ORIGINAL PAPER - EXPLORATION GEOLOGY

Natural fractures characterization by integration of FMI logs, well logs and core data: a case study from the Sarvak Formation (Iran)

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Abstract

Carbonate reservoirs in Iran are the most important and main sources of oil and gas production. Hydrocarbon flow rates from carbonate reservoirs heavily rely on the development of natural fractures. This study focuses on the role of natural fractures on reservoir quality considering the Sarvak carbonate reservoir (southwest Iran) as the second most important oil reservoir of Iran. To identify small-scale fractures around the borehole walls, cores description and image logs were utilized. Due to high cost of coring, lack of orientation and low core recovery in fractured zones indirect methods based on image logs and conventional well logs were exploited for fracture characterizations. For this purpose, a complete set of well data including image logs (FMI), well-log-derived porosity and permeability data together with petrophysical logs were employed. Interpretation of image logs allows different types of natural structures such as open, vuggy, partly-filled and filled fractures, bedding planes and stylolites to be identified. Comparisons between the petrophysical-log and image-log interpretations provide useful relationships with reservoir characteristics. Neutron and sonic logs show a direct relationship with fracture porosity, while the density log displays an inverse correlation with fracture porosity. Neutron-density and neutron-sonic cross-plots show that the dominant lithology of the studied well is limestone with minor fractions of dolomite and shale. Total porosity ranges from 2 to 30%, while the contribution of secondary porosity, on average, is below 3%. Relationships between fracture-frequency diagrams and reservoir permeability show that high permeability zones are well correlated with the high frequencies of open and vuggy fractures and zones that have flowed oil and associated gas in production tests. Natural fracture characterization based on systematic and integrated interpretations of image logs and petrophysical data can play an important role in optimizing field development, resource recovery and production from the Sarvak reservoir. Once calibrated, this method also offers potential as an exploration tool.

Keywords Reservoir fractures · FMI well logs · Sarvak carbonate formation · Reservoir quality

Introduction

Carbonate reservoirs contain a large amount of oil and gas-in-place. It is estimated that 60% of the world's oil reserves and 40% of the world's gas reserves are present in these reservoirs (Sadeq and Yusoff 2015; Lee et al. 2015; Dou et al. 2011; Esrafili-Dizaji et al. 2015; Kosari et al. 2017; Ezati et al. 2018; Gupta 2019; Wang et al. 2020). The naturally fractured reservoirs (NFR) are a challenge for the oil industry due to their importance in hydrocarbon production and the technical complexity they represent. Well productivity in carbonated formations is influenced by fracture systems that govern the fluids flow within reservoirs (Alcantara et al. 2019; Zaremoayedi et al. 2022). The quality of this type of reservoir is defined by two factors: "hydrocarbon storage" and "production capability." The hydrocarbon storage capacity is defined by the effective porosity and connected pore types located within the confines of a hydrocarbon trap (Peters et al. 2012; Anees et al. 2022). One of the most effective types of porosity is fracture porosity. A slight increase in fracture porosity can cause substantial

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changes in a formation permeability in directions parallel to the fractures. Hence, natural fractures can make significant contributions to permeability and/or porosity, reservoir behavior and field production performance, particularly in carbonate reservoirs (Nelson 2001; Ameen and Hailwood 2008; lai et al. 2017).

It is effective to detect and characterize fracture patterns and their subsurface distributions to better explore and identify potential productive/non-productive zones in oil and gas fields (Jiang et al. 2022; Ashraf et al. 2020; Ullah et al. 2022). Fractures play an important role in many reservoirs in creating possible pathways for hydrocarbon flow and migration by enhancing the overall formation's permeability (Prioul and Jocker 2009; Khoshbakht et al. 2012; Prioul and Jocker 2009; Tokhmchi et al. 2010; Ameen et al. 2012; Khoshbakht et al. 2012; Lyu et al. 2016; Lai et al 2017; Zahmatkesh et al. 1994; Serra and Serra 2004; Serra 1989; Milad and Slatt 2018; Laongsakul and Dürrast 2010; Saedi et al. 2017). Usually, the behavior of a fractured reservoir is very different from a non-fractured reservoir, due to the higher permeability of fractures compared to the matrix permeability. In this regard, the investigation of fractured reservoirs to quantify their effective porosity and permeability tends to be a lengthy process and more challenging than matrix-controlled reservoirs (Nie et al. 2013; Nelson 2001; Kosari et al 2017). The heterogeneities of fracture networks often significantly affect the flow performance of fractured reservoirs (Gong and Rossen 2017). If natural fractures are not characterized in early stages of field production, future field development plans can be blurred (Bratton et al. 2006; Alvarez et al. 2020). Unfortunately, natural fractures in oil reservoirs are often ignored or evaluated with oversimplified techniques, leading to the wrong decision being made in exploration and production programs incurring high costs (Voorn et al. 2015). As such a large proportion of known global oil and gas resources is located in naturally fractures reservoirs (NFCRs), the fractures in these reservoirs warrant more detailed and systematic evaluation as fractures are an integral part of petroleum production (Dusseault and Shafiei 2011; Shafiei et al. 2013, 2018). Iran, as one of the largest oil producers in the Middle East and the world, has many fractured carbonate reservoirs. The majority of them are located in the southwest of Iran. It is essential to recognize the fracture patterns and their distributions in these reservoirs, as it paves the way for an exploration, production and development of potential oil and gas fields (Badakhshan et al. 1998; Khoshbakht et al. 2012). This study reports new quantified findings on the impact of *in situ* fractures (open, vuggy, partly filled and filled), bedding planes and stylolites delineated by the Full-bore Formation Micro-Imager (FMI) wellbore log, coupled with information from other petrophysical well logs, on the reservoir quality and potential productivity of the Sarvak Formation. Integration of FMI, petrophysical logs and core analysis data (porosity and permeability) establish useful relationships between fracture types and densities within the most permeable zones of the Sarvak. The research into systematic tectonic-related fractures provides a better understanding of fracture pattern distributions. Such information can be utilized to improve fracture network modeling. The current study makes efforts to distinguish the relationship between fracture type and fracture density and linking them to interpreted porosity and permeability as an effective tool for improving oil and gas fields development offers. The described indirect fracture analysis method is less expensive than other fracture identification methods and offers the additional advantage of determining the impact of fracture on porosity and reservoir permeability.

Geological setting

The field under study is located in the structural zone referred to as the Abadan Plain, forming part of the Zagros basin (SW Iran). The studied field is situated within the Mesopotamian Foredeep sub-basin that is surrounded by the Arabian Plate and the Dezful Embayment (Saadatinejad and Sarkarinejad 2011). Due to the alluvial overburden, geological knowledge of that sub-basin is limited to wellbore data including drill cuttings, cores, logs and other geophysical data (Assadi et al. 2018). The available data suggest that the Quaternary alluvium along with the subsurface sedimentary layers has been folded in the north–south direction (Motiei 1996, 1993). The Abadan Plain structurally belongs to the Arabian Platform and follows the Arabian-type (N-S) structural trend, which is in contradiction to the typical Zagros-type structural trend (NW–SE) (Shakeri and Parham 2013).

The Dezful Embayment and Abadan Plain (SW Iran, Fig. 1) host a substantial portion of the Iran's oil resources (Abdollahie Fard et al. 2006; Tabatabaei et al. 2015). The Sarvak Formation (Middle Cretaceous), which is the main producing reservoir unit in the studied oilfield, comprises the most prolific carbonate oil reservoir of the Abadan Plain, and the second most important reservoir, in terms of oil and gas production in the entire Zagros Basin (Assadi et al. 2016; Malekzadeh et al. 2020). The Bangestan Group includes the Sarvak and Ilam Formations, which account for approximately 37% of Iran's oil reserves. It is ranked second after the giant Oligo-Miocene Asmari Formation (45%) (Gholami Zadeh 2019; Esrafili-Dizaji and Rahimpour-Bonab 2019).

