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A Review of Reservoir Rock Typing Methods in Carbonate Reservoirs: Relation between Geological, Seismic, and Reservoir Rock Types

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Abstract

Carbonate reservoirs rock typing plays a pivotal role in the construction of reservoir static models and volumetric calculations. The procedure for rock type determination starts with the determination of depositional and diagenetic rock types through petrographic studies of the thin sections prepared from core plugs and cuttings. In the second step of rock typing study, electrofacies are determined based on the classification of well log responses using an appropriate clustering algorithm. The well logs used for electrofacies determination include porosity logs (NPHI, DT, and RHOB), lithodensity log (PEF), and gamma ray log. The third step deals with flow unit determination and pore size distribution analysis. To this end, flow zone indicator (FZI) is calculated from available core analysis data. Through the application of appropriate cutoffs to FZI values, reservoir rock types are classified for the studying interval. In the last step, representative capillary pressure and relative permeability curves are assigned to the reservoir rock types (RRT) based upon a detailed analysis of available laboratory data. Through the analysis of drill stem test (DST) and GDT (gas down to) and ODT (oil down to) data, necessary adjustments are made on the generated PC curves so that they are representative of reservoir conditions. Via the estimation of permeability by using a suitable method, RRT log is generated throughout the logged interval. Finally, by making a link between RRT's and an appropriate set of seismic attributes, a cube of reservoir rock types is generated in time or depth domain. The current paper reviews different reservoir rock typing approaches from geology to seismic and dynamic and proposes an integrated rock typing workflow for worldwide carbonate reservoirs.

Keywords: Hydraulic Flow Units (HFU), Petrophysical Rock Types (PRT), Seismic Facies, Reservoir Rock Types (RRT), Carbonate Reservoirs

1. Introduction

Reservoir rock typing is an important step in any reservoir characterization and modeling study. There are different sources of subsurface data for rock typing. By definition, a rock type is defined as a set of properties several rocks have in common. The rock type attributes can be sedimentary (such as lithology, fossil content, sedimentary textures, diagenesis, or in general microfacies), petrophysical (electrical logs), or reservoir parameters (porosity, permeability, and capillary pressure). Generally, it can be stated that any meaningful classification of reservoir rocks, which differentiates and describes them based on special characteristics of the reservoir, can be attributed to rock typing. Such

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characteristics could be related to sedimentary attitudes (sedimentary rock typing), petrophysical well logs (electrofacies), and pore system properties (flow unit), and they can be extended to seismic data (seismic facies), geomechanical parameters, and reservoir dynamic data. In fact, rock typing technique can effectively be used for unraveling the reservoir heterogeneity, for describing the reservoir zones, and for the interpretation of fluid flow within the reservoir. Therefore, it makes a good connection between the static properties and the dynamic behavior of reservoirs.

Actually, reservoir rock typing has as an important impact on hydrocarbon in place calculation. Each rock type is characterized by a representative capillary pressure and relative permeability curve. In other words, a saturation height function is to be assigned to each reservoir rock type. The saturation height function is of prime importance in water saturation modeling in the transition zone. Accordingly, the height function aids in acquiring a much more reliable water saturation model. Water saturation is an important parameter in oil in place calculation, and that is why reservoir rock typing is a fundamental issue in any reservoir development plan. To date, many researchers have applied different methods to reservoir rock typing. They can be identified based on the microscopic study of thin sections, well logs classification (electrofacies analysis), or reservoir data such as porosity, permeability, and capillary pressure.

The important issue is that rock types are defined and characterized based on core data, but, due to time and budget considerations, only limited wells and intervals are cored. However, a reservoir modeler needs a continuous log of rock types throughout the reservoir interval in all wells. For this reason, the import weight of rock typing relies on well log data which are available in all drilled wells even horizontal wells. That is, rock types are defined based on core data, but they are predicted and propagated from well logs for uncored intervals. In this regard, estimation methods such as statistical and intelligent techniques are of important use to make quantitative relations between well logs and rock types or their associated parameters. For example, permeability is an important input for reservoir rock typing, and it is required to be estimated from well logs. To date, many researchers have tried to create quantitative relations between rock properties derived from core data and well logs (Kadkhodaie et al., 2006; Rezaee et al., 2006 & 2007; Kadkhodaie et al., 2010 & 2014; Rebelle, 2014; Karimian-Torghabeh et al., 2014; Ranjbar-Karami et al., 2014; Golsanami et al., 2015; Chandra et al., 2015; Gharechelou et al., 2016; Shirmohammadi et al., 2017; Sfidari et al., 2014 & 2018).

In the current paper, different reservoir rock typing approaches are reviewed, and finally an integrated method employing data from different sources, including sedimentology, petrophysical logs, and routine and special core analyses data is proposed.

2. Rock typing: concepts and methods

Rock typing in hydrocarbon bearing strata, especially carbonate reservoirs, has always been a challenging issue since there in no universal approach to reservoir rock typing, and data limitation in each hydrocarbon field imposes difficulties in applying the standard methods. It is evident that the most efficient approach is using an integration of cores, well logs, RCAL (routine core analysis), and SCAL (special core analysis) data so that they can best represent the storage capacity (porosity) and fluid flow capacity (permeability) of a reservoir. Another important issue is to determine how many rock types can be defined for a hydrocarbon reservoir. Actually, the number of the rock types is controlled by the complexity degree of every reservoir since few rock types cannot address the heterogeneity of the reservoir, and having too many rock types makes it difficult to predict and model them in subsequent steps. Usually, sedimentologists define too many microfacies based on the petrographic studies of thin sections (say 20 or more microfacies) especially for the carbonate reservoirs, while dynamic data always show that flow properties are not controlled by such a large number of rock types. In fact, sedimentologists examine the details of what they see under microscope and derive many attributes for defining microfacies or petrofacies. For example, a fossiliferous mudstone and a non-fossiliferous mudstone are two different microfacies, while they may have near zero porosity and permeability (non-reservoir facies). That is, from the standpoint of porosity and permeability, they fall into the same group of rock types, but from the sedimentological and paleontological aspect, they are classified into two different rocks. As another example, we may consider grainstone and mudstone, which are two different facies. However, due to the impact of the diagenetic processes, grainstone can be cemented, and its porosity and permeability are reduced; thus, it falls in the range of a non-reservoir mudstone. Alternatively, as a result of fracturing and dissolution, the porosity and permeability of a non-reservoir mudstone can be enhanced to the level of a porous and permeable grainstone. That is why we need to merge microfacies with similar depositional settings and diagenetic behavior so that we reach a reasonable number of rock types controlling storage capacity and fluid flow. In this regard, analyzing thin sections, petrophysical logs, RCAL, and SCAL data together along with the other reservoir information (such as formation tests) will aid with the identification of flow units in formation.

3. Rock typing approaches

3.1. Depositional rock types

Depositional rock types are in relation to sedimentary environment and primary porosity and permeability. They are defined irrespective of diagenetic impacts on carbonate or clastic rocks.

a. Facies (microfacies and petrofacies)

Facies is a general term used to classify rocks which have some properties in common based on core description and under the microscope such as mineralogy, texture, fossil content, and depositional environment. Normally, the term facies is referred to as microfacies when we deal with carbonate rocks, and it is called petrofacies when we study clastic rocks (e.g. sandstone).

