Implications of controlling factors in evolving reservoir quality of the Khatatba Formation, Western Desert, Egypt

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Abstract

This paper sheds light on the role of petrophysical properties, framework grains and its textural properties, capillary pressure, diagenetic constitutions and events as controlling factors in evolving sandstone quality of the Khatatba Formation in the Western Desert, Egypt. Petrophysical analyses coupled with petrographic observations and diagentic studies have been carried out for many core samples in order to infer the controlling factors of reservoir quality. It has been observed that the sandstone quality of the Khatatba Formation have been adversely affected from well to well in the study area and from zone to zone in the same well and formation. Good- quality sandstones have been found with the porosity ranges from 10–17% and permeability ranges from 100 –1000 mD. The petrographic study indicates the presence of many open hydraulic fractures and dissolution phenomena which all took place in multiple phases during the late digenetic stage, leading to improvement in the reservoir quality. Dramatic reservoir quality deterioration has been recorded in many zones. The reduction of permeability and fluid pathways in addition to the mechanical compaction, solid bitumen occupying many pore spaces and fractures are observed in many zones. These cause major destroy in reservoir quality that leading to lowering the oil production compare to the initial estimation.

Index Terms: Khatatba Formation, formation damage, diagenesis, fractures, reservoir quality

1. Introduction

In the Western Desert of Egypt, the deep clastic reservoirs of the Jurassic age are an attractive petroleum exploration target. The Western Desert still has significant hydrocarbon potential, as recent oil and gas discoveries have suggested[1], with as much as 90% of oil reserves and 80% of gas in the Western Desert basins yet to be discovered[2]. The study area (***Figure 1***), lies in the northern part of the Western Desert between latitudes 30° 30''- 31° 30'' N and longitudes 26° 30''- 28° 00'' E.

The great oil potentiality of the Western Desert has attracted the interest of numerous researchers, authors, and oil companies. Several researchers and authors have made significant contributions related to the regional geology, petroleum prospects, source rock evaluation, sedimentology, and tectonic evolution of individual parts of the basin and adjoining areas[3-19].

The Middle Jurassic Khatatba Formation in the North Western Desert of Egypt has very good source-rock potential for hydrocarbon generation. Most of this generated hydrocarbon was expelled into coarse-grained sandstones within the Khatatba Formation, which is bounded by organic-rich shales that are source rock. The organic matter is mainly derived from the marine environment. Source-rock thickness, thermal maturity, and total organic carbon (TOC) contents

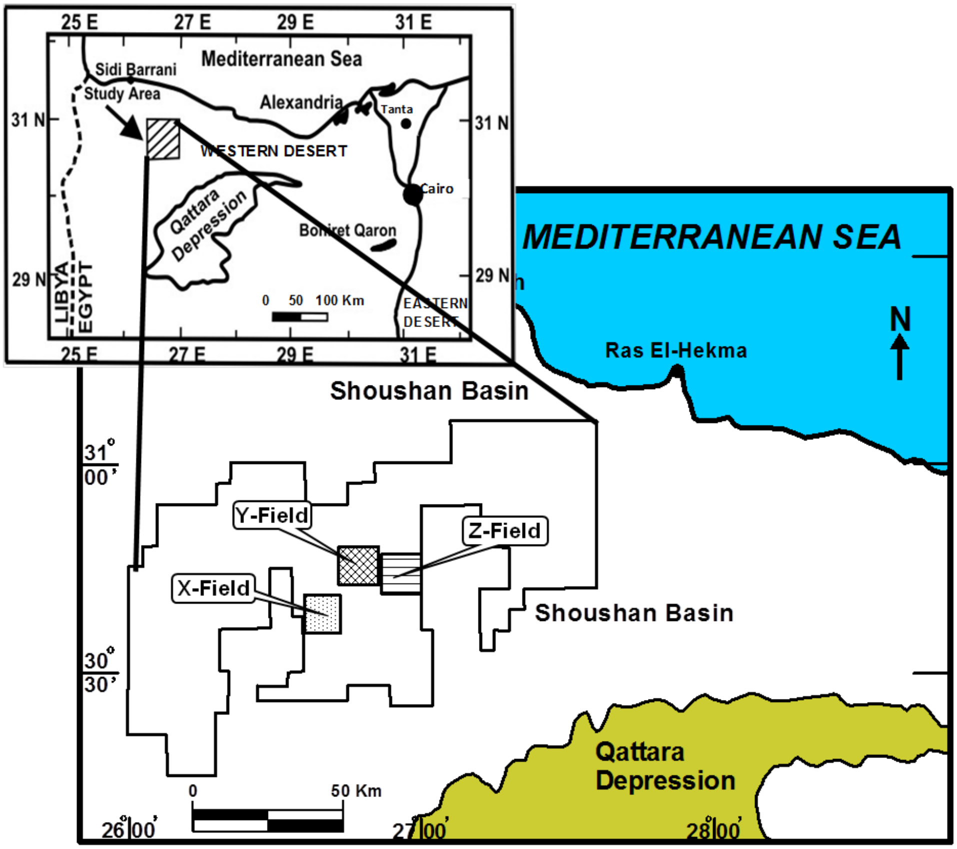

Figure 1. Location map for the study area in the North Western Desert of Egypt (modified after Shalaby et al., 2012)

controlled the amount of hydrocarbon generated and expelled from the shales. Source rock in these shales is mixed oil- and gas-prone[15-17]. The Khatatba Formation represent as the oil reservoir in the thermally mature part of the basin and have been extensively cored; thus, they offer the opportunity to examine major controls on reservoir quality. In this study, we have examined the porosity and permeability relationship of the reservoir sandstones, their close dependency on petrographic properties and diagenetic events considering the data analysed from three different producing oil fields namely X, Y and Z fields. Finally we have delineated the implications of different controlling factors in evolving the sandstone of the Khatatba Formation quality which is really critical for the area of study in terms of further exploration and production.

2. Stratigraphy and tectonic setting

The North Western Desert of Egypt consists of a number of sedimentary basins (***Figure 2***) that received a thick succession of Mesozoic sediments (***Figure 2***). The stratigraphic section of the North Western Desert (***Figure 3***) which includes the Shoushan Basin, ranges in age from Paleozoic to Tertiary. The post- Paleozoic succession in this area comprises four major cycles: Middle Jurassic, Lower Cretaceous, Upper Cretaceous, and Eocene to Miocene[4]. Each cycle begins with fluvio-deltaic siliciclastics and ends with marine carbonates[20].

The North Western Desert is characterized by a Paleozoic section overlying the crystalline basement. The Mesozoic–Tertiary sedimentary wedge is interrupted by an east–west trending structural high, which separates the Abu Gharadig Basin from a series of coastal basins. This pattern of basins and highs is masked under gently dipping, outcropping Miocene deposits[5,21]. The Shoushan Basin, which is the largest of the coastal basins, is a half-graben system affected by many tectonic faults (***Figure 2b***), with a maximum thickness of 7.5 km of Jurassic, Cretaceous, and Paleogene sediments[22-23].

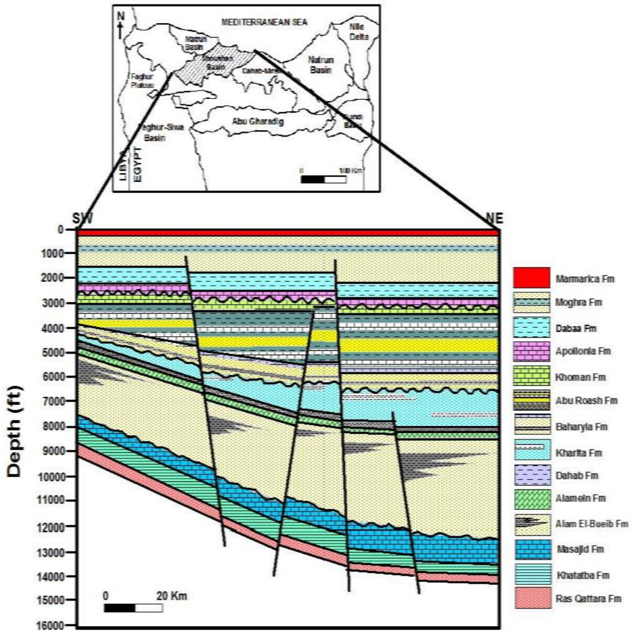

Figure 2. 2-D subsurface cross sectional view along some wells in the study area (Shalaby et al., 2013, modified after Al Sharhan and Abd El-Gawad 2008).

