ORIGINAL ARTICLES

Petrophysical Characteristics of the Nubia Sandstone Along the B –Trend, Southern Gulf of Suez, Egypt, Based on the Hydraulic Flow Units Concept.

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ABSTRACT

The Gulf of Suez rift basin is considered the most prolific oil reservoir province in Egypt. It is produced oil from the Miocene and pre – Miocene rocks. The pre – Cenomanian Nubia Sandstone sediments are considered one of the most important reservoirs in the Gulf of Suez. It consists mainly of sandstone intercalated by thin layers of clays. It thins southward along the Gulf of Suez. Based on the pore scale, the Nubia Sandstone is a heterogeneous reservoir. We used the hydraulic flow unit concept to differentiate the Nubia Sandstone section into flow zones. Based on statistical methods, at least eight HFU can be identified within the Nubia interval. This study indicates that the HFU is controlled essentially by the permeability, which in turn controlled by the pore throat size. The pore throat size is a function of the pore type, which is determined by the depositional facies and the subsequent diagenetic processes. Presence of clays and heavy minerals, as well as feldspars, which altered subsequently to kaolinite, led to significant reduction in porosity and permeability, and finally led to poor reservoir quality zones.

Key words: hydraulic flow unit – Gulf of Suez – Nubia Sandstone – reservoir.

Introduction

The hydraulic flow unit (HFU) concept has been developed to identify and characterize rock types, based on geological and physical parameters at pore scale. It can be used essentially to improve the permeability prediction and well to well rock properties correlations. The hydraulic flow unit (HFU) is defined as a mappable portion of the total reservoir, within which geological and petrophysical properties that affect the flow of fluids, are consistent and predictably different from the properties of other reservoir rock volumes (Ebanks et. al. 1992). They recognized the following characteristics for HFU:

- A flow unit is a specific volume of a reservoir; it is composed of one or more reservoir-quality lithologies and any non reservoir-quality rock types within that same volume, as well as the fluids they contain.
- A flow unit is correlative and mappable at the interwell scale.
- A flow unit zonation is recognizable on wireline logs.
- A flow unit may be in communication with other flow units.

The hydraulic flow units are controlled by geological and petrophysical reservoir rock properties. The geological properties include rock texture and mineralogy, and sedimentary structures while the petrophysical properties include porosity and permeability, which are controlled by depositional facies and diagenetic processes. Within a single facies zone, a few HFU can be present and on contrary, one HFU can include several depositional facies, depending on their textural and mineralogical characteristics (Svirsky et al. 2004). Amaefule et al. (1993) showed that it is not possible to get good reservoir description without introducing the pore throat parameters and bridging the gap between microscopic attributes from routine core plugs and macroscopic log derived characterization, as they introduced the concept of reservoir quality index (RQI) to define the pattern of flow units.

Methods for HFU zonation include application of Lorenz plots and the use of the flow zone indicator concept. Martin et al. (1997) and Chekanis and Kharrat (2009) used Winland equation (1972) to define the HFU. All these methods require the knowledge of porosity and permeability distributions. Gunter et al. (1997) described a technique for combining the porosity, permeability, and bed thickness data for flow unit identification. They utilized the Stratigraphic Modified Lorenz (SML) plot for flow characterization. This method of flow unit determination requires only the routine porosity and permeability data (from logs and/or cores). It is independent of facies identification and uses simple crossplotting techniques. The SML plot is a crossplot of “cumulative flow capacity” – defined as the product of average permeability and thickness of an interval (kh) – versus “cumulative storage capacity” – defined as the product of average porosity and thickness of the same interval (Φh).
On the other hand, Amaefule et al. (1993) introduced three parameters to determine the HFU, which can be defined, according to the following equations:

\[ RQI = 0.0314 \sqrt{\frac{K}{\Phi}} \]  
\[ \Phi_z = \frac{\Phi_e}{(1 - \Phi_e)} \]  
\[ FZI = \frac{1}{\sqrt{F_{sg} S_{gv}}} = \frac{RQI}{\Phi_z} \]

