Title: Dealing with Unique Minerology in Petrophysical 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, volcanic 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 (Winardi, Surjono, Amijaya, & Suryanto, 2021) and Australia (Ellis, 2016), 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 (Clavier , Heim, & Scala, 1976; Kennedy, 2004) 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) (Fredrich, Fossum, & Hickman, 2007), in fields offshore Brazil (Armelenti, et al., 2021) and Egypt ( Ali Ali, Emad El Din Abd Elrazik, Shebl Azam, & Ahmed Hassan, 2016), 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 (Marisa, et al., 2018).

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 (Feng, Ren, Zhang, & Qu, 2020). 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 (Jong, Kessler, Madon, & Mohamad, 2019).

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 (Saxena & McDonald, 2009). However, for some even less encountered minerologies, there are few if not no standard interpretation methods to be found within existing literature and hence much uncertainty in how to handle them.

In this paper we will discuss, via several case studies of less encountered minerologies, 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) opalines and (b) volcaniclastics (tuffs and ash). 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: Opalines

## Background

Opaline rocks are named as such because they contain opal, a hydrated silica mineraloid which can form in hydrothermal springs, volcanic, and marine environments. They can also be biogenic in nature as in the case of diatomites. Opals have multiple forms and phases and are typically classified into opal-A, opal-C, and opal-CT. Opal-A is amorphous, lacking a crystalline structure. With increasing diagenesis, opal-A morphs into a more stable paracrystalline opal-CT which contains layers of intergrowth and displays characteristics of both cristobalite and tridymite (Curtis, Gascooke, Johnston, & Pring, 2019). With time, these opals turn into quartz, the most stable of the silica polymorphs. Across all these transitions, the petrophysical properties of the rocks change significantly and hence opalines encompass a wide range of characteristics.

This range of petrophysical characteristics is important in determining the role of opalines in hydrocarbon storage, where they can act as both reservoirs and seals. In terms of reservoir potential, opaline rocks can be characterized by their high porosity which makes it possible to store hydrocarbons (Derkowski, Środoń, & McCarty, 2015). The porosity can drop from above 55% in opal-A to about 25% in opal-CT, and permeabilities drop from an already low <10mD to negligible levels in opal-CT and quartz (Chaika & Dvorkin, 2000; Reid & McIntyre, 2001). However, these opal-CT and quartz reservoirs still have potential to store hydrocarbons, as displayed in the Monterey Formation of Elk Hills field in California and Yurihara field in Japan, where such reservoirs have proven to produce (Reid & McIntyre, 2001; Tsuji, Masui, & Yokoi, 2011). Chaika & Williams (2001) have also classified these types of siliceous reservoirs into two groups – Matrix porosity-dominated (Group 1) as in previous examples, and fracture-dominated. Their study shows the importance of being able to recognize the two different groups of opalines in better evaluating the reservoir potential of a field.

The low permeability of opalines also allow them to act as seals which trap hydrocarbons. This was seen in the Yurihara field in Japan, where the less porous and permeable opal-CT seals in hydrocarbons within the more permeable quartzose porcelanites below. However, in shallower sections of opal-CT, confining pressure was not sufficient and permeabilities increased to values similar to the underlying quartzose porcelanites, allowing hydrocarbons to escape (Tsuji, Masui, & Yokoi, 2011).

The storage or sealing capabilities of opalines may also be affected by several other factors. One such factor is the clay content of the opalines. Tsuji et al. (2011) find that higher clay content can make opalines better seals, while lower clay content improves their reservoir potential. Lithology of the opalines can also determine how brittle the reservoir can be, for example opaline chert can be much more fractured than opaline porcelanite (Reid & McIntyre, 2001). Lastly, the differences in response to heat between opal-A and opal-CT means that when using steam injection in the extraction of hydrocarbons, opal-A becomes less permeable, and this makes opal-CT a more equally viable option despite normally having lower permeabilities than opal-A (Dietrich, 2017).

Overall, the existing literature suggests that there is no one defined course of action in evaluating the reservoir potential of opalines, owing to their wide range of types and characteristics. At the same time, all the three main types of opal have shown promise in their ability to act as producing reservoirs and hence should not be glossed over without more careful examination in logs. In the following sections, we document our approach to examining the hydrocarbon potential of a well which had penetrated opalines.

