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Rock Typing and Reservoir Zonation of the Asmari Formation in a gas field, Persian Gulf

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ABSTRACT

In this study, the geological and petrophysical methods were combined to investigate the reservoir characteristics of the Asmari Formation in one of the gas fields in the Persian Gulf. The key focus of this study is to categorize rock types and define reservoir zonation. Initially, sedimentary facies were identified through the analysis of the core samples and the petrographic studies. Subsequently, the depositional environments of each facies were interpreted. After assessing the reservoir quality of sedimentary facies, various rock typing methods, including FZI, R_{35}, and Lucia methods, were used to categorize the reservoir rocks. Finally, reservoir zonation was carried out based on the integration of information and the NCRQI method. According to this study, the Asmari Formation in the studied field consists of 10 sedimentary facies deposited in a carbonate ramp environment during the Rupelian and Chattian stages. From the perspective of frequency, coralgal reef facies play a significant role in this platform, while from a reservoir standpoint, the thin-bedded ooid grainstones are the most important reservoir facies. The high variability in porosity and permeability data for each facies indicates the importance of diagenetic changes in reservoir quality and porosity distribution. A comparative analysis of rock typing methods revealed that the reservoir rock is composed of five reservoir rock types, associated with different sedimentary facies, pore sizes, and reservoir properties. Finally, based on the integration of geological and petrophysical information, the reservoir rock was divided into five reservoir zones, with reservoir zones As-2 and As-4 being the most important due to their relatively high porosity and permeability.

Keywords: *Asmari Formation, Rock typing, Flow Zone Indicator, Winland method, Reservoir zonation.*

1. Introduction

The primary objective of the reservoir quality assessment is to categorize hydrocarbon-bearing formations according to their production potential (Abbaszadeh et al., 1996; Amaefule et al., 1993; Gomes et al., 2008). To achieve this objective, two fundamental properties of reservoir rock are essential: porosity, which represents the rock's ability to store fluids, and permeability, which represents the rock's ability to allow fluid flow. Porosity and permeability are the two crucial properties for reservoir rock typing or zonation studies, and they can be directly measured from core samples.

Several methods have been suggested to facilitate the process of conducting appropriate rock typing, including the Flow Zone Indicator (FZI), Winland R_{35} and Lucia methods. Hydraulic Flow Units (HFU) are among the most widely adopted methods for accurately describing and characterizing carbonate reservoirs. Amaefule et al. (1993) in their work, introduced three fundamental parameters: the reservoir quality index (RQI), the pore volume-to-grain volume ratio (φz), and the flow zone indicator (FZI). Amaefule's approach relies on the clustering of FZI values for the zonation process. According to Tiab and Donaldson (2023), samples sharing identical FZI values possess similar pore throat sizes, establishing them as part of the same flow unit.

Winland (1972) utilizes the pore throat radius concept for rock type classification. Within the Winland empirical relationship, the strongest statistical correlation is observed when the pore throat size aligns with a 35% cumulative mercury saturation curve, referred to as the pore throat radius R_{35} (Aguilera, 2002). The Lucia's petrophysical classification method (Lucia, 1995) is employed to categorize rocks into three distinct classes, enhancing our understanding of their petrophysical characteristics. The cornerstone of the Lucia classification is the idea that pore-size distribution governs permeability and saturation, and this distribution is intricately linked to the rock fabric.

Siddiqui et al. (2006) introduced a reservoir zonation method using the cumulative RQI, referred to as the normalized cumulative reservoir quality index (NCRQI). According to this method, if we consider the total productivity of a well as a linear combination of individual flow zones, then a straightforward summation and normalization of permeability, RQI, or FZI, starting from the bottom of the well, allows for a convenient comparison with the normalized cumulative plot obtained from an open-hole flowmeter test. In such a plot, consistent zones are represented by straight lines, and the slope of each line indicates the overall reservoir quality within a specific depth interval. A lower slope corresponds to better reservoir quality. In this study, initially, the sedimentary facies and depositional environment of the study area are examined, followed by a discussion of the reservoir quality of each facies. Subsequently, using the integrated and comparative methods (FZI, Winland R_{35}, and Lucia's petrophysical classification), rock typing is performed, and finally, reservoir zonation will be carried out based on geological and petrophysical information using the NCRQI method.

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2. Studied field

The studied field is located in the eastern part of the Persian Gulf on Qeshm Island (Fig.1). The structure of this field is an anticline with a general northwest-southeast trend and approximate dimensions of about 20 kilometers in length and 6 to 10 kilometers in width on top of the Asmari. The mentioned field was drilled in 1990 with the initial purpose of drilling and evaluating the reservoirs of the Khami and Bangestan groups (Ghazban et al., 2007). Surprisingly, it led to the discovery of gas from the Asmari Formation, which was not expected to be present in that region.

In this field, the Asmari Formation, with a thickness of 160 meters, serves as the main reservoir. This formation is predominantly composed of limestone and argillaceous limestone with interbedded layers of shale and marl. It is underlain by the Pabdeh Formation and overlain by the Gachsaran Formation. The continuous coring of the Asmari Formation in one of the wells in this field is the subject of study in this article. Previous studies indicate that fractures do not play a significant role in the field's production.

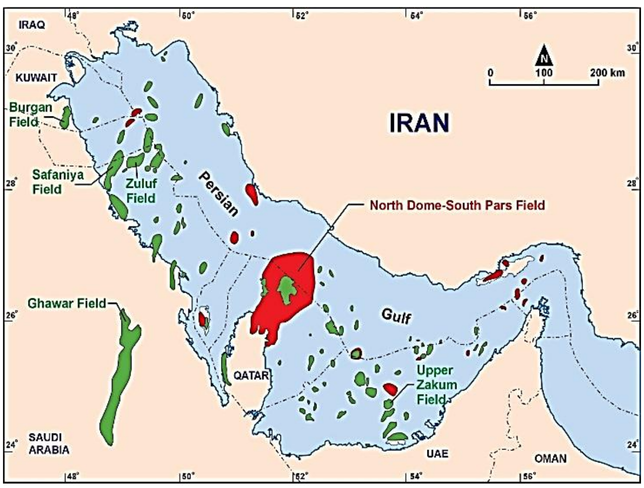

Fig.1) The location of studied field in the eastern side of the Persian Gulf.