The Sarvak Formation is a thick carbonate unit deposited in the Neotethys Southern Margin of Zagros Basin (Pakparvar et al. 2017; Bordenave and Hegre 2010; Ezati et al. 2018; Soleimani et al. 2013). In terms of stratigraphy, the Sarvak Formation comprises three types of limestone units reaching a maximum thickness of 821 m. The lower boundary of the
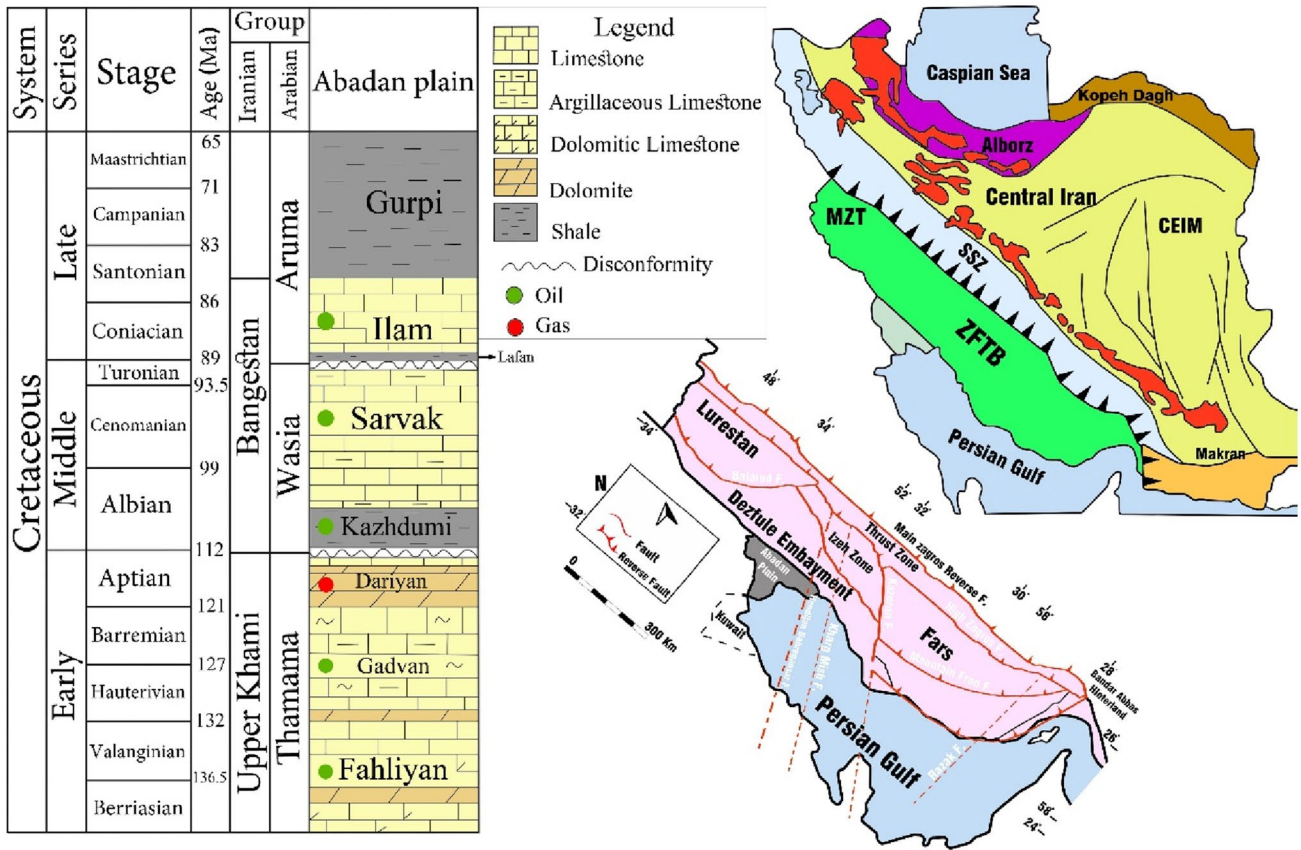
Fig. 1 Zagros structural divisions and stratigraphy column of Abadan Plane

Sarvak Formation overlies the Kazhdomi Formation, while the upper boundary, defined by the Turonian unconformity, varies from place to place. The lower limestone unit of the Sarvak Formation (254.5 m thick) consists of argillaceous micritic limestone with lenticular bedding and thin-layered marl interbeds. The middle Sarvak unit (524.5 m thick) contains massive chalky limestones with iron-rich siliceous carbonates. The top 42 m of the formation includes a massive limestone (unit 3) layer with its uppermost strata consisting of a weathered brecciated ferruginous limestone (Leturmy and Robin 2010). The top of Sarvak Formation is comprised of the Lafan shales (Fig. 1). There are different methods available for detecting the lithology from well-log data. The lithological components of Sarvak Formation were identified in the studied well by applying the density-neutron cross-plot. The density-neutron cross-plot is widely used for distinguishing limestone, dolomite, sandstone, shale and anhydrite (Diana Morton-Thompson 1993). As shown in Fig. 2, the major lithologies present in the studied well are limestone and dolomite. The total porosity of the Sarvak Formation ranges from 2 to 30% and effective porosity ranges from 2 to 27%. The secondary porosity contribution is less than 3%. In this study, the neutron-derived porosity is considered to
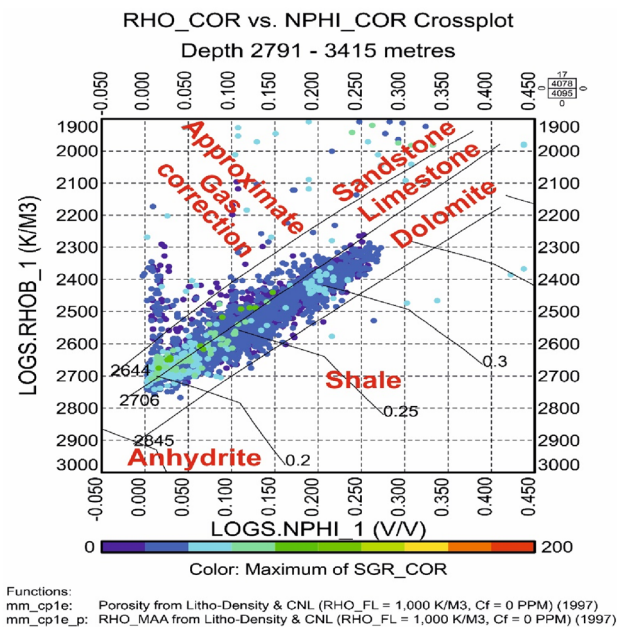
Fig. 2 Corrected neutron-density cross-plot

reflect total porosity, and the sonic-derived porosity is considered to reflect effective porosity. The difference between total and effective porosity is, therefore, considered to be a measure of secondary porosity.

The studied field is associated with a north–south trending anticline. The Sarvak Formation has been completely penetrated by the studied wellbore and image logs, together with a suite of standard petrophysical logs which has been recorded across the formation.

Material and methods

The study is implemented in three stages (Fig. 3): (1) processing and interpretation of image log and petrophysical well logs; (2) classification and data analysis and (3) linking interpreted results to productive/non-productive zones within the Sarvak formation. Initially, raw Full-bore Formation Micro-Imager (FMI) images and petrophysical logs data were corrected for environmental effects. Using the corrected data, sedimentary features such as bedding planes and stylolites, together with tectonic features such as fracture types (continuous open, isolated open, partly filled and filled), were identified and classified. For each identified feature, rose diagrams and density charts were generated to quantify their characteristics and distributions. Dip analysis software (Dips) was employed to draw contour diagrams of the identified image-log features. DT vs. fracture porosity, NPHI vs. fracture porosity and RHOB vs. fracture porosity cross-plots were generated to investigate the relationship between fractures and petrophysical data. Fracture porosity is obtained using image logs, and matrix porosity is obtained from petrophysical logs. Since fractures are considered as part of effective porosity. Fracture porosity is obtained from the difference between the matrix porosity and the total porosity.

