Master Thesis

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Master Thesis

Technical Feasibility and Economic Benefit of using AICDs in Horizontal Well Completions of a North Sea Field

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Feb 2015

AFFIDAVIT

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

(Mokhles MNEJJA)

Leoben, 25th of February 2015

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Mokhles MNEJJA

Abstract

During the recent years installation of Inflow control devices completions has become more common in new wells. ICDs have proven to be an operationally simple and reliable completion solution. The primary benefits of installing ICDs are reduced water /gas production, increased hydrocarbon production and balanced inflow from the entire reservoir section. Recently, AICDs, the new generation of ICDs, have been employed successfully in few wells. AICD offers much better results in restricting less viscous unwanted fluid.

This thesis considers the application of AICDs on the X_South field development in North Sea. The AICD completion design of the Well_X was made using NETool^{TM} and Eclipse ^{TM} simulators. Different well development strategies were considered in this work. A quick economic evaluation was carried out to estimate the economic benefits of the AICD completion design.

A recommended completion set up of the well_X has been put forward. In the recommended completion set up AICDs, open hole packers and blank pipes has been used. The AICDs completion is enabling to reduce significantly the gas/water production. However, I was not able to increase the oil production but I succeed in keeping it almost unchanged.

The sand management of the Well_X has been studied in this work. I investigate the use of open hole gravel pack along with AICDs. New techniques have been introduced by services companies to gravel packing horizontal well equipped with AICDs. However these techniques have been successfully used in wells with horizontal section less than that of well_X.

Keywords: ICD/AICD, Open Hole Gravel Pack, Horizontal Well, reservoir management, completion design, NETool^{TM}, Eclipse^{TM}/Petrel^{TM}, multisegmented well modeling, erosion

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List of abbreviations

ICD.	Inflow Control Device
AICD	Autonomous Inflow Control Device
SAS	Stand Alone Screen
ESS	Expandable Sand Screen
OHGP	Open Hole Gravel Pack
ORAT	Oil Rate
BHP	Bottom Hole Pressure
SSD	Sliding Side Door

Chapter 1 Introduction

1. Thesis General

This thesis considers the horizontal oil production well Well_X of the X_South field in North Sea and the application of Autonomous Inflow control Devices (AICDs) in the lower completion. AICD is the next generation of Inflow Control Devices (ICDs). AICD is a technology used for increasing the production of oil and limiting the production of water and gas as well as equalizing the inflow. The AICD device affects the inflow from the reservoir into the well by creating an extra pressure drop over the completion and restricting the flow path for unwanted fluids (water/gas) once they do breakthrough. A result of that is an uneven inflow profile and lower gas/water production. Uneven inflow in horizontal wells is common due to differences in permeability and the difference in drawdown along the wellbore (Heel-Toe effect).

The sand management of the Well_X has been studied in this work. I investigate the use of open hole gravel pack (OHGP) along with AICDs. Up to now OHGP in combination with inflow control were successfully placed in horizontal section up to 400 m. This length is at least 2 times shorter than Well_X length.

For the thesis a review of applicable industry and academic literature has been done and relevant information related to autonomous inflow control extracted. The main sources of information has been SPE articles, other industry articles, internal documents in OMV and public information from company web pages.

From researched literature the technology has been referred to as AICD and Rate Controlled Production (RCP). For this thesis it is referred to as AICD. The main parts of the thesis are the literature review, simulation work, analysis of the results and conclusions.

The thesis has mainly focused on the AICD technology provided by Tendeka, since they have been awarded the contract for the lower completion supply at X_South field.

Simulation work was done using NETool™ and Eclipse™ software. Petrel™ is used to implement AICD completion before running Eclipse™ simulations. The main objective of the thesis has been to highlight the optimal configurations of the AICDs in the Well_X lower completion.

The completion will be designed to maximize life of well by minimizing capital and operating costs and maximizing potential hydrocarbon production and minimizing gas/water production. A robust sand control completion which minimizes skin needs to be provided.

2. Outline of Report

This project is presented in six chapters, outlined as follows:

Chapter one is a basic overview of the project

Chapter two presents the objective of controlling the inflow in the well. It describes the inflow control devices (ICD/AICD), summarizes the difference between ICD/AICD, shows the physics behind these devices, and explains the method s to model them. Finally some successful field application of ICD/AICD was presented.

Chapter three presents the methods used to limit the sand production in open hole horizontal wells. It describes the operation of gravel packing in horizontal well (alpha/beta).

Finally, it shows the challenges behind gravel packing a completion equipped with ICD/AICD and presents how to overcome this limitation.

Chapter four introduces the useful data for the candidate (X_South) field and well (Well_X) and presents their production performance. Then it gives a detailed description of the steps taken to achieve optimal AICD completion design using NETool ^{TM} and Eclipse^{TM} simulations packages. Finally, the results of the modeling work were presented.

Chapter five discuss the results presented in chapter 4. A Quick economic evaluation was presented. After that, the erosional risk of AICD/screen was presented. Then it shows the effect of changing the well strategy on AICD completion design and the effect of using the optimum AICD completion design in the field production performance. Finally, it discuss the capability of Eclipse to model and simulation a completion equipped with AICDs.

Chapter six presents the conclusions from this study, and makes recommendations for future adaptation.

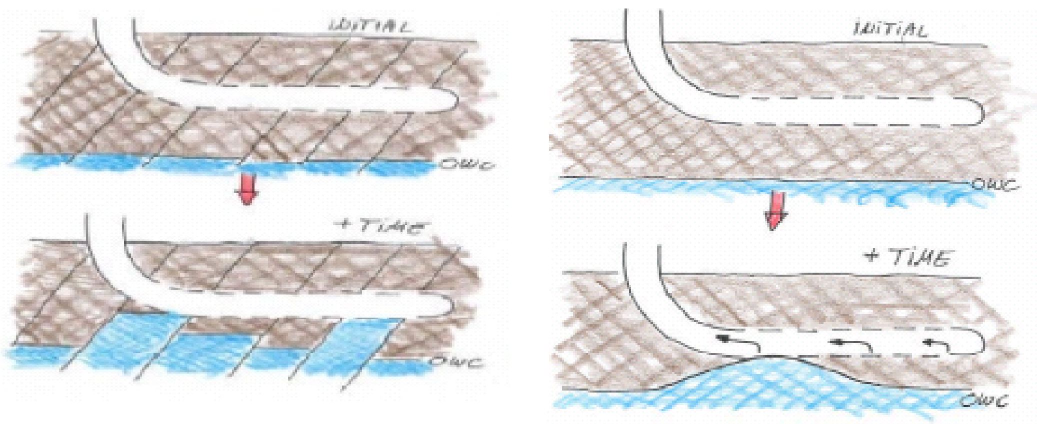
Chapter 2 ICD/AICD Theory

1. Overview of Inflow Control

Horizontal wells and multilateral wells became popular solution over the years for field developments. Horizontal wells increase wellbore exposure to reservoir due to the higher extension of horizontal section length compared to a vertical well. Such wells proved to increase ultimate recovery, lower the cost per unit length or make the production from thin oil column reservoirs (e.g. Troll Field in Norway) profitable [1,2].

However, the increase in well length and exposure to different reservoir formations presents some drawbacks:

- In homogeneous highly productive sandstones reservoirs, horizontal wells have uneven flow profile leading to cresting/coning effects. In general we observe a Heel to Toe Effect (HTE) which shows the tendency to produce more at the Heel than at the Toe of the well due to frictional pressure drop. Therefore, In case of excessive increase of producing rate and/or horizontal length, HTE can lead to a limited sweep efficiency, see figure 1 right [3].
- In carbonate reservoirs or in heterogeneous sandstone reservoirs, HTE is also present but the main issue in these kinds of reservoirs are permeability variations and fractures which lead to uneven inflow profile and accelerate water and gas breakthroughs through highly productive zones, see figure 1 left [4].



Heterogeneous Reservoir　　　　Homogeneous Reservoir

Figure 1: Production challenges due to horizontal well for the case of homogeneous and heterogeneous reservoir [5]

1.1. Inflow Control Methods

We just mentioned several challenges related to horizontal wells and therefore solutions need to be provided. It exists different ways to achieve controlling the inflow from the reservoir:

- Varying perforation density in order to make the inflow more uniform, one can increase the amount of the perforations in the direction of the toe of the well [6].
- Using remotely operated flow restriction called Interval Control Valves (ICVs). The principle is to actively control inflow coming from different reservoir zones. The remote surface control could be electrically or hydraulically [7].
- Using passive flow restrictions called ICDs, between the formation and the base pipe. ICD is a relatively new completion technology mainly for horizontal wells. ICDs passively equalize the inflow from the reservoir (the restriction is set at the time of the installation and cannot be changed without recompleting the well), see figures 2, 3 [7].
- Using the autonomous inflow control devices (AICDs) which are the new generation of ICDs. They have the same function as ICDs before water/gas breakthrough which is equalizing the inflow from the reservoir. However, it restricts the flow of unwanted less viscous fluid (gas/water) once they do breakthrough [7].

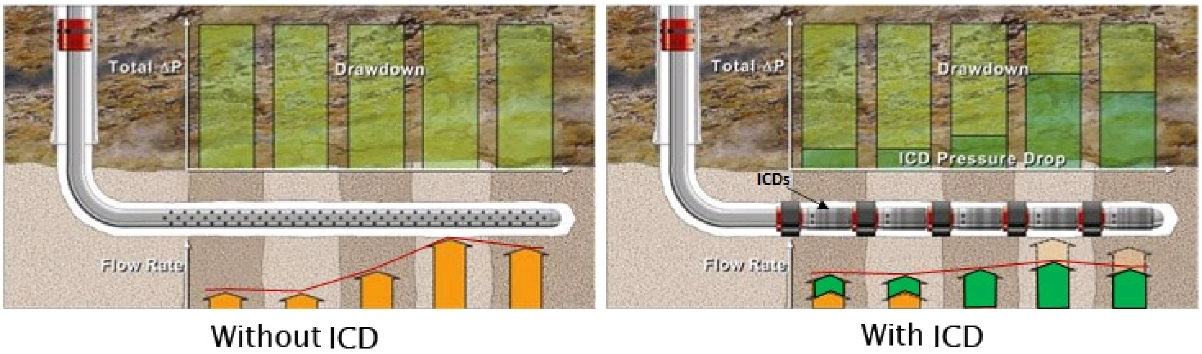


Figure 2: Effect of ICDs on the production profile in the case of heterogeneous formation [8]

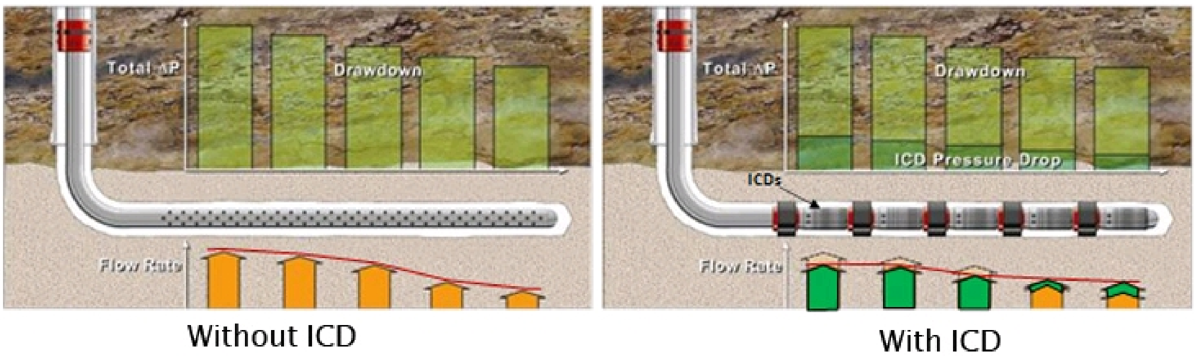


Figure 3: Effect of ICDs on the production profile in the case of homogeneous formation [8]

1.2. Inflow Control Devices ICD/AICD

Inflow control devices and especially the AICDs are the focus of this study. In fact, the perforation density variations lost most of its attractiveness after the arrival of ICVs and ICDs/AICDs.

An ICD is a choking device installed in the lower completion and is run as a part of the completion string and is mounted on a screen joint, see figure 4. The ICD device creates an extra pressure drop across the completion to increase flow resistance and gives a higher drawdown on the formation that will change the inflow along the well [9,10].

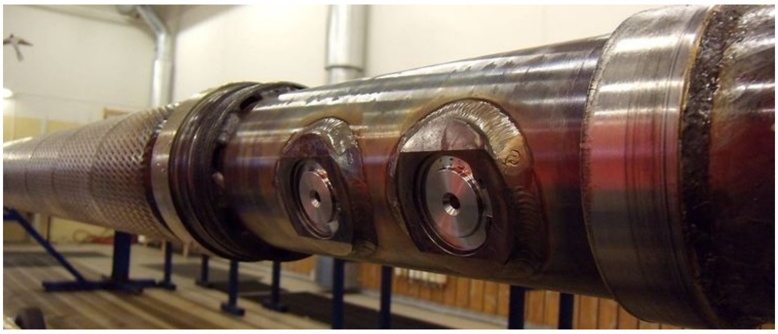
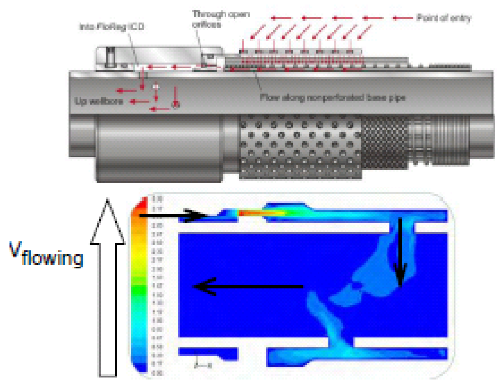


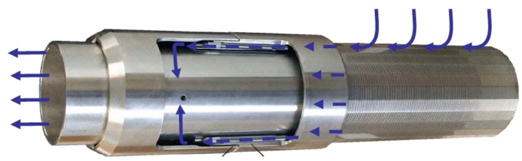
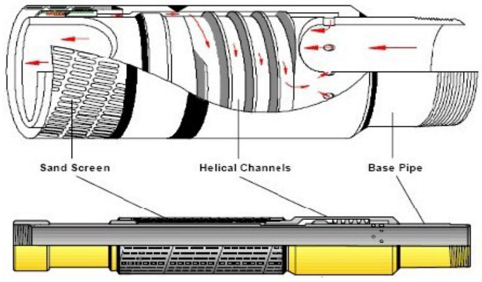
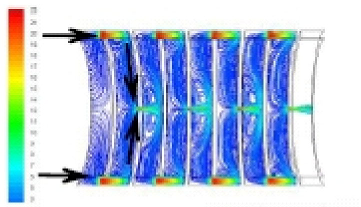
Figure 4: Completion joint equipped with two inflow control devices [11]

ICDs were first used at the Troll field in the North Sea in 1992 by Norske Hydro (Statoil). The type of the used ICDs was nozzle restriction. But today there are several types of ICDs from different suppliers available in the market. However, they can be grouped into two different types: Low Velocity ICD (LOVICD) and High Velocity ICD (HIVICD). The LOVICD includes channel and hybrid type. The velocity through these ICDs is less than 50 m/s. The HIVICD includes orifice (nozzle) and tube type. The velocity through these ICDs is greater than 50 m/s [12].

The current ICD technology in the market is indicated in the following table:

Table 1: ICDs Market Overview

Type	Characteristics	Providers	Figures
Nozzle	-Small Flow Area -High Velocity -viscosity Insensitive - density dependent - Adjustable	FlowReg Schlumberger Resflow Weatherford Equiflow Halliburton	

Tube	-Small Flow Area -High Velocity -Partially viscosity Insensitive - density dependent - Adjustable	EquiFlow Halliburton	
Helical	-Big Flow area -Low velocity -Strongly viscosity dependant - density independent - Not adjustable	Equalizer Baker Hughes	
Hybrid	-Big Flow area -Low velocity -Viscosity sensitive - Density dependent -Adjustable	Equalizer Baker Hughes	 

The Autonomous Inflow Control Device (AICD) was developed by Statoil and it is the new generation of ICDs (see figure 5). It is considered between the passive and the active kind of inflow control devices. AICD is a device which utilizes dynamic fluid technology to differentiate between fluid flowing through the device to maximize oil production. It works like a passive ICD during oil production, but restricts the inflow of unwanted water and gas at breakthrough. Originally, AICD is being piloted for use in heavy oil developments [13].

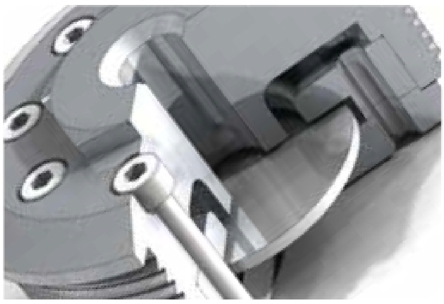
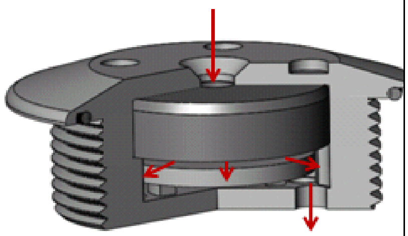
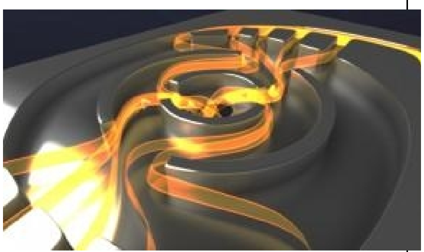


Figure 5: Statoil's patented autonomous inflow control device (AICD) [13]

There are two main AICDs providers in the market: Tendeka and Halliburton see Table 2. Tendeka's product is Flosure Nozzle which is licensed from Statoil for worldwide use. The Tendeka's AICD consists only of only one movable part, the free floating disc. The disc rests at the seat allowing maximum flow area for the passing fluid. This device is autonomous, that means it operates entirely without the need for human interventions and it does not require electric or hydraulic power. The position of the disc depends on the fluid properties and the flow conditions. The Halliburton's AICD works differently from Tendeka's AICD as there is no moving part. This device is able to change the flow path of the fluid. In fact, it directs oil flow through one path while redirecting flow of water or gas through a more circuitous path [14].

Typically, AICD is installed for each screen section. However, for certain applications up to four devices may be mounted per screen section.

Table 2: AICDs Market Overview

Providers	Figures
Tendeka, Flosure Nozzle	 
Halliburton, EquiFlow AICD (Fluidic diode)	 

In figure 6 an example of well installation is shown. The fluids are flowing from the reservoir through the screen and then enters the AICD and exits into the production tubing

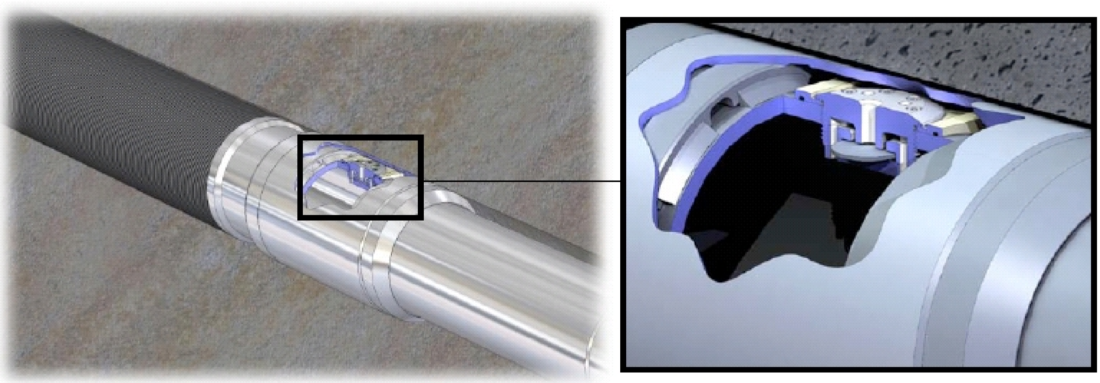


Figure 6 : AICD connected to the base pipe in a sand screen joint in the well [13]

2. Difference between ICD and AICD

The AICD have two functions when it is installed into a well. The first is the same as conventional ICD is to balance the influx profile across the horizontal completion by limiting entry into production tubing to a certain few opening. This additional choke balances production flux from high perm and low perm zones and minimizes coning at the heel. Both of these effects delay the unwanted fluid production (water/gas) breakthrough. In fact, the early production of these fluids could reduce the productivity of a well and can potentially kill oil production from the well.

The second function of an AICD is to create a highly restrictive flow path for unwanted fluids (water/gas) once they do breakthrough. Typically unwanted fluids have a lower viscosity than that of the wanted fluid, oil. The flow path through the AICD is designed to be progressively more restrictive as the viscosity of the produced fluid decreases, see figure 7. This characteristic is excellent at minimizing water and gas production. Generally, AICDs control gas production in low to medium viscosity oil wells and control water and gas in heavy oil wells [13,15].

AICD provides a flow restriction that is not only rate dependent but depends on the properties of the fluid. That means AICD depends on both the viscosity and the density of the fluid, however ICDs may depend just on viscosity or density depending on the type of the device.

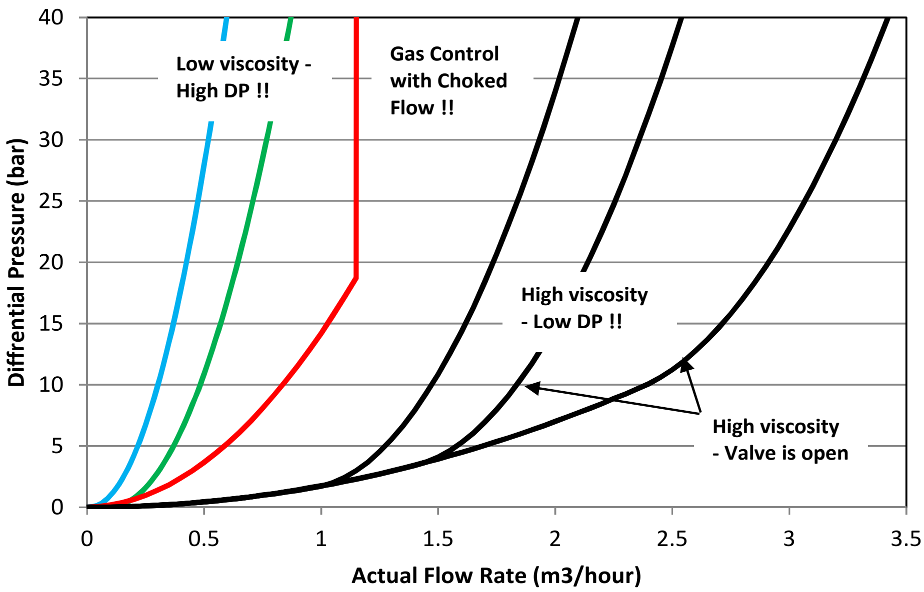


Figure 7: AICD viscosity dependency in reverse [16]

However, helical channel type ICDs restricts higher viscosity fluid. So if oil has higher viscosity than water or if gas is the problem, channel ICD does not work well. That is why people are using AICD today for heavy oil reservoirs, which is on purposely restricting low viscosity fluid. Nozzle type ICDs is used when the oil viscosity is close to water viscosity or lower due to their lower sensitivity to viscosity. Finally, AICDs are generally used when the viscosity ratio of the unwanted and wanted fluid is high. Moreover, the further the well from gas/water breakthrough, the better the use of AICDs, see figure 8.

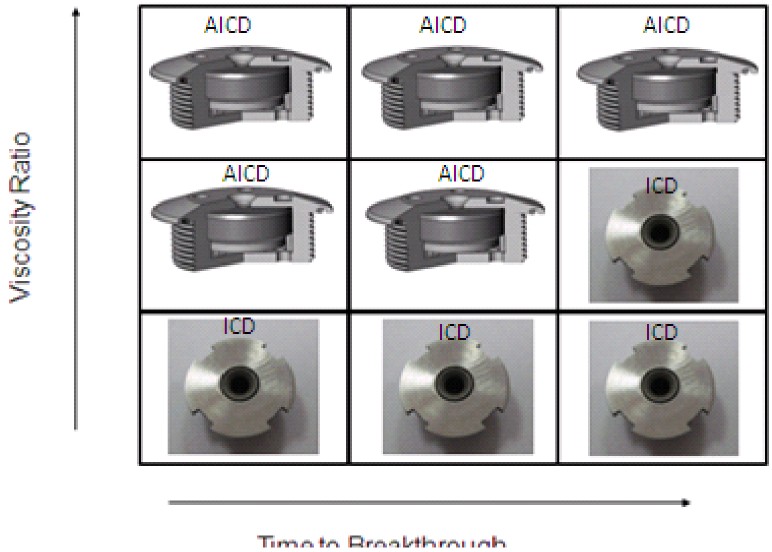


Figure 8: ICD Vs AICDs [17]

3. ICD/AICD Physics

As I discussed in the previous sections, ICD/AICD generates additional pressure drop to restrict the flow path for unwanted fluids (water/gas) once they do eventually break-through. They depend on the flow rate and they are viscosity and /or density dependent in according with which type of device.

