A Study of the Impact of Intelligent Well Technology on Reservoir Development

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ABSTRACT

Intelligent Well Technology (IWT) employs zonal flow control managed by flow rate and phase cut measurement. IWT flexibly controls production and/or injection, reducing well count and intervention expenses. IWT balances the drawdown along the wellbore while, accelerating production by extending the plateau period and decreasing the decline rate while delaying the unwanted fluid breakthrough.

This thesis present single and multiple wells applications of IWT using three "real" field reservoir models, in these models the normal reservoir engineering duty was performed, e.g. well location and design which then included when IWT is applied to these models.

Unlike the previous publications, when the benefits from IWT was based on better tubing performance or co-production of different reservoirs, this thesis presents a systematic methodology to improve the reservoir management as a whole using IWT.

The unique aspect of this thesis is the determination of added value from IWT including all field components (reservoir, downhole control, vertical lift, and surface facilities) on a real field example and optimise the system using up-to-date optimisation tool that incorporate each element in the system during the optimisation procedure.

This thesis concluded to that IWT could improve the reservoir management once the performance of the reservoir simulation model is correctly understood and powerful optimisation tool is used.

DEDICATION

This thesis is dedicated to my beloved parents

ACKNOWLEDGEMENT

In The Name of Allah, Most Gracious, Most Merciful

Praise be to Allah, the Sustainer of the world, the one who blessed me with the spirit and energy to carry out this research, and taught me what I did not know. Peace and blessings be upon the Prophet Mohammad, his family and all his companions.

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Finally, and most deeply, I thank all my family members, wife and my children for their patience and support.

DECLARATION

I, Salem Mohamed Elmsallati, confirm that this work submitted for assessment is my own and is expressed in my own words. Any use made of the work of other authors in any form (e.g. ideas, equations, figures, text, tables, programs) is properly acknowledged at the point of their use. A list of the references employed is included.

Signed ....Elmsallati..........

Date ....11/07/2005..........

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NOMENCLATURE

Symbols

A	Cross Sectional Area (ft^2 or m^2)
C_v	Flow or discharge coefficient for the valve (dimensionless).
c_u	Units Conversion Constant (dimensionless).
C_D	Choke Discharge Coefficient
Co	Oil Compressibility (psi^{-1} or bar^{-1})
Cw	Water compressibility (psi^{-1} or bar^{-1})
f	Fanning Friction Factor
δP_{total}	Total Pressure loss (psi or bar)
P_c	Capillary pressure, (psi or bar)
k	Permeability in milliDarcy
d_{eff}	Equivalent Flow Diameter (ft or m)
ID_t	Tubing Inner Diameter (ft or m)
OD_t	Tubing Outer Diameter (ft or m)
δP_{choke}	Pressure loss across a Choke (psi or bar)
$\delta P_{pipe.fric}$	Pressure loss across a Pipe (psi or bar)
α	Biot's coefficient
ID_c	Casing Inner Diameter (ft or m)
ρ	Density of the fluid mixture (kg/m^3 or lb/ft^3)
σ^1	Effective Stress (N/m^2 or Ib/in^2)
L	Length of Tubing in the Choke Segment (ft or m)
σ	Normal Stress (N/m^2 or Ib/in^2)
p	Pore Pressure (psi or bar)
p_n	Powers to which each phase ratio is raised.
Q_n	Flow Rate from Zone n (stb/day or sm^3/day)
v	Fluid Flow Velocity (m/s or ft/s)

v_p	Flow Velocity through the choke segment (m/s or ft/s)
w_n	Weighting Factor
ΔX	Cell dimension in X direction (ft or m)
ΔY	Cell dimension in Y direction (ft or m)
ΔZ	Cell dimension in Z direction (ft or m)

Abbreviations

ALQ	Artificial Lift Quantity
BCF	Billion of Cubic Feet
BHP	Bottom Hole Pressure (psi or bar)
BOPD	Barrel of Oil Per Day
BU	Build Up test
CAPEX	Capital Expenses
ESP	Electrical Submersible Pump
FBHP	Flowing Bottom Hole Pressure (psi or bar)
GAP	System Optimiser Program
GOC	Gas-Oil-Contact (ft or m)
GOR	Gas Oil Ratio (sm^3/sm^3 or scf/stb)
ICOS	Intelligent Completion Optimisation System
ICV	Interval Control Valve
ID	Internal Diameter (ft or m)
I-well	Intelligent Well
IWT	Intelligent Well Technology
LP	Linear Programming
m	Meter
M	One Thousand
mD	milliDarcy
$MULT_i$	Multiplier Factor for i time step
NPV	Net Present Value
OGIP	Original Gas In Place (sm^3 or SCF)
OOIP	Original Oil In Place (sm^3 or STB)

OPEX	Operating Expenses
OWC	Oil- Water- Contact (ft or m)
P	Pressure (psi or bar)
Pb	Bubble Point Pressure (psi or bar)
QP	Quadratic Programming
S	Skin factor
sm^3	Cubic Meter in Standard Conditions
SQP	Sequential Quadratic Program
SS	Sub Sea
STB	Stock Tank Barrel
Swi	Initial water saturation
THP	Tubing Head Pressure (psi or bar)
TVD	True Vertical Depth (ft or m)
VFP	Vertical Flow Performance
WOR	Water Oil Ratio
wrt	With Respect To
X,Y and Z	Orthogonal Directions

Chapter 1

1. Introduction

In this thesis the term "Intelligent Well Technology" (IWT) will refer to completion of the well with Interval Control Valves (ICV) combined with measurements of the flow parameters at a zonal level via pressure, temperature and multi-phase flow meters. This "state-of-art" well completion technology offers great flexibility to monitor and control wells without well intervention. (Williamson, et al. 2000).

1.1 Thesis objectives

This thesis aims to evaluate the impact of the intelligent completions on the reservoir development by using up-to-date modelling and optimisation techniques. It will highlight the lessons gained by studying the application of IWT to a number of "real-field" examples. These lessons can be used by a reservoir engineer when faced with having to make a decision on whether to install such high-tech equipment.

1.2 Thesis layout

Many factors should be considered when deciding whether to install IWT and, more specifically, what type of equipment should be used in a particular case. This thesis is divided into ten chapters (Figure 1.2.1) covering a number of aspects of IWT. This includes techniques for the modelling, control and optimisation of this equipment. IWT application to three different types of reservoirs will be discussed.

Chapter 2 reviews the available techniques in the reservoir simulator (Eclipse from GeoQuest 2002) to model the detailed completion aspects of long horizontal wells. IWT is typically installed in such wells. The multi-segment option in Eclipse will be used. The importance of the frictional component of the pressure drop over along (horizontal) completion will be shown to have a direct affect on the production rate per unit length at different points in the wellbore. This leads to a large variation in the well's inflow performance along its length. This inflow performance pattern will be used to develop ideas to locate and operate the ICVs along the length of the completion.

Chapter 3 studies the importance of pressure drop calculation along the wellbore in a real field case. The subject of the productivity of horizontal wells as a function of well length and placement within a thin oil column has been well discussed in the literature for relatively simple situation where analytical solutions are available. This chapter reviews this literature and illustrates the resulting practical consequences by using a numerical reservoir simulator to study a case history (NH Field) with both complex geology and complex reservoir fluid properties.

Chapter 4 shows that NH field case is a good candidate for IWT application. The techniques available to model ICVs are discussed and the operating philosophy for such valves in a thin oil column reservoir is illustrated.

ICVs are usually used to balance the production profile along the completion length by splitting the well into two (or more) sections, with the aim of optimising the production (maximizing net oil while delaying the gas and water breakthrough). Another application of IWT is presented in

Chapter 5 where the use of IWT to optimise production from compacting reservoirs is discussed. This chapter reviews the potential value creation through development of a compacting reservoir using IWT compared to a conventional completion. The flexibility to monitor and control production at both the Zone and Reservoir level offered by IWT made it worthwhile to examine whether permeability damage due to compaction could be minimized by optimising the draw down around the wellbore in order to increase the recovery in such (compacting) reservoirs.

Chapter 6 illustrates another type of added value from the IWT. Scale management control is used in a field example and shows that IWT can deliver value by treating each zone independently using the flexibility offered by the ICVs. It also shows the importance of the modelling technique based on "injected tracers" which was used to develop understating of the movement of the injected seawater. IWT also gave the ability to manage the scale inhibitor placement.

In the previous chapters we looked at the application of IWT at the well level, in the next three chapters we will use the Chapter 6 field case to examine field management at the reservoir level. Chapter 7 presents the field case (The S-Field) and reviews the potential value creation if the field had been developed using IWT. The S-Field is an oil reservoir with a strong aquifer drive located in the Norwegian section of the North Sea. The reservoir simulation model, which has been history matched for 6 years of production, is used as the basis for this study.

Chapter 7 discuss the methodology developed to quantify the extra oil achievable through the use of an intelligent completion compared to a conventional well development. It shows how development of the field with intelligent completions can deliver greater recovery with a reduced numbers of producers. It also shows that optimum zone management can extend the plateau production period, delay water production and increase the ultimate recovery.

Chapter 8 discuss the application of IWT in injection wells. IWT installed in injection wells can deliver great flexibility in the control of the water injection process. This chapter discusses how development of the field with IWT injectors can deliver more recovery with reduced numbers of injectors. Inclusion of IWT injection well gives the operator the flexibility to control injection into each zone - an ability that was not available in the real case conventional development; even when many more injection wells were drilled.

In Chapter 9 an automatic optimisation technique of the ICVs is used and compared with the manual optimisation procedure developed in chapter 7. This chapter uses the link between Reveal (Reservoir simulator developed by Petroleum Experts, 2003) and Gap (a Network Flow Optimiser developed by Petroleum Experts, 2003) to identify the value that intelligent completions can deliver compared to the conventional completions.

In Chapter 10 the conclusions and recommendations for future studies in this field of research are discussed.

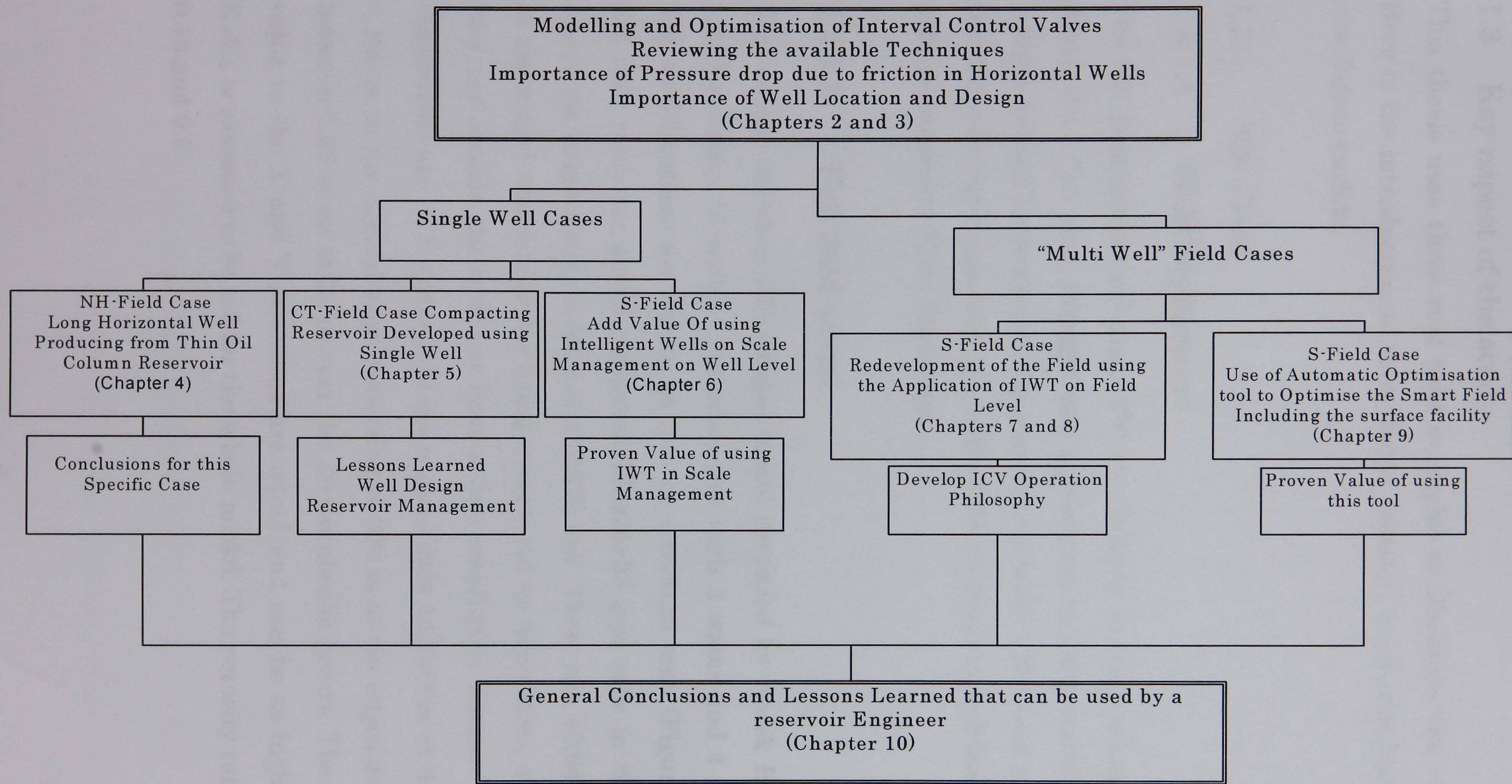


Figure 1.2.1 Organization of research into single and multi well cases. Following a background thesis chapters address the series in boxes from left to right, leading chapter of the conclusions

1.3 Key aspect of the study

This thesis uses three real field examples to illustrate the value of IWT. Here is the introduction to these fields, location, geological background and simulation models.

1.3.1 NH Field

1.3.1.1 Field background

The NH field is situated some 150 km offshore in the Norwegian sector of North Sea. The field, brought into production in 1999, contains a thin oil column located between gas cap and bottom water. The field produces from the Brent Group sands with the bulk of the oil reserves contained within the high permeability Etive Formation.

1.3.1.2 Full field model

The history matched NH Eclipse model prepared by Norsk Hydro (Figure 1.3.1) contains 13 wells, 7 oil producers with 2 water and 4 gas injectors. The well locations are shown in the top structure map (Figure 1.3.2). The full field reservoir model contained 138x35x39 grid cells in the X,Y and Z directions respectively, a total of 188,370 cell. There are 49,644 active cells in the model, the remainder being designated as non-active, either because they are outside the model or have a very small pore volume. The grid cell dimensions are: $\Delta X = 100$ m in the central area and 200m at the edges, $\Delta Y = 100$ m in the central area increasing to 500 m at the edges and ΔZ varies between 0.25 m up to 20 m over the 39 simulation layers. The permeability value in the X and Y directions are equal and can be as high as 9 Darcy. K_v/K_h is assumed to be 0.3 for the whole model. The porosity ranges between 0.15 and 0.2.

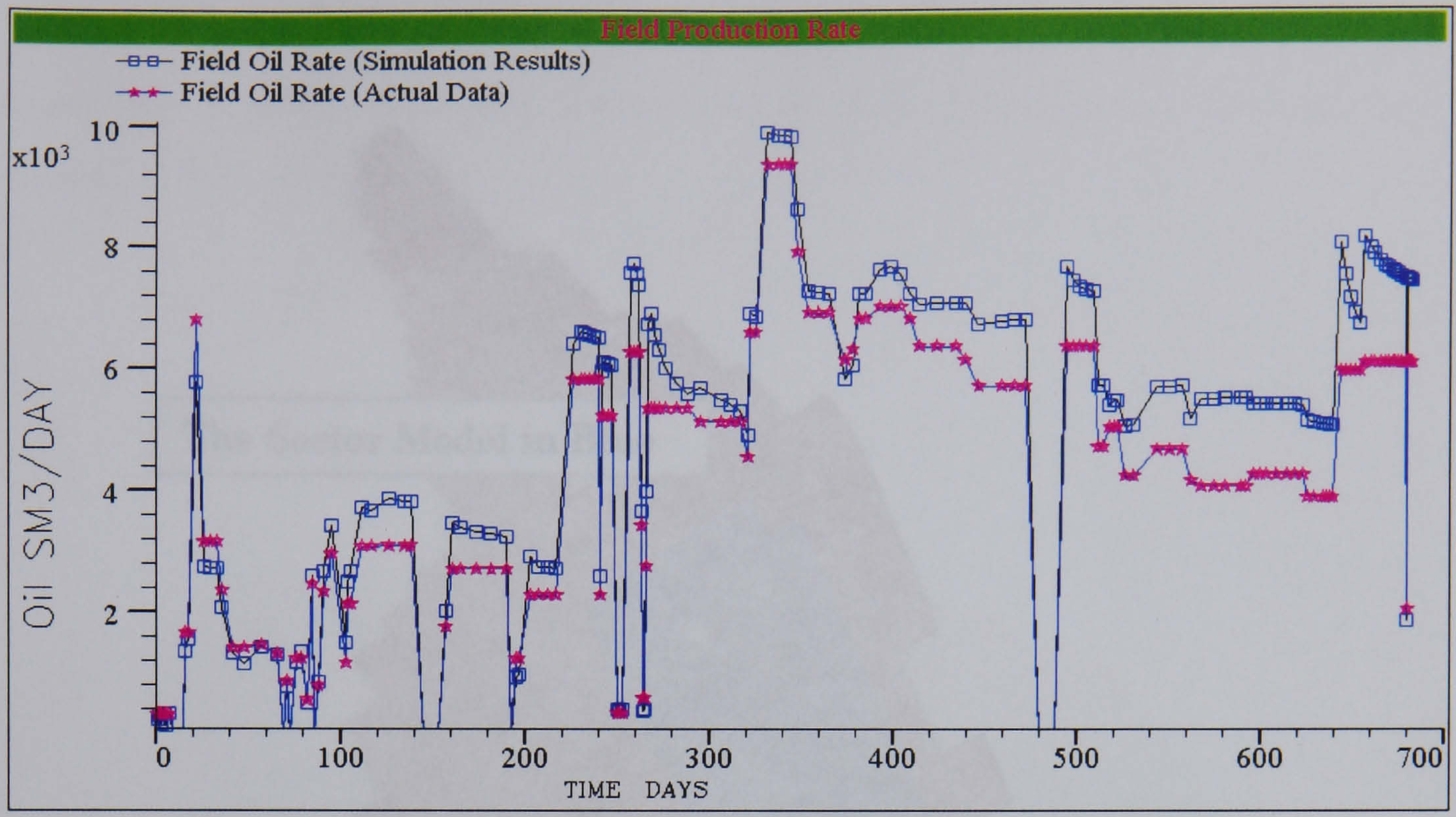


Figure 1.3.1 The field oil production rate for the history-matching period

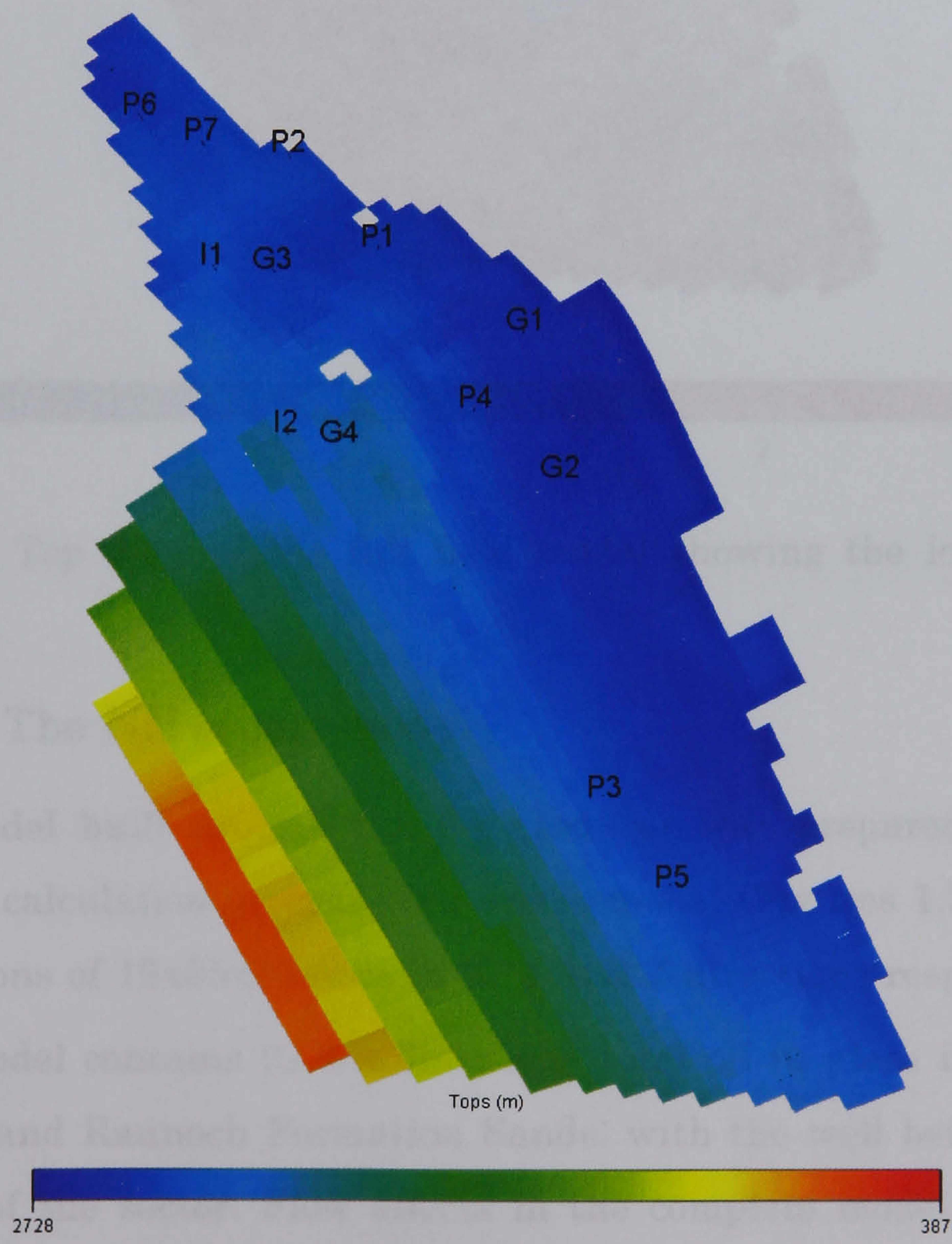


Figure 1.3.2 Top structure map of the full field model shows the well locations

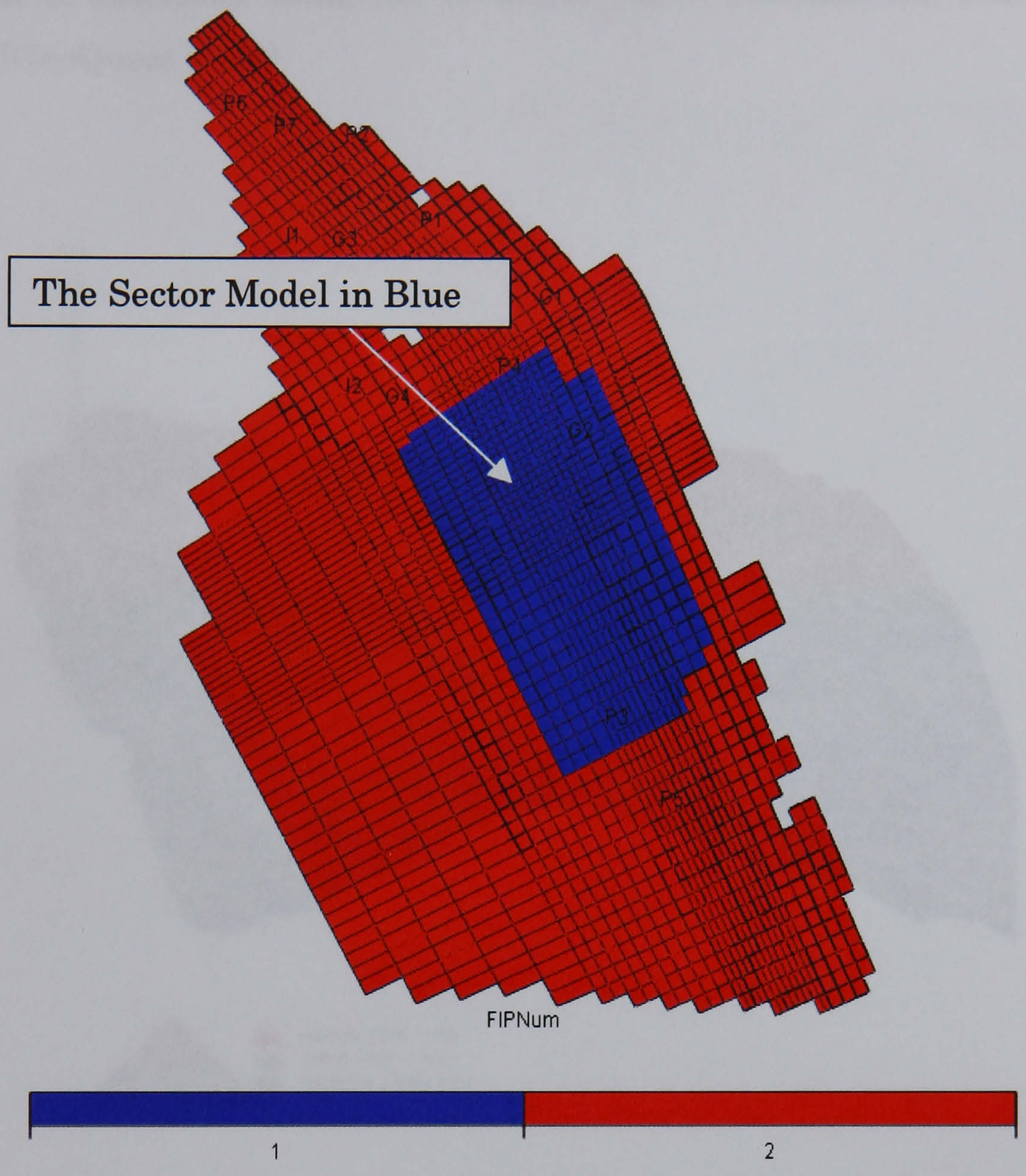


Figure 1.3.3 Top view of the full field model showing the location of the sector model.

1.3.1.3 The NH sector model

A sector model built around the P4 producer was prepared in order to simplify the calculation process. The sector model (Figures 1.3.3 and 1.3.4) has dimensions of 19x35x19 cells in X, Y and Z directions respectively. The P4 sector model contains 22.6 million sm^3 total oil in place in the Tarbet, Ness, Etive and Rannoch Formation Sands; with the well being located in the middle of the sector. Flow effects in the complete model are included using Eclipse's flux keyword. Friction pressure loses across the horizontal wellbore are calculated using the multi-segment model. The well completion was divided into segments and the flow into each segment from the reservoir is described using the transient, three-dimensional, uniform flux model. (GeoQuest 2002).

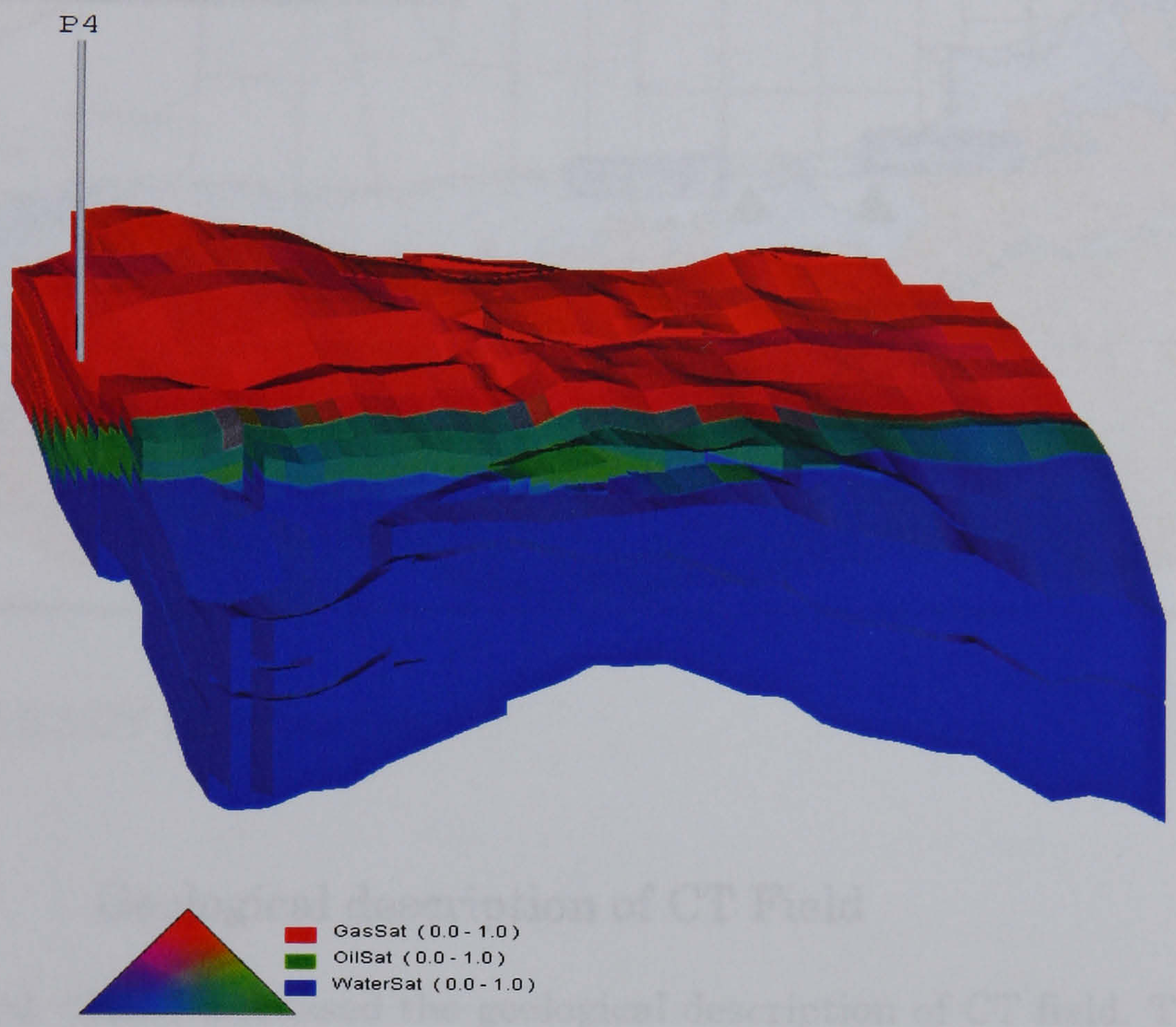


Figure 1.3.4 The P4 Well is located in the middle of the sector completed in the thin oil column.

1.3.2 CT Field

1.3.2.1 Field background

CT Field is located approximately 170 miles south-southwest of New Orleans in some 2,100 feet of water (Figure 1.3.5). One of the major concerns facing the CT development team was that the production was planned from two, separate, unconsolidated sands. IWT was thought to be the tool that could help to solve some of the resulting challenges. The high cost of IWT developments make it essential that the reservoir behaviour is sufficiently well understood that a confident "Value-Proposition" can be made before making the decision to install such technology in the field.

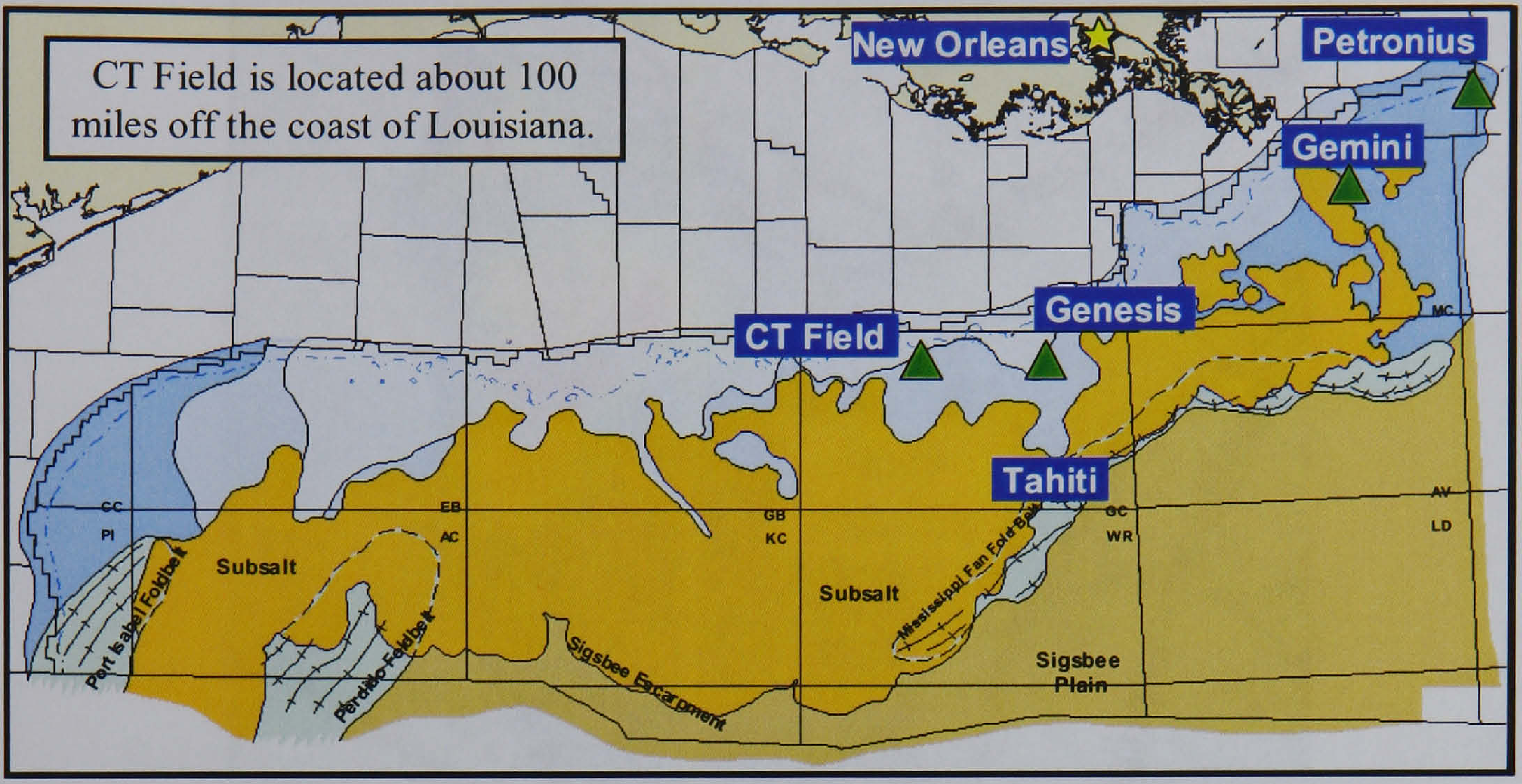


Figure 1.3.5 CT Field location

1.3.2.2 Geological description of CT Field

Ring et al. (2004) discussed the geological description of CT field. The gross reservoir interval thickness is approximately 2,200 ft at depths ranging from 15,000 to 17,500 ft ss. The initial development consisted of production from the B4 and B4.5 sands in the Terrace via well PROD1. This well will be the subject of this study.

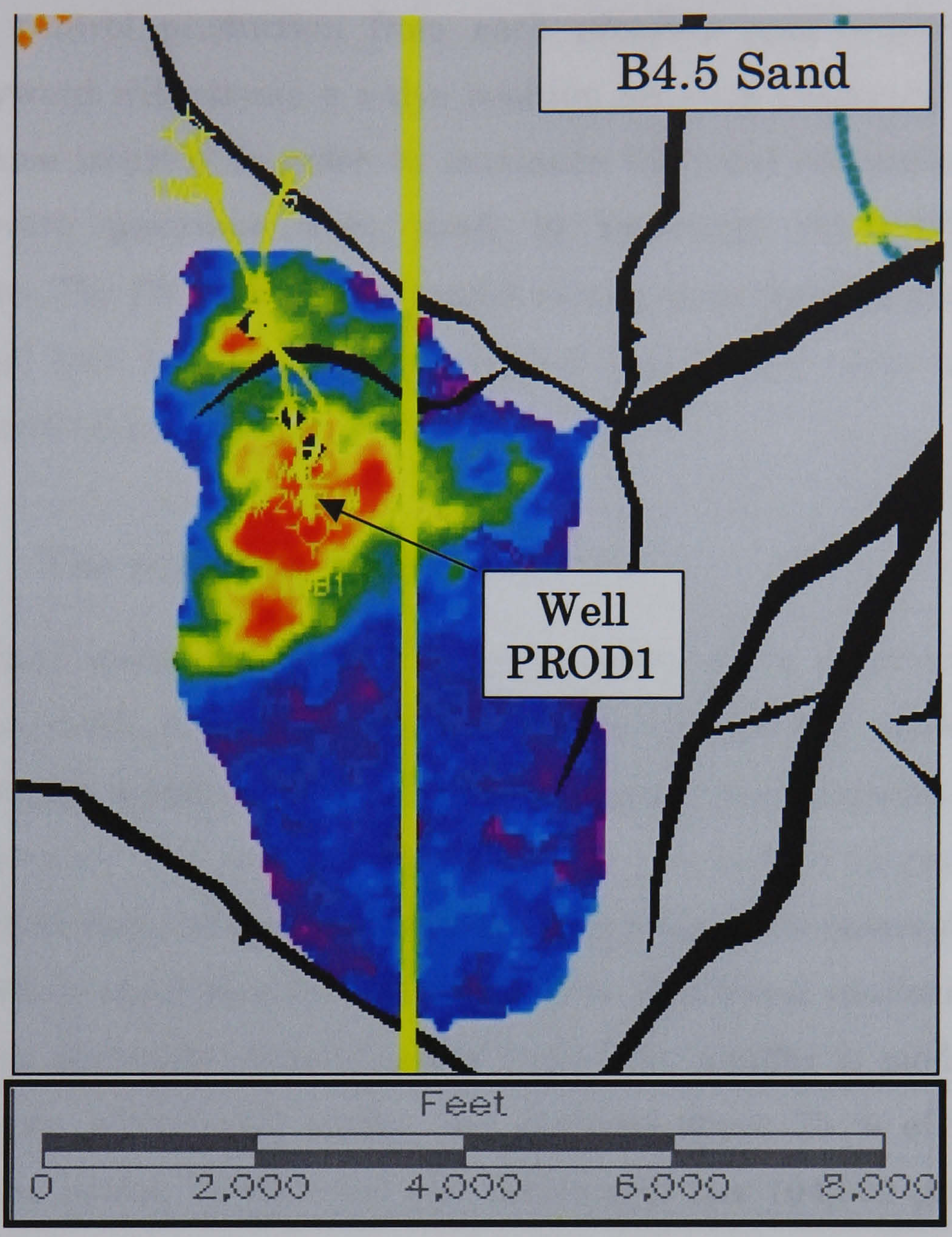


Figure 1.3.6 CT (B4.5) sand top structure map showing the main faults.

1.3.3 S-Field

1.3.3.1 Field background

S-Field is an oil reservoir with a strong aquifer drive located in the Norwegian sector of the North Sea; it has been called the S-Field in this thesis. Statoil (the operator) made the three-dimensional, history matched reservoir model. This field, developed with seven producers and three injectors, has 6 years of production data available. The base case (which is similar to the real field development) considers a conventional completion system where all the zones were produced without any form of downhole control. The IWT case uses a variable ICV controlled intelligent completion system to control production from each pressure zone separately. The control keyword will choose a valve position for each producing zone at a specified time interval in order to maximize the total oil production. Ten discreet valve positions were used to represent the variable ICV performance. The IWT completion model results were then compared with a conventional base case scenario to provide a quantitative value assessment of incremental oil production.

1.3.3.2 The reservoir model

The operator, using the Eclipse reservoir simulation program and the SimOpt automatic history-matching program, created the model. A two-phase, oil-water model with corner point geometry was built with use of the Resview program. The reservoir simulation grid consists of 55 grid blocks in the x-direction and 100 grid blocks in the y-direction. The reservoir grid has 19 layers whose resolution varies with location. The finest resolution is to be found in the rectangle containing the wells. The aquifer is modelled with approximately 40,000 grid blocks and contains about 75 % of the active blocks in the model. In total the simulation grid has 104,500 grid cells, of which 51,179 are active. The operator obtained a good history match, the main history matching challenge being to match the observed Upper Brent flow pattern where there was communication between the slumped fault blocks and the central area.

The Brent Group reservoir is divided into the Upper and Lower Brent sands with separate two pressure regions (Figure 1.3.7) The Upper and Lower Brent pressure regions are separated by the Ness 6 barrier, which has been modelled as an inactive layer i.e. the only communication between these two pressure regions is across faults included within the model.

Corbett (2002) has discussed the reasons for splitting the Lower Brent into two reservoirs units (Etive and Rannoch Formations) according to their petrophysical properties, in this model Etive has more than 5 times value of permeabilities compared to the Rannoch, a factor should be taken into account when locating the downhole control valves.

The original development philosophy of the field specified that the completion zone for each well should be assigned to only one of these two pressure regions i.e. commingled production was explicitly avoided.

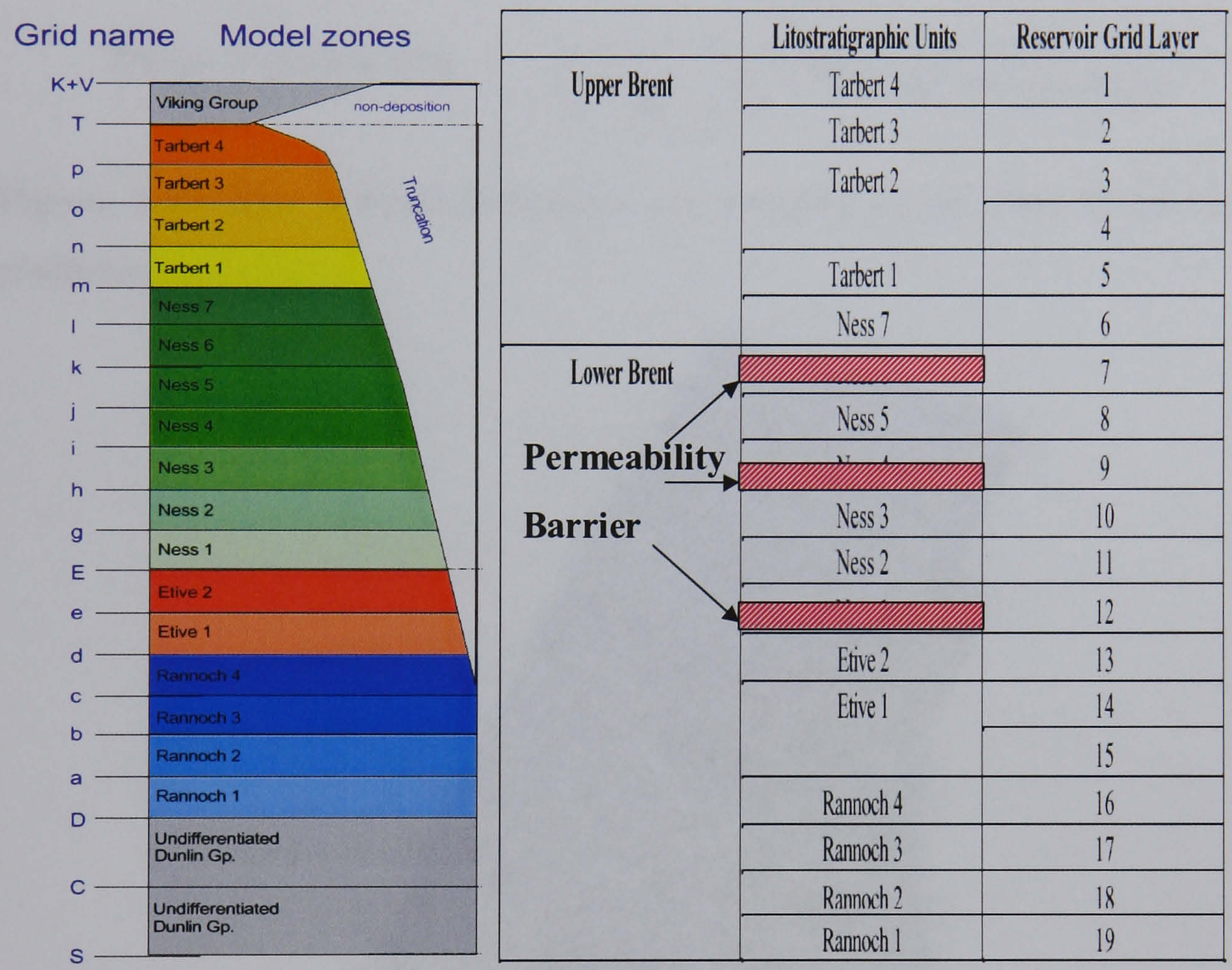


Figure 1.3.7 Reservoir Zonation compared to the Reservoir Grid Layer

The field is developed with two production templates (M and L) and one injection template (K). Figure 1.3.8 shows the location of the templates with respect to the host Platform. Note that pressure drop due to wellbore, tubing and pipeline friction is explicitly incl

uded in the field and reservoir performance calculations. Figure 1.3.9 shows the location of the existing wells.

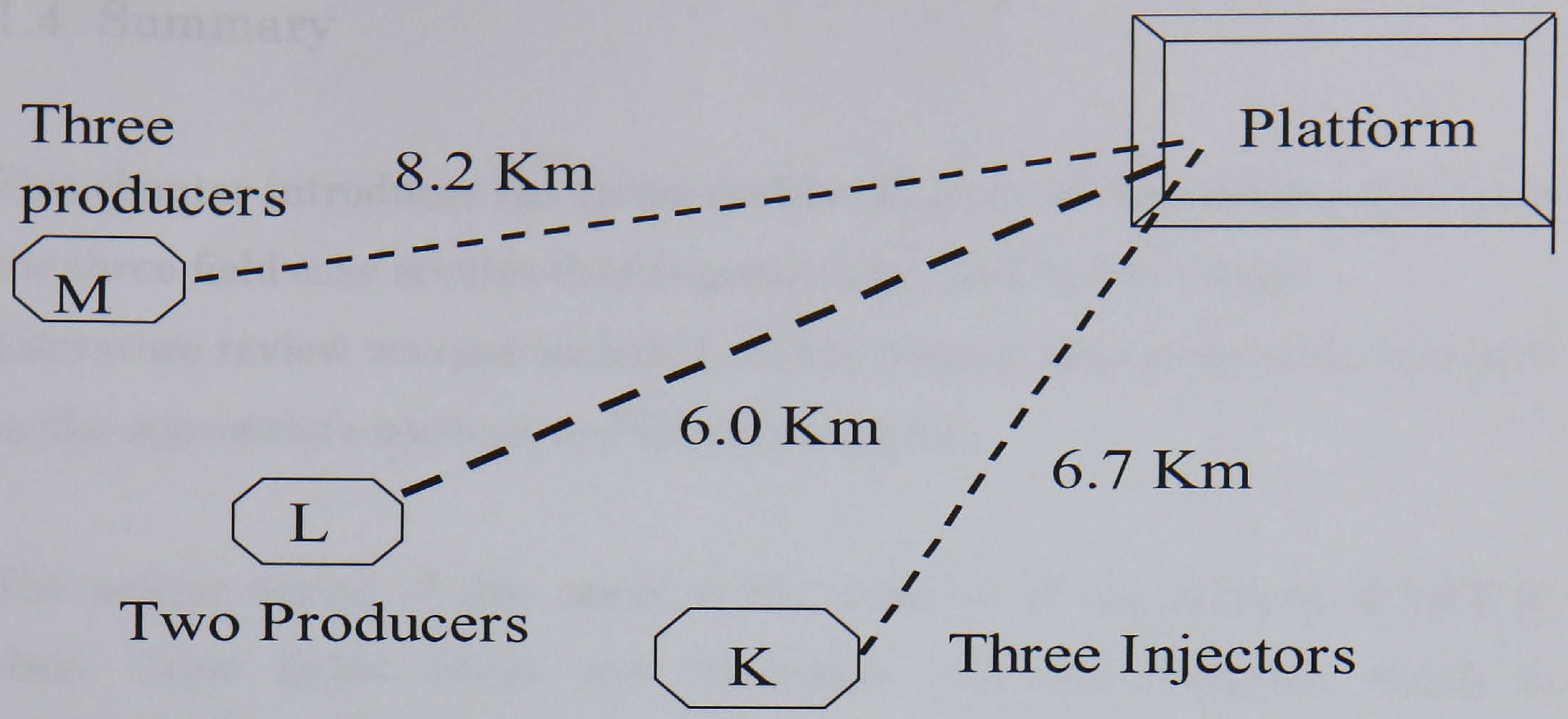


Figure 1.3.8 The S-Field templates are located about 7Km from the host platform

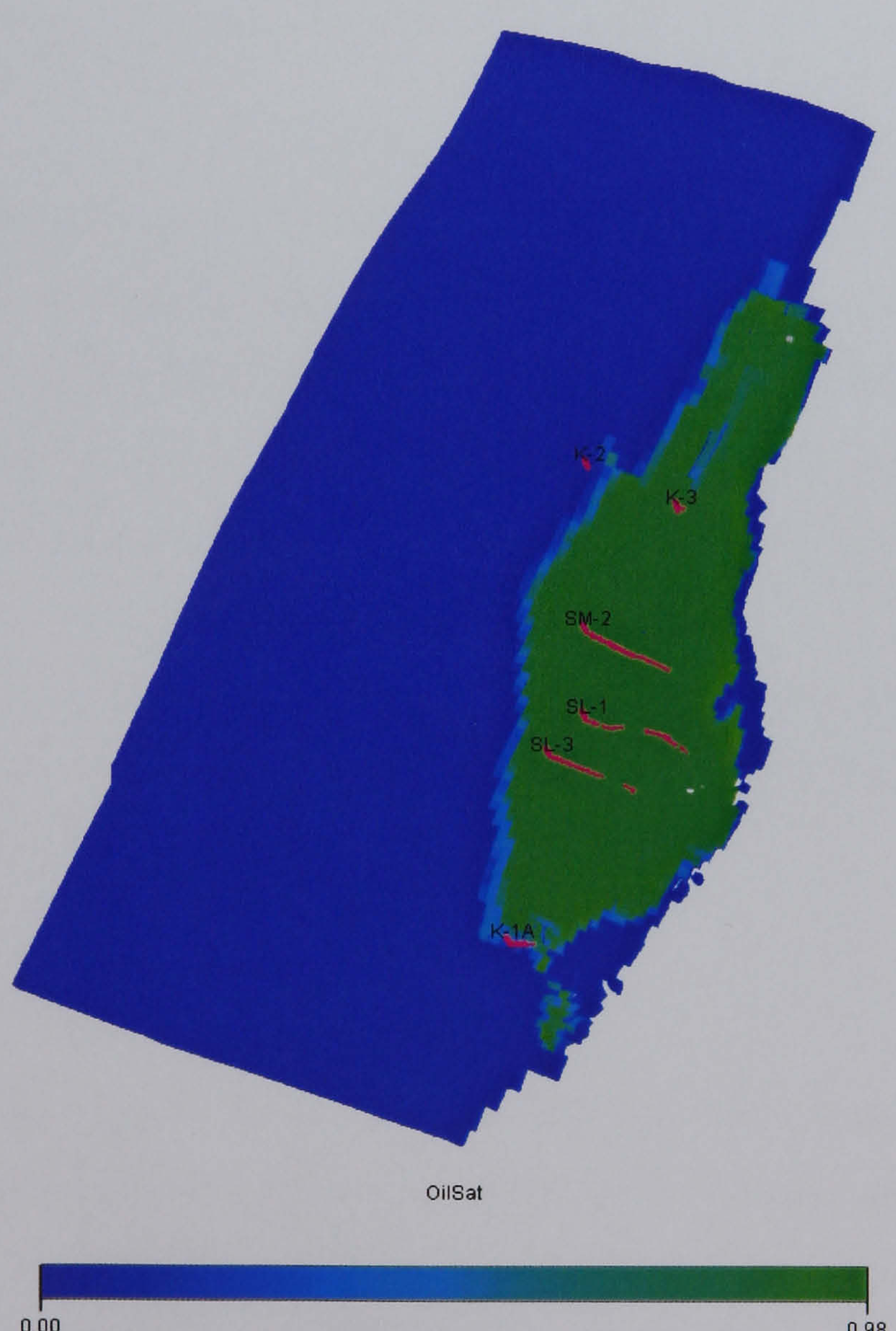


Figure 1.3.9 S-Field map shows the location of the existing wells

1.4 Summary

This chapter introduces the thesis outline. It gives a brief introduction to all the three field case studies that is going to be used in this thesis.
Literature review was not included in this chapter as is going to be reviewed in the appropriate sections in following chapters.

The unique aspect of this study is the analysis of applications of IWT in these three fields shows the challenges and opportunities, which is summarised at the end of this thesis.

Chapter 2

2. Modelling of Intelligent Wells

In this chapter we will review the techniques available in Eclipse (GeoQuest 2002) to model in detail the pressure drop across a horizontal well using the multi-segment option. This option allows the user to calculate the pressure drop due to friction along a completion (horizontal) section, given the properties of each segment of the well model.

N.B. All equations presented in this chapter have been obtained from the relevant sections of Eclipse (GeoQuest 2002) and ICOS (PETEC 2002) reference manuals.

2.1 Modelling of horizontal wells

The fraction of the total pressure drop across a conventional vertical or deviated well completion due to friction is normally small due to the relatively short length of the completion. In horizontal wells, however, the length of the completion (often perforated) section may extend to many thousands of meters. If the frictional component of the pressure drop over this length is significant it will thus result in a variable drawdown over the length of the reservoir inflow section. This will have a direct affect on the production per unit length at different points in the wellbore, often causing a large variation in the well's inflow performance along its length. In fact, it has been realised for a number of years that, in high productivity wells where the well drawdown has a similar magnitude to the frictional pressure drop, there comes a point at which extending the length of the horizontal well will not increase the well production i.e. the pressure in the wellbore is equal to the reservoir pressure at wellbore locations beyond this critical point. (Babu and Odeh 1989a). This approach is further considered in Chapter 3 where a case history of the impact of horizontal well length on well performance is described.

2.1.1 The multi-segment well model

Well inflow effects can be included in numerical reservoir simulation by splitting the completion zone into a number of segments, typically one segment for every reservoir grid block that the well passes through (Holmes et al. 1998 and Holmes 2001). Their paper discuses the use of the multi-segment wellbore option to study the interaction of the reservoir with the multi-segment model of a horizontal well completion containing an interval control valve (ICV).

2.1.2 Connection from the grid block to the segment

The wellbore is divided into an arbitrary number of segments; the appropriate number of segments will depend on the degree of accuracy with which the well is to be modelled. For example, a separate segment may be placed adjacent to each reservoir grid block in which the well is completed (Figure 2.1.1). It is also possible for a segment to accept flow from more than one reservoir grid block. Additional segments may be used to represent blank (un-perforated) lengths of casing. Additional details of how the flow comes from the reservoir to the segment can be found from Holmes et al 1998.

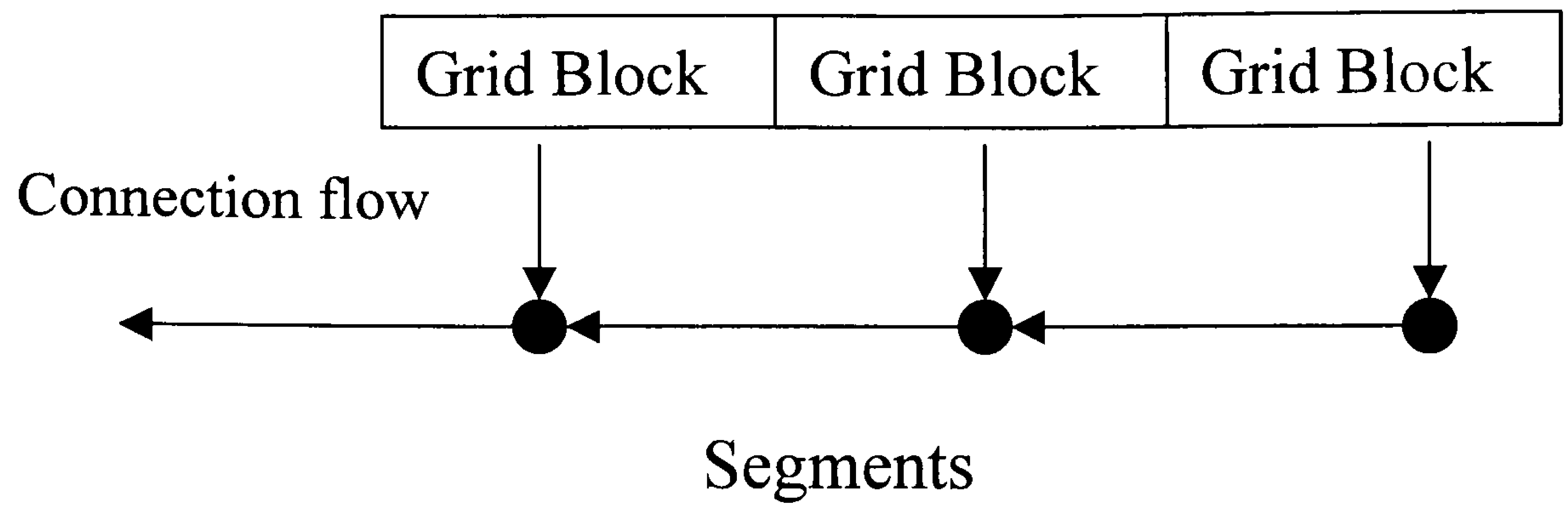


Figure 2.1.1 Shows an example of allocating connection flows to segments (GeoQuest 2002)

2.1.3 Modelling of pressure drop in multi-segment model

The Eclipse multi-segment well model, offers a choice of three methods for calculating the pressure drop across each segment (GeoQuest 2002). These are:

1. A homogeneous flow model, in which all phases flow with the same velocity (Hagedorn and Brown 1965).
2. A simple 'drift flux' flow model, which allows the phases to flow with different velocities. (Shi et al. 2003).
3. Interpolation of a pre-calculated pressure drop table. Here, pressure loss data as a function of outlet pressure, flow rate, water fraction and gas fraction are supplied in the form of a Vertical Flow Performance (VFP) table. (Sachdeva et al. 1996).

In this thesis the Eclipse default option was used which is the Homogenous flow model. Hydrostatic, friction and acceleration pressure drop was included when calculating the pressure drop across the segment.

2.1.4 Segment structure

A single-bore well will just consist of a series of segments arranged in sequence along the wellbore. A multi-lateral well will have a series of segments along its main stem, while each lateral branch, consisting of a series of one or more segments, connects at one end to a segment on the main stem. i.e. a multi-segment well can be considered as a collection of segments arranged in a gathering network or tree topology. Figure 2.1.2 shows such a segment structure for multi-lateral well.

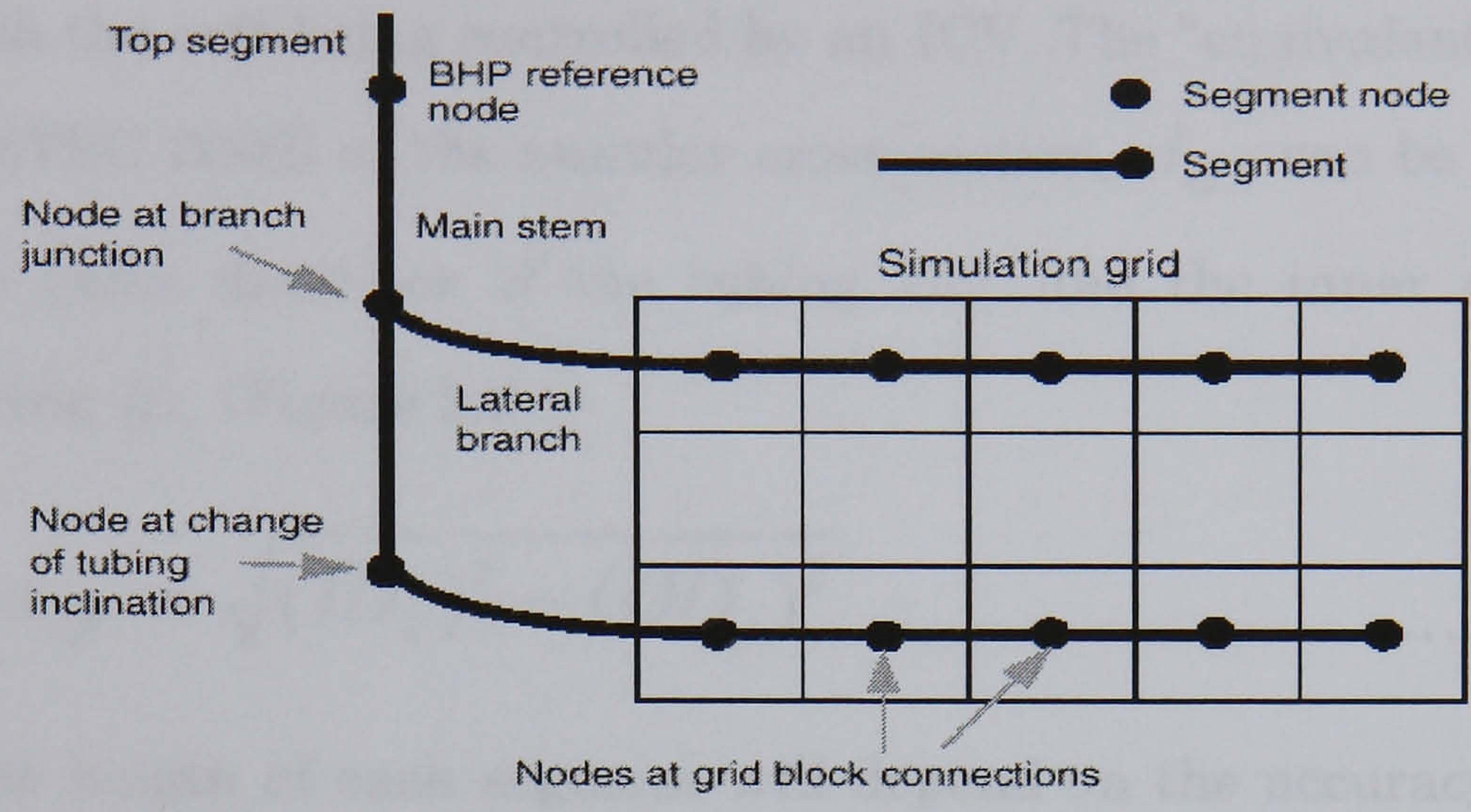


Figure 2.1.2 A multi-lateral, multi-segment well (GeoQuest 2002)

2.2 Modelling of well completions with downhole control valves

Simulation of wells containing flow control devices requires a detailed well model. This model must be able to determine the phase flow rate and the pressure for each connection along the perforated length. The number of segmentation should be enough to model the number of ICVs included in the model i.e. one segment cannot be used to model more than one ICV.

2.2.1 Building a multi-segment model with annular geometry

A multi-segment model of a completion with ICVs must include fluid flow from the reservoir into the casing/tubing annulus, then through the valve and finally into the tubing. Each of these will be represented by different segment of appropriate (different) length and diameter. Figure 2.2.1 and Figure 2.2.2.

1. *Tubing segment*: these segments are the main stem on the wellbore. The flow path is through the tubing inner diameter (ID_t). The length of each segment will depend on the accuracy required from the flow model.

Typically, one segment is given the same length as that for each reservoir grid block.

2. *The annulus segment*: the annulus is divided into a number of sections with the exit being controlled by an ICV. The "equivalent flow diameter" (PETEC 2002) of the annular cross section, d_{eff}, can be calculated from the outer diameter of the tubing OD_t and the inner diameter of the casing ID_c (Figure 2.2.1)

$$d_{eff} = \sqrt{(ID_c)^2 - (OD_t)^2} \qquad \text{Equation 2.1}$$

The length of each segment will depend on the accuracy required from the flow model. Typically, each segment is given the same length as that of the corresponding reservoir grid block. Alternatively, one segment can accept flow from more than one grid block or one grid block can flow into more than one segment.

3. *The valve segment*: this valve segment is the connection between the annulus and the tubing. It is best modelled based on the actual physical properties of the valve; its length is thus equal to the valve length. The diameter and roughness are created similarly. The choke performance is modelled using a Choke Discharge Coefficient whose value is determined by flow tests carried out by the manufacturer or operator. A change in the valve segment's property replicates choking back the flow across the valve.

Figures 2.2.1 and 2.2.2 show the actual well configuration and how the multi-segment model is used to simulate the flow from the reservoir in to the annulus segment and then through the valve segment into the tubing.

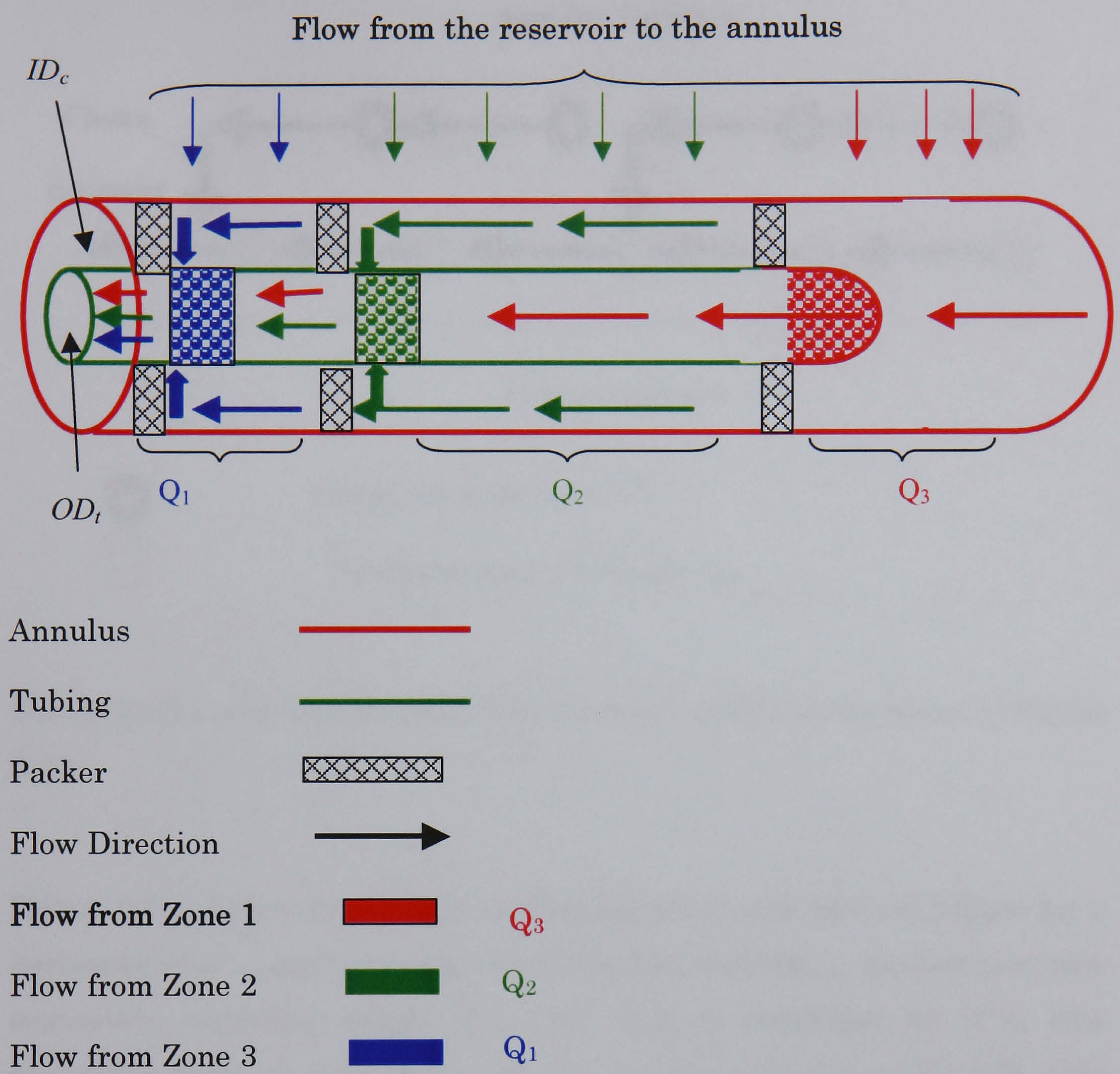


Figure 2.2.1 The well configuration showing the direction of flow from three separate zones

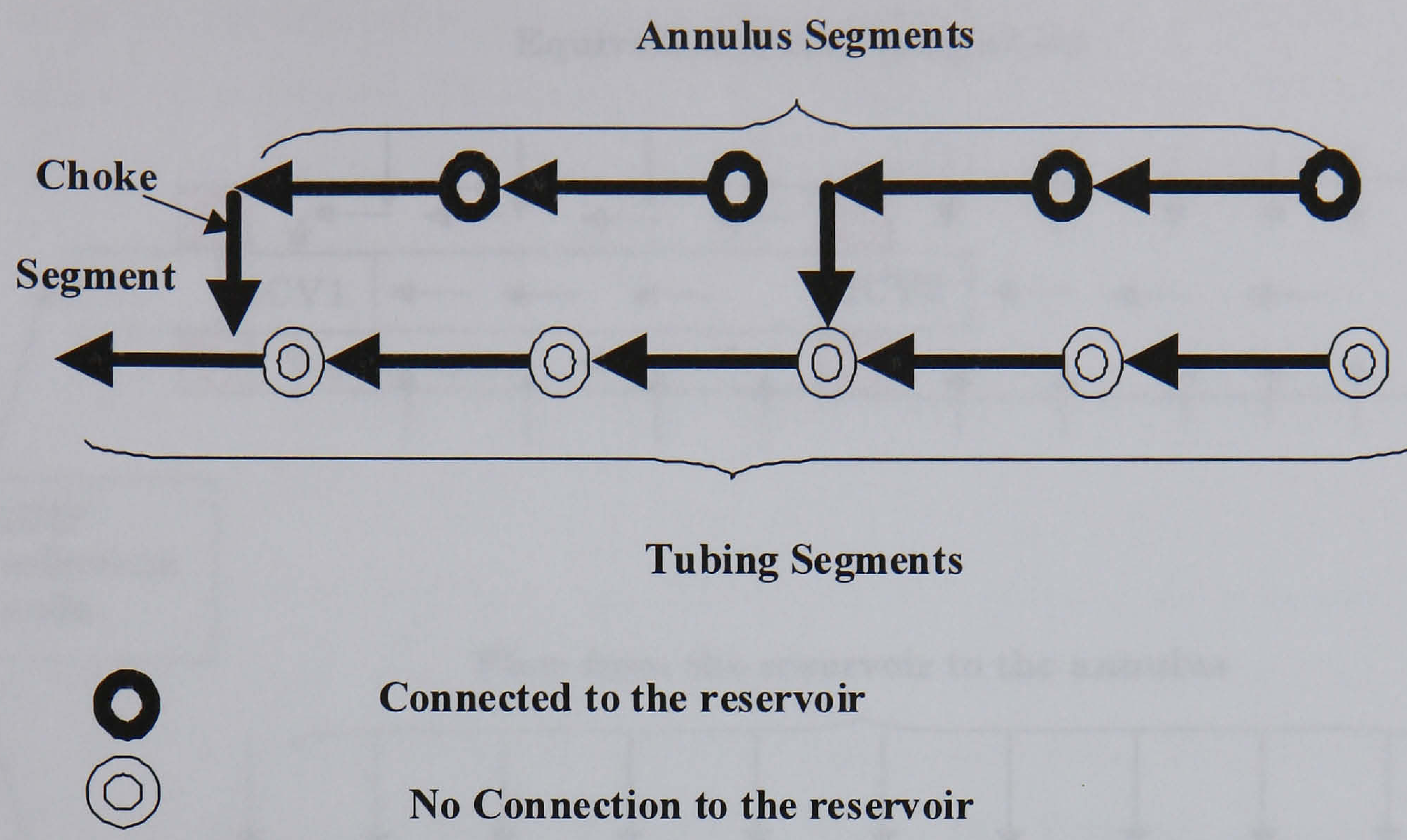


Figure 2.2.2 multi-segment model for the well configuration shown in Figure 2.2.1

Figure 2.2.3 shows the segment numbering connection used by Eclipse for a horizontal well completed with two ICVs. The wellbore is divided into two, separately controlled zones. The first zone is controlled by ICV_1 (the connection between segment 2 and 12) and the second zone by ICV_2 (the connection between segments 6 and 7). Tubing to surface flow is modelled by interpolation within a separate VFP table.

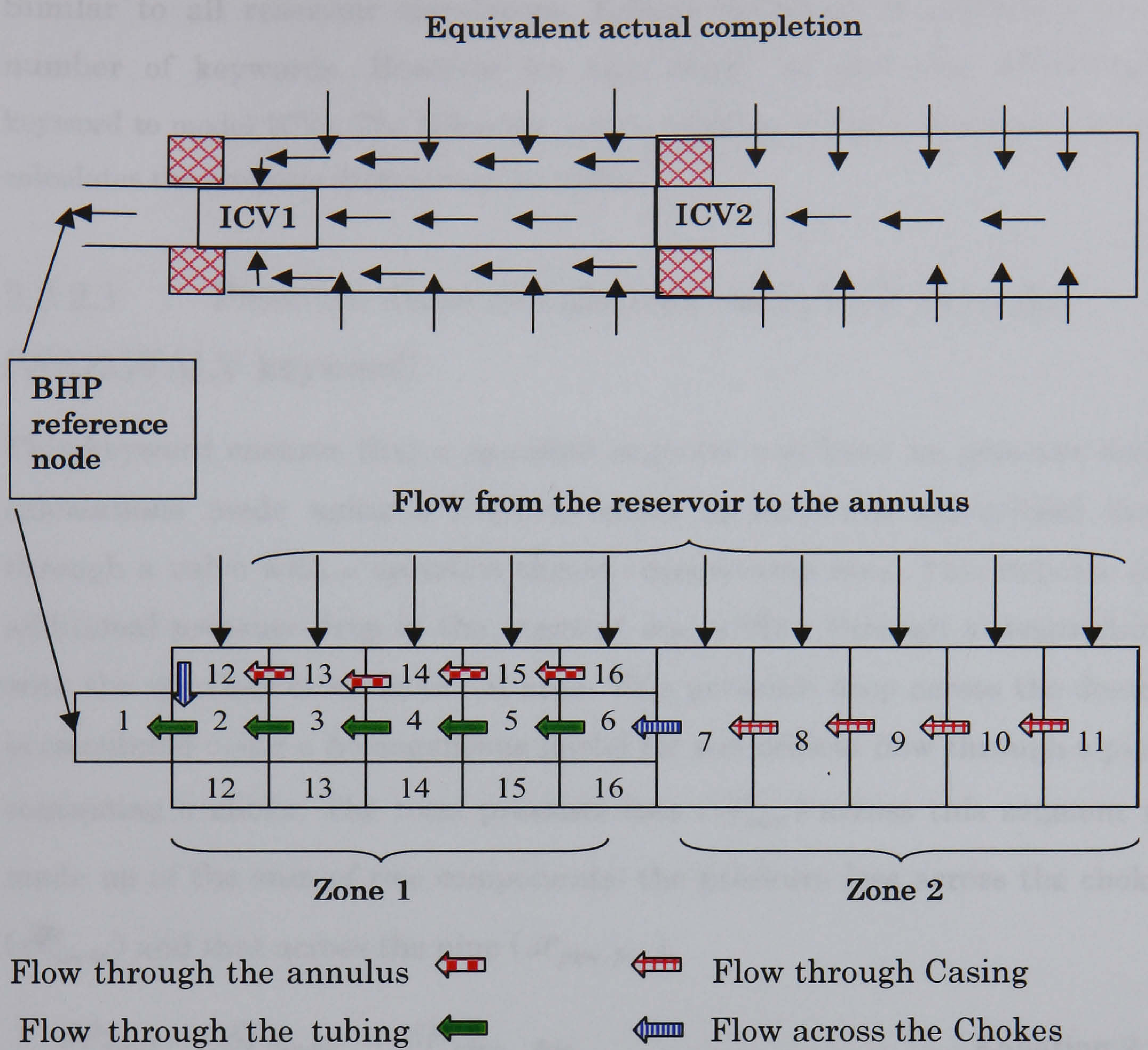


Figure 2.2.3 Example of well completed with two ICVs – Segments 1-11

2.2.2 ICV modelling options

The downhole completion system employs isolation packers set between the (well cemented) production liner and tubing. They split the perforated zone into a number of separate zones, allowing independent control of the inflow from each zone. The mechanical installation of this more complex completion is difficult, time consuming and more prone to error than the equivalent conventional completion. Such "intelligent" completions are more expensive to install and, in order to obtain the maximum benefit, it is important to be able to model and predict the well performance and the interaction of these complex systems with the reservoir.

Similar to all reservoir simulators, Eclipse operation is controlled by a number of keywords. However for this study we will use WSEGVALV keyword to model ICVs. The following section explains in detail how this keyword calculates the pressure drop across the valve.

2.2.2.1 Pressure drops calculations using built-in model (WSEGVALV keyword)

This keyword ensures that a specified segment will have its pressure drop calculations made using a built-in model to represent sub-critical flow through a valve with a specified throat cross-section area. This imposes an additional pressure drop in the segment due to flow through a constriction with the specified cross-sectional area. This pressure drop across the device is calculated using a homogeneous model for sub-critical flow through a pipe containing a choke. The total pressure loss (δP_{total}) across this segment is made up of the sum of two components: the pressure loss across the choke (δP_{choke}) and that across the pipe ($\delta P_{pipe.fric}$):

$$\delta P_{total} = \delta P_{choke} + \delta P_{pipe\ .fric} \qquad \text{Equation 2.2}$$

N.B. Pressure losses due to acceleration and change in elevation are ignored, since the valve segment is short.

δP_{choke} accounts for the effect of the choke. It's calculated as:

$$\delta P_{choke} = c_u \left(\frac{\rho v_c^{\ 2}}{2 C_v^{\ 2}} \right) \qquad \text{Equation 2.3}$$

Where:

c_u is a units conversion constant (2.159E-4 in field units system).

ρ is the density of the fluid mixture (lbm/ft³ in field units system)

v_c is the flow velocity of the mixture through the constriction (ft/s in field units system)

C_v is the (dimensionless) flow or discharge coefficient for the valve. This value is supplied by the valve manufactures.

$\delta P_{pipefric}$ accounts for all other friction pressure loss in the segment containing the choke. It uses the standard expression for the homogeneous flow frictional pressure loss across a pipe

$$\delta P_{pipefric} = 2c_u f \frac{L}{ID_t} \rho v_p^2 \qquad \text{....................................... Equation 2.4}$$

Where:

f is the Fanning friction factor. This is calculated using Reynolds number and the Roughness of the tubing in the choke segment. Davies, 2001 explain in detail how it is calculated.

L is the length of tubing in the choke segment.

v_p is the flow velocity of the mixture through the choke segment

ID_t is the internal diameter of the tubing into which the choke has been built.

The tubing opposite the completion zone usually has smaller diameter than the bulk of the well's production tubing (Figure 2.2.4). e.g. A well completed with a 6-in ID sand screen across the completion interval would typically have a 6-in ID tubing installed from the top of the liner to the surface and a 3.3-in ID tubing across the completion interval (the diameter has to be reduced to allow installation of the isolation packers). The ICV (or choke section) has a further reduced diameter of 2.8-in ID.