Taking the logarithm of the both sides results in:

\[ \log RQI = \log \Phi_z + \log FZI \]  

Where: \( \Phi_e \) is the effective porosity in fraction, \( k \) is the permeability in md, \( RQI \) is the reservoir quality index in \( \mu \text{m} \), \( \Phi_z \) is the normalized porosity index, \( FZI \) is the flow zone indicator in \( \mu \text{m} \), \( F_s \) is the shape factor, \( \tau \) is the tortuosity and \( S_{gv} \) is the surface area per unit grain in \( \mu \text{m}^{-1} \). The FZI model can be converted to 3D discrete rock type (DRT) by using the following equation (Chekani and Kharrat 2009):

\[ \text{DRT} = \text{round} \left( 2 \log (FZI) + 10.7 \right) \]

Equation (4) indicates that for any HFU, log - log plot of RQI vs. \( \Phi_z \) will yield a straight line with unit slope. The value of the FZI constant can be determined from the intercept of the unit slope straight line at \( \Phi_z = 1 \). Samples with different FZI values will lie on other parallel lines. Samples that lie on the same straight line have similar pore throat attributes and, thereby, constitute a specific hydraulic unit. According to Amaefule et al. (1993) the rocks containing authigenic pore lining, pore filing and pore bridging clays, as well as fine grained poorly sorted sands tend to exhibit high surface area and high tortuosity, hence low FZI. In contrast, the clean, coarse grained and well sorted sands exhibit lower surface areas, lower shape factor, lower tortuosity, and higher FZI values. Each HFU should be distributed according to the normal distributions with corresponding mean FZI values close to the true FZI. For FZI in \( \mu \text{m} \) and \( \Phi_e \) in fraction, the permeability in md can be calculated, as the following:

\[ K = 1014(FZI)^2 \left( \frac{\Phi_e^3}{(1 - \Phi_e)^2} \right) \]

Winland (1972) carried out regression analyses on 322 sandstone samples to develop an empirical relationship between porosity, permeability and pore throat size. He found the best fit at 35% mercury saturation. The Winland equation has the following form:

\[ \log r_{35} = 0.732 + 0.588 \log K - 0.864 \log \Phi \]

Where: \( r_{35} \) is the pore aperture radius corresponding to the 35th percentile in micron, \( K \) is the permeability in md and \( \Phi \) is the porosity in percentage. The core samples of a given petrophysical flow unit have similar \( r_{35} \) values which are used to define the HFU categories, as the following:

- Megaport units with \( r_{35} > 10 \mu \text{m} \).
- Macroport units with \( 2 < r_{35} < 10 \mu \text{m} \).
- Mesoport units with \( 0.5 < r_{35} < 2 \mu \text{m} \).
- Microport units with \( 0.1 < r_{35} < 0.5 \mu \text{m} \).
- Nanoport units with \( r_{35} < 0.1 \mu \text{m} \).

**Background on geologic setting:**

The Gulf of Suez rift basin is considered the most prolific oil province in Egypt. According to the EGPC (1996) and Alsharhan (2003), more than 800 exploratory wells were drilled in the Gulf basin resulted in 230 oil discoveries and more than 80 oilfields. Therefore, a stream of technical papers was released and still concerned the geological, geophysical and geochemical Gulf of Suez aspects (e.g. Garfunkel and Bartov 1977; RRI 1986; Richardson and Arthur 1988; Montenat et al. 1988& 1998; Patton et al., 1994; Schutz 1994; EGPC 1996; Bosworth et al. 1998; Bosworth and McClay 2001; Moustafa 2002; Jackson et al. 2006; and Wilson et al. 2009). Due to the Late Oligocene – Early Miocene rifting, the Gulf of Suez stratigraphic succession was divided...
into three megasequences. The pre – rift megasequence extended from Cambrian to Eocene, providing excellent reservoirs and source rocks (Fig. 1). The oil reservoirs sourced from this succession is typically oil – prone type and occasionally oil – gas prone (Alsharhan 2003). The syn – rift megasequence extended from Oligocene to Miocene, providing both good reservoirs and the ultimate sealing of the generated hydrocarbons. The post – rift megasequence extended from Pliocene to Recent.