HIVICDs (nozzle and tube type) are viscosity independent but density dependent. The pressure drop in HIVICDs follows Bernoulli equation.

The pressure drop of nozzle/orifice ICD depends on the diameter of the nozzle and is following this equation [18]:

$$\Delta P = \frac{1}{2} K \rho v^2 = K \frac{\rho Q^2}{2A^2}$$

Where K is the discharge or loss coefficient which a characteristic of the ICD; ρ is fluid density; Q is flow rate; A is flow area and v is fluid velocity.

Another expression for this pressure drop found in the literature is as following [19]:

$$\Delta P = \frac{\rho v^2}{2{C_d}^2}$$

Where C_d depends on the ICD manufacturer and it is between 0.6 and 0.68 for Weather-ford tool and between 0.9 and 1.0 for Schlumberger tool.

If a tube type ICD is used, another term has to be added to account for friction loss in the tube [18].

$$\Delta P = \rho \frac{v^2}{2} \left(f \frac{L}{d} + K \right)$$

L is the length of the tube; d is the tube diameter; f is the coefficient of friction.

The LOVICDs (channel and hybrid type) are viscosity dependent. The channel ICD flow equation is as following [19]:

$$\Delta P = \left(\frac{\rho_{cal}}{\rho_{mix}}\frac{\mu_{mix}}{\mu_{cal}}\right)^{1/4} \cdot \frac{\rho_{mix}}{\rho_{cal}} \cdot a_{ICD} \cdot q_{ICD}{}^{2}$$

ΔP is the pressure drop; a_{ICD} is the ICD strength value based on a 12 m length (one joint). q_{ICD} is flow rate per ICD; $\rho_{mix}$is the fluid mixture density; μ_{mix} is the fluid mixture viscosity; ρ_{cal} is the calibration density; μ_{cal} is the calibration viscosity.

The AICD model is a general expression for differential pressure across the valve as a function of fluid properties and volume flow [13,15]. The function is expressed by:

$$\Delta P = f(\rho, \mu). a_{AICD}. q^{x}$$

Where $f(\rho, \mu)$ is an analytic function of the mixture density and viscosity. a_{AICD} is a user-input ‘strength ‘parameter, q is the local volumetric mixture flow rate and x is a user input constant. AICDs will have different design for different oil fields. The model constant x and a_{AICD} are dependent on the AICD design and the fluid properties, based on the experimental data the flow constant and calibration properties in the AICD model can be defined.

The function $f(\rho, \mu)$ is defined as:

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

Where y is a user-input constant and ρ_{cal} and μ_{cal} are the calibration density and viscosity respectively. q is in [Sm3/day] and ΔP in [bar].

The mixture density and viscosity are defined as:

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

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

Where α is the volume fraction of the phase. The function is validated against several experimental data series performed with different range of oil viscosity.

The model for the differential pressure across the AICD is empirical and developed from experiments performed in 2006-2008 by Statoil. Figure 9 shows an example of AICD function compared to data from tests performed in Statoil’s multiphase flow test laboratory [13].

For Tendeka AICD, the a_AICD, x, y coefficients are generated by an internal engine based on the disc diameter, the fluid properties and the actual field condition (i.e. water control versus gas control or both).

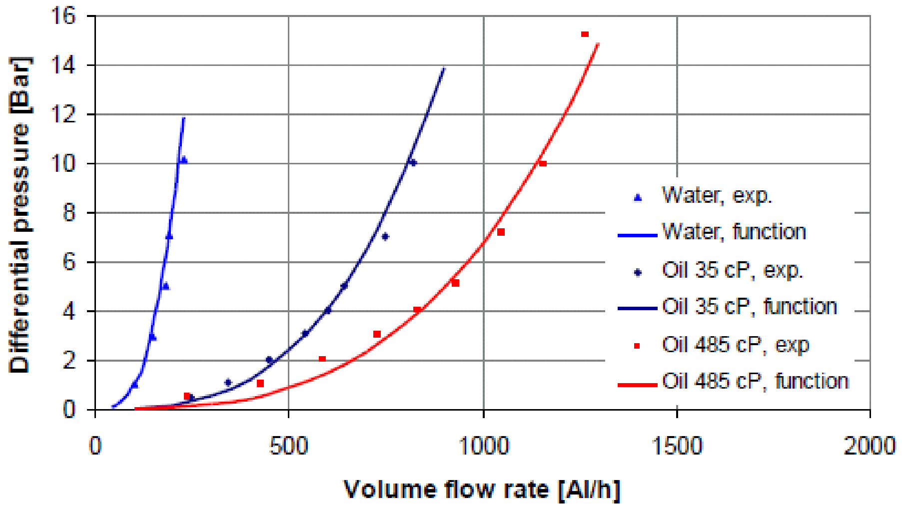


Figure 9: Comparison of AICD function with experimental data [13]

The principle of AICD is shown in figure 10. The reservoir fluids will go through a screen to housing where the AICD valve is located via an annulus. The screen is shown to the right in figure 10. The AICD is composed of a moving part which is the disc and two static parts which are the inner seat and the outer seat.

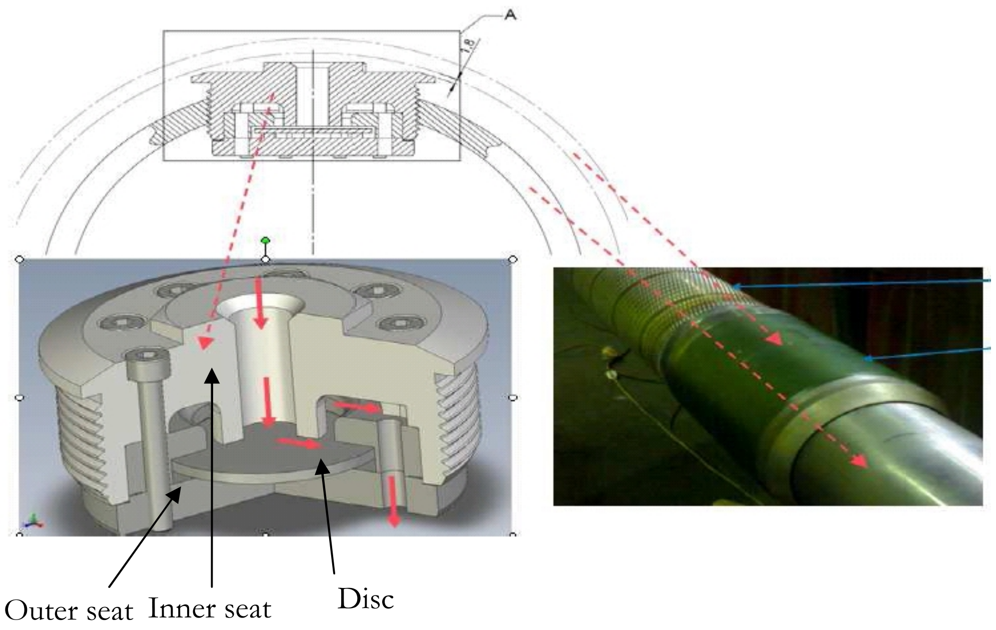


Figure 10: The principle of AICD [20]

The performance of the AICD is based on the Bernoulli principle. That means along a streamline, the sum of the static pressure, the dynamic pressure is constant. The Bernoulli equation for fluid flow along a streamline with respect to the stagnation point (the point at which the fluid is at rest, hence the velocity is zero):

$$P_1 + \frac{1}{2}\rho {v_1}^2 = P_0$$

This states that the stagnation pressure (P_0) is the sum of the static pressure and the dynamic pressure at a point in the flowing side of the disc (further upstream).

The AICD restricts the flow rate of low viscous fluids (gas/water). For example when gas is flowing through the device, it has high velocity and therefore high dynamic pressure ($\frac{1}{2}\rho v_1{}^2$). Using the Bernoulli equation the pressure at the flowing side of the disc P_1 will be lower.

The higher pressure behind the disc (stagnation pressure) P_0 will press it in the direction of its seat and reduce the flow area, due to the pressure difference between the two sides [13,15], see figure 11.

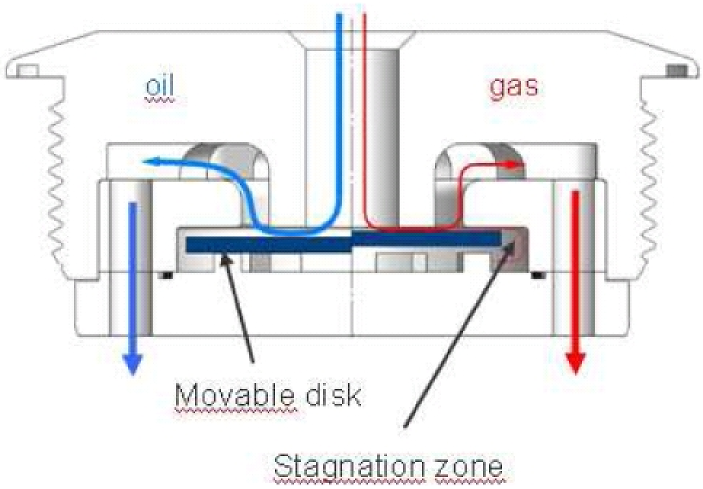


Figure 11: Sketch of AICD with typical streamlines for oil and gas [20]

To summarize, low viscosity gas reduces friction pressure and causing very high velocity thereby "sucking" the disc against the seat thereby restricting gas flow. High viscosity oil increases friction pressure – pushing the disc away from the seat and thereby increasing oil flow.

Several key concepts about the functionality of AICDs should be noted. First AICDs do not separate oil from water or gas. Rather AICDs vary the restriction according to the fluid which is passing through them. Therefore, the pressure differential across the completion will be greater for high water or gas zones than high oil zones. This distinctive function allows reservoir engineers to model the completion with lower initial pressure differentials across the completion than a conventional ICD completion [21].

Second, AICD doesn't completely shut off the unwanted fluid. A complete shut off tool without control lines or the requirement for intervention would be termed as Autonomous Inflow Control valves (AICV) [21].

Figure 12 shows a comparison between the Tendeka FloSure AICD and a passive nozzle based ICD. Pressure drop versus flow rate for water, oil and gas is plotted for visualization of the mobility control imposed by the AICD. The closer the water, oil and gas lines are together, the better the mobility control. It should be noted that most wells will not water or "gas-out" completely over a short period of time, hence the benefit of a controlled in-flux over time to maximize recovery [17]. Moreover, we can notice that AICD control much better the unwanted fluid (water/gas) than ICD, as the solid lines goes to the left of the extended lines in the figure 12. Figure 13 shows a theoretical comparison of a SAS vs. ICD vs. AICD completion [21].

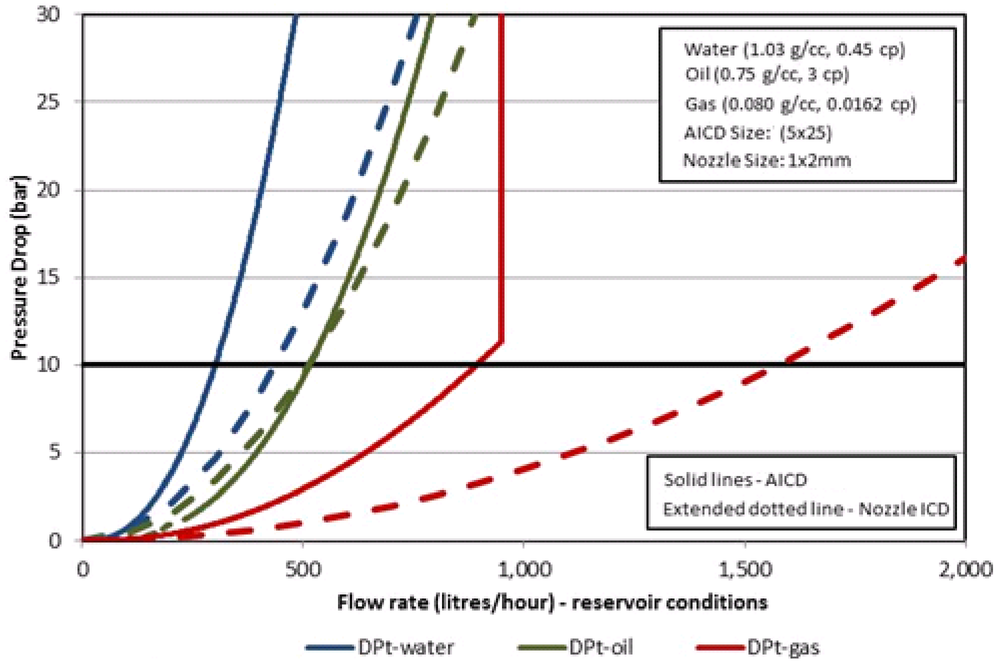


Figure 12: AICD flow performance versus ICD [17]

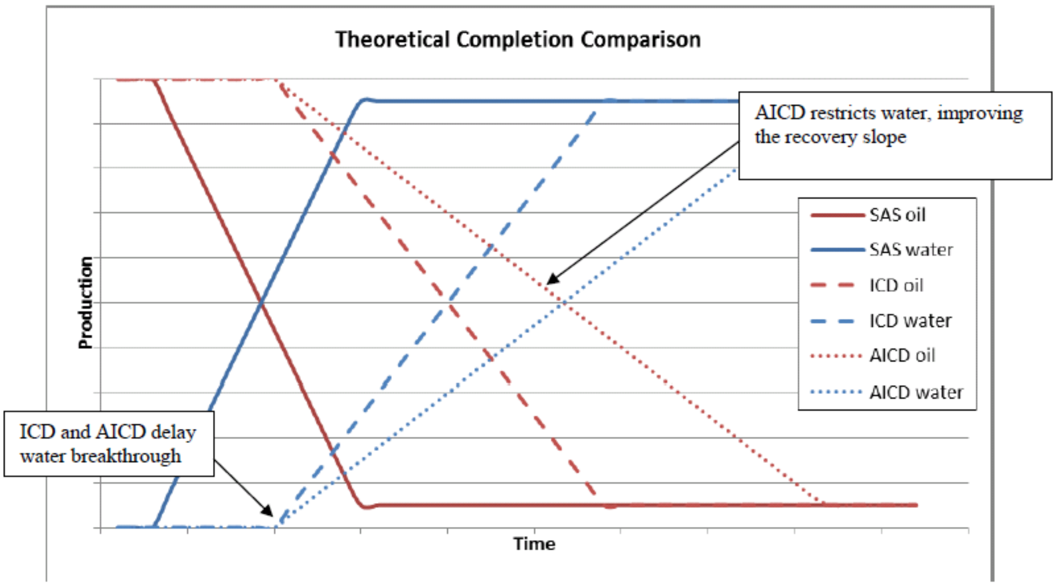


Figure 13: Theoretical comparison of a stand-alone screen vs. ICD vs. AICD completions [21]

4. ICD/AICD Modeling Tools

✓ Static Modeling: NETool™

NETool™ software is a steady-state, network-based simulator for quick calculation of multiphase fluid flow through a well completion and the near-wellbore region. The well completion and the near-wellbore region are represented by a distribution of nodes that may be interconnected by flow channels. Specification of the completion details leads to an appropriate pressure drop correlation for each flow channel, whether that is the formation, annulus or a range of completion paths [22].

The general node configuration is presented in figure 14. The uppermost row of nodes in this figure shows the layer of reservoir nodes (also called external nodes). The next four rows of nodes represent annuli within the well, and the lower most row represents the inner production tubing. The number of annular layers depends on the completion type [22].

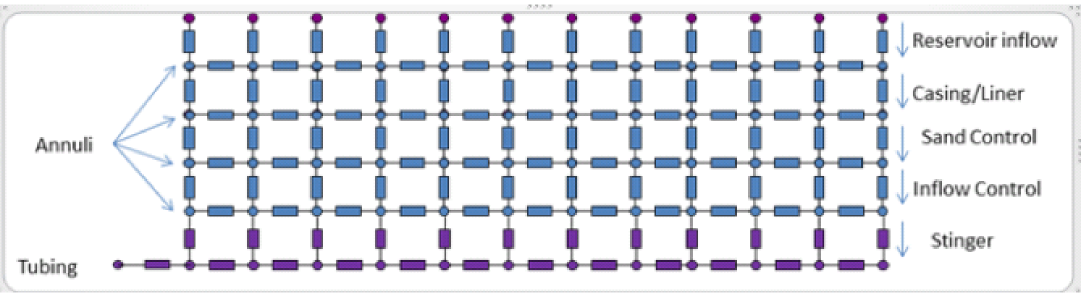


Figure 14: NETool™ general node configuration [22]

What NETool™ does is that it creates a sector model for the well to be studied and it uses the reservoir data from the reservoir simulator model. Therefore, the data describing the reservoir in the near wellbore area is retrieved from Eclipse™ in our case and upscaled while conserving the complex, reservoir geological description. The flow from the near wellbore nodes (i.e. reservoir grid blocks) into the well completion are represented by a specified number of nodes which can be connected in a variety of ways in order to simulate flow through annular spaces, SASs/Gravel Pack, ICDs/AICDs and through the tubing [22].

The possibility to import Eclipse™ data and use that to simulate the well makes the results from NETool™ more accurate and in line with Eclipse™. With NETool™ only one well can be studied at a time.

NETool™ cannot read all Eclipse™ information it does not import any restriction put on the well in Eclipse™. These restrictions have to be put in manually (restrictions in BHP, oil rate, liquid rate, downhole flow rate could be used).

In order to have an accurate and consistent NETool™ model, it is required to match it to Eclipse™ data for each time step. The most important outputs to be matched between Eclipse™ and NETool™ are BHP, liquid rates and gas rate if the well is producing much gas.

Unfortunately, the current NETool™ version cannot be coupled to a reservoir simulator. i.e. automated interaction between the reservoir and wellbore models is not possible. Its availability would have allowed a full evaluation of the completion's performance. Such coupling is essential to fully capture the time dependent depletion effects associated with a particular completion design.

✓ Dynamic modeling: Eclipse™

The Static modeling tool doesn't capture the dynamic effect of the reservoir. Therefore dynamic modeling is essential. Commercial tools used by E&P and services companies include Eclipse™, Reveal™, Quiklook®. I will talk here just about Eclipse Simulator as this is what I used in my study.

Eclipse™ 100 is black oil, finite difference reservoir simulator with the capability to model ICDs/AICDs with and without annular flow isolation through its Multi-segment Well

Model [23]. This model divides the wellbore into a number of segments. The individual segments can be part of the annulus, tubing or an ICD/AICD [24], figure 15.

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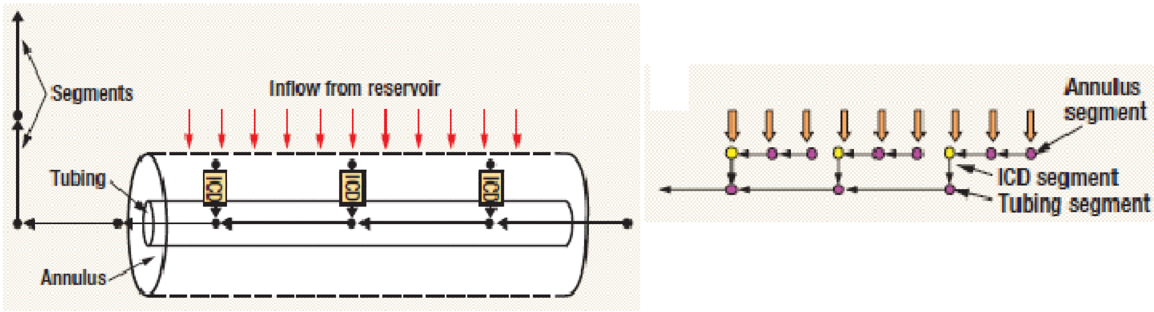


. Figure 15: The ICD/AICD flow direction model as applied in Eclipse™ [24]

Eclipse™ contains a number of preprogrammed keywords which can be used to model various ICD/AICD. Here the most useful keywords for ICD/AICD modeling , see Table 3:

Table 3: Eclipse ICD/AICD keywords [23]

ICD/AICD type	Keyword
Helical Channel ICD	WSEGSICD
Labyrinth Channel & tube ICD:	WSEGLABY
Nozzle ICD	WSEGVALV
AICD	WSEGAICD

These keywords use the inflow relationship across an ICD into the tubing equation described above. A brief description of these keywords and the equations they employ along with some illustrative examples of their applications can be found in reference [23].

WSEGTABL is another keyword which can be applied to model all of these devices. It uses device specific flow performance curves in a tabulated format to interpolate the pressure drop through the device for different flow rates [23].

Finally, the advantage of the flow in the annulus is also supported. However there are some limitations like only one ICD/AICD can be used for each tubing segment in the well and NETool™ does not have this limitation.

✓ Summary ICD/AICD Modeling Strategy

Appropriate modeling techniques of wells equipped with ICD/AICD were derived to achieve an optimum completion design and well performance. These include:

1. Sizing tools (Example NETool™) which model the performance of ICD/AICD completion at snapshot of time.
2. Evaluation tools (Example Eclipse™) which account for the time dependent performance of the completion throughout the life of the well.

5. ICD/AICD Field Applications

The advantages of the ICD technology have been now recognized by many operators through its application to different types of fields since their first application in the Troll field. Baker Hughes reported that 2 million feet of helical-channel ICD joints had been installed by mid 2008 [25]. Weatherford reported the installation of ICDs in more than 173 wells [26]. Statoil reported more than 120 installations in North Sea wells [27]. Saudi Aramco reported the installation of ICDs in more than 200 wells spread over several fields [28], see figure 16.

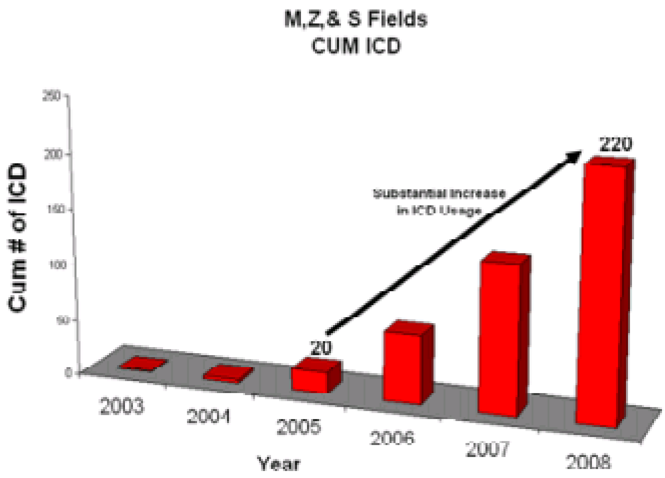


Figure 16: ICD Growth in Saudi Arabia Offshore Fields [28]

In the literature, just one ICD failure has been reported. It is the case of a well in North Sea. The completion selection for this field was Stand Alone Screen (SAS) with ICDs and ICV to regulate flow from two different reservoir sands. The well was not flowed back after completion and it was put in suspension for 3 months. Therefore, the well failed to flow when the well attempted to be cleaned up. In fact, the screen assembly was plugged and most probably the ICDs. The reason for this failure is that the fluid system used for the well is not compatible with the completion run. And another reason is not flowing back the well immediately after completion [29].

The autonomous ICDs are relatively new, so its field application is not that much reported in the literature. Statoil reported the successful application of its AICD in Troll field [15]. Halliburton reported the successful application of its AICD (fluidic diode type) in Central and South America heavy oil (Colombia, Ecuador Mexico...) [21,30].

Statoil compared the effect of AICD and ICD on gas production in the Troll field. Troll Oil field is producing from thin oil column only 4-7 meters thick [31] and it has an associated thick gas cap. An early gas breakthrough occurred due to the short distance to gas/oil contact.

To do this comparison, Statoil planned two-branch well with parallel branches through the same reservoir sands. The GOR development in the two branches is different. AICD completed branch is better than a conventional branch with ICD, see Figure 17. In fact, passive ICD will not reduce or stop the gas breakthrough as the GOR developed after breakthrough [15].

