Geological Attributes from Conventional Well Logs: Relating Rock Types to Depositional Facies in Deepwater Turbidite Reservoirs
Chicheng Xu, SPE, The University of Texas at Austin; Carlos Torres-Verdín, SPE, The University of Texas at Austin; Ronald J. Steel, The University of Texas at Austin

Abstract

Grain size and bed thickness are important geological attributes for sedimentary facies analysis and reservoir quality ranking in deepwater turbidite reservoirs. Grain size controls reservoir quality and has causative or correlational effects on most well logs. Additionally, bed thickness affects well logs in various ways because of different vertical logging-tool resolutions. The objective of this paper is to quantitatively classify rock and bed types based on conventional well logs to assist facies interpretation and stratigraphic reservoir modeling.

We model physical properties and well-log responses originating from clastic reservoirs with different grain-size distributions in the context of deepwater turbidite systems. The model accounts for fluid effects introduced by capillary transitions and salty connate water. Petrophysical relationships are examined between grain sizes and pore geometry as inferred from the combined effects of initial connate-water saturation and reservoir capillary pressure. From modeling, we derive several quantitative petrophysical attributes which correlate significantly with grain size. A list of such attributes includes volumetric concentration of shale, total porosity, neutron-density porosity difference, and reservoir quality index (RQI). Rock classification is then performed based on a relevant set of attributes to detect and rank different rock types with specific grain-size distributions. Concomitantly, a quantitative rock classification scheme using three-dimensional Thomas-Stieber diagrams constructed with gamma ray, bulk density, and resistivity logs is used to classify petrophysical zones based on their average bed thicknesses. A dual-attribute rock classification scheme is proposed to better associate rock types with depositional facies.

The above-mentioned rock-classification and bed-typing methods are synthesized and applied to a turbidite field from the Gulf of Mexico. We perform facies analysis based on the vertical succession of rock types (grain sizes) and the inferred variations of bed thickness. The field case demonstrates that these two geologic attributes have great potential in reducing uncertainty and non-uniqueness in the construction of stratigraphic reservoir models. Results indicate that the classified rock types and their petrophysical ranking agree with core data while the interpreted facies fit into the depositional context as inferred from core descriptions and seismic horizons.

Introduction

Rock classification (or simply rock typing) is an emerging reservoir description tool that elicits broad research interests in the oil and gas industry. It has become increasingly important in modern reservoir description to invoke close integration of multi-discipline, multi-physics, and multi-scale subsurface data including pore imaging, core measurements, well logs, seismic amplitude data, well testing, and production surveillance (Gunter et al., 1997a). Interestingly, the definition of rock type still remains ambiguous and sometimes arguable in many situations as it depends highly on the specific description purposes to be achieved by geoscientists and engineers. Geologists consider rock types as depositional facies or lithofacies which emphasize the genesis of rock formations to enable 3D stratigraphic reservoir modeling (Fisher, 1982; Kerans and Tinker, 1999; Muto and Steel, 2007; Slatt, 2007). Petrophysicists define rock types based on pore geometry that relates all static and dynamic petrophysical properties (Archie, 1950 and 1952). Reservoir and production engineers group rock types as
flow units that are stratigraphically continuous intervals of similar geologic and petrophysical features to upscale reservoir grids for efficient fluid-flow simulation (Gunter et al., 1997b). Noteworthy is that reservoir characterization teams are working toward a common objective: to construct a verifiable reservoir model populated with accurate petrophysical properties for reserves estimation and production forecasting (Lucia, 1999). Therefore, developing new rock classification schemes and workflows that serve multiple characterization purposes from different disciplines remains a challenging but important task.