There are several classification schemes for facies. Normally, Folks's (1980) and Pettijohn's (1987) classification is used to group petrofacies. There are many classification approaches to carbonate rocks such as Dunham (1962), Buxton and Pedley (1989), Wilson (1975), and Flugel (1982 & 2004). Among them, Dunham's classification is popular in petroleum industry as he was a petroleum geologist and his classification was simple and applied. Dunham's classification is a way of describing the composition of calcareous rocks in hand specimens. Both microfacies and petrofacies could be considered as sedimentary rock types. Sedimentary rock types (SRT) are classified into primary (depositional) and secondary (diagenetic) rock types.

b. Facies association

A group or bin of sedimentary facies used to define a particular sedimentary environment is called facies association. For example, all the facies found in a mid-ramp environment may be grouped together to define a shoal facies association. A sedimentary or depositional environment describes the combination of physical, chemical, and biological processes associated with the deposition of a particular type of sediment and consequently the rock types that will be formed after lithification if the sediment is preserved in the rock record. In most cases, the environments associated with particular rock types or associations of rock types can be matched to existing analogues. However, the further back in geological time sediments were deposited, the more likely that direct modern analogues are not available.

3.2. Diagenetic rock types

Diagenetic rock types are in relation to the classification of rocks based upon processes happening after the sedimentation of rocks. The main diagenetic processes include bioturbation, compaction, dissolution, dolomitization, micritization, neomorphism, carbonate and anhydrite cementation, and pore filling. Some researchers (Cai-neng et al., 2008) use diagenetic facies to describe and classify the reservoir rocks based on their diagenetic features.

3.3. Petrophysical rock types

An electrofacies is a set of log responses which characterize rock types and permit it to be distinguished from other (Serra, 1984). The concept of "electrofacies" was a particularly useful contribution by Serra and has widely been adopted as a bridge to connect logging measurements with the classical facies approach of sedimentary geology. Electrofacies can be defined manually through looking at log shapes or using cluster analysis methods, and they are then identified by localized clouds of points. However, the intelligent analyst intervenes at this stage to ensure that the final clusters have interpretable geological meaning based on core observations or geological insight.

3.4. Hydraulic flow units

Hydraulic flow units (HFU's) are defined as correlatable and mappable zones within a reservoir which control fluid flow. This concept is strongly related to flow zone indicators (FZI) which are unique parameters characterizing each hydraulic flow unit. The relation between reservoir quality index (RQI), FZI, and void ratio (ϕ_z : the ratio of pore volume to solid volume) is given by (Amaefule et al., 1993):

$$Log\ RQI = Log\ FZI + Log\varphi_z \tag{1}$$

$$\varphi_z = \frac{\varphi}{1-\varphi} \tag{2}$$

RQI and *FZI* can be calculated using the following equations:

$$RQI = 0.0314\sqrt{\frac{K}{\varphi}} \tag{3}$$

$$FZI = \frac{RQI}{\varphi_z} \tag{4}$$

where, k is permeability in mD, and ϕ represents fractional porosity. The *FZI* can be understood in terms of the relationship between the volume of void space (ε) and its geometric distribution (*RQI*). Rocks with a narrow range of FZI values belong to a single hydraulic unit, i.e. they have similar flow properties (Prasad, 2003; Granier, 2003; Guo et al., 2007; Comes et al., 2008; Kadkhodaie and Amini, 2009; Askari and Behrouz, 2011; Xu et al., 2012; Ghiasi-Freez et al., 2012a; Dezfoolian et al., 2013; Yarmohammadi et al., 2013; Nouri-Taleghani et al., 2015; Palabiran et al., 2016; Riazi, 2018). The relationship between ε and *RQI* has been used to show that samples with similar *FZI* values lie close together on a semi-log plot of porosity versus permeability (Amaefule et al., 1993). The porosity-permeability relationship on the plot can be defined uniquely in each hydraulic unit. On the basis of Amaefule et al.'s (1993) studies, permeability variations in a reservoir can be understood by storing its cored data in hydraulic units with similar *FZI* values. Accordingly, *HFU's* are defined by the classification of Log *FZI* data using several approaches available in literature. Discrete rock type (*DRT*) is an alternative way of flow unit classification. *DRT* is defined as follows:

$$DRT = ROUND\left(2 \times Ln\left(FZI\right) + 10\right) \tag{5}$$

3.5. Electrical rock type

Electrical flow units (EFU) are defined as zones with similar electrical flow properties. They are characterized with a current zone indicator (CZI) (Rezaee et al., 2007):

$$CZI = \sqrt{\frac{\phi/F}{\varepsilon}} \tag{6}$$

where φ, F, and ε are porosity (fraction), formation factor, and pore to matrix volume ratio (PMR) respectively. Electrical radius indicator (*ERI*) is calculated by:

$$ERI = \sqrt{\left(\frac{\phi}{F}\right)} \tag{7}$$

Then,

$$CZI = \frac{ERI}{\sqrt{\varepsilon}} \tag{8}$$

CZI is a factor which can be used to separate reservoirs with nearly identical *m* and *a* values where the variation in *F* is a function of porosity. Units with the same electrical flow properties have been proposed for any sample with a defined range of *CZI* (Rezaee et al., 2007).

Yarmohammadi et al. (2013) applied the electrical flow units approach to a deep sandstone reservoir of Shah Deniz gas field. The main reservoirs include Balakhani VIII and sandy packages II & III of Fasila group. They showed that high reservoir quality units correspond to high *CZI* zones (Figure 1).

3.6. Winland's and Pittman's method

H. D. Winland (Amoco Production Company), who was interested in sealing potential, developed an empirical relationship among porosity, air permeability, and the pore aperture corresponding to a mercury saturation of 35% (r35) for a mixed suite of sandstones and carbonates. Winland ran regressions for other percentiles (e.g. 30, 40, and 50), but the best correlation (highest *R*) was obtained at 35%. No explanation was given for why 35% resulted in the best correlation. His data set included 82 samples (56 sandstones and 26 carbonates) with low permeabilities that were corrected for gas slippage and 240 other samples with uncorrected permeabilities (Kolodzie, 1980):

Winland's R35 Equation is as follows:

$$Log\,(R35) = 0.732 + 0.588 \times log\left(K\right) - 0.864 \times log\left(\varphi\right) \tag{9}$$

