TUTORIAL

What is It About Shaly Sands?
## Shaly Sand Tutorial No. 2 of 3

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Editor's comment: This article is the third in a series of short "tutorial-like" notes styled to mentor users of digital well logs in becoming confident practitioners of petrophysics.

When we left Shaly Sands Tutorial No. 1, Easy Money was riding high basking in the glow of having mastered the interpretation of low-contrast/low-resistivity shaly sandstone formations. Or so he thought. Only too soon, Easy Money crashed and burned by missing a low-resistivity pay zone in what appeared to be a clean sandstone. Since it looked to be shale-free, straight Archie was used resulting in too-high water saturation to be considered as pay in a clean sandstone. How, you ask, was this zone recognized as a productive hydrocarbon-bearing zone? It is obvious from the scenario explained above that a logs-only interpretation was a bust. However, two very important data streams had yet to be reconciled: First, the mud log showed a substantial gas show, coupled with a drilling break and faster drilling through the entire zone. Second, Archie's directive to all his petrophysicists was "Don't forget to look at the rocks!" So naturally a fast-drilling zone with gas shows had to be investigated with sidewall samples. Solvent cuts at the wellsite indicated oil, and overnight we had cookouts that also indicated oil. Sample examination determined that the sandstone was moderately shaly! How could all of our usual logging methods missed that this rock was shaly? Well, Easy Money had more work to do to explain what happened and convince his team members that he would never miss this sort of zone again. I urge the reader to continue on with the remaining Shaly Sand Trilogy Tutorials and learn how Easy Money made sense out of these contradictory indicators by studying the chemical structure and physical chemical properties of clay minerals.

At this juncture of our journey on Shaly Sands, we include Fig. 8 from the Shaly Sands Tutorial Part 1 (*Petrophysics*, February, 2018).
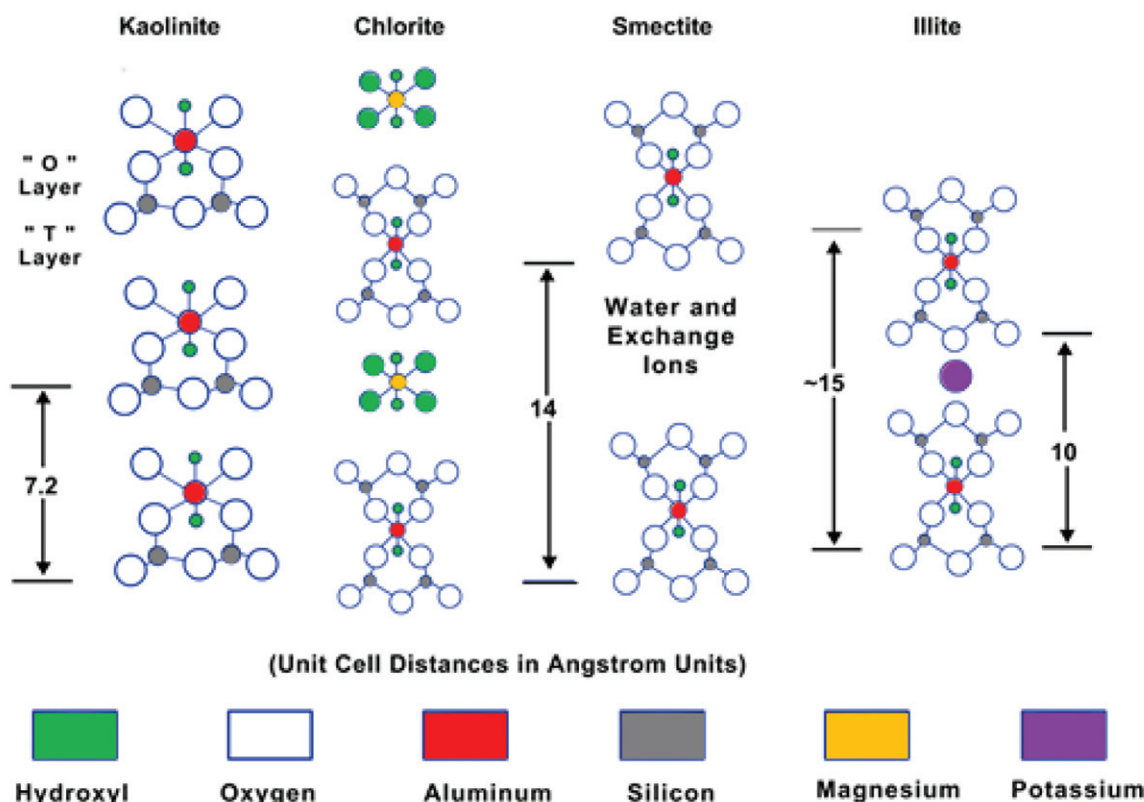
Fig. 8—The chemical structures of the "Big Four" clay mineral species using Grim's (1968) notation. Left to right: kaolinite, chlorite, smectite, and illite. The legend shows the correspondence between color and atomic species.]

