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Fracture Characterization and Their Impact on the Field Development

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ABSTRACT

Fracture characterization is a biggest challenge for the geoscientists in clastic and nonclastic reservoirs. With the advancement of all technical capabilities, in the acquisition of surface and subsurface geological data, still it is extremely difficult to understand, characterize, and predict the distribution of fractures in a field. Image logs can successfully be used to locate and to provide directional trends of fractures near the wellbore. However, capturing all the fractures in one well and to predict their flow behavior can still be a challenge. In this paper, a case study of a fractured carbonate reservoir will be presented. The field is currently producing about 500 bbl of oil per day through fractures. Four wells have been drilled on the structure to drain the oil reserves. Water flooding is being carried out in the field for the last 9 years for pressure maintenance and now 80 % water is being produced. The reservoir has very low primary porosity and permeability, and the flow is through fractures only. Based on the fracture data of three wells, a new well was drilled, located ideally at a structurally higher position, in crestal area of the field. Image data showed abundance of fractures with different orientation in the well bore but the well didn't flow and that led to its suspension. In this study, fracture data from image logs is compared with outcrop analogs and seismic reflection and interpretation data. In this paper, limitation of the available information, importance of understanding the stress regime, integration of geological and geophysical data and lesson learned from the current evaluation of the fracture system and their impact on development of a field in Powar basin will be presented.

GEOLOGICAL AND RESERVOIR OVERVIEW

Fimkaser oil field was undertaken as a case study for understanding and characterization of the fracture. The field is located in the Himalayan foreland in North Pakistan and represents fault related anticline as shown in Figure 1. It was discovered in 1989 by Gulf Petroleum and later on handed over to the OGDCL. The producing formations are Chor Gali and Sakessar limestone of Eocen age. These reservoirs are generally of low/non matrix porosity (1-3.5 %) and may be classified as type-1 of Nelson (1981), in which fractures provide essential porosity and permeability. In these types of carbonate reservoirs, secondary mouldic/vuggy and fracture porosity is important for storage of hydrocarbons. However, high permeability may be present in vuggy zones by solution enhancement of pore throats that creates an interconnected system of vugs (Camacho et al 2002.). Open hole wire line logs are used to identify vuggy zone but vugs are not always recognized by conventional logs due to their limited vertical resolution (Ausbrooks et al 1999). Four wells have been drilled vertically on the Fimkasar structure and among them two wells FMK-1(ST) and FMK-4 were sidetracked with maximum deviation of 42 degrees on this structure for hydrocarbon production. The structural correlations of all wells are illustrated in Figure 2. FMK-1(ST) and FMK-2 are drilled as producers from fractured Sakessar and Chor Gali formations, respectively. FMK-3 was drilled for water injection to maintain reservoir pressure as the reservoir pressure has gone below bubble point pressure. The injector is located in the western part of the structure and is about 2.5 km from the FMK-1(ST). After three months of water injection from March to June 1996, decline in oil production of 2000 BOPD was regained to 3833 BOPD. Subsequently in June 1998, water breakthrough in FMK-1(ST) has occurred and oil production gradually decreased to current production of 350 BOPD with 1300 bbl of water. Figures 3 and 4 illustrate the performance of the wells. Generally, these reservoirs are tight with matrix permeability range 0-0.3 mD based on core analysis while fracture permeability determined by the well test analysis range 3500-4200 mD. Therefore, a good network of fractures has to be present between the producer (FMK-1(ST) and injector (FMK-3) for sustained oil production from 1996 to 1998 and subsequent water cuts as shown in Figure 3.

RESERVOIR LITHOLOGY AND STRUCTURE

The Fimkassar structure, created in the late phase of Himalayan Orogeny, is a northeast to southwest trending steeply dipping asymmetrical anticline cored by thrust fault on its southern limb. However, the crestal part and both plunges are well preserved. This major fault, which marks its southern limit, is a thrust with approximate throw of more than 100 meters. The depth structure map of the field shows Sakesar reservoir at a depth of 3500 meter (Figure 1).

Chor Gali and the Sakesar formations are the two main reservoirs while Murree shale provides the top seal. An other formation underlying Sakesar is identified as Nammal Formation of Eocene age in all wells. Chor Gali Formation is primarily composed of dolomite and shale at its base. Dolomite is mainly dense, argillaceous and fossiliferous. The shale is medium hard, fissile, pyritic and slightly calcareous. Chor Gali encountered in FMK-1ST and FMK-3 has very good matrix porosity ranging from 10- 21% due to dolomitization but

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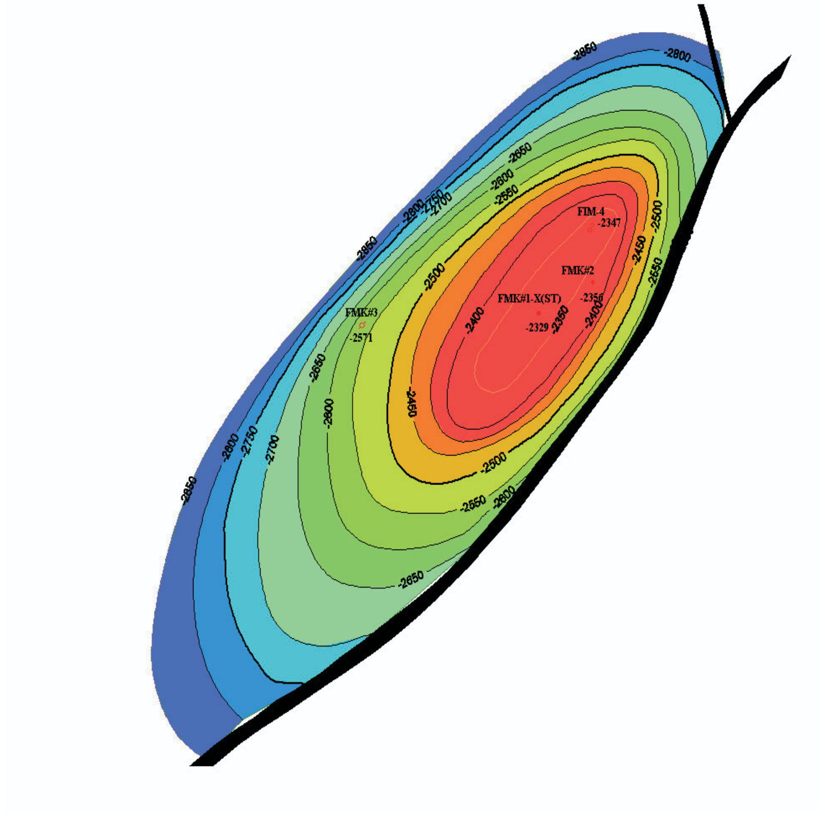


Figure 1- Depth structure map of the Field oil bounded by contour of 2600 MSS.

