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Mixed Reservoir Wetting in Unconventional Reservoirs and Interpretation of Porosity/Resistivity Cross Plots, Derived From Triple-Combo Log Data

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Summary

Measurements of fluid wetting characteristic are made routinely on rock samples. However, there are no published petrophysical models to differentiate between oil-wet and water-wet fractions of a reservoir sequence using commonly available log suites.

This presentation builds on our previous publication that describes the unconventional reservoir petrophysical model we have developed (Holmes 2014). Essentially, we define four porosity components, namely total organic carbon, clay porosity, effective porosity (inorganic), and effective porosity (organic). This last component, which is associated with total organic carbon, is an indirect calculation if the first three components do not sum to total porosity.

Porosity/resistivity plots can be constructed for the total porosity and interpreted in a standard fashion. These will mostly indicate a water-wet system when the effective porosity (inorganic) fraction is examined. A second porosity/resistivity plot compares resistivity with effective porosity (organic), and is interpreted to indicate Archie saturation exponents of much larger than 2 – frequently in excess of 3 – indicating the oil-wet fraction of the reservoir system. Additionally, the plots suggest very low values of the cementation exponent of 1.0.

Examples from the Bakken of North Dakota and the Wolfcamp of Texas are presented showing quantitative distinction of water-wet vs. oil-wet reservoir components.

Nomenclature

Mnemonic	Description	Mnemonic	Description
V_{SH}	Volume of shale	R_t	Formation resistivity
Phi_T	Total porosity	**a**	Archie empirical factor, usually assumed to be 1.0
Phi_E	Effective porosity (inorganic)	**m**	Archie cementation exponent, a rock property, often assumed to be 2.0
Phi_{Clay}	Clay porosity	**n**	Archie saturation exponent, a fluid property, often assumed to be equal to m
$Phi_{Organic}$	Effective porosity (organic)	S_W	Total water saturation (clean formation)
$Phi_E + Phi_{Organic}$	Effective porosity (total)	S_{WE}	Effective water saturation (clean formation)
TOC	Total organic carbon	$S_{W\ Organic}$	Effective porosity (organic) water saturation
R_W	Water resistivity	S_{Wi}	Irreducible water saturation

Table 1: Nomenclature of the mnemonics used in this paper

Introduction

It is commonly recognized that mixed wetting occurs in unconventional oil reservoir systems – part of the porosity fabric is water-wet and part is oil-wet. Measurements are made on rock samples to define wetting characteristics. However, in addition, there are data available from triple-combo log suites which can be analyzed to define wetting characteristics.

Holmes (2014) presented an unconventional reservoir petrophysical model and defined four porosity components (Figure 1):

- Total organic carbon (TOC)
- Clay mineral porosity
- Standard effective porosity (inorganic)
- Effective porosity (organic)

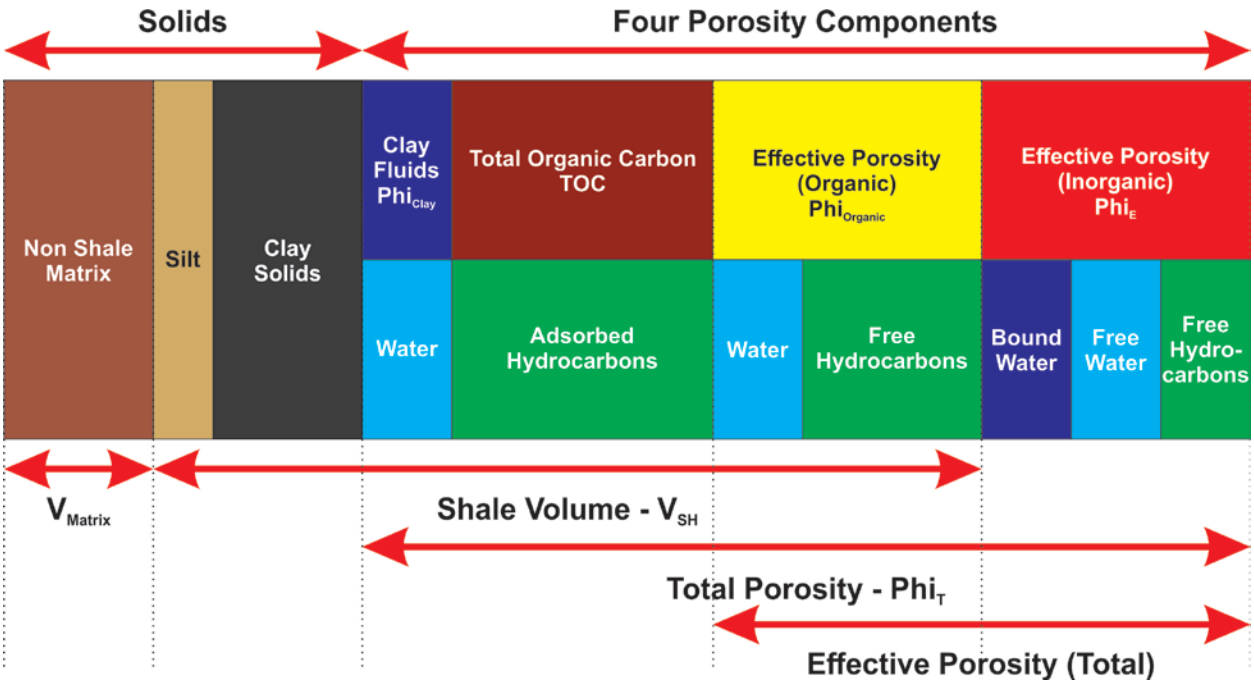

Figure 1: For unconventional reservoirs, properties are quite different from conventional reservoirs, with unique petrophysical attributes. The shale component requires detailed analysis.

In addition to examining the influence of clay fluids, it is necessary to define the contribution of the other components on log responses.

This paper addresses the analysis of the shale components using deterministic approaches involving triple-combo log suites. Particular emphasis is directed to differentiating electrical responses of the clean formation and shale.

The goal is to calculate the four porosity components (Figure 1):

- Effective porosity (inorganic) (Phi_E) – clay-free porosity in the non-shale fraction
- Clay Porosity (Phi_{Clay})
- Effective porosity (organic) ($Phi_{Organic}$) – A small volume (mostly less than 5% of the total rock volume) and contains free hydrocarbons and formation water
- Total Organic Carbon (TOC) – a combination of kerogen and bitumen and contains adsorbed hydrocarbons

The recognition of effective porosity (organic) is a new term required in the analysis of unconventional reservoirs. Also required is the recognition that the traditional term “effective porosity” refers only to the inorganic porosity development. “Effective porosity (total)” is an additional new term to recognize the sum of the inorganic and organic porosity elements.

Effective porosity (organic) is secondary porosity associated with TOC, generated during the thermal maturation process of organic material.

Glorioso, et al (2012) published examples of secondary porosity derived from SEM images (Figure 2).

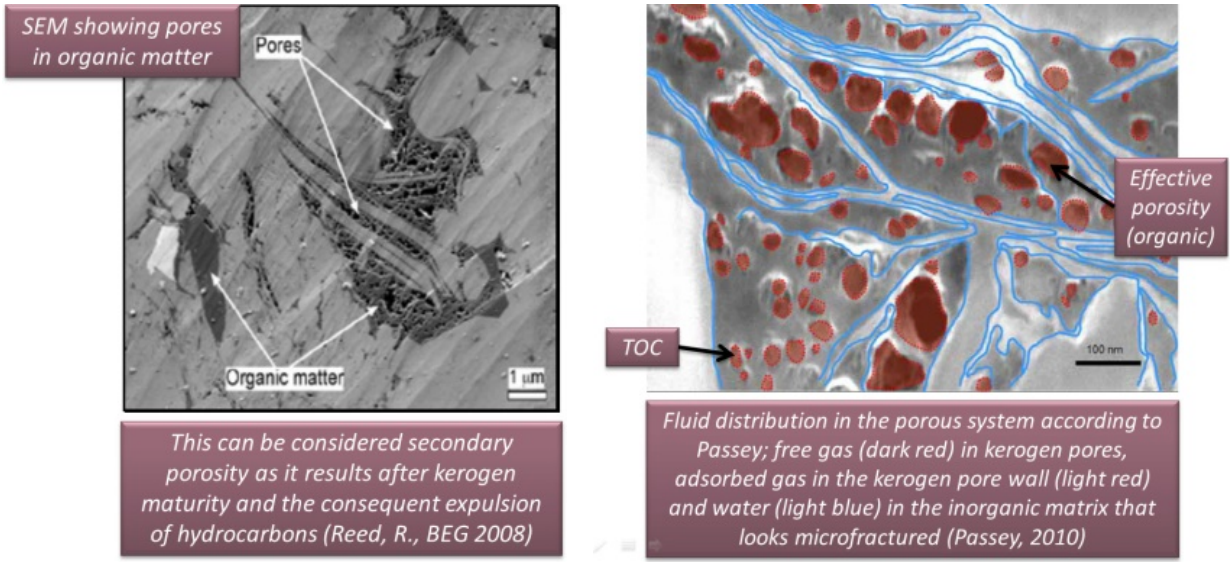

Figure 2: SEM showing pores in organic matter on the left (Glorioso 2012) and fluid distribution in the porous system on the right (Passey 2010).

