Porosity and permeability distribution and their impaction on fluid production in carbonate reservoir rocks

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Abstract

Reservoir parameters including porosity and permeability are predominantly influence fluid flow movement and production rate in carbonate reservoir rocks. This impaction is corresponding to heterogenous distribution of these reservoir parameters which leading to anisotropic fluid production in the same reservoir intervals. In this work, the magnitude of matrix porosity and permeability were measured from core plug samples and available wireline log data was used for the porosity calculations in Baba Formation from Bai Hassan field. Besides of the petrophysical examinations, fluid loss data and formation test repeater results were used for evaluation of the impaction of porosity and permeability distribution on fluid flow and rate of hydrocarbon production. The rock types in the Baba Formation are characterized by a comprehensive distribution of measured matrix porosity and permeability. The magnitude of the effective porosity is started from 0.01 as the minimum value to 0.45 as the maximum with an average of 0.20 throughout the studied intervals which have been used for this study. The magnitude of measured matrix permeability is ranged from 0.01 mD to 827.04 mD with an average of 123.52 mD. The magnitude of average fracture porosity was 0.0036 and average fracture permeability was 0.394 mD. The rate of production is frequently controlled by the magnitude of matrix permeability throughout the studied wells. The highest rate of oil production is coincided with the highest magnitude of average matrix permeability and the lowest level of oil production was recorded was derived from the lowest magnitude of an average matrix permeability.

Keywords: Baba Formation; Fracture; Permeability; Reservoir; Carbonate.

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Introduction

The structure of the Bai Hassan field extends parallel to Kirkuk structure at its southwestern side within the Kirkuk embayment zone of Iraq Zagros basin. This anticline was identified by a stratigraphically complex area comprising multiple facies developments of a complicated diagenetic history. It is located within the Foothill Region of the northwest-southeast trending Zagros Fold and Thrust Belt, Figure (1). The field has been mapped previously as northwest-southeast trending doubly plunging anticline manifested as classic four-way structural closures (Dunnington, 1958).

The field consists of two domes with the SE – NW direction, Kithka Dome and Dauod Dome separated by a narrow saddle called Shahal saddle. It is mostly appeared that the Shahl Saddle is associated with a deep seated, axis-perpendicular, extension fault that was reactivated and influential in the structurally development of Bai Hassan during Miocene compression and folding. It is also likely that the structure is still in compression (NOC, 1992). Kithka dome is bigger in size and higher structurally by (335m) than Dauod dome (Buday, 1980). Dipmeter data attained on drilled wells show local dips in excess of 50 degrees that are most likely associated with faults. The top of the structure is relatively flat with dips less than 10 degrees. As a Tertiary reservoir Baba Formation has its importance in the process of petroleum exploration in Iraq and the region. Baba Formation was first defined by Bellen in 1956 from Kirkuk oil well-109, lithologically consists of porous dolomitized limestones, in surface outcrops the limestone has a chalky appearance, which is mostly massive, with some bedded parts (Bellen et al., 1959).

The Baba Formation in the Bai Hassan oil field is considered as the dominant reservoir rocks of the tertiary petroleum system. The reservoir productivity of this rock is predominantly varied throughout the field from the same interval. The initial rates of production obviously fluctuated from the drilled intervals in the same limb and between the two identified domes of the Bai Hassan structure. This phenomenon created a challenge during the production and development stage of the field for arranging and stabilizing rate of production and marketing from the Bai Hassan field.

