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Rock typing and reservoir zonation based on the NMR logging and geological attributes in the mixed carbonate-siliciclastic Asmari Reservoir

Sajjad Gharechelou[1], Abdolhossein Amini[1]*, Ali Kadkhodaie[2], Ziba Hosseini[3], Javad Honarmand[4]

[1] *Department of Geology, Faculty of Science, University of Tehran, Tehran, Iran*

[2] *Department of Earth Science, Faculty of Natural Science, University of Tabriz, Iran*

[3] *Department of Geology, Faculty of Science, Ferdowsi University of Mashhad, Mashhad, Iran*

[4] *Research Institute of Petroleum Industry, Petroleum Geology Department, Tehran, Iran*

**Corresponding author, e-mail: ahamini@ut.ac.ir*

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Abstract

Determination of rock types in hydrocarbon reservoirs results in more accurate reservoir modeling and gridding. Most of rock typing methods restrict to some aspects of the studying rocks, by which minor attention is taken to factors such as multi-scale and multi-modal pore types and sizes, sedimentary textures, diagenetic modifications and integration of dynamic data. Rock typing of a mixed carbonate-siliciclastic reservoir by integration of its static and dynamic behaviors and sedimentary textures is practiced here as an effective technique for reservoir characterization. Porosity, permeability and pore size distributions are investigated as the static behavior and capillary pressure, water saturation and irreducible water saturation as dynamic behavior of the rocks. Results from the analysis of core data in available intervals and continuously NMR data through the whole well of the studying reservoir are involved in this study. Initially, based on the Flow Zone Index method, while considering geological attributes, 7 rock types are determined. Next, the petrophysical properties of the rock types including capillary pressure, water saturation and irreducible water saturation are combined into the rock types. Afterward, pore types, facies characteristics, texture and diagenetic overprints are involved in the rock type's classification to capture spatial trends and relationships. Due to the close relationship between depositional sequences and diagenetic processes, the defined rock types are tracked in the sequence stratigraphic framework. Using the mentioned parameters, the rock types are defined in the cored intervals and then predicted in non-cored intervals by NMR data. The rock types are established to provide a clue on the high and low permeable zones and to apply for more accurate reservoir zonation.

Keywords*: Asmari Reservoir; Capillary Pressure; Rock Type; Reservoir Zonation; Mixed Carbonate-Siliciclastic Reservoirs*

Introduction

Hydraulic properties of reservoir rocks are critical in exercising their drilling strategies and petrophysical characteristics. Porosity and permeability are two important parameters controlling the fluid flow in porous media (De Marsily, 1986). Permeability estimation is more important than that of porosity in the reservoir evaluation. Permeability measuring on core data, although reliable, is expensive, time consuming, and restricted only to the cored intervals. Moreover, depending on the sampling strategy and recovery, preservation and preparation of some severe discrepancies from reservoir conditions may occur. Because of their continuous nature, the well logs data are proper substitute for permeability determination (Song, 2013). In this regard, NMR logging technique is recommended for continuous estimation of porosity, permeability, capillary pressure (Pc), water saturation (Sw), irreducible water saturation (Sw_{ir}) and pore size distribution both in sandstone and carbonate hydrocarbon reservoirs (e.g. Prammer, 1994; Prammer *et al.,* 1996; Coates *et al.,* 1998, 1999; Hidajat *et al.,* 2002; Glover *et al.,* 2006; Revil & Florsch, 2010; Weller *et al.,* 2010; Hossain *et al.,* 2011; Weller *et al.,* 2013; Dillinger and Esteban, 2014). Among several models and equations two common models and empirical equations are preferred here. Numerous techniques are used for quantitative rock typing, by which rocks are classified into distinct units (e.g. Frank *et al.,* 2005; Gomes *et al.,* 2008; Peralata, 2009; Kralik *et al.,* 2010; Shabaninejad *et al.,* 2011; Al Ameri and Hesham, 2011; Tillero, 2012; Xu *et al.,* 2012; Southworth *et al.,* 2013; Aliakbardoust and Rahimpour-Bonab, 2013; Skalinski *et al.,* 2013; Gharechelou *et al.,* 2015; Hassall *et al.,* 2015; Skalinski *et al.,* 2015; Chandra *et al.,* 2015; Gharechelou *et al.,* 2016; Gharechelou *et al.,* 2016). In this study the static and dynamic properties of the rocks and their geological attributes are integrated for rock typing. In this approach, a given rock type is imprinted by unique porosity, permeability, pore size/type, capillary pressure and water saturation. Similarly, the geological attributes of the rock types as texture, facies parameters, diagenetic features and pore types are marked. The rock types are then discussed in the sequence stratigraphic framework.

The ability of NMR technique in measuring of porosity, permeability, capillary pressure and water saturation signifies it for continuous rock typing along the wellbores. Classifying the rocks into groups with specific geological and petrophysical characteristics eases better determination of reservoir zonation and detailed description of the reservoir. Including the texture, facies characteristics and pore types would result to a refined reservoir modeling. Since the fluid flow, capillary pressure and saturation in sedimentary rocks are controlled by depositional and diagenetic process, the studying rocks are classified based on petrophysical NMR data (TCMR, KSDR and Timur, pseudo Pc and Sw, pore size and sorting) in the geological framework (texture, facies and diagenetic feature).

The main objective of this research is continuous rock typing along the wellbore which lets to track these multi-scale geological-petrophysical features in the sequence stratigraphic framework, and more robustly at the field scale. Furthermore, one of the main advantages of using geological framework in rock typing method and distribution of reservoir zones in the field scale is comfort reliable reservoir simulation.

Geological Setting

The Oligo-Miocene Asmari Formation is the youngest and most prolific reservoir horizon in SW Iran. The base of formation in the Zagros fold belt is aged the Early Rupelian and its top is related to mid-Burdigalian that is overlain by evaporates and marls of the Gachsaran Formation (Motiei, 1993). This productive fractured reservoir produces more than 80% of total Iranian crude oil (Motiei, 1993). The Oligo-Miocene cyclic succession of southwest Iran (Asmari Formation) in the studied oilfield is composed of mixed carbonate-siliciclastic rocks of limestone, dolomite, anhydrite and sandstone. Such important lithological variation has led to temporal and special heterogeneity in the reservoir quality.

The studied field is located in the southwest of Zagros Mountains, on the northwestern edge of the Dezful Embayment (Fig. 1). The Dezful Embayment is a structural zone that contains most of the Iranian oilfields and is characterized by a low elevation and few outcrops of the Asmari Formation. This area is one of the most prolific oil provinces in the Middle East (e.g. Haynes & McQuillan, 1974; Wennberg *et al.*, 2006). This structural embayment is located in the central Zagros fold-thrust belt, and is the result of the Tertiary continental collision between the Arabian Plate and Iranian blocks (Berberian & King, 1981), that is still active (Allen *et al.*, 2004; Regard *et al.*, 2004). This belt extends from the Taurus Mountains in NE Turkey to the Strait of Hormuz in South Iran (Minab Fault). Structures within the fold-thrust belt include asymmetric anticlines with a NW-SE trend, hosting giant and supergiant reservoirs of Iran.

Figure 1. Location map of the studied oilfield in Dezful Embayment. The field has NW-SE trending in the SW of Iran.

Material and Methods

This study is established on data from cores and logs of three wells of the Asmari reservoir in the Cheshmeh-Khosh oilfield. The petrophysical parameters of the reservoir and its zonation by Iranian Central Oil Field Company (ICOFC) are also involved (Table 1). Based on the petrophysical properties and lithology variations, the formation is divided into 5 zones namely As1 to As5 from top to the base by ICOFC.

Table 1. Petrophysical properties and reservoir zonation of the Asmari Formation (by ICOFC geologists).

Reservoir Zone	Gross (MD)	Net Pay (MD)				
	Thickness (m)	Thickness (m)	Net Pay/Gross	Phi (%)	SW (%)	K (mD)
Asmari-1a	43.80	26.67	0.61	9.96	37.76	0.06
Asmari-1b	19.50	8.84	0.45	7.68	42.45	0.03
Asmari-2a	34.76	13.72	0.39	12.81	41.56	0.13
Asmari-2b	8.00	7.01	0.88	19.77	21.05	192.46
Asmari-3	28.80	16.76	0.58	14.23	29.99	1.98
Asmari-4	84.26	38.56	0.46	16.75	20.96	47.77
Asmari-5	92.00	0.61	0.01	4.96	38.51	0.01

Porosity and permeability data derived from routine core analysis. Some 430 core plugs (20 mm diameter and 80 mm length) from the zones are investigated for determination of petrophysical and geological properties. Porosity was determined in two stages. Initially, each sample was placed in a sealed matrix cup. Helium held at 100 psi reference pressure then was introduced to the cup. From the resultant pressure drop the unknown grain volume was determined using the Boyle's Law then the void volume was calculated. For permeability calculation, the samples were placed into a hydrostatic cell with an ambient confining pressure of 400 psi. The confining pressure was used to prevent bypassing of air around the sample when the measurement was made. A known air pressure was then applied to the upstream face of each sample, creating a flow of air through the core plug. Air permeability for each core sample was calculated using Darcy's Law through knowledge of the upstream pressure, flow rate, viscosity of air and sample dimensions.