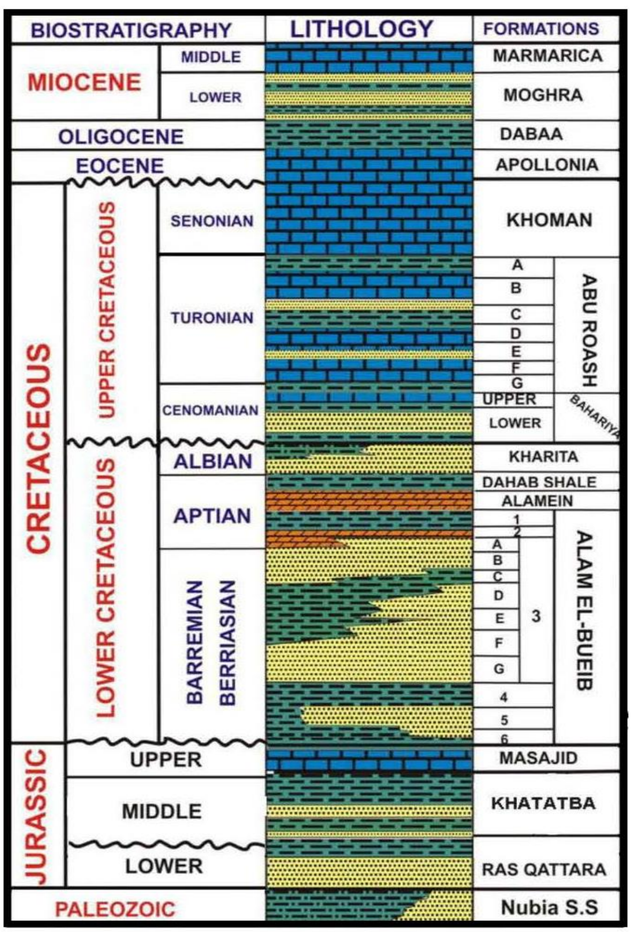

Figure 3. Simplified lithostratigraphic succession in the Western Desert of Egypt.

The earliest cycle consists of Early Jurassic non-marine siliciclastics (Ras Qattara Formation), which are underlain by the Paleozoic Nubian sandstone and are overlain by the Middle Jurassic Khatatba Formation (***Figure 3***). This Middle Jurassic Khatatba Formation is composed mainly of shales and sandstones, with a few shallow marine limestone beds. The Khatatba Formation overlies the Ras Qattara Formation and underlies the Masajid Formation and interpreted to be formed by fluvio-deltaic clastics grading upward into marine shales and limestones. The Khatatba Formation occurs in the subsurface and has been informally subdivided into lower and upper parts. The lower part of the Khatatba Formation is formed by meander-belt facies, which are overlain by an interval of braided-stream sandstones interbedded with coastal-swamp coals and carboniferous shales [24].

These sandstones are oil and gas reservoirs in some fields, whereas the coaly shale and shale facies represent the area's main hydrocarbon source rocks[26-28,18]. The coaly shales act also as seals, and thus, the Khatatba Formation represents a typical hydrocarbon source-seal-reservoir system. The upper part of the Khatatba Formation (***Figure 3***) is formed by shallow marine sandstones and shales, grading upward into a thin-bedded sequence of shale and limestone, which is a transitional unit toward the carbonates of the Masajid Formation. This formation is capped by unconformity, which records a period of uplift, tilting, partial erosion, and karstification of the Jurassic succession.[24,27]

The Upper Jurassic, shallow-marine carbonates of the Masajid Formation were deposited and represent the maximum Jurassic transgression. The Masajid Formation was either eroded from, or was not deposited on parts of the north Qattara Ridge and Umbarka Platform, although continuous marine sedimentation occurred in the Matruh sub-basin and in the SidiBirrani area. A major unconformity separates the Masajid Formation from the overlying Alam El Bueib Formation at the base of the second cycle, whose basal interval is composed of Early Cretaceous shallow-marine sandstones and carbonates. These are followed by marine shale and a succession of massive fluvial sandstones. The sands are overlain by the alternating sands, shales, and shelf carbonates of Alam El Bueib, culminating in the Alamein dolomite associated with the Aptian transgression[25]. The Dahab shale marks the end of this cycle. The continental and shoreline sandstones of the Kharita Formation are overlain by the shallow-marine and nearshore deposits of the Bahariya Formation (Early Cenomanian). A marked deepening of depositional conditions is indicated by the deposition of the Abu Roash (G) Member (Late Cenomanian). Widespread transgression occurred during the Senonian time with deposition of the Abu Roash (F) to (A) Members (predominantly carbonates). The unconformably overlying the Khoman Chalk Formation was deposited only in the North Western Desert of Egypt. The cycle is terminated by an unconformity, above which lies the Eocene Apollonia Formation. Above this are the Dabaa and Moghra formations (marine clastics), which are capped by the Marmarica Limestone[2].

3. Experimental approach

Several core plug samples for the sandstone of the Khatatba Formation have been collected from three different oil fields in the study area in order to carry out the sedimentological studies and petrophysical analyses. Data have been obtained from the X, Y, and Z fields in the North Western Desert of Egypt. The petrophysical study has been carried out on some given samples, where the main parameters available were porosity, horizontal, and vertical permeability values. The petrographic studies have been completed using thin sections under polarizing microscope and scanning electron microscope (SEM). JEOL FESEM JSM 7600F SEM machine has been used to get better images in order to delineate the impact of different controlling factors on the evolution of reservoir quality. Standard thin sections have been prepared and were impregnated with blue epoxy to aid in the identification of pore spaces and open natural fractures, and they were stained to facilitate mineral identification. All thin sections were studied petrographically, and the diagenetic processes and products were analysed and described in detail in order to evaluate the mineral composition, cements, and pore spaces. A scanning electron microscope (SEM) study has been done, to confirm the identification of the different clay minerals, to determine the pore structure, and to determine the mode of clay occurrence within the pore spaces in the reservoir core samples.

4. Results and Discussion

Petrophysical analysis and reservoir properties: Porosity-permeability relationships

The petrophysical studies of the selected samples from the X, Y and Z fields indicate that the Khatatba sandstone is characterized by a wide variation of porosity and permeability data. We have been observed the presence of two distinctive zones or groups, each one with its own distinctive properties. Group-I or “good quality reservoir,” is characterized by high porosity and permeability values. On the other hand, the Group-II or, “poor quality reservoir”, is suffering big destruction of the petrophysical parameters in terms of porosity and permeability in that interval. This wide variation of results has been observed from well to well in the same field or from zone to zone in the same well, which can affect the productivity of reservoirs.

In the X-Field, the data are obtained from the X-3 and X-6 wells. It is observed from both a porosity-permeability relationship and a horizontal-to-vertical permeability relationship, (***Figure 4a*** and ***4b***), that the Khatatba sandstones show the presence of two distinctive separations between X-3 and X-6 wells. All plotted points from X-3 (***Figure 4a*** and ***4b***) are located in the upper right side of both graphs, which feature high porosity and permeability, while all plotted points from X-6 are located in the lower left side, at which low porosity and permeability are recorded (***Figure 4a*** and ***4b***).

In X-3, 56 data points have been plotted, while all available data reflect the presence of good reservoir quality, which is characterized by very good and optimistic petrophysical results. The measured core porosity is very high when accompanied by both vertical and horizontal

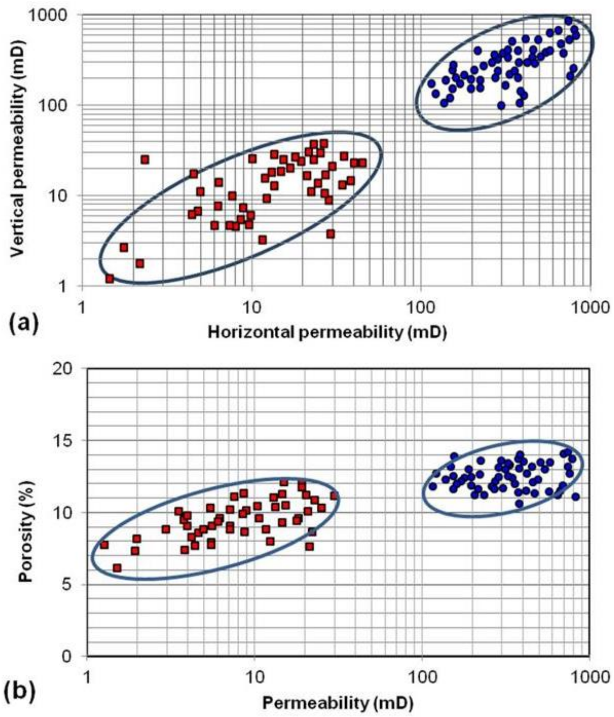

Figure 4. Cross plots showing two groups of reservoir quality in X Field: a) vertical permeability vs horizontal permeability, b) porosity vs permeability.

permeabilities, indicating good quality reservoir zones in this well. Porosity values are in the ranges of 10.6–14.2%. High permeability is recorded, while the horizontal permeability (HK) range is from 115 - 819 mD and the vertical permeability (VK) range is from 100 - 851mD (***Figure 4a*** and ***4b***).