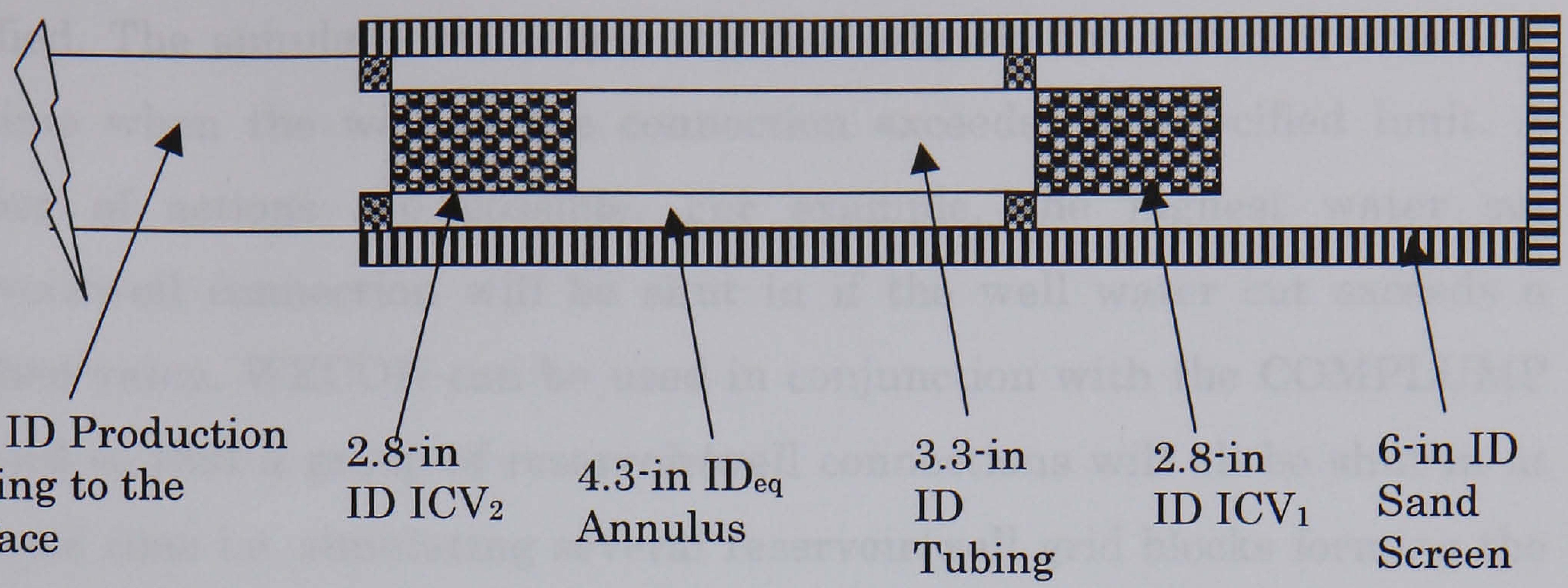


Figure 2.2.4 Example of well Completed with two ICVs

2.3 Valve setting optimisation

Reservoir simulation studies are used to evaluate the performance of the field over a number of years. In practice, each production zone is controlled from the surface by monitoring the zone's phase flow. Adjustments are made to the valve setting at regular intervals, either based on measurements made by pre-installed sensors monitoring that particular zone's performance or by estimating the zone production by shutting all the zones sequentially and evaluating the resulting changes in the total well flow rate. The aim is to achieve the same effect within the Eclipse simulation by optimising the valve setting so as to increase oil production and decrease the produced water and gas (i.e. increase production rate and, hopefully, total recovery).

2.3.1 Using of the WECON keyword to simulate an On/Off valve

The WECON keyword acts as an On/Off choke. It can be used to shut off a single reservoir/well connection or group of connections when their production flows exceed a specified limit. The use of WECON is not optimum; it is not possible either to re-open that connection again or to partially choke the flow back to certain limit if one does not want to close the connection completely. The action to be taken by WECON has to be specified. The simulator will then automatically do the action specified at the time when the well or the connection exceeds the specified limit. A number of actions are possible. For example, the highest water cut reservoir/well connection will be shut in if the well water cut exceeds a specified value. WECON can be used in conjunction with the COMPLUMP keyword so that a group of reservoir/well connections will all be shut in at the same time i.e. simulating several reservoir/well grid blocks forming the zone controlled by a particular ICV. The advantages and disadvantages of the WECON keyword are described in Table 2.1.

Advantages	Disadvantages
• Easy to use • User specifies minimum economic well rate, to use phase cut etc • Select segment that contributes most to failure to meet well production constraints and close it, then further segment are also closed as well production meet the constraint again. • Can be used in conjunction with COMPLUMP keyword to control number of well connections at the same time.	• Selected segment fully closed (On/Off effect only, no progressive choking and no re-opening in the same run) • Further segments are then shut in an effort to meet well production constraint until well dies and it will not be open again unless the simulation has been restarted.

Table 2.1 Advantages and disadvantages of using the WECON keyword

2.3.2 Use of ACTIONS keyword to define valve setting rules

This keyword allows the user to set up rules for the segment representing the valve using one of the triggering conditions this can be the segment flow rate or water cut or gas oil ratio or segment pressure, these values can be assigned as upper or lower limit. In this thesis we have used either water cut or gas oil ratio.

If the segment exceeds this limit a certain action will then take a place. This action changes the segment properties, using the valve modelling keyword described previously. It is also possible to specify the time that these actions should be carried out e.g. once for every month. The advantages and disadvantages of the ACTIONS keyword are described in Table 2.2.

Advantages	Disadvantages
• Sets fixed choke setting to each ICV	• Very time consuming • User has to manually evaluate many valve setting to identify optimum choke value • Difficult for more than 2 ICVs per well.

Table 2.2 Advantages and disadvantages of using the ACTIONS keyword

2.3.3 ICOS (Intelligent Completion Optimising System)

PETEC (2002), a Norwegian software company, market the ICOS program, which has been designed to automatically operate the ICVs. ICOS builds a multi-segment model with annular geometry, including the valves. ICOS will automatically calculate a multiplier factor ($MULT_i$) for each zone based on how much oil, gas and water is being produced. This multiplier factor is then used to control the operation of the segment representing the valve. This multiplier can be calculated using one of the following equations:

$$MULT_i = \frac{1}{1 + w_1 (R_{1i})^{p1} + w_2 (R_{2i})^{p2}} \qquad \text{...... ....Equation 2.5}$$

Or

$$MULT_i = \left(1 - \left(\frac{R_{1i}}{R_{1\max}}\right)^{p1}\right) \times \left(1 - \left(\frac{R_{2i}}{R_{2\max}}\right)^{p2}\right) \qquad \text{..................Equation 2.6}$$

Where:

- R_1 and R_2 are the Water and Gas-Oil-Ratios (WOR and GOR).
- $R_{1\max}$ & $R_{2\max}$ are the maximum allowed values for the water & gas-oil ratios. (The interval will be shut in if one of these values is exceeded).
- w_1 and w_2 are weighting factors and p_1 and p_2 are powers to which each phase ratio is raised. (These values have to be specified by the user based on how harder the choking is (i.e. the higher the w_s and p_s the harder the choking is).

Usually equation 2.5 is used unless the user has to assign maximum value of WOR and/or GOR at which the zone will be closed

The $MULT_i$ value increases as the water and/or gas oil ratio increases, leading to harder choking of the valve controlling that zone's production. ICOS normalizes the multipliers before determining these choke ratios for each time step. This ensures that one valve remains fully open at each time step i.e. its multiplier equals one. ICOS also allow users to set the time in which this operation is carried out.

The WELTIME keyword of ICOS is used to define the start time for adjusting the choke positions for one specific well i.e. the start time represents the earliest time that choke adjustments will be implemented in the simulation.

2.3.3.1 Advantages and disadvantages of ICOS multiplier equations

The first Equation used to calculate $MULT_i$ consists of two parts:

1. *The water part*: $\{w_1(R_{1i})^{p1}\}$: The effect of the water on the value of the multiplier can be increased by using higher values of w_1 & p_1.
2. *The gas part*: $\{w_2(R_{2i})^{p2}\}$: The GOR (R_2) is numerically greater than the WOR – hence its effect will be bigger. This is reduced using smaller values of w_2 & p_2. The chosen value of w_n & p_n will depend on whether water or gas production should be reduced the most.

This equation has the advantage of setting different choking policy for each phase.

The second Equation consists of two parts:

1. *The water part* $\left(\frac{R_{1i}}{R_{1\max}}\right)^{p1}$: This equation is used when a maximum value of the WOR has to be specified. The multiplier can also be controlled using different values of p_1. The ICV will be shut in when this value is reached
2. *The gas part*: $\left(\frac{R_{2i}}{R_{2\max}}\right)^{p2}$: This part of equation can be used to set up maximum gas oil ratio at which the valve is shut in. The multiplier is also controlled using different values of p_2.

The advantage of this equation is that it can be used when there are constraints on the WOR and/or GOR due to surface facility limitation.

The advantages and disadvantages of the ICOS keyword are described in Table 2.3.

Advantages	Disadvantages
• Can handle unlimited number of valves and setting changes during the same Eclipse run	• User has to specify choking policy controlling the extent of ICV choking • One ICV always remains fully open - this may not always be optimum if a wellhead choke is not included in the simulation.

Table 2.3 Advantages and disadvantages of using ICOS.

2.4 Summary

This chapter has reviewed the issue of modelling and controlling ICVs. It has discussed the methods available in Eclipse that will be used in this thesis their application and limitations can be summarized in the following:

Applications

1. Multi-segment model can be used to calculate the pressure drop along the wellbore by splitting it into number of segments.
2. Flow through the Intelligent Well completion can be modelled using Multi-Segment network by including the flow from grid block to the annulus segments and through the choke segments to the tubing.
3. ICV control can be modelled by introducing extra friction drop to the valve segment once it meets certain criteria of production and pressure.

Limitations

1. WECON keyword can only model On/Off valve positions.
2. ACTIONS keyword require a preset of rules that has to be followed in order to optimise the production, these rules will become very complicated once the number of valves per well increases as well the number of valve status.
3. ICOS optimisation also requires selection of the degree of choking based on the most unwanted fluid to be produced.

Chapter 3

3. The Importance of the Pressure Drop in Optimal Well Design

The productivity of horizontal wells as a function of well length and placement within a thin oil column has been well discussed in the literature for relatively simple situation where analytical solutions are available (Babu and Odeh 1989b). This chapter reviews this literature and illustrates the resulting practical consequences by using a numerical reservoir simulator to study a case history with both complex geology and complex reservoir fluid properties.

The frictional pressure drops across the completion (horizontal) section is an important factor when high permeability reservoirs are developed by high rates wells. The NH-Field (Chapter 1) case study concerns the development of a 40m thick oil column reservoir located in a heterogeneous sand body. The objective was to develop an optimum well design. It well illustrates the impact of friction pressure on the well performance. The impact of the well location, well length and diameter as well as the height above the oil-water contact on the well performance were also studied.

The performance of a range of well designs with a completion zone length varying between 1,500 and 3,000 m long, placed between 3m and 12m above the Oil-Water-Contact (OWC) and equipped with a selection of well completion designs was studied. In addition, reverse of the well azimuth was tested with the aim of studying the impact of the permeability heterogeneity on the fluid flow into and along the wellbore. This study will confirm the conclusions of the analytically-based solutions mentioned earlier. However, it will also show how the analytical conclusions have to be modified based on knowledge of the detailed geology in the simulation model.

3.1 Literature review

A horizontal well may be several times more productive than a vertical one draining the same rock volume. This is because it has greater connectivity to the reservoir than a normal, vertical well. However, its greater drilling expense and, frequently the need to complete it with larger diameter tubing compared to a vertical well, requires that a detailed model of the horizontal well is developed to ensure that accurate predictions of the well performance are made. Many analytical models to calculate the productivity of horizontal wells and their pressure drop along the horizontal section are available in the literature (e.g. Joshi, 1988). One problem identified was that the flow in the wellbore can become turbulent due to the high production rates, resulting in a dramatic increase in flow resistance. Babu and Odeh (1989a) recognised that, in high rate or smaller diameter wells, the friction pressure loss can increase to a value comparable to the producing drawdown. This consideration leads to the identification of a maximum well length and the requirement that the along-hole well pressure gradients are properly modelled within the reservoir simulation process.

Conventional reservoir simulators calculate the well productivity using Peaceman's equation for equivalent block radius and the well block pressure

(Peaceman, 1983). In the horizontal well case, the well is completed through a number of reservoir simulation grid blocks and flow from the reservoir grid block into the well is calculated using the normal flow equations. Two methods are available within Eclipse to model the pressure drop due to friction in the horizontal completion and well. The first is a global friction model requiring the length, diameter and the roughness of tubing to be input. The second method uses the multi-segment well model, where the wellbore is divided into a number of segments and the pressure loss across each segment is calculated separately (Chapter 2).

3.2 The effect of pressure drop in long completions and the optimum completion length

The contact with the reservoir will increase as the length of a horizontal well increases. At the same time the resistance to flow along the well will also increase. The overall performance of a horizontal well depends on the balance of these two opposing factors. Penmatcha, et al (1999) showed that ignoring the wellbore frictional effects could lead to unrealistically high production estimates and longer breakthrough times for water or gas entry into the wellbore. Breakthrough of gas or water tends to occur first at the heel of the well due to the wellbore pressure profile. If the friction losses are neglected the water will move with a more "piston like displacement" giving an even breakthrough profile along the well length. The multi-segment well model has been used to find the optimum well length for a particular horizontal well case using a sector model from the full field model.

3.3 The effect of the ranging horizontal length on the well's productivity

3.3.1 The problem to be addressed by this study

The high productivity NH field wells have a production drawdown over the reservoir that can be the same order of magnitude as the frictional pressure drop along the well length. The effect of this is a skewed pressure profile along the horizontal well, resulting in the majority of the production to be drawn from the heel of the well instead of being produced evenly along the entire completion length. This results in a tendency for early breakthrough of water and/or gas at the heel of the well. Wells located in thin oil column reservoirs are especially prone to this type of production profile. Consequently, the volumes of gas and water produced with the oil increase significantly. Also reduced oil production will occur when gas or water processing / disposal constraints exist.

The study objectives was to find the optimum well design (location above oil water contact and well length) for the P4 well in NH field. This design will be able to maximise the total oil production within certain constrains. In practice this implies that any reduction in the "free" oil produced due to fingering of gas through the high permeability, Etive formation sands should be minimised.

3.3.2 Simulation model

All simulations were run with a maximum liquid well production limit of 4,000 sm^3/day liquid and $2*10^6$ sm^3/day gas and a minimum tubing head pressure of 125 bar. The liquid limit reduced the initial potential oil production for the first 3 months. The gas limit became operative once the well was no longer capable of producing 4,000 sm^3 /day liquid. This gas limit continued to operate until the later years when the minimum tubing head pressure control was exercised.

A series of simulations with P4 well lengths between 1,500 and 3,000m were made in order to examine the effect of the horizontal completion length (Table 3.1).

Completion Zone Length	Cumulative Total Oil (10^6 sm^3)	Cumulative Free Oil (10^6 sm^3)	Cumulative vaporized oil (10^6 sm^3)	Cumulative water (10^6 sm^3)	Cumulative total Gas (10^9 sm^3)
1,500 m	2.87	1.44	1.43	2.52	5.49
1,750 m	2.90	1.48	1.43	2.60	5.48
2,000 m	3.03	1.62	1.41	2.84	5.48
2,250 m	3.13	1.73	1.40	2.91	5.48
2,500 m	3.27	1.90	1.38	3.21	5.48
3,000 m	3.35	1.97	1.38	3.02	5.48

Table 3.1 The well length scenarios compared

The relation between the cumulative total oil vs. time for the all cases is shown in Figure 3.3.1. It shows that there is an increase in production with any increase in the completion length. However this increase may not be economic if it is not enough to cover the cost of extra drilling time.

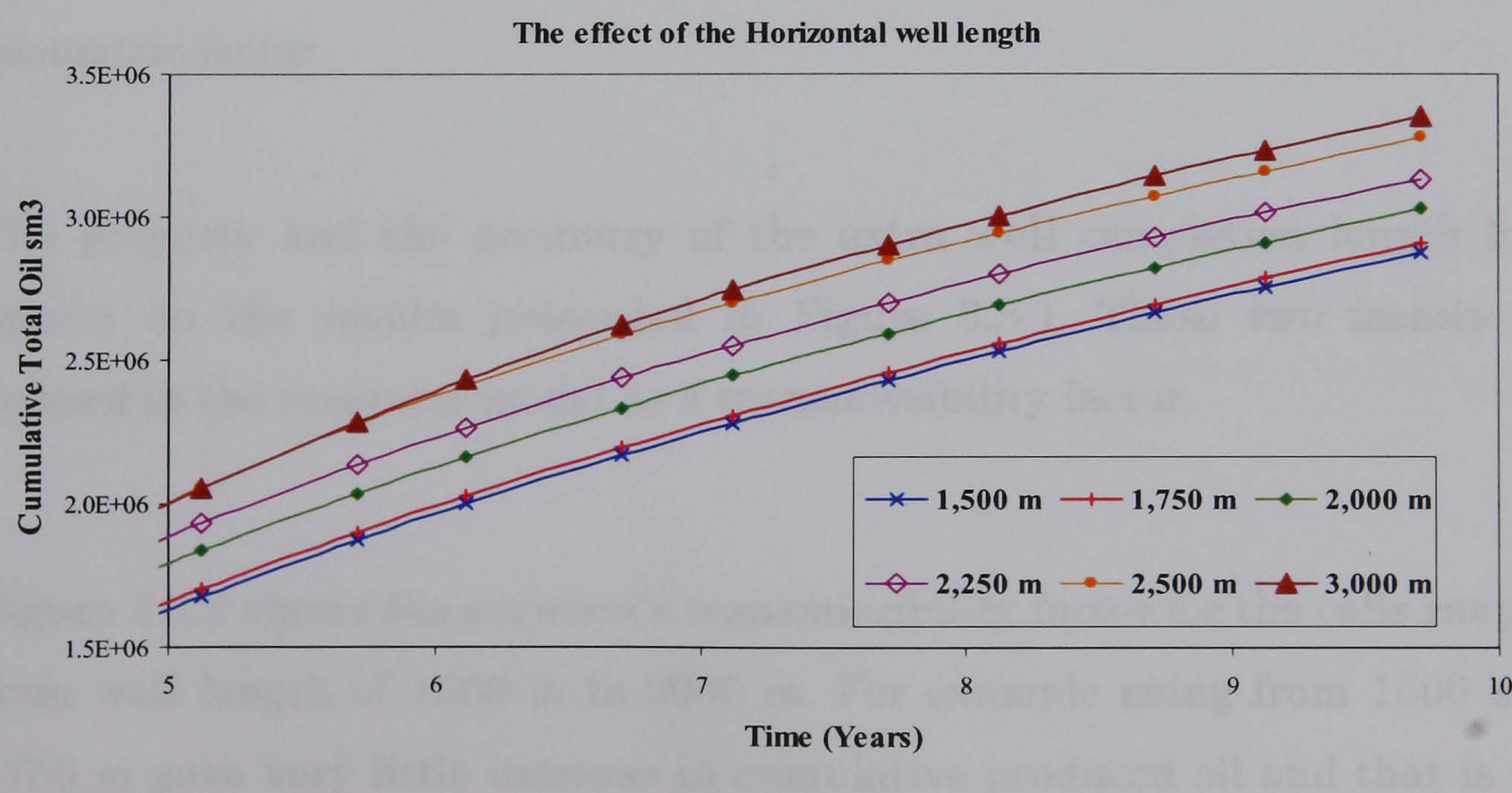


Figure 3.3.1 Cumulative oil vs. time for the completion length scenarios defined in Table 1.1

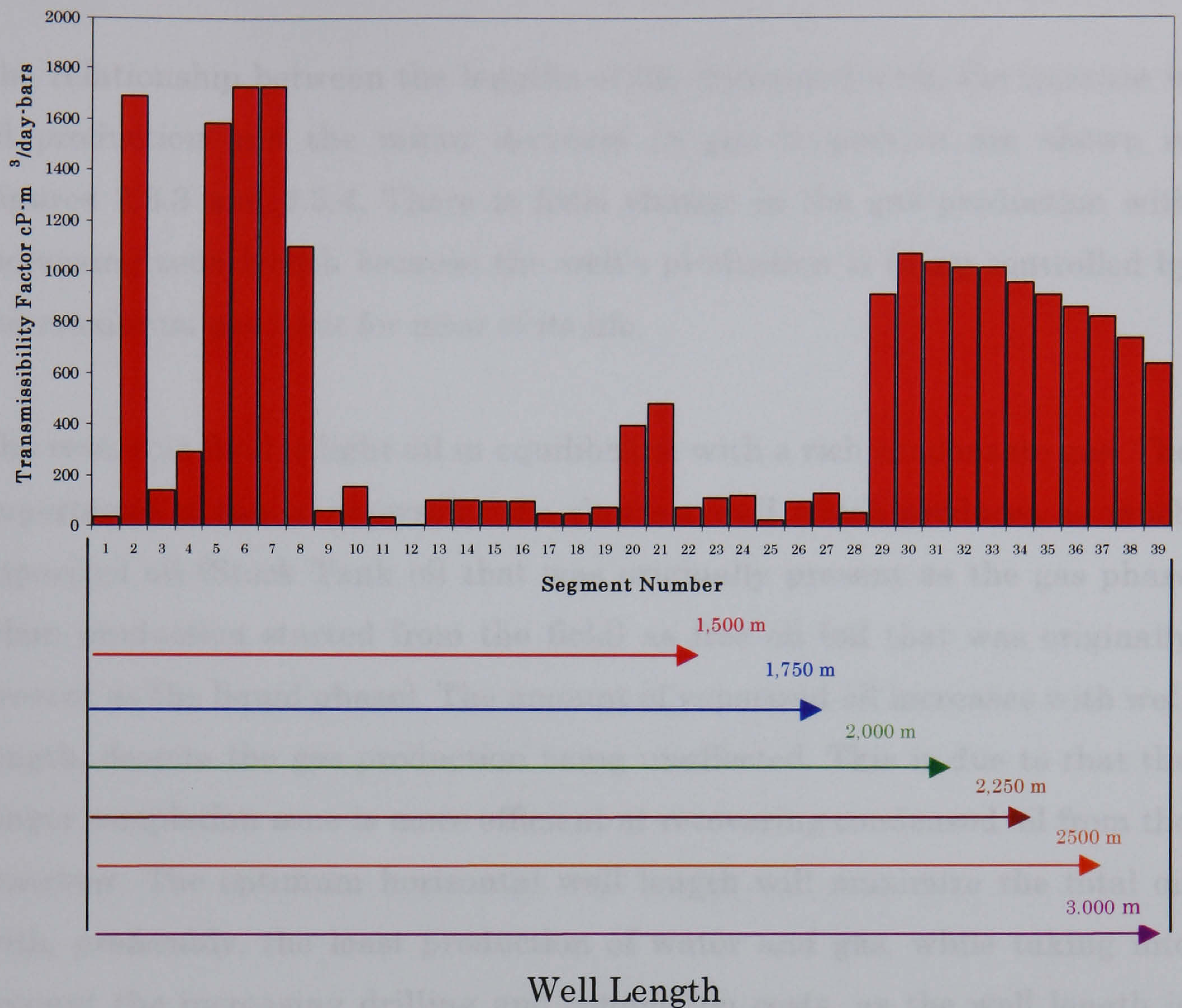


Figure 3.3.2 Transmissibility factor for all segments that the well is completed in – It shows that it differ due to the cell property and to the geometric factor

The property and the geometry of the extra well completion length have impact on the results presented in Figure 3.3.1. These two factors are defined in the reservoir model as a transmissibility factor.

Figure 3.3.2 shows the segment's transmissibility factor for the cells ranging from well length of 1500 m to 3000 m. For example going from 1500 m to 1750 m gave very little increase in cumulative produced oil and that is due to the poor quality of the extra completion length.

The relationship between the lengths of the horizontal well, the increase in oil production and the minor decrease in gas production are shown in Figures 3.3.3 and 3.3.4. There is little change in the gas production with increasing zone length because the well's production is being controlled by the maximum gas limit for most of its life.

The reservoir fluid is light oil in equilibrium with a rich condensate gas. The importance of this is shown by the shortest well which produces as much vaporized oil (Stock Tank oil that was originally present as the gas phase when production started from the field) as free oil (oil that was originally present as the liquid phase). The amount of vaporized oil increases with well length, despite the gas production being unaffected. This is due to that the longer completion zone is more efficient at recovering condensed oil from the reservoir. The optimum horizontal well length will maximize the total oil with, preferably, the least production of water and gas, while taking into account the increasing drilling and completion costs, as the well length is increases. The optimum well length for this particular case is judged to be 2,400 m.

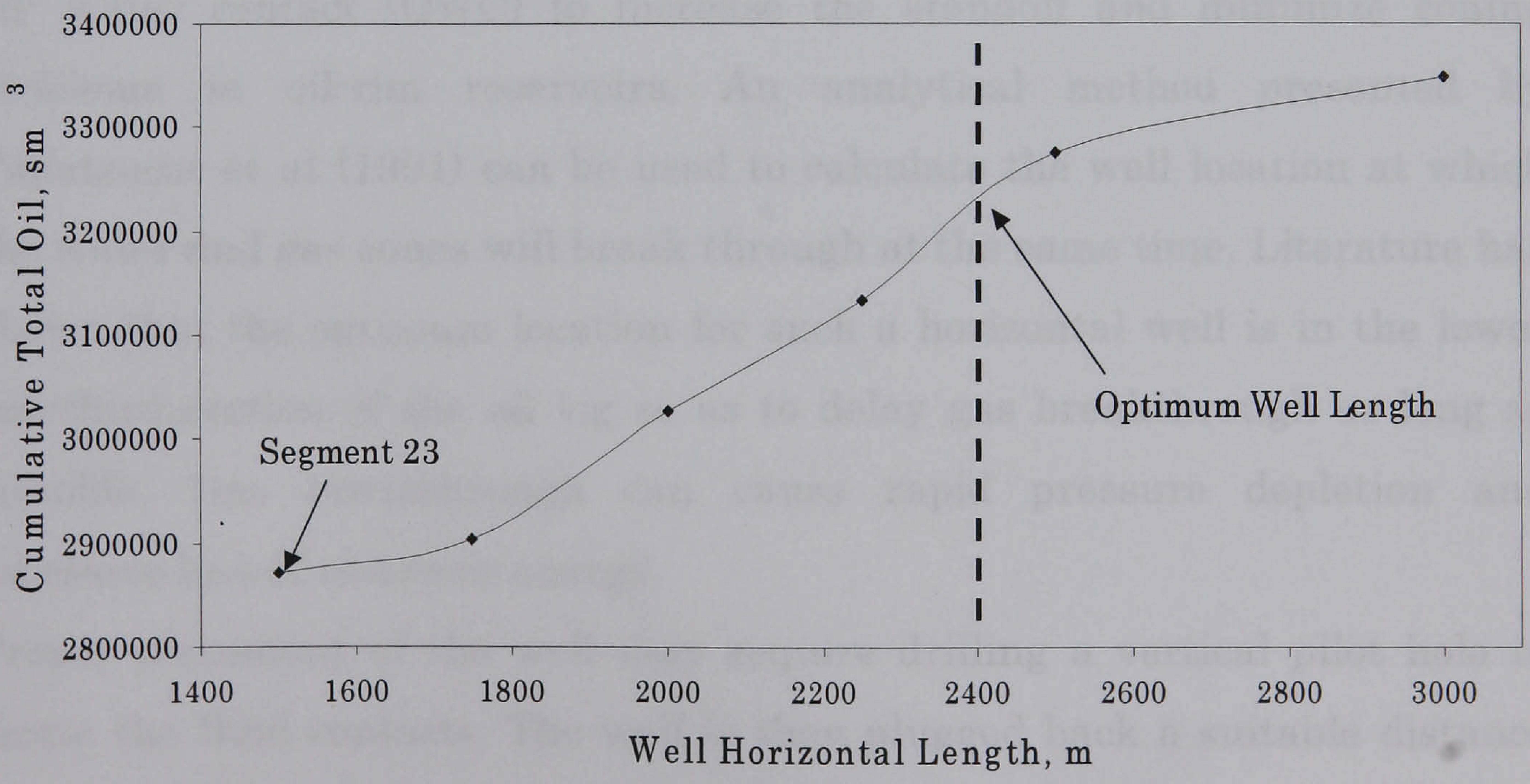


Figure 3.3.3 The effect of the horizontal well length on the Oil Production.

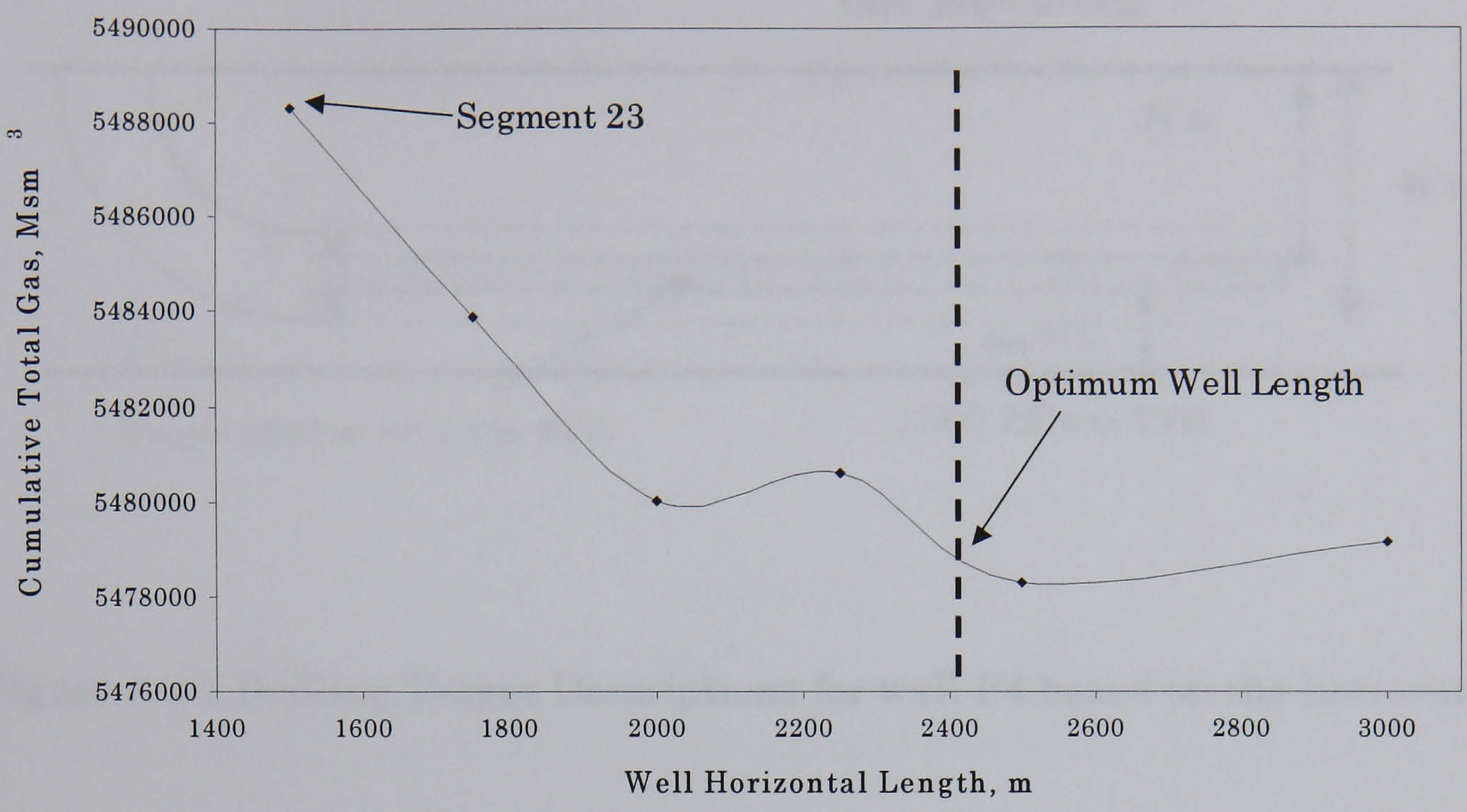


Figure 3.3.4 The effect of the horizontal well length on the gas production.

3.4 Horizontal well placement

Horizontal wells are often drilled distant from the gas-oil contact (GOC) or oil- water contact (OWC) to increase the standoff and minimize coning problems in oil-rim reservoirs. An analytical method presented by Papatzacos et al (1991) can be used to calculate the well location at which the water and gas cones will break through at the same time. Literature has shown that the optimum location for such a horizontal well is in the lower one-third section of the oil leg so as to delay gas breakthrough as long as possible. Gas breakthrough can cause rapid pressure depletion and excessive loss of reservoir energy.

Proper placement of the well may require drilling a vertical pilot hole to locate the fluid contacts. The well is then plugged back a suitable distance and then sidetracked to place the horizontal portion at the targeted height in the reservoir.

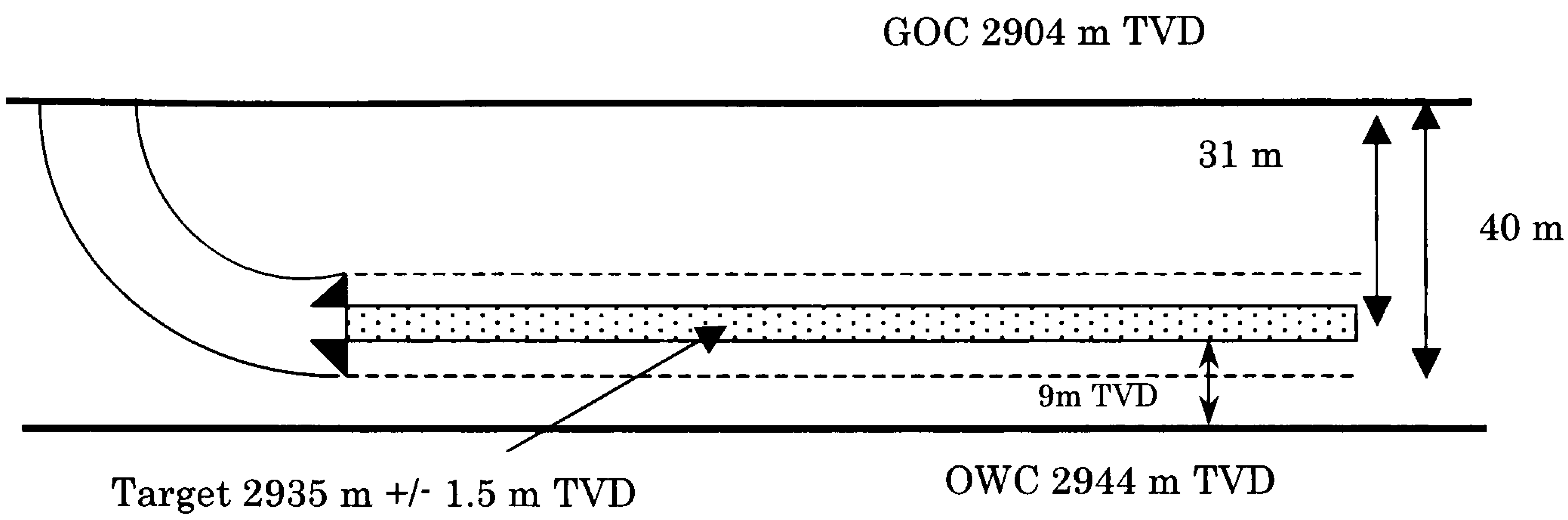


Figure 3.4.1 Drilling Target Descriptions for well P4 based on the literature

3.4.1 Simulation results

The reservoir simulation model described earlier was used to evaluate the total oil production. This showed that the optimal horizontal well position (Figure 3.4.1) was located some 9 m above the OWC i.e. 31 m below the GOC. Figure 3.4.2 shows that, only a small penalty in lost oil production is paid by reduced total oil production if a lower well track is drilled. By contrast, a much larger penalty occurs when a higher well track is followed (due to the greatly increased gas production). These results suggest a target well track of 9m above the OWC with a tolerance of + 1m and –3m or 8m +/- 2m. This is within the achievable +/- 1.5 m drilling tolerance suggested by Barry et al. (1998).

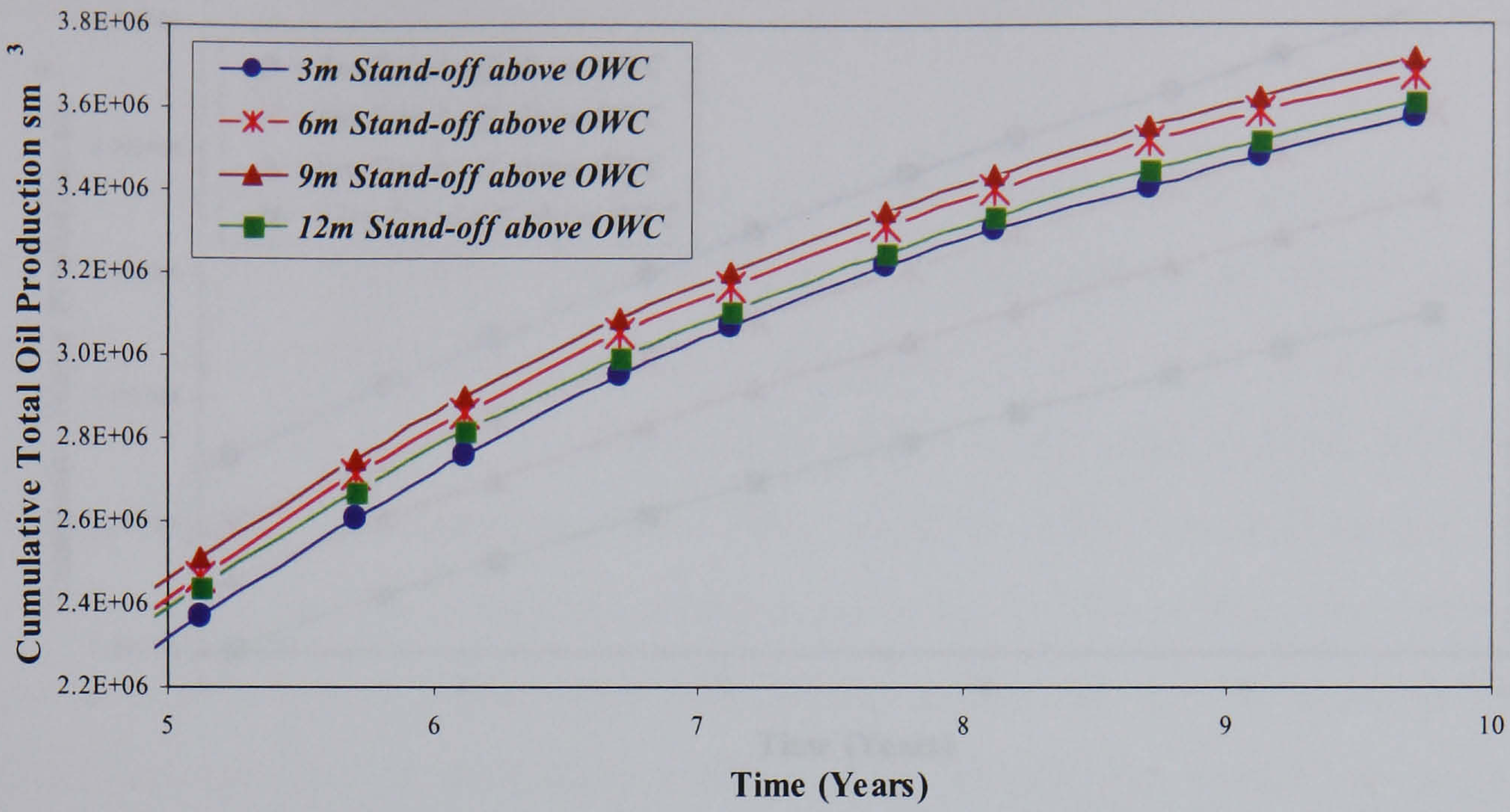


Figure 3.4.2 The effect of the horizontal well placement on the oil production

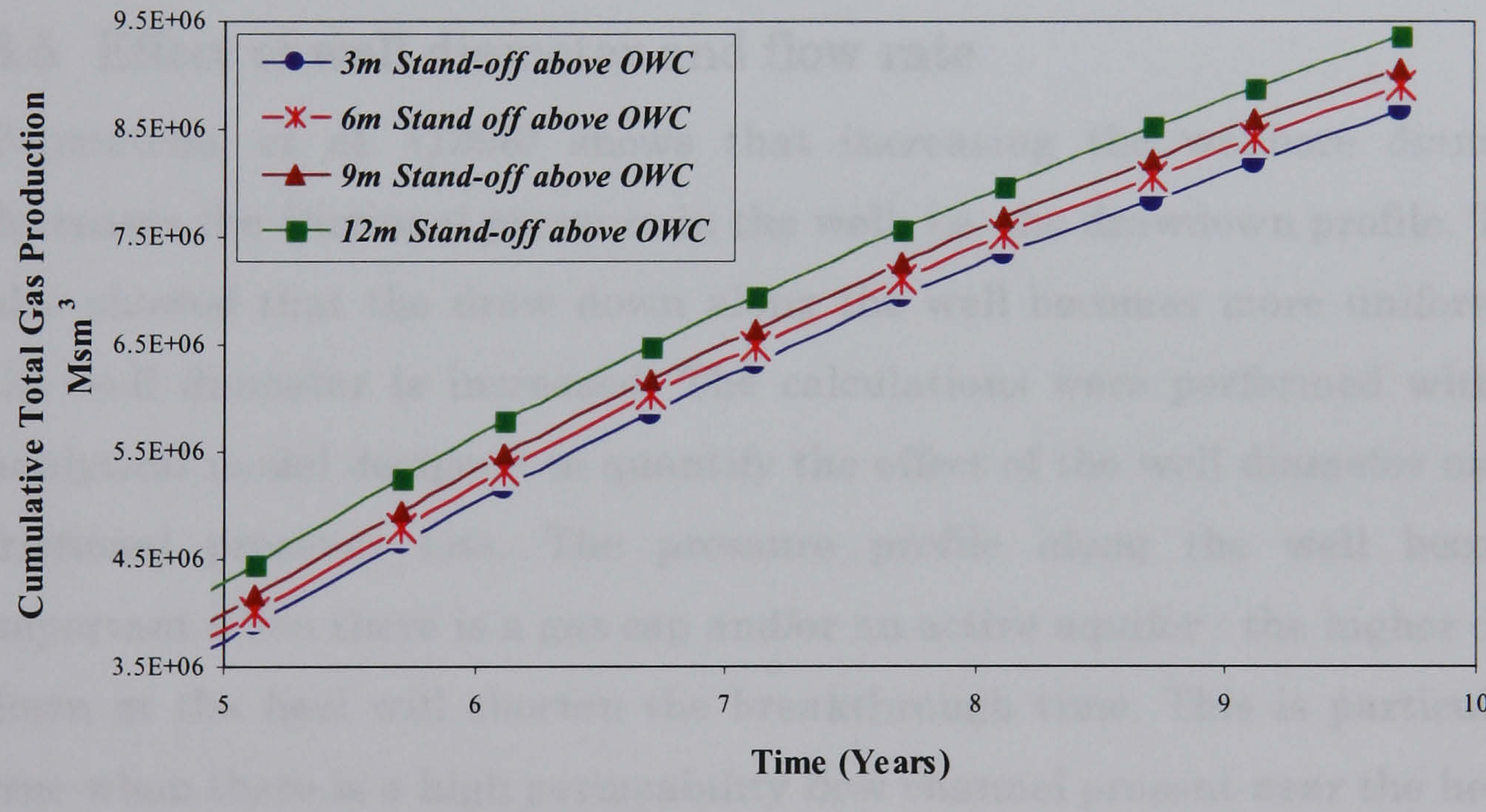


Figure 3.4.3 The effect of the horizontal well placement on the gas production

The well placed 9m above the OWC maximizes the total oil production (Figure 3.4.2) but does not produce the least gas (Figure 3.4.3) or water (Figure 3.4.4).

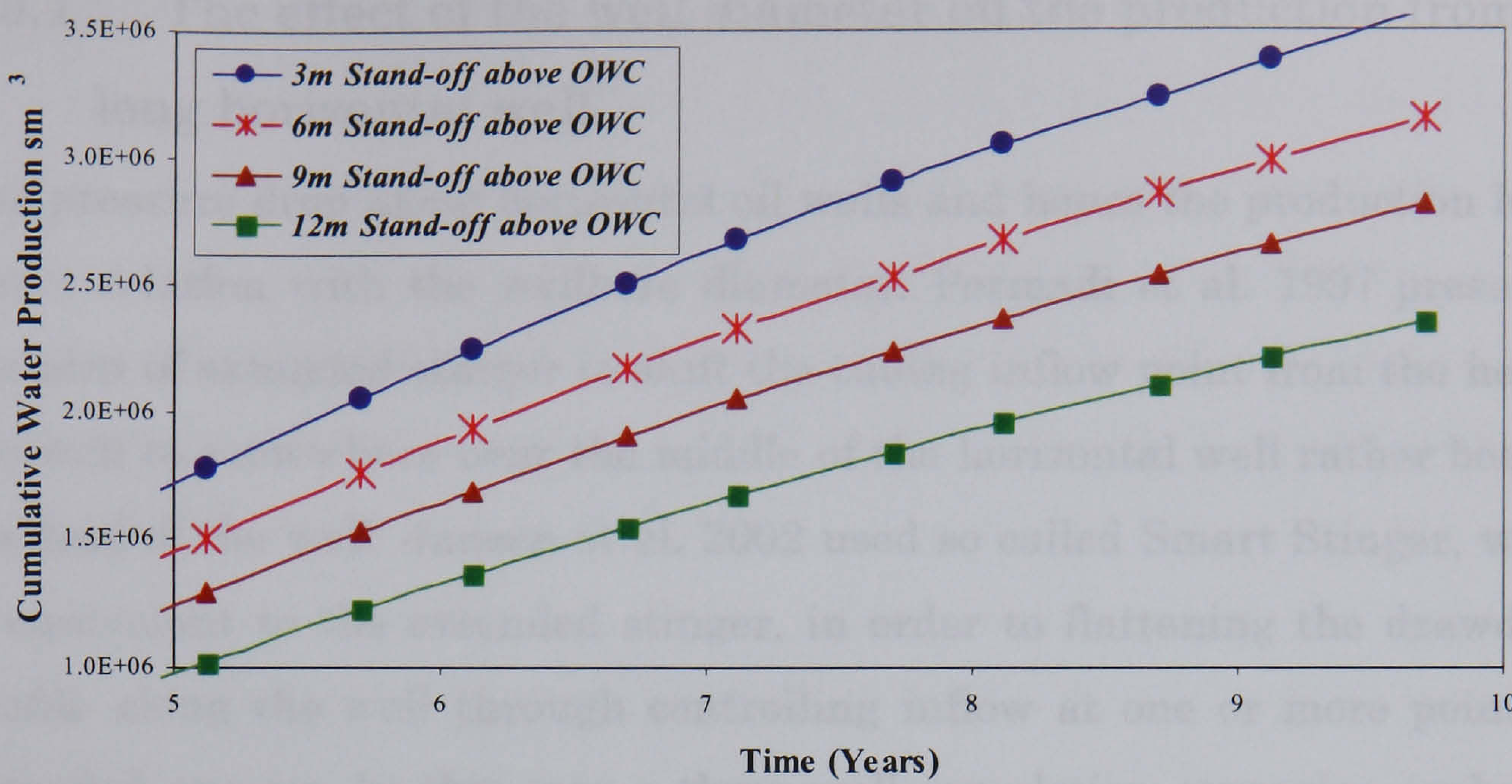


Figure 3.4.4 The effect of the horizontal well placement on the water production.

3.5 Effect of well diameter and flow rate

Penmatcha, et al. (1998) shows that increasing the wellbore diameter decreases the frictional pressure in the well. i.e. the drawdown profile. They also showed that the draw down along the well becomes more uniform as the well diameter is increased. The calculations were performed with an analytical model designed to quantify the effect of the well diameter on the frictional pressure loss. The pressure profile along the well becomes important when there is a gas cap and/or an active aquifer - the higher draw down at the heel will shorten the breakthrough time. This is particularly true when there is a high permeability flow channel present near the heel of the well. These wellbore pressure effects can be reduced by drilling a larger diameter well or producing the well at a lower flow rate.

It should be noted that these wellbore pressure drop effects are magnified by the larger pressure drops associated with two-phase flow. This is especially true if the well track is not perfectly horizontal; but rises and falls, producing high (gas collection) and low (water collection) points.

3.5.1 The effect of the well diameter on the production from long horizontal well

The pressure drop along horizontal oil wells and hence the production has a direct relation with the wellbore diameter. Permadi et al. 1997 presented the idea of extended stinger to shift the tubing inflow point from the heel of the well to somewhere near the middle of the horizontal well rather been at the heel of the well. Jansen et al. 2002 used so called Smart Stinger, which is equivalent to the extended stinger, in order to flattening the drawdown profile along the well through controlling inflow at one or more points in extended stinger. In this case a three well completion scenarios, including stinger, have been studied in order to design an optimum horizontal well completion.

Case Name	Completion Description	Cumulative Total Oil Production (10^6 sm^3)	Cumulative Total Gas Production (10^9 sm^3)	Cumulative Water Production (10^6 sm^3)
Case 1 (Base Case)	2,000 m 6" ID casing	3.59	8.73	3.58
Case 2 (Narrow Wellbore)	2,000 m 3.3" ID tubing	3.30	8.66	2.80
Case 3 (Stinger)	First 600 m with 3.3" ID tubing & 1,400 m with 6"ID casing	3.42	8.55	2.92

Table 3.2 Shows the description and the performance of the three cases

Table 3.2 describes the cases chosen and lists their production performance. The base case with larger diameter gave the greatest oil where the effect of friction is minimized with smaller diameter case the cumulative oil is reduced by 8% and that is due to the effect of the narrower diameter. Where the extended stinger completion increased the oil by 4% compared to the narrower diameter case and that is due to the reduction of the drawdown at the heel of the well (Figure 3.5.1).

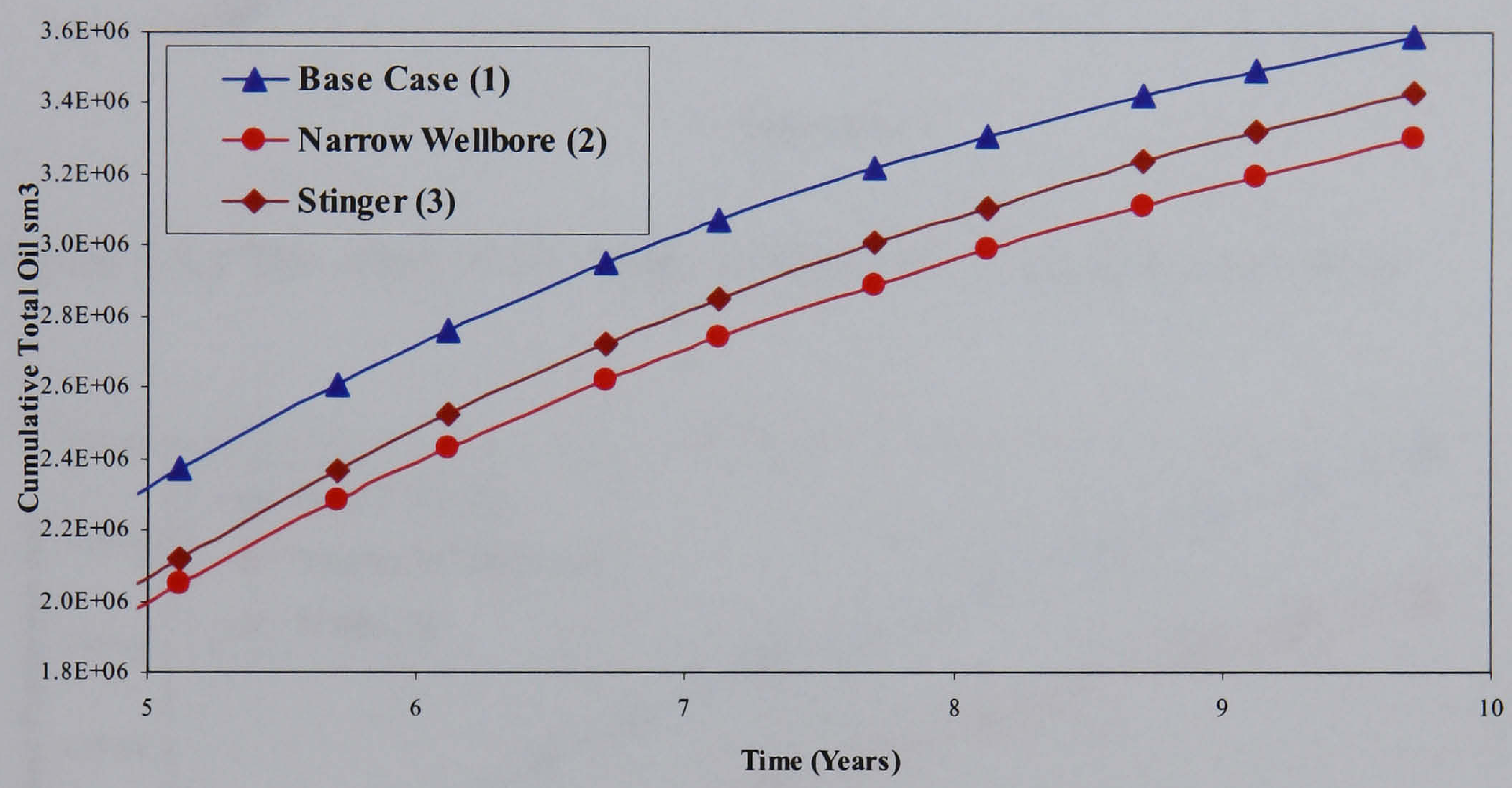


Figure 3.5.1 The effect of the wellbore diameter on the oil production

All cases gives similar gas production profile as the simulation is controlled by fixed gas production (Figure 3.5.2). The water response to the reduction in the wellbore diameter is shown in Figure 3.5.3. The decrease in the well diameter has great impact on the water production. In general the extend stinger is the best, compared with the smaller diameter case, as it help in flattening the drawdown along the wellbore and reduce the water production.

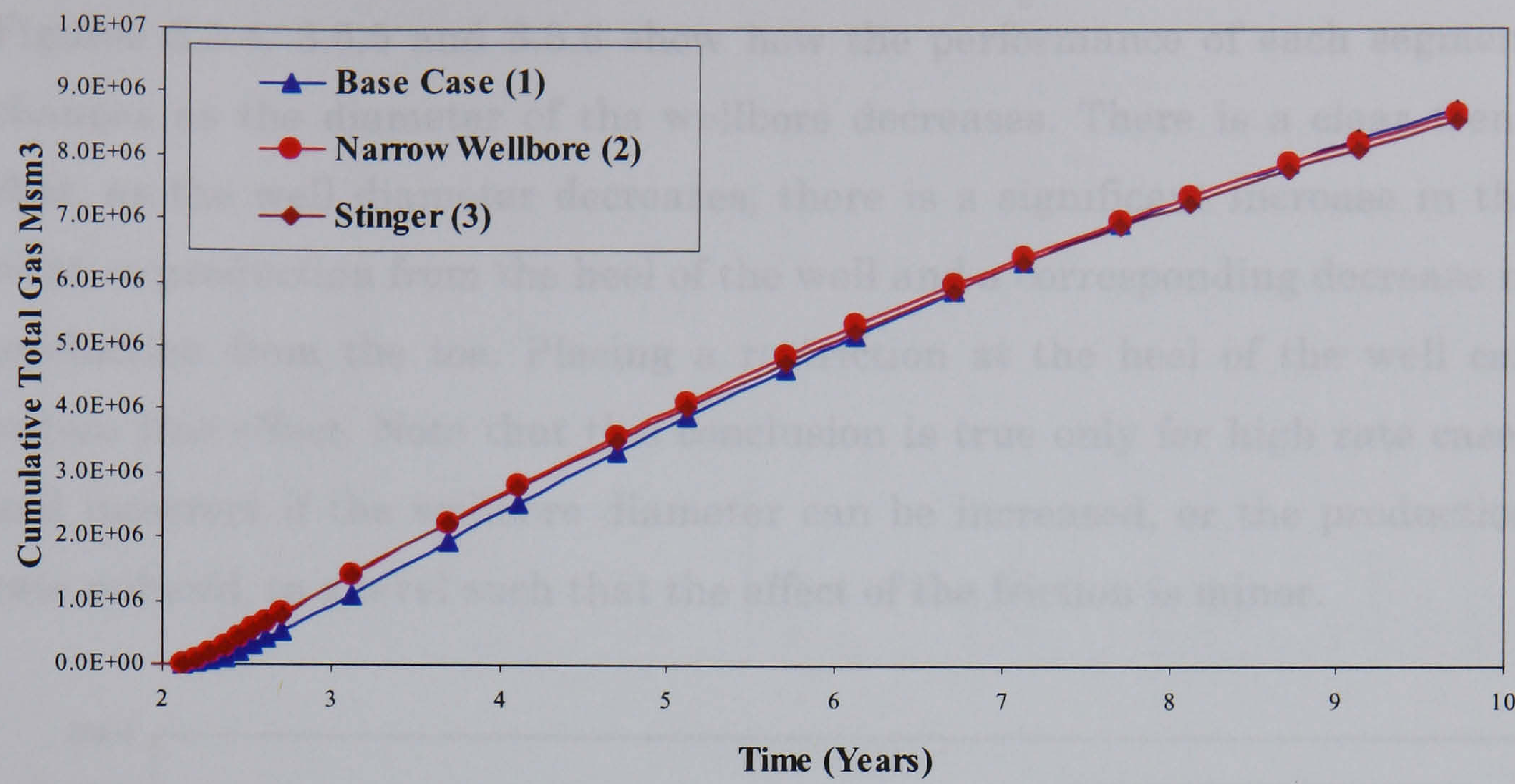


Figure 3.5.2 The effect of the wellbore diameter on the gas production

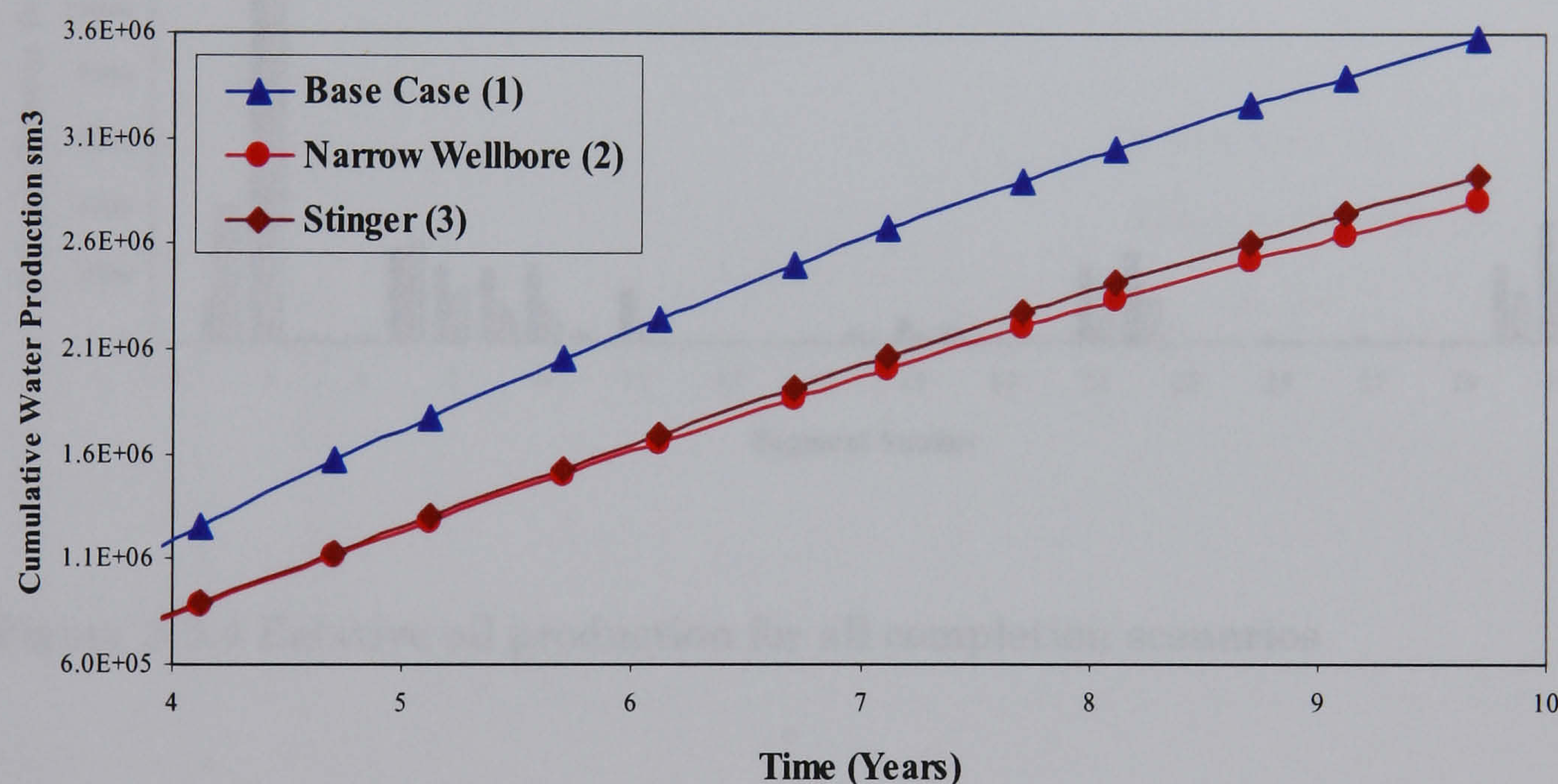


Figure 3.5.3 The effect of the wellbore diameter on the water production

3.5.2 Segment performance

One of the benefits of using the multi-segment model is that the segment inflow performance can be calculated, (remember that the lengths of the segments are not all the same). This information can be used to identify which fluid (and at what rate) oil, gas and water enter the wellbore from each reservoir grid block with IWT we can control.

Figures 3.5.4, 3.5.5 and 3.5.6 show how the performance of each segment changes as the diameter of the wellbore decreases. There is a clear trend that, as the well diameter decreases, there is a significant increase in the relative production from the heel of the well and a corresponding decrease in production from the toe. Placing a restriction at the heel of the well can reduce this effect. Note that this conclusion is true only for high rate cases and incorrect if the wellbore diameter can be increased, or the production rate reduced, to a level such that the effect of the friction is minor.

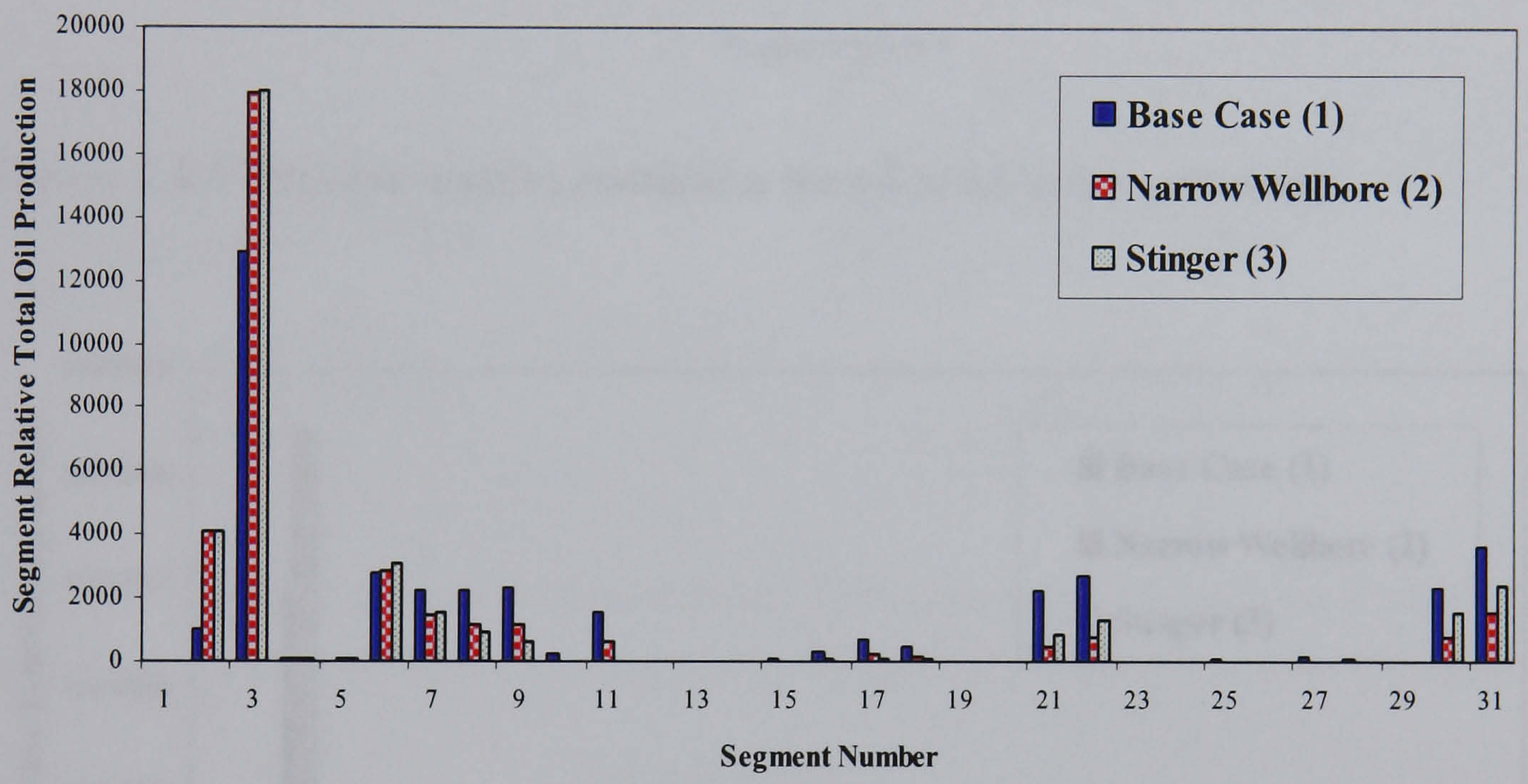


Figure 3.5.4 Relative oil production for all completion scenarios

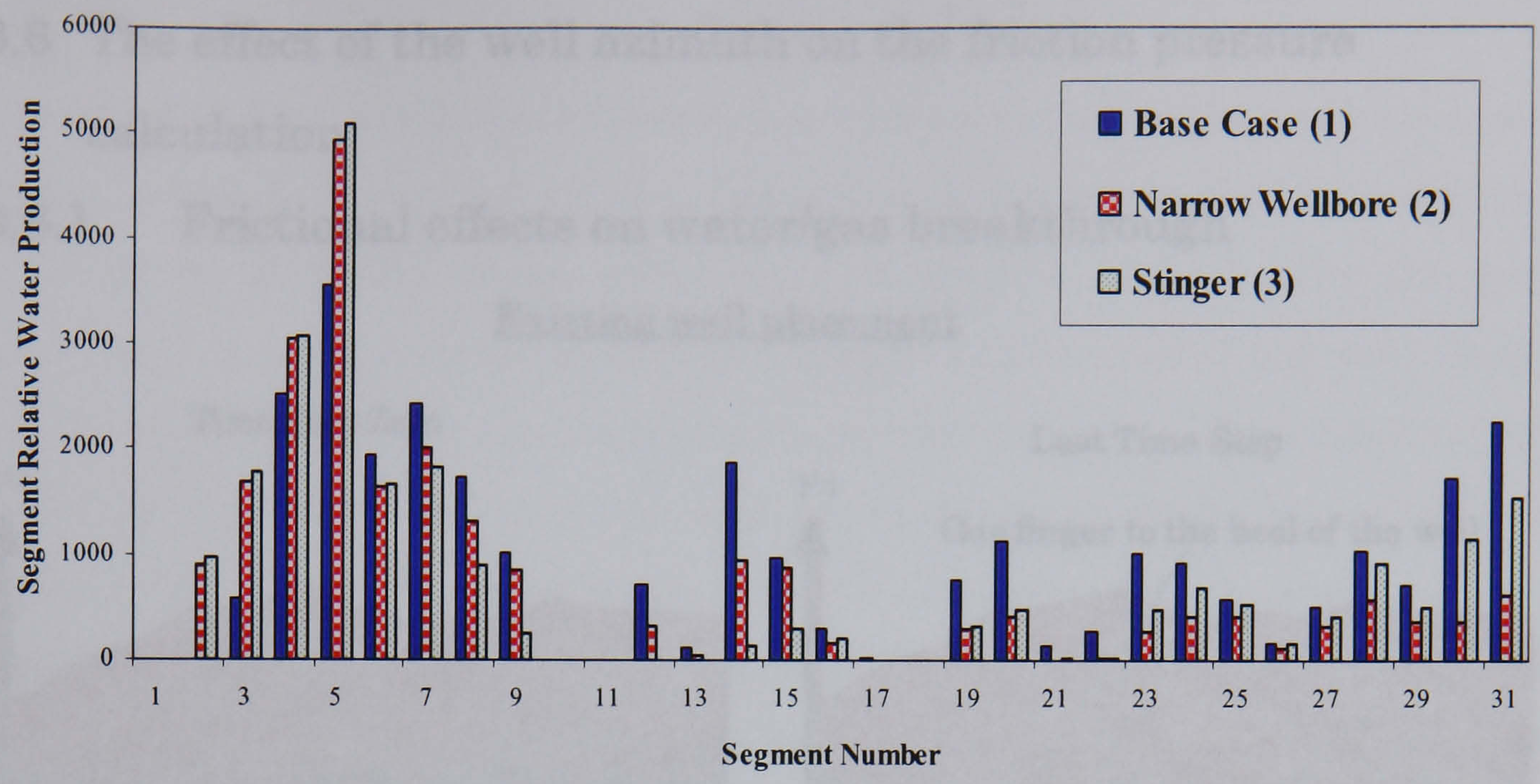


Figure 3.5.5 Relative water production for all completion scenarios

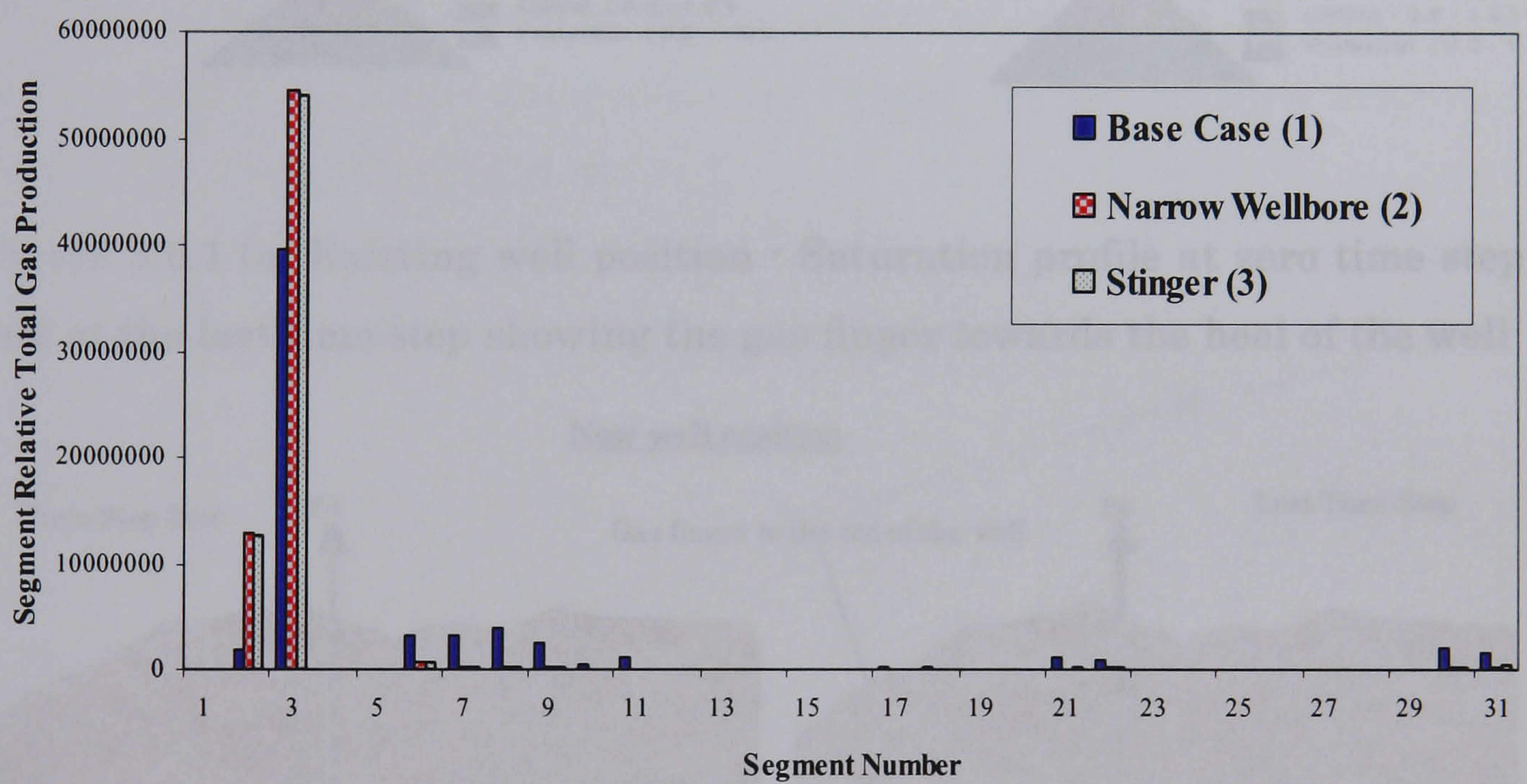


Figure 3.5.6 Relative gas production for all completion scenarios

3.6 The effect of the well azimuth on the friction pressure calculation

3.6.1 Frictional effects on water/gas breakthrough

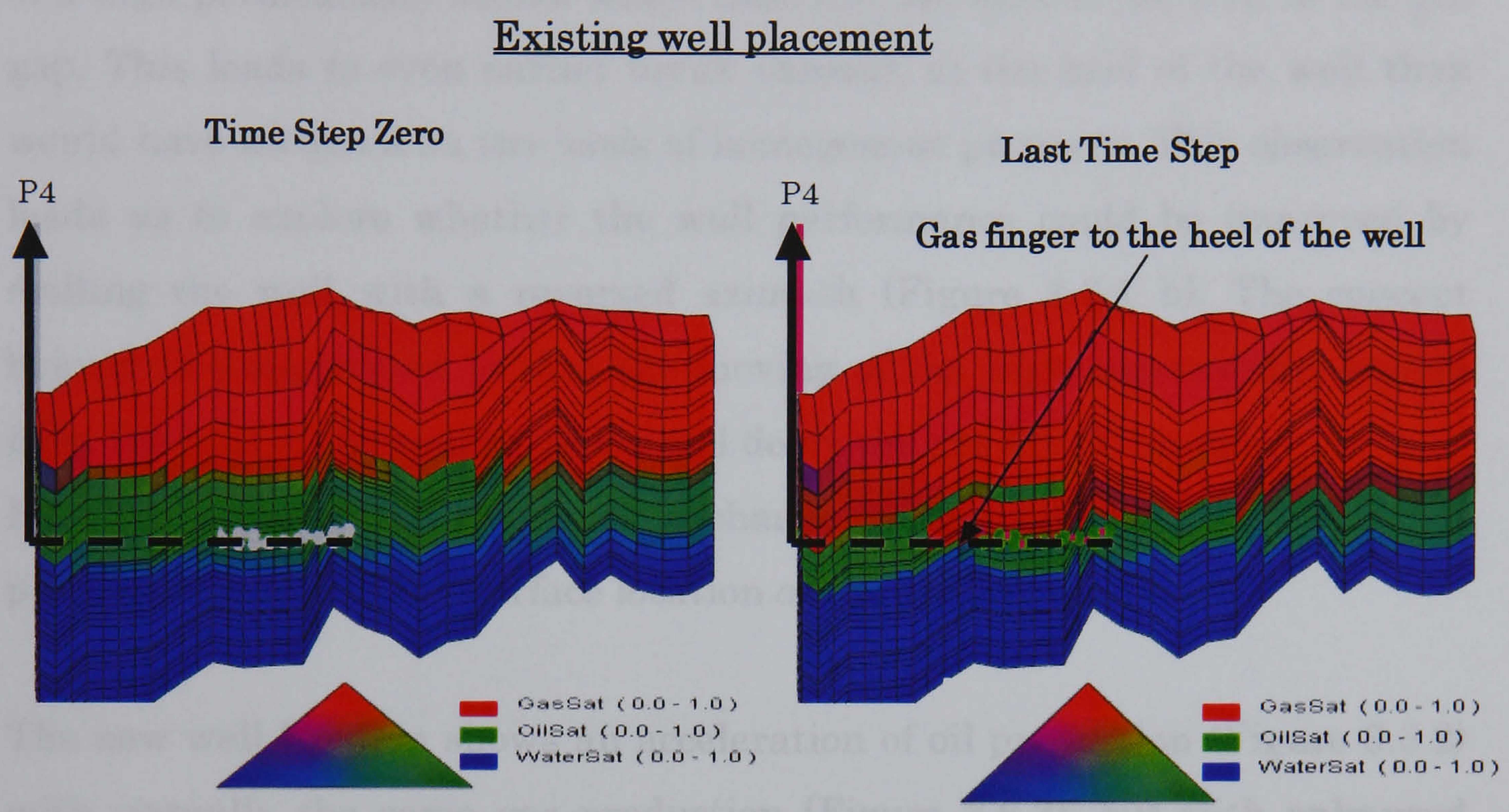


Figure 3.6.1 (a) Existing well position - Saturation profile at zero time step and at the last time step showing the gas finger towards the heel of the well

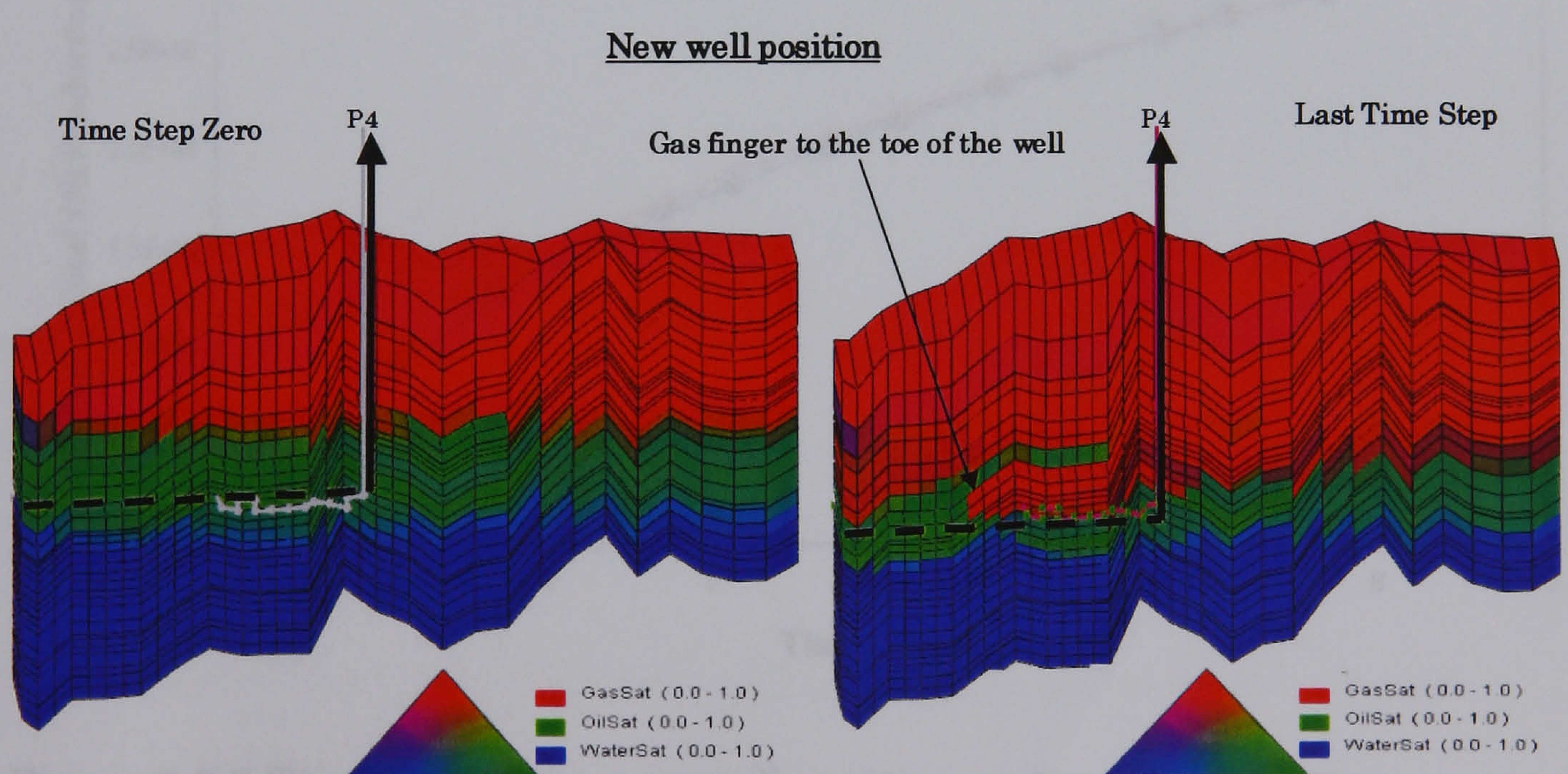


Figure 3.6.1 (b) New well position - Saturation profile at zero time step and at the last time step showing the gas finger towards the heel of the well

The effect of friction on breakthrough tendencies at the heel of the base case well is shown in Figure 3.6.1 a & b. This effect is accelerated by the presence of a high permeability streak which connects the heel of the well to the gas gap. This leads to even earlier break through at the heel of the well than would have occurred on the basis of homogenous property. This observation leads us to explore whether the well performance could be improved by drilling the well with a reversed azimuth (Figure 3.6.1 b). The concept behind this suggestion is that the moving of the high permeability streak from the heel of the well to its toe will delay the gas breakthrough.
Note: It is recognised that such a change in the well design is often not practical e.g. due to the surface location of the drilling platform).

The new well location shows an acceleration of oil production (Figure 3.6.2) with virtually the same gas production (Figure 3.6.3); but with enhanced water production (Figure 3.6.4).

