Research Article

Comparison Between Homogenous and Heterogeneous Reservoirs: A Parametric Study of Water Coning Phenomena

Frzan F. Ali [1, a], **Maha R. Hamoudi** [2,b*], **Akram H. Abdul Wahab** [3,c]

[1] Department of Petroleum Engineering, College of Engineering, Knowledge University, Erbil, Iraq
[2,3] Department of Natural Resources Engineering and Management, School of Science and Engineering, University of Kurdistan Hewler, Erbil, Iraq
E-mail: [a]frzan.ali@knu.edu.iq, [b]m.hamoudi@ukh.edu.krd, [c]a.hamoodi@ulh.edu.krd.

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Abstract

Water coning is the biggest production problem mechanism in Middle East oil fields, especially in the Kurdistan Region of Iraq. When water production starts to increase, the costs of operations increase. Water production from the coning phenomena results in a reduction in recovery factor from the reservoir. Understanding the key factors impacting this problem can lead to the implementation of efficient methods to prevent and mitigate water coning. The rate of success of any method relies mainly on the ability to identify the mechanism causing the water coning. This is because several reservoir parameters can affect water coning in both homogenous and heterogeneous reservoirs. The objective of this research is to identify the parameters contributing to water coning in both homogenous and heterogeneous reservoirs. A simulation model was created to demonstrate water coning in a single-vertical well in a radial cross-section model in a commercial reservoir simulator. The sensitivity analysis was conducted on a variety of properties separately for both homogenous and heterogeneous reservoirs. The results were categorized by time to water breakthrough, oil production rate and water oil ratio. The results of the simulation work led to a number of conclusions. Firstly, production rate, perforation interval thickness and perforation depth are the most effective parameters on water coning. Secondly, time of water breakthrough is not an adequate indicator on the economic performance of the well, as the water cut is also important. Thirdly, natural fractures have significant contribution on water coning, which leads to less oil production at the end of production time when compared to a conventional reservoir with similar properties.

Keywords: Water Coning, Homogeneous Reservoirs, Heterogeneous Reservoirs, Production Optimization.

1. Introduction

Water production is one of the most common phenomena during the exploitation of oil. Normal rise of oil water contact, water coning, and/or water fingering are the reasons for such phenomena. This serious problem is quite common in the Middle East where large oil reservoirs have water aquifers or active water drives underneath. When excess water production exists, the costs associated to surface facilities, artificial lift systems, corrosion and scale problems increases. Besides, the recovery factor decreases as oil is left behind in the displacement front. These factors reduce the economic indicators. In order to optimize production, the drastic influence of water production must be soon detected, and the source of such problems must be identified in order to apply effective and suitable techniques to control water production (Gasbarri et al., 2007).

The cause of water coning is an imbalance between the viscous and gravitational forces around the completion interval. In other words, the flow of oil from the reservoir to the well introduces an upward dynamic force upon the reservoir fluids. This dynamic force is due to wellbore drawdown causes the water at the bottom of the oil later to rise to a certain point at which the dynamic force is balanced, by the height of water beneath that point. Now as the lateral distance from the wellbore increases, the pressure drawdown and the upward dynamic force decrease. Thus, the height of the balance point decreases as the distance from the wellbore increase. Therefore, the locus of the balance point is a stable cone shaped water oil interface. At this stable situation oil flows above the interface while water remains stationary below the interface (Gasbarri et al., 2007).

This work addresses the water coning issues in a conventional and naturally fractured reservoir via a numerical simulation approach on a single-well radial cross-section using commercial reservoir simulator (ECLIPSE 100). Understanding the key parameters affecting water coning in both homogenous and heterogeneous reservoirs will lead accurate identification of the problem and effective solution to mitigate or control the water production. This is an effective production optimization approach for water producing reservoirs.

1.1. Coning Development

Producing oil from a well which is overlying water may cause the oil/water interface to deform into a bell shape. This deformation is called water coning and occurs when the vertical component of the viscous force exceeds the net gravity force (Hoyland et al., 1989). Therefore, two forces control the mechanism of water coning in oil and/or gas reservoirs: dynamic viscous force and gravity force. Water coning phenomenon constitutes one of the most complex problems pertaining to oil production (Saad et al., 1995). Coning phenomenon is more challenging in fractured reservoirs owing to their heterogeneous and high permeable medium of the fractures compared to matrixes (Foroozesh et al., 2008). On the other hand, water coning in naturally fractured reservoirs often result in excessive water production which can kill a well or severely curtain its economics life due to water handling (Beattie & Roberts, 1996).

In the study of water coning phenomenon both in conventional and fractured reservoirs, three parameters are determined: critical rate, breakthrough time and water cut performance after breakthrough. It is of essence to understand the term critical rate. At a certain production rate, the water cone is stable with-it apex at a distance below the bottom of the well, but an infinitesimal rate increase will cause instability and water breakthrough. This limiting rate is called the critical rate for water coning (Hoyland et al., 1989). Therefore, critical rate is defined as the maximum allowable oil flow rate that can be imposed on the well to avoid a cone breakthrough (Salavatov & Ghareeb, 2009).

In fractured reservoirs, critical rate is influenced by extra factors such as fracture storativity (ω), fracture transmissivity (λ), fracture pattern and their interaction to matrixes; especially around the wellbore (Namani et al., 2007). Bahrami et al. (2004) stated that because of heterogeneity and non-uniform fracture distribution in naturally fractured reservoirs, the development of cone is asymmetrical, and estimation of critical rate and breakthrough time requires modelling with an understanding of fracture pattern around the producing well.