Walls, et al (2016) give an example from the Wolfcamp (Figure 3) to recognize:

- Mineral associated porosity
- Organic matter (OM)
- Porosity associated with organic matter (PAOM)

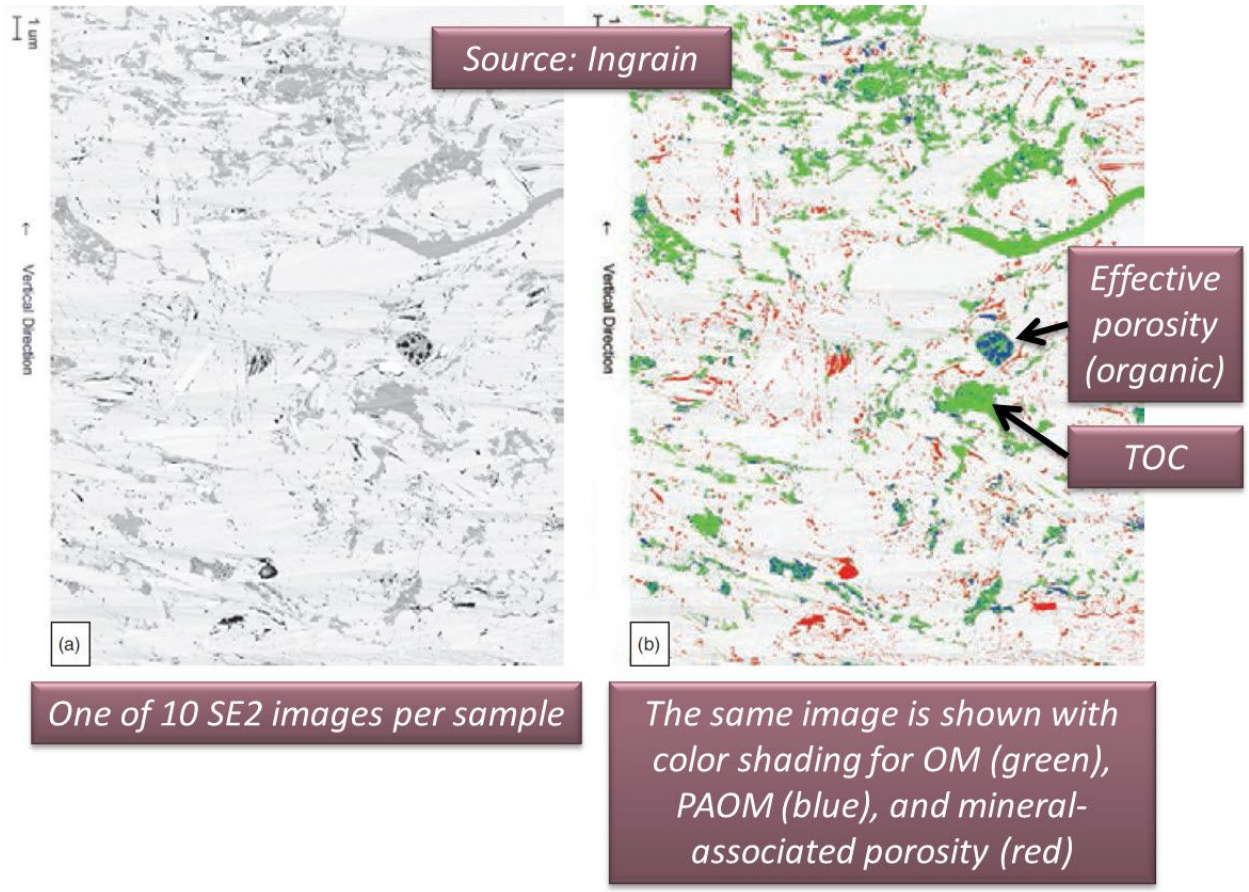

Figure 3: Ingrain (2016)

Kumar (2015) shows a distinction between water-wet clean formation and oil-wet shale formation from the Bakken (Figure 4). The analysis involved preferential sorption of fluids, which depends on the polarity of the rock surfaces.

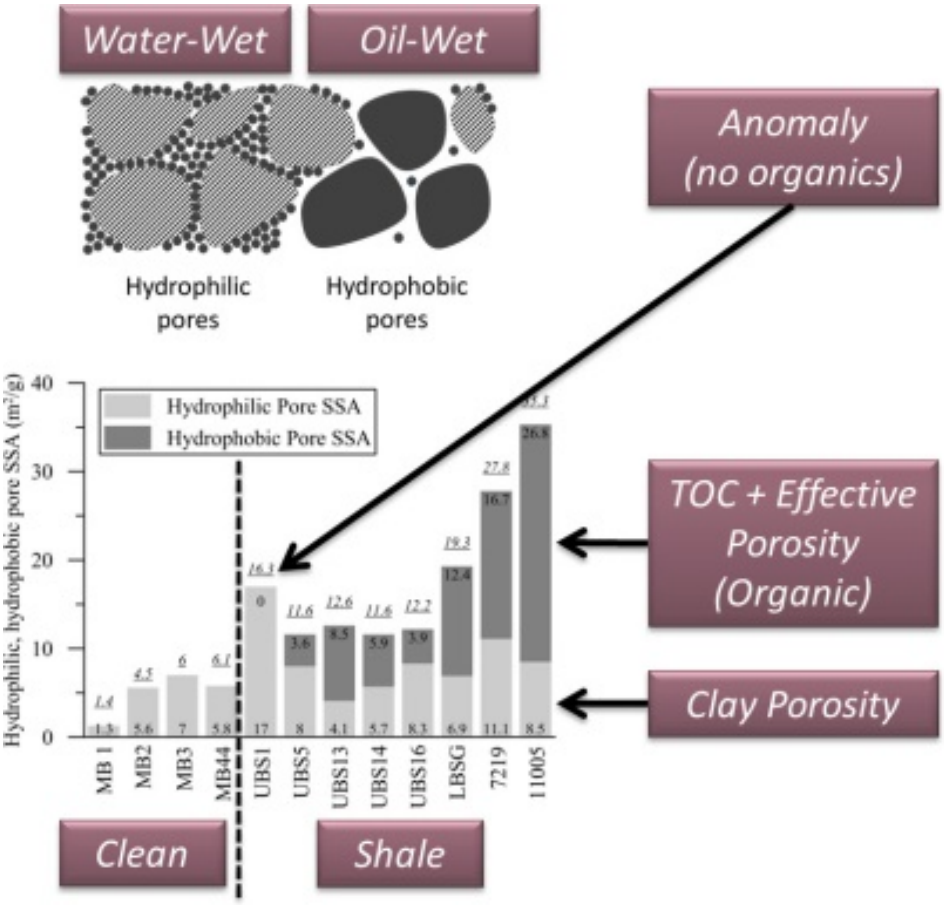

Figure 4: Kumar (2015)

The emphasis of this paper is to examine resistivity responses of the effective porosity (inorganic) fraction as compared with those of the effective porosity (organic) fraction. Effective porosity (organic) is equivalent to free gas in kerogen pores.

Procedures to Identify the Four Porosity Components in Unconventional Reservoirs

The following analytic procedures are used:

1. A standard shaley formation analysis is performed to quantify:

    a. Shale Volume – V_{SH}
    b. Total porosity – Phi_T
    c. Effective porosity (inorganic) – Phi_E
    d. Fluid components in effective porosity (inorganic)
    e. Matrix volume and petrophysical responses – V_{ma}

    A density/neutron combination to calculate porosity is preferred, as this is essentially not affected by changing matrix density and fluid content (gas vs. oil and water)

2. Total organic content (TOC) is calculated using two techniques:

   a. The Passey, et al (1990) ΔlogR technique (Figure 5) is used to differentiate between organic rich and organic lean shales. The calculation of TOC (in weight percent) can be made for any available porosity log. Input of the level of organic metamorphism (LOM) or vitrinite reflectance (Ro), a measurement of thermal maturity, is required. This is best determined from calibration with core or cuttings measurements, or from a knowledge of thermal maturity of the reservoir.