For subsurface studies, whole core samples and well logs are the main sources of high-resolution geological data. Routine geological work infers grain size and bed thickness from slabbed core samples. However, in most cases whole core spans a very limited segment of the reservoir. Log-core integration is therefore necessary to extrapolate geological properties from cored depth intervals to remaining wells and into the reservoir. Rock classification based on core data is relatively simple because petrophysical properties are rigorously measured under the same protocol. However, rock classification using downhole well logs is more challenging and is subject to great uncertainty. Four technical issues immediately arise when moving from core data to well logs for rock typing, namely data quality, indirect measurements, variable reservoir conditions, and scale discrepancy (Xu, 2013). These compounded technical problems were initially defined by Archie as the “geometrical problem” (1950). In the present paper, we aim to address the issue of indirectness. Indirectness lies in using physical measurements to estimate petrophysical properties and interpret geological attributes. In fact, most well logs are simultaneously sensitive to grains, texture, structure, and fluids. Table 1.1 summarizes the sensitivity of various well logs to rock petrophysical properties and geological attributes. It is found that none of the logs are directly sensitive to grain size and only a few logs have good sensitivity to bedding structure. Grain size information can only be indirectly inferred from the pore geometry formed in-between grains. Moreover, well logs highly sensitive to pore geometry and bedding structure are also significantly influenced by fluid content, as in the case of resistivity logs. Therefore, fluid effects on well logs need to be cautiously accounted for before inferring grain and bed properties.

Table 1—Sensitivity of well logs to petrophysical properties and geological attributes (modified from Serra and Abbot, 1980).

<table>
<thead>
<tr>
<th></th>
<th>Composition</th>
<th>Texture</th>
<th>Structure</th>
<th>Fluid</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gamma Ray</td>
<td>High</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>PE Factor</td>
<td>High</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>Neutron Porosity</td>
<td>Medium</td>
<td>Medium</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Bulk Density</td>
<td>Medium</td>
<td>Medium</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td>Electrical Resistivity</td>
<td>Low</td>
<td>Medium</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Acoustic Slowness</td>
<td>High</td>
<td>Medium</td>
<td>Medium</td>
<td>High</td>
</tr>
<tr>
<td>Magnetic Resonance</td>
<td>Medium</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
</tbody>
</table>

The ultimate goal of rock classification is to associate petrophysical rock types with geological framework and reconcile them with seismic facies to propagate rock-type associated petrophysical properties into the reservoir model. This endeavor is difficult without understanding the cause-and-effect relationship between pore geometry and rock geological attributes such as grain size and bed thickness. Hence, it is necessary to investigate the sensitivity of well logs to those geological attributes and the associated pore geometries in the presence of different fluid-saturation conditions resulting from either hydrocarbon migration or mud-filtrate invasion. In this paper, we show the causative and correlational impacts of grain size on various types of logs. In addition, the relationships between gamma ray log and other logs are interpreted to reveal the underlying bed thickness information as emphasized in Thomas-Stieber diagrams. We propose an integrated petrophysical workflow and a dual-attribute rock classification scheme to better relate rock types to geological facies in deepwater turbidite reservoirs. A field case from the central Gulf of Mexico is used to test the workflow and classification schemes.
Grain-Size Analysis from Well Logs

Grain size is directly associated with depositional energy. Large grains are deposited under highly energetic flow conditions, whereas small grains are deposited under low flow energy (Reading, 1996). Grain size information provides key data for geologists in their facies interpretation work (Glaister and Nelson, 1974). In addition, grain-size distribution determines the pore-size distribution of most clastic rocks when diagenesis effects are not significant. Consequently, grain size information becomes a good indicator of reservoir quality in terms of hydraulic capacity.

Grain size is typically measured from core samples or outcrops with a laser particle size analyzer (LPSA). To date, there exists no effective physical measurement capable of measuring grain size directly at downhole conditions. However, there are some causative and correlational effects between grain size and physical logs. In the following section, we briefly review the relationships between grain size and gamma ray, neutron, density, resistivity, and NMR logs.

**Gamma Ray Log.** Gamma ray logs are sensitive to the natural radioactivity of rock formations. The radioactive elements (U, K, Th) are predominantly associated with small grains such as silt or clay (Serra and Serra, 2003). Consequently, often there is a correlation between gamma ray log and grain-size distribution. In fact, the gamma ray log has been long used as a single indicator of grain size in many geological field studies because the gamma ray log is more readily available than other logs (Pirson, 1983; Rider, 1990). In clastic reservoirs, the gamma ray log is sufficient to separate clean sands, shaly sands, and shales (or siltstones). Figure 4 Track 2 shows the typical gamma ray log responses of clean sands, shaly sands, and shales (or siltstones). However, the gamma ray log alone cannot effectively distinguish clean sands of different grain sizes.

