Using NMR, Core Analysis, and Well Logging Data to Predict Permeability of Carbonate Reservoirs: a Case Study

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Abstract. Fluid flow through porous media is a function of permeability for petroleum and gas reservoirs. This study investigated the distribution of permeability in the Nasiriya oilfield. The value of effective porosity was obtained from well log data and used to predict permeability using three methods: applied empirical correlations using interactive Petrophysics (IP) software (Version 3.5), core data measurements, and nuclear magnetic resonance (NMR). Nasiriya oil field is one of the large oil fields in southern Iraq, and the Mishrif formation, the area of the case study, consists of the following units from top to bottom: a cap rocks unit; the Upper Mishrif (unit 1); a shale unit; the first reservoir unit (2), a Barrier rocks unit; and the second reservoir unit (3). A 3D model was built by using Petrel software (2009), and the LAS files used to digitize the contour map of the reservoir layers were obtained from Didger3 software. The total number of 3D grids in the model was 5,394,480, with 336 grids in the I direction, 169 in the J direction and 95 in the K direction. Scaling up was done by using the geometric method for permeability, and sequential Gaussian simulation was used in the distribution of petrophysical properties. The results of distribution showed the importance of each zone and the best permeability value was recorded in the second reservoir layer, which varied from 1 md to 100 md.

1. Introduction
Permeability refers to the ability of a reservoir formation to allow fluid movement through its porous medium. Rock permeability, k, controls the direction of flow and the discharge of reservoir fluids into the formation. Henry Darcy derived the first equation that defines permeability in terms of measurable quantities in 1858, so it is usually called Darcy’s Law.

To understand the physics of fluid flow and the transport processes through porous media, researchers require a detailed knowledge of pore scale geometry for each porous media (Baldwin et al., 1996). Permeability increases with increases in the continuity of pores, and the behaviours and petrophysical properties of complex carbonate reservoirs show high levels of nonlinearity because such reservoirs are heterogeneous in nature, displaying many forms of heterogeneity due to varying rock properties. Estimation of the volume of hydrocarbons and their flow patterns depends on porosity, permeability, and fluid saturation, and these are thus the key variables for characterising a reservoir. Porosity can be determined by a variety of logging devices, such as a formation density log, sonic log, or neutron log.

Carbonate reservoirs have particularly high heterogeneity as compared with homogeneous sandstone reservoirs, with far greater variation in pore throat geometry due to the fact that carbonate reservoirs tend to have more complex pore systems than sandstone (Mazzullo, 1986). The conduction rate of a single pore is proportional to the fourth power of its diameter; thus, if the pore diameter is doubled, then the flow rate under the same pressure gradient will be 16 times greater (Tarek, 2010). The exact division of pore space into pore body and throat entities is arbitrary, however, and not easy to define in a unique way (Dullien, 1991).

Permeability can be estimated from empirical correlations if core data analysis is not available. Porosity, pore size, and pore throat geometry are the main parameters that control permeability (Timur, 1968),
and permeability cannot be measured directly using well logging tools. Conventional methods thus use empirical relationships to calculate permeability based on porosity logs. Formation compressibility, sorting, cementation, layering and clay swelling are also parameters that affect permeability, however (Mohaghegh et al. in 1997; Saner et al. 1997; Lucia, 2007; Schlumberger, 2008).

Nuclear magnetic resonance (NMR) can measure permeability based on porosity, free fluid index, and bounded fluid volume. The most important feature of NMR logging is its ability to record a real-time signal that can be used to determine permeability (Hamada and Al-Sharifi, 2010; Guowen et al., 2019).

The main objective of the current study is estimation and comparison of results for permeability using different models, including laboratory measurements, nuclear magnetic resonance (NMR) data, and well log data for porosity and other petrophysical properties.

2. Methodology
The data from five wells was provided by the Oil Exploration Company for the Ministry of Oil. The porosity logs were used to determine the effective porosity based on the Neutron and density logs. The permeability was calculated based on effective porosity and irreducible water saturation. Interactive Petrophysics (IP) software was used to make environmental corrections and to determine the effective porosity to predict the permeability from two models (Timur and Schlumberger, K3 from chart) (Schlumberger, 2008). The study investigated three layers in the Mishrif formation (1, 2, and 3). Conventional air injection method and Nuclear Magnetic Resonance measurements from the Petroleum Technology Department at the University of Technology (taken using an Iraq model Geospec 2/53 Magent-S04600) were also used to determine the permeability of 66 core samples (22 samples for each studied layer). Finally, Petrel software was used to build a 3D model of permeability in the different layers of Mishrif formation in the studied wells. In this model, the total number of grids was 5,394,480, with 336 grids in the I direction, 169 in the J direction, and 95 in the k direction. The permeability values were scaled up based on the geometric method and Sequential Gaussian simulation was applied to the distribution of this important petrophysical property.

