

THE USES OF SURFACE AREA DATA OBTAINED ON RESERVOIR CORE SAMPLES

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Abstract

Surface area measurements performed on reservoir core samples can provide important characterisation data. Surface area controls or partially controls permeability, irreducible water saturation and excess conductivity. At this time surface area is rarely measured during routine core analysis, which is perhaps unfortunate given the potential uses of the data.

The main objective of this work is to describe and illustrate the potential uses of surface area data measured during the course of a 2 year project performed to develop a set of methods to extend the interpretive capability of core data. During this work a number of interesting and useful correlations have been found between surface area and other petrophysical parameters. Some of the correlations appear to be generally applicable, whilst others are more tenuous and require further investigation. Previous work is briefly reviewed and the correlations obtained are discussed from a theoretical basis, and illustrated using real data.

Surface area is shown to correlate well with permeability and irreducible water saturation. Surface area data generated from cuttings may allow the geoscientist to obtain permeability/irreducible water saturation data from uncored wells based on formation specific correlations. The relationship between surface area and cation exchange capacity allows surface area data to be used as a core based shaliness parameter, particularly when measured CEC data is available to calculate surface charge density. A limited data set also appears to show a useful and theoretically justifiable relationship between surface area and the clean sand (shale corrected) 'm' cementation exponent. These relationships are illustrated using our own and previously published data.

Surface area data has also been shown (in previous work) to correlate with the NMR decay constant T_1 . In addition, surface area data may be useful for assessing Klinkenberg effects, and enhancing the understanding of 'flow units'.

Introduction

Over the last two years we have measured surface area data using a polar molecule adsorption technique on cores from a number of Australasian oil and gas reservoirs. The main objective in performing these measurements was to obtain a core based shaliness parameter. However, during the course of this work it became apparent that surface area data (particularly when expressed in units of area per unit pore volume, ie m^2/cm^3) provided

additional useful information. The importance of this simple parameter has largely been ignored by the core analysis business, to the extent that surface area is rarely measured in routine core studies. The comments of Pollard and Reichertz (1952) are still relevant in 1998. *“It is somewhat surprising that the investigation of the specific surface of reservoir rocks, either for the above purpose, (calculating permeability using the equation of Carmen) or for other uses, has not received more attention by the petroleum industry. It is to be expected that the specific surface of reservoir rock affects or controls many of the properties which the petroleum geologist and engineer are concerned with in respect to the recovery of oil.”*

Permeability Versus Surface Area

The main rock property controlling permeability is pore-throat size distribution, so it is perhaps difficult to fathom why permeability and surface area often appear to correlate well on a reservoir by reservoir basis (**Figure 1**). The correlation would appear to be due to two main factors, (1) as grain size decreases permeability decreases and surface area increases, and (2) diagenesis acts to decrease permeability and increase surface area in a systematic fashion within a particular facies. The factor relating to diagenesis follows the reasoning of Nelson (1994) who explains porosity versus log permeability trends as follows. *“As rocks from a common source are compacted and undergo diagenesis, pore space is reduced and permeable pathways are progressively occluded in a systematic way that maintains a consistent relationship between f and R .”* Adding to this statement we may say that “diagenesis systematically increases surface area and reduces permeability”.