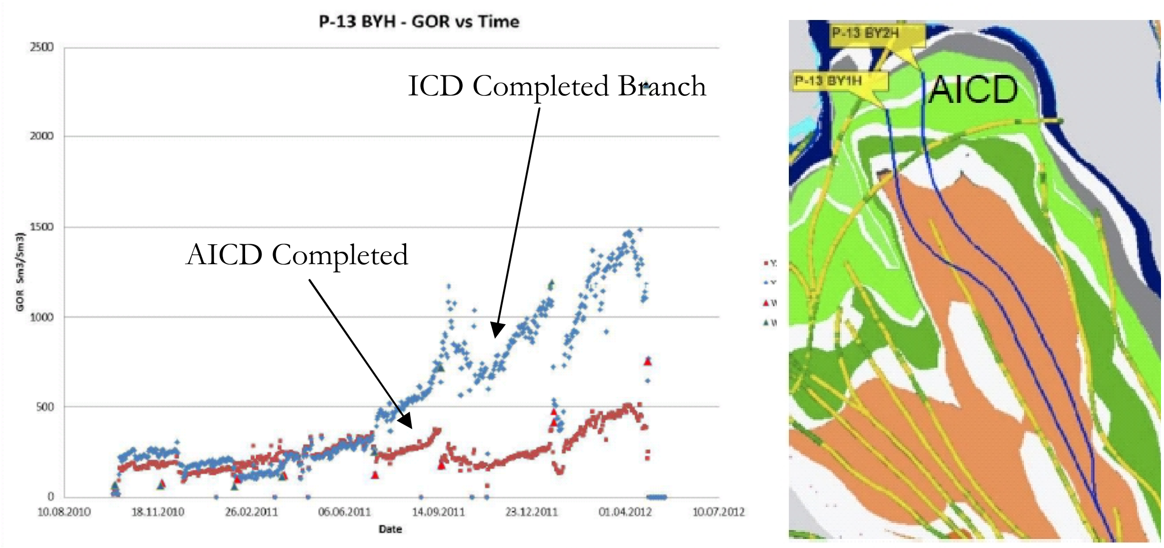


Figure 17: Left: Troll P-13 BYH – Gas oil ratio development as function of production time;
Right: the two-branch well [15]

Chapter 3 Open Hole Sand Control System

1. Open Hole Sand Control Techniques

The sand production is the production of small/large amounts of solids together with the reservoir fluid. The sand production could cause associated problems including the wear and erosion of surface and down hole production equipment and the casing/liner collapse.

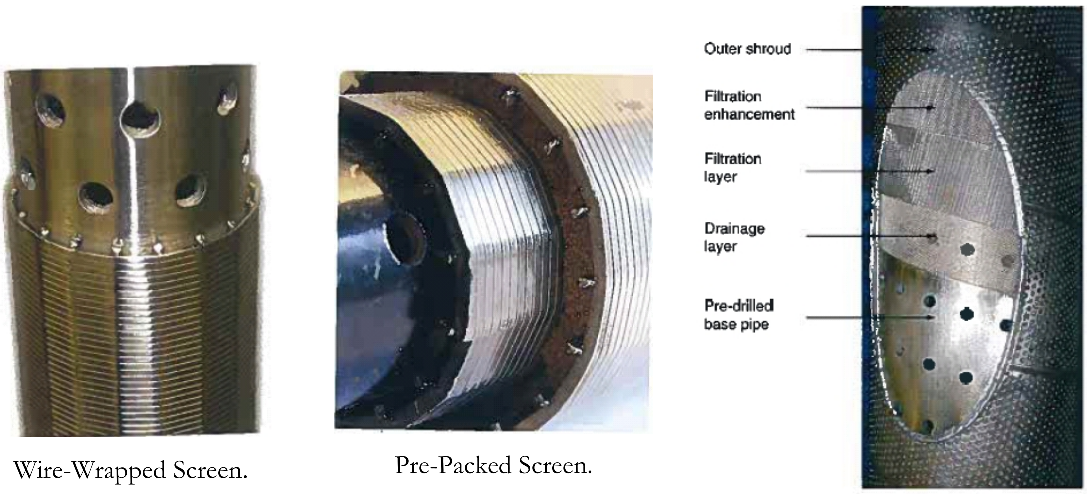
Some of the most common sand exclusion techniques used for horizontal completions includes: Stand Alone Screen (SAS), Expandable Sand Screen (ESS) and Open Hole Gravel Pack (OHGP) [32]. The choice of one of these techniques depends on reservoir and production conditions.

✓ Stand Alone Sand Screens (SAS):

Stand Alone Sand Screen perform as a down hole filter. A number of different screens are commercially available and are subdivided into three main types: Wire wrapped screens, Pre-packed screens, Premium Screens (metal mesh), see figure 18.

SAS have better reliability if the formation is well sorted, clean and with large grain size. Besides, they offer reliability in sand control at low cost and with less operational complexity than other open hole sand control completions [33].

Slotted liners can be used for sand control instead of SAS. However, it is difficult to make the slots small enough to stop fine sands. In fact, a saw can cut slots down to around 0.025 in, but a laser can be used to cut finer slots [34].



Wire-Wrapped Screen.

Pre-Packed Screen.

Typical Premium Screen Construction

Figure 18: Different types of Screen [34]

✓ Expandable Sand Screens (ESS):

ESS is a premium downhole sand control device. The screen is expanded in the well to the wellbore. It can be expanded as much as certain percentage of its initial ID depending on the provider of the product, see figure 19. Besides the sand control effect, ESS has benefit annular flow reduction the same as gravel pack (note that the open hole gravel pack will be explained in the following paragraph) with the ease of installation of a stand-alone screen [35].

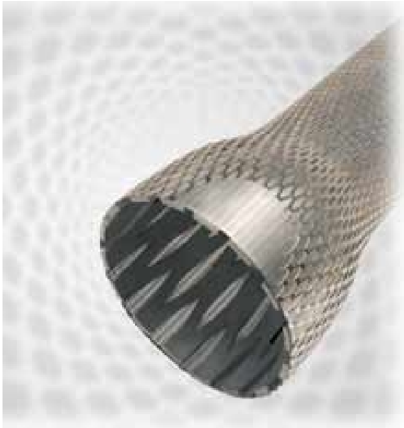


Figure 19: Expandable Sand Screen [36]

✓ Open Hole Gravel Pack (OHGP):

Originally, OHGP is used in deviated or vertical wells. Since the mid-1990s, it becomes a common form of sand control particularly in horizontal wells where they can be very productive. The principle of OHGP is to fill the annular space between screen and sand face with gravel to stop formation sand from being produced, see figure 20.

The OHGP is generally used for high heterogeneity of formation sand, with a wide range of sand particle size. Despite the perfectness of the OHGP for zero tolerance sand production, gravel packing is complex and weather sensitive operation in offshore operation. [34]

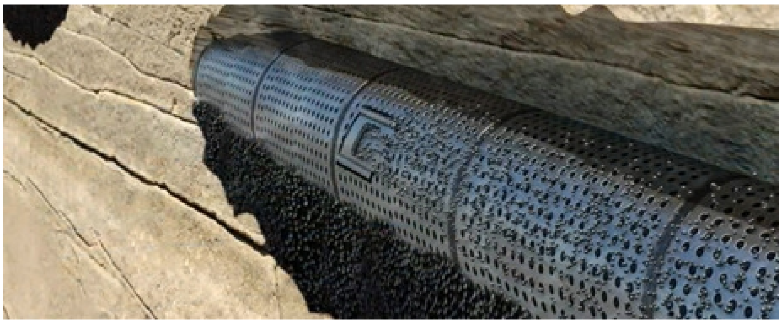


Figure 20: Open Hole Gravel Pack and its associated screen [37]

Two main forms of open hole gravel pack are in common use: circulating packs and alternate path (shunt tubes). Each technique can be used in conjunction with wire wrapped, pre-packed or premium screens. An alternate path-OHGP is pumped with a much higher gravel concentration than a circulating-OHGP, and therefore it takes less time. However the surface equipment required and the operational complexity associated with handling the carrier fluid can present a significant challenge [34].

The selection between these three techniques of sand controlling depends on formation sand particle distribution (sorting and size). To quantify the level of sorting, a uniformity coefficient (UC) is introduced which is D40/D90 (D40 and D90 are the sieve sizes at the 40 and 90 percentile). The smaller this coefficient, the well sorted is the sand. [38]

An example of a selection guideline of the open hole sand control technique is described by the following chart [38], see figure 21.

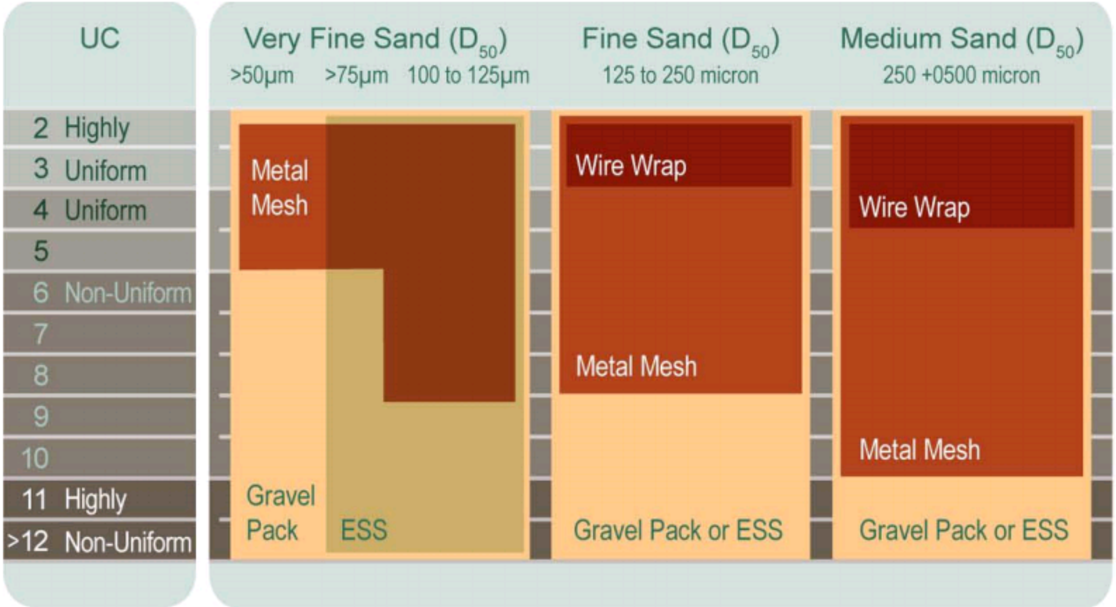


Figure 21: Sand Control Selection Guidelines [38]

2. Circulating OHGP in Horizontal Well

The placement of the gravel in an OHGP is following these steps [34], see figure 22:

1. The screen is run with a wash pipe, after that the gravel pack packer is set.
2. A low concentration gravel is circulated into the annulus between the screen and formation. The circulating fluid (usually water) has little capability (velocity around 1 ft/s) to transport the gravel in suspension and gravel settles out and forms a dune.
3. At a critical dune height (generally at 70 – 90 % of open hole area), the water flow above the dune is fast enough (around 5-7 ft/s) to turbulently transport the gravel.
4. The dune extends along the well by dune action, which is known as the alpha wave, until it reaches the toe of the well. Meanwhile, fluids are returning via the screen/wellbore annulus and the toe of the well to the wash pipe. There will also be some fluid entering the screen and flow in the wash pipe/screen annulus to the toe of the well and then enter to the wash pipe.
5. Because of the fluid is circulated, any space after the end of the wash pipe will receive very little gravel. The alpha wave will stop at the end of the wash pipe.
6. The pressure increases because fluid now has to flow through the pack and the screen to reach the wash pipe. The gravel is then progressively packed back until reaching the heel. This is known as beta wave. The fluids are often pumped at lower rates to avoid high pressures that could fracture the formation.
7. The beta wave hits the heel of the well and further pumping is impossible.

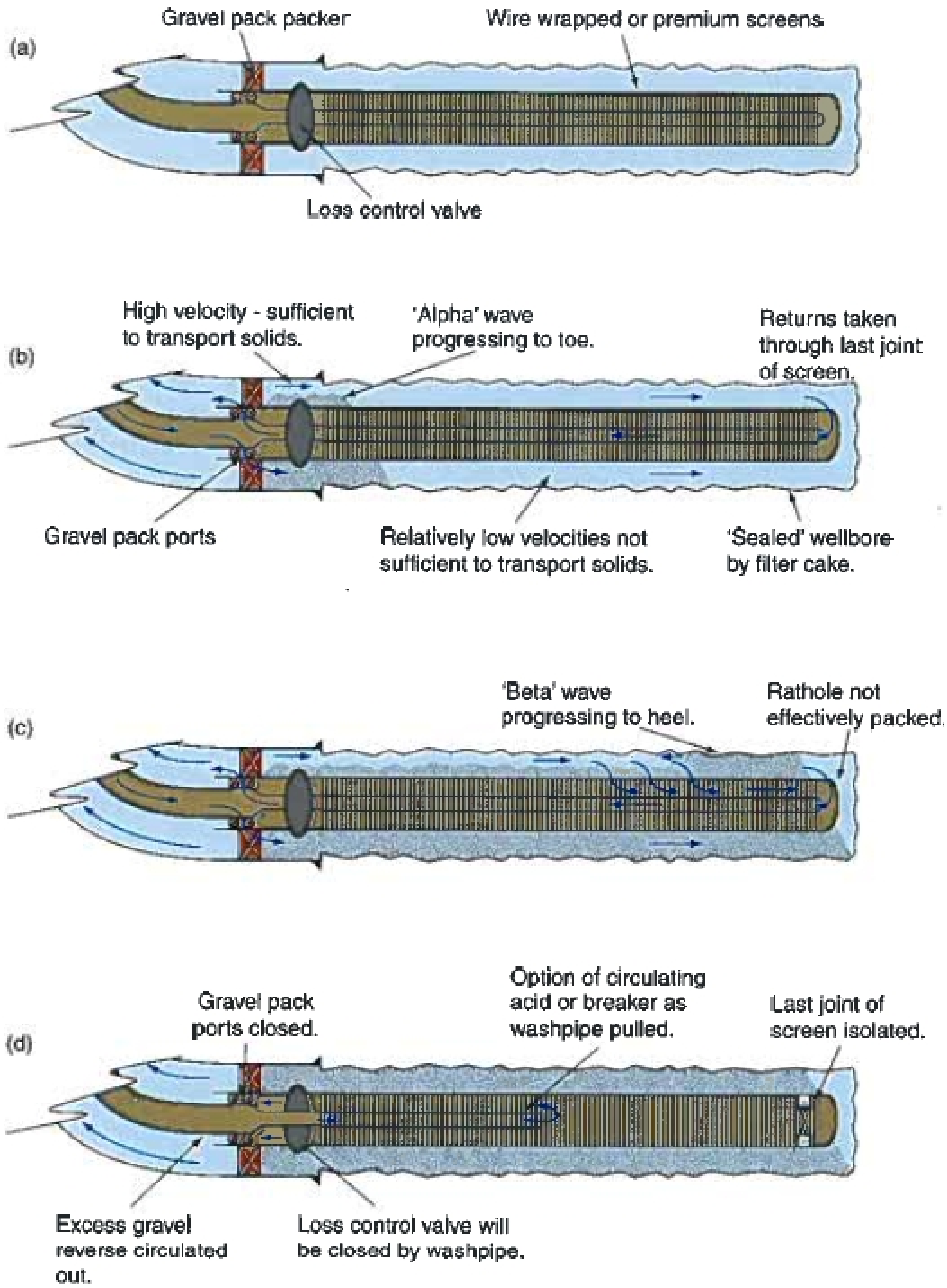


Figure 22: Circulating Pack Sequence [34]

3. Open Hole Sand Control Techniques along with Inflow Control

Normally the down hole flow control devices ICD/AICD are equipped with sand control system to prevent the sand production and the erosion of the equipment. Zonal isolation which could be swellable packers are also installed together with down hole flow control to limit the annular flow and hence avoid screen erosion.

Many successful field applications of standalone screen with ICD/AICD have been reported [21,39,40,41]. However, few case histories on gravel packing of an ICD/AICD completion have been reported in the literature [42,43]. The longest horizontal section length that was reported is 1395 ft.

In fact, achieving a complete gravel pack with sand control screens that have inflow control devices (ICD/AICD) can be challenging due to:

- ICD screens restrict fluid from entering the screens/washpipe annulus resulting in a lower alpha dune height.
- Pumping rate during beta wave placement must be slowly reduced to stay below fracture pressure.

Firstly, let's go back to the standard OHGP alpha/beta wave water pack operation. The alpha wave runs from Heel to Toe and the washpipe ends at the Toe to permit the return of the fluid. During alpha wave-placement, a portion of the flow enters the screen/washpipe, and the remainder stays in the screen/wellbore annulus.

As I discussed in the previous chapter, ICD/AICD was designed to restrict the water production and minimize the entry points into the screen. That means restricting the fluid from entering the screen/washpipe annulus. This makes gravel packing an ICD/AICD completion extremely hard if not impossible.

With this flow restriction, an increase in the flow velocity in the screen/wellbore annulus occurs. The increased flow velocity outside the ICD screen will result in a lower alpha-wave height. This reduced alpha wave height was taken into account when determining the pump rate necessary to ensure that the screen was covered during alpha-wave placement. Meanwhile a solution should be provided to allow the fluid enter the washpipe and this could be made possible if an alternate flow path were introduced into the completion. The solution proposed by Baker is adding a closable sliding side door (SSD) screen to the toe section [43], see figures 23 through 25.

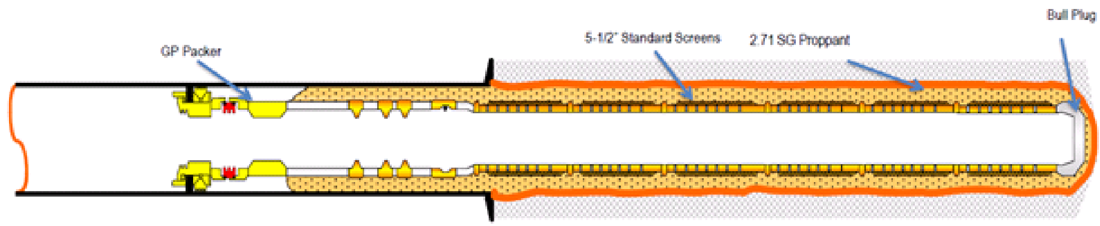


Figure 23: Typical Architecture for Horizontal open Hole Gravel pack Wells with standard screens [43]

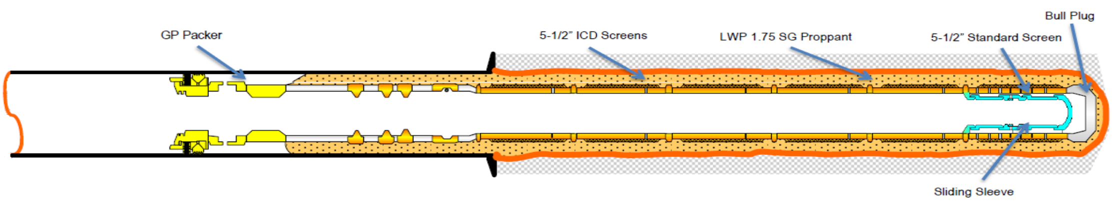


Figure 24: Typical Architecture for Horizontal Open Hole Gravel Pack Wells with ICD screens [43].

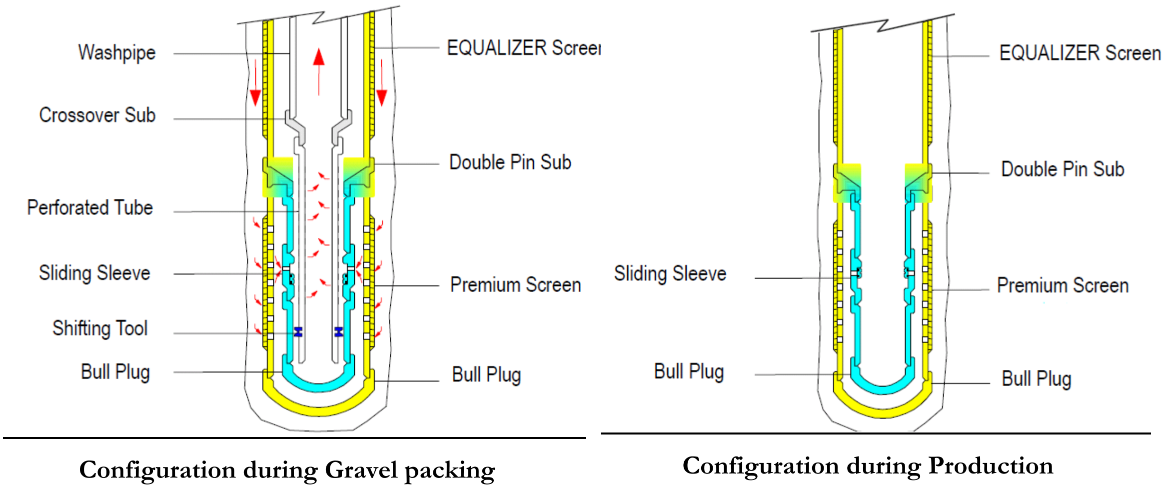


Figure 25: Configuration during Gravel packing during Production [43]

After the alpha wave is complete, that means it has reached the Toe of the well, the beta wave will initiate. As the beta wave travels, screens are successfully covered from the Toe to heel. As the beta waves move to reach the heel, a high pressure drop needed for the fluid to flow through ICD into the base screen/wash pipe annulus. This added resistance for fluid flow to enter the ICD screen causes a large increase in pressure drop during beta-wave placement and therefore a significant pressure rise in the screen/wellbore annulus. That's why, for the OHGP with ICD/AICD screen, the pump rate during beta-wave placement must be slowly reduced to a certain rate to stay below fracture pressure [42,43].

With the described solution, Baker successfully used OHGP with ICDs in Etam oil field in Gabon [43] and with AICDs in offshore Brazil for Statoil. However, for the case Ocelote field in Columbia, Schlumberger proposed another solution. In fact, they complete the well with ICD in three steps. Firstly, the well is completed with screen and zonal isolation system (packers). Then the well is gravel packed with 100% efficiency. Finally, two weeks after completing the well, an ICD internal string in run. The max horizontal section length of the well that was reported is 1100 ft, see figure 26. The drawback of this technique is that the diameter of the producing tubing is reduced from $5^{1/2}$ (screen diameter) in to $4^{1/2}$ in (ICD joint diameter) and hence the production rate is reduced [42].

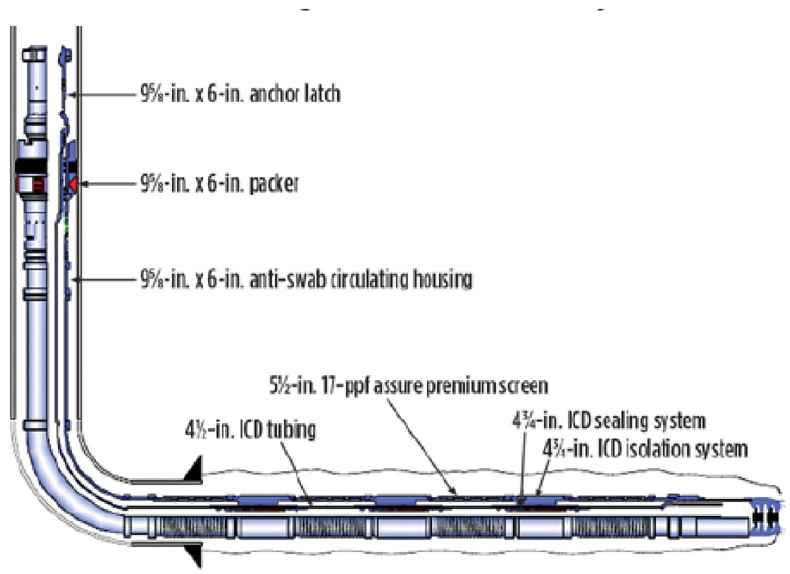


Figure 26: Schematic of the gravel pack assembly including the ICD internal tubing and internal isolation system [42]

Chapter 4 Simulations and Results

1. Input Data for X_South Field

I summarized the most useful reservoir and fluid data for the X_South field in table 4. The VIP® simulation model was built by the operator and converted to an Eclipse™ model by a consulting firm. I added a local grid refinement (LGR) around the well to improve the accuracy of the results during AICD completion design.
X_South is an oil reservoir that contains high quality sand with porosity between 25% and 30% and permeability between 200 mD and 2000 mD. The permeability has very heterogeneous distribution and this is due to the variation of the grain size.
X_South comprises producer injector pair. The Well_X is a horizontal oil producer well with OH length ~920m where 200m of poor quality sand/shale. The injector well has an open hole length of ~800m with small amount of poor quality of sand/shale.

Table 4 : Input Data for X_South Field

X_South Field	
Where	North Sea
First Oil (expected)	2016
Reservoir type	Sandstone
Number of Wells (planned)	1 Oil Producer (Well_X) + 1 Water Injector (Well_Y)
Type of Well	Horizontal well with short radius
Reference Depth	MSL
RT [m]	32
Water Depth [m]	378
OWC Depth [ft]	6,961.9
GOC Depth [ft]	6,820.9
Init Reservoir Pressure@ OWC [psia]	3,133.8
Bubble Point Pressure Pb [psia]	3,095
Initial Rs [Scf/Stb]	0.3934
Fluid Properties	

Oil viscosity @RC [cp]	3
Oil density @SC [lb/ft^3]	56.3
Gas viscosity @RC [cp]	0.02
Gas density@ SC [lb/ft^3]	0.045
Water viscosity@ RC [cp]	0.5
Water density@ SC [lb/ft^3]	62.6
Oil Gravity (deg API)	26
Gas Gravity	0.58
Reservoir Properties	
K_v [mD]	0 – 50
K_h [mD]	38 – 546
Porosity [%]	25 – 27
X_South Simulation Model	
Number of grid cells	< 7.7 million (298 x 216 x 120)
Number of active cells	< 20,000
Dx = Dy [ft]	164
Dz [ft]	6.8 – 13.2
LGR	3 x 3 x 1

2. Input Data for Well_X

The Well_X is oil producing well. It produces from 2 sand geobodies (the yellow and green bodies as it is indicated in figure 27). Between these 2 zones, a shale zones is laying. The well is passing through 200 m of a shale barrier zone. The total horizontal section length is around 920 m.

