Title: Dealing with Unique Minerology in Petrophysics Logs

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**Abstract:** XXXXX

**One-Sentence Summary:** This paper aims to discuss the petrophysical considerations that need to be made for unique mineralogy that is sometimes seen in logs, like tuffs, vaolcanic ash and opalines

Introduction

Most petrophysical models are built with an understanding that the most oil and gas deposits are found in basins that have an underlying mineral system that is sedimentary in nature. These sedimentary basins are primarily composed of minerals that are either silicates (), such as quartz, feldspars, micas and other clays, or carbonate ( (chalk, dolomite, limestone), and while the nature of the petrophysical properties and reservoir type are very much dependent on the environment of deposition and can vary across sedimentary basins (homogeneous, heterogeneous, tight, layered or laminated), our main petrophysical equations are designed to deal with these select basket of minerals. However, we know from both individual as well as collective industrial experience that there are instances where unique minerals are encountered in fields drilled around the world.

In Indonesia [1] and Australia [2], for instance, pyritic sandstones are encountered in some hydrocarbon bearing reservoirs. These have some interesting effects on the logs, from having high densities to low resistivity responses. Kennedy and Clavier et al both discussed the impact of pyrite (FeS2) on modern logs [1, 2] and noted that while pyrite has a variety of effects on resistivity and nuclear tools, such that measured values can be drastically different from those typically encountered

In the Gulf of Mexico (GOM) [5], in fields offshore Brazil [6] and Egypt [7], evaporite salts (halite, anhydrite, and sylvite) layers can overlie depositional basins or be present within producing reservoirs. While salt acts as an excellent sealing facies, due to its non-net nature with its very low porosity and permeability, salt encountered in reservoir sands has a deleterious effect on logs; resistivities can be very high (due to a lack of accessible pore space), density is well constrained since minerals are pure, with either very high or low values dependent on the elements present, and neutron can be either very high or very low dependent again on the nature of the salt type [8].

Some minerals encountered in hydrocarbon bearing reservoirs result in missed pay opportunities (low resistivity/ low contrast pay) and/or can appear as non-net sands if higher potassium (K), thorium (Th), or uranium (U) contents are not properly accounted for (hot sands). The Northern Carnarvon Basin in Australia, for example, contains reservoir sands in the Mungaroo Formation which are glauconitic in nature [9]. Glauconite is an iron rich clay variety, and is ductile and compacts under overburden conditions, potentially occluding primary porosity. Properly accounting for glauconite in a reservoir firstly requires an understand of the microporous nature of the glauconite particle itself. Hot sands are present in the Tenggol Arch, offshore east Peninsular Malaysia and are characterized by higher gamma ray (GR) signature associated with Th. This needs to be accounted for, otherwise the evaluation of clay proportions would be incorrect, resulting in an underestimation of net sand. The accounting of the hot sand components also allows for the proper correlation across wells at the field scale [10].

In all the above examples, literature adequately describes how such reservoirs should be dealt with. In almost all cases, the fundamental petrophysical equations derived for volume of shale (VSH), porosity (f) and saturation (Sw) will apply, so long as appropriate corrections/ calibrations are used. There are exceptions to the rule, however. If salt, for example, is encountered in a continuous zone but deposited as its own layer, then petrophysicists may choose to either treat the zone as non-net and not interpret or else, adopt a simplistic, but consistent method, given that there are no set standard industry equations. In this case, the interpretation goal is not to determine salt properties, but rather to allow for comparison across large areas with salt bearing intervals, and to avoid interpreter bias. A simplistic method could be VSH from GR, total porosity from nuclear magnetic resonance (if available), density or sonic (but with consistent end points) and Sw set to 1. If there is salt present as pore filling material, then adopting an interpretation method as described by Saxena and McDonald is perhaps the way to go [11].

In this paper, we will discuss, via several case studies, some of the experiences and interpretation methods in dealing with unique situations observed in our work and how they are quantified for petrophysical applications. We will discuss wells that have intersected (a) volcaniclastics (tuffs and ash) and (b) opalines. We will explain how we have addressed such petrophysical challenges and discuss which tools are perhaps the most reliable in discriminating potential mineral signature.

Case Study 1: Volcaniclastic Reservoirs

Background

Tuffaceous reservoirs are known to contain hydrocarbons which can sometimes be of significant volumes, examples being in China and South America. However, such reservoirs are relatively underexplored and underproduced, fundamentally because they are challenging to understand. Typically, if tuff facies are encountered in conventional reservoirs, they are ignored. Yet, a proper understanding of how such reservoirs behave may prove appealing to explorers looking for the next big “whale” in exploration.

