UNIVERSITY OF SÃO PAULO
ESCOLA POLITÉCNICA

Bruno da Cruz Schaefer

New Methodology to Improve the Optimization of Intelligent Well Completion Using Production Parameters in Real-Time

SÃO PAULO
2022

BRUNO DA CRUZ SCHAEFER

New Methodology to Improve the Optimization of Intelligent Well Completion Using Production Parameters in Real-Time

Revised Version

Master's thesis presented to the Escola Politécnica of University of São Paulo to obtain Master of Science degree in Mineral Engineering.

Concentration Area: Mineral Engineering.

Advisor: Prof. Dr. Marcio Augusto Sampaio Pinto.

SÃO PAULO
2022

Este exemplar foi revisado e corrigido em relação à versão original, sob responsabilidade única do autor e com a anuência de seu orientador.

São Paulo, 24 de novembro de 2022.

Assinatura do autor: ______________________________

Assinatura do orientador:

Prof. Dr. Marcio Augusto Sampaio Pinto
Depto. de Engenharia de Minas e de Petróleo
Escola Politécnica da USP

Digitally signed by MARCIO AUGUSTO SAMPAIO PINTO
DN: cn=MARCIO AUGUSTO SAMPAIO PINTO, o=UNIVERSIDADE DE SAO PAULO, ou=USP, email=marciosampaio@usp.br, c=BR
Date: 2022.12.01 15:00:56 -03'00'

Catalogação-na-publicação

Schaefer, Bruno da Cruz
New Methodology to Improve the Optimization of Intelligent Well Completion Using Production Parameters in Real-Time / B. C. Schaefer -- versão corr. -- São Paulo, 2022.
72 p.

Dissertação (Mestrado) - Escola Politécnica da Universidade de São Paulo. Departamento de Engenharia de Minas e de Petróleo.

1.Reservatórios de Petróleo 2.Completação 3.Engenharia de Petróleo I.Universidade de São Paulo. Escola Politécnica. Departamento de Engenharia de Minas e de Petróleo II.t.

BRUNO DA CRUZ SCHAEFER

New Methodology to Improve the Optimization of Intelligent Well Completion Using Production Parameters in Real-Time

Revised Version

Master's thesis presented to the Escola Politécnica of University of São Paulo to obtain Master of Science degree in Mineral Engineering.

SÃO PAULO
2022

FOLHA DE AVALIAÇÃO

SCHAEFER, B.C. **New Methodology to Improve the Optimization of Intelligent Well Completion Using Production Parameters in Real-Time**. 2022. Dissertação (Mestrado em Engenharia Mineral) – Escola Politécnica, Universidade de São Paulo, São Paulo, 2022.

Aprovado em:

Banca Examinadora

Prof. Dr.: ________________________________

Instituição: ________________________________

Julgamento: ________________________________

Prof. Dr.: ________________________________

Instituição: ________________________________

Julgamento: ________________________________

Prof. Dr.: ________________________________

Instituição: ________________________________

Julgamento: ________________________________

To my late aunt, professor Olga Cruz, for her dedication to education and relentless encouragement of scientific thinking.

ACKNOWLEDGEMENTS

I would like to thank my wife, Michele, and my family for all the support and motivation during the development of this thesis.

I would also like to thank my advisor, Prof. Dr. Marcio Sampaio, for sharing his knowledge, ideas and insights that contributed a lot to this work.

Thanks to my colleagues at USP: Paulo, Marum, Leo, Mayara, Lívia, Nathália and Eduardo, for the time shared with coffee and studies.

My gratitude to the Well Completion and Intervention community from Petrobras and a special thanks to Eduardo Schnitzler, Luciano Gonçalez, Rafael Camel and Felipe Volponi, for the contribution to this work.

My appreciation to the ones that provided the resources needed for this study: Laboratory of Reservoir Simulation and Management (LASG) and University of São Paulo for providing the infrastructure, CEPETRO/UNISIM Group for the benchmark used in the thesis and Computer Modelling Group (CMG) for the simulation software and technical support.

"The boldness of asking deep questions may require unforeseen flexibility if we are to accept the answers."

Brian Greene

RESUMO

SCHAEFER, B. C. **Nova Metodologia para Melhorar a Otimização de Completação Inteligente Utilizando Parâmetros de Produção em Tempo Real**. 2022. Dissertação (Mestrado) – Escola Politécnica, Universidade de São Paulo, São Paulo, 2022.

Sistemas de completação inteligente – *Intelligent Well Completion* (IWC) – têm sido utilizados para melhorar o gerenciamento da produção de reservatórios de petróleo nos últimos 20 anos, com resultados expressivos em reservatórios heterogêneos. A associação de IWC com simulação de reservatório geralmente resulta em economia durante o desenvolvimento do campo, mas traz consigo alguns desafios na otimização das válvulas de completação inteligente. Este trabalho propõe uma nova metodologia para identificar poços candidatos à instalação de válvulas de completação inteligente do tipo *interval control valves* (ICV) com otimização da produção utilizando simulação em tempo real. Com o auxílio de um mapa de qualidade do valor presente líquido (VPL) gerado a partir de um caso base de completação convencional no simulador, a metodologia proposta identifica potenciais camadas do reservatório para agrupamento no poço produtor, de forma a controlar a produção por zonas e reduzir o tempo computacional no posicionamento de válvulas ao longo do poço. A estratégia de produção utiliza valores de vazão otimizados gerados internamente pelo simulador, reduzindo significativamente o número de variáveis na etapa de otimização. O fluxograma foi aplicado em dois estudos de caso em uma configuração *five-spot*, utilizando uma seção de reservatório extraída do *benchmark* UNISIM-II, com características similares ao do Polo Pré-Sal da Bacia de Santos (PPSBS). O agrupamento das camadas foi limitado em até três zonas produtoras com uma ICV em cada zona, levando em conta aspectos operacionais que permitam a replicabilidade em campo. No primeiro estudo de caso foi utilizada a modelagem padrão de poço do simulador, o que resultou em dificuldades no acoplamento de pressões de fundo entre zonas produtoras, comprometendo o uso desta solução em outros cenários. A modelagem de poço foi aprimorada para o segundo estudo de caso, com a utilização das funções do pacote *iSegWell* dentro do simulador, que permitiu um melhor detalhamento da completação implementada (modelagem do poço, uso de obturador mecânico, melhor modelagem da coluna de produção, interdependência de pressão entre canhoneados, queda de pressão na coluna de produção etc.). Esta nova estratégia de modelagem e controle em tempo real de ICV apresentou uma redução de 92% no número de variáveis no processo de otimização quando comparada com uma estratégia similar de controle proativo. O custo computacional permaneceu o mesmo de uma estratégia mais simples, reativa, de monitoramento de *water cut* (WCUT) e houve um incremento no VPL de +14,32% comparado ao caso base. Os resultados mostram que o VPL – e consequentemente o ganho econômico das ICVs – é muito dependente do cenário econômico. Mesmo assim, a metodologia apresentada tem potencial para aplicação em cenários complexos, sem aumentar o número de variáveis de otimização como, por exemplo, ICVs de multi-posição ou de posição continuamente variável.

Palavras-chave: Completação inteligente, Válvulas de controle, Simulação de reservatório, Otimização.

ABSTRACT

SCHAEFER, B. C. **New Methodology to Improve the Optimization of Intelligent Well Completion Using Production Parameters in Real-Time**. 2022. Thesis (Master) – Polytechnic School, University of São Paulo, São Paulo, 2022.

Intelligent well completion (IWC) has been successfully deployed over the last twenty years to improve reservoir management, with better results in heterogeneous reservoirs. Associating IWC with reservoir simulation usually results in economic gains for field development, along with challenges in optimizing ICV settings. This work proposes an efficient workflow to identify well candidates for interval control valves (ICV) application and production optimization using parameters in real time. From a net present value (NPV) quality map generated for the conventional completion base case, the methodology searches for potential reservoir layer grouping in the producer well, to control zonal flow, without expending too much computational time in valve positioning. ICV control strategy uses real-time production guide rates generated by the simulator, reducing optimization parameters. The proposed workflow was applied to two case studies in a five-spot configuration, using an extracted reservoir section of the UNISIM-II benchmark, which has similar properties to the Santos Basin Pre-Salt Cluster (SBPSC). Layer grouping was limited to three independent production zones, with one ICV for each zone, as operational aspects were considered in the study. The first case study used the simulator standard well structure, resulting in difficulties in bottomhole pressure (BHP) coupling among production zones, with a negative impact in methodology replicability for other scenarios. Well modeling was improved for the second case study, with CMG's iSegWell suite, that allowed for more detailed completion implementation in the simulator (wellbore modelling packer positioning, tubing string modelling, perforation-to-perforation pressure dependencies, tubing pressure drop, etc.). This novelty strategy for ICV modelling and real-time control delivered a significant reduction of 92% in optimization parameters, compared to a similar proactive strategy. Computational cost for the proposed new strategy remained at the same level of a common reactive approach of water cut (WCUT) monitoring and there was an increase of +14,32% in NPV compared to the base case. Results show that NPV – and IWC economic gain – are highly dependent on the economic scenario. Nevertheless, the methodology has potential for application in more complex simulations, with greater number of wells or optimization parameters, like multi-position or continuously variable position ICV.

Keywords: Intelligent well completion, ICV, Reservoir simulation, Optimization.

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS

BHF	–	Bottomhole flowrate
BHP	–	Bottomhole pressure
CAPEX	–	Capital expenditure
EOR	–	Enhanced oil recovery
GOR	–	Gas-oil ratio
Gp	–	Cumulative gas production
ICV	–	Interval control valve
IOR	–	Improved oil recovery
IWC	–	Intelligent well completion
MPFM	–	Multiphase flowmeters
NOC	–	National Oil Company
Np	–	Cumulative oil production
NPV	–	Net present value
OPEX	–	Operational expenditure
PDG	–	Permanent Downhole Gauge
PLT	–	Production logging tool
PPSBS	–	Polo Pré-Sal da Bacia de Santos
PSO	–	Particle swarm optimization
SBPSC	–	Santos Basin Pre-Salt Cluster
STG	–	Gas production stream
STL	–	Liquid production stream
STO	–	Oil production stream
STS	–	Solvent production stream
STW	–	Water production stream
UBA	–	User block address
WCUT	–	Water cut
Winj	–	Cumulative water injection
Wp	–	Cumulative water production

SUMMARY

1 INTRODUCTION

An intelligent well allows for downhole parameter monitoring and remote operation, enabling the operator to make changes to bottomhole conditions, like choking or completely shutting an interval control valve (ICV) without the need of an intervention rig. Intelligent well completion dates to the late 1980s, with the first well equipped with real-time permanent downhole gauges (PDG) to monitor pressure and temperature. In the 1990s, the first downhole flow control system was deployed in a well (RENPU, 2011). Fast-forwarding from the numbers presented by Renpu (2011) of more than 130 intelligent wells around the world in the year of 2004, nowadays there are several examples of successful intelligent well completion (IWC) deployment for field development. Adeyemo *et al*. (2009) presents the case of Agbami field, Chevron's first offshore asset in Nigeria and National Oil Company (NOC) Petrobras alone reached a milestone in the Santos Basin Pre-Salt Cluster (SBPSC) of 100 wells equipped with intelligent completion from 2012 to 2019 (SCHNITZLER *et al*., 2015, 2019, 2021). IWC project design and execution is constantly evolving to adapt to challenges in deep-water well construction. Figure 1 shows the typical scenario for the Brazilian pre-salt area.

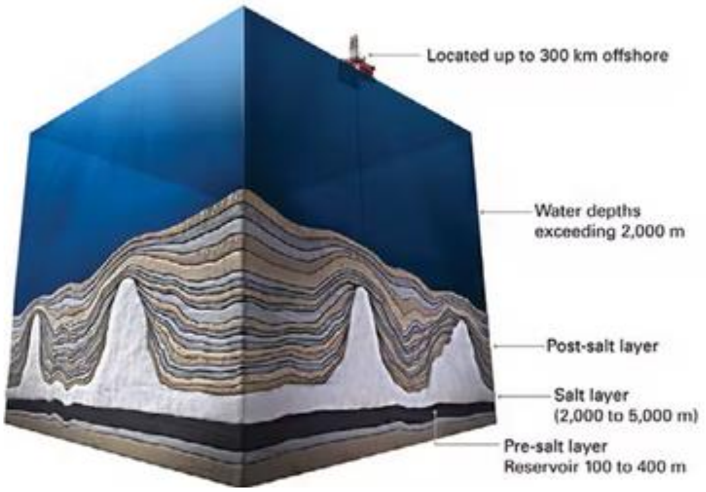

Figure 1 - Brazilian pre-salt reservoir scenario. Source: RODRIGUES *et al*. (2018).

IWC technology has already proven itself as a powerful tool to improve oil recovery in different economic scenarios and heterogeneities of reservoirs. It can prevent early water/gas breakthrough, optimize production and control water cuts/pressures by zone. The ability to handle downhole well flow separately makes IWC useful in reservoir management. When working with thick heterogeneous reservoirs, the permo-porous properties can vary significantly in the extension of the well. The necessity to control zonal flow for better reservoir management makes IWC useful when trying to obtain a higher recovery factor.

Reservoir simulation is an important tool to process the data provided by IWC to improve reservoir management and update production forecast. Recently, there has been some development on simulation software to use multi-segment well tools but still without the desired flexibility. The focus of reservoir simulators is flow behavior and far-field effects, while IWC relies on near wellbore effects, so the search for a reliable IWC design in the simulator should be a concern.

Another issue is the intrinsic optimization problem that comes with the use of ICVs to control downhole flow. The number of possibilities in valve settings, along with the rest of operational variables involved in the optimization process, may render the solution unfeasible for field applications. There is the need for quick decision between drilling and which kind of completion to install: conventional or intelligent. Therefore, efficient IWC optimization is also a concern.

The present dissertation focuses on a workflow to identify potential well candidates for IWC and to reduce the number of variables during the optimization of control valves. First, a simplified methodology is proposed to group layers for ICV application, to achieve a completion design that could easily be applied in the field. Then, three control strategies for IWC control and optimization are proposed: one common strategy of water cut (WCUT) monitoring is suggested for ICV (reactive control) and two new strategies (proactive controls) – usually applied to group of wells (SAMPAIO; GASPAR; SCHIOZER, 2019) – are suggested to be applied to a group of layers, to model and control zonal flow, using production parameters in real-time, decreasing the number of variables in the optimization process.

1.1 OBJECTIVES

The objective of this work is to present a new methodology to optimize the control valves with reduction of variables, comparing conventional and intelligent wells, to assess the effectiveness of IWC and its potential application in a scenario of heterogeneous carbonate reservoirs, like the SBPSC.

1.1.1 Specific Objectives

The specific objective of this work is to design a new methodology that:

a) establishes a scenario for IWC application in an expedite way. The methodology will focus on reservoir management through IWC optimization, considering that wells are already positioned (there will be no analysis/optimization of well positioning in the reservoir model);
b) could be replicated and deployed on the field. Operational aspects will be considered to ensure that the methodology could be applied to real case scenarios when considering project design and execution. Well modelling in the reservoir simulator should represent real case behavior;
c) reduces the number of optimization variables. The reduction in optimization variables will reduce computational cost to make the whole process more efficient. This is also in line with objective “b”, so the methodology execution time is compatible with well construction timespan, when considering a full reservoir model.

2 LITERATURE REVIEW

The literature review focus on the main topics of the proposed methodology for this dissertation.

2.1 IWC AND RESERVOIR SIMULATION

IWC and reservoir simulation have a close relationship as simulation plays an important role in evaluating IWC economic gain and estimating future production.