These are the challenges of studying water in fractured reservoirs. In these reservoirs, the extent and stabilization of cone growth depend on factors such as; oil zone thickness, mobility ratio, the extent of the well penetration and vertical permeability; of which the most important parameter is the total production rate (Namani et al., 2007). Moreover, water coning depends on the properties of the porous media, distance from the oil-water interface to the well, oil-water viscosity ratio, production rate, densities of the fluids and capillary effects. Conversely, in fractured reservoirs this problem is more complicated because of the dual porosity system in the fractured reservoir which results in formation of two cones (i.e., coning in the fracture and matrix). Depending on the rates, a fast-moving cone may be developing in the fracture whilst a slow-moving cone is observed in the matrix. The relative position of the two cones is rate sensitive and is a function of reservoir properties (Al-Aflagh & Ershaghi, 1993). The key parameter in determining water coning tendency is the vertical to horizontal permeability ratio, k_v/k_h. The existence of natural fractures however often results in high values of k_v/k_h providing conditions conducive to water coning (Beattie & Roberts, 1996). Therefore, high vertical permeability in fractures is bound to accelerate the coning process resulting in lowering of the critical rates and more rapid breakthrough times. In addition, the favored path for fluid flow through the fractures and the uneven fracture conductivities commonly observed in naturally fractured reservoirs is expected to affect wells regardless of their structural position (Al-Aflagh & Ershaghi, 1993). Understanding the effect of various rock and fluid properties such as oil thickness, absolute permeability, completion interval location, production rate, fluid viscosity and density is very crucial (Foroozesh et al., 2008).

2. Methodology

Water coning in vertical wells is considered as one of the most complex problems facing any well during its production life. In the past, water coning phenomena in naturally fractured reservoirs were studied using a homogenous model due to its convenient use, ease of simulation of work, and cost. However, it is not very well understood which well/reservoir parameter affects water coning in a conventional reservoir, and how different that relationship is to a naturally fractured reservoir. Accurate results of water coning in a naturally fractured reservoir cannot be obtained if a homogenous model is used in the simulation work.

In this research, the following work has been performed:

1- Create Conventional Model1 and Naturally Fractured Model1
2- Compare Conventional Model1 with Naturally Fractured Model1 in order to prove the quality and accuracy of the simulation work. (Both models having the same reservoir and well properties, including similar porosity-permeability of the fractured layer to the matrix layers in the naturally fractured model).
3- Modify Naturally Fractured Model1 to create the Base Case of a Naturally Fractured model. Unlike in the previous case, a realistic porosity and permeability will be given to the fractured layers.
4- In order to check the effect of different well/reservoir parameters on water coning in conventional reservoir, sensitivity analysis for Base Case Conventional Model will be conducted by changing 8 parameters and simulating the water coning performance for each case. This way, the effect of each parameter will be evaluated and compared to the Base Model of Conventional Model.
5- In order to check the effect of different well/reservoir parameters on water coning in Naturally Fractured Reservoir, sensitivity analysis for Base Case Naturally Fractured Model will be conducted by changing 11 parameters and simulating the water coning performance for each case. This way, the effect of each parameter will be evaluated and compared to the Base Model of Naturally Fractured Model.
6- By this stage, a comprehensive sensitivity analysis has been performed and the effect of different parameters will be shown for both Conventional Model and Naturally Fractured Model.
7- Since similar sensitivity analysis was conducted for both Conventional Model and Naturally Fractured Model. A comparison between Conventional Model and Naturally Fractured Model for each sensitivity case. In other words, because each well/reservoir parameter was changed equally in both model's sensitivity analysis, comparison of water coning phenomena in both Conventional Model and Naturally Fractured Model will be presented.

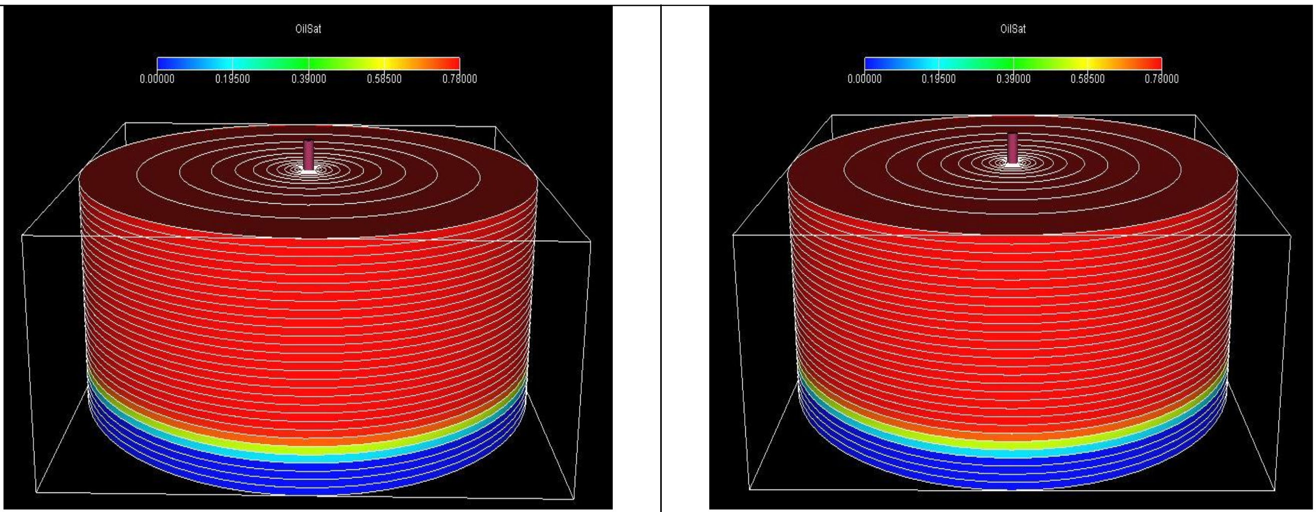
2.1. Reservoir Simulation Work

The simulation work has been conducted between Conventional Reservoir and Naturally Fractured Reservoir using ECLIPSE 100 simulator. The simulator is an adaptable dual porosity dual permeability simulator that accounts for matrixes and fractures, porosity and permeability respectively.