3. Materials and Methods

For the analysis of facies types and reservoir characteristics of the Asmari Formation, the recovered cores have been investigated in detail before the plugging. All macroscopic features including the lithology, structures, fossils, visible pores, and oil shows were collected and recorded on the standard sheets. Description of these cores was supplemented by well logs and the results of previous studies.

After the preliminary macroscopic studies, the cores were marked and sampled with approximate 0.3 m (1 ft) spacing. Where plugging was not possible (due to the crushing and weakness of cores), chips samples were picked for preparing thin-sections. From all samples, a total of 654 thin-sections were prepared and stained by Alizarin Red S for routine petrographic studies. Then, all thin-sections were examined petrographically and classified based on their sedimentological and diagenetic characteristics (such as mineralogy, texture, structure, pore system, diagenetic features etc.). According to the sedimentological characteristics, facies were defined and interpreted by comparing them to the similar studies and standard models.

To measure the porosity and permeability, all plugs were cleaned by organic solvents (toluene and methanol). Each core plug (1.5 inch in diameter) was tested at ambient condition. In routine core analysis, porosity values are obtained using Boyle's law. This method is commonly used to measure grain volume by a helium porosimeter and bulk volume. To measure the permeability values, Darcy's law is applied using a gas permeameter apparatus at ambient conditions under steady-state flow. In overall, 502 core plugs were tested to evaluate their porosity and permeability.

To determine the FZI, the Winland R_{35} and the Lucia methods were employed, while reservoir zonation was accomplished through a combination of data and the Normalized Cumulative Reservoir Quality Index (NCRQI) method.

4. Facies Analysis

Core analysis show that the Asmari Formation in the studied field is mainly composed of coralliferous limestone in the lower and middle parts with foraminifer-bearing argillaceous limestones and marl in the upper part.

Table 1) The facies characteristic of the Asmari Formation in the studied field.

Facies code	facies name	dominant component	sedimentary structure	depositional environment
F-1	Sandy, bioclastic marl/shale	quartz sand, bivalve, ostracoda	lamination	peritidal
F-2	Sandy, lithoclastic mud/wackestone	quartz sand, intraclast	fenestral	peritidal
F-3	Ostracoda, small foraminifer wacke/ mudestone	ostracoda, Miliolid, Discorbis, Rotalia	lamination, bioturbation	lagoon
F-4	Bioclast, foraminifer wacke/floatstone	ostracoda, green algae, gastropoda, Miliolid, Peneroplis, Austrotrillina	lamination, bioturbation	lagoon
F-5	Foraminifer, ooid pack/grainstone	ooid, Favreina, Miliolid, Reussella, Peneroplis	cross-bedding, massive	shoal
F-6	Red algae, foraminifer pack/grainstone	red algae, Miliolid, Peneroplis, Austrotrillina	cross-bedding, massive	shoal
F-7	Bioclast, red algae float/rudstone	red algae, bryozoan and echinoderm	bioturbation	proximal mid-ramp
F-8	Sandy, echinoderm red algae wacke/ packstone	quartz sand, red algae, echinoderm	lamination, bioturbation	proximal mid-ramp
F-9	Red algae, coral float/boundstone	coral, red algae, bryozoan and echinoderm	bioturbation	proximal mid-ramp
F-10	Large, hyaline foraminifer wacke/packstone	Nummulites, Operculina, Lepidocyclina, coral red algae, bryozoan and echinoderm	bioturbation	distal mid- ramp

Based on macroscopic examinations of cores and thin-section analysis, 10 facies have been recognized in the Asmari Formation. Detail characteristics of these facies and their interpreted depositional settings are summarized in Table 1. Similar facies and depositional model were described by Aqrawi et al. (2006) and van Buchem et al. (2010) for this formation. Several microphotographs of the identified facies are presented in Fig.2. To document the facies changes during the platform evolution, the vertical arrangement of facies is present in a sedimentological log (Fig.3).

