

Article

Field and Numerical Analysis of Downhole Mechanical Inflow Control Devices (ICD and AICD) for Mature Heavy Oil Fields

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Abstract

The challenge of excess water production in mature heavy oil reservoirs presents significant environmental and economic concerns. This study evaluates the effectiveness of inflow control devices (ICDs) and autonomous inflow control devices (AICDs) for managing water production in heavy oil reservoirs with strong aquifer drives. Our investigation comprises two field implementations and a computational fluid dynamics (CFD) study. In the first field implementation, both ICDs and AICDs achieved substantial water reduction (25% and 32%, respectively) compared to conventional slotted liner completions, with ICDs demonstrating superior oil production performance, extending well life by approximately 30% and doubling accumulated oil. The second field implementation featured rate-controlled production (RCP) devices, showing that two AICD wells together produced 60% more accumulated oil and 40% less water than a single conventional well, effectively relieving surface facility bottlenecks. Full 3D Navier–Stokes simulations for a third field implementation revealed that passive ICDs outperformed AICDs under specific draw-down and spacing conditions, challenging the industry preference for newer technologies. The study's findings, which include quantifiable reductions in the carbon footprint associated with decreased power consumption, provide valuable insights for operators seeking to optimize water management while minimizing environmental impact, advancing the sustainable oil production practices aligned with UN Sustainable Development Goals 7 (Affordable and Clean Energy), 9 (Industry, Innovation and Infrastructure), and 13 (Climate Action).

Keywords: heavy oil; water control; inflow controller; water management; ICD; AICD; CFD simulations



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1. Introduction

Hydrocarbon production involves a multiphase flow of water and crude oil and gas, flowing through porous media from the reservoir to the wellbore via a pressure differential. Those fluids are then produced at the surface by lifting and transporting them for separation, filtering, and pumping, and to the destination, usually for sale or disposal, depending on the fluids. Although there is a large variety of oil/gas reservoirs in Colombia, consistent with worldwide heavy oil reserves, the prospects of heavy crude oil represent more than 32% of the country's total reservoirs (Figure 1) [1–3].

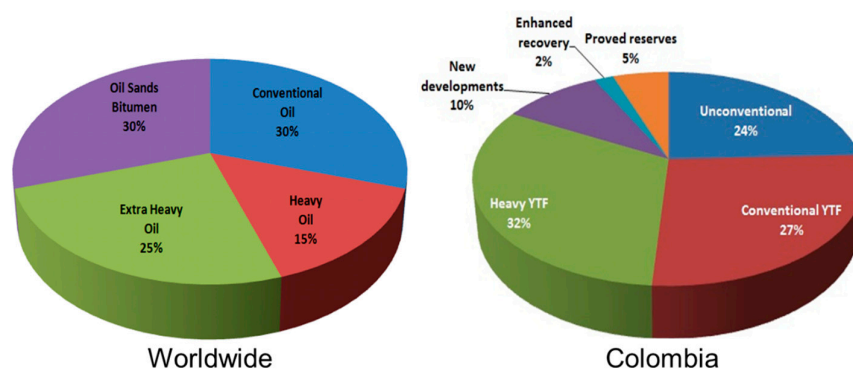


Figure 1. Oil distribution by type worldwide and in Colombia [1–3].

Heavy oil production is inextricably linked to water production. Typically, this type of reservoir is called an active water-drive reservoir, initially associated with sufficiently large volumes of water or aquifers to naturally flood the entire oil reservoir, either releasing or sustaining the reservoir pressure. Due to a high difference in the viscosity in a highly permeable porous medium, the adverse mobility ratio allows more water flow than oil, thus favoring water production instead of oil. When the fluids flow through the reservoir rocks, the water moves faster, leaving behind a considerable amount of oil caused by the uneven sweep of oil [4]. As the water production increases, it can reach a point where oil production becomes economically unviable and ecologically damaging, with a larger carbon footprint being a key concern [5,6].

In heavy oil wells, water displaces the oil relatively quickly, and above 70% of the well's life cycle, the water cut could be higher than 90% [7]. This issue is commonly experienced in mature oil reservoirs, where water cut values can reach above 90%. In other words, for every barrel produced, 90% is water. The movement of two phases, the oil–water flow in the reservoir, has been studied. A summary of the main contributions can be found in an extensive review by Pinilla et al. [8].

Additionally, horizontal wells are often preferred to increase the contact area with the reservoir compared to vertical well completions in situations like thin reservoirs, edges, and bottom water reservoirs. This approach offers practical benefits in terms of reservoir management and production efficiency. However, reservoir heterogeneity and the heel-toe effect create an uneven influx of fluids along the horizontal section, leading to problems such as water coning/creeping, the early breakthrough of water, and imbalanced production profiles. Once a water breakthrough occurs, generally but not exclusively via coning near the heel, the oil production decreases significantly because of the limited flow contribution from the toe (i.e., non-coning section). In any case, the high volume of water produced alongside oil represents wasted energy, as extracting and separating it requires additional processing. That means a bigger carbon footprint, jeopardizing the environment as it translates into a higher emission of greenhouse gases. This issue reveals the inefficiency of producing oil at high water cuts, thus reducing the energy return over investment. Hence, water control offers an outstanding opportunity to lower the carbon footprint, enabling continued oil production in a sustainable pathway.

In summary, heavy oil reservoir wells often have a high water cut (>90%), producing a significant amount of water along with oil. This additional water adds weight and further increases the volume of fluid that needs to be lifted, leading to higher power consumption (Figure 2). Power consumption in lifting operations increases as more fluids are transported to the surface (Figure 2A). Consequently, lifting costs rise exponentially with water cut, particularly when water production exceeds the 80% threshold (Figure 2B) [9].

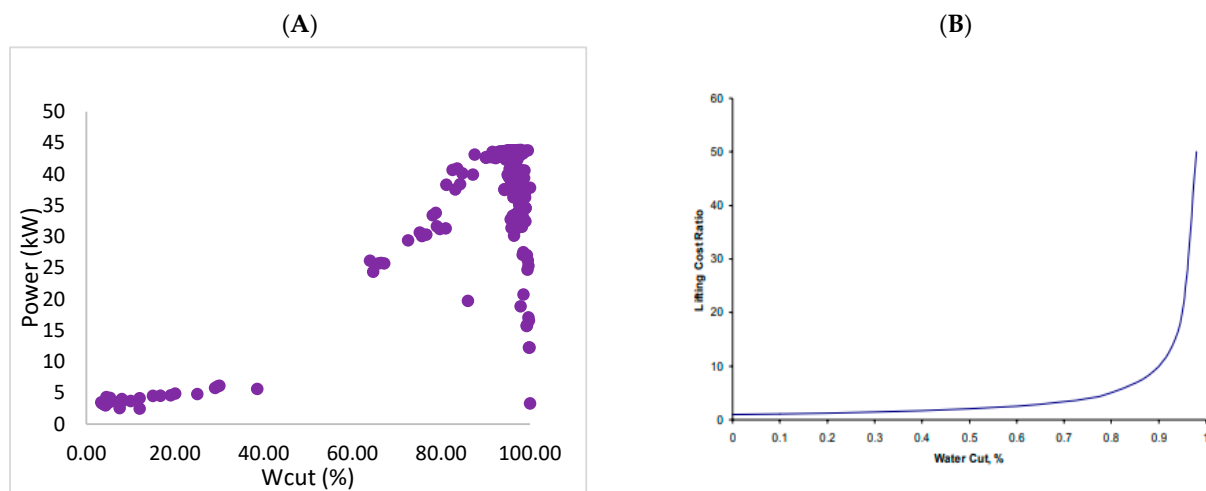


Figure 2. (A) Power consumption, (B) lifting cost for a conventional horizontal well [9].

For the reasons above, water management production in heavy oil wells has become a critical innovation point to reduce water production while maintaining or maximizing oil production. Advancing sustainable oil production requires innovative water management technologies that reduce environmental impact while optimizing resource recovery. This approach aligns with UN Sustainable Development Goals 7 (Affordable and Clean Energy), 9 (Industry, Innovation and Infrastructure), and 13 (Climate Action). These technologies minimize carbon footprint, improve energy efficiency, and promote responsible resource utilization in mature heavy oil fields.

Two primary mechanisms exist to control downhole water influx from the reservoir.

First are the chemical injection methods that target the water phase in the reservoir to carry out the following:

- Increase water viscosity and change phase mobility ratio: polymers can be injected to increase the water's viscosity, making it flow more slowly and allowing oil to flow more freely;
- Change water flow path: gels or foams can be injected to block specific pathways within the reservoir, diverting water flow away from the wellbore and towards oil-rich zones;
- Emulsion disruption: chemicals can break down emulsions (mixtures of oil and water) that can hinder oil flow.

The main advantage of chemical water shut-offs over mechanical solutions is that they deal more directly with unwanted water production instead of hiding it behind an obstruction device. They are tailored to target specific reservoir zones where unwanted water enters the wellbore. This allows for more precise control over the water flow than mechanical devices that may block off entire sections, potentially affecting the oil flow. They can travel deeper into the reservoir, potentially reaching areas inaccessible to mechanical devices like packers or plugs. This allows for the treatment of water influx even in complex wellbore geometries. Additionally, chemical treatments can sometimes remediate existing problems by plugging established water channels within the reservoir, which is partially reversible and allows for adjustments if needed. However, their success depends on a complete characterization of the reservoir and injection chemicals, compatibility, and accurate placement of the injected chemicals [10]. Chemical injection methods require careful planning and selection of the right chemicals for the specific reservoir conditions, considering the rock fluid interaction, geological formation, and reactions in multiphase fluids with additives. Improper selection can have negative consequences.

