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Simulation of the mulltizones clastic reservoir: A case study of Upper Qishn Clastic Member, Masila Basin–Yemen

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ABSTRACT

The Upper Qishn Clastic Member is one of the main oil-bearing reservoirs that are located at Masila Basin –Yemen. It produces oil from many zones with different reservoir properties. The aim of this study is to simulate and model the Qishn sandstone reservoir to provide more understanding of its properties. The available, core plugs, petrophysical, PVT, pressure and production datasets, as well as the seismic structural and geologic information, are all integrated and used in the simulation process. Eclipse simulator was used as a powerful tool for reservoir modeling. A simplified approach based on a pseudo steady-state productivity index and a material balance relationship between the aquifer pressure and the cumulative influx, is applied.

The petrophysical properties of the Qishn sandstone reservoir are mainly investigated based on the well logging and core plug analyses. Three reservoir zones of good hydrocarbon potentiality are indicated and named from above to below as S1A, S1C and S2. Among of these zones, the S1A zone attains the best petrophysical and reservoir quality properties. It has an average hydrocarbon saturation of more than 65%, high effective porosity up to 20% and good permeability record (66 mD). The reservoir structure is represented by faulted anticline at the middle of the study with a down going decrease in geometry from S1A zone to S2 zone. It is limited by NE-SW and E-W bounding faults, with a weak aquifer connection from the east.

The analysis of pressure and PVT data has revealed that the reservoir fluid type is dead oil with very low gas liquid ratio (GLR). The simulation results indicate heterogeneous reservoir associated with weak aquifer, supported by high initial water saturation and high water cut. Initial oil in place is estimated to be around 628 MM BBL, however, the oil recovery during the period of production is very low (<10%) because of the high water cut due to the fractures associated with many faults. Hence, secondary and tertiary methods are needed to enhance the oil recovery. Water flooding is recommended as the first step of oil recovery enhancement by changing some of high water cut wells to injectors.

1. Introduction

Reservoir simulation is very efficient tool that help in making decisions with regard to the development of operating fields, locating further producing wells, and the implementation of enhanced oil recovery tasks. It constitutes a focal point of integrated datasets of many categories, i.e. geological, petrophysical, reservoir PVT, and production as well as facilities of computer science and modeling techniques.

Simulation of hydrocarbon reservoir refers to the construction and operation of a model which may be either physical or mathematical, and could imitates the behavior of actual reservoir. A mathematical model is represented by a set of equations that are subject to certain assumptions and could describe the active physical processes in the reservoir. The purpose of simulation is to estimate the field performance (e.g., oil recovery) under one or more producing schemes.

Reservoir modeling usually utilizes a specific computer model to

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describe the fluid flow which allows in-depth analysis of the reservoir (Aziz and Settari, 1979). The computer models are reservoir simulators that design flow in porous media, and they are used to represent, clarify and attempt to solve challenges encountered during flow. It is considered a sort of reservoir management that ensures ultimate recovery of hydrocarbon where operational and financial expenses are greatly minimized (Fanchi, 2006).

Reservoir modeling can estimate the initial oil, gas and water in place with high accuracy since it considers all the detailed information like oil, water and gas saturations distribution within the reservoir in addition to the rock and fluid compressibilities and porosity variation within the reservoir. Capillary pressure is a very important parameter that should be taken in account while estimating the initial oil in place (IOIP). Among the popular simulators that are commonly used in simulating wide range of reservoirs, is the Eclipse simulator which is developed by Schlumberger Company. It has several built-in simulation modules for different reservoir types like, black oil, compositional oil, etc. (Geoquest Schlumberger, 2001; Eclipse, 2009).

A wide range of data categories should be gathered and prepared before running the simulation process. This includes geological and petrophysical information, reservoir performance review, model selection, history matching, predictions and recording output (Carlson, 2003).

The current study focuses on simulating and modeling the Qishn sandstone reservoir. It is a multizone clastic reservoir that is located on the Sharyoof oil field (Block 53)- Masila basin at the east central part of Yemen (Fig. 1). The different petrophysical properties of the sandstone reservoir as concluded from well log and core analyses beside the production, PVT and pressure data are all integrated and used to enhance the simulation model. This includes measurements of core porosity and permeability, water/hydrocarbon saturation, experimental relative permeability of oil and water and capillary pressure measurements as well as specific seismic structural and geological data.

2. Geological setting & reservoir properties

The Marib-Shabowah sedimentary province is very important area in Yemen that includes two large basins, i.e. the Masila basin, and the Jiza-Qamar basin. Masila rift basin is one of the most important basins that is located in middle of Yemen and encounters many hydrocarbon fields with good oil-bearing reservoirs. It is deposited as a result of the Gondwana breakup in the Late Jurassic-Early Cretaceous age during the separation of the African Arabian plate away from the Indian Madagascar plate. Almost all of the Masila oil fields with its hydrocarbon-bearing reservoirs are explored in the Say'un-Masila rift graben, within the Lower Cretaceous-Late Jurassic clastic deposits (Naji and Khalil, 2010).

The details of the different processes and the essential elements that constituted the petroleum system of the Masila basin, is still under investigation. Till now only one petroleum system "Madbi-Biyadh/Qishn" has been identified. An extensive overview has shown that the Madbi shale of the Late Jurassic age is the main

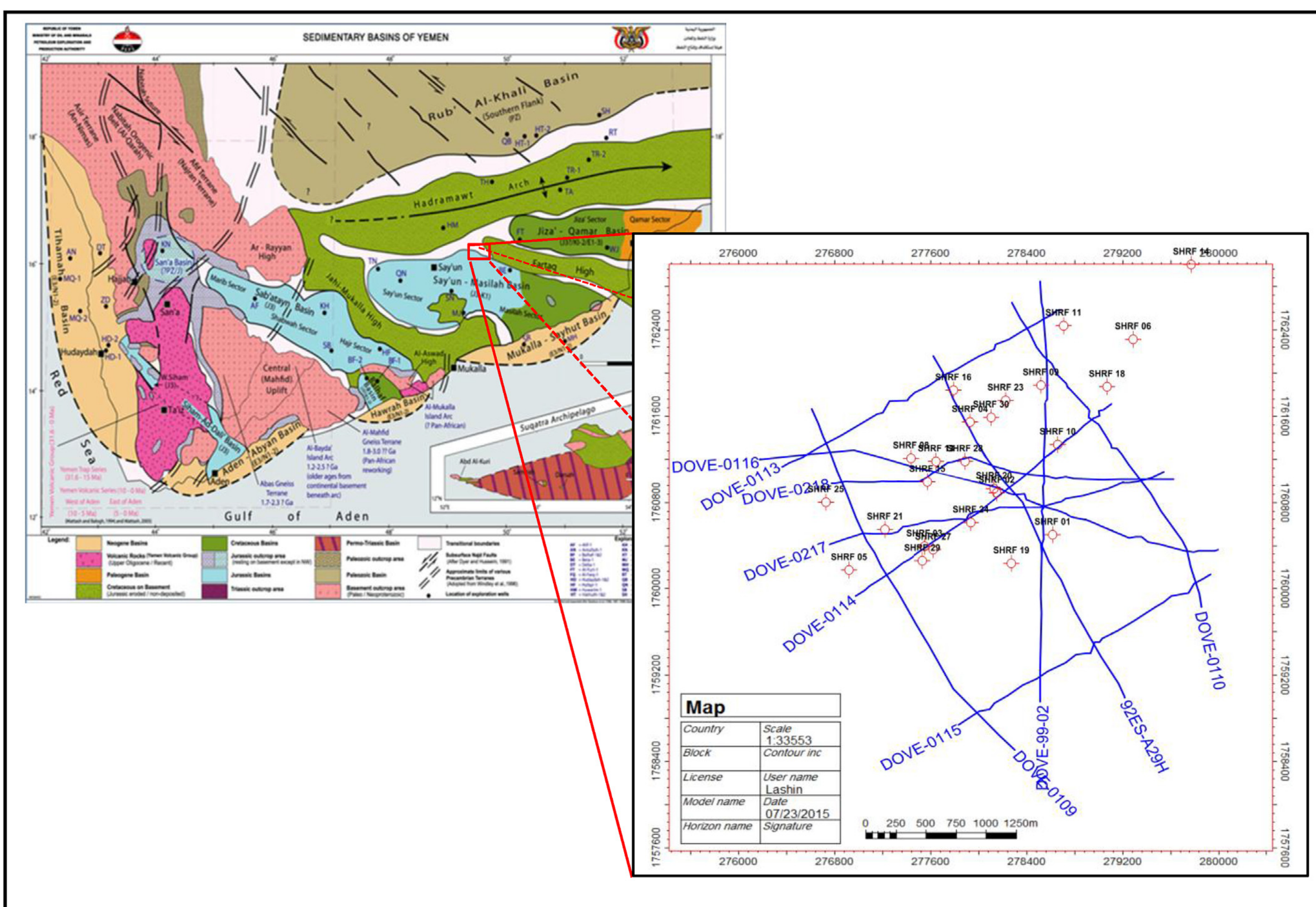

Fig. 1. Location map of Sharyoof oil field showing the well location and seismic lines (after PEPA, 2007; As-Saruri and Wiefel, 2012; Lashin et al., 2016).

source rock, while the reservoir rocks are represented by the Lower Cretaceous Biyadh/Qishn sandstones (Hakimi, 2011; Hakimi et al., 2011, 2012).

Sharyoof field is among the most interesting hydrocarbon-bearing fields that are located in Masila basin and produces oil from the Lower Cretaceous clastic deposits (Qishn Formation). The area is nearly flat with no topographic features and is located about 950 m above sea level. The Qishn Formation is deposited conformably above the Biyadh Formation and is divided into two members; Upper Qishn Carbonate and Lower Qishn Clastic Members. The Upper Qishn Carbonate Member consists of laminated to burrowed lime mudstone and wackestone interbedded with terrigenous mudstone and black fissile shales. It acts as a regional seal rock in the Masila basin and deposited under an alternating open and closed deep marine environment (Beydoun, 1998; PEPA, 2004, 2007, 2011; Al-Matary and Ahmed, 2012). The stratigraphic column of Sharyoof field area is represented in Fig. 2.

Qishn sandstone reservoir exhibits more than 90% of the oil reserves that are encountered in the Qishn Formation, Tawilah Group. Hydrocarbons are also discovered in more seven reservoirs of sedimentary (clastics and carbonates of Lower Cretaceous and Middle to Upper Jurassic) and granitic origin (fractured basement and metamorphic rocks) (Halbouty, 2003; As-Saruri and Wiefel, 2012).