**Neutron Porosity and Bulk Density Log.** Both neutron porosity and bulk density logs are dominantly sensitive to total pore volume and pore-filling fluids in clean sands. In many clastic reservoirs, the porosity formed by grain deposition has small variability. However, the total pore volume will be significantly changed by cementation which is mainly comprised of silts and clays (Neasham, 1977). As a result, low porosity rock tends to be associated with silt- or clay-size grains. In addition, the presence of silts or clays will increase the bound water volume that remains in the rock pore system after hydrocarbon migration. The hydroxyl in clay minerals gives rise to a high hydrogen index which increases the apparent neutron porosity. On the other hand, clay or silt cementation increases the bulk density of rocks when solid cement replaces the original fluid in the pore space. As a result, neutron and density porosity logs separate when they are plotted on the same track using the correct matrix. The separation or difference between neutron and density porosity is an indicator of clay volume. Figure 4, Track 3 shows the typical neutron porosity and bulk density logs across clean sands, shaly sands, and shales. Neutron-density separation is smallest in clean sands and largest in shales. However, neutron porosity and bulk density logs still lack the ability to differentiate sandstones of different grain sizes but with the same porosity.

**Resistivity and NMR Logs.** We use a simple pore network model to study the cause-effect chain connecting a series of rock properties including grain size, pore size, capillary pressure, water saturation, electrical conductivity, and NMR transverse relaxation time $T_2$. Figure 1 shows two thin sections of pore network systems formed by large (Type A) and small (Type B) grain sizes, respectively. Large grain sizes generate large pore sizes accordingly, resulting in a $T_2$ distribution with large $T_2$ values (Fig. 2). When these two rocks are subjected to the same capillary pressure induced by hydrocarbon migration at reservoir conditions, rock type A exhibits both lower capillary-bound water saturation and clay hydration water saturation (Hill et al., 1979), and consequently lower electrical conductivity (Fig. 3). Therefore, in a hydrocarbon-bearing zone, resistivity logs become sensitive to pore size, i.e., petrophysical rock types. Rock types with higher hydraulic conductivity tend to have lower electrical conductivity (or higher resistivity) in hydrocarbon-bearing zones in the presence of capillary pressure. Figure 4 Track 4 describes the typical resistivity log responses observed across clean sands, shaly sands, and shales in a hydrocarbon zone.

Figure 1 — Thin sections describing pore network systems formed by different grain sizes. Left Panel: large grain size; Right Panel: small grain size (Xu et al., 2013).
Figure 2—Modeling of pore-size (left panel) and NMR $T_2$-distributions (right panel) for two different rock types (Xu et al., 2013).

Figure 3—Modeling of drainage capillary pressure and resistivity-height relation for two different rock types. $P_c$: capillary pressure (left panel); HAFWL: height above the free water level (FWL) (right panel); $R_t$: bulk rock resistivity (Xu et al., 2013).

Figure 4—Simulated well logs across different rock types. Track 1: Depth; Track 2: Gamma ray log; Track 3: Neutron porosity (sandstone porosity units) and bulk density logs; Track 4: Resistivity log; Track 5: Rock types. Logs are simulated with software UTAPWeLS\textsuperscript{1}.

\textsuperscript{1} The University of Texas at Austin’s Petrophysics and Well Log Simulator
Correction of Free Water in Capillary Transition Zones. The presence of free water in a capillary transition zone disrupts the correlation between electrical conductivity and hydraulic conductivity. Xu and Torres-Verdín (2012) proposed a correction method by linking Leverett’s RQI with in-situ capillary pressure ($P_c$) and initial connate-water saturation ($S_w$) using the empirical J-function model (Darling, 2005; Torres-Verdín, 2012):

$$S_w = S_{wirr} + aJ^b \Rightarrow J(S_w) = \left(\frac{S_w - S_{wirr}}{a}\right)^b,$$