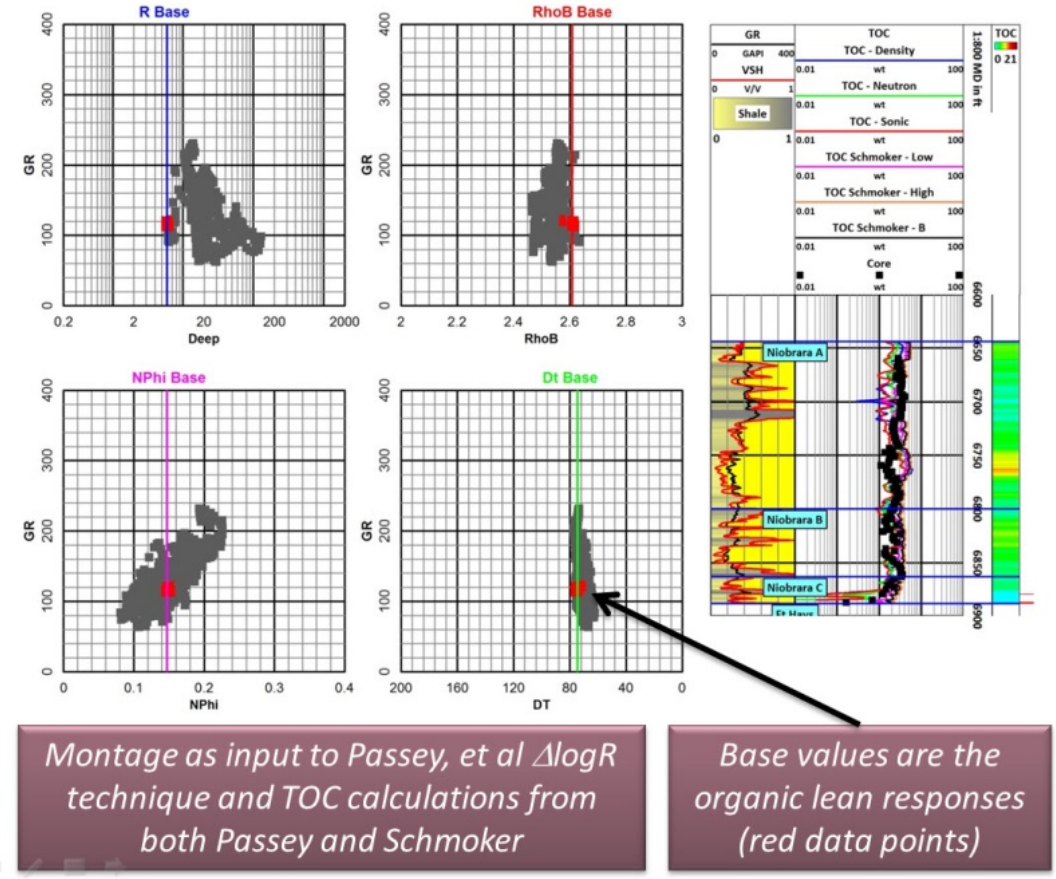

Figure 5: Passey – calibrating for ΔlogR (left) and the output (right) for TOC from the Passey and Schmoker techniques

   b. Schmoker (1989) relates TOC to density response, recognizing TOC has a significantly lower density than most of the other reservoir components.

For both methods it is necessary to convert TOC in weight percent to volume percent. TOC density ranges from about 1.1 g/cc to 1.8 g/cc, and is probably a function of thermal maturity. Choice of the correct density is important since the range is so large.

3. From the standard density/neutron measurements, all non-shale components together (with TOC volume calculations) are subtracted to yield a shale-only density/neutron comparison (Figure 6). This provides an estimate of clay mineral species

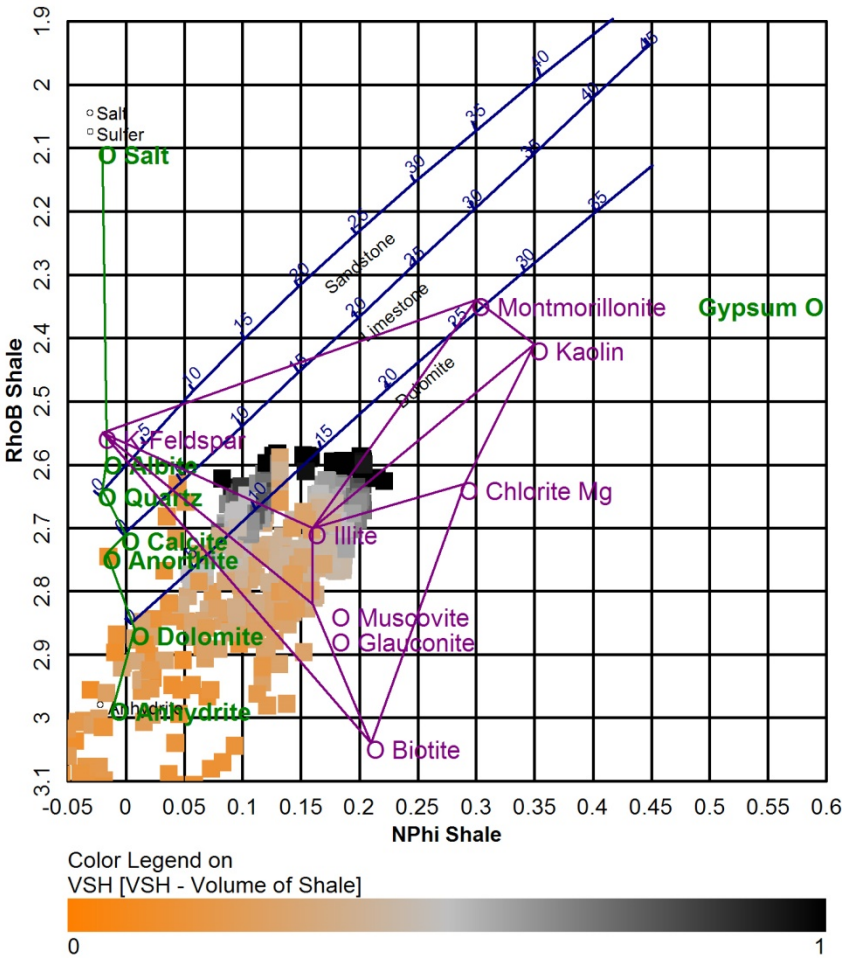

Figure 6: Shale-only density/neutron comparison

The non-shale components are:

Effective porosity (inorganic) – accounting for fluid content
Matrix volume – accounting for rock lithology
Total organic carbon as a volume fraction

All non-shale components are calculated on a 100% rock volume using individual values of shale volume. Clay porosity is calculated as the product of cross plot porosity and V_{SH}.

4. Effective porosity (organic) is calculated by subtracting the other porosity components from total porosity:

$$Organic\ Porosity = Total\ Porosity - Effective\ Porosity - Clay\ Porosity$$

Clearly, effective porosity (organic) is zero or greater. If negative values are calculated it might be a consequence of incorrect estimates of shale volume and TOC volume and/or an incorrect assumption of

TOC weight percent. A depth plot of effective porosity (organic) will help in the interpretation – data cannot fall in the pink shaded region (Figure 7).

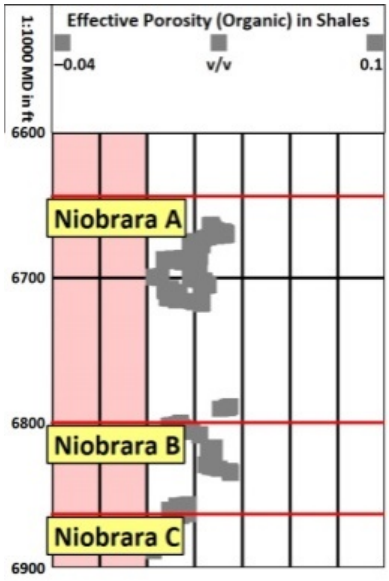

Figure 7: Depth plot of Effective porosity (organic) – negative values are impossible and indicate the need to revisit the effective porosity (organic) calculations

Influence of Reservoir Wetting on Archie Parameters

Archie (1942) presented an empirical equation to determine water saturation:

$$S_W{}^n = \frac{aR_W}{Phi_T^m \times R_t}$$

Where:

S_W	=	water saturation
a	=	empirical factor, usually assumed to be 1.0
R_W	=	water resistivity
R_t	=	formation resistivity
m	=	cementation exponent, a rock property, often assumed to be 2.0
n	=	saturation exponent, a fluid property, often assumed to be equal to m
Phi_T	=	total porosity

As wettability to oil increases, ‘n’ also increases (Keller 1953, Sweeney and Jennings 1960, Ransom 1995).

Graphical interpretation of log porosity vs. log resistivity cross plots (Pickett 1966) can be used to interpret m, n, and R_W. Alignment of data not residing on the 100% S_W line can be used to estimate n. Buckles (1965) derived a relationship between effective porosity (inorganic), Phi_E, and irreducible water saturation, S_{Wi}.

$$Phi_E \times S_{Wi} = constant$$

$Phi_E \times S_{Wi}$ is the bulk volume of irreducible or immobile water.

The magnitude of the constant (mostly between 2% and 10%) is dependent on rock lithology and rock fabric. Holmes (2009) suggested that the Buckles relation is a specific solution to a more general relation:

$$Phi_E{}^{Q} \times S_{Wi} = constant$$

The exponent Q is frequently 1.0 (original Buckles), but can range from about 0.8 to 1.6.

