Investigation on the impact of rock physical properties on permeability variation: case study for the reservoir heterogeneity development

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Various factors are controlling the reservoir petrophysical characteristics and their evolution. Investigations have shown that control on reservoir characteristics and heterogeneities and essentially permeability can be ascribed to textural and physical properties of the rocks. Variation in grain size distribution and their arrangement is one of the factors responsible for the discrepancy on the petrophysical characteristics and essentially permeability and heterogeneity. Thus and in the case study, reservoir quality assessment can be supported by the calculated different physical properties of the considered samples. The pore radius, the R_{35} as well as the S_{gv} (surface grain volume) which can be of big contribution towards the reservoir performance capability and essentially the reservoir permeability. They can be of a relative discord with obtained permeability results. Application of the Kozney-Carman equation relating measurable rock properties versus permeability was also conduct in this case study. It is aimed to support assessment rock quality and permeability sustainability. It has revealed the value of the reservoir based on a correlation between measured and theoretical permeability determinations. Of importance for the reservoir anisotropy investigation on permeability are the subsequent events mainly diagenetic which have affected these petrophysical properties. They can be illustrated through the degree of compaction affecting the considered material and leading to dissimilarity in obtained permeability values. For that purpose, microscopic investigation has indicated variable significant effect. These effects provide a direct impact on fluid path circulation in addition to the change in reservoir pore geometry. These latter parameters create a direct consequence on tortuosity and cementation constraints in addition to the formation resistivity factor. Obtained results were in a reverse relation with the permeability values. Thus, these acquired results are not only characterizing permeability evolution according to the selected sandstone samples but also the complexity of the fluid paths geometry. Defined and combined to each other, these properties allow the scale up of reservoir heterogeneity and its evaluation.

Key words: permeability variation, reservoir heterogeneity, physical properties, fluid flow

1. Introduction

Oilfield reservoirs are mainly controlled by porosity and permeability evolution. This evolution is based on the assessment of rock properties. Determination of these properties, based on factors such as textural, dynamic conductivity-resistivity of fluid and formation contents as well as formation factor. These factors constitute an important test for the evaluation of reservoir quality and its degree of heterogeneity. In view of that, microscopic and megascopic investigations are advanced in this case study for the control of fluid circulation and saturation. Results and their variation, regarding petrophysical characteristics and mostly permeability, are of primary interest for reservoir heterogeneity. Heterogeneity reservoir inquiry with permeability related to fluid flow circulation has been well approached by various previous studies. Previous studies have stressed on the importance of reservoir heterogeneity in combination with the strength of the drive mechanism and deposits type, in controlling recovery efficiency. Van de Graff, et al.[20], in their investigation, found that the East Texas Field which is a relatively homogeneous reservoir from deltaic deposits with a strong water drive, the recovery has reached 85% of movable OOIP. However, opposite is the fluvial dominated reservoir where the recovery has reached almost 57%. Thus, the poorer recoveries clearly reflect higher degrees of reservoir heterogeneity and reservoir properties variation. Arya A.U., et. al[4], found that reservoir heterogeneity determination and its impact are related to fluid flow circulation where the permeability factor has played an important role in each defined flow channel. Mohaghegh S., et.al.[13] found that reservoir heterogeneity can be referred to a non uniform non-linear special distribution of rock properties. This can be referred to a defined hydraulic unit. Hewett T.A.[9], found that the theory of the fluid flow in heterogeneous porous media is related to transport properties which might be determined in simulating the structure of the spatial correlations regarding the permeability distribution.

