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Association of the Flow Units with Facies Distribution, Depositional Sequences, and Diagenetic Features: Asmari Formation of the Cheshmeh-Khush Oil Field, SW Iran

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ABSTRACT

The Oligo-miocene Asmari formation is one of the most important hydrocarbon reservoirs in the southwest of Iran. In order to evaluate reservoir quality and the factors controlling reservoir properties, detailed geological and petrophysical studies were carried out on 242 m of core samples from Asmari reservoir. This study is a part of a larger project that examines depositional history and reservoir properties of the Asmari formation in the Cheshmeh-Khush field. Macroscopic and microscopic studies resulted in the determination of 5 shallow marine carbonate facies (from proximal open marine to tidal setting) and also 5 silisiclastic lithofacies (including channel, barrier, tidal, and shoreface sandstones). Based on the integrated results from sedimentological and paleontological studies, Sr isotopes dating, gamma-ray logs, and seismic data analysis, 5 depositional sequences with constituent system tracts were distinguished. In this research, the reservoir characterization of the Asmari reservoir were carried out through the integration of geological and petrophysical properties. In the first step, 21 hydraulic flow units (HFU or FU) were identified and then, to achieve better lateral correlation and modeling, HFU's were merged to 17. The results from this study showed different behaviors of the silisiclastic and carbonate facies next to the fluid flow. The findings of this study indicate that the lateral and vertical distribution of channel-filled sandstones (such as units 2 and 8) are strongly controlled by the geometry of depositional facies. Thus, the correlation and modeling of flow units, solely on the basis of lithology and thickness, and regardless of facies and its geometry, will cause different facies (such as coastal and channel-filled sandstones) with different geometry, and reservoir quality are placed incorrectly in a single flow unit.

In the carbonate parts of Asmari formation, the effect of diagenetic processes on reservoir quality is much higher than the facies. Hence, the LST limestones of unit 17, as a result of calcite cementation, were changed to a thick, distinct, correlatable, and barrier unit. On the other hand, dolomitic intervals that have not been affected by anhydrite cementation have formed porous and permeable carbonate reservoir units (such as units 18 and 21).

Keywords: Asmari Formation, Reservoir Quality, Flow Units, Sequence Stratigraphy, Facies Modeling

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INTRODUCTION

Categorization of a reservoir into permeable and non-permeable units is the most important step in the 3D modeling of reservoirs. These units, known as flow units, are widely used in reservoir characterization [1, 2, 3, 4, 5]. The term flow unit is applied to a distinct horizon in the reservoir with definite petrophysical characteristics [6]. Such units, which are discriminated from neighboring units based on their petrophysical properties, are mappable and correlatable in the field/regional scale.

The parameters that influence fluid flow are thought to be primarily related to the geometrical attributes of the pore-throat distribution. The pore geometry is controlled by mineralogy and texture. Therefore, an HFU can include several facies types, depending on their depositional characteristics.

Detailed analysis of facies and sequences of the hydrocarbon reservoirs, especially the carbonate types, and their correlation with reservoir properties show that the porosity and permeability of the reservoirs are not fully dependent to the facies characteristics. Although there are some correlation between textural and petrophysical properties of the facies, their reservoir characteristics are independent of facies type [7]. In this regard similar facies may show various petrophysical properties or various facies may show similar petrophysical characteristics. This is why most facies models do not demonstrate the distribution of reservoir parameters. Due to the significant role of diagenesis on the reservoir properties, an efficient reservoir model should include discrepancy of both facies characteristics and diagenetic features. A reservoir model that provides the pattern of petrophysical properties and correlates the properties with depositional setting provides great help in combination of geological descriptions and engineering calculations. Such a model provides superior view from the distribution of reservoir parameters.

The Oligo-Miocene Asmari formation in the Cheshmeh-Khush (CK) field is comprised of carbonate and siliciclastic facies with a variety of diagenetic features. The discrepancy of facies characteristics and diagenetic features through time (vertically) and space (laterally) have resulted in the heterogeneity of reservoir, especially in the carbonate part. This study aims to determine the flow units of the Asmari formation, using the porosity and permeability values from petrophysical logs and the stratigraphic modified Lorenz (SML) plot and to correlate them with the distribution of the facies, sequences, and diagenetic features. The results related to the facies analysis, sequence stratigraphy, and diagenetic studies are mainly taken from the first author's Ph.D. thesis.

EXPERIMENTAL PROCEDURES

Geological Setting

The Cheshmeh-Khush (CK) oil field is located in the northwest edge of Dezful embayment (DE), one of the major geological zones of Zagros range, about 180 km in the northwest of the Ahwaz city (Figure 1A). It is adjacent to Danan (the south of Lurestan) and Paydar (the north of DE) fields in the north and south respectively. The CK field has been the center of attention for petroleum geologist since 1966, when the first oil well was drilled in the field by National Iranian Oil Company [8].

The Oligo-Miocene succession in the DE consists of a relatively thick sedimentary system with a large variation in lithologies and depositional settings [9]. In different parts of the DE, lithologies differ from carbonate/evaporate to siliciclastic; moreover, depositional environments change from shallow/ deep marine carbonate platform to a siliciclastic shelf. These mixed carbonate-siliciclastic system is the most important hydrocarbon reservoir, producing oil and gas since the early twentieth century [9].

In the studied field, the Asmari formation is dominated by carbonate facies inter-fingering with sandstone intervals (Ahwaz member), so it is known as a mixed siliciclastic-carbonate reservoir (Figure 1B). The thickness of the formation is about 320 m in the field. In the CK field, the Oligo-Miocene Asmari formation is laid over the shales and argillaceous limestones of the Pabdeh formation concordantly and is overlaid concordantly by the evaporates of the Gachsaran formation (Figure 1B) [9].

On the basis of seismic data, the length and width of the CK anticline in the Asmari horizon is about 28.5 km and 4.5 km, respectively [8].

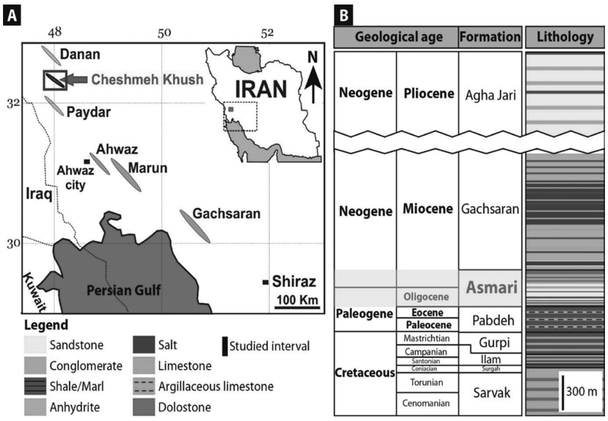

Figure 1: (A) the location map of the CK field and (B) its stratigraphic column [9].

Materials and Methods

Porosity and permeability, as the main controls of fluid flow in the hydrocarbon reservoirs, were used for the flow unit determination here. In this study, 242 m core samples from three key wells (wells: 5, 7, and 9) were examined. 720 core plugs were taken from the cored intervals of the Oligo-Miocene Asmari formation. The samples were studied for sedimentological analysis and were measured for its porosity and permeability. In order to analyze visual pore spaces, thin section samples were impregnated with blue dyed epoxy. Wire line logs (including density, neutron, and sonic logs) were used to determine the porosity of entire (cored and uncored) intervals. In order to predict permeability, a quantitative integration of porosity/permeability measurements and well log data from the major reservoir intervals is carried out using an artificial neural network (ANN) [10, 11].

Since core measurements are usually taken at irregular spacing, comparisons to regularly spaced log data require some scheme for infilling. In this study, this was carried out through the interpolation of porosity, density, and permeability data.

The flow units are normally determined on the basis of the flow zone indicator (FZI) introduced by Ebanks et al. [6], or stratigraphic modified Lorenz (SML) plot introduced by Gunter et al. [12]. Both methods are tried here, but the latter is preferred due to the better correlation of its results with depositional facies and sequences especially in siliciclastic parts.