Adeyemo et al. (2009) presented a case study of Agbami field where the IWC data for the first third of the field was used in reservoir simulation, aiding in real-time decision-making, and reviewing the rest of the predicted development plan. The use of IWC allowed for additional oil recovery and better reservoir management to achieve production forecast of the reservoir model. Operationally, there was capital expenditure (CAPEX) reduction through reduction of in-fill drilling or workover operations and operational expenditure (OPEX) reduction by eliminating production logging tool (PLT) runs to analyze individual zonal production/injection.

Yao, Blanco and Alvarez (2020) used reservoir simulation with IWC to improve selective injection in a mature oilfield in Colombia that was already in the beginning of the abandonment campaign. Reservoir simulation allowed the redevelopment of the field, with new strategy for waterflooding, in-fill drilling and well intervention – again, CAPEX reduction - improving oil recovery in 45% compared to their base case.

2.2 QUALITY MAPS AND NPV ANALYSIS

Quality maps can be used as an indicator of parameter quality to help in decision making processes (Fornel and Le Ravalec, 2016) or as visual aid for results analysis. One of the main uses is to analyze optimal well placement in the reservoir as can be seen in Maschio, Nakajima and Schiozer (2008), Le Ravalec (2012) and Fornel and Le Ravalec (2016).

Cavalcante Filho (2005) tested the use of quality maps with different approaches. The "fixed producers" method was intended to save computational time from testing every possible position of a well in the model. Instead of varying the position of one well in several simulations, fixed producers were distributed along the reservoir and only one simulation run was made with all the producers opened. This dissertation proposes a similar approach to generate the quality map, but with all layers working as the fixed producers, to verify in one run which layers are the main contributors to total production of the well.

Avila (2020) discuss the difficulty in assessing the impact of IWC gain if not by economic indicators. The analysis of reservoir indicators as estimated total oil recovery or cost savings by reduction of in-fill drilling depends on assumptions that not necessarily are in accordance with the whole project team, so usually economic parameters such as net present value (NPV) are preferred.

2.3 INTERVAL CONTROL VALVES

The necessity to remote control downhole flow makes ICVs an essential part of an IWC system.

The fidelity to real-life IWC systems is also an issue of concern, if the methodology used in simulation is to be transferred to field operation. Brazilian pre-salt commonly used configuration is a direct-hydraulic control system for the ICVs. A typical direct-hydraulic control system is constituted of “N+1” control lines, where “N” is the number of ICVs. When considering the necessity for downhole chemical injection, for a three-zone (three ICVs) completion design, it would be necessary four hydraulic control lines plus four chemical injection lines (one for each zone and one for the tubing string above the upper production zone), which already represents a challenge for field deployment (RODRIGUES et al., 2018).

The state of the art for IWC is a fully electric downhole control system, as presented by Amjad (2020), eliminating the use of hydraulic lines. Hydraulic control lines are still a limitation for increasing ICV number in a well. There is also the risk of damaging the hydraulic lines and losing IWC functionality during installation of intelligent open-hole completion.

In the work of Schnitzler *et al*. (2015, 2019, 2021) one can observe the evolution of IWC design for a typical well in the Brazilian Pre-salt area, with 2 or 3 zones (therefore, 2 or 3 ICVs) that started with cased hole completion, and it is now migrating to open-hole completion, focused on CAPEX reduction during installation and future workover interventions.

2.3.1 ICV Modelling in a Reservoir Simulator

Reservoir simulation can help identify and understand how ICV could affect oil flow and reservoir sweep. Schnitzler et al. (2021) modelled the flow through a new design of ICV to verify if the valve itself would be a restriction for production in the tubing string.

Many reservoir simulators focus on modelling the flow through porous media, prioritizing overall field behavior over individual wells. This difference between field and wellbore scale usually results in lack of flexibility in commercial software when representing completion equipment. This difficulty in implementing completion tools leads the reservoir engineer in the search for adaptations when modelling wellbore effects. Muradov, Elthaer and Davies (2019) proposed an approach to model Autonomous Flow Control Device (AFCD) through flow performance with manual coding and in-house reservoir simulator.

Some research in reservoir simulation was made by placing one ICV on each layer, generating a higher number of valves per well, as showed in the work of Almeida, Pacheco and Vellasco (2007), Ranjith et al. (2017) and Sampaio, Barreto and Schiozer (2015). While this approach can be effective for individual layer flow analysis, not always this simulation scenario can be replicated on the field due to complex well configuration and high number of parameters to optimize.

The alternative to use multi-segment well functionality is also analyzed by Avila (2020) but, for the specific scenario, different production zones are simulated in separated models. Therefore, the author advises that even with new tools for IWC available in commercial simulators, some level of customization will probably still be necessary to adapt for a particular case.

Besides the modelling of the ICV and how it will behave controlling pressure drop and flow through the valve, research has also been made on optimization of ICV positioning as one can see in Barreto and Schiozer (2015), Goh, Tan and Zhang (2016) and Sampaio, Gildin and Schiozer (2015). ICV positioning can easily turn into an optimization problem of its own, due to the high number of possibilities for quantity and distribution of ICVs in the well.

2.3.2 ICV Control and Optimization

The first thing to consider, when doing a comparative analysis of IWC application, is that conventional completion should have its results optimized before converting the well to IWC, as observed by Barreto, Gaspar and Schiozer (2016) and Morais, Fioravanti and Schiozer (2017), to avoid overestimated results.

WCUT can be measured by surface sensors as Coriolis flowmeters or multiphase flowmeters (MPFM). For subsea wells, there are also subsea multiphase flowmeters (MPFM) that can be deployed right next to the subsea well, eliminating time delay from wellhead through flowline until the production platform. This WCUT data can be used for IWC monitor and control. Arsalan et al. (2015) present developments on downhole water cut measurement but its application depends on completion project design.

Vasper, Mjos and Duong (2016) proposed a proactive control for ICV and an alternative closed loop optimization, based on the produced stream. The closed loop optimization had a smaller increase of optimization parameters as the initial scenario got more complex. The proactive control showed a much higher computational cost.

Besides the usual higher computational cost of optimization when using proactive control with ICVs, there is also the issue of preemptively acting the ICV and the associated uncertainties of defining ICV cycling frequency. Abellan and Noetinger (2010) proposed a methodology for optimizing data acquisition based on information theory that could be used to define ICV cycling strategy, preventing an exaggerated number of cycles that would not aggregate new information in simulation results.

Grebenkin, Muradov and Davies (2015) studied active ICV control and different types of valves. The research focused on simpler on/off valves to reduce the number of optimization parameters. The simulation aimed at maximizing the oil production rate after the peak production period, to minimize the drop in overall field production. They concluded that on/off valves showed results slightly under the optimal solution, but the extra computational effort to use multi-position ICVs, for a small gain, could not be attractive in every scenario. Operationally, on/off ICVs have a simpler design and are more reliable in the long run. Small economic gains using more complex types of ICVs (multi-position or continuous-variable opening) should be thoroughly analyzed and accounted for uncertainties, as future ICV failure and the necessity of well intervention may negatively compensate the small projected economic gain.

De Brito and Durlofsky (2020) were able to apply production control methodologies, used in total well production to individual ICV control, as each ICV were an independent well. Being able to control ICV flow makes the relation of “ICV ratio to well production” similar to “well ratio to field production”, which may allow some customization in ICV control using tools already available for application in wells.

The use of a real time completion design was experimented by Goh, Tan and Zhang (2016) to reduce the dependency of static initial data. The authors based the completion design from single well dynamic modelling and real time decision making during well construction, with more realistic results specially when working with marginal reservoirs. However, the authors alert to the high computational cost of this approach and recommend it to be used in simpler, single-well modelling.

Avila (2020) used an optimization methodology that searches for pressure drops along the well that obey the constraints for commingled production. After establishing the wellhead pressure through adjustment of production choke, the routine verifies if pressure drops along the ICVs and the maximum reservoir drawdown are inside the operational parameters, to allow simultaneous production through different ICVs. This optimization is more focused on simultaneous operation to consequently increase oil recovery, as operational constraints were the main concern in this case. Avila also pointed out that many commercial simulators now have built-in multi-segment well modelling tools but the integration of this tools with optimization of ICV settings is still a challenge. Part of the methodology of the present dissertation is focused exactly on this matter, implementing IWC optimization with the built-in iSegWell package and CMG's black-oil simulator IMEX.

3 METHODOLOGY

This work proposes an efficient methodology for IWC design and optimization, considering operational restrictions for ICV installation. The methodology is divided in two parts, as shown in Figure 2.

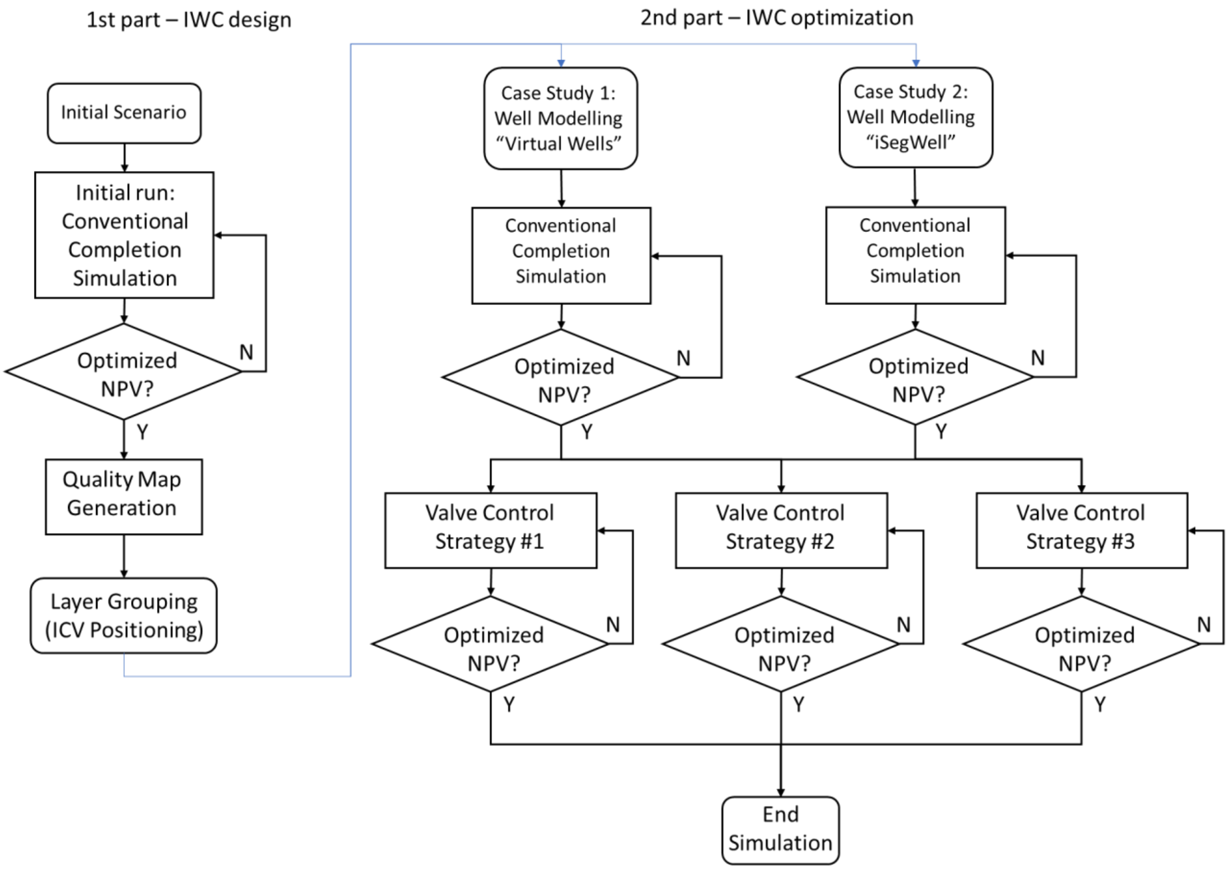

Figure 2 - Proposed methodology for IWC design and optimization.

3.1 IWC DESIGN

IWC design starts with conventional completion simulation and optimization. The results from the initial simulation run are used to generate a quality map to analyze which layers can be grouped together and where to position the ICVs, dividing the production zones in the well.

3.1.1 Conventional Completion Simulation and Optimization

The first step is to run the simulation with all layers open (i.e., perforated) for the producer. This first run with conventional completion must have its NPV optimized before moving to IWC, as observed by Barreto, Gaspar and Schiozer (2016) and Morais, Fioravanti and Schiozer (2017). The optimization of conventional completion is necessary to ensure that the IWC simulation will not generate over-optimistic results when compared to the base case.

3.1.2 Quality Map Generation

The results from the optimized initial run are used to generate a quality map. The quality map should provide inputs for layer grouping and definition of number of ICVs. After the optimization of conventional completion, NPV is analyzed by layer, generating a quality map for the producer well. NPV must be calculated for each layer and normalized by the maximum NPV in the optimized conventional completion to generate the map, similar to a production log profile from a PLT. The deterministic economic scenario used to calculate the NPV is the one suggested in UNISIM-II-D benchmark case study by Santos and Schiozer (2018).

The main objective of the quality map is to allow faster decision making when positioning the ICV, as ICV placement can usually turn into an optimization problem of its own. Optionally, quality maps can be generated as an auxiliary analysis with parameters like cumulative oil production (Np), cumulative water production (Wp), cumulative gas production (Gp), Gas-Oil ratio (GOR) or WCUT.

3.1.3 Layer Grouping and ICV Positioning

The layers are grouped together by analyzing more profitable zones (positive NPV on the quality map) to decide where to position the ICV and maximize profitable production layers. Due to technical restrictions for field application, the maximum number of grouped zones for this work was defined as three, considering a direct-hydraulic control system for the ICV in a vertical producer well. The ICV configuration is similar to the one presented by Schnitzler *et al.* (2015) in Figure 3, with one ICV for each grouped zone.

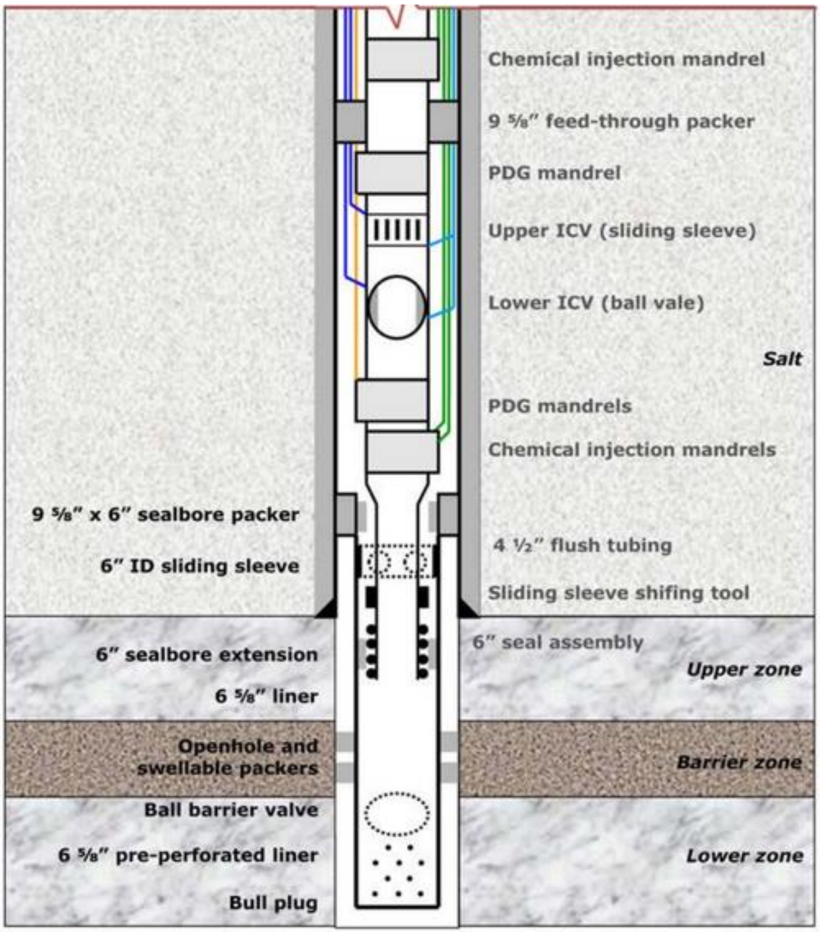

Figure 3 - Typical Brazilian pre-salt IWC design (Schnitzler et al., 2021).