In the X-6 well, in which 49 samples have been collected (***Figure 4a*** and ***4b***), it is found that a reduction in both porosity and permeability has been recorded. Porosity values are in the range of 6.1–12%, which is accompanied by a severe reduction in permeability in both directions. The HK recorded was 1.4– 44.7mD, while the VK was in the range of 1.2–37mD.

The results prove that the Khatatba sandstone in X-3 is characterized by very good reservoir properties in terms of porosity and permeability. They also indicate very good permeable zones, which allow the fluid to migrate and increase the productivity of the formation. In case of X-6, the data reflect that the formation has been subjected to the effect of formation damage in that well.

The petrophysical study has been carried out on data collected from the Y and Z fields. The Z-23 and Y-2X wells have been selected to study the reservoir characterization and changes in petrophysical parameters in both wells (***Figure 5*** and ***6***). A total of 62 samples have been analysed from the Z-23 well, while 44 samples have been analysed from the Y-2X well. It is observed that the Khatatba sandstone in both wells has been classified into two distinctive zones (***Figure 5*** and ***6***).

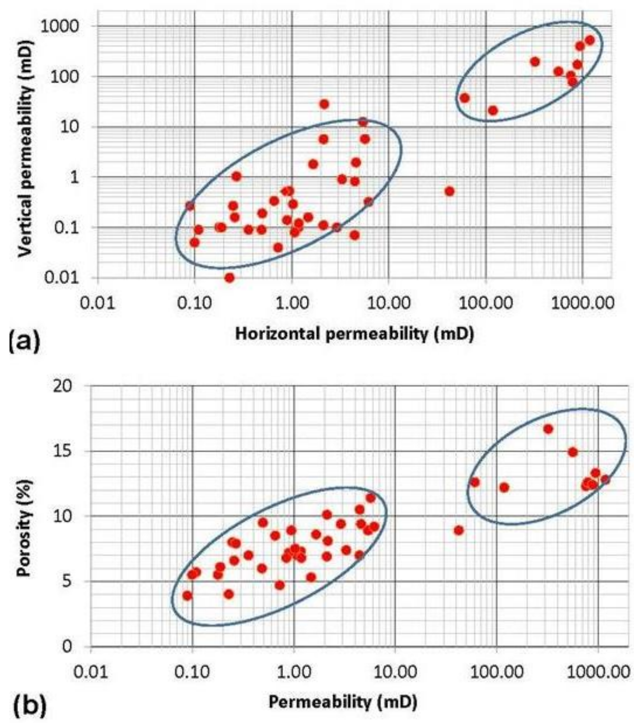

Figure 5. Cross plots showing two groups of reservoir quality in Y-2X Well: a) vertical permeability vs horizontal permeability, b) porosity vs permeability.

The same observations have been recorded in the Y-2X well (***Figure 5a*** and ***5b***). Two distinctive zones have been detected with specific petrophysical parameters. Zone-1 has good reservoir quality and is plotted in the upper right side in both graphs (***Figure 5a*** and ***5b***). Porosity is observed to be very good, in the range of 12–17%. Horizontal and vertical permeabilities are recorded as 20-600mD and 60–1300mD, respectively.

The zone affected by poor reservoir quality is presented in the lower left side in both cross-plots (***Figure 5a*** and ***5b***). Severe reduction in permeability is observed which reflects very low values in the range of 0.01–10.5mD and 0.09 - 7mD for both horizontal and vertical permeability respectively. Porosity in this zone is considered high where it records the values as being from 4–11.5%, but this zone is suffering severe destruction in permeability in both directions.

In the Z-23 Well (***Figure 6a*** and ***6b***), the first group (in the upper right portion of the graphs) indicates good reservoir quality with high porosity and permeability. Porosity values are in the range of 8 - 17%, which is accompanied by the excellent horizontal and vertical permeabilities of 11-1000 and 30 – 2000mD respectively.

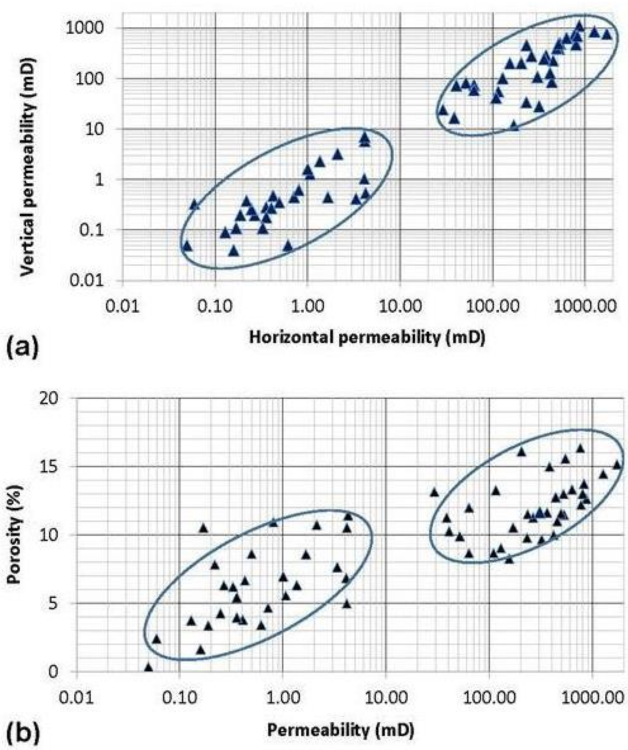

Figure 6. Cross plots showing two groups of reservoir quality in Z-23 Well: a) vertical permeability vs horizontal permeability, b) porosity vs permeability.

The second group is plotted in the lower left side of both graphs, and it reflects very low porosity and permeability. Permeability values are recorded in the range of 0.05 – 5mD and 0.02 - 9mD for vertical and horizontal permeabilities respectively (***Figure 6a*** and ***6b***). Porosity is quite low, with recorded values ranging from 0 - 11.2%.

Petrographic description and reservoir properties

The petrographic and sedimentological studies have been carried out on some samples selected from the three oil fields. It was important to study the petrography of the Khatatba sandstones using thin sections and SEM analyses. This may help to estimate the origin and evolution of porosity and permeability and the presence of any diagenetic processes that influenced the reservoir quality.

The classification of Pettijohn et al. (1987)[29] was used for the description of the studied samples. The petrographic study indicates that the Khatatba sandstones are mostly quartz arenite, composed of more than 90% quartz and about less than 3% of non-quartz content (***Figure 7***). Most framework grains are mostly subangular to subrounded with some rounded grains (***Figure 7a*** and ***7c***), and are generally moderately to well- sorted[19]. Khatatba sandstones are mainly composed of varying grain sizes ranging from fine, medium, and coarse to very coarse sand (***Figure 7b*** and ***7d***). The histograms showing the variations of grain size in some selected samples of Khatatba sandstone in the X-Field are illustrated in ***Figure 7b*** and ***7d***.

The petrographic observations are consistent with porosity-permeability relationships (***Figure 4*** and ***6***) showing the presence of both primary and secondary intergranular pore types in the studied core samples. The porosity and permeability have been affected by different factors, leading to classifying and discriminating the plotted points into two different groups of data sets. One group represents the good reservoir-quality zones with good petrophysical parameters, while the other group represents the areas that are suffering poor reservoir quality.

In X Field

The petrographic description has been carried out in order to discover the reasons for the variation in the porosity and permeability of the Khatatba sandstones between the X-3 and X-6 wells (***Figure 8*** and ***9***). The petrographic description of the X-3 well, which has high porosity and

