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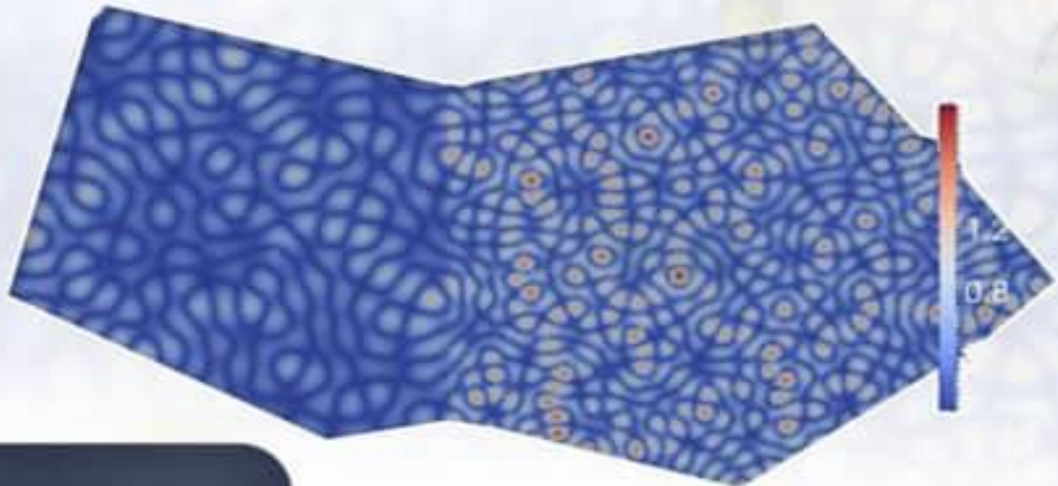

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Petrophysical Charaterizations of Some Reservoir Formations in Ghani Oilfield, Libya

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A B S T R A C T

This study has been conducted on three types of reservoir rocks for core analysis of samples denoted by R-1, R-2 and R-3 of Ghani oil field from three reservoir include Farrud, Facha and Mabruk formations respectively. This analysis includes determination of physical characteristics e. g. porosity (∅), permeability (k), formation factor (FF) and resistivity index (RI). The purpose of this study is to how core petrophysical data might be most investigating effectively applied to the petrophysical prediction of petrophysical properties from core samples analysis. For Farrud reservoir of R-1 shows that the relation between degree of saturation (S_w) and relative oil permeability(K_{ro}) equal the relative permeability of water(K_{rw}) at which the intersection point between the two curves ; whereas, the flow with the same rate. FF and RI are vary with ∅ and the RI is a function of S_w. The gas-oil relative permeability have been expressed graphically. Whereas, the intersection point between the two curves (K_{ro}) equal the (K_{rg}), at which both oil and gas are flow with the same rate. A similar results were obtained from Facha reservoir, R-2. The petrophysical properties of core samples for R-3 of Mabruk Formation have been performed including∅, k, and S_w. The comparison between the three reservoirs by correlation between the average values such as ∅, k, grain density and RI; shows that the average of Mabruk reservoir k greater than the other two reservoirs, while the other properties seem to be close together.

1 Introduction

The analysis of petrophysical data seeks to describe the formation under study by quantifying certain of its properties such as porosity, permeability, fluid saturation and mineralogy. The natural ordering of geological systems arising from the controlling influences of sedimentary environment, other rock-forming processes and rock mechanics imparts an ordering to the petrophysical properties of interest. Recognition of the inherent ordering, usually manifest as structure in the petrophysical data available for analysis, assists both in the identification of the petrophysical interpretation model to be applied, and in the characterization of the variation present in the formation to facilitate the quantification of geologically distinctive genetic units in terms of their petrophysical properties.

A definition of petrophysical rock types might be 'classes of rock characterized by differences in physical properties. The properties of interest could be the basic formation properties that we seek to measure in petrophysical analyses, viz. density, resistivity, hydrogen, index, acoustic travel time or they might be the formation parameters of porosity, permeability, capillarity, saturation etc. that we infer from out

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measurements of the basic properties. The fundamental controlling phenomena for nearly all of these properties are the quantity, shape, size and connectivity of the pore system (i.e. the pore geometry of the rock). Together with the mineralogy and texture of the rock fabric, both of which, jointly and severally, control the pore geometry, these are the fundamental subjects of importance in petrophysical investigations (Steve Cannon., 2016).

Figure 1 illustrated the integrated petrophysical evaluation data. On the other hand, logs do not measure porosity, permeability or water saturation; they make measurements of various parameters and relationships between the rock and the fluids to allow computer programs to process and interpret the results. The petrophysicist role is to validate and organize the input data and to understand and calibrate the results.

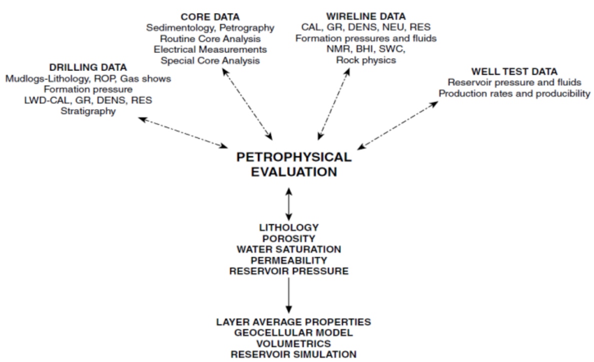

Figure (1). The integrated petrophysical evaluation data (Steve Cannon., 2016)

2 Cores and Logs

The two primary sources of reservoir information acquired during drilling of a well are cores and logs. Coring can be an expensive and time-consuming process that is usually reserved for potential reservoir sections. When the top reservoir is reached, signaled by a rapid increase in drilling rate and the presence of hydrocarbon shows, drilling is halted and the drill string recovered and the bit replaced with a core barrel. Core barrels are usually made up of 30 ft lengths of pipe with a special coring head and retrieval mechanism, the catcher.

There are in fact an inner and an outer barrel that can rotate independently; the inner barrel is the repository for the core as it is being cut. Upon retrieval at the surface, the core is stabilized and sent to shore for analysis; on occasion, some samples are evaluated at the well site, but this is becoming less and less common (Steve Cannon., 2016).

3 Study Objectives

This study is mainly aimed to take some initial steps towards this goal by how core petrophysical data might be most investigating effectively applied to the petrophysical prediction of petrophysical properties from core samples analysis. Also, to integrate petrophysical data of core samples to qualify and quantify reservoirs in order to assess the production potential of Farrud, Facha and Mabruk reservoirs in Ghani oilfield. The objectives include:

1. Interpretation of porosity, permeability and saturation data.
2. Comparison of the petrophysical core data of investigated formations with each other's.
3. Integration of all the available data to evaluate the wells performance.

4 Materials and Methods

4.1. Sample Preparation

Full diameter cores from different sections of Farrud, Facha and Mabruk reservoirs in the Ghani field (Figure 2), were supplied for use in this special core analysis study. From each formation, a full diameter core piece was taken for conventional core analysis determinations, and three one and half inch diameter plug samples were drilled for core analysis tests using tap water as the bit lubricant. These samples are briefly described with respect to depth and lithology. The rock types of these formations can be characterized as carbonate rocks represented by limestone and dolomitic.