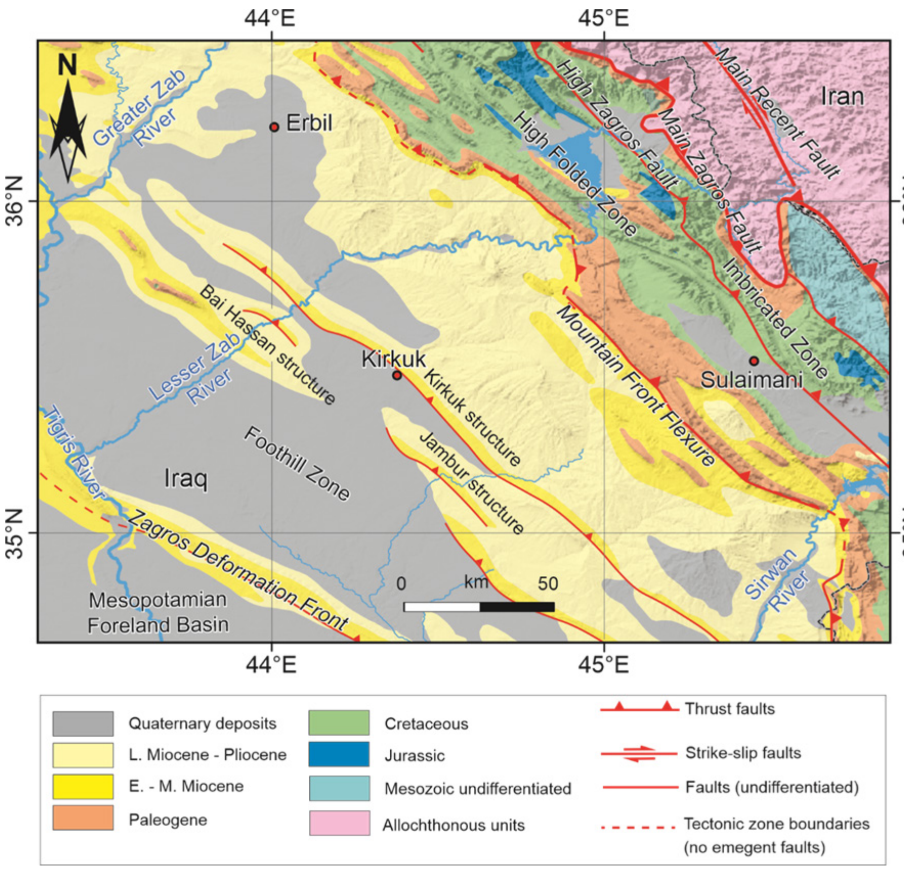

Figure 1. Geological map of the northeast of Iraq contains the dominant surface north-west and south-east trending structures. Bai Hassan locates in the Low Folded Zone (Foothill) of the Zagros basin which parallels to the Kirkuk, Jambur and other fields, modified from (Zebari et al., 2020).

This research works on the investigation of the quantitative distribution of porosity and its connection with the magnitude of permeability in the carbonate reservoir rocks of the Bai Hassan field in order to predict the lateral and vertical reservoir quality distribution throughout the studied field. It also examines fluid distribution and the level of the production based on these two parameters. The outcome of this research provides a clear vision for drilling new wells in development plan from the highest potential position in the field for producing the maximum rate of hydrocarbon. In addition, these results can be used as correlation data for supporting exploration strategy in the newly discovered field of the Kurdistan region licensed blocks.

Materials and Methodologies

The measured data for this study have been collected from five drilled wells of the Tertiary reservoir rock interval of Baba Formation in Bai Hassan oil field. The data cover core plug measurements of carbonate samples and composite wireline log raw data with in different intervals. The subsurface sections have been selected based on the location of the wells and position of the Bai Hassan structure with in the Kirkuk embayment zone. The preferred location of the wells started from the northwest to the southeast of the structure including well BH-20, BH-50, BH-78, BH-86, and BH-96, Figure (2). Well locations, elevations, the thickness of Baba Formation in the studied wells in addition to the depth intervals and type of data were used in this study are listed in Table (1).