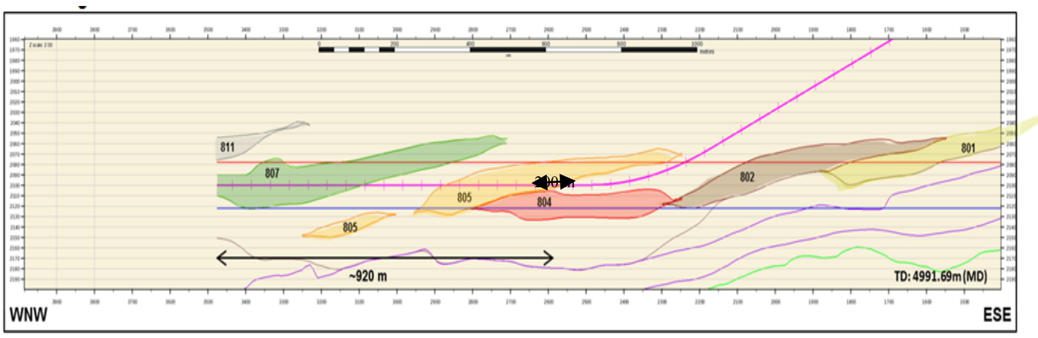


Figure 27: Well_X Geological Position

I summarized the most important information of the Well_X in Table 5. The production from the well was controlled by two different strategies depending on the objective of the simulation study.

Well_X control mode 1: ORAT target with THP lower limit and Artificial Lift

Well_X control mode 2: BHP lower limit and Artificial Lift.

Table 5: Input Data for Well_X Well

Well_X Trajectory	
Completion selection for oil wells	OpenHole Gravel Pack with AICDs
Hole Size	8.5”
Well length MD (Toe) [ft]	16,386.8
Heel MD [ft]	13,242.32
TVD [ft]	6,889.76
Casing Shoe MD	12,675.6
Open Hole Section Length [ft]	3,711.2
Horizontal Section Length [ft]	3,144.48
Control Targets and Limits	
THP [Psia]	234,7
ORAT [stb/day]	7340
Artificial Lift Quantity [Mscf/day]	7500
BHP [Psia]	1200

3. X_South field Challenges

Two main challenges regarding the AICD completion design for the X_South field could be mentioned:

- Choking the water: The oil viscosity in the X_South field is 3 cp. The viscosity ratio oil over water is 6. This low ratio makes the AICD completion design more challenging job. AICD has been successfully installed in 2.6cP oil. A greater viscosity difference gives better AICD performance. The value in gas shut off is always significant due to the low gas viscosity.
- Sand control: The sand control in needed for Well_X due to the low unconfined compressive strength of the formations to maintain sand production within the 3 lbs/1000bbls (total liquid). A range of open hole completion types have been installed in X_South field (SAS, OHGP, ESS). It is planned to use OHGP for Well_X and the challenge is the maximum horizontal section length that was reported for gravel packing a well completed with ICD/AICD which is 400 m, and in our case it is 920 m. In this AICD completion design study we considered the case of SAS. In fact, in terms of flow modeling and simulation, the additional pressure drop due to screen and gravel pack is comparable.

4. X_South Field Production Performance

The X_South field is producing from 2 zones which are partially connected. These 2 zones are separated by a non productive shale zone. After simulating the reservoir with the first control mode (ORAT control), I found that both zones produce the same amount of oil. However, zone 1 is producing much more water due to its connection to an active aquifer. Besides, zone 2 is producing more gas as it is connected to a gas cap (see figure 28). The simulation results are summarized in table 6.

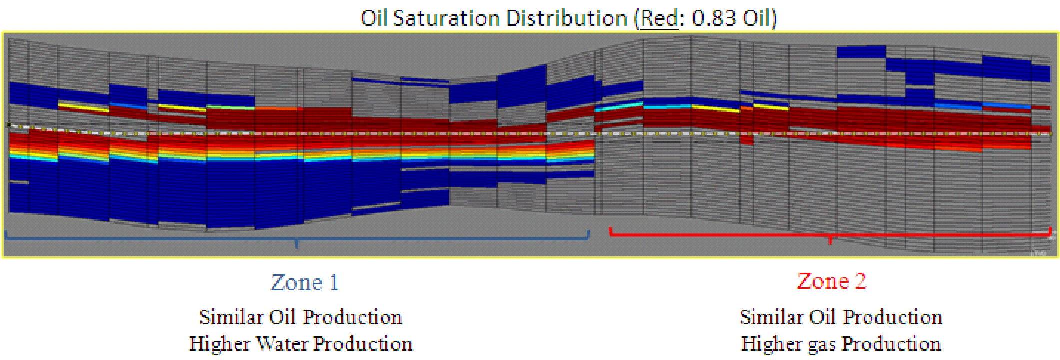


Figure 28: Oil, Gas and Water Production from zone 1 and zone 2 of Well_X

Table 6: Oil, Gas and Water Production from Zone 1 and zone 2 of Well_X

	Zone 1		Zone 2		Total
Cumm Oil Prod (MMSTB)	49.81	48.2 %	53.52	51.8 %	103.33
Cumm Water Prod (MMSTB)	67.22	79.9 %	16.94	20.1 %	84.16
Cumm Gas Prod (BSCF)	11.3	33.5 %	22.4	66.5 %	33.7

The oil production rate, gas production rate and water production rate over the time from well_X, zone 1 and zone 2 are respectively plotted; see figures 29, 30 and 31. The gas is produced in early well life form both zones. However, the water starts to be produced much earlier in zone 1 than in zone 2. The water breakthrough in zone 2 is 1000 days.

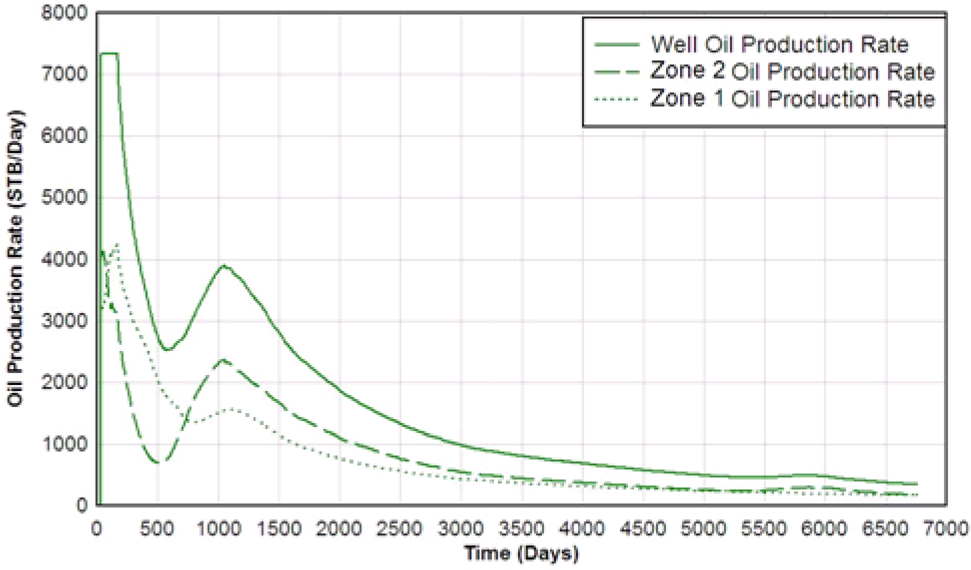


Figure 29: Oil Production Rate over the time from zone 1 and zone 2 of Well_X

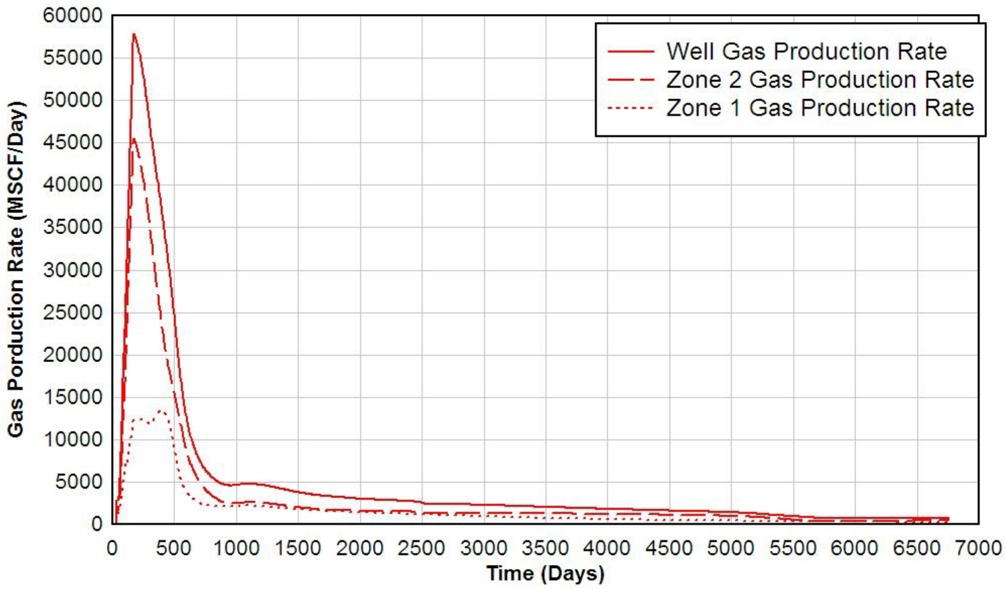


Figure 30: Gas Production Rate over the time from zone 1 and zone 2 of Well_X

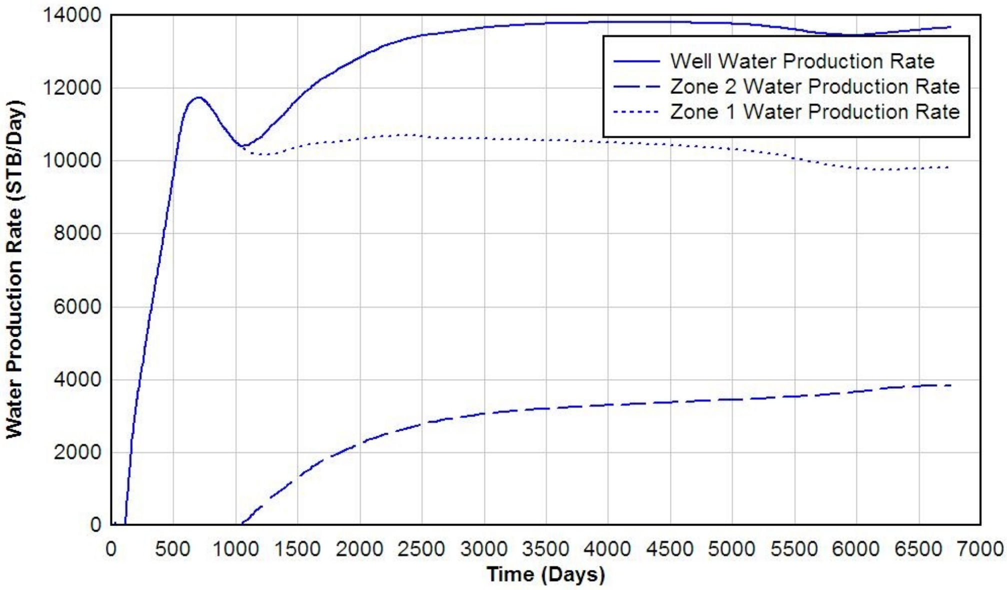


Figure 31: Water Production Rate over the time from zone 1 and zone 2 of Well_X

From table 5, the difference in terms of MD between the casing shoe and the heel is around 175 m. This difference is translated in Eclipse simulation model to 2 well connections. We are considering in this short study, the effect of shutting the first and/or the second well connection. Therefore, we study the effect of starting the oil production from the heel, see figure 32.

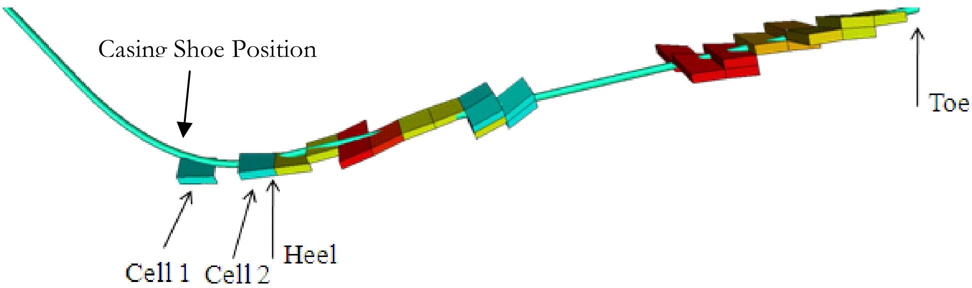


Figure 32: Casing Shoe, Heel and Toe Position

The result of this simulation study is summarized in table 7. I remark that by starting the production from the heel, I lose 1.5 % in terms of cumulative oil production and the water production is decreased by almost the same amount (2%). As I am reducing as much oil as water by closing the two first connections, it is better to keep producing from all the open hole section (from casing shoe to the Toe).

Table 7: Effect of shutting connections 1 and/or 2 on water, oil and gas production

	Start Production from Heel	Start Production from Cell 2
Cumm Oil Prod	-1.5 %	-1.2 %
Cumm Gas Prod	-0.2 %	-0.18 %
Cumm Water Prod	-2.0 %	-0.8 %

5. Well_X Modeling and Pressure Drop Calculation Petrel™/ Eclipse™

The well models available in Eclipse™ are the standard well model (default model), as well as multi-segmented well model.

The well model that is used to compute the amount of fluid that the well is producing:

$$q = C_f M\left(P_{Cell} - P_{bhp} - \Delta P\right)$$

Where C_f is cell connection factor. It is a measure of transmissibility between the grid block and the well connection.

M is the fluid mobility computed using the fluid model and the rock physics functions.

P_{Cell} is the pressure in the grid cell that the well is penetrating.

P_{bhp} is the bottom hole pressure of the well. This is the pressure at the reference depth of the well (usually at the topmost connection to the grid).

ΔP is the pressure difference between the pressure inside the wellbore at the connection and the bottom hole pressure.

For the standard well model, the pressure drop due to acceleration and friction is assumed to be small and is therefore neglected. Hence, the difference in pressure between the bottom hole pressure and the connection is computed as the hydrostatic head.

$$\Delta P = \Delta P_{hyd} = \rho g h$$

If the grid cells are not aligned horizontally, the depth of a horizontal well undulates since the depth of a connection is interpreted as the depth of the center of the cells that the connection is placed. Consequently, the pressure along the wellbore computed using the standard well model can vary from connection to connection, even when the trace is horizontal. For the case of Well_X, the results are shown in the figure 33.

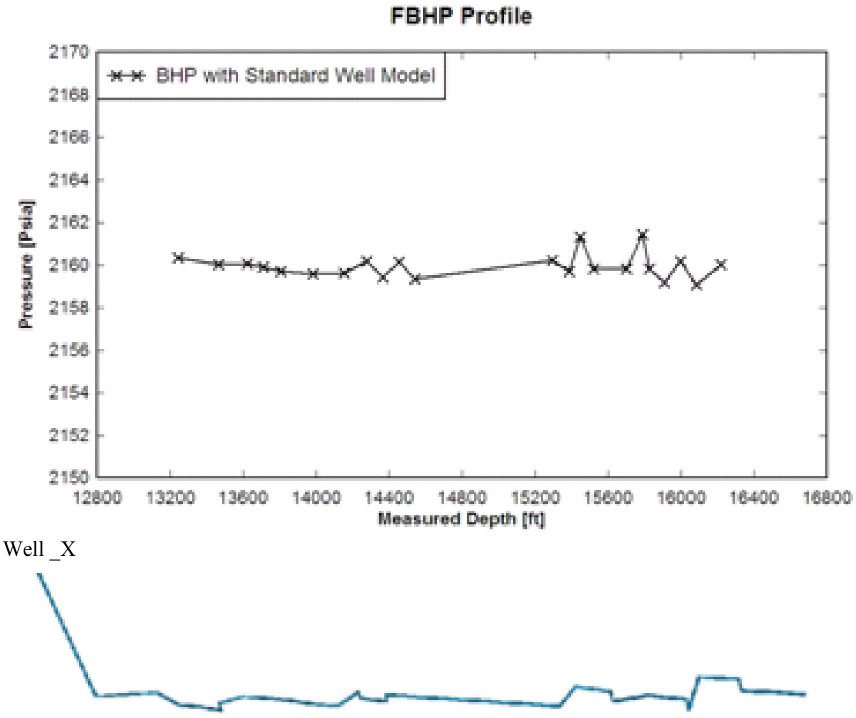


Figure 33: Top: Fluctuation in BHP through the horizontal section of Well_Prod.
Bottom: depth of the Well_Prod horizontal well undulates

There are several reasons why the standard well model is not suitable to model the behavior of a horizontal well:

- In the standard well model, the pressure drop due to friction is neglected. For horizontal wells this contribution can be significant.
- The pressure drop along a well can undulate due to the layout of the grid and not because the well trace is actually varying in depth.
- Pressure drops caused by down-hole devices (AICD, ICD) cannot be included with the standard well model.

To overcome the shortcomings of the standard well model when modeling horizontal well, more rigorous well model called the multi-segment well model could be used. As the name suggests, it involves dividing the well into multiple segments in much the same way as you divide the reservoir into multiple grid blocks; see figure 34. By considering the frictional pressure losses in the well, the flowing bottom hole pressure profile for Well_X is plotted in figure 35. The frictional pressure losses along the well are negligible (around 10 psi).

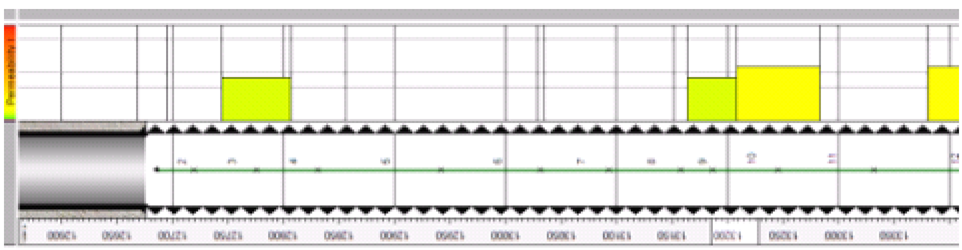


Figure 34: Modeling Well_X using Well Segmentation option. In this case a segment per cell was chosen (Snapshot from Petrel)

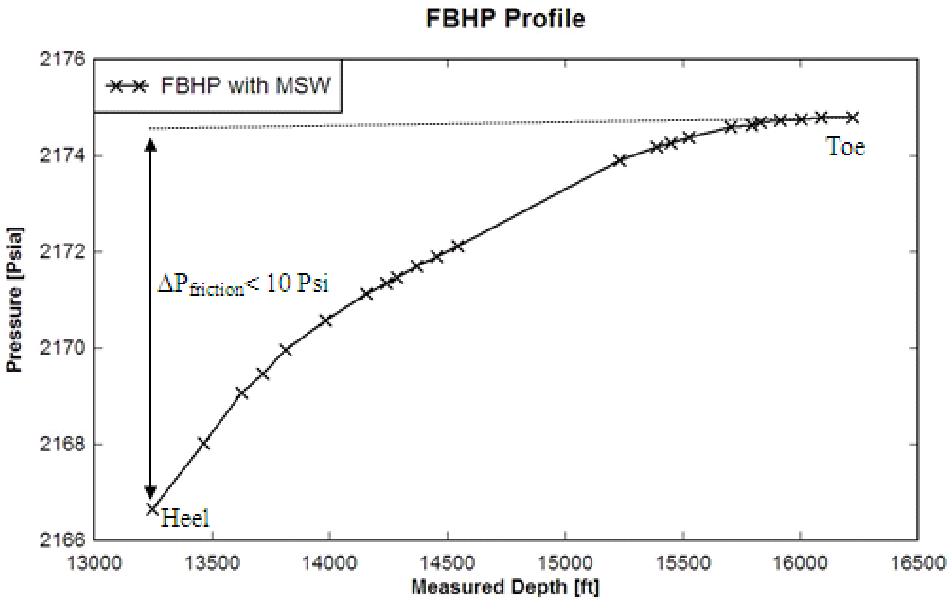


Figure 35: FBHP of Well_X in case of modeling the well using multisegmented option

Finally, to check the validity of the well segmentation model in Well_X, I run two Eclipse simulations. In simulation case 1, the well_X is modeled using standard well model. In simulation case 2, the well_X is modeled using multisegmented well model. The ORAT well control was used in both cases. I compared the total water, gas and oil production of the two cases. The results are summarized in table 8. No difference exists between the two models. However, we have to use multisegmented well option to model well_X as this is the only way to include down-hole devices (ICDs, AICDs).

Table 8: Oil, Gas and Water Production difference between the two well models

	%
Cumm Oil Prod	+0.03
Cumm Gas Prod	-0.03
Cumm Water Prod	+0.06

6. Static Simulation of Well_X Well with NETool™

6.1. Matching Well Trajectory Eclipse™/ NETool™

The directional survey of the Well_X was entered into NETool™. In the beginning, a small discrepancy was found for Well_X trajectory which was adjusted by re-importing the well survey into Petrel™ and changing the coordinate system and the reference depth used in Petrel™. The well_X trajectory in Petrel ™ and in NETool™ are shown in figure 36.

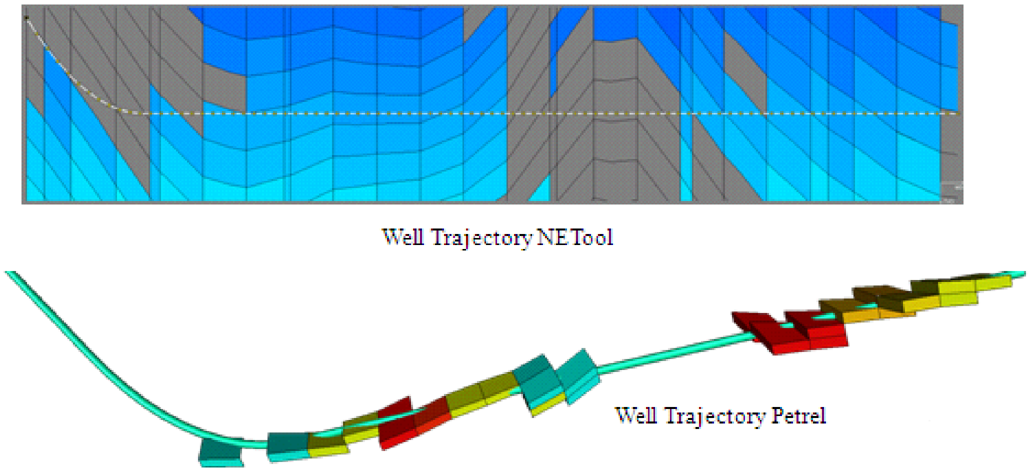


Figure 36: Well_X trajectory in Petrel ™ and in NETool ™

Finally, the well path in Eclipse™ and NETool™ almost matched. In fact, the well is intersecting the same grid cells except one well connection. This difference is due to the fact that a trajectory point is located in frontier of two adjacent cells (79, 124, 21) and (80, 123, 21) as it is shown in figure 37. Consistency in well trajectory between NETool™ and Eclipse™ is important as this will determine much of the wells behavior.