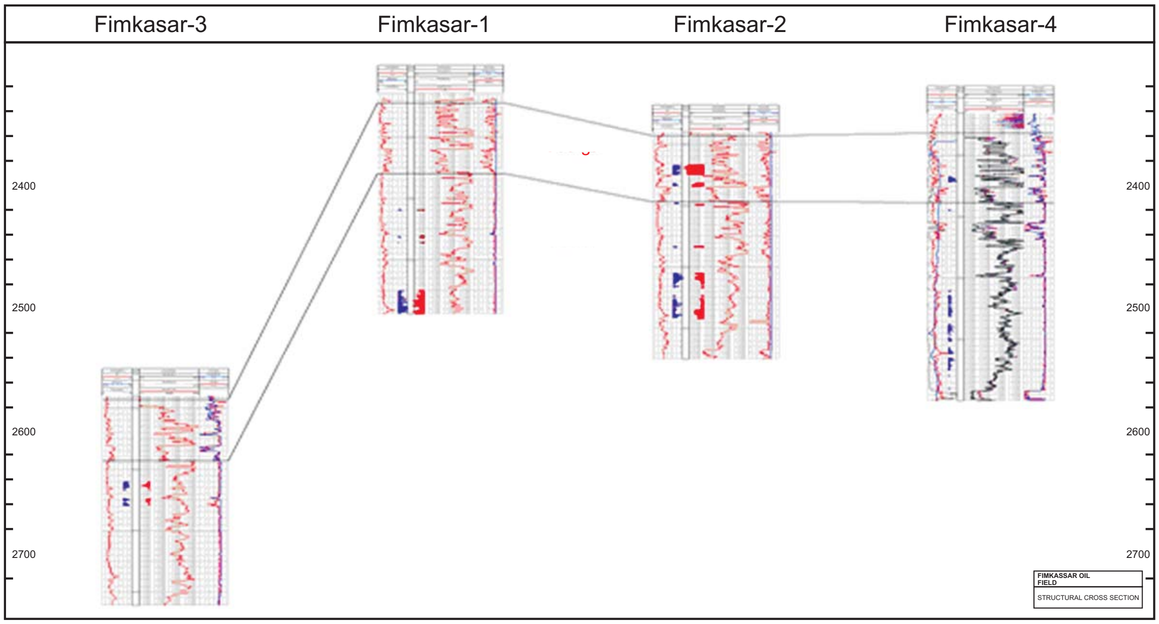


Figure 2- Structural correlation of the wells with fracture density.

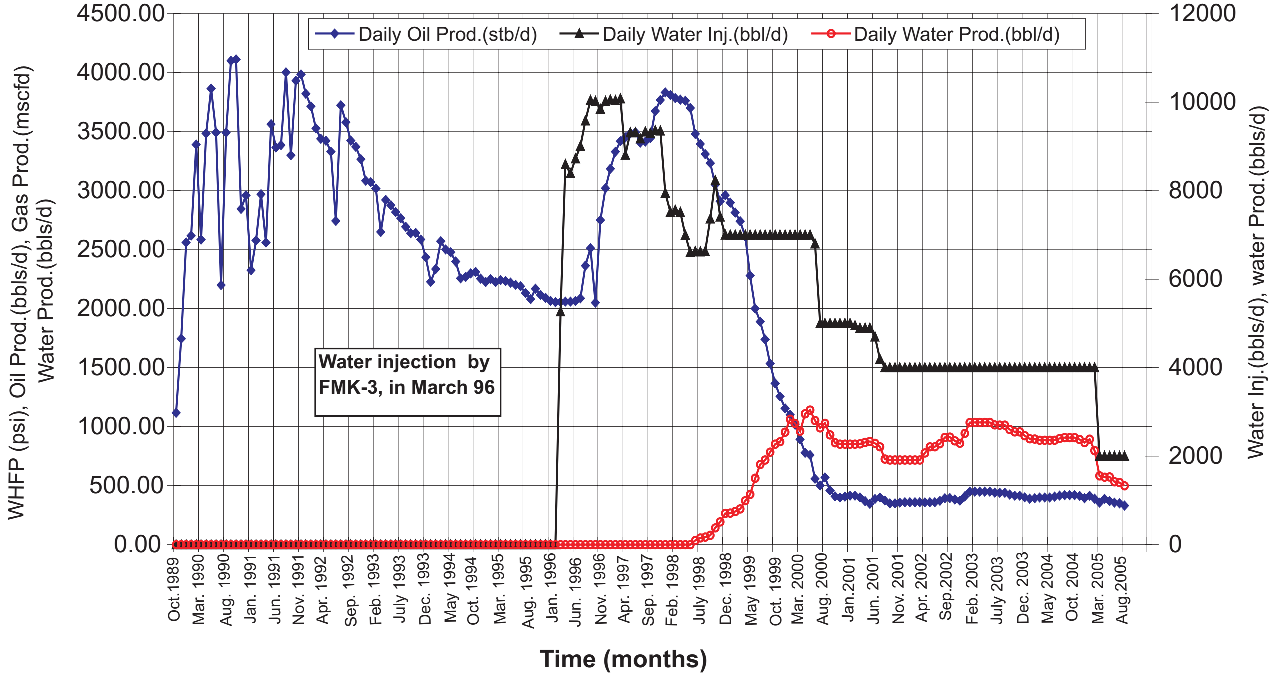


Figure 3- Well performance of FMK-1(ST).

