Reservoir quality estimation using a new ternary diagram approach applied to carbonate formations in north-western Iraq

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Abstract. A new reservoir quality ternary plot (RQTP) of effective porosity, shale volume, and matrix is presented in this study. We show it to be a useful tool for first-order estimation of the petrophysical zones and reservoir classes of each unit within a reservoir. Subsequently, we combine the RQTP results with permeability and fracturing intensity data in carbonate rocks to provide a better overall characterisation of reservoir quality. The approach has been applied to the Butmah Formation, a thick variable carbonate succession of Liassic (Lower Jurassic) rocks in north-western Iraq. The RQTP approach divides carbonate reservoirs into classes according to: (i) a measure of porosity, (ii) the fraction of shale, and (iii) the fraction of non-shale matrix. The outcome of applying this model to the Butmah Formation indicates that the best reservoir quality is identified in Unit 4, which consists of fine to medium dolomite rocks. These rocks are not associated with anhydrite cement or dissolved later due to late dissolution, presenting as clean carbonate with complex pore network heterogeneity. These types of rocks were classified as Rc2 and Rc3 using the RQTP Model. By contrast, the worst reservoir qualities (Rc7) were identified in Unit 1 which is composed of cemented limestone that shows low pore network heterogeneity (predominantly uniform pore sizes), low porosity, and poor permeability.

Keywords: Wireline log analysis, carbonates, reservoir quality ternary plot, porosity, permeability

1. INTRODUCTION

The quality of a reservoir is defined by its capacity to store and deliver hydrocarbons (Gluyas and Swarbrick 2004). The hydrocarbon storage capacity is characterised by the effective porosity and the gross volume of the reservoir, whereas the deliverability is a function of absolute and relative permeabilities to the fluids it contains (Asquith and Krygowski, 2004; Tiab and Donaldson, 2012).

Hence, the determination of these controlling factors is crucial in identifying and classifying reservoir quality. This is especially the case in carbonate reservoirs which exhibit spatially-distributed variable petrophysical parameters, including porosity and permeability, over a wide range of scales. Such heterogeneity in the petrophysical properties of the rock influence hydrocarbon extraction by controlling fluid flow at microscopic and reservoir scale (Lucia,1995; Lønøy, 2006; Ehrenberg et al., 2008; Hollis et al., 2010; Tiab and Donaldson, 2012). High-quality characterisation of the rocks which compose carbonate reservoirs is an essential step in the characterisation and management of the reservoir as a whole (Lucia, 1995; Ferket et al., 2003).

This paper introduces a reservoir quality classification scheme which depends on effective porosity, shale volume, and matrix percentages that can be calculated from wireline log data using a ternary plot. Ternary plots have been used since Newton and Meyer in the 18th century (Howarth, 1996), and have been used in Geology since Maxwell (1848) employed them to study polarised light from minerals. They are now commonly used to classify different three-phase mixtures, particularly in Earth sciences, metallurgy and physical chemistry (Sabine and Howarth, 1998). However, ternary diagrams have never been used to classify reservoir quality of hydrocarbon reservoirs.

No descriptive classification of carbonate reservoirs for the prediction of reservoir quality exists in the scientific and engineering literature. Most of the previous studies on reservoir quality have focused on using two or more techniques to characterise the petrophysical properties of reservoir formations.

The similarities in the three petrophysical properties (porosity, permeability, and pore throat) have been used to identify flow units, and hence resolve challenges encountered in the exploration and production of carbonate reservoirs (Amaefule et al., 1993; Gunter et al., 1997; Martin et al., 1997). According to these researchers, the identified flow units can be used to map reservoir performance, characterise stratigraphic sequences and predict the location of stratigraphic traps. However, this approach is local and cannot be generalised to other reservoirs for which the identified flow units vary from reservoir to reservoir.

Lim (2005) identified reservoir properties (porosity and permeability) from wireline log data in offshore Korea using fuzzy logic curve analysis to find the best association between well logs with core porosity and permeability data. Subsequently, he used a neural network technique to improve transformation between the selected well logs and core measurements. The results give more reliable reservoir property estimations in each single reservoir compared to conventional computing methods. Fuzzy logic, genetic algorithm and neural network approaches (Cuddy and Glover, 2000; 2002) have subsequently been used by other researchers to manage uncertainties in petrophysical measurements, to predict porosity, permeability, and fluid saturation, and to predict the producing intervals in oilfields without extra computational cost (Oltunji et al., 2010; Wang et al., 2013; Baziar et al., 2014; Chaki et al., 2014; Rafik and Kamel, 2016).

Both Ozken et al. (2011) and El Sharawy and Nabawy (2016) have used the statistical correlation between petrophysical properties of lithofacies that were described from core analysis and log data to predict field-scale reservoir quality. This technique is limited but can show good results in characterising a single formation or a specific stratigraphic succession.

Al-Khalifah et al. (2020) have recently shown that neural network and genetic algorithm approaches are capable of predicting permeability in tight carbonates better than any other tested method, but did not extend their work to the prediction of reservoir quality. Application of machine learning techniques directly to reservoir quality is hampered by the lack of a single, standard, and well-accepted definition of reservoir quality.

On the other hand, an integrated, multi-disciplinary approach for correlating core facies, petrophysical wireline facies, and seismic data has been used by many researchers (Davies et al., 1997; Dasgupta et al., 2000; Russel et al., 2002; Yan, 2002; Zawila et al., 2005; Ulasi et al., 2012; Al- Hasani et al., 2018) in order to provide models of flow interaction between high permeability rock and fracture systems. This technique has added value in the characterising of heterogeneity formations, but requires very large datasets to give a general description or classification of such systems.

Most of the later approaches used complex integrated techniques to characterise the reservoir quality of reservoir formations that are often modified from reservoir to reservoir to take account of local conditions. Hence, the reservoir quality assessments they provide are qualitative and cannot be compared. By contrast, the RQTP approach proposed in this work has the advantage of being applicable to all carbonate reservoirs using a simple and unchanging protocol that is easy to apply and leads to a classification which can be compared with the results from other reservoirs.

Subsequently, we show that the resulting Reservoir Quality Ternary Plot (RQTP) Model is an effective tool for quick-look reservoir quality estimation of any carbonate formation using three simple items of data that are routinely obtained from well logs. Moreover, we show that the RQTP can provide very important information about the effect of fracturing on the reservoir quality, together with information on lithology, pore network heterogeneity, and permeability.

2. MODEL DEFINITION

In this study, we have developed a new approach to reservoir quality classification which involves plotting shale volume, effective porosity, and matrix percentages in the form of a ternary diagram. The ternary diagram characterises the amount of shale as the shale volume percentage (V_{sh}, %), quantifies pores using the effective porosity (ϕ_{eff}, %), and represents the matrix contribution by the remaining fraction out of 100% ($1-\phi_{tot}$, %).

The ternary diagram has been used before for many purposes, such as classifications of different kinds of rocks including clastic and carbonate rocks, but it has never previously been used to classify reservoir quality. Consequently, in this work, the ternary diagram of the percentages of shale volume, effective porosity and rock matrix is used for classifying the reservoir quality into classes and zones under the name of reservoir quality ternary plot (RTQP).

