A Comprehensive Approach to the Design of Advanced Well Completions

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A thesis submitted for the degree of Doctor of Philosophy

Institute of Petroleum Engineering

Heriot-Watt University

Edinburgh – Scotland, UK

March, 2013

Volume I

This Thesis is submitted in two volumes

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Abstract

Advanced Well Completions (AWCs) employing Downhole Flow Control (DFC) technology such as Inflow Control Devices (ICDs), Interval Control Valves (ICVs), Autonomous Inflow Control Devices (AICDs) and/or Annular Flow Isolations (AFIs) provide a practical solution to the challenges normally encountered by conventional wells. Both oilfield operating companies and several researchers have developed workflows to identify the optimum well location and field development well configuration. However, all these approaches do not at present consider optimising advanced well completions employing DFCs.

The objective of this thesis is to provide an automated, comprehensive workflow to identify the optimum advanced well completion design that ensures an optimum well performance throughout the well’s and field’s life.

This study starts by describing the history of ICD, AICD, ICV and AFI development with emphasis on the (near and) fully commercially available types and their areas of application. The thesis then reviews the flow performance of available ICD, ICV and AICD types. It reviews the available advanced completion modelling techniques and their historical development. This allows provision of guidelines on how to model DFC technologies performance when combined with AFIs over the well’s life. It shows how the value of such well-construction options can be quantified using these tools.

The thesis introduces a novel workflow outlining the process of designing ICD completions with or without AFIs for different well architectures applied in different reservoir types for production or injection purposes. The workflow incorporates: the ICD restriction sizing; the requirement for AFI, their frequency and distribution; the impact of ICD reliability throughout the life of the well, the effect of uncertainty on the design parameters, installation risks and the resulting economic value.

This workflow is then extended to the design and evaluation of AICD completions, through identification of the optimum control of water and excess gas production.

The value and applicability of the proposed workflow is verified using synthetic and real field case studies. The latter include three oil fields (H-Field, S-Field and U-Field), one thin oil column/gas condensate field (NH-Field) and a gas field (C-Field). These cases also illustrated the value which can be gained from the application of Downhole Flow Control technologies.
Dedication

I dedicate this thesis to “Allah” followed by my beloved mother (Fatima Marzoq Al-Khelaiwi) and father (Turki Manee Al-Khelaiwi) for their prayers, support and encouragement. I also dedicate this work to my wife (Amal) my son (Albaraa) and my daughter (Khowla) for their patience.
Acknowledgement

In the Name of Allah, the Most Gracious, the Most Merciful

First and foremost, I would like to acknowledge my study supervisor (Professor David R. Davies) for his guidance, continuous support and encouragement during the course of this study.

My gratitude goes to the Management of Saudi Aramco for their financial and moral support as well as Heriot-Watt University “IW&FsT” JIP members for their valuable discussions during this study. My special thanks to Odd.Helge-Inderhaug, Roger Nibo, Sigurd Erlandsen, Peter Griffith, Richard Straub, Line Skarsholt for provision of the field models. I also would like to thank Mike Konopczynski and A. Ajayi for initiating the ICD and ICV comparison study.

I would like to express my appreciation to the staff at the Institute of Petroleum Engineering at Heriot-Watt University including: Alan Brown, Claire MacMillan and Anne Mothers for their support.

I extend my thanks to the “IW&FsT” team members, Dr. Salem Elmsallati, Dr. Farhad Ebadi, Dr. Fajhan Al-Mutairi, Dr. George Aggrey, Dr. Vasily Birchenko, Dr. Khafiz Muradov, Dr. Yang Qing, Yousef Rafiei and Ivan Gerbenkin for the fruitful discussions.

I also would like to thank Geoquest, AGR, PETEX, Sciencesoft and EPS for provision of their software.

I would like to appreciate all the support and encouragement that I received from my family members and friends including: Mashhoor, Tahani, Amani, Afnan, Nada, Shoroug, Majed, Aunt Liz, Uncle Ali, Uncle Sami, Uncle Saleh, Faisal, Ali, Fawaz, Naif, Othman and Mohamad.

Finally, most deeply and most patiently, I sincerely thank my mother (Fatima), father (Turki), wife (Amal) and children (Albaraa and Khowla) for their prayers, moral support and patience.
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Nomenclature

Symbols

\(A\) Drainage area (ft\(^2\))
\(A\) Multiplier
\(a\) \((A)ICD\) strength value (psi/(rft\(^3\)/day)\(^x\) or bar/(rm\(^3\)/day)\(^x\))
\(Aor\) Orifice strength rating values
\(Anz\) Nozzle strength rating values
\(avg\) Values at the average pressure
\(b\) Extension of the drainage volume in the y direction (ft)
\(B\) Formation volume factor (bbl/stb or rm\(^3\)/Sm\(^3\))
\(C_{(Re)}\) Discharge coefficient based on Reynolds number (dimensionless)
\(C_d\) Discharge coefficient based on the valve position (dimensionless)
\(C_f\) Conversion factor
\(C_u\) Conversion factor
\(CVX(X)\) Valve flow coefficient as a function of the valve position X
\(d\) Diameter (m or ft)
\(D\) Diameter (m or ft)
\(De\) Dean Number
\(e\) Acceptable accuracy
\(f\) Fanning friction factor
\(h\) Reservoir (segment) height (ft)
\(i\) Segment number
\(ICDR_{bar}\) ICD rating in bar
\(ID\) Inner diameter
\(J_s\) Specific productivity index (stb/day/psi)
\(K\) Pressure loss coefficient
\(k\) Permeability (md)
\(L\) Length (feet or meter)
\(l\) Length (ft)
\(n\) Number of stages
\(o\) Extension of the drainage volume in the x direction (ft)
\(OD\) Outer diameter
\(PI\) Productivity Index
$P$  Pressure (psi or bar)
$q$  Volumetric flow rate
$Q$  Volumetric flow rate
$R$  Producing gas-liquid ratio (scf/bbl)
$re$  Drainage radius (ft)
$Re$  Reynolds number
$R_f$  Absolute roughness of the pipe
$rw$  Wellbore radius (ft)
$s$  Formation damage (Skin)
$S$  Formation damage (Skin)
$S.G.$  Specific Gravity
$SV$  ICV opening size (1/64th in)
$T$  Temperature (°R)
$x$  Volume flow rate exponent (dimensionless)
$x_b$  Extension of the drainage volume in the x direction (ft)
$xo$  x coordinate of centre of segment
$x_n$  Effective nozzles diameter
$y$  Viscosity function exponent (dimensionless)
$z_o$  Z coordinate of centre of segment
$a_{o,g,w}$  Volume fraction of oil, gas and water phases at in-situ conditions
$\beta$  Ratio of restriction diameter to upstream pipe diameter (dimensionless)
$\delta P$  Pressure drop across the restriction (psi or bar)
$\epsilon$  Gas expansibility factor (dimensionless)
$\epsilon_w$  Inversion Water cut
$\lambda$  Curvature ratio
$\mu$  Fluid viscosity (cp, Kg/m-s or Pa-s)
$v$  Fluid flow velocity (m/s)
$\rho$  Fluid density (lb/ft$^3$ or Kg/m$^3$)
### Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>3D</td>
<td>Three Dimensions</td>
</tr>
<tr>
<td>4D</td>
<td>Four Dimensions</td>
</tr>
<tr>
<td>AFI</td>
<td>Annular Flow Isolation</td>
</tr>
<tr>
<td>AICD</td>
<td>Autonomous Inflow Control Device</td>
</tr>
<tr>
<td>(A)ICD</td>
<td>Autonomous and Passive Inflow Control Devices</td>
</tr>
<tr>
<td>AICV</td>
<td>Autonomously Actuated Inflow Control Valve</td>
</tr>
<tr>
<td>AWC</td>
<td>Advanced Well Completions</td>
</tr>
<tr>
<td>Bar</td>
<td>Pressure unit</td>
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<tr>
<td>CAPEX</td>
<td>Capital Expenditure</td>
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<tr>
<td>CFD</td>
<td>Computational Fluid Dynamics</td>
</tr>
<tr>
<td>CLF</td>
<td>Control Line Free Inflow Control Valve</td>
</tr>
<tr>
<td>Conv</td>
<td>Conventional Completion</td>
</tr>
<tr>
<td>cp</td>
<td>Centipoise (viscosity unit)</td>
</tr>
<tr>
<td>D</td>
<td>Darcy</td>
</tr>
<tr>
<td>DFC</td>
<td>Downhole Flow Control</td>
</tr>
<tr>
<td>DP-ICV</td>
<td>Discrete Positions Inflow Control Valve</td>
</tr>
<tr>
<td>DPr</td>
<td>Different Pressure Regime</td>
</tr>
<tr>
<td>DTS</td>
<td>Distributed Temperature Sensing</td>
</tr>
<tr>
<td>Dv</td>
<td>Deviated</td>
</tr>
<tr>
<td>ECP</td>
<td>External Casing Packers</td>
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<tr>
<td>ED</td>
<td>Electrically Actuated Inflow Control Valve</td>
</tr>
<tr>
<td>ERA</td>
<td>Electrode Array Resistivity</td>
</tr>
<tr>
<td>ESP</td>
<td>Electric Submersible Pump</td>
</tr>
<tr>
<td>ESS</td>
<td>Expandable Sand Screens</td>
</tr>
<tr>
<td>EZIP</td>
<td>External Zonal Isolation Profiler</td>
</tr>
<tr>
<td>ft</td>
<td>Feet</td>
</tr>
<tr>
<td>G</td>
<td>Gas</td>
</tr>
<tr>
<td>GAP</td>
<td>General Application Program</td>
</tr>
<tr>
<td>GOC</td>
<td>Gas Oil Contact</td>
</tr>
<tr>
<td>GOR</td>
<td>Gas Oil Ratio</td>
</tr>
<tr>
<td>GP</td>
<td>Gravel Packs</td>
</tr>
<tr>
<td>GWC</td>
<td>Gas Water Contact</td>
</tr>
</tbody>
</table>
H  High Dependence
HC  Helical Channel-type ICD
HCl  Hydrochloric acid
HD  Hydraulically Actuated Inflow Control Valve
Hr  Horizontal
HTE  Heel-Toe-Effect
I  Injector
ICD  Inflow Control Device
ICV  Interval Control Valve
ID  Internal Diameter
IGI  Internal Gas Injection
in  Inch
IPR  Inflow Performance Relationship
IsGL  In-situ Gas Lift
ISO  International Organisation for Standardisation
Kg/m³  Kilogram per cubic meter
L  Low Dependence
LT  Long Tube
M  Moderate Dependence
m  meter
md  millidarcy
ML  Multilateral
mm  millimeter
N  No dependence
N  Number of Inflow Control Valves installed in a completion
NZ  Nozzle-type ICD
OD  Outer Diameter
On/Off  Fully Open or Fully Close positions of an Inflow Control Valve
OPEX  Operating Expenditure
OWC  Oil Water Contact
P  Producer
PFP  Perforated Pipes
Poly.  Polynomial
PPL  Pre-Perforated Liners
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>PPSAS</td>
<td>Pre-Packed Stand-Alone-Screen</td>
</tr>
<tr>
<td>PSC</td>
<td>Passive Stinger Completion</td>
</tr>
<tr>
<td>PVM</td>
<td>Parallel Virtual Machine</td>
</tr>
<tr>
<td>PVT</td>
<td>Pressure/Volume/Temperature</td>
</tr>
<tr>
<td>RFID</td>
<td>Radio Frequency Identification</td>
</tr>
<tr>
<td>SAS</td>
<td>Stand-Alone-Screens</td>
</tr>
<tr>
<td>scf</td>
<td>Standard cubic feet</td>
</tr>
<tr>
<td>Scf/stb</td>
<td>Standard cubic feet per stock tank barrels</td>
</tr>
<tr>
<td>SCRAMS</td>
<td>Surface-Controlled Reservoir Analysis and Management System</td>
</tr>
<tr>
<td>SFC</td>
<td>Swellable Flow Constrictors</td>
</tr>
<tr>
<td>Sm$^3$/day</td>
<td>Standard cubic meters per day</td>
</tr>
<tr>
<td>Sm$^3$/day/bar</td>
<td>Standard cubic meters per day per bar</td>
</tr>
<tr>
<td>Sm$^3$/day/ICD</td>
<td>Standard cubic meters per day per bar per Inflow Control Device</td>
</tr>
<tr>
<td>SP</td>
<td>Swellable Packers</td>
</tr>
<tr>
<td>SPL</td>
<td>Slotted Liners</td>
</tr>
<tr>
<td>SSD</td>
<td>Sliding Side Doors</td>
</tr>
<tr>
<td>ST</td>
<td>Short Tube</td>
</tr>
<tr>
<td>stb</td>
<td>Stock tank barrel</td>
</tr>
<tr>
<td>stb/day</td>
<td>Stock tank barrel per day</td>
</tr>
<tr>
<td>stbo/day/psi</td>
<td>Stock tank barrel of oil per day per pound per square inch</td>
</tr>
<tr>
<td>stbo/day/ICD</td>
<td>Stock tank barrel of oil per day per Inflow Control Device</td>
</tr>
<tr>
<td>Stim</td>
<td>Stimulation</td>
</tr>
<tr>
<td>Super-K</td>
<td>Very high Permeability (&gt;10,000 millidarcy)</td>
</tr>
<tr>
<td>UDQ</td>
<td>User Defined Quantity</td>
</tr>
<tr>
<td>V</td>
<td>Vertical</td>
</tr>
<tr>
<td>VLP</td>
<td>Vertical Lift Performance</td>
</tr>
<tr>
<td>VPE</td>
<td>Variable-Productivity-Effect</td>
</tr>
<tr>
<td>VP-ICV</td>
<td>Variable Positions Inflow Control Valve</td>
</tr>
<tr>
<td>W</td>
<td>Sand Flow rate (Kg/s or Kg/day)</td>
</tr>
<tr>
<td>WAG</td>
<td>Water-Alternating-Gas</td>
</tr>
<tr>
<td>WC</td>
<td>Water Cut</td>
</tr>
<tr>
<td>%</td>
<td>Percentage</td>
</tr>
<tr>
<td>&quot;</td>
<td>Inch</td>
</tr>
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List of Publications and Presentations by the Candidate


Chapter 1  Introduction and Motivation

Optimal exploitation of Hydrocarbon resources from different types of geological traps requires the utilisation of wells with different architectures (ranging from vertical to extended reach multilateral) while individual well objectives include:

- Exploration and appraisal
- Observation
- Hydrocarbon production
- Water, gas, steam or air injection
- Etc.

Horizontal and multilateral completions are a proven, superior development option compared to conventional solutions in many reservoir situations. This is due to their ability to improve sweep efficiency, delay water or gas breakthrough by reducing the localised drawdown and distributing of the fluid influx over a greater wellbore length. However, these wells also present many challenges caused by their complexity and the increased length of the well’s exposure to the reservoir. These challenges include: 1) drilling and completion, 2) clean up, 3) stimulation and 4) reservoir drainage control.

However, a major challenge facing all well architectures is premature breakthrough of water in both oil and gas production wells and also gas in oil production wells. Similarly, a major challenge facing all injection wells is the uneven distribution of the injected fluid. Both challenges can be caused by:
- Reservoir productivity heterogeneity.
- Variations in the reservoir pressure in different regions or layers of the reservoir penetrated by the wellbore.
- Variation of the fluid properties in reservoir sections crossed by the wellbore.
- The frictional pressure in horizontal wellbores that leads to a difference in the specific influx rate between the heel and the toe of the well, especially when the reservoir is (relatively) homogeneous.
- Variations in the distance between the wellbore and fluid contacts e.g. due to multiple fluid contacts, an inclined wellbore, a tilted oil-water contact, etc.
- Variation in the distance between the wellbore and reservoir boundaries e.g. inclined reservoirs.

Advanced Well Completions (AWCs) employing Downhole Flow Control (DFC) technology such as Inflow Control Devices (ICDs), Interval Control Valves (ICVs) and/or Autonomous Inflow Control Devices (AICDs) provide a practical solution to all these challenges.

AWC combined with newly developed reservoir management techniques optimise the recovery of modern, complex completions. DFC technologies deployed in the wellbore and along the tubing provide an unprecedented ability to support these objectives. 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.

Annular flow, leading to severe erosion "hot-spots" and/or the plugging of screens, is another challenge faced when advanced well completions are applied in a high permeability, low strength formations. Fractured, layered and more heterogeneous formations require, in addition to the installation of DFC, the installation of Annular Flow Isolation (AFI). The “traditional” External Casing Packers (ECPs), ranging from mechanically to inflatable set devices, have been extended by the addition of the new technologies of Swellable Packers (SP) and Swellable Flow Constrictors (SFC). The latter provide this annular isolation in an operationally simple manner.

Intelligent well and field development and management processes rely on the development of geologic, analytical and numerical engineering models and their subsequent updating as more information becomes available. Activities include 3D-seismic interpretation and its integration with geologic attributes for mapping reservoir
horizons, structure, and faults. This is followed by populating the simulation grid with rock and petrophysical properties. Multiphase flow simulation and generation of alternative field development plans are then explored. Previously, such development plans relied on the application of conventional wells with minimal emphasis on the well configuration or completion performance. Continuous updating and history matching of such models with production and 4D-seismic data are essential to ensure optimum exploitation of the hydrocarbon resource.

This process has to change with the advent of Advanced Well Completions. Downhole Flow Control technologies enabled field and well redevelopment without the need for workovers or interventions. While updating models is the ideal application of the data generated by the permanent sensors installed in the advanced well completions (Figure 1-1). This resulted in the onset of two new processes (Figure 1-1):

1. A real or semi-real-time, iterative production optimisation strategy based on continuously updated models and intelligently controlled advanced completions.
2. An automated comprehensive workflow incorporating the modelling, design and optimisation of non-conventional well configurations and advanced completions.

![Figure 1-1: Field development planning](image)
Several researchers as well as field operators have developed workflows to identify the optimum well location (vertical, horizontal or multilateral configuration) within the reservoir. These workflows often consider uncertainties in the reservoir and well as well as field and facility operating parameters. Some of these approaches have proposed selection methodologies for the optimum well completion from a sand production control perspective. However, all approaches published to-date did not consider optimising the AWCs employing DFCs.

The overall objective of this thesis then is to provide a practical workflow to identify the optimum advanced well completion design that ensures an optimum well performance throughout the well’s and field’s life.

1.1 Thesis Objective

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 (PFP) 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.

The recently introduced “Reactive” or Autonomous ICD achieves not only passive control of the fluid influx along the wellbore; but also reactive control of the unwanted fluids (gas and water). The new device is Autonomous in the sense that it does not require any (human or artificial) intervention to reduce its inflow area at the onset of water or excess gas production.

An ICV is an “Active” downhole flow control valve which is operated remotely (from the surface) through a hydraulic, electric, electro-hydraulic or wireless actuation system. Different ICV trim designs and functionality (ranging from on/off to infinitely positioned valves) are commercially available. Hundreds of wells around the world are now equipped with remotely operated ICVs of varying complexity and capability.

The rapid acceptance and deployment of the ICV technology compared to ICDs and AICDs triggered a great interest in studying and further developing a management technology for their operation. Over the past ten years, many researchers as well as operators have proposed numerous techniques to customise the design, facilitate the installation, optimise the operation and enhance the reliability of such valves. Some of these techniques will be summarised later in this thesis.

By contrast, ICDs have only gained popularity in the past 5-6 years outside their initial application in the Troll field some years ago. Recently, ICD applications have
increased almost exponentially; with only limited number of studies being available. AICDs are still in the concept development and evaluation phase with only two reported installations to date. The above were the main drivers behind the initiation of this study and publication of this thesis which proposes a methodology to design the ICD, AICD and AFI completions for both production and injection wells and will shed light on possible application environments for these developing technologies.

1.2 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 describes the history of ICD, AICD, ICV and AFI development with emphasis on the available types and their areas of application. The ICD’s, ICV’s, AICD’s and AFI’s flexibility will be shown by their integration with each other and other conventional and advanced production and injection technologies (such as gravel packs and distributed flow monitoring systems) in vertical, horizontal and multilateral wells. In addition, currently unexplored applications of these technologies will be proposed. The chapter also summarises the results of a comprehensive, comparative study of the functionality and applicability of the DFC technologies. It provides a basic selection criteria based on the thorough analysis of the DFC’s advantages in major reservoir, production, operation and economic areas. The systematic approach and tabulated results of this comparison form the basis of a screening tool of the potential applicable control technology for a wide range of situations.

Chapter 3 studies the flow performance of available ICD, ICV and AICD types. It reviews available advanced completion modelling techniques and their historical development. It also provides guidelines on how to model their performance when combined with AFIs over the well’s life. It will be shown how the value of such well-construction options can be quantified using commercially available, simulation and author developed tools. These techniques will thus be used as part of the value quantification process for both the evaluation of completion options and for their detailed design.

Chapter 4 focuses on “Passive” flow control devices (ICDs). It introduces a workflow outlining the process of designing ICD completions with or without AFIs for vertical, deviated, horizontal and multilateral wells drilled in homogeneous, heterogeneous or layered reservoirs for production or injection purposes. The workflow
incorporates: identifying an AFI requirement, AFI frequency and distribution; the impact of ICD reliability throughout the life of the well on economic performance; the effect of uncertainty in the reservoir parameters; installation risks and the resulting economic value.

**Chapter 5** builds on the workflow developed for ICD completion design to evaluate “Reactive” inflow control devices (AICDs). It outlines a methodology to identify the optimum initial opening area, the optimum value of the Gas Oil Ratio (GOR) or Water Cut (WCT) that triggers choking and the optimum choke sizes (variable or constant) that ensure optimum well performance when completed in different reservoir and fluid types.

**Chapter 6** contains six case studies. These include three oil fields (Channelised reservoir, H-Field and S-Field), a thin oil column/gas condensate field (NH-Field), a gas field (C-Field) and a water-alternating-gas (WAG) injection well (U-Field). These case studies will be used to illustrate the applicability of the developed techniques and the value gained from their application in the design and identification of the optimum DFC for each case. The chapter will also include synopses of the author’s publications summarising the work conducted during the course of this study. This work aims to enhance the value gained from AWCs.

**Chapter 7** summarises the conclusions of this study and provides recommendations for future research.
Chapter 2  Introduction to Advanced Well Completions

2.1  Introduction

Horizontal and multilateral wells have become the basic well architecture in many current field developments. Advances in drilling technology during the past 20 years facilitated the drilling and completion of long (extended reach) horizontal, multilateral and “snake” wells whose primary objective is to maximise the reservoir contact and intersect multiple layers (reservoirs). The increase in reservoir exposure through an extended well length helped lower the drawdown pressure required to achieve a given production flow rate by enhancing the well productivity [1, 2]. Major operators have proved the ability of such wells to increase the field’s reserves and to decrease the unit technical costs. The production from thin oil column reservoirs (e.g. parts of the Troll West Field) has become a reality thanks to such wells [3, 4].

However, the increase in wellbore length and exposure of different reservoir facies and layers comes at a cost. Frictional pressure drop caused by fluid flow in horizontal sections results in higher drawdown-pressure in the heel section of the completion; causing an unbalanced fluid influx. Coning of water and/or gas toward the heel of the well will be observed after some time. Variable distribution of permeability, layering, pressure and/or fluid properties along the wellbore and laterals will also result in a variation of the fluid influx along the completion, early breakthrough of unwanted fluids and uneven sweep of the reservoir.

Annular flow is another challenge often encountered when horizontal wellbores are completed with SAS, Pre-Perforated Liners (PPL) or Slotted Liners (SPL). These completions do not normally employ any form of isolation between the casing and the
formation (i.e. ECPs). However, evidence of annular flow has been observed in such completions, even when limited number of annular flow isolations was installed (Figure 2-1). Annular flow is a function of many parameters; such as the size of flow area between the sandface and the liner (or screen) outer diameter, the production rate, etc. The presence of annular flow results in the erosion and transport of sand grains. This causes erosion of the sandface and the formation of "hot-spots" through erosion and plugging of the sand screens [5, 6]. Gravel packs (GP) or Expandable Sand Screens (ESS) can minimise (or eliminate) annular flow; but often also have a significant impact on the well productivity and/or involve a complex installation operation [6, 7].

Advanced Well Completions (AWC) provide a solution to all such challenges.

Advanced Well Completions (AWC) are completions that are capable of managing the fluid flow into or out of the length of the wellbore in order to optimise the well performance. This objective is achieved through employment of DFC technologies such as ICDs, AICDs and ICVs combined with AFIs.

An ICD is a sandface completion technology specifically developed to help balance the flow contribution along the length of the wellbore. Extensive flow-loop testing and subsequent field experience have proved the ability of ICDs to increase the field reserves by extending the well’s production plateau period, minimising the water/gas coning and minimising annular flow velocity.

AICDs are advanced form of ICDs, which combine both passive and reactive control of fluid influx. An AICD is a combination of an ICD and a fluid phase-sensitive (e.g. density-sensitive) valve that reduces the flow area open to a specific wellbore segment.

Figure 2-1: Annular flow in SAS completion with limited number of AFIs [8]
based on changes in the produced fluid phases. The changes in the flowing fluid phases are often caused by influx of gas or water. Although, this technology has not yet been proven in the field, it is expected to add value to the well performance by autonomously controlling gas influx in oil wells and water influx in oil or gas wells.

ICVs combine the function of ICDs and AICDs due to their capability of imposing a proactive as well as a reactive form of well inflow control. The proactive control advantage of ICVs could be based on the provision of an equalised intervals contribution. Alternatively, they can be managed by reservoir simulation models which are continuously updated with the information provided by pressure, temperature, electromagnetic or seismic monitoring systems installed along the length of the complete wellbore [9] which can detect an approaching water and/or gas front. Similarly, downhole flow rate, pressure, temperature and phase cut measurement devices, either individually or in combination, provide the necessary information to reactively control the individual zones after the breakthrough of unwanted fluids.

AFI is a crucial part of an ICD, AICD and ICV completions to ensure the maximum incremental value due to their installation is achieved. These technologies can be applied individually or in combination in well architectures ranging from vertical to multilateral wells designed for either production or injection purposes. Examples of the integration of these components in horizontal and multilateral well completions are illustrated in Figure 2-2 and Figure 2-3. In addition, ICVs could also have been installed within the ICD base pipe in these figures. Each supplier provides a different mechanical design for each of these technologies. Their differences and similarities are summarised in the following sections of this chapter.

Figure 2-2: (A)ICD and AFI wellbore placement. N.B. Annular isolation may be installed at each joint or between multiple joints
2.2 Advanced Well Completion Components

Advanced well completions may incorporate many components ranging from sensing to flow control devices. However, in this thesis, only DFC technologies (ICDs, AICDs and ICVs) available as of year 2010 and their primary auxiliary component (AFI) are studied.

2.3 Historical Development of Downhole Flow Control Devices (ICDs)

Norsk Hydro introduced the ICD technology in the early 1990s as a means to enhance the performance of Troll Field horizontal wells. The Troll field is a giant gas field located on the Norwegian shelf of the North Sea. A thin oil column (4-27 meter thick) is overlain by a large gas cap and underlain by an aquifer in the western part of the field. The field was originally developed as a gas field in the “thin-oil-column” part of the field since the production of such thin oil column was deemed non-viable using conventional wells. Two horizontal wells were then drilled and long-term well tests were conducted to determine the ability of such wells to economically drain the oil [10, 11]. The wells were completed with large diameter, pre-packed, slotted liners to reduce the effect of frictional pressure losses along the wellbore. The results of the long-term, tests indicated that a significant oil production potential existed. A very high well PI of ~ 6,000 Sm³/day/bar was measured. This is some 5 - 10 times higher than that expected from a vertical well. Only a small drawdown pressure of 0.5 – 1.0 bar is thus sufficient to produce the well at a target rate of 3,000 – 5,000 Sm³/day.

A new field development plan was then developed based on horizontal wells. However, the production logging of the first test well indicated that 75% of the production was coming from the first half of the horizontal section. This is indicative of the significant effect frictional pressure losses along the length of the completion can
have on the well performance. The frictional pressure drop was shown to be of a similar order of magnitude to that of the drawdown [10].

Three completion options were proposed to overcome this problem:

- A “Passive Stinger Completion” (PSC) (Figure 2-4),
- A variable density perforation programme (Figure 2-5) and
- An innovative Device to control the inflow: the ICD [12].

A PSC consists of an extended tubing installed in the horizontal section to shift the inflow point from the heel of the well to a point near the middle of the horizontal section; reducing the pressure difference between the heel and toe of the horizontal section to the inflow point and the toe (Figure 2-4).

![Figure 2-4: A “Passive Stinger Completion”](image)

A variable perforation density completion reduces the fluid influx to the heel section of the well by limiting the number of perforations in that section compared to the well’s toe section (Figure 2-5).

![Figure 2-5: Variable Perforation Density controls fluid coning at the heel of the well](image)

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 2-6). 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. The labyrinth channels’ length and diameter could be adjusted to achieve the required pressure drop to balance the inflow along the length of the completion. Reservoir simulation studies indicated that the best completion option was to install the ICDs along the length of the completion resulting in an extension of the plateau period by 50% [12]. This design was commercially developed by the inventor (Inventech, originally a subsidiary of Ziebel and later a subsidiary of Tejas [13]) of this concept. A similar ICD design was then produced by Baker Oil Tools for commercial manufacturing by altering the labyrinth channels design to helical channels.

![The original Inflow Control Device](image)

**Figure 2-6:** The original Inflow Control Device [12]

### 2.4 Passive Flow Control: Inflow Control Devices (ICDs)

ICDs can also be called Passive Flow Control devices due to their inactive flow control nature. The pressure drop through the ICD will change if the type of fluid flowing through the ICD restriction changes. However, the ICD restriction cannot be adjusted after the equipment is installed in the wellbore. 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.

### 2.5 ICD Types

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). All these ICD designs can either be mounted on a SAS for application to unconsolidated formations, or they can be combined with a debris filter (to prevent blockage of the flow restriction) when used in a consolidated formation. The produced fluid passes through the screen (or debris filter) along the outer surface of the base pipe into an ICD chamber where a specially designed restriction is constructed in all ICD types (the Flotech-FloMatik ICD is an exception). The fluid then flows into the inner section of the base pipe (Figure 2-7). The Flotech-FloMatik ICD differs from this design since the fluid flow is from the formation (annular space), through the ICD restriction and then into the inner section of the base pipe. The fluid flow path is reversed for injection applications.

**Figure 2-7: General ICD fluid flow path**

### 2.5.1 Labyrinth Channel-type ICD

The Labyrinth-type ICD uses a labyrinth channel to create the pressure resistance (Figure 2-8) [14]. Produced fluids pass through the screen into a chamber where a specially designed labyrinth fluid flow path is constructed. The length and diameter of the labyrinth channel is chosen so as to produce the desired pressure drop across the device at a specific flow rate. The pressure drop created by the fluid flow; through the channel is highly dependent on the fluid viscosity and velocity but it is less dependent on density; especially when the tool is installed in a perfectly horizontal wellbore. This dependence on frictional pressure losses rather than acceleration pressure losses makes the device less susceptible to erosion. However, the pressure drop will be strongly influenced if the oil-water mixture flow forms an emulsion, which changes the fluid viscosity.
2.5.2 *Helical Channel-type ICD (Production EQUALIZER™)*

The helical channel-type ICD was developed by Baker Oil Tools as a modification of the labyrinth ICD. The device uses a number of helical channels with a pre-set diameter and length to impose a specific differential pressure at a specified flow rate (Figure 2-9). The produced fluid flows from the formation through a narrow annular space into multiple screen layers mounted on an inner jacket. The fluid then flows along the solid base pipe of the screens to the ICD chamber where the chosen number of channels impose the desired choking before the fluid passes into the inner section of the casing; either through holes of pre-set diameter or a slotted mud filter. The latter is installed to prevent the screen from being contaminated by kill mud during any future, well killing operation.

*Figure 2-9: A helical channel-type ICD [15]*

This ICD is available with a choice of six flow resistance ratings (0.2, 0.4, 0.8, 1.6, 3.2 and 6.4 bar at a water flow rate of 26 Sm³/day/ICD joint [16]). These different pressure drops are achieved by altering the diameter, length and number of channels incorporated into the device [15]. Extensive flow tests have been carried out in which the pressure drop at different flow rates was recorded for the different ICD ratings (see
Section 3.3 for a sample of these flow test measurements and the derived flow correlation).

The design of both channel-type ICDs causes the pressure drop to occur over a greater distance compared to the slot, nozzle and orifice-type ICDs; an advantage that potentially reduces the erosion or plugging of the ICD ports. However, this also implies that the pressure drop imposed by the ICD will change as the flowing fluid’s viscosity changes. This typically occurs as the flowing fluid type, phase, pressure or temperature changes due to water or gas breakthrough. This effect will be magnified if an oil-water emulsion is formed.

Baker Oil Tool developed a slot-type ICD to minimise the helical channel-type ICD dependence on viscosity.

2.5.3 **Slot-type ICD (Hybrid EQUALIZER™)**

The slot-type ICD was developed by Baker Oil Tools as a modification of the helical channel-type ICD design that minimises the pressure drop dependence on fluid viscosity. This ICD comes in two designs:

1. A design which uses a sequence of circular discs. Each disc contains two slots with pre-set size to impose a specific deferential pressure at a specified flow rate (Figure 2-10 A) [17]. The number of discs (stages) installed in the ICD chamber determines the pressure drop across the ICD.

2. A design which is adjustable at the wellsite. This design divides the restriction chamber into 4 quadrants (Figure 2-10 B). Each quadrant is designed to impose a specific pressure drop at a specified flow rate. This is achieved by varying the number of stages in each quadrant (i.e. increasing the number of stages to increase the pressure drop Figure 2-11). This ICD design is claimed to have the lowest dependency on fluid viscosity (Figure 2-12) while at the same time maintaining the channel-type ICD’s resistance to erosion.

The flow characteristics of this device are similar to that of a multi-stage choke [18]. Both designs of this device are provided in similar pressure drop ratings to helical channel-type ICDs (i.e. 0.8, 1.6, 3.2 and 6.4 bars at a water flow rate of 26 Sm³/day/ICD joint).
Figure 2-10: (A) Fixed slot-type ICD (B) Adjustable slot-type ICD [17]

Figure 2-11: Quadrant stages of an adjustable slot-type ICD [17]
2.5.4 Tube-type ICD (*EQUIFLOW*™)

The Tube-type ICD was developed by Easywell Solutions (now a Halliburton subsidiary). The device uses a number of flow tubes with a pre-set diameter and length to impose a specific differential pressure at a specified flow rate (Figure 2-13 A and B) [19]. This device combines the effect of pressure drop created by flow through a restriction and that of a straight tube. The number and length of the tubes are varied to achieve the required pressure drop. This gives the tube-type ICD greater flexibility to suit the produced or injected fluid properties.

Figure 2-13: (A) A diagram of tube-type ICD (B) Actual tube-type ICD [19]
2.5.5 Nozzle-type ICD (ResFlow\textsuperscript{TM}, ResInject\textsuperscript{TM}, FloMatik-Sub\textsuperscript{TM} and FloRight\textsuperscript{TM})

There are two providers of nozzle-type ICDs: a) Reslink  (a Schlumberger subsidiary, Figure 2-14 [20]) and b) Flotech  (a Tendeka subsidiary, Figure 2-15 [21]). Both providers use nozzles to create the pressure resistance. Produced fluid passes into a set of preconfigured nozzles, which control the fluid flow into the internal section of the liner. The number and diameter of the nozzles are chosen so as to produce the required pressure drop across the device at a specific flow rate. Constricting the fluid flow to a number of nozzles makes the pressure drop highly dependent on the fluid density and velocity, but less dependent on viscosity. However, high fluid flow velocity combined with sand production is one of the major causes of equipment failure due to erosion. Erosion resistance materials are used in the Reslink nozzles (hard ceramic) as well as Flotech nozzles (tungsten carbide).

The design of a Reslink production well ICDs (ResFlow\textsuperscript{TM}) differs from their ICD intended for injection wells (ResInject\textsuperscript{TM}). The nozzles of the production ICD are grooved into the base pipe (Figure 2-14); while they are mounted on a jacket welded around the base in the injection well ICD (Figure 2-16). This injection design helps reduce the jetting (and erosion) effect on the ICD shroud caused by the fluid exiting the nozzles. Both designs employ nozzles that vary in size and can be easily replaced at the wellsite (Figure 2-17) if a different pressure drop is required.

Flotech FloMatik\textsuperscript{TM} and FloRight\textsuperscript{TM} also differ. The FloMatik\textsuperscript{TM} is designed for application in a consolidated formation since its design enables the fluid to flow directly through the nozzle without passing through a screen or debris filter. The FloRight\textsuperscript{TM} ICD design incorporates both a SAS ahead of the ICD chamber and a check valve within each nozzle to eliminate back flow through the nozzle. The latter can be very beneficial both in injection and production applications.

![Figure 2-14: Reslink, ResFlow\textsuperscript{TM} Nozzle-type ICD [20]](image)
2.5.6 **Orifice-type ICD (FloReg™ and FluxRite™)**

Both Weatherford FloReg-ICD and Schlumberger FluxRite-ICD employ multiple orifices to produce the required differential pressure for flow equalisation {(Figure 2-18 [23]) and (Figure 2-19 [24])}. Each ICD consists of a number of orifices of known diameter and flow characteristics. The orifices are part of a jacket installed around the base pipe within the ICD chamber in FloReg-ICD as opposed to the FluxRite-ICD where the orifices are grooved in the wall of the base pipe (a similar design to the Reslink™ ResFlow™ ICD). Although, the exact location of the orifices within the
FloReg-ICD chamber is different to that of FluxRite™ or nozzle-type ICDs, the flow characteristics are judged to be similar; though with a minor difference in the flow coefficient value and its small dependence on fluid viscosity. The orifice size of both orifice-type ICDs is fixed. However, a different pressure resistance values can be achieved by reducing the number of open orifices. This can be modified easily on the wells site by plugging or unplugging orifices (Figure 2-17).

![Figure 2-18: FloReg™ orifice-type ICD][23]

![Figure 2-19: FluxRite™ Orifice-type ICD][24]

### 2.6 Comparison of ICD Types

The difference in pressure drop dependency of each ICD type affects their area of application. Generally, ICDs can be applied to perform the following:

1. **Minimise the fluid influx imbalance along the wellbore which can be caused by:**
   
   a. Heel-Toe Effect caused by frictional pressure drop along the wellbore.
   
   b. Productivity Variation Effect caused by variation in the well productivity parameters along the wellbore (or from multiple laterals). This includes permeability, pressure, density, viscosity, Formation Volume Factor, Skin, wellbore or reservoir radius.