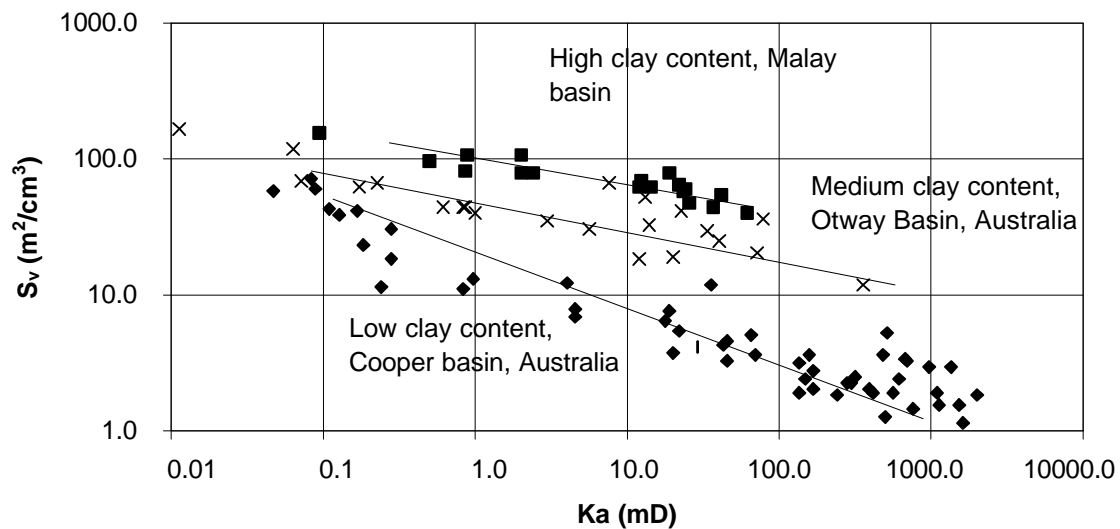


Figure 1: Surface area per unit pore volume versus air permeability for three sandstone reservoirs with varying clay contents.

It is important to stress that no universal correlation exists between permeability and surface area, eg **Figure 1** shows that three 100 mD sandstones from different reservoirs may have orders of magnitude variation in their surface areas.

Irreducible Water Versus Surface Area

The relationship between surface area and irreducible water saturation has been commented on by a number of authors including Zemanek (1989) and Ransom (1984). Zemanek reported an excellent correlation ($R^2 = 0.975$) between irreducible water saturation (obtained at 50 psi air/brine capillary pressure) and surface area. We use the term 'irreducible' with due recognition to the fact that it is a useful concept rather than a valid term. That is, irreducible water signifies that the capillary pressure curve has become asymptotic so that only relatively small changes in water saturation occur as capillary pressure is increased. **Figure 2** supports the close relationship between 'irreducible' water and surface area. In addition **Figure 2** shows the tendency for low surface area samples to approach a minimum S_w and for high surface area samples to remain fully saturated.

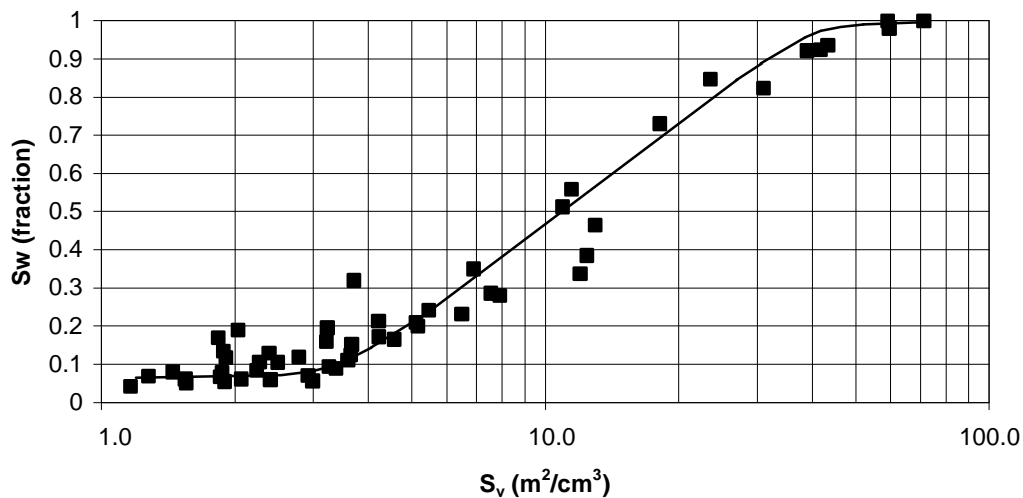


Figure 2: Surface area per unit pore volume versus water saturation obtained at 50 psi air /brine porous plate capillary pressure, from a Cooper Basin (Australian) reservoir.

From this and previous work we may postulate that the primary drainage capillary pressure curve is made up of two parts, irreducible (immobile) water which is surface area controlled, but may be decreased (layer thinning) by the application of higher capillary pressures, and mobile water that is pore throat size distribution controlled. Hall *et al.* (1983) calculated that the pore water saturation (immobile) present in the Athabasca tar sands equated to a 15 nm thick film of water. **Figure 3** shows a cross plot of theoretical (assuming 15 nm coverage) versus measured 'irreducible' water saturation. Examination of the data trend in **Figure 3** (solid line) compared with equality line (dashed) indicates a reasonable correlation. It should be noted this simple calculation combines layer water and pendular water. Hall *et al.* (1983) estimated the true layer thickness to be approximately 6

nm with the remaining water present as pendular water. A method of estimating the pendular water has been presented by Melrose (1987), and it is probable that improved predictions of ‘irreducible’ saturation may be obtained by properly combining the adsorbed layer water saturation with the pendular water saturation, rather than using the simple assumption of an increased layer thickness to account for pendular water.