Different types and scales of heterogeneity and permeability influence hydrocarbon recovery in different ways. At the megascopic scale, large faults and boundaries of genetic sediment bodies largely determine a real sweep in producing fields. Macroscopic heterogeneities such as

Table 1. Indicating the main calculated physical parameters and petrophysical results

Samples	k (measured) mD	ϕ %	R_{apex} μm	r_{mh} μm	S_{gv} μm^{-1}	ϕ_Z	F_R	ϕ_R	k(cal) mD	log R_{35}	R_{35} μm
QK1	112	13	2.6	1.3	0.115	0.149	8.85	0.0029	112	0.9736	9.4
QK2	803	17	6.1	3.05	0.067	0.205	3.30	0.00713	803	1.3768	24
QK3	16.4	16	0.9	0.45	0.423	0.19	23.00	0.0058	16.4	0.4063	2.5
QK4	225	15	3.4	1.72	0.103	0.176	6.25	0.00467	225	1.0986	13
QK5	1725	23	7.7	3.85	0.078	0.299	2.25	0.02052	1725	1.4587	29
QK6	1760	30	8.3	4.17	0.06	0.25	2.23	0.0551	1760	1.5163	33
QK7	461	23	4	1.99	0.15	0.299	4.35	0.02052	461	1.1219	13
QK8	116	18	2.3	1.13	0.195	0.22	8.7	0.00867	116	0.8607	7.3
QK9	272	13	4.1	2.03	0.074	0.149	5.66	0.0029	272	1.2015	16
QK10	576	16	5.3	2.67	0.071	0.19	3.89	0.0058	576	1.315	21
QK11	272	14	3.9	1.96	0.083	0.163	5.67	0.00371	272	1.1733	15
QK12	271	13	4.1	2.03	0.074	0.149	5.68	0.0029	271	1.2001	16

permeability zonation and faulting system (fractures) affect both vertical and horizontal sweep.[7] At the mesoscale and microscale, facies and thin sections analysis the predicted reservoir characteristics development can be predicted.

Al-Khidir[2] studied bimodal pore size distribution for the Shajara reservoir Formation to characterize the reservoir heterogeneity. Al-Khidir K.E., et al.[2] used the concept of the fractal dimension to support the heterogeneity model of the considered reservoir.

In the considered case study, the obtained petrophysical characteristics and fluid properties variation can be approached through the formation resistivity factor. This factor can be of great contribution towards the approval of the primarily permeability development and prediction of the reservoir heterogeneity. In addition, permeability estimation and its performance are very sensitive to the physical parameters from which the formation resistivity factor depends: tortuosity (τ), cementation factor (m), porosity as well as the surface grain volume (S_{gv}).[3] Thus, the use of the overall can be a matching support for evaluating the permeability evolution and the reservoir heterogeneity impact. The acquired results of the calculated permeability method based on the flow zone indicator and reduced porosity allow another issue for correlating and sustaining the measured laboratory permeability and deducing the reservoir heterogeneity.

Consequently the investigation we are leading is carried out through the following approaches.

Permeability evolution and correlation based on selected sandstone samples collected from various Middle East Areas. Among the aims intended to be achieved are:

- Core description,
- Experimental work based on measurement of petrophysical characteristics
- Formation resistivity factor determination
- Kozeny - Carmen equation for the theoretical prediction of permeability
- Physical properties determination and stimulation
- Permeability and heterogeneity evolution versus the overall individually physical parameters.
- Results and interpretation
- Conclusion

2. Reservoir Characteristics Measurements:

2.1 Core Samples Description

The material which has been used consists on sandstone samples collected from different parts in the Middle East Area. It has been found with different degrees of consolidation, cementation and grain size distribution. The detailed microscopic description has given the following notifications:

Mineralogical composition includes mainly quartz dominance rock type. Grains are varying from medium to coarse in their size. Contact between grains indicated variation in compaction depending on their consolidation, with better arrangement for samples presenting good to moderate sorting and roundness (Fig 1, 2, 3 and 4).

2.2. Porosity Measurement

Samples porosity (ϕ) was measured in PNGE (Petroleum and Natural Gas Eng Laboratory) using a wide mouthed flask pressovac pump forceps, filter paper and volumeter and balance. Results on the porosity are in Table 1.

2.3 Permeability

Permeability (k) measurement was achieved at King Abdul-Aziz City for Sciences and Technology (KACST, Riyadh- KSA).