The shale volume is the calculated proportion of shale in reservoir formations that is reflected by high values in the gamma-ray log due to the natural radioactivity in shale. The calculated shale volume is expressed as a decimal fraction or percentage (V_{sh},%) (Asquith and Krygowski, 2004).

Effective porosity is the fractional volume of interconnected pores in rock and its prediction is essential for estimating reserves and planning production operations in hydrocarbon reservoirs (Pramanik et al., 2004). It is approximately equal to the density-neutron porosity in free shale carbonate formations (Schlumberger, 1989). Consequently, shale volume is crucial in the calculation of effective porosity.

We have also examined the use of potential porosity in place of effective porosity, recognising that while effective porosity has been in common use in the hydrocarbon industry for decades, it is being slowly replaced by the concept of potential porosity, which bases the judgement of potentially productive porosity on the diameter of pores and pore throats. Only small mesopores as pore spaces above a threshold value of 50 μm in diameter for oil or 5 μm in diameter for gas count as potential porosity (Luo and Machel, 1995).

The remaining space in the rock is occupied by the non-shale framework or matrix of the rock. It is expressed as a percentage of the total rock volume (Mat, %). This implies that the rock matrix value accounts not only for the clean fraction of the solid matrix, but also the associated porosity that is not included in the effective porosity or potential porosity. That some forms of porosity can count as matrix may seem counterintuitive. However, isolated pores and fluid-filled inclusions do not take part in the transport of fluid within reservoirs. Such isolated pores can be assumed to be grains (matrix) during the calculation of effective porosity. When considering effective porosity, the porosity which is counted as matrix is that which occurs in completely isolated or unproduceable pores or is that associated with shales. When considering potential porosity, the porosity which is counted as matrix is any porosity which is isolated or in the form of apparently connected pores whose size is less than the appropriate threshold value for oil or gas.

We have divided the ternary space into reservoir classes and petrophysical zones according to their shale volume, effective porosity and matrix. The contacts between the classes and zones were identified carefully according to accepted distinctions for effective and potential porosities and shale volumes in the literature reviews (Pettijohn, 1957; Leighton and Pendexter, 1962; Leverson, 1967; North, 1985). For example, for carbonate rocks, it is common for a carbonate rock containing less than 15% clay minerals to be called limestone, 15-25% to be called argillaceous limestone, 35-65% marl, 65-75% calcareous mudstone, and more than 75% mudstone (e.g., Pettijohn, 1957). Consequently, we have used 20% as a contact between the clean rock (clean carbonate) and mixed carbonate and clay content, and 60% as a contact between the mixed carbonate/clay and shale (mudstone).

There are many quantitative classifications of porosity in carbonate rocks that cover the range from less than 0.1% to 48% (e.g., Leverson, 1967, North, 1985). This large range of porosities arises from the extremely wide scope of rock textures that are produced by multiple diagenetic processes. For the purposes of the ternary plot used in this study, five porosity ranges, each of 10%, were defined on an *ad hoc* basis, covering the entire observed range of porosities, and approximately corresponding to the qualitative ranges poor, fair, moderate, good, and very good (e.g., Leverson, 1967, North, 1985), respectively.

Consequently, the RQTP is divided into nine Reservoir Classes (RC1 to RC9) of the reservoir rock (Figure 1), which subdivide into nineteen Petrophysical Rock Zones in order to make the classification more discriminatory. These Petrophysical Zones have each been given a two or three letter code. Each reservoir class and petrophysical zone represents rocks with a different range between the three ternary end-members, as shown in Figure 1 and summarised in Table1.

Figure 1. The Reservoir Quality Ternary Plot (RQTP), defined in this work, with defined reservoir classes and Petrophysical zones (see also Table 1).

Reservoir Class 1 (RC1) - high porosity, clean carbonates

This reservoir class consists of three petrophysical zones with porosity higher than 20% and shale volume less than 20%:

1- Extremely high porosity, matrix-dominated rock, 50% ≤ ϕ_{eff} < 40% (Em)

2- Very high porosity, matrix-dominated rock, 40% ≤ ϕ_{eff} < 30% (Vm)

3- High Porosity, matrix-dominated rock, 30% ≤ ϕ_{eff} < 20% (Hm)

Reservoir Class 2 (RC2) - high porosity, shaly carbonates

This reservoir class is composed of six petrophysical zones, all with porosity higher than 20% and shale volume values of (20-60%):

1- Extremely high porosity, shaly matrix-dominated rock (Esm)

2- Very high porosity shaly, matrix-dominated rocks (Vsm)

3- High porosity, shaly matrix-dominated rocks (Hsm)

4- Extremely high porosity, matrix-dominated shaly rocks (Ems)

5- Very high porosity, matrix-dominated shaly rocks (Vms)

6- High porosity, matrix-dominated shaly rocks (Hms)

Reservoir Class 3 (RC3) - high porosity, carbonate shales

This reservoir class consists of two petrophysical zones, all with porosity higher than 20% and shale volume more than 60%:

1- Very high porosity shale rocks (Vs)

2- High porosity shale rocks (Hs)

Reservoir Class 4 (RC4) - moderate porosity, clean carbonates

This reservoir class is characterised of one petrophysical zone with an effective porosity range of (10-20%) and a shale volume less than 20%:

1- Medium porosity Matrix-dominated rocks, 10% ≤ ϕ_{eff} < 20% (Mm)

Reservoir Class 5 (RC5) - moderate porosity, shaly carbonates

This reservoir class consists of two petrophysical zones with porosity range of (10-20%) and shale volume of (20-60%):

1- Medium porosity matrix-dominated shale rocks,10% ≤ ϕ_{eff} < 20% (Msm)

2- Medium porosity shale-dominated matrix rocks, 10% ≤ ϕ_{eff} < 20% (Mms)

Reservoir Class 6 (RC6) - moderate porosity, carbonate shales

This reservoir class is composed of one petrophysical zone with porosity range of (10-20%) and shale volume more than 60%:

1- Medium porosity shaly rocks (Ms)

Reservoir Class 7 (RC7) - low porosity, clean carbonates

This reservoir class consists of one petrophysical zone with porosity less than 10% and shale volume less than 20%:

1- Low porosity matrix-dominated rocks (Lm)

Reservoir Class 8 (RC8) - low porosity, shaly carbonates

This reservoir class is characterised by two petrophysical zones with porosities less than 10% and shale volume range of (20-60%):

1- Low porosity shaly matrix-dominated rocks (Lsm)

2- Low porosity shale-dominated matrix rocks (Lms)

Reservoir Class 9 (RC9) - low porosity, carbonate shales

This reservoir class consists of one petrophysical zone with porosity less than 10% and shale volume range more than 60%, and into which most gas shales would fall.

1- Low porosity shaly rocks (Ls).

Table 1. Reservoir classes and petrophysical zones with the effective porosity and shale volume description.