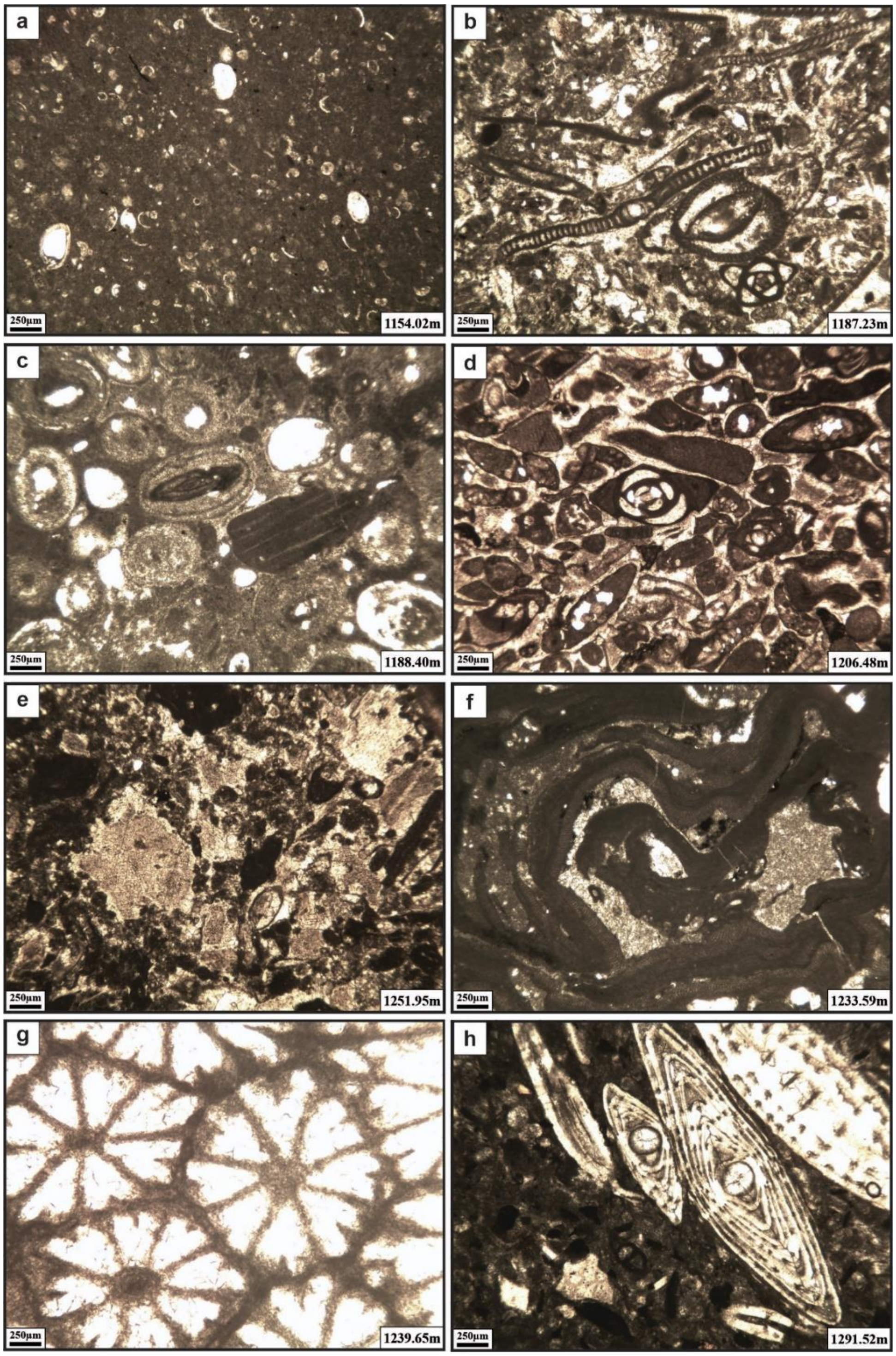

Fig.2) The microphotographs of recognized facies in the studied field; a) ostracoda, discorbid, small rotaliid wacke/mudstone (MF-3) b) bioclastic, imperforate foram wackestone (MF-4); c) ooid pack/grainstone (MF-5); d) red algae, foram pack/grainstone (MF-6); e) sandy, echinoderm, red algae wacke/packstone (MF-8); f) bioclast, red algae float/rudstone (MF-7); g) coralgal float/boundstone (MF-9); h) nummulite wacke/packstone (MF-10).

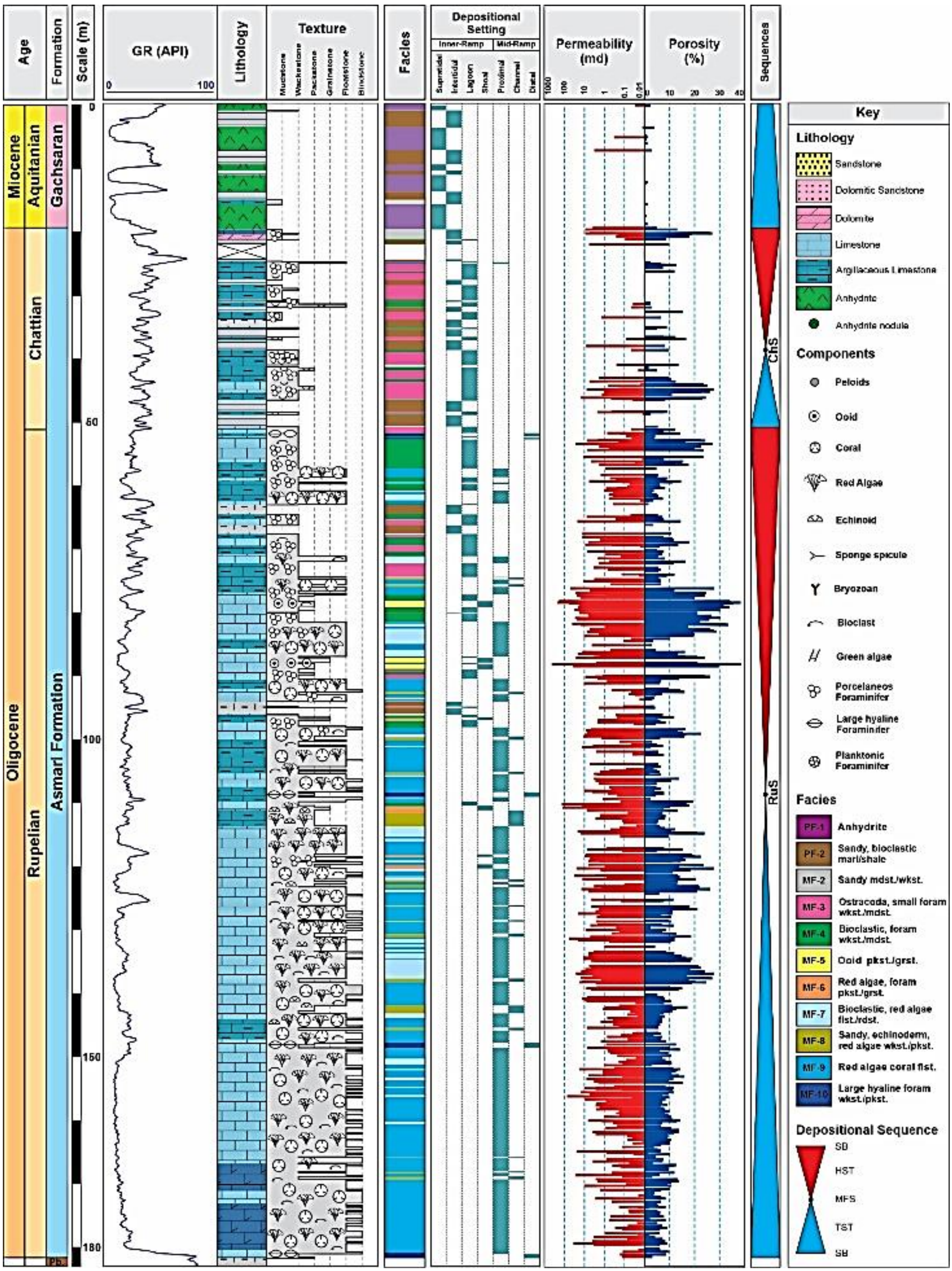

Fig.3) The sedimentological log of the Asmari Formation in the studied field, containing gamma ray log and porosity-permeability (poroperm) data.

5. Depositional Environment

Facies analysis of the recovered cores allowed us to reconstruct an environmental model for the Asmari Formation in the studied field. This facies model contributes to a deeper understanding of reservoir distribution and geometry. Based on the facies assemblages, it is evident that the Asmari carbonates were deposited in a carbonate ramp setting, which began during the Rupelian and continued into the Chattian. Key carbonate factories within this platform included red algae-coral patch reefs and oolite/skeletal shoals, which developed extensively across the carbonate ramp. As the deposition environment shallowed towards the top of the formation, facies changes indicated periodic clastic influx from landward areas. Fig. 4 presents a schematic sedimentary model for the Asmari Formation in the well under study.

