ARID ZONE JOURNAL OF ENGINEERING, TECHNOLOGY & ENVIRONMENT
AZOJETE September 2020. Vol. 16(3):561-568
Published by the Faculty of Engineering, University of Maiduguri, Maiduguri, Nigeria.
Print ISSN: 1596-2490, Electronic ISSN: 2545-5818
www.azojete.com.ng

ORIGINAL RESEARCH ARTICLE

ENHANCING OIL RECOVERY THROUGH WATERFLOODING

A. S. Grema, M. K. Mahlon, A. S. Kolo and U. H. Taura

Department of Chemical Engineering, University of Maiduguri, Maiduguri, Borno State

**Corresponding author's email address: a.grema@unimaid.edu.ng*

ARTICLE INFORMATION

Submitted 08 Oct., 2019
Revised 10 June, 2020
Accepted 20 June, 2020

Keywords:
EOR,
Reservoir
Waterflooding,
NPV,
MRST,
five-spot pattern

ABSTRACT

Waterflooding is a simple and cheaper means of improving oil recovery from a reservoir by injecting water into the reservoir. Economic considerations suggest injection and production wells must be optimally placed considering reservoir geology, fluid properties, and well orientation. This study focuses on the effects of well placement and orientation on the performance of waterflooding process. The reservoir has a dimension of 2500 ft by 2500 ft by 150 ft. It is homogenous in porosity and heterogeneous in permeability. The performances of three cases considered in the study were evaluated and compared. Water production rates, bottom hole pressure limits for producer wells, well water cut and net present value (NPV) over the entire production period were considered in evaluating their performances. Reservoir modeling and simulation were carried out using MATLAB Reservoir Simulation Toolbox (MRST). It was verified from the investigation that Case III has a maximal production rate of 1,110,188.6 stb/day (stock tank barrel per day), decreasing to 11,005 stb/day after a span of 1400 days with a pressure decrease. Consequently, it was considered a better choice in terms of well placement. It was also estimated to have a maximal Net Present Value of 19.8 billion dollars, which makes it economically viable.

1.0 Introduction

Waterflooding process is a secondary oil recovery effort that involves injection of water into an oil well reservoir to increase the underground pressure thereby increasing oil recovery (Grema and Cao, 2016). However, waterflooding processes are faced with constitutive recovery mechanism in terms of well placements, which determines the maximal recovery of oil at a given point in time. Well placements predominantly play a role as regards to production rates which serves as a consideration to which various oil companies identify in order to determine oil-water ratio (Grema and Cao, 2017). The placement of injection wells determines the oil and water production rates. It is for this reason that estimation of oil recovery in terms of well placements is considered. Reservoir models are expressed by nonlinear partial differential equations (PDEs) which constitute unsteady states and dimensions in the region of time and space (Grema and Cao, 2017). There are a lot of exorbitance in the demand of power and energy in the oil and gas sector and it has been estimated that oil recovery through the use of primary (natural) mechanism is intermittently reducing with time. This is why significant need for Enhanced Oil recovery (EOR) arises (Grema and Cao, 2013). Oil recovery is associated with what is called Recovery Factor (RF) which is defined by the amount of oil that is produced as a given fraction of the main oil in the reservoir (Ahmed, 2006). The oil Recovery Factor (RF) is written mathematically as shown in Equation 1, (Ahmed, 2006):

$$RF = \frac{OIP_{(Original)} - OIP_{(Now)}}{OIP_{(Original)}} \tag{1}$$

RF indicates the Recovery Factor, $OIP_{(Original)}$ indicates the initial oil in the reservoir, $OIP_{(Now)}$ indicate the remaining oil in the reservoir.