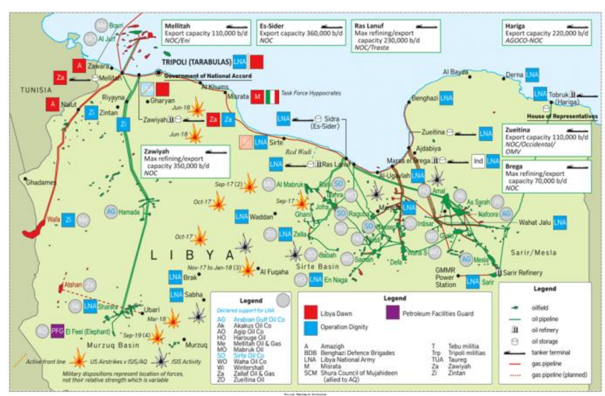

Figure (2). Location map of Ghani and other oilfields (Arabian Gulf Petroleum Company., 2018)

The size and form of samples used in laboratory vary from drilling cuttings, loose sands and coarse pieces of consolidated rocks up to samples of regular geometrical shape. The most commonly core samples used form is the cylinder. The cylindrical samples or as known as core plugs are cut from the full diameter cores, about 10 cm in diameter sampled (Figure 3).

Figure (3). Full diameter core (left) and core plugs (right) cut for laboratory measurements

The plug and full diameter samples were trimmed to right cylinder cleaned in hot refluxing xylene and methanol to remove residual hydrocarbons and salts and dried in an oven at 60˚C.

4.2. Water-Oil Relative Permeability

Following gas-oil relative permeability tests four samples were scheduled to undergo water-oil relative permeability testing. Water-oil relative permeability were performed using simulated formation brine as a displacing phase. Incremental volumes of water and oil produced were recorded as a function of time.

4.3. Factor of Formation Resistivity and Resistivity Index

Eight core plug samples, labeled 1A through 8A were scheduled to undergo electrical resistivity tests. The clean dry samples were evacuated and pressure saturated with simulated formation brine.

4.4. Gas-Oil Relative Permeability

Eight core plug samples were scheduled for gas-oil relative permeability tests. The clean dry samples were evacuated and pressure saturated with simulated formation brine.

5 Literature Review

Several authors have been studied the petrophysical using cores, logs, well test, publications, and production data.

5.1. Overview

(Paul & Gaffney., 2003) the role of core samples for the investigation of reservoir petrophysical characterizations and correlation between the static and dynamic reservoir models.

The integrated analysis petrophysical well core data is required for the study essentially focused on reservoir properties e. g. lithology, depositional environments, shale volume porosity (Φ), permeability (K), fluid saturation, net pay thickness, among others from well logs and cores, which are variables that determine reservoir quality. The relationships between these parameters showed linear trends (Ulasi et al., 2012).

An engineer or geologist or geophysicist can interpret the log readings to reach certain conclusions about the formation. Fresh water, oil and gas are poor conductors of electricity, so they are high resistivity. By contrast, the formation waters are salty enough that they conduct electricity with ease. The formation waters generally have low resistivity because of high salinity. Hydrocarbon saturation and formation porosity are the two key parameters determined from core that are used in the evaluation of a subsurface reservoir as a potential hydrocarbon producer (Ahammod et al., 2014).

Presented study which performed on the core samples to determine and evaluate the petrophysical properties of oil field. The evaluated properties include porosity, permeability, fluid saturation, net/gross thickness and mobility which are all inferred from geophysical wire-line logs. He concluded that these reservoir parameters are significant to evaluate reservoir performance and satisfactory for hydrocarbon production (Amigun & Odole., 2003).

was studied the Gir Formation at Ghani and Ed Dib Fields, Eastern Libya of Eocene (Ypresian) age comprises which a 500-1000m sequence of carbonates and evaporites deposited. He demonstrated that 70% of dolomites previously considered to be reservoir have little or no mobility and thus no reservoir potential, and permitted refined and more reliable calculations of oil in-place and producible reserves (Henry Williams., 2014).

Found that the analyses of well log data evaluate the hydrocarbon potential of reservoirs and quantitative interpretation determined parameters useful to compute the volume of identified oil and gas within the reservoir as well as estimate reservoir properties required for ease of developing and producing the field (Osinowo et al., 2018).

6 Results and Discussion

6.1. Core Analysis Techniques

The present study shows the experimental results of core analysis carried out on samples from three wells are R-1, R-2 and R-3 of Ghani oil field from three reservoir formations include Farrud, Facha and Mabruk formation respectively. This analysis includes:

1. Determination of physical characteristics e. g. porosity, permeability.

2. Formation factor and resistivity index measurements.

6.2. Core Analysis of Well No. R-1

6.2.1. Farrud Reservoir

6.2.1.1. Measurements of Water-Oil Relative Permeability

These measurements of water-oil relative permeability with connate water were carried out on four samples from Farrud Formation with numbers 3V, 5V, 9V and 13V.

6.2.1.2. Relative Permeability Investigations

All the tests previously mentioned were conducted in two-fluid systems, one of which was always gas. From these data we can concluded which are shown in Figure 4 through Figure 11 that relative permeability was substantially independent of fluid viscosity but was some function of pore-size distribution, pressure and fluid saturations.

The fluids used in obtaining these data were water and air in the core sample tests, where water is the wetting fluid. The curve labeled K_{rw} denotes the relative permeability to water, while that labeled K_{ro} denotes the relative permeability to oil.

The trends which are presented in these figures The K_{rw} curve is typical of the trend of relative permeability curves for the wetting phase in a porous system regardless of whether that phase is water. The relative permeability to the wetting phase shows a rapid decline in value for a small decreases in an original high saturation of that particular phase. The relative permeability for the wetting phase normally approaches zero or vanishes at saturations of the wetting phase greater than zero. Likewise, the K_{ro} curve is typical of the relative permeability to a non-wetting phase, whether that phase is gas, oil, or water.

From relation between degree of saturation and relative permeability, we can noted that the intersection point between the two curves, the relative permeability of oil (K_{ro}) equal the relative permeability of water(K_{rw}), at which both oil and water are flow with the same rate. This does not mean that the amount of flow of both two fluids are equal, because of their different viscosities, hence the water will flow in great amount comparing with oil. This point is varies from sample to another due to the different porosities and permeability.

On the other hand, water-oil relative permeability have been presented in Tables 1 through 4 (Appendix A); and expressed graphically for the different samples as shown in Figure 4 through Figure 7.

