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Review

Downhole flow controllers in mitigating challenges of long reach horizontal wells: A practical outlook with case studies

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Production and injection in long reach horizontal wells pose several challenges in production optimization, flow assurance and reservoir management. Horizontal wells are known to be superior to vertical wells in terms of productivity, however, they are also susceptible to early water and/or gas cut production due to the heel-toe effect and/or permeability contrasts. Uniform distribution of water injection into all zones can also be a challenge in case of high-permeability streaks and fractures. To negate some of the adverse reservoir properties and to control the flow profile of production and injection fluids, downhole flow control devices are increasingly in use and beneficial in regulating flow, improved overall reservoir sweep, improved productivity from the tail section of the well and reduced water coning or gas cusping. Wellbore hydraulics for a long reach well completed with downhole valves have great influence on the reservoir performance and recovery in the long run. This paper presents a discussion aimed at better understanding of the critical challenges that long reach horizontal wells are prone to in terms of completion, as well as the developments so-far that have been applied to capture the physics across the long horizontal section. Three case studies are also discussed with some details emphasizing practical experiences of such wells.

Key words: Downhole flow controllers, horizontal wells, inflow control devices (ICD), internal control valves (ICV), production enhancement.

INTRODUCTION

Application of horizontal drilling technology in oil field development and production operations has grown significantly over the past decade. It has been achieving commercial viability since late 1980's which encouraged horizontal drilling in various geographic regions and geologic settings. Achievable horizontal borehole length grew swiftly as drilling technologies advanced. Horizontal displacements nowadays have been extended over 20,000 ft. Completion and production techniques have also developed for the horizontal borehole environment at equal pace.

Numerous potential advantages are associated with horizontal wells namely, well productivity, sweep efficiency and delayed water and gas coning due to increased wellbore-reservoir contact area.

These can be summarized as follows (Salamy, 2005):

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(1) Minimized unit development costs.
(2) Minimized unit operating costs.
(3) Minimized drawdown at a given flow rate.
(4) Minimized water and gas breakthrough (in homogeneous reservoir).
(5) Maximized long term performance.
(6) Maximized production rate / PI.
(7) Maximized sweep efficiency / reserves.

Despite numerous advantages of drilling those long Maximum Reservoir Contact (MRC) wells and multilaterals, they are associated with unprecedented challenges in the areas of drilling and completion, mostly due to the complex wellbore fluid dynamics resulting from the extra exposure with the reservoir (Salamy, 2005).

Production from conventional well is controlled at surface by manipulating the wellhead choke to control the production of gas and/or water in high GOR – WOR wells. This technique is no longer sufficient in MRC wells because having such a long contact between the wellbore and the reservoir does not drain the reservoir uniformly. In MRC wells, premature breakthrough of unwanted fluids (gas and/or water) occurs due to several reasons, some of which are listed and further discussed below.

(1) Frictional pressure losses along the wellbore which is sensitive to the length of the wellbore, a phenomenon known as the heel-toe-effect.
(2) Reservoir permeability heterogeneity due to the geological setting of the reservoir in the depositional environment.
(3) Variation in the distance between the wellbore and the gas/water flood front due to factors such as an inclined wellbore or tilted flood front.
(4) Variations in reservoir pressure due to penetration of several pressure regions of the reservoir.
(5) Variation in encroachment of injected water and gas profile along the wellbore due to permeability heterogeneity and heal-toe effect in the injector wellbore.

The heel-toe-effect is defined by the difference in the specific inflow/outflow rates between different sections of the wellbore, particularly evident when comparing the near shoe section (the heel) and the near target depth section (TD – the toe). This phenomenon arises due to the frictional pressure drop along the wellbore which becomes more and more significant when its value approaches the threshold drawdown pressure. The heel-toe phenomenon is most evident in high permeability reservoirs producing at high fluid rates which in turn generate increasing significant frictional coefficient along the wellbore. To prevent or minimize this phenomenon in high permeability reservoirs, drilling a larger diameter hole or limiting to shorter laterals are technically feasible option, however this may not be economically feasible (Minulina et al., 2012).

The other three challenges (listed 2, 3, and 4 above) may possibly be mitigated (at least theoretically) through an optimized and accurate design of wellbore trajectory. Inadequate identification of the parameters during the time of designing the trajectory or even during actual drilling, will lead to improper designing of the completion for the drilled well (Raffin et al., 2007).

Production from horizontal wells imposes even greater challenges as they are vulnerable to various factors impacting production such as well cleanup and water coning or gas cusping (which are mainly caused by reservoir heterogeneity, depicted by permeability contrasts within the wellbore). On the other hand, water injectors are susceptible to an uneven flow profile, poor sweep efficiency and large amount of bypassed oil due to inability to achieve even distribution of water into all penetrated zones. These challenges are usually attributed to reservoir heterogeneity, permeability anisotropy, presence of fractures and/or faults and also the frictional losses causing unintentional thermal fracturing during water injection (Minulina et al., 2012). In long horizontal injection wells, even if permeability heterogeneity is less significant, the heel-toe effect caused by severe frictional pressure loss may flood the heel zone early in the injection period and cause early water breakthrough in the nearby producers, leaving behind large recoverable reserve in the toe section (Birchenko et al., 2010).

In highly heterogeneous and fractured reservoirs with openhole completion (completions with pre-drilled or slotted liners without packer segmentation are also considered “openhole completion” in this article), excessive flooding in high permeability streaks may be resulted, while lower permeability streaks may undertake little or no water. Therefore, the risk of non-uniform water injection and early water breakthrough in the adjacent production wells should be expected (Garcia et al., 2009).

The movement of reservoir fluids between injectors and producers in conventional completions are controlled by reservoir and fluid properties but also governed to a large degree by injection and production rates and profiles. Profound understanding of the reservoir topology, its geological setting and connectivity of various compartments, and the dynamic interactions between wells are critical for setting optimal field development plans and production strategies. Therefore, decisions concerning production and injection rates, well placement, and completion design are all affected by the outcomes of dynamic reservoir simulations during its lifespan (Garcia et al., 2009).

Proven and practical solutions to the above challenges when addressed collectively in well completion design are currently termed as smart completions, by which downhole inflows and outflows are controlled by various devices attached during well completion. The principle is to control or restrict the flow from the annulus into the production string or vice versa (Daneshy et al., 2010).

The distribution and setting of the restrictions are designed carefully to improve the areal and vertical sweep efficiency by establishing a stable flood front around the wellbore and hence preventing unwanted fluid breakthrough (Ouyang, 2009). Two major types of smart completion devices are as follows:

(1) Internal Control Valves (ICV)
(2) Inflow Control Devices

To design an effective smart completion, it is essential to perform dynamic reservoir simulation, which demonstrate the potential benefits of utilizing smart completions in both injectors and producers, especially in highly heterogeneous reservoirs. Employing a smart completion design to balance out the influx of a producer well or the out flux of an injector well, that is, attempting to create a uniform and stable flood front in the reservoir, provides tangible benefits in terms of delayed water breakthrough, increased production rate and optimized injection rate and hence increased recovery (Aadnoy and Hareland, 2009; Gao et al., 2007).

However, installing smart completion in a long horizontal well may incur a huge additional completion cost and may impact profitability of the project. Instead, a simpler completion solution such as slotted liner (with or without zonal isolation packer) may be an attractive solution in profiling produced oil or injection water in a relatively homogenous reservoir. Another solution which could be more attractive compared to the simple slotted liners in terms of technical and cost effectiveness is the engineered slotted liner or the Limited-Entry Liner (LEL). The LEL can compensate the variation in reservoir permeability across the long horizontal section by varying both the density and the size of the openings or slots in the liner (Burtsev et al., 2006; Chow et al., 2009).