## Case Study Parameters

At a recently concluded drill campaign in 2017, an opaline rich reservoir was penetrated offshore South America. The drilled Well DS 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.

## 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 DS; 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.

## Interpretation Results - Well DS

A set of basic logs (GR, RES and D-N) (see Figure 7) as well as core samples are present in Well DS. 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. This large effect is best explained in Figure 1, which shows the significantly lower grain densities of opaline samples (~2.2g/cc) compared to the sandstone and limestone intervals (2.6-2.72g/cc). 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.

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| **Figure 1:** Histogram of grain densities of samples from the same field as Well DS |

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| **Figure 2:** Scanning Electron Microscope (SEM) images from Well DS. **Left**: An elongate pore (P) hosting zeolite crystals (Z) within the microporous smectitic-illitic clay (Cl) and opal lepisphere (Ls) matrix. Intraparticle porosity is also found within a radiolarian (Rd) fragment. **Right**: Close up of a typical microporous matrix of flaky detrital smectitic-illitic clay (Cl) and opal lepispheres (Ls). Contains scattered zeolite crystals (Z), cryptocrystalline calcite (CxCal), and coccoliths (Cc). |

A series of core measurements done on collected sidewall core samples in Well DS, which showed that samples had good porosity, ranging from 25-41 %. The permeability, while low at < 10mD, were in line with analogs found elsewhere. These values are distinct from the sandstone and limestone intervals from other wells in the area (Figure 3) and match up well to the porosities and permeabilities of opalines published in existing literature (Reid & McIntyre, 2001; Tsuji, Masui, & Yokoi, 2011). The samples plot in the same region as opal-CT porcelanites from Tsuji et al., which is consistent with the classification of our samples.

Interestingly, Well DS sample points appear to lie firmly on the ‘Group 2’ trendline proposed by Chaika & Williams, suggesting a fracture-dominated reservoir (Figure 4). However, based on thin sections and SEM images (Figure 2), Well DS samples hold a degree of matrix porosity through micropores, while fractures do not readily show up in these sample. The characterisation may still be accurate as it is possible that the limited Well DS samples do not fully capture the extent of fracturing within the opal-CT reservoir, as analogue reservoirs with the same lithology have shown presence of microfractures throughout porcelanite layers (Reid & McIntyre, 2001).

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| **Figure** 3**:** Crossplot of permeability and porosity for Well DS and nearby wells |

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| **Figure** 4**:** Crossplot of grain density and porosity for various samples, including Well DS. Adapted from Tsuji et al. (2011). |

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| **Figure 5:** Thin sections from Well DS. **Left**: Opal-rich microlaminae (Op) with intercalated bands of weakly colloform opal (OpBnd). Carbonaceous material (Cb) is also seen within microlaminae. Globular microfossils, microfossil moulds, and planktonic foraminifera are visible as bright spots throughout (Mf). **Right**: Visible matrix porosity (MP) grading to microporosity within opal matrix seen with mouldic porosity (MdP). Intraparticle porosity is hosted by a partly cemented planktonic foraminifer (IaP) partially infilled by ferroan calcite (FC). Isolated micrite trails (MtT) also observed. |

For the petrophysical interpretation, we have firstly spliced, and depth aligned the logs. Environmental corrections are a challenge as the minerals are unique, but because the borehole is in good shape, we have assumed that the environmental corrections as provided by the logging contractor is generally adequate. From the gamma ray (GR), we observe that opaline has a highly variable GR signature, with values ranging from 30 to 90 GAPI. We attribute this to variable interspersed clay content in the depth interval. Resistivity shows no invasion effect but shows high resistivity spikes associated with cemented intervals. Overall, however, the resistivity response is fairly lazy and does not show significant variation throughout. There are intervals where the resistivity is higher, which we note to be related to the presence of higher porosities potentially. Interestingly, there is an interval from 1063 – 1068 mMD, where the resistivity is the highest. From 1068 -to 1078 mMD, there also appears to be a “transition zone like” behaviour. When viewed in connection with the density-neutron (RHOB-NPHI), this same zone shows a “hydrocarbon effect” (cross-over) which disappears as one goes deeper. The same “hydrocarbon effect” is also observed when an overlay of the compressional and shear sonic is viewed. We show a cross-plot of RHOB and NPHI and RHOB-PEF in Figure 6

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| **Figure 6:** Density-Neutron and RHOB-PEF Cross-plot |

In this well, we observe from the cross-plot that points lie somewhere between the limestone-dolomite trendline, although at the tail ends where porosities are high. Our recommended approach is to therefore interpret the well as you would a conventional petrophysical analysis, but with properly applied calibration to account for the extremely high porosities. We evaluate volume of shale (VSH) as a minimum of the GR and RHOB-NPHI, followed by the evaluation of volume of clay (VCL).