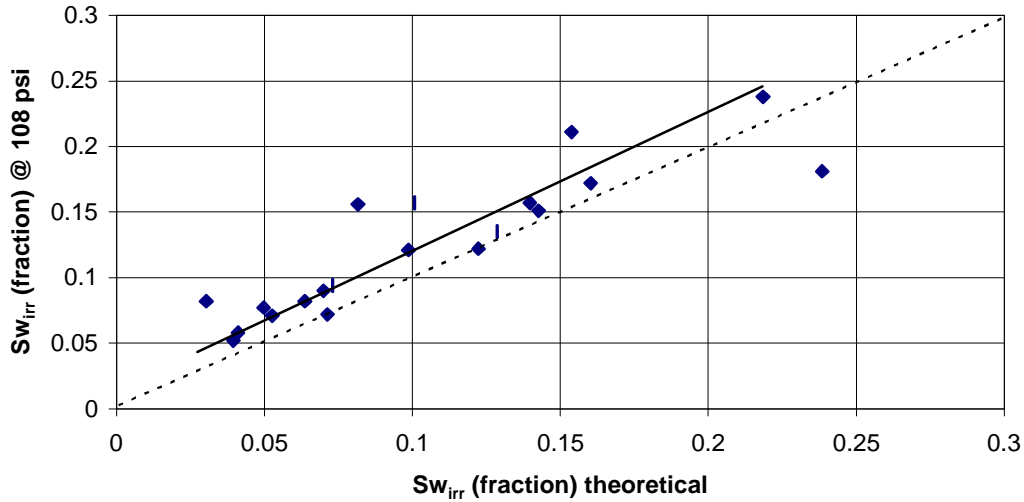


Figure 3: A crossplot of water saturation calculated from surface area, (assuming a 15 nm coverage) against water saturation measured at 108 psi air-brine capillary pressure for a set of samples from a Bonaparte basin (Australian) reservoir.

Cation Exchange Capacity Versus Surface Area

The relationship between specific surface area and cation exchange capacity (CEC) has long been noted in the soil sciences and by a number of workers in the petroleum sector. Patchett (1975) showed that CEC and surface area were linearly related, which presupposes that surface charge density is approximately constant for all clays, a theory that Clavier, Coates and Dumanoir (1977) used to support their dual water model. Assuming constant surface charge density may be an over simplification, since there is evidence that surface charge density will depend on mineralogy Newman (1987) and equilibrating brine properties, Bolt (1957) and Revil and Glover (1997). The fundamental equation relating Q_v the CEC (or charge) per unit pore volume to surface area and surface charge density is:

$$Q_v = S_v \frac{\sigma}{96.5} \quad (1)$$

Where:

- σ = surface charge density (C/m²)
- Q_v = cation exchange capacity per unit pore volume (meq/cm³)
- S_v = Surface Area per unit pore volume (m²/cm³)
- 96.5 = Conversion factor from coulombs to milliequivalents

By cross plotting Q_v against surface area the linear relationship between Q_v and surface area can be supported and the surface charge density calculated for the formation under investigation. **Figure 5** is a crossplot of surface area and Q_v for two sets of samples. Set 1 from a Cooper Basin reservoir (Central Australia), with Q_v calculated from CEC data obtained using the ammonium chloride technique on uncrushed samples, and derived from Co-Cw data using the Waxman Smits model. The set 2 data is from a Malay basin reservoir with Q_v again calculated from CEC data. The surface charge density of these formations may be calculated as 0.30 C/m^2 and 0.34 C/m^2 respectively.