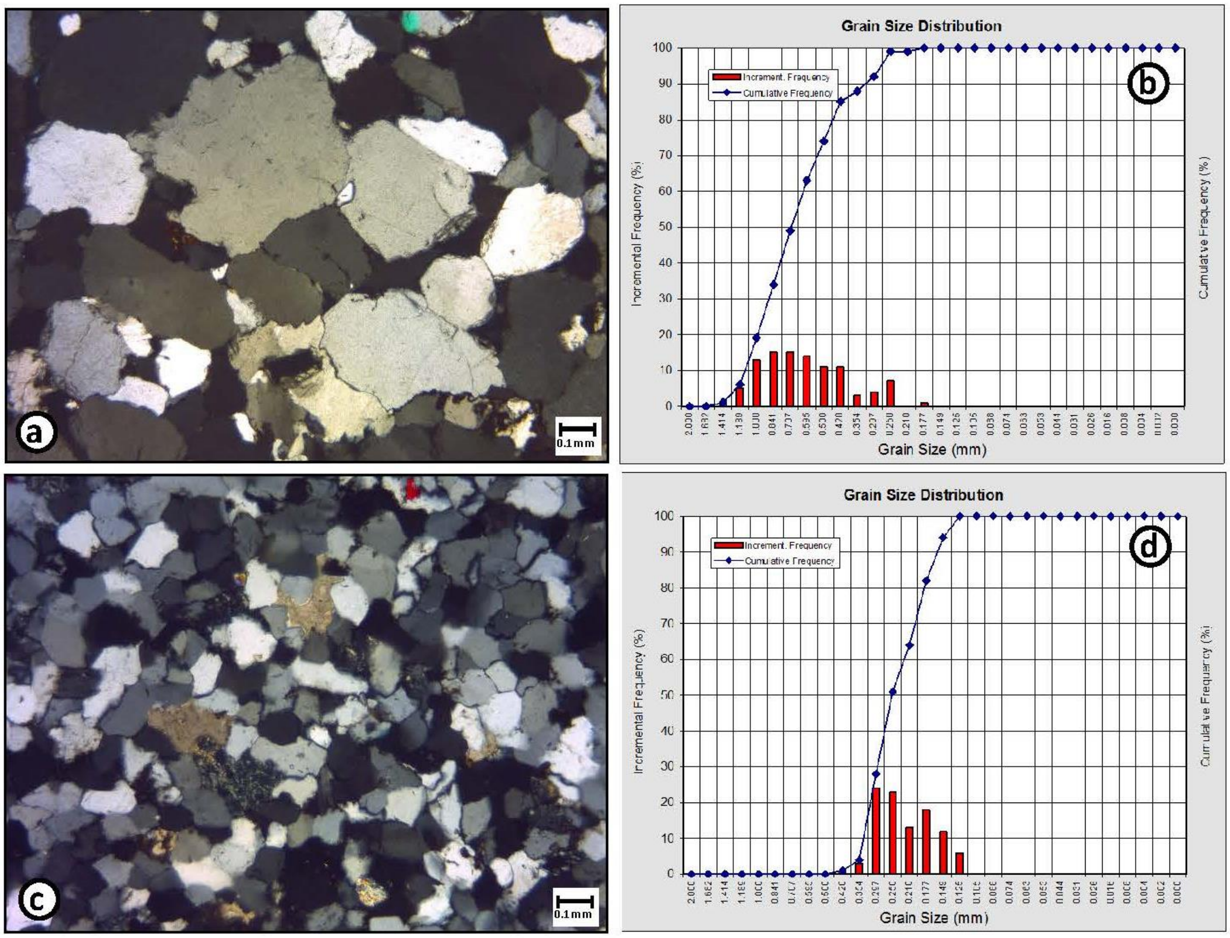

Figure 7. Grain size and grain shape in the Khatatba Sandstone in the study area. a & b) coarse grain sandstone with average grain size, c & d) fine grain sandstone with average grain size.

permeability, is illustrated in ***Figure 8***. Coarse to very coarse sandstones are observed (***Figure 8a*** and ***8c***), while primary pores are the abundant pore types (***Figure 8a*** and ***8b***). The porosity values of good-quality Khatatba sandstones in the X-3 well fall within relatively high values ranging from 10 - 14%; see ***Figure 4***. The increasing porosity and permeability of the Khatatba sandstone in the X-3 well reflect the presence of less-advanced diagenesis. This is associated with the dissolution processes (***Figure 8d***), which increase the porosity and permeability.

Petrographic observations in the X-6 well (***Figure 9***) show a reduction in porosity and permeability that is also coincident with petrophysical parameters (***Figure 4a*** and ***4b***). This may indicate that porosity in the sandstone interval of the X-6 well is severely affected by mechanical compaction and mineral cementation. Calcite cement splashes all over the quartz grains, filling all pore spaces (***Figure 9b***). According to thin-section observations, the clay minerals in the sandstones consist mainly of kaolinite (***Figure 9a*** and ***9c***). Authegenic kaolinite staining with bitumen is observed to be filling in the pore spaces between the detrital quartz grains (***Figure 9d***). The dispersed kaolinite is easily recognized as the most abundant clay mineral with variable amounts. Kaolinite has been interpreted as a by-product at the expense of K-feldspar at a temperature greater than 100^{o}C[30] and belongs to the late diagenetic history. Bitumen is found to be invading all primary and secondary pore spaces[17] and permeable zones (***Figure 9b, 9c*** and ***9d***). This also implies that porosity reduction was due to a decrease in grain size and an increase in cement. Thus, the porosity reduction appears to be pre- and post-depositional controlled. The detrital quartz grain contacts are transformed from point to long

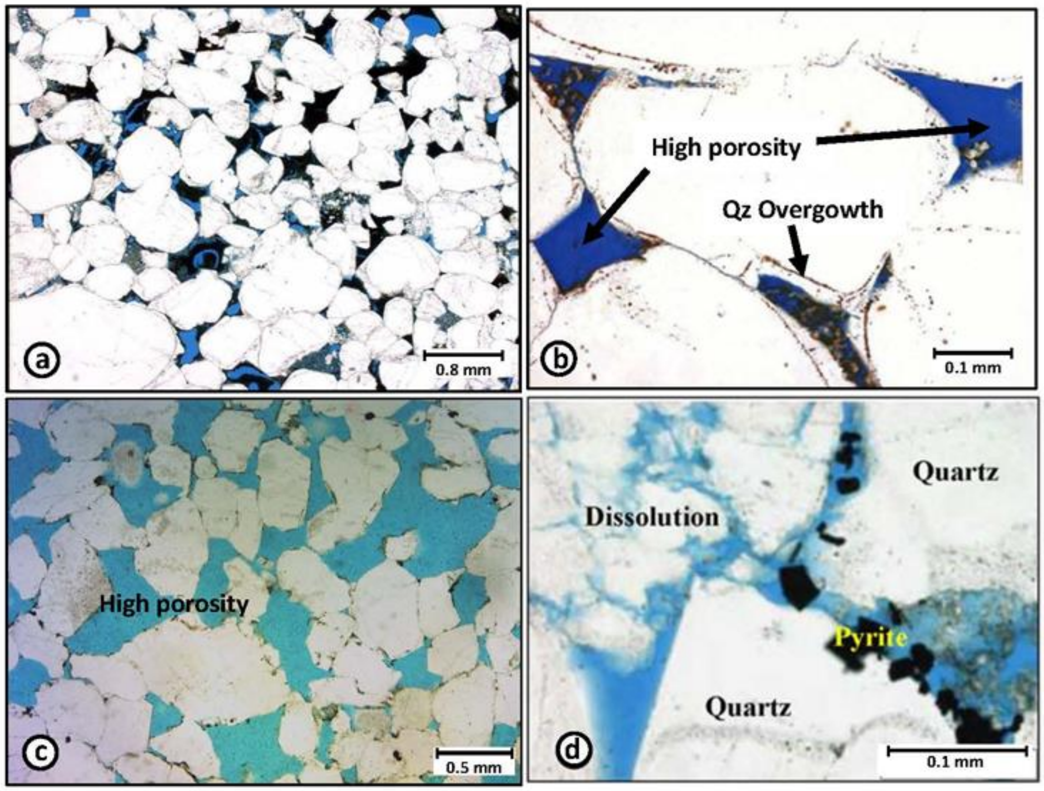

Figure 8. Good quality reservoir in sandstone of the Khatatba Formation in X-Field. a & c) primary intergranular porosity in quartz arenit sandstone with low diagenetic effect. b) Quartz overgrowth affecting some detrital grain with no effect on porosity. d) Dissolution of quartz grains increasing permeability with some pyrite cube indicating reducing environment.

and concavo-convex contacts due to sever mechanical compaction, which reduce the permeability (***Figure 9d***). SEM images have been taken (***Figure 9e*** and ***9f***) showing kaolinite filling the pore spaces between Qz grains, (***Figure 9e***). It is also observed that pyrite cubes are available, indicating a reducing environment (***Figure 9f***).

In Y Field

In the Y-2X well, the visible, intergranular porosity in the Khatatba Formation is related to the abundance of natural open hydraulic fractures that occurred during the higher mechanical compaction process (***Figure 10***). Increasing vertical permeability when compared to horizontal permeability in all examined samples can be interpreted to the presence of these open hydraulic fractures and secondary porosity (***Figure 10b***). The examined thin sections indicate that the primary porosity is abundant (***Figure 10a*** and ***10c***), and it is recorded at a high percentage (12 – 17%). The good-quality zones of the Khatatba sandstones in the Y-2X well are characterized by a very wide range of permeability more than 1000mD (***Figure 5a*** and ***5b***). It can be concluded that, the permeability values increase due to the pervasiveness of primary porosity and secondary porosity, represented by a large number of intergranular pores (***Figure 10a, 10b*** and ***10c***) and the presence of open macro and micro fractures (***Figure 10b***).