The Ultra-Perm™ 400 was utilized. It consists on advanced precision mass flow meters and pressure transducers to bring steady-state gas flow measurements to a new level of sophistication. By combining automated

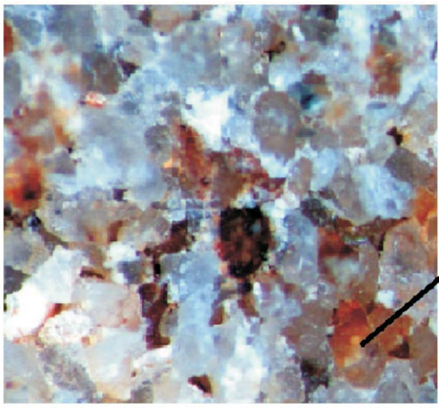

Fig 1. Consolidated sample view in the microscope showing grain size distribution dominated by the high frequency of fine to medium quartz grains where the compaction is relatively moderate. Partial oxidation is present affecting the angular to sub angular grains. Magnification: 62, Focus: 7.87 mm, Field: 3.7 mm, Porosity = 12.5%, Permeability = 224.75 mD.

Sl. 1. Konsolidirani uzorak, prikaz mikroskopom pokazuje raspodjelu veličine zrna gdje dominira visoka učestalost finih do srednjih zrna kvarca, relativno umjereno zbijenih. Prisutna je djelomična oksidacija koja djeluje na uglasta i poluuglasta zrna. Povećanje: 62, fokus: 7,87 mm, djelokrug: 3,7 mm, poroznost = 12,5%, propusnost = 224,75 mD.

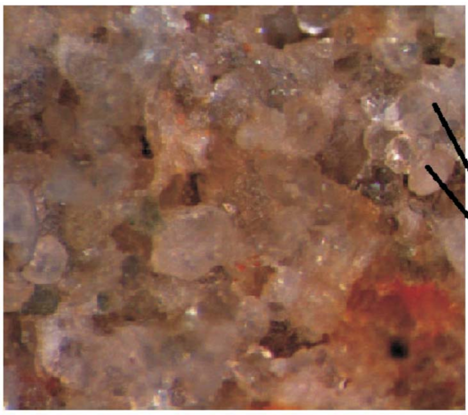

Fig. 2. Core sample with a microscopic view showing homogeneous grain size distribution where the compaction is almost moderate. Magnification: 50, Focus: 7.19 mm, Field: 4.6 mm, Porosity = 15%, Permeability = 280.00 mD.

Sl. 2. Uzorak jezgre, prikaz mikroskopom pokazuje homogenu raspodjelu veličine zrna s gotovo umjerenom zbijenošću. Povećanje: 50, fokus: 7,19 mm, djelokrug: 4,6 mm, poroznost = 15%, propusnost = 280,00 mD.

data acquisition and real time graphical display with mass flow determinations, the accuracy, validity and precision of the data is enhanced. The obtained results on permeability measurement are in Table 1.

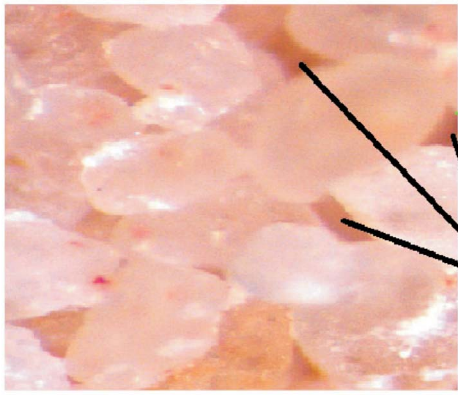

Fig 3. Almost unconsolidated to semi-consolidated sandstone sample illustrating the lack of cement with perfect homogeneous grain size with a uniform distribution and the high roundness level, Magnification: 64, Focus: 8.95 mm, Field: 3.6 mm, Porosity = 30%, Permeability = 1 761.27 mD.

Sl. 1. Konsolidirani uzorak, prikaz mikroskopom pokazuje raspodjelu veličine zrna gdje dominira visoka učestalost finih do srednjih zrna kvarca, relativno umjereno zbijenih. Prisutna je djelomična oksidacija koja djeluje na uglasta i poluuglasta zrna. Povećanje: 62, fokus: 7,87 mm, djelokrug: 3,7 mm, poroznost = 12,5%, propusnost = 224,75 mD.