The stratigraphic distribution of facies and fossil assemblages allows for the identification of distinct sedimentary settings within the Asmari carbonate ramp. The overall pattern of depositional facies signifies a transition from a mid-ramp to a shoal, further progressing into a lagoon, and eventually into a peritidal zone. In simpler terms, the initial depositional environment was open marine, gradually transitioning into a more restricted marine condition where fine clastics were deposited. The vertical arrangement of facies reflects cyclic deposition patterns, with transitions between different facies typically occurring gradually within each cycle.

Overall, the sedimentary evolution of the Asmari platform in the eastern Persian Gulf can be divided into two distinct phases. Throughout much of the Rupelian, the region maintained a depositional environment characterized by shallow open marine conditions, particularly in the mid-ramp area. During this period, the platform saw extensive development of red algae-coral patch reefs. However, by transition into the Chattian, deposition gradually became more restricted due to a shallowing of the water. Furthermore, there was a shift in depositional conditions marked by the influx of clastic materials. These changes in the depositional environment are evident through the increasing clay content in the facies lithology and the presence of several horizons of shale/marl, which suggest heightened erosion or uplift in the source area.

6. Reservoir properties of facies

Within Asmari reservoir, porosity exhibits a wide range, spanning from 1% to 38%, with an average of 11%. Permeability, on the other hand, varies from less than 1 millidarcy (mD) to over 400 mD, with an average of 6 mD. The primary porosity of facies is primarily inherited from their original depositional settings, and subsequent diagenetic processes may either enhance or diminish these primary reservoir properties.

In this formation, the majority of porosity is of secondary origin, resulting from the dissolution of metastable grains, leading to the formation of vuggy and moldic pores, as well as fracturing. Additionally, the well-preserved porosity in these strata is attributed to the relatively shallow depths of burial. These sediments are buried at depths ranging from 1100 to 1300 meters below sea level in the eastern Persian Gulf.

Several factors have played a crucial role in controlling the reservoir properties and distribution within the Asmari carbonates in the studied field. Among these factors, facies types, clay content, dissolution, and fracturing are the most significant. The sandy shale/marl facies (MF-1) with porosity levels less than 5% do not contribute to the reservoir and instead form non-reservoir units and cap rock (see Table 2 and Fig. 5). The highest reservoir quality is found in the ooid grain/packstone (MF-5) facies due to ooid leaching during meteoric diagenesis (see Table 2 and Fig. 5).

Several facies, specifically MF-3, MF-4, MF-5, MF-7, and MF-8, display a considerable degree of variability in their reservoir properties. This variability underscores the significant reservoir heterogeneity that exists within these facies. In these facies, porosity displays a complex nature; primarily resulting from dissolution processes that remove metastable grains (see Table 2 and Fig. 5). In the case of MF-9 (red algae-coral bound/floatstone), although most samples have porosity levels below 15%, permeability varies widely, ranging from nil to 70 millidarcies (mD).

Petrographic examinations have confirmed that microfractures play a significant role in influencing reservoir quality in these facies (see Table 2 and Fig. 5). The large hyaline foram wacke/packstone (MF-10) is characterized by generally poor to fair reservoir properties. In these facies, porosity typically falls below 15%, and permeability is usually less than 1 mD.

7. Hydraulic Flow Unit concept

A flow unit is characterized as a distinct volume of rock exhibiting consistently predictable pore-throat properties within the porous medium, which distinctly set it apart from other units and play a pivotal role in determining the hydraulic characteristics of the rock (Abbaszadeh et al., 1996; Amaefule et al., 1993; Gomes et al., 2008). A reservoir can be partitioned into flow units to analyze its behavior under varying production strategies, and this division can stem from either

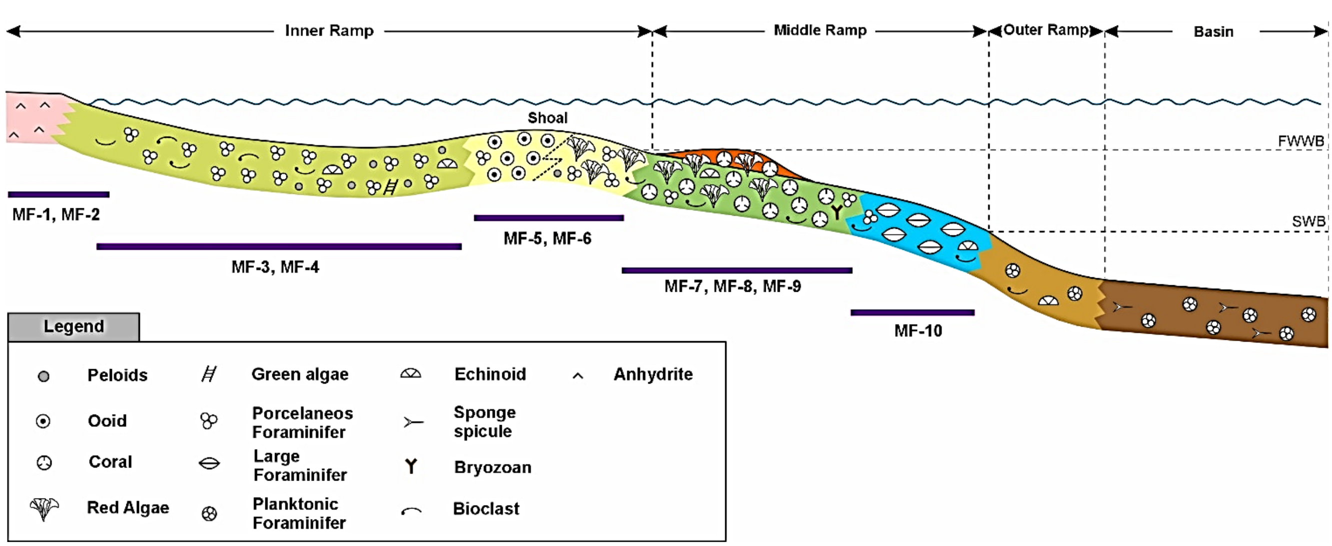

Fig. 4) The conceptual depositional model for the Asmari Formation.

Table 2) Average reservoir properties of various facies in the studied cores.