Facies Analysis and Sequence Stratigraphy

The Asmari formation in the CK field is comprised of two distinct parts. The lower part (Oligocene in age) is dominated by sandstone facies, whereas the upper part (Miocene in age) is dominated by carbonate (limestone and dolomite) facies. While compared with those in literature [14, 15, 16, 17, 18, 19, 20, 21, 9, 22, 13], the combination of the results from core description and petrographic studies led to the determination of 12 carbonate and 5 siliciclastic facies the characteristics of which are summarized in Table 1 and illustrated in Figure 2. The carbonate facies are classified into 5 facies association (facies belt) using Buxton and Pedley (1989) [23] and Flugel (2010) [24] criteria.

Table 1: Major characteristics of the carbonate and siliciclastic facies of the Asmari formation in the CK field [13].

Facies			Description	Depositional Environment
Carbonate facies	A		Planktonic foraminera bioclast wackestone	Distal open marine
	B	B1	Large benthic foraminifera bioclast packstone	Proximal open marine
		B2	Red algae, echinoderm, and Neorotalia bioclast packstone	
	C	C1	Ooid grainstone	Shoal/Lagoonal shoal margin
		C2	Bioclast, Faverina ooid grainstone	
		C3	Miliolid, Denderitina grainstone	
	D	D1	Miliolid bioclast packstone	Lagoon
		D2	Miliolid, Denderitina wackestone/packstone	
		D3	Coral boundstone	
	E	E1	Massive dolomitized mudstone	Intertidal zone
		E2	Dolomitized mudstone along with anhydrite interlayers	
		E3	Peyssonnelia* packstone	
Siliciclastic facies	F		Sandstone with intercalations of open marine carbonate, Planolithes and Paleophycus ichno-fossils	Lower shoreface to offshore
	G		Erosional based conglomerate, channel shape ((log correlation), chaotic nature (seismic data	Channel/incised valley fills
	H		Massive, fossil barren shale	Upper shoreface
	I		Unconsolidated, dolomite cemented, well sorted sandstone, with intercalations of lagoonal car-bonates	Barrier
	J		Flasser bedded siltstone, sandstone and shale	Intertidal zone

Peyssonnelia is a genus of thalloid red alga*

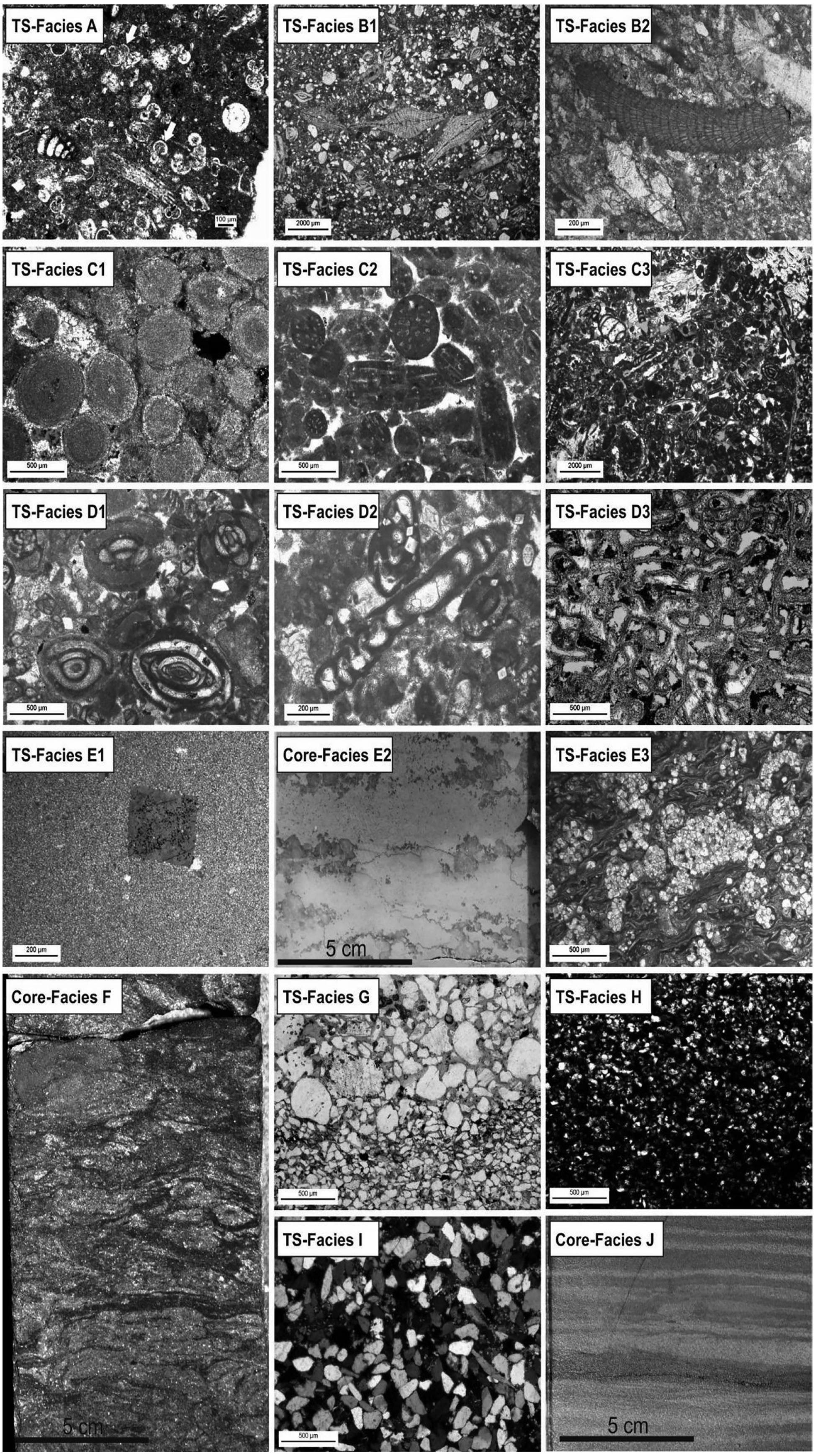

Figure 2: Macro and microscopic photographs from depositional facies of the Asmari formation in the studied field.

Sequence stratigraphy of the formation was carried out on the basis of the integrated results from sedimentological and paleontological studies, Sr isotopes dating, gamma-ray logs, and seismic data analysis [13]. Among sedimentological evidence like karstification (at the top of sequences 3 and 4), the presence of lowstand sandstone intervals (at the basal part of sequences 2 and 3) and vertical depositional pattern play the main role in the identification of sequence boundaries (Figure 3). Several index fossils such as Archaias sp., Elphidium sp.14, *Bolelis melocurdica*, and the association of large benthic foraminifera were used to determine the age of each sequence. On this basis, 5 depositional sequences with constituent systems tracts were distinguished (Figure 4).