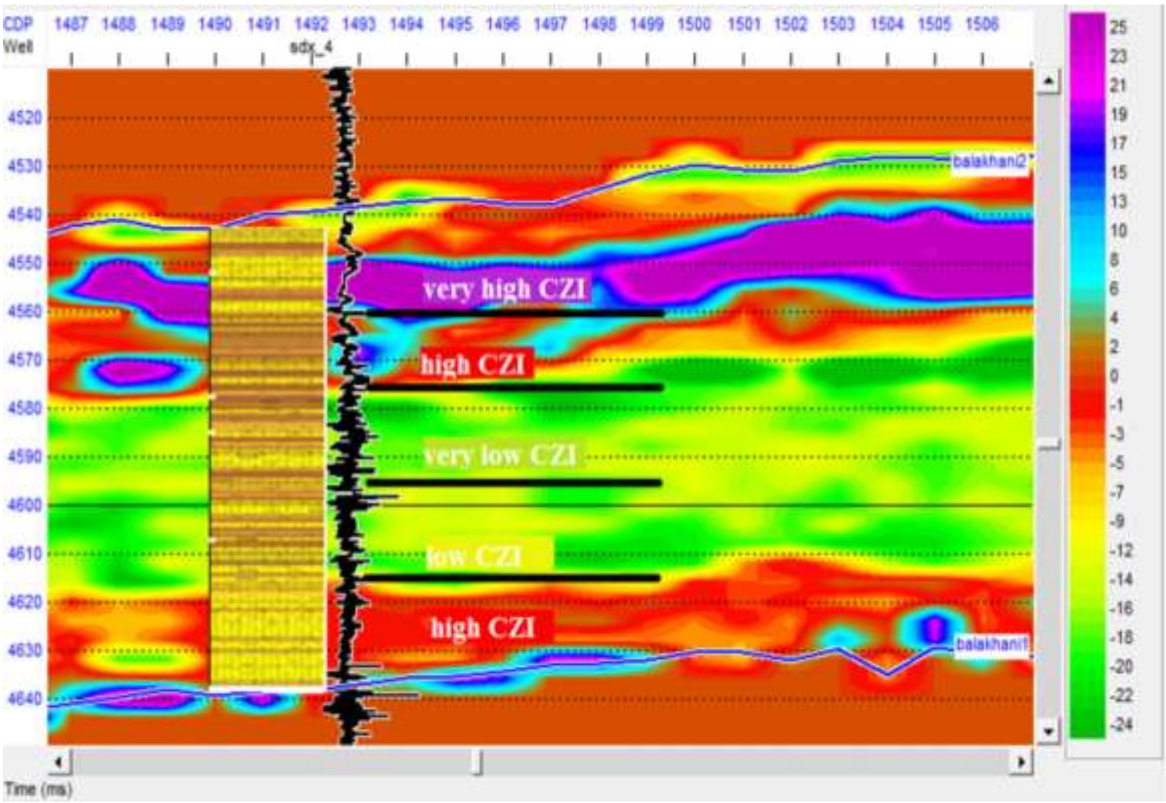

Figure 1
A 2D section of *CZI* distribution correlated with lithological column in well SDX-04, Shah Deniz gas field; Good pay sandstones correspond to high *CZI* values (Yarmohammadi et al., 2013).

Other empirical correlations similar to Winland's equation are proposed by Pittman (1989) as follows:

$$Log\ (R10) = 0.459 + 0.500\times log(K) - 0.385\times log(\varphi) \tag{10}$$

$$Log\ (R15) = 0.333 + 0.509\times log(K) - 0.344\times log(\varphi) \tag{11}$$

$$Log\ (R20) = 0.218 + 0.519\times log(K) - 0.303\times log(\varphi) \tag{12}$$

$$Log\ (R25) = 0.204 + 0.531\times log(K) - 0.350\times log(\varphi) \tag{13}$$

$$Log\ (R30) = 0.215 + 0.547\times log(K) - 0.420\times log(\varphi) \tag{14}$$

$$Log\ (R35) = 0.255 + 0.565\times log(K) - 0.523\times log(\varphi) \tag{15}$$

$$Log\ (R40) = 0.360 + 0.582\times log(K) - 0.680\times log(\varphi) \tag{16}$$

$$Log\ (R45) = 0.609 + 0.608\times log(K) - 0.974\times log(\varphi) \tag{17}$$

$$Log\ (R50) = 0.778 + 0.626\times log(K) - 1.205\times log(\varphi) \tag{18}$$

$$Log\ (R55) = 0.948 + 0.632\times log(K) - 1.426\times log(\varphi) \tag{19}$$

$$Log\ (R60) = 1.096 + 0.648\times log(K) - 1.666\times log(\varphi) \tag{20}$$

$$Log\ (R65) = 1.372 + 0.643\times log(K) - 1.979\times log(\varphi) \tag{21}$$

$$Log\ (R70) = 1.664 + 0.627 \times log(K) - 2.314 \times log(\varphi) \tag{22}$$

$$Log\ (R75) = 1.880 + 0.609 \times log(K) - 2.626 \times log(\varphi) \tag{23}$$

Studies show that Pittman's equations are useful for sandstone reservoir. The relationship between porosity/permeability and pore throat radius using Winland's equation is illustrated in Figure 2. In order to validate Winland's equation in pore throat radius calculation, the following steps are to be taken:

a) Calculate the pore aperture corresponding to a mercury saturation of 35% by using Pc curves;
b) Estimate R35 by using Winland's equation from porosity and permeability of the core plugs;
c) Compare the R35 value measured by Pc curves with the R35 value estimated by Winland's equation.

Usually, the measured and estimated R35 values would agree well for almost all the samples. For example, the measured and estimated R35 values of Arab formation (Figure 3) show a good correlation coefficient of 87%.

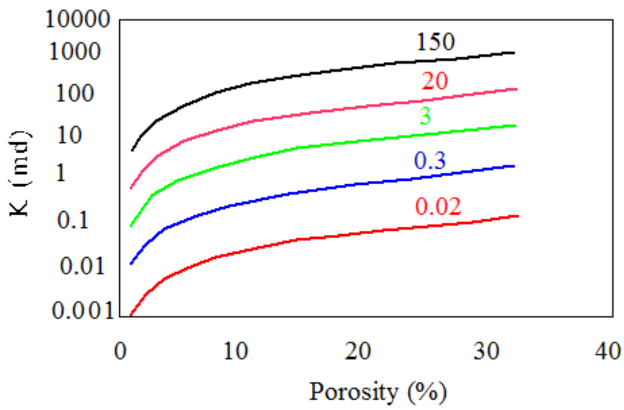

Figure 2
The relationship between porosity/permeability and pore throat radius using Winland's equation (Potter, 2010).

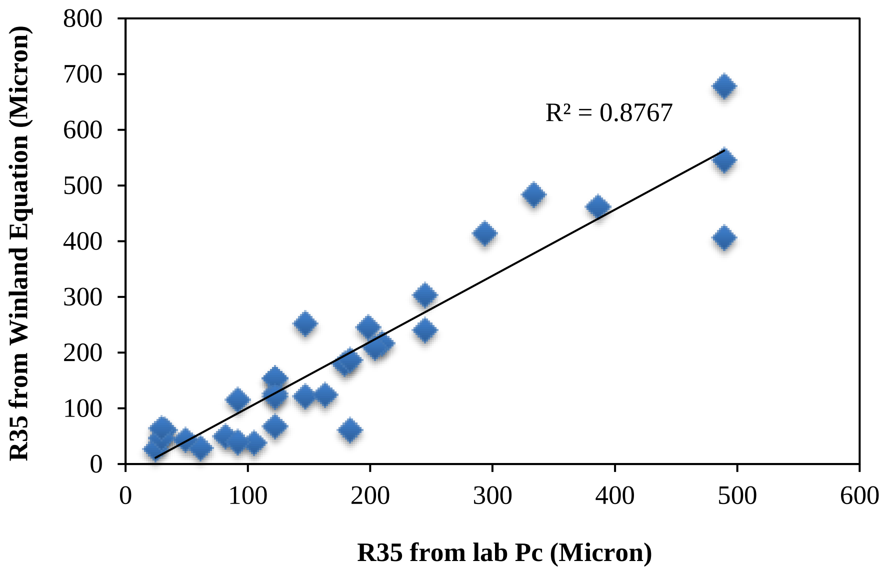

Figure 3
A comparison between the measured (by Pc curves) and the estimated R35 values for all the samples in Arab reservoir, Salman oilfield, Iran.