Compared to the Formation Micro-Scanner (FMS) tools, FMI tools are better able to image all parts (360°) of the wellbore wall (Serra 1989), whereas the resistivity image (FMS) represents only about 80% of the borehole coverage in an 8.0-inch diameter borehole (Rider 2002; Brown et al. 2015; Moreau and Joubert 2016; Folkestad et al. 2012). The FMI-oriented image has a vertical resolution of 5 mm (0.2 in.) (Rider 2002; Folkestad et al. 2012; Schlumberger Educational Service 2004; Wilson et al. 2013; Brekke et al. 2017; Lai et al. 2018). To obtain a better model for the relationship between permeability and fracture porosity, image-log-derived fracture density needs to be correlated with other petrophysical log data. Fractures are considered as a planar feature within the formation and after unwrapping the cylindrical borehole, the fractures are seen as a sinusoidal wave on the unwrapped
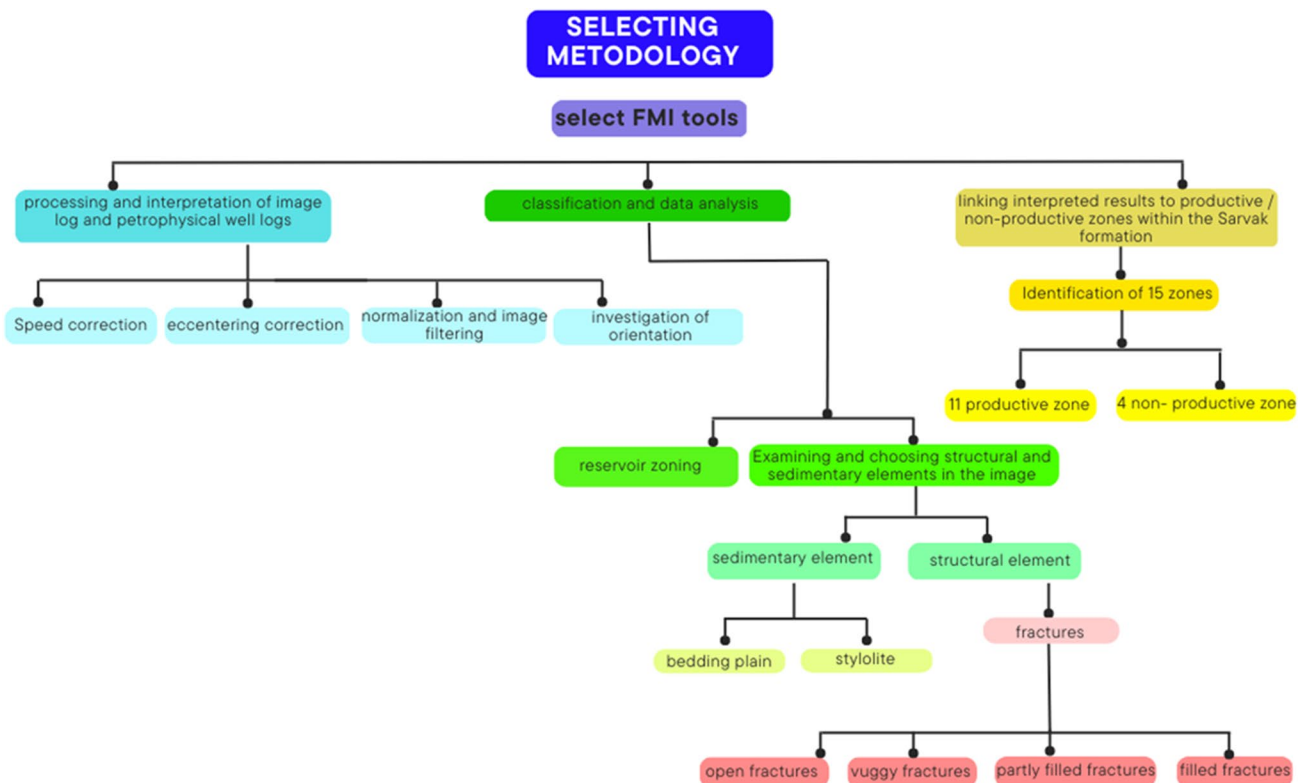

Fig. 3 Flowchart of methodology used in this study for fracture characterization
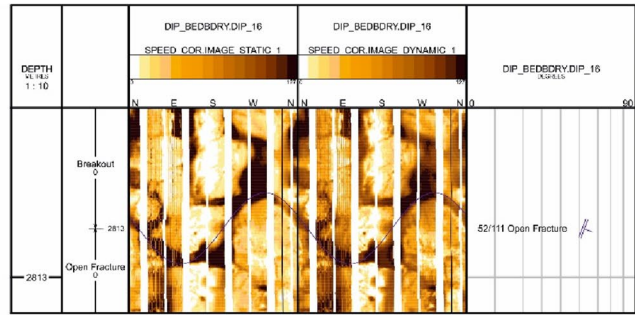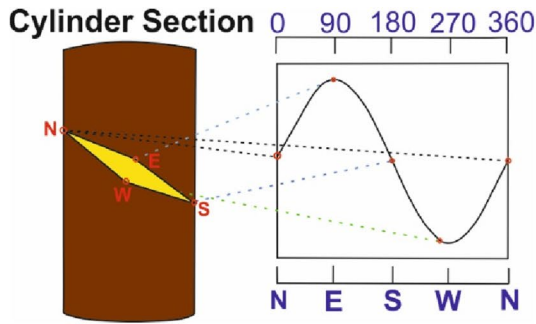
Fig. 4 Sketch showing the appearance of a fracture intersecting a wellbore at an inclined angle, and how it displays on an unwrapped image log as a sinusoidal pattern

image logs (Fig. 4). Relatively high and sudden changes in electrical resistance are features of fractures that can be differentiated by their changing color and with trends that extend through substantial sections of the FMI images. Fractures may be filled with a variety of materials, each of which is associated with a different resistivity. Resistivity values recorded by the image log are less than the background rock when the fractures are filled with conductive materials.

Results

According to the drilling and petrophysical data, Sarvak Formation in the studied well includes 15 zones, 11 of which are recognized as oil zones (Fig. 5). Natural fractures identified in this study were be divided into four categories including open fractures, vuggy fractures, partly-filled fractures and filled fractures. Open fractures are the most widespread types of fractures in the well (Fig. 6). Usually, the presence of open fractures controls the permeability in the carbonate reservoirs (Ngwenya et al. 2003; Boro et al. 2014; Li et al. 2018; Shafiei et al. 2018; Bagheri and Falahat 2022). In other words, one of the most important factors controlling the fluid transmissibility in the reservoir is the presence of natural open fractures. Accordingly, petroleum engineers can pay more attention to open and vuggy fractures compared to the other types of fractures, as they are more likely to be associated with the fluid flow and productivity. Each fracture set can be investigated in terms of the orientation of individual features (Figs. 6 and 7). In addition, the density of occurrence can be compared for each feature versus depth to determine the frequency distribution of each type of feature and relationships between those frequency distributions.

Natural fractures interpretation

A total of 117 natural fractures were detected that could be divided into four categories including open fractures,
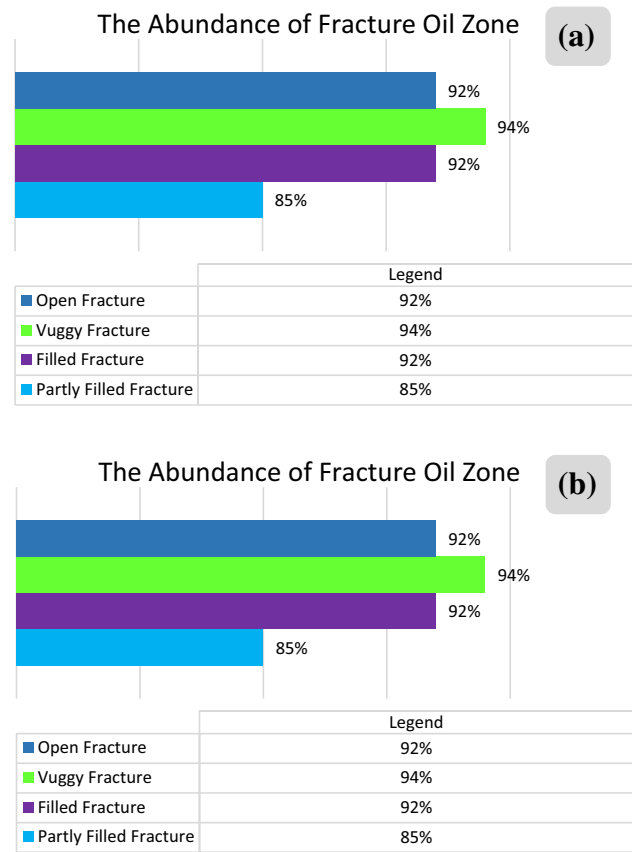
Fig. 5 Abundance of fractures: **A** in Sarvak Formation of studied well (2791–3415 m) and **B** in oil-producing zone of studied well (3791–3000 m)