On the Pickett plots, the green lines are chosen as linear data alignments of rocks belonging to a singular value of $Phi_E \times S_{Wi}$. The slope of the alignment is a function of n. If the data show a negative slope then n < m. If positive then n > m. Intersection with the S_W = 100% line is $Phi_E \times S_{Wi}$.

Interpretation of Pickett Plots – Effective Porosity (Inorganic) and Effective Porosity (Organic)

Pickett plots can be constructed for both the clean formation (Figure 8) and shale (Figure 9).

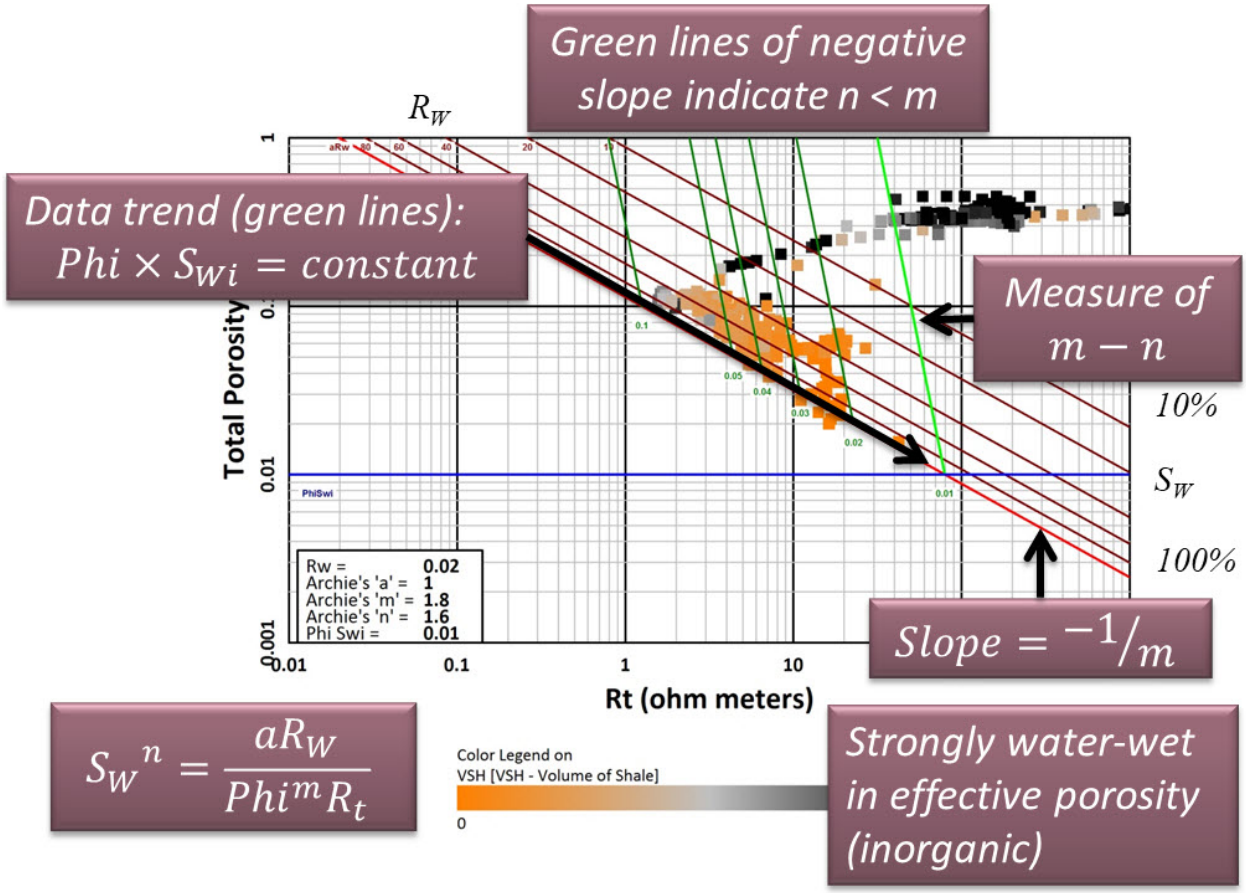

Figure 8: Clean formation Pickett plot using Total Porosity

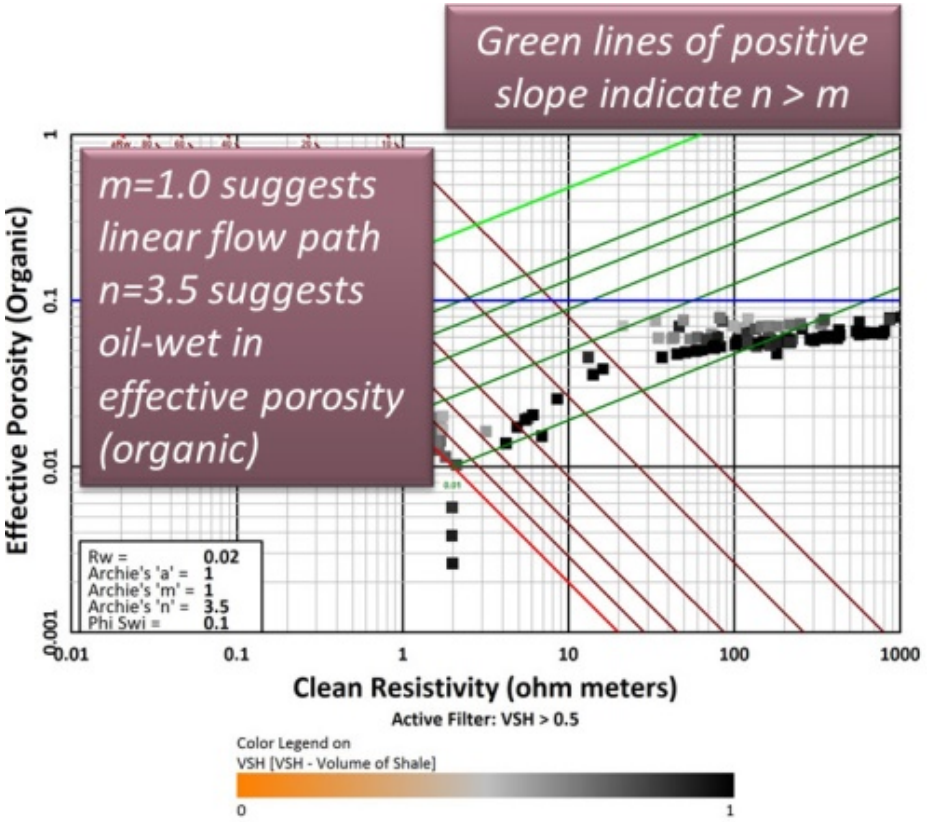

Figure 9: Shale fraction Pickett plot using effective porosity (organic). The data suggests an oil-wet system for the effective porosity (organic) fraction.

The two porosity/resistivity plots are interpreted to involve quite different values of Archie 'm' and 'n'. For the clean formation (orange data), values are consistent with a standard Archie interpretation of a strongly water-wet system (Figure 8). Alignments of data for S_W < 100% indicate a grouping of data that satisfies the Buckles relation with constants ranging from 0.02 to 0.07.

For the shale formation (Figure 9) a comparison of effective porosity (organic) with resistivity show remarkably different trends. The cementation exponent 'm' is very low (1.0) suggesting linear flow path for low effective porosity (organic). The saturation exponent 'n' (3.5) suggests an oil-wet system. The interpretation is that effective porosity (organic) is closely associated with organic content, and might indeed be a consequence of porosity creation caused by thermal maturation. As oil is generated, it is the initial fluid injected into the newly-created porosity, which then becomes oil-wet.

Oil-in-Place – Clean and Shale Fractions

$$\text{Clean Formation Oil-in-Place} = \frac{Net\ h \times Phi_E \times (1 - S_{WE}) \times Drainage\ Area}{Oil\ Formation\ Volume\ Factor}$$

$$\text{Shale Formation Oil-in-Place} = \frac{Net\ h \times Phi_{Organic} \times \left(1 - S_{W\ Organic}\right) \times Drainage\ Area}{Oil\ Formation\ Volume\ Factor}$$

Cutoff values applied:

Value	Clean	Shale
V_{SH}	0 – 50%	50 – 100%
Phi	5% (Phi_E)	2% ($Phi_{Organic}$)
S_W	0 – 50% (S_{WE})	0 – 50% ($S_{W\ Organic}$)

A drainage area of 640 acres was assumed and an oil formation volume factor of 1.3 RB/STB.