3.7. Lucia method

Lucia proposed a cross-plot of porosity versus permeability (Figure 4) to define the petrophysical classes of carbonate rocks (Jennings and Lucia, 2001). He placed inter-particle porosity at the porosity axis (horizontal axis) and permeability at the y-axis. Two interpretations can be made from Lucia cross-plot as given below:

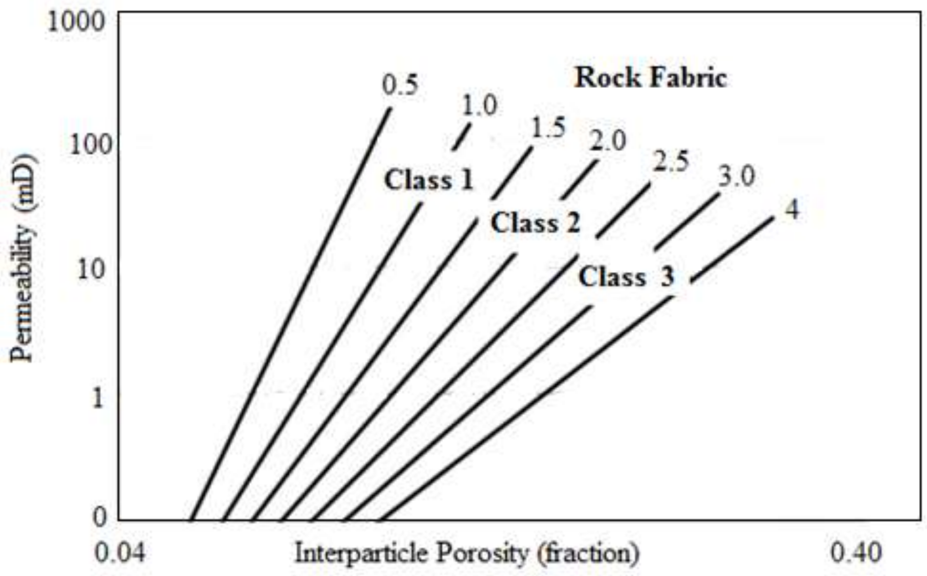

Figure 4
Lucia cross-plot of interparticle porosity versus permeability for the determination of petrophysical classes and rock fabric number (Jennings and Lucia, 2001).

a. Determination of petrophysical class

Generally, three petrophysical classes can be defined based on Lucia diagram (Lucia, 1999):

Class 1: grainstones, dolomitic grainstones, and coarse crystalline dolomites;

Class 2: grain dominated packstones, fine to medium grain dominated dolopackstones, and medium mud dominated dolostones;

Class 3: mud supported facies (mud dominated packstones, wackestones, and mudstones);

It is worth mentioning that Lucia divided the porosities into interparticle and vuggy. Vuggy porosity is itself classified into separate vugs and touching vugs. Accordingly, if some parts of porosity are of separate vug type, they should be subtracted from total porosity since they have no impact on permeability. Lucia (2009) showed that in separate vugs, permeability cannot be estimated from rock fabric number and the petrophysical class of rocks; for this reason, interparticle porosity is set to the porosity axis.

b. Determination of rock fabric number (RFN)

By plotting porosity and permeability data of every carbonate reservoir, its rock fabric number can be determined. As it is seen from Lucia cross-plot (Figure 4), rock fabric number, which varies from 0.5 to 4, is an important number for permeability calculation. The relationship between interparticle porosity (ϕ_{ip}), permeability, and RFN is expressed by Equation 24.

$$\log k = (9.7982 - 12.0838\log(RFN)) + ((8.6711 - 8.2965\log(RFN)) \times (\log \varphi_{ip})) \quad (24)$$

3.8. Buckles method

Buckles in 1965 stated that there is a hyperbolic relationship between irreducible water saturation and porosity. That is, the product of porosity and water saturation for each rock type is a constant value.

$$\varphi \times S_{wir} = C \quad (25)$$

It is worth mentioning that Buckles value is the same as the bulk volume of water (BVW) and Equation 25 can be written as follows:

$$\varphi \times S_{wir} = BVW \quad (26)$$

The concept of Buckles method is illustrated in Figure 5. As it can be seen, the product of Sw_{ir} and porosity is a constant value. If we consider two arbitrary points on the cross-plot of Figure 5, the porosity and water saturation for the first point is 0.05 and 0.8 respectively, while they are respectively equal to 0.2 and 0.2 for the second point. As the fitting function is a hyperbolic, the product of porosity and water saturation for both points is equal to 0.04. For the determination of rock types based on Buckles method, simply the multiplication of porosity and water saturation is calculated; afterwards, by applying cutoffs to the product log, rock types are identified. The determination of the cutoff applied to the product of porosity and water saturation logs depends on the expert's experience and the heterogeneity of the reservoir. An example of rock type classification based on Buckles method is shown in Figure 6.

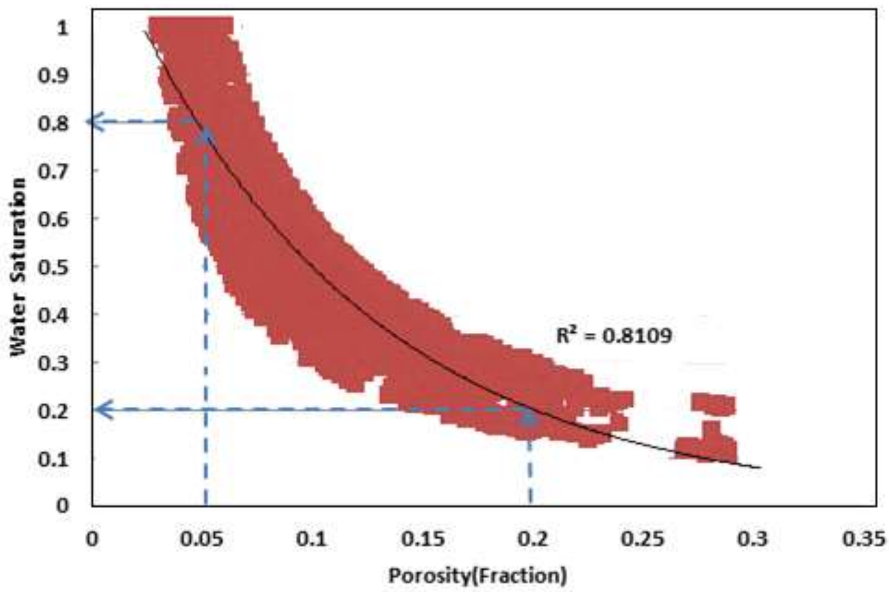

Figure 5
Cross-plot showing the concept of Buckles method; the product of S_{wir} and porosity is a constant value.

Applying logarithm operator to both sides of the Buckles equation, we obtain:

$$\log S_{wir} = \log C - \log \varphi \quad (27)$$

In this case, the relationship between porosity and connate water saturation will be linear. Buckles method can be generalized for the all reservoir rock types based on the following equation:

$$\varphi^{Q} \times S_{wir} = C \tag{28}$$

where, the exponent Q ranges from 0.8 to 1.3. Q is derived from plotting $\log S_{wir}$ versus $\log \phi$ and calculating the slope of the line fit to the plotted data points (Figure 7). As shown in Figure 8, in case of having two different rock types, two different Buckles constants will be obtained.

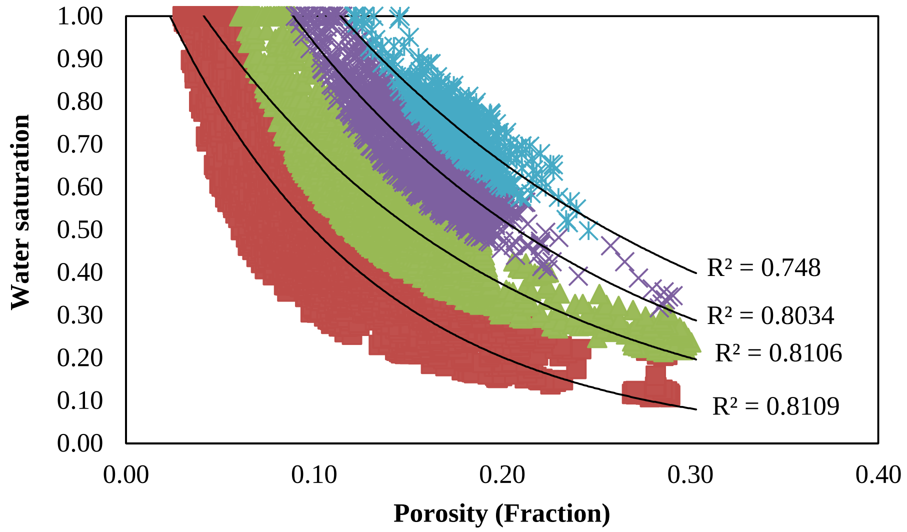

Figure 6
An example of rock type classification based on Buckles method in a carbonate reservoir.