2.1. Reservoir properties

The Upper Qishn Clastic Member is made up mainly of shaly sandstone and minor calcareous sandstone, with considerable amount of shale. The better chances for more hydrocarbon storage and net pay values may exist in the northern, eastern, and southern parts of that basin which have good enough thickness, high effective porosity, minor shale content, and little water saturation. As identified from well logs, Qishn Clastic Member is classified into three main units (S1, S2 and S3) with different reservoir characteristics and hydrocarbon potentiality. The most important is the S1 unit, which is further subdivided into subunits, i.e. S1A, S1B, and S1C and S2. The detailed analysis revealed that S1A and S1C are the main hydrocarbon-bearing zones, then comes S2 unit with little potentiality (Omran and Alareeq, 2014; Lashin et al., 2016).

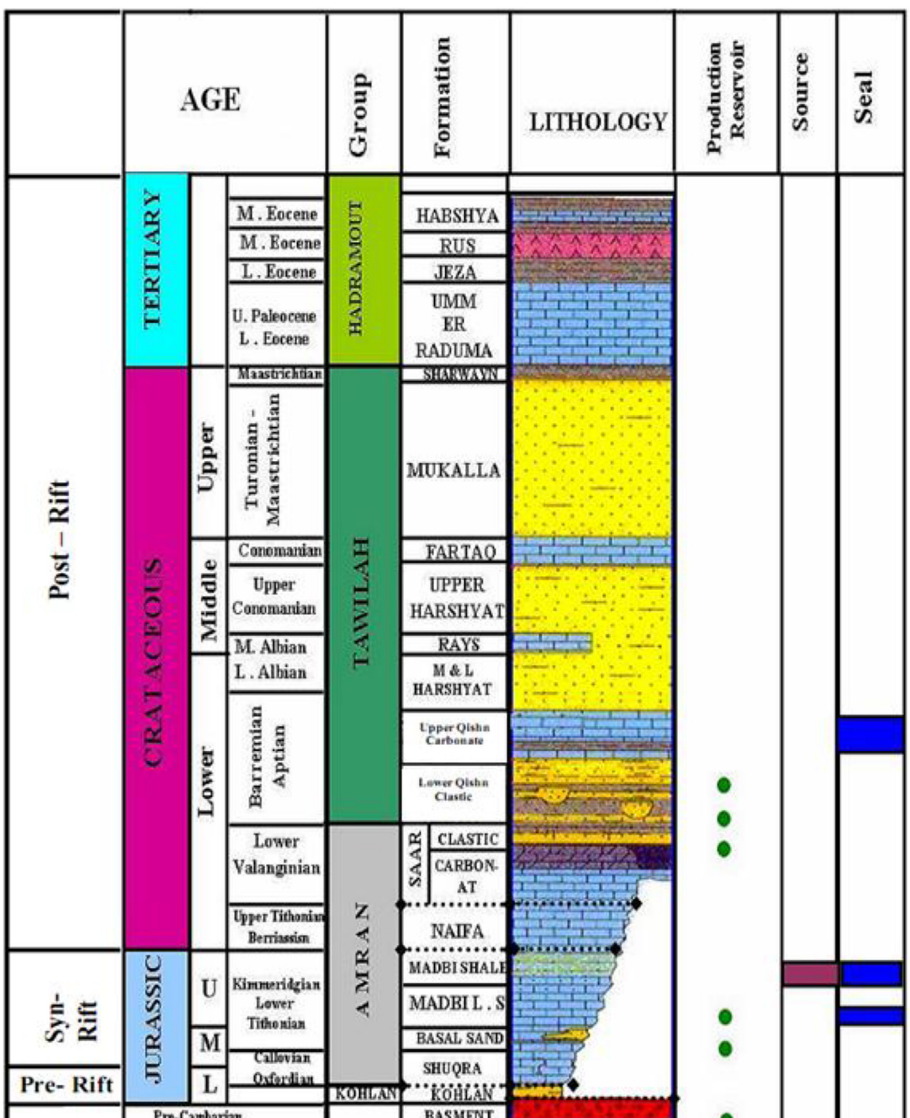

Fig. 2. Stratigraphic column of the Masila basin including study area (Canadian Oxy Company, 2003).

Structurally, Sayun–Masila basin was affected by many faults trending NW–SE and NE–SW as a result of the Gulf of Aden and Red Sea rifting throughout Tertiary age. The analysis of the 2D interpreted seismic sections had clarified that the structure of Sharyoof field area is represented by a big middle horst of faulted anticlinal-structure. The entrapment of hydrocarbons seems to be controlled by the faulted anticlinal-structure and the stratigraphic position of the clastics reservoir associated with the overlying thick-sealing sediments.

3. Datasets & methodology

The available data used in this work include core plugs, petrophysical, production, and PVT, in addition to geological/structural data. The core data include measurements of porosity and permeability, experimental oil and water relative permeability and water saturation and capillary pressure measurements. As the reservoir consists of four subunits (S1A, S1B, S1C and S2), therefore, the data for each subunit is prepared and analyzed, individually. The following measurements and analyses are performed prior to gather the necessary information to develop a geological model of the reservoir, attain the different reservoir properties and after that to run the simulation process.

3.1. Development of geological model

The first step in reservoir simulation is to provide a precise reservoir description and to develop a geological model prior to the simulation process. The geological model is based mainly on the geological information gathered from well records, stratigraphic positions of layers, and petrophysical interpretations as well as the seismic structural elements.

The petrophysical data are based mainly on the information gathered from the work of Omran and Alareeq, 2014 and Lashin et al., 2016. They analyzed the well logging data of 26 wells scattered in Sharyoof field area and concluded that S1 zone of the Qishn reservoir contains three potential sub-units (S1A, S1B and S1C). These subunits beside S2 unit contribute to the main hydrocarbon potentiality in Sharyoof oil field. Faults and seismic structural data that are obtained from the interpretation of the 2D seismic sections are incorporated in the geological model to capture the geometry of the reservoir with its subunits. The occurrences of the implied hydrocarbons are investigated (laterally and vertically) through number of fluid distribution maps and vertical petrophysical analogs.

3.2. Laboratory measurements

3.2.1. Core plug measurements

The core-derived porosity and permeability are obtained from the analysis of the available three core samples taken from SHRF-02 well. An empirical relationship was created for the three S1 subzones (S1A, S1B and S1C) and applied for other wells. These core samples were used also to perform the relative permeability test (flooding test). Prior to apply these data in the reservoir simulation, the average relative permeability was used in order to consider the heterogeneity of the reservoir in terms of porosity, permeability and water saturation. The oil and water relative permeability and capillary pressure measurements were conducted using two methods. The first was the centrifuge method and the second was the mercury injection method.

3.2.2. PVT & production data

The available crude oil measurements (PVT) of six wells that include the most important reservoir properties, i.e., reservoir pressure and temperature, the fluid densities, gas/oil ratios, oil formation volume factors, oil viscosity, fluid and rock compressibilities, are used.

The available production data of twenty wells (SHRF-1 to SHRF-20, see location map at Fig. 1) was recorded and collected daily therefore the average monthly production for each well was calculated. The oil production in these wells started on December 15, 2001 (SHRF-2 well). Well completion data is also provided in the input file of the simulator to avoid assuming a production from the entire pay-zone interval.

3.3. Reservoir gridding & simulation technique

Reservoir simulation is the process of predicting the behavior of a real reservoir from the analysis of a model of that reservoir (Yaghi, 2013). It has a key role in the development and management of a specific reservoir and requires preparing a huge dataset concerning the reservoir dimensions and properties.

Heterogeneity causes problems in formation evaluation and reservoir simulation because reservoirs occupy enormous volumes, but there is limited core and log control. According to the geological and petrophysical analysis, Qishn sandstone was found to be heterogeneous.

All the essential data needed to be used in the simulator input file, i.e. grid cell dimensions, top, bottom and cross thickness was allocated. Similarly the porosity, permeability and water saturation data was assigned for each grid. Since the reservoir consists of four layers with different thickness varying from point to point data, the thicknesses (ΔZ) of all the grids were estimated and fed to the input file. The reservoir dimensions were considered based on the information of the reservoir geometry as derived from the petrophysical and structural analyses. The reservoir is considered to be rectangular in shape depending on its extensions. According to the reservoir length and width, the reservoir area was divided into 200×200 grids based on the Krigging method with grid length (ΔX) and width (ΔY) of 225 ft and 102 ft, respectively (Surfer, 2009).

The aquifer volume (in BBL), aquifer strength or productivity index (in STB/D/psi) and its total compressibility were estimated as well as the datum depth. In addition, the aquifer connection (reservoir face) with the reservoir was determined in order to feed this information to the data input file. Fetkovich aquifer model (built-in model with Eclipse) was used since it is a simplified approach based on a pseudo steady-state productivity index and a material balance relationship between the aquifer pressure and the cumulative influx (Fetkovich, 1969; Eclipse, 2009). This model assumes that the pressure response is felt uniformly throughout the entire aquifer. Also, it is best suited for smaller aquifer that may approach a pseudo steady-state condition quickly and eventually reduces the consuming time of simulation runs. The aquifer inflow is modeled by the equation:

$$Qai\,dt = d(Wai) = J\alpha i[pa + pc - pi + \rho g(di - da)]$$

where; Qai is the aquifer to connecting grid block I inflow rate, Wai is the aquifer to grid block I cumulative influx, J is the specified Productivity Index of the aquifer, αi is the area fraction for the connection to grid block I, pa is the pressure in the aquifer at time t, pi is the water pressure in a connecting grid block I, ρ is water density in the aquifer, di is the grid block depth, da is the datum depth of the aquifer., and pc is the capillary pressure.

The reservoirs layers/zones with different permeability and porosity are modeled by simplified capillary J-function to be used in the input file of the reservoir simulator. This step is very important to account for the heterogeneity of the reservoir in terms of the variation of capillary pressure within the reservoir because of the high dissimilarity of the water saturation. Leverett (1941) J-function concept was used as an averaging tool in order to consider the heterogeneity of the reservoir in terms of porosity, permeability and water saturation.

The Leverett J-function is a dimensionless function of water saturation describing the capillary pressure.

$$J(S_w) = \frac{Pc(Sw)\sqrt{\frac{k}{\phi}}}{\gamma \cos(\theta)}$$

where:

S_w is the water saturation measured as a function of capillary pressure.
P_c is capillary pressure, psi
k is the effective permeability, mD
ϕ is the porosity, dimensionless
θ is the contact angle, degree
γ is the surface tension, dyne/cm

Eclipse 2009.1 software which is one of the leading reservoir simulators in the oil industry has been used in this study. It requires information about the reservoir rock and fluid properties as well as the production data. This task is time consuming especially with the high heterogeneity of the reservoir and the large number of producing wells. FloViz module is used to model and visualize the reservoir (Geoquest Schlumberger, 2001). This tool improves understanding of reservoir heterogeneity effect on the fluid flow in porous media and help in studying the different scenarios of water flooding that can enhance the oil recovery during the reservoir development. It also assists in the selection of the best locations for injection wells, the water injection rate and injection pressure according to the flooding scheme (5-spot pattern, 7-spot pattern … etc.).