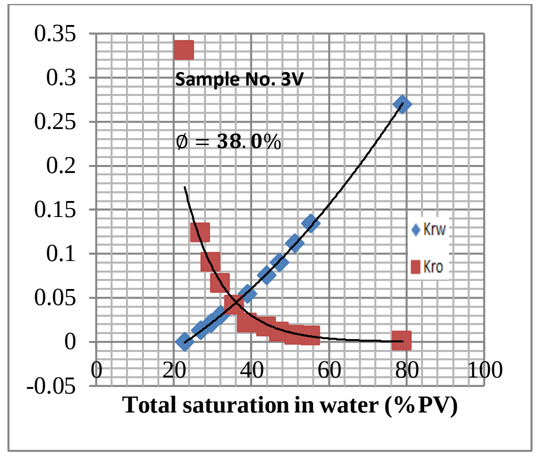

Figure (4). k_{ro}/k_{rw} versus total saturation in water (%PV)

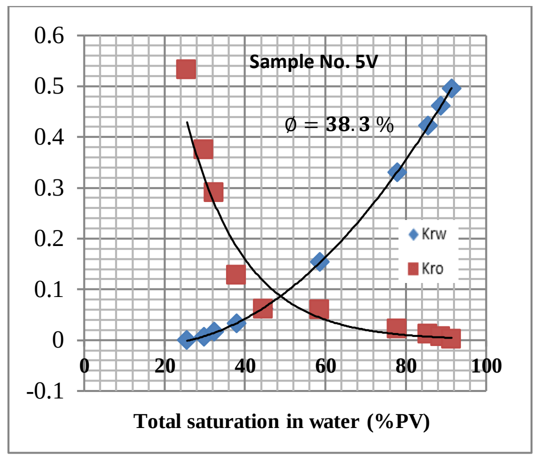

Figure (5). k_{ro}/k_{rw} versus total saturation in water (%PV)

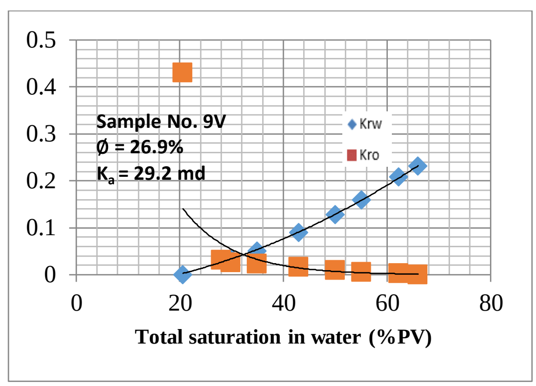

Figure (6). k_{ro}/k_{rw} versus total saturation in water (%PV)

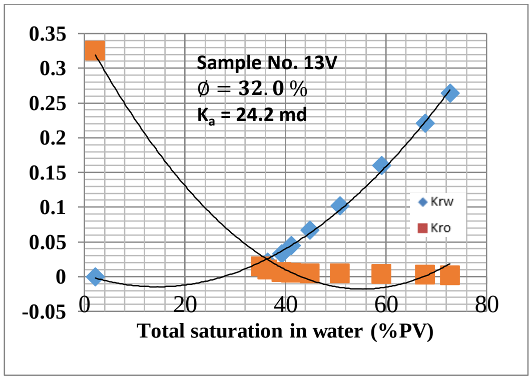

Figure (7). k_{ro}/k_{rw} versus total saturation in water (%PV)

Bilogarthmical crossplots of k_w/k_o , k_{ro}/k_{rw} ratios and total saturation in water (%PV), are illustrated in Figure 8 through Figure 11.

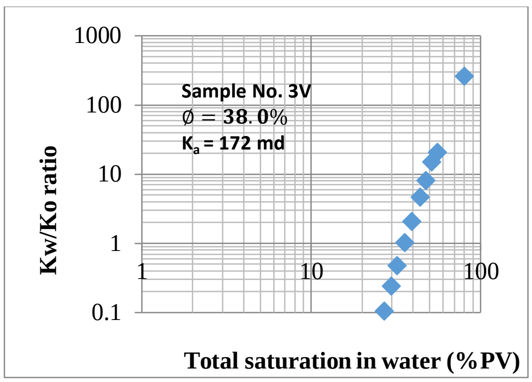

Figure (8). $\frac{k_w}{k_o}$ ratio versus total saturation in water (%PV)

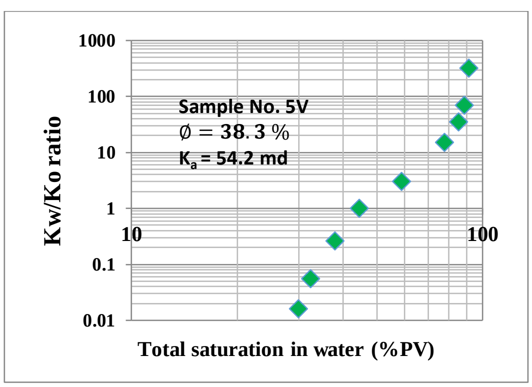

Figure (9). The $\frac{k_w}{k_o}$ ratio versus total saturation in water (%PV)

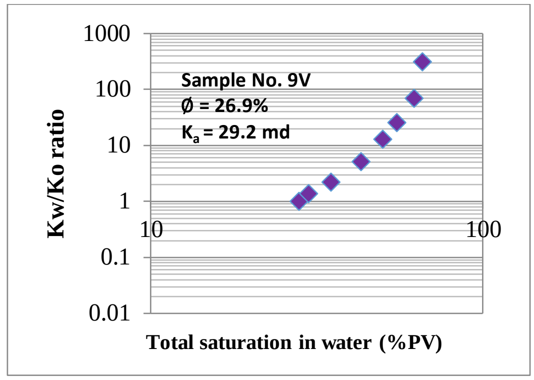

Figure (10). $\frac{k_w}{k_o}$ ratio versus total saturation in water (%PV)

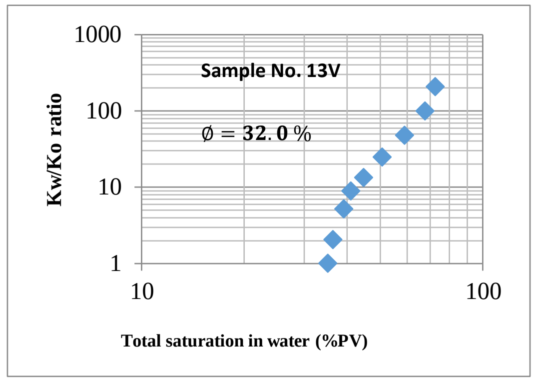

Figure (11). $\frac{k_w}{k_o}$ ratio versus total saturation in water (%PV)

6.2.1.3. Formation Resistivity Factor and Resistivity Index

There are some petrophysical characterization parameter such as formation resistivity factor, permeability, porosity, grain density, water saturation and resistivity index have been estimated for core samples are presented in Table 5 (Appendix A).

Resistivity and formation factor vary with porosity in somewhat the manner described by the previously. Rarely do natural formations have such uniform pore geometry. It is more common to express formation factor as:

$$FF = a\emptyset^{-m}$$
[1]

Where a and m are unique rock properties.