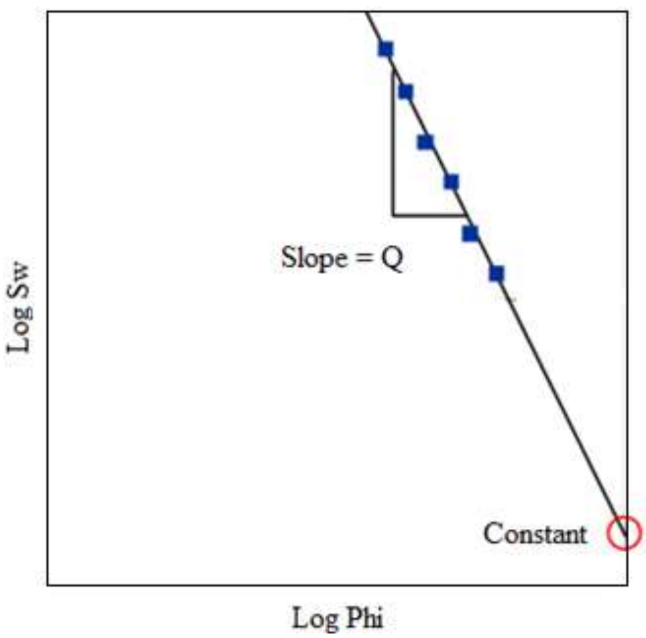

Figure 7
An example of calculating Buckles constant for a certain rock type (Holmes et al., 2009).

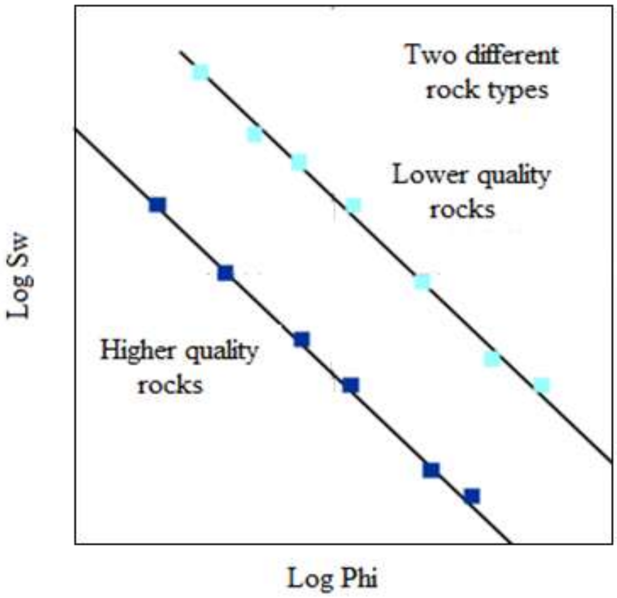

Figure 8
In case of having two different rock types, two different Buckles constants will be obtained (Holmes et al., 2009).

3.9. Reservoir rock types

Reservoir rock types (RRT) are classified according to properties that pertain to fluid behavior within the rock such as porosity, permeability, capillary pressure, irreducible water saturations, and relative permeability. Actually, reservoir rock types are categorized by properties important to hydrocarbon storage and flow.

The rock texture is a function of pore throat size distribution along with the porosity and permeability relationship, which will be studied in this section. The pore throat size can be calculated from capillary pressure data of mercury intrusion experiments (drainage case). Equation 29 is used to calculate the hydraulic pore throat radius.

$$r = \frac{2(0.145)\sigma \cos\theta}{P_c} \tag{29}$$

where, r (μm) is hydraulic radius, and σ= 480 dyne/cm; θ, contact angel, equals 140˚, and P_c stands for capillary pressure.

The values of pore throat size vary as a function of mercury saturation, in which a distribution trend is obtained. Another method to evaluate the pore throat size distribution is given by Ritter and Dark (1945) as described by Equation 30.

$$D(R_i) = \left(\frac{P}{r_i}\right) . \frac{d(V_0 - V)}{dP} \tag{30}$$

where, V_0 is void volume, and V defines unfilled volume after intrusion; $D(R_i)$ stands for distribution function value; P represents mercury intrusion pressure, and R_i represents pore throat size radius.

The samples that show similar pore throat size distributions belong to the same rock type class. Once more, rock type classes are defined as units of rocks (consisted of multiple lithofacies) with similar petrophysical correlations and common porosity and permeability bins in the poro-perm domain. The reservoir quality index (*RQI*) is a useful parameter for rock type classification. This is established since r_{peak} correlates well with *RQI* (see the example shown in Figure 9).

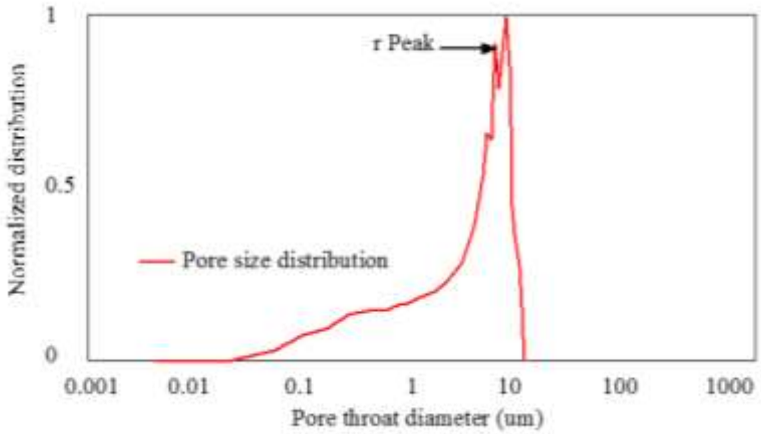

Figure 9
Cross-plot showing the relationship between pore throat size and SHg/d log(ri)

In this section, an example of reservoir rock type determination in Sarvak formation (Azar oilfield) is described. After screening RCAL porosity and permeability data and removing fractured and unreliable samples, reservoir quality index and flow units were calculated for the cored intervals. As seen in Figure 10, considering the break (inflection) points in the cumulative plot of Log(*FZI*) data, three hydraulic flow units are recognized for the Sarvak formation. The Log(*FZI*) range of the identified flow units is as follows.

$$HFU1{:}\ Log\left(FZI\right) < -0.44;\ HFU2{:} -0.44 < Log\left(FZI\right) < 0.25;\ HFU3{:}\ Log\left(FZI\right) > +0.25$$

The discrimination of the identified flow units in the porosity versus permeability plot is shown in Figure 11. As seen, a few data fall into HFU1, making it difficult to predict them from well logs in the subsequent stage of the study. Accordingly, HFU1 & HFU2 were merged into a single flow unit (HFU1). That is, two general HFU's were identified for the Sarvak formation (Figure 12). Porosity data analysis shows that P_{50} in the cumulative porosity plot of Log(*FZI*) values corresponds to 10%. Accordingly, the two flow units of the Sarvak formation were divided into four reservoir rock types through applying the porosity cutoff of 10%. HFU1 was divided into low porosity (HFU1) and high porosity (HFU3). Similarly, HFU2 was divided into HFU2 (low porosity) and HFU4 (high porosity). The log(*FZI*) and porosity range of the final reservoir rock types are listed below (Figure 13).