(1)

together with Leverett’s capillary pressure model (1941), given by:

$$RQI = \sqrt{\frac{k}{\phi}} = \frac{J(S_w)}{P_c} \times \cos \theta = \left(\frac{S_w - S_{wirr}}{a}\right)^b \times \cos \theta,$$

(2)

where $S_w$ is initial water saturation, $S_{wirr}$ is irreducible water saturation (which is set to 0.01 lower than the minimum water saturation in the entire reservoir column, Darling, 2005); $a$ and $b$ are constants derived from core-measured capillary pressure curves; $\cos \theta$ is the product of interfacial tension and contact angle, which is assumed constant in the same reservoir; $P_c$ is in-situ reservoir capillary pressure in psi.

Shale Distribution and Bed Typing from Well Logs

Bedding structure together with bed thickness is often a key parameter for geologists to interpret sedimentary facies (Campbell, 1967). Thinly bedded or laminated formations are persistent only in some special depositional facies (Passey et al., 2006). High-resolution image logs provide the best estimation of bedding structures but are not commonly available in all wells. Thomas-Stieber’s diagram (Thomas and Stieber, 1975 & 1977) is a widely applied petrophysical interpretation tool used to diagnose shale distribution in siliciclastic reservoirs as being laminated, dispersed, or structural (Fig. 5; Torres-Verdín, 2012). Thomas-Stieber diagram assumes two end members: clean-sand and pure-shale. Several trends are also defined to reveal different geological processes yielding different shale distributions which are associated with different mixing laws reflected on logging measurement physics and the underlying petrophysical properties (Xu and Torres-Verdín, 2013). As a consequence, rocks with different values of shale volumetric concentration and distribution appear in different locations when projected onto a Thomas-Stieber diagram (Fig. 6). Xu and Torres-Verdín (2013) proposed a graphical clustering method to classify petrophysical zones of different bed thickness in a 3D Thomas-Stieber diagram (Fig. 7).

Figure 5—Three nominal forms of shale distributions in siliciclastic reservoirs: (a) laminated shale, (b) dispersed shale, and (c) structural shale.
Figure 6— Thomas-Stieber diagram constructed with bulk density and gamma ray logs. Red circle dots: pivoting points; Blue dashed lines: trend lines; shaded elliptical regions: uncertainty bounds.

Figure 7— Rock classification and bed typing via $k$-means cluster analysis (Press et al., 2007) on a 3D Thomas-Stieber diagram constructed with gamma ray, bulk density, and resistivity logs.
Integrated dual-attribute rock classification workflow based on well logs and core data.

**Dual-Attribute Rock Classification Workflow**

Rock types defined by grain size and bed thickness should be integrated to achieve a better reservoir description in multi-well field studies. Figure 8 shows an integrated dual-attribute rock classification workflow based on standard petrophysical log-analysis and core-calibration. Grain size and bed thickness information are propagated from cored intervals to log-covered intervals via step-by-step calibration and validation. Therefore, the final rock types derived from well logs in multiple wells are geologically consistent for facies interpretation and stratigraphic reservoir modeling. Furthermore, rock type information needs to be returned to standard petrophysical analysis for more accurate rock-type-specific processing.

**Field Case: Marco Polo Field, Gulf of Mexico**

The Marco Polo field is a Miocene turbidite oil field located in the central Gulf of Mexico (Fig. 9; Contreras et al., 2006). Marco Polo minibasin resides in a tectonically active salt environment (Fig. 10; Jackson et al., 2008). The depositional system is interpreted as a submarine fan complex developed in a mini-basin with stacked progradational turbidite lobes. Reservoirs consist primarily of sandy turbidite facies interbedded with some siltstone and muddy debris-flow facies. Reservoir rocks are mainly unconsolidated sandstones of very fine to fine- to medium-size grains. Thin-bedded zones are common across the entire reservoir. In this study, we evaluate only the two hydraulically connected, hydrocarbon-bearing sandstone units: M40 and M50 in three wells. These sands are buried at depths between 12,000 and 13,000 ft TVD and dip toward the west (Fig. 11). Core measurements indicate that the structureless and plane-parallel laminated sandstones exhibit porosities as high as 35%, as well as 100 – 2000 md of nominal permeability. Well logs from three wells are used for rock typing. Well no. 1 was drilled with oil-base mud and penetrated a capillary transition zone and the FWL. Wells nos. 2 and 3 were drilled with water-base mud where the M40-50 sands are located more than 500 ft above the FWL (Fig. 11).
Figure 9 — Geographic location of the Marco Polo field in the Gulf of Mexico (Contreras, 2006).