20
All ICD types can achieve this objective.

2. Reduce the flow of a specific (unwanted) fluid phase (i.e. act as a Phase Filter):
   a. Reduce oil associated gas flow due to the high volumetric flow of gas. This can be achieved by all ICD types; though other equipment characteristics, such as the ICD erosion potential, can limit the choice of nozzle/orifice-type ICDs in this case.
   b. Reduce oil associated water flow due to the density difference between oil and water. This can be achieved by nozzle, orifice, slot and short tube type ICDs due to their pressure drop dependence on density. The pressure drop through channel and long tube type ICDs is dependent on the fluid viscosity; which will encourage water flow through the ICD (providing the water has the lowest in-situ viscosity). These ICD pressure drop dependencies are described in details in Chapter 3.

Table 2-1 lists the major similarities and differences between the commercially available ICDs as of 2009. This can be used as a qualitative decision making tool in defining the appropriate ICD for a specific application.
Table 2-1: Comparison of commercially available ICD types

<table>
<thead>
<tr>
<th>ICD Pressure Drop Element</th>
<th>Channel</th>
<th>Slot</th>
<th>Tube</th>
<th>Nozzle</th>
<th>Orifice</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tejas</td>
<td>Baker</td>
<td>Baker</td>
<td>Halliburton</td>
<td>Reslink</td>
</tr>
<tr>
<td></td>
<td>LT</td>
<td>ST</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Source of Pressure drop:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Friction</td>
<td>H</td>
<td>H</td>
<td>L</td>
<td>H</td>
<td>L</td>
</tr>
<tr>
<td>Acceleration</td>
<td>L</td>
<td>L</td>
<td>H</td>
<td>L</td>
<td>H</td>
</tr>
<tr>
<td>Oil associated fluid phase restriction:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
</tr>
<tr>
<td>Water</td>
<td>L</td>
<td>L</td>
<td>H</td>
<td>L</td>
<td>H</td>
</tr>
<tr>
<td>Importance of Emulsion</td>
<td>H</td>
<td>H</td>
<td>N</td>
<td>H</td>
<td>L</td>
</tr>
<tr>
<td>Risk of Erosion</td>
<td>L</td>
<td>L</td>
<td>M</td>
<td>L</td>
<td>L</td>
</tr>
<tr>
<td>Risk of Plugging</td>
<td>L</td>
<td>L</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>Flexibility at Wellsite</td>
<td>L</td>
<td>L</td>
<td>L</td>
<td>L</td>
<td>H</td>
</tr>
</tbody>
</table>

LT = Long Tube, ST = Short Tube, Dependence: H= High, M= Moderate, L= Low, N = No dependence

Note:

**All ICDs** are normally installed in open hole.

**All ICDs** can be combined with Stand-Alone Screen (SAS) or Debris filter.

**All ICDs** respond to differences in the fluid flow due to permeability variations.

**All ICDs** do not require installation of control lines or gauges.

**All ICDs** can be customised to reservoir permeabilities > 100 md.

The following section describes some of the published ICD applications to achieve the above objectives.
2.7 Published ICD Applications

The advantages of the ICD technology have now been recognized by many operators through its application to different types of fields since their first application in the Troll Field. Baker Oil Tools reported that 2 million feet of helical-channel ICD joints had been installed by mid-2008 [25] while Statoil reported more than 120 installations in North Sea wells [26] and Saudi Aramco reported the installation of ICDs in more than 200 wells spread over several fields [27]. These include the installation of ICDs in 220 laterals completed in three of its Arabian Gulf Offshore Fields [28]. A review of some of the published ICD applications will be given.

2.7.1 ICD with SAS in Horizontal Wells

The first ICD application was of the helical channel-type ICD. The longest horizontal section to be completed in the Troll Field [26], Well M-22, had a horizontal section length of 3,619 meters and was completed with 279 joints of SAS equipped with ICDs. Numerical simulation indicated that a "stair step" arrangement was the optimum completion design with the highest strength ICD (3.2 bar) at the heel section of the well and a SAS without ICDs toward the toe of the well [26]. The ICD strength distribution along the well is listed in Table 2-2. Annular isolation with External Casing Packers (ECPs) to prevent flow along the length of the sandface was not employed (Figure 2-20). The stair step design was later modified to a single ICD strength of 3.2 bar along the entire horizontal section. It was argued that the simulator showed that only a small difference in the cumulative oil production was predicted for the two completion designs; while the simplified operational logistics at the wellsites (how does one ensure that the different strength of ICDs are run into the hole in the correct order at the rig site?) was a significant benefit.

<table>
<thead>
<tr>
<th>Joint Type</th>
<th>Number of Joints</th>
<th>Flow Resistance Rating (bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Screen-1</td>
<td>115</td>
<td>0</td>
</tr>
<tr>
<td>ICD-1</td>
<td>23</td>
<td>0.2</td>
</tr>
<tr>
<td>ICD-2</td>
<td>20</td>
<td>0.4</td>
</tr>
<tr>
<td>ICD-3</td>
<td>33</td>
<td>0.8</td>
</tr>
<tr>
<td>ICD-4</td>
<td>39</td>
<td>1.6</td>
</tr>
<tr>
<td>ICD-5</td>
<td>49</td>
<td>3.2</td>
</tr>
</tbody>
</table>
Another important reason that influenced the decision to utilize a single ICD strength was the inability to calculate both the magnitude and the effect of annular flow between the screen and the sandface with the reservoir simulators available at that time. It was speculated that there was a significant annular flow of produced fluid from the region where high strength ICDs were installed to that with the lower strength ICD [16].

![Figure 2-20: The Troll Well M-22 ICD completion configuration](image)

### 2.7.2 ICD with Debris Filter in Horizontal Wells

Although most of the published ICD applications are in sandstone formations, their application in Carbonate formations is increasing. ICD application in Carbonate and consolidated Sandstone formations does not require the installation of screens. A single layer, debris filter can be used instead. Both channel and nozzle type-ICDs integrated with debris filter have been installed in a giant Middle Eastern Oil Field [29]. The reservoir pressure in this field is maintained by powered water injection which had already been operational for some years. This caused high differential pressure between the permeable layers and high water flow through fractures to the oil producers, causing cross flow in the conventional openhole, horizontal completions employed in this field. The nozzle-type ICD completion, provided by Flotech, was installed in a horizontal producer which was originally producing with an openhole. The ICD completion succeeded in equalising the contribution from the multiple layers; eliminating cross flow and reducing the water cut from 30% to 10% at similar total liquid flow rate.

### 2.7.3 Integration with Annular Flow Isolation

ICDs can only eliminate annular flow if the formation shows a highly homogenous permeability distribution along the length of the horizontal wellbore. Variations in productivity, pressure, hole size or undulation along the wellbore can trigger annular flow even when ICDs are installed. In practice, AFIs are necessary to ensure that the full benefits of ICD installation are achieved. Different forms of AFIs are available
commercially (see Section 2.17). Many of the reported ICD applications included some form of AFI [8, 30, 31, 32]. For example, the Z-253 well [33] completed in the Zuluf Field, offshore Saudi Arabia, utilized four Mechanical ECPs in conjunction with single strength channel-type ICD to segment a 2200 ft-long wellbore (Figure 2-21 [33]). The placement of the ECPs was based on separating zones of different permeability. This completion enhanced the productivity and equalised the inflow of the well compared to its neighbour; a conventionally cemented and perforated well.

Figure 2-21: Z-253 ICD completion with External Casing Packers (ECP) for annular isolation [8]

Swell Packers (SPs) were used for annular isolation in the West Brae 16/7a-W8z well [34]. This horizontal well was completed with multiple ICD strengths ranging from 3.2 bar at the heel to 0.8 bar at the toe. SPs were installed when the ICD strength changed. This completion increased the well production rate by 5,000 bopd and delayed water breakthrough compared to offset wells.

The above example applications were for sandstone reservoirs. In carbonate reservoirs, however, annular flow isolation has a second objective. ECPs or SPs were installed in conjunction with (multiple) lengths of blank pipe (or very limited number of ICDs) to prevent unwanted fluid influx from fractured or super-K permeability zones. Alternatively, they are installed with ICDs to restrict the inflow of oil followed by free gas from the gas cap or water from the aquifer through fractured, high permeability zones. An example of the former is the installation of 35 ICDs in a slimhole well (Well-A) in a Saudi Arabian carbonate reservoir [35]. A total of five openhole packers were set along the completion zone. Two of these packers were combined with 250 ft of blank pipe to isolate a highly fractured zone which had been initially identified by mud losses during the drilling operation and confirmed by image logging. The remaining packers were utilized to separate zones of different permeability. Installation of 20 ICD joints along with eight external packers was used in Well SHYB-257 to
reduce the well Gas Oil Ratio (GOR) from 4,000 scf/stb to 2,450 scf/stb by restricting
the free-gas influx through high permeability zones [36]. Another example is the
installation of one ICD joint across the fractured interval instead of a blank pipe. This
was performed in Well-B of another Saudi Arabian Carbonate reservoir [37]. This
installation facilitated a controlled oil production from the fractured interval and is
expected to mitigate water production after breakthrough.

Installation of a nozzle-type ICD with annular isolation was reported in Well
Sakhalin-1 in the Chayvo field [38]. The completion string design incorporated a pre-
drilled liner across the low permeability zones and ICDs across the high permeability
zones with SPs to separate the two completion components (Figure 2-22). This helped
equalise the inflow profile along the well by minimising the contribution from the high
permeability zone, which was expected to dominate the production and suppress the
contribution of the low permeability zones.

![Figure 2-22: Well Sakhalin-1 ICD with Predrilled liner completion with SP [38]](image)

2.7.4 **Integration with Artificial Lift**

Artificial lift is usually implemented to revive dead wells or to enhance the
productivity of existing producers by lowering the well bottom hole pressure and
boosting the vertical lift energy. In horizontal wells this will further aggravate the
influence of pressure drop along the wellbore, encouraging increased coning of water or
gas. The combination of ICDs with artificial lift will help minimise this effect. Wells
in Z- and M-Fields, located in the Saudi section of the Arabian Gulf, and in the Troll
and Grane fields, located in the Norwegian shelf of the North Sea, have reported the
combination of ICDs with different forms of artificial lift including conventional gas
lift, Auto gas lift using the gas-cap gas (Figure 2-23) and Electric Submersible Pumps
(ESP) [30, 31, 39].
Integration with Gravel Pack

ICD installation and integration with AFI aims to eliminate annular flow, a primary cause of sand particles becoming dislodged from the sandface and then transported along the annulus. Screen erosion and plugging, in addition to many sand production related problems at the surface, will result. Gravel packing in both conventional and horizontal wells has been proven to eliminate (or minimise) sand production in various fields. Helical channel-type ICDs combined with a horizontal gravel pack were applied to the ET-6H well in the Etame oil field [40], offshore Gabon, to eliminate potential sanding problems and delay water breakthrough (Figure 2-24).

Integration with Multilateral and Intelligent Completion

Simulation results have indicated that the installation of ICD completions in the individual laterals of a dual or higher level multi-lateral well helps balance the contribution along the lateral and even-out the water and gas fluid front movement towards each lateral in both homogeneous and heterogeneous formations [15]. However, the flow contribution of each lateral toward the total well flow rate will vary if the laterals have (1) different effective productivities or (2) are completed in different reservoir facies or at different vertical depths. This will cause water or gas to breakthrough in one lateral before the other, reducing the total well performance. This effect can be alleviated by combining an ICD completion along the well laterals with
installation of an ICV at the mouth of each lateral. ICVs can be remotely controlled to adjust each lateral’s flow contribution either proactively or upon the onset of unwanted (water or gas) fluid production.

An integrated ICD completion with a level 4 multilateral junctions equipped with ICVs to control the production from each lateral was installed in the Z-Field, offshore Saudi Arabia (Figure 2-25) [32, 41], the Troll Field and the Grane Field, both offshore Norway.

Figure 2-25: ICD completion integrated with ICVs in a level 4 multilateral well [41]

Another option would be to install ICDs along the motherbore, with multiple ICDs installed across the mouth of each lateral and AFI installed between the laterals’ mouths. This completion type allows the operator to utilise ICDs to balance the contribution from multiple laterals instead of ICVs. This wellbore completion configuration was installed in a 3-7/8” short radius trilateral well drilled and completed in Arab-D reservoir in the Giant Ghawar field, Saudi Arabia [42]. Flotech ultra-slim (2-7/8”) nozzle-type ICD was installed along the motherbore and across the mouth of two laterals. The well production log matched expectation with a water cut of 0%.

Figure 2-26: ICD completion integrated in a trilateral well [42]
2.7.7 **Water Injection Wells**

In contrast to the previously described applications, ICDs have also been applied in vertical (slightly deviated) and horizontal water injection wells. These include: a vertical water injector in Urd Field (Staer-Norne Area) [43] and horizontal water injection wells in the Stag, Erha and Marlim Fields. ICD completions were installed in these wells to equalise the water injection and pressure support to multiple layers of varying permeability while minimising the potential for wormhole and thermal fracture creation. For example, wormholes were created in the Stag Field between injectors and producers when they were both completed with pre-perforated liners. These wormholes were sufficiently large to allow the injected water to travel from the injection well to the production well over a distance of 2130 ft in less than 3 hours.

Both Well J-1H, a vertical water injection well in the Urd Field, and Stag 32H employed Nozzle-type ICDs with a constant nozzle area across multiple reservoir layers. A nozzle-type ICD completion was also used in Stag 33H (horizontal) producer, while the Urd Field producers employed ICVs.

The two Erha North Horizontal Water Injectors also employed Nozzle-type ICDs to equalise the fracturing potential of injected water over multiple reservoir zones and to minimise the risk of unbalanced injection due to fracture development in the top reservoir zone 22. Erha injector-3 had 80, 4-mm injection nozzles distributed over 5 ICD joints (16 nozzles per ICD joint); while Erha Injector-4 had a 128, 4-mm nozzles distributed over 8 ICD joints. Helical channel-type ICDs were applied in the water injection Marlim Well 8-MLS-81HP-RJS, the ICD completion being integrated with gravel pack to eliminate annular flow and sanding. The exception was the Stag 32H well which used SPs to isolate any possible annular flow between the reservoir layers.

All of these completions were deemed to have achieved their stated objectives.
### Summary of ICD Applications

Table 2-3 summarises all the published ICD applications up to end of year 2009 along with the ICD type and the reason for its application.

**Table 2-3: Summary of Published ICD Applications**

<table>
<thead>
<tr>
<th>Field</th>
<th>Well Type</th>
<th>Well Configuration</th>
<th>ICD Type</th>
<th>Permeability</th>
<th>Challenges</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alvheim [44]</td>
<td>P</td>
<td>Hr&amp;ML</td>
<td>HC</td>
<td>&gt; 3 D</td>
<td>VPE, W &amp; G coning</td>
</tr>
<tr>
<td>Brae (West) [34]</td>
<td>P</td>
<td>Hr</td>
<td>HC</td>
<td>0.01-12 D (6 D)</td>
<td>VPE, W &amp; G breakthrough</td>
</tr>
<tr>
<td>Chayvo [38, 45]</td>
<td>P</td>
<td>Hr</td>
<td>NZ</td>
<td>&gt; 1 D</td>
<td>VPE, W &amp; G coning</td>
</tr>
<tr>
<td>De Ruyter [46]</td>
<td>P</td>
<td>Hr&amp;ML</td>
<td>NZ</td>
<td>Not Specified</td>
<td>VPE, W &amp; G breakthrough</td>
</tr>
<tr>
<td>Emlichheim [44]</td>
<td>P</td>
<td>Hr</td>
<td>NZ</td>
<td>1-10 D</td>
<td>VPE &amp; W breakthrough</td>
</tr>
<tr>
<td>Erha [22]</td>
<td>I</td>
<td>Hr</td>
<td>NZ</td>
<td>&gt; 3 D</td>
<td>VPE</td>
</tr>
<tr>
<td>Etame [40]</td>
<td>P</td>
<td>Hr</td>
<td>HC</td>
<td>0.05-1.8 D</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>Grane [47]</td>
<td>P</td>
<td>Hr&amp;ML</td>
<td>HC</td>
<td>7 D</td>
<td>HTE &amp; G coning</td>
</tr>
<tr>
<td>Giant Carbonate Field</td>
<td>P</td>
<td>Hr</td>
<td>HC&amp;NZ</td>
<td>300-2000 md</td>
<td>VPE, W &amp; G production</td>
</tr>
<tr>
<td>Khurais [48]</td>
<td>P&amp;I</td>
<td>Hr</td>
<td>HC</td>
<td>Not Specified</td>
<td>VPE &amp; W breakthrough</td>
</tr>
<tr>
<td>Komsomolskoe [49]</td>
<td>P</td>
<td>Hr</td>
<td>NZ</td>
<td>21 md - Unknown</td>
<td>VPE &amp; W breakthrough</td>
</tr>
<tr>
<td>Marlim [50]</td>
<td>I</td>
<td>Hr</td>
<td>HC</td>
<td>2 D</td>
<td>VPE</td>
</tr>
<tr>
<td>M-Field [28]</td>
<td>P</td>
<td>Hr&amp;ML</td>
<td>HC&amp;NZ</td>
<td>&gt; 3 D</td>
<td>W &amp; G coning</td>
</tr>
<tr>
<td>Ringhorne [51]</td>
<td>P</td>
<td>Hr</td>
<td>NZ</td>
<td>&gt; 1 D</td>
<td>W &amp; G coning</td>
</tr>
<tr>
<td>S-Field [28]</td>
<td>P</td>
<td>Hr</td>
<td>HC</td>
<td>1 - &gt; 3 D</td>
<td>VPE &amp; W</td>
</tr>
<tr>
<td>Field</td>
<td>Well Type</td>
<td>Well Configuration</td>
<td>ICD Type</td>
<td>Permeability</td>
<td>Challenges</td>
</tr>
<tr>
<td>-----------------------</td>
<td>-----------</td>
<td>--------------------</td>
<td>----------</td>
<td>--------------</td>
<td>------------</td>
</tr>
<tr>
<td>Shaybah [31, 36]</td>
<td>P</td>
<td>Hr&amp;ML</td>
<td>HC</td>
<td>10-200 md</td>
<td>VPE &amp; G</td>
</tr>
<tr>
<td>Simsima [52]</td>
<td>P</td>
<td>Hr</td>
<td>HC</td>
<td>&gt; 100 md</td>
<td>VPE &amp; W</td>
</tr>
<tr>
<td>Urd (Staer -Norne) [43]</td>
<td>I</td>
<td>D</td>
<td>NZ</td>
<td>0.1-2.0 D</td>
<td>W</td>
</tr>
<tr>
<td>Stag [53]</td>
<td>P&amp;I</td>
<td>Hr</td>
<td>NZ</td>
<td>100-300 md and 1-2 D</td>
<td>VPE &amp; W</td>
</tr>
<tr>
<td>Troll [16]</td>
<td>P</td>
<td>Hr&amp;ML</td>
<td>HC</td>
<td>6 D</td>
<td>HTE &amp; G coning</td>
</tr>
<tr>
<td>Vankorskoe [49]</td>
<td>P</td>
<td>Hr</td>
<td>HC</td>
<td>10, 150, 550 md</td>
<td>VPE, W &amp; G</td>
</tr>
<tr>
<td>Zuluf [33]</td>
<td>P</td>
<td>Hr&amp;ML</td>
<td>HC</td>
<td>3.5 D</td>
<td>VPE &amp; W coning</td>
</tr>
<tr>
<td>Unnamed Fields (Saudi) [29]</td>
<td>P</td>
<td>Hr</td>
<td>HC&amp; NZ</td>
<td>Not Specified</td>
<td>VPE &amp; W production</td>
</tr>
</tbody>
</table>


2.8 Potential ICD Applications

ICD technology still has the potential to add value in further types of applications despite the wide diversity of already published ICD applications. This thesis will explore such applications and provide model studies to show that ICD completions can add value in the following situations:

2.8.1 Gas Production and Water-Alternating-Gas (WAG) Injection Wells

Gas and Water-Alternating-Gas (WAG) injection wells also suffer from Heel-Toe Effect (HTE) and/or Variable Productivity Effect (VPE) along the wellbore or laterals. ICD completions can equalise the gas or WAG injection and improve the injection flood front and distribution across homogeneous, heterogeneous or layered formations.
2.8.1 **Gas Fields**

ICD application in gas fields can also add value in contrast to the published applications which have focused on liquid (oil and water) production and injection. ICDs can equalise the gas influx from homogeneous or heterogeneous layer or non-layered reservoirs and fields. In addition, the ICD’s ability to encourage liquid flow when associated with gas flow can be beneficial in (retrograde) gas condensate reservoirs. Since this will assist in moving the condensed hydrocarbon without the need to increase the gas production rate (i.e. gas stripping). Furthermore, ICD completions can control the sand production from unconsolidated gas formations since annular flow can be minimised or eliminated when combined with AFIs. This may eliminate the need for gravel packing. However, two limitations should be considered when evaluating such completions. These include: water production (which can be encouraged by the ICD application) and the high erosion potential of sand laden gas production.

The design of the ICD completion for such potential applications along with synthetic and real field case studies describing the advantages and disadvantages of such applications can be found in Chapter 4 and Chapter 6.
2.9 Reactive Flow Control: Autonomous Inflow Control Devices (AICDs)

This "Advanced" form of ICDs was introduced by Hydro [54] in conjunction with Easywell Solutions after nearly a decade of ICD application, a time period during which Inflow Control Valves (ICVs) were developed for intelligent wells [55]. The AICD, which adds an active element to the passive ICD, is activated by changes in the fluid characteristics when a new phase (water or excess gas) influx, e.g. a change in the density of the fluid mixture. The device is autonomous; it does not require any human or other interaction as required by ICVs. The AICD concept was developed to overcome the problem of localised water influx in the Grane and Brage North Sea fields, and to help control the gas-cap gas influx in the "thin oil column" area of the Troll field.

2.10 AICD Types

The AICD combines a passive ICD section with an active section. As of year 2010, four AICD types were being developed. Three of the designs for the AICD’s active section are based on the concept of buoyancy to open or restrict/shut the valve. The fourth design is based on an osmosis-based swelling of a material to control the opening and shutting of the valve. A new design was introduced later [246] which applies a hydro-cyclone mechanism to restrict the water and excess gas influx based on the fluid viscosity changes. This device was not analysed in this thesis.

2.10.1 Flapper-type AICD

The flapper-type AICD was developed by Baker Oil Tools [56]. The flapper is used to control the flow of fluid from the channel ICD chamber to the inner section of the casing (Figure 2-27).

![Figure 2-27: A Flapper-type AICD [56]](image)

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 influx. The flapper uses a counterweight installed opposite the
flapper (Figure 2-28). The closing rate of the valve can be tailored to the desired valve actuation conditions by changing the counterweight's mass. A Gravity Ring is also included in the design. It orientates the flapper as the completion is run in the wellbore. An expandable rubber seal placed to the rear of the Gravity Ring expands on contact with the produced hydrocarbons. The rubber expansions process is gradual; causing the sealing of the equipment in place to occur after the completion equipment has been installed in its final position.

![Components of the Flapper-type AICD](image)

**Figure 2-28: Components of the Flapper-type AICD [56]**

The valve design also incorporates a bypass orifice that allows (a limited) continuous flow to create a back pressure high enough to allow the oil production at other screen joints to continue. This orifice will also allow excess gas to bleed off slowly causing the valve to open as the gas cone recedes; allowing increased oil production. Simple changes in the AICD design allow the flapper to control water production or to control both water and gas production. The former will require orientating the AICD flapper 180° from the gas density sensitive device. The flapper in this case will be lifted to the closed position by the denser fluid as the water influxes. The combined gas and water AICD will employ both gas and water density sensitive flappers (Figure 2-29).

![An AICD for Water and Gas control](image)

**Figure 2-29: An AICD for Water and Gas control [56]**
2.10.2 **Ball-type AICD (Oil Selector™)**

The ball-type AICD is provided by Easywell Solutions (a Halliburton subsidiary) [55, 57]. This device is similar to the flapper type in its dependence on the fluid density to establish a buoyancy based actuation of the valve. However, the two designs differ. The ball-type AICD uses metallic balls to shut off "Active" nozzles that control the flow from the AICD chamber to the inner section of the casing (Figure 2-30). The nozzles can be designed to impose a specific pressure drop across the device (i.e. act as an ICD) or be sufficiently large to allow fluid flow with minimal restriction.

![Figure 2-30: A Ball-type AICD [58]](image)

The balls lie at the bottom of the device during dry oil production in an AICD designed for water control. The density of the produced fluid mixture will increase as the water cut increases causing the balls to float upwards and to start shutting the nozzles one after the other (Figure 2-31). Oil-floating balls are used when the valve is designed to control gas production. The balls’ density allows them to float in the oil phase. The produced fluid density reduces once gas has broken through, allowing the floating balls to sink and plug the flow nozzles (Figure 2-32). 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. 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.
Figure 2-31: The balls lie at the bottom of the device during dry oil production i.e. prior to water influx then they start to rise when water production starts [58]

Figure 2-32: The balls float at the top of the device when oil phase is produced then start to descend once gas production increases [58]

2.10.3 **Swellable-type AICD**

The Swellable-type AICD is being developed by Statoil for water influx control [54, 59]. The water limiting device uses the principle of osmosis or thermodynamic absorption, depending on the swellable material, to 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 2-33). 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). The desired flow
restriction for water influx control is achieved by installing multiple devices in a single screen joint.

Figure 2-33: Statoil Swellable-type AICD [54]

2.10.4 Disc-type AICD

The Disc-type AICD was also introduced by Statoil for gas influx control (Figure 2-34) [245]. This AICD uses a spring to impose a specific pressure on the movable disc to reduce the fluid flow area based on the change in the fluid properties. The flow of liquid through the device will maintain the disc in the open position. However, excess gas influx will allow the spring to increase the back pressure on the disc and cause it to shut off the flow path (Figure 2-34). The number of devices to be installed within each screen joint is chosen so as to achieve the desired flow restriction. The flow opening area of the device can also be designed to impose a specific pressure drop that will help equalise the influx along the horizontal wellbore (i.e. act as an ICD).

Figure 2-34: Fluid flow diagram of Statoil’s Disc-type ICD [245]
2.10.5 **Remote-type AICD**

The Remote-type AICD uses Radio Frequency Identification (RFID) to operate a specific AICD sleeve. This AICD type is provided by Petrowell [60]. This device consists of an RFID signal reader, a hydraulic pump, a sleeve and a power source. This reactive device is currently installed on a FloReg™ orifice-type ICD (Section 2.5.6).

The sleeve opening/closing instructions are programmed in a small electronic chip (Figure 2-35 A [60]). These chips are then injected into the well to pass through the RFID reader (Figure 2-35 B [61]) which decodes the instruction and initiates actuation of the sleeve. The hydraulic pump powered by a battery or a downhole power source is used to actuate the sleeve which is installed on the inner side of the ICD base pipe. This sleeve can isolate the fluid flow path from the ICD chamber to the inner section of the ICD production tubular. Sleeve actuation can be triggered by the operator once water or excess gas production is detected.

The ability to open and close the device remotely confers a greater advantage even though this AICD type does not respond directly to the unwanted fluid influx. The limitation of this device is the need for electrical power for the signal receiver and sleeve actuation. Batteries currently provide the required power, though their use limits the operational life to a maximum of 2 years. Development of downhole power generation offers a potential solution.

![Figure 2-35: RFID transmitter (A) [60] and reader (B) [62]](image-url)
2.11 Comparison of AICD Types

**Water-triggered AICDs** will initially assist the well outflow performance due to its restriction of the produced water until the well ceases to flow. However, the AICD completion imposes a large pressure drop across the sandface and drastically limits the well productivity if artificial lift is used to lift the well without removing the AICD completion. This limitation must be accounted for when considering such completion.

**Gas-triggered AICDs** will assist the well’s inflow and outflow performance by limiting the amount of free gas flowing through the wellbore. However, this will also limit the ability of the well to be used as a future gas production well e.g. for reservoir blowdown.

The above illustrates how the various AICDs designs and their expected performance differ. Table 2-4 lists the similarities and the differences between the types of AICDs:

**Table 2-4: Comparison of available AICD types**

<table>
<thead>
<tr>
<th>Active Element</th>
<th>Ball Halliburton</th>
<th>Flapper Baker</th>
<th>Swellable Baker Hydro</th>
<th>Disc Hydro</th>
<th>Remote RFID</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Flexibility to uncertainty in design fluid properties</strong></td>
<td>L</td>
<td>L</td>
<td>L</td>
<td>L</td>
<td>H</td>
</tr>
<tr>
<td>Control line or gauges requirement</td>
<td>N</td>
<td>N</td>
<td>N</td>
<td>N</td>
<td>N</td>
</tr>
</tbody>
</table>

**Risk of:**

- **Erosion**
  - H
  - L
  - M
  - M
  - M
  - L
- **Plugging**
  - H
  - M
  - M
  - M
  - L
  - L
- **Sensitivity to emulsion**
  - M
  - M
  - M
  - M
  - M
  - N
- **Operational flexibility**
  - L
  - L
  - M
  - M
  - M
  - H

H = High dependence, M = Moderate dependence, L = Low dependence, N = No dependence

**Note:**

All AICDs can be combined with Stand-Alone Screen (SAS) or a Debris Filter to prevent blockage of the flow restriction device

All AICDs can act as or be combined with ICDs if an extra pressure drop is required to equalise the fluid influx along the wellbore (or lateral).
All AICDs are not recommended for application in injection wells; except when installed to limit the backflow of oil or gas into the wellbore when the injection is stopped. Use of simple check valves would be more appropriate here.

2.12 Potential Applications of AICD

The AICD technology was in the testing stages in 2009 with no reported field installations. Therefore, only potential application areas can be highlighted at this stage where the application of AICDs to equalise the contribution of the different wellbore sections and to control (or shut off) water or excess gas production after breakthrough will result in the following:

1. Enhanced overall well performance and accelerated hydrocarbon recovery.

2. Elimination of the need for well interventions to isolate zones showing unwanted fluid breakthrough. Such interventions can typically result in the loss of all the completion length below the breakthrough point.

3. A large savings in the well operating costs compared to a small capital investment.

Potential application areas include:

2.12.1 Layered Reservoirs (Compartmentalized Reservoirs)

Reservoirs with varying productivity and permeability barriers (e.g. shale) between the high and low productivity zones form a good potential application of AICDs. Both the reservoir layers and the wellbore can have a vertical, deviated (i.e. tilted) or horizontal orientation. Figure 2-36 provides an illustration of horizontal wellbore crossing vertically oriented, low and high permeability layers with water breakthrough occurring at the high permeability layer. Early breakthrough of unwanted fluid can occur, even when equalisation of the fluid influx from zones with limited productivity contrast is achieved. AICDs can minimise (or eliminate) the water and/or excess gas production; enhancing the well performance.
2.12.2  \textit{Fractured Reservoirs}

Fractures intersected by the producing wells can be directly connected to the aquifer or the gas cap. They are a common cause of early water and gas breakthrough (Figure 2-37). This is usually prevented by avoiding intersection of the well with such fractures (i.e. well placement) or by isolating the fractures using blank pipe (see section 2.4.2) and straddle packers. Application of AICDs can equalise the contribution of fractures with the matrix contribution and control or shut off water or excess gas production after breakthrough.

2.12.3  \textit{Reservoirs with Varying Oil-Water-Contacts}

The level of Oil-Water-Contact (OWC), Gas-Water-Contact (GWC) or Gas-Oil-Contact (GOC) in some mature and green fields can vary (Figure 2-38) due to the:

1. Existence of isolating faults that eliminate fluid and pressure communication between the different reservoir blocks,

2. Variable contribution from production wells, or
3. Communication with other producing fields through the aquifer.

The equalisation of the fluid influx into the wellbore in this case will maintain the original variation in the OWC, GWC or GOC level. AICD completion in such situations will mitigate and isolate the water or gas producing zones.

![Figure 2-38: Different Oil Water Contacts](image)

2.12.4 **Thin-Oil-Column Reservoirs**

Thin oil column reservoirs with large gas caps that provide pressure support are expected to benefit from the application of AICDs. This is especially true if the reservoir is characterized by low permeability or a high degree of permeability heterogeneity. The AICD will minimise the contribution from the individual wellbore compartment where gas breakthrough has already occurred, allowing efficient sweep of the oil in the remaining completion zones. The existence of flow barriers in the reservoir will enhance this performance.

2.12.5 **Coning Situations**

AICD application in coning wells will slow down the rate of cone propagation in vertical, deviated and horizontal wells. The AICD will minimise the contribution of a particular wellbore compartment after gas or water breakthrough; enabling more efficient oil recovery. Once again, the existence of flow barriers in the wellbore and reservoir will enhance this performance.

2.12.6 **Heterogeneous Reservoirs (Heterogeneous Layers)**

Heterogeneous reservoirs (or heterogeneous layers in a multi-layer reservoir) also form a good potential application of AICDs. The AICD can minimise the water or gas production and enhance the well performance. However, such application may require an increased number of AFIs.
In addition to the above situations, AICDs will add value if applied in gas fields to equalise the contribution of different reservoir layers and to control (or shut off) water production after breakthrough. The added value of this technology in the above situations will be illustrated in Chapter 5 and Chapter 6.

2.13 Active Flow Control: Interval Control Valves (ICVs)

Active flow control devices, or Interval Control Valves – ICVs, offer both proactive and reactive flow control functionality (Figure 2-40). They were developed in the early 1990s. Welldynamics together with Baker Oil Tools, Weatherford and Schlumberger provide this technology.

ICVs can be controlled remotely, wirelessly or autonomously. Remotely actuated ICVs can utilise control lines or can be control line-free. Hydraulic, electric or electro-hydraulic actuation systems can be used to control the ICV movement remotely through control lines or wireless signals sent from the surface (providing a Control line-free completion). ICVs can also be actuated wirelessly or autonomously. Wireless actuated ICVs utilise Radio Frequency Identification (RFID) systems to convey control messages from surface to the ICV. Autonomously actuated ICVs use pre-set actions which have been programmed into an electronic module directly linked to the ICV actuation system. These pre-set actions can be programmed either before or after the ICV installation.
2.14 ICV Types

Similar to the previous flow control technologies, ICVs have different designs and operating mechanisms based on their intended application and provider. Most of ICV providers offer similar ICV functionality but with a different ICV operating mechanism (actuation system). For example, RFID and Autonomous actuated ICVs (AICV) have been introduced recently [64, 65]. Their big advantage is that these require only one or no control lines to surface.

The ICV trim designs vary depending on the provider and the intended application (i.e. the fluid to be controlled, the erosion potential, etc.). The ICV types are categorised by the available ICV opening positions. The two common types of ICVs currently available are those with: 1) Discrete positions (including On/Off) or 2) Variable positions.

2.14.1 Discrete-positions ICV (DP-ICV)

The discrete positions ICV can have between 2 and 12 opening positions ranging from fully open to fully closed. These openings are chosen to allow optimum control of the unwanted fluid phase. For example, good control of excessive gas influx requires that the majority of openings are relatively small with only 2 or 3 large ones. In contrast, water influx control requires the openings to be evenly spaced out between the closed and fully open positions. These valves are actuated using a hydraulic, electric or electro-hydraulic system.

2.14.2 Variable-positions ICV (VP-ICV)

Variable positions ICV (e.g. SCRAMS [66]) can have any desired opening size and be controlled by using an electrical actuation system. This ICV type has found limited application compared to the DP-ICV due to its lower reliability and higher cost.
2.14.3 *Control Line-free ICVs (CLF-ICV)*

The major limitation of the DP and VP type ICVs arise from the number of control lines required to actuate each ICV. Currently, both the electric and hydraulic actuation systems require N+1 control lines to be installed (N being the number of ICVs). This has limited installation of ICVs to the Motherbore only with a maximum of six ICVs per completion. These limitations are being mitigated by the development of control line-free, RFID and autonomously actuated ICVs.

The CLF-ICV is provided by Petrowell [60] similar to the remote-type AICD (Section 2.10.5). A battery operated hydraulic pump is used to actuate the valve from one position to the other based on the instruction conveyed through an RFID, a small electronic chip [61] which contains the ICV’s instructions. These chips are injected into the well to pass through the downhole RFID reader which decodes the instruction and initiates the ICV actuation.

These ICV systems also suffer from the limitation of needing a power source for the signal receiver and the ICV’s action.

2.14.4 *Autonomous-ICV (AICV)*

The Autonomous-ICV is being developed by Saudi Aramco, Schlumberger and Halliburton-Welldynamics to control both water and gas influx [54]. The proposed AICV system differs from the standard intelligent well system (i.e. a well employing pressure and temperature sensors along with a surface controlled ICV through multiple control lines). The proposed completion includes phase identification and monitoring system consisting of Electrode Array Resistivity (ERA) sensors. The ERA sensors detect and monitor the approaching water front. The employment of only one control line per well to transmit the required power to all the installed ICVs and monitoring systems increases the number of ICVs which can be installed in a multi-branched well. Its integration with a control line-free system along the laterals overcomes the limitation that control line-free systems require a short range distance for signal travel and power transmission.
Figure 2-41: An ICV [67]

2.15 Comparison of ICV Types

Table 2-5 compares the available ICV types based on their actuation systems.

Table 2-5: Comparison of available ICV types based on positions and actuation systems

<table>
<thead>
<tr>
<th>Active Element</th>
<th>Discrete Positions</th>
<th>Variable Positions</th>
<th>Control Line Free RFID</th>
<th>Autonomous AICV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flexibility</td>
<td>L</td>
<td>H</td>
<td>H</td>
<td>H</td>
</tr>
<tr>
<td>Control line requirement</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>Reliability</td>
<td>H</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>Installation Location Flexibility</td>
<td>L</td>
<td>L</td>
<td>M</td>
<td>H</td>
</tr>
</tbody>
</table>

RFID = Radio Frequency Identification, ES = Electric Signal, AICV = Autonomous Interval Control Valve, H = High dependence, M = Moderate dependence, L = Low dependence, N = No dependence

Note:

All ICVs can be installed in injection and production wells

All ICVs can be installed in openhole or integrated with SAS, PPL, Expandable tubular, (A)ICD, gravel pack or cemented and perforated casing.
A detailed comparison of all three inflow control technologies (ICDs, AICDs and ICVs) are covered in Section 2.21.

2.16 ICV Applications

ICVs gained popularity since their introduction to the oil industry with the first ICV application taking place in 1997 in the Snorre field by Statoil. Shell commenced ICV installations in 1998 and in 2004 Saudi Aramco installed its first ICV systems in Shybah and Haradh-III fields [68, 69]. However, the uptake of this technology by some field operators was delayed after the first few installations due to concerns about reliability [70]. For example, the survival rate of the ICVs installed in the Snorre field reduces from 85% to 58% once the first installations are included in the statistics (Figure 2-42 [70]). The initial installations employed an electrically actuated system (e.g. SCRAMS). Hydraulically actuated ICV have proved to be more reliable and are now being installed in greater numbers (Figure 2-43 [68]).

