

**A Comprehensive Approach to the Design of Advanced Well
Completions**

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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.

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Chapter 5 Autonomous Inflow Control Device Completion Design

5.1 Introduction

An AICD is a newly developed technology which adds an “intervention-free”, reactive, flow restriction to the ICD’s passive flow restriction. Both density and phase dependant technologies are available, their action being triggered by water or free gas influx. Water influx into a gas producing well will increase the flowing fluid’s density, causing a water-triggered AICD to restrict the flow area and reduce the flow rate from the well section where water breakthrough has occurred. Similarly, a gas influx would reduce the average fluid density of an oil producing zone, giving a reduction in the flow area of a gas triggered AICD. The technology employed depends on the supplier, Flappers, Balls, Disc and Swellable elements have all been proposed. The plate design of this technology has been deployed in an oil field in Norway and resulted in an improvement in the well performance [233]. The others are still in the design and flow loop testing stages. The development work continues since simulations predict a great potential value from its application, allowing monetisation of currently uneconomic hydrocarbons. Proposed applications for AICD completions were summarized in Chapter 2. Gas production wells could also be candidates for AICD completion application as will be discussed in this chapter along with the case studies summarised in Chapter 6.

Chapter 3 provided guidelines to ensure proper modelling of AICD completions over the well life. Similar to ICD completions, annular flow must be accounted for when AICDs are installed with only a limited number, or no, packers. In fact, the effectiveness of the AICD completion is dependent on the installation of AFIs since annular flow, both prior to and after water or gas breakthrough, has already been shown to create completion problems [117]. Further, proper AFI placement may increase the well potential, especially in fractured reservoirs or reservoirs dominated by high permeability streaks [220, 128].

This chapter builds on the workflow for the design of ICD completions (Chapter 4) and offers the completion engineer some practical steps for a comprehensive design methodology for AICD completions which incorporates the major factors affecting the AICD equipped well’s performance.

5.2 AICD Completion Design Workflow

AICDs are mounted on a screen joint and offer flow equalisation effect of the fluid influx into the wellbore in a manner similar to that employed by ICD completions. In addition, AICDs offer a reactive action that restricts the influx of an unwanted fluid. This AICD completion design follows the same workflow as that described in Section 4.3 (Figure 4-1) for ICD completions, with the exceptions that the optimum AICD restriction size will be identified here. The workflow is divided into two parts:

- a. Identification of the initial opening size provides optimum equalisation of the fluid influx to the wellbore.
- b. Identification of the optimum reactive restriction that will minimise the influx of unwanted fluid into the wellbore.

5.3 Identification of Optimum Initial AICD Restriction Size

The flow equalisation effect of AICDs can be achieved by defining an initial AICD flow restriction size that will equalise the contribution along the wellbore in a similar manner to the ICD. Therefore, the techniques described in Chapter 4 for the ICD completion design can be applied to identify the initial flow restriction size of an AICD. The constant ICD sizing technique (Section 4.4.3) forms the best option for identifying the initial AICD size since this will ease the reactive restriction sizing process as well as the installation operation logistics. This identification process applies to all types of AICDs.

5.4 Optimum Reactive AICD Restriction Identification

The reactive element of the available AICDs is triggered by changes in the influx fluid density or composition due to flow of a different phase. The objective of the reactive part is to impose additional restriction to the initial AICD restriction size to minimise the influx of that unwanted phase. This makes the reactive AICD restriction design highly dependent on the physical process of the phase's influx from the reservoir sandface into the wellbore. The following section will layout the underlying equations describing the physical process; which will then be used to design the reactive AICD restriction.

5.4.1 Basic Concepts:

The mobility of fluid phases in the reservoir formation is a function of their relative permeability. Figure 4-1 shows an example of an oil/water relative permeability curves

which highlights the phase mobility against their volumetric percentages in formation. Since the well productivity is also a function of the relative permeability of the flowing phases (Equation 5-1 for oil wells and Equation 5-2 for gas wells), the preferred phase productivity will reduce once the breakthrough of a second phase occurs, with the reduction being a function of the volumetric percentage of the breakthrough phase. Hence, the reactive AICD restriction should be based on the productivity changes of the preferred phase.

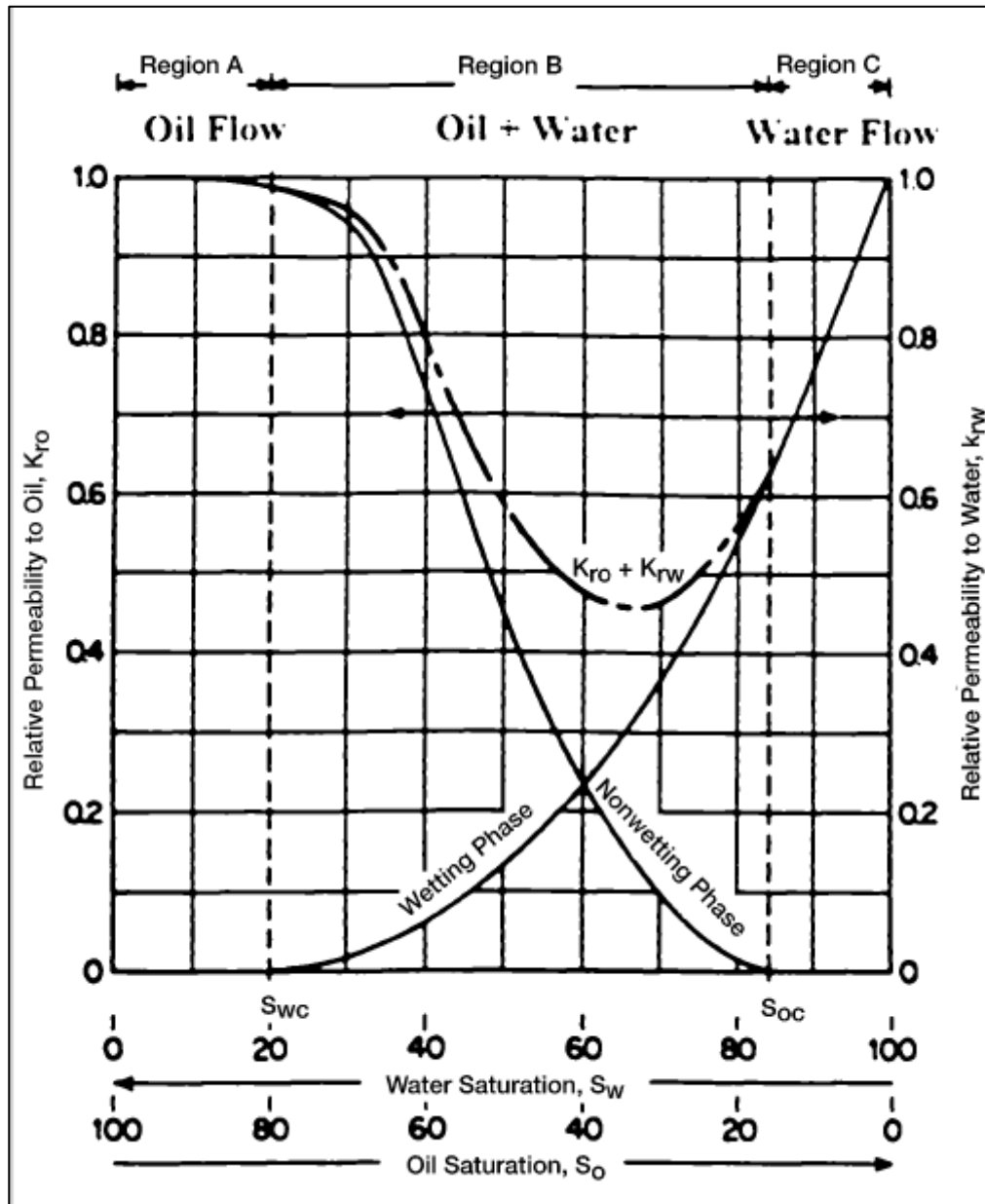


Figure 5-1: Sample relative permeability curves of oil and water [175]

$$PI_o = \frac{0.00708h}{B_o \left[\ln \left(\frac{r_e}{r_w} \right) - 0.75 + s \right]} \left(\frac{kk_{ro}}{\mu_o} \right) \quad \text{Equation 5-1}$$

$$PI_g = \frac{7.08(10^{-6})h(kk_{rg})}{(\mu_g B_g)_{avg1} \left[\ln \left(\frac{r_e}{r_w} \right) - 0.75 + s \right]} \quad \text{Equation 5-2}$$

Where:

- k = Absolute permeability (md)
- k_{ro} = Oil relative permeability
- k_{rg} = Gas relative permeability

5.4.2 **Reactive AICD restriction sizing:**

The optimum restriction of the invading phase can only be achieved by restoring the productivity of the preferred phase. Hence, the additional reduction of the AICD restriction's (initial) size should be designed to reduce the difference between 1) the preferred phase productivity when only one phase is flowing and 2) the preferred phase productivity when two phases are flowing. The degree of restriction (i.e. gradual vs. immediate shut-off) will be dependent on the:

- Percentage of unwanted fluid flow within the flowing fluid mixture.
- Shape of the relative permeability curves.
- Preferred phase initial productivity index (i.e. when only one phase is flowing).
- Ratio of the reduced productivity of the preferred phase to its initial productivity.
- The reservoir and wellbore pressure at each unwanted fluid flow percentage.

The following steps should be followed to identify the optimum restriction:

1. The well performance should be modelled at the initial reservoir and wellbore conditions as described in Chapter 3. This model should include the initial AICD restriction effect.
2. The productivity index of the preferred phase (e.g. oil) should be calculated for every wellbore segment, as part of step 1, using the appropriate productivity index correlation while accounting for the absolute and relative permeability values of the reservoir segment and the initial AICD restriction.

3. The productivity index of the preferred phase should be calculated for every wellbore segment with incremental increase in the percentage of the unwanted fluid. The incremental increase should be set based on the maximum percentage of unwanted fluid for the well and the type of AICD that will be installed as follows:
 - i. The maximum allowed flow rate of the unwanted fluid for the well should be divided by the number of wellbore segments.
 - ii. The maximum percentage cut of the unwanted fluid from each segment should be calculated based on the unwanted fluid flow rate per segment and the total fluid flow rate of that segment.
 - iii. The segment maximum percentage of unwanted fluid should be divided by the number of restrictions in the AICD (e.g. number of nozzles of a ball-type AICD) to identify the number of increments that the unwanted fluid percentage should be divided into. This assumes that all restrictions in the device have similar sizes. If the restrictions differ in size then the percentage should be divided accordingly.
4. The required differential pressure that the AICD restriction has to impose can be identified using Equation 5-3 for oil wells and Equation 5-4 for gas wells. They are based on the ratio of the reduced PI to the initial PI of the preferred phase.

$$\delta P_{AICD} = \bar{P}_r - \frac{PI_{ored}}{PI_{oin}} (\bar{P}_r - P_w(i) - \Delta P_{ICD}) - P_w(i) \quad \text{Equation 5-3}$$

Where:

PI_{ored} = Reduced oil productivity (stb/day/psi)

PI_{oin} = Single phase oil productivity
(stb/day/psi)

$$\delta P_{AICD} = \bar{P}_r - \frac{PI_{gred}}{PI_{gin}} (\bar{P}_r - P_w(i) - \Delta P_{ICD}) - P_w(i) \quad \text{Equation 5-4}$$

Where:

PI_{gred} = Reduced gas productivity (Mscf/day/psi)

$$PI_{gin} = \text{Single phase gas productivity} \\ (\text{Mscf/day/psi})$$

This required pressure drop can be calculated at:

- i. The initial reservoir and wellbore conditions (Equation 5-3 and Equation 5-4).
- ii. The reservoir and wellbore conditions at the time when the exact incremental percentage of the unwanted fluid is reached. These conditions can be estimated using either reservoir simulation or appropriate pressure decline estimation mechanism (e.g. P_D -function or pre-set pressure curves). In this case, Equation 5-5 or Equation 5-6 should be used for oil or gas wells respectively to account for any changes in the well operating pressures.

$$\delta P_{AICD} = \overline{P_{rin}} - \frac{PI_{ored}}{PI_{oin}} \left(\overline{P_{rred}} - P_{wred}(i) - \delta P_{ICDred} \right) - P_{win}(i) \quad \text{Equation 5-5}$$

Where:

$\overline{P_{rin}}$ = Average reservoir pressure at single phase oil flow stage (psi)

$\overline{P_{rred}}$ = Average reservoir pressure at reduced productivity (psi)

$P_{win}(i)$ = Segment wellbore pressure at single phase oil flow stage (psi)

$P_{wred}(i)$ = Segment wellbore pressure at reduced oil flow (psi)

$\delta P_{ICDred}(i)$ = Segment pressure drop across the ICD restriction at reduced oil flow (psi)

$$\delta P_{AICD} = \overline{P_{rin}} - \frac{PI_{gred}}{PI_{gin}} \left(\overline{P_{rred}} - P_{wred}(i) - \delta P_{ICDred} \right) - P_{win}(i) \quad \text{Equation 5-6}$$

5. The AICD pressure drop can then be translated to a restriction size using the appropriate correlation. These are listed in Chapter 3 (e.g. Equation 3-35 for a ball-type AICD).

The implementation of these steps can result in different choking (restriction) sizes for each segment based on the absolute permeability and relative permeability curves of

that segment in addition to the variable initial AICD restriction size. This type of choking (variable choking AICD – VC-AICD) is suitable for layered and channelized reservoirs and will result in the optimum completion performance over the well life.

To ease the installation operation, constant restriction sizes (constant choking AICD – CC-AICD) for all the segments of the wellbore can be designed and installed. This mandates that constant size ICD (i.e. initial AICD restriction opening) is used across all the wellbore segments. Such completion can be designed as follows:

1. The well performance should be modelled at the initial reservoir and wellbore conditions with the constant size ICD completion as described in Chapter 3.
2. The productivity index of the preferred phase (e.g. oil) should be calculated, as part of step 1, for every wellbore segment using the appropriate productivity index correlation while accounting for the absolute and relative permeability values of the reservoir segment along with the constant initial AICD restriction size designed to equalise the fluid influx to the wellbore. The constant initial AICD restriction size will minimise the difference between the segments' preferred-phase productivity; making the initial preferred phase productivity of all segments almost equivalent.
3. The productivity index of the preferred phase should be calculated for every wellbore segment with incremental increase in the percentage of the unwanted fluid while accounting for the constant initial AICD restriction size. The incremental increase should be set based on the maximum percentage of unwanted fluid for the well and the type of AICD that will be installed in a similar manner to the step 3 of the VC-AICD design process. Since the productivity of all segments is controlled by the constant initial AICD restriction, these will result in almost equivalent preferred phase productivity increments.
4. The required differential pressure that the AICD restriction has to impose to minimise the unwanted fluid influx can be identified using Equation 5-3 for oil wells and Equation 5-4 for gas wells based on any of the wellbore segments since their initial and reduced preferred phase productivities are almost equivalent due to the

inclusion of the constant initial AICD restriction. Similar to the VC-AICD, the required pressure drop can be calculated at:

- i. The initial reservoir and wellbore conditions.
 - ii. The reservoir and wellbore conditions at the time when the exact incremental percentage of the unwanted fluid is reached.
5. The AICD pressure drop can then be translated to a restriction size using the appropriate correlation.

Once the AICD restriction sizes are identified, the AICD completion design workflow follows the process described in Chapter 4 for designing ICD completions.

5.5 Summary

AICDs provide an additional reactive restriction to the influx of unwanted fluids such as water in oil or gas producing wells. This reactive restriction can be designed based on the productivity of each segment of the wellbore especially the absolute and relative permeability of the segment. The reservoir and wellbore pressure used in the restriction calculation can either be the reservoir and wellbore pressures at the time of the completion design or the estimated values at the water or excess gas influx percentage required for the restriction. The decline in the reservoir and wellbore pressures later in the well life can be estimated using reservoir simulation or appropriate pressure decline estimation mechanism. This will minimise the error in the reactive restriction sizing. Once the AICD restriction sizes are identified, the AICD completion design workflow follows the process described in Chapter 4 for designing ICD completions.

Chapter 6 Case Studies

6.1 Introduction

This Chapter describes the application of the proposed (A)ICD completion design techniques on six field cases. These include: three oil fields with varying characteristics, one gas field, one gas condensate field and one water-alternating-gas (WAG) well. Such case studies show the range of (A)ICD completion applications as well as the ability of the proposed design technique to accommodate such diversity. This chapter also includes synopses of the author's publications during the course of this study. These provide valuable recommendations to enhance the performance of the AWCs. Three full publications are provided in Appendices A. 6-1, 6-2 and 6-3. The remaining publications are available in the open literature and referenced in this thesis.

6.2 Channelised Reservoir (Synthetic) Case Study

6.2.1 Introduction

A channelised, heterogeneous reservoir model (Figure 6-1), representative of a reservoir located in the North Sea, was used as a test case to illustrate how five of the DFC selection criteria can be used to compare the performance of ICD and ICV completions.

The reservoir-development proposal consists of a horizontal wellbore that crosses two High Productivity (HP) channels with permeability ranging from 1 to 4,100 md without distinctive layering or fluid-flow barriers (see Figure 6-2 and Table 6-1). The reservoir fluid is 19°API with a solution-gas/oil ratio (R_s) of 260 scf/stb and a viscosity of 10.1 cp at the reservoir conditions. The porosity and permeability values were distributed stochastically throughout the reservoir, with pressure support provided by an aquifer.

The initial (base-case) conventional completion, perforated along the full wellbore length, produced at a maximum liquid-production rate of 12,600 stb/day. This leads to an uneven influx rate along the wellbore and an irregular movement of water in the reservoir. This was eventually followed by water breakthrough at various locations along the wellbore.

Both ICV and (A)ICD completions were installed to optimise the well performance and to verify some of the claimed advantages for the three technologies.

A total of 62 ICDs were installed along the full wellbore length to achieve the following:

- Equalise the fluid-influx rate along the wellbore.
- Equalise the water encroachment toward the well to enhance the reservoir sweep efficiency.
- Minimise the annular flow that might result from SAS or ICD completions without annular-flow isolation (AFI).

Two ICVs were installed to separate the HP channels, the heel ICV having a 4-in diameter flow opening while the toe ICV's flow opening size was 3 inch diameter. They were operated to:

- Control the contribution from each channel zone after water breakthrough.
- Minimise the zonal water production.
- Increase the cumulative oil recovery from the well.

6.2.2 ICD Completion Design

An optimum flow-restriction size of a nozzle-type-ICD was applied along the wellbore. The choice of the ICD flow restrictions diameters was based on the differences in the well segment's PI. A total of 30 AFIs were installed along the completion at a frequency of one AFI to every second ICD joint.

The ICD completion equalised the fluid influx along the wellbore and increased the cumulative oil production by 1.7% while optimising the ICV opening increased the cumulative oil production by 2.0%.

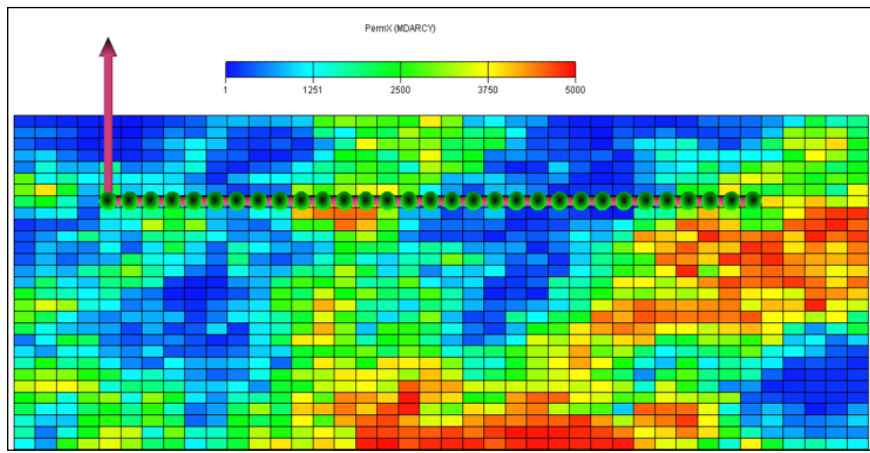


Figure 6-1: The channelised reservoir

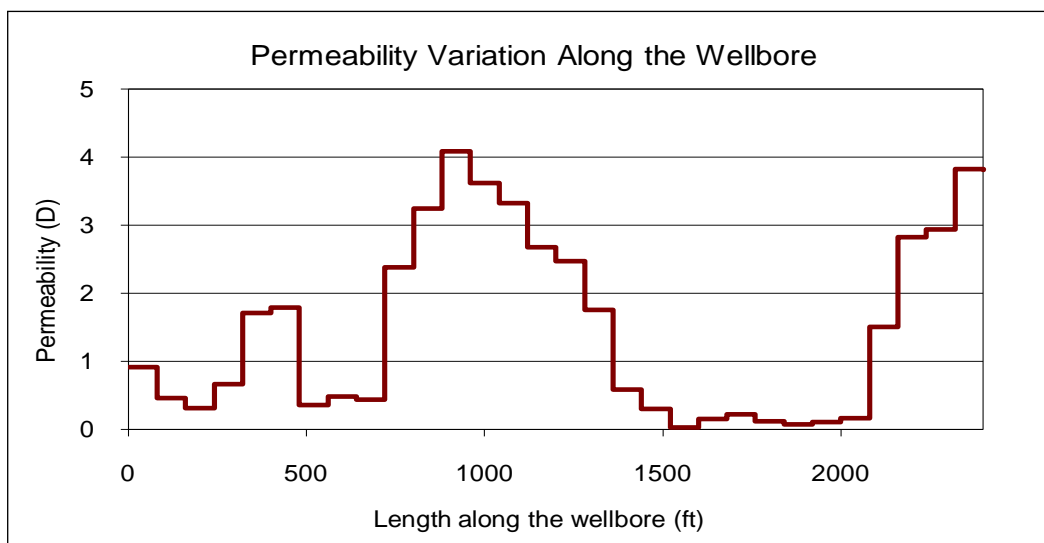


Figure 6-2: Permeability distribution

Table 6-1: Channelised reservoir and horizontal wellbore properties

Reservoir & Fluid Properties	Value	Wellbore Dimensions	Value
Model size	40 x 20 x 50	Length (ft)	~2480
Gridblock size (ft)	80 x 120 x 10	Openhole Diameter (in)	8.5
Porosity (%)	10 - 40	ICD Screen OD (in)	6.625
Permeability (md)	1 - 5000	ICD Screen ID (in)	6.0
K_v/K_h	0.1	ICV OD (in)	5.5
Initial Pressure (psi)	3500	ICV ID (in)	4.0
Oil Density ($^{\circ}$ API)	19	Casing ID (in)	6.0
Oil Viscosity (cp)	10.1		

6.2.3 *Modelling-Tool Availability and the Need for AFI*

The ICD-completion design that equalised the fluid influx along the full wellbore length was tested with two levels of AFI. The initial design called for AFI devices to be installed at every second ICD joint due to the highly variable permeability heterogeneity along the wellbore. The resulting well performance was compared with an ICD completion containing a much reduced number of AFI devices (AFI devices being placed at 400-ft intervals or one to every ten ICD joints). This was done to allay fears that an excessive number of drag-inducing AFI devices were being run without reaping an increase in the well's recovery.

The second completion's lack of AFI across the heterogeneous sandface reduced the added value from this ICD-completion to such an extent that it was equivalent to a SAS completion. A flowmeter survey performed inside the production conduit can measure an apparently equalised inflow, even when there is an unbalanced contribution from the sandface due to significant annular flow along the length of the completion. This state of affairs can be recognised by employing recent advances in the analysis of temperature and pressure data coupled with data measured in the annulus [223].

6.2.4 *Equipment Reliability*

The impact of different ICD-and ICV-failure scenarios on the well performance has been studied. The reduced ICD and ICV well performances resulting from the various failure scenarios were compared with the "no-failure" case. The no-failure case is the case when the optimally controlled ICV completion and the optimum ICD completion were installed across the total well length. This resulted in an increase of 2% and 1.7% in the well's cumulative production, respectively. The lost-oil recovery caused by failure of these technologies is calculated by subtracting the cumulative oil production at a specific failure time from the cumulative oil production of the no-failure case.

Four ICD-completion-failure scenarios were considered:

- a. Complete plugging of ICDs during the installation or well cleanup (within 7 days of start of production)
- b. Sudden plugging of ICDs during the well life (e.g. flowback of spent acid after acid treatment)
- c. Gradual plugging of ICDs during the well life
- d. Gradual erosion of ICDs during the well life

Each scenario was evaluated for ICD failure across the:

- HP zones only. The remaining ICDs across the low-permeability zone are open to flow.
- Low-permeability zones only. The remaining ICDs across the HP zones are open to flow.
- Both HP and low-permeability zones.

Nine ICV-failure scenarios (six for each ICV and three for both) were analysed:

- Fail at fully open position at installation time.
- Fail at fully closed position at installation time (one ICV only).
- Fail partially closed at installation time.
- Fail as is (the current optimum valve position at a specific time).
- Fail safe in the fully closed position during well life.
- Fail safe in the fully open position during well life.

Figure 6-3 shows the well oil-production loss because of the failure of one or both ICVs. As expected, ICV failure in a closed position at the time of installation had the most pronounced impact on the well performance (Figure 6-3). For example, the upper ICV (ICV-1) failure in closed position during the well-completion installation restricts the well production to the lower zone (ICV-2), resulting in a 50% reduction in the amount of oil that could have been recovered if the failure either did not occur or could have been mitigated. Similarly, ICD plugging during installation or cleanup has the most pronounced impact on the well performance (Figure 6-4). This failure mode can be mitigated by opening the ICV to the fully open position or by retrieving the completion if the packers have not yet been set or by a well intervention. ICV failure at the fully open position has an adverse, but less drastic, impact on the well performance.

ICD plugging along the complete well length has a large impact on the well performance; particularly if this occurs during installation or cleanup (Figure 6-4). Gradual erosion of ICDs during the life of the well had a lower impact. It will be appreciated that the failure impact of both technologies during the well life is a field- and time-dependent issue that cannot be easily generalized. This comparison of ICD and ICV failure is included as an example of the type of sensitivity study that can be performed.

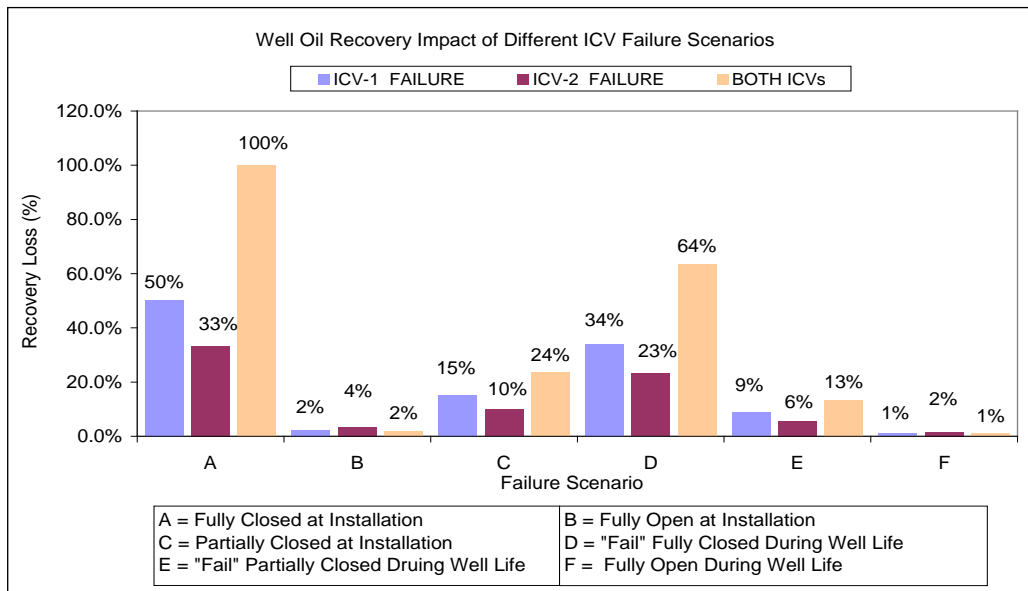


Figure 6-3: Impact of ICV failure on total recovery

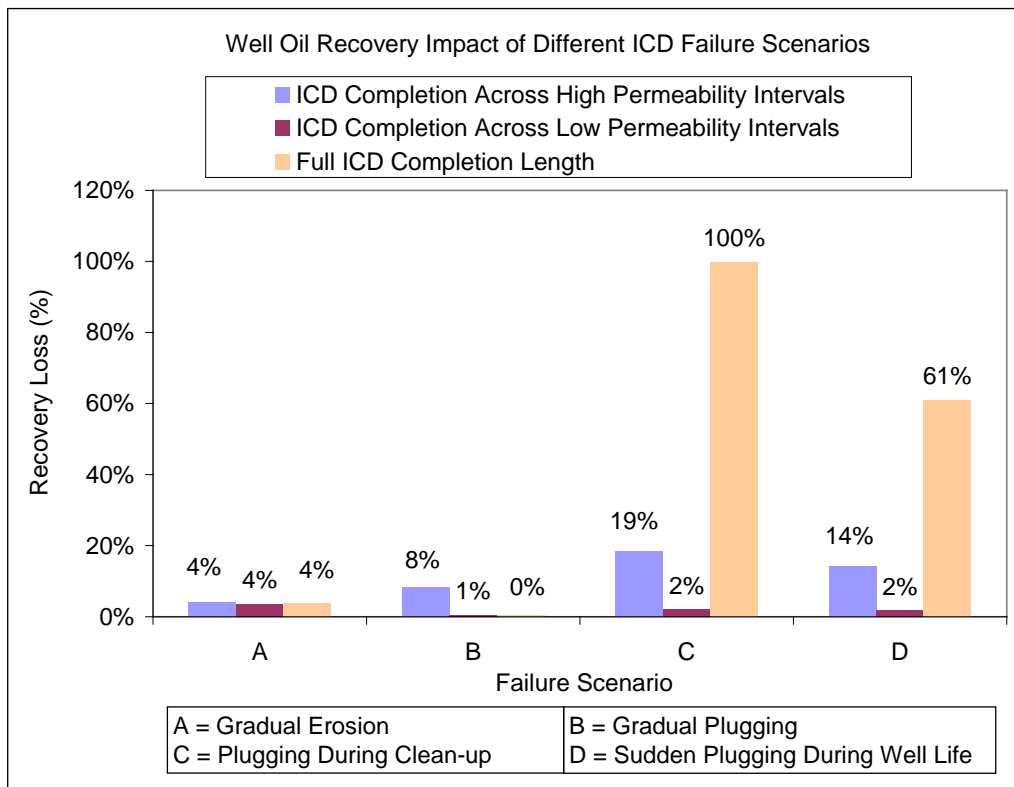


Figure 6-4: Impact of ICD failure on total recovery

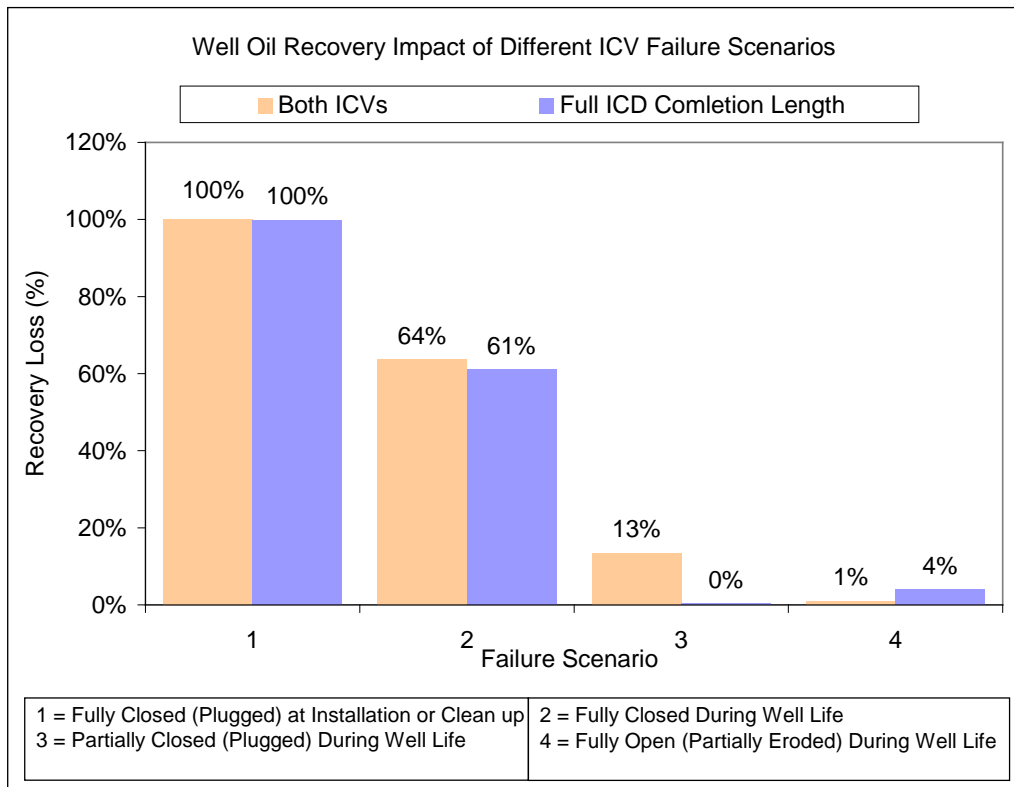


Figure 6-5: Comparison of ICV and ICD failure impact on total recovery

ICV failure has a greater impact on the well performance than an individual ICD failure (Figure 6-5).

6.2.5 *Improved Cleanup*

Formation damage caused by the drilling and completion process is frequently caused by losses of completion fluid into the near-wellbore region and plugging of the sandface. The wellbore was completed with an SAS completion, an optimum ICD completion or with ICVs to control the flow from the two HP channels. In all cases, the following steps were carried out to model the near-wellbore damage:

- Gravity slumping of the lost completion fluid (because of its density being higher than reservoir oil) was ignored. The well's cleanup performance to thus be studied without this additional complication.
- Local grid refinement around the wellbore.
- Fluid saturation and relative permeability around the wellbore were modelled to represent completion-fluid invasion and the extra resistance to oil flow caused by pore plugging and permeability impairment.
- Sandface plugging with a mudcake requiring high lift-off pressure (Appendix A. 6-3).

The ICVs were operated sequentially on the basis of the completion-fluid return rate [i.e., the heel ICV was fully opened to impose the maximum allowable drawdown until the water-flow rate reduced to a specified limit (100, 1,000, or 2,000 STBW/D)]. This zone was then shut-in, and the toe zone was fully opened.

A comparison of SAS-, ICV-, and ICD-completion cleanup performance is indicated in Table 6-2 and Figure 6-6 and Figure 6-7. The SAS completion resulted in slow and irregular cleaning of the wellbore. The ICV completion indicated a better performance because a higher drawdown was applied to each zone. The ICV application also illustrated the need to identify the optimum point to switch between the zones. Excessive time spent on cleanup of one or more zones results in deferred oil production without any noticeable benefits from an improved cleaning process.

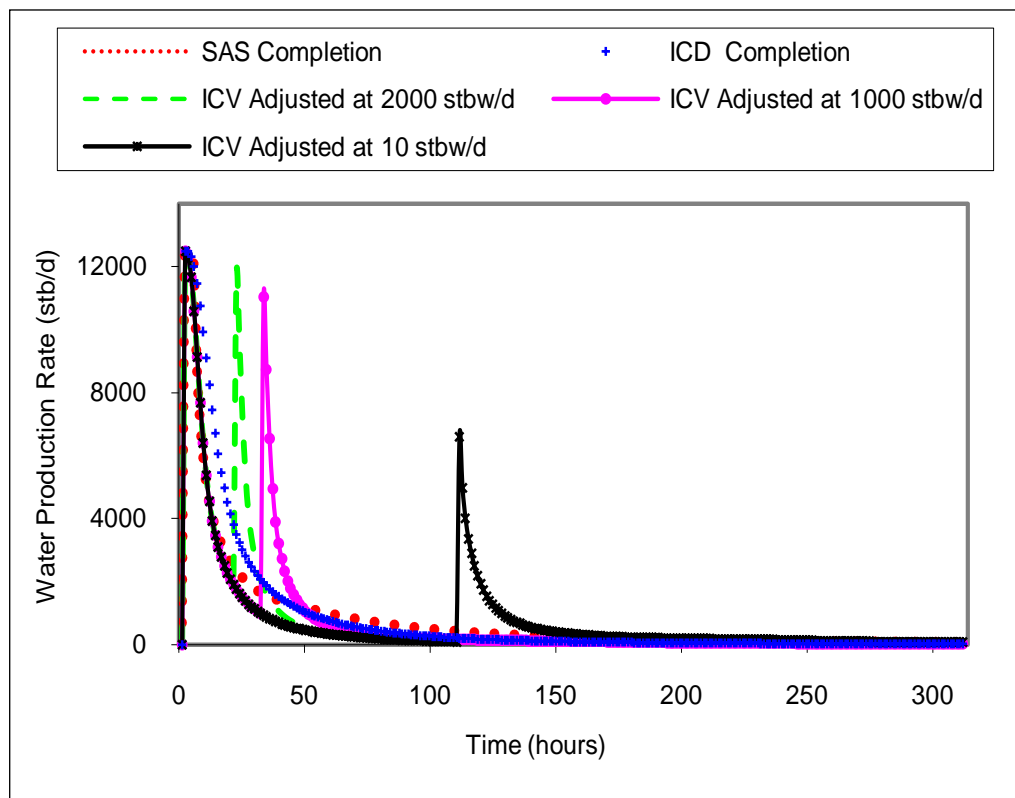


Figure 6-6: Cleanup water return rate

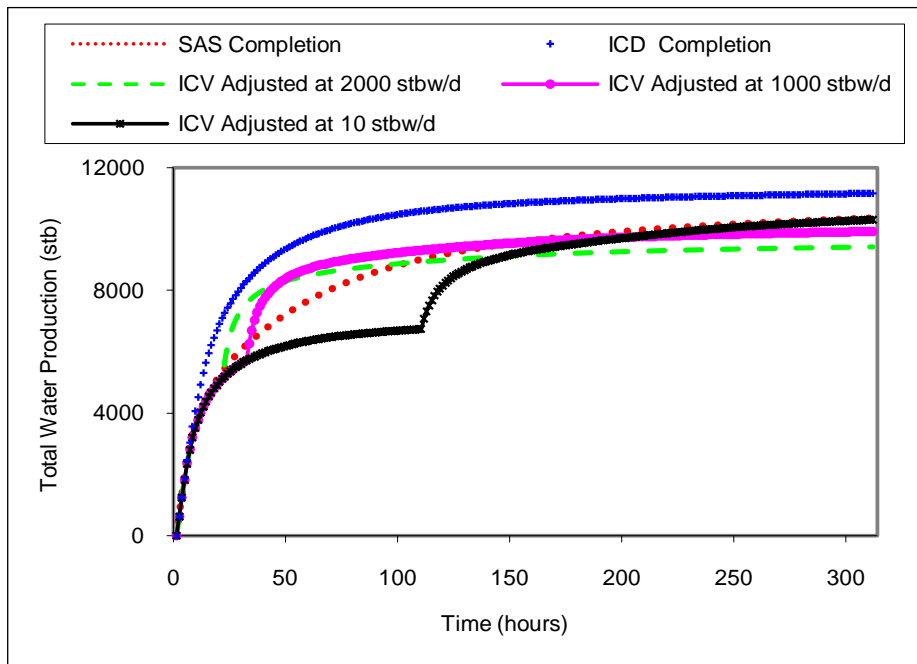


Figure 6-7: Cleanup total water return

The ICD completion with AFI installed at every second joint gave the best cleanup performance. It resulted in a brine recovery of 98.6% compared to 91.8% from the SAS and the ICV completion (Table 6-2). This is because of the ICD’s ability to encourage the lower-permeability zones to contribute to the flow earlier in the well life. This ability was confirmed when a similar recovery was obtained when layering was introduced along the wellbore. However, ICVs do have the ability to impose a higher drawdown to lift off the mudcake at a specific zone. Achieving a reasonably large drawdown across the mudcake is more difficult with an ICD completion than with an ICV. This aspect is discussed in detail in Appendix A. 6-3.

Table 6-2: Cleanup performance of ICDs and ICVs

Case	Total Brine Return in 15 Days	Brine Recovery
	(stb)	(%)
Brine lost to formation	11,364	-
SAS	10,431	91.8
ICV – 100	10,436	91.8
ICV – 1000	9,964	87.7
ICV – 2000	9,450	83.2
ICD	11,210	98.6

6.2.6 *Equipment Cost*

The heterogeneous reservoir illustrated in Figure 6-1 was situated at a depth of 6,500 ft TVD. It could be either a low-strength sand or a strong carbonate formation. The 2,400 ft completion section could either have a full ICD completion or two ICVs controlling the contribution from the two HP zones (Figure 6-2). Only these completion elements were included in the cost calculation (Table 6-3 and Table 6-4) because the remainder of the two completions will be similar. The ICD cost is estimated to be approximately 30% higher than that of an SAS completion [cost approximately USD 400/ft for 5½-in. equipment [197] while an on/off ICV costs approximately USD 150,000. The low strength sand formation is expected to collapse around the ICD-screen, providing annular flow isolation and eliminating the need for external packers. The AFI was therefore limited to four packers to ensure isolation of the highly heterogeneous zones in the soft-sandstone case. Wellbore collapse around the ICD cannot be relied on to provide AFI in the strong-carbonate case. Hence AFI devices installed at every second joint (see Section 6.2.5). Table 6-3 and Table 6-4 indicate that, for our example, a two-ICV completion has a higher capital cost than the ICD completion for the soft-sandstone case where sand control is required. The two-ICV completion has a lower capital cost than an ICD completion for the strong-carbonate case. The cost for a three-zone ICV completion and an ICD completion is similar for this carbonate case.

Table 6-3: Simplified ICD completion cost for two reservoir rock type

ICD Completion Cost Comparison			Soft Sandstone	Strong Carbonate
Equipment	Cost (\$)	number of units	Subtotal (\$)	Subtotal (\$)
ICD per ft (SST/Carbonate)	520/260	2400	1,248,000	624,000
Production Packer per unit	100,000	1	100,000	100,000
Isolation Packer per unit	80,000	1	80,000	80,000
Swell packer per unit (SST/Carbonate)	30,000	4/33	120,000	990,000
Wellhead	175,000	1	175,000	175,000
Total ICD Completion Cost			1,723,000	1,969,000

Table 6-4: Simplified ICV completion cost for two reservoir rock type

ICV Completion Cost Comparison			Soft Sandstone	Strong Carbonate
Equipment	Cost (\$)	number of units	Subtotal (\$)	Subtotal (\$)
ICV per unit 4.5"/3.5"	150,000/ 120,000	1+1	270,000	270,000
Control lines-Flatpack 3 line - per ft	20	6400	136,000	136,000
Control lines- Flatpack 2 line - per ft	18	1600	28,800	28,800
Clamp per unit 4.5"/3.5"	135/100	195/65	32825	32,825
Surface unit per unit	150,000	1	150,000	150,000
Production Packer Feed-through per unit	130,000	1	130,000	130,000
Isolation Packer Feed- through per unit	100,000	1	100,000	100,000
Extra Tubing along wellbore per ft	80	1600	128,00	128,000
Production Liner cement+perf per ft	250	2400	0	600,000
Modified Wellhead	185,000	1	185,000	185,000
SAS per ft (SST/ Carbonate)	400/0	2400	960,000	0
Total ICV Completion Cost			2,120,525	1,760,625

6.2.1 Gas lift

The channelised reservoir model was divided into two layers: an oil layer at the bottom and a separate gas layer at the top. The well was located near the oil/water contact (OWC) to represent a poorly performing producer with high-water-cut production. The well quickly ceased to flow against a wellhead pressure of 360 psi

because of the high water cut. The objective of the study is to quantify the potential advantages of in-situ gas lift using an ICD or an ICV to control the gas flow. This concept is field-proven using a wireline-serviceable choke installed in a side-pocket mandrel and an ICV. The ICD had a fixed restriction throughout the well life, while the ICV's flow restriction required careful optimisation to ensure maximum oil production despite a gradually increasing operating wellhead pressure (360, 380, and 420 psi.).

Figure 6-8 clearly indicates the advantage of adding the in-situ gas lift because the well without artificial lift ceased to flow less than 100 days after the start of production. The ICD-equipped well was able to produce for a longer period (slightly less than 500 days), but ceased to flow once the operating wellhead pressure was increased to 420 psi. ICV optimised gas injection extended the well life to 1,100 days, coping relatively well with the changing water cut and increasing operating wellhead pressure.

ICV actuation enabled a gradually increasing gas injection and wellhead pressure (Figure 6-9). In this study, the low uncertainty in the reservoir properties and the application of an optimum ICD restriction size assisted the ICD completion in this case, a factor that is uncommon in practice.

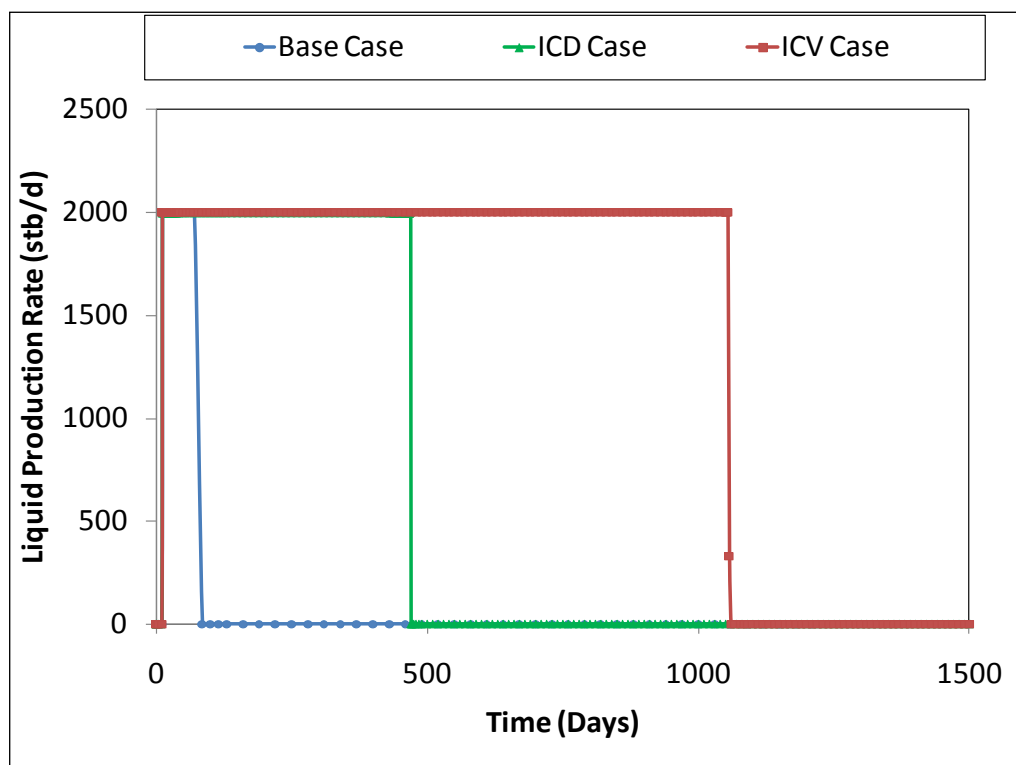


Figure 6-8: Liquid production with gas lift using ICD and ICV

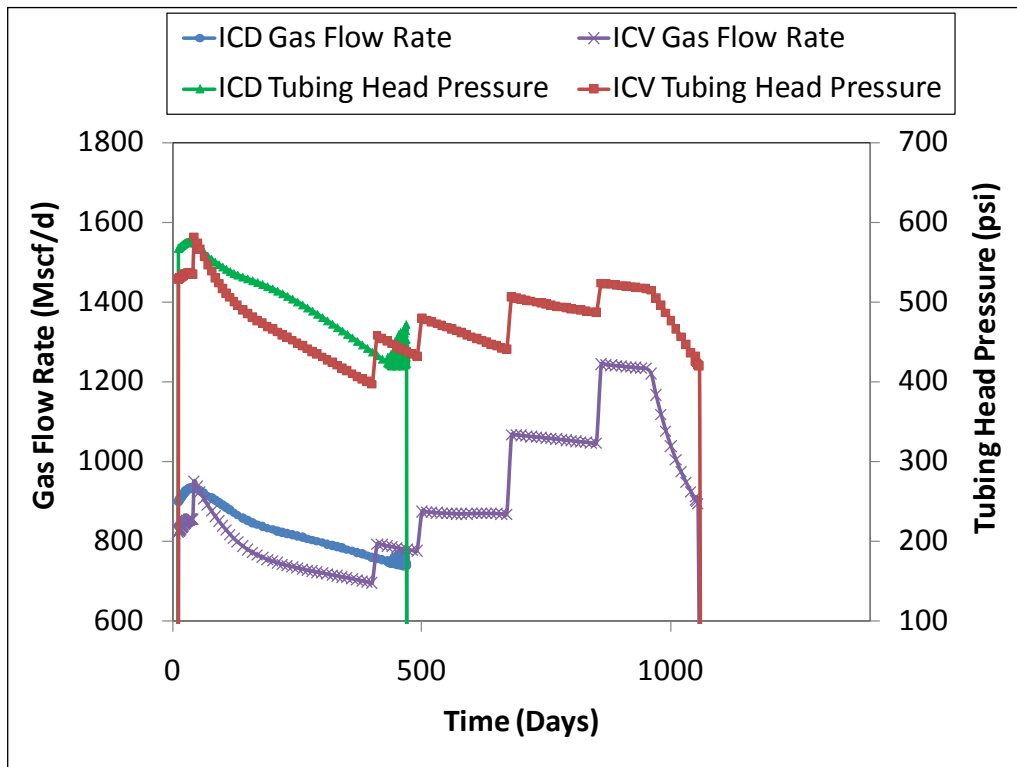


Figure 6-9: Gas injection rate and tubing head pressure compared for ICD and ICV

6.2.1 Summary

A synthetic channelised reservoir model was used in this case study to illustrate the how the five of the DFC selection criteria described in Chapter 2 can be used to evaluate the performance of ICD and ICV completions. This case also supports the conclusions drawn from the comparison between the two technologies. This can also be extended to include AICDs.

