Simulation of Oil Recovery Through Advanced Wells Using a Transient Fully Coupled Well-Reservoir Model

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Abstract
Oil recovery can be enhanced by maximizing the well-reservoir contact using long horizontal wells. One of the main challenges of using such wells is the early breakthrough of unwanted fluids due to the heel-toe effect and heterogeneity along the well. To tackle this problem, advanced wells are widely applied today. The successful design of such wells requires an accurate integrated dynamic model of the well and reservoir. This paper aims at developing appropriate integrated well-reservoir models for achieving optimal long-term oil recovery from advanced well models.

In this study, OLGA® which is a dynamic multiphase flow simulator is implicitly coupled to ECLIPSE™ which is a dynamic reservoir simulator for developing accurate models to simulate oil production from advanced wells under various production/injection strategies. A realistic heterogeneous light oil reservoir with an advanced horizontal well is used as a case study. Flow Control Devices (FCDs) are the key component of advanced wells and the functionality of the main types of FCDs in improving the oil production, minimizing the cost and carbon footprint is investigated.

According to the obtained results, by implementation of FCDs the water breakthrough time is delayed by 180 days and the cumulative water production with ICD, AICD, and AICV completions is reduced by 26.8%, 33.1%, and 49.1%, respectively, compared to the open-hole case. Besides, the results show that linking OLGA and ECLIPSE is a numerically stable and accurate approach for modeling the interaction between the dynamic reservoir and dynamic well behavior for simulation oil recovery from advanced wells.

Keywords: Advanced well, ICD, AICD, AICV, OLGA-ECLIPSE coupling

1. Introduction

The DNV Energy Transition Outlook 2022 projects that oil, and gas will still fulfill 39% of the world's energy needs in 2050 (DNV, 2022). Therefore, in an energy transition period, improving the efficiency of the oil recovery methods is important for several reasons. The improved efficiency of the oil recovery methods can lead to cost savings. Moreover, enhancing the oil recovery methods is important to maximize the amount of oil that can be extracted from existing fields so that the resources can be utilized as efficiently as possible (Aakre *et al*., 2013).

To maximize the oil production and recovery, it is important to obtain maximum reservoir contact and to prevent the negative effects of early gas or water breakthroughs. Long horizontal wells can be used to achieve this goal (Aakre *et al*., 2013).. However, there are some challenges associated with horizontal wells, such as early gas/water breakthrough, caused by the water coning effect towards the heel due to the heel-toe effect and heterogeneity along the horizontal well (Moradi *et al*., 2020). To address this issue, inflow control technologies like passive inflow control devices (ICDs), autonomous inflow control devices (AICDs), and autonomous inflow control valves (AICVs) are widely used in oil well completion (Birchenko *et al*., 2010; Aakre *et al*., 2013).

ICDs can balance the drawdown pressure along the horizontal well, thus preventing an early water breakthrough, but they cannot choke the water once it eventually enters the well. The use of AICDs will provide both a delay in the early water breakthrough as well as the possibility of partially choking back water or gas automatically after the breakthrough. AICVs are designed to delay the early breakthrough behaving like AICD until the breakthrough and they can almost completely choke back water or gas autonomously after the breakthrough. Consequently, applying inflow control technologies in horizontal well completions and using Enhanced Oil Recovery (EOR)/Improved Oil Recovery (IOR) technologies would have significant potential to extract non-recoverable oil resources cost-effectively (Mathiesen et al., 2011; Moradi *et al*., 2020; Moradi *et al*., 2022; Moradi, Moldestad and Kumara, 2023).

Before implementing new technologies in an existing reservoir, conducting oil production simulations is standard practice. OLGA is a dynamic multiphase flow simulator for production wells and ROCX and ECLIPSE are reservoir simulation tools. By coupling OLGA with ROCX or ECLIPSE, multi-phase flow behavior in the total oil production can be simulated (Moradi *et al.*, 2022; Moradi, Moldestad and Kumara, 2023). The ROCX software is unable to simulate reservoirs with IOR methods such as water flooding while ECLIPSE does offer this capability. ROCX simulations also tend to have relatively longer computation times compared to ECLIPSE. Moreover, ROCX can be used to model near-wellbore reservoir, but ECLIPSE has the facility to model the full reservoir (Schlumberger, 2020). Many studies have focused on linking ROCX to OLGA due to the limited specifications required. However, there is a research gap when it comes to the coupling of ECLIPSE and OLGA for simulation of oil production through advanced wells. This paper aims to provide more insight into the simulation of oil recovery from advanced wells by developing transient fully coupled well-reservoir models using OLGA and ECLIPSE.