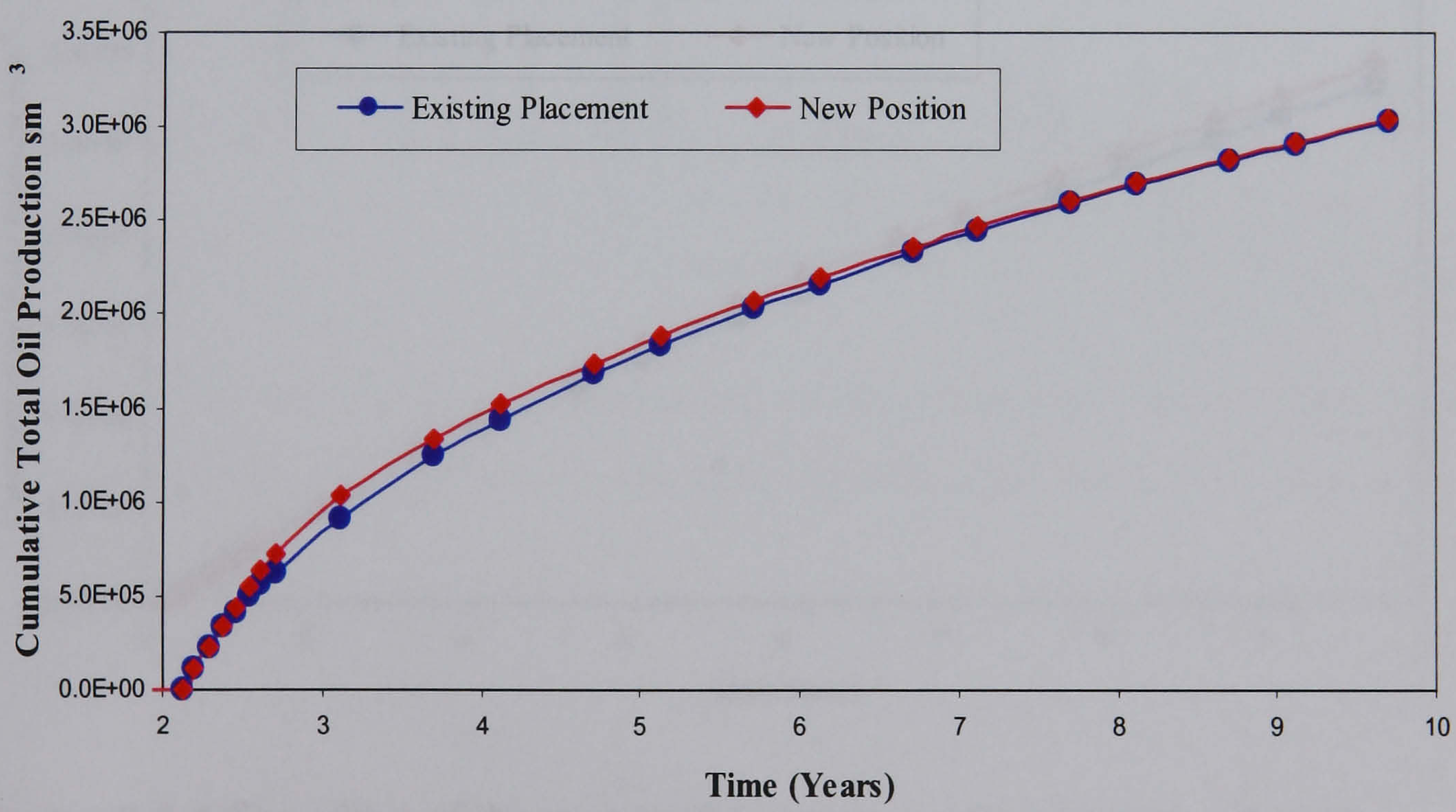


Figure 3.6.2 The effect of the new well position on the oil production

Figure 3.6.3 The effect of the new well position on the gas production

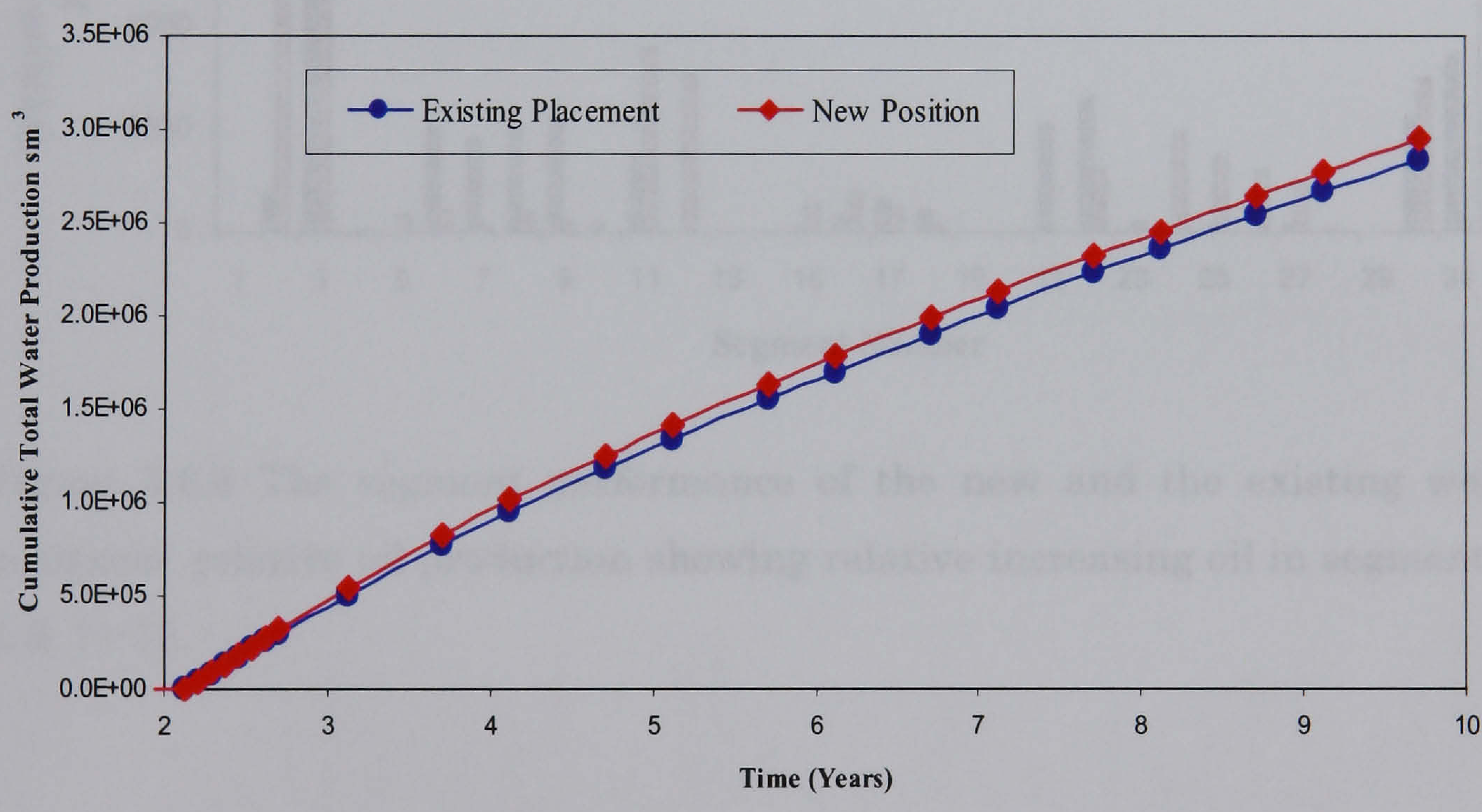


Figure 3.6.4 The effect of the new well position on the water production

3.6.2 Analysis of the segment performance for the two well placement scenarios

Figures 3.6.5 to 3.6.7 show the segment oil, gas and water production (in both cases segment 1 refers to the heel of the well). The tendency for greater production near the heel of the well is clear.

N.B Segment 1 is the first connection between the well and the reservoir both cases, i.e. they represent different reservoir grid blocks.

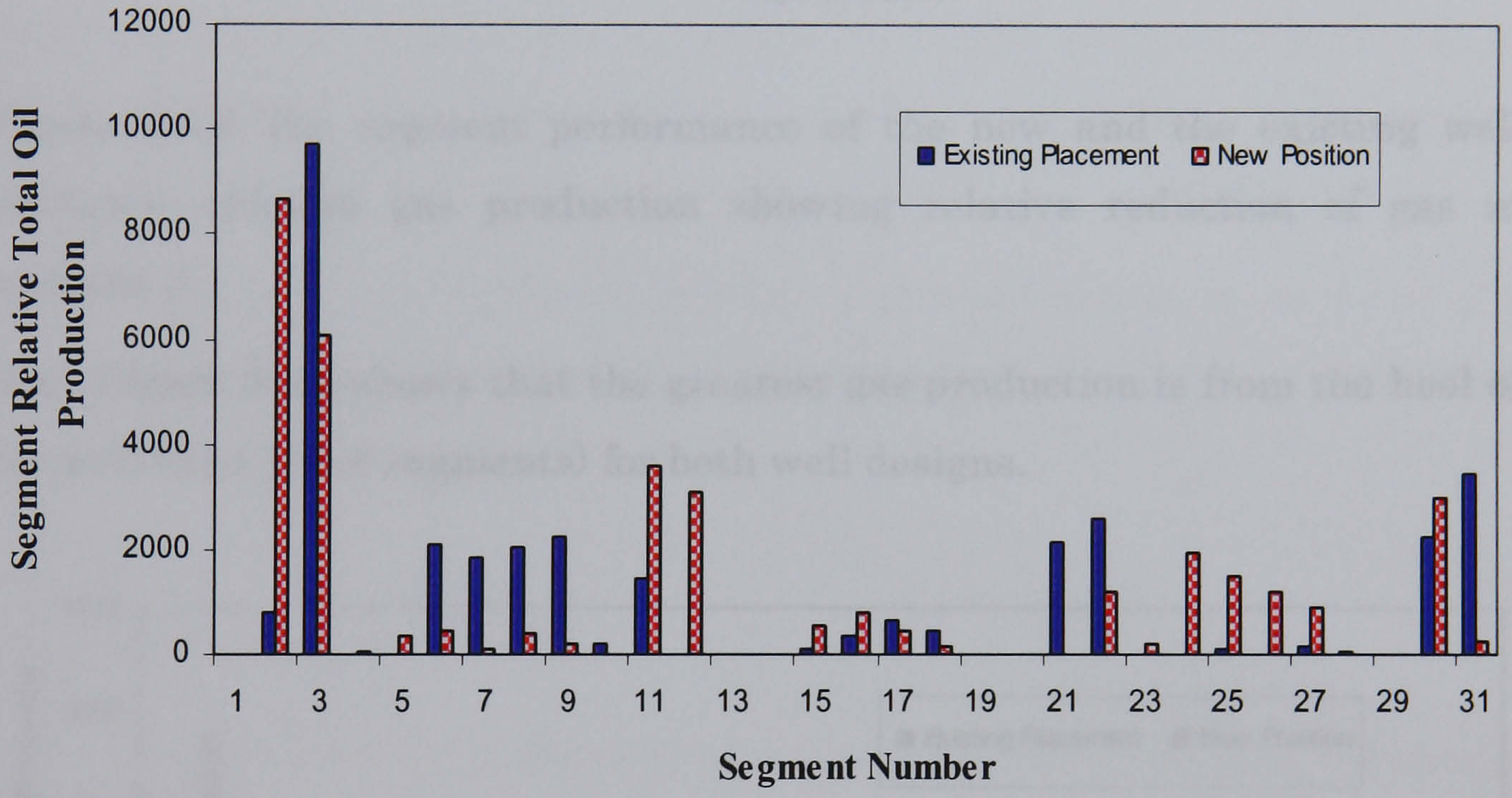


Figure 3.6.5 The segment performance of the new and the existing well positions- relative oil production showing relative increasing oil in segments 2 & 11-13.

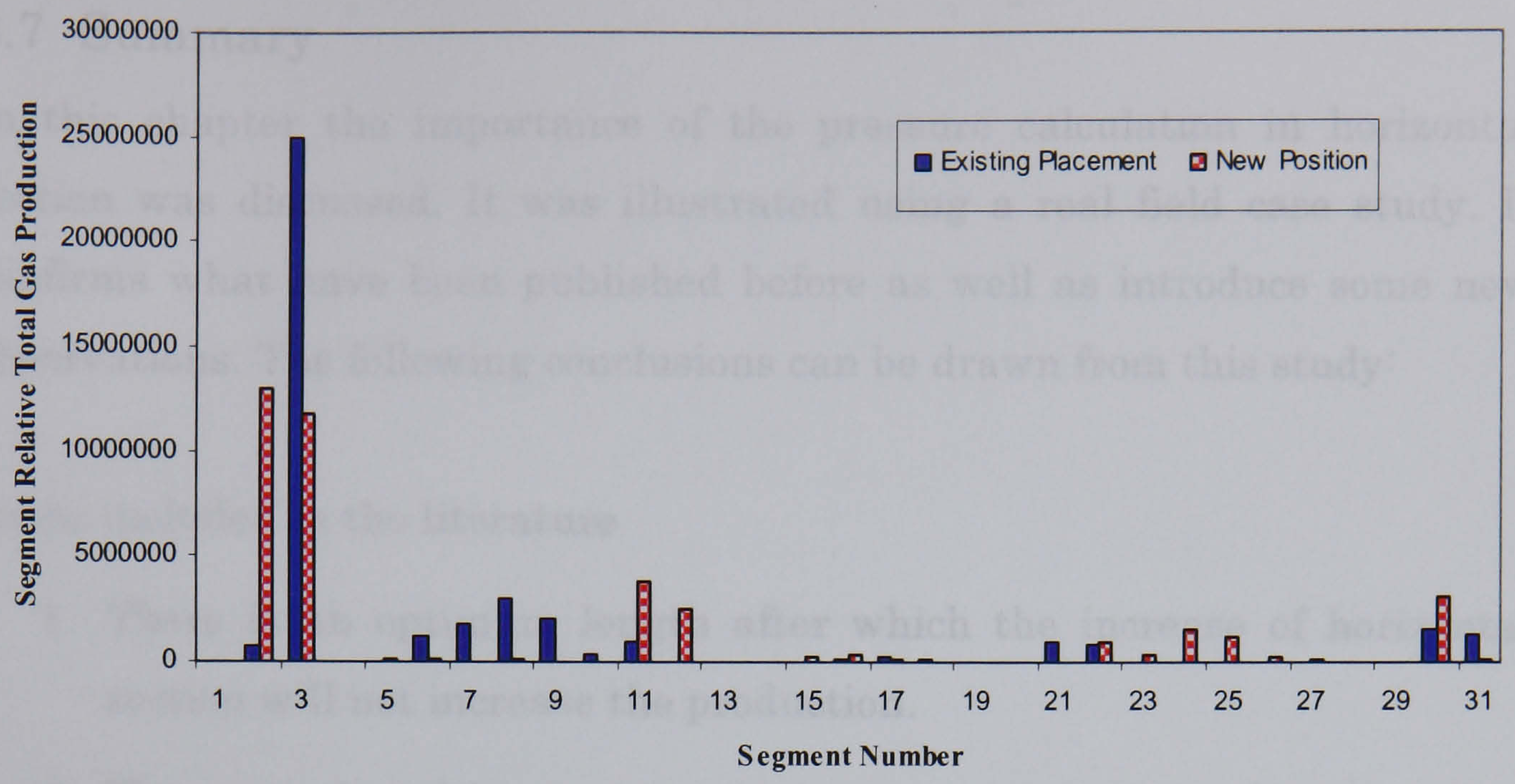


Figure 3.6.6 The segment performance of the new and the existing well positions- relative gas production showing relative reduction of gas in segment 3.

Note Figure 3.6.6 shows that the greatest gas production is from the heel of the well (first three segments) for both well designs.

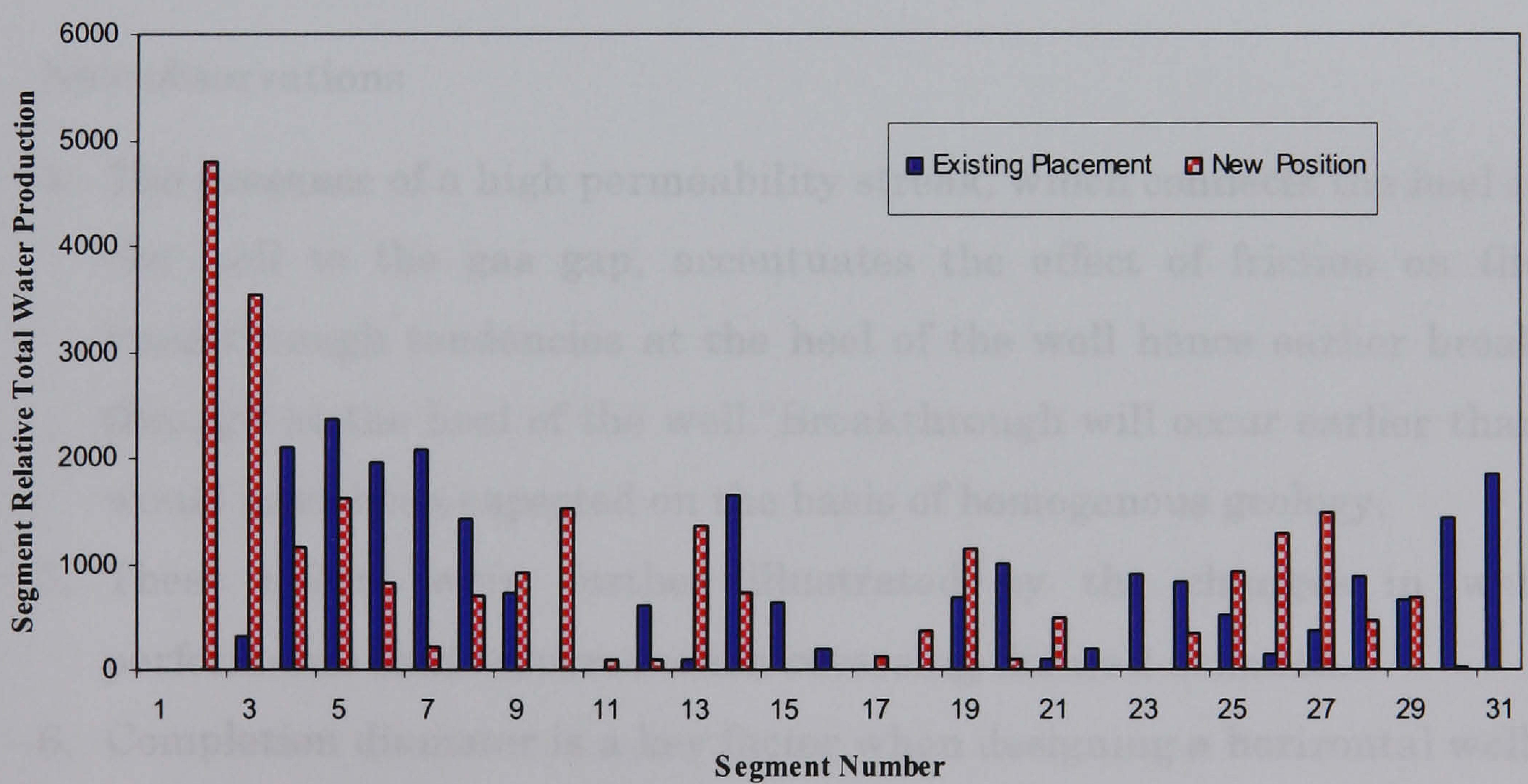


Figure 3.6.7 The segment performance of the new and the existing well positions- relative water production showing relative increasing water in segments 1-3

3.7 Summary

In this chapter the importance of the pressure calculation in horizontal section was discussed. It was illustrated using a real field case study. It confirms what have been published before as well as introduce some new observations. The following conclusions can be drawn from this study:

Items included in the literature

1. There is an optimum length after which the increase of horizontal section will not increase the production.
2. The use of multi-segment option to model horizontal wells allow calculation of the effect of the pressure drop along the horizontal section.
3. Friction pressure drops across the horizontal section is an important factor when high permeability reservoirs are developed by high rates wells.

New observations

4. The presence of a high permeability streak, which connects the heel of the well to the gas gap, accentuates the effect of friction on the breakthrough tendencies at the heel of the well hence earlier break through at the heel of the well. Breakthrough will occur earlier than would have been expected on the basis of homogenous geology.
5. These effects were further illustrated by the changes in well performance that occurred when reversing the well azimuth.
6. Completion diameter is a key factor when designing a horizontal well. There is a significant increase in the relative production from the heel of the well and a corresponding decrease in production from the toe if the well diameter decreases. Placing a restriction at the heel of the well can reduce this effect in the high productivity well example used.

Chapter 4

4. Production Optimisation using Intelligent Well Technology in a High Productivity, Thin Oil column Reservoir – NH Field case study

Chapter 2 discuss the modelling issues of ICVs using the multi-segment option to build a detailed well model within reservoir simulation model. Still, an optimisation method is required to maximize the production and take advantage of the flexibility offered by the ICVs. Yeten et al (2002) discuss the production optimisation intelligent wells using gradient based, optimisation procedure for the control of a smart multilateral well and applies their algorithm to several example cases. Their work showed that, for some of the synthetic cases considered, a substantial (up to 65%) increase in cumulative oil recovery using optimised smart wells could be achieved, though in others the increase was relatively low. Chapter 4 will evaluate commercially available tools for this purpose - the reservoir simulator Eclipse is used to model and control the ICV action using the detailed, multi-segment, well model. Three different optimisation techniques were tested on the NH field case (Chapter 1). The methods used are the WECON and ACTIONS keyword of Eclipse and the ICOS software program (Chapter 2), (Elmsallati et al. 2005a) and (Elmsallati et al. 2005c).

4.1 NH – simulation model

The performance of the P4 well (2000 m horizontal length and located 4 m above the OWC) was simulated using the same control parameters discussed in Chapter 3 (4000 sm^3/day liquid, $2*10^6$ sm^3/day gas and 125 bar THP). The multi-segment well model (Chapter 2) within Eclipse was used to model the ICV using the WSEGVALV keyword.

4.2 ICV control techniques

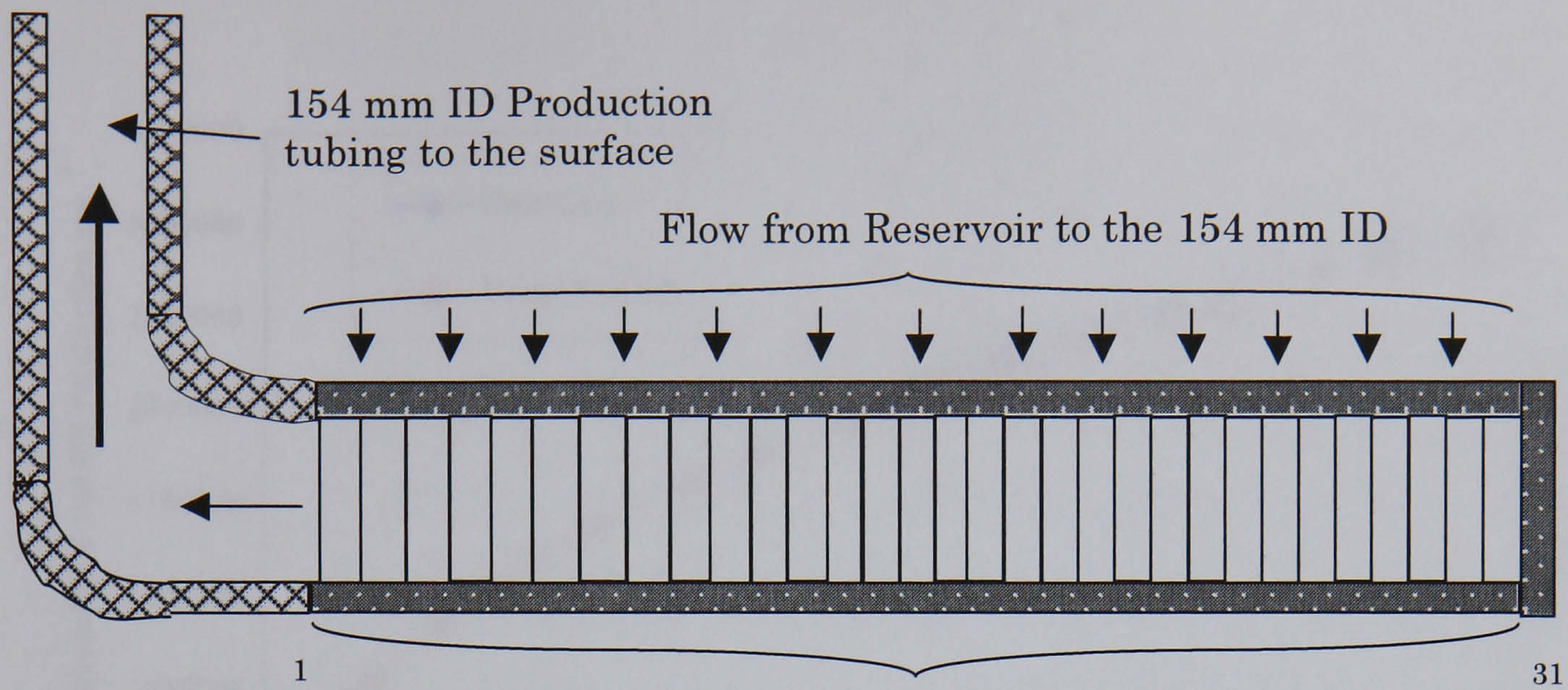
Three different ICV control techniques have been discussed in details (see Chapter 2) are:

1. The well economic limit (WECON) keyword can be used as on/off valve when (i) the complete well or (ii) a single or (iii) a group of reservoir/well connection(s) exceed a specified gas or water flow limit.
2. The Eclipse ACTIONS keyword.
3. The ICOS software program

4.2.1 Use of WECON keyword to optimise the production

4.2.1.1 The Base Case

The 2,000m horizontal length well P4, completed with a 154 mm ID sand screen and a 154 mm ID production tubing to the surface, has been used as the base case (Figure 4.2.1).



The well bore is divided into 31 segments of different length. Each segment acts as an On/Off valve

Figure 4.2.1 Use of WECON to model each segment as an On/Off valve

4.2.1.2 Example showing the use of WECON

The P4 well completion (Figure 4.2.1) was divided in to 31 segments, each segment representing the well crossing one grid block. WECON with its On/Off control action is used to control reservoir grid block well connection. As the simulation proceeds it will check, at the specified times, whether the well {or group of connection(s)} limitation (water cut fraction of 0.4 in this case) is exceeded. If this is the case, an action will be taken to shut off the worst offending connection (i.e. the one producing the most water). As the simulation continues, the water cut will increase again, so the action will be repeated as long as the water cut continues to increase OR until the well can no longer flow (for a naturally flowing well) OR all the reservoir / well connections are shut off (for an artificial lifted well).

Figures 4.2.2 and 4.2.3 show the improvement achieved by using the keyword WECON. The average water cut is reduced from 60% to less than 40 %. This reduction is evaluated against a 3.8% reduction in cumulative total oil production.

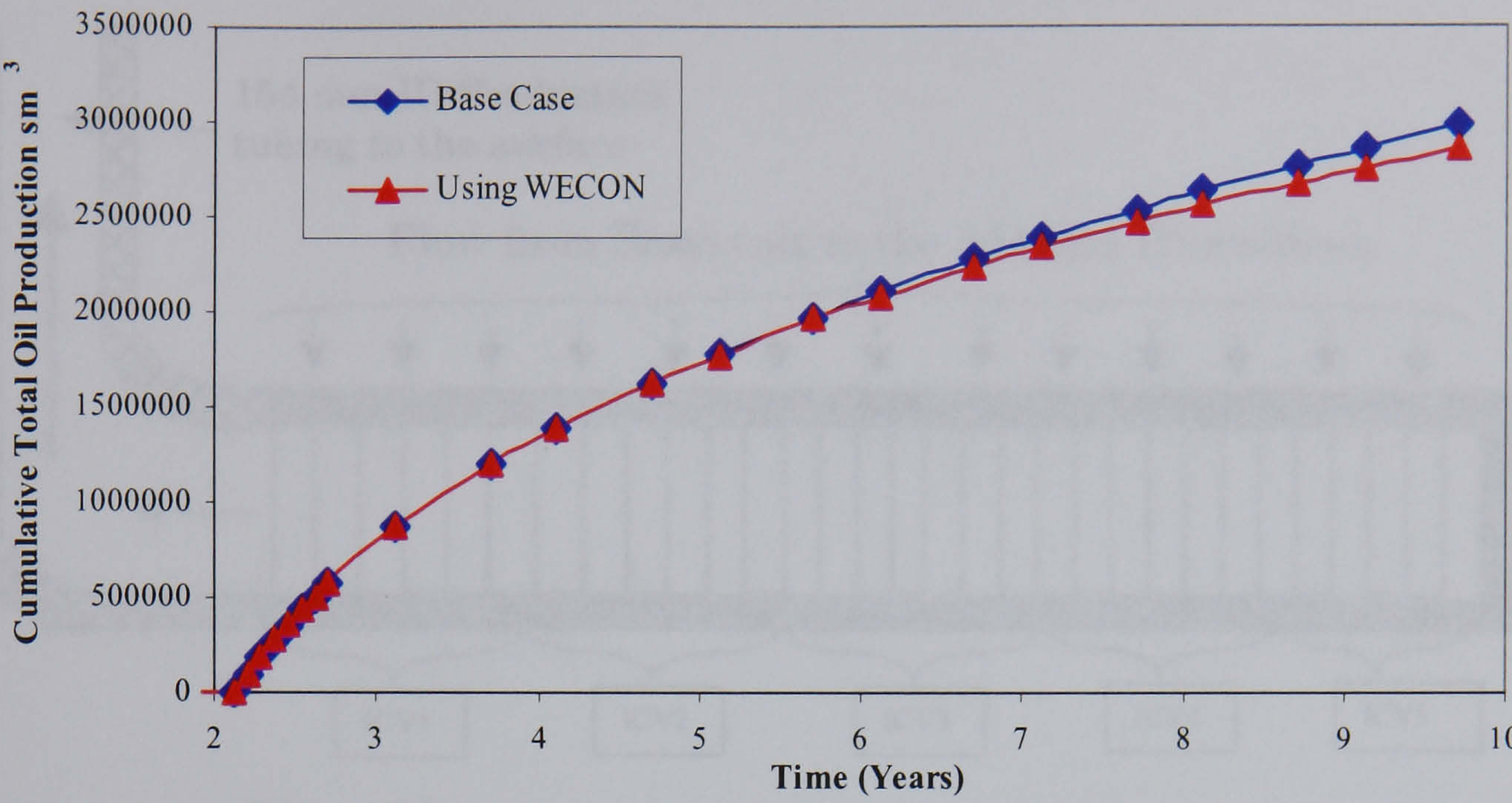


Figure 4.2.2 Performance of the well (cumulative total oil) with and without use of the keyword WECON

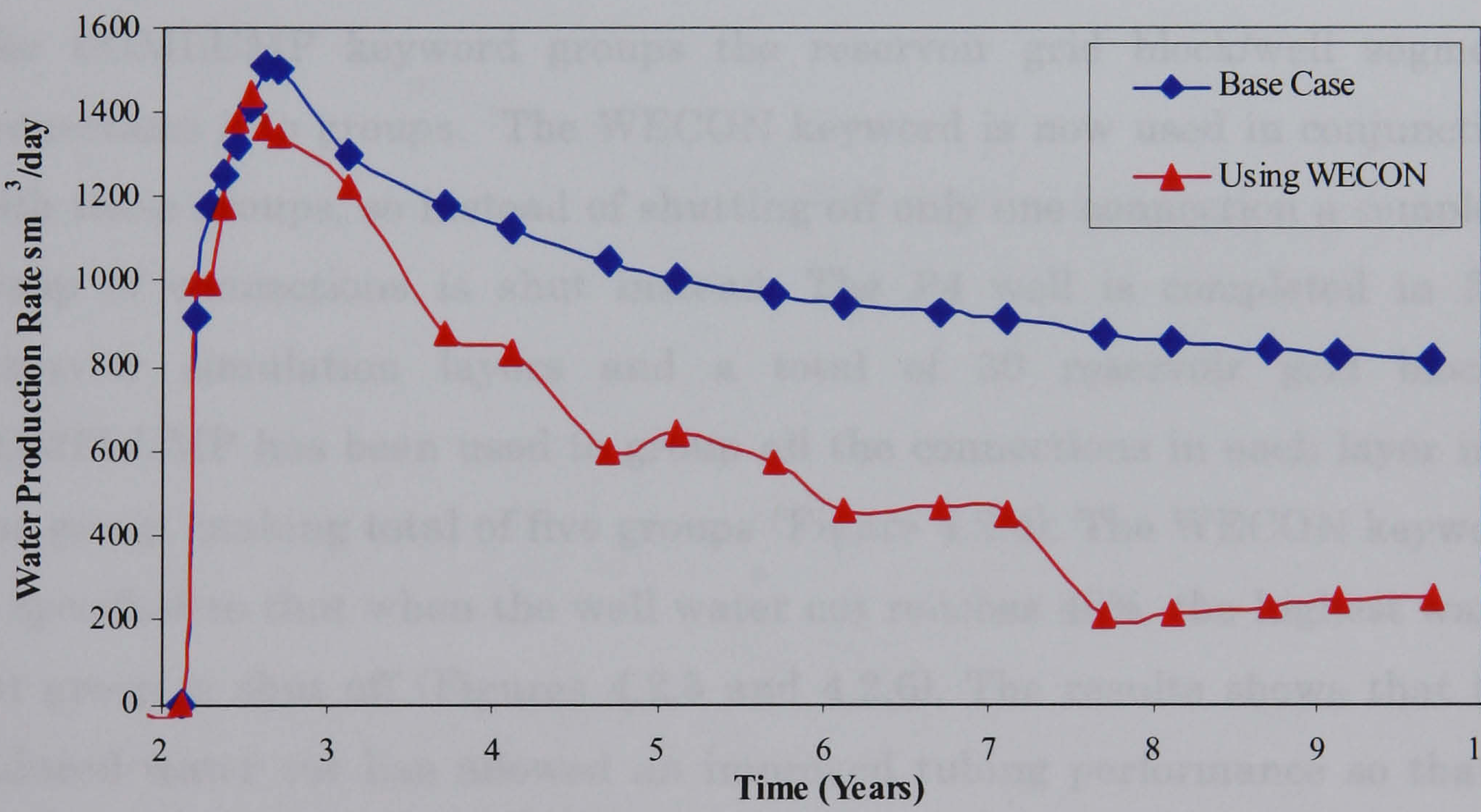


Figure 4.2.3 Performance of the well (water production) with and without use of the keyword WECON

4.2.1.3 The use of WECON in conjunction with COMPLUMP

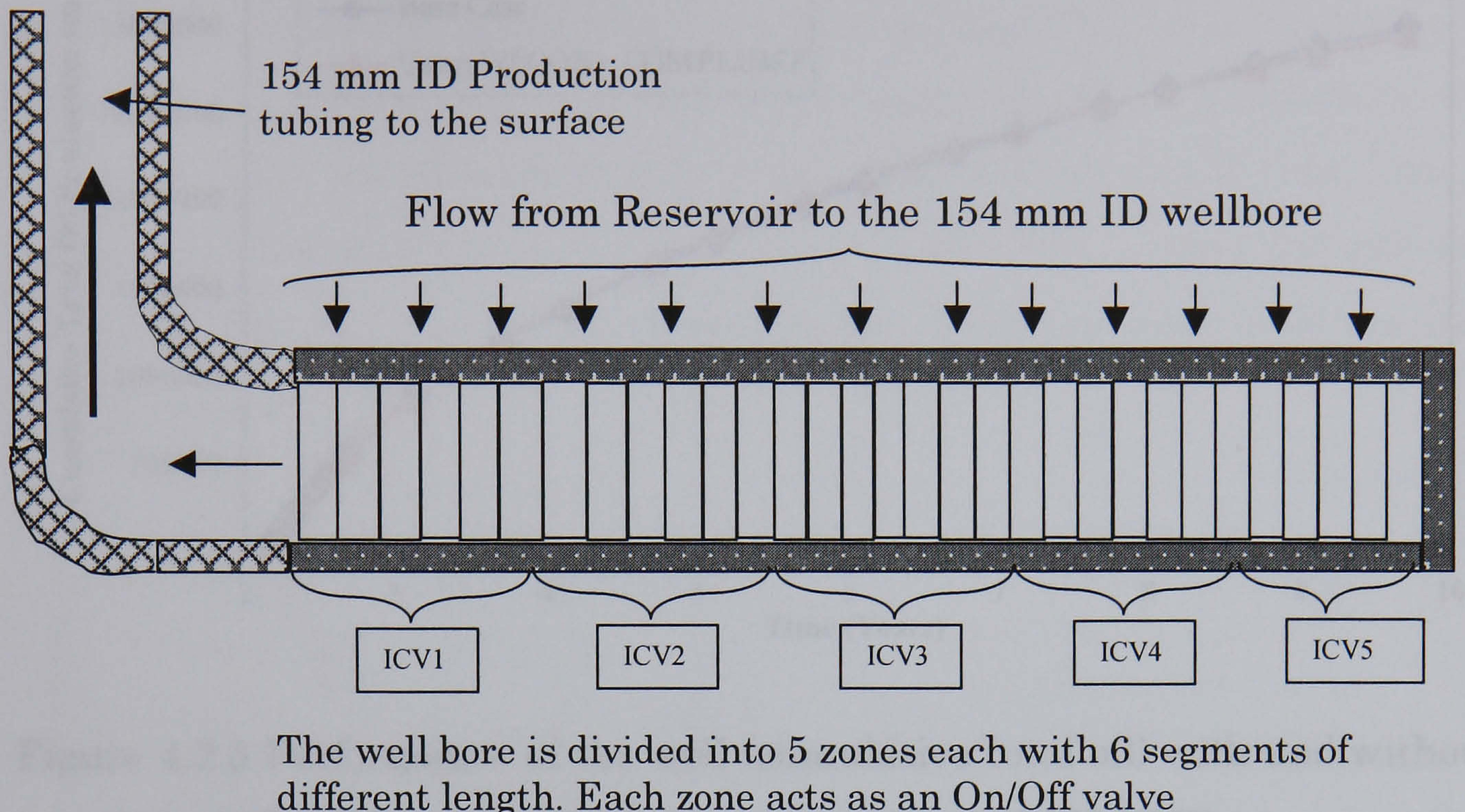


Figure 4.2.4 Combined use of WECON +COMPLUMP to model less number of On/Off valves

The COMLUMP keyword groups the reservoir grid block/well segment connections into groups. The WECON keyword is now used in conjunction with these groups, so instead of shutting-off only one connection a complete group of connections is shut instead. The P4 well is completed in five reservoir simulation layers and a total of 30 reservoir grid blocks. COMPLUMP has been used to group all the connections in each layer into one group, making total of five groups (Figure 4.2.4). The WECON keyword is specified so that when the well water cut reaches 40%, the highest water cut group is shut off (Figures 4.2.5 and 4.2.6). The results shows that the reduced water cut has allowed an improved tubing performance so that a marginally higher oil production was achieved in the mid life of the well. The final water production is double that in the previous case and the cumulative oil loss is now reduced to 1.7 %.

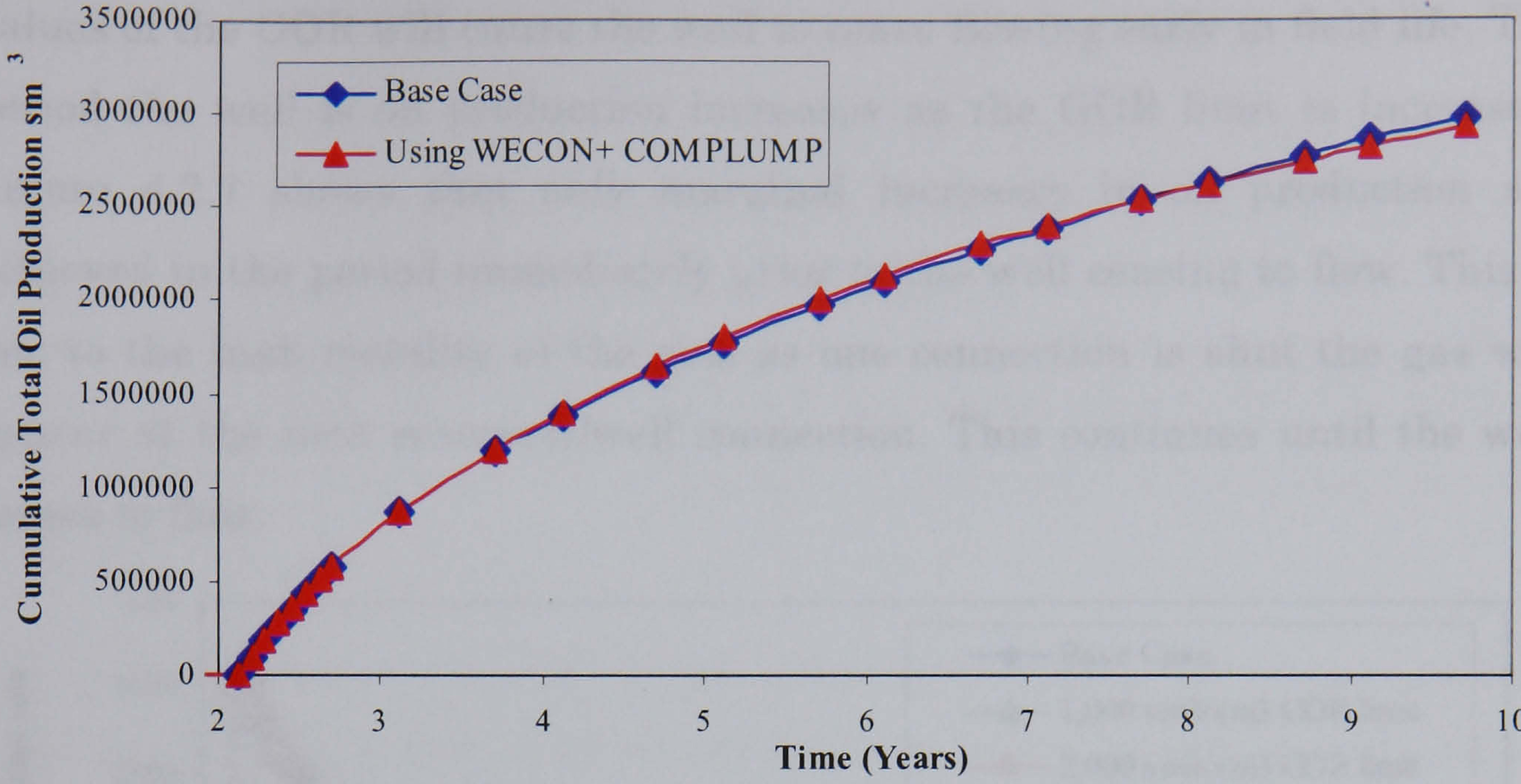


Figure 4.2.5 Performance of the well (cumulative total oil) with and without use of the WECON keyword in conjunction with COMPLUMP

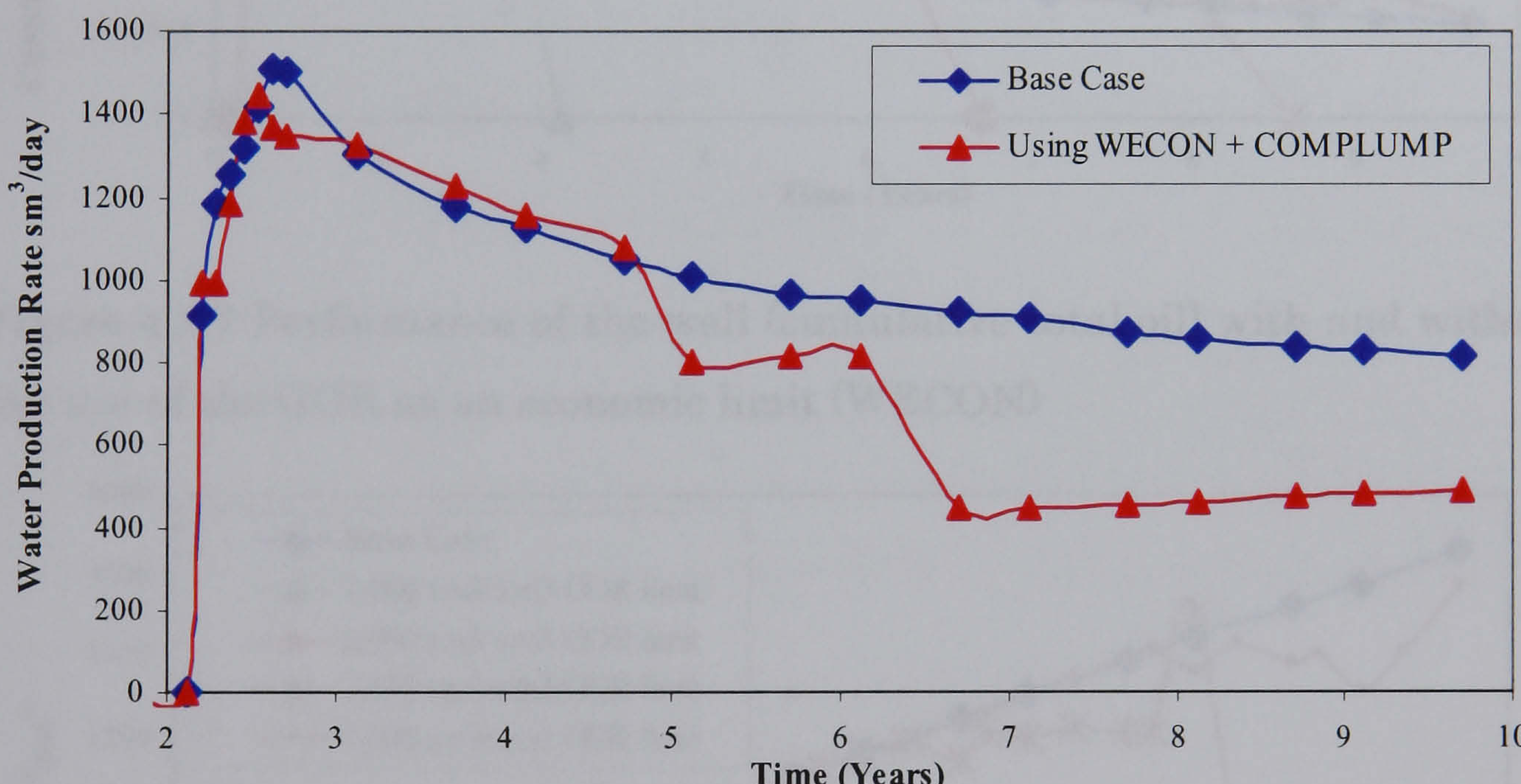


Figure 4.2.6 Performance of the well (water production rate) with and without use of WECON keyword in conjunction with COMPLUMP

4.2.1.4 Impact of WECON on gas production

In the previous section the water cut was used as the economic limit when the reservoir connection(s) should be shut in. In this section the GOR is used as an economic limit – a range of values between 1000 and 3000 sm^3/sm^3 GOR being used. Figures 4.2.7 and 4.2.8 show that using lower values of the GOR will cause the well to cease flowing early in field life. The period the well is on production increases as the GOR limit is increased. Figure 4.2.7 shows that only marginal increases in oil production are achieved in the period immediately prior to the well ceasing to flow. This is due to the high mobility of the gas; as one connection is shut the gas will appear at the next reservoir/well connection. This continues until the well ceases to flow.

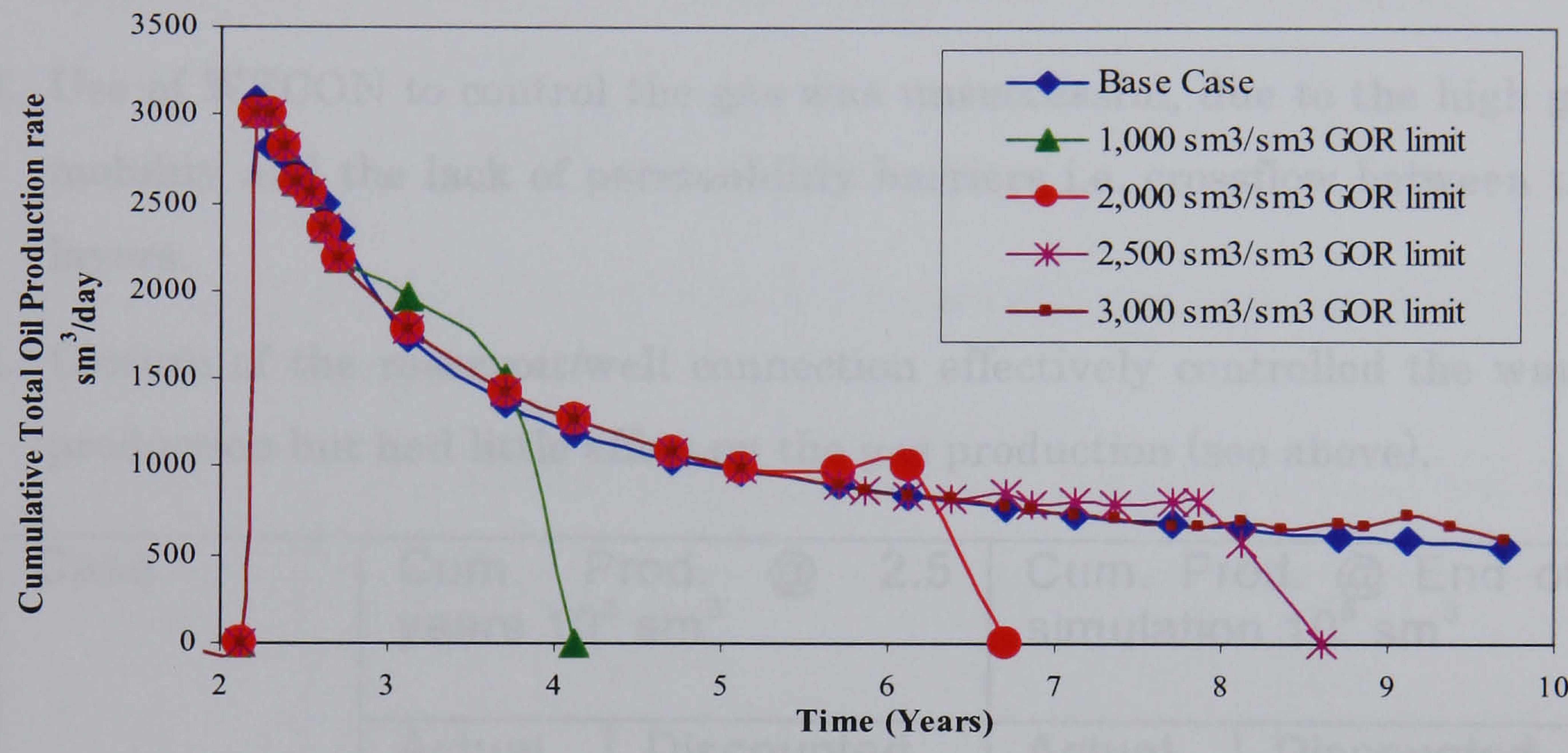


Figure 4.2.7 Performance of the well (cumulative total oil) with and without the use of the GOR as an economic limit (WECON)

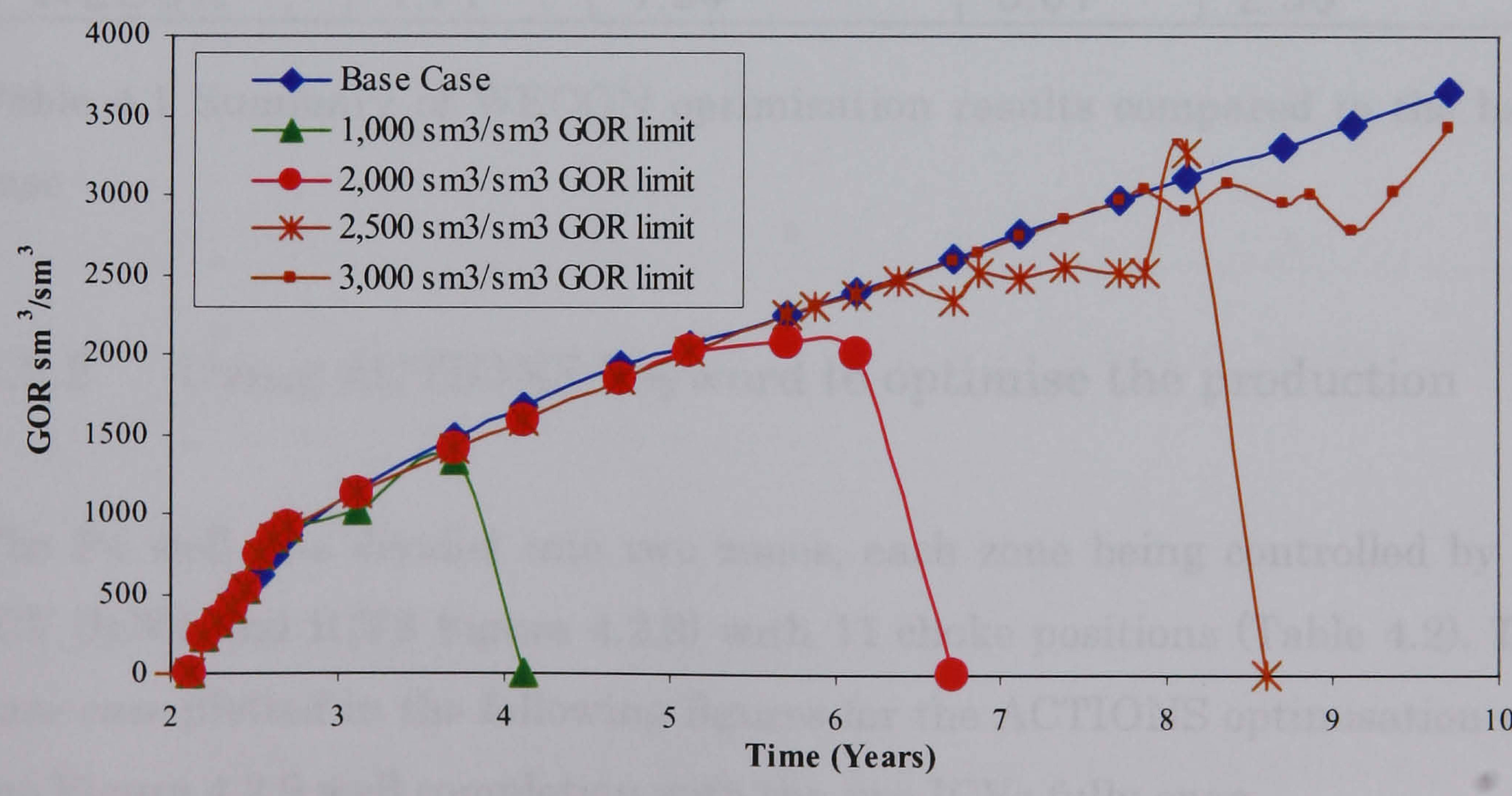


Figure 4.2.8 Performance of the well (GOR) with and without the use of the GOR as an economic limit (WECON)

4.2.1.5 Summary of WECON optimisation results

1. The use of WECON accelerated the oil production during the first 2.5 years by 5.3%. This will become 6.4% at the end of the simulation run once it discounted (at 10% per year). (Table 4.1)
2. Use of the WECON keyword allowed the overall water cut to be reduced from 60 % to less than 40%, although a significant oil production penalty results.
3. Use of WECON to control the gas was unsuccessful, due to the high gas mobility and the lack of permeability barriers i.e. crossflow between the layers.
4. Closure of the reservoir/well connection effectively controlled the water production but had little effect on the gas production (see above).

Case	Cum. Prod. @ 2.5 years 10^6 sm^3		Cum. Prod. @ End of simulation 10^6 sm^3	
	Actual	Discounted 10% per year	Actual	Discounted 10% per year
Base Case	1.62	1.46	2.97	2.21
WECON	1.71	1.54	3.01	2.36

Table 4.1 Summary of WECON optimisation results compared to the base case

4.2.2 Using ACTIONS keyword to optimise the production

The P4 well was divided into two zones, each zone being controlled by an ICV (ICV1 and ICV2 Figure 4.2.9) with 11 choke positions (Table 4.2). The base case plotted in the following figures for the ACTIONS optimisation use the Figure 4.2.9 well completion with the two ICVs fully open.

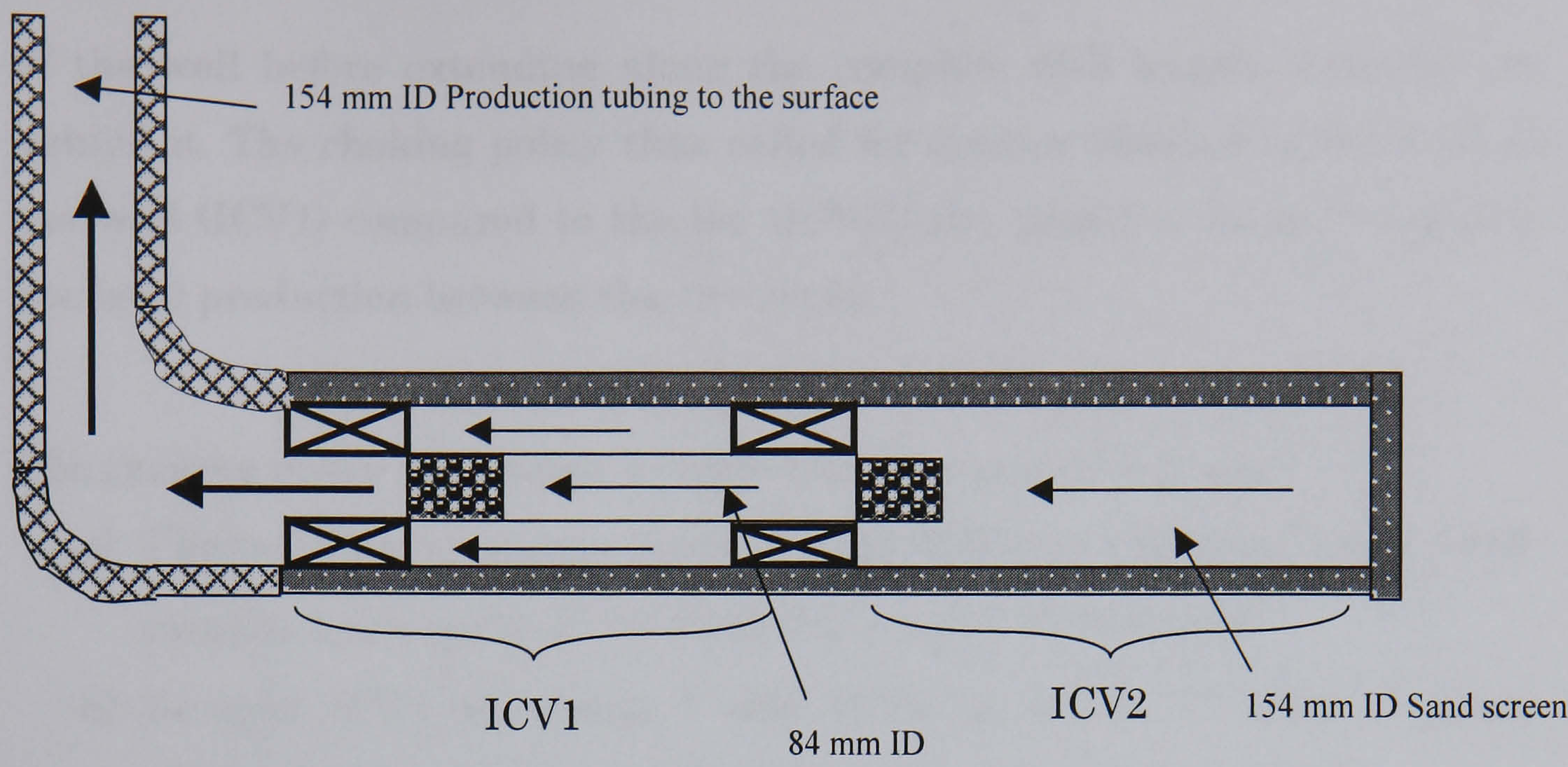


Figure 4.2.9 Well P4 is divided in to two separate zones each controlled with an ICV (ICV1 and ICV2).

Status	Flow Area of equivalent pipe (in^2)	Diameter of equivalent pipe (in)
0 (Shut)	0.000	0.000
1	0.055	0.265
2	0.110	0.374
3	0.155	0.444
4	0.215	0.523
5	0.319	0.637
6	0.472	0.775
7	0.626	0.893
8	0.856	1.044
9	1.163	1.217
10	1.776	1.504
11 (Fully Open)	8.073	3.206

Table 4.2 The ICV positions based on a real ICV installed by Norsk Hydro in analogue Oseberg field (Erlandsen, 2000)

4.2.2.1 Choice of ICV choking policy

An effective choking policy can only be set up once an understanding of the reservoir and well flow performance has been developed. Reservoir simulation output, such as Figures 4.2.10 to 4.2.12 shows the fluid distribution at different times. It is clear that free gas first cusps to the heel of the well before extending along the complete well length, trapping oil behind it. The choking policy thus called for greater choking at the heel of the well (ICV1) compared to the toe (ICV2); the objective being to balance the (gas) production between the two zones.

The choking policy (developed by trial and error procedure) was:

a) Choke ICV1 to status 3 and Choke ICV2 to status 9 when GOR exceeds 1,800 sm^3/sm^3 (to control gas influx at the heel).
b) Re-open ICV1 to status 7 and ICV2 to status 11 after 3 years production (to maintain well productivity later in the well life).

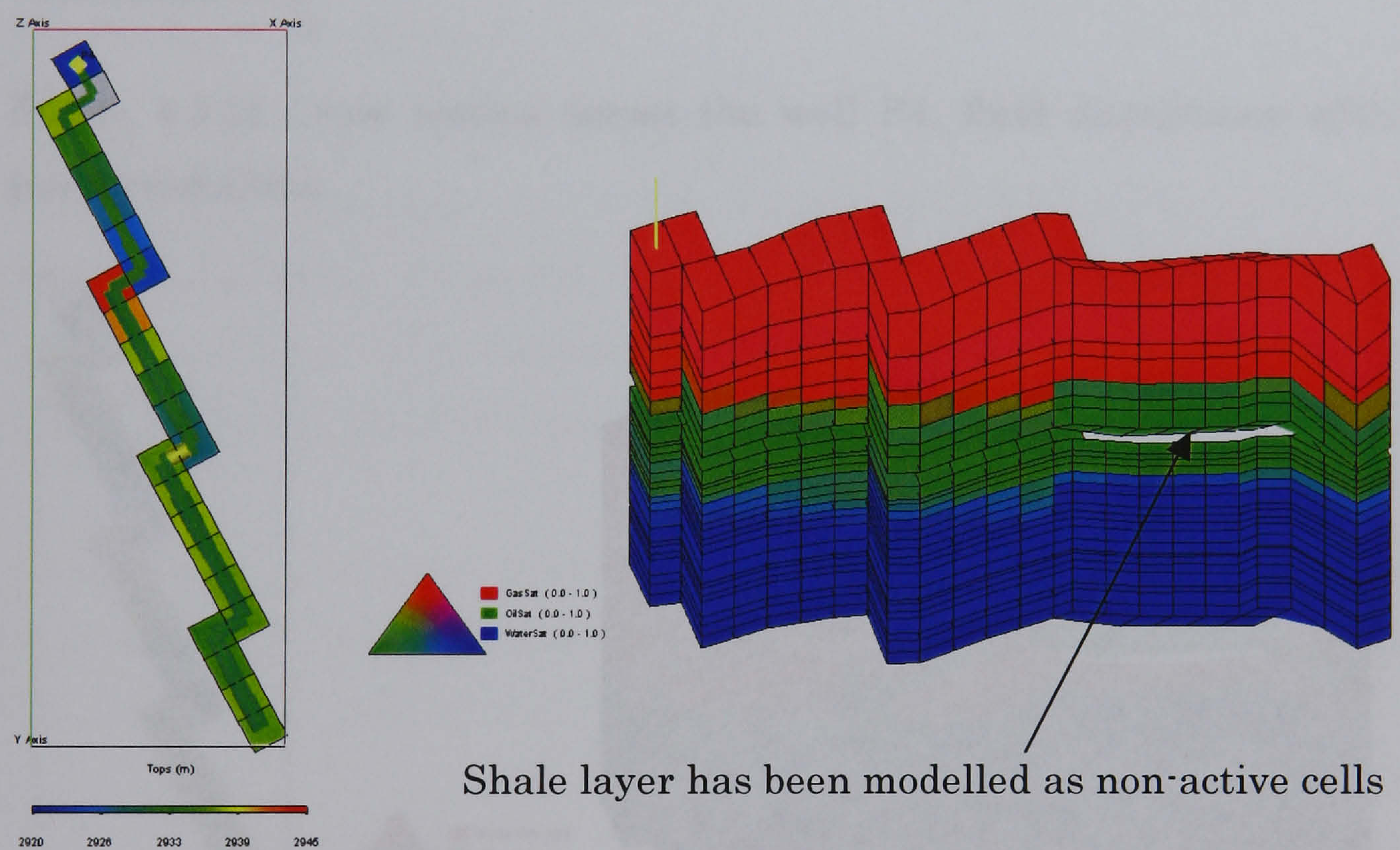


Figure 4.2.10 Cross section across the well P4 zero time showing the fluid distribution

Figure 4.2.11 Cross section across the well P4, fluid distribution after 2 years production.

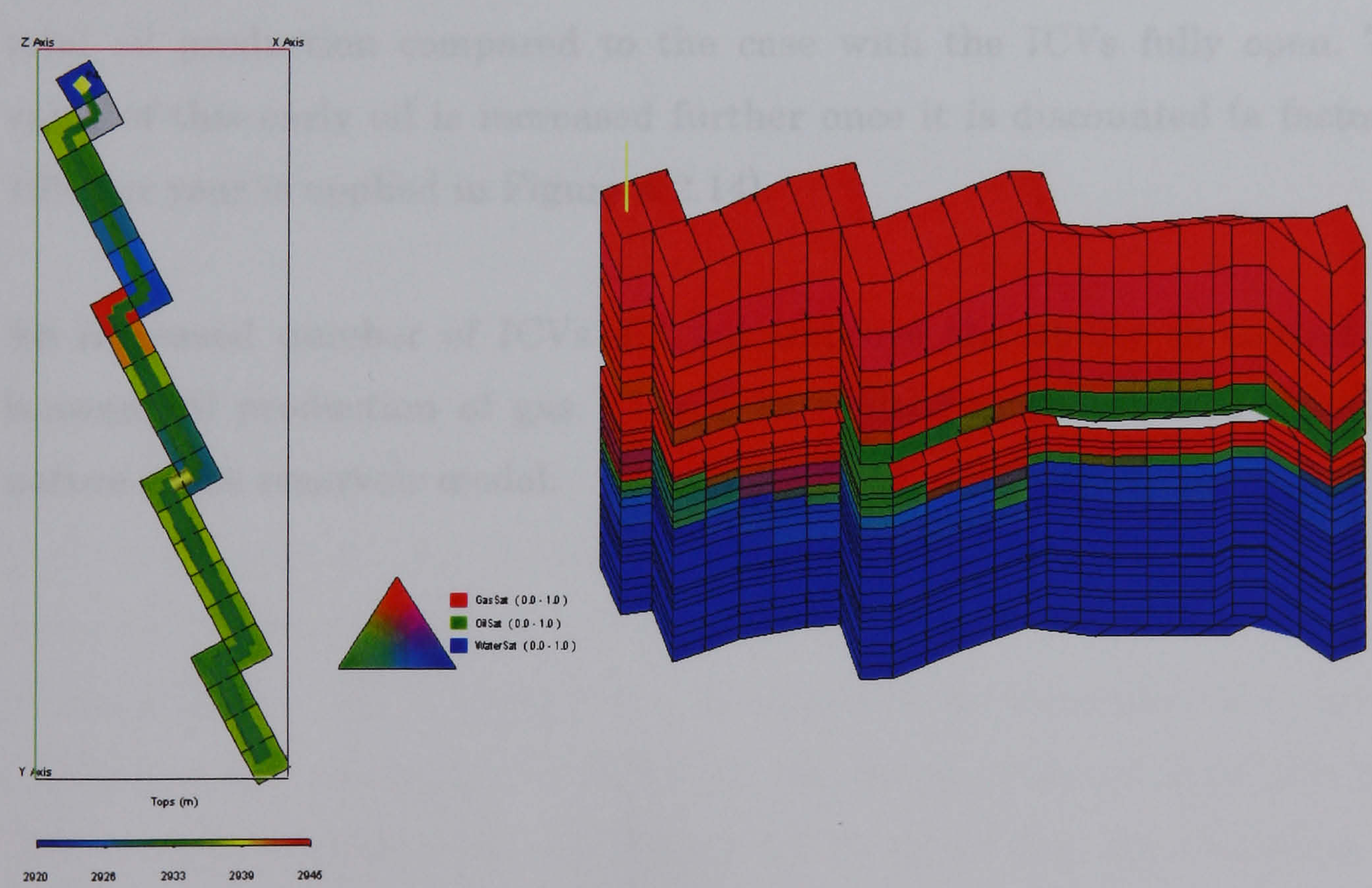


Figure 4.2.12 Cross section across the well P4, fluid distribution at the end of the simulation

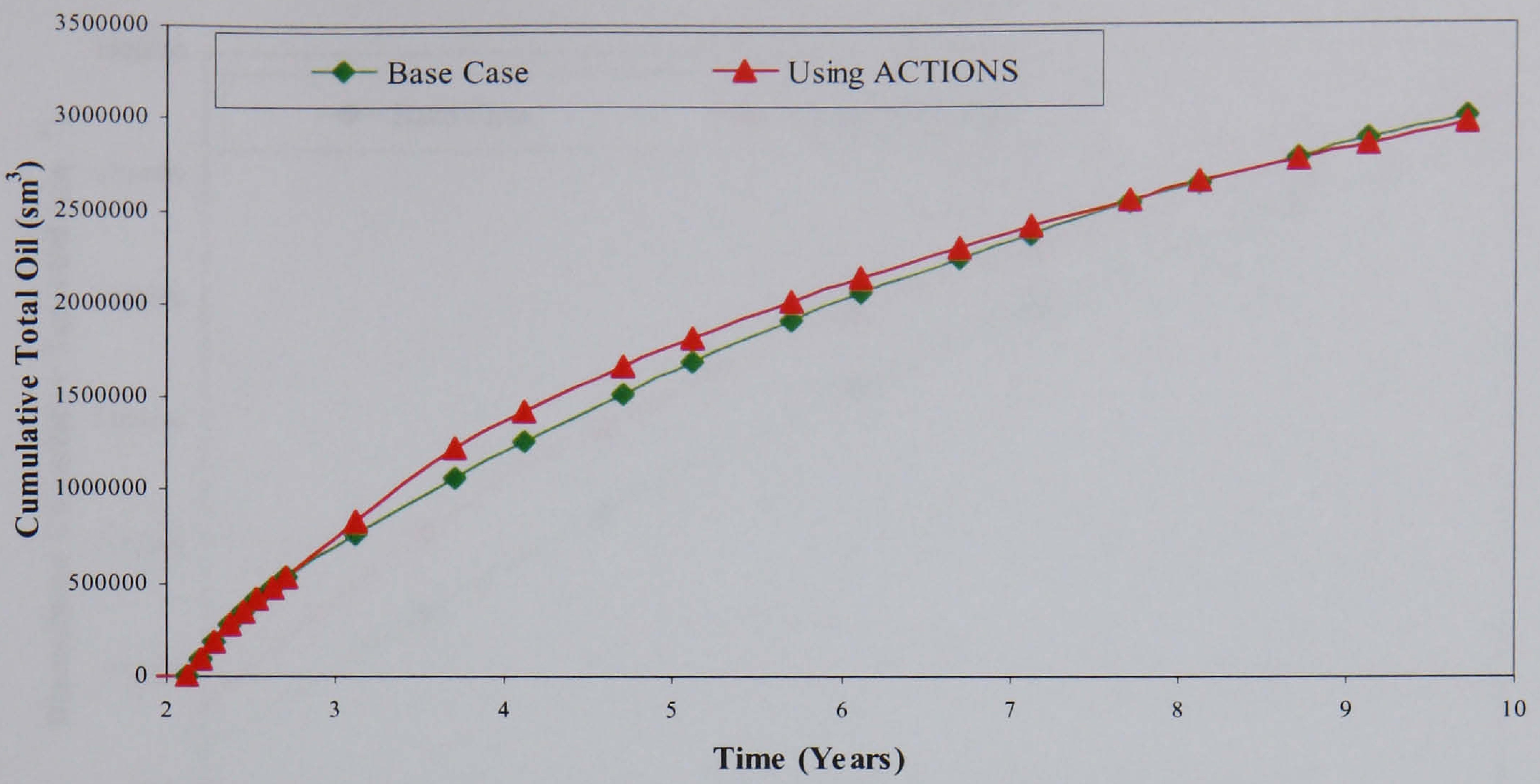


Figure 4.2.13 Performance of the well (Cumulative Total Oil) with and without use of the control valves

Figure 4.2.13 shows that ACTIONS achieves a significant increase in the total oil production compared to the case with the ICVs fully open. The value of this early oil is increased further once it is discounted (a factor of 10% per year is applied in Figure 4.2.14).

An increased number of ICVs did not improve the ability to control the (unwanted) production of gas. This is attributed to the layered crossflow nature of the reservoir model.

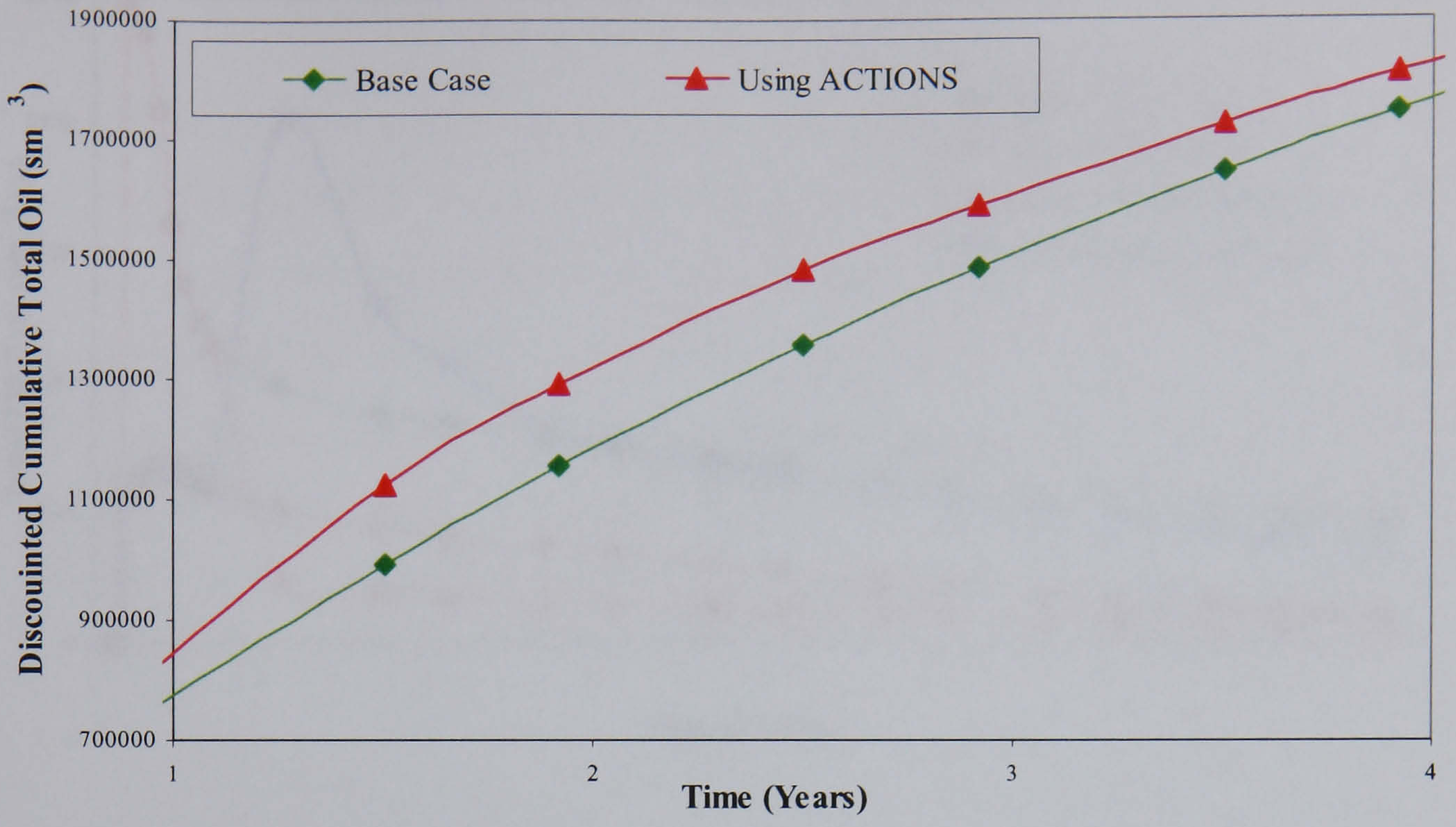


Figure 4.2.14 Performance of the well (discounted at 10% per year cumulative total oil) with and without use of the control valves*

** Time 0 years in this figure is equivalent to 2 years in Figure 4.2.13*

4.2.2.2 Zone performance

Comparing the "with ICV" performance of each zone to the original performance "without ICV" allows one to evaluate in detail what is happening. Figure 4.2.15 shows that choking back zone 1 as it reached the GOR limit allowed more oil to be produced from zone 2. This continued for some time until the oil production decreases again as the gas production increased. It was decided to adjust the zone performance so that they both produce at the same GOR. This is expected to maximise the net oil production by decreasing the excessive gas being produced from the heel. This was successfully achieved; Figure 4.2.16 shows that the two zones are producing at the same GOR by setting the ICVs to different positions.

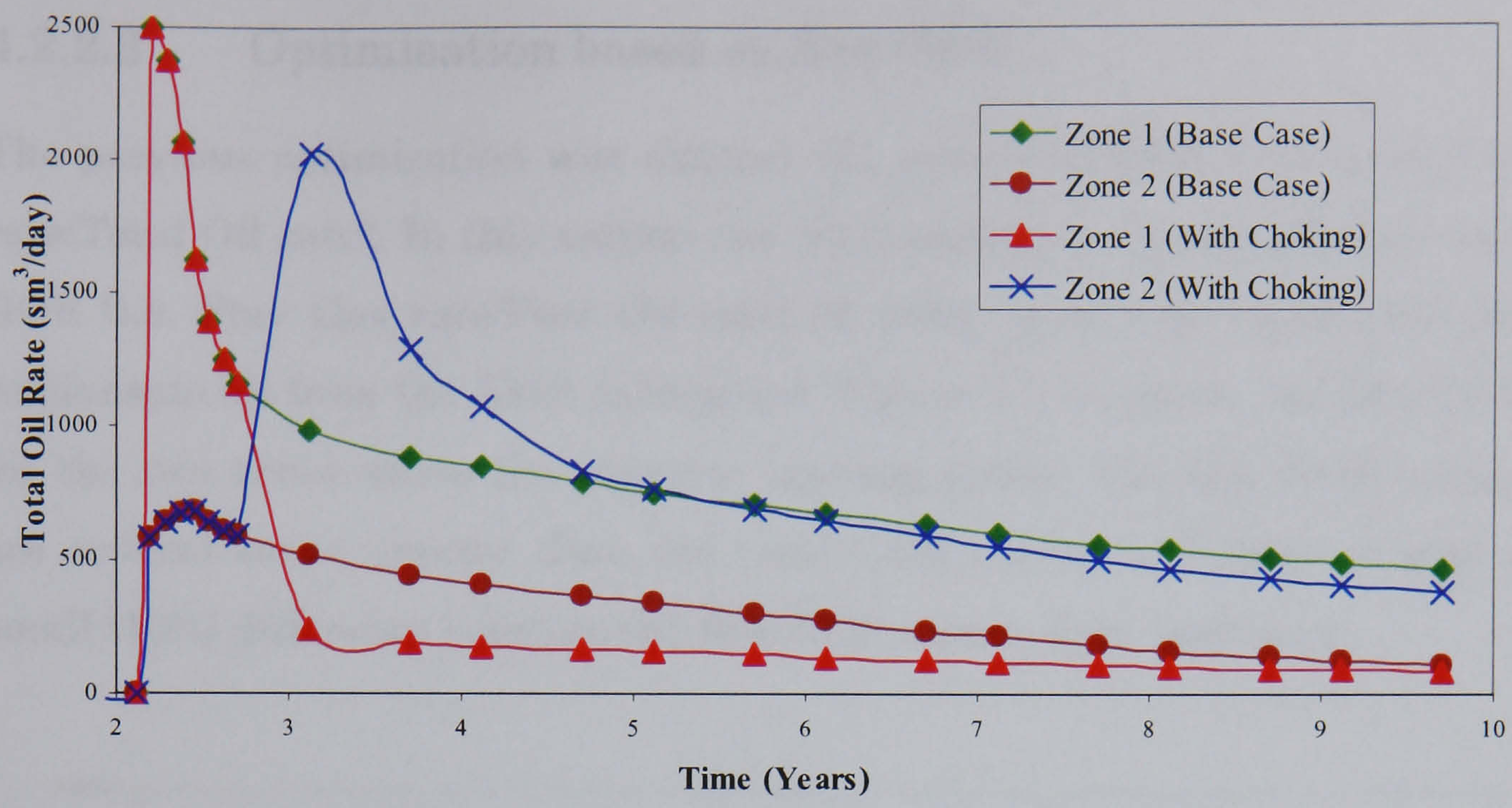


Figure 4.2.15 Zone Performance (total oil rate) with and without use of ICVs.