- **RRT0:** Non-reservoir rock type (below cutoff, Porosity <0.02);
- **RRT1:** Log FZI < +0.25 & Porosity < 0.1;
- **RRT2:** Log FZI > +0.25 & Porosity < 0.1
- **RRT3:** Log FZI < +0.25 & Porosity > 0.1;
- **RRT4:** Log FZI > +0.25 & Porosity > 0.1

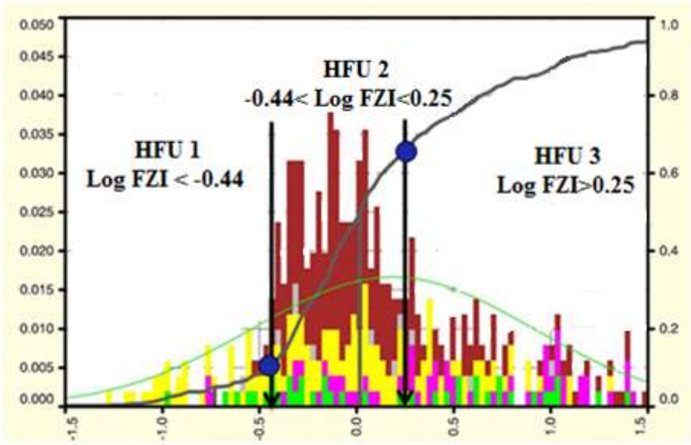

Figure 10
Cumulative density plot of Log(*FZI*) data, Sarvak formation.

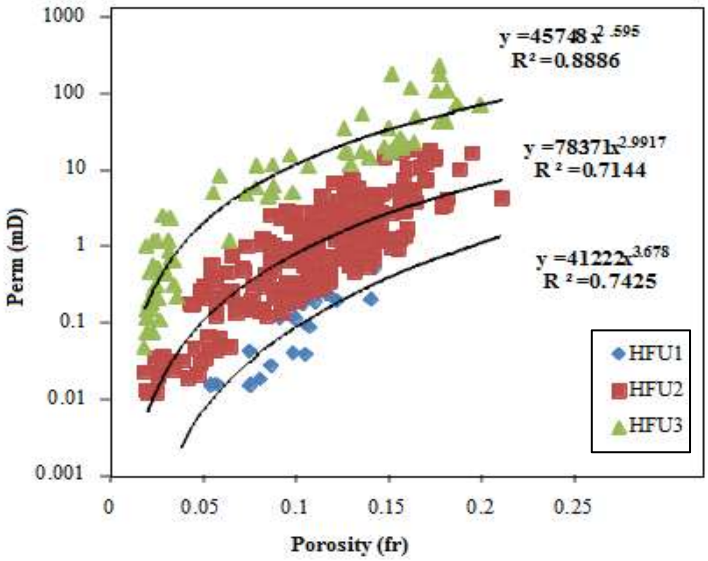

Figure 11
Discrimination of flow units in porosity versus permeability plot, Sarvak formation.

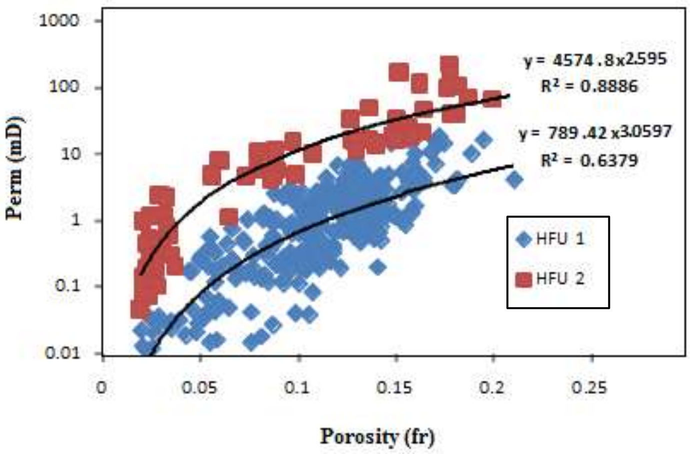

Figure 12
Discrimination of the identified flow units in the porosity versus permeability plot, Sarvak formation; HFU1 & HFU2 were merged, so two main flow units were identified.

a. Linking between reservoir rock types and sedimentary facies

In this step, we try to make a link between rock types based on flow units and the sedimentary facies derived from core description and/or thin-sections petrographic study. Actually, it is hard to find appropriate equivalent microfacies for each individual reservoir rock type. For example, each reservoir rock type can be in connection with all of the sedimentary microfacies. This mismatch arises from the fact that diagenetic imprints make the reservoir behavior complex. For instance, as mentioned earlier, ooid grainstone and mudstone are two different microfacies, but, due to the diagenesis, they can have the same flow properties in terms of storage capacity (porosity) and flow properties (permeability). As a result of destructive diagenetic factors such as cementation, grainstones behave as mudstones, and mudstones can show high porosity and permeability due to dissolution and fracturing processes. However, diagenetic facies can be a good solution to overcome such mismatches. Accordingly, we tried our best to find appropriate equivalents of microfacies for each reservoir rock type. A geological connection to reservoir rock types is illustrated in Figure 13 for Sarvak reservoir rock types. It is clear that RT1 is in connection with low energy mudstone having low porosity and permeability. It receives the fourth rank in terms of reservoir quality. RT2 (third rank) is characterized by low porosity wackestone having relatively high permeability. RT3 is linked to high porosity but low to medium permeability microfacies such as packstone to grainstone. RT3 is ranked second from a reservoir quality point of view. RT4 comes first in terms of reservoir quality and is characterized by well sorted peliod to ooid grainstones. Figures 14-16 represent the pore size distribution of RRT1 to RRT4. It is obvious that from RRT1 to RRT4, pore size increases from micropores to mesopores, and macropores. To summarize, reservoir quality increases from RRT1 to RRT4. Saturation height function of RRT1- RRT4 is represented in Figure 17.