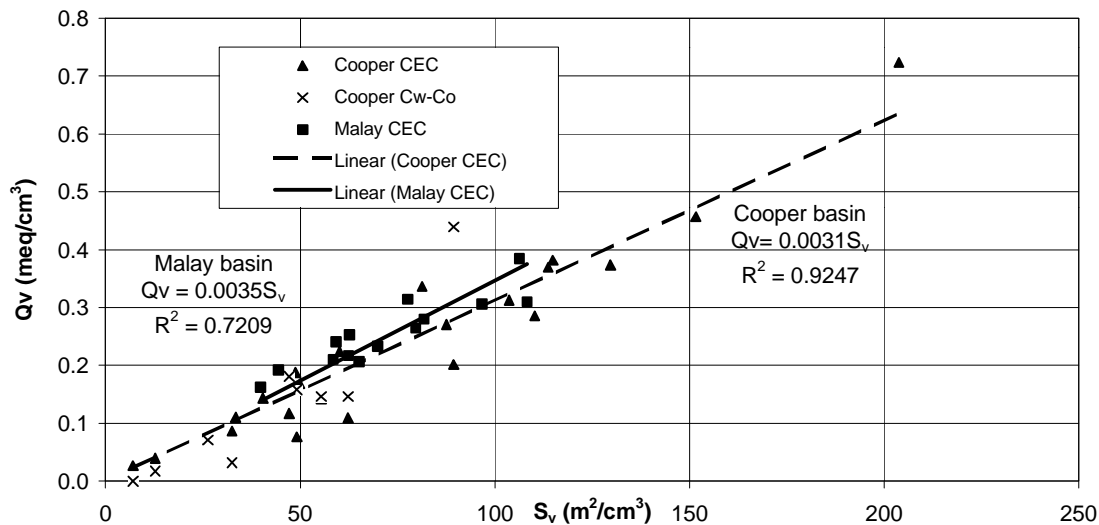


Figure 5: Q_v versus surface area, Cooper basin and Malay basin.

By virtue of the direct relationship between surface area and Q_v we may say that surface area data is a readily available source of excess conductivity information, and that surface area is perhaps the optimum (and most readily available) core analysis based V shale indicator. A further consequence of this relationship is that high surface area formations irrespective of the source of that surface area, ie whether clay or non-clay, will contribute excess conductivity. This statement is supported by the work of Evers and Iyer (1975) who confirmed the presence and importance of surface conductivity in clean sands from fresh water aquifers. Diederix (1982) noted that rough glass beads produced decreasing ‘n’ saturation exponent with decreasing water saturation illustrating interface conductivity, associated with a non-clay mineral.

Following the approach of Worthington (1995), we may use surface area data to define whether a formation should be classified as Archie or non-Archie. Q_v can be determined using **Equation 1**, then excess conductivity (C_x) calculated using an appropriate shaly-sand model. For example, using the Waxman Smits model we may calculate the excess conductivity (C_x) as BQ_v/F^* where B is the equivalent cation conductance, and F^* the clean sand formation factor (obtained from the relationship $F^* = 1/\phi^{m^*}$). Once values of C_x have been obtained they may be compared to calculated values of C_o^* , (again using the

relationship $F^* = 1/\phi^{m^*}$ and C_w) then, if $C_x > 0.1C_o^*$ a shaly sand model is applicable. This approach may of course be used if traditionally measured Q_v data is available; however the relative rapidity and sampling frequency attainable with surface area measurement techniques means that this data may be obtained relatively early in the formation evaluation cycle.

Many log based shaly sand models rely on an estimate of V_{shale} to determine excess conductivity. The reliability of other V_{shale} estimators (whether log or core based) may be assessed by comparison with surface area data. **Figure 6** shows a crossplot of surface area (per unit weight) versus API gamma (total and potassium response only). The gamma data were measured on shielded 3.8 cm diameter plug samples with long count times (up to 90 minutes). For this formation we can say that the gamma response provides a good estimate of surface area (hence Q_v and hence excess conductivity) particularly when the contributions of uranium and thorium to the total gamma are removed.