vuggy fractures, partly-filled fractures and filled fractures. The number of open fractures is 55, which are divided into three main sets with average dips and dip azimuths about 43°/336°, 47°/92° and 45°/228°, respectively. The number of vuggy fractures is 35, and they consist of two main categories with an average dip and dip azimuth about 44°/253° and 42°/045°, respectively. It seems that partly-filled and filled
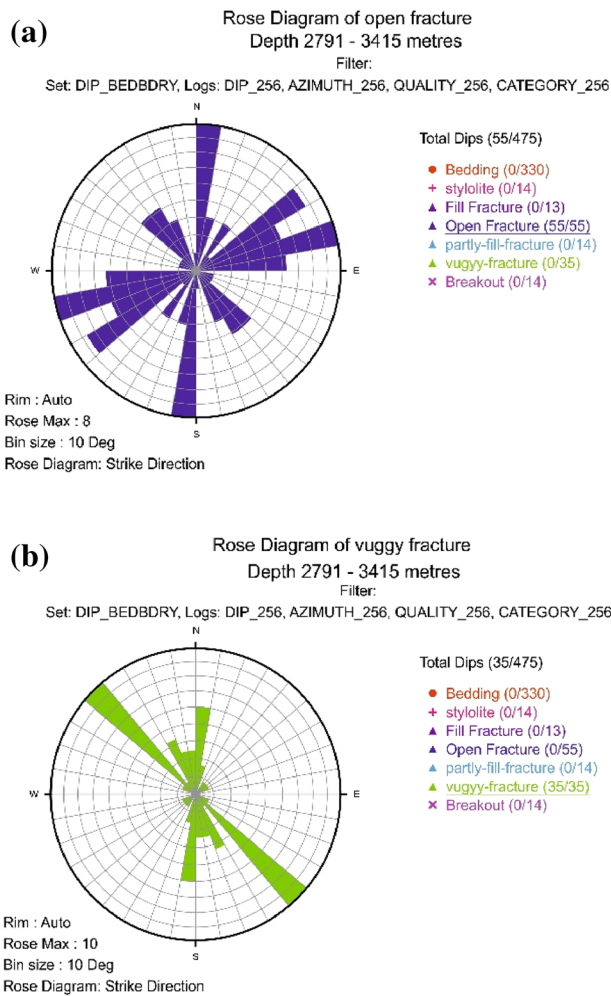
Fig. 6 Rose diagram of open fractures (**a**) and vuggy fractures (**b**)

Fig. 7 Rose diagram of filled fractures (**a**) and partly-filled fractures (**b**)

fractures have the same origin because their dispersions are centered at about the same depth. Also, these two features have the same orientation according to contour diagrams. There are 14 partly-filled fractures, with an average dip and dip azimuth of about 46°/350°. The number of filled fractures is 13, with an average dip and dip azimuth of about 42°/003° (Figs. 6, 7 and 8). The results show that as the magnitude of fracture porosity increases, the DT and NPHI log values increase but density readings decrease.

Bedding plane control on fracture density

According to the drilling and petrophysical data, the studied well has 11 oil-producing zones; the highest numbers of fractures were found in these zones. The fracture density log (Fig. 8) shows that the highest fracture density is in the upper part of the Sarvak Formation. The maximum density is from the depth of 2791 to 3000. According to the

frequency diagram, the upper parts of well display more massive layering, while thinner layers characterize the lower parts of the Sarvak Formation (Fig. 9).

In the studied well, 384 bedding planes were identified according to variations in color and/or lithology. The average dip of the bedding planes is 2° (i.e., almost horizontal), and the mean azimuth is 81°. Comparison made between fracture density and bedding revealed that fracture density in thick-bedded intervals is greater than in the thin-bedded zones (Fig. 9). A total of 14 stylolites were identified in the studied well. Stylolites are seen in image logs in the form of conductive, often flat or wave-like lines with near-vertical, short components oscillating unevenly through the formation. The average dip of stylolites in the well is 2 degrees (i.e., almost horizontal), and the mean azimuth is 89°. Stylolites in this well are primarily parallel with the bedding planes, suggesting that they have a sedimentary origin. They are common in cemented and compact carbonate intervals around the world (Fig. 10).

Fig. 8 Lower-hemisphere pole projection for all fractures, stylolites and bedding planes

Sedimentary Structures

Bedding Planes   Stylolite

Tectonic Structures

Open Fracture   Vuggy Fracture

Partly-Filled Fracture   Filled Fracture
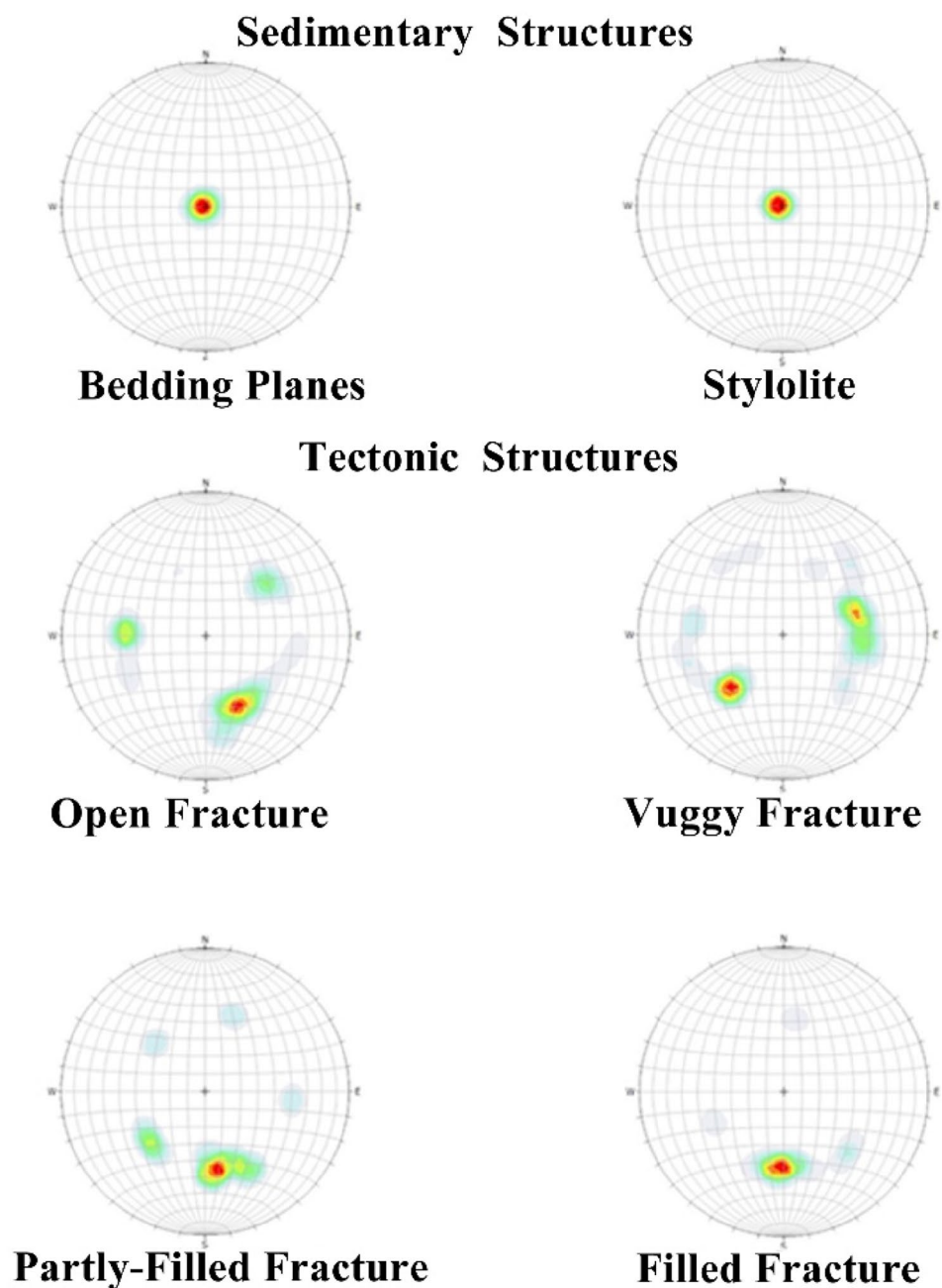
Fracture density relationships with permeability and production flow rates