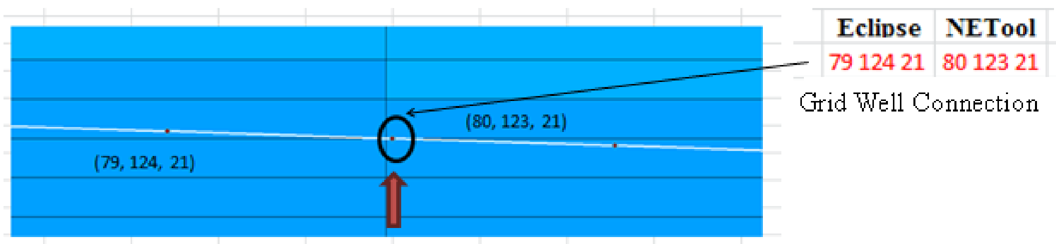


Figure 37: Difference between well connections in Eclipse™ and NETool™

6.2. Matching Well Performance without Inflow Control Eclipse™ / NETool™

As NETool™ is static simulator, simulations should be run in certain chosen timesteps. The chosen timesteps for Well_X are: 0, 120 days (0.3 year: water breakthrough zone 1), 184 days (0.5 Year: peak gas production), 365 days (1 year: peak water production zone 1), 730 days (2 Years: water breakthrough zone 2), 1096 days (3 years), 1826 days (5 years), 3652 days (10 Years).
In order to have an accurate and consistent NETool™ model, it is required to match it to Eclipse™ data for each chosen timestep. In fact, it is important to have the same well PI in both simulators.
Since NETool™ cannot read all Eclipse™ information, it does not import constraints put on the well in Eclipse. For Well_X the well constraint that has been used is Oil rate. The

most important outputs to be matched between Eclipse and NETool™ are BHP, total downhole flow rate, GOR and WCUT.
Generally, for simple Eclipse™ models we usually observe match within 5% on all parameters without any calibration. If the model is complex, e.g. it contains non-neighboring connections, saturation hysteresis, many small dead blocks spread everywhere or other advanced features there might be a big difference (100%).
The new improvement in NETool™ that includes adding the same method as Eclipse™ to calculate PI, importing the relative permeabilities from Eclipse^T. etc. I am able to get better match.
The difference between NETool™ and Eclipse™ for BHP is less than 5%. For GOR, it is less than 18%. For WCUT, it is less than 2%. And finally, the biggest difference is in total downhole flow rate which is less than 35%. These results are explained much more in details in figure 38.
One reason of this remarkable discrepancy in downhole flow rate between the two models is the complexity of the X-South field. In fact it contains a huge number of dead blocks (shale zones). It was difficult to have better match between the two models despite the help of a NETool™ expert.

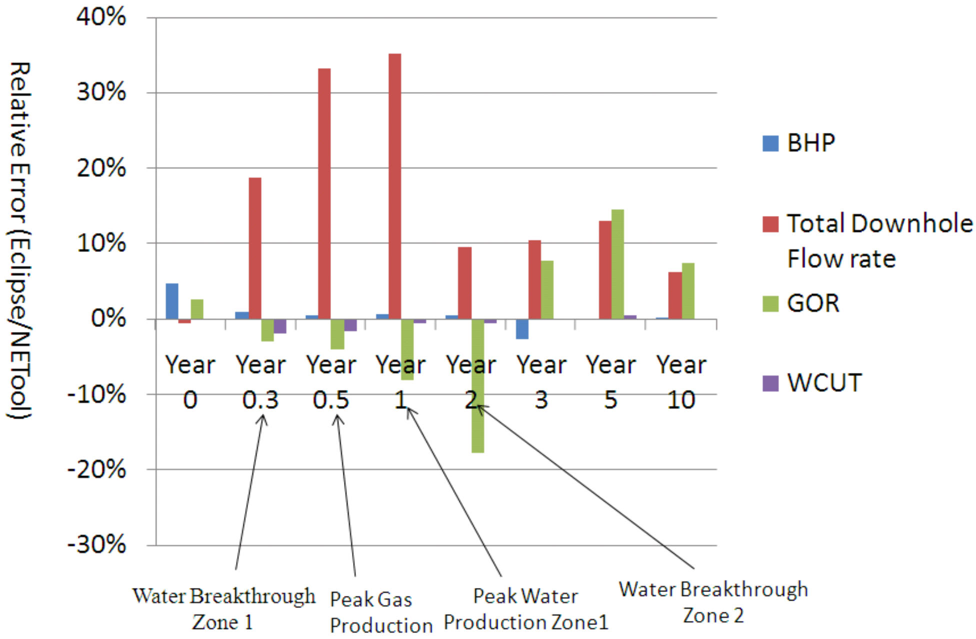


Figure 38: Difference between Eclipse™ and NETool™ in terms of BHP, GOR, WCUT and Total downhole flow rate for the chosen timesteps

I tried to move the trajectory point from cell (80, 123, 21) to the cell (79, 124, 21) to have full coincidence of Eclipse™ and NETool™ trajectory as it is indicated in figure 39.

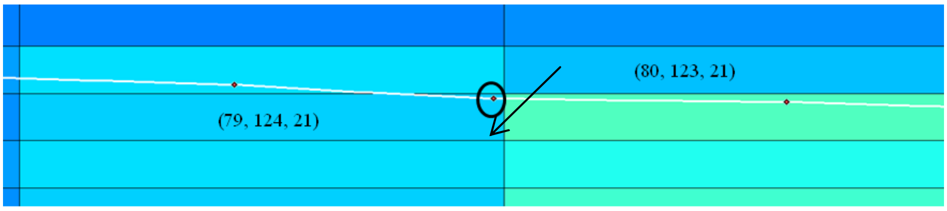


Figure 39: Moving trajectory point

The effect of this change on the accuracy and the consistency of the NETool™ model is not very noticable. The maximum difference between the two NETool™ models (before and after moving the trajectory point) is just 5% for the total downhole flowrate. These results are explained much more in details in figure 40.

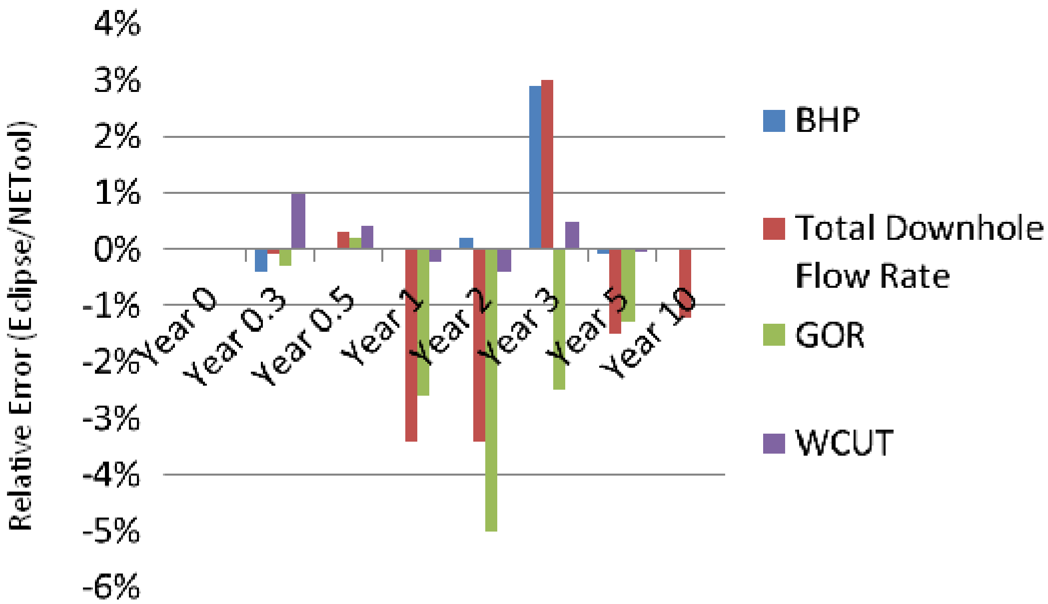


Figure 40: Difference between the two NETool™ models is terms of BHP, GOR, WCUT and Total downhole flow rate for the chosen timesteps.

6.3. Well Segmentation with NETool™

Generally, three imbalance scenarios that arise in horizontal wells could be identified: a) variable productivity effect (VPE), b) Heel Toe effect (HTE), or c) both VPE and HTE. For the well_X, the frictional pressure loss in the Heel is negligible. It is less than 1 bar. That's why the pressure drawdown along the wellbore is constant as it is shown in figure 41. Therefore, the HTE is not the dominant process.

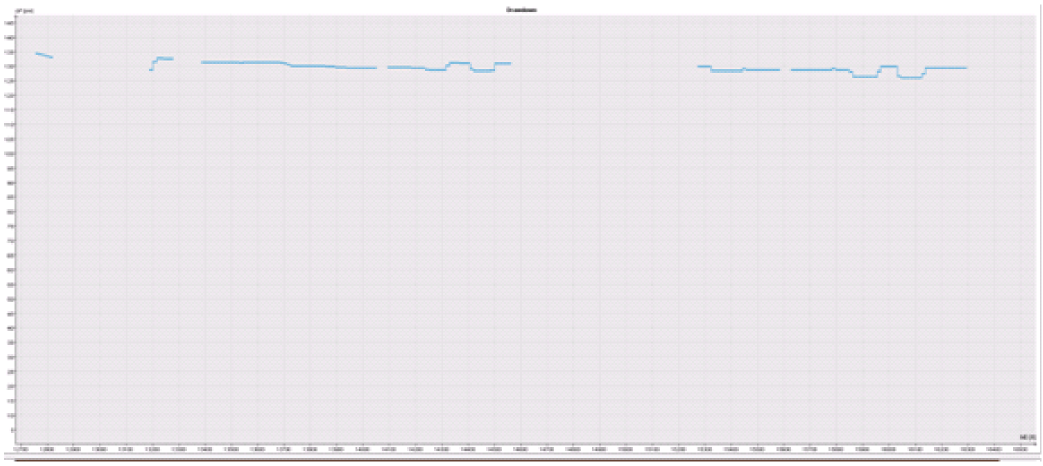


Figure 41: Pressure drawdown along the open hole section of the Well_X at year 0

To quantify the variable productivity effect, the ratio of total downhole fluid influx from the low and high productivity intervals is calculated. From a NETool™ snapshot of the downhole flow rate at year 0 (see figure 42), the highest rate is 7.3 Rb/day/ft and the lowest rate is 0.62 Rb/day/ft. Therefore, the ratio between these two extremes values is 11.7. In ideal case, this value should be near 1 which means I have an even flow along the wellbore. Therefore, the VPE is the dominant process in the well_X. This variation in productivity is due to the heterogeneity in the reservoir which is indicated by variation in horizontal and vertical permeabilities along the open hole well section, see figure 43. This variation in productivity is causing uneven flow and an early high gas/water production.
That's why the objective of adding AICDs in the lower completion is to reduce the VPE ratio to as close to unity as possible without compromising the overall well deliverability.

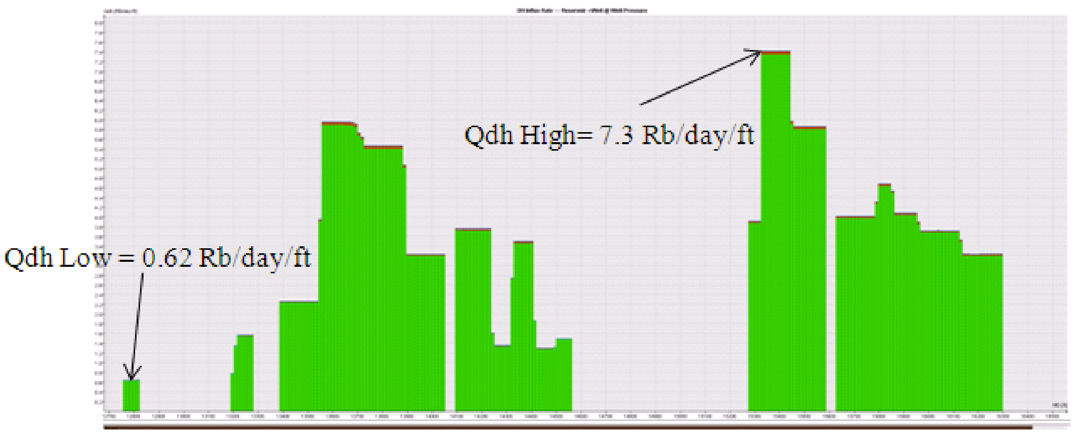


Figure 42: Downhole Flow Rate along the open Hole section of Well_X at year 0

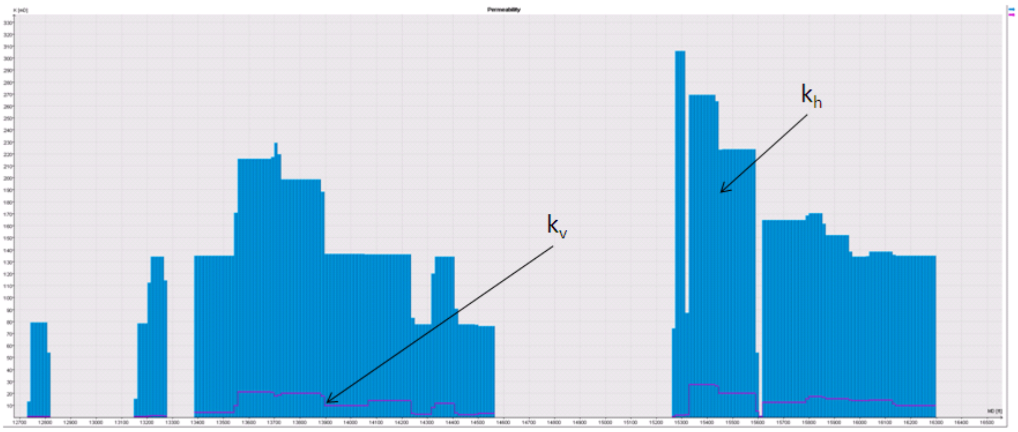


Figure 43: Vertical and Horizontal Permeability along the open Hole section of Well_X

In NETool™, the well_X is divided into 59 segments. Each segment has a 12 m length which is the same as the length of the commercial AICD joint. The well is divided into compartments by installing open hole packers based on:

- Static wellbore parameters (e.g. variation in permeability)
- Dynamic changes (e.g. change in saturation along well grid blocks from Eclipse restart file).

Initially, based on the type of the formation sand/shale, the well is divided into compartments. The productive sand zone is separated by two packers from the rest of the formation. The shale zone is isolated behind blank pipe or packer depending on the length of the zone, see figure 44. The zonal isolation is required in this case to prevent shale mobilization due to annular flow which may lead to screen plugging.

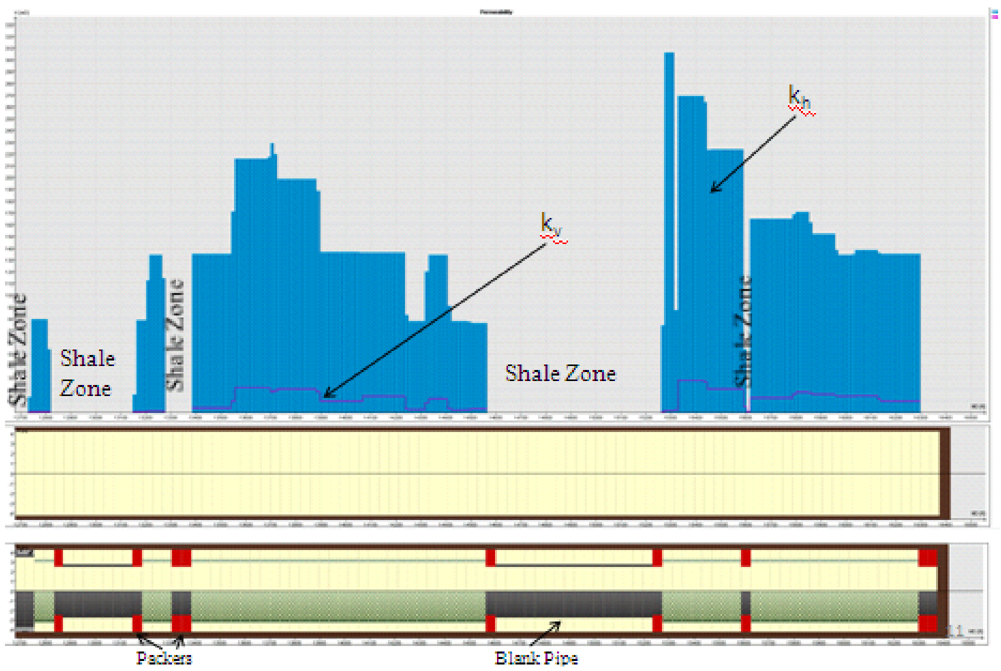


Figure 44: Well_X segmentation and initial packers/blank pipe placement

Then, on the basis of the permeability profile and on the flowing fluid, the well is divided into separate segments. It is important in well segmentation to avoid mixing large permeability variations in the same segment, see figures 44 and 45.

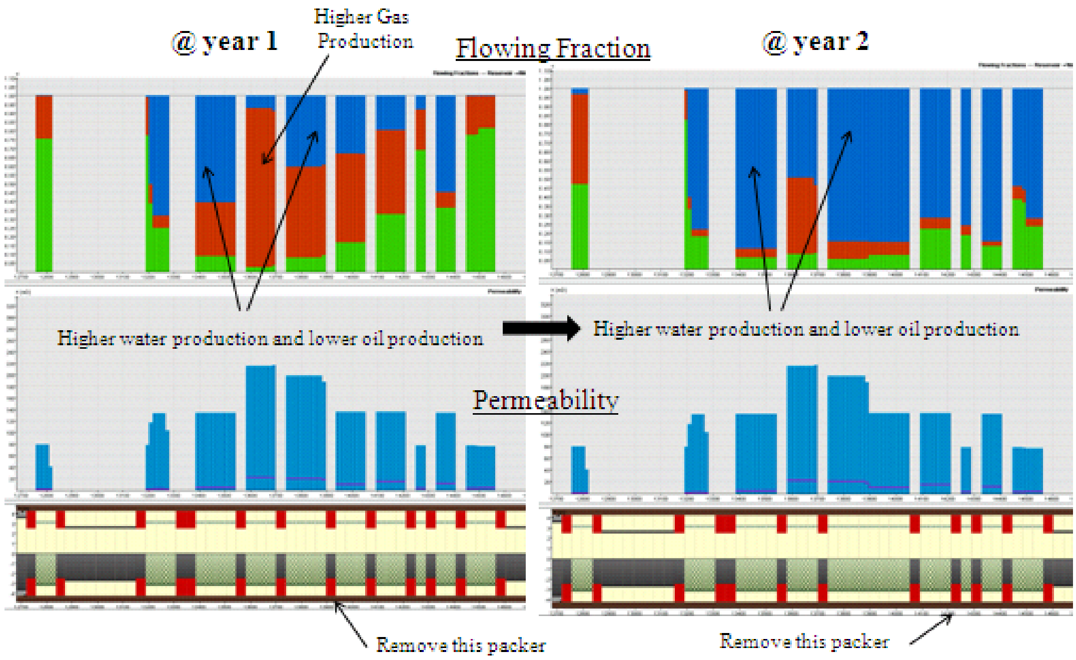


Figure 45: zone 1 Segmentation based on permeability profile and flowing fluid

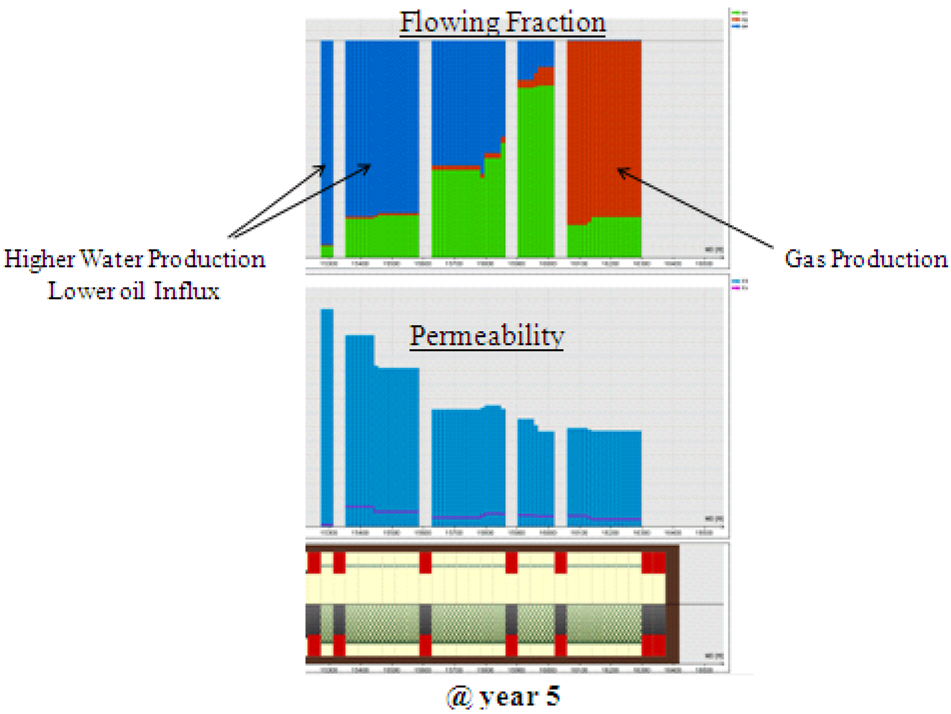


Figure 46: zone 2 Segmentation based on permeability profile and flowing fluid

Finally, I obtained a complex segmentation with 13 compartments and 18 packers as it is described in figure 47. The complexity of the tool string, with the high number of open hole packers that can be deployed safely in the well makes the completion not optimum. In fact, this design doesn't follow one of the rules for practical completion design which is to keep the completion as simple as possible to avoid any operational problem.

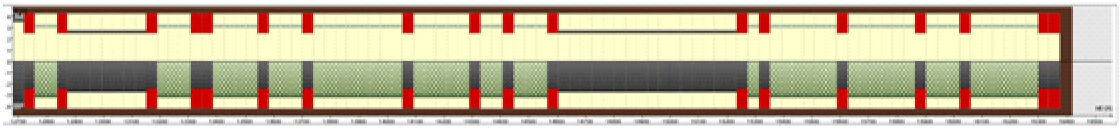


Figure 47: Complicated Segmentation

Hence, I tried to simplify the actual segmentation based on permeability profile and early water/gas breakthrough zones. Three cases can be obtained with between 6 and 9 compartments, see figure 48.

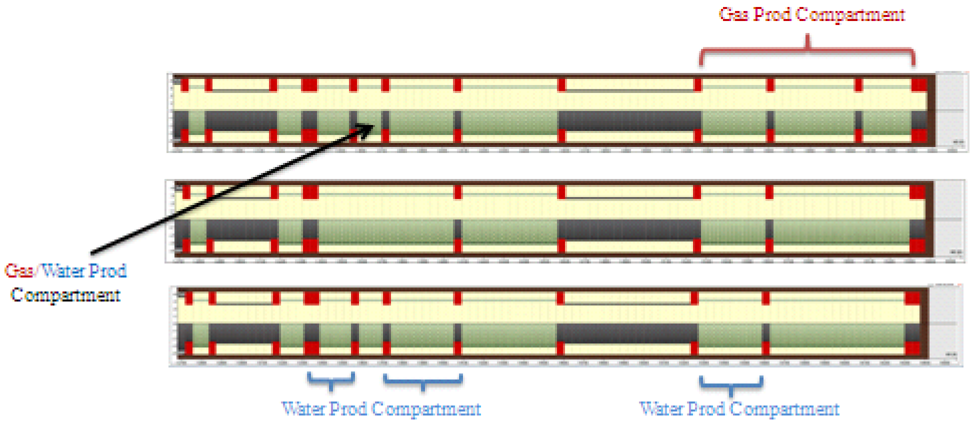


Figure 48: Simpler Segmentation cases

6.4. AICD completion design

Five scenarios are considered for AICD completion design:

- Choking gas production zone: And therefore which compartment I need to choke to reduce gas production.
- Choking highly gas/water production zone: I select the zone that are facing early water/gas breakthrough to choke them.
- Equalize the downhole influx: I choke the well based on the objective to equalize the downhole influx at well startup.
- Increase the downhole level choking: examine the effect of over-choking the well
- Completion Optimization: based on the results of the four previous scenarios, I tried to define the optimum completion designs.

a. Choke gas production

The objective of the first scenario is to choose gas production. Hence, I need to determine which compartments I should choke. That's why four completion cases were defined: case 1, case 2, case 2b and case 2c. A uniform AICD diameter was chosen (5mm).

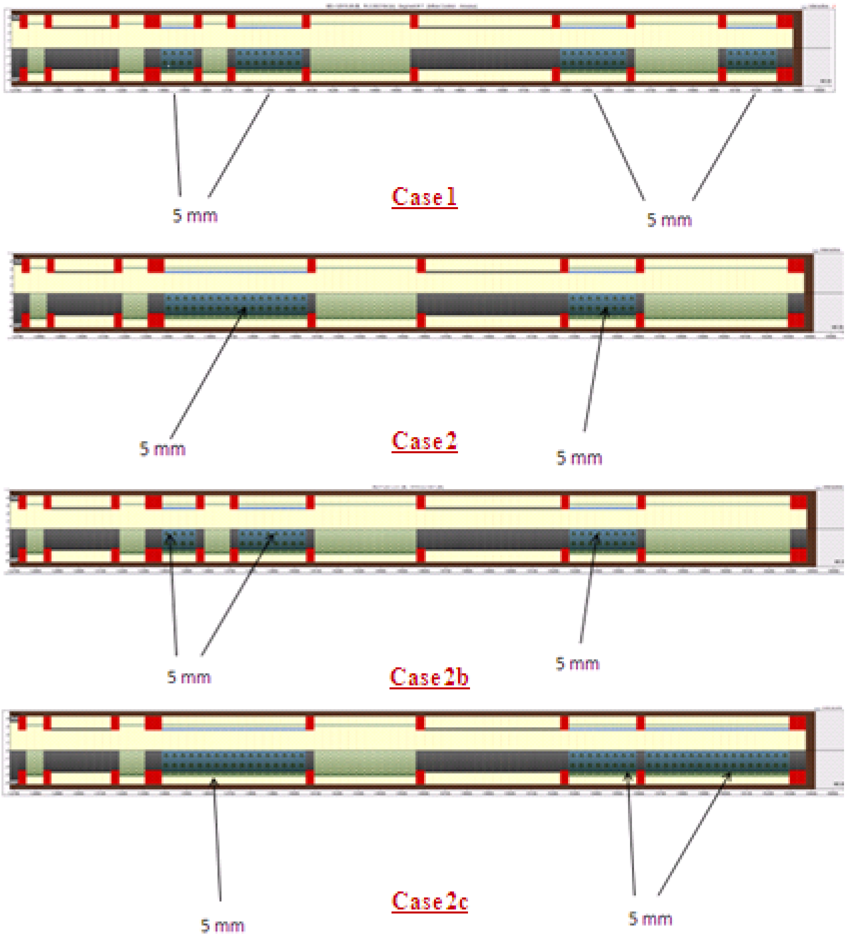


Figure 49: Choking gas production zones

b. Choking highly gas/water production zones

In the second scenario, I tried to choke the highly gas/water production zone. In fact, it is possible to target and choke only those well compartments that are likely sources of early water or gas breakthrough. Three cases were defined: case 2d, case 2c and case 2e, see figure 50. I choose the same level of choking in each compartment (5 mm AICD), just in the last case I tried to increase the level of choking (2.5 mm AICD) of the highly water productive zone. As right now I am not dealing with an optimization problem. In fact, the level of choking can be adjusted to create the desired production profile.