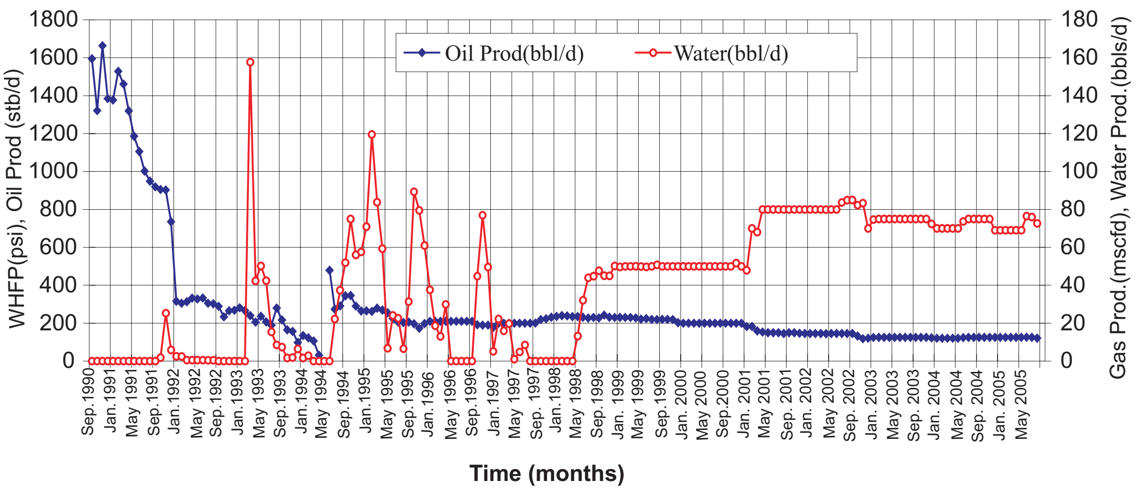


Figure 4- Well performance of FMK-2 .

has very low permeability. This low matrix permeability was proved by two open hole DSTs on this reservoir which did not flow any hydrocarbon. This indicates that matrix has no conductivity of its fluid. Chor Gali encountered in the FMK-2 is highly fractured through which production of oil is being obtained.

The Sakesar is predominantly composed of limestone of light gray to dark gray in color, containing fractures with minor amount of shale. The Sakesar reservoir encountered in all three wells are fractured without any correlation. In Injector well, upper part of the reservoir is fractured while in the two producers, lower part of the formation is fractured. Water is being injected in the upper part of the Sakesar through well-3 which is structurally 244 meters lower than the producer. The production from this formation is through the fractured area in both wells(FMK-1 and FMK-2). All the isopachs for Sakesar reservoir are prepared using a reservoir limit of 2600 meters subsea. This is the last closing contour on the top of the Sakesar limestone.

SEISMIC INTERPRETATION & FAULT'S EFFECT

An interpreted seismic line is shown in Figure 5 for the geometry and development of the Fimkasar Field. It shows a major decollement in the Salt Range Formation above the basement and the development of Fimkaser Field as a fault-related anticline. Generally, large faults of 10-200 m offset are reported to have less than 1 % porosity (Antonellini and Mollema, 2002). Whereas, the porosity of breccia in faults with small offset of 1-10 meters is very high, upto 10 %. Furthermore, significantly high fracture density near the faults is observed with porosity of about 2.4 % and the permeability upto 3000 mD in zones next to large offset faults (1-200m). Good seismic reflections from key horizon in the hanging wall of the fault are observed in Figure 5. The reflections from the footwall are poor, possibly due to brecciation and bending of layers. The key reflections in the forelimb of the structure are

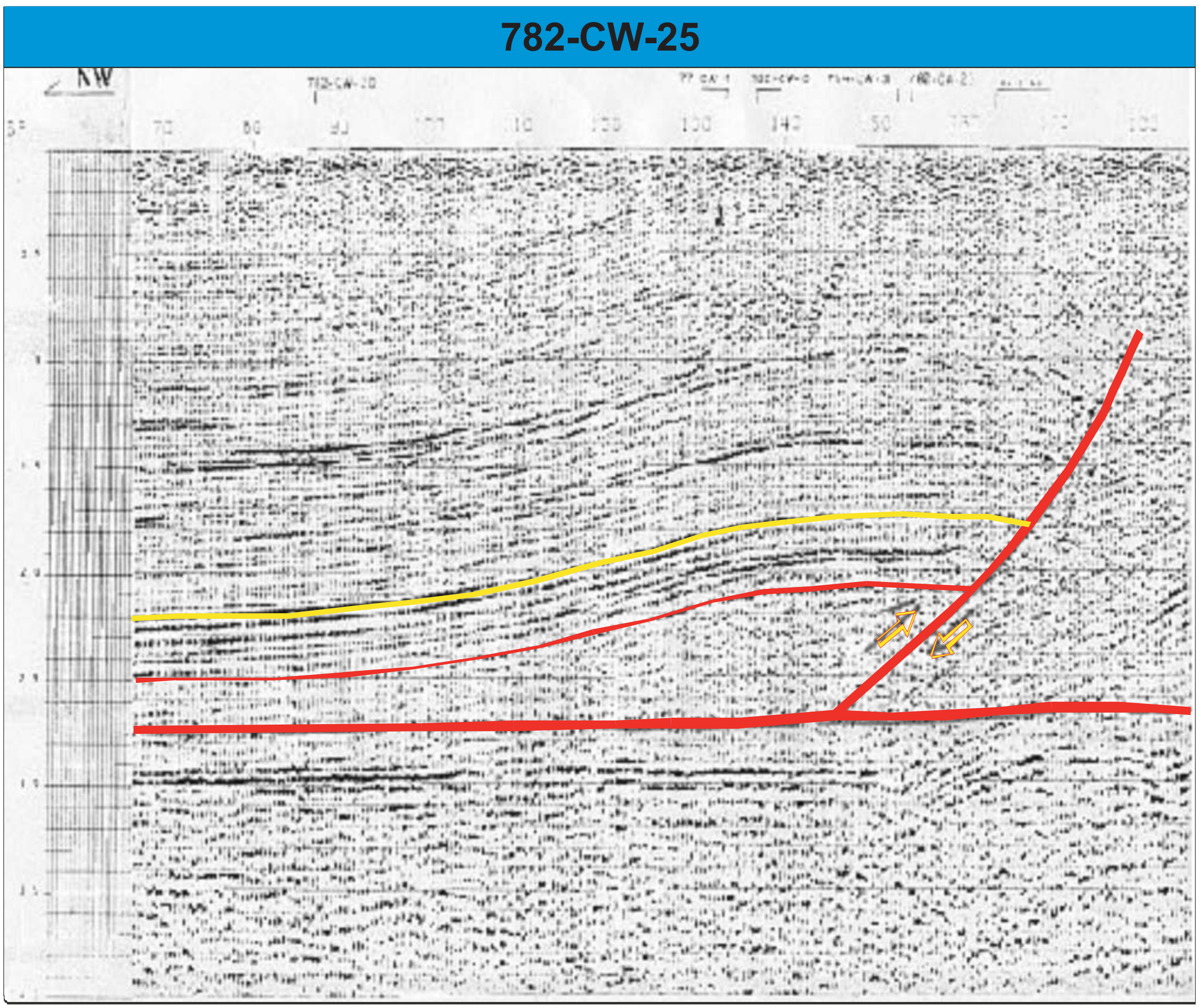


Figure 5- Seismic section of Fimkaser Field.

observed to exhibit reduced seismic resolution possibly due to steepness of the forelimb and fractures while backlimb of the structure is relatively gentler, with a general flat crestal area. In the crestal part, the reflections are fairly good and continuous without disruption by seismic faults. The sub-seismic faults and fractures are not visible.