The intervals suffering low reservoir quality in the Khatatba sandstone in the Y-2X well reflect a slightly lower measured core porosity in the range of 4 - 11.5% (***Figure 11***). Petrographic observations are also coincident with petrophysical parameters showing that porosity and permeability in this sandstone interval are severely affected by mechanical compaction and mineral cementation (***Figure 11a - d***). Authegenic kaolinite is found to be filling all primary pores between the quartz grains (***Figure 11a*** and ***11c***). Quartz overgrowth (***Figure 11c***), which acts as a

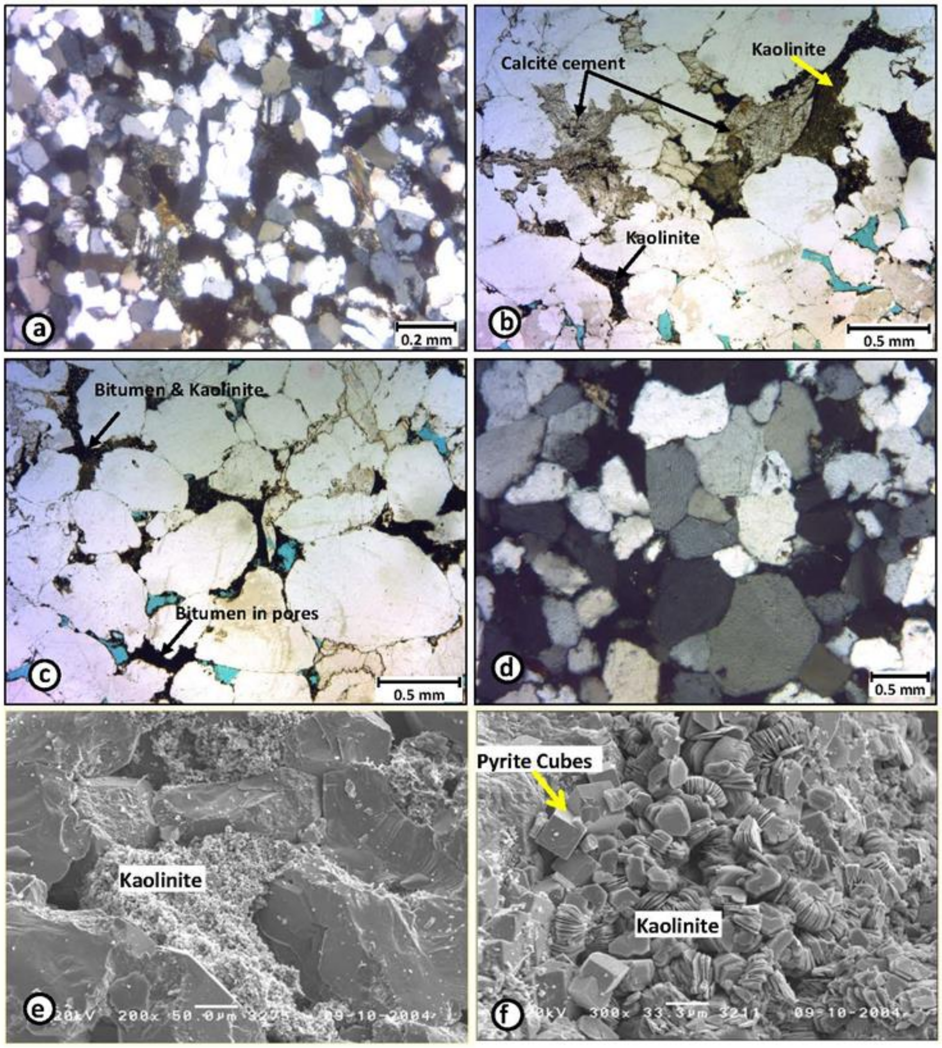

Figure 9. Low quality reservoir in the Khatatba Formation in X-Field. a & b) authigenic kaolinite and calcite cement filling the pore spaces, c) bituminous material with kaolinite filling in most of primary porosity, d) mechanical compaction, point, long, concavo-convex contacts are available, e & f) SEM image showing Kaolinite filling the pore spaces between Qz grains, f) Pyrite cubes are available for reducing environment.

pore-occluding phase, coupled with the authegenic kaolinite is destroying the porosity and permeability of the sandstone. Bitumen is also detected as blocking all available pore spaces and permeable zones (***Figure 11b*** and ***11c***). It is also filling all fractures and small fissures (***Figure 11d***) found in the sandstone of the Khatatba Formation in the Y-2X well, leading to severe loss in both porosity and permeability. Thus, the pervasive secondary porosity represented by a large amount of macro and micro fractures found in the good reservoir interval has been destroyed in the poor quality interval. These permeable zones have been sealed or blocked due to the invasion of bituminous materials in the permeable zone in addition to mechanical compaction as well as, carbonate and kaolinite cement precipitation (***Figure 11***).

In Z-Field

The petrographic descriptions of thin sections in the Z-23 well (***Figure 12*** and ***13***) indicate the presence of a higher number (8 - 17%) of primary intergranular pore types (***Figure 12***). Less diagenetic processes allow the formation to retain more permeability [VK: 30 - 2000mD, HK11 - 1000mD] (***Figure 12a, 12b*** and ***12d***). Increasing vertical permeability is also attributed to the presence of many open fractures and fissures, which are not affected much by diagenesis or any

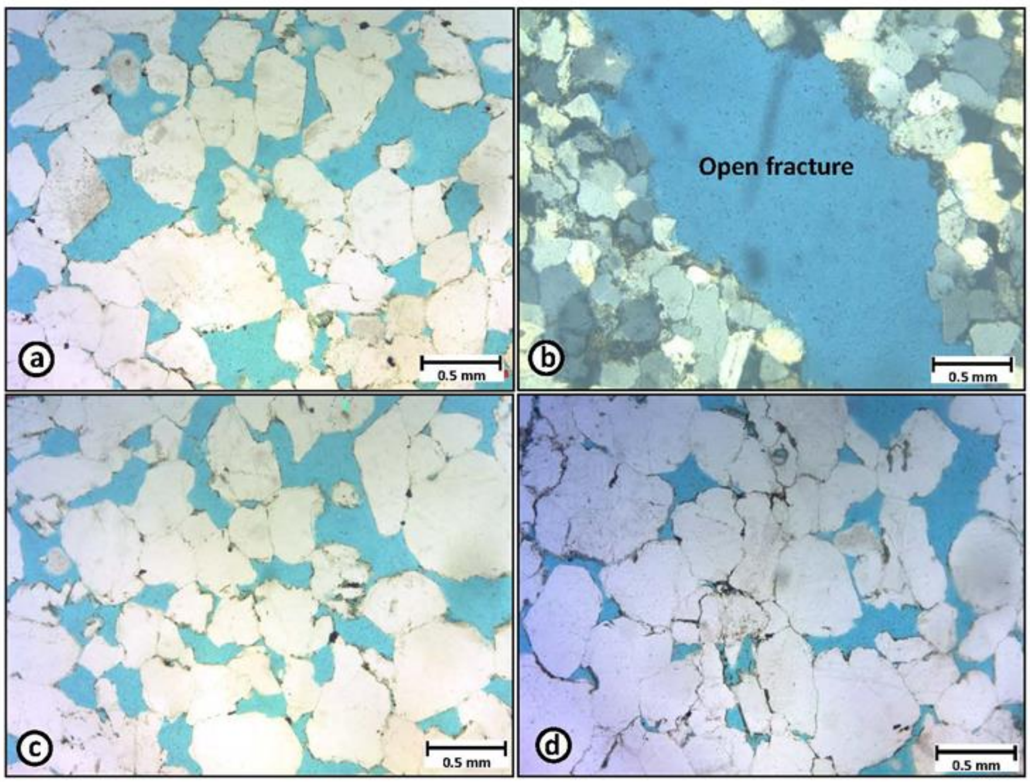

Figure 10. Good quality reservoir in sandstone of the Khatatba Formation in Y Field. a, c & d) primary intergranular porosity in quartz arenit sandstone with no diagenetic effect, and b) Open micro and macro fractures enhancing permeability.