Figure 10 — Salt tectonics background of the Marco Polo minibasin (Jackson et al., 2008).

Figure 11 — Seismic cross-section with the three well trajectories considered in this paper.
Core-Based Rock Typing and Grain Size/Bed Thickness Interpretation

Petrophysical rock types are first established using routine core porosity-permeability measurements. Six petrophysical rock types were identified from the histogram distribution of Leverett’s RQI (Fig. 12). Table 2 summarizes the statistical distributions of petrophysical properties for each rock type. We observe that rock types 1 - 3 exhibit a largely overlapping porosity range. Their average horizontal permeability exhibits a ratio around 2 – 2.5, which indicates that their average pore-throat radius ratio is close to 1.5. Laser grain size measurements for rock types confirmed that the controlling factor for permeability was mean grain size. Reservoir quality decreases with decreasing grain size. Grain size measurements for rock types 2, 4, and 5 are listed in Table 3 for comparison. Different bed types identified from core photographs are compared in Table 4 for facies interpretation.

![Figure 12 — Core-based hydraulic rock typing via Leverett’s RQI.](image)

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Porosity (p.u.)</th>
<th>Permeability (md)</th>
<th>RQI (μm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RRT1</td>
<td>33.6 ± 1.8</td>
<td>1099 ± 291</td>
<td>56.8 ± 7.2</td>
</tr>
<tr>
<td>RRT2</td>
<td>33.3 ± 2.1</td>
<td>549 ± 130</td>
<td>40.4 ± 4.9</td>
</tr>
<tr>
<td>RRT3</td>
<td>31.5 ± 4.4</td>
<td>179 ± 63.7</td>
<td>23.4 ± 3.4</td>
</tr>
<tr>
<td>RRT4</td>
<td>24.1 ± 6.1</td>
<td>42.9 ± 19.1</td>
<td>13.1 ± 2.1</td>
</tr>
<tr>
<td>RRT5</td>
<td>19.7 ± 3.9</td>
<td>11.3 ± 3.9</td>
<td>7.5 ± 1.1</td>
</tr>
<tr>
<td>RRT6</td>
<td>19.6 ± 3.7</td>
<td>4 ± 1.5</td>
<td>4.4 ± 0.86</td>
</tr>
</tbody>
</table>
Table 3—Comparison of grain-size distribution data for rock types 2, 4, and 5.

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Grain Size Distribution</th>
<th>Description</th>
<th>Facies Interpretation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>&lt;image&gt; Sand, Silt</td>
<td>Dominated by sand-size grains with a narrow distribution in the large-size mode (i.e., good sorting).</td>
<td>Turbidite channel infill including channel lag.</td>
</tr>
<tr>
<td>4</td>
<td>&lt;image&gt; Sand, Silt</td>
<td>Dominated by silt-size grains with only a small proportion of sand-size grains. Overall distribution is widely spread (i.e., relatively poor sorting).</td>
<td>Channel levee or channel margin with thin, fine-grained beds.</td>
</tr>
<tr>
<td>5</td>
<td>&lt;image&gt; Sand, Silt</td>
<td>Dominated by silt-size grains with an overall wide distribution (i.e., poor sorting).</td>
<td>Overbank deposits possibly including thin debris flows.</td>
</tr>
</tbody>
</table>

Table 4: Comparison of core photographs of different bed types.