DEVELOPMENT DRILLING

After the detail evaluation of the fracture system and simulation study of the field (Jadoon et al 2002), additional oil potential was determined in the NE part of the field. A well was required to drain the reserve associated in this part of the reservoir. According to the available fracture data based on the FMI from three wells, fractures were distributed in the field accordingly. FMK-4 was drilled 2 km NE of the FMK-1(ST) and about 1 km north of FMK-2, both producers. In FMK-1(ST), a NE-SW trending fracture network parallel to the fold axis was detected based on electrical resistively logs (Formation Micro scanner- FMS). This well had produced about 4000 bbl/d oil with initial formation pressure of 5709 Psia. This producing network of fractures was expected to continue towards NE in FMK-4 that is drilled at a structurally higher position near the NE plunging end of the structure. However, in this well, dominantly NW-SE trending fractures perpendicular to the fold axis with a less dominant NE-SW oriented set of open fractures in Chor Gali and Sakessar limestone with depleted formation pressure of 3400 Psia was observed. Fracture orientations in all wells on depth structure map are shown in Figure -6. During DST, oil was found with no formation water even no injection water was there as shown in the model.

FMK-4 (ST) was sidetracked with about 42 degrees SSW deviation from the existing vertical borehole. Relatively higher density of open fractures was encountered in the sidetrack based on acoustic image logs (Ultrasonic Borehole Imager), but again with dominant proportion of NW-SE trending open fractures. On testing, an oil column in Sakessar reservoir was raised to 2476 meters while in Chor Gali well unloaded oil column. After DST, well could not produce possibly due to poor connectivity of fracture network system with the major producing fracture system that orient in East-West direction. Eventually, due to very limited recharging of hydrocarbon, well was suspended

FRACTURE CHARACTERIZATION

Fracture characterization is the understanding of fracture occurrences, determination of their orientation, density, aperture and distribution. Open fractures intersecting wellbore, are commonly detected on cores and image logs (both resistivity and acoustic). Image logs are conveniently used for detection, distribution, and characterization of fracture network during drilling. Both electrical and acoustic images are available in four wells of Fimkaser field. In this article our aim is to review surface and subsurface informations about fractures in the Fimkassar field and integrate all information obtained from the drilling of FMK-4 well for fracture characterization to explore why FMK-4 couldn't produce. For this purpose, outcrop, thin section data is integrated with the subsurface bore hole image logs, reservoir pressure, and seismic data to study fractures on different scales to address the problem of their distribution, classification, and impact on the development of the field (Figures 3-9).

FRACTURE ORIENTATION AND DEVELOPMENT

Electrical images are acquired in wells FMK 1-3 while acoustic images were acquired in FMK-4 for fracture detection. The borehole images acquired by acoustic logs from vertical and deviated hole are illustrated in Figure 7a. Based on bore hole image analysis, main feature are plotted on rose diagram as shown in Figure 7b. Generally in all four wells, three main fracture sets are recorded with dominant trend in NE-SW, NW-SE and N-S directions across the field. These fracture sets are mutually perpendicular and oblique to each other. NE-SW striking set of fractures is parallel to the structural trend (fold axis) and bedding. NW-SE striking set of fractures is perpendicular to the fold axis and bedding. Whereas NS striking set is oblique to the fold axis or bedding. Outcrop analog of Chor Gali Formation from Potwar plateau (Figures 8a,b) shows two sets of well-developed fractures with mutually perpendicular relationship similar as interpreted on to those image logs. Therefore, pattern and orientation of fractures observed at the subsurface are similar to those at the surface. However, fracture density at the surface out crops is higher than the equivalent situation in the subsurface, possibly due to the combined effect of weathering and unloading (Nelson 1979). These two sets of open fractures can clearly be interpreted as tensional (perpendicular to fold axis) and extensional (parallel to fold axis). Such fractures are reported earlier by several workers such as Stearns and Friedman 1972, Nelson, 1979, Cooper 1991, and discussed previously by Jadoon et al 2002 with reference to the Fimkaser Field.

The tensional fractures develop parallel to the in-situ horizontal stress direction (Hmax). They are generally high-angle features and are considered as most open for flow of fluids (Florez Nino et al., 2005). The extensional fractures develop parallel to fold axis and bedding due to folding. A change in dip magnitude of such fracture from high angle to low angle may be observed with bending of layers, after their development. High-angle extensional fractures are most open. This set of open fractures develops perpendicular to compressive Hmax, unlike the tensional open fractures. However, it is this set which has produced about 4000 BOPD from Sakessar Limestone through FMK-1(ST) in DST while this well has produced about 12 MMSTB, cumulatively.

The fracture characterization and development on the Fimkassar field is based on the available limited surface and subsurface data. A relatively detailed classification and characterization of fracture is provided elsewhere with inclusion of sheer fracture bands oblique to the bedding and fold axis (Jadoon et al 2005) and tensional stylolites related fracture development due to overload and pressure solution activity in carbonate reservoirs (Wall et al 2006). Fractures due to stylolites are also reported from exposed carbonate reservoir on the Kohat plateau (Khan et al 2007). The stylolites related fractures are widely detected based on the image logs from the high porosity carbonate reservoir in the Middle East.

FRACTURE DENSITY AND DISTRIBUTION

Density of fractures in sedimentary strata is influenced by several factors. The most critical of these factors are (1) mechanical properties of lithology, (2) bed thickness, (3) structural position and strain (Jadoon et al., 2002, Florez-Nino et al. 2005). Laminated and dense strata are generally observed to have higher density of fractures (Jadoon et al 2005). Therefore, a particular reservoir zone may be fractured across a field. However, a change from predicted pattern may also be observed, mainly due to strain variation that can cause shear bands and excessive fracturing.