Having this figure available for reference is ideal; I shall be referring to this figure in subsequent discussions. The emphasis will be to explore the atoms and their properties, their positions in the molecular structure of the clay minerals and the distinctive differences between the members of the "Big Four." It is these atomic and molecular properties that give rise to the perturbations of logging-tool responses that make our quest for understanding unexpected tool responses so interesting. It is truly "the thrill of the hunt" that leads us to find correct interpretations from a combination of downhole tool responses, mud logs, and core analyses results and yield in-situ petrophysical properties of rocks from reservoirs we can never see except in our mind's eyes (and, of course, the pictures developed and drawn by expert subsurface geologists).

The first anomalous tool response we cover is the unrealistically high porosity values produced in 100% water-saturated shales by a compensated thermal-neutron logging tool, e.g. the CNL, which can read 35 porosity units (p.u.) when the actual porosity is 10 p.u. These devices respond to the variation in the amount of hydrogen in the pore space and are calibrated in 100% freshwater-filled calcite. For this rock type, limestone, the only place one finds hydrogen is in the pore space as part of water, H_2O. However, shales can contain 25 to 55% clay minerals and we observe in "Figure 8" that all of the members of the "Big Four" contain hydrogen as an integral part of their chemical/molecular structures. The thermal neutrons used to detect and measure the presence of hydrogen by CNL tools, or any other thermal-neutron tool, cannot distinguish between hydrogen in liquids and hydrogen in solids, such as clay minerals. In Figure 8 one observes that hydrogen is present as part of the hydroxyl ions (OH^-) which are included only in the alumina octahedral molecule. It now becomes obvious that in 2:1 clay minerals, e.g., smectite and illite, there is much less hydrogen than in 1:1 clay minerals, e.g. kaolinite and chlorite. Thus if we wish to quantify the effect of clay minerals on CNL measurements, we must first determine the clay mineral type(s) and their quantity(ies). Fortunately, the morphology of clay minerals does not affect CNL measurements, only the volume moderated by the hydrogen index (HI) of a particular clay mineral, e.g., (V_{Illite}) (HI_{Illite}). The hydrogen index of 1:1 clay minerals is almost twice that of 2:1 clay minerals. Thus it is much more difficult to extract a value of total porosity from any logging suite using the CNL than if we use the density log, e.g., LDT, alone when we have core data to give us ρ_{ma} (grain density). Because the original CNL calibration was in freshwater-filled limestone, there must be a shift to obtain the equivalent sandstone response. There are many fewer calibration points for sandstone, and for shaly sandstones, the shale component does not fall on the sandstone line, even if the clay mineral has the same ρ_{ma} as the sandstone fraction, because the "Big Four" clay minerals, each plotted as a pure mineral, fall near the dolomite calibration line. Additionally, corrections for borehole temperature, pressure (density), flushed zone temperature, pressure (density), salinity of the borehole and flushed zone, mud type and mud-weighting material are required before proceeding with the interpretation of CNL measurements. The propagation of many small errors introduces a significant error in the result. This latter fact was verified beautifully by Jay Patchett many years ago (Patchett and Coalson, 1979). Therefore, I feel we have answered the original response of 100% water-filled shales reading way too high on a CNL response. If one has 55% bulk volume of any mix of clay minerals in this shale, one can easily explain a 30- to 40-p.u. response in a 10-p.u. water-filled shale. And we can expect problems if one uses the CNL in a scheme to calculate volumetric concentration of shale, V_{sh} (Note that V_{sh} is not equal to volumetric concentration of clay minerals, V_{clay}) to use in a shaly-sand interpretation equation and not take into account the clay mineral species. The presence of residual gas in the flushed zone makes this computation even dicier.