Several research findings have been reported on waterflooding process as it is the commonest recovery methods (Adeniyi et al., 2008; Jansen et al., 2008; Jansen et al., 2009). The prominent usage of waterflooding process is attributed to the fact that it remains one of the cheapest means of oil recovery (Adeniyi et al., 2008). Grema and Cao (2013) investigated the changes which occur in the performance of petroleum reservoirs and oil production wells before and after applying the waterflooding technique. Optimization of reservoir waterflooding was carried out considering the effect of geological uncertainties such as porosity, permeability and reservoir size (Jansen et al., 2008; Jansen et al., 2009; Grema and Cao, 2020). Oil reservoirs are faced with typical water production problems such that the oil recovery is curtailed by the prevalence of excess water breakthrough at the point of recovery. Similarly, Grema and Cao (2016) investigated the problems associated with waterflooding, where they implemented a typical feedback control mechanism that could expedite and maximize the optimal oil recovery hence reducing early water breakthrough. A typical application to reservoir simulation is in the future prediction of flow performance in a reservoir, and as such prudent plans and techniques can be applied to improve and optimize the recovery of oil economically. Reservoir simulations can also be used to provide insights on the mechanism and behavior of fluid flow dynamics in a porous medium (Jansen, 2011).

The aim of this study is to investigate the effects of well placement and orientation on the performance of waterflooding process. Three cases of well location and orientation were considered; the performance of which were compared in terms of field oil production rate (FOPR), field water production rate (FWPR), total field oil production (FOPT), bottom hole Pressure(BHP), total field water production(FWPT), well water cut (WWCT) and net present value(NPV) for all well models.

2 Methodology

2.1 Rock and Fluid Properties

2.1.1 Rock Properties

The reservoir considered has a dimension of 2500 ft x 2500 ft x 150 ft and it is divided into three layers of equal thickness along the vertical axis. The number of cells in the x, y, and z directions are 5, 5 and 3 respectively. The depth of reservoir top is given to be 8000 ft with a homogeneous porosity of 0.2. Table 1 shows the permeability information in x, y, and z directions. This is necessary to enable the simulation of the process.

Table 1: Rock permeability

	Layer 1	Layer 2	Layer 3
Permeability in x direction	200 mD	1000 mD	200 mD
Permeability in y direction	150 mD	800 mD	150 mD
Permeability in z direction	20 mD	100 mD	20 mD

The rock compressibility at 4500 psia is given as 4x10-6 psi-1.The grid was divided into 3 sub grid data each having 25 cells defined in the reservoir geometry. The grid was extracted separately for the purpose of generating permeability on each defined sub grid data. For a heterogeneous distribution of permeability, cell data structure was created for the three cases in order to verify the range of distribution on each predefined cells in all three layers. Figure 1 shows the permeability distribution in each grid structure for all three cases.

Case I Case II Case III

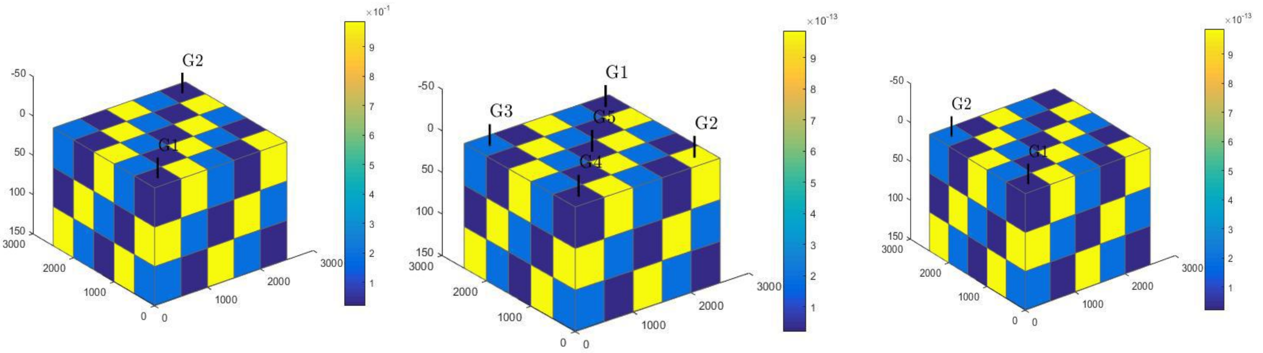

Figure 1: Wells and Permeability distribution for all cases

2.1.2 Fluid Properties

Generating Relative Permeability and Capillary Pressure

The ability of one phase to move strictly depends on the environment at a particular location; the relative permeability of one phase works in conjunction with the saturation of the other phase present at the same location (Adeniyi et al, 2008). Relative permeability was used to denote the movement of a phase in the present of multiple phases from one point to another taking into account of the saturation as a function (Ahmed, 2006). In the MATLAB interface, defining relative permeability and capillary pressure as a function of water saturation was done in a tabular form. The table is a four column array in which the first column is interpreted to be water saturation, the second column denotes water relative permeability, and the third is oil relative permeability while the fourth column denotes oil-water capillary pressure function. See Lie et al. (2012) for detailed explanation.