Code	Facies	Arithmetic mean		Geometric mean	
		Porosity(%)	Permeability (mD)	Porosity(%)	Permeability (mD)
MF-1	Sandy, bioclastic marl/shale	4.25	2.71	3.51	0.21
MF-2	Sandy, lithoclastic Mud/Wackestone	20.52	4.67	19.83	1.87
MF-3	Ostracoda small foram wacke/mudstone	11.80	2.27	10.05	0.14
MF-4	Bioclast foram wacke/floatstone	13.44	6.47	10.83	0.50
MF-5	Ooid pack/grainstone	31.45	106.41	30.95	64.33
MF-6	Red algae, foram pack/grainstone	15.56	19.50	14.66	3.40
MF-7	Bioclast red algae float/rudstone	14.69	5.97	12.67	1.55
MF-8	Sandy, echinoderm, red algae wacke/packstone	11.03	2.27	9.79	0.34
MF-9	Red algae coral bound/floatstone	8.70	3.78	7.41	0.46
MF-10	Large hyaline foram wacke/packstone	7.08	0.63	5.41	0.16

geological or engineering perspectives. Nevertheless, for a comprehensive comprehension and modelling of the spatial distribution of reservoir properties, it is imperative to merge 1D engineering data with 3D geological data (Gomes et al., 2008).

A hydraulic flow unit is characterized as the representative elementary volume of the entire reservoir rock, exhibiting internal geological and petrophysical properties that consistently determine fluid flow and are predictably distinct from the properties of other rock formations (Amaefule et al., 1993). The primary petrophysical units within a reservoir, often referred to as rock types, can be identified through the utilization of FZIs during routine core plug analysis. It is essential to note that these petrophysical properties, such as porosity and permeability, should exhibit minimal variation within a specific rock type. This consistency implies that having knowledge of either porosity or permeability can significantly improve the accuracy of predicting the other property.

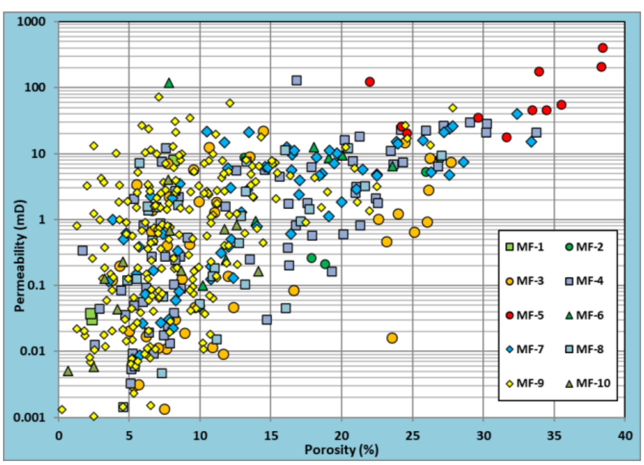

Fig. 5) The cross plot of porosity vs. permeability in the various facies of the studied Asmari cores.

The hydraulic unit concept, as proposed by Amaefule et al. (1993), has been chosen as the framework for categorizing the reservoir into discrete petrophysical types. Each of these unique reservoir types is characterized by a distinct FZI value.

Tiab and Donaldson (2023) define a hydraulic flow unit as a continuous geological volume within a specific reservoir area, exhibiting remarkably uniform petrophysical and fluid properties. These properties distinctively govern its static and dynamic interaction with the wellbore.

This method is based on a modified version of the Kozeny-Carman model (referenced in Amaefule et al. (1993)) and incorporates the concept of mean hydraulic radius. Kozeny (1927) and Carman P (1937) conceptualized a porous medium as an assembly of capillary tubes, merging Darcy's law for porous medium flow with Poiseuille's law for flow within tubes.

8. Flow Zone Indicator (FZI)

The FZI is a valuable parameter that quantifies the flow behavior of a reservoir. It establishes a connection between petrophysical properties at different scales, from small-scale core plugs to large-scale wellbore assessments. FZI also encapsulates flow zones by considering factors like surface area and tortuosity. Its mathematical representation is (Amaefule et al., 1993):

$$FZI = RQI / NPI = \{(.0314\sqrt{K/\Phi})\} / \{\Phi / (1-\Phi)\} \quad (1)$$

Where,

FZI = Flow Zone Indicator, μm.

K=Permeability, md.

A flow zone indictor, FZI, is defined as:

$$FZI = \frac{1}{\sqrt{F_s \tau S_{gv}}} \quad (2)$$

The reservoir quality index, RQI, is defined as follows:

$$RQI = 0.0314\sqrt{k/\varphi_e} \quad (3)$$

Where φz, the normalized porosity is:

$$\varphi_z = \left(\frac{\varphi_e}{1-\varphi_e}\right) \quad (4)$$

Eq. 6 then becomes:

$$RQI = \varphi_z * FZI \quad (5)$$

Taking the logarithm of both sides of Eq. 8 gives:

$$logRQI = log\varphi_z + logFZI \quad (6)$$

The hydraulic flow unit (HFU) approach has proven valuable for classifying rock types and predicting flow properties, serving as an integrative tool for the petrophysical characterization of reservoirs. This technique involves the calculation of FZI from core data, originally introduced by Amaefule et al. (1993). It incorporates the normalized porosity index (NPI) and RQI through equation 6. We determined the number of hydraulic flow units in three different ways:

8.1. Histogram Analysis

When we create a histogram of the FZI data, it assumes the shape of a normal distribution, representing "n" HFUs (Abbaszadeh et al., 1996). As the FZI distribution is a combination of multiple log-normal distributions, a histogram of the logarithmically transformed FZI values should reveal the presence of "n" normal distributions. The histogram chart displaying poroperm values measured from the Asmari Formation is presented in Figure 6, from which we can distinguish five distinct hydraulic flow units (HFUs).

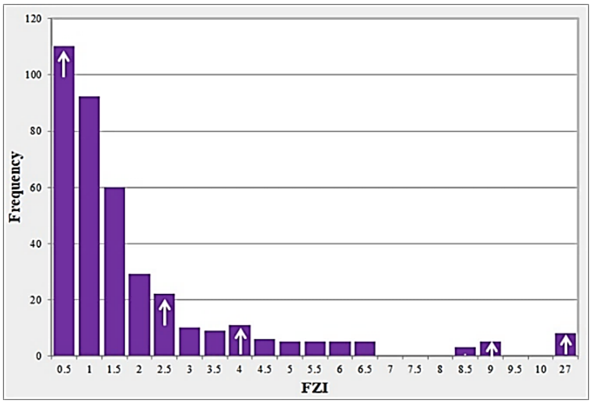

Fig.6) The histogram of the FZI values in the Asmari Formation.