COMMON CHALLENGES IN HORIZONTAL PRODUCTION WELLS

As mentioned previously, horizontal wells do enhance wellbore-reservoir contact, oil production, and reduce the number of wells needed to develop a certain field compared to vertical wells. However, there are several associated challenges that must be addressed prior to the design and development of a field with horizontal wells (Augustine, 2002). These challenges are discussed next.

Coning

Most reservoirs have an underlying water zone and/or an overlaying gas cap. When production is started, a ressure sink occurs along the wellbore. The fluids flow towards the point in the wellbore where the drawdown is maximum. In some cases, coning in horizontal wells could be expedited because of the heel-toe effect and the variable permeability distribution along the well bore (Richardson et al., 1987).

Heel-Toe effect

Between the first point of contact of the wellbore with the reservoir (heel) and the end of the wellbore (toe), there will be a frictional pressure drop along the horizontal section of the wellbore. For long horizontal wells with high flow rates, frictional and acceleration effects can cause significant pressure drop and therefore reduce the effective wellbore conductivity. This implies that the fluid influx can be greater at the heel and gradually lower towards the toe as fluids experience frictional pressure drop as they move from the toe to the heel (Birchenko et al., 2010). In homogenous reservoirs, water and gas cone towards the heel is frequent, resulting in premature water/gas breakthrough (Figure 1 Left). One solution of this problem is to introduce flow restriction in accordance to the pressure drop profile, using inflow controllers. When Inflow Control Devices (ICD) and zonal isolation packers are in place, the fluid influx will be restricted at the heel, thus flow from toe side will be eased (Al Marzouqi et al., 2010). Oil flow towards the wellbore would be more uniform, thus delaying water breakthrough as depicted in Figure 1 right.

Variable permeability and pressure distribution

The rock matrix along the wellbore varies in permeability consequently leading to an uneven inflow, giving an effect similar to pressure contrasts. The fluids seek the path of least resistance and therefore flow through the high permeable zones and fractures, resulting in water or gas breakthrough at these points along the wellbore. As clearly shown in Figure 2, the ICD integrated completion is used to equalize the pressure drop between the different sections, ultimately balancing the fluid influx.

Premature water/gas breakthrough

Due to coning and near wellbore formation fracturing and damage, water and gas may enter the well at an earlier stage of production than anticipated. This results in less oil production, and more amount of the unwanted fluids, leading to a higher processing costs and system bottlenecking. This is to be considered during the completion design stage as it may influence the produced volume of oil. Proper flow controller integration during completion design can delay the water and gas from entering the well, effectively extending the lifespan of the well. When water or gas eventually enters the well, the higher mobility fluids choke the inflow, according to

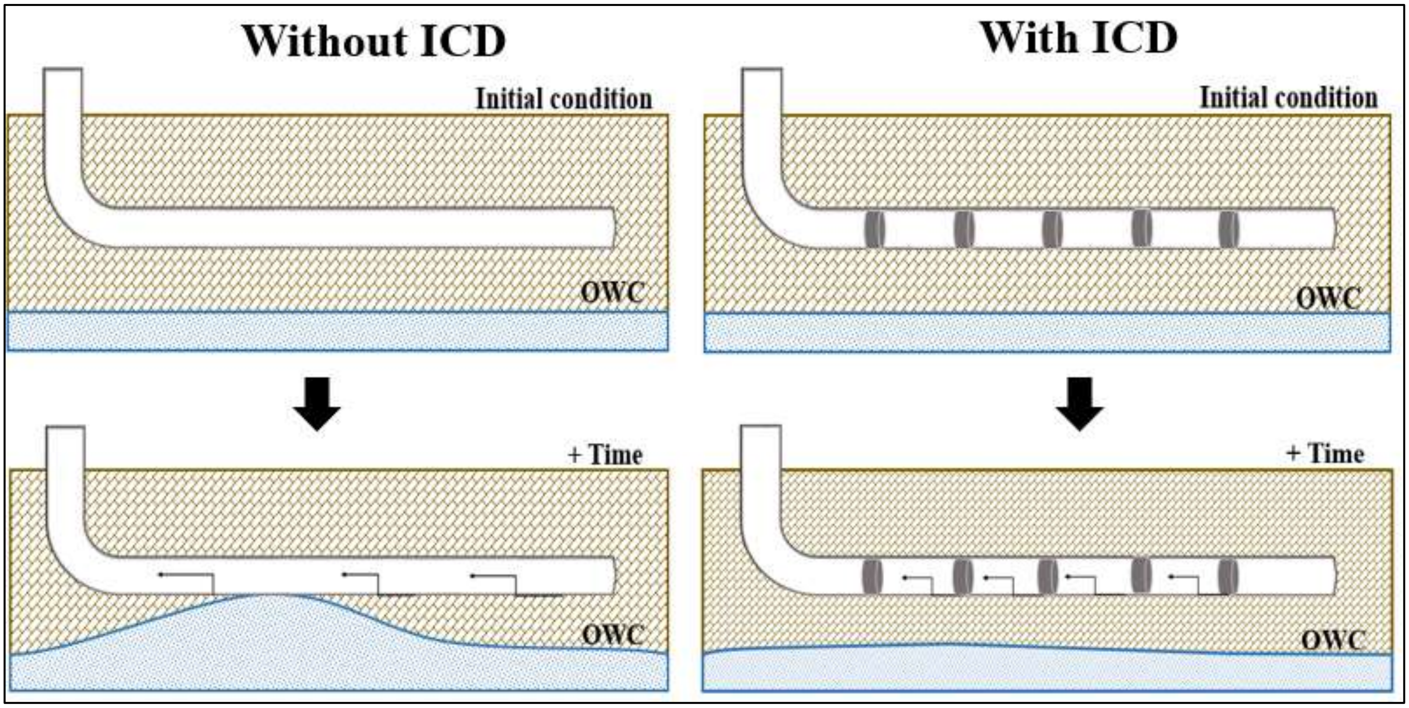

Figure 1. Combined effect of Coning and Heel-toe effect in homogeneous reservoir and mitigation using ICD.
Source: Jokela (2008).