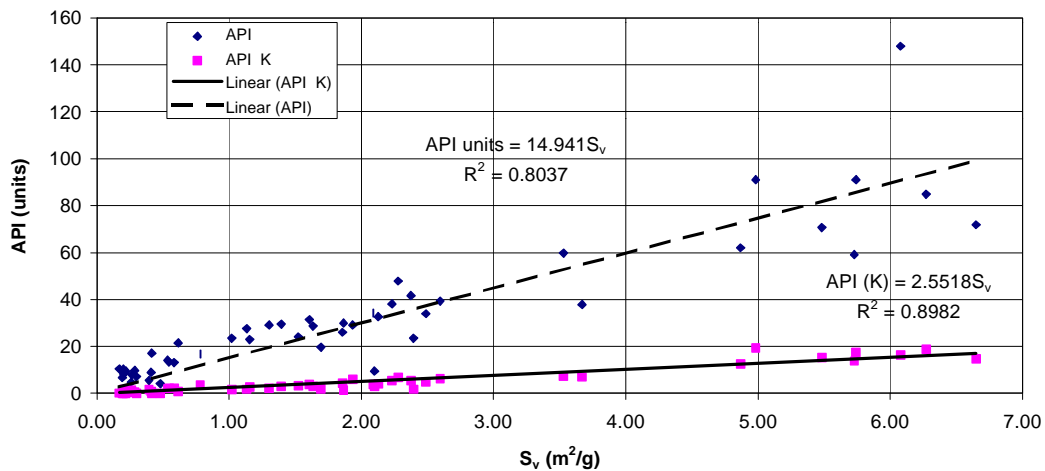


Figure 6: Surface area per unit weight versus API total and API potassium response only, from a Bonaparte basin well.

From theoretical studies and measured data it is apparent that the excess conductivity (over and above Archie conductivity) is intimately associated with surface area, where that excess conductivity is due to interface conductivity. The excess conductivity associated with minerals such as pyrite (matrix conductivity) cannot be classified as interface conductivity and cannot be assessed by surface area measurements.

Formation Factor Versus Surface Area

Ransom (1984) commented on the relationship between the m cementation exponent and surface area as follows, “ m is minimised when grain surface area to grain volume ratio is minimised (for each value of grain radius)”, ie the greater the degree of roughness the higher the m^* . **Figure 7** shows a plot of m^* versus surface area per unit pore volume.

m^* data was obtained from multi-salinity measurements on 9 samples from a Cooper Basin (central Australia) reservoir and calculated using the Waxman and Smits (1968) model.

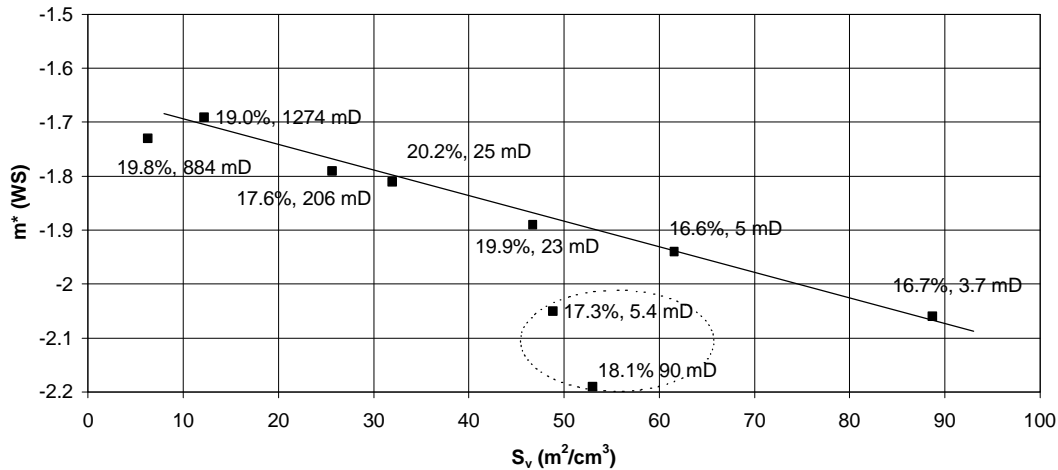


Figure 7: Clean sand cementation exponent vs surface area, from a Cooper basin well.

From this data it is apparent that as surface area per unit volume increases m^* increases, this may be expected given that m is related to tortuosity and as surface area increases then tortuosity will increase. Also apparent is the trend between electrical tortuosity (m^*) and flow tortuosity (K). The relationship obtained with these samples needs confirmation; however at this time we may say that a relationship appears to exist between surface area and the clean sand cementation exponent, ie m^* . If this proves to be a general relationship then m^* data at regular sampling intervals may be extrapolated from surface area data across reservoir intervals leading to improved water saturation estimates.

NMR Response Versus Surface Area

Our studies did not include NMR measurements; however for the sake of completeness some referral to the correlations obtained between surface area and NMR data is warranted, since NMR measurements are increasingly used to evaluate immobile and free fluid saturations and pore size distribution. Based on measurements of 100 sandstone cores Sen *et al.* (1990) obtained the correlations shown in **Figure 8** between pore volume to surface area ratio (V_p/S_v), permeability to fluid flow K , cation exchange capacity per unit pore volume Q_v , and the proton NMR decay constant T_1 , in water saturated rocks.