Fracture density from all four Fimkaser wells is compared for fracture occurrence (Figure 9). The comparison shows that lower part of Sakessar Limestone is fractured in FMK-1(ST), FMK-2 and FMK-4. Whereas low density of fractures is observed in upper part of the Sakessar reservoir in the above three wells. On the contrary, high density of open fractures is observed in the upper part of Sakessar in FMK-4. Chor Gali is generally non-fractured in FMK-1(ST) and FMK-3. But, it shows similar density of fractures in FMK-2 and FMK-4. The similarities of fracture density may be related to lithology and bed thickness. Whereas, variation may be related to proximity to a fault, structural position, and strain. This implies that fracture density across the field may be predicted to some extent, based on the lithology and bed thickness with variations based on the strain distribution. However, these observations mentioned above are based on available data of four wells, which may be insufficient for a conclusive comment about fracture density variation in different reservoir zones of Chor Gali and Sakessar Limestone. Carbonate reservoirs are complex, with a heterogeneous system of porosity and permeability due to the two medium of flow (matrix & fracture). Of these, Type-1 carbonate reservoirs are tight with essential fracture porosity and permeability (Nelson, 1981). In all case, but more essentially in Type-1 carbonate reservoirs, fracture characterization is critical for geological modeling and reservoir management. Sakessar and Chor Gali reservoirs because of low/non matrix porosity may be classified as Type-1 carbonate reservoirs. Therefore, an understanding of fractures is required for reservoir management of any field.

In Fimkaser Field, two main sets of open fractures are observed. They are interpreted as tensional (perpendicular to fold axis) and extensional (parallel to fold axis). In addition, a component of shear conjugate (oblique to fold axis) fractures are observed in FMK-3 and FMK-4(ST) (Figure 6). Such open fracture sets, with variable trends, with respect to an anticlinal structure, are reported earlier and classified by Stearns and

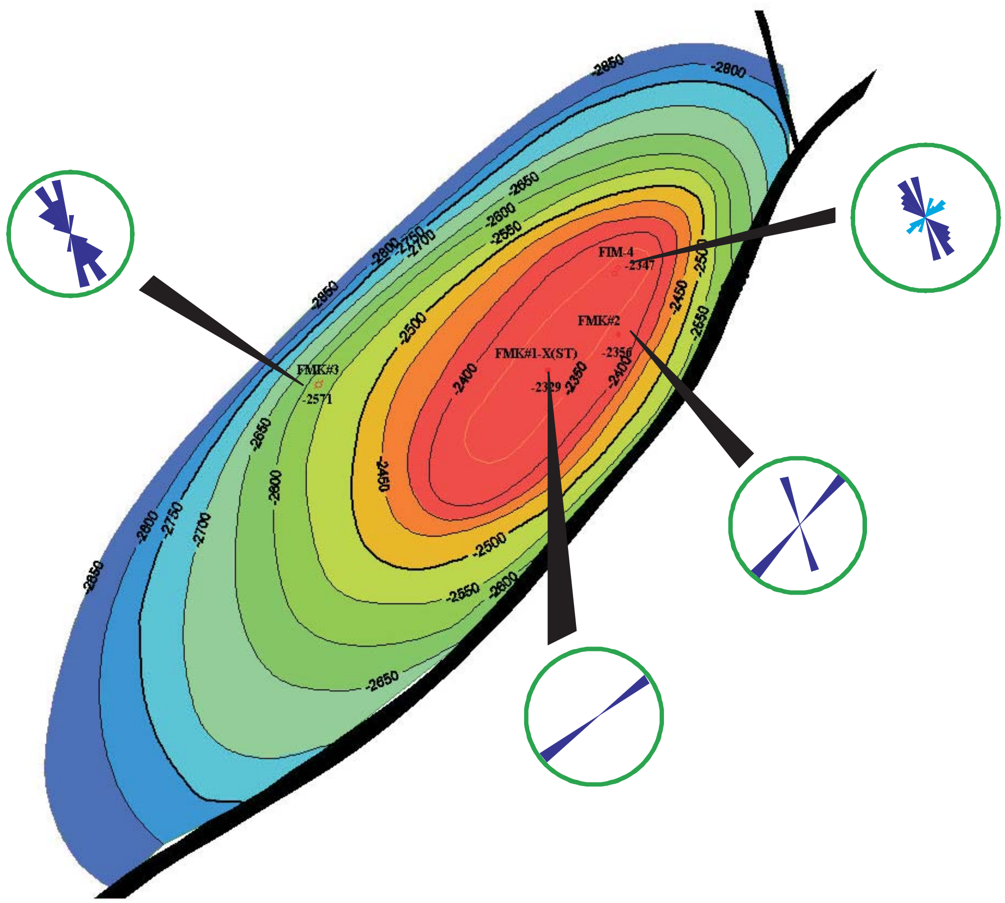
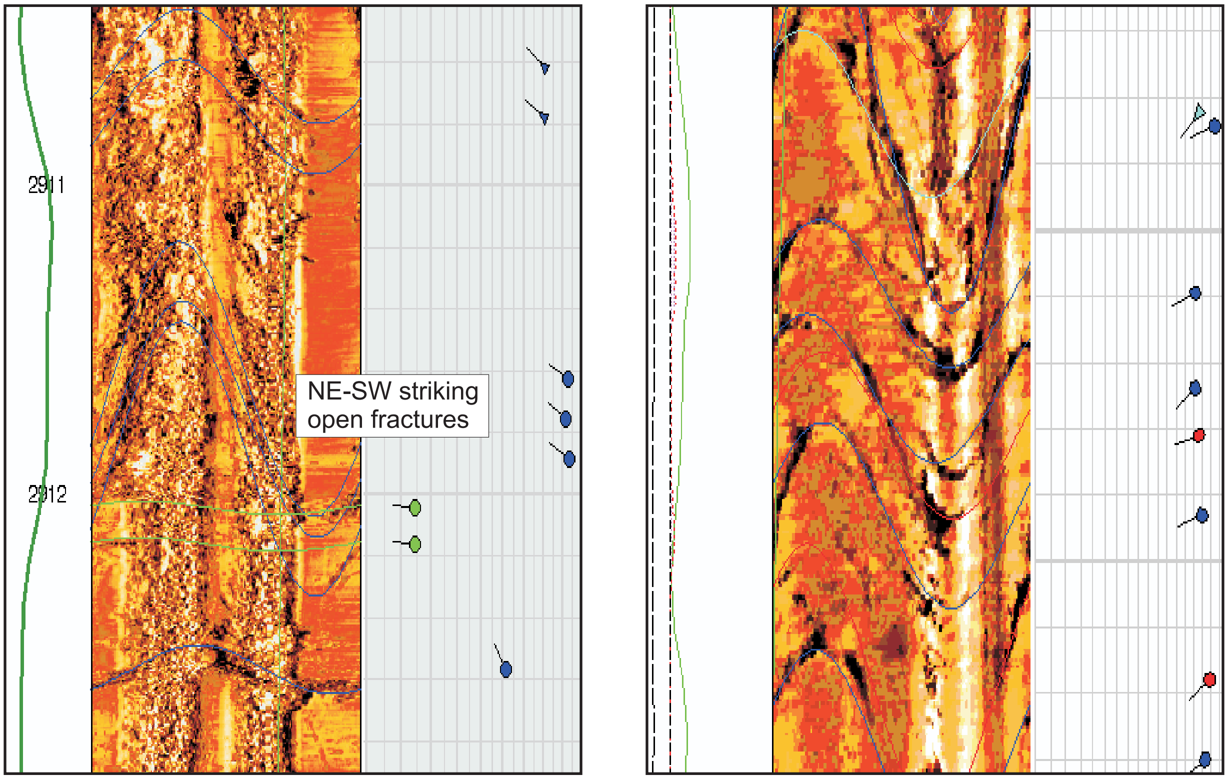


