MAXIMIZING THE IMPACT OF ROUTINE CORE ANALYSIS ON SPECIAL CORE AND LOG ANALYSIS: UNCONSOLIDATED SANDSTONES

Ted Griffin/Core Laboratories
John Shafer/Reservoir Management Group, Inc.

ABSTRACT

Core analysis begins at the wellsite with natural gamma activity measurements, gamma-gamma density measurements, and digital photos of core exposed at inter barrel ends. Core analysis continues at the lab with X-ray CT imaging of the full diameter core and core plugs, Dean Stark saturations, permeability, porosity, and particle size distribution data at a sampling rate of one per foot. Profile permeability measurements using a probe permeameter, detailed core description, and a sand log from digitally processing visible and UV slabbed core photos provide rock quality information at a higher sampling rate.

Water saturation data in the case of core obtained with oil-based mud system can provide an early indication of the validity of the Archie parameters prior to availability of capillary pressure and electrical property data. Particle size distribution (PSD) measurements on each core analysis sample assist in lithofacies assignment and can be used to predict permeability and irreducible water saturation.

Detailed core description and high-density routine core analysis data provide information that clarifies the uncertainty in the log-derived net hydrocarbon volume. This is particularly important for sand-shale laminations that are significantly less than one foot thick and thus below the resolution of most well logs. Routine core analysis data also provide an indication of the range in lithofacies and rock properties, which is required to optimize a special core analysis program.

INTRODUCTION

Special core analysis and detailed log analysis of cored wells often require months to a year for completion. The initial log analysis pass is done within a few days of the completion of the logging runs and is based solely on minimally processed log data. Typically, an intermediate log analysis is done after completion of the routine core analysis and involves more advanced processing. The final log analysis is done after completion of advanced processing of the log data and integration of special core analysis results, such as capillary pressure and electrical properties. This paper will focus on the support of routine core analysis during the intermediate log analysis stage, providing an early assessment of reservoir quality to the reservoir engineer, and assisting the core analyst in selecting the number of plugs and the range of special core analysis measurements. The process is demonstrated by way of example from an unconsolidated sandstone oil reservoir.

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PROTOCOLS

The following is a summary of the wellsite handling and core analysis measurement protocols used for an unconsolidated core. The most important requirement for a successful project is that all those who are involved in the project and in using the data such as the drilling engineers, wellsite core hands, core analysts, log analysts, reservoir geologists and the engineers meet and review project objectives and protocols. For completeness we have included several recommended protocols that were not utilized for the cored well described here.

Wellsite

Core recovery in unconsolidated reservoirs can be problematic given the formation's limited cohesive strength. Core quality can be adversely impacted by coring hardware, mud properties, tripping procedure and core handling at the surface. As a result, pre-coring planning is a prerequisite in each of these areas to ensure core integrity.

Three continuous 90' cores were taken in a highly interbedded interval to evaluate reservoir potential. The cores were acquired using a core barrel equipped with a full-closure core catcher, a vented inner barrel and a low invasion, anti-whirl bit. A synthetic invert oil base mud system was used. Coring protocol was established and executed to optimize core quality, including a carefully designed trip out procedure to eliminate solution gas induced damage. This procedure was prepared using the reservoir fluid bubble point and GOR. Full core recovery was obtained in each case with very limited coring and retrieval-induced damage.

Wellsite core stabilization procedures have been developed specifically for unconsolidated sediments to minimize core handling before the core is protected from mechanical damage. Both full-length freezing in dry ice or the full-length epoxy stabilization (details provided in the Appendix) achieve protection prior to segmenting the barrel into more readily manageable 3' segments. For this well, stabilization by freezing was selected due to the ready availability of relatively low-cost dry ice.

Each 90' core barrel was broken into three 30' inner barrel components and transported from the derrick to the designated work area in a rigid core barrel shuttle. Each inner barrel was pulled horizontally out of the shuttle and directly onto rollers and into individual 32' long insulated aluminum freezing compartments. Orientation lines and depths were placed on each inner barrel and a digital thermal probe was installed in one barrel to measure temperature at the core center. Natural gamma activity and gamma-gamma bulk density were measured at this stage to: correlate depths, to estimate core porosity to ensure that the interval desired was obtained, and to locate zones of lost core or rubblized zones.

After preliminary observations were made, dry ice was placed around the inner barrel in each freezer compartment. No further core handling was permitted until the core temperature reached –80°F for a period of 4 hours. Each 30' inner barrel was cut into ten, 3' segments. Brief core descriptions were made of the exposed ends of the core sections (Note: Although not taken in this case, digital photographs can be taken to record lithology, the extent of whole mud invasion and fluorsesence). The ends of the segments were capped and placed in an insulated aluminum transport container designed to contain 90' of segmented core and 750 pounds of dry ice. Patch-type indicators for extreme tilt and shock were applied to each container to monitor handling.

The wellsite core-end photos, natural gamma activity, and gamma-gamma bulk density data are available within hours of the core surfacing. This information precedes well log data and can be transmitted digitally from rig-site to exploration headquarters.