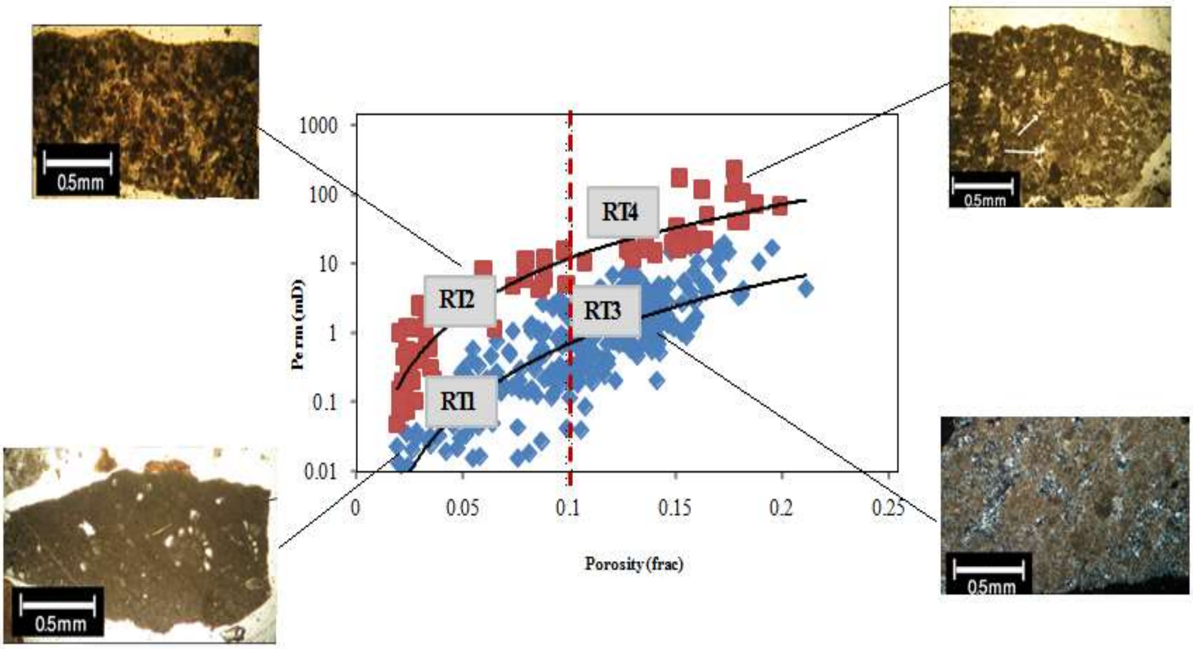

Figure 13
Linking between RRT and SRT in Sarvak formation, Azar oilfield.

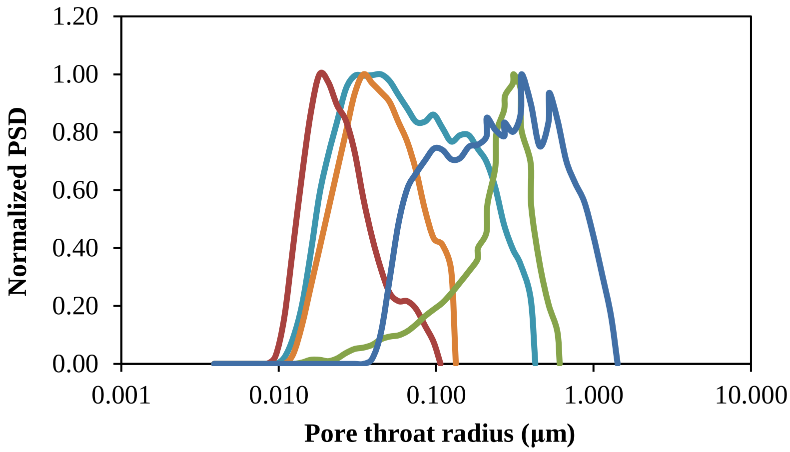

Figure 14
Pore size distribution of RRT1 and RRT2; generally, RRT1 and RRT2 are characterized by very small pores (micropores).

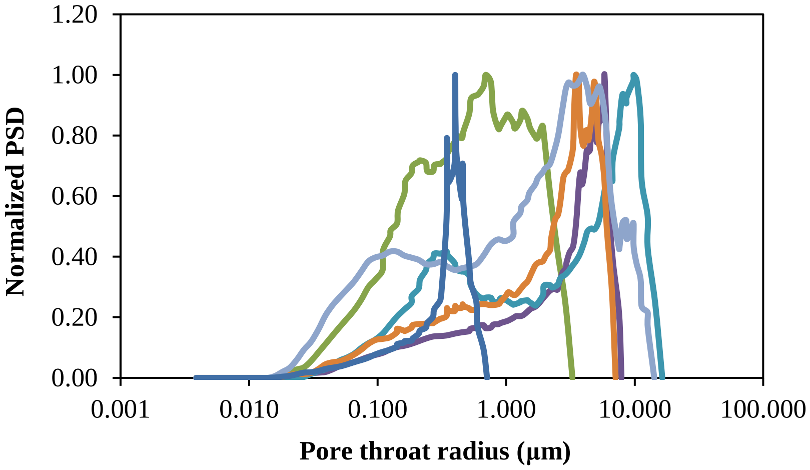

Figure 15
Pore size distribution of RRT3; RRT3 is characterized by small to medium pores (mesopores).

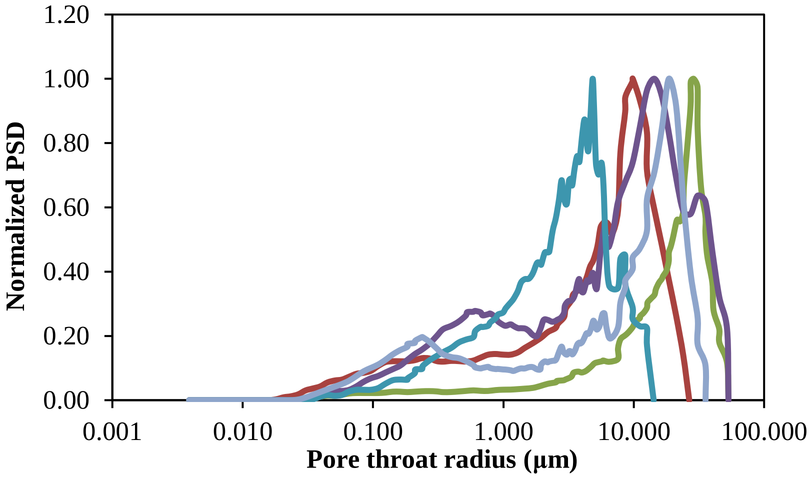

Figure 16
Pore size distribution of RRT4; RRT4 is characterized by medium to large pores (macropores).

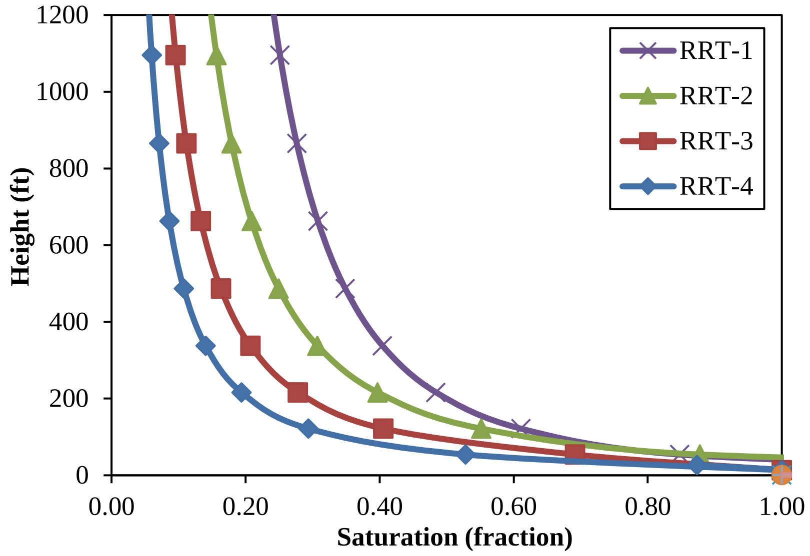

Figure 17
Saturation height functions of RRT1-RRT4.

4. Permeability estimation and RRT propagation for uncored wells

Formation rock permeability is an important flow parameter associated with subsurface production and injection. Its importance is reflected by the number of available techniques (well-log evaluation, core measurements, and well testing) typically used to estimate it. The knowledge of appropriate interrelationships among the various techniques allows meaningful permeability comparisons and correlations. Studying the relationships between permeability and petrophysical data revealed that there is a strong relationship between reservoir permeability and well logs, including gamma ray, neutron, density, sonic, and deep resistivity. Meanwhile, the ratio of micro to shallow and the ratio of shallow to deep resistivities (e.g. MSFL/LLS and LLS/LLD) can be considered as effective inputs for permeability estimation. For example, in highly permeable formations, where mud filtrate can invade deeply into formation, MSFL is closer to LLS readings, while in impermeable formations LLS is almost similar to LLD.