![Figure 2-42: ICV survival rate in Statoil Snorre field [70]](image)
These and other reported ICV systems were installed to achieve the following objectives:

1) Commingle oil and/or gas production from (or injection into) multiple zones (or reservoirs) in a field.

2) Actively manage the water and/or gas flood front and hydrocarbon sweep efficiency.

3) Actively manage water dump-flood or internal gas injection between reservoirs for pressure maintenance and hydrocarbon sweep.

4) Control auto (in-situ) gas lift gas injection.

5) Control and shut-in excessive sand, water and/or gas producing formations.

6) Optimise the field production or injection in real time.

7) Isolate and protect the hydrocarbon bearing formation from workover and intervention fluids.

8) Divert stimulation fluids.

ICVs have been applied in gas, oil and water wells to serve the objectives highlighted above. Most of these applications have been summarised in reference [71].
AFIs form crucial components of any intelligent well completion incorporating ICV(s) since annular isolation is needed to separate the controlled intervals. The reported ICV installations include SPs as well as mechanically and hydraulically set ECPs. ICVs have been also installed in open holes; perforated and pre-perforated casings; expandable tubular; SASs and gravel packed completions. The reported number of ICD completed wells exceeds the number of reported ICV well installations. However, a comprehensive review of the ICV applications (up to 2009) indicated ICVs have been installed in a greater number of fields than those using ICDs. Table 2-6 summarises the reported ICV applications.

**Table 2-6: Summary of Published ICV Applications**

<table>
<thead>
<tr>
<th>Field</th>
<th>Well Type</th>
<th>Well Configuration</th>
<th>ICV Type</th>
<th>Challenges</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aquila [72, 73]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>Oseberg [74, 75]</td>
<td>P</td>
<td>Hr&amp;ML</td>
<td>EH&amp;HD</td>
<td>VPE, G &amp; W production</td>
</tr>
<tr>
<td>Gullfaks [76]</td>
<td>P</td>
<td>Dv</td>
<td>EH&amp;HD</td>
<td>VPE, DPr &amp; W production</td>
</tr>
<tr>
<td>Aconcagua [77]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W production in a gas field</td>
</tr>
<tr>
<td>Camden Hills [77]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W production in a gas field</td>
</tr>
<tr>
<td>King's Peak [77]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W production in a gas field</td>
</tr>
<tr>
<td>SW Ampa [78]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>IGI for pressure maintenance</td>
</tr>
<tr>
<td>Douglas [79]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W production in conjunction with ESP and DTS</td>
</tr>
<tr>
<td>Machar [80]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>Saih Rawl Field [81]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>Iron Duke [82]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; G breakthrough and production</td>
</tr>
<tr>
<td>Bugan [82]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; G production (faulted field)</td>
</tr>
<tr>
<td>Na Kika [83, 84]</td>
<td>P</td>
<td>Dv</td>
<td>HD</td>
<td>VPE, G &amp; W production</td>
</tr>
<tr>
<td>Field</td>
<td>Well Type</td>
<td>Well Configuration</td>
<td>ICV Type</td>
<td>Challenges</td>
</tr>
<tr>
<td>------------------------</td>
<td>-----------</td>
<td>--------------------</td>
<td>----------</td>
<td>------------------------------------------------------</td>
</tr>
<tr>
<td>Egret [85]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>IsGL from a separate gas zone</td>
</tr>
<tr>
<td>Veslefrikk [86]</td>
<td>I</td>
<td>Hr</td>
<td>HD</td>
<td>WAG injection</td>
</tr>
<tr>
<td>S-Field(Saudi) [32]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>VPE &amp; W breakthrough</td>
</tr>
<tr>
<td>Shaybah [31, 36]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>VPE &amp; G production</td>
</tr>
<tr>
<td>Tyrihans [87]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>VPE, G &amp; W coning</td>
</tr>
<tr>
<td>Troll West [88]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>G &amp; W production</td>
</tr>
<tr>
<td>Champion [89]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE, DPr, G &amp; W production</td>
</tr>
<tr>
<td>Agbami [90, 91]</td>
<td>P&amp;I</td>
<td>Hr&amp;ML</td>
<td>HD</td>
<td>VPE, DPr &amp; W production</td>
</tr>
<tr>
<td>Qurn Alam [92]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>VPE, Stim &amp; W production</td>
</tr>
<tr>
<td>Zuluf [32, 100]</td>
<td>P</td>
<td>V&amp;ML</td>
<td>HD</td>
<td>IsGL, VPE &amp; W production</td>
</tr>
<tr>
<td>Marjan [33, 32]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>Abqiq [94, 93]</td>
<td>P</td>
<td>Dv&amp;ML</td>
<td>HD</td>
<td>IsGL from a gas cap, VPE &amp; W production</td>
</tr>
<tr>
<td>Haradh-II &amp; III [94, 95]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>Piltun-Astokh (Sakhalin II) [96]</td>
<td>I</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W injection</td>
</tr>
<tr>
<td>Minagish [97]</td>
<td>DF</td>
<td>V</td>
<td>HD</td>
<td>DmpF from a water aquifer to the oil reservoir, Dpr &amp; W injection</td>
</tr>
<tr>
<td>Khurais [48]</td>
<td>P</td>
<td>ML</td>
<td>HD</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>St. Joseph [98]</td>
<td>I</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W injection</td>
</tr>
<tr>
<td>Skinfaks/Rimfaks [99]</td>
<td>P</td>
<td>Hr</td>
<td>HD</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>Snorre [70]</td>
<td>P&amp;I</td>
<td>Hr</td>
<td>EHD</td>
<td>VPE &amp; W production</td>
</tr>
<tr>
<td>Sleipner Øst [101]</td>
<td>PI</td>
<td>NA</td>
<td>ED</td>
<td>Gas producer/injector</td>
</tr>
</tbody>
</table>

Annular Flow Isolation (AFI)

Annular flow, or fluid flow in the annular space between the completion tubular and the sandface or the cemented and perforated casing, is one of the major challenges encountered by both production and injection wells. Different forms of Annular Flow Isolation (AFI) technology have been developed in recent years to eliminate annular flow and minimise its impact. These completion technologies range from conventional isolation packers to gravel packs. This section will review the commercially available AFI devices and illustrate some common applications.

Causes of Annular Flow

Annular flow occurs in fully or partially open annuli due to the following factors:

- The relatively large annular flow area compared to the area of the inner flow conduit,
- Permeability variations along the wellbore,
- Commingled production from zones with different pressures.
- Poor gravel packing of the annular space especially in horizontal wellbores
- Uneven collapse of the formation around the completion tubular due to the variability of the formation strength along the wellbore and/or the inadequate drawdown.

Annular Flow Impact

The occurrence of annular flow has an adverse impact both on the sandface completion integrity and the well productivity. It can result in the following:

1. Sand grain "dislodging", sorting and transportation along the length of the well.
   This leads to:
   a. Plugging at parts of the annulus caused by settling of the larger sand particles in areas where the fluid flow velocity reduces or where reduced flow paths have formed through partial collapse of the sand around the completion tubuling.
   b. Plugging of the screen mesh caused by fine (often shaly) particles separated from the rest of the sand particles through a sorting process.
c. Further erosion of the sandface due to the high velocity flow of sand laden fluid.

2. Erosion of the sandface completion tubing and the formation of "hot-spots" in the heel section of horizontal and multilateral wellbores or close to the AFI locations. The latter is caused by the divergence of the fluid flow direction toward the screen or pre-perforated liner in high concentration.

3. Loss of well productivity due to the formation damage caused by:
   a. Formation plugging.
   b. Uneven influx of fluid along the length of the wellbore.
   c. Uneven clean-up of the sandface and damaged zone around the wellbore.

2.19 AFI Types

Isolation of annular flow can be achieved using packers, gravel packs or simply by allowing the sandface to collapse around the completion string. However, packers are the most common type of AFIs since gravel packs are usually applied to minimise sand production and are also frequently a cause of high well impairment. Gravel packs can sometimes include packers, especially if a high pressure difference between the producing zones exists (or is expected). Also, deliberately collapsing the sandface around the completion string often results in irregular accumulation of the sand in the annular space and may not achieve its intended purpose. Openhole packers can be divided into six categories:

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

More details of each type are provided in the following section:

2.19.1 Mechanically and Hydraulically Set External Casing Packers

The application of ECPs to isolate annular flow in ICV and ICD completions has been reported by many operators. Mechanically and hydraulically set packers are very
similar in nature; the main difference between the two types being the packer setting mechanism. The elastomeric element of a mechanical ECP is set by shifting a sleeve allowing the wellbore hydrostatic pressure to flood an atmospheric chamber and apply a force that hydrostatically sets an elastomeric sealing element. Hydraulically set packers are set by pressurising the inner section of the completion string and exerting a specific differential pressure across the packer. This will shear a pin and set the elastomeric seal. The main advantages of such packers include:

- The ability to withstand high differential pressures (in the range of 8,000 to 10,000 psi).
- The ability to withstand corrosive environments.
- Proven, long-term reliability.

However, hydraulically set packers cannot be applied as openhole AFIs in (A)ICD completions since the inner completion section needs to hold a high pressure in order to set the packer which cannot be achieved with open (A)ICDs. This limits their application to ICV completions and (A)ICD completions where Hydro-mechanical valves [102] are used to isolate the (A)ICD restriction chamber provided that the Hydro-mechanical valves shear pressure is higher than the packer setting pressure. However, there is a risk of not setting the packer as a result of the premature triggering of the Hydro-mechanical valves. In practice, Hydro-mechanical are commercially available but are not widely used, yet. More details on the use of Hydro-mechanical valves as an isolation barrier can be found in Section 2.21.3.

2.19.2 Inflatable Packers

Inflatable packers are set by pumping cement slurry into the packer sealing element to inflate the elastomer and provide a seal against the wellbore wall. After completion of the inflation process, the cement is left to set and then drilled to allow access to the lower part of the completion. This type of packers should not be used in (A)ICD or ICV completions due to the risk of plugging the (A)ICD restriction or damaging the ICV equipment.

2.19.3 Expandable Packers

Expandable packers are elastomeric elements mounted on an expandable tubular or expandable screen. Expandable tubular and screens are normally designed to expand to a certain diameter. However, this is not always sufficient for annular flow isolation
since sections of the hole may be washed out. Expandable packers can only be applied to provide annular flow isolation when suitable hole sections exist. They can withstand a differential pressure of 3,000 psi [103] if used correctly.

Expandable packers require a mechanical or hydraulic expansion tool with a larger diameter than the inner diameter of the completion string. Expandable solid tubular, expandable pre-perforated or pre-drilled liners and expandable sand screens (ESS) are available. However, current (A)ICDs are made from non-expandable material and cannot be easily integrated with expandable packers. A hydraulic expansion tool could thus only be operated at the AFI location, with the result of an irregular inner diameter completion base pipe. Such an operation would be both costly and risky. Expandable packers are not recommended for use in (A)ICD completions or as part of an ICV tubing string. However, they can be used as part of the sandface completion in which an ICV tubing string is installed.

2.19.4 Chemical Packers

Chemical packers use thixotropic cement slurry to isolate the annular space between slotted or pre-perforated liners and the formation over a limited interval. The slurry is injected through the slotted liner into the annulus using coiled tubing and retrievable straddle packers. The slurry is designed to form an impermeable high strength plug immediately after it reaches the formation. All fluid remaining between the straddle packers needs to be removed before it sets. This type of packers can be applied with ICDs provided that a slotted liner is used in the location of the packers in order to protect the ICD joints. However, such an application should be considered with great caution since these packers have many limitations. These include:

1. The application of such packers is limited to horizontal wellbores since the slurry will slump if applied in vertical and deviated wells.

2. An open annulus at the top section of the borehole may result if the cement did not set prior to significant gravity slurry slumping.

The use of such packers with AICDs is not recommended since the slurry can damage the reactive element of the AICD.

2.19.5 Swell Packers and Constrictors

SPs have gained great popularity in recent years. This is due to their simplicity, ease of installation operation and proven reliability. There are two types: oil-swelling and
water-swelling. Both types consist of two components: a polymer and a flexible material [104]. The type of flexible material and polymer chemical components vary depending on the supplier. However, the basic expansion mechanism dictates that the polymer swells when immersed into a liquid with similar solubility parameters. This is due to the strong affinity between the polymer and the liquid. The polymer swelling causes the flexible material to expand and enlarge the volume of the packer. Both types are made up of three parts: an inner core which is highly swellable, a diffusion barrier and an outer core which swell slowly [105].

The Oil swelling process is based on thermodynamic absorption which makes the swelling process highly dependent on the oil properties [104]. For example, oil swelling elastomers swell faster in light oils compared to heavy ones. Water swelling elastomers, which depend on an osmotic process for expansion, prove that swelling is highly dependent on the water salinity and acidity with fresh water allowing such packers to swell faster than when exposed to salty water.

Laboratory tests showed that [104, 105]:

- The swelling of both types of packers can be affected by the contamination of the wellbore fluids.
- Oil-swelling packers have higher absorption and consequent expansion in native crude oil (i.e. oils containing aromatic and/or naphthenic hydrocarbons) compared to oil-based mud.
- Swelled oil-swelling packers can be affected by highly concentrated Hydrochloric acids stimulation fluids. However, they are not affected by low concentrations Hydrochloric acid and other types of acids.
- Swelled oil-swelling packers are not affected by water.
- Water-swelling packers do not swell in water with a low or high pH value.
- Swelled water-swelling packers can shrink (i.e. reduce in size) when exposed to acids such as HCl acid, formic acid or combinations of these two acids. This is potentially important when such packers are installed in water injection wells since (multiple) acid stimulation are often required during the well’s life.

The pressure difference that can be handled by any swell packer reduces as the diameter to which the packer is expanded increases. This is illustrated in Figure 2-44 for different packer sizes.
Swell Constrictors are short, 1 to 2 ft-long swell packers that are mounted on the blank section of the (A)ICD base pipe. They can only control annular flow if smaller pressure differences exist compared to the longer swell packers. Improvements to the current limit are being explored by field operators and suppliers of the technology [105].

Oil and water swelling packers and constrictors have been applied in vertical, deviated, horizontal and multilateral wells installed in carbonate or sandstone formations for both injection and production purposes. They have been installed in cased and open hole completions and integrated with conventional casing, SASs, PPLs, Expandable Sand Screens, Expandable tubular, conventional tubing, gravel packs, ICDs and ICVs. Their objectives vary greatly, being used to:

- Isolate annular flow, water producing zones, gas producing zones and fractures.
• Isolate between laterals, layers or reservoirs with varying pressures and fluid properties.

• Hold the cement in place and divert stimulation fluids and fractures.

SPs have also been used as a form of autonomous control of wellbore sections where water is expected to breakthrough (Figure 2-46 [92]). This application is called External Zonal Isolation Profiler (EZIP). It allows the high productivity sections (fractures, super-K, etc.) of wellbore to contribute to the dry oil production; then, it eliminates the need for wellbore intervention after water breakthrough by isolating the breakthrough zone through swelling of water SPs. By end of 2006, more than 148 wells were equipped with EZIP completions [107]. This completion has also been integrated with Sliding Side Doors (SSD). However, this requires wellbore intervention to isolate the SSD after water breakthrough [108].

![Expandable Zonal Inflow Profiler](image)

Figure 2-46: EZIP using SPs to isolate water breakthrough sections [107]

There have been two failed completions in Saudi Aramco wells due to both completions becoming stuck while running in a hole; but no reported downhole SP failures up to 2009.

2.19.6 Gravel Packs and Collapsed Sands in Annulus

Gravel packing is a proven technique for sand control. It also provides AFI since any annular flow will be highly restricted if not completely eliminated. This does not imply that gravel packs should be applied for the sole reason of annular flow elimination; however they can eliminate the need to install packers or constrictors in highly unconsolidated formations.
Collapsing the sandface around the completion deliberately (or accidently) can restrict, and in some instances eliminate, annular flow. However, such isolation is not reliable and highly dependent on the effectiveness of the collapsed sand packing around the wellbore. Any voids can still cause cross flow from the inner flow conduit to the annular space then back into the completion. This behaviour can cause continuous erosion of the sandface and outer surface of the completion tubular (e.g. SAS).

2.20 Comparison of AFI Types

Not all AFI types can be applied in an (A)ICD and/or ICV completions due to the limitation caused by the difficulty in generating enough pressure to activate the packer setting mechanism or by the potential (A)ICD or ICV damage which may result from the packer setting mechanism. Table 2-7 summarises the similarity and differences between the available AFI types and provides a qualitative tool to select the appropriate AFI for an (A)ICD or ICV completion.

**Table 2-7: Comparison of 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

2.21 Comparison of Downhole Flow Control Technologies

The application areas of the ICV, ICD and AICD technologies have developed over recent years so that they overlap [71]. A comprehensive comparison of ICV, ICD and AICD application has been performed (Figure 2-47 and Table 2-8) in terms of reservoir,
production and cost engineering. The reasons behind the choices made are summarised in the following sections of this chapter and in an earlier publication [109]. As can be seen, a number of factors have to be considered by both reservoir and production engineers; while other factors concern one discipline only. The first eight factors are summarised below but expanded to include the AICD, having been previously described in detail for ICVs and ICDs [109]:

Figure 2-47: ICD, ICV and AICD comparison framework
### Table 2-8: Conventional cased hole, ICD, ICV and AICD completions compared

<table>
<thead>
<tr>
<th>Aspect</th>
<th>ICD vs. cased hole</th>
<th>ICD vs. ICV</th>
<th>AICD vs. ICV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uncertainty in Reservoir Description</td>
<td>ICD</td>
<td>ICV</td>
<td>AICD</td>
</tr>
<tr>
<td>More Flexible Development</td>
<td>ICD</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Length of Control Interval</td>
<td>ICD</td>
<td>ICD</td>
<td>AICD</td>
</tr>
<tr>
<td>Tubing Size</td>
<td>=</td>
<td>ICD</td>
<td>AICD</td>
</tr>
<tr>
<td>Value of Information</td>
<td>=</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Control of Lateral</td>
<td>=</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Control within Lateral</td>
<td>ICD</td>
<td>ICD</td>
<td>AICD</td>
</tr>
<tr>
<td>Commingled Production</td>
<td>ICD</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Long Term Equipment Reliability</td>
<td>Conv</td>
<td>ICD</td>
<td>ICV</td>
</tr>
<tr>
<td>High Formation Permeability</td>
<td>ICD</td>
<td>ICD</td>
<td>=</td>
</tr>
<tr>
<td>Mid-to-Low Formation Perm.</td>
<td>ICD</td>
<td>ICV</td>
<td>=</td>
</tr>
<tr>
<td>Modelling Tool Availability</td>
<td>Conv</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Reservoir Isolation Barrier</td>
<td>=</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Acidizing / Scale Treatment</td>
<td>ICD</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Improved Well Clean-Up</td>
<td>ICD</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Equipment Cost</td>
<td>ICD</td>
<td>ICD</td>
<td>AICD</td>
</tr>
<tr>
<td>Installation Complexity</td>
<td>ICD</td>
<td>ICD</td>
<td>AICD</td>
</tr>
<tr>
<td>Installation Risk</td>
<td>Conv</td>
<td>ICD</td>
<td>AICD</td>
</tr>
<tr>
<td>Aspect</td>
<td>ICD vs. cased hole</td>
<td>ICD vs. ICV</td>
<td>AICD vs. ICV</td>
</tr>
<tr>
<td>------------------------</td>
<td>--------------------</td>
<td>-------------</td>
<td>-------------</td>
</tr>
<tr>
<td>Installation Time</td>
<td>ICD</td>
<td>ICD</td>
<td>AICD</td>
</tr>
<tr>
<td>In-situ Gas Lift</td>
<td>Conv</td>
<td>ICV</td>
<td>ICV</td>
</tr>
<tr>
<td>Gas Fields</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas Inflow Equalisation</td>
<td>ICD</td>
<td>ICD</td>
<td>AICD</td>
</tr>
<tr>
<td>Water Production Control</td>
<td>Conv</td>
<td>ICV</td>
<td>AICD</td>
</tr>
</tbody>
</table>

1. **Uncertainty in reservoir description** – ICVs prove to deliver higher recovery and reduced risk compared with ICDs due to its ability to adjust to unforeseen circumstances. AICDs often deliver the most recovery since they control smaller segments of the wellbore.

2. **More flexible development** – ICVs have more degrees of freedom than (A)ICDs, allowing more flexible field development strategies to be employed. Both proactive and reactive control can easily be applied with an ICV while real time optimisation can only be achieved with an ICV.

3. **Number of controllable zones** – The maximum number of ICVs installed in a single completion to date is six. On the other hand, the number of (A)ICDs which can be installed in a wellbore section is only limited by the number of packers, cost and/or drag forces limiting the reach of the completion string.

4. **Inner flow conduit diameter** – The larger flow conduit diameter gives the (A)ICD an advantage over ICV since the ICV’s reduced inner flow conduit diameter increases the “heel-toe” effect compared to an (A)ICD for comparable borehole sizes.

5. **Formation permeability, fluid phases, production/injection rates and productivity variation** – ICVs and (A)ICDs are capable of equalising the inflow from heterogeneous reservoirs. (A)ICD application in low permeability reservoirs greatly reduces the well productivity unlike ICVs. A high (A)ICD strength may be needed to achieve a high level of inflow uniformity which in turn may reduce the overall well productivity or injectivity. However, simultaneous analysis of other parameters such as fluid phases along with the
formation permeability is often required to decide which of the two technologies to select:

a. The appropriate degree of inflow equalisation must be determined in cases where complete inflow uniformity is not required. E.g. when the distance between the wellbore and the original or an invading fluid front varies significantly along the wellbore length.

b. ICVs and (A)ICDs can equally be used to manage produced oil and gas flow distribution. However, (A)ICDs are more useful in reducing volumes of associated gas-cap gas or water [110] production while ICVs may require frequent actuation (i.e. application of a controller at short time intervals [111]) to manage the high associated gas production rates.

c. Oil-water emulsions can form due to the shear created by high velocity fluid flow within an advanced completion incorporating a small diameter flow restriction. This emulsion causes the fluid’s viscosity to increase, hindering the well’s outflow performance.

d. The pressure drop/liquid flow rate relationship is largely linear across the reservoir and quadratic across the (A)ICD or ICV. The ratio of these pressure drops and the subsequent flow rate is the main factor in the (A)ICD and ICV completion’s design. However, unlike ICVs, the nature of (A)ICD completions makes its "equalisation" efficiency highly dependent on the operating conditions. E.g. this efficiency will decrease if the well operates at a lower flow rate from the design flow rate.

e. (A)ICD completions can control many intervals within a zone as well as a number of zones of varying productivity along the wellbore. The limit to such completion is the minimum (A)ICD restriction size that can practically be applied with the minimum risk of erosion, plugging or emulsion creation potential. ICV completions are limited by the number of valves that can be installed in a single completion.

6. **Value of information** – Indications of gas and water influx or rate allocation is an advantage which can be gained in both ICV and (A)ICD completions when equipped with appropriate gauges [113]. Recently, fibre optic for Distributed Temperature Sensing (DTS) was also installed in an ICD completion [112]. However, the value of information from ICVs can be increased due to the ability
to remotely control the flow rate of individual zones in addition to measuring data. This gives ICVs the advantage over (A)ICDs.

7. **Multilateral well applications** – ICVs can currently only be installed in the well’s mother bore due to limitations of available control umbilical technology to connect to both the mother bore and laterals at the junction. (A)ICDs can be installed to equalise and control the flow within individual laterals. This difference in applicability leads to the integration of ICV and (A)ICD technologies for optimum completion of multilateral wells.

8. **Multiple reservoir management** – ICVs and (A)ICDs have been applied to equalise the inflow from multiple layers within a single reservoir or multiple reservoirs. The optimum choice between these three technologies for a particular well will depend on the specific reservoir, fluid and completion architecture. However, ICVs have been proven to optimally control the commingled production and prevent the cross flow between multiple reservoirs. ICVs also allowed gas and water transfer between different layers for sweep improvement and pressure support. (A)ICDs have a limited capability to perform these tasks.

### 2.21.1 Modelling-Tool Availability

The majority of currently available reservoir simulators such as NEXUS-VIP™, STARS™, POWERS™, and EMPOWER™ are capable of modelling downhole-flow-control devices that can act as either (A)ICDs or ICVs. These software(s) divide the wellbore into an arbitrary number of segments representing sections of the tubing, annulus, and/or flow-control devices. The connections between the segments resemble a “trunk-and-branch” architecture; flow from one or more segments always converges to a single segment in the direction of the topmost segment. This modelling technique, though adequate for ICVs, has limited suitability for (A)ICD completions because of its inability to model the following:

1. Nodes with divergent fluid flow (i.e. splitting or looping flow between the annulus and the (A)ICD). Trunk-and-branch modelling is acceptable for homogeneous reservoirs, or when annular flow isolation is installed at every (A)ICD joint. It is inadequate for heterogeneous reservoirs and when partial or no annular flow isolation is installed. This results in a (possibly large) fraction of the fluid inflow from the reservoir not passing completely through the (A)ICD at the first opportunity, but choosing instead to flow in the annulus along a significant fraction of the well.
2. Annular flow occurs unless there is an isolation packer installed in the annular space between the (A)ICD and the formation sandface at every tubular joint or unless the annulus is packed with gravel or collapsed formation sand. An open annulus allows high-rate fluid inflow, resulting after gas or water breakthrough in high-rate annular flow along the whole completion. This high-rate annular flow will reduce the oil production and the recovery from the remainder of the completion [117]. The early, post-breakthrough well performance of an (A)ICD completion is not captured properly by trunk-and-branch modelling. Further, the cumulative oil production will often be overestimated because of the omission of annular flow.

Annular flow is thus an important aspect in (A)ICD-completion modelling and design. It can be modelled only by software with algorithms that can emulate splitting and re-joining (or looping) flow paths. Current software(s) that incorporate this modelling capability include Eclipse 2008™ [118] and Reveal 7.0™ [119]. Network modelling software, NETool™ [120] and GAP™ [121] can also be used, though they need to be coupled to a reservoir simulator if the dynamic performance of the completion is to be captured at all stages of the well’s life.

ICVs can be modelled easily in the current versions of most well and reservoir simulators, giving them an advantage over (A)ICDs in terms of modelling-tool availability.

2.2.1.2 Long-Term Equipment Reliability

(A)ICD reliability can be evaluated in terms of erosion or plugging of the (A)ICD flow restriction. The definition of ICV reliability is more complex. Further, there is a large difference in the flow rates controlled by the three technologies; an (A)ICD is designed to control a much lower flow rate than an ICV.

ICV reliability is often discussed in terms of the “system” and the “mission” reliability [122, 123, 124, 125]. The ICV system consists of five main components: surface-control equipment, control lines, connectors, gauges to monitor the flow, and the valve itself. Each of these main components consists of several subcomponents. For example, a hydraulically operated ICV consists of a moving sleeve or ball containing the valve-opening trim, a hydraulic chamber to translate the hydraulic pulses into mechanical movement of the valve, and a stationary housing. The failure of any of the five, main ICV components (or their subcomponents) is considered a system failure. However, the ICV is installed as part of a much larger well or field infrastructure. It will
be unable to achieve its objective following failure of external components, such as a gravel pack or a packer, that are not part of the ICV system itself. This type of failure is a called mission failure.

This concept of mission and system failure can also be applied to (A)ICD completions. The failure of the (A)ICD’s flow restriction because of erosion or plugging would be a system failure because this is the (A)ICD’s main component, while failure of a standalone sand screen (SAS), gravel pack, or annular-flow isolation installed in conjunction with (A)ICDs is a mission failure.

Here, the comparison will be restricted to the reliability of the ICV’s valve and that of the (A)ICD’s flow restriction.

The different ICD (nozzles, orifices, tubes, and helical and labyrinthine channels) and AICD (ball, flapper, disc and swellable) designs vary in their resistance to erosion and plugging. Slurry flow testing has indicated that the nozzle and orifice ICD designs are more prone to erosion than the helical-channel design [126]. However, the available information on the downhole inflow distribution of all ICD completions with a variety of flow-restriction designs has indicated an equalized fluid influx along the length of the ICD completion [38, 50, 117, 127, 128]. For example, a flowmeter survey run after 4 months of production in a well completed with nozzle-type ICDs indicated a near-uniform contribution along the wellbore [127] in a well completed in a sandstone reservoir producing at a flow rate of 6,000 to 7,000 stb/day [approximately 110 stb/day/ICD joint].

The long-term benefits of ICD completions were observed some 5 years after the introduction of ICD technology by a 4D-seismic survey conducted in 2003 on the Troll-West oil rim. This survey indicated that the wells completed with ICDs maintained excellent equalization of the approaching gas front [4, 129, 130] despite these wells having been produced at critical flow rates with a high gas/oil ratio. Erosion of the helical, channel-type ICDs would be expected to result in localized high gas concentrations, which would have been detected by the seismic survey. A common ICD design is used for both production and injection, aside from one nozzle-type ICD [22] that minimizes erosion of the ICD chamber shroud (deflector) by mounting the nozzles on a jacket welded around the base pipe (Figure 2-16).

Sand, scale, or asphaltene deposition can cause ICD plugging. However, the plugging potential of ICDs because of sand deposition can be reduced by using SAS or
gravel packs. These completions prevent production of those sand particles sufficiently large to plug the ICD’s flow restriction. Furthermore, a minimum flow-restriction diameter can be introduced into the ICD design process to minimise the plugging risk if the sand-control measures fail. Scale and asphaltene plugging has to be prevented or treated chemically because it cannot be held back mechanically. ICD plugging has not been reported to date, even though screen plugging is a problem frequently observed in sand-control completions [6, 131]. However, both the inflow rate per screen joint and the annular flow rate are considerably lower in an ICD completion than the peak flow flux rate experienced in a typical (conventional) sand-control completion. A reduced rate of screen plugging is therefore expected. Note that, in the context of this study, screen plugging represents a mission failure rather than an ICD system failure.

AICDs have just been made available commercially and their track record is very limited, but it is expected that their moving element will increase their chance of failure compared to ICDs.

Erosion of the ICV trim or shroud can lead to failure of the ICV to maintain the desired pressure drop. The ICV-trim design can be modified to minimise such erosion effects [132, 133, 134]. Partial or complete plugging of an ICV because of deposition of scale or asphaltene can be minimised by regularly cycling the valve through its various settings. Inability to adjust the valve to the required position is a significant mode of ICV system failure. Such failure could be because of the valve or from any other components that make up the actuation system. Unfortunately, the industry-reported ICV-reliability data do not distinguish between these two types of failure. However, the data clearly indicate that the actuation system and the valve-operation mechanism are the main factors affecting the ICV reliability. Hydraulically actuated valves have a higher reliability than electrically actuated or electrohydraulic valves [124]. They usually have a limited number of settings; while the electrically driven or electrohydraulic valves can offer any desired setting between the fully closed and fully open positions. The sophistication of an electrical or electrohydraulic system is often compounded with multiple pressure and temperature gauges installed at each interval. The additional complexity of such systems can greatly reduce the system reliability [122, 123, 124, 125]. Statoil reported a mission-failure rate (this includes system failures) of 25% on the early systems installed in the Snorre A and B platforms [135]. Later statistics reported a system failure rate of 39% for 36 valves installed in the Snorre B [136].
However, more-recent ICV installations have resulted in increased ICV system reliability. Shell [68] reported a doubling of the number of valves installed between 2003 and 2006 with a very limited increase in the total number of failures (Figure 2-43). The 5-year survivability for the ICV system is currently 96% for the all-hydraulic control system.

Despite this improvement in ICV reliability, the (A)ICD has an intrinsically simple design with a reduced risk of failure compared to the more complex ICV. Furthermore, the impact of a single ICD failure on the well performance is much lower than that for an ICV failure.

2.21.3 Reservoir-Isolation Barrier

An ICV is accepted as a reservoir-isolation barrier [137] during intervention operations (e.g. for removal of the wellhead), reducing the rig time and the well-intervention costs. Furthermore, the likelihood of formation damage is reduced by not exposing the reservoir to the workover fluid. Recently, the combination of an ICD with a Hydro-mechanical valve system that isolates the flow path between the screens and the ICD was reported [102]. This can be suitable for isolating the formation temporarily after the initial completion installation [102]. The AICD will naturally restrict completion fluid flow into the wellbore but, depending on its type, may not restrict the fluid flow from the wellbore to the formation. Therefore, the Hydro-mechanical valves used for the ICDs can also be integrated with the AICD completion joints to temporarily isolate the formation fluid flow into the production tubular.

The ICV thus has the advantage over the (A)ICD for isolating the formation from the fluid in the inner tubing string and providing a two-way, flow-isolation barrier.

2.21.4 Improved Cleanup

Formation damage caused by drilling or workover can affect the well performance significantly [138, 139, 140, 141]. Long horizontal and multilateral wells crossing heterogeneous, possibly multiple, reservoirs and suffering from increased frictional pressure drop along the wellbore often show greater formation damage than conventional wells. This is because of the increased exposure time of the formation to the drilling and completion fluid in addition to the greater overbalance pressure often applied during the drilling of such wells. This gives increased importance to the cleanup process used to remove formation damage.
The typical well-cleanup process involves either the well flowing naturally or aided by artificial lift. This can be effective in conventional wells (including short or medium-length horizontal wells); however this definitely does not provide adequate cleanup for very long horizontal wells. The differential pressure between the heel and the toe of the horizontal section increases once the completion fluid is removed from the well, making mudcake and invaded-fluid removal at the toe section more difficult. Furthermore, permeability variation along the wellbore plays a major role in the cleanup process because it can result in differential cleanup caused by partial cleaning of the mudcake.

ICVs can control the contribution from long horizontal sections or laterals, while ICDs installed along a horizontal lateral can equalise the contribution from small sections of the wellbore. This gives advantages to both technologies. In essence, ICVs can be used to open individual intervals (zones) or laterals sequentially, allowing the maximum allowable drawdown per zone to be applied. This ensures that each zone is cleaned up properly. Surface monitoring of the water return or the downhole pressure drops measured by the ICV gauges can be used to monitor the cleanup efficiency of a specific zone before the next zone is opened. However, higher drawdowns are not always advantageous because they may result in increased sand production or coning in thin oil columns.

ICDs, on the other hand, equalise the inflow contributions so that the low and high-productivity sections behave in a similar manner. This helps filter cake to “lift off” from long wellbore sections and allows faster flowback of the invaded fluid, assuming that sufficient pressure drop can be generated to lift off the filter cake. This implies that producing the ICD-completed wellbore at low flow rates may not provide adequate cleanup [127]. The ICD restriction size depends on the value of the design flow rate, which is normally chosen to equalise the inflow contribution from both the high- and low-productivity zones. The design, or an even higher, flow rate is thus essential to achieve proper cleanup. Successful use of nozzle-type ICDs for improved cleanup has been reported [127, 142].

AICDs restrict the flow back of drilling and completion fluid from the near wellbore area. Their ability to improve the cleanup of the near wellbore formation can be aided by cleanout valves, if installed as an integral part of each AICD section.
On balance, ICVs have the advantage for well cleanup over (A)ICDs, though this may change for specific applications. More details on the cleanup of AWCs are at Appendix A. 6-3.

2.21.5 Selective Matrix Treatment

Acid stimulation is the most frequently employed matrix treatment. It is the standard treatment for reducing near-wellbore formation damage caused by drilling, completion, injection, or production processes. Acid washing, a process that employs the same chemicals, is used to remove corrosion products and scale from inside the tubing and the perforations. It can be used as a standalone process or as a precursor to matrix acidizing. Pumping the acid through a coiled-tubing run to the top of the upper ICV or (A)ICD will avoid plugging the formation or the (A)ICD’s flow restriction with debris that is frequently created when bullheading acid from the surface via an old or dirty completion.

A key factor in the success of matrix acidizing is the uniformity of the acid placement. Enhanced acid distribution can be aided by pumping the acid into the well through coiled tubing and by the addition of diversion agents to the acid. However, acid-placement difficulties increase with completion length and complexity (e.g. the presence of liners or multiple laterals) and greater permeability variations along the wellbore. The likelihood of coiled tubing lock up also increases with wellbore length. However, vibration tools, tractors, and lateral-entry finders have all been used successfully to extend coiled-tubing reach [143, 144, 145, 146]. Despite this, coiled-tubing lockup remains a problem, causing suboptimum treatments in long horizontal and multilateral wellbores. Self-diverting acids can be used when coiled-tubing reach is less than lateral length [147], though at an increased treatment cost.

Both ICVs and ICDs provide a solution to this problem. They have significant advantages over conventional completions in terms of selective matrix treatments such as acidizing and scale-inhibitor treatments:

1. ICVs reduce costs by [148, 149]:
   - Eliminating the need for coiled tubing.
   - Providing the ability to stimulate a single zone or lateral of a multi-zone completion.
2. The acidizing of AICD completions vary with the AICD type. The disc and swellable water reactive AICDs are expected to restrict the flow of water based acid to the formation. Similarly, ball and flapper type AICDs are expected to restrict the flow back of spent acid. This undesirable effect limits the AICD suitability for application in wells where frequent acidizing operations are expected to take place to improve the formation deliverability.

3. The ICD’s equalising effect ensures uniform placement of the treatment fluid. ICDs have the advantage in matrix-acidizing treatments of an individual reservoir, though this advantage is not risk-free because the ICD’s flow restriction may become plugged by:
   - Debris released by the acid from the tubing wall and carried to the ICD during the acid treatment.
   - Spent acid flowing back into the well carrying formation solids and/or emulsions.

Acid fracturing is a very different type of acidizing treatment. It requires injection of a much larger volume of acid at a high rate and pressure that is sufficient to fracture the formation. The (A)ICD’s flow restriction may prevent this [22].

ICVs have a much wider range of applications compared to ICDs, though ICDs have the advantage for the specific application of matrix treatment to a single reservoir.

2.21.6 Equipment Cost

Purchase, installation, and operation (including maintenance) costs play a major role in the choice of advanced-well-completion equipment. These costs can vary greatly, being controlled by factors such as the well location, surface and downhole environments, produced-fluid compositions, and installation risks. In addition, completion designs vary significantly from one well to the next. Furthermore, ICVs and (A)ICDs are not installed in isolation. They form part of a larger completion; hence comparison of the cost of a single (A)ICD joint with that of an ICV is not sensible. However, it can be assumed that an ICV normally has the higher cost because of its greater functionality.