Core Analysis Overview

Natural gamma activity was measured at the lab initially to verify wellsite gamma calibration and to provide a higher sampling density (continuous as opposed to 1 to 2 samples per foot). The 3 foot core sections were CT scanned to observe bedding for slab cut orientation, to establish the quality of recovered core, to aid in the sampling process, and to generate a bulk density log to further correlate core and log data. Two full-length longitudinal views (0 and 90 degrees) and 3 radial views selected on a case-specific basis were made for each 3' segment. These scans provided the first definitive insight into the core available for special core analysis requirements.

The core was slabbed longitudinally to produce a 1/3 diameter geological slab and a 2/3 diameter petrophysical slab. The petrophysical slab was tightly wrapped with saran wrap to prevent short-term core saturation change and was maintained in the frozen condition pending sample selection. The geological slab was thawed. The surface was prepared for observation and digital photography by removing the cutting debris. Digital photographs were taken under visible and ultraviolet lighting conditions immediately to capture core features and fluorescence color and intensity.

A sampling strategy was designed using well logs, core data and a preliminary geological core description. Horizontal plugs were taken statistically at a frequency of one per foot except in massive shales in which cases sampling frequency was reduced. Vertical plugs were planned at a frequency of one per six feet. Samples, 1.5" diameter, were drilled from the dry ice frozen slab sections using liquid nitrogen as the bit lubricant. The samples were kept frozen in sealed sample containers pending analysis. At this stage, core samples can be X-ray CT scanned for disturbance and whole mud invasion. Each plug can be graded and assigned a CT ranking so that acceptable quality plugs can be partitioned between special and routine core analysis. At the analysis stage, the samples were trimmed to appropriate length and were encapsulated with nickel foil and stainless steel screens. The weights and densities of all packaging materials were recorded so the net weights and grain volumes could be derived to calculate porosity and grain density without unjacketing the samples.

Encapsulating materials were seated to the samples at nominal confining stress (300 psig) to minimize mechanical hysteresis by starting frozen and partially thawing at stress. A total of 249 statistical samples (same position within each foot interval) were prepared for standard analysis. Additional samples (411) were prepared in this fashion and were archived frozen in sealed vials for additional and special testing. This method of long-term storage of selected core plugs has proven significantly more efficient and cost-effective than long-term frozen storage of the entire petrophysical slab section.

A pilot drying study was initiated using representative samples of the lithofacies. The nine samples were low-temperature dried to remove the bulk of the water, thereby reducing the likelihood of the subsequent production of hydrochloric acid from the reaction of water with chloroform. Samples were then batch-extracted to remove hydrocarbons in a low temperature, sidearm-style Soxhlet extractor using a chloroform-methanol azeotrope followed by methanol to remove salt. The samples were dried in a humidity oven at 145°F at 45% relative humidity. Comparative physical measurements at these drying conditions and at subsequent drying conditions included air permeability, porosity and grain density. The samples were then dried using a vacuum oven at 145 °F and finally, in a convection oven at 231°F.

Based on the results of the pilot drying study, the decision was made to use cool solvent batch extraction combined with humidity drying as described above in preparation for the physical measurements. The measurements were followed by an additional weight after a vacuum oven-drying step. The measured constant humidity-dried porosity (effective) and the weights before and after drying provide a means to calculate a total porosity. The decision was also made to use the Dean Stark method for water and oil contents on an end trim, about 1/3 of the original plug length, to scale these data to the remaining 2/3 section of core plug to obtain saturations.

Air permeability was determined using the steady-state method at nominal confining pressure (400 psig) and at simulated reservoir net confining stress. Porosity was determined using the Boyle's Law method with helium at the same confining stress as the permeability measurements. These measurements on unconsolidated sands are very sensitive to confining stress, thus increasing the importance of correctly converting reservoir stress conditions to the net confining stress for lab measurements.

Archived end trims were used selectively for petrologic measurements. Particle size distribution (PSD) measurements were made on every sample by laser diffraction. These measurements were used to calculate V_{shale}, V_{clay}, surface area and to predict air permeability and a capillary pressure curve. These data were available for preliminary log evaluation weeks before the routine core analysis plugs were thoroughly extracted.

Probe permeability measurements were made on the geological slabs in the highly interbedded facies at a frequency of ten per foot to define the permeability distribution in the sand/silt laminations not specifically represented by drilled samples. Limited sampling of the more massive intervals (four per foot) was undertaken to correlate probe to core plug permeability.

RESULTS AND DISCUSSION

Petrophysical Log

The core and log data for 270 feet of core from this well are summarized in Figures 1 & 2. Figure 1 is summary of some of key core and log data presented in a petrophysical format using the appropriate core-to-log shifting as described in the next section. In track one is a shaliness comparison. V_{shale} calculated from the log gamma and the PSD data (fraction below 31 microns) on core samples are compared. The gamma log does not provide much character. The core is quite interbedded which will be described in more detail later in the section "NTG on Laminated Core". The fine scale sand-shale laminations will potentially causes large differences in measurement response between core plug (cubic centimeters) and the reservoir rock volume (cubic meters) probed by the well logs. The core plugs V_{shale} calculated from PSD data tend to track the log V_{shale}, even though the volumes of rock sampled by the two techniques are very different.