Second, mechanical water control solutions include inflatable plugs, downhole separators, dual horizontal completion, stinger completion, swellable packers, through-tubing patches, and inflow controllers [11–13], which can obstruct the pathway of the flow of the fluids from the reservoir. Mechanical shut-off is cheaper, has lower risk, is easier to remove, and its impact can be observed within hours, while chemical solutions may require months to years. Nevertheless, their performance depends on precisely identifying water zones, because an inaccurate diagnosis can obstruct oil production [9,10].

Inflow controllers were introduced in the 1990s and are considered advanced or intelligent well completions because they can manage the fluid flow into the length of the wellbore to improve well performance [11]. However, conventional completion methods including slotted liners, screens, and perforated casings cannot adequately control water inflow from the reservoir [14]. Inflow controllers have been used in the O&G (Oil and Gas) industry for over 30 years to control the fluid flow and even the draw-down distribution along the wellbore's length, as well as to manage clean-up efficiencies and production contributions from different intervals [15,16]. Thereby, the water/gas (unwanted fluids) production is reduced, while the oil production is maintained [17].

An extensive and accurate review of water shut-off mechanical devices was conducted by Asuaje et al. [18]. Using the Onepetro SPE database, this paper focuses on the primary downhole water control mechanical devices used in the industry. It covers inflow controller development, emphasizing the available designs and their performance comparison through case studies from the academic literature. Moreover, it includes a compilation of the existing modeling techniques that allow the performance of inflow controllers to be studied.

In this context, this study presents the performance of different mechanical control devices in two heavy oil fields. Finally, full Navier–Stokes simulations in a heeled horizontal wellbore are presented, studied, and discussed to understand and optimize the performance of inflow control devices. This study aims to show the scientific community, engineers, and stakeholders in the O&G industry with interests in reducing energy consumption and environmental impact and financial feasibility, the advantages of implementing the technologies related to ICDs with field implementations in mature heavy oil fields.

While previous studies have compared ICD and AICD technologies [4,19], our work offers several unique contributions: (1) we provide a comprehensive comparison across multiple fields with direct performance metrics in similar geological settings, (2) we integrate field data with advanced 3D computational fluid dynamics (CFD) modeling that solves the complete Navier–Stokes equations for both laminar flow in the reservoir and turbulent flow near the wellbore, unlike the simplified 1D approaches used in previous studies that rely on closure relations, (3) we quantify carbon footprint reductions associated with water control, addressing a critical industry sustainability gap, and (4) we challenge the industry preference for newer AICD technology by demonstrating conditions where simpler, passive ICDs may offer superior performance. Our findings are particularly valuable for operators of mature heavy oil fields seeking to optimize water management while minimizing environmental impact.

Also, the case study highlights the value of CFD simulation techniques in analyzing oil wells' mechanical water shut-off strategies. By providing a comprehensive understanding of fluid flow behavior, CFD simulations empower operators to make informed decisions that maximize production efficiency while minimizing environmental impact.

2. Methodology

For this study, two complementary approaches are presented: (i) field implementation and (ii) complete 3D numerical study. Concerning field implementations, over the

years, inflow control technologies have been developed and implemented in Colombia's production fields. In 2011, when the technology was still emerging in Colombian oil fields, passive and autonomous inflow control devices were introduced in Field #1. Subsequently, as a follow-up to the field laboratory, advanced autonomous inflow control devices were deployed in Field #2 in 2018.

In the computational fluid dynamics (CFD) study, simulations were employed as an alternative and supplementary evaluation technique. CFD has proven to be a highly effective instrument for analyzing and resolving intricate issues, particularly within the O&G energy sector [20–22]. A numerical study on Field #3 involved simulating the unstable displacement of fluids within the well. Table 1 summarizes all the projects executed on downhole water management devices since 2011.

Table 1. General reservoir information for each field.

General Information	Field #1	Field #2	Field #3
Depth (TVDSS)	2100–2400	2500–2700	2500
Lithology	Sandstone	Sandstone	Sandstone
Producer formation	Basal sand	Basal sand	C7/Basal sand
Production mechanism	Strong water drive	Strong water drive	Strong water drive
Temperature (°F)	145–147	147–156	150–160
Initial pressure (psi)	1100	1260	1300
Bubble point (psi)	108	108	119
Current reservoir pressure, psi	980	1250	1290
Gas–Oil ratio, PCN/BN	7–8	7–8	7–8
Gravity API	12.7–13.8	10.6–11.7	9.9–11.3
Oil viscosity @ reservoir temperature, (cP)	200–600	500–2500	400–1000
Formation water salinity (ppm)	800–1100	965	850–1200
Residual oil saturation, %	25–42	38–44	34
Volumetric factor, (RB/STB)	1.03	1.03	1.03

2.1. Field Descriptions

2.1.1. Heavy Oil Field #1

As far as has been reported, inflow control technology was first implemented in Colombian heavy oil fields in 2011, in a heavy oil well (11.3 to 14.4 °API) from the C7 unit of the Carbonera Formation, with an oil production of 260 kSTB [23]. The reservoir had a 25–32% porosity and permeability between 5 and 13 Darcys [23].

In this field, efforts were made to solve the high water production in horizontal producer wells of heavy oil in non-consolidated sandstones using ICD and AICD technology. The presence of a strong aquifer in the reservoir was one of the main challenges, and to address it, water production was delayed as much as possible. Historically, numerous wells had to be shut down in this field due to the ecological and economic unviability consequences of the high water output.

Moreover, the primary objectives of this first test were to increase the oil recovery factor, minimize surface facilities and associated costs, delay water entry into the wells, produce rapidly, and reduce damage formation and treatment well reduction.

As a pilot test, seven wells were completed with downhole flow control devices, three (3) ICDs, and four (4) AICDs. An ICD (inflow control device) is passive well-completion hardware installed against the formation sand face, within perforated pipes, or mounted on sand screens. It restricts the inlet flow, reducing and delaying gas/water production. An AICD combines a passive and a fluid phase-sensitive actuator that facilitates the flow area depending on changes in fluid properties. This device could or may not have mobile parts. These are autonomous because they do not require intervention to reduce their inflow area at the onset of water or excess gas production in oil wells. Oil and water production profiles were compared against four (4) conventional horizontal liners. It is clarified that the inflow control devices used in the completions came from different manufacturers, each with a different working principle [23].

2.1.2. Heavy Oil Field #2

This field is an expansion adjacent to Field #1. The field produced 13.5 °API oil in sandstone reservoirs of the Tertiary Arenas Basales unit, which lie directly in the basement. Oil production from the field was approximately 3000 barrels per day, with an associated water production of 60,000. Field #2 presents many challenges to operations, from the high water cut and related energy costs to produce and dispose of large quantities of water to the requirement to drill and complete new horizontal development wells per year to sustain production. With less than 10% of the oil-in-place recovered, this field still has significant potential in the future.

2.1.3. Heavy Oil Field #3

Also located in the southern Llanos basin, with an area of approximately 593 thousand acres, Field #3 started its output in 2014 through an early production system. The field produced 9.9 to 11.3 °API oil in sandstone reservoirs of the Tertiary Arenas Basales unit, which lie directly in the basement. Production from the field is approximately 5000 barrels per day, with an associated water production of 130,000.

2.2. General Description of the Reservoirs

Table 2 summarizes the main reservoir and fluid characteristics. Table 3 shows the general cases, varying types of completion, downhole pressure, and distance between inflow control devices.

Table 2. General petrophysical information per field.

General Information	Field #1	Field #2	Field #3
The volume of clay (%)	2–5	3–7	3–8
Porosity (%)	28–32	28–32	28–32
Permeability (D)	5.0–13.0	1.0–6.5	1.0–6.0
Initial water saturation (%)	30–50	40–60	30–50

Table 3. Numerical cases, varying types of completion, downhole pressure, and distance between inflow control devices.

Type of Completion	Pressure (psi)	Distance Between Inflow Control Devices (ft)
LINER	1140	-
	1160	-
ICD	1140	30
		100
	1160	30
		100
AICD	1140	30
		100
	1160	30
		100

2.3. Mechanical Devices for Downhole Water Control (Inflow Controllers)

Inflow controllers, introduced in the 1990s, are advanced well completions that actively regulate fluid flow within the wellbore, leading to improved performance. Unlike traditional completions like open-hole liners and perforated casings, inflow controllers can effectively balance fluid inflow rates. While the oil and gas industry has utilized inflow controllers for over three decades to manage fluid flow, draw-down distribution, and production contributions, their implementation remains controversial for many operators. A brief description of the primary devices is presented below.

2.3.1. ICD

An ICD is a passive well completion hardware installed against the formation sand face, within perforated pipes, or mounted on sand screens, which restricts the inlet flow, reducing and delaying gas/water production [11,19]. ICDs use friction (minor hydraulic losses), restriction (significant hydraulic losses), or a combination to create an additional pressure drop to balance the inflow into and pressure distribution in the well. The main types offered by the industry are channel and orifice/nozzle [16,19]. Although ICDs are a simple and cost-effective solution for delaying water coning, their main disadvantage is that they are passive. Once the water breaks through, the choking effect cannot be adjusted without intervention [4,13].

2.3.2. AICD

AICDs combine passive and reactive mechanisms to control the fluid influx in oil wells. They feature a fluid phase-sensitive actuator that automatically reduces the flow area in response to changes in fluid properties, such as the onset of water or excess gas production. These devices can operate without requiring external intervention and may or may not include mobile parts.