(A)ICDs and ICVs are installed in addition to the regular completion equipment (i.e. tubing, accessories, wellhead, etc.).

1. (A)ICDs are usually combined with:
• SAS, debris filters, or gravel pack, depending on the formation strength.
• Annular-flow isolation in the form of (external) packers.
• Blank pipe to isolate shale or fractured zones.

2. ICVs equipped for remote operation require equipment and accessories such as:
• Control lines for hydraulic or electric-power transmission from the surface.
• Clamps to attach the control lines to the tubing.
• Feed-through packers to segment and isolate the wellbore.
• Wellhead designed with control-line feed-throughs (penetrators).
• Surface readout and control unit.

More-complex ICVs require additional equipment. For example, the typical multi-position, balanced hydraulic ICVs provided by an ICV vendor require \( N+1 \) downhole control lines, where \( N \) is the number of valves run. Successful installation of such complex completions requires strict adherence to a precise running and testing procedure. Once installed, regular cycling of the ICV trim is required to maintain valve integrity. A full completion-design comparison should take all these and other factors into account, weighing the benefits against the costs and risks.

The cost of an ICV completion (cemented and perforated casing, two or more ICVs) is generally higher than that of most (A)ICD completions, although this will be well-architecture and location dependant. The addition of a more extensive monitoring system, often considered to be an integral part of the ICV completion, will add to the ICV’s cost.

ICDs thus have the advantage for equipment cost.

2.21.7 **Installation Risks**

Risks encountered during installation of a completion with (A)ICDs or ICVs vary greatly.

1. (A)ICD-completion risks include:

• Completion string becoming stuck before reaching the intended depth while the presence of the (A)ICDs precludes the ability to circulate the string down through debris, mudcake, or washouts. This is of particular concern if a
variable (A)ICD-flow-restriction design, blank pipe, or packers are included in the completion design.

- Screens or (A)ICD flow restrictions becoming plugged or damaged by debris, mud, or emulsions. This risk can be mitigated by use of the industry’s standard installation procedures for SAS (e.g. aggressive cleaning of the drilled hole, careful preparation of the completion fluid, use of degradable protection film around the screen, rigorous centralisation).

- External (mechanical or hydraulic) packers that fail to set. This packer-setting risk can be reduced by using self-energising “swell” packers; however, there is no definitive way to confirm that the packer has set in an (A)ICD completion. Once set, swell packers can be difficult, if not impossible, to retrieve.

2. ICV installation is a more complex process, requiring dedicated handling procedures and specially trained personnel. Handling the valve equipment itself is relatively simple compared to the installation of the integrated control and monitoring systems. These require extra rig time compared to (A)ICDs. Mounting the valve and gauges in the appropriate locations and clamping the control lines to the tubing string together with the necessary multiple packer feed-throughs is a challenging task requiring great care. The risks involved with an ICV completion include:

- Damage to the ICV system components. These risks are minimised by good job planning and an experienced crew. In addition, the condition of the valves and sensors can be monitored continuously while running in the hole, and the completion can be pulled if damage or failure is identified.

- Improper coupling of hydraulic or electric lines, resulting in complete or partial loss of the ICV control-system and/or the monitoring-system data transmission. This risk can be mitigated by colour coding of the control lines.

- Early setting of the isolation packers requires a fishing operation to retrieve the tubing string. This risk can be mitigated by using packers with an anti-premature-set feature.
A detailed risk analysis should be conducted before the installation of both ICVs and (A)ICDs. However, the overall installation risk to the long-term performance of ICVs is higher than that for (A)ICDs. Some of the ICV system failures previously highlighted can be attributed to installation damage.

It is clear that an (A)ICD-completion installation is simpler and more reliable.

2.21.8 In-situ Gas Lift

ICVs have been applied in several fields to optimise in-situ gas lift in poorly producing wells [85, 93, 130, 150, 151, 152, 153, 154]. In-situ gas lift employs gas from an associated gas cap or a separate gas reservoir, unlike regular gas lifted wells where the gas is injected from surface. Field experience has shown that proper regulation of this gas-flow rate into the tubing, as provided by ICVs, is required to optimise the fluid-production rate and to cope with changes in the well operating conditions (e.g. a rising water cut or a declining reservoir pressure). ICVs can also isolate the gas zone during well shut-ins or interventions.

In-situ gas flow can be controlled in a conventional completion by a valve installed in a side-pocket mandrel with a wireline changeable orifice. Current ICD designs provide a fixed flow restriction that cannot be altered in response to changes in the total-liquid-production rate and gas- and oil-zone pressures, or to changing tubing-pressure profiles. Furthermore, they cannot isolate the gas zone for well closure or intervention. AICDs are designed to isolate access gas injection into oil producing wells and hence are not suitable for such application.

ICVs thus have the advantage for in-situ gas lift.

2.21.9 Gas Fields

Gas fields can have a wider permeability range than oil fields while the gas can also exhibit a wider range of pressure/volume/temperature (PVT) properties than that associated with conventional oil. The low viscosity of gases implies that in the absence of reservoir flow barriers cross-flow between layers of different permeability can become significant with small differences in layer pressure. However, the absolute flowing drawdown pressures into the well can vary greatly, being a function of permeability, flow velocity, flow regime, and absolute pressure. All these parameters can change drastically during the well’s exploitation of the reservoir. It is thus necessary to evaluate the success of the ICV or (A)ICD completion design in achieving the
desired control objective over the planned lifetime of the completion. The comparison criteria highlighted previously can also be used for gas field's application, with the following comments:

(i) **Dry Gas Fields**

AWCs are applicable in high productivity, dry gas fields. ICDs can be applied to equalise the contribution from heterogeneous, layered reservoirs as long as reservoir flow barriers exist between the layers. Their application in lower-permeability formations is ineffective because of the ICD’s extra pressure drop. ICVs can be applied to minimise the drawdown or isolate sand producing formations. An example of such an ICV completion is in the Na Kika field to shut-off high-sand-producing zones [83, 84, 155, 156, 157]. However, sand production combined with a high gas-flow velocity creates increased erosion potential for the flow restriction of both ICDs and ICVs. This requires careful equipment testing and identification of appropriate trim design before installing such completions. Obviously, AICDs do not add value in dry gas fields.

(ii) **Wet Gas Fields**

In this thesis, wet gas refers to a gas field where the gas is being displaced by water from a water aquifer or water injection. ICVs have been applied successfully in many gas fields to shut-off water or high-sand-producing zones. ICVs also have the ability to control the gas production from multiple zones regardless of the formation permeability or fluid properties if the ICV trim is sized appropriately. Erosion caused by the high sand-flow velocity or condensation by pressure and temperature drop across the ICV flow restriction can be mitigated by changing the valve setting.

ICDs can be applied in wet-gas reservoirs to equalise the contribution from multiple layers with varying productivity. This can delay water breakthrough and improve the well performance. Similarly, ICD application in a thin oil column formed in a (retrograde) gas-condensate field will enhance the oil recovery. This is due to their equalisation effect and their favouring of liquid to gas flow. This behaviour can be justified by the following:

Since an ICD flow performance is similar to a fixed choke performance, an increase in the gas content of a gas-liquid mixture flow results in an increase in the pressure drop through the ICD. This will enhance the flow restriction and reduce the flow rate through that section of the completion. The opposite is true in the case of gas fields; i.e. the high
pressure drop caused by gas flow through the ICD restriction will reduce once a liquid starts to flow with the gas. This will reduce the pressure drop through the ICD, increasing the liquid inflow rate. An ICD completion is thus advantageous in an oil producer, since oil production is encouraged; but has inherent disadvantages in gas wells with water production since it exacerbates water production after breakthrough.

AICDs are similar to ICDs with the exception that their reactive functionality enables them to overcome this inherent ICD deficiency. I.E. they will minimise water flow from water breakthrough intervals while increasing total gas recovery with the advantages of the ICD described above.

(iii) Retrograde Gas-Condensate Fields

Hydrocarbon liquids may condense from the gas phase in the near wellbore completion zone and/or the wellbore itself during depletion of retrograde gas-condensate fields. The condensed liquid is often a major revenue earner. The extent of this condensation depends on the produced fluid’s PVT properties and the (current) reservoir pressure and temperature.

ICVs add value to this type of field by controlling the drawdown pressure, minimising water influx and sand production while enhancing oil (condensate) recovery. By contrast, ICD application will decrease the bottom hole pressure required to achieve a given production rate, resulting in increasing condensate saturations and reduced flow velocities. This leads to an impaired well productivity under some circumstances. Liquid production will be favoured over gas by the ICD because of the latter’s high, volumetric flow rate. The reduced pressure drop through the ICD will automatically increase the pressure drawdown (and flow velocity) from that zone (or section). The resulting increased liquid recovery adds value; providing that the well has sufficient outflow capacity to prevent liquid loading reducing the well’s production rate.

AICD completions have a unique advantage when applied to gas-condensate fields since they can minimise water production due to their ability to distinguish between water and condensate production. AICDs can also be applied to discourage gas production from higher productivity or dryer gas layers; encouraging oil and condensate production. This is especially true in heterogeneous reservoirs with no flow barriers between the layers.
(A) ICDs can reduce the sanding tendency in all these application due to their ability to reduce annular flow.

In summary, ICVs have the advantage over ICDs for application to gas wells. Yet, AICDs provide greater advantage compared to both ICDs and ICVs in equalising the fluid influx to the wellbore and reducing water production in gas fields.

2.22 Summary

Advanced Well Completions are capable of managing the fluid flow into or out of the wellbore in order to optimise the well performance. They provide solutions to many field operation challenges. Their advantages over conventional completions have been recognised by many operators. AWCs consist of one or all of the following components: Inflow Control Devices (ICDs), Inflow Control Valves (ICVs), Autonomous Inflow Control Devices (AICDs) and Annular Flow Isolations (AFIs). Each of these technologies can be provided in different types and configurations with each type having various advantages and disadvantages. These completion technologies can add value to oil and gas production from green and brown fields. However, the modelling and design of the optimum advanced well completion needs to be applied in order to realise the expected value. This objective will be illustrated in the following chapters.
Chapter 3  Advanced Well Completion Performance and Modelling

3.1  Introduction

As indicated in Chapter 2, the various components of Advanced Well Completions can be applied in different reservoir types and wellbore configurations to control single or multiple fluid phases. Experience has shown that proper modelling of AWCs is essential to achieve an optimum completion design and an optimum well performance. Modelling enables the quantification of the value which can be gained from the application of these technologies providing a (reliable) wellbore and reservoir simulation model that matches the actual (or proposed) application is available. This chapter reviews the:

1. Available AWC modelling techniques and identifies their advantages and limitations.
2. Well’s inflow/outflow performance.
3. Downhole Flow Control devices (ICV, ICD and AICD) performance and their interaction with the well inflow.

This chapter describes a simple but reliable, modelling approach of the full AWC and each of its components. This modelling approach can be used both to design AWCs as well as evaluate their performance.

3.2  Fluid Flow Path

Hydrocarbons (i.e. oil and gas) with or without associated aquifers are trapped in deep reservoirs. Exploitation of these reservoirs requires the movement of oil and gas through the permeable reservoir rock to the production wellbore. In some cases, water and/or gas is injected into the reservoir to assist in the exploitation process. Depending on the wellbore configuration and completion, the fluid flowing from the reservoir can either flow:
A) Through an openhole to the production tubing entry point.

B) Along the annular space between the sand-face and the completion outer surface before it enters the production tubular.

C) Directly through the completion tubular and any intermediate flow control device (i.e. (A)ICDs or ICVs) to the production tubing entry point.

The fluid flow continues through the production tubular followed by the surface network to the production processing plants (Figure 3-1). This flow path is reversed when an injection process is considered.

Each and every step of the fluid flow path can influence the (lateral) well performance at any stage of the well’s life. Therefore, capturing these factors is important when designing the well completion and rigorously evaluating its influence on the well performance over its expected life.

Fortunately, this can be partially achieved by the modelling techniques currently, commercially available. However, an understanding of when such techniques are necessary rather than using simpler approaches is valuable since the use of these sophisticated software(s) does not always repay for their cost and the engineering man hours required to use them.

Figure 3-1: Hydrocarbon production flow path {derived from [158]}
3.3 Advanced Well Completion Modelling Stages

The design of advanced well completions involves two important stages: 1) sizing and 2) evaluation of the completion performance (Figure 3-2).

![Diagram of AWC modelling stages]

### Figure 3-2: AWC modelling stages

3.3.1 Sizing Stage

The objectives of the sizing stage include:

- Identification of the appropriate (A)ICD restriction size and distribution.
- Identification of the required AFI frequency and type.
- Accounting for uncertainties in the design parameters.

A snapshot of the well performance at a specific time in the well’s life is required to achieve these objectives. These calculations require models of the reservoir’s inflow/injection performance coupled to the wellbore and completion flow performance. The latter calculations are carried out using two different modelling techniques (Figure 3-3):

1. A “Trunk-and-branch” modelling approach which considers direct fluid flow from the sand-face through any intermediate device to the inner section of the base pipe. The flow is always in the direction of the topmost point of the wellbore (i.e. annular flow is not considered). This calculation method is used to size the (A)ICD or ICV restriction, optimise the AFI distribution and evaluate the uncertainty in the design parameters.

2. A “Network” modelling approach which accounts for simultaneous annular flow between the sand-face and the completion outer surface (shown using dashed arrows in Figure 3-3) along with the flow through the (A)ICD restriction and flow in the inner section of the completion base pipe. This is used to (1) evaluate
the completion performance and resulting risks when suboptimal or no AFIs are installed, and (2) identify the required AFI frequency and type especially that the standard and low clearance completion tubular sizes shown in Figure 3-4 can result in significant annular flow.

Both of these techniques are suitable for evaluating the impact of reservoir uncertainties on the design parameters.

**Figure 3-3: Sizing stage modelling techniques**

**Figure 3-4: Standard (including low clearance) wellbore and completion sizes [159]**
3.3.2 **Evaluation Stage**

The evaluation stage focuses on the equipment reliability and economic value. As opposed to the sizing stage, the evaluation stage requires an estimate of the well performance over its expected life. Therefore, the evaluation stage requires a more complex 3D reservoir simulation coupled, implicitly or explicitly, to a wellbore/completion simulation to model the well and reservoir performance over time. Chapter 4 describes the workflow for the sizing and evaluation stages once the modelling requirement has been described below.

3.4 **Available Models for the Sizing Stage and Their Limitations**

Few researchers have investigated the flow performance of wells completed with AWCs using reservoir and wellbore/network simulators.

3.4.1 **Available ICD Completions Modelling Techniques and Their Limitations**

Only two researchers have studied the inflow performance of wells completed with ICDs (i.e. without the use of commercial reservoir or wellbore/network simulation programs). The equations used to determine the productivity of such wells make the following assumptions:

- The wellbore is perfectly horizontal.
- The horizontal wellbore is flowing under infinite conductivity.
- The reservoir permeability distribution along the wellbore is homogeneous (uniform). Hence the wellbore suffers from HTE only.
- No fluid flows through the annular space between the sand-face and the completion.

One of the primary differences between these models is the geometry of the drainage area and the pressure drop calculation of the ICD restriction.

A thorough investigation and development of a numerical model of steady single-phase flow into a horizontal wellbore completed with a nozzle-type ICD situated in an anisotropic reservoir has been reported [160]. This model could calculate the flux distribution along the wellbore for a specified pressure drawdown or determine the ICD properties when the flux or reservoir pressure drawdown along the wellbore is specified.

A simpler approach to estimate the effect of HTE in perfectly horizontal wells using a pseudo-linear flow model and an average specific productivity index was recently
proposed [161]. The resulting fluid influx was used to size the ICD restrictions along the wellbore.

These two models share the same limitations; by not accounting for:

1. Different wellbore configuration and deviation (i.e. vertical, deviated or multilateral wellbores).
2. Permeability variation along the wellbore, i.e. they cannot be applied to heterogeneous reservoirs.
3. Simultaneous fluid flow in the tubing, annulus and through the ICD.

ICDs were originally proposed and commercially developed for application in horizontal wells completed in homogeneous, sandstone reservoirs. However, the review of the various published applications of ICD completions in Section 2.7 showed that this is no longer the case. More heterogeneous reservoir environments, such as fractured carbonate reservoirs and different well architectures are benefiting from ICD installation. These are applications that require accurate modelling of the completion (Section 3.5).

3.4.2 Available AICD Completion Modelling Techniques

Currently, there are no established modelling techniques for AICD completions performance. This need can be met by using a general pressure drop device model which is available in both reservoir simulators and in wellbore/network simulators. Both techniques will be described (Section 3.7.2 and 3.12.2, respectively).

3.4.3 Available ICV Completion Modelling Techniques and Their Limitations

Few ICV completion modelling techniques have been proposed in the literature apart from reservoir and wellbore/network simulators [161, 162, 163]. The proposed techniques include:

1. Formation productivity or injectivity indices for separate production or injection zones.
2. Pressure drop calculation of the fluid flow through the ICV.
3. Pressure drop calculation of the commingled fluid flow through the tubing.

All of these techniques use the general engineering concept of nodal analysis, but employed different models to describe the pressure-drop/flow-rate relationship.

A modified surface choke model has been used to describe the relationship between the pressure drop and the flow rate through the ICV [162]. This model was based on
Sachdeva’s choke model with a modification to the calculation of the critical-subcritical boundary condition. This modification was introduced to account for the ICV’s upstream and downstream geometries and different ICV choking positions. This model was shown to better match the measured experimental data than the original Sachdeva’s model. The modified correlation was used in a production allocation program developed for multiple zone injection well management.

The use of Perkins’s [164], Sachdeva’s [165], or Sun’s [162] choke models to describe the pressure-flow rate relationship for ICVs was suggested. It was proposed to couple any of these models to the formation productivity index via an Integrated Inflow Performance Relationship (IPR) concept [161]. The resulting integrated IPR accounts for the zonal productivity index and the pressure-flow rate relationship of the fluid flow through the ICV and the tubing. However, this technique ignores the pressure drop due to fluid flow through the annular space (or lateral) prior to the ICV.

A 3D modelling technique for wells with complex trajectories completed in heterogeneous reservoirs and controlled with ICVs was proposed [163]. The reservoir heterogeneity was represented by an effective permeability and a skin value at the wellbore. In addition, the wellbore is segmented and the calculation of the pressure drop in the wellbore was for a single phase, oil flow. The Reynolds number used for the friction factor calculation was based on the fluid influx rate. The ICV choke model used was for single phase, sub-critical flow through a restriction, which is based on Bernoulli’s equation for flow through nozzles. However, this technique does not account for any pressure drops due to fluid flow in the annulus or lateral prior to the fluid entering the ICV.

Although all of these techniques are adequate for modelling ICV completions, they lack the ability to model:

1. Influx from a heterogeneous reservoir into a zone controlled by an ICV.
2. Wellbore pressure drops for non-horizontal wells or when multiple phases are present.
3. Annular flow along the production or injection zone (or lateral) prior to entry into the ICV.
4. Integrated (A)ICD and ICV completions.
3.4.4 **Proposed Modelling Technique**

The deficiencies highlighted above can be rectified by the use of a reservoir and wellbore modelling approach which divides the reservoir, wellbore and completion into individual segments (sections). This approach efficiently captures:

1. Productivity variations, due to permeability, viscosity, wellbore deviation, etc. variation; and pressure distribution along the wellbore and laterals.
2. Flow performance of the completion equipment. (This includes the SAS, the (A)ICD and/or the ICV).
3. Flow performance of the completion’s inner section (i.e. the pressure drop due to flow along the inner tubing or base pipe).
4. Variation in the wellbore configuration (i.e. conventional or multilateral well), reservoir configuration and fluid phases (i.e. single or multi-phase).
5. Divergent fluid flow geometries between the annulus, (A)ICD, ICV and tubing (i.e. not “trunk-and-branch”).

The integrated IPR concept has been shown to be a good technique for designing and analysing the performance of ICV completions (i.e. where an ICV is used to control the production from a zone with minor pressure drop along the zone). However, each AWC type requires some modification of the general modelling technique. These modifications and application to the design of AWCs are described in Sections 3.5-3.11.

3.5 **Inflow Performance of Wells**

The well’s inflow or injection performance, often referred to as the Productivity or Injectivity Index (PI or II), is a description of the relationship between the pressure drop across the formation and its resulting flow rate. Appropriate equations describe a steady state, pseudo-steady state or transient flow conditions and single or multi-phases can be chosen. Many researchers have investigated the flow performance of wells under different flow conditions and have developed different models for estimating the well’s flow performance index for a wide range of boundary conditions. The developed well inflow performance indices vary with well architecture (vertical or horizontal), reservoir depletion stage (above or below the bubble point pressure) and the fluid phases being produced or injected.

It is proposed to segment the reservoir and wellbore into a number of segments in the direction of the wellbore. The height (or length depending on the wellbore orientation) of each segment can be set to any length required. For example, this can be the completion equipment’s joint length (~ 40 ft for an ICD joint). This value will be
considered as the maximum segment length. The edges of each reservoir segment are modelled as a no-flow boundary. The reservoir and fluid properties (the permeability, pressure, viscosity, etc.) within a segment are constant. However, these values can vary between segments and along the wellbore. This gives the model the ability to account for a wide range of reservoir heterogeneity, fluid properties, wellbore elevation and reservoir/wellbore pressures along the wellbore.

### 3.5.1 Vertical and Deviated Wells

The classical, single phase, steady state, radial flow PI of a vertical well [158] is used to calculate the productivity of an individual segment when the well is vertical (or deviated) and flowing oil above the bubble point pressure:

\[
PI = \frac{k_o h}{141.2 B_o \mu_o \left( \ln \frac{r_e}{r_w} + S_t \right)}
\]

Equation 3-1

Where:
- \( PI \) = Productivity index (stb/day/psi)
- \( k_o \) = Effective permeability to oil (md)
- \( h \) = Reservoir (segment) height (ft)
- \( B_o \) = Oil formation volume factor (bbl/stb)
- \( \mu_o \) = Viscosity of oil (cp)
- \( r_e \) = Drainage radius (ft)
- \( r_w \) = Wellbore radius (ft)
- \( S_t \) = Total skin factor (dimensionless)

Wellbore deviation is accounted for by a partial penetration skin factor, which forms part of the total skin factor, \( S_t \). The effect of relative permeability (i.e. flow of other phases) is accounted for via a mobility term (Equation 3-2):

\[
PI = \frac{k h \left( \frac{k_{ro}}{B_o \mu_o} \right)}{141.2 \left( \ln \frac{r_e}{r_w} + S_t \right)}
\]

Equation 3-2

Where:
- \( k \) = Absolute permeability (md)
- \( k_{ro} \) = Relative permeability of oil

The pseudo-steady state PI can be used if the well is producing from a rectangular-shaped reservoir (Equation 3-3).
\[ PI = \frac{kh}{141.2 \left( \ln \frac{r_e}{r_w} - 0.75 + S_t \right)} \left( \frac{k_{ro}}{B_o \mu_o} \right) \]  

Equation 3-3

Alternative models can be chosen if they are calibrated to the actual well performance.

### 3.5.2 Horizontal and Multilateral Wells

Many researchers have investigated the flow performance of horizontal and multilateral wells under transient, steady and pseudo-steady state flow conditions. Analytical, semi-analytical and numerical solutions are available to estimate horizontal well’s productivity. Some researchers included a coupling of the wellbore pressure drop with a single phase productivity index.

In general, the horizontal well performance models can be divided into three categories: Analytical models, semi-analytical models and numerical models. Reviews of published single phase, horizontal well performance relationships were presented in reference [166] and [167].

The majority of the analytical equations used to determine the productivity of horizontal wells make use of the following assumptions [166]:

- Infinite conductivity of the horizontal wellbore.
- Homogeneous (uniform) reservoir permeability distribution along the wellbore.
- The wellbore penetrates the reservoir either fully or partially.

The primary difference between these models is the geometry of the drainage area. This can be radial, elliptical, rectangular or a combination of different geometries. However, these models overestimate the well productivity since they omit the pressure drop along the wellbore. Further, any reservoir productivity variation along the wellbore due to permeability, pressure or fluid property heterogeneity is not included.

Numerical models use systems of differential equations to simulate simultaneous, single and multi-phase fluid flow in homogeneous and heterogeneous reservoirs and wellbores with complex architecture. These can estimate both horizontal and multilateral wells performance accurately as well as account for variation in the wellbore orientation and in reservoir and fluid properties. An example of the former process was presented [168] through the development of a numerical model to estimate the horizontal well productivity which included the wellbore hydraulics. This model
was compared to analytical and semi-analytical models and proved to be superior for accounting for the effect of wellbore friction on the fluid influx. An example of the latter process was also reported [169]. This model has been incorporated in reservoir simulation programs (e.g. Eclipse™ [170]). Such models can be used to predict the productivity of horizontal and multi-lateral wells completed with AWCs producing from, or injecting into, multiple reservoirs. However, such models are complex and are often incorporated in simulation packages. Obtaining access to them can be expensive and their use is often limited to reservoir engineers specialised in reservoir simulation.

Semi-analytical models offer a good solution to the design challenge. They are formed by a combination of an analytical productivity model and numerical calculation of the pressure drop along the wellbore. For example, a model was presented recently [167] which estimate the productivity of horizontal and multilateral wells in a manner similar to the modelling process proposed in this thesis. This modelling technique segments the wellbore into small sections and calculates the productivity of each reservoir section using a steady state flow correlation [171] and a single phase pressure drop calculation [189] for fluid flow in the wellbore. However, this modelling technique did not consider the completion or any intermediate devices between the reservoir and the wellbore. It also did not account for multiphase fluid flow, as required when designing AWCs.

Babu and Odeh [172] presented a pseudo-steady state productivity model for horizontal wells completed in a rectangular-shaped reservoir. It assumed a uniform flux in the development of the productivity model; allowing the pressure to vary between the toe and the heel of the well. This model has two advantages. It accounts for the effect of:

1. Full reservoir penetration by the wellbore, and
2. Fluid convergence towards the toe and the heel when the reservoir is not fully penetrated by the wellbore.

Babu and Odeh [172] model assumes that the pressure at the midpoint of the wellbore provides the best representation of the well’s performance. This is incorrect when describing a complete wellbore. However, this model can be used to describe the productivity of a single wellbore segment since:

1. It includes the effect of fluid convergence towards the toe and the heel if the wellbore is not fully penetrating the reservoir.
2. The fluid influx at the midpoint of the segment length is representative of the average property values once the reservoir and wellbore are segmented.

3. The use of a pseudo-steady state productivity model is preferred when a reservoir with a gas cap or an aquifer is being modelled.

Babu and Odeh [172] productivity model is used in this work to estimate the productivity of individual segments of the wellbore when designing AWCs of horizontal and multilateral wells (Equation 3-4).

\[
PI = \frac{b \sqrt{k_x k_z}}{141.2 \left( \ln \frac{C_H \sqrt{A}}{r_w} - 0.75 + S_R \right)} \left( \frac{k_{ro}}{B_o \mu_o} \right) \text{ Equation 3-4}
\]

Where:
- \( b \) = Extension of the drainage volume in the y direction, here \( b \) represents the direction of the wellbore (ft)
- \( k_x \) = Permeability in the x direction (md)
- \( k_z \) = Permeability in the z direction (md)
- \( A \) = Drainage area of the segment, \( oh \), (ft²)
- \( S_R \) = Skin resulting from partial penetration

\( C_H \) is:

\[
C_H = 6.28 \left( \frac{o}{h} \right) \left[ \frac{k_z}{k_x} \left( \frac{1 - x_o}{o} + \left( \frac{x_o}{o} \right)^2 \right) \right] - \ln \left( \sin \frac{180^\circ z_o}{h} \right) - 0.5 \ln \left( \frac{o}{h} \right) \left( \frac{k_z}{k_x} \right) - 1.088 \text{ Equation 3-5}
\]

Where:
- \( o \) = Extension of the drainage volume in the x direction (ft)
- \( h \) = Reservoir thickness (ft)
- \( x_o \) = x coordinate of centre of segment
- \( z_o \) = z coordinate of centre of segment

\( S_R \) is included in the toe and the heel segments only if the well does not penetrate the full length of the reservoir. The skin value is zero if the well is fully penetrating as well as for all intermediate segments along the wellbore. \( S_R \) is calculated using Equation 3-6 or Equation 3-7 depending on the ratio of length over the square root of the permeability in the x and y plane of the reservoir. Equation 3-6 is used when:

\[
o/(k_x)^{0.5} \geq 0.75b/(k_y)^{0.5} \gg 0.75h/(k_z)^{0.5}
\]

Equation 3-7 is used when:

\[
b/(k_y)^{0.5} \geq 1.33o/(k_x)^{0.5} \gg h/(k_z)^{0.5}
\]
\[ S_R = P_{xyz} + P'_{xy} \quad \text{Equation 3-6} \]
\[ S_R = P_{xyz} + P_{xy} + P_y \quad \text{Equation 3-7} \]

The formulations of \( P_{xyz}, P_{xy}, P'_{xy} \) and \( P_y \) are provided in reference [172].

The horizontal well models presented by Furui [171] or Butler [173] can be applied for a steady state production condition instead of the above pseudo-steady state model. However, these models assume that the horizontal wellbore penetrates the full length of a rectangular-shaped reservoir. The skin factor proposed by Babu and Odeh [172] should be added to these models to account for flow convergence to the toe or the heel segments when this condition is not met [174]. Equation 3-8 provides the formulation of Furui [171] model including the partial penetration skin [174].

\[
PI = \frac{b_h \sqrt{k_x k_z}}{141.2 \ln \left( \frac{h \sqrt{k_x}}{k_z} \right) + \frac{\pi x_h}{h \sqrt{k_z}} - 1.224 + S + S_R} \frac{k_{ro}}{B_o \mu_o} \quad \text{Equation 3-8}
\]

Where:
\[ x_h = \text{Extension of the drainage volume in the x direction, here } x_h \]
\[ \text{represents the direction perpendicular to the wellbore (ft)} \]
\[ s = \text{Formation damage (dimensionless)} \]

**Note:**

The vertical well productivity model can, sometimes, be an adequate depiction of the performance of small sections of horizontal and multilateral wells when completed in heterogeneous reservoirs. This is due to the:

1. Segmentation of the reservoir and wellbore into small sections
2. Factors which can influence the behaviour of advance well completions. This concept will be clearer once the effect of heterogeneity away from the wellbore is explained (Section 4.4). However, the horizontal and vertical permeability has to be used to calculate the effective permeability as proposed by Peaceman D.W. [169]. In addition, the vertical reservoir height should be set equal to the wellbore segment length.

### 3.5.3 Gas Wells

Gas wells, as with oil wells, can produce under transient, steady and pseudo-steady state flow conditions. However, unlike oil wells, the productivity varies depending on
the reservoir pressure. Ahmed, T. [175] proposed that the productivity potential of gas wells with a reservoir pressure greater than 3,000 psi can be described by Equation 3-9:

$$PI_g = \frac{Q_g}{(\bar{P}_r - P_{wf})} = \frac{7.08 \times 10^{-5} k_g h}{(\mu_g B_g)_{avg1} \left[ \ln \left( \frac{r_c}{r_w} \right) - 0.75 + s \right]}$$  \hspace{1cm} \text{Equation 3-9}

Where:

- $PI_g$ = Productivity of gas (Mscf/day/psi)
- $Q_g$ = Gas flow rate (Mscf/day)
- $\bar{P}_r$ = Average reservoir pressure (psi)
- $k_g$ = Effective permeability to gas (md)
- $\mu_g$ = Gas viscosity (cp)
- $B_g$ = Gas formation volume factor (ft$^3$/scf)
- $avg1$ = Values at the average pressure calculated using Equation 3-10

Where:

$$P_{avg1} = \frac{\bar{P}_r - P_{wf}}{2}$$  \hspace{1cm} \text{Equation 3-10}

However, use Equation 3-11 where the reservoir pressure falls between 3,000 and 2,000 psi [175].

$$PI_g = \frac{k_g h}{1422T \left[ \ln \left( \frac{r_c}{r_w} \right) - 0.75 + s \right]}$$  \hspace{1cm} \text{Equation 3-11}

Where $T$ is the temperature in degrees Rankin (°R).

Further, use Equation 3-12 where the reservoir pressure is lower than 2,000 psi 175:

$$PI_g = \frac{k_g h}{1422T (\mu_g z)_{avg2} \left[ \ln \left( \frac{r_c}{r_w} \right) - 0.75 + s \right]}$$  \hspace{1cm} \text{Equation 3-12}

Where $z$ is the gas compressibility factor.

The gas viscosity and compressibility factors should be calculated at the average pressure ($avg2$) calculated using Equation 3-13:

$$P_{avg2} = \sqrt{\frac{\bar{P}_r^2 - P_{wf}^2}{2}}$$  \hspace{1cm} \text{Equation 3-13}
These models can be used to estimate the productivity or the injectivity of gas wells. Horizontal and multilateral gas wells can be segmented similar to horizontal and multilateral oil wells.

### 3.6 Flow Performance and Modelling of ICDs

Published data on fluid flow through ICDs from four major suppliers is sub-critical (Figure 3-5, Figure 3-6, Figure 3-7 and Figure 3-8).

**Figure 3-5: Flow test data for a helical channel-type ICD 16**

**Figure 3-6: Flow test data for an orifice-type ICD (maximum of 10-open-orifices)**

[176]
Sub-critical flow is observed in ICDs due to their design and their limited capacity to handle very large pressure drops. In addition, fluid flow through ICD restrictions can be considered homogeneous due to the small size of the flow restriction. Each ICD type
has a characteristic description of the flow behaviour, requiring its own modelling technique:

### 3.6.1 Helical Channel-type ICD

Flow of single-phase (water) and two-phase water and air through helical pipes has been extensively studied by many researchers [179, 180, 181]. One of the distinguishing features between flow in helical pipes and straight pipes is presence of a centrifugal force effect (Dean, W.R. [179]). This centrifugal force causes the critical Reynolds number (Re) for the transition from laminar flow to turbulent flow to be a function of the Dean number (De) and the Curvature ratio (λ) [179]:

\[
De = Re^{0.5}
\]

Equation 3-14

Where:

\[
\lambda = \frac{d_c}{DEP}
\]

Equation 3-15

\[
\lambda = \text{Curvature ratio}
\]

\[
d_c = \text{Helical channel diameter (m)}
\]

\[
DEP = \text{Base pipe external diameter, curvature diameter (m)}
\]

\[
Re = \text{Reynolds number (dimensionless) calculated using:}
\]

\[
Re = \frac{\rho v d_c}{\mu}
\]

Equation 3-16

\[
\rho = \text{Fluid density (Kg/m}^3\text{)}
\]

\[
\mu = \text{Fluid viscosity (Kg/m-s)}
\]

\[
v = \text{Fluid flow velocity (m/s)}
\]

The critical Reynolds number for small helical pipes has a larger value than that for straight pipes 180.

Examination in 2006 of a cutaway example of a helical channel-type ICD indicated that:

1. The ICD restriction chamber contains multiple channels forming a helix around the base pipe, Figure 2-9.
2. This particular ICD was claimed to impose a pressure drop of 1.6 bar when 26 Sm\(^3\)/day of water passed through the ICD via a:
   a. Restriction chamber extending over a length of approximately 1.5 ft.
   b. Channel diameter of approximately 0.033 ft.
   c. Channels separator (metallic wall) thickness of approximately 0.010 ft.
3. A “stronger” ICD designed to impose a pressure drop of 3.2 bar required a 0.5 ft of restriction chamber length. The channels dimensions were not visible in this ICD.

The manufacturer can vary: (1) the number of channels, (2) the channel diameter and (3) the channel length in order to achieve the required pressure drop. Unfortunately such details of the ICD channel dimensions are not normally published. Hence, the performance of the helical channel-type ICD can only be described by its strength value (i.e. the pressure drop generated at the standard water flow rate of 26 Sm$^3$/day). The helical channel-type ICD modelling technique introduced in Eclipse™ reservoir simulator [170] should therefore be used.

This modelling technique is based on:

1. The Chisholm pressure multiplier concept. This relates the pressure drop caused by the flow of multiple phases through the ICD to the pressure drop caused by liquid flow (i.e. a calibration fluid which is water in this case) through the ICD.

\[
\phi_{L1}^2 = \frac{(\delta P)_{TP}}{(\delta P)_{L1}}
\]  

Equation 3-17

Where:

\( \phi_{L1} \) = Two or three phase frictional multiplier

\((\delta P)_{TP} \) = Pressure drop due to two or three phase flow through the helical channel

\((\delta P)_{L1} \) = Pressure drop due to liquid flow only (water in this case) through the helical channel

2. An empirical constant called the ICD strength \((a_{ICD})\). This is related to the flow resistance rating of each ICD joint.

Chen and Guo [181] indicated that a modification of the Chisholm pressure multipliers adequately fits the measured pressure drop when a three-phase fluid flows through a horizontal helical pipe. Eclipse™ reservoir simulator [170] applied this approach to calculate the pressure drop through a helical channel-type ICD since its flow characteristics when liquid only flows through the device is already known.