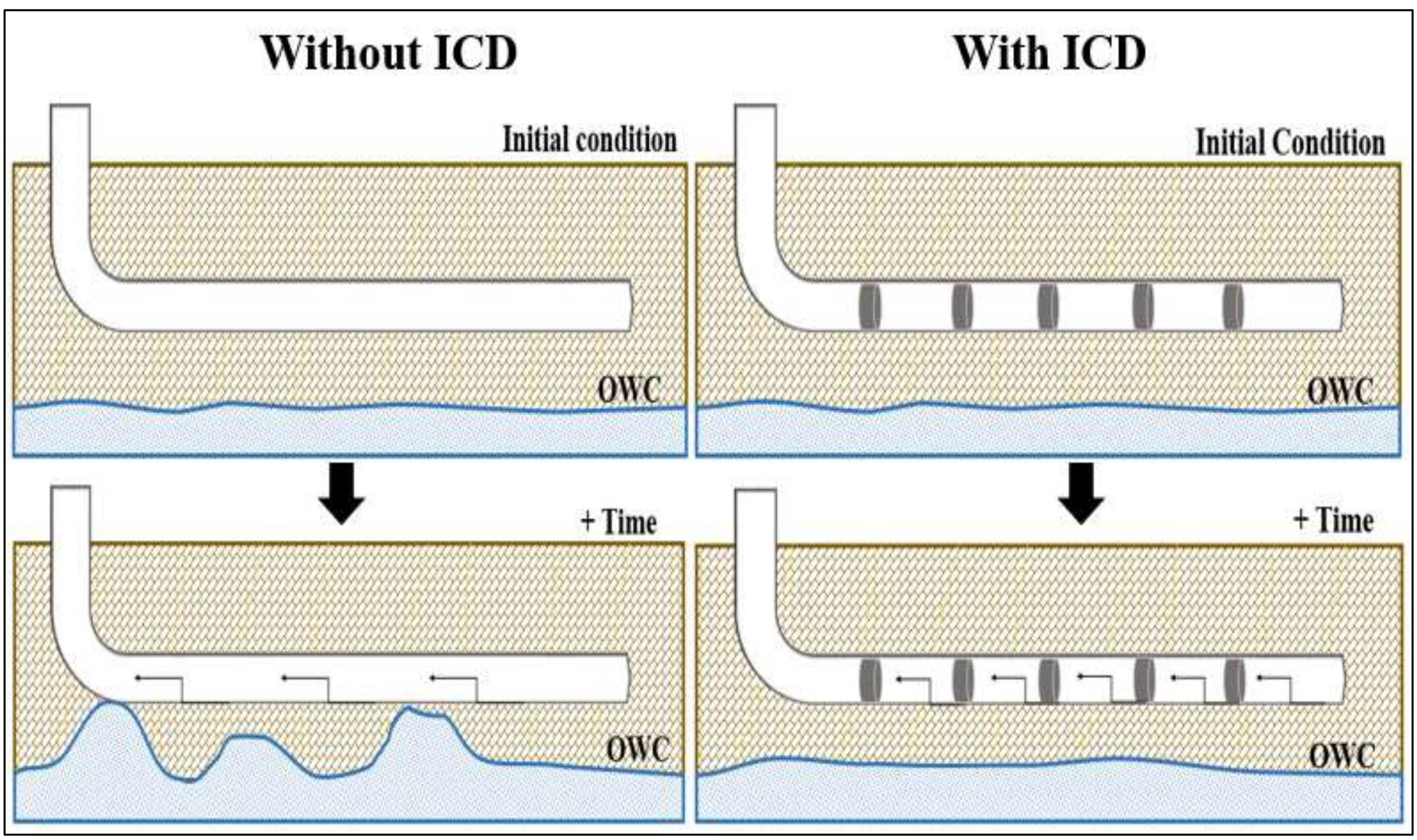

Figure 2. Mitigating effect of ICD in heterogeneous reservoir.
Source: Jokela (2008).

pressure drop in Bernoulli's equation (Al-Khelaiwi and Davies, 2007):

$$\Delta \mathrm{P} = \rho \, . \frac{v^2}{2}, \;\; v = \frac{\mathrm{q}}{\mathrm{A}} \tag{1}$$

where ΔP is the pressure drop, ρ is the density of the fluid, v is the fluid flow speed, q is the flow rate and A is the area of the cross-section of the horizontal hole.

Poor wellbore clean-up

Long reach horizontal wells are prone to increased levels of formation damage (more positive skin factor) due to the increased exposure of the formation to the drilling and completion fluids under overbalance conditions. The result of formation damage is basically an additional pressure drop resulting in decreased productivity as illustrated in the equations below.

$$\Delta \mathrm{P}_{DD} = \Delta \mathrm{P}_{ideal} + \Delta \mathrm{P}_{skin} \tag{2}$$

$$J = \frac{q}{\Delta \mathrm{P}_{DD}} = \frac{q}{\Delta \mathrm{P}_{ideal} + \Delta \mathrm{P}_{skin}} \tag{3}$$

where ΔP_{DD} is the total pressure drawdown, ΔP_{ideal} is the pressure drawdown without formation damage, ΔP_{skin} is the additional pressure drawdown due to skin, J is the productivity index and q is the flow rate.

The residual filter cake after drilling a well requires optimum and uniform well flow to pop up and flow back the residual cakes. This process is usually termed as well clean-up. Due to the non-uniform influx in horizontal wells, zones that experience low productivity finds difficulty in removing the filter cakes, resulting in higher skin and poor well clean-up. A common way to do wellbore clean-up is by increasing drawdown. However, the extended length of the horizontal well imposes a variation in the drawdown along the horizontal section, making it impossible to ensure that there is sufficiently enough high drawdown to remove the filter cake and reduce the formation damage, particularly in the toe area of the hole (Al-Khelaiwi et al., 2009). Additionally, pushing the drawdown into high values may not always be gainful; as this may lead to wellbore collapse, accelerated water and/or gas coning and encouraging sand production (Maclachlan and Harper, 2016).

Achieving an even inflow profile through the equalizing effect of ICD is beneficial to efficiently clean the long horizontal wells; particularly for those horizontal wells with large variation in reservoir parameters and where there is a significant heel-toe effect. Sequential opening and closing of valves allows imposing higher drawdown on one zone after another, providing better clean-up than conventional completion and resulting in better near wellbore pressure profile and higher well productivity as illustrated in Figure 3 (Jones et al., 2009; Raffn et al., 2008).

COMMON CHALLENGES IN HORIZONTAL INJECTION WELLS

Non uniform outflow

At formations with heterogeneous/stratified geology, the injected water seeks the path of least resistance in both the near wellbore and throughout the sweep zones. This results into non-uniform sweep and lower recoverable reserves (Chen et al., 2011). In homogenous reservoirs, the injection pressure is highest at the heel of the wellbore; the outflow of water will be concentrated at the heel while reduced amounts reach the toe. Figure 4 illustrates the heel-toe effect with a garden hose analogy which has a set of openings in it.

ICD integrated completions can regulate the high intake zones. While the low permeable zones will have larger openings so that a more uniform flow across the whole wellbore can be achieved. This way, the heel-toe effect, the permeability contrasts effect, and fractures effect can be mitigated (Neylon et al., 2009). Also, applying an ICD integrated completion in an injector well results in an even water distribution throughout the wellbore, resulting in enhanced sweep effect as shown in Figure 5.

Fracturing

Water injection can impose formation damage and induce fractures in the near wellbore region. The most common causes are thermal induced stress changes, changes in pore pressure and injection pressure build-ups due to plugging. These fractures can have very high permeability causing the injected water to flow in larger quantities into the fractures. After some time, the fractures grow wider because of erosion effects and pressure differences. The water will then flow along fractures and high permeability zones even more, reaching the producer earlier than anticipated (Gadde et al., 2001). Using ICDs in addition to zonal isolation can reduce the risk of thermal fracturing, by regulating the flow from high intake to low intake area.

Early water breakthrough

In the presence of the naturally occurring fractures, and high permeability streaks, the water outflow will be focused on these sections, and ultimately reach the producer prematurely. Zones with lower permeability will experience a reduced sweep or none at all. In addition to the reduced overall production and the bypass of potential recoverable oil reserves, the increased amount

