Abstract

Inflow Control technology has been employed in long, horizontal wells completions since the early 1990s. Their introduction prompted the extension of reservoir and well simulators to support their modelling and optimisation. More recently, Autonomous Flow Control Devices (AFCDs) have further improved well performance. However, the impact of AFCDs on reservoir management cannot yet be confidently predicted since their (autonomous) discrimination and control of the different fluid phases presents new modelling challenges that require extension of today’s wellbore/reservoir models and workflows. Novel methods to visualise and optimise AFCD completions are also required.

This thesis shows how to use widely available, commercial codes to reliably simulate wells completed with AFCDs. Workflows for the optimal design and quantification of the economic value of such completions have been developed.

The resulting predictions are compared with published data (AFCD calibration curves). They are used to evaluate the AFCD-completions “added-value” for a range of reservoir types, device specifications and fluids. This work particularly addresses:

i. Performance of the device - little published data on AFCD multi-phase flow performance is available. Also, commercial reservoir simulators provide just one equation to capture the underlying physics of all AFCD types.

ii. Wellbore model - a representative reservoir/wellbore model and the previously ignored physics (stratified flow in the annulus and well trajectory alteration) are now essential since an AFCD’s performance is strongly fluid-sensitive.

The above AFCD modelling and optimisation challenges are addressed by:

1) Developing an AFCD performance model that honours published data. Equations and modelling recommendations for several commercial AFCDs along with a range of modelling options, some novel and bespoke, are presented. The impact of uncertain multiphase flow performance on the AFCD well’s “Added-Value” is quantified.

2) Increasing the accuracy of commercial well/reservoir simulators when modelling AFCD completions by recommending how to model the well trajectory, the reservoir/well segmentation and the multiphase flow performance.

3) Comparing the performance of optimised AFCD- and ICD-completions in multiple reservoir models to illustrate how various reservoir management challenges can be met.
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# DECLARATION STATEMENT

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Nomenclature

Q, q  Flow rate (sm$^3$/d)
L  Length (m)
A, A_c  cross-section area (m$^2$ or mm$^2$)
f  Fanning friction factor
p  Pressure (bar)
ρ  Fluid density (kg/m$^3$)
V, v  fluid velocity (m/s)
Δp, δp, dP  Pressure drop (bar)
D  Diameter (mm)
μ  fluid viscosity (cP)
C, C_u, C_f  Constant (unit convergence)
aAICD  Autonomous flow control device strength (bars/((kg/m$^3$)(rm$^3$/day))$^x$))
bAICD  Autonomous flow control device strength (m$^{(x+2)}$)
x  Volume flow rate exponent
α  In-situ volumetric fraction
a,b,c,d,e,f,g  Mixture components specified manually (usually assumed to equal 1)
Δt  Change in time (day)
Δm  Change in mass (kg)
w  Mass flow rate (kg/s)
C_0  Profile parameter
V_d  Drift velocity (m/s)
V_g  Flow velocity of the gas phase (m/s)
V_m  Volumetric flux (or average velocity) of the mixture (m$^3$/d)
ℓ_{seg}  Length of the wellbore segment (m)
ℓ_{aicd}  Length of the valve’s joint (m)
C_d, C_v  Flow coefficient of the valve
gpm  Gallon per minute
psi  Pound per square inch
sm$^3$/day, sm$^3$/d  Standard cubic meter per day
o, w, g  Denote oil, water and gas respectively
P_{wf}  Flowing bottom hole pressure
crit  Critical
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>cp</td>
<td>Centipoise</td>
</tr>
<tr>
<td>Kg</td>
<td>Kilogram</td>
</tr>
<tr>
<td>m</td>
<td>Meter</td>
</tr>
<tr>
<td>in</td>
<td>Inch</td>
</tr>
<tr>
<td>md</td>
<td>Milli-Darcy</td>
</tr>
<tr>
<td>Θ</td>
<td>Angle of inclination from the vertical</td>
</tr>
<tr>
<td>x, b, v, z, y</td>
<td>Parameters describing the AFCD performance</td>
</tr>
<tr>
<td>f(wc)</td>
<td>Water cut function</td>
</tr>
<tr>
<td>B</td>
<td>Formation volume factor</td>
</tr>
<tr>
<td>Pr</td>
<td>Reservoir pressure</td>
</tr>
<tr>
<td>Pt</td>
<td>Tubing pressure</td>
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</tbody>
</table>
Abbreviations

3D Three Dimensions
acc Acceleration
AFCD Autonomous Flow Control Device
AFI Annular Flow Isolation
AFC Autonomous Flow Control
AICD Autonomous Inflow Control Device
AICV Autonomous Inflow Control Valve
AWC Advanced Well Completion
BHP Bottom hole pressure
BT Breakthrough
cal Calibration
Capex Capital Expenditure
CFE Completion Flow Efficiency
Capex Capital Expenditure
CWC Critical Water Cut
DFC Downhole Flow Control
E Efficiency
EOR Enhanced Oil Recovery
FBHP Flowing Bottom Hole Pressure
FCD Flow Control Device
FD-AICD Fluidic Diode-AICD
fric Friction
GOR Gas Oil Ratio
GP Gravel Packs
HTE Heel Toe Effect
HU Holdup
hyd Hydrostatic
ICD Inflow Control Device
ICT Inflow Control Technology
ICV Interval Control Valve
IOR Improved Oil Recovery
KPI Key Performance Indicators
LGR Local Grid refinement
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
</tr>
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<tbody>
<tr>
<td>LS</td>
<td>Lower segment</td>
</tr>
<tr>
<td>mix</td>
<td>Mixture</td>
</tr>
<tr>
<td>MPF</td>
<td>Multi-Phase Flow</td>
</tr>
<tr>
<td>MSW</td>
<td>Multi-Segment Well</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>Opex</td>
<td>Operating Expenditure</td>
</tr>
<tr>
<td>PI</td>
<td>Productivity index</td>
</tr>
<tr>
<td>PLT</td>
<td>production logging tool</td>
</tr>
<tr>
<td>RCP</td>
<td>Rate Controlled Production</td>
</tr>
<tr>
<td>Re</td>
<td>Reynolds number</td>
</tr>
<tr>
<td>SAS</td>
<td>Stand-Alone-Screens</td>
</tr>
<tr>
<td>seg</td>
<td>Segment</td>
</tr>
<tr>
<td>SAGD</td>
<td>Steam Assisted Gravity Drainage</td>
</tr>
<tr>
<td>SCF</td>
<td>Standard cubic feet</td>
</tr>
<tr>
<td>Sep</td>
<td>Separator</td>
</tr>
<tr>
<td>STB</td>
<td>Stock tank barrel</td>
</tr>
<tr>
<td>US</td>
<td>Upper segment</td>
</tr>
<tr>
<td>val</td>
<td>valve</td>
</tr>
<tr>
<td>VFP</td>
<td>Vertical lift performance table</td>
</tr>
<tr>
<td>WC, WCT</td>
<td>Water Cut</td>
</tr>
<tr>
<td>WWC</td>
<td>Well Water Cut</td>
</tr>
<tr>
<td>WSR</td>
<td>Water Swelling Rubber</td>
</tr>
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</table>
List of Publications and Presentations by the Candidate


Chapter 1 Introduction and Motivation

1.1 Introduction

Well drilling and completion technology has improved considerably for the past three decades. Long horizontal wells have become very common and several successful applications are reported for different reservoir environments. It allows increased recovery and hence creates more economic value compared to conventional solutions in many reservoir situations. This is due to their ability to improve the drainage area, sweep efficiency, well productivity, and delay water or gas breakthrough (BT) by reducing the localised drawdown as well as distributing the fluid influx over a greater wellbore length. In fact, long horizontal wells (more than 2 km) allow (previously) uneconomical oil rim reservoirs to be monetised (e.g. Troll field’s oil reserves in the North Sea [1, 2]). Extended reach wells with multi-laterals and varying trajectories are likewise very common, especially for offshore applications, targeting extra reservoir contact for each well [3] {Figure 1-1}.

![Figure 1-1: Comparative (to Rio de janeiro and Manhattan) illustration of an advanced multilateral well size (Courtesy of Statoil)](image)

These wells, present many challenges caused by their complexity (in terms of placement and operations) and the increased well’s exposure to the reservoir which comes with additional control requirements for the extended length and the encountered heterogeneity. The tendency to drill long/complex extended reach wells is challenged by several factors some of which are listed in Table 1-1.

Advanced well completions employing Downhole Flow Control (DFC) technology such as Inflow Control Devices (ICDs), Interval Control Valves (ICVs) and/or Autonomous Flow Control Devices (AFCDs), are designed to provide practical solutions to the production constraints, generally associated with complex well topologies.
Table 1-1: Example challenges associated with extended reach wells

<table>
<thead>
<tr>
<th>Challenge</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost</td>
<td>High cost compared with simple vertical or the (relatively) short wells.</td>
</tr>
<tr>
<td>Operation challenges and risks during well placement</td>
<td>a) Drilling issues (equipment failure, hole collapse, washout, geosteering challenges, problematic zones etc.). &lt;br&gt;b) Drilling capabilities (equipment limitations).</td>
</tr>
<tr>
<td>Reservoir description</td>
<td>a) Geological structure (faults, multiple targets etc.). &lt;br&gt;b) Sand property and continuity (uncertainty). &lt;br&gt;c) Close to contact (limited reservoir/target thickness). &lt;br&gt;d) Distorted fluid saturation distribution (due to production, fingering etc.). &lt;br&gt;e) Variation in reservoir pressure in different regions or layers of the reservoir penetrated by the well (production problems). &lt;br&gt;f) Variation of the fluid properties in reservoir sections crossed by the wellbore (new downhole equipment work according to fluid properties).</td>
</tr>
<tr>
<td>Production constraints (operation and equipment design)</td>
<td>a) Uneven production/uneven drawdown caused by (1) the heel toe effect (See Figure 1-2 “a”) or (2) more commonly by the heterogeneity (see Figure 1-2 “b”) &lt;br&gt;b) Sand production. &lt;br&gt;c) Equipment failure. &lt;br&gt;d) Artificial lift issues. &lt;br&gt;e) Reservoir drainage control (reservoir management for source/sink interaction). &lt;br&gt;f) Early breakthrough (unwanted fluid Control, see for example Figure 1-2 “b”). &lt;br&gt;g) Workover challenges. &lt;br&gt;h) Cross flow between laterals. &lt;br&gt;i) Well clean up. &lt;br&gt;j) Well stimulation. &lt;br&gt;k) The complex flow regimes and the related inflow/outflow performance. &lt;br&gt;l) Multiphase flow considerations such as (fluid accumulation at the low points and high points, fluid reinvasion at low points, increased production-skin at the heel due to altered saturation near the wellbore (Sw), back flow within the wellbore (or) liquid loading etc.)&lt;br&gt;m) Infill wells in mature fields often experience high initial water production with a further rapid rise of water cut, resulting in high water production.</td>
</tr>
</tbody>
</table>
An ICD is a “passive” (or fixed) choking device installed against the formation sandface as part of the well completion hardware (i.e. behind Gravel Packs (GP), within perforated pipes or mounted on Stand-Alone-Screens (SAS)). It aims to balance the well’s inflow (or outflow) profile, minimise the annular flow and, in some cases, restrict the influx of excess gas or water at the cost of a limited, extra pressure drop.

ICDs do not provide an optimal well design after breakthrough of the unwanted phases, despite their ability to balance the well inflow profile and achieve a, selective, uniform sweep towards a horizontal well in early years. Field experience has taught that ICD completions balance the well influx initially, but may not offer the optimal solution throughout the well’s life due to the changes in the inflow conditions as the well matures (e.g. in the depletion stage [4]). On the other hand, ICVs are active and can be controlled from surface to optimise the well performance. Several proactive and reactive control approaches have been developed to achieve optimum flow conditions with ICV-completions. The major limitation of ICVs arise from the number of control lines required to actuate each ICV. Hence limited number can be installed for each well (typically 4 to 5).

An industry-wide effort has been on-going for some years to develop an inflow control device which has the ability to spontaneously and selectively shut-off (or) control the unwanted fluids at the valve. The value of such a device was discussed in several publications. Ouyang, 2009 considered the benefit of applying ICDs with efficient phase filtering capabilities for reducing the water production. He concluded by recommending that “efforts should be pursued to develop an intelligent ICD system that can filter and
selectively block unwanted fluid (water) entry. Such an ICD system could certainly benefit the industry and lead to the wide spread application of ICDs for reducing water production” [5].

Autonomous Flow Control Devices (AFCDs) have been recently introduced to, and much appreciated by, well completion industry. They have the ability to spontaneously adapt to changing down-hole conditions in a way that controls unwanted fluids while preferentially producing the desired fluid. Their deployment has proved successful in meeting the challenge of dealing with unwanted fluids on a layer-by-layer basis. They showed a superior production performance when compared with Passive Inflow Control Devices (e.g. Troll field [1]). The pressure drop across an AFCD changes in response to the phase fractions of the local, down-hole, fluid inflow. They are designed to restrict the flow of unwanted fluids by imposing an increased pressure drop that preferentially increases the production of the desired fluid. The unique ability of AFCDs to discriminate and control the different fluid phases immediately raises the question: are we modelling them correctly? This is one of the main questions that this work is dealing with.

Al-Khelaiwi, F.T.M., 2013 have worked intensively in the area of Advanced Well Completions (AWCs). He concludes: “The area of advanced well completion design is rich in challenges and future areas for research; AICD is a promising technology that is still in its infancy”. The study recommended a thorough research to unlock the added value from the application of the AFCD technology to provide a “higher level of understanding of the AICD capabilities” [6].

The above successful field experience, their optimisation potential, and the new modelling challenges associated with AFCD technology were the main drivers for this study. The overall objective of this thesis, is to provide methods and workflows to improve the modelling accuracy, as well as, to understand AFCD-completion performance in horizontal wells in comparison with passive inflow control technology. This would help in understanding the latest technologies associated with this type of wells, their range of application, success measures, the optimisation techniques and the possible improvements in their physical design and function.

1.2 Thesis Objective

The thesis focuses on the Inflow Control Technology (ICT) applications and the limitations of current analysis techniques when applied to AFCDs. Fluids enter or leave the wellbore radially through the production tubing at various locations; altering the flow behaviour along the wellbore and complicates modelling of the problem. Various
parameters play a significant role on the AFCD-completion: e.g. multiphase flow regime, the flow rates of various fluids, inflow/outflow format, well inclination, fluid properties, and well geometry.

Very few technical reports and published papers exist that discuss in details the AFCDs modelling aspects (accuracy and efficiency) and optimization workflows, despite the multiple types available and their perceived positive impact on reservoir management. AFCD technology opened the door for new solutions and presented complex modelling challenges at the same time.

The thesis addresses the following points in relation to the deployment of AFCD technology:

1) A single formula incorporated in various modelling tools is being widely used for modelling the AFCD performance. This modelling technique should be reviewed for:
   a) The parameters describing the AFCD performance are not explained against the device physical description (e.g. diameter or reaction to wanted and unwanted fluids).
   b) Non-physical modelling results obtained when using the AFCD performance parameters suggested in various software.
   c) How an “active” AFCD-completion performance can soundly be compared against a “passive” ICD-completion (assuming the same respond to oil flows on both cases).
   d) Multiple types of AFCDs available employing different physics; may require different modelling techniques.
   e) Understanding the impact of changing the AFCD performance on the reservoir model (before and after the unwanted fluid breakthrough).

2) As a result of the AFCDs sensitivity to the properties of the flowing fluids, their proper engineering application necessitates a robust understanding of the downhole flow condition, namely the multiphase flow and the various phases’ distributions along the production well length.

3) AFCD-completion provides an unlimited number of control points for the fluid flow along the wellbore. However, their actions are completely autonomous allowing no remote control after deployment. Hence, proper modelling and optimisation workflows are required to:
1) Achieve the maximum added value from Autonomous Flow Control (AFC) technology.
2) Soundly compare the added value against other flow control technologies.
3) Evaluate the risk associated with the deployment of this (relatively) new technology.

The aim of this thesis is to improve the reliability of coupled well/reservoir simulation of advanced wells completion employing AFCDs. Accuracy and efficiency are the two main areas to improve the state-of-the-art modelling capabilities.

### 1.3 Thesis Layout

The objectives required the thorough study and evaluation of several factors. The details of which are laid out in the following format:

**Chapter 2** provides an introduction to inflow control technology. It describes the various types of inflow control technology in term of their capabilities, their objectives, and their reported field applications with special focus on AFCDs. Comparisons are made between passive ICDs and autonomously active FCDs explaining the need for improved understanding of AFCDs functioning in downhole conditions.

**In chapter 3,** first, the accuracy of existing methods is evaluated by comparing the capability of the available models in capturing the published data. To date, there is only one model available in the commercial reservoir simulation software, with no guideline published for the physical meaning of the associated parameters. This chapter will explain the physical meaning of these (performance) modelling parameters in relation to the (A)FCDs working philosophy. Then it defines how/whether this model, can be used to match the published performance data (laboratory data). Finally, its accuracy is evaluated, since the primary focus was on implementing new improvements in terms of modelling accuracy.

Next the chapter introduces the concept of equivalent nozzle size to compare the AFCD performance against the conventional ICDs. This concept allowed comparison and quantification of the added value associated with the autonomous reaction as compared with passive ICDs. The concept has been widely accepted [7-9]. Furthermore, systematic analysis of the relative performance of an ICD, AICV and AICD technology, based on this published technical performance is presented. It shows how the available model can be used to understand the interaction between the reservoir and the AFCDs reaction to unwanted fluids at different levels of aggressiveness.
Performance equations and modelling recommendations for accurately honouring the published AFCDs performance are also presented for each of the commercially available AFCD types. Modelling options are presented (not only restricted to what the current software provide in term of performance equation). The software capabilities are extended to allow modelling different equations using multidimensional tables. Finally, example case studies for AFCD modelling and added value evaluation are presented in several field conditions for real field scenarios and synthetic models representing actual fields’ production problems.

In chapter 4, first the modelling accuracy is further investigated by taking into account the combination of physics and parameters that may influence the AFCD-completion performance in a real field environment/application. The parameters investigated include the Multi-Phase Flow (MPF) performance and the impact of the simplifications that are often made when modelling the performance of such advanced completions in a (coupled) well/reservoir simulator (e.g. well trajectory, reservoir/well segmentation, employed multiphase flow model etc.). The impact of averaging the segment’s multi-phase flow properties on AFCD’s pressure drop calculations and wellbore modelling accuracy is evaluated for different well conditions. Recommendations are made to increase the modelling accuracy of commercial well/reservoir simulators. A new generalised AICD formula is presented.

Engineering data provided by: (i) the production logging tool (PLT) and (ii) laboratory experiments reveal a prevailing stratified flow environment in the horizontal section of the wellbore. The effect of this flow behaviour on the performance of advanced wells, is not captured by the current well/reservoir modelling techniques. Second, this chapter explains the latest improvement made in ECLIPSE (a reservoir simulation software) capability to capture and represent the published wellbore flow dynamics. A novel extension of the Multi-Segment Well (MSW) application is developed to provide a solution to various intelligent wells simulation challenges. The model validation against the published AICV performance is presented.

Third, Case studies are presented whereby, the performance of the passive inflow control devices completions and the phase sensitive devices, such as AICVs, is evaluated and compared in a stratified flow environment.

Finally, efficiency is taken into consideration by focusing on the combination of modelling methods and the resulting simulation time consideration.
In chapter 5, Guidelines for AFCD performance modelling and optimization are presented. A robust, optimal design framework is proposed that allows for reservoir model uncertainties.

This chapter offers an insight into how and why such completion can improve well production, and what the optimal AFCD completion design may look like following the discussions on the previous chapters. The oil recovery for various AFCD functionalities have been examined for different types of reservoirs. Five reservoir models have been used to investigate the impact of autonomous downhole control on field production. The global optimum solution for the given production constraints and the selected completion options was identified by use of a full factorial experiment that considered all possible combinations of variables to investigate the complete search space. The understanding developed from the completion performance of these “hypothetical” AFCDs indicates what an optimal AFCD-completion design would be, and how it compares with other FCD-completion designs.

Next, the robustness of AICD completions in an uncertain reservoir geology is investigated and compared against the passive (equivalent) and optimum ICDs.

Further, the impact of MPF uncertainty on AFCD-completion performance and value prediction is investigated. The variations in the AFCD model and the description of the near wellbore grid scale is investigated in a sector model, extracted from a real field application.

Finally conclusion from the AFCD optimisation studies are laid out.

Chapter 6 summarises the conclusions of this study and provides recommendations for future work.

For efficiency of the modelling and applicability of this research, the methods and workflows developed as part of this study are implemented in leading integrated well/reservoir simulators. The added value of AFCD is investigated under different types of reservoir conditions, technical limitations and fluid types.
Chapter 2 Introduction to Advanced Well Completions

2.1 Introduction

The development in the well drilling technology necessitated a parallel evolution in the completion technology and design. Most of the challenges associated with the new well trajectories can be efficiently dealt with at the downhole completion level by the application of Flow Control Device (FCDs) to control the inflow/outflow performance aiming for an improved oil sweep in the reservoir, reduced unwanted fluid production, and sustainable production.

The generic term “intelligent well” or Advanced Well Completions (AWC), is used to signify that some degree of direct monitoring and/or control equipment is installed within the well completion. The flow control can either be spontaneous (automatic) or with some operator intervention. Hence they are wells capable of monitoring and managing the fluid flow into or out of the length of the wellbore in order to better control the reservoir, well, and production processes (i.e. fit-for-purpose smart well systems). An example of such completion is given in Figure 2-1.

![Figure 2-1: Example for a smart well (courtesy WellDynamics)](image)

From the above definitions, the main functionalities of intelligent wells are downhole flow control and sensing. The majority of intelligent well applications have been in offshore platform and subsea installations, driven largely by: (1) increasing ultimate recovery “Troll”, (2) reducing surface facilities, (3) reducing the number of wells required to develop a structure, (4) accelerating production and (5) improving the economics by,
e.g., avoiding future well intervention cost. Controlling unwanted fluids is an additional fundamental factor. Figure 2-2 provides the relative business value contribution of a typical intelligent well completion technology as evaluated in the Norwegian industry [11].

![Percentage ranking of intelligent completion business driver diagram](image)

**Figure 2-2: The relative business value contribution of a typical intelligent well completion technology as evaluated in the Norwegian industry [11]**

The reduction in capital expenditure of a development project is critical, in today’s economics. For intelligent wells, this means that one well is required to develop a larger reservoir volume and increase recovery per well. In other words, the same (or preferably better) field performance must be realized by less number of intelligent wells than the base case development plan “with conventional wells”. Using extended reach horizontals, multilaterals or commingled completions equipped with intelligent well technology have reportedly allowed for: (1) a reduced the number of wells required to develop a structure, (2) increased well productivity, and (3) reduced development cost [3, 12].

To overcome the operational challenges of the required complex well architectures, intelligent well technology provides control and monitoring of the downhole fluids’ movement.

Downhole monitoring enhances the operators understanding of the reservoir and recovery process allowing faster and more informed operational decisions. The added values are “improved utilization of asset infrastructure, reduced effluent production, accelerated production, improved hydrocarbon recovery, and better selection of infill well locations and numbers of wells to efficiently develop an asset” [12].
Inflow/outflow control of fluids at the well level provides solutions to several production challenges. Advanced Well Completion (AWC) include the identification and integration of a set of rules in a single tool to design a well completion that allow for an optimised production and well control. Figure 2-3 details the main components of AWCs such as, annular flow isolation (AFI), Inflow Control Devices (ICDs), Interval Control Valves (ICVs) and Autonomous Flow Control Devices (AFCDs). These components are discussed in details below.

In general, AWCs’ business drivers will differ for each field application and operator. Increased hydrocarbon recovery, accelerated production, and controlling unwanted fluids are the main key value drivers for “intelligent well - AWC” technology adoption [12]. Quantifying some of the added values (detailed below) from AWC can be challenging. This is drawn from the number of parameters involved in the process of designing, optimising and evaluating an AWC as depicted in Figure 2-4. It requires a thorough knowledge of the reservoir, and a competent modelling capabilities.

The development in AWC capabilities and the new physics involved in their designs need to be fully captured in the modelling and optimisation process to allow exploiting their perceived positive impact. For example, the more recent AFCDs allow for “autonomous” discrimination and control of the different fluid phases encroaching from the reservoir into the well. They have presented new modelling challenges that require extension of today’s wellbore/reservoir models and workflows.
2.2 Overview of Inflow control problems

Horizontal well technology has become a standard drilling technology in the oil and gas industry. More and more petroleum engineers have recognized the importance of pressure drop along a horizontal well and significantly affect the performance of the horizontal well. Due to pressure drop along horizontal wells and other practical and economic concerns, multilateral horizontal wells have been introduced since the early 1990s. By redistributing the flow of the long horizontal well into several shorter laterals, the fluid velocity becomes lower, resulting in small pressure drop values along each lateral. Similarly, several efforts have been made to reduce wellbore pressure drop along a horizontal well and to improve the performance [13].