Coates *et al.* (1998) recently developed a new estimator (SBV1) from the T_2 spectrum, which represents the partition between free and bound water. Quoting from Coates *et al.* “*This representation is based on the concept that water wet pores contain a layer of irreducible water on their surfaces*”. This explanation may also be used to explain the correlation between surface area and ‘immobile’ water saturation discussed earlier, and by association the correlation between T_2 and surface area is highlighted.

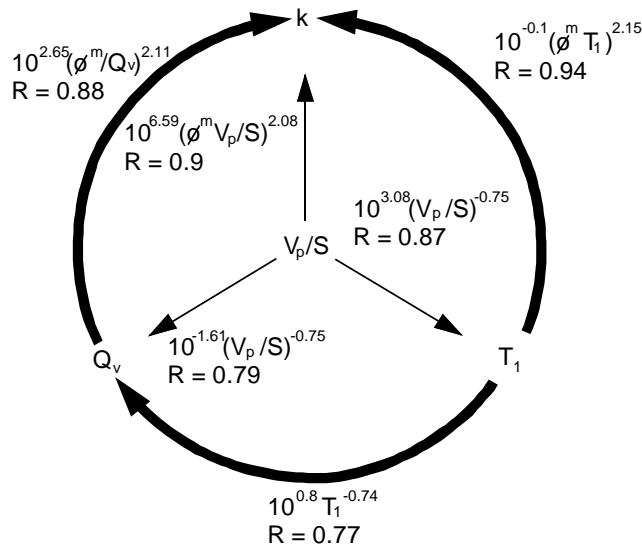


Figure 8: The inverse of surface area to pore volume ratio versus permeability, T_1 and Q_v , from Sen *et al.* (1990).

Characterisation Of Hydraulic Flow Units

A number of theoretical relationships for calculating permeability exist in the literature; most of these owe their derivation at least in part to the Kozeny Carman equation, Carman (1956). An integral part of this equation is the mean hydraulic radius, defined as the pore volume divided by the pore surface area, ie the inverse of surface area per unit pore volume. With surface area data it is possible to calculate the Kozeny Constant (the product of the shape factor and fluid flow tortuosity). The availability of surface area data also clarifies the definition of Hydraulic (flow) units as defined by Amaefule *et al.* (1988), since surface area per unit grain volume, tortuosity and shape factor are lumped as one in the FZI parameter.

Evaluation Of Klinkenberg Permeability

There is a requirement when using permeability data to define a non-reactive base permeability, which is usually considered to be the Klinkenberg permeability (equivalent liquid permeability). Most routine permeability data is acquired using gas at a single mean pressure because of the additional expense and time needed to obtain Klinkenberg data. Gas permeability always exceeds Klinkenberg permeability because of the phenomena of gas slippage, which is related to the mean free path of gas molecules and the number of gas molecule/surface collisions that occur. It seems logical? that the number of gas molecule/wall collisions would depend on the surface area.

If this is indeed the case (we have not verified this experimentally) then we can say that the ratio of measured gas permeability to the Klinkenberg permeability depends on, (1) the

mean free path of the gas, which is a function of pressure, temperature, relative molecular mass and viscosity (2) the pore and throat size distribution, ie permeability, and (3) the internal surface area. This leads to the possibility of calculating Klinkenberg permeability from a gas permeability measurement with knowledge of the permeability, the surface area and the mean pressure (perhaps removing the need to perform multi flow pressure gas permeability measurements). Indeed it is apparent that methods exist for determining surface area from multi-pressure permeability measurements, Igwe (1985).

Uses Of Surface Area Data

The relationship between surface area and permeability/irreducible water may be used for predicting permeability/irreducible water from cuttings in uncored wells if representative cuttings can be obtained and formation specific correlations are available.

A universally applicable correlation may exist between surface area and irreducible water for water-wet systems. Recognition of this relationship may lead to a better understanding of water saturation distribution in real reservoir systems where physical and chemical changes may lead to situations where the water saturation distribution does not mirror that obtained in the simple laboratory system.

Surface area data can be used to predict excess conductivity, allowing the geoscientist to determine early in the life of the reservoir whether a shaly-sand model is applicable and cross check other shaliness indicators. Surface area data may prove useful for predicting Klinkenberg permeability and reservoir flow unit distribution.

Conclusions

The internal surface area of reservoir rocks may be considered as a fundamental petrophysical property that should be measured on a regular basis in hydrocarbon reservoir sections to promote understanding of other core and log measured attributes.

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