The following explains how this modelling technique is derived:

Substitute the conventional correlation for frictional pressure drop due to homogenous flow in pipes for \(\delta P\) (Equation 3-18) in Equation 3-17:
\[ \delta P_p = \frac{C_f f_{\text{mix}} L \rho_{\text{mix}} q^2}{d^5} \]  
\text{Equation 3-18}

It translates to:

\[ \phi_{L1}^2 = \frac{C_f f_{\text{mix}} L \rho_{\text{mix}} q_{\text{ICD}}^2}{d^5} \]  
\text{Equation 3-19}

For the same ICD dimensions, this simplifies to:

\[ \phi_{L1}^2 = \frac{f_{\text{mix}} \rho_{\text{mix}}}{f_{L1} \rho_{L1}} \]  
\text{Equation 3-20}

The Blasius equation (Equation 3-21) can be used for the calculation of the friction factor:

\[ f' = 0.316 (\text{Re})^{-0.25} \]  
\text{Equation 3-21}

Then:

\[ \phi_{L1}^2 = \left( \frac{0.316}{(\rho_{\text{mix}} v d_c / \mu_{\text{mix}})^{0.25}} \right) \left( \frac{\rho_{\text{mix}}}{\rho_{L1}} \right) \]  
\text{Equation 3-22}

This simplifies to:

\[ \phi_{L1}^2 = \left( \frac{\rho_{L1} \mu_{\text{mix}}}{\mu_{L1} \rho_{\text{mix}}} \right)^{0.25} \left( \frac{\rho_{\text{mix}}}{\rho_{L1}} \right) \]  
\text{Equation 3-23}

Where:

\[ \delta P_p \quad = \text{Pressure drop due to flow in a pipe} \]
\[ C_f \quad = \text{Conversion factor (shown in Table 3-1)} \]
\[ f' \quad = \text{Fanning friction factor, described in Section 3.6.3} \]
\[ L \quad = \text{Pipe length} \]
\[ d \quad = \text{Pipe diameter} \]
\[ \rho_{\text{mix}} \quad = \text{Density of the fluid mixture at in-situ conditions calculated using:} \]
\[ \rho_{\text{mix}} = \alpha_o \rho_o + \alpha_w \rho_w + \alpha_g \rho_g \]  
\text{Equation 3-24}
\[ \rho_{o, g, w} \quad = \text{Density of oil, gas and water phases at in-situ conditions} \]
\[ \alpha_{o, g, w} \quad = \text{Volume fraction of oil, gas and water phases at in-situ conditions} \]
\[ \mu_{o, g, w} = \text{Dynamic viscosity of oil, gas and water at in-situ conditions} \]

\[ \mu_{\text{mix}} = \text{Mixture viscosity (the calculation of this term is explained below)} \]

**Table 3-1: \( C_f \) values**

<table>
<thead>
<tr>
<th>Unit system</th>
<th>( C_f )</th>
<th>Density</th>
<th>Flow rate</th>
<th>Length</th>
<th>Diameter</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>METRIC</td>
<td>7.00x10^{-4}</td>
<td>Kg/m³</td>
<td>m³/s</td>
<td>meter</td>
<td>meter</td>
<td>bar</td>
</tr>
<tr>
<td>FIELD</td>
<td>3.24x10^{-5}</td>
<td>lbm/ft³</td>
<td>ft³/s</td>
<td>ft</td>
<td>ft</td>
<td>psi</td>
</tr>
</tbody>
</table>

\( \alpha_{ICDS} \) is related to the flow resistance rating of each ICD joint (Equation 3-25) via the calibration test that measures the pressure drop created by a standard fluid (liquid) flow through the ICD.

\[
\alpha_{ICDS} = \frac{\delta P_{ICDL}}{q_{ICDL}^2}
\]

Equation 3-25

Where:

\( \delta P_{ICDL} \) = Pressure drop across the ICD restriction caused by standard liquid flow (psi or bar)

\( \alpha_{ICDS} \) = Standard ICD strength value (psi/(scf/day)² or bar/(Sm³/day)²)

\( q_{ICDL} \) = Standard liquid (volumetric) flow rate through the ICD (scf/day or Sm³/day)

The \( \alpha_{ICDS} \) value has to be converted to reservoir conditions using (Equation 3-26):

\[
\alpha_{ICD} = \frac{\alpha_{ICDS}}{B_{CL}^2}
\]

Equation 3-26

Where:

\( \alpha_{ICD} \) = ICD strength value (psi/(rft³/day)² or bar/(rm³/day)²)

\( B_{CL} \) = Calibration liquid formation volume factor (bbl/stb or rm³/Sm³)

Typical helical channel-type ICD (standard) strength values are listed in Table 3-2. These values were calculated using Equation 3-25 from the published flow testing data (Figure 3-5 [16]). These values remain relatively constant for different flow rates, as will be illustrated for the orifice-type ICD (Figure 3-14). The calculated data (Figure 3-9) was fitted with a linear correlation (Equation 3-27), which can be used to estimate the helical channel-type ICD strength value for any ICD rating.

\[
\alpha_{ICDS} = 0.0012(\text{ICD}R_{bar}) - 0.00004
\]

Equation 3-27

Where \( \text{ICD}R_{bar} \) is the ICD rating in bar.
Table 3-2: Calculated ICD strength values

<table>
<thead>
<tr>
<th>ICD Strength Rating (bar)</th>
<th>$a_{ICDS}$ Values</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>bar/(Sm$^3$/day)$^2$</td>
</tr>
<tr>
<td>0.2</td>
<td>0.00021</td>
</tr>
<tr>
<td>0.4</td>
<td>0.00040</td>
</tr>
<tr>
<td>0.8</td>
<td>0.00093</td>
</tr>
<tr>
<td>1.6</td>
<td>0.00183</td>
</tr>
<tr>
<td>3.2*</td>
<td>0.00371</td>
</tr>
</tbody>
</table>

*3.2 bar ICD $a_{ICD}$ value is an extrapolation of the lower ICD strength values using Equation 3-27 as shown in Figure 3-9.

Figure 3-9: Strength values of helical channel-type ICDs and their extrapolation

The pressure drop $(\delta P)_{TP}$ caused by a multi-phase fluid flow through this ICD can be achieved by:

1. Rearranging Equation 3-25 to solve for $\delta P_{ICDL}$ and substituting its value in place of $(\delta P)_{L1}$ in Equation 3-17.
2. Rearranging Equation 3-17 to solve for $(\delta P)_{TP}$ and substituting Equation 3-23 in place of $\phi_{L1}^2$. This results in the following [170]:

\[
y = 0.0012x - 0.00004 \\
(Equation 28)
\]
\[
\delta P_{ICD} = \left( \frac{\rho_{cal} \cdot \mu_{mix}}{\rho_{mix} \cdot \mu_{cal}} \right)^{0.25} \cdot \frac{\rho_{mix}}{\rho_{cal}} \cdot \alpha_{ICD} \cdot q_{ICD}^2
\]

Equation 3-28

Where:

- \( \delta P_{ICD} = (\delta P)_{TP} \) the pressure drop across the ICD restriction (psi or bar)
- \( \rho_{cal} \) = Calibration fluid density (lb/ft\(^3\) or Kg/m\(^3\))
- \( \mu_{cal} \) = Calibration fluid viscosity (cp)
- \( \rho_{mix} \) = Mixture fluid density (lb/ft\(^3\) or Kg/m\(^3\))
- \( \mu_{mix} \) = Mixture fluid viscosity (cp)
- \( q_{ICD} \) = Fluid (volumetric) flow rate through the ICD (rft\(^3\)/day or rm\(^3\)/day)

The mixture viscosity can be calculated using:

\[
\mu_{mix} = (\alpha_o + \alpha_w)\mu_{emul} + \alpha_g \mu_g
\]

Equation 3-29

Where \( \mu_{emul} \) is the viscosity of the oil-water emulsion at in-situ conditions.

The emulsion viscosity is dependent on the volume fraction of the oil and water phases at the local conditions. The fluid flowing through an ICD can be a single phase, two-phases or even three-phases, depending on the application environment.

The flow patterns and pressure drop of two-phase (oil-water) and three-phase (air-oil-water) flow in horizontal and vertical helical pipes has been studied [181]. It was observed that the water-cut corresponding to the phase inversion point for an oil-water mixture (the point at which the dispersed and continuous phases change) occurs at a lower value in horizontal helical pipes than in horizontal straight pipes. However, in the absence of a correlation to define the phase inversion water cut (\( \varepsilon_w \)) in horizontal helical pipes, a correlation for a horizontal, straight pipe can be used (Equation 3-30) [181]:

\[
\varepsilon_w = 0.5 - 0.1108 \log \mu_o
\]

Equation 3-30

Where \( \mu \) is the dynamic viscosity of the oil in cp.

Equation 3-30 can be used to identify the critical water cut at which an inversion from oil to water as the continuous phase takes place (Point A in Figure 3-10) based on the oil viscosity.
When the oil is the continuous phase, the emulsion viscosity can be calculated using [170]:

\[
\mu_{\text{wio}} = \mu_o \left(1 - \frac{1}{0.8415 \alpha_{wl} + 0.7480} \right)^{2.5}
\]  
Equation 3-31

When the water is the continuous phase the following can be used [170]:

\[
\mu_{\text{oiw}} = \mu_w \left(1 - \frac{1}{0.6019 \alpha_{ol} + 0.6410} \right)^{2.5}
\]  
Equation 3-32

Where:
- \(\mu_{\text{wio}}\) = Water in oil emulsion viscosity (cp)
- \(\mu_{\text{oiw}}\) = Oil in water emulsion viscosity (cp)
- \(\alpha_{wl}\) = In-situ water-in-liquid fraction
- \(\alpha_{wl} = \alpha_w / (\alpha_w + \alpha_o)\)  
  Equation 3-33
- \(\alpha_{ol}\) = In-situ oil-in-liquid fraction
\[ \alpha_{ol} = \alpha_{o} / (\alpha_{w} + \alpha_{o}) \]  \hspace{1cm} \text{Equation 3-34}

### 3.6.2 Nozzle and Orifice-type ICDs

The flow through nozzle and orifice-type ICDs can be represented by Bernoulli’s model for flow through a constriction. This model can be used since frictional pressure drops are normally negligible and only acceleration effects caused by the restriction of the fluid flow area contribute to the pressure drop through such designs. These multiple nozzles/orifices devices can be represented by a single nozzle/orifice that accounts for the cumulative flow.

ISO-5167 [182] provides a comprehensive description of this flow type for single or multiphase flow of gas, oil and/or water (Equation 3-35):

\[ \Delta P_{ICD} = \frac{8C_{u} \rho_{mix} q_{ICD}^{2} \left(1 - \beta^{4}\right)}{C_{(Re)}^{2} \varepsilon^{2} \pi^{2} d_{no}^{4}} \]  \hspace{1cm} \text{Equation 3-35}

Where:

- \( C_{u} \) = Conversion factor shown in Table 3-3
- \( C_{(Re)} \) = Nozzle/orifice discharge coefficient based on the Reynolds number (dimensionless)
- \( d_{no} \) = Nozzle/orifice diameter (units shown in Table 3-3)
- \( \varepsilon \) = Gas expansibility factor (dimensionless)
- \( \beta \) = Ratio of nozzle/orifice diameter to upstream pipe diameter (dimensionless), calculated using Equation 3-36:

\[ \beta = \frac{d_{no}}{D_{cr}} \]  \hspace{1cm} \text{Equation 3-36}

- \( D_{cr} \) = Clearance diameter of the ICD restriction chamber ahead of nozzles/orifices (units shown in Table 3-3), calculated using Equation 3-37:

\[ D_{cr} = \sqrt{d_{chout}^{2} - d_{chin}^{2}} \]  \hspace{1cm} \text{Equation 3-37}

- \( d_{chout} \) = Chamber outer diameter (units shown in Table 3-3)
- \( d_{chin} \) = Chamber inner diameter (units shown in Table 3-3)
Table 3-3: $C_u$ values [170]

<table>
<thead>
<tr>
<th>Unit system</th>
<th>$C_u$</th>
<th>Density</th>
<th>Velocity</th>
<th>Flow rate</th>
<th>Diameters</th>
<th>Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td>METRIC</td>
<td>1.0x10^{-5}</td>
<td>Kg/m^3</td>
<td>m/s</td>
<td>m^3/s</td>
<td>meter</td>
<td>bar</td>
</tr>
<tr>
<td>FIELD</td>
<td>2.159x10^{-4}</td>
<td>lbm/ft^3</td>
<td>ft/s</td>
<td>ft^3/s</td>
<td>ft</td>
<td>psi</td>
</tr>
</tbody>
</table>

$C_{(Re)}$ is a function of the Reynolds number which is a function of the flow rate. Hence, the pressure drop through the ICD ($\delta P_{ICD}$) can be calculated analytically when the flow rate and the ICD diameter are known. By contrast, calculation of $\delta P_{ICD}$ requires an iterative process when the diameter and/or the flow rate through the ICD need(s) to be evaluated. $C_{(Re)}$ can be specified instead of being calculated to make the latter process analytical. In this case, $C_{(Re)}$ will be referenced as $C_d$.

For nozzle-type ICD use Equation 3-38 [182] to calculate $C_{(Re)}$:

$$C_{(Re)} = 0.99 - 0.2262\beta^{4.1} - \left(0.00175\beta^2 - 0.0033\beta^{4.15}\frac{10^6}{\text{Re}_D}\right)^{1.15}$$

Equation 3-38

For an orifice-type ICD use Equation 3-39:

$$C_{(Re)} = 0.8318 - 0.2262\beta^{4.1} - \left(0.00175\beta^2 - 0.0033\beta^{4.15}\frac{10^6}{\text{Re}_D}\right)^{1.15}$$

Equation 3-39

Where:

- $\text{Re}_D = \text{Reynolds number of the flow in the region upstream of the nozzle/orifice}$:

$$\text{Re}_D = \frac{4q_{ICD}\rho_f}{\pi\mu_f D_{cr}}$$

Equation 3-40

- $\rho_f = \text{Fluid density (Kg/m}^3\text{)}$
- $\mu_f = \text{Fluid viscosity (Pa-s)}$

Equation 3-38 was calibrated based on the flow test data of the orifice-type ICDs to produce Equation 3-39.
3.6.3 Labyrinth Channel and Flow Tube-type ICD

The fluid flow through labyrinth channel and tube-type ICDs is essentially flow through a pipe. In addition, small diameter tubes or channels confine the flow from a large flow area, prior to the ICD restriction chamber, to the tubes (or channels) leading to an additional pressure drop. The individual flow tubes (and channels) come in standard sizes. For example, the standard individual tube length is 4 inch [183]. The number and length of the tubes or channels are adjusted to achieve the required pressure drop. This implies that the length of the restriction determines whether flow through this type of ICD is dependent on frictional or acceleration effects or both; The acceleration effect is expected to become dominant in short tubes and channels while the frictional effect will be more important in long tubes and channels. Therefore, the best approach to the calculation of the pressure drop through such ICDs is a combination of the pressure drop calculation through an orifice and a pipe. The gravitational effects calculation can be simplified by neglecting, even when the ICD is installed vertically, since the:

- Tubes are relatively short
- Fluid flowing through the restriction travels in both an upwards and a downwards direction between the tubes/channels before flowing into the inner section of the base pipe.

The pressure drop through these devices can be calculated by Equation 3-41:

\[
\delta P_{ICD} = \frac{8C_d \rho_{mix} q_{ICD}^2 (1 - \beta^4)}{C_{f(Re)}^2 \varepsilon^2 \pi^2 d_{tl}^4} + \frac{C_f f L \rho_{mix} q_{ICD}^2}{d_{tl}^5}
\]

Equation 3-41

Where:

- \( \delta P_{ICD} \) = \( f(acceleration) + f(friction) \)
- \( C_f \) = Conversion factor, shown in Table 3-1
- \( f \) = Fanning friction factor, described below
- \( L_{tl} \) = Tube/Labyrinth channel length
- \( d_{tl} \) = Tube/Labyrinth channel diameter

The friction factor \( f \) depends on the Reynolds number. Some available models distinguish between laminar and turbulent flow-regimes while others apply a single model, making it more convenient to apply and providing a continuous function. Four widely used friction factor models are (Hagen-Poiseuille [184], Haaland [184], Romeo [184] and Churchill [184]). Haaland and Romeo use different equations to estimate
laminar and turbulent flow friction factors while Churchill proposed a single equation to cover both regimes. The Hagen-Poiseuille model is widely used to estimate the friction factors for laminar flow (i.e. for Reynolds number values lower than 2100). They have been compared by estimating the friction factor for flow through a 1.5 ft-long, 0.08 ft-diameter pipe representing a tube/labyrinth channel ICD. The results of this comparison are listed in Table 3-4.

Table 3-4: Comparison of the results of four friction factor estimation models

<table>
<thead>
<tr>
<th>Reynolds Number</th>
<th>Hagen-Poiseuille</th>
<th>Haaland</th>
<th>Romeo</th>
<th>Churchill</th>
</tr>
</thead>
<tbody>
<tr>
<td>723</td>
<td>0.0885</td>
<td>0.0757</td>
<td>0.0706</td>
<td>0.0885</td>
</tr>
<tr>
<td>1800</td>
<td>0.0355</td>
<td>0.0530</td>
<td>0.0515</td>
<td>0.0355</td>
</tr>
<tr>
<td>2820</td>
<td>0.0227</td>
<td>0.0455</td>
<td>0.0447</td>
<td>0.0452</td>
</tr>
<tr>
<td>7232</td>
<td>0.0089</td>
<td>0.0342</td>
<td>0.0342</td>
<td>0.2610</td>
</tr>
<tr>
<td>14,464</td>
<td>0.0044</td>
<td>0.0285</td>
<td>0.0287</td>
<td>0.2301</td>
</tr>
</tbody>
</table>

Table 3-4 indicates that the Haaland and Romeo equations agree over a wide range of flow rates. The Churchill model closely matches the Hagen-Poiseuille model for flow rates with Reynolds number values lower than 2100. However, the Churchill model results started to deviate significantly from the other three models for Reynolds numbers greater than 2800. It is therefore proposed to use Hagen-Poiseuille (Equation 3-42) to estimate the friction factor values for laminar flow (i.e. Reynolds number values under 2100) and Haaland (Equation 3-43) to estimate the friction factor values for transition and turbulent flow (i.e. Reynolds numbers greater than 2100).

\[
f = \frac{64}{\text{Re}} \quad \text{Equation 3-42}
\]

\[
f = \left[ 1.8 \log \left( \frac{6.9}{\text{Re}} + \left( \frac{R_f}{3.7d_{el}} \right)^{10/3} \right) \right]^{-2} \quad \text{Equation 3-43}
\]

Where \( R_f \) is the absolute roughness of the pipe in the same units as the diameter.

3.6.4 **Slot-type ICD**

Figure 2-10 (A) showed that the slot-type ICD distributes the pressure drop over number of stages. In the fixed device, each stage consists of two of slots positioned 180 degrees apart with each subsequent slot positioned with 90 degrees rotation from the
previous slot. In the adjustable device Figure 2-10 (B), each stage contains only one slot which is located within a small radial distance to the next slot.

![Image of fixed and adjustable slot-type ICDs]

**Figure 3-11: (A) Fixed slot-type ICD and (B) Adjustable slot-type ICD [17]**

Similar to the helical channel-type ICDs, the pressure drop through the slot-type ICD can be calculated using two techniques:

**1. If the slot and channel dimensions are known (or to be calculated):**

The fluid pressure decreases while flowing through both the slot and the channel in a single stage. The resulting effect of fluid flow through both a constriction and a channel means it can be treated in a similar manner to a tube and labyrinth channel-type ICD (Equation 3-41). However, the length of the channel in the second term of Equation 3-41 should be replaced by the radial length fraction of the circumference of the base pipe; i.e. the distance travelled by the fluid before it enters the subsequent slot. The dependence of the discharge coefficient on the Reynolds number can also be reduced by using the pressure loss coefficient ($K$) instead. The $K$ values of this ICD are relatively constant for Reynolds number values higher than 1,000 (Figure 3-12). The variation in $K$ values with slot size is very small; hence an average $K$ value of 6.7 (Figure 3-12) may be used for all slot sizes. A correlation has been prepared for Reynolds numbers lower than 1,000 (Equation 3-44, Figure 3-13) by fitting this equation to selected $K$ values.

$$K = -3 \cdot 10^{-8} Re^3 + 6 \cdot 10^{-5} Re^2 - 0.0399 Re + 17.231$$  \hspace{1cm} \text{Equation 3-44}

The assignment of a single $K$ value for all flow rates and slot sizes also reduces the effect of fluid viscosity on the pressure drop calculation is ignored making this device insensitive to the fluid viscosity. Also, the second term in Equation 3-45, representing the pressure drop due to the flow in the channel, is very small due to the relatively small length and large channel diameter for the fixed slot-type ICD. It can also be ignored when modelling an adjustable slot-type ICD for the same reasons.
Figure 3-12: Pressure loss coefficient of a slot and helical channel-type ICDs (derived from [185])

Figure 3-13: Matched pressure loss coefficient values of a slot-type ICD

The pressure drop through the device is thus the cumulative pressure drop through the stages:
\[ \delta P_{ICD} = \sum_{i} \left( \frac{8KC_{u}\rho_{mix}q_{ICD}^{2}(1 - \beta^{4})}{\varepsilon^{2}\pi^{2}d_{i}^{4}} + \frac{C_{f}\pi D_{be}\rho_{mix}q_{ICD}^{2}}{d_{i}^{5}} \right) \]  

Equation 3-45

Where:

- \( K \) = Pressure loss coefficient
- \( D_{be} \) = Base pipe external diameter
- \( i \) = Stage
- \( n \) = Number of stages

2. If the ICD strength is provided (or to be calculated):

The provision of the ICD strength value instead of its actual dimensions allows the helical channel-type ICD modelling technique (Equation 3-28) to be used with the weighted average viscosity of the fluid mixture (Equation 3-46) instead of the emulsion viscosity.

\[ \mu_{mix} = \alpha_{o}\mu_{o} + \alpha_{w}\mu_{w} + \alpha_{g}\mu_{g} \]  

Equation 3-46

### 3.6.5 ICD Modelling Simplification and Similarities

1st technique:

The performance of all ICD types (except the regulated-type ICD) can be modelled using Equation 3-28. This is supported by flow tests for the orifice-type ICDs [176] which showed that the ICD strength values depend only on the open flow area and are independent of the flow rate (Figure 3-14).

The ICD strength values for each ICD type can be obtained from the ICD’s flow test data. Equation 3-46 should be used to describe the mixture fluid viscosity instead of the emulsion viscosity (Equation 3-29) except when:

a. Employing a helical channel-type ICD or

b. If the produced fluid has a tendency to form emulsions. Note that, an increased pressure drop will also be observed in long tube and labyrinth channel type-ICDs.
Table 3-5 and Table 3-6 list the strength values for various configurations of the orifice and nozzle-type ICDs, respectively. These values were calculated based on the flow test data of a 10-orifice ICD (Figure 3-6 [176]) and the modelled flow performance of various nozzle type ICDs (Figure 3-7 [177]). Note that the nozzle $a_{ICD}$ values have been based on the flow of an oil phase with a density of 900 Kg/m$^3$ and a formation volume factor of 1.13.

**Table 3-5: Calculated 10-orifice-type ICD strength values**

<table>
<thead>
<tr>
<th>Orifice ICD Closed Holes</th>
<th>$a_{ICD}$ Values</th>
<th>$a_{ICD}$ Values</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>bar/(Sm$^3$/day)$^2$</td>
<td>psi/(scf/day)$^2$</td>
</tr>
<tr>
<td>0</td>
<td>0.002436</td>
<td>0.0000283</td>
</tr>
<tr>
<td>1</td>
<td>0.003042</td>
<td>0.0000354</td>
</tr>
<tr>
<td>2</td>
<td>0.003875</td>
<td>0.0000451</td>
</tr>
<tr>
<td>3</td>
<td>0.00492</td>
<td>0.0000572</td>
</tr>
<tr>
<td>4</td>
<td>0.006751</td>
<td>0.0000785</td>
</tr>
<tr>
<td>5</td>
<td>0.009618</td>
<td>0.0001119</td>
</tr>
<tr>
<td>6</td>
<td>0.015066</td>
<td>0.0001752</td>
</tr>
<tr>
<td>7</td>
<td>0.026491</td>
<td>0.0003081</td>
</tr>
<tr>
<td>8</td>
<td>0.059955</td>
<td>0.0006973</td>
</tr>
</tbody>
</table>
Table 3-6: Calculated nozzle-type ICD strength values

<table>
<thead>
<tr>
<th>Nozzle ICD Configurations</th>
<th>$a_{\text{ICD}}$ Values</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>bar/(m$^3$/day)$^2$</td>
</tr>
<tr>
<td>6x4mm</td>
<td>0.000118</td>
</tr>
<tr>
<td>2x3+4x4mm</td>
<td>0.000161</td>
</tr>
<tr>
<td>2x2.5+4x4mm</td>
<td>0.000186</td>
</tr>
<tr>
<td>4x4mm</td>
<td>0.000265</td>
</tr>
<tr>
<td>4x2.5+2x4mm</td>
<td>0.000334</td>
</tr>
<tr>
<td>6x3mm</td>
<td>0.000372</td>
</tr>
<tr>
<td>2x(3+4)mm</td>
<td>0.000434</td>
</tr>
<tr>
<td>2x2.5+4x3mm</td>
<td>0.000462</td>
</tr>
<tr>
<td>2x(2.5+4)mm</td>
<td>0.000548</td>
</tr>
<tr>
<td>4x2.5+2x3mm</td>
<td>0.000587</td>
</tr>
<tr>
<td>4x3mm</td>
<td>0.000838</td>
</tr>
<tr>
<td>2x4mm</td>
<td>0.001060</td>
</tr>
<tr>
<td>2x(2.5+3)mm</td>
<td>0.001167</td>
</tr>
<tr>
<td>4x2.5mm</td>
<td>0.001737</td>
</tr>
<tr>
<td>2x3mm</td>
<td>0.003351</td>
</tr>
<tr>
<td>2x2.5mm</td>
<td>0.006949</td>
</tr>
</tbody>
</table>

The data has been fitted to a 6th order polynomial (Equation 3-47 and Equation 3-48) and plotted in Figure 3-15 and Figure 3-16. The ICD strength values for other nozzle sizes and orifice configurations can now be easily derived.

Note that a comparison of the above data (Table 3-5, Table 3-6 and Table 3-2) for different types of ICDs indicates that the standard range of orifice and nozzle-type ICDs provide a greater restriction than standard helical channel-type ICDs. In particular, the commercially available 16-orifice ICD provides the lowest minimum strength values of all ICD types, and hence provides the widest range of restrictions that can be made available at the wellsite.
A_{or} = 4 \cdot 10^{-6} x_o^6 - 8 \cdot 10^{-5} x_o^5 + 0.0006 x_o^4 - 0.002 x_o^3 + 0.0031 x_o^2 - 0.0011 x_o + 0.0024 \\
Equation 3-47

A_{nz} = -3 \cdot 10^{-5} x_n^3 + 0.0008 x_n^2 - 0.0067 x_n + 0.02 \\
Equation 3-48

Where:

\( A_{or} \) and \( A_{nz} \) = Orifice and nozzle strength rating values, respectively.

\( x_o \) and \( x_n \) = Number of plugged orifices and effective nozzles diameter, respectively.

Figure 3-15: Orifice-type ICD strength values (aICD) and their correlation
A 2nd simplified technique:

The flow performance of all ICDs (except the regulated-type ICD) can also be modelled using Equation 3-35 with the appropriate discharge coefficient when the fluid flowing through the ICD is a dry gas, water or oil with an in-situ viscosity of 1 cp or an oil/water mixture. Denser oils with their high viscosity will cause a higher frictional pressure drop when flowing through helical channel, labyrinth channel and long tube-type ICDs. The discharge coefficient can be obtained from the total loss factor ($K$) (this can be either measured in flow tests or estimated from Computational Fluid Dynamics (CFD) models). The use of a constant discharge coefficient value for orifice, slot, nozzle and short tube-type ICDs is supported by the reported $K$ values for the different configurations of a 10-orifice-type ICD (Figure 3-17 [176] and Table 3-7). Here, the maximum variation in $K$ values was 0.2 (~0.04 in $C_{Re}$ values) between 2 and 10 open orifices for different flow rates. This allows a simplified calculation procedure for these four ICD types.

However, the use of such a constant value for the discharge coefficient is not correct for all ICD types; since the $K$ values for the helical channel-type ICDs varies with the flow rate (Figure 3-12). A more accurate estimation of their performance can be made.
by calibrating Equation 3-38 with the flow test data for this type of ICDs when such data becomes available.

Figure 3-17: Pressure loss coefficient of an orifice-type ICD [176]

Table 3-7: Calculated 10-orifice-type ICD $C_{(Re)}$ values

<table>
<thead>
<tr>
<th>Weatherford Orifice ICD Open Holes</th>
<th>$C_{(Re)}$ Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>0.8230</td>
</tr>
<tr>
<td>9</td>
<td>0.8228</td>
</tr>
<tr>
<td>8</td>
<td>0.8227</td>
</tr>
<tr>
<td>7</td>
<td>0.8238</td>
</tr>
<tr>
<td>6</td>
<td>0.8277</td>
</tr>
<tr>
<td>5</td>
<td>0.8181</td>
</tr>
<tr>
<td>4</td>
<td>0.8341</td>
</tr>
<tr>
<td>3</td>
<td>0.8371</td>
</tr>
<tr>
<td>2</td>
<td>0.8405</td>
</tr>
</tbody>
</table>

3.6.1 Regulated-type ICD

The performance of the regulated-type ICD has not been made public. However, its flow behaviour is expected to be similar to a surface choke valve in critical flow since it is designed to maintain a constant flow rate through the device regardless of changes in
the upstream or downstream pressure. This indicates that the fixed flow restriction is designed to minimise the pressure loss through the restriction while the regulator continually adjusts the flow area of this device’s restriction to maintain the critical flow conditions. The performance of this device can therefore be modelled using Equation 3-49 [170], which applies a multiplier \( A \) to achieve and maintain the required flow rate.

\[
\delta P_{ICD} = A(q_{ICD} - q_{req})
\]

Equation 3-49

Where:

\( A \) = Multiplier

\( q_{req} \) = Required ICD flow rate

### 3.7 Flow Performance and Modelling of AICDs

Modelling of flow in AICDs can be based on the above flow model for ICDs. However, the smaller flow paths present in all AICD types may lead to critical flow conditions; especially, when the fluid has a high gas fraction.

Several AICD devices have been patented in recent years, but only limited information on their detailed mechanical designs has been published. The technology is still in the development phase with new, unproved designs being developed. Two approaches are required for flow modelling of the devices where some details have been published:

1. Discrete restriction AICDs (include flapper, ball, disc and remote-types).
2. Continuous restriction and swellable AICDs.

All AICDs can be combined with an ICD or they act as an ICD themselves. The AICD should thus be modelled as a single or a dual function device. The performance of the two categories of AICD and possible modelling techniques will now be described.

#### 3.7.1 Flapper, Ball, Disc and Remote-type AICD

The reactive element of a flapper, ball, disc and remote-type AICDs can be modelled using Equation 3-35. The real device will have multiple flow paths, but they can be represented by a single restriction equal to the cumulative area open to flow. A gradual or sudden increase (or reduction) in the device restriction can be modelled by the appropriate reduction (or increase) in the restriction’s size (i.e. the nozzle diameter). This could be triggered by an increase or a reduction in the water or gas content of the produced fluid. In the case of ball and remote-type AICDs, a range of water cuts (WC)
or gas-oil ratios (GOR) can be specified for each restriction flow area. The flapper and disc-type AICDs exhibit two settings: “fully-open” and “severely-restricted”. The change between these two areas occurs at a specific fluid density corresponding to a specific WC or GOR.

The disc-type AICD is the only one where flow data has been made available. Figure 3-18 compares the flow performance of the disc-type AICD with that of a 0.2 bar helical channel-type ICD. Figure 3-19 shows their fitted performance in standard cubic meters per day.
The initial AICD restriction size in Equation 3-35 should be specified to represent the appropriate ICD size (i.e. equalised fluid influx) when the AICD is integrated with or, independently, acts as an ICD. Alternatively, the ICD can be modelled using one of the functions described in section 3.6.

3.7.2  **Swellable-type AICD**

Information on the swellable-type AICD is very limited with only the pressure drop/flow rate relationship when oil or water flows through the AICD being available (Figure 3-20 [186]). The data indicates that the device restricts water flow with the flow restriction increasing as the water flow rate increases (Figure 3-20). Therefore, the gradual swelling of this AICD type can be considered to impose an increasing reduction in the flow area as the water content of the flowing mixture increases. Note that the water swelling properties of swell packers used as AFI (Section 2.19.5) have been found to be highly dependent on the water composition [104]. This could be important if they share a common technology.

![Figure 3-20: Swellable-type AICD flow test data [186]](image)

Oil must be used as the calibration fluid for this device since water will trigger the swelling process. The oil flow data, which also show quadratic relationship between the pressure drop and flow rate (Figure 3-21) was used to calculate the plotted AICD strength values. The AICD strength values thus exhibits a dependency on both the flow rate and the flow area.
Figure 3-21: Flow correlation for Swellable-type AICD based on flow test data [186]

The swellable AICD can thus be modelled using the formulation (Equation 3-50) incorporated in the Eclipse™ 2009 reservoir simulator [170].

\[
\delta P_{AICD} = \left( \frac{\rho_{mix}^2}{\rho_{cal}} \right) \left( \frac{\mu_{cal}}{\mu_{mix}} \right)^y \cdot a_{AICD} \cdot q_{AICD}^x
\]

Equation 3-50

Where:
- \(\delta P_{AICD}\) = Pressure drop across the AICD restriction (psi or bar)
- \(q_{AICD}\) = Fluid (volumetric) flow rate through the AICD (rft³/day or rm³/day)
- \(a_{AICD}\) = AICD strength value (psi/(rft³/day)\(^x\) or bar/(rm³/day)\(^x\))
- \(y\) = Viscosity function exponent (dimensionless)
- \(x\) = Volume flow rate exponent (dimensionless)

\(a_{AICD}\) can be calculated using Equation 3-51 for oil flow after conversion to reservoir conditions:

\[
a_{AICDS} = 0.0131q_{AICDS}^{-0.707}
\]

Equation 3-51

Where:
- \(q_{AICDS}\) = Fluid (volumetric) flow rate through the AICD (scf/day or Sm³/day)
- \(a_{AICDS}\) = AICD strength value (psi/(scf/day)\(^x\) or bar/(Sm³/day)\(^x\))
The resulting pressure drop in Equation 3-50 combines the effect of the ICD and the reactive element of the AICD. The flow rate exponent can be used to appropriately represent the relationship between the pressure drop and flow rate through the AICD. Similarly, the viscosity function exponent can be used to describe the effect of the fluid viscosity on the behaviour of the (A)ICD combination.

Note that the fluid mixture viscosity used in this formulation is the average fluid viscosity (Equation 3-46) and not the emulsion viscosity (Equation 3-29), unless this device has been integrated with a helical channel-type ICD.

The two AICD modelling techniques (Equation 3-35 and Equation 3-50) are interchangeable. I.e. they both can be used to model the performance of any AICD in a manner similar to that described for ICDs (3.6.5). The \( a_{AICD} \) corresponding to each flow area can be used when Equation 3-50 is used. Otherwise, \( a_{AICD} \) values can be calculated for the optimum AICD. Alternatively, use of Equation 3-35 identifies the flow area.

3.8 Flow Performance of ICVs

ICVs act in a similar manner to surface chokes, although the ICV’s restriction is shorter (Figure 3-22). Flow through the ICV is sub-critical for most ICV applications. The exception involves aggressive restriction of high pressure zones containing fluids with a high gas fraction. The pressure drop across the ICV can be significant in these cases and the ICV can operate in the critical region.

![Figure 3-22: Flow performance for a discrete position ICV [187]](image)

Figure 3-22: Flow performance for a discrete position ICV [187]
Some surface-choke models account for both flow regimes; e.g.:

- Critical and sub-critical flow; e.g. Perkins [164] and Sachdeva [165].
- Critical and sub-critical flow with slip between the phases within the choke restriction; e.g. Hydro’s models [188, 190].

However, the application of these models is cumbersome. The majority of available surface-choke models described for only one of these flow regime (Gilbert [191], Al-Twailib [191], Osman and Dukhla [191], etc.). It is therefore proposed to model flow through an ICV by a simplified version of Equation 3-35 (Equation 3-52 [170]).

\[
\delta P_v = \frac{8 C_u \rho_{mix} q_v^2}{\pi^2 C_d^2 d_v^4}
\]

Equation 3-52

Where:

\( \delta P_v \) = Pressure drop across the ICV restriction (units shown in Table 3-3)

\( q_v \) = Fluid (volumetric) flow rate through the ICV (units shown in Table 3-3)

\( d_v \) = ICV restriction diameter size (units shown in Table 3-3)

\( C_d \) = Discharge coefficient based on the valve position (dimensionless)

This model is proposed since it:

1. Assumes that frictional pressure drops are negligible and only acceleration effects caused by the restriction of the fluid flow area contribute to the pressure drop through the ICV.
2. Does not relate the pressure drop through the ICV to the upstream flow area which can vary if the ICV is installed in an openhole completion.
3. Can be calibrated to actual ICV performance using the discharge coefficient.
4. Can represent an ICV with multiple openings by their cumulative area.

Gilbert’s surface choke model (Equation 3-53 [191]) is widely used for modelling critical flow of hydrocarbons through valves, or, in this case, an ICV:

\[
P_{ad} = \frac{10 R^{0.546} q_v^{1.89}}{S_r}
\]

Equation 3-53

Where:
\[ P_{us} = \text{Upstream pressure (psi)} \]
\[ R = \text{Producing gas-liquid ratio (scf/bbl)} \]
\[ S_V = \text{ICV opening size (1/64th in)} \]

### 3.9 Modelling of Screens, Pre-packed Screens and Gravel Packs

SAS, Pre-Packed SAS (PPSAS) and Gravel Packs (GP) often installed along with the AWC but are not themselves AWC components. A SAS may have single, dual or even triple screen layers, while PPSAS consist of the annular space between two screens being packed with resin coated gravel. PPSAS completions experience an additional pressure drop compared to regular SASs.

The pressure drop across a SAS, PPSAS and GP or the permeability of these components can be calculated using Equation 3-54 [192].

\[
\delta P_{PGSAS} = \frac{q_{PGSAS} \mu_{mix} \ln \left( \frac{OD_{PGSAS}}{ID_{PGSAS}} \right)}{7.08 L_{PGSAS} k_{PGSAS}} \tag{Equation 3-54}
\]

Where:

- \( OD_{PGSAS} \) = Outer diameter of SAS, PPSAS or GP
- \( ID_{PGSAS} \) = Inner diameter of SAS, PPSAS or GP
- \( L_{PGSAS} \) = Length of SAS, PPSAS or GP
- \( k_{PGSAS} \) = Permeability of SAS, PPSAS or GP

### 3.10 Modelling of Fluid Flow in the Wellbore, Completion and Tubing

Many researchers have studied and developed analytical, semi-analytical and numerical correlations describing the behaviour of single or multi-phase flow of gas, oil and water in vertical, inclined and horizontal pipes. Each correlation is based on field or laboratory experiments conducted within specific ranges of pipe inclination, fluid mixture composition and fluid influx positions along the pipe.

The pressure drop in the annulus, inner section of the base pipe, and tubing has to be calculated using a representative multiphase flow correlation. These correlations have often been modified at a later date due to field experience [159].

Beggs and Brill [193] developed the most widely used correlations for fluid flow in horizontal and inclined pipes. This correlation accounts for elevation, acceleration and friction pressure drops; for both single and multiphase flow (where it accounts for the many flow regimes and the hold-up effect of the multiple phases). Hagedorn and Brown
[158] have provided flow correlations for multiphase flow in vertical pipes. This work therefore uses the Beggs and Brill correlation to model flow in horizontal and inclined tubular while Guo et al.’s [158] modification of Hagedorn and Brown is used to model fluid flow in vertical sections i.e. within ±20° of the vertical. A detailed description of these flow correlations can be found in references [158] and [193].