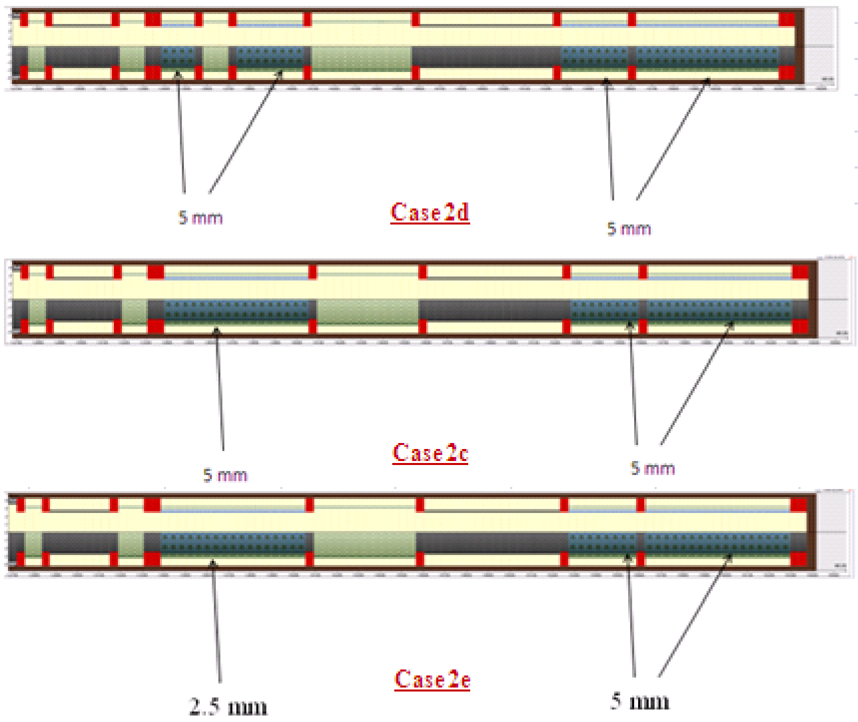


Figure 50: choking highly gas/water production zones

c. Equalizing the downhole influx

In this scenario, I tried to choke the well based on the objective to equalize the downhole influx at well startup. By equalizing the influx, I improve the sweep efficiency and I reach an even flow along the wellbore and therefore improve the oil recovery from the low productive zones. The downhole flow rate is uneven in the well startup as it is indicated in figure 51. Four completion cases were identified: case 3b_New, case 3d_New, case 4_New and case 5_New, see figure 52. I increased the level of choking from one case to another. As a result, we had an even flow along the wellbore and we reduced the VPE ratio from 11.7 to between 7 and 3 depending on the case, see table 9.

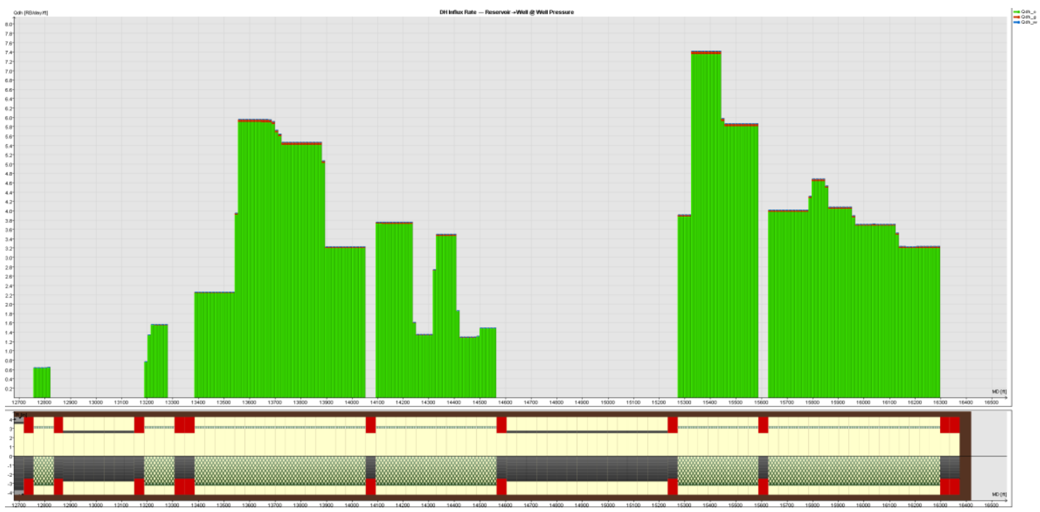


Figure 51: Downhole Fluid Flow Rate @year 0

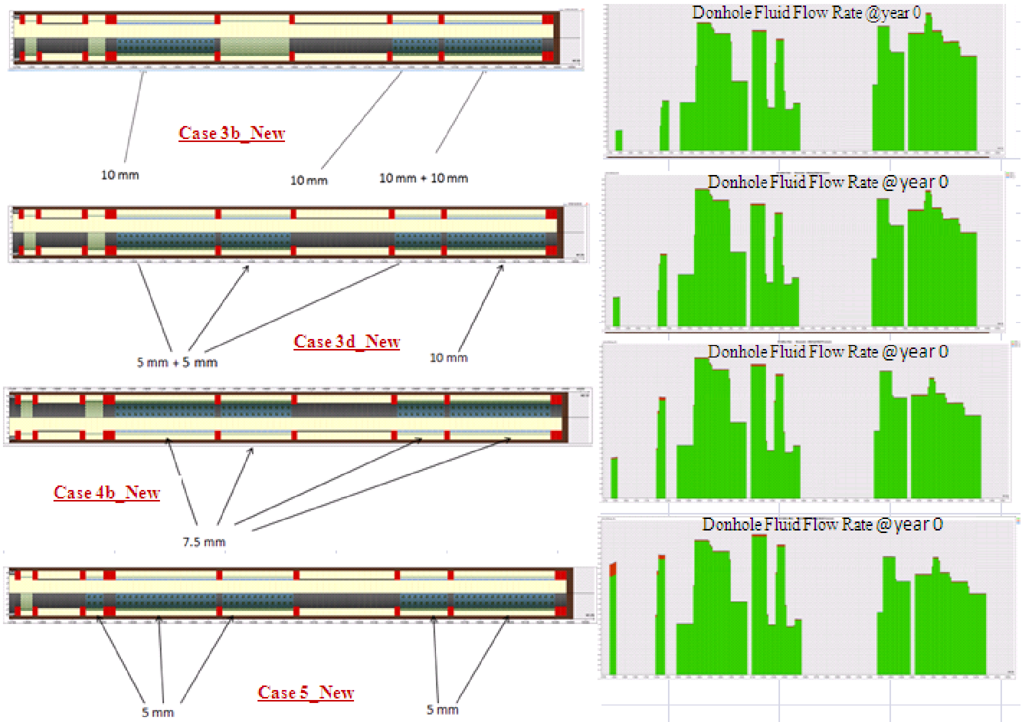


Figure 52: Equalize the influx

Table 9: VPE Ratio for influx equalizing cases

Design Case	VPE Ratio
Base Case	11.7
Case3b_New	7.0
Case3d_New	4.5
Case4_New	3.4
Case5_New	2.9

d. Increase the downhole level of choking

In this scenario, I tried to investigate the effect of increase the level of downhole choking of the well_X. Three cases are considered: case 4, case 5 and case 6, see figure 53.

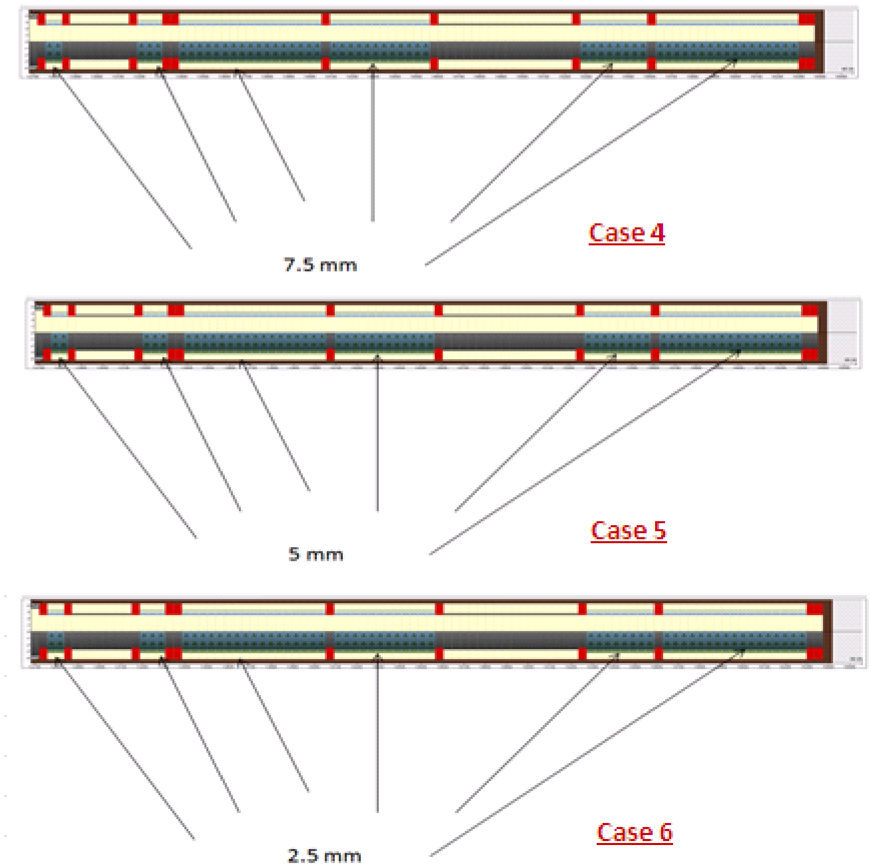


Figure 53: increase the downhole level of choking

e. AICD optimization

In this part of the AICD completion design, I tried to optimize the completion design based on the results of the 4 first scenarios. Three cases are considered: case 9, case 9b and case 2f, see figure 54. In the two first completion designs, all the open hole section of the well is choked with different levels of choking. I increased the choking of the zones that are facing early water/gas production. In the last case, case 2f, I choked just the zone that are facing early water/gas breakthrough and keeping the low productive zones open.

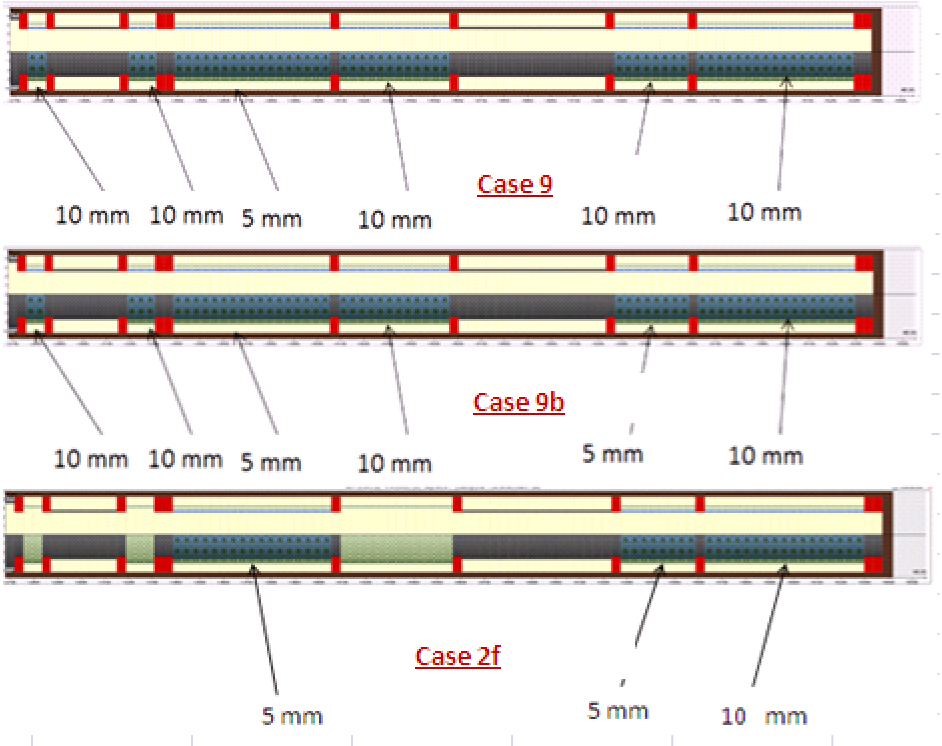


Figure 54: AICD Optimization Cases

7. Dynamic Simulation of Well_X Well with Eclipse™

Subsequent to the NETool™ modeling, the results were implemented into X_South Eclipse™ model. Simulations in Eclipse™ were run for all the cases discussed in the previous section. Simulations in Eclipse™ were over life of the field. AICDs installed in all the open hole section (AICD could be active or not). Local grid refinement was used to improve the accuracy of the results and to link each AICD to a grid cell.

7.1. Inactive AICD Vs Open Hole

First of all, I tried to simulate the case of open hole when the AICDs were set in the entire well. In this case, the AICD considered inactive and should behave like open valve with very reduced differential pressure. Therefore, I used very low strength coefficient a_AICD equal 2.10 10^{-12} as it is indicated in figure 56. The maximum pressure drop per segment in this case is 60 psi as it is indicated in figure 57. I simulated with Eclipse™ this case using ORAT control mode (mode 1).The result shown in table 10 indicates that there is no difference in terms of production performance between the open hole case and the inactive AICD case. The maximum relative difference is 0.3 % (cumulative oil production).

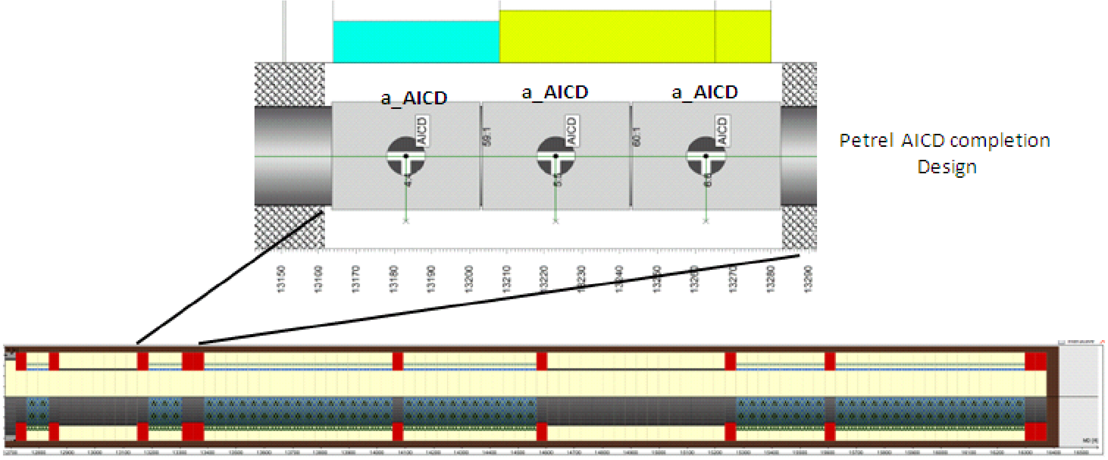


Figure 55: AICDs set in all the open hole section

a_aicd	2.100000E-012	psi*day/lb
mu_cal	1	cp
rho_cal	62.428	lb/RCF
x	2.863	prop
y	0.489	prop

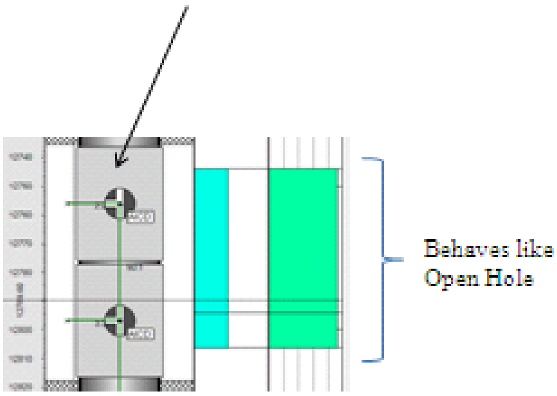


Figure 56: Inactive AICD vs. Open Hole

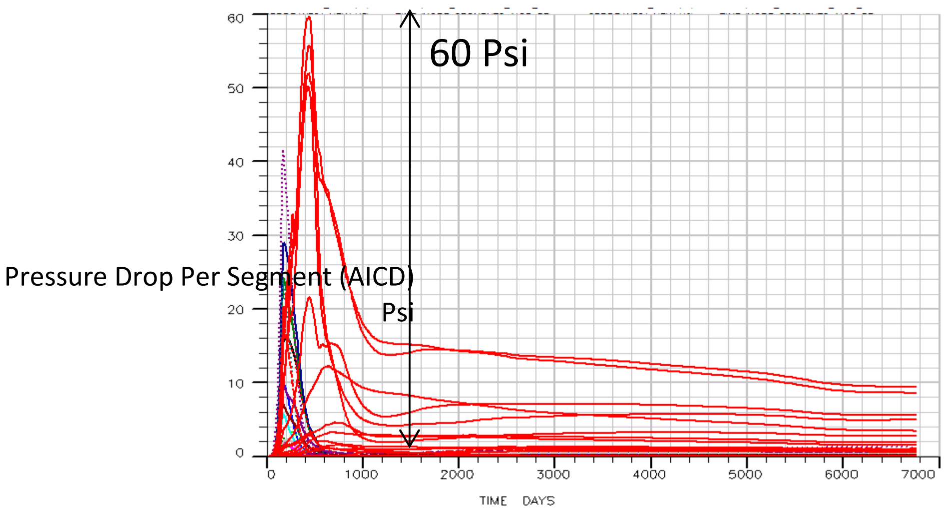


Figure 57: Pressure Drop per inactive AICD

Table 10: Relative difference in production performance between inactive AICD and Open Hole

	Relative Difference (%)
Cumm Water Prod	+ 0.12 %
Cumm Oil Prod	+ 0.3 %
Cumm Gas Prod	+ 0.07 %

7.2. LGR for AICD Completion Modelling:

A Local grid refinement (LGR) 3x3x1 around the well was used. That means around the well and with a distance of 100 m every cell is divided into 9 cells (3 in the X direction and 3 in the Y direction), see figure 58.

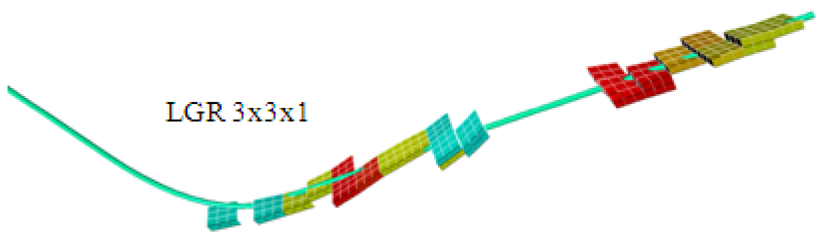


Figure 58: LGR 3x3x1

LGR was used to link each AICD to tubing segment (grid cell). In fact, Eclipse™ has the limitation that just one AICD can be used for each segment. NETool™ does not have this limitation. In this case I avoid having an equivalent AICD that replace the AICDs belongs to the segment, see figure 59.

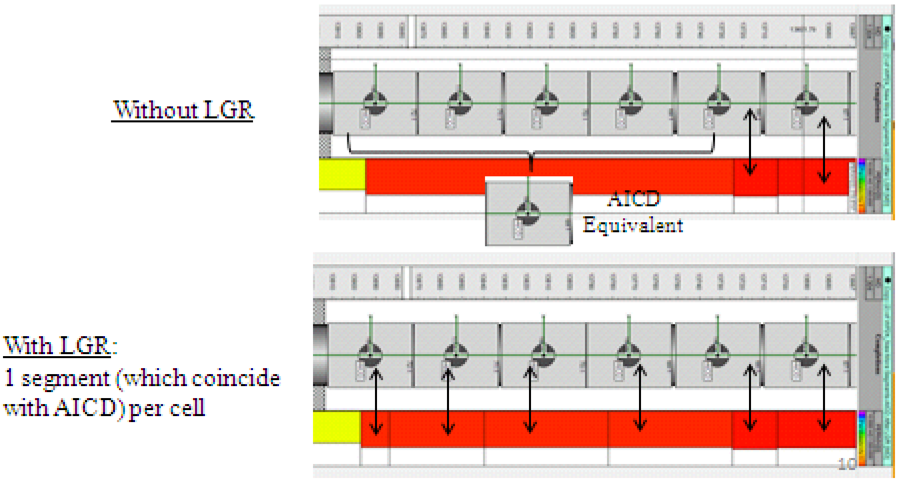


Figure 59: AICD with and without LGR

7.3. Eclipse™ Simulation Results

I simulated all the AICD completion cases described in section 6.4 using Eclipse™ and using ORAT control mode (mode 1).

a. Chok gas production

The results of Eclipse™ simulation for the four cases: case 1, case 2, case 2b and case 2c is shown in table 11. In the first three cases, the AICDs were not able to chok gas production and just in the last case (case 2c), the gas production is reduced by more than 16% compared to the base case (open hole). Therefore, I need to chok completely the zone 2 (highly gas production zone) and the high productive compartment in zone 1 as it is indicated in figure 60.

Table 11: Eclipse Simulation Results for Scenario 1

	ΔPT Oil (MMSTB)	ΔPT Water (MMSTB)	ΔPT Gas (BSCF)	% Oil	% Water	% Gas
Case 1	-0,19	-11,23	-0,65	-1,9	-13,3	-1,9
Case2	-0,61	-21,38	-0,28	-5,9	-25,4	-0,8
Case2b	-0,30	-12,66	-0,12	-2,9	-15,0	-0,4
Case2c	-0,37	-22,36	-5,57	-3,6	-26,6	-16,5

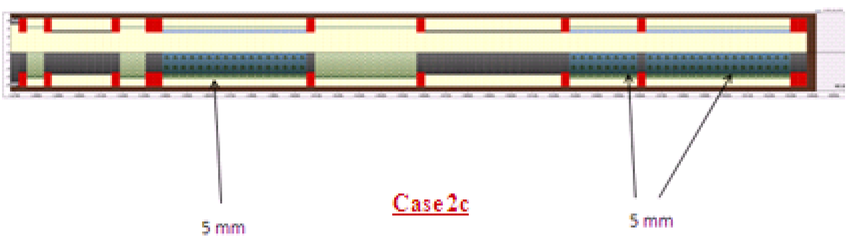


Figure 60: Case 2c AICD completion design

b. Choking Highly gas/water Production Zones

To compare the difference cases, I introduce two different ratio water/oil and gas/oil. The water/oil ratio respectively the gas/oil ration is how much water/gas I could restrict by reducing the oil production by 1% compared to the base case. As an example, if the water/oil ratio is 7 %, that means by reducing 1% of oil (compared to the base case), I am able to restrict 7% of water (compared to the base case). Hence, the higher is this coefficient; the better is the completion design.

By choking just highly gas/water production zones (the zones that are facing early gas/water production) and by taking into account the coefficient described in the previous paragraph, I found that the case 2c is the better than the two other cases. In this case the water/oil ration is 7.4 and gas/oil ratio is 4.6, see table 12.

However, for the case 2d, I noticed that oil production is increased by 0.2 %, but the water production is decreased by just 8.1 %.