By plotting F factor against porosity on a log-log plot for a number of similar rock types, it is possible to obtain the slope of the line, m, or the cementation factor (Figure 12). The value of m varies for different rock types as a function of degree of cementation, ranging from < 1.6 for poorly cemented rocks to > 3.5 for very well cemented rocks; the default_value of m is usually 1.8-2.2 (Figure 13). The tortuosity factor, a reflects the complexity of the connected pores and is usually set to 1.0. The principle of estimation and experimental determination. Plotting the results of each measurement determines a slope m that relates FF to porosity, known as the exponent of cementation.

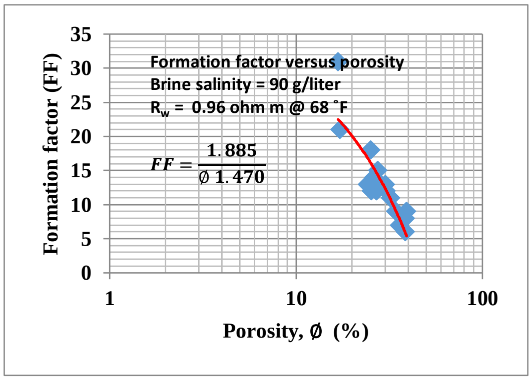

Figure (12). Correlation diagram between FF and porosity Ø

Oil and gas are not electrical conductors. Their presence in an element of reservoir or in a core sample will reduce the mean cross sectional area of the flow path for an electric current and increase the length of the flow path, thus increasing the resistivity.

Resistivity index is defined as the ratio of rock at any condition of gas, oil and water saturation to its resistivity when completely saturated with water:

$$RI = \frac{R_t}{R_o} = S_w^{-n}, \quad or \ \frac{1}{SW^n}$$

[2]

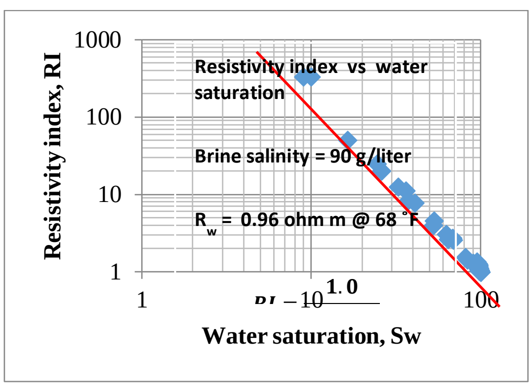

Figure (13). Correlation diagram between S_w and RI

Thus, the resistivity index is a function of water saturation. It is also a function of the pore geometry. The presence of cation exchangeable clays_(smectites, or mixed layer clays), cause apparently low resistivity index values to be observed.

6.3. Core Analysis of Well No. R-2

6.3.1. Facha Reservoir

The core samples analysis of well R-2 of Facha reservoir include water saturation and permeability.

6.3.1.1. Water Saturation and Porosity

Also, from the results of experimental work on a core samples of Facha Formation of water saturation, height above free water level and porosity, exhibit that the water saturation as a function of height above free water level and porosity are presented in Table 1 (Appendix B) and Figure 14.

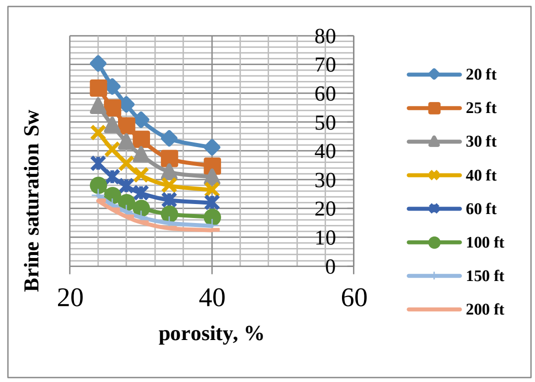

Figure (14). Water saturation as a function of height above free water level and porosity

6.3.1.2. Porosity–Permeability Correlations

Both porosity and permeability play an important role in reservoir description because the former describes reservoir storage capability, while the later describes the ability of the rock formation to transmit fluids. However, cross plots of these reservoir variables show that porosity seldom has a statistical correlation to permeability significant enough to develop predictive models.

Since permeability depends on the interconnection between pore space there is not theory, or in fact, a unique relationship between the porosity of a rock and its permeability. For unconsolidated rock, it's possible to establish relationships between porosity and either some measure of apparent pore diameter and permeability. However, these have very limited application.

In some cases, there is sometimes a reasonable relationship between the porosity of a rock and its permeability, although for a given porosity, permeability can vary widely. Figure 15 shows porosity–permeability correlation obtained from core analysis.

The correlation of Figure 15 consists of different reservoir samples from core analysis. It is obviously that increase of permeability with an increase in porosity, the correlation shows the wide spread, lack of close relation between porosity and permeability.

The core porosity values were plotted against to permeability values as shown in Figure 15, and both regression equation and correlation coefficient (r) were computed for set pints. The computed regression equation of y = 0.0567x + 24.421 was used to fit a regression line to the points for Facha reservoir. The correlation coefficient r of 0.7356 shows strong linear relationship between the two variables in this reservoir by linear fitting.

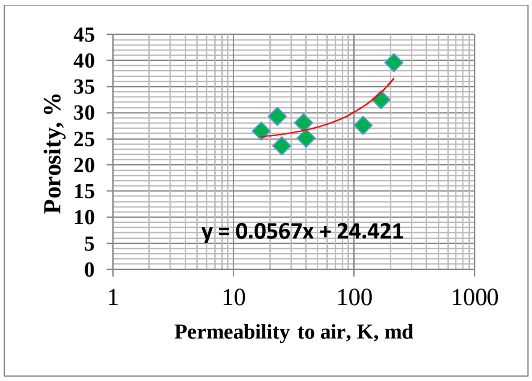

Figure (15). Relationship between porosity and permeability

On the other hand, Figure 16 shows the relationship between porosity and formation resistivity factor (FF) on a bilogarithmical plot. While Figure 17 gives the relation between brine saturation and resistivity index (RI), both of them illustrate a linear regression coefficient.

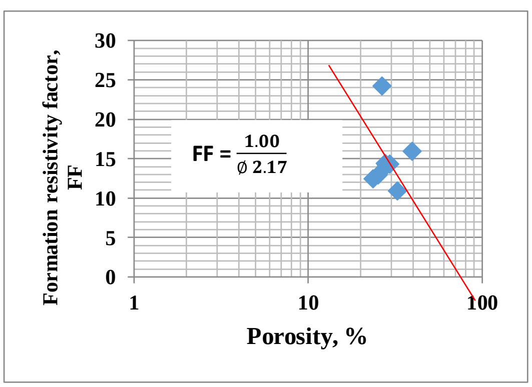

Figure (16). Relationship between porosity and formation resistivity factor (FF)

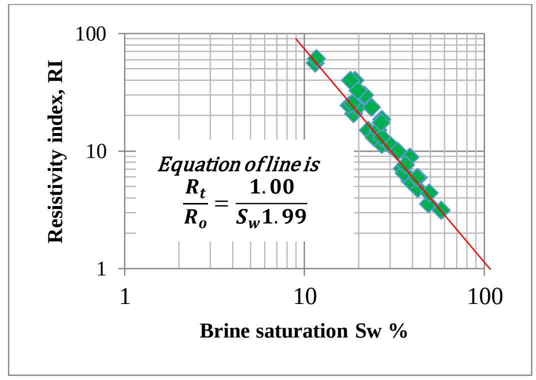

Figure (17). Relationship between brine saturation and resistivity index (RI)

6.3.1.3. Gas-Oil Relative Permeability

On the hand, the same eight core samples have been investigated for gas-oil relative permeability. The gas-oil relative permeability have been expressed graphically for the different samples as shown in Figure 18 through Figure 25, also, given in Tables 2 to 9 (Appendix B).