The conventional reservoir radial model comprises of 30 layers in the Z direction and 30 grids in the r direction. A producing well with a radius of 0.11 m (4.3") is placed at the center with the producing intervals between layer 1 and 6. The model is depicted in Figure 1. The reservoir is 500 m in width and 80 meters in depth. There is an active aquifer at the bottom of the reservoir that is supporting the reservoir in terms of pressure. The top 16 meters of the reservoir has been perforated in 360 degrees.

The naturally fractured radial model comprises of 59 layers (30 layers of matrix and 29 layers of fractures) in the Z direction and 30 grids in the r direction. A producing well with a radius of 0.11 m (4.3") is placed at the center with the producing intervals between layer 1 and 12. The model is depicted in Figure 1(B). The reservoir is 500 m in width and 80 meters in depth. There is an active aquifer at the bottom of the reservoir that is supporting the reservoir in term of pressure. The top 16 meters of the reservoir has been perforated in 360 degrees. The natural fracture model is created with 30 layers of matrix (large layers of low permeability-low porosity) and 29 layers of fracture (small layers of high permeability-high porosity).

It is important to clarify that both models are having the same porosity, permeability (matrix and fractured layers), reservoir thickness, water oil contact, aquifer depth, PVT data, well and completion design, oil flowrate (500 m^3/day), bottom hole pressure limit (105 Bars), and simulation run period.



A- Conventional Model 1 at the beginning of the simulation run – Oil Saturation (Model Exaggerated by 400%)	B- Naturally Fractured Model 1 at the beginning of the simulation run – Oil Saturation (Model Exaggerated by 400

Figure 1. 3D Model of both Conventional Model and Naturally Fractured Model.

From Figure 2, it can be observed that both conventional model and naturally fractured model have been created equally since they have performed similarly. From Figure 2(A) and Figure 2(B), it is clear how oil saturation has been reduced in the bottom layers of the model as the well has been producing for 3 years. From Figure 2(C) and Figure 2(D), it can be seen how water saturation has increased and approached the upper layers at the end of the simulation.

2.2. Quality check of the models

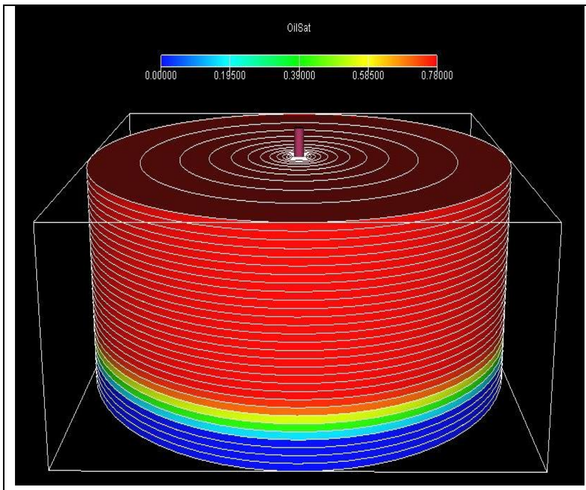
Before the simulation work began, the accuracy of the simulation work must be proven. This way, if both models performed the same way in term of oil production, water production and water saturation at the producing interval, then it can be proven both models are equal Figures 3 to 5.

Figures 3 and 4 show that both base case of Conventional Model 1 and Natural Fractured Model 1 produced exactly the same amount of oil and water with the same flowrate performance. Again, this is due to the fact that both models have the same properties yet the Conventional Model 1 is 30 layers and Naturally Fractured Model 1 is 59 layers. Figure 5 shows the water production vs time in Conventional Model 1 and Naturally Fractured Model 1 versus time.

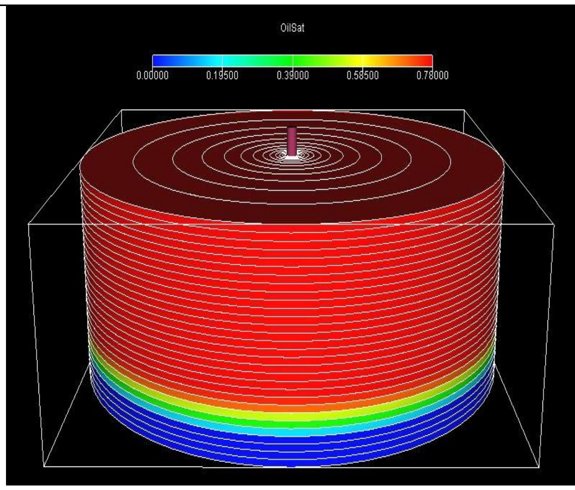
Figures 6, 7, 8 and 9 show a comparison Base Model of the Conventional Reservoir to Base Model of Naturally Fractured Model for the oil production rate, cumulative oil production, water production, and the water saturation at the producing interval, versus time, respectively.

It is clearly shown from the 3D model and the graphs that both Base models are performing differently after a realistic property of fractured layers were introduced in the fractured model. The Conventional model produced oil for a longer period until reaching the bottom hole pressure limit which was set to 105 bars (1522 psi). The Fractured model has water breakthrough after 132 days while the conventional model has water breakthrough after 138 days. Lastly, water saturation at the producing interval of the Naturally Fractured model increased more rapidly when compared to the Conventional model.