From a seismic perspective, these rocks can sometimes undergo rapid and prominent chanced in thickness, and with seismic generally lower resolution, prediction for thin layers tends to be error prone. Additionally, some volcanic rock the have similar compositions (volcanic breccia vs rhyolite) have different petrophysical properties, depending on whether the minerals present cause the tuffs to be more alkaline. The alkalinity of tuffs is determined by the type and concentration of minerals, such as feldspars, that make up the rock. An increase in alkalinity causes chemical weathering, dissolution, and results in the formation of new minerals, all of which can have an effect on the bulk properties.

The flow mechanism in such reservoirs is governed by numerous variables; the very nature of the tuffaceous facies means that pore structure, pore type/ size, mineralogy, and rock-fluid interactions impact reserves estimation, recovery factor and sweep efficiency at the reservoir scale. Pore scale distribution of fluids within the rock will, in turn, determine petrophysical and geophysical response of the reservoir rock. Conventional logging methods may not necessarily work well in tuffs as they contain trace amounts of radioactive minerals, and grains sometimes contain surface roughness at the nanoscopic scale that impacts how fluids are distributed.

Case Study Parameters

We will discuss 2 wells from 2 different oil producing fields. Well #1 in Field A was drilled in the Gulf of Mexico (GOM) and had ash and volcanic beds present within an intersected Tortonian formation. This well was logged with modern “conventional” petrophysical logs, with a full log suite of GR, density-neutron (D-N) and resistivity (RES). Well #2 in Field B was drilled in South America and had been logged with older “Russian style” logs, with uncompensated GR, N and RES.

Approach:

The main challenge with the interpretation of any tuff facies is the lack of a universally accepted interpretation methodology, because of variability in the logs and fields. Indeed, it becomes necessary to design a “fit-for-purpose” method, guided by the question as to what benefit delineating the tuff facies would bring, as well as the type of data with which you must work with. For Well #1, the goal is to correlate the volcaniclastics across wells to determine field wide correlatability. For Well #2, the goal was to (a) determine the petrophysical properties of the tuffs and (b) predict, away from well control, what the potential for hydrocarbon presence would be.

Generally, in tuff reservoirs, bulk density decreases while the radioactivity signature increases. Rhyolitic and dacitic tuffs exhibit densities of approximately 2.65 g/cc, which can lower to ~2.25 g/cc as the minerals alter to glass. Felsic tuffs also have high gamma ray readings (100-200 API units) due, in most cases, to higher Th concentrations. Increased radioactivity could also be from association with potassium (K)-rich minerals like orthoclase, sanidine, microcline (KAlSi3O8) and anorthoclase ((Na,K)AlSi3O8). Sonic slowness will vary, but is typically in the range of 50-55 ms/ft, with lower values being associated with unaltered rocks, while higher values being rocks that are more silicified. Electrical properties (especially n) will be lower (m = 0.83-0.9, n = 0.6-0.64) as well, given the generally microporous nature of such Tuff samples. However, this must be verified by actual core measurements ideally.

To summarise, most volcanics have a slow sonic, “hot” gamma ray, low density and generally low resistivity signature.

Results and Discussion - Well #1

Cross-plots of logging parameters are simple and effective methods which are generally used to discriminate volcanic lithology and lithofacies in drilled wells [72-73]. Primary logging parameters includ natural gamma (GR), natural gamma-ray spectral logging (U, Th and K), electrical resistivity (RT), NPHI porosity, RHOB density, acoustic log (DT), photoelectric absorption coefficient (Pe) as well as compound parameters M and N. Two of theses parameters are plotted in a X and Y coordinate system, different regions are divided by the concentration of data points, then will be assigned with corresponding geological information. Generally, this method is used firstly on well sections with known lithology and lithofacies, so as to make master plates which are then applied to the other unknown sections in the same area. Applications in the Songliao Basin show that GR-Th, Pe-Th and M-N cross-plots are the most effective methods for discriminations of volcanic lithologies (Figure 5). Moreover, logging facies’ analysis and FMI image interpretation are used to identify the textures and structures of volcanic rocks, and then finally determine the discrimination of volcanic lithology and lithofacies in detail.