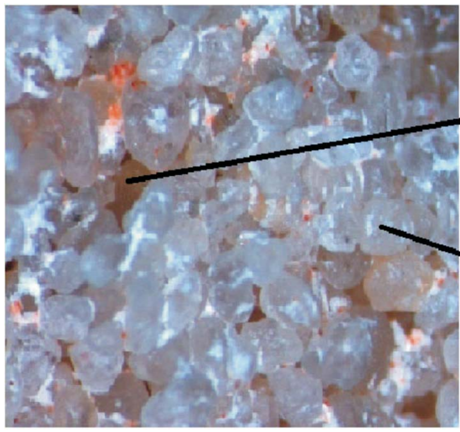

Fig 4. Core No. 6: The high roundness and the homogeneous grain size distribution are the real contributing factors in the increase of permeability and porosity for this case. Intergranular porosity with a certain degree of interconnection is well visible. Magnification: 31, Focus: 7.33 mm, Field: 7.5 mm, Porosity = 24%, Permeability = 1 725 mD.

Sl. 4. Jezgra br.6. Velika zaobljenost i homogena raspodjela veličine su čimbenici koji pridonose povećanju propusnosti i poroznosti za ovaj slučaj. Dobro je vidljiva međuzrnska poroznost s određenim stupnjem međusobne povezanosti. Povećanje: 31, fokus: 7,33 mm, djelokrug: 7,5 mm, poroznost = 24%, propusnost = 1 725 mD.

3. Physical Properties Determination

According to the objectives in this investigation, the conducted experimental work, we conducted, it was mainly based on the type of formation with a fully water saturation process. Starting from that, inquiry on the physical parameters effect respectively becomes necessary. This aims were intended to the characterization of the type of the considered reservoir regarding a given saturating brine water with regard to the reservoir characteristics and heterogeneity.

3.1 Formation Resistivity Factor

As we know the relation is as follow the greater is the porosity of the formation, the lower is the resistivity (R) and the lower is the Formation Resistivity Factor (F).[3] However consideration of this relation is also related to structure and pore size distribution as well as other properties.[18,12]

As stated previously, an important relationship exists between the resistivity of a fully water saturated formation (R_o) and the resistivity of the contained water (R_w), the ratio of these two values is called formation resistivity factor which is establish as:

$$F = \tau / \phi^m \tag{1}$$

where:

- F formation resistivity factor
- τ tortuosity factor, depending on the type of the lithology
- m cementation exponent from 1 to 3
- ϕ porosity of the considered sample measured in the PNGE laboratory

When the rock is saturated at 100% with water the formation resistivity factor becomes:

$$F = R_o R_w \tag{2}$$

where:

- R_w the resistivity of the fluid usaed in the laboratory (ohms-meter)
- R_o resistivity of the rock saturated at 100% with water (ohms-meter)

As stated above, the formation resistivity factor is depending on the cementation factor, the saturation exponent (n) and the tortuosity factor. Theses parameters constitute the most important sources of uncertainty regarding permeability determination and evolution.[21] They are subjected to clean and non clean formations, including their degree of consolidation.

In the case study and according to the type of lithology, determination of formation resistivity factor (F) was calculated according to Archie's equation[3] (Table 1).

3.2 R_{apex}, R_{35} Determination

3.2.1 R_{apex}

Determination of the R_{apex} (pore radius corresponding to the apex) is intended to characterize the distribution of pore spaces within the considered core samples. It is aimed mainly to consider the core sample pore space evolution and heterogeneity affecting the fluid flow circulation for the case study. It is calculated according to Pitman[15,16] equation which is as follow:

$$\log R_{apex} = -0.226 + 0.466 \log k \tag{3}$$

3.2.2 R_{35}

Pore throat radius corresponding to 35% mercury saturation was calculated from measured permeability and porosity using Winland equation which is stated as:

$$\log R_{35} = 0.732 + 0.558 \cdot \log k - 0.864 \cdot \log \phi \tag{4}$$

This parameter is related to the effective pore structure. Accordingly, it is related to the permeability evolution since the R_{35} is intended to assess the ability of the fluid circulation within the available interconnected pores. It is supporting the R_{apex} values and thus, the permeability or fluid flow ability circulation. The R_{35} can be correlated to the obtained permeability values. Thus, it is related to the effective pores as well as the pore radius. This latter can also be obtained from the experimental work based on mercury injection and deduced capillary pressure.[11] The R_{35} can be intended not only to grade the reservoir quality but also to predict hydrocarbon accumulation at upgrade scale.