It is clear that ICVs form better alternative compared to ICDs when it comes to modelling tool availability and gas lift control. However, ICDs form better alternative when it comes to equipment reliability and impact of failures; heterogeneous formation cleanup; and equipment cost.

6.3 The S-Field Case Study

6.3.1 Introduction

The S-field is located in the Norwegian sector of the North Sea. The field was originally developed with seven conventional wells completed on only one of the two, separate pressure regimes present in the four reservoir sands. Previous studies identified significant extra value (11 % in cumulative oil production [202]) would have been gained if it had been developed with a reduced number (5) of producers with 18 ICVs.

6.3.2 The S-Field Challenges and Study Objective

A detailed description of the reservoir simulation model has been published previously [234]. This has included the reservoir layering, the rock and fluid properties, the production and injection well completions and the Interval Control Valves (ICV) locations. Figure 6-10 indicates the reservoir layering. Key parameters include:

- Low oil viscosity.
- High gas-oil-ratio.
- Very high formation permeability.
- Strong aquifer support.
- Presence of two regions of differing pressure due to low permeability layer splitting the reservoir into two zones.

These parameters result in very high deliverability wells.

The (hypothetical) intelligent well development plan called for the installation of five intelligent wells with a total of 18 completion intervals each controlled by its own interval control valve (Figure 6-11). A group of three and two wells were respectively connected to two Subsea templates (SM and SL). The proposed wells replaced the existing seven conventional producers that were originally used to develop the field. A full description of the well completion models and network piping was published previously [234].

Automatic optimisation of the ICVs was applied using the optimiser available in the General Allocation Program (GAP) provided by Petroleum Experts. The optimiser employed a time step interval of 15 days i.e. at the end of every 15-day time-step the production from each zone was evaluated and the ICVs adjusted to reduce the WC and GOR. Utilization of the automatic optimiser improved the cumulative oil production by

11.6% compared to the 7 conventionally completed producers. The additional cumulative oil production was mainly produced during the decline period.

The S-field will now be used in this study to compare the benefits gained from the application of ICD and ICV completions on a field scale.

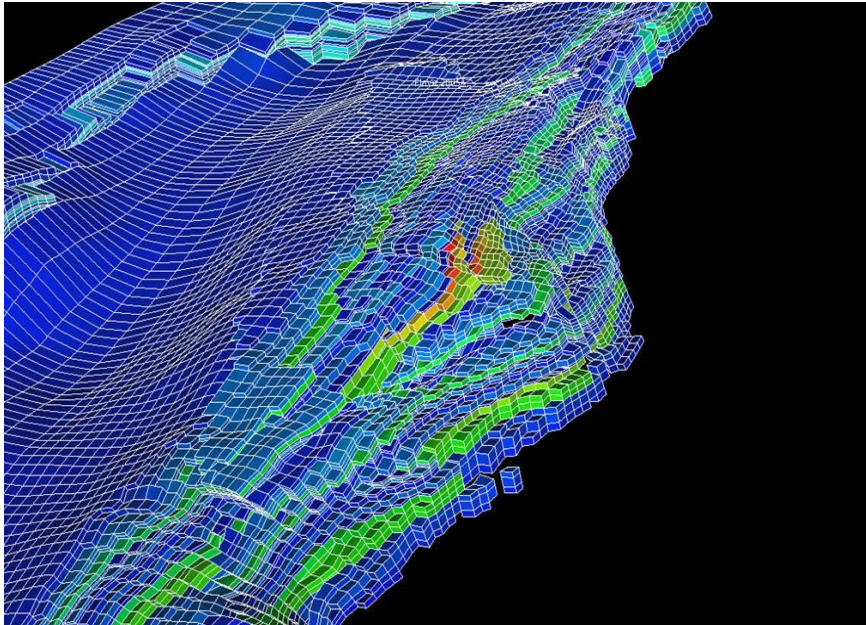


Figure 6-10: The reservoir simulation model (oil zones in green colour)

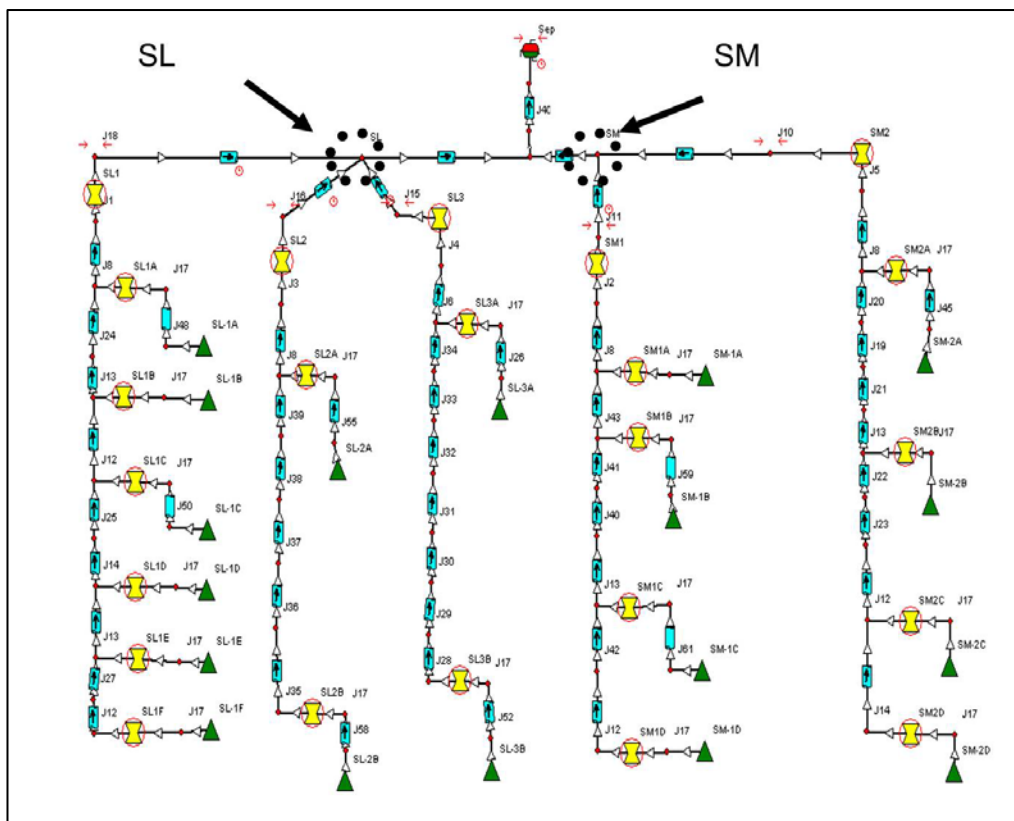


Figure 6-11: The Wellbore/Surface network model

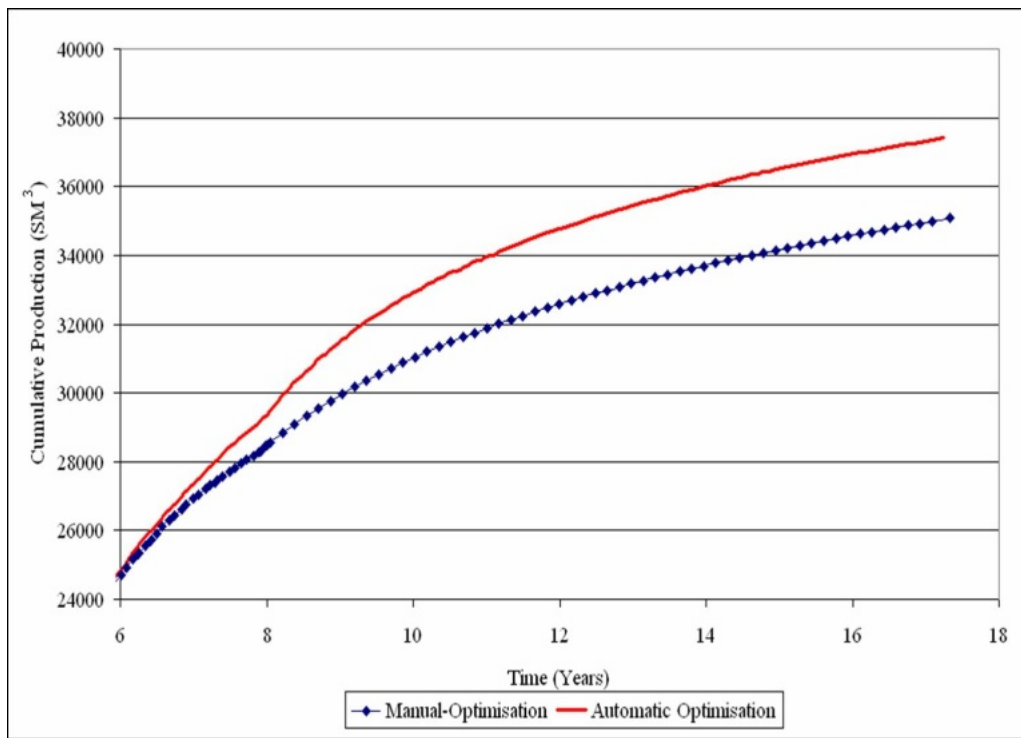


Figure 6-12: Comparison of cumulative oil production of manual & automated S-Field production optimisation

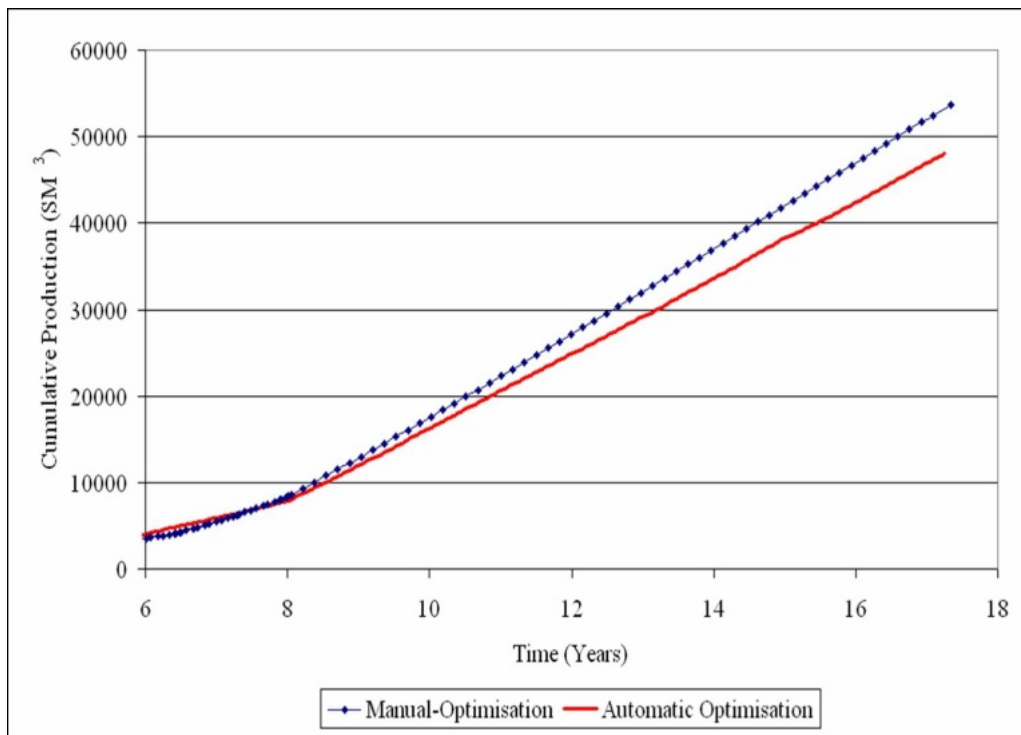


Figure 6-13: Comparison of cumulative water produced by manual and automated S-Field production optimisation

6.3.3 ICD Completion

The production well's ICV completions were replaced by a nozzle-type, ICD completion employing either variable-size ICDs or constant-size ICDs across all producing zones in the single wellbore (Table 6-5 and Table 6-6). The objectives were to:

- Equalise the fluid influx from multiple layers with varying pressures and rock properties.
- Delay water breakthrough and enhance full field performance.

Table 6-5: S-Field wells' layer parameters and variable-size ICD completion

SM-1			SM-2					
k	Pressure	IDn*	k	Pressure	IDn*			
(md)	(psi)	(meter)	(md)	(psi)	(meter)			
134	4827	0.0048	135	4398	SAS			
245	4507	0.0062	937	4413	0.0083			
669	4582	0.0054	699	4422	0.0083			
1299	4570	0.0055	447	4386	0.0092			
1195	4304	0.0150	114	4540	0.0095			
1373	4298	SAS	2579	4586	0.0069			
1192	4449	0.0063	-	-	-			
SL-1			SL-2			SL-3		
k	Pressure	IDn*	k	Pressure	IDn*	k	Pressure	IDn*
(md)	(psi)	(meter)	(md)	(psi)	(meter)	(md)	(psi)	(meter)
690	4353.4	SAS	943	4318.2	SAS	151	4380.5	SAS
3042	4360.8	0.0101	692	4308.5	0.0077	489	4374.5	0.0076
713	4401.6	0.0083	692	4311.7	0.0077	689	4382.3	0.0071
147	4505.4	0.0073	151	4319.2	0.0075	690	4376	0.0073
816	4514.3	0.0061	2920	4691.2	0.0047	4502	4619.3	0.0047
5563	4594	0.0055	3241	4674.4	0.0047	4430	4614.2	0.0047
5256	4578.9	0.0055	-	-	-	4358	4609.2	0.0047
4003	4621	0.0053	-	-	-	-	-	-
* IDn is the effective nozzle diameter of each ICD joint								

Table 6-6: S-Field wells' constant-size ICD completion

IDn*				
(meter)				
SM-1	SM-2	SL-1	SL-2	SL-3
0.0054	0.0078	0.0055	0.0058	0.0057
* IDn is the effective nozzle diameter of each ICD joint				

The ICD completion design workflow described in Section 4.4.3 was used to identify a constant-size ICD that maintained an optimum level of equalisation (~55 %) between the producing zones in each well without reducing the total well liquid rate. Applying this completion strategy to all producers resulted in a 2.4 % increase in the cumulative oil production when compared with the conventional well completion.

The greater ability of a variable-size ICD completion to equalise the fluid influx along each wellbore is illustrated by well SM-2, a well that is completed across 4 layers with highly variable permeability (Table 6-5). ICDs were selected for 3 of the 4 layers while SAS was applied across the layer with the lowest productivity and pressure. This ensured equalisation of the fluid influx into the wellbore (Figure 6-14). Crossflow between the reservoir layers, even while the wells were producing, had occurred when the five wells were conventionally completed. This was eliminated by the ability of the ICD completion to maintain the commingled bottom hole pressure below the reservoir pressure of all producing zones. Despite this completion helped delay the water breakthrough (Figure 6-15), it also significantly reduced the oil production due to the limited contribution from the low productivity layer. Applying this completion strategy to all the wells in the field resulted in 3.9 % increase in cumulative oil production compared to the conventional well completion.

The ICV completions in the case of the S-Field proved superior due to the ICV's inherent ability to dynamically optimise the production from (or injection to) the multiple layers (Table 6-7).

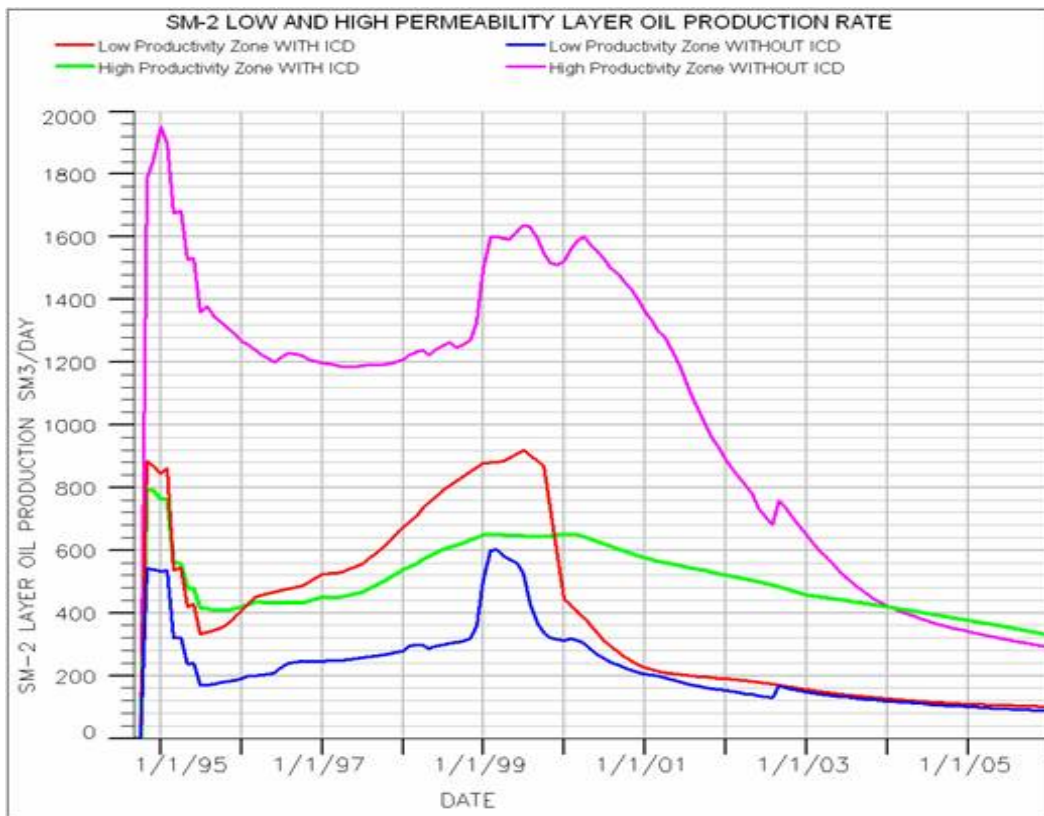


Figure 6-14: SM-2 layer oil production

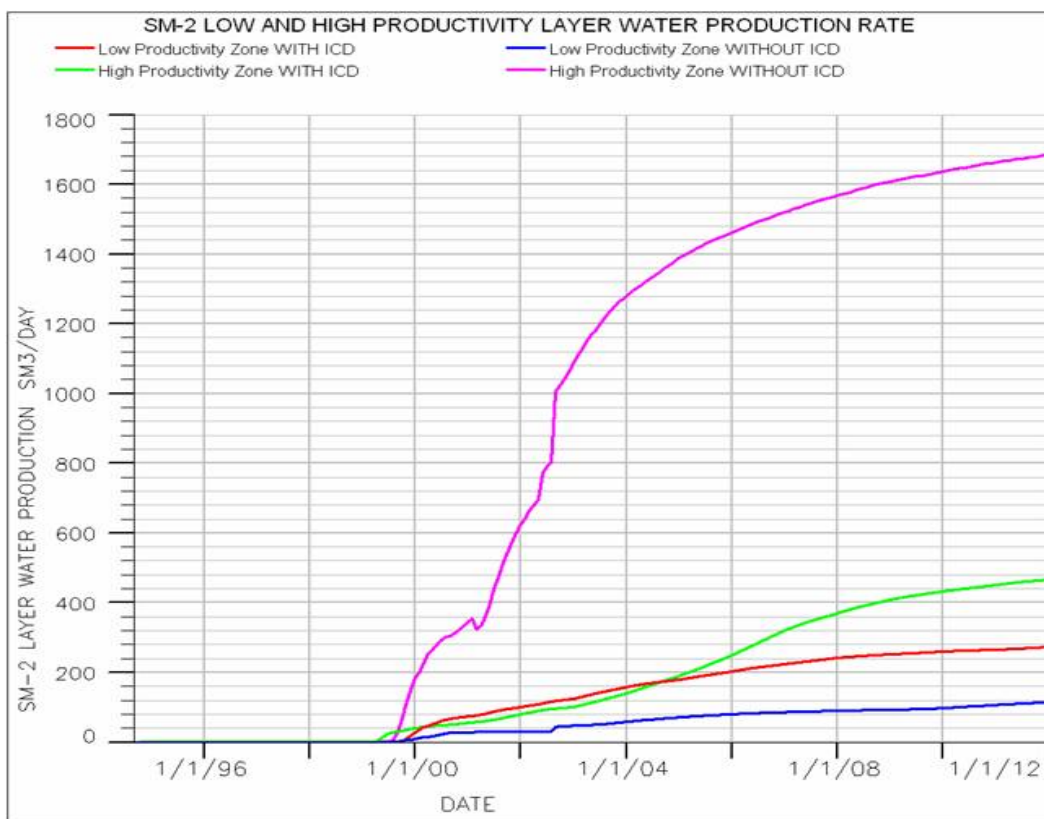


Figure 6-15: SM-2 layer water production

Table 6-7: S-Field performance was improved by ICD and ICV completions

Case	Cumulative Production (MMSm ³)			Recovery Improvement
	Oil	Water	Liquid	(%)
Base-case (7 Conventional wells)	33.6	74.7	108.3	-
5 Constant-size ICD Completed Wells	34.4	64.6	99.0	2.4
5 Variable-size ICD Completed Wells	34.9	75.2	110.1	3.9
5 Wells with 18 ICVs	37.5	48.2	85.7	11.6

6.4 The H-Field Heavy Oil Case Study

6.4.1 *Introduction*

The H-field is located in the Norwegian sector of the North Sea, 115 miles west of Stavanger, in water depth of 420 feet (128 meters). The field was discovered by Statoil (Hydro at the time) in 1991, and has been developed with an integrated production and drilling platform located 185 kilometres west of Haugesund [235].

Production in the H-field started on September 23, 2003 with 9 pre-drilled production wells producing at 70% of the plateau rate. As of January 2006, 16 producing wells and 3 injection wells had been drilled and completed [47]. Two injection wells are used for gas injection to provide pressure support in the reservoir, while a third injector disposes of drill cuttings and produced water. A total of 37 wells are to be drilled on the field of which 31 will be production wells [235].

The field is expected to produce for 30 years with a peak production of 230 thousand barrels of oil per day with a total recovery of 755 million barrels of oil.

6.4.2 *Geological and Fluid Description*

The H-reservoir consists of a massive, predominantly fine to medium grained, moderate to well sorted, turbidite sandstones of the Heimdal Formation of Palaeocene age. The sand, enclosed in the Lista shales, is found at a depth of around 1,700 meters below sea level [236]. The H-Field sandstones are very friable, slightly cemented quartz grains. They show excellent reservoir properties with permeability in the 5-10 Darcy range (k_v/k_h ratio close to unity) and with an average porosity of 33% [47].

Production drilling experience in the H-Field showed that shale sections may be encountered close to the reservoir boundaries. Image logs have revealed that these often have steep boundaries caused by a deformational origin associated with sand injections, folds and faults. The topmost part of the main sand exhibits extensive water escape structures and, within the upper Lista shales above the main Heimdal sand, a number of oil-filled injection sands occur (Figure 6-16) that cut the shale lamination (Figure 6-17). These sands become fewer and thinner upwards in the Lista section; with most of them being far below seismic resolution [236].

The field contains a heavy, biodegraded oil with an API gravity of 19.5° (895 – 940 Kg/m³), a high viscosity of 12 cp at reservoir temperature and a low solution gas (Rs) of 15 Sm³/Sm³. A long transition zone exists above the Oil Water Contact (OWC) due to

the small density difference between the oil and the formation water (1,018 Kg/m³) (Figure 6-16) [47, 237].

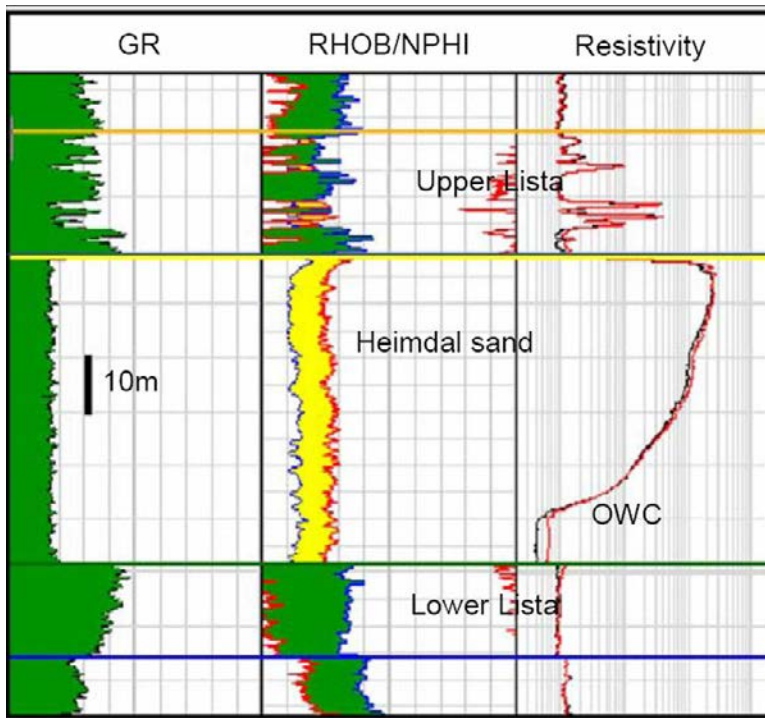


Figure 6-16: H-Field well log showing thin sands within the Lista shale and a long transition zone above the OWC [236]



Figure 6-17: Core photo showing Lista shale with injection sands [236]

6.4.3 Field Development Plan

The initial reservoir pressure was ~170 bar, a value below that required for long-term production at the well target (Plateau) rate by natural flow. Hence, gas lift was installed in all producers to aid lifting the produced fluid to surface. A reservoir drive mechanism is also required to sweep the oil to the producers and to maintain the reservoir pressure above the bubble point pressure (approximately 50-60 bars). Both water and gas injection was evaluated for this purpose. Both of these fluids have a higher mobility than the viscous H-Field oil; hence special measures are required to prevent coning. Such coning will be accentuated by the H-Field's k_v/k_h value of close to unity. Gas injection was found to be the favourable option due to:

- Crestal gas injection allows lateral rather than vertical movement of the gas due to the greater density difference between the oil and gas compared to oil and water. The downward, vertical movement of the gas will only be noticed when faults or shales act as barriers to horizontal flow. No clear evidence of such compartmentalisation has been observed in the H-reservoir. Gas injection will also help recover some of the oil present in the injection sand at the upper boundary of the reservoir (the upper Lista shale).

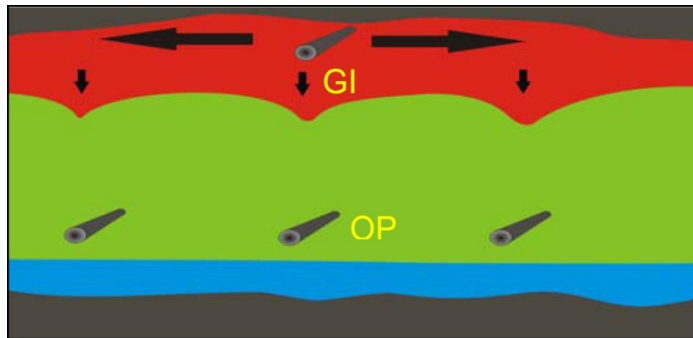


Figure 6-18: Injected gas movement toward oil producers (GI is gas injector, OP is oil producer) [47]

- The injected water's flow direction, on the other hand, is determined by the mobility difference of water and oil with the small density difference between oil and water having a negligible effect on the flow pattern. The higher water mobility will thus result in strong coning toward the producers.

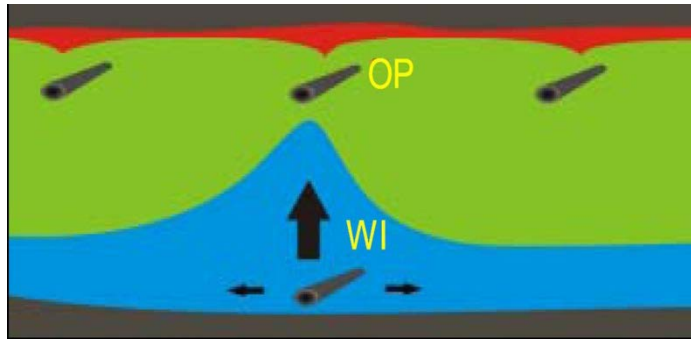


Figure 6-19: Injected water flow direction (OP is oil producer, WI is water injector) [47]

An Extended Well Test was performed on a well-placed about 16 meters from the OWC [47]. This resulted in an actual water cut of 8% compared to the expected (simulated) water cut of 50%. This limited water coning justified the placement of the producing wells low in the oil column when combined with gas injection to reduce the remaining oil saturation to as low a value as possible.

6.4.4 Challenges and Study Objectives

The H-field's development plan addresses many major field development concerns including an irregular (unpredictable) reservoir structure combined with the long transition zone between the oil and water phases. These and other challenges, such as the highly reactive shale layers encountered when long horizontal wells are drilled and the control of the gas and water influx into and along the individual horizontal laterals, complicate the field development planning and well placement decisions in this field.

The operator drilled and completed multi-lateral wells to produce this field. Inflow Control Devices (ICDs) and Inflow Control Valves (ICVs) were applied in these wells to equalise the fluid influx into the horizontal sections of each lateral and to manage the contribution of the laterals to the overall well production. The 2006 ICD completion design applied employed a single strength, channel-type ICD which is expected to be able to successfully equalise the fluid influx into the tubing along the completion's length. A Production log (PLT) run inside the completion's flow conduit confirmed this prediction (Figure 6-20) [47, 238].

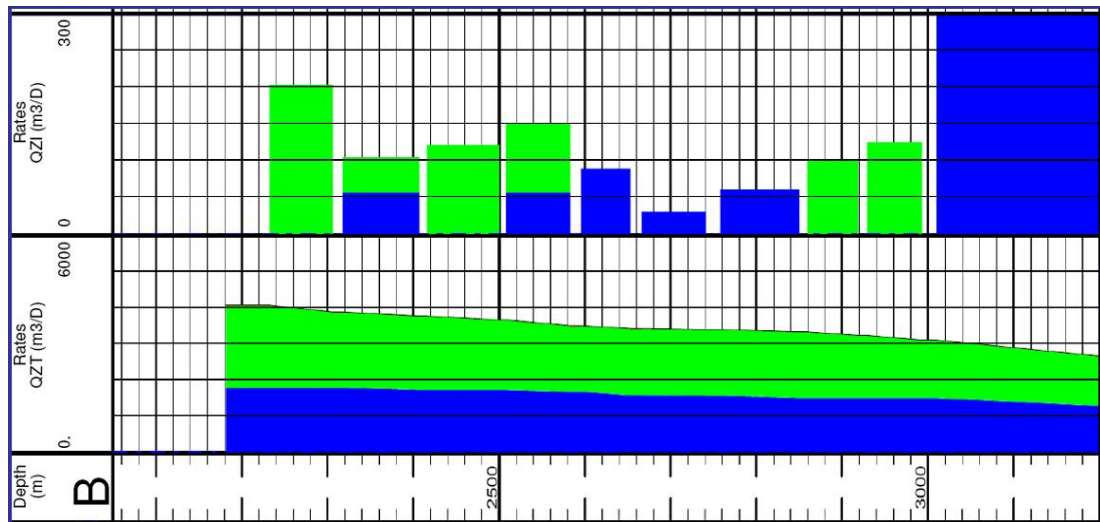


Figure 6-20: PLT log in a H-field ICD completion [238]

However, an equalised influx along the completion's length does not necessarily mean an equalised influx into the wellbore (i.e. equalised flow from the formation to the annular section of the well). This occurs because a completely open annulus between the ICD devices and the formation will encourage flow from any high productivity zones. Such uneven influx at the sand face can be prevented by installing AFIs to separate the zones of varying productivity. Formation (sandface) collapse around the ICD screens can also limit such flow; though evidence of such formation collapse has only been identified in one H-Field well by 2009.

The operator's standard completion strategy is to apply AFIs at shale section boundaries only with the long (heterogeneous) sand sections being fully open to annular flow. The potential for annular flow, and the resulting unbalanced (sandface) inflow contributions between the well's high and low productivity zones, was studied because its existence would result in early gas or water breakthrough; jeopardizing the well's maximum possible recovery. The overall completion design should therefore include both ICDs and AFIs if recovery from the well is to be maximised.

Another completion challenge to be addressed is whether the installation of ICVs at the mouth of the laterals will add value by optimising the oil production.

The H-Field's operator is one of the champions of the development of AICD technology for application to the H and other fields. The design methodology and added value of an AICD completion is a challenge that will be addressed here.

Potential interference between laterals, the optimum lateral elevation and their effect on the well productivity also needed to be investigated in addition to the application of these advanced technologies.

In summary, the challenges to be studied are:

1. Optimum well lateral elevation.
2. Maximum interference between laterals.
3. Operation strategy for ICV's when installed at the mouth of the laterals.
4. ICD and AFI completion design.
5. AICD completion performance and design.

Overcoming these challenges will assist in identifying the added value from the application of advanced well completions in the H-Field. In addition, manual identification of the appropriate design of AWC will be applied to show the value of the design techniques proposed in Chapter 4 and 5.

6.4.5 *Reservoir Model Description*

The H-field simulation model was supplied by the operator. It was a fine grid, Eclipse 100 model. The model contains 90 X 168 X 20 grid blocks with combination of rectangular and corner-point geometry grid to reflect the actual field structure (Figure 6-21). The porosity and permeability values had been distributed stochastically with an average value of 33% and 6 Darcy, respectively.

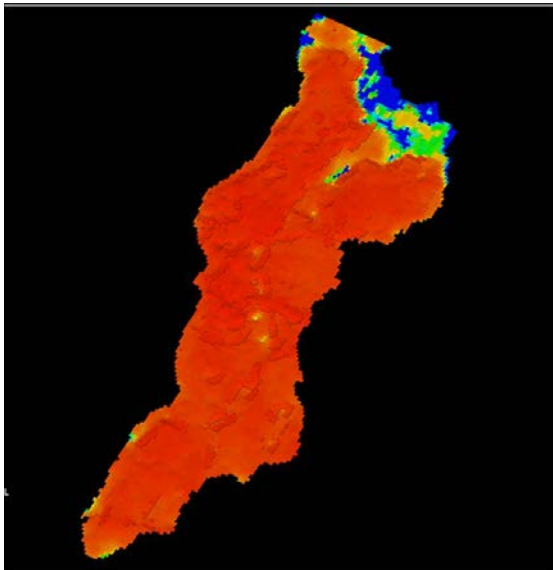


Figure 6-21: The H-Field simulation model

The field is being developed by 31 producers, 3 gas injectors and 3 water injectors. The three gas injection wells were distributed across the field with a well in the north, centre and south. The gas injectors are highly deviated or horizontal with the horizontal section located at the top of the reservoir. The water injectors are also distributed

across the field to provide appropriate support, the wells being positioned at the bottom of the reservoir, beneath the OWC.

All the oil producers are located at the same elevation, of some 10 meters above the OWC. A water aquifer has been attached to the model and history matched to reflect the depletion of the reservoir pressure from its initial (1977) value of 180.2 bars at the OWC that recorded at the start of production (167.7 bars). This reduction in reservoir pressure was caused via the communication aquifer with other producing fields in the area. The initial (2003-2005) production period has also been history matched. Fifteen of the 31 producers commenced their operation during the history matched production period. Table 6-8 highlights the field operation conditions at the beginning of year 2006.

Table 6-8: January 2006 H-field operating conditions

Parameter	Value
Oil production rate	37.6 M Sm ³ /day
Water production rate	17.86 M Sm ³ / day
Liquid production rate	49.35 M Sm ³ / day
Gas injection rate	7.2 MM Sm ³ / day
Gas lift rate	1 MM Sm ³ /day/well

The production constraints of the H-Field simulation model change depending on the production phase as follows:

Early Phase - I (2006 - 2010):

- Field oil production rate limit of 37,600 Sm³/day.
- Field water production rate limit of 17,860 Sm³/day.
- Field liquid production rate limit of 49,350 Sm³/day.
- Field gas production rate limit of 1 MM Sm³/day until 2007 when a processing plant upgrade increases the gas production rate limit to 5.3 MM Sm³/day.
- Field water injection rate limit of 4,000 Sm³/day.
- Field gas injection rate limit of 11 MM Sm³/day.
- Planned Maintenance shut downs.

Late Phase - I (2011 - 2013):

- The field water injection rate is increased from 4,000 to 15,000 Sm³/day.

Phase - II (2013 - 2030):

- The field water injection rate is reduced to 8,000 Sm³/day.
- The injection well constraints during these phases were adjusted accordingly.

All the producing wells had a BHP limit of 120 bar, a THP limit of 10 bar and a gas production rate limit of 0.5 MM Sm³/day.

All wells completed during the history matched period (2003-2005) carried their production rates constraint into the prediction period. New wells completed during the prediction period had an initial production rate of 5,000 Sm³/day which was then allowed to decline.

A sector of the full field, simulation model containing two producers was developed for this study. The sector model is located at the far north-east portion of the field where drilling of new multi-lateral wells was planned (Figure 6-22). The sector model runs under fluid influx rather than pressure influx to allow the injected gas to flow from the main model into the sector model (no injectors were included in the sector model).

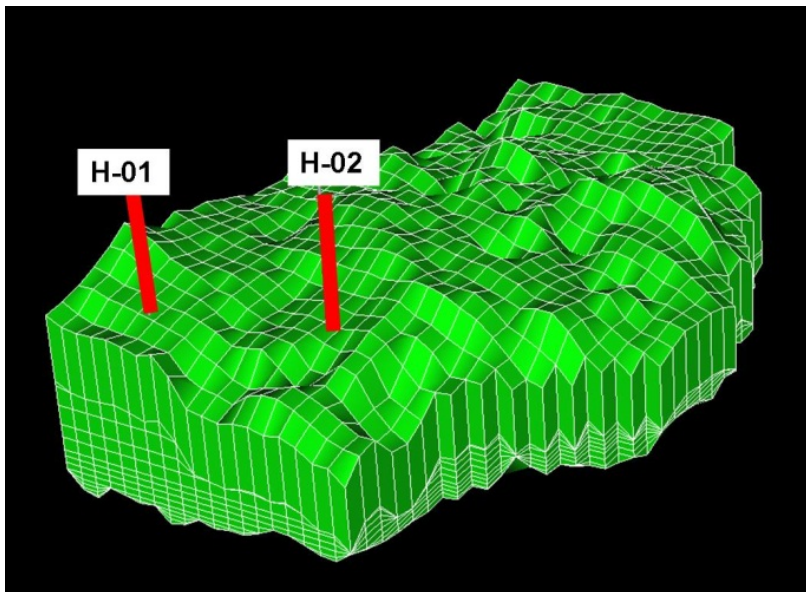


Figure 6-22: The H-Field Sector model

The selected sector model contained 19.84 MM Sm³ Oil in Place (OIP). The recovery factor achieved in this sector model via the H-01 and H-02 wells under the initial constraints for 30 years is 64.3%. The H-02 well, which is close to the reservoir boundary, was chosen by the operator for this study. H-02 is a dual-lateral production well. Lateral-1 (L-1) contained 33 segments extending over length of 1,657 meters while Lateral-2 (L-2) contained 30 segments extending over 1,484 meters (Figure 6-23). The completion zone was drilled with an 8.5 inch diameter bit and completed with a 6-inch ID production casing. A 7-inch tubing was installed above the completion. The

reservoir simulator supplied by the operator employed a cased hole completion without annular flow (i.e. the fluid flows from the grid block directly into the inner casing section).

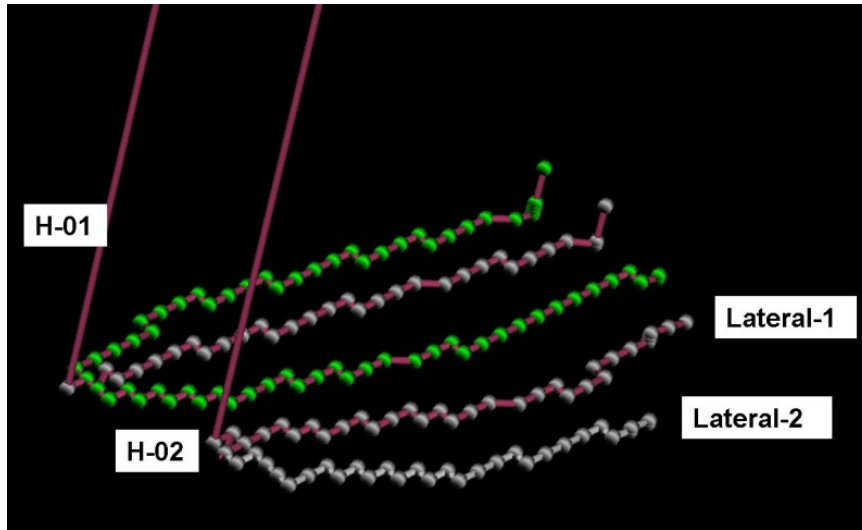


Figure 6-23: The H-02 dual-lateral well selected for this study

Initial study of this well showed that a reduced gas production rate limit of 0.2 MM Sm³/day rather than the planned, field limit of 0.5 MM Sm³/day gave an accelerated oil recovery during the first ten years of production (Figure 6-24).

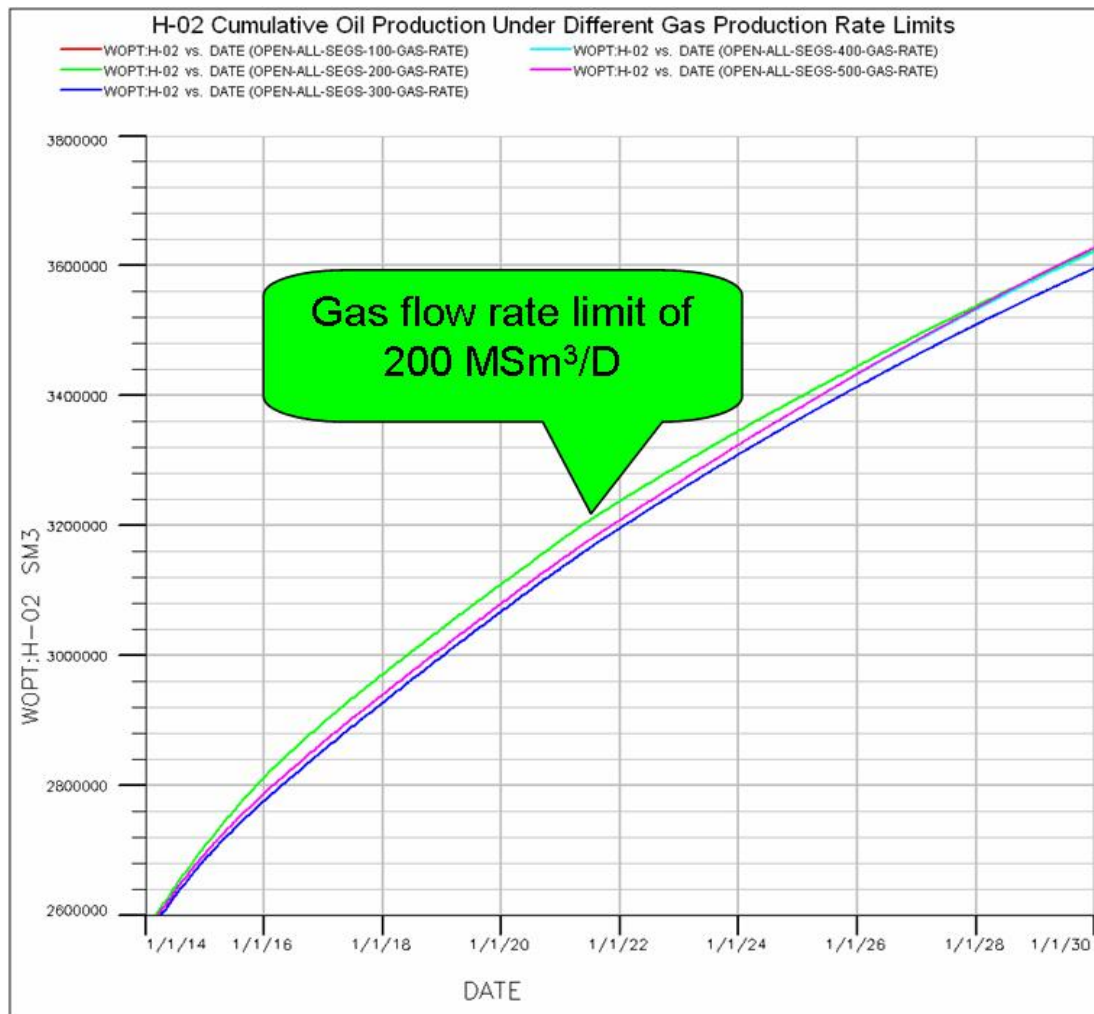


Figure 6-24: Reduced gas flow rate limit increases cumulative oil recovery

The initial H-02 case had the following characteristics:

- All well segments are connected to the reservoir grid blocks.
- The oil production rate of L-2 is less than that of L-1 due to L-1's greater length which resulted in a greater PI.
- Gas breakthrough occurs in L-2 first due to its close proximity to the reservoir boundary, creating a higher drawdown compared to L-1.
- The cumulative H-02 oil production was 3.623 MM Sm³.

6.4.6 *Communication between the Laterals*

Interference between laterals is a common completion problem with multilateral wells. This is especially true when the laterals have a short separation distance. The H-Field has high reservoir permeability and the gas cap is in close proximity to the laterals. These factors may complicate the choking operation of the ICVs. The restriction of one

of the lateral's production rate at the onset of gas breakthrough was found to cause the gas to flow rapidly through the high permeability reservoir to the other lateral.

An interference (or communication) test was therefore conducted to identify how many segments should be closed along each lateral to provide adequate isolation between the laterals. A "trial and error" study was performed in which different segments near the mouth of both laterals were shut in. It should be noted here that the isolation of a segment consistently result in a lower cumulative oil production from the well. This highlights the value of increased well/reservoir contact in the exploitation of this field (and supports its development by long horizontal and multilateral wells).

The maximum cumulative production was achieved when one segment in L-1 and 3 segments from L-2 were isolated (Figure 6-25). This provides a distance of 100 meters between the laterals. The cumulative oil production from the H-02 well reduced to 3.532 MM Sm³ (a reduction of 91 M Sm³) as a result of the reduced reservoir contact (Figure 6-26).