According to the fracture density diagram, the Sarvak reservoir in the studied well can be divided into two parts: an upper part with high fracture density between 2791 and 3070 m and a lower part with very low fracture frequency between 3070 and 3415 m. The Sarvak Formation has thick, massive layers in the upper part and thin layering in the lower part. By constructing fracture density and porosity diagrams and matching them with the reservoir permeability logs (Fig. 11), it is apparent that in the upper parts of the

well, the fracture density is high. This high fracture density contributes substantial fracture porosity to certain zones of in the upper part of the Sarvak Formation and increases the permeability in those zones. Of the 15 zones in the studied well, 11 of them can be considered as potentially productive zones. Some 93% of the continuous open fracture, and isolated open fractures are located in these 11 zones. These 11 zones extend between depths of 2791 and 3070 m. In this study, two types of continuous open fracture and isolated open fracture are considered as fractures with a positive effect on porosity and permeability in the Sarvak reservoir. Figure 12 shows the cross-plot of fracture density

Fig. 9 Density (fractures per 1/M) logs of bedding planes (track 2), stylolites (track 3), open fractures (track 4), vuggy fractures (track 5), partly-filled fractures (track 6), filled fractures (track 7) and total fractures (track 8)
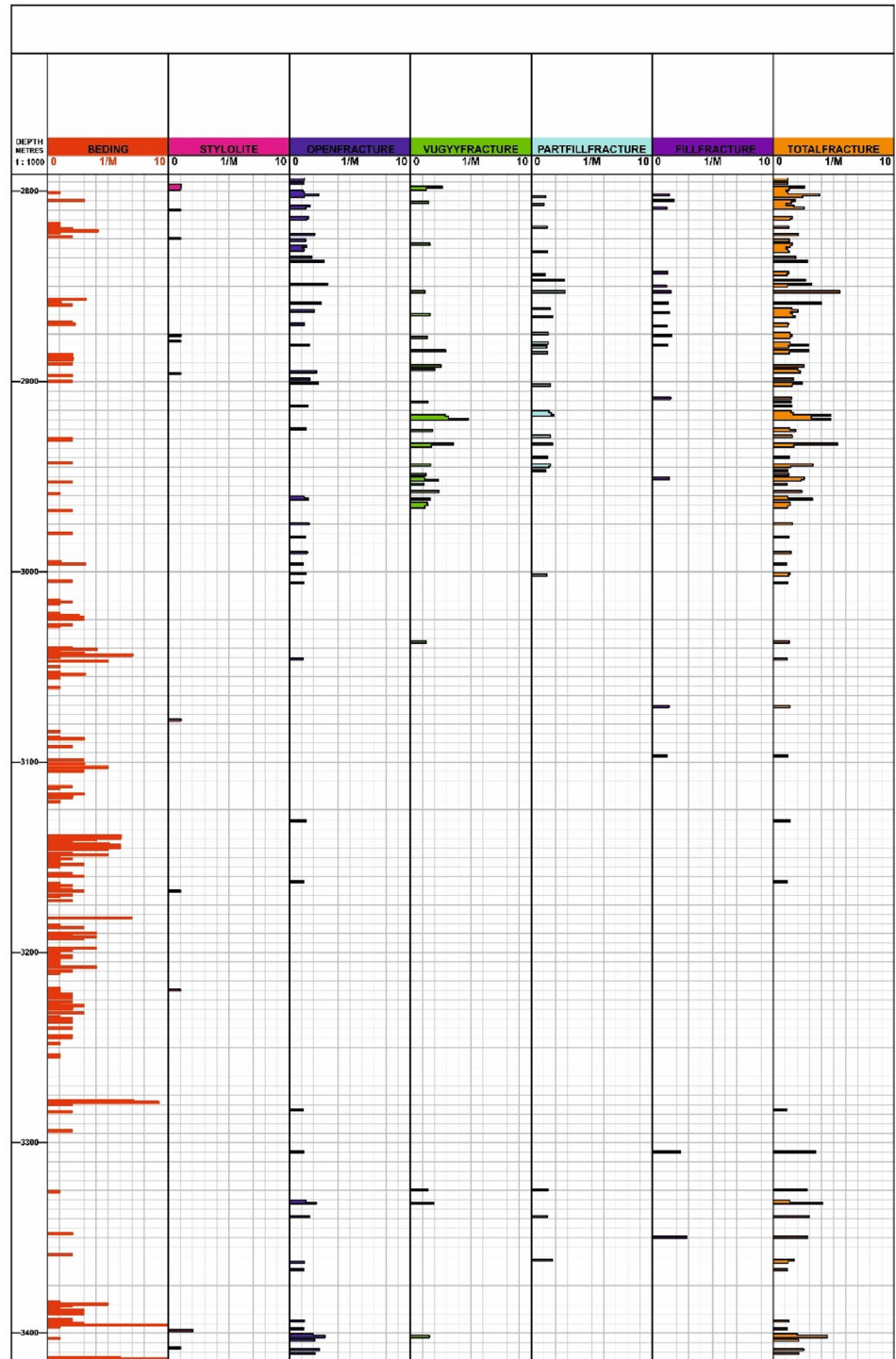
versus permeability. The permeability clearly increases with increasing frequency of fractures (Fig. 13).

In the zones where the fracture density is greatest (Fig. 11), it can be seen that fracture porosity contributes a much larger portion to the total porosity. By considering the permeability log, calculated porosity and frequency of fractures together, it is generally apparent that fracture porosity correlates positively with permeability. The results of

production tests show that for the depth interval 2791–3070, oil production rate was 1996 bbl/d, and the gas production was 0.6 mmcf/d. Figures 14, 15, 16, 17 and 18 display composite logs related to specific zones within the Sarvak Formation of the studied well.