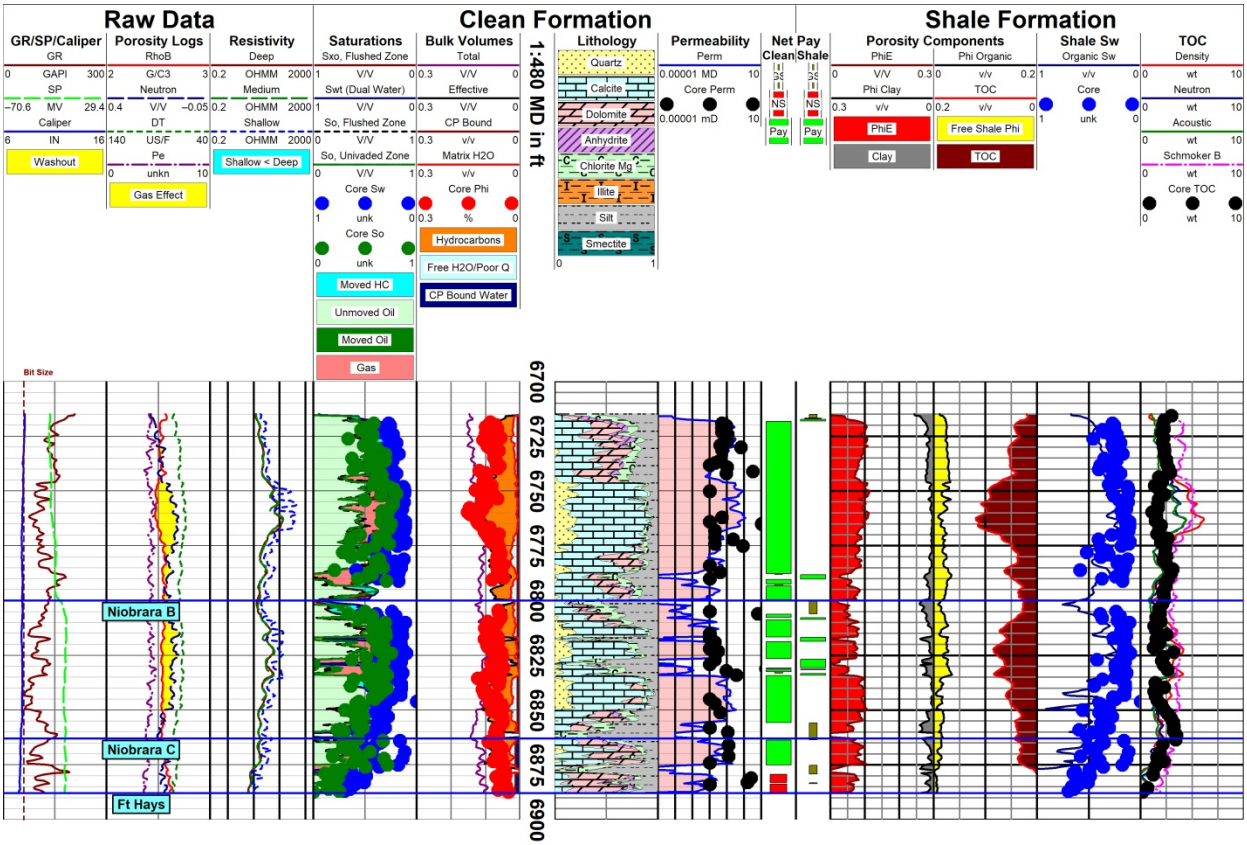

Figure 10: Oil-in-place comparison clean vs. shale formation

Oil-in-place (MMBO)	Clean	Shale	Ratio Clean : Shale
Niobrara A	29,720	1,183	25.1
Niobrara B	9,801	635	15.4
Niobrara C	2,540	0	-
Total	**42,061**	**1,818**	**23.1**

Examples

For each example the following plots are presented:

- TOC montage
- Shale-only density/neutron cross plot
- Effective porosity (organic) verification plot
- Clean formation total porosity vs. resistivity cross plot
- Effective porosity (organic) vs. resistivity cross plot
- Oil-in-Place – Clean and Shale Fractions

Bakken Oil Reservoir, North Dakota

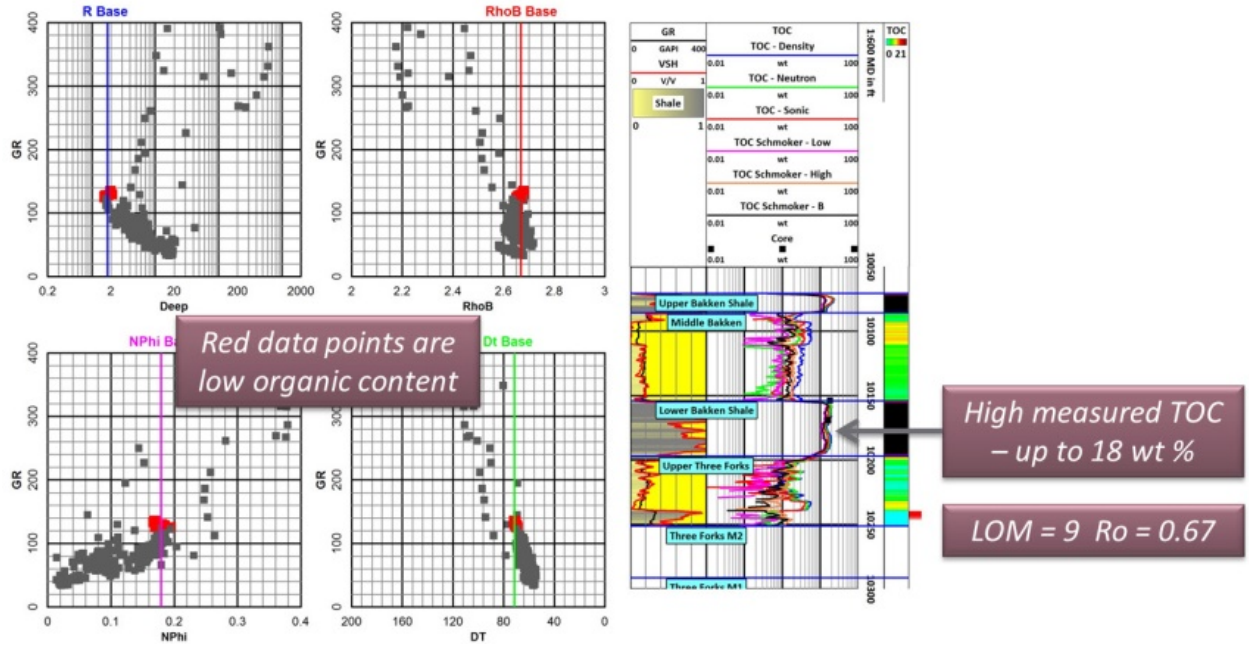

Figure 11: Bakken oil reservoir – TOC montage

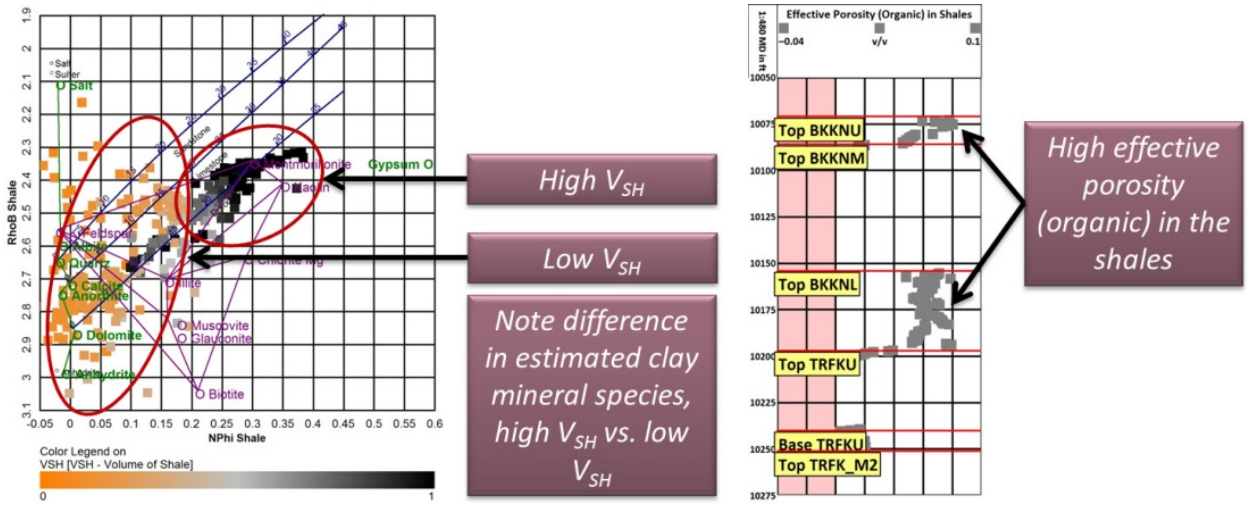

Figure 12: Bakken oil reservoir – shale density/neutron cross plot on the left and effective porosity (organic) verification plot on the right