The variation of relative permeability with water saturation required in running the reservoir model is shown in Table 2. The oil and water densities at surface conditions are respectively given as 49 lbs/ft^3, and 63 lbs/ft^3 while the initial reservoir pressure is given as 4500 psia.

Table 2: Fluid properties (1000mD)

Water saturation	K_{rw}	K_{ro}	P_{cow}(Psi)
0.15	0.0	0.9	4.0
0.45	0.2	0.3	0.8
0.68	0.4	0.1	0.2
	0.55	0.0	0.8

2.2 Net present Value (NPV)

The possible worth of investment for all the three studied cases was estimated. Net present value is the value of all future cash flows (positive and negative) over the entire life of an investment discounted to the present (Grema and Cao, 2016). A positive NPV indicates that the projected earnings generated by a project or investment (in present dollars) exceed the anticipated costs (also in present dollars). Generally, an investment with a positive NPV will be profitable, and an investment with a negative NPV will result in a net loss. This concept is the basis for the Net Present Value Rule, which dictates that the only investments that should be made are those with positive NPV values. The Net Present Value is calculated using Equation 2 (Grema and Cao, 2016):

$$J^k = \left\{ \frac{\sum_{j=1}^{N_{prod}} \left[r_0 \left(y_{0,j} \right)^k - r_{wp} \left(y_{w,j} \right)^k \right] - \sum_{i=1}^{N_{inj}} r_{wi} (u_{wi,i})^k}{(1+b)^{\frac{t^k}{\tau}}} \right\} \Delta t^k \qquad (2)$$

where:

r_{wi} is the Water injection cost, r_{wp} is the Water production cost, r_0 is the Oil price per barrel, $u_{wi,i}$ is the Water injection rate, y_w is the Water production rate, $y_{0,j}$ is the Oil production rate, N_{prod} is the Number of production wells, N_{inj} is the Number of injection wells, b is the Discount factor, Δt^k is the Time step size, t^k is the Actual time period for which NPV is computed, τ is the time unit. Here, yearly discount factor was taken to be given as 0.05, oil price to be 70 dollars per barrel, water production handling cost to be 6 dollars per barrel and the water injection cost to be 6 dollars per barrel. The NPV parameter applies to all cases of the reservoir model.

2.3 Case Studies

2.3.1 Case I: Quarter Five-Spot Pattern

For the first case, the wells were arranged in a quarter five-spot pattern as shown in Figure 2. Two wells were added at the opposite corners of the reservoir and perforated throughout the layer in the z-direction (vertically), with an injection well named ‘G_2’ and production well named ‘G_1’. Precise data required in addition of well could be the bottom hole pressure, perforation cells, and injection/production rate.

.

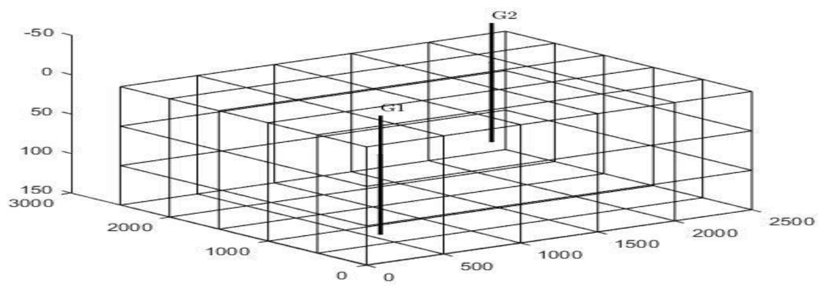

Figure 2: Reservoir Grid and Well Positioning for Case I

2.3.2 Case II: Five-Spot Pattern

Here, the wells were placed in a five-spot pattern and perforated throughout the layers as shown in Figure 3. This consists of four injection wells, one at each corner of the reservoir geometry and a production well in the middle of the geometry. The injection wells are named G_1, G_2, G_3, G_4 and the single production well named G_5 (Figure 3).