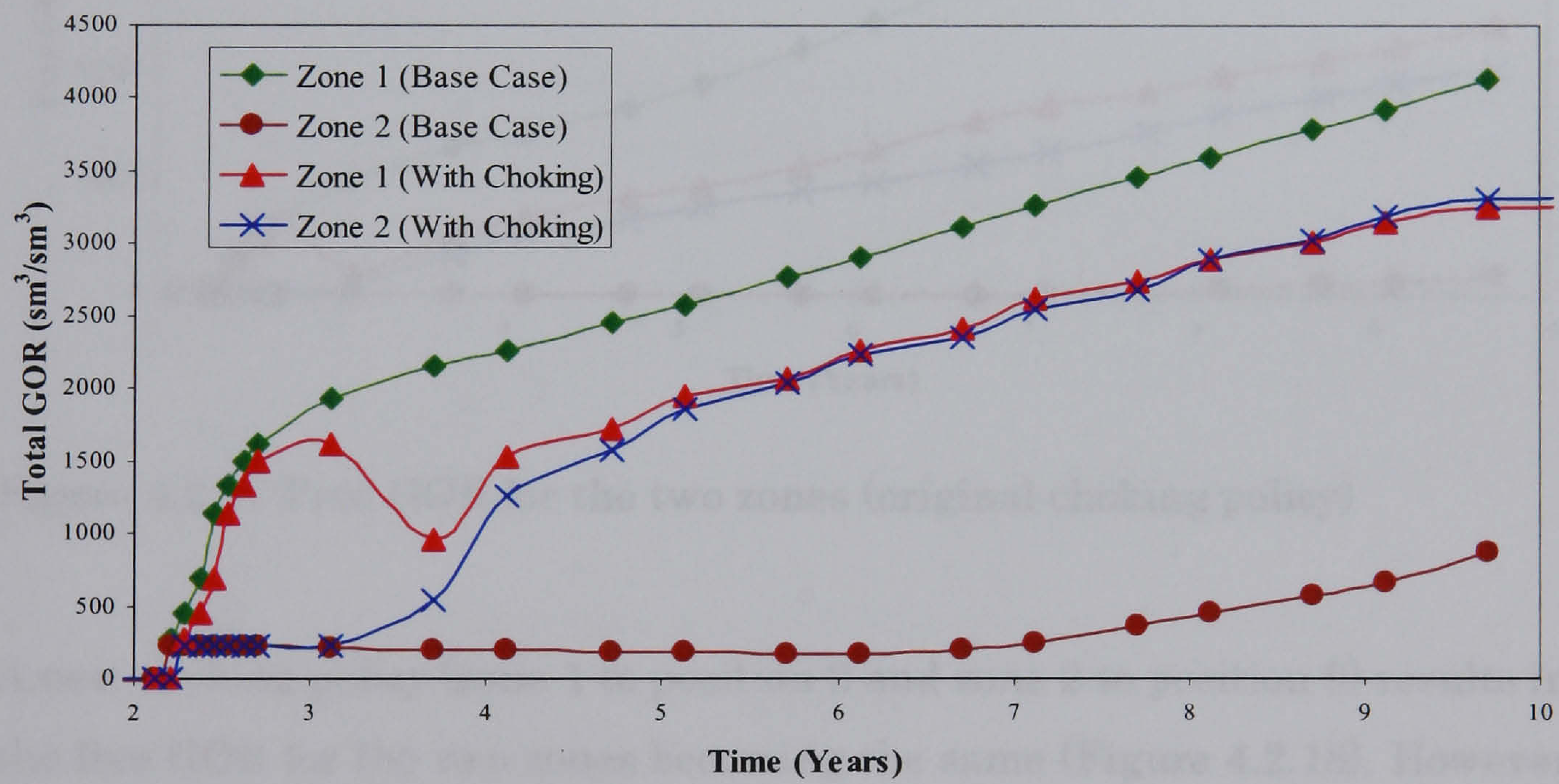


Figure 4.2.16 Zone Performance (total GOR) with and without use of ICVs.

4.2.2.3 Optimisation based on free GOR

The previous optimisation was against the total well GOR (i.e. Total Gas rate/Total Oil rate). In this section the optimisation is against the free well GOR (i.e. Free Gas rate/Free Oil rate) in order to be able to exclude the condensate oil from the GOR calculation. Figure 4.2.17 shows the free GOR for the two zones using the previous choking policy. The free GOR values are several times greater than the total GOR values and there is now a small (10%) difference between the free GOR values from each zone.

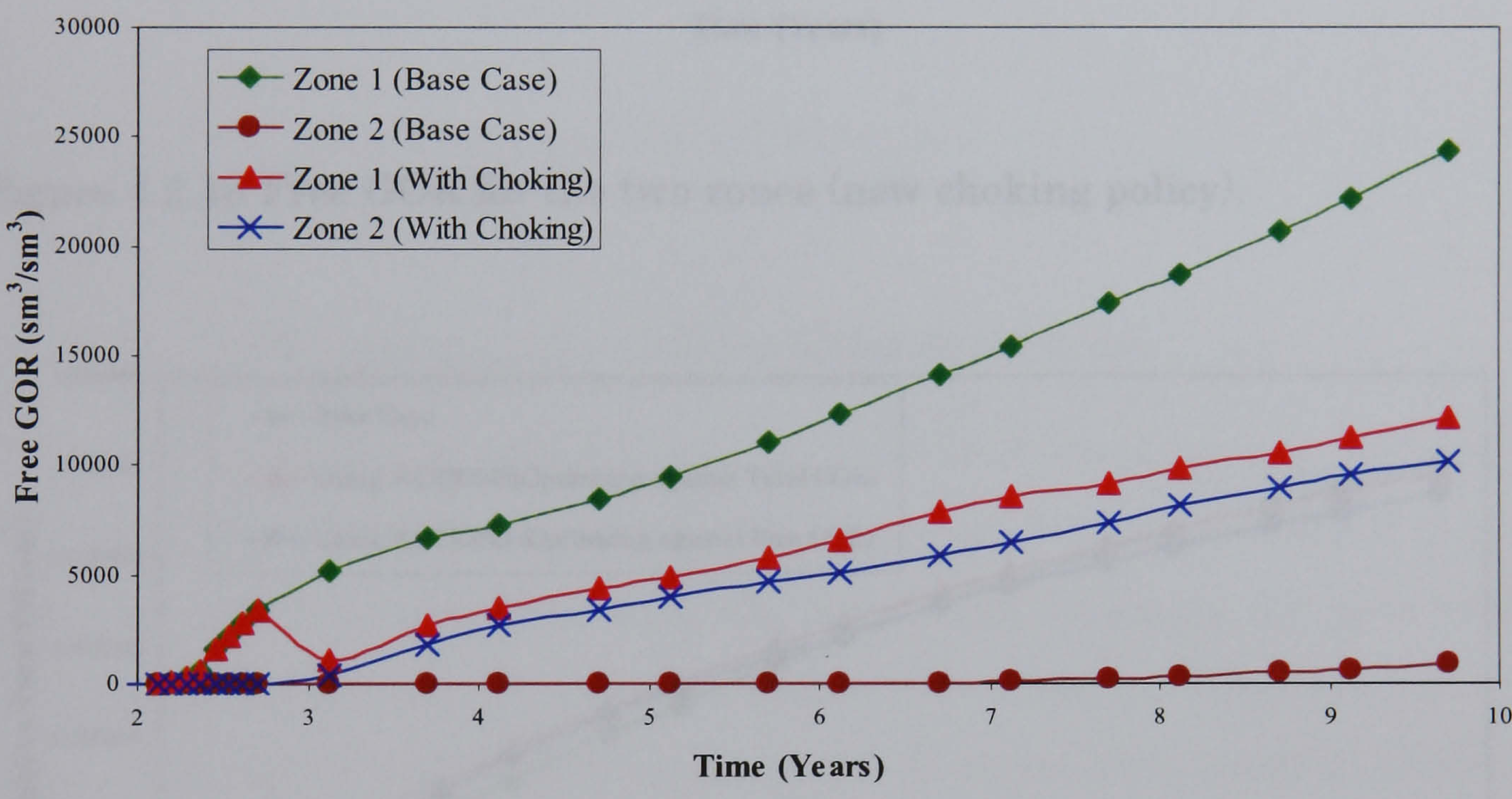


Figure 4.2.17 Free GOR for the two zones (original choking policy)

A new choking policy (zone 1 to position 2 and zone 2 to position 9) results in the free GOR for the two zones becoming the same (Figure 4.2.18). However the total cumulative oil decreases compared to the base case (Figure 4.2.19). This is because optimising the free oil production alone is not sufficient – the (vaporized) stock tank oil production becomes greater than the free oil production after the well has been producing for 30 months (Figure 4.2.20).

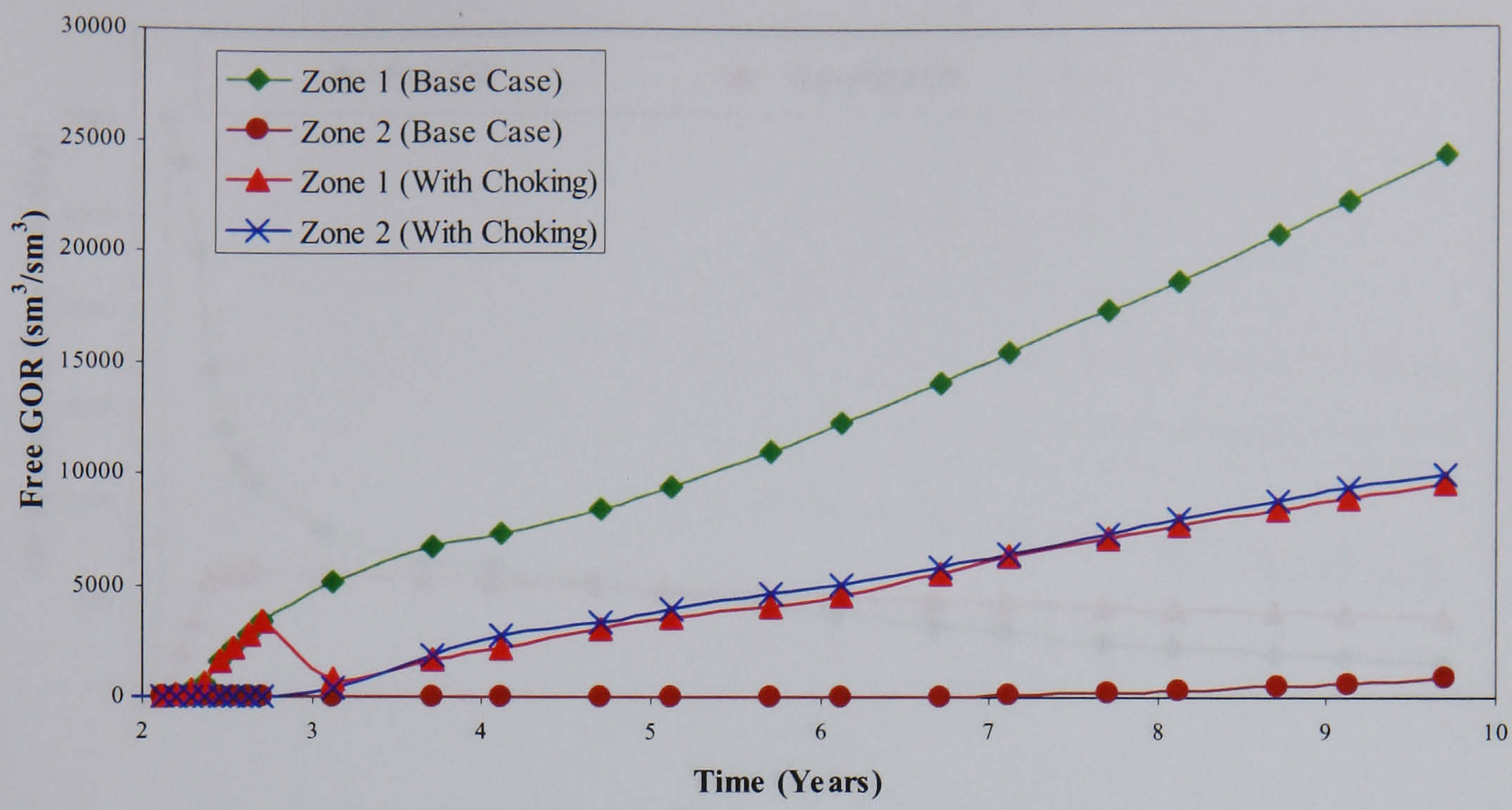


Figure 4.2.18 Free GOR for the two zones (new choking policy).

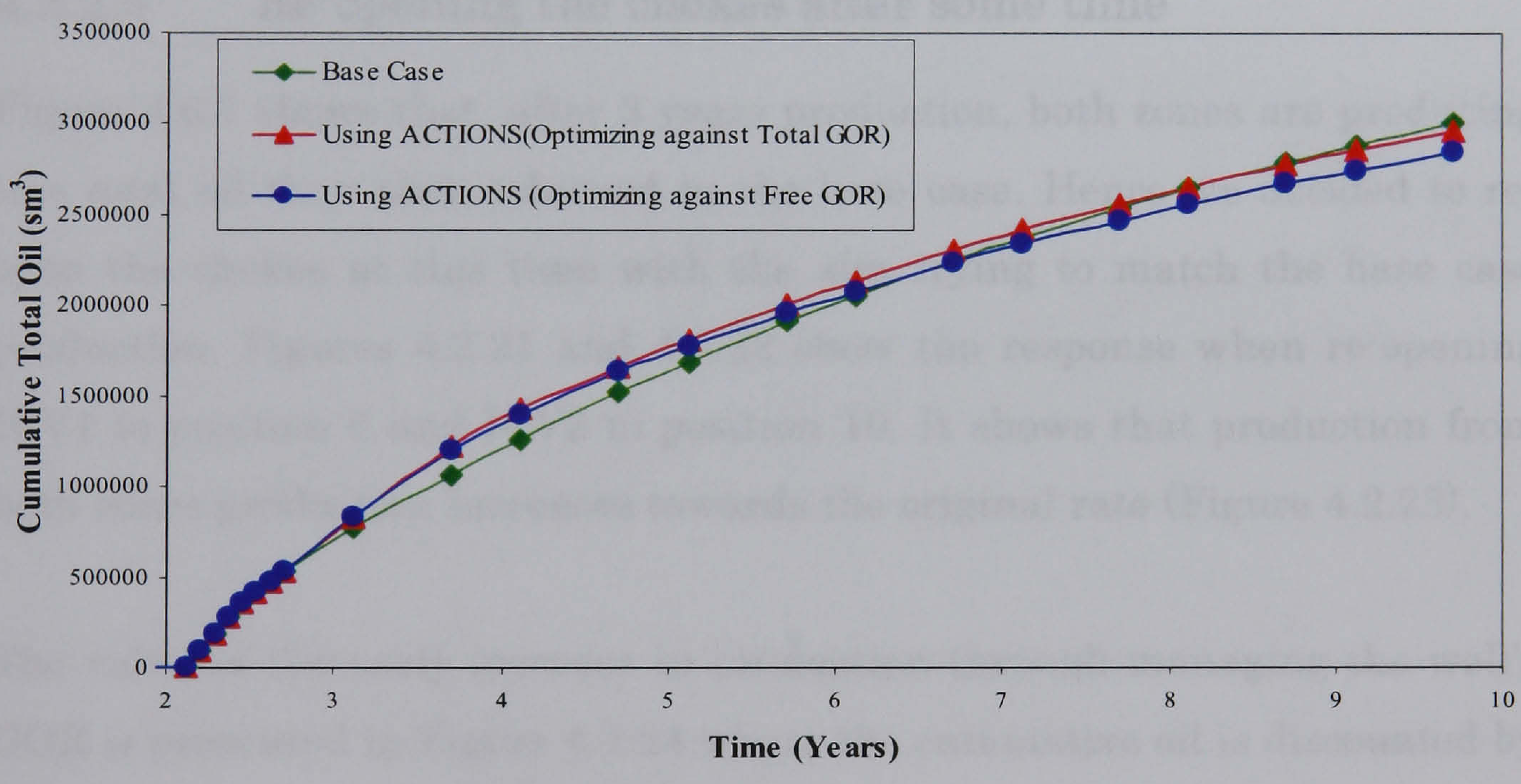


Figure 4.2.19 Cumulative total oil (base case and for the two different choking policies)

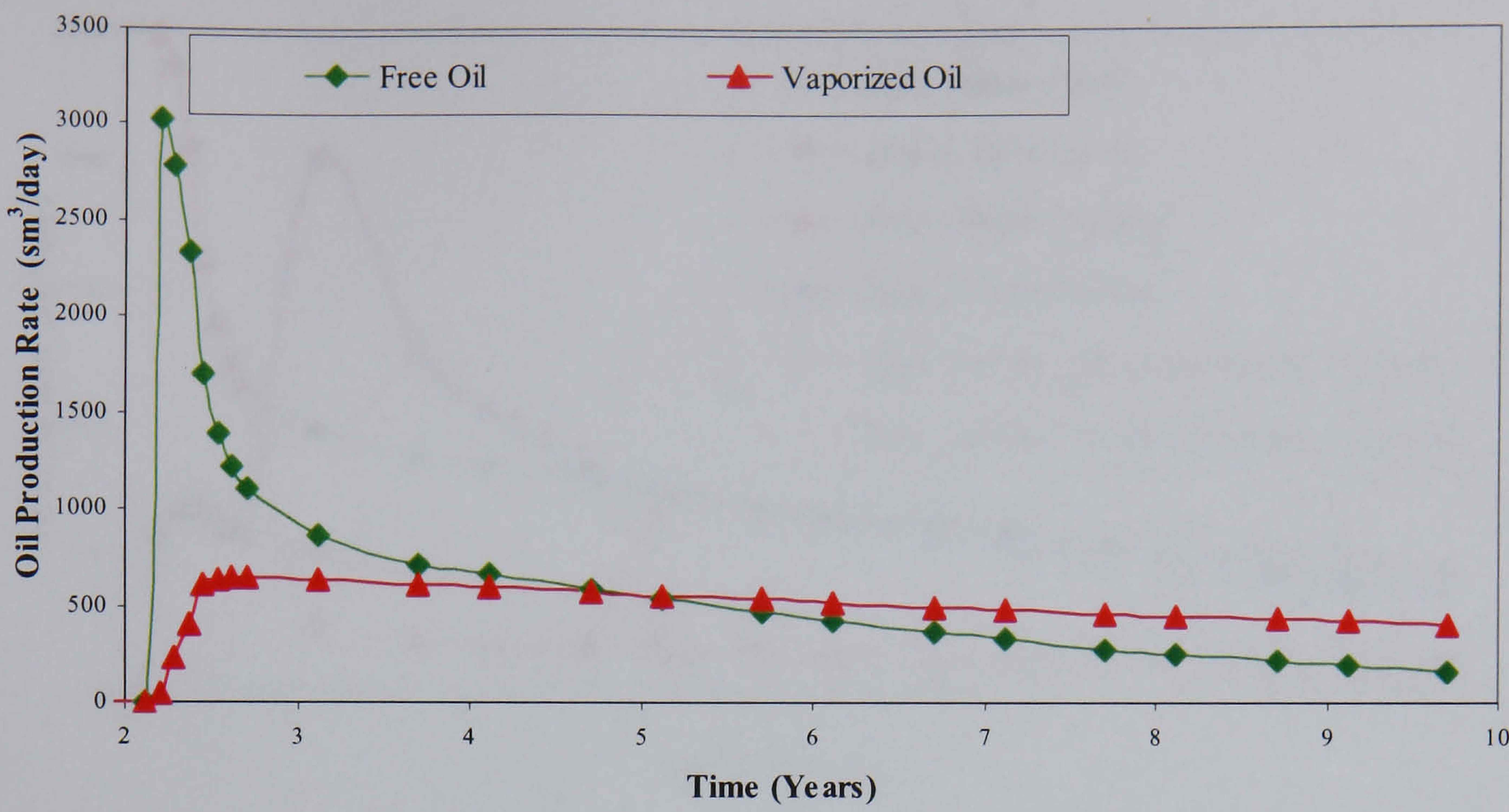


Figure 4.2.20 Free oil vs. vaporized oil with time

4.2.2.4 Re-opening the chokes after some time

Figure 4.6.7 shows that, after 3 years production, both zones are producing less total oil than they achieved in the base case. Hence we decided to re-open the chokes at this time with the aim trying to match the base case production. Figures 4.2.21 and 4.2.22 show the response when re-opening ICV1 to position 6 and ICV2 to position 10. It shows that production from both zones production increases towards the original rate (Figure 4.2.23).

The value of the early increase in production through managing the well's GOR is presented in Figure 4.2.24 where the cumulative oil is discounted by 10% per year.

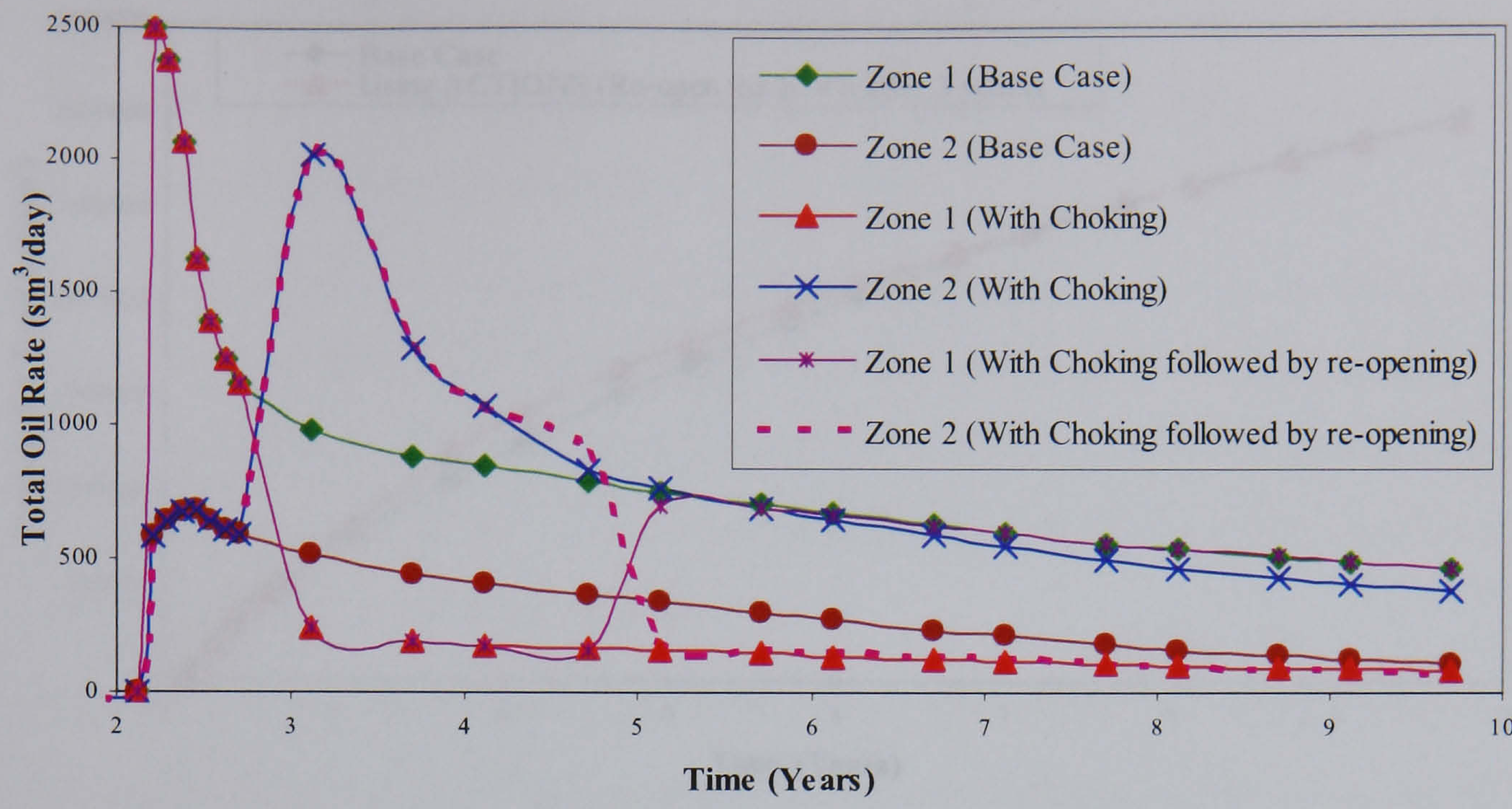


Figure 4.2.21 Zone performance (total oil rate) - the impact of re-opening the ICVs after 3 years production.

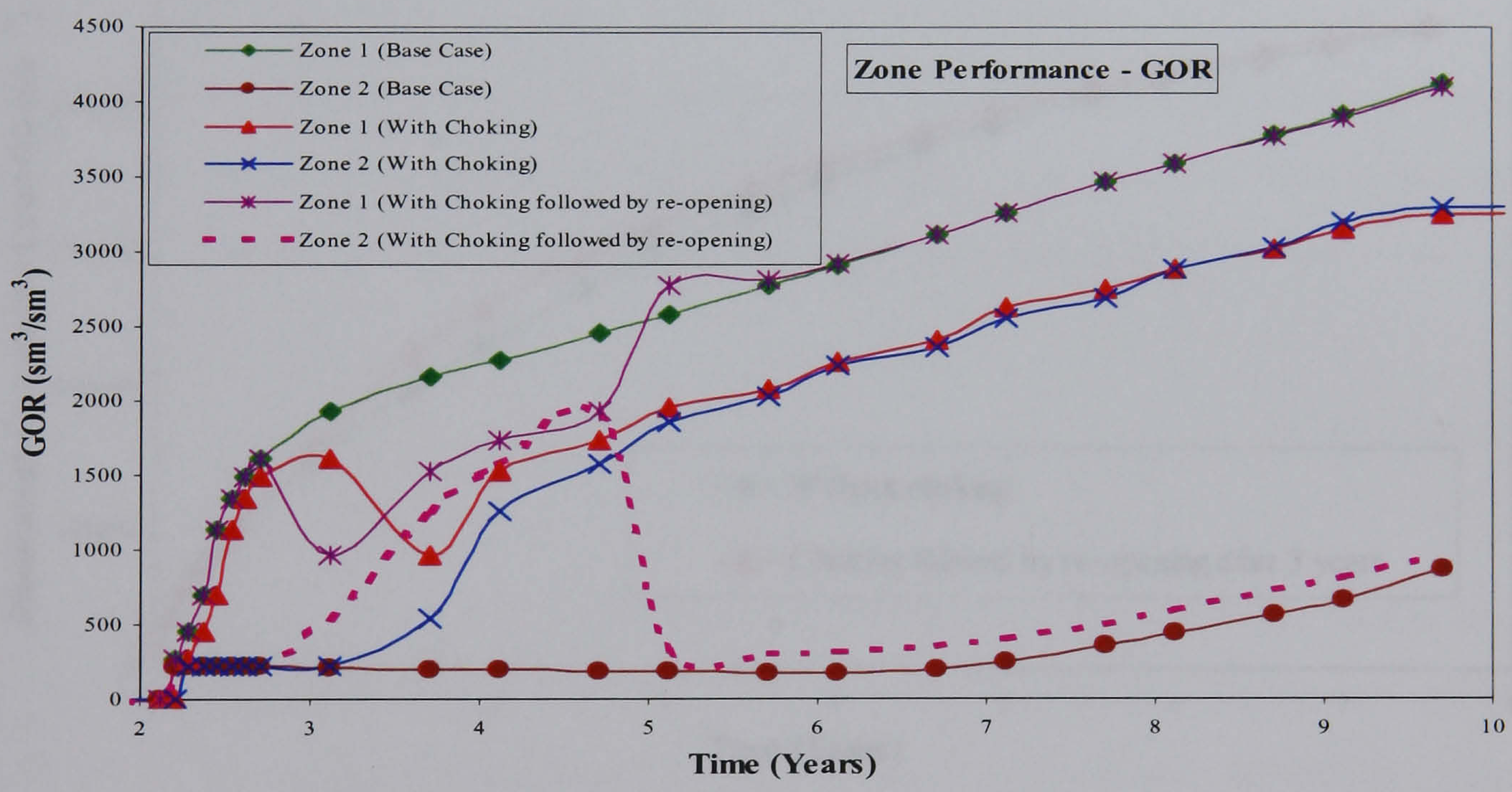


Figure 4.2.22 Zone performance (total GOR) - the impact of re-opening the ICVs after 3 years production

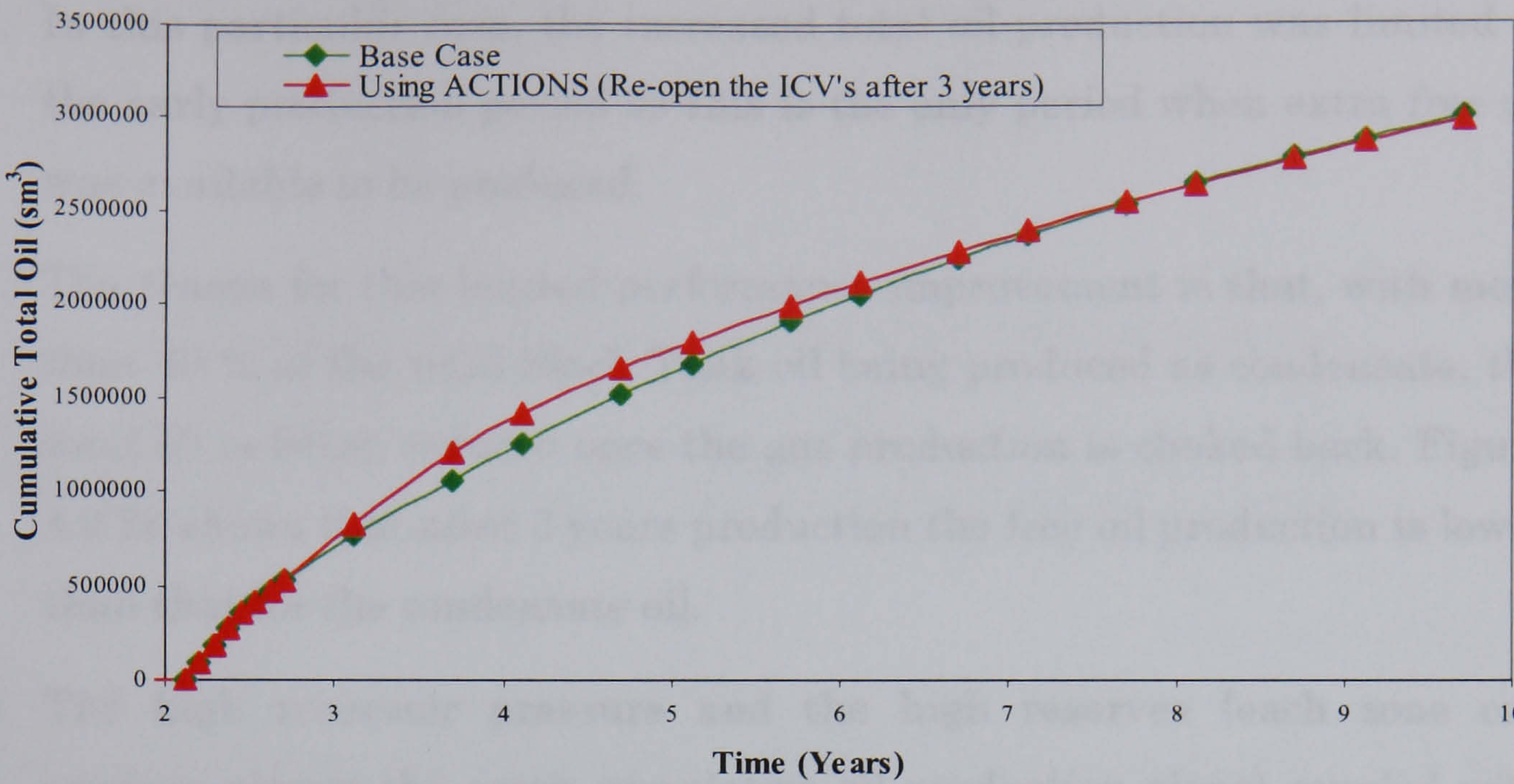


Figure 4.2.23 The well performance (cumulative total oil) by re-opening the valves after 3 years

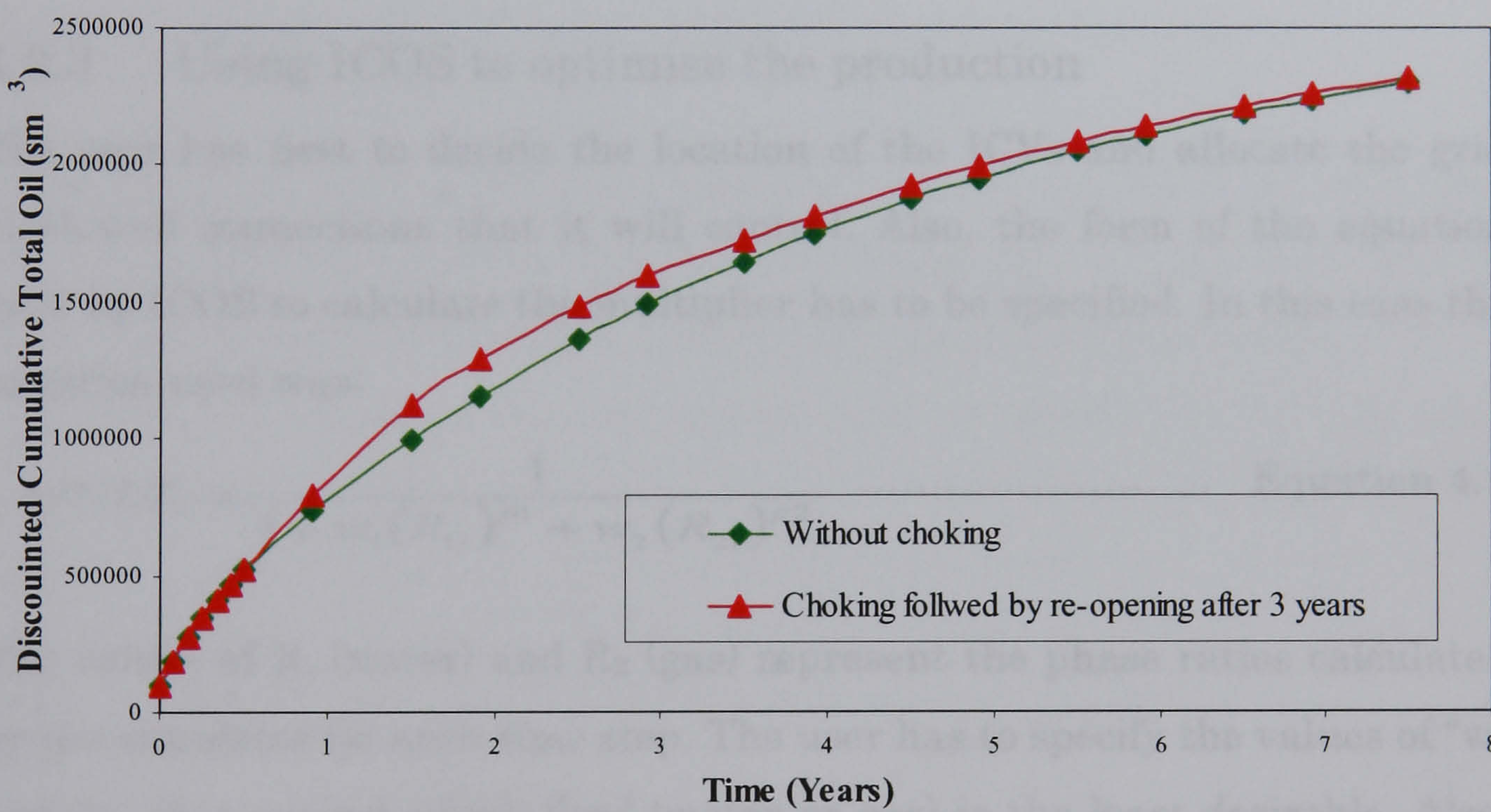


Figure 4.2.24 The well performance (cumulative total oil discounted @10% per years) by re-opening the valves after 3 years

4.2.2.5 ACTIONS optimisation results

1. Use of ACTIONS allowed optimisation of production from the two zones. This increased the cumulative oil production in the early time while allowing both zones to produce at the same GOR.

2. In this particular case, the increased total oil production was limited to the early production period as this is the only period when extra free oil was available to be produced.
3. The reason for this limited performance improvement is that, with more than 40 % of the total Stock Tank oil being produced as condensate, the total oil is being reduced once the gas production is choked back. Figure 4.2.20 shows that after 3 years production the free oil production is lower than that for the condensate oil.
4. The high reservoir pressure and the high reserves (each zone can produce almost the same cumulative oil production alone) coupled with complex fluid properties and the crossflow nature of the layers limit the potential for optimisation for this particular case.

4.2.3 Using ICOS to optimise the production

The user has first to decide the location of the ICVs and allocate the grid block/well connections that it will control. Also, the form of the equation used by ICOS to calculate the multiplier has to be specified. In this case the equation used was:

$$MULT_i = \frac{1}{1 + w_1 (R_{1i})^{p1} + w_2 (R_{2i})^{p2}} \quad \text{.......................... Equation 4.1}$$

The values of R_1 (water) and R_2 (gas) represent the phase ratios calculated by the simulator for each time step. The user has to specify the values of "w" and "p" that control which fluid (water or gas) is the least desirable. Also, they control the value to which the valve will be choked (as the value increases the choking will be harder). ICOS will calculate $MULT_i$ for each ICV followed by a normalisation process to ensure that one valve, which has the lowest $MULT_i$ value, remains fully open (i.e. $MULT_i$ = 1 after normalisation). The choking of the other ICV is then related to this new value of $MULT_i$.

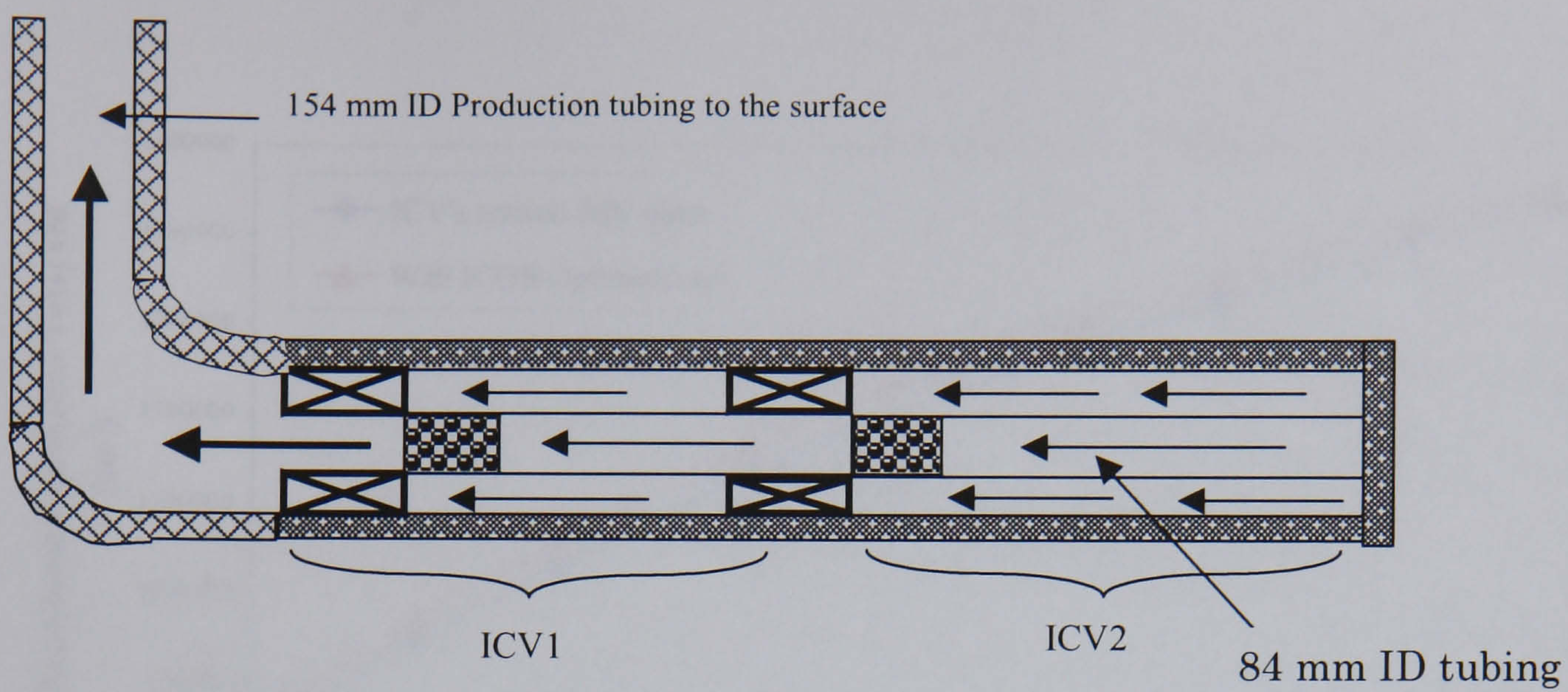


Figure 4.2.25 The well completion required by ICOS to simulate 2 ICV well completion showing that the smaller diameter is extended to the end

Figure 4.2.25 shows the well completion used for the ICOS runs. The diameter of 84 mm ID tubing is extended to the end of the well.

Figures 4.2.26 and 4.2.27 show the performance of the well with and without ICOS optimisation. The default values for "w" (0.5) and "p"(1.5) were used. It can be seen that ICOS correctly identifies that choking of ICV1 is required to increase the cumulative total oil production as this zone produces the most gas.

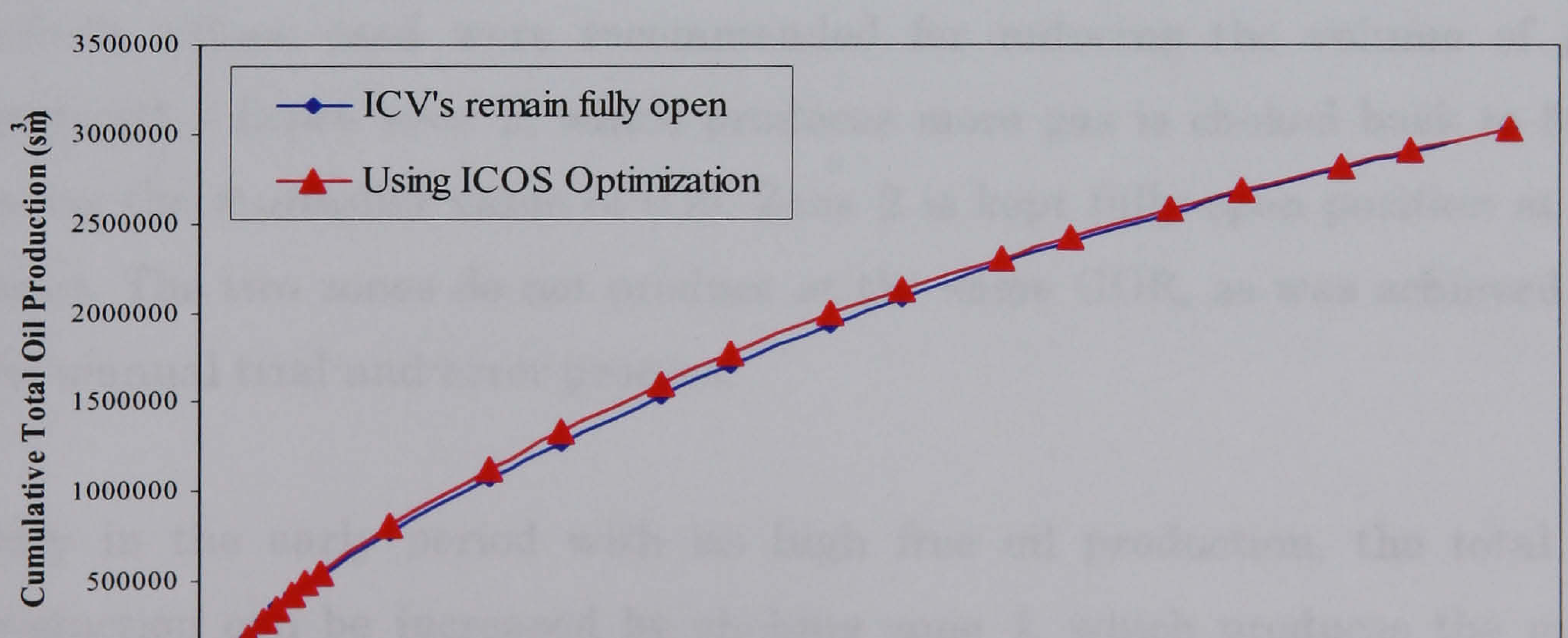


Figure 4.2.26 Performance of the well (cumulative total oil) with and without use of ICOS optimisation

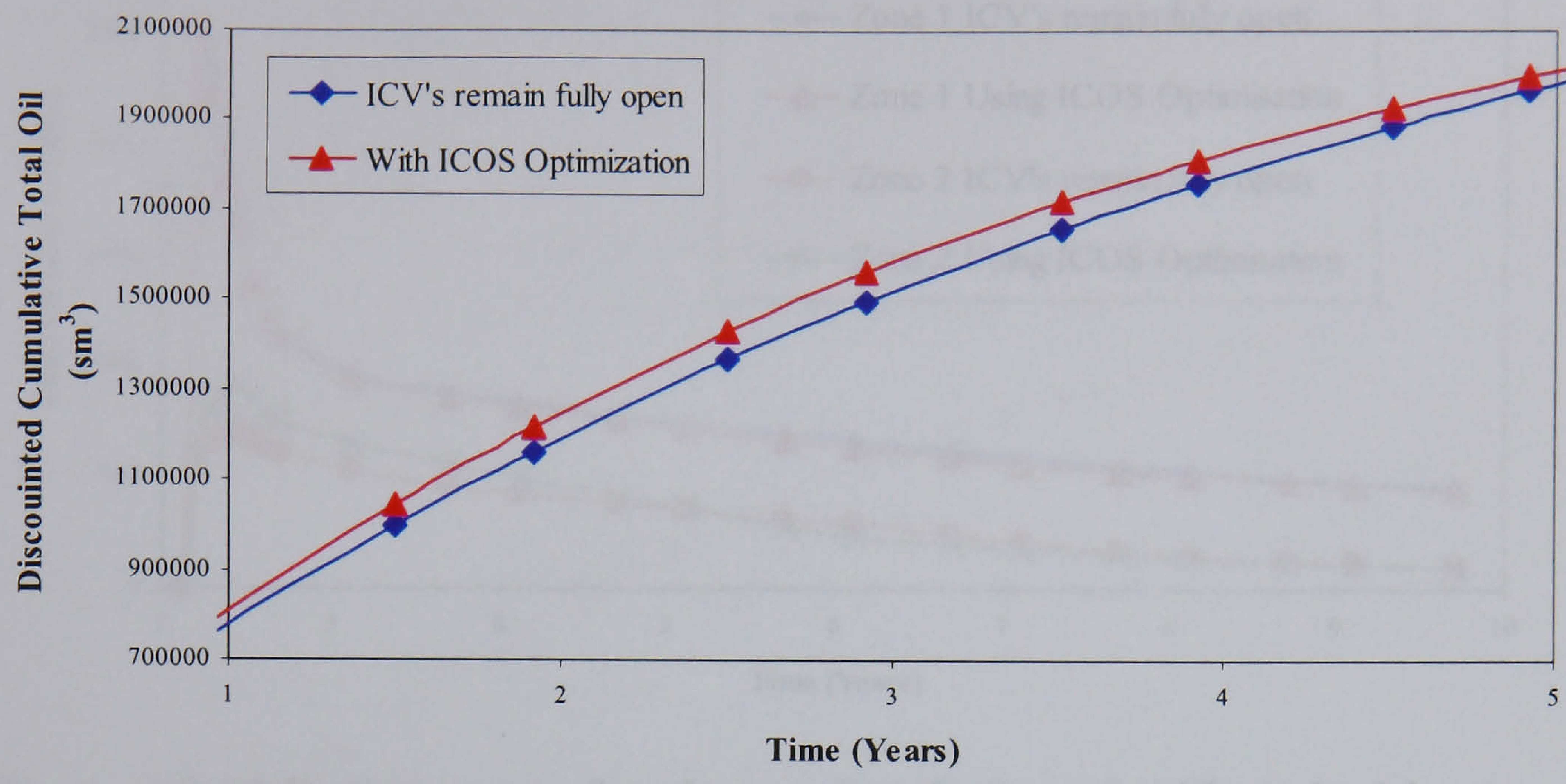


Figure 4.2.27 Performance of the well (discounted at 10% per year - cumulative total oil) with and without use of ICOS optimisation*

- *Time 0 years in this figure is equivalent to 2 years in Figure 4.2.26*

4.2.3.1 Zone performance

Figures 4.2.28 and 4.2.29 show the performance of each zone separately. They show the reaction of zone two when choking zone one, and hence help to understand the degree of communication between the different zones. The default values used were recommended for reducing the volume of gas produced – hence zone 1, which produces more gas is choked back to 80% (using the multiplier value of 0.2). Zone 2 is kept fully open position at all times. The two zones do not produce at the same GOR, as was achieved by the manual trial-and-error process.

Only in the early period with its high free oil production, the total oil production can be increased by choking zone 1, which produces the most gas. The opportunity to increase the total oil production becomes less once the vaporized oil production becomes the major source of total oil production. (Figure 4.2.20 showed the relation between the free and vaporized oil with time).

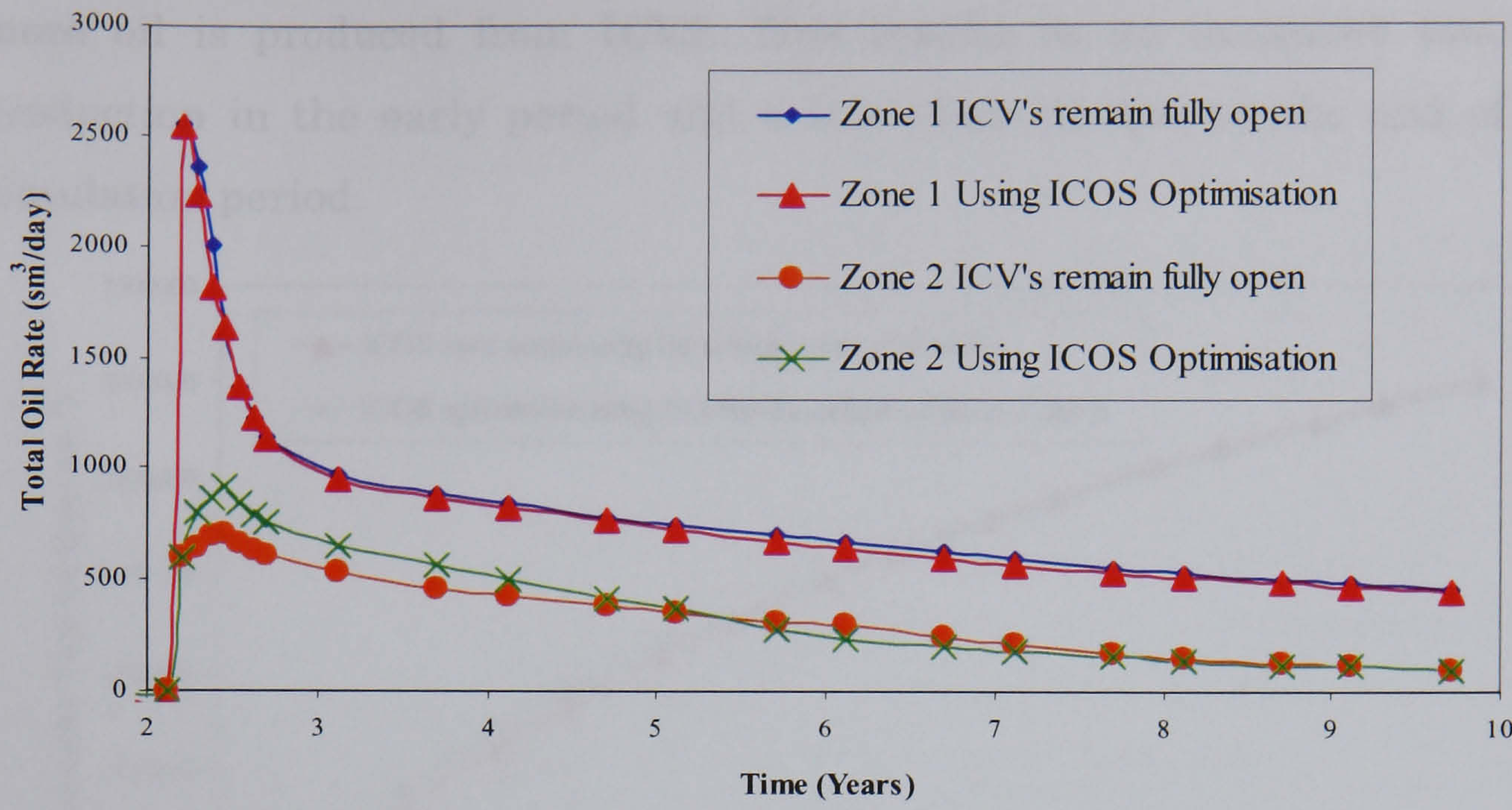


Figure 4.2.28 Performance of each zone (total oil rate) with and without use of ICOS

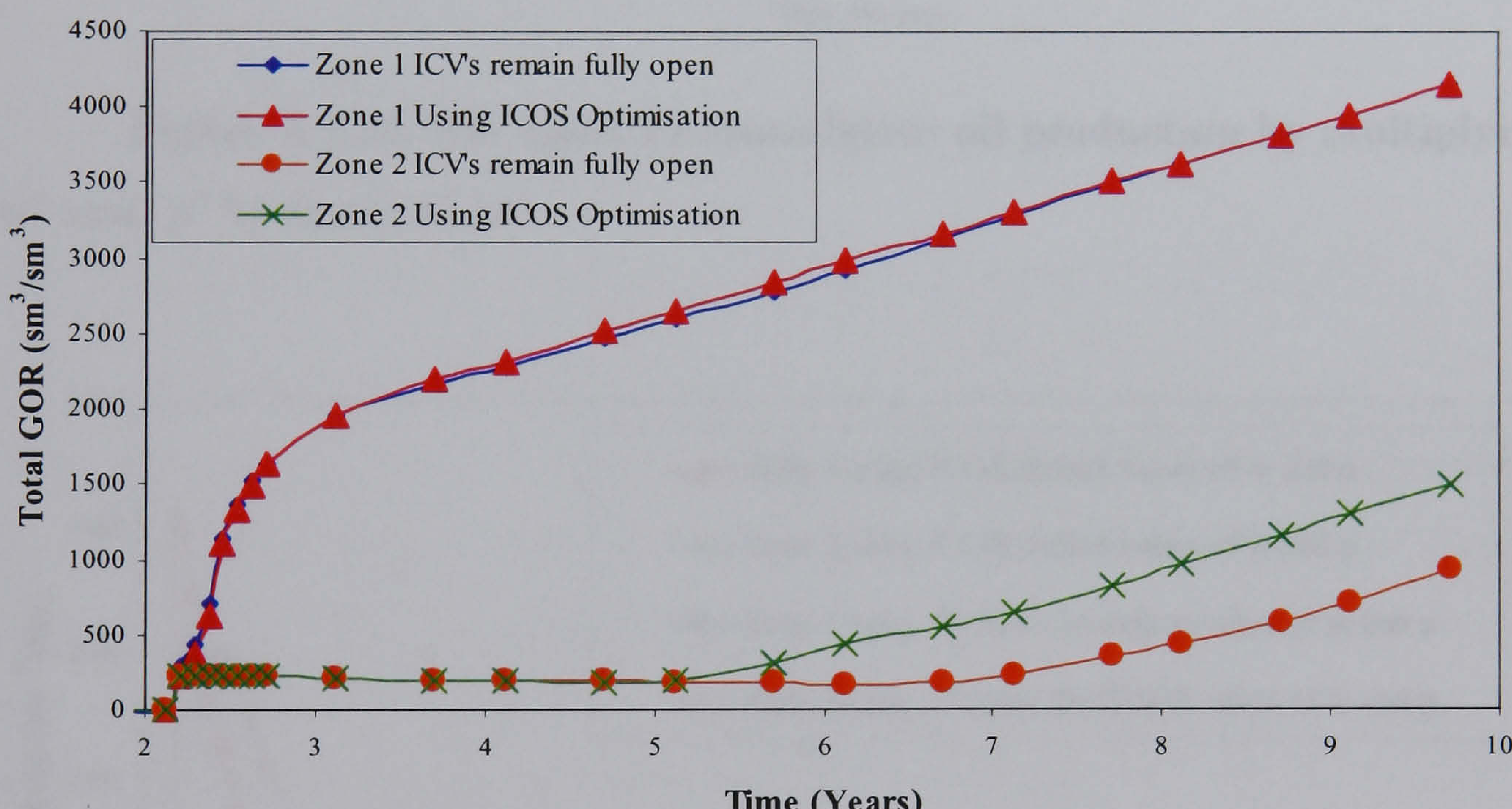


Figure 4.2.29 Performance of each zone (total GOR) with and without ICOS

4.2.3.2 The effect of greater choking of the gas phase

The default values of "w" (0.5) and "p" (1.5) were used in the previous section; more severe choking of the ICV can be achieved by specifying larger values. Figures 4.2.30 and 4.2.31 show the results of increasing "w" and "p" to 10 times greater than the default values. ICV1 is now choked harder so more oil is produced from ICV2. This results in an increased total oil production in the early period and a less than 1% loss by the end of the simulation period.

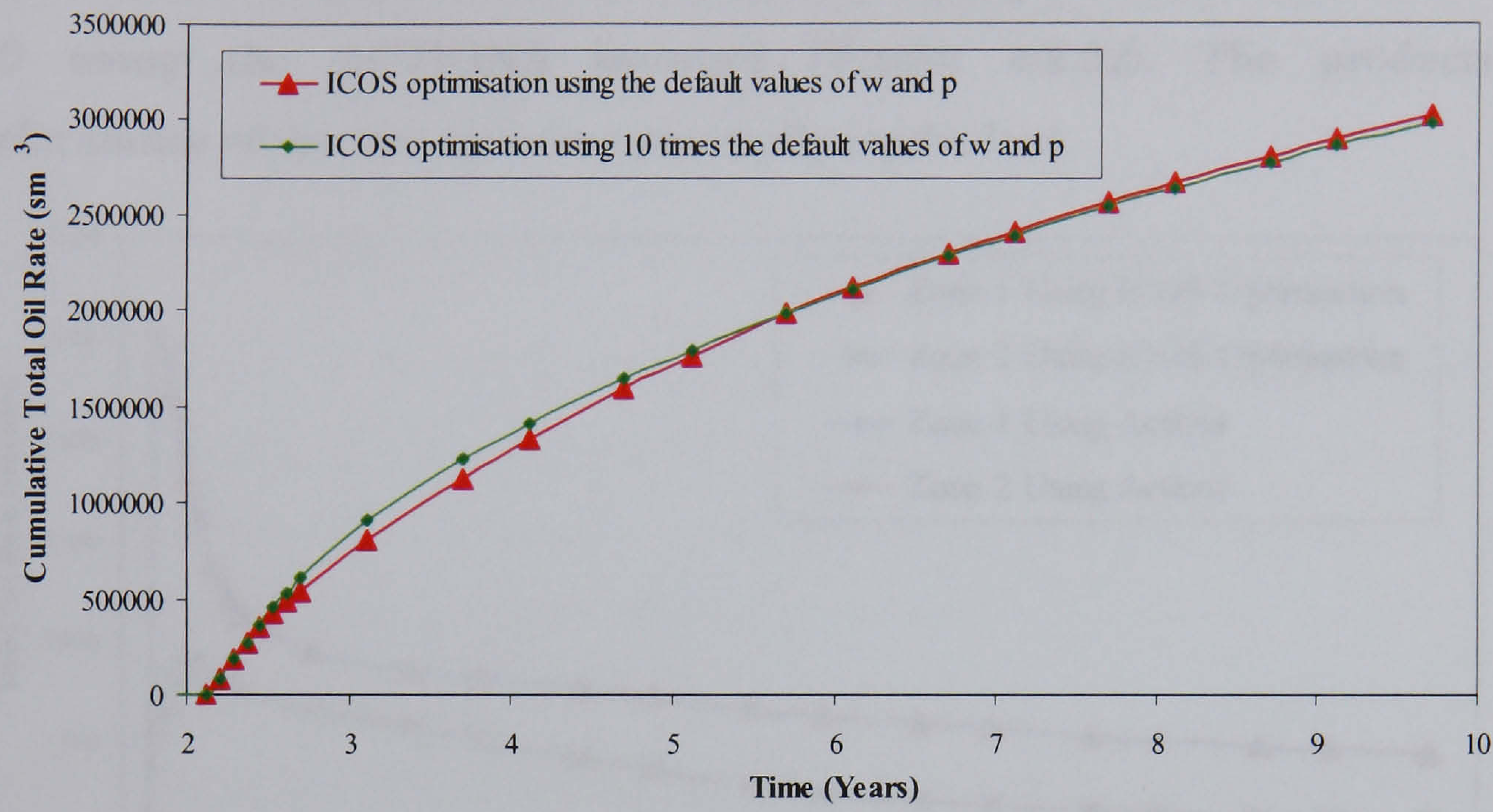


Figure 4.2.30 The effect on cumulative oil production by multiplying "w" and "p" by factor of 10

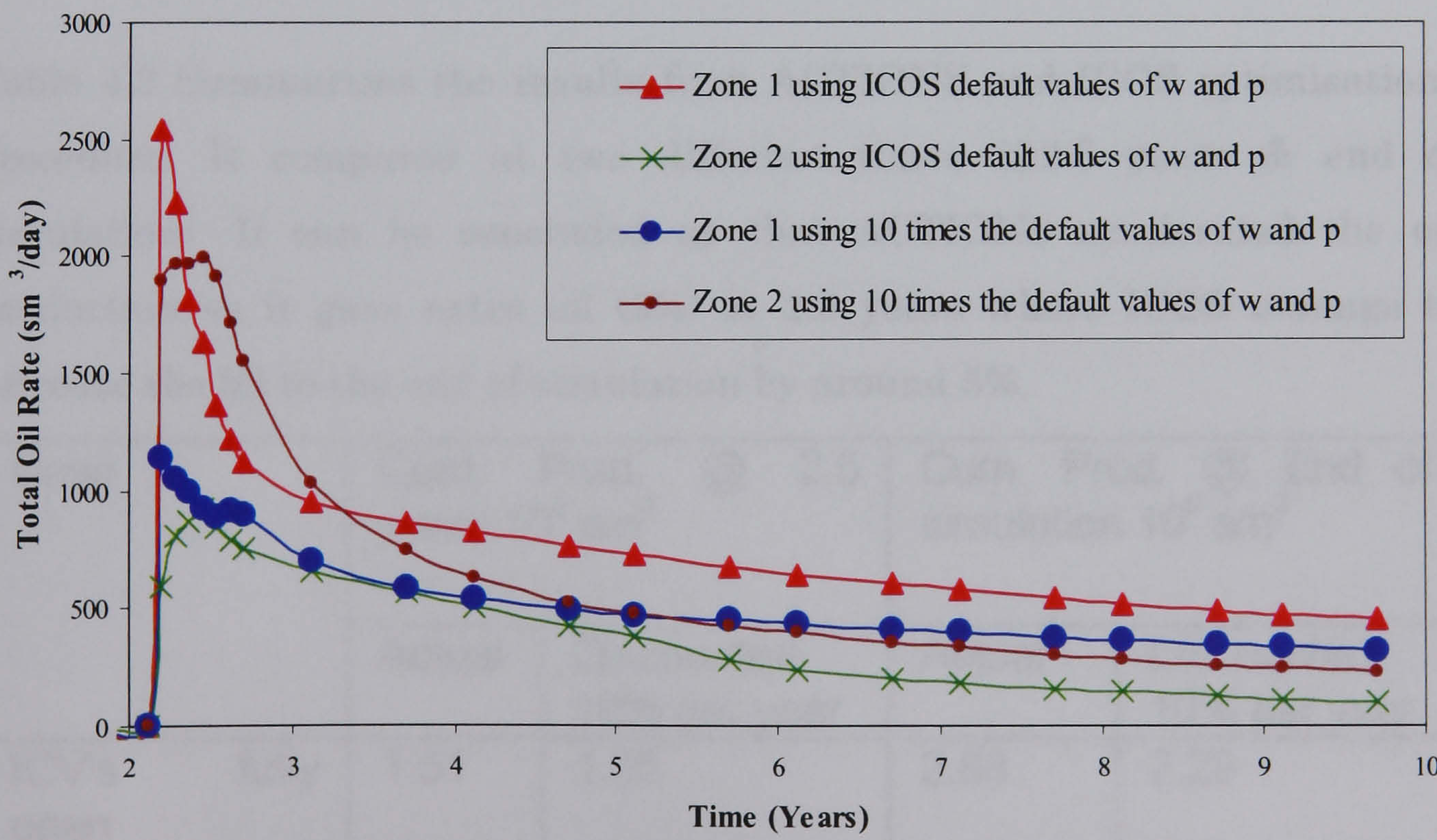


Figure 4.2.31 The effect on zonal oil production by multiplying "w" and "p" by factor of 10.

4.2.3.3 Guidance on use of ACTIONS vs. ICOS

For this case, ICOS automatic optimisation is equivalent to choking ICV1 to a cross sectional area of 4.65 in² (value between position 10 and 11 Table 4.2) using the ACTIONS keyword (Figure 4.2.32). The production performance of the two cases is essentially equivalent.

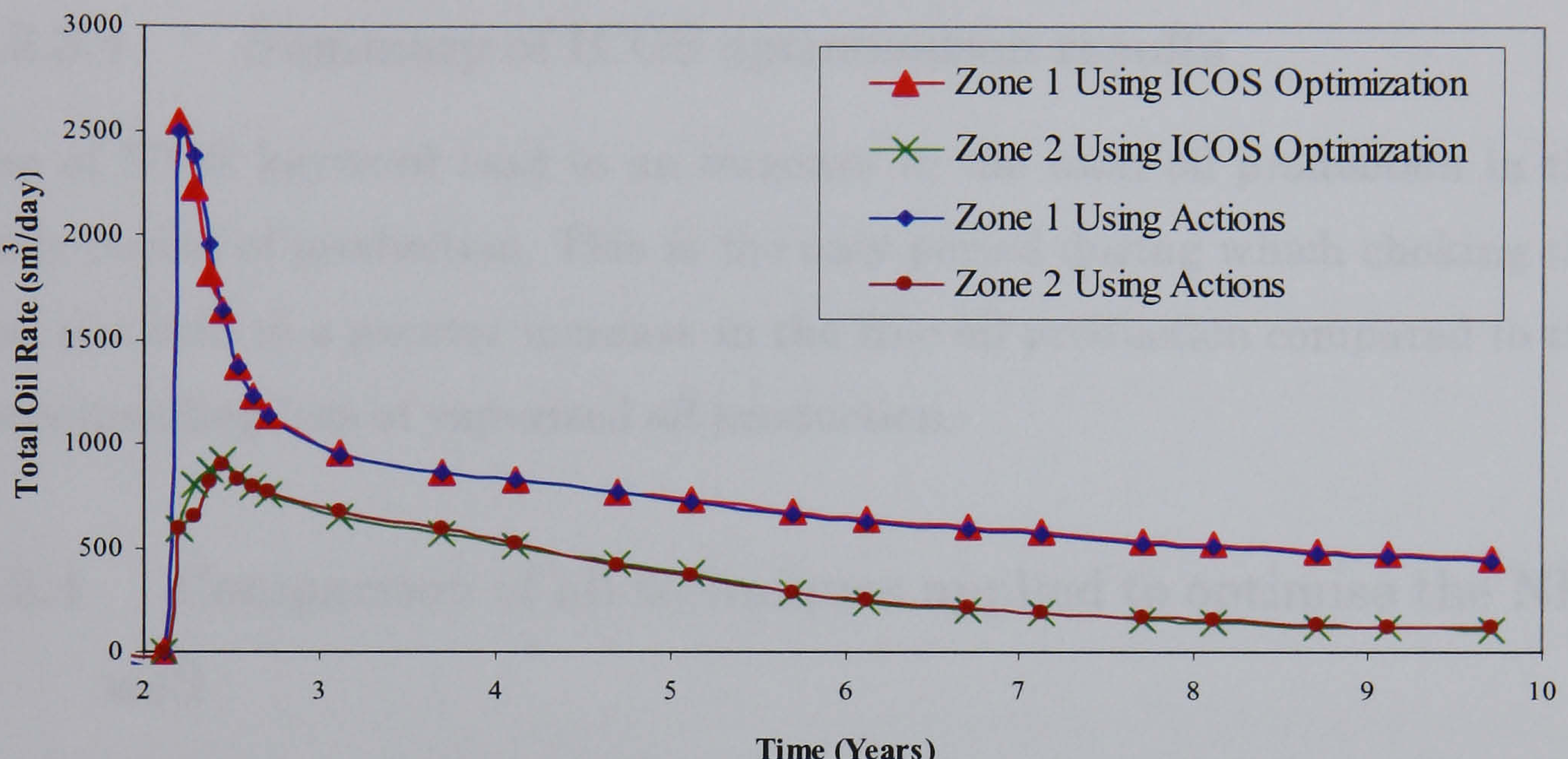


Figure 4.2.32 Comparison between ICOS and ACTIONS optimisations

Table 4.3 Summarises the results from ACTIONS and ICOS optimisations procedure. It compared at two different times (@2.5 years & end of simulation). It can be concluded as that ACTIONS accelerated the oil production as it gave extra oil (9%) at 2.5 years where ICOS manage to increase the oil to the end of simulation by around 5%.

Case	Cum. Prod. @ 2.5 years 10^6 sm^3		Cum. Prod. @ End of simulation 10^6 sm^3	
	Actual	Discounted 10% per year	Actual	Discounted 10% per year
ICV's fully open	1.51	1.35	2.88	2.29
ACTIONS	1.65	1.48	3.00	2.31
ICOS	1.59	1.43	3.02	2.33

Table 4.3 Comparison between ACTIONS and ICOS optimisation results

Generally, ICOS and ACTIONS are essentially using the same approach of modelling ICVs, however the automatic calculation of ICOS multiplier give it the ability to optimise greater number of ICVs compared to ACTIONS which become difficult to set rules for optimisation when the number of ICVs is more than two.

4.2.3.4 Summary of ICOS optimisation results

Use of ICOS keyword lead to an increase in the total oil production in the early period of production. This is the only period during which choking the free gas lead to a greater increase in the free oil production compared to the corresponding loss of vaporized oil production.

4.2.4 Comparison of all techniques applied to optimise the NH well

1. All cases gave similar cumulative total oil at the end of the project. Any differences could often be accounted for by the different completions (smaller diameter completions tend to limit gas and hence vaporized oil production). The CAPEX is assumed equal in all the cases.
2. Use of an on/off choke (WECON) did limit water production but also limited the associated free oil.
3. Variable choking (ACTIONS & ICOS) achieved extra free oil production in the early period (giving accelerated project Pay-Back) and was shown to also have the potential to increase the total project oil recovery
4. ACTIONS is potentially more flexible and easier to use than ICOS. The results of using ACTIONS can be understood for a two ICV completion – but this understanding is difficult to achieve for more than two zones. A trial-and-error approach, possibly coupled to a further optimisation process, can then be used.
5. Optimisation of both the ICOS weighting factors & the ACTIONS settings is required. This has to be repeated as these factors & settings change during the project lifetime.

6. It should be remembered that the benefit derived from IWT managing uncertainties in the fluid contact positions and in the geological description has not been accounted for in these calculations.

4.3 Summary

This chapter discuss the application of IWT in one well in a real field example. This application shows limited increase in oil production using IWT compared to the previous publication where the synthetic models were used and high recovery increase was achieved.

1. The value of IWT in thin oil column case studied was limited to the extra oil achieved in the early project life (first 2.5 years) and that was due to the following reasons:
    a. Fluid property of the produced oil, where most of the oil produced after the first 2.5 years was condensate, so choking the downhole gas production will reduce the total oil produced.
    b. Crossflow nature of the reservoir layers prevents the control on each zone independently.
2. Installing the 2 ICVs was beneficial in terms of:
    a. Balancing the drawdown across the horizontal wellbore, which help to produce both zones at the similar GOR.
    b. Reduce the gas production from the hell through the high permeability streak.
3. This study thus present the challenges of this kind or IWT applications and it helps to:
    a. Develop IWT design and operation philosophy,
    b. Illustrate the advantages, disadvantages and utility for well optimisation of available keywords within commercial simulation packages.
    c. Draw recommendations on when to use ACTIONS or ICOS based on the number of ICVs installed. ACTIONS can be used and understood if the number of ICVs is less than two, where ICOS can be used for greater number of ICVs.

Chapter 5

5. Production management in a compacting reservoir using IWT – CT Field case study

This chapter reviews the potential value creation through development of a compacting reservoir using IWT and other techniques compared to the current well development. It discusses how development of the field with optimum well location and completed with IWT completions can deliver more recovery (Elmsallati et al. 2005d).

5.1 Rock compaction review

Rock compaction is the result of increased stresses on the fabric of a weak formation due to the reduction in reservoir pressure resulting from fluid production. The fluid present within the rock pore space partially balances the weight of sediments above the reservoir, so when the production starts and the reservoir pressure reduces, the effective stress acting on the formation. Increasing the formation compaction can seriously damage the producing interval by introducing extra pressure drop due to skin. The example discussed by Charlez (1997) indicates that after 7 months of production rocks can compact up to 0.3 m around the wellbore while the rock is still in the original condition at a distance of 200 m away from the wellbore. The effective stress on the porous material at any point is equal to the external stress applied to the material minus the pore pressure times Biot's coefficient (Equation 5.1).

$$\sigma^1 = \sigma - \alpha p \quad \text{...} \quad \text{Equation 5.1}$$

Where:

σ^1 is the Effective Stress

σ is the Normal Stress

α is Biot's constant. (It can be measured in the laboratory if core material is available)

p is the pore pressure

The flowing consequences from this equation have been discussed in the literature. Soares, et al. (2003) developed a mathematical model for radial oil flow towards wells in a deformable porous media. The solution is in the form of explicit analytical formulae. They applied their model to the R reservoir (Brazil) and compared the results with laboratory data. Petro, et al. (1997) used pressure transit testing to evaluate and understand the characterization of compaction and fines migration in deepwater, turbidite, Gulf of Mexico sand. They used this information to design a successful stimulation treatment.

Comprehensive, rock mechanical data for the permeability reduction due to rock compaction and/or fines migration was measured as a function of effective stress for core material recovered from the CT Field (Chapter 1). The resulting relationship between the pressure depletion and the reduction in permeability was input into the reservoir simulation model (GeoQuest 2002).

5.1.1 Measurements of the compaction in the lab

The reduction in permeability as a function of pressure depletion was measured in the lab using a cleaned core sample, after measuring the initial porosity, permeability and saturations using the "Rate Type Compaction Method" first developed by de Waal and Smits (1998). Here different draw-down rates are simulated by increasing the effective stress at different rates and then estimating the impact of pore volume collapse and deformation on the horizontal permeability as a function of pore pressure. Figure 5.1.1 shows the change in permeability (Transmissibility Multiplier) and pore volume as function of pressure depletion for a core plug from the CT field. It will be seen later that the results are in agreement with those obtained from well pressure transit test; (note that the well test dated 10th May 2001 gave an anomalously high value compared to the lab results Figure 5.1.1). Rock compaction option will be modelled as a combined Transmissibility and Pore volume multiplier using the appropriate Eclipse keyword (ROCKTAB).

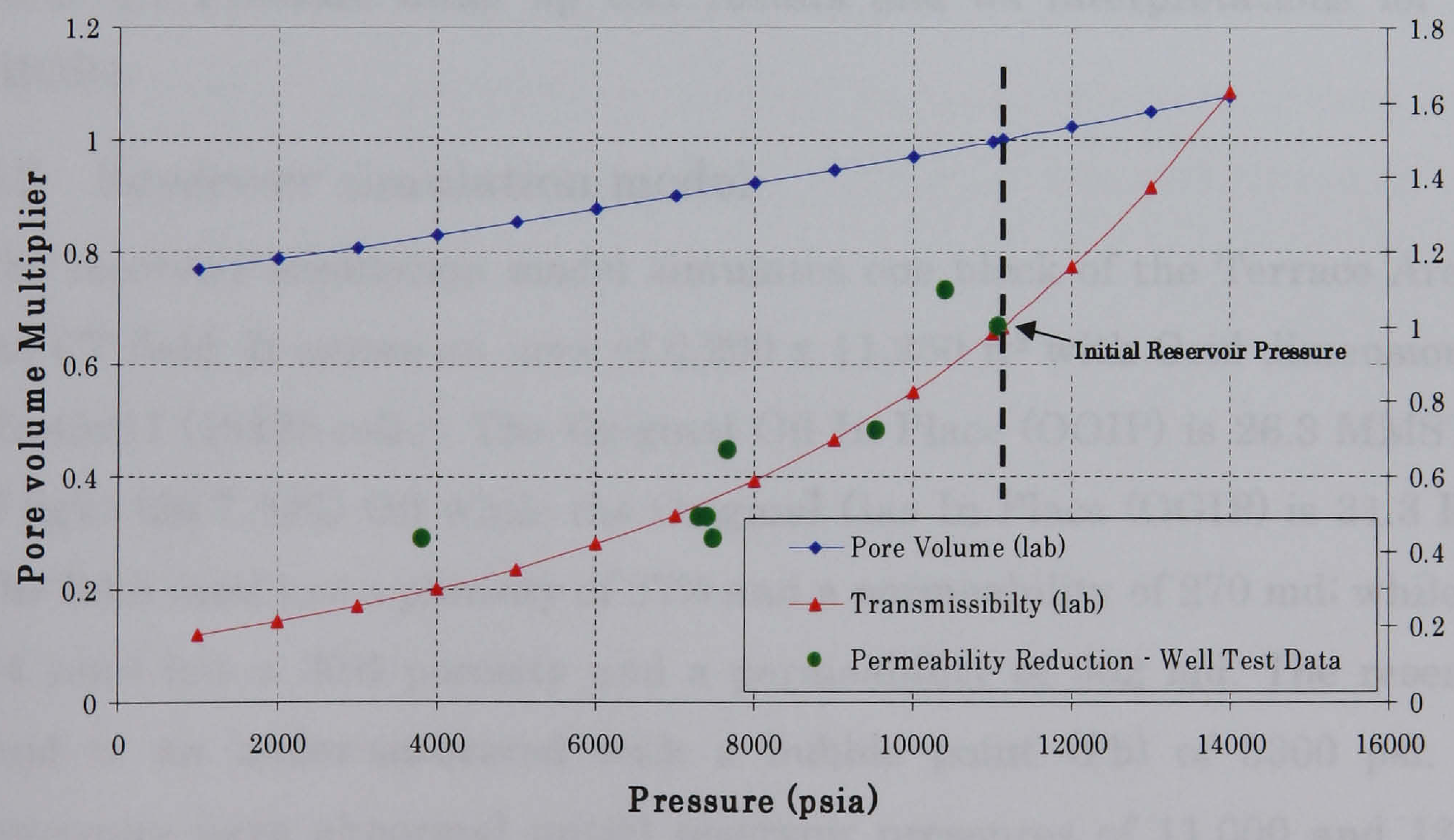


Figure 5.1.1 The rock compaction option modelled as transmissibility and pore volume multiplier - PROD1 well data

5.1.2 Reservoir compaction in CT field

The CT field is a typical deepwater, compacting, compartmentalized layered reservoir. Such a complex reservoir requires that each formation zone to be managed independently. A series of pressure transit tests are available for the vertical well PROD1 (Table 5.1). This table confirms that the measured formation permeability is being reduced as the formation pressure depletes.

Date	Total BU Time (hrs)	Oil Rate (BOPD)	Gauge FBHP (psi)	K (md)	Radial PI (bopd/psi)	Total Skin	Delta P Skin (psi)
Flowback	5.8	3970	11083	255	8.9	3	127
05/10/01	73.0	3800	10415	280	12.6	0	1
06/02/02	4.4	3671	9543	184	8.3	0	50
06/07/02	4.0	7553	7654	171	6.9	1	450
20/08/02	5.3	6332	7298	125	4.6	2	650
19/09/02	2.7	5200	7401	125	4.6	2	550
13/10/02	181.9	5150	7494	110	3.9	2	620
11/12/02	52.4	5000	3818	110	3.9	2	600

Table 5.1 Pressure build up test results and its interpretations for well PROD1.