Under certain situations, such as oil rim development, short multilateral wells may not provide the feasible (or practical) solutions, and long horizontal wells may still provide the most feasible economic option [2]. Such complex developments require a sufficient level of control to ensure that the full length of the well is contributing to the production. Furthermore, unwanted fluid control is envisaged to provide a greater added value from such topology by allowing the wanted fluid to have the priority to flow.

In the following sections we detail some of the main inflow/outflow problems.
2.2.1 Uneven Production along the Wellbore Length

2.2.1.1 Heel-to-Toe Effect (HTE)

This is a common problem associated with long horizontal wells. The flow of the fluid from the reservoir and into a horizontal well (or vice versa) naturally varies along the well length due to either: (1) frictional pressure losses (the heel–toe effect) [Figure 2-5 “a”] or (2) reservoir permeability heterogeneity [Figure 2-5 “b”]. Such variations usually negatively affect the oil sweep efficiency and the ultimate recovery [14, 15].

![Diagram of Pressure vs Distance from heel](image)

**Figure 2-5:** inflow distribution affected by the HTE and the reservoir heterogeneity

HTE encountered during a thin oil reservoir development was the first problem that led to the development of the AWCs technology. The ICD technology was introduced by Norsk Hydro in the early 1990s. The main purpose was to enhance the performance of Troll Field horizontal wells [13].

The Troll field, located on the Norwegian shelf of the North Sea, was originally considered to be a gas field. This is due to the thin oil column of 4 to 27 meter thickness being overlain by a large gas cap and underlain by an aquifer in some parts of the field. The oil production was deemed non-viable from this reservoir when conventional wells were considered. With the development of drilling technology, two horizontal wells were then drilled to evaluate such wells’ potential in monetising the oil [6, 16, 17]. The testing confirmed a significant oil production with a very high well Productive index (PI) of ~ 6,000 Sm$^3$/day/bar measured (5 - 10 times higher than expected from a conventional vertical well). With a targeted flow rate of 3,000 – 5,000 Sm$^3$/day only a small drawdown pressure of 0.5 – 1.0 bar was sufficient.
Production Logging found that 75% of the production was coming from the first half of the horizontal section. This is indicative of the significant effect the frictional pressure losses along the length have on the well performance when compared with the required (small) drawdown [16].

Brekke and Lien, 1994 [13] suggested three simple methods to improve the production performance in high-permeability thin oil zones by reducing the effect of wellbore pressure drop. The proposed completion methods included: (1) stinger completion to redistribute the frictional pressure loss along the wellbore by changing flow direction {Figure 2-6}, (2) reduced perforation density to create an optimal sand face pressure profile {Figure 2-7} and (3) same as point 2 but by introducing inflow control device along the wellbore while maintaining the perforation density{Figure 2-8}.

![Figure 2-6: A “Passive” Stinger Completion [13]](image)

![Figure 2-7: Variable Perforation Density controls fluid coning at the heel of the well [13]](image)
Their analysis showed that “the use of stinger completion method, in combination with reduced perforation density, can provide up to 25% increase in well productivity during the early part of the producing life, and the control of inflow to the wellbore by flow redistributions was found to be a stable and efficient method that provided up to 66% increase in the well productivity” [13].

The original Inflow Control Liner Device (ICD) concept “had a number of labyrinth channels installed within a pre-packed screen mounted on a solid base pipe {Figure 2-8}. The fluid flowing from the formation passes through both the screen and the channels before entering the casing’s (liner’s) internal bore via predrilled holes in the base pipe” [6]. To achieve the required pressure drop, the labyrinth channels’ length and diameter could be adjusted allowing the inflow along the length of the completion to be balanced {Figure 2-9} [13].
2.2.1.2 Reservoir heterogeneity

The increased length of the well’s exposure to the reservoir, comes with additional length and heterogeneity control requirements (long exposure to the reservoir means more heterogeneity along the wellbore length). The production fluid will naturally follow the least flow resistance path in the reservoir (Figure 2-5 “b”). This phenomenon results in an uneven production at different points along the well depending on the flow capacity at each point. Different directions and magnitudes of fluid encroachment into the wellbore relative to the reservoir flow capacity in the near wellbore depicted in Figure 2-10.

Controlling and (potentially) equalizing the production along the wellbore can improve the oil recovery (sweep efficiency) and delay breakthrough. Although, evenly distributed production along the entire well length might not provide the optimal well performance. Today, the widespread rule-of-thumb for inflow control completion design is: for an AWC design to be effective in equalizing the flow in or out of the well from each section along the wellbore, the differential pressure across each section should be on the same order of magnitude as the average drawdown on the reservoir [18]. However, recent studies have shown that the level of inflow/outflow equalization applied by an AWC design, has to be carefully designed since it increasingly reduces the well’s PI for greater levels of equalization [19].

Furthermore, the new AWC technology (e.g. AFCDs) is designed to offer phase selectivity or rate control, taking the opportunity for optimisation to a new level.

AWC design for solving reservoir heterogeneity problems depends on an understanding of permeability distribution, which is one of the hardest information to obtain at the time of designing the completion (i.e. before actually drilling the well). The reservoir conditions (e.g. heterogeneity, pressure support etc.) need to be understood to achieve a robust AWC design.

![Figure 2-10: Different directions of fluid encroachment into the wellbore relative to the reservoir flow capacity in the near wellbore area.](image-url)
2.2.1.3  *Loss of well productivity due to the formation damage*

In relation with long horizontal wells, loss of well productivity due to the formation damage can result from (1) formation plugging due to production and drilling activities, and (2) uneven inflow/outflow of fluid along the length of the wellbore at the start-up/clean-up period. Uneven clean-up of the sandface and the damaged zone along the “long” horizontal wellbore can result in a severe loss in the well potential [6].

2.2.2  *Annular flow*

The occurrence of annular flow has an adverse impact both on the sandface completion integrity, the well productivity and the efficiency of AWCs. Annular flow promote potential risks of [6]:

1. Sand production behind the screen and subsequent plugging or erosion.
2. Well integrity due to high velocities.
3. Ineffective control of the produced/injected fluids.

2.2.3  *Control of unwanted fluids*

Wells encounter unwanted fluid encroachment at various locations and production times. Upon breakthrough into the system, unwanted fluids (e.g. water and (or) gas) flow with a greater mobility compared with oil therefore considerably hinder the oil production. Furthermore, surface facility is usually designed with a specific handling capacity for the produced fluids (oil, water and gas). Such surface facility limitations require several engineering actions to optimise the system. Optimisation is required to allow for maximum utilisation of the total system capabilities in favour of the required fluid (e.g. oil). Drilling new wells does not always increase total production. Controlling and optimising the current resources may allow the company to achieve the targeted production rates with minimal expenditure.

To give an example of how the control of unwanted fluids may be of a paramount importance for improving oil production (even when compared with drilling new wells). Figure 2-11, a simple production system shows a reservoir being producing from well 1. Adding an “identical” well (well 2) to such a system does not double the oil production (for the same flow conditions) if the system happened to produce gas (a low viscosity fluid) along with the oil. The gas slippage along with the friction losses at the surface lines would results in a greater gas production than originally produced resulting in less oil increment than would be expected if single phase is flowing through the system.
Furthermore, if the flow line to the separator happened to be long enough, the oil production may even drop below the original value when only well 1 was producing.

![Diagram of a simple system illustrating the impact of unwanted fluid control in the system](image)

**Figure 2-11: Simple system illustrating the impact of unwanted fluid control in the system**

Unwanted fluid control can take various forms:

1. **Surface control** by imposing extra pressure drop at the surface choke to limit the total fluid production. Here the total production of the well is hindered (e.g. Troll [1]).

2. **Downhole control**: which can be implemented by (a) workover (e.g. to close the most affected zone) various shut-off techniques are available (chemical or mechanical), (b) downhole flow control device and (c) downhole unwanted fluid reinjection.

Such problem is exacerbated in conditions such as: completions close to reservoir fluid contact, revitalization of highly depleted reservoirs when affected challenged by injection conformance and fluid mobility issues. These are some of the challenges faced in mature fields leading eventually to low oil production and high water cut/GOR. In such environments when long horizontal wells are placed, the critical rate for oil production without coning is uneconomical [20]. Gas and water controlled at the sandface level has been shown to add considerable value in field applications [1, 21, 22]. Below we discuss specific issues with GOR control and heavy oil production and the impact expected from downhole control of unwanted fluids.
2.2.3.1  **Tackling the gas coning problem**

Field experience shows that the gas oil ratio (GOR) becomes strongly rate dependent after “free” gas breakthroughs from the gas cap into the well’s completion. GOR prediction and control is thus the key competency required for achieving optimum production [23].

“The underlying cause of the rate dependence is that, the oil rate from the parts of the well that is exposed to the gas-cap is limited by the gravity driven flow of oil towards the well. An increase in production rate will marginally increase the oil production from those parts. On the other hand, the gas rate is approximately proportional to drawdown” [23]. Thus, variation in drawdown will influence gas rate more than it influences oil rate, leading to rate dependent GOR. Furthermore, field production is often limited by the gas handling capacity of the surface facilities.

The traditional workflow for preventing and controlling gas breakthrough is to delay the onset of gas coning by limiting the well’s drawdown and, after “free” gas cap gas breakthrough, to reduce the well’s production rate to achieve an acceptable GOR level.

The possibility of a cheap downhole control of gas (and water) - at the sandface level - with minimum intervention and without interrupting the well production in such production conditions is attractive.

2.2.3.2  **Heavy Oil recovery challenges**

The definition of heavy oil varies between regions and operators. Considering heavy oil as being liquid petroleum with an API gravity of 22° or lower and a viscosity at reservoir conditions of 100 cP or greater; such heavy oil reservoirs present several challenges for proper reservoir drainage such as [24]:

1. Unfavourable mobility compared to water.
2. Water injection associated with early water breakthrough, reduced oil rates and high water production
3. Heterogeneity leads to an uneven drainage and can result in severe pressure differentials across the reservoir formations and fault blocks, leaving un-swept hydrocarbons and reduced overall production.
4. Infill wells in mature fields often experience high initial water production with a further rapid rise of water cut, resulting in high water production.
5. Low recovery factor.
6. Thermal recovery processes (e.g. steam injection and SAGD) have the additional complication of achieving even steam distribution along the wellbore.
7. Completion equipment is exposed to high temperatures in case of thermal recovery.

8. Artificial lift is generally required due to the poor inflow and outflow well performance.

9. Production often contains abrasive solids and corrosive gasses.

Porturas F., 2016 has detailed some of the challenges of heavy oil production encountered in Latin America some of which are tabulated in Table 2-1.

**Table 2-1: Heavy oil production challenges encountered in Latin America [18]**

<table>
<thead>
<tr>
<th>Field</th>
<th>Production challenges/attributes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Onshore</td>
<td>a) Small to very low production.</td>
</tr>
<tr>
<td></td>
<td>b) High water cut.</td>
</tr>
<tr>
<td></td>
<td>c) Regions comprising light oil and heavy oil accumulations.</td>
</tr>
<tr>
<td></td>
<td>d) Unswept hydrocarbons.</td>
</tr>
<tr>
<td></td>
<td>e) High levels of formation heterogeneity or relative thin oil rim.</td>
</tr>
<tr>
<td>Offshore</td>
<td>a) The studied fields have reached the mature phase.</td>
</tr>
<tr>
<td></td>
<td>b) High water injection (exceeding 800,000 bpd) presents injection conformance challenges, resulting in high water production (close to 350,000 bpd).</td>
</tr>
<tr>
<td></td>
<td>c) Calcium carbonate scales and plugging jeopardize production and shorten the life of the completion.</td>
</tr>
<tr>
<td>New fields</td>
<td>a) Variable API gravity.</td>
</tr>
<tr>
<td></td>
<td>b) Complex lithology (varied lateral and vertical reservoir continuity, compartmentalization).</td>
</tr>
<tr>
<td></td>
<td>c) Low pressure support.</td>
</tr>
<tr>
<td></td>
<td>d) H2S and CO2 content (hardware metallurgy).</td>
</tr>
<tr>
<td>Ultra-heavy oil</td>
<td>a) Exploited with thermal EOR.</td>
</tr>
<tr>
<td></td>
<td>b) High water production,</td>
</tr>
<tr>
<td></td>
<td>c) Unswept hydrocarbons and reduced production rates resulting from poor steam injection distribution, characterized by partial reach.</td>
</tr>
<tr>
<td></td>
<td>d) Non-uniform and localized steam injection, instead of heating the entire wellbore section.</td>
</tr>
<tr>
<td>General</td>
<td>a) Reservoirs, in all cases, are (will be) affected by uneven drainage and can result in severe pressure differentials across the reservoir.</td>
</tr>
</tbody>
</table>
formations and across fault blocks, consequently leaving unswept hydrocarbons and reduced production rates.

b) Variable reservoir continuity and quality.

c) Mature fields have low production and high water cut, even for infill wells (newly drilled).

Some of these challenges can be dealt with at the completion level by the application of FCDs to increase oil recovery by improving oil sweep in the reservoir and reducing the water cut in the production wells (points 1 to 5). Standard techniques used onshore (Production Logging, cement or gel squeezes, setting a plug, isolation with blank pipe, etc.), are frequently not available offshore where highly deviated wells and high intervention costs limit the scope for workover operations. Furthermore, identification of breakthrough location and unswept oil can be challenging/expensive. The efficiency of the new AFCD technology’s is investigated on this thesis through improved modelling.

### 2.2.3.3 Other Potential Applications

Other potential applications (but not limited to) are:

1) Steam Assisted Gravity Drainage (SAGD):

   Recent publications have indicated that some inflow/outflow problems in a SAGD horizontal well pair can be solved with AWCs [25]. The main benefit of AWCs for SAGD is to improve the well life and recovery process by [26]:

   a) Managing the sweep efficiency by controlling a uniform steam chamber.

   b) Delaying the steam breakthrough by controlling the water cut. Steam breakthrough will reduce the recovery process because steam will have created a path and will directly go to the producing well without removing the oil.

   c) Balancing the repartition of steam chamber which is often not uniform due to friction loss.

   d) Improving the well clean-up.

2) Gas fields:

   Balancing the inflow is not (generally) a concern in gas wells (especially for homogeneous formation). The concept of flow control as applied in AWCs, may in fact contradict the requirements for optimal development for gas fields. AWCs
works on the principle of imposing an additional pressure drop, to restrict the flow, allowing for the desired controlled production. Whereas, in gas fields it is often required to produce with high rates initially, taking advantage of higher diffusivity of the gas relative to water (material balance) [27].

Two main gas production problems exist which can be dealt with at the completion level implying AWCs:

a) The water production and the resulting liquid loading [28].

b) The risk of high annular velocity [29].

2.3 Background to inflow control technology

The technology application started by the introduction of Interval Control Valves (ICVs). Followed by AWCs employing ICDs which was first introduced in the North Sea in the mid-1990’s [13]. They have since become a commonly applied technology for different reservoir/fluid conditions in production as well as injection wells. The FCD completion idea is simple: the well’s production/injection interval is divided into zones using e.g. packers. The in/out-flow from zones is controlled by FCDs (flow restrictions) incurring different pressure losses in different zones thus modifying the in/outflow profile as required.

The key flow control components (depicted in Figure 2-3) of an AWC are:

1) Passive Inflow Control Device (ICDs).

2) Autonomous Flow Control Device (AFCDs).

3) Interval Control Valves (ICVs).

4) Annular Flow Isolation (AFI).

![Figure 2-12: An example of (A)ICD, ICV and AFI completion [6]](image)

A conceptual schematic view of a well with various FCDs is shown in Figure 2-12. A wide range of commercial FCDs is now available that significantly differ in their design, configuration and flow performance {Figure 2-13}. A comprehensive overview of the ICD and ICV technology is available in Al-Khelaiwi, F.T.M, 2013 [6].
The evolution of these devices from passive (or fixed) chokes to autonomously actuated control of fluid flow has supported the development planning and production optimisation of many fields [1, 18, 21].

2.3.1 Objectives of Inflow Control Devices

Different reservoir environments contain different production challenges. Table 1-1 discussed various issues related with long horizontal wells from different perspectives (i.e. reservoir, drilling and production). The related inflow/outflow problems discussed in section 2.2 can result in severe pressure differentials across the reservoir formations and across fault blocks, leading to unswept hydrocarbons, reduced production rates, development strategy being dominated by unwanted fluid control etc. AWCs emerged as simple and practical solutions for such problems. Moreover, the successful field implementations (& proof of concept trials) since 1990 have encouraged a rapid developments for the technology.

2.3.1.1 Overview of benefits from IWs usage

Table 2-2 summarises the approved benefits from intelligent well and AWC (inflow control technologies in particular) [4, 6, 11, 14, 18, 30].
<table>
<thead>
<tr>
<th>Function</th>
<th>Added value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Improved well clean-up</td>
<td>Minimizing the effects of formation damage caused by drilling.</td>
</tr>
<tr>
<td>Equalizing the flux along the well path (minimize HTE and heterogeneity effect)</td>
<td>Delay the breakthrough and elongate free oil production. Improved sweep efficiency and recovery.</td>
</tr>
<tr>
<td>Delay unwanted fluid breakthrough</td>
<td>Reduce production of undesirable water or gas.</td>
</tr>
<tr>
<td>Control unwanted fluid production</td>
<td>More oil, reduced facility constraints etc. (AICD, ICV). Control of early BT or coning which may occur at any location along the well</td>
</tr>
<tr>
<td>Reduced annular flow</td>
<td>Reduces the risk of sand production behind the screen and subsequent plugging or erosion.</td>
</tr>
<tr>
<td>Enable surface controlled production from each zone or lateral</td>
<td>Optimize production and reservoir management.</td>
</tr>
<tr>
<td>Allow production testing of individual zones</td>
<td>Limited interventions with minimal production interruption.</td>
</tr>
<tr>
<td>Accelerate Production</td>
<td>Can be designed to allow for higher initial oil production and a controlled production after BT.</td>
</tr>
<tr>
<td>Formation prone to scale precipitation, initial anti-scaling inhibitors treatments, and later for anti-scaling fluid distribution along the well</td>
<td>Avoid scaling inhibitor concentrated at a specific location along the well (due to un-even injection, HTE, heterogeneity, pressure difference)</td>
</tr>
<tr>
<td>Commingled production with Zonal control</td>
<td>The increase in the cumulative production.</td>
</tr>
<tr>
<td>Reduce Capital Expenditure (Capex)</td>
<td>Reduction in well count.</td>
</tr>
<tr>
<td>Reduce Operating Expenditure (Opex)</td>
<td>Well’s ability to respond immediately to unexpected changes which transfers into intervention-cost savings and a minimal production deferment.</td>
</tr>
<tr>
<td>Reduce risk, increase recovery, NPV and extend the economic life of the well</td>
<td></td>
</tr>
</tbody>
</table>
Evaluation techniques include [18, 31-34]:

1- PLT, tracers, DTS, etc.

2- Production data analysis:
   a) Rate according to plan.
   b) Fluid control (delayed BT, favourable GOR and (or) WCT development).
   c) Pressure difference at BT.
   d) History matching.
   e) Nodal analysis.

3- Static and dynamic analysis at well, group or field level.

4- Cost reduction (less intervention, less equipment, etc.)

Further details on AWCs’ benefit and successful implementation available in Table 2-3 and in Appendix (1) by Porturas F., 2016.

Table 2-3: Summary of AWC’s Proven Benefits and Future Potentials [18]

<table>
<thead>
<tr>
<th>PRODUCTION MODE</th>
<th>INJECTION MODE</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Balance influx along the entire wellbore</td>
<td>1. Minimize wellbore effects, fracture corridors and “highways”</td>
</tr>
<tr>
<td>2. Adjust pressure and balance average well drawdown</td>
<td>2. Uniform fluid injection distribution e.g. gas, water, steam, CO2, low salinity fluids, etc.</td>
</tr>
<tr>
<td>3. Minimize, delay and restrict early water coning (coning could happen anywhere along the wellbore)</td>
<td>3. Selective zone stimulation and acidification treatment</td>
</tr>
<tr>
<td>4. Minimize, delay and restrict gas coning (specially valuable and beneficial in reservoirs with harsh environments, H2S and CO2, store underground)</td>
<td>4. Selective injection</td>
</tr>
<tr>
<td>5. Aid further wellbore clean up (unique differential pressure attribute and acting as a function of time)</td>
<td>5. Better injection profile without ramps and sours</td>
</tr>
<tr>
<td>6. In reservoirs with active bottom and lateral aquifers</td>
<td>6. Achieve injection conformance</td>
</tr>
<tr>
<td>7. Applicable both in low to high deviated wells</td>
<td></td>
</tr>
</tbody>
</table>

**COMMON TO BOTH FIELD OPERATIONAL MODES**

1. Minimize Heel-To-Toe effects
2. Slim solutions in challenging well trajectories and un-stable geomechanically drilled formations
3. Inner strings for value added workovers
4. Formations prone to scale precipitation (initial anti-scaling inhibitors treatments, and later applied for anti-scaling fluid distribution along the well accordingly operators field timing and strategy)
5. Increase well PI in mature fields and injectivity index (injector wells)
6. Achieve better area sweep and reservoir drainage and injection conformance
7. Mature fields and thin oil and gas reservoirs; stabilize and or maintain WOC and OGC in a steady situation (re-injecting gas and water for pressure maintenance)
8. Optimize contribution of fracture corridors and “high permeability highways”

**ADDITIONAL BENEFITS**

<table>
<thead>
<tr>
<th>ADVANCED INSTALLATIONS AND HYBRID</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Accelerated production and or field managed production strategies</td>
</tr>
<tr>
<td>b. Gas storage</td>
</tr>
<tr>
<td>c. IOR and or EOR reservoir initiatives</td>
</tr>
<tr>
<td>d. Nano-particles and or fluids evenly distributed along the well (the advantage is having a architecture ready to receive and evenly distribute any treatment fluids)</td>
</tr>
<tr>
<td>f. Non-conventional reservoirs</td>
</tr>
</tbody>
</table>

**AICD HARDWARE PERFORMANCE: VERIFICATION AND MONITORING**

| 1. PLT, wireless Tracer logs, DTS, etc. | 5. Total liquid rate production accordingly with target rate |
| 2. Historical production data | 6. Favorable WCUT development |
| 3. Static and dynamic simulations at Well, Group and Field levels | 7. HSE and flawless field operations |
| 4. Multi-phase flow Nodal Analysis and History matching | |
Some added values are difficult to quantify, including [35]:

a) Early data acquisition to improve the infill drilling.
b) Identification of key variables that need to be measured.
c) Mitigation of the downside risks.
d) Health, safety and environmental dividends from unmanned operations.
e) Smaller environmental footprint due to reduction of the number of wells and production of unwanted fluid.
f) Opportunity to acquire relevant data in wells to be abandoned.

An optimum design employing the appropriate technology is required to achieve the full potential of AWCs. The functions of the various wellbore completion components and their impact on the total well performance efficiency, and hence the success of the chosen FCD, needs to be fully understood and captured in the model used for the design optimisation process.

2.3.2 Describing the fluid flow path in AWCs

AWCs are normally installed in an open-hole completion (i.e. no casing). The AWCs flow control components {Figure 2-3} are then mounted on the production tubing which extends to the well total depth (TD) {Figure 2-12}. Depending on the type of formation and the formation hardness and sand production risks, the annulus between the production tubing and the formations can be filled with gravel or left completely open to flow. All of the flow control devices can either be mounted on a Stand Alone Screen (SAS) “for application to unconsolidated formations, or they can be combined with a debris filter” [36] (to prevent blockage of the flow restriction) when used in a consolidated formation {Figure 2-14} [6].

The production stream passes through the annulus, which can be completely open (with wire wrapped screen, or expandable screen) or may contain GP, into the inner screen (or debris filter) along the outer surface of the base pipe (see e.g. Figure 2-15). The fluid then continue to the (A)FCD housing where a specially designed flow control device is placed, controlling the flow into the inner section of the base pipe by applying different physics {Figure 2-14}. The fluid flow path is reversed for injection applications. There are few exceptions to the flow path described above (e.g. the Flotech-FloMatik ICD [6].)
2.4 Advanced wells completion flow control components

AWCs include the identification and integration of a set of rules in a single tool to design advanced well completions that is capable of optimising the production, reduce expenditure, and mitigate the risk. Figure 2-3 details the main flow control components of AWCs to be discussed in the following sections.

In order to achieve the targeted flow control for each individual zone, it is crucial to suppress the annulus flow. Annular flow isolation is discussed next.
2.4.1 **Annular Flow Isolation (AFI)**

2.4.1.1 **Causes of Annular Flow**

As described in section 2.3.2, the annulus between the production tubing can be left completely open or may be partially open due to, e.g., an incomplete GP job (or) uneven collapse of the formation around the completion. This flow conduit has a relatively large flow area, compared to the area of the inner flow conduit (e.g. the FCDs). Therefore the annulus provide the least resistive flow path, potentially allowing the fluid to bypass the designed (flow control) restriction.