Figure 6- Fracture Orientation in four well.



(a) Deviated hole (b) Vertical hole

Figure 6a- Acoustic bore hole Images of Fracture from FMK-4 Well .

Statistical Plots Of High Angle Features

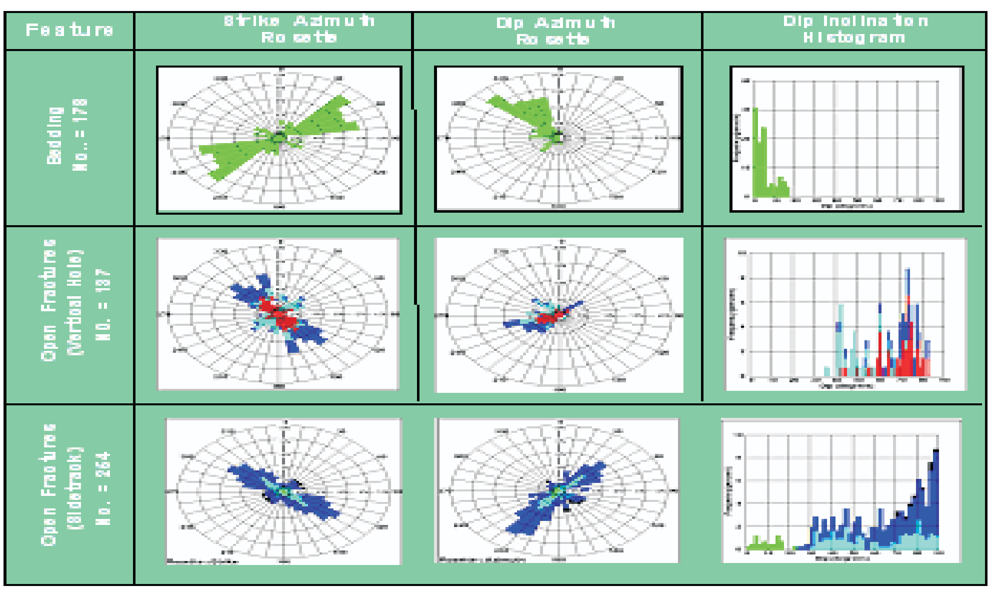


Figure 7- Rose diagram showing fracture orientation and other feature.

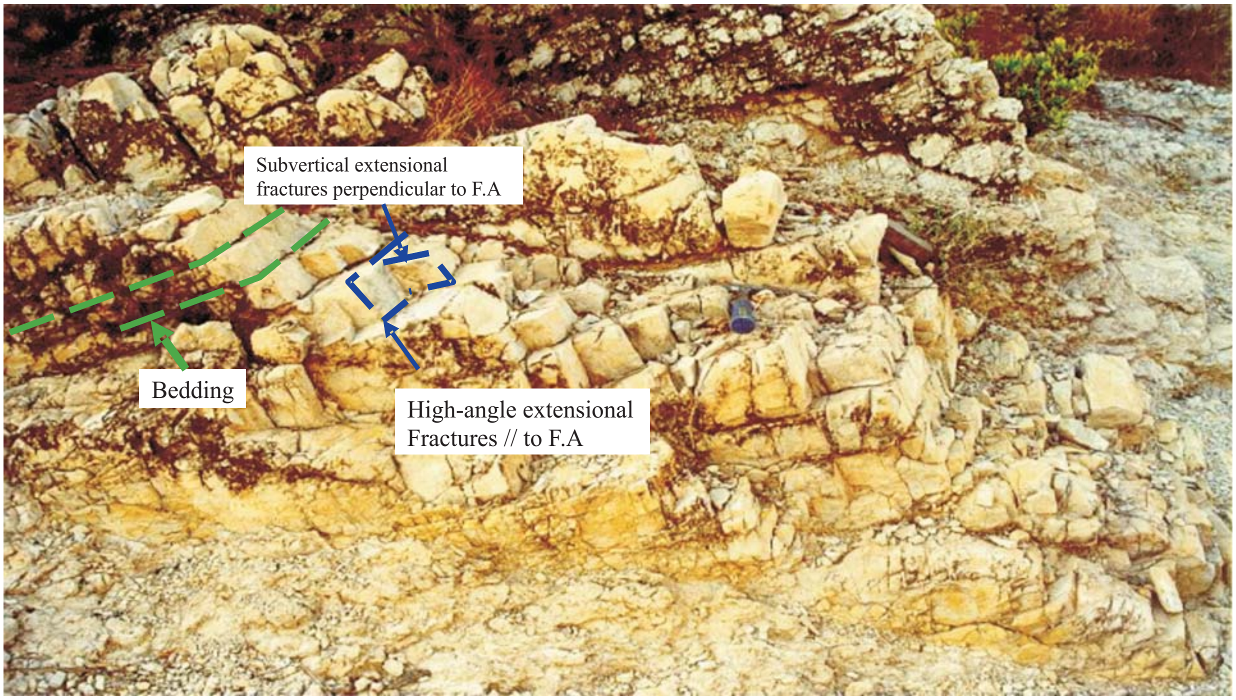


Figure 8a- Chor Gali out crop showing fracture pattern.