From relation between degree of saturation and relative permeability, we can noted that the intersection point between the two curves the relative permeability of oil (K_{ro}) equal the relative permeability of gas(K_{rg}), at which both oil and gas are flow with the same rate. This does not mean that the amount of flow of both two fluids are equal, because of their different viscosities, hence the gas will flow in great amount comparing with oil. This point is varies from sample to another due to the different porosities and permeability.

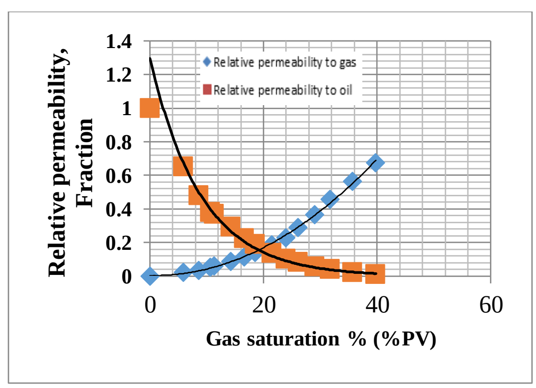

Figure (18) Relative permeability to oil and gas for sample 1C

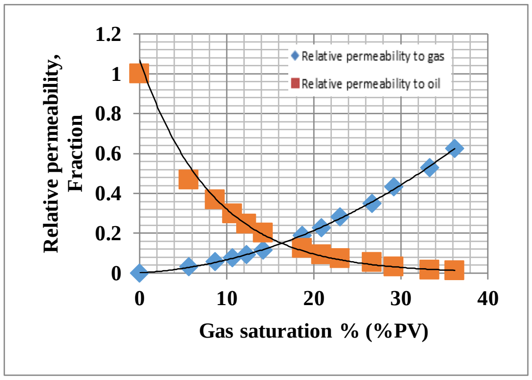

Figure (19) Relative permeability to oil and gas for sample 2C

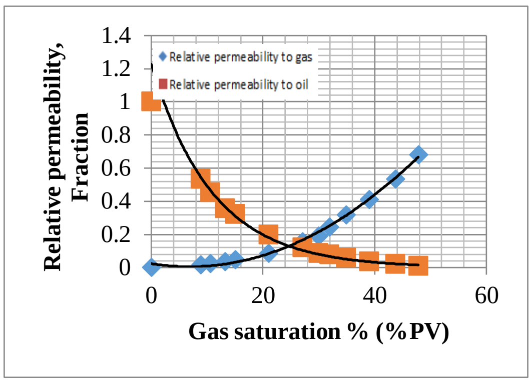

Figure (20) Relative permeability to oil and gas for sample 3C

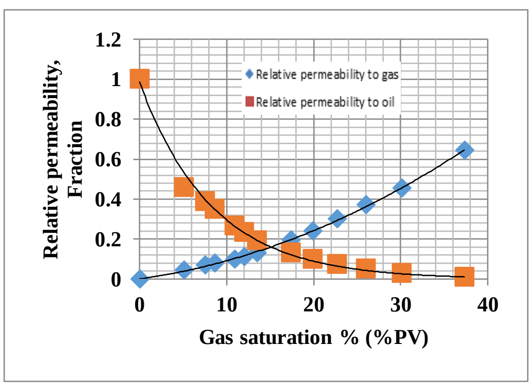

Figure (21) Relative permeability to oil and gas for sample 4C

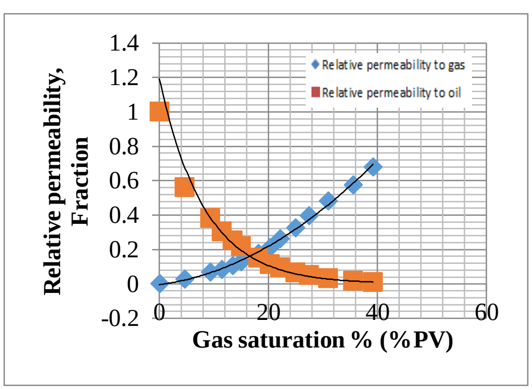

Figure (22) Relative permeability to oil and gas for sample 5C

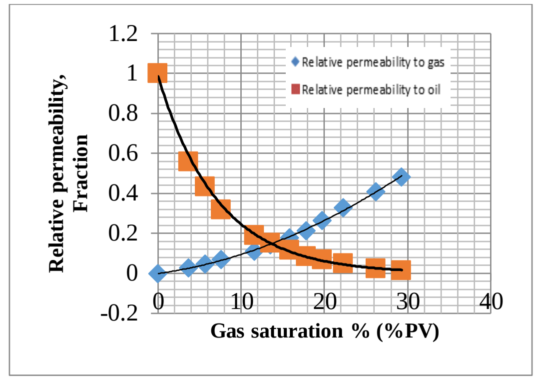

Figure (23) Relative permeability to oil and gas for sample 6C

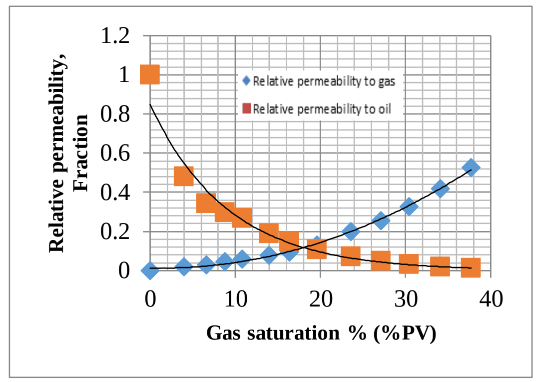

Figure (24) Relative permeability to oil and gas for sample 7C

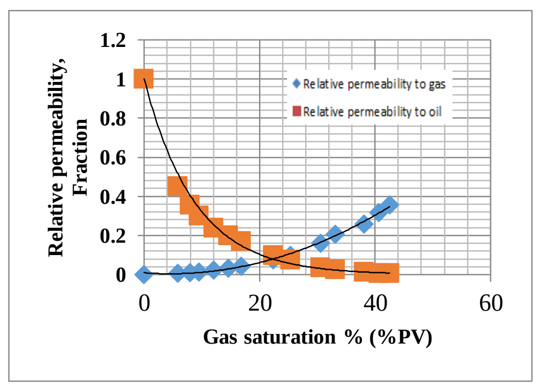

Figure (25) Relative permeability to oil and gas for sample 8C

6.4. CORE ANALYSIS OF WELL NO. R-3

6.4.1. MABRUK RESERVOIR

The petrophysical properties of twelve core samples from well No. R-3 of Mabruk Formation have been performed on include porosity, permeability and brine saturation as depicted in Table 1 (Appendix C).