Now to discuss the problem of a shaly sandstone that appears to be clean on a gamma-ray log response. This is one of the pathological cases that when encountered one never forgets. When one is used to observing shaly sandstones show up as higher gamma-ray responses, one can be lulled into thinking that this condition is ubiquitous. Ah, such is life! We give high status to imperfect humans and are disappointed when these same humans make stupid mistakes. Please take a look at the atoms in the molecular structures of the "Big Four" in "Figure 8." Look for the atoms that we know produce gamma rays of sufficient energy such that they can exit the formation and enter the sonde to be measured by an internal scintillation detector, e.g., potassium (K), thorium (Th) and uranium (U). The only such atom that we find in "Figure 8" is a potassium ion in illite. Thus we might incorrectly conclude that every shale that has a gamma-ray signature must contain Illite. Well, again we see that life is not that simple. But to some extent the concept of illite everywhere is supported by the statistical fact that the most abundant clay mineral in the earth's crust is illite—just not the only one. Thorium and uranium ions can be triply charged and adsorb tightly to the surface of minerals in the subsurface. Clay minerals have 10^6 larger specific surface (surface-to-volume ratio) than quartz. Hence clay minerals will always grab the lion's share of these ions. They displace sodium exchange ions. Therefore, clay minerals that have high exchange capacity will also have more than their volume share of thorium and uranium. Recall that the order of magnitude of exchange capacity is: chlorite < kaolinite

<< illite <<< smectite. Accordingly, chlorite ends up having very, very little radioactive signature. Thus, when it is the dominant clay mineral in a rock formation, the formation can pass for clean rather than the shaly formation that it actually is. The second fact is that chlorite grows in thick forests perpendicular to grain surfaces; on thin sections it looks like the grain is fuzzy.

This morphology of chlorite on the surface of sandstone grains gives rise to abundant microporosity. Because of the chlorite pore's small size, its capillary pressure is quite high and the pores tenaciously hold on to their water, leading to a quite high pore volume of irreducible water. In many cases, this fuzz can hold 50 to 60% water, but will not produce a drop. Only the 40 to 50% hydrocarbons will flow. Also this high irreducible pore volume of water leads to many, many water filled paths to flow electric current and the result is a low resistivity, very low in many cases. Hence the pathologic case is a high porosity, chlorite shaly sandstone with chlorite in the grain-coating morphology, resulting in low resistivity, even when hydrocarbon-bearing, and with low gamma-ray response. Chlorite fuzz on the grains can easily be observed with a hand lens on sidewall-core samples. You must look at the rocks or you will miss this one. Thanks for the advice, Archie! Easy Money forgot this lesson and mistook the zone for a clean sandstone (chlorite has little gamma-ray activity) with low resistivity (chlorite platelets growing perpendicular to the grain face produce abundant microporosity that will remain water-filled, thereby resulting in low resistivity.) Thus, we explain the bust mentioned in the first paragraph.

We cannot lose sight of the fact that more than just porosity and hydrocarbon saturation must be considered for us to label a zone as "pay." The determination of relative permeability of the hydrocarbon phase and the absolute permeability of the zone must be deduced in order to predict the inflow performance of this zone; can we pay off the completion costs? Will sustained flow last long enough to pay out facilities and connections to existing pipelines? These are questions that need the synergy of petrophysical, geological, reservoir and production engineering to find a reliable answer. But there is a petrophysical measurement that is a root cause and understanding or lack thereof for predicting inflow performance. The quantity I refer to is the ubiquitous V_{sh}, the fractional bulk volume of shale in a "pay" zone.

There are numerous equations using V_{sh} as a parameter to compute rock properties, such as effective porosity and water saturation, in shaly sandstones. Unfortunately, users of these numerous equations have at least a dozen empirical methods to choose from when they need V_{sh}. Since V_{sh} has been used as a parameter in equations for over 60 years, few equations come with instructions on how to compute V_{sh}

since everyone "knows" how to determine V_{sh} anyway! But now I am going to upset all those in the "know" and discuss why one should never compute and use V_{sh} in a routine manner, particularly when having to make "pay" calls in high-risk wells.