2. Inflow control technologies

Horizontal wells often face issues like water and gas coning, as well as early water breakthroughs due to reservoir heterogeneity and the heel-toe effect. To address these challenges, passive and autonomous inflow control technologies have been introduced. By implementing these technologies in horizontal wells, balanced drainage can be achieved, leading to increased oil production and improved recovery rates.

2.1. Passive inflow control devices (ICD)

ICD limiting the flow by creating an additional pressure drop to achieve an evenly distributed flow profile along a horizontal well as shown in Fig. 1. This pressure drop is a function of the liquid flow rate, the density of the fluid, and the viscosity of the fluid, though the viscosity plays a less important role.

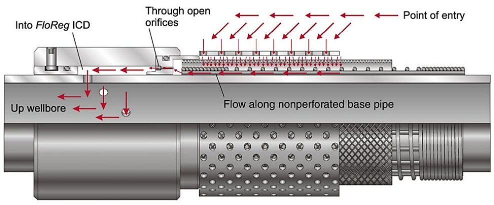

Figure 1: Orifice(nozzle) type ICD (Birchenko, Muradov and Davies, 2010).

As a result of an even production rate along the well, water/gas breakthrough could be delayed significantly. Specifically, ICDs are designed to apply a specific differential pressure at a specified flow rate through the device. The main disadvantage of passive ICDs is that they cannot choke back the water after the breakthrough. In this situation, the whole well is choked in order to prevent the increase of the water cut, greater than the capacity of the separation facilities, which in turn results in a reduction in oil production (Moradi and Moldestad, 2020). This study uses the orifice (nozzle) type ICDs. The orifice type ICDs create a resistance when the fluid tries to enter the well, by forcing the flow through a set of small-diameter nozzles or orifices. The governing equation of the nozzle-type ICD, derived by Bernoulli's equation, is as follows (Moradi and Moldestad, 2020):

$$\dot{Q} = C_D A \sqrt{\frac{1}{1-\beta^4}} \cdot \sqrt{\frac{2\Delta P}{\rho}} \tag{1}$$

where $\dot{Q}$ is the volume flow rate of the fluid passing through the ICD, ΔP is the pressure drop over the ICD and, ρ is the fluid density and $\beta = d/D$ (where d and D are the diameters of the orifice and production tubing respectively). C_D is the *discharge coefficient* and it is calculated as; $C_D = A_{vc}/A$. Here, A_{vc} is the minimum jet area just downstream of the orifice called *Vena Contracta*.

2.2. Autonomous inflow control devices (AICD)

To address the limitations of ICDs, that cannot control the water and gas production after breakthrough, AICDs were developed. The AICDs can function as an ICD until a breakthrough occurs, and then automatically control and reduce the water and gas production. The AICD combines passive inflow control with an active control element to produce a pressure drop to autonomously restrict the flow of the unwanted fluid with no need for surface control.

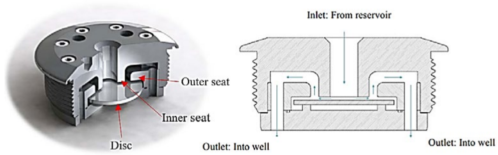

Figure 2: Schematic diagram of Statoil's RCP valve (Mathiesen, Aakre and Werswick, 2011).

Among the various designs of AICDs, the most widely used type is known as Rate Control Production (RCP), developed by Statoil and this study used RCP valves as the AICDs. As shown in Fig. 2, the RCP valve consists of 3 parts, a free-floating disc, an inner seat, and an outer seat. When the valve is in operation, the force acting on the disc is the sum of the pressure forces acting on both sides of the disc. The working method is based on Bernoulli's principle. When more viscous fluids flow through a valve, friction loss increases and the pressure recovery of the dynamic pressure decreases. As a result, the pressure on the outlet side of the valve (top side of the disc in Fig. 2), decreases, leading to a reduced force on the disc towards the inlet. This causes the disc to move away from the inlet, thereby increasing the flow area available, and boosting the flow rate of the high viscous fluid. This works vice versa for low viscous fluids like water and gas, resulting in autonomously reduced production of unwanted fluids. Statoil developed a governing equation for the differential pressure across the RCP valve, δP and it validated with experimental data, which is:

$$\delta P = f(\rho, \mu) \cdot a_{AICD} \cdot q^{x} \tag{2}$$

Where, a_{AICD} and x are user input model constants, which depend on different RCP designs for different oil fields and their fluid properties. The function $f(\rho, \mu)$ is an analytic function of the fluid mixture density ρ and viscosity μ, defined as:

$$f(\rho, \mu) = \left(\frac{\rho_{mix}^2}{\rho_{cal}}\right) \cdot \left(\frac{\mu_{cal}}{\mu_{mix}}\right)^{y} \tag{3}$$

Here, y is a user-defined constant, ρ_{cal} and ρ_{mix} are calibration and mixture density and μ_{cal} and μ_{mix} are calibration and mixture viscosity, and they can be defined as follows, while α is the volume fraction of each phase:

$$\rho_{mix} = \alpha_{oil}\,\rho_{oil} + \alpha_{water}\,\rho_{water} + \alpha_{gas}\,\rho_{gas} \tag{4}$$

$$\mu_{mix} = \alpha_{oil}\,\mu_{oil} + \alpha_{water}\,\mu_{water} + \alpha_{gas}\,\mu_{gas} \tag{5}$$

2.3. Autonomous inflow control valves (AICV)

AICV is a new type of inflow control device developed by InflowControl AS, and it can equalize the inflow before the breakthrough like AICD. As opposed to AICDs, which can partially close against unwanted fluids, AICVs can almost completely choke low-viscosity fluid, such as water or gas.

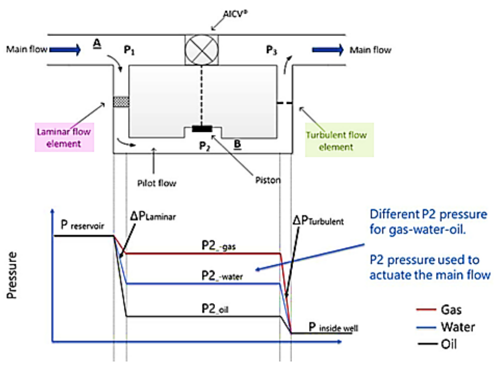

Figure 3: Simplified sketch of the flow paths in AICV and pressure changes inside for different fluids (Aakre, Mathiesen and Moldestad, 2018).

AICVs are fully self-regulating and do not rely on any external control systems and are designed to achieve the autonomous functionality by distinguishing between fluids based on their density and viscosity. The fundamental theory behind the AICV operation is the difference between the pressure drop in a laminar flow restrictor and a turbulent flow restrictor shown in Fig. 3. The laminar flow restrictor is like a pipe segment, and pressure drop across a laminar flow restrictor $\Delta P_{Laminar}$ can be expressed, as a relation of fluid viscosity μ, velocity v, pipe length L and pipe diameter D (Aakre *et al.*, 2013).

$$\Delta P_{Laminar} = \frac{32 \cdot \mu \cdot \rho \cdot v \cdot L}{D^2} \tag{6}$$

The turbulent flow restrictor can be considered as an orifice plate, and the pressure drop across the turbulent flow restrictor $\Delta P_{Turbulent}$ can be expressed as a relation of fluid density ρ, velocity v, and geometric contact K (Aakre *et al.*, 2013).

$$\Delta P_{Turbulent} = K \cdot \frac{1}{2} \cdot \rho \cdot v^2 \tag{7}$$

According to these relationships, $\Delta P_{Laminar}$ depends on the viscosity the fluid, while $\Delta P_{Turbulent}$ depends on the density of the fluid. When a viscous fluid such as oil passes through a laminar flow restrictor, it experiences a greater pressure drop than fluids with a low viscosity such as water and gas. A low-viscosity fluid, on the other hand, experiences a lesser pressure drop across the laminar flow restrictor, resulting in a higher pressure in chamber 'B' (P2) in Fig. 3. Due to the high pressure, a piston in chamber 'B' will be actuated, closing the valve. AICVs are designed based on these principles to remain fully open for oil while almost completely closed to prevent the flow of unwanted fluids.