Comparative analysis between the volcanic facies and logging facies of drilling core sections is aimed at revealing and summarizing the relationship between geologic properties and logging responses, so as to solve the multiplicity of interpretation by logging parameters, and then set up identification standards of logging facies in the study area. Identification of logging facies is by means of configuration analysis of logging curves including SP, GR, RT, ML, RHOB, as well as dip logging interpretation. Moreover, the standard logging facies could be interpreted as lithofacies on the basis of geologic data.

Electrical conductivity of volcanic reservoirs is mainly influenced by lithology, porosity and permeability, saturation, content of metal elements and also burial depth. Occurrence of hydrocarbons will greatly increase the resistivity, while it will obviously decrease with water. The shape of logging curves and their assemblages are related closely to volcanic lithologies as well as their textures and structures which have become good markers for discrimination of volcanic lithofacies. For massive volcanic rocks, the framework is the main medium of conduction. Under this circumstance, lithology, lithofacies and burial depth are the main controlling factors to the conduction of rocks and changes of logging curve shapes. For example, intermediate-felsic volcanic rocks of vent facies are characterized with high-GR and mid-RT, and their logging curves appear as a high amplitude dentiform and peak shape. While basalts of volcanic vent facies show low-GR and the tuff displays low-RT.

The Mesozoic volcanic rocks are the most important gas reservoirs in the northern Songliao Basin. Five lithofacies and 15 sub-facies have been recognized in the volcanic rocks. The best reservoirs were generally found in three of the 15 sub-facies including pyroclastic bearing lava flow, upper effusive and inner extrusive sub-facies. The corresponding logging characteristics are as follows. The pyroclastic rock-bearing lava flow sub-facies show high-GR values with high amplitude dentiform and medium to mid-high RT with low frequency, low amplitude dentiform. The upper effusive sub-facies show high GR with high amplitude dentiform and mid-high RT with finger and peak shapes. The inner extrusive sub-facies show high GR with medium amplitude dentiform and mid-high to high RT with medium amplitude dentiform. In addition, crypto-explosive and outer extrusive sub-facies may also be good reservoirs. The occurrence of hydrocarbons will cause a remarkable increase of resistivity, while water does the contrary. The changing of resistivity without influence of fluids from low to high are respectively followed as volcanogenic sedimentary facies, extrusive facies, explosive facies, volcanic conduit facies and effusive facies [[74](https://www.intechopen.com/chapters/41663#B74)].

Results and Discussion - Well #2

Well #2 is an onshore South American well, drilled in the late 40’s and logged with older “Russian style” logs. Old mudlogs described the volcanic facies as composed primarily of basalts, or andesitic and interbed with clays, carbonates, sandstones. In some places, tuff conglomerates were intersected as well. Cuttings were also observd to have undergone severe mechanical stress under dynamic metamorphism.

Petrophysically, it proved impossible to trace the vintage of the logs; while the operator had digitized copies of the data, there was no proper trace of when this data was digitized, or if there was any manipulation being done to the digital data, as the operator no longer had access to the sephia or paper logs. There was no header information to share, no information as to how the logs were calibrated, and the well had numerous vintages of neutron but it was unclear how they were generated/corrected. Data was poor, with badly washed-out holes. Thankfully, the operator had done a field wide study with samples of core taken from analog wells, although this was a very limited data set.

Given this, we opted to follow the mantra “keep it simple” and to consider the reservoir holistically, across scales that span nine orders of magnitude. We started our analysis by firstly looking at thin sections and cores to cement our understanding of the facies, particularly the pore morphology (nm scale), before moving on to the macro properties, such as porosity-permeability and trapped residual saturation (mm to cm scale). As logging tools are not designed to measure tuff properties accurately, we next applied a statistical approach and calibrated our log measurements to core on a field-wide basis (cm to m scale). We combined our calibrated properties with the structure and stratigraphy at the geological scale (m to km). To close the loop, we tied our results to the production profile and estimated recovery factor, which was cross-checked against reservoir engineering principles. Through this integrated approach of understanding the field at multiple scales, we could deterministically define the boundary for static properties, statistical results from the DCA and finally probabilistic volumes via a Monte Carlo simulation.