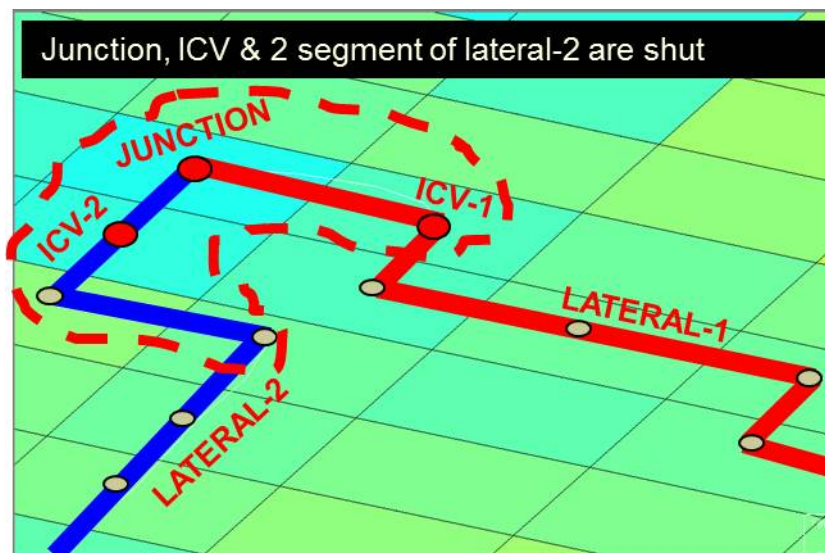


Figure 6-25: Isolating Segments in both laterals to reduce communication

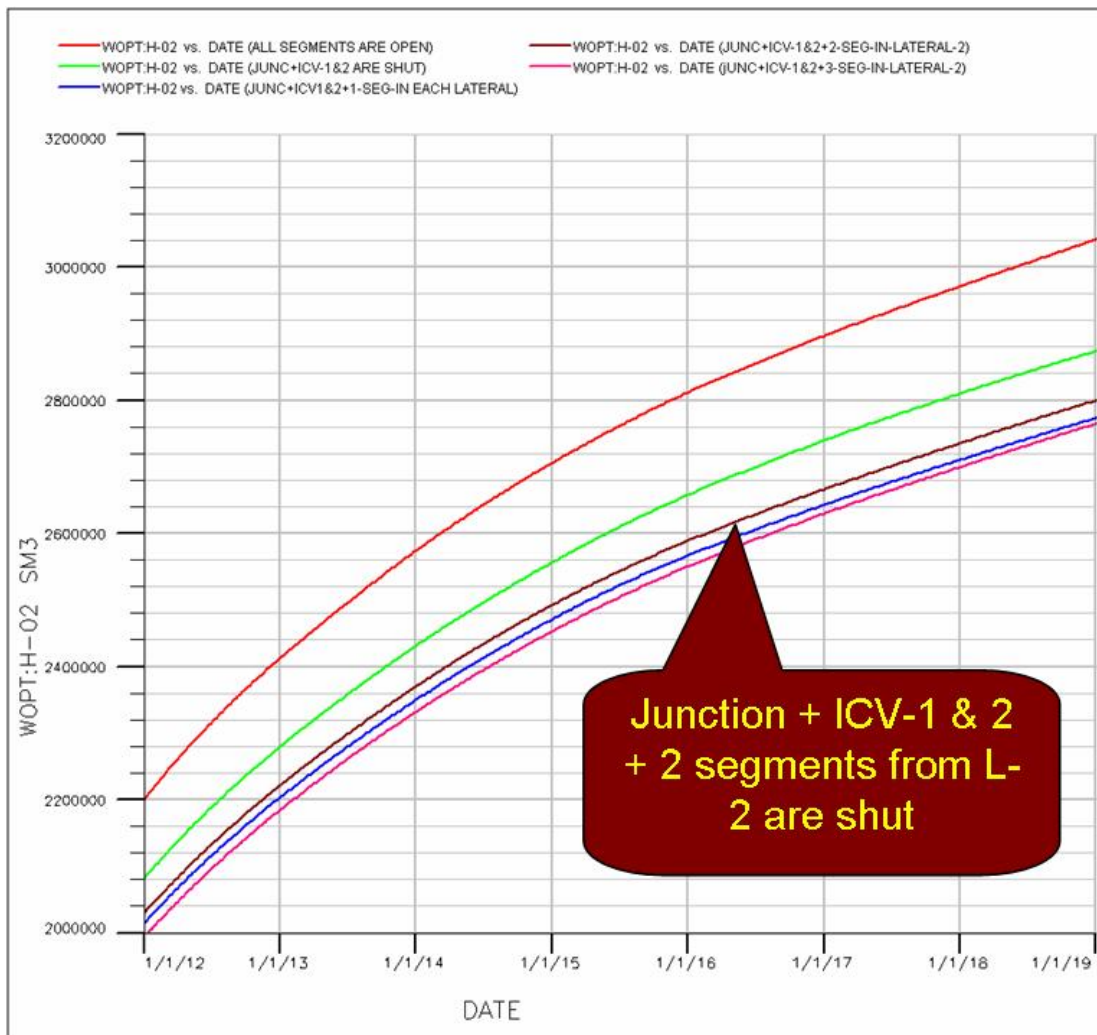


Figure 6-26: Lateral communication testing

6.4.7 *Lateral Placement Optimisation*

The lateral's elevation from the OWC or the reservoir's bottom shale layer is the second most important factor which influences the well's cumulative oil production. Similar to the other wells in the field, both laterals of the H-02 well were located at the field's standard elevation. The distance between the OWC (or bottom of the reservoir) and the well was only 3.5 meters at the well's heel section and 11 meters at its toe section (Figure 6-27).

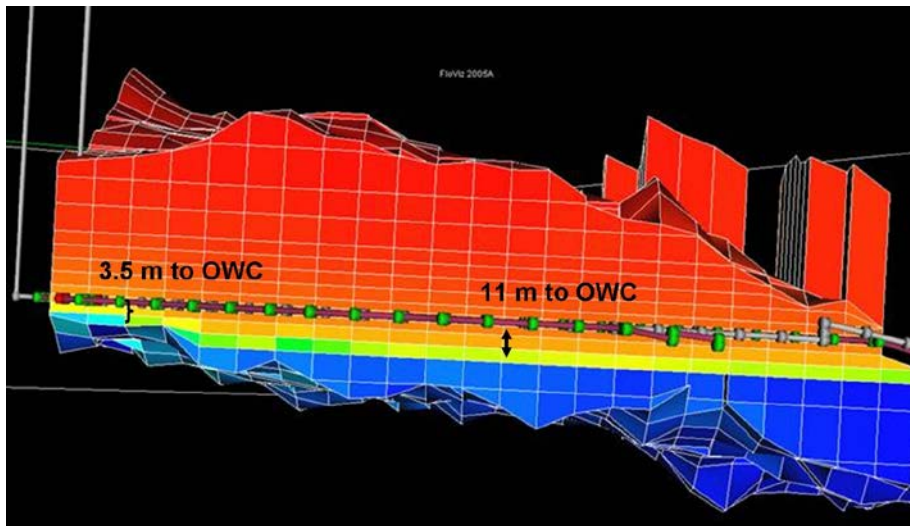


Figure 6-27: Distance between H-02 laterals and OWC (or bottom of the reservoir)

The influence of the lateral elevation on the well's performance was analysed for L-1 rather than L -2 since:

- Gas breakthrough occurs first in L-2, hence any upward displacement of the lateral would accelerate the occurrence of gas breakthrough. Any downward movement of L-2 is expected to increase the water production from the well significantly; since it is already producing at 39 % water cut, almost double the (21 %) water cut of L-1.
- Any change in L-1 elevation depth was found to reduce the cumulative oil production from the well (Figure 6-28). Upward movement of the lateral resulted in increased cumulative gas production (Figure 6-29) while downward movement resulted in increased cumulative water production (Figure 6-30).

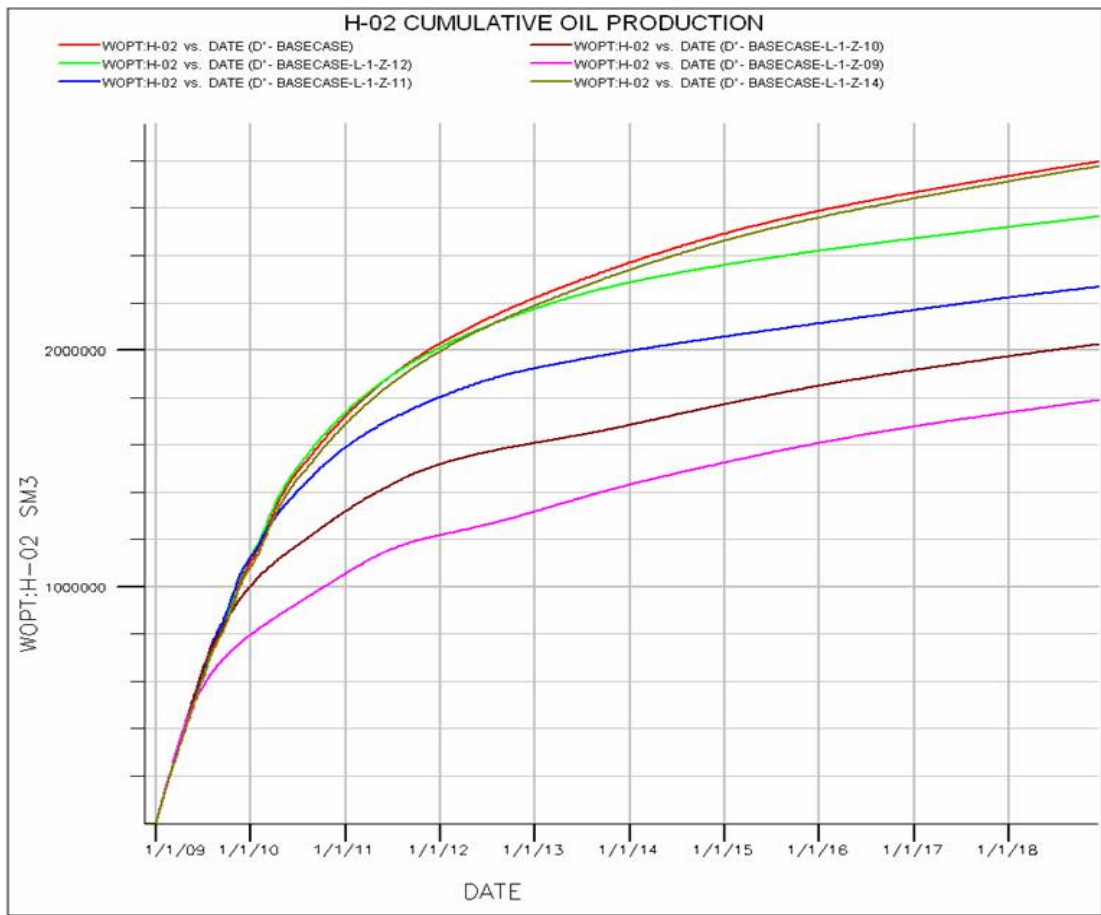


Figure 6-28: Effect of lateral elevation on cumulative oil production

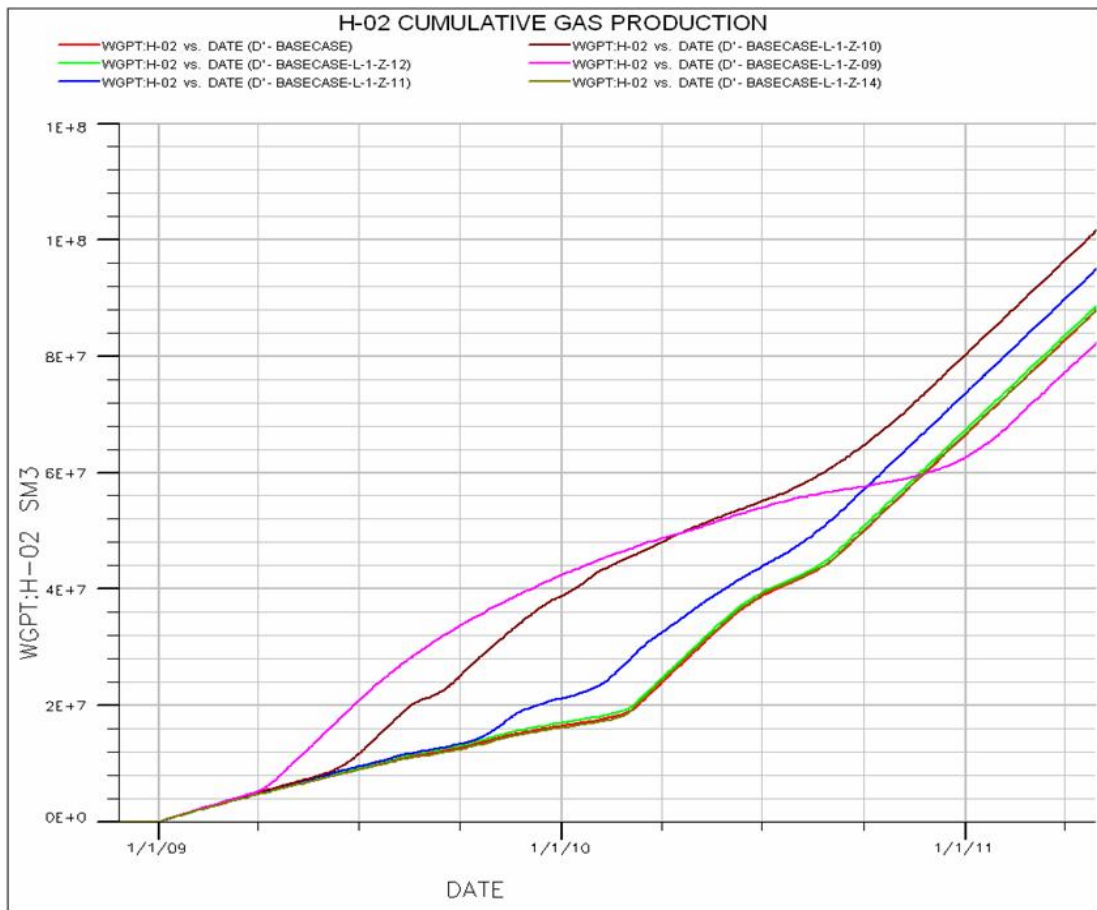


Figure 6-29: Effect of lateral elevation on cumulative gas production

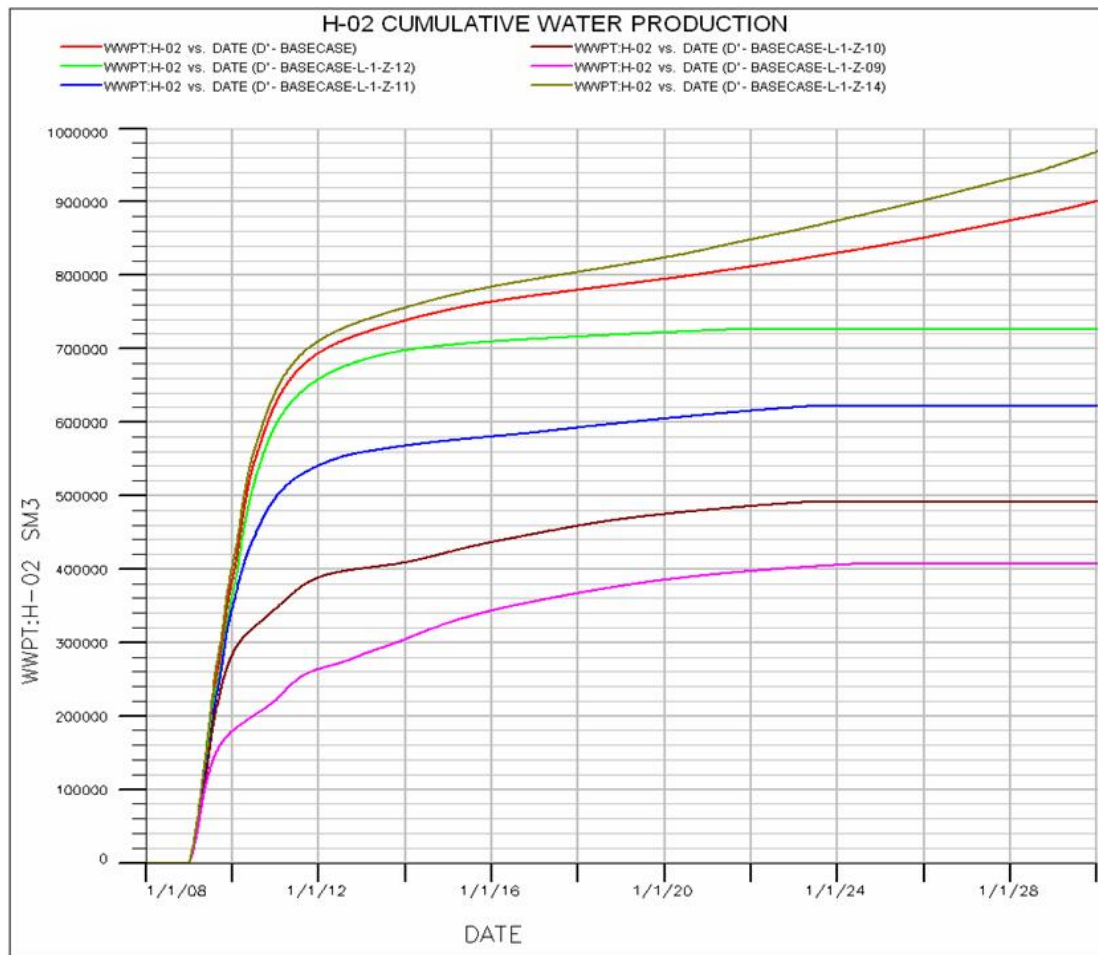


Figure 6-30: Effect of lateral elevation on cumulative water production

6.4.8 Inflow Control Devices (ICDs) Design

The objectives of the ICDs installation in the H-02 well are to:

- Equalise the fluid influx into each lateral.
- Equalise the gas flood front's movement towards the well to enhance the reservoir sweep efficiency.
- Minimise excessive annular flow resulting from a SAS or an ICD completion without AFIs.
- Increase the cumulative oil recovery from the well.

(i) Analysis of wellbore influx imbalance

The fluid influx to the wellbore is affected by two factors: the HTE and the VPE. The HTE is caused by the frictional pressure drop along the length of the lateral's production conduit. It can be significant when a heavy, viscous fluid flows from the toe to the heel of a long lateral, such as those employed by the H-02 well. The VPE is caused, in this case, by the variable permeability distribution along each lateral. The combination of

these two effects resulted in both high annular flow from the toe to the heel section of the well and an unbalanced fluid influx to the wellbore when a SAS completion was applied in the well model (Figure 6-31, Figure 6-32 and Figure 6-33).

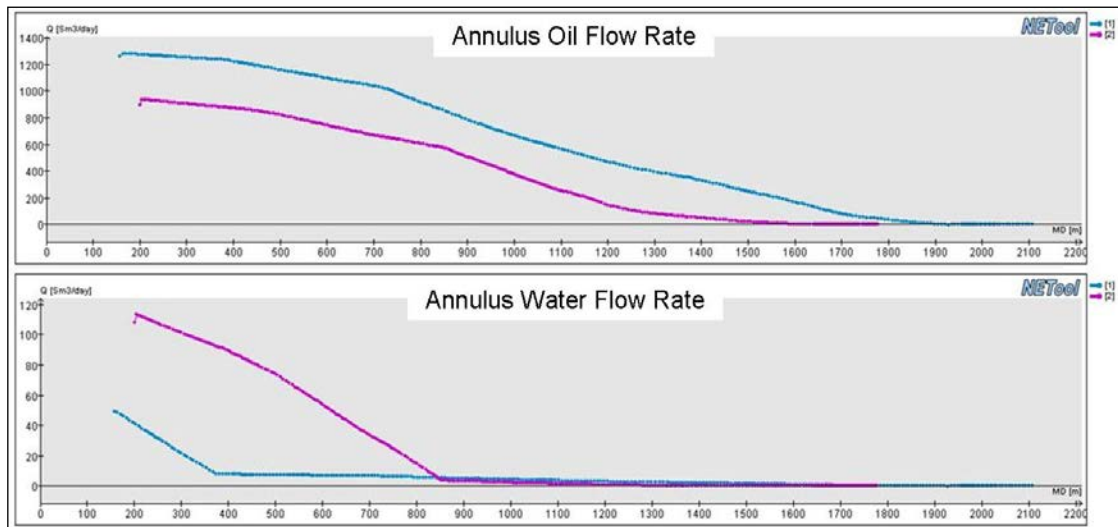


Figure 6-31: Annular flow from toe to heel section when SAS completion is installed (1 is L-1 and 2 is L-2)

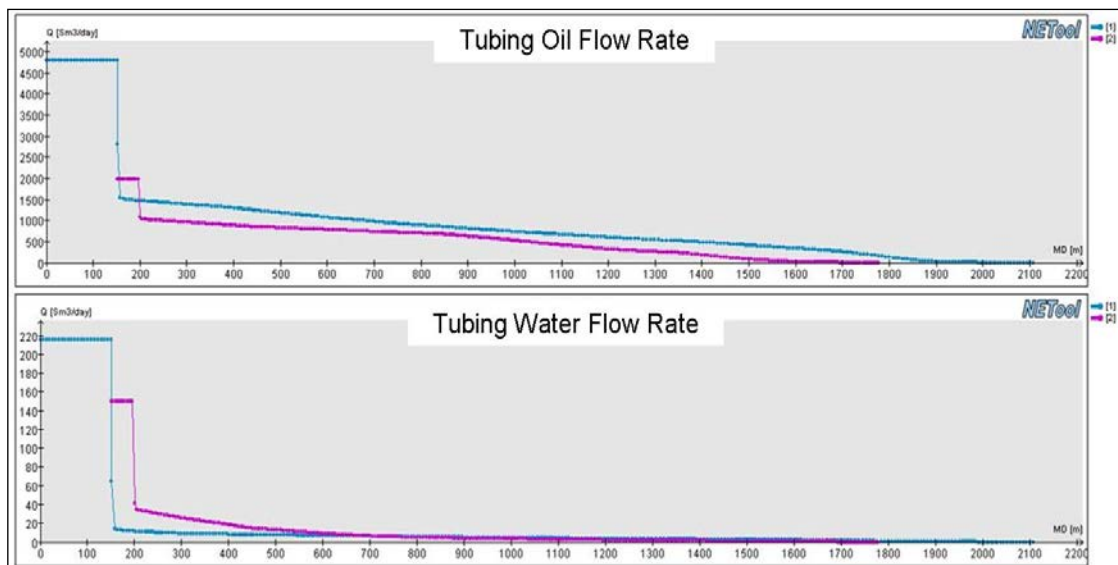


Figure 6-32: Tubing flow from toe to heel section when SAS completion is installed (1 is L-1 and 2 is L-2)

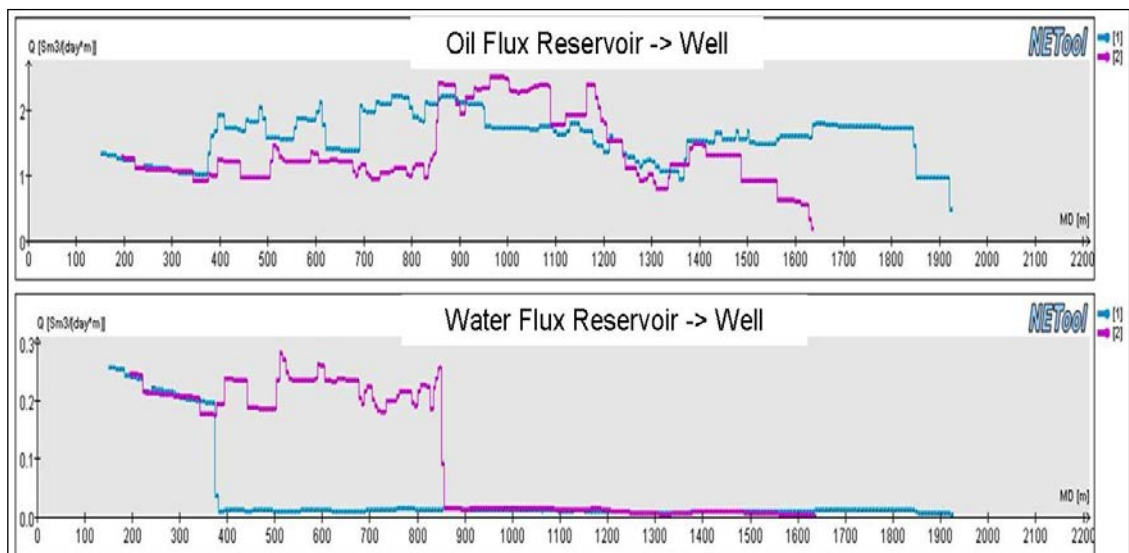


Figure 6-33: Unbalanced influx into both laterals when SAS completion is installed (1 is L-1 and 2 is L-2)

(ii) Identification of optimum ICD restriction

NETool™ is a well completion modelling tool which has the ability to model the performance of an ICD completion as a snapshot in time. The operator's current practice for completing H-field wells is to use constant strength, 3.2 bar channel-type, ICDs. This choking factor of this ICD is the greatest available. As described earlier, AFIs were only installed by the operator when shale layers are encountered. This philosophy will be examined and compared to the well completion with low strength (0.2 bar) ICDs or a SAS completion.

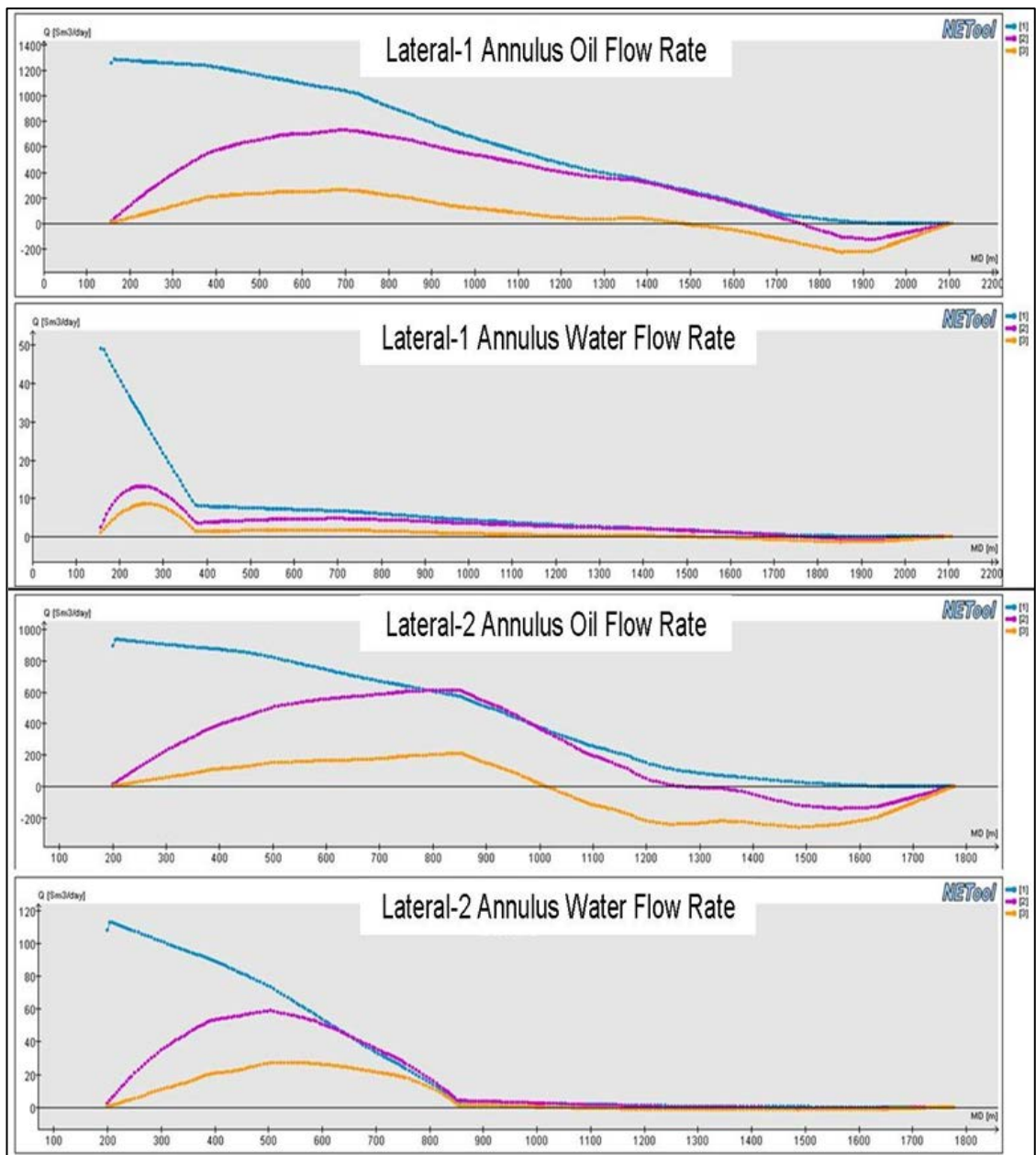


Figure 6-34: Comparison of annular flow when SAS, 0.2 bar and 3.2 bar ICD completions are employed (1 is SAS, 2 is 0.2 bar and 3 is 3.2 bar ICDs)

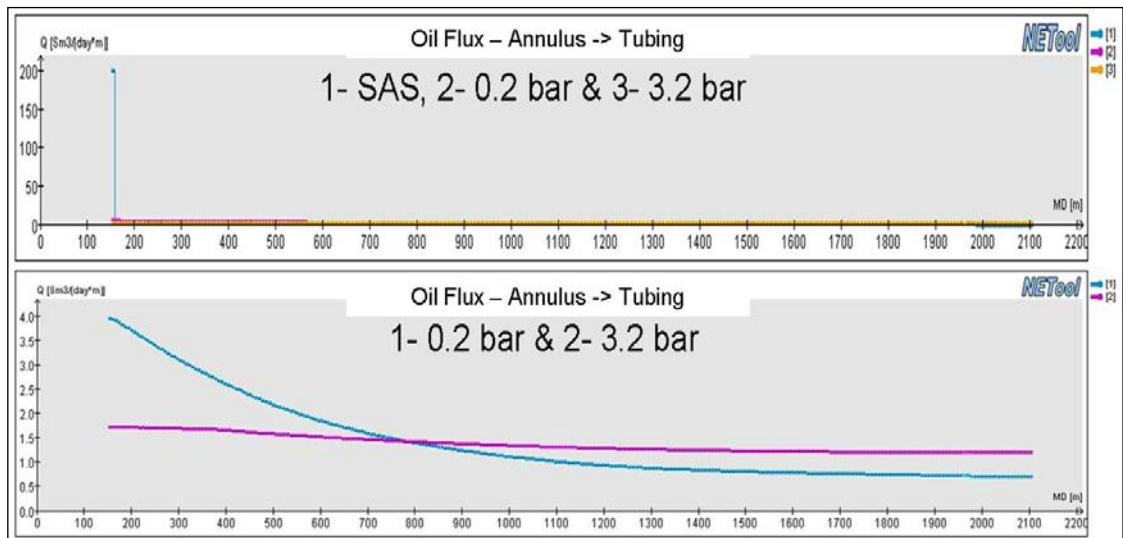


Figure 6-35: Comparison of fluid influx into the tubing when SAS, 0.2 bar and 3.2 bar ICD completions are employed

Figure 6-34 and Figure 6-35 clearly shows the effect of the 3.2 bar ICD completion. It reduces the annular flow and improves the equalisation of fluid influx into the tubing of both laterals. However, Figure 6-34 and Figure 6-36 indicate that the fluid influx from the reservoir to the wellbore is not equalised due to the lack of AFIs between the high and low productivity intervals, despite the reduced contribution from the heel section of each lateral.

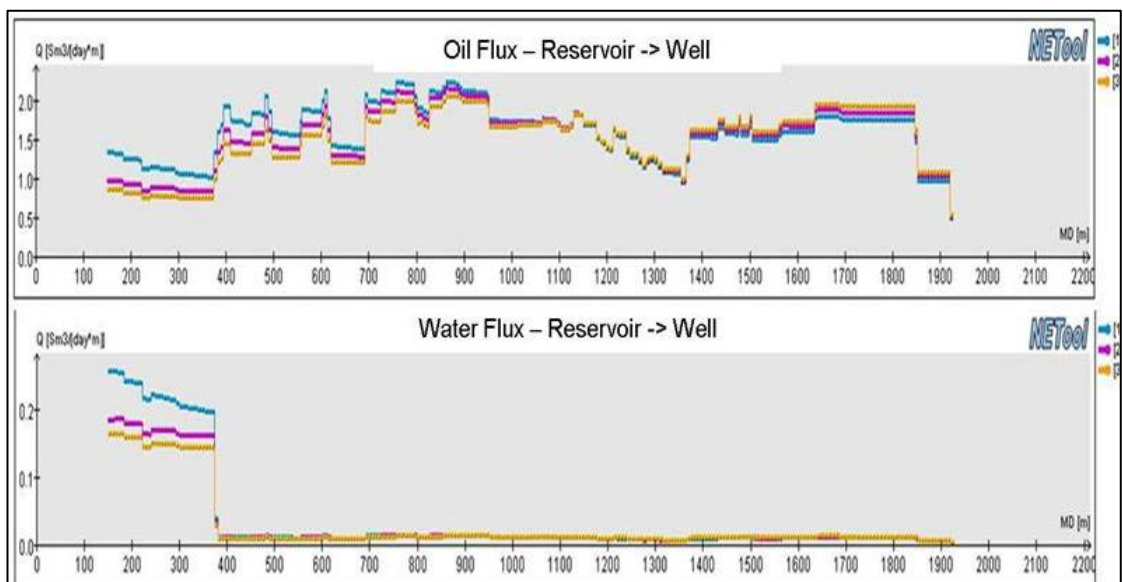


Figure 6-36: Comparison of fluid influx into the wellbore when SAS, 0.2 bar and 3.2 bar ICD completions are employed without AFIs (1 is SAS, 2 is 0.2 bar and 3 is 3.2 bar)

The application of AFI in the form of a gravel pack or collapsed formation sands around the wellbore eliminates the annular flow and balances the formation contribution (Figure 6-37). Furthermore, the 3.2 bar ICD completion, when combined with AFIs at every ICD joint, gives the best equalisation of fluid influx to the wellbore compared to the lower (1.6, 0.8, 0.4, or 0.2 bar) strength ICDs (Figure 6-38).

The cumulative oil produced from the 3.2 bar (strong) ICD completion, as calculated by Eclipse™ 100 reservoir simulator, also reduces (Figure 6-39); even though an AFI is assumed to be present at every ICD joint. This reduced production is attributed to the increased water production from the toe section of the well due to the equalised contribution (Figure 6-41 and Figure 6-42); while an increased drawdown created by the 3.2 bar ICD completion causes an earlier gas breakthrough with higher concentration (Figure 6-40).

A 3.2 bar, constant strength ICD completion thus does not appear to be optimum completion.

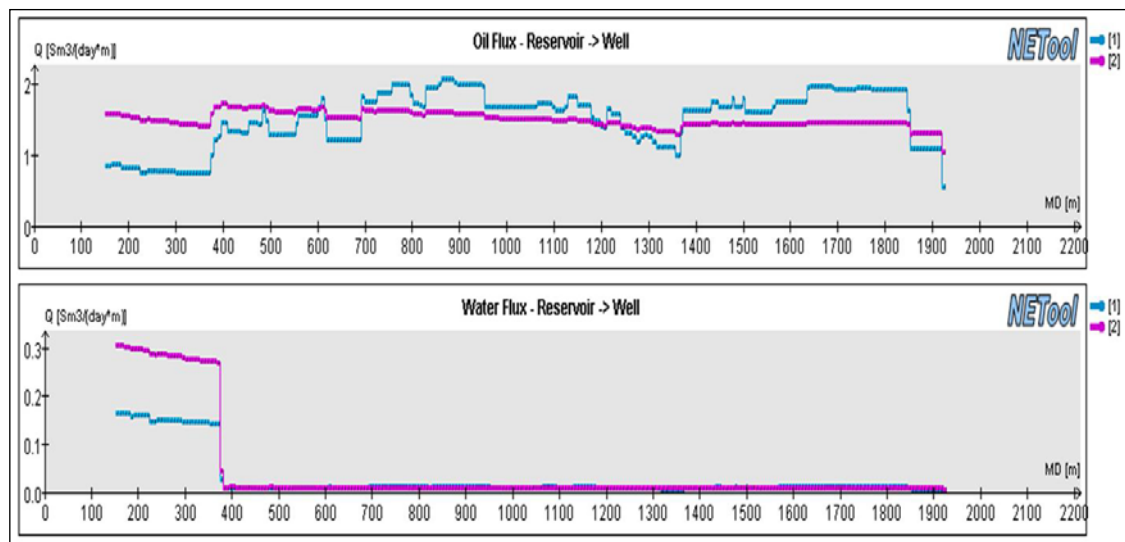


Figure 6-37: Fluid influx to the wellbore when formation sands collapses around the 3.2 bar ICD completion (1 is open annulus and 2 is collapsed annulus)

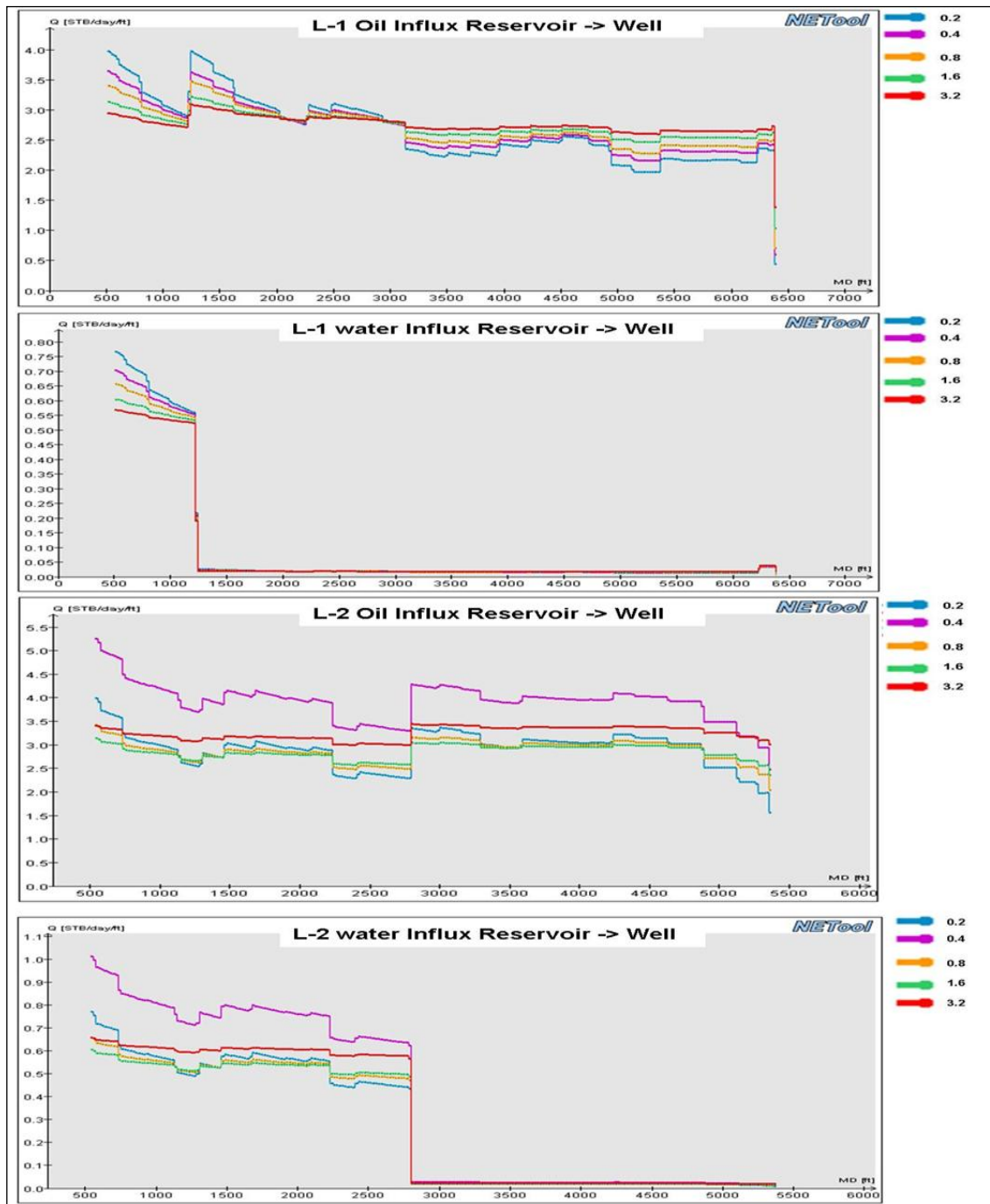


Figure 6-38: Oil and water influx imbalance reduction when 3.2 bar ICD is applied in both laterals

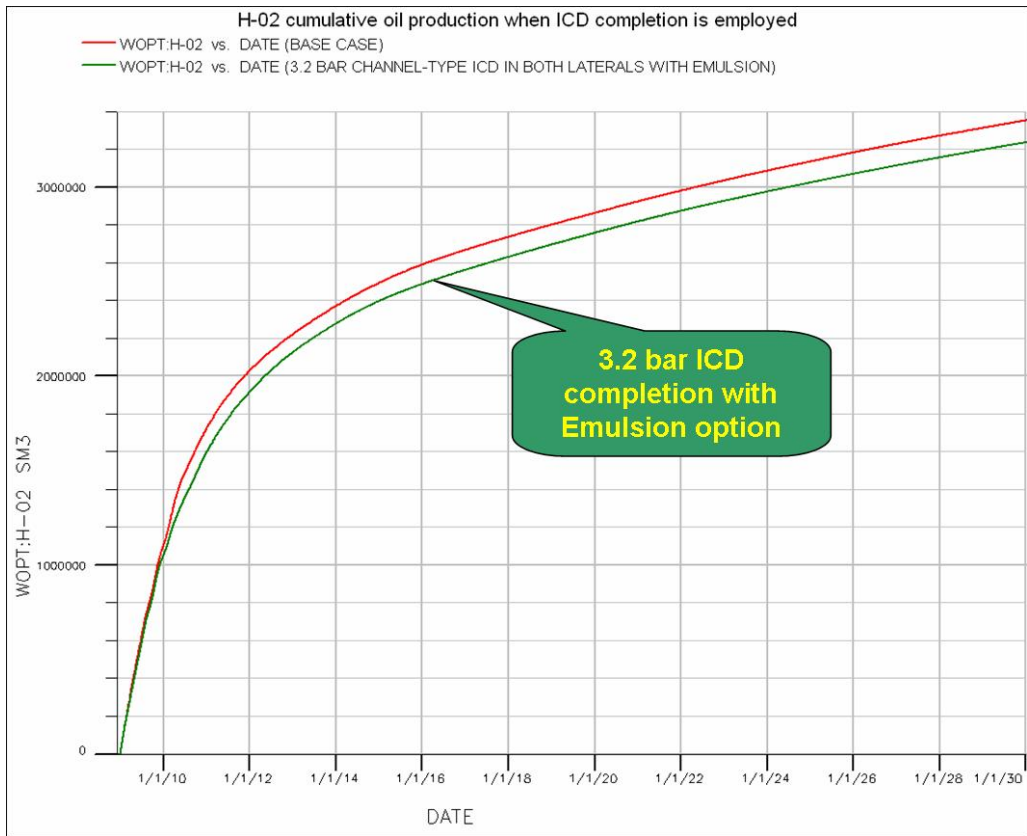


Figure 6-39: H-02 well performance with 3.2 “standard” ICD completion

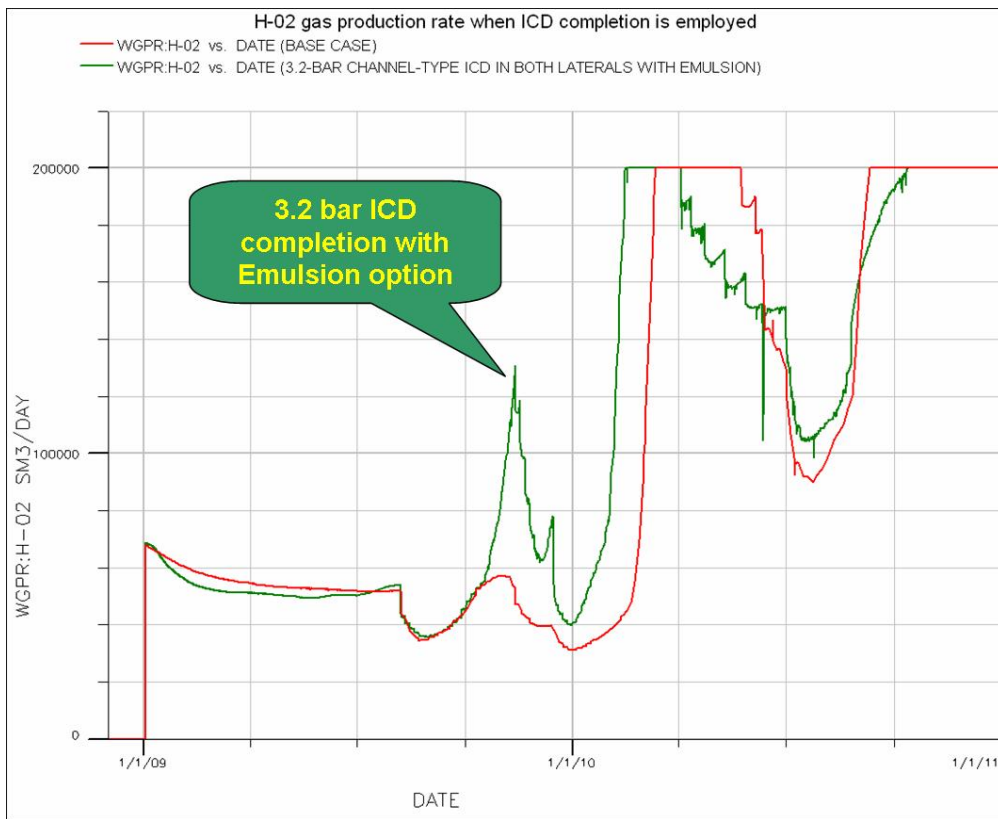


Figure 6-40: H-02 well gas production rate when a 3.2 bar ICD completion is applied

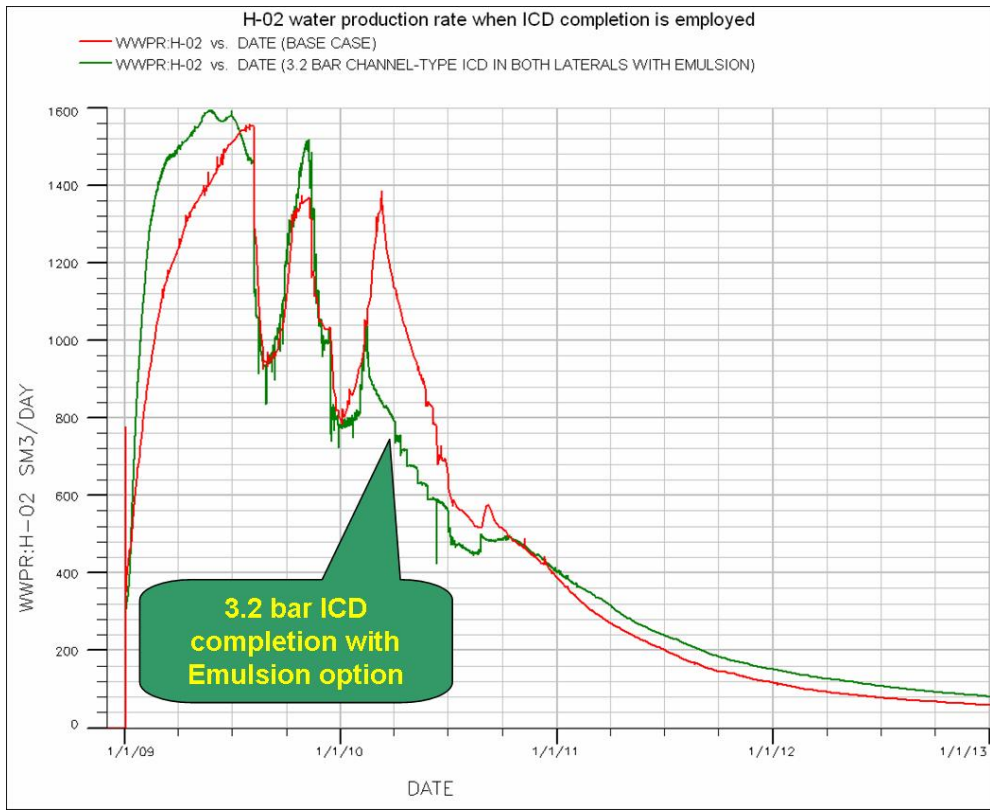


Figure 6-41: H-02 well water production rate when a 3.2 bar ICD completion is applied

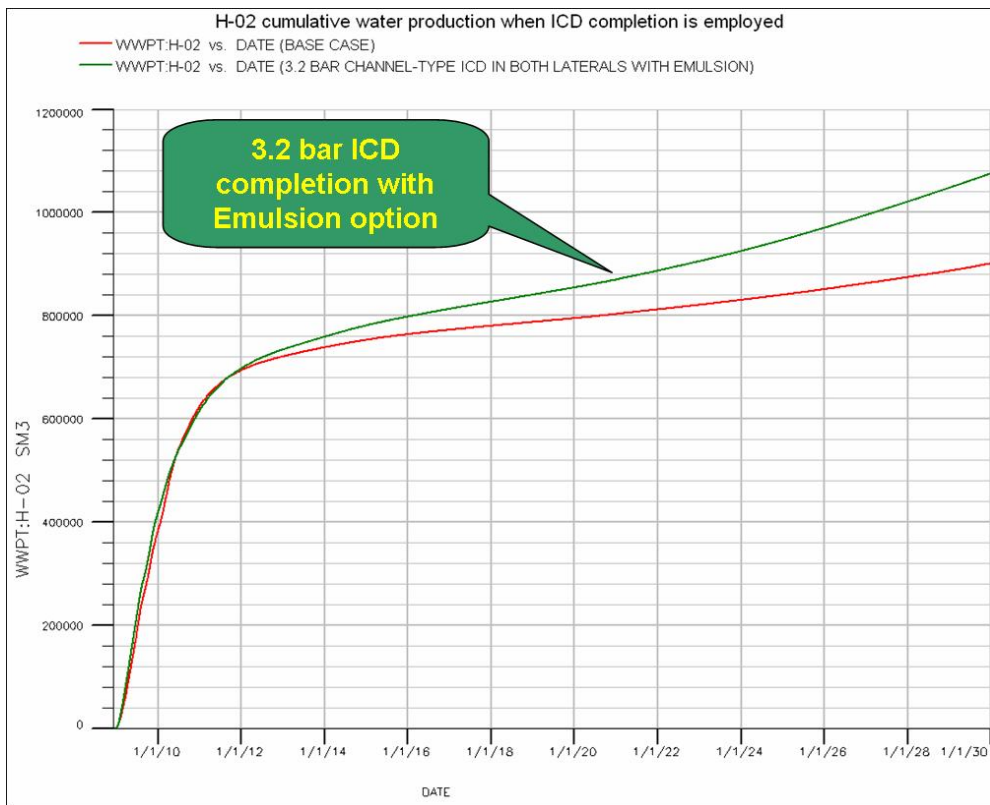


Figure 6-42: H-02 well cumulative water production when a 3.2 bar ICD completion is applied

An optimisation study to evaluate the role of ICD strength along each lateral and AFI placement for enhancing the completion's performance was therefore initiated. A comparison of the available ICD types was also conducted at the same time so as to find the best ICD type to be installed.