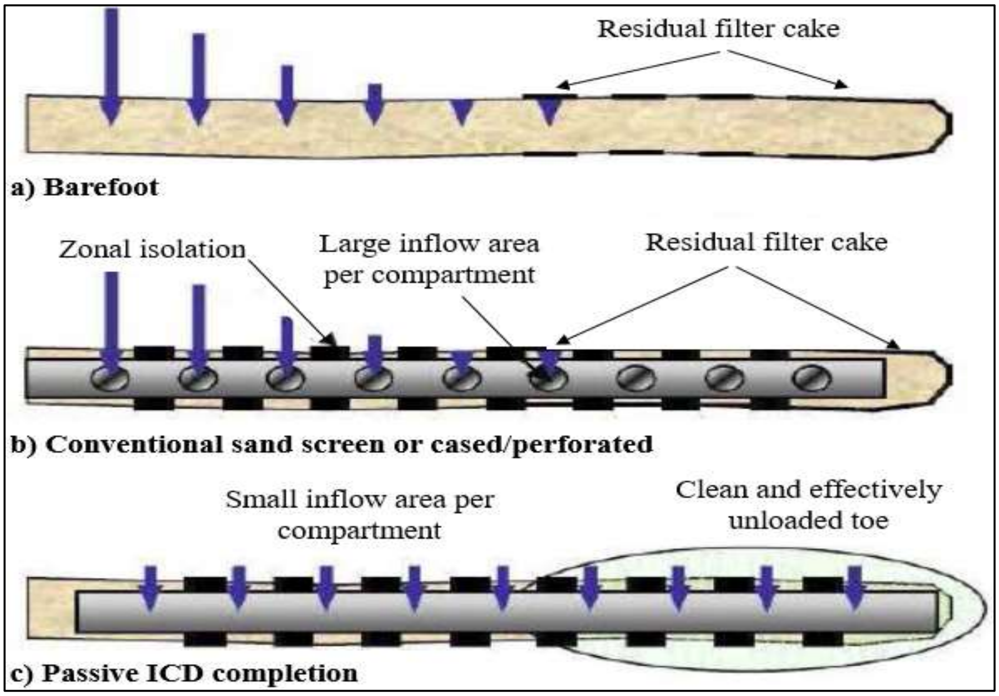

Figure 3. Well cleanup properties for barefoot, sand screen and ICD Completion, respectively. Source: Raffin et al. (2007).

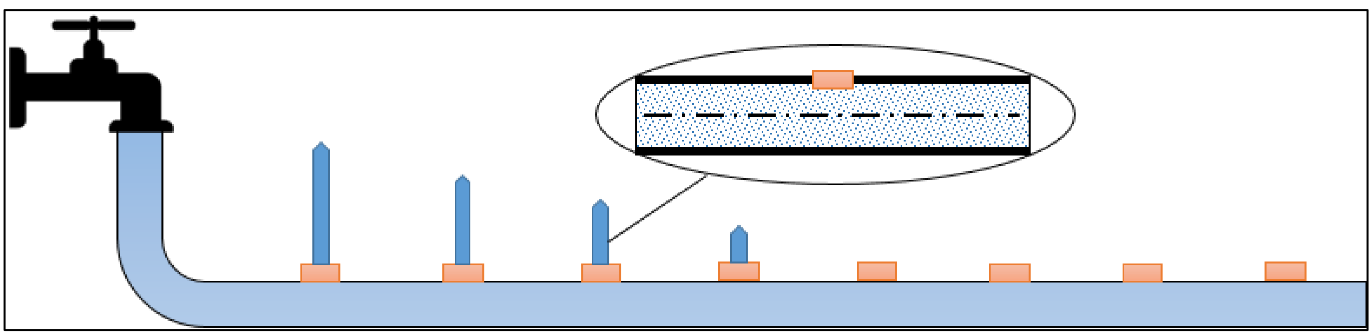

Figure 4. The heel-toe effect illustrated with a garden hose figure with a set number of openings (open hole case). Source: Jokela (2008).

of produced water will have higher processing cost and therefore impact short and long term profit generation. Water flow profiling with the help of inflow controllers are designed to mitigate this issue by enabling a more even influx along the wellbore (Augustine et al., 2006; Youl, 2011).

MECHANICAL CONFORMANCE TECHNOLOGY

A conformance technology is a method of managing the profile and controlling the volume of unwanted water or gas production. Before 1990s, the common practice was the use of chemical treatments such as relative permeability modifiers or polymer gels, known as chemical conformance modification (Thornton et al., 2010). In the 1990s, the demand for the mechanical conformance technologies arose after the development of the first inflow control valve (ICD); as they proved that their CAPEX and deployment overhead is relatively small compared to their advantages. ICDs were installed in thousands of wells worldwide over the last decade and are considered a mature well-completion technology. They mainly work to equalize the inflow along the horizontal wells by imposing additional pressure drop in the more flow contributing zones and consequently reducing the drawdown within the interval (Smith et al., 2016); as explained by the following equations.

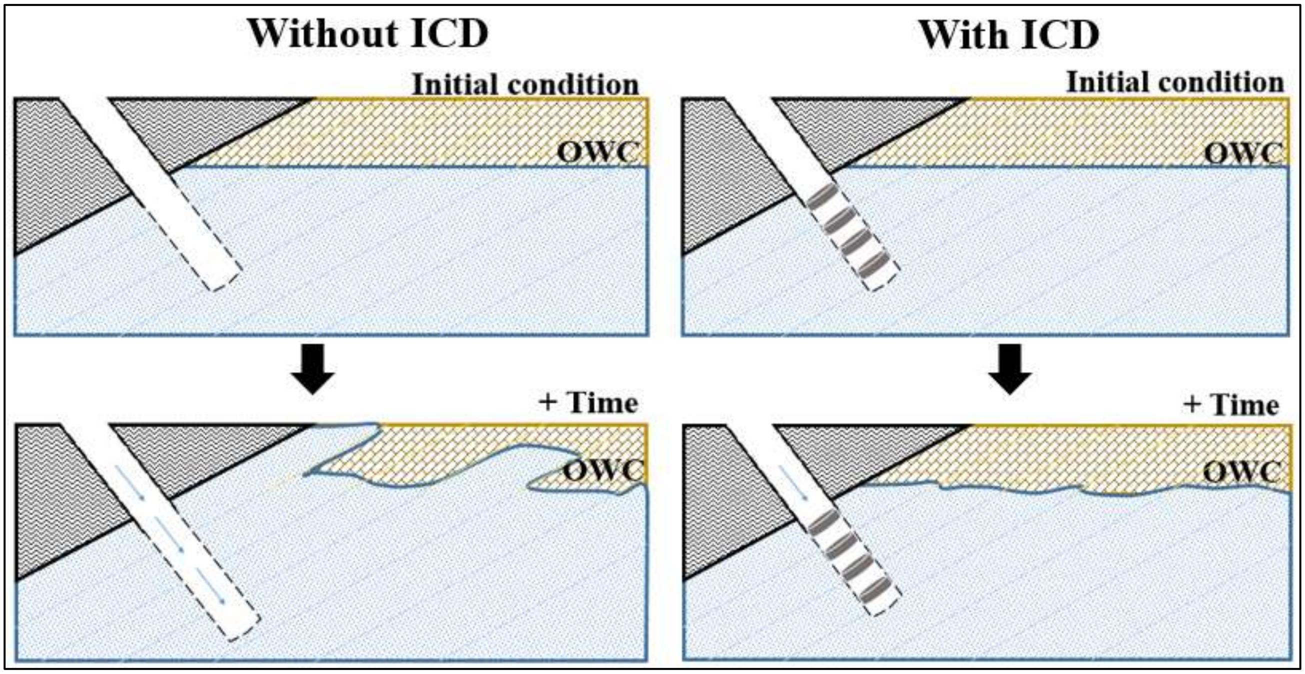

Figure 5. Injection profile in heterogeneous reservoir with and without an ICD solution.
Source: Neylon et al. (2009).

$$\Delta P_{ICD} = P_{nw} - P_{wf} \quad (4)$$

$$\Delta P_{DD} = P_r - P_{nw} \quad (5)$$

where ΔP_{ICD} is the pressure drop across the ICD, P_{nw} is the flowing well pressure, P_{wf} is the flowing bottomhole pressure, ΔP_{DD} is the total drawdown pressure and P_r is the reservoir pressure.