As an input, user creates text file with a set of keywords that must be located in particular section. Such data file gives complete description of a reservoir. The dimensions were selected to be 200 × 200 × 4 and the total number of grids assigned is of 160,000 grid cells.

Finally the simulation process will result in, 1) an estimate for initial fluid in place, gas, oil and water production and recovery, 2) pressure and fluid saturation distributions in the entire reservoir, 3) history matching of the reservoir as well as 3D visualization of the reservoir.

4. Results

The results implied from the measurements of core plugs, analysis of pressure and PVT data and the reservoir simulation and modeling are represented in Figs. 3–18.

Fig. 3 shows the vertical reservoir analog of SHRF-4 well that was selected as an example to demonstrate the properties and hydrocarbon potentiality of the Qishn clastic reservoir. This well is located in the north-western part of Sharyoof field (see Fig. 1 for

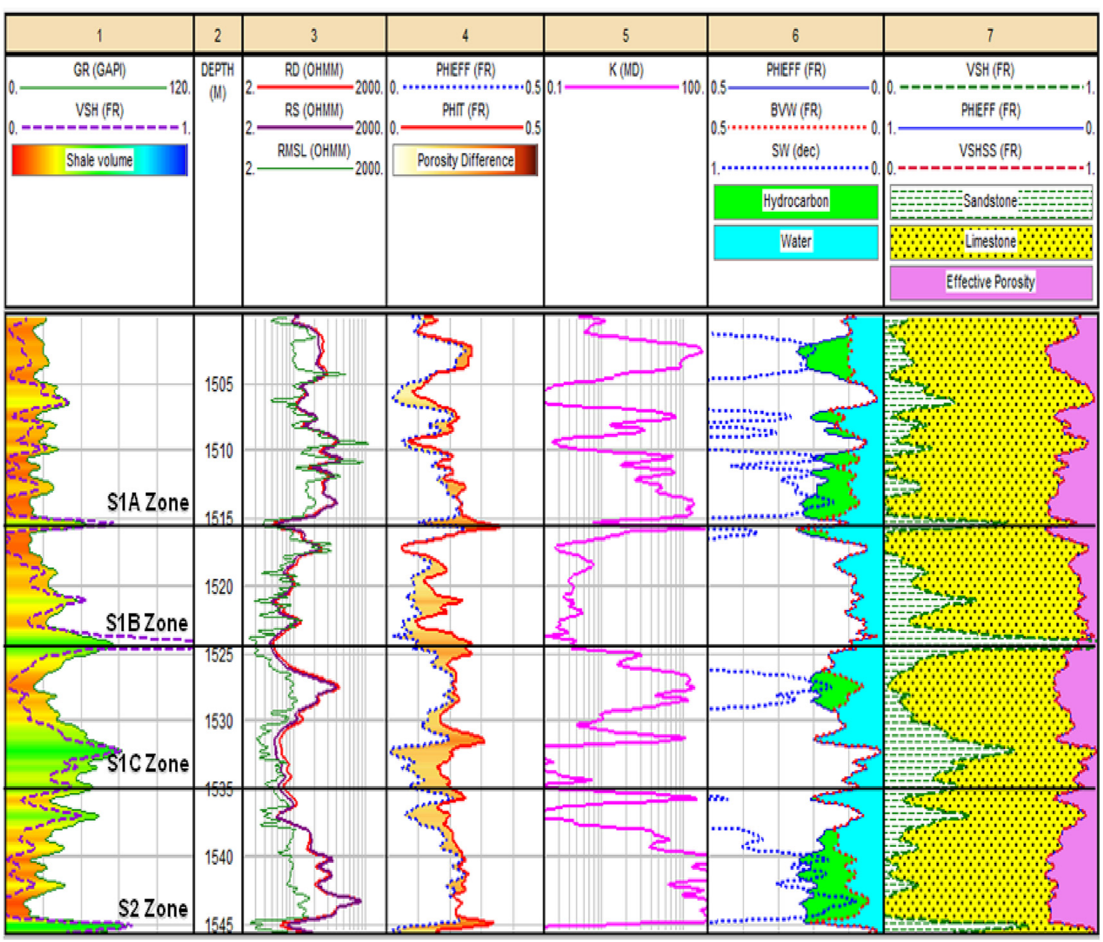

Fig. 3. Vertical petrophysical analog of Qishn clastic reservoir, SHRF-4 well.

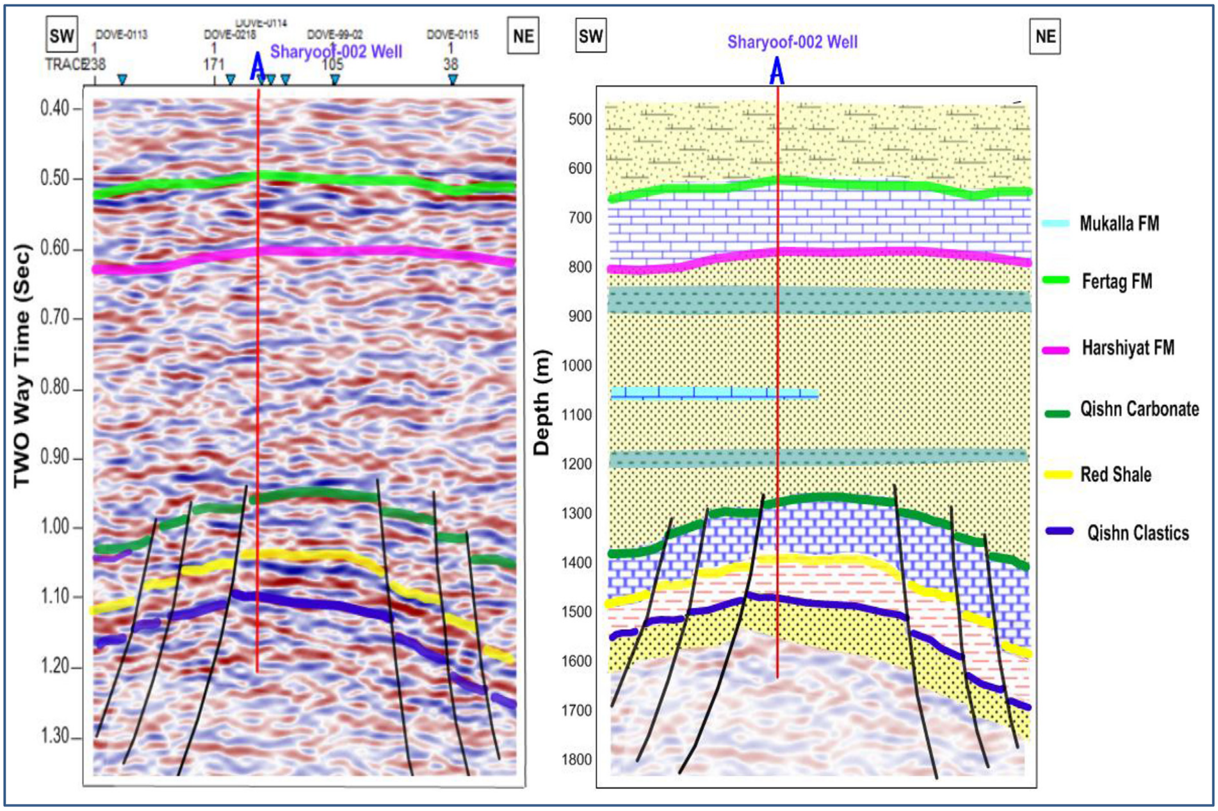

Fig. 4. An interpreted NE-SW geo-seismic cross-section (A29H) passing through the study area.

location). Hydrocarbons are indicated at two levels in S1A zone. An upper zone (1501.5 m and 1505 m) with good porosity of 24%, average permeability of 66 mD, hydrocarbon saturation of 60% and low shale volume of 8%, and a lower low-permeability zone (1510 m and 1515 m) with hydrocarbon accumulation up to 71%, an effective porosity range of 12%–24%, and shale volume less than 5%. Meanwhile for S1C zone, hydrocarbons are indicated at the middle (1526.5 m and 1529 m) with an average hydrocarbon saturation of 45%, and high effective porosity up to 21%. Another good hydrocarbon anomaly is located at the lower part of S2 zone (depth range of 1538 m–1544.7 m). Average values of 24%, 12%, 68% and 32% are recorded in front of this zone for the effective porosity, shale volume, and water and hydrocarbon saturations, respectively. In general, the higher hydrocarbon content is associated with good permeability and effective porosity values. This is indicated by the tight separation between total and effective porosities where no meaningful deference is indicated in 4th track. While, S1A zone attains the best reservoir properties, no hydrocarbon accumulations are recorded in front of the S1B zone.

One interpreted geo-seismic cross-section is represented in Fig. 4. It shows that Qishn clastics reservoir is affected by big horst of a faulted anticline structure at the middle bounded by a group of simple normal faults at the extreme boundaries. The orientation of these faults is mainly to the NE-SW and E-W directions. Most of the drilled wells are penetrating through horst structure. The reservoir is capped and sealed by a good thickness of impervious shales (Red Shale) and carbonates (Qishn Carbonates Member). The underlying section of the Madbi shales (Jurassic rifts) constitutes the main source rock of the generated hydrocarbons (USGS, 2002).

Figure 5a, b and c clarifies the fluid distribution (water and hydrocarbon) and permeability maps for the three hydrocarbon-bearing zones ((S1A, S1C, and S2) within the reservoir area, as well as the reservoir/aquifer boundaries (modified after Lashin et al., 2016). A number of NW-SE and E-W faults are bounding and cutting through the reservoir at the northwest and southern parts. It seems that the reservoir extension is bounded by one major NE-SW sealing fault at the north and northwest, while a series of E-W faults draw the limits of the reservoir at the southern parts. However, the reservoir is supported by a weak aquifer connection from the east. Furthermore, the reservoir geometry and volume decrease downward as moving from the reservoir zones S1A to S2. These maps revealed that most of the detected hydrocarbons (for S1A, S1C, and S2 zones) are located as NE-SW oriented closures at the middle of the study area. The reservoir becomes much poorer in properties towards the northeast where hydrocarbon saturation reaches less than 25% and permeability record is around zero.

Fig. 6 shows the core-derived porosity and permeability relationship for each of the different sub-units of S1 zone (S1A, and S1C) and S2. The following equations are concluded:

$$\text{For S1A,}\quad K = 0.0172e^{0.4344\phi} \quad \left(R^2 = 0.81\right)$$

$$\text{For S1C,}\quad K = 0.0007e^{0.6365\phi} \quad \left(R^2 = 0.92\right)$$

$$\text{For S2,}\quad K = 0.0007e^{0.6365\phi} \quad \left(R^2 = 0.93\right)$$

where, K is the permeability, mD, and ϕ is the effective porosity, fr.