Besides making the scenario more feasible for field applications, these restrictions also help to reduce the number of parameters for the optimization stage. The number of ICV will depend on the existence of low permeability layers – barrier zones – between grouped producer zones.

As previously stated, ICV representation is made by grouping and operating production layers together. This can be implemented in different ways in the simulator, and, in this work, it is discussed in the well modelling stage, during IWC optimization.

3.2 IWC OPTIMIZATION

The second part of the methodology, after the ICVs are in place, is to implement and optimize control strategies for these ICVs, to maximize NPV. In the present work, two alternatives for well modelling in IMEX black-oil simulator are proposed, namely "Case Study 1" with virtual wells and "Case Study 2" with iSegWell toolkit. For each case study, the conventional completion is simulated and optimized to establish its base case, without any ICV operation. Then, three ICV control strategies are proposed for IWC optimization: one reactive approach (strategy #1) based on WCUT limitation and two proactive control strategies based on production guide rates, defined in the simulator, for each zone (strategy #2 and #3). Finally, these strategies are also optimized to obtain the maximum NPV.

3.2.1 Well Modelling

Two types of well modelling are proposed to replicate wellbore effects in the reservoir simulator:

a) use overlapped "virtual wells" for each production zone to emulate zonal flow: with virtual "single zone" producer wells positioned in the same location tied together to a production group, one can emulate the real producer well. Usually this is a simplified workaround for the lack of adequate tools in reservoir simulators to represent completion equipment and wellbore effects. This is the representation used in "Case Study 1". Figure 4 shows an example of layer grouping, resulting in two production zones (one ICV for each zone) with virtual wells "P1" and "P2", where each producer well accesses a different producer zone.

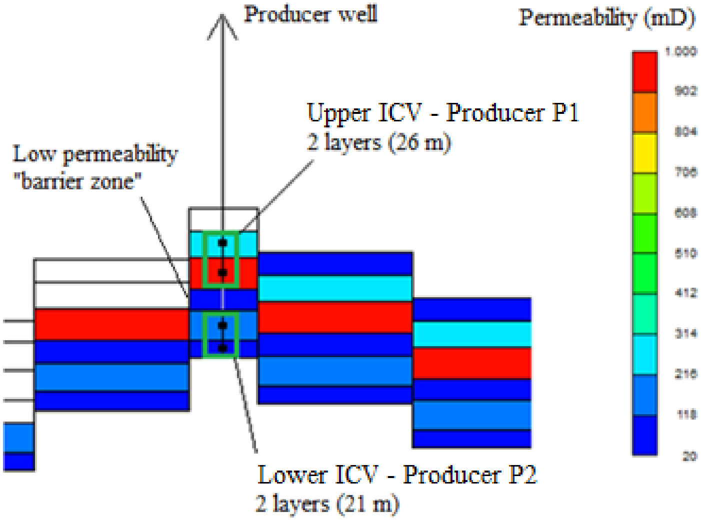

Figure 4 - Example of well modelling with virtual wells.

b) use dedicated completion equipment modelling tools like iSegWell: the case studies are implemented using IMEX black-oil simulator, by Computer Modelling Group (CMG), which has a suite for intelligent completion simulation called "Intelligent Segmented Wells (iSegWell)". The well is modelled with IWC using iSegWell structure and each zone is assigned back to a conventional "virtual producer well" in IMEX (the same structure with virtual wells tied to a production group of Case Study 1 presented in 'a'). The difference, in this case, is that iSegWell is responsible for well modelling and wellbore effects while the "conventional" part of IMEX will be used only to apply control strategies for the ICVs and totalize the production stream in a production group. This is the representation used in the "Case Study 2".

To allow the use of "production guide rate" feature either with the GUIDE or the INGUIDE keyword (see strategies #2 and #3 respectively, in section 3.3) available in IMEX, it is mandatory to have a production group defined, as both keywords are only applicable to wells and not to individual layers or control lumps in the simulator. That is why, even with the use of iSegWell toolkit, production must be assigned back to virtual wells in Case Study 2.

3.2.2 Valve Control Strategies

The proposed control strategies for the ICVs are as follows:

a) strategy #1: simulate On/Off ICV operation based on WCUT limit. This type of reactive control uses a fixed threshold for the WCUT, above which the ICV is closed. Control types can be modified from on/off ICV to multi-position ICV if desired, with the associated extra computational time. Multi-position and continuous variable opening ICV should allow for a finer flow control, but the addition of intermediate positions in the valve would increase computational effort during optimization processes in this scenario. In a more complex scenario, the use of a reduced-order model could be considered (JANSEN; DURLOFSKY, 2017), especially if using a full-scale reservoir model;

b) strategy #2: simulate multi-position or continuously variable ICV with proactive ICV operation, based on production guide rates provided by the user and a priority formula. This control strategy uses the *GUIDE keyword of the CMG simulator. The production guide rates are provided for each time step, acting preemptively before water breakthrough. This is expected to have higher computational cost as the guide rates will be optimized for each time step, increasing the number of optimization variables. The apportionment of production is made using a priority formula as shown in Equation 1 below:

$$Priority(iw) = \frac{A_0(ig) + \sum_{i=1}^{nph} A_i(ig) * Q_i(iw)}{B_0(ig) + \sum_{i=1}^{nph} B_i(ig) * Q_i(iw)} \tag{1}$$

where *iw* is the priority index for an ICV contributing to a targeted group (*ig*) (entire well in this work), A_i and B_i (i=0, nph) are the weighting coefficients for the numerator and denominator, respectively. All the weighting coefficients are non-negative real numbers and at least one A_i and one B_i must be non-zero (IMEX User's Guide, 2022). The weighting coefficients (for production, nph is equal to 6) are showed in Table 1.

Table 1 - Priority formula coefficients.

i	**CONST**	***STO**	***STG**	***STW**	***STS**	***STL**	***BHF**
NUMER	A_0	A_1	A_2	A_3	A_4	A_5	A_6
DENOM	B_0	B_1	B_2	B_3	B_4	B_5	B_6

where STO, STG, STW, STS, STL and BHF are oil, gas, water, solvent, liquid streams and bottom-hole fluid rates, respectively. To prioritize wells with lower WCUTs, the coefficients A_1, A_3 and B_3 are supplied.

c) strategy #3: simulate multi-position or continuously variable ICV with proactive ICV operation, based on internal production guide rates provided by the simulator. As the guide rates are generated internally by the simulator, there is no need to add this guide rates as optimization parameters, therefore reducing the number of variables to optimize. The guide rates vary in real-time according to production parameters of the field, acting preemptively as in strategy #2. The commercial simulator can use internal guide rates for apportioning production rate among wells in a group (IMEX User's Guide, 2022). This control uses the *INGUIDE keyword of CMG simulator.

The novelty of this work is using both GUIDE and INGUIDE keywords in strategy #2 and #3 to control ICVs as “virtual wells”. Both keywords only work to apportion production among wells inside a production group. The representation of “ICVs in a well” as “virtual wells in a group” allows the use of GUIDE/INGUIDE to control zonal flow from ICVs to the well, as it would do for several wells to the production group. Thus, the “ICV production versus total well production” dynamic is implemented as “virtual well production versus total production group”.

All three control strategies are also optimized for maximum NPV as the last step of the methodology.

4 CASE STUDIES

Case studies were made with the application of the previous methodology in a reservoir model based on a Brazilian offshore field. As mentioned before about ICV positioning, optimal well placement also frequently develops into an optimization problem of its own, making it impossible to test all possible well positions, as stated by Fornel and Le Ravalec (2016). The present dissertation uses a five-spot configuration in a reservoir section extracted from UNISIM-II benchmark for initial condition definition and focus on the expedite proposed workflow.

4.1 INITIAL SCENARIO

The basis for both case studies is the same and is based on the UNISIM-II benchmark. This section details the initial scenario (with the reservoir model, the operational constraints, the economic scenario for NPV calculation and the optimization constraints), the initial run and its NPV optimization, with the resulting quality map and layer grouping.

4.1.1 Reservoir Model

The methodology was applied to an extracted sector of the UNISIM-II-D benchmark model (Santos and Schiozer, 2018), which is a synthetic dual-permeability model with properties similar to the Brazilian pre-salt reservoirs, with thick vertical net pay and highly heterogeneous. A grid section of 11 x 11 x 30 blocks was extracted from the full model. The wells were positioned in a five-spot configuration, with water injection as secondary recovery method. Figure 5 shows the reservoir section with the five-spot configuration for the wells and the effective permeability in mD – “i” direction.

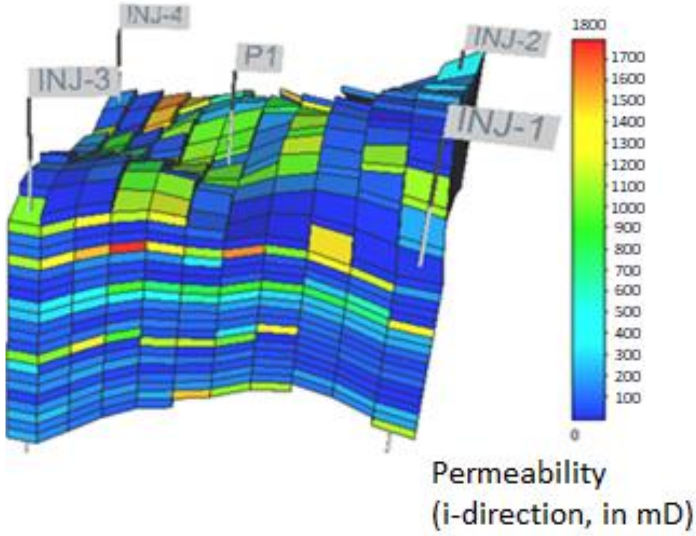

Figure 5 - Reservoir section – 11x11x30 blocks.

Injector wells were positioned on the corners of the sector and all the layers were completed for water injection. The producer well was positioned in the center of the sector with all the layers completed, for the conventional completion simulation run. Figure 6 shows the cross-section of the producer well, where one can observe that only the layers from 10 to 25 are inside active blocks in this region and how the permeability varies along the vertical extension of the well.

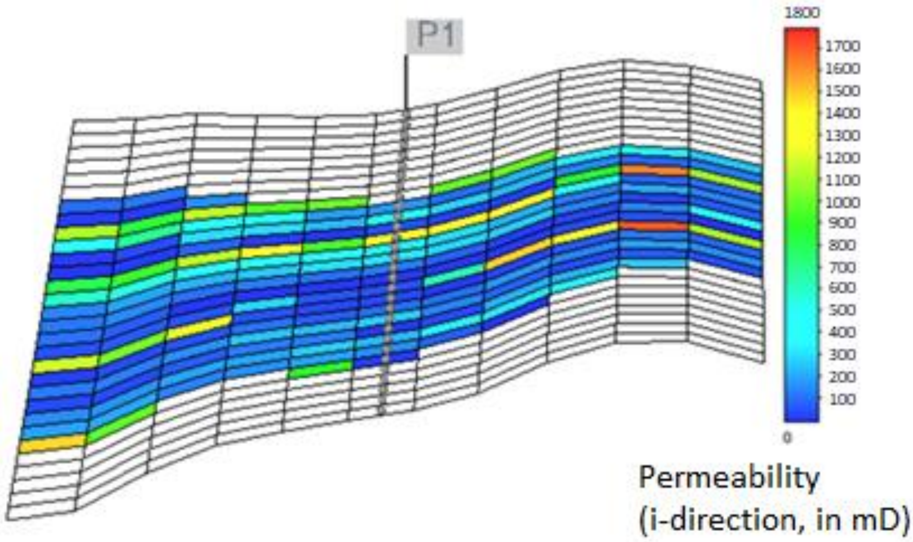

Figure 6 - Cross-section of the producer well showing permeability variation.

4.1.2 Operational Constraints

The operational constraints for the simulation were also based on the UNISIM-II-D benchmark model (Santos and Schiozer, 2018) and are listed in Table 2.

Table 2 - Well operational constraints from UNISIM-II benchmark (Santos and Schiozer, 2018).

	Producer	**Injector**	**Unit**
Water rate	-	max 5000 (total) max 1250 (each well)	m^3/d
Liquid rate	max 3000	-	m^3/d
BHP	min 275 max 450	max 480	kgf/cm^2

A trigger was set in place to start the water injection through the injector wells when the BHP of the producer falls to 275 kgf/cm^2 (min. BHP for producers established in the benchmark). With multiple producer wells, injection can start when the first producer drops below a specified pressure or a time window can be used (for example, after “n” years of production, which can be optimized). Initially, WCUT monitoring in the producer was set to 0.95 and GOR monitoring limited to 750 m^3/m^3 for the first simulation run.

4.1.3 Economic Scenario

The deterministic economic scenario used was the one proposed by UNISIM-II-D benchmark. Platform investment in the benchmark considers 32 wells connected to the platform. In this work, platform investment was reduced proportionally to the number of wells in the five-spot configuration, to a value of 175 MM USD. It is also important to notice that the Brent Crude Oil Price considered in the study was US$ 41.00 / barrel, based on the UNISIM-II-D benchmark. Economic parameters, from UNISIM-II-D, are presented in Table 3.

Table 3 - Economic parameters from UNISIM-II benchmark (Santos and Schiozer, 2018).

Parameter	**Value**	**Unit**
Oil price	257.9	USD/m^3
Gas price	0.026	USD/m^3
Oil production cost	48.57	USD/m^3
Gas production cost	0.013	USD/m^3
Water production cost	4.86	USD/m^3
Water injection cost	4.86	USD/m^3
Drilling and completion of vertical well	50.34	MM USD
Connection well-platform	13.30	MM USD
1^{st} ICV (each well)	1.00	MM USD

Additional ICV (each well)	0.30	MM USD/ICV
Abandonment cost	4.13	MM USD
Annual discount rate	9%	-
Corporate tax rate	34%	-
Social tax rate – over gross revenue	9.25%	-
Royalties rate – over gross revenue	10%	-

4.1.4 Optimization Constraints

The conventional completion configuration was optimized with CMOST® software, from the CMG suite, using Particle Swarm Optimization (PSO) to maximize the NPV. The parameters used in PSO are presented in Table 4. The default values provided by CMOST were used, except for the population size that was increased to 50, due to the expected high number of simulations.

Table 4 - PSO parameters.

Parameter	Value
Inertia Weight	0.7298
Cognition Component (C1)	1.49618
Social Component (C2)	1.49618
Population Size	50

The optimization constraints are presented in Table 5.

Table 5 - Optimization parameters from UNISIM-II benchmark.

Parameter	Initial value	Min. value	Max. value	Unit
BHP Injector	480	0	480	kgf/cm^2
BHP Producer	275	275	450	kgf/cm^2
BHP Producer - Inj Trigger	275	275	450	kgf/cm^2
Oil prod. rate	3000	10	3000	m³/d
Water inj. rate	1250	0	1250	m³/d
WCUT	0,95	0,90	0,99	-

The optimization for each proposed strategy with IWC is also made using PSO with CMOST and the parameters from Table 4 and Table 5. For the initial run and Case Study 1, there was not a fixed criteria for minimum number of experiments. Optimization was set with a high number of experiments and the processes were monitored until it was detected a stabilization tendency. For Case Study 2, a fixed criteria was defined as is shown in Equation 2.

$$number\_of\_experiments = 400 * number\_of\_variables \qquad (2)$$

Consequently, computational cost for each control strategy is highly dependent on the number of optimization variables.