3.3 Tortuosity

Tortuosity (τ) was determined from Donaldson, E.C.[8] as follows:

$$\tau^2 = \phi_R / \left(2 \cdot k \cdot S_{gv}^{\ 2}\right) \tag{5}$$

where:

- τ tortuosity factor
- ϕR the reduced porosity defined from Amaefule1 and
- S_{gv} (surface grain volume) as defined below.

The tortuosity factor can be also determined from the formation resistivity factor and porosity as follow:

$$\tau = F \cdot \phi \tag{6}$$

with

$$F = \tau / \phi^m$$

This parameter can be used to evaluate the shrinking of pores leading directly to the variation of pore shape. It results on the reduction of interconnections rendering the fluid flow more complex to circulate.

Hence, permeability (k) and tortuosity (τ) are related to each other.

3.4 Surface grain volume (S_{gv})

This parameter is concerned with the surface area per unit grain volume (μm^{-1}), which is equal to:

$$\phi_z / R_{mh} \tag{7}$$

where:

- ϕ_z the porosity group defined as the ratio of effective porosity to $(1-\phi_e)$[1]
- R_{mh} hydraulic radius defined from the pore radius according the capillary pressure P_c.

This parameter is also intended to support the R_{apex} and R_{35} in order to evaluate the flow circulation. It is related to the main hydraulic radius of the considered sample. Support of this statement is known as: the higher is surface area per unit grain volume; the lower is the permeability and consequently the R_{apex} and R_{35} (Table 1).[2]

3.5 Theoretical Permeability Calculation:

This parameter was aimed to process a correlation with the measured permeability. Results on this parameter are ascribed to Kozeny Carmen relation. This relation deals with measured porosity, surface area grain volume and the constant *C*. The constant *C* is a product of tortuosity and shape factor. The theoretical permeability is given as follows:

$$k = FZI^2 \cdot \phi_{IR} \tag{8}$$

where *FZI* is the flow zone indicator related to shape factor, tortuosity and surface area per unit grain volume.

Determination of this factor allows better relationship with the obtained permeability from laboratory experimental work. It can also reveal the liability and control on the acquired permeability outcome. Results on this process are shown in Table (1).

The assessment of these two parameters coupled with other reservoir support the characterization of the reservoir heterogeneity in addition to its quality.

4. Interpretation

The petrophysical characteristics measurements were variable according to the type of selected samples as viewed in the Figures 1, 2, 3, and 4. Theses samples are subjected to variable degrees of compaction affecting their pore space structure as well as their interconnection pore throats. Such effect results on permeability differentiation and porosity changes. Relation between pore space and permeability depends on the efficiency of the pore throat geometry. This condition is set as an important issue to evaluate reservoir quality. The existence of different variation on permeability can match various flow unit zones corresponding to different geometrical pore spaces and pore throats available, leading to diverse flow units presence. Moreover, variation of pore geometry and its attributes are a key factor in defining various zones leading to the determination of reservoir heterogeneity. Amaefule, J.O. et al.[1] in their investigation, have stated that physical parameters variation such as the pore geometry and the hydraulic units are responsible for the presence of several flow parts corresponding to the different degrees of reservoir heterogeneity.