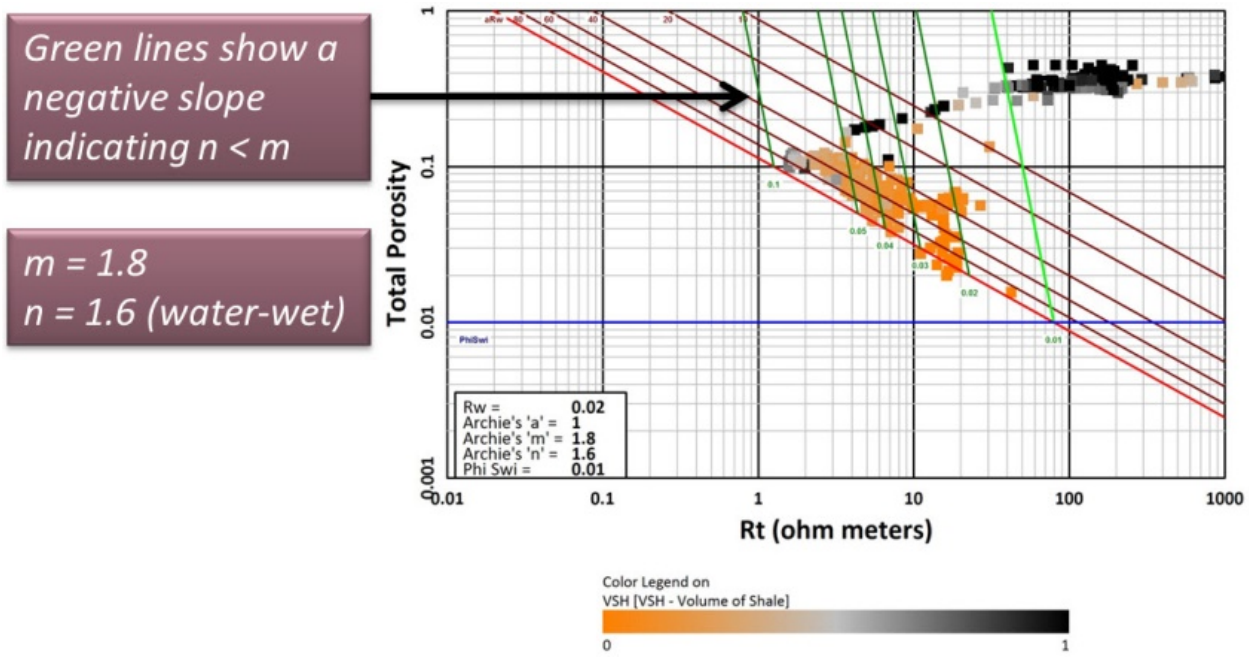

Figure 13: Bakken oil reservoir – clean Pickett plot

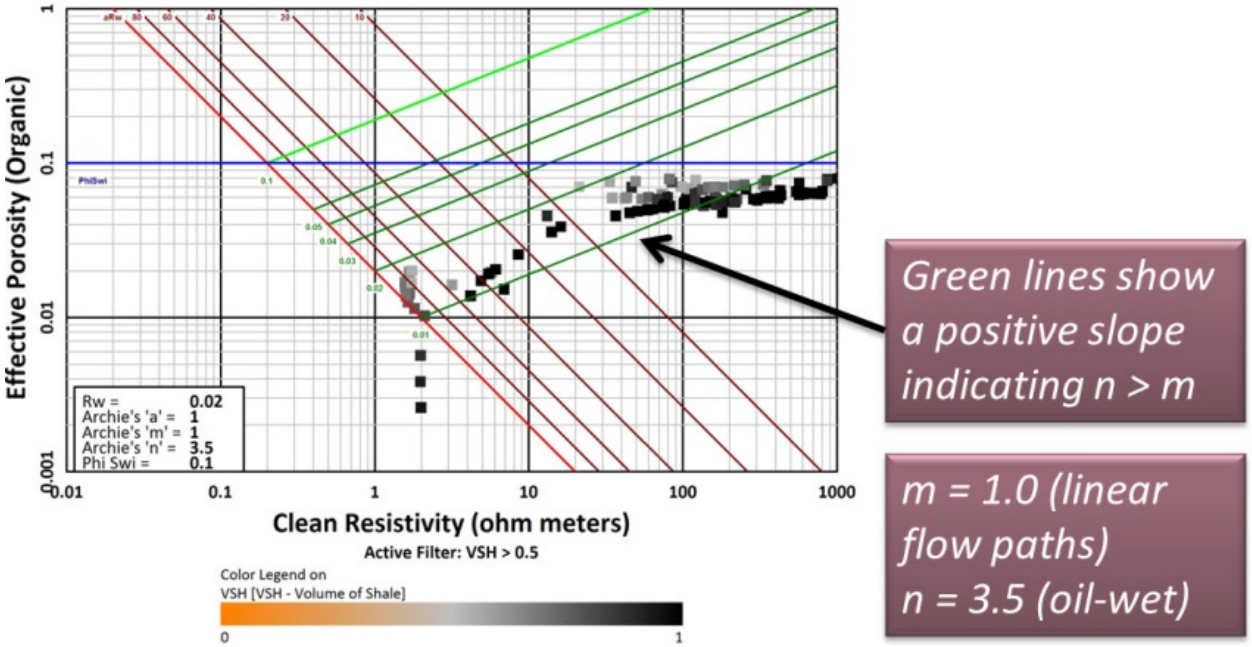

Figure 14: Bakken oil reservoir – shale Pickett plot

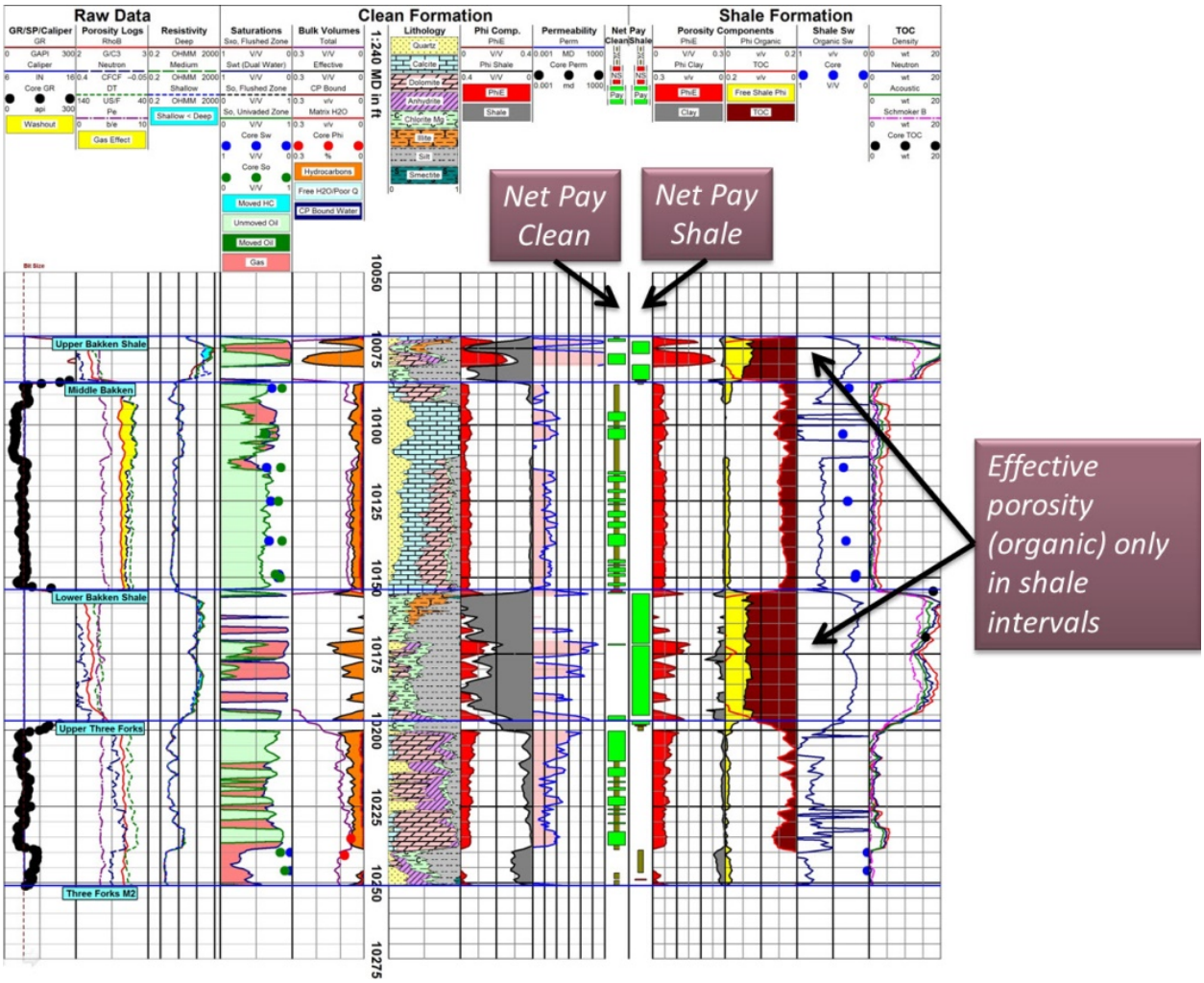

Figure 15: Bakken oil reservoir – oil-in-place comparisons clean vs. shale formation

Note: a thin (4.5 ft.) layer in the Upper Bakken Shale has a significant volume of oil-in-place for values of V_{SH} less than 50%.