Annular flow occurs in fully or partially open annuli due to several factors, such as [6]:

1. Permeability variations along the wellbore.
2. Commingled production from zones with different pressures.

The occurrence of annular flow has an adverse impact both on the sandface completion integrity and the well productivity. Table 2-4 provides the expected impact of annular flow on the well performance.

**Table 2-4: Annular Flow Impact [6]**

<table>
<thead>
<tr>
<th>Problem</th>
<th>Consequence/ Impact</th>
</tr>
</thead>
</table>
| Sand grain "dislodging", sorting and transportation along the length of the well. | 1. Plugging at parts of the annulus.  
2. Plugging of the screen mesh caused by fine (often shaly) particles.  
3. Erosion of the sandface due to the potential high velocity flow.  
4. Formation of "hot-spots due to divergence of the fluid flow direction toward the screen or pre-perforated liner. |
| Loss of well productivity | 1. Formation plugging.  
2. Uneven influx of fluid along the length of the wellbore.  
3. Loss of AWC’s added value.  
4. Uneven clean-up of the sandface and damaged zone around the wellbore. |
2.4.1.2 AFI Types

Isolation of annular flow can be achieved using packers (or) gravel packs. Formation collapse can potentially provide sufficient flow isolation. However, packers are the most common type of AFI. Gravel packs are mainly applied to minimise/control sand production, but also provide a significant resistance to flow in the annulus (based on simulation results and experience) [36].

Open-hole packers can be divided into six categories the details of which can be found in Al-Khelaiwi, F.T.M., 2013 [6]:

1. Mechanically set packers.
3. Inflatable packers.
4. Expandable packers.
5. Chemical packers.
6. Swell (elastomers) packers (SP).

Table 2-5 gives a Comparison of the available AFIs.

<table>
<thead>
<tr>
<th>Packer Type</th>
<th>Mech./Hydr.</th>
<th>Inflatable</th>
<th>Expandable</th>
<th>Chemical</th>
<th>Swell</th>
</tr>
</thead>
<tbody>
<tr>
<td>Applicability in (A)ICD and ICV completions</td>
<td>Y</td>
<td>N</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>Operational Flexibility</td>
<td>H</td>
<td>H</td>
<td>M</td>
<td>M</td>
<td>H</td>
</tr>
<tr>
<td>Control line feed-through</td>
<td>Y</td>
<td>N</td>
<td>N</td>
<td>Y</td>
<td>Y</td>
</tr>
<tr>
<td>Risk of:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Premature setting</td>
<td>M</td>
<td>L</td>
<td>L</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>Damage/loss of isolation</td>
<td>L</td>
<td>M</td>
<td>L</td>
<td>M</td>
<td>L</td>
</tr>
<tr>
<td>Pressure difference</td>
<td>H</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
</tbody>
</table>

Y = Yes, N = No, Dependency: H = High, M = Moderate, L = Low
2.4.1.3 AFI Applied for AFCD Completion

FCDs provide different levels of control satisfying various reservoir management’s requirements. The recently introduced AFCDs, for example, allow for a selective phase control. They can increase flow resistance to water and (or) gas flows and apply “in principle” minimum resistance to oil flow. However, such application may require a special attention to the annulus flow in order to control the flow from each zone optimally and successfully. This may lead to an increased number of AFIIs being required. On the other hand, a limited number of packers can be installed in a single wellbore (typically 5 – and in some field applications – up to 20).

From the above, the AFI distribution require optimisation considering (but not limited to):

1. The reservoir heterogeneity and pressure variations.
2. Number of zones to control.
3. Number of wells (laterals for example).

The AFI optimisation is beyond the scope of this thesis (see Moradi, M., et al., 2014 for further reading on this subject).

2.4.2 Passive inflow Control Device (ICDs)

Passive inflow control devices (ICDs) provide fluid flow control from (or into) the reservoir by introducing a rate-dependent pressure drop at different sections along the well completion. Horizontal (or deviated) wells are normally segmented with multiple annular packers that create zonal isolation, to allow for an efficient (selective) flow control of the individual zones.

The following points are known about passive ICDs:

1. An ICD is a passive fixed choke which cannot be adjusted after installation.
2. Passive ICDs works without any connection or actuation from the surface, and without any intervention by the operator.
3. ICDs are mainly used to mitigate inflow variation in heterogeneous reservoir and heel-toe effect in homogenous reservoir by imposing additional pressure drop across the completion.
4. ICDs have also been used to mitigate the risk of high annulus velocity in gas wells [29].
5. Recently, ICD-completions have been introduced as an effective solution to some concerns on Steam Assisted Gravity Drainage (SAGD) schemes.

6. ICD can potentially delay water breakthrough by facilitating more even flow distribution and hence lead to more recovery [6, 14].

7. The pressure drop across the device/valve must be limited to an acceptable level compared with reservoir drawdown. The general consensus on their design is that: for the ICD-completion to be effective in balancing the inflow/outflow from each section along the length of the wellbore, the pressure differential across each ICD must be of the same order of magnitude as the (average) drawdown on the reservoir [18].

8. ICDs do not have the ability to actively modify the amount of fluid being produced after, coning of an undesirable fluid at that completion joint has occurred. ICDs are thus considered to be a proactive FCD since they are installed early in the life of the well and their control of the well’s inflow profile is during the period prior to water and/or gas breakthrough.

9. Thus ICD-completion design should be taken carefully considering an adequate understanding of the reservoir characteristics such as: (a) fluid property, (b) rock properties and (c) pressure behaviour. More importantly, the design should also take into account the prediction of these factors [4]. The pressure performance as well as the unwanted fluid breakthrough (timing and control) are important parameters to insure optimum well performance.

2.4.2.1 Typical commercial ICD design

The “six leading suppliers of ICD technology (Tejas, Baker Oil Tools, Easywell Solutions-Halliburton, Reslink-Schlumberger, Flotech and Weatherford) have developed unique ICD designs for the mechanism that creates the flow resistance (Labyrinths and Helical Channels, Slots, Tubes, Nozzles and Orifices respectively)” [6]. Table 2-6 and Table 2-7 provide details on the various passive ICD deigns. Comprehensive details and analysis are available on Al-Khelaiwi, F.T.M, 2013.
Table 2-6: Main ICD types [6]

<table>
<thead>
<tr>
<th>Types</th>
<th>Manufacturer</th>
<th>Feature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labyrinth Channel</td>
<td>Tejas</td>
<td>Pressure drop is highly dependent on fluid viscosity and velocity</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Less susceptible to erosion</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Strongly influenced in the case of emulsion</td>
</tr>
<tr>
<td>Helical channel</td>
<td>Baker Oil</td>
<td>Six flow resistance rating achieved by altering the diameter, length and number of channels</td>
</tr>
<tr>
<td></td>
<td>Tool</td>
<td></td>
</tr>
<tr>
<td>Slot-Type</td>
<td>Baker Oil</td>
<td>Modification of Helical channel</td>
</tr>
<tr>
<td></td>
<td>Tool</td>
<td>Minimize the pressure drop dependence on fluid viscosity</td>
</tr>
<tr>
<td>Tube Type</td>
<td>Easy well</td>
<td>Combines the effect of pressure drop created by flow through restriction and that of a straight tube</td>
</tr>
<tr>
<td></td>
<td>solution</td>
<td></td>
</tr>
<tr>
<td>Nozzle Type</td>
<td>Reslink</td>
<td>In the high fluid velocity with sand production, erosion resistance materials are used</td>
</tr>
<tr>
<td></td>
<td>Flotech</td>
<td></td>
</tr>
<tr>
<td>Orifice Type</td>
<td>Weatherford</td>
<td>Employ multiple orifice to produce for flow equalization</td>
</tr>
<tr>
<td></td>
<td>Schlumberger</td>
<td>Can be modified on the wellsite easily by plugging or unplugging orifice</td>
</tr>
</tbody>
</table>

Table 2-7: Current types of passive inflow control devices (courtesy of, Schlumberger, Baker Hughes, and Halliburton)

Labyrinth Helical slot Tube type Nozzle/Orifice type See also Figure 2-15 Helical-channel type

2.4.2.2 The pressure drop across passive ICDs

The fundamentals of inflow control technology where described by Al-Khelaiwi, F.T.M, 2013 and Birchenko, V.M, 2010 [6, 14]:

32
(1) The pressure drop across the device/valve must be limited to an acceptable level compared with reservoir drawdown and

(2) The device/valve should create a high enough pressure drop to obtain the required flow rate distribution (or level of flow equalization) along the length of the wellbore.

The optimal operating conditions which results in a breakeven point between the sacrificial pressure loss and the enhanced oil production determines the value derived from this type of well completion [6, 19].

The magnitude of pressure drop induced by ICD is highly dependent on (1) the dimensions of the installed flow restriction (i.e. orifice/nozzles or channels) and (2) the number of restrictions installed along the completion. The degree of restriction is generally referred to as “ICD strength”, providing the magnitude of pressure drop imposed by ICD and can be calculated using the Equation 2-1.

\[ \Delta p_{ICD} = aq^2 \]  

Equation 2-1

Where:

\[ a = \begin{cases} 
\left( \frac{\rho_{cat} \mu}{\rho \mu_{cat}} \right)^{1/4} & \frac{\rho}{\rho_{cat}} l_{ICD}^2 B^2 a_{ICD} & \text{for channel ICD} \\
\frac{C_u \rho l_{ICD}^2 B^2}{C_d^2 d^4} & \text{for nozzle or orifice ICD} 
\end{cases} \]  

Equation 2-2

A detailed analysis for their single phase and MPF performance can be found in Mayer, C.S.J., et al., 2014 [37] (see also [4, 38]).

### 2.4.2.3 ICD design workflow, modelling and optimisation

Several methods have been proposed for ICD-completion design and optimisation. The ICD-completion design proposed by Al-Khelaiwi, F.T.M, 2013 consist of {Figure 2-16}:

1. Identifying the optimum ICD:
   - Identification of the inflow imbalance causes.
   - Identification of the required pressure drop (magnitude of restriction):
     - Optimum nozzle (orifice) size.
     - Channel (tube) diameter.
     - Frequency of ICDs.
2. Identifying the AFI requirements:
   - AFI frequency & type.

3. Account for uncertainty:
   - Geological uncertainty.
   - Measurement/correlation uncertainty.

4. Evaluating the completion reliability and installation risks:
   - Erosion effects.
   - Plugging effects.
   - Choice of ICD type.
   - Wellbore not reaching Total Depth (TD).
   - Screen Plugging.

5. Quantifying Economic Value:
   - Net Present Value (NPV), Key Performance Indicators (KPI), etc.

The completion efficiency evaluation and added value quantification require consideration for the completion long term impact on the well performance when it is in communication with the reservoir. This stage can be carried out with computational reservoir simulators demanding thorough understanding of the entire production performance from the reservoir to the coupled well and completion performance.

![Diagram](image)

**Figure 2-16: ICD completion design workflow [39]. This workflow has been modified in chapter 5 to properly size and optimise AFCDs**

Due to the nature of the completion process and the restrictions onsite (e.g. off-shore space limitation), the ICD completion design is normally prepared against a poorly know reservoir prior to drilling the well. Moreover, after the well is drilled, the completion equipment normally allocated a very short time (e.g. within 48 hours) to run in hole.
Meaning that, any necessary changes (see the evaluation stage above) must comply with the allocated rig time. Static modelling tools (analytical models) are generally used in this stage [14].

However a static modelling tool, being very simple, has the limitations of simple description of reservoir property, ignoring the surrounding geology and behaviour and ignoring important physics (e.g. MPF flow behaviour) inside the wellbore. Therefore, dynamic simulators have advantages over analytical modelling:

- Ability to account for annular flow which is ignored in the analytical models by considering a direct flow from reservoir to the base pipe.
- In addition to that, dynamic modelling is capable of dealing with three dimensionless property distribution while static modelling use average value for the properties (Permeability etc.).

Figure 2-17 provides an example difference in describing flow path between the analytical model and the dynamic model.

![Figure 2-17: Example difference between numerical and analytical model](image)

However, using numerical simulator for ICD design is time-consuming. For this reason, quick analytical modelling has been developed and widely used by the industry for ICD completion design. Analytical modelling for ICD design allow the engineers to perform [14]:

- Assessment of the ICD-completion performance when more accurate reservoir data (e.g. from logging) become available. Based on which the engineer may perform:
  - Fast analysis of the adjustments required on the ICD design (e.g. at the wellsite) to obtain the production rate target or other targets.
- Verification of numerical simulation results.
Further details on ICD application and limitations can be found in Al-Khelaiwi, F.T.M, 2013 and Birchenko, V.M, 2010 [6, 14]. Appendix (2) provides a list of issues related to completion components’ utilization in AWC.

2.4.3 **Active, Interval Control Valves (ICVs)**

ICVs, unlike ICDs, are “Active” devices. ICVs are controlled from the surface in order to reduce undesired fluid production, improve the recovery factor, avoid costly well interventions and reduce production uncertainty [35].

The ICVs can be also divided into three types (Grebenkin, I.M., 2013) [41]:

1) On/Off valves with two positions; either fully open or fully closed.
2) Discrete valves with a fixed, normally 10 or fewer, number of positions.
3) Infinitely variable valves which can have any position between fully open and closed. These valves provide the most flexible control.

Choice of an efficient control strategy is a difficult problem. All optimization strategies can be divided into two main types: “proactive” and “reactive” [42]. “Reactive” optimization requires the AWC to respond to the current inflows into the well; either flow rates, WC or GOR. By contrast, a “proactive strategy can change the invading front’s behaviour; delaying the unwanted fluid’s breakthrough and increasing the sweep efficiency” [41].

A number of different Reactive and Proactive Production strategies have been published in the literature. The main strategies, and the results for their application to optimise intelligent wells, are summarised in Grebenkin, I.M., 2013 [35].

ICV technology today, provides a limited number of valves per well. This is due to the required lines connected to surface to allow for valves actuation (note that the control can either be electric, hydraulic or electrohydraulic {Figure 2-13}).

ICVs are not discussed any further in this thesis. New devices (AFCDs) with more complex physics and working principles have recently been developed. They necessitate new: design ideas (due to different objectives), modelling validation and extension and uncertainty assessment (due to various MPF effects). AFCD are discussed next.

2.4.4 **The Reactive Flow Control: Autonomous Flow Control Devices (AFCDs)**

2.4.4.1 **Introduction**

An industry-wide effort has been on-going for some years to develop an inflow control device which has the ability to spontaneously and selectively shut-off/control the
unwanted fluids at the valve level. The value of such a device was discussed in several publications, e.g. Ouyang, 2009 [5] considered the benefit of applying ICDs with efficient phase filtering capabilities for reducing the water production. He concluded by recommending that “efforts should be pursued to develop an intelligent ICD system that can filter and selectively block unwanted fluid (water) entry. Such an ICD system could certainly benefit the industry and lead to the wide spread application of ICDs for reducing water production”.

AFCDs, the latest development in flow control technology, add phase selectivity to the passive ICD’s performance by autonomously creating an additional flow restriction to unwanted fluids. AFCD technology is currently in the rapid development phase with several new ideas being proposed {Table 2-8}. Several types of AFCDs have passed the proof of concept stage and become commercially available; while others are still in the engineering development phase [43].

AFCDs features include [44]:

- Operates autonomously.
- Contains no electronics, or connections to the surface.
- Requires no intervention.
- Will cease flow restriction if unwanted fluid recedes.
- Designs available to produce oil and restrict either water, gas or steam.
- Utilizes innovative dynamic fluid technology to direct/control the flow.
- Functions as a standard ICD prior to water/gas breakthrough.
- Each device functions independently for precise response to the reservoir.
- Some of them contains moving parts and some of them don’t.

AFCDs, a development of the passive ICD, combine passive inflow control with an active, flow control element. The active element ensures that the differential pressure across the AICD is dependent on the composition and properties of the flowing fluid as well as the flow rate. The device reacts autonomously to changes in fluid properties by (1) changing the geometry of the fluid’s flow path or (2) altering the flow path itself as a function of the controlling properties [45]. The resulting fluid selectivity is achieved by both devices creating an additional restriction to flow of the unwanted fluids without any connection to the surface. Figure 2-18 provides an example for the conceptual AFCD reaction towards wanted and unwanted fluids.
2.4.4.2 AFCD First Field Application

AFCD technology field application started in 2008 with the Rate Controlled Production (RCP) AICD-completion field deployment in Troll Field with the basic interest of controlling gas production [1]. A multilateral well named (P-13 BYH) with two “horizontal” laterals completed with two different FCD technologies, namely BY1H completed with ICDs and BY2H completed with RCP-AICDs. The two laterals, with 191 m spacing, are located within a similar permeability field as shown in the permeability map depicted in Figure 2-19.

Figure 2-19: Permeability map for Troll field nearby well P-13 [1]
With these specifications, the two wells’ gas production performance was considerably different. Examination of the cumulative oil production (Figure 2-20) show that, the lateral BY2H (with RCP completion) has produced approximately 20% more oil than the other lateral (BY1H) (Halvorsen, M., et al., 2012) [1]. This is attributed the additional downhole control applied by the improved RCP resistance to gas flow compared with passive ICDs. This downhole control has resulted in a reduced need for surface control of gas production established from the surface facility gas handling constraints.

![Figure 2-20: P-13 BYH GOR vs. Cumulative oil production performance [1]](image)

### 2.4.5 AFCD types and various ideas

AFCD technologies can be categorised, based on their current market status, as:

A. Initial concepts, no reports of engineering development.
B. Commercial AICDs.
C. Recently announced with engineering development in progress.

Based on their working principle, AFCDs can be categorised as:

1. AICDs which **restrict** the flow of unwanted fluids after breakthrough.
2. AICV, by contrast, are designed to autonomously **stop** unwanted fluids (water or gas) production after breakthrough.

AICDs and AICVs are both autonomously reversible, reacting to the local conditions of fluid properties and pressure. Table 2-8 below provides a background of the various AFCD ideas/designs and a description of their operation principle.
<table>
<thead>
<tr>
<th>AFCD description</th>
<th>AFCD design</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Swellable-type AICD [6, 46]</strong></td>
<td></td>
</tr>
<tr>
<td>The valve works on the basis of one of two principles depending on the swellable material: (1) the principle of osmosis or (2) thermodynamic absorption. Using one of these principles the valve can sense the change in flowing fluid properties. The expansion of the swellable membrane material due to the flow of water, forces an inner plate (with spiral flow paths) to limit the flow area and hence restrict the fluid flow path to the inner part of the casing {Figure 2-21}. The spiral fluid flow path through the device can also be designed to impose a specific pressure drop designed to equalise the influx along the horizontal wellbore (i.e. act as an ICD).</td>
<td></td>
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<tr>
<td></td>
<td><img src="image1.png" alt="" /></td>
</tr>
<tr>
<td><strong>Ball-type AICD [6, 47]</strong></td>
<td></td>
</tr>
<tr>
<td>The device works on a buoyancy based actuation of the valve. The ball-type AICD uses metallic balls to shut off &quot;Active&quot; nozzles depending on the flowing fluid density to control the flow from the AICD chamber to the inner section of the production tubing. If the AICD is designed for water control, the balls reside at the bottom of the</td>
<td></td>
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<tr>
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<td><img src="image2.png" alt="" /></td>
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</table>
device during dry oil production. As the water cut increases, the density of the produced fluid mixture will increase causing the balls to float upwards and to start blocking the nozzles one after the other {Figure 2-22}.

For gas production control, oil-floating balls are used. The balls’ are designed to float in the oil phase. Upon breakthrough, the density reduces allowing the floating balls to sink and shut the flow nozzles {Figure 2-23}. The device also contains bypass nozzles (~20% of the total flow area). The bypass nozzles allow the fluid flow through the device to continue even after the all the active nozzles are shut {Figure 2-24}. This maintains a pressure drop across the completion to hold the balls in their shut-in positions whenever fluid is flowing. The device can be reset to the open position by shutting-in the well.

**Floating flapper [6, 49]**

The device utilises the buoyancy principle in the actuation of the valve. The flapper is specially designed to remain open when the density of the production fluid matches the oil density and to close once the production fluid density decreases significantly due to gas or

---

*Figure 2-23: Ball-type AICD to control gas [48]*

*Figure 2-24: Ball-type AICD [48]*
water influx (Figure 2-25). The flapper uses a counterweight installed opposite the flapper (Figure 2-25 “B”). The closing rate of the valve can be designed to the desired valve actuation conditions by changing the counterweight’s mass. The design also include (1) a Gravity Ring which controls the device orientation during the completion installation and (2) an expandable rubber seal placed to the rear of the Gravity Ring expands gradually on contact with the produced hydrocarbons to seal the equipment in place after the completion equipment has reached its final position in the well.

**Water Swelling Rubber (WSR-AICD) with nozzle ICD base [50]**

This AICD works based on the combination of nozzle-based ICD type combined with a water swelling rubber (WSR) constructed as shown in Figure 2-27. The WSR installed in the nozzle swells once water breakthrough occurs. The swell increment is a function of the water content as illustrated in Figure 2-28. The valve can potentially be used for oil or gas wells to stop water.
WSR-AICD with Hybrid ICD [51]
Combines a labyrinth ICD and a water swelling rubber (WSR) {Figure 2-29}. Similar to the standard hybrid ICD, each of the flow paths has two flow slots cut at 180° angular spacing, and each set of slots staggered a 90° phase with the next set. Thus the flow must turn after passing through each set of slots. The WSR installed in the slot swells once in contact with water, and the swell increment depends on the water content as illustrated in Figure 2-30.

BECH AICD [4, 11, 52]
Figure 2-31 and Figure 2-32 illustrates a design of a prototype valve.
The valve is developed to overcome the non-linearity of flow regulated/traditional ICDs, which obviously leads to a relative flow change between the heel and the toe of the horizontal well.
The valve is designed to provide a constant flow rate at various locations along the well regardless of pressure variations. This is achieved by a reservoir pressure (P₂) controlled piston which can be set to a pre-determined flow rate {Figure 2-33}. Its percentage stem opening is hydraulically adjusted by
the varying reservoir pressure to satisfy the pre-set flow rate. The valve maintains constant flow through a mechanism consisting of a spring/loaded membrane with a needle. The reservoir pressure is choked through a nozzle which forms the principle element for setting flow rate before fluid flows in the production tubing. Hence when reservoir pressure is low, the spring/needle will open, maintaining constant flow and likewise when reservoir pressure increases (which is unrealistic in nature except in a gas injection operation), the pin closes to maintain a constant flow rate. The device is an autonomous, downhole flow regulator designed to regulate the inflow or outflow of fluids as desired.

See also: **Autonomous Flow Controller Device (AFD)** [53]

**Adaptive Inflow Control system** [54, 55]

Adaptive Inflow Control system consist of: (1) a well screen, (2) a labyrinth ICD {Figure 2-43} configured to suite specific field conditions and (3) Adaptable Flow Control (AIC-AICD) capable of self-adjustment depending on fluid rate, pressure and phase composition. The AIC-AICD is
located at several exit points as depicted in Figure 2-37.
The ICD chamber functions to gradually increase the hydraulic impedance to liquid flow which reduces the stream pressure. The hydraulic impedance is increased by simultaneous multiple change of flow direction and flow acceleration, deceleration, merging and splitting. The system allows to equalize the inflow profile of horizontal wells as well as controlling the unwanted fluids. Flow control is achieved due to the design of the AIC-AICD and adjustment of the flow rate through the valve providing for the required valve activation (opening or closing) pressure drop at the pre-set flowrate.

A special unit is design for gas flow control [54, 55].

**Y-shaped (AICD) [56]**
The valve works on the combination of two flow components: (1) the y-shaped fluid director directing the flow, and (2) the disk-shaped restrictor restricting the flow {Figure 2-38}. A disk-shaped restrictor can be connected with several y-shaped fluid directors. The y-shaped fluid director comprises the main pipe and the branch pipe with a branch
angle less than 90 degrees. And both pipes have the same diameter. The main pipe enters the disk-shaped restrictor tangentially, while the branch pipe enters tangentially or radially. Therefore, the maximum number of the y-shaped fluid directors a restrictor can connect with depends on the entry mode of the branch pipe and its branch angle (2 to 4 “tangential” – 4 to 24 “radial”) {Figure 2-38}. The Y-shaped fluid director uses the balance between the inertial forces and the viscous forces in the fluid to change the passages. That is, the larger the inertial force, the more likely the fluid is to maintain its original flow direction, and flow through the main pipe. In addition, the larger the viscous force, the more likely the fluid is to change its original flow direction, and flow through the branch pipe instead {Figure 2-39 and Figure 2-40}.

Recently new designs introduced with engineering development in progress, e.g. Adaptive Inflow Control System [54, 55]. Moreover, we are also aware of some ideas and designs that are under development and investigation (research) with no published performance (see e.g., [57, 58]). Therefore, the list provided above is not exclusive and no doubt more concepts of optimised autonomous reactions will emerge following the continuous interest, research and field observations concerning this technology (see e.g. the observation in section 2.5.3.1.1 and the future work recommendations in section 6.2). Three AFCD types are commercially available with reported field applications:

(a) The Rate Controlled Production (RCP-AICD) technology [1].
(b) The Fluidic Diode (FD-AICD) technology [59].
(c) The AICV technology [60].