Fig 5. Porosity measurement equipment at the PNGE Laboratory

Sl. 5. Oprema za mjerenje poroznosti u PNGE laboratoriju

In this conducted investigation, the use of the formation resistivity factor has revealed variation in its values. Similar results are related to the samples characteristics (Table 1). According to the obtained results (Figure 7), permeability versus formation resistivity factor is a negative correlation since: the increase of one parameter corresponds to the decrease of the other (Figure 7). This statement is due to the constraints affecting the formation resistivity factor. Among these restrictions is the tortuosity character for each sample: samples are different in their physical characteristics from each other, including their degree of compaction leading to a distinction in pore throat interconnection. Thus, the tortuosity factor variation can be an essential regulator for the fluid circulation pathway. Accordingly, it has a large contribution on the permeability values evolution. In its comparison versus permeability, the tortuosity parameter is also indicator of a negative correlation with the permeability as stated previously: an increase of the permeability corresponds to a decrease of the tortuosity and vice versa (Figure 8). This statement displays the importance of the path in use during the fluid flow circulation and its impact on the ability of this fluid to be drained.[10] The observed increase in tortuosity can generate the decrease in the effective porosity rendering the reservoir more complex regarding fluid flow circulation. Cementation exponent and effective porosity are also of a big contribution towards the variation of the values of permeability as well as the heterogeneous evolution from one sample to another. The results are concerned with

Fig 6. Ultra Perm 400™ used for measurements of permeability (*k*) at KACST Research Center

Sl. 6. Ultra Perm 400™ korišten za mjerenja propusnosti (*k*) u istraživačkom centru KACST

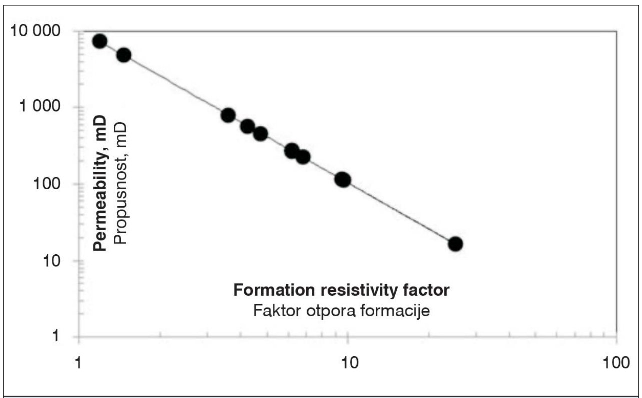

Fig 7. Relation between the formation resistivity factor and the permeability is inversely proportional
Sl. 7. Odnos između faktora otpora formacije i propusnosti je obrnuto proporcionalan

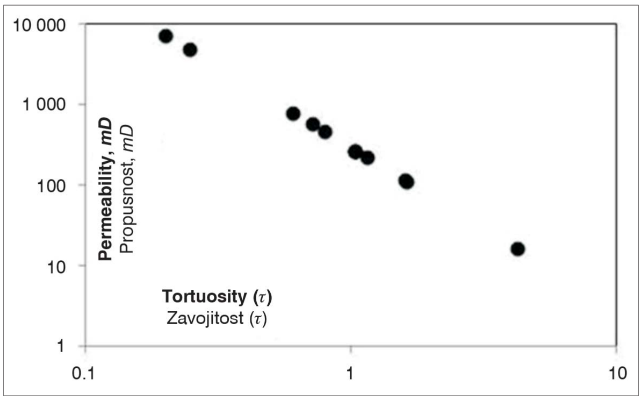

Fig 8. Tortuosity, which is related to the complexity of the fluid flow circulation, is inversely proportional the permeability values for the considered samples
Sl. 8. Zavojitost koja je u vezi s cirkulacijom fluida, obrnuto je proporcionalna vrijednostima propusnosti za ispitivane uzorke

the revelation that high value of tortuosity are evidence of reduction of pore space or pore throat leading to decrease and complexity of fluid flow circulation and therefore permeability values (Figure 8).

Obtained results on pore radius corresponding to Rapex derived from the measured permeability using Pittman[16] equation were shown in table 1. Plot of these parameters versus each other has led to the following notification: R_{apex} increases with increasing fluid flow circulation (Figure 9). R_{apex} values are indicator of the movement of the fluids as well as their migration and accumulation within the considered reservoir. Plot of permeability versus R_{apex} (Figure 9) indicates that pore radius increases with increasing permeability. Such relation reflects again the ability of fluid flow circulation related to the reservoir quality and its anisotropy. It can be deduced that this ability circulation can be referred to the aspects of the pore and pore throat geometry. In addition and from the obtained results, R_{apex} is scaled from 2.18 up to 37.58 micrometers variation (Table 1). It can support the wide range of the reservoir heterogeneity.