The mechanical conformance technologies were fast developed both in technology and number of deployment in proportion to the huge increase in the number of long horizontal wells drilled and completed (Lauritzen et al., 2011). The long reach wells access a much bigger portion of the reservoir than the vertical and deviated wells, and thus, are exposed to higher permeability heterogeneity. The advanced completion equipment and downhole devices are supposed to maintain a uniform production profile along the horizontal section, and manage the breakthrough of the unwanted fluids (Shi et al., 2016). The completion strategies includes, but are not limited to, open hole, cased hole, slotted liners, downhole inflow regulators and valves, sand screens, and engineered slotted liners.

There are two main aspects in an effective mechanical conformance technology (Thornton et al., 2010):

(1) Proper selection of the downhole control device
(2) Proper placement of the selected flow control device

There exist so many types and models of the downhole control devices, and the selection is rather not so complicated. The main challenge however is the proper placement of the control devices and the segmentation of the horizontal wellbore. This is the subject of next discussed.

Wellbore simulation

A well is represented as node (sink or source) in a conventional reservoir simulator. In the reservoir simulator, the well model is used to correlate block pressure, production rate, and bottomhole pressure. A skin factor is used to count for the other completion designs. However, a simple skin factor is not enough to represent the wellbore hydraulics and how it changes over time. Unfortunately, at earlier times, there was no method to properly place the downhole tools and to accurately diagnose the conformance challenge related to well completion (Wang et al., 2008; Edmonstone et al., 2015).

Service providers and operating companies critically demand to have asoftware that simulates wellbore hydraulics in order to count for the pressure drops across the variable completion components along the horizontal drain (Grubert et al., 2009). Some vendors create a steady state simulator that models multi-phase flow across the wellbore region.

These software calculate overall production performance, inflow profile, pressure profile, and flow rates in tubing and annulus. The static or the steady state simulator requires reservoir input data such as well boundary conditions, reservoir pressure, phase mobility, and solubility factors. The steady state simulator works to enhance the design of the completion and the selection of the downhole devices. Hence, since it is a static simulator, the wellbore hydraulics simulation is done at a single time step (Carvajal et al., 2013; Awad et al., 2015).

Coupling dynamic and static simulators

The static or steady state simulator can be used to create a detailed model of the wellbore completion but only has a simplistic representation of the reservoir. Therefore, by coupling steady state and the numerical simulators, we can leverage the capabilities of each software to make more accurate models. A coupled model dynamically captures the coupled effects of wellbore hydraulics and reservoir simulation improving the accuracy of the simulation. Some of the reported advantages of coupling static and dynamic modeling include (Vasper and Gurses, 2013):

(1) The use of properties distribution such as permeability and water saturation becomes more accurate and therefore contributes to a more accurate fluid flow predictions.
(2) Compartment sizes, packer locations, predicted pressure and flow profiles can be further optimized.
(3) Unwanted fluids breakthrough time can be computed.
(4) Considers other producers/injectors and their cumulative production/injection effect.

Preparing the coupled simulation model is a significant undertaking that requires additional effort than that required for using any of the standalone softwares. Simulation runtime also increases significantly. While an individual static model takes seconds to converge, the steady state simulator requires additional time when coupled. The coupled model is also less stable requiring more pipe flow iterations and shorter time steps (Wang et al., 2008). Due to this increased amount of overhead, coupling is only undertaken when the increase in accuracy justifies the additional cost.

Therefore, the most common uses of such coupled models are in the following situations (Jackson et al., 2012):

1) When the completion has a direct impact on reservoir performance and overall field recovery (e.g. annular flow impacts on performance).
2) When complex completions such as ICDs are used to improve reservoir recovery performance.

The coupled simulator is used specifically to optimize the design of the completion string and the downhole equipment as per the following (Thornton et al., 2010):

(1) Calculate the effect of the downhole device on the overall reservoir performance forecast.
(2) Obtain better understanding of the reservoir mechanics.
(3) Decrease operational risks and costs.
(4) Enhance the design of the completion and consequently maximizing NPV to the operator.
(5) Study placement strategy for the downhole barriers and packers.
(6) Assist in material and equipment selection and therefore save OPEX on possible future well intervention operations such as workover or stimulation.

FIELD APPLICATIONS – CASE STUDIES

The coupled simulation is relatively an up-to-date practice. There are very few field examples that are published in the literature. The following are some field applications of the coupled modeling methodology, emphasizing the practical experiences of horizontal wells with smart completions.

Case study 1

A study has been conducted in ADMA-OPCO in order to assess the efficiency of implementing inflow control devices in improving the recovery from a highly heterogeneous under-saturated carbonate reservoir. This study was part of a major development plan where the company was attempting to implement smart completion technologies, ICD being one of them. A sector model was extracted from the full field model so that simulations can be run and then evaluations can be made for the different sector models (Marir et al., 2011).

As mentioned earlier, implementing ICD integrated completion designs in oil producers or water injectors generally delivers considerable enhancement in reservoir control by balancing the fluid flow front and achieving a uniform flow profile. There are however certain challenges where the demand for utilizing ICDs arises. Those challenges are as follows:

(1) Non-uniform drawdown distribution, known as heel-toe effect.
(2) Permeability contrasts.
(3) Mobility contrasts.
(4) Variation in reservoir pressure.
Based on the listed challenges, several completion cases were put in place for investigation. The cases that were investigated in this research are the following:

Case 1: Open hole oil producer (as reference case) + Open hole water injector.

Case 2: Cased hole oil producer with ICDs along the total drain + Open hole water injector.

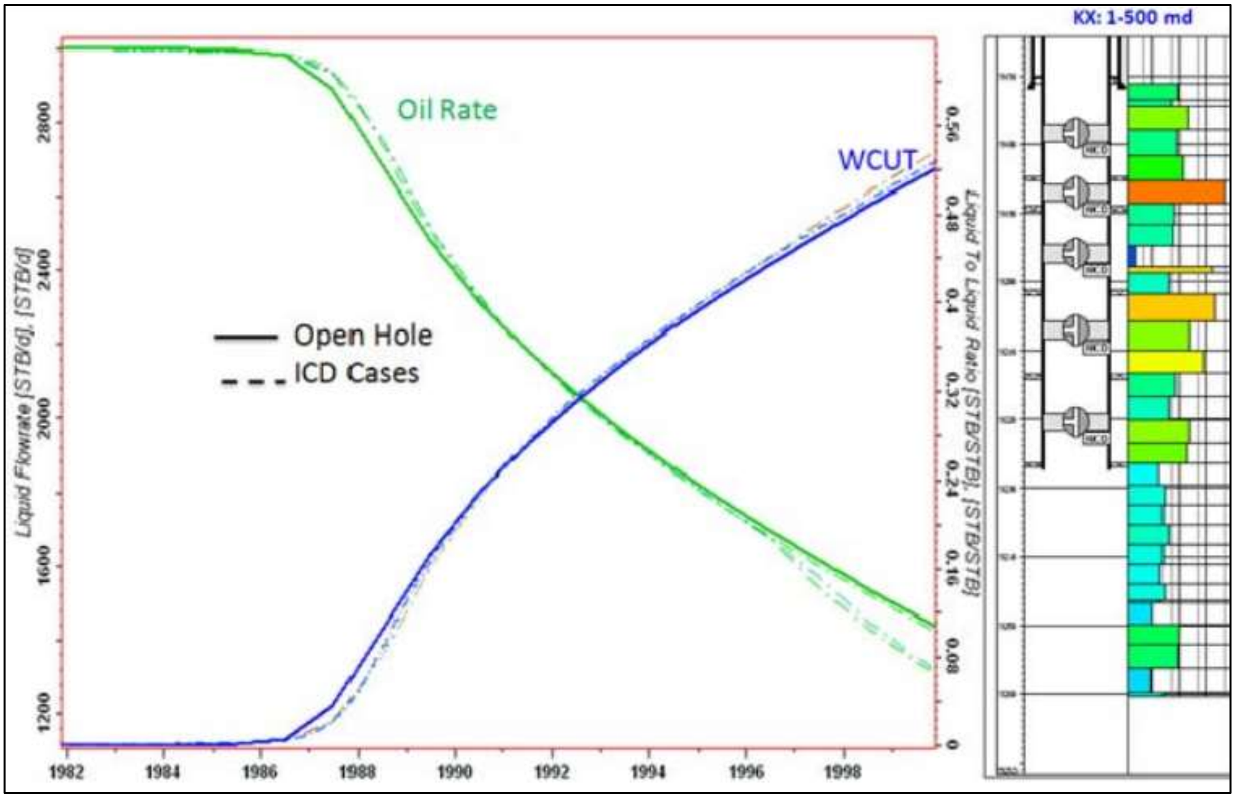

Figure 6. Well performance with and without ICDs in Reservoir A.
Source: Marir et al. (2011).