Being the main focus of the thesis, RCP-AICD, FD-AICD and AICVs are discussed next.

2.5 AFCDs with field application record for further discussion

Commercial AFCDs are available with different design concepts {Table 2-8}. Three main AFCD types (RCP-AICD, FD-AICD and AICVs) where selected for further research and analysis because of: (1) the reported engineering development, (2) the reported successful field applications, and (3) the “relative” availability of the valve’s performance data.

Details of the three AFCD are provided below.

2.5.1 The RCP-AICD technology

2.5.1.1 Historical background and design specifications

The RCP-AICD that was originally installed in Troll field was developed by Statoil. The working principle is described by Mathiesen, V., et al., (2011) and Halvorsen, M., et al., (2012) [1, 61]. The function of the RCP is based on the Bernoulli principle by neglecting elevation and compressibility effect, and expressed as:

\[ p_1 + \frac{1}{2} \rho V_1^2 = p_2 + \frac{1}{2} \rho V_2^2 + \Delta p_{friction \ loss} \]  

Equation 2-3

Where:

- \( p_1 \) is the static pressure,
- \( \frac{1}{2} \rho V_1^2 \) is the dynamic pressure and \( \Delta p_{friction \ loss} \) is the friction pressure loss.

The RCP device uses a floating disc to alter the geometry of the flow path when the properties of the flowing fluid change. In Figure 2-41, a picture of the RCP valve is shown. The flow path through the device is marked by arrows.

Figure 2-41: The Original RCP-AICD design with flow path depicted [1]
The RCP-AICD is designed to restrict the inflow of low viscosity fluids. Such fluids when flowing through the RCP, the pressure at the top side of the disk would be lower than that of the oil (due to the high fluid velocity). The total force acting on the disk would then move the disc towards the inlet reducing the flow area. In contrast, for a more viscous fluid, the pressure on the bottom side of the disk decreases resulting in a lower force acting on the disc from the bottom and the disk moves away from the inlet allowing the fluid to flow with the maximum area designed. Figure 2-42 shows the single phase flow valve performance.

![Figure 2-42: the RCP-AICD singlephase flow performance][1]

Halvorsen et al. 2016 [10] have reported significant mechanical design modifications implemented on the original RCP valve design described by Mathiesen et al. (2011) and Halvorsen et al. (2012) [1, 61] that improved completion integration, robustness and longevity. The new AICD design now comprises only three components: (1) the valve body, (2) the nozzle and (3) the disk, {Figure 2-43}.

![Figure 2-43: The modified RCP-AICD design][10]

The original design’s larger size resulted in part of the device intruding in the production pipe main flow path; adding an unnecessary pressure drop across the completion and,
more importantly, interfering with workover/intervention tools. Downsizing the RCP prevented such problems and enabled the deployment of intelligent completions within the sandface completion. It improved supply chain management as screens originally manufactured with passive ICDs no longer require reworking when installing AICDs. Halvorsen M., et al., 2016 have indicated that “the current TR7 RCP valve is less than half the diameter and height of the original RCP installed in the first wells at Troll, a success that was achieved by a combination of simplifying the fluid path through the RCP and modifying the fabrication of the device. The modified RCP-design AICD is small enough to be installed within standard passive ICD housings” [10] {Figure 2-44}.

![Design evolution of the RCP from the original AR2(I), with revised fluid path TR7 (m), and with a revised construction TR7-2 (r) [10]](image)

**Figure 2-44: Design evolution of the RCP from the original AR2(I), with revised fluid path TR7 (m), and with a revised construction TR7-2 (r) [10]**

### 2.5.1.1 **Observation on RCP-AICD performance**

The critical flow is achieved at a lower pressure ratio between the pressure upstream and downstream of the valve compared with the rule-of-thumb of 0.5 ratio [37] (see e.g. Figure 2-42). This effect is not captured in the modelling practice today (unless using a tabled performance where this observation can be included –detail on using tables for modelling valves’ performance is provided in chapter 3).

### 2.5.1.2 **RCP-AICD deployment**

Each RCP-AICD joint {Figure 2-45} typically have up to four threaded ports. Within each port an AICD, a passive ICD, a chemical treatment valve or a blank plug can be allocated [10]. The fluid enter from the reservoir into the annulus between the production pipe and the sandface. From the annulus, the fluid passes through the sand screen and flow along the annulus between the filter and the base pipe into the RCP-AICD housing. The fluids then flow through the AICD joining the production stream that is flowing to the surface as depicted by the arrows in Figure 2-45.
The recent deployment of the RCP-AICD in Troll field, shows that it is possible (in principle) to change the nozzle size of the AICD at the rig. This development provides a high degree of flexibility to address the reservoir uncertainty. However, the optimisation of such adjustments to the completion design require more understanding of the valves function and interaction with the reservoir in the oil mode and gas or water mode (chapter 5 studied the impact of such AICD design alteration on oil production for different case studies).

2.5.1.3 RCP-AICD field applications

Halvorsen, M., et al., 2012 described the RCP-AICD early application in the Troll Field [1]. More than 75 wells in the field have been completed with RCP AICDs since the technology is approved for full field implementation [10]. More than 50 laterals and 700 single wells had been equipped with RCP-AICD completion globally [62]. Semikin, D., et al., 2015 [33] monitored the downhole performance for RCP-AICD to control gas production by adding chemical sensors to the RCP-AICD completion. Their analysis confirmed the autonomous RCP reaction to gas breakthrough at multiple zones in the well.

2.5.1.4 RCP-AICD conventional modelling technique

Mathiesen et. al., (2011) and Halvorsen et. al., (2012) provided the following expression to model the performance of RCP-AICDs [1, 61].

\[
\delta p = \left[\frac{\rho_{mix}}{\rho_{cal}}\right] \cdot \left[\frac{\mu_{cal}}{\mu_{mix}}\right]^y \cdot a_{AICD} \cdot q^x
\]

Equation 2-4

Where \(a_{AICD}\) is a constant called “strength” of the AFCD, \(q\) is the volume flow rate exponent, \(y\) is the viscosity function exponent and \(\rho_{cal}\) and \(\mu_{cal}\) are the calibration fluid’s density and viscosity respectively. \(\rho_{mix}\) and \(\mu_{mix}\) are the volumetric averages of the fluid density and viscosity respectively defined as follows:

\[
\rho_{mix} = (a_{oil})^a \cdot \rho_{oil} + (a_{water})^b \cdot \rho_{water} + (a_{gas})^c \cdot \rho_{gas}
\]

\[
\mu_{mix} = (a_{oil})^a \cdot \mu_{oil} + (a_{water})^b \cdot \mu_{water} + (a_{gas})^c \cdot \mu_{gas}
\]
Where, \( \alpha \) is the in-situ volumetric fraction and \((a,b,c,d,e,f,g)\) are the mixture components specified manually (usually assumed to equal 1).

Voll et. al., 2015 [63] “have described a workflow for generating field specific regression coefficients using linear and non-linear methods” Halvorsen et. al., 2016 [10].

To our knowledge there is no physical explanation published for the parameters \( x, y, a_{\text{AICD}} \), how they relate to the actual valve’s design and what combinations of these parameters actually physically possible for the AFCD completion design studies. These questions are answered in chapter 3 with more systematic approaches provided for obtaining the relevant (generalised – not field specific) parameters.

2.5.2 The FD-AICD technology

2.5.2.1 Historical background and design specifications

Fluidic Diode (FD) Autonomous Inflow Control Device, also known as (Equiflow), utilizes the difference in inertia between oil and water to change the flow path of the two phase. The Device works based on the vortex principle by which the less viscous water takes a longer path to reach the nozzle, experiencing a higher pressure drop than for the more viscous oil that travels directly to the nozzle.

Unlike the other AICDs, the fluidic diode AICD works without moving parts. Eliminating moving parts and narrow flow paths has the advantage of reducing the risk of plugging and erosive damage of the tool. Changes in fluid viscosity, density and rate change the fluid flow path. The AICD can be made sensitive to the fluid properties by tuning the flow path geometry. The density and flow rate affect the inertial forces, while the viscosity and flow rate influence the viscous forces. The flow takes the straight pathway when the inertial forces are dominant. By contrast, the flow will tend to spread through all the pathways splitting between the divergent pathway and the straight pathway when the viscous forces are dominant (Figure 2-46 “A” and “B”) [59].

The choice of the passage way is determined by: (1) the geometry of the AICD and (2) the properties of the fluid and (3) the flow rate of the fluid. Viscous oil takes the short direct path to the exit (Figure 2-46 “A”), resulting in a high flow rate. Water and gas spin before exiting, creating a high restriction and significantly reducing the rate (Figure 2-46 “B”). The phase fraction is unaffected, for multiphase flow, with the rate being controlled by the percentage of unwanted fluid. Fripp, M., et. al., 2013 described the physics behind FD-AICD’s performance [59].
Different ranges of the FD-AICD are currently available commercially [44, 45, 64-66]:

1) Range 1: for light oil (0.3 - 1.5 cP).
2) Range 2: for light to medium oil (1.5 - 10 cP).
3) Range 3: for light, medium and heavy oil (3 - 200 cP).
4) Range 4: for heavy and extra-heavy oil (150+ cP).

Figure 2-46: CFD simulation results on a simplified AICD showing the fluid flow pathways dependence on the fluid properties (mainly viscosity). (A) Streamline for oil flow and (b) stream lines for water flow and (c) actual valve design [59]

Figure 2-47 to Figure 2-50 show performance curves for the FD-AICD ranges for (in-situ) oil viscosities between 0.2 cP and 1000 cP, gas (0.02 cP) and water. The higher flow resistance for water is clearly shown in their diagrams.

Figure 2-47: FD-ACD range 3B. Little difference observed in the performance above 99 cP viscosity [65]  

Figure 2-48: FD-ACD range 4B. Little difference observed in the performance for viscous fluids [65]
2.5.2.2 FD-AICD deployment

Up to four FD-AICD inserts can be mounted on a 12 m long tool’s joint (Figure 2-51), though some cases, e.g. see [45], required up to eight insets to provide the necessary initial flow requirement (see section 2.4.2.3).

Figure 2-52 shows the flow path across the completion (see section 2.3.2).
2.5.2.3 **FD-AICD field applications**

Least, B., 2013, Gualdrón, M.B.G., et al., 2015 and Porturas, F., 2016 [8, 18, 45], described case studies where the FD-AICD improved the well performance by both increasing the early oil production and decreasing the water production from several fields in Latin America. Similarly, Negrescu, and Leitao Junior 2013 [21], described the use of FD-AICD to control the expected early water breakthrough in the heavy oil environment of the Peregrino field. FD-AICD proved successful in Peregrino field and the technology is set for full field implementation based on the success criteria specified prior to the initial field trial [67].

2.5.2.4 **FD-AICD conventional modelling technique**

The same approach as described above for RCP-AICD (section 2.5.1.4) is being used today for modelling FD-AICD performance. Static modelling tools such as Netool is used for completion design.

Another method proposed is based on the following formula (Halliburton):

\[
\delta p = K \cdot \frac{8 \rho_{mix}}{3.14 n^2 D_h^4} \cdot q^2
\]

Equation 2-5

where: \( K = f (Re) \) found by fitting the experimental data and \( Re = \frac{4 \rho_{mix} q}{3.14 D_h \mu_{mix}} \)

Concerns with this approach are:

1) The accuracy of the polynomial curve fitting of the experimental data and also how general the obtained solution can be (e.g. for different field specifications).
2) The fixed flow rate exponent limits the flexibility of the possible solutions (data fitting).
3) The Reynolds number (Re) has to be calculated at each time step and hence a new (k) value should be obtained and integrated with the solution convergence process, see appendix (3) [68]. Note: only one equation is available on the simulation software.

These concerns are addressed and solutions proposed in chapter 3.
2.5.3 The AICV technology

2.5.3.1 Historical background and design specifications

The AICV consists of a passive (main) flow module and an active (by-pass/pilot) flow module with a diaphragm whose movement depends on the pressure drop created by flow of the produced fluids through a laminar and a turbulent flow element (Figure 2-55). The AICV’s performance thus depends on the difference of the produced fluids flow behaviour in these elements [60, 69]. Flow of the reservoir fluids through the elements creates a differential pressure drop that results in a moving piston closing the main fluid flow path. AICVs can be designed to autonomously stop unwanted fluids (water or gas) production (with only by-pass flow of 1% of the main flow) or restrict unwanted fluid production (by-pass flows up to 20% of the main flow area). By contrast, AICDs always restrict the flow of unwanted fluids, depending on the valve’s geometry, fluid properties and flow conditions, after breakthrough.

Figure 2-55 is a cross-section of the AICV currently being commercialised. It has two flow paths:

1) Passive part: The main flow area connecting the annulus with the production tubing.

2) Active part: A bypass flow consisting of a moveable element (piston) together with laminar and turbulent flow elements (pilot flow).

The laminar flow element is a pipe element, and the pressure drop may be expressed as:

\[ \Delta p = \frac{32 \mu v L}{D^2} \]  
Equation 2-6

Where \( \mu \) is the fluid viscosity, \( v \) is the fluid velocity, \( L \) and \( D \) is the length and diameter of the pipe respectively. The fluid will undergo a pressure drop that is proportional to the fluid viscosity, the fluid velocity and geometrical dimensions in the laminar flow element.

The turbulent flow element is an orifice where the pressure drop can be expressed as:

\[ \Delta p = C \frac{1}{2} \rho v^2 \]  
Equation 2-7

where \( C \) is a geometrical constant. The turbulent flow element’s pressure drop is independent of viscosity, but proportional to the density, the fluid velocity squared and a geometrical constant. Different flow elements will have different flow characteristic for the gas water and oil due to different fluid properties.
Figure 2-53 and Figure 2-54, show the valve in the open and closed positions. The arrows depicted describe the flow paths where the thin blue lines show the pilot flow path and the thick blue arrow show the main flow from the annulus through the valve and into the base pipe (the horizontal arrows).

The force balance above and below the piston controls its position. This is best illustrated by Kais, R., et al., 2016 with the aid of Figure 2-55 as: “the force $F_1$ on the upper part of the piston ($p_1 \cdot A_1$) is acting downwards and the force $F_2$ below the piston ($p_2 \cdot A_2$) is acting upwards. $F_{\text{fric}}$ is a friction force, which works against the direction of movement. $F_3$ is acting downwards on the outer part of the piston. The pressure drop for the main flow is located at the smallest passage between the piston and the seat, as shown in Figure 2-55. When the net force ($F_1 - F_2 + F_3 \pm F_{\text{fric}}$) is positive, the valve is in the open position and if the net force is negative, the valve closes. The inlet pressure, $p_1$, is always higher than $p_2$, and $A_2$ has to be larger than $A_1$. The ratio between $A_1$ and $A_2$ is a design parameter and the optimum ratio is dependent on the properties of the oil and the gas/water” [34].

The physics behind AICV technology was described in [60, 69].
Figure 2-56 provides the performance curves for oil, water and gas. As can be seen, and from the discussion above, the valve has a stepwise performance with the valve opening or closing at a specific threshold which depends on the fluid’s properties.

![Performance curves for AICV for oil, water and gas](image)

**Figure 2-56: Performance curves for AICV for oil, water and gas [34]**

### 2.5.3.1.1 Observation on AICV performance

The AICV may potentially allow some level of unwanted fluid volume (e.g. water in Figure 2-56) to be produced before reaching to a complete production shut-off. This level can be an optimisation parameter to basically allow good water to flow and only restrict the bad water (similarly for lifting gas). Such a design (if proved experimentally and possible technically) can improve the scope of completion optimisation significantly as it allows consideration for the system outflow performance while controlling the unwanted fluids. Note that, before the activation threshold, the AICV works as a passive device which may invite more gas production initially. In many cases, a device which may respond to gas inflows at multiple fractions can add more value.

### 2.5.3.2 AICV deployment

The AICV can be selected based on the pressure rating. The operating company defines the initial nozzle size (as optimum ICD size) and may also define the level of restriction to be implemented by the AICV. The manufacturing company will then design the appropriate AICV for that specific application and test the product in their laboratories for the produced fluid properties.

In chapters 3 and 5, we explain why this might not be the best practice and may actually hinder the optimisation potential that can be provided by AFCDs.
2.5.3.3 AICV conventional modelling technique

The same approach as described above for RCP-AICD (section 2.5.1.4) is being used today for modelling AICVs’ performance [70]. The AICVs, have a step-wise reaction to unwanted fluid. A specific threshold of unwanted fluid fraction is required to actuate the valve’s autonomous reaction [69]. Equation 2-4 does not capture such behaviour.

Solutions provided in chapters 3 and 4.

2.6 AFCD deployment main concerns

The following concerns arise hindering the optimum utilisation and value quantification of the new AFCD technology:

a) Little published data on AFCDs’ single-phase and multi-phase flow performance available.

b) The previously ignored physics (stratified flow in the annulus and well trajectory alteration) are now essential since an AFCD’s performance is strongly fluid-sensitive.

c) Commercial reservoir simulators provide just one equation to capture the underlying physics of all AFCD types.

d) ICV-completions allow a limited number of controlled layers whereas an AFCD-completion provides an unlimited number of control points which can have an autonomous action that is present at the time of deployment. (N.B. The full advantage of the (in principle) high number of (A)FCD control points is only
achieved if a similar number of AFI’s are also installed). Hence, proper modelling and optimisation workflows are required to:

1) Achieve the maximum added value from Autonomous Flow Control (AFC) technology.
2) Soundly compare the added value against other flow control technologies
3) Evaluate the risk associated with the deployment of this (relatively) new technology.

The aim of the thesis is to improve the reliability of coupled well/reservoir simulation of advanced wells completion employing AFCDs and to evaluate their performance against passive ICDs thereafter.

2.7 Conclusion

Horizontal well technology has become a standard drilling technology in the oil and gas industry. More and more petroleum engineers have recognized that pressure drop along a horizontal well plays an important role in affecting the performance of the horizontal well.

The generic term “intelligent well” or Advanced Well Completions (AWC), is used to signify that some degree of direct monitoring and/or control equipment is installed within the well completion. Such wells capable of monitoring and managing the fluid flow into or out of the length of the wellbore in order to better control the reservoir, well, and production processes (i.e. fit-for-purpose smart well systems). The flow control can either be spontaneous/automatic or with some operator intervention.

An introduction to inflow control technology is provided. This chapter discussed the various types of inflow control technology in term of their capabilities, their objectives, and their reported field applications with special focus on AFCDs.

AWC implementation is driven largely by: (1) increasing the ultimate recovery, (2) reducing surface facilities, (3) reducing the number of wells required to develop a structure, (4) accelerating production and (5) improving the economics by, e.g., avoiding future well intervention cost. Controlling unwanted fluids is an additional requirement.

Quantifying the added value from an AWC can be a challenging task. Figure 2-4 draw together the multiple parameters involved in the process of designing, optimising and evaluating an AWC. It requires a thorough knowledge about the reservoir, and a competent modelling capabilities.
The AWCs’ design for reservoir heterogeneity problem depends on the understanding of permeability distribution, which is one of the hardest information to obtain at the time of designing the completion (i.e. before actually drilling the well). The reservoir conditions (e.g. heterogeneity, pressure support etc.) need to be fully understood for a robust AWC design. Furthermore, the new AWC technology (e.g. AFCDs) offers phase selectivity or rate control, providing ever greater scope for optimisation. Multiple types of AFCDs are available commercially today.

The development in AWC capabilities and the new physics involved in their designs needs to be fully captured in the modelling and optimisation process to allow exploiting their perceived positive impact. AFCDs present new modelling challenges that require extension of today’s wellbore/reservoir models and workflows. The functions of the various wellbore completion components and their impact on the total well performance efficiency, and hence the success of the chosen FCD, needs to be fully understood and captured in the model used for the design optimisation process.

AFCD modelling is discussed next in chapter 3.
Chapter 3 Autonomous Flow Control Completions’ Performance and Modelling

3.1 Introduction

Advanced well Completion (AWC) is a technology that requires fast solutions to save time on the rig upon completion installation. The original AWC design that was prepared with considerable uncertainty may not be suitable/optimal for the actual conditions after the well is drilled (see e.g. Table 1-1 for challenges associated with extended reach wells). In some cases it is useful to use either an Inflow Performance Relationship (IPR) or a simplified reservoir model to determine inflow or outflow rates and adjust/optimise the AWC design accordingly. Such simple analytical models and techniques, as discussed in chapter 2, play a role in [14]:

(i) Saving time on the rig during AWC optimisation/redesign.
(ii) Quick feasibility studies, e.g. screening ICD installation candidates.
(iii) Verification of numerical/simulation results.
(iv) Communicating best practices without referring to specific products.

Numerical simulation allows a superior (important) physics embodiment than analytical models, hence enhanced prediction, optimization and quantification of the AWC Added Value can be perceived.

Multiphase flow in a wellbore can be important to model an AWC’s performance. Estimation of the fluid transfer between a reservoir and a wellbore is necessary before a wellbore model can be applied to calculate pressure drop, liquid holdup and flow pattern along the wellbore. On the other hand, the pressure drop and liquid fraction within the wellbore affect the sandface pressure distribution along the completion and thus the mass transfer between the reservoir and wellbore [15, 71]. Therefore, “unless wellbore pressure drop is very small and can be neglected, reservoir inflow/outflow and wellbore flow must be solved simultaneously” (Ouyang, L.-B., 1998) [72]. Furthermore, the reservoir inflow/outflow cannot always be predicted analytically. The analytical model accuracy in this case is affected by various parameters such as: (a) reservoir heterogeneity, (b) irregular boundary, (c) layers communication (e.g. Figure 2-17) etc. Reservoir simulator needs to be used in such situations to estimate the mass transfer between the reservoir and the wellbore, i.e., the inflow or outflow distribution along the wellbore at various production time [71]. This is of particular importance in evaluating and understanding new concepts and ideas for improved oil recovery (IOR) [70].
Autonomous Inflow Control Device (AICD) reacts to unwanted fluid phases (gas and water) restricting their flow in-situ, which potentially improves recovery (the detailed AICD performance and types are discussed in chapter 2). There is only a handful of publications describing their application, less so regarding their appropriate modelling and sizing. No wonder – the AFCDs for the first time discriminate fluid phases in the wellbore and as such require new solutions to the methodologies of wellbore flow modelling, well completion design, and the in-well flow control value evaluation.

AFCD-completions are frequently designed using steady-state well production simulators, though input from a dynamic, reservoir simulator is preferred - as mentioned above - since this allows the modification in a single well’s completion performance to be projected and understood in the context of the total field recovery and reservoir uncertainty.

The currently used AFCD performance modelling approach, as introduced ad-hoc in the simulators, is physically controversial as well as recognised as needing update.

Figure 3-1: Research challenges for an improved AFCD modelling accuracy

To improve the accuracy of AFCDs modelling, solutions and enhancements are required for three basic categories {Figure 3-1}:

1) **The proper incorporation of the stand-alone valve performance in the simulator:**

Limited data has been published to date about the AFCDs’ single phase performance. These data must be honoured accurately during simulation with considerations for changing fluid properties during simulation (with time) due to changing well/reservoir flow conditions (mainly pressure). Furthermore, the standalone AFCD (single valve) performance data is not available (aside from a recent publication that shares a very limited data for one type [10]). The functions
of the various wellbore completion components and their impact on the given well performance need to be fully understood to achieve the full potential of AWCs. This chapter will provide solutions for this problem.

2) The annulus flow:
In field applications, annular flow isolation is an important part of the AWC as detailed in chapter 2. Due to several considerations (mostly technical but also commercial), a limited number of packers is normally installed in an AWC. Therefore, several AFCDs are placed together in one wellbore section between two packers sharing the same annulus. The multiphase flow, physics, consideration to AFCDs and modelling solutions are discussed in detail in chapter 4.

3) Optimum design, uncertainty and risk:
The impact of the AFCD and wellbore modelling uncertainty on the AFCD completion optimisation solutions. It is routine to size and evaluate an AFCD completion using commercial simulation, but is seldom appreciated how robust the result is within the context of the completion performance modelling uncertainty. Several elements of such optimisation and uncertainty analysis are described in chapter 5 of this thesis.

Two main points are addressed in this chapter to allow for better evaluation of the perceived added value from these intelligent completions:

(d) The currently “widely applied” AFCD performance modelling approach does not suite all types of AFCDs and is recognised to be physically and practically controversial.

(e) The published data on the valves performance, especially multi-phase flow, is limited; especially for the stand-alone (single) AFCD multi-phase flow (MPF) performance. Hence, sensitivity analysis is required to evaluate the devices’ impact.