Core and log depth (rescaled) are presented in Track #2. Track #3 presents the deep resistivity log data and core air permeability measured at reservoir net confining stress. Reservoir/core heterogeneity is very apparent from the permeability variability over a short distance interval. Track #4 compares the vacuum-dried core porosity as obtained from core plug measurements at reservoir net confining stress with the density log calculated porosities. The agreement is good given the reservoir/core heterogeneity, variable grain densities, and the measurement volume sampling differences.

The fifth Track compares the water saturations as obtained from both the log and the core measurements. The log water saturations are based on a first pass analysis using Archie's equation and the deep resistivity log, density log porosity, and assumptions for Archie's parameters Rw, "m", "n", and "a". One core saturation profile is based on the Dean Stark data and the other profile is calculated from the capillary pressure simulated from PSD data. Both core saturation profiles (one measured and one predicted) track the log saturations reasonably well.

The core porosity-permeability cross-plot is presented in Figure 2. Each core plug has been assigned a lithofacies based solely on the PSD data, since the PSD was the first rock characterization data to be available. As one would expect, the shaly samples lay in the bottom left-hand corner of Figure 2, while the clean sand samples are located in the top right hand corner. At any given porosity there are approximately two orders of magnitude variability in permeability.

Figures 1and 2 have provided a general low-resolution overview of the log and core data. The remaining figures will provide higher resolution comparisons.

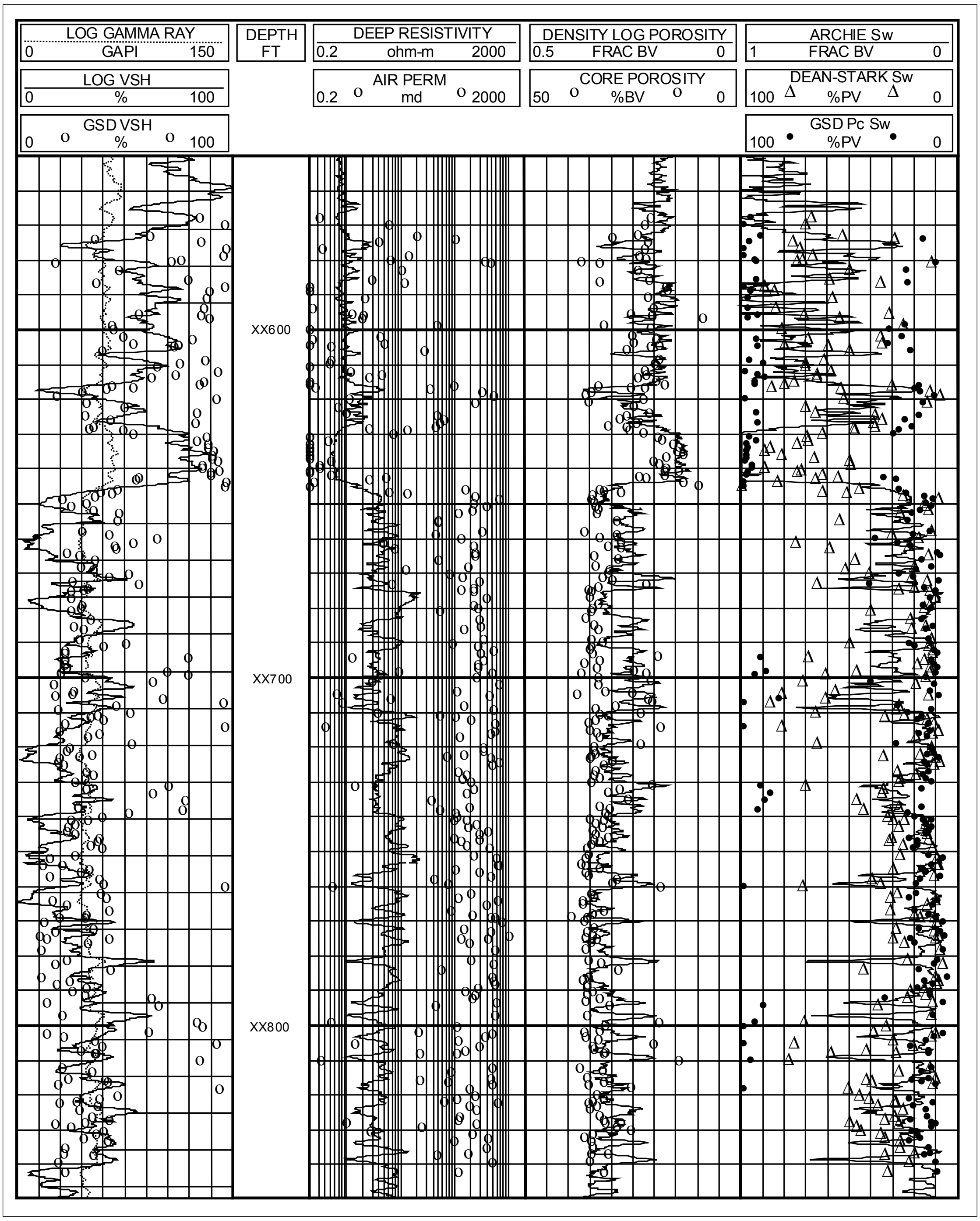

Figure 1: Comparison of log and core data. Each track of the log is described in the text of the paper.