Beside the cores, the NMR log from the wells which was continuously recorded by the CMR (Combinable Magnetic Resonance) tool of Schlumberger is used in this study. The NMR work for measurement of the rock properties is based on magnetization of hydrogen nuclear spine (Freedman, 2006). The echo spacing was fixed at 600 µs in this study. To determine the transversal relaxation time distribution were performed at a Larmor frequency of 7 MHz. The NMR porosity is calculated using the total signal amplitude, the bulk volume and hydrogen index. T_1 and T_2 distributions in NMR logging provided useful information about reservoir rock and fluid properties. The lithology-independent NMR log of the studying heterogenous formation was found useful for our purpose.

For depositional and diagenetic features of the formation high-resolution petrographic studies accompanied with image analysis on 623 blue-dyed thin section were carried out. The thin sections were prepared from core plugs with about one feet interval. The sedimentary facies are determined based the sedimentological characteristics of the rocks, while comparing with standard microfacies defined in the literature (e.g. Dunham, 1962; Buxton & Pedley, 1989; Wilson, 1975; Flügel, 2010; Miall, 2016).

Sedimentary Features

Both textural and diagenetic features are found significant on pore system control and reservoir quality of the studied formation. So that, depositional and diagenetic features are involved in facies analysis and pore system validation.

The Oligo-Miocene Asmari Formation in SW Iran is composed of carbonate, mixed carbonate-evaporite and mixed carbonate-siliciclastic facies (Van Buchem *et al.,* 2009), with a mixed carbonate-siliciclastic nature in the studied field. Petrographic investigation of the carbonate part resulted in the recognition of 12 microfacies, namely MFA1 to MFE3 (Table 2), representing open marine to intertidal sub-environments.

Table 2. Microfacies and facies associations (facies belts) of the Asmari carbonates in the studied wells. The main components, grain properties, and mineralogy of the microfacies are illustrated.

MF Code	**Microfacies name**	**Lithology, color and texture**	**Grain size and sorting**	**Components**		**Facies association**	**Interpretation (environment)**
				Skeletal	**Non-skeletal**		
MF A	Mudstone, bioclastic wackestone with planktonic foraminifera	Clayey-limestone, gray to black, mudstone to wackestone	Calcilutite, poorly sorted	Globigerina, lenticulina, Amphistegina		MF B1, MF B2	Deep open marine
MF B1	Bioclastic packstone with large benthic foraminifera	Lime, light brown, wackestone /packstone	Calcarenite–calcilutite, poorly/moderately sorted	Lepidocyclina, Asterigerina, Amphistegina, Heterostegina, Operculina, Ostrea,Operculina		MF A, MF B2	Shallow open marine
MF B2	Bioclastic, red algae, echinoderm, rotalia packstone	Lime, gray to cream, Packstone	Calcarenite–calcilutite, moderately sorted	Lithothamnium, Lithophyllum, Asterigerina rotula ‹Operculina complanata ‹Amphistegina lesson, Lepidocyclina		MF A, MF B2, MF C1	Shallow open marine
MF C1	Ooid grainstone	Lime, dolomite, light yellow, grainstone	Calcarenite, calcirudite, well sorted	Ooid		MF C2, MF C3, MF B2,	Barrier, shoal
MF C2	Bioclastic, faverina, ooid grainstone	Lime, brown, grainstone	Calcarenite, well sorted	Dendritina ‹Milliolid, Gastropoda, Faverina asmaricus, Foraminifera		MF C1 and C2, MF D1 and D2	Barrier, shoal
MF C3	Miliolid, dendritina grainstone	Lime, dolomite, cream to blacky gray, grainstone	Calcarenite, well sorted	Fossil fragments, Peneroplis evolutus, foraminifera, Dendritina ‹Milliolid, Ooid, Peloids		MF C2, MF D1 and D2	Barrier, shoal
MF D1	Miliolid bioclast packstone	Lime, dolomite, light gray to light brown, grainstone	Calcarenite-calcilutite, poorly/moderately sorted	Echinoderms, Red algae, Bivalves, Dendritina ‹Milliolid, Gastropoda		MF D2 and D3, MF C3	Lagoon
MF D2	Miliolid, denderitina wackestone-packstone	Lime, dolomite, gray to light brown, wackestone-packstone	Calcarenite-calcilutite, moderately sorted	Foraminifera, ‹Dendritina ‹Milliolid, Gastropoda, Bivalve fragments, Borelis, Peneroplis, Peloids, Charophyta		MF D3, MF D1, MF C3	Lagoon
MF D3	Coral boundstone	Lime, cream, brown, boundstone	Calcarenite-calcilutite, moderately sorted	Coral		MF E1, MF D2 and D1	Lagoon
MF E1	Non-laminated fine-grained dolomitized mudstone	Dolomite, anhydrite, lime, cream to brown, mudstone	Calcilutite, well sorted	Anhydrite nodules		MF D3, MF E2 and E3	Intertidal
MF E2	Laminated fine-grained dolomitized mudstone with evaporate interlayers	Dolomite, anhydrite, lime, cream to brown, mudstone	Calcilutite, well sorted	Anhydrite nodules		MF E1 and E3	Intertidal
MF E3	Stromatolite boundstone	Lime, dolomite	Calcarenite-calcilutite, moderatly sorted	Stromatolite		MF E2 and E1	Intertidal

The microfacies are grouped into five facies associations based on their genetic relationships. These facies associations indicate deep open marine (MFA), shallow open marine (MFB1 & MFB2), barrier/shoal (MFC1, MFC2 and MFC3), lagoon (MFD1, MFD2 and MFD3) and intertidal (MFE1, MFE2 and MFE3) sub-environments (Fig. 2). In the siliclastic part of the formation, 5 petrofacies (PF) are recognized which include lower shoreface to offshore sandstones (PFF), incised valley filled sandstones (PFG), upper shoreface silty/sandy shale (PFH), barrier island fined-grain well-sorted sandstone (PFI) and intertidal sandstone with shale interlayers (PFJ) (Fig. 2). Distribution of digenetic features in both carbonate and siliciclastic facies clearly shows that their development is highly affected from the energy level of sedimentary environments, so called eodiagenetic (Worden and Morad, 2003) (Fig. 2).