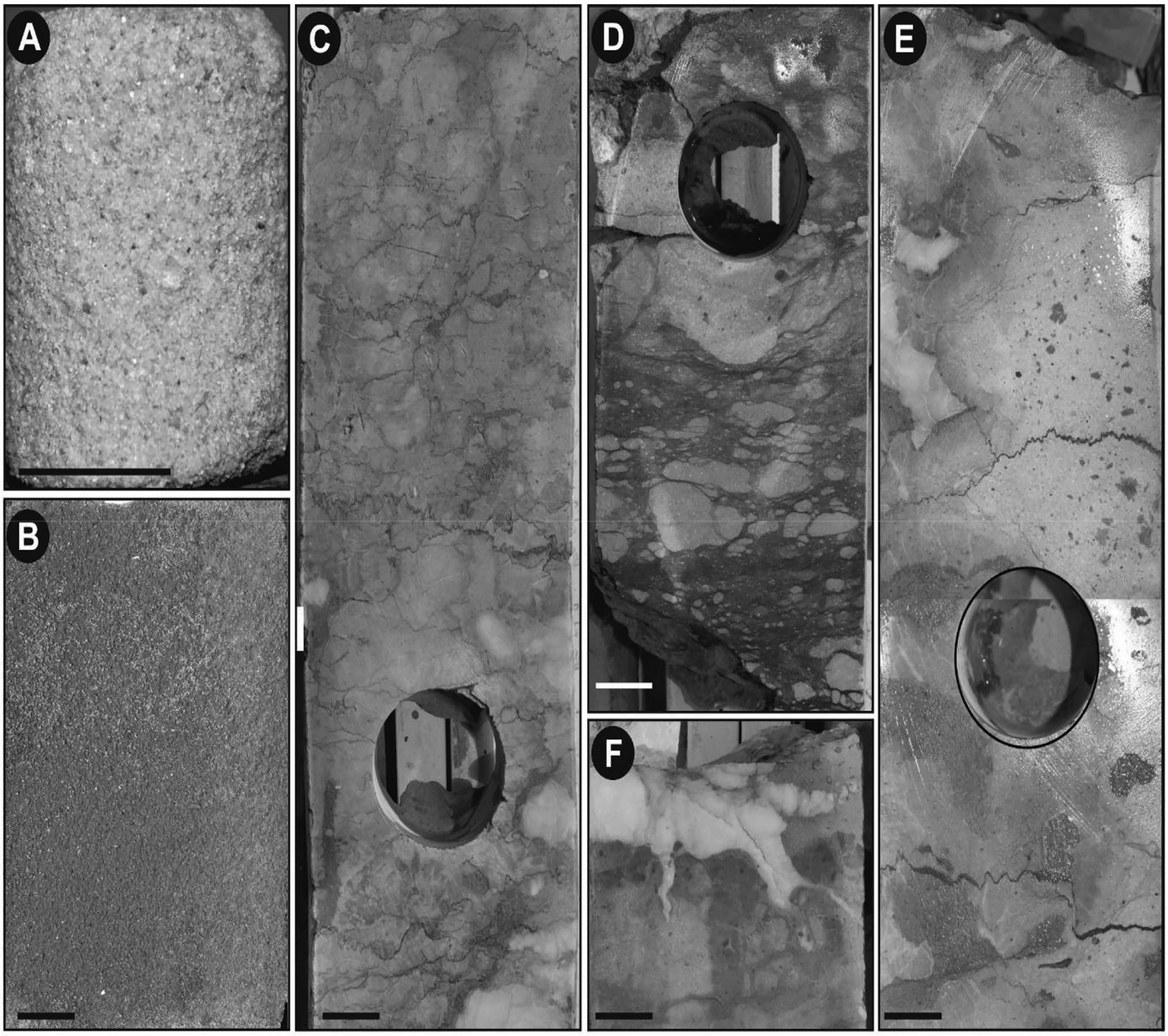

Figure 3: Core photographs from lowstand sandstones (A and B) and karstified surfaces (C-F) as two main pieces of evidence for identifying sequence boundaries in the Asmari formation in the studied field.

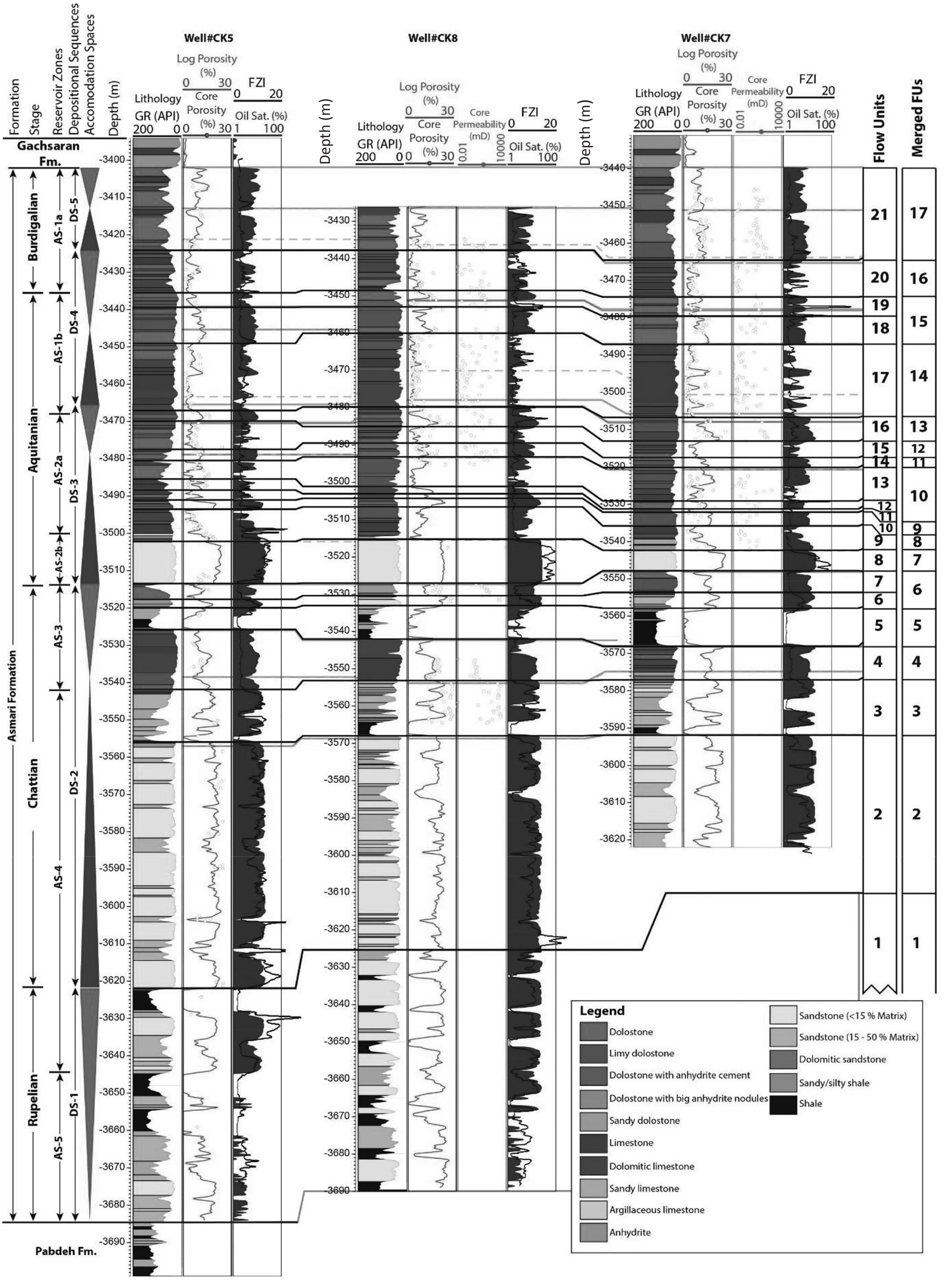

Figure 4: Comparison of flow units determined by SML and FZI methods in 3 key wells of the studied field.

Initially, depositional sequences were identified based on the presence of karstified surfaces (as sequence boundaries in carbonate sequences 4 and 5), channel-filled sandstones (as lowstand systems tracts in sequences 2 and 3), and vertical facies changes. Accordingly, five third order depositional sequences were introduced. Limestones with large-benthic foraminifera (in sequence 2) and ooid/skeletal grainstones (in sequences 3, 4 and 5), as the deepest facies, were attributed to maximum flooding surface. This study showed that due to the shallow carbonate facies and diagenetic effects, the relationship between petrophysical logs and sequence surfaces (SB & MFS) is not reliable. Hence, after identifying sequences based on sedimentological characteristics, the gamma log and Sr-dating results were used solely for the purpose of the correlation of time lines.

Ordering of the sequences was based on the results from the relative age determination of the formation [13] and data from Sr isotope dating [25]. Four systems tracts (i.e. LST, TST, HST, and FSST) were distinguished in most sequences [26, 27]. In the oldest sequence (seq. -1), only the falling stage systems tract is observed. In other words, the lower boundary of the formation is marked as a regressive surface here. The 4 major systems tracts (i.e. LST, TST, HST, and FSST) are distinguishable in the sequences 2, 3, and 4. The youngest sequence (seq. -5) is composed of the LST, TST, and HST. The falling stage of this sequence is recorded within the overlying Gachsaran formation, so the upper boundary of the formation is a regressive surface too (Figure 5).

Unlike the carbonate samples, in siliciclastic samples of the Asmari formation, there is a good linear relationship between the core porosity and permeability. On the other hand, the samples of the whole studied interval were not available. Therefore, in this study, after calibrating the core and well log porosities, log derived effective porosity were used.