Thin Section, Scanning Electron Microscope and Core

An analysis of the thin sections of the tuffacaceous facies showed characteristic needle fragments of volcanic origin along with a series of heterogeneous pore sizes, and complex minerology (albite, polycrystalline quartz, fine grained plagioclase, carbonates and abundant detrital clay matrix). Tuff is complicated because it is hard to define/separate into macro/meso/micro porosity, primarily due to (a) surface roughness and (b) no clear boundary in pore sizes, but we can observe that the pore space is made up of such a distribution of macropores and micropores with mesopores acting to bridge the 2 other pore types. We observed that the micropores are in connection (blue filled space) while there are clay present in macropore, and which itself appears isolated. We also observed there to be calcite-filled flow channels present within fractures in the rock. The fracture is possibly an indication of the brittle nature of the tuff rock.



Core Calibrated Porosity-Permeability Trends

Vintage core data described the tuffaceous facies as being either coarse, medium, or fine grained. This classification is general, however, and there was no mention in the data of how this definition was determined. However, if all the data is plotted in the form of a porosity-permeability cross-plot, one observes that three are clear separation of the core into 3 distinct groups. In particular, it can be generally observed that, for the same porosity value, coarse grained tuffs have a higher permeability in contrast to the fine-grained material. Additionally, the data is highly scattered, with some pockets of fine-grained tuffs having very high porosity-permeability values. Again, this alludes to the highly heterogeneous nature of the volcanic facies. Still, the range of values (for this field) has a majority of the XXX

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Trapped Gas Saturation

Petrophysical Evaluation

VSH is interpreted from RESDEEP, PHIn is interpreted from N (not hydrocarbon and invasion corrected) using the “high-low” method where high and low porosity points are calibrated to end-points from core (26 points) provided by the operator. SWT is interpreted using the modified Simandoux or Archie method; both results appear similar. ERCE has assumed a salinity value of ~90,000 ppm NaCl equivalent (provided by the client) with a=1, m=2 and n=2; electrical properties are based on analogue data.

Case Study 2: Opalines

Background

Opaline is a type of sedimentary rock that is composed primarily of silica, typically in the form of chalcedony or quartz. It can form in a variety of environments, including hot springs, evaporite basins, and shallow marine environments.

The occurrence of opal as a producing reservoir is uncommon; however, when such reservoirs are found, they tend to be prolific producers with the ability to produce for many years. Indeed, in numerous examples from California and Japan, these reservoirs have continually produced for ~30 years. Opaline reservoirs can have a high porosity and permeability, which allows fluids to flow through it easily. Additionally, it can act as a seal rock, trapping hydrocarbons and preventing them from escaping. Opaline can be an important source rock for hydrocarbons, and can also trap oil and gas that has migrated from other source rocks. It is often found in sedimentary basins, and can be productive in both onshore and offshore oil and gas fields.

Case Study Parameters

At a recently concluded drill campaign in 2017, an opaline rich reservoir was penetrated offshore South America. The drilled Well #3 met with pre-drill expectations observed on the seismic, with a thick net reservoir that had good porosity characteristics characterized by a brightening on the amplitudes. The well was defined as a technical success, and proved the presence of effective source, with evidence of hydrocarbon presence in the well in the form of a collected gas sample downhole.

A set of basic logs (GR, RES and D-N) as well as core samples are present in Well #3. The effect of opal on the logs is varied; it is observed that opaline has a smaller effect on sonic and neutron logs but has a larger effect on the density log. Both photoelectric effect (PEF) and bulk density correction (DRHO) logs do not show significant anomalous values; DRHO is ~ 0.058 ± 0.012 g/cc and PEF is ~3.73 ± 0.79. As the well was wet, the effect on resistivity is unclear, but given its microporous nature, resistivity suppression is very possible.

Approach:

The distribution of opal in reservoir rocks can be heterogeneous. Additionally, since it shows up as a bright on seismic due to its highly porous nature, there is a need to its overall effect on the raw log measurements and use that as calibration parameters in to support seismic driven exploration campaigns. This was the goal of the analysis of the opaline reservoir in Well #3; an evaluation of its concentration, distribution in the reservoir (vertically and horizontally) and concentration which could improve quantitative analysis and de-risk other potential opportunities.

Results and Discussion - Well #3

A series of core measurements done on collected sidewall core samples in Well #3, which showed that samples had good porosity, ranging from 25-41 %. The permeability, while low at < 10 mD, were in line with analogs found elsewhere.

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Figure :Moo Moo

***Discussion and Implications:***

***AAA****:*

***BBB:***

***CCC:***

***DDD:***

***EEE:***

**Limitations of Study and Conclusions:**

# **References**

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