4.1.5 Initial Run

For the initial conventional completion simulation, the producer well was completed (perforated) in layers 10 to 25, corresponding to the active blocks in the grid. The simulation was run and optimized with the operational and optimization constraints mentioned previously.

4.1.6 Quality Map Generation and Layer Grouping

After the optimization of conventional completion, a “NPV x layer” quality map was generated for the producer well. The map analysis allowed for identification of potential independent production zones, to define the number of ICVs in the producer well.

4.2 CASE STUDY 1 – WELL MODELLING WITH “VIRTUAL WELLS”

The Case Study 1 used virtual wells to simulate each production zone separately. Upper zone production (layers 11 to 15) was assigned to well “P1” and lower zone production (layers 21 to 23) to well “P2”. Both “virtual wells” were placed overlapped, in the center of the reservoir, and their production was tied to the same production group to compute the total production of both zones.

For the second part of the methodology, IWC optimization, the first step would be to simulate the conventional completion to establish the base case for the case study. As this scenario is very similar to the initial run with conventional completion, i.e., there is no significant change in wellbore effects, the only difference is the representation of ICVs with virtual wells, the optimized initial run is used as the base case for Case Study 1.

For the three proposed control strategies, optimization parameters were adapted to consider both virtual wells P1 and P2 for WCUT monitoring, as is shown in Table 6. Optimization of BHP trigger was discarded based on the optimization of the initial run and injection wells were defined to start injection when the BHP of the producer well falls under 450 kgf/cm^2.

Table 6 – Optimization parameters with virtual wells.

Parameter	Initial value	Min. value	Max. value	Unit
BHP Injector	480	0	480	kgf/cm^2
BHP P1	275	275	450	kgf/cm^2
BHP P2	275	275	450	kgf/cm^2
Oil prod. rate	3000	10	3000	m^3/d
Water inj. rate	1250	0	1250	m^3/d
WCUT P1	0.95	0.90	0.99	-
WCUT P2	0.95	0.90	0.99	-

4.2.1 Strategy #1 – Reactive WCUT Monitoring

ICV control for strategy #1 was based on a reactive approach. A trigger setting was designed for WCUT monitoring. The WCUT trigger was initially set at 95% to shut the virtual well and this parameter was later optimized. In this case, all seven variables from Table 6 were used in the optimization process with a total of 10000 simulations run.

4.2.2 Strategy #2 – Proactive User-Provided Guide Rates

Strategy 2 uses guide rates provided by the user to control the production guide rate of each zone, by controlling each virtual well. These guide rates change every time step for optimal results. Production rates were apportioned with the priority formula (Equation 1), prioritizing the virtual well with lowest WCUT in each time step.

Considering two virtual wells and a thirty-year production period (operating the ICVs every year), there are sixty guide rates to optimize adding up to the seven optimization variables from Table 6, for a total of 67 variables in the optimization stage. The optimization for this strategy was made with 15000 simulations run.

4.2.3 Strategy #3 – Proactive Internal Guide Rates

In strategy 3, the guide rates were generated internally by the simulator in real time, for every time step. Production rates were apportioned with the priority formula (Equation 1) as in strategy #2. Compared to a classic proactive control of opening and closing ICV through the productive life of the well (as seen in strategy 2), this strategy significantly reduced the optimization parameters. Even though being a proactive strategy and using real-time data, optimization scenario was the same as strategy #1 with seven optimization parameters from Table 6 and 10000 experiments.

4.3 CASE STUDY 2 – WELL MODELLING USING “ISEGWELL”

Case Study 2 was originally planned to be made with a full-field reservoir, using the UNISIM-II-H benchmark, focusing on the 20-year period available in the model dedicated to production strategy development and reservoir management. During the development of Case Study 1, it was observed that purely using virtual wells would make the BHPs of both virtual wells uncoupled (more details in section 5.2.1.5). Therefore, the need for a general solution demanded more refined well modelling before applying this methodology to a full-field model, changing the focus of Case Study 2 to improvement in IWC modelling with iSegWell.

The iSegWell package works as an extra layer over the conventional well declaration in IMEX. Figure 7 shows an overview of the well modelling with IMEX standard structure and the interaction with iSegWell.

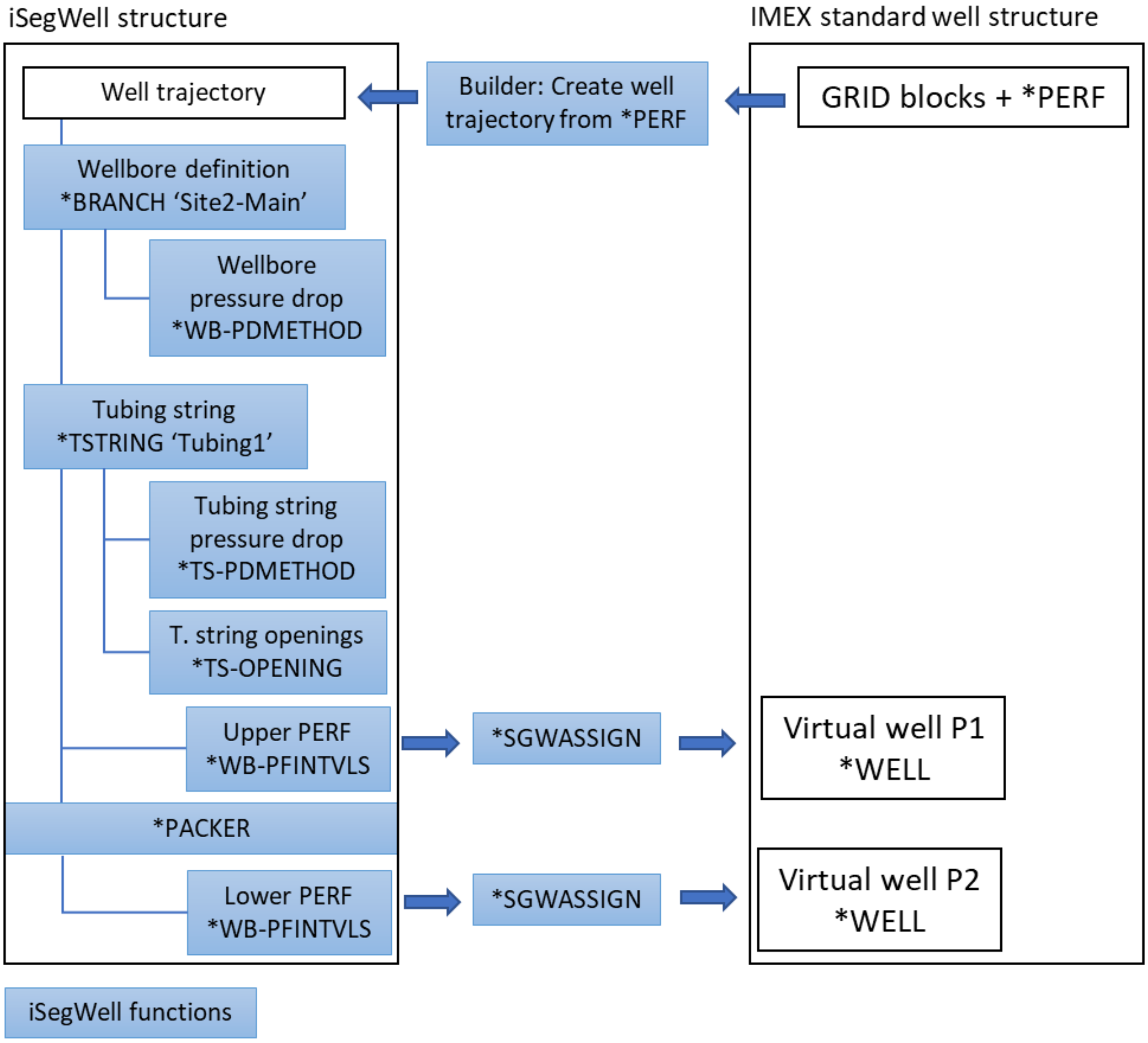

Figure 7 - Overview of IMEX and iSegWell structures in Case Study 2.

The first step is to create a well trajectory from the reservoir grid. IMEX standard structure for well declaration consists of reservoir grid blocks where the user must set the perforations (through the *PERF keyword) on the desired layers to establish a flow path from the reservoir to the well. On the other hand, iSegWell uses a more detailed trajectory through entry/exit points in each block with reference to "measured depth" (MD), like real drilling trajectory. CMG's Builder was used to create the well trajectory and correlate the reservoir grid to block boundaries. An extract of the trajectory can be seen in Figure 8, with the correlation from conventional User Block Address (UBA) to measured coordinates and measured depths for entry and exit points in each block.

```
WB-BLOCKBDYS 'Site2-Main'
BEGIN
** UBA         x-entry      y-entry      z-entry      md-entry        x-exit       y-exit       z-exit       md-exit
6 6 1     312864.40    7481900.70    4734.81      4734.81        312863.84    7481900.19    4740.28      4740.38
6 6 2     312863.84    7481900.19    4740.28      4740.38        312862.73    7481899.17    4745.77      4746.08
6 6 3     312862.73    7481899.17    4745.77      4746.08        312861.61    7481898.15    4751.26      4751.77
6 6 4     312861.61    7481898.15    4751.26      4751.77        312860.49    7481897.13    4756.75      4757.47
6 6 5     312860.49    7481897.13    4756.75      4757.47        312859.36    7481896.11    4762.25      4763.17
6 6 6     312859.36    7481896.11    4762.25      4763.17        312858.24    7481895.09    4767.74      4768.87
6 6 7     312858.24    7481895.09    4767.74      4768.87        312857.12    7481894.07    4773.23      4774.56
6 6 8     312857.12    7481894.07    4773.23      4774.56        312855.99    7481893.05    4778.72      4780.26
6 6 9     312855.99    7481893.05    4778.72      4780.26        312854.86    7481892.03    4784.21      4785.96
```

Figure 8 - Extract of block boundaries and well trajectory for Case Study 2.

With the block boundaries set, the next step was to set the flow paths for each production zone, with the perforated intervals in each zone to the main wellbore branch. A packer was set to isolate the zones, so upper zone production was set to flow through the main wellbore, while a tubing string was set as the flow path to the lower zone. Figure 9 shows a representation of the final wellbore scheme for Case Study 2.

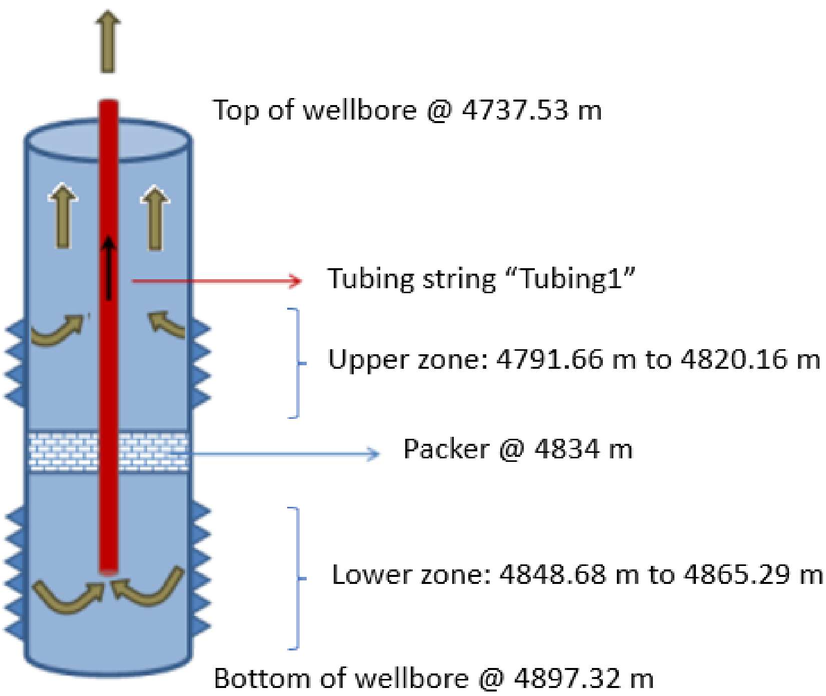

Figure 9 - Wellbore scheme for producer well with iSegWell structure (adapted from IMEX User Manual, 2021).

Pressure drop methods for wellbore and tubing string were defined as 1.32 psi/m gradient. Tubing string was set at the top of the lower zone (4848.68 m) and it was left fully open at the bottom of the string, without any pressure drop through it. Productivity indexes for the perforated intervals and for the producer well were set at the default value of 1.0.

The last step was to assign each perforated interval in the wellbore back to a virtual well in the standard structure with *SWGASSIGN keyword. Similar to Case Study 1, upper zone was assigned to virtual producer “P1” and lower zone to virtual producer “P2”. Both virtual wells also tied to the same production group to totalize production and enable control of the ICVs through GUIDE and INGUIDE with strategies #2 and #3, respectively.

4.3.1 Conventional Completion Simulation and Optimization

Differently from Case Study 1, there were significant changes in wellbore modelling in Case Study 2 when compared to the conventional completion from the initial run, due to the use of iSegWell toolkit. To make a fair comparison, the changes implemented in wellbore modelling for Case Study 2 were also applied to conventional completion. The number and position of the ICVs were kept the same, based on the quality map of the initial run, as the change in wellbore modelling would not qualitatively affect flow distribution along the layers.

The base case was rerun with iSegWell and reoptimized to establish the base NPV for this scenario. Table 7 shows the optimization parameters for the conventional completion with iSegWell. “Oil production rate” was removed as a parameter from optimization and kept only as maximum operational constraint for the producer well, as flow rates were controlled by BHP. Number of experiments was set to 1600 as defined in Equation 2.

Table 7 - Optimization parameters for conventional completion with iSegWell.

Parameter	Initial value	Min. value	Max. value	Unit
BHP Injector	480	0	480	kgf/cm^2
BHP Producer	275	275	450	kgf/cm^2
Water inj. rate	1250	0	1250	m^3/d
WCUT Producer	0.95	0.90	0.99	-

4.3.2 Valve Control Strategies for Case Study 2

Valve control strategies for Case Study 2 were the same as applied to Case Study 1. The difference was in the optimization parameters, where “oil production rate” was removed like in the base case for this Case Study.

Table 8 shows the parameters for strategies #1 and #3 for Case Study 2 with five optimization parameters and number of experiments set to 2000 as defined by Equation 2. For strategy #2, it is the same as Case Study 1, where the GUIDE rates need to be optimized, adding sixty extra optimization parameters (from 30-year production of operating two ICVs every year) to the ones defined in Table 8, to a total of sixty-five optimization parameters. Strategy #2 continues to have higher computational cost with 26000 experiments as defined by Equation 2.

Table 8 - Optimization parameters for strategies #1 and #3 in Case Study 2.

Parameter	**Initial value**	**Min. value**	**Max. value**	**Unit**
BHP Injector	480	0	480	kgf/cm^2
BHP Producer	275	275	450	kgf/cm^2
Water inj. rate	1250	0	1250	m^3/d
WCUT P1	0.95	0.90	0.99	-
WCUT P2	0.95	0.90	0.99	

5 RESULTS

This chapter presents the main results of the proposed methodology applied to case studies mentioned in the previous chapter.

5.1 RESULTS FOR IWC DESIGN

The results for the initial run with conventional completion before and after the optimization of NPV, with the resulting quality map and definition of layer grouping are presented in this section.