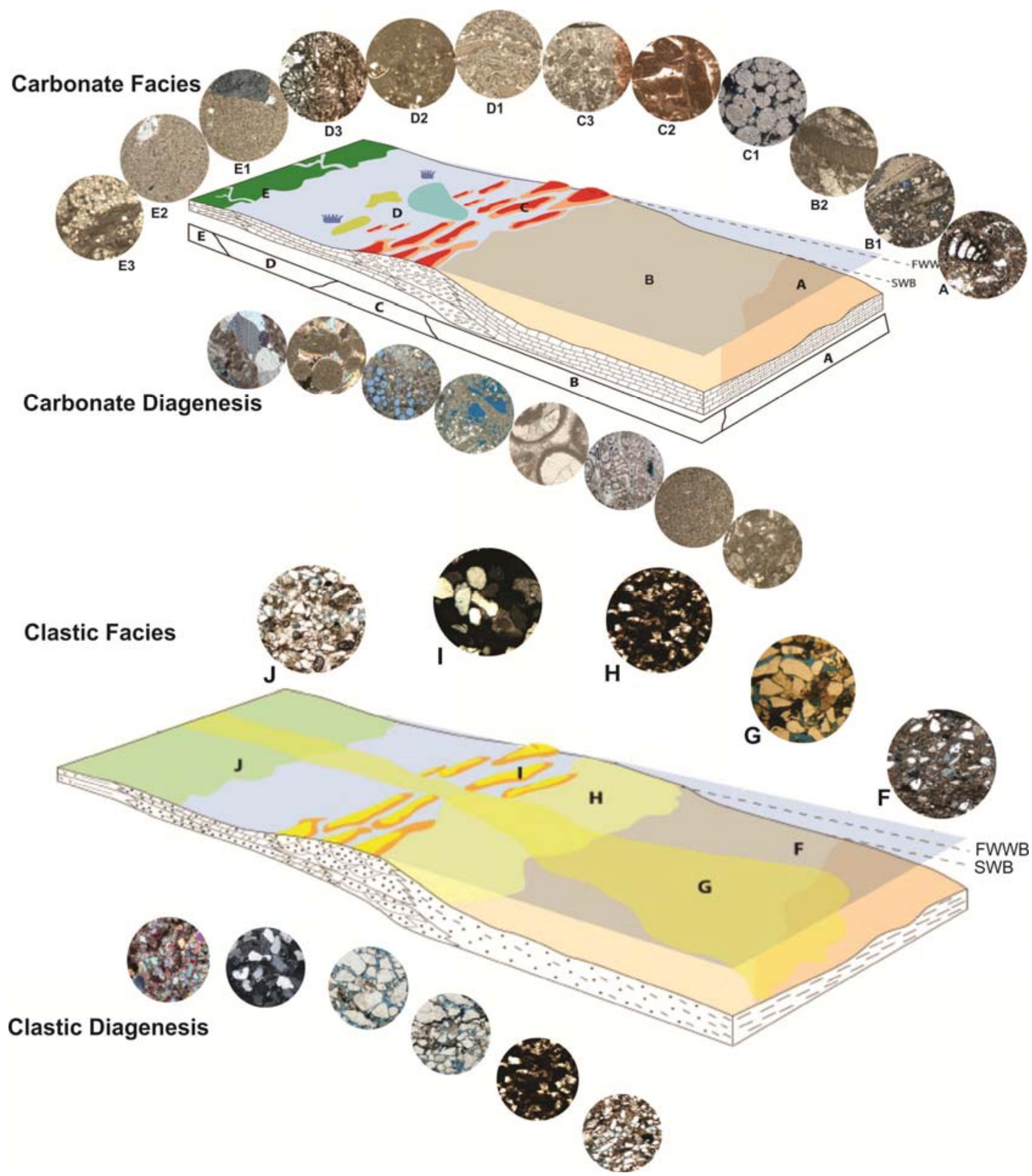


Figure 2. Conceptual depositional model for the carbonate (upper) and clastic (lower) parts of the Asmari Formation in the studied oilfield. Location of the determined microfacies and petrofacies and distribution of main diagenetic features (dissolution, cementation, dolomitization, clay infiltrate and compaction).

More susceptibility of the carbonate facies to diagenesis, affecting the pore system and reservoir quality, can be understood from such a distribution.

Results from petrographic studies, and image analyses show that the marine phreatic, meteoric, and some burial diagenetic processes have affected the reservoir facies. These findings are similar to those from cathodolominescence and isotope analyses of the formation in previous works (Honarmand, 2013; Gharechelou *et al.,* 2016). Dissolution, cementation, dolomitization, mechanical and chemical compaction are the most important diagenetic features that have changed the initial rock fabric and pore system in the studied reservoir (Fig. 2). Various pore types most likely inherited from the primary fabric and the diagenetic processes. Calcite, dolomite and silicious cements, compaction, clay infiltration and partially dissolution are common diagenetic features of the siliciclastic part. These diagenetic features have changed most macropores to micropores in the sandstone facies.

The sequences of the studied succession are determined based on the petrographic results (this study) and isotope analyses from previous works (Honarmand 2013, Gharechelou *et al.*, 2016, Daraei *et al.,* 2016). The siliciclastic (Oligocene) and carbonate (Miocene) parts of the Asmari Formation are composed of two (Ds_1 and Ds_2) and three (Ds_3 to Ds_5) 3rd-order depositional sequences respectively.

Petrophysical Aspects

Being more susceptible to diagenetic overprint, the carbonate part of the formation shows complicated and various pore types (i.e. moldic, vug, intrafossil, interparticle, intercrystalline and microporosity). Fracture pore type in some part of the field influence the reservoir quality (Kosari *et al.*, 2015) but it isn't the main pore type in the reservoir. Various pore types leads to heterogeneity of the reservoir, and a poor correlation between porosity and permeability (Fig. 3). Diagenetic processes had inferior effects on the siliciclastic part of the reservoir, in which the intergranular is the common pore type, and simple and explicit relationships between porosity and permeability are observed (Fig. 3).

The NMR log is found successful in predicting permeability, in this formation, especially in carbonate part with various pore types. The routine and widely used models of Timur-Coates and SDR (Schlumberger-Doll Research) are used for such a purpose (Coates *et al.*, 1991; Kenyon *et al.*, 1988; Kenyon, 1997; Coates *et al.*, 1999). In the SDR model permeability is calculated using fallowing equation (Hidajat *et al.*, 2004):

$$K_{SDR} = C \times \emptyset^4 T_{2LM}^2 \quad (1)$$

where K_{SDR} is the permeability (mD), Ø is the fractional NMR derived porosity, T_{2LM} is the logarithmic mean value of the NMR, T_2 relaxation time in seconds, and C is a formation dependent variable.

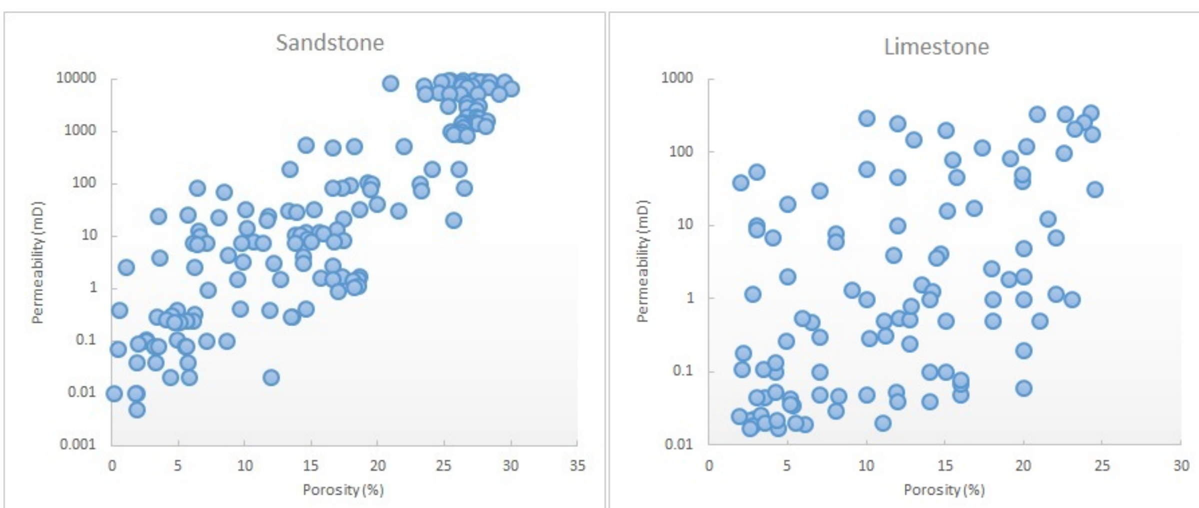


Figure 3. Porosity-permeability correlation in clastic (left) and carbonate (right) parts of the studied formation. Intergranular porosity is common pore type in the clastic rocks but carbonate rocks have various pore types.

The second model is based on the free fluid model of Coates (equation 2), a variation of the Timur equation where the irreducible water saturation is replaced by Bulk Volume of Immovable fluid (BVI) and Free Fluid Index (FFI) that represent the volumes of immobile and movable water respectively (Timur 1969; Coates *et al.,* 1991, 1998):

$$K_{Coates} = \left[\left(\frac{\emptyset}{c}\right)^2 \left(\frac{FBI}{BVI}\right)\right]^2 \quad (2)$$

where Ø is the total porosity (%), and C a constant that normally used to adjust the NMR logs. This equation builds permeability model from surface area, pore size and grain size principles (Carman, 1937; Berg, 1970; Swanson, 1981). The C parameter in the equation (2) defines a pore geometry index that ascribes to the ratio of pore body to pore throat sizes (Jorand *et al.,* 2011; Delle Piane *et al.,* 2013; Timms *et al.,* 2015). This ratio is roughly supported by the petrographic studies.

The estimated permeability values are compared with those from 429 core samples that are determined by routine core analysis (cf. Purcell, 1949; Thomeer, 1960; Huet *et al.,* 2007). Results show better correlation of the K_{SDR} and the K_{Timur} in the carbonate and siliciclastic parts respectively (Fig. 4).

Capillary pressure is a critical data in evaluating the pore structure, pore size distribution and fluid distribution within the reservoir. The connate water saturation and its distribution are directly related to the capillary pressure. The mercury injection is used as a standard technique for determination of capillary pressure on the core plugs. Since the data of mercury injection capillary pressure are only available from the cored zones, they have limitation for evaluation of pore structures continuously along the whole wellbore.

Figure 4. Correlation between predicted permeability from Timur-Coates and SDR models and those of core plugs. The Timur-Coates model in carbonate part has poorer correlation than the SDR model, whereas in clastic part it has greater correlation than the SDR model. Generally, the NMR log based permeability in the clastic parts (right) are more accurate than that of carbonate parts (left).