In this chapter we first present the way of setting and using the currently available AFCD modelling approach when limited, single-phase AFCD lab test data are available (still a very common situation). Then we introduce a dimensionally consistent way of presenting the AFCD performance. One of the parameters in the conventional AICD formula is assumed redundant. Using this approach, a novel, universal formula is derived describing AFCD performance for different fluids in accordance with the published laboratory data. The new formula incorporates a new AFCD MPF expression which facilitates matching
the AFCD flow loop tests and capturing their MPF performance in reservoir simulation more conveniently, while honouring the single-phase flow performance. One set of parameters can be derived for each AICD type to represent the performance for different fluids in accordance with the published laboratory data.

3.2 Background to AFCD Modelling

3.2.1 Modelling of Fluid Flow in the Wellbore, Completion and Tubing

The coupled well reservoir simulator consists of the following solutions (pictured in Figure 3-2):

1) The reservoir flow.
2) The flow from the reservoir to the annulus.
3) The flow along the annulus.
4) The flow through the (A)FCD.
5) The flow along the tubing to the surface.

![Figure 3-2: Advanced Well Completion Modelling in Reservoir Simulators [6]](image)

Most of the commercially-available reservoir simulators divide the wellbore into a number of segments that represent sections of the tubing, annulus and the flow control devices. The connection between the segments is designed such that the flow from one or more segments always converges in a single downstream segment. An example is provided in Figure 3-3.

The multi-segment well model introduced by Holmes, J.A., et al., 1998 [73], has provided a tool to model the pressure drop along the wellbore in a coupled well-reservoir simulator. For simplicity, gas, oil and water were treated as a homogeneous mixture. It has been made easy to compare different solutions for known oil-field production challenges; such as heavy/viscous oil production, the presence of near-by fluid contacts, reservoir heterogeneity, etc. in a coupled well/reservoir model {see also Table 1-1}. These all are often associated with early breakthrough of unwanted fluids and the consequent reduction in the field’s recovery. Hence, suggestions to the improvements in a single well’s production in the context of the total field recovery and reservoir uncertainty was made possible. It is important to highlight that the simplifications made on the MSW model
(e.g. fluid flow is treated as a homogeneous mixture) were good enough for a passive
AWC, whereas the modelling accuracy and added value quantification of AFCDs, unlike
the passive FCDs, requires further research due to their (designed) multiphase flow
sensitivity.

A multi-segment well is “a collection of segments arranged in a gathering tree topology
[74]. Each segment consist of a node and a flow path determining the connection
between each segment and the other segments in the structure. For each segment the
following parameters are defined” {Figure 3-3} [74]:

\begin{enumerate}
  \item The physical position of each node.
  \item The connectivity between segments by their numbers.
  \item The Geometry: Length, diameter, roughness, volume and area of each flow path.
  \item The flow performance calculation method (pressure and rate).
\end{enumerate}

![Figure 3-3: Example of multi-lateral well segmentation as applied in ECLIPSE](image)

Each segment may have several inlets from other segments or several reservoir
connections (cells) {Figure 3-4}. However, a cell can only be connected (flow) to one
segment. A segment can be any integral component of an AWC (e.g. annulus, pipe,
restriction etc.).

With such (discretised) structure, the material balance requires that:

1. The flow out of a segment ($Q_{pn}$) is defined as the summation of flow from all the
cells connected to this segment ($q_{pi}$), plus the inflow from all the connected
segments ($Q_{pi}$) minus the accumulation:

$$Q_{pn} = \sum Q_{pi} + \sum q_{pi} - \frac{\Delta m_{pn}}{\Delta t}$$  \hspace{1cm} \text{Equation 3-1}
2. The segment pressure drop is calculated based on the main three components (friction, hydrostatic and acceleration) as:

\[ \Delta p_{total} = \Delta p_{fric} + \Delta p_{hyd} + \Delta p_{acc} \]  

Equation 3-2

3. The segment pressure \( p_n \) is calculated as the pressure of the downstream segment \( p_{n-1} \) in addition to the pressure losses in between them:

\[ p_n = p_{n-1} + \Delta p_{fric} + \Delta p_{hyd} + \Delta p_{acc} \]  

Equation 3-3

![Figure 3-4: Illustration of segment flow (Courtesy of Schlumberger), where “p” denotes phase, (1, 2, and 3) represents flow from other segments and (a, b, c) represents flow from reservoir blocks.](image)

Different methods are available in simulators to determine the pressure drop at each segment (completion component):

I. Homogeneous flow model.

II. Drift flux flow model.

III. Built in flow performance equations for some of the completion components (e.g. valves).

IV. Pre-calculated pressure drop table (available in ECLIPSE).

The idea of discretising the well to various segments and then connecting them and calculating flow performance (pressure and rate) allows adding the following into the reservoir/well coupled solution:

a) Pressure drop due to friction (and acceleration) along the wellbore for each component along the wellbore.

b) More accurate calculation of hydrostatic pressure gradient along the wellbore compared with the case were the well was considered to be a single entity.
c) Improved modelling of cross flowing wells (fluids injected into the formation represent the local wellbore contents at each point along the wellbore).

(a), (b) and (c) are particularly important when there is:

- Cross flow between laterals.
- Phase slippage within the wellbore e.g. using the Drift Flux model (slip refers to the ability of one phase to flow at a greater velocity than another phase).
- Various downhole devices.
- Varying well trajectory.

3.2.1.1 The Pressure Drop Calculation across Pipes as Applied in Reservoir Simulators

Multiphase flow effects in the wellbore flow conduits (e.g. pipes, annuli and valves) can have a strong impact on the wells' inflow/outflow performance. In the case of horizontal or multilateral wells, for example, the resulting pressure losses calculated based on the multiphase flow assumption for each completion component in the well can lead to a loss of production at the toe, overproduction at the heel, liquid loading, crossflow etc. In order to model and thereby optimize the performance of wells coupled to reservoirs, accurate multiphase flow models must be incorporated into reservoir simulators.

Within the context of petroleum engineering, the three types of pipe flow models most commonly used are [75]:

1) Empirical correlations:

Curve fitting of experimental data is used to generate empirical correlations that are generally limited to the range of variables explored in the experiments. Such correlations can be flow pattern specific or flow pattern independent.

2) Mechanistic models:

Mechanistic models are considered “the most accurate as they introduce models based on the detailed physics of each of the different flow patterns. From a reservoir simulation perspective, however, mechanistic models can cause difficulties because they may display discontinuities in pressure drop and holdup at some flow pattern transitions. Such discontinuities can give rise to convergence problems within the simulator. One approach to avoid these convergence issues is to introduce smoothing at transitions” (Shi, H., et al., 2003) [75].

3) An alternative approach is to apply a homogeneous pipe flow model [75].
3.2.1.1 The Homogeneous Flow Model

Homogeneous flow models are relatively simple, continuous and differentiable. The homogeneous model as applied in most reservoir simulation software assumes there is no slip between the phases. The hydrostatic pressure drop, $\Delta p_{\text{hyd}}$, is calculated from flow weighted average of phase densities and the frictional pressure drop, $\Delta p_{\text{fric}}$, is calculated using Fanning friction factor [76]:

$$\Delta p_{\text{fric}} = 2f \frac{L}{D} \rho v^2$$  \hspace{1cm} \text{Equation 3-4}

The Acceleration pressure drop, $\Delta p_{\text{acc}}$, is calculated from the difference between velocity heads into and those out of each segment:

$$\Delta p_{\text{acc}} = H_{v,\text{out}} - \sum_{\text{inlet}} H_{v,\text{in}}$$  \hspace{1cm} \text{Equation 3-5}

The velocity head is given by:

$$H_v = \frac{0.5w^2 c_f}{A^2 \rho}$$  \hspace{1cm} \text{Equation 3-6}

Where: $A$ is the cross-section area of the segment, $f$ is the Fanning friction factor, $L$ is the length of the segment, $w$ is the mass flow rate of the fluid mixture through the segment, $D$ is the segment’s diameter, $\rho$ is the in-situ density of the fluid mixture, and $C_f$ is a units conversion constant.

Such simple homogeneous models, which neglect slip between the fluid phases (i.e., the fluid phases all move at the same velocity), fails to capture the complex relationship between the in situ volume fraction and the input volume fraction. Furthermore, it fails to capture essential physics that is expected to considerably impact the performance of phase selective AWCs. Hence a more accurate (yet with maintained simplicity) model is required.

3.2.1.1.2 The drift flux slip model:

The drift flux model is a simple correlation that is continuous across the range of flowing conditions. The basic drift-flux model was “first introduced by Zuber and Findlay [Zuber et al 1965]. It has since been refined by many researchers (e.g. Ishii et al 1977, Nassos and Bankoff 1967, Wallis 1969, Hasan and Kabir 1999, Ansari et al. 1994) and has been widely used for modelling both liquid-gas and oil-water pipe flow” (Shi, H., et al., 2003) [75]. It includes the effects of slip and as such it enables the phases to flow with different
velocities. Considering gas/liquid flow, in all but downward flow, the gas phase will flow with a greater velocity than the liquid phase. Slip, thus, increases the liquid holdup fraction for a given flowing gas-liquid ratio, thereby increasing the hydrostatic head component.

The drift-flux model for two-phase flow describes the slip between gas and liquid as a combination of two mechanisms [75]:

1) The non-uniform profiles of velocity and phase distribution over the pipe cross-section (see Figure 3-5). The gas concentration in vertical gas-liquid flow tends to be highest in the centre of the pipe, where the local mixture velocity is also fastest. Thus, when integrated across the area of the pipe, the average velocity of the gas tends to be greater than that of the liquid.

2) The other mechanism results from the tendency of gas to rise vertically through the liquid due to buoyancy.

Two basic parameters are applied to capture these phenomena: (a) the profile parameter ($C_0$), the concentration profiles or (distribution coefficient) which describes the effect of the velocity and (b) the drift velocity ($V_d$) describing the buoyancy effect. Using these parameters (which in turn depend on the system variables), in situ phase volume fractions (holdup) can be calculated from the phase flow rates [73].

A formulation that combines the two mechanisms is [75]:

$$ V_g = C_0 V_m + V_d $$

Equation 3-7

Where $V_g$ is the flow velocity of the gas phase, averaged across the pipe area and $V_m$ is the volumetric flux (or average velocity) of the mixture.

Figure 3-5: Profile and local slip mechanisms in the drift-flux model [75]
For three-phase mixtures, the above formulation is used to model the total slip between the gas phase and the combined liquid phase. Followed by calculation of the slip between the oil and water. The mixture liquid phase properties (density, viscosity) are calculated as an average (volume fraction weighted) of the oil and water properties. This treatment neglects any tendency of the oil-water mixture to form emulsions, but it is a common method of applying two-phase flow correlations to (oil-water-gas) mixtures in a well [75].

The local vertical slip velocity will produce counter-current flow (phases flowing in opposite directions) when the mixture velocity is small enough (~ in the order of 1 cm/s) [73]. Full description of the drift-flux calculation, for vertical and inclined wells, can be found in [73-75]. The assumption of representing the mixture properties as a simple homogeneous mixture is discussed in chapter 4.

3.2.1.1.3 Interpolating the pressure drop from pre-calculated VFP tables

Multi-dimensional tables can be constructed to (a) describe the pressure drop along a certain length of tubing at the appropriate angle of inclination or (b) incorporate a formula that describes the performance of a valve when not included in the software. The pressure drop along a segment is interpolated from the respective multidimensional table and can be scaled according to the length of the segment. This method has been used extensively in this study to model the performance of AFCDs with the new methods presented as explained below.

3.2.2 Incorporating (A)FCD Performance in Reservoir Simulator

From the discussion above, the (A)FCDs’ performance can be incorporated in a commercial reservoir simulator’s wellbore model as:

(A) A formula relating the pressure drop across the AFCD to the phase flow rates and the fluid properties. Such equation should be accurate, but simple enough to allow the simulator to converge without adding significant computation complexity.

There are several built-in models in various simulators that represent sub-critical flow through different valve types. Various mathematical equations describing the performance of different FCDs are detailed in chapter 2. The simulators normally incorporate the following methods (e.g. ECLIPSE [74]):

- A built-in model that corresponds to a ‘labyrinth’ flow control device.
- Another built-in model calculates the pressure drop across an inflow control device that is placed around a section of the tubing and diverts the inflowing fluid from the adjacent part of the formation through a sand screen and then
into a spiral constriction before it enters the tubing.

- A built-in model that corresponds to an ‘autonomous’ inflow control device. This particular model is addressed in detail in this chapter.
- A built-in ‘flow limiting valve’ model, which is a hypothetical device that reacts dynamically to limit the flow rate of oil, water or gas (at surface conditions) through a segment to a specified maximum value, by sharply increasing the frictional pressure drop across the segment if the limit is exceeded.

(B) A **tabulated input** in the form of a multidimensional table(s) describing the performance of all FCDs or each FCD having its performance described by its own table (Figure 3-6):

![Diagram of tabulated input for (A)FCD performance](image)

**Figure 3-6: Illustration of AFCDs’ performance provided as a tabulated input for simulator**

This approach is available in some of the software and is particularly useful where a specific formula to describe the AFCD performance is either not available in the simulator or inappropriate.

**Important considerations** when applying this method for (A)FCD performance modelling in reservoir simulators include:

- **The linear interpolation error:**
  The pressure drop is interpolated linearly from the given dimensions (rate, WC, GVF, pressure downstream, and pressure upstream).
A practical solution to effectively reduce the severity of the error is to increase the number of entries where the mismatch is more severe and keep a small number of entries where this is not a problem. The resulting interpolation error can then decrease significantly. Frequent flow rates and watercuts for a given case may need to have finer domain resolution to decrease the overall error. This might require simulation work to be performed prior to table generation such that the most frequent values can be given the appropriate weight in the table generated.

- **Pressure scaling:**
Segments along a well may change their length and might also have different number of valves per joint. The pressure drop should be scaled appropriately (according to the segment’s length or change in TVD) before applying it to each segment. Consider a table applied to segments with different inclinations, scaling should be [74]:

- Based on length – (1) if frictional pressure loss is dominant when modelling a pipe flow and (2) for modelling the correct number of valves.
- Based on change in TVD – if hydrostatic pressure loss is dominant when modelling pipe flow.

For AFCDS the pressure drop is scaled and not the rate (as per the common practice when applying the built in flow performance models discussed in section (A) above).

Considering the pressure drop formula:

\[ dp_{seg} = VFP_{val}(q_{seg})^{aica} \]  

Equation 3-8

And describing the number of valves as \( \frac{\ell_{seg}}{\ell_{aica}} \) where \( \ell_{aica} \) is the length of the valve’s joint and \( \ell_{seg} \) is the length of the wellbore segment in the model at each location along the wellbore, then:

\[ q_{seg} = \frac{\ell_{seg}}{\ell_{aica}} q_{val} \]  

Equation 3-9

Then to scale the interpolated segment (single valve) pressure drop (correctly) to the multiple valves that the segment actually represents:

\[ dp_{val} = A \times dp_{seg} \]  

Equation 3-10

Where:
\[ A = \left( \frac{q_{val}}{q_{seg}} \right)^{x_{aid}} = \left( \frac{\rho_{aid}}{\rho_{seg}} \right)^{x_{aid}} \]  

Equation 3-11

- **Handling reverse flow:**
  - Negative flow (away from well head) may occur in cross flowing wells.
  - Flow rate may be less than the smallest value entered in pressure drop tables.
  - Three options are available for handling reverse flow as explained in Figure 3-7.
    1) Fix lookup value at first flow point – if hydrostatic pressure drop dominates.
    2) Reverse flow, reverse pressure drop – if frictional pressure drop dominates.
    3) Extrapolate pressure drop with flow – not recommended.

![Figure 3-7: Handling reverse flow using VFP tables in wellbore flow modelling (Courtesy of Schlumberger)](image)

- **Multiple tables might be required** within one simulation or to perform different simulation scenarios:

For example, if any of the dimensions of the table (the flow rate range, the fluid properties, etc.) is to be changed when running a further simulation cases (e.g. sensitivity to flow rate is to be conducted), then a new table should be generated that employs a new range for the varying parameter. This is important to reduce the linear interpolation error associated with the dimensions of the table as discussed above.

- **Increased simulation time** (reduced convergence efficiency – also depends on the table size and model’s complexity).
3.3 Single Phase Flow Performance and Modelling of AICDs

3.3.1 The Conventional AFCD formula

Equation 2-4 [1, 61] (repeated below for illustration), was the first and only one introduced into the reservoir simulators and is still widely used today for different AFCD types [10, 70, 77], even though the contemporary AFCD types were developed after the formula had been introduced:

$$\delta p = \frac{\rho_{mix}^2}{\rho_{cal}} \cdot \left(\frac{\mu_{cal}}{\mu_{mix}}\right)^y \cdot a_{AICD} \cdot q^x \quad \text{Equation 3-12}$$

Where $a_{AICD}$ is a constant called “strength” of the AFCD, $x$ is the volume flow rate exponent, $y$ is the viscosity function exponent and $\rho_{cal}$ and $\mu_{cal}$ are the calibration fluid’s density and viscosity respectively. $\rho_{mix}$ and $\mu_{mix}$ are the volumetric averages of the fluid density and viscosity respectively defined as follows:

$$\rho_{mix} = (a_{oil})^a \cdot \rho_{oil} + (a_{water})^b \cdot \rho_{water} + (a_{gas})^c \cdot \rho_{gas} \quad \text{(1a)}$$

$$\mu_{mix} = (a_{oil})^e \cdot \mu_{oil} + (a_{water})^f \cdot \mu_{water} + (a_{gas})^g \cdot \mu_{gas} \quad \text{(1b)}$$

Where, $\alpha$ is the in-situ volumetric fraction and $(a,b,c,d,e,f,g)$ are the mixture components specified manually (usually assumed to equal 1).

Equation 3-12 has been incorporated in several commercial well and reservoir simulators. Seemingly, it has been developed ad-hoc by extending the classical ICD formulae to capture the single-phase AFCD performance curves by varying three parameters: $x$, $y$, and $a_{AICD}$.

To our knowledge, no guidance or proof is available as to whether it captures the multi-phase performance of AFCDs accurately, or the trio of parameters $x$, $y$, $a_{AICD}$ can be translated to the situation of different fluid properties, or what combinations of $x$, $y$, $a_{AICD}$ are actually physically possible for the AFCD completion design studies.

To overcome this problem an empirical method to parametrise Equation 3-12 was introduced and published as a function of two parameters: the restriction sizes of an equivalent nozzle that represents the device’s performance when it is exposed to either oil or water/gas [70]. The assumption of $x=2$ was made to honour the approach of presenting the AFCD as an imaginary nozzle of a varying size. The introduction of this method helped the engineers to “soundly” design and test several AFCDs that match the
reservoir fluid’s properties. This has allowed the concept of autonomous flow control to be tested in various reservoir conditions and compared against the available (proved successful) flow control devices [7-9].

The following sections provide a detailed explanation of this equation, its application in designing the optimum well AFCD-completion configuration using the proposed workflows. They provide answers to the following questions:

1) What are the optimum AFCD performance parameters for specific combinations of field and fluid properties? The value calculated from Equation 3-12 depends significantly on the properties of the reservoir fluids.

2) What is the preferred range of parameters in Equation 3-12 to improve production in a particular application?

3) What is a suitable way to incorporate Equation 3-12 in a workflow for optimizing the number and location of AFCDs in a well completion?

3.3.2 Parametrizing the Conventional AFCD Formula

Bernoulli’s equation results in a value of 2 of the flow rate exponent for flow through a nozzle or an orifice. Our AFCD workflow describes the flow restriction imposed by an AFCD as nozzles of varying strengths, or flow areas, which are dependent on the properties of the flowing fluid and the local conditions at each simulation time-step.

The general formula which describes the base strength (K) for (A)FCDs is:

$$\Delta p = [K]\rho Q^2$$  \hspace{1cm} \text{Equation 3-13}

Where,

$$K = \left\{ \begin{array}{ll}
\frac{C_u}{2C_v^2A_c^2} & \text{Nozzle} \\
\frac{\rho}{\rho_{cal}} \cdot \left( \frac{\mu_{cal}}{\mu} \right)^\gamma \cdot a_{AICD(V)} & \text{orifice} \\
\end{array} \right. \text{type ICD} \hspace{1cm} \text{Equation 3-14}

\text{AFCD}

Where $C_u$ is a unit conversion constant, $A_c$ is the cross-sectional area of the valve constriction and $C_v$ is the flow coefficient of the valve (assumed to equal 1 due to the expected high values of Reynolds number across the nozzles).

The limited, available multi-phase flow performance data of an AICD forces us to make the following two assumptions when modelling a multi-phase AICD completion in a well/reservoir simulator:
1. Equation 3-12 describes the performance of an AICD.

2. The AICD completion performance is independent of the fluid flow regimes upstream of the AICDs. The impact of this assumption is addressed in chapter 4.

These assumptions allow the calculation of valve’s flow area for a specific AFCD’s performance and produced fluid properties from the combination of Equation 3-13 and Equation 3-14. The parameters used in Equation 3-12 can then be identified with the aid of the AFCD expression for K (Equation 3-14). This allows AFCD flow performance to be modelled in many commercial reservoir simulators. The resulting workflow, described in (Figure 3-8), to find the parameters in Equation (Equation 3-12) for two-phase flow (oil/water or oil/gas) only requires available AFCD performance (pressure drop vs. flow rate) data from single-phase flow experiments.

Reversing the workflow allows the AFCD performance curves to be designed for any field with specific fluid properties by considering a combination of ICD strengths (area open for oil flow) together with the percentage area shut-off for water and/or gas flow.

Table 3-1 is based on the standard nozzle areas provided by one of the main ICD suppliers. One of these is used in step two of workflow (1) below, allowing K to be obtained from equation (Equation 3-14). The equivalent AFCD parameters can then be calculated for the required “% area shut-off upon breakthrough” (steps 1 and 2). The flow through an AICV, e.g., is almost completely stopped upon breakthrough, with only the pilot, or bypass, flow element remaining open. The equivalent diameter of this bypass element varies based on the fluid properties in order to produce the required level of restriction (shut-in) upon unwanted fluid breakthrough. The minimum diameter is typically 1.0 mm, but due to the length and shape of the laminar and turbulent flow elements, the flow resistance can be equivalent to an orifice with relatively small diameter (e.g. in the order of 0.1 to 1.0 mm). The AFCD thus behaves as a Nozzle type ICD (NICD) prior to breakthrough, after which flow is reduced up to 99%.

Please note we do not recommend this approach for modelling AICVs’ performance. More modelling methods are presented below and in chapter 4. In this section we illustrate how the currently available model can be used in a more systematic manner to simulate the performance of a generalised AFCD as well as to replicate the performance of the available AICDs.
Figure 3-8: Workflow (1) Calculation of the AFCD performance modelling parameters to be used in Equation 3-12
An AFCD’s design and its operation imply that the dimensions of the main flow area (open for oil) and the equivalent area upon unwanted fluid breakthrough all influence its operation and interaction with the reservoir inflows. The AFCD modelling approach presented here, by simplifying the devices mode of operation, allows the well-completion design engineer to either investigate the viability of controlling unwanted fluid production at the level of the individual completion joint for different applications or to compare the AFCD’s performance with the equivalent ICD or other form of FCD. Furthermore, it can be used for sensitivity and optimization analysis to provide a better estimate of the added value for a specific, field application (details in chapter 5).

Table 3-1: The standard, nozzle-type ICD flow areas provided by one of the main suppliers

<table>
<thead>
<tr>
<th>Nozzle size (mm)</th>
<th>Number of nozzles per joint (12 m)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Total nozzle area (mm²)</td>
<td></td>
</tr>
<tr>
<td>1.6</td>
<td>2.01</td>
</tr>
<tr>
<td>2.5</td>
<td>4.91</td>
</tr>
<tr>
<td>4</td>
<td>12.56</td>
</tr>
</tbody>
</table>

The above approach was used, to generate and examine potential AFCD designs for several applications: light oil and gas, heavy oil and water and extra-heavy oil and steam. The suitable parameters are selected for each scenario and a workflow to select the optimal values of these parameters for each application is used. For example, the resulting Table 3-2 parameters describe the performance of hypothetical AFCD designs while Figure 3-9 shows the resulting performance plots. The size of the equivalent area at breakthrough was fixed; though the nozzle area (and hence its strength) was varied. Note that the practical considerations have not been addressed at this stage, for example, whether it is possible to manufacture a valve that delivers the modelled flow performance. However, this step is considered important to widen the search for optimum AFCD design and therefore to evaluate the existing valves’ performance against the global optimum design if applicable.
Figure 3-9: AFCDF performance compared with the equivalent Nozzle type ICD for light oil and Gas. The lines represent the calculated equivalent ICD performance and the points represent the AFCDF performance.