Oil-in-place (MMBO)	Clean	Shale	Ratio Clean : Shale
Upper Bakken Shale	3,573	1,593	2.24
Middle Bakken	3,836	0	-
Lower Bakken Shale	1,065	7,366	0.14
Upper Three Forks	4,706	120	39.2
Total	**13,180**	**9,079**	**1.45**

Midland Basin (Wolfcamp) Oil Reservoir, Texas

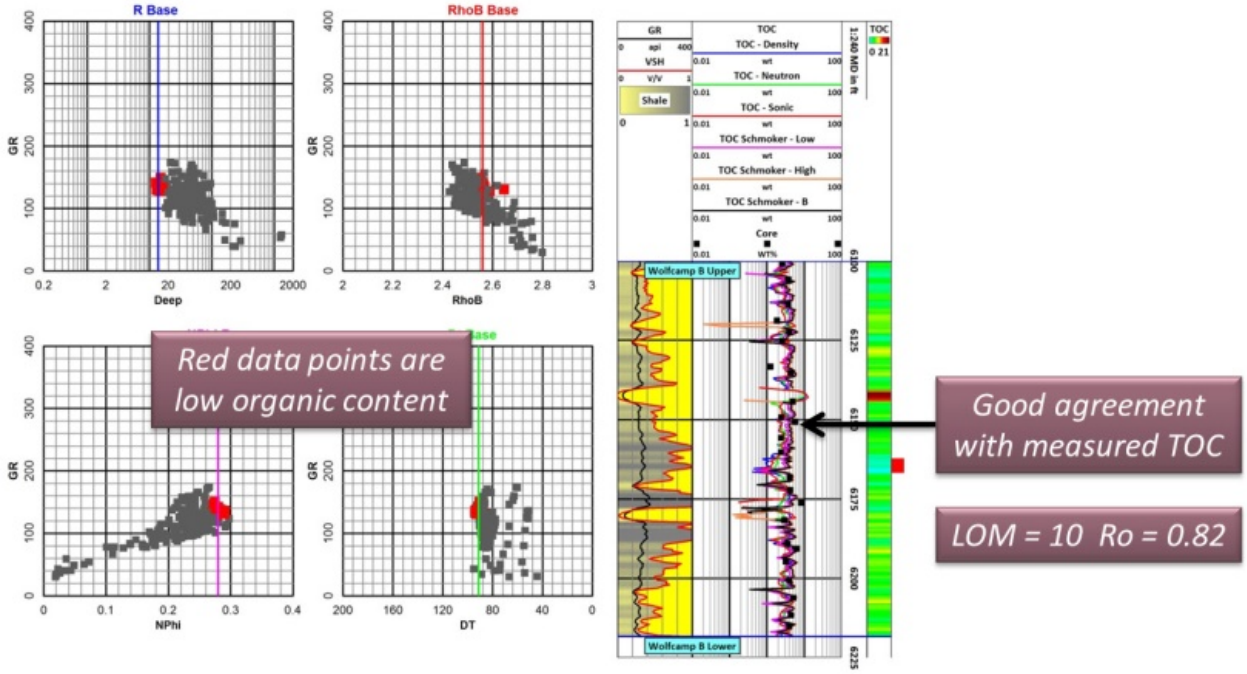

Figure 16: Midland Basin (Wolfcamp) oil reservoir – TOC montage

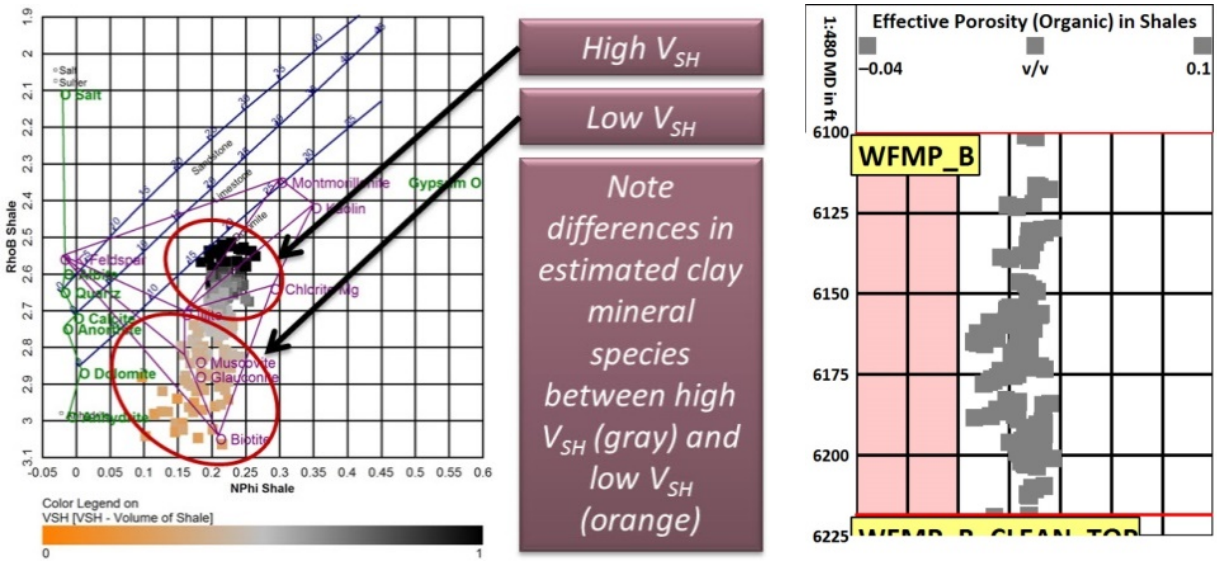

Figure 17: Midland Basin (Wolfcamp) oil reservoir –shale density/neutron cross plot on the left and effective porosity (organic) verification plot on the right