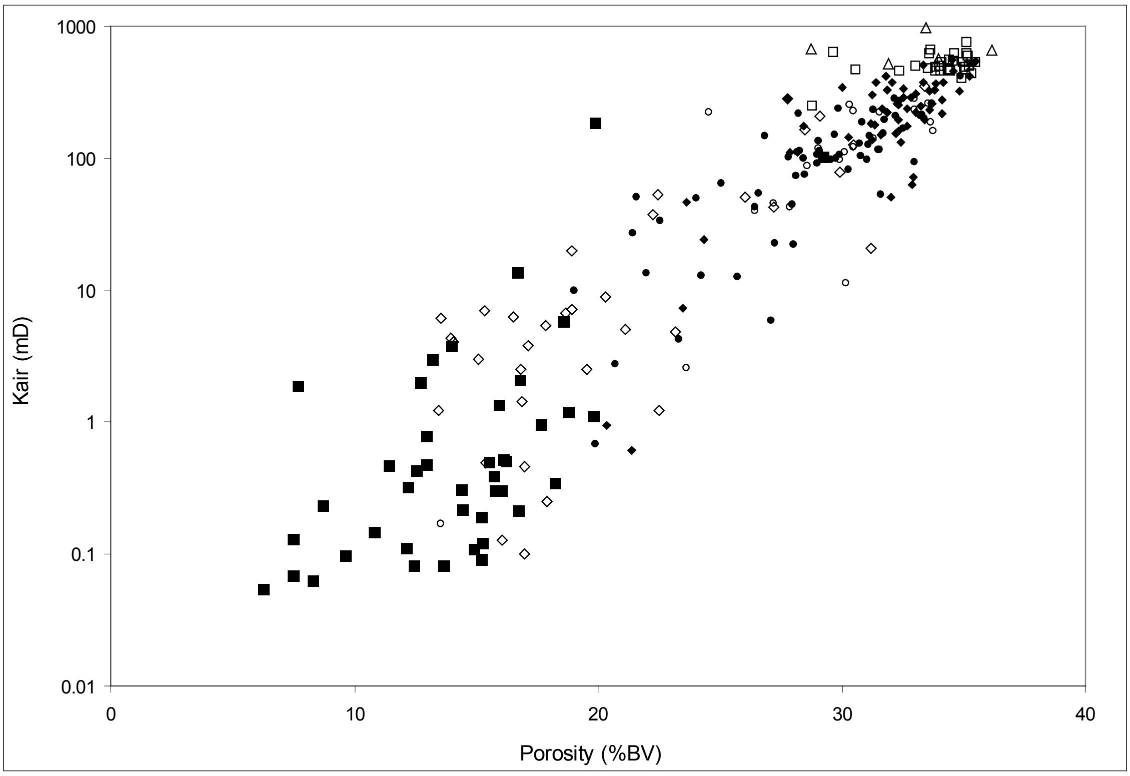

Figure 2: Porosity (%BV) versus air permeability (md) measurements performed at reservoir net confining stress. Porosity- permeability data are split into GSD data based lithologies. Sand: very fine to silt, shaly (open circle); sand: very fine to silt, slightly shaly (solid diamond); sand: very fine grain, very slightly shaly (open triangle); Sand: very fine to silt, very slightly shaly (open square); silt, very shaly (open diamond); silt to very fine grain sand, shaly (solid circle); shale (solid square).

Core-to-Log Depth Shifting

Core-to-log depth matching is critical for accurate formation evaluation. Core-to-log depth shifting is most difficult when reservoir rock has either low vertical variation such as massive sandstones, or high vertical variation such as highly laminated rock.

Wellsite core gamma-gamma measurements (while core is still in barrel) can provide core bulk density measurements that can be converted to porosity. This core bulk density porosity are compared with core plug porosity and density log porosities in Figure 3 over a 24-foot section of the core. A tool malfunction precluded the recovery of an optimum set of data for this well. Under normal circumstances, the agreement between log porosity and core gamma-gamma measurements would have been much better. The core measurements, including the gamma density porosity, are point measurements compared to the large volume averaged by log porosity and yet the agreement is reasonable.