The correlation of Figure 26 consists of different reservoir samples from core analysis. It is obviously that the increase of permeability is slightly with an increase in porosity, the correlation shows the wide spread, lack of close relation between porosity and permeability. However, Figure 26 depicts the relationship between porosity and permeability with a simple linear regression of weak correlation coefficient 0.1971.

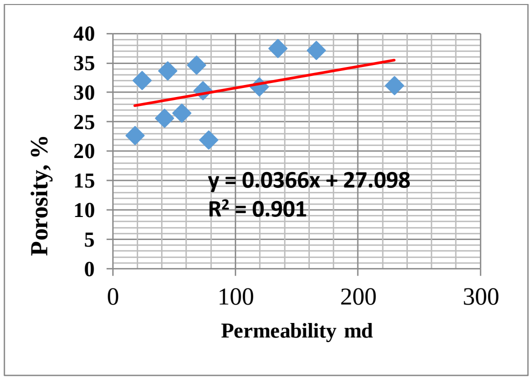

Figure (26). Correlation between porosity and permeability of investigated samples

Figure 27 gives a correlation between the average values of some petrophysical properties such as porosity, permeability, grain density and formation resistivity factor of investigated reservoirs of Farrud, Facha and Mabruk. It is obviously that the average of Mabruk reservoir permeability greater than the other two reservoirs, while the other properties seem to be close to each other's.

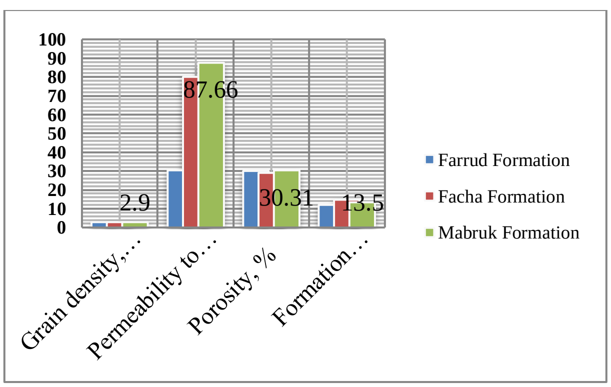

Figure (27). Correlation between the petrophysical properties of investigated reservoirs

7 Conclusions

From the previous study that have been carried out on three different reservoir rocks for Farrud, Facha and Mabruk to estimate the petrophysical properties of formation bearing hydrocarbons through different analyses include porosity ($\emptyset$), permeability (k), formation factor (FF) and resistivity index (RI) we can concluded the following:

The laboratory investigations of relative permeability of *Farrud reservoir* for well R-1 show that the relation between degree of saturation (S_w) and relative permeability gives an intersection point between the two curves, the relative permeability of oil (K_{ro}) equal the relative permeability of gas(K_{rw}), at which both oil and gas are flow with the same rate.

Bilogarthmical crossplots of k_w/k_o , k_{ro}/k_{rw} ratios and total saturation in water, illustrated variable trends, this is attributed to the different properties of studied samples.

The core samples analysis of well R-2 of *Facha reservoir* includeS_w, and k. The relation between S_w is a function permeability. Also, the results of water saturation, $\emptyset$and k are obviously show that S_w is a function of permeability.

The relationship between porosity and formation resistivity factor (FF) on a bilogarithmical plot and the relation between brine saturation and resistivity index (RI), both of them gives a linear regression coefficient.

From relation between degree of saturation and relative permeability, we can noted that the intersection point between the two curves the relative permeability of oil (K_{ro}) equal the relative permeability of gas(K_{rg}), at which both oil and gas are flow with the same rate. This point is varies from sample to another due to the different porosities and permeability.

For well No. R-3 of *Mabruk Formation* study performed on $\emptyset$, k, and S_w, the results revealed that the correlation of different reservoir samples from core analysis show that the increase of k is slightly with an increase in $\emptyset$.

The comparative study between the three reservoir rocks has been carried out by correlation between the average values of some petrophysical properties such as $\emptyset$, k, grain density and formation resistivity factor of investigated formations of *Farrud*, *Facha* and *Mabruk*. Whereas, the average of Mabruk reservoir k greater than the other two reservoirs, while the other properties seem to be close together.

8 Recommendations

In the light of the previous study we can recommend the following:

1. It is important to study the petrophysical properties of formation bearing hydrocarbons to evaluate this formation and enable us to estimate the hydrocarbon reserves.
2. Petrophysical parameters must be study to determine reservoirs performance.

3. To perform a correlation between the different formation to evaluate these parameters.
4. Comparing between laboratory investigations of petrophysical properties and results that have been obtained by different well logs.

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Appendices

Appendix A

Table (1) Relative permeability water/oil measurements

Sample No.: 3V

Permeability to air K_a = 172 md	Porosity ø = 38%
Permeability to liquid K_L = 155 md	Connate water S_{cw} = 22.8%
Permeability to oil K_o = 51.3 md	Oil in place (%PV) S_o = 77.2%
Permeability to water K_w = 31.4 md and with residual oil	Residual saturation (% PV) S_{ro} = 34.3
	Oil recovery (% PV) R_o = 42.9%

Total saturation in water (%PV)	$\frac{k_w}{k_o}$ ratio	Rel. perm. to water (Fraction) k_{rw}	Rel. perm. to oil (Fraction) k_{ro}
22.8	0	0	0.331
27.0	0.105	0.013	0.124
29.6	0.240	0.021	0.090
32.1	0.470	0.031	0.066
35.7	1.01	0.042	0.042
39.1	2.05	0.055	0.021
44.0	4.60	0.076	0.017
47.3	8.10	0.090	0.011
51.2	15.0	0.112	0.0075
55.3	20.6	0.135	0.0066
79.0	260	0.270	0.0008

Table (2) Relative permeability water/oil measurements

Sample No.: 5V

Permeability to air K_a = 54.2 md	Porosity ø = 38.3%
Permeability to liquid K_L = 46.2 md	Connate water S_{cw} = 25.6%
Permeability to oil K_o = 24.6 md	Oil in place (%PV) S_o = 74.4%
Permeability to water K_w = 22.9 md and with residual oil	Residual saturation (% PV) S_{ro} = 8.6
	Oil recovery (% PV) R_o = 65.8%

Total saturation in water (%PV)	$\frac{k_w}{k_o}$ ratio	Rel. perm. to water (Fraction) k_{rw}	Rel. perm. to oil (Fraction) k_{ro}
25.6	0	0	0.532
29.9	0.016	0.006	0.375
32.4	0.055	0.016	0.290
37.9	0.26	0.033	0.127
44.6	1.01	0.062	0.061
58.6	3.05	0.154	0.059
77.9	15.0	0.330	0.022
85.5	35.0	0.423	0.012
88.8	70.5	0.462	0.0066
91.4	317	0.495	0.0016