5.2 Reservoir simulation model

The reservoir simulation model simulates one block of the Terrace Area of the CT field. It covers an area of 6,200 x 11,250 ft^2 with Grid dimensions of 25x45x17 (19125 cells). The Original Oil In Place (OOIP) is 26.3 MMSTBO of light (36.7 API) Oil while the Original Gas In Place (OGIP) is 31.3 BCF. The B4.5 sand has a porosity of 27% and a permeability of 270 md; while the B4 sand has a 30% porosity and a permeability of 902 md. The reservoir fluid is an under-saturated with a bubble point (Pb) of 5300 psi. The reservoirs have abnormal initial reservoir pressures of 11,000 and 12,000 psi at depths between 15,000 and 16,000 ft ss True Vertical Depth (TVD).

Figure 5.2.1 is showing the faults across the block. These faults divide the B4.5 sand into three separate compartments with only partial communication between the aquifer and the B4.5 sand.

5.2.1 History matching challenges – single zone completion

The PROD1 well developing the CT-Field was put on production in July 2001. The simulation model had been history matched for the 15 months of production up until September 2003. This history match indicated that all the faults in the B4.5 sand were completely sealing. Production data after September 2003 indicated that the B4.5 sand's production recovery was exceeding the initial expectations. The producing sands appear to be bigger than originally thought and to shows less compartmentalization, allowing communication with an aquifer. This field production performance and pressure data has been used to improve the model's history match by introducing a Transmissibility Multiplier in the Y and Z directions of 2% for the three faults shown in Figure 5.2.1. The relative permeability curves also had to be modified (critical water saturation increased by 5%, this change delayed the water breakthrough) in order to match the water production. The simulation ran under oil production control excellent match was obtained however the gas production was not well matched an that is because of the constant GOR is assumed but that was not the case in the observed data where the GOR slightly vary from one measurement to an other (Figure 5.2.2 (a-d)).

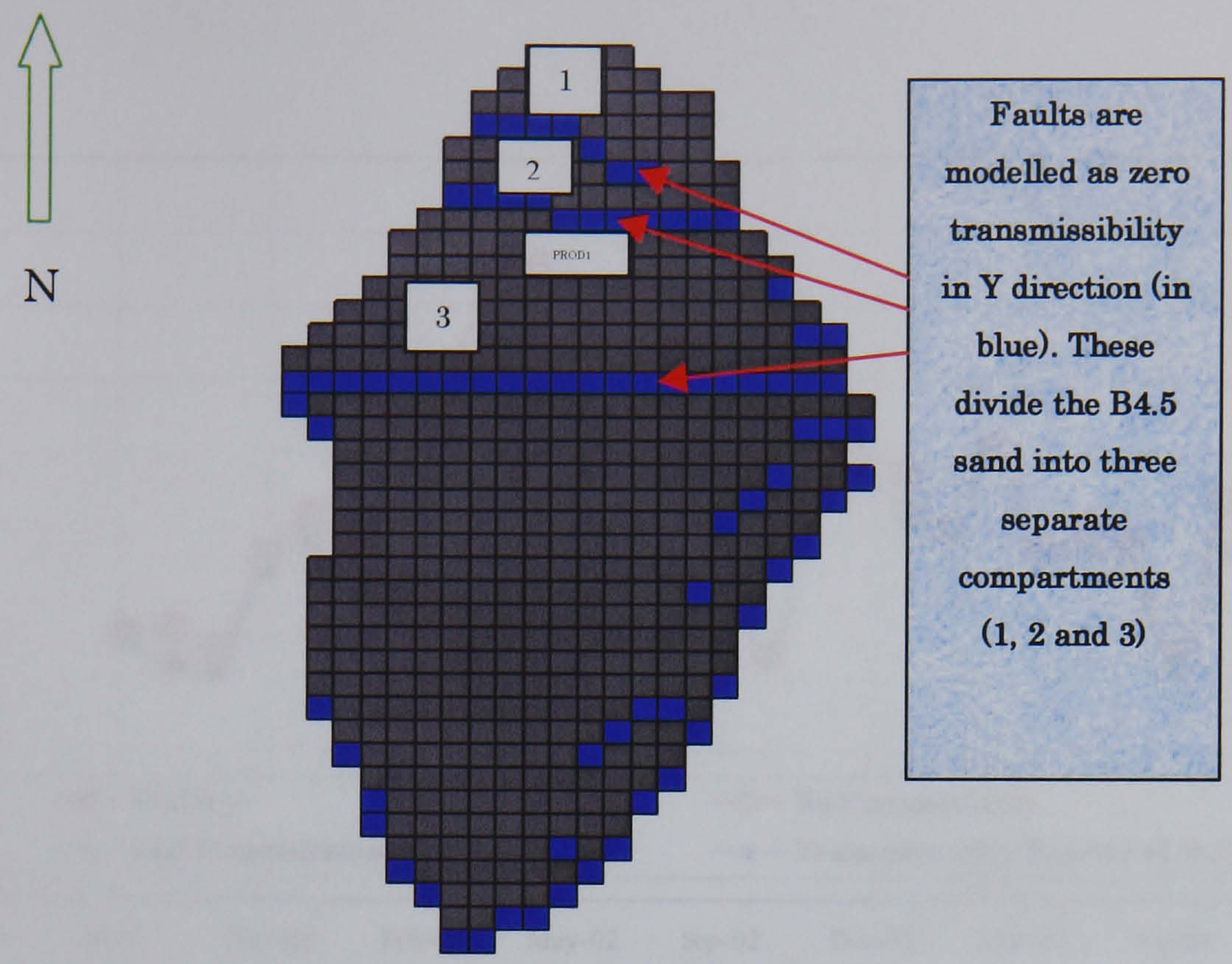


Figure 5.2.1 Top view of the B4.5 sand showing the location of the faults

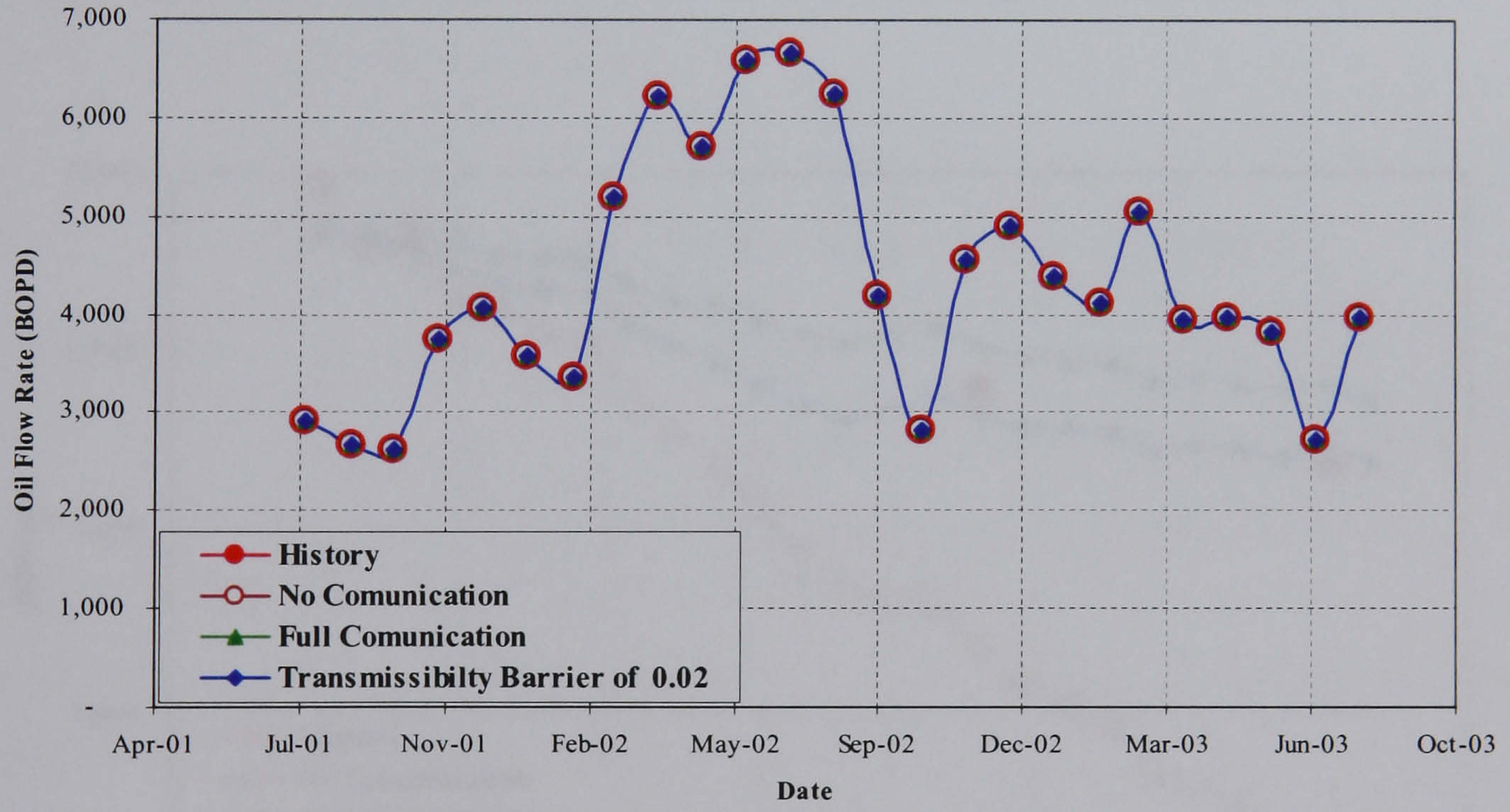


Figure 5.2.2 (a) PROD1 well oil flow rate for the different models compared to the observed data

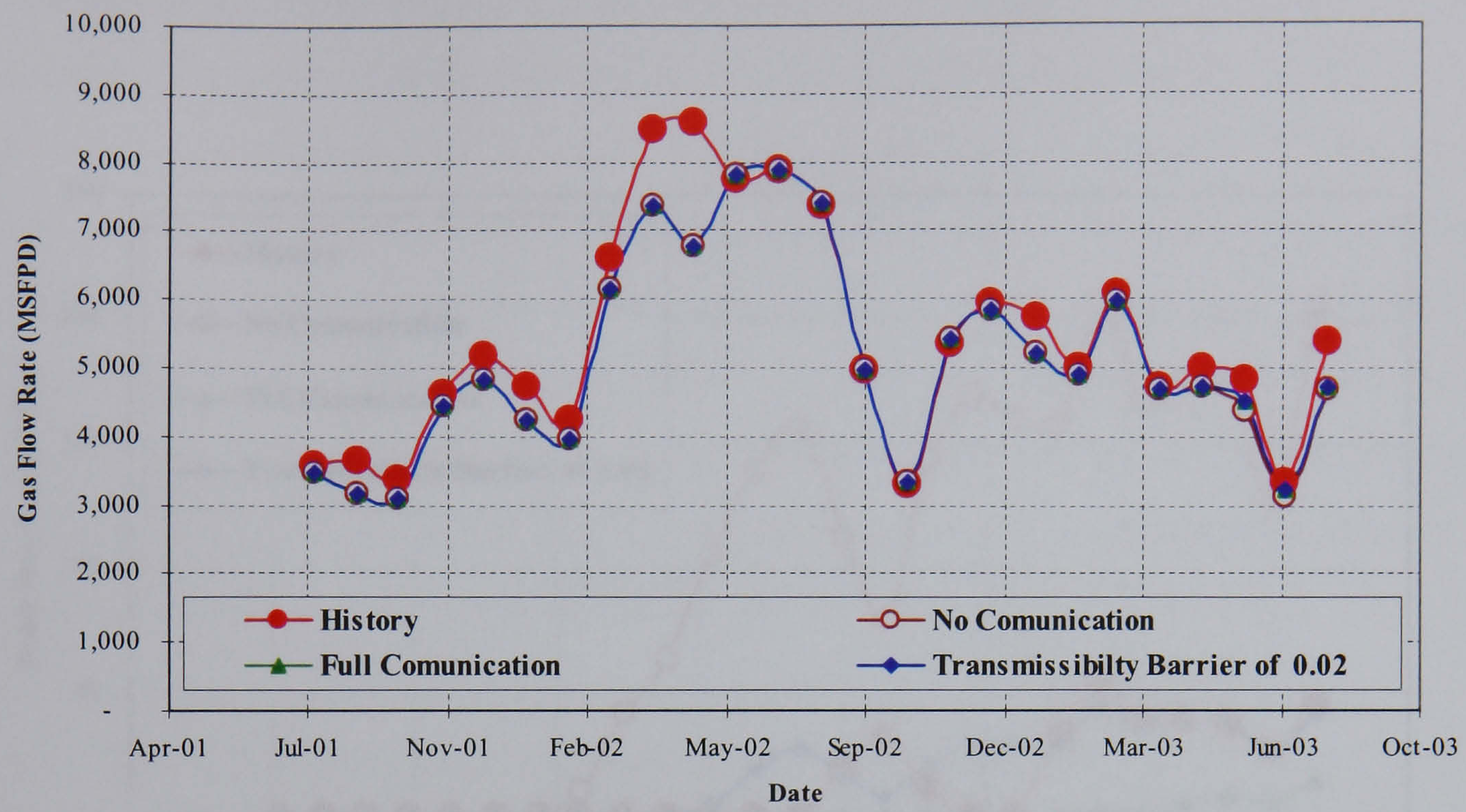


Figure 5.2.2 (b) PROD1 well gas flow rate for the different models compared to the observed data – the mismatch is due to using of constant GOR

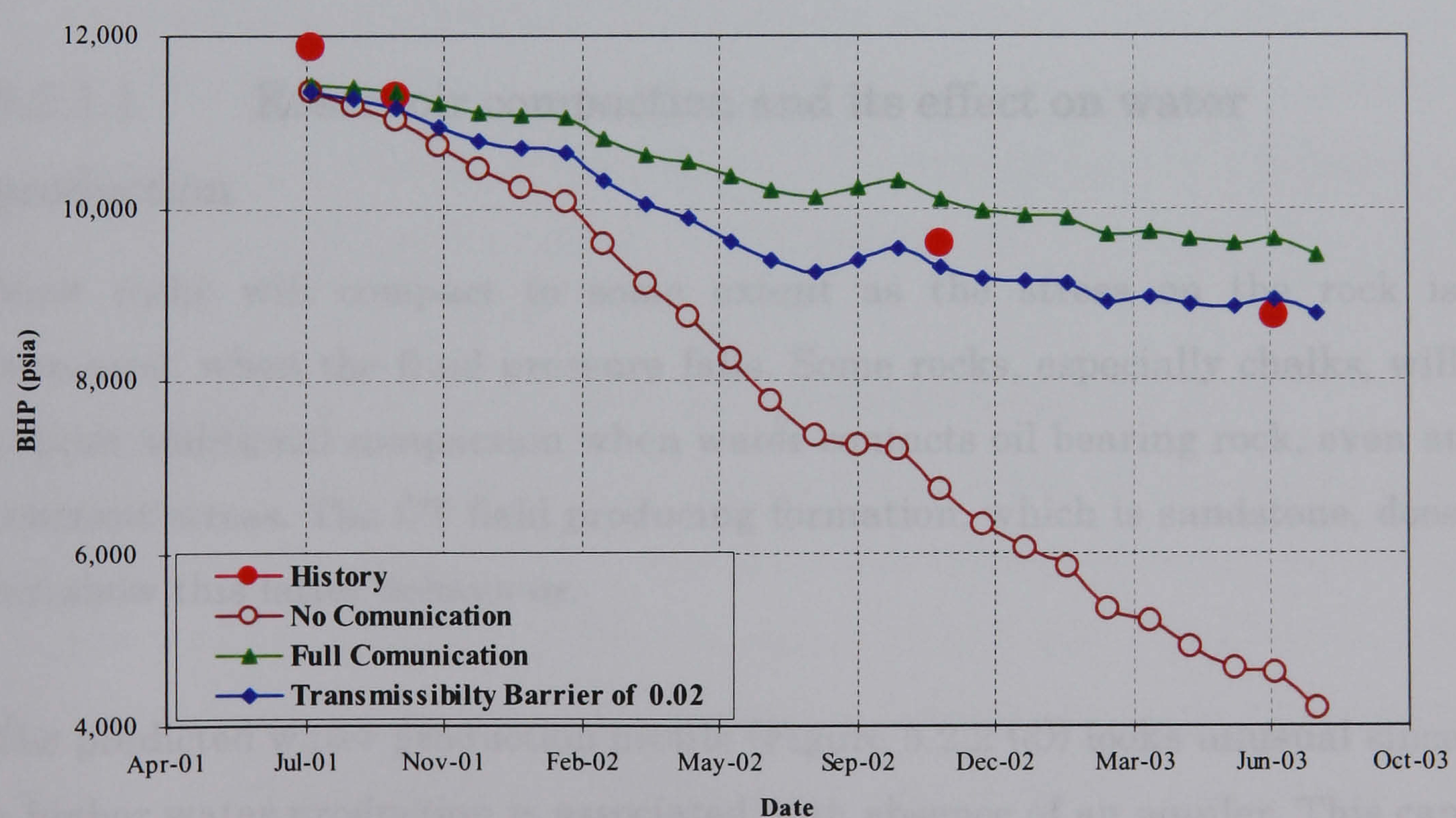


Figure 5.2.2 (c) PROD1 well bottom hole pressure for different models compared with the observed data showing that the model of 0.02 transmissibility gives the best match

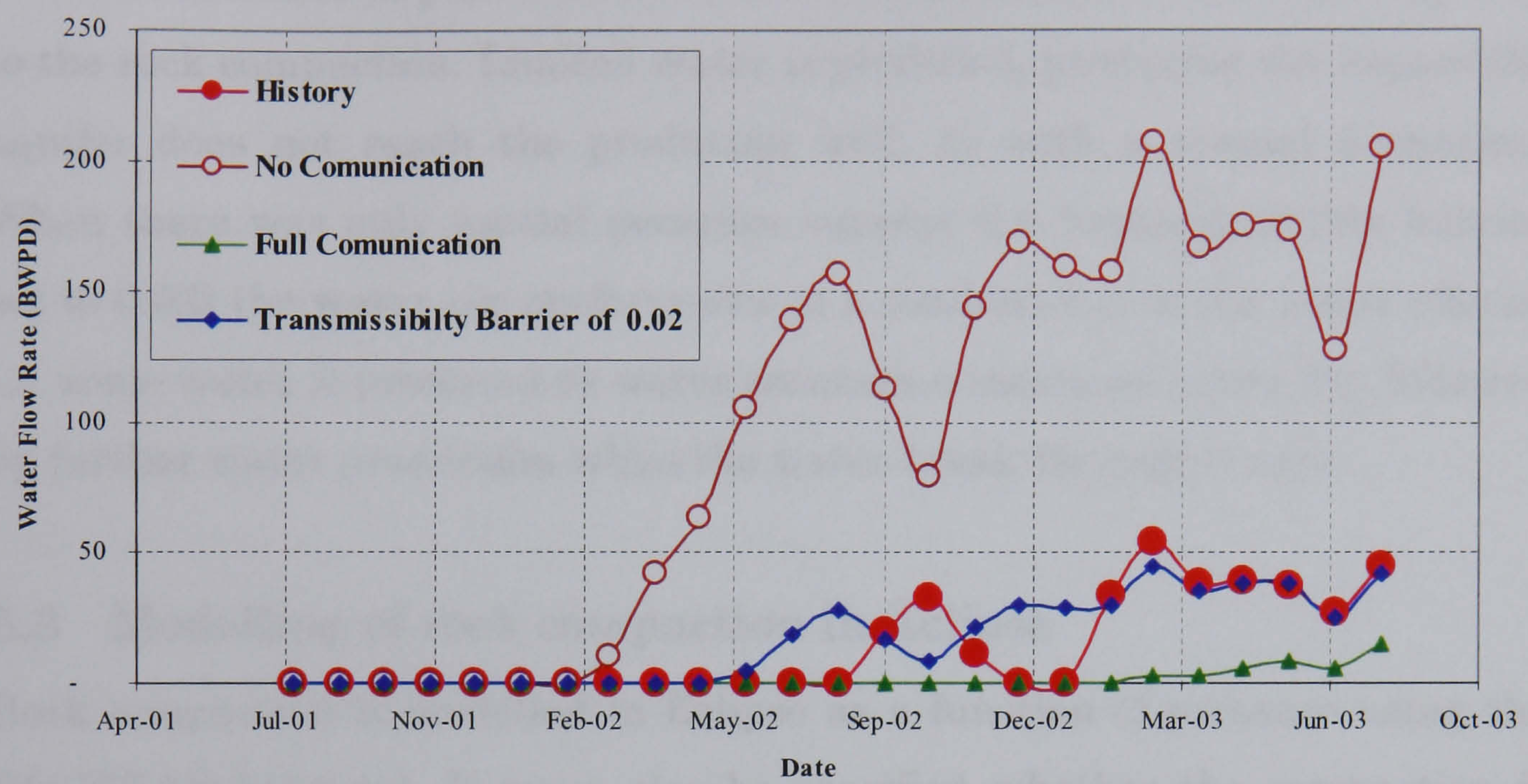


Figure 5.2.2 (d) PROD1 well water flow rate for the different models compared with the observed data

5.2.1.1 Reservoir compaction and its effect on water production

Most rocks will compact to some extent as the stress on the rock is increased, when the fluid pressure falls. Some rocks, especially chalks, will exhibit additional compaction when water contacts oil bearing rock, even at constant stress. The CT field producing formation, which is sandstone, does not show this latter behaviour.

The predicted water production profile (Figure 5.2.2 (d)) looks unusual since a higher water production is associated with absence of an aquifer. This can be explained as follows: There is a greater decrease in reservoir pressure when pressure support is absent (no aquifer). Greater rock compaction leads to a greater reduction in pore volume. This gives an increased water saturation allowing mobilization of the water. This "rock squeezing" effect

(Han et al, 2002) explains why water is produced in the model in the absence of pressure support. The presence of the aquifer produces sufficient pressure support so that the reservoir pressure remains constant. There is thus no reduction in pore volume, while water saturation does not vary due to the rock compaction. Limited water is produced, producing the expanding aquifer does not reach the producing well, as with a normal formation. When there was only partial pressure support (i.e. transmissibility barrier set to 0.02) the water cut performance is a combination of the above effects. i.e. some water is produced as water saturation increases above Sw_i followed by further water production when the water break-through occurs.

5.3 Modelling of rock compaction in Eclipse

Rock compaction is modelled in Eclipse as a function of pressure using the ROCKTAB keyword. It must also be specified whether the compaction is assumed to be reversible or irreversible since the pressure in a grid block may later increase. These two options (fully reversible or irreversible) may be too simplistic, a hysterisis option is also available. The preferred data source, as in this field study, is obtained by performing rock mechanical test to measure pore volume and transmissibility multipliers as a function of pressure on a core from the actual field (Figure 5.1.1).

5.4 Application of intelligent completions in the CT field

This chapter presents how IWT can be used to optimise the production from the CT field. In addition to the normal optimisation parameters studied in chapter 4 and in later chapters in this thesis, this chapter will also examine optimisation of the drawdown around the wellbore in order to evaluate whether it was possible to minimize the permeability damage due to pressure depletion induced by the compaction process. A three-dimensional, history matched Eclipse (GeoQuest 2002) reservoir model was made available for the CT-Field. This initial development of the field targeted production from the B4 and B4.5 zones which were developed with one well PROD1. It was brought on production in July 2001 at a reduced rate of well. However because of failure in the B4 completion during the flowback, an isolation sleeve had to be set across this interval. Hence only the B4.5 sand was produced for 3 the years until July 2004. The B4 sand was then planned to be put on production; with the intention to continue production until the end of the field life. This scenario formed the base case for the study. The IWT case uses a variable ICV completion system to control production from each pressure zone separately. The manual optimisation procedure presented in chapter 4 will be used to control the ICV setting so as to maximize the total oil production. The IWT completion model results were then compared with the base case scenario to provide a quantitative value assessment of incremental oil production.

5.4.1 Value of intelligent completions in compacting reservoirs

Akram et al. (2001), Balinas (2002), Brouwer et al. (2002), Sharma et al. (2002), and Johnston et al. (2002) have discussed the potential benefits from IWT for a two-reservoir-sand system. In these field applications improved production performance was achieved from commingled completion zones (or reservoirs) with very different properties or when different fluids are being produced. The new factor introduced in this chapter is the high level of reservoir rock deformation occurring due to formation pressure depletion during oil production.

The value of IWT was identified using different scenarios that include well locations, completions and a study the effect of water injection on reservoir performance. They will all be compared to the existing well case. All cases use a similar constraint of a minimum oil rate of 1,000 bopd, a maximum water oil ratio of 1.7 and a minimum tubing head pressure of 214 psia. The field was planned to be produced over a 10 year time period.

5.4.2 Cases studied

History: Conventional vertical well model. In this case there is only one vertical well completed in the B4.5 sand from July 2001 until July 2004 when the B4.5 sand shut and the B4 sand perforated. This is equivalent to the well's existing development plan.

Base Case: Conventional vertical well model selectively completed in B4 and B4.5 sands. In this case the well is completed in both sands from day one to the end of the field life, allowing cross flow between the two sands.

Case 1: Similar to base case but completed with two ICVs so that each zone can be managed independently. (Figure 5.4.1)

Case 2: Similar well to base case till July 2004 when the well is sidetrack and re-completed with a deviated borehole and conventional completion (No ICVs were installed in this case)

Case 2-a One ICV controls flow from/into the lower zone (cross flow not allowed)

Case 2-b Two ICVs control flow from both zones (cross flow not allowed)

Case 2-c as case 2 with a water injection well to maintain pressure and reduce compaction. Cross flow not allowed in this case.

Case 2-d as case 2c with ICV installed to control production from the B4.5 sand.

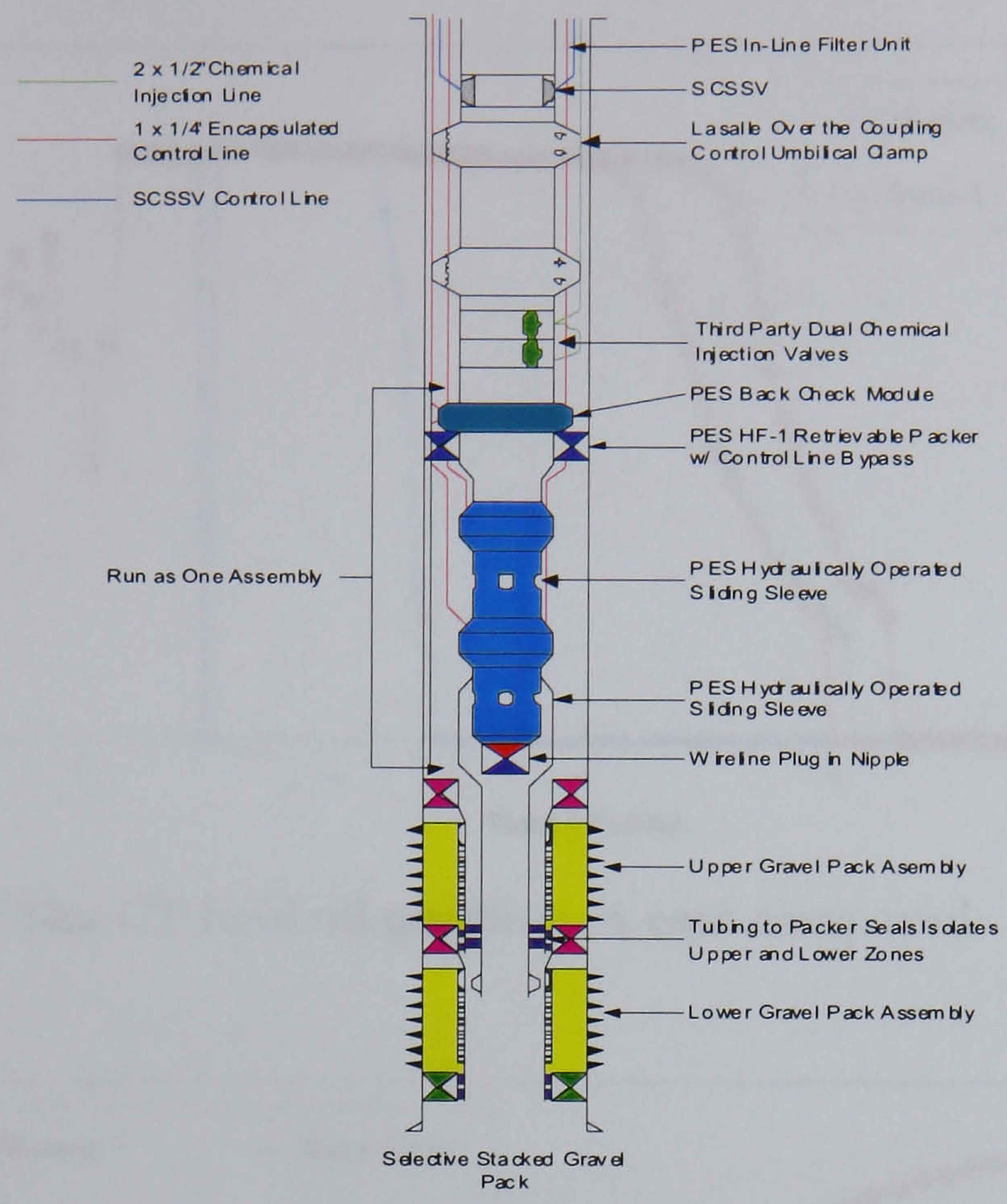


Figure 5.4.1 Case 1 well completion diagram – Total of two ICVs installed

5.4.3 Simulation results and discussion – Base Case & Case 1

Figure 5.4.2 (a-d) shows the simulation results for the Base cases and case 1 compared to the history. In the history (consecutive, independent production of the sands) the well ceases to flow after 5 years when the FTHP falls below the minimum value of 214 psia. Base cases and case 1 allow both sands to continue to produce for the longer production period of 8 years. This ability to stay on production for a longer period leads to a greater oil production compared to the history. ICV installation in both sands (Case 1) aimed to maximize oil production by minimizing the compaction effect and managing the drawdown around the wellbore. Due to limitation of the manual optimisation procedure used this aim was not achievable and the only benefit obtained was the reduction in the water production without any increase in oil (N.B. This was not the original target of installing the ICV). Proper analysis of this case requires a better optimisation tool i.e. one that can simultaneously optimise drawdown and minimize the compaction effect while maximizing the volume of oil produced.

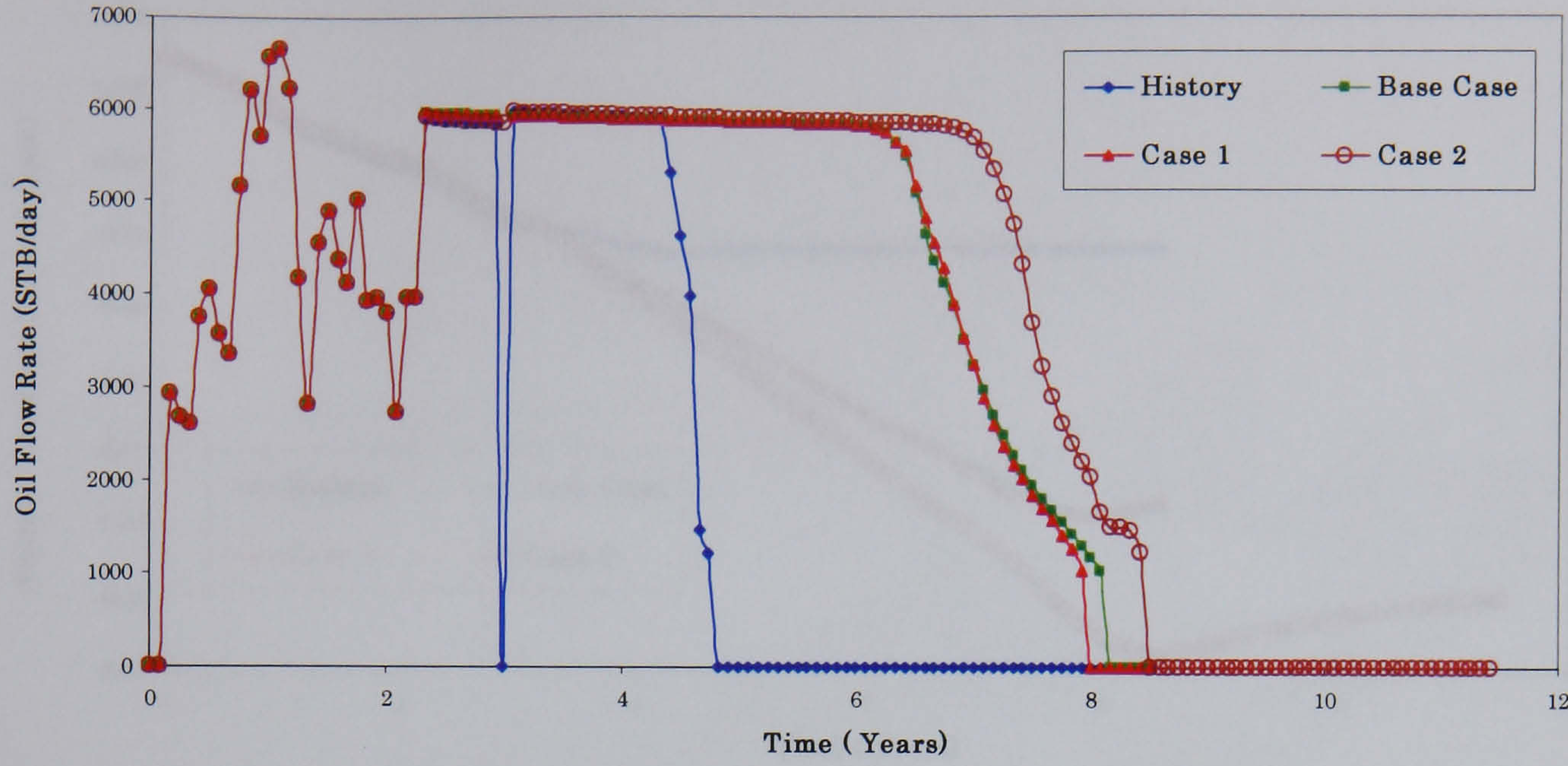


Figure 5.4.2 (a) The CT field oil production rate compared

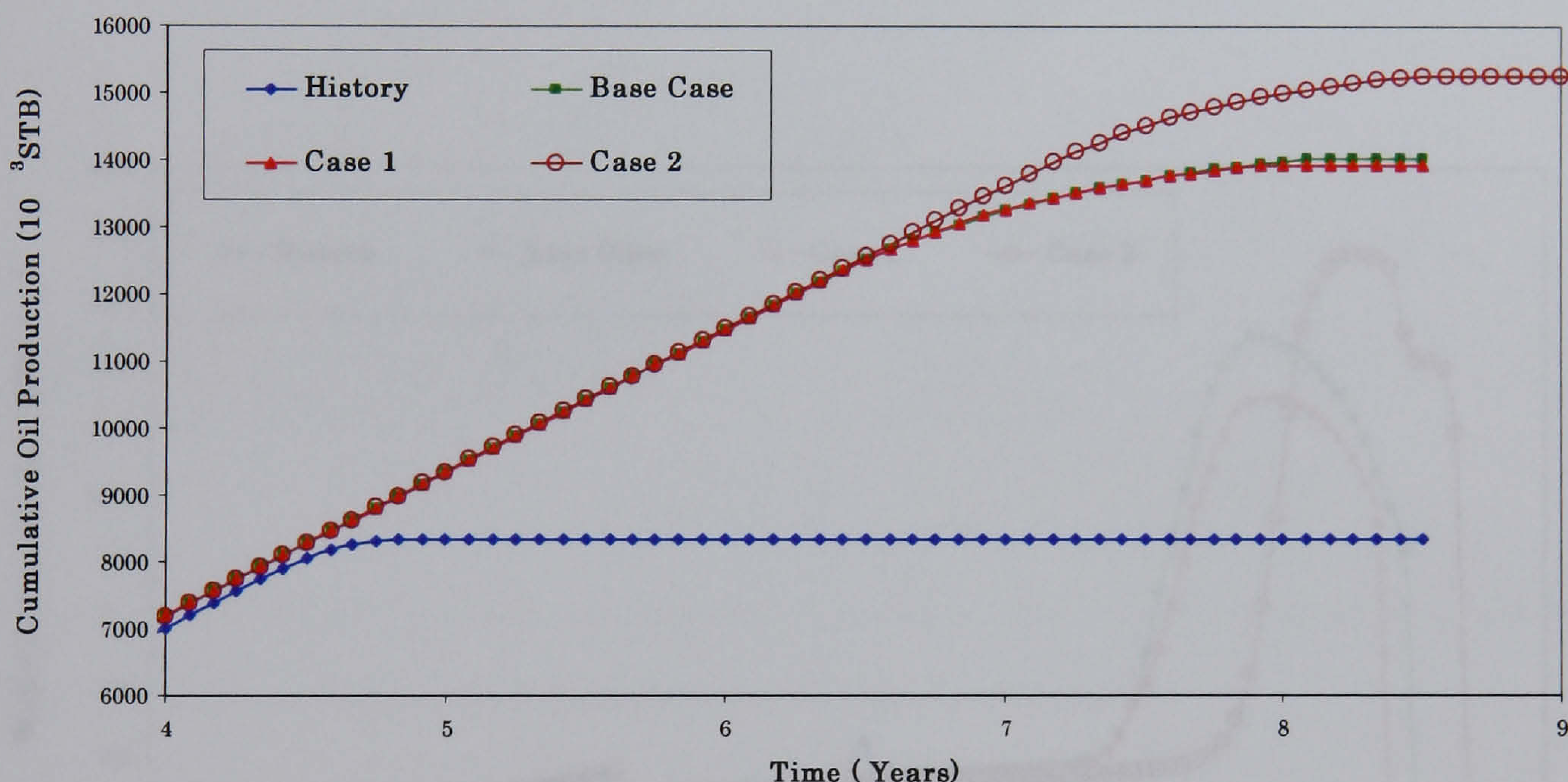


Figure 5.4.2 (b) Cumulative CT field oil production compared

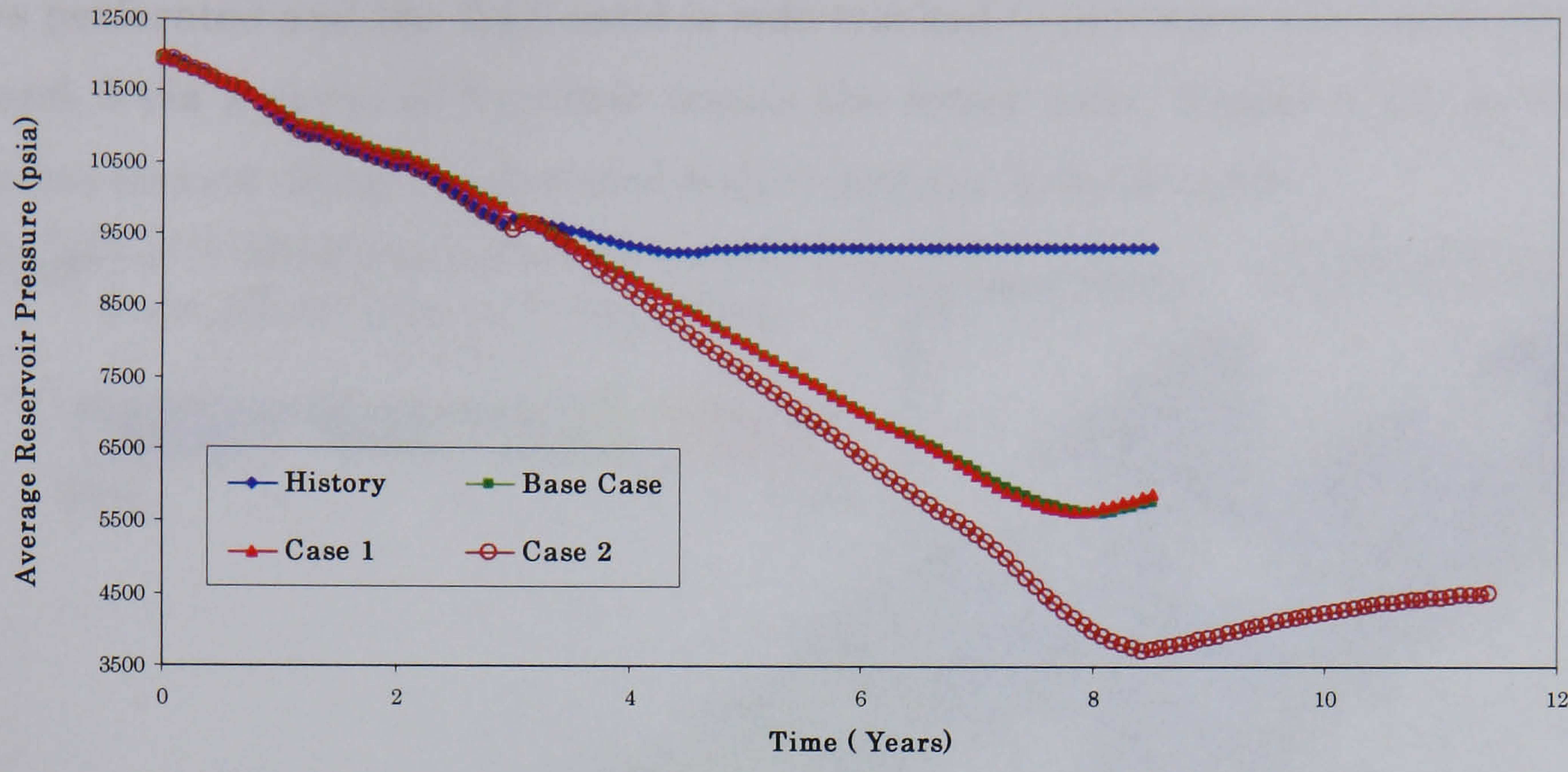


Figure 5.4.2 (c) CT Field average reservoir pressures compared

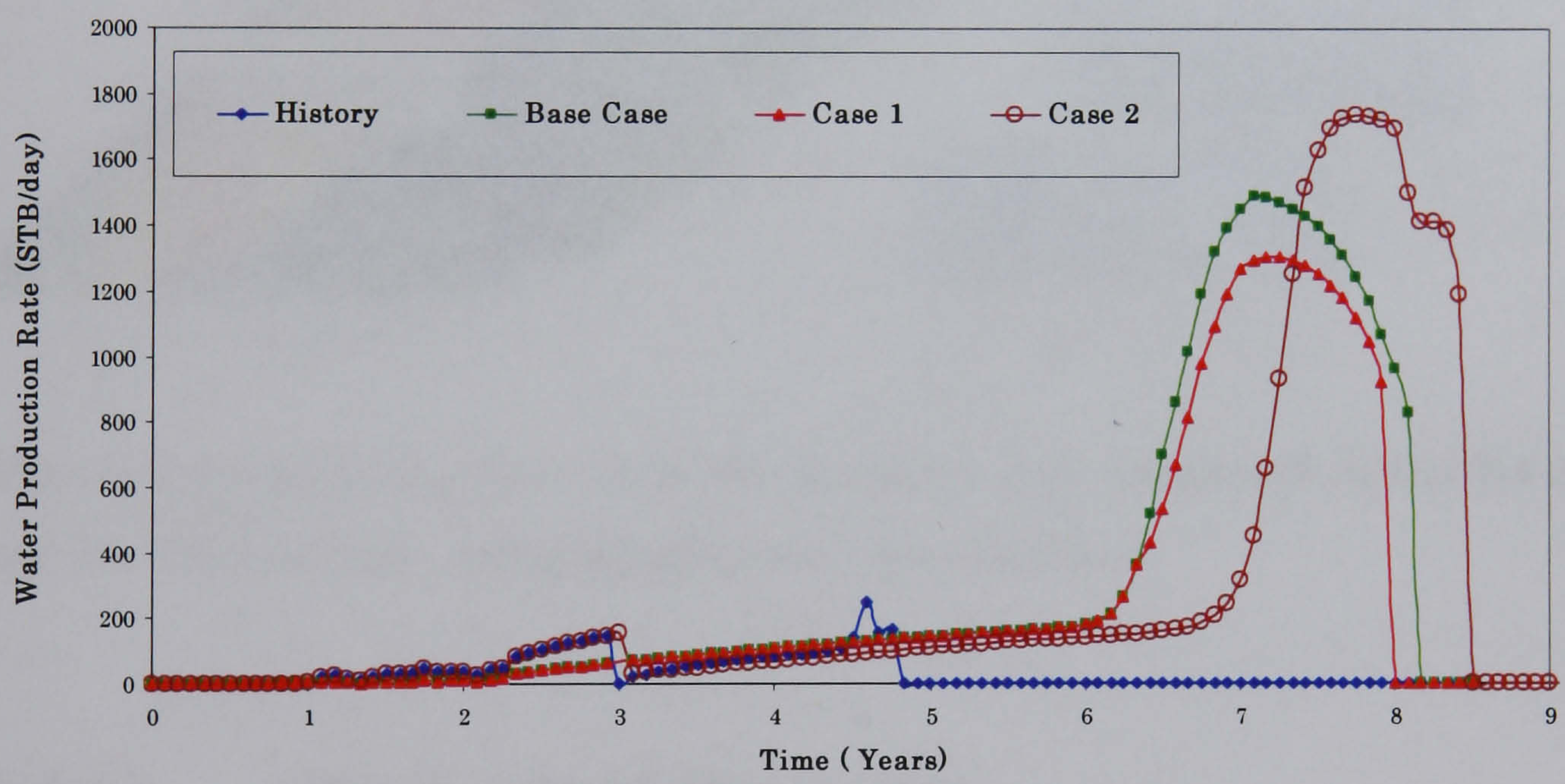


Figure 5.4.2 (d) CT Field water production rate compared.

5.4.4 Case 2 - change the well geometry by side-tracking

The B4.5 sand is separated into three compartments by two main sealing faults in the Y direction (see Figure 5.2.1). The vertical well used in the history and base case and case 1 is only completed in compartment (1). The other two compartments (2 &3) remain without development. The plan is to produce compartment (1) from July 2001 until July 2004 when the B4 sand is perforated and the B4.5 sand is side-tracked to penetrate compartments 2 and 3 via a deviated borehole across the lower zone. Figure 5.4.3 shows a cross section along the deviated well completed in both sands.

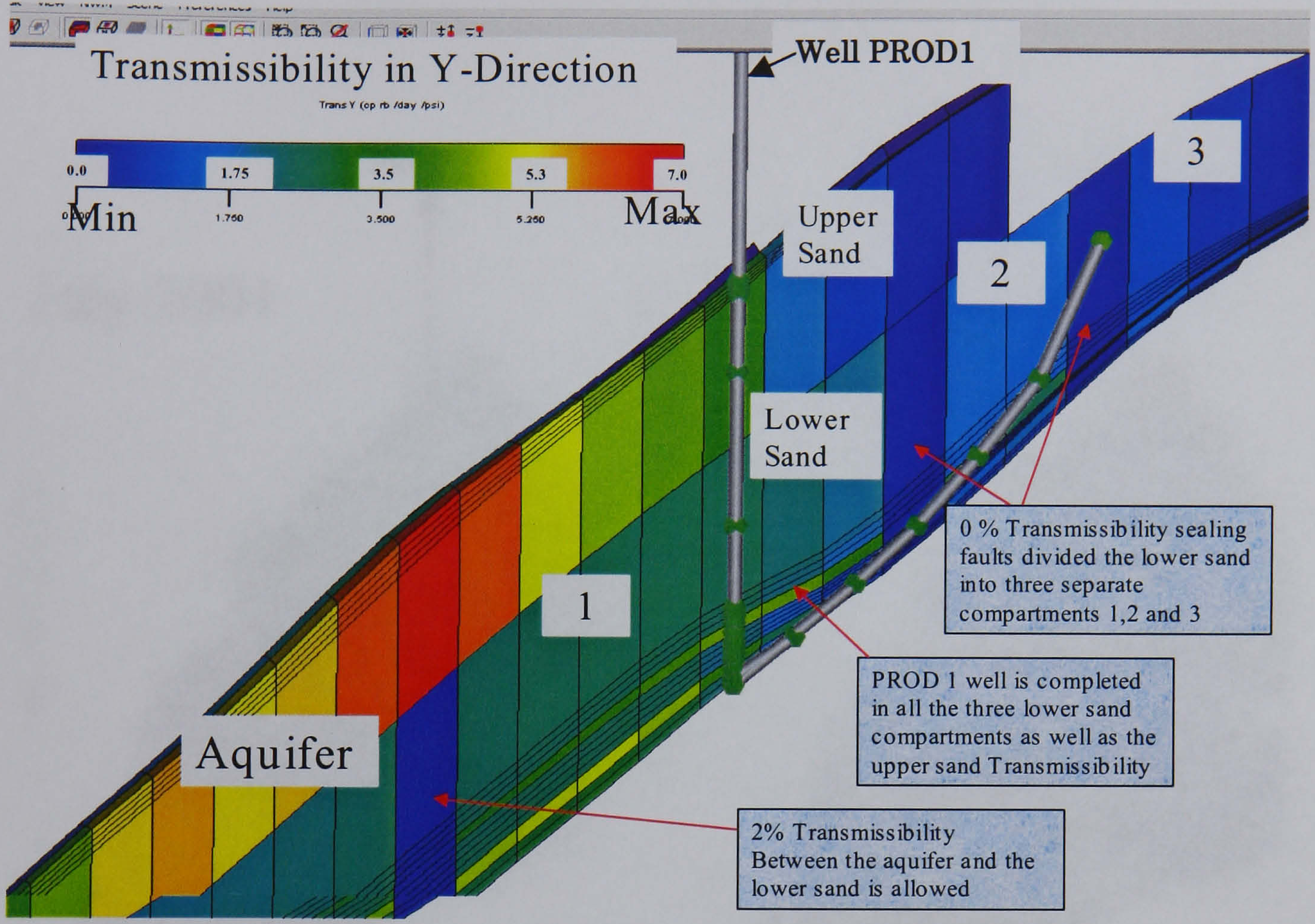


Figure 5.4.3 Cross section along the deviated well completed in the B4 and the B4.5 formations – compartments 1,2 &3 identified.

5.4.4.1 Case 2 – simulation results

The side track extended the plateau period by one year and delayed the water breakthrough. This allowed a significant increase in recovery from the B4.5 sand which continued until the well ceased production when the FTHP fell below 214 psia. Figure 5.4.2 (a-d) shows the performance of case 2 compared with the previous cases. It can be observed that the side-tracked well achieved a very good sweep efficiency (Figure 5.4.4).

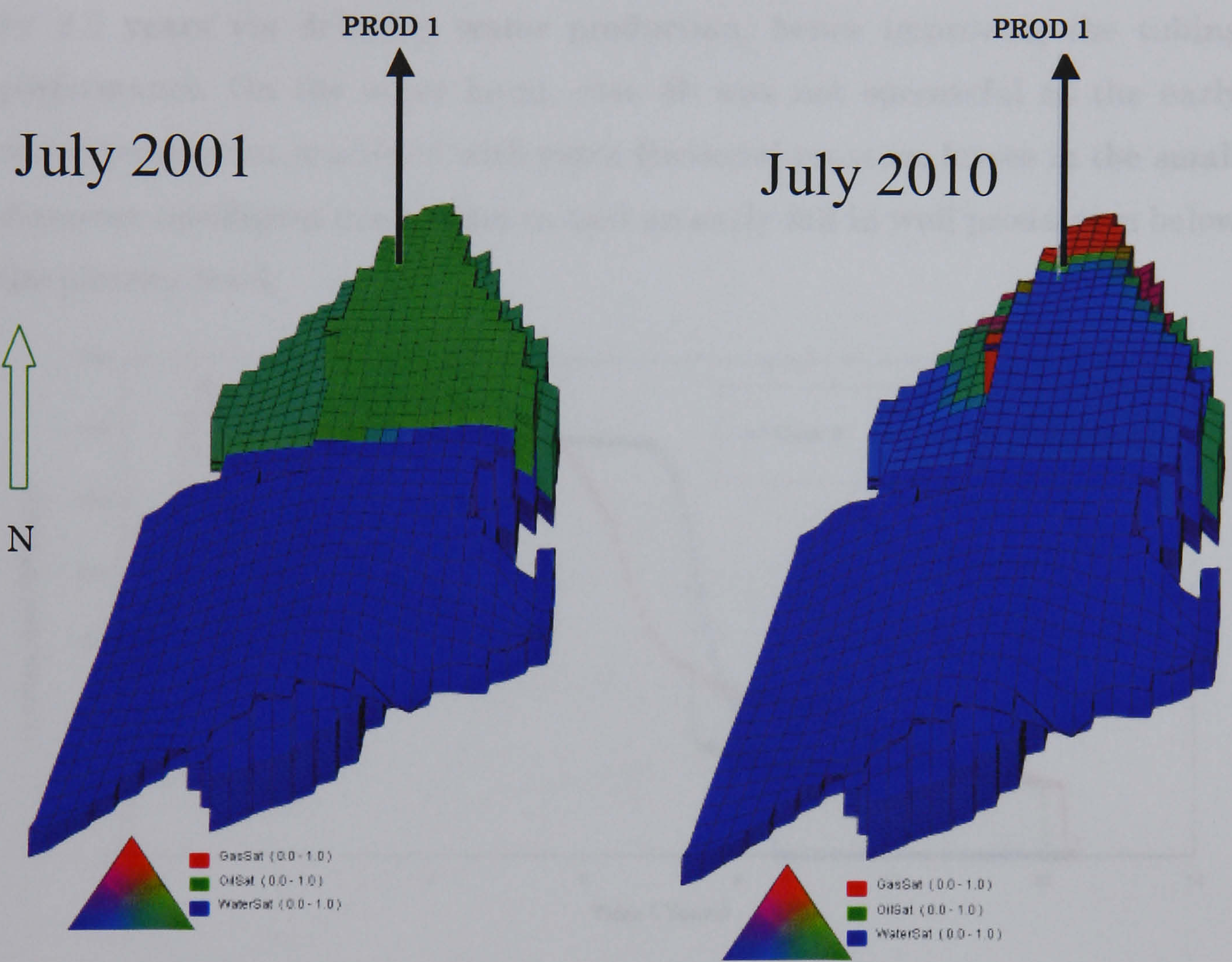


Figure 5.4.4 3D view of the CT Field shows the good oil sweep is obtained after side-tracking the well

5.4.4.2 Case 2 – further options - Case 2-a & 2-b

The B4.5 and the B4 sand are completely isolated from each other by shale and will thus develop different pressure regimes. ICVs could be installed in cases 3-a and 3-b in order to control the production from each sand independently and also to prevent wellbore cross flow between the zones. One ICV is installed in Case 2-a. This is increased to two ICVs, one opposite each sand, in case 2-b. This latter scenario produces independent flow control of each zone.

Figure 5.4.5 (a-c) show that case 2-a (the installation of one ICV to choke back production from the B4.5 sand) was beneficial. It extended the well life by 2.5 years via delaying water production, hence improving the tubing performance. On the other hand, case 2b was not successful as the early water production combined with extra frictional pressure losses in the small diameter intelligent completion caused an early fall in well production below the plateau level.

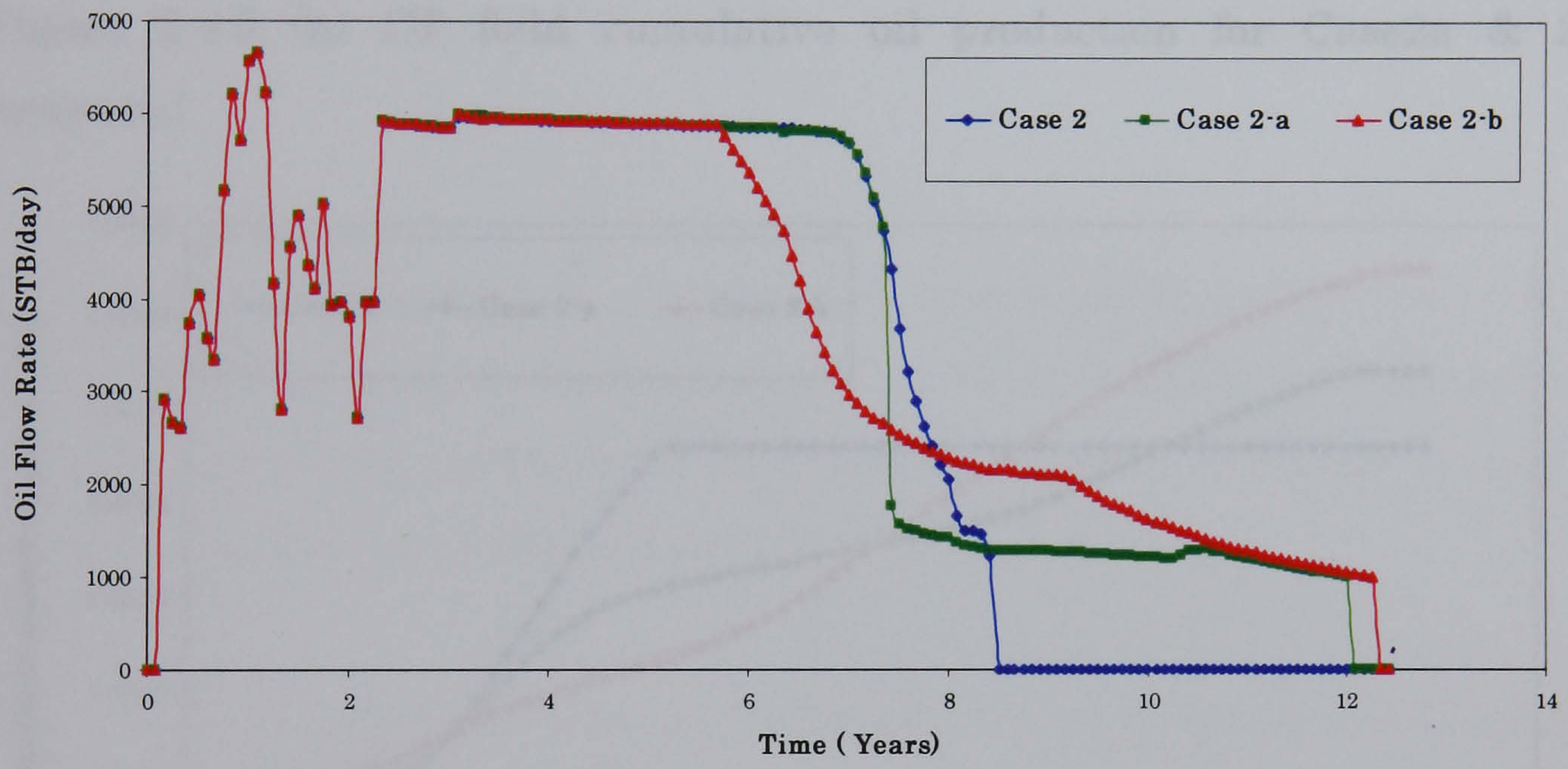


Figure 5.4.5 (a) CT Field oil production for Case 2a & 2b compared

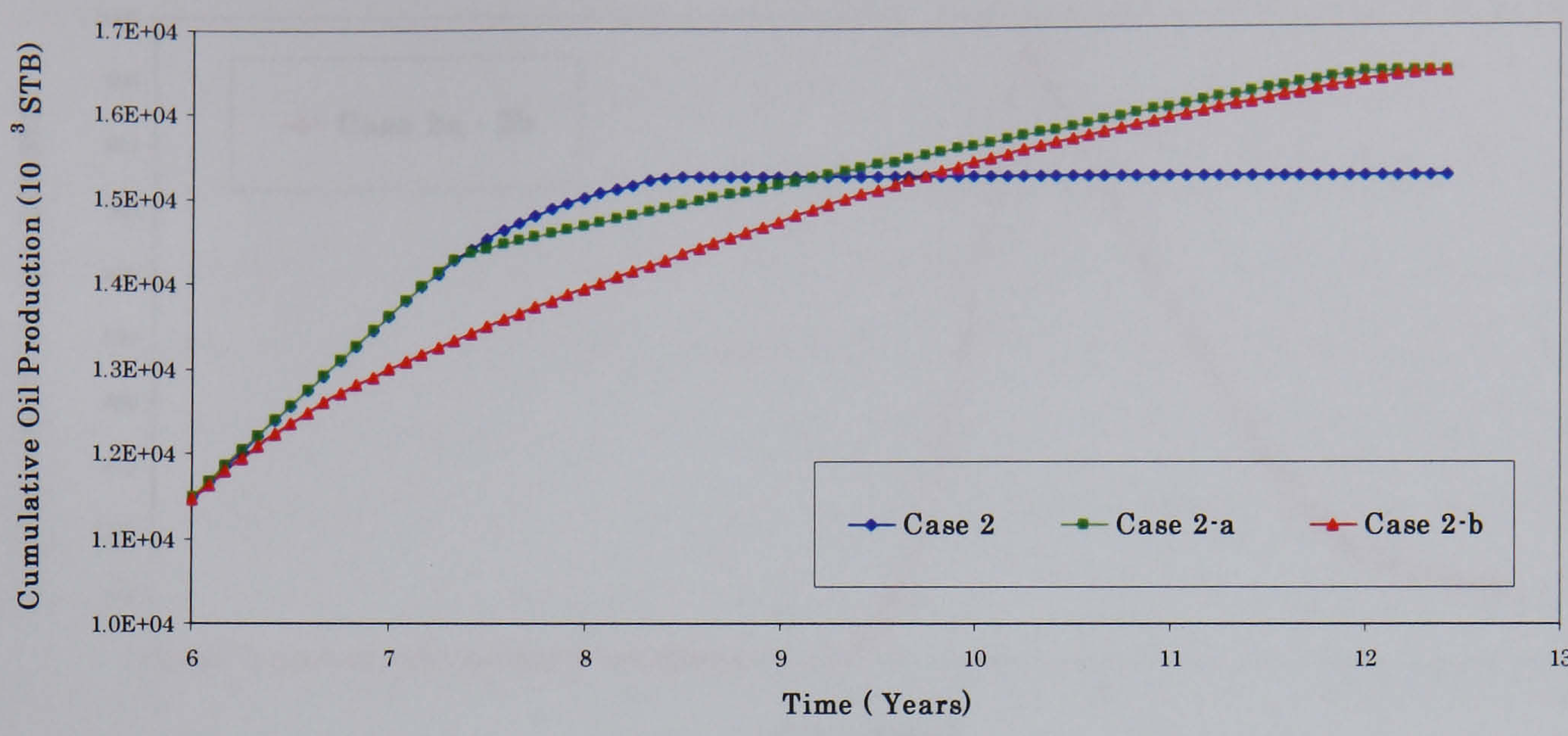


Figure 5.4.5 (b) CT field cumulative oil production for Case2a & 2b compared

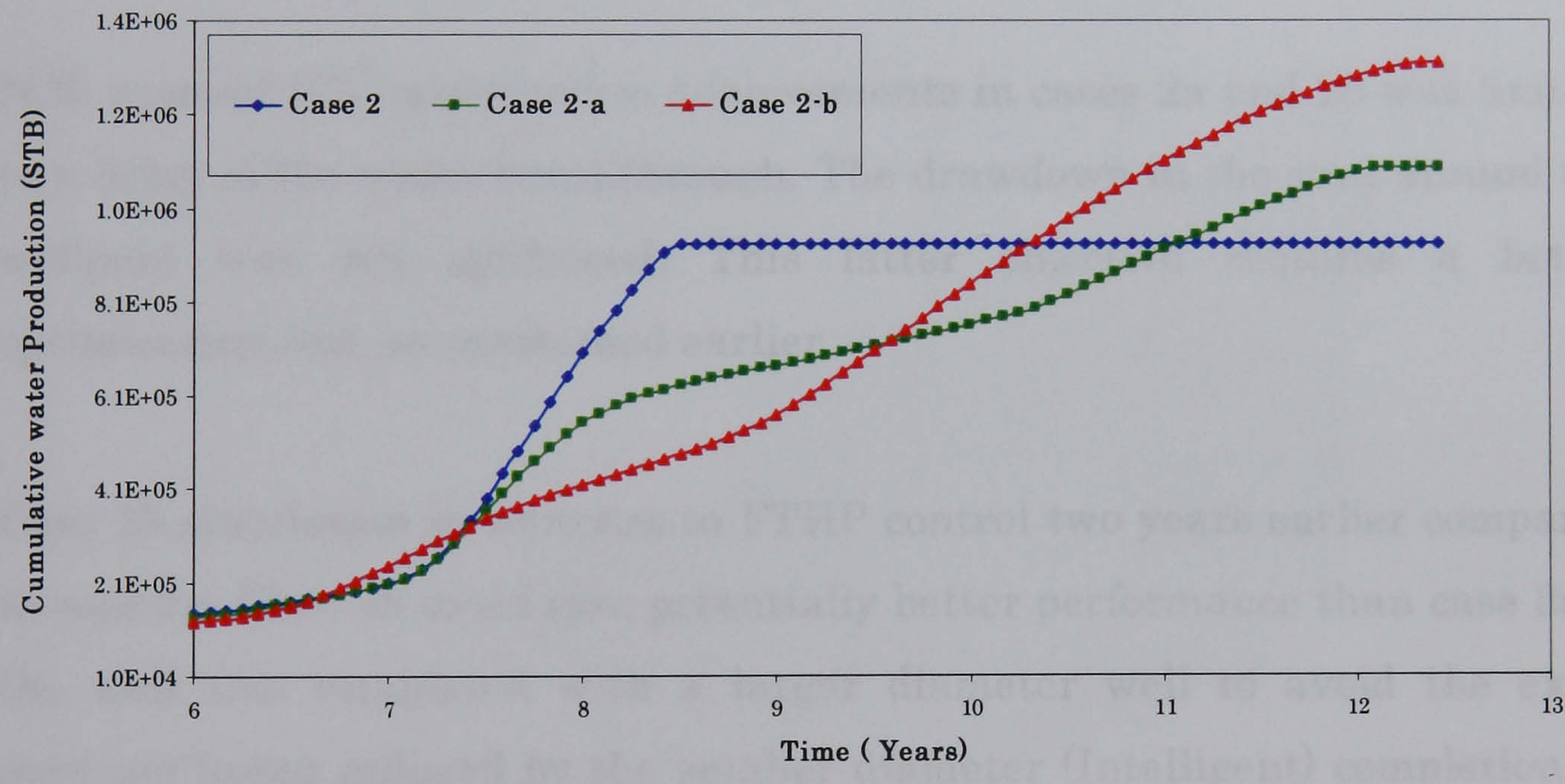


Figure 5.4.5 (c) CT field cumulative water production for Case2a & 2b compared

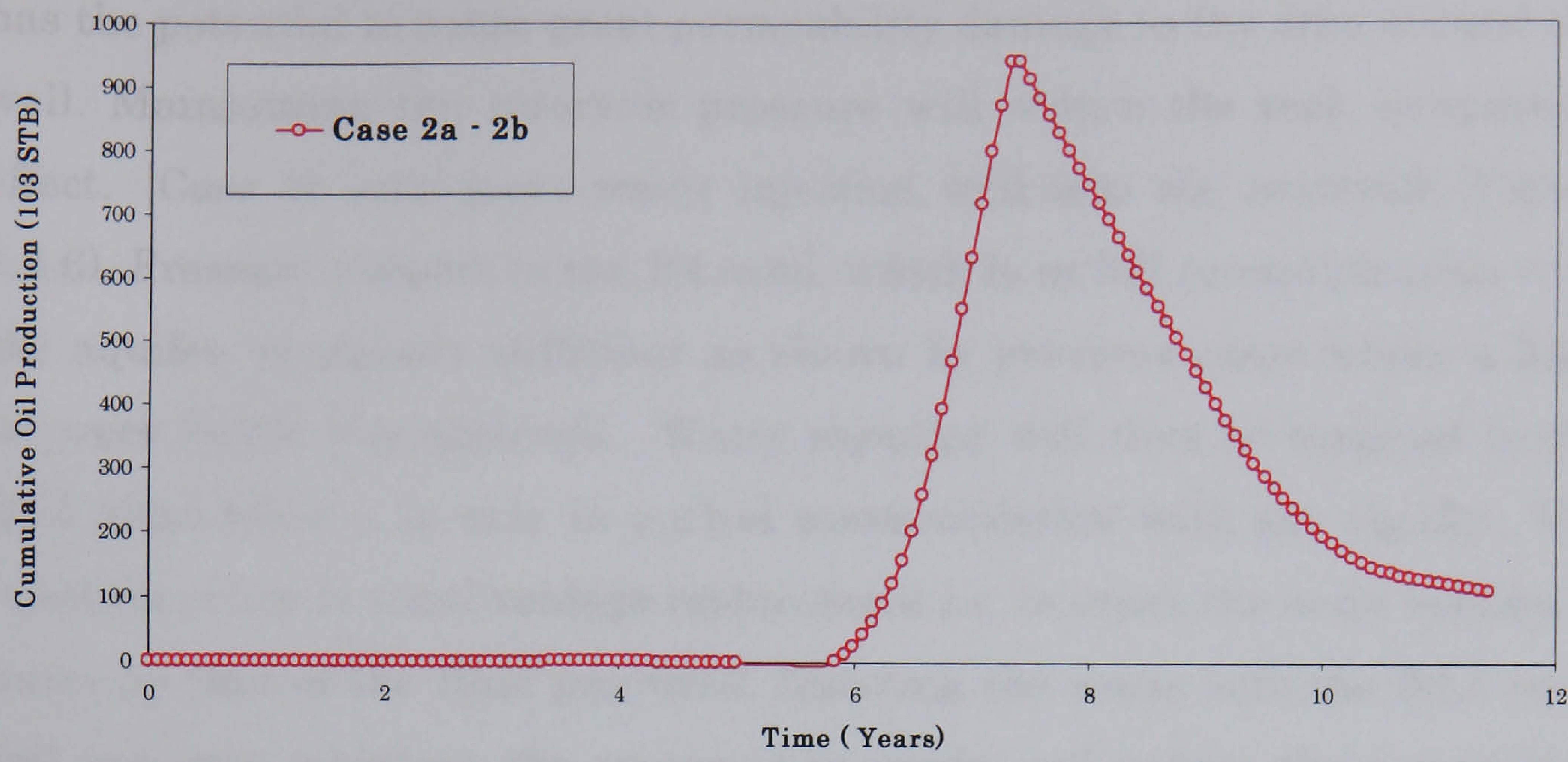


Figure 5.4.5 (d) Difference in cumulative oil production between Case 2a and 2b

N.B. manual ICV optimisation achievements in cases 2a and 2b was limited to a delay of the water breakthrough. The drawdown in the area around the wellbore was not optimised. This latter objective requires a better optimisation tool, as mentioned earlier.

Case 2b simulation in switches to FTHP control two years earlier compared to case 2a. Case 2b could give potentially better performance than case 3a if the well was completed with a larger diameter well to avoid the extra pressure losses induced by the smaller diameter (Intelligent) completion. It should also be noted that a particularly high (>75%) recovery was achieved from B4 sand. This is due to the reservoir being simulated as homogenous with no permeability barriers present.

5.4.5 Value of water injection cases 2-c & 2-d

Water Injection is the most commonly used improved oil recovery method. The main objective is to keep pore pressure more or less constant in the reservoir during oil expulsion. As discussed earlier, pressure depletion in highly unconsolidated, over-pressured sand reservoirs, such as CT Field, has the potential to cause great permeability damage to the area around the well. Maintaining the reservoir pressure will reduce the rock compaction effect. Case 2c introduces water injection well into the reservoir (Figure 5.4.6). Pressure support to the B4 sand, which is in full communication with the aquifer, is already sufficient as shown by previous cases where a high recovery factor was achieved. Water injection will thus be targeted to the B4.5 sand since it is only in partial communication with the aquifer. The injection policy is zonal voidage replacement i.e. to inject the same volume of water as that of the fluid produced. Injecting the water into the B4.5 sand will not only maintain the reservoir pressure and reduce the compaction effect, but it will also improve the sweep efficiency; leading to a further increase in the recovery from the B4.5 sand.

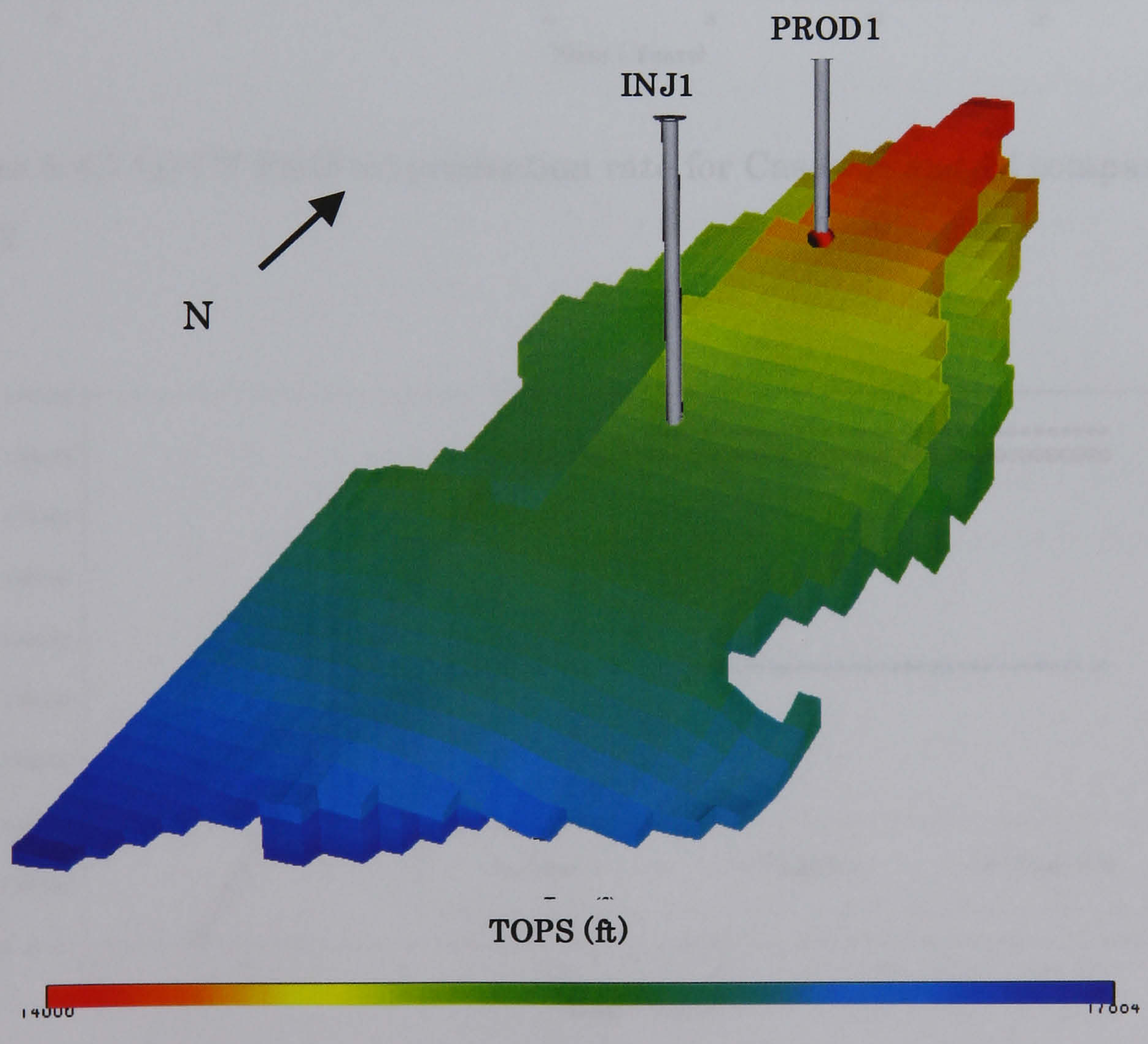


Figure 5.4.6 CT Field model showing the location of the Injection well along with the existing producer

Case 2c uses a conventional producer with water being injected into the B4.5 sand. In Case 2d, the producer is completed with an ICV to control production from the B4.5 sand Figure 5.4.7 (a-c).