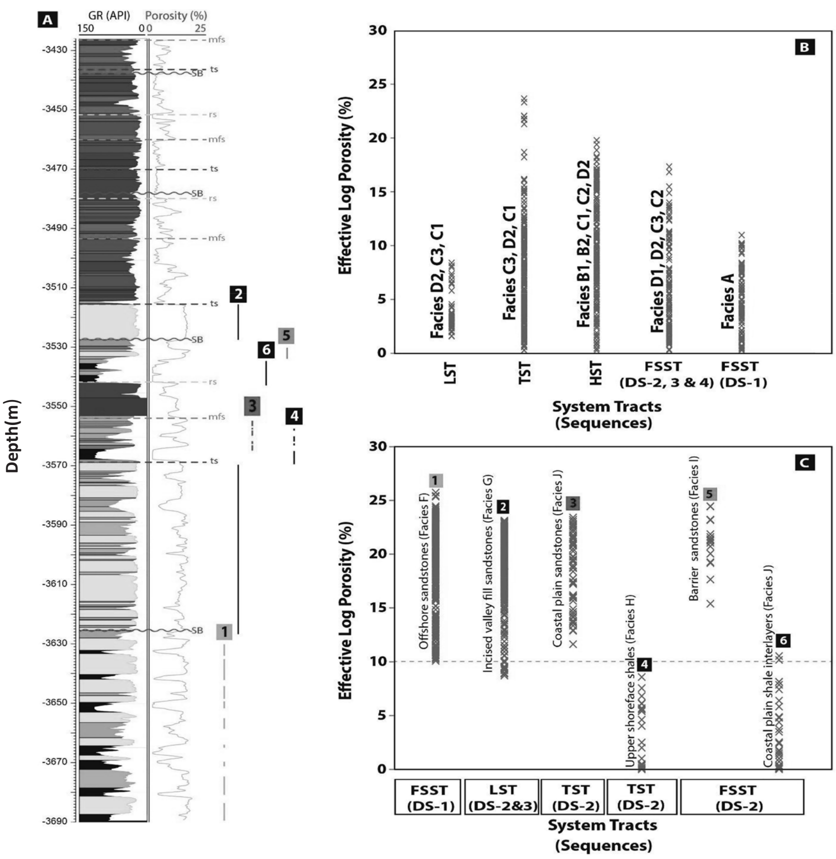

Figure 5: (A) position of the sequences and their constituent systems tracts and facies in well CK-8 along with log-derived porosity values. Correlation between sequences, systems tracts and porosity values in the (B) carbonated dominated and (C) siliciclastic dominated parts of the formation.

The detailed study of carbonate facies on macro and micro scales indicates the significant effects of diagenesis on the facies after deposition. A variety of post depositional changes in a single facies during burial seems responsible for its different petrophysical characteristics. In this study, diagenetic processes and the products of the formation are comprehensively investigated by core description, petrographic studies, SEM and CL analyses, and the stable isotopes (C & O) investigation of samples from 3 key wells [22, 13]. The results show that dolomitization, dissolution, and compaction are the main controls of reservoir quality in the carbonate-dominated part of the formation. The role of compaction (Figure 6A) and cementation (Figure 6B) in the decrease and that of dolomitization (Figures 6G and 6H) and dissolution (Figure 6F) in the increase of reservoir quality is evident in the petrographic studies. In terms of composition, the cement occurs in calcite (Figures 6B and 6C) and anhydrite/celestine (Figures 6D and 6E) forms. Intercrystalline porosity, detectable in the SEM studies (Figure 6H) has created high porosity and permeability in the dolomitized facies. Limited cementation (early diagenetic) seems responsible for the minor compaction of some facies, the preservation of their inter-particle porosity, and finally high reservoir quality.

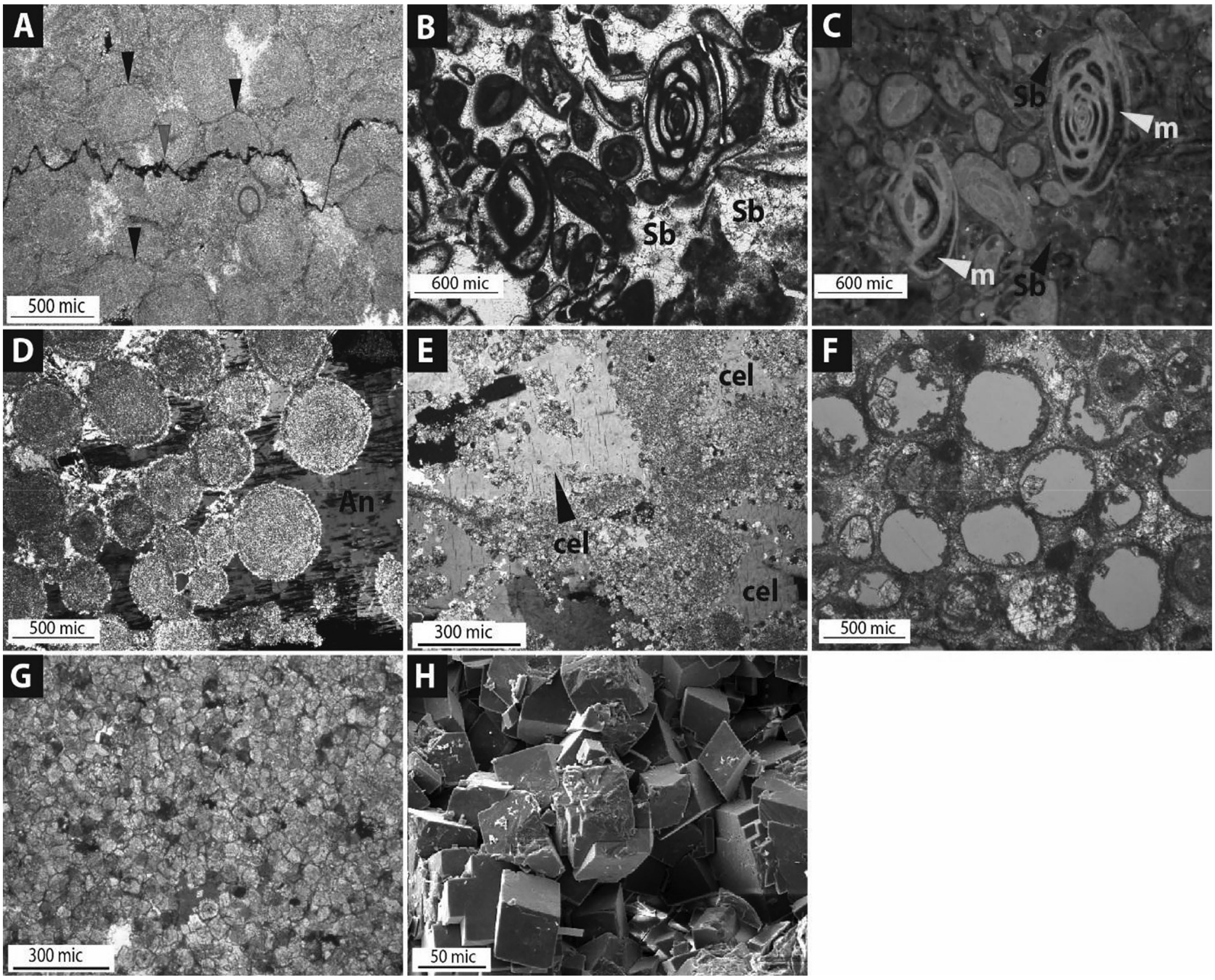

Figure 6: Photomicrographs representing major diagenetic features responsible for reservoir quality of the carbonate facies: (A) mechanical compaction; (B) shallow burial calcite cement (sb); (C) the shallow burial (sb) and marine (m) calcite cement differentiated by CL; (D) intergranular anhydrite cement (An); (E) celestine (cel) plugging; (F) dissolution of ooid grains producing moldic porosity (blue-died); (G) dolomitization responsible for the development of intercrystalline porosity; (H) the SEM photomicrograph of (G).