Table 12: Eclipse Simulation Results for Scenario 2

	ΔPT Oil (MMSTB)	ΔPT Water (MMSTB)	ΔPT Gas (BSCF)	% Oil	% Water	% Gas	Water/Oil	Gas/Oil
Case2c	-0,37	-22,36	-5,57	-3,6	-26,6	-16,5	7,4	4,6
Case2d	0,02	-6,82	-5,09	0,2	-8,1	-15,1	--	--
Case 2e	-0,49	-26,32	-5,75	-4,8	-31,3	-17,1	6,6	3,6

c. Equalizing the downhole influx

By setting as a scenario equalizing the downhole influx at the well start up, and based on the ratio defined before, I found that the case 3b_New is better than the other 3 cases, see figure 61. In fact, in this case, the water/oil ratio is equal 7.9 and Gas/oil ratio is 1.8 %. The water, gas, oil production is decreased by 10%, 2.3 %, 1.3% respectively, see table 13.

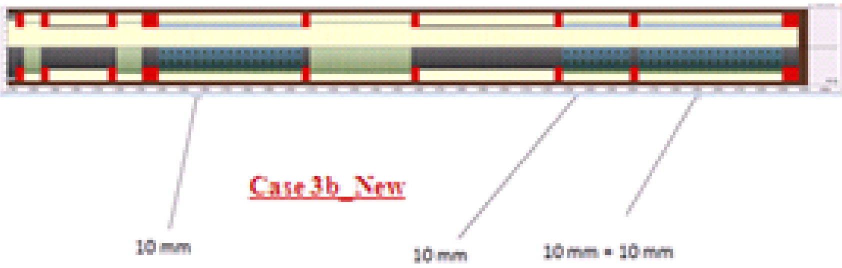


Figure 61: Case 3b_New AICD completion design

However, the compartment that was chocked with two 10 mm devices per joint is underchoked this is way the decrease in gas production is negligible (2.3%). In case 3b_New even all the zone 2 is choked but with different level of choking, the gas production was not restricted and this is due to the fact that the gas could escape and move horizontally and flow in the direction of low restrictive compartment. This could be due to the high mobility of the water.

Table 13: Eclipse Simulation Results for Scenario 3

	ΔPT Oil (MMSTB)	ΔPT Water (MMSTB)	ΔPT Gas (BSCF)	% Oil	% Water	% Gas	Water/Oil	Gas/Oil
Case3b_New	-0,13	-8,43	-0,78	-1,3	-10,0	-2,3	7,9	1,8
Case3d_New	-0,54	-27,35	-2,92	-5,2	-32,5	-8,7	6,2	1,7
Case4_New	-0,78	-36,14	-4,33	-7,5	-42,9	-12,8	5,7	1,7
Case5_New	-1,67	-55,00	-8,26	-16,2	-65,3	-24,5	4,0	1,5

d. Increase the downhole level of choking

I increased the level of choking by decreasing the diameter of the AICD in case 4, case 5 and case 6. In this scenario, the water/oil and gas/oil ratios are lower than the previous cases. That means I am over choking the well and restricting much more both the oil and the water, see table 14.

Table 14: Eclipse Simulation Results for Scenario 4

	ΔPT Oil (MMSTB)	ΔPT Water (MMSTB)	ΔPT Gas (BSCF)	% Oil	% Water	% Gas	Water/Oil	Gas/Oil
Case4	-0,84	-37,38	-4,45	-8,1	-44,4	-13,2	5,5	1,6
Case5	-1,72	-55,14	-8,31	-16,6	-65,5	-24,7	3,9	1,5
Case6	-3,95	-74,28	-15,10	-38,2	-88,3	-44,8	2,3	1,2

e. AICD optimization

Finally, for AICD completion optimization scenario, case 2f is the best case with highest water/oil and gas/oil ratio compared to all the previous cases. In this case, I am able to restrict more than 16% water and around 8 % of gas by reducing just 1.6 % of oil., see table 15.

Table 15: Eclipse Simulation Results for Scenario 5

	ΔPT Oil (MMSTB)	ΔPT Water (MMSTB)	ΔPT Gas (BSCF)	% Oil	% Water	% Gas	Water/Oil	Gas/Oil
Case9	-0,76	-32,27	-3,14	-7,4	-38,3	-9,3	5,2	1,3
Case9b	-0,85	-35,80	-3,75	-8,2	-42,5	-11,1	5,2	1,4
Case 2f	-0,17	-14,10	-2,63	-1,60	-16,70	-7,80	10,44	4,88

If I go in details to AICD completion in case 2f (figure 62), I am choking just the highly productive compartments with different level of choking. In the zone 1, I choked the highly productive zone with 5 mm AICD, but in zone 2 I choked the highly water productive compartment by 5 mm and the other compartment with 10 mm AICD to improve the oil production compared to case 2c (improve from -3.6 % to -1.6 %). However, with the case if I am not able to choke that much the water respectively the gas. In fact I am choking around 40 % water and 60% gas less compared to case 2c, see table 16.

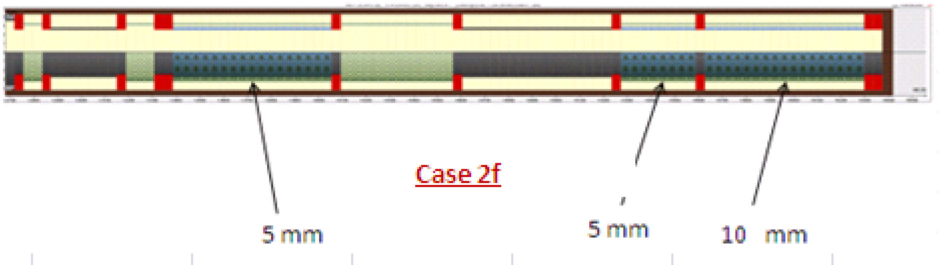


Figure 62: Case 2f AICD completion design

Tableau 16: Production Performance Comparison between Case 2c and case 2f

	ΔPT Oil (MMSTB)	ΔPT Water (MMSTB)	ΔPT Gas (BSCF)	% Oil	% Water	% Gas
Case2c	-0,37	-22,36	-5,57	-3,6	-26,6	-16,5
Case 2f	-0,17	-14,10	-2,63	-1,6	-16,7	-7,8

Chapter 5 Discussion

1. Optimum AICD Completion Design

From the Eclipse simulation results discussed in the previous chapter, I can notice that:

- Any choking of the low permeability segments will also reduce flow from these segments. These segments pose no threat for early water or gas breakthrough and do not require any choking.
- Even in the higher permeability segments that are likely sources of early water or gas breakthrough, computation of the proper choking level is critical to avoid excessive choking of any interval because this will harm cumulative oil production.
- Compromise between reducing gas/water production and the oil production is critical. Therefore, it is very important to choke the flow in a way that does not limit well daily and cumulative production beyond what is necessary.

From the AICD completion optimization described in the previous chapter, I found that it is better to choke the high water/gas production zones. If the objective of the AICDs it to reduce mainly the water production and don't harm that much the oil production, in this case the optimum design corresponds to case 2f, see figure 63. I propose to use 11 packers, 2 blank pipes and a total number of 42 Joints of AICDs with 12 m length each (25 AICDs that have 5 mm diameter and 17 AICDs that have 10 mm diameter).

Figure 63: Optimum AICD completion design

To show the effect of this completion design on the long term production performance, I run Eclipse simulations with oil rate well control and lower THP limit. The BHP, THP and Oil rate is plotted over the time in figure 64. The Water cut and gas oil ratio is reduced over the time as it is shown in figures 65 and 66. The maximum GOR reduction is 50% and increase is 200%. The maximum WCUT reduction is 32% and increase is 1%. The THP, BHP and Oil Rate over the time is shown in figure 63. The water breakthrough in zone 2 is delayed by around 200 days, see figure 67.

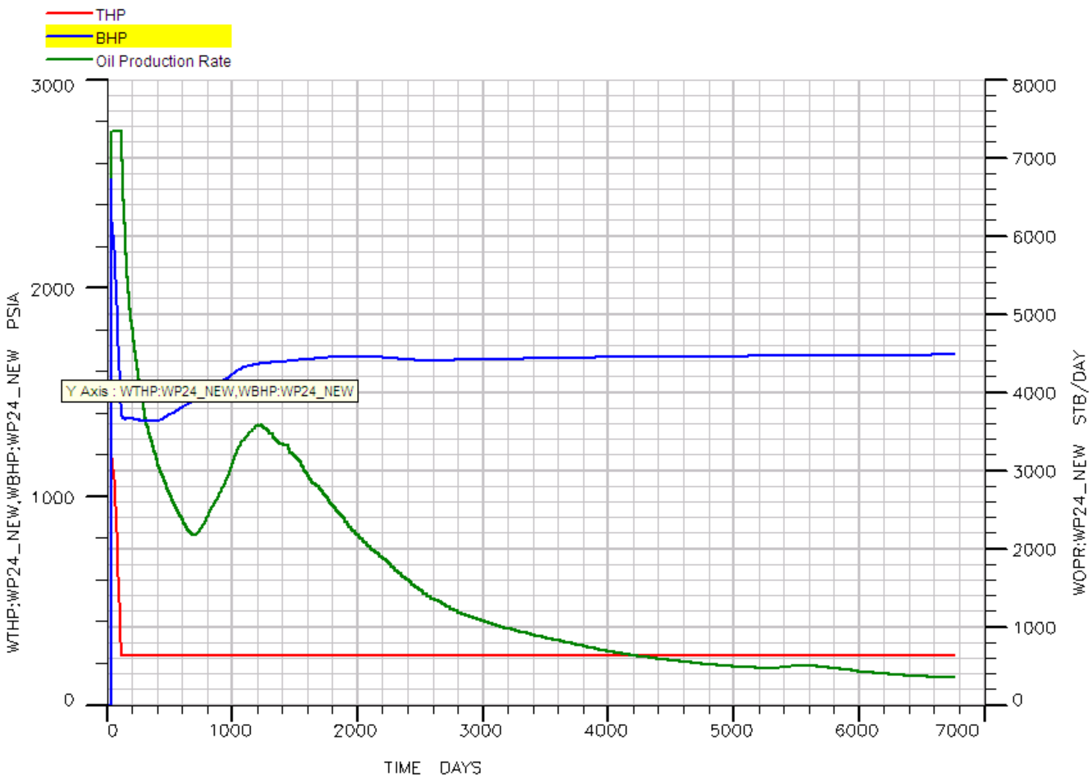


Figure 64: THP, BHP and Oil production rate over the time

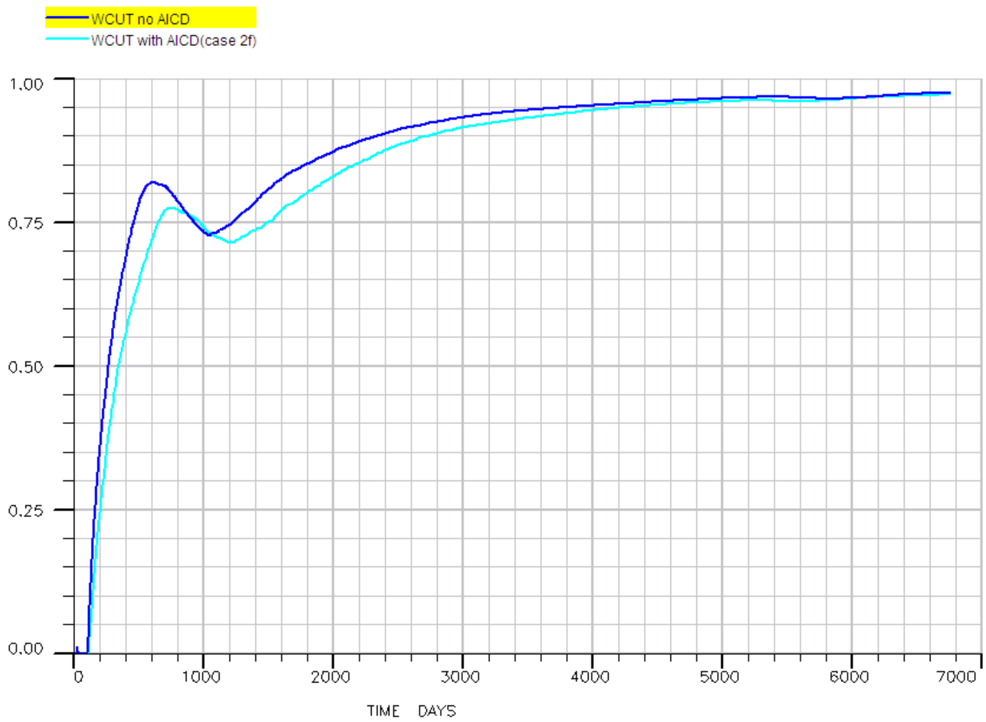


Figure 65: Water Cut over the time for the case of a completion with and without AICDs

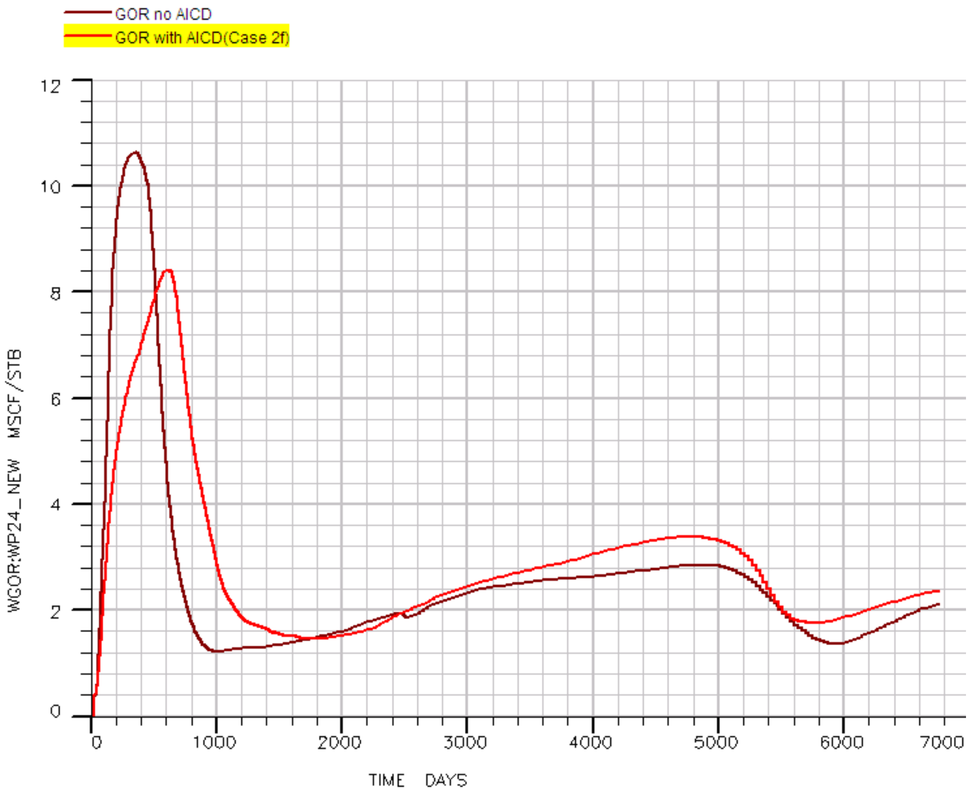


Figure 66: Gas Oil Ratio over the time for the case of a completion with and without AICDs

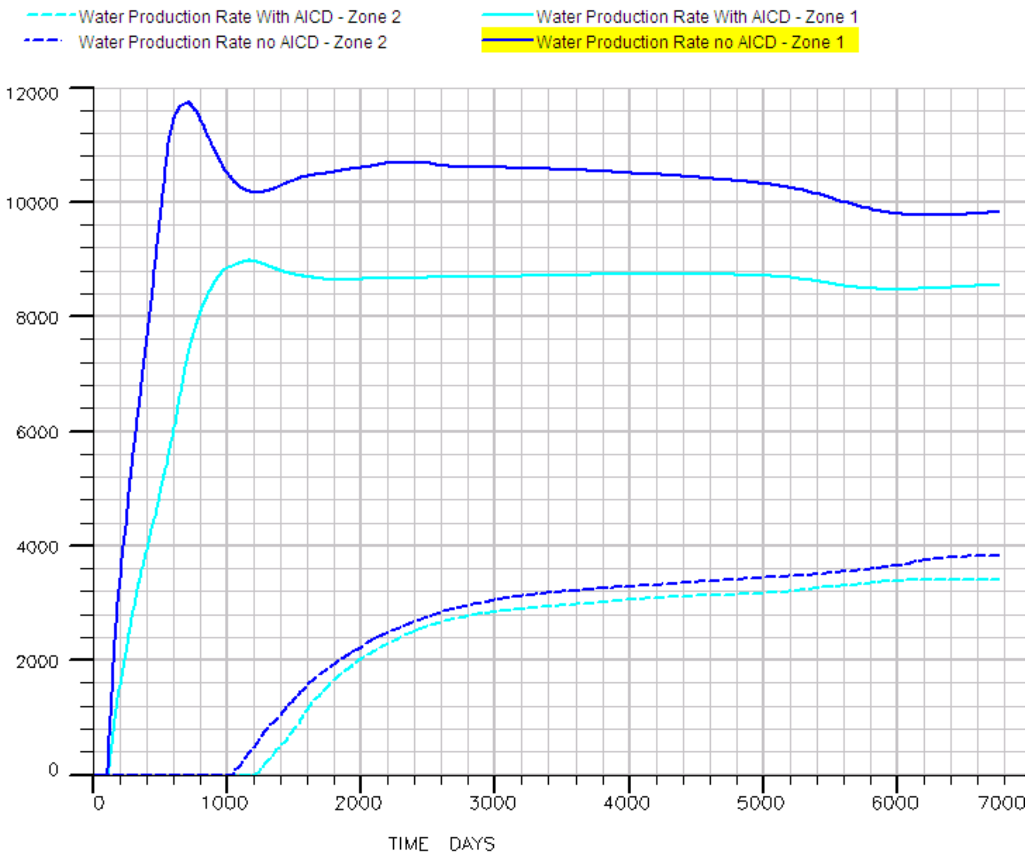


Figure 67: Water Production Rate per zone

2. Economic Evaluation

A quick economic evaluation has been carried out to estimate the difference in profit due installing AICDs completion. As I discussed in the previous chapter, by running a completion equipped by AICDs the water/gas production is decreased however the oil production is increased or slightly decreased depending on the case. As an input for the economic analysis, the oil price is assumed 100$/day. The operating cost for handling 1 barrel of produced water is assumed 11.2$. Finally the operating cost to handle a thousand standard cubic feet of gas is assumed 6.5$, see table 17. The additional costs include engineering and modeling costs, AICDs costs and the cost of completion modifications. This additional cost is estimated 1.7 MM$. These values have been provided by OMV branch office.

Table 17: Economic Input Data

Oil ($/bbl)	Water ($/bbl)	Gas ($/Mscf)
100	11,2	6,5

The difference in profit between the base case and the case with AICDs (ΔProfit) is summarized in table 18. For the best completion design, case 2f, the ΔProfit is estimated 157 MM$. However, the maximum ΔProfit that I got is 533 MM$ in case 6. In this case I am over choking the well as besides a huge reduction in water/gas production, more than 38% in oil production is restricted. The table 19 compares the effect of installing AICDs on production performance for case 6 and case 2f.

Table 18: Results Quick Economic Evaluation

Cases	ΔProfit (MM $)
Case2c	248
Case2d	109
Case 2e	281
Case3b_New	85
Case3d_New	270
Case4_New	354
Case5_New	500
Case4	362
Case5	498
Case6	533
Case9	304
Case9b	339
Case 2f	157

Table 19: Effect of installing AICDs on production performance for case 6 and case 2f

	ΔPT Oil (MMSTB)	ΔPT Water (MMSTB)	ΔPT Gas (BSCF)	% Oil	% Water	% Gas	Water/Oil	Gas/Oil
Case 6	-4,0	-74,3	-15,1	-38,2	-88,3	-44,8	2,3	1,2
Case 2f	-0,2	-14,1	-2,6	-1,6	-16,7	-7,8	10,4	4,9

3. Erosional Risk – AICDs with SAS

In case I decide to use AICDs with SAS instead of OHGP to control the sand production, an erosional risk of the screen and AICDs could appear.

To prevent screen erosion, the annular flow velocity must be reduced as much as possible [14, 15]. This can be done by installing open hole packers in the well. In order to investigate the risk of sand screen erosion the equation published by BP will be used to determine the risk of screen erosion. The equation is $C = V_p \cdot \sqrt{\rho_m}$.

Where C- factor calculated based on velocity in the annulus V_p and downhole fluid mixture densityρ_m. The C-factor ranges for risk of erosion is as follows:

- C< 30: low risk of erosion
- 30<C<60: medium risk of erosion
- C>60: high risk of erosion

In this study, I consider the optimum AICD completion design case (case 2f). The chosen timestep is 184 days which corresponds to the time of peak gas production and therefore the highest flow velocity. In this case, the annulus velocity V_p= 2.2 ft/s and the ρ_m= 45 lb/ft3 see figure 68. By using the above equation, C-factor is equal to 15 which is less than 30; therefore, the screen has a low risk of erosion.

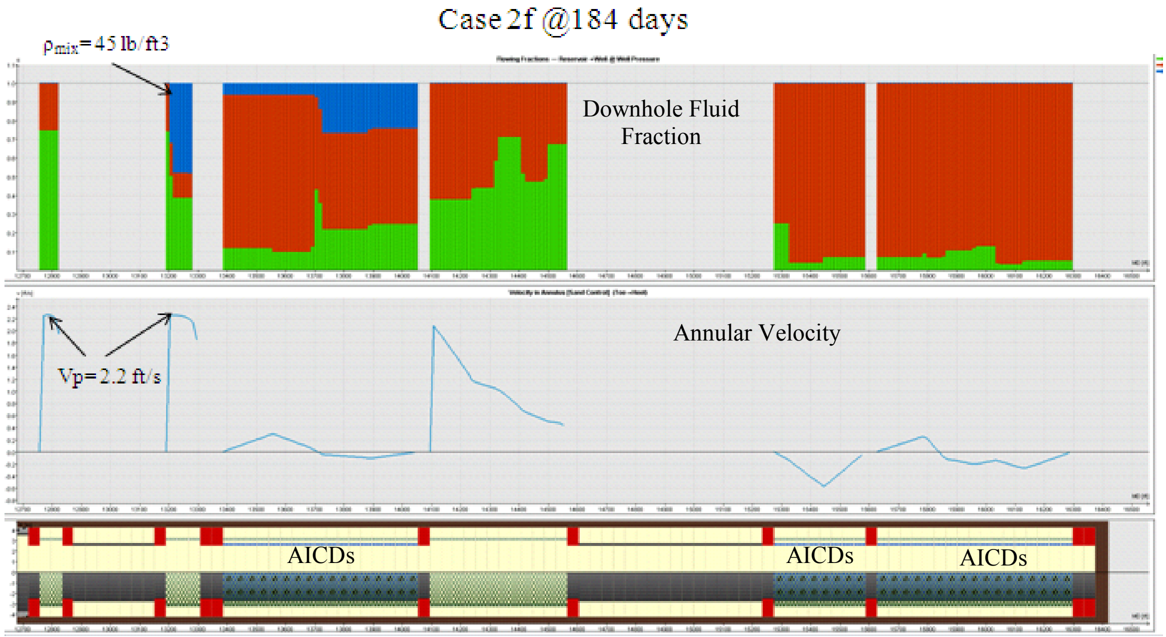


Figure 68: Erosion Risk Case 2f

From figure 68, I can notice that AICDs virtually eliminate annular flow. In more heterogeneous reservoir, the restrictions will cause a small amount of both forward and reverse annulus flow as inflow devices are distributed across the length of the screen. Annular sand transport is therefore reduced. Sand entering the wellbore will build up where it enters and quickly pack that local annular gap, thus potentially reducing screen plugging and erosion.

If the completion experiences screen erosion, the AICD might also be eroded or it can be plugged due to loss of sand control. From our AICDs provider, the only information that I got regarding erosion is that they tested AICD at 30bar differential pressure simulate 10years of 5ppm solid production. If a risk of erosion could be manifested, AICDs material could be modified to ceramic which is very hard material and exhibit an erosion resistance. Stainless steel can be eroded if the right metallurgy is not chosen.

4. Effect of well strategy BHP/ORAT on AICD completion design

In this part of the discussion, I will study the effect of changing well strategy on AICD completion design. Previously, I used oil rate and THP control as the way of controlling the well. In this study I will use just bottom hole pressure as a way to control the well. The BHP_is 1200 Psi and the Artificial Lift Quantity is 7500 Mscf/day. The oil rate in the start of production is more than 15,000 bbl/day, see figure 69.