In wells from Fields #1 and #3, fluidic diode/cyclone AICDs were installed. These AICDs function by leveraging variations in discharge coefficients, which are influenced by the Reynolds number and affect the pressure drop across the device. This design allows the AICD to preferentially restrict the water and gas flow while maintaining a more favorable flow profile for oil, enhancing oil recovery efficiency. The device achieves this without altering the flow path, instead creating a restriction profile that varies depending on the

fluid's inertial and viscous properties, resulting in varying pressure drops and the selective control of fluid flow [24,25].

2.4. Field Implementation Study: Inflow Control Devices Installed

2.4.1. Field #1

Completion details implemented in Field #1 wells can be found in Gómez Gualdrón, M. [23].

2.4.2. Field #2

As a second case in 2018, in Field #2, three wells were completed with a new generation of AICDs of the rate-controlled production (RCP) type—two with a horizontal completion of 800 ft and one of 1200 ft in length. The horizontal length was portioned into 100 ft sections with two AICD-RCP devices per section. A schematic of the completion is shown in Figure 3.

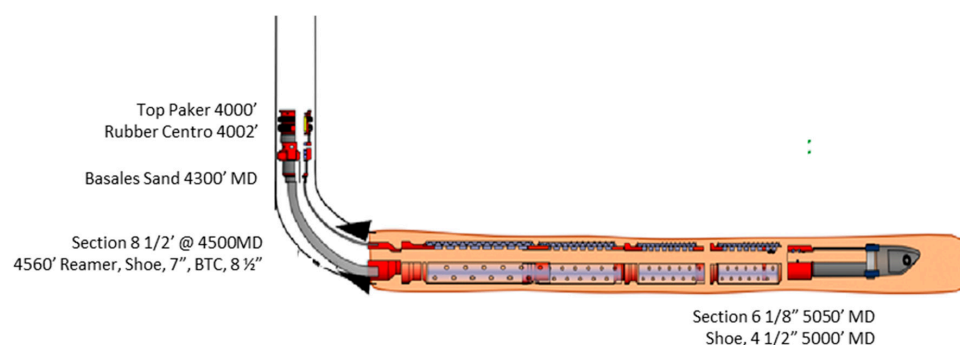


Figure 3. Schematic of completion with AICDs.

The RCP device's working principle is the interaction between the different reservoir fluids and the moving internal parts, managing to control the inlet flow autonomously [26]. For example, rated-controlled production (RCP) valves remain open when oil passes through and are closed autonomously when water starts to get through, reducing the inflow. This automatization mechanism is attributed to the differential pressure change that generates the different phases' viscosities.

Throughout the production period of the well, depending on the amount or proportion of the undesired fluid (water or gas), these devices must operate by varying the degree of plugging, and consequently, the effective flow area from 100% (fully open) to 0% open (totally closed). This device manufacturer commonly calibrates their designs to allow a minimum flow, thus avoiding the well's total closure. Figure 4 demonstrates how the AICD plugging element position changes over the well's operational lifetime compared to the fixed position of an ICD device. In the case of the ICD, it will behave as a fixed choke because it does not have a control element. As shown, after the breakthrough, RCP devices will start to close; meanwhile, ICD devices will always have the same area exposed to the reservoir.

Figure 4 demonstrates the average behavior of the degree of openness of passive and active inflow control devices (ICDs and AICDs) over the operational lifetime of a well. The wells in the figure are completed with tube-deployed ICDs and AICDs housed within a slotted liner, which provides a structural basis while allowing for fluid entry. The figure compares these advanced completions against a conventional well that utilizes only a slotted liner, highlighting the differences in performance and the advantages of using inflow control devices to manage fluid production more effectively.

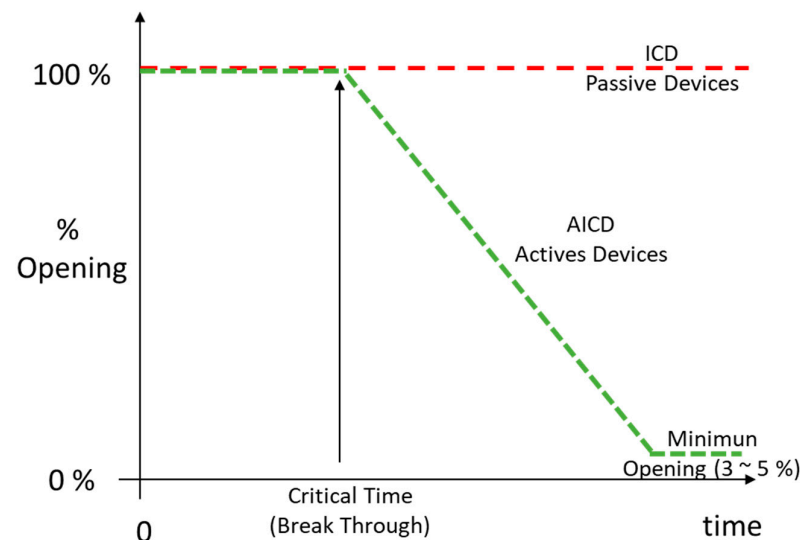


Figure 4. Effect of openness of passive and active inflow control devices over time.

2.4.3. Field #3: Digital Twin in CFD Technology

Previous studies demonstrated that CFD codes could explicitly simulate heavy oil–water flow, even emulating viscous fingering (VF) and its characteristic dynamics in core flood experiments [27]. Seeking to understand the performance of downhole water control devices and select the most suitable one for implementation in Field #3, full Navier–Stokes, 3D, transient simulations were performed. Consequently, the numerical model was built to simulate a heavy oil production well and visualize the fluid’s motion from the reservoir into the well, including the bottom aquifer’s unstable displacement and breakthrough event near the wellbore [28]. Table 4 shows all simulations performed for passive (ICDs) and active devices (AICDs). The effect of the downhole well flowing pressure and distance between the inflow control devices were studied. Simulations of a well completed with slotted liners were also carried out as a reference.

Table 4. Reservoir, well dimensions, and aquifer pressure.

Parameter	Value
Oil–Water contact (TVD-ft)	2500
Top basal sands (TVD-ft)	2969
Well length (ft)	763
Completion diameter (in)	4.5
Completion type	Slotted liner
Slots per foot	224
Bottom hole flowing pressure P_{wf} (psi)	Variable

2.5. The CFD Model—Geometry

The numerical models were made based on a methodology found in the literature [29]. As a consequence, STAR-CCM+ v17[®], a commercial CFD software (Version 17) that numerically solves the full Navier–Stokes equations, continuity, momentum, and energy conservation, was used. Previous simulation works have demonstrated that full 3D CFD simulations bring a good response with downhole fluids’ movement phenomena [8,27,29,30]. Sensitivity analysis considering discretization scales, reservoir properties, and fluid properties have been carried out, delighting in the outstanding predictions of simulations. In Pinilla et al. [29], a sensitivity analysis was conducted by varying the oil and rock physical proper-

ties to determine if the numerical model could predict the fluid dynamics' differences near the wellbore due to these variations. More than 25 numerical experiments were conducted for this sensitivity analysis. All these simulations were numerically converged, conservative, stable, and physically reproduced on what is reported in the literature. The displacement stability is strongly influenced by variations in the permeability and the phases' viscosity contrast. Both variables ultimately affect the mobility ratio and, consequently, the strength of the viscous forces.

The near-wellbore reservoir consisted of a 29×50 ft rectangular section totaling 763 ft. The horizontal section of the well completion has a 4.5 in diameter and has been installed on the top of the reservoir and center. The reservoir, slotted liner, and horizontal well fluid domain are shown in Figure 5, and the general dimensions are in Table 5.

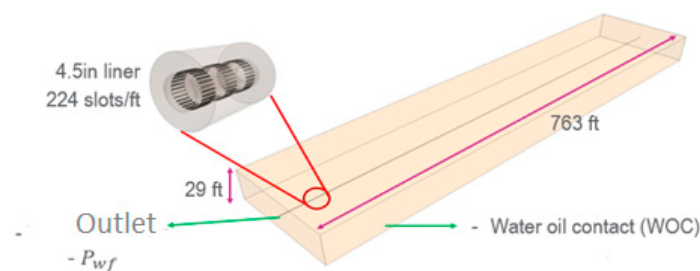


Figure 5. Domain geometry and initial and boundary conditions are used to conduct a numerical study [29].

Table 5. Physical properties obtained from field measurements and used in the CFD reservoir scale model [31].

Parameter	Value
Oil viscosity (Pa·s)	6.9×10^{-1}
Oil density (kg/m^3)	987.6
Water viscosity (Pa·s)	1.0×10^{-3}
Water density (kg/m^3)	1000
Surface tension Oil–Water (N/m)	3.4×10^{-2}
Contact angle ($^\circ$)	30.0

Horizontal fluid domain changes were also observed when ICDs/AICDs were numerically studied. Two flow path configurations of ICDs/AICDs were studied, one short with a 30 ft length and one large with a 100 ft length. Each section was built in detail considering the flow screen with the device housing, two devices opposed per section, and the swell packer used as a barrier between sections. Figure 6 shows the top device. The total horizontal length for the well with inflow control devices is the same as for the well with a slotted liner. Each device was set up as an orifice with a 2 cm diameter. In the case of ICDs, the opening of the inlet is constant throughout the simulation, with a diameter of 2 cm for each nozzle.

The internal walls of well completions and ICD/AICD orifice walls have been considered smooth walls; previous studies reported consistent results and a pressure drop along the well completion and devices [27,30,32,33]. The hole interface boundary condition was simplified to reproduce the AICD's opening and closing operation. As long as the water cut of the total flow entering the orifice was less than 99%, the orifice remained open.