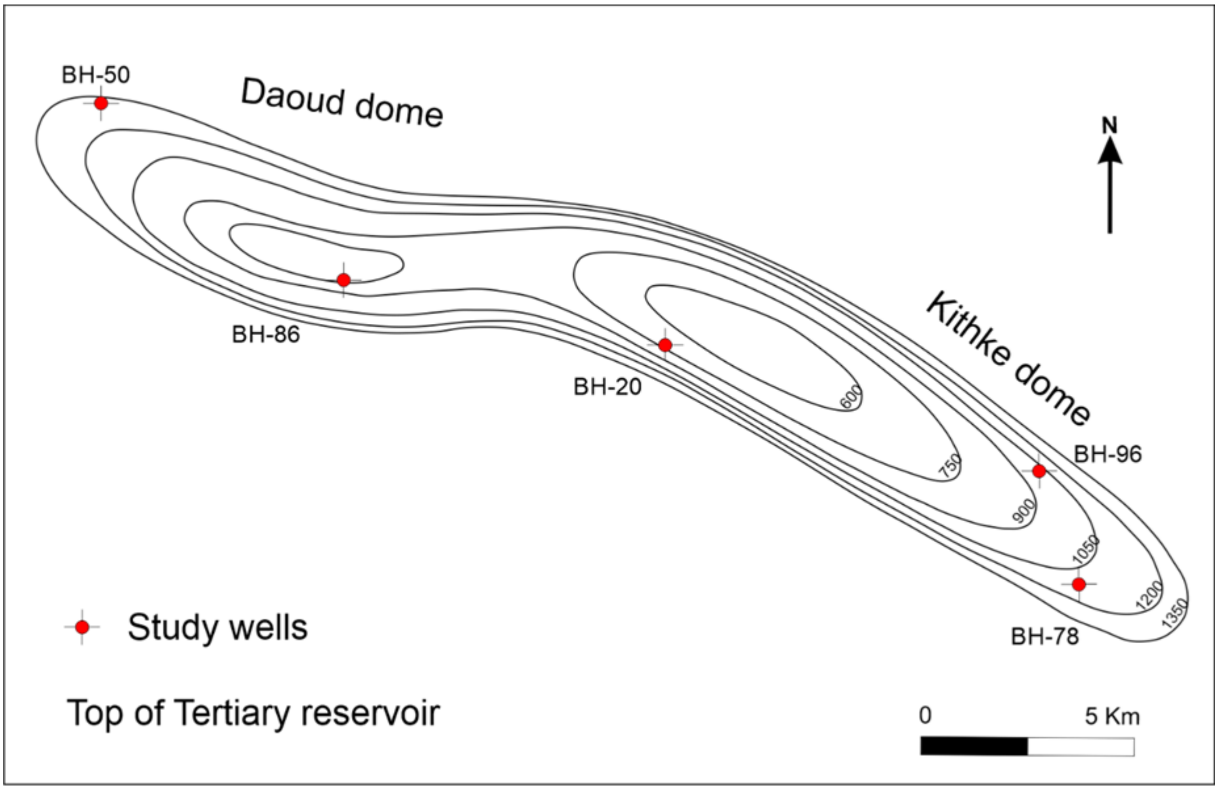

Figure 2. Contour map on the top of the Tertiary reservoir rocks of Bai Hassan field structure, modified from (Mustafa etal.,2020). The anticline composes of two dominant domes; Daoud, and Kithke. The studied wells including BH-20, BH-50, BH-78 BH-86 and BH-96 were drilled in different positions of the field.

The core analysis encompassed 143 plug measurements for matrix porosity and permeability obtained from the cored interval, achieved from the North Oil Company-Kirkuk laboratory. The porosity was measured using Boyle's law of gas expansion technique (Spain,1992) and applying nitrogen gas for grain and pore volume calculation for the plug sample, equation (1). The permeability of the same sample was measured based on modified Darcy's law steady state equation for single point measurement (Ross,2011) and consequently klinkenberg-corrected permeability for each sample was calculated, equation (2). Besides of these measurement dynamic data which include test results were obtained from repeat formation tester tool for the studied intervals have been used for this study.

$$\phi = \frac{(VB - VG)\ 100}{VB}$$

ϕ : matrix porosity, fraction.

VB : sample bulk volume, cm3.

VG : rock grain bulk volume, cm3.

$$K = \frac{14700 \mu Q L}{A \Delta P}$$

K: Permeability, mD.

Q: Flow rate, cm3/sec.

A: Surface area of the sample cm2.

ΔP: Differential pressure, psi.

μ: Dynamic viscosity of the fluid, centipoises.

L: Length of the sample, cm.

Table 1. The studied wells with their elevations and collected data.