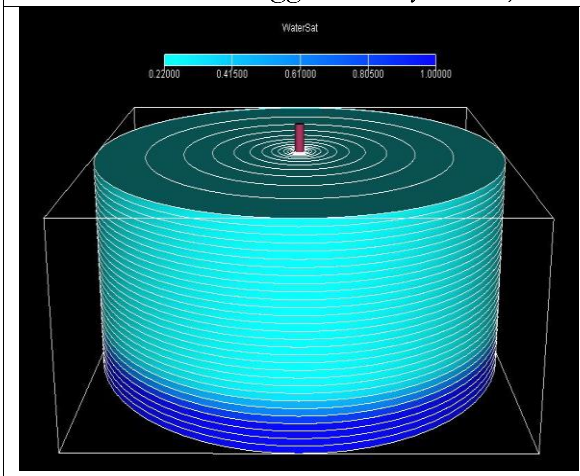
Now, since an accurate Conventional Model Base Case and Naturally Fractured Model Base were created and proven. Sensitivity analysis on both Base Cases will be performed to study the effect of different well/reservoir parameters on water coning.



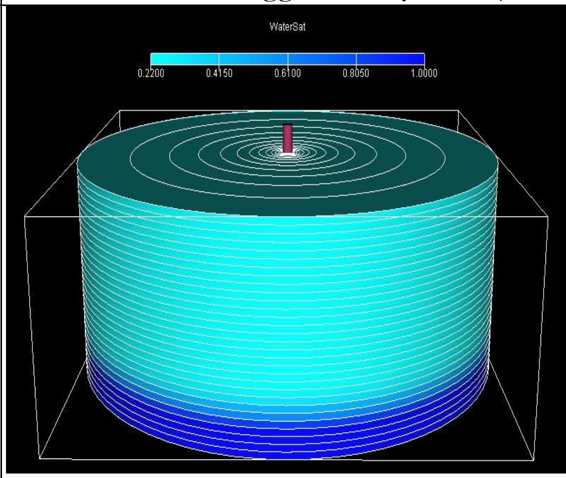
A- Conventional Model 1 at the end of the simulation run (3 years) – Oil Saturation (Model Exaggerated by 400%)



B- Naturally Fractured Model 1 at the end c simulation run (3 years) – Oil Saturation (M Exaggerated by 400%)



C- Conventional Model 1 at the end of the simulation run (3 years) – Water Saturation (Model Exaggerated by 400%)



D- Naturally Fractured Model 1 at the end (simulation run (3 years) – Water Saturation (Exaggerated by 400%)

Figure 2. Comparing 3D of both Conventional Model and Naturally Fractured Model at the end of the simulation run.

2. 3. Sensitivity Study

After creating a Base Case of Conventional Reservoir and a Base Case of Naturally Fractured Reservoir, a sensitivity study was conducted, where 8 parameters for both the Conventional Reservoir Model, and the Naturally Fractured Reservoir Model were run through a simulation. Each parameter was changed and compared to the base case of each reservoir model. This way, the effect of the change of each parameter can be seen and compared.

The sensitivity study was conducted by changing 8 parameters from the Base Case. In other words, 8 parameters of the Conventional Base Case have been changed four times (increased roughly by 10% and 20% then decreased roughly by 10% and 20%). A similar approach has been used for the Naturally Fractured Model. Later the effects of each

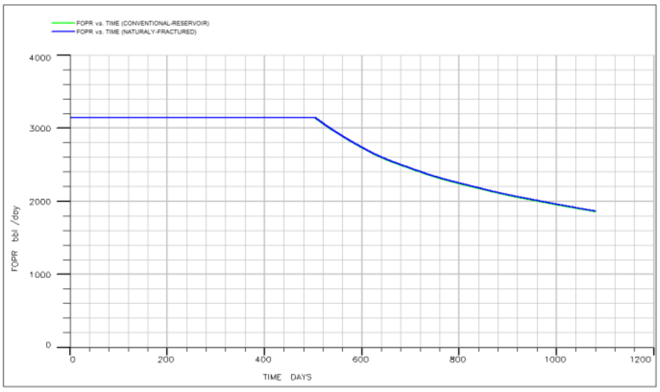


Figure 3. Oil Production vs time in Conventional Model 1 and Naturally Fractured Model 1.

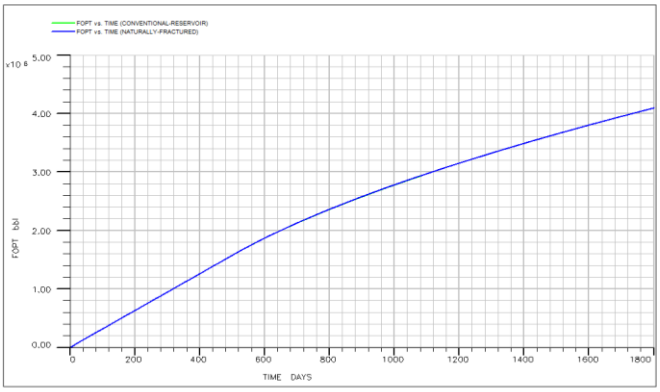


Figure 4. Cumulative oil Production vs time in Conventional Model 1 and Naturally Fractured Model 1 versus time.