Reservoir class	Rock zone	Effective porosity (%)	Shale volume (%)
RC1	Em	>40	<20
	Vm	30-40	<20
	Hm	20-30	<20
RC2	Esm	>40	20-40
	Vsm	30-40	20-40
	Hsm	20-30	20-40
	Ems	>40	40-60
	Vms	30-40	40-60
	Hms	20-30	40-60
RC3	Vs	30-40	60-70
	Hs	20-30	60-80
RC4	Mm	10-20	<20
RC5	Msm	10-20	20-40
	Mms	10-20	40-60
RC6	Ms	10-20	>60
RC7	Lm	<10	<20
RC8	Lsm	<10	20-40
	Lms	<10	40-60
RC9	Ls	<10	>60

Reference to Figure 1 shows that the boundaries between the Reservoir Classes are imposed upon the model with no account taken of the dataset to which it is being applied. This is to ensure that the classification scheme is the same when applied to different reservoirs by different researchers, and hence inter-reservoir comparisons are valid. Effective porosity ranges are 0-10%, 10-20% and 20-50% to reflect the general petrophysical experience that reservoirs with porosities less than 10% are likely to be low productivity, at least conventionally, while reservoirs with over 20% porosity will have good storage capacity, and reservoirs between 10% and 20% might represent more typical values of porosity, commonly encountered. There are no ranges including porosities over 50% as these will not be encountered in natural reservoirs. Unlike porosity, shale fraction can vary over the complete range from 0% to 100%. In modern petrophysics and with reservoir stimulation techniques we can produce hydrocarbons from rocks which are completely clean (i.e., no shale) to shale oil and gas reservoirs which approach 100% shale. Consequently, four ranges were chosen: 0-20%, 20-40%, 4-60%, and 60-100%. Conventional reservoirs commonly fall into the first of these categories, and for these saturations are often calculated without recourse to shaly sand electrical models (Glover, 2015). The second range represents reservoirs where shale is sufficiently prevalent for shaly sand electrical models to be required, while the third and fourth ranges represent unconventional shale reservoirs, the first of which is likely to contain sufficient clastic material to be frackable, and the latter is likely to be unproductive even with stimulation, but to form barriers to flow, compartmentalising reservoirs or forming cap-rocks.

In line with our ranges for porosity, we define three ranges for the matrix component, which depend on the previous two parameters, where $V_{sh}+\phi_{eff}+Mat=100\%$. The choice here is whether the boundaries in the classification scheme run parallel to the shale axis or not. We have made a decision to retain this parallel behaviour partially to keep the classification model as simple as possible, partially because our data fell within the ranges when defined this way, and partially because it simplifies statistical analysis of really defined count data. The resulting 9 Reservoir Class scheme is a balance of simplicity and sophistication that is designed to be easy to use. More detailed analysis can be carried out by subdividing the classes, which we consider later in the paper.

While effective porosity has been used in the hydrocarbon industry for many years, the concept of potential porosity may be replacing it in future. Potential porosity is that porosity which contains hydrocarbon that can be mobilised by the range fluid pressure differences that may exist naturally in a reservoir or be imposed artificially (Gluyas and Swarbrick 2004; Worden et al., 2018). To this end, it is considered that only small mesopores connected by pore throats greater than 50 μm can transport oil or water and those greater than 5 μm can transport hydrocarbon gas (Luo and Machel, 1995). Below these thresholds a combination of capillary forces and viscous drag results in fluid not being able to flow except at pressures which are not found naturally or artificially in reservoirs.

One should note that the distinction between effective and potential porosity is important because for clays the connected porosity might be as high as 40 to 50% where the potential porosity is commonly less than 1%, which is the reason why clays are not produced in conventional reservoirs even if they contain hydrocarbons.

In this work, we confine ourselves to using effective porosity as a basic parameter because, at present, it is the most commonly used porosity parameter in reservoir characterisation as well as being easy to calculate from log data. The disadvantage of using the effective porosity occurs for clay-rich and shaly formations, where the low effective porosity is controlled by shale volume, whereas the potential porosity is lower as it is controlled by both shale volume and pore throat size.

We have compared the RQTP outcomes using potential porosity instead of effective porosity on 20 samples to examine and quantify the difference between using the two types of porosity in the RQTP protocol. The results of this comparison are shown in Figure 2 and summarised in Table 2. For porosities greater than about 10%, the ratio of the potential porosity to effective porosity was found to be about 0.8, but decreases substantially to as low as 0.404 as the porosity falls. Clearly, there is a more significant discrepancy between the two parameters as the overall porosity falls. The main reason for this is the removal of porosity in the form of very small pores and pores connected by small pore throats that do not take part in flow, and these are more likely to occur in tight, low porosity rocks. Another possible source of the discrepancy may be associated with fracturing, which increases with grain size (Sinclair, 1980; Nelson, 2001), and hence pore and pore throat size (Glover and Walker, 2009).

Figure 2. Reservoir Quality Ternary Plot (RQTP) showing the positions of 20 samples for which both effective porosity (blue circles) and potential porosity (red circles) data was available. The potential porosity is lower than effective porosity in all cases with the plotted points moving parallel to the lines of the same degree of shaliness (see also Table 2).

It is recognised that the concept of potential porosity better models micro-scale processes of fluid flow in reservoirs, but it is expensive and time-consuming to implement as it requires mercury injection capillary pressure (MICP) measurements on all relevant samples. By contrast, the use of effective porosity, while less accurate, is easy and cheap to use and can use a huge existing measurement database.

Table 2. Comparison between effective and potential porosity measurements.

Sample No.	Stratigraphic Unit	ϕ_{eff} (%)	ϕ_{pot} (%)	ϕ_{pot}/ϕ_{eff} (-)
1	4	2.9	2.1	0.724
2	5	8.6	7.3	0.849
3	4	14.9	13.8	0.926
4	5	8.2	7.0	0.854
5	4	15.8	13.2	0.835
6	5	5.2	2.1	0.404
7	4	13.4	11.1	0.828
8	5	4.6	3.2	0.696
9	4	14.2	12.0	0.845
10	4	21.0	16.9	0.805
11	4	17.0	14.7	0.865
12	4	12.5	10.1	0.808
13	5	21.7	18.1	0.834
14	4	17.9	14.6	0.816
15	4	24.9	19.2	0.771
16	4	8.6	4.7	0.547
17	4	16.8	12.6	0.750
18	4	17.9	13.0	0.726
19	4	22.2	18.5	0.833
20	4	18.6	12.4	0.667

3. PRIMARY CASE STUDY – THE BUTMAH FORMATION

3.1 Introduction

The new RQTP approach has been applied to the Butmah Formation (Liassic-Lower Jurassic) which is a compartmentalised reservoir in the Butmah oilfield north-western Iraq (Mohammed Sajed and Glover, 2020). The Butmah Formation is an example of a thick variable carbonate succession, deposited in a shallow sea. It represents a challenging carbonate formation for applying the proposed RQTP approach because formation shows both varied lithology and variable petrophysical properties.

The Butmah Formation was deposited during the Liassic sequence (Lower Jurassic) of the late Permian-Liassic megasequence (AP6) of Jassim et al. (2006). The study area was affected by extension at the northern and eastern margins of the Arabian plate during the middle to late Triassic, giving rise to rifting, and then slow thermal subsidence in Norian-Liassic times. Accordingly, the formation is composed of evaporites and shallow lagoonal carbonates as a uniform marginal marine clastic deposit (Figure 3) (Jassim and Goff, 2006; Aqrawi et al., 2010).

Figure 3. The location of the Butmah and Ain Zalah oilfields in north-western Iraq with respect to the palaeography of the late Liassic (after Jassim et al., 2006).