In the lower part of the studied well (3070–3415), there is no oil production. This could be an indication of that depth interval being outside of structural closure, or that
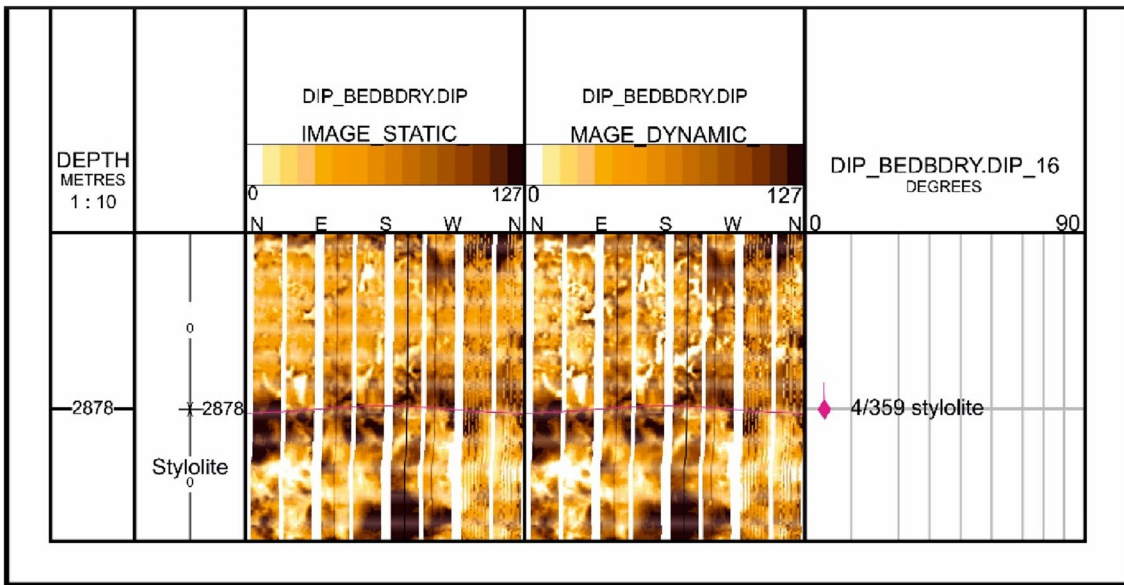
Fig. 10 An image-log example of a stylolite in the studied well (2878 m)
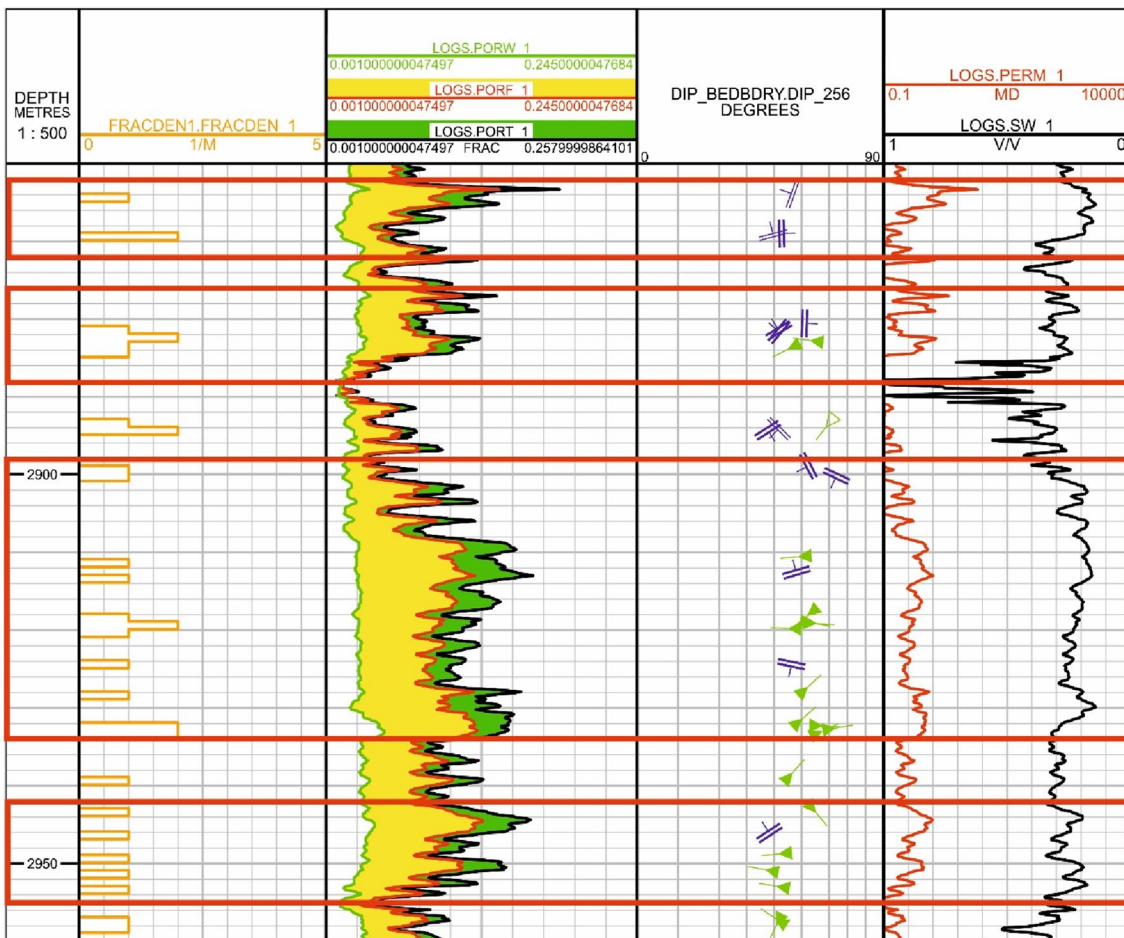
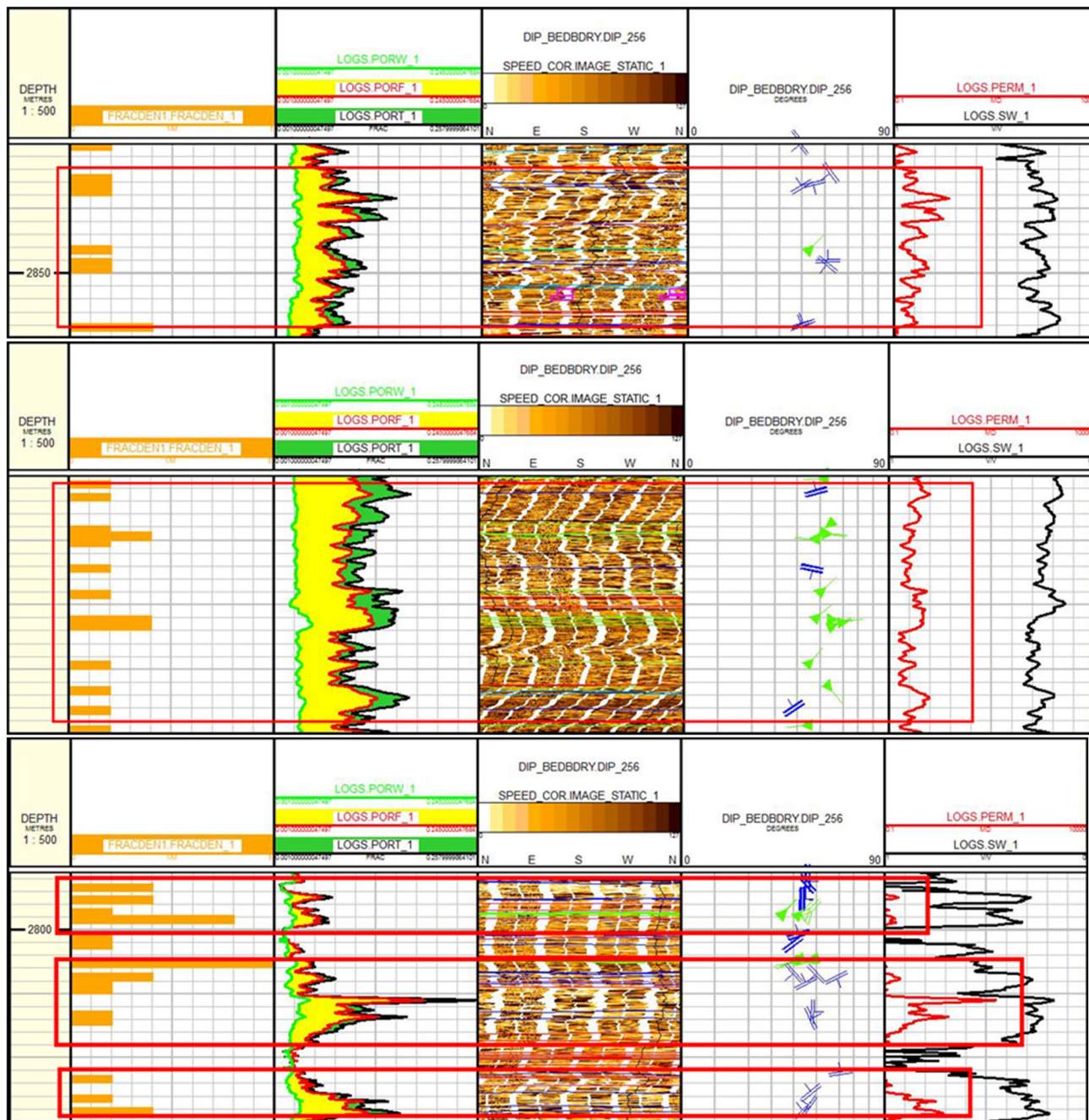**Fig. 11** Permeability variations across the fractured zones

Fig. 13 Permeability variation wit fracture density in fractured zones

identification and provides the additional benefit of determining fracture porosity and its effects on reservoir permeability. The potential exists to correlate reservoir zones with specific fracture types and densities from one well to another across a reservoir. This could facilitate mapping prospective zones within a reservoir with volumes that do not necessary lie within specific bedding planes or stratigraphically-defined intervals. In cases where other information is available such as core information (with high recovery) and/or specialist petrophysical logs, fracture type using the proposed method could be usefully correlated with other rock properties. This method can be extremely beneficial in assisting with field development decisions by providing highly accurate and detailed fracture analysis at low cost. In particular, it can help to design specific trajectories for planned deviated production wells, ensuring that they encounter the most productive fractured reservoir zones at the optimum orientation.