8.2. Normal Probability Analysis

A normal probability plot of the FZI reveals "n" linear distributions, with each line corresponding to a distinct HFU (Abbaszadeh et al., 1996). In this context, a probability plot, often represented as the cumulative distribution function, is essentially the integral of the probability density function derived from the FZI data histogram. Each of these normal distributions, when plotted on the probability plot, appears as a distinct straight line, enabling us to identify and quantify the number of HFUs (Fig. 7).

Consequently, the count of straight lines observed in the probability plot can serve as an indicator of the number of HFUs within the reservoir. A probability plot has been generated for both the calculated FZI values obtained from the Asmari Formation in the studied well (see Fig.7). As evident from these plots, it is possible to discern the presence of five distinct HFUs in the Asmari samples.

8.3. Error Analysis method

This method facilitates the determination of the optimal number of flow units within the analyzed cores. Using this approach, we calculated the Mean Square Error (MSE) for different numbers of HFUs. Subsequently, we plotted the error values against the number of HFUs. As the number of HFUs increases, there comes a point where the reduction in error becomes smaller and eventually negligible. At this juncture, the MSE can be employed as a criterion for establishing the required number of HFUs for the reservoir classification.

Figure 8 displays a plot of MSE against the number of HFUs, clearly illustrating a decreasing trend in the MSE curve as more HFUs are added. In the case of Asmari, this curve flattens out when five HFUs are included, indicating that this number provides a reasonable representation of the data. In Fig.9, poroperm values of various rock types are plotted in a scattered cross plot.

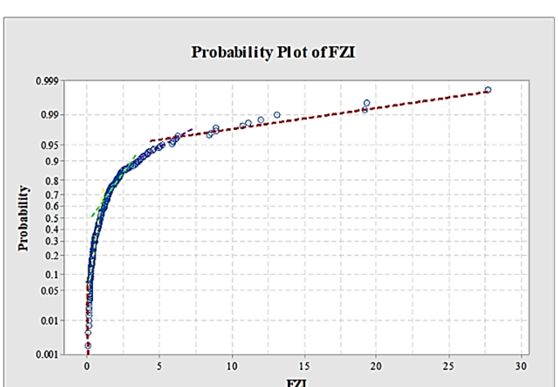

Fig.7) The cumulative probability plots of the FZI values in the Asmari Formation.

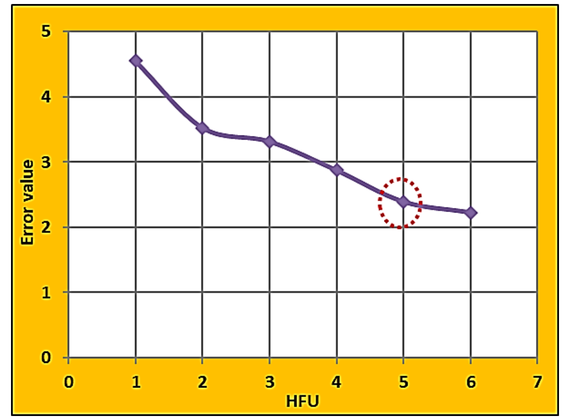

Fig. 8) The graph of MSE versus number of HFU's for the Asmari Fm.

9. R_{35} approach

The Winland R_{35} method, represented as [Log R_{35} = 0.732 + 0.588 (Log Kair) – 0.864 (Log Φ)], draws its foundation from the interplay among porosity, permeability, and pore throat radius, specifically at the 35% mercury saturation point during capillary pressure measurements (Aguilera, 2002). This methodology is notably dependable in rocks characterized by predominantly intergranular porosity, such as sandstone, where the configuration of pores and pore throats closely aligns with the overall rock texture.

Carbonate pore systems are usually composed of various pore types; hence, the Winland method may not be as reliable when used to assess reservoir quality in carbonate reservoirs. In the context of carbonate reservoirs, the Pittman's modification of the Winland method has demonstrated superior accuracy. Therefore, samples from carbonate formations must be tested for the reservoir quality using the modified Winland R_{35} equation (Pittman, 1992):

$$\text{Log } R_{35} = 0.255 + 0.565 \text{ Log } k - 0.523 \text{ Log } \varphi_e$$

Winland (1978) divides pore throat sizes into the following categories: megaport (>10 μm), macroport (10-2 μm), mesoport (2-0.5 μm), microport (0.5-0.1 μm), and nanoport (<0.1 μm) (Table.3).

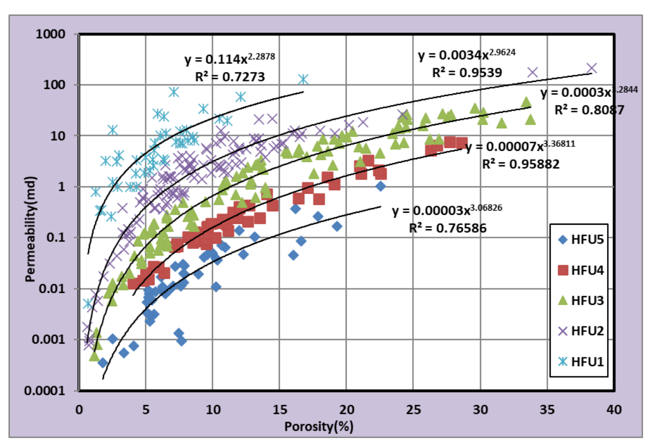

Fig.9) The cross plots of porosity versus permeability for various rock types.

Table 3) The Winland's classification based on pore-throat sizes.

Pore-throat Name	Pore-throat Size	In this study
Megaport	>10 μm	Class 1
Macroport	10-2 μm	Class 2
Mesoport	2-0.5 μm	Class 3
Microport	0.5-0.1 μm	Class 4
Nanoport	0.5-0.1 μm	Class 5

To differentiate flow units, we have generated iso-pore-throat radius cross-plots by the calculated R_{35} values derived from the Winland equation. The poroperm cross-plot for the Asmari samples has been plotted on the Winland standard diagram, as depicted in Figure 10. Employing this methodology to evaluate the Asmari Formation in the analyzed well has led to the identification of five distinct rock types or classes. These classes are numerically categorized from 1 to 5, with a descending R_{35} value serving as the key distinguishing factor among them.