These equations can be further applied to provide a good approximation for the permeability in other wells, whenever core data are not available. A good matching is observed between the porosity and permeability ranges obtained from the core measurement with those obtained from logging analyses (R^2 ranges

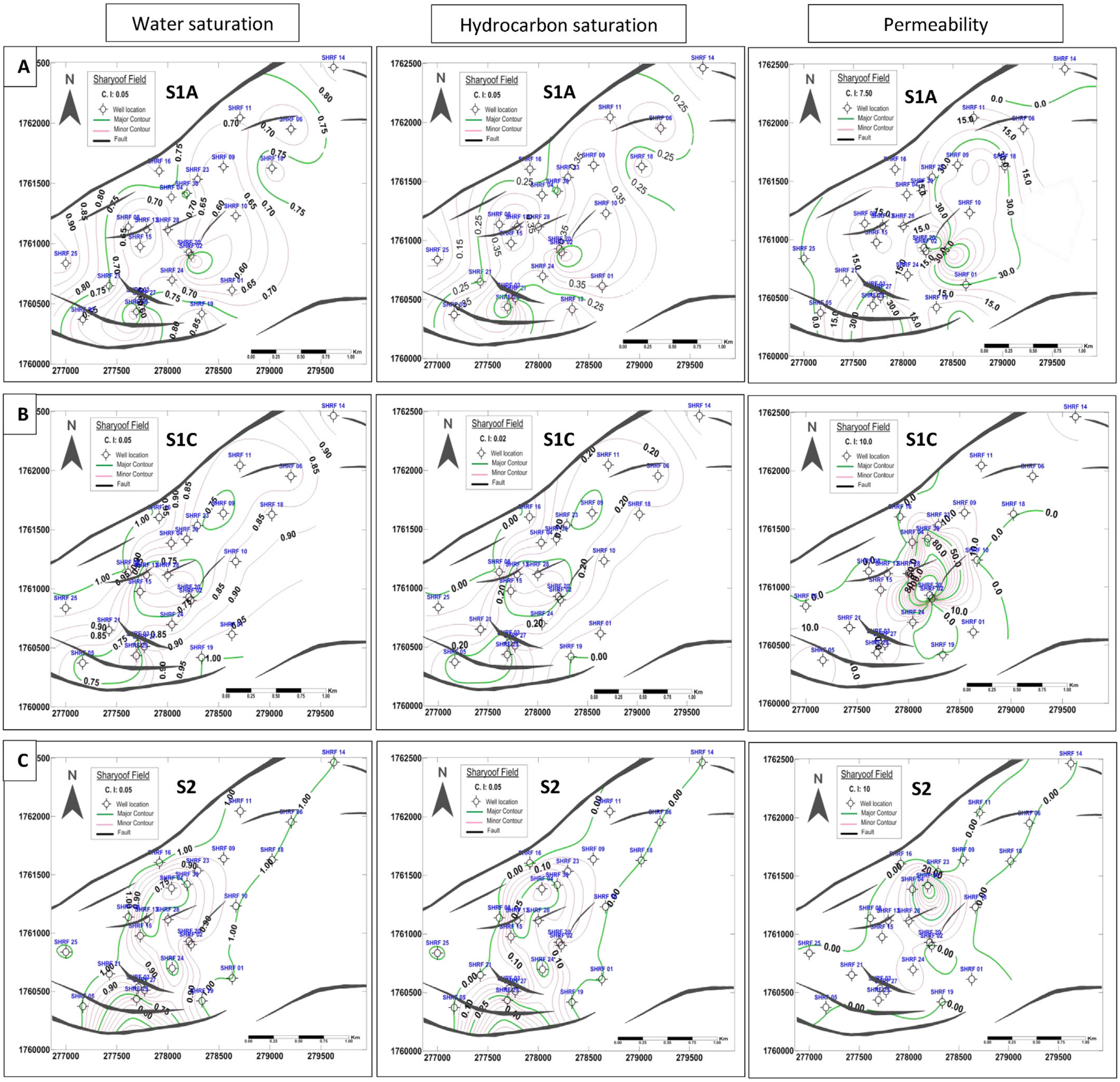

Fig. 5. Water saturation, hydrocarbon and permeability distribution maps of (a) S1A unit, (B) S1C unit and (C) S2 unit.

from 0.8 to 0.93). Three core flooding experiments were done on three core samples taken from different locations of the reservoir. The relative oil and water permeability curves were constructed based on these experiments. Fig. 7 shows the oil and water average relative permeability versus water saturation for the three core samples. Furthermore, the results of the mercury injection capillary pressure test are plotted in Figs. 8 and 9.

The average initial water saturation was found to be 0.10 which is conformed to petrophysical analysis. As stated earlier Qhisn sandstone is not isotropic, in terms of the porosity, permeability, capillary pressure and water saturation distributions and hence the relative permeability varies thought the reservoir. Because only one oil/water relative permeability curve can be used as an input in the simulator, the concept of J-function is used (Leverett, 1941). The J-function is inversely proportional to the water saturation and its-maximum value is corresponding to the initial water saturation of 0.10 (Fig. 9).

As mentioned above, six crude oil samples were used to conduct the experimental PVT test. The average bubble point pressure of these samples was about 34 psia. The average reservoir pressure was 1415 psia with an average reservoir temperature of 140 °F. The Constant Composition Expansion test (CCE) or flash test data and the pressure vs. oil viscosity data are presented in Fig. 10 (A & B). Based on the PVT data the reservoir fluid type is believed to be dead oil where the gas liquid ratio (GLR) is too low. In addition, the average bubble point pressure is determined to be 34 psia which confirm the dead nature of the crude oil. Tables 1 and 2 represent the fluid densities at surface conditions and the PVT properties of

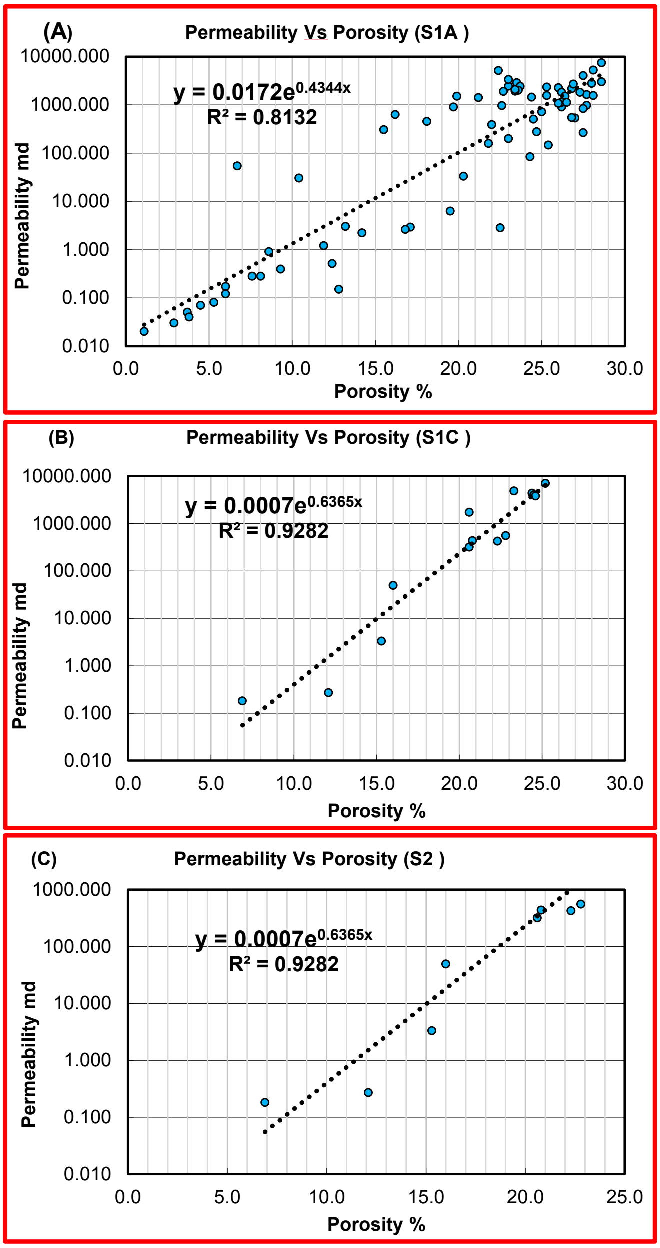

Fig. 6. Core porosity-core permeability relationship for Qishn clastic reservoir, SHRF-2 well: a) S1A unit, b) S1C unit and c) S2 unit.

live oil (without dissolved gas).

The oil and water productions in addition to the water cut versus producing time are estimated. Among the total drilled 29 wells, only 23 wells were producing while the other wells are dry. As shown in Table 3, production did not start at the same time for all wells. While SHRF-2 well was the first producing well (Fig. 11A), SHRF-1 well was drilled first. SHRF-1 well was used as an observation well and started production 23 days later as presented in Fig. 11B. However, it was noted that SHRF-2 well has the highest total oil production during the production period, whereas the lowest total oil production was for SHRF-16 well (Fig. 12).

The completion of the wells was taken into account during the simulation process according to the available data otherwise it was assumed that the well is completed through the whole productive pay zone interval. For example some of the wells were completed in two isolated zones (i.e. Layers S1A and S1C) while others were completed only in the upper zone (layer S1A) to prevent water coning.

5. Discussions

The results obtained from the simulator are categorized into 3D-visualization model, initial fluid in place estimation, pressure distribution in the reservoir, fluid saturation distribution in the entire reservoir, oil and water production and recovery estimation and history matching (Figs. 13–18).

5.1. Visualization model

The visualization model shows the heterogeneity of the reservoir in terms of reservoir top and thickness variation (Fig. 13). It also shows the movement of oil and water phases towards the producing wells during the production. The fluid movement depends on several parameters like pressure difference between the reservoir average pressures and wells flowing bottom-hole pressures and relative permeability of oil and water which affect the mobility ratio of the moving fluids in the porous media. Based on the petrophysical properties, it was noted that the reservoir is associated with an aquifer extending towards the northeast direction. This aquifer is weak, small and highly fractured (See, Fig. 5).

Fig. 13(A & B) displays 3D representation of the Qishn reservoir from two view angles. It shows the initial oil saturation distribution in the four zones of the reservoir indicating that zone one (layer S1A) has the highest oil saturation compared with the other three zones (Fig. 13 A). Fig. 13B demonstrates that S2 zone is almost water saturated except the middle part of the zone which attains an average oil saturation of 40%.

5.1.1. Initial oil in place

The reservoir was divided into small segments or grids that attain all the detailed information. The necessary equations were applied for each grid to sum-up the total fluid in place for all grids. This procedure gives much better estimation of the fluid in place compared to other conventional methods. The results show that the proven oil reserve is about 628 MMBBL and 63 MSCF as solution gas reserve. The low initial gas in place indicates that the type of reservoir fluid is dead oil. The volume of water was also estimated to be 1.10 MMMBBL.