The orifice's border is closed, preventing fluid entry at a concentration greater than 99%. Due to simulator conditions, this model's limitation is that the orifice could not reopen

automatically. We are refining the model so that future simulations include the opening and closing effects.

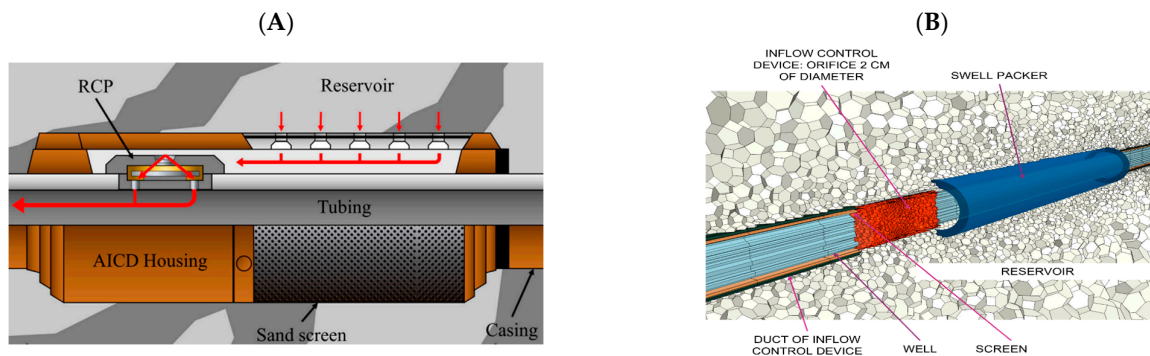


Figure 6. Fluid domain of a section with inflow control device. (A) ICD/AICD flow path, (B) grid representation [33].

Discretization and Mesh

As demonstrated by Pinilla et al. [27], unstructured meshes are particularly significant for modeling viscous fingering phenomena in reservoirs. These meshes offer substantial computational cost benefits compared to structured alternatives (Figure 7). Compared to structured meshes, they require fewer elements to accurately represent the complex flow paths associated with viscous fingering. This translates to fewer computational resources needed to simulate the model, and ultimately allows for a more detailed representation of viscous fingering, breakthrough events, and flow displacement within the reservoir.

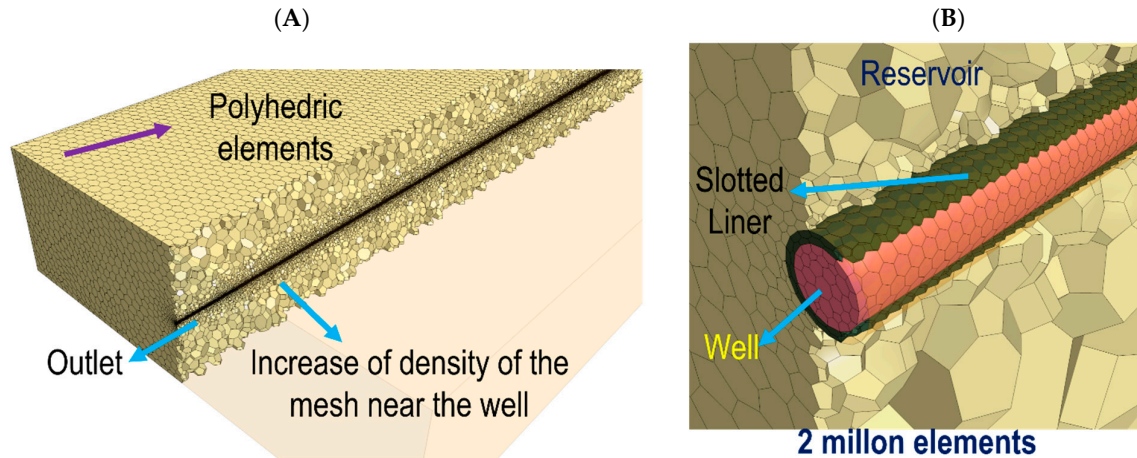


Figure 7. Representation of the mesh used in numerical study. (A) General view, (B) well completion [29].

On the other hand, the completion with inflow control technology was modeled using a hybrid mesh. That means polyhedric elements in the reservoir and inflow control devices, semi-polyhedric elements in the well and duct of fluid production, and cylindric elements in the screen. The arrangement was made due to the complexity of the modeling of inflow control devices and the additional subsequential computational cost, which would have been high (Figure 8).

Previous works carried out size independence studies, and the final numbers of mesh elements have been published in the literature [29].

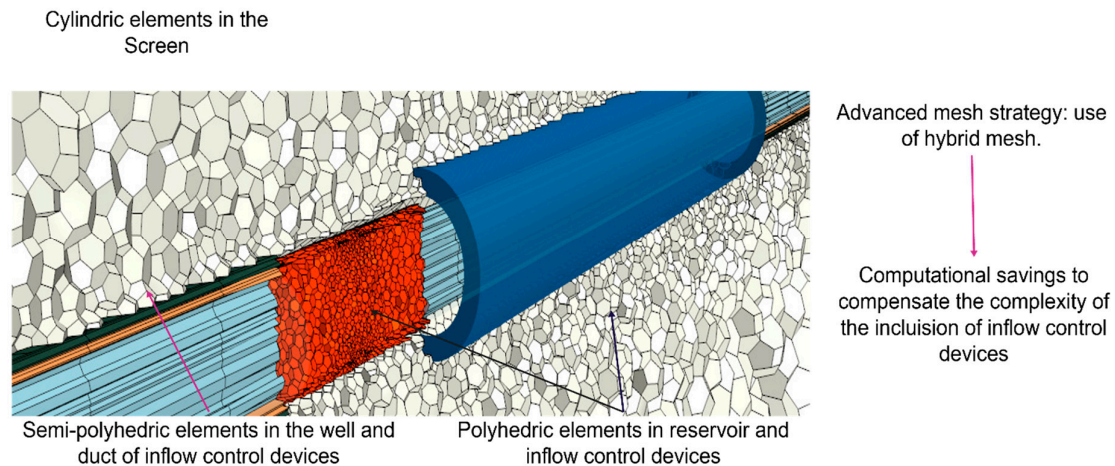


Figure 8. Representation of the mesh used in the numerical study. Inflow control completion.

2.6. Physical Models

The Eulerian–Eulerian volume of fluid (VOF) was used to simulate the immiscible displacement for all simulations. This is a numerical technique for tracking and locating the free surface (or fluid–fluid interface), and can accommodate the evolving shape of the interface. In the Euler–Euler approach, the different phases or components in a multiphase system are assumed to be continuous functions of space and time, and their sum is equal to one that shares the same flow pressure. This means that phases are considered to occupy the same space simultaneously, but their properties (like density and viscosity) are tracked separately. Conservation laws are applied for each phase to derive governing equations closed by theoretical or empirical constitutive relations. By solving the governing equations of fluid flow (Navier–Stokes equations) for both oil and water, along with the VOF equation that tracks the volume fractions, the method simulates the movement and interaction of the two fluids. Additionally, viscous fingering was captured using the model of the High-Resolution Tracking Interface Capturing Scheme in the second order to solve and capture the oil–water interface, thus the unstable displacement. The CFD model also considers gravity for phase segregation and as an external force that competes against viscous forces.

Finally, the fluid properties are summarized in Table 6, assuming incompressible flow for both phases. The $k-\omega$ turbulence model with the SST transitional model was implemented to predict the turbulent flow conditions of the multiphase flow in the completion and the well, especially at high water cuts.

Table 6. Rock properties and saturation conditions.

Parameter	Value
Permeability (d) (min–max)	1.15–3.59
Porosity—(min–max)	0.276–0.312
S_{wi} (Min – max)	0.179–0.571

Initial and Boundary Conditions

To predict the movement of the aquifer and the production profiles quantitatively, the reservoir’s permeability, porosity, and initial water saturation were implemented, as shown in Figure 9. This means that heterogeneity in the reservoir was considered. The heterogeneous rock properties are from well logging measurements, and their ranges are presented in Table 6.

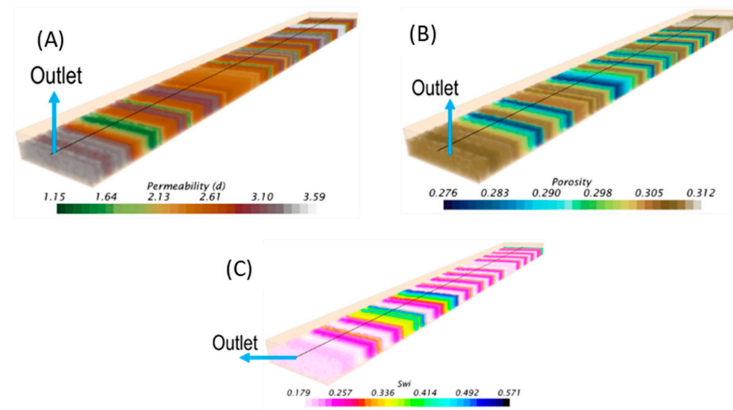


Figure 9. Heterogenous profile of (A) permeability, (B) porosity, and (C) initial water saturation of the numerical study.

3. Results

3.1. Field Implementations—Field #1

The initial field test comprised eleven wells: three with ICDs, four with AICDs, and four as reference wells completed with slotted liners. Preliminary well-to-well analysis of cumulative fluid production, as shown in Figure 10, indicates that implementing downhole water control devices reduced water production by 75% compared to a conventional well (slotted liner). From this perspective, inflow control technology can be deemed successful.