![Generalized stratigraphic column of the central trough of the Southern Gulf of Suez.](image_url)

The studied area is located along the central axis of the Suez rift at the southern structural trend called “B-Trend” (Fig. 2). This prolific trend extends from the Morgan Accommodation Zone in the north until Shadwan and Gubal islands in the south (Fig. 2). The Southern Gulf of Suez represents a complicated structural area, as a consequence to the intense tectonic activities associated with the rifting of the Gulf of Suez. Subsidence, uplift,
tilted fault blocks and unconformities in association with sea level changes, as well as sediments supplies were controlled the configuration of the Gulf of Suez rift basin and its depositional facies during the Miocene time.

Well C

GULF OF SUEZ

Well D

Well B

Well A

GEBEL ARABA

GEBEL QIBLIAT

SINAI

RAS MUHAMMED

RED SEAGIFATUN IS.

HURGHADA

ABU SHAAR

EL MELLAHA

BASIN

ESH

ASHRAFI IS.

GEISUM IS.

TAWILA IS.

GUBAL IS.

SHADWAN IS.

ABU GERFAN

GEMSA BASIN

RANIM IS.

SHAOB ALI

MORGAN

NESSIM

AMAL

WALY GS365

GS327

SIDKI GH378

EAST ZEIT

ASHRAFI IS.

Fig. 2: Location map of the study wells, showing the major structural trends in the Southern Gulf of Suez (modified after Bosworth et al., 1998). All the study wells distributed throughout the B- Trend.

The term Nubia was introduced by Russegger (1937) to describe the clastic sediments which cover the southern part of Egypt and Northern Sudan. The term usually applied for all sediments below Cenomanian. Later, Beets (1948) subdivided the Nubia section into four units for exploration purposes. This subdivision usually used till now in oil companies. These units are, from base to top, Nubia D, Nubia C, Nubia B and Nubia A. However, the Egyptian stratigraphers tend to divide the Nubia facies into four formations, from base to top, the Araba, Naqus, Qiseib and Malha. In the Southern Gulf of Suez Province, only the Araba and Naqus formations (corresponding to Nubia D and Nubia C, respectively) are occurred (Gameel and Darwish 1994). The Araba Formation consists of sandstones with kaolinitic, illitic and calcareous cements and is interbedded with thin siltstone, while the Naqus Formation comprises medium to coarse-grained sands and sandstones, with minor clay and kaolinitic interbeds at the top of the unit (Alsharhan, 2003).

The Pre – Cenomanian Nubia Sandstone is considered one of the most prolific oil reservoirs in the Gulf of Suez. It produces oil from many fields throughout the Gulf of Suez. According to Alsharhan (2003), the Nubia sandstone represents about 17% of the production potential in the Gulf of Suez. Most of the Nubia Sandstone
The Nubia sandstones were subjected to several diagenetic processes, such as compaction and pressure solution, cementation (iron oxide or silica), pore fillings, replacement and recrystallization (Alsharhan and Salah 1997). Combination of these diagenetic processes resulted in the reduction of porosity and permeability.

The Pre–Cenomanian deposits in the study area, which rested unconformably on the basement, consist mainly of sandstone with intercalations of shale deposited in fluvial braided system, graded to aeolian environment. The clay is mainly kaolinite with traces of illite and heavy thorium-bearing minerals (Fig. 3). The section thickness generally decreases southward along the Gulf of Suez. The Nubia Sandstone reservoir, according to Gameel and Darwish (1994), is ranged from poor to high quality reservoir rock, based on the attribute of petrographic and petrophysical investigations.

**Study area and data:**

Four wells, distributed along the B–Trend, were chosen to study the hydraulic flow characteristics of the Nubia Sandstone. The studied wells are belonging to three oil fields. All the wells were penetrated the Nubia Sandstone; either reached the basement (wells A, B and C) or drilled through some Nubia interval (well D). The thickness generally increases northward along the B–Trend. It ranges from about 120 ft in well B to more than 700 ft in well C. The well to well correlation indicates that well C is the complete one, regarding to the studied wells (Fig. 4). For the wells A and B, only the lower section was encountered. The encountered Nubia section consists mainly of sandstone, with an intercalated thin layer of shale. The lowermost part exhibits high gamma-ray readings due to the presence of heavy minerals that derived from basement.