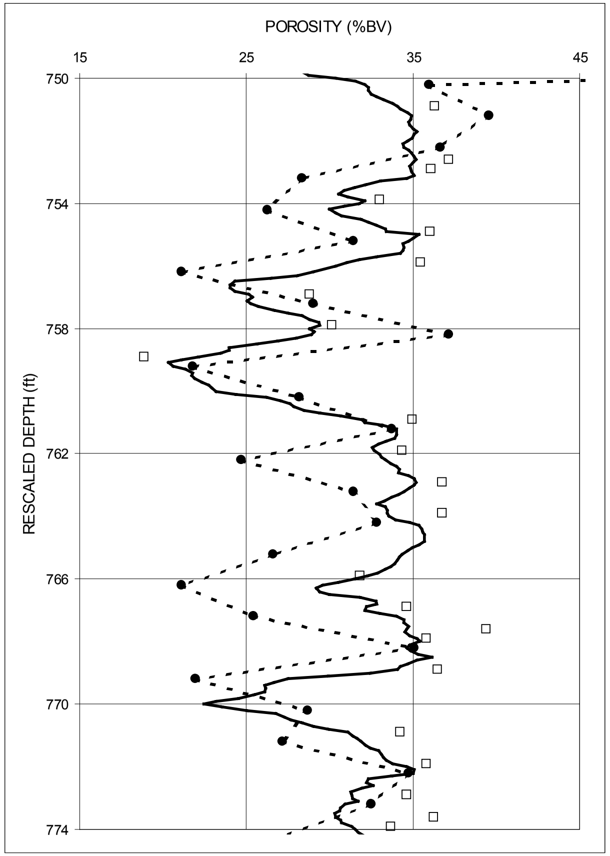

Figure 3: Comparison of core and log derived porosities. Solid line is the porosity calculated from the density log, the dashed line and solid circle is the porosity calculated from core gamma-gamma measurements, and the open square is the porosity obtained from core plugs measured at reservoir net confining stress.

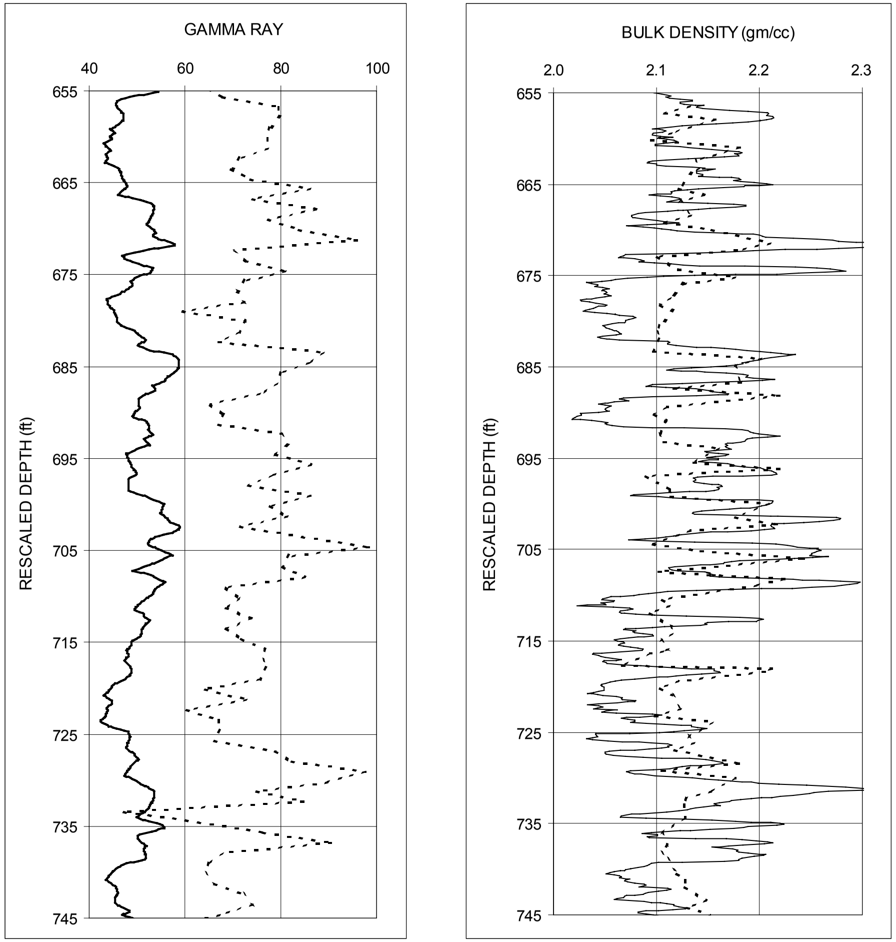

Figure 4: Depth shifting core-to-log. Left Side: Comparison of log gamma (solid curve) and core gamma, API units, (dotted curve). Right side: Density log (solid curve) and x-ray CT scan cross-section average density scaled to bulk density (dotted curve).

When the core gamma and the log gamma do not appear to provide accurate assessment of the core-to-log depth shift as illustrated in the left hand side of Figure 4, one looks to other core and log properties to provide the depth shift information. Such possible combinations could be core and log porosities, Dean-stark saturations and log derived saturations, etc. One combination not typically thought of is comparing the density log with the bulk density calculated from the x-ray CT radial cross-sections scans that are available before any other core analysis data are available.

The average CT number for the core cross-section scans is calculated on a one cm radial slice. Typically one obtains at least one CT slice per foot. The CT radial cross-section scans are cropped to remove fluids and muds in the annulus. The average CT number is converted to a pseudo bulk density and these results are presented on the right hand side of Figure 4. A depth shift of 4.7 feet appears to provide a good overall match for the 90' core #2 between density log and the CT number derived density.