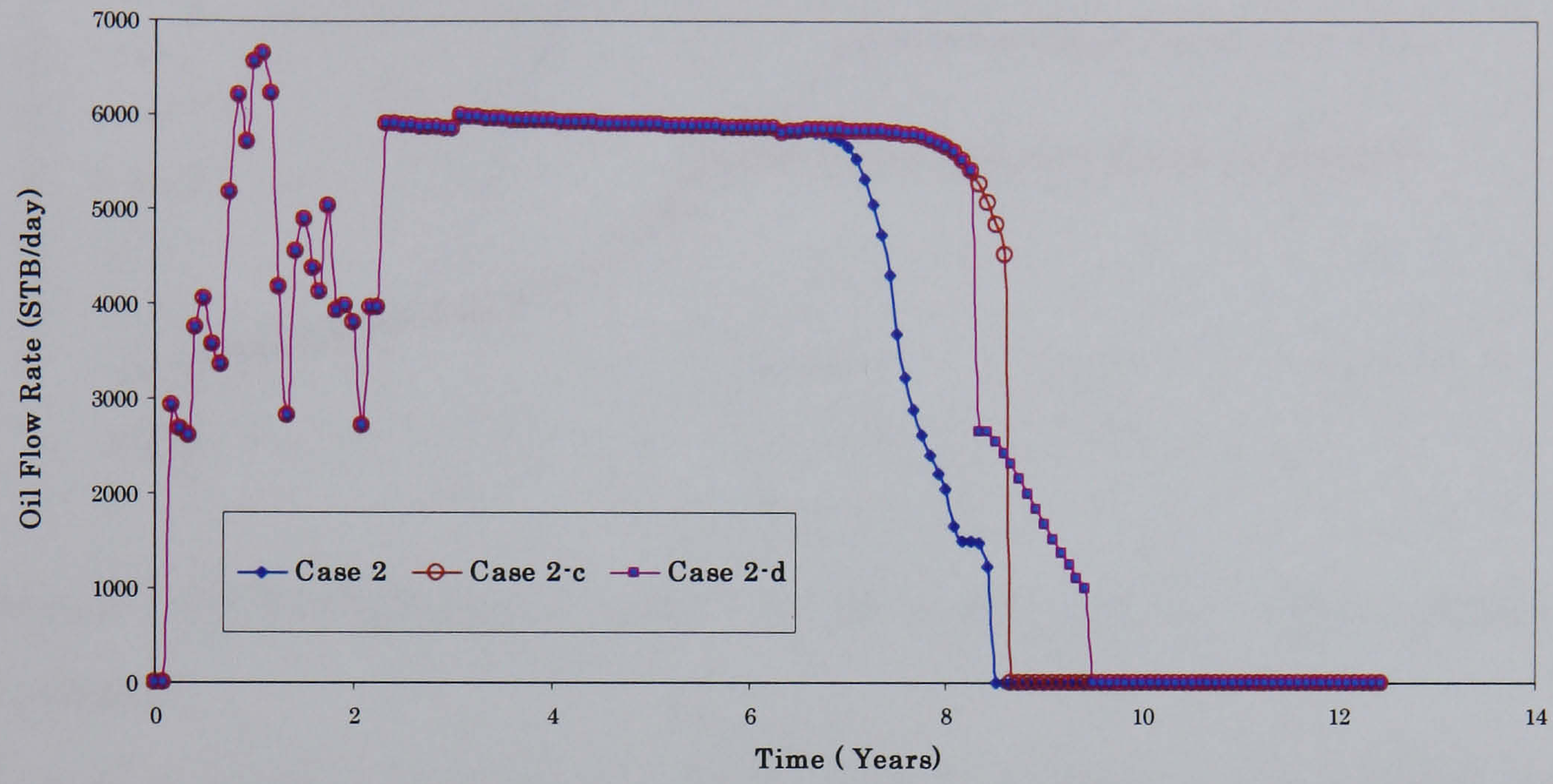


Figure 5.4.7 (a) CT Field oil production rate for Cases 2c and 2d compared to case 2

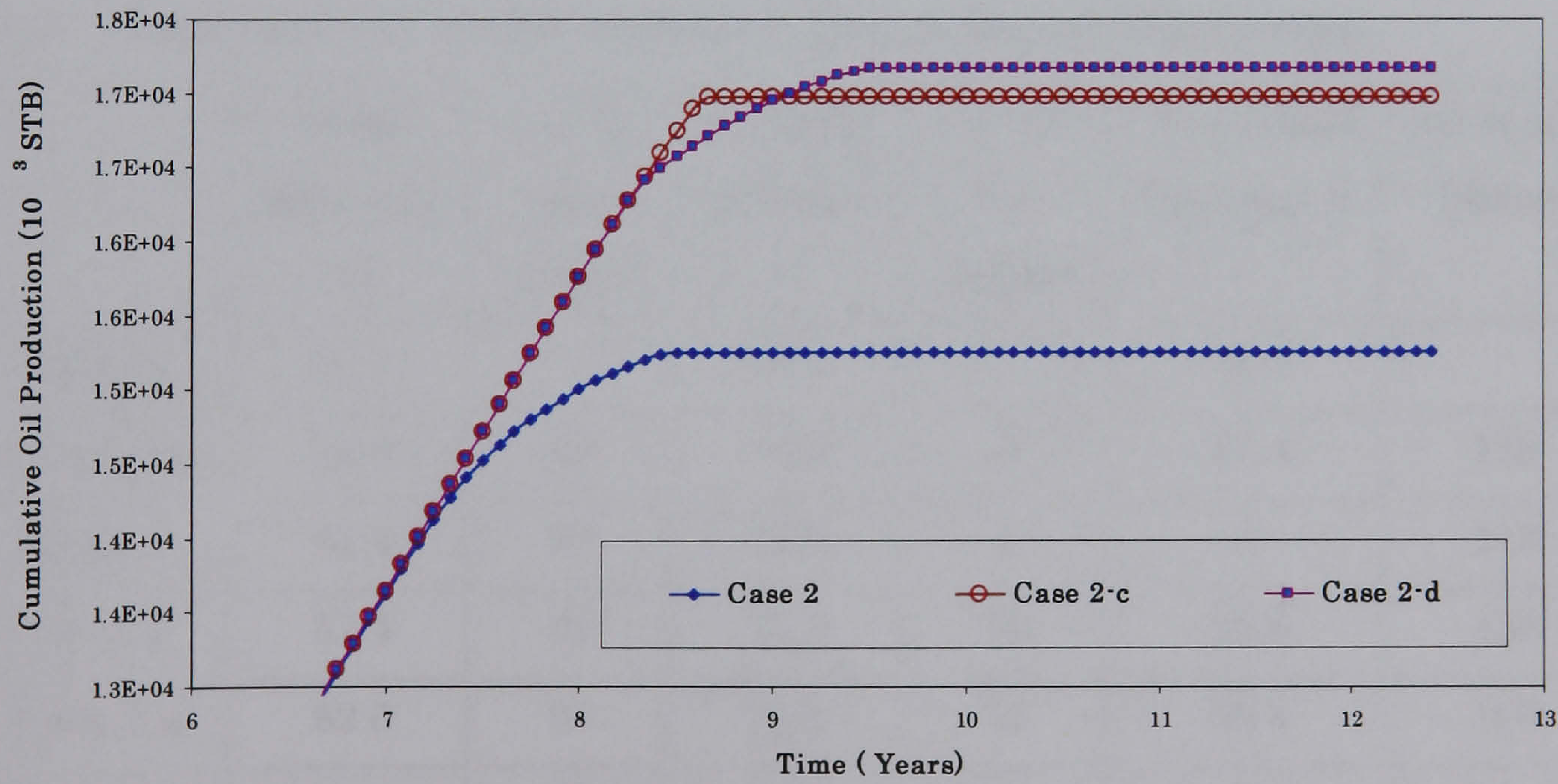


Figure 5.4.7 (b) CT Field cumulative oil production for Cases 2c and 2d compared to case 2

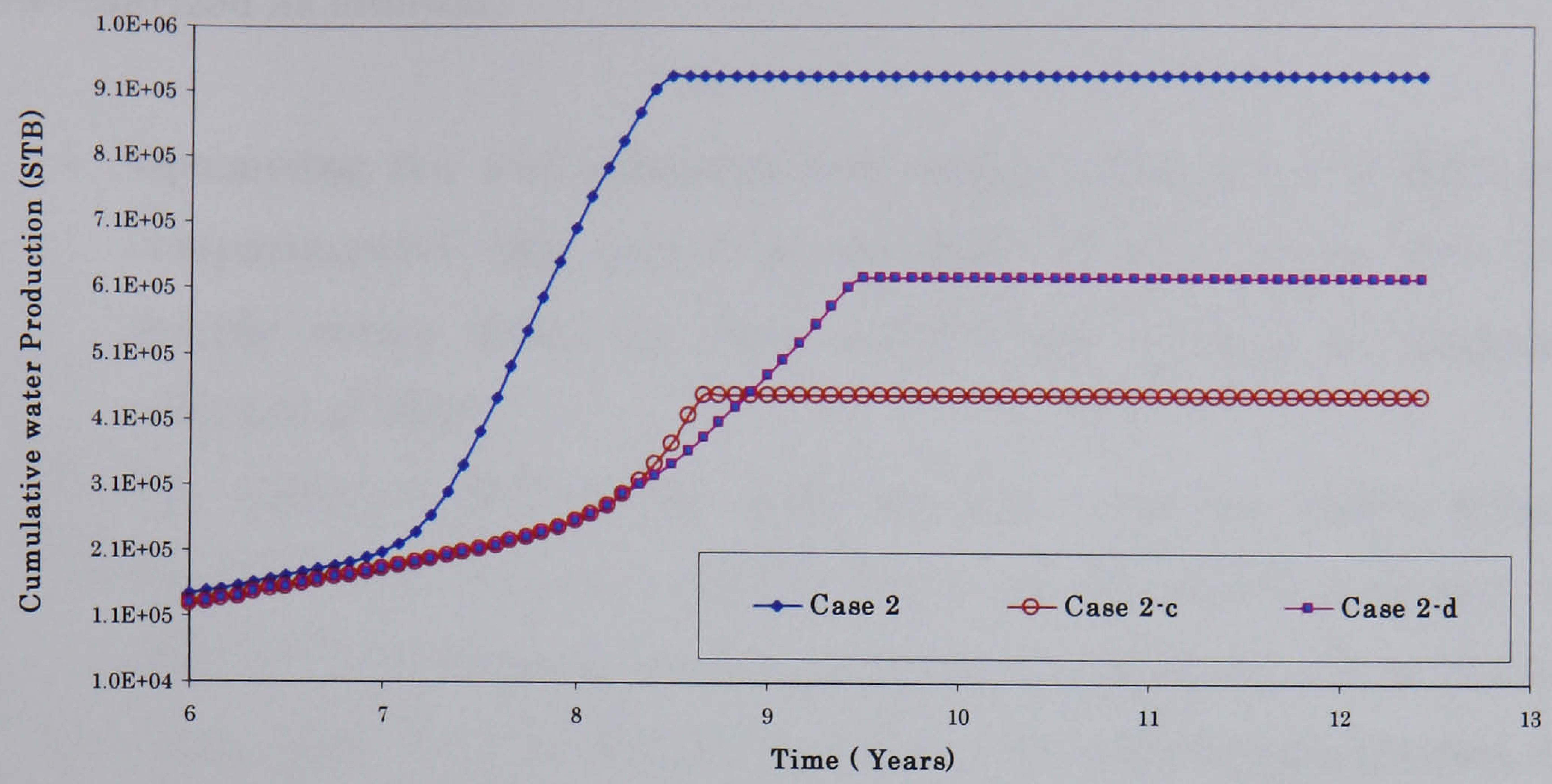


Figure 5.4.7 (c) Cumulative water production for Cases 2c and 2d compared to case 2

Injection of the water in the B4.5 sand (Case 2c) was successful. The resulting pressure maintenance of the B4.5 sand further extends the plateau period. Also installing one ICV for the B4.5 sand extends well life by almost one year by improving the tubing lift performance.

5.5 Comparison of the recovery factor for all the Cases

	Field Recovery %	+/- % wrt history	B4 Sand Recovery %	+/- % wrt history	B4.5 Sand Recovery %	+/- % wrt history
History	31.4	-	70.4	-	22.4	-
Base Case	52.8	68	76.4	9	47.4	112
Case 1	52.4	67	76.1	8	47	110
Case 2	57.4	83	77.3	10	52.8	136
Case 2-a	62.0	97	78.1	11	58.4	160
Case 2-b	62.0	97	78.5	11	58.3	160
Case 2-c	63.9	104	73.3	4	61.8	176
Case 2-d	64.8	106	74.2	5	62.6	179

Table 5.2 Recovery factor for all the cases

This study results are summarized in Table 5.2. The results may be summarized as follows:

1. Optimising the well geometry and design (sidetrack 3 of B4.5 sand compartments): this increased the field oil recovery by 60%. This mainly comes from the B4.5 sand which showed an increased recovery of 136%.
2. The value of IWT in the different well scenarios (using manual optimisation): an extra 14% increase in the field's recovery was achieved by installing one ICV to control the production from the B4.5 sand – This could be further increased once a better optimisation tool becomes available.
3. The value of water injection in the B4.5 sand: Maintaining the B4.5 sand pressure helps to reduce the effect of rock compaction while improving the sweep efficiency. This increases the recovery from the B4.5 sand by 16%.

5.6 Economic analysis

In order to compare the different case scenarios evaluated, a simple economic study has been carried out based on the following assumption resulting from discussion with ChevronTexaco:

- Cost of vertical well (Drilling and Completion) is US \$ 20 million
- Cost of sidetracked well (Drilling and Completion) is US \$ 25 million
- Cost of the installing Intelligent Completion in the well is US \$ 2 million (including 2 ICVs).
- Cost of the injection well (drilling and completion) is US \$ 13 million

Table 5.3 summarises the economic analysis based on the above assumption showing that IWT can double the income compared to the existing well with conventional completions.

Options tested	CAPEX 10^6 US $	Total Oil (10^6 STB)	Income at US $20/bbl net sale price 10^6 US $	Net income increase w.r.t. History 10^6 US $	Source of improvement
History	20	8.3	166	-	-
Sidetrack The B4.5 sand	25	15.3	306	135	Better reservoir management
Installation of IWT	27	16.4	328	155	Better sweep
Value of water Injection	40	17.1	342	156	Reduces compaction & better sweep

Table 5.3 Economic analysis showing value of water injection and deviated well but limited value of IWT.

5.7 Summary

This chapter discussed a new application of IWT, which has not been published before.

The conclusions from this chapter can be classified into two categories: general reservoir management and IWT conclusions.

Reservoir management conclusions

1. CT field shows value of well design as all cases studied redevelopment options gave greater oil recovery from the B4.5 sand compared to the

existing well design. Care should be taken that the reduced completion diameter associated with IWT does not limit the well production.

2. Maintaining the pressure can deliver extra oil by keeping the well on plateau for longer and delay the water breakthrough.
    a. This conclusion was supported by Ring et al. (2004), they reported that the well 237#2 (similar reservoir property) deliver the most contribution to the success of the field development and that is because of the pressure was maintained by the aquifer and hence the permeability reduction was minimised.
3. Water injection maintained the reservoir pressure, and reduced the effect of the rock compaction, leading to further improvement in recovery.

IWT Conclusions

Although the value of IWT to manage the drawdown around the wellbore was not achieved but this study recommend that better optimisation tool can be used to achieve this objective.

1. There is a potential value creation through development of a compacting reservoirs using IWT compared to a conventional well development.
    a. The value was created by commingling separated reservoirs (allowing a longer well producing life and by improved tubing performance resulting from managing the water production.
    b. The manual optimisation tool used was shown not to be sufficient for managing the draw down around the wellbore so that permeability damage can be minimized as a means of increasing recovery in compacting reservoirs.

Chapter 6

6. The impact of Intelligent wells for scale management – S Field Case study

This chapter discusses the potential advantages of IWT on Scale management. The S-Field (discussed in detail in Chapter 1) will be used as a field example. This chapter aims to study the possible benefits that can be added to scale management as result of using ICV technology.

6.1 Introduction to scale deposition

6.1.1 Scale deposition

Oil field scales are typically hard inorganic minerals that precipitate from a brine solution. There are two principal types of scale concerning the oil industry: sulphate scale and carbonate scale. The most common types of sulphate scale are barium sulphate ($BaSO_4$), strontium sulphate ($SrSO_4$) and calcium sulphate ($CaSO_4$), while calcium carbonate ($CaCO_3$) is the most common type of the carbonate scale (Mackay and Sorbie1999).

6.1.2 Problems associated with scale formation

Scale can be formed by mixing of incompatible brines. Two incompatible brines that react chemically with each other will precipitate. The scale formation by itself is not a problem, but the tendency to be deposited and to adhere to solid surfaces followed by growth of the initial deposits is the problem. Scale maybe deposited in the reservoir rock, tubing (Figure 6.1.1), perforations, subsurface safety valves, chokes, electrical submersible pump, separators, etc.; resulting in blockage problems in these components. Flow rate reductions may cause damage to valves and ESP functions (Davies 2001).

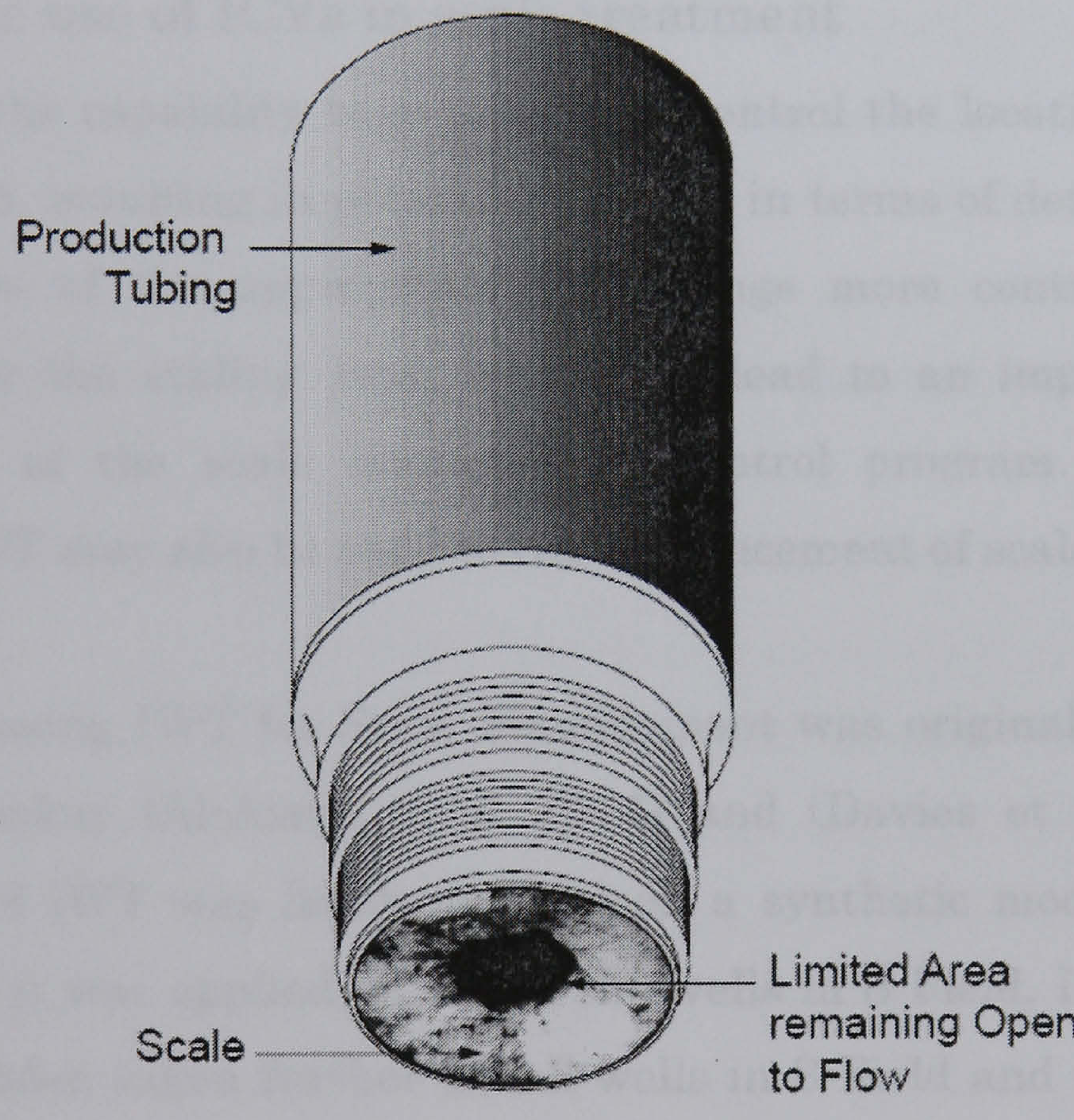


Figure 6.1.1 Restriction of tubular flow area due to scale control precipitation (Davies 2001)

6.1.3 Scale treatment

The most common method used to prevent the scaling problem is scale inhibitor squeeze treatment. Scale inhibitor squeeze treatments aim to prevent the scale formation by adding sufficient scale inhibitor to the produced water prior to its production into the wellbore. In these treatments the scale inhibitor solution is injected into reservoir in the scaling region. The injected inhibitor is retained by adsorption to the formation rock. Typically the treatment requires a 24-hour shut-in period (loss of production) after the interval of one month operational set-up reasons (Crabtree et al. 1999).

In order to achieve a successful scale inhibitor squeeze treatment, it is important to inject a sufficient volume of the inhibitor in the right place. (i.e. the rock through which the scaling brine will flow into the well).

6.1.4 The use of ICVs in scale treatment

IWT brings the capability to monitor and control the location of the water breakthrough, resulting in potential benefits in terms of detecting the scale zone. Closure of the appropriate ICV brings more control in terms of shutting only the scaling zone, which can lead to an improved economic performance of the scale management control program. The flexibility offered by IWT may also be used to control placement of scale inhibitor.

The idea of using IWT for Scale Management was originally developed by Mr. Eric Mackay (Al-Alawi et al. 2005) and (Davies et al. 2005a). The application of IWT was firstly applied on a synthetic model to prove the concept then it was applied on one of the wells in S-Field. In this study the concept has been taken further for all wells in S-Field and using two water injection scenarios.

6.2 Application of the use of ICVs in scale treatment in S-Field

The S-Field reservoir is interpreted as consisting of four zones with distinctive variations in their permeability. Chapter 7 of this thesis discuss S-Field redevelopment using five intelligent producer with two different water injection scenarios, one with conventional three injectors and the other is one smart injector, the injectors are injecting seawater to support the reservoir pressure and provide sweep, based on field and zonal voidage replacement criteria. We will use these two cases to identify how the ICVs could be used in scale management, since modelling both the total water breakthrough and seawater breakthrough at a valve level showed that seawater was only breaking through at some of the valves (Figures 6.3.2 to 6.3.5).

6.2.1 Benefit of using ICVs in scale treatment

Closing only the scaling zone instead of closing the entire well prior to treatment will result in a greater reduction in oil production, during the period prior to the squeeze treatment. In addition, injection of scale inhibitor into a conventional well or an IWT well with all valves open, will result in inefficient placement of inhibitor. However, controlling this process by only injecting the inhibitor via the scaling valve into the scaling layer as a result of from opening only one ICV and closing the rest could result in more effective placement of inhibitor and hence improved cost efficiency.

6.3 S-Field – Intelligent producers and conventional injectors

As mentioned before, the S-Field reservoir consists of four separate layers (Tarbert, Upper Ness, Lower Ness and Etive-Rannoch). The existing water injection scheme consists of three conventional injectors. However the water was only injected to Tarbert and Etive-Rannoch but no water was injected to Ness Formation. Table 6.1 shows the details of all producing valves installed in five intelligent producers and corresponding to the formation they control the production from.

Production Wells	Well SM-1	Well SM-2	Well SL-1	Well SL-2	Well SL-3
Tarbert	SM-1A	SM-2A	SL-1A	SL-2A	SL-3A
Upper Ness	SM-1B	SM-2B	SL-1B	N/A	N/A
Lower Ness	SM-1C	SM-2C	SL-1C	N/A	N/A
Etive-Rannoch	SM-1D	SM-2D	SL-1D, SL-1E & SL-1F	SL-2B	SL-3B

Table 6.1 Shows the eighteen ICVs in production wells and the formations in which they are installed.

6.3.1 Monitoring of seawater movement

Figure 6.3.1 shows the concentration of seawater at the last time step, it indicate that there is only seawater production from the zones completed in Tarbert or Etive-Rannoch and very little water from the Upper Ness. There is no seawater production from Lower Ness Formation (see Table 6.1). Details of reservoir model layering description can be found in Chapter 1.

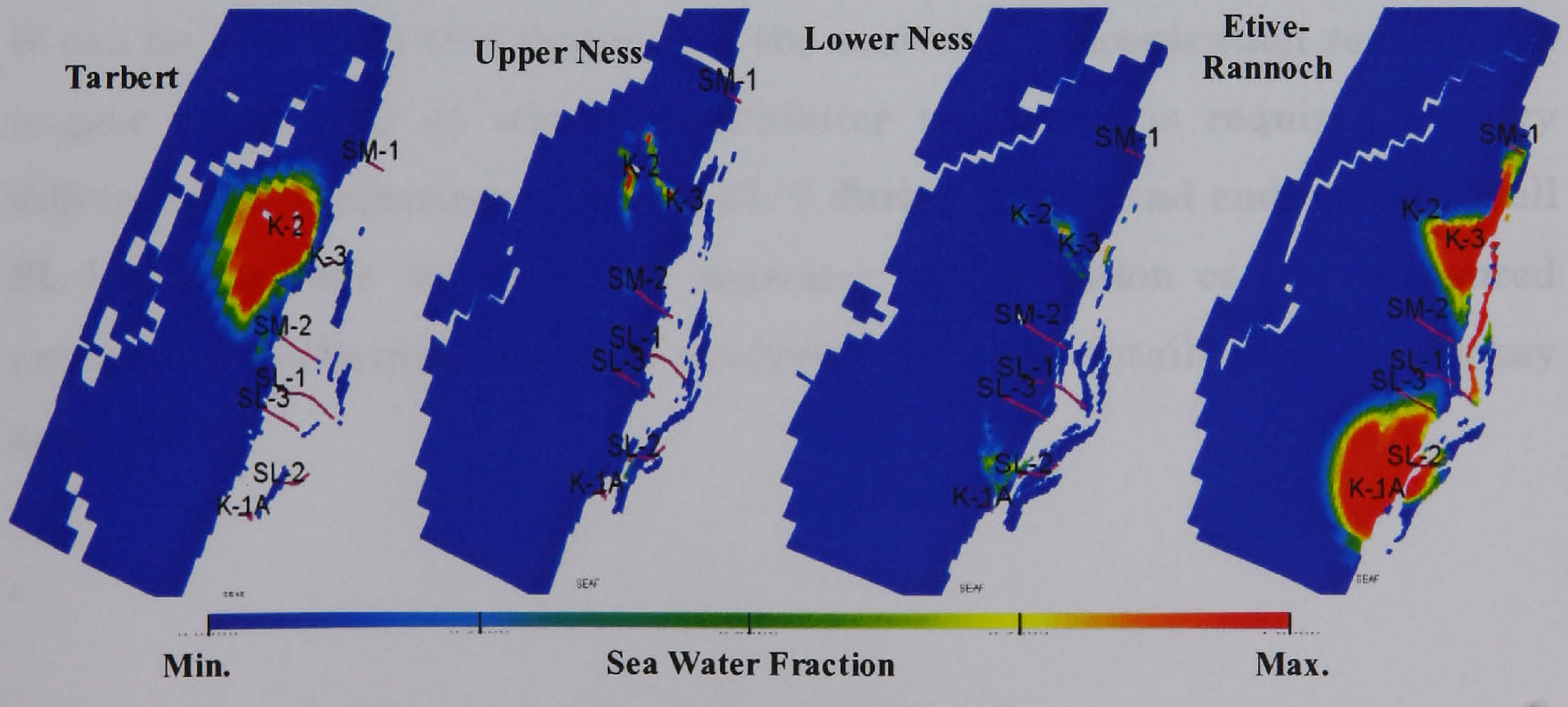


Figure 6.3.1 Conventional Injection: Seawater is mainly produced from the two zones targeted by injection (Tarbert & Etive-Rannoch) – Reservoir dip is 6°

Figure 6.3.2 shows the total (formation + sea) water flow rate versus time for the all-producing wells. The (total) water breakthrough time is similar for all the wells.

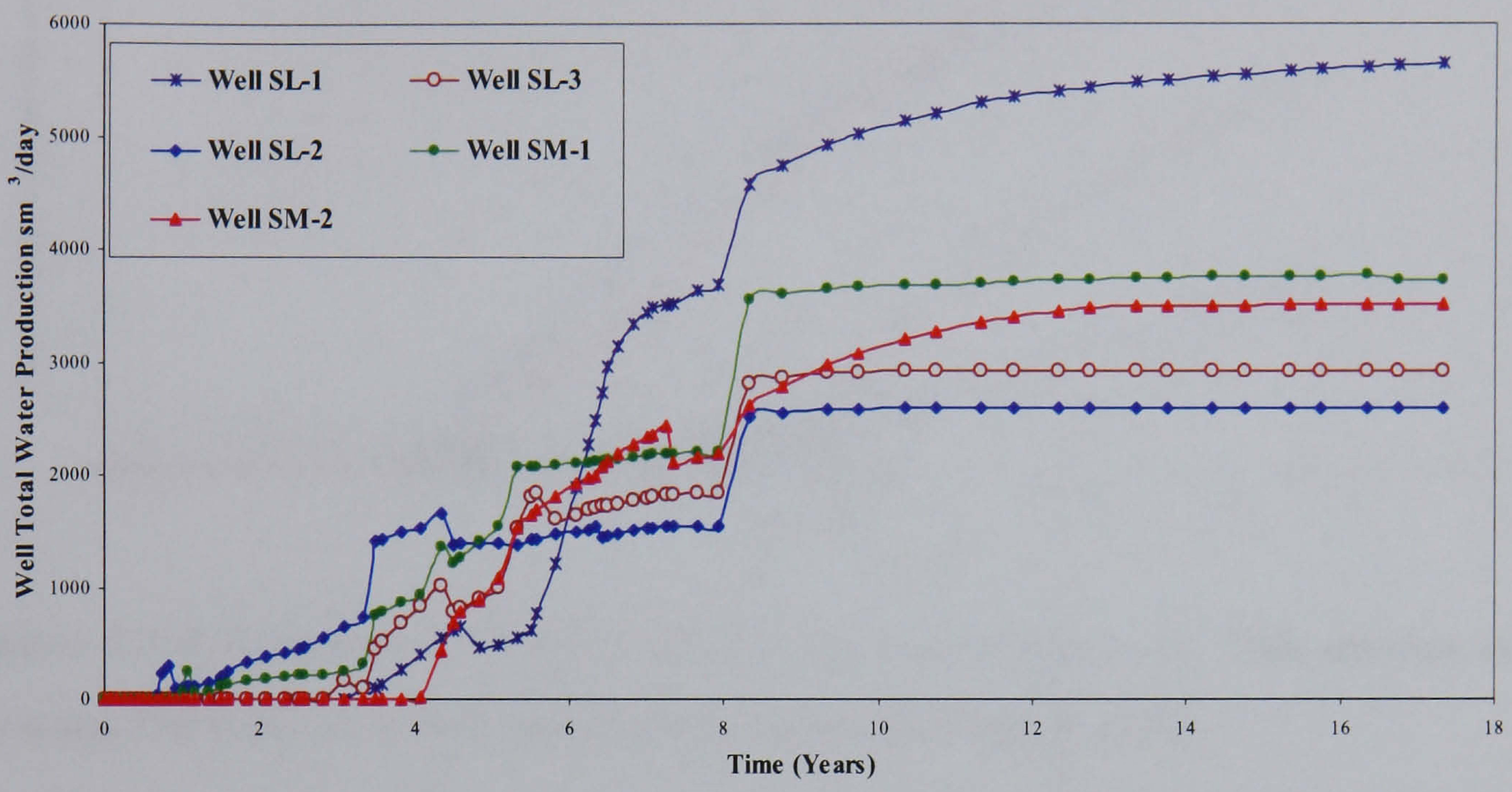


Figure 6.3.2 S-Field total water production per well - Conventional injectors

A seawater tracer was introduced into the model allow calculation of both the well and the ICV seawater flow rates and concentrations. The seawater concentration for all producing wells versus time is plotted in Figure 6.3.3. It can be seen from this figure that the seawater concentration reaches the trigger value (2%) at which an inhibitor treatment is required at very different times; starting with well SL-2 during year 4 and ending with Well SL-1 during year 10. (N.B. 2% seawater concentration can be measured practice by performing nine ion analysis - for more details refer to Mackay at al. 2000).

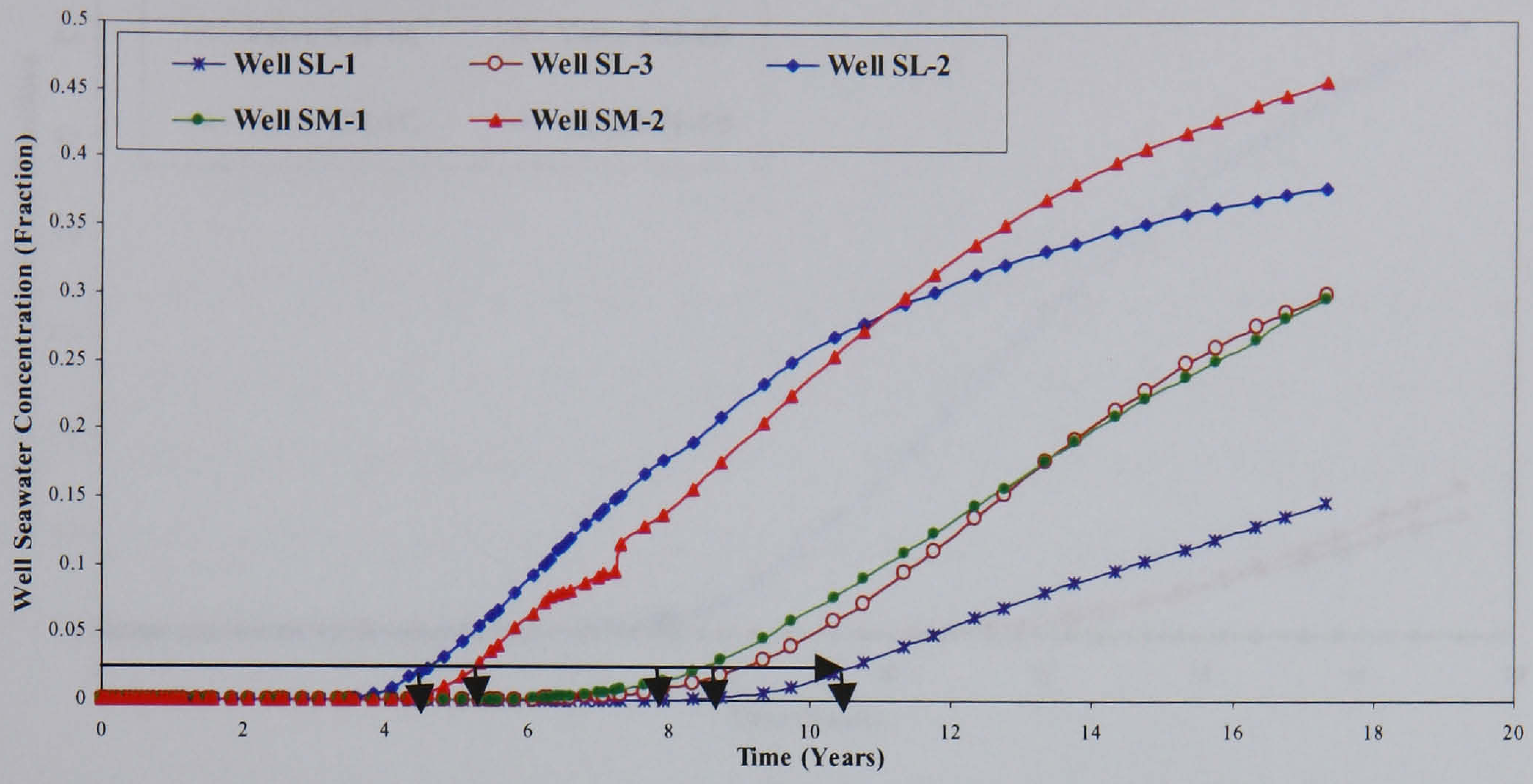


Figure 6.3.3 Seawater concentration for all producing wells. The arrows is showing the time at which well seawater concentration is 2%

6.3.1.1 Analysis of seawater production at the ICV level.

Seawater is injected into Etive-Rannoch Formation only by the existing water injection system (described previously). Hence seawater will not be produced from all the ICVs installed in the production wells (Table 6.1). Figures 6.3.4 and 6.3.5 show the zonal seawater concentration for two production wells (SM-1 and SM-2) as an example of this type of behaviour. In these two wells the seawater is produced from only three out of the four valves installed. It was also noted that there was 4-year gap in seawater breakthrough between ICVs SM-1A and SM-1B. It will thus not be necessary to treat the whole well with inhibitor during this time period.

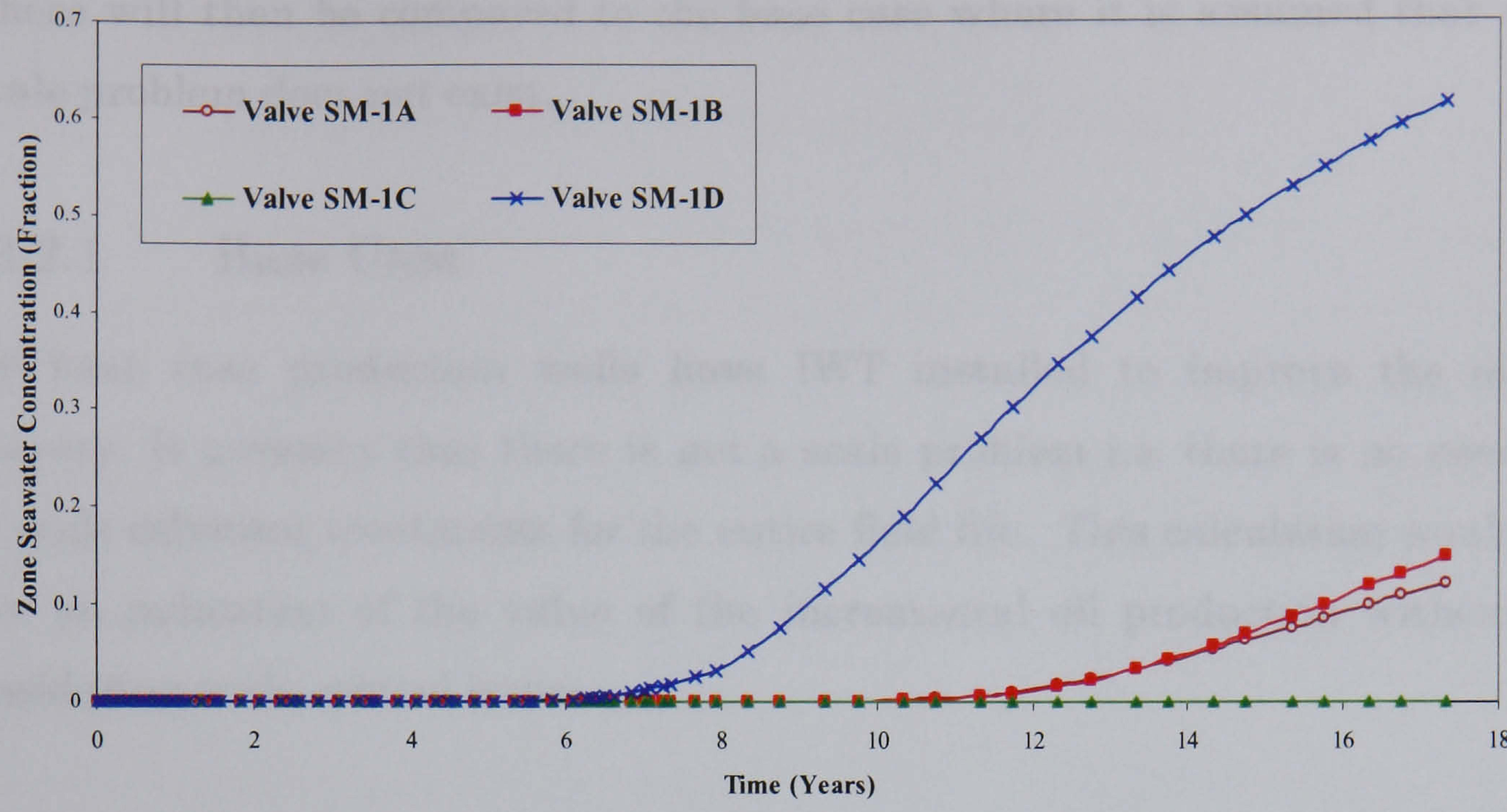


Figure 6.3.4 Well SM-1 valves seawater concentration

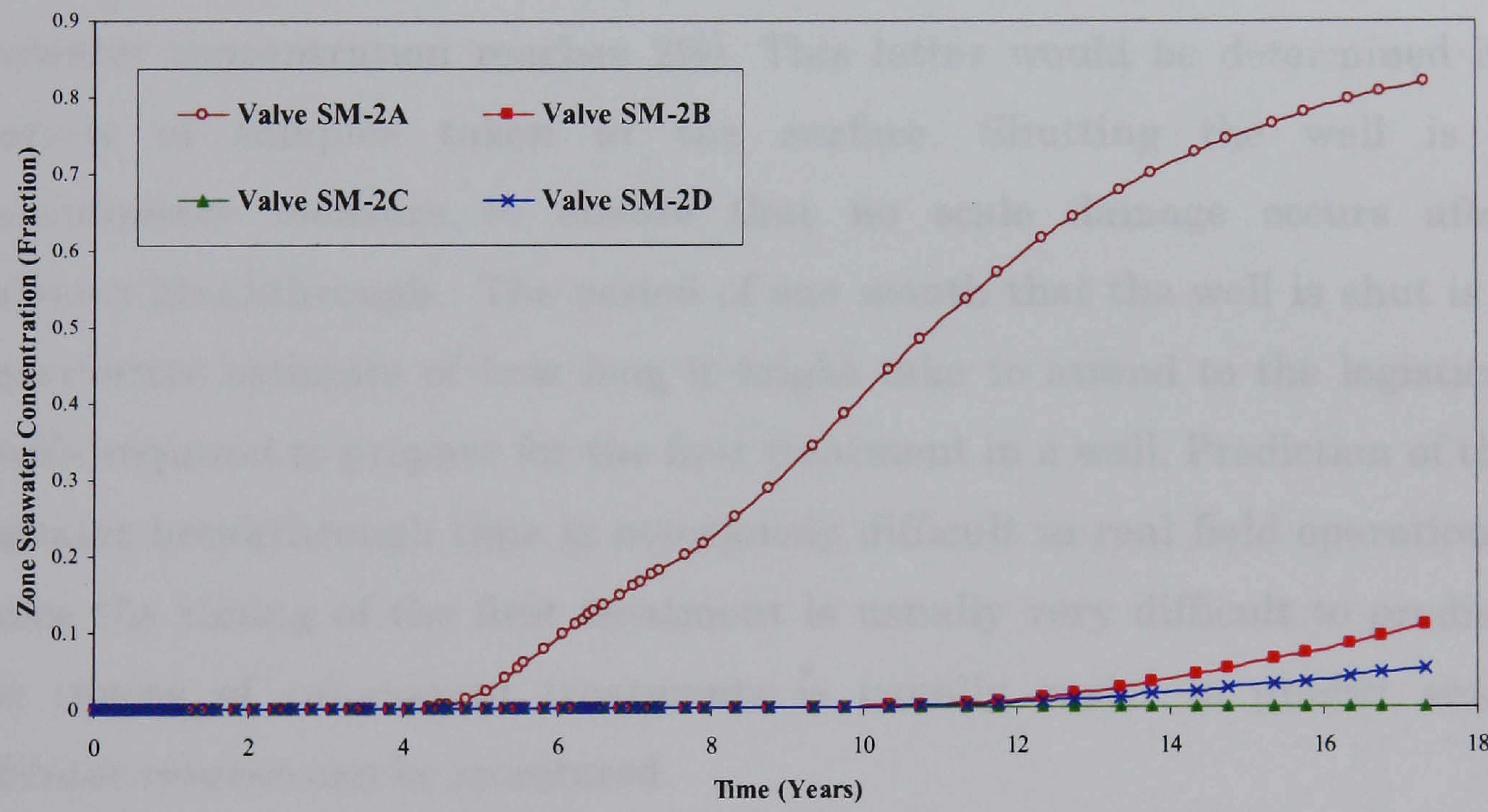


Figure 6.3.5 Well SM-2 valves seawater concentration

6.3.2 Options for scale treatment

In order to value the ability to treat the scaling zones individually we have run two cases assuming two different scale inhibitor treatment scenarios.

(1) Treat the whole well or

(2) Treat only the zone that produces the seawater.

These will then be compared to the base case where it is assumed that a scale problem does not exist.

6.3.2.1 Base Case

The base case production wells have IWT installed to improve the oil recovery. It assumes that there is not a scale problem i.e. there is no need for scale inhibitor treatments for the entire field life. This calculation would give an indication of the value of the incremental oil production without considering scale control issues.

6.3.2.2 Case One (*IWT installed in all production wells but not used for scale inhibitor placement)*

The entire well is shut for one month when seawater breakthrough occurs (seawater concentration reaches 2%). This latter would be determined by analysis of samples taken at the surface. Shutting the well is a precautionary measure to ensure that no scale damage occurs after seawater breakthrough. The period of one month that the well is shut is a conservative estimate of how long it might take to attend to the logistical details required to prepare for the first treatment in a well. Prediction of the seawater breakthrough time is notoriously difficult in real field operations. Hence the timing of the first treatment is usually very difficult to predict. The timing of subsequent treatments is usually easier to predict since inhibitor returns can be monitored.

6.3.2.3 Case Two (*IWT installed in all production wells and used for scale inhibitor placement)*

Closing the offending ICVs when their seawater concentrations reaches 2% (assuming this can be detected and measured), for one month to avoid scale damage, while production from the other zones is maintained.

6.3.3 Simulation results and discussion

6.3.3.1 Close the entire well for scale treatment

Figure 6.3.6 shows the results for case one. It is realized that a further treatments are required when inhibitor is depleted, with the assumption that it can be programmed without excessive lost production. Figure 6.3.7 shows the loss of well production during the time of treatment preparation. Note that the wells returned to production after the squeeze treatment, but the squeeze treatment itself was not included in the model due to its small volume.

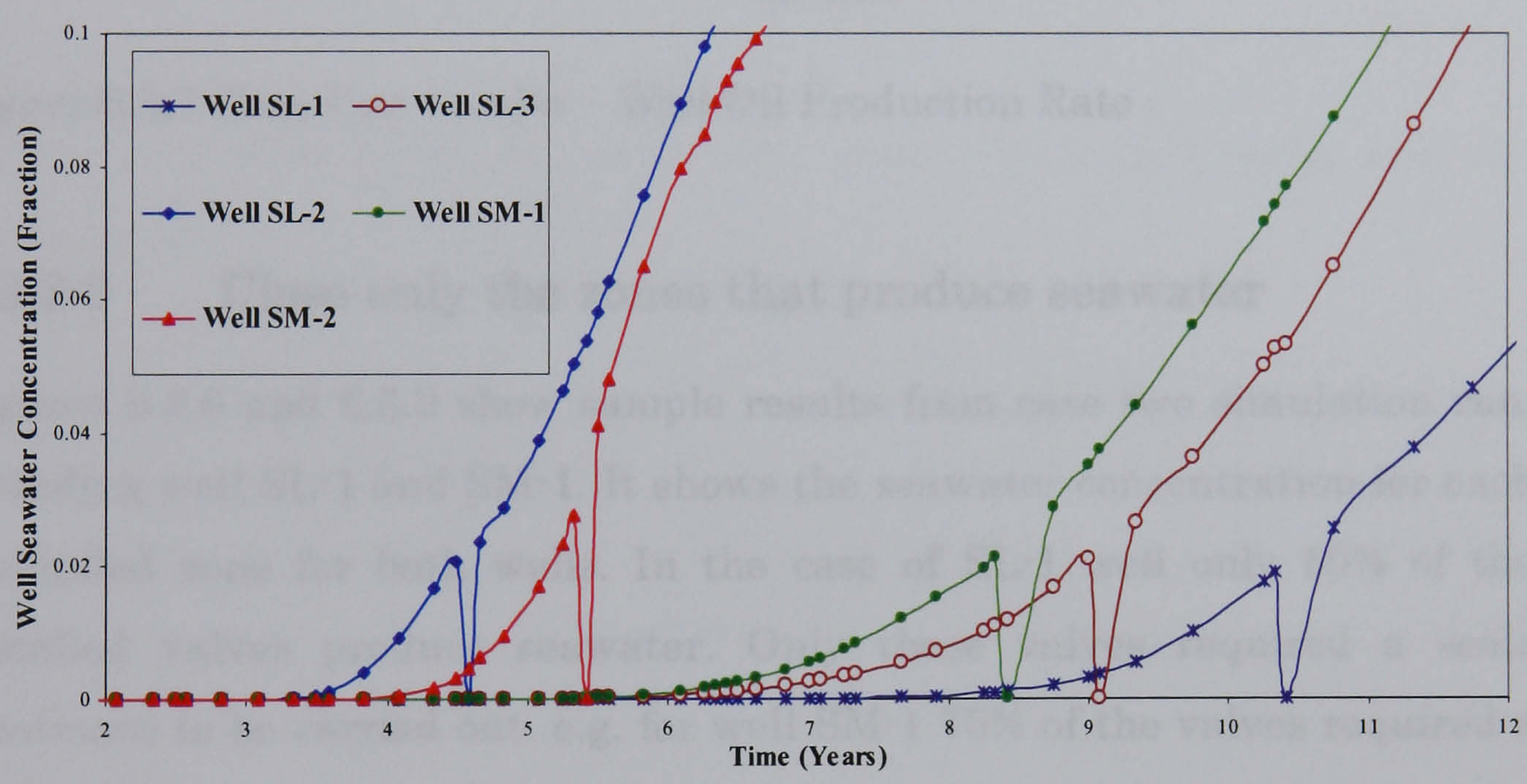


Figure 6.3.6 S-Field simulation results for Case one – Scale treatment at the well level

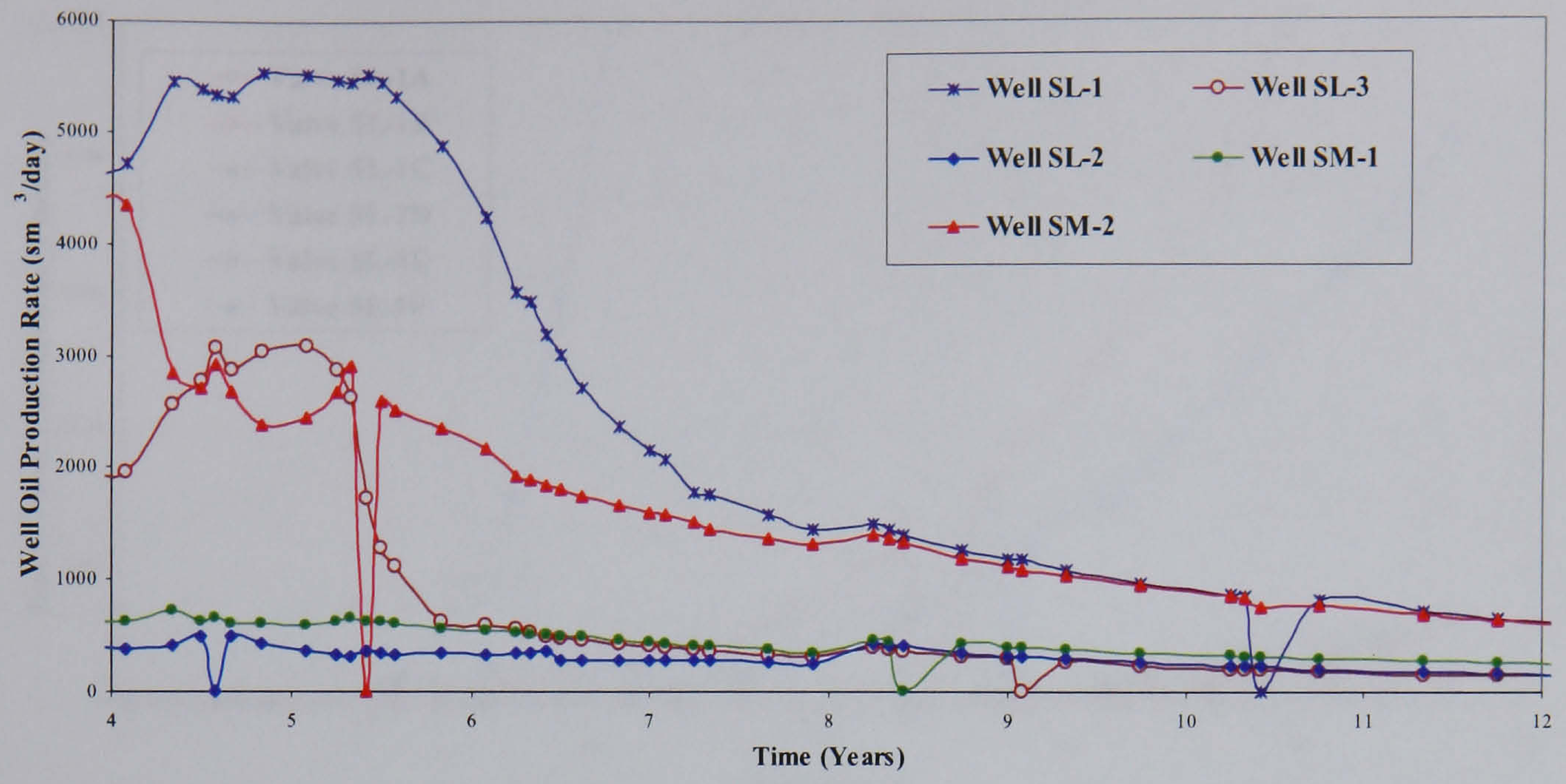


Figure 6.3.7 Case One results – Well Oil Production Rate

6.3.3.2 Close only the zones that produce seawater

Figures 6.3.8 and 6.3.9 show sample results from case two simulation run, including well SL-1 and SM-1. It shows the seawater concentration for each controlled zone for both wells. In the case of SL-1 well only 50% of the installed valves produce seawater. Only these valves required a scale treatment to be carried out. e.g. for well SM-1 75% of the valves required a scale treatment.

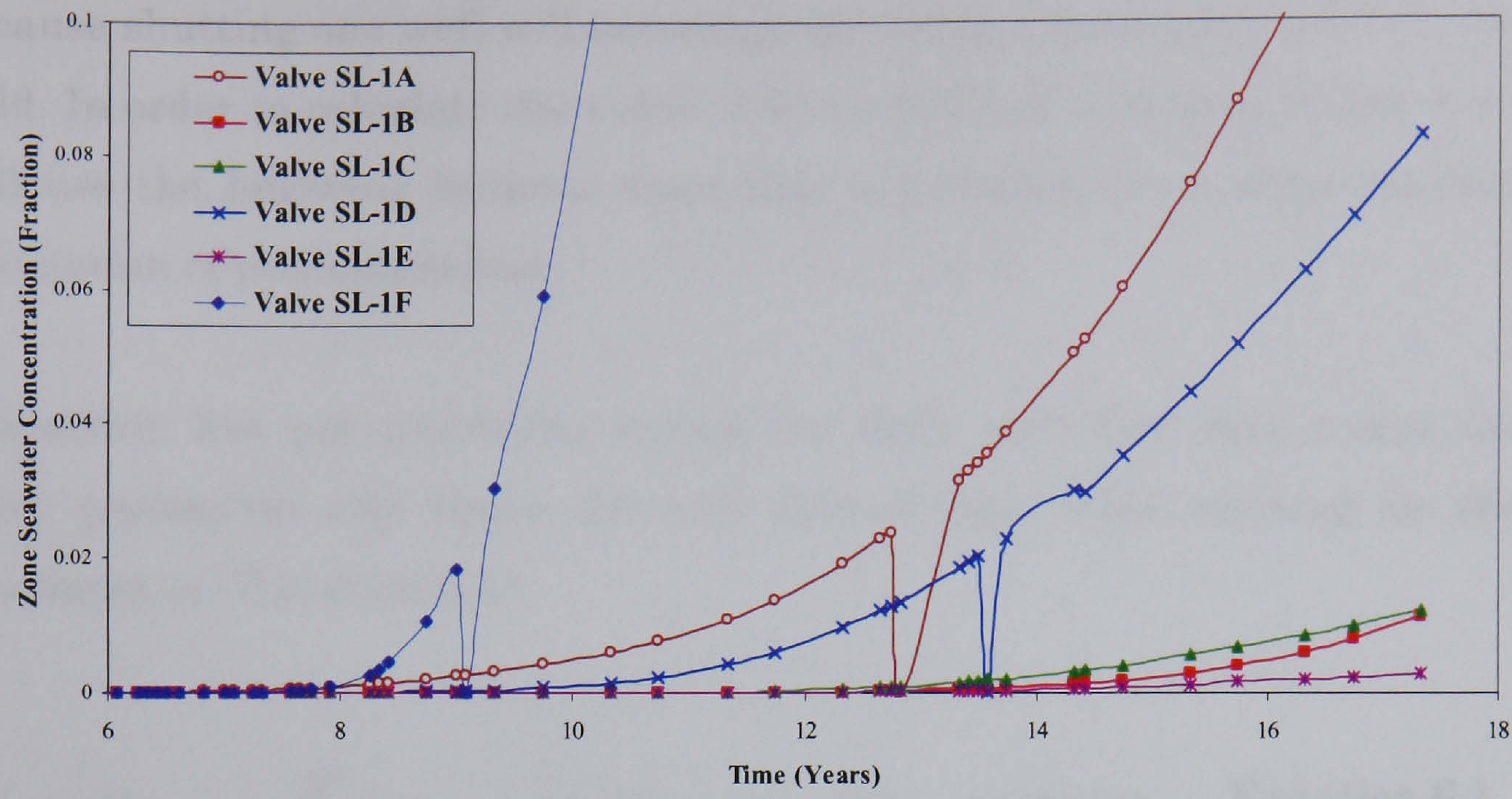


Figure 6.3.8 Simulation results for Case Two – Well SL-1 zonal seawater concentration

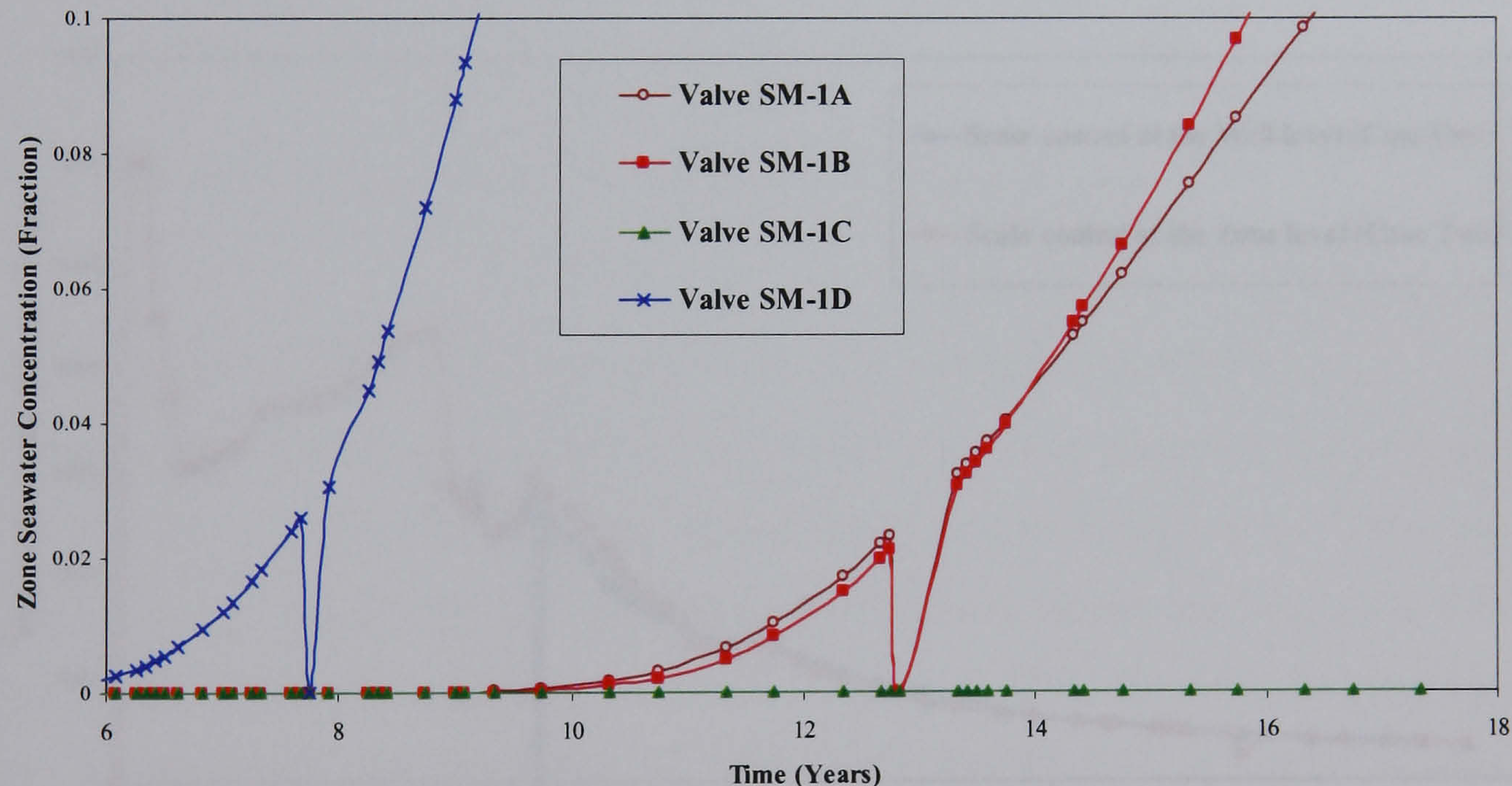


Figure 6.3.9 Simulation Results for Case Two – Well SM-1 Zonal seawater Concentration

6.3.3.3 Comparison between the two cases

It is not been possible to compare the well production profile for both cases directly due to the way that the Eclipse model is set-up in this case. This is because shutting one well will encourage production from other wells in the field. In order to calculate the value of using ICVs in scale management we will use the following formula since this is judged to be a more realistic calculation of production loss:

Production lost per treatment equals the daily well flow rate minus the valve production rate times the well shut-in time while waiting for the treatment or (Equation 6.1):

$$\Delta V = \left(Q_{oil\,(well)} - \sum_{i=1}^{i=n} Q_{oil\,(valve)} \right) * Days\_of\_lost\_production \quad \text{..Equation 6.1}$$

Where:

ΔV is the volume of deferred oil production per treatment and

n is the number of the valves that need treatment

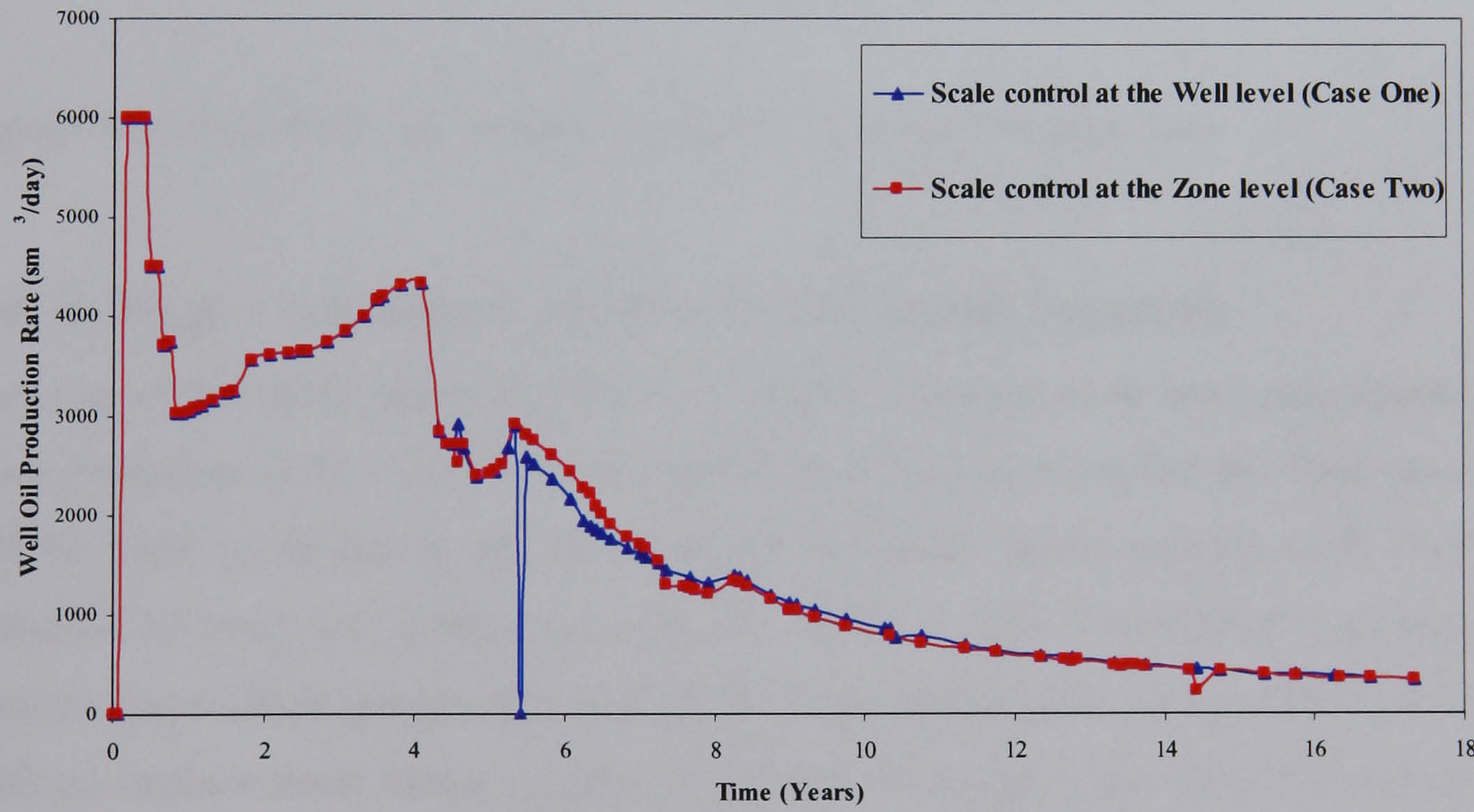


Figure 6.3.10 S-Field comparison between case one and case two – SM-2 well's oil production rate.

The time of seawater breakthrough is a key factor controlling the economics of the difference between a well treatment and a valve treatment. The economic effect will be greater when seawater breaks through earlier i.e. when the production capacity of the other zones in the well are at their greatest. Figure 6.3.11 shows the difference in field oil production rate between the two cases. It shows the drop in production due to closing the whole well for the treatment period compared to the small drop in production due to closing only one valve.

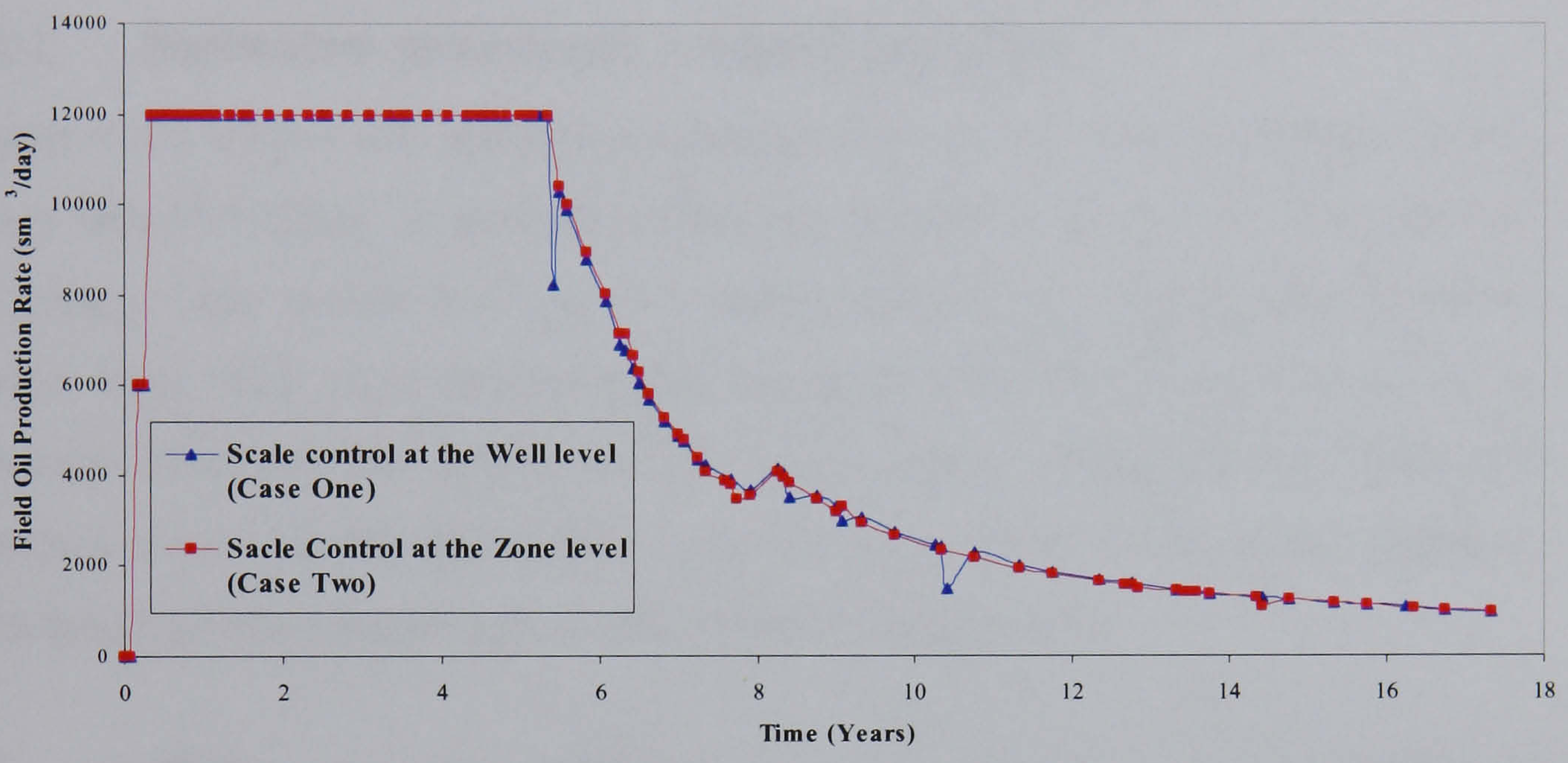


Figure 6.3.11 S-Field Oil Production Rate – Cases One and Two

6.4 S-Field – intelligent producers and smart injectors

Because of multiple layered S-Field a smart injection case was introduced (background to this case to be described in detail in Chapter 8). This case will be used to illustrate the advantages of Smart Scale control with IWT installed in both the producers and the injector. The Intelligent Injection system gives much greater control of the Injection Profile. It achieves zonal voidage replacement using a reduced number of wells. It gives better sweep (higher recovery). In order to bring scale control advantages. Three cases, similar to those defined in section 6.3.2, were tested.

Base Case: Intelligent Producers and Injectors - no scale damage takes place.

Case One: Shut entire Intelligent Production well when seawater concentration reaches 2 % for one month until squeeze treatment can be carried out.

Case Two: Intelligent production well closes scaling ICV when its seawater concentration reaches 2 % for one month until treatment can be carried out.

6.4.1 Seawater movement – smart injection

Figure 6.4.1 shows the seawater concentration at the last time step for the smart injection case. It indicates that the seawater is now injected into all the zones. This occurs because the smart injection system was designed to ensure that each zone received the required amount of water to keep its pressure constant i.e. zonal voidage replacement. However the seawater does not reach all the wells due to the location of the single smart injector. This fact will play major role in the scale management.

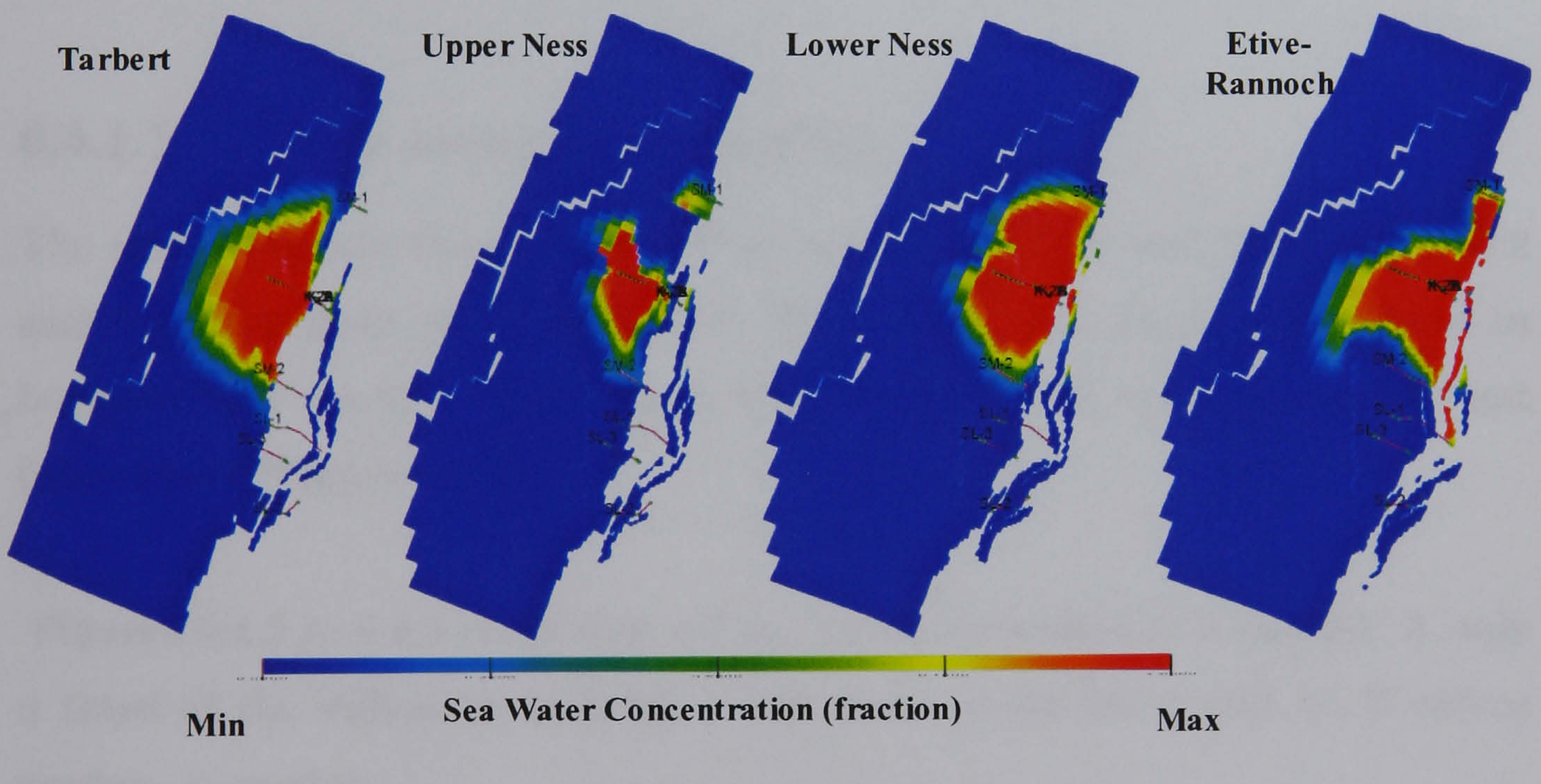


Figure 6.4.1 S-Field seawater concentration per layer at last time step– Smart Injection Case

Figure 6.4.2 shows that only three wells produce seawater (compared to the five wells for the conventional injector case). This is due to the relative location of the smart-Injector-Producer wells, resulting in no seawater production from wells SL-2 and SL-3 (i.e. no scale problem in these two wells).

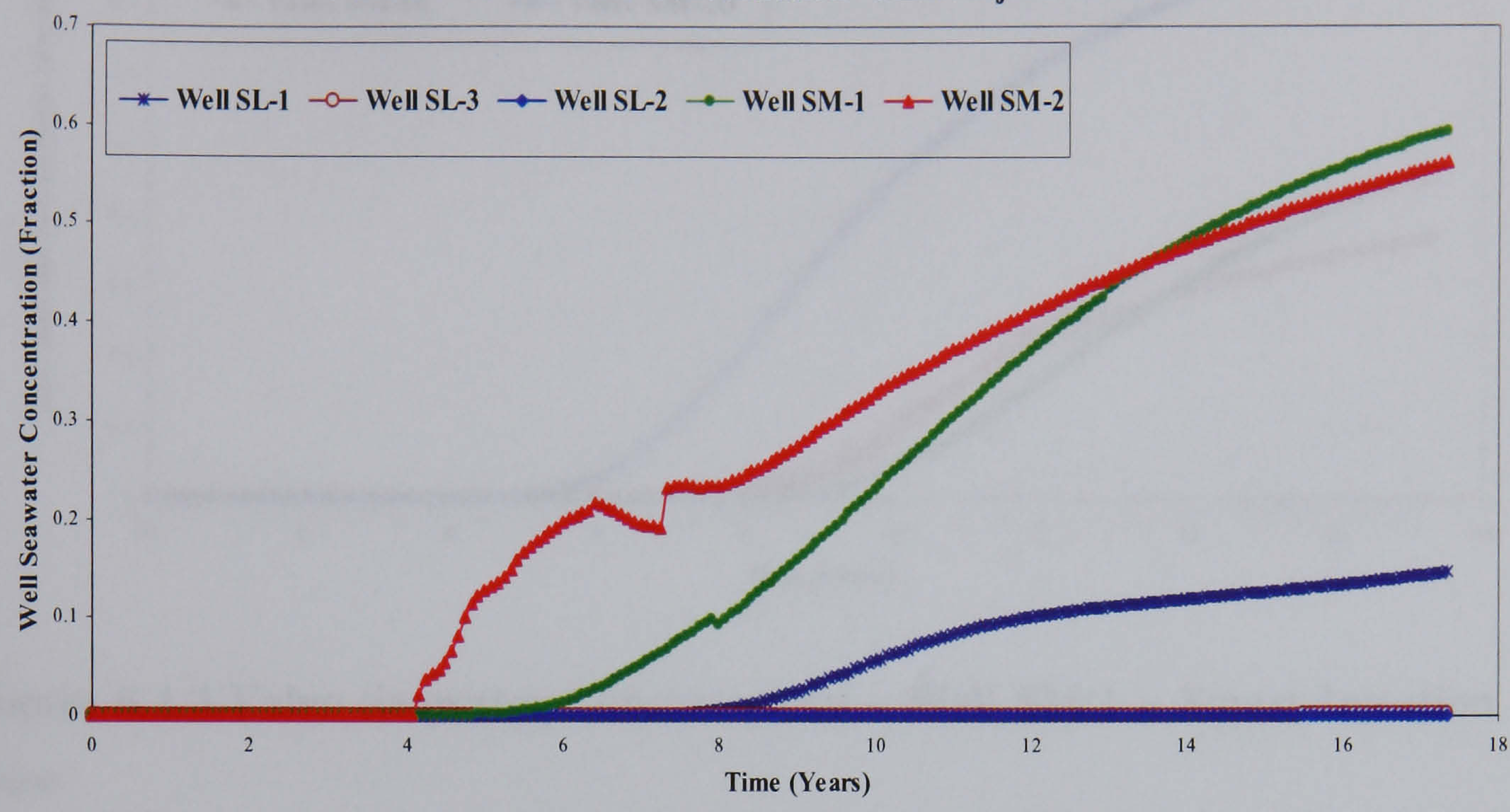


Figure 6.4.2 S-Field wells seawater concentration in the Smart Injection Case

6.4.1.1 Zone seawater production

The smart Injector (See Chapter 8) is located between well SM-1 and SM-2 and very far from wells SL-2 and SL-3, with SL-1 being somewhere in between. The result is that seawater is produced from certain wells and not from others (Figure 6.4.2).

Figures 6.4.3 to 6.4.5 show that all the valves in wells SM-1 and SM-2, only a third of the valves in well SL-1 and none of the SL-2 and SL-3 valves produce seawater.