3. Multi-segment well model (MSW)

The Multi-Segment Well model is a special extension available in ECLIPSE that offers comprehensive and accurate modeling facilities for the fluid behavior in advanced wells. There is a complex relationship between pressure gradients and changes in fluid composition induced by specific components of advanced wells. The MSW can be used to model this behavior. This model divides the production tubing into several one-dimensional segments. There is a node and a flow path, and each segment contains its own set of independent variables to describe the fluid conditions in that region. The variables for each segment are evaluated by solving material balance equations for each phase or component, and using the pressure drop equation that incorporates local hydrostatic, frictional, and acceleration pressure gradients (Schlumberger, 2020; Moradi *et al.*, 2022; Moradi, Moldestad and Kumara, 2023).

4. Development of the OLGA/ECLIPSE model

OLGA serves as a dynamic multiphase flow simulator for the production well, while ECLIPSE functions as a reservoir simulator that can be integrated with OLGA as a plug-in. The combination of OLGA and ECLIPSE provides a tool for modeling and simulating multiphase flow from the reservoir pore to the production pipeline.

4. 1. Development of the reservoir model in ECLIPSE

4.1.1. Grid

The dimensions of the synthetically designed reservoir using MRST are mentioned in Tab. 1.

Table 1: Dimensions of the reservoir.

Dimension	Value
Length of the reservoir (x)	1500m
Width of the reservoir (y)	500m
Height of the reservoir (z)	50m

The horizontal oil production well is positioned in the x-direction of the reservoir (length), 5 m below the top of the reservoir. For improved oil recovery, a horizontal water injection well with 20 perforations is used and it is positioned in the x-direction, 45 m below the top of the reservoir.

Table 2: Number of cells and their sizes in the grid.

Direction	Number of cells	Size of the cells
x	nx = 30	50 m (constant)
y	ny = 10	50 m (constant)
z	nz = 5	10 m (constant)

Generally, FCDs are installed with a sand screen and the length of one production joint is 12.4 m of the well. Since the reservoir length (x-direction) is 1500 m, 120 FCDs can be placed along the well. However, it is complex to simulate the real well with a huge number of FCDs as it consumes a long simulation time. Therefore, one equivalent FCD is used to represent 4 real FCDs. Thus, 30 cells are considered in x-direction and 30 FCDs are used along the well. In y and z-directions, 10 and 5 cells are considered respectively. The grid settings in ECLIPSE, including the number of cells in each direction and their sizes are given in Tab. 2. The 3D view of the reservoir and wells completed with FCDs is given in Fig. 4.

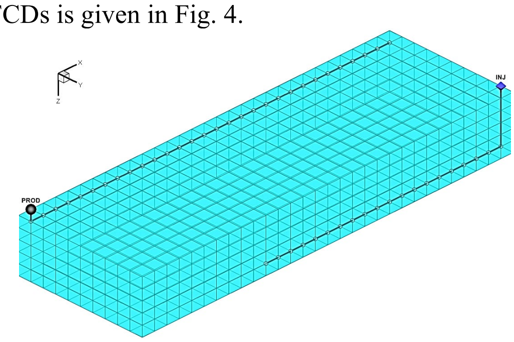

Figure 4: 3D view of the reservoir with wells.

4.1.2. The fluid and rock properties of the reservoir

It is assumed that the synthetically designed reservoir has conditions similar to the Troll field in the North Sea, containing a viscous oil with a viscosity of 2.7 cP. Therefore, the reservoir fluid can be considered as black oil type (oil viscosity is 2 to 3 – 100 and up). Reservoir fluid properties and some rock properties used for the OLGA/ECLIPSE model are listed in Tab. 3.

Table 3: Fluid and rock properties of the reservoir.

Property	Value
Oil density	950 kg/m^3
Oil viscosity	2.7 cP
Water density	1100 kg/m^3
Gas density	0.67 kg/m^3
Solution GOR	50 Sm^3/Sm^3
Porosity	0.15-0.27
Initial water saturation	0.12
Reservoir pressure	130 bara
Reservoir temperature	68 ^{0}C

4.1.3. Relative permeability

The reservoir is considered as a heterogeneous sandstone reservoir. In this study, the *log-normal absolute permeability* of the reservoir is assumed in the range 100 - 800 mD s to account for the uncertainty in the reservoir.