(iii) Optimisation of the ICD completion design

The productivity index of each lateral completion grid block can be retrieved from the reservoir simulation model. However, these values are usually overestimated and need to be adjusted using appropriate pseudo-skin values [239, 240]. An alternative approach is to consider each reservoir grid-block a segment and record their permeability to be used along with the other reservoir and wellbore parameters as input to the well performance modelling process (as proposed in Chapter 3). This enabled the calculation of each grid-block's productivity index and flow contribution. The grid-block PI values were then used to calculate the required pressure drop across each ICD joint to achieve an optimum equalisation of the fluid influx into each lateral.

The laterals differ in their flow contribution to the well's overall flow rate. ICVs installed at the mouth of the lateral to control the laterals contribution. The ICD completion design approach described in Section 4.5.3 step number 1 was therefore adopted to identify the optimum ICD with constant restriction size for each lateral.

The resulting design indicated that different ICD restriction sizes should be installed for each lateral. A channel-type ICD with constant restriction size (strength) of 0.8 bar was identified for L-1 and 1.6 bar for L-2. It should be noted that the difference in equalisation between the constant and variable strength ICD completions is not significant for this case (Figure 6-43 and Figure 6-44).

An increased cumulative oil production can be achieved from the well by applying the proposed completion as indicated in Figure 6-45.

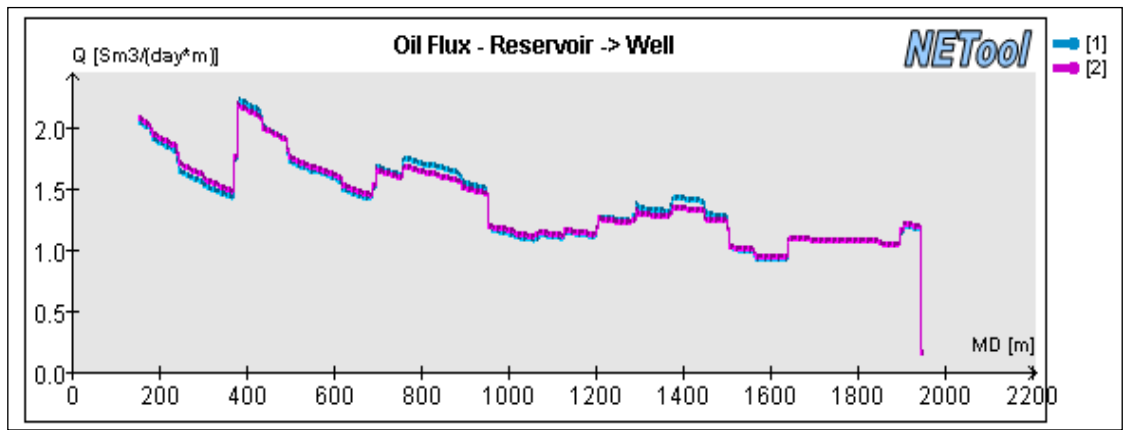


Figure 6-43: Comparison of variable (1) and 0.8 bar constant (2) ICD strength distribution effect on fluid influx into L-1

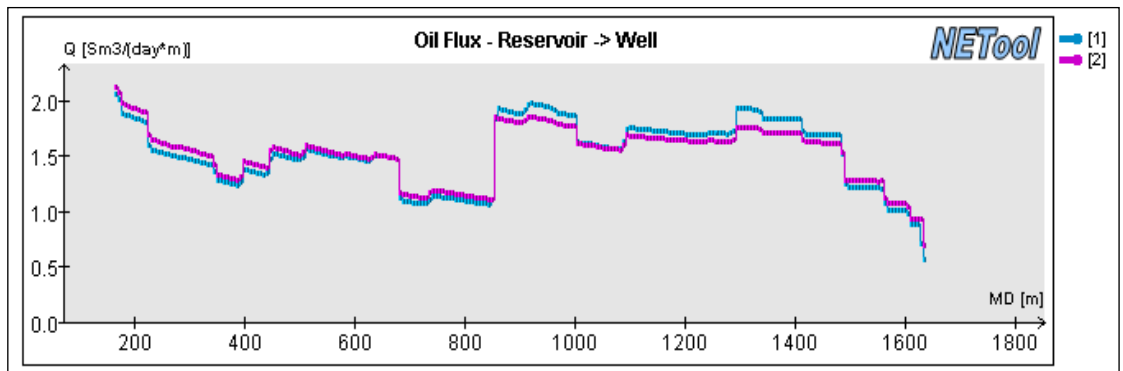


Figure 6-44: Comparison of Variable (1) and 1.6 bar constant (2) ICD strength distribution effect on fluid influx into L-2



Figure 6-45: Comparison of the H-02 ICD and the base case completions

6.4.9 Autonomous Inflow Control Devices (AICDs) design

Autonomous ICDs are newly developed "reactive" flow elements which can be integrated with the regular ICDs. A complete description of the available AICD types can be found in Section 2.9. The AICD installation objective in the H-02 well is to restrict the excess gas production and its design for each lateral starts with the optimum ICD completion as the initial AICD restriction size. Since the channel-type ICD was chosen for this completion, it can be combined with an on-off element triggered at different GOR levels equivalent to a flapper device as provided in practice. Despite this, the application of a ball type ICD will be evaluated as well. The latter can be designed to offer gradual reduction gas production through gradual reduction in the nozzle flow area at different GOR levels

(i) Identification of appropriate AICD design

Ball Type AICD Application

The initial area available for flow at an ICD joint is reduced by 20 % at every triggering GOR value. The effective total flow area of the ICD is thus separated into 6 equally sized nozzles. This type of response could be provided if homogenous or stratified liquid-and-gas flow is present within the device. Five balls of constant density (stratified flow case) or of varying density but constant size (homogenous flow case) could be used to progressively block the nozzles.

Table 6-9 lists typical nozzle (orifice) choking areas at the specified GOR triggering values. The GOR trigger value range is 50 – 250 Sm³/Sm³. The performance of a range of orifice sizes (from 6 x 4 mm orifices/ICD joint to 6 x 1.6 mm orifices/ICD joint) was examined. This covers the range currently offered by one AICD provider (Easywell Solutions). The optimum orifice diameter was found to be 1.6 mm (Figure 6-46).

Table 6-9: AICD choke areas and trigger GOR values for 1.6 mm orifices

TRIGGER VALUE	SEGMENT 128 AREA (m ²)	SEGMENT 129 AREA (m ²)
SGOR < 50	0.0000362	0.0000603
SGOR > 50	0.0000302	0.0000503
SGOR > 100	0.0000241	0.0000402
SGOR > 150	0.0000181	0.0000302
SGOR > 200	0.0000121	0.0000201
SGOR > 250	0.0000060	0.0000101
SGOR is Segment Gas Oil Ratio		

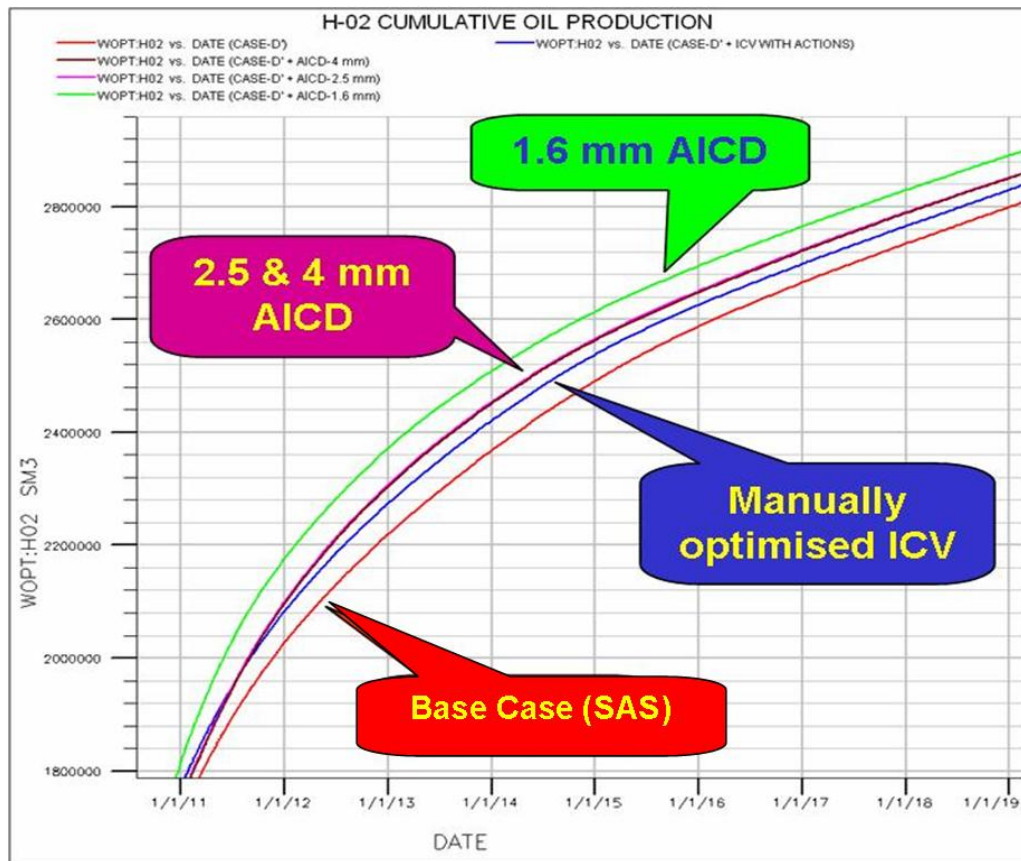


Figure 6-46: AICD completion performance for the H-02 well

The effect of varying the GOR trigger value range was then studied for the optimum AICD (6 x 1.6 mm orifices). The final choke trigger GOR values were initially selected to maintain each segment's GOR at approximately 50% of the lowest segment GOR within the lateral after gas breakthrough period (Figure 6-47 and Figure 6-48). I.e. at 50% of the GOR value level that would have been experienced with SAS completion. Figure 6-47 indicates this value to be 250 Sm³/Sm³, resulting in the intermediate choke trigger values found in Table 6-9.



Figure 6-47: GOR performance of selected ICDs from well H-02, L-2 showing both high and low GOR segments

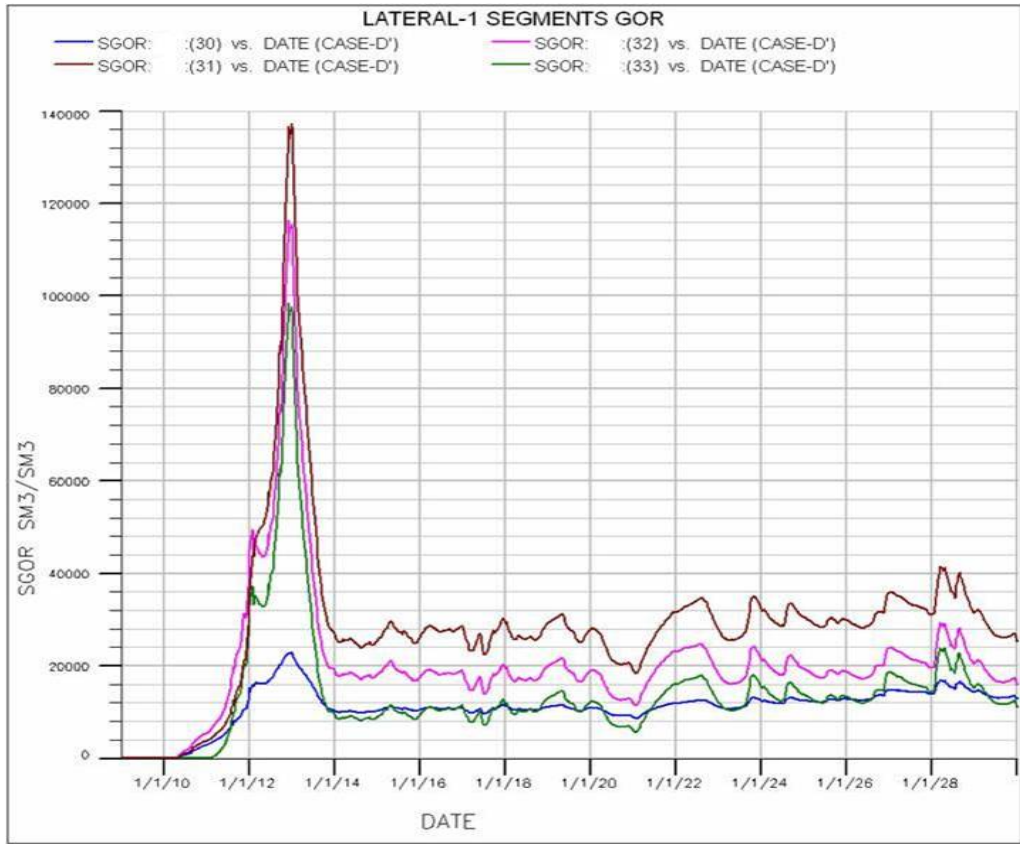


Figure 6-48: GOR performance of selected ICDs from well H-02, L-1 showing both high and low GOR segments

Flapper Type AICD Application

The initial flapper opening size which is shut-off when the triggering GOR value is reached was set at 1.6 mm/Nozzle/ICD joint. Complete, segment shut-off at a specified GOR value reduces the cumulative oil production (Figure 6-49 and Figure 6-50). These figures show that well production quickly completely stops once AICD action starts. This is due to the rapid movement of gas along the lateral as the segments close. A reversible AICD or an AICD with a by-pass nozzle may give a better performance.

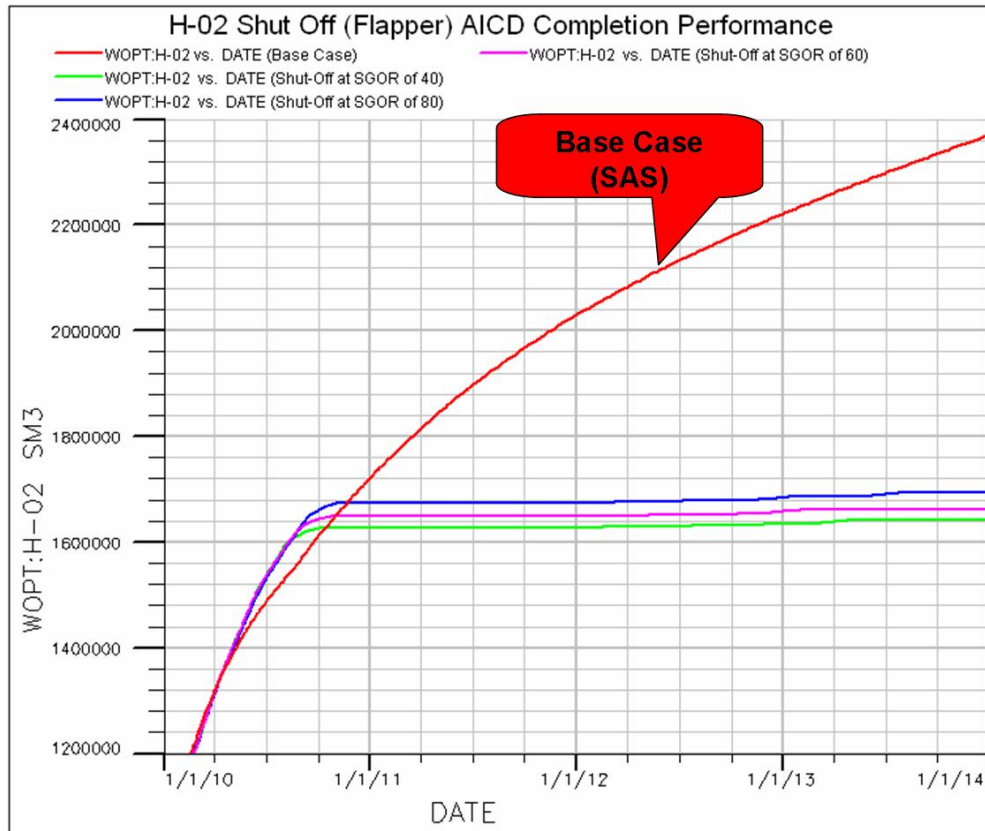


Figure 6-49: Well H-02 cumulative oil production when completed with an on-off (flapper) AICD

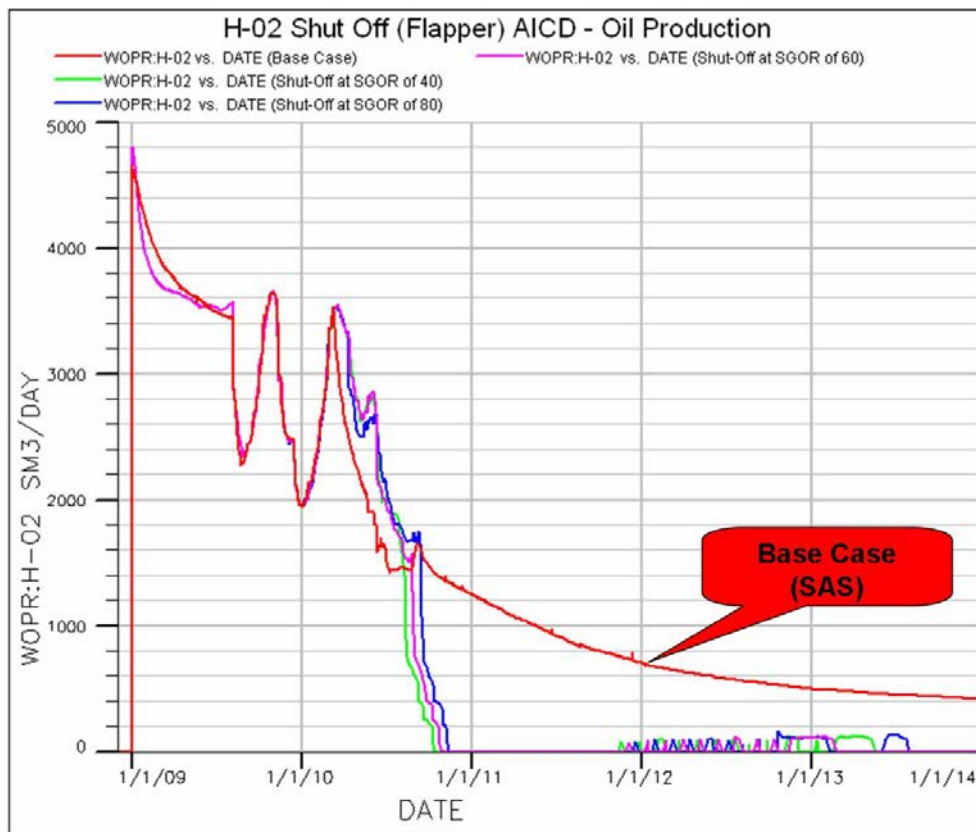


Figure 6-50: Well H-02 oil production rate when completed with an on-off (flapper) AICD

6.4.10 Comparison of Advanced Inflow Control Systems

A preliminary comparison of the different Advanced Completions applied in the H-02 well is shown in Figure 6-51.

The AICD technology gave the highest cumulative oil production through proper control of the gas production from both laterals.

The manually optimised ICV accelerated the oil production compared to the channel type ICD.

The channel type ICD application resulted in a higher cumulative oil production toward the end of the H-02 well life compared to the SAS completion (base case).

As stated earlier, optimisation techniques for these advanced completions are being developed and will be applied to properly quantify the value which can be gained from their application.

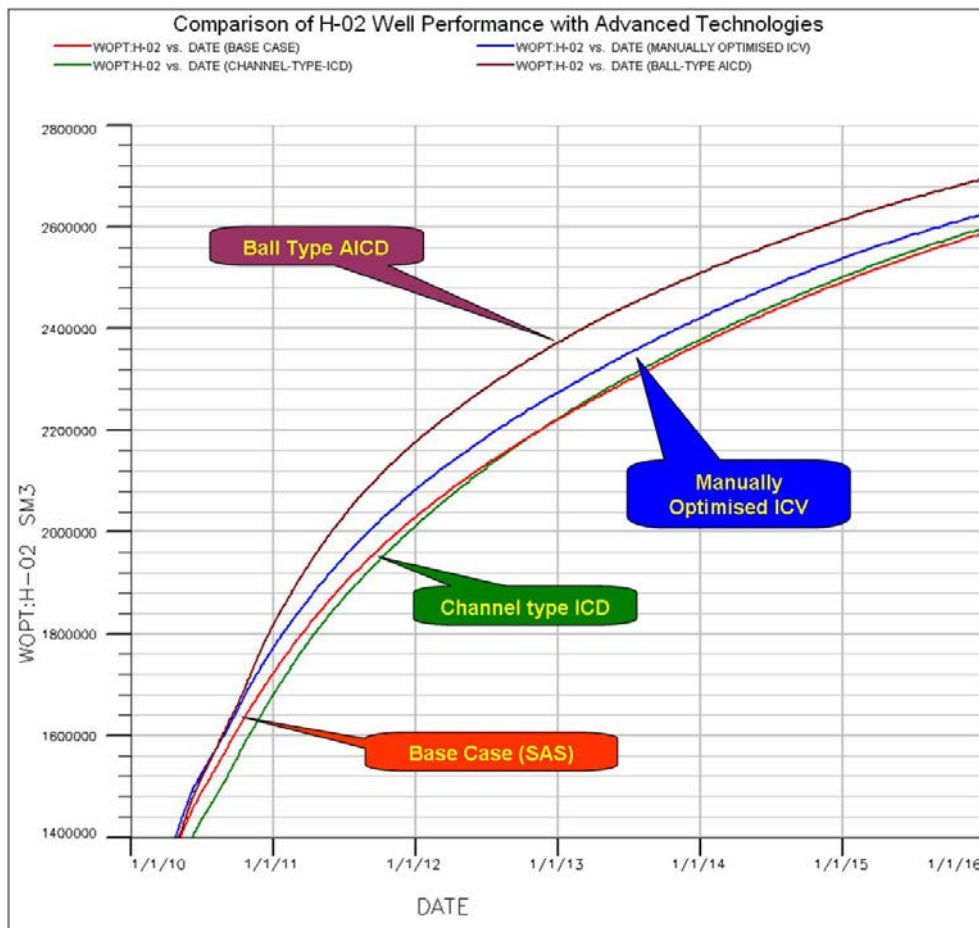


Figure 6-51: Comparison of well H-02 performance with advanced completions

6.5 C-Gas Field Case Study

6.5.1 Introduction

The C-field is a three-layer, stacked pay offshore gas field (Figure 6-52 241). The three sands vary in their rock properties and pressures (Table 6-10). All sands contain gas with the same properties (gas density of 0.08 lbm/ft³ and viscosity of 0.0122 cp at surface conditions). A water column exists at the crest of the upper layer, while edge gas/water contacts exist in the bottom two zones. The field's production constraints are

- Water/gas ratio of 100 stb/MMscf.
- Minimum production rate of 3 MMscf/day.
- BHP limit of 1,300 psi.

A reservoir-simulation model consisting of 42×225×30 gridblocks was used to identify the value derived from installation of ICV and (A)ICD completions in this field instead of a conventional completion. The ICV and (A)ICD completions were designed for a vertical producing well with commingled production from the three sands.

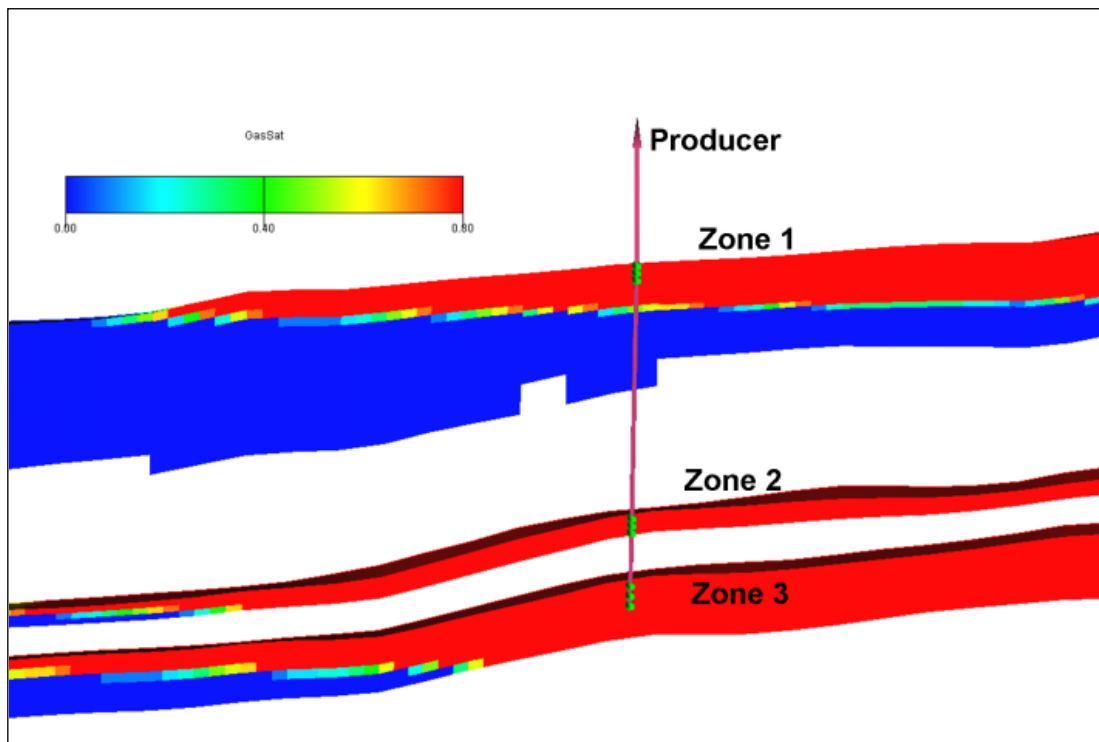


Figure 6-52: C-Gas field layers

Table 6-10: C-Gas field layer's properties

Sand	IGIP	Max. Gas Leg Thickness	Layer Pressure	Horizontal Permeability	Average Porosity
	(Bscf)	(ft)	(psi)	(md)	(%)
Upper Sand	32.8	197	2,894	950	23%
Middle Sand	32.9	65	3,322	600	23%
Lower Sand	36.2	190	3,405	50	15%
Total	101.9	-	-	-	-

6.5.2 Conventional Completion Performance

The conventional completion designs are not effective in this field. Commingled flow from the three zones results in high water production from the upper sand (Figure 6-53), early cessation of gas production (Figure 6-54) and gas crossflow between the zones (Figure 6-55). Selective (or alternate) production of each zone prevents crossflow between the layers and allows shutting off the water. However, the resulting outflow performance of the well was poor with only a low total gas recovery from the three layers being achieved (Figure 6-56 and Table 6-11).

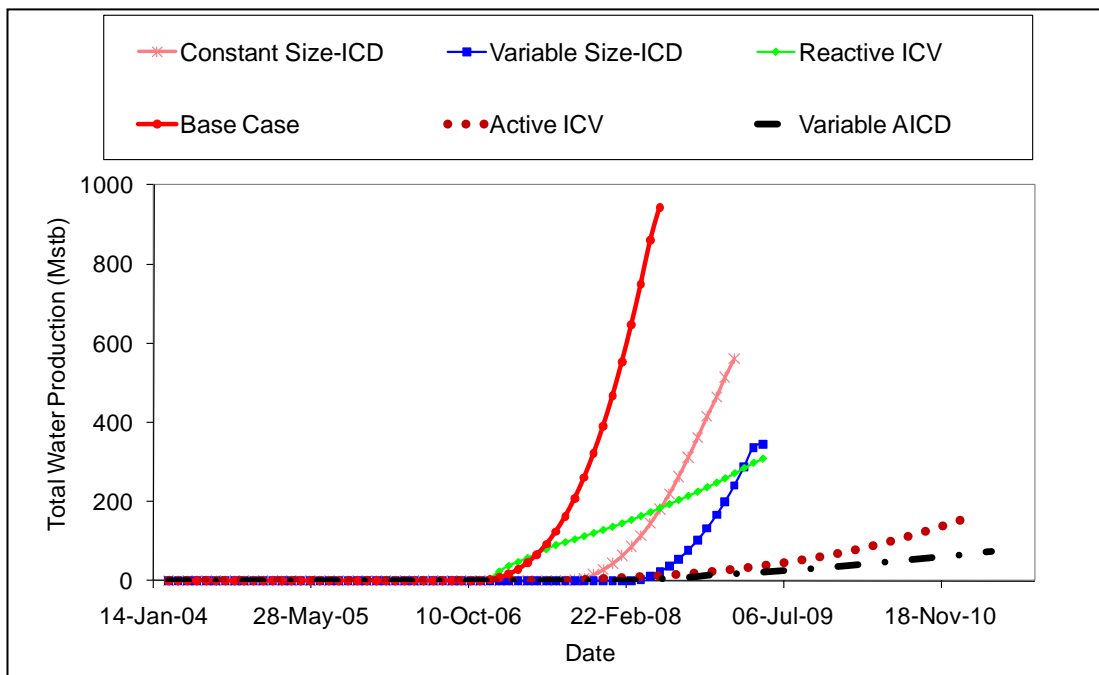


Figure 6-53: Total water production for all completions

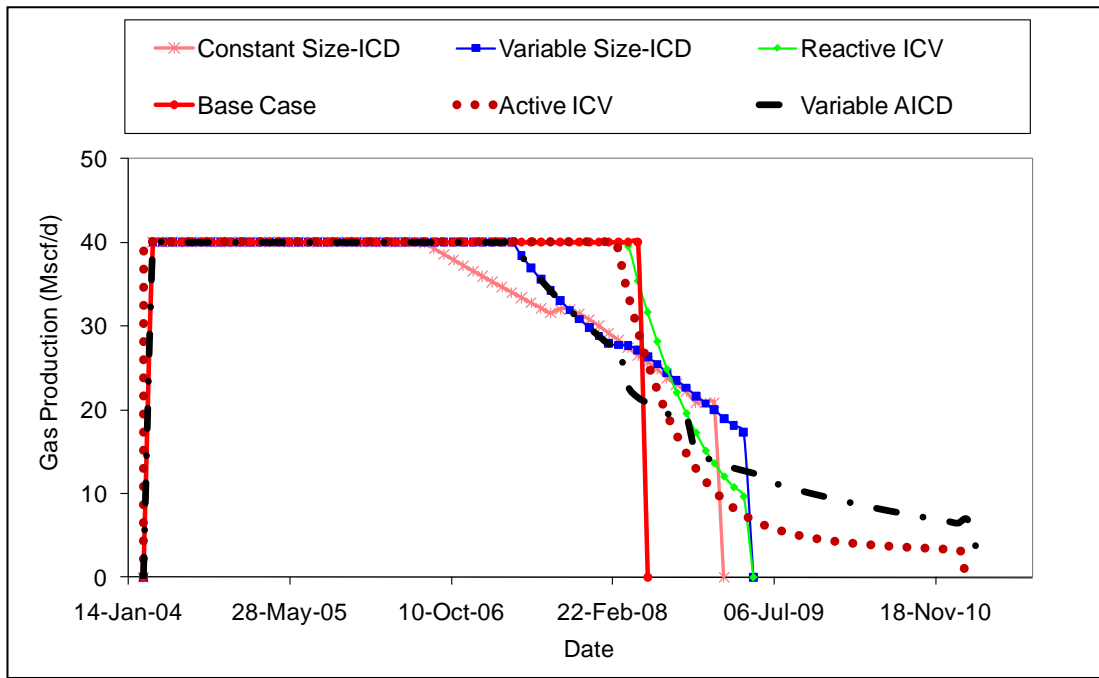


Figure 6-54: Gas production rate for all completions

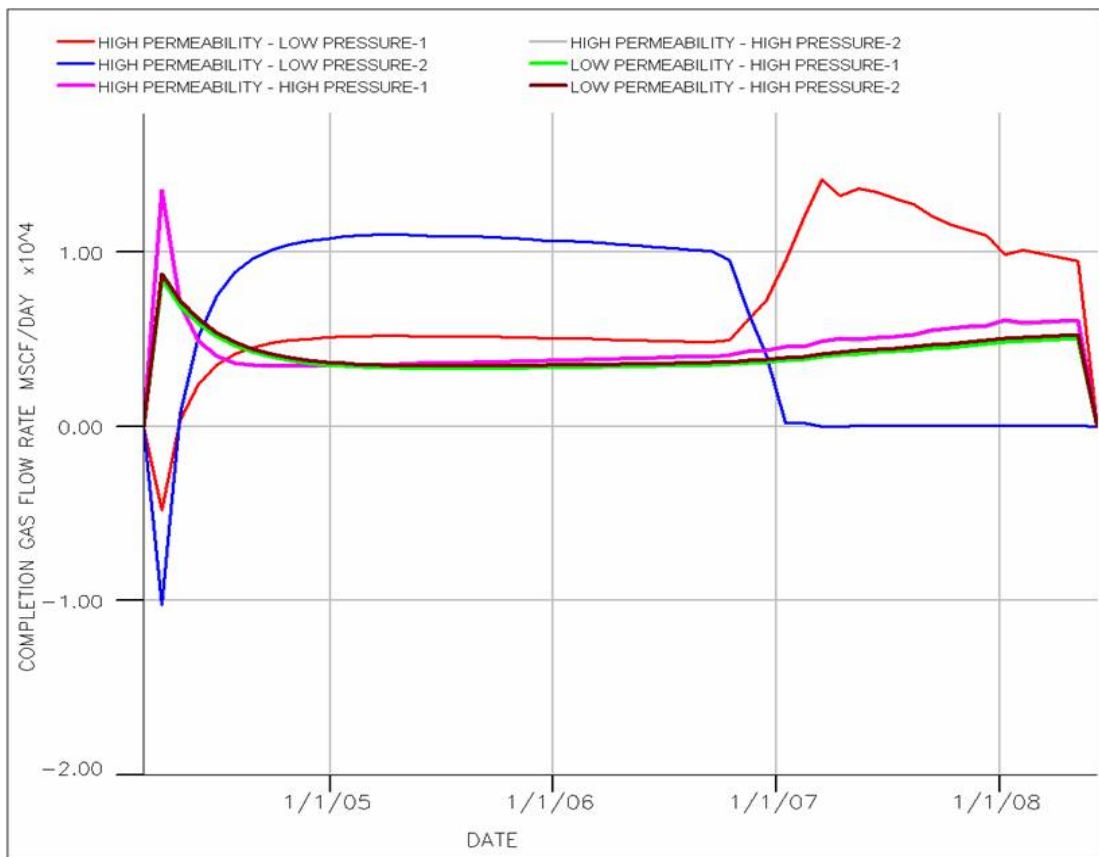


Figure 6-55: Crossflow prevented by ICD completion

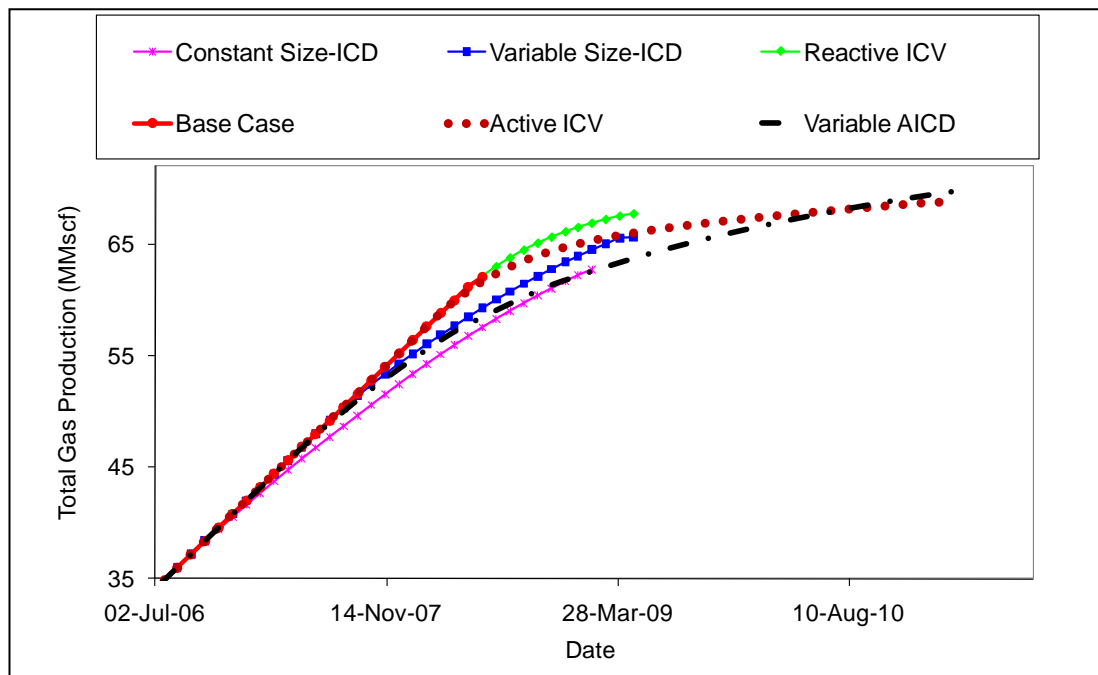


Figure 6-56: Cumulative gas production for all completions

Table 6-11: C-field production performance with different completions

Case	Cumulative Production		Recovery Compared to Commingled Production Case (%)
	Gas (Bscf)	Water (Mstb)	
Base-case (Commingled Production)	62.1	943.8	-
Constant-Size ICD Completion	62.7	561.2	+ 1.0
Variable-Size ICD Completion	65.6	345.3	+ 5.6
3 ICVs (Reactive Control)	67.6	298.3	+ 8.9
3 ICVs (Active Control)	68.7	158.4	+10.6
AICD Completion	69.9	11.1	+11.9

6.5.3 ICD Completion Performance

Both variable- and constant-size ICD completions were designed to equalise the contribution from the three zones while preventing crossflow by maintaining the wellbore pressure below that of the zone with the lowest pressure. Both (1-constant and 2-variable) ICD completions successfully prevented gas crossflow between the zones (Figure 6-57). It also delayed water production from the well by equalising the

contribution of the individual zones, resulting in an increased cumulative gas production (Figure 6-56 and Table 6-11). In this example, the ICD completion was optimised under conditions of low uncertainty to delay water production. However, the inherent ICD tendency to favour liquid flow rather than gas flow resulted in an increased rate of water production from the breakthrough zone compared to that of the conventional, commingled completion (Table 6-12). This unfavourable ICD behaviour restricts its application in water-wet gas fields.

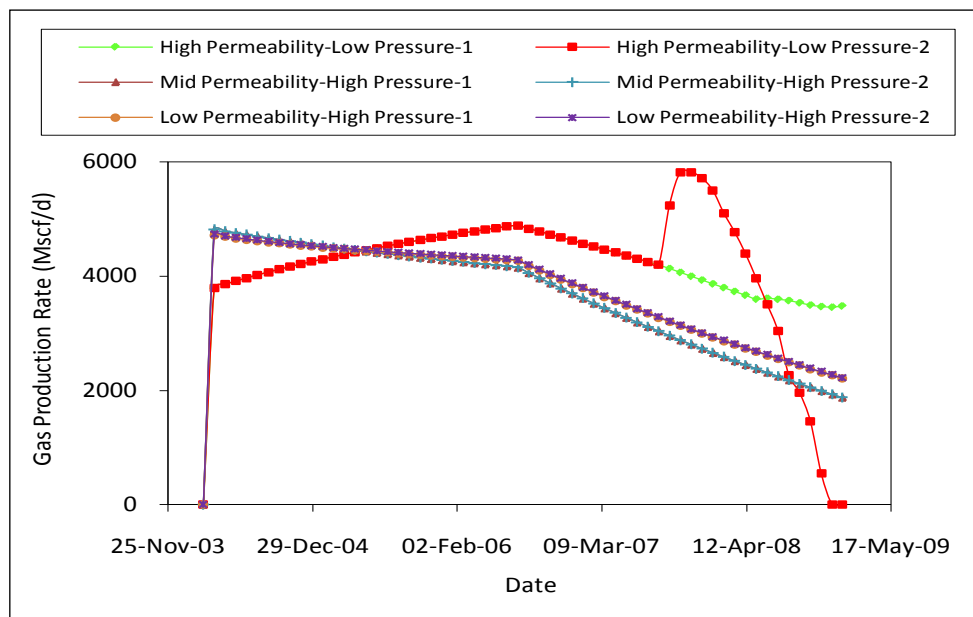


Figure 6-57: Crossflow prevented by ICD completion

Table 6-12: The ICD completion performance after water breakthrough

Time after water breakthrough / Case (days)	Water Production Rate (stb)		Percentage Increase (%)
	Base-case (Commingled Production)	Variable-Size ICD Completion	
60	116	152	31
150	357	510	43
300	793	1,179	48
Total Water Production from the Water Breakthrough Zone after 300 days (Mstb)	112.0	165.7	48

6.5.4 *ICV Completion Performance*

The ICV completion includes a valve that reactively or actively regulates the gas and water production from each zone. Reactive control of the ICV completion involved reducing the ICV's flow area once water production was observed at that zone. This has reduced water production (Figure 6-53) and has resulted in higher cumulative gas production (Figure 6-56) compared to the conventional completion. Active valve control is a combination of using the ICVs to proactively equalise the contribution from the three zones (delay water production) and reactively control the water production after water breakthrough. As indicated in Figure 6-56 and Table 6-11, this has extended the well life with an increase in the cumulative gas production and great reduction of the produced water. However, frequent actuation of the ICV was required to cope with the changing layer pressures and water cut.

6.5.5 *AICD Completion Performance*

The AICD completion was designed to equalise the contribution from the three zones as well as to minimise the water influx rate after breakthrough. It successfully prevented gas crossflow as well as delayed water breakthrough and minimised water influx after breakthrough. The AICD provides inflow control at every joint. Hence its water restriction ability is much finer than that of an ICV completion while overcoming the ICD's tendency to favour liquid over gas flow with its reactive functionality. This resulted in an increased cumulative gas production (Figure 6-56 and Table 6-11), but recovery was delayed compared to ICVs and ICDs due to the AICD imposing restrictions on the well's productivity. Remember that the AICD operation does not require either surface control or well intervention.

6.6 NH-Gas Condensate Field Case Study

6.6.1 Introduction

The NH field is a Norwegian, gas condensate field with a thin oil column which is underlain by a water aquifer and overlain by a large gas cap (Figure 6-58). The gas is rich of volatile oil at a pressure of 434 bars while the oil is also rich of gas. The bubble point pressure of the oil is only 10 bar less than the reservoir pressure; hence a large amount of gas would be liberated from the oil by a small pressure drop.

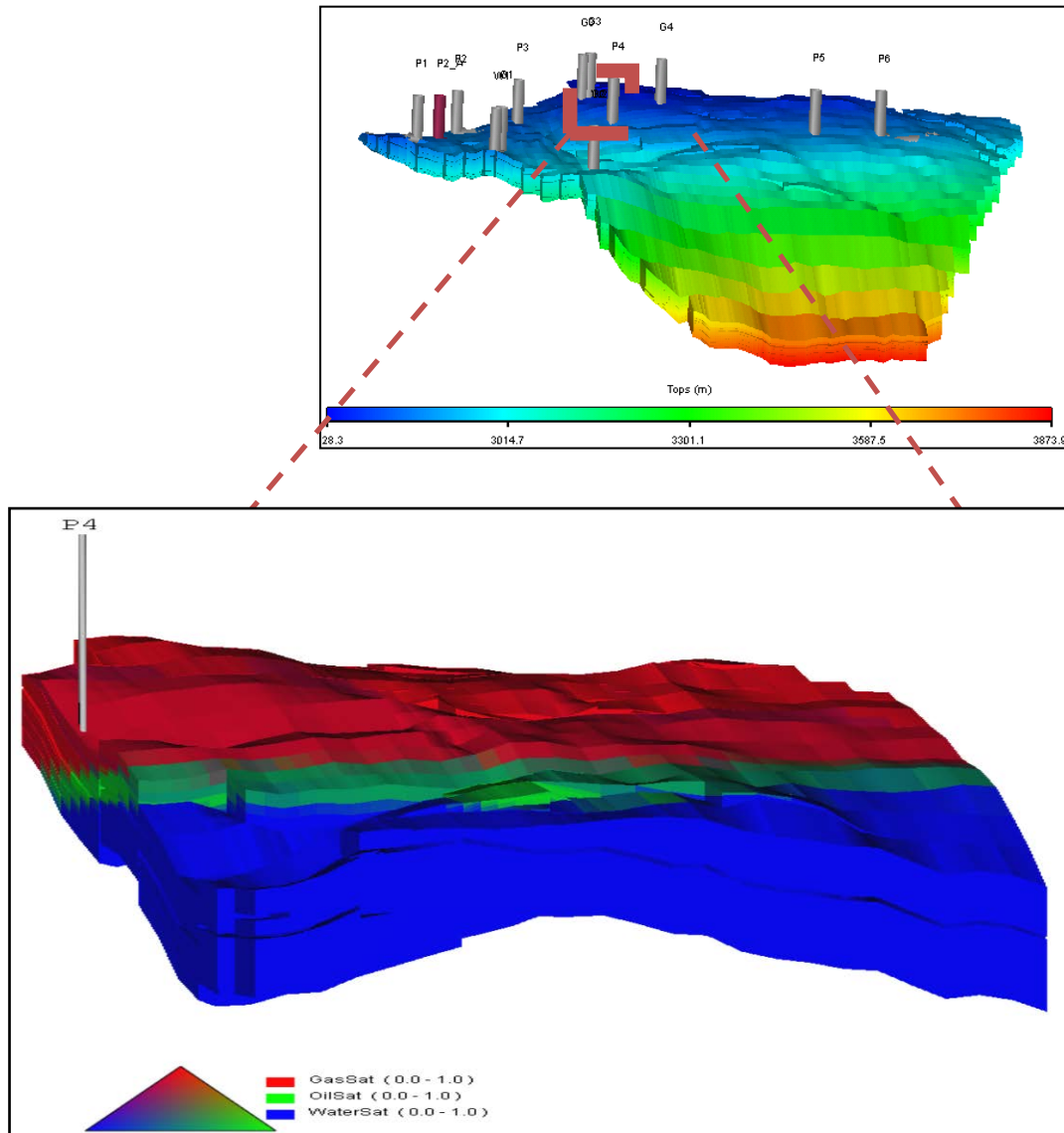


Figure 6-58: Full field and sector models showing the NH-field's thin oil column

6.6.2 Reservoir Model Description

The full field model consists of 138x35x39 grid cells in the X, Y and Z directions, respectively. The reservoir permeability varies between 100 and 9,000 md with porosity

between 15 and 20%. The full field model contains 7 oil producers, 2 water injectors and 4 gas injectors.