To overcome this problem, the pseudo capillary pressure curves by the NMR logging are constructed (cf. Xiao & Zhang, 2008; Jin *et al.,* 2012). In this method reservoir capillary pressure curves are constructed consecutively along the whole wellbore, then the pore types are evaluated.
The NMR transverse relaxation time (T_2) is known as a representation of pore size distribution. Reservoir pore structure information is directly gained from the NMR log (cf. Altunbay *et al.,* 2001). Then with a proper calibration, the T_2 distributions is converted to the pore size distribution. By using the NMR log the pore body size is measured instead of the pore throat size (Kenyone, 1997). For obtaining continuous readings of capillary pressure, the NMR T_2 distribution is converted to Pc data using equation 3 (cf. Washburn, 1921).

$$P_c = \frac{2\sigma cos\theta}{r} \tag{3}$$

where σ is the surface tension, θ is the constant angle between fluid interface and pore wall, and *r* is pore throat. The relationship between capillary pressure and the NMR T_2 distribution is expressed in equation 4.

$$P_c T_2 \cong \varepsilon \tag{4}$$

where ε is a function of rock type and pore size or equivalently T_2 (Edwards, 2005). The equation shows that the Pc can be calculated directly from T_2 once the parameter ε is determined. The relationship between pore radius and T_2 can also be formulated as equation 5.

$$\text{Pore radius } (\mu m) = 6\rho \frac{T_2}{1000} \tag{5}$$

where ρ is the surface relaxivity (μm/s). Using these equations, pseudo Pc and pore radius are continuously calculated along the wellbore (Fig. 5). Corresponding to a calculated Pc, the water saturation is also computed from the T_2 distribution (equation 6):

$$S_w(T_2) = \frac{1}{\emptyset_T} \int_{T_{2min}}^{T_2} dT_2' \emptyset(T_2') \tag{6}$$

where $\emptyset_T$ is total porosity, $\emptyset(T_2)$ is the T_2 distribution in porosity units, and T_{2min} is the minimum T_2 of the distribution. Generation of Sw and Pc from NMR logging seems to be the only way for continuous calculation of Sw-Pc of each rock type along the wellbore (Fig. 5). Rock typing parameters that are derived from NMR logging, such as capillary pressure, water saturation, pore body size, permeability, porosity, irreducible water saturation (capillary bound fluid) and T_2 distribution, are shown in Figure 5.

Morphology of T_2 distribution spectra provides clues to pore structure (Henderson, 2004). The T_2 time is a measure of surface-to-volume ratio. The rapid-relaxation in T_2 time corresponds to smaller pore sizes while longer T_2 relaxation times are associated with larger pores. The mean value of T_2 distribution, qualitatively suggests the porosity sorting and pore volume.

Discussion

Permeability, as the most important parameter of hydrocarbon reservoirs, is used here for the rock typing. The permeability models are calibrated over a particular zone of interest and verified by core data. The SDR and Timur-Coates models are used to predict permeability in the Asmari reservoir (Fig. 11, Track 11). Commonly, in the carbonate part of the formation, the reservoir rock is oil-wet and in the clastic part is water-wet. Correlating with permeability from core data, the Timur-Coates model in carbonate part has lower significance than the SDR model (Figs. 4 and 6). The presence of hydrocarbons in the BVI (oil-wet) component may result in overestimation of BVI, consequently to the underestimation of permeability. In siliciclastic part of the formation the Timur-Coates model has better correlation than that of SDR (Figs 4 and 6). In general, the permeability prediction in clastic part is more accurate than the carbonate part because of water-wet sandstone reservoir rock and good correlation between porosity, pore body and pore throat size, and pore connectivity.

Rock typing is performed here using NMR data which provide robust continuous permeability estimation and reservoir zonation. In this way the reservoir rocks are classified into 7 RTs according to their static and dynamic behavior, in the framework of sedimentological properties (Fig. 11 and Table 3). The hydraulic flow units (HFU) of the formations are also determined to establish the relationship between porosity and permeability for each rock type (cf. Amaefule *et al*., 1993). In division of HFUs, facies type, texture and common pore types are considered. Based on the Flow Zone Index (FZI) method (Abbaszadeh *et al.,* 1996; Al-Ajmi & Holditch, 2000; Tiab & Donaldson, 2004; Uguru *et al.,* 2005; Shahvar & Kharrat, 2012) 4 rock types in the carbonate and 3 rock types in the siliciclastic parts of the formation are detected (Fig. 7). Porosity and permeability of the rock types that obtained from NMR logging (TCMR, K_{SDR} in carbonate part and K_{Timur} in calstic part), are presented in cross plots (Fig. 7). Results from rock typing of the formation show that the RT_1 and RT_2 in carbonate part and RT_5 and RT_6 in siliciclastic part form the main reservoir zones, the RT_3 and RT_7 have low reservoir quality and the RT_4 has no reservoir quality.

Capillary pressure (Pc) and water saturation are synthesized by NMR logging and combined to the defined rock types (Figs. 8 and 11). Capillary pressure and irreducible water saturation are generally increased from RT_1 to RT_4 in carbonate part and from RT_5 to RT_7 in the siliciclastic part. The RT_1 and RT_5 with the best reservoir quality, have lowest Sw_{ir} and displacement pressure with interparticle/intercrystalline pore types.

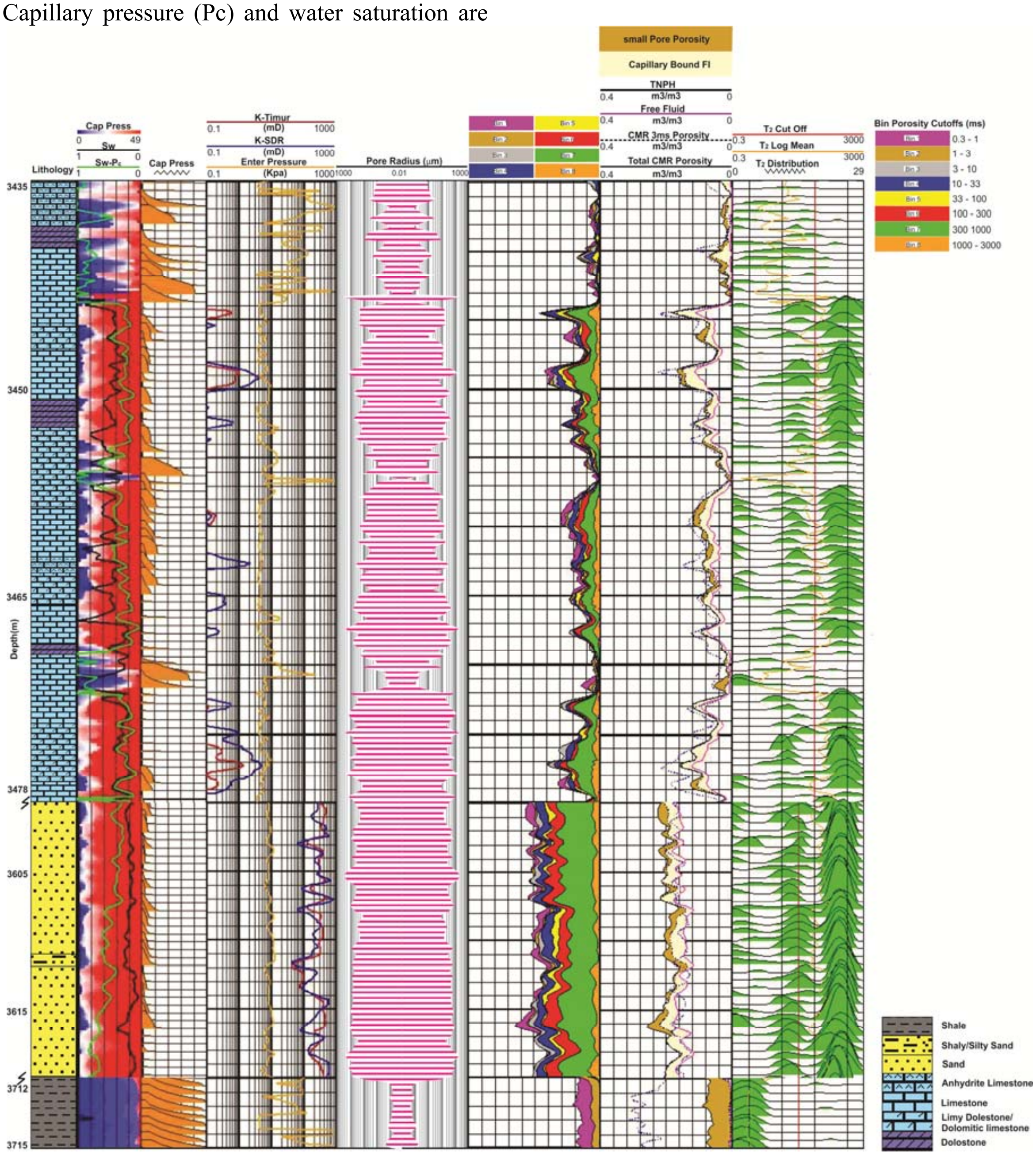


Figure 5. Continuous correlation of static and dynamic parameters calculated by NMR and used in the rock classification. Track 1: Lithology; Track 2: Pseudo capillary pressure curve and water saturation (eq. 6); Track 3: Pseudo capillary pressure curves; Track 4: Calculated KTimur and KSDR by eqs. 1 & 2 and enter pressure by eq. 4; Track 5: Continuous pore size distribution calculated by eq. 5; Track 6: Bin porosity; Track 7: Porosity, free fluid, bound fluid (Swir) and small pore porosity; Track 8: T2 distribution.