Core vs. Log Saturations

The core was cut with a synthetic invert oil-based mud (OBM). The core-derived water saturations are considered to be representative of the reservoir if the cored interval is above the transition zone and if whole mud contamination is negligible (Woodhouse, 1998; Ringen et al, 1999). These water saturation data provide an early indication of the validity of Archie's parameters used to calculate water saturations. This sensitivity test can be made long before any electrical properties or capillary pressure data are available. The core water saturations are compared with the first pass log-derived water saturations in Figure 5 for 100' of core. In the more massive clean sandstones, there is good agreement between the two saturations. In the finely laminated sand-shale intervals, the core samples may be at the same scale as the rock heterogeneity while the log is averaging a much larger volume of rock, thus agreement is not as good.

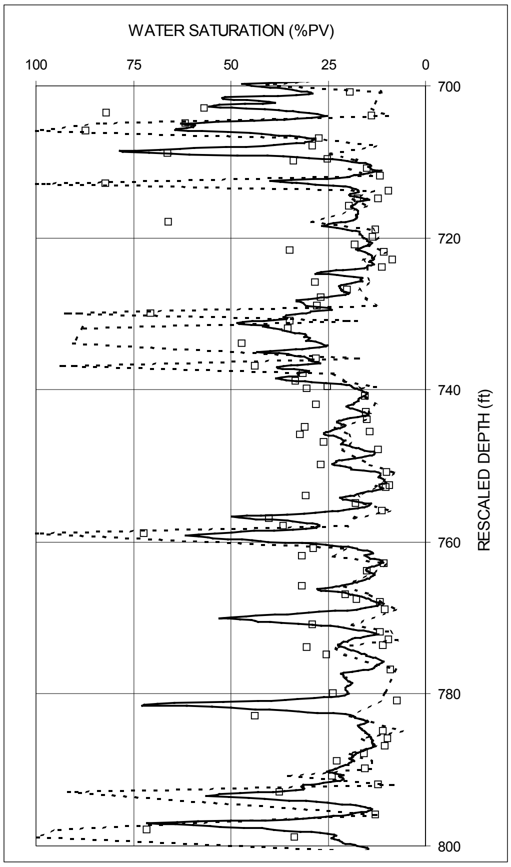

Figure 5: Comparison of core and log derived water saturations. Solid line is Archie's saturation from deep resistivity and density log, open squares are the core Dean-Stark Sw's, and the dotted line are the water saturations calculated from capillary pressure curves predicted from the PSD data.

Saturation data from a third method, which is based on the capillary pressure response predicted from the PSD data, are also provided in Figure 5. The PSD data represent a distribution of grain "body" sizes, from which a pore throat distribution can be simulated (Berg, 1975). Capillary pressure is calculated from the pore throat distribution using the Laplace equation. Generally there is a good match between the Dean Stark water saturations and those predicted by the PSD data. These PSD-derived capillary pressure saturations are available weeks-to-months prior to Dean Stark saturations. Depth intervals where there is relatively good or bad agreement constitute areas of focus for capillary pressure measurements.

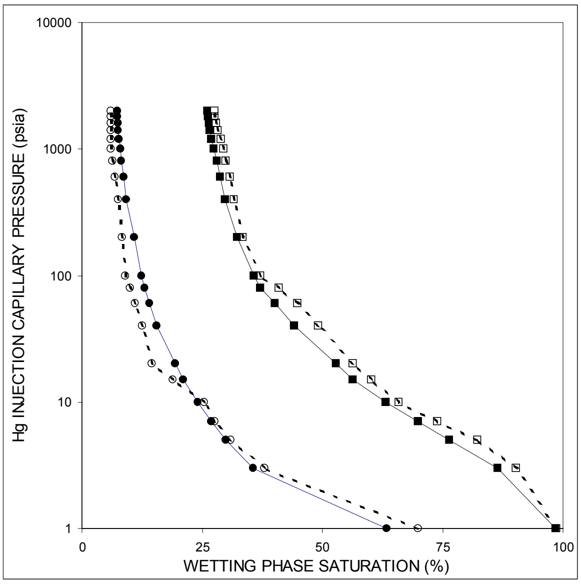

Figure 6: Capillary Pressure Data: Comparison between MICP and GSD predicted Pc for two samples (sample #1: open (MICP) and solid (PSD) circles; sample #2: open (MICP) and solid (PSD) squares).

Converting particle-size distribution to capillary pressure compares favorably with the mercury injection capillary pressure (MICP) data, as indicated in Figure 6. Often PSD-derived capillary pressure data are within +/- 5 saturation percentages of the MICP data. Since particle-size analysis does not capture the spatial distribution of particles in a disaggregated sample (i.e., laminations) the shape of the predicted capillary pressure curve could potentially be in error. Also this algorithm does not account for the presence of microporous grains (cherts, rock fragments, or leached feldspars) that would likely increase the irreducible saturation (Shafer et al, 2000).

NTG on Laminated core

Net-to-gross (NTG) is one of the more difficult values to quantify in a highly interbedded reservoir. The sand-shale laminations are well below the resolution of the logs and even statistical sampling of the core may not provide an accurate assessment. If the sand-shale laminations are smaller scale than the diameter of the core sample, as was the case in portions of this well, then core plug measurements cannot possibly quantify NTG.