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Core Photos</th>
<th>Description</th>
<th>Facies Interpretation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thick sand</td>
<td>&lt;image&gt;</td>
<td>Structureless coarse-grained sandstone with no clear internal lamination.</td>
<td>Amalgamated turbidite channel deposits.</td>
</tr>
<tr>
<td>Laminated sand-shale</td>
<td>&lt;image&gt;</td>
<td>Interbedded sand-shale sequence with variable net-to-gross ratio.</td>
<td>Channel levee or margin deposits.</td>
</tr>
<tr>
<td>Thick shale or siltstone</td>
<td>&lt;image&gt;</td>
<td>Fine-grained shale or siltstone.</td>
<td>Overbank deposits, possibly with debris flow.</td>
</tr>
</tbody>
</table>
Log-Based Rock Classification and Bed Typing

Core-calibrated, conventional well-log analysis is first performed to provide relevant petrophysical properties, such as volumetric concentration of shale, total porosity, and connate-water saturation. We classify rock types via $k$-means cluster analysis (Press et al., 2007) on several relevant petrophysical attributes including shale volume, total porosity, neutron-density separation, water saturation in the irreducible zone, and well-log-derived RQI as in Eq. (2) in the capillary transition zone. The classified rock types are consistent with core data concerning both petrophysical properties and grain size. Figure 13 shows an interval with log-based rock classification results. A clear fining-upward grain-size trend is observed in both core and the log-derived rock types in the interval of 13,574 – 13,580 ft. The high-resolution grain-size information provides geologists useful data for facies interpretation.

Figure 13 — Example of a fining-upward unit identified from vertical stacking of petrophysical rock types. Track 1: Depth; Track 2: Gamma ray log; Track 3: Neutron (in apparent sandstone porosity units) porosity and bulk density logs; Track 4: Induction resistivity logs; Track 5: Rock types of different grain-size distributions; Track 6: Core permeability.

Relating Rock Types to Geological Facies in a Single Well

In a single well, we analyze the stacking pattern or trend of the classified rock types that bear grain-size and bed-thickness information. Similar neighboring rock types are grouped as distinct facies from the adjacent rock type groups. Figures 14 and 15 show two intervals with their sedimentary facies interpretations. Amalgamated channel facies are composed mainly of thick and coarse-grained sandstones. Both bed thickness and grain size decrease in the levee or channel margin facies. Overbank deposits are mainly shales or siltstones. The interpretation is consistent with observations contained in Table 3 and Table 4.
Figure 14—Rock typing and facies interpretation in the key well of the Gulf-of-Mexico case. Tracks 1-4: basic well logs; Tracks 5-6: standard well-log analysis, saturation-height for rock types 1 to 3; Tracks 7: distribution of rock types; Track 8: interpreted sedimentary facies.

Figure 15—Rock typing and facies interpretation in the key well of the Gulf-of-Mexico case. Tracks 1-4: basic well logs; Tracks 5-6: standard well-log analysis, saturation-height for rock types 1 to 3; Tracks 7: distribution of rock types; Track 8: interpreted sedimentary facies.
Stratigraphic Correlation with Multi-Well Logs. After rock classification, bed typing, and facies interpretations are performed in individual wells, a multi-well cross-sectional view can be constructed for stratigraphic analysis. Figure 16 shows the corresponding results from the three well penetrations. The locations of these wells in a submarine fan complex with stacked progradational lobes are consistent with the interpretation made from seismic horizons. Stratigraphic analysis together with the estimated petrophysical properties can then be integrated with seismic amplitude data for populating a reservoir model.

Figure 16—Use of rock-type and bed-type distributions in multiple wells to assist sedimentological and stratigraphic interpretation. The upper panel shows the Thomas-Stieber diagram constructed with bulk density and gamma ray logs in each well below. The lower panel shows the log tracks in each well with the following information: Track 1: Depth; Track 2: Gamma ray log; Track 3: Neutron (in apparent sandstone porosity units) porosity and bulk density logs; Track 4: Induction resistivity logs; Track 5: Bed type; Track 6: Rock type of different grain-size distribution.