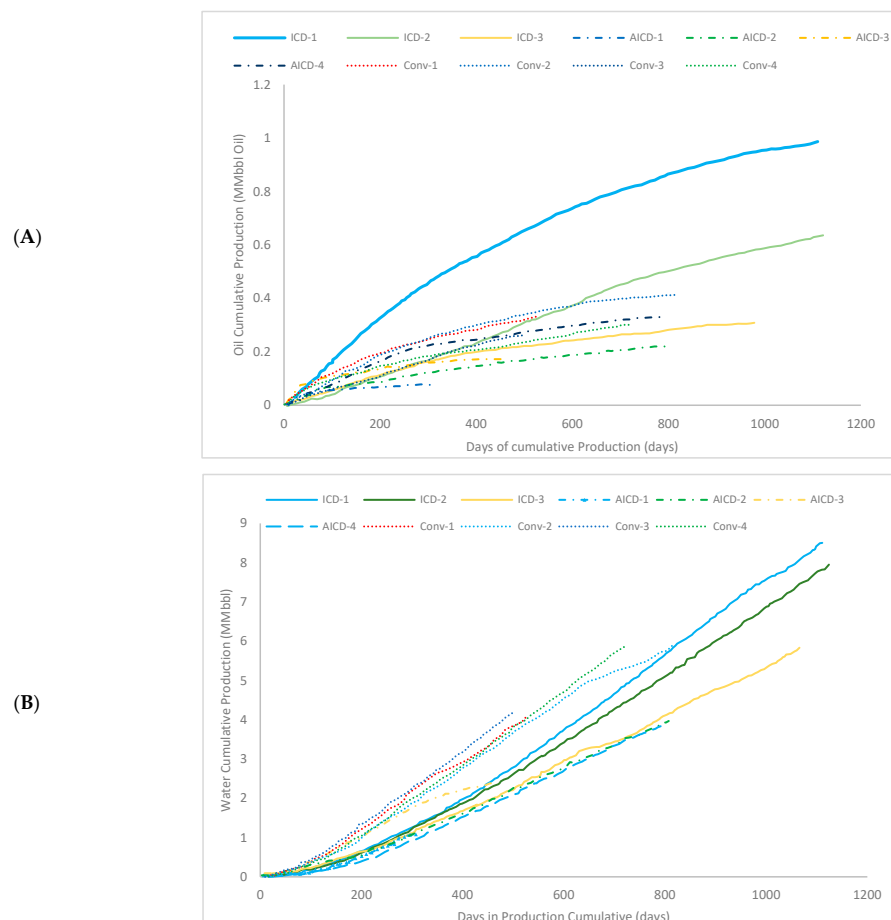


Figure 10. Oil (A) and water (B) cumulative production in Field #1 by well [23].

Power and carbon footprint estimation wells: this observation could be a critical factor in dismissing the technology's effectiveness, as operational expense (OPEX)—which refers to the ongoing costs of running and maintaining a well, such as energy consumption, water treatment, and maintenance—savings from reduced water production might not offset the revenue losses due to decreased oil production, depending on the oil price scenario.

In 2011, when the average oil price exceeded USD 100 per barrel, any loss in oil production could not be justified, especially considering that the capital expenditure (CAPEX) for wells with ICDs/AICDs was higher than that for conventional wells.

Two wells with ICDs showed outstanding performance for the same working days, doubling the final recovery of oil with still less water. Furthermore, this extended the productive life of these wells.

Knowing that many variables could have influenced these wells' fluid production, Figure 11 plots the average fluid output for completion types.

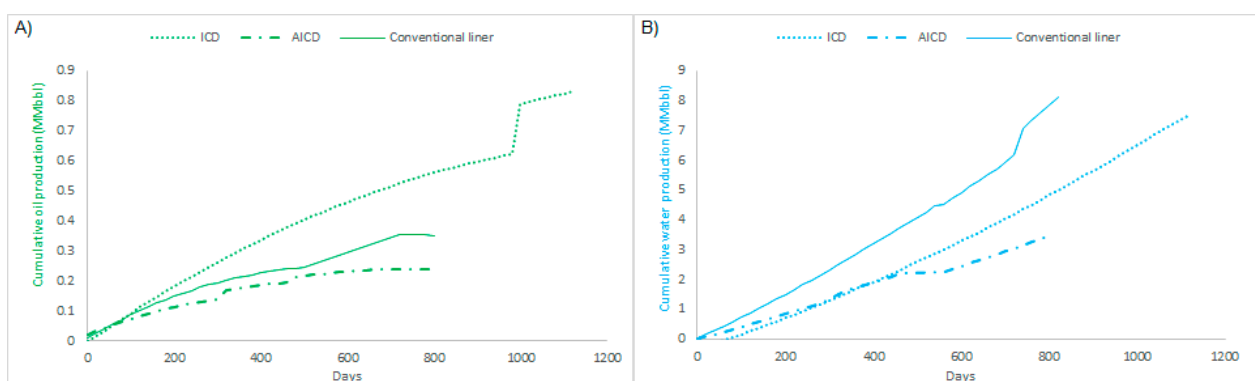


Figure 11. Average cumulative oil (A) and water (B) production from a conventional vs. ICD and AICD completion in Field #1.

First, completions with ICDs have the most significant amount of cumulative oil and water in the set of wells. The reason behind production is the longevity of the well. With ICDs, the life cycle is around 1100 days, representing 66% more of the lifetime of the wells. Meanwhile, wells with conventional completion last around 800 days, and completions with AICDs last almost 700 days. The cessation of well production is due to economic considerations and limitations in disposal capacity, not always due to the limitation of the capacity of the equipment, but rather due to limits imposed by environmental licenses given by regulatory entities.

However, when analyzing ICD technology globally, it is essential to note that there is no reduction in the average cumulative oil from all wells, maintaining up to a 50% water reduction. This means the reservoir displacement efficiency increases when ICDs are installed, thereby increasing the well recovery factor. The discontinuity jump in the ICD's average production plot (Figure 11) is because only the best two wells operated after 1000 days (Figure 10). On the other hand, the average production plot for wells equipped with AICDs reveals an approximate 33% reduction in oil production compared to slotted liners. This observation could be attributed to the increased flow restriction inherent to AICDs, which aligns with the lower cumulative water production observed in Figure 11B.

Inflow control devices (ICDs) and autonomous inflow control devices (AICDs) are specifically designed to regulate the flow of fluids from different zones within a wellbore. By installing these devices, operators can effectively prevent water from entering the wellbore, significantly reducing the absolute amount of production water. However, it is essential to note that their primary function is restricting the unwanted water influx, which can lead to a lower overall fluid production, including oil and water.

Figure 11 suggests that a well with ICD technology will have more oil at the end of the production cycle when it outlasts a well with conventional or AICD longevity completion. It demands outstanding in-field operability for its success. This is aligned with what was concluded by Gómez Gualdrón et al. [23]. These installations are beneficial and successful in non-consolidated formations. They show higher performance than a conventional completion, reduce water cut, sweep fluids better in the reservoir, and delay potential early breakthrough, favoring less mobile oil (730 cP viscosity) to be produced.

3.2. Field Implementations—Field #2

In 2018, a second field test was scheduled under a less favorable oil price scenario (USD 70 per barrel) with a new generation of AICDs known as RCP (rate-controlled production) devices. Furthermore, the AICD test in this new field was driven by severe water production restrictions due to bottlenecking on water transport pipelines and processing facilities. Figure 12 shows the cumulative oil and water production from three wells, two completed with AICDs and one completed with a slotted liner.

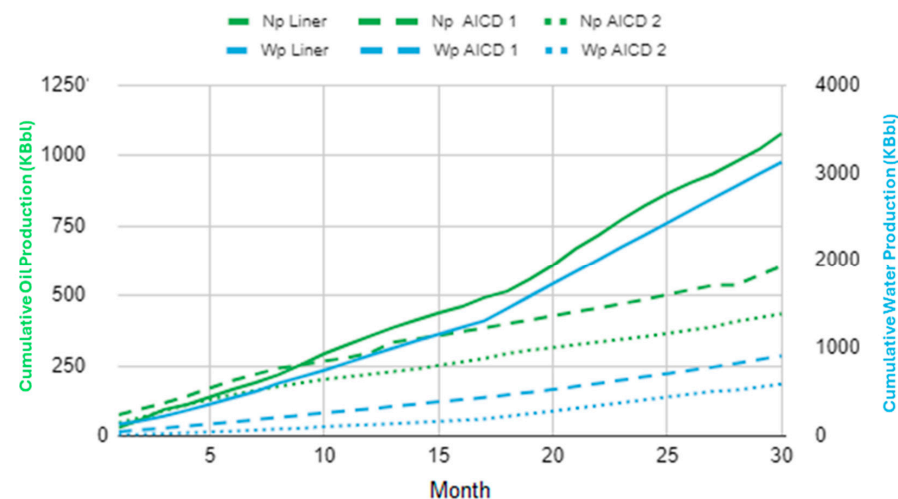


Figure 12. Cumulative production profiles of oil and water of conventional vs. AICD completions.

As expected, during the whole productive time concerning the amount of water production, wells completed with AICDs experienced a relevant water reduction compared to the conventional one, even though there was a variation of 35.3% between the AICD-2 and AICD-1. It shows the impossibility of having two equal production rates even though the completions were technically the same. What is relevant and clear is the vast difference in water production between the well with the slotted liner and the AICD-1 and AICD-2, which were 70.8% and 81.1%, respectively.