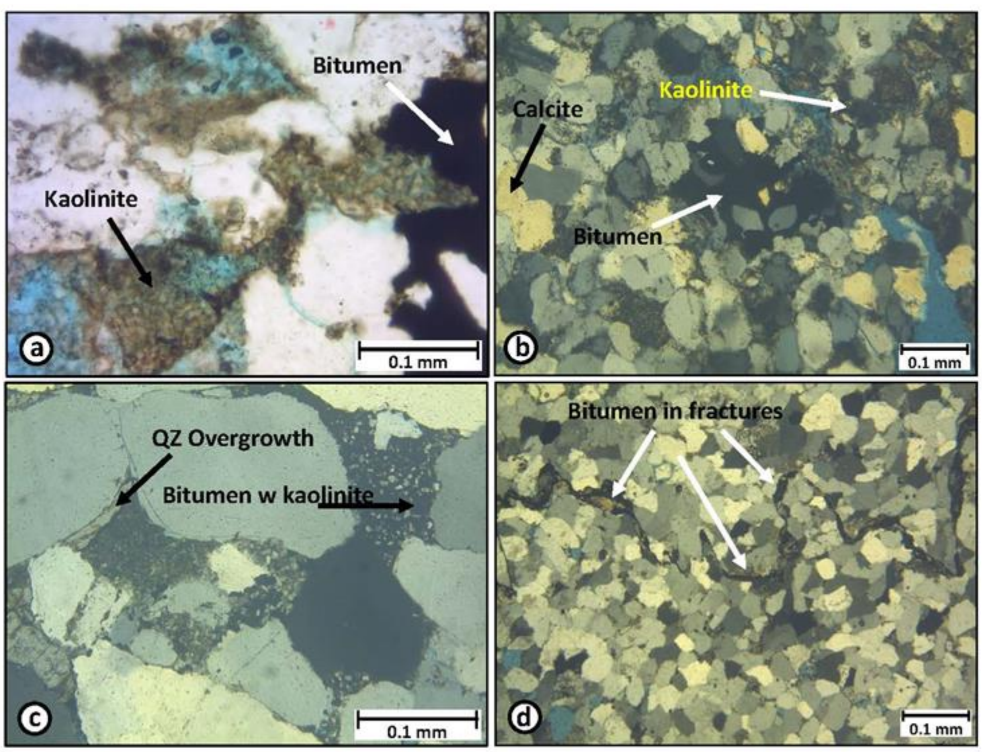

Figure 11. Low quality reservoir in sandstone of the Khatatba Formation in Y Field. a) authigenic kaolinite filling the pore spaces, b) bituminous material filling in most of primary and secondary porosity, c) quartz overgrowth together with kaolinite staining with bitumen, and d) micro fractures are fully occupied with bitumen.

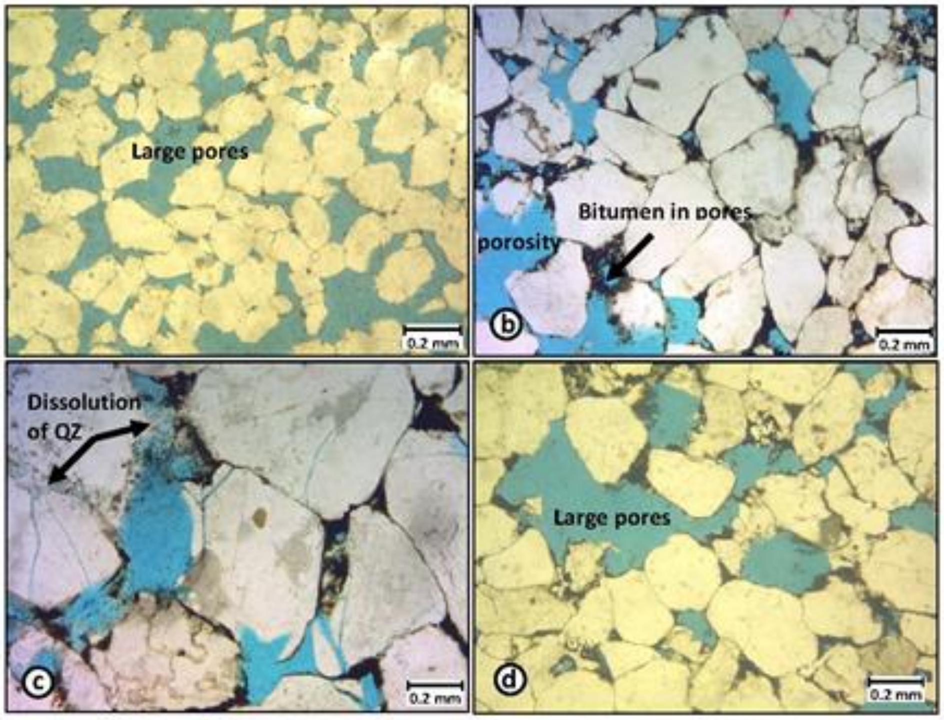

Figure 12. Good quality reservoir in sandstone of the Khatatba Formation in Z-Field. a) Primary intergranular porosity in quartz arenit sandstone with no diagenetic effect, b, c, & d) primary intergranular porosity containing few bitumen with no effect on permeability, c) dissolution of detrital quartz grain increasing porosity and permeability.

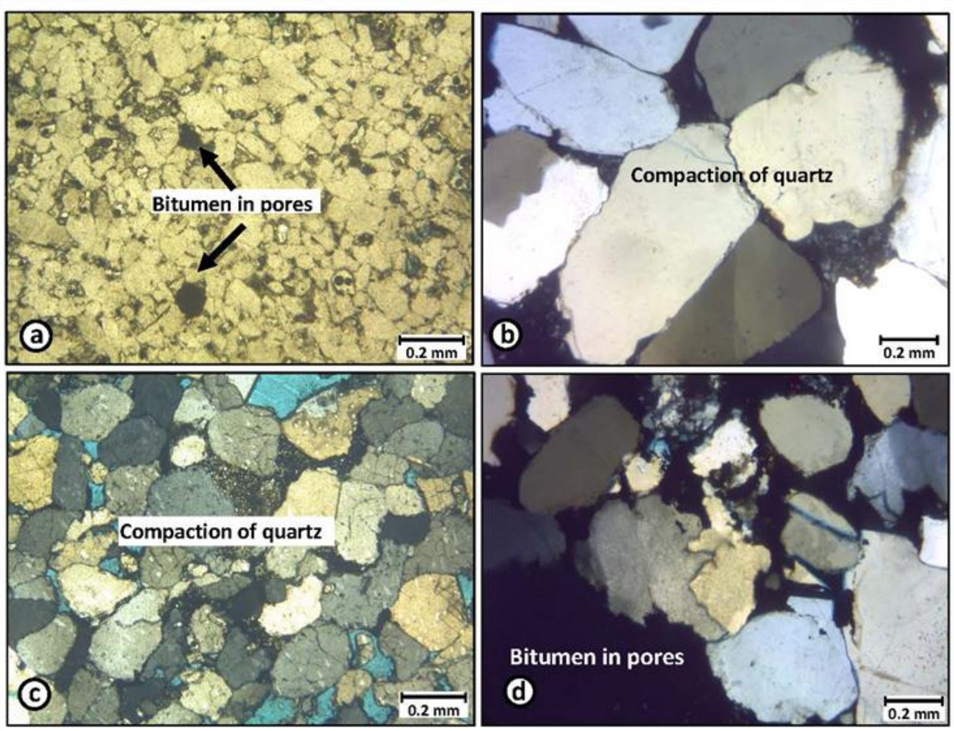

Figure 13. Low quality reservoir in sandstone of the Khatatba Formation in Z-Field. a) fine grain sandstone with bitumen blocking all pore spaces, b & d) severe compaction with kaolinite and bitumen in the remaining pores, c) crushed quartz grains by severe compaction.

formation damage. The process of dissolution is another important agent that has been recorded as enhancing the porosity and permeability of good reservoir zones in the Z-23 well. The dissolution of authigenic mineral or grains can enhance the secondary porosity type[31]. Reservoir quality of the good Khatatba sandstones in the Z-23 well is affected to some degree by dissolution, which enhanced the reservoir porosity and permeability (***Figure 12c*** and ***12d***). This resulted from the dissolution of carbonate cement and, detrital quartz grains. Evidence of dissolution has been detected, including corrosive contacts (***Figure 12c***). The presence of some bitumen trying to occupy the pore spaces has also been observed. Fortunately, a small amount of bitumen accompanied by the dissolution of quartz helps the formation to maintain good porosity and permeability when compared with the other damaged reservoir (***Figure 12b, 12c*** and ***12d***).

In the Z-23 well, poor quality reservoir zones are also observed in the sandstone of the Khatatba Formation in many samples, reflecting a sharp reduction in permeability, with a very low permeability value of less than 10mD. The maximum recorded permeability was 5mD and 9mD for both vertical and horizontal permeability respectively (***Figure 6a*** and ***6b***). Porosity is observed as being inversely correlated with digenetic processes represented by quartz overgrowth and authegenic clay mineral in the form of kaolinite (***Figure 13***). The occurrence of kaolinite as a result of the post-depositional dissolution of Khatatba sandstones indicates that k-feldspar was previously more widespread before they were getting dissolved. All digenetic features have been observed to be affecting the detrital quartz grain contacts. ***Figures 13b, 13c*** and ***13d*** show the presence of point, long, and concavo-convex contacts due to severe mechanical compaction, which results in reduction of porosity. Black-colored bituminous materials are also detected as filling in the pore spaces and blocking all pores and permeable zones (***Figure 13b*** and ***13d***).