Table (3) Relative permeability water/oil measurements

Sample No.: 9V

Permeability to air K_a = 29.2 md	Porosity ø = 26.9%
Permeability to liquid K_L = 24.2 md	Connate water S_{cw} = 20.6%
Permeability to oil K_o = 10.4 md	Oil in place (%PV) S_o = 79.4%
Permeability to water K_w = 5.6 md and with residual oil	Residual saturation (% PV) S_{ro} = 34.0
	Oil recovery (% PV) R_o = 45.4%

Total saturation in water (%PV)	$\frac{k_w}{k_o}$ ratio	Rel. perm. to water (Fraction) k_{rw}	Rel. perm. to oil (Fraction) k_{ro}
20.6	0	0	0.430
28.0	1.0	0.032	0.032
29.9	1.4	0.036	0.026
34.9	2.2	0.050	0.023
43.0	5.2	0.090	0.017
50.0	13.1	0.128	0.0097
55.1	26.1	0.159	0.0061
62.2	70.0	0.208	0.0030
66.0	315	0.231	0.0008

Table (4) Relative permeability water/oil measurements

Sample No.: 13V

Permeability to air K_a = 24.2 md	Porosity ø = 32.0%
Permeability to liquid K_L = 21.2 md	Connate water S_{cw} = 32.2%
Permeability to oil K_o = 6.9 md	Oil in place (%PV) S_o = 67.8%
Permeability to water K_w = 5.6 md and with residual oil	Residual saturation (% PV) S_{ro} = 27.3
	Oil recovery (% PV) R_o = 40.5%

Total saturation in water (%PV)	$\frac{k_w}{k_o}$ ratio	Rel. perm. to water (Fraction) k_{rw}	Rel. perm. to oil (Fraction) k_{ro}
2.2	0	0	0.325
35.1	1.0	0.015	0.015
36.4	2.05	0.021	0.010
39.2	5.20	0.033	0.0063
41.1	8.90	0.045	0.0051
44.8	13.50	0.067	0.0049
50.8	25.0	0.102	0.0041
59.1	48.0	0.160	0.0033
67.8	100.0	0.221	0.0022
72.7	210.0	0.264	0.0013

Table (5) Petrophysical characterization parameter of core samples

Sample No.	Depth, ft.	Grain density, gr/cm^3	Permeability to air, K, md	Porosity, %	Formation resistivity factor, FF	Water saturation S_w	Resistivity index, RI
3V	5947	2.83	119	38.5	8.0	100	1
						98.1	1.05
						83.6	1.41
						64.4	2.63
						37.4	8.33
						16.4	50.00
						10.0	333.23
5V	5954	2.84	32.9	38.5	6	100	1
						99.5	1.01
						99.2	1.05
						98.0	1.12
						96.5	1.23
						36.1	11.11
						9.0	333.23
7V	5955	2.75	2.1	26.1	14	100	1
						98.9	1.02
						98.0	1.05
						96.8	1.09
						81.7	1.54
						52.7	4.00
						26.0	20.00
9V	9560	2.74	15.3	27.0	12	100	1
						99.2	1.03
						97.7	1.08
						90.1	1.30
						68.6	2.70
						53.0	4.55
						32.5	12.50
13V	5982	2.70	11.6	32.0	11	100	1
						99.0	1.04
						98.1	1.09
						96.8	1.27
						62.6	3.03
						40.8	7.69
						24.5	25.00
17V	5993	2.74	0.4	17.2	21	100	1
						98.8	1.01

						98.2	1.12
						97.7	1.18
						97.4	1.23
						95.0	1.35
						69.0	2.56
$\bar{x}$		2.77	30.22	29.88	12.0		

$\bar{x}$ = Values average

FACHA FORMATION

Appendix B

Table (1) Water saturation, height above free water level and permeability of Facha reservoir

Selected Permeability to air, md	Water saturation S_w (%VP) Height above free water, feet							
	Height above free water, feet							
	20	25	30	40	60	100	150	200
	Water saturation S_w (%VP)							
15	90.6	78.3	70.8	59.7	46.8	40.0	36.2	34.0
20	81.4	71.4	64.4	53.7	41.3	35.2	31.5	29.4
30	69.3	60.6	54.3	45.2	36.0	30.3	26.7	24.8
40	64.5	56.2	50.2	41.1	33.7	27.8	24.2	22.3
50	60.4	52.3	46.4	38.0	31.7	26.2	22.6	20.7
70	55.9	48.0	42.3	35.3	29.8	24.6	21.1	19.2
100	51.3	43.6	38.3	32.8	27.9	23.2	19.6	17.8
200	45.8	38.7	34.3	29.9	25.6	21.2	18.2	16.4

Table (2) Gas-oil relative permeability

Sample identification: 1C Sample depth: 5,772 feet Permeability to air: 47 md		Porosity: 26.3 % Initial water saturation: 12.8 % Effective permeability to air: 39 md	
Gas saturation % (%PV)	Gas-oil relative permeability ratio	Relative permeability to gas*, fraction	Relative permeability to oil*, fraction
0.0	0.000	0.000	1.000
5.9	0.032	0.021	0.652
8.6	0.073	0.035	0.481
10.6	0.136	0.052	0.381
11.3	0.162	0.060	0.370
14.3	0.303	0.089	0.293
16.6	0.500	0.112	0.223
18.5	0.739	0.141	0.190
21.5	1.360	0.188	0.138
23.9	2.220	0.228	0.103
26.1	3.520	0.291	0.083
29.0	6.440	0.365	0.057
31.7	11.20	0.458	0.041
35.7	24.40	0.564	0.023
39.8	62.40	0.674	0.011

* Relative to the effective permeability to oil at initial water saturation

Table (3) Gas-oil relative permeability

Sample identification: 2C Sample depth: 5,775 feet Permeability to air: 27 md		Porosity: 25.6 % Initial water saturation: 8.0 % Effective permeability to air: 20 md	
Gas saturation % (%PV)	Gas-oil relative permeability ratio	Relative permeability to gas*, fraction	Relative permeability to oil*, fraction
0.0	0.000	0.000	1.000
8.8	0.034	0.018	0.533
10.5	0.051	0.023	0.452
13.2	0.097	0.035	0.358

15.0	0.146	0.047	0.322
21.0	0.435	0.087	0.199
27.1	1.270	0.156	0.123
29.9	2.160	0.190	0.088
31.9	3.130	0.243	0.078
34.9	5.240	0.318	0.061
39.0	10.90	0.411	0.038
43.7	26.40	0.536	0.020
47.8	61.20	0.683	0.011