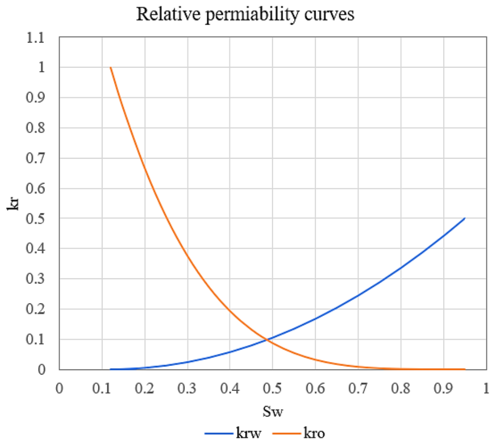

Figure 5: Generated relative permeability values.

The generalized Corey model can be used to calculate the *relative permeabilities* of oil and water using the ECLIPSE software, and the generated relative permeability values are plotted in Fig. 5 where, krw and kro are the relative permeabilities of water and oil respectively.

4.1.3. Initial and boundary conditions

The reservoir model in ECLIPSE assumes an initial oil saturation of 0.88, water saturation of 0.12, and no gas saturation. The production well is regulated with a constant Bottom Hole Pressure (BHP) of 115 bar. With a mean porosity of 0.21, the total void volume of the reservoir is calculated as 7875000 m^3. For 1500 days in operation, approximately two-thirds of the reservoir liquid is expected to be produced. Therefore, the required water injection flow rate by a single injection well is estimated to be 3500 m^3/day. However, this flow rate cannot be applied due to the industry's maximum allowable injection pressure limitation of 180 bar. Therefore, it was decided to inject water through 20 similar perforations in the horizontal water injection well, each one with a water flow rate of 175 m^3/day. Furthermore, in practical oil and gas production, the total liquid production from a well can be limited by the maximum capacity of the surface facilities. In the study, for the open-hole case model, the maximum liquid production rate is set to 2400 m^3/day.

4.2. Development of well model in OLGA

In the OLGA model, production well consists of two parts: wellbore, and production tubing. It is specified as both pipes are made with the same material combination, where the internal pipe is made of 9 mm thickness of API 5L Grade B carbon steel and other layers consist of two 2 cm concrete layers as shown in Fig. 6.

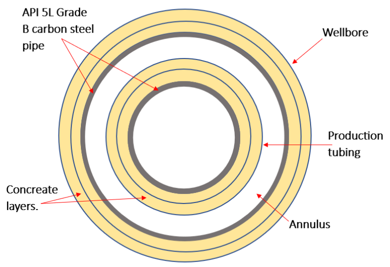

Figure 6: Material structure of wellbore and production tubing.

4.2.1. Tables and curves

By performing non-linear curve fitting for experimental data, the relationship of the autonomous functions of AICD/AICV with respect to the Water Cut (WC) can be determined (Moradi *et al.*, 2022; Moradi, Tavakolifaradonbe and Moldestad, 2022).

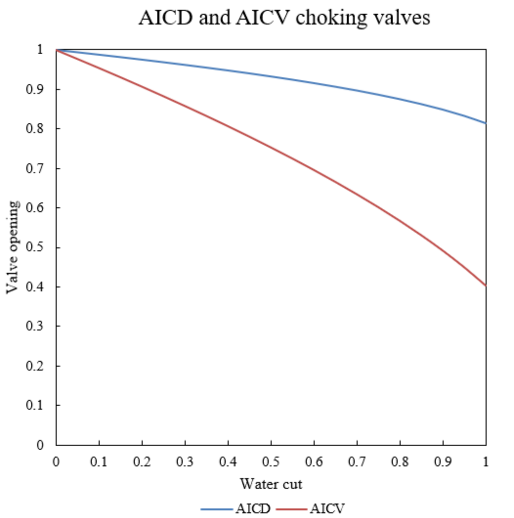

Figure 7: AICD and AICV choking valves for oil viscosity 2.7 cP for 15 bar pressure drop.

These autonomous functions of FCDs are implemented in the OLGA models, based on the pressure drawdown, 15 bar in this case, by employing a table controller and a transmitter for each FCD.

This table controller gets the measured WC data from the transmitter and provides corresponding control signals to partially close the FCDs for choking the fluid passing through them (Moradi *et al.*, 2022). The generated valve opening values of AICD and AICV with respect to WC is plotted in Fig. 7.