The available data are well logs, and routine and special core analyses. These log data include gamma-ray, natural gamma-ray (well C), neutron, density, sonic, resistivity (shallow and deep), dipmeter and litho–density tool. In addition, routine core analyses are available for the four wells. The routine core analyses include horizontal and vertical permeabilities, porosity, fluid saturation and grain density. In well A, the encountered Nubia section is about 230 ft thick of mainly sandstone with a thin layer of shale. The Nubia interval shows good reservoir quality, as indicated from the good separation between density and neutron logs, with high formation resistivity (reached 2000 ohm.m). However, the lower third part is characterized by high gamma-ray, decrease in resistivity and high clay content. This change in facies is resulted in reduction of porosity and permeability, as well as an increase in water saturation. Two core plugs, representing the lowermost 80 ft, were analyzed provided 80 cored samples. The cored permeability is ranged from 0.07 to 177 md with an average value of 13.8 md. The cored porosity is ranged from 0.012 to 0.177 with average value of 0.091. The grain density has an average value of 2.65 g/cc.

In well B, about 120 ft thick of the measured depth were encountered consisting of sandstone. Good reservoir quality can be detected from the enough separation between density and neutron logs, low gamma-ray, as well as high formation resistivity. However, the lowermost 35 ft indicated low reservoir quality, as a result of the high clay content and the reduction of permeability and hydrocarbon saturation. In this well, two core plugs were analyzed provided us with 110 samples. The cored interval covered the most encountered section. Permeability is ranged from 0.004 to 1610 md, with an average value of 169 md. The cored porosity is ranged from 0.012 to 0.177 with average value of 0.091. The grain density has an average value of 2.65 g/cc.

**Fig. 3:** Identification of clay minerals, from thorium and potassium, for well C (after Schlumberger, 1985).
In well C, 713 ft thick were encountered of mainly sandstone with some intercalations of thin shale layers. Four thin shale layers are distributed throughout the lower part. Excellent reservoir characteristics were predominant for the upper 320 ft. This part is characterized by high formation resistivity (2000 ohm.m) with very low clay content, as well as very low water saturation. Downward, the reservoir quality begins to decrease gradually with an increase of the clay volume. Routine core analyses were carried out on 13 core plugs. These core plugs covered about 600 ft thick. Permeability is ranged from 0.01 to 1050 md, with an average value of 68 md. The porosity is ranged from 0.016 to 0.204, with an average value of 0.133. The grain density has 2.64 g/cc of average value.

In well D, about 532 ft thick were drilled of mainly sandstone, with some intercalations of thin layers of shale. The drilling program did not reach the basement, due to the oil – water contact was encountered at the lower part. One core plug was analyzed, providing eleven core samples. Permeability is ranged from 0.2 to 886 md, with an average value of 156 md. The porosity is ranged from 0.016 to 0.173, with an average value of 0.09. The average grain density is 2.77 g/cc.

Special core analysis was performed on six core samples for the well B, giving six mercury injection capillary pressure curves (Fig.5). From this SCAL, we can conclude the best-fit equation, that determines the relation between permeability, porosity and pore throat radius. The equation has the following form, with a coefficient of determination ($r^2$) = 0.99:

$$r_{30} = 0.594 + 0.786 \log (k) -1.199 \log (\Phi)$$

(8)

Where: $r_{30}$ is the pore size corresponding to a mercury saturation of 30% in micron, $K$ is the permeability in md and $\Phi$ is the porosity in %. 

Fig. 4: Well – to well correlations using gamma -ray and sonic logs, illustrating the missed sections. Black bars refer to the cored intervals.
Fig. 5: Capillary pressure for the available SCAL in well B. The curves illustrate four hydraulic flow units.