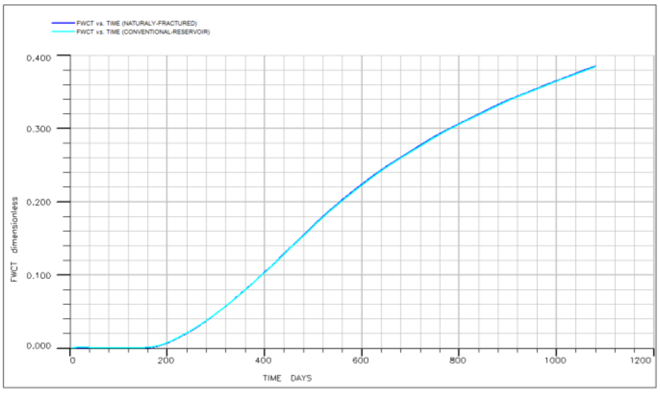


Figure 5. Water Production vs time in Conventional Model 1 and Naturally Fractured Model 1 versus time.

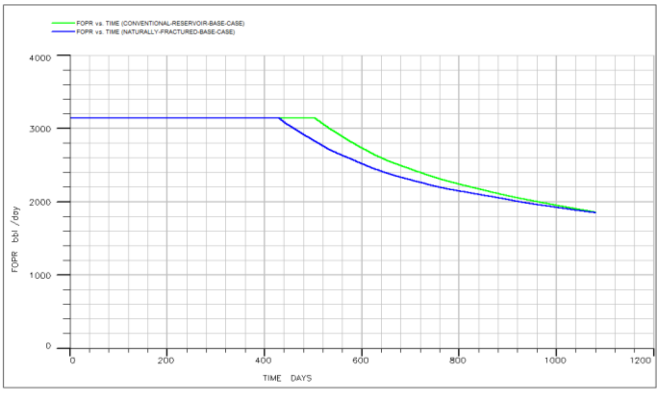


Figure 6. Conventional Model Base Case vs Naturally Fractured Model Base Case (Oil Production vs Time).

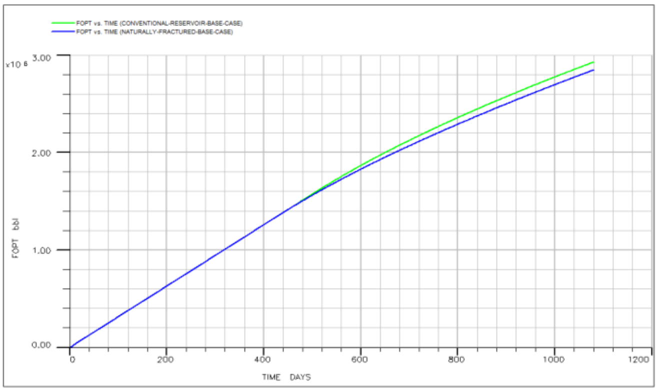


Figure 7. Conventional Model Base Case vs Naturally Fractured Model Base Case (Cumulative Oil Production vs Time)

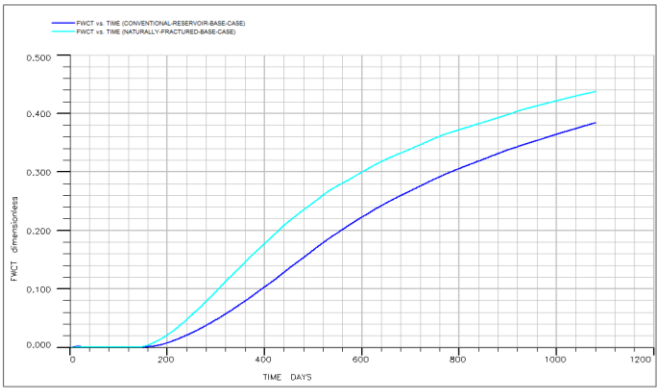


Figure 8. Conventional Model Base Case vs Naturally Fractured Model Base Case (Water Production vs Time)

sensitivity case has been compared to each other in order to understand the different performances between the two models.

Parameters changed for the sensitivity study.

1- Anisotropy Ratio
2- Production Rate

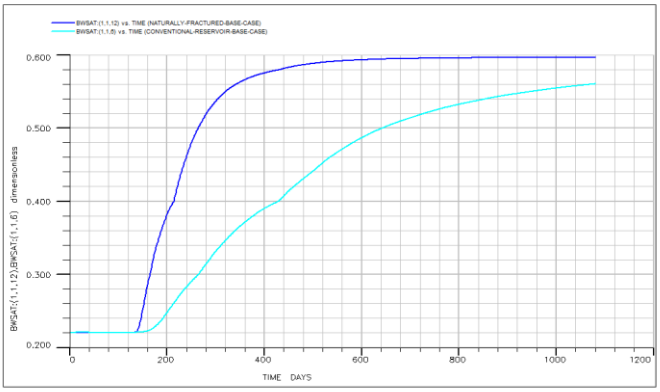


Figure 9. Conventional Model Base Case vs Naturally Fractured Model Base Case (Water Saturation at the producing interval vs Time)

3- Perforated Interval Thickness
4- Perforation Depth
5- Density Difference
6- Wellbore Design Effect
7- Aquifer Thickness
8- Reservoir Thickness

3. Results and Discussion

Figure 10 shows that the Naturally fractured reservoir produced higher water cut than the Conventional reservoir model at the end of production time (3 years). Figure 11 shows that the Naturally Fractured reservoir faced earlier water breakthrough than conventional reservoir in all sensitivity cases. Figure 12 shows that the naturally fractured reservoir produced less cumulative oil produced when compared to conventional reservoir.

Comparing the Naturally Fractured Reservoir Model with the Conventional Reservoir Model Figures 10 to 12.

