTELY ALL ASSUMPTIONS MADE!!!
Fig. 2: Comparison of UT-CS’s simulation of countercurrent imbibition with (a) Blair’s (1960) water imbibition into an oil-field core of 1.27 cm radius at 11.1 seconds after the onset of imbibition, and (b) Poolad-Darvish et al.’s (2000) water imbibition into a 20 mD core, which is 20 cm in length, at various time intervals. What are the solid lines in panel b?

Fig. 3: Time variation of the radial distribution of (a) aqueous phase pressure, and (b) oil phase pressure for Poolad-Darvish et al.’s (2000) countercurrent water imbibition into a 20 mD core, which is 20 cm in length.

Fig. 4: Two dimensional distribution of relative change in core water saturation for WBMF invasion into a 6.5-feet long water-wet whole core (a) with, and (b) without a 1.5-feet thick layer of excellent rock quality.
Fig. 7: Radial distribution of (a) oil saturation, and (b) gas saturation after 2 hours from the onset of OBMF invasion into a water-wet whole core of good rock quality with varying overbalance pressure. EXPLAIN THE LABELS AND THE VARIOUS CURVES!!!
Fig. 8: Radial distribution of (a) water saturation, and (b) oil saturation after 2 hours from the onset of WBMF and OBMF invasion into a water-wet whole core with varying reservoir rock quality. WHY ARE THE AXES LABELS SO LARGE!! PLEASE make them uniform across the paper for ALL the figures!!! Explain the legend and the curves. Why are the label fonts so large? Use a uniform font size!!

Fig. 9: Radial distribution of relative change in (a) oil saturation, and (b) water saturation after 2 hours from the onset of OBMF and WBMF invasion, respectively, into water-wet whole cores extracted from different reservoir depths along the transition zone of the reservoir. EXPLAIN ALL THE CURVES AND LABELS!!

Fig. 10: Radial distribution of water saturation after 2 hours from the onset of WBMF and OBMF invasion into a whole core of good rock quality under varying conditions of rock wettability and presence of surfactants. EXPLAIN ALL THE CURVES AND LABELS!!
Fig. 11: Radial distribution of water saturation after 2 hours from the onset of WBMF invasion into a whole core with varying (a) mudcake entry pressure, and (b) relative permeability and formation capillary pressure. EXPLAIN THE VARIABLES AND FIGURES!

Fig. 12: Two-dimensional distribution of (a) water saturation, and (b) oil saturation due to ahead-of-the-bit invasion of WBMF and OBMF invasion, respectively, into a water-wet whole core of good rock quality. ARE YOU USING Percent or fraction to describe saturations and concentrations UNIFORMLY across the paper?

Fig. 13: Two-dimensional distribution of water saturation at 2 hours after the onset of WBMF invasion into a water-wet whole core of good rock quality cored at core-cutting speed of (a) 30 ft/hr, and (b) 10 ft/hr. AXES LABEL SIZE?