Capillary pressure and reservoir properties

The role of diagenesis in the formation damage of the Jurassic Khatatba Formation is interpreted on the basis of pore size, pore geometry, and capillary pressure relationship. Reduction in pore throat and pore size increases the capillary pressure of the sandstone of the Khatatba Formation, leading to the destruction of permeability. In petrophysical analyses, the high pressure mercury injection has been applied to some selected samples at different depths in both the X-3 and X-6 wells. In X-3, the selected sample depths are at 13193 and 13208 ft., while in X-6, they are at 13388, 13419, and 13423 ft (***Figure 14*** and ***15***). It is found that the pressure relationship shows a typical drainage capillary pressure curve obtained by displacing the wetting phase from a porous medium with a non-wetting phase. The drainage capillary pressure curve shows that a minimum positive pressure (Pd) must be applied to the non-wetting phase in order to initiate the drainage[32]. This minimum pressure, which is known as the displacement pressure (Pd), is considered to be the threshold pressure or the entry pressure, which affects the size of the largest pores connected to the surface of the medium.

Tiab and Donaldson (2004)[32] concluded that, if the rock does not have a strong wettability preference for the initially saturating fluid, then the displacement pressure will be zero. If the rock has a strong preference for the displacing fluid, then no pressure is required in order to initiate the displacement because it will occur spontaneously. In this case, the capillary pressure will start at the initial fluid saturation of less than 1. As the pressure of the non-wetting phase is increased, smaller and smaller pores are invaded by the non-wetting fluid. Eventually, the wetting phase becomes discontinuous and can no longer be displaced from the medium by increasing the capillary pressure. Therefore, the irreducible wetting-phase saturation is achieved for the porous medium at a high capillary pressure. They also mentioned that at the irreducible wetting-phase saturation, the capillary pressure curve becomes nearly vertical. The irreducible wetting-phase saturation is a function of the grain size (pore size), the wettability of the medium, and the interfacial tension between the wetting and non-wetting fluids.

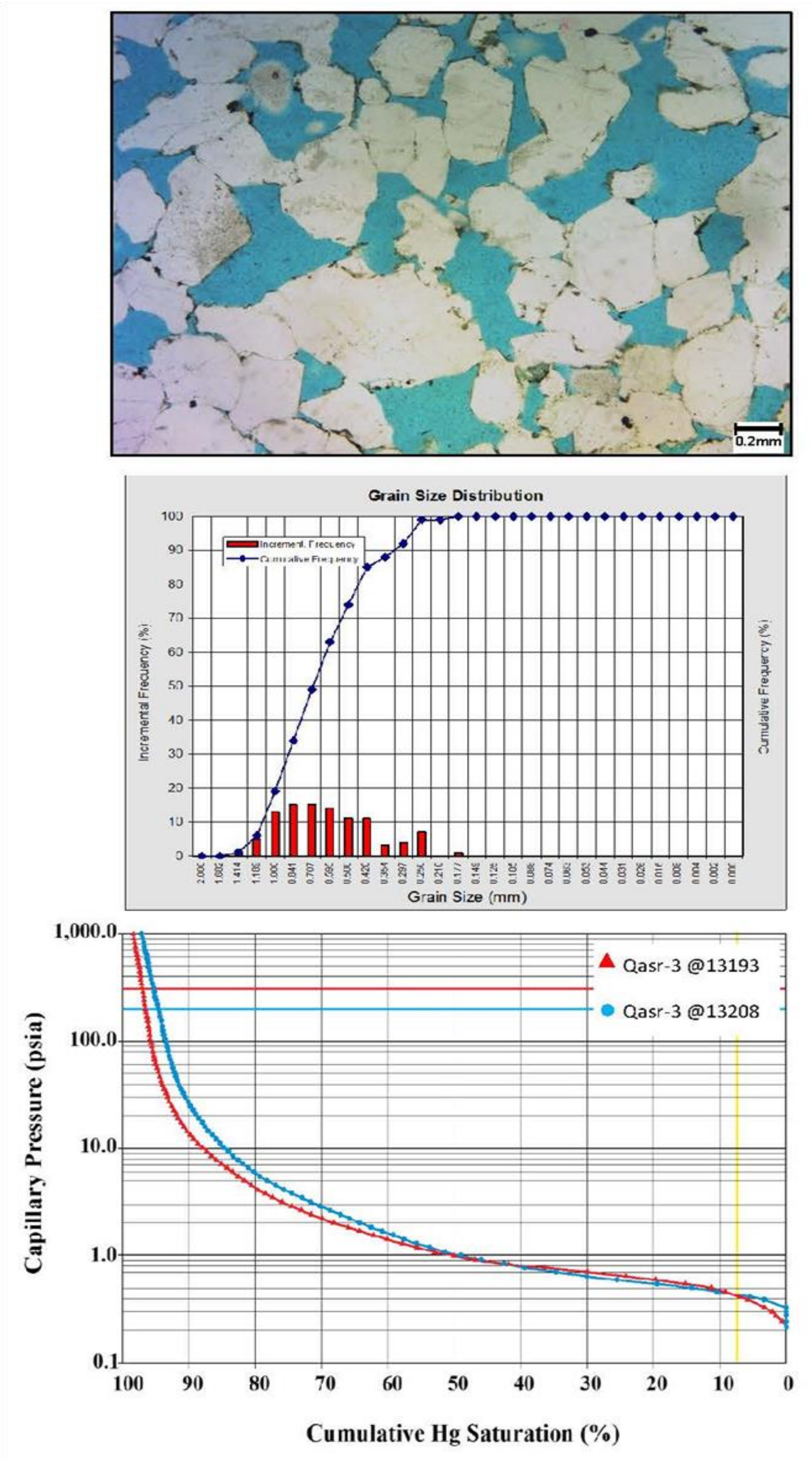

Figure 14. Shows the relationships between grain size, pore size, and capillary pressure. Low displacement pressure is recorded for high porosity, coarse grain sandstone

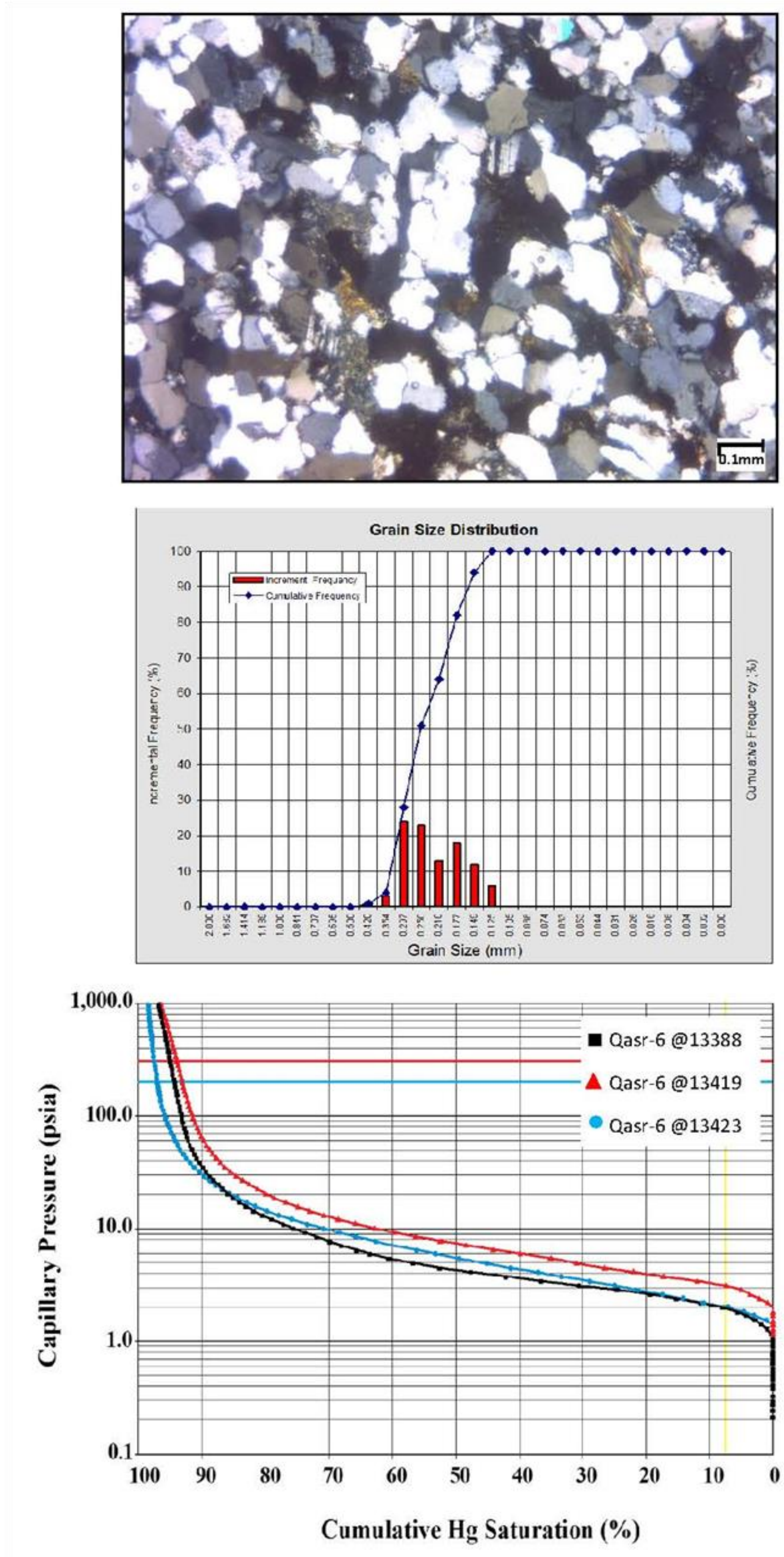

Figure 15. Shows the relationships between grain size, pore size, and capillary pressure. High displacement pressure is recorded for low porosity, fine grain sandstone.