3.11 Wellbore and Completion Productivity Prediction with the “Trunk-and-branch” Modelling Approach Process

The “trunk-and-branch” modelling technique is used for two, significantly different purposes during the design of AWCs:

1. To identify misbalance of the fluid influx along the wellbore and/or to identify the water or gas influx prior to the installation of the AWC.
2. To identify the optimum (A)ICD or ICV restriction size and type.

3.11.1 Modelling Process for Influx Content and Misbalance Identification

Figure 3-23 illustrates the fluid’s flow path from the reservoir segment to the inner section of the completion (tubing) in the first phase of the sizing stage. This is achieved through the coupling of the reservoir and wellbore flow.

Figure 3-23: Reservoir/wellbore “trunk-and-branch” fluid flow model

The fluid influx from the reservoir into each tubing segment is:

\[ q_{in}(i) = PI_s(i)\left[\overline{P_r}(i) - P_w(i)\right] \]  

Equation 3-55

Where:

\( q_{in} \) = Segment fluid influx rate  
\( PI_s \) = Segment productivity index  
\( \overline{P_r} \) = Segment reservoir pressure (the average reservoir pressure if pseudo-steady state productivity index is used or pressure at the reservoir boundary if steady state productivity is used)  
\( P_w \) = Segment wellbore pressure
The fluid flowing from each tubing segment node towards the topmost node is the sum of the fluid influx from the reservoir and the fluid flowing from the bottom segment. The exception is the first node from the bottom (toe) of the well where the tubing flow rate is equivalent to the fluid influx rate:

\[ \sum_{i=1}^{i} q_s(i) = q_m(i) + \sum_{i=1}^{i-1} q_s(i) \]  
Equation 3-56

\[ q_t = \sum_{i=1}^{i-n} q_s(i) \]  
Equation 3-57

Where:
- \( q_s \) = Wellbore segment flow rate
- \( q_t \) = Total well flow rate at the topmost segment of the well
- \( n \) = Total number of segments

The modelling process proceeds as follows (Figure 3-24):
1. A pressure is assigned at the 1\textsuperscript{st} tubing node at the bottom (toe) of the well. The assigned pressure value should result in a volumetric fluid influx equivalent to the required total well flow rate divided by the number of reservoir segments along the wellbore.
2. The pressure drop due to this fluid flow along the tubular segment is calculated.
3. Based on this pressure drop, the pressure in the following tubing node is assigned.
4. Steps 2 and 3 are repeated until the topmost segment of the well is reached.
5. The resulting flow rate is compared to the specified flow rate, if the well is rate controlled, or the pressure (wellhead or bottom hole) is compared to the specified pressure if the well is pressure controlled.
6. This will most likely result in a higher flow rate than required; therefore the process is iterated by reducing the initially assigned wellbore pressure until the required total well flow rate or pressure is matched within the required accuracy:

\[ |q_{Rq} - q_t| \leq e \]  
Equation 3-58

\[ |P_{Rq} - P_t| \leq e \]  
Equation 3-59

Where:
- \( q_{Rq} \) = Required total well flow rate
- \( P_{Rq} \) = Required flowing wellhead or bottom hole pressure
\[
\begin{align*}
q_t & = \text{Total well flow rate at the topmost node of the well} \\
Pt & = \text{Wellhead or bottom hole pressure at the well’s topmost node} \\
e & = \text{Acceptable accuracy}
\end{align*}
\]

Figure 3-24: Flow diagram for well’s performance and misbalance estimation

3.11.2 Modelling Process for the (A)ICD Restriction Sizing

Figure 3-25 illustrates how the segment productivity is coupled with the appropriate (A)ICD flow correlations to enable the calculation of the fluid influx into the completion base pipe. This integration simplifies the process and enables an analytical solution to the fluid influx formulation. The separation of the two flow correlations (i.e.
productivity index and flow control device) necessitates an iterative process (semi-analytical solution) to identify the resulting flow rate from each segment.

An example of this coupling is shown below for the nozzle/orifice-type ICDs. The ICD flow correlation is coupled with the vertical well productivity model since the fluid influx into the tubing in this case is also a function of the pressure drop through the ICD. Equation 3-55 is thus modified to:

\[ q_{ICD}(i) = P_{ICD}(i)[\bar{P}_r(i) - P_w(i) - \Delta P_{ICD}(i)] \]  

Equation 3-60

Where \( P_{ICD} \) is the productivity of a reservoir segment with a length equivalent to the (A)ICD.

The pressure drop through the (A)ICD is dependent on the (A)ICD type. Here, the pressure drop through a nozzle/orifice-type ICD with a discharge coefficient independent of the flow rate (\( C_d \)) is used; transforming Equation 3-60 to:

\[ q_{ICD}(i) = P_{ICD}(i)[\bar{P}_r(i) - P_w(i)] - P_{ICD}(i)\left(\frac{8C_u}{\pi^2}\left(\frac{\rho_{mix}^2 q_{ICD}^2 (1 - \beta^4)}{C_d \tau^2 d_{w}^4}\right)(i)\right) \]  

Equation 3-61

Simple manipulation of Equation 3-61 yields the following quadratic equation:

\[ \frac{8C_u}{\pi^2} \left(\frac{P_{ICD} \rho_{mix} (1 - \beta^4)}{C_d \tau^2 d_{w}^4}\right)(i)q_{ICD}^2(i) + q_{ICD}(i) - P_{ICD}(i)[\bar{P}_r(i) - P_w(i)] = 0 \]  

Equation 3-62

This is a quadratic equation of the form:

\[ aq_{ICD}^2 + bq_{ICD} + c = 0 \]  

Equation 3-63

The positive root solution to Equation 3-62 is:
\[
q_{ICD}(i) = -1 + \sqrt{1 + \frac{32C_u}{\pi^2} \left( \frac{P_{ICD}^2 \rho_{mix} \left(1 - \beta^4\right)}{C_d \epsilon^2 d_{no}^4} \right) i \left(\overline{P_r}(i) - P_w(i)\right) + \frac{16C_u}{\pi^2} \left( \frac{P_{ICD} \rho_{mix}}{C_d \epsilon^2 d_{no}^4} \right) i}
\]

Equation 3-64

Coupled equations of other (A)ICD types are summarised in Table 3-8.

<table>
<thead>
<tr>
<th>(A)ICD Type</th>
<th>Coupled Equation</th>
</tr>
</thead>
</table>
| Slot and Helical channel            | \[
q_{ICD}(i) = -1 + \sqrt{1 + \frac{32C_u}{\pi^2} \left( \frac{P_{ICD}^2 \rho_{mix} \left(1 - \beta^4\right)}{C_d \epsilon^2 d_{no}^4} \right) i \left(\overline{P_r}(i) - P_w(i)\right) + \frac{16C_u}{\pi^2} \left( \frac{P_{ICD} \rho_{mix}}{C_d \epsilon^2 d_{no}^4} \right) i}
\]

| Tube and Labyrinth channel          | \[
q_{ICD}(i) = -1 + \sqrt{1 + \frac{32C_u}{\pi^2} \left( \frac{P_{ICD}^2 \rho_{mix} \left(1 - \beta^4\right)}{C_d \epsilon^2 d_{no}^4} \right) i \left(\overline{P_r}(i) - P_w(i)\right) + \frac{16C_u}{\pi^2} \left( \frac{P_{ICD} \rho_{mix}}{C_d \epsilon^2 d_{no}^4} \right) i}
\]

| Flapper, Ball, Disc and Remote      | \[
q_{ICD}(i) = -1 + \sqrt{1 + \frac{32C_u}{\pi^2} \left( \frac{P_{ICD}^2 \rho_{mix} \left(1 - \beta^4\right)}{C_d \epsilon^2 d_{no}^4} \right) i \left(\overline{P_r}(i) - P_w(i)\right) + \frac{16C_u}{\pi^2} \left( \frac{P_{ICD} \rho_{mix}}{C_d \epsilon^2 d_{no}^4} \right) i}
\]

| Swellable (q is quadratic)          | \[
q_{ICD}(i) = -1 + \sqrt{1 + 4 \left( \frac{P_{ICD}^2 \rho_{mix} \left(1 - \beta^4\right)}{C_d \epsilon^2 d_{no}^4} \right) i \left(\overline{P_r}(i) - P_w(i)\right) + \frac{16C_u}{\pi^2} \left( \frac{P_{ICD} \rho_{mix}}{C_d \epsilon^2 d_{no}^4} \right) i}
\]

| Swellable (q is linear)             | \[
q_{ICD}(i) = \frac{\left(\overline{P_r}(i) - P_w(i)\right)}{2 \left( \frac{\rho_{mix}}{\mu_{cal}} \right)^{1/2} a_{ICD}(i)}
\]
The modelling process of this stage follows the same steps listed above for the phase cuts and misbalance identification process.

3.11.3 Modelling Process of ICV and Multilateral Well Completions

The modelling process of an ICV or a multilateral well completion is similar. Figure 3-26 shows a model for a dual-lateral (or two-zone) completion. These zones or laterals can be equipped with (A)ICDs or produced as openhole completions with or without ICVs. This approach enables the integrated modelling of ICVs, (A)ICDs and multilateral completions.

![Figure 3-26: Fluid flow model for a multilateral and an ICV completion](image)

The productivity and flow process of laterals with or without ICVs and ICV zones with or without (A)ICD completions can be identified using the modelling process described below (Figure 3-27):

1. A pressure is assigned at the furthest annulus node of the lateral (zone) furthest from the wellhead. This chosen pressure value should result in a volumetric fluid influx rate equivalent to the required total well flow rate divided by the number of reservoir segments along the wellbore.

2. Steps 2 through 4 of the modelling process described in Section 3.11.1 for the identification of the fluid influx misbalance are performed as stated for the nodes located downstream of the node assigned in step 1. This is continued until reaching the node where the fluid flowing through this lateral or zone mixes with the second furthest lateral from the wellhead (i.e. the mouth of the next lateral or ICV mixing point {M point in Figure 3-26}).
3. Steps 1 and 2 of this modelling approach are performed for the second lateral or zone until the mouth of this lateral or mixing point M highlighted above is reached.

4. The mixing node pressure calculated in steps 2 and 3 are compared. Then, step 3 is repeated until the two pressures match within the specified tolerance:

\[ |P_m - P_L| \leq e \]  \hspace{1cm} \text{Equation 3-65}

Where:

- \( P_m \) = Tubing pressure at laterals mixing point
- \( P_L \) = Lateral pressure at its mixing point

5. Steps 2 through 4 of this modelling process are repeated for the other laterals until the topmost node in the well is reached. The required pressure or flow rate if the well is flow rate controlled is now compared to the calculated node pressure.

6. Steps 1 through 5 of this process are repeated until the two pressure or flow rate values match within the specified tolerance (Equation 3-58 or Equation 3-59).

These modelling processes also identify the total well productivity with and without AWCs.
Figure 3-27: Flow diagram of ICV and multilateral well completion Performance estimation
3.12 The “Network” Approach Modelling Process

The network modelling approach overcomes the limitation of the “trunk-and-branch” technique by allowing the fluid influx from the sand-face to split between the completion and the open annulus (Figure 3-28). This modelling technique is needed to:

1. Optimise the AFI frequency and distribution.
2. Evaluate the completion performance where suboptimal or no AFIs are installed.

These two factors are described in details in Section 4.6.

This modelling approach can be performed using commercially available software. Examples are the specialised wellbore modelling software (such as NETool™ [194]) or general production network modelling programs (such as GAP™ [121], Pipesim™ [195] and Reo™ [196]).

![Network modelling of fluid flow in AWCs with open annulus](image)

**Figure 3-28: Network modelling of fluid flow in AWCs with open annulus**

3.12.1 Wellbore Modelling Technique (NETool™)

NETool™ [194] is a network based modelling tool with the capability to calculate steady state, multiphase fluid flow/pressure drops through a variety of well completions.

The data describing the reservoir in the near wellbore area is retrieved from a reservoir simulation model and upscaled while honouring the complex, reservoir geological description. The flow from the near wellbore nodes (i.e. reservoir grid blocks) into the well completion are represented by a specified number of nodes which can be connected in a variety of ways in order to simulate flow through annular spaces, SASs, ICDs, ICVs or other completion equipment and through the tubing. This simulator includes a number of flow correlations which model helical channel, labyrinth channel, tube, nozzle and orifice-type ICDs and ICVs in different reservoir, wellbore and fluid flow environments. A good illustration of the capabilities of this software has been presented in reference [197] and in Section 6.4.8.
This software is adequate to achieve the objectives of the network modelling stage which were highlighted previously (Section 3.12).

It is unfortunate that the current NETool\textsuperscript{TM} version cannot be coupled to a reservoir simulator. I.e. automated interaction between the reservoir and wellbore models is not possible. Its availability would have allowed a full evaluation of the completion’s performance and allowed quantification of any flow behind the AFI. This evaluation requires an automated transfer of the reservoir/wellbore productivities from the reservoir simulator to the wellbore model and the return of the specific control parameters from the wellbore simulator (after accounting for the completion performance, annular flow, etc.) at every time step of the simulation. Such coupling is essential to fully capture the time dependent depletion effects associated with a particular completion design.

3.12.2 \textbf{Subsurface/Surface Network Modelling Software(s)}

The modelling of (A)ICD modules and ICVs has successfully been tested in three, steady state, subsurface/surface network solver software(s):

- The General Allocation Program (GAP\textsuperscript{TM} provided by Petroleum Experts [198, 199]).
- Pipesim\textsuperscript{TM} (provided by Schlumberger Information Services [195]).
- Reo\textsuperscript{TM} (provided by e-Petroleum Services-Weatherford [196]).

All these software(s) are capable of modelling both merging and diverging fluid flow at any network node i.e. the physics of the split flow between the annulus and through the (A)ICD to the tubing can be captured. Commercial tools allowing GAP\textsuperscript{TM}, Pipesim\textsuperscript{TM} and Reo\textsuperscript{TM} to be coupled to many reservoir simulators are also available [200]. In addition, GAP\textsuperscript{TM} and Reo\textsuperscript{TM} have the ability to automatically optimise choke settings and connection (Wells/inflows) pressures.

This section will describe the application of GAP\textsuperscript{TM} for the modelling of AWC components, though similar workflows can be implemented in the other two programs. GAP\textsuperscript{TM} is capable of modelling a downhole wellbore completion connected to a surface network through Vertical Lift Performance (VLP) tables or via pipes of specified dimensions and deviations by choosing one of the available flow correlations that can accurately match the actual well’s performance. The downhole completion can contain in-line chokes (valves) that are either fixed or controllable. These devices are modelled using built-in flow correlations or the device’s response can be customised by use of
programmable elements. Programmable elements allow the user to define any equipment as a pressure loss element. (A)ICDs and ICVs performances have been modelled by use of the available choke models within GAP\textsuperscript{TM} with the aid of programmable elements.

### 3.12.3 Modelling All (A)ICD and ICV Types

The (A)ICD and ICV pressure drop correlations described previously in Section 3.6, 3.7 and 3.8 can be used when designing GAP\textsuperscript{TM}'s programmable elements to calculate the pressure drop through these devices. This approach can reproduce the exact pressure drop calculated for a single (A)ICD or ICV. The programmable elements can then be distributed in the completion model (Figure 3-29) so as to simulate an (A)ICD installed between the annulus and inner tubing or an ICV controlling the contribution from zones or laterals. Examples of (A)ICD and ICV programmable element codes are provided in Appendix A.3-1.

![Figure 3-29: The wellbore configuration in the network modelling software](image)

The inline choke model in GAP\textsuperscript{TM} is based on the conservation of energy equations with a provision of a discharge coefficient correction multiplier [201]. This multiplier is used to correlate the calculated pressure drop through a particular ICV or (A)ICD type with the actual flow test data measured for the device. For example, a $C_d$ correction multiplier value of 1.06 and 1.09 was found to match the actual data reported for the nozzle and orifice-type ICDs, respectively. A larger correction value of 1.33 was found necessary when matching the multiphase flow performance for both types of ICD with data produced using the Eclipse\textsuperscript{TM} reservoir simulator. These chokes can then be distributed as in Figure 3-29.
The same modelling technique previously described in section 3.6.5 can often be used for all ICV and (A)ICD types. This is especially true for low viscosity oils since pressure losses due to the choking effects will be much more significant than any frictional effects.

Pipesim\textsuperscript{TM} and Reo\textsuperscript{TM} have similar choke modelling capability to that of GAP\textsuperscript{TM}; though they employ different choke flow correlations. This can be solved by matching the performance of the different software or by modifying the choke performance models to match the ICV and/or (A)ICD’s performance. Examples of such models are provided in reference [202].

3.13 Modelling for the Evaluation Stage

The modelling of AWCs during the design evaluation stage was paved in the early 1990s [12]. The performance of an ICD completion was modelled using a horizontal well in an in-house, wellbore modelling program. Then, the resulting sand-face pressure of the ICD completion in the wellbore simulator was applied to a “frictionless well” in a reservoir simulator [12]. This approach was later improved by integrating the wellbore and reservoir simulators [203]. In this approach, the horizontal ICD completion was simulated in the wellbore simulator which was coupled to 3D, two phase, reservoir simulator.

The horizontal wellbore simulator employs a general network solver for calculation of steady state flow through the wellbore completion with the option of applying one of several multiphase flow correlations. The horizontal wellbore is modelled as a network of nodes in a “trunk-and-branch” topology; starting from the sand-face connection point (at each reservoir grid block) to the tubing bottom/head output point. Various flow variables; including (phase) rates, total reservoir fluids, bottom hole and tubing head pressures could be set as the well control parameter in the wellbore network simulator.

An iterative, explicit coupling technique of the reservoir and wellbore simulators was used. The reservoir simulator supplied the reservoir pressure and connection productivity indices to the wellbore simulator which, in turn, calculated the pressure drop through the completion to the output point.

This technique achieves the objectives of the evaluation stage for a specific design since it accounts for the time dependent effects of the completion. However, it does not account for flow splitting between the annulus and the tubing. Instead, this model forced the fluid flowing from the reservoir connection (grid block) to flow through the ICD and into the tubing. This technique is adequate for specific situations e.g. the presence
of frequent AFI s, gravel pack, etc. but is not realistic whenever significant annular flows are encountered. The inclusion of annular flow is critical for:

1. Proper design of annular isolation points in a heterogeneous reservoir where an optimum AFI design cannot be achieved without the need to model annular flow.

2. For the evaluation of the completion performance throughout the life of the well if a non-optimum or no AFI completion has been installed.

3.14 Available Modelling Techniques for the Evaluation Stage

There are proprietary as well as commercial software which evaluate the performance of the completion throughout the life of the well. Some of these are described below:

3.14.1 **SINDA/FLUINT**

Augustine, J. [15] presented a complex integrated reservoir/wellbore modelling technique for helical channel-type ICDs using SINDA/FLUINT fluid dynamics software package. SINDA/FLUINT is a finite difference, network flow analyser. The reservoir parameters governing the three dimensional fluid flow, such as reservoir permeability and fluid viscosity, were modelled as flow resistance parameters. This modelling technique is reported to be cumbersome and time consuming.

3.14.2 **Eclipse™ Reservoir Simulator**

Eclipse™ 100 [170] is black oil, finite difference reservoir simulator with the capability to model (A)ICDs and ICVs with and without annular flow isolation through its Multi-segment Well Model [114]. This model divides the wellbore into a number of segments as described earlier in the modelling for sizing stage. The individual segments can be part of the annulus, tubing or an (A)ICD or ICV placed between them (Figure 3-30).

Versions of the simulator software that were developed prior to the “2008” version enabled a “trunk-and-branch” topology of the flow between the wellbore segments. However, this limitation was removed in the “2008” and later versions. The wellbore can be modelled as a “network” of nodes. This enables separate flows to join or a single flow to split during the fluid movement towards the topmost segment. This provides an accurate representation of the wellbore. This simulator contains a number of pre-programmed keywords which can be used to model various AWC components. Table
3-9 lists the AWC components and the most appropriate keywords to model their performance. A brief description of these keywords and the equations they employ along with some illustrative examples of their applications can be found in reference [170].

![Diagram](image)

**Figure 3-30:** The ICD and ICV flow direction model as applied in Eclipse™ 100 [204]

**Table 3-9: AWC components and modelling keywords**

<table>
<thead>
<tr>
<th>AWC component</th>
<th>Type</th>
<th>Modelling Keyword</th>
</tr>
</thead>
<tbody>
<tr>
<td>ICD</td>
<td>Helical Channel</td>
<td>WSEGSICD</td>
</tr>
<tr>
<td></td>
<td>Labyrinth Channel &amp; Tube</td>
<td>WSEGLABY</td>
</tr>
<tr>
<td></td>
<td>Nozzle, Orifice &amp; Slot</td>
<td>WSEGVALV</td>
</tr>
<tr>
<td></td>
<td>Regulated</td>
<td>WSEGFLIM</td>
</tr>
<tr>
<td>AICD</td>
<td>Flapper, Ball, Disc &amp; Remote</td>
<td>WSEGAICD</td>
</tr>
<tr>
<td></td>
<td>Swellable</td>
<td>WSEGAICD</td>
</tr>
<tr>
<td>ICV</td>
<td>Discrete</td>
<td>WSEGVFLIM</td>
</tr>
<tr>
<td></td>
<td>Variable</td>
<td>WSEGMULT</td>
</tr>
</tbody>
</table>

WSEGTABL [170] is another keyword which can be applied to model all of these devices. It uses device specific flow performance curves in a tabulated format to interpolate the pressure drop through the device for different flow rates. These keywords are normally interchangeable when correctly applied.
In addition, the recently introduced keyword (UDQ), standing for User Defined Quantity, enables the user to model the pressure drop through AWC components using any of the flow correlations described previously. The use of multiple UDQ keywords allow the user to implement some aspects of the (A)ICD sizing process within the reservoir simulator after an initial (very) short time step to estimate the well performance. These will then be used to equalise the influx of oil or gas and restrict the flow of unwanted fluids for the entire well life.

3.14.3 **Reveal™ 7.0 Reservoir Simulator**

Two flow correlations which have recently been included in the Reveal™ 7.0 [119] reservoir simulator can be used for the modelling of ICD and ICVs. These flow correlations are similar to that of Eclipse WSEGSICD and WSEGVALV (Equation 3-28 and Equation 3-52). These can be used to model all types of ICDs and ICVs, including any emulsion effect. Reveal™ 7.0 also has the capability to model the split flow between the annulus and the flow control component. This is an advantage that both Reveal™ and Eclipse™ have over reservoir simulators which are not capable of modelling annular flow or flow control equipment. However, this version of the software does not allow the flow area or strength of the ICD to be modified during the life of the well based on water or gas influx, limiting its applicability for AICD modelling. This limitation could be overcome by including a subroutine (program) that will instruct the simulator to change the completion settings due to water or gas influx, providing the user has sufficient programming knowledge.

3.14.4 **VIP-NEXUS™ Reservoir Simulator**

Landmark’s VIP-NEXUS™ [205] reservoir simulator is also capable of modelling AWCs in a “trunk-and-branch” topology. The downhole flow control equipment can be modelled using its internal valve flow correlation.

\[
\delta P = CVX(X) \frac{q^2}{\rho_{\text{mix}}}
\]

Equation 3-66

Where \( CVX(X) \) is the valve flow coefficient as a function of the valve position \( X \).

The program allows the modeller to provide valve flow coefficient tables which are based on the valve setting. This approach can either be used for a pressure control valve which fits all the (A)ICD and ICV types or it can be used for a rate control valve.

The disadvantage of the modelling approach available in VIP-NEXUS™ is its lack of ability to model the split flow between the annulus and through the completion.
However, this limitation can be overcome by coupling this reservoir simulator to a subsurface/surface network simulator. This will be explained in the following section.

3.14.5 \textit{STARSTM Reservoir Simulator}

The latest version of STARSTM [206] reservoir simulator can divide the wellbore into small segments through its discretized wellbore model to capture the frictional pressure drop in horizontal wells. This modelling approach also enables it to model fluid circulation from surface through the tubing into the formation and back through the annulus to surface. However, it is not capable of modelling (A)ICD or ICVs properly since it does not include any correlation describing the flow through restrictions. The impact of some AWC components can be partially modelled through manipulation of the completion parameters. For example, the effect of a two position ICV (i.e. open/shut) can be represented by opening and shutting the wellbore connection to the gridblock. In addition, this simulator does not allow for split flow between the annulus and the completion to be modelled.

However, this simulator can also be coupled to a subsurface/surface network simulator.

3.15 Integrated Reservoir and Wellbore Simulation for AWC Performance Evaluation

This section describes integration techniques of reservoir and wellbore models in order to overcome the following limitations:

1. Reservoir simulators which cannot model AWCs or the ones that can model AWC components but cannot capture the effect of annular flow.
2. Wellbore network simulators which cannot capture the time dependent, dynamic effects of the reservoir depletion throughout the life of the well.

This technique can also be extended to surface facility network modelling. Most of the published reservoir/surface network integration systems are:

- Incorporated in the reservoir simulators through implicit, full or partial, coupling of the subsurface/surface network with the reservoir (e.g. Coats et al. [205] and EclipseTM [170]).
- Commercially available, explicit products which provide “tight” or “partial” coupling of the two simulators. Some of these employ parallel, open server computing architecture, e.g. RevealTM [119], Gokhan et al. [207], Ghorayeb et
al. [208], Kosmala et al. [209] and Venkataraman and Mueller [195]; while others couple the two simulators directly, e.g. S3Connect\textsuperscript{TM} [200] (Figure 3-31).

- Specially developed programs for specific application which are not commercially available (e.g. Hyder et al. [210]).

---

**Figure 3-31: Commercially available integrated full-field simulation and optimisation software**

Reservoir simulators which have the capability of modelling advanced well configurations such as Eclipse\textsuperscript{TM} have a fully coupled reservoir/network model that is solved simultaneously at the end of each simulator’s Newton iteration. This approach decomposes the wells and the facility networks into small domain models [205]. These are then run simultaneously and iterated to solve the equations for each domain. The utilization of such coupling architecture often reduces the simulation time and provides accurate results when compared to explicitly coupled models with data exchange at every time step. The explicit, partially coupled, model delivers accurate results when the reservoir simulator-wellbore calculation boundary is limited to the reservoir/wellbore connection points (the perforations).
There are a number of commercial software packages which offer the capability to integrate reservoir and subsurface/surface models explicitly. However, not only are there differences in the degree of coupling between the individual software programs, but some of these links usually place high demands in terms of computing power, network architecture and manual intervention of the engineer.

One of the early coupling examples is presented by Gokhan et al. [207] of a “tight” coupling interface between the reservoir simulator Eclipse™ and the network simulator and optimiser NETOPT™ provided by Invensys. The coupling was based on a Parallel Virtual Machine (PVM) interface and required convergence of the surface and reservoir simulators results at every time step. This requirement results in the necessity of multiple iterations of both models to reach a convergence point.

S3Connect™ and Resolve™ [213] are robust and efficient linking tools developed to couple commercial reservoir simulators such as Eclipse™ 100 and 300, Reveal™, VIP-NEXUS™ and STARS™ with subsurface/surface network simulators and optimisers such as GAP™ and Reo™. These have been successfully applied in this study. Other coupling programs such as Avocet™ [211] and NETOPT™ are also commercially available.

3.15.1 Advantages of Integrated Production Modelling

Integrated production modelling is a concept that has been in development within the industry since the 1970s [214]. However, the application of this concept gained a lot of momentum in recent years due to successful, early application to Field Development Planning. The speed of development has increased further with the advent of ever increasing computer power along with the advent of the “Intelligent Field” concept and Real-Time Optimisation [215]. Integrated production modelling has now become essential to take advantage of the investment in downhole sensors, downhole flow control valves and the associated data networks. Real-time production optimisation had now become a realistic possibility in creating value where suitable algorithms are used [216, 217].

Such an integrated modelling system allows dynamic well network and surface facility deliverability and capacity constraints to be closely coupled with the reservoir simulation model. Integrated systems bring many other advantages, including the:

- Integration of engineering disciplines (i.e. reservoir, production and facility engineers), allowing better decisions to be made.
• Flexibility to rapidly modify the surface and subsurface networks configuration and the individual component settings to respond rapidly to, possibly unforeseen, changes in the asset’s operational conditions.

• Ability to recognise, at an early stage, slowly developing differences between the modelled and the actual reservoir performance. This also requires adjustment of the reservoir model.

• Ability to easily recognise changes in the:
  o Well’s inflow performance (e.g. development of a “skin” requiring well stimulation for its removal) or
  o Well’s outflow performance requiring adjustment of the flow correlations used to model fluid flow in the network elements
The observed field behaviour should be closely matched once these changes are implemented.

• Ability to quantify the costs of surface facility capacity constraints, allowing convincing justifications to be easily prepared for management’s approval of facility extensions or modifications.

Several commercially available, reservoir simulators have the facility to reflect the fluid flow behaviour and pressure drop across some of the surface network components by hydraulic (or Vertical Lift Performance) tables for some years. This was frequently limited in the number of components that could be included in the hydraulic network and the gathering topology of the network architecture in which flow from any node in the network can only be directed to another node [205, 218, 219]. This is not the case when an integrated production system model is available since flow from any node in the network can be directed to multiple subsequent nodes rather than one node only [220].

3.15.2 Reservoir/Subsurface/Surface Coupling Methodology

Any commercially available, 3D, reservoir simulation software (such as Eclipse™ 100 and 300, Reveal™, STARS™ and VIP-NEXUS™) with the capability to be linked to a surface network modelling software can be used. A frictionless horizontal wellbore can be modelled in the reservoir simulator with controllable connection pressures (or flow rates) at each grid block. If this is not possible, then each grid block connection has to be modelled as a well with either a controllable bottom hole pressure or a controllable flow rate, but without a Vertical Lift Performance Table.
The coupling of the bottom hole nodes (at the sand-face) of these connections into one (vertical, inclines, horizontal or multilateral) completion is then constructed in the subsurface/surface network modelling software, GAP™ in this case. The separate wells are connected within the reservoir simulator by a frictionless downhole network with a common output node that can be used for comparison with the wellbore model output node pressure or rate value. This will ensure convergence between the two models at the topmost node. It is preferred that the grid block length size, in the direction of the wellbore, matches the (A)ICD joint length since the modelling of fluid flow from one inflow connection to multiple pipes might introduce fluid circulation which could not possibly be present in the “real world” (Figure 3-32).

![Diagram of fluid circulation](image)

**Figure 3-32: Fluid circulation when an inflow is connected to multiple annular segments**

“Partial” coupling is followed by S3Connect™ to link the reservoir simulation model to the subsurface/surface network model. In this approach the exchange of data between the two models takes place at every user specified time-step. The linkage utilizes the restart functionality of the reservoir simulator extensively. The coupling is initiated from the restart file of a reservoir simulation run so that the reservoir simulation model is run for a short time step. Only then, each well required data is transferred to the subsurface/surface network simulator.

There are two data transfer methodologies depending on the chosen well data input functionality in the network optimiser [121]. The first method requires the reservoir
pressure in the vicinity of the well along with the well Productivity Index (PI), Gas-Oil Ratio (GOR) and water cut (WC). The second method requires multiple well bottom hole pressures and their associated flow rates, WCs and GORs to be available in a look-up table format.

The input for the second methodology is generated by the linkage tool as follows:

1. The reservoir pressure in the wellbore and the vicinity of the well is recorded by the linkage tool.
2. Multiple well bottom hole pressures are generated within a range slightly higher and lower than the original bottom hole and near wellbore pressures.
3. Multiple reservoir simulation time steps are then conducted for short or long time steps (as defined by the user) to obtain the fluid flow rates, GORs and WCs associated with the newly calculated well bottom hole pressures.
4. The above data are then used to populate the completion look up table in the network optimiser GAP.
5. The network model is then solved and the optimum production rate or control pressure is allocated to each completion. These liquid flow rates or control pressures are imposed as target values on the reservoir simulator for the next time step.

The advantages of this coupling method include the [200]:

- Elimination of the requirement for a Parallel Virtual Machine (PVM) interface with the reservoir simulator.
- Ability to modify the well configuration (ICVs and AICDs) at any time-step specified by the user for the optimised run.
- Coupling taking place at the user specified time stepping.

“Tight” coupling is applied by Resolve™ which uses PVM or Message Passing Interface (MBI) architecture to link all reservoir simulators, apart from Reveal™, with GAP™. “Tight” coupling has a slightly different data exchange process compared to “partial” coupling process of S3Connect™. The reservoir and wellbore simulators are iterated until the optimum flow rates or control pressure recommended by the wellbore simulator is returned by the reservoir simulator (i.e. both models converge within an acceptable tolerance).
3.16 Validation of Modelling Techniques

All the modelling techniques presented above have been validated using actual data whenever possible or with modelled data.

3.16.1 Validation of Well Productivity Modelling

The actual well performance normally varies from one well to the next. The proposed well productivity estimation technique was therefore compared to the performance of both a vertical and a horizontal well modelled in Wellflo™ (a recognised well modelling software provided by Weatherford/EPS [221]). Table 3-10 summarises the well data employed for this comparison. It represents a vertical well containing two layers at the same elevation (i.e. the pressure drop calculation was not considered between the layers). The horizontal well example was completed in a homogeneous reservoir with the pressure drop due to flow along the horizontal completion being considered.

The proposed well modelling technique matched the commercial well simulator results (Figure 3-33 and Figure 3-34).
Table 3-10: Vertical and horizontal well model properties

| Reservoir Dimensions | Radius (ft) for Vertical Wellbore (Width - Perpendicular to Horizontal Wellbore) | 1,000
| Regions (Vertical / Horizontal) | 2 / 35
| Region Length (ft) | 40
| Region Height (ft) | 40
| Permeability (md) | Vertical Well Region (1 & 2) | 1,000 & 500
| | Horizontal Well Region (All 35) | 1,000
| | $K_v/K_h$ | 1.0
| | Relative Permeability | Oil phase only
| Fluid Properties | Pressure (psi) | 3,000
| | Temperature (°F) | 160
| | Oil Density (lbm/ft$^3$) | 53.65
| | API Gravity | 33.0
| | Gas Oil Ratio (GOR) (scf/stb) | 500
| | Oil Formation Volume Factor (bbl/stb) | 1.23
| | Oil Viscosity (cp) | 1.0
| Well Dimensions | Completion Length (ft) (Vertical / Horizontal) | 80 / 1,400
| | Wellbore Diameter (ft) | 0.708
| | Wellbore Roughness (ft) | 0.00015
| | ICD/SAS OD (ft) | 0.625
| | ICD/SAS ID (ft) | 0.5
| | Annulus Equivalent ID (ft) | 0.333
| | Vertical Depth (ft) (Vertical / Horizontal) | 7,800 / 6,600
Figure 3-33: Comparison of proposed vertical well productivity calculation (Excel) with results from the Wellflow™ well simulator

Figure 3-34: Comparison of proposed horizontal well productivity calculation (Excel) with results from the Wellflow™ well simulator
3.16.2 Validation of Downhole Flow Control Devices Modelling

Most of the modelling techniques presented in Section 3.6 for the flow control devices have been validated against published actual flow data or against (approved) modelled data where possible. Figure 3-35 shows a match between the reported and calculated helical channel-type ICD flow data. Water flow through this ICD type was modelled using Equation 3-28. The average ICD strength values listed in Table 3-2 were used to model different flow rates and their corresponding pressure drops through the different ICD ratings.

Figure 3-35: Comparison of published helical channel-type ICD data with Equation 3-28

Figure 3-36 shows a small percentage difference between the reported nozzle-type ICD data and the data modelled using Equation 3-35. This analysis was performed for two flow rates selected from Figure 3-7 using an oil phase with a density of 900 Kg/m$^3$ and a viscosity of 1.5 cp. (The fluid used to produce Figure 3-7 [177]). However, a simplified form of Equation 3-38 (i.e. Equation 3-52) with a constant discharge coefficient of 0.9535 [222] was applied since the upstream pipe diameter required for application of Equation 3-38 was not provided [177]. Also, a better match was achieved when water with a density of 1000.25 Kg/m$^3$ was used instead of the oil (Figure 3-36).

Figure 3-37 shows a small percentage difference between the reported flow test data of orifice-type ICDs and the modelled ICD performance using Equation 3-35. The fluid
used for this analysis has a density of 1000.5 Kg/m³ and the upstream pipe diameter is 2.61 inch [176]. The discharge coefficient values were calculated using Equation 3-39.

Figure 3-36: Comparison of published nozzle-type ICD data with Equation 3-35

Figure 3-37: Comparison of published orifice-type ICD data with Equation 3-35

The strength values of the slot-type ICD can be calculated from the flow test data shown in Figure 3-8 in the same manner as for a helical channel-type ICD. However,
this data is incomplete since the fluid properties were not specified. For simplicity, the red colour line representing a fluid with a viscosity of 52 cp was used for this analysis and the ICD strength values for each ICD rating calculated. Then, the average ICD strength value for each ICD rating was used to model the ICD performance using Equation 3-28. Figure 3-38 shows a small difference between the published performance model for this ICD and the results of Equation 3-28.

![Figure 3-38: Comparison of reported slot-type ICD data with Equation 3-28](image)

Flow test data for the disc and swellable-type AICDs have been made available (Figure 3-18 and Figure 3-20) although restriction opening sizes were omitted. AICD strength values (e.g. Figure 3-21) can be calculated from the reported data despite this limitation by using Equation 3-51 for the swellable-type AICD followed by application of Equation 3-50 to estimate the performance of the AICD (Figure 3-39). Note that the strength values are dependent on the flow area which will be changing in the AICD as water or gas influxes. For example, the strength values for the disc-type AICD indicate an increase in the flow restriction (Figure 3-40). Flow test data for other AICD types has not been published.

The ICV performance under subcritical flow has been made available (Figure 3-22 [187]). However, the upstream pipe diameter used in this testing was not provided hence Equation 3-52 was used to match the performance of this ICV. The discharge coefficient values for this ICV were back calculated from the flow test data and the
average value applied for the pressure calculation. Figure 3-41 shows a match of selected positions and flow rates of this ICV’s performance. Critical flow data through ICVs has not been published.

Figure 3-39: Comparison of the reported swellable-type AICD performance and Equation 3-50

Figure 3-40: Strength values for disc-type AICD
The performance of the flow control equipment highlighted above can also be matched by the Eclipse™ reservoir simulator; the NETool™ ICD and ICV models; as well as with the GAP™ inline programmable elements and choke valves. In addition, the applications of all of the modelling techniques (proprietary or commercial) will be shown throughout the following chapters with more details in Chapter 6.