Profile permeability measurements using a probe permeameter (tip diameter of 0.02 foot) were obtained over the depth interval displayed in Figure 7 at 10 measurements per foot. These permeability data are compared with the "sand log" from digitally processing visible and UV images of slabbed core using a 0.1-foot window (see Appendix for more details). Figure 7 also includes core plug air permeability measurements. The probe permeability data track the sand log reasonably well. It is very obvious that the core plug permeability data alone provide little indication of the degree of core and formation heterogeneity.

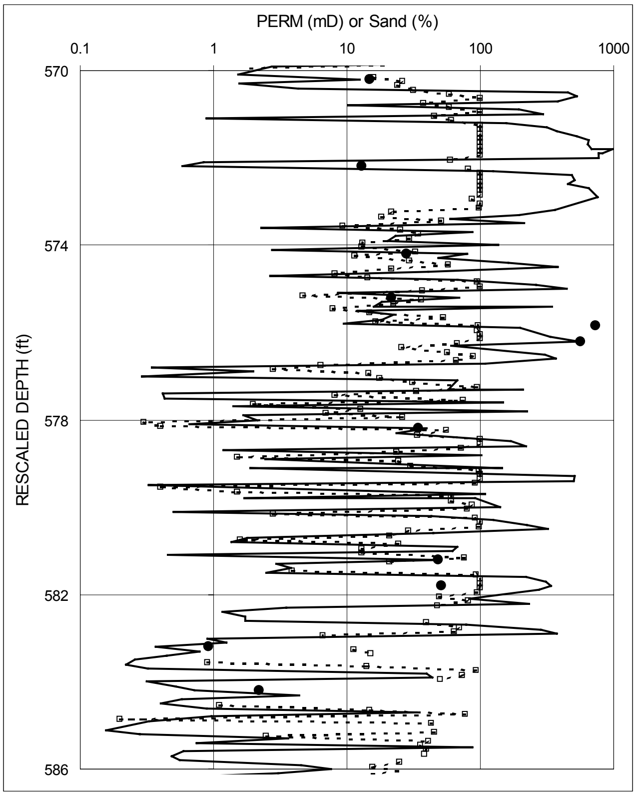

Figure 7: Comparison of high resolution permeability from probe permeability (solid line) with core plug permeability (solid circles) and the % sand from core photo image analysis. 0.1 foot window (open squares and dashed line).

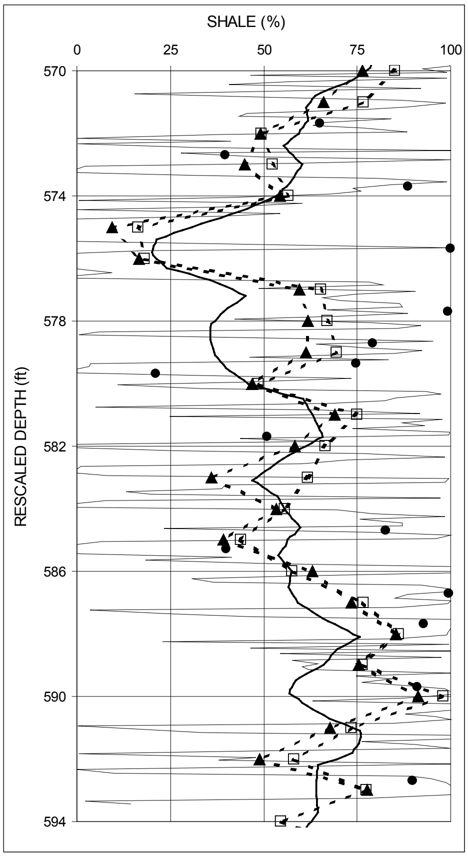

Figure 8: Net-to-Gross Analysis. Comparison of % shale from: detailed core description 1.0 foot window (dashed line & open squares), core photo image analysis, 1.0 foot window (dashed line & solid triangles), core photo image analysis, 0.1 foot window (light solid line), and Vshale, %, from log gamma (heavy solid line), and core GSD data (solid circles).

Detailed core description with a resolution of 0.001 foot can provide an accurate assessment of the NTG. Such data were collected for the three 90 foot cores from this well and an example of these data is illustrated in Figure 8. The core description data were summarized as to sand and fluorescing silts, non-fluorescing silts, and shales. The non-fluorescing silt and shale data, "shale", are presented in Figure 8 tabulated over 1.0 and 0.1-foot windows. Since Figure 8 compares this core description NTG data with the V_{shale} calculated from the gamma log (resolution is greater than a vertical foot), the 1.0-foot window summary was used. Also presented in Figure 8 are the digital image analyses of the core photographs utilizing visible and UV light images using both 1.0-foot and 0.1-foot windows. For comparison purposes, the V_{shale} calculated from core plug PSD data (point source data) are also included.

The shale logs obtained from core description and core photo digital image analysis track each other very closely and both reasonably match the log gamma V_{shale}. The log match provides additional verification that we have used the correct core-to-log depth shift. V_{shale} calculated from the core plug PSD does not match the 1-foot resolution shale log from either core description or digital image analysis again indicating that the core laminations are at a scale much less than one foot. The plug V_{shale} values more closely match the shale log calculated using 0.1-foot window core photo digital image analysis, which is closer to plug scale.