This study employed a sector of the history matched field model (Figure 6-58). The sector model contains 19x35x19 active cells with 22.6 MMSm³ OOIP, 14.8 MMSm³ of which is in the liquid phase and 7.8 MMSm³ is in the gas phase. The gas cap contains 25.4 MMSm³ of the GOIP. A horizontal well was completed in the thin oil column of the sector model to maximise the reservoir exposure, reduce gas and water coning and enhance the oil recovery.

6.6.3 Challenges and Study Objectives

Fluid influx into the horizontal wellbore when completed with a 6-inch SAS was dominated by:

- HTE caused by the frictional forces along the 6,560 ft long wellbore.
- VPE caused by permeability contrast between two reservoir-regions with average permeabilities of 135 and 2400 md (Figure 6-59).

This caused the gas to breakthrough at the heel early in the well's life a factor which impacted the well's overall performance.

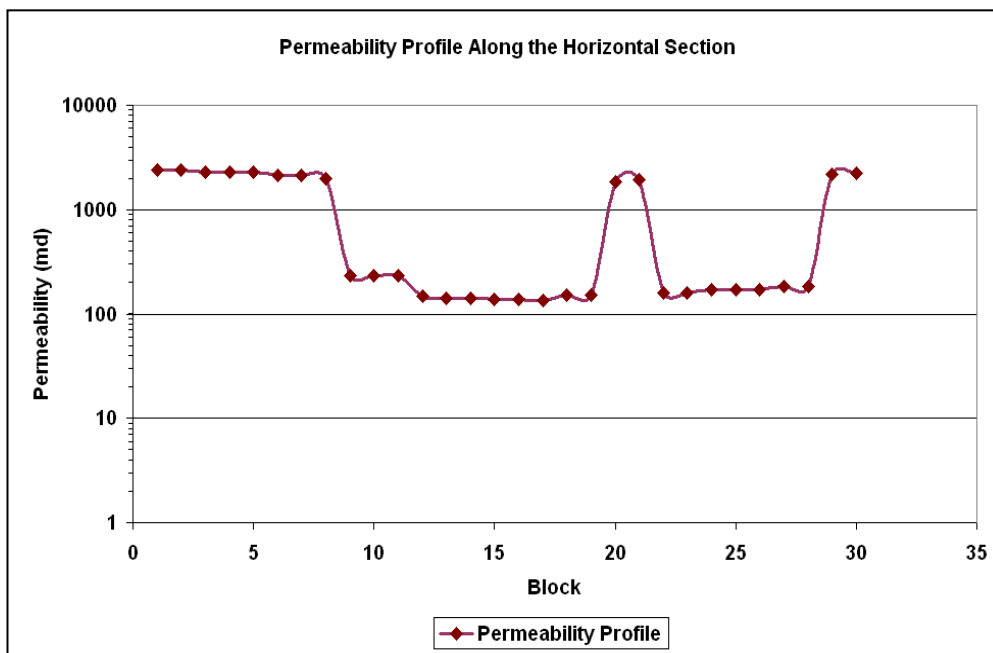


Figure 6-59: Permeability distribution along the NH horizontal well

The objective of this study is to verify if an (A)ICD completion application can mitigate such challenge and enhance the well performance; while giving production priority to the “free” oil under the following constraints:

- Liquid production rate of 2 MSm³/day.

- Gas flow rate of 2 MMSm³/day.
- Tubing head pressure limit of 90 bars.
- Bottom hole pressure of 180 bar.

AWCs were designed and applied in the studied horizontal wellbore.

6.6.4 Conventional Completion

A SAS completion with AFIs installed at every wellbore segment resulted in:

- Higher condensate (i.e. vaporised oil) production compared to the “free” oil production (Figure 6-60).
- A high gas influx after 18 months which limited the oil production from the well (Figure 6-61).
- Gas breakthrough from different wellbore locations was caused by the HTE and the reservoir heterogeneity (Figure 6-61).
- Very low “free” oil recovery was achieved (Table 6-13).

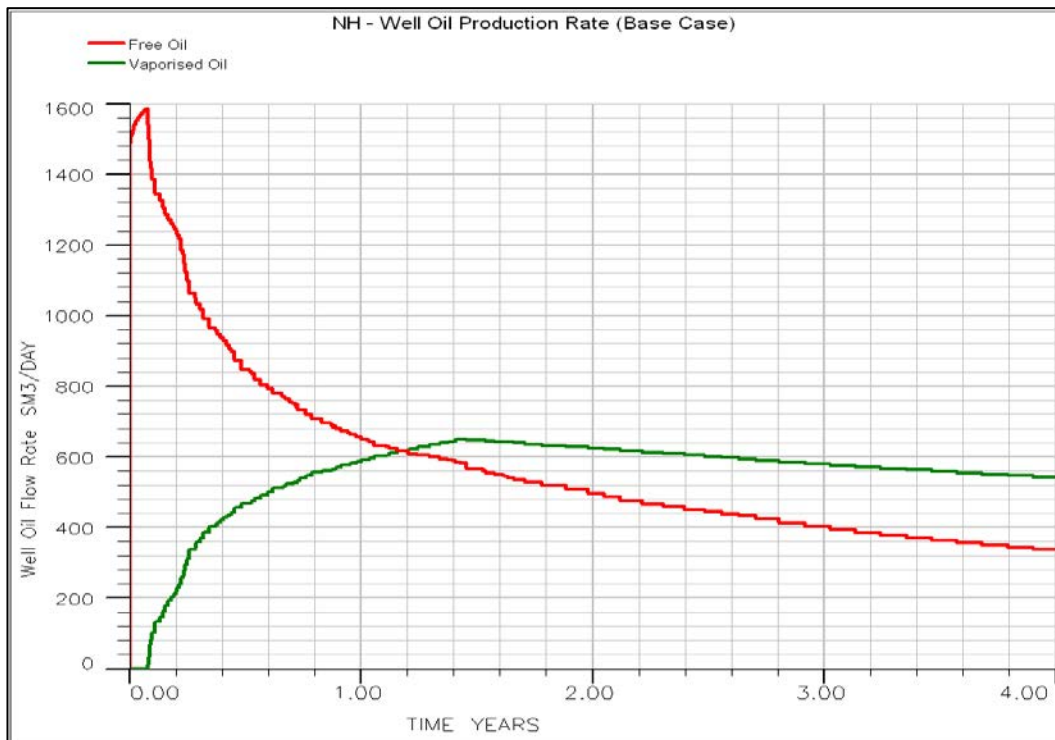


Figure 6-60: Free oil and liquid condensate (vaporised oil) production rate

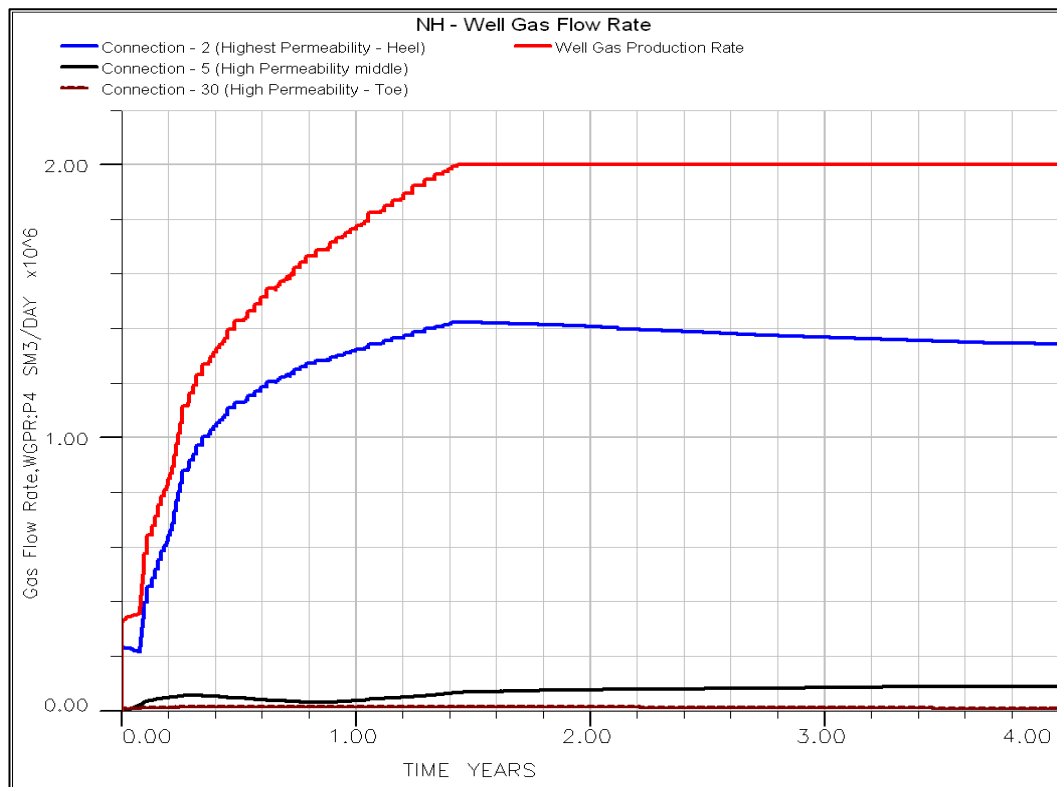


Figure 6-61: High gas flow rate from the heel section

Table 6-13: Results of AWCs application in the NH thin oil column field

Case	Thin Oil Column Recovery (%)	Increment in Total Recovery (%)
Base Case (SAS)	3.7	-
Constant ICD	4.7	27
Variable ICD	4.7	27
Intelligent Well: 2 ICV	5.4	46
AICD Completion	6.1	65

6.6.5 ICD Completion

A constant-size ICD completion was designed to equalise the fluid influx into the wellbore using the approach proposed in Chapter 4 Section 4.5.2 for overcoming HTE. This completion resulted in an improved oil recovery compared to the SAS completions (Table 6-13). Gas cross-flow between reservoir zones occurs if a variable-size ICD completion had been applied instead due to the higher restriction imposed on the high permeability interval (Figure 6-62). The performance of both constant and variable-size

ICD completions was poor compared to the ICV completion's performance described below.

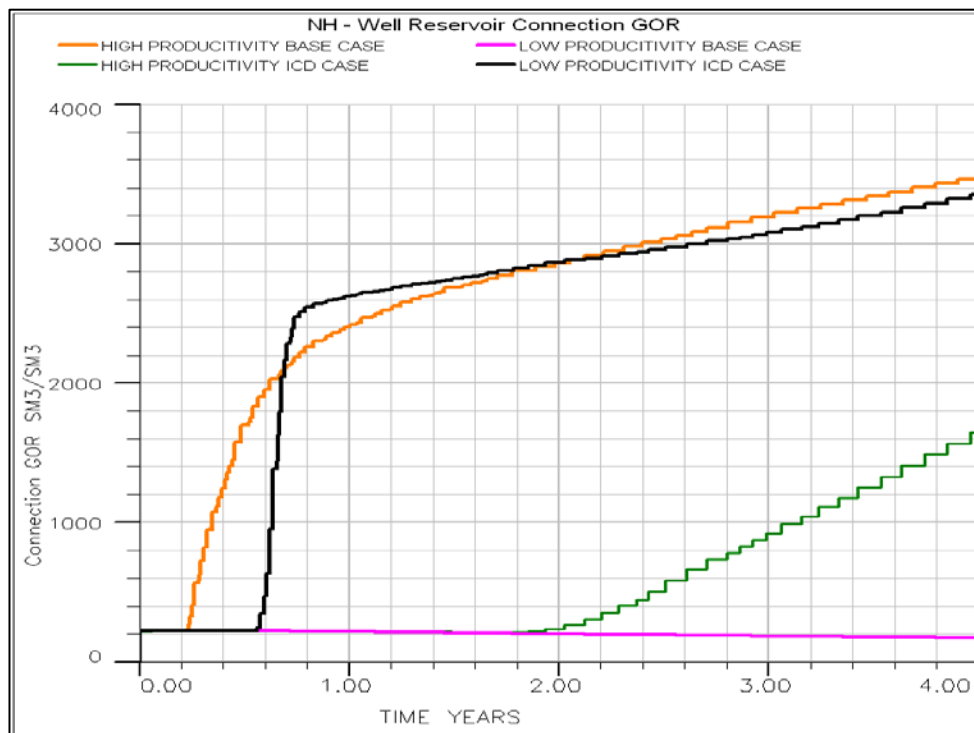


Figure 6-62: Cross flow of gas from high to low permeability due to variable ICD restriction

6.6.6 ICV Completion

Two ICVs were installed in the horizontal wellbore to control the flow from the high and low productivity sections at the heel and around the middle of the horizontal section. They were able to control the gas flow and enhance the “free” oil as well as that of condensate (Table 6-13). However, the ICV’s ability to control the gas influx was limited compared to the (A)ICDs due to the absence of flow barriers in the reservoir. Crossflow between the high and low permeability zones increased whenever the ICV’s restriction is increased. The reduction of water production was also limited compared to the other AWCs.

6.6.7 AICD Completion

The AICD completion design started with the constant-size ICD as an initial restriction size to equalise the fluid influx along the wellbore and added a reactive restriction based on the constant design approach described in Chapter 5 Section 5.4.2 to minimise the gas influx rate after breakthrough. As Table 6-13 indicates, the AICD

completion performed better than the ICV and ICD completions. This was due to its ability to:

- Control the gas inflow to the wellbore at much smaller intervals compared to the ICV completion.
- Minimise gas crossflow within the reservoir (Figure 6-63).

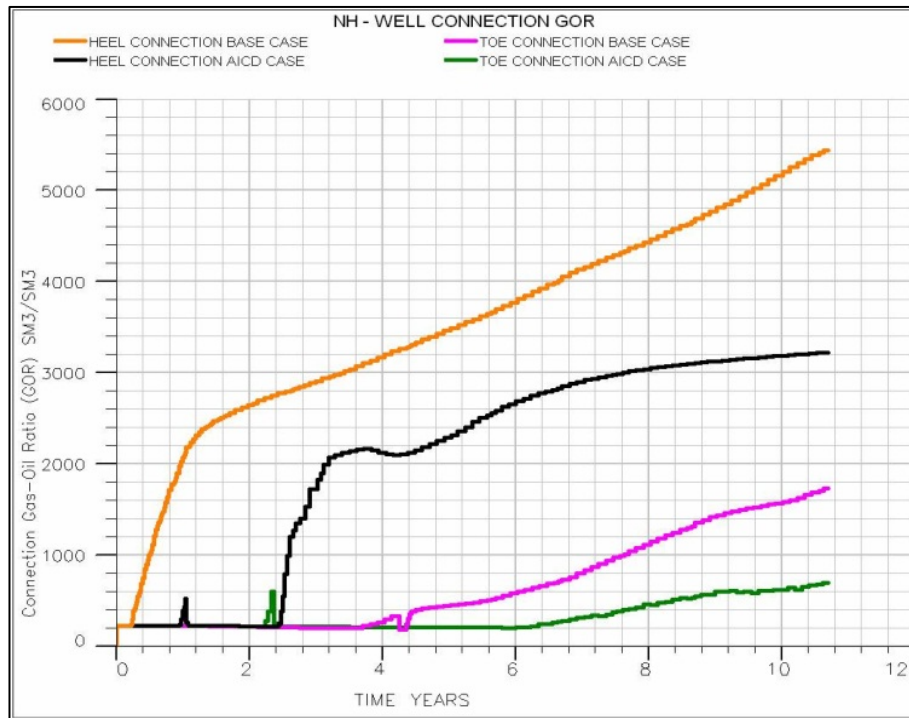


Figure 6-63: Effectiveness of AICDs in restricting gas production

6.7 U-Field Case Study

6.7.1 Introduction

The application of an ICD completion to equalise the injection of gas, water or water and gas in water-alternating-gas well has been investigated using real field data from a Norwegian oil field being developed as a water-alternating-gas (WAG) injection project. The aim of this study was to determine if ICDs are capable of equalising water or gas injection as efficiently as their equalisation performance during production. Further, application of an ICD completion to WAG injection has not been explored prior to this work. Hence, if successful, this will extend the application envelope of ICD completions. In particular, it will be determined if an ICD completion can eliminate possible initiation and propagation of thermal fractures due to excessive, local water injection rates. Elimination of fractures was viewed by the operator as adding value.

The U-Field employed 3 WAG producers and 4 WAG injectors. The operator plans to drill a new WAG injector in the field. The data from this well will be used for this analysis. The reservoir, fluid and wellbore parameters of the proposed application are listed in Table 6-14.

Table 6-14: U-Field reservoir, fluid and wellbore parameters

Reservoir and Fluid Properties	Value	Wellbore Dimensions	Value
Reservoir Depth (feet)	12,300	Length (feet)	~3444
Reservoir Height (feet)	1,258	Number of zones	6
Temperature (°C)	150	Openhole Diameter (inch)	8.5
Porosity (%)	12	ICD Screen OD (inch)	5.5
Matrix Permeability (md)	15 - 30	ICD Screen ID (inch)	5.0
High Permeability Streak (md)	700	Gas Injection Rate (Mscf/day)	35,000
kv/kh	0.1	Water Injection Rate (stb/day)	30,000
Pressure (psi)	6500		
Injectivity Index (stb/day/psi)	24.2		
Gas Density (Kg/m ³)	255		
Gas Viscosity (cp)	0.03		
Formation Volume Factor	0.000656		
Z-Factor	1.12		
Water Density (Kg/m ³)	1,000		
Water Viscosity (cp)	1.13		
Formation Volume Factor	1.0		

6.7.2 ICD Completion Application

The purpose of the ICD completion installation in this well is to equalise the water and gas injection into the reservoir zones and prevent the potential injection imbalance that could result in thermal or hydraulic fractures being formed. The water injectivity index into the matrix is expected to be 0.28 stb/day/psi/40 ft joint completion length. However, the operator expected that uncontrolled injection into a particular zone could lead to 25 fold injectivity increase (6.62 stb/day/psi per 40 ft joint). Continued injection into this zone was expected to lead to the creation of thermal fractures; further accentuating the injection imbalance leading to early water breakthrough and decreasing

recovery. In addition, the gas injectivity of the matrix is determined to be 16.0 Mscf/day/psi/40 ft joint rising to 375.2 Mscf/day/psi/40 ft joint if thermal fracturing occurred.

Designs have been prepared for both a variable- and a constant-size ICD completion. These designs were based on the approaches provided in Chapter 4. The required pressure drop across an ICD in a variable ICD completion design for an equalised injectivity in the presence of a fracture was estimated to be 941 psi for water injection and 24.1 psi for gas injection. This translates to an ICD restriction with 2.7 mm nozzle diameter for water or a 4 mm diameter for gas. This ICD would be installed across the fractured zone while a SAS installation across the remainder of the completion is required to provide complete equalisation. This requires knowledge of the location of the high permeability streak. Also, AFIs must be installed between any ICDs and SAS joints. The equalised flow rate will impose a pressure drop of 941 psi across the 2.7 mm nozzle ICD, greatly increasing its erosion potential.

Complete equalisation of gas injection requires a larger 4 mm nozzle per ICD. During water injection, this size ICD will provide a 91% equalisation level if applied as a constant size ICD across the wellbore length (Figure 6-64). This is the preferred design since the location of the high permeability streak is unknown. Limited number of AFIs should be installed to prevent fractures from developing after the start of injection.

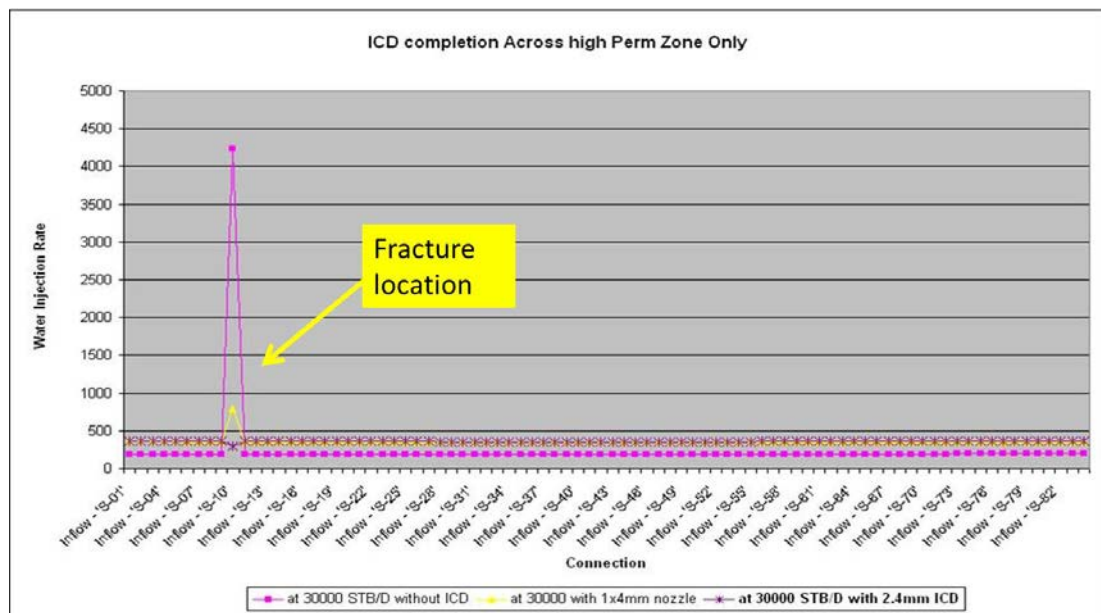


Figure 6-64: Water Injection without, with 4 mm nozzle and 2.4 mm nozzle ICDs

This study did not use a reservoir simulation model to study the completion performance since it was warranted based on the data available. A detailed well performance modelling was sufficient to conclude that:

- ICD completions can be applied to water, gas and WAG injection wells.
- Such completions provide an economically attractive option compared to ICVs.
- The design techniques described in Chapter 4 can be applied.

6.8 Synopsis of Publications

This section summarises the author's publications which include some work that was indirectly related to this thesis and hence was only cited as an appendix to this chapter. Each publication adds value in terms of the ideas presented and recommendations which aims to enhance the performance of the AWCs if applied. A list of the Author publications and contributions is provided at page number xxvi.

6.8.1 Successful Application of a Robust Link to Automatically Optimise Reservoir Management of a Real Field [202]

Realistic modelling is essential for both the planning and the optimal operation of Oil and Gas Fields. Such a model for modern well or field development architecture requires coupling of the reservoir simulator with the well/surface facility network model when making choices as to the reservoir and production management strategies to be employed. Such close coupling is not, currently, readily available; particularly when the reservoir simulator, the well/surface facility simulator and, potentially, the optimiser programs are provided by different suppliers.

This publication presented the successful testing results of a newly developed "link tool" that integrates the reservoir simulation model with a subsurface/surface network model, allowing (automatic) optimisation of the full network performance. The tool supplies the simulation results to the surface network simulator/optimiser, which in turn, reconfigures the intelligent well completion zones by use of Inflow Control Valves (ICVs) and wellhead or manifold in order to maximise the total production against the well and facility constraints. The network targets are then returned to the reservoir simulator in a simple manner at each time step.

The S-Field, which proved to be a very suitable case study for illustration of the value of "Intelligent" Field development techniques, has been used to verify the applicability and value added from the application of the new coupling tool. The automatic, optimal control of the S-Field's five intelligent production wells by

application of the S3Connect "link tool" (provided by Sciencsoft) to couple Eclipse100™ reservoir simulator (provided by Schlumberger) with the General Allocation Program (GAP™) surface network modeller and optimiser (provided by Petroleum Experts).

The application of this coupling and optimisation technique resulted in:

1. A 11.6% increase in the cumulative oil production and 10.0% decrease in water production from the simulated S-Field performance with five intelligent well completions compared to the seven conventional well completions (7% increase in oil production compared to five commingled producers) .
2. Reduction in the running time of the coupled simulation compared to the running time of the tightly coupled models.
3. Elimination of the need to link the simulation programs using a Parallel Virtual Machine (PVM) interface and enhancement of the coupled simulation stability.
4. Ease of simulator coupling process and visualisation of the simulation results.

The coupled modelling advantages highlighted in this publication have been included in Chapter 3. This publication is provided in Appendix A. 6-1.

6.8.2 Inflow Control Devices: Application and Value Quantification of a Developing Technology [220]

Horizontal and multilateral completions are a proven, superior development option compared to conventional solutions in many reservoir situations. However, they are still susceptible to coning toward the heel of the well despite their maximizing of reservoir contact. This is due to frictional pressure drop and/or permeability variations along the well. Annular flow, leading to severe erosion "hot-spots" and plugging of screens is another challenge. Inflow Control Devices (ICDs) were proposed as a solution to these difficulties in the early '90s. ICDs have recently gained popularity and are being increasingly applied to a wider range of field types. Their efficacy to control the well inflow profile has been confirmed by a variety of field monitoring techniques.

An ICD is a choking device installed as part of the sandface completion hardware. It aims to balance the horizontal well's inflow profile and minimise the annular flow at the cost of a limited, extra pressure drop. Fractured and more heterogeneous formations require, in addition, the installation of annular isolation. The new technologies of Swell

Packers and Constrictors can provide this annular isolation in an operationally simple manner.

This paper describes the history of ICD development with an emphasis on the designs available and their areas of application. These technical criteria are being illustrated using published field examples. The flexibility of an ICD is illustrated by its integration with other conventional and advanced production technologies e.g. SAS, AFI, artificial lift, gravel packs and intelligent completions in both horizontal and multilateral wells.

It also shows how the value of such well-construction options can be quantified using commercially available, modelling simulators. Simple, but reliable, guidelines on how to model the performance of ICDs over the well's life is provided. This technique was the first to account for both annular flow as well as inflow to the ICDs in an ICD completion with no or only limited number of packers and thus can be used as part of the value quantification process for both the evaluation of completion options and for their detailed design.

This publication was the first to highlight the need for a double packer configuration in a variable-size ICD completion to mitigate the fluid crossflow between the different reservoir zones around the wellbore.

The review and comparison of the ICDs types and performance as well as the modelling of AWC with annular flow, which were highlighted in this publication, have been included in Chapter 2 and Chapter 3. This publication is provided in Appendix A. 6-2.

6.8.3 Advanced Wells: A Comprehensive Approach to the Selection between Passive and Active Inflow Control Completions [242]

Advances in well architecture from conventional wells to horizontal and then multilateral wells in order to maximise the reservoir contact has been paralleled by advances in completion-equipment development. Passive inflow-control devices (ICDs) and active interval-control valves (ICVs) provide a range of fluid-flow control options that can enhance the reservoir sweep efficiency and increase reserves. ICVs were used originally for controlled, commingled production from multiple reservoirs, while ICDs were developed to counteract the horizontal well's heel/toe effect. The variety of their applications has proliferated since these beginnings with their application areas now overlapping, resulting in a complex, time-consuming process to select between ICVs or ICDs for a particular well's completion.

This publication summarises the results of a comprehensive, comparative study of the functionality and applicability of the two technologies. It tabulates a selection process on the basis of the thorough analysis of the ICD and ICV advantages in major reservoir, production, operation, and economic areas. It provides detailed analysis of the operational and economical aspects, such as proper modelling, gas- and oilfield applications, equipment costs and installation risks, long-term reliability, and technical performance.

The results of this work's systematic approach form the basis of a screening tool to identify the most appropriate control technology for a wide range of situations. This selection framework can be applied by both production technologists and reservoir engineers when choosing between passive or active flow control in advanced wells. The value of these guidelines is illustrated by their application to synthetic- and real- oil and gas field case studies. This comparison framework has been expanded to include AICDs and summarised in Chapter 2.

6.8.4 *Advanced Well Flow Control Technologies Can Improve Well Cleanup* **[243]**

Formation damage created during drilling or workover operations significantly reduces the performance of many wells. Long, horizontal and multilateral wells crossing heterogeneous, possibly multiple, reservoirs often show greater formation damage than conventional wells. This is partly due to the longer exposure of the formation to the drilling and completion fluid due to the well geometry, the greater overbalance pressure often applied during drilling such wells and the poorer cleanup experienced with the lower drawdowns and greater completion length associated with horizontal wells.

The typical well clean-up process involves flowing the well naturally or aided by artificial lift to remove the external and internal mudcake and flow-back the mud filtrate. This process can be effective in conventional wells, but is not adequate in long horizontal and multilateral wells suffering from increased frictional pressure drop along the wellbore and heterogeneity. The cleanup efficiency can be improved by employing Advanced Well completions. Inflow Control Valves (ICVs) control the contribution from individual laterals or for a limited zone of the horizontal wellbore. Inflow Control Devices (ICDs) equalise the contribution along the (long) completion length. In addition, Autonomous ICDs can manage the influx of unwanted fluids.

This paper studies the cleanup performance of wells completed with these advanced, downhole flow control technologies. It provides valuable insights into how these

completions improve the well cleanup process and compares the ability of (A)ICD and ICV technologies to provide the optimum:

- Drawdown to lift off the filter cake formed by different mud systems (without causing sand production).
- Recovery rate of the invaded mud filtrate.

This paper proposes the use of cleanout valves to support the cleanup of AICDs along with guidelines for Advanced Well Completion cleanup in general. Simulated results of synthetic and real field cases allowing a comprehensive comparison of conventional and AW completions' cleanup performance are included to support the proposed process. This publication is provided in Appendix A. 6-3.

6.8.5 *Advanced Sand-Face Completion Design and Application in Gas and Gas-Condensate Fields [244]*

Sand-face completion technology for gas wells has evolved to overcome problems associated with sand and water production. Frac-packs, gravel packs, screens and oriented or selectively perforated completions have all been applied to gas wells to maintain wellbore integrity and control expected, late-life production challenges. However, none of these completion designs are capable of managing variable productivity, pressure or sanding tendency when producing multiple reservoir layers into a single wellbore. The result is premature water and (often) sand production. Intelligent completions employing Interval Control Valves (ICVs) can successfully manage these problems. However, not only are there limitations on the number of zones that can be separately controlled, but the hardware is also susceptible to the increased erosion potential of the high flow velocities associated with gas production.

Inflow Control Devices (ICDs) are an alternative Advanced Well Completion (AWC) technology. An ICD employs a passive flow restriction mounted on each joint of tubing or sand-control screen. The Autonomous Inflow Control Device (AICD) adds an "Active" water shut-off element to the flow equalisation provided by the standard ICD. An (A)ICD completion consists of multiple joints of (A)ICD equipped tubing separated into the required number of zones by Annular Flow Isolation (AFI). Such completions have the ability to equalise the gas inflow from many more layers (or even separate reservoirs) than is possible with an ICV or separated conventional completion.

This paper presents a critical evaluation of the ICD and AICD technologies together with a novel design methodology for their application to gas and gas-condensate fields. This is complemented by two case studies based on real data from both a gas and a thin-

oil-column gas-condensate field. These studies are used to illustrate the application of the design workflow along with the potential advantages and added value gained by installing (A)ICD completions.

This design methodology and the field studies provide the basis for an extension of the (A)ICD's application envelope to gas fields. These guidelines proposed in this paper are included in Chapter 4 and Chapter 5 while the case studies are included in Chapter 6.

6.9 Summary

This chapter has shown that:

1. ICD and AICD completions can potentially add value when applied to oil, gas and gas-condensate fields as well as water and WAG injection. This extension of their current, field application envelope was illustrated by their application to a gas field, a gas-condensate field and a WAG injector. Their performance was contrasted with that of a conventional (SAS) and an ICV completion.
2. It was shown that the design of (A)ICD and ICV completions for both oil and gas applications can be performed in two stages: sizing and evaluation.
3. Evaluation of the optimum completion performance over the well's life can be performed using reservoir and wellbore simulation techniques.
4. Special attention should be given during the design process to the:
 - a. Erosion potential of these completions.
 - b. ICD completion's ability to increase liquid as opposed to gas production.
 - c. Impact of any additional restriction imposed by the AWC on the well potential.

Chapter 7 Conclusions and Recommendations

7.1 Conclusions

Major challenges faced by all wells during their production lifetime, irrespective of the well architecture include:

- 1) Premature breakthrough of unwanted fluids (water and/or gas).
- 2) Uneven distribution of the injected fluid in the injection wells.
- 3) Annular flow, leading to severe erosion, "hot-spots" and plugging of the screens or sandface. This latter occurs in both production and injection wells.

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 these challenges.

This thesis has provided a comprehensive, practical workflow to identify the optimum advanced well completion design that ensures an optimum well performance throughout the well's and/or field's life (Figure 7-1). This workflow provides guidelines for selecting, modelling and designing the most appropriate AWC for a specific application while at the same time it provides recommendations for the proper evaluation of the AWCs design.

The workflow starts by screening the candidate well for AWC applicability. If applicable, the well productivity and fluid flow misbalance should be calculated using the appropriate models. The ICD restriction sizing process should then be performed and verified against the minimum acceptable restriction size. The appropriate ICD type should be selected to minimise the erosion, plugging, emulsion and unwanted fluid

influx potential as well as minimising unit cost. AICD restriction sizes should be designed at this stage if AICDs are applicable.

The appropriate AFI frequency and distribution which minimise the annular flow should be identified. (A)ICD restriction sizes should be adjusted to account for the chosen number of AFIs and the longer completion sections if it is judged not to be practical to install the optimum AFI distribution. Any uncertainties in the completion design parameters should be accounted for and (A)ICD sizes as well as the AFI distribution should be adjusted as required.

Finally, the designed (A)ICD completion performance should be modelled throughout the well's life using appropriate techniques. This latter calculation allows the economic value to be evaluated in comparison with any alternative completion options via a comparison of completions NPVs. Redesigning the (A)ICD completion may be required if its NPV is lower than that achieved by the alternative completions.

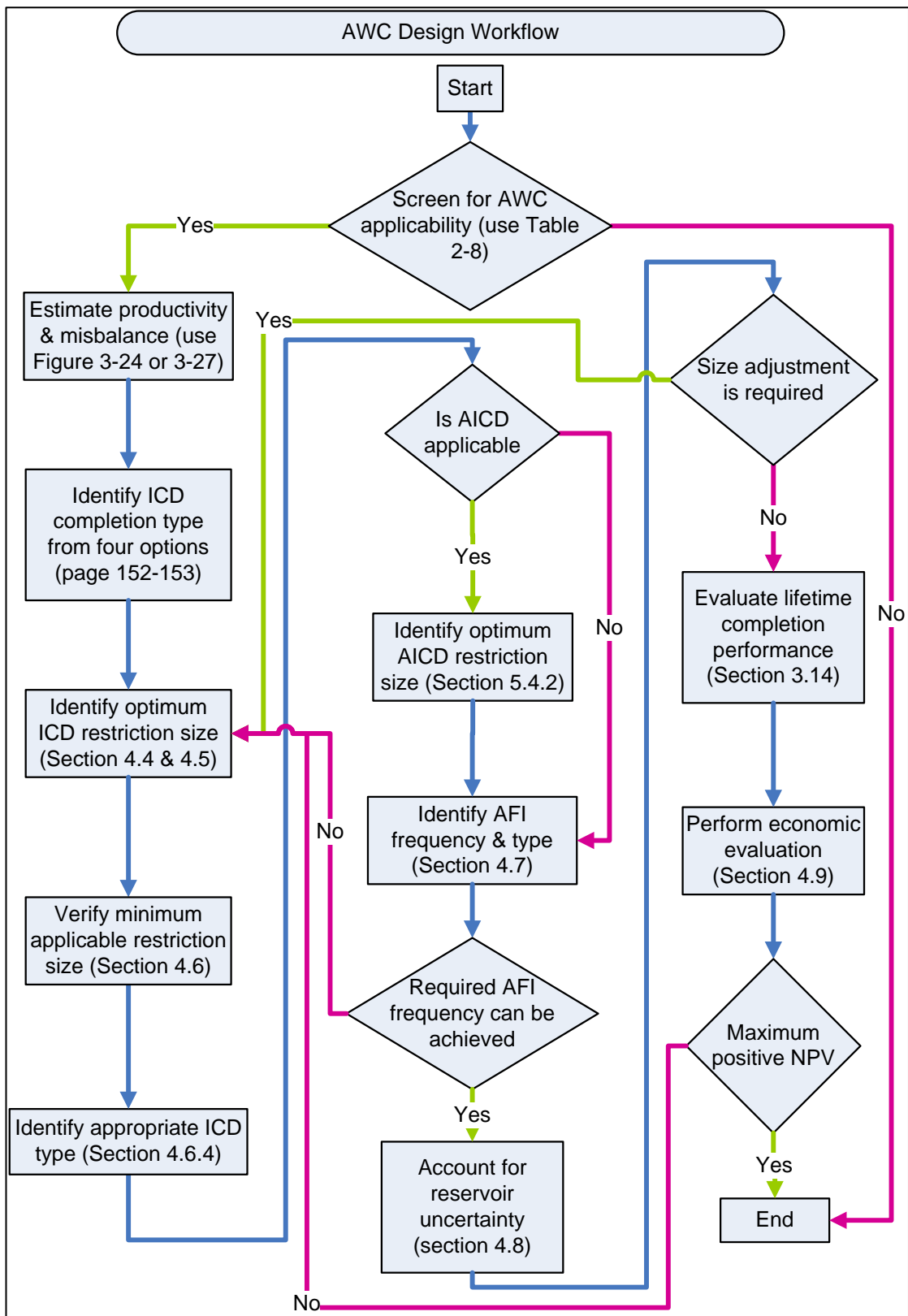


Figure 7-1: Comprehensive workflow for designing AWCs

The following conclusions can be drawn from this thesis:

1. Advanced Well Completions (AWCs) are completions that are capable of optimising the performance of long, often horizontal, wells or laterals by managing the fluid flow into (production) or out of (injection) the complete length of the completion. They consist of Downhole Flow Control (DFC) Technologies and Annular Flow Isolations (AFIs).
2. Many Downhole Flow Control (DFC) technologies are commercially available. There are significant differences in their design, configuration and performance. DFCs currently include Inflow Control Devices (ICDs), Inflow Control Valves (ICVs) and Autonomous Inflow Control Devices (AICD). An optimum design employing the appropriate technology is required to realise the full value of an Advance Well Completion.
3. The efficiency with which ICDs can optimise the well influx profile and prolong the well life by mitigating water and gas coning as well as premature flood front breakthrough has been proven in a wide range of reservoir environments.
4. ICDs with different configurations such as nozzles, orifices, slots, tubes, helical channels, and labyrinth channels are available. Similarly, AICDs are being developed with, among others, ball, flapper, disc, swellable and cyclone forms. These vary in their resistance to erosion, plugging and friction as well as their flexibility for reconfiguration at the well site. The strength and weakness of each type make them more or less suited to a specific environment.
5. Commercially available ICVs differ in the number of open positions and in their actuation systems. The latter is currently limiting the number of ICVs that can be installed in a well to a maximum of six. The development of control-line free ICVs will unlock this bottleneck and greatly enhance their application potential and value.
6. Annular flow may hinder the performance of AWCs, hence an appropriate number of AFIs need to be installed to eliminate annular flow and enhance the completion performance. AFIs are also commercially available in a variety of forms. Currently, swellable packers and constrictors form the best option for AWCs due to their flexibility and ease of installation.

7. Factors controlling the selection between ICVs and (A)ICDs have been reviewed and a framework for comparing ICV and (A)ICD technology has been developed. Key criteria drawn from the production, reservoir, economic and operational areas were considered. The following conclusions can be drawn from this comparison:
- a. *Reservoir description uncertainty:* ICVs have been proven to deliver higher recovery and reduced risk compared with ICDs since the former can be adjusted to manage unforeseen circumstances. AICDs can provide even greater value than ICVs since they control smaller segments of the wellbore.
 - b. *More-flexible development:* ICVs allow more-flexible field-development strategies to be employed with their actions being implemented in real time.
 - c. *Number of controllable zones:* The number of (A)ICDs that can be installed in a horizontal section is limited by the number of packers, the cost and/or resulting drag forces that limit the reach of the completion string as it is run into the hole.
 - d. *Inner flow-conduit diameter:* The larger diameter flow-conduit gives the (A)ICD an advantage over an ICV for a comparable borehole size.
 - e. *Formation permeability:* Both ICVs and (A)ICDs are capable of equalising the inflow from (or outflow into) heterogeneous reservoirs. However, (A)ICD application in low-permeability reservoirs greatly reduces the well productivity, unlike ICVs. Simultaneous analysis of other parameters along with the formation permeability is often required to make a proper selection between the two technologies.
 - f. *Fluid phases:* While both ICVs and ICDs can be used equally to manage the produced oil and gas or the injected-gas flow distribution, ICDs are more useful in reducing volumes of associated gas-cap gas while ICVs are preferred for controlling water production. AICDs can be used to reduce both fluids effectively compared to ICVs and ICDs.
 - g. *Productivity variation:* (A)ICD completions can passively control a number of zones of varying productivity along the wellbore. ICV

completions are limited by the number of valves that can be installed in a single completion.

- h. *Value of information:* Indications of gas and water influx or rate allocation is an advantage that can be gained in both ICV and (A)ICD completions if equipped with appropriate gauges. However, an ICV is itself be a source of information and can respond to newly identified behaviours because of its greater functionality.
- i. *Multilateral-well applications:* ICVs currently can be installed only in the well's main bore, while (A)ICDs can be installed to equalise the flow within individual laterals. ICVs have been proved to optimally control commingled production and prevent crossflow between multiple reservoirs. (A)ICDs have a limited capability to perform these tasks.
- j. *Multiple-reservoir management:* Both ICVs and (A)ICDs are capable of equalising the inflow from multiple layers within a single reservoir or from multiple reservoirs. The optimum choice between these two technologies for a particular well will depend on the specific reservoir and completion architecture.
- k. *Modelling-tool availability:* ICVs can be modelled reliably in current reservoir and network simulators, while current (A)ICD-completion modelling capabilities have limited availability.
- l. *Long-term equipment reliability:* An (A)ICD is simpler and hence more reliable than an ICV.
- m. *Reservoir isolation barrier:* ICVs are being used as reservoir-isolation barriers.
- n. *Improved cleanup:* ICVs encourage low-productivity-interval contribution to the flow that improves the total productive length of the wellbore faster. ICVs have the advantage when a high filter-cake-lift off pressure is required. AICDs often require the inclusion of a cleanout valve to improve their cleanup potential.
- o. *Selective acidizing and scale treatment:* ICVs allow both matrix and fracture acidizing and help eliminate the requirement for placement of the fluid by coiled-tubing in newly completed wells.

- p. *Equipment cost:* An ICV is more expensive than an (A)ICD because of its greater functionality. However, full economic quantification of the value associated with each completion remains a field-specific task.
 - q. *Installation risks:* The (A)ICD-completion installation operation is simpler and hence more reliable than ICVs.
 - r. *Gas lift:* ICVs can provide auto-lift to a poorly performing oil well by controlling the inflow of gas-cap gas or gas from a separate reservoir to lift.
 - s. *Gas field:* ICVs have an advantage over ICDs and have been applied successfully to wells completed in many gas fields. AICDs can provide greater potential if designed and applied effectively.
8. Publications on ICD applications have emphasised the need for use of appropriate techniques to optimise the design and recognise the full value of such completions. This can be achieved by using the comprehensive workflow to model and optimise the ICD completion in any well configuration using simplified, or commercially available, tools that is presented in this thesis.
 9. Proper (A)ICD and/or ICV completion modelling should include the formation productivity, the (A)ICD and/or ICV pressure drop, the tubing flow performance and the annular flow performance. The integration of these correlations can take trunk-and-branch or network topologies. The trunk-and-branch topology can be used in optimising the (A)ICD restriction size while the network topology can be used in identifying the appropriate AFI distribution and subsequent evaluation of the completion performance.
 10. The proposed AWC modelling approach in this thesis has been validated and compared with widely-used commercially available software.
 11. Commercially available wellbore/reservoir simulators have improved their AWC modelling capabilities significantly over the recent years. Many of them can currently account for both annular flow and time dependent effects simultaneously; enabling the evaluation and optimisation of the well completion design.
 12. An innovative and comprehensive ICD completion design workflow has been proposed. The workflow consists of four main processes:

- a. *Identification of the optimum ICD restriction size:* Design procedures are provided for the complete or optimum equalisation of different completion configurations. These include vertical, deviated, horizontal and multilateral wells with variable or constant ICD sizes distribution along the wellbore along with blank pipes or pre-packed screens when appropriate. Erosion, plugging and emulsion creation potential are all accounted for within the design.
 - b. *Identification of AFI requirement:* This process optimises the AFI distribution along the completion length based on ICD sizes distribution, productivity variation, geological markers, formation correlation length and annular flow velocity. The process also identifies the best AFI type for the intended application.
 - c. *Accounting for reservoir and wellbore uncertainties:* The workflow proposes constructing a probability distribution function of the variable reservoir parameter values and selecting the d_{50} value for the design of the ICD completion. This enhances the completion's potential by adding value in all the envisaged reservoir scenarios.
 - d. *Quantifying the economic value:* The optimised AWC completion should add greater value than a conventional completion.
13. The ability to automatically and reliably optimise the ICD completion adds great value to this workflow, saving engineering time that would otherwise be spent on "trial and error" manual alteration of the ICD strengths.
 14. The proposed design workflow is applicable to AICD completions by accounting for the relative permeability effect of the flowing fluids. The identification of the optimum variable and constant size designs for restricting water or excess gas flow is an outcome of the proposed design procedure.
 15. Single-well and full-field case studies have been developed to illustrate the value of and applicability of the proposed (A)ICD completion design in addition to the ICVs and (A)ICDs ability to improve both oil and gas production.
 16. An AWC cleanup procedure has been proposed to enhance the performance of these completions and maximise their added potential.

7.2 Recommendations

The area of advanced well completion design is rich in challenges and future areas for research. AICD is a promising technology that is still in its infancy and hence an investigation of the added value from the application of this technology forms the logical extension of this thesis. The proposed investigation should provide higher level of understanding of the AICD capabilities and an application envelope to simplify the verification of its potential value for a specific application. This should include unexplored areas of thermal recovery through Steam Assisted Gravity Drainage (SAGD) and in-situ combustion applications. It is recommended that the study use a value driven approach to the optimisation of the AICD completion design while accounting for the uncertainty in the reservoir, wellbore and production parameters in addition to the risks imposed by the proposed design.

The rate of well productivity change concept which was applied in this study has been instrumental to the identification of the optimum constant size ICD completion for different well configurations and applications. Extending the application of this concept to optimise the performance of other well performance related operations can add value. An example of this is the optimisation of the well clean-up process and identification of the appropriate time to switch production between laterals in a multilateral well.