Table 3-2: AFCDF performance parameters

<table>
<thead>
<tr>
<th>AFCDF modelling inputs</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calibration fluid density (kg/m^3)</td>
<td>1000</td>
</tr>
<tr>
<td>Calibration fluid viscosity (cp)</td>
<td>0.5</td>
</tr>
<tr>
<td>Rate exponent</td>
<td>2</td>
</tr>
<tr>
<td>Viscosity exponent</td>
<td>3</td>
</tr>
<tr>
<td>Gas density (kg/m^3)</td>
<td>90</td>
</tr>
<tr>
<td>Oil density (kg/m^3)</td>
<td>780</td>
</tr>
<tr>
<td>Gas viscosity (cp)</td>
<td>0.02</td>
</tr>
<tr>
<td>Oil viscosity (cp)</td>
<td>1.0</td>
</tr>
<tr>
<td>Equivalent Nozzle area for oil flow (mm^2)</td>
<td>26</td>
</tr>
</tbody>
</table>

The same approach can be used to match any published AFCDF performance. An example for matching an existing AICD performance is provided in Figure 3-10 with the fitting parameters listed in Table 3-3.

Figure 3-10: Example for matching FD-AICD performance with (a) an equivalent nozzle size and (b) an arbitrary curve fitting (data from [65])
Table 3-3: Example for matching FD- AICD performance with (a) an equivalent nozzle size and (b) an arbitrary curve fitting.

<table>
<thead>
<tr>
<th>x</th>
<th>2</th>
<th>x</th>
<th>1.6</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nozzle diameter (mm)</td>
<td>1.9</td>
<td>Initial diameter (mm)</td>
<td>1.4</td>
</tr>
<tr>
<td>Equivalent shut-in Diameter (mm)</td>
<td>1.17</td>
<td>Shut-in Diameter (mm)</td>
<td>1.15</td>
</tr>
<tr>
<td>% shut-off</td>
<td>63%</td>
<td>% shut-off</td>
<td>35%</td>
</tr>
</tbody>
</table>

(a) matching FD- AICD performance with an equivalent nozzle size
(b) matching FD- AICD performance with an arbitrary curve fitting

3.3.2.1 Advantages and Disadvantages of the Conventional AFCD Equation

Advantages:

- Available in the most commonly used (analytical and numerical) software.
- With the understanding derived here for this equation, it remains very useful because it allows for testing the concept of AFCD in terms of two diameters (arbitrary). Hence, optimised AFCD performance can be investigated on a large range of AFCD-hypothetical designs (extended widely), not only restricted to the current available devices potential or capabilities. This optimum scenario, once identified, can then be tuned to fit the capabilities of one of the existing devices to the best possible degree. Such analysis (e.g. in chapter 5) can be used as a guide to encourage designers to develop an AFCD that has the flexibility to change the oil and the unwanted fluid responses easily and optimally at the wellsite if deemed necessary (e.g. the passive ICDs size/design are frequently changed at the wellsite).
- It allows the autonomous devices to be modelled and compared against the exact equivalent passive ICD-completion (with no phase selectivity).

Disadvantages:

- Lack of unique solution for each AICD type. For example several solutions can be derived once the (x) exponent is altered (e.g. see Figure 3-10). Multiple solutions, means increased uncertainty and also leads to different MPF performance, as shown in Figure 3-11.
- Further to the point above the derived (matching) parameters require update for each field, depending on the reservoir fluid properties. RCP and FD-AICD have been tested for different fluids (single phase flow). A generalised equation that matches the performance of all tested fluids is considered to be more descriptive to a better representation of the valve’s actual flow physics. This is essential for
coupled well/reservoir simulators since significant changes in fluid (mainly oil in this application) viscosity occur as the reservoir depletes. The impact of this change will not be accurately and automatically incorporated within the simulation calculation. Meaning that, the parameters are designed for the oil properties at initial conditions and hence any changes in the oil properties will not be considered in the performance of the device accurately.

- The expression does not allow for a step-wise AICV performance to be modelled as it incorporate a continuous multiphase flow performance calculation.

![Figure 3-11: The problem of multiple solutions available for matching the FD-AICD single-phase performance](image)

### 3.3.3 Dimensionally Consistent AICD Performance Formula

As mentioned above, the available AFCD performance formula (Equation 3-12) does not guarantee accuracy or physical representation of the multi-phase flow performance. Not surprisingly, many AFCD manufacturers, as well as operators, are looking for an updated, more accurate performance correlation. Below we present an example of such solution derived using the classical (in fluid mechanics) dimensional analysis method [78].

Equation 3-12 is an empirical equation, and does not seem to be dimensionally consistent. For instance, if the equation is re-written in a simplified form by combining all of the constants into a single constant \( b_{\text{AICD}} \), the following expression can be formulated depending on the AFCD size, fluid properties (density and viscosity), and rate:

\[
\delta p = \left( \frac{\rho_{\text{mix}}^x}{\mu_{\text{mix}}^y} \right) b_{\text{AICD}} \cdot q^x
\]

**Equation 3-15**

The constant \( b_{\text{AICD}} \) responsible for the AFCD sizing alone should only depend on length dimension, but has the unexpectedly complicated dimensions of:

\[
[b_{\text{AICD}}] = \text{Mass}^{y-z+1} \cdot \text{Time}^{x-y-2} \cdot \text{Length}^{3z-3x-y-1}
\]

**Equation 3-16**
For instance, other pressure drop equations for fluid flow (e.g. Darcy flow through porous media) can be split into a fluid description part and a conduit (e.g. porous media) description part, where the conduit is described only in length dimensions (e.g. Darcy). Hence we can ignore the impact of mass and time on the AFCD strength ($b_{\text{AFCD}}$) considering the AFCD flow performance equation should be symmetrical to other fluid flow equations. By removing the time and mass dependencies the following was observed:

$$y = x - 2 \text{ and } z = x - 1 \quad \text{Equation 3-17}$$

From equation (3-12), the viscosity exponent ($y$) and the density exponent ($z$) are redundant and actually a function of the rate exponent ($x$). The AFCD formula is there for [79, 80]:

$$\delta p = \left[ \frac{\rho_{\text{mix}}^{x-1}}{\mu_{\text{mix}}^{x+2}} \right] b_{\text{AFCD}} \cdot q^x \quad \text{Equation 3-18}$$

Where $b_{\text{AFCD}}$ has a dimension of (length)$^{-2(x+2)}$.

Parameters of this universal formula ($x$ and $b$) can be further adjusted to fit each AFCD type to represent the performance for different fluids in accordance with the published laboratory data.

**3.3.3.1 Remarks on equation 3-12 and equation 3-18**

When compared with Equation 3-18, Equation 3-12 may give a good fit, but it is not entirely valid since it contains an extra degree of freedom (both an $x$ and a $y$ term rather than just an $x$ term). Furthermore, Equation 3-12 has density exponent equal to 2 ($z = 2$). If this is substituted in Equation 3-17 with time and mass exponents set to zero, we can find that $y = 1$ and $x = 3$. Meaning not only that $y$ is dependent on $x$, and so is therefore unnecessary, but more importantly that there is just one possible value for $x$. The constraint preventing other solutions is the dimensional effect of setting the density exponent to 2. It is not apparent why the exponent of the density term should be exactly 2 for all types of AFCDs employing different physics in their autonomous action to unwanted fluid and different geometries [80].

Considering the fluid flow path described in section 2.3.2, the flow regime through the restriction (e.g. an ICD) was found to be always turbulent with more than 99% of the pressure drop exists at the restriction [4]. Laminar flow is governed by the fluid viscosity, while turbulent flow is governed by the density (see e.g. Equation 2-6 and Equation 2-7).
Now considering equation 3-18, when the flow rate exponent is = 2, the pressure drop becomes a function of density and when the rate exponent is = 1 the pressure drop is a function of viscosity (i.e. satisfying both boundaries).

For AICDs, the rate exponent can be found through fitting a dimensionless pressure
\[ P_D = \frac{\Delta \rho q^2}{\mu^4} \]
vs. Reynolds number (Re) to the experimental data involving all the tested fluids [80] (see the next section).

As described in chapter 2, the working principle of an AICD (even at turbulent flow) is envisaged to involve both:

1) Density impact (flow through a nozzle).
2) A purposely built viscosity impact to distinguish unwanted fluids of low viscosities. E.g. the RCP-AICD and the FD-AICD utilise the stagnation pressure and the fluid inertia principles respectively (function of the fluid’s viscosity).

As such, if the rate exponent is identified to be = 2 (e.g. from laboratory experiments) then equation 3-18 is not suitable to capture both impacts described above. Equation 3-12 can be used instead.

Equation 3-18 has been extended (in chapter 4) to allow for an enhanced MPF performance modulation.

3.3.4 Matching FD-AICD and RCP Published Single Phase Flow Performance

Although Equation 3-12 may give accurate enough results (e.g. Figure 3-10), a more optimal solution resembling Equation 3-18 is used to match the FD-AICD type 3B performance provided for four different fluids in Table 3-4. The match is done for water and 99 cP oil curves (only), producing a generalized Equation 3-19 matching FD-AICD performance for all tested fluids (Figure 3-12). This good match signifies the superiority of the new approach presented here compared with the conventional Equation 3-12. Not only because of the less number of variables used for describing the performance, but more importantly because of the proven ability of Equation 3-19 to accurately honour the changes in the single phase properties due to changing reservoir conditions (e.g. pressure and temperature “SAGD”) during the production life of the field and accurately (and simply) incorporate that in simulation. Whereas changing the fluids’ properties would require modification of the AFCD performance parameters if Equation 3-12 is used in simulation depending on the severity of the alteration.
\[ \delta p = \left[ \frac{\rho_{\text{mix}}^{1.5}}{\mu_{\text{mix}}^{0.5}} \right] b_{\text{AICD}} \cdot q^{2.5} \] 

Equation 3-19

where: \( b_{\text{AICD}} = 6 \times 10^{-6} \text{ m}^{4.5} \) produced for the following units - density (kg/m\(^3\)), viscosity (cp), flow rate (m\(^3\)/d).

Figure 3-12: Comparison of FD-ACD range 3B function (Equation 3-19) with Experimental Data [65]

This approach is recommended to be used for matching the performance of the FD-AICD as well as RCP-AICD as shown in Figure 3-12 and Figure 3-13. However, AICV require another approach for incorporating its performance in a well/reservoir simulation. The AICV solution is described in section 3.5 of this chapter.

Figure 3-13: Comparison of RCP-AICD (Equation 3-20) with Experimental Data [10]
\[ \delta p = \left[ \frac{\rho_{\text{mix}}^{1.2}}{\mu_{\text{mix}}^{0.2}} \right] \cdot b_{\text{AICD}} \cdot q^{2.2} \]  

Equation 3-20

where: \( b_{\text{aicd}} = 17 \times 10^{-6} \text{ m}^{-4.2} \) produced for the following units - density (kg/m\(^3\)), viscosity (cp), flow rate (m\(^3\)/d).

Table 3-4: The performance of single FD-AICD Insert Range 3. Data from [65]

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Rate (gpm)</th>
<th>Differential Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 cP Water</td>
<td></td>
<td></td>
</tr>
<tr>
<td>62 lb/ft(^3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>109 °F</td>
<td>0.53</td>
<td>58</td>
</tr>
<tr>
<td></td>
<td>0.95</td>
<td>220</td>
</tr>
<tr>
<td></td>
<td>1.18</td>
<td>364</td>
</tr>
<tr>
<td></td>
<td>1.37</td>
<td>512</td>
</tr>
<tr>
<td></td>
<td>1.52</td>
<td>655</td>
</tr>
<tr>
<td>Note: at these conditions, water viscosity is known to be 0.5 cP.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 cP Oil</td>
<td></td>
<td></td>
</tr>
<tr>
<td>53 lb/ft(^3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>84 °F</td>
<td>1.08</td>
<td>58</td>
</tr>
<tr>
<td></td>
<td>1.8</td>
<td>215</td>
</tr>
<tr>
<td></td>
<td>2.2</td>
<td>367</td>
</tr>
<tr>
<td></td>
<td>2.5</td>
<td>510</td>
</tr>
<tr>
<td></td>
<td>2.71</td>
<td>646</td>
</tr>
<tr>
<td>45 cP Oil</td>
<td></td>
<td></td>
</tr>
<tr>
<td>53 lb/ft(^3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>77 °F</td>
<td>1.52</td>
<td>58</td>
</tr>
<tr>
<td></td>
<td>2.5</td>
<td>215</td>
</tr>
<tr>
<td></td>
<td>3.15</td>
<td>365</td>
</tr>
<tr>
<td></td>
<td>3.56</td>
<td>515</td>
</tr>
<tr>
<td></td>
<td>3.93</td>
<td>665</td>
</tr>
<tr>
<td>99 cP Oil</td>
<td></td>
<td></td>
</tr>
<tr>
<td>54 lb/ft(^3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>97 °F</td>
<td>1.21</td>
<td>57</td>
</tr>
<tr>
<td></td>
<td>2.43</td>
<td>214</td>
</tr>
<tr>
<td></td>
<td>3.72</td>
<td>365</td>
</tr>
<tr>
<td></td>
<td>4.41</td>
<td>506</td>
</tr>
<tr>
<td></td>
<td>4.8</td>
<td>651</td>
</tr>
<tr>
<td>229 cP Oil</td>
<td></td>
<td></td>
</tr>
<tr>
<td>55 lb/ft(^3)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>76 °F</td>
<td>1</td>
<td>58</td>
</tr>
<tr>
<td></td>
<td>2.42</td>
<td>220</td>
</tr>
<tr>
<td></td>
<td>3.38</td>
<td>362</td>
</tr>
<tr>
<td></td>
<td>4.07</td>
<td>505</td>
</tr>
<tr>
<td></td>
<td>4.65</td>
<td>659</td>
</tr>
</tbody>
</table>
3.3.4.1 Advantages and Disadvantages of the Proposed Formula (Equation 3-18)

Advantages

- It matches most of the tested fluids for RCP and FD-AICD. Hence the derived equations is envisaged to be directly applicable in any reservoir/fluid conditions.
- A reduced number of performance modelling parameters (one of the parameters in Equation 3-12 is redundant).

Disadvantages

- As detailed above, the new equation ignores the impact of mass and time, related to fluid flow (kg/sec), on the AFCD length (e.g. moving the disc and thus changing the AFCD flow geometry “or” flow path). The formula failed to match the performance of FD-AICD range 3 and 4 for high viscosity fluids as shown in Figure 3-14 and Figure 3-15 (data from Table 3-4 and Table 3-5).
- The equation reduces to passive nozzle equation once the flow rate exponent is defined to be equal to 2. The viscosity term will cancel with zero exponent and the density exponent becomes 1. If an AFCD performance is defined from the laboratory tests to have \( x = 2 \), then the conventional AFCD equation {Equation 3-12} is recommended for modelling the performance instead since it allows the incorporation of the autonomous reaction at this specification.
- Equation 3-12 is also required instead, if the \( x \) has a value of less than 2 (e.g. based on laboratory experiments). If such performance exists then, substituting in Equation 3-18, the viscosity exponent is negative. This results in modelling a reverse effect to the viscosity than expected. The valve will then allow low viscosity fluid to flow with minimal restriction and vice versa for viscous fluids.
- Observation: After a specific “viscosity” threshold, the AFCD performance seems to be independent of further viscosity changes (Figure 3-14 and Figure 3-15). This performance is not fully captured in Equation 3-18. The parameters derived from the formula Equation 3-18 need to be checked against the valve performance curves published for similar fluid properties.
- Observation 2: the MPF response of AFCDs is yet to be addressed. This could be overcome if the dimensionally consistent Equation 3-18 is multiplied by a dimensionless formula (e.g. dependence on Re and/or water cut) in order to introduce extra matching parameters to eliminate the mismatches or viscosity-ratio reverse problem. Such approach is introduced later in the thesis.
The discussions above are concerning single phase flow performance across AICDs. AICDs are described with a continuous reaction to the properties of the flowing fluid. AICVs on the other hand, are known to have a somewhat stepwise performance as detailed in chapter 2. The Multi-Phase Flow (MPF) impact on modelling and added value evaluation of AICDs completions is discussed next.
Table 3-5: The performance of single FD-AICD Insert Range 4. Data from [65]

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Rate (gpm)</th>
<th>Differential Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 cP Water</td>
<td>0.41</td>
<td>57</td>
</tr>
<tr>
<td>62 lb/ft³</td>
<td>0.76</td>
<td>213</td>
</tr>
<tr>
<td>109 °F</td>
<td>0.99</td>
<td>359</td>
</tr>
<tr>
<td>1.17</td>
<td>514</td>
<td></td>
</tr>
<tr>
<td>1.31</td>
<td>647</td>
<td></td>
</tr>
<tr>
<td>233 cP Oil</td>
<td>1.07</td>
<td>57</td>
</tr>
<tr>
<td>55 lb/ft³</td>
<td>2.06</td>
<td>210</td>
</tr>
<tr>
<td>79 °F</td>
<td>2.59</td>
<td>359</td>
</tr>
<tr>
<td></td>
<td>3.01</td>
<td>506</td>
</tr>
<tr>
<td></td>
<td>3.32</td>
<td>650</td>
</tr>
<tr>
<td>449 cP Oil</td>
<td>0.96</td>
<td>58</td>
</tr>
<tr>
<td>56 lb/ft³</td>
<td>2.1</td>
<td>218</td>
</tr>
<tr>
<td>94 °F</td>
<td>2.78</td>
<td>364</td>
</tr>
<tr>
<td></td>
<td>3.28</td>
<td>505</td>
</tr>
<tr>
<td></td>
<td>3.74</td>
<td>659</td>
</tr>
<tr>
<td>747 cP Oil</td>
<td>0.77</td>
<td>58</td>
</tr>
<tr>
<td>56 lb/ft³</td>
<td>2.06</td>
<td>218</td>
</tr>
<tr>
<td>88 °F</td>
<td>2.78</td>
<td>365</td>
</tr>
<tr>
<td></td>
<td>3.36</td>
<td>512</td>
</tr>
<tr>
<td></td>
<td>3.76</td>
<td>627</td>
</tr>
<tr>
<td>1002 cP Oil</td>
<td>0.61</td>
<td>58</td>
</tr>
<tr>
<td>57 lb/ft³</td>
<td>1.84</td>
<td>220</td>
</tr>
<tr>
<td>79 °F</td>
<td>2.69</td>
<td>361</td>
</tr>
<tr>
<td></td>
<td>3.33</td>
<td>508</td>
</tr>
<tr>
<td></td>
<td>3.87</td>
<td>646</td>
</tr>
</tbody>
</table>

3.4 The Standalone-AICD Multiphase Flow Performance

AFCD(s) can be installed at every tubing joint, as is normally the case for ICDs (hundreds of ICDs are installed in a horizontal well completion). However, the number of packers installed in order to segment the wellbore into zones is limited (up to a few tens), so
normally several devices are installed in the same zone, i.e. share the same annulus. A conceptually picture is provided in Figure 3-16 that shows several devices installed in two zones separated by a packer. One of the zones is producing both oil and water. Stratified flow occurs within the annulus exposing some of the valves to water and some of the valves to oil.

![Diagram of several devices in two zones](image)

**Figure 3-16: A conceptual picture illustrating several devices installed in two zones separated by a packer with stratified flow observed in the zone that produces both oil and water (to the left).**

It’s important to realise that the models discussed in this chapter refer to the stand-alone AFCD performance. Multiphase flow effects in wellbore can have a profound impact on the performance of the AFCD completion (completion is a combination of the devices, packers, annuli, etc.). This is because the AFCD imposes a non-linear pressure loss depending on the flowing fluid composition, and it makes a significant difference whether oil and water/gas flow in turn across an AFCD as single phases (stratified flow case), or as a mixture (homogeneous flow case). So the AFCD-completion performance is expected to be intrinsically reliant on wellbore multiphase flow description (e.g. flow regime, velocities, conduit geometry, etc.).

The AFCD-completion performance modelling challenges (as opposed to the stand-alone AFCD performance discussed above) and the solutions will be addressed in chapter 4. The accurate AFCD-completion model is envisaged to incorporate both solutions: (1) accurate stand-alone AFCD multi-phase flow (following the solutions provided in this chapter along with published laboratory data) and (2) accurate annulus flow model (following the renowned fluid segregation physics).

A robust and informative sensitivity study of the stand-alone performance of any AFCD is provided in detail study in chapter 5. A generalised equation {Equation 4-4} to incorporate the standalone AFCD performance in simulation is provided in chapter 4.
3.4.1 The Impact of Stand-alone AFCD MPF on Modelling Results

To illustrate how considerable the impact of the stand-alone AFCD MPF assumptions can be on the AICD completion modelling, consider a wellbore section with 1 AICD (or e.g. laboratory test for an AICD joint with one valve) producing 10 m$^3$/d of liquid with 50% WC. Let’s assume the single phase AICD performance is described as shown in Figure 3-12 following Equation 3-19.

Let us now assume a slow MPF performance (i.e. the AICD reacts slowly to the increasing water cut), then based on the flow condition above the pressure drop is expected to be 5.2 bar as depicted in Figure 3-17 (slow). As mentioned earlier, very limited MPF performance is published. Hence a sensitivity analysis is required to evaluate the possible impact on completion performance. Now, assuming linear and fast MPF performance (i.e. the AICD reacts linearly (or) more aggressively to the increasing water cut) the calculated pressure drop is 9.6 and 18.7 bar respectively {Figure 3-17}.

Notice that changing the stand-alone AICD MPF assumption in this example has resulted in doubling the pressure drop across the zone if slow vs. linear MPF disruptions are assumed. Moreover, four times difference in pressure drop (or even more) is observed if slow vs. fast MPF disruptions are assumed.

Similarly, fixing the pressure and observing outflow performance, significant differences in the flow performance can be calculated for slow, linear and fast MPF performance (e.g. in this case 13, 10, and 7.8 sm$^3$/day respectively).

Figure 3-17: Stand-alone AICD illustrative performance for slow, linear and fast MPF distributions with explanatory signs – Fixed rate calculation

Figure 3-18: Stand-alone AICD illustrative performance for slow, linear and fast MPF distributions with explanatory signs – Fixed pressure drop calculation
Such significant changes in the sandface pressure and the inflow rate profile will affect the water displacement front, any differential depletion between zones and, as a result, the reservoir’s dynamic response to production. AFCD-completion performance modelling challenges caused mainly by: (a) the stand-alone AFCD MPF uncertainty and (b) the annulus flow modelling accuracy, is addressed in chapter 4 and chapter 5.

3.5 Flow Performance and Modelling of AICVs

3.5.1 Describing AICV performance in a well/reservoir simulator

The AICV is different in its performance to other types of AICDs. The AICV as described in chapter 2, is a stepwise device (i.e. it changes from one mode to another depending on a specific threshold). The AICV can either be in the open mode (for oil) or the (nearly) closed mode (for unwanted fluids) when a specific downhole condition is met (in terms of the unwanted fluid percentage). The AICV published performance shows that the threshold to switch between modes is (98%) for unwanted fluid (e.g. water or gas) [69].

When applied in conventional reservoir simulation, considering a standalone performance as described above, the AICV will likely to stay in the oil mode almost all the time and may in fact never shut for most of the models where the unwanted fluid percentage will never reach the 98% water cut threshold in any segment assuming a complete homogeneous flow (conventional reservoir simulation). This is also drawn from the fact that, one completion section (between two packers) will have different PIs resulting in somewhat a single phase inflows at different locations along that section, where water will breakthrough naturally at the high PI zones and the low PI zones will remain contributing oil (depending on their PIs). However, in reality, different flow regimes can be formed downhole including the stratified flow (most likely flow regime in horizontal sections). Therefore some of the valves will be actually immersed in single phase fluid (for example water), some will be producing both oil and water and others will be in oil. Example of such situation is depicted in Figure 2-57. This makes a big difference to the completion performance compared to the conventional simulation.

3.5.2 The Problem of Modelling a Well Segment Equipped with AICVs

From the discussion above, the stand-alone AICV performance should be modelled differently than the methods proposed for AICDs in this chapter. The AICV threshold of (98%) has been implemented in simulation however, in most of the reservoir models this threshold never reached – making an AICV completion exactly the same as ICD completion with an equivalent size.
In the case of oil and water/gas flow, the multi-modal response of the device makes a unique case. The segregated flow in the annulus makes the device(s) react sequentially to either oil or water/gas, as opposed to the “homogeneous flow” modelling approach that is traditionally assumed in reservoir simulators. Capturing the sequential reaction of the device to either oil or water in a reservoir simulator is challenging.

A model/formulae to solve this problem has been derived (Thanks to Muradov K.). It offers a more accurate way of modelling AFCD completion performance in a commercial reservoir simulator. Note that this concept of a flow control dependent on the inflow performance is relatively new to the industry (and so is the AFCD!).

It is believed that some AFCDs react to water only when the WC reaches certain limit, despite of the annulus water holdup (HU) and whether or not the AFCD is submerged in water. Other AFCDs are believed to respond to water only when submerged to water, i.e. when the annulus water HU reaches a certain critical value (not necessarily corresponding to level of the AFCD position). We assume the situation of the “critical” condition, i.e. the condition when the critical HU or WC is reached and the device(s) starts responding to both oil and water flows. If there are multiple AFCDs in one well segment, then this happens when all but one are already in the 100% water production mode, while the last AFCD (e.g. the one at the top of the segment, or the farthest from the water source) is intermittently exposed to either oil or water flow.