3. Results and Discussion
In this study, the data from five wells was used to determine permeability based on log and core analysis. The effects of the environmental conditions on the porosity log data were eliminated or minimised using environment correction in the IP software. The sample permeability results with vertical depth, as determined based on porosity logs and irreducible water saturation, are shown in the third track in Figure 1.
3.1 Cut-off
The net pay zone is the portion of the gross thickness when porous that is permeable to reservoir fluid, defined as an arbitrary porosity cut-off. The permeability cut-off is usually the starting point for net pay determination (Cabb et al., 1998). It is considered to be the controlling parameter that directly separates reservoirs from non-reservoir rocks (Widarsono, 2010), as pores with permeability less than cut-off values will not allow fluids to flow. In oil reservoirs, the permeability cut-off value is usually less than 0.1 md. The determination of porosity cut-off values relies on generating a porosity-permeability relationship from the core or log measurements, however. A value of 6.3% was thus determined as the porosity cut-off from a semi logarithmic porosity versus permeability cross-plot of the studied formation, as shown in Figure 2.
3.2 Permeability 3D Static Model

The use of 3D models is necessary to execute numerical simulation of reservoir performance. These models were built using Petrel software (2009). Data preparation is the basis for any geologic model, being important to construct a 3D static model of the well head, well tops, and well logs. The required data included:

1. Well head: Provides significant information for each well including location (Northing and Easting), total depth, well name, and, optionally, a well symbol.
2. Well tops: several geological units intersect with the well path to generate the well tops for each unit. Tops are essential to build up the surface of each unit of the Mishrif formation in the studied field.
3. Well logs: this data gives information about effective porosity and permeability for all studied wells. Table 1 shows the full required input data for the 3D model.

| No | Data               | Format                        | Type       |
|----|--------------------|-------------------------------|------------|
| 1  | Well Data          |                               |            |
|    | Well Headers       | Well heads (*.*)             | Well       |
|    | Well Deviations    | Well Path deviation (ASCII) (*.*) | Well     |
|    | Well logs          | Well log(LAS 3.0)(*.Las)     | Well       |
| 2  | Well Tops          | ASCII (*.*)                   | Well Tops  |
| 3  | Fault Data         |                               |            |
|    | Fault Polygons     | Lines (ASCII) (*.*)          | Lines      |
|    | Fault Sticks       | Lines (ASCII) (*.*)          | Lines      |
| 4  | Isochoric Data     | Grid (ASCII) (*.*)           | Surface    |

Figure 2: Porosity cut-off for Mishrif Formation
Figures 3 to 8 show the permeability distributions in the main units (1, 2, and 3) of Mishrif formation.

**Figure 3:** Permeability model of unit 1.

**Figure 4:** Quality Histogram for permeability of unit 1.
Figure 5: Permeability model of unit 2.

Figure 6: Quality Histogram for permeability of unit 2.
3.3 Nuclear Magnetic Resonance Measurements

The use of Nuclear Magnetic Resonance (NMR) Measurements offers accurate pore volume, porosity, and permeability measurements for the core plug. In this study, 66 core samples were used to determine permeability from the NMR measurements. Figures 9 to 11 show samples of the permeability results from the NMR measurements.
Figure 9: Permeability results from NMR for sample 10

Figure 10: Permeability results from NMR for sample 23
Figures 1 to 8 illustrate the distribution of permeability from the log models. These figures show good permeability in the studied units in the Mishrif formation, with values varying from 1 md to 100 md in the first unit. The quality histograms show a reasonable variation between log and core results, which occurs as the permeability models are built based on porosity values that may be affected by the borehole environment parameters such as mud filtrate resistivity, mud resistivity, temperature, bit size, mud weight, and borehole diameter.

Figures 9, 10, and 11 show samples of the NMR permeability results, which ranged between 3 and 57 md; the accuracy of this method depends mainly on the accuracy of the air vacuum in the core saturation measurement, such that good saturation measurements offer good results. Table 2 shows a comparison between the core, NMR, and permeability from CPI measurement models. This table shows that the minimum permeability was determined by NMR measurements, while the log models suggested the highest values of permeability.

| Layers | Average $K_{\text{CORE}}$ | Average $K_{\text{CPI}}$ | Average $K_{\text{NMR}}$ |
|--------|-------------------------|-------------------------|-------------------------|
| 1      | 11.56                   | 22.89                   | 10.73                   |
| 2      | 17.61                   | 27.86                   | 13.45                   |
| 3      | 19.74                   | 29.53                   | 16.77                   |

4. Conclusions
In this study, permeability was determined using three methods, based on well logs and core analysis data. The empirical models offered maximum values of permeability, while the NMR measurements offered minimum permeability and identified layer three as a highly permeable zone in comparison with the other two layers of the Mishrif formation studied. The permeability distribution 3D model also indicates that the Mishrif formation is highly heterogenic.
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