Appendix A. 3-1

ICD Programmable Elements using a nozzle pressure drop correlation with constant discharge coefficient

// To calculate the pressure drop across a nozzle-type ICD:

// ICD restriction area

A = 1.057E-04;

//Cd is discharge coef,

Cd = 0.953462589;

// WDEN IS WATER DENSITY

WDEN = 62.4;

// ODEN IS OIL DENSITY

ODEN = SOG*WDEN;

// GDEN IS GAS DENSITY

GDEN = SGG;

//QL IS LIQUID FLOW RATE

QL = (QOILIN+QWATIN)*5.61;

// QF IS FLUID FLOW RATE

QF = (QL)+(QGASIN/1000000);

//OFVRAC IS OIL FLOW FRACTION

OVFRAC = (QOILIN*5.61)/QL;

// WVFRAC IS WATER FLOW FRACTION

WVFRAC = (QWATIN*5.61)/QL;

// GVFRAC IS GAS FLOW FRACTION

GVFRAC = QGASIN/(QGASIN+QL);

// MXDEN IS MIXTURE DENSITY

MXDEN = (ODEN*OVFRAC)+(WDEN*WVFRAC)+(GDEN*GVFRAC);

// VF IS FLOW VELOCITY

VF = (1/86400)*(QF/A);

//PRESOUT IS THE PRESSURE OUT OF THE ICD

PRESOUT = PRESIN-(0.0002159*((MXDEN*(POW(VF,2)))/(2*(POW(Cd,2)))));

ICD Programmable Elements using a helical channel flow correlation

```
// 3.2 bar aICD = 0.00003663, 1.6 bar aICD = 0.00001838;  
// 0.8 bar aICD = 0.00000930, 0.4 bar aICD = 0.00000535;  
// 0.2 bar aICD = 0.00000361;  
AICD = 0.00003663;  
DCAL = 62.443567566;  
VISCAL = 1;  
OILVIS = 0.4;  
WATVIS = 0.328;  
GASVIS = 0.0022;  
BO = 1.39372;  
BG = 0.00354;  
BW = 1.01774;  
WDEN = 62.443567566;  
ODEN = SOGIN*WDEN;  
GDEN = SGGIN*0.076362;  
QOILRES = QOILIN*BO;  
QWATRES = QWATIN*BW;  
QGASRES = QGASIN*BG;  
QLRES = QOILRES+QWATRES;  
WATLVF = QWATIN/QLRES;  
OILLVF = QOILIN/QLRES;  
QF = (QGASRES/(1000000*5.615))+QLRES;  
OVFRAC = QOILIN/QF;  
WVFRAC = QWATIN/QF;  
GVFRAC = QGASIN/QF;  
OXDEN = ODEN*OVFRAC;  
WXDEN = WDEN*WVFRAC;  
GXDEN = GDEN*GVFRAC;  
MXDEN = OXDEN+WXDEN+GXDEN;  
LVFRAC = WVFRAC+OVFRAC;  
OVFRACL = OVFRAC/LVFRAC;  
WVFRACL = WVFRAC/LVFRAC;  
UEMLO = OILVIS*(POW((1/(1-(0.8415*WVFRACL/0.7480))),2.5));
```

```

UEMLW = WATVIS*(POW((1/(1-(0.6019*OVFRACL/0.6410))),2.5));
UGASVIS = GASVIS*GVFRAC;
UMIXO = LVFRAC*UEMLO;
UMIXW = LVFRAC*UEMLW;
IF (WATLVF<0.5)
UMX=UMIXO+UGASVIS;
ELSE
UMX=UMIXW+UGASVIS;
QFS = (POW(QF*5.615,2));
PRESOUT = PRESIN-
((POW((DCAL*UMX)/(MXDEN*VISCAL),0.25))*((MXDEN/DCAL)*AICD*QFS));

```

AICD Programmable Element using a nozzle pressure drop correlation with constant discharge coefficient

```
// AICD RESTRICTION AREAS
```

```

AICD1 = 0.00000244;
AICD2 = 0.00000465;
AICD3 = 0.00001082;
AICD4 = 0.00002128;
AICD5 = 0.00004047;
DCAL = 62.443567566;
VISCAL = 1;
OILVIS = 0.4;
WATVIS = 0.328;
GASVIS = 0.0022;
BO = 1.39372;
BG = 0.00354;
BW = 1.01774;
WDEN = 62.443567566;
ODEN = SOGIN*WDEN;
GDEN = SGGIN*0.076362;
QOILRES = QOILIN*BO;
QWATRES = QWATIN*BW;
QGASRES = QGASIN*BG;

```



```

QLRES = QOILRES+QWATRES;
WATLVF = QWATIN/QLRES;
OILLVF = QOILIN/QLRES;
QF = (QGASRES/(1000000*5.615))+QLRES;
OVFRAC = QOILIN/QF;
WVFRAC = QWATIN/QF;
GVFRAC = QGASIN/QF;
OXDEN = ODEN*OVFRAC;
WXDEN = WDEN*WVFRAC;
GXDEN = GDEN*GVFRAC;
MXDEN = OXDEN+WXDEN+GXDEN;
LVFRAC = WVFRAC+OVFRAC;
OVFRACL = OVFRAC/LVFRAC;
WVFRACL = WVFRAC/LVFRAC;
UEMLO = OILVIS*(POW((1/(1-(0.8415*WVFRACL/0.7480))),2.5));
UEMLW = WATVIS*(POW((1/(1-(0.6019*OVFRACL/0.6410))),2.5));
UGASVIS = GASVIS*GVFRAC;
UMIXO = LVFRAC*UEMLO;
UMIXW = LVFRAC*UEMLW;
if (WATLVF<0.5)
UMX=UMIXO+UGASVIS;
else
UMX=UMIXW+UGASVIS;
QFS = (POW(QF*5.615,2));
if (WATLVF<0.12)
PRESOUT=PRESIN-
((POW((DCAL*UMX)/(MXDEN*VISCAL),0.25))*((MXDEN/DCAL)*AICD1*QFS)
);
else
if (WATLVF<0.18)
PRESOUT=PRESIN-
((POW((DCAL*UMX)/(MXDEN*VISCAL),0.25))*((MXDEN/DCAL)*AICD2*QFS)
);
else

```

```

if (WATLVF<0.25)
PRESOUT=PRESIN-
((POW((DCAL*UMX)/(MXDEN*VISCAL),0.25))*((MXDEN/DCAL)*AICD3*QFS)
);
else
if (WATLVF<0.32)
PRESOUT=PRESIN-
((POW((DCAL*UMX)/(MXDEN*VISCAL),0.25))*((MXDEN/DCAL)*AICD4*QFS)
);
else
if (WATLVF<0.39)
PRESOUT=PRESIN-
((POW((DCAL*UMX)/(MXDEN*VISCAL),0.25))*((MXDEN/DCAL)*AICD5*QFS)
);

```



SPE 107171

Successful Application of a Robust Link to Automatically Optimise Reservoir Management of a Real Field

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1. Abstract

Realistic modelling is essential for both the planning and the optimal operation of Oil and Gas Fields. Such a model for modern well or field development architecture requires coupling of the reservoir simulator with the well/surface facility network model when making choices as to the reservoir and production management strategies to be employed. Such close coupling is not, currently, readily available; particularly when the reservoir simulator, the well/surface facility simulator and, potentially, the optimiser programs are provided by different suppliers.

We have had the opportunity to test a newly developed “link tool” to integrate the reservoir simulation model with a subsurface/surface network model, allowing (automatic) optimisation of the full network performance. The tool supplies the simulation results to the surface network simulator/optimiser, which in turn, reconfigures the intelligent well completion zones by use of Individual Control Valves (ICVs) and wellhead or manifold in order to maximise the total production against the well and facility constraints. The network targets are then returned to the reservoir simulator in a simple manner at each time step.

The authors have used the S-Field over a number of years which proved to be a very suitable case study for illustration of the value of “Intelligent” Field development techniques. This paper discusses the automatic, optimal control of the S-Field’s five intelligent production wells by application of a “link tool” (*Supplier 1*) to couple the reservoir simulator (*Supplier 2*) with a surface network modeller and optimiser (*Supplier 3*). N.B. The latter two suppliers are among the market leaders within their segments.

2. Introduction

The integration of the reservoir simulator with the wellbore and surface facility models forms an essential part of the “intelligent” field concept. It allows accurate management of the reservoir(s) potential under specified well, facility or other constraints. The full value of such an integrated modelling workflow is only realised when a flow network optimisation capability that maximizes oil production (or other measures of value) is included in the software package. The optimiser works by making adjustments to the production strategy throughout the field life through its close coupling with the reservoir, wellbore and surface facility models.

Many commercial software packages offer the capability to integrate subsurface and surface models. However, not only are there differences in the degree of coupling between the individual software programs, but these links usually place high demands in terms of computing power, network architecture and, frequently, manual intervention of the engineer. In this paper we will illustrate a successful application of a robust and efficient linking tool developed to couple a commercial reservoir simulator with a surface network simulator and Sequential Quadratic Programming (SQP) optimiser^{1,2}. The S-Field (a case study based on redevelopment of a real field with an Advanced or Intelligent Well development strategy) has been previously studied in-depth. It has been found to be a very useful case history to illustrate the potential advantages of implementing an Advanced Well development scheme^{2,3}. We have been able to show how the SQP optimiser can be used to increase the recovery compared to manual optimisation. This was achieved with a limited engineering manpower compared to the previous manual optimisation approach while the computer power requirements were less than that anticipated with other commercial optimisation software packages.

2.1 Advantages of integrated production modelling

Integrated production modelling is a concept that has been in development within the industry since the 1970s⁴. However, the application of this concept gained a lot of momentum in recent years due to successful, early applications 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 Optimisation⁵. Integrated production modelling had 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^{6,7}.

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:
 - Well’s inflow performance (e.g. development of a “skin” requiring well stimulation for its removal) or
 - 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 simulators have had 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 (Figure 1)^{8,9,10}. Further, flexibility to modify the network components settings once the simulation had started is not available. This could only be included by stopping the simulation, manually making the necessary changes and then restarting the simulation. This illustrates why any flow matching to observed field performance of the network components (i.e. pressure drop in pipes and compressors) has to be performed ahead of the simulation. This is not the case when an integrated production system model is available since modifications can be

scheduled or entered during the simulation pauses. Also, flow from any node in the network can be directed to multiple subsequent nodes rather than one node only¹⁸.

3. Literature review

Most of the published reservoir/surface network integration systems are:

- Commercially available products employing parallel, open server computing architecture with full or partial coupling of the two simulators (Figure 2)^{12,13,14,15},
- Incorporated in the reservoir simulators through implicit, full or partial, coupling of the subsurface/surface network with the reservoir, or
- Specially developed programs for specific application within an organisation that have not been made generally (commercially) available.

One of the early coupling examples is the development by Hepguler et. al.¹² of a tightly coupling interface between the reservoir simulator provided by *Supplier 2* and the network simulator and optimiser provided by *Supplier 4*. 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.

On the other hand, Coats et. al.¹⁰ have developed a fully coupled reservoir/network model that is solved simultaneously at the end of each simulator’s Newton iteration. The capability of modelling advanced well configurations was included. The model decomposes the wells and the facility networks into small domain models. These are then run simultaneously and iterated to solve the equations for each domain. The utilization of such coupling architecture is often time consuming when compared to explicitly coupled models with data exchange at every time step. Further, 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).

An example of the latter has been published recently by Hyder et al.¹⁶. He presented their work to optimise the quality of the crude oil production from three reservoirs with different crude properties producing from a giant Saudi Arabian field. This optimisation involved minimising the volume of light crude oil required for blending with heavier production so as to meet the quality requirements in order to maximise the value of the exported crude. They developed a driver to loosely couple Saudi ARAMCO’s in-house developed reservoir simulator to a commercially available surface network optimiser through the vendor’s communication software.

4. History of the field case study

The S-field is located in the Norwegian sector of the North Sea. The field was originally developed with seven conventional wells completed on only one of the two, separate

pressure regimes present in the four reservoir sands. A study by Elmsallati³ identified significant extra value would have been gained from the application of intelligent well technology if it had been used to develop the field. At the time of the first study, a (commercial) link between a surface network modelling software with optimisation capability and the reservoir simulator provided by *Supplier 2* was not available. The optimum choking policies of the modelled intelligent wells were implemented manually using the "Action" triggering techniques available for many years within the reservoir simulator. This methodology allowed him to identify a significant increase in the field recovery compared to the actual, conventional Field Development Plan that had been implemented. However, it proved to be an exhaustive task, both in terms of the time and engineering effort required as well as the computing power employed.

Sometime later, a (commercial) coupling software became available which was able to link the network optimiser and the reservoir simulator provided by the same vendor (*Supplier 3*). The S-Field reservoir model was thus transferred from the old reservoir simulator (*Supplier 2*) to the new reservoir simulation software (*Supplier 3*) to take advantage of this new opportunity². As expected, this shift produced different values in term of the Oil-Originally-In-Place and the cumulative oil production due to the differences in the calculation methods employed by the two reservoir simulators. Extra value was identified since the optimiser identified extra opportunities during the field's decline phase compared to manual techniques. This work thus proved the potential application of such technique to optimise the full field production in an efficient and automated manner.

In this study, on the other hand, we were able to successfully couple the original reservoir simulator to the same surface network model and produce even better results than the previously reported manual optimisation of the ICV settings with the "Actions" Keyword. Our results are not quantifiably comparable to the results of the second study (discussed in the previous paragraph) because of the differences in the calculation methodology employed by the reservoir simulators.

4.1 The S-Field reservoir simulation model

A detailed description of the reservoir simulation model has been published previously³. This included the reservoir layering, the rock and fluid properties, the production and injection well completions and the Interval Control Valves (ICV) locations. Figure 3 indicates the reservoir layering. Key parameters are the:

- Low oil viscosity,
- High gas-oil-ratio,
- Very high formation permeability,
- Strong aquifer support and
- Presence of two regions of differing pressure due to low permeability layer splitting the reservoir into two zones.

These parameters result in very high deliverability wells.

4.2 Wellbore and surface network model

The (hypothetical) advanced well development plan called for the installation of five intelligent wells with a total of 18 completion intervals each controlled by its own interval control valve (Figure 4). A group of three and two wells were respectively connected to two Subsea templates (SM and SL). The proposed wells replaced the existing seven conventional producers that were originally used to develop the field. A full description of the well completion models and network piping was published previously³.

5. The coupling of subsurface/surface models

The methodology followed by *Supplier 1* to link the reservoir simulation model to the subsurface/surface network model is a "loose coupling" in which 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 model. There are two data transfer methodologies, depending on the chosen well data input functionality in the network optimiser¹¹. 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 through the following steps:

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 from the recorded pressures with an incremental range higher and lower than the original bottomhole and near wellbore pressure.
3. Multiple reservoir simulation time steps are then conducted for short or long time steps (user defined) 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.
5. Next, the network model is solved and the optimum production rate is allocated to each completion using the network chokes (representing the ICV of the intelligent well completion). These liquid flow rates are imposed as target rates in the reservoir simulator for the next time step.

The advantages of this coupling method include the¹⁷:

- Elimination of the requirement for a Parallel Virtual Machine interface with reservoir simulator.
- Ability to modify the well configuration at any time-step specified by the user for the coupled optimisation run.

- Coupling taking place at the user specified time stepping.

6. Results and Discussion

The S-Field hypothetical development plan utilized five oil producers with 18 intelligent completion zones and three conventional water injectors. Elmsallati et. al. previously published results employing manual optimisation of the ICV settings to control the contribution of each zone will be used as the base case for this study. The automatic optimisation technique reported here employed a time step interval of 30 days i.e. at the end of every 30 day time step the production from each zone was evaluated and adjustment of ICVs settings was triggered by pre-set WC and GOR limits. These limits were modified through multiple iterations of the simulation model to achieve the optimum cumulative oil production from the field.

Utilization of the automatic optimiser with the new coupling technique improved the cumulative oil production by 7.0% compared to manual optimisation. The additional cumulative oil production was mainly produced during the decline period which proved to be particularly difficult to optimise using the manually selected value for the "Actions" keyword (Figure 5). Also, the cumulative water production was reduced by 10.0% (Figure 6). The time required to complete a fully coupled and optimised simulation run is about 8 hours for 18 years of the field life.

However, one difficulty was identified during the work. The automated optimiser did not maintain a stable plateau for the 30 day-time step. Therefore, a time step length optimisation study was carried out in which the 30 day-time step was sequentially reduced to a 5 day time step; yielding an optimum time step value of 15 days. This choice was based on the:

- Stability of the plateau period (Figure 7),
- Time required for the 18 year simulation period to run. Figure 8 illustrates the change in the coupled simulation run time based on the length of the time step, and
- Adverse effect of employing such frequent choking strategy on the reliability of such completions¹⁹.

Similar results were achieved when the coupling was introduced after the plateau production period had finished. This was done in order to verify if any added value can be gained if this type of optimisation techniques was introduced at different points of the field production life.

The oscillation of the automatically optimised results is a persistent challenge that has been identified by several authors^{2,16,20}. In our, case, the oscillation was partially attributed to the well bottomhole reference depth mismatch between the models which was rectified later, and partially due to the none convergence of the network solver causing optimiser fluctuation between choking alternatives in an attempt to identify the best possible solution.

This paper has illustrated the advantages of using the link

software to couple the reservoir simulator provided by *Supplier 2* and the network optimiser provided by *Supplier 3*. Similar advantages could have no doubt been derived from the coupling of other commercial reservoir and surface network simulators to a different surface network optimiser. This has not been tested, but the vendor claims that the software is capable of such links.

7. Conclusions

1. The new coupling technique between the commercial software provided by *Supplier 2* and *Supplier 3* was successfully applied to the S-Field.
2. The time required to configure and conduct the coupled simulation run was short compared to the manual identification of ICV adjustment triggering values and appropriate settings to optimise the full field cumulative production.
3. The need to link the programs using a Parallel Virtual Machine interface was eliminated.
4. The linking software is commercially available. It can be expected to be capable to link other commercial reservoir simulators to surface network optimisers after suitable testing.

Acknowledgement

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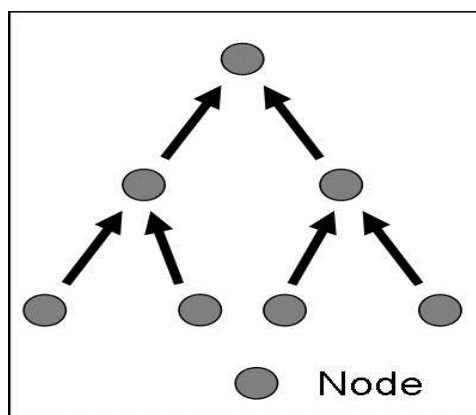


Figure 1: Network Configuration in Reservoir Simulation

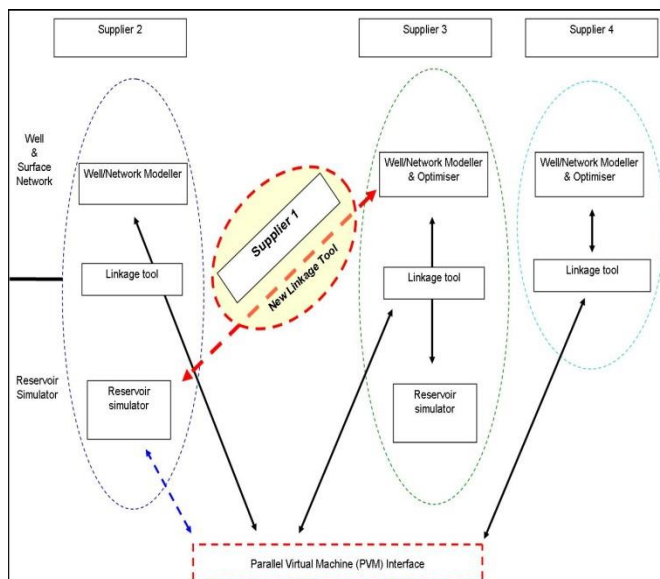


Figure 2: Commercially available integrated full-field simulation and optimisation software

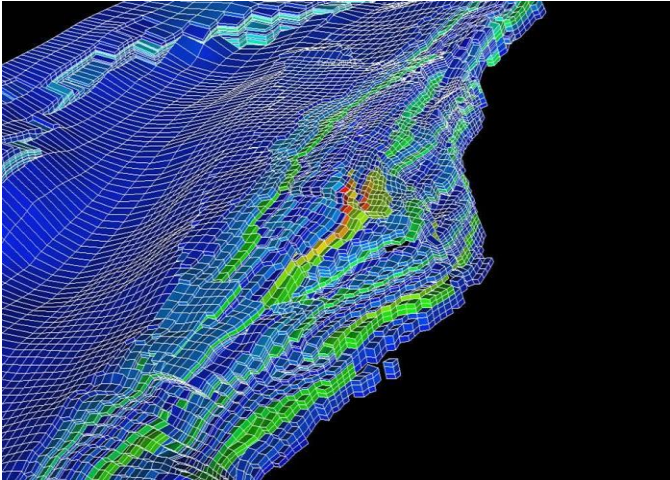


Figure 3: The reservoir simulation model (oil zones in green colour)

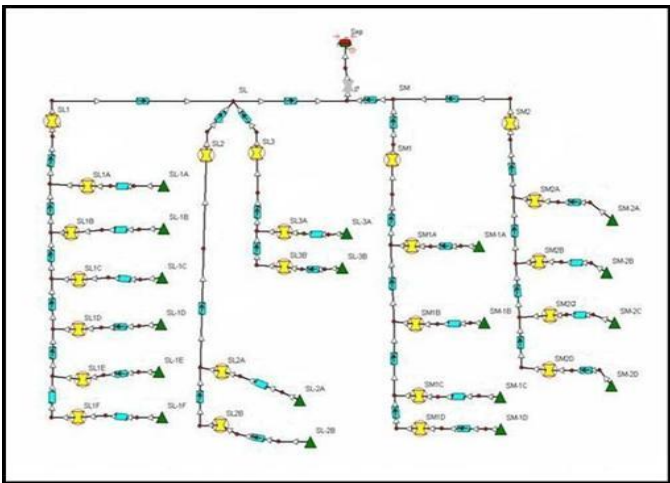


Figure 4: The Wellbore/Surface network model

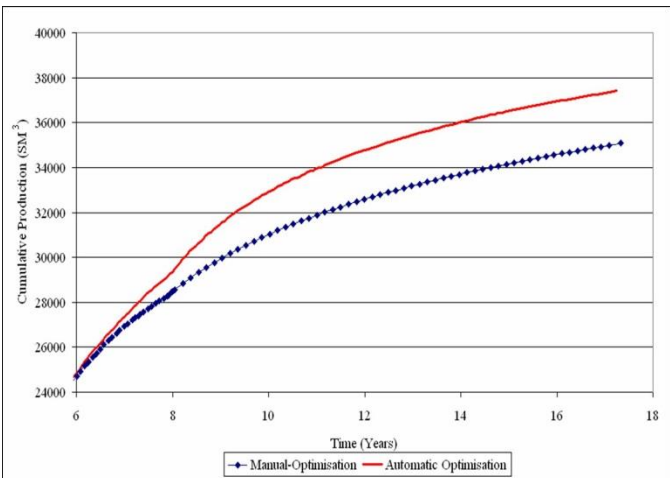


Figure 5: Comparison of cumulative oil production of manual & automated S-Field production optimisation

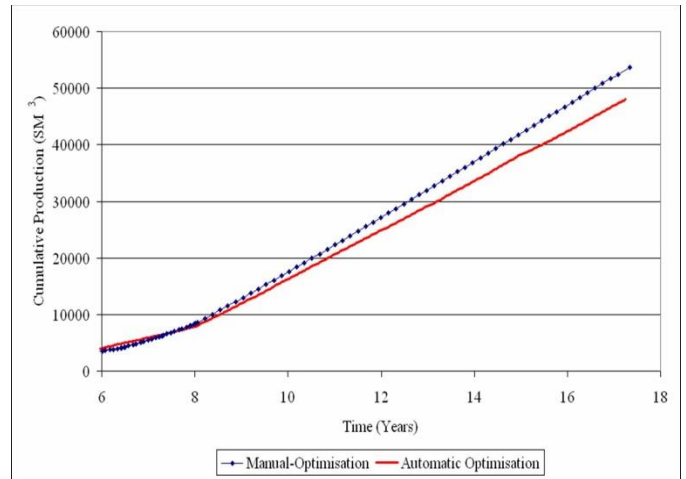


Figure 6: Comparison of cumulative water production of manual & automated S-Field production optimisation

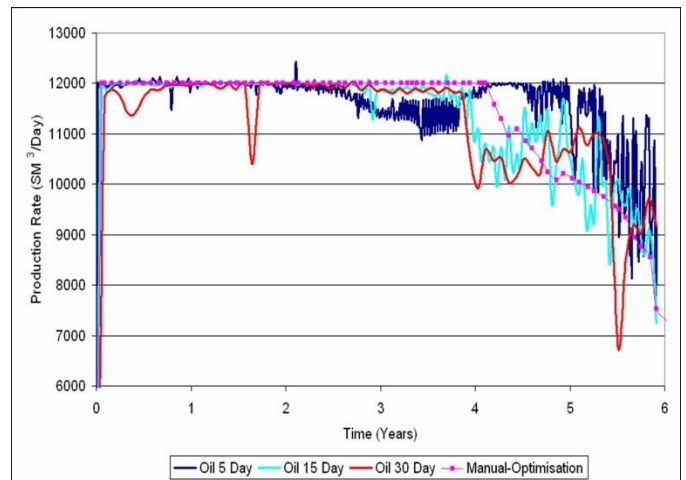


Figure 7: Comparison of the stability of the oil production rate as a function of the time step length with manual optimisation.

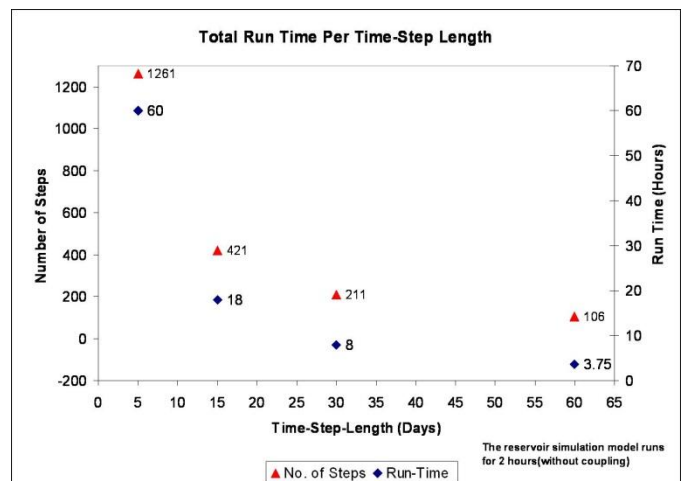


Figure 8: Simulation run time and number of steps as a function of time step length



SPE 108700

Inflow Control Devices: Application and Value Quantification of a Developing Technology

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Abstract

Horizontal and multilateral completions are a proven, superior development option compared to conventional solutions in many reservoir situations. However, they are still susceptible to coning toward the heel of the well despite their maximizing of reservoir contact. This is due to frictional pressure drop and/or permeability variations along the well. Annular flow, leading to severe erosion "hot-spots" and plugging of screens is another challenge. Inflow Control Devices (ICDs) were proposed as a solution to these difficulties in the early '90s. ICDs have recently gained popularity and are being increasingly applied to a wider range of field types. Their efficacy to control the well inflow profile has been confirmed by a variety of field monitoring techniques.

An ICD is a choking device installed as part of the sandface completion hardware. It aims to balance the horizontal well's inflow profile and minimize the annular flow at the cost of a limited, extra pressure drop. Fractured and more heterogeneous formations require, in addition, the installation of annular isolation. The new technologies of Swell Packers and Constrictors can provide this annular isolation in an operationally simple manner.

This paper describes the history of ICD development with an emphasis on the designs available and their areas of application. These technical criteria will be illustrated using published field examples. The ICD's flexibility will be shown by its integration with other conventional and advanced production technologies e.g. Stand-Alone-Screens, annular isolation, artificial lift, gravel packs and intelligent completions in both horizontal and multilateral wells.

It will be shown how the value of such well-construction options can be quantified using commercially available, modelling simulators. Simple, but reliable, guidelines on how

to model the performance of ICDs over the well's life will be provided. This technique can thus be used as part of the value quantification process for both the evaluation of completion options and for their detailed design.

1 Introduction

Horizontal and multilateral wells are becoming a basic well architecture in current field developments. Advances in drilling technology during the past 20 years facilitated the drilling and completion of long (extended reach) horizontal and multilateral wells with the primary objective of maximising the reservoir contact. The increase in reservoir exposure through the extension of well length helped lower the pressure drawdown required to achieve the same rate and enhance the well productivity¹⁻². Major operators have proved the advantages of such wells in improving recovery and lowering the cost per unit length. The production from thin oil column reservoirs (e.g. The Norwegian Troll Field) became a reality thanks to such wells³⁻⁴.

However, the increase in wellbore length and exposure to different reservoir facies came at a cost. Frictional pressure drop caused by fluid flow in horizontal sections resulted in higher drawdown-pressure in the heel section of the completion, causing an unbalanced fluid influx. Hence, coning of water and gas toward the heel of the well was observed. Variable distribution of permeability along the wellbore also results in variation of the fluid influx along the completion and an uneven sweep of the reservoir.

Annular flow is another challenge often encountered when horizontal wellbores are completed with Stand-Alone-Screens (SAS) or with pre-perforated/Slotted liners. Neither of these completion options employs any form of isolation between the casing and the formation (i.e. external casing packers). Annular flow, which is dependent on many parameters such as the size of the clearance between the sandface and the liner (screen) outer diameter, still imposes several problems including: dislodging of the sand grains causing erosion of the sandface, formation of "hot-spots" and plugging of the sand screens⁵⁻⁶. Previously, the elimination of such phenomenon required the utilization of gravel packs or installation of Expandable Sand Screens (ESS), which often had a significant impact on the well productivity and/or involved a very complex operation⁶⁻⁷.

Inflow Control Devices (ICDs) are a new sandface completion

technology specifically developed to help balance the contribution along horizontal wellbores. Extensive flow-loop testing and subsequent field experience have proved the potential of ICDs to extend the well life by extending the plateau period, minimizing water and gas coning, minimizing annular flow and increasing recovery.

2 Historical Development

Norsk Hydro introduced the ICD technology in the early 1990s as a means to enhance the horizontal wells performance of the Troll Field. The Troll field is a giant gas field located on the Norwegian shelf of the North Sea. The field contains a thin oil column (4-27 meter thick) overlain by a large gas cap and underlain by an aquifer. 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 oil⁸⁻⁹. The wells were completed with large diameter pre-packed slotted liners to reduce the effect of frictional pressure losses along the wellbores. The long-term test results indicated that a significant oil production potential existed. The initial flow rate of the first well was four times that expected from a vertical well. The well PI was very high ~ 6,000 Sm³/day/bar; which is some 5-10 times higher than that expected from a vertical well. This also meant that a small pressure drop of only 0.5 – 1.0 bar is sufficient drawdown pressure to produce the well at a target rate of 3,000 – 5,000 Sm³/day.

A new field development plan was then put in place that employed horizontal wells. However, the production logging of the first test well indicated that 75% of the contribution was coming from the first half of the horizontal section. This is indicative of the significant effect frictional pressure losses can have on the performance of the horizontal wells once this frictional pressure drop is of the order of magnitude of the drawdown⁸.

Three completion options were proposed to overcome this problem including: a stinger method, reduced perforation density and an innovative Inflow Control Liner Device (ICD)¹⁰. This latter, the original ICD concept had a number of labyrinth channels installed within a pre-packed screen mounted on a solid base pipe (Figure 1). The fluid flowing from the formation passes through the screen and the channels before entering the casing (liner) internal section through predrilled holes in the base pipe. The labyrinth channels’ length and diameter can be adjusted to achieve the required pressure drop to balance the inflow along the length of the liner. 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%. The ICD design was then modified by Supplier 1 for commercial manufacturing by altering the labyrinth channels to helical channels.

3 ICD Designs

Three of the worlds 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 (Channels, Nozzles or Orifices). All these designs can be mounted on a Stand-Alone-Screen (SAS) for application to unconsolidated formations or they can be combined with a debris filter for use in consolidated formations.

3.1 Channel-type ICD

The channel-type ICD was developed by supplier 1 as a modification to the original labyrinth ICD. The device uses a number of helical channels with a preset diameter and length to impose a specific differential pressure at a specified flow rate (Figure 2). The produced fluid flows from the formation through a limited 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 onto the inner section of the casing; either through holes of preset diameter or a slotted mud filter installed to prevent the screen from being contaminated by kill mud during any future, well killing operation.

This ICD is available with five flow resistance ratings (0.2, 0.4, 0.8, 1.6 and 3.2 bar) based on the diameter, length and number of channels incorporated into the device¹¹. These choking values were measured at a flow rate of 26 Sm³/day/ICD joint for the design fluid¹². This reference reports the carrying out of extensive flow tests in which the pressure drops at different flow rates were recorded for the different ICD ratings. A sample of these flow test measurements was included in this reference.

The specific design of the channel-type ICD causes the pressure drop to occur over a longer interval compared to the nozzle and orifice-type ICDs, an advantage that is deemed to reduce the possibility of erosion or plugging of the ICD ports. However, this device depends on friction to create a differential pressure in addition to the acceleration effect. This implies that the actual pressure drop created will be more susceptible to emulsion effects.

3.2 Nozzle-type ICD

The nozzle-type ICD was developed by Supplier 2. The device uses nozzles to create the pressure resistance (Figure 3)¹³. The fluid passing through the screen is collected in a chamber where a set of preconfigured nozzles control the fluid flow from the chamber to the inner section of the liner joint. The number and diameter of the nozzles are chosen so as to produce the desired 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 is one of the major causes of erosion, especially when combined with sand production.

3.3 Orifice-type ICD

Supplier 3 employs multiple orifices to produce the required differential pressure for flow equalization (Figure 4)³⁸. 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 as opposed to the nozzles type ICD. Different pressure resistance values are achieved by reducing the number of open orifices. Although, the exact location of the orifices within the ICD chamber is different to that of Supplier 2's nozzle-type ICD, the flow characteristics are expected to be similar, though with minor difference in the flow coefficient value. More details on these differences between these designs will be explained in the modelling section.

4 Published Applications

The advantage of this technology was recognized by many operators through its application to different fields. The first application of ICDs was reported in the Troll Field for which the technology was originally developed. ICDs have since gained rapid acceptance throughout the industry. The following is a revue of published applications of ICDs to both sandstone and carbonate formations.

4.1 ICD with SAS in Horizontal Wells

As indicated above the first ICD application was of the helical channel-type ICD. One of the reported ICD installations is in the longest horizontal section to be completed in the Troll Field. Well M-22 had a horizontal section length of 3,619 meters. It was completed with 279 joints of SAS equipped with ICDs. The numerical simulation indicated that a "stair step" arrangement 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 is the optimum completion design¹⁴. Annular isolation with External Casing Packers (ECPs) to prevent flow along the length of the formation face was not employed. The stair step design was later modified to single ICD strength of 3.2 bar along the entire horizontal section due to the insignificant increase in the simulated cumulative oil production predicted for the optimised (stair step) design and to simplify the operational logistics at the wellsite (how to ensure that the different strength of ICDs are run into the hole in the correct order). Another important reason that influenced the decision to utilize a single ICD strength was the inability to calculate the magnitude of the above annular flow in the available reservoir simulator. There were worries that a significant flow from the region of the high strength ICD to that of the lower strength ICD might exist¹². This concern will be addressed in chapter 6 of this paper where this modelling deficiency is removed.

4.2 Integration with Annular Isolation

One claimed advantage of ICDs is the elimination of annular flow. However, this will only be achieved if a highly homogenous permeability distribution exists along the length of the horizontal wellbore. Variations in permeability, hole size or undulation along the wellbore can trigger annular flow even when ICDs are installed. In practice, annular isolation is a necessity to ensure that the full benefits of ICD installation are achieved. Different forms of annular isolation are available

in the industry at this stage, including: Inflatable or Mechanical External Casing Packers (ECPs), Swell Packers (SPs), Constrictors and Expandable Packers. Many of the reported ICD applications included one of these packer types^{17, 19, 20, 22}. The Z-253 well was completed in Zuluf Field, offshore Saudi Arabia, utilized four Mechanical ECPs in conjunction with single strength channel-type ICD to segment a 2200 ft-long wellbore^{14, 15}. The placement of the ECPs was based on the permeability of each hole section. This completion enhanced the productivity and equalized the inflow of the well compared to its neighbour a conventionally cemented and perforated well. SPs were used for annular isolation in the West Brea 16/7a-W8z well¹⁸. This horizontal well was completed with multiple ICD strengths ranging from 3.2 bar at the heel to 0.8 bar at the toe with swell packers installed when the ICD strength changed. This completion allowed an increase in the well production by an incremental rate of 5,000 barrels of oil per day and delayed water breakthrough compared to the offset wells.

The above example applications were for sandstone reservoirs. In carbonate reservoirs, however, annular isolation has a second objective. ECPs or SPs were installed in conjunction with (multiple) lengths of blank pipe to cover fractured or super-K permeability zones. Alternatively, they may be installed with ICDs to restrict the inflow of free gas from the gas cap through 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 reservoir²⁴. A total of five openhole packers were set along the completion string two of these packers were combined with the 250 ft of blank pipe to isolate the highly fractured zone which had been identified through mud losses during the drilling and image logging operations. The remaining packers were utilized to separate the different permeability zones. 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 gas-cap-gas influx through the high permeability zones²³.

All above examples were channel-type ICD applications. Installation of a nozzle-type ICD with annular isolation was reported in Well Sakhalin-1 in the Chayvo field²¹. 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. This helped equalize the inflow profile along the well by minimizing the contribution from the high permeability zone, which was expected to dominate the production and suppress the contribution of the low permeability zones.

4.3 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, hence, encouraging increased coning of water or gas. The combination of ICDs

with artificial lift will help minimize this effect. Wells in Saudi Arabian Z and M fields and in the Troll and Grane fields in the Norwegian shelf of the North Sea have reported the combination of ICDs with different forms of artificial lift. The latter included conventional gas lift, gas-cap gas (In-situ gas) lift and Electric Submersible Pumps (ESP)^{16, 19, 20}.

4.4 *Integration with Gravel Pack*

ICD installation and integration with annular isolation aims to eliminate annular flow, a primary cause of sand particles becoming dislodged from the sandface and being transported along the annulus. Screen erosion and plugging, in addition to many sand production related problems at the surface will result. However, experience with gravel packs in conventional and horizontal wells have proven their ability to eliminate or minimize sand production in various fields. In the Etame oil field, offshore Gabon, channel-type ICDs combined with a horizontal gravel pack was applied to the Subsea ET-6H well both to eliminate potential sanding problems and to delay water breakthrough²⁵.

4.5 *Integration with Multilateral, Intelligent Completion*

Simulation results have indicated that the installation of ICD completions in individual laterals of dual or higher level lateral well in a homogeneous formation helps even out the water and gas fluid front movement towards each lateral¹¹. However, if the laterals are completed in different reservoir facies or at different vertical depths, then water breakthrough in one lateral before the other will lead to a deterioration of the total well performance. This effect can be alleviated by combining an ICD completion along the well laterals with installation of Inflow Control Valves (ICVs) at the mouth of each lateral. The ICVs can be remotely controlled to adjust each lateral's flow contribution upon the onset of unwanted (water or gas) fluid production.

An integrated ICD completion with level 4 multilateral junctions equipped with ICVs to control the production from each lateral was implemented in the Z Field, offshore Saudi Arabia²².

5 *ICD Commercially Available Modelling Techniques*

Brekke et al.¹⁰ paved the way for the modelling of ICD completions. They represented a horizontal well in an in-house, wellbore modelling program and the resulting sand-face pressure of the ICD completion in the wellbore simulator was applied to a "frictionless well" in the reservoir simulator. Later, Brekke et al.²⁷ proposed an integrated wellbore/reservoir simulation approach in which, simulation of the originally proposed labyrinth ICD in a horizontal wellbore simulator was coupled with a 3-D, two phase reservoir simulator. The horizontal wellbore simulator employs a general network solver for calculation of steady state flow through the wellbore completions with the option of applying one of several multiphase flow correlations. The horizontal wellbore is modelled as a network of nodes in a gathering tree topology; starting from the sand-face

connection point (at each reservoir gridblock) 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 parameters in the wellbore network simulator.

An iterative coupling technique was used. The reservoir simulator supplied the reservoir (reference) pressure and connection productivity indices to the wellbore simulator which, in turn, calculated the pressure drop through the completion to the output point. The application of this technique resulted in a very good convergence in the wellbore simulator calculated oil flow rates. However, the indicated wellbore representation in the published paper did not account for flow splitting between the annulus and the tubing, which means that the flow from the reservoir connection (gridblock) is forced to flow through the ICD and into the tubing. This latter may not be an accurate representation of what happens in practice, though the technique is an adequate modelling approach when there is a homogeneous permeability distribution along the wellbore. However, the inclusion of annular flow is critical for the proper design of the ICD strength distribution and selection of annular isolation points when a heterogeneous reservoir simulation model is coupled with a wellbore model. Also, automated identification of required ICD strengths for each wellbore section is preferable over the (manual) iteration of the required labyrinth length to achieve the required pressure drop.

5.1 *ICD Modelling in Reservoir Simulator*

EclipseTM 100 is black oil, finite difference reservoir simulator which has the capability to model ICDs through its Multisegment Well Model²⁸, which divides the wellbore into a number of segments (Figure 5). The individual segments can be part of the annulus, tubing or an intermediate device between the two (i.e. an ICD or ICV). Flow from one or more reservoir gridblocks can be directed to a single annular (or tubing) segment. It should be noted that the "2005a" version of the simulator allows the flow from one or more segments to be directed to only one segment in the direction of the topmost segment. Previous simulator versions used a special keyword allowing a wellbore segment to be identified as a Labyrinth ICD. Recently, a new keyword which accurately models the ICD flow behaviour through the proportionality constant relating the flow rate to the pressure drop through the ICD was introduced¹². This was included after the development and extensive testing of the helical channel-type ICD (chapter 3.1). The authors can confirm that this keyword accurately matches the flow test data published in reference 12 when single phase fluid was used.

This technique is equivalent to that used by Brekke et al.²⁷. This approach is highly recommended when analysing the benefits of ICD application in homogenous reservoirs where split flow between the annulus and tubing is not expected to be significant. Identification of the proper ICD distribution with or without annular isolation is a relatively uncomplicated process in this type of reservoir.

Other reservoir simulators which are capable of modelling

downhole control valves in a network are also limited to the gathering tree type networks with merging nodal flows³⁷.

5.2 ICD Modelling in Wellbore Simulator

NETool™ is a commercially available well completion modelling and planning simulator²⁹. It is a network based modelling tool with the capability to solve steady state multiphase fluid flow through a variety of well completions. The data describing 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 gridblocks) into the well completion are represented by a specified number of nodes which can be connected in a number of different ways in order to simulate flow through the annular space, through any completion equipment such as ICDs or through the tubing. This simulator includes four specific correlations that model helical channel-type, nozzle and orifice-type ICDs in different reservoir and fluid flow environments with great accuracy. A very good illustration of the capabilities of this software has been presented by Ouyang et al.²⁹. Unfortunately, the current commercially available version of the software (2.5) is not coupled with a reservoir simulator. Automated interaction between the reservoir and wellbore models as proposed by Brekke et al.²⁷ is therefore not possible. The 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 annular flow and different packers settings) at every time step of the simulation is necessary when it is required to capture the time dependent depletion effects associated with the planned completion design.

5.3 Other Models for Channel and Nozzle-type ICDs

Augustine¹¹ presented a complex integrated reservoir/wellbore modelling technique using channel-type ICDs in the SINDA/FLUINT fluid dynamics software package. The software is a finite difference, network analyzer. Augustine's model represents the reservoir parameters governing the three dimensional fluid flow, such as reservoir permeability and fluid viscosity, as flow resistance parameters.

SINDA/FLUINT is relatively cumbersome to use and only a limited number of petroleum engineers are familiar with its use.

Atkinson et al.³⁰ conducted a thorough investigation and developed a mathematical model of steady single-phase flow into a horizontal wellbore completed with ICDs in an anisotropic reservoir. They solved the one-dimensional, singular, integro-differential equation numerically. The model can be used to find the flux distribution along the wellbore for a specified pressure drawdown and to determine the ICD properties when the flux or reservoir pressure drawdown along the wellbore is known. Annular flow is not included in this model nor is it currently commercially available.

6 Proposed Modelling Approach

ICDs were originally proposed and commercially developed

for homogenous sandstone reservoir. However, the review of the various published application of ICD completions in chapter 4 has shown that this is no longer the case. More heterogeneous environments including fractured carbonate reservoirs are benefiting from the application of this technology. Such applications require accurate modelling of the completions, as discussed in chapter 5. In this chapter, we will follow on the steps of Brekke et al.²⁷ by utilizing an integrated reservoir/wellbore approach which, can be used to optimise the distribution of ICD nozzle/orifice configuration along the horizontal section, account for annular flow which is key parameter in locating external isolation and can be extended to surface facility network modelling as well.

6.1 Reservoir Simulator

The reservoir simulator could be any, commercially available, 3-D, finite difference reservoir simulation software with the capability to be linked to a surface network modelling software. In this paper we will use the Eclipse™ 100 black oil reservoir simulator. Eclipse™ 300 (compositional reservoir simulator) and Reveal™ have also been tested in this study and achieved similar results to those reported here. These simulators allow the reservoir gridblocks to have any suitable geometry (i.e. Cartesian, radial or unstructured). A frictionless horizontal wellbore can be modelled in the reservoir simulator with controllable connection pressures or flow rates at each gridblock. If this is not possible, then each gridblock connection has to be modelled as a well without Vertical Flow Performance Table (VFP) but with controllable bottom hole pressure or flow rate. The coupling of the bottom hole nodes (at the sandface) of these connections into one (horizontal or inclined) completion is then constructed in the subsurface/surface network modelling software. However, within the reservoir simulator, the separate wells can be connected in a frictionless downhole network with common output node that can be used for comparison with the wellbore model output node pressure or rate value. This will ensure conversion between the two models at the topmost node. It is preferred that the gridblock length size, in the direction of the wellbore, matches the ICD joint length since the modelling of fluid flow from one inflow connection to multiple pipes might introduce flow circulation.

6.2 Subsurface/Surface Network Solver and Optimiser

The modelling of ICD modules was successfully tested in three, steady state, subsurface/surface network solver software(s): The General Allocation Program (GAP™ provided by Petroleum Experts), Pipesim™ (provided by Schlumberger) and Reo™ (provided by e-Petroleum Services-Weatherford). All of these software(s) are capable of modelling merging flow as well as diverging flow nodes, allowing the capture of split flow between the annulus and through the ICD to the tubing. In this paper we will focus on the utilization of GAP™ due to its ability to automatically optimise choke settings and connection (Wells/inflows) pressures together with the availability of commercial tools allowing its coupling to many reservoir simulators.

GAP™ allows the user to model a downhole wellbore completion that can be connected to a surface network through Vertical Lift Performance (VLP) tables or through pipes with a choice of multiple flow correlations that can be matched accurately to the well performance and deviation. The downhole completion could contain in-line controllable or fixed chokes, valves. These devices can be modelled by built-in flow correlations or by programmable elements. Programmable elements allow the user to define any equipment as a pressure loss element. Both the existing choke model in GAP™ and the programmable element will be used to model the ICD effect as follows:

6.2.1 Modelling of the channel-type ICD:

Both single and two phase flow of steam (or air) and water through helical pipes have been studied extensively by many researchers, especially for the design and evaluation of heat exchangers. One of the distinguishing factors between flow in helical pipes and flow in straight pipes is the centrifugal force effect, which was initially characterized by W. R. Dean³¹. The effect of the centrifugal force is to cause the critical Reynolds number (Re) at which the transition from laminar flow to turbulent flow occurs to be a function of the Dean number (De) and the Curvature ratio (λ):

$$De = Re(\lambda)^{\frac{1}{2}} \quad \text{Equation 1}$$

Where:

$$\lambda = d / D \quad \text{Equation 2}$$

Where d is the pipe diameter and D is the helical diameter. Ju³² found that the critical Reynolds number, responsible for the transition from laminar to turbulent flow, for flow through small helical pipes is much greater than its match in straight pipes. However, when modelling helical channel-type ICD in network modelling software, it should be considered that the fluid flowing through the ICDs could be a single phase, two-phases or even three-phases, depending on the application environment.

Chen, et al. have studied the flow patterns and pressure drop of two phase (oil-water) and three phase (air-oil-water) flow in horizontal helical pipes³⁴. They observed that the water-cut at which phase inversion point (the point at which the dispersed phase changes into a continuous phase and the continuous phase changes into a dispersed phase) occurs at a lower value in helical pipes than in horizontal straight pipes. The phase inversion water cut (ϵ_w) in a horizontal straight pipe in an oil-water system was referred to Arirachakaran, which can be obtained as follows:

$$\epsilon_w = 0.5 - 0.1108 \log \eta \quad \text{Equation 3}$$

Where η is the dynamic viscosity of the oil in cP.

Chen, et al.³⁴ also indicated that a modification of the Chisholm pressure multipliers, which are based on the Lockhart-Martinelli method, fits the measured pressure drop through the horizontal helical pipes adequately and Chen's equation can therefore be applied to calculate the pressure drop through a helical channel-type ICD. However, the ICD

channel dimensions have not been published. Hence the above, more fundamental approach to the calculation of pressure drops can not be used. We therefore used the pressure drop calculation procedure followed in Eclipse™ reservoir simulator in an element in GAP™, reproducing the exact pressure drop calculated by Eclipse™ for a single ICD.

The programmable elements can be distributed in the completion model as indicated in Figure 6 so as to resemble an ICD installed between the annulus and inner tubing.

6.2.2 Modelling of the nozzle/orifice-type ICD:

The pressure drop through nozzles and orifices is best described by the ISO 5167-1. Here, the derivation of the relation between the mass or volumetric flow rate and pressure drop starts from the well known Bernoulli's equation. The differences in fluid flow behaviour through nozzles and orifices are reflected in the Coefficient of Discharge (C_d) values.

The inline choke model in GAP™ is based on the conservation of energy equations with a provision of a Discharge Coefficient correction multiplier³⁶. This multiplier is used to correlate the calculated pressure drop through a particular nozzle or orifice-type ICD with the actual flow test data measured for the device. These chokes can be distributed in the same manner followed for the channel-type ICD using a Programmable Element.

In many situations, this modelling technique could also be used to model channel-type ICDs. For example, when low viscosity oil flows through the device the choking effects will be more pronounced than the frictional effects. This allows normal choke models to be used to model the device's performance.

The ICD (nozzles/orifices) sizes can be adjusted automatically using the Sequential Quadratic Programming (SQP) capability of GAP™ to equalize the fluid influx along the horizontal section of the well. Minor adjustments to the connections' weighting factors in the optimisation process might be required to accurately control the contribution of each section of the well.