- The naturally fractured reservoir model faced water coning earlier than conventional reservoir model when comparing the same change in anisotropy ratio in both conventional reservoir model and naturally fractured model. As the naturally fractured reservoir model faced water coning due to the fast-moving cone in the fractured layers.
- The naturally fractured model flows a shorter period on the plateau stage, but the conventional model flows for longer periods when comparing the same change in anisotropy ratio in both the conventional reservoir model and the naturally fractured reservoir model. After the flowrate of each case starts to decrease, the decline rate of each case is relatively similar. This means that a wrong decision can be made, if a naturally fractured reservoir is simulated with a conventional model. Since the conventional model predicts late water coning phenomena, and a longer plateau stage, while the naturally fractured reservoir would have an early water breakthrough with a shorter production life in the plateau stage.
- The naturally fractured reservoir faced earlier water breakthrough than the conventional reservoir model when comparing the same change of anisotropy ratio in both models. Not only that, but also the naturally fractured reservoir model produced higher water cut percentage at the end of production time (3 years)
- The Anisotropy ratio decreases water breakthrough time delays in both the conventional reservoir model and the naturally fractured model. Having said that, this inversely proportional relationship between the anisotropy ratio and water breakthrough time is a non-linear relationship. As the anisotropy ratio decreases, more cumulative oil is produced at the end of production time.
- The naturally fractured reservoir model has an early and more rapid increase of water saturation at the producing interval when compared to the conventional reservoir model. As the fractured layers of the

naturally fractured reservoir model causes faster arrival of water cone to the wellbore and leading to early water breakthrough, thus leading to reduction in oil flowrate. On the same oil flowrate, the naturally fractured reservoir model flows shorter in the plateau stage, and the oil flowrate drops earlier when compared to the conventional reservoir model. The naturally fractured reservoir model has earlier water breakthrough on the same oil flowrate. This indirectly proportional relationship is true for both the conventional reservoir model and the naturally fractured reservoir model (inversely proportional relationship).

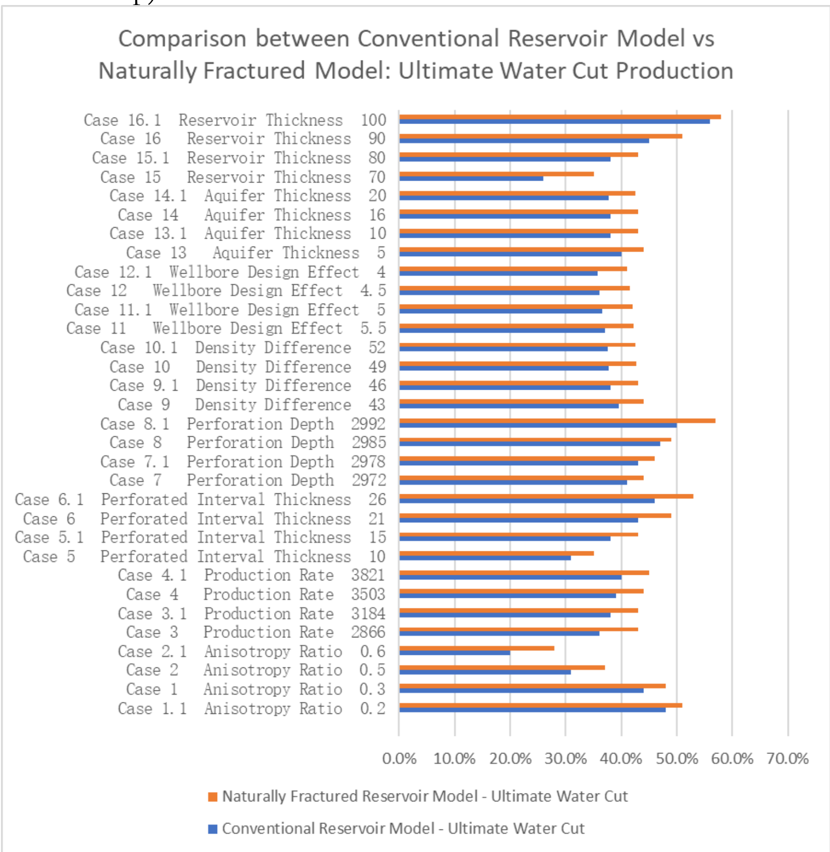


Figure 10. Comparison between the Conventional Reservoir Model vs the Naturally Fractured Model: Ultimate Water Cut Production.

- Early and rapid increases of water saturation occur at the producing interval of the naturally fractured reservoir when compared to the conventional reservoir at different perforation interval thicknesses. Oil flows for shorter periods in the plateau stage when compared to the conventional reservoir for the same perforation interval thicknesses. This is because of the water breakthrough timing in each case. As the water cone reaches the wellbore, the well would produce water and oil at the same time, leading to reduction in oil flowrate. Not only that, but also larger cumulative amounts of oil have been produced in the naturally fractured reservoir model when compared to the conventional reservoir model. This inversely proportional, yet non-linear, relationship is true for both the conventional and the naturally fractured reservoir model.
- Water saturation at the producing interval increased more rapidly in the naturally fractured reservoir model when compared to the conventional reservoir model for the same perforation depth. This is due to the fact that the fractured layers contribute by the fast-moving cones in a horizontal direction. Leading to faster cone movement and early water breakthrough. At the same perforation depth, the naturally fractured reservoir model flows in the plateau stage for a shorter period of time than the conventional reservoir model. As the water cone reaches the wellbore more quickly leading to a decreasedoil flowrate.