Let us begin the narrative on V_{sh} by making sure that everyone "knows" what the proper definition of shale is. First and foremost one must understand that there is NOT a single rock type named shale. Shale is defined as a mixture of two size ranges of particles, irrespective of what the particles are. We use the Wentworth size scale which uses the median grain size of any sample of particles to define the ranges in common use for cobble, pebble, gravel, sand, silt and clay. Silt covers the range 4 to 62 μm while clay includes particles smaller than 4 μm. Note that there is no mineral type specified in the Wentworth scale. One source of confusion arises because one group of minerals that falls in the clay-sized range is the clay minerals. Clay-sized particles can also be quartz, feldspar, calcite, siderite, dolomite, kerogen, etc. Shales are then defined as a mixture of silt-sized and clay-sized particles, with at least 25% by volume being clay minerals. These particles are carried by rivers, which flow into the ocean, e.g., the Gulf of Mexico. Once the river water flows into the Gulf it spreads out, its velocity drops inversely proportional to the distance from the river mouth. Fast-flowing water can carry sand-sized particles, but once the river flows into the Gulf its velocity can no longer carry sand-size particle and they settle to the bottom as river-mouth bars. The finer particles are then carried further away from the river mouth until the velocity drops to where the silt-sized particles drop to the bottom. Finally, in deeper water the velocity is low enough that even clay-sized particles can settle out. Because the velocity of the river changes through the seasons, the places where the particles settle move farther then closer then farther then closer to the river mouth resulting in the mix we call "shale." Closer to the river mouth, shales are silt-rich, while those farthest from the river mouth become clay-rich, and of course any intermediate distances will have fluctuations of the volume of each of the size ranges of particles. Thus, at any distance and/or depth we can find no single rock type we can call shale. It is a continuum of mixes of silt-sized and clay-sized particles, and therefore we must characterize each shale layer, bed, or zone as unique. This process I have described is called detrital deposition of shales and silts and sands. Seasonal flow in this environment gives rise to laminated sandstones and shales. The thickness of any sandstone or shale layer is subject to seasonal changes and thus exists in an infinite number of combinations. A shale layer above a sandstone layer and/or below a sandstone layer may be clay-rich or silt-rich and if the sandstone layer is a shaly sandstone,

we must determine which of the over- or underlying shale to use when describing the shale laminations in the shaly sandstone. I recommend asking for help from your team's geologist when making this important decision. Let us add a few more specifics about shales to help us use the terms correctly. I think it would be valuable, especially for new professionals, to define/clarify the differences between claystone, mudstone, and shale. These terms are frequently, and oftentimes incorrectly, used interchangeably.

In particular, shales are defined as LAMINATED indurated rocks with >67% clay-sized minerals, whereas mudstone, which may have the same texture and composition as a shale, lacks the lamination and fissility of a shale (Jackson, 1997). While some might say "the difference is semantics" or "who cares," geologists will argue that the difference has significant implications for identifying and defining different depositional environments and constructing the underlying reservoir geological model, which ultimately has significance for planning production.

Mudstone is a more general term that can include, clay, silt, claystone, siltstone, shale etc. According to some definitions, this term should be used when the volumes of clay, silt, and sand are unknown, not specified, or cannot not be precisely identified (Jackson, 1997).

We frequently speak of massive shales based on well-log signatures; however, in the strict sense, unless we know for sure (high-resolution well logs, perhaps) that the stratigraphic unit in question (or formation) is actually laminated, it is more likely a mudstone.

Note: In addition to water velocity affecting settling rate of particles, there is an effect that is specific to clay minerals. Recall that the surfaces of clay minerals have negative charge defects that we have called exchange-ion sites. When in rainwater, creek water, river water there are no dissolved sodium ions to balance out the negative charges. The best that can happen is the positive ends of the polar water molecules can orient to the negative defect thus wetting the surface. But the negative charge is still there and when clay-mineral platelets are dispersed in rainwater, individual clay-mineral platelets see each other's negative aura and repel each other offsetting gravitational settling. Once the river deposits reach the salty ocean, mixing gradually raises the salinity. The result of this process is higher salinity surrounding the clay-mineral platelets being held in suspension. Once the salinity nears seawater concentration, the dissolved ions now shield a clay-mineral platelet from its neighbors and when the clay-mineral platelets bump into each other, they form aggregates that are much larger, which in turn causes them to settle faster, and in bays in the Mississippi bird's-foot delta are fed by longshore currents parallel to the coast. These bays are sheltered, resulting in quiet water, which is an ideal place for clay-mineral platelet aggregates to settle. The result is mud with all type of benthic worms, clams, etc. and the final product is a bioturbated clay-mineral-rich shale.

The fluid velocity gives us a picture of the laminated environment at the time of deposition. Of course, the river keeps on dumping sediment into the Gulf and sediments settle, compact, and become buried by more sediment. As a given layer is buried deeper, temperature increases and grain solubility increases. The result is that higher concentrations of ions that are needed to grow clay minerals are present. At this juncture of burial and increased depths, authigenic clay minerals can form in the pores of sandstones. The particular species of clay mineral generated depends upon the atomic ions and their concentrations present—but note that these are clay minerals are not, I repeat, NOT shales. The morphology of the clay-mineral platelets depends upon the clay mineral being generated; at least at this juncture. With higher temperature and pressure, some species of clay minerals can undergo transformation to another species. This transformation results in loss of interlayer water and exchange ions. For a different species, silica and water are lost during the transformation. For both clay-mineral species undergoing this diagenetic change, the end result is a morphology that results in loss of permeability. The loss of water by both minerals contributes to overpressure in the pore fluid of the shale.