The Butmah Formation is not exposed in Iraq, but it is penetrated by exploration and production wells, which show that it has a thickness of 162-500 m in north-western Iraq (Jassim et al., 2006). The thickness of the formation in the wells within the study area is provided by well Butmah-15, which shows the formation to have a thickness of 402 m at this location.

The type section of the Butmah Formation was defined by Dunnington (1958) from well Butmah-2 in the Low Folded Zone of northern Iraq as a 500 m thick heterogeneous carbonate unit which is divided into three parts. The lower part (120 m thick) consists of limestone interbedded with anhydrite. This is overlain by a 180 m layer of oolitic and pseudo-oolitic, argillaceous and dolomitic limestone with sandstone and shale beds. The upper part was described as about 200 m thick and is composed of oolitic, pseudo-oolitic and detrital limestones with some beds of argillaceous limestone, shale and anhydrite (Jassim et al., 2006).

Fossils of the Butmah Formation are recorded by Bellen et al. (1959) as bioclasts of gastropods and other macrofossil debris, sponge spicules, fish debris, ostracods and coprolitic pellets (*Favreina sp.*). Moreover, *Glomospira sp.* (throughout), *Archaediscus sp.* (except the uppermost part), *Problematina sp.,* and small textularids are also present. It is thought that the lower part of the Butmah Formation was deposited during a marine transgression across Iraq and passes up into tidal flat and sabkha deposits, whereas rare fossils indicate restricted cyclic sediments (Aqrawi et al., 2010).

3.2 Methods and materials

3.2.1 Lithofacies and effective porosity

The determination of lithology in this study was carried out by calibrating the wireline log response with identified lithological units from the core and cutting samples. In this work, the term 'lithofacies' has been used to describe the lithology of the studied formation, while the term 'stratigraphic unit' has been used for describing the vertical distribution of a lithofacies within the formation.

Digital copies of gamma-ray, density, neutron, and sonic logs from well Bm-15 in the Butmah oilfield were provided by the North Oil Company (NOC) of Iraq. The digital copies were digitised using NeuraLog® (Version 4.1) and redrawn and analysed by Interactive Petrophysics® software (Version 4.3) from Senergy Inc.

The use of a combination of density and neutron logs provides a powerful tool for the identification of total and effective porosity in carbonates, and has allowed us to interpret the complex pore networks in the carbonate rocks we are studying. The bulk porosity was calculated as the arithmetic mean of both the neutron log and the density log. More detail on calculating the effective porosity is provided in the RQTP Input parameters section below.

3.2.2 X-ray diffractometry (XRD)

Five samples were pulverised using a ball mill within an agate chamber at the X-ray diffraction facility of the University of Leeds. These powder samples were front loaded into standard Bruker plastic holders. The samples were analysed with a Bruker D8 machine using Cu Kα1 radiation, a Germanium primary monochromator and a Lynx Eye detector. All the samples were scanned at 40 kV, 40 mA from 2-86˚, with an increment of 0.0105˚ and a count time of 2 s/step.

The data was analysed using two software packages: Bruker's EVA® for phase identification and TOPAS® Rietveld refinement for phase quantification (Klug and Alexander, 1974). The Rietveld method refines a crystal structure by comparing the measured diffraction pattern with that calculated from a known crystal structure. A least-squares refinement was used to optimise the structure parameters.

3.2.3 Permeability

A suite of 43 core plug samples, 1.5 inches in diameter and 2.0 inches in length, were obtained from the North Oil Company, from the cored intervals of the three formations within the studied wells. The core plug samples were cleaned using Soxhlet extraction (McPhee et al., 2015), and then dried in a temperature controlled oven at 60°C for 48 hours.

Permeability (k) was measured using a steady-state method (Ross, 2011) for high permeability samples (k > 1 mD), and a pulse-decay permeameter (Jannot et al., 2007; Zhang et al., 2000; Jones, 1997) for lower permeability samples (k ≤1 mD), using helium as the probe gas, and with a confining pressure of 4500 psig. The use of either of these techniques on tight rocks with small pores results in there being insufficient helium molecules per unit pore volume for continuum-based conventional fluid mechanical equations to provide accurate gas flow permeabilities. When this occurs, permeability measurements made at low gas pressures in small pores lead to an overestimation of the measured (or apparent) permeability. This is called the Klinkenberg or gas slippage effect (Tiab and Donaldson, 2012) and must be corrected for.

To correct the gas slippage effect, we applied the Klinkenberg correction on the samples tested at effective stresses of 900 psig and at pore fluid pressure (750, 600, 450, and 300) psig respectively for all experimental measurements (Klinkenberg, 1941; Rushing et al., 2004; Haines et al., 2016). The resulting Klinkenberg-corrected permeability was used later for comparison with the permeability that was evaluated using the multilinear regression method in order to estimate permeability in the non-cored intervals.

The confining pressure at which the measurements were made is high in order to mimic the pressure conditions in the reservoir. Such high pressures have the potential for modifying the pore structures and result in different measured permeabilities compared to measurements made at surface conditions (usually 500 psig.). However, the surface condition measurements should be viewed as anomalous measurements as they are not made at in situ conditions. The difference in permeability between the two sets of conditions can be significant for any clastic or carbonate rock, is usually greater for rocks which have larger porosities, for which there is much scope for compaction, and rocks whose connectivity depends upon thin pore throats, which are very sensitive to closure at higher pressures.

3.2.4 Potential porosity

Potential porosity was measured using Mercury injection capillary pressure (MICP) tests. Intrusion pressure up to 60,000 psig was carried out on 20 cleaned, evacuated samples which were chosen on the basis of their porosity, and permeability. The measured samples were approximately 15 mm to 10 mm, and the intrusion data were obtained using a Micromeritics Autopore IV 9250 apparatus (Giesche, 2006). The pore throat size distributions and the potential porosity were then calculated based on the Young-Laplace equation (Washburn, 1921; Jennings, 1987; Katz and Thompson, 1987; Glover et al., 2006).

3.3 Lithology and fracture description

It is common to use the neutron-density cross plot to determine formation lithology (Asquith and Krygowski, 2004; Rider and Kennedy, 2018). We have also examined core and cutting samples to determine that the Butmah Formation consists of three main lithofacies. Fractures were evaluated at macroscopic scale using images from core logging (Figure 4c-d) and associated core descriptions, with limited evidence provided by gamma ray, density and neutron logs (Figure 4a-b). Fractures were also evaluated at the microscopic scale by the description and analysis of thin sections.

Figure 4. (A) Shale volume of the Butmah Formation in well Bm-15 at 1:2000 scale with depths removed for confidentiality. The red and green lines in the gamma ray track represent the clean carbonate line and the shale line, respectively. (B) Bit size, caliper, gamma-ray, density, neutron, and sonic logs from an interval within well Bm-15 in the Butmah oilfield at 1:200 scale. (C) Lithofacies 1, Unit 5 of the Butmah Formation, typified by limestone with anhydrite nodules and fractures at well Bm-15. (D) Lithofacies 2, Unit 4 of the Butmah Formation typified by dolomite interbedded with anhydrite and fractures at well Bm-15.

Lithofacies 1. This lithofacies consists of microcrystalline limestone with or without anhydrite nodules. It is repeated three times in the Butmah Formation in well Bm-15 as units 1, 3, and 5. Fracturing was identified in the upper part of Unit 1 and Unit 3, and Unit 5 as shown in (Figure 5). Neutron-density cross plots of this lithofacies show that limestone is the main lithology, and is associated with anhydrite in U.5. The porosity of this lithofacies is generally less than 10%, with the highest porosity occurring in U.3 (Figure 6).