The frequency of the main diagenetic features in the carbonate facies indicates the extensive effect of nearly all facies by these features (Figure 7). Moldic and vuggy pore spaces are the main dissolution secondary porosities in the formation. Dissolution, as the main cause of porosity and permeability raise, is more frequent in the allochems (skeletal and non-skeletal), leaving biomoldic, oomoldic and vuggy porosity. The summation of more frequent dissolution porosities (moldic and vuggy) in different facies is considered as a dissolution index in the carbonate facies (Figure 7D). Apart from petrographic studies, the density of the facies is used as a parameter for their dolomitization rate. It is based on the difference of the calcite, dolomite, and anhydrite densities, 2.71, 2.84, and 2.95 g/cm^3 respectively. In this regard, except for the facies of open marine (A and B), other facies are widely affected by dolomitization (Figure 7E).

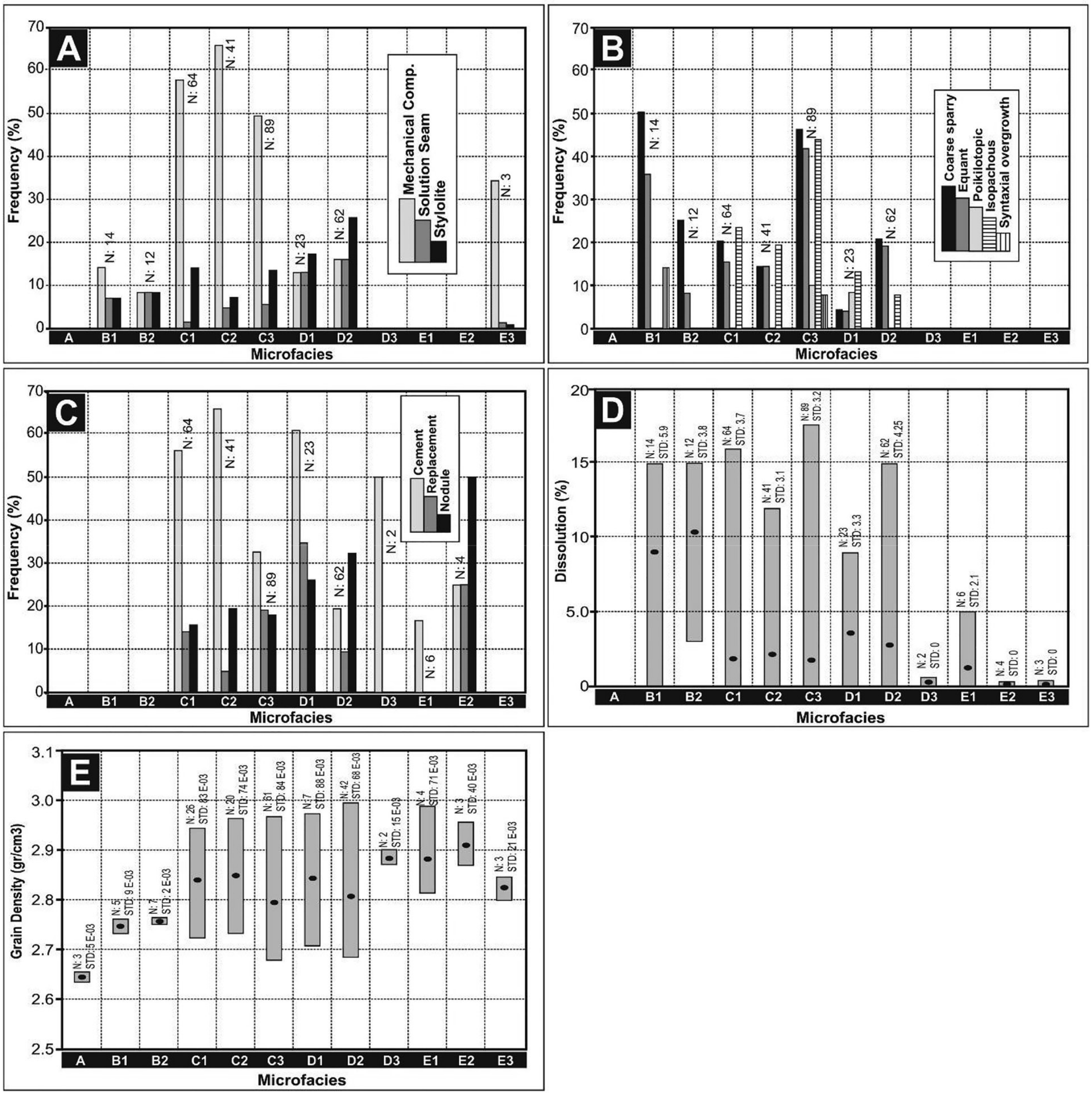

Figure 7: Frequency of major diagenetic features in the carbonate facies of the studied formation.

Unlike carbonate intervals, in siliciclastic parts of the Asmari formation, diagenetic process was very limited, so it had no significant effect on reservoir quality.

Flow Units Determination

In the FZI method [6] the flow units are determined on the basis of reservoir quality and normalized porosity indices. The reservoir quality index (RQI) is determined by permeability to porosity ratio using the fallowing equation [1]:

$$RQI = 0.0314\sqrt{\frac{K}{\phi}}$$

where the porosity value is expressed in percent and permeability (K) value is given in millidarcy. The flow unit determination by the RQI requires the normalized porosity index (NPI) that is determined by the fallowing equation:

$$NPI = \frac{\phi}{1-\phi}$$

The RQI/NPI ratio, which is known as the FZI, was calculated for the studying rocks by which the main flow units are discriminated (Figure 4). In this method, the units with various porosity and permeability values showed similar RQI. Moreover, in heterogeneous parts of the reservoir with a large variation in porosity and permeability values (carbonate intervals) and a high vertical variation of RQI, the correlation of flow units in field-scale was challenging. To overcome this problem, the SML plot method was also tried. In this method, the porosity, permeability, and thickness of units are used for the determination of the flow units. On the SML plot the cumulative flow capacity (CFC) is drawn against the cumulative storage capacity (CSC), (Equations 1 and 2).

$$\left(K_h\right)_{cum} = \frac{K_1\left(h_1-h_0\right)+K_2\left(h_2-h_1\right)+\ldots+K_i\left(h_i-h_{i-1}\right)}{\sum K_i\left(h_i-h_{i-1}\right)} \quad (1)$$

$$\left(\phi_h\right)_{cum} = \frac{\phi_1\left(h_1-h_0\right)+\phi_2\left(h_2-h_1\right)+\ldots+\phi_i\left(h_i-h_{i-1}\right)}{\sum \phi_i\left(h_i-h_{i-1}\right)} \quad (2)$$

The porosity (φ) value is expressed in percent, while the permeability (K) value is given in millidarcy; *h* represents the sampling intervals in feet.

Using the log-derived porosity and permeability values and the sampling interval of 0.15 m, the CSC versus CFS diagrams were plotted based on the Gunter et al. [12]. The results led to the determination of 21 flow units in 3 key wells of the studied field (Figures 8 and 9). A slope discrepancy in the diagrams represents the variation of reservoir quality (porosity and permeability). In other words, the breaks on the diagram demonstrate the border of flow units.