### 3.17 Summary

The various components of Advanced Well Completions can be applied in different reservoir types and wellbore configurations to control single or multiple fluid phases. Appropriate modelling techniques of AWCs were devised to achieve an optimum completion design and well performance. These include (Figure 3-42):

1. Sizing tools which model the performance of AWCs at a snapshot of time. These tools integrate:
   - Well productivity indices of different well configurations
   - (A)ICD and ICV flow correlations
   - Multi-phase pipe flow correlations
   - Annular flow effects
2. Evaluation tools which account for the time dependent performance of the completion throughout the life of the well. These include:
   - Commercially available reservoir and wellbore simulation tools
   - Integrated field development modelling tools

Appropriate use of these two techniques allows:
- Productivity Index estimation for a range of different well and AWC configurations.
- Fluid influx (outflow) misbalance identification and quantification.
- Determination of location and impact of AFI.
- Unwanted fluid (water and gas) influx identification and quantification.
- (A)ICD and ICV applicability identification and added value quantification.
- (A)ICD and ICV restriction sizing.
- Design parameters uncertainty and reliability quantification.

Figure 3-42: AWC modelling components
Chapter 4 Designing Inflow Control Device Completions and Annular Flow Isolation

4.1 Introduction

Inflow Control Devices are a relatively new technology which is gaining popularity in the petroleum industry with an increasing range of applications in various reservoir and well types. The primary objective of this technology is to balance the fluid flow into or out of the wellbore. A comprehensive review of ICD completion applications was summarised in Chapter 2. Gas production and injection and WAG injection wells are also potential candidates for ICD completions. They will be discussed in this chapter along with the application of ICDs in vertical and deviated wells.

Chapter 3 provided guidelines for proper modelling of ICD completions over the complete well life. Annular flow must be accounted for when ICDs are installed with no or a limited number of packers. Annular flow, both prior to and after water or gas breakthrough, has already been shown to create completion problems [117]. The proper placement of Annular Flow Isolation (AFI), an important aspect of ICD completion design, may increase the well’s potential. This is especially true in fractured reservoirs and reservoirs dominated by high permeability streaks [220, 128].

The application of ICDs is no longer restricted to balancing the “Heel-Toe” effect (HTE) in horizontal wells completed in relatively homogeneous reservoirs. It is now applied in reservoirs with a varying productivity index along the wellbore caused by the heterogeneity of the reservoir matrix or the existence of fractures or layering (Chapter 2). However, the design of each of these completions requires a different procedure. This chapter offers the completion engineer a customised workflow for the design of ICD completions with specific steps covering the major factors affecting the performance of such completions. Before delving into the technique, the next section gives a brief review of the ICD technology.
4.2 Brief Review of ICD Technology

A number of the world’s leading suppliers of technology to the upstream oil and gas industry have developed their own, unique ICD design for the mechanism to create the flow resistance (helical or labyrinth channels, tubes, nozzles, orifices or slots). These designs can be mounted on a Stand-Alone-Screen (SAS) or combined with a debris filter for use in consolidated formations.

The channel, slot and long tube-type ICDs use a number of channels or flow tubes with a pre-set diameter and length to impose a specific deferential pressure at a specified flow rate. These designs cause the pressure drop to occur over a longer interval compared to the nozzle, orifice and short tube-type ICDs, an advantage that is deemed to reduce the possibility of erosion or plugging of the ICD ports [126]. However, these devices depend on friction to create the differential pressure in addition to the acceleration effect. This reliance on friction magnifies the effect of pressure drop if emulsion is formed.

The nozzle, orifice and short tube-type ICDs, as the names indicate, use a number of very short restrictions to create the pressure resistance. The number and diameter of the restrictions are chosen so as to produce the desired pressure drop across the device at a specific flow rate. These multiple flow restrictions make the pressure drop highly dependent on the fluid density and velocity, but less dependent on viscosity. However, high fluid flow velocity is one of the major causes of erosion, especially when combined with sand production [126].

The increasing application of these devices in various reservoir types, such as fractured carbonates and sandstones, and the different well configurations (vertical, horizontal and multilateral wells) highlight the value of this technology. However, modelling indicates that the value proposition is not always clear and a proper design workflow is required for the completion both prior to and post drilling of the well [128, 115].

Chapter 3 presented a comprehensive overview of the available and possible modelling techniques of ICD completions. These factors include modelling the:

1. Formation productivity (or injectivity).
2. ICD flow performance.
3. Tubing flow performance to the topmost point of the well.
4. Annular flow.
5. Reservoir exploitation effect throughout the well life.
4.3 ICD Completions Design Workflow

The main factors that should be considered in the design of an ICD completion are:

1. The ICD restriction (channel, tube, nozzle, orifice or slot) size which will ensure balanced fluid flow from/to all zones.
2. Existence of annular flow and any subsequent requirement for AFIs.
3. Uncertainties in the completion design parameters including the reservoir productivity or injectivity (and any of its subcomponents) and the wellbore/completion modelling tools.
4. Economic value of the completion expressed in an appropriate indicator (e.g. Net Present Value).

These factors are interrelated in a non-linear, iterative manner (Figure 4-1) and form the basic steps to design an ICD completion. The following sections provide simple guidelines which can assist completion engineers in developing an optimum ICD completion design in a limited time.

![ICD Completion Design Steps Diagram]

**Figure 4-1: ICD completion design workflow**

4.4 Identification of Optimum ICD Restriction Size

The initial propose of the ICD completion is to balance the fluid flow into or out of the wellbore. The secondary objective of ICD completion is to minimise the amount of gas or water produced after breakthrough. Therefore, the identification of the required
restriction size per ICD joint is essential to achieve the required equalisation. However, the identification of the appropriate ICD size or pressure drop is dependent on the following:

1. The well configuration (i.e. deviation, laterals, etc.).
2. The minimum restriction size that can be installed in practice without inflecting installation or reliability problems.

The well deviation dictates two important factors in the ICD size identification process:

A. The objective of the ICD installation: the frictional effects have a small influence on the well productivity or injectivity in vertical wells. This limits the application of ICDs in these wells to the Variable Productivity Effect (VPE) and in minimising the volumes of gas or water production. By contrast, the HTE caused by the frictional pressure drop along the lateral(s) in horizontal and multilateral wells in addition to the VPE is often more important than hydrostatic head effects.

B. The productivity index calculation methodology used to calculate the ICD size also depends on the well deviation.

Once the well deviation is defined, the appropriate well modelling technique (i.e. productivity index and wellbore pressure drop calculation methods) can be specified. The pressure drop across the ICD, and hence the ICD restriction size, can then be identified.

Analysis of actual and potential ICD applications has indicated that there are four, generic completion types employing ICDs:

1. ICDs installed across the high influx, high productivity or high pressure sections and Pre-Perforated Liner (PPL) or SAS installed across the low influx sections. These sections can be intervals of varying characteristics along the wellbore, separate zones or different laterals.

2. Constant ICD restriction size installed across the whole length of the producing interval.

3. Variable ICD restriction size: For example, ICDs with small nozzle sizes (i.e. high pressure drop) are installed across the high productivity sections and ICDs with larger nozzle sizes (i.e. low pressure drop) are installed across the low productivity sections. This description also applies to ICD completions in which a constant ICD restriction size is used but the number of ICDs installed across
each zone is varied and coupled with blank pipes. This imposes a similar effect
to varying the ICD restriction sizes but with simplified installation operation.

4. ICDs installed across the low productivity sections and blank pipe across shale,
fractures and super-K zones.

The decision to install one of these completion types is mainly based on the
productivity of the reservoir zones, the level of equalisation required, the existence of
annular flow, the complexity of the installation operation and the reliability of the
completion to maintain a relatively equalised fluid flow for the longest period of time.
These factors will be analysed in the following sections.

First, the underlying equations describing the physical process will be introduced;
then they will be used to design the ICD completion for each of the listed completion
configurations.

4.4.1 Basic Concepts:

The basic concept behind any ICD completion design is simple: the fluid flow
through any two ICDs located in a well should either be equivalent or equalised to the
“optimum” point.

An “equivalent” inflow (or outflow) rate per tubular joint \( q_{eq} \) can be calculated by
dividing the target well flow rate by the number of standard tubular (i.e. ICD, SAS,
PPL, etc.) joints which can be installed across the producing zones (Equation 4-1).

\[
q_{eq} = \frac{q_t}{N_j}
\]

Where:

- \( q_{eq} \) = Equal segment influx rate (stb/day)
- \( N_j \) = Number of completion joints

The “optimum equalisation”, which can also be called the “maximum beneficial
degree” of equalisation, is reached when the undesirable impact of the ICD completion
on the well potential becomes similar to the benefits of its installation. In this case, the
inflow or outflow rate per joint will not be constant, but will have been significantly
equalised along the length of the completion. Guidance on how to identify this value
will be given in Section 4.4.3 of this chapter. However, exceeding the "maximum
beneficial degree" of equalisation will:

1. Significantly reduce the well bottom hole flowing pressure required to achieve
the same production flow rate. This will be reversed in injection wells meaning
that the pressure required to inject a specific amount of fluid will increase which will demand higher pumping capacity.

2. Reduce the well’s cumulative oil production when the well produces under natural depletion.

3. Accelerate the need for artificial lift installation in production wells which will impact the well OPEX.

4. Increase the wellhead pressure in injection wells; increasing the injection pump’s pressure specification and the well’s CAPEX and OPEX.

Therefore, this point can be declared as the optimum ICD restriction size if a complete equalisation is harmful or cannot be achieved.

Subsequently, if the fluid flow through an ICD is represented by \( q_{ICD} \) then complete or optimum equalisation along the wellbore requires that:

\[
q_{ICDH} = or \approx q_{ICDR}
\]

Equation 4-2

Where:

- \( H \) = High productivity, injectivity or inflow/outflow zone
- \( R \) = Reference zone productivity, injectivity or inflow/outflow

The reference zone is the lowest productivity, injectivity or contribution zone in the well which is capable of delivering an “equal” inflow or outflow rate under the specified well operating constraints. This implies that a low productivity zone which is not capable of delivering the \( q_{eq} \) should not be considered the reference zone since any ICD completion that is designed to equalise the flow rate from this low productivity zone with the rest of the well will hinder the well capability to deliver the well target flow rate. In addition, the operating constraints can be a specific target flow rate; a specified bottom hole flowing pressure {for example, equivalent to (or higher than) the bubble point pressure}; a minimum tubing head pressure that maintains a certain production from the well without artificial lift; or any other well constraints.

The flow rate from a section of the well equivalent in length to the size of an ICD joint is governed by the productivity of that section \((PI_{ICD})\).

\[
PI_{ICD} = J_s \cdot l_{ICD}
\]

Equation 4-3

Where:

- \( J_s \) = Specific productivity index (stb/day/psi)
- \( l_{ICD} \) = Length of ICD joint (ft)

Hence, the flow rate through an ICD from a section of the well is:
\[ q_{ICD}(i) = PI_{ICD}(i)\left[\overline{P}_r(i) - P_w(i) - \delta P_{ICD}(i)\right] \]  

Equation 4-4

Where:

- \( \overline{P}_r \) = Segment average reservoir pressure (psi)
- \( P_w \) = Segment wellbore pressure (psi)
- \( \delta P_{ICD} \) = Pressure drop across the ICD (psi)
- \( i \) = Segment number

This flow rate can be translated to a change in pressure using the appropriate correlation relating the flow rate through the ICD \( q_{ICD} \) to the pressure change across the ICD. This specific equation choice depends on the ICD type (see Section 3.6). For example, Equation 3-35 in Section 3.6 describes the pressure drop as a function of flow rate through a nozzle/orifice-type ICD.

The following should be noted before delving into the ICD restriction identification:

1. Although reference is always made to a production well, the proposed techniques are applicable to both production and injection wells. However, the additional pressure drop imposed by the ICD completion should be added to the reservoir pressure in injection wells while the pressure is subtracted from the reservoir pressure in production wells.

2. It is apparent that the well must be produced at a lower surface/bottom hole flowing pressure \( P_{wf} \) to overcome the ICD completion restriction and achieve the well’s target production flow rate. It is assumed that the new \( P_{wf} \) can be achieved by modifying the surface choke opening. The additional pressure drop caused by an ICD completion in injection wells will require additional injection pump capacity.

3. The proposed ICD sizing techniques initially assumes that both AFI’s and reservoir permeability barriers exist between the high and low contributing sections (zones). Validity of this assumption will be tested later in the annular flow discussion (Section 4.7).

4. Although reference is always made to a high and a low productivity zones, these can be high and low injectivity, contribution or pressure sections, etc. depending on the well completion objective. In addition, the low productivity zone used for the design of the ICD completions in the following sections is the “reference zone” described above.

5. An oil well and gas well example of ICD completion designs is provided in Section 4.4.2 for this first ICD sizing method. This illustrates the workflow’s
applicability to both fluid phases. For simplification, only two zones (i.e. wellbore intervals) of high and low productivity and single-phase flow of oil or gas will be described. The oil well example will be used in the subsequent sections while the gas well example will not. However, case studies of gas and gas condensate production as well as WAG injection wells are provided in Chapter 6 to show the performance of the other ICD completion designs.

4.4.2 ICD across High Productivity Zone(s) and SAS (or PPL) across Low Productivity Zone:

This type of completion is recommended in vertical, deviated, horizontal or multilateral wells where:

1. Annular flow across the low productivity zone is not significant.
2. Sanding tendency is low.
3. Low productivity zone is allowed to flow at the maximum possible rate.

The following workflow will be applied to identify the required pressure drop across the ICD:

1. Calculate the productivity of the well with nodes at each ICD joint length of the completion using the appropriate well modelling (i.e. productivity and wellbore pressure drop) technique described in Section 3.5.
2. Calculate the “equal” flow rate per tubular joint ($q_{eq}$) using Equation 4-1.
3. Identify the low productivity zone and calculate the wellbore pressure ($P_w$) required to drawdown and produce the equalised flow rate per joint ($q_{eq}$) from that zone. In addition, calculate and add the pressure drop through the SAS or PPL, if it will be installed across the low productivity zone, based on the equalised flow rate per joint ($q_{eq}$). Note: use Equation 3-54 from Section 3.9.
4. Calculate the required bottom hole flowing pressure ($P_{wf}$) using Equation 4-5 to produce the target well flow rate assuming the whole completion is made up of the low productivity zone ($P_{IICDL}$) rather than the composite $PI$ of the whole completion. This is performed because the purpose of this completion is to deliver an equal influx rate from both the high and low productivity zones by reducing the productivity of the high productivity zone(s) to match that of the low productivity zone or by reducing the influx rate of the high contribution zone to the equal influx rate.
\[ P_{wf} = \overline{P_{rl}} - \delta P_{PGSAS} - \left( \frac{q_{eq}}{P_{ICDL}} \right) \]  

Equation 4-5

Where:

- \( P_{wf} \) = Bottom hole flowing pressure (psi)
- \( \overline{P_{rl}} \) = Average reservoir pressure of low productivity zone (psi)
- \( \delta P_{PGSAS} \) = Pressure drop across a gravel pack or SAS (psi)

5. Calculate the \( \delta P_{ICD} \) that minimises the contribution of the high productivity (or contribution) zone to an equal contribution with the low productivity zone using Equation 4-7. This Equation was achieved by equating Equation 4-4 for the high and low productivity zones (Equation 4-6).

\[ PI_{ICDH} \left( \overline{P_{rl}} - P_{wH} - \delta P_{ICD} \right) = PI_{ICDL} \left( \overline{P_{rl}} - P_{wL} - \delta P_{PGSAS} \right) \]  

Equation 4-6

Equation 4-6 will reduce to the following:

\[ \delta P_{ICD} = \frac{\overline{P_{rl}} - \frac{PI_{ICDL}}{PI_{ICDH}} \left( \overline{P_{rl}} - P_{wL} - \delta P_{PGSAS} \right) - P_{wH}} \]  

Equation 4-7

The PI ratio in Equation 4-7 can be further simplified to the ratio of the PI components. For example, Equation 4-7 can be simplified to Equation 4-8 if the permeability is the component causing the productivity variation. Note that this assumes that the wellbore and reservoir radii and skin values are the same in all zones:

\[ \delta P_{ICD} = \overline{P} - \frac{k_{L}}{k_{H}} \left( \frac{h_{L}}{PI_{L}} - \frac{h_{H}}{PI_{H}} \right) - P_{wH} \]  

Equation 4-8

If the wellbore pressure drop is negligible, hence:

\[ \delta P_{ICD} = \frac{q_{t}}{N_{ICD} \cdot l_{ICD}} \left( \frac{h_{L}}{PI_{L}} - \frac{h_{H}}{PI_{H}} \right) + \delta P_{PGSAS} \]  

Equation 4-9

Equation 4-9 can also be expressed as:

\[ \delta P_{ICD} = \frac{q_{s-eq}}{J_{sL}} - \frac{q_{s-eq}}{J_{sH}} + \delta P_{PGSAS} \]  

Equation 4-10

Where \( q_{s-eq} \) is an equalised, specific flow rate.

6. The pressure drop across the ICD can be transformed into an ICD restriction size using the appropriate ICD flow correlation provided in Section 3.6.

The installation of such completion will achieve an equal contribution from all zones providing the inflow from the low productivity zone is not affected by factors such as annular flow, etc.
The procedure described above can be applied for multiple-zone completion to reduce the contribution of all the high productivity zones to match the rate of the reference zone.

**Example – 1:** A well is completed across an oil reservoir with two zones of high and a low permeability (1,000 md and 500 md). The total well-reservoir length is 80 ft (40 ft across each zone). The well produces oil with an API gravity of 33°, a formation volume factor of 1.23 and a viscosity of 1.0 cp at a reservoir pressure of 3,000 psi. The target total flow rate is 1,000 stb/day. A SAS completion (with negligible pressure drop) of this well would have required a bottom hole flowing pressure ($P_{wf}$) of 2,979 psi to produce the target well rate. This would have resulted in an unbalanced contribution from the high and low permeability zones (i.e. 666 stb/day and 333 stb/day, respectively, Figure 4-2). The contribution ratio of the two zones agrees with their permeability ratio (i.e. $k_L/k_H = q_L/q_H = 0.5$).

Equation 4-8 can be used to calculate the required ICD pressure drop to equalise the contribution of the two zones. An ICD that imposes a pressure drop of 15.75 psi should be installed across the high permeability zone (Figure 4-3). This pressure drop translates to 8.6 mm nozzle-diameter per ICD joint. The required $P_{wf}$ to achieve the target well rate in this case is 2,969 psi (Figure 4-4).

![Figure 4-2: Inflow Performance of the high and low permeability zones and the composite (total) well performance](image)
Figure 4-3: Required $\delta P_{ICD}$ to equalise the contribution from the high and low permeability zones

Figure 4-4: Equalised contribution from the high and low permeability zones

Example – 2: A well is completed across a gas reservoir made up of a high and a low permeability zone (300 md and 50 md). The total well-reservoir length is 80 ft (40 ft across each zone). The well produces gas with a density of 16.5 lbm/ft$^3$ and viscosity of 0.02 cp at a reservoir pressure of 4,000 psi. Production of the target total flow rate is 5 MMscf/day after installation of a SAS completion (with a negligible pressure drop) requires a bottom hole flowing pressure ($P_{wf}$) of 3,993 psi with an unbalanced contribution from the high and low permeability zones (4.3 MMscf/day and 0.7
MMscf/day respectively, Figure 4-5). Once again, the contribution ratio of the two zones agrees with their permeability ratio (i.e. \( k_L/k_H = q_L/q_H = 0.16 \)).

In this case, an ICD which imposes a pressure drop of 21.3 psi should be installed across the high permeability zone (Figure 4-6). This pressure drop translates to 11.4 mm nozzle-diameter per ICD joint. The required \( P_{wf} \) to achieve the target well rate in this case is 3,974 psi (Figure 4-7).

**Figure 4-5: Inflow Performance of high and low permeability zones and composite (total) well performance**

![Figure 4-5](image)

**Figure 4-6: Required \( \delta P_{ICD} \) to equalise the contribution of the high and low permeability zones**

![Figure 4-6](image)
4.4.3 Constant ICD Restriction Size across Producing Zones:

The design process changes slightly when constant number and size restrictions are installed in all ICD joints. The flow contribution across the well completion now becomes more, but not entirely, equal. The $P_{wf}$ based on the composite PI of the well can now be used since the productivity of the high contributing zone(s) is not reduced to a value equivalent to that of the low contributing zone. The ICD restriction size is used for the ICD flow rate calculation instead of the pressure drop; i.e. the restrictions sizes are the same rather than the ICD pressure drops which will vary due to the different zonal contributions. Hence, the coupled segment productivity and ICD flow correlations should be used to identify the optimum ICD restriction size. These have been listed in Table 3-8 for different ICD types. Equation 3-64 is an example of the nozzle/orifice-type ICD flow correlation coupled with a productivity index.

\[
q_{ICD}(i) = \frac{-1 + \sqrt{1 + \frac{32C_u}{\pi^2} \left( \frac{PI_{ICD}^2 \rho_{mix} (1 - \beta^4)}{C_d \varepsilon^2 d_{no}^4} \right) (i) \left[ P_i(i) - P_w(i) \right]}}{16C_u \frac{PI_{ICD} \rho_{mix}}{\pi^2 \left( \frac{C_d \varepsilon^2 d_{no}^4}{} \right) (i)}}
\]

Equation 4-11

This should be substituted in Equation 4-12 to calculate the well’s total flow rate:
\[ Q_t = \sum_{i=1}^{n} q_{ICD}(i) \]  

Equation 4-12

A standard iterative technique (such as Excel’s Numerical Solver™) can be used to identify the optimum ICD restriction size (e.g. the value of \( d_{no} \) in Equation 3-64).

The iterative calculation proceeds as follows:

1. Calculate the productivity of the well (i.e. composite productivity without ICDs) with nodes at each ICD joint length of the completion using the appropriate productivity model and technique (Section 3.5).
2. Use the composite \( P_{wf} \) required to produce the target well flow rate without ICD completion as an initial \( P_{wf} \) for the ICD completion. Then, iterate the ICD restriction size to achieve the target well flow rate at that \( P_{wf} \).
3. Iterate \( P_{wf} \) by reducing its value and iterating the ICD restriction size with each \( P_{wf} \) to achieve the target well flow rate.
4. Calculate the rate of reduction in the productivity of the low productivity zone using Equation 4-13.

\[
\delta P_{I_{ICDL}} = \left( \frac{q_{ICDL}}{P_r - P_w(i)} \right)_n - \left( \frac{q_{ICDL}}{P_r - P_w(i)} \right)_{n+1} \tag{Equation 4-13}
\]

Where:
\( n \) = Iteration number \( n \)
\( n+1 \) = Iteration number \( n+1 \)

5. Identify the optimum ICD restriction size where the rate of reduction in the productivity of the low productivity zone is at its maximum value (Maximum \( \delta P_{I_{ICDL}} \)):

\[
\max[\delta P_{I_{ICDL}}] = \max\left[ \left( \frac{q_{ICDL}}{P_r - P_w(i)} \right)_n - \left( \frac{q_{ICDL}}{P_r - P_w(i)} \right)_{n+1} \right] \tag{Equation 4-14}
\]

The productivity of both the low and high productivity zones will always decline with a smaller ICD restriction. However, the rate of change in the productivity reduction of the low productivity zone will always increase then decrease creating an upwards curve. The maximum value of this curve corresponds to an optimum ICD restriction size, which maximises the equalisation while minimising the reduction in the total well productivity.
Alternatively, the minimum acceptable $P_{wf}$ value can be specified, making for faster calculation while minimising the impact of the ICD’s installation on the well potential.

The procedure described above can also be applied to equalise the contribution of multiple-zone completions. In this case, the rate of change in the productivity reduction of the zones with productivity values lower than the highest productivity zone will display an upward curve as a result of the smaller ICD restriction. The optimum ICD restriction size is the one corresponding to the maximum rate of productivity change of the reference zone.

**Example:** Figure 4-8 and Figure 4-9 show this effect for an oil well completed across a high and a low productivity zones with similar dimensions and fluid properties to the example provided in Section 4.4.2. As indicated in these figures, the reduction in the restriction (nozzle) size equalises the contribution of the two zones with negligible impact on the $P_{wf}$ required to produce the target well rate until a point is reached where further reduction in the restriction size will have a drastic impact on the $P_{wf}$ with negligible improvement in the equalisation effect. The optimum ICD restriction size is at the maximum rate of change in the productivity of the low productivity zone (Figure 4-10).

An ICD with a nozzle diameter of 11.9 mm should be installed across both zones requiring a $P_{wf}$ of 2,973.6 psi to achieve the target well rate (Figure 4-10). This completion imposes a pressure drop of 6.7 psi on the high productivity zone and 2.5 psi across the low productivity zone.
Figure 4-8: Smaller nozzle size reduces well $P_{wf}$ for a given total flow rate, but increases equalisation

Figure 4-9: Smaller nozzle size reduces well flow rate but increases equalisation
4.4.4 Variable ICD Restriction Size across Producing Zones:

The third case is where a variable ICD restriction size is applied across the sand-face. A high pressure drop ICD is now installed across the high contributing zone and a lower pressure drop ICD is installed across the low contributing zone. Installation of a lower strength ICD across the low contributing zone instead of a SAS, a PPL or a constant size ICD has the advantage of:

- Minimising or eliminating any annular flow across the low productivity zone,
- “Smoothing-out” the small fluid influx misbalance within the zone if the zone permeability varies slightly,
- Eliminating any water or gas injection misbalance due to the creation of thermal or hydraulic fractures,
- Minimising the pressure drop across the low productivity zone in the case where a constant size ICD would either impose a high pressure drop across the low productivity zone or not offer an acceptable level of equalisation without significantly impacting the well potential.

An alternative, but equivalent completion design is to vary the number of ICDs installed across the sand-face while maintaining a constant ICD restriction size. The use of only one size of ICD at the well site simplifies the installation operation. The
reduction in the number of ICDs while maintaining the required pressure drop across a specific zone is achieved by installing blank pipes between the ICDs as required.

The design of the variable ICD completion should apply the following steps:

1. Identify the ICD restriction size to be installed across the low productivity zone as follows:
   - Specification of an equal size ICD for installation across the low productivity zone to equalise the fluid inflow across this zone (see Section 4.4.3). OR
   - Installation of an ICD across the low productivity zone to minimise potential annular flow across this zone if AFIs (in the form of small constrictors) are not used within the zone. See Section 4.7 for quantification and impact of the annular flow. OR
   - Specification of an ICD with the largest restriction size (lowest strength) for installation across the low productivity zone to minimise potential unbalanced injection if thermal fractures develop.

2. Specify the required degree of flow equalisation between the high and low productivity zones:
   a. Equal contribution from all zones: Use the pressure drop across the ICD installed across the low productivity zone ($\delta P_{ICDL}$) in place of the $\delta P_{PGSAS}$ in Equation 4-7, Equation 4-8, Equation 4-9 or Equation 4-10 to calculate the required pressure drop across the ICD installed across the high productivity zone and its corresponding restriction size.
   b. Optimum equalisation between (but not equal contribution from) the producing zones with constant size ICDs across the reminder of the completion apart from the lowest productivity zone: apply the procedure discussed in Section 4.4.3 to all zones apart from the lowest productivity zone to identify the size of a constant ICD restriction design. I.e. this design omits any contribution from the lowest productivity zone.

**Example:** Two lower permeability zones (300 and 350 md) have been added to the two producing zones (500 and 1,000 md) in the oil well example described in Section 4.4.2. The objective is to design an ICD completion that will equalise the fluid inflow across the sand-face for target well flow rate of 2,000 stb/day. In addition, it has been specified that a low strength ICD should be installed across the lowest productivity zone to minimise the potential increase in inflow from this zone that would have occurred
compared to a SAS. All zones are producing the same fluid and have the same dimensions. Figure 4-11 shows the zonal contribution in the absence of an ICD completion.

Figure 4-11: Well performance without ICD completion

The completion design Places ICDs with the largest commercially available restriction nozzle diameter of 9.8 mm for a nozzle-type ICD across the lowest productivity zone (300 md) and follows these steps:

1. The equalised inflow rate from each zone is 500 stb/day, hence the installation of the 9.8 mm-nozzle ICD results in a pressure drop of 9.3 psi across the lowest productivity zone.

2. Inclusion of this pressure as $\delta P_{PGSAS}$ in Equation 4-7 allows calculation of the pressure drop required across the ICDs installed in the other 3 zones. The resulting ICD restriction sizes and pressure drops are listed in Table 4-1:
Table 4-1: Variable size ICD completion

<table>
<thead>
<tr>
<th>Permeability (md)</th>
<th>Permeability Ratio to Lowest Permeability</th>
<th>( \delta P ) across ICD (psi)</th>
<th>ICD Nozzle Diameter (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,000</td>
<td>0.30</td>
<td>39.5</td>
<td>6.8</td>
</tr>
<tr>
<td>500</td>
<td>0.60</td>
<td>26.6</td>
<td>7.5</td>
</tr>
<tr>
<td>350</td>
<td>0.86</td>
<td>15.5</td>
<td>8.6</td>
</tr>
<tr>
<td>300</td>
<td>1.00</td>
<td>9.3</td>
<td>9.8</td>
</tr>
</tbody>
</table>

This completion results in an equal contribution from each of the 4 zones (Figure 4-12). Note that the productivity index of the lowest permeability zone is reduced compared to its initial value (from 9.5 to 8.7 stb/day/psi) due to the impact of the ICD.

Figure 4-12: Equalised contribution from all zones with a reduction in the PI of the lowest permeability zone due to ICD installation

4.4.5 **ICD across the Producing Zone and Blank Pipe across Shale, Fractures or Super-K Layers:**

This case employs constant or variable ICD sizes across the sand-face and a blank pipe across shale, open fractures or super-K intervals. Shale layers may swell and then collapse when contacted by water. Production from open fractures and faults should be
avoided if they are in direct contact with the aquifer or gas cap due to their very high productivity. The effective permeability contrast is so high that equalisation of the contribution from these fractures (or faults) with the matrix contribution might not be possible without exceeding the ICD erosion or plugging limits.

The solution is to install a blank pipe with AFI across these shale layers or open fracture sections to eliminate potential problems arising from the interaction of the shale with the produced or injected fluid and/or prevent the contribution from such fractures.

The design of the ICD completion across the producing zones will follow the procedures discussed earlier while the blank pipe locations will depend on:

1. The minimum permeability ratio \( k_R \) value of the shale zone, where there is essentially no flow contribution, to the producing zone (Equation 4-15). For example, all layers with a \( k_R \) value equivalent or less than 0.01 should be identified as shale layers and isolated.

\[
k_R = \frac{k_{\text{shale}}}{k_{\text{prod-zone}}} \tag{4-15}
\]

2. The permeability, productivity or contribution ratio of the producing zone compared to that of the fracture or fault. A similar argument to that employed above for shale layers, fractures with a very high (0.01) productivity index contrast compared to the producing intervals (Equation 4-16) should be isolated since this cannot be equalised to an acceptable degree within the design limits of an ICD.

\[
PI_R = \frac{PI_{\text{prod-zone}}}{PI_{\text{frac}}} \tag{4-16}
\]

3. Violation of the erosion and plugging potential limits of the ICD. A detailed description of the applicability of this factor will be provided in Section 4.6.

4. The ability of the additional pressure drop imposed by the application of PPSASs or GPs to adequately minimise the erosion or plugging potential of the ICD.

**Example:** Consider an increase in the permeability and reservoir pressure of the highest permeability zone, which was described in Section 4.4.4 example were increased from 1,000 md and 3,000 psi to 10,000 md and 3,500 psi, respectively; simulating the performance of a highly fractured zone. Also, consider a reduction in the permeability of the low productivity zone from 300 md to 100 md.
Achieving an equalised fluid influx across the completion would have not been possible. Therefore, placing blank pipe across the fractured zone would have been the most appropriate solution provided that:

1. There is communication between the fractured zone and another producing zone.
2. Any oil can be recovered via another producer.
3. The above assumes that the fracture produces the required hydrocarbon fluid saturation. The fracture should always be isolated by blank pipe if the open fracture is connected to a zone of unwanted fluid (water or gas).

4.5 ICD Completion Designs for Different Well Architecture:

The design of ICD completions in different well architectures is governed by the inflow/outflow performance of these wells. The differences in productivity index and wellbore pressure drop from the bottom to the topmost point of the sand-face completion between vertical, horizontal and multilateral wells are the main factors affecting the design of ICD completions installed in these wells.

4.5.1 Vertical and Deviated Wells

Government regulations often restrict operators from commingling the production from or injection into multiple reservoirs unless a proper scheme for fluid allocation between the reservoirs has been completed. It is assumed here that this has been provided by soft-sensing based on distributed pressure and/or temperature measurements [223]. This makes possible the application of ICDs to multiple layers of the same reservoir or multiple reservoirs. The wellbore pressure drop across the sand-face in vertical and deviated wells is largely attributed to hydrostatic effects (i.e. changes in elevation). Pressure changes due to acceleration and frictional effects are often much smaller; limiting the added value from ICD application in such wells to situations where zones with variable productivity or pressure are encountered.

The productivity or pressure changes along the wellbore can be equalised completely, or to an optimum degree, by the installation of any of the ICD completion designs (Section 4.4); as shown by the analysis of the completion.

4.5.2 Horizontal Wells

ICDs were originally developed to overcome the effect of the pressure drop along horizontal wellbores (HTE). However, ICD applications have expanded in recent years to include layered and fractured reservoirs in an effort to overcome the Variable
Productivity Effects (VPE). Three imbalance scenarios that arise in horizontal wells can be identified: a) VPE, b) HTE or c) both VPE and HTE.

The ratio of fluid influx from: 1) the low and high productivity intervals, or 2) the equal influx rate and the influx rate at the heel of the horizontal well should be estimated (Equation 4-17) and compared to distinguish between these effects or determine the most dominant one. The fluid influx can be calculated using the wellbore performance modelling technique described in Chapter 3 (without an ICD completion). The objective of the ICD completion is to reduce this ratio to as close to unity as possible without compromising the overall well deliverability.

\[ q_{inR} = \frac{q_{eq}}{q_{inh}} \]  

Equation 4-17

Where:
- \( q_{inR} \) = Influx rate ratio
- \( q_{eq} \) = Equal influx rate (stb/day or Sm\(^3\)/day)
- \( q_{inh} \) = High Influx rate (stb/day or Sm\(^3\)/day)

The following should be considered to design the ICD completion for horizontal wells:

A. The change in the productivity along a horizontal wellbore can become dominant in situations where:
   - Faults, fractures or super-K streaks are intersected.
   - The pressure drop along the wellbore is small compared to the drawdown pressure due to a large wellbore size or a low reservoir permeability.

The ratio of VPE in these cases will be smaller than the ratio of HTE. Any of the ICD completion designs described in Section 4.4 can be used to overcome the imbalance in this case. For example, Equation 4-9 or Equation 4-10 can be used to identify the maximum pressure drop required across the high productivity zones if the wellbore is completed across the same reservoir. Alternatively, Equation 3-64 and Equation 4-12 can be used to define a constant size ICD that would be installed across all zones. A variable ICD size, PPSAS, GP or blank pipes can also be installed, as described earlier.

B. In HTE situations, the fluid influx at the heel section is higher than the equal fluid influx rate that can be achieved if the pressure drop due to friction along the wellbore is not considered. On the contrary, the fluid influx at the toe is
lower than the equal fluid influx rate. Here, the different ICD completion designs proposed in the previous section can be applied to equalise the fluid influx along the wellbore.

1. The following should be noted when applying the complete equalisation technique:

A. The productivity at the heel and toe of a horizontal well completed in a reservoir with homogeneous permeability is actually the same if each wellbore section is exposed to the same drawdown pressure. Equation 4-7 then simplifies to:

\[ \Delta P_{ICD} = P_{wL} + \Delta P_{PGSAS} - P_{wH} \]  

Equation 4-18  

\( P_{wL} \) in this case is \( P_{w-eq} \) (the required wellbore segment pressure to achieve an equal fluid influx rate into each wellbore segment). \( P_{wH} \) changes along the wellbore segments due to changes in the frictional pressure. It also changes in the remaining segments after an ICD size is assigned to the segment nearest the heel. Subsequently, the calculation of the required pressure drop across the ICD and the ICD size for each segment in a multi-segment completion has to be performed sequentially and iteratively following these steps:

a) The wellbore performance should be modelled without ICD completion.

b) The ICD pressure drop required for the topmost segment at the heel should be identified using Equation 4-7.

c) The well performance should be modelled again with this ICD installation at the topmost segment in order to capture the change in the wellbore pressure of the second segment.

d) The second topmost segment ICD pressure drop should then be calculated using its \( P_{wH} \).

e) The previous 3 steps should be repeated for the following segments towards the toe until the ICD pressure drop requirement for the segments with influx rate higher than the equal rate are identified.

f) The resulting completion from the previous steps will result in lower flowing bottom hole pressure with some of the segments towards the toe having an influx rate higher than the equal flow
rate. The previous 4 steps should now be repeated until all the segments with influx rate higher than the equal rate are assigned their proper ICD pressure drops.

g) The ICD restriction sizes should then be calculated based on the required pressure drop and final flow rate through each ICD.

B. This approach results in a different ICD size for each segment of the wellbore starting from the topmost heel segment and ends with a SAS being installed at the furthest segment(s) from the heel.

2. The iterative process described in Section 4.4.3 should be applied to identify a single ICD restriction size for the optimum equalisation of the whole completion and for ease of the completion installation operation. Noting that:

A. The rate of change of the well productivity should be used to identify the optimum ICD restriction size. The rate of change of the well rate-dependent productivity will increase and then decrease; forming an upward curve if the $P_{wf}$ is reduced at constant intervals for the iterations.

B. The optimum ICD restriction size is achieved at the maximum rate of change in the well productivity.

3. The influx ratio of the high and low productivity sections should be compared to the influx ratio of the heel and equal influx rate ratio when both VPE and HTE are significant. Then, the dominant effect should be used to identify the optimum ICD size. If the ratios are close to being equivalent, then any one of the two methods highlighted above will equalise the fluid influx into or out of the wellbore. AFIs are required in this completion to ensure that the completion objective is achieved. The identification process of the AFIs frequency and type will be described in Section 4.7.

**Example:** A horizontal well (see Table 3-10 for details) fully penetrates an oil reservoir with total well-reservoir length of 1,400 ft divided into 40-ft segments. The well produces oil at a target well flow rate of 25,000 stb/day.