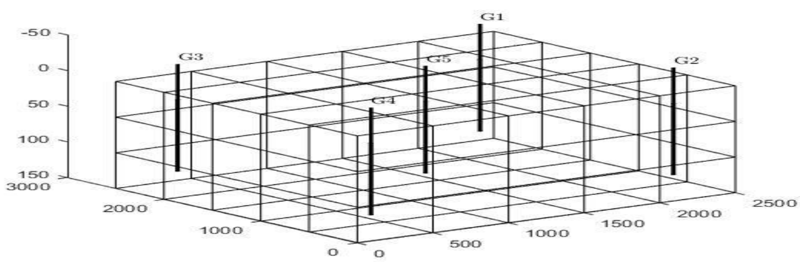

Figure 3: Reservoir Grid and Well Positioning for Case II

2.3.3 Case III: Horizontal Wells

Here two horizontal wells G_1 (production) and G_2 (Injection) placed parallel to each other were considered (Figure 4). All other rock and fluid modeling parameters assume their previous values. Well G_1 is specified with a bottom hole pressure to estimate the oil and water production rates, while G_2 is specified with a water injection rate to estimate the variation in the bottom hole pressure. From Figure 4, the production and injection wells were placed and perforated at the first two layers.

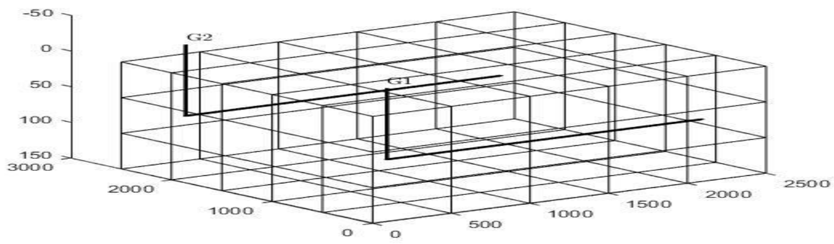

Figure 4: Reservoir Grid and Well Positioning for Case III

For all these cases, MATLAB Reservoir Simulation Toolbox (MRST) was used to setup and run the model. Detailed explanation on how to setup and run a reservoir simulation model using MRST can be found in Lie et al. (2012) .

3 Results and Discussion

3.1 Case I

The production rates and well water cuts for Case I are shown in Figure 5.

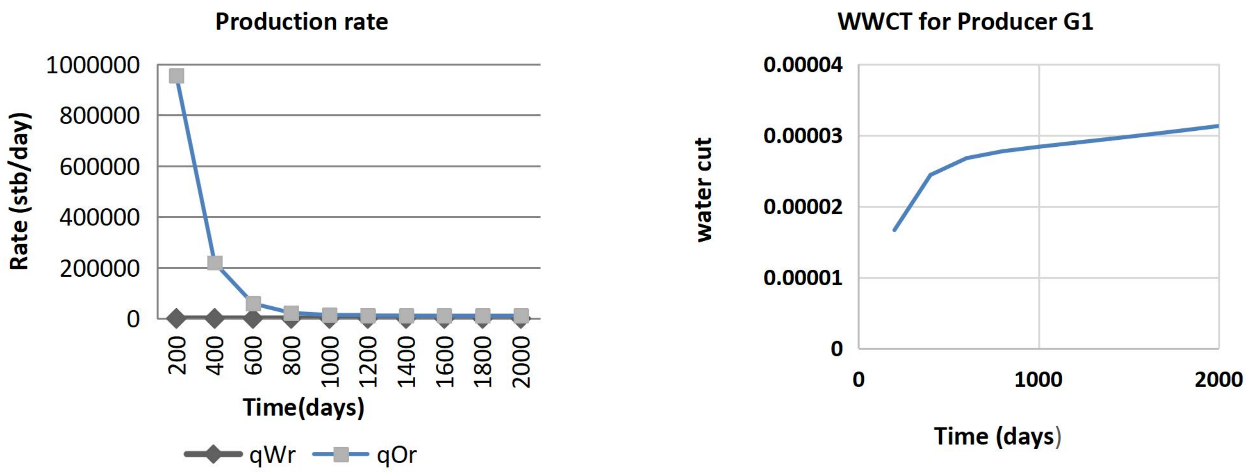

Figure 5: Production rate and WWCT for Case I

Figure 5 illustrates a maximal recovery of oil with a production rate of 955,346.89 stb/day during water injection period of 400 days. After that period, there was a reduction in production rates as the bottom hole pressure reduces (Figure 6), and then a steady rate of 11,582.45 stb/day was realized going down at a negligible rate for the complete period of 2000 days. The well water cut shows a negligible effect on the production rates during the span of recovery.