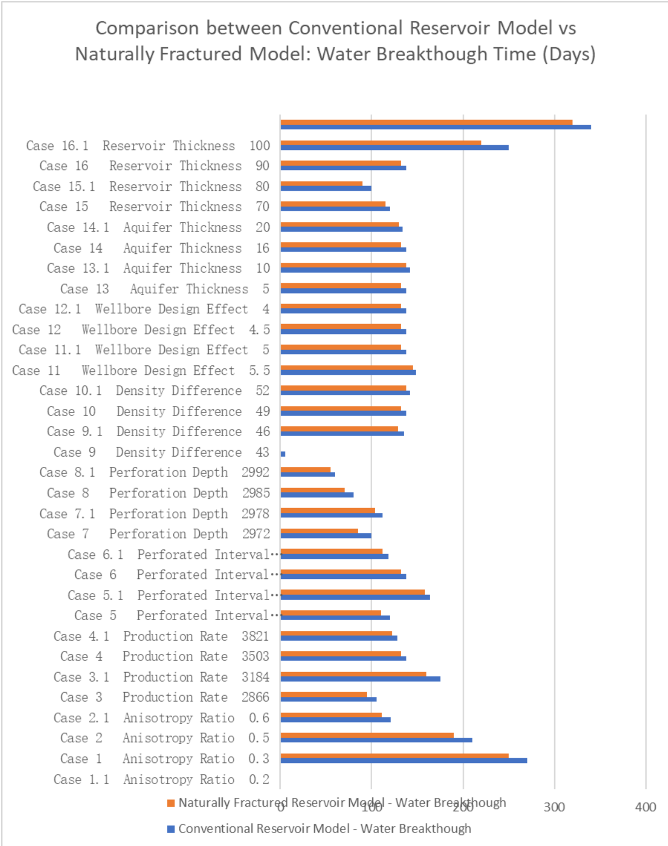


Figure 11. Comparison between the Conventional Reservoir Model vs the Naturally Fractured Model: Water Breakthrough Time (Days).

- At the same perforation depth, the naturally fractured reservoir produced higher water cut with earlier water breakthrough time when compared to the conventional reservoir model. As the perforation depth decreases, water breakthrough time is delayed. This is true for both the conventional reservoir model and the naturally fractured reservoir model (linear, inversely proportional relationship). As the perforation depth decreases, higher cumulative oil is produced at the end of the production time (3 years). This is true for both the conventional reservoir model and the naturally fractured reservoir model. It can be observed that at lower perforation depths, the relationship is non-linear, as the conventional reservoir model decreases in cumulative oil production at lower perforation depths.
- The naturally fractured reservoir faces more rapid increase in water saturation at the producing interval when compared to the conventional reservoir model for the same change in oil density. Having said that, the change of oil density has a small influence on increase of water saturation interval for both models.
- The naturally fractured reservoir model flowed in the plateau stage for a shorter period when compared to the conventional reservoir model for the same oil density difference. This is true for both the conventional reservoir model and the naturally fractured reservoir model.
- The naturally fractured reservoir model faced early water breakthrough and more rapid water cut production when compared to conventional reservoir model for the same change of oil density in both cases. As the oil density decreases, water breakthrough time is delayed. This linear and inversely proportional relationship is true for both the conventional reservoir model and the naturally fractured reservoir model. As oil density decreases, more oil is produced in terms of cumulative volume at the end of production time (3 years). This linear and inversely proportional relationship is true for both the conventional reservoir model and the naturally fractured reservoir model. As the oil density increases, larger water cut is produced in term of percentage at the end of

the production time (3 years). This non-linear and inversely proportional relationship is true for both the conventional reservoir model and the naturally fractured reservoir model.

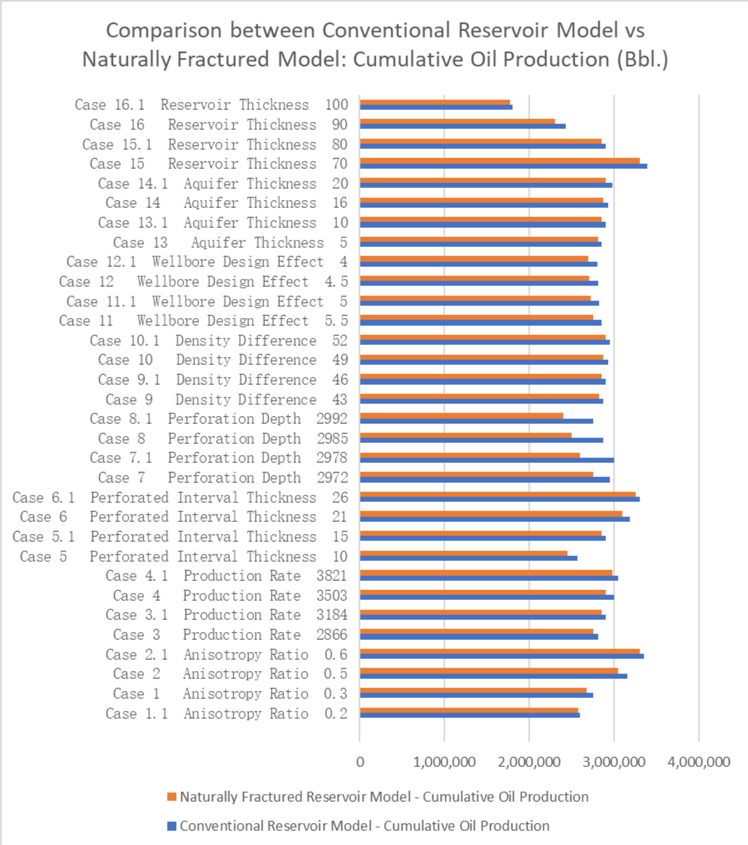


Figure 12. Comparison between the Conventional Reservoir Model vs the Naturally Fractured Model: Cumulative Oil Production (Bbl.).