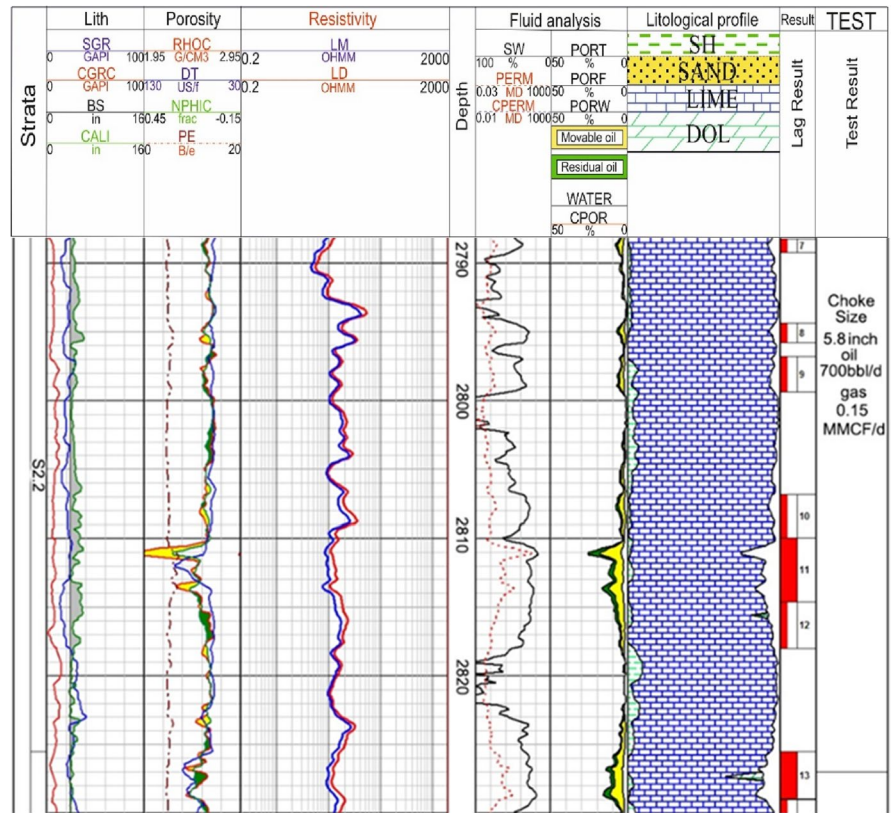**Fig. 14** Composite well log for production zones within depth interval 2790–2825 m

Fig. 15 Composite well log for production zones within depth interval 2830–2860 m
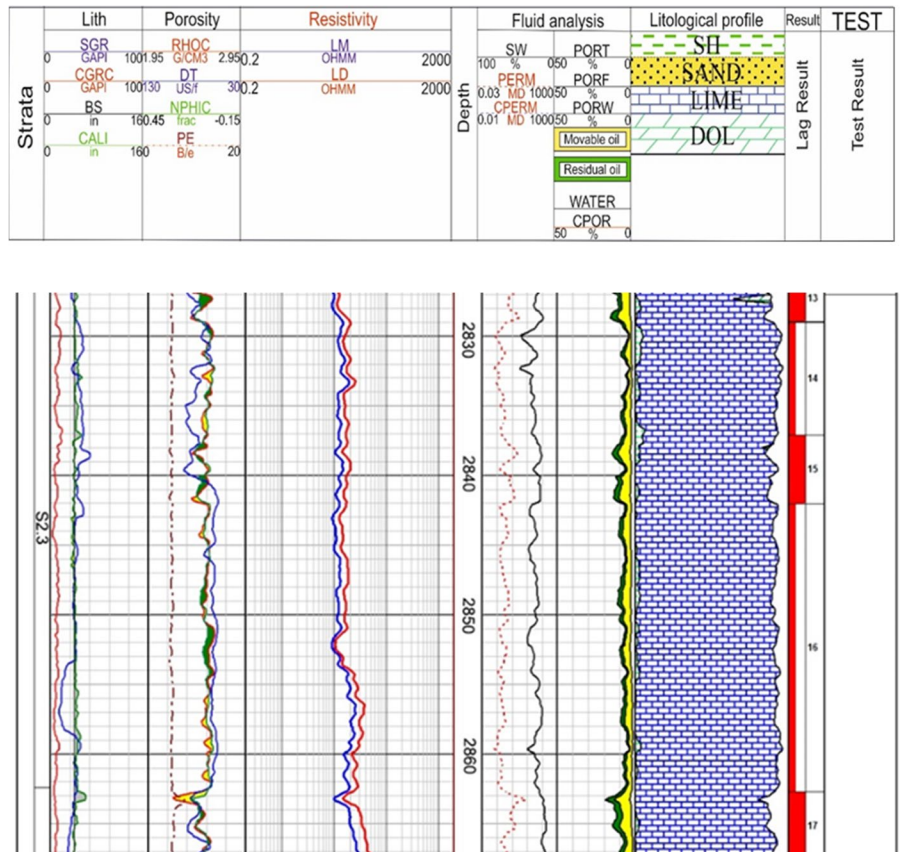
Fig. 16 Composite well log for production zones within depth interval 2870–2900 m
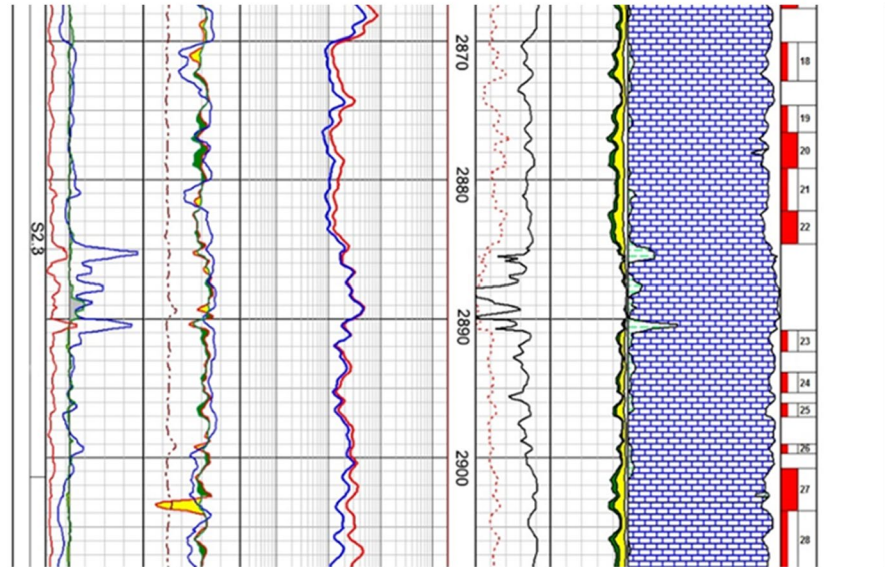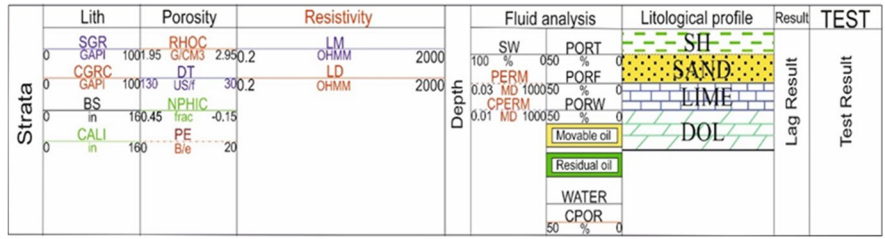