The completion performance when the WC is below the above-defined critical condition is relatively straightforward to model traditionally with the single-phase AFCD performance curve extensively described by Eltaher E., et al., 2014 [43]. Unfortunately, such “non-critical” period can be short, let alone the AFCDs completions are designed to actually react to water, so by default they operate within the “critical” condition. Hence the findings of this work are still relevant.

3.5.2.1 Problem Statement:

1. A single AFCD is installed across the well segment.
2. The AFCD performance can be described as $dP_{AFCD} = a_{AFCD,w} \cdot \dot{Q}^2_w$ in the water mode and $dP_{AFCD} = a_{AFCD,o} \cdot \dot{Q}^2_o$ in the oil mode.
3. Flow rates are such that the flow in the annulus is stratified (or, more generally, segregated). This means that the AFCD can be open to either water or to oil flow at a time.

*Note: In a more complete study one has to check the critical velocities/rates, fluid properties, and wellbore configuration where this assumption is violated.*

4. $P_{\text{tubing}}$ (also called $BHP$ or $P_{\text{wf}}$) and $P_{\text{reservoir}}$ can be considered constant during a reservoir simulation time-step. This also means that $\Delta P$ can be considered constant during a reservoir simulation time-step. (The validity of this condition is confirmed by reservoir simulation studies.)

### 3.5.2.2 Assumptions:

1. Assume there is a critical water hold up $HU_{w,crit}$ in the annulus so that when $HU_w \geq HU_{w,crit}$ the AFCD is mostly exposed to water, and otherwise – to oil.

   *NB1: For instance this can be a water hold up so that the water surface is across the AFCD position, or it can be an experimental value (e.g. 98%).*

   *NB2: Note that we are only assuming that this $HU_{w,crit}$ is constant during a simulation time-step, not necessarily throughout the whole production period.*

   *NB3: As long as this assumption is valid we can ignore the well segment trajectory or other well geometry or flow related factors at this stage in this study.*

2. Consider a situation when the annulus water hold-up $HU_w$ is such that $HU_w = HU_{w,crit}$. Then the AFCD is going to be exposed to a series of oil and water flows. This is easy to comprehend assuming that the water hold up is suddenly higher than the critical water hold-up. The AFCD will be exposed mostly to water and the well segment outflow will be water only $Q_{l,\text{outflow}} = Q_{w,\text{outflow}}$, while the well segment inflow $Q_{\text{inflow}}$ will consist of both oil and water (given that $0 < WC_{\text{inflow}} < 1$).

   Moreover, $Q_{l,\text{inflow}} = Q_{w,\text{outflow}}$ from the mass balance considerations when the $P_{\text{annulus}}$ is stabilised at a particular mode. So basically the segment outflows water which is replaced by water and oil. Essentially, the water hold up in the annulus will be decreasing until it reaches the critical value, after which the AFCD will generally “switch” to the oil mode and the process will continue in the oil mode.

   We are not concerned at this stage how often the AFCD will be exposed to oil or water. This may depend on the transient flow effects in the system, segregated flow regime parameters, CFD effects, etc.
**Our assumption** is that such fluctuations will happen at least twice during the simulation time step (e.g. duration_of_1_oil_mode + duration_of_1_water_mode <= 1-3 months).

3. Linear Inflow Performance Relationship assumption is valid during a simulation time step. I.E. \( J_i (P_{res} - P_{annular}) = Q \) applies.

4. Frictional pressure drop in the annulus is negligible compared to the drops across the reservoir and completion (this normally holds true mainly because the AFCD completion is designed and installed to act as such).

**Additional assumptions required for simplifying the solution:**

1. The AFCD is designed to promote and reasonably equalise oil inflow so that

   \[ dP_{AFCD, oil mode} \leq (P_{reservoir} - P_{annular, oil mode}) \]

2. The AFCD is designed to restrict water inflow so that

   \[ dP_{AFCD, water mode} \gg (P_{reservoir} - P_{annular, water mode}) \]

### 3.5.3 Performance of a Well Segment with Single AICV

Consider a well segment – i.e. the section between two adjacent packers and assume it is equipped with one AICV, Equation 3-21 and Equation 3-22 are proposed for modelling the performance of this segment at the critical WC threshold. The equation aims to smooth the performance of the AICV-completion for better convergence stability when applied in a coupled well/reservoir simulator.

\[
dp_{AFCD} = a_{AFCD, \cdot} \cdot Q_o^2 \quad \text{Equation 3-21}
\]

\[
\overline{a_{AFCD}} = a_o (1 - WC) + a_w WC^2 + \frac{WC (1 - WC)}{J_i} \sqrt{\frac{a_w}{\Delta P}} \quad \text{Equation 3-22}
\]

The average AFCD strength is now a function of the inflow performance as well as of the AFCD performance. Note that the critical water hold-up value is not present and its value is therefore irrelevant here. Derivation is provided in Appendix (4) for brevity.

*Note that when \( WC=0 \) then \( \overline{a_{AFCD}} = a_o \) while when \( WC=1 \) then \( \overline{a_{AFCD}} = a_w \).*

For simplicity, we recommend incorporating into the reservoir simulators a further simplified version of

\[
\overline{a_{AFCD}} = a_o (1 - WC) + a_w WC^2 + \frac{WC (1 - WC)}{J_i} \sqrt{\frac{a_w}{\Delta P}} \quad \text{Equation 3-22}
\]
When the WC is high enough for the system to start flowing in the oil-water mode sequentially:

\[ a_{AFCD} \approx a_w WC^2 \]  \hspace{1cm} \text{Equation 3-23}

Note that:

1. This particular derivation is valid for a well segment containing a single AICV. So it should be applied in the situations where the annular flow isolation is modelled across each well segment (e.g. for the no annular flow option in Eclipse).

2. In case of multiple AFCDs per well segment we expect to have multiple, critical water hold-up values resulting in a multistage curve. Derivation of such a system is provided below.

3. Note that if the single-phase performance of an AFCD cannot be acceptably described as a quadratic function of rate, and instead is proportional to the rate in the power of \( x \), then it is possible to make adjustments to the derived formulae based on the \( (x-2)/2 \) order.

### 3.5.4 Performance of a Well Segment with Multiple AICVs

Consider a well segment – i.e. the section between two adjacent packers. Assume it is equipped with \( n \) AFCDs of the same type.

\[ a_{AFCD} \approx \frac{n^2}{J_i \Delta P} \left( (1-WC) \left( \gamma(n-1)+1 \right) + (WC-(1-WC)\gamma(n-1)) \frac{J_i \sqrt{\Delta Pa_w}}{n} - 1 \right) \]

\[ \left( (1-WC) \left( \gamma(n-1)+1 \right) + (WC-(1-WC)\gamma(n-1)) \frac{J_i \sqrt{\Delta Pa_w}}{n} \right) \]

Equation 3-24

Further, simplifying this equation for high WC values gives a result similar to Equation 3-22

\[ a_{AFCD} \approx a_w (1-WC) + a_w WC^2 + \frac{WC (1-WC)}{J_i} \frac{a_w}{\sqrt{\Delta P}} \]  \hspace{1cm} \text{Equation 3-22}

, with a minor correction (can be ignored in many cases) due to the multiple AFCDs in a segment:
Equation 3-21 and Equation 3-25 are proposed for modelling the performance of this segment at the critical WC (threshold) conditions. Derivation is provided in Appendix (4) for brevity.

3.5.5 Implementation of the AICV-segment Models into Reservoir Simulation

Implementation of the above solutions should be made as follows:

1. If WC or HU < critical, model as: Eltazy et al 2014 [43] or preferably as a passive nozzle.
2. If WC or HU = critical, adjust the AFCD model equation in the reservoir simulator by changing $a_{AFCD}$ to $a_w WC^2$.
3. The table method described in section 3.2.2 is to be used to incorporate the AICV model above in a reservoir simulator.

The above is a realistic approach to model AFCD performance that takes into account the annular flow segregation.

3.6 Preparing AFCD-completion Wellbore Model

AFCD completion modelling requires:

1. Simulation of the real number of devices installed. This approach employs an accurate model of a completion with 1 device per tubing joint of 12 m length. It requires modelling both the well and the reservoir at the same scale. Some softwares (e.g. ECLIPSE) require Local Grid Refinement (LGR) “at the joint (12 m) resolution” along the wellbore. This increases the number of reservoir and well calculations and the simulation’s complexity; often leading to convergence problems, increased simulation time and interrupted simulations. This is especially true when dealing with gas production and long horizontal wells. OR
2. Simulate the performance of several adjacent AFCDs as a single, equivalent AFCD by the appropriate modification of its properties; i.e. use an upscaled wellbore model that represents the combined performance of a number of AFCDs which are then connected to a single, larger, reservoir grid block. The results calculated by this approach provide a similar accuracy to that of the more detailed wellbore model if the well is perfectly horizontal and a homogeneous flow in the
annulus is assumed. The added advantage of such simplification is the increased
calculation efficiency (more commonly applied by simulation engineers).

Annulus segmentation of the wellbore model with respect to the reservoir heterogeneity
and AFI distribution are also important factors that need to be considered in both cases.
Modelling the performance of an upscaled FCD includes either:

1. Segment length flow scaling (available in some commercial software). Flow
through a single representative device is given by the equation:

\[
q_{ALCV} = q_{cell} \times \frac{L_{AFCD}}{L_{tubing}}
\]

Equation 3-26

Where \( q_{AFCD} \) is the scaled volume flow rate used in the pressure drop calculation
(Equation 3-12), \( L_{AFCD} \) is the length of an actual AFCD joint and \( L_{tubing} \) is the length of
the tubing segment across which a single upscaled AFCD is installed in the model and
\( q_{cell} \) is the volume flow rate through the segment (and the flow rate from the reservoir into
the upscaled completion segment) \( OR \)

2. Changing the FCD’s strength. This can be applied in all software containing
Equation 3-12 by upsampling the strength of a single device to represent \( n \) devices
by using:

\[
a_{FCD} (U) = \frac{a_{FCD}}{(n)^x}
\]

Equation 3-27

3. Pressure scaling instead of rate when tables are used to incorporate the AFCD
performance, as detailed in section 3.2.2 of this chapter.

3.7 Guidelines for AFCD Performance Modelling and Optimization

Experience modelling FCD performance indicated the following points to be important:

1- Understand the chosen FCD performance curves with respect to the fluid
properties:
   a) Is the provided AFCD performance suitable for the properties of the fluids in
      the reservoir model?
   b) What are the conditions at which the fluid properties were specified?
      • Fluid properties at well/reservoir conditions are required when
        describing the FCD performance and calculating the pressure drop
        across the FCD.
• Fluid properties at standard conditions are normally required by commercial reservoir simulators.

2- AFI is an important factor to be considered, e.g. the number and location of packers. Hence appropriate wellbore model segmentation should be specified.

3- Calculate the well’s maximum possible liquid production rate. Too few AFCDs result in high flow rate across each valve. This leads to an increased pressure drop across the AFCD completion and a reduced well production potential.

4- Evaluate the pressure distribution across the well and then relate it to other possible constraints, such as total and critical coning flow rates, sand production, artificial lift, etc., when modelling the well under drawdown or BHP constrained production. The resulting drawdown should be considered during completion optimization.

5- “Like-with-like” comparison of the added value from various intelligent completion options requires that all FCD completion designs have a similar performance during early (only oil) production. This gives a better understanding of the advantage associated with the different FCD functionalities.

3.8 Case Studies phase (1)

All the modelling techniques presented above have been validated using actual data whenever possible or with synthetic data. Several reservoir/well completion problems have been tackled in this section to verify the applicability of different types of AFCDs and their impact on production. Based on this work, a detailed AFCD-completion’s sensitivity and optimisation study is presented in chapter 5.

3.8.1 Homogeneous, Heterogeneous and Compartmentalised (O/G) Reservoirs

3.8.1.1 The gas coning problem

Production from an oil rim field is often limited by the gas handling capacity of the surface facilities. Optimal production in such fields critically depends on selecting the correct surface choke position. Wells producing at a low multiple of the “oil rim” GOR produce at their maximum allowable production rate; while wells showing excessive “free” gas cap gas breakthrough are choked to maximize the total liquid production from the other wells while filling the field’s gas handling capacity. Optimum choke management is a challenge given the time varying nature of the GOR-rate dependence and the contradictory well THP-choke performance prior to free gas cap gas breakthrough as opposed to the wells showing gas coning. This is further complicated when the wells’
outflow performances interfere with each other due to several wells producing to the same flow line, as illustrated in Figure 3-19. Hauge and Horn, 2005 have detailed the impact of these challenges on Troll field production operations and the solutions implemented to solve them [81]. In some cases, the well are put on stop-cock mode for few days to allow the gas to retreat (gravitationally).

![Figure 3-19: Optimum choke control challenge due to several wells producing to the same flow line](image)

In the following section, the effectiveness of an AFCD well completion option for controlling gas production in a horizontal well producing from an oil rim reservoir with a big gas cap was investigated. We have studied and compared the performance of different intelligent well completions in a synthetic, oil-rim reservoir model associated with a large gas cap that mimics performance of a sector of a large North Sea field. Published data characterize this field as having a thin (~ 4 - 27 m) oil column.

### 3.8.1.2 Model Description

The reservoir consists of lightly compacted sands with high permeabilities, up to several Darcies, containing a light oil rim sandwiched between a large gas cap and an aquifer (Figure 3-20). A low drawdown is sufficient to deliver a high oil production rate from a long horizontal well in this case. Unfortunately, the high permeability favours early water and/or gas breakthroughs. Table 3-6 lists the model’s parameters.

![Figure 3-20: Synthetic model dimensions and fluid distribution. Right: Well location shown in a cross section slice](image)
Table 3-6: Synthetic model general properties for sector model mimicking the Troll field

<table>
<thead>
<tr>
<th>Variable</th>
<th>value</th>
<th>Units</th>
<th>Fluid properties:</th>
<th>value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geometry:</td>
<td></td>
<td></td>
<td>Length (x direction) 5000 m</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Width (y direction) 1000 m</td>
<td></td>
<td></td>
<td>Oil Gravity 23.8 °API</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Height (z direction) 260 m</td>
<td></td>
<td></td>
<td>Oil density at res. conditions 780 Kg/m³</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid blocks in x direction 94 -</td>
<td></td>
<td></td>
<td>Oil viscosity at res. conditions 1 cp</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid blocks in y direction 26 -</td>
<td></td>
<td></td>
<td>Bubble point pressure 225 bar</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid blocks in z direction 51 -</td>
<td></td>
<td></td>
<td>Solution gas oil ratio (GOR) 100 Sm³/Sm³</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Accumulation:</td>
<td></td>
<td></td>
<td>Water density at res. conditions 0.73 Kg/m³</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depth of GOC 2200 m</td>
<td></td>
<td></td>
<td>Gas viscosity at res. conditions 0.014 cp</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas column 200 m</td>
<td></td>
<td></td>
<td>Depth of OWC 2240 m</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil column 40 m</td>
<td></td>
<td></td>
<td>Well length 2300 m</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depth of OWC 2240 m</td>
<td></td>
<td></td>
<td>TVD Location 2220 m</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir:</td>
<td></td>
<td></td>
<td>Casing OD 7 in</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal permeability 2000 md</td>
<td></td>
<td></td>
<td>Casing ID 6.4 in</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vertical permeability 200 md</td>
<td></td>
<td></td>
<td>Pipe OD 5.5 In</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Porosity</td>
<td>0.28</td>
<td>-</td>
<td>Pipe ID 5 in</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Simulation period:</td>
<td>1000</td>
<td>Days</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 3-7: Production constraints for case 1, 2 and 3

<table>
<thead>
<tr>
<th>Variable</th>
<th>value</th>
<th>Units</th>
<th>Variable</th>
<th>value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum BHP</td>
<td>87</td>
<td>bar</td>
<td>Minimum BHP</td>
<td>87</td>
<td>bar</td>
</tr>
<tr>
<td>Maximum GOR</td>
<td>200</td>
<td>Sm³/Sm³</td>
<td>Maximum GOR</td>
<td>800</td>
<td>Sm³/Sm³</td>
</tr>
<tr>
<td>Maximum water cut</td>
<td>-</td>
<td>-</td>
<td>Maximum water cut</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Maximum liquid rate</td>
<td>3000</td>
<td>Sm³/d</td>
<td>Maximum liquid rate</td>
<td>3000</td>
<td>Sm³/d</td>
</tr>
<tr>
<td>Maximum gas rate</td>
<td>2</td>
<td>10⁶ Sm³/d</td>
<td>Maximum gas rate</td>
<td>2</td>
<td>10⁶ Sm³/d</td>
</tr>
</tbody>
</table>

The wellbore completions investigated in this case study are: Stand-alone screen (SAS), Nozzle-type ICD, and AFCD [Table 3-2].

The well’s 2300 m long completion crosses 46 reservoir grid cells of length 50 m each. Each cell is completed with one upscaled FCD representative of the performance of four, “real” FCDs installed every 12.5 m. Annular flow isolation (AFI) is modelled at every annular segment.

3.8.1.2.1 Well Surface Control Strategies Applied

Several strategies which reproduce the operational practices in “real” field production operations for gas breakthrough control have been applied to control the reservoir simulator when evaluating the reservoir – well interaction for various well completion options [82] (Lundberg, 2011). These strategies are:
1) Surface choking to maintain a fixed surface gas rate (traditional well production constraint).

2) Surface choking once the GOR threshold value (e.g. 800 Sm$^3$/Sm$^3$) is exceeded. The well’s producing GOR is reduced by closing the surface choke; however the well’s GOR will start to increase again and further well choking is triggered at the GOR limit. This operation continues until the oil production rate is reduced below the well’s economic limit. Production is then continued in “stop-cock” mode (e.g. one week of production followed by shutting-in the well for two weeks to allow the gas cone to retreat).

3) Continuous surface choking to maintain a fixed surface GOR. This surface well control can be automated to achieve a stabilized (fixed GOR) well production

4) Implement AFCD completion technology. AFCDs, by contrast, selectively implement a local gas-reduction strategy by restricting only those down-hole well completion sections that experience free gas production; potentially delaying “free” gas production and increasing oil production from the unaffected wellbore sections.

The above gas control strategies have been applied to three, different realisations of the synthetic reservoir model (Figure 3-20). These cases are (1) a homogeneous model, (2) a model with permeability heterogeneity and (3) a model with compartments. The production constraints applied to all cases are listed in Table 3-7.

3.8.1.3 Case 1: A Homogeneous Reservoir

Konieczek, J., 1990 describes the standard approach to managing oil rim reservoirs is to initially produce at the highest possible oil rate followed by surface choking to control the production of “free” gas from the gas cap [83]. The strategy employed in the homogeneous model in this study produced at the initial liquid production rate of 3000 (Sm$^3$/d) until the gas production constraints (GOR and/or gas rate) were violated, after which the well production was choked back (Figure 3-21).

Gas breakthrough occurs in the heel section for all well completions, SAS, ICDs and AFCDs, after which the surface choke control was implemented once the GOR limit was exceeded (Figure 3-21 and Figure 3-22).
Figure 3-21: Gas oil ratio and gas production rate for the selected completions. (Homogeneous reservoir)

Figure 3-22: Saturation profile after 1600 Days for (from left to right) SAS, NICD and AFCD completions

All FCDs demonstrate a better performance when compared with an SAS completion. This is achieved by delaying gas breakthrough and increasing cumulative oil production, as illustrated in Figure 3-22 which compares the vertical movement of the gas oil interface after 1600 days (see the red circles highlighted by the arrows). All FCDs delay the arrival of the gas cap and achieve a longer oil plateau period (Figure 3-23 “left”). Figure 3-23 “right” illustrates the AFCD’s completion advantage of increasing oil production by controlling the gas breakthrough at the producing completion sections.

Also, all scenarios, including AFCD s, eventually required surface choke control of the gas production due to the movement of the gas along the horizontal section. This behaviour is a consequence of the high reservoir permeability and the strict, surface GOR constraint.
Figure 3-23: Oil production rate and cumulative production for the selected completions. (Homogeneous reservoir)

The performance of a single wellbore section for all completions is compared in Figure 3-24. The production from the AFCD completion matches the production from the equivalent ICD initially (due to them having the same differential pressure) with the differences developing after gas breakthrough. This performance shows the importance of workflow (1) {Figure 3-8} allowing, for the first time, AFCD parameters to be acquired with a physical meaning (the nozzles’ diameters) and for its performance to be compared soundly with the relevant passive ICD. Therefore granting the ability of understanding the impact of adding an autonomous reaction module to a (previously) passive completion.

Figure 3-24: A comparison of the performance of a single wellbore section for all completions. (Homogeneous reservoir)

Few, if any, reservoirs can be treated as being homogeneous. “Real” reservoirs show a combination of permeability variation (heterogeneity) together with some degree of compartmentalization. Cases 2 and 3 study the effects of these reservoir types on the performance of the above well completions.

3.8.1.4 Case 2: Reservoir Permeability Variation

Variations in the reservoir permeability result in an unbalanced fluid influx rate along the horizontal section, accelerating the breakthrough of unwanted fluids, limiting the sweep efficiency and reducing the oil recovery.
The Troll oil field which has extensively employed long horizontal wells with ICDs; it is characterized by several reservoir units of two types of sandstone, a coarse-grained sand with permeability layers varying between 1 and 30 Darcies and a fine-grained sand of a few hundred milli-Darcies [2]. This reservoir description was reproduced in a box model by a repeating series of reservoir layers with a wide range of permeabilities that cut the path of the horizontal well (Figure 3-25). The permeability was distributed stochastically within the specified range for each sand type and appropriate porosity and relative permeability tables specified.

Figure 3-25: (A) The box model with repeating Sand units of varying permeability. (B) Enlarged cross section along the wellbore showing the horizontal well penetrating multiple sand units

As expected, some locations along the length of the horizontal well experienced earlier gas production compared to others. The ICD completed well, {Figure 3-26 “left”}, continued to produce with no down-hole control after gas breakthrough. This was followed by surface choke control as described previously. The down-hole reactive control of the AFCD completed well {Figure 3-26 “right”} achieved greater oil production until all 46 AFCD completion sections had closed.

Figure 3-26: Gas oil ratio and cumulative production for the selected completions. (Heterogeneous reservoir)

It was observed that (A)FCDs delivered a higher “added value” (increased oil) for reservoirs with increased heterogeneity.
3.8.1.5 Case 3: Reservoir Compartmentalization

A real hydrocarbon accumulation may consist of several blocks (structures) with similar or varying reservoir and fluid properties, e.g. the Troll oil field described has a gas cap thickness which varies from 0 to more than 150 m in different reservoir blocks. In case 3 we evaluate the effect of varying levels of gas cap pressure support associated with two adjacent reservoir compartments having the same reservoir and fluid properties (Table 3-6). This scenario (Figure 3-27) was modelled by introducing a non-active streak into a homogeneous box model in order to simulate a no-flow barrier (or fault). The gas cap size was increased in one compartment and slightly reduced in the other in Figure 3-28.

Figure 3-27: Horizontal well producing from two reservoir compartments with varying pressure support

This scenario is also to some extent analogous to a vertical or deviated producer with a comingled production from reservoir layers of different permeabilities and/or varying pressure support as, for example, found in two overlying reservoirs where one of them receives edge and the other bottom aquifer support.

Figure 3-28: A homogeneous reservoir model permeability with a non-active streak. The toe compartment shows reduced gas cap pressure support
The toe compartment is deprived of the higher level of pressure support from the gas cap associated with the first compartment; hence more than 70% of the well’s total production is contributed by the heel compartment, with the gas production starting at the heel. Surface control is triggered shortly after gas production starts and the well production rate is limited by this GOR constraint (Figure 3-29). The AFCD completion demonstrated a significant advantage compared with other completions since it remains longer on liquid rate control by isolating the gas producing zones locally while allowing the unaffected wellbore sections to produce more.

Figure 3-29: Gas oil ratio and oil production rate. (Combined production from the two compartments)

Note that:

1. Extra oil production from other wells in the field is now possible if the surface facilities are gas handling constrained.
2. The AFCD well’s extended production period under liquid rate control from both reservoir “blocks” resulted in it also producing the highest cumulative (free and associated) gas production (Figure 3-30). The AFCD reduced the “free” gas production by ~ 90% as compared with the ICD-completion prior to the GOR limit being reached during the period of liquid rate control. The AFCD completion allows production from both compartments, resulting in a further increase in the total oil and gas production until the whole wellbore is producing free gas and all AFCDs are shut. It is important to mention here that the AFCD modelled with a high restriction to gas to investigate the value gained from downhole gas control as compared with surface control.
In addition to the increased oil production and the controlled gas production there is another important observation in case 3. Once the surface control is triggered, there is a gas cross-flow from the high pressure compartment through the wellbore into the lower pressure block of the model for both SAS and ICD completions. Fluid flow streamlines have been generated to visualize reservoir flow, the impact of the various intelligent completion scenarios as well as that of variations in the pressure distribution on the well’s production performance. The gas cross-flow between different reservoir pressure regions is displayed in Figure 3-31, Figure 3-32 and Figure 3-33.