4.2.2. Flow component

Fig. 8 shows the simplified sketch of one oil production zone in OLGA model.

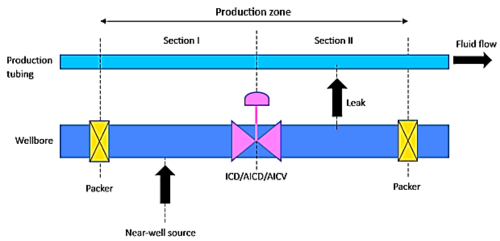

Figure 8: Simplified sketch for one oil production zone.

The production zones are separated by packers to prevent reservoir fluid from flowing in between adjacent zones through annulus. The near-well source in the OLGA model is used to connect OLGA with ECLIPSE accordingly. Then the fluid enters the wellbore through section I after passing through the FCD in Fig. 10. The fluid that enters the wellbore passes to the production tubing via the leak in section II. This setup was proposed by Haarvard Aakre in 2012 and this method has been used for many research (Moradi and Moldestad, 2020).

To develop the OLGA model, two flow paths are required for the wellbore and the production piping with a length of 1500 m for each. As the internals of wellbore and production tubing are made out of API 5L Grade B carbon steel, absolute roughness is considered as 4.572 x 10^{-5} m for both pipes (NEELCONSTEEL, 2022). The diameter of the production tubing and wellbore are assumed as 0.1397m and 0.2159m, respectively. It is assumed that oil is produced from 30 zones in the well, each of which contains two hypothetical sections as shown in Fig. 10. The production well has 30 FCDs. Since one valve is equivalent to 4 real valves, the diameter of one valve (ICD/AICD/AICV) is 0.0042 m considering the Discharge Coefficient (CD) as 0.85. When the valves are not implemented in the horizontal well, it is called “open-hole” completion. which is in a fully open state. The open-hole diameter is set as 0.12 m considering CD as 0.85. Under the case conditions, it is set to run the model for 1500 days with a minimum time step of 0.00001 seconds and a maximum time step of 1000 seconds. To solve the mass equations, a first-order discretization scheme is selected.

4.2.3. Boundary conditions

Boundary conditions of the OLGA model are set as following Tab. 5.

Table 5: Boundary conditions of the OLGA model.

Flow path name	Boundary Name	Boundary Type in OLGA
Wellbore	Inlet	Closed node
	Outlet	Closed node
Production tubing	Inlet	Closed node
	Outlet	Pressure node, Pressure =115 bar, Temp. = 68˚C

4. Results and discussion

4.1. Results validation with multi-segment well (MSW) model

Since the OLGA-ECLIPSE combination is a new approach, a result validation can be performed to prove its accuracy compared to other modeling and simulation methods. A case was considered for the oil recovery from an advanced horizontal well with AICD well completion followed by vertical water flooding. As shown in Fig. 9, the results obtained by the MSW model and the linked OLGA-ECLIPSE model, are overlapping and this implies that the effort on coupling OLGA-ECLIPSE has been successful.

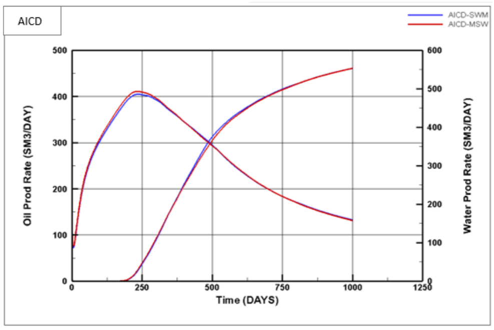

Figure 9: Results validation with MSW model.

4.2. Oil production over water breakthrough

When the oil is produced from a horizontal well, the phenomenon of water coning causes a decrease in the production efficiency. Over time, this leads to an early water breakthrough and a significant reduction in oil production. Typically, the overall oil production gradually increases until a breakthrough occurs. However, once the breakthrough happens, more and more water is pushed toward the well, which in turn suppresses and reduces the oil production. Separating water from the oil during production involves specialized equipment and processes, leading to increased costs. Additionally, the disposal of produced water poses challenges as it often requires treatment to meet environmental regulations. Therefore, delaying water breakthroughs and minimizing water production are crucial to achieve optimal production efficiency and cost reduction in the oil extraction process.