Fig. 17 Composite well log for production zones within depth interval 2910–2950 m
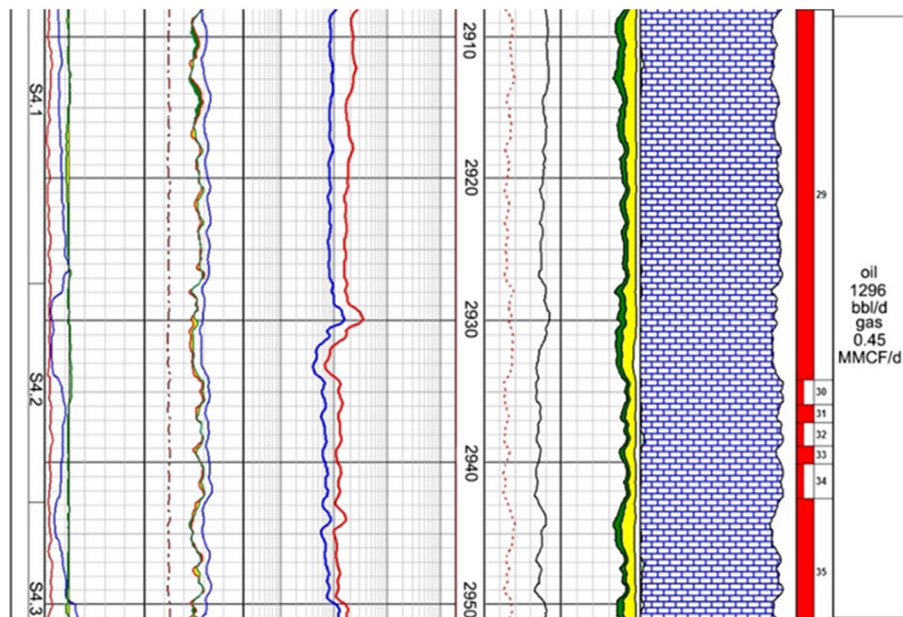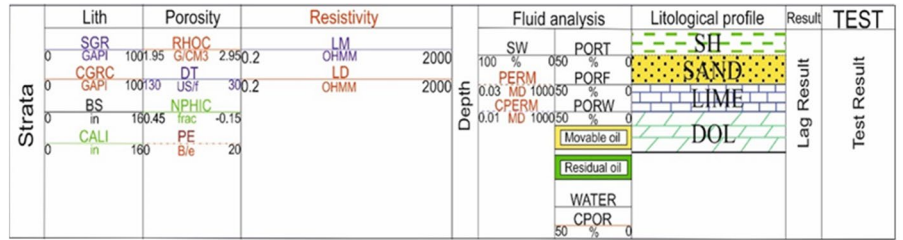
Fig. 18 Composite well log for the non-productive zone of the studied well which flowed saline water from depth interval 3070–3140 m
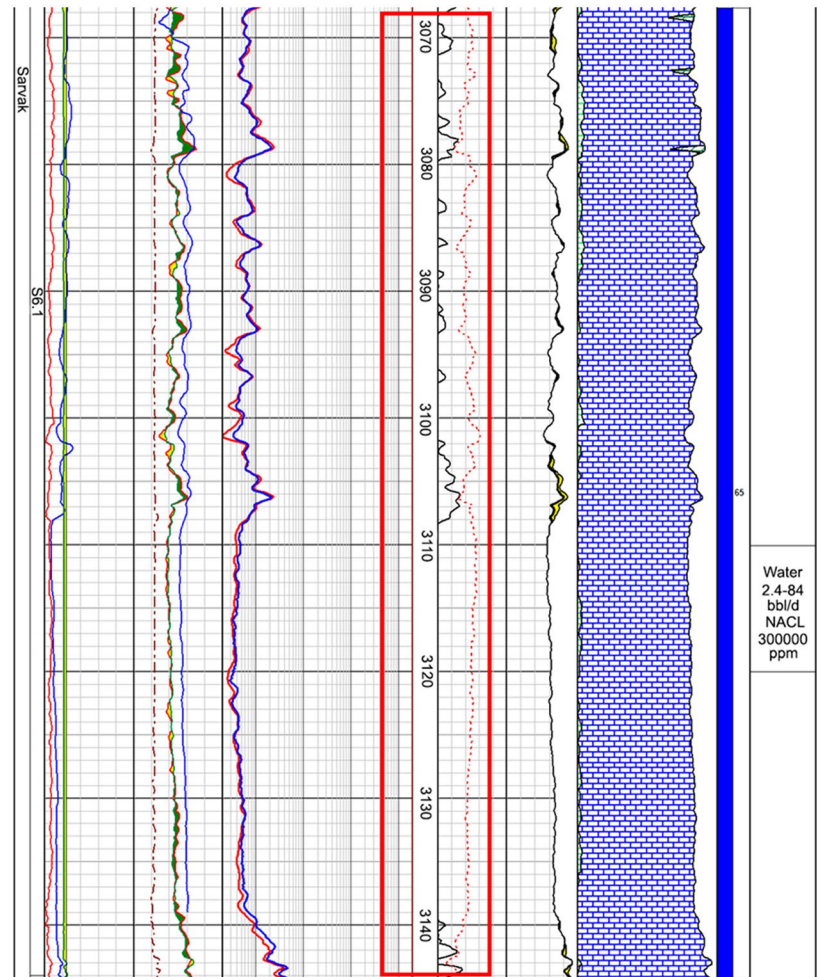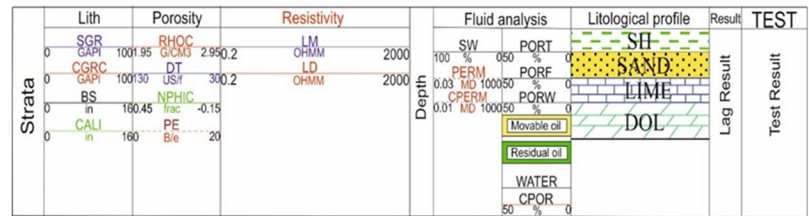
Conclusion

Considering the results obtained from image logs of this study, the followings are concluded.

- Bedding planes are determined to be oriented predominantly in N–S directions with an average dip and dip azimuth about 2 degrees and 79 degrees, respectively. A total of 117 natural fractures were detected that could be divided into four categories including open fractures, vuggy fractures, partly-filled fractures and filled fractures. A total of 55 open fractures were detected,

and these are divided into three main sets. Average dip and dip azimuth of the three sets of open fracture are about 43°/336°, 47°/92° and 45°/228°, respectively. The number of vuggy fractures detected was 35. This type of fracture consists of two main categories with average dip and dip azimuth of about 44°/253° and 42°/045°, respectively. It seems that these two categories of vuggy fractures have the same origin as their dispersion is about the same depth. Also, these two sets have the same orientations according to contour diagrams. The number of partly-filled fractures detected was 14, with an average dip and dip azimuth about 46°/350°, respectively. The

number of filled fractures detected was 13, with an average dip and dip azimuth of about 42°/003°.

- The porosity volume experiences some changes throughout the Sarvak Formation. Total porosity changes were measured in the formation from 2 to 30%. Matrix porosity varied from 2 to 27%, indicating that secondary (fracture) porosity has less than 3% contribution to total porosity. Although the amount of fracture porosity is very low, it seems to have contributed substantially to permeability in the well sections where the density of open and vuggy fractures is high.
- Change in the permeability diagram combined with change in fracture density in formation zones, where permeability has increased, is likely to be caused by the density and type of the fractures present.
- By comparing the petrophysical and density diagrams, we find that the upper part of the Sarvak reservoir (2791–3000 m) has good reservoir potential for exploitation and enhanced oil recovery (EOR).
- Matrix porosity in this section shows a substantial increase, suggesting that it has good potential to become a productive oil and gas reservoir.
- Future development of the studied field would benefit from drilling vertical wells in the upper Sarvak Formation where open fractures exist. Most of the fractures which were detected in the studied well were open.
- Typically, in the studied well, high permeability is located in specific zones of the Sarvak Formation corresponding to those zones displaying a high density of open fractures. Four high-density fracture zones were identified in the Sarvak Formation based on the integrated image log and other available petrophysical data.

Declarations

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