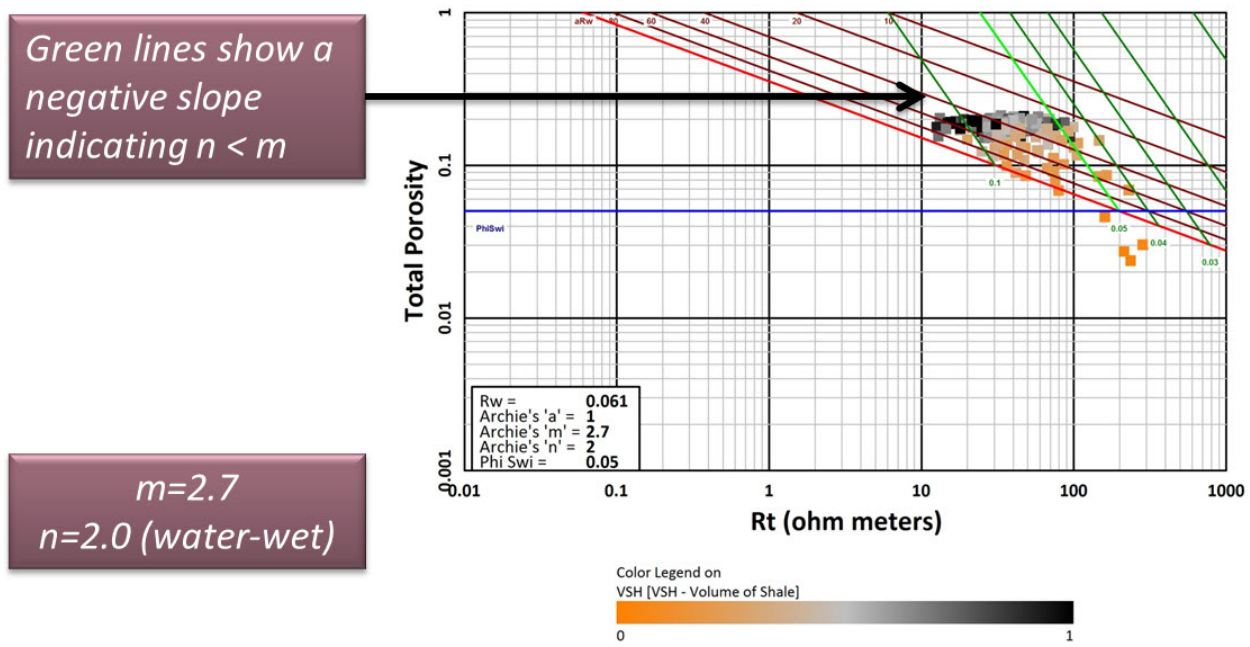

Figure 18: Midland Basin (Wolfcamp) oil reservoir – clean Pickett plot

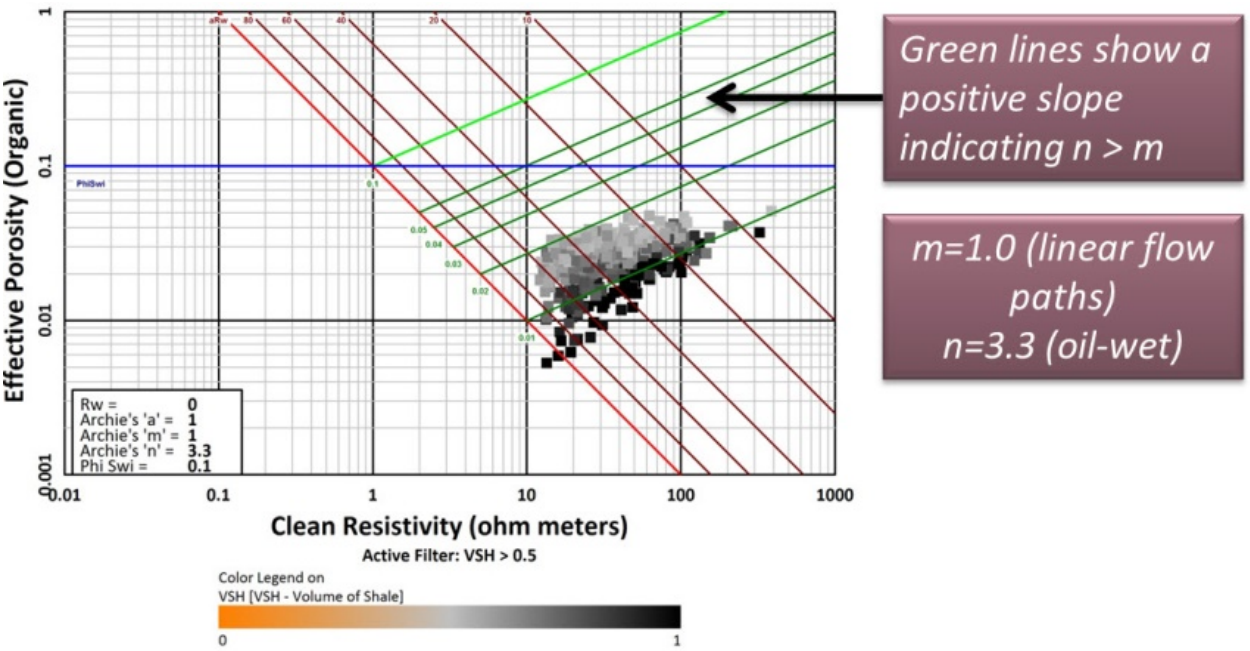

Figure 19: Midland Basin (Wolfcamp) oil reservoir –shale Pickett plot

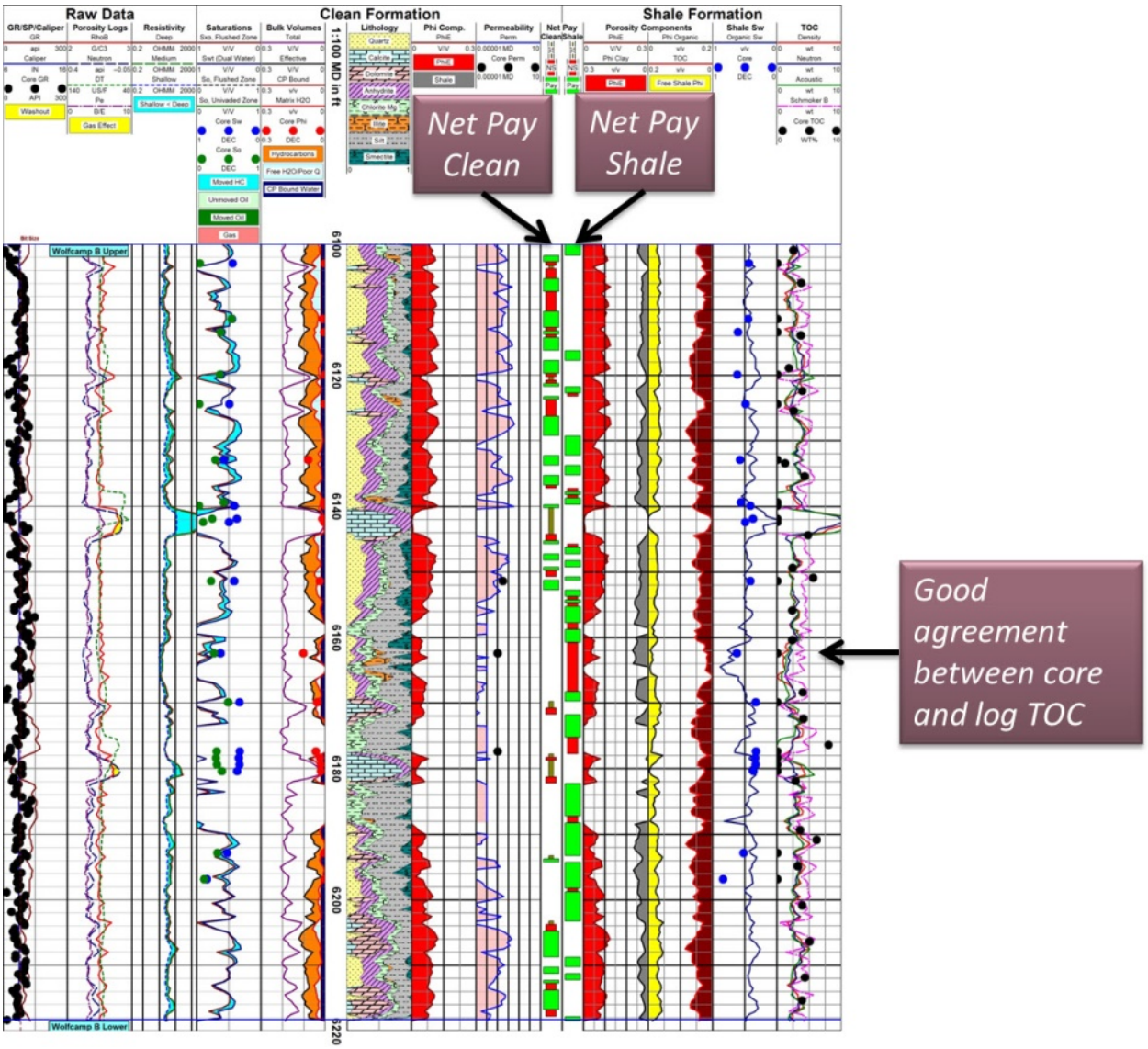

Figure 20: Midland Basin (Wolfcamp) oil reservoir – oil-in-place comparisons clean vs. shale formation

Oil-in-place (MMBO)	Clean	Shale	Ratio Clean : Shale
Wolfcamp B Upper	7,763	18,579	0.29

Conclusions

A technique is presented to estimate differential reservoir wetting in organic rich reservoir systems, using standard open-hole triple-combo logging suites. A minimum combination of GR/density/neutron/resistivity is required. Following a standard shaley formation analysis, data are analyzed to subtract from density and neutron responses the contribution of the non-shale and TOC fractions, level-by-level. For the shale-only porosity log responses, it is then possible to define clay porosity and small volumes of non-TOC shale porosity, here termed effective porosity (organic).

Two sets of porosity/resistivity cross plots are constructed:

1. Standard total porosity vs. resistivity: This is interpreted to define Archie parameters cementation exponent 'm' and saturation exponent 'n'. From the value of 'n' it is possible to determine reservoir wetting. Low values (mostly less than 2) indicate a water-wet system. In the examples presented here, all are water-wet.
2. Effective porosity (organic) vs. clean resistivity: All examples show consistently low values of cementation exponent 'm', suggesting linear flow paths for this porosity segment. They also show higher values of the saturation exponent 'n' (sometimes much higher) than for the clean porosity responses, suggesting an oil-wet condition.

It is proposed that the effective porosity (organic) component is generated during the thermal maturation process, as oil is generated and expelled from the organic material. Consequently, the newly generated pore system will be exposed to oil at inception, and is likely to be oil-wet. The very low values of cementation exponent 'm' would suggest that as the porosity system is forming, it is accompanied by the creation of linear flow paths.

Comparisons of porosity vs. water saturation for the clean formation indicate that for some of the examples the clean formation has significant levels with variable Buckles numbers, suggesting a range of rock types. However, the same comparison for the shale formation suggests the effective porosity (organic) has no mobile water, and mostly a single rock type as reflected in the Buckles number.

For all examples, data are presented showing values of oil-in-place for both the clean and shale formation. The data indicate that there are significant volumes of potentially mobile oil in the shale fraction, not residing in the TOC.
The recognition of effective porosity (organic) is a new term required in the analysis of unconventional reservoirs. Also required is the recognition that the traditional term "effective porosity" refers only to the inorganic porosity development. "Effective porosity (total)" is an additional new term to recognize the sum of the inorganic and organic porosity elements.

As far as we are aware, this is a novel approach and provides quantitative data as to which fraction of the reservoir is water-wet and which is oil-wet. Since it can be applied to any well with a triple-combo logging suite, the methodology has widespread application and should provide a much better understanding of reservoir behavior from an engineering viewpoint. Further refinement is planned by examining a data set with cores to compare log calculations with core analyses directed to measuring pore wettability.

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