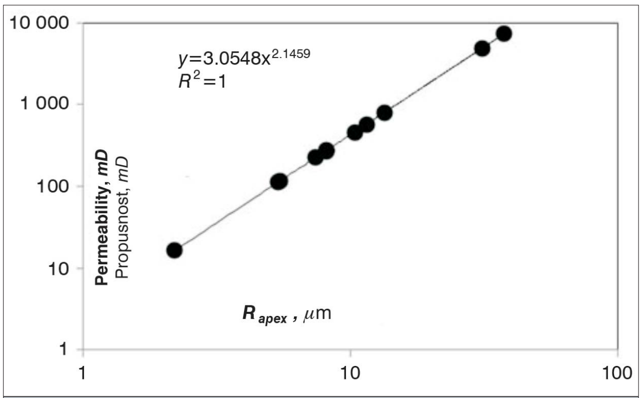

Fig 9. Relation between Rapex and permeability (k) where the increase of one of the parameters corresponds to an increase of the other. This is demonstrating that interconnection is well matching the increase of permeability
Sl. 9. Odnos između Rapex i propusnosti (k) u slučaju kada povećanje jednog parametra odgovara povećanju drugog. To pokazuje da je međusobna povezanost dobra i slaže se s povećanjem propusnosti

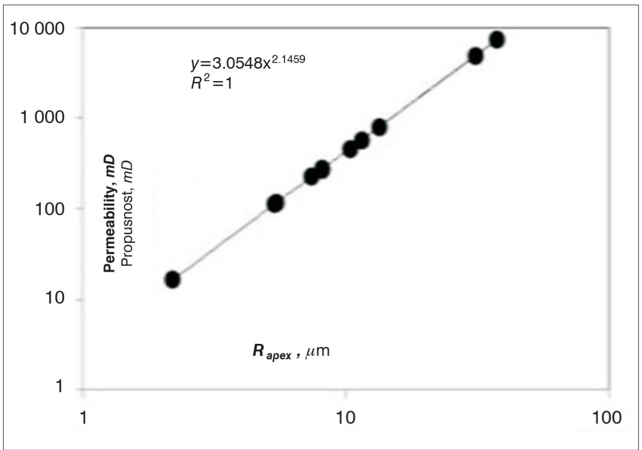

Fig 10. R_{35} is matching positively the variation of permeability (*k*) for the considered values
Sl. 10. R_{35} se za razmatrane vrijednosti očigledno podudara s varijacijama propusnosti (*k*)

This heterogeneity is also maintained by the calculation of R35 which indicates results oscillating between 2.54 μm and 75.93 μm (Figure 10).Thus, outcomes from the R_{apex} and R_{35}, in this investigation and according to the scale for reservoir classification, the related considered reservoir can be classified within the following scale of classification (2001)[12]: one segment as megaporous (R_{35} > 10 μm), another segment as macroporous (2-10 μm) and a third segment as mesoporous for R_{35}: (0.5- 2 μm) (Figure 10) and (table 1). This classification is proving the heterogeneity existing between the different core measurements.

Consideration and correlation between the permeability and pore radius R_{35} as shown in (Fig. 10) demonstrates the variation of permeability which is set to be in

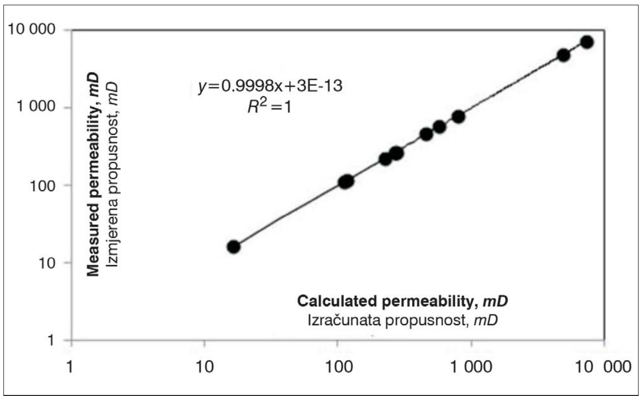

Fig 11. Support of the measured permeability is well approved by the theoretical calculated permeability (*k*)
Sl. 11. Potvrda mjerene propusnosti je dobro potvrđena teorijski izračunatom propusnosti (*k*)