Studied Wells	Elevation from KB (m)	Samples		Composite log	Baba Formation		
		Core	Cutting		Top m	Bottom m	Thickness m
BH-20	254.22	8	-	Porosity logs	1380	1422	42
BH-50	260.5	16	-		1420	1501	81
BH-78	245	26	-		1678	1719	41
BH-86	271	-	10		1180	1273	93
BH-96	247	-	10		961	1032	71

The fracture porosity and permeability from the studied intervals was calculated from the tested intervals using following equations (3 and 4). The results of these equations are representing the tested intervals which are relevant with the producible zones within the drilled wells.

$$\emptyset_f = 0.00173 \left[\frac{J B_o \mu_o \log \frac{r_e}{r_w}}{h} \right]^{\frac{1}{3}} \qquad (3)$$

$$K_f = \frac{J B_o \mu_o \log \frac{r_e}{r_w}}{23.6 h} \qquad (4)$$

$\emptyset_f$: fracture porosity, fraction.

Kf: fracture permeability, mD.

J : productivity index, m3/day/psi.

B_o : oil formation volume factor, 1.31.

μ_o : viscosity of oil, centipoise, 1.30.

h: production interval thickness, meter.

$\frac{r_e}{r_w}$: well radius affected by production / well radius, meter.

Results and discussion

The magnitude of the measured matrix porosity in well BH-50 which was drilled in the northern-east limb of the Daoud dome is characterised by wildly distribution throughout the selected samples. The minimum value of the matrix porosity is 0.05 and the maximum measured matrix porosity is 0.37 with 0.24 as average matrix porosity, as shown in table (2). These magnitudes of the measured matrix porosities are modified to 0.02 as the minimum value of the matrix porosity to 0.36 as the maximum values and 0.16 of average porosity in well BH-20 which was drilled in the southern-west limb of the Kithke dome. The magnitude of the measured effective porosity in well BH-78 which is located in the same side of well BH-20 in the Bai Hassan field starts from 0.01 to 0.35 and 0.19 is the average measured porosity in this well.

The matrix porosity values in well BH-50, BH-20 and BH-78 are measured from the core samples while in well BH-86 and BH-96 are calculated from the gamma ray logs.

Table 2: Static parameters of the measured and calculated effective matrix porosity in the Baba Formation throughout the selected wells in the Bai Hassan field.

Well	Location	Matrix porosity (-)			
		Minimum	Maximum	Mean	Standard deviation
BH-50	Northeastern limb of Daoud dome	0.05	0.37	0.24	0.07
BH-86	Southwestern limb of Daoud dome	0.01	0.27	0.17	0.04
BH-20	Southwestern limb of Kithke dome	0.02	0.36	0.16	0.10
BH-78	Southwestern limb of Kithke dome	0.01	0.35	0.19	0.06
BH-96	Northeastern limb of Kithke dome	0.06	0.45	0.21	0.06

Well	Location	Matrix porosity (-)			
		Minimum	Maximum	Mean	Standard deviation
BH-50	Northeastern limb of Daoud dome	0.05	0.37	0.24	0.07
BH-86	Southwestern limb of Daoud dome	0.01	0.27	0.17	0.04
BH-20	Southwestern limb of Kithke dome	0.02	0.36	0.16	0.10
BH-78	Southwestern limb of Kithke dome	0.01	0.35	0.19	0.06
BH-96	Northeastern limb of Kithke dome	0.06	0.45	0.21	0.06

The magnitude of the measured matrix permeability in the Baba Formation was achieved from the steady

state technique using nitrogen gas as an injected fluid. Similar to the matrix porosity the magnitude of the matrix permeability is characterised by an isotropic and wide range of distribution throughout the available core samples which starts from microdarcies to millidarcies. The highest magnitude of the measured matrix permeability was observed in well BH-50 which has five orders of the magnitude of the permeability, table (3). The magnitude of the matrix permeability in this well started from 0.090 mD to 827.04 mD with an average of 123.79 mD. The same magnitude of permeability has been recorded in well BH-78 which has the minimum matrix permeability 0.01 mD and maximum average permeability 721.71 mD with an average of 148.32 mD. The measured matrix permeability in well BH-50 started from 0.030 mD to 523.69 mD with an average of 118.40 mD.