During the first ten months of operation, the three wells experienced similar behavior regarding oil production. Although the oil production from the AICD wells is almost equal to that of conventional wells, its growth slope was less favorable. This resulted in more than 35% additional cumulative oil for the conventional well in the following months. Nevertheless, with this increase in oil, one should not lose sight of the fact that water production has increased, reporting a linear rise. It should be kept in mind that excess water will bottleneck production trunk lines and processing facilities.

For the AICD wells, it stands out that the losses in fluid production (oil and water) are not given just for implementing AICDs themselves. As expected, AICDs should diminish the effective area of the inlet flow when the water reaches the wellbore, causing water and oil flow restrictions. However, as explained, the total closure of the inflow area is not possible because the devices are designed with a minimum operational flow area to

prevent total well shut-in. These two AICD wells cannot be thoroughly compared against the conventional ones due to operational constraints. These two wells have not been able to operate at a higher rate due to surface facility limitations for water handling, and production priority was given to the slotted liner well.

This situation opens the discussion for an optimization problem. Comparing well to well, it is expounded that there could be an important loss of oil production by 54%, with a reduction of almost 76% in water production. Nevertheless, this reduction in water could debottleneck the daily water treatment process, as less fluid needs to be treated. In other words, the proper management of production, achieving fluid restrictions, and water reduction in wells with AICDs represent a possibility of turning on other wells and greatly compensating for the losses in producing AICD wells.

The question is as follows: Would it be more efficient to operate two AICD wells than one with a slotted liner?

For illustration purposes, the oil and water production rate of the two AICD wells was combined into one and compared with those of the conventional one, as shown in Figure 13.

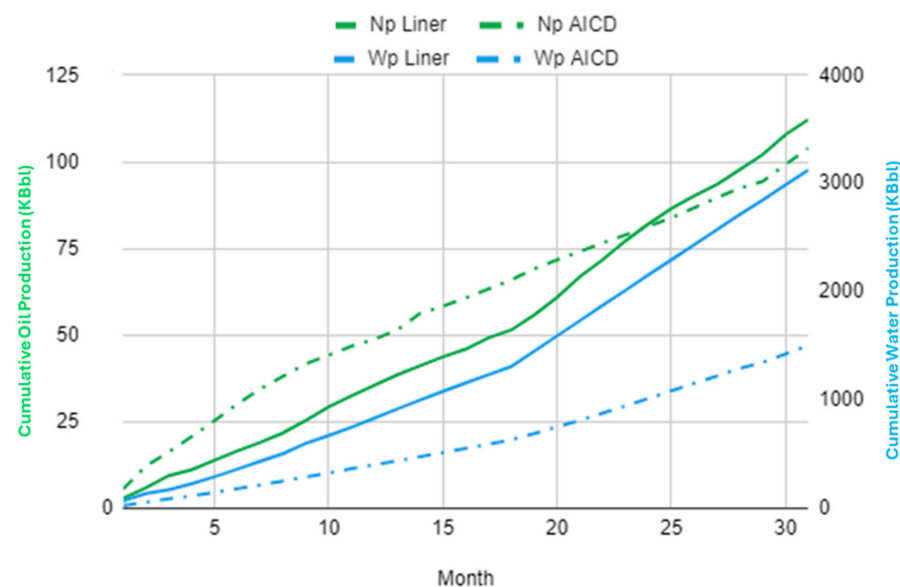


Figure 13. Cumulative production profile of oil and water.

First, the total cumulative oil production of the well with an AICD is 7% less than that of the conventional well. Meanwhile, the cumulative water production rate reduction is more significant; the AICD sum of wells produced 52% less water than the water produced with the conventional well. Looking closely at the behavior at 31 months, the water production rate of the conventional completion has exponential growth. In the meantime, more linear growth can be seen in the well with the AICD, which shows the controlled movement of water from the reservoir to the wellbore—resulting in almost the same oil production with two AICD technology wells compared to one conventional well. This water reduction opens up two possibilities:

1. Debottleneck capacity in the treatment facilities opens the possibility of increased oil production by shut-in in more wells. From an ecological standpoint, oil barrels would be environmentally friendly, as they optimize the power consumption per barrel and the impact of the carbon footprint.
2. If no more oil production is added, and water reduction is kept, less water must be treated at the facility, and savings in OPEX and carbon footprint impact can be made. Further analysis of the carbon footprint will be presented in the next section.

3.3. Power and Carbon Footprint Estimation

Nowadays, sustainability and environmental impact are essential concepts for any industry. In the function of the availability of the data for each well, the power consumed by and the carbon footprint of each well was estimated using the following equations:

$$\text{Power} = \frac{(W_{\text{cut}} \times \rho_{\text{H}_2\text{O}} + (1 - W_{\text{cut}}) \times \rho_{\text{oil}})gHQ}{\eta} \quad (1)$$

For carbon footprint [34], it used the following equation:

$$\text{kg CO}_2 = \text{Energy(kWh)} \times 0.136 \left(\frac{\text{kgCO}_2}{\text{kWh}} \right) \quad (2)$$

Figure 14 demonstrates electric energy consumption at different water cut values in conventional and AICD completions.

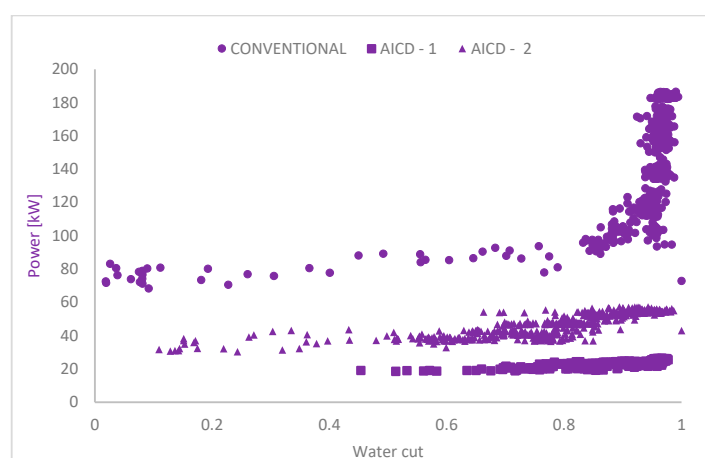


Figure 14. Power vs. water cut (%), conventional vs. AICD completions.

The well with a conventional completion needed more power as the water cut rises to function. The ESP pump's design and the lifted fluids are two main reasons for this behavior. First, the ESP used in the conventional well is two times bigger than the ESP of the other wells, showing an overdesign of the artificial lifting system. Second, more fluids are produced in a conventional well as there is no restriction to the fluids; they are compared to the wells with AICD completions. These combined factors necessitate larger pumping systems that handle higher fluid volumes, resulting in power consumption up to 5 times greater than AICD wells. The reduced power consumption in AICD wells translates to significant OPEX savings, which directly improve reserves and EUR (Estimated Ultimate Recovery) at both well and field levels. Supporting this economic analysis, Figure 15 presents the cumulative CO₂ emissions comparison per well.

Proportional to energy consumption, the conventional well is expected to exponentially produce the most CO₂ emissions. As the water cut increases over time, CO₂ emissions will increase rapidly. Conversely, the wells with AICDs do not follow the same trend. As the water cut increments over time, the emissions will grow steadily, almost linearly, producing up to a five times smaller carbon footprint and aiding the environment.

The emissions estimates presented in this study are based on power consumption, focusing on the energy required to lift fluids to the surface. While these estimates provide valuable insights into the relative environmental impact of different well completions, it is essential to note that they do not fully capture all sources of emissions, particularly those associated with water handling, treatment, and disposal.

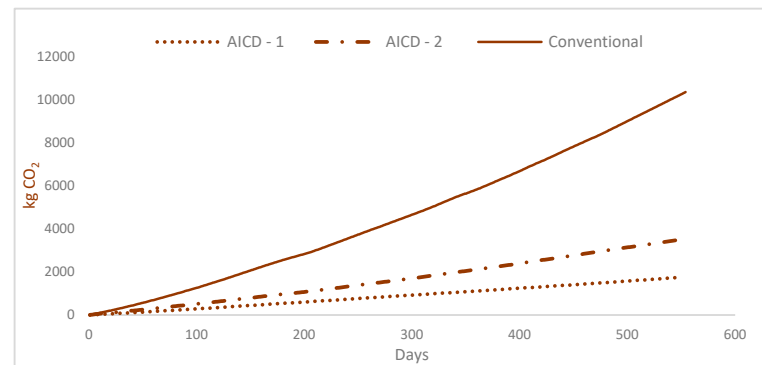


Figure 15. Cumulative CO₂ emissions of conventional vs. AICD completions.

Despite this limitation, the emissions data presented here remain relevant for comparing the environmental performance of ICDs, AICDs, and conventional wells. These estimates highlight the potential benefits of using inflow control devices to reduce the overall carbon footprint, particularly by minimizing water production and the associated energy consumption.

Nevertheless, a more comprehensive emissions model, which includes contributions from water handling and other sources, would provide a fuller picture of environmental impact. Future work should aim to develop such a model to enhance the accuracy and applicability of emissions estimates in evaluating the sustainability of different completion strategies.

3.4. Numerical Study—Field #3

After two technological field tests, the results were inconclusive and still do not provide security for mass implementation in heavy crude oil fields. What is more, the results are controversial, since even though a reduction in water production is always reported, in some cases, a decrease in oil is noted too, while in others, even an increase. In any case, under the scenario of high prices, reducing water with a decrease in oil does not seem attractive for this type of field.

The recent pandemic, with less favorable oil prices and even negative values, has again opened the possibility of implementing these technologies more often. For this reason, to reduce uncertainties before proceeding to a new in-field installation, simulations were carried out with advanced CFD techniques, which minimize the uncertainties around the performance of the bottom water control devices.

