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 and volcanics, opalines, CO2 and helium

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].

Aside from unique minerologies, reservoirs can also sometimes intersect formations where the primary fluid is CO2, H2 or He. In terms of their logging characteristics, they appear almost like hydrocarbon bearing reseroivrs, albeit with some nuanced differences.

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) volcanoclastics (tuffs and ash), (b) opalines, and wells where the pore fluid is primarily (c) CO2 or (d) helium. 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.

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.

Petrophysical 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 have to 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.

Results and Discussion - Well #1

Results and Discussion - Well #2

It was impossible to trace the vintage of the older “Russian style” 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.

The approach taken here was to “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

Trapped Gas Saturation

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.

Petrophysical 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

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.

Case Study 3: CO2 for Sales Gas

Background:

Petrophysical Approach:

Results and Discussion

Case Study 4: Exploring for Helium

Background:

Petrophysical Approach:

Results and Discussion

Table 1: Blah Blah

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| *Moo* | *Moo* |

Figure 7:Moo Moo

***Discussion and Implications:***

***AAA****:*

***BBB:***

***CCC:***

***DDD:***

***EEE:***

**Limitations of Study and Conclusions:**

# **References**

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