**Determination of the number of HFU:**

As mentioned earlier, the HFU can be determined using several methods such as SML plot, FZI and r35. Numerous authors used Winland equation (r35) to determine the reservoir rock types rather than the HFU (Boada et al. 2001; and Rushing et al. 2007). Figure (6) illustrates the number of HFU that can be determined by using r35. In well A, four reservoir rock types can be detected, ranging from nano to macro pore types. The majority of data is clustered around the micro and meso pore types. In well B, five reservoir rock types can be detected ranging from nano to mega pore types. The data are scattered throughout the plot without cluster area, indicating a high degree of heterogeneity. In well C, five reservoir rock types can be detected, also in this well, ranged from nano to mega pore types. The majority of data are clustered around the meso and macro rock types. In well D, four reservoir rock types can be detected for this short interval. The rock types are ranged from micro to megaport.

The stratigraphic modified Lorenz (SML) plot can be used too to determine the number of HFU. It is a plot of flow capacity versus storage capacity. The change in slope indicates a new flow unit, while the horizontal trend can be treated as a barrier where no flow occurred. Figure (7) shows the SMLP for all wells. We can determine at least six HFU in well A for the cored interval with three barriers. We can conclude that about 45% of the fluid flow has been occurred from the depth interval between 10628 and 10638 ft (Fig. 8). This figure indicates also high degree of heterogeneity in this well. In well B, six HFU can be determined in this well with two barriers. It can be concluded that about 52% of the flow come from the interval between 10688 and 10712 ft depth (Fig. 8). The heterogeneity of the reservoir increased downward as indicated from the increasing the separation between storage capacity and flow capacity lines. In well C, at least nine HFU can be determined with four barriers. We can detect that about 25% of the flow come from the interval between 10904 and 10952 ft depth. It can be concluded that the degree of heterogeneity is varied considerably along the well. From 10900 ft depth upward, the reservoir can be treated as homogenous. However, from 10900 ft depth downward, the heterogeneity increased. In well D, three HFU occurred in the cored interval.

The number of HFU, based on FZI technique, can be determined by several methods. Log – log plot of RQI versus \( \Phi_z \) yielded a straight line with intercept determines FZI. Figure (9) illustrates such plot for the studied wells. Applying the DRT method yielded at least five HFU for well A (Fig.10). In well B, six HFU can be detected. In well C, 13 HFU can be determined, while in well D, only two HFU could be observed. The change
in slope, according to Nooruddin and Hossain (2011), is related to changing in the cementation exponent. This change can be observed obviously in well B (Fig. 10). This change in the cementation exponent may help in the explanation of the high degree of heterogeneity for this well.

Fig. 6: Pore throat size, from permeability and porosity plot.

Fig. 7: Stratigraphic modified Lorenz (SML) plot, to identify the hydraulic flow units.
Fig. 8: SML plot showing reservoir flow and storage capacity for studied wells. We note that increasing heterogeneity in wells A, B & D.

Fig. 9: Log – log plot of log RQI against Φz.

Statistical methods, such as histograms and cumulative probability plots can be used to further accurate differentiations the number of HFU (Figs. 11&12). The cumulative probability can be used to estimate the FZI boundaries for the HFU. In well A, five HFU can be detected. In well B, six HFU can be detected, while in well C, nine HFU are occurred.
Fig. 10: Log – log plot of the permeability against porosity, using DRT.

More accurate results can be obtained by using Ward's hierarchical clustering method. The advantages of this method are its high accuracy and user independency. It is used to get some sense of the possible number of clusters and the way they merge, as seen from the dendrogram. Then the clustering is rerun with only a chosen optimum number, in which to place all the cases. It starts from a number of HFU equal to the number of samples and then gradually merge the samples with similar FZI values into joint clusters. To validate the optimum
number of HFU, we used the sum of square errors (SSE), as an indicator for such determination. In this method, we plot SSE against the number of HFU in which the SSE decreased as HFU increased. At certain HFU number, the SSE is nearly constant. After this certain number, SSE is almost constant with small variations, which can be neglected. This certain number can be considered the optimum number of HFU (Fig. 13). According to this method, we can detect five HFU for well A, seven HFU for well B, eight HFU for well C and four HFU for well D (Fig. 14).