5.1.1 Initial Run

Initially, the producer well was closing after 16 years of production for breaking the WCUT limit of 95%. The objective function in the optimization process was set to maximize NPV, which increased the WCUT limit to 99% and extended production time until end of simulation period. As can be observed in Figure 10, Np slightly increased and Wp increased, due to the extension of production time. Extra income from oil production compensated water production costs.

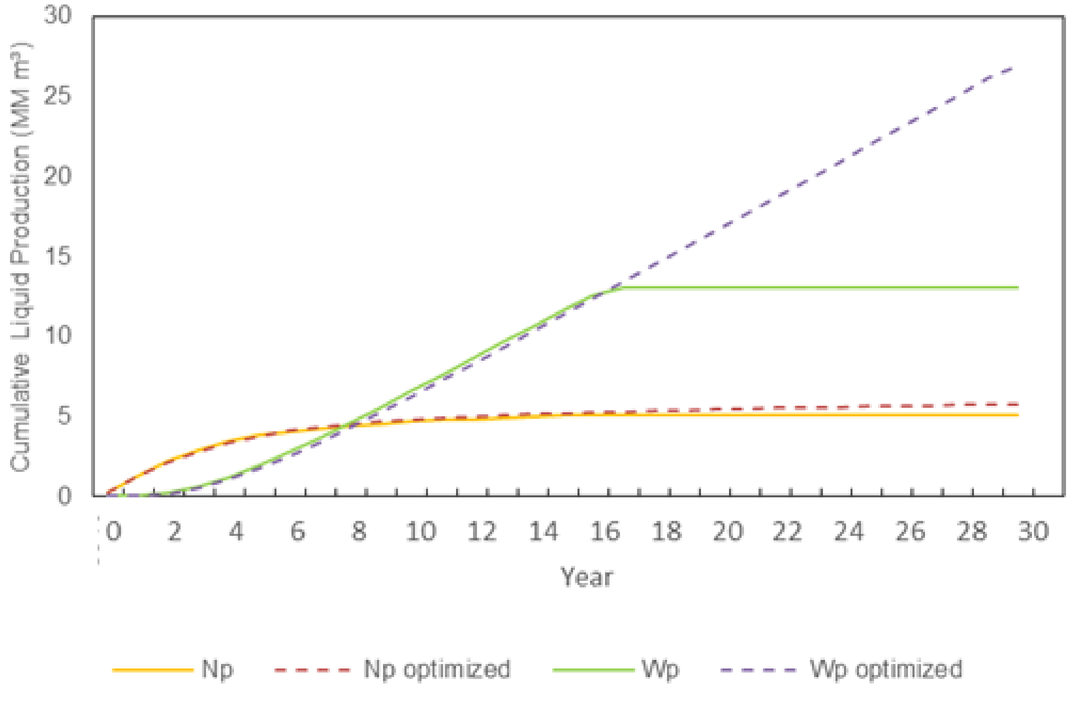

Figure 10 - Oil and water production for conventional completion in the initial run.

The optimized NPV obtained for the initial run was 65.41 MM USD.

5.1.2 Quality Map Generation and Layer Grouping

With the optimized results from the initial run with conventional completion, NPV was analyzed for the producer well. The NPV analysis was broken down by layers to generate the quality map of the well and identify potential candidates for layer grouping. Figure 11 presents the NPV by layer, normalized by the highest NPV value from layer 13.

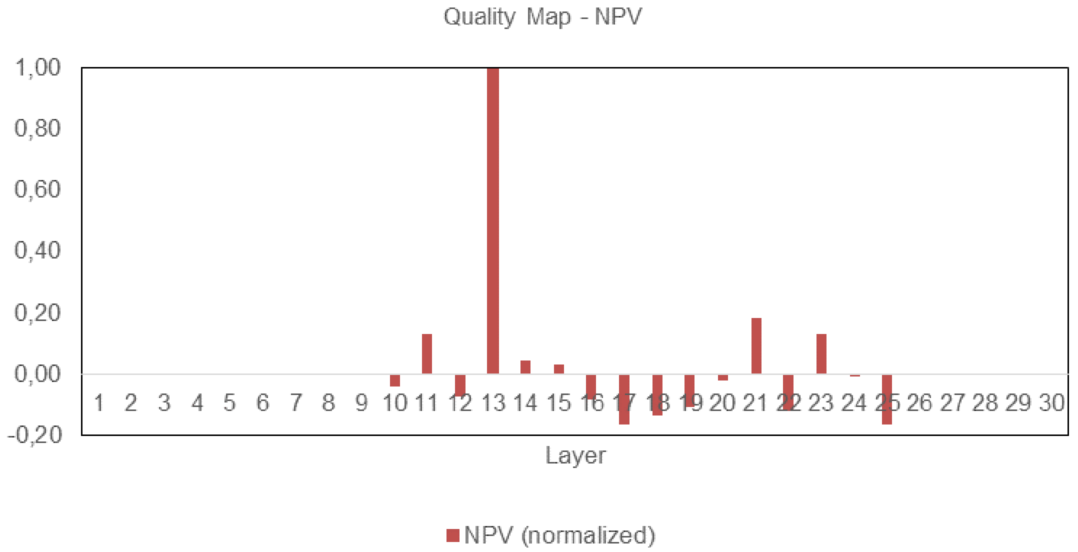

Figure 11 - NPV - normalized by maximum value.

Considering only the active blocks from layers 10 to 25 and the NPV results from Figure 11 , the layers were grouped in 2 zones:

- Upper zone – upper ICV: from layer 11 to 15.
- Lower zone – lower ICV: from layer 21 to 23.

Field restrictions were considered for a barrier zone of 5 layers (layers 16 to 20) to set a production packer between the two producer zones. The section to be considered a barrier zone must have low vertical permeability values, to prevent crossflow between zones through the reservoir. Figure 12 shows the final diagram for setting completion equipment.

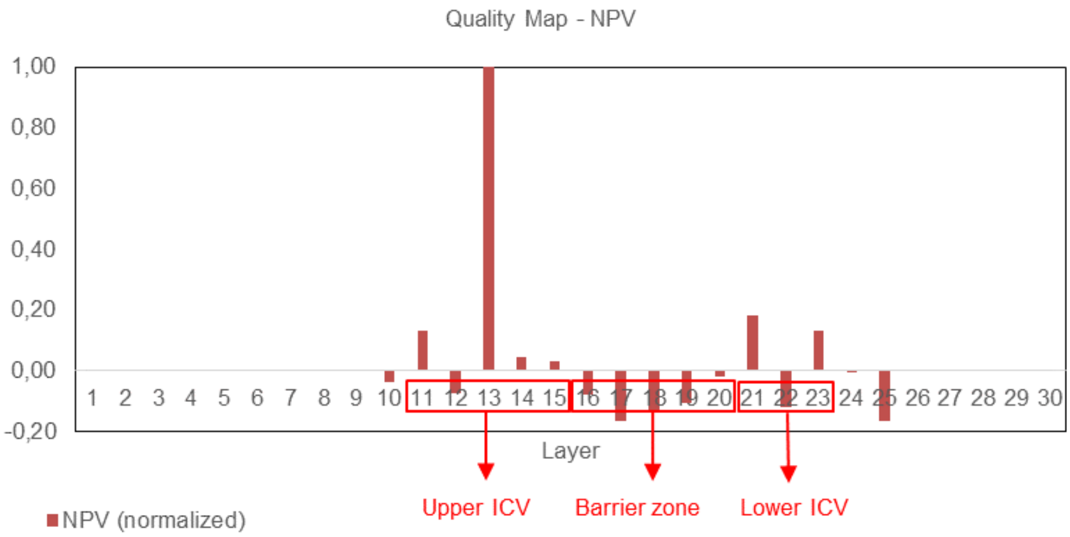

Figure 12 - Position of completion equipment based on quality map.

5.2 RESULTS FOR IWC OPTIMIZATION

After optimizing the initial run and defining the grouped zones and number of ICVs, this section presents the results for implementation of well modelling and optimization of the control strategies proposed in the methodology.

5.2.1 Case Study 1

The base case for comparison in Case Study 1 was the optimized initial run with conventional completion. Results from this section are all compared to the base case.

5.2.1.1 Challenges during development of Case Study 1

During the development of Case Study 1, it was observed that the BHP of both wells P1 and P2 were unlinked to each other, as can be seen in Figure 13.

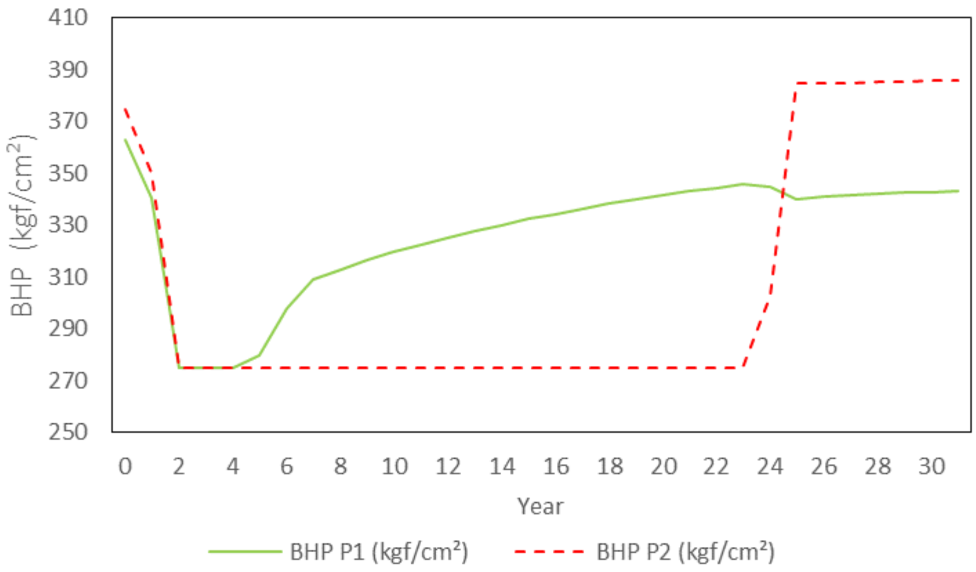

Figure 13 - BHP of P1 (upper zone) and P2 (lower zone)

The simulator did not understand both virtual wells as being the same – real – well. Figure 13 shows different values for "BHP P1" and "BHP P2" as would occur if the production zones (in this case, virtual wells) were completely independent, completely unrelated to what was originally intended. It was necessary to find a way to couple both wells together and this was the main difficulty in the development of Case Study 1. Two trigger variables were used in the simulator to tie both BHPs together and implemented in all strategies in Case Study 1. Considering the BHP from P1 as the most restrictive condition in this case, BHP from P2 was targeted to follow BHP values from P1.

Figure 14 presents BHP of both zones (P1 and P2) linked to each other, after implementation of the trigger variables.

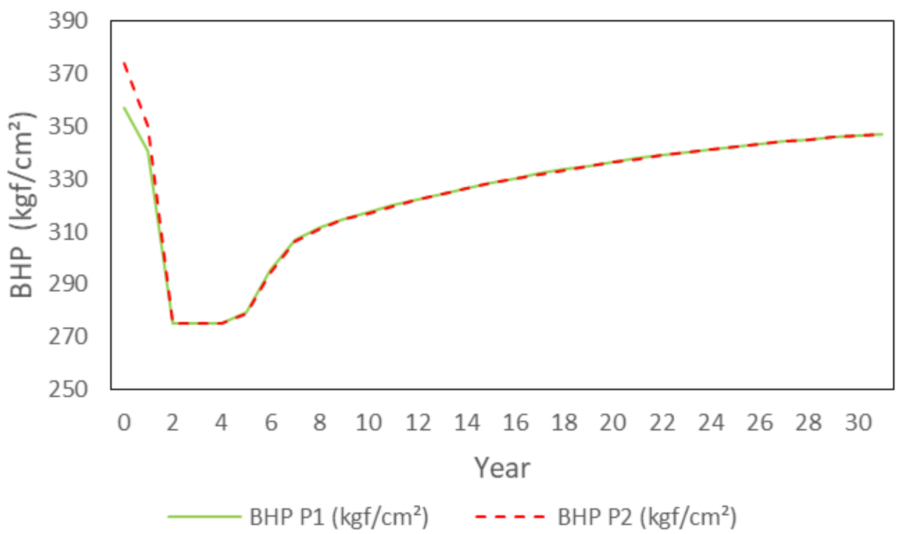

Figure 14 - BHP of P1 (upper ICV) and P2 (lower ICV) after coupling.

This was a specific solution for a simple scenario that would not be feasible considering various well-to-well interactions in a full-field model. A restriction in a well could interfere with another well or events like the beginning of production of a new well could generate a chain reaction of interferences that would make this solution invalid. These particularities led to the search of a better solution using iSegWell in Case Study 2.

It is also worth mentioning that, as BHP of P2 was targeted to follow BHP of P1, it was later observed that the optimization of BHP from P2 did not have any real effect on production, because after the simulation had started, no matter the initial value of BHP from P2, it would converge to the same as P1.

5.2.1.2 Results for strategy #1

Results for optimized strategy #1 with virtual wells and reactive approach with WCUT monitoring compared to the base case are shown in Figure 15.

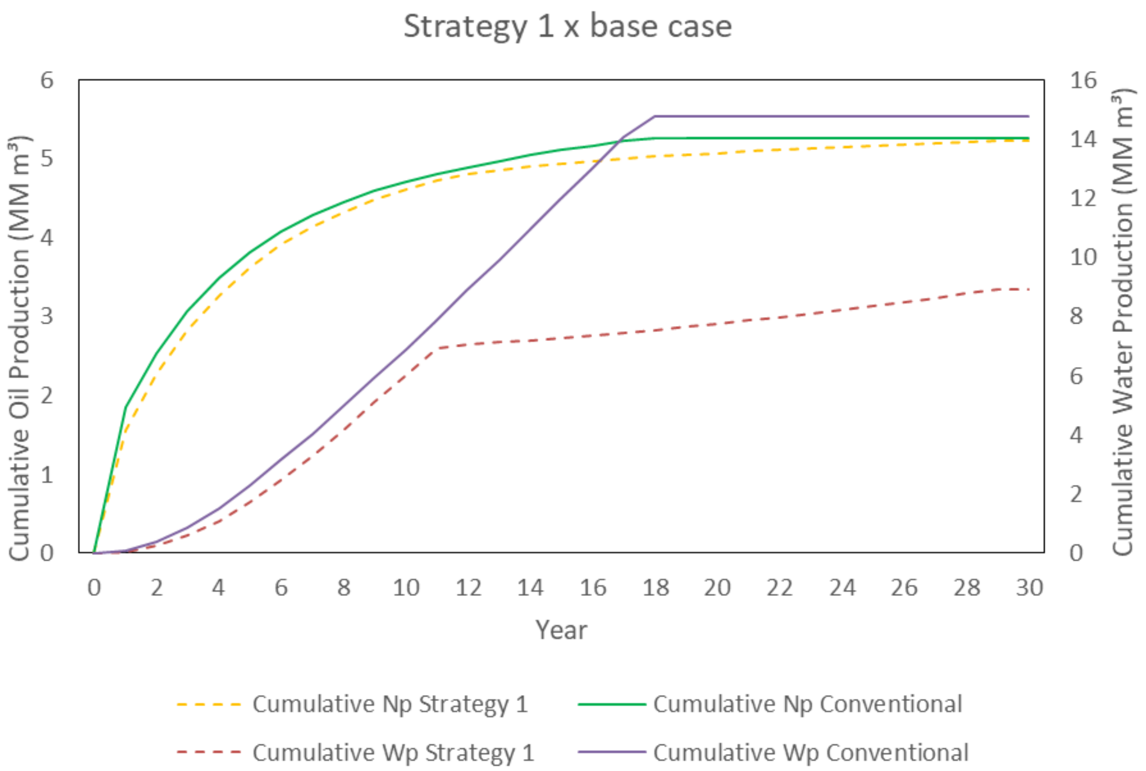

Figure 15 - Oil and water production for strategy #1 with virtual wells, compared to the base case.