A numerical study comparing the behavior of passive and active devices was developed, using a slotted liner completion as a reference.

The simulations results illustrate the three following effects:

1. Effect of AICD vs. ICD vs. slotted liner;
2. Effect of spacing between devices;
3. Effect of the draw-down.

Figure 16 shows the production profiles and cumulative production for a downhole flowing pressure of 1160 psi, corresponding to a draw-down of 10%. ICDs, AICDs, and slotted liners were simulated in three completion configurations. Two different arrangements, every 30 ft and every 100 ft, were analyzed for the disposition of water control devices.

The most notorious result of the simulation was the total closure of the AICDs in the early operational days. The AICD control devices were close to nearly 100% in a short period of production time, 10 and 30 days, for either 100 ft or 30 ft spacing horizontal well completion, respectively. Total closure would represent a total loss of oil production, and the manufacturers are aware of that fact. That is why, for actual field implementation,

the providers design their devices for a substantial water restriction, but not for a total closure, as explained in Figure 4. This partial AICD closing was numerically challenging to reproduce and impossible to perform in the present work. Nevertheless, keeping in mind the assumptions and conditions of the simulations, numerical results installing AICDs show a loss of oil production in this type of well (Figure 16). This is consistent with the field results observed in the implementation of Field #1, where AICD wells recovered less oil than conventional and ICD ones (Figure 10).

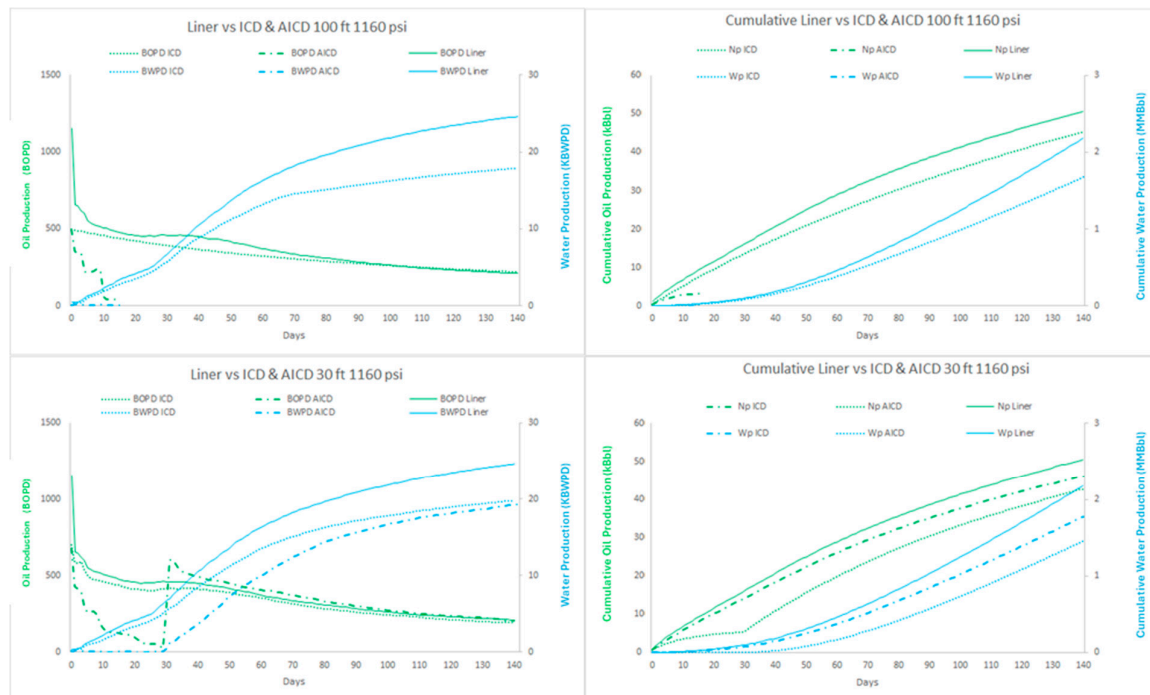


Figure 16. Oil and water production profiles are daily (**left**) and cumulative (**right**), at 1160 psi, with varying distances between inflow control devices.

So, to further understand this phenomenon and to allow simulations to continue, a boundary condition change has been numerically forced, allowing the reopening of the AICDs in the 30 ft completion well. This would represent only a numerical exercise with the same operational time condition. AICDs will be 100% open, acting like ICDs and not through physical or practical possible action in the field.

The second most revealing thing about these simulations, referring to the slotted liner as a reference, is the confirmation of the following:

1. Water reduction due to water control devices, referred to as conventional completion with slotted liner, is always obtained:
 - a. AICD_{30 ft}: 34.0%
AICD_{100 ft}: Non-apply
 - b. ICD_{30 ft}: 18.5%
ICD_{100 ft}: 23.2%
2. Regarding oil production, the configuration of every 30 ft is more favorable than 100 ft because it represents a lower production loss:
 - a. AICD_{30 ft}: 9.3%
AICD_{100 ft}: Non-apply
 - b. ICD_{30 ft}: 8.8%
ICD_{100 ft}: 8.4%

3. Over time, the difference in oil production between the three completions is reduced, maintaining a significant reduction in water. Performing more extended simulations could bring relevant information for the future.

On the other hand, there are minor differences of less than 0.4% in the total amount of oil produced between the 100 ft and the 30 ft devices and a 4.7% difference in the total water produced, representing 1 million barrels between simulations of 30 ft and 100 ft ICDs. This suggests that having less distance between devices would produce less water, with a minimal decrease in oil production and the same draw-down during the production time.

When the bottom hole flowing pressure was reduced to 1140 psi, simulations consistently increased the total oil and water relative to the 1160 psi bottom hole flowing pressure (Figure 17). The simulated time was 80 days.

1. Water reduction due to water control devices, compared to conventional completion with slotted liner at 1140 psi:
 - a. AICD_{30 ft}: 43.3%
AICD_{100 ft}: 78.5%
 - b. ICD_{30 ft}: 20.4%
ICD_{100 ft}: 19.4%
2. Comparing the oil production, the configuration of every 30 ft is more favorable than that of 100 ft because it represents a lower loss of production:
 - a. AICD_{30 ft}: 20.7%
AICD_{100 ft}: 44.4%
 - b. ICD_{30 ft}: 9.5%
ICD_{100 ft}: 13.9%

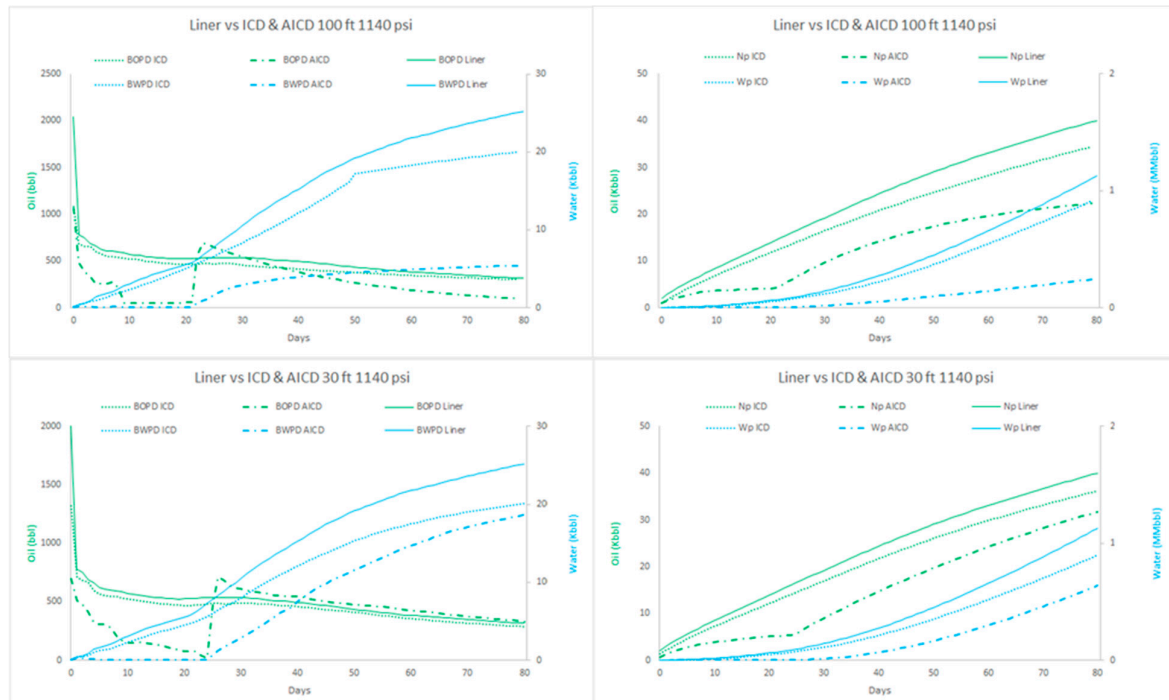


Figure 17. Oil and water production profiles are daily (left) and cumulative (right), at 1140 psi, with varying distances between inflow control devices.

All the tendencies obtained for the first draw-down simulations remained the same. However, as expected, the fluid production rates were higher with a higher draw-down. In other words, it was observed that the completions with devices at any length and liner

with a pressure of 1140 psi produced more oil and water than their equivalent completions at 1160 psi. It becomes clear that draw-down management techniques will help to optimize the water control device's performance. The amount of oil produced by ICDs at a pressure of 1140 psi had a minimal difference compared to the oil production of the liner at a 1160 psi pressure. It was suggested that a liner completion could reach the results achieved by the inflow control devices at 1140 psi and 1160 psi, which is even better as it considers the less amount of water produced.