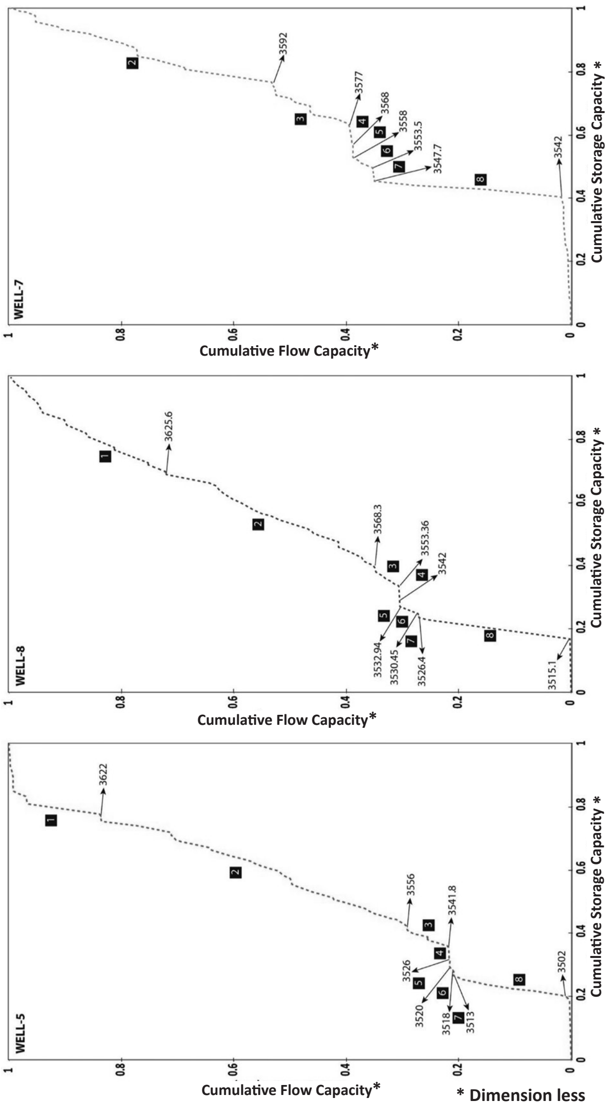

Figure 8: SML plot for siliciclas-tic parts of the Asmari formation in wells 5, 7, and 8 of the CK field. The lowest flow unit (FU-1) has not been penetrated in well 7.

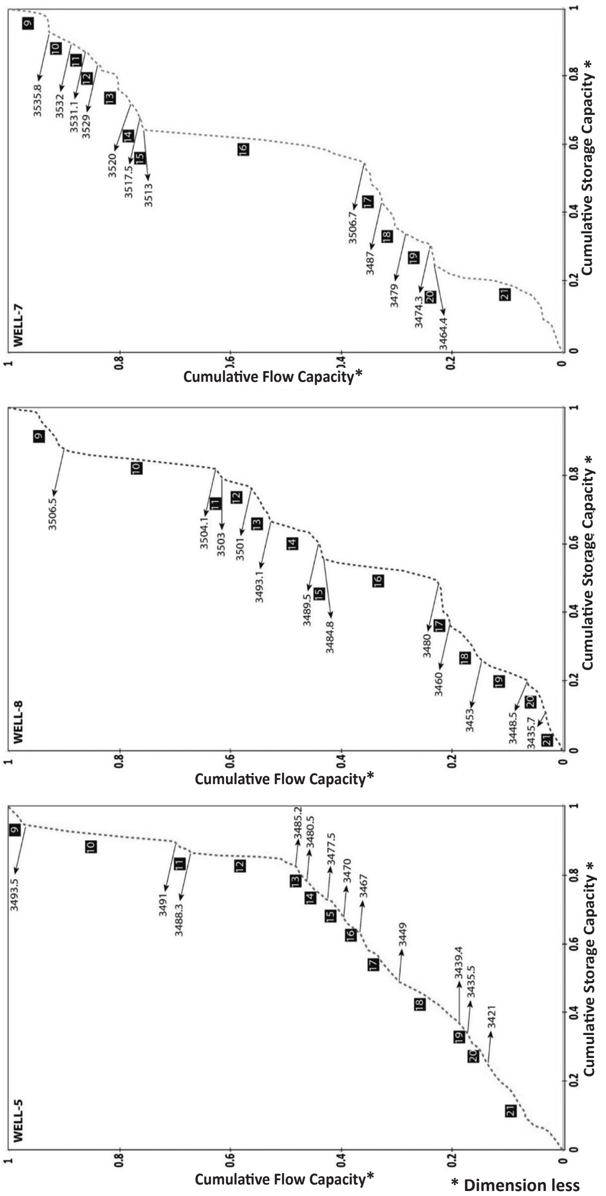

Figure 9: SML plot for carbonate parts of the Asmari formation in wells 5, 7, and 8 of the CK field.

The shaley (impermeable) and sandy (permeable) units are associated with gentle and steep slopes on the diagrams respectively (Figures 8 and 9).

Due to the significant difference in the porosity and permeability values of sandstones with carbonates, their contact is marked by a steep slope on the diagram, so it is considered as a sharp flow unit border. However, within the limy units, the variations of porosity and permeability are insignificant, so the borders of flow units are indistinct.

The carbonate-dominated part of the formation, with a low porosity and permeability variation, is marked by a gentle slope on the diagrams. In this regards, the discrimination of the flow units is rather difficult within this portion. To overcome the problem, the diagrams of the carbonate dominated portion are portrayed separately (Figure 9). Considering the slope deviation on the diagrams as the flow unit border, 13 flow units were determined in this part of the formation (numbered 9 to 21) (Figure 9).

Based on slope deviation on the diagram, 8 flow units (numbered 1 to 8) were determined in the siliciclastic-dominated parts of the formation (Figure 9). These flow units of the sandy horizons are correlatable in the 3 key wells and across the field (Figure 4).

The correlation of the flow units of the carbonate horizons across the field is not easily achievable. This is most likely related to various diagenetic features in the carbonate facies (see below). Upscaling technique is used for field-scale correlation and modeling of the flow units within the carbonate horizons of the formation [28]. For example, the combination of flow units 11, 12, and 13 resulted in the definition of a new larger scale unit which was more useful in the correlation. In this manner, reservoir 21 flow units are merged to 17.

The comparison of outcomes from the two used methods (Figure 4) shows that the contacts of flow units in the sandy parts of the formation exactly coincide with the horizons of FZI variations. Such a correlation is not observed in the carbonate parts, where the flow units show a greater internal variation in reservoir characteristics. Nevertheless, considering the thickness in the SML method makes it more precise in the flow unit analysis.

Linking Flow Units to Depositional Facies, Diagenetic Events, and Sequences

The correlations of the flow units, depositional facies, and sequences in the studied field show that the controlling parameters are different in the lower (sand–dominated) and upper (carbonate-dominated) parts of the formation (Figure 4).

In the sand-dominated part, reservoir quality is controlled by facies type and systems tracts. In other words, depositional conditions are the main controls of reservoir quality here (Figure 5). The upper shoreface shales (facies H) have the lowest reservoir quality among the siliciclastic facies, which is related to the gentle slopes on the CSC-CFC diagram (Figure 8). Therefore, the shale intervals were considered as non-reservoir zones. The barrier sandstones (facies I) and incised valley fill sandstones (facies G) have the highest reservoir quality among the siliciclastic facies, which is related to steep slopes on the CSC-CFC diagram (Figure 8). The sandy facies are the main constituents of the sequences 1, 2, and 3 of the studied formation.

The sandstones of lower shoreface to offshore sub-environments (facies F) are mainly developed as the FSST of the sequence 1. They are mainly correlated with the flow unit 1 (see Figure 8). The incised valley fill sandstones/conglomerates (facies G) characterize the LST of the sequences 2 and 3. They are correlated with flow units 2 and 8. The barrier sandstones (facies I) are developed in the FSST of the sequence 2; they are correlated with flow unit 6. The sandstones of intertidal zone (facies J) characterize the TST of the sequence 2 and are correlated with flow unit 3; such associations reveal a good correlation between the flow units and depositional facies and sequences in the siliciclastic-dominated part.

The carbonate-dominated part of the formation is mainly composed of facies associations C (shoal), D (lagoon), and E (intertidal). The facies associations of A and B principally occur as intercalations of the sandy part. The flow units of the carbonate-dominated part of the formations (9 to 21) do not properly correlate with the related facies and sequences. In this part, a single flow unit may correlate with a range of facies or vice versa. The reservoir quality of the carbonate facies is mainly controlled by diagenetic features. On the basis of depositional settings, the shoal facies (ooid and bioclast grainstones) are expected to show high reservoir quality. However, some facies of this group occur in a low reservoir quality range due to the massive cementation. Conversely, some facies of the lagoon environment, which are expected to show a low reservoir quality, occur in a high reservoir quality range due to dissolution and/or dolomitization. In this regard, for the correlation of flow units with facies and sequence in the carbonate part, the diagenetic features of the facies should be taken into account.

The correlation of the flow units with siliciclastic facies and sequences (Figure 5) revealed the tiny role of post-depositional (diagenetic) processes on their reservoir quality. The insignificant role of diagenetic features on the reservoir quality of these facies is also understood from their petrographic studies. Negligible calcite and clay cements are the only porosity/permeability control diagenetic features observed in these facies.