The reactive approach closes the upper ICV (virtual well P1) due to water breakthrough after eleven years of production, and the lower ICV (virtual well P2) stays open. There is a major reduction and a delay in the cumulative water production compared to the conventional completion, with a minor loss in oil production. In this case, with a thirty-year horizon, the lower ICV did not closed, as the WCUT limit was not reached. When looking at field application, this result could lead to a simplification in the completion project, eliminating the lower ICV and reducing equipment cost. However, the lower ICV was not removed in this study, for a more general approach and to perform a fair comparison with other strategies.

The calculated NPV in this scenario is 62.46 MM USD, 4.51% lower than the base case, influenced mainly by the additional investment in IWC. Economic gain was not high enough to compensate the cost of ICVs.

Table 9 presents the optimized parameters for strategy #1 with virtual wells.

Table 9 - Optimized parameters for strategy #1 with virtual wells.

Parameter	**Value**	**Unit**
BHP Injector	480	kgf/cm^2
BHP P1	275.73	kgf/cm^2
BHP P2	275.73	kgf/cm^2
BHP Producer - Inj Trigger	450	kgf/cm^2
Oil prod. rate	3000	m^3/d
Water inj. rate	797.77	m^3/d
WCUT – ICVs	0.9339	-

5.2.1.3 Results for strategy #2

Strategy #2 uses guide rates provided by the user to control the oil rate of each zone, by controlling each virtual well. While this allows for proactive control, acting the ICV before water breakthrough, it also significantly increased the number of optimization variables, as the guide rates changed in every time step.

Figure 16 shows the cumulative oil and water production for strategy #2. There is a small gain in Np with a reduction and delay in Wp like strategy #1, resulting in a NPV of 68.91 MM USD, 5.35% higher than the base case.

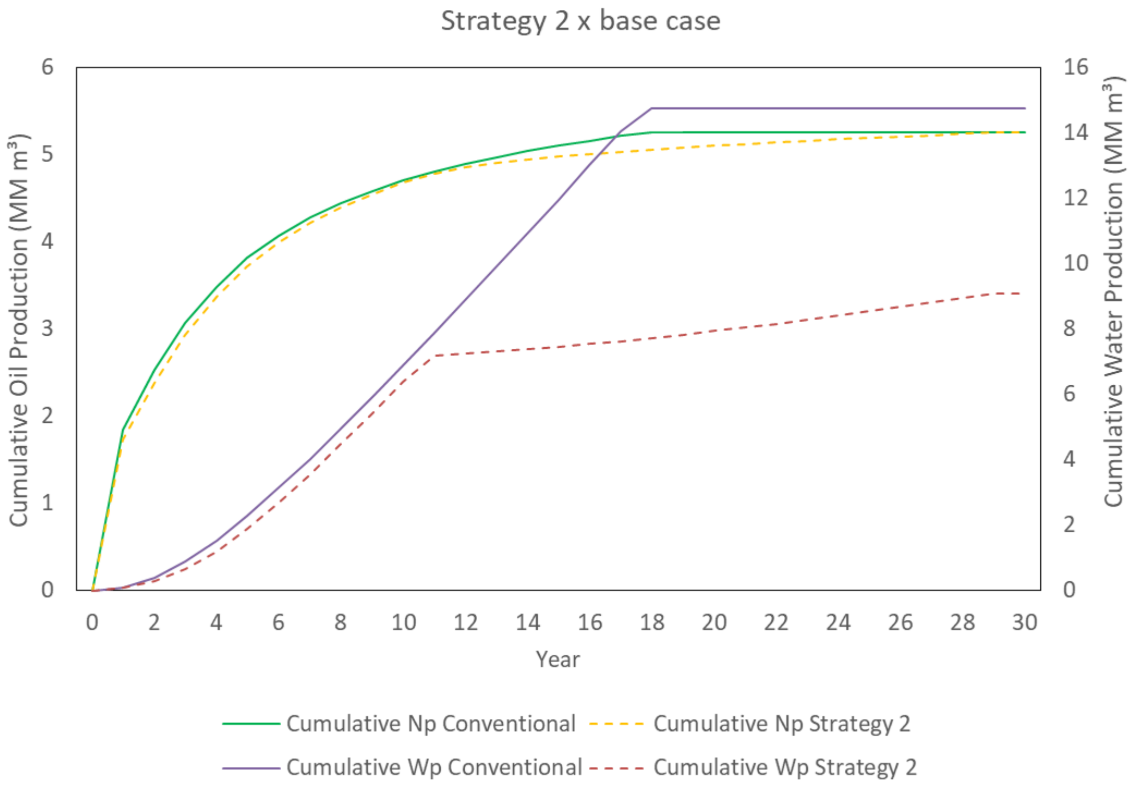

Figure 16 - Oil and water production for strategy #2 with virtual wells, compared to the base case.

Table 10 shows the optimized parameters for strategy #2.

Table 10 - Optimized parameters for strategy #2 with virtual wells.

Parameter	**Value**	**Unit**
BHP Injector	479.99	kgf/cm^2
BHP P1	275	kgf/cm^2
BHP P2	275	kgf/cm^2
BHP Producer - Inj Trigger	439.48	kgf/cm^2
Water inj. rate	829.38	m^3/d
WCUT – Upper ICV	0.9379	-
WCUT – Lower ICV	0.9835	-

Additional to the parameters on Table 10, there were also 60 more optimization variables in this strategy (30 guide rates for oil production in each zone, that are not shown here as they are not comparable to any other parameter from strategies #1 or #3). Therefore, this is the strategy with the highest computational cost.

5.2.1.4 Results for strategy #3

Strategy #3 used guide rates provided internally, in real-time, by the simulator. This also allowed for proactive control as it acted the ICV in each time step, as seen in strategy #2, but without adding optimization variables for the guide rates in every time step, so optimization stage was equal to strategy #1 in computational cost.

Figure 17 shows the cumulative oil and water productions for strategy #3, compared to the base case. NPV with this strategy is 69.63 MM USD, 6.45% higher than the base case and the best result among the proposed strategies.

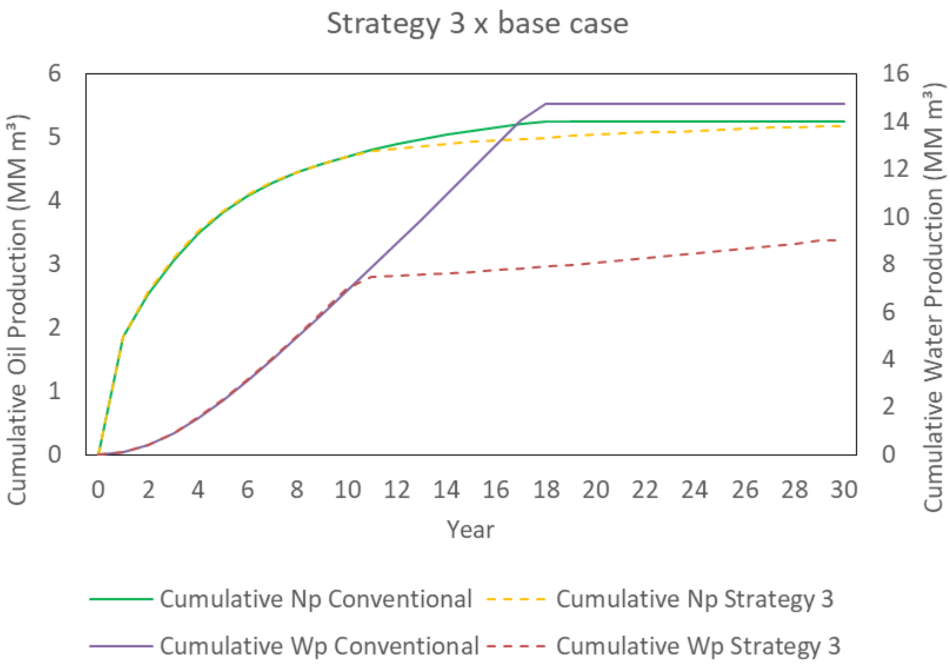

Figure 17 - Oil and water production for strategy #3 with virtual wells, compared to the base case.

Table 11 presents the optimized parameters for Strategy 3. In this case, only seven variables were used in the optimization process for a proactive approach and a total of 10000 simulations run.

Table 11 - Optimized parameters for strategy #3 with virtual wells.

Parameter	**Value**	**Unit**
BHP Injector	446.81	kgf/cm^2
BHP P1	275	kgf/cm^2
BHP P2	275	kgf/cm2
BHP Producer - Inj Trigger	402.37	kgf/cm^2
Water inj. rate	957.53	m³/d

WCUT – Upper ICV	0.9412	-
WCUT – Lower ICV	0.8976	-

5.2.1.5 Summary of results for case study 1

Table 12 presents a summary of the results from Case Study 1. Percentages of Np, Wp, Water Injection (Winj) and NPV of each proposed strategy are related to the base case.

Table 12 - Comparative analysis of the strategies.

	Base Case	**Strategy #1**	**Strategy #2**	**Strategy #3**
Np (MM m³) **ΔNp**	5.253	5.223 (-0.57%) -0.03	5.255 (+0.03%) +0.002	5.180 (-1.33%) -0.073
Wp (MM m³) **ΔWp**	14.752	8.916 (-39.56%) -5.836	9.090 (-38.58%) -5.662	8.991 (-39.26%) -5.761
Winj (MM m³) **ΔWinj**	22.608	16.796 (-25.71%) -5.812	16.987 (-24.86%) -5.621	16.737 (-25.97%) -5.871
NPV (MM USD) **ΔNPV**	65.41	62.46 (-4.51%) -2.95	68.83 (+5.35%) +3.42	69.63 (+6.45%) +4.22

As can be seen in Table 12, there is a small fluctuation in Np values for all strategies and, in this case, higher Np does not necessarily mean higher NPV. In this case study, as the Np values are not so different among strategies, a small anticipation of oil production or delay in water production had more influence over NPV than absolute values of Np and Wp, resulting in higher NPV for strategies 2 and 3.

As expected, the use of IWC improved water management, reducing Wp and Winj in all strategies. Nevertheless, IWC would not be recommended with reactive control in this study, as the NPV obtained was smaller than the base case.

The results with a proactive approach were better (strategies #2 and #3) with higher NPV than the base case. Strategy #2 would be highly discouraged due to the number of parameters in the optimization stage, needing too much computational effort, even though NPV was higher than the base case. This strategy could benefit of optimization in cycling frequency (ABELLAN; NOETINGER, 2010), reducing the necessity to cycle all ICVs every timestep. Strategy #3 presented the best solution, with a good balance between computational cost and optimal result.

Table 13 shows a comparison for the optimization stage in Case Study 1 to analyze the computational cost in each case. The use of the INGUIDE feature allowed for proactive control without adding too much computational cost (i.e., number of parameters).

Table 13 - Comparative analysis of optimization in Case Study 1.

	Conventional Completion	**Strategy 1**	**Strategy 2**	**Strategy 3**
Number of parameters	6	7	67	7
Simulations run	4000	10000	15000	10000
Simulations needed for optimal solution	824	9312	10584	3679

5.2.2 Case study 2

This section presents the results for Case Study 2 with the proposed well modelling using iSegWell structure.

5.2.2.1 Conventional Completion with iSegWell

The base case for comparison in Case Study 2 was the optimized conventional completion with the iSegWell structure, without any ICV operation. Results from Case Study 2 are all compared to this base case and Figure 18 shows its cumulative oil and water production.

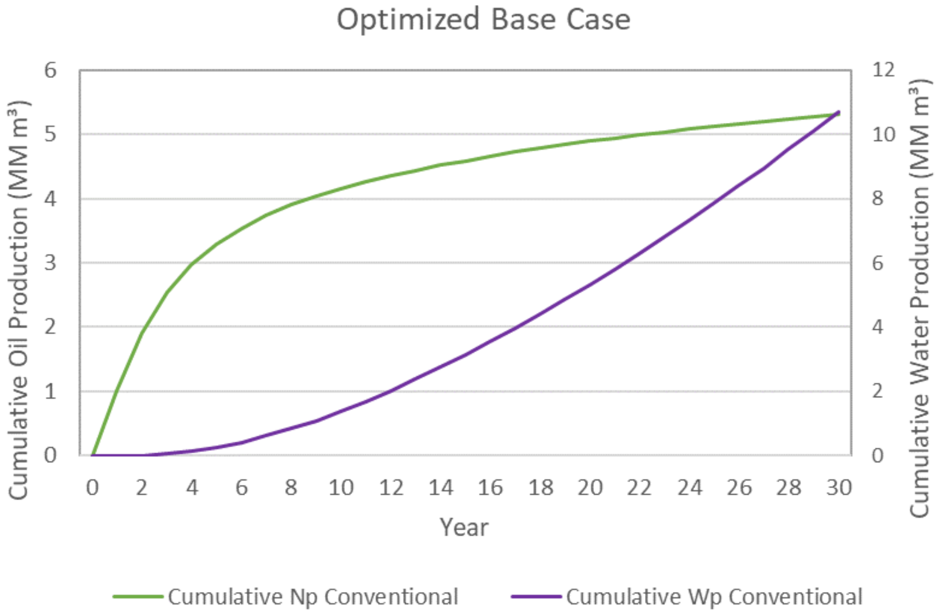

Figure 18 - Oil and water production for conventional completion with iSegWell.

Optimization was made with four variables for a total number of 1600 experiments, as defined in Equation 2, and resulted in a NPV of 34.84 MM USD. Table 14 shows the optimized parameters for the base case with iSegWell.

Table 14 - Optimized parameters for the base case with iSegWell.

Parameter	**Value**	**Unit**
BHP Injector	480	kgf/cm^2
BHP Producer	275	kgf/cm^2
Water inj. rate	1104.88	m^3/d
WCUT Producer	0.99	-

There was a reduction in the number of optimization variables after analysis of the results from case study 1, by removing the optimization of the BHP trigger to start injection. Additionally, BHP for producer needs only one variable as iSegWell already considers that the perforated intervals are pressure-dependents from each other.

5.2.2.2 Results for strategy #1

Results of cumulative liquid production for optimized strategy #1 with iSegWell and reactive approach with WCUT monitoring, compared to the base case, are shown in Figure 19.

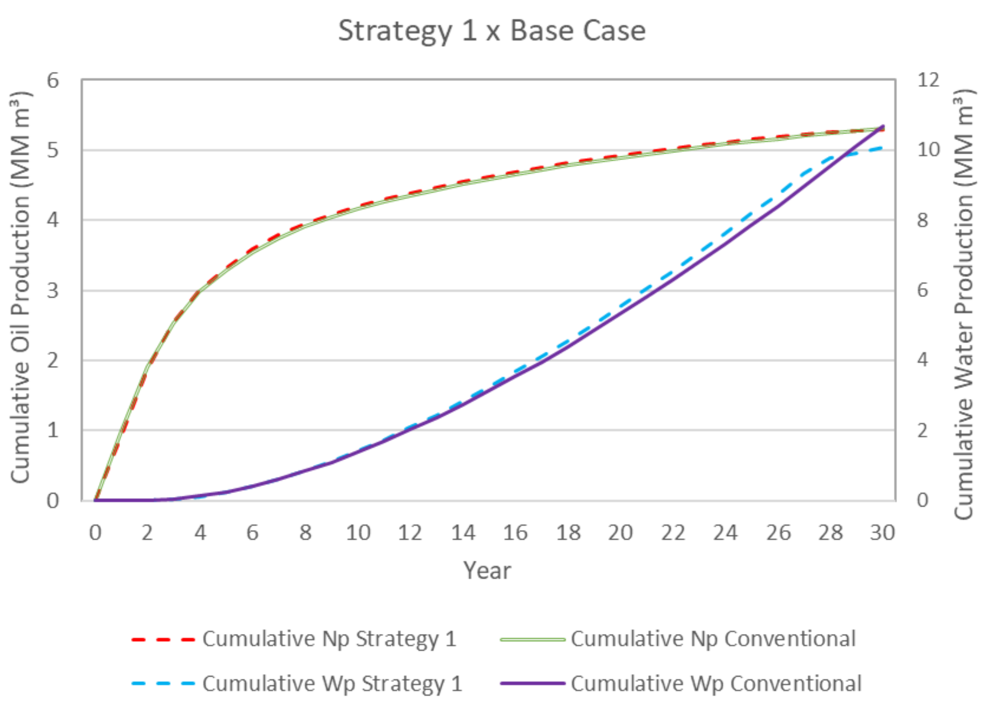

Figure 19 - Oil and water production for strategy #1 with iSegWell, compared to the base case.