Case 3: Cased hole oil producer with ICDs in the upper zone and open hole in the lower zone + Open hole water injector.

Case 4: Cased hole oil producer with ICDs + Water injector + High permeability streak crossing the producer & the injector.

Different design parameters were considered, such as the number of ICDs, number of nozzles, nozzle sizes, and number of compartments (swellable packers).

The results of this study showed that implementing ICD integrated completions led to uniform production distribution along the horizontal drain. However, it did not show significant improvement in the recovery of oil (Figure 6).

This unexpected outcome was investigated. It is believed that the relative permeability data used in the simulation are limited and may present weakness in describing the fluid flow in different rock type. The reservoir consists of different units which make the use of ICDs viable, while the sector model used in this study acts as a tank, so the fluid that was restricted to flow in a certain compartment will be basically produced from another compartment. This conclusion is very important and advises a careful selection of the sector model that should be used in this type of work.

Case study 2

Conventional simulation modeling generally neglects the pressure distribution within the wellbore. It is assumed that the fluid inflow across each completed interval is directly proportional to the length of the wellbore and the permeability of the reservoir cell. Vertical lift performance curves are used to estimate the tubing head pressure. In reality, there is a friction pressure drop which has a significant impact on the pressure distribution along the wellbore. There will be a higher inflow at the heel of the well since fluids there are subject to less friction pressure. Conventional simulation modeling does not count for such pressure variation in the wellbore (Minulina et al., 2012).

Wellbore modeling tools allow simulation of multilateral wells considering wellbore friction, and downhole choking devices. This is done by providing a thorough description of fluid flow in the wellbore. Coupling the wellbore model and the reservoir model gives a precise tool for designing and planning multilateral and horizontal wells.

The wellbore is subdivided into multiple segments in a process that is known as multi-segmentation. Each segment or compartment is represented by a node and describes flow path to its parent segment node. Modeling is done with nozzles, chokes, and other smart completion devices. Different keywords are used for modeling the wellbore segments and their connection to the reservoir nodes. This allows the engineer to precisely describe the completion characteristics that control the flow along, across, and within the wellbore. Hereby, it is important to mention that detailed information about the completion components and their characteristics and functionality is of high importance to simulate near wellbore flow behavior with reasonable accuracy. It also allows comparison between different completion designs with different completion components. The following shows the steps of designing an ICD completion (Minulina et al., 2012):

(1) "Use the reservoir simulation model to forecast the production profile and water saturation throughout the life of the field. Extract a permeability profile along the lateral length of the well from the reservoir model grid."
(2) "Use a software such as "NeTool^{TM}" to design an ICD configuration that delays water or gas breakthrough and promotes oil production for the life of the well. Consider several options and determine the best configuration."
(3) "Confirm initial model using real time logs during drilling."
(4) "After reaching TD, refine the ICD design using real time log and a quick petrophysical evaluation for fluid saturation and permeability."
(5) Use the multi-segment option and the detailed wellbore modeling to re-run the reservoir simulation. This is to double check the initial design and make necessary changes."
(6) "Observe sensitivities to heterogeneity, behind pipe channeling, and well spacing."
(7) "The final design should be reviewed with the well engineer for operational considerations before submitting to the completion engineer and the company man on the rig to start operations."

The concerned field, where the ICD completion is designed and implemented, is located offshore of Nigeria. It is considered as an excellent reservoir in terms of high porosity and permeability, but suffers from high permeability contrast (500 mD -15 D). Some of the flow intervals have very high permeability and are connected to the aquifer. Other sections have lower permeabilities and restricted lateral extent.

Static and dynamic simulations were run in order to come up with a unique completion design that is suitable for this field. One of the primary objectives of having such unique completion design is to block the rapid water encroachment from the highly permeable intervals. The following completion designs were considered during the modeling phase:

(1) Cased hole perforations.
(2) Slotted liners.
(3) Wire wrapped screen.
(4) Inflow control devices.

All producers were completed with ICD integrated completions. The first two injectors were completed with wire-wrapped screens and blank pup-joints. The remaining injectors were completed using nozzle type ICD integrated completions. A producer and an injector pair was used as an example to study the effects of implanting ICDs in the wells. Three different scenarios were considered and compared. Those scenarios were the following:

(1) Standard completion screens for both the producer and the injector.
(2) ICD completion for the producer and standard screen for the injector.
(3) ICD completions for both the producer and the injector.

Simulation results show that the ICD integrated completion for the producer only had a slightly higher recovery when compared to the wrapped screen completion. However, the scenario which had ICD completion for both the producer and the injector had a noticeable improvement in the recovery when compared to the of ICD completion for the producer only scenario. In addition, scenario 3 showed a better improvement in delaying water production. Figure 7 clearly demonstrates these results (Minulina et al., 2012).

The static simulator can show precisely how much the ICDs would influence the production for the inserted saturation data in the simulator. However, the timing of those saturations that was predetermined by the dynamic simulator was not accurate. This was because the ICDs would delay the breakthrough of the water and/or gas, and thus the saturation distribution would be different. In order to obtain more accurate results, the dynamic simulator was used in parallel with the static simulator.

Another important observation is that LWD logs that were obtained while drilling could be used to fine tune saturation and permeability data. Simulation could then be re-run and final adjustments be made on the completion design using the real time data.

For the injectors, simulations showed that ICD integrated completions gave a uniform and evenly distributed water front, while the wrapped screen design had preferential flow at the heel of the well. Behind pipe flow is an issue for the injectors because water would take the easiest flow path and having the ICDs in the completion would become useless. To solve this, there should be some isolation between the different ICD compartments. In consolidated formations such as carbonates, this can be done by implementing isolation devices such as swellable packers. In soft formations such as sandstones, this can be simply resolved by pre-producing the injectors in order to collapse the annulus and minimize behind pipe isolation.