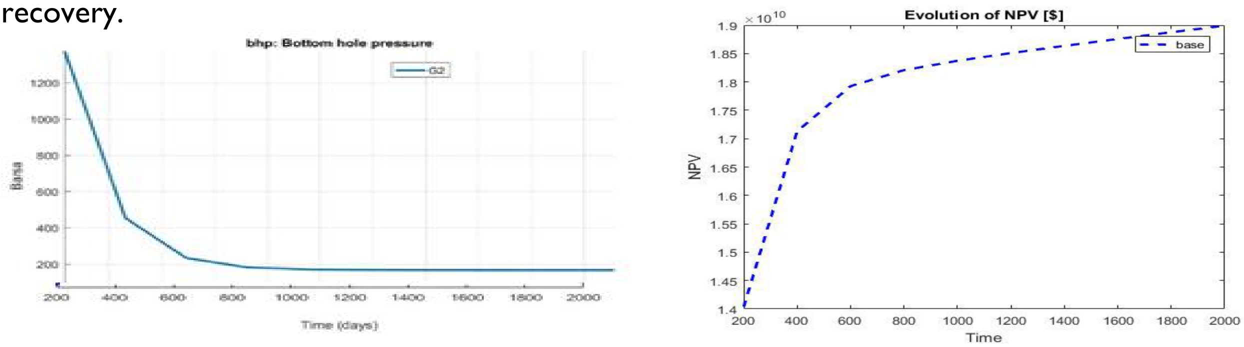

Figure 6: BHP and NPV Evolution for Case I

An estimate of 19 billion dollars (6.6 trillion naira) NPV was estimated for a complete span of 2000 days (Figure 6). The bottom hole pressure for the producer well indicates reduction along the entire life span of the well recovery. It also indicated that the total field oil production rate is analogous to the field oil and water production rate; this is because single productions wells were considered and simulated.

3.2 Case II

The production rates and well water cut for Case II are shown in Figure 7.

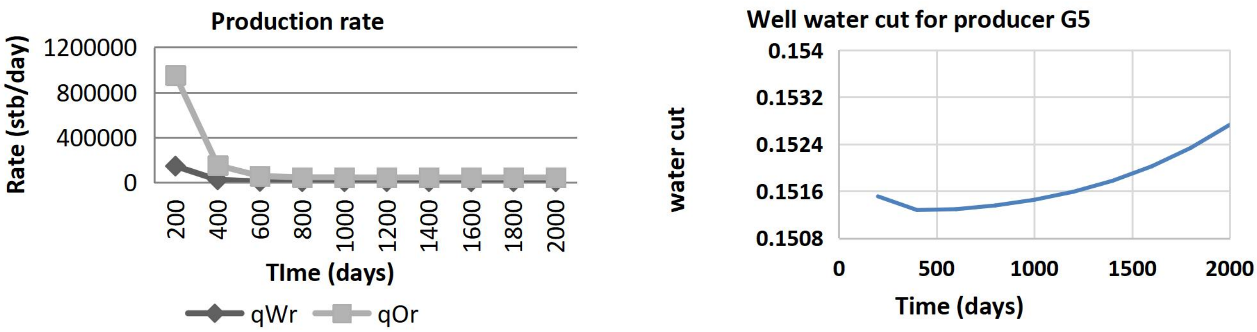

Figure 7: Production rate and WWCT for Case II

Case II has a constant oil production rate of 37,343.089 stb/day for the next 400 days with a rapid decrease in water production (Figure 7). The oil production estimate verified an incremental well water cut as a result of the number of water injection wells. Although it can be considered maximal due to the long term oil production estimate, it is obviously limited by the excessive amount of water breakthrough. Case II shows an estimate of 17 billion dollars (6 trillion naira) of NPV calculated for a complete span of 2000 days (Figure 8).