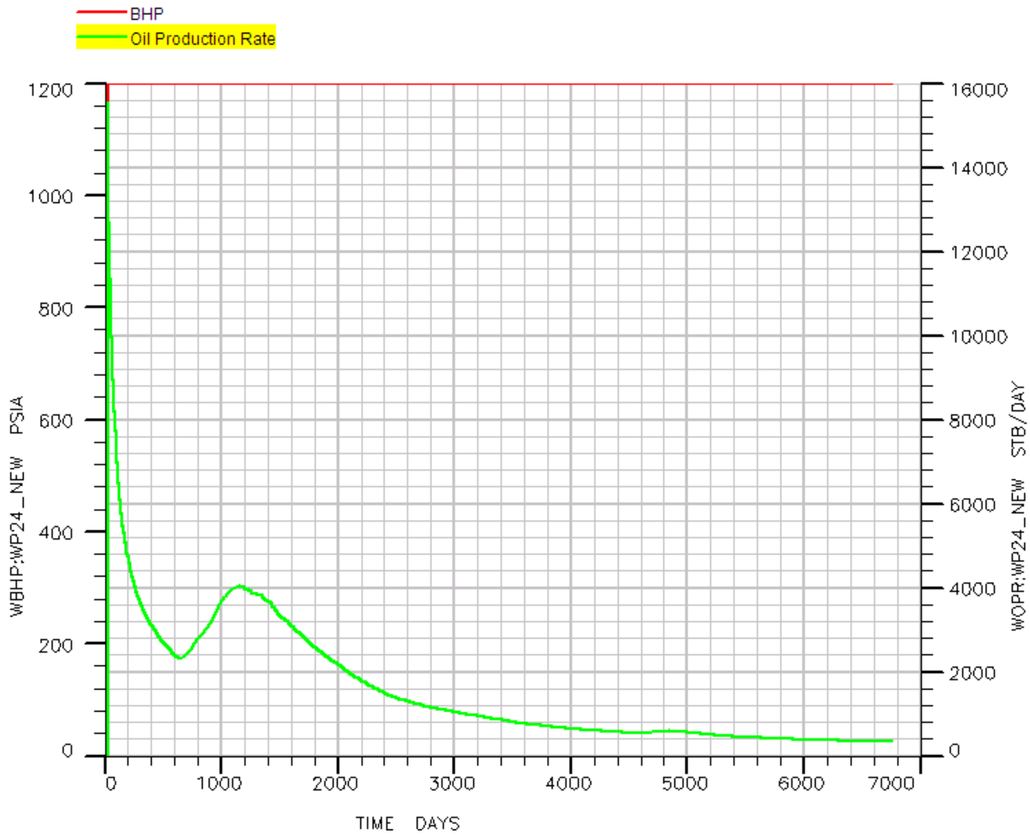


Figure 69: BHP and Oil Production Rate for the case 2f

I compared the case 2f and case 2c with both well control modes. I found, with BHP control mode, the oil production is increased and the water/gas production is decreased, see figure 70.

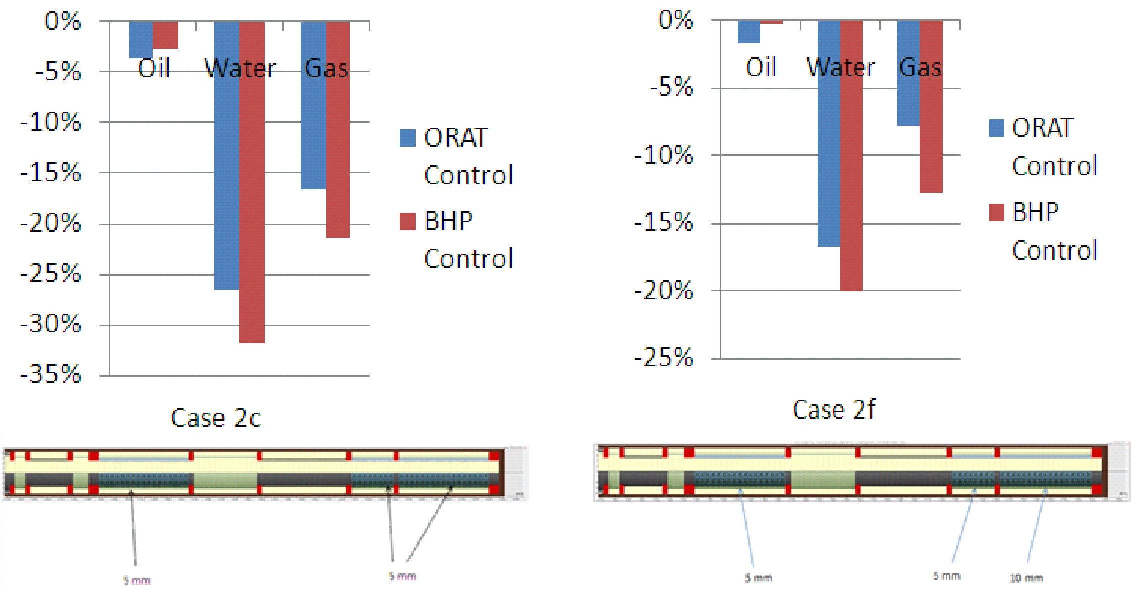


Figure 70: Comparison of the case 2f and case 2c for both well control modes

I tried to optimize the AICD completion design for the case of using BHP as a well control mode. I find that for optimum AICD design is also case 2f. I can reduce more than 20% of water production and reduce the gas by more than 12% and keeping the oil production almost the same (a small reduction by 0.2%). Economically, I am able to get more than 270MM$ difference in profit by installing AICDs in lower completion, see table 20.

Table20: AICD completion Optimisation with BHP control mode

	ΔPT Oil (MMSTB)	ΔPT Water (MMSTB)	ΔPT Gas (BSCF)	ΔProfit (MM $)	% Oil	% Water	% Gas
Case 2d_BHP	+0.31	-2.01	-6.75	95	+2.9	-1.8	-18.1
Case 2c_BHP	-0.28	-34.47	-8.00	409	-2.6	-31.8	-21.4
Case 2f_BHP	-0.02	-21.77	-4.74	271	-0.2	-20.1	-12.7

5. Effect of AICD Completion design on production performance

In this part of the report, I will try to summarise the effect of installing AICDs in the lower completion for both well control modes. The AICD optimum completion design is case 2f as mentioned before, see figures 71, 72 and 73.

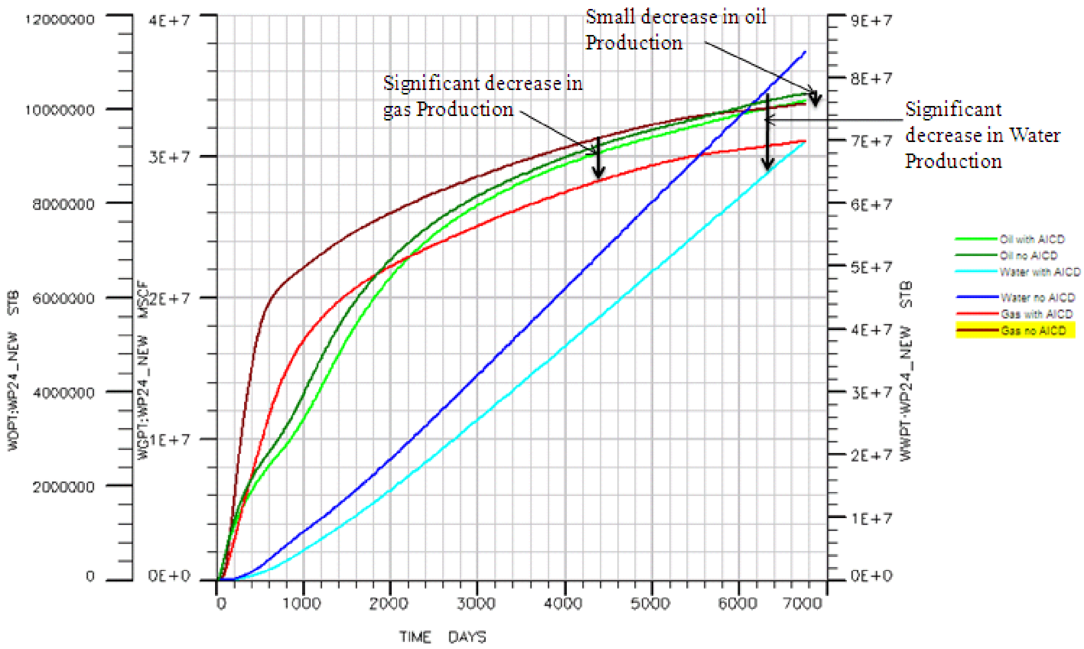


Figure 71: AICDs effect on production performance for case 2f and Oil rate well control mode

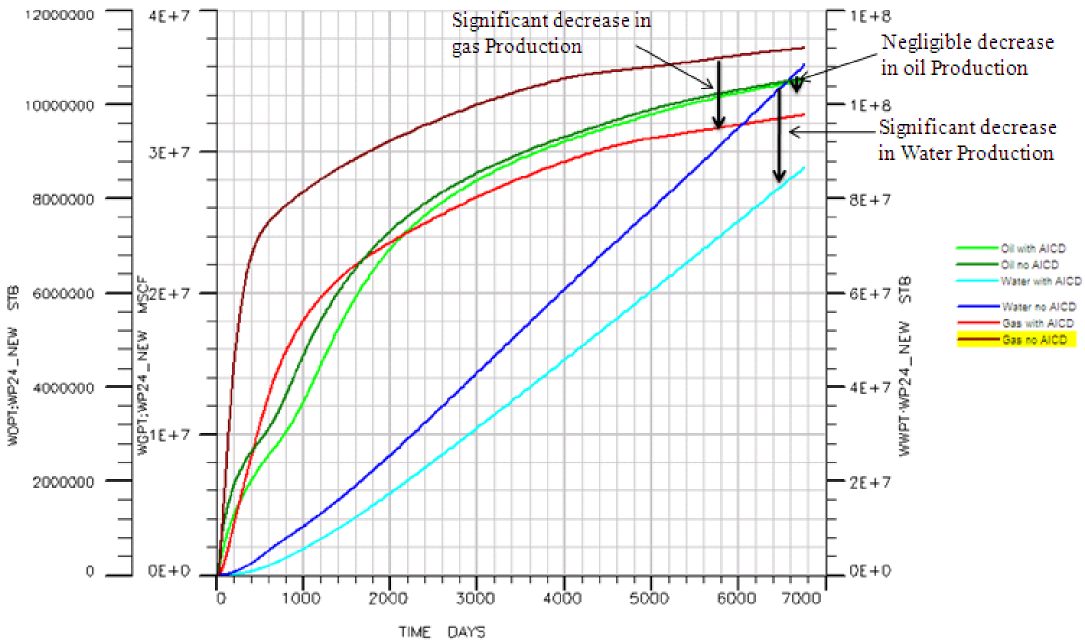


Figure 72: AICDs effect on production performance for case 2f and BHP well control mode

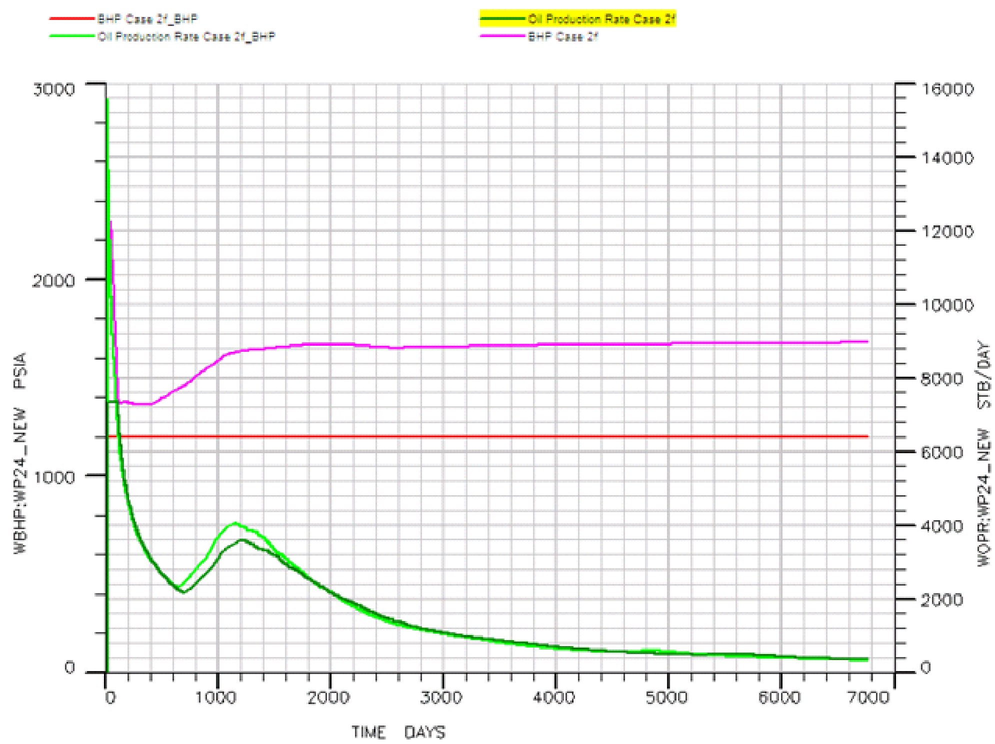


Figure 73: BHP and Oil production rate for case 2f and for both well control modes

6. Effect Capabilities of Reservoir Simulator “Eclipse^{TM}“ for AICD completion Design

I will discuss in this section the capabilities of Eclipse^{TM} to simulate AICD completion as accurate as it was designed in NETool^{TM}.

In NETool^{TM}, the well divided into 12 m segments (the length of an AICD joint). In each segment an averaged flow rate is assigned and a number of AICDs could be installed, see figure 74.

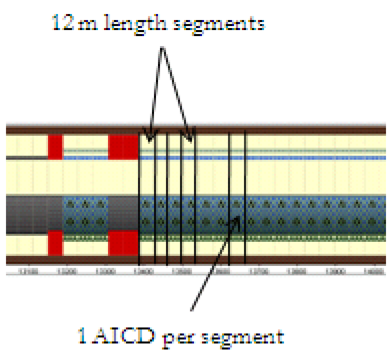


Figure 74: NETool^{TM} AICD Modeling

In Eclipse^{TM}, there is different ways for well segmentation, see figure 75:

- A segment per cell option: This creates a separate segment for each grid cell that connects to the wellbore. This allows more accurate modeling of flow from the grid into the well. However, it creates many more segments.

- By entering the maximum segment length. This length should be greater than the grid cell size otherwise the defaulted option (segment per cell will be applied). This option is useful if the grid cell size is very small, like the case of a thin layered reservoir.

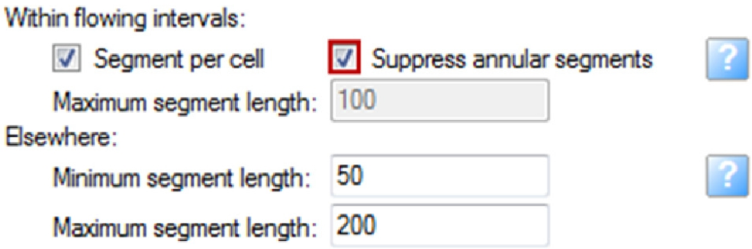


Figure 75: Well Segmentation Parameters (Petrel)

For the Well_X, I do not have very small size cells, therefore to have more accurate models, I used segment per cell option. Moreover, I have some cells with high length, this is why I tried to use a LGR (3x3x3). In this case I create smaller grid cells(approximately the size of a joint: 12 m).

When simulating in Eclipse^{TM}, only one AICD can be used for each segment in the well. NETool^{TM} does not have this limitation. Hence, by having the length of segment similar to the length of the AICD, I can apply one AICD per segment. Moreover, in this case each grid cell is connected directly to AICD segment node. This is why the annular flow modeling in not needed.

By applying AICDs in all the open hole section, just four small cells were not connected directly to an AICD, see figure 76. This has not a big effect on the completion design results.

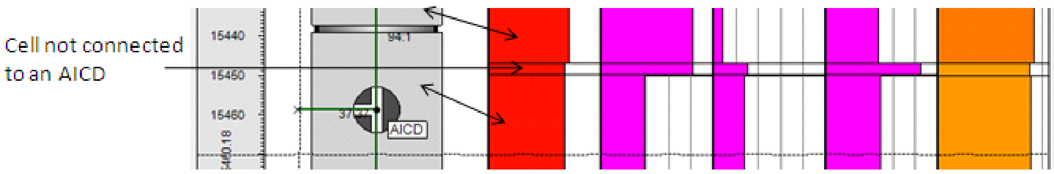


Figure 76: Cell not connected to an AICD

In our model, I have AICDs connected to small cells (size less than AICD joint length) and AICDs that are connected to longer cells (size more than AICD joint length), see figure 77.

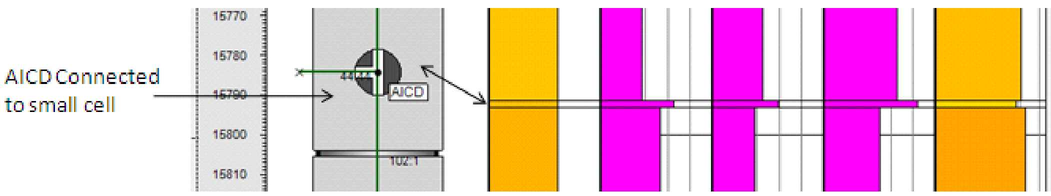


Figure 77: AICD connected to small cell

In our Eclipse^{TM} modeling, I did not use “flow scaling” option. That means in this case, the inflow rate for each AICD is the same as the flow rate to the cell that it is connected. This is different from the way that NETool^{TM} is modeling the flow rate per segment (AICD) as it is doing an average, see figure 78. Figure 79 shows the difference in oil flow rate per segment (AICD) in NETool^{TM} and Eclipse^{TM}.

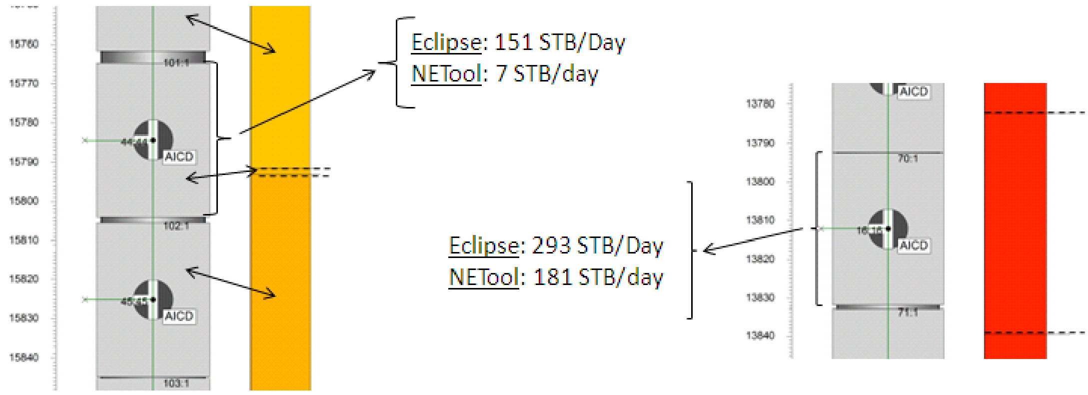


Figure 78: Influx flow rate per AICD for the case of NETool™ and Eclipse™

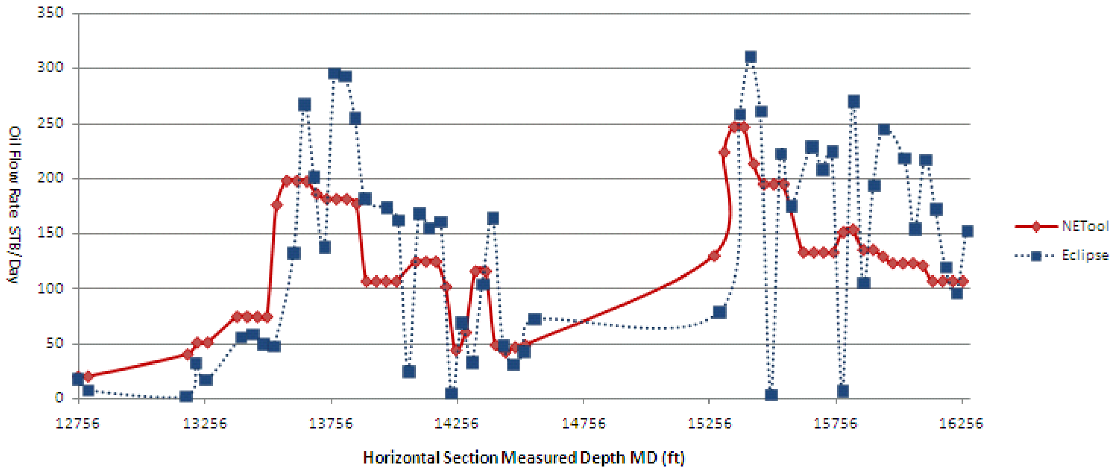


Figure 79: Oil Flow Rate per Segment (AICD) in NETool™ and Eclipse™

Therefore, due to the difference in oil flow rate per AICD, a significant difference in pressure drop per segment between NETool™ and Eclipse™ was observed, see figure 80.

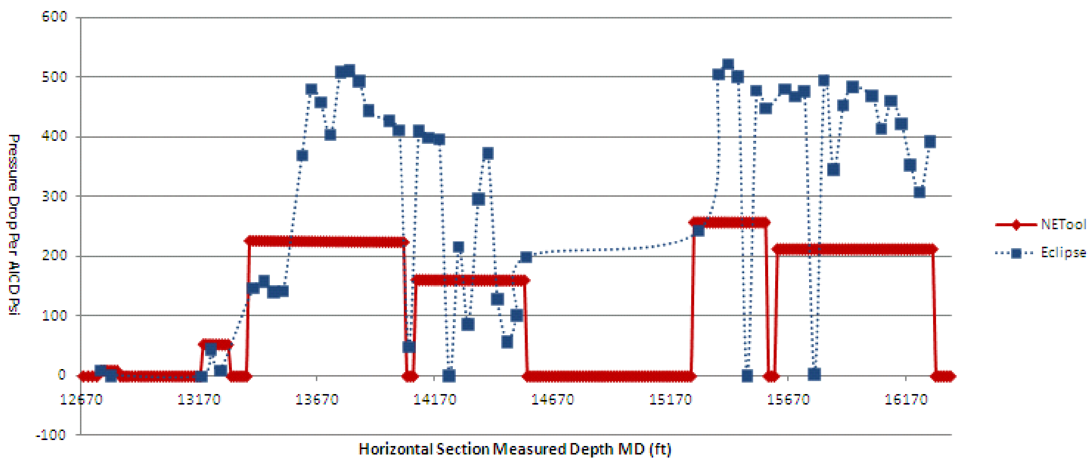


Figure 80: Pressure Drop per Segment (AICD) in NETool™ and Eclipse™

Therefore, the flow scaling is important and it was not done automatically by Eclipse™. The flow scale factor should be equal to the AICD length divided by the length of the tubing segment (in our case the size of the grid cell) that the device encases. Therefore, the new flow rate per AICD should as it is indicated in the following equation:

$$q_{AICD} = q_{seg} \frac{l_{AICD}}{l_{tubing}}$$

Where q_{AICD} is the flow rate per AICD, q_{seg} is the flow rate per tubing segment, l_{AICD} is AICD length and l_{tubing} is tubing length.

Chapter 6 Conclusions and Recommendations

A substantial amount of papers, presentations and reports on ICD/AICD technology has been reviewed for the thesis (see references). This review generally indicates a positive benefit on oil, water and production from installations of ICDs/AICDs. It has been shown that AICDs will equalize the inflow along the wellbore before that water/gas breakthrough, same as ICDs. However, AICDs restrict much better the low viscous unwanted fluids once they breakthrough.

From the reviewed literature and simulation work, it is clear that an ICD completion is a simple and reliable solution X_South oil well studied. AICDs have proven to be beneficial for optimizing oil, gas and water production in other fields.

AICDs are density and viscosity dependent. The less viscous is the fluid; the much better is the restriction and the performance of the device. For the X_South field it is easy to restrict the gas production but challenging to restrict the water production due to the narrow oil-water viscosity difference (water viscosity id 0.5 cp and oil viscosity is 3 cp).

NETool™ and Eclipse™ simulation have been performed for well_X. Different scenarios for AICDs design have been studied includes: choking all the open hole section, choking the highly productive zone and equalizing the influx at well start up. Besides, two well strategies have been studied: an oil rate control and a bottom hole pressure control.

The optimum AICD design is to choke highly gas/water productive zones using 5 mm and 10 mm AICDs. I am able to significantly reduce water/gas production and keeping the oil production almost unchanged (a reduction by 1.6 % in case of ORAT well control and by 0.2 % in case of BHP well control).

A quick economic evaluation has been done to estimate the benefit of installing AICD completion. For the optimum AICD design, delta profit is more than 150 million dollars. However, we can get much better delta profit even by reducing significantly the oil production. In fact this is due to the high OPEX of water handling.

No risk of screen erosion was identified in case of using SAS to control sand production. Open hole gravel packing in horizontal well completed with AICDs is possible and proven effective by running AICDs in inner string or by adding a closable Sliding sleeve (SSD) screen to the toe section

Future work

This AICD study could be improved in the future by:

- Improve the Eclipse™ AICD modeling by using the "flow scaling" option to scale the oil flow rate per device.
- Better constraining the well based on surface facilities. Water shut-off (constrained by total liquid capacity of the FPSO) and gas shut off (potential short term gas export constraint).

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