A SAS completion of this well (with negligible pressure drop) would have required a bottom hole flowing pressure ($P_{wf}$) of 2,971 psi to produce the target well rate. The well exhibits a pronounced HTE (Figure 4-13), since the reservoir is homogeneous and the produced fluid is viscous. The oil influx at the first heel segment is 931 stb/day, considerably higher than the average segment contribution of 714 stb/day while the furthest toe segment contributes 636 stb/day.
An ICD completion designed for complete equalisation of the contribution from the horizontal section was designed using the method described in step 1 (above). It was then applied across to all the completion segments; the resulting ICD restriction sizes being recorded in Table 3-9. This completion reduced the heel segment contribution to 716 stb/day while increasing the toe segment influx rate to 711 stb/day (Figure 4-14) with $P_{wf}$ of 2,968 psi.

**Table 4-2: Variable ICD restriction sizes to overcome HTE**

<table>
<thead>
<tr>
<th>Segment</th>
<th>ICD nozzle size (mm)</th>
<th>Segment</th>
<th>ICD nozzle size (mm)</th>
<th>Segment</th>
<th>ICD nozzle size (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>11.5</td>
<td>14</td>
<td>16.1</td>
<td>27</td>
<td>36</td>
</tr>
<tr>
<td>2</td>
<td>11.7</td>
<td>15</td>
<td>16.7</td>
<td>28</td>
<td>44.6</td>
</tr>
<tr>
<td>3</td>
<td>12.0</td>
<td>16</td>
<td>17.3</td>
<td>29</td>
<td>SAS</td>
</tr>
<tr>
<td>4</td>
<td>12.3</td>
<td>17</td>
<td>18</td>
<td>30</td>
<td>SAS</td>
</tr>
<tr>
<td>5</td>
<td>12.5</td>
<td>18</td>
<td>18.7</td>
<td>31</td>
<td>SAS</td>
</tr>
<tr>
<td>6</td>
<td>12.8</td>
<td>19</td>
<td>19.6</td>
<td>32</td>
<td>SAS</td>
</tr>
<tr>
<td>7</td>
<td>13.2</td>
<td>20</td>
<td>20.5</td>
<td>33</td>
<td>SAS</td>
</tr>
<tr>
<td>8</td>
<td>13.5</td>
<td>21</td>
<td>21.6</td>
<td>34</td>
<td>SAS</td>
</tr>
<tr>
<td>9</td>
<td>13.9</td>
<td>22</td>
<td>22.9</td>
<td>35</td>
<td>SAS</td>
</tr>
</tbody>
</table>
As stated earlier, it is operationally simpler to install a single-size ICD completion instead of the variable-size ICD completion. The approach described in step number 2 (above) was used; resulting in an optimum nozzle type ICD of 6.8 mm diameter, being chosen. The $P_{nf}$ was 2,889 psi (Figure 4-15). Application of this ICD size reduced the heel contribution to 741 stb/day and increased the toe influx rate to 704 stb/day; improving the equalisation and reducing the HTE imbalance as indicated in Figure 4-16.

<table>
<thead>
<tr>
<th>Segment</th>
<th>ICD nozzle size (mm)</th>
<th>Segment</th>
<th>ICD nozzle size (mm)</th>
<th>Segment</th>
<th>ICD nozzle size (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>14.2</td>
<td>23</td>
<td>24.4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>14.7</td>
<td>24</td>
<td>26.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>15.1</td>
<td>25</td>
<td>28.4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>15.6</td>
<td>26</td>
<td>31.5</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Figure 4-14: Equalised influx rate using variable ICD restriction size along the horizontal well completion
4.5.3 Multilateral Wells

The advantages of installing ICDs to equalise the fluid influx along each lateral in a multilateral well have been reported by many operators (Chapter 2). In addition to the
factors discussed in Section 4.5.1 and 4.5.2, identification of the optimum ICD size to be installed in a multilateral well depends on:

- The company completion philosophy. Operators may prefer to install the same size ICD in both laterals to ease the complexity of the installation operation. However, the installation of different size ICDs in each lateral will prove more beneficial in some cases.
- Fraction of each lateral completion contribution to the total well flow rate.
- Laterals elevation and distance from the gas-oil, oil-water and/or gas-water contact. Equalising the laterals contribution can cause an early breakthrough of the unwanted fluid to one of the laterals since laterals can be located at different elevation and distance from the unwanted fluid contact.
- Laterals trajectory orientation which will determine the segment’s productivity.
- Integration of ICDs with ICVs. An ICV can be used to manage the individual lateral’s productivity to the total well production while the ICD completion can manage the influx along the length of the lateral.

One of two approaches can be taken to account for these factors in the identification process of the optimum ICD sizes:

- Each lateral can be handled individually based on a) its natural contribution or b) an allocated (pre-set) contribution to the target well flow rate followed by combining the outcomes from all the laterals. The allocated contribution (b) can be achieved by an integrated ICD-ICV completion.
- The equalisation of fluid influx to all the well segments (i.e. all laterals) can be designed at the same time based on the target well flow rate.

**Note:** The second process can impose severe restriction on the well’s total productivity since the ICDs are being used to equalise all the segments to that of the lowest productivity segment. The use of ICDs to equalise the segment contributions to the lateral flow rate and ICVs to equalise the laterals contribution to the total well flow rate is the better alternative.

1. **Design of ICD completion for each lateral individually:** The process should follow the steps listed below:
   
   a. Identify the well productivity and performance using the technique described in Chapter 3.
   
   b. Identify the contribution ratio of each lateral to the total well flow rate.
      
      The lateral flow rate identified in the previous step should be used in the
following steps if the objective of the ICD application is to equalise the fluid influx within the lateral based on the laterals’ natural contribution ratio. Alternatively, the target lateral flow rate (e.g. an equal lateral contribution) should be used if the well is going to be equipped with ICVs to control the lateral’s contribution to the total well flow rate.

c. Divide the flow rate (contribution) of each lateral by the number of segments to identify the target equalised fluid influx per segment.

d. Identify the dominant imbalance factor within each lateral and design an ICD completion following the process described for horizontal or vertical wellbores. This will maintain an equalised fluid influx to each lateral with a minimum pressure drop across the ICD completion.

2. **Simultaneous design of ICD completions for all laterals:** This completion design process can be used when the laterals are drilled in a heterogeneous reservoir (or multiple reservoirs) imposing a VPE on the well. This completion design process equalises the contribution of all the well segments; hence it is also applicable when cross flow between the laterals is expected. It should be noted, however, that this completion design may impose an unnecessary relatively high penalty (or pressure drop) in order to achieve an influx rate equalisation along each lateral.

This completion design follows the steps listed below:

a. The total well flow rate should be divided by the total number of completion segments to identify the equalised ICD flow rate per segment of the whole reservoir contact length.

b. The process is then similar to the identification of horizontal or vertical wells ICD sizes:

   i. In the case of VPE, the reference (low) productivity zone is identified and the ICD size of all the other segments is calculated using the appropriate procedure described in Section 4.5.1 and/or 4.5.2; depending on the laterals orientation.

   ii. HTE dominates horizontal laterals. The two approaches described in Section 4.5.2 for horizontal wells can be followed for the whole multilateral well to achieve complete or optimum influx equalisation to all well segments. The complete equalisation process should start with the topmost segment of the lateral with
the lowest influx rate at its furthest segment from its heel. Otherwise, the optimum equalisation approach with single ICD restriction size should be performed for the whole completion, requiring iteration of the ICD size until the rate of change of the total productivity of the lowest productivity lateral reaches its maximum value. This assumes that the laterals vary in their productivity. Otherwise, the optimum equalisation value can be reached at the maximum rate of change of the total well productivity.

**Example:** A multilateral well with two opposing horizontal laterals that fully penetrate an oil reservoir with a total well-reservoir length of 1,400 ft for each lateral. Each lateral has the same properties as the horizontal well listed in Table 3-10. The well should produce at a target oil flow rate of 50,000 stb/day.

Each lateral is completed with a SAS with negligible pressure drop requiring a bottom hole flowing pressure ($P_{wf}$) of 2,970 psi to produce the target well rate, 25,000 stbo/day being allocated to each of the two laterals. A pronounced HTE is present in each lateral (Figure 4-17) since the reservoir is homogeneous. The oil influx at the first heel segment of each lateral is 930 stb/day, considerably higher than the average segment contribution of 714 stb/day, while the furthest toe segment contributes 636 stb/day.

The approach described in steps number 1 or 2 (above) can be applied to design a single size completion in each lateral since the laterals are symmetrical. Here, step number 2 was applied where the completion of both laterals was designed simultaneously. The optimum ICD diameter size for each lateral was 6.8 mm for a nozzle type ICD at flowing bottom hole pressure of 2,888 psi. The application of this ICD size reduced the heel contribution in each lateral to 742 stb/day while the toe influx rate of each lateral was increased to 704 stb/day (Figure 4-17).
4.6 Minimum ICD Restriction Size Limit

Identification of the minimum ICD restriction size which can be applied in a particular well completion depends on three factors:

1. Erosion velocity.
2. ICD plugging.
3. Emulsion generation.

The size limit applies mainly to the nozzle/orifice/slot type ICD design since the channel/tube type design can be manufactured to a diameter that will not risk becoming plugged or eroded. Further, the channel/tube type ICD is not expected to generate an emulsion; though the pressure drop across the channels/tubes will increase if an emulsion already exists. This can be advantageous since a greater than expected pressure drop over water producing zones will decrease the contribution of such zones. This is only true if the other zones are producing dry oil. The presence of emulsion will decrease the well’s total oil performance if the majority of the completion zones experience emulsion. However, the emulsion viscosity will decrease at high water cuts when a low viscosity water continuous phase is formed instead of a (viscous) oil phase or emulsion.

Three types of ICDs (nozzle, orifice and channel) have been tested for their erosion potential at the Southwest Research Institute [126]. The tests revealed that the channel
type ICD was the most resistant to erosion; while the orifice and nozzle type ICDs showed significant erosion potential when exposed to high velocity flow of sand laden fluids. This erosive limit need not to be considered when producing from carbonate formations since solid particles are normally not produced with the reservoir fluids.

4.6.1 Erosion Velocity

The potential for ICD erosion should be estimated at one or more times throughout the life of the well. Several published erosion models are potentially applicable when identifying the ICD’s minimum restriction size. However, the majority of these models require data about the amount of expected sand production, the sand particles shape factor, the material hardness, the angle of impact, etc. This requires dedicated experiments to provide the necessary data. An example of one of these models is the generalised API RP 14E model (Equation 4-19 [224]):

\[
h = F_M F_S F_P F_{r/D} \frac{W V_L^{1.73}}{d_{no}^2}
\]

Where:

- \(h\) = Penetration rate (m/s)
- \(F_M\) = Empirical constant of material hardness
- \(F_S\) = Empirical factor for sand hardness
- \(F_P\) = Equipment material penetration factor
- \(F_{r/D}\) = Penetration factor for elbow radius (can be set to 1 in straight pipes)
- \(W\) = Sand flow rate (Kg/s)
- \(V_L\) = Particle impact velocity (m/s)
- \(d_{no}\) = ICD nozzle/orifice diameter (inches)

Such data is often not available to the design engineers. Alternatively, simpler forms of API RP 14E erosion model can then be used. Model one (Equation 4-20 [225]) relates the erosion velocity to the density of the produced fluid, the nozzle diameter and sand flow rate. While Model 2 (Equation 4-21 [226]) relates the erosion velocity to the fluid density only which is adequate in the absence of information about the expected sand production. Example of limits for the acceptable fluid flow velocity through a nozzle, orifice or short tube type ICD can be based on these velocities:
\[ v_e = \frac{d_{no} \sqrt{\rho_m}}{20\sqrt{W}} \]

Where:

- \( v_e \) = Maximum acceptable velocity (m/s)
- \( \rho_m \) = Mixture density (Kg/m³)
- \( d_{no} \) = Nozzle/orifice diameter (mm)
- \( W \) = Sand flow rate (Kg/day)

\[ v_{ef} = \frac{C_s}{\sqrt{\rho_{mf}}} \]

Where:

- \( \rho_{mf} \) = Mixture density in field units (lbm/ft³)
- \( v_{ef} \) = Erosion velocity in field units (ft/s)

\( C_s \) is a constant with the following values:

- 200 for solid-free fluids with continuous service.
- 100 for corrosive/erosive fluids with continuous service.
- Alternatively, the value should be selected from the table below, using the \( C_s \) values recommended for downhole valves [227], if the sand concentration is known or can be predicted:

**Table 4-3: \( C_s \) values at different sand concentrations [227]**

<table>
<thead>
<tr>
<th>Sand Concentration (pptb)</th>
<th>( C_s ) Value (ppm)</th>
<th>C-factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2.9</td>
<td>177</td>
</tr>
<tr>
<td>2</td>
<td>5.7</td>
<td>150</td>
</tr>
<tr>
<td>3</td>
<td>8.6</td>
<td>136</td>
</tr>
<tr>
<td>4</td>
<td>11.0</td>
<td>127</td>
</tr>
<tr>
<td>5</td>
<td>14.0</td>
<td>120</td>
</tr>
<tr>
<td>6</td>
<td>17.0</td>
<td>115</td>
</tr>
<tr>
<td>7</td>
<td>20.0</td>
<td>111</td>
</tr>
<tr>
<td>8</td>
<td>23.0</td>
<td>107</td>
</tr>
<tr>
<td>9</td>
<td>26.0</td>
<td>104</td>
</tr>
<tr>
<td>10</td>
<td>29.0</td>
<td>102</td>
</tr>
</tbody>
</table>
These estimates of flow velocity can be applied for completions in both sandstone and carbonate producing formations. Note that many Production Engineers consider Equation 4-21 predicts conservative values.

The long term reliability of a sandstone ICD completion to maintain the required equalisation along the wellbore should also be evaluated using Equation 4-22 [228] erosion model. This requires prediction of the expected sand production volume and the rate of erosion of the ICD’s restriction over the life of the well. The latter information is usually obtained through experiments similar to the erosion data provided in reference [126]. For example, pumping 1,000 lbs of sand at a concentration of 5,000 ppm through an orifice ICD at a rate of 5.5 GPM resulted in an orifice metal mass loss of 0.017 gram. This relatively low metal loss reduced the orifice’s differential pressure by 53.1% [126].

Such data can be used to guide the choice of the most appropriate ICD type for a particular application.

\[
t_{sl} = \frac{4M_{loss}}{C\pi d_{no}^2 \nu_{aicd} k_{sf} \rho_s V_p \cdot SE_s}
\]

Equation 4-22

Where:

- \( t_{sl} \) = Projected erosive flow period (s)
- \( M_{loss} \) = Nozzle/orifice mass lost during the flow period of the well
- \( C \) = Conversion constant (cc/ft³)
- \( d_{no} \) = Effective diameter of the nozzle or orifice
- \( \nu_{aicd} \) = Maximum acceptable fluid flow velocity (ft/s)
- \( k_{sf} \) = Sand particles shape factor (ranging from 1 to 3)
- \( \rho_s \) = Sand specific gravity (gram/cc)
- \( V_p \) = Volumetric particle fraction in the fluid
- \( SE_s \) = Specific erosion or erosive wear for an \( s \) μm particle size (gram/gram) passing through the nozzle or orifice at a specific flow rate. \( SE_s \) can be estimated from experimental data using:

\[
SE_s = \frac{m_{metalloss}}{m_{particles}}
\]

Equation 4-23

Where:

- \( m_{metalloss} \) = Nozzle or orifice mass lost during the test (gram)
- \( m_{particles} \) = Total mass of erosive particles passing through the nozzle or orifice (gram)
4.6.2 **ICD Plugging**

Produced sand and fines or scale/waxy asphaltene precipitation can cause plugging of the ICD restriction. Such ICD’s plugging requires larger sand grains which can be prevented from flowing towards the ICD by installing a SAS or GP. However, these completions may themselves undergo plugging and permeability loss [6, 131]. Further, a minimum flow restriction diameter can be specified during the ICD design process to minimise the risk of plugging in the case that the sand control measures fail.

Scale and asphaltene plugging has to be chemically prevented or treated since it cannot be “held back” mechanically. ICD plugging has not been reported to-date; even though screen plugging is a problem frequently observed in sand control completions [6, 131]. However, both the inflow rate per screen joint and the annular flow rate are considerably lower in an ICD completion than in a typical (conventional) sand control completion, hence a reduced rate of screen plugging can be expected.

SAS design guidelines aim to allow bridging of large sand particles on the screen while allowing particles smaller than a minimum size to pass through the screen mesh. This sand bridging has been extensively studied, hence it is proposed to use the same criterion for the partial or complete blocking the ICD nozzle or orifice. Therefore, the minimum ICD restriction diameter should be 4 times larger than the diameter of the $d_{90}$ sand particles that are expected to be able to flow to the wellbore under the bottom hole producing conditions (Equation 4-24).

$$d_{no} \geq 4d_{sn} \quad \text{Equation 4-24}$$

Where:

$$d_{sn} = d_{90} \text{ sand particle diameter}$$

4.6.3 **ICD Emulsion Creation**

All the previously described parameters are related to single phase flow through the ICD. The ICD potential for creating emulsion or increasing the viscosity of an existing emulsion is related to the simultaneous flow of oil and water through the ICD restriction.

An emulsion is a dispersion of droplets of one liquid in another immiscible liquid (i.e. it can be either oil-in-water or a water-in-oil emulsion). The shear rate at which oil and water will create an emulsion is highly dependent on the properties of these liquids and cannot be generalised for all crude types. Emulsions are not normally observed in natural flow, perforated completions due to the low shear environment. Exposure to a
high shear rate environment, such as the one experienced in chokes and pumps, often result in emulsion formation. ICDs, being designed to restrict the flow, expose the produced fluid to an increased shear rate which may cause emulsion to be created. The highest shear rates are experienced in nozzle/orifice type ICDs where a high pressure drop is exerted over a much shorter length compared to that generated by a channel/tube/slot type ICDs.

Many oils at reservoir conditions are considered Newtonian fluids, allowing Equation 4-25 to be used to convert the fluid velocity into shear rate [229]:

\[
\gamma = \frac{8v}{d_{no}}
\]

Equation 4-25

Where:

\(\gamma\) = Shear rate (S⁻¹)

### 4.6.4 Appropriate ICD Type Identification

Chapter 2 described different types of ICD designs and their varying characteristics. A preliminary comparison highlighting the level of ICD design flexibility and reduction of unwanted fluid after breakthrough by the different ICD types was summarised in Section 2.6. This comparison can act as a qualitative guide to identify the appropriate ICD for a specific application. In addition, quantitative analysis of the erosion, plugging and emulsion creation potential as well as the ICD’s long term reliability are factors that can be used to identify the most suitable ICD.

The following workflow will help guide the process of identifying the most appropriate type of ICD:

1. The reservoir rock type should be identified (sandstone or carbonate formation which indicates if the equipment erosion could be an issue).
2. The unwanted fluid (water or gas) should be identified since the nozzle/orifice/slot and short tube type ICDs are better at restricting water and gas influx.
3. The requirement for flexibility to modify the ICD completion design at the wellsite should be identified based on the level of uncertainty in the design parameters.
4. The optimum ICD restriction size should be identified. If the restriction size of nozzle/orifice/short tube type ICDs violates the erosion, plugging or emulsion
creation limits then the ICD type should be limited to channel and long tube type ICDs.

5. The ICD type with the lowest cost per unit should be selected.

4.7 Annular flow

One of the important factors to the success of the ICD completion application is the proper allocation of Annular Flow Isolations (AFIs). Various authors have reported measurement of a perfectly equalised fluid influx into the inner part of the ICD base pipe using production logs. Some of these ICD completions included a limited number of AFIs or no AFIs at all. However, it should be noted that the equalised influx inside the ICD base pipe is not indicative of an equalised influx from the reservoir into the annular space behind the ICD. The ability of ICDs to minimise the annular flow to “near zero” in perfectly horizontal wellbores drilled in perfectly homogeneous reservoirs is widely accepted and have been proven through experiments and modelling [230]. However, annular flow rapidly increases with increase in reservoir heterogeneity, making installation of AFIs a necessity to realise the benefits of ICD completions. Various types of AFIs are available commercially e.g. external casing packers, inflatable packers, chemical packers, swell packers (and swell constrictors), gravel packing, etc.

Swell packers have gained great popularity in recent years, particularly for application to horizontal and multilateral well completions. This is due to their simplicity, ease of installation and operation as well as their proven reliability. Swellable Constrictors have a limited length of packing material, often mounted on the ICD joint. Gravel packing of the annular space can also be regarded as a form of annular flow isolation in addition to being a sand production mitigation technique.

Several researchers have suggested simulating annular flow by using multiple skin values in designing the SAS or pre-perforated completions; however, this technique quantifies neither the magnitude of any annular flow nor its impact on the completion longevity. Modelling of annular flow associated with SAS, pre-perforated liner or ICD completions can be performed using network analysis technique [194]. The network comprises of nodes representing the annular segments, tubing segments and SAS or ICD segments. This enables proper quantification of the annular flow performance and allocation of the isolation accordingly. A number of software(s) are commercially available and can be used to perform this task; as described in Section 3.12.
The following factors should be considered when identifying the number and location of the AFIs that should be installed in a completion.

4.7.1 **AFI Frequency Identification**

Completions are normally designed on the basis of the well proposal prior to the drilling of the well and subsequently refined after well logging is completed. The number of annular flow isolations required to install an ICD completion and enhance its equalisation potential can be identified based on the:

- Productivity variation along the completion.
- Geological markers and geological correlation length (CL).
- Annular flow velocity.

**A. Productivity variation along the completion**

As indicated above, equal-size ICDs are capable of minimising annular flow in perfectly homogeneous formations. Since this ability reduces as the heterogeneity of the reservoir increases, AFIs should be installed as per the following:

1. If the ICD completion is intended for complete equalisation of the fluid influx from the reservoir and employs ICDs with varying restriction sizes along the wellbore, then an AFI should be installed whenever the ICD restriction size changes and between all SAS joints. This is required to enable realisation of this completion value. Equation 4-26 should be applied to achieve this.

   \[
   N_{AFI} = \sum_{i=1}^{n} x_{ICDi} \]

   Equation 4-26

   Where:

   \[ x_{ICD} = 1 \quad \text{if} \quad r_{ICDi} \neq r_{ICDi+1} \]

   \[ x_{ICD} = 0 \quad \text{if} \quad r_{ICDi} = r_{ICDi+1} \]

   \[ N_{AFI} = \text{Number of AFIs} \]

   \[ r_{ICD} = \text{ICD restriction size} \]

   \[ n = \text{Number of ICDs} \]

2. If the ICD completion is intended for optimum equalisation with constant ICD restriction size along the wellbore, then AFI should be installed at the joint where the ratio of the annular flow rate over the ICD influx rate equals or exceeds the equalisation imbalance ratio expected from the constant size ICD completion. The equalisation imbalance ratio \((E_{imr})\) is:
\[
E_{imr} = 1 - \frac{q_{ICDL}}{q_{ICDH}}
\]

Equation 4-27

Where:

\[q_{ICDH} = \text{Influx rate from high productivity zone through the ICD modelled without annular flow (stb/day or Sm}^3/\text{day)}\]

\[q_{ICDL} = \text{Influx rate from low productivity zone through the ICD modelled without annular flow (stb/day or Sm}^3/\text{day)}\]

This is because, initially, the constant size ICD completion assumed that an AFI was installed at every ICD joint; forcing the fluid influx from the reservoir to the inner tubing of the ICD through the ICD restriction. This results in an acceptable imbalance of fluid influx, (optimum equalisation) into the tubing.

The fluid influx to the inner part of the ICD (tubing) will be constant while the influx from the reservoir to the wellbore will not since the AFI is not considered in the modelling of the wellbore with annular flow. The acceptable equalised influx imbalance resulting from the constant size ICD completion must also be maintained in the ICD completion annular space so as to ensure that the objective of the completion is achieved. This can be accomplished through the following steps:

a. The wellbore performance should be modelled with ICDs but without AFIs.

b. The ratio of annular flow rate to ICD influx rate should be calculated at every wellbore segment starting from the furthest toe segment from the heel to the topmost segment of the wellbore.

c. An AFI should be placed at the joint where the ratio of the annular flow to ICD influx rate is equivalent or exceeds the equalisation imbalance ratio.

\[N_{AFI} = \sum_{i=1}^{n} y_{ICDi}\]

Equation 4-28

Where:

\[y_{ICD} = 1 \quad \text{if} \quad \frac{q_{an}}{q_{ICD}} \geq E_{imr}\]

\[y_{ICD} = 0 \quad \text{if} \quad \frac{q_{an}}{q_{ICD}} < E_{imr}\]

\[q_{an} = \text{Annular flow rate (stb/day or Sm}^3/\text{day)}\]
\( q_{ICD} = \text{Flow through the ICD modelled with annular flow} \)
\( \text{(stb/day or Sm}^3/\text{day}) \)

**B. Geological markers and correlation length**

The geological markers are often used by geologists to identify the tops of distinctive layers in a reservoir or multiple reservoirs that act as flow isolation barriers such as reservoirs cap rock or shale layers. The number of markers that are (or expected to be) encountered by the well can be used to identify the number of AFIs required to isolate each layer.

Alternatively, the correlation length (CL), the distance over which the petrophysical properties in the reservoir correlate, can be used to identify the width of distinctive reservoir channels, hydraulic flow units or layers along the wellbore. AFIs should be installed to isolate individual channels or hydraulic flow units and layers if they have distinctly different properties.

Geological markers act as flow barriers if they have a low permeability. The ratio of the low to high permeability defined by Equation 4-29 can still be used to identify the barrier location and frequency and hence the location and number of AFIs. The permeability ratio will have a very low value, representing a large contrast of permeability or productivity over a small wellbore length (Equation 4-29), when the wellbore crosses a flow barrier.

\[
N_{AFI} = \sum_{i=1}^{n} e_{ICD_i} \quad \text{Equation 4-29}
\]

Where:

\[
e_{ICD} = 1 \quad \text{if } k_{ri} < 0.01
\]

\[
e_{ICD} = 0 \quad \text{if } k_{ri} > 0.01
\]

\[
k_{ri} = \begin{cases} 
\frac{k_i}{k_{i+1}} & \text{if } (k_{i+1} - k_i) > 0 \\
\frac{k_{i+1}}{k_i} & \text{if } (k_{i+1} - k_i) < 0
\end{cases}
\]

The CL is a useful parameter when different hydraulic flow units are caused by different reservoir facies that are not fully isolated by impermeable layers. Prior knowledge of the CL value or the expected number of hydraulic flow units which might be encountered by the well can be used to identify the number of required AFIs (Equation 4-30).
\[ N_{AFI} = \frac{L}{CL} \] 

Equation 4-30

Where \( L \) stands for the lateral length across the sand-face.

A permeability ratio similar to the geological marker identification, highlighted above, also applies to fractured reservoirs, the fracture permeability being so much higher than the matrix permeability that AFI located between the fractured sections and matrix sections is required. Knowledge of the fracture locations, permeability (or width) is required to determine the packer location and frequency. Identification of such features and their properties requires image logs [128, 231]. Open faults should be treated similarly.

The permeability of the fracture can be calculated if the width of the fracture is known.

\[ k_{frac} = 54000000 \cdot W_d \] 

Equation 4-31

Where \( k_{frac} \) is the fracture permeability in milli-darcy and \( W_d \) is the width of the fracture in inches [232].

Reference [128] applied an ICD completion to equalise the fluid influx from a fractured carbonate reservoir. The completion contained a packer at each ICD joint; i.e. the number of packers equalled the number of ICD joints. This was due to the high frequency of fractures encountered along the wellbore.

C. Annular flow velocity

The annular flow velocity is highly influenced by the ratio of the annulus to tubing diameters. A limit on the acceptable annular flow velocity can be set based on Equation 4-21 estimate of erosion flow velocity.

As mentioned earlier, this correlation is regarded as being a conservative estimate of maximum allowable flow velocity and when handling sand laden fluids. However, ill-defined parameters such as (1) the irregularity of the wellbore diameter along the length of the wellbore, (2) the plugging of specific sections of the screen with mud cake after an incomplete clean-up operation and (3) the fragile nature of (low strength) sand-face compared to that of the metallic completion all necessitate the use of a conservative estimate of the allowed annular velocity. An AFI should be installed between the ICD joints if the fluid flow velocity along the annular space exceeds the erosion velocity specified by Equation 4-21.
\[ N_{AFI} = \sum_{i=1}^{n} z_{ICDi} \]  

Equation 4-32

Where:

\[ z_{ICD} = 1 \quad \text{if} \quad v_{an} \geq \frac{C_s}{\sqrt{\rho_m}} \]

\[ z_{ICD} = 0 \quad \text{if} \quad v_{an} < \frac{C_s}{\sqrt{\rho_m}} \]

There may be a requirement for additional AFIs that will be dependent on the communication between the high and low productivity zones in the near wellbore region. This can only be identified by an integrated wellbore and reservoir simulation modelling exercise.

4.7.2 **AFI type identification**

Some of the factors that should be considered in the selection of the type of AFI to be installed include:

- Reservoir heterogeneity and rock type.
- Limits on the pressure drop across the AFI.
- Impact on well productivity.
- Installation operation risks and costs.

The reservoir heterogeneity in this case refers to the frequency of change in productivity (or permeability) along the wellbore which is a major factor in distinguishing between the type of AFIs that can be installed. For example, suppose the effective permeability value changes every ICD joint with the ratio of the low to the high permeability zone is higher than 0.01. A slip-on, swell constrictor mounted on every ICD joint will be a better alternative compared to operationally more complex external casing packers or a gravel pack with its potential to reduce the well productivity. However, packers can be set if the pressure difference between any reservoir zones which exceeds the capability of a constrictor. Additional factors to be considered when choosing between a gravel pack, a constrictor or a packer include:

- Rock type (i.e. carbonate or sandstone) since gravel pack is not normally applied in carbonate formations.
- Reduced ICD base pipe diameter if a gravel pack is installed plus any reduction in well inflow performance caused by the gravel pack.
Gravel pack installation is complex, time consuming and costly. It is normally avoided if possible.

The installation of constrictors within a layer or a distinctive hydraulic flow unit is sensible since minor permeability variation can be expected to exist within a layer or hydraulic flow unit as opposed to the significant pressure differences which can often observed between the separate layers.

Flow constrictors can be installed within the hydraulic flow unit to eliminate annular flow and minimise the influence on the low permeability sections of water or gas breakthrough in the reservoir’s higher permeability sections.

Gravel packs are normally only applied in sandstone reservoirs, hence constrictors should be applied in carbonate reservoirs when a high frequency of AFIs is required.

Guidelines to aid this selection process are listed below:

- Gravel pack should be applied in sandstone reservoirs if the number of AFIs (\(N_{AFI}\)) identified using Equation 4-26, Equation 4-28, Equation 4-29, Equation 4-30 or Equation 4-32 exceeds the number of tubular joints that are installed across the sand-face. Constrictors should be applied at every ICD joints if gravel packing will drastically impact the well performance and/or the gravel pack installation is deemed not possible.

- Constrictors or packers should be installed if the number of AFIs is equivalent or less than the number of joints. Also, constrictors or packers should be applied in carbonate reservoirs if the identified number of AFIs exceeds the number of tubular joints.

- Constrictors should be applied where the differential pressure in the annulus is 50 psi or less and the productivity/permeability ratio value is higher than 0.01.

- Packers should be applied where the differential pressure in the annulus exceeds 50 psi and/or the productivity/permeability ratio is equal to or less than the 0.01.

- Equation 4-33 shows a workflow that can help ease this process.
Where:

\[ T_{AFI} = \begin{cases} 
GP & \text{if } N_{AFI} > N_{icdj} \\
\text{Cons} & \text{if } \delta p_{au} \leq 50\ \text{psi} \\
Pak & \text{if } \delta p_{au} > 50\ \text{psi}
\end{cases} \]

\[ \begin{align*}
&N_{AFI} \leq N_{icdj} \\
&k_r > 0.01 \\
&N_{AFI} \leq N_{icdj} \\
&k_r \leq 0.01
\end{align*} \]

Equation 4-33

It may not be possible to install the optimum number of AFIs required for achieving the ICD completion design described above for operational cost or other reasons. In this case, the ICD restriction size should be adjusted based on the chosen (non-optimum) AFI placement. This implies that larger sections of the wellbore will have to be handled in the identification of the optimum ICD restriction size. The resulting completion may not deliver optimum well performance, but it can be expected to add value compared to a conventional completion.

### 4.8 Accounting for Uncertainties

The major uncertainties that influence the design of an ICD completion are related to the uncertainty in the geological and the fluid properties. This is due to the high dependence of the ICD completion design process on the completion segment inflow productivity and/or fluid influx distribution along the wellbore.

The permeability is the most influential parameter on the value of the productivity index because it has the largest variation range compared to the other components of the formation inflow equation (Equation 3-1). It is not normally possible to define the well productivity profile distribution along the wellbore with sufficient accuracy definitive for completion design prior to drilling the well; the required parameters having to be extracted from reservoir simulator built on a geological model. These parameters become better defined after drilling and logging the well, but significant uncertainty in the extracted parameters, especially the permeability, must still be accounted for.
An evaluation of the impact of uncertainty in the reservoir permeability variation away from the wellbore on the ICD completion performance has been completed by keeping the permeability at the wellbore sandface unchanged in the reservoir realisations. Analysis of the results indicated that an ICD completion’s performance and hence design is independent of this source of uncertainty. This is not surprising since an ICD completion is designed to equalise the fluid influx into the wellbore from the near wellbore region. Therefore, such uncertainty should not need to be accounted for in the design of the ICD completion.

The following process should be used to account for the uncertainty in the productivity variation along the wellbore (caused by geological or fluid property variation) in the design of ICD completions:

1. A Probability Distribution Function (PDF) of the productivity parameter underlying the uncertainty in the productivity values of each segment (or foot length) along the wellbore length should be generated.

2. The ICD completion design should be based on the $d_{50}$ (or average value) of the productivity distribution of each reservoir segment along the wellbore. This can be the mean value of a normal distribution or the geometric mean of logarithmic distribution of the segment parameter values, as appropriate. For example, several values of permeability can be introduced at the same location ($x_i$) along the wellbore representing a normal, logarithmic, triangular or any other form of PDF distribution. The ICD completion is then designed based on the mean value of the permeability distribution of each segment calculated as indicated above. This design process will add value in all possible variation of the reservoir petrophysical properties along the wellbore.

The appropriate AFI distribution should then be designed for the optimum completion. Use of the above workflow will save time and resources compared to the conventional approach of running multiple reservoir simulations to fine tune the completion design.

4.9 **Economic Value**

The final step of the completion design is the evaluation and quantification of its economic value. The most popular form of economic evaluation is a Net Present Value (NPV) calculation. The net present value can be calculated based on the cash flow of the project which in the case of the ICD completion performance requires simulation of the
reservoir, wellbore and completion performance throughout the life of the well in the following process:

1. Once the ICD completion is designed, the ICD and alternative completion cost should be calculated based on the technology provider’s estimation and used as the capital investment in the cash flow calculation. Any other investment for artificial lift installation or anticipated treatments should be accounted at the expected time of the investment.

2. The ICD completion performance should be modelled in full field or a sector reservoir model over the well life, taking into account any artificial lift installation or chemical treatments.

3. The performance of the alternative completions (e.g. SAS) should be modelled as well. The model should account for annular flow or skin resulting from the lack of AFIs or installation of gravel pack.

4. The resulting oil production profile of the ICD and any alternative completions should be multiplied by the anticipated oil price over the production period to generate the revenues profile.

5. The cash flow profile should then be discounted at the appropriate rate and the NPV should be calculated for both completions.

6. Comparison of the ICD and alternative completion NPVs will provide a good indication of the value of the ICD completion installation. Frequently, the NPV of the ICD completion is higher than that of alternative completions. Redesigning the ICD completion should be considered if the NPV of the ICD completion is less than the NPV of the alternative completions. For example, reducing the equalisation may achieve a higher NPV. Parameters that may reduce the NPV include:

   a. Early breakthrough of unwanted fluid e.g. caused by tilted or uneven fluid contacts in the zones that are being equalised. In this case, a reduction in equalisation should delay the breakthrough of unwanted fluid.

   b. Requirement of artificial lift during the well life. In this case, a new minimum bottom hole flowing pressure should be set to ensure that the well continues to flow naturally or will delay the artificial lift requirement.
c. High cost of ICD completion. In this case, the number of ICDs and AFIs can be reduced and replaced with blank pipes while maintaining the well productivity.

7. The incremental reduction in equalisation should stop where the equalisation ratio of the ICD completion matches the alternative completion equalisation ratio.

A further important factor to be considered is any risks that might arise during completion installation operation. Typical risks to be analysed are: the completion getting stuck before reaching the total depth of the wellbore, the swell packer setting prematurely, the screens becoming plugged with drilling mud, etc.

Evaluation of such risks and mitigating their impact depend on field experience and modelling of the completion installation process. For example, the drag forces while running the completion can be calculated using a drilling drag simulator over all the wellbore sections from surface to total depth. Any well trajectory dog-legs and the appropriate friction factors for the completion components and the completion fluid (mud) are required here. Such simulations can ensure that the completion will reach and can be set at the intended depth with a minimal risk of becoming stuck, or packers setting prematurely, at a shallower depth.

4.10 Summary

This chapter introduced a novel, comprehensive approach to the design of vertical, deviated, horizontal and multilateral well completions incorporating both Inflow Control Devices (ICDs) and Annular Flow Isolations (AFI). These completion components meet the challenges of:

1. Uneven fluid flow towards or away from the well which is caused by frictional pressure drop along the horizontal sections, uneven distribution of productivity, formation layering, pressure variation, etc.

2. Completion damage by high velocity, annular flow of solids laden fluid.

3. Uncertainty in the reservoir, wellbore, completion and modelling parameters used for the completion design.

4. Completion reliability with respect to erosion.

5. Added value calculation for the completion.

ICDs are choking devices designed to balance the well’s production/injection profile at the cost of a limited, extra, pressure drop. The integration of ICDs with AFI
technologies enhances the performance of both production and injection wells by managing the above problems. ICDs without AFIs are only capable of eliminating annular flow when applied to fairly homogeneous formations. Inclusion of AFIs is often essential to minimise annular flow and maximise completion longevity. Completion design requires identification of the most appropriate location, frequency and type (Constrictors, Packers or Gravel Pack) of annular isolation.

This chapter built on the proposed modelling guidelines for the prediction of ICD completion performance and, as such, is a key step in the design and value quantification process for ICD completions. A workflow has been developed to automatically optimise ICD and AFI completions design for a particular set of reservoir and fluid properties. Use of a coupled reservoir and completion simulator ensures that the chosen completion is optimum over the well’s life. Uncertainty is minimised by optimally designing this completion for the full range of possible well inflow performance that can be envisaged from the reservoir description.

The value of the proposed methodology was illustrated by its application to simple well architectures including vertical, horizontal and multilateral wells. This technique will also be applied to real field case studies (Chapter 6).