5.1.2. Pressure distribution

The pressure values of all the reservoir grids were estimated based on the oil and water saturations as well as J-function based on the capillary pressure tests. Fig. 14 shows the initial pressure distribution within the upper S1A zone of the reservoir which was estimated and generated using the FloViz module. It can be seen that the initial pressure was about 1574.6 psia at time of zero in all cells within the reservoir (Fig. 14A). Meanwhile the pressure distribution after about one year of production was dropped around the producing wells and reached near to 860 psia as shown in Fig. 14B. On the other hand, Fig. 14C displays the pressure distribution after two years of production, where the pressure dropped into about 854 psia in all cells within the reservoir. The area located in the upper right corner shows an exception, where the pressure reached to 1217 psia due to non production contribution.

5.1.3. Oil and water production and recovery estimation

The Sharyoof field started producing on December 15, 2001 till now. Only two years of production were simulated since simulation of the full period of production needs full data sets, much time as well as high machine memory capacity. During the first two years of the reservoir life time only 6 wells (SHRF-1, SHRF- 2, SHRF-3,

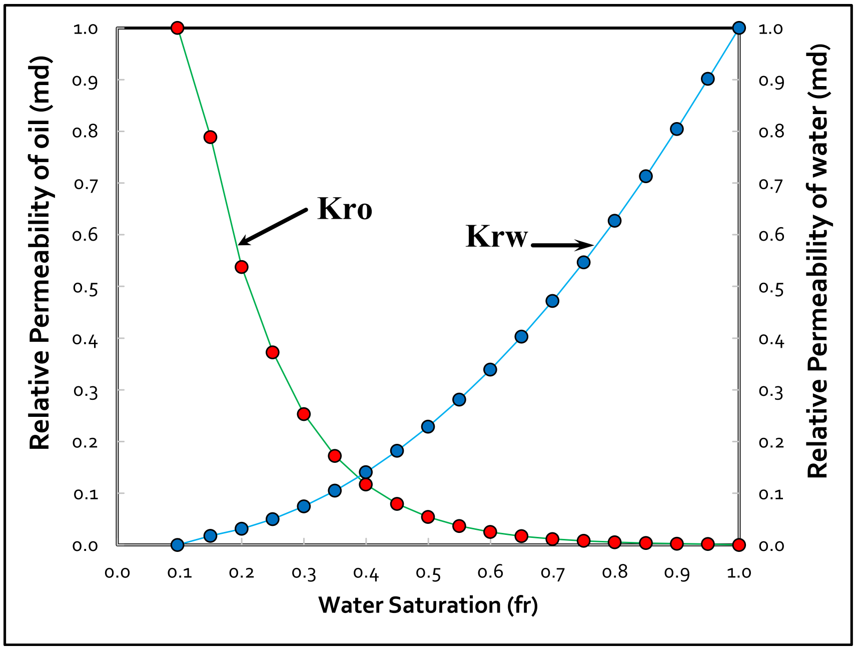

Fig. 7. Average relative permeability plot of SHRF-2 well.

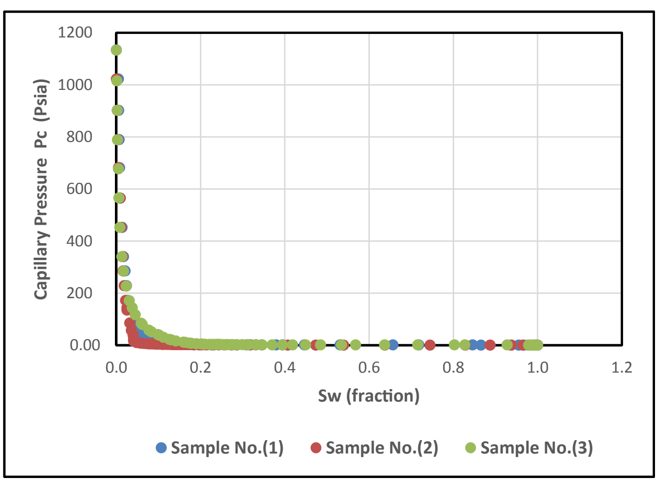

Fig. 8. The capillary pressure plot of the three core samples, SHRF-02 well.

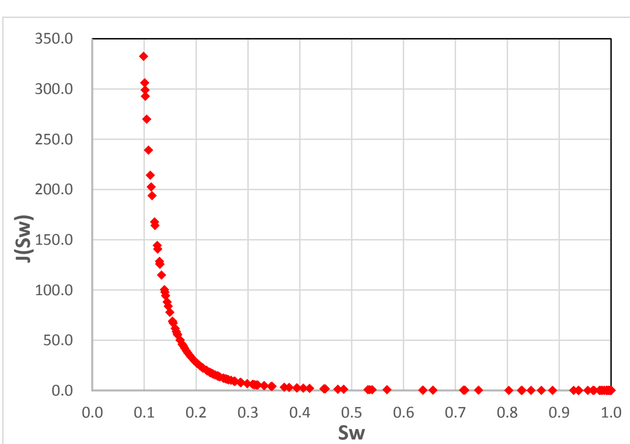

Fig. 9. The dimensionless J-function plot.

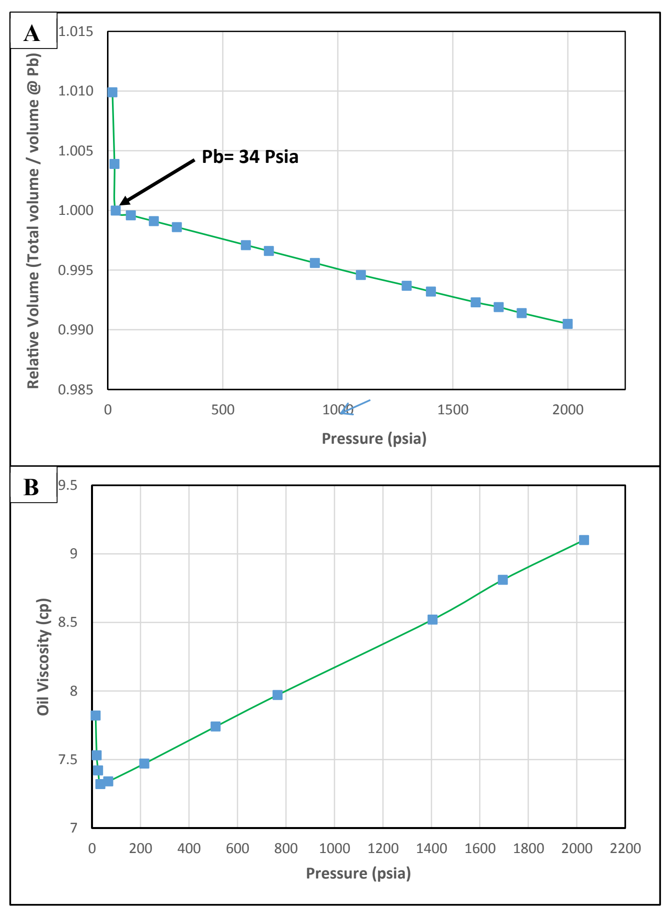

Fig. 10. A) The pressure-volume plot of the Constant Composition Expansion test (CCE) and B) the pressure-oil viscosity plot.

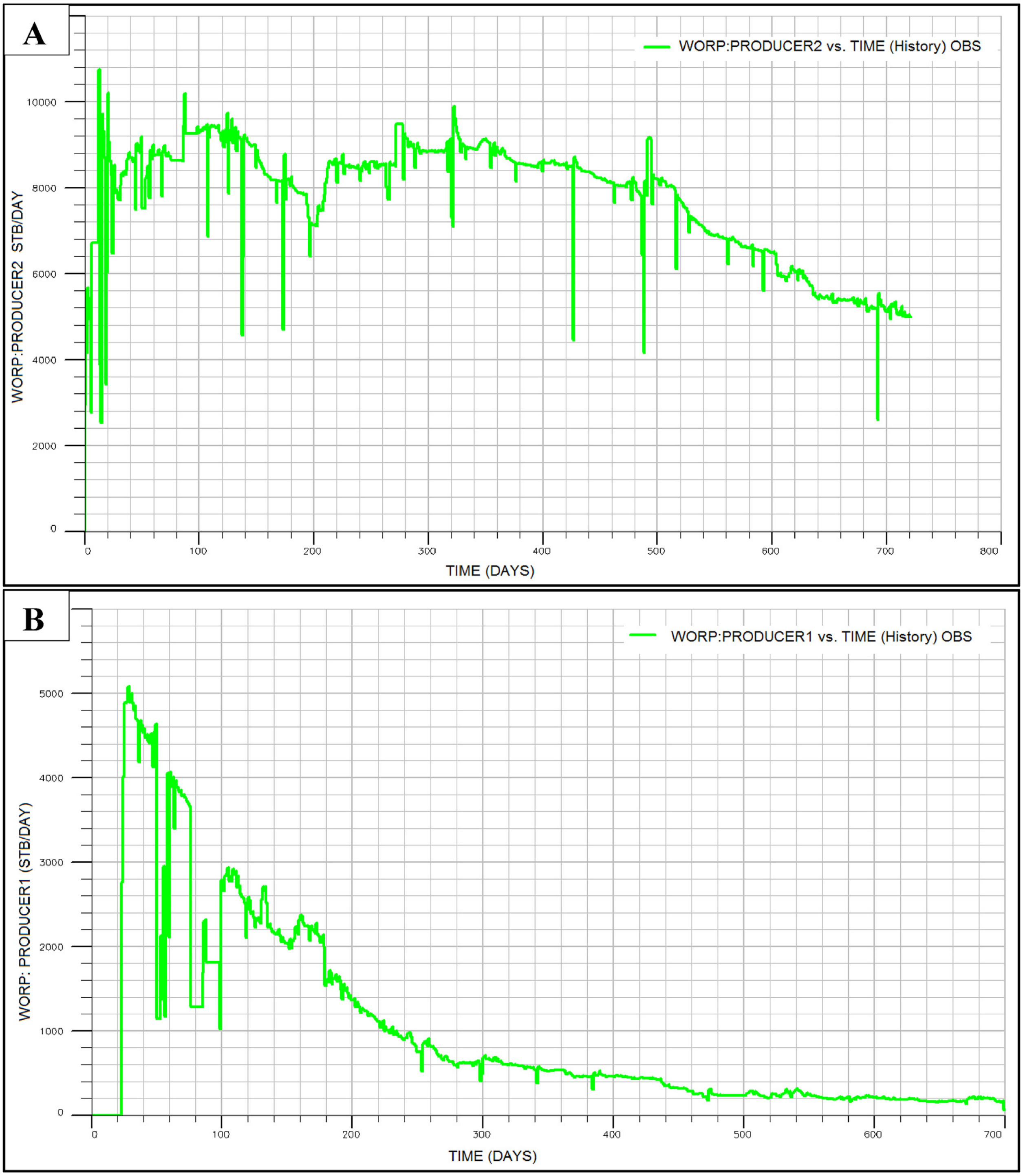

Fig. 11. The oil production during the first two years of, A) SHRF-2 well and B) SHRF-1 well.