Conversely, the results from the correlation of flow units with the carbonate facies, while combined with their petrographic, SEM, and CL studies, indicate the major role of diagenesis on their reservoir quality (Figure 10).

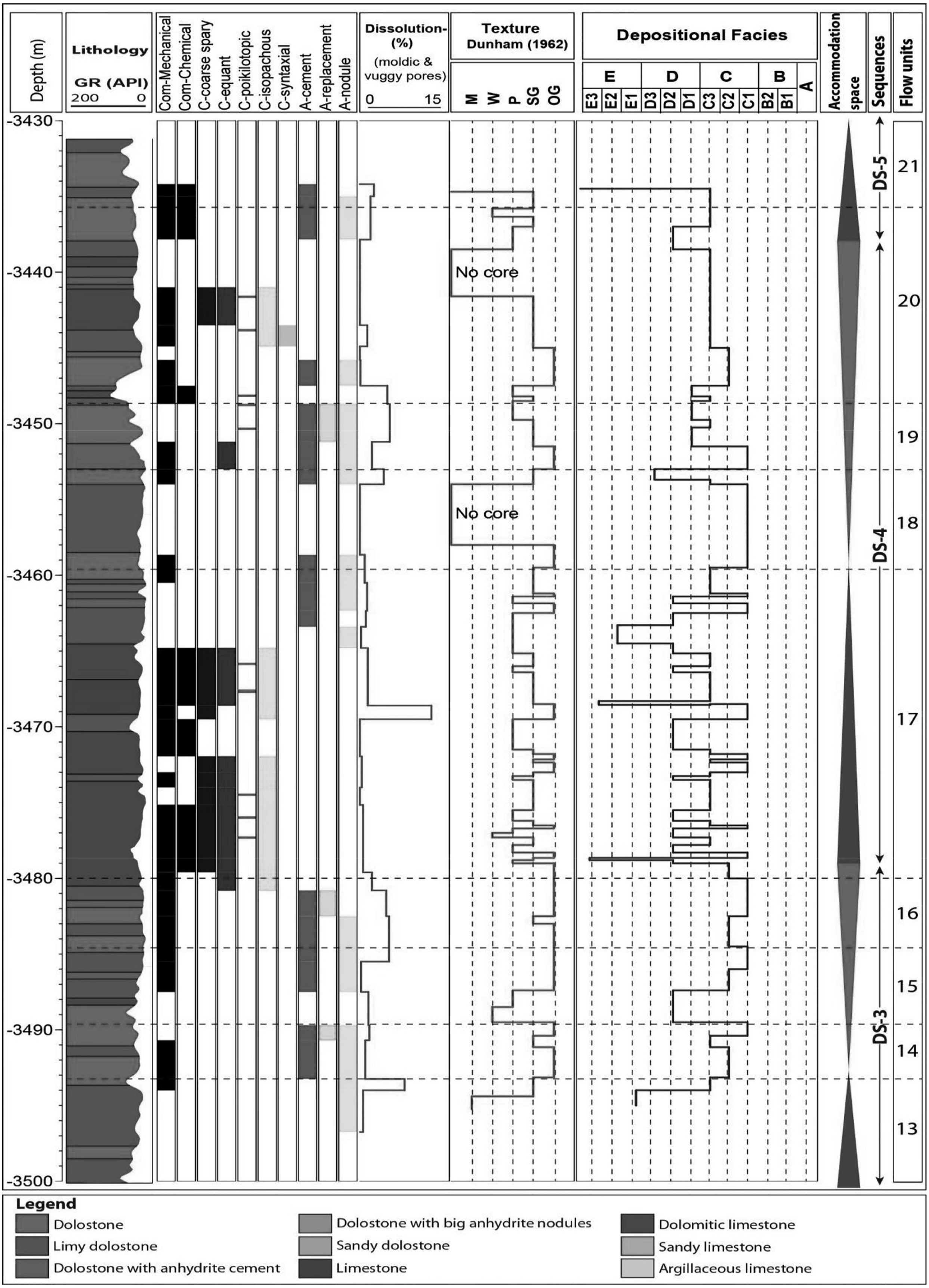

Figure 10: Correlation of flow units, depositional facies, sequences, and major diagenetic features in the carbonate-dominated part of the formation; C= Calcite; A= Anhydrite; Com= Compaction; M= Mudstone; W= Wackestone; P= Packstone; SG= Skeletal grainstone; OG=Ooid grainstone.

Various effects of diagenetic processes on the heterogeneity of the carbonate facies, both in time (vertically) and space (laterally) make their correlation with the flow units complicated (Figures 4, 9, and 10). No distinct principle between the flow units and the carbonate facies can be issued. In this part of the formation, only the boundaries of correlatable flow units across the field are used for modeling. In other words, some flow units are combined to create a new, wide scale, and correlatable flow unit. The combination of flow units 11, 12, and 13 resulted in the definition of a new larger scale unit which was more useful in the correlation (Figure 4).

To summarize the relation of facies/sequences and diagenesis with the flow units, porosity and permeability values, oil saturation, lithology, facies type, major diagenetic features, sequences, and system tract of the studied formation are shown together in Tables 2, 3, and 4. The significance of the depositional conditions of the siliciclastic facies and diagenetic features of the carbonate facies in the flow unit determination is well demonstrated here.

Table 2: Petrophysical and geological characteristics of the flow units in the well CK-5.

FU	Depth (m)		$Ø_{Average}$	$K_{Average}$	S_{oil} (%)	Lithology	Facies	Diagenetic Events	Systems Tracts	Sequence
	From	To	(%)	(mD)						
21	3402	3421	9.1	1.25	7.2	D (65%), L (35%)	C3, C2, D2	DLM, DIS, AN CEM	HST, TST	DS-5
20	3421	3435.5	4.8	0.486	3.75	L, D, LD, DL	C3, C1, D2, D1	DLM, AN CEM, DIS	LST, FSST	
19	3435.5	3439.4	5.07	0.62	4.13	D	C3, D2	DLM, AN CEM, DIS	FSST	DS-4
18	3439.4	3449	10.6	2.26	7.6	D	D2, C2, C1	DLM, AN CEM, DIS	HST, TST	
17	3449	3467	4.7	0.58	3.5	L (70%), D (30%)	C3, D2, C1, D3	CAL CEM, DLM	TST, LST	
16	3467	3470	10.8	2.04	9.15	D, LD	C1, C3	DLM, DIS	FSST	DS-3
15	3470	3477.5	5	0.55	3.4	D	C1	DLM, AN CEM, DIS, COM	HST	
14	3477.5	3480.5	11.3	2.26	8.8	D	C1	DLM, AN CEM, DIS,	HST, TST	
13	3480.5	3485.2	7.6	0.912	3.76	D	D1, D2, E1	DLM	TST	
12	3485.2	3488.3	9.8	10.7	3.8	L	C3, D1	CAL CEM	TST	
11	3488.3	3491	7.3	1.74	3	L (50%), D (50%)	C3	CAL CEM, DLM	TST	
10	3491	3493.5	15.08	17.4	12.2	D		DLM	TST	
9	3493.5	3502	8.5	37.03	0.072	DL, LD	D1, B1	CAL CEM, DLM, DIS	TST	
8	3502	3513	21.6	1319.3	19.09	S	G		LST	
7	3513	3518	11.4	56.95	6	D	D	DLM, DIS	FSST	DS-2
6	3518	3520	16.5	178.25	11.6	S	I		FSST	
5	3520	3526	8.7	0.5	1.43	Sh	H		FSST	
4	3526	3541.8	11.6	5.97	7.8	L/DL	B	CAL CEM, DLM, DIS	HST	
3	3541.8	3556	17.2	391.9	10.4	S and Sh	J		TST	
2	3556	3622	19.6	626	15.9	S and basal congl.	G		LST	
1	3622	Top Pabdeh	11.5	154.6	3.7	Arg. S, L	F		FSST	DS-1

D: Dolostone; DL: Dolomitic limestone; LD: Limy dolostone; L: Limestone; S: Sandstone; Sh: Shale; Arg.: Argillaceous; Congl.: Conglomerate; DLM: Dolomitization; DIS: Dissolution; AN CEM: Anhydrite cementation; CAL CEM: Calcite cementation; COM: Compaction

Table 3: Petrophysical and geological characteristics of the flow units in the well CK-8.