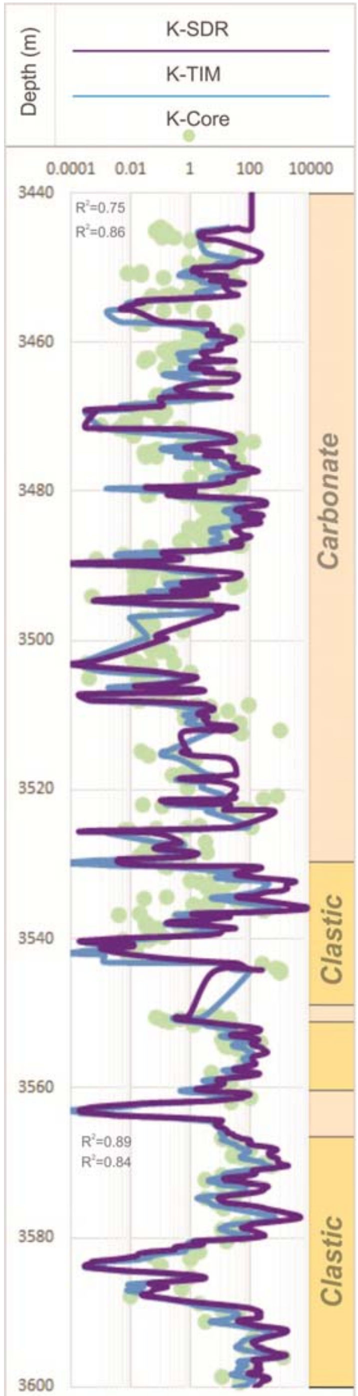
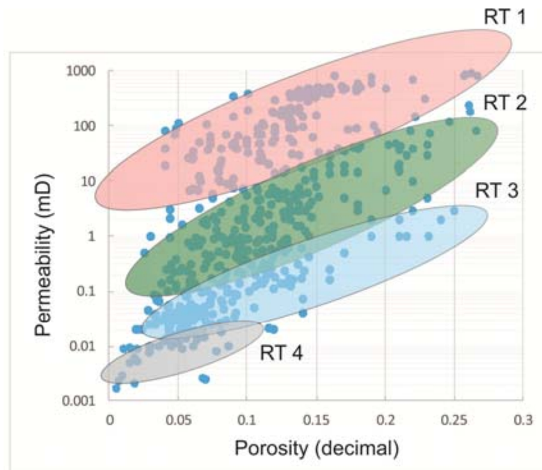
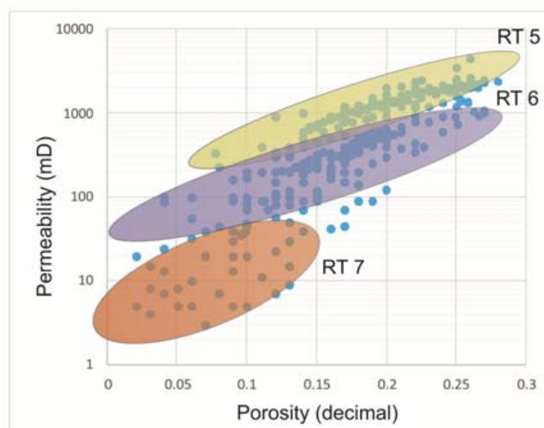


Figure 6. Correlation between predicted permeability by SDR and Timur-Coates models and those from core data in the studied formation. In the carbonate part, the SDR model has better correlation while in the calstic part the Timur-Coates model has a better correlation. Predicted permeability in clastic part has a better correlation than the carbonate part.

These rock types create high producible reservoir zones. The RT_2 is separated from RT_1 based on sedimentary textures and diagenetic features (presence of large molds and vugs in the RT_2). In comparison to the RT_1, the RT_2 shows lower reservoir quality and petrophysical properties. It is mainly due to change of its pore system by dissolution and cementation.



Facies	RT	FZI Values
Carbonate	1	6 - 10
	2	3 - 6
	3	1.5 - 3
	4	0.1 - 1.5



Facies	RT	FZI Values
Clastic	5	8 - 12.5
	6	4 - 8
	7	1.5 - 4

Figure 7. Classification of the studying rocks based on flow zone index (FZI) and some sedimentological features. The RTs 1, 2, 5 and 6 are the main reservoir zones, the RTs 3 and 7 are low-quality reservoir zone and the RT4 no-nreservoir quality zone.

The RT_3 and RT_6 have low reservoir quality that is due to microporosity pore type and high capillary pressure. The RT_4 and RT_7 are the non-reservoir rock types because of extensive cementation in their pore spaces.

By constructing the NMR capillary pressure curves, pore body radius distribution are calculated by equation 5. The curves are used to evaluate reservoir pore structures and characterize the favorable layers (rock types). Distinct reduces in the pore body radius from RT_1 to RT_4 in carbonate part and RT_5 to RT_7 in siliciclastic part are observed. Outcomes from the equation 5 show higher pore body radius in the siliciclastic part of the formation (Fig. 5 track 5). Morphology of T_2 distribution is affected by the pore types and porosity values. Small pore spaces have low T_2 relation time (bellow 100 millisecond) and large pore spaces have longer T_2 relaxation (upper 100 millisecond). Accordingly, from the morphology of the T_2 relation time, the pore sorting and the amount of pore volume (the area under the T_2 curves) can be understood. Pore sorting and pore volume of the carbonate rocks are reduced from RT_1 to RT_4 and those of siliciclastic part from RT_5 to RT_7 (Fig. 9). Results from this study clearly show that texture, facies characteristics, diagenetic features and pore types are four main parameters that effect the RTs and reservoir zonation in the studying reservoir (Fig. 11). The RT_1, with the best reservoir quality, is marked by well-preserved interconnected and sorted interparticle and intercrystalline porosities (Figs. 10a and 11) in the well-sorted ooid grainstone facies of high-energy shoal and barrier environments.

Table 3. The average value of static and dynamic parameters of determined rock types. In each RTs main sedimentological features are shown.

Rock Type	Porosity (%)	Permeability (mD)	Pore Radius (μm)	Swir (%)	Pc (Kpa)	FZI	Reservoir Quality	Pore type	Texture and Facies
1	17	350	30	11.2	19	8	High	Interparticle, Intercrystalline	Ooids Grainstone, Shoal and Barrier
2	12	40	12	28.6	101	4.5	Medium	Moldic, Vug	Intraclasts, and Bioclasts Grainstone, Wackestone, Shoal and Back-shoal
3	4	0.05	2	65	300	1.5	Low	Microporosity	Wackestone and Pacckstone, Intertidal, Lagoon, Back-Shoal
4	2	0.01	0.5	79	700	0.3	Non-reservoir	Cemented Interparticle	Wackestone, Cemented Grainstone, Shoal and Back-Shoal
5	21	1600	70	9.1	7	10	Very High	Intergranular (Macropore)	Arenite, Barrier Island and Incised Valley Filled
6	15	300	30	17.2	29	6	High	Intergranular (Mesopore)	Lithic Arenite/wacke Shoreface, Barrier Island and Channel fill sediments
7	8	20	7	89.3	250	2.5	Low	Microporosity	Quartz Wacke and Sandy Mudstone, Lower Shoreface to Offshore, Upper Shoreface and Intertidal

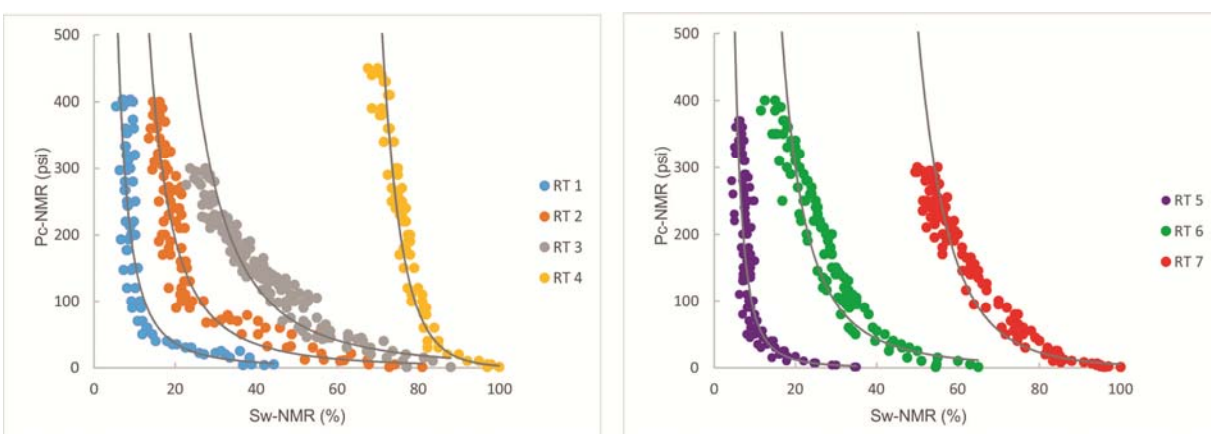


Figure 8. Classified pseudo capillary pressure curves in determined rock types.