![Graphs showing cumulative probability and cumulative probability against FZI for wells A, B, C, and D.](image)

**Fig. 12:** Identification of the number of HFU, using probability plot.

![Graphs showing SSE against numbers of HFU for wells A, B, C, and D.](image)

**Fig. 13:** Identification of the number of HFU, using SSE.

It can be noted that the r35 method can’t be help in identifying the hydraulic flow units. It can be used to detect the rock types rather than hydraulic flow units. Other methods give closeness results as noted in other wells (Table 3). Extreme flow unit number for well C using DRT method indicated that this method gives more
Table 1: Statistical description for the HFU in well C.

<table>
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<th>No. of HFU</th>
<th>S. size</th>
<th>statistics</th>
<th>Phicore</th>
<th>Kcore</th>
<th>Pota</th>
<th>Thor</th>
<th>Uran</th>
<th>Vsh</th>
<th>FZI</th>
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<td>5.15</td>
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<td>0.1</td>
<td>1.6</td>
<td>0.53</td>
<td>2</td>
<td>0.93</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Avg</td>
<td>12.5</td>
<td>5.7</td>
<td>0.15</td>
<td>4.4</td>
<td>1.3</td>
<td>7</td>
<td>1.3</td>
<td>1.5</td>
</tr>
<tr>
<td>HFU8</td>
<td>92</td>
<td>Max</td>
<td>19.5</td>
<td>5.6</td>
<td>1.9</td>
<td>61.7</td>
<td>8.7</td>
<td>65</td>
<td>0.89</td>
<td>1.26</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Min</td>
<td>2.7</td>
<td>0.01</td>
<td>0.1</td>
<td>1.96</td>
<td>0.5</td>
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<tr>
<td></td>
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<td>Avg</td>
<td>10.7</td>
<td>0.79</td>
<td>0.26</td>
<td>7.7</td>
<td>1.9</td>
<td>12</td>
<td>0.5</td>
<td>0.44</td>
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</table>

Prediction of hydraulic flow unit in the uncored interval:

Before any attempt to predict the HFU, we must be sure that the available logs are calibrated, environmentally corrected and the core and log data are accurately depth matched. Several statistical methods can be used to predict the FZI from the log data. The simplest one is the multiple regression analysis (MRA). Other complicated methods can be used such as the Fuzzy logic and artificial neural network (ANN).

For the MRA, one can't predict an equation to be used for all intervals. We need an equation corresponding to each HFU. Even within a HFU, more than one equation is required to improve the quality of prediction. So, the uncored intervals can't be predicted using this method. Therefore, the ANN can be used for such purpose, in which we use the IP software program to improve the prediction quality and to predict the uncored intervals. In this method, we used the GR, RHOB, PHIE and ILD logs as inputs and the FZI as output. Then, we divided the interval into zones and run train neural network. The train is repeating several times till reaching the best results (Fig. 15).

Results and Discussions

The Nubia Sandstone sediments in the Southern Gulf of Suez, Egypt, can be considered as a heterogenous reservoir, based on pore scale. For macro scale, the matter walks in the same track. Complete Nubia section is seldom to encounter in the drilled wells of this area. The reason can be attributed to the erosion processes and/or the effect of faulting. Both factors are used for delineating the distribution of the encountered Nubia Sandstone in the Southern Gulf of Suez. Well – to well correlations are useful to detect the common intervals and the missed parts, as well as to determine the role of unconformity and/or faulting with the aid of dipmeter. The thickest section was encountered in well C. In wells A&B, only the lowermost part is encountered. Dipmeter indicates that faulting is responsible for such missing in both wells (Fig. 16). For wells C & D, the dipmeter indicates that an unconformity separates the Nubia section from the overlying sediments. Such an unconformity may be responsible for the missed strata at the top of the drilled sections (Fig. 16).