Case study 3

This case study presents a conformance design on a

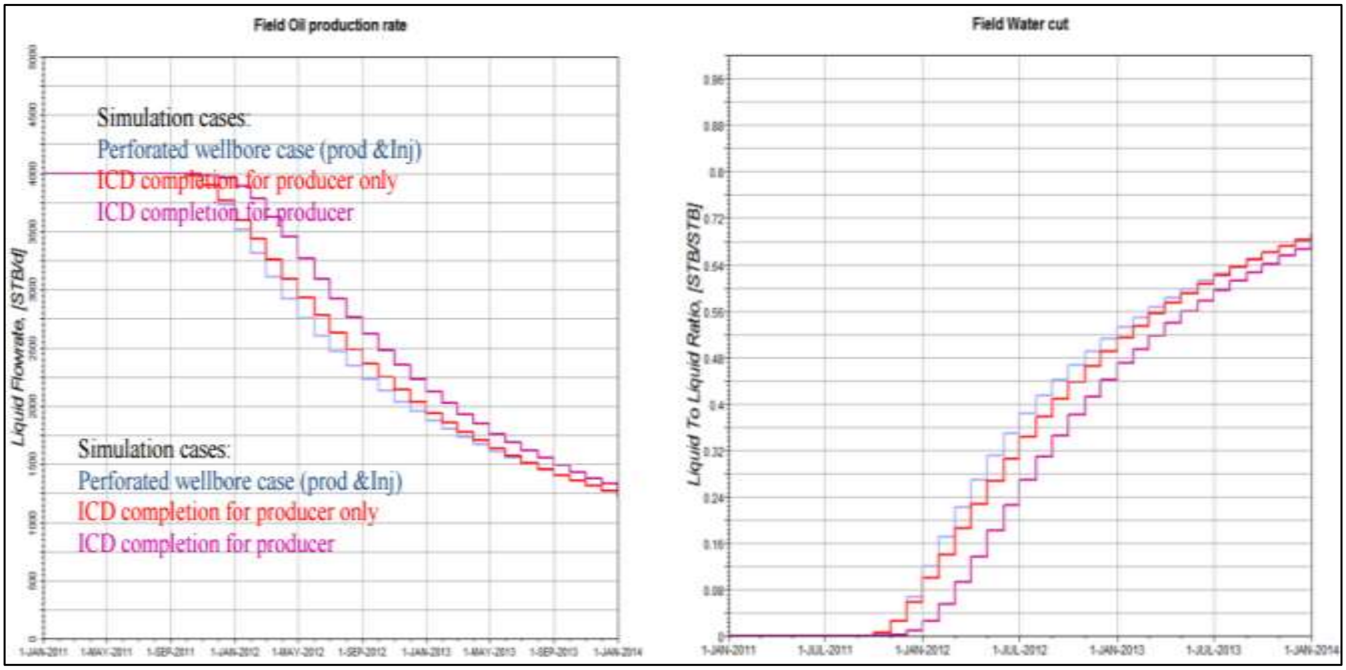

Figure 7. Field performance profiles, oil production (Minulina et al., 2012).

deviated well. The main concern in this well was the excessive water production from strong active aquifer. Huge quantity of produced water had to be re-injected into the reservoir though it was not necessary for pressure maintenance point of view. Figure 8 shows the production history of the first well in the study. The dots represent the actual production while the connected lines represent the history match resulted from the simulator (Thornton et al., 2010).

The well was planned to be completed with an ICD integrated completion in order to reduce the water cut and increase the produced oil. It can be observed from Figure 8 that there is a good match between the simulated and actual production. This gave extra confidence to go ahead and use the model to design an optimum ICD integrated completion.

The coupled simulator was used to study the fluid saturation changes in the reservoir. This enabled the reservoir and completion engineers to optimize the placement of ICDs and swellable packers in the wellbore.

Figures 9 and 10 show the oil and water production rates respectively for the base scenario and the ICD completion scenario. It is clearly shown in the figures that the ICD integrated completion enhanced the oil production and reduced the production of water.

CONCLUSION

The importance of this review stems from the fact that many future wells could benefit from the practices mentioned here. Challenges, mitigation practices, field applications and wellbore simulation are subjects that were comprehended in this paper. A summary of the main highlights can be listed as below:

(1) The demand for utilizing ICDs have been arising over the past decades to overcome certain critical challenges associated with production/injection in long reach horizontal wells. These include, but not limited to, water coning, heel-toe effect and permeability and mobility contrasts.

(2) There are significant advantages in coupling the dynamic simulator with the static or steady state simulator. The coupled model provides detailed information on the annulus and tubing flow taking into account the effect of the downhole completion tools i.e. it operates by integrating wellbore nodal analysis into reservoir simulation to reflect the impact of the wellbore hydraulics on the reservoir flow and recovery in the short and long term.

(3) The field cases presented in this paper shows the positive impacts of implementing the ICDs designs and coupled modeling on both history matching and reservoir production performance prediction. They also emphasized that the coupled modeling helps in material and equipment selection and therefore save OPEX on possible future intervention operations.

(4) Future opportunities to develop smart completions and their simulators further are there in terms of determining the operating envelope containing the range of parameters suitable for downhole controllers.

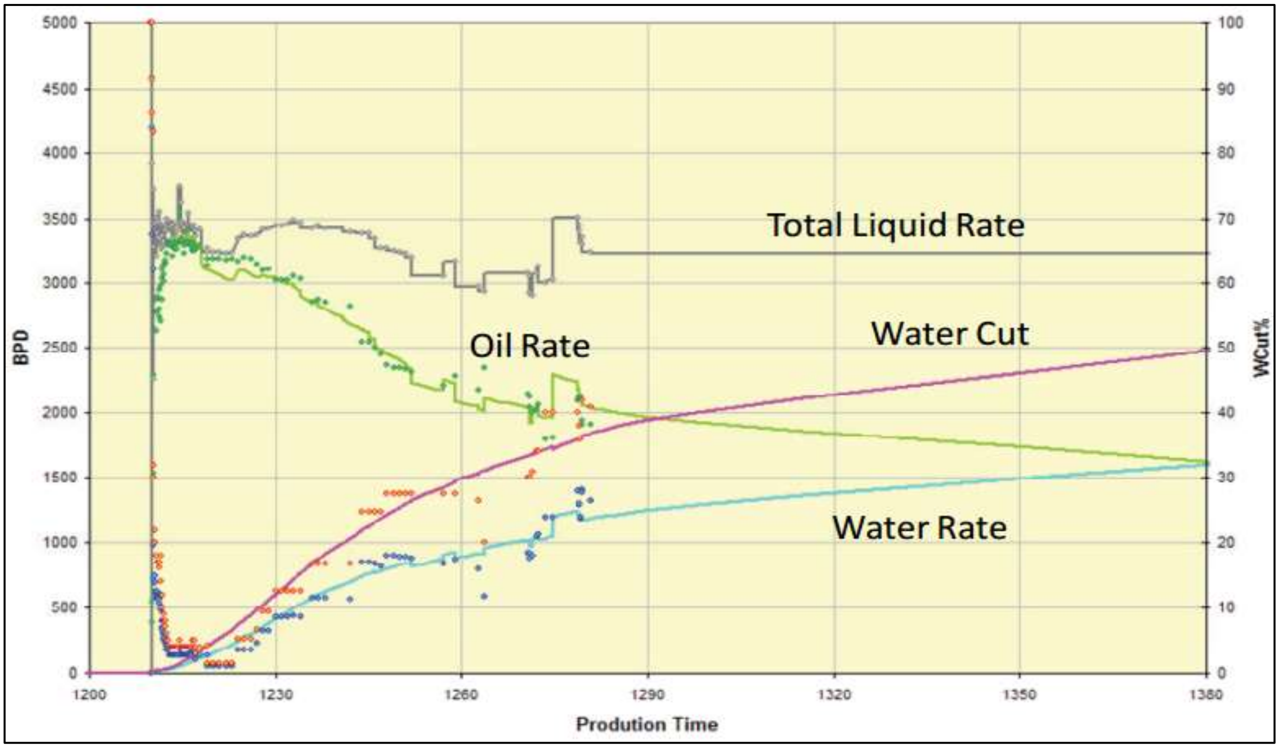

Figure 8. Production and simulator history match.
Source: Thornton et al. (2010).