SHRF 4, SHRF-5 and SHRF-6) were producing at Sharyoof field and these wells were considered in simulation process (Fig. 15A). Fig. 15B shows the simulated oil production of these wells during the first two years.

Similarly, the water production and water cut for the six wells were simulated and plotted versus time. Fig. 16A exhibits the total oil recovery during the first two years for the six wells. It was noted that only 2% of the original oil in place was recovered during the first two years. This implies that reservoir driving mechanism is too weak since there is no gas in solution driving mechanism. Also, the aquifer volume is too small and its productivity index is too low. Furthermore, some of the simulated wells were equipped with Electric Submersible Pump (ESP) after some time of production because the well flowing bottom hole was not enough to left the oil. The average reservoir pressure decline during the first two years of the reservoir time life is represented in Fig. 16B. It shows a decline from 1500 PSI to less than 900 PSI. Meanwhile, Fig. 16C shows the bottom hole pressure (BHP) of one selected well (SHRF-3 well),

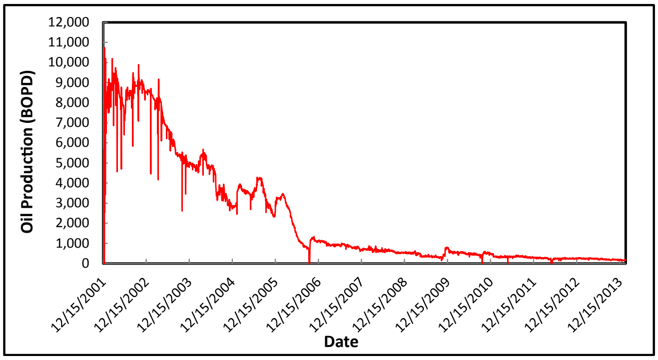

Fig. 12. The oil production history of SHRF-2 well.

5.1.4. History matching

The reservoir model is validated by matching the simulated results with the observed or real data collected during production. Among the important parameters that are used in history matching, is the observed oil production versus time which is compared with the simulated oil production of the same wells. Based on the availability of the data, other parameters can be used in history matching such as, well water production, water cut, bottom-hole pressure and average reservoir pressure. The oil production data of six wells is used in history matching process. Fig. 17A shows an example of the oil production match of SHRF-1well. Both of the actual well production and the simulated results show dramatic decline of production especially during the early time (first three months) where oil production drops from 5000 BBL/D to almost 2500 BBL/D. The match between the actual and the simulated data is very good and accepted. The observed oil production of SHRF-1 well is fluctuated especially during the early period of production

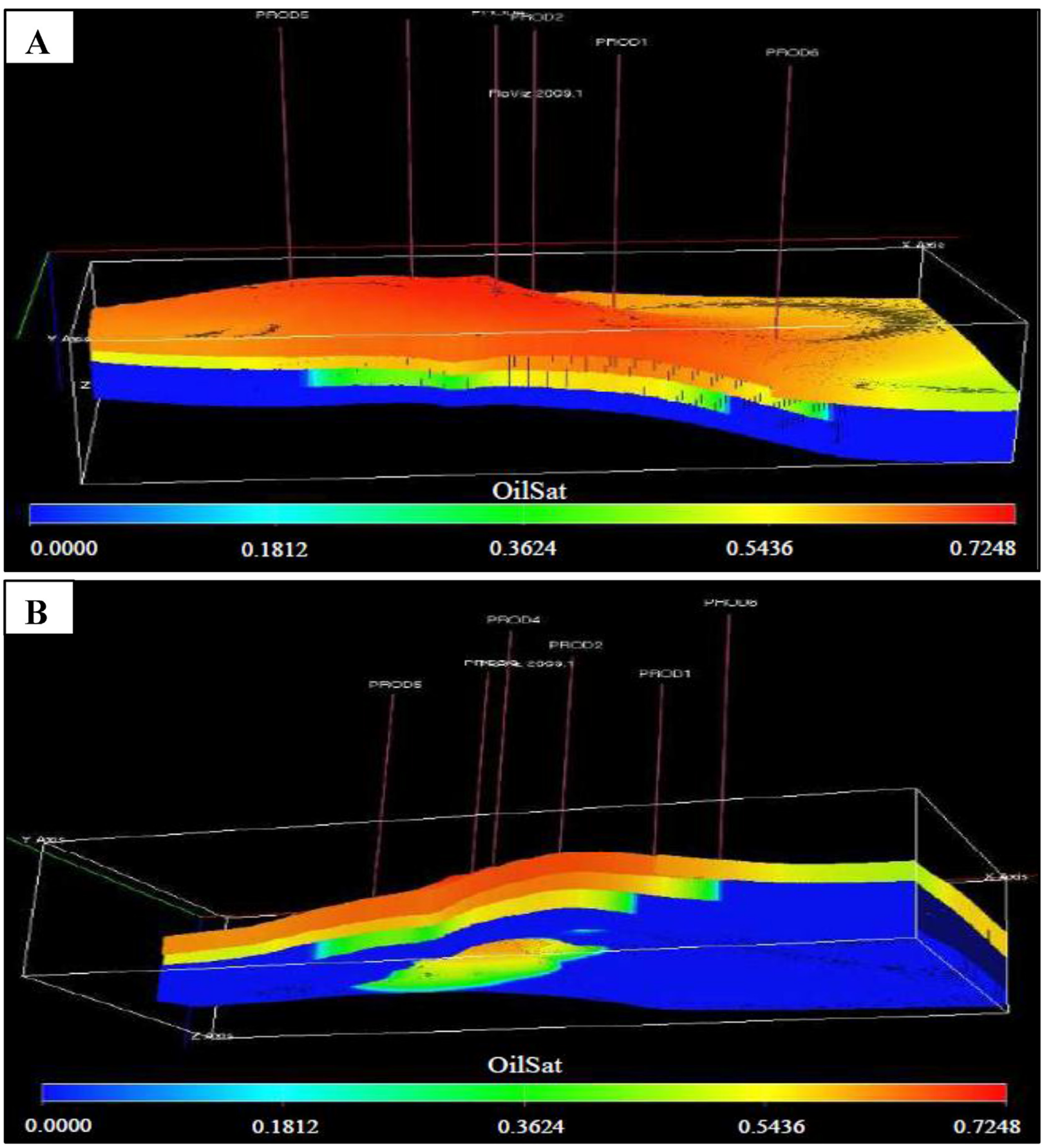

Fig. 13. 3D initial oil saturation distribution in the reservoir, A) lateral view and B) bottom view.

where a significant BHP drop is observed during the early time during the first 100 day of production from more than 1400 PSI to less than 100 PSI.

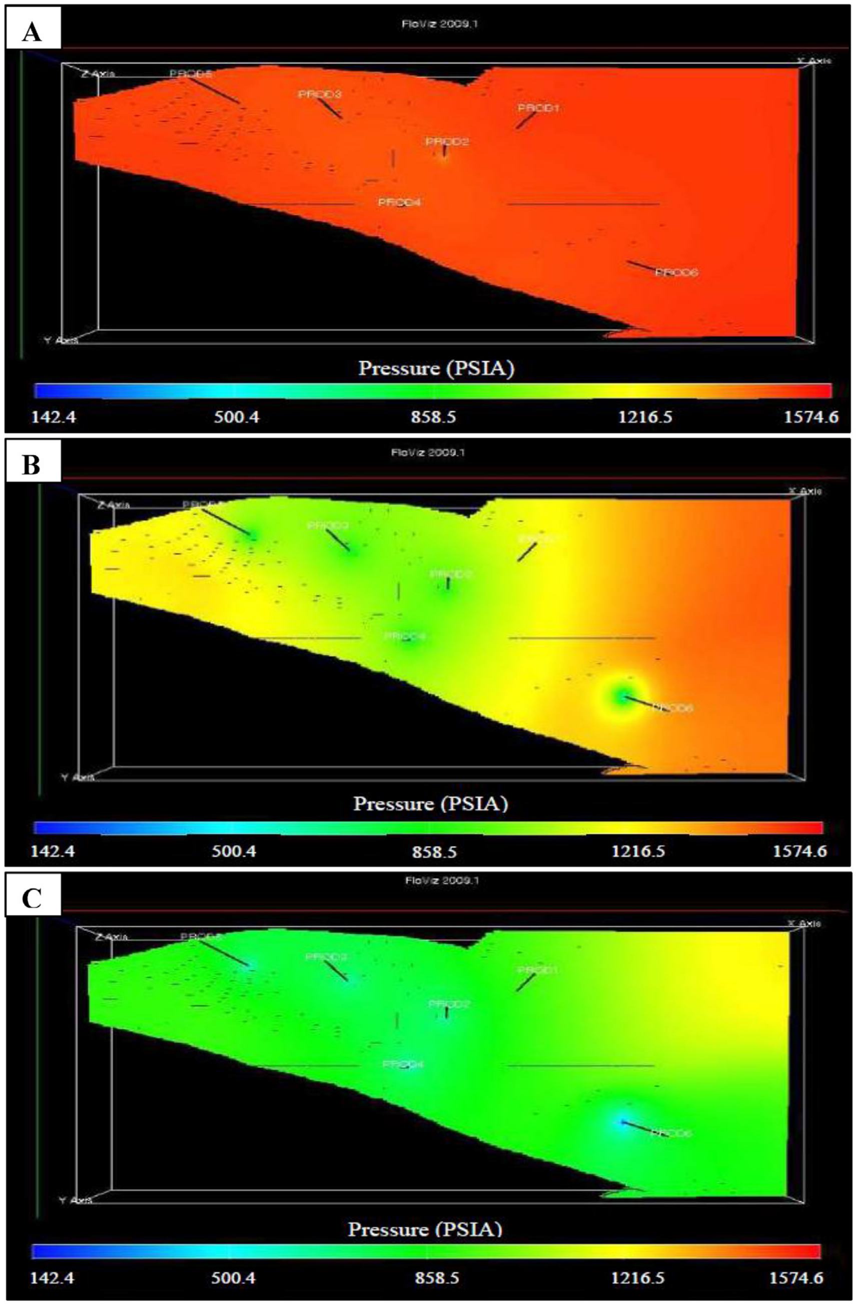

Fig. 14. A) Initial pressure distribution, B) Average pressure distribution after one year of production, and C) Average pressure distribution after two years of production, within the upper S1A zone of the Qishn reservoir.

time. Such fluctuation is not related to the reservoir performance but is due to pump condition. It is noted also that oil production sometimes drops to zero due to pump problems, which means stop in production for several days to replace the pump. Fig. 17(B & C) displays another example of good oil production match in both of the SHRF-2 and SHRF-3 wells, respectively. However, the performance of SHRF-2 well is much better compared with the other wells with an average oil production of 7000 BBL/D.