FU	Depth (m)		$Ø_{Average}$ (%)	$K_{Average}$ (mD)	S_{oil} (%)	Lithology	Facies	Diagenetic Events	Systems Tracts	Sequence
	From	To								
21	3426	3435.7	8	1.3	6.5	D (75%), L (25%)	C3	DOL, AN CEM, COM, DIS	HST, TST	DS-5
20	3435.7	3448.5	5.4	1.1	4	D, DL, LD	C3, C1, C2, D2	DOL, AN and CAL CEM, COM, DIS	LST, FSST	
19	3448.5	3453	8.2	6.6	6.9	D	C1, C2, C3, D1	DOL, AN CEM, COM	FSST, HST	
18	3453	3460	11.9	4.2	8.7	D, LD	C2, C1	DOL, AN CEM, COM	HST	DS-4
17	3460	3480	4.35	0.44	2.5	L (70%), LD (20%), D (10%)	C3, C1, D2	DOL, AN and CAL CEM, COM	TST, LST, FSST	
16	3480	3484.8	11.7	18.2	10.2	D, LD	C1, C2	DOL, AN CEM, DIS, COM	HST	
15	3484.8	3489.5	7.1	0.9	4.8	D, LD	C1, C2, D2	DOL, AN CEM, COM	HST	
14	3489.5	3493.1	11.9	9.8	9.9	D	C1, C2	DOL, AN CEM, COM	HST	
13	3493.1	3501	9	2.2	4.2	LD	E1, E2, E3, D2	DOL, AN CEM	TST	DS-3
12	3501	3503	11.7	10.9	4.8	L	No core		TST	
11	3503	3504.1	13.2	3.7	9.7	L	No core		TST	
10	3504.1	3506.5	22	55.9	19.3	D	No core		TST	
9	3506.5	3515.1	10.4	6.3	5.9	LD (60%), L (30%), D (10%)	No core		TST	
8	3515.1	3526.4	25.8	3992.5	24.2	S	G		LST	
7	3526.4	3530.45	14.6	28.5	11.95	D	D	DOL, DIS	FSST	
6	3530.45	3532.94	26.3	1721	22.1	S	I		FSST	
5	3532.94	3542	12.9 (5.5)	28.7	0.023	Sh	H		FSST	
4	3542	3553.36	14.9	4.6	10.1	L/DL	B	CAL CEM, DOL, DIS	HST	DS-2
3	3553.36	3568.3	17.8	566.9	10	S and sh	J		TST	
2	3568.3	3625.6	22.5	1178.2	18.6	S and basal congl.	G		LST	
1	3625.6	Top Pabdeh	21.5	820.8	10.4	Arg. S and L	F		FSST	DS-1

D: Dolostone; DL: Dolomitic limestone; LD: Limy dolostone; L: Limestone; S: Sandstone; Sh: Shale; Arg.: Argillaceous; Congl.: Conglomerate; DLM: Dolomitization; DIS: Dissolution; AN CEM: Anhydrite cementation; CAL CEM: Calcite cementation; COM: Compaction

Table 4: Petrophysical and geological characteristics of the flow units in the well CK-7.

FU	Depth (m)		$Ø_{Average}$ (%)	$K_{Average}$ (mD)	S_{oil} (%)	Lithology	Facies	Diagenetic Events	Systems Tracts	Sequence
	From	To								
21	3440	3464.4	9.6	5.7	7	D (70%), L (30%)	D2, C3	DOL, AN CEM, DIS, COM	HST, TST	DS-5
20	3464.4	3474.3	5	0.76	3.1	L	C3, C1, D2	DOL, AN/ CAL CEM, DIS, COM	LST, FSST	
19	3474.3	3479	7.9	5.7	6.1	D	C1, C3	DOL, AN CEM, DIS	FSST, HST	DS-4
18	3479	3487	11	3.5	6.6	D	C1, C2, C3	DOL, AN CEM, DIS, COM	HST	
17	3487	3506.7	5.3	0.9	3.1	L	D2, C3, C2, C1	DOL, AN/ CAL CEM, DIS, COM	TST, LST	
16	3506.7	3513	15.2	38.7	13.6	LD, L	C1, C3	DOL, AN CEM, DIS, COM	FSST, HST	DS-3
15	3513	3517.5	7.5	1.1	4.4	D, LD, L	C1	DOL, AN CEM, DIS, COM	HST	
14	3517.5	3520	13.1	3.7	11	D	No core		HST	
13	3520	3529	11.6	4	5.6	LD, D, L	D2, C1	DOL, AN CEM, COM	TST	
12	3529	3531.1	13.3	4.5	6.2	D	D2, C3	DOL, AN CEM, DIS, COM	TST	
11	3531.1	3532	5.6	0.6	0.7	L	D2, C3	DOL, AN CEM, DIS, COM	TST	
10	3532	3535.8	16.3	12	10.9	D	D2	DOL, DIS, COM	TST	
9	3535.8	3542	11.5	14.25	1.6	L, LD	D2, C2, C3	DOL, AN/ CAL CEM, COM	TST	
8	3542	3547.7	23.5	2703	20.96	S	G		LST	
7	3547.7	3553.5	14.45	9.45	10.9	D	D		FSST	DS-2
6	3553.5	3558	19.7	289.3	14.3	S	I		FSST	
5	3558	3568	10.1	5.05	0.76	Sh	H		FSST	
4	3568	3577	16.5	29.3	11.6	L/DL	B		HST	
3	3577	3592	16.6	319.2	9.5	S and sh	J		TST	
2	3592	3624.2	19.5	612.3	15.2	S and basal congl.	G		LST	

D: Dolostone; DL: Dolomitic limestone; LD: Limy dolostone; L: Limestone; S: Sandstone; Sh: Shale; Arg.: Argillaceous; Congl.: Conglomerate; DLM: Dolomitization; DIS: Dissolution; AN CEM: Anhydrite cementation; CAL CEM: Calcite cementation; COM: Compaction

CONCLUSIONS

In recent years, petroleum engineers have used different methods to determine the reservoir zones or hydraulic flow units. Winland, FZI, and SMLP methods as well as rock typing by using por-perm data are among the most common methods. Although these methods have been widely used in the oil industry, in all of them, the distribution of flow units is solely based on reservoir characteristics, and well locations are presented. On the other hand, based on previous studies and this study, pore characteristics (volume, size, type, and connectivity) in sedimentary successions is controlled by sedimentological (including facies and diagenetic) characteristics. Therefore, introducing techniques, in which reservoir properties and controlling parameters are used together, will be of great efficiency and in predicting the distribution of reservoir properties in the study area. In the current work, an integrated study was carried out on a mixed carbonate-silisiclastic succession of the Asmari formation. The results showed that the lateral and vertical distribution of some reservoir flow units (such as sandstone units 2 and 8) are strongly controlled by the geometry of depositional facies. This study showed that the correlation and modeling of flow units, solely on the basis of lithology and thickness, and regardless of facies and its geometry, will cause different facies (such as coastal and channel-filled sandstones) to be placed in a single flow unit. However, the lateral and vertical distribution and reservoir quality of these coastal and channel-filled sandstones in the Asmari formation are quite different. Also, in sequence stratigraphic framework, these sandstones were placed in different sequences (sequences 2 and 3) and systems tracts (FRST and LST). In the carbonate parts of Asmari formation, the effect of diagenetic processes on reservoir quality is much higher than the facies. Thus, the LST limestones of unit 17, as a result of calcite cementation, were changed to a thick, distinct, correlatable, and barrier unit. On the other hand, dolomitic intervals which have not been affected by anhydrite cementation have formed porous and permeable carbonate reservoir units (such as units 18 and 21).

In this integrated geological-petrophysical case study, for each flow unit, reservoir characteristics, facies, diagenetic events, and system tracts were presented. Thus, according to the relationships between these characteristics in the studied field, the prediction of reservoir properties in any given situation will be possible, which will be covered in our future studies.

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