* Relative to the effective permeability to oil at initial water saturation

Table (4) Gas-oil relative permeability

Sample identification: 3C Sample depth: 5,789 feet Permeability to air: 68 md		Porosity: 28.4 % Initial water saturation: 18.10 % Effective permeability to air: 52 md	
Gas saturation % (%PV)	Gas-oil relative permeability ratio	Relative permeability to gas*, fraction	Relative permeability to oil*, fraction
0.0	0.000	0.000	1.000
5.7	0.066	0.031	0.468
8.7	0.156	0.057	0.368
10.7	0.251	0.075	0.297
12.3	0.374	0.092	0.245
14.2	0.576	0.116	0.201
18.7	1.540	0.189	0.123
20.9	2.450	0.228	0.093
23.0	3.770	0.280	0.074
26.7	6.530	0.349	0.054
29.2	13.00	0.432	0.033
33.3	30.50	0.529	0.017
36.2	57.80	0.626	0.011

* Relative to the effective permeability to oil at initial water saturation

Table (5) Gas-oil relative permeability

Sample identification: 4C Sample depth: 5,792 feet Permeability to air: 38 md		Porosity: 26.7 % Initial water saturation: 12.8 % Effective permeability to air: 33 md	
Gas saturation % (%PV)	Gas-oil relative permeability ratio	Relative permeability to gas*, fraction	Relative permeability to oil*, fraction
0.0	0.000	0.000	1.000
5.1	0.095	0.044	0.456
7.5	0.176	0.068	0.388
8.6	0.227	0.079	0.350
10.9	0.377	0.100	0.265
12.0	0.474	0.110	0.232
13.5	0.687	0.129	0.191
17.4	1.510	0.194	0.129
19.9	2.460	0.239	0.097
22.7	4.190	0.299	0.072
26.0	7.660	0.372	0.049
30.1	15.80	0.454	0.029
37.3	74.80	0.642	0.0086

* Relative to the effective permeability to oil at initial water saturation

Table (6) Gas-oil relative permeability

Sample identification: 5C Sample depth: 5,805 feet Permeability to air: 26 md		Porosity: 29.5 % Initial water saturation: 13.0 % Effective permeability to air: 18 md	
Gas saturation % (%PV)	Gas-oil relative permeability ratio	Relative permeability to gas*, fraction	Relative permeability to oil*, fraction
0.0	0.000	0.000	1.000
4.6	0.052	0.029	0.560

9.3	0.176	0.067	0.380
11.5	0.283	0.085	0.302
13.5	0.430	0.107	0.250
15.0	0.586	0.127	0.217
18.2	1.160	0.175	0.152
20.3	1.850	0.211	0.114
22.2	2.760	0.261	0.094
25.0	5.100	0.324	0.063
27.4	8.170	0.397	0.049
30.9	18.70	0.481	0.031
35.5	38.30	0.576	0.015
39.2	91.00	0.681	0.0075

* Relative to the effective permeability to oil at initial water saturation

Table (7) Gas-oil relative permeability

Sample identification: 6C Sample depth: 5,831 feet Permeability to air: 115 md		Porosity: 35.2 % Initial water saturation: 11.6 % Effective permeability to air: 85 md	
Gas saturation % (%PV)	Gas-oil relative permeability ratio	Relative permeability to gas*, fraction	Relative permeability to oil*, fraction
0.0	0.000	0.000	1.000
3.7	0.048	0.027	0.560
5.7	0.105	0.046	0.436
7.6	0.216	0.069	0.320
11.6	0.580	0.111	0.192
13.5	0.919	0.142	0.154
15.8	1.530	0.180	0.117
17.8	2.460	0.215	0.087
19.7	3.750	0.266	0.071
22.3	6.610	0.329	0.050
26.2	15.70	0.408	0.026
29.3	34.30	0.482	0.014

* Relative to the effective permeability to oil at initial water saturation

Table (8) Gas-oil relative permeability

Sample identification: 7C Sample depth: 5,849 feet Permeability to air: 56 md		Porosity: 29.5 % Initial water saturation: 17.0 % Effective permeability to air: 44 md	
Gas saturation % (%PV)	Gas-oil relative permeability ratio	Relative permeability to gas*, fraction	Relative permeability to oil*, fraction
0.0	0.000	0.000	1.000
4.0	0.038	0.018	0.479
6.6	0.084	0.029	0.342
8.8	0.150	0.044	0.296
10.8	0.217	0.058	0.266
14.0	0.406	0.077	0.189
16.4	0.649	0.095	0.147
19.6	1.220	0.130	0.107
23.6	2.740	0.199	0.073
27.1	5.240	0.256	0.049
30.4	10.40	0.328	0.031
34.1	21.50	0.417	0.019
37.7	45.60	0.525	0.012

* Relative to the effective permeability to oil at initial water saturation

Table (9) Gas-oil relative permeability

Sample identification: 8C Sample depth: 5,857 feet Permeability to air: 249 md		Porosity: 37.3 % Initial water saturation:19.2% Effective permeability to air: 211 md	
Gas saturation % (%PV)	Gas-oil relative permeability ratio	Relative permeability to gas*, fraction	Relative permeability to oil*, fraction
0.0	0.000	0.000	1.000
5.8	0.018	0.008	0.451
7.9	0.031	0.011	0.357
9.5	0.047	0.014	0.301
12.0	0.091	0.022	0.238
14.6	0.166	0.033	0.200
16.8	0.254	0.043	0.171
22.3	0.752	0.075	0.099
25.3	1.23	0.098	0.074
30.5	4.470	0.162	0.036
33.1	7.650	0.206	0.027
38.1	21.10	0.258	0.012
40.6	36.90	0.318	0.0086
42.5	55.80	0.355	0.0064

* Relative to the effective permeability to oil at initial water saturation

Appendix C

Table (1) Petrophysical properties of Mabruk Formation

Sample No.	Depth, ft.	Perm. To air, md	Porosity, %	Water saturation S_w (%V_P) versus Pressure (psig)						
				Pressure (psig)						
				1	2	4	8	15	35	40
				Brine saturation S_w (%V_P)						
3S	6118	67.95	34.65	100	100	47.50	33.12	17.50	14.30	14.12
6S	6121	134.30	37.45	100	100	66.25	35.63	20.00	17.14	16.75
7S	6124	44.64	33.62	100	100	100	51.25	34.06	25.00	24.00
8S	6125	73.17	30.27	100	100	75.00	43.75	26.25	18.57	17.00
14S	6131	23.61	32.06	100	100	100	71.38	41.58	15.46	12.24
18S	6135	165.67	37.10	100	100	65.91	36.33	17.75	7.61	6.64
32S	6151	42.23	25.57	100	100	93.75	50.63	31.25	25.00	23.75
33S	6153	119.18	30.92	100	90.45	59.96	38.31	26.58	21.45	21.48
36S	6155	55.84	26.43	100	100	100	54.38	40.31	28.86	27.50
38S	6157	229.53	31.09	100	100	36.17	18.71	14.69	12.24	11.79
39S	6160	77.96	21.85	100	90.00	55.00	31.25	15.00	7.90	7.60
40S	6162	17.80	22.65	100	100	100	75.63	44.10	33.30	33.30
$\overline{x}$		87.66	30.31							

$\overline{x}$ = Values average

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