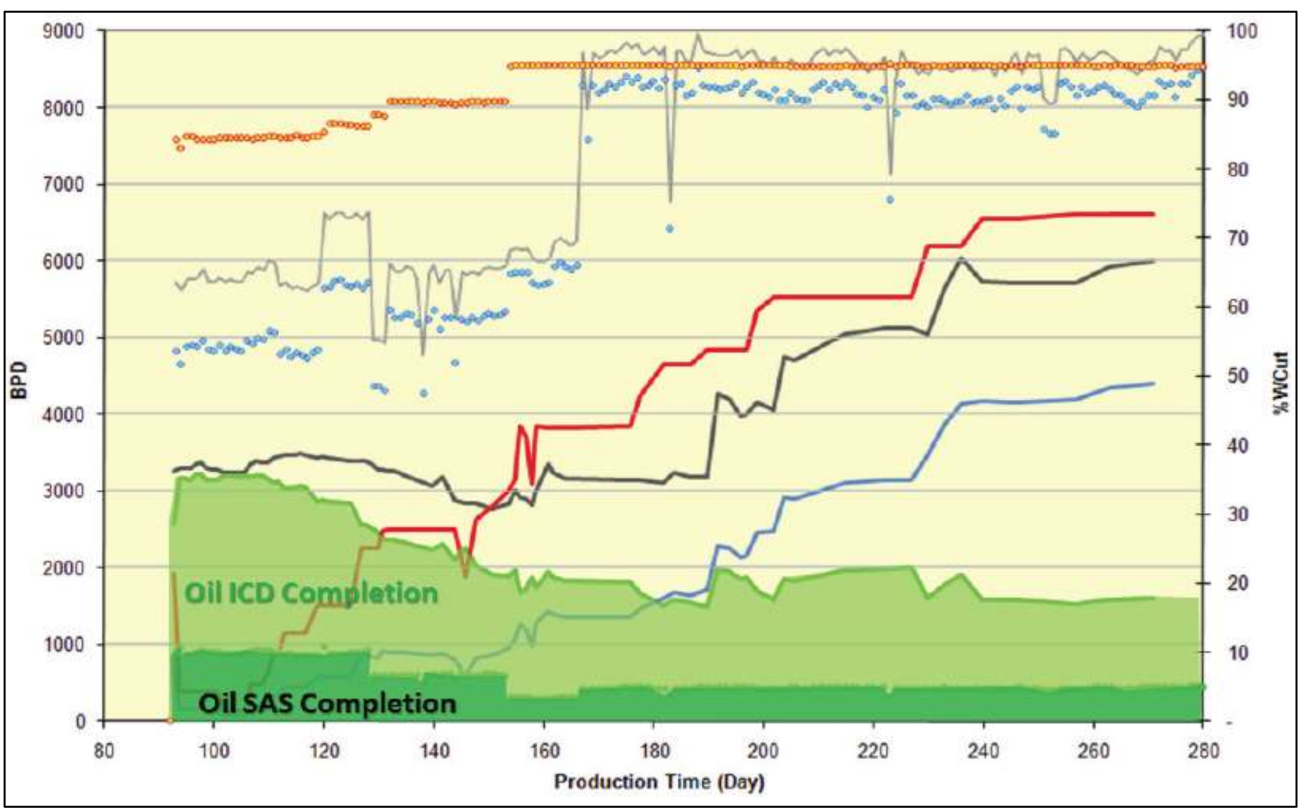

Figure 9. Oil production comparison between standalone screen (SAS) completion and ICD completion.
Source: Thornton et al. (2010).

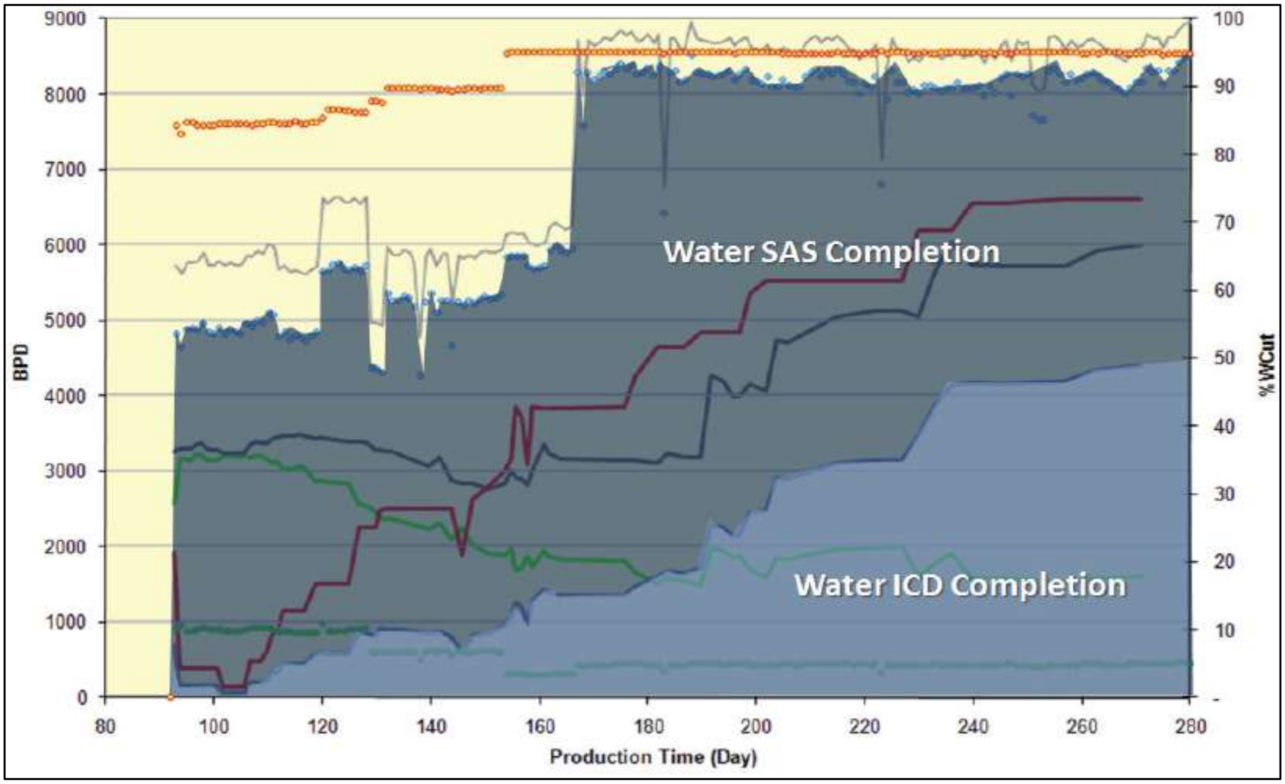

Figure 10. 1Water production comparison between standalone screen completion and ICD completion.
Source: Thornton et al. (2010).

NOMENCLATURE

$\boldsymbol{A}$, Cross-sectional area of the horizontal hole; $\Delta \boldsymbol{P}$, Pressure drop; $\Delta \boldsymbol{P}_{\boldsymbol{DD}}$, Total pressure drawdown; $\Delta \boldsymbol{P}_{\boldsymbol{ICD}}$, Pressure drop across the ICD; $\Delta \boldsymbol{P}_{\boldsymbol{ideal}}$, Pressure drawdown without formation damage; $\Delta \boldsymbol{P}_{\boldsymbol{skin}}$, Additional pressure drawdown due to skin; $\boldsymbol{J}$, Productivity index; $\boldsymbol{P}_{\boldsymbol{nw}}$, Flowing well pressure; $\boldsymbol{P}_{\boldsymbol{r}}$, Reservoir pressure; $\boldsymbol{P}_{\boldsymbol{wf}}$, Flowing bottomhole pressure; $\boldsymbol{\rho}$, Density of the fluid; $\boldsymbol{q}$, Fluid flow rate; $\boldsymbol{v}$, Fluid flow speed.

CONFLICT OF INTERESTS

The authors have not declared any conflict of interests.

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