3.5. Completion Proposal—Field #3 Implementation

The CFD study's result, comparing passive and active inflow control devices with a conventional slotted liner completion, led to the recent design of an ICD completion in the third heavy oil field (Figure 18).

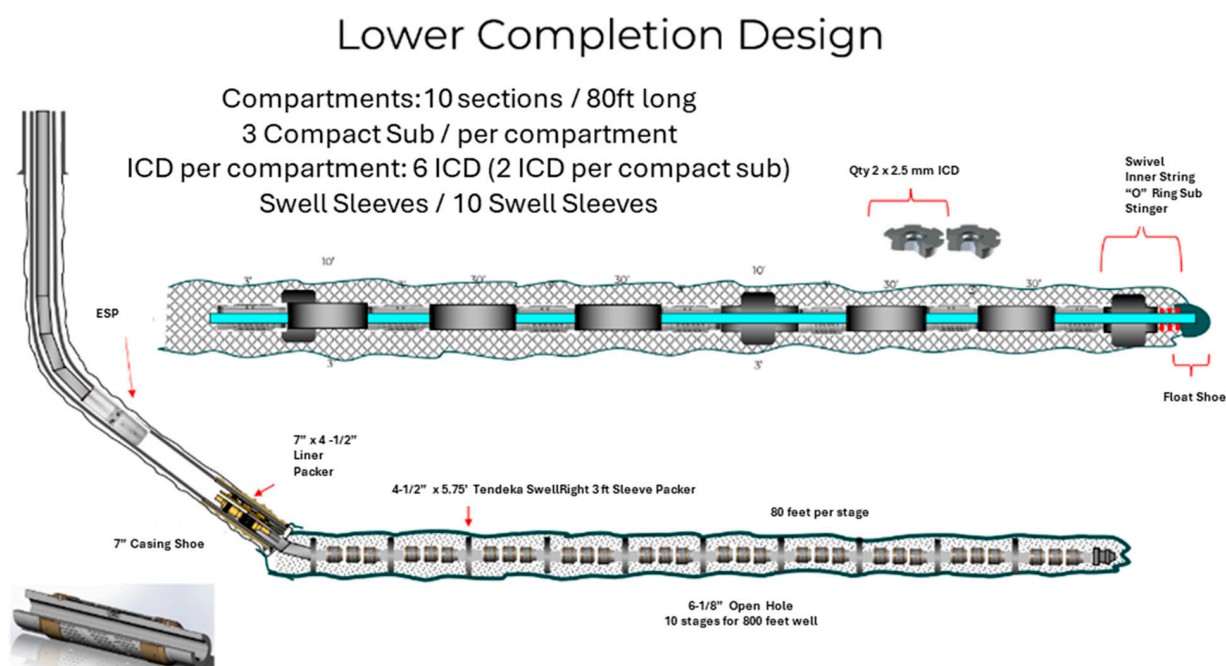


Figure 18. Lower completion design of wellbore in Field #3.

This well was drilled and finished in December 2022, but the results were unavailable when this article was written.

4. Discussion and Future Work

This study analyzed the performance of various downhole mechanical inflow control devices (ICDs and AICDs) across different mature heavy oil fields. The key findings demonstrate each control method's unique characteristics and effectiveness in managing water production.

1. ICDs:

- Field #1: ICDs showed a significant reduction in water production (approximately 75%) compared to traditional slotted liner completions. This method also exhibited a longer well operational time, extending the productive life of the wells by about 30%. However, a reduction in oil production was noted in some wells, raising concerns about overall effectiveness when considering operational cost savings versus oil production loss.
- Field #3 (numerical study): The CFD simulations revealed that passive ICDs consistently reduced water production by 18.5% to 23.2%, depending on device

spacing. These simulations underscored the importance of optimizing device spacing and draw-down management to enhance performance.

2. AICDs:

- Field #1: AICDs reduced water production by approximately 32%. Although they outperformed ICDs in reducing water production, they were less effective in maintaining oil production, diminishing the overall economic benefits.
- Field #2: A new generation of AICDs, rate-controlled production (RCP) devices, were implemented. These devices reduced water production by 70.8% to 81.1% compared to conventional completions. However, the cumulative oil production was lower, indicating that while AICDs are effective in water control, they require further optimization to avoid significant oil production losses.

3. Water Control Characteristics:

- Field-specific observations: The fields studied showed that high water cuts are a common challenge in heavy oil reservoirs with strong aquifer drives. The implementations highlighted that while ICDs and AICDs effectively reduce water production, their implementation depends on specific reservoir characteristics and operational goals.
- Environmental impact: The study also emphasized the environmental benefits of using inflow control devices. ICDs and AICDs reduce the carbon footprint by decreasing the power consumption needed for lifting and processing produced fluids.

Further research should focus on the following:

- Optimization of Control Methods: Improving the design and deployment strategies of both ICDs and AICDs to balance water control with minimal oil production loss;
- Advanced Simulations: Utilizing CFD and other numerical techniques to refine the understanding of fluid dynamics in different reservoir conditions and optimize the placement and configuration of control devices;
- Field Trials and Long-Term Studies: Additional field trials and long-term performance evaluations will be conducted to gather comprehensive data on these technologies' economic and environmental impacts in various operational scenarios.

5. Conclusions

This comprehensive study of horizontal well completions with downhole inflow control technology in mature heavy oil reservoirs, including field data analysis and numerical simulations, has provided valuable insights into the effectiveness of inflow control devices (ICDs and AICDs) in heavy oil fields. The study of nineteen horizontal well completions confirms that inflow control devices consistently reduce water production, with values ranging from 15% to over 50% compared to traditional slotted liner completions. This water reduction contributes to ecological efforts, decreasing energy consumption and reducing carbon footprint.

However, under high oil price scenarios, water reduction may not always compensate for the financial impact of oil production losses. The effect of inflow control devices on oil production remains unclear, as ICDs appear to maintain or even increase oil production, while AICDs' substantial water reduction may jeopardize oil production. Field data from two AICD wells suggest that two AICD wells can perform better than one slotted liner well, producing only 7% less oil while reducing water production by over 50%. This result confirms that inflow control devices align with environmental objectives by reducing power consumption and carbon footprints.

While the capital expenditures for wells with inflow control devices are higher than those for conventional wells, the investment is justified by the minimal decrease in oil production and the significant reduction in water production. Additionally, a 50% reduction in CO₂ footprint is achieved, leading to decreased power consumption and operational expenditures. This reduction has the potential to sustain or increase field reserves, although further detailed studies are recommended to estimate the final impact.

CFD studies confirmed that all inflow control devices reduce the water produced, and that optimal draw-down management can mitigate the impact of oil production for ICD wells. The results suggest that passive inflow control devices may represent an effective solution for water management in heavy oil reservoirs with characteristics similar to Field #3, as they can decrease water production by up to 20% while potentially maintaining or even increasing oil production over extended operational periods. However, it is important to emphasize that these findings apply specifically to reservoirs with properties comparable to those examined in our research. Optimal device selection remains dependent on field-specific characteristics, including permeability distribution, viscosity contrast, aquifer strength, and operational considerations. In this context, CFD modeling has proven to be a high-performance and reliable tool for technology selection, enabling operators to make informed decisions based on physics-driven simulations before committing to costly field implementations. This approach bridges the gap between theoretical predictions and practical applications, providing a cost-effective pathway to optimized water management strategies in mature heavy oil fields.

To sum up, implementing inflow control devices in mature heavy oil fields can result in reduced water production, a lower carbon footprint, and potential enhancements in oil production. This study's findings provide valuable information for operators and stakeholders seeking to optimize the performance of downhole mechanical inflow control devices and enhance environmental performance in O&G operations.

Future research will pursue several complementary directions to build upon this study's findings. First, we aim to enhance our CFD modeling capabilities by implementing progressive throttling mechanisms for AICDs that better represent their real-world behavior beyond the current binary approach. Systematic long-term monitoring of the Field #3 ICD implementation will provide crucial validation data and insights into extended performance. We also envision developing a multi-scale modeling framework that bridges our detailed CFD simulations with field-scale reservoir models to better predict drainage patterns and recovery factors. Additional work will focus on creating optimization algorithms for device placement based on reservoir heterogeneity profiles, expanding our environmental impact analysis through comprehensive life cycle assessments, and exploring adaptive control strategies that can respond to evolving reservoir conditions throughout well life. Together, these research directions will advance our understanding of inflow control technologies and further improve their application in mature heavy oil fields.

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Nomenclature

Variable	Description	Units
W_{cut}	Water cut	(0 – 1)
Q	Total fluid rate	(m^3/s)
g	Gravity	(m/s^2)
H	Pump head	(m)
S_{wi}	Initial water saturation	(0 – 1)
η	Pump efficiency	(0 – 1)
ρ_{fluid}	Fluid density	(kg/m^3)

Glossary

BOPD	Barrels of Oil Per Day
BWPD	Barrels of Water Per Day
ICD	Inflow control device
AICD	Autonomous inflow control device
RCP	Rate-controlled production
P_{wf}	Bottom hole flowing pressure [psi]
O&G	Oil and Gas
CFD	Computational fluid dynamics
VOF	Volume of fluid
ESP	Electrical Submersible Pump
EUR	Estimated Ultimate Recovery
BHP	Bottom hole pressure
WC	Water cut
TVDSS	True Vertical Depth Subsea
API	American Petroleum Institute
CAPEX	Capital expenditure
OPEX	Operational expenditure
SDG	Sustainable Development Goals

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