The measured matrix effective porosity and Klinkenberg-corrected gas permeability from plug samples of carbonate rock intervals were achieved from the Baba Formation in Bai Hassan field are shown in a semi-log poroperm plot in the Figure (3). A non-linear trend of enhancing the magnitude of the corrected gas matrix permeability can be observed with increasing the amount of porosity throughout the measured samples. The plotted corrected gas permeability ($K: mD$) as a function of the gas porosity ($\emptyset : fraction$)has power law relationships with a coefficient of determination (R2=0.6845) and this correlation can be presented on the empirical module as shown in equation (5).

$$K = 11129 \times \emptyset^{3.52} \qquad (5)$$

Table 3. Static parameters of the measured matrix permeability in Baba Formation.

Well	Location	Matrix permeability (mD)			
		Minimum	Maximum	Mean	Standard deviation
BH-50	Northeastern limb of Daoud dome	0.09	827.04	123.79	176.23
BH-20	Southwestern limb of Kithke dome	0.03	523.69	46.39	109.33
BH-78	Southwestern limb of Kithke dome	0.01	721.71	148.32	174.87

This relationship is derived from a complex and heterogenous rock microstructure and pore system in the studied carbonate reservoir rocks (Rashid et al.,2015; Rashid etal.,2017; Hussein et al.,2018; Mustafa et al.,2020). This anisotropy created a wide range of porosity and permeability distributions throughout the reservoir rocks including 37 porosity units and five magnitude orders of permeabilities, Figure (3). The magnitude of measured matrix porosity and permeability is predominantly related to the reservoir rock fabrics (Zangana etal.,2022). The lithology of the Baba Formation in this field comprises of three distinctive rock types including dolomite(dolostone), dolomitic limestone and limestone. The dolomite rock unit contains macro-intercrystalline pores which provided the highest magnitude of matrix porosity and permeability. The magnitude of measured matrix porosity in this rock type ≥ 0.10 and the magnitude of measured matrix permeability ≥ 100 mD to 827.04 mD. The best reservoir quality and highest potential rock types corresponded to this rock type. This rock type is predominantly common in the north eastern limb (flank) of Daoud dome and south-western limb of the Kithke dome. However, once the dolomite rock pores are filled with anhydrite minerals the reservoir quality is totally destroyed as the pore space and throat occluded by anhydrite minerals. The hydraulic connectivity and permeability with occurrence of anhydrite filling rocks are reduced and the lowest permeability throughout the measured samples was observed in the anhydrite pore filling intervals.

The reservoir quality of limestone rock type is totally opposed to the dolomite rock type in term of pore system and magnitude of porosity and permeability. The pore system is dominantly consisting of micro-intercrystalline pores that were preserved between the calcite crystals. The magnitude of porosity in this rock type < 0.09 and value of permeability is located in tight reservoir rock as the measured permeability throughout the selected samples are lower than 1.0 mD. This reservoir rock type is observed in the north-eastern limb of the Kithke dome and limited extensions have been observed in the south western flank of the Daoud dome.