Fig. 10 shows the observed results for the WC over time for different well completions. The open-hole breakthrough occurs on the 620th day of operation while it is on the 800th day for all the other advanced well completions.

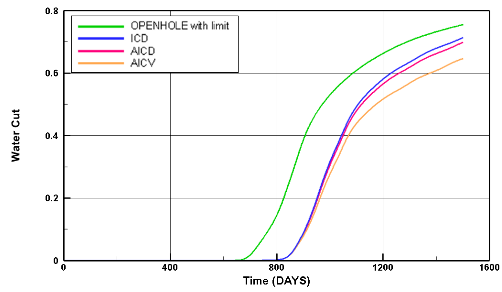

Figure 10: Water cut over the time for different FCD completions.

The implementation of FCDs has significantly delayed the water breakthrough and significantly reduced the total water production over time as expected. This is beneficial for oil recovery with a minimum cost. Until the breakthrough both AICVs and AICDs have behaved like ICDs. After the breakthrough, their autonomous function choked the water considerably and AICVs show their ability to choke more water compared to AICDs.

4.3. Accumulated oil and water production

The simulation results for the accumulated oil and water production are given in Fig. 11. According to the results, compared to the open-hole case, the cumulative oil productions from ICD, AICD, and AICV completions have increased by 2.22%, 1.7%, and 0.2%, respectively, at the end of 1500 days of operation. Moreover, the cumulative water production of ICD, AICD, and AICV is considerably reduced by 26.8%, 33.1%, and 49.1%, respectively, compared to the open-hole case. This indicates that implementation of FCDs in horizontal wells has enhanced the oil recovery to some extent, in addition to the reduction of water production.

Interestingly, the AICV completion has reduced water production by almost half (49.1%), due to the ability of completely choking of low viscous fluids. According to Fig.11, at the end of 1500 days of operation, the WC for AICD and AICV are 0.65 and 0.7 respectively. At this time, based on the vale opening plot in Fig. 9, the value openings for AICD and AICV are 0.95 and 0.65 respectively. This implies that, when the WCs increase with time, the more choking effects of AICDs and AICVs can be expected.

Moreover, it can be noted that, according to the cumulative oil production, the open-hole case initially has a higher oil production compared to the other well completions. But, due to the early water breakthrough after 620 days (open-hole case), the water that enters the wellbore has suppressed the oil production, resulting in higher accumulated water production and lesser accumulated oil production at the end of the operation.

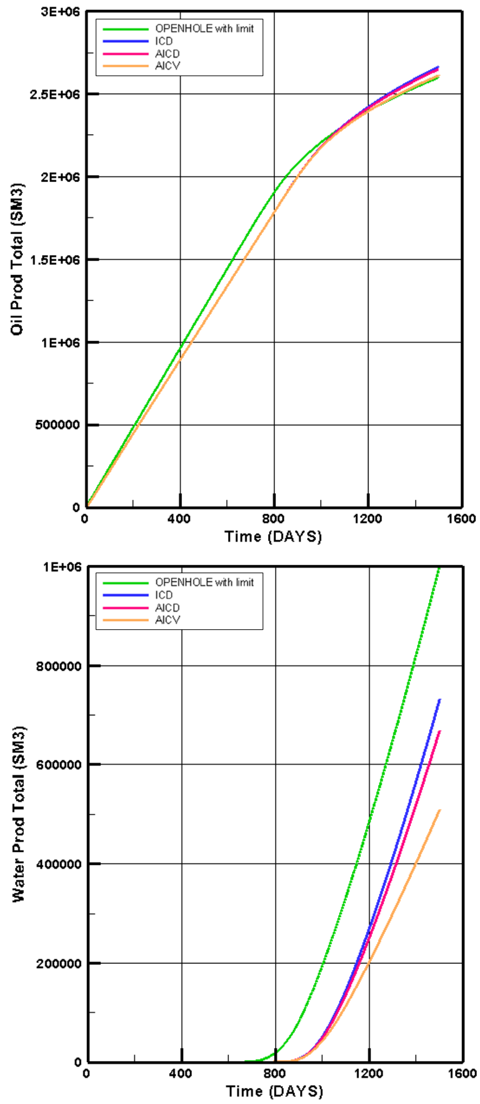

Figure 11: Accumulated oil and water production for open-hole and for different FCD completions.