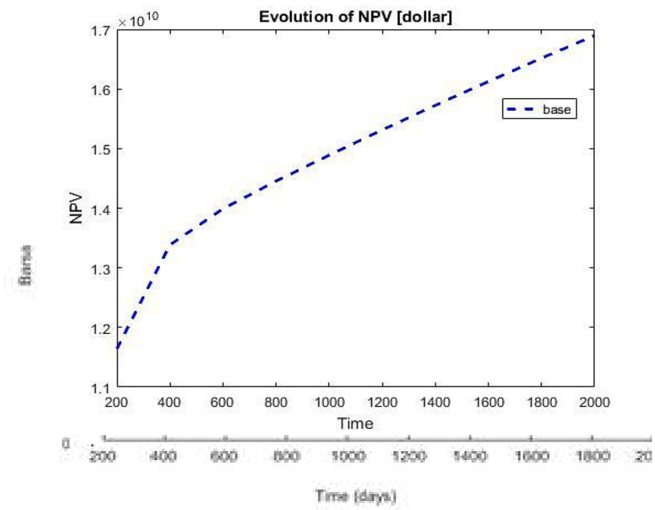

Figure 8: BHP and NPV Evolution for Case II

The same analogy in terms of field oil and water production rates and total field oil production rate is applied to this case as it is to the first case.

There is a substantial decrease in the bottom hole pressure at an early start of recovery due to a fast and exceeding water injection from five injection wells flowing at the same constant rates (Figure 8). This factor gives rise for a high BHP at a shorter period of time, and it will likewise result in an undesired amount of water production.

3.3 Case III

The production rates and well water cut are shown in Figure 9.

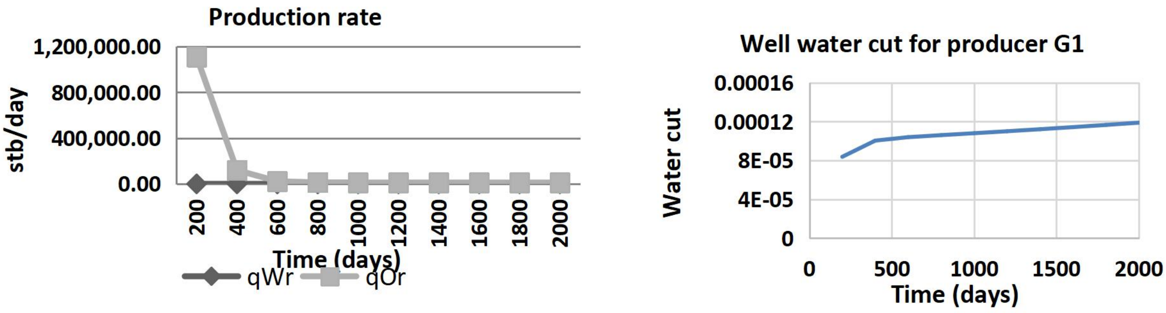

Figure 9: Production rate and WWCT for Case III

Case III indicates a maximal oil recovery of 1,110,188.60 stb/day decreasing down to 11,019.06 stb/day as the reservoir pressure decreases within a span of 1200 days (Figure 9). There is no much flow discrepancy between case 1 and 2 since the same constant flow is recorded at the same time span, but it is seemingly a better choice since it has a maximal flow for a longer time span as compared to case 1 and case 2. This gives it a better choice of consideration. Case III shows an estimate of 19.5 billion dollars (6.8 trillion naira) NPV calculated for a complete span of 2000 days (Figure 10).