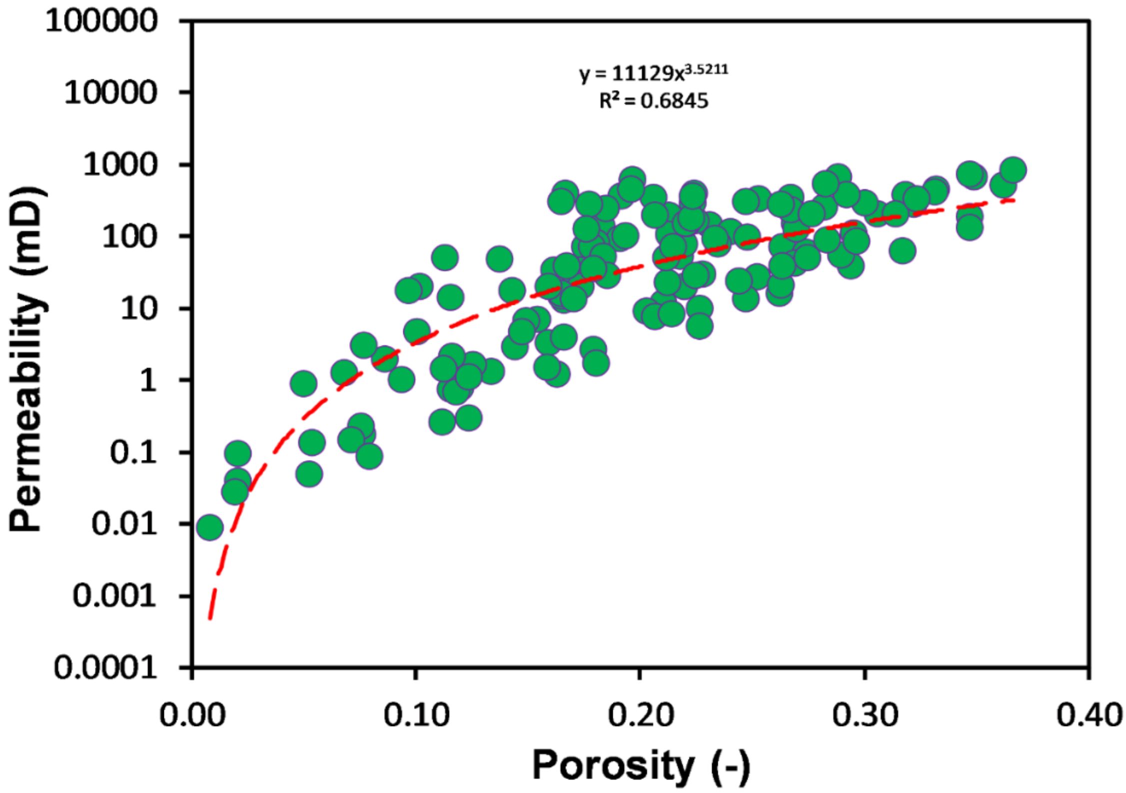

Figure 3. The measured Klinkenberg-corrected gas permeability as a function of the measured gas porosity for the achieved plug samples of Baba Formation in Bai Hassan field.

The most complex and complicated reservoir rock type is observed from the dolomitic limestone rock fabrics which are mineralogical composed of a mixture of calcite and dolomite minerals with some variable percentages of these two components. The pore system contains micro-intercrystalline pore between dolomite crystals, macro-intra-granular and macro-vuggy pores. The vugs are classified as isolated pores where they are interconnected through intercrystalline pore space with a small pore throat sizes. These pore throat sizes distribution gave a varied range magnitude of permeability which started from 1 mD to greater than 40 mD. The non-linear relationship between the matrix porosity and permeability in the poroperm plot, figure (3) is related to the ratio of pore size to pore throat size in the intragranular and vuggy pores. The pore size in this type of pores have a macro scale while the pore throat sizes have nano scales. This contrast in size distribution between pores and pore throats started from intragranular pore which pore size 6 time is larger than pore throat size in the same pore system to 14 times in vuggy pores. The dolomitic limestone reservoir type interval is frequently extended throughout the south-western limb of the Kithke dome.

The magnitude of average matrix porosity increases toward the north of the field including north-eastern limb of the Daoud dome and toward the southern part of the field which is covered by the south-western limb of the Kithke dome. The magnitude of porosity variations is influenced by pore size distribution in the Baba Formation. The highest values of the measured matrix porosities were observed in macro-intercrystalline pores between dolomite crystals and intragranular-vuggy pores of dolomitic limestone rock type. The magnitude of the matrix porosity in these two limbs are nearly similar and about 10 units of the matrix porosity is higher than the opposite limb of the same dome. The magnitude of matrix porosity was changed obviously in the dolomitic limestone rock type based on calcite and anhydrite filling pores extensions. The value of porosity increase in the dolomitic limestone once the pores were preserved and decreased when the rock fabrics contains fine crystalline of dolomite and the pores were filled with calcite and anhydrite cement. This rock type is available with high intensity of fractures in the northern east limb of the Kithke dome and southern west limb of the Daoud dome.