As can be seen in Figure 20, upper ICV is closed reactively due to WCUT restriction after 27 years of production, so only the lower zone contributed to the last three years of production.

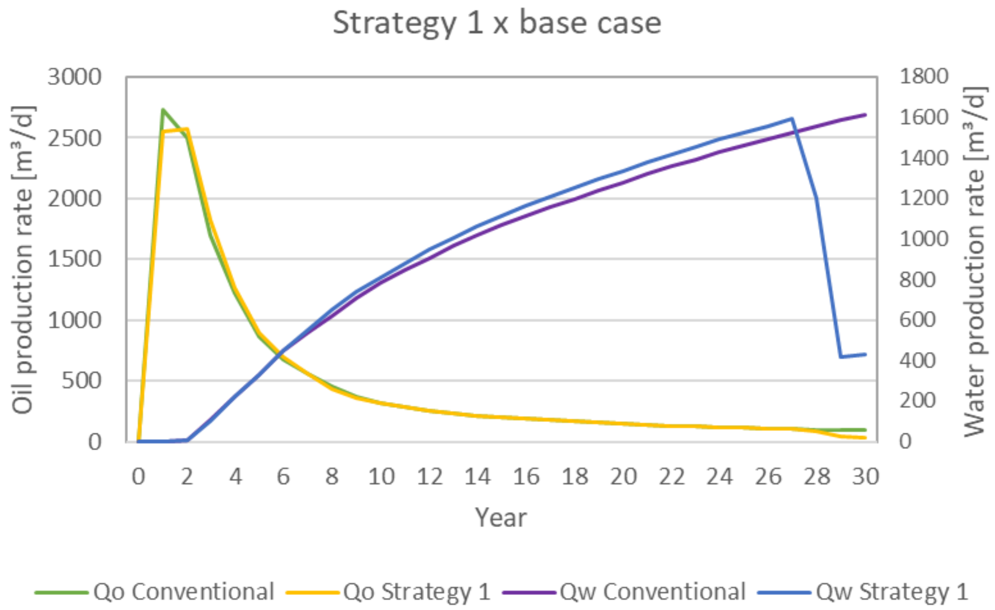

Figure 20 - Oil and water production rate for strategy #1 with iSegWell, compared to the base case.

There was a very small difference in Np of -3% for strategy #1 compared to the base case, that is practically invisible in Figure 19, but NPV obtained was 38.40 MM USD, an increase of 10,22% compared to the base case. Optimization was run with five variables as is shown in Table 15, with a total of 2000 experiments.

Table 15 - Optimized parameters for strategy #1 with iSegWell.

Parameter	**Value**	**Unit**
BHP Injector	446	kgf/cm^2
BHP P1	275	kgf/cm^2
Water inj. rate	957.51	m^3/d
WCUT – Upper ICV	0.9416	-
WCUT – Lower ICV	0.9002	-

This was the only scenario that BHP injector was not optimized at the maximum constraint of 480 kgf/cm^2 and Winj was also inferior, and this was compensated by lower WCUT limit values.

5.2.2.3 Results for strategy #2

Figure 21 shows the cumulative oil and water production for strategy #2 with iSegWell. This control strategy gave an extra boost on Np compared to strategy #1 and was practically equal to the base case, with associated increase in Wp.

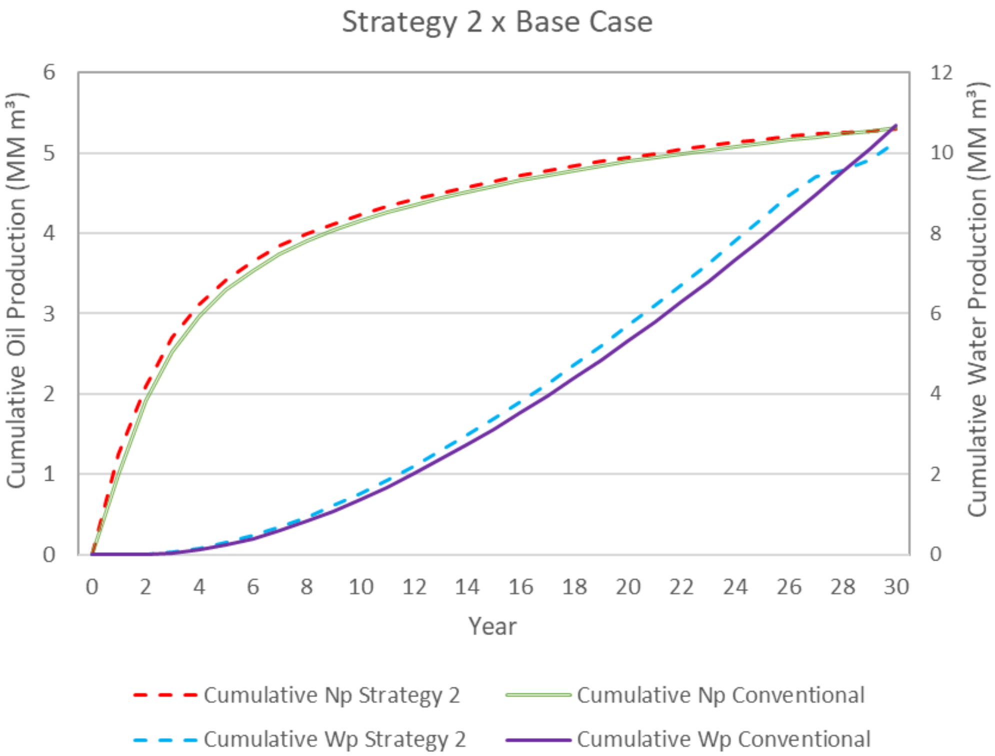

Figure 21 - Oil and water production for strategy #2 with iSegWell, compared to the base case.

As can be seen in Figure 22, the control strategy closed the upper ICV after 27 years of production for not respecting the minimal BHP constraint of 275 kgf/cm² for the producer well. As the GUIDE rates change in every simulation time step, the strategy reopened the ICV two years later, when BHP for the upper ICV was recovered by waterflooding from the injector wells.

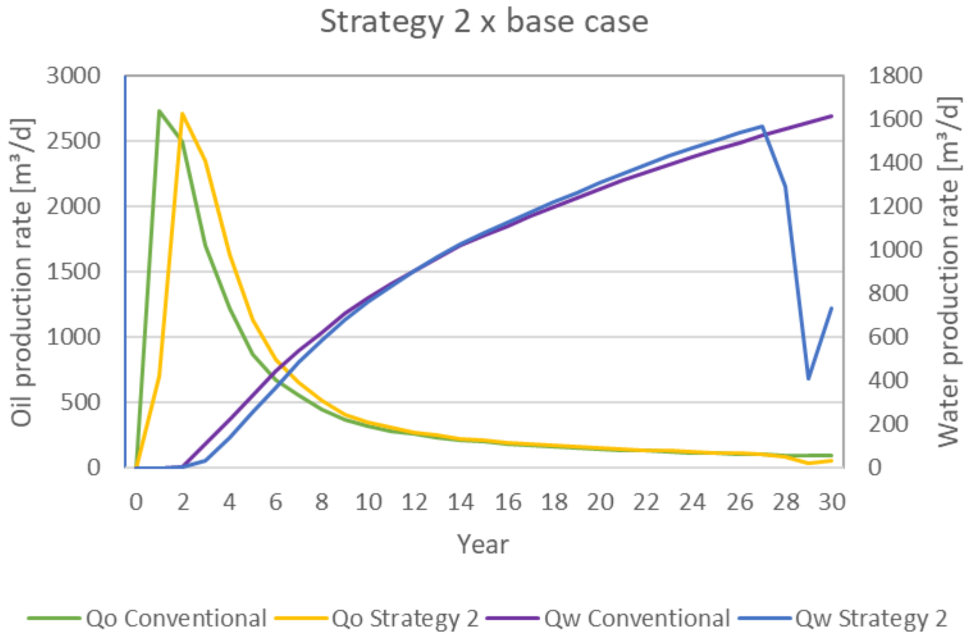

Figure 22 - Oil and water production rate for strategy #2 with iSegWell, compared to the base case.

Anticipation on oil production resulted in an optimized NPV of 38,83 MM USD, 11,45% higher than the base case, after 26000 experiments and 65 optimization variables (five from Table 16 plus sixty more from the yearly GUIDE rates that are not shown here for lack of comparison with strategies #1 and #3). Table 16 shows the optimized parameters for strategy #2 with iSegWell.

Table 16 - Optimized parameters for strategy #2 with iSegWell.

Parameter	**Value**	**Unit**
BHP Injector	480	kgf/cm^2
BHP P1	275	kgf/cm^2
Water inj. rate	1117.88	m³/d
WCUT – Upper ICV	0.9805	-
WCUT – Lower ICV	0.9880	-

5.2.2.4 Results for strategy #3

Figure 23 shows the cumulative oil and water production for strategy #3 with iSegWell, compared to the base case. Proactive control with INGUIDE was able to achieve +1% on Np with +8% in Wp, but still the highest NPV among strategies of 39.83 MM USD, 14.32% higher than the base case and the best result among the proposed strategies for Case Study 2.

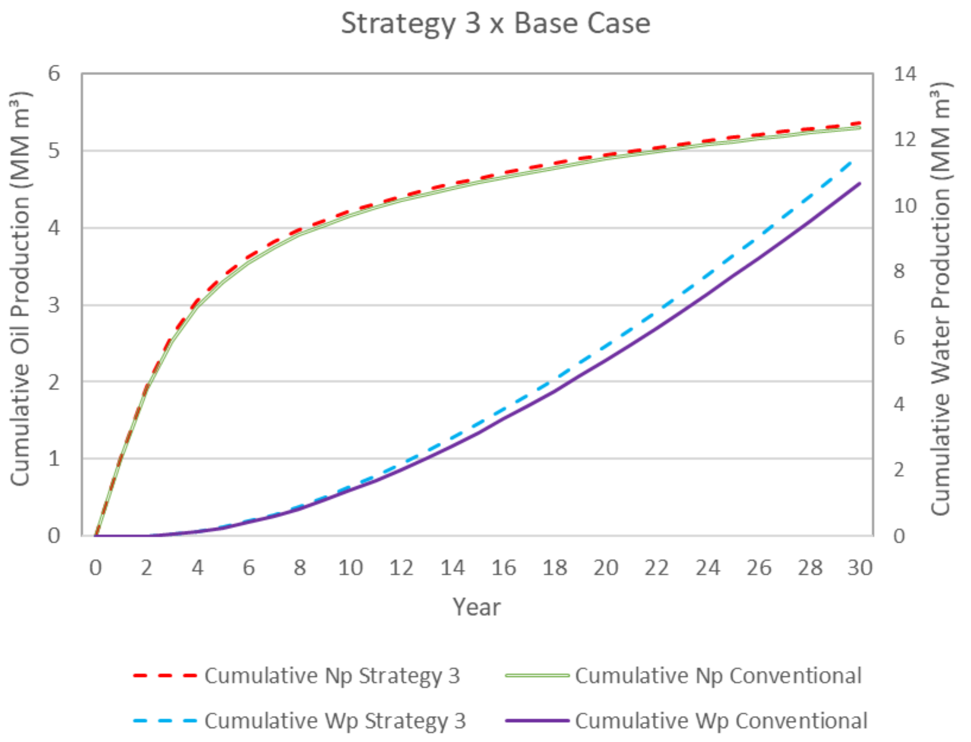

Figure 23 - Oil and water production for strategy #3 with iSegWell, compared to the base case.

WCUTs were kept under the optimized constraint so both ICVs stayed open during the whole production period, as can be seen in Figure 24.

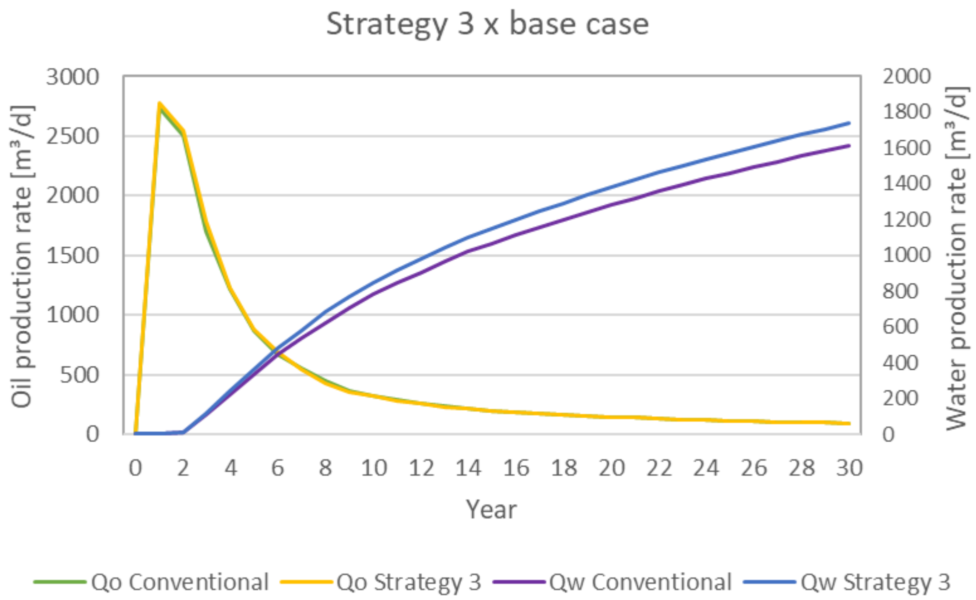

Figure 24 - Oil and water production rate for strategy #3 with iSegWell, compared to the base case.

Table 17 shows the optimized parameters after 2000 experiments.

Table 17 - Optimized parameters for strategy #3 with iSegWell.

Parameter	Value	Unit
BHP Injector	480	kgf/cm^2
BHP P1	275	kgf/cm^2
Water inj. rate	1125.02	m^3/d
WCUT – Upper ICV	0.99	-
WCUT – Lower ICV	0.9898	-

5.2.2.5 Summary of results for case study 2

Table 18 presents a summary of the results from Case Study 2. Percentages of Np, Wp, Water Injection (Winj) and NPV of each proposed strategy are related to the respective base case.

Table 18 - Comparative analysis of the strategies.

	Base Case	Strategy #1	Strategy #2	Strategy #3
Np (MM m³) **ΔNp**	5.306	5.289 (-0.32%) -0.017	5.301 (-0.09%) -0.005	5.357 (+0.96%) +0.051
Wp (MM m³) **ΔWp**	10.694	10.073 (-0.06%) -0.621	10.276 (-3.91%) -0.418	11.539 (+7.91%) +0.845
Winj (MM m³) **ΔWinj**	18.719	18.095 (-3.33%) -0.624	18.295 (-2.27%) -0.424	19.640 (+4.92%) +0.921
NPV (MM USD) **ΔNPV**	34.84	38.40 (+10.22%) +3.56	38.83 (+11.45%) +3.99	39.83 (+14.32%) +4.99

As can be seen in Table 18, fluctuation in Np values for all strategies in this case were also small, like Case Study 1.