Lithofacies 2. This lithofacies is composed of dolomite interbedded with shale and some anhydrite nodules. It occurs between 2544 and 2608 m in Unit 2 of the Butmah Formation in well Bm-15, and represents 17.8% of the total thickness at this location (Figure 5). According to the neutron-density cross plot (Figure 6), this lithofacies consists of dolomite with a mean porosity less than 10%, which is associated with some anhydrite.

Lithofacies 3. This lithofacies, which is found in Unit 4, is the most common in the studied well, representing 53.4% of the gross thickness of the Butmah Formation at well Bm-15. It is composed of dolomite with anhydrite nodules, and is interbedded with anhydrite layers (Figure 5). This lithofacies is affected by fracturing and has oil shows in the interval (2362-2440 m). The neutron-density cross plot shows the presence of dolomite with anhydrite, and porosities ranging from very low to almost 40% (Figure 6).

Figure5. Stratigraphic units of the Butmah Formation at well Bm-15.

Figure6. Neutron-density cross plots of Lithofacies 1 (U.1, U.3, U.5), Lithofacies 2 (U.2), and Lithofacies 3 (U.4) of the Butmah Formation at well Bm-15.

3.4 RQTP Input parameters

Shale volume was determined from the gamma-ray log in the standard way, first by calculating the gamma-ray index (Larionov, 1969).

There are a number of ways of converting the gamma-ray index into a shale volume. The simplest is just to set one equal to the other. Otherwise, the gamma-ray index is used to calculate the shale volume via a non-linear relationship using either a chart or mathematical equation (Larionov, 1969).

$$V_{sh} = 0.33(2^{2\,I_{GR}} - 1)\,, \qquad \textbf{(1)}$$

where V_{sh}= shale volume.

The shale volume of the Butmah Formation was calculated using IP software and equation (1) for formations older than Tertiary (Figure 4A). The calculated shale volumes were compared against values of shale volume derived from X-ray diffraction measurements. The comparison showed good agreements between the outcome measurements (Table 3).

Table 3. Comparison between the shale volumes calculated from the computed gamma-ray log and X-ray diffraction technique.

Unit	Sample No.	CGR (%)	XRD (%)
Unit 4	B1	6.2	5.5
	B2	4.7	4.1
	B3	9.4	7.6
Unit 5	B4	5.8	3.9
	B5	4.3	3.1

As previously discussed, there is some question about which type of porosity is the most relevant for the RQTP. In this case study we have used the effective porosity, calculated using the standard methodology. Initially, the total porosity is the ratio of the volume of pore spaces in the rock to the total rock volume, and was calculated from the arithmetic mean of the porosities that were calculated from the density and neutron logs (Asquith and Krygowski, 2004). The effective porosity was then calculated using

$$\phi_e = \phi_b(1 - V_{sh}), \qquad \textbf{(2)}$$

Where ϕ_e= effective porosity (fractional), ϕ_b= bulk porosity (fractional), and V_{sh}= shale volume (fractional) (Schlumberger, 1989). The matrix value used by the RQTP is easily calculated by subtracting the total porosity (expressed as a fraction) from unity.

The porosity of the Butmah Formation covers a wide range from very low (less than 0.1%) to high (>40%). When expressed as a set of histograms (Figure7), it can be seen that the highest porosity is recorded in Unit 4 which is composed of Lithofacies 3 (Figure 7e), while the lowest porosity is recorded in Lithofacies 2 (Unit 2) (Figure 7c).

Table 4 shows that the arithmetic mean porosity in the Butmah Formation is (6.5±3.2%), whereas the low value of the mode is 0.5%, indicating that there are many more small porosities than there are large ones. Figure 7 shows that, with the possible exception of unit five (Figure 7f), the porosity is not distributed normally. In the circumstances the arithmetic mean and standard deviations calculated and given in Table 4 are relatively meaningless, so Table 4 also includes the modal value of porosity for each unit.

Figure7. (a) The effective porosity of the Butmah Formation at well Bm-15 plotted as a stacked histogram including all the identified units. The remaining parts of the figure show individual effective porosity histograms: (b) U.1, (c) U.2, (d) U.3, (e) U.4, and (f) U.5.

Table 4. Porosity of the Butmah Formation at well Bm-15 as a function of interpreted units.

	Porosity (%)				
Unit	**Min**	**Max**	**Std Dev**	**Arithmetic Mean**	**Mode**
Unit 1	0.2608	18.21	3.99	5.41	2.5
Unit 2	0.0001	29.82	4.37	4.06	1.5
Unit 3	1.0831	39.66	6.66	10.40	2.5
Unit 4	0.0048	42.10	8.65	7.10	0.5
Unit 5	0.0096	20.69	3.26	6.70	7.5
All Units	0.0001	42.10	7.25	6.59	0.5

All the identified units in the Butmah Formation show a unimodal distribution of porosity, but with different porosity ranges, i.e., the effective porosity range of 0-5% (poor porosity) was high in U.1 and U.2, moderate in U.3 and U.4 and low in U.5. According to Table 4, the widest porosity distribution occurs for U.4 (0.0048-42.1%), followed by U.3 (1.0-39.6%), U.2 (0.0001-

29.8), U.5 (0.0096-20.6%), and U.1 (0.26-18.2%). These porosity distributions show that, with only very few exceptions, the Reservoir Classes representing high reservoir quality (RC1 to RC3) were identified only in U.4 and U.3, while the porosity distribution range was between poor (RC5 to RC9) and moderate (RC4 to RC6) in units U.1, U.2 and U.5.

3.5 The RQTP application

The application of the RQTP methodology, as described earlier in Section 2 of this paper, to the heterogeneous Butmah Formation shows that the formation is composed of a wide range of reservoir classes. The full analysis is given in Table 5 and Figure 8, with Figure 8a summarising all of the results, and the other parts of the figure representing each of the units recognised within the formation separately.

It was expected that the Butmah Formation would exhibit rocks classified into many of the classes and zones because it is recognised to be significantly heterogeneous. The majority of rock samples from any of the units fell into the low porosity zones Lm to Ls, with most occurring in Lsm and Lm; however, there were examples of rocks occurring in the medium porosity zones, the high and very high porosity (H and V) zones, and even a few in the extremely porous E zones.

Analysis of the distribution of samples on a unit by unit basis (Figure 8b-f) shows a distribution which is often restricted to one or two zones, with minor occurrences in a few others. This observation leads us to believe that in choosing to define 19 zones in the initial RQTP model, we have defined neither too many nor too few.

Table 5. Reservoir rock classes of the Butmah Formation (1314 plotted points).

Abundance	Reservoir class	Occurrence (% of total)	Rock zone(s)
1	7	46.32	Lm
2	8	32.14	Lsm, Lms
3	5	7.91	Msm, Mms
4	2	4.49	Hsm, Vsm, Hms,
5	4	3.96	Mm
6	9	2.36	Ls
7	1	2.44	Hm, Vm, Em
8	6	0.38	Ms

Figure 8. (a) Staged ternary plot of the framework components of the Butmah Formation illustrating the reservoir rock classes and zones. The remaining parts of the figure show individual ternary plots for each unit: (b) U.1, (c) U.2, (d) U.3, (e) U.4, and (f) U.5.