From the core data provided, we know the average clay content is XX%, and apply this as a multiplier to VSH. Porosity is interpreted using RHOB-NPHI, with grain density calibrated to the core data. Note that the core data has an average grain density of 2.2 g/cc; however, we use values of between 2.1-2.3 g/cc depending on the interval. We adjust the values such that we have a match between interpreted grain density (RHOGC, track 4 from the left) and core based grain density (black squares in track 4 from the left). Still, our match between total porosity (PHIT, track 2 from the right) and core porosity (black squares in track 2 from the right) is sometimes less than perfect.

For instance, while our core grain density is seen to be properly calibrated, our porosities show a slight mismatch from 1063 to 1068 mMD. In other intervals, however, the match is very good. We attribute this to challenges with getting accurate porosity measurements in opaline rich cores, as well as inaccuracies in the log measurements. As opal is essentially microporous is nature, core cleaning, drying, and therefore measurement of porosity/permeability can sometimes be inaccurate. Similarly, as mentioned previously, environmental corrections to such intervals is difficult. However, in general, we note that PHIT and core porosity follow a similar trend.

For saturation, we use dual water as the preferred method, but only to account for the clay effects, more than the opaline. We note there is hydrocarbons interpreted from 1063 to 1078 mMD. However, there is no pressure or samples at this depth to prove if this is mobile in any way.

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| **Figure 7:**Logs from Well DS |

## Discussion

The unique porous microstructure of opaline as observed from Figure 2 and Figure 5, as well as the observation of fracture or matrix dominated properties (Figure 4) means opaline reservoirs could potentially be classified as “Low Resistivity Low Contrast (LRLC) Pay”. While Well DS did not have any definitive evidence of hydrocarbons and existing literature does not cover the behaviour or mechanisms behind the potential of opalines as LRLC pay, the observations made of the microstructure for the well above is very similar to those made in sandstones and carbonate reservoirs elsewhere which have LRLC characteristics (Ashqar, 2016; Ayadiuno, 2017; Belevich, 2017; Boyd, Darling, & Tabanou, 1995). Most LRLC wells have been characterized as low resistivity, high fluid saturation, but good oil flow/production. The typically responses of resistivity can be from 1 - 5 ohmm (Worthington, 2000), which aligns with values of resistivity previously found in high opal-CT content reservoir rocks (~5 ohmm) (Reid & McIntyre, 2001). LRLC pay occurs when the absolute value of the resistivity is so low that pay zones are overlooked. LRLC pay can occur where the water saturation as calculated from the resistivity is incorrect and overestimates the true water saturation of the formation. The issue is then to find improved methods for calculating the true water saturation, either by modification of the calculation algorithm used from the resistivity, or possibly by obtaining saturation data by an alternative and independent means. Either scenario involves an understanding of why the water is effectively not mobile, and to develop some means for predicting which rocks will flow dry oil and which will flow wet, from rocks with the same water saturations. It has often been assumed that micritized grains containing water may be able to “short circuit” the resistivity measuring current. If the matrix of the opaline rock contain micro-fractures/fractures, then it is also possible that filtrate has invaded these intervals and caused an overall suppression to the resistivity response. -computer tomography imaging of core plugs and good image logs would help address some of this uncertainty.