Different from Case Study 1, ICV closing due to earlier water breakthrough was not a common scenario. ICV closing due to WCUT was only observed for the upper zone in the final period of production in strategy #1. The indication to use IWC in this scenario should be analyzed carefully, as to deploy an IWC just to close an ICV after 27 years of production brings uncertainties to the project design. One can also observe in strategy #1 that the increase in NPV was more influenced by the optimization of water injection than by IWC itself. Finally, considering operational aspects, a probable future workover intervention during the productive life of the well would be easier (and cheaper) with conventional completion, so IWC with reactive control would not be advised in this scenario.

Strategy #2 and #3 benefited from the proactive approach of ICV operation to obtain higher NPVs than the base case. For strategy #2, IWC helped reduce Wp and, for strategy #3, higher Np meant higher NPV, even with higher associated water production.

Table 19 shows a comparison for the optimization stage in Case Study 2 to analyze the computational cost in each case. The use of the INGUIDE feature allowed for proactive control without adding extra computational cost (i.e., number of parameters). Strategy #3 with proactive control and real-time data had the same number of optimization variables as strategy #1 that was a reactive WCUT approach.

Table 19 - Comparative analysis of optimization in Case Study 2.

	Conventional Completion	**Strategy 1**	**Strategy 2**	**Strategy 3**
Number of parameters	4	5	65	5
Simulations run	1600	2000	26000	2000
Simulations needed for optimal solution	1458	1197	17774	1641

6 CONCLUSION

This work presented a methodology for expedite IWC design and optimization, with a novelty approach for ICV control optimization with real-time production parameters and focus on reduction of optimization variables.

Optimization gains in conventional completion were higher than in IWC, corroborating the results of Barreto, Gaspar and Schiozer (2016) and Morais, Fioravanti and Schiozer (2017).

The analysis of NPV through a quality map proved to be a valid tool to define the number of production zones and achieve faster ICV positioning. Results showed great improvement in overall water management. The quality map could be used to identify earlier water breakthrough zones and use the information from Wp instead of NPV to position ICVs, saving the extra time of NPV calculation for each reservoir layer. One should notice that NPV is highly dependent on the proposed economic scenario. When analyzing NPV values, it is important to notice that all proposed strategies have an extra cost associated with the ICV. If Np gain for IWC were clearly higher, the decision could be made only based on the Np and the process could be faster without NPV calculation.

IWC behaved differently from Case Study 1 to Case Study 2 due to different approaches on well modeling. NPV values maintained the same qualitative distribution when comparing the same strategies from different case studies, but the absolutes values for NPV in Case Study 2 were around 60% of the average NPV of Case Study 1. Therefore, well modelling should be a concern when simulating IWC, as wellbore effects can influence overall simulation results.

IWC presented improvement in NPV with proactive control (strategies #2 and #3) for both case studies. Strategy #3 was able to deliver an efficient simulation of IWC application, aiming at field replicability and compatibility with well construction timespan. Proactive control using INGUIDE in real time presented itself as the best solution, with computational effort in optimization stage similar to the simpler reactive control of strategy #1.

There was an expressive 89% (in Case Study 1) and 92% (in Case Study 2) reduction in optimization parameters with proactive control from strategy #2 to strategy #3, presenting itself as an interesting alternative for scenarios with higher number of optimization parameters, such as multi-position / continuous variable position ICV or a field study with more wells equipped with IWC. Proactive control is usually associated with difficulties when translating it to field application, but the proposed methodology allowed for real-time proactive control and computational effort equivalent to a commonly used reactive approach. However, BHP coupling among virtual wells should be a concern when using this kind of approach to emulate zonal flow control. If BHP constraints are implemented reasonably, “conventional virtual wells” can perform as expected for the real well, although lacking the flexibility in well modelling as it was seen with the iSegWell package. A comparison between the two types of modelling is advised for validation purposes when choosing the simpler option. Despite being relatively new and with improvements in each release in the last three years, the iSegWell suite presented itself as a robust and useful set of tools to represent wellbore effects and completion equipment.

The results of these strategies are more “flow related” than “valve position related”, which makes them more flexible to adapt to different types of ICVs. For the real-time strategy proposed, to control WCUT values with production curves, they must be properly fitted to the model.

As suggestion for future studies:

a) a simplification in quality map analysis like using Np or Wp as the basis to ICV positioning could save computational cost of skipping NPV calculation when optimizing conventional completion.

b) the use of strategy #3 in Case Study 2 (INGUIDE associated with iSegWell package) in more complex scenarios such as full-field simulation, with more intelligent wells, should be interesting to further analyze gains in computational effort compared to conventional well modelling in the simulator. Full-field simulation could also be tested to verify if there would be more expressive Np improvement in larger scenarios.

c) level of details in wellbore effects could be increased by modelling the ICVs as tubing string openings, with associated pressure drops in iSegWell, so there would be different values for BHP to both producers P1 and P2, equivalent to the formation pressure in each zone. Bottomhole pressure in the string could be monitored through wellhead pressure plus hydrostatic pressure from surface to bottom.

REFERENCES[1]

ABELLAN, A.; NOETINGER, B. Optimizing subsurface data acquisition using information theory. **Math Geosci**, v. 42, n. 5, p. 603-630, Jul. 2010. Available on: https://doi.org/10.1007/s11004-010-9285-6.

ADEYEMO, K. M.; AIGBE, C.; CHUKWUMAEZE, I.; MEINERT, D.; SHRYOCK, S. Intelligent well completions in Agbami: a review of the value added and execution performance. *In*: OFFSHORE TECHNOLOGY CONFERENCE, 2009, Houston. **Proceedings** [...]. Available on: https://doi.org/10.4043/20191-MS.

ALMEIDA, L.F.; PACHECO, M.A.C.; VELLASCO, M.M.B.R. **Valve control strategy optimization hybrid system for intelligent wells under uncertainties**. 2007. PhD Thesis, Pontifical Catholic University of Rio de Janeiro, Rio de Janeiro, 2007.

AMJAD, B.; OGUNSANWO, O.; BAWAZIR, M.; BATITA, N.; SIDDIQUI, M. Optimal downhole flow control completion designs in a fractured carbonate reservoir using reservoir-centric simulation approach. *In*: SPE ANNUAL TECHNICAL CONFERENCE & EXHIBITION, 2020, Houston. **Proceedings** […]. Available on: https://doi.org/10.2118/201462-MS.

ARSALAN, M.; AHMAD, T.J.; BLACK, M.J.; NOUI-MEHIDI, M.N. Challenges of permanent downhole water cut measurement in multilateral wells. *In*: ABU DHABI INTERNATIONAL PETROLEUM EXHIBITION AND CONFERENCE, 2015, Abu Dhabi. **Proceedings** […]. Available on: https://doi.org/10.2118/177665-MS.

AVILA, J. C. Forecasting intelligent-well completion production through a coupled reservoir model with custom functionality. *In*: OFFSHORE TECHNOLOGY CONFERENCE, 2020, Houston. **Proceedings** […]. Available on: https://doi.org/10.4043/30771-MS.

BARRETO, C.E.A.G.; SCHIOZER, D.J. Optimal placement design of inflow control valve using a dynamic optimization process based on technical and economic indicators. **Journal of Petroleum Science and Engineering**, v. 125, p. 117-127, Jan. 2015. Available on: https://doi.org/10.1016/j.petrol.2014.11.004.

[1] In accordance with Brazilian Association of Technical Standards (ABNT NBR 6023).

BARRETO, C.E.A.G.; GASPAR, A.T.F.S.; SCHIOZER, D.J. Impact of the use of intelligent wells on the evaluation of oilfield development and production strategy. *In*: SPE TRINIDAD AND TOBAGO SECTION ENERGY RESOURCES CONFERENCE, 2016, Port of Spain. **Proceedings** [...]. Available on: https://doi.org/10.2118/180861-MS.

CAVALCANTE FILHO, J.S.A. Methodology for quality map generation to assist with the selection and refinement of production strategies. *In*: SPE ANNUAL TECHNICAL CONFERENCE AND EXHIBITION, 2005, Dallas. **Proceedings** [...]. Available on: https://doi.org/10.2118/101940-STU.

COMPUTER MODELLING GROUP. **IMEX User's Guide.** Calgary: 2021.

DE BRITO, D.U.; DURLOFSKY, L.J. Well control optimization using a two-step surrogate treatment. **Journal of Petroleum Science and Engineering**, v. 187, Apr. 2020. Available on: https://doi.org/10.1016/j.petrol.2019.106565.

GOH, G.; TAN, T.; ZHANG, L.M. A unique ICD's advance completions design solution with single well dynamic modelling. *In:* IADC/SPE ASIA PACIFIC DRILLING TECHNOLOGY CONFERENCE, 2016, Singapore. **Proceedings** [...]. Available on: https://doi.org/10.2118/180672-MS.

GREBENKIN, I.; MURADOV, K.; DAVIES, D. A stochastic approach for evaluating where on/off zonal production control is efficient. **Journal of Petroleum Science and Engineering**, v. 132, p. 28-38, Aug. 2015. Available on: https://doi.org/10.1016/j.petrol.2015.04.037.

JANSEN, J.D.; DURLOFSKY, L.J. Use of reduced-order models in well control optimization. **Optimization and Engineering**, v. 18, p. 105-132, Mar. 2017. Available on: https://doi.org/10.1007/s11081-016-9313-6.

LE RAVALEC, M. Optimizing well placement with quality maps derived from multi-fidelity meta-models. *In*: EAGE ANNUAL CONFERENCE & EXHIBITION, 2012, Copenhagen. **Proceedings** [...]. Available on: https://doi.org/10.2118/154416-MS.

MASCHIO, C.; NAKAJIMA, L.; SCHIOZER, D.J. Production strategy optimization using genetic algorithm and quality map. *In*: SPE EUROPEC/EAGE ANNUAL CONFERENCE & EXHIBITION, 2008, Rome. **Proceedings** [...]. Available on: https://doi.org/10.2118/113483-MS.

MORAIS, V. L. R. S.; FIORAVANTI, A. R.; SCHIOZER, D. J. Methodology to estimate the economic impact of intelligent wells considering reservoir uncertainties. *In*: SPE RESERVOIR SIMULATION CONFERENCE, 2017, Montgomery. **Proceedings** […] Available on: https://doi.org/10.2118/182591-MS.

MURADOV, K.; ELTHAER, E.; DAVIES, D. Reservoir simulator-friendly model of fluid-selective, downhole flow control completion performance. **Journal of Petroleum Science and Engineering**, v. 164, p. 140-154, May 2018. Available on: https://doi.org/10.1016/j.petrol.2018.01.039.

RANJITH, R.; SUHAG, A.; BALAJI, K.; PUTRA, D.; DHANNOON, D.; SARACOGLU, O.; HENDROYONO, A.; TEMIZEL, C.; AMINZADEH, F. Production optimization through utilization of smart wells in intelligent fields. *In*: SPE WESTERN REGIONAL MEETING, 2017, Bakersfield. **Proceedings** […]. Available on: https://doi.org/10.2118/185709-MS.

RENPU, W. **Advanced Well Completion Engineering**. 3rd ed. Waltham: Gulf Professional Publishing, 2011.

RODRIGUES, D.N.; MINASSA, L.B.; NUNES, R.S.; COSTA, L.C.P. Intelligent completions as a key technology in Brazilian presalt. *In***:** OFFSHORE TECHNOLOGY CONFERENCE, 2017, Rio de Janeiro. **Proceedings** […]. Available on: https://doi.org/10.4043/28056-MS.

RODRIGUES, D.N.; MINASSA, L.B.; NUNES, R.S.; COSTA, L.C.P. Intelligent completions play key role in Brazilian presalt development. **Offshore**, Jan. 2018. Available on: https://www.offshore-mag.com/drilling-completion/article/16755868/intelligent-completions-play-key-role-in-brazilian-presalt-development.

SAMPAIO, M. A.; BARRETO, C.E.A.G.; SCHIOZER, D. J. Assisted Optimization Method for Comparison between Conventional and Intelligent Producers Considering Uncertainties, **Journal of Petroleum Science & Engineering, v.** 133, p. 268-279, Sep. 2015. Available on: https://doi.org/10.1016/j.petrol.2015.06.023.

SAMPAIO, M.A.; GILDIN, E.; SCHIOZER, D.J. Short-term and long-term optimizations for reservoir management with intelligent wells. *In*: SPE LATIN AMERICA AND CARIBBEAN PETROLEUM ENGINEERING CONFERENCE, 2015, Quito. **Proceedings** […]. Available on: https://doi.org/10.2118/177255-MS.

SAMPAIO, M.A.; GASPAR, A.T.F.S.; SCHIOZER, D. J. Optimization of well rates under production constraints, **Int. J. Oil, Gas and Coal Technology,** v. 21, n. 2, p. 131-148, May 2019. Available on: https://www.inderscienceonline.com/doi/abs/10.1504/IJOGCT.2019.099586.

SANTOS, S. M. G.; SCHIOZER, D.J. **Case Study for Field Development and Management - Selection of Production Strategy based on UNISIM-II, UNISIM-II-D benchmark**, Center for Petroleum Studies – University of Campinas, Brazil, 2018. Available on: https://www.unisim.cepetro.unicamp.br/benchmarks/files/UNISIM-II-D.pdf.

SCHNITZLER, E.; SILVA FILHO, D. A.; MARQUES, F.H.; DELBIM, F.K.; VELLO, K.L.; GONCALEZ, L.F.; FONSECA, T.C. Road to Success and Lessons Learned in Intelligent Completion Installations at the Santos Basin Pre-salt Cluster. *In*: SPE ANNUAL TECHNICAL CONFERENCE AND EXHIBITION, 2015, Houston. **Proceedings** […]. Available on: https://doi.org/10.2118/174725-MS.

SCHNITZLER, E.; GONÇALEZ, L.F.; ROMAN, R.S.; DA SILVA FILHO, D.A.S.; MARQUES, M.; ESQUASSANTE, R.C.; DENADAI, N.J.; DA SILVA JUNIOR, M.F.; GUTERRES, F.R.; GOZZI, D.S. 100th Intelligent completion installation: a milestone in Brazilian pre-salt development. *In*: SPE ANNUAL TECHNICAL CONFERENCE AND EXHIBITION, 2019, Calgary. **Proceedings** […]. Available on: https://doi.org/10.2118/195935-MS.

SCHNITZLER, E.; GONÇALEZ, L.F.; ROMAN, R.S.; MARQUES, M.; GUTERRES, F.R.; DA SILVA JUNIOR, M.F.; CASTILHO, C.A.B. Buzios presalt wells: delivering intelligent completion in ultra-deepwater carbonate reservoirs. *In*: OFFSHORE TECHNOLOGY CONFERENCE, 2021, Houston. **Proceedings** […]. Available on: https://doi.org/10.4043/31116-MS.

VASPER, A.; MJOS, J.E.S.; DUONG, T.T.T. Efficient optimization strategies for developing intelligent well business cases. *In*: SPE INTELLIGENT ENERGY INTERNATIONAL CONFERENCE AND EXHIBITION, 2016, Aberdeen. **Proceedings** […]. Available on: https://doi.org/10.2118/181062-MS.

YAO, C.C.; BLANCO, W.F.; ALVAREZ, A.J. Improving oil recovery in the mature La Cira Infantas oilfield using multiphase flow simulation. *In*: SPE LATIN AMERICAN AND CARIBBEAN PETROLEUM ENGINEERING CONFERENCE, 2020, Bogota (virtual event). **Proceedings** […]. Available on: https://doi.org/10.2118/199140-MS.