Similar to the matrix porosity, the magnitude of measured matrix permeability is increased towards north and northeast of the Daoud dome and towards west and southern west of the Kithke dome. The permeability enhancement is controlled by the rock microstructure and pore system as the largest pore throat size provided the highest magnitude of measured matrix permeability in the macro intercrystalline pores of dolomite rock fabrics. The average matrix permeability from core samples in well BH-50 which is located in the north-eastern limb of the Daoud dome was 123.79 mD, while this magnitude reduced to 87.20 mD in the same interval in well BH-59 which is drilled in the south western flank of the Daoud dome. The same variations have been observed in the Kithke dome where the magnitude of average measured matrix permeability in well BH-78 which is drilled in the south-western flank of the dome and it is 148.32. This value is reduced to 92.30 in well BH-32 which is suited in the north eastern flank of the dome.

Fracturing is an effective parameter which modifies the hydrocarbon storage ability and pathways of the reservoir rock. Natural fractures were observed throughout most of the core samples that were obtained from the Baba Formation. Some of the fracture surfaces are filled with calcite and anhydrite cements which totally or partially closed the interconnected fracture system and destroyed the fracture permeability. These fractures are characterised by inclined to sub-vertical fractures angles which are ranged between 40°-70° and have an average distance of 15-30 centimeters (NOC,2004). Fracture intensity is controlled by the tectonic position of the field and location of the drilled field in the Bai Hassan structure. The fracture distributions and fracture opening surfaces have been compared with the drilling mud losses (NOC,1989). The selected wells including BH-50, and BH-78 were drilled in different positions in the Bai Hassan field and they have no mud losses recording within the Baba Formation drilled intervals as all the wells located in the limbs of the domes, Figure (4). This result is related to low fracture intensity and fracture surface filling with calcite minerals. However, an extensive mud loss was recorded in the drilled intervals of the Baba Formation throughout the crestal part of the field including BH-70, BH-54.

The magnitude of the calculated fracture porosities is too low in comparison with the measured matrix porosity of the same intervals. Numerically, the matrix porosities are two units of magnitude greater than the fracture porosities. Consequently, available hydrocarbon in this reservoir rocks are dramatically stored in the matrix porosity in both domes and the matrix porosity has direct impaction on the reservoir storage potential. In addition, the measured matrix permeability is three orders of magnitude higher than the calculated average fracture permeability in the same reservoir intervals.

The average matrix permeability for the Baba interval in BH-50 which is drilled in the north eastern flank of the Daoud dome was 123.79 mD while the magnitude of the fracture permeability in the same intervals is 0.591 mD, table (4). The same results can be seen for the magnitude of permeabilities in the south western limb of the Daoud and Kithke domes. The magnitude of the fracture permeabilities in the listed wells is nearly similar while the flow rates are different in each well. This relationship between the magnitude of fracture permeability and flow rate proves that the production rate does not depend on the fracture distribution in the studied intervals.

The presented production data as shown in table (4) indicates that the potential fluid flow path ways in the Baba Formation are formed by the intercrystalline pore throats type and the magnitude of matrix permeability is controlled by the pore throat size distribution. The highest rate of production (12500 bbl/day) was recorded in the dolomite rock type intervals of the Baba Formation in well BH-50 which has an average matrix permeability of 123.79 mD. In well BH-20, the initial rate of production was 9300 (bb/day) which coincides with matrix permeability 118.40 mD. The flow rate in well BH-59 is reduced to 2875 bbl/day in the Baba formation which corresponds to an average of matrix permeability of 87.20 mD.

Well	Location	Net pay (m)	Flow rate bbl/day	re/rw	Fracture porosity (-)	Fracture permeability (mD)
BH-50	NE-Daoud dome	70	12500	3.118	0.0042	0.591
BH-59	SW-Daoud dome	49	2875	3.013	0.0030	0.2187
BH-31	NE-Kithke dome	46	1400	3.118	0.0037	0.4153
BH-20	SW-Kithke dome	66.5	9300	3.118	0.0035	0.3526

Table 4. Fracture porosity and permeability with production rate of the selected wells.

The lowest level of oil production was recorded in well BH-31 which is equal to 1400 bbl/day, and it derived from an average matrix permeability 34.55 mD. These numerical relationships between the magnitude of average matrix permeability and flow rate clearly give the result of the production rate corresponds to the value of matrix permeability.