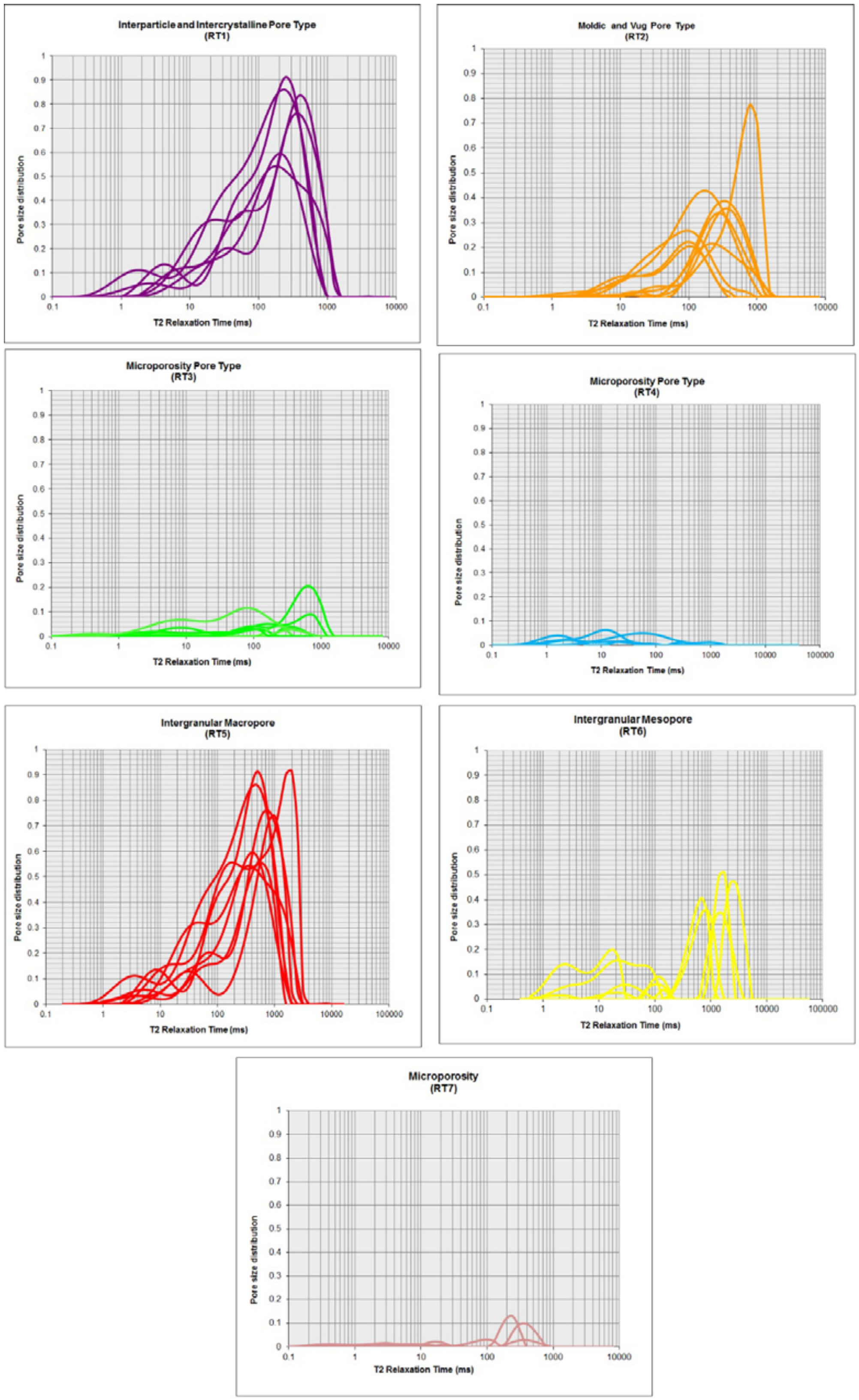


Figure 9. T_2 relaxation time for each rock type. The pore volume and pore sorting are reduced from RT_1 to RT_4 of carbonate rocks and from RT_5 to RT_7 of clastic rocks.

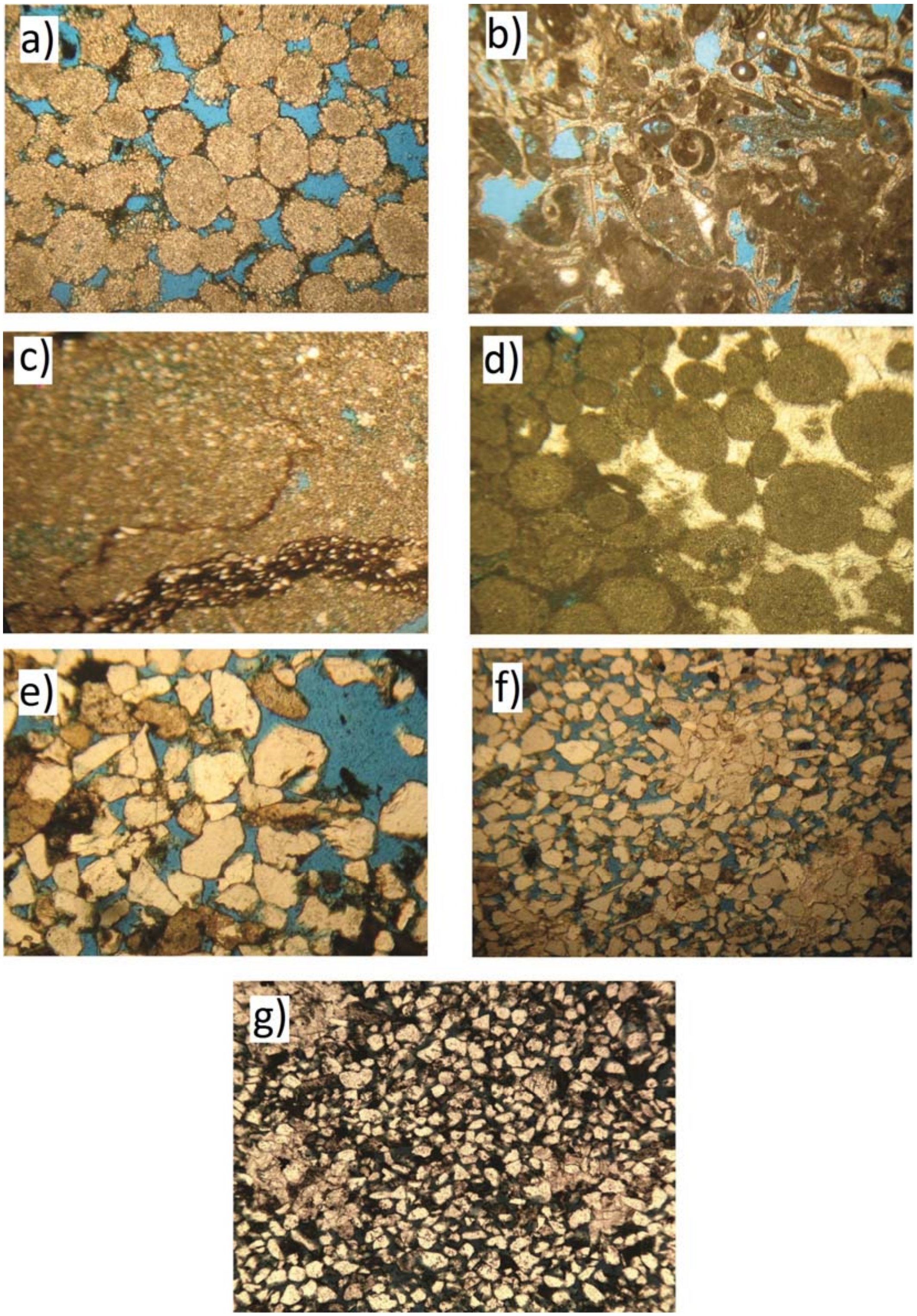


Figure 10. Facies characteristics, texture and pore types of the studied rock types. a) RT_1: dolomitized ooid grainstone (shoal facies) with interparticle pore type; b) RT_2: interaclastic back shoal packstone with extensive dissolution and moldic/vugs pore type; c) RT_3: lagoon to intertidal wackestone/mudstone with micro-dolomite (dolo-mudstone), stylolite and microporosity; d) RT_4: anhydrite cemented ooid grainstone (back shoal facies); e) RT_5: quartz arenite of barrier island and incised valley fills with intergranular macropore; f) RT_6: lithic/quartz wacke (shoreface and in-channel) with infiltrated clay and intergranular mesopore; g) RT_7: quartz wacke to sandy mudstone (lower shoreface to offshore) which is partially cemented.