6.3 Coupling of Reservoir/Wellbore Models

There are many coupling tools available commercially that would allow the integration of the reservoir simulation model and network solver and optimiser at the connection (sandface) level such as Resolve™, S3connect™, Field Planning Tool™, Avocet™, etc. The main task of the coupling tool is to transfer the full Inflow Performance Relationship (IPR) of each connection from the reservoir simulation to its counterpart in the network modelling software and to return the specified value of the controlling parameter for each connection to the reservoir simulator in an automated process³⁵. Experience has shown that it is better to use the pressure as the control parameter rather than liquid flow rate since the latter tends to produce oscillations in the results.

Only one or two time steps are required to capture the well flow behaviour and optimise its completion design as an initial step prior to modelling of the full well life. An evaluation of

the well flow characteristics if completed with conventional completion can be examined after the initial IPR tables are transferred to the wellbore network model. Then, an ICD completion with annular isolation can be modelled and optimised either automatically using the optimisation tools available in the network modelling software (GAP™) if the reservoir is relatively homogeneous; or manually through alteration of the number of ICD and their strength values for heterogeneous case.

Resolve™ (Provided by Petroleum Experts) was used in this study to couple the reservoir and well models. It allows a number of choices for the controlling parameter for each connection such as the Bottom Hole Pressure, Liquid Flow Rate, etc. In this study the Bottom Hole Pressure was used to control the contribution from each connection. IPR data tables for each well connection in the reservoir simulation model were generated and transferred to the wellbore network model, and subsequently the controlling bottom hole pressure for each connection was transferred back to the simulator for each time step.

6.4 Example Case Description

A synthetic reservoir simulation model containing 3 regions of moderate permeability ranging from 2,000 to 3,000 mD with Kv/Kh value of 0.1 was generated. The 2,000 mD regions are intersected by high permeability zones (5,000 mD) with widths of 40 and 80 ft (Figure 7). The model dimensions and fluid properties are summarized in Table 1. Also, a numerical aquifer was attached to the reservoir model to provide pressure support.

Table 1: Reservoir Properties

Length (ft)	4,000
Width (ft)	800
Height (ft)	400
Regions	3
Porosity (%):	
Each region	22, 25, 22
High permeability zones	28
Permeability (mD):	
Region 1 & 3	2,000
Region 2	3,000
High permeability zones	5,000
Kv/Kh	0.1
Relative permeability	Theoretical
Pressure (psi)	3,000
Temperature (°F)	150
Oil Density (lbm/ft ³)	58.0
Oil Viscosity (cP)	10.0

A horizontal well intersecting the high permeability layer was modelled in the network solver and optimiser program. The horizontal lateral is 3,000 ft-long connecting to 75 gridblocks. Each gridblock connection in the reservoir simulation model was matched with an inflow in the wellbore network model. The well dimensions are listed in Table 2. The wellbore dimensions were kept constant in the comparison between the

ICD and SAS completions to eliminate the effect of tubular size variation. The completion was sufficiently large so that friction along the openhole was small. Thus, the inflow profile will only reflect the effect of the permeability variation. Nozzle-type ICDs were modelled using inline chokes which were modified by suitable C_d multiplier.

Table 2: Well Dimensions

Length (ft)	3,000
Open hole diameter (ft)	0.7083
ICD Screen OD (ft)	0.6250
ICD Screen ID (ft)	0.5
Depth (ft)	4,815

6.5 Methodology

After the construction of both models, an initial coupling time step was run to transfer the IPR tables for each inflow/connection and establish a representative well inflow performance relationship in the network solver program. The wellbore was first modelled with 6-in Internal Diameter (ID) and 4-in equivalent annular diameter to resemble an open-hole SAS completion with annular flow. The annular segments at each edge of the high permeability zones were disabled to resemble annular isolation packers. The contribution of each connection when SAS with annular packers completion was applied is shown in Figure 8. It is apparent that the high permeability zones are dominating the well inflow performance.

The well was then completed with nozzle-type ICDs. Annular isolation was installed at each edge of the highly contributing zones to eliminate annular flow and force the produced fluid to pass through the ICDs installed at that depth. The minimum and maximum standard nozzle sizes were then set for each ICD to allow for automatic optimisation of ICD distribution along the horizontal section. High connection weighting values were given to the low contributing zones and low values to the high permeability zones in the optimisation process in order to enhance the optimiser's performance. GAP™ allocated high strength ICDs along the highly contributing zones and lower strength ICDs along the low permeability zones at the heel and toe sections of the well. The allocated nozzle sizes were adjusted slightly to match the available nozzle-type ICD sizes (Table 3). The application of this design resulted in a relatively equalized fluid influx along the wellbore (Figure 9). The coupled reservoir/wellbore models were simulated for the full economic life of the well after acceptance of this final completion design.

6.6 Results and Discussion

The optimisation of the ICD strength distribution along the horizontal section equalized the fluid influx early in the well life. However, it failed to maintain the equalized fluid front after 2 years of production and depletion of the reservoir pressure. The waterfront arrived at the wellbore shortly after its arrival in the SAS completion and in almost the same zones as indicated in Figure 10 and Figure 11. This behaviour is

attributed to the:

- 1) Transmissibility between the high permeability and low permeability zones in the near wellbore region is high; causing the fluid to cross flow behind the packer from the high to the low strength ICD region (Figure 12), and
- 2) ICD strengths being sufficient to ensure equalized flow when the layer pressures were of the same magnitude and the only distinguishing factor was the deliverability of each zone.

The above phenomena are not usually considered due to limitations of the currently available, ICD modelling software(s) (chapter 5).

ICD strength values and annular isolation packers were redistributed along the wellbore in order to eliminate these effects. It was found that two annular isolation packers each side of the high permeability zone was most effective. This double packer arrangement creates a transition zone between the high permeability zone and the low permeability zones along the wellbore

This novel arrangement is pictured in Figure 13. Two packers are installed at the edge of the high permeability zone and the extra packers are installed two ICD joints away from the high permeability zone. These ICD joints are of similar ICD strength to the ones installed across the high permeability zone.

This arrangement ensures that the 80 ft of low permeability formation next to the high permeability region continues to contribute to the flow without being restricted by the higher productivity zone. The simpler completion, expanding the distance between the packers to isolate the high permeability zone and a portion of the low permeability region, will result in a loss of effective, reservoir inflow length (Figure 14).

Installation of higher strength ICDs across the high permeability zone equalised the zonal contribution early in the well life (Table 3). Further optimisation was required after the water breakthrough locations were identified to ensure proper inflow management over the complete well life (Table 4). This final optimisation of the ICD completion resulted in an extension of the oil production plateau period (Figure 15) and a 11% increase above the SAS completion's cumulative oil production (Table 5).

6.7 ICD Placement Optimisation Loop

Optimisation of the ICD strengths and annular isolation distribution along the horizontal section of the well during the early production period will assist in delaying unwanted fluid breakthrough and help equalize the fluid influx into the wellbore. However, this might not be the optimum completion for the complete well life. Operators often use the models described in Chapters 5.1 & 5.3 to optimise the pattern of ICD strengths along the wellbore. The planned design is further optimised once the actual well logs are acquired.

The above example illustrates why it is necessary for any simulation designed to optimise the ICD strength distribution to include all stages in the well life. In particular:

1. Early, dry oil production,
2. Water or gas breakthroughs and

3. Development of pronounced variation in layer pressures. N.B. Stages 2 and 3 may occur at more than one time throughout the life of the well.

A multistage optimisation process is therefore required in which the initial ICD distribution is optimised to equalize the fluid influx to the wellbore. Then, an evaluation of this completion throughout the well life with consideration of annular flow is carried out. Further optimisation of the ICD distribution is performed at the onset of unwanted fluid due to variation in the reservoir fluid contacts or when a pronounced variation in the layer pressures is noticed. A re-evaluation of the new completion from the start of well life is then conducted and necessary further completion changes implemented and their performance evaluated.

This technique allows the modeller to properly capture the variation in the well completion performance over the well life and quantify the value generated from the completion design.

Also, the proposed ICD modelling and optimisation technique can be applied prior to the drilling of the well and/or after refining the simulation model with the acquired well data (logs) during and after drilling.

This workflow allows multiple realizations of the simulation model to be coupled to the wellbore model simultaneously. The modeller can thus evaluate multiple scenarios of the well completion before making decisions.

This modelling technique may not be necessary when designing completions for reservoirs with a homogeneous permeability distribution (unfortunately a relatively rare occurrence).

Managing unwanted fluid influx in carbonate formations is often a major production problem. The ICD/Swell Packer enable completion design was shown to give significant improved recovery in a model reservoir in which the high conductivity contrast approaches the values experienced in fractured and other carbonate formations. Translation of this favourable result to real well completion recommendations will require inclusion of several aspects of reservoir flow physics that have not been included here.

7 Additional Advantages

Some of the advantages from this modelling workflow are the:

1. Evaluation of the most applicable type of ICD for the appraised environment can be performed easily.
2. Effect of erosion or plugging of nozzles/orifices can be evaluated after an appropriate production period by an increase or reduction in the nozzle/orifice size.
3. Integration of ICDs with Inflow Control Valves (ICVs) controlling zone or lateral inflows from a multi-zone, single wellbore or a multilateral completion. ICV operation can be optimised to maximise recovery after unwanted fluid breakthrough occurs using a commercially available optimizer³⁵.

N.B. (Cross) flow from the open annulus back into the formation i.e. the case when the section of openhole annulus has a greater pressure than the reservoir gridblock forming the wellbore, can not be modelled at this stage.

8 Conclusions

1. The efficiency with which ICDs can optimise the well influx profile and prolong the well life by mitigating water and gas coning has been proven in a wide range of reservoir environments.
2. Previous publications on ICD applications have emphasized the need for techniques to optimise the design and recognize the full value of such a completion.
3. A simple technique to model and optimise the ICD completion in any well configuration using commercially available tools has been presented.
4. The ability to automatically optimise the ICD strength distribution along the horizontal section added a great value to this process in term of time that would otherwise have been spent on "trial and error" manual alteration of the ICD strengths.
5. The importance of this technique arises from the lack of current ICD modelling programmes that adequately accounts for both annular flow and time dependent effects simultaneously.

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10 Nomenclature

ECP	= External Casing Packer
ESP	= Electric Submersible Pump
ESS	= Expandable Sand Screen
ICD	= Inflow Control Device
ICV	= Inflow Control Valve
IPR	= Inflow Performance Relationship
SAS	= Stand-Alone-Screen
SP	= Swell Packer
C_d	= Coefficient of Discharge
D	= Helical diameter
De	= Deans number
ID	= Internal Diameter
Re	= Reynolds number
d	= Pipe diameter
λ	= Curvature ratio
ϵ_w	= Phase inversion water cut (Fraction)
η	= Dynamic viscosity of oil (cP)

Units:

stb/day	= Stock Tank Barrel per Day
scf/stb	= Standard Cubic Feet per Stock Tank Barrel
Sm^3/D	= Standard Cubic Meter per Day

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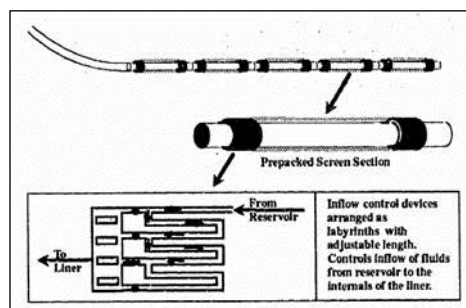


Figure 1: The original Inflow Control Device ^{10, 27}

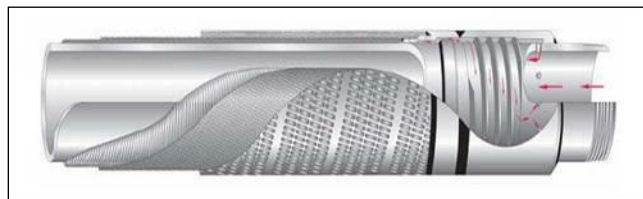


Figure 2: A helical channel-type ICD (Supplier 1¹¹)

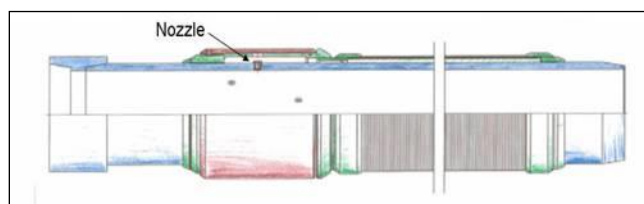


Figure 3: A nozzle-type ICD (Supplier 2¹³)

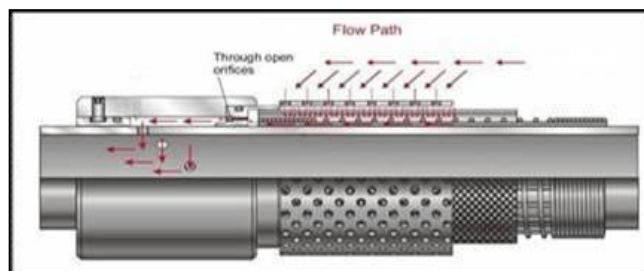


Figure 4: An orifice-type ICD (Supplier 3³⁸)

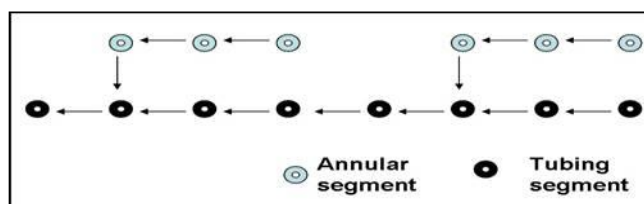


Figure 5: Multi-segment Well flow direction model as applied in EclipseTM 100²⁸

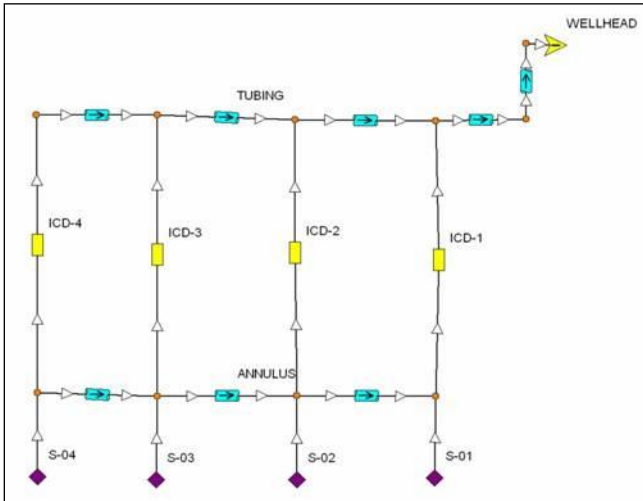


Figure 6: The wellbore configuration in the network modelling software

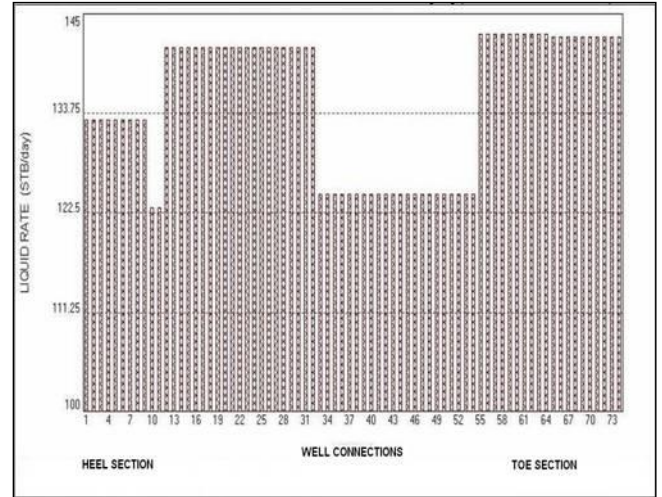


Figure 9: Equalised fluid influx into the wellbore at the beginning of well life with ICDs and completion together with annular isolation (Figure 13)

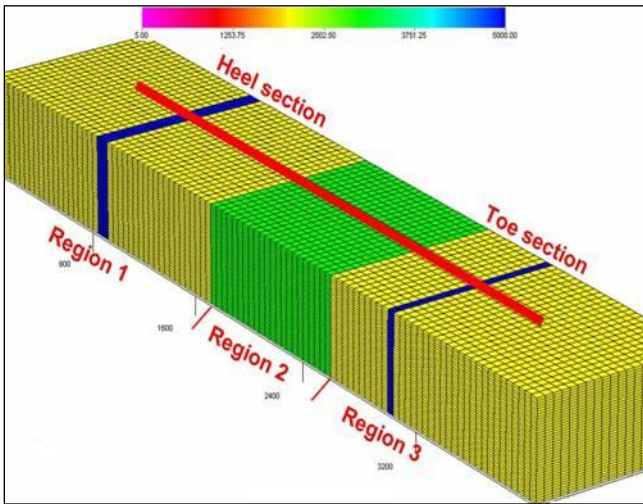


Figure 7: The reservoir simulation model. The well location is shown in red.

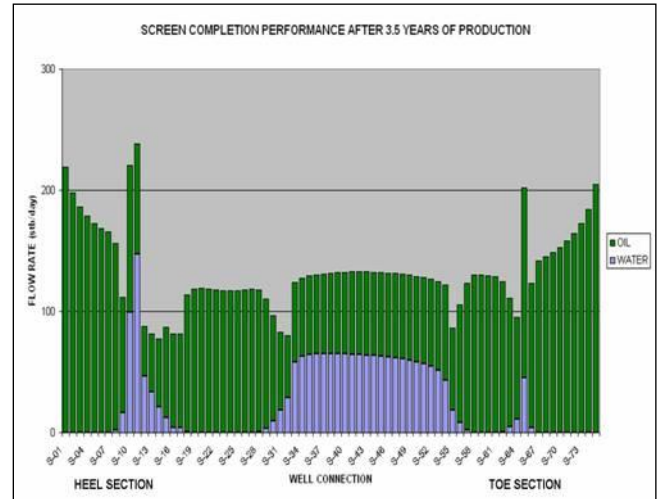


Figure 10: Water breakthrough locations for SAS completion with annular isolation (Figure 12) after 3.5 years of production

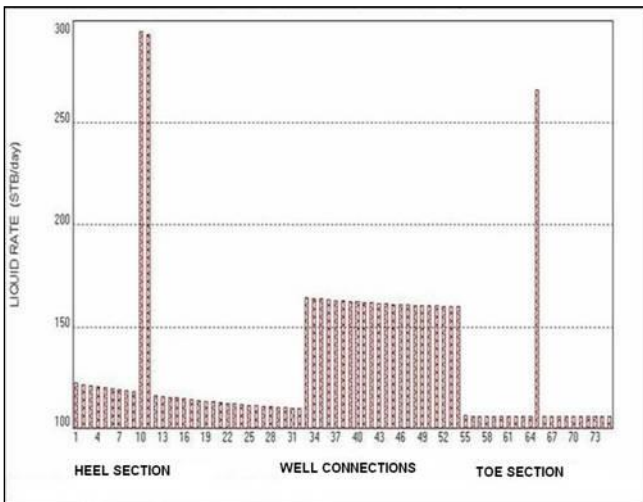


Figure 8: Fluid influx into the wellbore with a SAS completion and annular isolation (Figure 12)

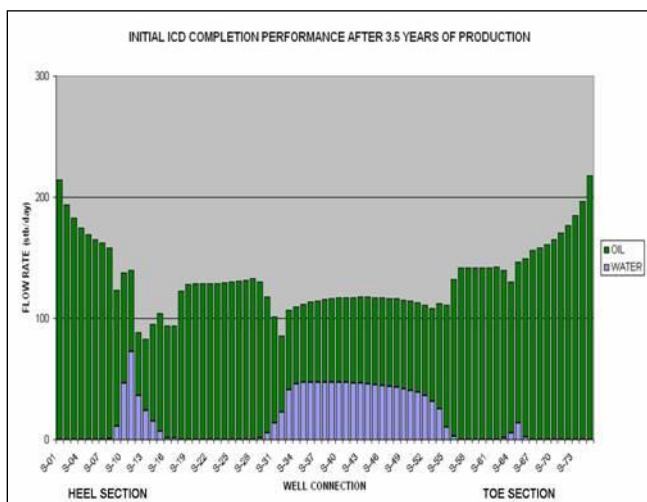


Figure 11: Water breakthrough locations for initial ICD completion with annular isolation (Figure 13) after 3.5 years of production

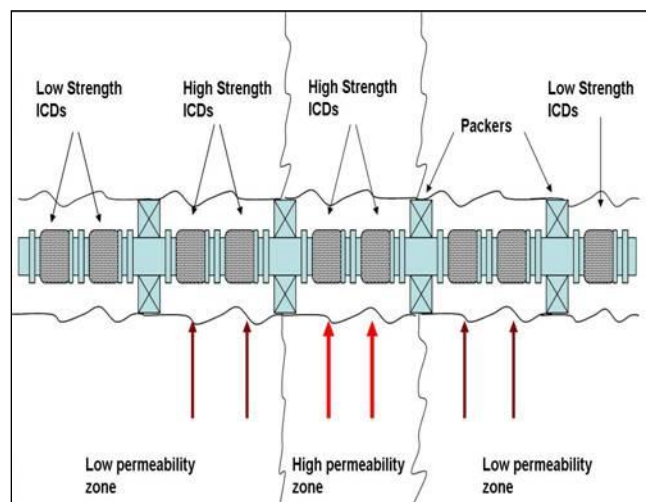


Figure 13: Effective ICD and Packer distribution around the high permeability zones

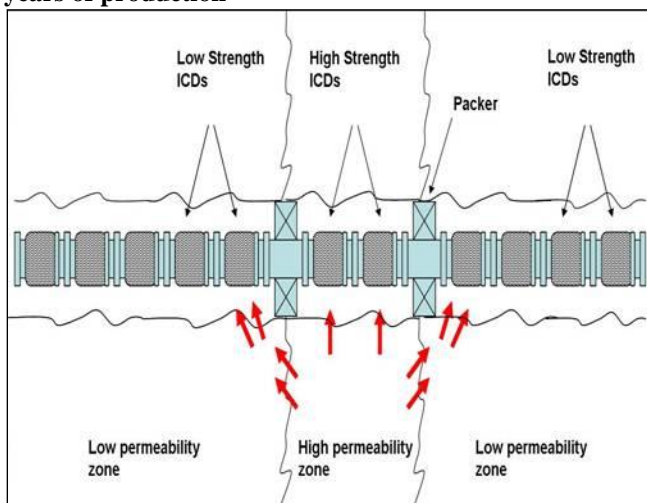


Figure 12: Annular Isolation does not control high permeability zone due to flow behind packer from high to low permeability zone.

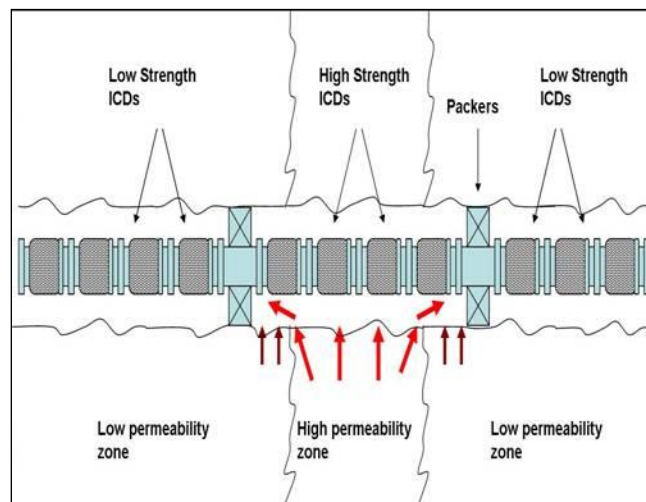


Figure 14: High permeability zone limits the contribution from any low permeability zones enclosed between the packers

Table 3: Initial ICD strengths distribution

Zone Number	Number of ICDs	Normalized Nozzles Effective Diameter
Zone 1	9	0.669
Zone 2	2	0.433
Zone 3	21	0.816
Zone 4	22	0.510
Zone 5	1	1 ^b
Zone 6	8	SAS ^a
Zone 7	1	1 ^b
Zone 8	1	0.433
Zone 9	1	1 ^b
Zone 10	9	SAS

Note: a) Pressure drop across SAS is low and values < 2 psi have no effect on model results

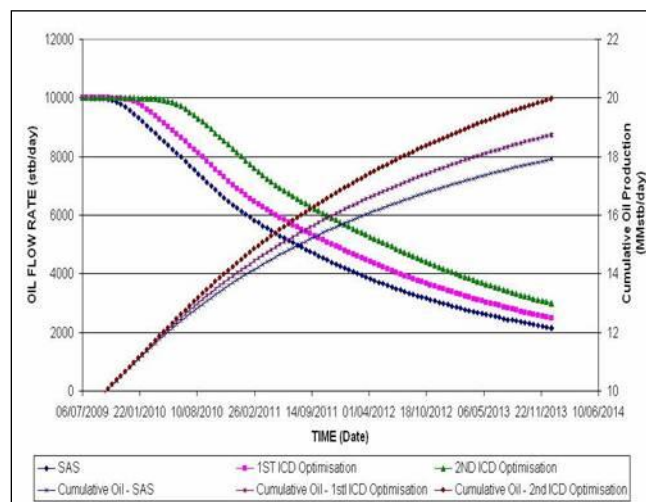
b) The nozzles' effective diameter is normalized to the lowest available ICD strength (i.e. largest nozzle diameter)

Table 4: Optimised ICD strength distribution

Zone Number	Number of ICDs	Normalized Nozzles Effective Diameter
Zone 1	7	0.669
Zone 2	6	0.361
Zone 3	18	0.770
Zone 4	27	0.361
Zone 5	6	SAS ^a
Zone 6	4	0.361
Zone 7	8	SAS ^a

Note: a) Pressure drop across SAS is low and values < 2 psi have no effect on model results

b) The nozzles' effective diameter is normalized to the lowest available ICD strength (i.e. largest nozzle diameter)

**Figure 15: Comparison of the Well Performance for the three completion designs****Table 5: Oil recovery for the completions studied**

Completion Design	Cumulative Oil Production (MMstb)	Increase above SAS (%)
SAS with Packers	17.9	-
Initial ICD Completion	18.8	5
Optimised ICD Completion	20.0	11



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Advanced Well Flow Control Technologies can Improve Well Cleanup

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Abstract

Formation damage created during drilling or workover operations significantly reduces the performance of many wells. Long, horizontal and multilateral wells crossing heterogeneous, possibly multiple, reservoirs often show greater formation damage than conventional wells. This is partly due to the longer exposure of the formation to the drilling and completion fluid due to the well geometry as well as to the greater overbalance pressure often applied during drilling such wells and poorer cleanup.

The typical well clean up process involves flowing the well naturally or aided by artificial lift to remove the external and internal mudcake and flow-back the mud filtrate. This process can be effective in conventional wells but is not adequate in long horizontal and multilateral wells suffering from increased frictional pressure drop along the wellbore and heterogeneity. The cleanup efficiency is improved by employing Advanced Well completions. Inflow Control Valves (ICVs) control the contribution from individual laterals or a specific zone along the extended horizontal wellbore. Inflow Control Devices (ICDs) equalise the contribution along the (long) completion length. In addition, Autonomous ICDs can manage the influx of unwanted fluids.

This paper studies the cleanup performance of such wells completed with these advanced, downhole flow control technologies. It provides valuable insights into how these completions improve the well cleanup process and compares the ability of (A)ICD and ICV technologies to provide the optimum:

- Drawdown to lift off the filter cake formed by different mud systems (without causing sand production).
- Recovery rate of the invaded mud filtrate.

Guidelines for Advanced Well Completion cleanup along with simulated results of synthetic and real field cases are included.

• Introduction

Formation damage is a deterioration of the near wellbore, reservoir formation characteristics. It has been described as: “*The impairment of the invisible, by the inevitable and uncontrollable, resulting in an indeterminate reduction of the unquantifiable*” [1]. Its causes include: “*physico-chemical, chemical, biological, hydrodynamic, and thermal interactions of porous formation, particles and fluids and mechanical deformation of formation under stress and fluid shear*” [2]. These processes can be triggered at all stages of the well or field’s life: drilling, workover, completion, gravel packing, production,

injection, stimulation, etc. Formation damage reduces the absolute formation permeability and/or causes an unfavourable relative permeability change; both of these will adversely impact the well and reservoir performance.

Increasing the well-reservoir contact has become an increasingly popular well construction option. It brings a number of potential advantages - increases in the well productivity, drainage area and sweep efficiency plus delayed water or gas breakthrough. Drilling, workover and (re)completion are all major interventions that result in severe formation damage in Extended Reservoir Contact (ERC) wells. External and internal mudcakes are often formed at the sandface in addition to mud filtrate invasion into the near wellbore area during these interventions. Increased levels of formation damage is to be expected in ERC wells compared to conventional wells due to the increased exposure to the reservoir, use of a higher overbalance pressure and the increased time required to drill and complete these wells.

Both water and oil based mud are used to drill ERC wells. Polymers are added to these mud systems to enhance their ability to suspend drill cuttings within the long and tortuous wellbores so that they can be circulated to surface. These polymers will absorb on water wet, formations; altering the irreducible water saturation around the wellbore and complicating the water based filtrate's flow back during the cleanup process.

These mud systems are also designed to form a highly impermeable, external mudcake at the sandface to minimise the volume of filtrate lost to the formation. The mudcake must be able to withstand both the shear imposed by the high velocity circulation of drilling fluid and cuttings along the sandface as well as mechanical erosion by the rotating drill pipe. In addition, the spurt loss as the mudcake is being formed and the constant movement of the drill pipe causes mud solids to be injected into the formation and form an internal mudcake. The necessary high differential pressure between the reservoir and wellbore required during the cleanup operation to lift off the internal and external mudcakes is a challenge in ERC wells. Their extended length causes a varying drawdown pressure between the lateral's Heel and Toe, making it difficult / impossible to ensure that a sufficiently high drawdown pressure is present at all points along the wellbore. Variation of specific productivity index along the wellbore (or lateral) due to permeability, pressure or fluid property variation are further factors that lead to significant variation in the drawdown pressure profile. The result is only partial liftoff of the mudcake and poor cleanup of the formation damage.

The extent (or depth) of filtrate invasion depends on the formation wettability, the type of drilling mud employed, the efficiency of mudcake formation, the overbalance pressure and the drilling and completion time. A miscible filtrate invasion process occurs when an oil based mud filtrate invades an oil bearing formation; while filtrate invasion from a water based mud in the same formation is an immiscible process. Both mud systems show immiscible invasion in a gas bearing formation. Different damage processes thus occur, depending on the mud system used and the formation's initial fluid saturation. Identification of the sources of formation damage is essential information for efficient design of the formation damage cleanup (or removal) process.

The typical well cleanup process involves either flowing the well naturally or assisting the flow by artificial lift. This process has proven to be effective in conventional vertical and deviated wells as well as in shorter horizontal wells. However it definitely does not provide adequate cleanup in long horizontal or multilateral ERC wells. The differential pressure between the Heel and Toe of the horizontal section increases once the completion fluid has been removed from the well; making mudcake and invading fluid removal at the Toe section harder. As stated earlier, permeability variation along the wellbore also plays a major role in the cleanup process as it can result in differential cleanup caused by a variable, partial removal of the mudcake.

Such inefficient cleanup can result in variable fluid influx along each lateral, premature breakthrough of water or gas, inefficient reservoir sweep and reduced hydrocarbon recovery. A previous publication [3] provided a brief discussion on cleanup as part of a comparative framework for the evaluation of the strengths and weaknesses of advanced and conventional completions. A companion paper [4] focused on the cleanup of intelligent well completions in layered reservoirs with homogeneous rock and fluid properties within each layer. The study was based on an early application of intelligent wells to commingle production from multiple, high productivity, North Sea reservoirs. This paper focuses on the impact and removal of formation damage incurred during drilling and workover operations in horizontal and multilateral wells completed in heterogeneous reservoirs without distinctive reservoir flow barriers. It allows further quantification of the improved natural cleanup achieved by advanced completions with downhole flow control equipment when compared with conventional Stand-Alone-Screen (SAS) completions. The effect of interference between the producing zones (or laterals) is explored as well as guidance for effective, advanced well completion cleanup.

- **Advanced Well Completions with Controlled Inflow**

Advanced well completions with controlled inflow employ Inflow Control Valves (ICVs), Inflow Control Devices (ICDs) and /or the newly developed Autonomous Inflow Control Devices (AICDs):

- A. An **ICV** is a downhole flow control valve which is operated remotely (from the surface) through a hydraulic, electric or electro-hydraulic actuation system (Figure 1). Different ICV trim designs and functionality ranging from on/off to infinitely positioned valves are commercially available. These valves enable sequential, selective cleanup of individual zones or laterals in multizone (multilateral) completions.
- B. An **ICD** is a passive flow restriction mounted on a screen joint to control the fluid flow path from the reservoir into the flow conduit (Figure 2). An ICD's ability to equalise the inflow along the well length is due to the difference of the physical laws governing fluid flow in (1) the reservoir and (2) through the ICD. Each provider of this technology has a unique design for the pressure drop creation. These currently include: Nozzles, Orifices, Tubes as well as Helical and Labyrinth Channels. The ICD's equalising effect on the fluid inflow is advantageous in the cleanup of wells where variation of fluid influx along the wellbore is significant due to reservoir heterogeneity and/or the Heel-Toe effect caused by the wellbore's frictional pressure drop.
- C. An **AICD** is a newly developed technology which adds an "intervention-free", reactive, flow restriction to the ICD's passive flow restriction (Figure 3). Both density and phase dependant technologies are available that are triggered by excessive water or gas influx. Water influx into an oil producing well will increase the flowing fluid's density, causing a water triggered AICD to restrict the flow area and reduce the flow rate from the well section were water breakthrough has occurred. Similarly, a gas influx would reduce the average fluid density, giving a reduction in the flow area of a gas triggered AICD. The technology employed depends on the supplier. Flapper, Ball, Plate and Swellable AICD elements are all available. This technology is still awaiting field deployment despite simulations predicting great potential value from its application.

The first ICV applications were to control commingled production of multiple reservoirs via a single flow conduit; while the initial ICD applications were to counteract the "Heel-Toe" effect in horizontal wells. The application area of both technologies has increased significantly since these early days. Current applications include mitigating inflow or injection imbalance and optimisation of well and field management in different geological structures and formation types. AICDs are being developed to combine the benefits of both ICVs and ICDs at the completion joint length-scale with the added advantage of being "intervention-free". The application areas of these technologies now overlap with two or even all three being integrated into a single completion. E.g. (A)ICDs installed along the laterals with ICVs at the lateral's mouth.

Annular Flow Isolation (AFI) is another crucial component of advanced well completions. It compartmentalises the wellbore and enhances the fluid flow equalisation or control imposed by the downhole flow control technologies. Annular flow occurs in wellbores completed across homogeneous, heterogeneous or layered reservoirs unless there is an:

1. ICD completion installed to minimise the annular flow caused by "Heel-Toe" effect and the differences between the flow area of the annulus and the tubing in prolific, homogeneous reservoirs.
2. Isolation packer installed in the annular space between the SAS, (A)ICD or ICV and the formation sandface at every SAS or (A)ICD joint or ICV controlled section.
3. Annulus packed with gravel or collapsed formation sand.

An open annulus allows high rate, fluid inflow from the high permeability section. Poor cleanup, reduced oil production and inefficient recovery result from the remainder of the completion. The presence of annular flow is thus an important aspect of the cleanup performance of a Stand Alone Screen (SAS), (A)ICD or an ICV completion. This has often been ignored in previous experimental and simulation studies due to the difficulty to model it correctly.

Recent advances in wellbore modelling made it possible to simulate annular flow in ICV completions and to more realistically evaluate its impact on the well performance. Annular flow modelling in SAS and (A)ICD completions requires special algorithms that can emulate splitting and rejoining (or looping) flow paths. Current reservoir simulation software that incorporates this modelling capability includes Eclipse 2008™ [5] and Reveal 7.0™ [6]. Network modelling software (e.g. OLGA™, NETool™ and GAP™ [7 - 9]) can also be used, though they need to be coupled to a reservoir simulator if the complete, dynamic cleanup performance of the completion is to be captured.

- **Formation Damage in ERC Wells**

Formation damage caused by drilling or workover can significantly affect the well's performance [10-13]. 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 due to the increased exposure time of the formation to the drilling and

completion fluid in addition to the greater overbalance pressure often applied during drilling such wells.

Several researchers have studied the mechanism of formation damage caused by drilling and workover and evaluated its impact on horizontal wells. Drilling and workover induced formation damage of wells takes place in three stages:

1. *Instantaneous damage caused by the drilling fluid spurt loss at the face of the drill bit.* This causes the fluidised material along with some mud particles to invade the formation rock and form an internal mudcake that will eventually restrict, if not plug, most of the near-sandface, permeable formation. This is followed immediately by the formation of an external mudcake with a very low permeability which minimises further solids and filtrate flowing into the formation.
2. *Dynamic filtration causes a continuous expansion of the filtrate invaded zone.* The filtrate saturation, and hence the magnitude of the formation damage, varies greatly in the invaded zone depending on the rate of filtration, overbalance pressure and drill bit's rate of penetration.
3. *Static filtration continues as long as the overbalance pressure is maintained after drilling is completed.* This process is slower than dynamic filtration, but it has a greater impact on multilateral wells than conventional or horizontal wells. This is due to the extra time spent:
 - Drilling new laterals from the main wellbore while maintaining overbalance on the already drilled laterals.
 - Completing multilateral wells when installing sand control measures in soft formations.

An oil based mud is often the system of choice for drilling ERC oil wells due to the:

- Reduced formation damage since it is compatible with the reservoir fluids.
- Minimisation or elimination of the negative impact of the imbibition process and the consequent alteration of the relative permeability compared to that experienced with a water based mud.
- Minimisation (or elimination) of shale swelling and consequent borehole collapse.

Water based mud is used in horizontal and multilateral gas wells to avoid the damage caused by the introduction of a third (oil) phase. Different mud systems can thus cause damage by different processes; all of which need to be mitigated to improve the post cleanup well productivity.

- **Cleanup of ERC Wells**

The typical well cleanup process involves two stages:

- *Wellbore cleanup* performed after drilling the wellbore or lateral [15]. This includes one or all of the following:
 - Circulation of solid free fluid to help clean the wellbore of deposited individual drill cuttings and loosely consolidated mudcake prior to installation of the completion.
 - Circulation of diesel or inhibited brine to replace the drilling and completion fluid. This reduces the average density of the fluid column above the producing formation.
- *Formation cleanup* after installing the completion and hooking-up the well to temporary or permanent production facilities. This employs:
 - Spotting chemicals at the formation sandface to assist in breaking the external and internal mudcakes.
 - Flowing the well naturally if the reservoir pressure is sufficient or:
 - Supporting the well's flow with temporary artificial lift. E.g. by injecting nitrogen through a coiled tubing which is reciprocated across and above the producing formation.
 - Using permanent artificial lift (e.g. gas lift or an Electric Submersible Pump) to increase the drawdown.

The well production during cleanup is controlled to a specific production rate or bottomhole / tubing head pressure limit. This is often set based on the rig or production facility capacity limitations.

The extended length and complexity of ERC wellbores presents extra challenges for well cleanup. These challenges, which vary depending on the laterals completion (i.e. bare openhole, SAS, pre-perforated liner, etc.), include, but are not limited, to:

1. Circulation of solid free fluids in the main bore and individual laterals may not be effective since debris removed from one lateral may flow into another one.
2. Completion fluid often remains in the individual laterals.
3. Spotting of chemicals which assist in breaking the mudcake may not be possible along the lateral if the coiled tubing is unable either to enter or reach the end of the lateral .
4. The latter considerations may limit coiled tubing, nitrogen lift only being available in the mother lateral or even limited to the above the well's heel.
5. The first lateral to be cleaned up, or those laterals with the highest productivity, may cleanup faster limiting the contribution (and cleanup) of lower productivity laterals.
6. Laterals crossing a heterogeneous formation or intersecting one or more high flow capacity

fractures may suffer from differential cleanup.

Improper cleanup and debris recovery from the wellbore can result in severe damage to downhole and surface equipment.

- **Advanced Well Completions Can Improve Well Cleanup**

ICVs control the flow contribution from long horizontal well sections or complete laterals; while ICDs installed along a lateral equalise the contribution from small sections of the wellbore. This gives advantages to both technologies. In essence, ICVs can be used to sequentially open individual intervals (zones) or laterals; allowing the maximum allowable drawdown per zone to be applied and ensuring that each zone is properly cleaned. This is essential when only a limited drawdown or flow rate can be applied. Higher drawdowns are not always advantageous since they can induce sand production and/or gas and/or water coning. In addition, an increased mud filtrate invasion may result from extended cleanup periods causing laterals interference. Surface and/or the downhole monitoring of the mud return, the total liquid flow rate and the pressure drop measured by the ICV's gauges can be used to monitor the cleanup efficiency of a specific zone and determine when it is clean or in danger of increased damage before the cleaning up of the next zone (or bringing it onto production) is commenced. All available ICV designs (ball or sliding sleeve) and types (multiple setting or open/close only) can provide improved well cleanup.

ICDs equalise the inflow contributions so that the low and high permeability sections behave in a similar manner. This helps filter cake lift-off from long wellbore sections and allows faster flow back of the invaded fluid; IF sufficient pressure drop can be generated to "lift-off" the filter cake. This implies that producing the ICD completed wellbore at low flow rates will often not provide adequate clean up. The size of the chosen ICD restriction depends on the value of the total completion flow rate used in the completion design process that lead to the selection of the optimum ICD flow restriction (which is normally chosen to equalise the inflow contribution from both the high and low productivity zones). Being able to flow at the design, or even a higher, flow rate is essential for achieving proper clean up in ICD completions. The various ICD designs will show different behaviour during the cleanup process, especially when the range of possible mud and completion fluid compositions is considered. The pressure drop through the labyrinth and helical channel and long tube type ICDs is friction-based - it relies on the viscosity of the fluid mixture; while the pressure drop through the nozzle, orifice and short tube type ICDs is acceleration-based and relies on the density of the fluid mixture passing through the ICD. In:

- *Water based mud:* the produced filtrate will be mainly low-viscosity brine. This causes the pressure drop to be lower through a viscosity dependent ICD compared to a density dependent ICD for the same flow rate. This reduced pressure drop will minimise the required drawdown pressure and encourage the mud filtrate flow back.
- *Oil based mud:* the produced filtrate flow back will be oil with a varying viscosity. This causes an opposite effect compared to flow of a water based mud through the viscosity dependent ICDs, giving the advantage to density dependent ICDs. Successful use of nozzle-type ICDs for improved cleanup when wells were drilled with oil based mud has been reported [17].

However, the advantage gained from the ability of the ICD completion to equalise the fluid influx along the wellbore length outweighs these differences. The mudcake flow back through the ICD will also depend on the integration of ICDs with screens or debris filters. A chemical wash (or soak) maybe required in some circumstances to ensure sufficient deterioration of the mudcake to allow it to flow through the screen and ICD restriction [16].

AICDs are designed to restrict the contribution from specific sections of the wellbore where water or gas breakthrough occurs. The installation of water-activated devices in a wellbore drilled with water based mud will restrict the water filtrate recovery from the formation and hence complicate, if not completely prevent, the cleanup operation. Oil based mud systems can be used when such a completion is proposed. However, these also contain a percentage of brine which can activate the device during the flow back operation. This is especially true for the ball and flapper type AICDs. The claimed ability of the swellable type AICD to delay AICD activation until a considerable amount of water has passed through the device is an advantage. The plate type AICD is designed for excessive gas shut-off and is unlikely to be affected by the mud system. However, a better solution to cleanup water-activated AICD completions is to install a Sandface Clean Out Valve (SCOV) [18] at each section of the wellbore that contains AICDs. These wellbore sections can contain multiple joints of AICDs installed between two annular flow isolation packers. The Sandface Clean out Valve (SCOV) in each section can be activated by pressure changes or by elapsed time. Multiple SCOVs can be installed in a single completion and can be opened sequentially to ensure proper cleanup of each section. An alternative would be to drill and complete these wells under-balanced. However, in this paper we focus on the common practice of overbalance drilling using water and oil based mud systems.

Gas-activated AICDs will not create complications during the cleanup process. In fact, the ICD part of the AICD will enhance the cleanup operation return in a similar manner to that discussed above for

ICD completions.

The following case studies illustrate the advantages of these devices on horizontal and ERC wells.

- **Case Studies**

Two horizontal and a multilateral well cases were used to study the advantages and disadvantages of (A)ICD and ICV application in heterogeneous and homogeneous reservoirs. The conclusions from these studies will provide the basis of our guidelines for an effective cleanup process. A realistic value from the application of advanced well completions can only be recognised when a combined reservoir and well simulator capable of employing a multi-segment well description of the pressure drops along the annulus and the tubing in addition to the pressure drops generated by multiple intermediate devices (an ICV or ICD). Modelling of the circulation of diesel or injection of nitrogen in the well requires a dynamic wellbore simulator that has the capability to model injection into the tubing and production from the annulus of the same well. Most other factors can be modelled using any one of several commercial, reservoir simulators with advanced wellbore modelling capability. These case studies employed a commercial reservoir simulator with SAS and ICD modelling capability [5]. The performance of the ICDs (i.e. the calculated pressure drop through the individual ICDs) installed between the annulus and the inner tubing was calibrated with full-scale, flow test data reported by the supplier [20]. Our detailed modelling ensured:

- Accurate modelling of the ICV and (A)ICD completions (with and without annular flow).
- Optimisation of ICV settings during the well and field life.
- A common basis upon which to compare the three completion options.

A channelised, heterogeneous reservoir model (Figure 4), representative of a real North Sea reservoir, was used as a “test-bed” for this work. The porosity and permeability values were distributed stochastically throughout the reservoir model. The 19° API reservoir fluid has a solution gas ratio (Rs) of 260 scf/stb and viscosity of 10.1 cP at reservoir conditions while pressure support was provided by an aquifer. We have used the model (Figure 4) to illustrate the:

- Magnitude of formation damage incurred by horizontal and multilateral wells and its impact on well performance.
- Effectiveness of (A)ICDs and ICVs in providing improved cleanup and enhanced well performance over the life of the field.

6.1 Formation Damage Modelling:

The wellbore was initially modelled as an injector which gradually increased in horizontal length. This was performed to relate the mudcake formation and filtrate invasion in the near wellbore region to the drilling rate of penetration (ROP). A steady ROP of 400 ft/day with an overbalance pressure of 600 psi was applied until the target (horizontal) wellbore length of 2,400 ft was reached. A water based mud was used to indicate the positive effect an ICV or ICD completion may provide and to also illustrate the severe impact such a mud system can have on an AICD completion. Previous mudcake and filtrate invasion modelling recommendations, which are based on laboratory core tests analysis [10, 12], formed the basis of our formation damage modelling.

6.1.1 External and Internal Mudcake:

The near wellbore region was refined to capture the influence of the external and internal mudcakes. The effect of both mudcakes was modelled by reducing the permeability of the 0.05 ft-thick gridblocks surrounding the wellbore. The existence of the mudcake significantly reduced the mud filtrate invasion into the high permeability sections of the wellbore (from 24,847 stb to 3,594 stb). The effect of the mudcake was then reduced if the liftoff criterion (a pressure drop of at least 25 psi across the cake) was achieved during well cleanup. This reduction in formation damage was captured by increasing the permeability of the blocks surrounding the wellbore to 40 % of their original value. This maintained a reduction in permeability to reflect the permanent damage caused by the internal mudcake invasion, which can not be reversed.

6.1.2 Filtrate Invasion:

The filtrate invasion of water based mud is also known to have an adverse impact on the reservoir permeability. This was represented by alteration of the relative permeability values around the wellbore depending on the mud filtrate saturation. These were modelled to represent an extra resistance to oil flow caused by pore plugging and permeability impairment [10-12]. However, the original irreducible water saturation was maintained. Gravity slumping of the lost completion fluid (due to its density being higher than the reservoir oil) was omitted. This allowed the well’s cleanup performance to be studied without this additional complication.

This formation damage modelling was applied in both the horizontal and multilateral wellbores. The multilateral well exhibited increased static filtration since the overbalance pressure was maintained on existing lateral(s) while the next lateral was being drilled. This resulted in a larger invaded zone around the first compared to the second lateral.

6.2 Case Study-1

The reservoir development proposal consists of a horizontal wellbore which crosses two high permeability channels with permeabilities ranging from 1 to 4,100 mD without distinctive layering or fluid flow barriers (Figure 5 and Table 1).

The initial (base case) SAS completion produced at a maximum liquid production rate limit of 8 Mstbl/d. ICV, ICD and AICD completions were installed to optimise the well performance and to verify the relative advantages of the three technologies.

ICDs were installed to:

- Equalize the fluid influx rate along the wellbore and provide better cleanup.
- Equalize the water encroachment towards the well to enhance the reservoir sweep efficiency.
- Minimize the annular flow that might result from the SAS or ICD completions without Annular Flow Isolation (AFI).