The erosion of existing sandstones and shales creates the source of sediments carried into rivers that form future sandstones and shales. Shales tend to flake and produce larger particles at the source. They are softer and do erode into smaller particles as they are transported, but some can survive as sand-sized shale particles that become deposited with sandstones. They will be found in load-bearing positions and are referred to as structural shale in the sandstone bed.

Thus, we now observe that a shaly sandstone can have the shaly portion located in different positions. The dominate mode of deposition for shale is as laminations. This is the detrital mode. Often the adjacent sandstone lamination has no shale or very little shale. Thus the productivity of clean sandstone laminae is not diminished by shale laminae, except by the geometrical reduction in thickness of the productive interval; 30 to 60 % shale laminations in a zone may still produce adequately with enough thickness because the sandstone laminations are clean or nearly so. If you have not had the chance to view a slabbed core of shaly sandstone, it can be an informative visit. Also, borehole imaging tools visually show, in false color, laminations and their thickness.

Structural shale also has little effect on producibility, as solid quartz grains are being replaced by porous shale grains. The gamma-ray response will be higher due to quartz grains

being replaced by shale grains, so the zone may appear too shaly to be pay. Look at the rocks to spot this situation.

When we encounter authigenic clay minerals we observe a disproportional reduction in producibility because clay minerals are located in pore spaces. Pore throats represent about 2% of the pore space, but just a small amount of clay minerals growing in the throat can reduce the permeability very quickly. Consequently, while this morphology is not a widespread problem, when authigenic clay mineral deposition occurs in pore throats it can limit production. Due to errors in measurements and statistical variations, observing 5% pore-filling clay minerals is approximately the lower limit for wireline gamma-ray tools, therefore once again, we must look at the rocks to detect below this level.

And here is the dilemma: If we rely on a simple gamma-ray response to determine V_{sh}, we will be observing the combined laminated, dispersed and structural shale components. For a given volume of shale, each of these modes results in a different porosity. Additionally, each of these modes of deposition affects the electrical response in different ways. Shale laminations give rise to anisotropic effects, but do not affect current flow in the clean sandstone layers. If one uses a V_{sh}, with adjacent shale resistivity to make a double-layer model correction, the correction will be too large. A V_{sh} shale correction for anisotropy is inadequate, while a V_{sh} correction for structural shale effects on electrical measurements gives rise to an overcorrection.

The discussion immediately above is aimed at establishing where simple V_{sh} methods can produce misleading results. At this juncture I have not given the reader any guidance on how to make appropriate corrections for differing modes of occurrence for shaliness. I will provide some guidance in the last chapter of the Trilogy on Shaly Sands, stay tuned…

REFERENCES

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ABOUT THE AUTHOR

E.C. Thomas is a consulting petrophysicist and owner of Bayou Petrophysics and provides technical training in shaly sand analyses and all other areas of petrophysics for Petroskills. E.C.'s professional career interests and publications have spanned the entire field of formation evaluation/reservoir characterization, i.e., petrophysics. In 1992, he wrote a biographical sketch of Gus Archie for *The Log Analyst* to commemorate the 50th anniversary of the publication of the Archie Equation.

E.C. retired from Shell E&P Technology Company as a Petrophysical Advisor where he actively pursued research and field evaluation topics in the area of Petrophysics for over 32 years. He also authored and taught basic, intermediate and advanced courses in petrophysics for more than seven years at Shell's Training Center. E.C. 's academic background includes a BS in Chemistry from LSU, a PhD in Physical Chemistry from Stanford University, and a year of postdoctoral research in Physical Chemistry at Princeton University

E.C. has served SPWLA and SPE in many capacities, including SPE Distinguished Lecturer and chairman of the 1998 Archie Conference. Professional recognitions have included invitations to serve as keynote speaker at several SPE and SPWLA regional and topical conferences, and at the 2005 SPWLA Annual Symposium. In 2000, E.C. received the SPWLA Distinguished Technical Achievement Award; and in 2004, the SPWLA Gold Medal Award for Technical Achievement. E.C. served as a Petrophysical Consultant to the President's Commission investigating the BP-Deepwater Horizon blowout and resulting oil spill. E.C. currently serves as a technical reviewer for *Petrophysics* and *SPE Reservoir Evaluation & Engineering.*