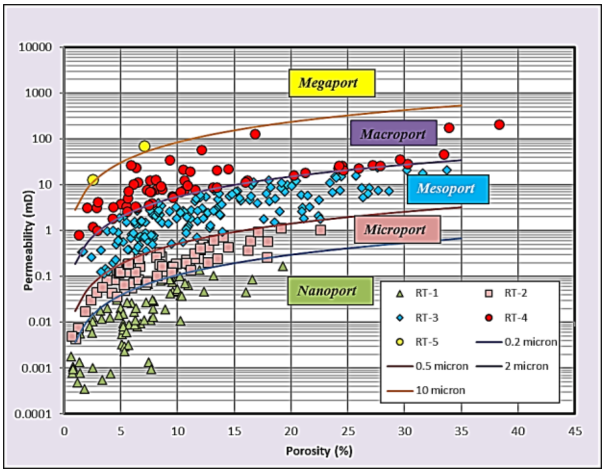

Fig. 10) Plot of the poroperm values classified based upon the HFU's on the Winland diagram to differentiate classes with close port-throat sizes. Numbers in top box are pore throat radius and lines are iso- pore throat lines. Accordingly, five classes have been established.

10. Lucia petrophysical classes

Lucia (1995) employed a geological approach for the classification of carbonate porosity. He categorized pore types into two main groups: interparticle and vuggy porosity. Within vuggy porosity, further divisions were made, distinguishing between separate vuggy pores and touching vuggy pores. Similarly, interparticle porosity was subdivided into grain-dominated and mud-dominated categories. In the context of defining reservoir quality, Lucia identified three geologically-based petrophysical rock classes that align with different rock fabrics. These classes generally correspond to porosity and permeability variations. Class 1 is characterized by grainstone fabrics, Class 2 comprises grain-dominated packstone fabric, and Class 3 is associated with mud-dominated fabric.

In the study by Lucia (1995), a comparative analysis was conducted by juxtaposing rock-fabric fields with cross-plots involving porosity, permeability, and R35 pore throat size, drawing upon the research of Pittman (1992). This investigation revealed a critical limitation: non-touching vuggy porosity cannot be effectively and reliably assessed for the reservoir quality using the Winland R35 criterion. This limitation arises from the inherent complexity of the mixture comprising separate vugs and variably sized "matrix" pores, which tend to fill with mercury at disparate rates and pressures. Consequently, the point at which 35% of the pore volume is saturated with mercury may not serve as a definitive indicator of the optimal combination of porosity and permeability (Figure 11).

Poroperm values extracted from the Asmari Formation have been plotted on Lucia's standard diagram, resulting in the identification of five distinct classes, as illustrated in Figure 13. It is worth noting that samples falling within class 5 exhibit remarkably low permeability values, signifying poor reservoir quality within this class.

11. Insights from various rock typing methods

The results of different rock typing methods may not necessarily align

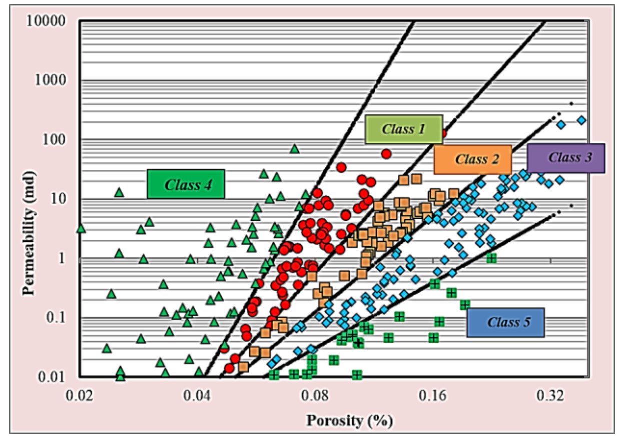

Fig. 11) The plot of the Asmari Formation samples on the Lucia's diagram to differentiate petrophysical classes (1 to 5).

with each other because, each method is based on specific underlying principles. These methods assist in identifying and categorizing the reservoir rock's nature from various perspectives. Overall, the integration of multiple data sources and analytical methods provides a comprehensive understanding of the reservoir's geological attributes and its potential as a productive hydrocarbon reservoir.

The summary of the correlation of results obtained from facies analysis and various rock typing methods is provided below.

a) Histogram analysis, normal probability analysis, and error analysis of the FZI results collectively indicate the presence of five distinct rock types within the dataset.

b) Rock Type 1 (RT-1) is compatible with rock fabric classes 3 and 4 of Lucia, which are primarily characterized by the presence of macroport in the R_{35} diagram. This rock type predominantly aligns with coral reef facies.

c) RT-2 primarily corresponds to rock fabric class 4 and, to a lesser extent, classes 3, 2, and 1 of Lucia. It is characterized by the presence of macropores and mesopores. This rock type generally aligns with various lithofacies.

a) RT-3 is predominantly characterized by the presence of microport and mesoport which is compatible with various rock fabric classes of Lucia. This rock type can generally correlate with various facies.

b) RT-4 is predominantly characterized by the presence of nanoport and microport pores and is compatible with lithofacies classes 1, 2, and 3, primarily. This rock type mainly aligns with various facies, notably facies 8 and 9.

c) RT-5 is mainly associated with classe 3 and, to a lesser extent, class 2 of Lucia, which is mostly characterized by the presence of nanoport in the R_{35} diagram. This rock type predominantly aligns with mud dominated facies (Ostracoda small foram wack/mudstone (MF-3) and Bioclast foram wacke/floatstone (MF-5)).

d) The results indicate that the reservoir rock is highly heterogeneous, and apart from facies, diagenesis also plays a significant role in shaping variations in pore characteristics and reservoir quality.

12. Reservoir zonation

To establish a zonation scheme for the Asmari reservoir in the studied field, we employed a combination of wireline logs (GR, RHOZ, NPHI), core data (facies, diagenesis, porosity-permeability data), and the NCRQI (Normalized Cumulative Reservoir Quality Index) method.

The NCRQI method, as outlined by Siddiqui et al. (2006), is based on the concept of combining porosity and permeability data into a RQI. In this approach, the NCRQI is calculated using the following equation:

$$NCRQI = \frac{\sum_{x=1}^{i} \sqrt{\frac{K_i}{\phi_i}}}{\sum_{x=1}^{n} \sqrt{\frac{K_i}{\phi_i}}}$$

Where "n" represents the total number of data points, and "i" indicates the number of data points at sequential steps of the calculation.