- Water saturation at the producing interval of the naturally fractured reservoir model increases earlier and more rapidly when compared to the conventional reservoir model for the same change of Tubing ID. Changing of the tubing ID has a small effect on water saturation at the producing interval in both reservoir models. Having said that, the water saturation remained almost unchanged in the case of naturally fractured model, yet water saturation changed slightly at the late stage of the production life. This is due to the fact that thin layers of the fractured reservoir are too insignificant to be affected by the tubing ID. However, in the case of the conventional reservoir, the layers are affected more and produce on the same oil flowrate. Both the conventional reservoir and the naturally fractured models had the same breakthrough time as the tubing ID didn't affect coning behavior. This is due to the fact that water coning occurs in formations below the wellbore. However, as soon as the water cone reaches the wellbore, the rate of increase of water coning varies depending on the tubing ID, as the larger tubing ID produces higher liquid flowrate leading to higher production of water. As the tubing size increases, larger quantities of oil are produced in terms of cumulative volume at the end of production time. This directly proportional reservoir model is true for both the conventional reservoir model and the naturally fractured reservoir model.
- The naturally fractured reservoir model flows in the plateau stage for a shorter period when compared to the conventional reservoir model for each aquifer thicknesses. As the naturally fractured model faced earlier water breakthrough and the larger aquifer faced earlier water breakthrough, that's why the naturally fractured reservoir model with the largest aquifer faced the earliest water breakthrough, and controversially, the smallest aquifer thickness in the conventional reservoir model faced the latest water breakthrough. Due to this reason, the naturally fractured reservoir flows in the plateau stage for a longer period. The naturally fractured reservoir

model faced earlier water breakthrough when compared to the conventional reservoir model. Not only that, but the naturally fractured reservoir model produced higher percentage of water cut at the end of production time (3 years), when compared to the conventional reservoir model for each aquifer thicknesses.

- As aquifer thickness decreases, water breakthrough time is delayed. This inversely proportional relationship is true for both the conventional reservoir model and the naturally fractured reservoir model. This way, more oil is produced in terms of cumulative oil production at the end of production time (3 years). This is true for both the conventional reservoir model and the naturally fractured reservoir model. Plus, as stated before, the naturally fractured reservoir model produces less cumulative oil than the conventional reservoir model. The main reason for this is the timing of the water cone reaching the wellbore. In case of a larger aquifer size, the water cone reaches the wellbore earlier, leading to a decrease in oil production flowrate and eventually decreasing cumulative oil production.
- Water saturation is different at the producing interval of both the conventional reservoir model and the naturally fractured reservoir model due to reservoir thicknesses. The naturally fractured reservoir model has earlier and a more rapid increase of water saturation at the producing interval at different reservoir thicknesses when compared to the conventional reservoir model. Not only that, but also the naturally fractured reservoir model has higher water saturation at the end of production time (3 years) when compared to the conventional reservoir model. Having said that, the differences between each case and between each model arequite significant. The naturally fractured reservoir model produces larger quantities of water cut when compared to the conventional reservoir model. In addition, the thickest reservoir in the naturally fractured reservoir has the largest water production with the earliest water breakthrough while the thinnest reservoir in the conventional reservoir model has the lowest water cut production with the latest water breakthrough time. As the reservoir thickness increases, water breakthrough time is delayed. This directly proportional relationship is true for both the conventional reservoir model and the naturally fractured reservoir model. Simply, the larger the reservoir thickness, the larger supply of volume of oil and the higher pressure as a support for the well, resulted in a weak and delayed water coning phenomenon.

4. Conclusions

- Increased reservoir thickness and anisotropy ratio delays water coning the most. Yet perforation depth might lead to the earliest water breakthrough time. In addition, perforation interval thickness and production rates come in second in terms of effectiveness. Perforation interval thickness and oil production flowrate affect water breakthrough significantly.
- Water breakthrough alone is not a good indicator for water coning. It is important to see how much water cut is produced after water breakthrough.
- Cumulative oil production is one of the most important parameters to look at, when it comes to comparing different sensitivity analysis cases. The well might face early water breakthrough or might have high water cut production, or even both. However, if at the end of the production time, it produced high cumulative oil production, then it can be considered an excellent choice for economic production.
- Generally, as water breakthrough occurs earlier, higher water cut is produced. When water breakthrough occurs later, more cumulative oil is produced in the naturally fractured reservoir.
- The naturally fractured reservoir produced higher water cut than the conventional reservoir model at the end of production time (3 years)
- The naturally fractured reservoir produced less cumulative oil when compared to the conventional reservoir.
- Underestimating the quantity and size of fractures in the reservoir will lead to inaccurate predictions of water coning.
- In the naturally fractured reservoirs, not only breakthrough happens earlier than in the conventional reservoir, but also the water production increases more rapidly than in the conventional reservoir.
- Water saturation at the producing interval is the direct response of oil production flowrate.
- Even though, natural fractures contribute significantly to the overall coning phenomena, the width of individual fractures has insignificant effect on water coning this is because the fractures are too small and thin to observe a noticeable change in production performance.

- The density of oil and well tubing ID have no effect on water breakthrough time. This is true for both the conventional and naturally fractured reservoirs.

5. Recommendations

- This research worked on water coning in a vertical well. It is recommended that this work to be taken further by studying water coning in a horizontal well.

- This research worked on water coning in an under-saturated reservoir (Oil-Water system). It is recommended that this work to be further researched by considering a saturated reservoir (Oil-Water-Gas system).

Nomenclature

hp: Perforation length, ft

M: Water oil mobility ratio, dimensionless

ϱo: Oil density, lb/cuft

ϱw: Water density, lb/cuft

tBT: Break through time, day

Pwf: Flowing bottom hole pressure, psi

WOR: Water Oil Ratio, dimensionless

rw: Wellbore radius, ft

ω: Storativity

Q: flowrate, STB/day

ID: Inside diameter, ft

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