The observed micritized structure of opal as well as diagenesis effect from interstitial dispersed clay present with opal grains can also cause LRLC pay. Micritization has a similar impact if distributed uniformly through the pore space; it behaves as would a laminated shale. Micritization involves the formation of a micrite envelope around the grain; this impacts the permeability more than the porosity. The alternating of fine-grained (clay) with coarse grained (opal) layers means that in the former, the pore space will be saturated with formation water due to high capillary pressure, while in the latter, it will be HC saturated. From a resistivity perspective however, the resistivity response is averaged such that the overall resistivity is low. A vertical and horizontal azimuthal resistivity measurement is required to separate “sand” vs “shale” signature. If the opal mineral has macroscopic and microscopic inclusions which can result in magnetic attraction (paramagnetism), this can also cause LRLC pay, but only if found in high quantities and in electrical continuity.

Case Study: 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.

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 Figure 8

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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.

Limitations of Study and Conclusions

Nomenclature

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| **°C** | degrees Celcius |
| **1P** | Proved |
| **2P** | Proved + Probable |
| **3D** | three dimensional |
| **3P** | Proved + Probable +Possible |
| **ABEX** | abandonment cost |
| **API** | American Petroleum Institute |
| **BCU** | Base Cretaceous Unconformity |
| **Bg** | gas formation volume factor, in scf/rcf |
| **Bo** | oil formation volume factor, in rb/stb |
| **Bscf** | thousands of millions of standard cubic feet |
| **CAPEX** | capital expenditure |
| **CGR** | condensate gas ratio |
| **CIT** | corporate income tax |
| **COT** | cargo oil tank |
| **cP** | centipoise; unit of viscosity |
| **CP** | cathodic protection |
| **CPF** | central processing facility |
| **CPI** | computer processed interpretation |
| **DCA** | decline curve analysis |
| **DST** | drill stem test |
| **ESP** | electrical submersible pump |
| **FPSO** | floating production storage and offloading vessel |
| **frac.** | fraction |
| **FSO** | floating storage and offloading vessel |
| **ft** | feet |
| **G&A** | general and administrative |
| **GIIP** | gas initially in place |
| **GLV** | gas lift valve |
| **GOC** | gas oil contact |
| **GOR** | gas oil ratio |
| **GRV** | gross rock volume |
| **GVI** | general visual inspection |
| **GWC** | gas water contact |
| **HRDZ** | hydrocarbon related diagenetic zones |
| **HWU** | hydraulic workover unit |
| **IT** | information technology |
| **km** | kilometres |
| **LKH** | lowest known hydrocarbon |
| **m** | metre |
| **M MM** | thousands and millions respectively |
| **MCI** | Montara Commission of Inquiry |
| **MD** | measured depth |
| **mD** | millidarcy |
| **MDT** | modular dynamic tester |
| **NOPSEMA** | National Offshore Petroleum Safety and Environmental Management Authority |
| **NPV xx** | net present value at xx discount rate |
| **NT DoR** | Northern Territory Department of Resources |
| **NTG** | net to gross ratio |
| **OBC** | ocean bottom cable |
| **ODT** | oil down to |
| **OPEX** | operating cost |
| **OWC** | oil water contact |
| **P&A** | plug and abandon |
| **P10** | high case (probabilistic) estimate (there should be a 10% probability of exceeding this estimate) |
| **P50** | mid or best case (probabilistic) estimate (there should be a 50% probability of exceeding this  estimate) |
| **P90** | low case (probabilistic) estimate (there should be a 90% probability of exceeding this estimate) |
| **PHIE** | effective porosity |
| **PHIT** | total porosity |
| **PIIP** | petroleum initially in place |
| **PLEM** | pipeline end manifold |
| **Possible** | Possible, as defined in Appendix 1 |
| **Probable** | Probable, as defined in Appendix 1 |
| **Proved** | Proved, as defined in Appendix 1 |
| **PRRT** | petroleum resource rent tax |
| **PSDM** | post stack depth migration |
| **PSTM** | post stack time migration |
| **R&M** | repairs and maintenance |
| **rb** | reservoir barrels |
| **rcf** | cubic feet at reservoir conditions |
| **RFT** | repeat formation tester |
| **RIC** | re-injection compressor |
| **scf** | standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit |
| **SPA** | sale and purchase agreement |
| **stb** | stock tank barrel (42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit) |
| **STOIIP** | stock tank oil initially in place |
| **SWE** | effective water saturation |
| **TVDSS** | true vertical depth sub-sea |
| **TWT** | two way time |
| **USD** | US Dollar |
| **WHP** | wellhead platform |
| **WOR** | water oil ratio |

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