Figures 14 and ***15*** show the relationship between grain size sorting, pore size distribution, and capillary pressure in both the X-3 and X-6 wells. ***Figure 14***, for the X-3 well, shows very good porosity in coarse-grain Khatatba sandstone (***Figure 14a***). The grain size distribution (***Figure 14b***) shows very coarse sandstone in the range of 0.250mm to 1.189mm, and all grains are homogenous and moderately well-sorted. The drainage capillary pressure curves for samples selected from X-3 (***Figure 14c***) have the least displacement pressure. Therefore, it has the largest pores connected to the surface. Its capillary pressure curve remains essentially flat as the wetting-phase saturation is decreased from 100% to 80%. This means that many of the pores are invaded by the non-wetting fluid at essentially the same capillary pressure. This indicates that the sandstone of the X-3 well has uniform pores or is well-sorted, which is consistent with data given in previous ***Figures 4*** and ***8***. It also reflects the least irreducible wetting-phase saturation (***Figure 14c***), indicating that it has relatively larger grains associated with large pores. The displacement pressure is very small, and it measured as 0.2 - 0.3 psi, which indicates that the sandstone is a coarse-grain, high- porosity reservoir.

The sandstone of the Khatatba Formation in the X-6 well, (***Figure 15***), is characterized by very fine to medium sand size (***Figure 15a***). The presence of fine- grained sand in combination with feldspar and authigenic kaolinite (***Figure 15a***) filling in the pore spaces is the result of a high reduction in porosity and permeability in that well. The grain size distribution is observed in ***Figure 15b***, which reflects fine to medium sand in the range of 0.125mm to 0.297mm. Capillary pressure curves in the X-6 well (***Figure 15c***) show higher displacement pressure when compared with those of the X-3 well. It is measured as 1–2 psi, which can be interpreted as resulting from pores that are smaller than those in the X-3 well. The capillary pressure curve at the high wetting-phase saturations is relatively flat, indicating good sorting. It has a higher irreducible wetting- phase saturation than does X-3, which is consistent with its finer grains and smaller pores.

Diagenesis and reservoir properties

It was important to study the Khatatba sandstones using thin sections petrography and SEM analyses. This may help to estimate the origin and evolution of porosity and permeability and the diagenetic processes that influenced the evolution of reservoir quality. In the Khatatba Formation, both textural frameworks and diagenetic processes have an important influence on the quality of the sandstone of the Khatatba Formation in terms of porosity and permeability. The effects of diagenetic processes on the sandstone of the Khatatba Formation include the reduction of porosity by compaction and cementation as well as, the enhancement of porosity by dissolution [33-35].

The best- quality rocks are characterized by medium to coarse grain size, good sorting with high percentages of detrital quartz, and low percentages of matrix and cement (quartz and calcite). Most quartz in sandstones occurs as rounded to subrounded monocrystalline fragments. Meanwhile, the development of the dissolution of feldspar and calcite cement contributes to the development and enhancement of secondary porosity and permeability. At the same time, open hydraulic fractures are present and are not affected by any blocking material, which provides great pathways for fluid movement (***Figure 10b***) in order, to enhance the petrophysical parameters[18].

Several secondary intergranular pores with some fractures and small fissures are also observed in the macroscopic and microscopic scale in the obtained samples from the sandstone of the Khatatba Formation (***Figure 8, 10*** and ***12***). The most important characteristics of the vast majority of fractures are that, they are typically observed as being open (non-mineralized) and, oriented sub-parallel , forming great pathways for fluid movement (***Figure 10b***). These open fractures are formed essentially due to mechanical compaction. These fractures enhance and increase the porosity and permeability. In the obtained core plug samples, the fractures have been observed in most of the samples from the top to downward of the formation. In this interval, the porosity increases with depth due to the occurrence of micro and macro fractures, which can be identified in the thin section under a polarizing microscope or even by the eye in core plug samples.

Destruction of reservoir is affecting many of the available porous and permeable zones in the Khatatba sandstone. Several important processes such as mechanical and chemical effects, the formation of quartz and calcite cements, and the development of authigenic kaolinite are acting strongly against the reservoir's quality, leading to a reduction in porosity and permeability. The intervals those suffering damage in the Khatatba sandstone have a measured core permeability in the range of 0 to maximum 44 mD. Grain contact changes from dominantly floating to point, long contact, and concavo- convex shapes due to the progressive burial and compaction effect (***Figure 13b*** and ***13d***). Worden and Morad (2000)[36] concluded that quartz overgrowths are an important reservoir quality- deteriorating mechanism in many deep petroleum reservoirs. In the Khatatba sandstones, quartz overgrowth, and the presence of carbonate and clay cements along with other cements strongly affect the reservoir properties (***Figure 9b*** and ***11c***). The presence of quartz cementation in the form of syntaxial quartz overgrowth, is a major cause of porosity and permeability loss in many petroleum reservoirs. In the analyzed samples, quartz overgrowth is one of the most important cements, which occurred during early diagenesis due to chemical compaction[19]. The quartz overgrowth is coating the detrital quartz grains, leading to decreasing pore radii and pore throat as well as increasing the capillary pressure, which results in the reduction of porosity and permeability. Calcite is one of the most important carbonate cement splashes into the Khatatba sandstones, leading to blocking many of the pore spaces and reducing the porosity and permeability. Authigenic kaolinite has been noticed as a pore-choking cement creates a permeability barrier (***Figure 9e, 9c, 11a*** and ***11c***) and may act as an irreducible water- saturation trap[37]. It increases in abundance and affects pore geometry and pore size distribution[18-19]. Formation damage is also affecting the vast majority of these fractures where they are observed to be totally sealed (closed, blocked) and fully occupied with bituminous materials, leading to the destruction of the expected porosity and permeability.

5. Conclusions

The sandstones of the Middle Jurassic Khatatba Formation in the North Western Desert of Egypt has been studied for reservoir quality analysis. It has been observed that the Khatatba Formation has different reservoir quality degrees. It can be discriminated into two distinctive zones in terms of reservoir quality. The good and poor reservoir quality zones can be identified from well to well, from field to field, and even within the same well. In good reservoir quality zones, primary intergranular porosity is common in addition to secondary porosity. The presence of open micro and macro fractures increases the permeability. Diagenesis took place in terms of the dissolution of feldspar, quartz, and calcite cement, which increases porosity and permeability and enhances the reservoir quality as well.

In case of low or poor reservoir quality zones, the diagenetic modification, which includes mechanical and chemical compaction, as well as the precipitation of authigenic cements, has been detected through petrographic observation. These cements occurred before oil was emplaced in the sandstones and include calcite, quartz overgrowth, and kaolinite. The dominant authigeneic cemet was the kaolinite invading most of the pore spaces and forming permeability barriers. Quartz overgrowth formed during early diagenesis due to chemical compaction. Calcite is generally the abundant pore- occluding cement. It develops as small euhedral crystals or as large crystals in the primary pores, and pyrite is also detected as a minor cement.

It is recommended that precautions must be taken into consideration during formation evaluation process of the Khatatba Formation in the Western Desert of Egypt. The poor quality reservoir zones that are observed within the Khatatba Formation in the north Western Desert may lead to misinterpretation and erroneous estimation of future oil production and forecasting.

Acknowledgements

The authors are deeply grateful to the Khalda Oil Company, Egypt for providing the rock samples and other petrophysical data for this study. The authors would like to appreciate the facilities provided from the Department of Geology, University of Malaya to complete this research. Also more grateful is extended to the University of Brunei Darussalam for providing all support and assistance to finish this work.

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