The worst case of matching is exhibited by SHRF-6 and SHRF-5 wells (Fig. 18A&B). Different scenarios of simulation are assumed in order to improve the match, but it seems that no meaningful improvements are achieved. However, the matching result of SHRF-5 well is better than that of SHRF-6 well (Fig. 18B). One possible reason of such mis-matching is the location of the SHRF-6 and SHRF-5 wells at the boundary of the reservoir, to the east and west of the study area, respectively where no sufficient data are available (see, Fig. 1 for location). The presence of minor dissecting faults as well as the high heterogeneity of the reservoir constitutes another reason. In general, the reached match for the other wells is good and can be accepted to validate the model.

Based on simulation results, different scenarios for oil production improvements can be formulated. The fact that oil recovery during the period of production is very low (<10%) due to high water cut related to presence of many dissecting fractures and faults, suggests applying additional secondary and tertiary methods to enhance the oil recovery. Water flooding is recommended as the first step of oil recovery enhancement by implementing some high water cut wells to be injectors. Also, further investigation on both

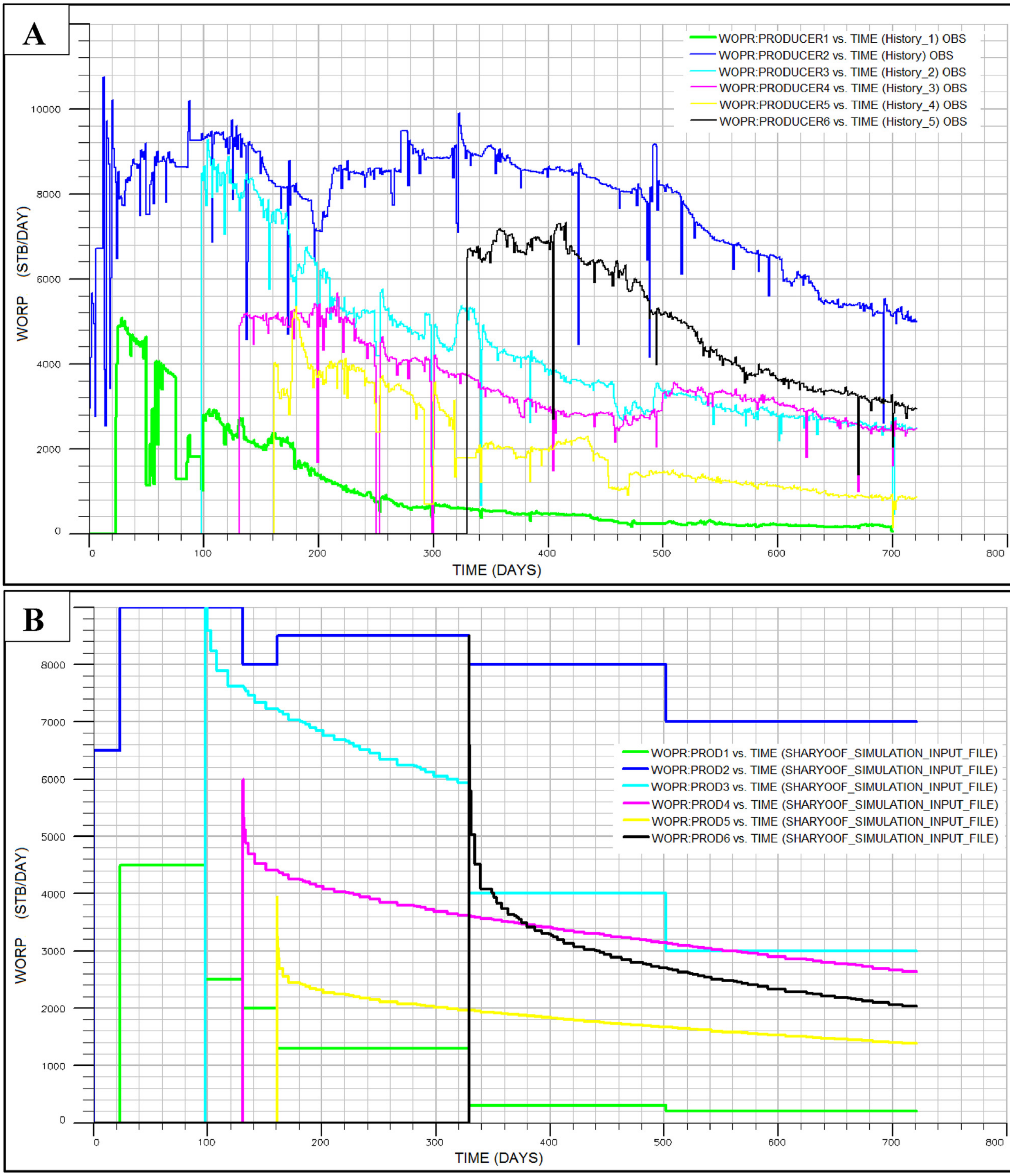

Fig. 15. A) The production history, and B) The simulated oil production of Sharyoof field during the first two years.

core samples and reservoir fluids, like wettability alteration is suggested in order to study the feasibility of implementing some new solvents (steam solvent co-injection) since the reservoir fluid is heavy and viscous.

6. Conclusions

The following are the most important points that are concluded from this study:

- A geological model is constructed for the Qishn sandstone reservoir based on the geological, petrophysical and seismic structural data, prior to simulate the reservoir.
- The reservoir is classified into four subunits (S1A, S1B, S1C and S2) with different petrophysical properties, out of them three are hydrocarbon-bearing (S1A, S1C and S2). S1A subunit is

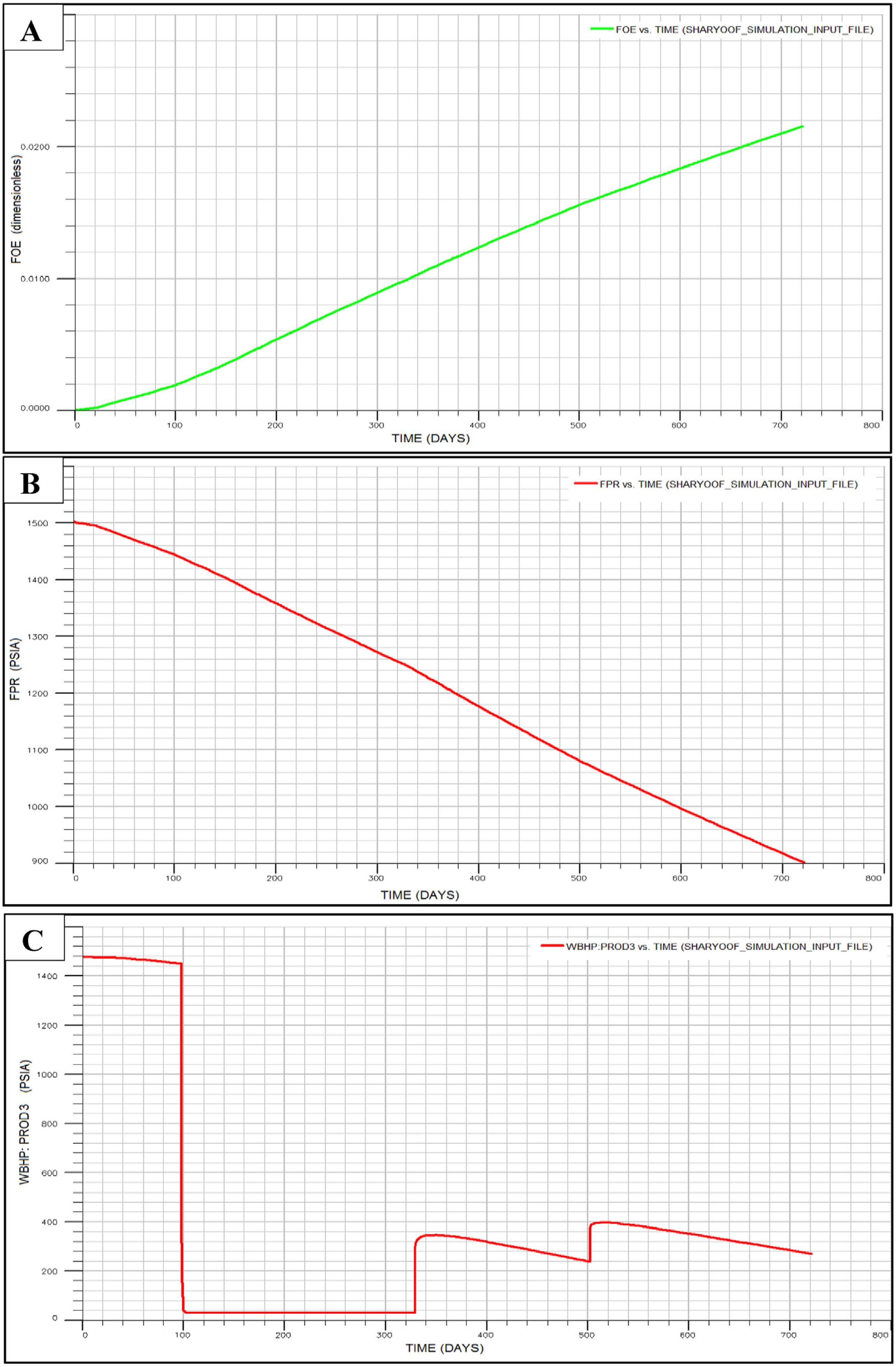

Fig. 16. A) The total oil recovery, B) Average reservoir pressure, and C) the bottom-hole pressure during the first two years, of SHRF-3 well.