Figure 8b- Chor Gali out crop showing fracture pattern.

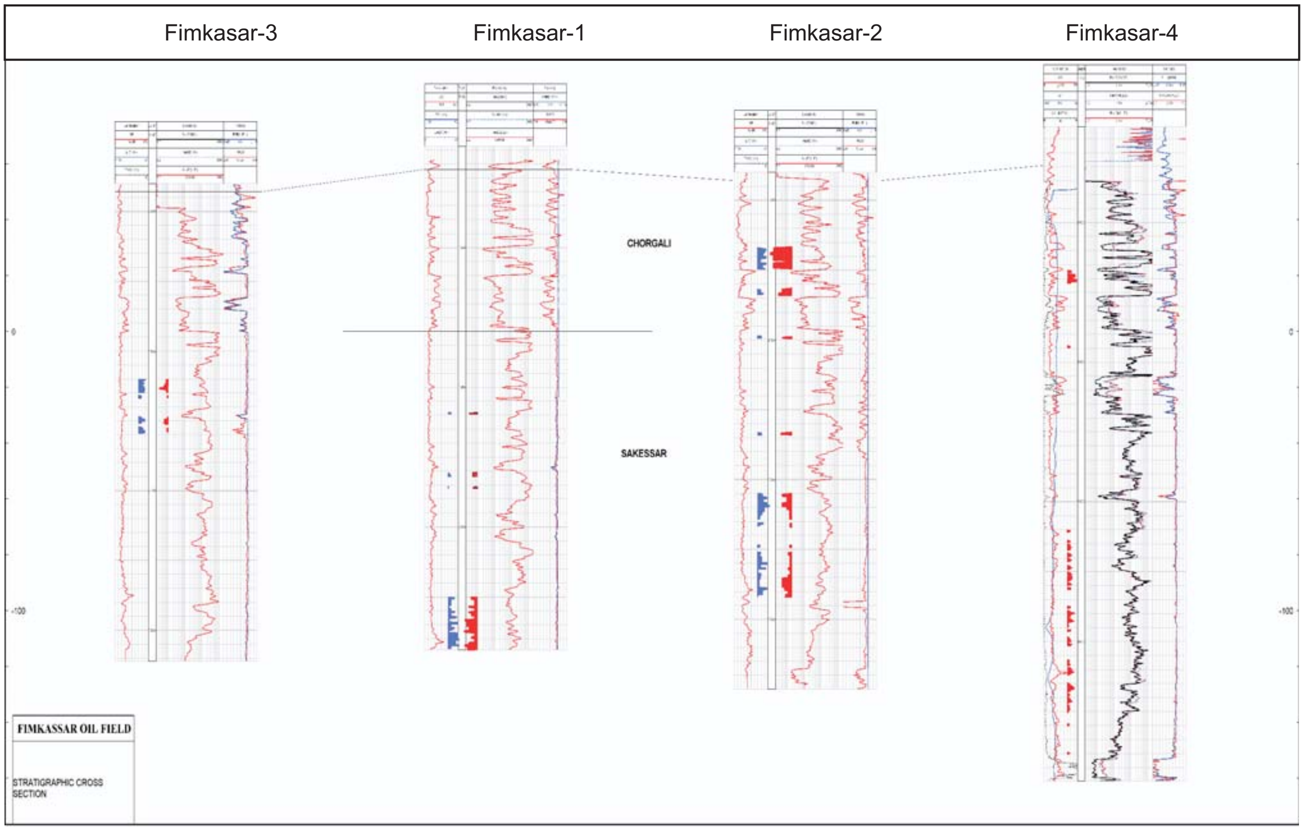


Figure 9- Fracture density in four wells of the field.

Friedman (1972) and Nelson (1979). A revised fracture model (Jadoon et al 2005) of a folded structure, with main open fractures sets as tensional, extensional, and shear conjugates are shown in Figure 10. Outcrop analog of fractures in Chor Gali Formation shows close spacing of fractures (< 1ft) in laminated, medium-bedded argillaceous limestone of similar thickness. This, one to one relationship of bed thickness and fracture spacing is similar to as reported by Florez-Nino et al (2005) with detailed outcrop studies from the Subandian Bolivia.

In FMK-1(ST) and FMK-3, a dominant extensional and tensional set of fractures are observed, respectively. FMK-1(ST) is a producer and FMK-3 is an injector. The fracture systems between the two wells that are about 2.5 km apart is considered to have good connectivity as reservoir pressure is maintained with water injection. Thus, fracture trends may laterally be extrapolated over some distance. With this consideration, FMK-4 was drilled at a structurally higher position than FMK-2 in line with NE-SW trending fractures in the latter. However, in FMK-4 and its sidetrack, dominantly tensional set of fractures were detected with main occurrence in Sakessar reservoir trending NW-SE contrary to the main producing set of fracture trending NE-SW. In this well, major set of fractures (NE-SW) are less developed and do not have enough connectivity for the flow of hydrocarbon. During the test of Sakessar and Chor Gali reservoir, oil column were raised to 2476 m in well in both formation at 3400 Psia formation pressure, however, the well didn't flow and later was suspended. This poor charging of the well by hydrocarbon from the main pool is attributed to a limited occurrence of extensional fractures, similar to those detected in FMK-1 (ST), or heavy barite mud that may have chocked the fractures, and fracture discontinuity between the two well.