AICDs were installed for the same reasons as ICDs plus:

- Minimize the water inflow after water breakthrough.

Two ICVs were installed to separate the high permeability channel; the heel ICV had a 4 in. diameter flow opening while the toe ICV's flow opening was 3 in. diameter. They were operated to:

- Control the contribution from each channel zone during the cleanup, dry oil production and after water breakthrough.
- Minimise the zonal water production.
- Increase the cumulative oil recovered from the well.

Optimum Nozzle-type ICD [9] and Ball-type AICD [24] flow restriction sizes were applied along the wellbore. The sizes of the (A)ICD flow restrictions were based on the differences in the well's local specific productivity index and oil-water relative permeability curves. More details of the (A)ICD completion design optimisation process are beyond the scope of this paper and will be provided in a future publication.

6.2.1 Improved Clean up:

We initially had to devaluate a base case (no formation damage) since the various completions will achieve different recoveries. Compared to the SAS completion the:

1. ICD completion equalised the fluid influx along the wellbore and increased the cumulative oil production by **1.7%**
2. Optimised ICV completion increased the cumulative oil production by **2.0%**.
3. AICD completion choked the water production at small intervals along the wellbore, resulting in a **4.6%** increase in the cumulative oil production.

The improved cleanup performance of the advanced completions when formation damage is present is summarised below. A sufficiently high flow rate (8 Mstbl/d) was used during cleanup so that the drawdown across the sandface was sufficient to lift off the mudcake for all completions. A low flow rate of 1,200 stbl/d was also included to verify the effect of a surface facility with a limited capacity to handle the filtrate flow back. The results of this study are presented in Figures 4-14 and Table 2.

6.2.1.1 SAS Completion Cleanup:

The SAS completion resulted in slow and irregular cleaning of the mud filtrate due to the irregular fluid influx from the reservoir (Figure 6). This resulted in an uneven influx rate along the wellbore and poor cleanup (Figure 11 and Figure 12). This was eventually followed by water breakthrough at various locations along the wellbore and an inefficient sweep of the reservoir. The main contributing factors to this poor cleanup are: 1) the permeability variation along the wellbore and 2) the existence of annular flow within each zone. Both these effects allow the high permeability sections of the wellbore and the near wellbore region to clean up faster than the low permeability sections. The already present differences in the inflow performance along the wellbore's length have thus been further exaggerated. The SAS completion was not able to lift off the mudcake or initiate flow at the low flow rate scenario (Figure 8) since the pressure drop across the mudcake is below the liftoff pressure of 25 psi.

6.2.1.2 ICD Completion Cleanup:

The ICD completion was designed to maintain optimum equalisation of the fluid influx from the 500 mD and 4,100 mD sands at 6 Mstbl/d. This completion concept was tested with and without AFIs. The

high variability of the permeability distribution along the wellbore required AFIs to be installed at every second ICD joint (this option has been made possible in actual completions by installation of Swellable Packers [21]). It is assumed that these packers can withstand the imposed differential pressure between the ICD sections. The resulting well performance was compared with a SAS, an AICD and an ICV completion.

The ICD completion with AFIs installed at every second joint gave the best inflow performance when flowed at 8 Mstb/d (Figure 11 and Figure 12). If a limit on annular flow velocity is imposed to protect the downhole completion equipment, then installing the optimum number of AFIs enables producing the well at high production rate; thus, enabling raising the plateau production rate and maximising the rate of return. This is due to the ICDs ability to encourage the lower permeability zones to contribute to the flow during the cleanup stage (Figure 6 and Figure 7) resulting in efficient clean up performance. This encouragement of low permeability zone production continued into the early phase of the well's life.

The lack of AFIs across the heterogeneous sandface reduced the added value from the ICD completion installation both for the cleanup process and the resulting well performance. An (A)ICD completion *without* AFIs in a heterogeneous sand will appear to have equalised fluid influx during production logging of the inner flow conduit. Thus a flowmeter survey will measure an (apparently) equalised inflow; even when the contribution at the sandface is unbalanced. This is due to the presence of annular flow. This state of affairs can be recognised by employing recent advances in the analysis of temperature and pressure data coupled with data measured in the annulus [14].

The additional pressure drop across the ICD completion itself can limit the sandface pressures that can be imposed across the mudcake. This limitation of not being able to achieve the mudcake's lift-off pressure gives inefficient well cleanup [16]. This effect was illustrated by reducing the cleanup well liquid flow rate to 1,200 stb/d. An inadequate drawdown pressure resulted; there was insufficient contribution from the high productivity zones to allow mudcake liftoff across these zones. Figure 8 illustrates this effect - irregular fluid influx and mudcake liftoff along the ICD completed wellbore can result from the irregular pressure distribution along the sandface, as a direct impact of the low production rate. An overbalance pressure remained toward the end of the horizontal wellbore a phenomenon which has been observed in an actual well [17].

This figure also illustrates the ability of the ICD to cleanup the whole wellbore length if the well flow rate is increased gradually. The low productivity sections will cleanup during the low flow rate period while the high productivity zones will cleanup as the well production rate increases. This is a consequence of the self-regulatory advantage of ICDs, especially if combined with the appropriate number of AFIs. However, maximum fluid influx equalisation and most efficient cleanup of the wellbore and formation will only occur when an ICD completed well is flowed at, or very close to, the flow rate specified for the ICD completion design.

6.2.1.3 ICV Completion Cleanup:

The ICVs were operated sequentially based on the completion fluid return rate. The Heel ICV was fully opened to impose the maximum allowable drawdown until the water flow rate reduced to a specified limit (60, 200 or 1,000 stbw/d). This zone was then shut and the Toe zone was fully opened (Figure 11 and Figure 12). The ICV application illustrated the need to identify the optimum point to switch between the zones – excessive time spent on zonal cleanup may result in loss of rig time and deferred oil production without any noticeable benefits from an extended cleaning process. The ICV completion's performance was similar to that of the SAS completion when a high drawdown was applied to each zone (Figure 12). This is due to the cleanup process being dominated by irregular fluid influx along each zone and the resulting slow cleanup of the low productivity sections (Figure 9).

A recent innovative technique [4] that indicates when a zone can be declared sufficiently clean (i.e. can be shut and another zone opened) was implemented. This resulted in the identification of the optimum time to shut the first zone and open the second zone for cleanup, then bring the full well completion on production (see ICV adjusted at 200 stbw/d - Figure 12).

ICVs have the ability to inflict a higher drawdown allowing mudcake liftoff at a specific zone when a flow rate limit is imposed. This can be illustrated by comparing the well performance after a lower flow rate concentrated the limited pressure drawdown on one zone (Figure 9) and achieve better cleanup (Figure 13 and Figure 14).

6.2.1.4 AICD Completion Cleanup:

The AICD can be designed to restrict the flow from water producing intervals gradually or aggressively or shut-off the fluid flow path completely. The performance of such devices during the cleanup will depend on their triggering water cut values and the aggressiveness of their choking. In this study, AICD devices designed to gradually minimise the water influx rate as the water cut increases were

installed along the length of the completion. These continued to gradually shut until the original flow area was reduced by 80%. This restriction was maintained by the AICD until the well was shut-in. The restriction was then reversed i.e. the AICD fully opened. This reflects the actual Ball-type AICD behaviour. It is also possible to install an open/shut SCOV for each completion section.

The AICD limited the ability of mud filtrate to flow back into the wellbore when the well was flowed at the high flow rate due to the AICD device restricting the flow rate in response to the water (or mud filtrate) production (Figure 11 and Figure 12). However, the AICD was able to impose sufficient drawdown pressure to lift off the mudcake from all the completion length and achieve better well cleanup in the low fluid flow rate scenario (Figure 13 and Figure 14). The device was essentially acting as an aggressive (i.e. highly restrictive) ICD.

The behaviour of an AICD that was designed to shut-off at a specific water cut would have isolated the complete section. An extra valve (e.g. SCOV) in each AICD completion section would have been required to enable cleaning up such completions.

In summary, the ICD completion has the advantage when installed across a heterogeneous sandface providing the pressure drop required to lift off the mudcake can be imposed. However, if the later condition is not possible, the selective opening of ICVs allows the limited, available pressure drop to be focused on one zone at the time resulting in better cleanup. The AICD completion further enhances the flow back of mud filtrate and cleanup efficiency when produced at low flow rates.

6.3 Case Study-2

The same reservoir model was used to study the cleanup performance of a dual-lateral well by changing the location of the main horizontal wellbore used in study-1 and adding a lateral (Figure 15). Both laterals crossed the two high permeability channels, but at different locations along the wellbores. All the other factors were maintained; except the total liquid flow rate constraint for the well which was increased to 15 Mstbl/d for the high flow rate scenario and 4 Mstbl/d for the low flow rate scenario. The results of the modelled clean-up performance when all the laterals were completed with either SAS, (A)ICD or ICV completions are summarised below. The mudcake lift-off pressure was achieved by all completions in the high rate scenario, as in study-1. All the completions employed in this case showed a relatively similar performance when flown both at high and low flow rates (Figure 16 and Figure 17). The exception was the integrated ICV and AICD completion performance in the high flow rate scenario.

1. ICD Completion Cleanup: The ICD completion design philosophy was to ensure that the contribution along each lateral is optimally equalised at a total well liquid rate of 10,000 stb/d. The ICD equalisation resulted in the best cleanup performance of all options studied.
2. ICV Completion Cleanup: Two ICVs were installed to control the contribution from each lateral. The two ICVs were operated sequentially during the cleanup operation based on the completion fluid return rate. The effective Productivity Indices (PIs) of the laterals varied since the lateral's length included different percentages of the two high permeability channels. The higher productivity lateral was cleaned up first. The improved (downhole) monitoring capabilities normally included in an ICV completion also reduced the lateral cleanup time to a minimum, saving rig time and reducing deferred oil production (Figure 18).
3. Integrated ICV-ICD Completion Cleanup: The integration of ICVs and ICDs into a single completion is being practiced in the North Sea and the Arabian Gulf [9]. This practice is expected to improve and accelerate the cleanup of each lateral. However, the installation of such completion in this case study did not show any added value to the cleanup process.
4. Integrated ICV-AICD Completion Cleanup: AICD devices were installed along each lateral while ICVs were installed at the mouth of each lateral. The ICV installation helped focus the cleanup operation on one lateral at the time, which enhanced the cleanup at low flow rates. However, the increased flow rate (in the high flow rate scenario) through the AICD devices resulted in poorer cleanup performance and slow filtrate rate of return (Figure 16). However, this does not negate the advantage of ICVs in:
 - a. Reducing the total water production from each lateral after water breakthrough later in the well life, and
 - b. Resetting (reversing) the AICDs devices to their fully open position by shutting-in individual laterals.

6.3.1 Interference between Laterals:

Interference between laterals is important during cleanup as well the better known effect of interference during production. To examine its effect, a third lateral was introduced between the existing laterals. This reduced the spacing between the laterals and allowed the drainage radius of each lateral to reach the others.

Opening the first lateral for cleanup with the other laterals closed caused the mud filtrate

surrounding the second and third laterals to be drawn further into the formation. This lead to increased formation damage and slower filtrate return. This interference effect does not occur when the laterals are installed further apart.

It is important that the engineer allows for this effect when implementing an extended cleanup period for an individual lateral.

6.4 Case Study-3:

This case study evaluates the performance of a reversible AICD completion cleanup with(out) SCOV compared with an ICV Completion. A horizontal well modelled in a dynamic wellbore simulator was used for this study. The well's horizontal section is 1600 ft long, subdivided into two zones with a packer. Both zones are homogeneous with a PI of 110 STB/d/psi each. It was assumed that facilities and sand production constraints limits the sandface pressure which can be imposed to a minimum value of 4300 psia (i.e. 300 psi of drawdown pressure). This drawdown is sufficient to lift off the mudcake along the whole wellbore length for all cleanup scenarios. A high, mobile mud filtrate volume of 35,000 bbl was assumed to have accumulated around the wellbore during the drilling and completion phase. The well completion string consists of multiple AICDs with and without SCOVs. These scenarios were compared to an ICV installed at each zone.

The reservoir performance was modelled using sequence of inflows along the wellbore. The cleanup operation was simulated by varying each inflow's time dependent PI. The well was initially displaced with diesel to clean the wellbore, remove the completion fluid and lighten up the fluid column to surface. Three scenarios were examined in this case. They include: 1) a single-zone AICD completion with and without SCOVs, 2) an ICV completion and 3) an integrated ICV and AICD completion (with and without SCOV). In the third scenario, the ICV was used to control the tubing flow from the Toe zone. The AICD devices modelled in this study are similar to those used in case study-1 and 2 with an added advantage of being autonomously reversible.

6.4.1 Cleanup of a Single-Zone AICD Completion:

The first ten days of production history are presented in Figures 19-21. The SCOV was installed in the open position and was set to close after 4.5 days. The diesel initially placed in the wellbore was displaced by the mud filtrate flowing from the formation (Figure 19). Then, the oil production started once the mud filtrate from the formation has been removed. The added advantage of installing (adding) a valve (either SCOV or ICV) at the sandface is clear; it accelerates the cleanup of the zone compared to the case where AICDs were installed without SCOV (Figure 19).

The bottom hole pressure gives a clear indication of the AICD completions performance. A steep reduction followed by an increase (i.e. downward hump) in the bottom hole pressure is indicative of the removal of the mud filtrate and start of oil production in such completions (Figure 20).

The AICDs' and the SCOV's relative open areas (the ICV is constantly 100% open) can indicate the zonal cleanup efficiency since the mud filtrate volume fraction in the zone is directly related to the AICDs' flow areas (Figure 21). Installation of single point or distributed monitoring systems (e.g. DTS and DPS) can thus be beneficial if used to estimate the zonal contribution to the total well flow rate [14]. The results of the integrated AICDs and SCOV completion do not differ much from that of the ICV completion. This is mainly caused by the cumulative flow area of all the AICDs installed across the zone being equivalent to that of the ICV or the SCOV.

In the case where the SCOV is programmed for a shorter time than needed to achieve sufficient cleanup, the remaining (open) area of the AICDs continues to flow the mud filtrate and successfully clean the formation as illustrated in Case Study-1 and 2.

6.4.2 Cleanup of the Remaining Zone(s):

Two scenarios were evaluated in this case to study the benefits of the ICV and AICD integration. These include: 1) An AICD completion across both zones allowing the heel zone to cleanup while the toe zone is being cleaned, or 2) An ICV which isolates the toe zone after it is sufficiently cleaned.

Figure 22 indicates that the heel zone (the second zone to clean up) will effectively clean by itself, if allowed to flow while the toe zone is being cleaned with or without SCOV. Although, the cleanup time of the heel zone is shortened slightly by the SCOV (Figure 23), the SCOV installation is not actually needed.

On the contrary, utilising an ICV to isolate the already cleaned zone and impose a higher drawdown on the second zone can lead to a faster cleanup (Figure 23).

Although these results can be indicative of the actual well performance, these are highly dependent on the well and reservoir conditions (e.g. well productivity, drawdown constraints, etc.). This highlights the necessity of modelling the cleanup process dynamically to achieve an optimum cleanup design.

This study indicates that an ICV, if economically viable, is the preferred option since the selective

cleanup of individual zones can be optimally implemented even if the SCOVs have been installed and pre-programmed to open/close at certain times.

- **Comparison of Advanced Completions Performance**

The above and previous studies [3, 4] have allowed us to compare the cleanup performance of the various Advanced Completions. Our findings are summarized below and illustrated in Table 3:

- **In Layered reservoirs** (with homogeneous properties within each layer):
 - ICV completions achieve more efficient cleanup compared with (A)ICD completions provided that a “Heel-Toe” effect caused by frictional pressure drop along the zone is not present. This is due to the ICV’s ability to selectively produce each layer and apply the optimum drawdown per layer. This produces a piston-like displacement that lifts off the mudcake and flow back the mud filtrate in each zone. The presence of a significant “Heel-Toe” effect requires the ICV’s performance to be enhanced by installation of ICDs along the zone or lateral. However, this requires higher tolerance for an increased downhole pressure drop.
- **In Heterogeneous formations** (possibly fractured):
 - (A)ICD completions are advantageous since the ICD’s equalising behaviour is capable of mitigating variable fluid influx caused by frictional pressure drop along the wellbore, “Heel-Toe” effect, and/or by the presence of a heterogeneous sandface. ICV completions can enhance well cleanup compared with a SAS completion, especially if a limited pressure drawdown can be applied. However, the fact that the ICV acts over the (long) length of the zone can lead to slow mud filtrate return from low permeability sections if high drawdown pressures are applied. This is caused by the differential contribution along the zone or lateral (i.e. higher fluid influx from the high productivity sections and low contribution from the low productivity sections). This can also be mitigated by the integration of the ICV with ICDs along the lateral or zone.
- **In Low flow rate or low drawdown situations:**
 - ICV completions provide the optimum cleanup compared with other advanced or conventional completions since the limited drawdown can be imposed on one zone at the time.
 - ICD completions may not be suitable in low drawdown or flow rate situations unless it is integrated with a valve (e.g. ICV or SCOV) to selectively apply this limited drawdown.
 - AICD completions are advantageous in low flow rate situations since their added restriction enhances the regulation of the fluid influx across the sandface and hence improve the mudcake lift-off and filtrate return rate. They may not be suitable in high flow rate situations since its restriction may reduce the filtrate return rate.

- **Risks During Cleanup Operation**

Advanced completions are not immune from the risks of cleanup operations. Such risks, in addition to the normal installation risks, might damage the downhole flow control devices or any of its auxiliary equipment. Several factors encountered during the flow back of wells have been blamed for plugging of SAS completions. These include:

1. Large sections of mudcake being lifted off the sandface and sticking onto the screen’s outer protection layer.
2. The screen’s permeable media (or filters) becoming clogged with particles from poorly dissolved mudcake or swelling shale.
3. Fines that are suitably sized to pass through the sand and block the filter mesh of the sand control media.
4. Zones with a very high inflow rate (hot-spots) near the heel section and/or near external packers. These are caused by the high, sand-laden, annular flow creating a hole in the screen.
5. Excessive pressure drawdown imposed by an artificial lift (e.g. Electric Submersible Pumps).

All of these factors can affect the advanced downhole flow control technologies and cause it to plug or render it inoperable. (A)ICDs are mounted on a SAS joint if they are installed in soft formations. Alternatively, a debris filter should be provided in strong formations. Damaged during installation will result in the (A)ICD being exposed to the mud flow back. This may cause plugging of the ICD’s flow restriction, the nozzle/orifice types will be especially prone to this type of damage. The flow ports of all types of AICDs, except the plate type, can also be plugged. The total device can become inoperable if sand and/or mud accumulate in the AICD chamber. These risks were not accounted for in the above analysis but should be considered during the design, installation and cleanup of such completions to avoid expensive remedial operations.

ICV completions have a lower risk of damage during cleanup operations.

- **Considerations for Effective Cleanup of Advanced ERC Completed Wells**

The following guidelines are recommended to achieve an optimum advanced well cleanup when completed across heterogeneous reservoirs:

1. SAS completions should be produced at fluid flow rates and drawdown pressures sufficient to lift off the mudcake and initiate filtrate flow back. High production rates should be avoided since this will result in high annular flow and poorer cleanup.
2. ICD completions can cleanup gradually if flowed at low production rates which are gradually increasing. However, the cleanup flow rate should be increased to match or exceed the design flow rate to achieve an optimum cleanup.
3. Gradually choking and reversible AICD completions can enhance the cleanup process of wells drilled with WBM if flowed at low production rates. They can restrict and/or complicate the cleanup process if flowed at high initial production rates. Shut-off AICDs should be combined with SCOVs to enable cleaning of the wellbore sections.
4. Plugging or Damage of (A)ICDs flow restriction leads to poorer cleanup. This can be prevented by installation of Screens or Filters to protect the active element [24].
5. ICV completions should be produced at flow rates sufficient to lift off the mudcake and initiate filtrate flow back. Flow rates significantly greater than this minimum level will lead to inflow imbalance along each zone.
6. The advantages from extending the cleanup time per lateral when ICVs are installed should be balanced against the effect of interference and increased mud filtrate invasion from other laterals.
7. The “optimum ICV opening strategy” to selectively clean individual zones should be implemented to achieve the best cleanup and save rig time [4].

- **Conclusions:**

1. Stand-Alone-Screen completions often results in poor well cleanup and differential mudcake lift-off due to the development of annular flow and productivity variation along the wellbore. This is true for both homogeneous, heterogeneous and layered reservoirs.
2. ICD completions results in the most efficient wellbore and formation cleanup provided that sufficient pressure drawdown and completion design flow rates can be applied. This especially true when installed across heterogeneous reservoirs.
3. AICDs acts as an aggressive ICD providing an enhanced cleanup when the mud filtrate is produced at low flow rates.
4. AICDs will restrict the clean up rate when flowed at high flow rates. A SCOV is required for each wellbore section to allow proper cleanup up if a complete shut-off type AICD is installed. A preliminary case study indicated the potential of the combined AICD/SCOV completion to provide an improved cleanup performance. An autonomously reversible AICD will maintain the well on production, where applicable, and eliminate the need to shut-in the well after the sufficient cleaning is achieved.
5. ICVs enable selective, sequential cleanup of multiple sections of the wellbore which often results in improved cleanup of each lateral or zone. This is true for both heterogeneous and layered reservoirs.
6. The advantage of ICVs is realised when the “optimum ICV opening strategy” is implemented resulting in shorter well cleanup time.

Acknowledgement

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Nomenclature

AFI:	Annular Flow Isolation
AICD:	Autonomous Inflow Control Devices
BHP:	Bottom Hole Pressure
ERC:	Extended Reservoir Contact
GOR:	Gas-Oil Ratio
GWC:	Gas-Water Contact
ICV:	Interval Control Valve
ICD:	Inflow Control Device
IPR:	Inflow Performance Relationship

K_h :	Horizontal Permeability
K_v :	Vertical Permeability
OD:	Outer Diameter
OWC:	Oil-Water Contact
PI:	Productivity Index
SAS:	Stand-Alone-Screen
SCOV:	Sandface Clean out Valve
scf/stb:	Standard cubic feet per stock tank barrels
Mstbo/d:	Thousands stock tank barrels of oil per day
Mstbl/d:	Thousands stock tank barrels of liquid per day
Mstbw/d:	Thousands stock tank barrels of water per day

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Table 1: Channelised Reservoir and Horizontal and Multilateral Wellbore Properties

Reservoir & Fluid Properties	Value	Wellbore Dimensions	Value
Model size	40 x 20 x 50	Horizontal (lateral) Length (ft)	~2,480
Gridblock size (ft)	80 x 120 x 10	Openhole Diameter (in)	8.5
Porosity (%)	10 - 40	(A)ICD Screen OD (in)	6.625
Permeability (mD)	1 – 5,000	(A)ICD Screen ID (in)	6.0
K_v/K_h	0.1	ICV OD (in)	5.5
Initial Pressure (psi)	3,500	ICV ID (in)	4.0
Oil Density ($^{\circ}$ API)	19	Number of laterals	3
Oil Viscosity (cP)	10.1		

Table 2: Study-1: Clean up Performance of SAS, (A)ICDs and ICVs Compared to Filtrate Volume Lost to Formation

Case	Total Filtrate Return (stbw)		Filtrate remaining in Formation (stbw)	
	High Flow Rate (after 15 Days)	Low Flow Rate (after 45 Days)	High Flow Rate (after 15 Days)	Low Flow Rate (after 45 Days)
Filtrate lost to formation	3,594	3,594	-	-
SAS	3,367	2,900	226	694
ICD	3,548	1,853	45	1,740
AICD	3,470	3,185	124	409
ICV – 60	3,283	2,871	311	723
ICV – 200	3,089	-	505	-
ICV – 1,000	2,237	-	1,357	-

Table 3: Summary of Studied Completions' Cleanup Performance

	Reservoir Type		Homogeneous									
	Completion		SAS		ICD		ICV		AICD		(A)ICD with SCOV	
	Permeability	Flow Rate	H	L	H	L	H	L	H	L	H	L
Mudcake Lift off	H		√	√	√	√	√	√	√	√	√	√
	L		X	X	X	X	√	√	X	√	√	√
Mud Filtrate Return	H		X	√	√	√	√	√	X	X	√	√
	L		√	√	X	√	√	√	√	√	√	√
	Reservoir Type		Layered									
	Completion		SAS		ICD		ICV		AICD		(A)ICD with SCOV	
	Permeability	Flow Rate	H	L	H	L	H	L	H	L	H	L
Mudcake Lift off	H		√	√	√	√	√	√	√	√	√	√
	L		X	X	X	√	√	√	X	√	√	√
Mud Filtrate Return	H		√	X	√	√	√	√	X	X	√	√
	L		√	X	X	√	√	√	√	√	√	√
	Reservoir Type		Heterogeneous									
	Completion		SAS		ICD		ICV		AICD		(A)ICD with SCOV	
	Permeability	Flow Rate	H	L	H	L	H	L	H	L	H	L
Mudcake Lift off	H		√	√	√	√	√	√	√	√	√	√
	L		X	X	X	√	√	√	X	√	√	√
Mud Filtrate Return	H		√	X	√	√	√	X	X	X	√	X
	L		√	X	X	√	√	√	√	√	√	√
			SAS	ICD	ICV	AICD	(A)ICD with SCOV					
Overall Performance (√)			13	17	23	15	23					
Overall Advantage												

H: High, L: Low, √ = Efficient cleanup, X = Inefficient cleanup.



Figure 1: An ICD [22]

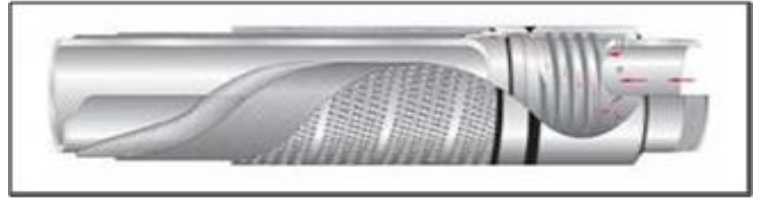


Figure 2: Channel-type ICD [20]

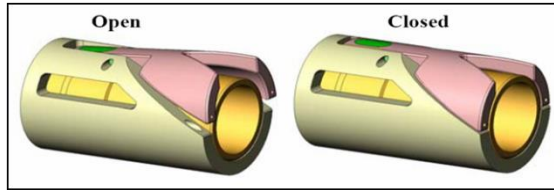


Figure 3: Flapper-type AICD [23]

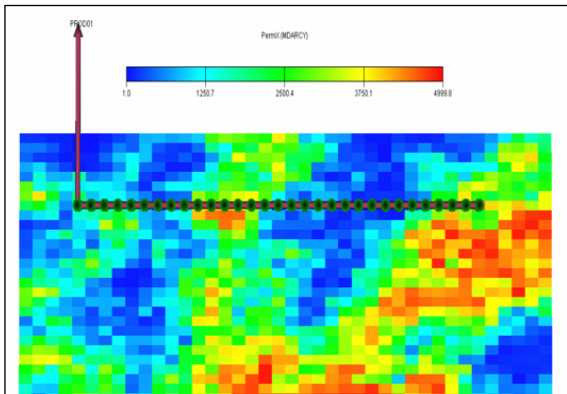


Figure 4: Study-1: A Channel Reservoir Model with horizontal well

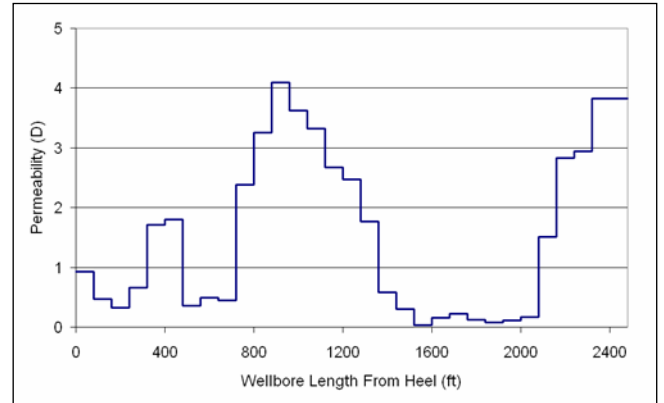


Figure 5: Study-1: Permeability Distribution along the Horizontal Completion

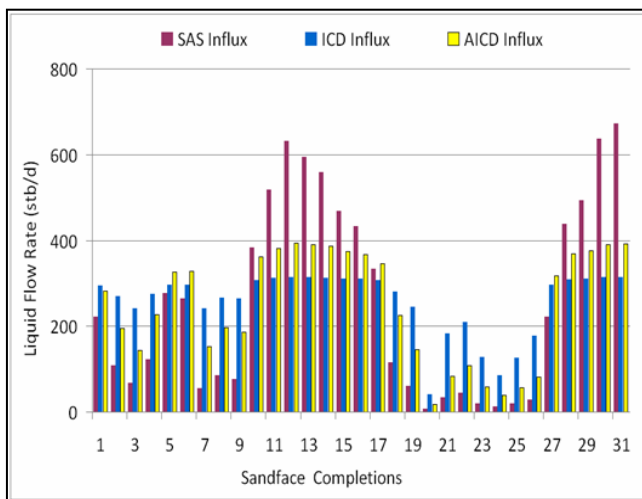


Figure 6: Study-1: Comparison of Liquid Influx in a SAS, ICD and AICD Completions at a Flow Rate of 8 Mstb/d with AFIs at Every Second Completion Joint

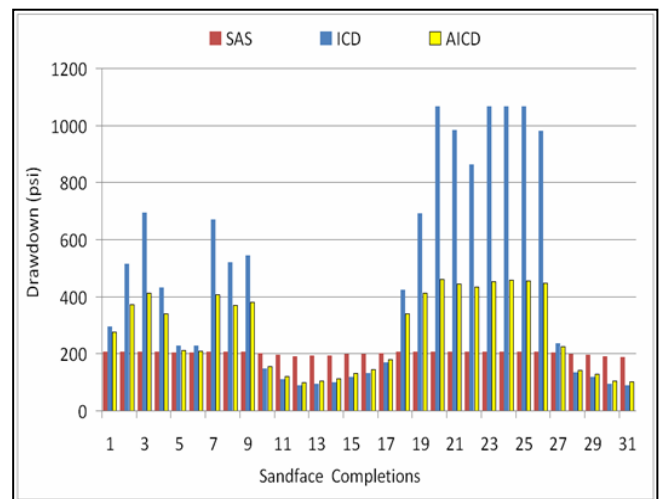


Figure 7: Study-1: Comparison of Drawdown Pressure in a SAS, ICD and AICD Completions at a Flow Rate of 8 Mstb/d with AFIs at Every Second Completion Joint

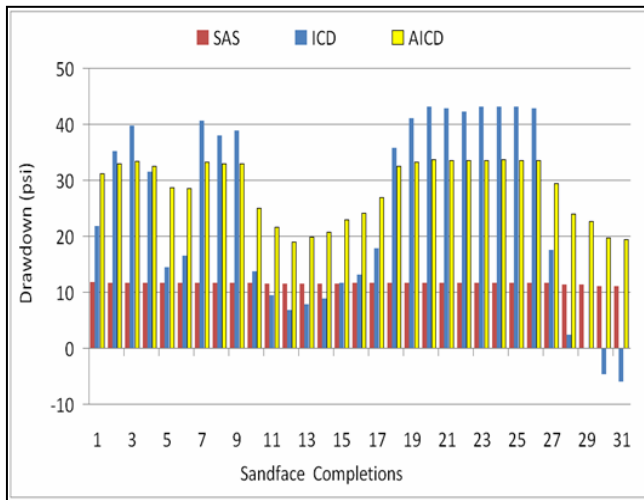


Figure 8: Study-1: Comparison of Drawdown Pressure in a SAS, ICD and AICD Completions at a Flow Rate of 1.2 Mstb/d with AFIs at Every Second Completion Joint

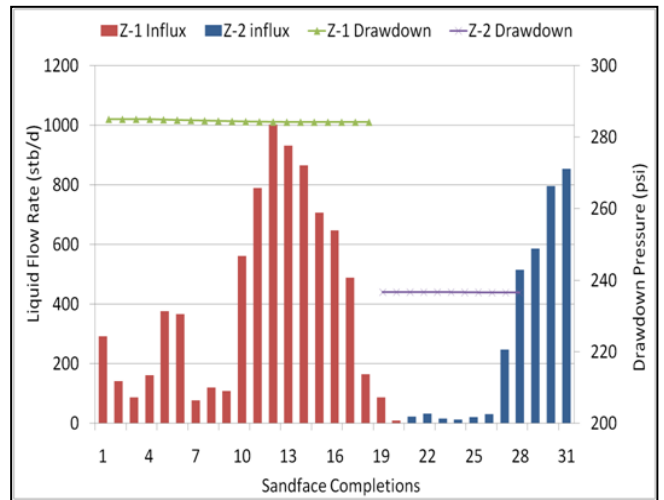


Figure 9: Study-1: Liquid Influx and Pressure Drawdown along an ICV Completion at a Flow Rate of 8 Mstb/d Across Each Zone

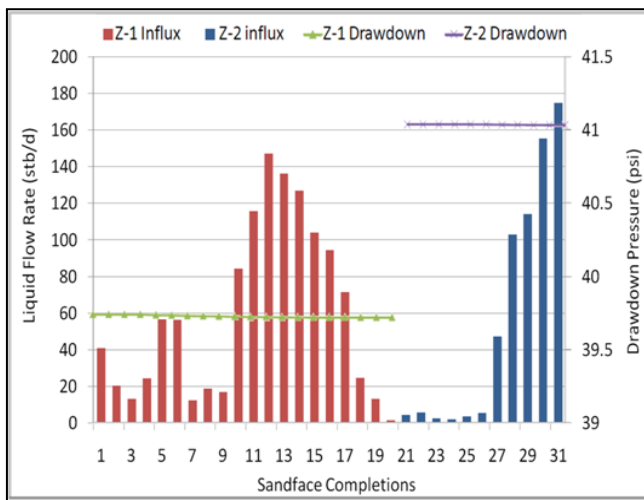


Figure 10: Study-1: Liquid Influx and Pressure Drawdown along an ICV Completion at a Flow Rate of 1.2 Mstb/d Across Each Zone

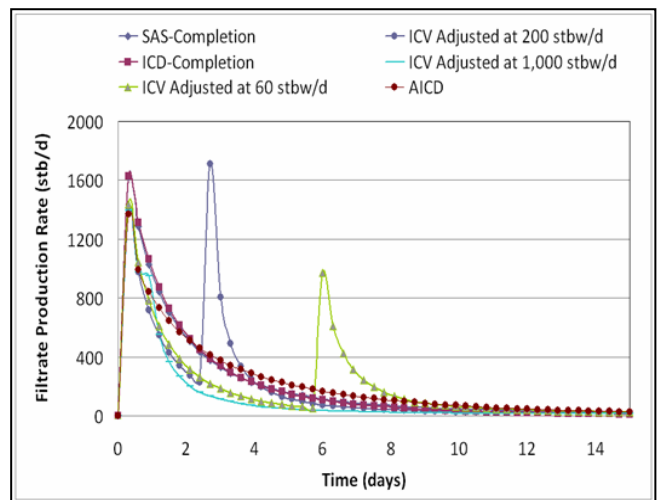


Figure 11: Study-1: Cleanup Filtrate Return Rate at a Flow Rate of 8 Mstb/d

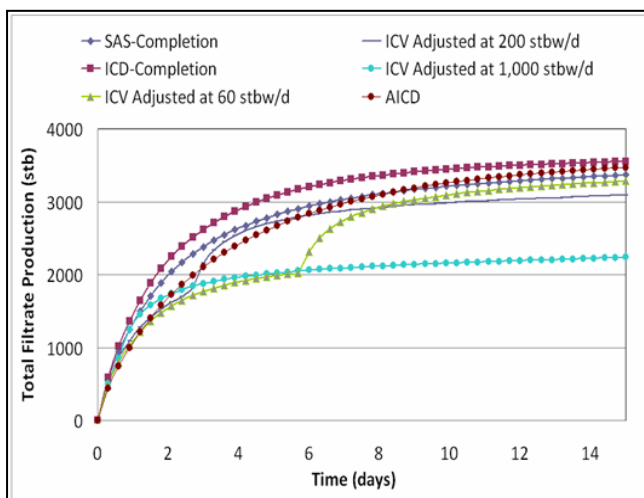


Figure 12: Study-1: Cumulative Cleanup Filtrate Return at a Flow Rate of 8 Mstb/d

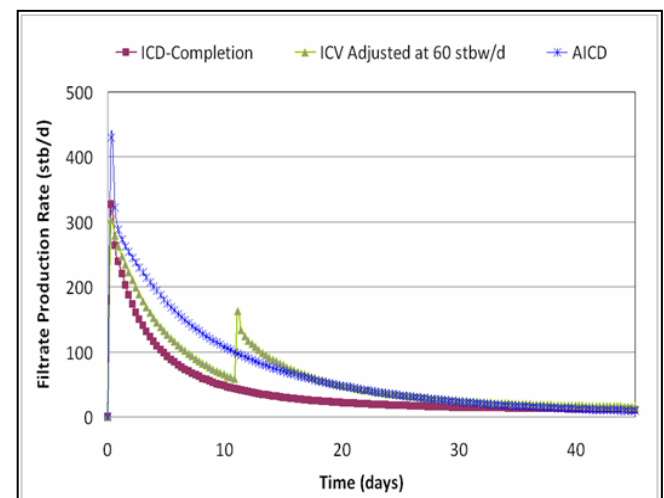


Figure 13: Study-1: Cleanup Filtrate Return Rate at a Flow Rate of 1.2 Mstb/d

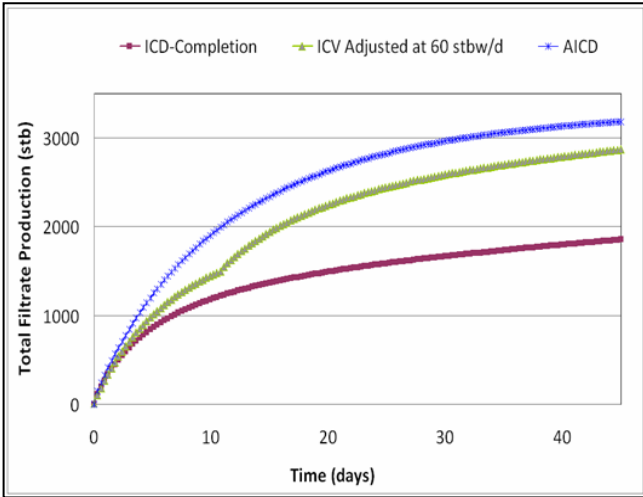


Figure 14: Study-1: Cumulative Cleanup Filtrate Return at a Flow Rate of 1.2 Mstb/d

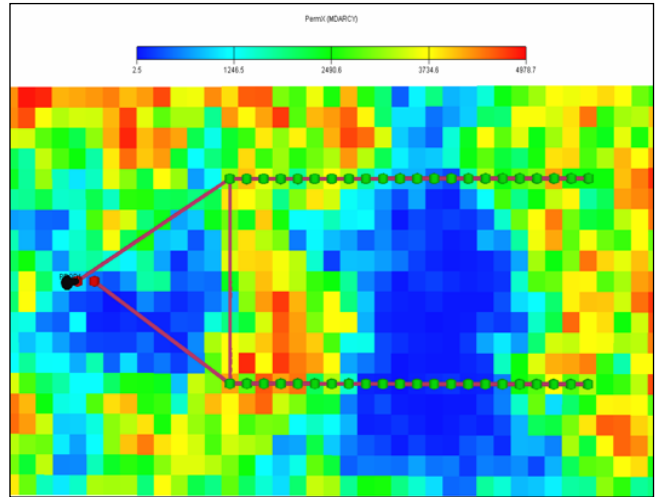


Figure 15: Study-2: Dual-lateral Wellbore

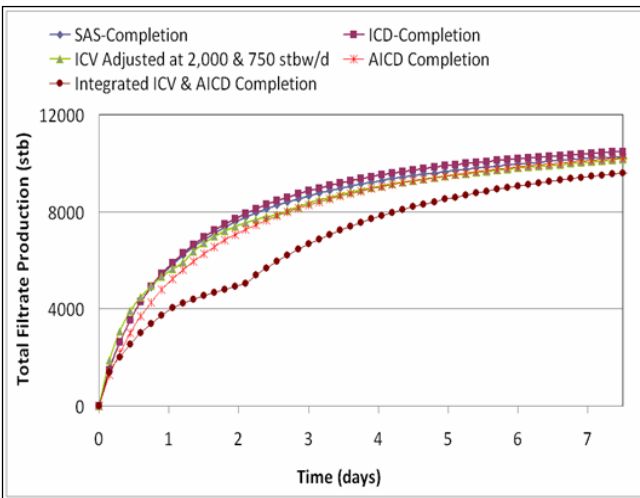


Figure 16: Study-2: Cumulative Cleanup Filtrate Return at a Flow Rate of 15 Mstb/d

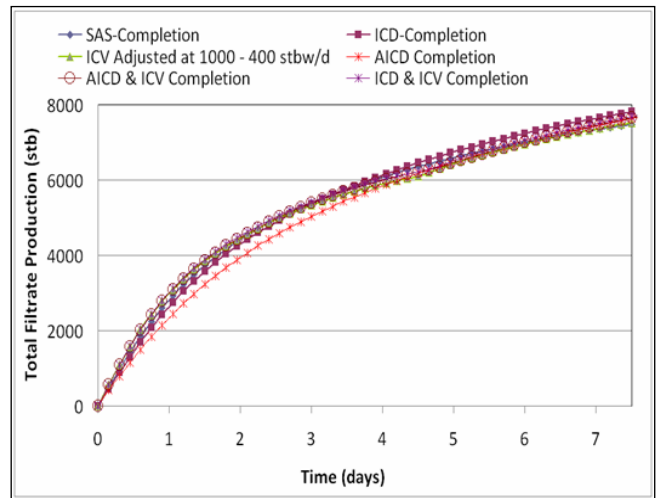


Figure 17: Study-2: Cumulative Cleanup Filtrate Return at a Flow Rate of 4 Mstb/d

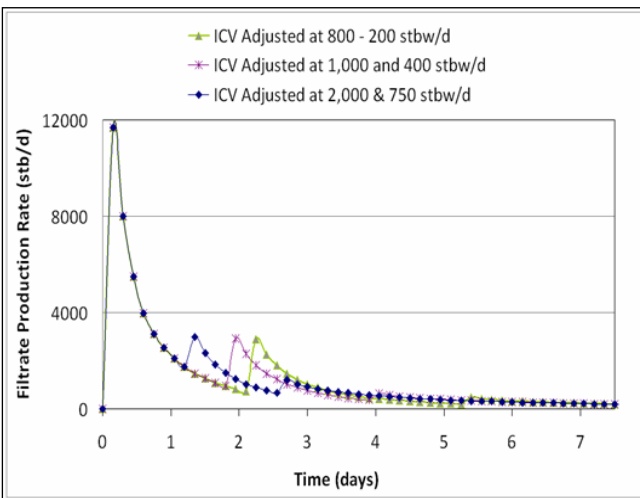


Figure 18: Study-2: Optimisation of ICV Opening Time

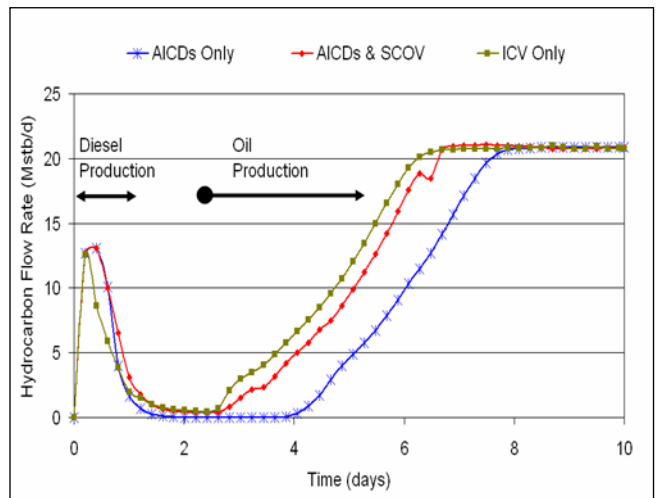


Figure 19: Study-3: Single Zone Cleanup, Hydrocarbon Flow Rates

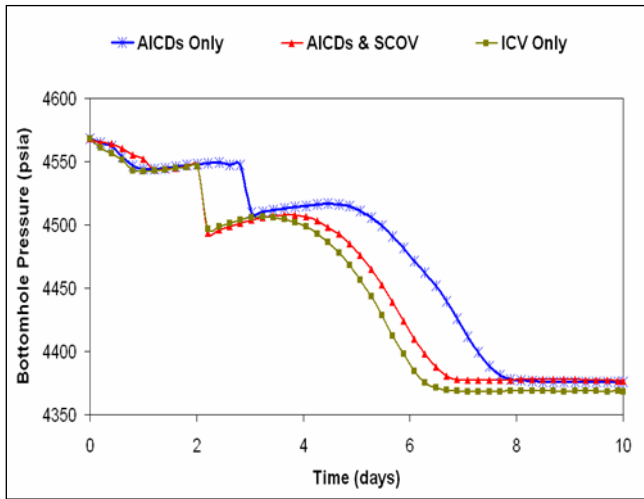


Figure 20: Study-3: Single Zone Cleanup (Tubing Intake Pressure Measured at the Heel)

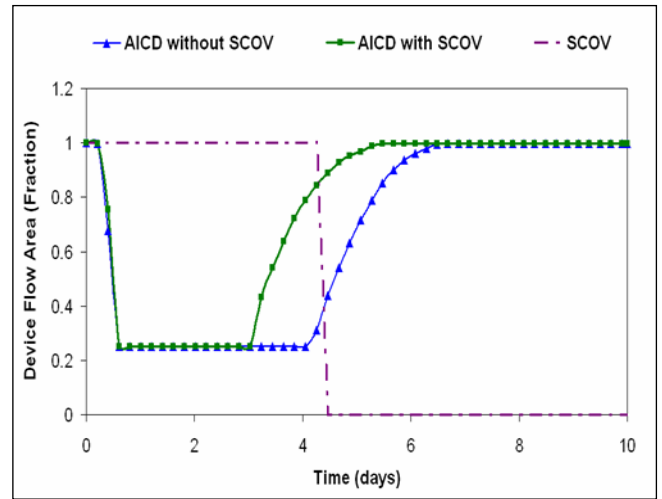


Figure 21: Study-3: Single Zone Cleanup, Device Relative Flow Areas

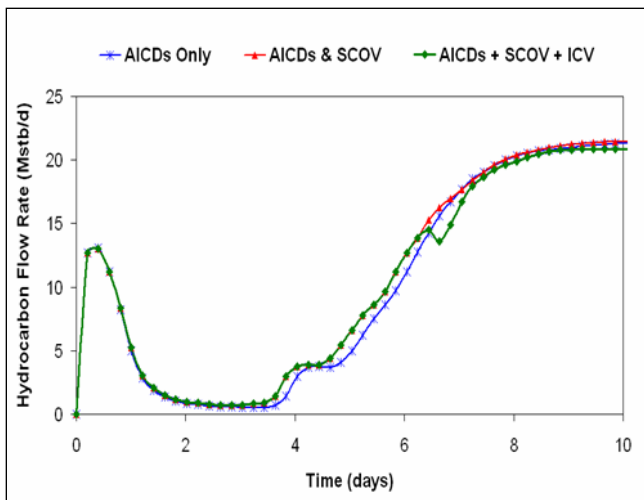


Figure 22: Study-3: 2nd Zone Cleanup, Hydrocarbon Flow Rates

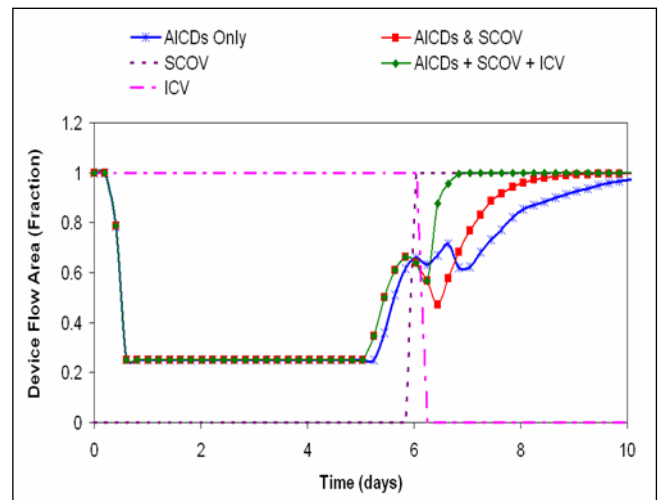


Figure 23: Study-3: 2nd Zone Cleanup, Device Relative Flow Areas

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