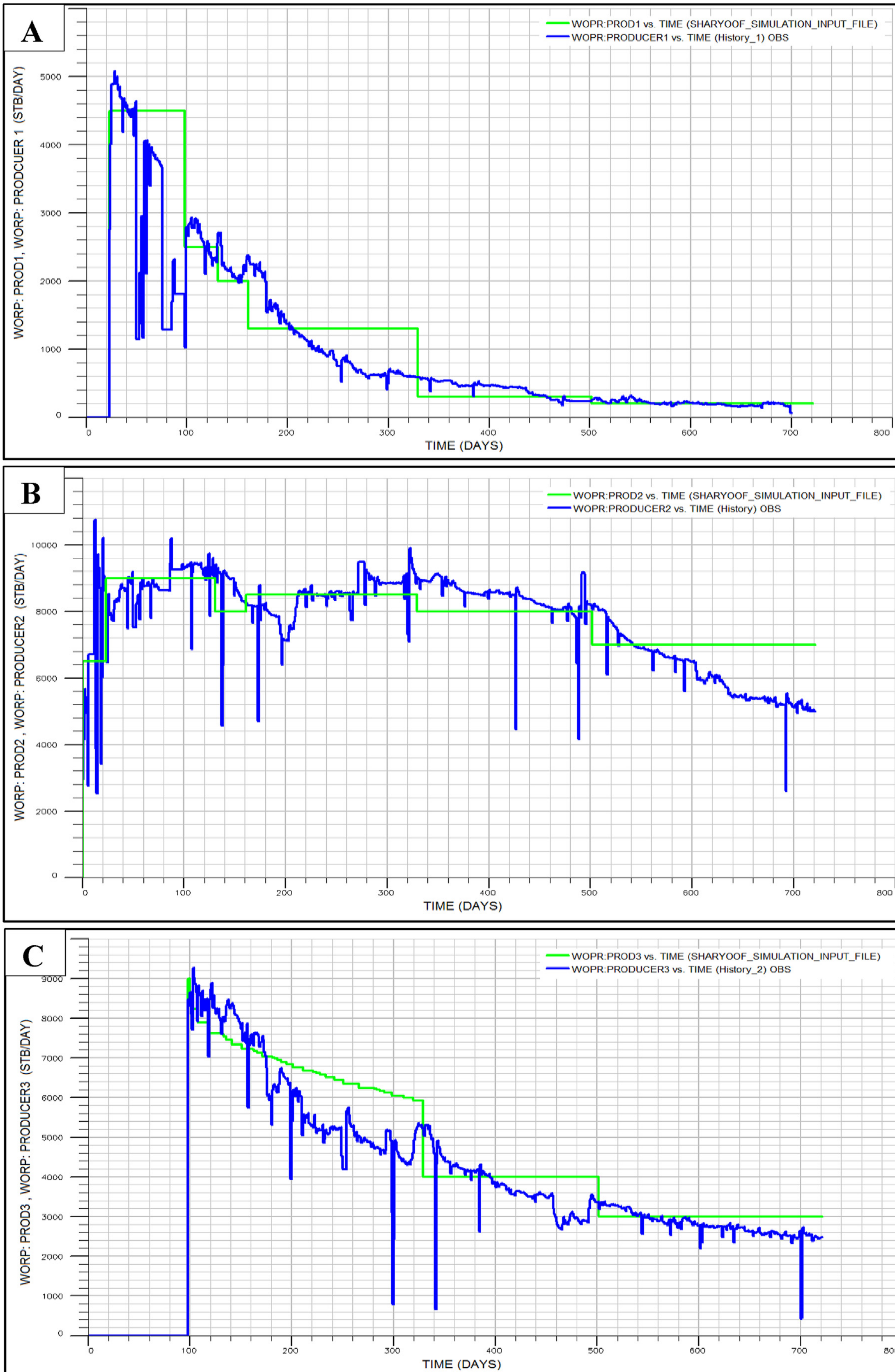

Fig. 17. Acceptable history matching during the first two years for A) SHRF-1 well, B) SHRF-2 well and C) SHRF-3 well.

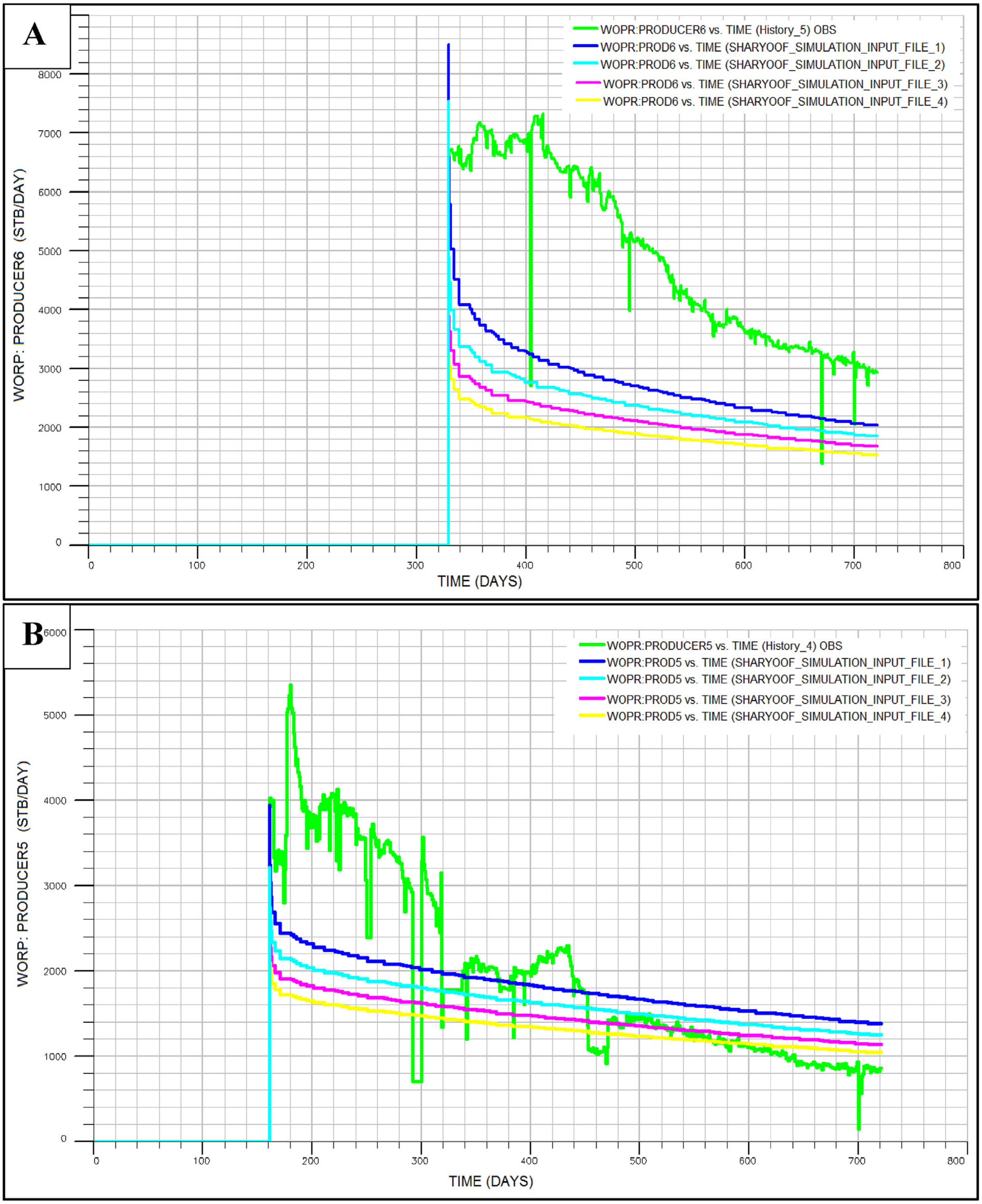

Fig. 18. Bad history matching of, A) SHRF-6 well, and B) SHRF-5 well and different scenarios to improve the matching.

considered the best reservoir in terms of low range of shale volume (4–21%), good total and effective porosities (16–23%, 11–20%) and good hydrocarbon saturation (up to 65%).

- The reservoirs zones of the Qishn sandstone is bounded with major NE-SW and E-W sealing faults at the extreme north-western and southern parts of the study area. The reservoir is connected with a weak aquifer from the east.
- The reservoir heterogeneity is high since the permeability and porosity variation is high. The initial water saturation distribution is varied indicating the presence of fractures throughout the entire reservoir causing high water production. The oil recovery is relatively low although the initial oil in place was promising.
- The visualization model of the reservoir has illustrated the phase's movement toward the producing wells. It showed the

Table 1
The fluid densities at surface condition.

Fluid	Oil	Gas	Water
Density(gm/cm^3)	0.8687	0.0011	1.010
Density (Ib/ft^3)	54.2069	0.06864	63.020

Table 2
The PVT properties of live oil (with dissolved gas).

GLR SCF/STB	P Psi	FVF BBL/STB	VIS CP
0.00070	14.70	1.025	7.820
0.00071	19.00	1.032	7.530
0.00071	25.00	1.041	7.420
0.00072	34.00	1.432	7.320
0.00073	67.00	1.396	7.340
0.00074	100	1.360	7.370
0.00074	200	1.324	7.460
0.00075	216	1.288	7.470
0.00076	510	1.252	7.740
0.00076	765	1.216	7.970
0.00077	1405	1.180	8.520
0.00078	1695	1.144	8.810
0.00079	2030	1.108	9.100
0.00079	3000	1.104	9.980
0.00080	5000	1.054	11.780

Table 3
Starting production time of the studied wells at Sharyoof oil field.

Well	Production	
	Start	End
SHRF-01	07-Jan-02	14-Nov-03
SHRF-02	15-Dec-01	Till date
SHRF-03	22-Mar-02	06-Oct-07
SHRF-04	19-Apr-02	04-Feb-14
SHRF-05	24-May-02	18-May-05
SHRF-06	08-Nov-02	04-Feb-14
SHRF-08	14-Mar-03	25-Aug-04
SHRF-09	03-Dec-03	04-Feb-14
SHRF-10	18-Jul-04	18-May-10
SHRF-11	25-Aug-04	04-Feb-14
SHRF-13	14-Apr-05	04-Feb-14
SHRF-14	18-May-05	Till date
SHRF-15	30-Aug-05	21-Mar-11
SHRF-18	21-Jun-06	08-Sep-07
SHRF-19	20-Oct-05	Till date
SHRF-20	08-May-06	12-Apr-13
SHRF-21	11-Jun-06	11-Dec-06
SHRF-23	08-Nov-06	04-Feb-14
SHRF-24	21-Feb-07	09-Jan-14
SHRF-27	14-Oct-07	11-Nov-07
SHRF-28	11-Nov-07	11-Jan-14
SHRF-29	12-May-08	07-Oct-09
SHRF-30	10-Jun-08	04-Feb-14

presence of enormous areas containing oil pockets that was not swept (the oil recovery is less than 10% during 13 years of production). Hence secondary and/or tertiary recovery is needed in order to improve sweep efficiency. Water flooding is recommended as the first step of oil recovery enhancement by changing some of the wells with high water cut to injectors.

- The proven oil reserve is about 628 MMBBL and 63 MSCF as a solution gas reserve. The volume of water was estimated to be 1.10 MMMBBL.
- Based on the reservoir modeling and simulation results, the water cut in the study area was very high therefore it is recommended to change the wells with high water cut to injectors, and convert some of these wells to observation wells to be used in the well interference test to estimate the permeability direction which can help in designing the water flooding process.
- It is recommended to drill injector wells in the aquifer as direct line drive pattern in order to support the pressure and enhance the oil production.

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