3.6 Permeability

There are many methods used to calculate permeability from wireline logs in reservoir rocks, most of which are empirical methods that seek to correlate permeability with other parameters that are more easily measured downhole, from porosity to NMR T_2 relaxation (e.g., Tixier, 1949; Timur, 1968; Coates, 1974; Coates, 1981). Permeability can be estimated with the NMR log (Glover et al., 2006; Rashid et al., 2015a; Rashid et al., 2017), by correlation of permeability with Stoneley wave velocity from modern full-waveform array sonic logs (Coates et al., 1999), from the pressure/time data obtained with formation-tester tools (e.g., the RFT tool) (Ahmed et al., 1991), using multiple variable regression (Mohaghegh et al., 1995;1997; Taghavi, 2005), from effective porosity (Taghavi, 2005), and recently using machine learning (Al-Khalifah et al., 2020). The mercury injection capillary pressure curve can be used in many ways, such as to characterise pore throat and pore size distributions within measured samples (Glover et al., 2006; Glover and Walker, 2009).

In this study, the permeability of the Butmah Formation was evaluated using the multilinear regression method based on the equation of Taghavi (2005).

$$\log k = a + bx_1 + cx_2 + dx_3 + \cdots + nx_i \quad \textbf{(3)}$$

where k = permeability, and a, b, c, d and n are constants, and the x are the values that are measurements obtained from individual wireline logs. Taghavi (2005) noted that gamma ray and bulk density have a negative relationship with porosity and permeability whereas high readings of neutron porosity and interval transit times are associated with high porosities.

For the Butmah Formation, Equation (3) becomes

$$\log k = 28 - 0.09GR + 5.5\rho_b + 23\phi_n + 0.04\Delta t, \quad \textbf{(4)}$$

by using gamma ray, bulk density, neutron porosity and acoustic travel time measurements, where k = permeability (mD), GR = gamma ray log reading (API), ρ_b = bulk density log reading (gm/cm^3), ϕ_n= corrected neutron reading (fractional), and Δt = interval transit time (µs/ft).

Comparison of the predicted permeability values from Eq. (4) with permeability values measured on cores shows the prediction to be good, with permeability ranging between 10 nD and 10 mD (Figure 9).

3.7 Petrofacies

Petrofacies are high-order lithofacies characterised by specific petrophysical properties (commonly porosity and permeability) that describe rock facies at wireline log scale, and that can be compared directly with core logging throughout the cored interval (Passey et al., 2006; De Ros and Goldberg, 2007).

Four petrofacies were recognised in the Butmah Formation, distinguished on the basis of experimentally measured porosity and permeability alone (Table 6 and Figure 9).

Table 6. Characterisation of petrofacies types according to their petrophysical properties.

Petrofacies	Porosity (%)	Permeability (mD)	Type
A	>20	0.1 – 10	Good
B	10-20	10^{-3} – 0.1	Moderate
C	1-10	10^{-5} – 10^{-3}	Fair
D	<5	10^{-7} – 10^{-5}	Poor

We have compared these standard petrofacies results to the results obtained for reservoir classes defined by the newly presented RQTP approach. Figure 9 integrates both analytical approaches in one figure. The broad similarity between the RQTP reservoir classes (green curve) and the petrofacies (rightmost column) is very clear. However, it is also clear that the RQTP approach retains more information about how the quality of the reservoir rock varies at a small scale. For example, rocks which appear as Petrofacies A show RQTP reservoir classes RC1 and RC2. These rocks consist predominantly of clean and wacke matrices, indicating that the main control on the reservoir quality of the Butmah Formation was diagenetically represented by dolomitisation and dissolution of the anhydrite cementation in some intervals. Petrofacies D are represented by reservoir classes RC8 and RC9, and are non-reservoir intervals. Consequently, the RQTP reservoir classes are sensitive to the same characteristics as standard petrofacies, but provide a greater ability to distinguish between more subtle changes in the reservoir quality. The RQTP approach recognises 19 reservoir zones, and if these are used instead of or as well as the reservoir classes, the potential for being able to make very fine distinctions in the link between reservoir quality, petrophysical properties and the history of the evolving pore microstructure will be even greater.

Fracturing was the main additional positive control on Petrofacies D in the Butmah Formation. The effect of diagenesis was associated with different degrees of fracturing, which created the final pore network of the Butmah Formation as either a hybrid diagenetic and fracturing pore system or an unfractured diagenetic pore system.

Figure9. The distribution of reservoir quality classes, estimated permeability and petrofacies of the Butmah Formation. The permeability curve in Track 5 was predicted using Equation (4) and compared with the core permeability. The identified petrofacies in Track 6 were determined according to Table 5.

4. SUPPLEMENTARY CASE STUDIES

4.1 Introduction

In this paper we have chosen to focus the application of the RQTP approach to the Butmah formation because its lithological variability and petrophysical heterogeneity makes it a challenging problem for the analysis of reservoir quality. In this section we apply the RQTP approach to a further 4 formations, each of which is less lithologically variable and more petrophysically homogeneous. The results from this section show how clearly the RQTP approach can describe a given formation, as well as expanding the number of example applications provided by the paper.

4.2 Lithological Summary

We have applied the RQTP approach to four carbonate reservoirs all of which occur in the Ain Zalah oilfield. This oilfield lies parallel to the Butmah anticline in northern Iraq (Dunnington, 1958) (Figure 3) and is offset from it by approximately 10 km to the North. The formations concerned are the Shiranish, Mushorah, Gir Bir, and Mauddud formations, all of which can be recognised in wells Az-16 and Az-29, and which are shown as summary lithological column and gamma-ray logs in Figure 10.

Figure 10. Stratigraphic units of the studied formations at well Az-16, including the Shiranish, Mushorah, Gir Bir, and Mauddud formations.

The Shiranish Formation is divided into four stratigraphic units consist mainly of limestone, marly limestone, and limestone interbedded with marly limestone. The Mushorah Formation is divided into two main stratigraphic units, the upper of which is predominantly limestone, while the lower is a dolomitic limestone interbedded with silica, chert and shale. The Gir Bir Formation is divided into two stratigraphic units which are composed of limestone and brecciated limestone, respectively, while the Mauddud formation consists predominantly of dolostone (Jasim and Goff, 2006; Aqrawi et al., 2010; Mohammed Sajed and Glover, 2020).

Consequently, while each of these formations is more homogeneous than the Butmah Formation, together, they also provided a large range of different lithologies and hence in petrophysical properties.

4.3 The RQTP application

The application of the RQTP approach to the heterogeneous Butmah Formation in Section 3 shows that this formation is composed of a wide range of reservoir classes. Here, we apply it the Shiranish, Mushorah, Gir Bir, and Mauddud formations to widen the number of carbonate formations studied in this paper. The results are shown in Figure 11.