Once the NCRQI is computed for each data point, the values are plotted against depth. Any shifts or variations in the slope of the NCRQI-depth curve can serve as indicators of the presence of flow zones within the reservoir. It is clear that a low slope indicates high-quality reservoir zones (speed zones), while zones with steep dips indicate baffle zones, and zones with nearly vertical slopes represent barrier or non-reservoir zones.

Based on log characteristics, core data, and the NCRQI approach, we have identified and separated five distinct reservoir zones within the Asmari reservoir, all of which are capped by the Gachsaran dense units (refer to Fig. 12). These zones are designated as As-1, As-2, As-3, As-4 and As-5 reservoir zones in a stratigraphic order. The most favorable reservoir unit is As-2, boasting an average porosity of 15% and an approximate permeability of 20 md on average. The As-4 is also a good reservoir unit with 13% average porosity. As for the other three units, As-1, As-3 and and As-5, they exhibit average porosity and permeability values of approximately less than 10% and 3 md, respectively.

Furthermore, the Gachsaran Formation serves as an effective cap rock for the Asmari reservoir. This cap rock primarily consists of tight anhydrite and shale/marl (MF-1). The thickness of the cored interval within the Gachsaran Formation is approximately 20 meters (see Fig. 12).

The general properties of these reservoir units are as follows:

As-1 Reservoir Unit: The As-1 reservoir unit is 78 meters thick and is primarily composed of lagoonal facies, including MF-1, MF-3, and MF-4. It is dominated by argillaceous limestone and shale/marl lithology, which is reflected in the serrated GR log response. The average porosity in this zone is 10%, and the average permeability is 4 md. Within this unit, there are three horizons characterized by tight facies, such as sandy and bioclastic shale/marl, which act as intraformational barriers. These barriers divide the As-1 reservoir unit into three subzones (Fig.12).

As-2 Reservoir Unit: The As-2 reservoir unit, with a thickness of 10 meters, exhibits an average porosity of 23% and an average permeability of 33 md. This reservoir unit is primarily composed of various facies, including MF-4, MF-5, and MF-7 all of which possess favorable reservoir properties. Notably, the ooid pack/grainstone facies (MF-6), acknowledged as the best reservoir facies in the studied field, is prominently developed within this zone. The predominant lithologies in this unit comprise limestone and to a lesser extent argillaceous limestone.

As-3 Reservoir unit: The As-3 reservoir unit, spanning 22 meters in thickness, is predominantly characterized by red algae and coral-bearing facies (MF-7 to 9) of the middle ramp setting. These facies exhibit poor to moderate reservoir quality, with an average porosity of 9.5% and an average permeability of 7.5 md. Lithologically, this zone is comprised of limestone, argillaceous limestone, and dolomitic limestone. The GR log signature for this unit appears relatively clean.

As-4 Reservoir unit: This zone has a thickness of 30 meters and is primarily composed of MF-7 and MF-9 facies, with lesser extents of MF-6 and MF-8. It exhibits an average porosity of 13.5% and an average permeability of 6.5 md, making it the second most productive unit after zone 2. The dominant lithology in this zone is pure limestone, as indicated by the clean GR log signature.

As-5 Reservoir unit: This zone corresponds to the lower intervals of the Asmari Formation and is primarily composed of limestone and dolomitic limestone, dominated by coral-bearing facies (MF-7 to 9). With a thickness of 40 meters, this zone exhibits poor reservoir characteristics, including an average porosity of 8% and an average permeability of 2 md.

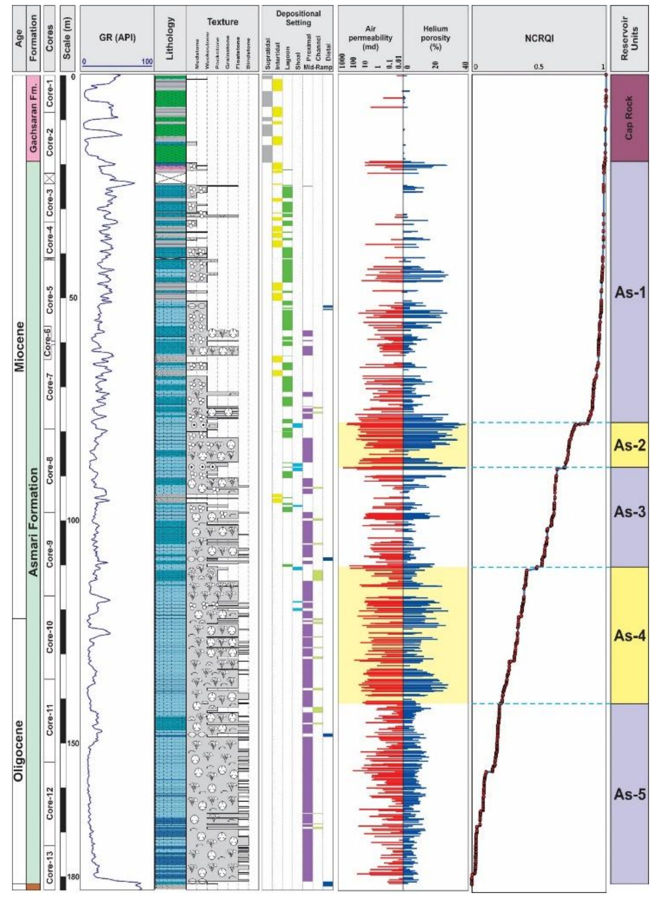

Fig. 12) Reservoir zonation of the Asmari reservoir in the studied field.

13. Results

1) Based on the integration of core and thin-section petrographic studies, the Asmari Formation in the studied field consists of 10 sedimentary facies that were deposited on a carbonate ramp during the Oligocene.
2) During the Rupelian stage, open marine facies with coral reefs and coarse hyaline foraminifera predominated, while during the Chattian stage, restricted marine facies were dominant. This overall trend indicates a reduction in depositional space during the deposition of this formation.
3) The sedimentary facies exhibit significant variations in porosity and permeability, indicative of the diagenetic processes' influence.
4) The best reservoir facies are associated with ooid grainstones in the middle parts of the formation.
5) Various rock typing methods, including the FZI, R35, and lithofacies, demonstrate that the reservoir rock comprises five distinct rock types with different properties.
6) By combining the data and the NCRQI method, the entire reservoir can be divided into five distinct reservoir zones.

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