Initially, most of the oil production is produced to the surface from the high pressure region. However, the SAS completion experiences gas cross-flow once the surface choke is operated, as illustrated by the streamlines in Figure 3-31.

The ICD completion, on the other hand, achieves some level of down-hole flow control across the high pressure region, allowing more oil to be produced from the lower pressure region when compared with the performance of the SAS completion, Figure 3-32 vs. Figure 3-31 “centre”. When surface choking control started the gas moves through the wellbore and into the lower pressure reservoir in stages as indicated by the numbers in Figure 3-32 “right” starting from the nearest ICD flowing “to the toe”. This effect is due to the pressure losses across the ICD completion. This gas cross-flow occurred three months later than with the SAS completion and continues for more than 12 months, after which a limited production resumed from the lower pressure compartment, Figure 3-32.
Figure 3-31: SAS completion case. (From left to right) streamlines showing gas saturation at three simulation steps; gas saturation just before the surface control starts; and gas saturation 1 month after the control starts. The arrows are for illustration of directions of flow in the reservoir and along the wellbore, red is for gas and green is for oil.

Figure 3-32: ICD completion case, (From left to right) streamlines showing gas saturation at three simulation steps; gas saturation just before surface control starts; and gas saturation 2 months after surface control starts. The arrows are for illustration of directions of flow in the reservoir and along the wellbore, red is for gas and green is for oil.

Figure 3-33: AFCD completion case, (From left to right) streamlines showing gas saturation at two simulation steps; gas saturation (in the middle and to the right) showing GOC movement in the two compartments, respectively. The arrows are for illustration of directions of flow in the reservoir and along the wellbore, red is for gas and green is oil.

After analysing the detailed well completion performance it is possible to assess the effect of having wellhead control as compared with AFCD completion’s down-hole gas production control. When considering the performance of one segment at the heel, as observed in Figure 3-34, when the gas breaks through into the segment the pressure drop across the ICD increases slightly due to the increased fluid velocity, so the gas production continues with minimal added restriction until the surface control is applied. The AFCD completion demonstrates a completely different behaviour – the more aggressive restriction provided by the AFCD (modelled in this case) sharply increases the differential...
pressure across the valve, limiting the local gas production. Both surface well production control and
down-hole gas shut off are capable of controlling the amount of gas-cap gas produced and the well’s GOR performance. This influence is shown in Figure 3-34 whereby the gas production has dropped significantly in the case of AFCD-completion. The gas cross-flow effect can also be seen in this analysis as illustrated in Figure 3-35 (NICD) showing the performance of the toe segment. This behaviour was not observed in the case of AFCD completion. This is because the differential pressure across the relevant AFCDs will increase limiting the drawdown in the affected section Figure 3-33, Figure 3-34 and Figure 3-35 once the gas breaks through at any section.

![Figure 3-34: ICD and AFCD production performance at the heel](image)

![Figure 3-35: ICD and AFCD production performance at the toe](image)

3.8.1.6 Discussion

The AFCD is the latest development in well inflow control technology. This process, ongoing since the first introduction of ICDs in the early 1990s, has provided solutions to an ever widening range of oil and gas field, well inflow management problems. A recent example is the development of autonomous FCDs for SAGD wells where a selective restriction/shut-off of steam, rather than water or gas, is required. Further applications will no doubt arise in the near future. From the studied examples it was observed that:

1) AFCD-completion shows production improvement in the selected case studies as compared with the conventional or ICD completion. Incremental oil production depends on well’s and reservoir’s production conditions.
2) A strict AFCD completion reduced the dependency of production rate on the produced GOR constraint. This benefit relatively increased with increasing levels of reservoir heterogeneity.
3) A comparison of the performance of SAS and ICD completions with surface choke control and an AFCD completion with combined down-hole and surface control indicates that:
   - ICD and AFCD completions in long, horizontal wells in high permeability, oil rim reservoirs increase oil production by managing the gas invasion front compared to a conventional SAS completion.
   - The only control of gas production in SAS and ICD completed wells once excessive “free” gas cap gas is being produced is via the surface choke, affecting the global (well) performance. AFCD completions perform better because they can also isolate gas at the level of an individual completion joint, allowing oil production to continue from the remainder of the well unhindered by surface choking (case 3).
   - This performance continues until all inflow intervals controlled by AFCDs experience gas breakthrough and autonomously restrict the flow.
   - A strict AFCD was able to eliminate the cross-flow of unwanted fluids between varying-pressure reservoir systems.
   - Well head choke control is also available to AFCD completions as part of its capabilities to control gas breakthrough if a low resistive AFCD is used in completion.

3.8.2 AICD Performance in Heavy Oil Reservoir

3.8.2.1 Heavy Oil Recovery Challenges

In this work, a sector model that is representative of typical oil field production management issues is used for exploring the potential of AFCDs in a heavy oil environment.

The definition of heavy oil varies between regions and operators. In this section, we define heavy oil as being liquid petroleum with an API gravity of 22° or lower and a viscosity at reservoir conditions of 90 cP or greater. Such heavy oil reservoirs present several challenges (see section 2.2.3.2).

Some of these challenges can be dealt with at the completion level by the application of FCDs to increase oil recovery by improving oil sweep in the reservoir and reducing the
water cut in the production wells (points 1 to 5). Standard techniques used onshore (Production Logging, cement or gel squeezes, setting a plug, isolation with blank pipe, etc.), are not practical offshore where highly deviated wells and high intervention costs limit the scope for such interventions.

The AICD-completion case study on Peregrino field concluded that, the expected effect of ICD/AICD technologies in the field’s heavy oil applications is to balance the inflow along the horizontal well section and to choke back the flow of water [21]. This is expected to increase oil recovery due to:

1- Improved oil displacement in the reservoir.
2- Reduced water production rate in the wells with ICD/AICD, allowing increased production from other wells that would otherwise be choked due to the field liquid production handling capacity constraints.

3.8.2.2 Model description

The model X2 is based on realistic field geometry, fluid properties and relative permeabilities. It contains a single multi-segmented horizontal oil producer with 1250 m completion interval.

Base case completion model includes 25 AICDs and 25 annular packers at 50 m spacing. The model description and properties are provided in Figure 3-36 and Table 3-8.

### Table 3-8: Model X2 properties (more details in Appendix 5)

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>OIIP</td>
<td>20.74 MM SM3</td>
</tr>
<tr>
<td>Permeability Ranging between 10 md ~ 5000 md</td>
<td>0.4</td>
</tr>
<tr>
<td>Kv/Kh</td>
<td></td>
</tr>
<tr>
<td>Oil density at surface</td>
<td>15.6 API</td>
</tr>
<tr>
<td>Oil viscosity at reservoir conditions</td>
<td>90 cP</td>
</tr>
<tr>
<td>Reservoir Pressure at (2240m)</td>
<td>236.68 bar</td>
</tr>
<tr>
<td>Bubble point pressure</td>
<td>43.8 bar</td>
</tr>
<tr>
<td>Solution GOR</td>
<td>13 SCF/STB</td>
</tr>
<tr>
<td>OWC</td>
<td>2361m</td>
</tr>
<tr>
<td>Aquifer</td>
<td>30 times Oil volume</td>
</tr>
<tr>
<td>Cells’ dimensions (m):</td>
<td>50x50x1</td>
</tr>
<tr>
<td>Liquid rate (LRAT) control</td>
<td>(1600sm³/d)</td>
</tr>
<tr>
<td>Bottom-hole pressure limit (BHP)</td>
<td>85 bar</td>
</tr>
</tbody>
</table>
Well X2 is placed near the Oil Water Contact (OWC) ~ 27m with considerably high aquifer support (sector model). The well’s configurations are provided in Table 3-9 and Figure 3-37.

Table 3-9 Well X2 configurations

<table>
<thead>
<tr>
<th>7” open hole</th>
<th>ID (in)</th>
<th>OD (in)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubing</td>
<td>4 7/8</td>
<td>5.5</td>
</tr>
</tbody>
</table>

Figure 3-37: well X2 initial completion

3.8.2.3 Model X2 performance evaluation:

Three main production challenges with this field, expected and observed from the sector model, are:

1. Heavy-viscous oil: the production of such type of oil is normally associated with (a) mobility ratio consideration (water fingers, by-pass oil, etc.) and (b) heel toe effect due to high viscosity in the relatively long horizontal wellbore.

2. Close by contact: early water breakthrough is expected due to the presence of a large aquifer near the well (< 27 m) joint by a high permeability (Table 3-8).
3. Permeability variation: risk of low recovery is present due to the fluid inflow focused at certain locations along the wellbore, by passed oil, sweep efficiency etc. In such conditions, a special attention is required for well completion in order to achieve optimum reservoir management.

Model X2 was initially tested with open-hole completion (i.e. no AWC) for evaluating the fluid movement in the reservoir and the severity of the challenges listed above. The resulting inflow distribution along the wellbore is depicted in Figure 3-38. Two main contributing sections can be observed from the flow rate values at different wellbore sections.

![Figure 3-38: Well X2 open-hole completion fluid inflow distribution for all the segments from (1) at the heel to (25) at the toe](image)

In order to properly evaluate the influx from, as well as the flow in the reservoir the reservoir flow capacity near the wellbore was studied such as:

\[
flow\ capacity = \sum_{z=1}^{z=5} k_x \cdot h
\]

Equation 3-28

Where the z values represents the (k) layer vertical dimension known as (i, j, k) and is selected guided by the streamlines evaluation of the drainage region near the wellbore (for open-hole completion). The resulting flow capacity map is shown in Figure 3-39 where:

- Four main regions for fluid flow within the reservoir (near the well) and into Well X2 can be spotted.
- Streamlines illustrate the directions of flow towards the wellbore as a result of reservoir flow capacity. It shows that 44% of the well length (sections 2 and 4) does not contribute significantly.
- Early water breakthrough observed.

The influx along the wellbore can then be divided into four regions as depicted in Figure 3-40.
Figure 3-39: Near wellbore reservoir flow capacity for well X2

Figure 3-40: Well X2 influx regions. All the segments depicted from (1) at the heel to (25) at the toe

Note: The common industry practice today is to design the AWC using analytical models based on the open-hole well log data and the permeability variation perceived. As mentioned in the introduction to this chapter, such fast solutions are required due to the nature of the completion operation at the wellsite when the well is drilled. However, the study done above for model X2 shows the importance of taking geology in consideration while making changes to the AWC design. The permeability along well X2 is symmetrical, whereas considerable differences can be seen once the geology surrounding the well is considered in the analysis. Totally different performance than that expected for well X2 resulted. To-date, well correlation and the geological model is updated continuously during drilling and changes to the well trajectory are made in real-time based on the data received from the geo-steering equipment (such as the fluid saturations (e.g. near contacts), the structure dipping and the shale/sand sequence etc.). The practice of AWC optimisation and any adjustments to the initial design must take all these valuable information in consideration (see e.g. [77]). This is essential due to the fact that
the AWC have a long term perspective since it is normally fixed and unchangeable during the well’s life. Furthermore, with the fixed completion consideration perhaps more investment (time on the rig) should be allocated for such sensitive/long impact decision. The impact of the geological uncertainty is investigated on this model employing (open-hole, ICD and AICD completions) and presented in chapter 5.

3.8.2.4 AICD completion vs. ICD and open-hole completions

AICD completion shows a superior performance compared to open-hole completion in term of equalizing the fluid influx distribution as shown in Figure 3-41 (full annular isolation is assumed). This is mainly due to the initial control AWC can impose on production rates at various locations along the wellbore (Equation 3-13). However, annulus isolation is essential for the successful application of this technology. In Figure 3-42, the flow from the reservoir block is directed to the relevant AWC joint due to the presence of AFI, whereas, Figure 3-43 shows the same influx as depicted in Figure 3-40 due to the absence of AFI. Without AFI the fluid moves freely in the annulus and is not restricted by the relevant AWC at each section along the wellbore. This is a complex problem, with more details can be found in (Moradi, M., et al., 2014) [84].

![Figure 3-41: Influx distribution with AICD completion (in blue) vs. open-hole completion (in red)](image1)

![Figure 3-42: Well X2 AICD completion with AFI inflow distribution](image2)
Several AICD designs were tested in model X2 with the main objective of improving the cumulative oil production while imposing minimal pressure loss across the completion as described in Figure 3-44. There is a tendency to increasing oil gain by imposing higher restriction at the main water contributing sections for the simulated period of time. The optimum design is selected based on the optimisation study detailed in chapter 5 with the modelling parameters and performance shown in Figure 3-45. The optimum AICD performance is characterized by a large nozzle size to impose a low restriction initially (for oil flow), followed by a gradually increasing restriction to MPF and a very aggressive resistance to single phase water inflows (Figure 3-45). Figure 3-46 shows the recovery for the open-hole, the selected AICD, and the equivalent ICD completions together with the BHP. Other, stricter, ICD designs were also compared against the equivalent ICD size to the selected AICD design (Table 3-10). In Figure 3-47, stricter ICD designs show an improved recovery as a consequence of reducing the well productivity index (PI) and the likelihood of imposing a high pressure drop at the depletion stage (not obvious on this example due to the high aquifer support). The ICD design strategy can differ according to the company’s objective in each application/field. The production plan can be case specific based on pressure, permeability, economics etc. Some wells may benefit from a good level of equalization while the production of others can be significantly affected at the depletion stage.
Figure 3-44: Several AICD designs tested in model X2 to improve oil production and minimise the pressure loss across the completion.

Figure 3-45: Selected optimum AICD design for well X2. The AICD performance “left” and the modelling parameters “right” produced from workflow 1 for the properties listed in Table 3-8.

Figure 3-46: Oil recovery for the open-hole, the selected AICD, and the equivalent ICD completions together with the BHP.
The ICD design is affected by other parameters and not only limited to the points discussed above. Further details on ICD analytical modelling and designs strategies based on long term/short term objectives can be found in (Parakasa, et. al., 2015) [19]. A more comprehensive comparison between AICDs and ICDs designs and a methodology for performance evaluation is provided in chapter 5.

Table 3-10: ICD designs selected for well X2 to compare against AICD-completion

<table>
<thead>
<tr>
<th>ICD design</th>
<th>Nozzle area (mm²) per joint (every 12.5 m of the wellbore section)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equivalent ICD to the selected AICD</td>
<td>48.7</td>
</tr>
<tr>
<td>ICD2</td>
<td>4.0</td>
</tr>
<tr>
<td>ICD3</td>
<td>2.0</td>
</tr>
</tbody>
</table>

Figure 3-47: High strength ICD designs (ICD2 and ICD3) tested in model X2 for oil production (left) and WBHP (right)

A production logging tool (PLT) analysis from reservoir simulation for the cases discussed above {Table 3-10} is presented below for water flow across the production tubing. The well flow with no water production initially and for 1 month {Figure 3-48}. 
The water starts to breakthrough in the middle section as expected from the flow capacity map in Figure 3-39. In Figure 3-49, the AICD and the equivalent ICD completions, with their minimal resistance to oil flow produce higher amount of water compared with the stricter ICD2 and ICD3 completions. ICD3 being of high strength, provides high level of equalization and slightly delayed breakthrough time. However, due to the very close water contact, the water breakthrough occur at the next time step {Figure 3-50}.

Figure 3-49: The water starts to breakthrough in the middle section
Figure 3-50: Due to the very close water contact, the water breakthrough occur at the early time steps even with very high ICD strength.

The water also starts to appear at the heel at 4 months of production for all completions (Figure 3-51). The AICD completion provide high level of water control (similar to a very strict ICD completion) while allowing very high oil production initially (similar to an open hole) (Figure 3-52 to Figure 3-54)

Figure 3-51: The water also start to appear at the heel at 4 months of production for all completions
Figure 3-52: The AICD completion water control compared with ICD completions

Figure 3-53: The AICD completion water control compared with ICD completions
3.8.2.5 Discussion

The results above show that, the ICD completion can be designed with different objectives. Not only to rectify the HTE, but also to control the high PI zones to allow for more oil in the long term. However, one should note that ICDs, being passive completions, can apply high pressure drop at the depletion stage.

Furthermore, the inevitable loss in well’s PI at the early production life (targeting flow equalization), limit their design flexibility to allow for more oil production initially (important for discounted NPV) and optimally controlled production at the breakthrough and depletion stages.

AICDs on the other hand, have different objectives. They are used mainly to control the unwanted fluid upon breakthrough. However, they can still be used to apply the necessary initial control and designed to produce a targeted unwanted fluid control. The optimum unwanted fluid control will vary from reservoir to reservoir and, furthermore, from one zone to the other within the same well. This optimisation is discussed in chapter 5.

Today, operators define the level of equalization required and then either (a) install one of the available AICDs relying on their built in autonomous reaction or (b) ask for a special design that considers the targeted initial flow and then completely shut-off the
zone upon reaching a specific threshold (e.g. AICVs). This practice severely limits that perceived added value from this new technology. As shown in Figure 3-8, an AICD design can involve a sensitivity on the:

1) Optimum initial size (for oil flow).
2) MPF response: very important since majority of the well life will be in this condition (details provided in Chapters 4 and 5).
3) Optimum reaction to single phase unwanted flow (important consideration should be given to the well outflow performance (more details in Chapters 4 and 5).

Figure 3-46 and Figure 3-47 are examples of the different ICD/AICD responses. The examples considered show that it is important to consider both the AFCD’s oil-restrictive and water-restrictive performance. The latter increases in importance as the formation’s heterogeneity increases (several models tested for AFCD optimisation in chapter 5).

In several studies, similar to section 3.8.3.4.2, we concluded that FCD completions with autonomous action (AFCD) autonomous reaction to unfavourable phase is likely to increases robustness of the design. However, the designs should always consider well deliverability (inflow/outflow) at later life when unwanted fluid BT and pressure depletion prevail [24]. The robustness of an optimum selected AFCD design compared with passive ICD design is evaluated in chapter 5 for various purposely built geological uncertainties.

3.8.3 Comparison between Different AICV Modelling Techniques

A conceptual model that is representative of typical oil field production management issues (described below) is used to compare the developed approach for modelling stepwise AFCD-completion performance with the conventional AICD equation (Equation 3-12) as well as the modelling approach provided by Aakre, H., et al., 2014 [85]. The aim is to improve the quantification of the potential of the stepwise AFCDs.

Aakre, H., et al., 2014 suggested the closing sequence, detailed in Table 3-11, in their paper describing the performance of an AICV-completion when exposed to oil and water. The completion used is equipped with 4 valves between a pair of packers employing stratified flow in a horizontal pipe.
Table 3-11: Zonal closing sequence and Water Cut (WC) [85]

<table>
<thead>
<tr>
<th>Number of valves open with oil</th>
<th>Number of valves starting to close (more than 98% water and less than 2% oil)</th>
<th>Number of valves closed</th>
<th>Water Holdup/critical water cut (CWC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>1</td>
<td>0</td>
<td>0.2</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>1</td>
<td>0.25</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>2</td>
<td>0.33</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>3</td>
<td>0.5</td>
</tr>
<tr>
<td>0</td>
<td>1</td>
<td>4</td>
<td>0.98</td>
</tr>
</tbody>
</table>

3.8.3.1 Model-OW Description

The model-OW used for this study was made analogous to an existing field employing AWC technology. The field is characterized by several reservoir units of two types of sandstone, a coarse-grained sand with permeability layers varying between 500 and 1000 milli-Darcies and a fine-grained sand of 50 to 300 milli-Darcies. This reservoir description was reproduced in a synthetic model by a repeating series of reservoir layers with a wide range of permeabilities that cut the path of the horizontal well (Figure 3-55). The permeability was distributed stochastically within the specified range for each sand type and appropriate porosity and relative permeability tables specified. Strong aquifer support is applied and the model is filled with a heavy oil of 18 API gravity and 90 Cp viscosity at downhole conditions.

Figure 3-55: A) the synthetic model-OW with repeating Sand units of varying permeability. B) Enlarged cross section along the wellbore showing the horizontal well penetrating multiple sand units.

The model-OW employed the following production and wellbore constraints during optimization process:

1. Each FCD joint is 12 m long and may have 1 and up to 4 nozzles.
2. FCD maximum open to flow diameters considered are similar to the Nozzle sizes as per Table 3-1.
3. Each wellbore segment (50 m) can have up to four joints.
4. Packers are located between all wellbore model segments, i.e. annular flow between the segments is not allowed (but allowed between the packers).

5. Flow rate is 3000 (Sm$^3$/day).

6. Well length (2300 m).

7. 100 bar minimum flowing bottom whole pressure (BHP) limit.

3.8.3.2 Results and Comparison

Variations in the reservoir permeability coupled with heel toe effect, result in an unbalanced fluid influx rate along the horizontal wells. This naturally leads to accelerating the breakthrough of unwanted fluids, limiting the sweep efficiency and reducing the oil recovery.

With passive ICD-completion, “as expected” some locations along the length of the horizontal well experienced earlier water production compared to others. The ICD completed well, continued to produce with no down-hole control after breakthrough.

Three other scenarios were then tested. These scenarios employed AFCD-completion modelled in three different methods as follows:

   (1) The closing sequence provided in Table 3-11.
   (2) The new equation for stepwise AFCDs.
   (3) AICD conventional equation {Equation 3-12}.

Figure 3-56 shows a comparison for the pressure drop across completion for one section along the wellbore. As can be observed from Figure 3-56 (a), the test was made such that all scenarios produce the same flow resistance for oil and only starts to differ/deviate after breakthrough. Figure 3-56 (2) shows that, ICD-completion remain passive and cannot differentiate based on the produced fluid. However AFCD started to react by imposing additional resistance to flow upon breakthrough. Notably, the new equation is in agreement with the published performance provided in Table 3-11. The conventional AICD model {Equation 3-12} fails to capture the stepwise nature of the device reaction to water breakthrough. Instead, Equation 3-12 results in a continuously increasing resistance to flow with advancing unwanted fluid fractions.
On the other hand, a stepwise AFCD-completion reacts at specific flowing conditions and maintain the position after that. This can be observed in the initial period whereby the cases of the new equation as well as the closing sequence demonstrated a higher pressure drop across completion as it reacts more aggressively compared with the simple MPF approximation employed by Equation 3-12 which does not take in consideration a stratified flow environment. At later production period the pressure drop across Equation 3-12 continues to improve, due to the advancing water, and is larger than that of the stepwise approach for which the next reaction step (closing a valve) is yet to be triggered. The final results is a much higher pressure drop across Equation 3-12 as compared with the stepwise modelling approach (Figure 3-57). It is important to highlight the instability in well performance predicted at late production period in Figure 3-57. This is associated with the valve’s step reaction. At late life, several locations along the well are invaded by water and the valves start to react and close.

The “unlikely” additional restriction and control applied by Equation 3-12 (described above) results in improvement in oil production from the less productive zones across the well in comparison to other scenarios. Therefore Equation 3-12 is considered to be over estimating (in this case) the expected ultimate recovery when evaluating the stepwise AFCDs potential (Figure 3-58).
3.8.3.3 Discussion

A novel approach developed to incorporate into a reservoir simulator, the flow performance of a downhole flow control completion equipped with flow control devices discriminating flowing fluids. We presented a realistic approach to model (stepwise) AFCD performance that takes into account:

1) Reservoir inflow performance.
2) The AICV performance.
3) The annular flow segregation.

The “homogeneous flow” modelling approach that is traditionally assumed in reservoir simulators is found to be inaccurate and may overestimate the well’s potential.

The proposed approach is in agreements with the published performance for one of the existing AFCDs.
3.9 Conclusion

AFCD-completions are frequently designed using steady-state well production simulators, though input from a dynamic, reservoir simulator is preferred. Numerical simulation allows a superior (important) physics embodiment than analytical models. This is of particular importance in evaluating and understanding new concepts and ideas for improved oil recovery. Hence, enhanced prediction, optimization and quantification of the AWC Added Value can be perceived.

To date, commercial reservoir simulators provide just one equation to capture the underlying physics of all AFCD types. To our knowledge, no guidance or proof is available as to whether it captures the multi-phase performance of AFCDs accurately, or the trio of parameters $x$, $y$, $a_{\text{AICD}}$ can be translated to the situation of different fluid properties, or what combinations of $x$, $y$, $a_{\text{AICD}}$ are actually physically possible for the AFCD completion design studies.

This chapter provides detailed guidelines for AFCD performance modelling along with workflows that allow engineers to evaluate the viability of an AFCD completion and its potential added-value.

AFCD performance models that honours published data are presented. Equations and modelling recommendations for several commercial AFCDs along with a range of modelling options are presented with the pros and cons of each identified. The AFCDs’ stand-alone MPF impact was evaluated.

The methods and workflows have been validated using actual data whenever possible or with synthetic data, and have been implemented in several scenarios which are representative of typical oil field production management issues. The analysis of these scenarios was made possible by the development of a novel methodology to verify the applicability of different types of AFCDs and their impact on production which also allowed optimization of the AFCD-design (further detail in chapter 5).

Chapter 3 discussions are concerning a standalone AFCD modelling. The impact of annulus multiphase flow is addressed in chapter 4 (next).