For the Shiranish Formation (Figure 11a), three of the four rock types occur in low to moderate reservoir classes RC4, RC5, RC7 and RC8, and essentially are co-located. These rock types include (i) limestone interbedded with marly limestone, (ii) marly limestone, and (iii) limestone of units 1 to 3, respectively. The remaining unit of the Shiranish Formation is also composed of marly limestone, but contains significant horizons of significantly higher effective porosities (up to about 35%), and consequently occurring in RC1 and RC2 in addition to those reservoir classes occupied by the other units of the Shiranish formation. Irrespective of their porosity, the marly limestone samples tend to occupy reservoir classes RC2, RC5 and RC8 compared to the limestone samples which occupy reservoir classes 4 and 7, corresponding to their larger shale fraction. The Shiranish Formation reservoir classes distribution is similar to units 1 and 5 reservoir of the Butmah Formation.

The two units composing the Mushorah Formation (Figure 11b) show significantly different patterns as would be expected from the difference between their lithoologies and lithological complexity. The upper unit in this formation is solely limestone, and occupies RQTP reservoir classes 7 and 8, indicating a predominantly low shale (<30%), low effective porosity (<10%) rock type that is clearly of low reservoir quality. The lower unit has significantly variable lithology, and this is reflected in the RQTP results, with values occupying 7 of the 9 available reservoir classes (RC1, RC4, RC5, RC7, RC8, RC9), covering the complete range of shale volumes and effective porosities, but not including both the highest porosities and highest shale volumes in the same sample. The lower unit appears to have a similar distribution to the shale interval U.2 of the Butmah Formation, while the upper unit (U2) appears similar to the reservoir class distribution in the limestone units (U1 and U5) of the Butmah Formation.

Both units of the Gir Bir Formation (Figure 11c) have effective porosities less than 10%. Unit 1 of the Gir Bir Formation is composed of recrystallized limestone with small porosities, low shale content and small grain sizes which result in very small permeabilities. It occupies RC7 in the RQTP classification and represents extremely low quality reservoir rock. The brecciated/conglomeritic limestone of Unit 2 in the Gir Bir Formation might have been expected to present higher porosities sufficient to extend the RC7 classification into RC4, but this does not occur. Instead, the additional pore space is occluded by disperse shales, resulting in RQTP reservoir classes of RC7 and RC8, and leading to permeabilities which are extremely low because there is little or no connectivity of what little effective porosity remains.

Finally, the Mauddud Formation (Figure 11d) consists of dolomite samples that show the same reservoir class distribution as Unit 4 of the Butmah Formation. The samples occupy predominantly reservoir classes RC4, RC5, RC7 and RC8, with a few outlying samples of high effective porosity and low shale volume in RC1. The majority of the samples occur in RC7, indicating low porosities and low shale content. However, higher effective porosities are possible and are associated with the process of dolomitisation and associated fracturing of the brittle dolomite minerals, while some of the new porosity has been filled by shales. Consequently, the dolomite of the Mauddud Formation is a good example of a seemingly simple single lithology according to well-logs and stratigraphy (Figure 10) containing a wealth of variation in its petrophysical properties and hence in its reservoir quality.

Figure 11. Staged ternary plot of the framework components of the studied formations illustrating the reservoir rock classes and zones. (a) The Shiranish Formation (b) the Mushorah Formation (c) the Gir Bir Formation, and (d) the Mauddud Formation.

5. DISCUSSION

5.1 RQTP model and controlling factors

After deposition, the rock composition (lithology) suffered from various diagenetic processes to initiate a pore network that was affected later by different kinds of fracturing to create the final pore network that is responsible for the permeability of any carbonate reservoirs (Figure12).

According to the results of using the RQTP Model, the identified controlling factors can be summarised using the ternary diagrams shown in Figure 12 and the analysis set out in the subsections below.

Figure12. Ternary plot for the framework components of the rocks with the controlling factors (a) Reservoir quality ternary plot (RQTP) Model, (b) lithology, (c) pore network heterogeneity, (d) fracturing control, and (e) permeability. The dark blue arrows indicate the relationship between these factors, whereas the red arrows refer to the three controls' effect on the RQTP Model. The green arrow refers to the permeability outcome depending on the RQTP Model.

5.1.1 RQTP Model and lithology

The lithology of the Butmah Formation was identified according to the comparison between the density-neutron and gamma-ray logs response and the core and cutting samples from the core intervals within the studied Formation. Fractures affect the carbonate reservoirs in varied amounts and intensity according to their lithology (Figure13). Connecting these properties with the RQTP gave a good agreement with the lithology of the Butmah Formation (Figure 12b). These agreements can be generalised to all carbonate formations as a new method for lithology estimation.

5.1.2 RQTP Model and pore network heterogeneity

Carbonate rocks commonly show a complex and irregular pore network and connectivity due to the spatial distribution of heterogeneity, occurring at different scales of measurement, analysis and observation (Agar and Geiger, 2014). Using the RQTP to characterise carbonate reservoir complexity is considered one of the most important methods that can provide a quick reliable estimation. Figure 12c illustrates that the degree of heterogeneity increases with increasing effective porosity, while the degree of heterogeneity is also increased for moderate shale volumes. The highest heterogeneity is characterised in RC2 and the lowest in RC7 and RC9.

5.1.3 RQTP Model and fracturing control

Fractures are present to varying degrees in carbonate rock and the internal geometry and distribution of these fractures play an important role in fluid flow and reservoir quality (Caine et al., 1996; Childs et al., 1997; Evans et al., 1997; Cello et al., 2003; Micarelli et al., 2003; Geraud et al., 2006; De Paola et al., 2007, 2008).

Fractures are controlled by many geological parameters, such as composition, grain size, porosity, bed thickness and structural position (tectonism) (Nelson, 2001). In carbonate rock, fine dolomite has a favoured grain (crystal) size and composition that enhances fracturing intensity, while coarse limestone has the lowest fracturing intensity (Sinclair, 1980; Nelson, 2001) (Figure13). Porosity in general decreases rock strength, and fracturing in rock depends on the brittle minerals present. By contrast, high porosity rock does not guarantee brittleness. However, fracturing in general is developed in shale with increasing the brittle minerals components (Ding et al., 2012)

Regarding the bed thickness, thinner beds are typically fractured at a closer spacing than thick beds (Nelson, 2001). The tectonic control affects carbonate rocks by different ways such as uplift, differential subsidence, active faulting and folding, where fracture intensity is higher in the finer grained rock (Burchette, 1988; Wilson and Hall, 2010).

Figure 12. Histogram illustrating the relationship between fracture intensity and lithology (composition and grain size) of carbonate rocks (after Nelson, 2001)

Application of these concepts to the RQTP provides a powerful tool for characterising the intensity of fractures in the different lithology and effect of fracturing on the reservoir quality of carbonate formations. Generally, fracturing intensity increases in fine grain crystals and similarly increases with increasing shale volume (Nelson, 2001). Fracturing also slightly increases or decreases the effective porosity of reservoir formations depending upon whether the fractures are open or occluded (Figure 12d). The highest fracture effect and intensity are recorded in RC2 and the lowest in RC7.

5.1.4 RQTP Model and permeability

Permeability is a crucial parameter in characterising any reservoir quality (Rashid et al., 2015b). Figure 12e summarises the combined effects of rock quality, lithology, fracturing and heterogeneity on permeability. It should be noted that the various classes for permeability are analogous to those for porosity. Comparison with the data from the Butmah Formation shows that the highest permeability values occur in RC1 and RC2 as good values. Good to moderate values were recorded in RC5 and RC6, followed by moderate to fair values in the RC6, RC8 and RC9. The lowest values of permeability were recorded in the RC7 as poor permeability.