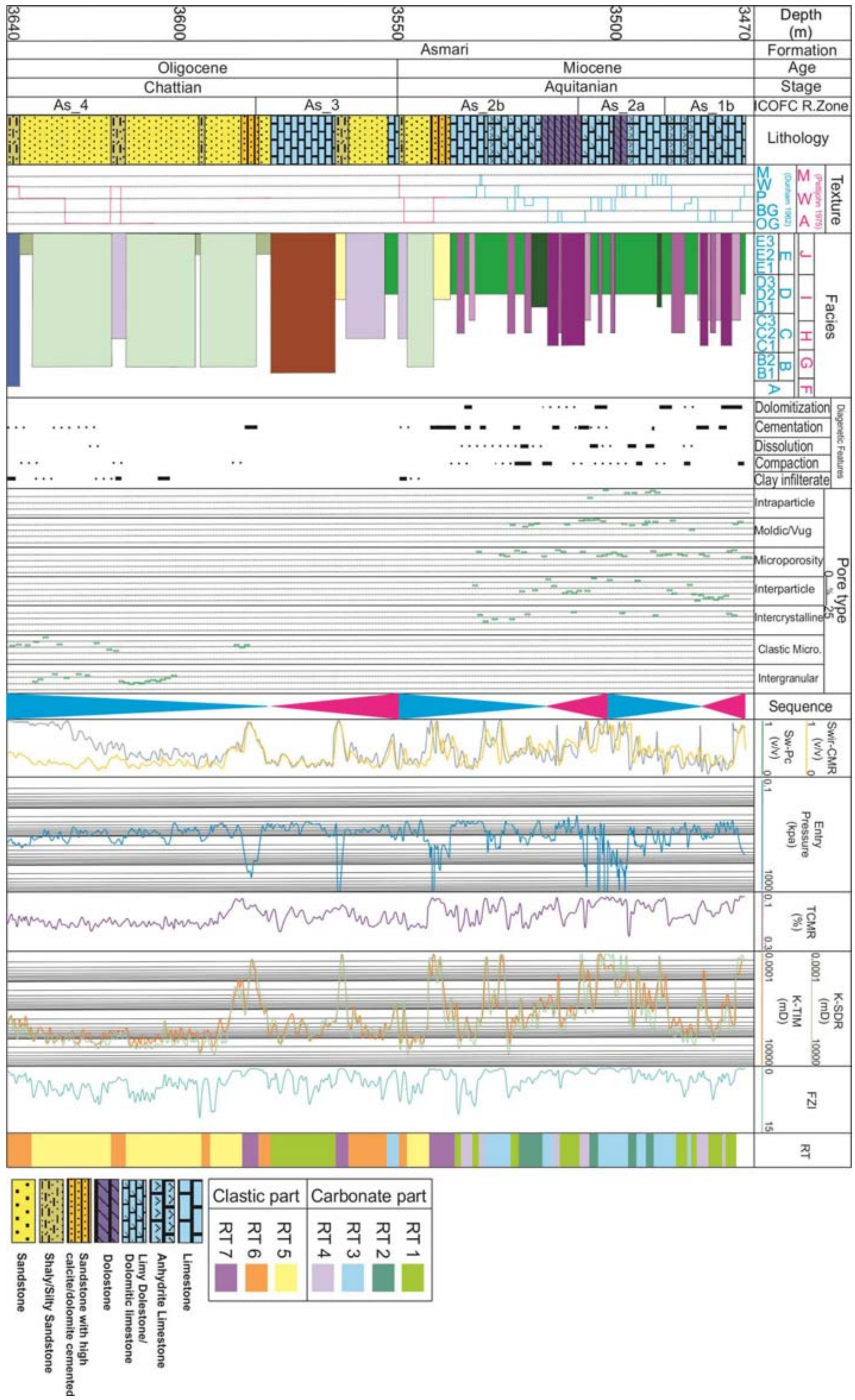


Figure 11. Continuous rock typing along the studied well based on sedimentological characteristics and static-and dynamic behavior. Track 1: Depth, formation age and reservoir zonation by ICOFC; Track 2: Lithology; Track 3: Rock texture in carbonate part (Dunham, 1962) and in clastic part (Pettijhon et al., 1987); Track 4: Defined facies from open marine to tidal flat; Track 5: Main diagenetic features that affect the reservoir quality; Track 6: The frequency of pore types; Track 7: Sequences; Track 8: Sw and Swir that are derived from NMR; Track 9: Pseudo capillary pressure from NMR log; Track 10: Porosity from NMR log; Track 11: Permeability calculated by SDR and Timur-Coates models; Track 12: FZI calculated by porosity and permeability of NMR; Track 13: Defined rock types.

Dolomitization and early mechanical compaction are the main diagenetic overprints in this rock type. RT_2 is characterized by connected moldic and vug pore types in the intraclast and bioclast grainstone and packstone facies of shoal and back-shoal environments (Figs 10b, 11). Dissolution and partially cementation are common diagenetic processes in this rock type. In the RT_3, microporosity is common pore type which has increased the Sw_{ir} and capillary pressure. This rock type is associated with wackestone and mudstone facies of lagoon and deep marine environments. Compaction, stylolitization, micritization and early dolomitization are common diagenetic features of this rock type (Figs. 10c, 11). The RT_4 and RT_1 have similar depositional remarks (grainstone and packstone), pore types (interparticle and intercrystalline) and depositional setting (shoal and back-shoal environments) but different cement content, porosity sorting, water saturation and dynamic properties (Fig. 11). Cementation is the main diagenetic feature in the RT_4 that has plugged most pore spaces by calcite, anhydrite and rarely dolomite (Fig. 10d). These diagenetic processes have reduced reservoir quality in the RT_4. Pore-filling cement increases from RT_1 to RT_4 in carbonate part (Figs. 10, 11). In general, increase in the Sw_{ir} and capillary pressure of the RTs are compatible with decrease in interparticle and intercrystalline pore types and pore sorting (Fig. 11).

In siliciclastic part of the formation, the intergranular pore type is changed from macropore to mesopore then to micropore from RT_5 to RT_7. This is the function of variation from high energy to low energy facies (Figs. 10e to 10g). The RT_5 is a semi-rounded course to medium-grained quartz arenite of high energy barrier-island and incised valley settings. Well sorted framework creates connected intergranular pore type that produces the main reservoir zone in this part of the formation (Figs. 10e, 11). The RT_6 is a medium to fine quartz greywacke of the shoreface to offshore settings. Well to moderate sorting, partial cementation, clay infiltration and compaction are responsible for change of pore size (from macro to micro) in this rock type (Figs. 10f, 11). The RT_7 and RT_5 are similar in terms of facies characters but various in terms of diagenetic features. Dolomitization and calcite cementation have plugged the pore system in the RT_7 (Fig. 10g).

Determined rock types are organized into classes (table 3) by incorporating static, dynamic and the geological properties (depositional textures, diagenesis and pore types). The defined rock types are then predicted on the geological framework in the field scale (Fig. 11) the results show that integrating the static and dynamic behavior of rocks with their sedimentological and diagenetic properties provides better clue on the reservoir zonation (Fig. 11). This approach helps to more accurate and applicable zonation of the studying formation than the former routine reservoir zonations (e.g. the ICOFC zonation in Table 1). The ICOFC reservoir zonation is only based on some petrophysical parameters without considering the geological attributes. It is also a large-scale reservoir zonation that is applicable only in well locations. The new applied method provides more precise and integrated reservoir zonation of the Asmari Formation in the studied field. The new approach predicts geological features throughout the field and has the potential to justify variations of reservoir quality in the sequence stratigraphic framework. This can be assessed by distribution of the studied facies, digenetic features, rock types and their petrophysical properties in the main constituent of the sequences (systems tracts).