A cumulative KH, permeability (Kair) times interval thickness (H), calculated over this highly laminated section of core #1, partially displayed in Figures 7 & 8, was about 1000 md-feet based on the core data and about 3500 md-feet based on the profile permeability data. The NTG over this same depth interval from core description and image analysis were 34% and 40% respectively, and was 48% from the profile permeability data assuming a 10 md sand cut-off.

Selecting SCAL plugs

When choosing special core analysis plugs, apart from obtaining a range in porosity-permeability values, one should also ensure that a range of lithofacies has been sampled. Plug characterization can come from detailed core description, PSD data, and UV intensity from image-processed core photos. If these core-assigned lithofacies can be correlated to log features, then one can predict reservoir quality in uncored logged wells and potentially aid in extrapolating to seismic facies. Capillary pressure measurements should focussed on a range of intervals where there is both a relatively good and bad agreement between core and log saturation data.

CONCLUSIONS

The following routine core analysis features have maximum impact on log analysis and special core analysis for unconsolidated core material:

- Meticulous attention to coring protocol and core stabilization at the wellsite are critical for obtaining the undisturbed core required for accurate core analysis to validate log results and as input to reservoir simulator.

- Wellsite bulk density and core gamma measurements provide immediate characterization of core for depth control and reservoir quality.

- CT scanning core can validate depth shifting and provide a core quality baseline for special core analysis interval selection.

- A particle size distribution on every sample can:
    - Assist in assigning core plugs for routine vs. special core analysis,
    - Validate log V_{shale},

- Predict capillary pressure response to assist in the preliminary assessment of Archie log parameters and location of the oil-water-contact.

- An accurate assessment of net-to-gross in a highly laminated sand-shale core requires the appropriate combination of the following: detailed core description, digitally processing visible and UV images of slabbed core, and profile permeabilities with a probe permeameter.

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APPENDIX
Annulus-Fill Core Stabilization Method
Several "annulus-fill" core stabilization materials are traditionally used (epoxy, gypsum). The inherent weakness of the traditional "annulus-fill" process, insofar as unconsolidated core is concerned, is the handling requirement prior to stabilization. The inner barrel containing the core must be segmented into 3' units, tilted to drain the mud, relocated to stabilize an "end-cap" and relocated/tilted for the final pour. A newly developed full-length barrel, "annulus-fill" method eliminates the handling requirement until the core is protected

The full-length barrel, Annulus-Fill method is new and eliminates the handling requirement until the core is protected. Pre-coring requirements include drilling, tapping and plugging holes in the barrel on 2' centers at the top (0°) and at two positions near the bottom (135° and 225°). After the core is cut, it is laid down in 30' (or greater) sections with the top ports on top. The plugs are removed to drain the mud and fittings are installed to create three manifolds along the length of the inner barrel (0°, 135° and 225°).

Low-pressure air (0.5 psig) is flowed into the top manifold to displace the remaining mud out of the two near-bottom manifolds. These manifolds are converted to epoxy injection manifolds for the final phase of stabilization. An injection station is used to mix A and B components and to flow at a controlled, low rate into the inner barrel. When the epoxy "breaks through" at the top manifold, the inner barrel is "shut in" and the epoxy curing process is continued for six to ten minutes. The inner barrel can now be marked and sectioned and readied for transport in a protected state.

Analysis of Core Photographs

Net sand was calculated using binary images digitized from core photographs taken under both white and ultraviolet light. A 'sand mask', a binary image of sand layers, was generated by progressively filtering the UV images using both color and intensity, and a 'fracture mask', a binary image of sampling induced fractures, was generated from the white light photographs. The sand mask is an image in which every pixel is either 'sand' or 'not sand', and is used to directly calculate the proportions of sand within the cored interval. The fracture mask insures that fractures are removed from the calculations. Once the sand and fracture masks are complete, the 'Sandshale' program is used to 1) assemble all of the individual images into an image representing the entire cored interval, and 2) calculate sand/not sand percentages. The sand/not sand percentages are calculated using a series of non-overlapping sub-samples taken at different intervals (1-foot, 6-inch, 3-inch, and 1/10 of a foot), creating a separate sand log at each scale.

The major problem with UV fluorescence is that it denotes the presence of hydrocarbons, not the presence of sand. Sand detection near or below the oil-water contact may not be possible. UV fluorescence may indicate sand where none is present. Typically, the shale zones above any hydrocarbon saturated sand layer also contain hydrocarbons. They fluoresce under UV light, but they are non-productive. When this is combined with the hydrocarbon seepage on the surface of the slabbed core, smearing of hydrocarbons on the core surface during processing, and the flushing of hydrocarbons from highly permeable sand layers, UV photographs are not the best source for net sand calculations. Normally, high-resolution images taken under white light are used for this purpose. However, where high-resolution imagery is unavailable, the sand masks can be prepared using both the UV and white light photographs. The UV photograph is used as a base while the corresponding white light photograph is used for validation. In cases where UV fluorescence does not allow for adequate delineation of a specific sand layer, the equivalent horizon can be highlighted in the white light image, copied, and merged with the UV image.

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