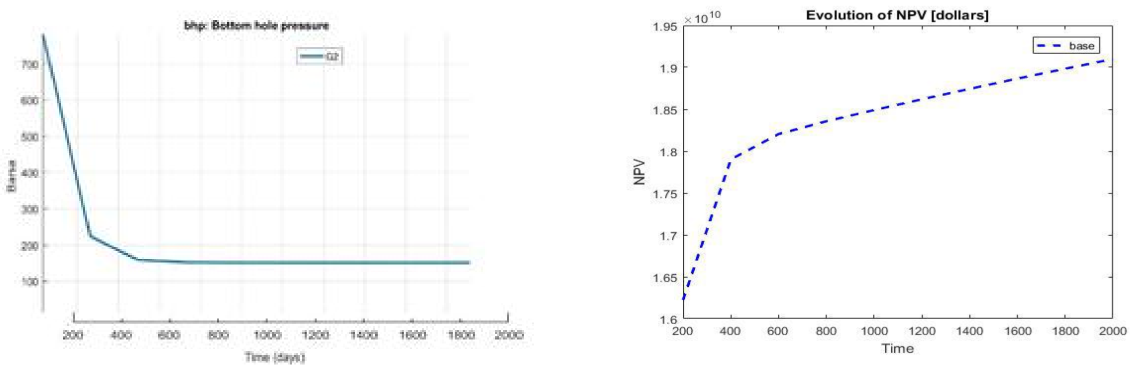

Figure 10: BHP and NPV evolution for Case III

It is obviously seen that, from the estimated results, Case III can be taken as a better investment as compared to the first two cases. The BHP shows an analogous reduction as compared to Case II and Case II.

Various factors assert Case III as a better choice in terms of well placement considering the recovery and investments. These factors are the field oil and water production rates, Net Present Value (NPV), well water cuts (WWCT) and the bottom hole pressure limits.

4 Conclusion

This study has employed the use of MRST to simulate three cases of reservoir waterflooding process. Several simulation outputs were analyzed to infer a better choice of consideration for all the three cases. NPV was used as the performance index for evaluation. Case I and Case II were close to maximum although an early water breakthrough and pressure decrease posed some uncertainties. They were also noted to have less oil recovery during the complete span of 2000 days. Maximum NPV was recorded by the simulation for Case III when compared to the first two cases. Therefore, the reservoir configuration presented by case III will make a better choice compared to the two other cases considered in this study.

It is recommended that next study should incorporate detailed costs of production facilities for better comparison.

References

Adeniyi, OD., Nwalor, JU. and Ako, CT. 2008. A Review on Waterflooding Problems in Nigeria's Crude Oil Production. Journal of Dispersion Science and Technology, 29 (3): 362-365.

Ahmed, T. 2006, Reservoir Engineering Handbook, Third ed, Gulf Professional Publishing, Burlington, USA.

Grema, AS. and Cao, Y. 2013. Optimization of Petroleum Reservoir Waterflooding using Receding Horizon Approach, in 8th IEEE Conference on Industrial Electronics and Applications, Melbourne, Australia, 397–402..

Grema, AS. and Cao, Y. 2016. Optimal Feedback Control of Oil Reservoir Waterflooding Process. International Journal of Automation and Computing, 13 (1): 73–80. https://doi.org/10.1007/s11633-015-0909-7.

Grema, AS. and Cao, Y. 2017. Receding Horizon Control for Oil Reservoir Waterflooding Process. Systems Science and Control Engineering, 5(1): 449-461. DOI: 10.1080/21642583.2017.1378935.

Grema, AS. and Cao, Y. 2020. Dynamic Self-Optimizing Control for Uncertain Oil Reservoir Waterflooding Processes. IEEE Transactions on Control Systems Technology (Article in Press). DOI: 10.1109/TCST.2019.2934072

Jansen, JD. 2011. Adjoint-based Optimization of Multi-Phase Flow through Porous Media–A Review. Computers and Fluids, 46(1): 40-51.

Jansen, JD. Bosgra, OH. and Van den Hof, PMJ. 2008. Model-based Control of Multiphase Flow in Subsurface Oil Reservoirs. Journal of Process Control, 18(9): 846-855.

Jansen, J., Brouwer, R. and Douma, SG. 2009. Closed Loop Reservoir Management. SPE Reservoir Simulation Symposium, 2-4 February 2009, Society of Petroleum Engineers, The Woodlands, Texas.

Lie, K., Krogstad, S., Ligaarden, I.S., Natvig, JR., Nilsen, HM. and Skaflestad, B. 2012. Open-Source MATLAB Implementation of Consistent Discretisations on Complex Grids. Computational Geosciences, 16(2): 297-322