CONTINUITY OF THE FRACTURE

Outcrop analog of fractures in carbonate rocks from north Pakistan (Hill Ranges) shows that fractures may be continuous and discontinuous over a unit length. Since open fractures have variable trends (tensional, extensional, conjugate), their mutual relationship and spacing results into zones of rare and abundant fractures. Fracture may occur as overlapping steps with and without hairline splays at their terminations, and as en-echelon features and shear bands. As a result zones of excessive fractures, porosity and permeability may develop in isolation from nearby zones of no/rare fracturing. The zones of excessive fractures with excessive secondary porosity (possibly up to 10%) are recognized to serve as storage for hydrocarbons (Jadoon et al 2005). Excessive, localized secondary porosity is observed both in Chor Gali and Sakessar carbonate reservoirs based on thin-sections (Mujtaba 2001). Chor Gali in Meyal-1 and Dakhni-3 wells are having about 10% localized secondary intercrystalline / vuggy / mouldic and fractured porosity due to dolomitization. Similarly, Sakessar Limestone in Dakhni field is observed to have excessive secondary mouldic and fracture porosity based on thin-sections (Figure 11). Shami and Baig (2002) have listed porosity of 2-8 % in Chor Gali and

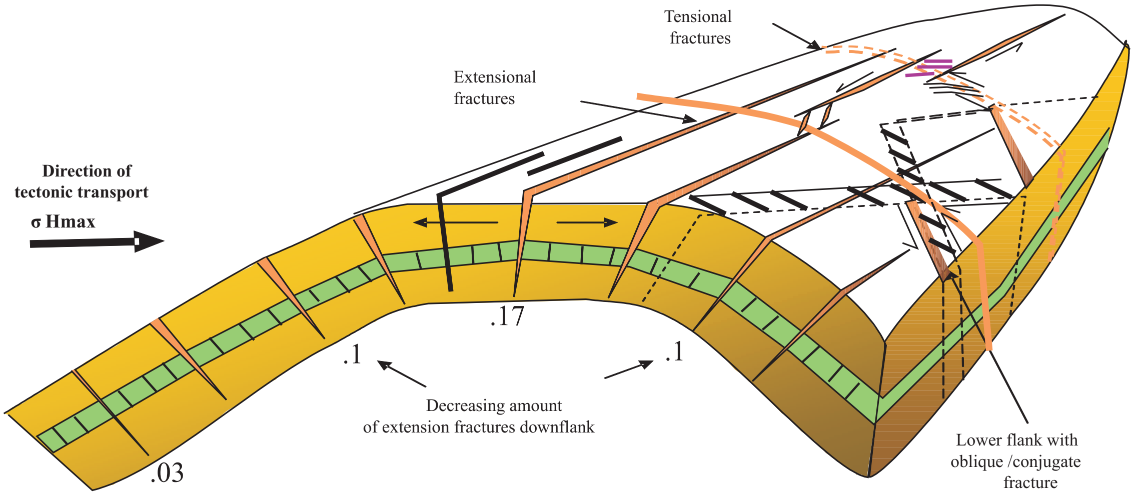


Figure 10- Fracture model of a folded structure (I. A.K. Jadoon et al 2005).

1-2.4% in Sakessar in the Potwar Plateau. A more detailed account of carbonate reservoirs and porosity/permeability variation with new model of fracture development is given by Jadoon et al 2005. This revised model of fracture development shows both continuous and discontinuous fractures with associated zones of excessive strain and fractures to address problems of variable well performance in low/none porosity carbonate reservoirs (Figure 10). The model implies that fracture analysis, based on surface and subsurface geological and geophysical data, is important for fractured carbonate reservoirs. Antonellini and Mollema (2002) showed that major seismic faults are often sealing due to brecciation of strata and fault gouge, whereas minor sub-seismic faults provide excessive fracture porosity and permeability.

Permeability exceeding 3388 mD is reported with fracture width of 1.25 mm (Belhaj et al., 2002). Earlier studies (Belhaj et al., 2002) showed that fracture aperture is a driving force for permeability changes and permeability increases with fracture width. Since permeability in a carbonate reservoir may vary drastically with respect to fractures and faults (Antonellini and Mollema, 2000), distribution of these features is crucial to predict sweet spots and zones of higher and lower permeability across a field. Low productivity in FMK-4 is mainly attributed to discontinuity of the producing fractures from the main pool of the field. It was observed that existence of the fracture is not only the parameter that governs the location of the wells, knowledge of continuity and orientations of fractures are essential for drilling successful oil producer.

CONCLUSIONS

1. Based on the limited surface outcrop and subsurface image log data, the most dominant open fracture trends are NE-SW and NS-SE. They are parallel and perpendicular to the structural trend (fold axis) respectively.
2. Fracture characterization has major impact on defining the development strategy of the field.
3. Open fracture trends in folded structure are partly related to stress and partly with the structural development.
4. Laminated and dense strata are generally observed to have higher density of fractures.
5. Fracture density may be related to lithology and bed thickness. Whereas, variation may be related to proximity to a fault, structural position, and strain.
6. Understandings of the stress regimes are extremely important in the development of naturally fractured carbonate reservoir.
7. Reprocessing and Interpretation of Geophysical data of the field is essential before drilling of the new development wells in complex naturally fractured carbonate reservoir under development.
8. Fracture continuity and orientation is the most important consideration in drilling of the well in fractured reservoir rather than existence of fracture only.

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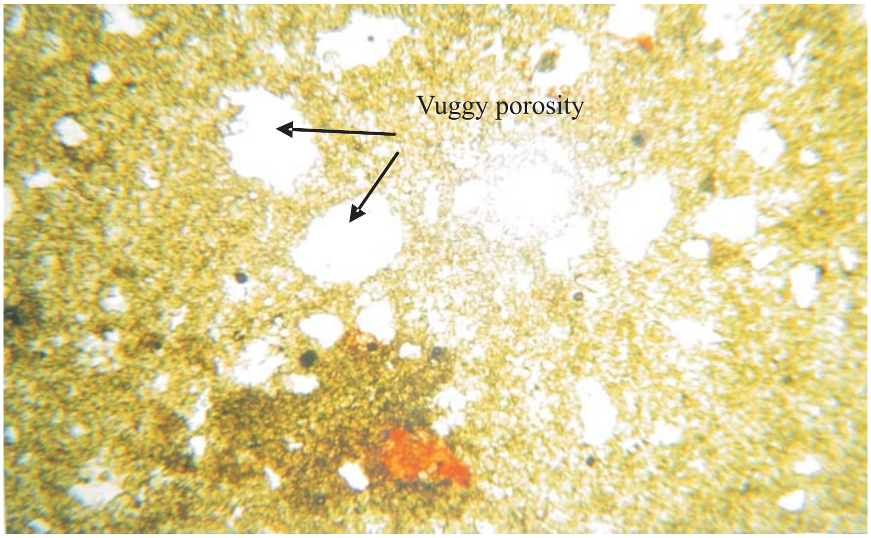

Figure 11- Thin-section of secondary vuggy/mouldic porosity in tight carbonate reservoir (Chor Gali) in Potwar (Mujtaba 2001).

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