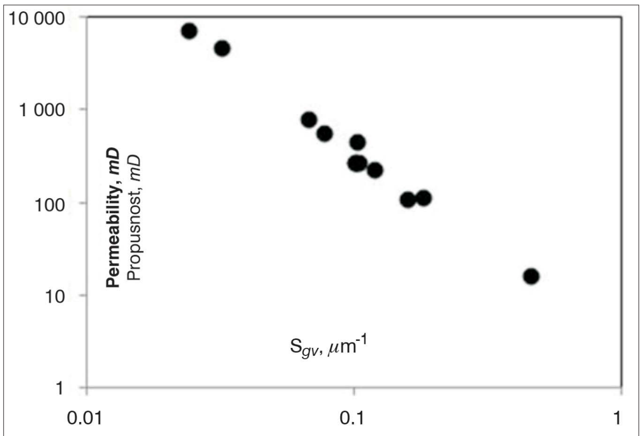

Fig 12. The S_{gv} evolution is inversely matching the increase of permeability (k)
Sl. 12. Napredovanje S_{gv} je obrnuto povećanju propusnosti (*k*)

harmony with R_{35}: an increase of R_{35} corresponds to an increase of k. Similar trend confirms the R_{apex} statement.

The measured permeability variation is also compared to the theoretical one. It is indicating that measured permeability is almost in agreement with the predicted one. This sustainability can make a constructive correlation between experimental approach and theoretical method we have been leading (Figure 11). These two approaches were proving the realistic results in terms of evaluation. They can be used in terms of prediction capability issues for any considered reservoir. Correlation between the different selected sandstone samples has revealed that the calculated surface grain volume per unit is also inversely proportional to the measured permeability (Figure 12). It indicates a negative correlation between each other: an increase of permeability corresponds to a decrease in surface grain volume and vice versa. We can state that, and for the case study: the finer grains correspond to the larger cumulative surface area per unit grain volume and, lower are the interconnection between pore spaces leading to the reduction of permeability. It can be comparably closer to the use of permeability versus textural parameter, where the impact of each textural factor has got its own impact on petropphysical characteristics evaluation. In their research study[6,19], found that petrophysical parameters can be predicted when textural parameters are set for any considered reservoir sample.

Therefore, combination of all these physical factors leads to a better understanding of the physical properties able to control permeability and heterogeneity. In addition, the overall can be used for prediction performance of the reservoir. Such status is a closer issue capable to set and forecast heterogeneous oil bearing formation.

5. Conclusion

Reservoir characteristics control and particularly permeability variation is well proved through the reservoir properties determination. The discrepancy in correlating permeability and the set of determined physical properties has provided evidence on the degree of dissimilarity regarding the qualitative and quantitative assessment. Pore space and their interconnectivity related to the formation factor cannot be in harmony with the fluid circulation ability. Results, on that focus, are well approving the considered statement. Impact of the tortuosity and cementation causes denote one of the essential parameters in the control of this setting and particularly for the permeability factor. Disharmony and incompatibility of the permeability can be amplified with the consideration of surface grain volume which is well illustrated in this investigation. Lastly, it is valuable to mention that the overall unsuitable relation between the different determined physical properties and the permeability has provided more complexity on the case study statements. These conditions, in all probability, contribute boosting the degree of reservoir heterogeneity.

Nomenclature:

k	permeability, mD
ϕ	porosity, %
R_{apex}	pore radius corresponding to apex, μm
R_{mh}	mean hydraulic radius, μm
S_{gv}	surface area per unit grain volume, μm^{-1}
ϕ_Z	normalized porosity index, dimensionless
F_R	formation resistivity factor,
ϕ_R	reduced porosity dimensionless
k_{cal}	calculated permeability, mD
$log\ R_{35}$	log pore radius corresponding to 35% mercury saturation, μm
R_{35}	pore radius corresponding to 35% mercury saturation, μm

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