Conclusions
Grain size and bed thickness are two geological attributes that can be interpreted from conventional logs in turbidite reservoirs. The petrophysical quality of young deepwater turbidite reservoirs is controlled chiefly by sedimentary grain sizes. Therefore, a link exists between petrophysical rock types and depositional facies which can be effectively applied in reservoir development efforts. Thomas-Stieber diagrams are useful in identifying thinly bedded or laminated zones which provide additional aid for facies interpretation. We propose an integrated petrophysical workflow that combines grain-size and bed-thickness attributes to reduce uncertainty in stratigraphic reservoir modeling. Reservoir capillary transition effects on resistivity logs need to be corrected for more accurate estimation of grain sizes. In the deepwater Gulf-of-Mexico field case, we confirmed that multi-well rock typing can assist sedimentary and stratigraphic studies which have potential applications for exploration in frontier basins or in deepwater environments, where subsalt or pre-salt reservoirs cannot be clearly imaged with seismic data and well drilling is limited due to high rig costs.
ACKNOWLEDGMENTS

We would like to thank Anadarko Petroleum Cooperation for providing the field data used for analysis and verification. The work reported in this paper was funded by The University of Texas at Austin’s Research Consortium on Formation Evaluation, jointly sponsored by Afren, Anadarko, Apache, Aramco, Baker-Hughes, BG, BHP Billiton, BP, Chevron, China Oilfield Services, LTD., ConocoPhillips, ENI, ExxonMobil, Halliburton, Hess, Maersk, Marathon Oil Corporation, Mexican Institute for Petroleum, Nexen, ONGC, OXY, Petrobras, PTTEP, Repsol, RWE, Schlumberger, Shell, Statoil, Total, Weatherford, Wintershall and Woodside Petroleum Limited.

Nomenclature

\begin{itemize}
  \item $a$ : Linear coefficient in empirical $J$ function, []
  \item $b$ : Exponent in empirical $J$ function, []
  \item $J$ : Leverett’s $J$ function, []
  \item $k$ : Permeability, [mD]
  \item $p$ : Density function of pore-throat size, []
  \item $P_c$ : Capillary pressure, [psi]
  \item $R$ : Pore-throat radius, [$\mu$m]
  \item $R_w$ : Bulk rock resistivity, [ohm.m]
  \item $R_w$ : Connate water resistivity, [ohm.m]
  \item $S_w$ : Water saturation, [frac]
  \item $S_{wirr}$ : Irreducible water saturation, [frac]
  \item $T_2$ : NMR Transverse relaxation time, [ms]
  \item $\phi$ : Total porosity, [frac]
  \item $\sigma$ : Interfacial tension, [dyne/cm]
  \item $\theta$ : Contact angle, [degree]
\end{itemize}

List of Acronyms and Log Curve Mnemonics

\begin{itemize}
  \item AHT1-9 : Array Induction Log (H) with Two Feet Resolution and 10-90 inch Depth of Investigation
  \item BS : Bit Size Log
  \item DRHO : Density Correction Log
  \item FWL : Free Water Level
  \item GR : Gamma Ray Log
  \item HAFWL : Height Above Free Water Level
  \item HCAL : Caliper Log
  \item HGR : Gamma Ray Log (High Resolution)
  \item K : Potassium
  \item K_Klink : Permeability Corrected with Klinkenberg Effect
  \item LPBA : Laser Particle Size Analyzer
  \item MICP : Mercury Injection Capillary Pressure
  \item NMR : Nuclear Magnetic Resonance
  \item NPHI : Neutron Porosity Log
  \item Pcow : Capillary Pressure between Oil and Water
  \item PE : Photo-Electric
  \item PHI_LOG : Porosity from Log
  \item Por : Core Porosity
  \item RHOB : Bulk Density Log
  \item RHOZ : Bulk Density Log (High Resolution)
  \item RQI : Reservoir Quality Index
  \item RRT : Reservoir Rock Type
  \item RT : Rock Type
  \item SH : Shale
  \item SS : Sandstone
  \item Sw_c : Core Water Saturation
  \item Sw_RT : Water Saturation for Rock Type
  \item Swt_LOG : Water Saturation from Logs
  \item T2LM : Algorithmic Mean of NMR Transverse relaxation time $T_2$
  \item Th : Thorium
  \item TVD : Total Vertical Depth
  \item U : Uranium
  \item UTAPWeLS : The University of Texas at Austin’s Petrophysics and Well Log Simulator
\end{itemize}
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