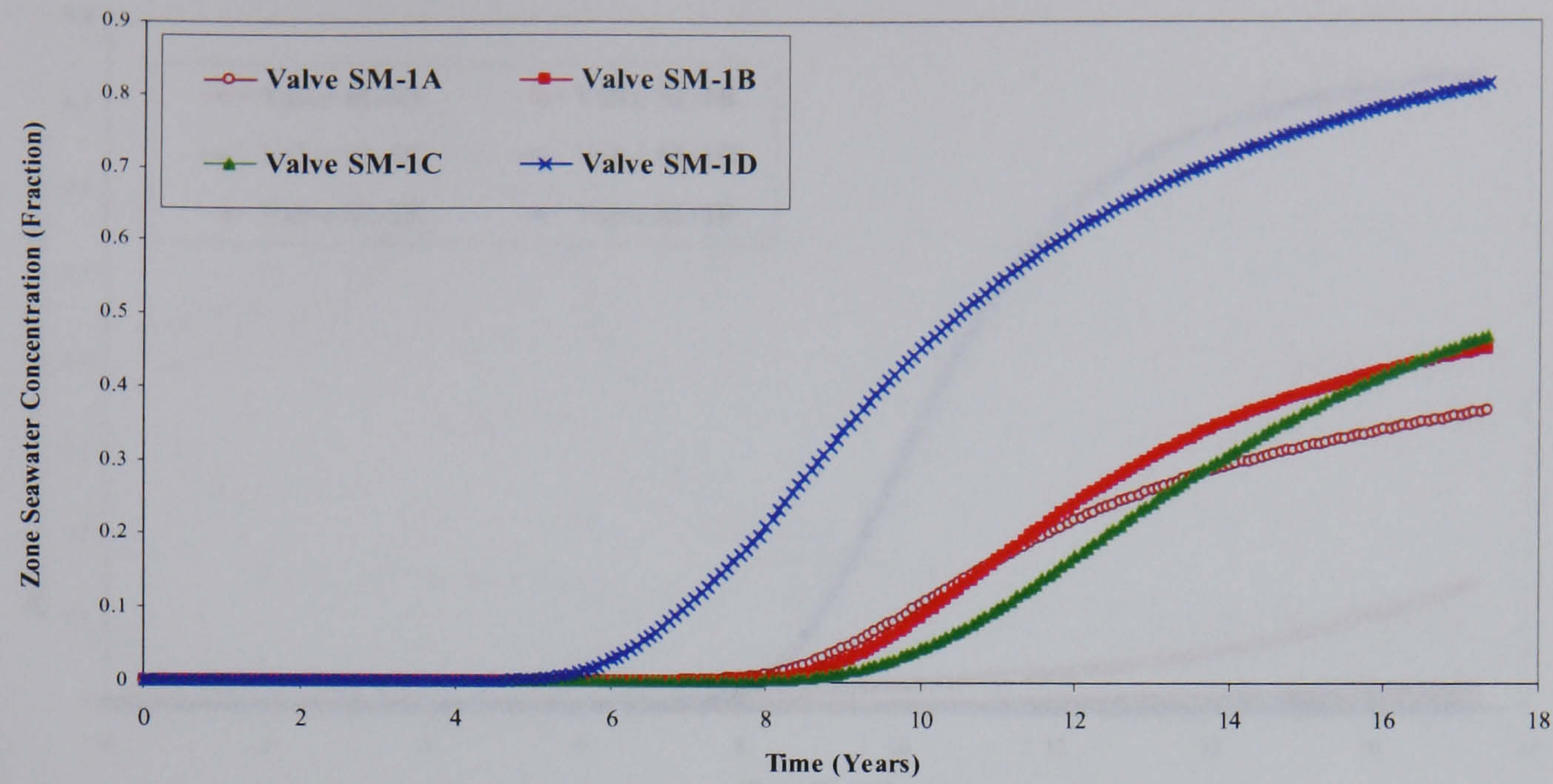


Figure 6.4.3 Valve Seawater Concentration – Well SM-1 – Smart Injection Case

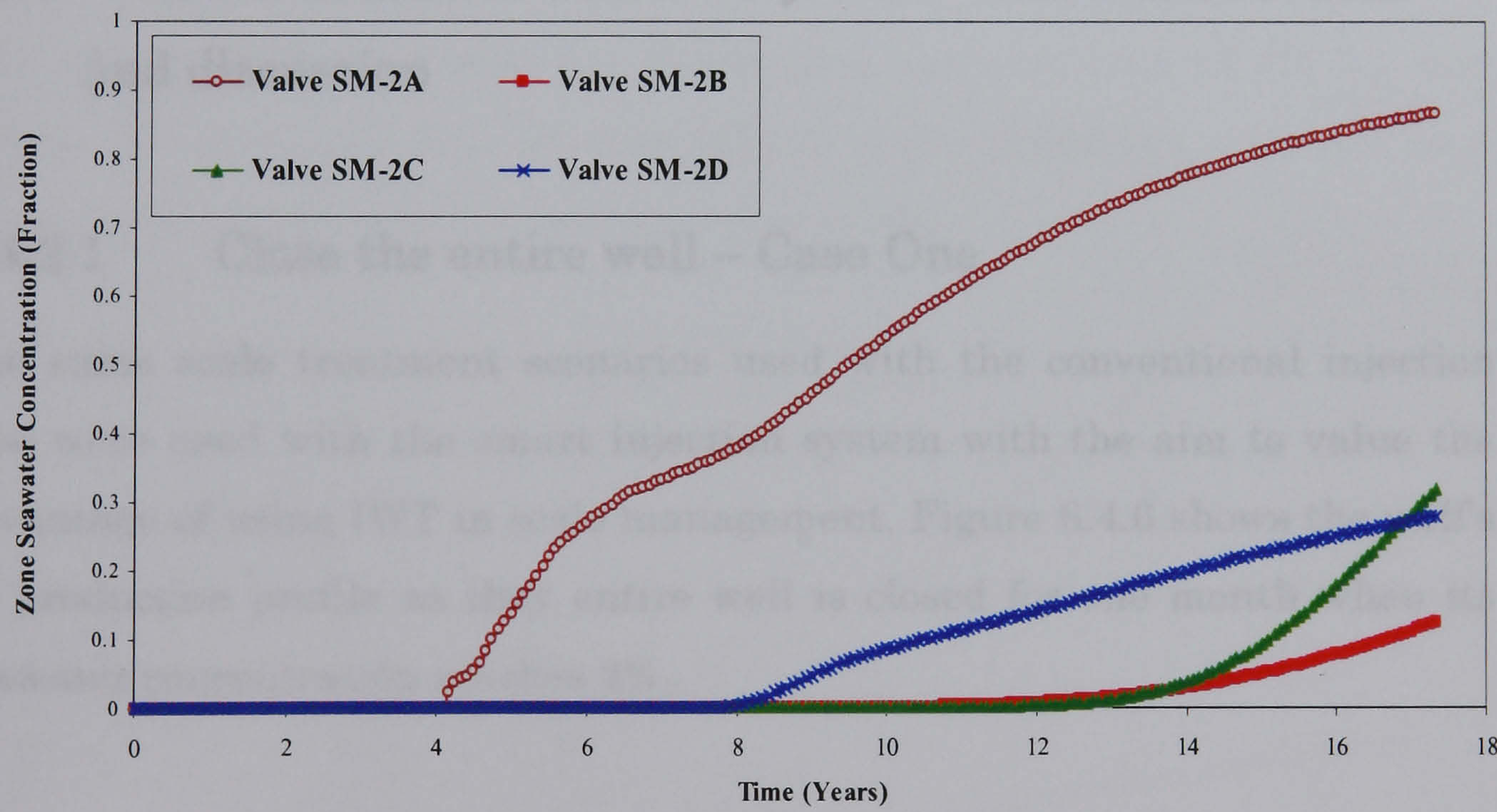


Figure 6.4.4 Valve seawater concentration – well SM-2 – smart injection Case

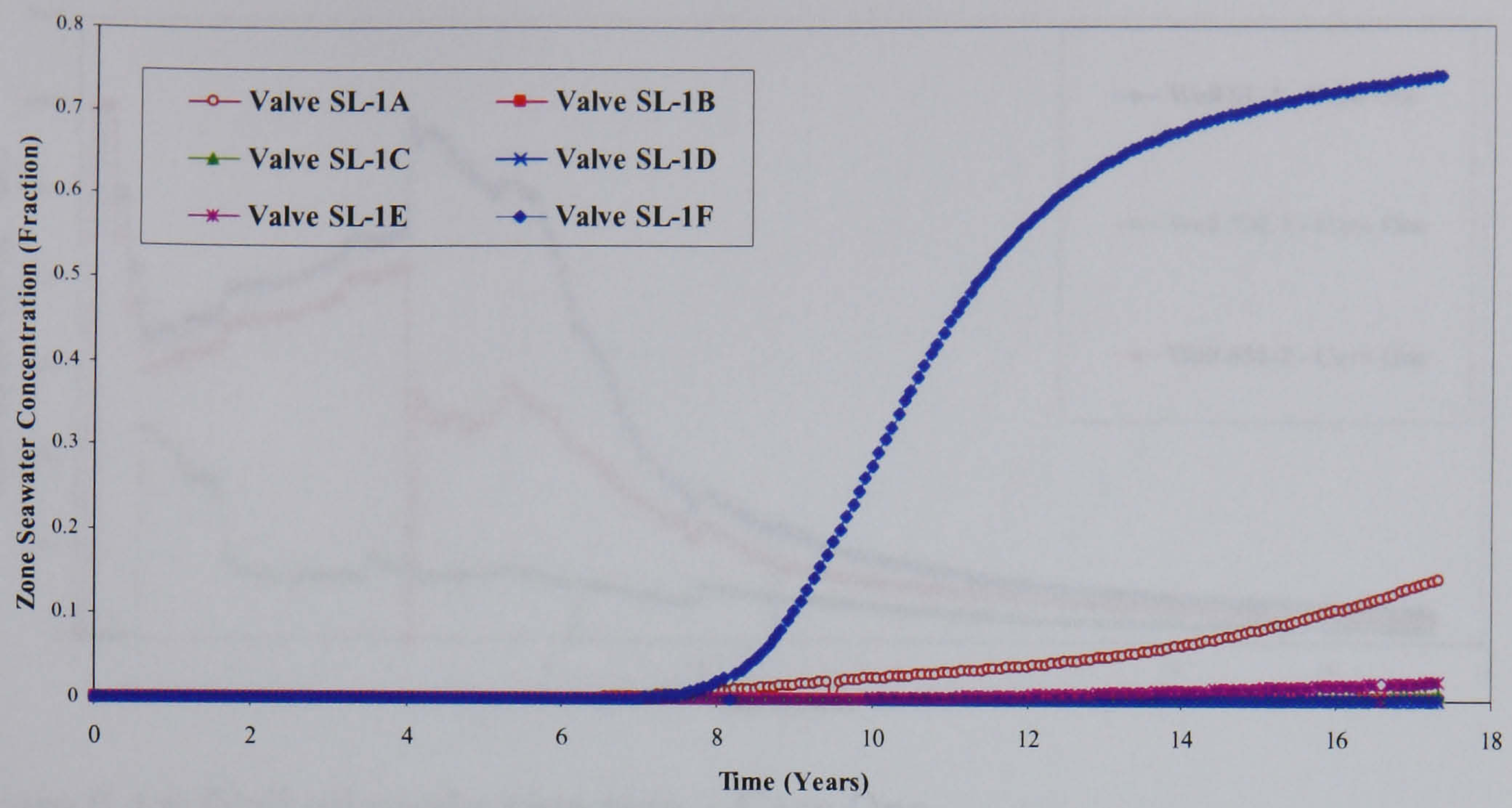


Figure 6.4.5 Valve seawater concentration – well SL-1 – smart injection Case

6.4.2 Scale treatment – smart injection – simulation results and discussion

6.4.2.1 Close the entire well – Case One

The same scale treatment scenarios used with the conventional injection case were used with the smart injection system with the aim to value the advantage of using IWT in scale management. Figure 6.4.6 shows the well's oil production profile as they entire well is closed for one month when its seawater concentration reaches 2%.

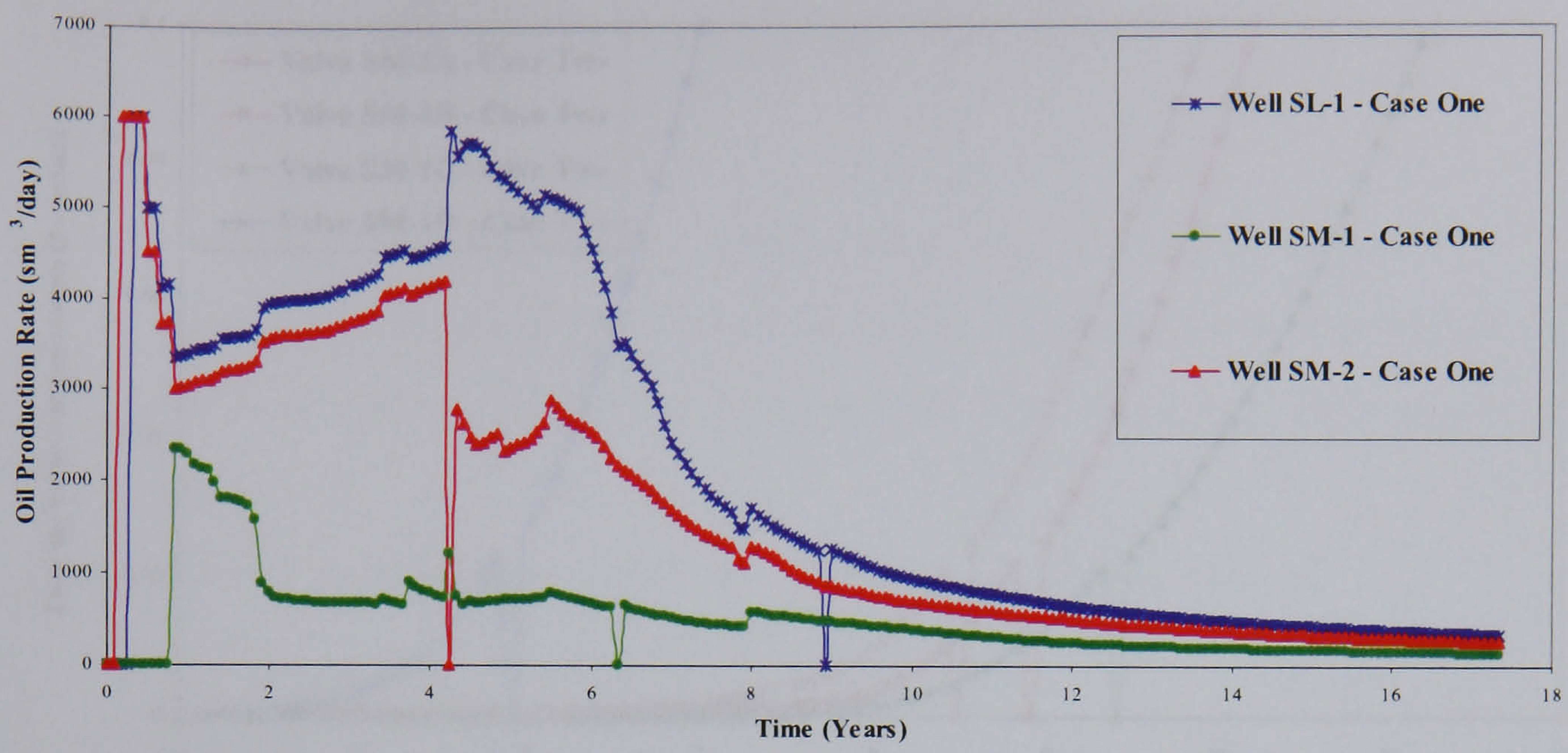


Figure 6.4.6 Well oil production rate – Case One.

6.4.2.2 Close only zone producing seawater - Case Two

Figures 6.4.7 to 6.4.9 show the seawater concentration for the valves in the wells that produce seawater. All zones in wells SM-1 and SM-2 produced seawater at different times are closed at a concentration of 2% for one month. For well SL-1 only the two (of six) zones producing seawater at a concentration of 2% are also closed for one month.

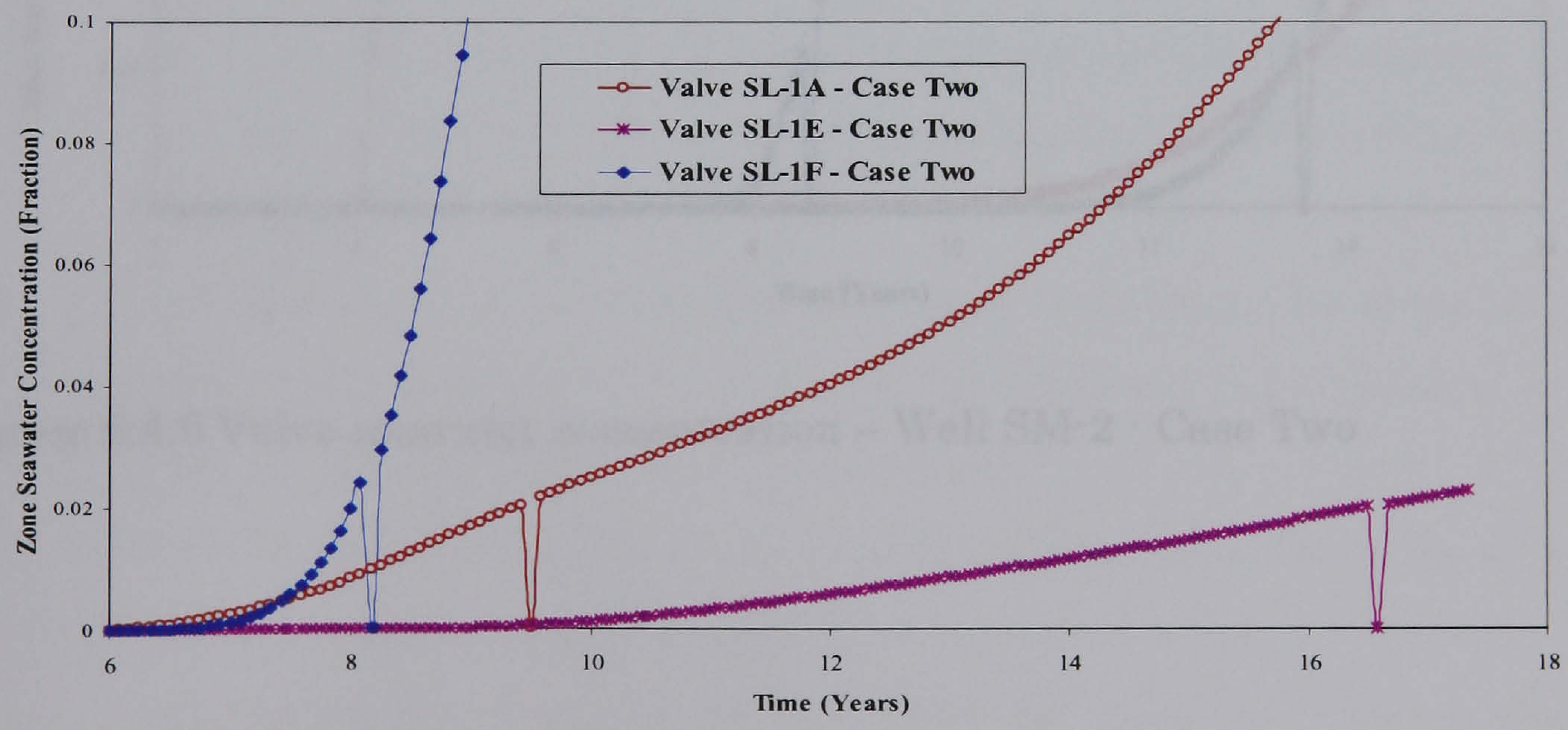


Figure 6.4.7 Valve seawater concentration – Well SL-1 - Case Two

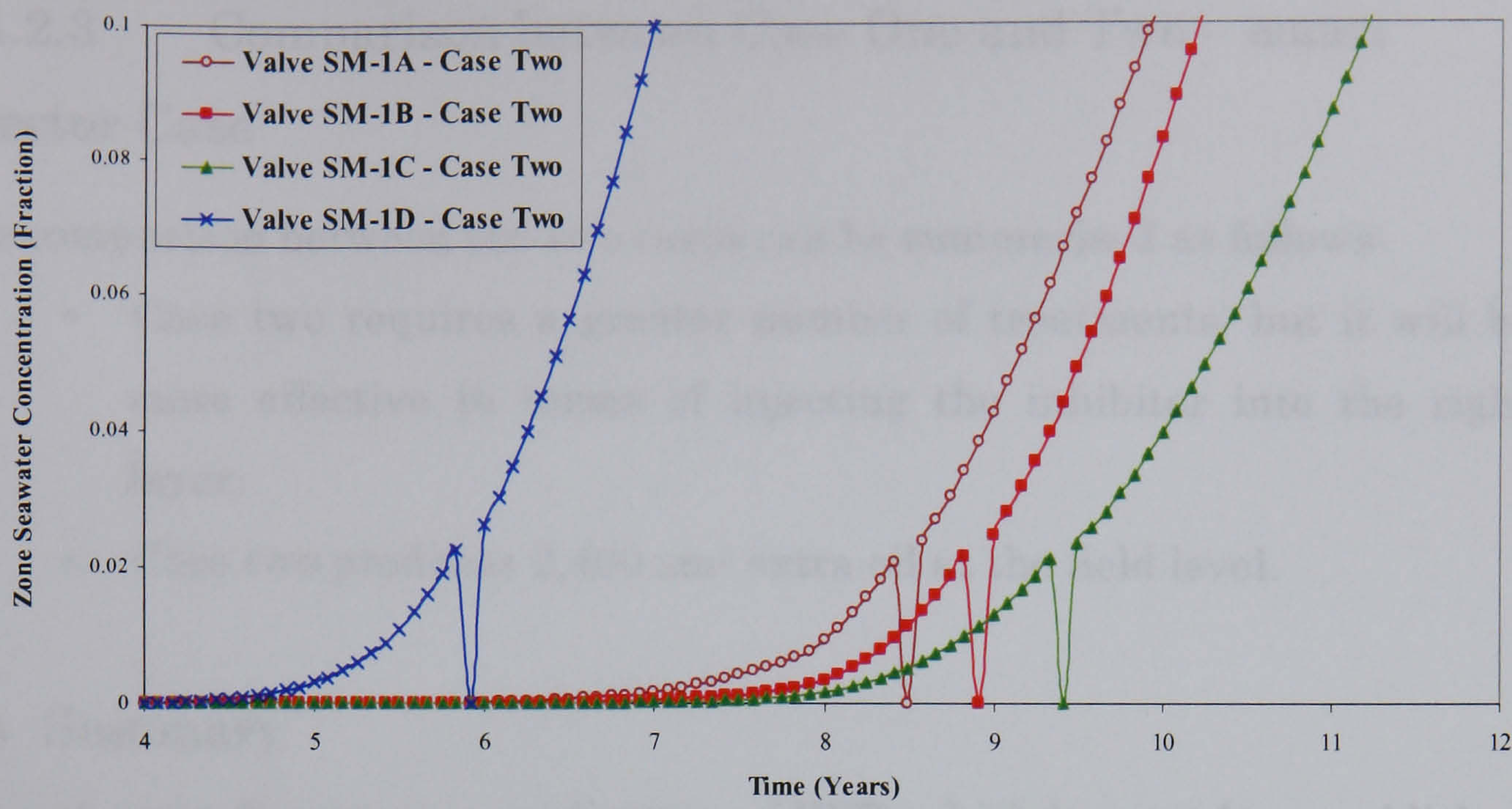


Figure 6.4.8 Valve seawater concentration – well SM-1 - Case Two

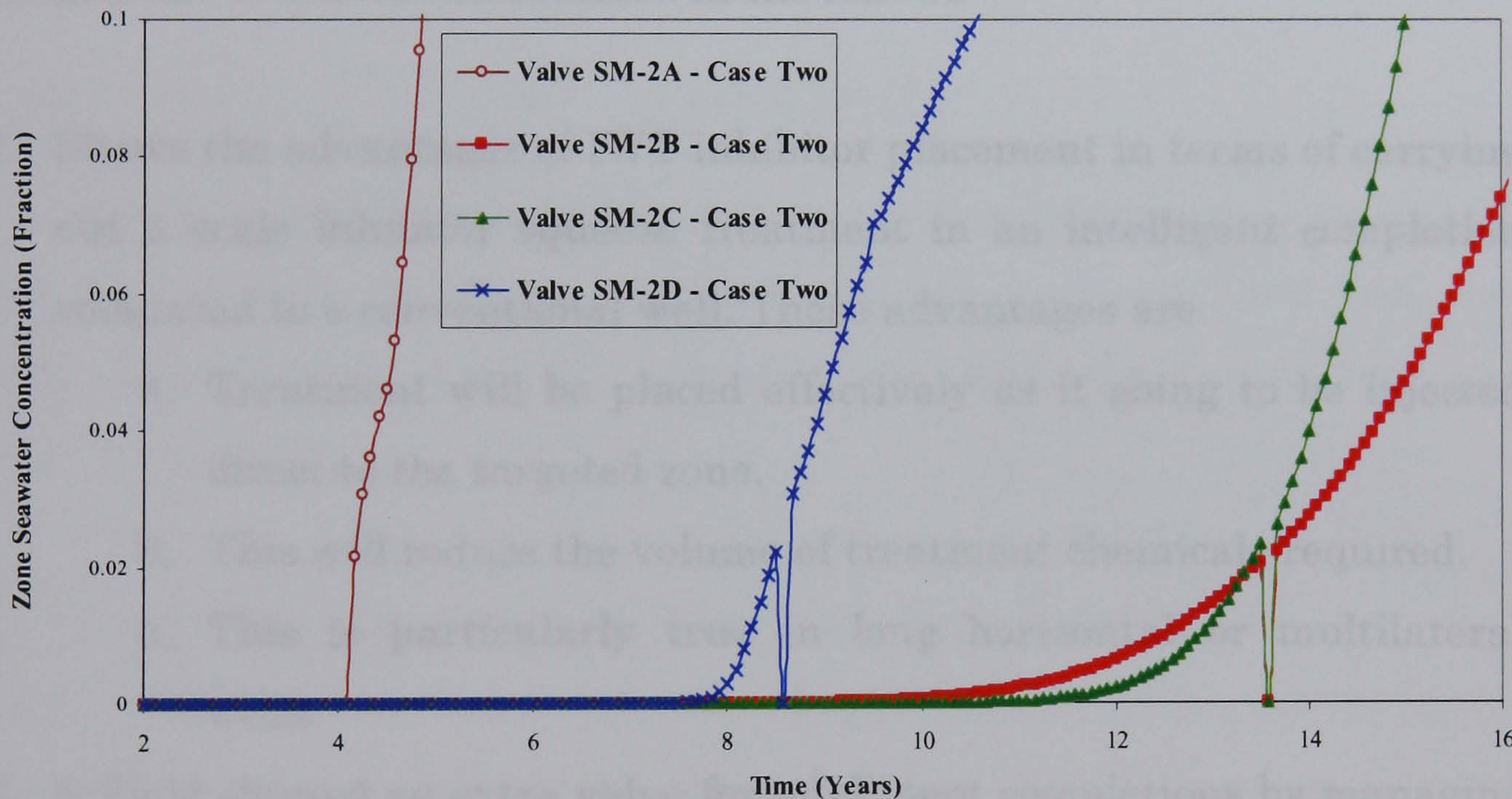


Figure 6.4.9 Valve seawater concentration – Well SM-2 - Case Two

6.4.2.3 Comparison between Case One and Two – smart injector Case

The comparison between the two cases can be summarised as follows:

- Case two requires a greater number of treatments; but it will be more effective in terms of injecting the inhibitor into the right layer.
- Case two produces 2,400 sm^3 extra oil at the field level.

6.5 Summary

This chapter discuss new application of IWT, which has not been published before. The added value from the intelligent completion in scale management; it can be summarised in the follows:

1. Shows the advantages of IWT inhibitor placement in terms of carrying out a scale inhibitor squeeze treatment in an intelligent completion compared to a conventional well. These advantages are.
    a. Treatment will be placed effectively as it going to be injected direct to the targeted zone.
    b. This will reduce the volume of treatment chemicals required.
    c. This is particularly true in long horizontal or multilateral wells.
2. S-Field showed an extra value for intelligent completions by managing the scale treatment per zone level, as that reduced time required to shut-off the well for operational preparation.
3. S-Field showed the impact of the location of the injection wells as a key when dealing with scale problem.
    a. Reservoir simulation models can be used to predict the seawater production (using tracers) and hence it can be minimised by reducing the injection points and controlling seawater profile (smart injection).

Chapter 7

7. Smart producers in an oil-water reservoir system – S Field case study

This chapter reviews the potential value creation through redevelopment using IWT of S-Field (Chapter 1). The objective is to evaluate how well suited commercially available, reservoir and well simulation tools can illustrate this value.

7.1 Production optimisation from "Intelligent Fields"

"Intelligent Fields" are the fields that equipped with systems which enable semi real time data and automatic complete asset management and optimisation" (Al-Rebdi 2005). The complete intelligent well system is capable of monitoring production and reservoir pressure and flows coupled with the ability to control downhole production processes without intervention. The control capability is achieved by using hydraulic, electric or electro-hydraulic controlled ICVs in fully open or closed mode or with variable choking capability. The benefits of IWT have frequently been demonstrated in field applications when the production performance from commingled completion zones and/or reservoirs is very different or when different fluids are being produced. In these operations the control devices are often used in an on/off mode (i.e. the branch is either opened or closed to production). This may not be the optimum way of operating these devices. Their potential benefits for production from a single reservoir have also been demonstrated e.g. smart wells ability to monitor and control flow rate and pressure makes them effective at controlling coning or cusping of water and gas.

Few authors have discussed the production optimisation from "intelligent fields" and the prediction methodologies required to achieve this with reservoir simulation. Gai (2001) developed a valve performance relationship based on inflow performance to optimise the valve settings in multilateral, IWT completion. Brouwer and Jansen (2002) presented a study in which the optimisation technique focused on reducing the difference in time of flight from the injector to producer in a water flood environment. The method involved including the well segment productivity index to maximise total well production. Ajayi and Konopczynski (2003) have described the process by which an optimisation technique was incorporated in the simulator, with the ability to model binary (on/off) and multi-position, downhole chokes installed in intelligent well. IWT accelerated production and maintained a longer plateau period when compared to conventional completion techniques for the multi-layered, commingled reservoir studied.

This study presents an optimisation process based on the use of a commercially available reservoir simulator. This simulator uses keywords with which the engineer can set his own optimisation criteria for both maximising the total field oil production and delaying the water production. The simulator was used to quantify the advantages of a re-development with IWT of S-Field. The results of this redevelopment will be compared with field development by conventional wells modelled very closely on the real situation. (Elmsallati et al. 2005b) and (Davies et al. 2005b)

7.2 S-Field performance

7.2.1 Methodology

The methodology was developed through a series of reservoir simulation runs designed to develop an understanding of the reservoir production process and to define an optimum choking and recovery policy. This involved issues such as encouraging oil production from poorly producing zones and minimising water production during periods in which the wells had excess production capacity. Appropriate sensitivity studies were also made to identify the optimum ICV operational parameters.

7.2.2 Case One

Case One, to which any additional value creation by the intelligent completion will be compared, is the existing seven production wells and three injection wells all located in their real positions. All the wells were produced under group control, though increased production constraints have been specified to reflect the greater productivity of the IWT wells.

The wells (Table 7.1) are brought on stream sequentially, timed to represent a one rig drilling campaign. The water injection is controlled by voidage replacement. 18 years of production history are simulated with facility capacity limitations of 12,000 sm^3/day of oil and 20,000 sm^3/day of liquid for the field and for each template. This was the target for the original field development plan. However the field did not produce at this rate due to operational problems. Maximum well production rate was set at 6,000 sm^3/day liquid. First stage separator pressure was initially 67 bar, decreasing to 25 after 8 years' production.

Well	Well Status	Perforation zone	Date on stream
M-1 H	Oil Producer	Tarbert	October XXX0
M-2 H + M-2A	Oil Producer	Etive, Ness & Tarbert	November XXX0
L-3 H	Oil Producer	Etive	March XXX1
L-4 H	Oil Producer	Etive & Tarbert	April XXX1
M-4 AH	Oil Producer	Rannoch & Ness	May XXX1
L-2 H	Oil Producer	Tarbert	June XXX1
L-1 H	Oil Producer	Etive & Rannoch	July XXX1
K-1 AH	Water Injector	Etive & Rannoch	December XXX0
K-2 H	Water Injector	Tarbert	January XXX1
K-3 H	Water Injector	Etive & Rannoch	February XXX1

Table 7.1 The base case wells (Case One)

Figure 7.2.1 shows the (conventional) completion design used for the case one wells.

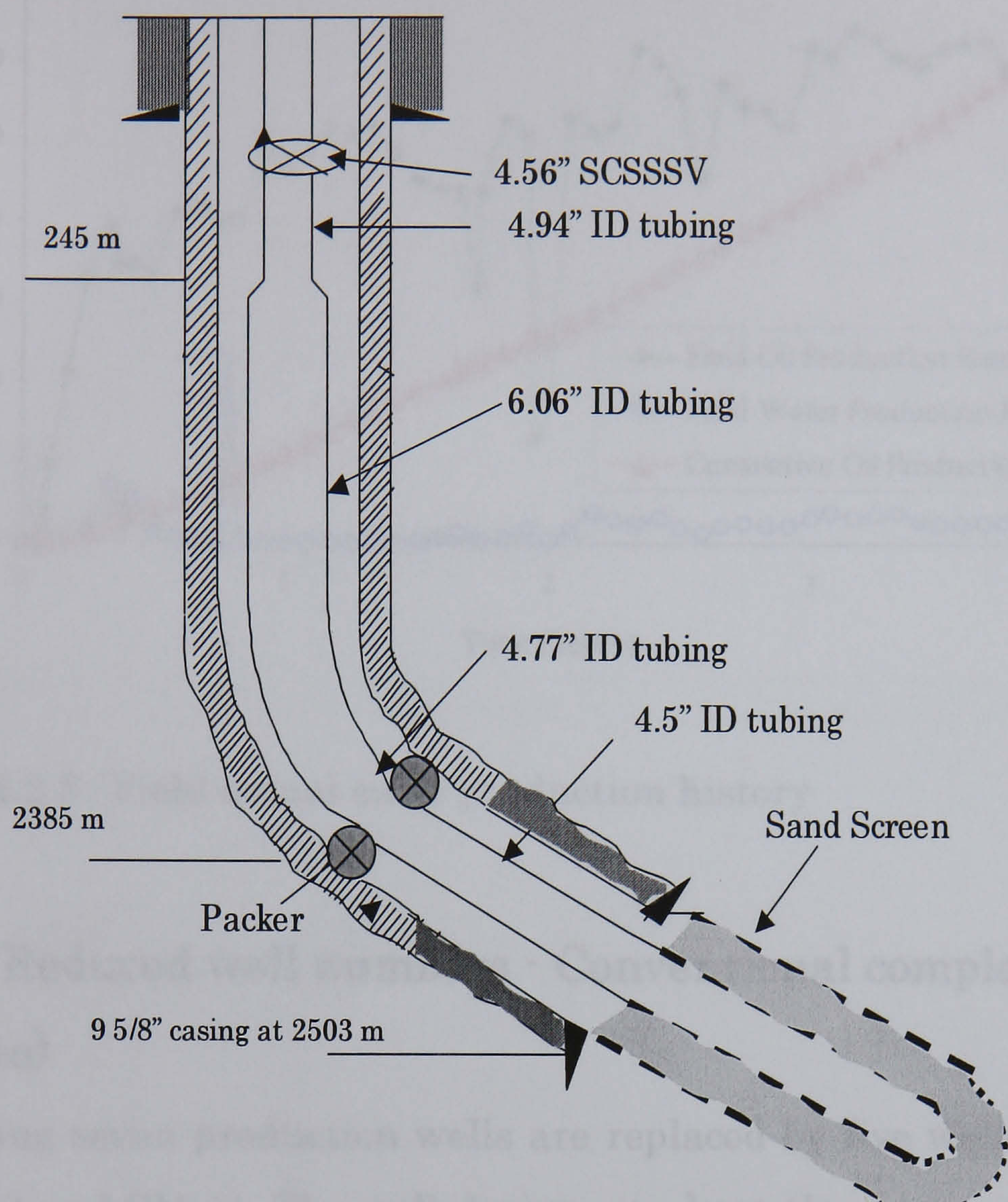


Figure 7.2.1 Conventional completion diagram for Case One wells.

7.2.3 Early production

The original field development plan called for 12,000 sm³/day oil production. Operational problems prevented this target being achieved, as can be seen from the actual production history Figure 7.2.2. However, Case One will assume that these operational problems did not occur i.e. the 12,000 sm³/day oil and 20,000 sm³/day liquid were achievable. The same constraints will then be used for both the Case One and the Intelligent well cases (Case Two and Three).

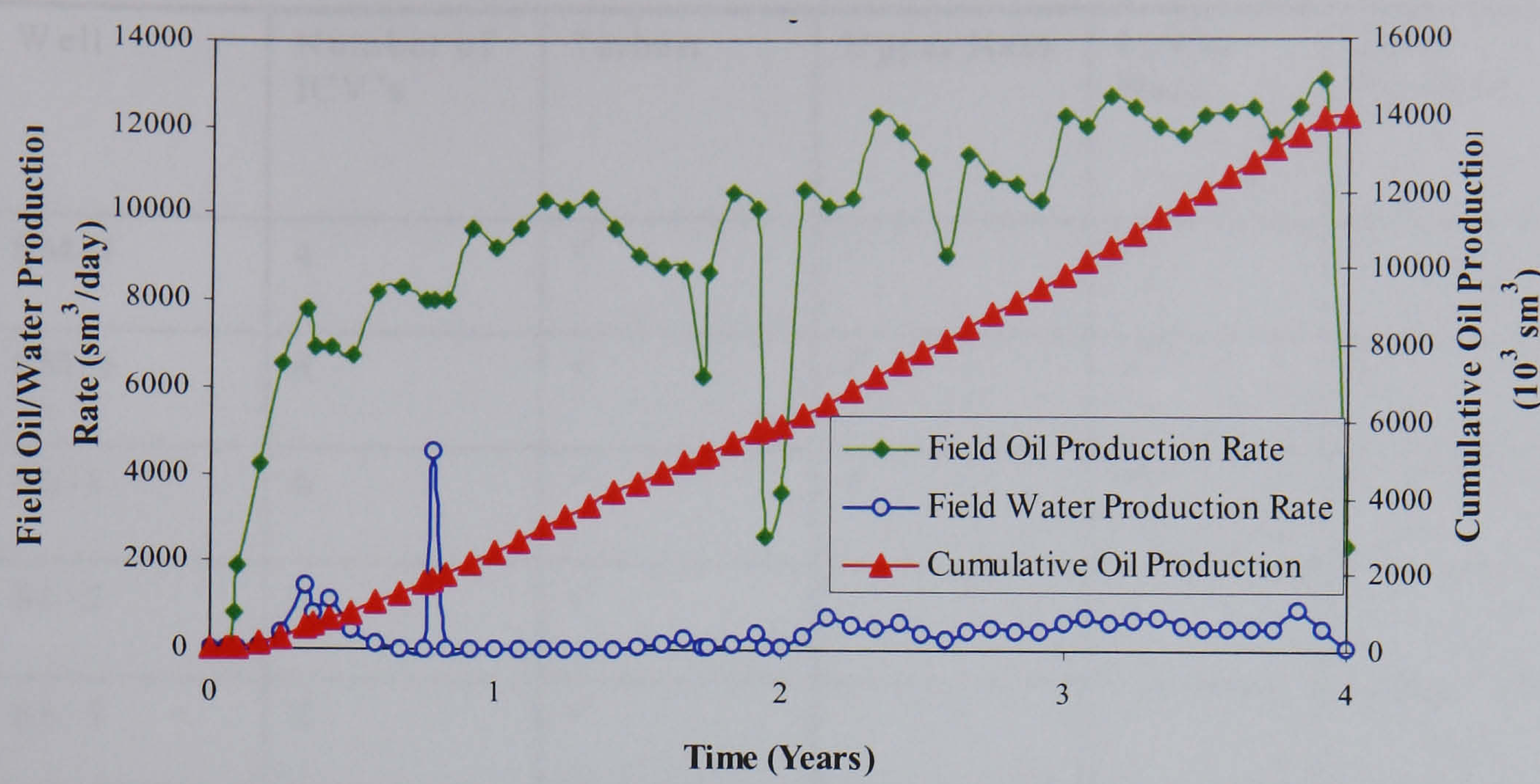


Figure 7.2.2 S- Field actual early production history

7.2.4 Reduced well numbers - Conventional completions (Case Two)

The existing seven production wells are replaced by five wells (SM-2, SL-1, SL-3, SL-2 and SM-1). The well design was kept the same as Figure 7.2.1; the completion intervals being extended to cover both pressure regions, allowing commingled production. This will be called Case Two.

7.2.5 Reduced well number – IWT completion (Case Three)

In this case the new wells are completed with ICVs. I.e. the hardware of an Intelligent completion is installed without control i.e. all ICVs are in fully open position. An intelligent completion requires installation of a smaller diameter flow path throughout the length of the completion interval (compare Figures 7.2.1 and 7.2.3). The fluid flows from the reservoir into the annulus and then through the ICV into the tubing. Each completion zone (or individual sand) is separated by an isolation packer; allowing each sand to be produced separately. ICV control was ONLY used to prevent any cross flow between the different pressure zones. Table 7.2 lists the location of the total of 18 ICVs installed.

Well	Number of ICV's	Tarbert	Upper Ness	Lower Ness	Etive Rannoch
SM-1	4	✓	✓	✓	✓
SM-2	4	✓	✓	✓	✓
SL-1	6	✓	✓	✓	✓ ✓ ✓
SL-2	2	✓			✓
SL-3	2	✓			✓

Table 7.2 Case Three wells with their ICVs and layers in which they were located

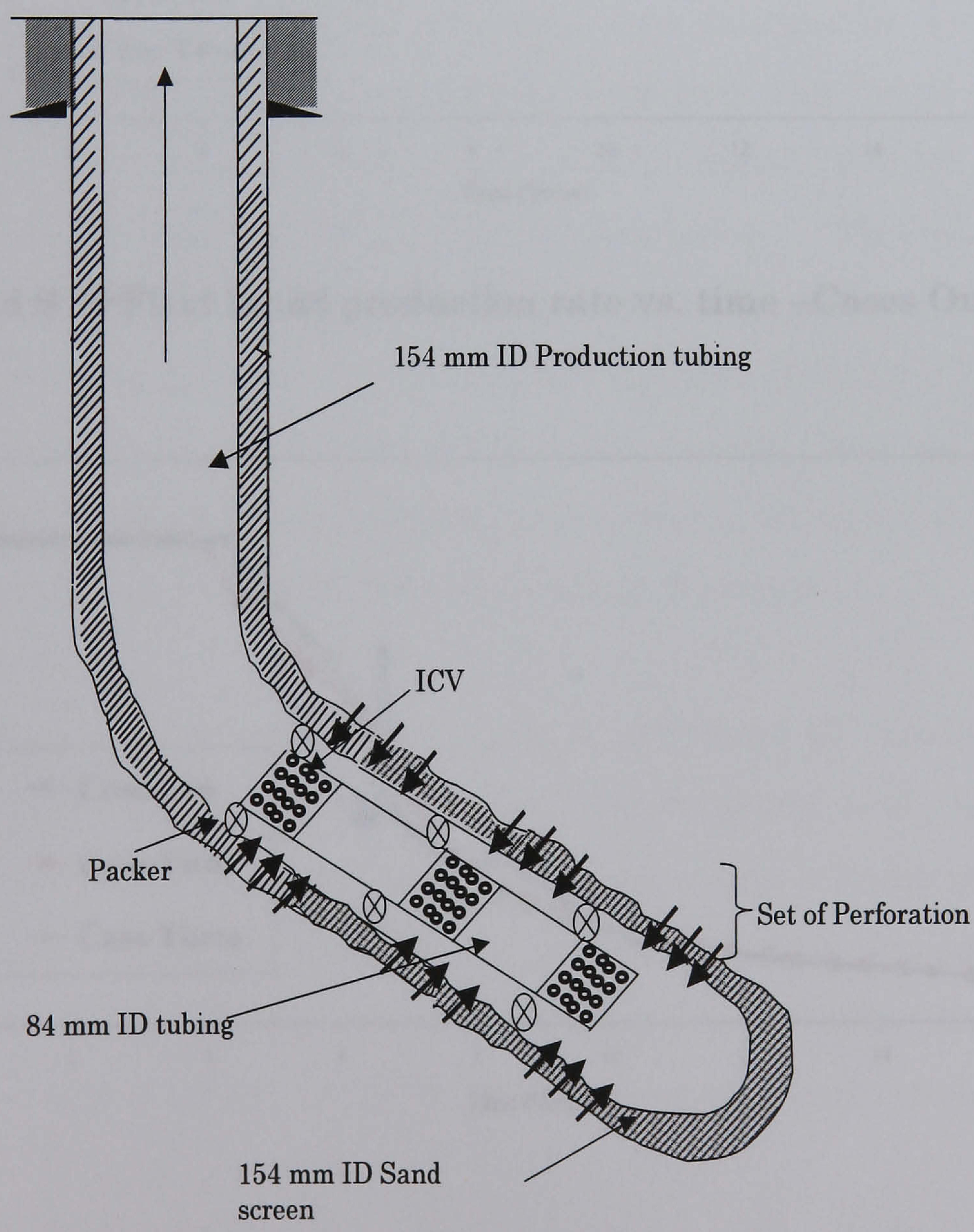


Figure 7.2.3 I-Well completion diagram as employed in Cases Three, Four and Five

7.2.6 The simulation results and development of an optimisation methodology

Figures 7.2.4, 7.2.5 and Table 7.3 summarize the simulation results for all the cases described.

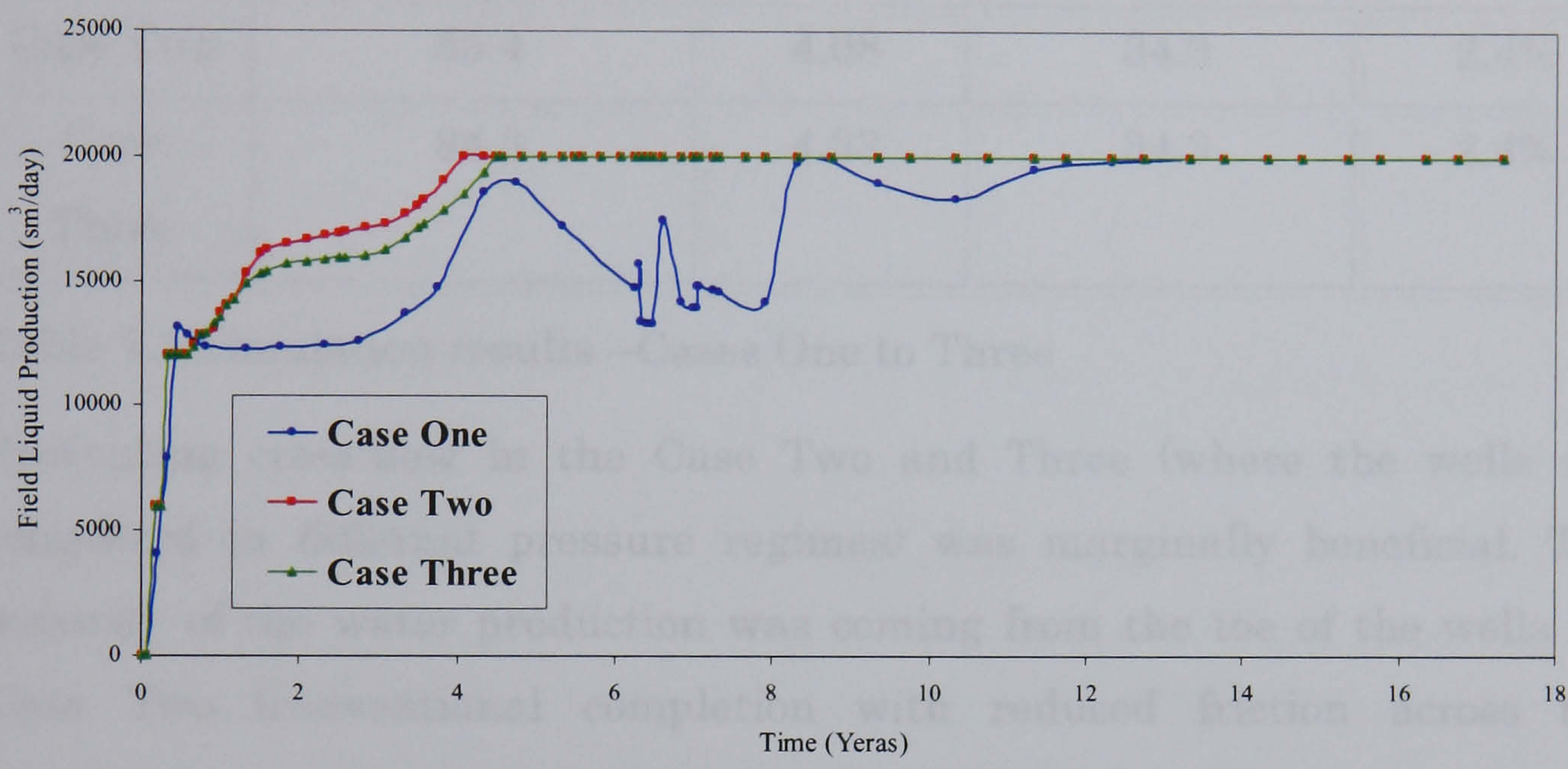


Figure 7.2.4 S- S-Field liquid production rate vs. time –Cases One to Three

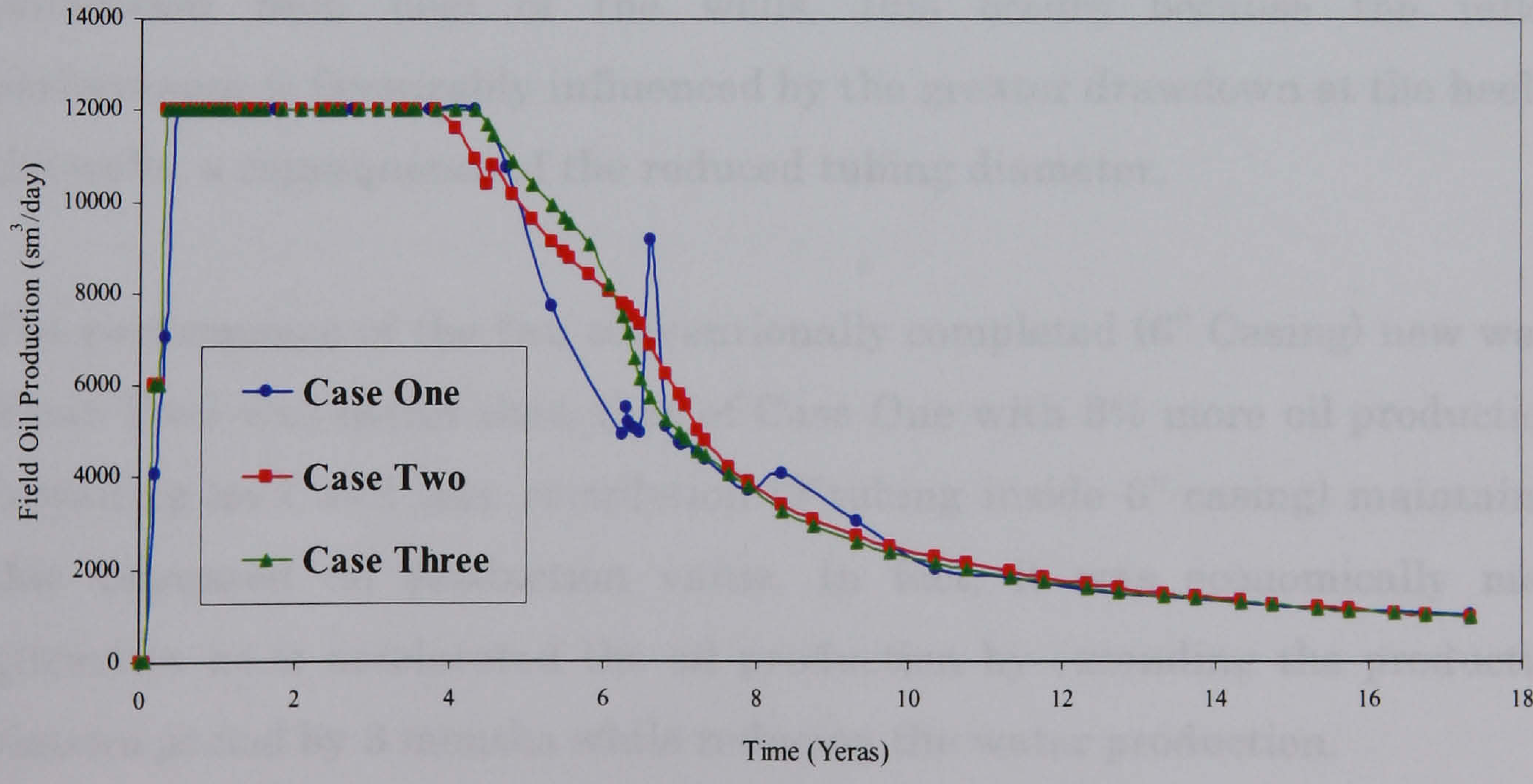


Figure 7.2.5 S-Field oil production rate vs. time –Cases One to Three

CASE NAME	Total Field Water Production (10^6 sm^3)	Length of Plateau (Years)	Total Field Oil Production (10^6 sm^3)	% Increase on base case
Case One	74.7	4.33	33.5	-
Case Two	85.4	4.08	34.3	2.4%
Case Three	84.3	4.33	34.3	2.4%

Table 7.3 Simulation results –Cases One to Three

Preventing cross-flow in the Case Two and Three (where the wells are completed in different pressure regimes) was marginally beneficial. The majority of the water production was coming from the toe of the wells for Case Two (conventional completion with reduced friction across the completed zones compared to an I-well completion). This is because the wells are orientated to point towards the advancing water front. However, in the I-well completion (Case Three) greater friction, increased oil production from heel of the wells, this occurs because the inflow performance is favourably influenced by the greater drawdown at the heel of the wells, a consequence of the reduced tubing diameter.

The performance of the five conventionally completed (6" Casing) new wells (Case Two) was better than that of Case One with 3% more oil production. Installing an I-well type completion (3"tubing inside 6" casing) maintained this increased oil production value. In fact, it was economically more attractive as it accelerated the oil production by extending the production plateau period by 3 months while reducing the water production.

Figure 7.2.4 shows the liquid production as a function of time for all cases. The new well design with its extended completion interval has increased the inflow performance and hence increased the well capacity. Note that oil production for all cases is being constrained to 12,000 sm^3/d for the period 0-4 years. The new wells have improved the liquid production compared to the Case One in the period 4-12 years. Even higher production would have been theoretically possible from Case Two onwards with production being constrained by the field processing capacity. By contrast, Case One production was constrained by the tubing head pressure limit (i.e. the well performance) in this period. This experience is summarized in Table 7.4.

Case Name	Production constraint (0 - 4 Years)	Production constraint (4-12 Years)	Production constraint (12 - 18 Years)
Case One	Field oil limit	Well Capacity	Field water & oil processing limit
Cases Two and Three	Field oil limit	Field water & oil processing limit	Field water & oil processing limit

Table 7.4 S-Field production performance summary

Figures 7.2.4 and 7.2.5 together with Table 7.4 allow the development of an optimisation methodology. It can be seen that the new wells have greater flow capacity than base case wells allowing 20,000 sm^3/day production for the complete period between 4 and 12 years.

a) During the plateau period IWT can:
    - Maximize recovery from zone showing the lowest recovery efficiency at the end of the project lifetime
    - Decrease water production during the plateau period (0 - 4 years).
b) Extend the plateau production period to more than 4 years.
c) Maximize the oil production in the post plateau (4 - 18) years by minimizing the template/field water production.

7.3 Optimisation sensitivities

In Case Three all the ICVs were left in the fully open position (apart from cross-flow being disallowed). The development of a choking policy for the I-Well completion requires answering the following questions:

1. At what water cut should ICV choking be initiated?
2. At which position should the valve be choked?
3. At which time the choking should take place.

The available commercial reservoir simulators did not include suitable optimisation routines at the time this study was carried out. Therefore three sets of systematic sensitivity studies were carried out to develop a choking policy that will answer these three questions.

7.3.1 Sensitivity to water cut

The choking policy called for each ICV zone to be choked to less than 1% of the original inflow area at chosen water cut values. This small flow area was chosen so that it had a large impact on the water production. All production wells were tested with the same choking policy.

7.3.1.1 Sensitivity to water cut – simulation results

Figure 7.3.1 summarises all the simulation results. It shows that optimal oil recovery occurs when choking takes place at a water cut of 95% i.e. water must be produced in order to produce oil. Thus choking at 10% water cut instead of 95% decreases the water production (AND injection) by 85%, but also decreases oil production by 11%. This occurs because the model is run with voidage replacement, so any reduction in water production automatically reduces the amount of injected water.

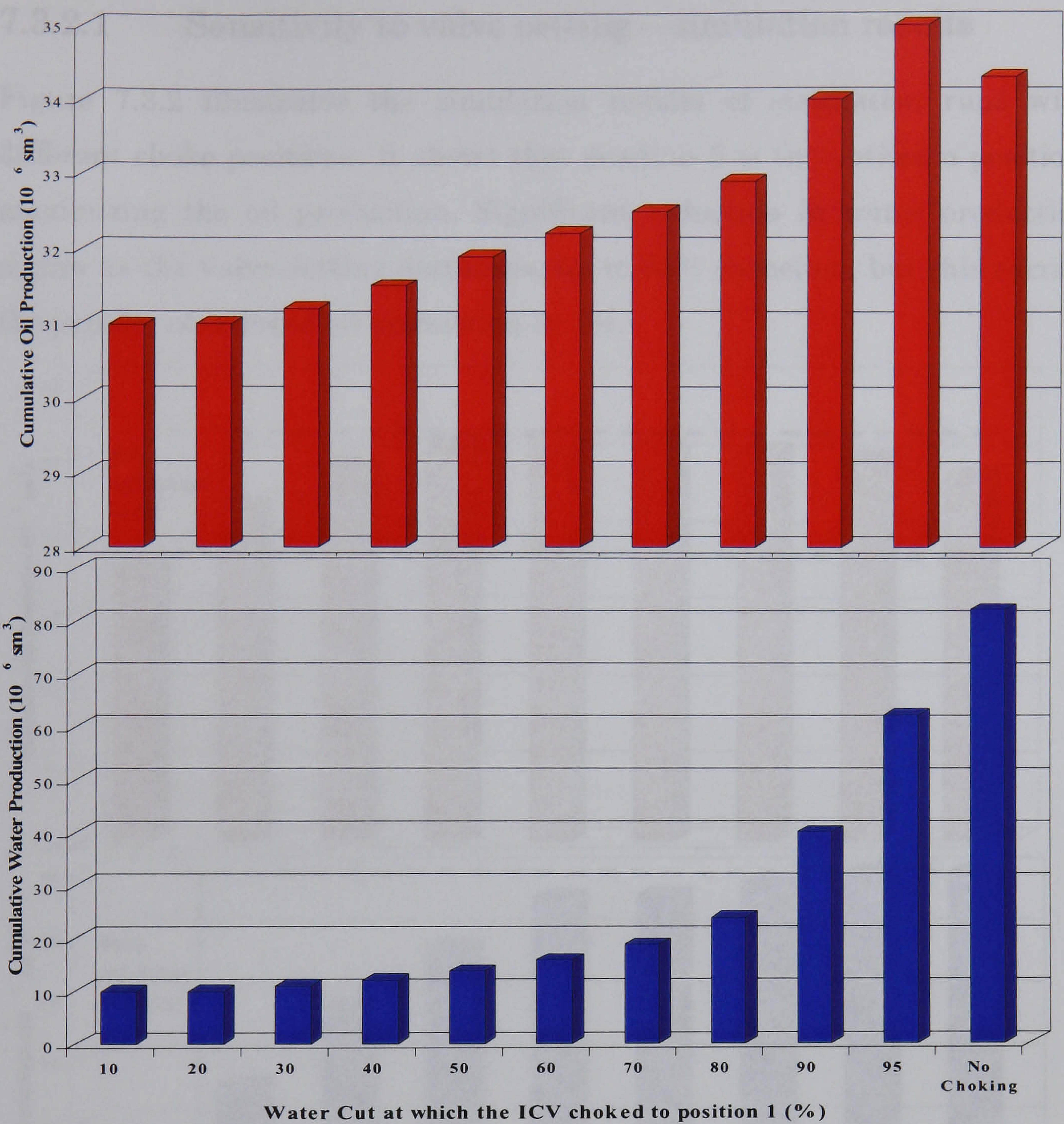


Figure 7.3.1 Sensitivity to water cut

7.3.2 Sensitivity to valve setting

The ICV control positions were available (Table 4.2.1 in chapter 4). The field production is controlled by the 12,000 sm^3/day oil capacity constraint for the first 5 years. Hence ICV choking will be implemented at 10% water cut during this period. The choking policy was changed after this period and the well's water cut was controlled at the 95% level during the subsequent 13 years.

7.3.2.1 Sensitivity to valve setting – simulation results

Figure 7.3.2 illustrates the simulation results of simulation runs with different choke positions. It shows that position 5 is the optimum position, maximizing the oil production. Significant reduction in water production occurs as the valve setting decreases, up to 56% reduction, but this carries the penalty of reduced oil production by 5%.

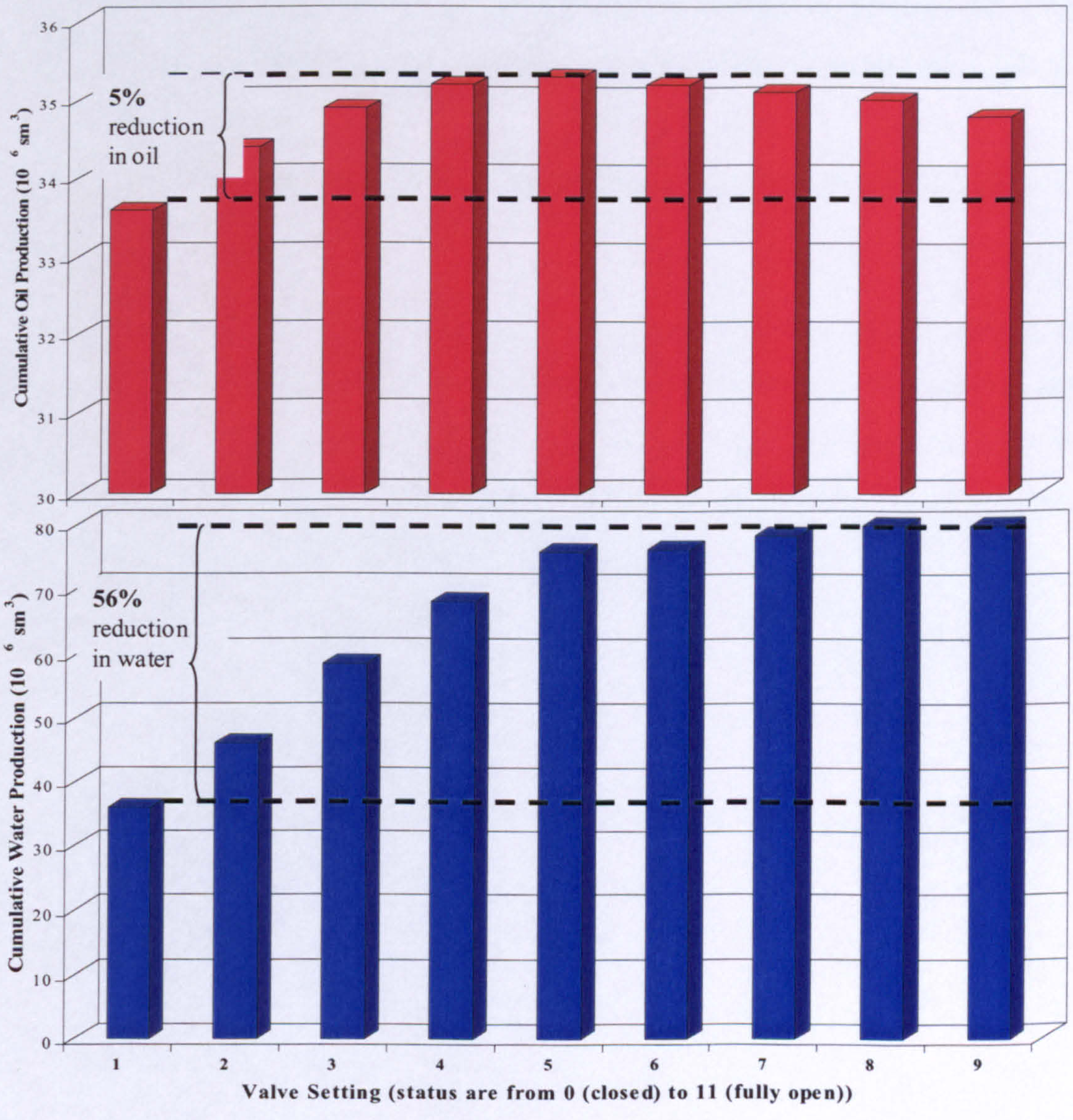


Figure 7.3.2 S-Field Optimisation - Sensitivity to valve setting (using 20% water cut limit for the first 5 years and 95% thereafter)

7.3.3 Sensitivity to the time that the choking take place

Valve position 5 and 40% water cut limit was chosen as the ICV setting to be used when the sensitivity to the time that the choking takes place was analysed. A range between 1 year and 10 years was used. Oil plateau production was experienced for first four years i.e. excess well capacity is available. Hence the only benefit of the ICV in this period is the reduction in water production and altering the oil inflow profile to favour the weaker, producing zones that show the lowest recovery of the original oil in place.

7.3.3.1 Sensitivity to the time that the choking take place – simulation results

Figure 7.3.3 show that it is possible to maintain the same length of oil production plateau (and ultimate recovery) irrespective of whether choke action to reduce water production commences in the first or fifth year. However the cumulative water production and associated operational costs can be minimized by this early choke control.

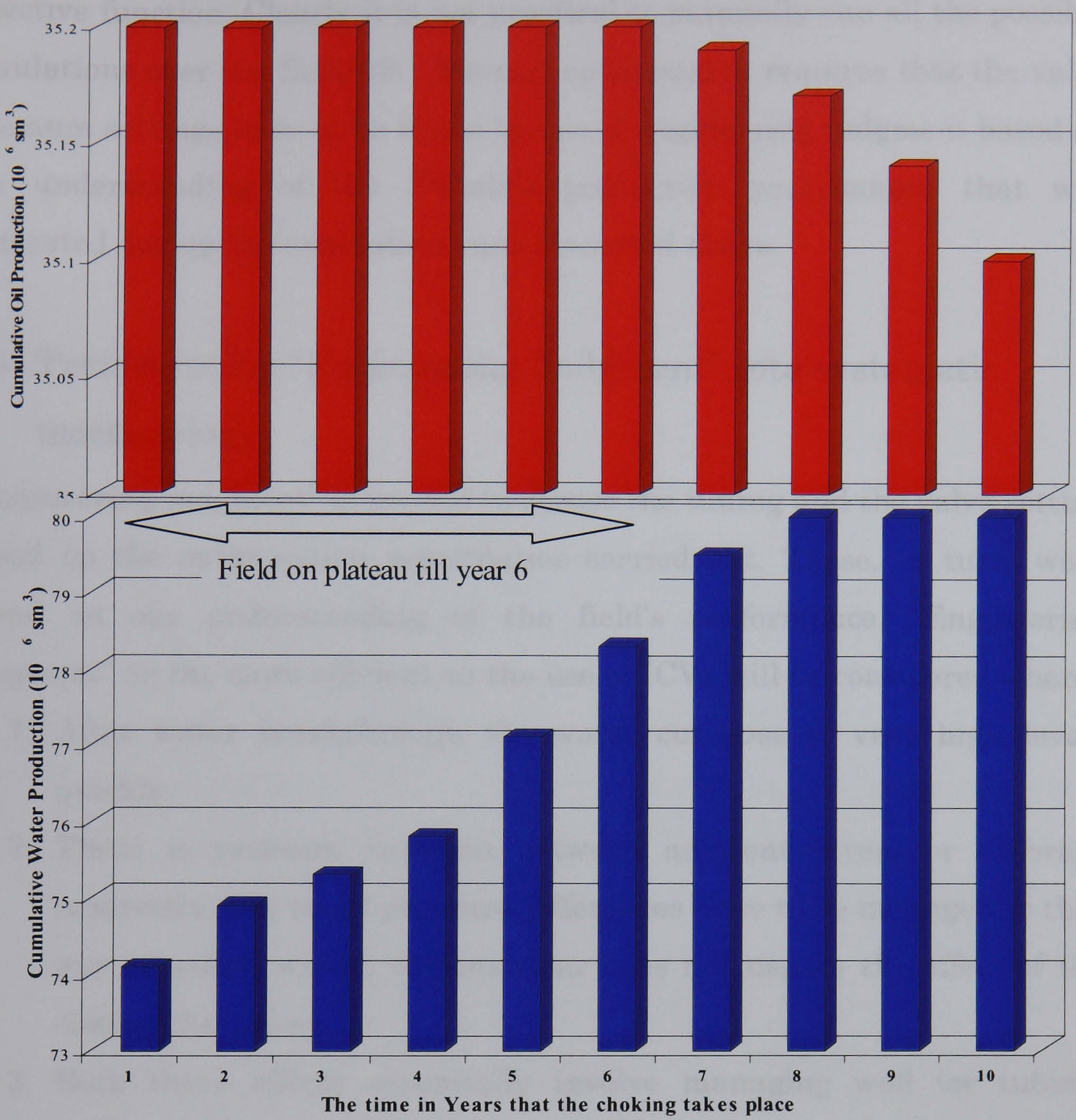


Figure 7.3.3 S-Field optimisation sensitivity to the time (relative to outset of production) that the choking takes place.

7.3.4 The limitations of manual optimisation

The wells are completed with 18 ICVs, and each ICV has 10 positions. Ideally a full optimisation to identify the combination of valve settings for each well, which will maximise field production, should be carried out once per month for the complete 18 years simulated production period. The available optimisation key word used is implemented manually rather than the ideal of an automatic optimisation technique which would achieve the above objective by being able to identify the minimum of an appropriate objective function. Clearly it is not practical to manually run all the possible simulations over the field life. Manual optimisation requires that the valve optimum settings have to be found by use of engineering judgment based on the understanding of the S-Field's production performance that was generated during the simulation runs discussed above.

7.4 Transforming "Engineering Judgment" into systematic methodology

"Engineering judgment" is needed to choose the timing and the valve setting based on the optimisation sensitivities carried out. These, in turn, were based on our understanding of the field's performance. "Engineering judgment" on the more efficient on the use of ICVs will be considered where:

1. After water breakthrough the water cut goes to very high levels quickly.
2. There is pressure isolation between adjacent layers or different reservoirs. The zonal pressure differences have to be managed so that any crossflow within the reservoir does not negate the effect of the closing the valves.
3. Both these effects essentially involve managing well (or tubing) performance. In this multiwell optimisation case we have already identified that the choking policy should achieve:
    - Maximum recovery during the plateau period from zones which show the minimum recovery at the end of the project lifetime.
    - Decreased water production during the plateau period (0-4 years).
    - Both the above will help to extend the plateau production period.
    - Maximum oil production in the post plateau period by producing from the lowest water cut wells.

7.4.1 Production periods observed from S-Field.

As discussed, the 18 year S-Field production history can be separated into three distinct production periods; each of which requires its own choking policy (Table 7.5).

Period	Challenges	Choking Policy	Implementation
1 0-5 years	The field produces under at maximum oil rate of 12,000-sm^3 oil/day. Most of the wells show water break-through during this time	Minimize the water cut in the first 5 years as the field is being produced at the maximum oil capacity.	Choke ICVs to position 3 when water cut >20%. Encourage oil production from the Ness Formation
2 > 5 years	Can optimisation extended plateau period?	Extend the plateau period as long as possible	Open ICVs to position 7 in order to extend the plateau (12,000 sm^3 oil/day) period by increasing well deliverability.
3 >10 years	The production decline period with increasing water & decreasing oil, the field produces at 20,000 sm^3 liquid/day	Maximise the oil production over the decline period.	Choke to position 5 (the optimum position) all ICVs at 50% water cut. The low recovery for Ness Formation (discontinuous reservoir) is the exception - Delay operating ICVs until 98% water cut (this will ensure maximum production from Ness Formation).

Table 7.5 The choking policy challenges and implementation

7.4.2 Simulation results

Implementing the above field management policy extends the plateau period by one year and increases the cumulative oil produced by 5%. Figure 7.4.1 and Figure 7.4.2 show the comparison between the optimised intelligent wells case (Case Four) and Case One. A summary of the results is presented in Table 7.6.

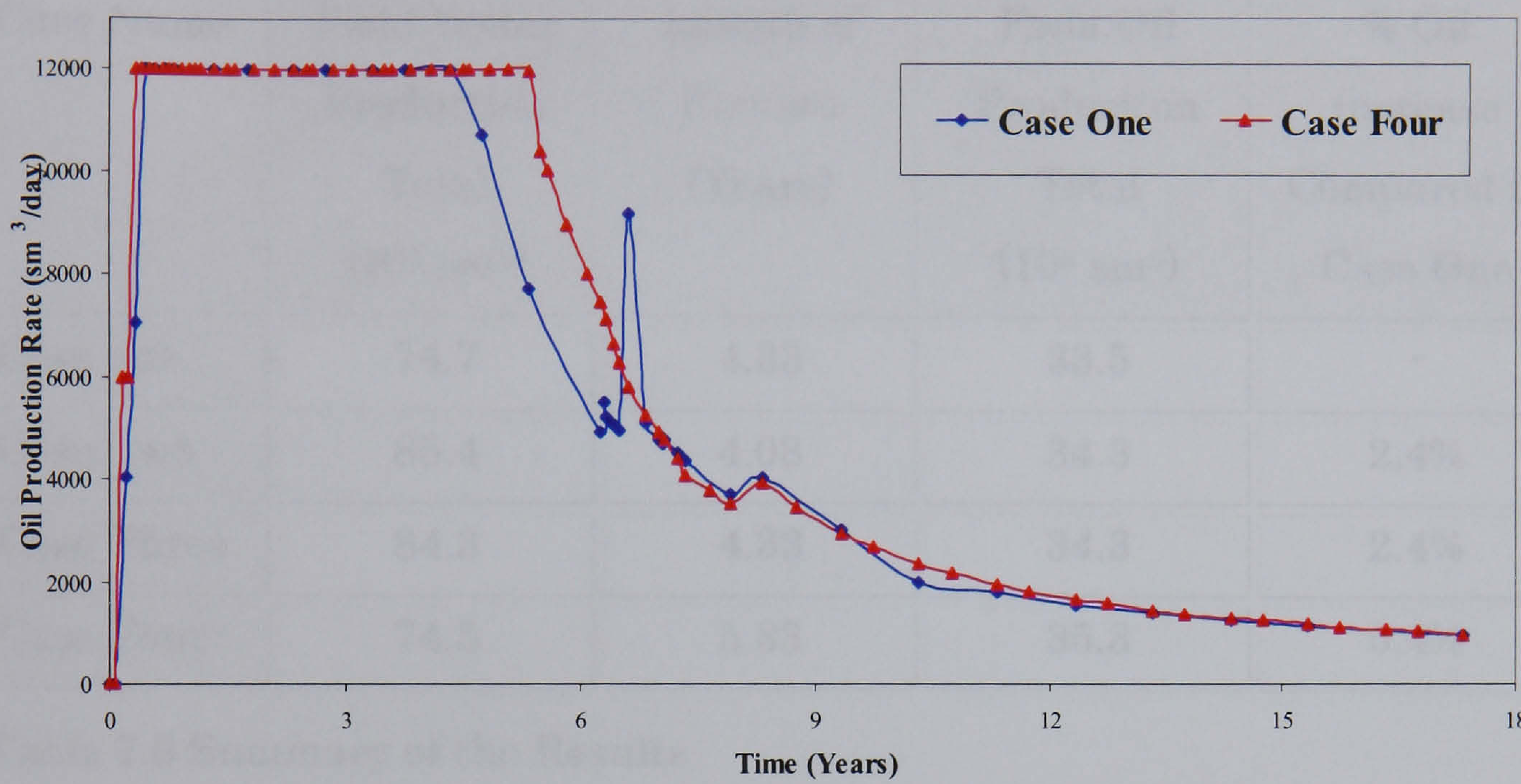


Figure 7.4.1 S-Field performance for Case One and Case Four.

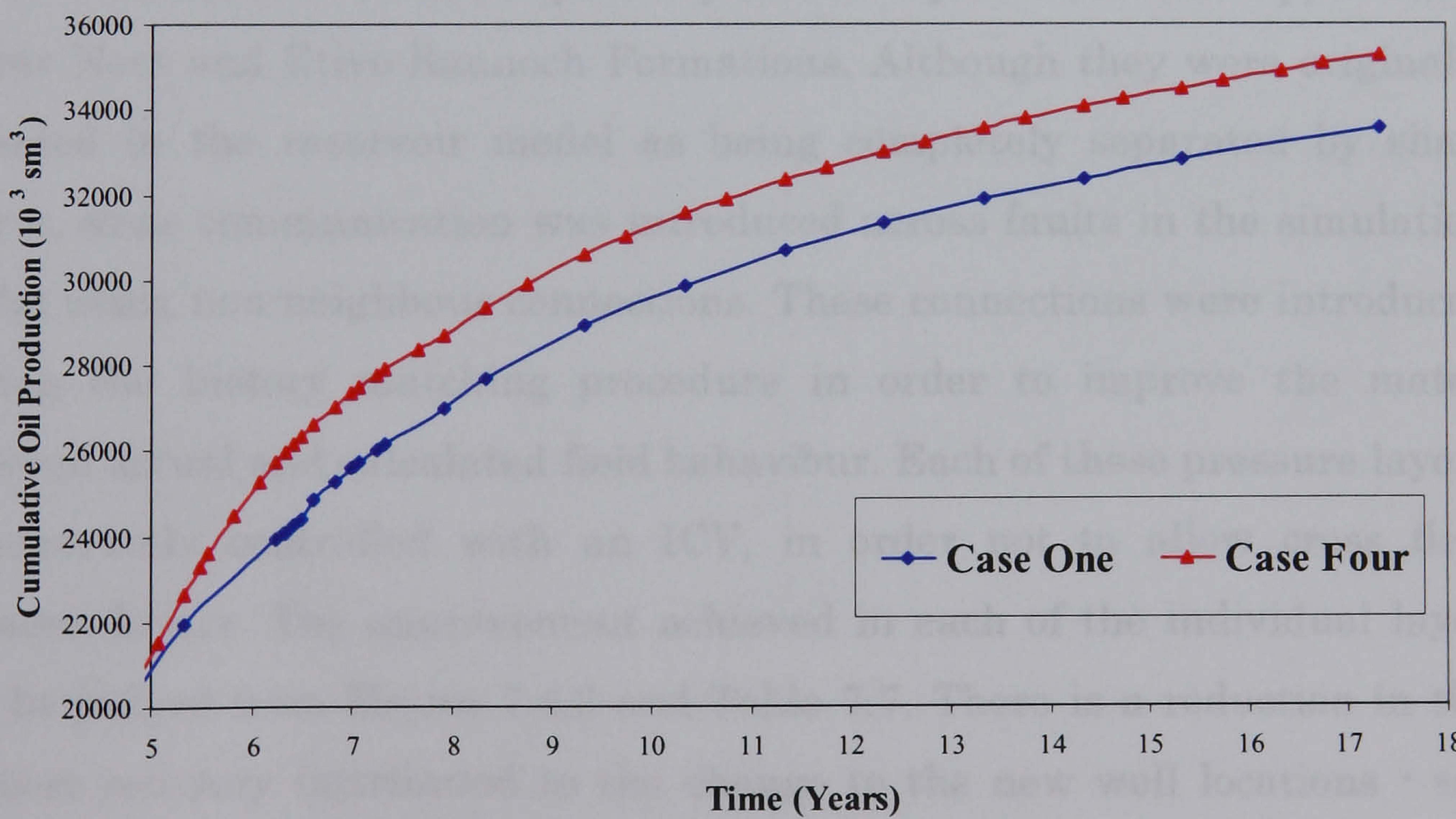


Figure 7.4.2 S-Field performance for Case One and Case Four

Case Name	Field Water Production Total (10^6 sm^3)	Length of Plateau (Years)	Field Oil Production Total (10^6 sm^3)	% Oil increase Compared to Case One
Case one	74.7	4.33	33.5	-
Case Two	85.4	4.08	34.3	2.4%
Case Three	84.3	4.33	34.3	2.4%
Case Four	74.5	5.33	35.3	5.4%

Table 7.6 Summary of the Results

7.4.3 The performance of the pressure layers

The S-Field consists of four separate pressure layers - Tarbert, Upper Ness, Lower Ness and Etive-Rannoch Formations. Although they were originally included in the reservoir model as being completely separated by shale layers, some communication was introduced across faults in the simulation model using non-neighbour connections. These connections were introduced during the history matching procedure in order to improve the match between actual and calculated field behaviour. Each of these pressure layers is separately controlled with an ICV, in order not to allow cross flow between layers. The improvement achieved in each of the individual layer can be judged from Figure 7.4.3 and Table 7.7. There is a reduction in the Tarbert recovery (attributed to the change to the new well locations - see section 7.2) but a significant increase in the recovery from all other layers was achieved. (Between 4% from Etive-Rannoch Formation and 19% from Upper Ness Formation)

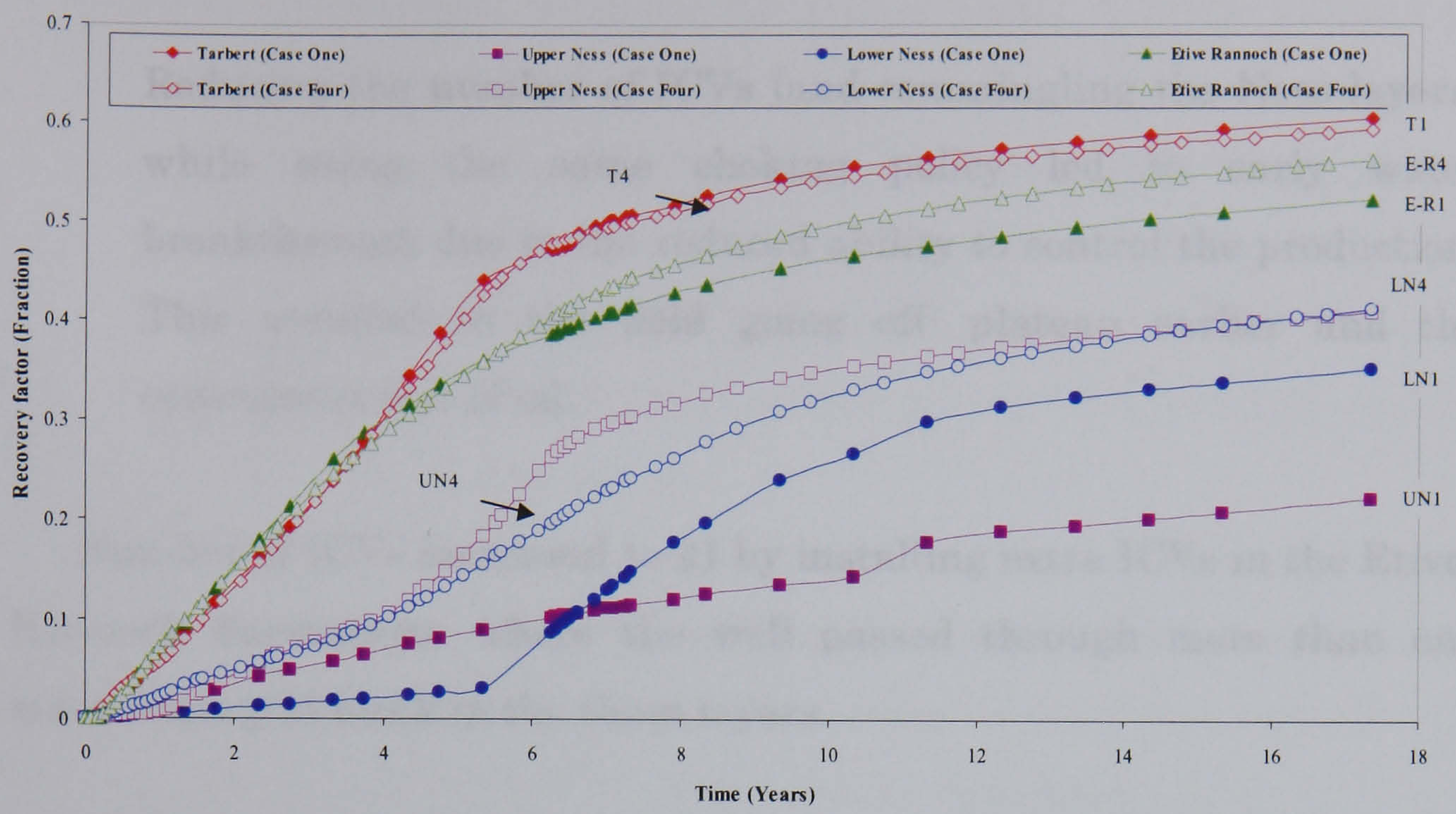


Figure 7.4.3 Layers recovery factor

		Recovery Factor (%)			
Layers	**% of OOIP**	**Case One**	**Case Two**	**Case Four**	**Case Four recovery increase compared to Case One**
Tarbert	40.2	60.4	58.5	59.4	-1.0 %
Upper Ness	3.5	22.3	37.8	41.1	+18.8 %
Lower Ness	12.0	35.4	34.4	41.4	+6.0 %
Etive-Rannoch	44.2	52.3	56.0	56.3	+4.0 %
All Field	100	52.5	53.8	55.2	+2.7 %

Table 7.7 Summary of oil recovery efficiency by isolated zone

7.5 Optimum number of ICVs

A further two I-well completion scenarios were studied in order to evaluate the effect of the number of ICVs.

1. Number of ICVs reduced to 13 by installing only one ICV per sand and by combining the Upper and Lower Ness Formations.

Reducing the number of ICVs (and commingling the Ness layers) while using the same choking policy led to early water breakthrough due to the reduced ability to control the production. This resulted in the field going off- plateau earlier and the consequent loss of oil.

2. Number of ICVs increased to 21 by installing extra ICVs in the Etive-Rannoch Formations where the well passed through more than one simulation grid block in the these layers.

The extra ICVs were not beneficial as there is full communication between the Etive Formation of wells SL-2 and SL-3. In fact, implementation of the same choking policy as used previously, resulted in a decrease in water with small decrease in oil production.