In order to estimate permeability, three different intelligent models, including fuzzy logic, neuro-fuzzy (local linear model trees (LOLIMOT)), and neural network are usually employed. Normally, datasets are divided into training and testing sets. The training set is used to train the intelligent models, and the testing set is used to measure their performance (Kadkhodaie et al., 2006; Sadeghi et al., 2011; Ghiasi-Friz et al., 2012b; Rastegarnia and Kadkodaie, 2013; Chitsazan et al., 2015; Nadiri et al., 2018).

5. Remarks and directions for future research

Reservoir rock typing is the process of integrating geological, petrophysical, seismic, and reservoir data to identify zones with similar storage capacity and flow capacity. In this study, all different approaches of rock typing were investigated and reviewed. Considering all the core and well log data resources, a universal flowchart of reservoir rock typing for different reservoirs is proposed (Figure 18). As it can be seen in Figure18, studying rock typing starts with investigating the sedimentary facies from the available cores and cuttings. Sedimentary rock type (SRT) will be identified based on core description and the microscopic study of thin sections. The results will be a set of microfacies or petrofacies along with the conceptual model of the depositional setting of reservoir rocks. In the second step, petrophysical rock types (PRT) are identified according to electrofacies analysis of well log data by using a classification method (e.g. cluster analysis, multi-resolution graph based clustering (MRGC), self-organizing maps (SOM) etc.). In the third step, hydraulic flow units (HFU) are determined by using conventional core analysis data, including porosity and permeability. There are different methods for flow unit determination such as Amaefule's method, Lucia's cross-plot, and Winland's/Pittman's equations. All the methods of flow unit determination need to be validated versus core results, and the optimal one, which is more consistent with SRT and PRT results, is chosen. In the fourth step, SCAL data need to be analyzed, and representative capillary pressure and relative permeability curves should be assigned to each reservoir rock type (RRT). Assigned or average *Pc* curves will aid in the determination of saturation height function analysis and pore size distribution within each reservoir rock type.

In the case of lacking any data relevant to step 1 through step 4, rock typing process will be terminated based on the available data up to that step.

The proposed rock typing flow chart will aid with complex carbonate reservoir characterization. The saturation height function derived from capillary pressure curves assigned to each rock type is a fundamental data for the construction and conditioning of water saturation model. Accordingly, defining rock types in a more meaningful and integrated way will lead to reducing uncertainty about the calculation of oil and gas in place.

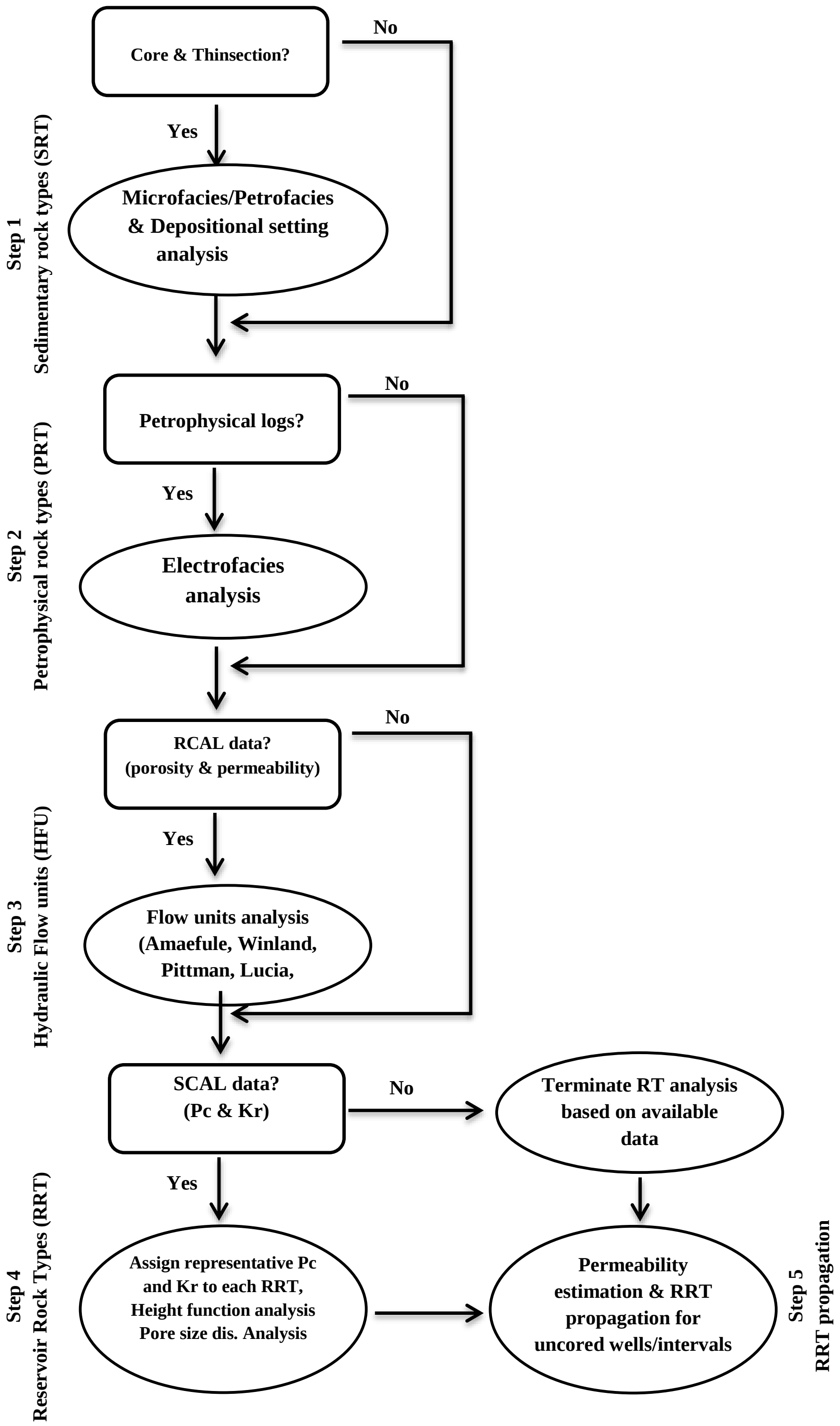

Figure 18
The proposed flowchart of integrated reservoir rock typing.

Nomenclature

BVW	: Bulk volume of water
CCAL	: Conventional core analysis

CZI	: Current zone indicator
DRT	: Discrete rock type
DST	: Drill stem test
DT	: Sonic log
EFU	: Electrical flow units
FZI	: Flow zone indicator
GST	: Gas down to
HFU	: Hydraulic flow unit
Kr	: Relative permeability
LLD	: Deep laterolog
LLS	: Shallow laterolog
MRGC	: multi-resolution graph based clustering
MSFL	: Microspherically focused log
NPHI	: Neutron porosity log
ODT	: Oil down to
Pc	: Capillary pressure
PEF	: Photoelectric factor log
PRT	: Petrophysical rock type
RCAL	: Routine core analysis
RFN	: Rock fabric number
RHOB	: Density log
RQI	: Reservoir quality index
RRT	: Reservoir rock type
SCAL	: Special core analysis
SOM	: Self-organizing maps
SRT	: Sedimentary rock type

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