Based on the statistical methods, at least eight HFU can be detected for the cored interval in well C. The cored interval represents about 80% of the total thickness. HFU1 is the best reservoir quality, while HFU8 is the poorest (Table 1). Gradual decreasing in reservoir quality takes place from HFU1 to HFU8. Generally, the hydraulic flow units are distributed throughout the reservoir with concentration of high quality at the middle and upper parts (Fig.14). In well A, five HFU can be detected labeled HFU1 to HFU5. In well B, seven HFU can be identified. Table 2 illustrates the correlation of HFU among the studied wells.
Fig. 14: Distribution of HFU, using hierarchical Ward's clustering method.

Fig. 15: Prediction of FZI in the uncored intervals, using IP software program.
Fig. 16: Dipmeter for B&C wells. We note that the normal fault is responsible for missing the upper part of the Nubia Sandstone in well A and unconformity for well C.

Table 2: Correlation between the HFUs in the studied wells.

<table>
<thead>
<tr>
<th>HFU</th>
<th>Well C</th>
<th>Well A</th>
<th>Well B</th>
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<tr>
<td></td>
<td>FZI</td>
<td>From</td>
<td>To</td>
</tr>
<tr>
<td>HFU1</td>
<td>0.09</td>
<td>0.9</td>
<td>0.49</td>
</tr>
<tr>
<td>HFU2</td>
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<td>1.65</td>
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<td>HFU3</td>
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<td>2.77</td>
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<tr>
<td>HFU4</td>
<td>2.8</td>
<td>3.9</td>
<td>4</td>
</tr>
<tr>
<td>HFU5</td>
<td>3.9</td>
<td>4.9</td>
<td>9.4</td>
</tr>
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<td>HFU6</td>
<td>5</td>
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<td>1.36</td>
</tr>
<tr>
<td>HFU8</td>
<td>8.1</td>
<td>11.47</td>
<td></td>
</tr>
</tbody>
</table>

Comparing the significance of permeability and porosity on the HFU appears that permeability plays the main role in determining the HFU (Fig. 17). Figure 17 indicates that the porosity of HFU7&8 (the lowest quality) covered nearly all the HFU porosity range. On the other hand, permeability values are restricted in a certain HFU with limited interference. Quick look, we can determine the order of such HFUs.

For RHOB & DT, there is a common interval, in which all HFU were fallen into it. It is 2.3 to 2.5 gm/cc and 65 to 75 μsec/ft, respectively. For gamma-ray, HFU1 is clearly the least radioactive, while HFU8 is the highest one.

For radioactive minerals; potassium, thorium and uranium, we can note that for potassium and thorium, the minimum value is the same for all HFU. However, the length of the bars can be used to differentiate between the HFUs. For uranium, the differentiation between the HFUs is not clear, except for the best and the worst HFU; namely, HFU1 &HFU8. For r30, the differentiation between HFU is perfect. Clear contrast is obvious.

So, it can be concluded that the HFU is controlled essentially by the permeability, which in turn is controlled by the pore throat size. The pore throat size is a function of pore types. The pore type is a function of the depositional facies and the subsequent diagene sis processes. Therefore, a depositional environment contained heavy thorium –bearing minerals and sediments derived from basement containing feldspars that altered to kaolinite and led to filling the pores of rock. Consequently, reduction in the permeability and porosity has been occurred. Finally, low grade hydraulic flow units are encountered such as for HFU7& HFU8.
Fig. 17: Parameters affecting the magnitude of HFU.

Conclusions:

- The Nubia Sandstone is a heterogeneous reservoir, based on the micro and macroscopic heterogeneity scales.
- Permeability is the main controlling factor in the determination of the reservoir fluid flow characteristics.
- Permeability is controlled mainly by the pore throat size, which is affected in turn by the depositional environment and the subsequent diagenetic processes.
- Presence of kaolinite patches, as well as heavy minerals, resulted in a significant reduction of porosity and permeability.
- Natural gamma-ray is a good indicator for the hydraulic flow unit.
- Artificial neural network is a powerful technique to predict the hydraulic flow unit in the uncored intervals.

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References