The low systems tract (LST) of the sequences are composed of packstone and wackestone, representing the lagoon (D2) and shoal (C1) facies belts (Fig. 12). High amount of mud/cement has resulted in the decreasing of interparticle pore type and its modification to microporosity. The late LST is dominated by peritidal and lagoonal muds with microporosity. The superiority of sabkha and peritidal settings in the late LST and succeeding hypersaline condition has led to cementation of the underlying strata, thus the change of their interparticle and vuggy pore types to micro- and meso-pores. Such facies and diagenetic processes characterize the main rock types (RT_3 and rarely RT_4) in the lowstan systems tract (Fig. 12). Transgressive systems tract (TST) of the sequences are generally composed of the lagoonal skeletal packstone (D2) and leeward-shoal grainstone in the lower part (Fig. 12). Dolomitization has locally created large intercrystalline pore type, resulting in a good reservoir quality in the constituent facies. The main body of the systems tract has been subject to cementation, compaction and micritization, which have partially plugged the interparticle and intercrystalline spaces and changed them to microporosity.

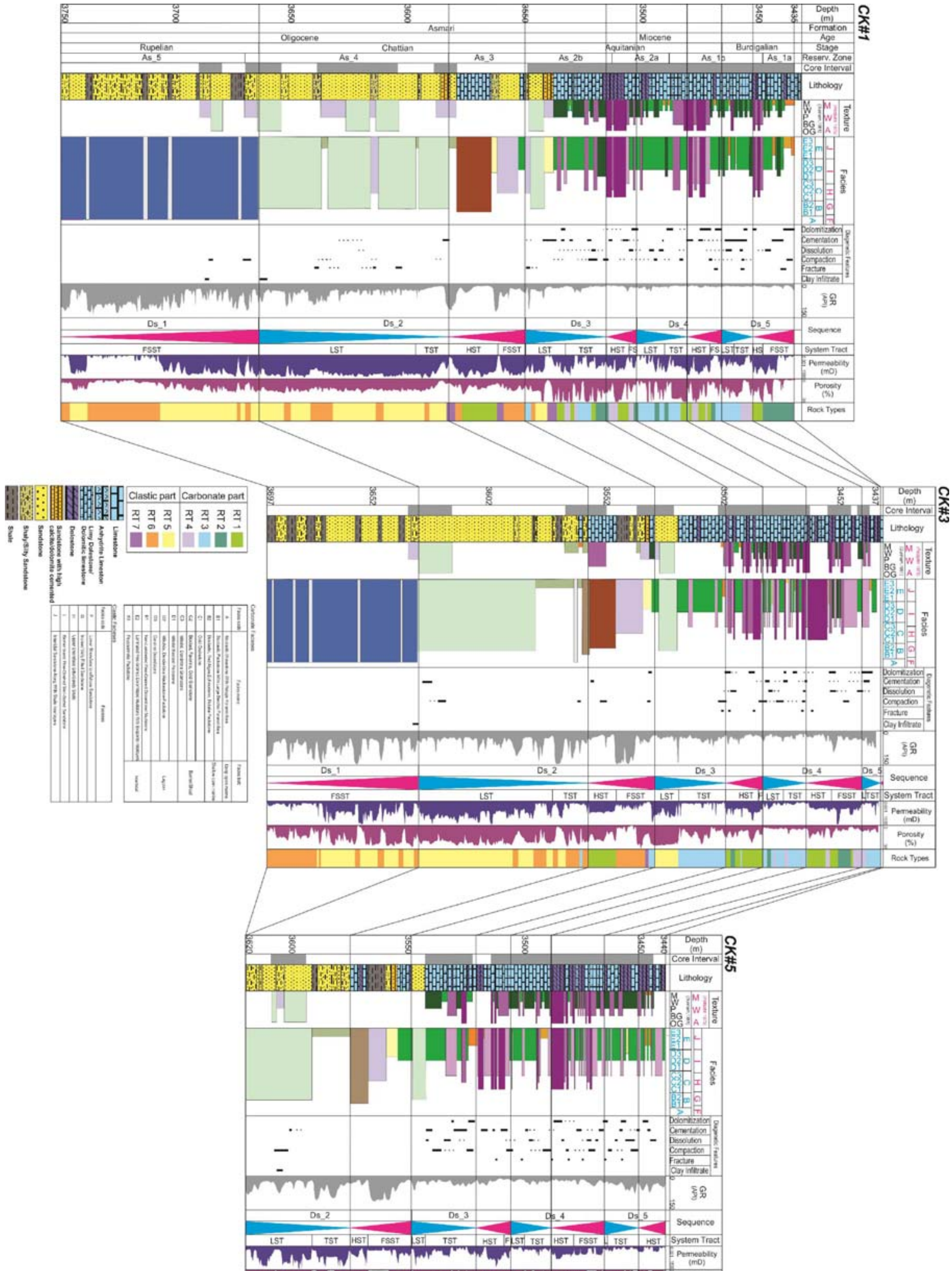


Figure 12. Correlation of rock types between studied wells and their sedimentological and petrophysical properties in the sequence stratigraphic framework.

The upper part of the TST is dominated by peritidal muddy facies (E1, E2) with prevailing microporosity and fine crystalline anhydrite cemented dolostone. The lower part of the TST is characterized by the RT_4 with interparticle porosity while the late TST by RT_3 (Fig. 12).

The Highstand systems tract (HST) of the sequences includes the shoal ooid grainstone and an alternation of lagoon (D2) and peritidal facies (E1, E2; Fig. 12). The RT_1 is the main rock type in this systems tract, that is marked by interparticle pore type. Relatively long period of subaerial exposure has resulted in dissolution of constituent facies, and development of moldic pore spaces within some ooid grainstone. The early HST is marked by shoal ooid grainstone and interparticle porosity (RT_1). Slight modification in the pore spaces of the late HST facies has occurred by anhydrite cementation and dissolution. So that, the early HST facies have greater reservoir quality than those of the late HST.

The falling stage systems tract (FSST) is composed of the lagoon skeletal packstone (D2) and thin intercalations of leeward-shoal skeletal grainstone and packstone (C3). All the facies have experienced particular subaerial exposure during which some moldic and intraparticle pore spaces are developed (RT_2) (Fig. 12). Furthermore, the clastic rock types of the formation with good reservoir quality (RT_5 and RT_6) are mostly developed in this systems tract and LST (Fig. 12). In some places of this systems tract, where the clastic rock types are fallowed by carbonate facies (RT_7), carbonate cementation has modified the reservoir quality in some extent (Fig. 12).

Distribution of the rock types in the sequence stratigraphic framework is illustrated in Fig. 12. These rock types along the wellbore are repeated similarly to sedimentary cyclicity with a regular pattern in the formation. This study shows that a blind rock typing without a good knowledge of geological framework leads to the results with lack of necessary correspondence with production behavior and unreliable reservoir modeling.

Conclusions

The Asmari Formation in the CK oilfield with siliciclastic, carbonate and evaporate facies and various diagenetic features is found a suitable case for the rock typing and reservoir zonation based on the NMR logging and geological attributes. Application of the NMR log in the estimation of permeability show higher correlation of the SDR model in carbonate and the Timur-Coates model in clastic part (85% and 89% respectively). The NMR log provides a robust continuous estimation of static and dynamic behaviors of reservoir rocks along the wellbores. It is more efficient than the conventional rock typing methods that is confined to core data, so to some intervals of limited wells of a field.

Integration of the NMR log with core-based methods has led to determination of 7 rock types in the studied formation. The rock types are defined based on their static (porosity, permeability and pore size/sorting) and dynamic behaviors (Pc, Sw and Sw_{ir}). The RT_1 and RT_5 show high reservoir quality, whereas the RTs 2 and 6 medium and the RTs 3, 4 and 7 no reservoir quality in this field. Pore types are the main controller of the static and dynamic behaviors of the reservoir rocks. Accordingly, determination of geological attributes is fundamental in reservoir characterization, because the pore types are the result of interactions between depositional texture and diagenetic overprints. Vertical distribution of the rock types allows formulating of the geological attributes in the sequence stratigraphic framework. A close relationship between the depositional sequences and post depositional modifications is observed. Such a relationships helps in better rock typing by consideration of statistic and dynamic behaviors and sedimentological features in the sequence stratigraphic framework.

This integrated scheme is found an improved approach on the reservoir zonation, compared to the previously used types (i.e. ICOFC reservoir zonations in this field). The integration of pore type, static properties and dynamic behavior optimizes the link between the different scales of observations. Accordingly, this approach helps to identify high and low permeable zones laterally and vertically at the field scale.

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