The following table summarises all the results of applying the RQTP Model.

Table 7. The outcome of applying the reservoir quality ternary plot (RQTP) Model for characterising carbonate reservoirs

Reservoir Class	Rock quality	Fracture intensity	Pore network heterogeneity	Permeability
RC1	Clean	Low	Uniform	Good
RC2	Wacke	Moderate	Complex	Good
RC3	Shale	High	Uniform	Good
RC4	Clean	Low	Uniform	Moderate-Fair
RC5	Wacke	Moderate-High	Complex	Good-Moderate
RC6	Shale	High	Uniform	Good-Moderate
RC7	Clean	Low	Uniform	Fair-Poor
RC8	Wacke	Low	Complex	Moderate-Fair
RC9	Shale	Low	Uniform	Moderate-Fair

5.2 Poroperm relationship and reservoir classes

Carbonate reservoir quality is affected primarily by cementation, dissolution, dolomitisation, recrystallization and fracturing (Mohammed Sajed and Glover, 2020). These controls can be clearly characterised by lithology, pore network heterogeneity, fracturing and permeability. Lithology represents a mixture of depositional facies and diagenetic effects. These two factors, with fracturing, control the creation of a variety of pore networks in carbonate rocks and hence produce rocks with different reservoir qualities, as judged by their porosity, permeability, and pore throat size distributions.

The poroperm-RC relationship (Figure14) shows that the best reservoir quality samples were represented by RC1 and RC2, together with a few samples of RC4 and RC5. However, most samples falling in RC4 and RC5 show moderate reservoir quality. Most of the plotted samples were characterised with porosity less than 10%, and classified in RC7 and RC8. Most of the worst reservoir quality samples were characterised in RC7 and RC8, while a few of these very low reservoir quality rocks occurred in RC4, RC6, and RC9.

Most of the samples with a shale volume of 0.6 and greater (i.e., the shaliest rocks in the dataset) are from Unit 2 and are classified by the RQTP in RC9, with a porosity less than 10% and a consequently low permeability (less than 0.01 mD). These rocks are clearly shown in Figure 7c as red symbols and in Figure 14 as yellow symbols. However, some of these V_{sh}>0.6 rocks exhibit enhanced permeability between 0.01 and 1 mD that is expected to be related to the presence of fractures. A few samples with V_{sh}>0.6 are classified by the RQTP in RC6, with porosities just over 10%. These samples also have raised permeabilities for the same reason.

Samples with low shale volumes and porosity less than 5% are classified by the RQTP in RC7. These samples have permeabilities less than 0.1 mD (Figure 14) and belong to the anhydrite cemented intervals which occur in all units of the Butmah Formation (Mohammed Sajed and Glover, 2020).

Figure 14. Porosity-permeability relationship showing sample distribution in the reservoir classes

5.3 RQTP and rock quality

The new model can be used as a reliable first-order estimation of any carbonate reservoir. However, the method has some limitations. One limitation is in the application of the model to shaly carbonates, where reservoir quality will be overestimated unless the method is implemented using potential porosity in place of effective porosity. The use of potential porosity reduces the potential efficiency of the RQTP because potential porosity requires mercury injection capillary pressure (MICP) measurements which are expensive to carry out on a statistically sufficient number of samples.

One of the goals of petrophysics is to determine the framework components and then to use them to provide a reliable indicator of reservoir rock quality. The RQTP approach can generally classify the reservoir quality of carbonate rock into three main types (Figure15):

Figure14. Rock quality groups according to the reservoir quality ternary plot (RQTP) Model.

Group 1: This group consists of reservoir classes RC1 (Em, Vm and Hm), RC4 (Mm) and RC7 (Lm). It includes clean matrix rocks (e.g., carbonates or evaporites), which exhibit a matrix porosity system (e.g., intergranular, intercrystalline, moldic and vuggy porosity) (Rashid et al., 2015). The porosity of rocks in this class may be derived solely from the matrix. However, there may also be an additional contribution to porosity by open fractures, forming a uniform, hybrid or dual porosity system (Ahr, 2008).

Group 2: This group includes reservoir classes RC2 (Esm, Vsm, Hsm, Ems, Vms, Hms), RC5 (Msm Mms) and RC8 (Lsm, Lms) and comprises wacke matrix rocks (e.g., shaly limestones, marly limestones). Once again, the porosity may be derived in part from the matrix, but according to the RQTP model, the fracturing effect is greater than in the earlier group. Consequently, these rocks commonly present with a hybrid or dual porosity system (Ahr, 2008).

Group 3: This group consists of reservoir classes RC3 (Vs, Hs), RC6 (Ms) and RC9 (Ls) and comprises shale rocks, with very little clastic element. Their small effective porosity is derived from natural or artificial fractures. Naturally fractured shales would be expected to occupy zone Ls, while hydraulic fracturing might locally translate the rocks into zones Ms and Hs, or in extreme circumstances into Vs. These rocks commonly present with a uniform porosity system and dominated by fractures (Ahr, 2008).

We recognise that both the reservoir classes and petrophysical zones promoted by this paper are the result of a set of complex interdependent diagenetic processes that are different for every rock. Recent success in using machine learning approaches to predict permeability in tight carbonate rocks (Al-Khalifah et al., 2020) leads us to believe that the application of neural networks and genetic algorithms to the recognition of reservoir classes and petrophysical zones and indeed petrofacies may not only be a useful technique in the future but perhaps capable of introducing a degree of quantitative analysis into our descriptions of the outcomes from various diagenetic processes.

6. CONCLUSIONS

The analysis of the reservoir quality of carbonate reservoirs has been approached using a new reservoir quality ternary plot (RQTP), which considers the fraction of matrix material, shale material and porosity in the formation. The porosity may be represented either by effective porosity or potential porosity according to the availability of data. The RQTP is described in this paper together with a case study in which it is applied and a discussion of how different geological factors control the position at which a given sample plots on the RQTP. The main conclusions are:

- The RQTP model is a simple and quick method to classify the reservoir quality of any carbonate reservoir based on three basic calculated percentages: $V_{sh}\%$, $Mat\%$, and $\phi_{eff}\%$ or $\phi_{pot}\%$.
- Comparison of the results of using effective porosity and potential porosity to represent rock porosity on the base axis of the ternary plot has been carried out for a database of 20 core plug samples. The core samples chosen for this comparison were taken from different core intervals within the reservoir and were chosen to cover as much of the ternary plot area as possible in order that the effect of using effective porosity or potential porosity could be judged over as much of the ternary plot as possible. The main result from this comparison is that the discrepancy between using the two different methods increases as shale volume increases and as porosity increases.
- The RQTP can be used as a useful tool to understand the controlling factors (lithology, pore network heterogeneity, and fracturing) that affect the reservoir and create the reservoir properties of carbonate rocks.
- The rock quality of carbonate reservoir as classified by the RQTP model is consistent with classifications based on petrofacies and on compositions, such as that splitting the rock into clean, wacke, and shaly groups.

The application of the RQTP model to sandstone reservoirs will be discussed in a further research paper. We recommend that the RQTP is used in conjunction with a standard poroperm plot to fully characterise the quality of a given carbonate reservoir.

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