4.4. Oil and water production rate

The simulation results observed for oil and water production rates are given in Fig. 12. Considering the oil production rates, the open-hole completion initially has the maximum oil production rate (~2265 Sm^3/d) compared to other advanced wells, and that production rate lasts until the water breakthrough only. Although the other advanced well completions have a 5.61% lower oil production rate at the beginning, it lasts for a longer period since the water breakthrough is delayed in advanced wells. But at the end of 1500 days of operation, the OPENHOLE case has achieved the lowest oil production rate as it does not have control over the water production after the breakthrough. And the open-hole case has also the highest water production rate from the beginning. It is generally undesirable to have a high total liquid flow rate. This is because there is then a need for larger surface production facilities to handle the increased liquid volume and higher costs associated with water separation. Ultimately, this situation leads to reduced revenue.

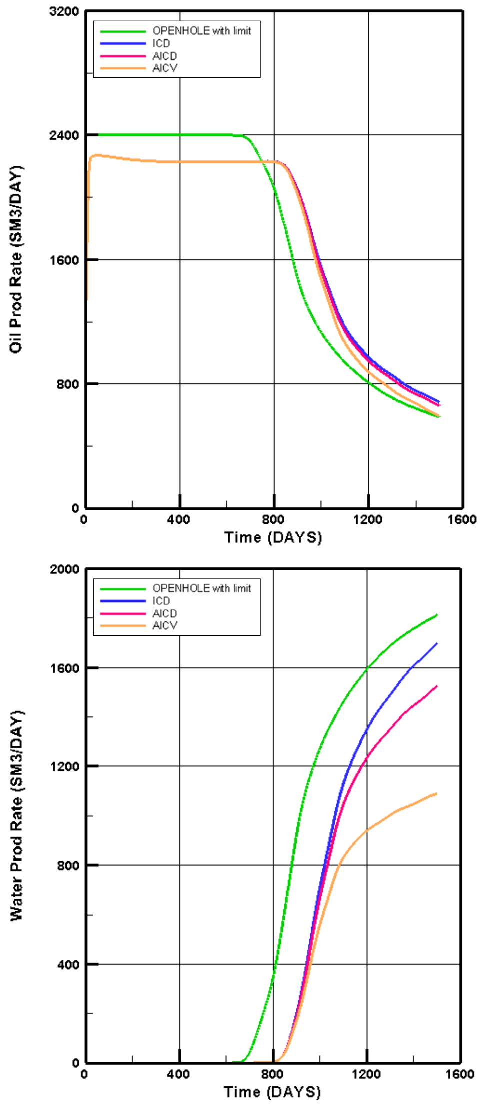

Figure 12: Volumetric oil production rates for open-hole and for different FCD completions.

Considering volumetric flow rates at the end of 1500 days, the ICD, AICD, and AICV completions have achieved 16%, 12.1%, and 1.3% increments in the oil production compared to the open-hole case. But end water production rates of ICD, AICD, and AICV completions have reduced by 6.2%, 15%, and 39.8% compared to the open-hole case. It appears that despite advanced well completions having a small impact on oil production rates because of the total liquid production limit, advanced wells can significantly reduce the water production by improving the oil production process in a cost-effective manner.

5. Conclusion

To achieve cost-effective oil production, it is important to address the problem of early water breakthrough in horizontal wells. Implementation of ICDs, AICDs, and AICVs evens out the inflows along the well and delays the water breakthrough. The AICDs and AICVs show similar behavior to ICDs before the breakthrough. Advanced wells equipped with FCD completions result in a significant decrease in the production of water after the breakthrough and with a little increase of accumulative oil production compared to the open-hole completion, while AICVs show the best performance in choking water.

The autonomous function of AICD and AICV can be clearly seen if the WC exceeds around 0.9. But the oil production should last longer than 1500 days in order to achieve a higher WC. Therefore, it is recommended to extend the simulation period to observe the true impact of utilizing advanced well technologies for achieving more efficient oil production processes. Realistic results obtained from the simulations in this study indicate that the coupling of the well simulator OLGA and reservoir simulator has been a successful effort in simulating total oil production and this combination can be further applied to more advanced scenarios to compare its effectiveness with other oil production simulators.

Acknowledgment

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