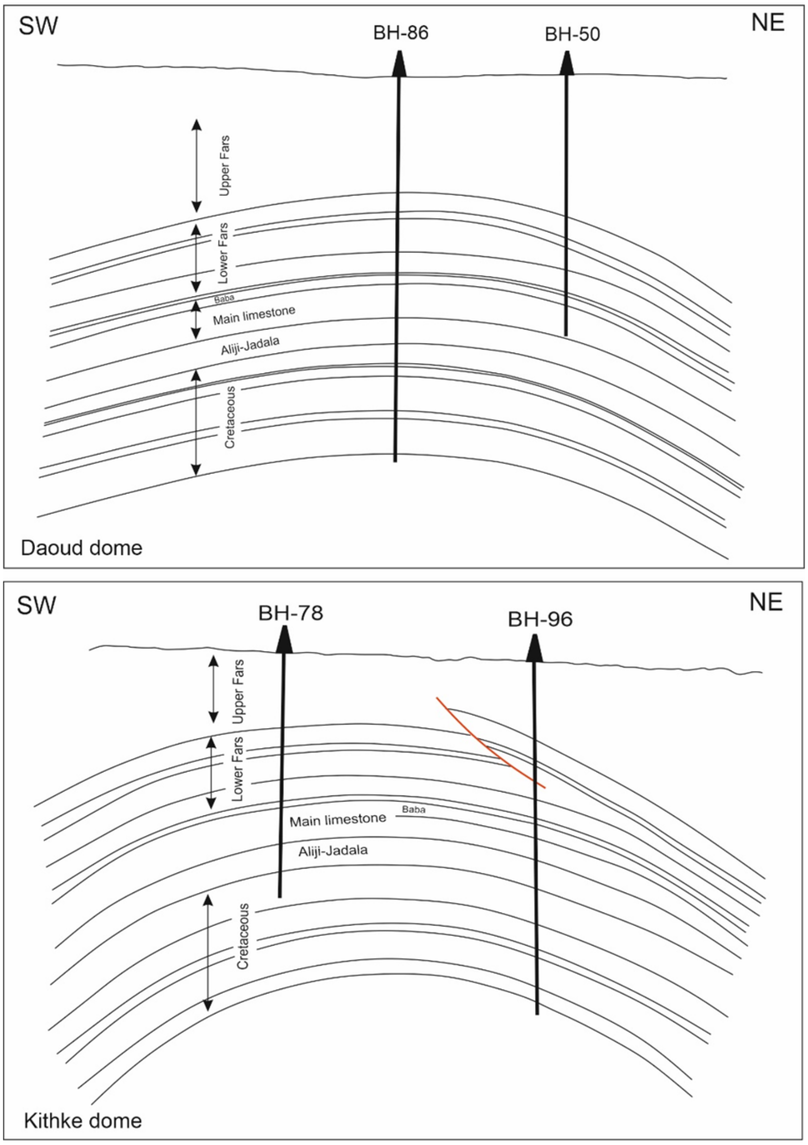

Figure 4. Diagram of Daoud and Kithke domes of Bai Hassan field. It shows the locations and paths of drilled well which are used in this study (NOC,1989).

4- Conclusions

This study analysed reservoir properties in heterogenous carbonate reservoir of the Baba Formation in the Bai Hassan field in Kirkuk embayment zone. The contribution of measured porosity and permeability in fluid flow and production rate has been examined using core samples, wireline logs, well tests and mud log data. The dominant outcomes of this work are summarised as follows:

- The rock types in the Baba Formation are characterized by an extensive distribution of matrix porosity and permeability in the Bai Hassan field. The magnitude of matrix porosity and permeability is predominantly influenced by pore structures and lithological components of the rock types of the Baba Formation.

- The value of matrix porosities are two units greater than the fracture porosities and available hydrocarbon in this reservoir rocks are dominantly stored in the matrix porosity throughout the field and the matrix porosity has effective role on the reservoir storage potential.

- The matrix permeability is three orders of magnitude higher than the calculated average fracture permeability in the same reservoir intervals as a result the production is mainly provided through matrix permeability which depends on the intercrystalline pore throat types in dolomite minerals of dolostone rock type.

- The matrix permeability value controlled the rate of production throughout the studied wells and the numerical relationships between the magnitude of average matrix permeability and flow rate clearly give the result of the production rate is corresponding to the value of matrix permeability.

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