7.6 Systematic methodology for IWT derived from this chapter

Redevelopment of S-Field using IWT has led to an increase in the field recovery. Although IWT will not installed in S-Field but the lessons learned from this case can be used elsewhere in field with similar characterisations.

These lessons learned can be classified as systematic methodology that can be applied into any other field; this will include some rules and guidance:

1. Using of reservoir simulation to identify the value of IWT requires that the model is well understood.
2. Rules for optimising the production using the flexibility of the ICVs - This can be divided into three periods based on the project life:
    i. Plateau period: during this period the field is producing the maximum oil and hence the optimisation should

consider to delay the water break through as long as possible and priories production from the poorer layers.

ii. Extending the plateau and decline period: This period is very critical- delaying the water breakthrough by choking the water produced zones and use the good quality layers during this period will certainly extend the plateau period.

iii. Decline and tail-end period: once the water breaks through it will increase and the oil will decrease, the need for powerful optimisation tool becomes very clear in order to get the maximise oil and reduce water.

3. In this particular case there was limited oil located in the poorer zone and hence the big improvement in recovery from these zones does not alter the field recovery. However in other field cases the improvement from poorer zones may have great impact on the field recovery.

7.7 Summary

The cases studied in previous publications were commingled reservoirs produced via a conventional or a multilateral well so the value generated often based on better tubing performance or co production of different reservoirs. In this chapter we applied IWT at a field level, which has not been published before. The interesting points in this chapter are:

1. Start developing of a systematic methodology based on the understanding of S-Field.
2. Present a control policy useable by reservoir simulators employing manual control keywords in order to increase field recovery.
3. Development of a methodology to quantify the extra oil achievable through the use of an intelligent completion compared to a conventional well development.

4. This chapter discusses how development of the field with intelligent completions can deliver more recovery with reduced numbers of producers.

5. It also shows that optimum zone management can extend the plateau production period, delay water production and increase the ultimate recovery.

Chapter 8

8. Smart Injection and Economic Evaluation Of the Added Value from IWT – S-Field

This chapter is an extension to chapter 7. It discusses the application of IWT in Injection wells in S-Field. Intelligent Completions can be used in the Injection wells or to allow the well to be used as a combined production and injection well as well as in producers using their great flexibility to control the field's injection management. This chapter discusses how development of the field with smart injection can deliver greater recovery with a reduced number of injectors. It also reviews the economic analysis of the added value from IWT in S-Field.

8.1 Applications of IWT in water injection wells

Although IWT was not applied in real development of S-field but its application has an impact on the development on the nearby fields that operated with the same operator Skarsholt et al. (2005) discussed actual installation of IWT in production and injection wells in Snore field, which is nearby S-Field and they both operated by Statoil. The idea of installing intelligent completions into injection wells is well discussed in the literature. Yu et al. (2000) have discussed the role of "smart" water injection, they reported that the installation of intelligent completion in the injection well would allow the completion to deal with the geological uncertainty associated with modelling the reservoir. Brouwer and Jansen (2002) used optimal control theory to develop optimisation algorithms for the valve settings in smart wells applied in injectors and producers for water flooding of heterogeneous reservoirs.

Smart injectors were successfully installed and operated in Snorre Field, located in the Norwegian sector of the North Sea (Skarsholt et al. 2005). Installation of intelligent completions in the injectors allowed the collection of pressure data at the reservoir layer level. This information was used to understand the behaviour of the producers as a function of the water produced. The result was an improved sweep efficiency resulting in less water and more oil production.

8.2 Application of smart water injection in S-Field

The S-Field (Chapter 7) uses water injection as a means of pressure support. S-Field is shown to be a good candidate for smart water injection as it consists of four separate pressure regions partially connected through the faults.

8.2.1 The weakness of the existing water injection system in S-Field

The cases studied in chapter 7 employed voidage replacement with water injection using three conventional injectors, two being completed in the Tarbert and one in the Etive-Rannoch Formations. No water was injected into the Ness Formation and hence the only pressure support comes expanding of the water zone, neither analytical nor numerical aquifer was included in the model. However, a large part of the water zone was modeled as a water leg, hence it was not possible to calculate the injectivity of the aquifer. It was suspected that this policy might not be ideal since there is only limited, if any, communication between the Tarbert and the Etive–Rannoch with the Ness. Thus extra recovery might be possible by using smart injection to ensure voidage replacement for each isolated zone. Further, field development cost will be reduced if it proven possible to replace the 3 conventional injection wells with a single smart injector.

8.2.2 Smart injector placement

A sensitivity study revealed that an injector located into S-Field between K-2 and K-3 is optimum. This well should be completed in all the four pressure zones (Figure 8.2.1). So that the benefit of improved the zonal pressure management can be realised, a "smart injector" was also designed to inject water under individual zone voidage constraint into the aquifer of the Tarbert, Upper and Lower Ness, Etive and Rannoch layers.

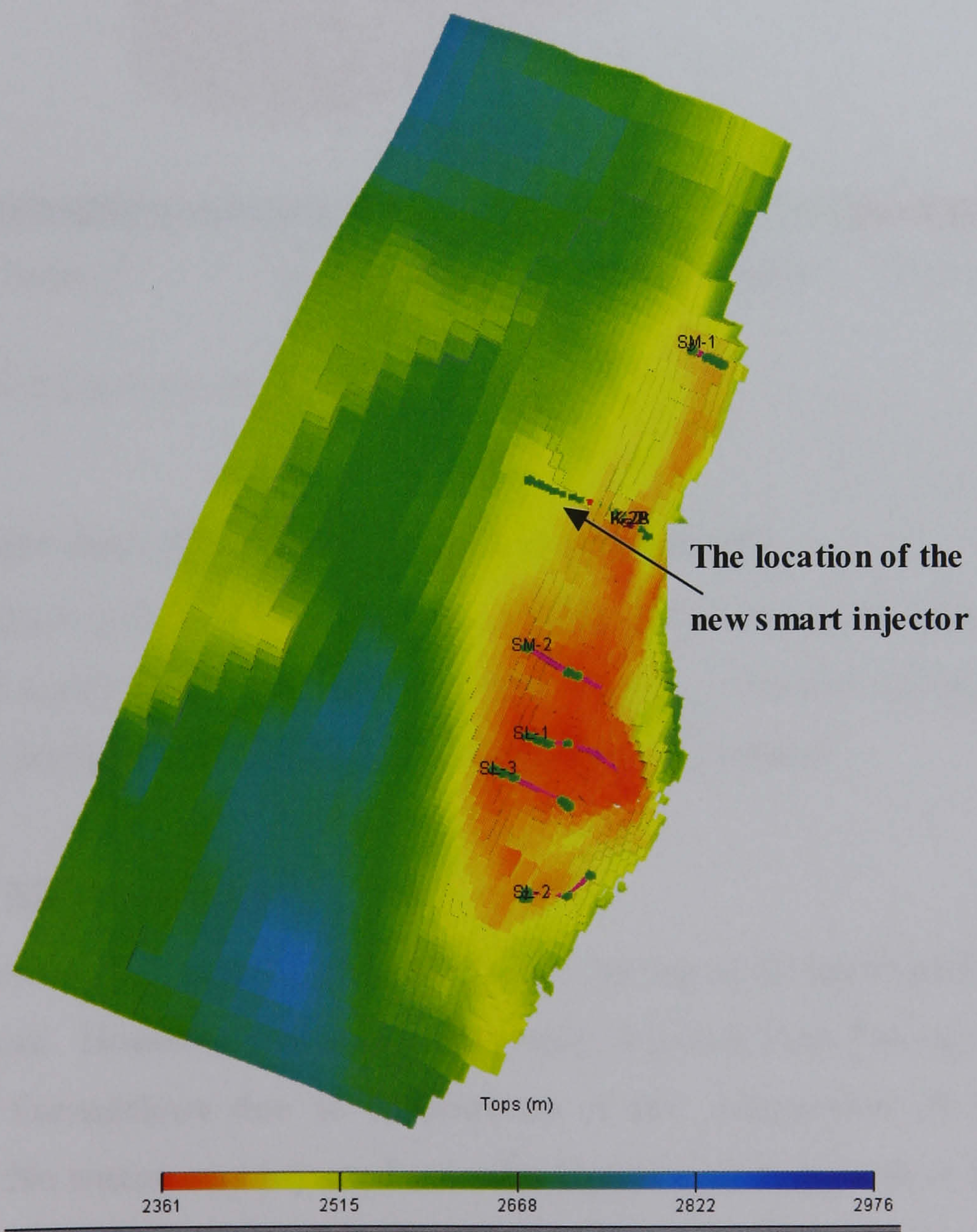


Figure 8.2.1 S-Field Top Structure map- smart injector location

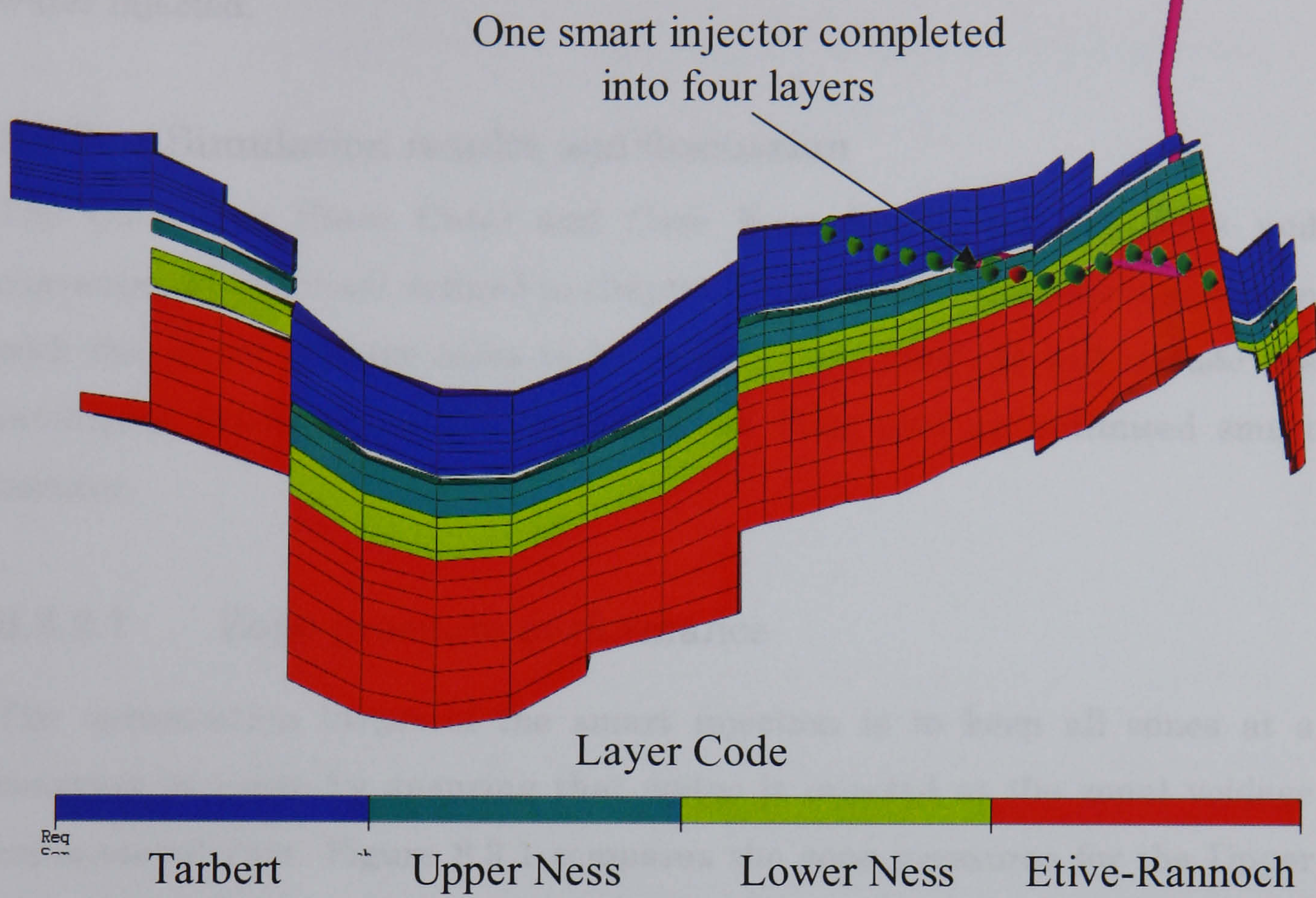


Figure 8.2.2 Location of the smart injector

8.3 Smart injection – policy and methodology

The Injection policy chosen for this smart injection study was to inject a volume of water into each zone that was equal to volume of liquid produced from that particular zone. i.e. zonal voidage replacement.

8.3.1 Methodology

The Eclipse model, used in chapter 7, was set-up so to inject at field voidage replacement. However the water was only injected into Tarbert and Etive-Rannoch Formations due to limitations of the completion of the existing injectors. No water was injected into the Upper and Lower Ness Formations, causing an over pressuring the first two zones and pressure depletion of the two Ness zones. In this chapter, we will extend the model so that it automatically injects volumes of water equivalent to that of the liquid produced from each pressure zones. This was achieved by a monthly balancing of the volume of liquid produced from each zone and the volume of water injected.

8.3.2 Simulation results and discussion

The Case One (Base Case) and Case Four (intelligent producers and conventional injectors) defined in chapter 7 will be used here for comparison with the smart injector cases to be called "Case Five". It will include the intelligent producers optimised from Case Four plus an optimised smart injector.

8.3.2.1 Zone pressure performance

The optimisation target of the smart injection is to keep all zones at a constant pressure by ensuring that water is injected at the zonal voidage replacement rate. Figure 8.3.1 compares the zone pressures for the Upper and Lower Ness for Case One and Case Five. There is an initial fall in pressure (water injection started 3 months later than production). Remember, artificial pressure support is only present in Case Five (the I-injector) for the Lower Ness. Only aquifer pressure support is allowable for these zones in Case One.

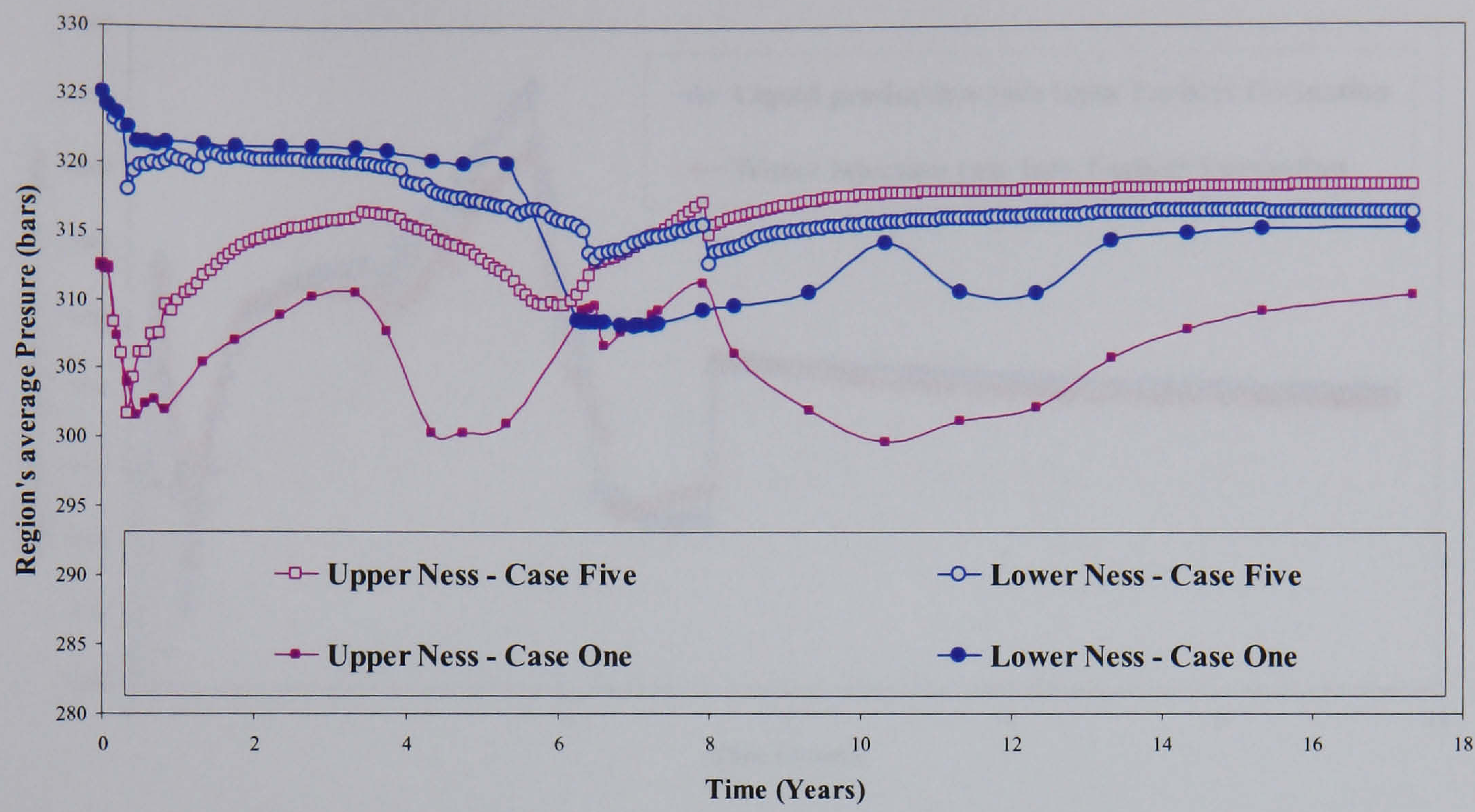


Figure 8.3.1 S-Field Ness Formation pressures for Case One and Case Five

Zone voidage replacement was achieved in the model by using the monthly production results from Case Four and estimating the required injection rate based on the volume of liquid produced. This was then used in the smart injection run (Case Five). Figure 8.3.2 shows how effective this technique is at replacing the liquid volume produced from the Tarbert Formation. The same policy was applied to all the zones. The pressure was held reasonably constant, even during the period when the management of the field changed rapidly from 12,000 sm^3/day oil to 20,000 sm^3/day liquid (year 5). This improved reservoir management scheme not only improves Ness recovery by implementing a full water drive, but also delays the water break through; helping the field to stay on production plateau for longer (Figure 8.3.3). The cumulative total oil production is also increased (Figure 8.3.4). Table 8.1 shows how the combination of intelligent producers and injectors produces the highest oil recovery.

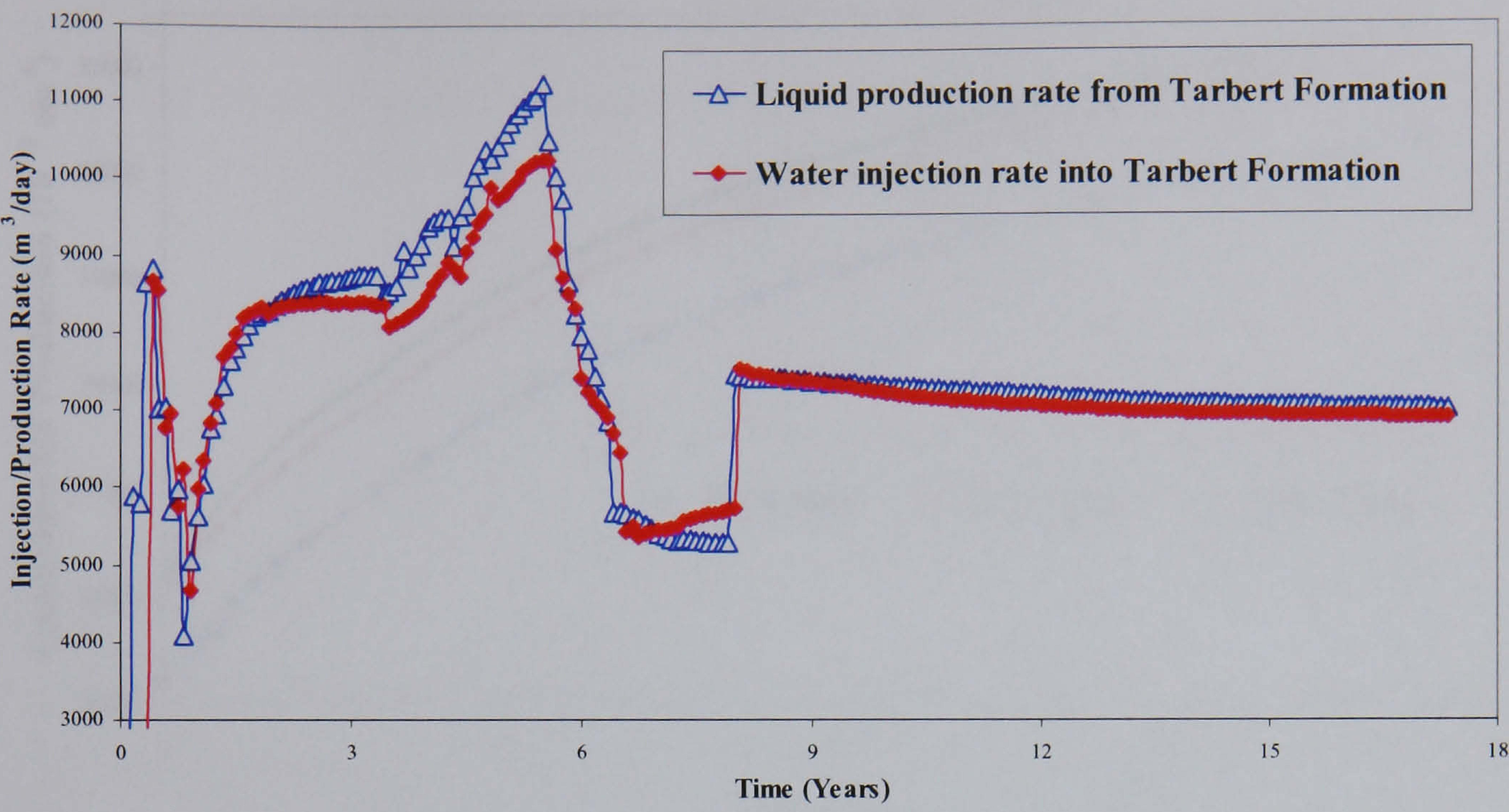


Figure 8.3.2 Tarbert Formation - zonal voidage replacement is achieved.

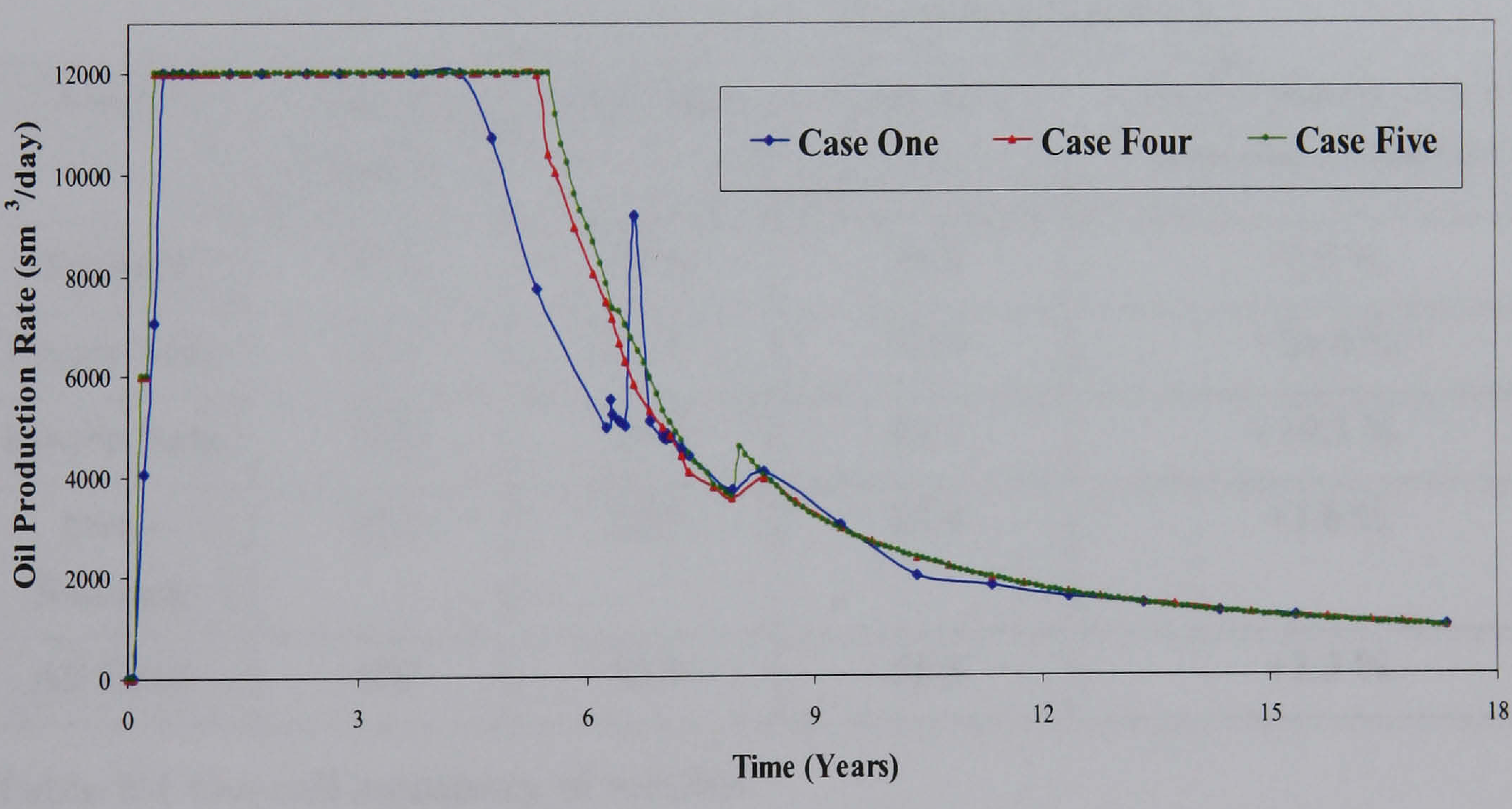


Figure 8.3.3 The smart injector extends the plateau production period further

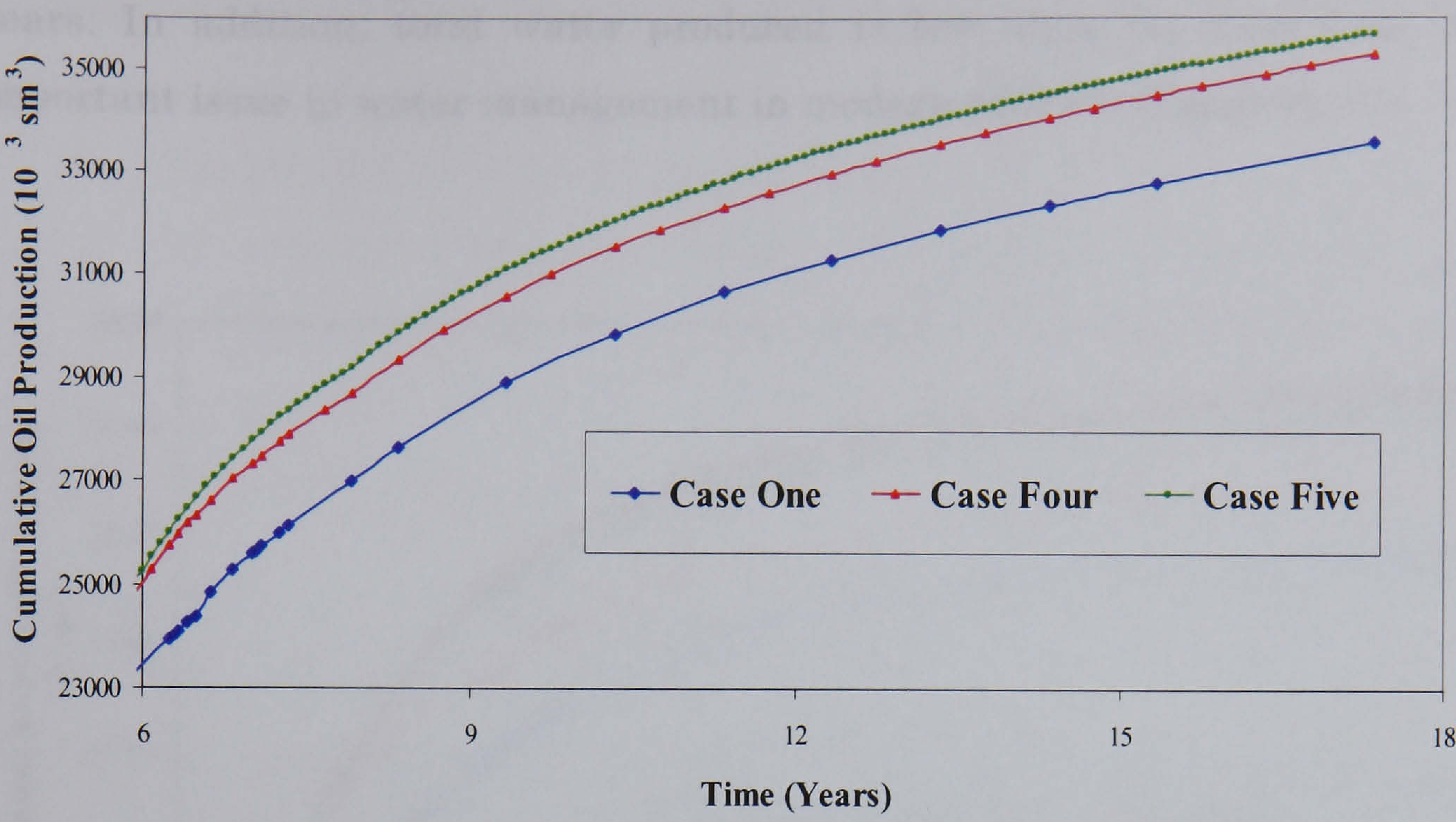


Figure 8.3.4 Extra oil is produced in the smart Injector Case

		Recovery Factor (%)		
Layers	% of OOIP	Case One	Case Five	Case Five recovery increase compared to Case One
Tarbert	40.2	60.4	59.8	-0.6 %
Upper Ness	3.5	22.3	42.7	+20.4 %
Lower Ness	12.0	35.4	45.7	+10.3 %
Etive-Rannoch	44.2	52.3	55.9	+3.6 %
All Field	100	52.5	55.8	+3.3 %

Table 8.1 Overall summary of results

8.4 Economic analysis

The production acceleration effect of IWT is even more clearly seen when the oil volumes are discounted at rate of 10% pa (Figure 8.4.1). This discount factor emphasises the extra value created by the encouraging early production. Case Five achieves the same discounted oil volume after 6 years production as Case One produced during the complete field lifetime of 18 years. In addition, total water produced is less than for Case One, an important issue in water management in modern oilfields (Figure 8.4.2).

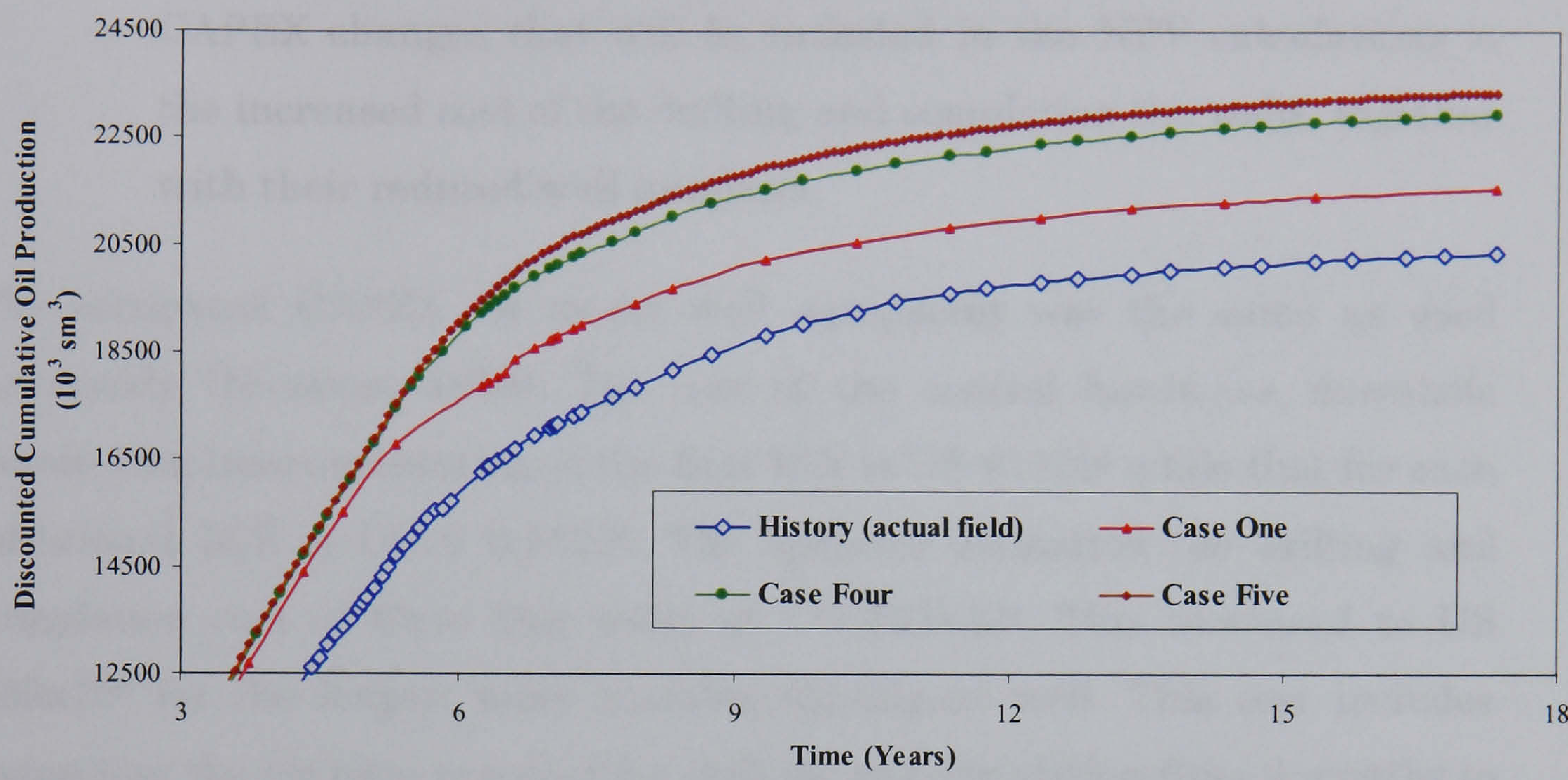


Figure 8.4.1 S-Field cumulative oil production discounted at 10%

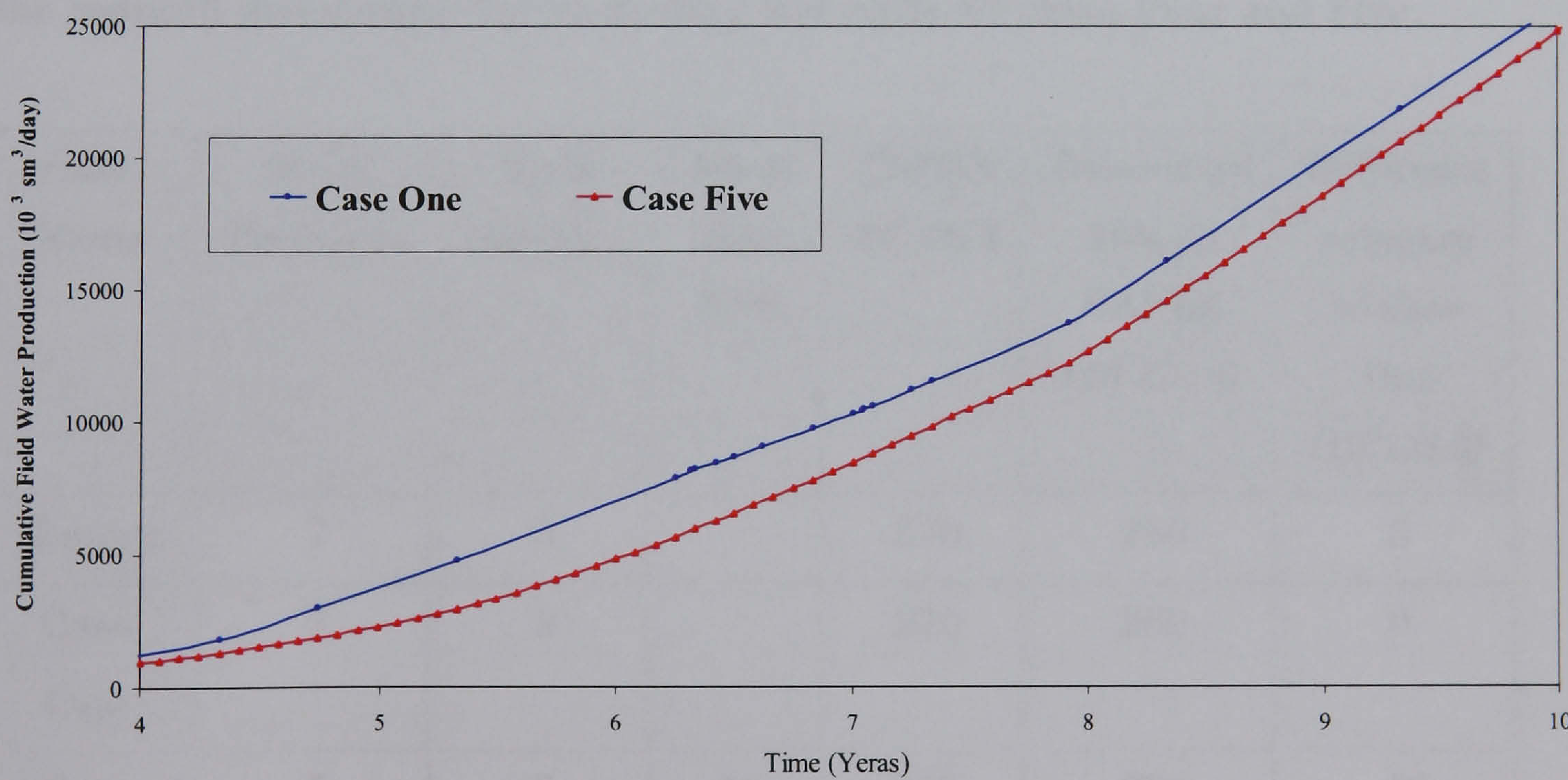


Figure 8.4.2 S-Field cumulative water productions for Case One and Case Five

Net present value calculations for all the cases were carried out based on the following set of assumptions:

- The OPEX will be the same in all cases.
- All non-well CAPEX will be the same for all cases. i.e. the only CAPEX changes that will be included in the NPV calculations is the increased cost of the drilling and completion the wells, together with their reduced well numbers.

The estimated CAPEX for smart well equipment was the same as used previously (Houston, 1999). The cost of the control hardware, downhole monitoring instrumentation of the first ICV is US $\$1*10^6$ while that for each additional ICV is US $ $0.5*10^6$. The operator estimated the drilling and completion cost of Case One wells at US $\$27x10^6$. This increased to US $\$33x10^6$ for the longer, more complex Intelligent well. This cost includes extending the rig time required for drilling and completion from 2 months to 3 months. (N.B. suitable adjustments were also made to the drilling schedule describing the well timing). Table 8.2 shows the well CAPEX and the reduced investment due to drilling less wells for cases Four and Five.

Case Name	No. of Producers	No of Injectors	No of Total ICVs	CAPEX 10^6 US $	Discounted 10% pa CAPEX (10^6 US $)	Difference compare to Case One (10^6 US $)
History	7	3	-	270	260	0
Case One	7	3	-	270	260	0
Case Four	5	3	18	258	250	-10
Case Five	5	1	22	212	206	-54

Table 8.2 CAPEX for all the cases compared to the base case.

Table 8.3 Summaries the estimated differences in value creation for all cases where the discounted oil volumes have been recorded and then valued at US $ 20/bbl net income throughout project life. All cases achieved greater income than the actual history. The reduced CAPEX requirements for the IWT completion can be seen to form a significant part of the extra value creation.

Case Name	Cumulative Oil (10^3 sm³)	Cumulative Oil Produced after discounting at 10% (10^3 sm³)	Net income assuming US $20/bbl ($10^6$ US $)	Increased net income compared to Case One	Net present value compared to Case One
History	32.42	20.39	2450	-	-
Case One	33.56	21.58	2590	-	-
Case Four	35.26	22.95	2750	164*10^6 US $	172*10^6 US $
Case Five	35.69	23.36	2800	214*10^6 US $	268*10^6 US $

Table 8.3 Increased value derived from increased income and reduced Capex.

Figure 8.4.3 summarises the performance of the field during the first four years of production. It shows a comparison between the actual field history and the optimised Case Five, which includes intelligent completions in both the injectors and producers. N.B this comparison is based on the assumption that the higher deliverability of IWT will have avoided the well performance problems experienced by real S-Field in its early years. The results show that Case Five produces 20% extra oil than the actual history by the end of year four.

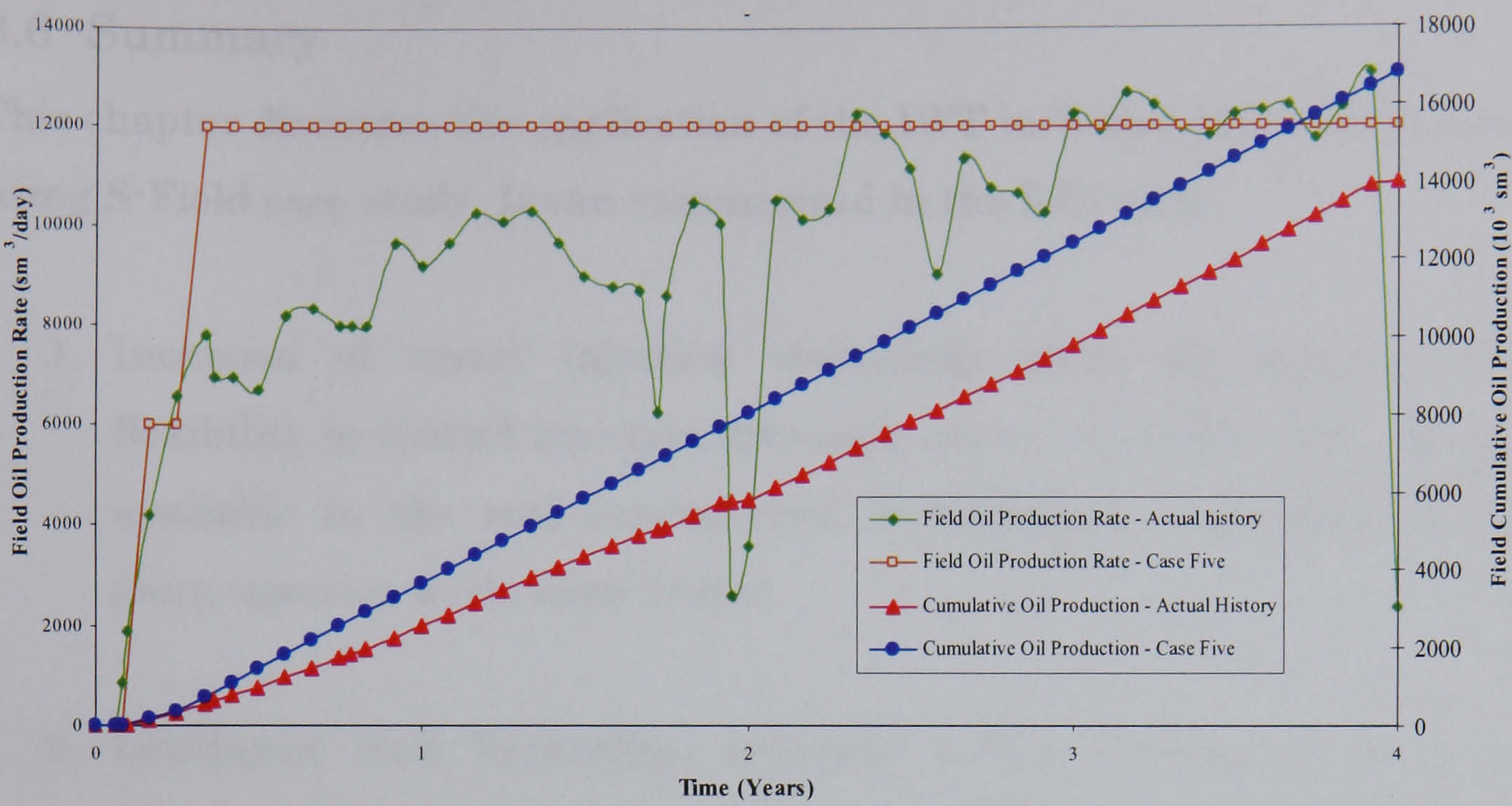


Figure 8.4.3 A Comparison between the actual history performance and Case Five

8.5 Systematic methodology for IWT derived from smart injection application in S-Field

Redevelopment of S-Field using IWT installed in the injectors has led to an increase in the field recovery and that is mainly because of the water being injected into all the layers compared to the existing water injection system. Continuation of the systematic methodology started in chapter 7, these rules and guidance can be added.

1. Voidage replacement per zone gave extra recovery from the poorer zones compared to the conventional water injection system.
2. This zonal voidage replacement can only be achieved with the use of IWT in both producers and injectors.
3. Transferring the value achieved by IWT to NPV showed that this kind of application can add significant improvement to the project economy.

8.6 Summary

This chapter discusses the application of the IWT in Water Injection System using S-Field case study. It can summarized in the following:

1. Inclusion of smart injection technology gives the operator the flexibility to control injection into each zone - an ability that was not available in the real conventional development, even when many more injection wells were drilled.

2. Intelligent Well Technology delivered a 3.3% increase in reserves. This translated, at a discounted value at 10% pa, into an extra oil production of $23.36*10^3$ sm^3, equivalent to US \$ $214*10^6$ assuming a net income of US \$ 20/bbl is achieved.

3. The reduction in well CAPEX through well numbers allowed a further US \$ $54*10^6$ of value creation. This CAPEX reduction is thus a significant contributor to the overall project value.

Chapter 9

9. Automatic ICV optimisation for a whole field

In the previous chapters we used Eclipse's manual optimisation techniques in order to justify the value of the IWT. Although that method has proved its value, it was concluded that even better results could have been obtained with an automatic optimisation tool. In this chapter we will use tools that are currently being developed by petroleum experts (Petroleum Experts 2002), these tools consist of a link between REVEAL (a Reservoir simulator) and GAP (a Network optimiser) to identify the potential added value of intelligent completions. GAP uses the Sequential Quadratic Programming (SQP) method to set well and zone rates in the well and facility flow network of a reservoir simulator (REVEAL). These rates are chosen so that production objectives are maximized, subject to any constraints on pressures and flow rates.

This chapter shows that the automatic optimisation using "GAP" with the control at the zone level can significantly increase the production achieved with both manual optimisation and conventional field level control. It also proved that the use of automatic optimisation is valuable when building a "value statement" for the implementation of IWT in a particular field study (Elmsallati et al. 2005e).

9.1 Automatic production optimisation (using conventional well) in reservoir simulation

Production and Injection wells are usually connected together by a surface network containing pipes, chokes, pumps, etc. numerous studies have been performed in order to set the flow rate per well or per group of wells. Different tools have been used to meet constraints inherent to this network of these facilities. Reservoir modellers have to optimise rate allocation to optimally determine well rate setting so that network objectives and constraints are simultaneously satisfied. Previous published work in this area includes:

1. Lo et al. (1993) and Fang and Lo (1996) used linear programming methods to optimise oil production subject to surface facility capacity constraints. Their facilities model was coupled with a simplified representation of the reservoir. Each well or well group was represented by a rate stream that was calculated from "well histories" determined by full-field simulation runs.

2. Hepguler et al. (1997) connected a facility network model with black-oil simulator using a non-linear SQP optimiser. For each time step the facility model and the reservoir model are iteratively solved until the reservoir outflow matched the network inflow.

3. Wang et al. (2002) used a SQP to solve the problem of simultaneously optimising the allocation of well rates and lift-gas rates. The proposed method was tested on several examples. Results show that the method is capable of handling flow interactions among wells and can be applied to a variety of problems of varying complexities and size.

4. Davidson and Beckner (2003) used SQP to set well rates in a facility network of a reservoir simulator. SQP was used to meet the objectives of maximizing the oil production subject to constraints on pressures, flow rates and stream compositions. The approach was tested with both black oil and compositional models of hydrocarbon fluids properties. The examples show how the method has been formulated, individual well rates are set and how unrealistic conditions are handled.

5. Kosmala et al. (2003) developed a link between reservoir simulator with a surface network to facilitate reservoir and production management. An optimiser (based on SQP) was included in the network simulator to ensure that optimal management of the coupled system was achieved. They have tested their tool using a simple (synthetic) reservoir model and on two North Sea field cases. For all case, the optimum oil production is achieved either by adjusting the valve settings or by optimising the gas lift allocation.

9.2 Introduction to the optimisation

The goal of any optimisation procedure is to find the highest or lowest global value of an objective function. The application of the optimisation is widely used e.g. Wang et al (2004) developed a method based on which they described gas-lift optimisation problem and investigated its performance against multiple existing methods. Their method reduced the CPU time for optimisation and has smaller impact on reservoir simulator convergence. On other application Gosselin et al. (2003) used gradient-based algorithm to develop software to perform history matching using time lapse seismic. The algorithm was used to minimize the objective function, which in their case was the mismatch when combining production, pressure and time-lapse seismic data.

Generally speaking, if the objective function does not have a smooth surface or the search space is large, then the optimisation techniques often use the derivative or gradient of the objective function in their search. There are several methods for optimisation available in the literature e.g. (ranked in order of complexity):

- Simplex (Linear programming) or Equal Slope
- Non-Linear optimisation
    - SQP

9.2.1 Linear programming

"This term refers to the techniques used to solve constrained optimisation problems in which both the objective function and the constraint function are linear" (Zachary 2005). This method is widely used as it is easy to apply but it can only be used to solve linear problems and linear constraints.

9.2.2 Non-linear programming

"Non-linear programming is the process of solving a system of equalities and inequalities over a set of unknown real variables, along with an objective function to be maximized or minimized" (Bazaraa 1979). This procedure is more complex compared to the linear programming. It is only used if the problem is non-linear problems and it has non-linear constraints. SQP is one method of solving non-linear problems.

9.3 Numerical optimisation

Optimisation techniques are used to find a set of design parameters, $x=x_1,x_2,\ldots\ldots\ldots,x_n$, that can, in some way, be defined as optimal. In a simple case this might be the minimization or maximization of a chosen system characteristic that is dependent on *x*. In a more advanced formulation the objective function, *f(x)*, has to be minimized or maximized.

Sun and Sun (2002) classified numerical optimisation methods into three categories:

- *Search method* if only the evaluation of objective function is needed in each iteration.
- *Gradient method* if only the values of the gradient vector m and the objective function needs to be calculated in each iteration.
- *Second order method* if the Hessian matrix H needs to be calculated in each iteration.

An efficient and accurate solution to this problem depends not only on the size of the problem in terms of the number of constraints and design variables; but also on characteristics of the objective function and constraints. When both the objective function and the constraints are linear functions of the design variable, the problem is known as a Linear Programming (LP) problem. Quadratic Programming (QP) concerns the minimization or maximization of a quadratic objective function that is linearly constrained.

9.3.1 GAP optimisation

The GAP optimiser is capable of handling non-linear optimisation problems using the SQP approach (Gockenbach, 2003). It was originally designed for optimising lift gas allocation to individual wells in large gas lift projects in order to achieve the optimum solution at each time step. In addition, the GAP optimiser has been used for alteration of well backpressure by adjusting the wellhead choke size. For this case the optimiser has to honor fixed boundary conditions (e.g. separator & reservoir pressures) and other constraints such as:

- Maximum oil and/or gas production
- System constraints
- Maximum water production
- Minimum pressure constraint
- Velocity constraints.

GAP attempts to optimise the hydrocarbon production using the rate of change of the production rate with respect to the rate of change of controllable variables e.g. choke size. It has the capability to model naturally flowing, gas lifted and ESP production/injection wells. It can use either gross revenue or maximum oil production as the objective function.

9.3.1.1 GAP's optimisation procedure

GAP first performs a system solve using the existing control variable settings (input into the simulator). It then obtains the derivative information with respect to the system objective function for each control variable is obtained (quadratic response), based on which penalty functions are to be applied as required to meet violated constraints (e.g. partially close one or more of the wellhead chokes). GAP's SQP optimiser uses its quadratic approximation of the system (the virtual model) to recommend, after a wide search of the solution space, new control variable settings (Petroleum Experts 2003). Iterations are performed to approach the optimal solution. The GAP network in the case described in this thesis starts at the reservoir level. It includes all well/completion inflows and then uses lift curves to model the vertical flow. Finally the surface network facilities are included and the constraints can then be considered at the appropriate levels e.g. well, joint and separator.

9.3.1.2 Appropriateness of SQP IWT optimisation application

SQP is the most widely used algorithm for non-linearly constrained optimisation (Becerra 2003). The use of SQP or other non-linear techniques is essential when studying non-linear (strongly interacting) systems (changing one variable in such systems can alter the entire network solution space). I.e. the true system response cannot be inferred from the responses of individual components without taking their interaction into account. The response of the changing solution space is included within the SQP method whereas a linear method assumes a constant solution space.

9.3.1.3 Advantages of using SQP

The advantages of GAP's use of SQP can be illustrated by the non-linear system example of a gas lift injection network with two wells (Petroleum Experts 2003). The objective is to determine the optimum gas lift injection rate in each well to maximise production from the system. Linear programming techniques work by guessing the lift gas Injection rate from the well response and then calculating the response of the surface pipelines. This then gives a new wellhead pressure based on the system pressure drops. A new well performance curve can then be constructed.

The actual system behaviour however is more complex. The pressure drop in the pipeline will cause the backpressure of each well to change every time a new Gas Lift Injection rate iteration is made. The SQP technique has the ability to calculate the response of every element in the system. i.e. not only how the pressure will change with changing flow rates but also how the gas lift injection rate will impact the pressure. These responses are built-into the calculations. The actual behaviour for the wells can then be constructed and the optimum solution found. A tool with the similar attributes is needed to optimise IWT responses of a system with more than two ICVs. Here, one needs to take into account the affect of each ICV setting on the whole system, rather just on the individual zone that it is controlling.

9.4 Production optimisation of "Intelligent Wells" using ICVs

Optimisation of ICVs is a complex problem because there are many variables to be considered. The objective function in this case could be the Net Present Value (NPV) of the project, the cumulative oil production from the field or some other criteria. These objective functions will be of a high dimension and will in general have an extremely rough surface. Further, due to the complexity of the production scenarios that must be assessed, ICV optimisation requires the use of a reservoir simulator to evaluate the cost functions.

Production optimisation from "intelligent wells" and the methodologies required to couple this with reservoir simulation has been studied by Naus et al (2004). They developed an operational strategy for commingled production with variable ICVs using sequential linear programming, they applied their optimisation strategy in a reservoir simulator where the algorithm was tested in two reservoir settings and in both cases the optimisation resulted in accelerated oil production compared to the conventional, surface controlled production. Further references to the work that has been published in IWT optimisation area can be found in chapters 4 and 7.

9.4.1 S-Field automatic optimisation using GAP optimiser

The objective of this study was to evaluate the potential of SQP, as implemented in the GAP's optimiser, to:

1. Extend the plateau period further than that achieved by manual optimisation and
2. To produce extra oil in the decline (tail- end) production period.

9.4.1.1 S-Field REVEAL model

The original S-Field Eclipse model (Chapter 7) was converted to the REVEAL simulator and linked to the GAP optimiser using RESOLVE software (acknowledgment to Steve Todman from Petroleum Experts for his help in this section). Eclipse and Reveal models are identical in terms of geological modelling, reservoir properties e.g. PVT properties, relative permeability curves and the location and completion design of production and injection wells as well as the lift curves for production wells. However due to the use of different control mode each simulator is using (Eclipse uses its own optimiser in order to meet the production constraints where REVEAL is using GAP's optimiser to optimise the production) the performance of the models was different. Figure 9.4.1 is the comparison between the two models of Eclipse and REVEAL. Figure 9.4.2 is REVEAL's S-Field saturation map (Oil is Green where the water is Blue) showing the location of the five producers (SM-1, SM-2, SL-1, SL-2 and SL-3) and three injectors (K-1, K-2 and K-3).

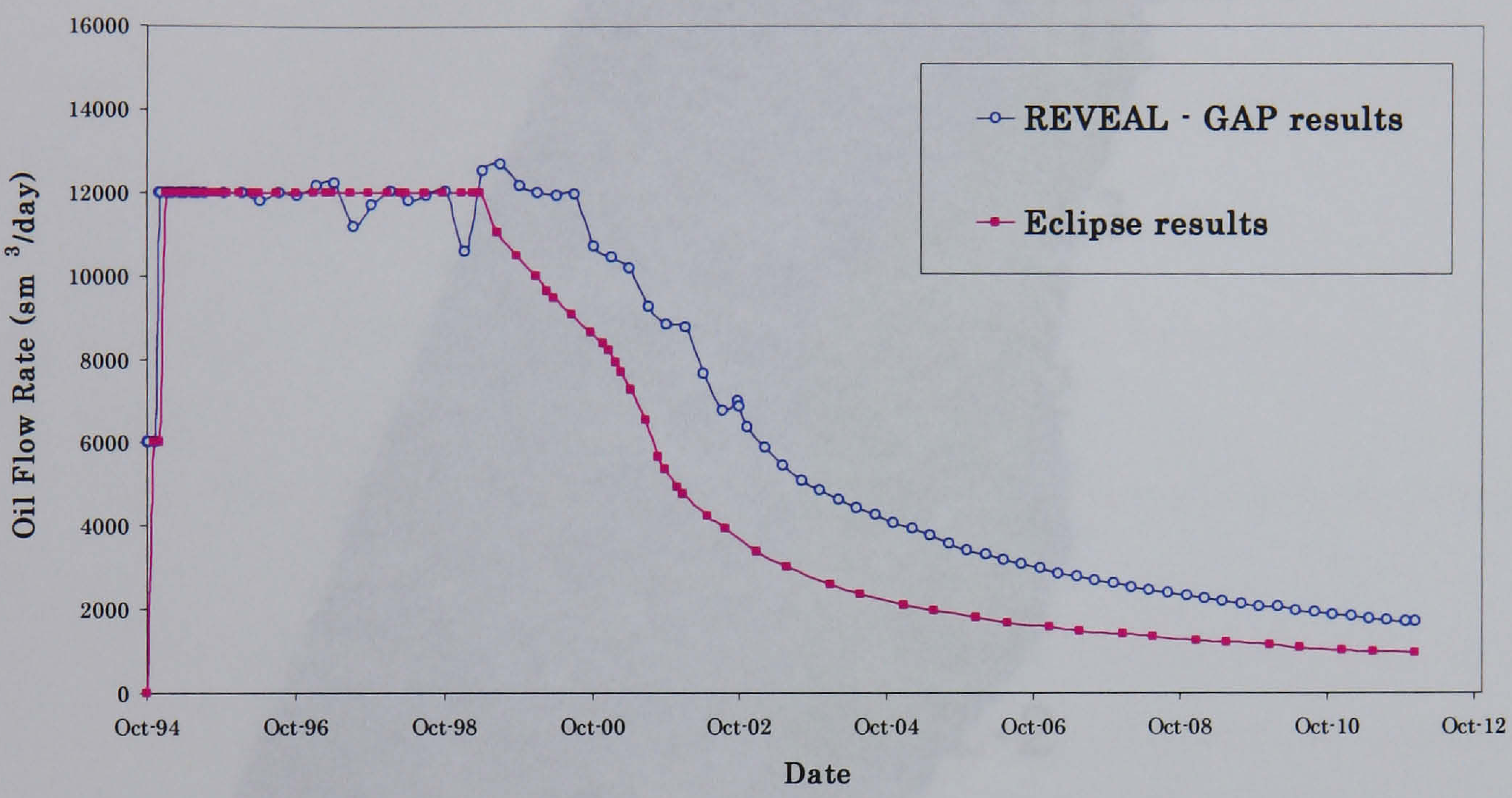


Figure 9.4.1 Comparison between the Eclipse and REVEAL models

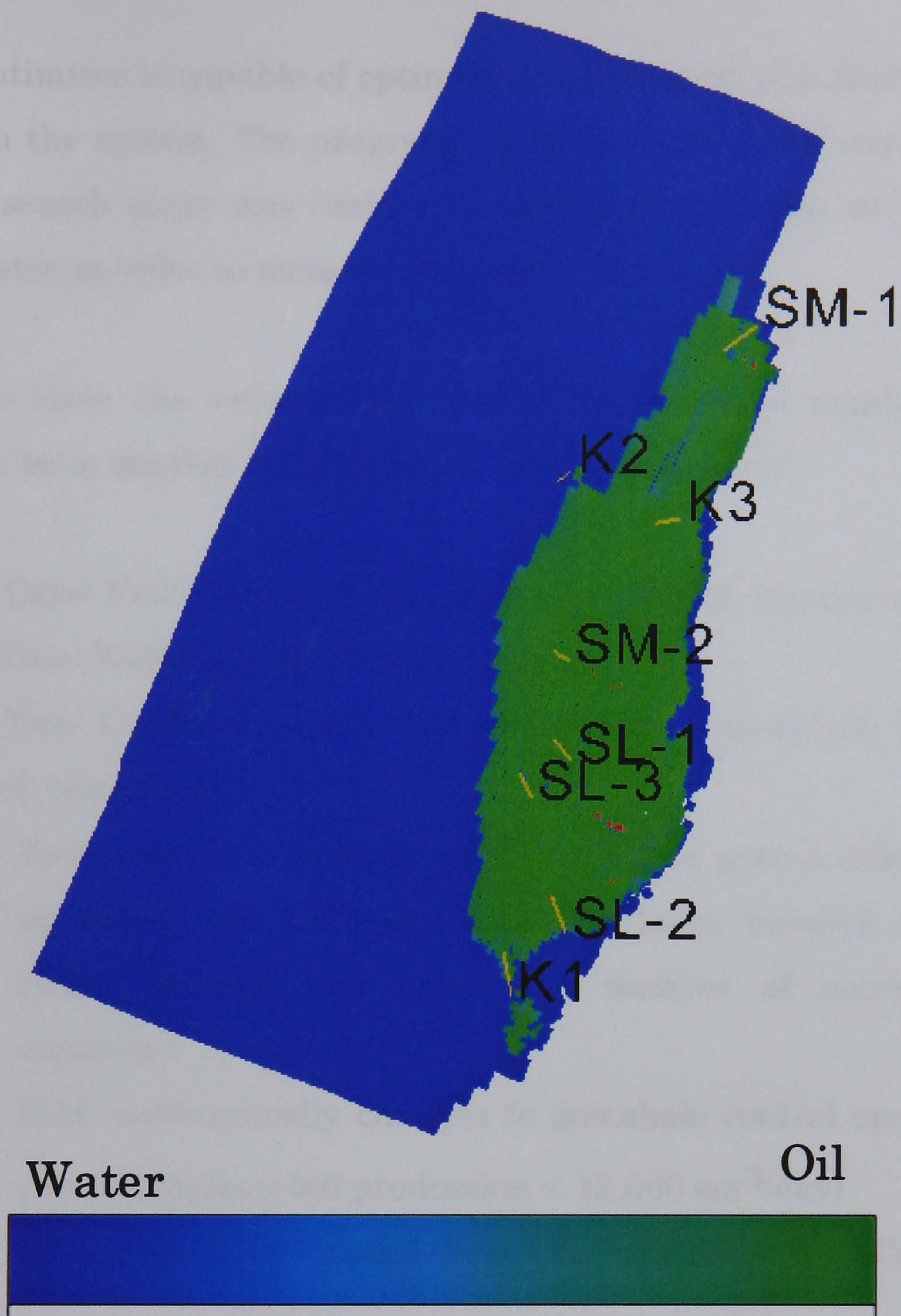


Figure 9.4.2 S-Field model in REVEAL showing the saturation distribution and the well location

9.4.1.2 S-Field GAP model

Figure 9.4.3 shows the GAP model of S-Field. It includes the 18 production zones, divided into five producers; each of these zones is controlled with an ICV. VFP curves are used to model the lift performance. The five producers then divided into two groups (SM and SL templates), each of which is connected by a separate pipeline to the separator, situated on the host platform.

The GAP optimiser is capable of optimising the position of a choke placed at any point in the system. The program's default choke model was used. The optimiser's search space was limited by setting a minimum and maximum choke diameter in order to increase the calculation speed.

In order to show the value of the downhole control, a number of GAP models have been studied using different control scenarios:

- Base Case: Field control: Single choke prior to the separator.
- Case One: Well Control: Wellhead choke.
- Case Two: Combination of wellhead control and downhole (zone level) control. Note that:
    - Zone control is applied AFTER plateau period only (the SQP optimiser had difficulty with the large number of possible choke settings and hence the number of potential valid solutions)
    - GAP automatically changes to downhole control once the field goes off plateau (oil production < 12,000 sm^3/day)
- Case Three: Downhole Control Only (the Intelligent Well Case)

All these cases use similar production constraints (12,000 sm^3/day of oil, 20,000 sm^3/day of liquid and a separator pressure of 67 bars which reduces to 25 bars after 8 years of production). All cases start in October 1994 and run for 18 years.

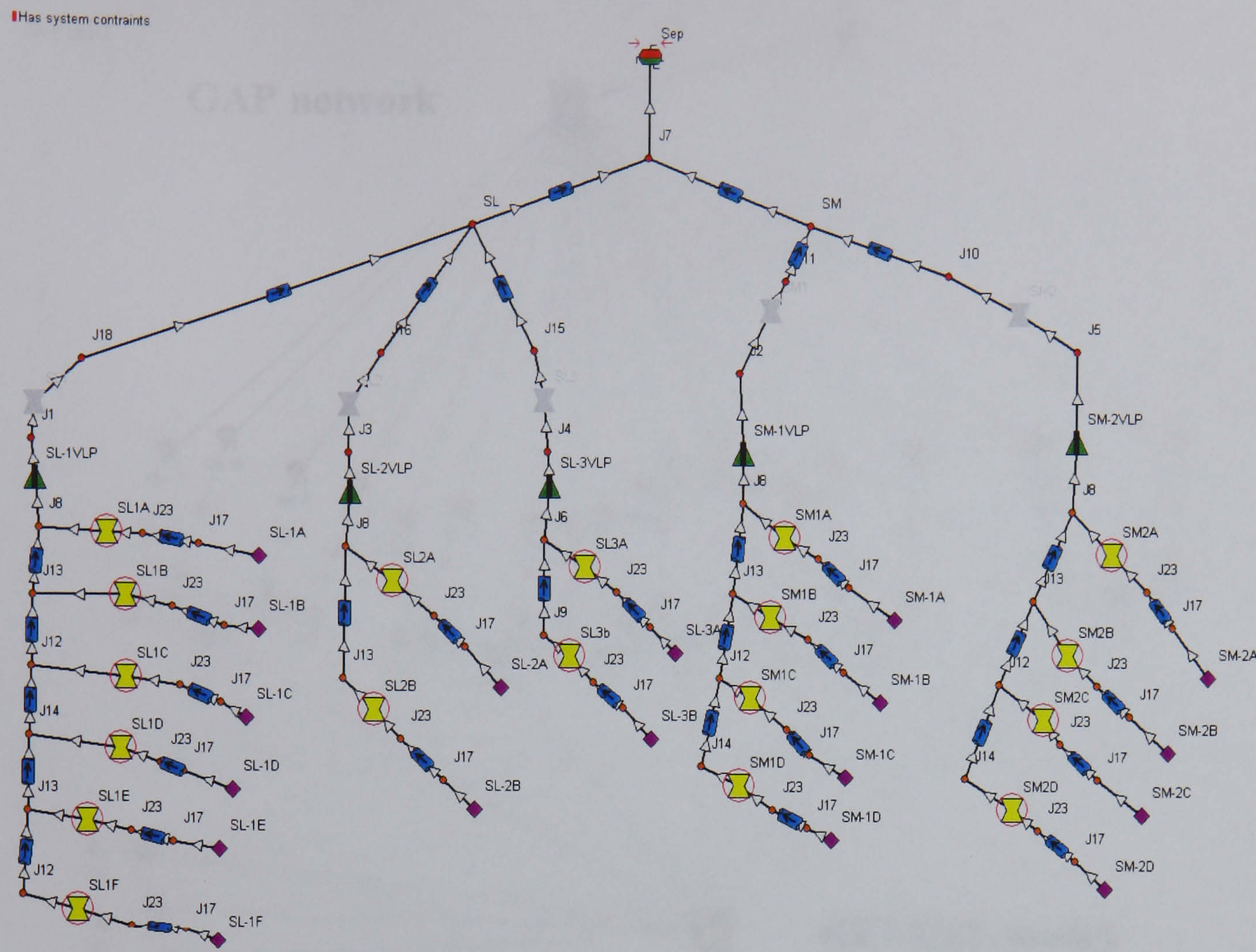


Figure 9.4.3 S-Field GAP network model showing the system elements

9.4.1.3 S-Field RESOLVE model

Figure 9.4.4 shows the link (generated by the RESOLVE software) between the REVEAL's completion level inflows and the GAP network. Water injection is included in the REVEAL model, but it was not part of the optimisation procedure.

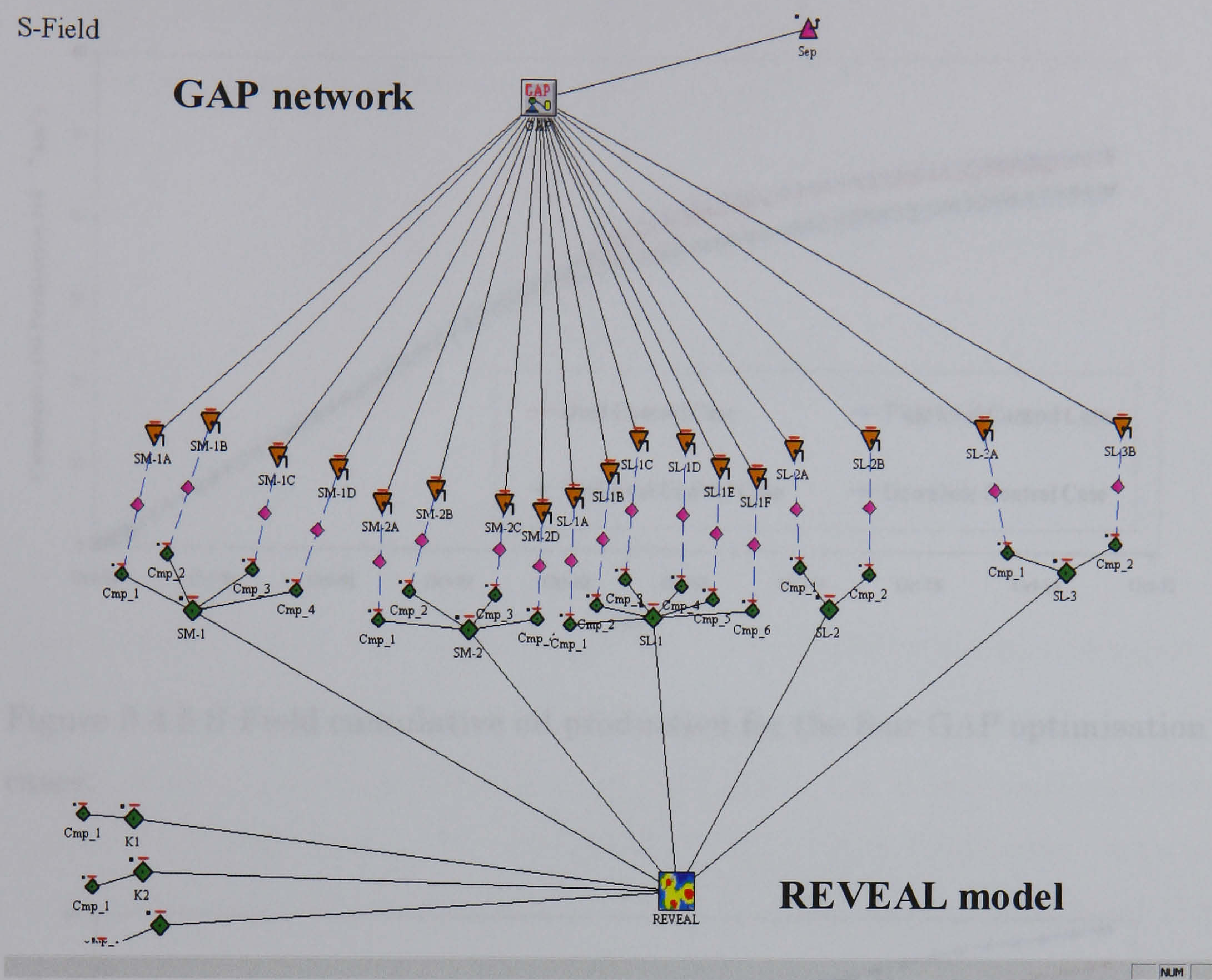


Figure 9.4.4 S-Field model showing RESOLVE linking the Simulator (REVEAL) and the optimiser (GAP).

9.4.2 Simulation results and discussion

All cases run for 18 years (similar to the Eclipse runs). The GAP-REVEAL computational time was usually three times longer than the equivalent Eclipse run time. Figures 9.4.5, 9.4.5(a) and 9.4.6 show the simulation results of the cases studied. Downhole control has increased the cumulative oil produced by extending the plateau period and managing the production during the decline period.

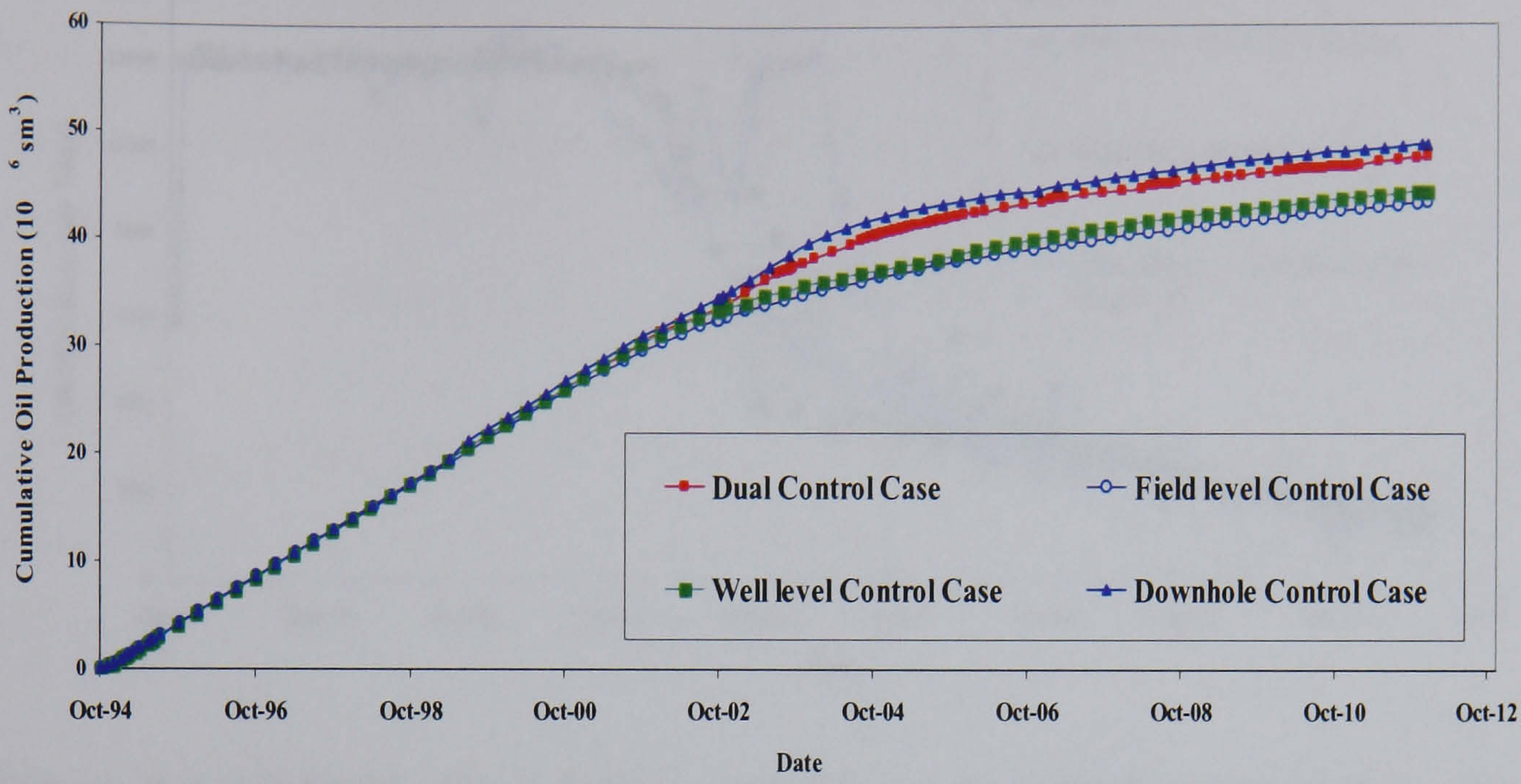


Figure 9.4.5 S-Field cumulative oil production for the four GAP optimisation cases.

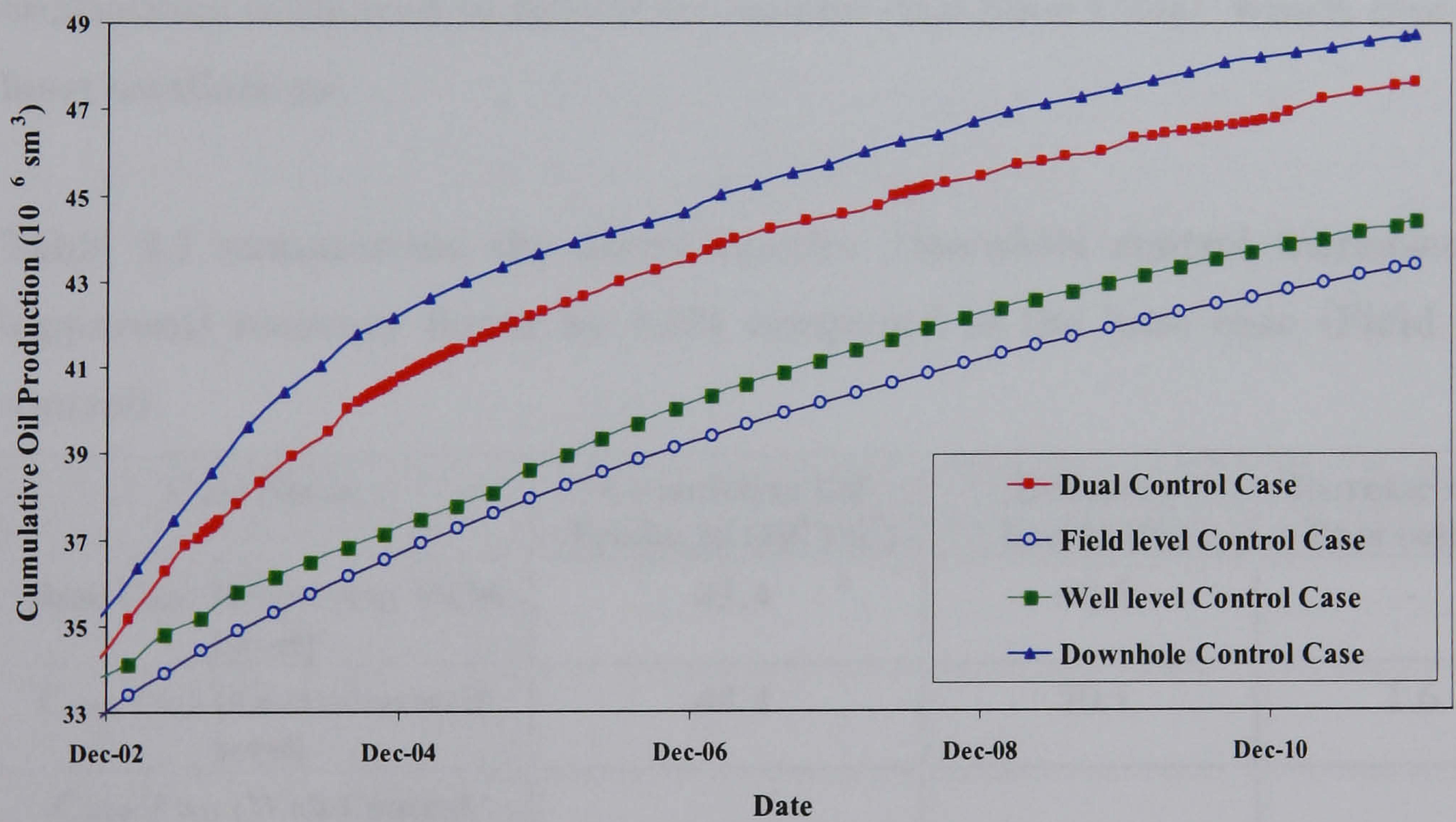


Figure 9.4.5 (a) S-Field cumulative oil production for the four case showing the extra oil gained during the decline period

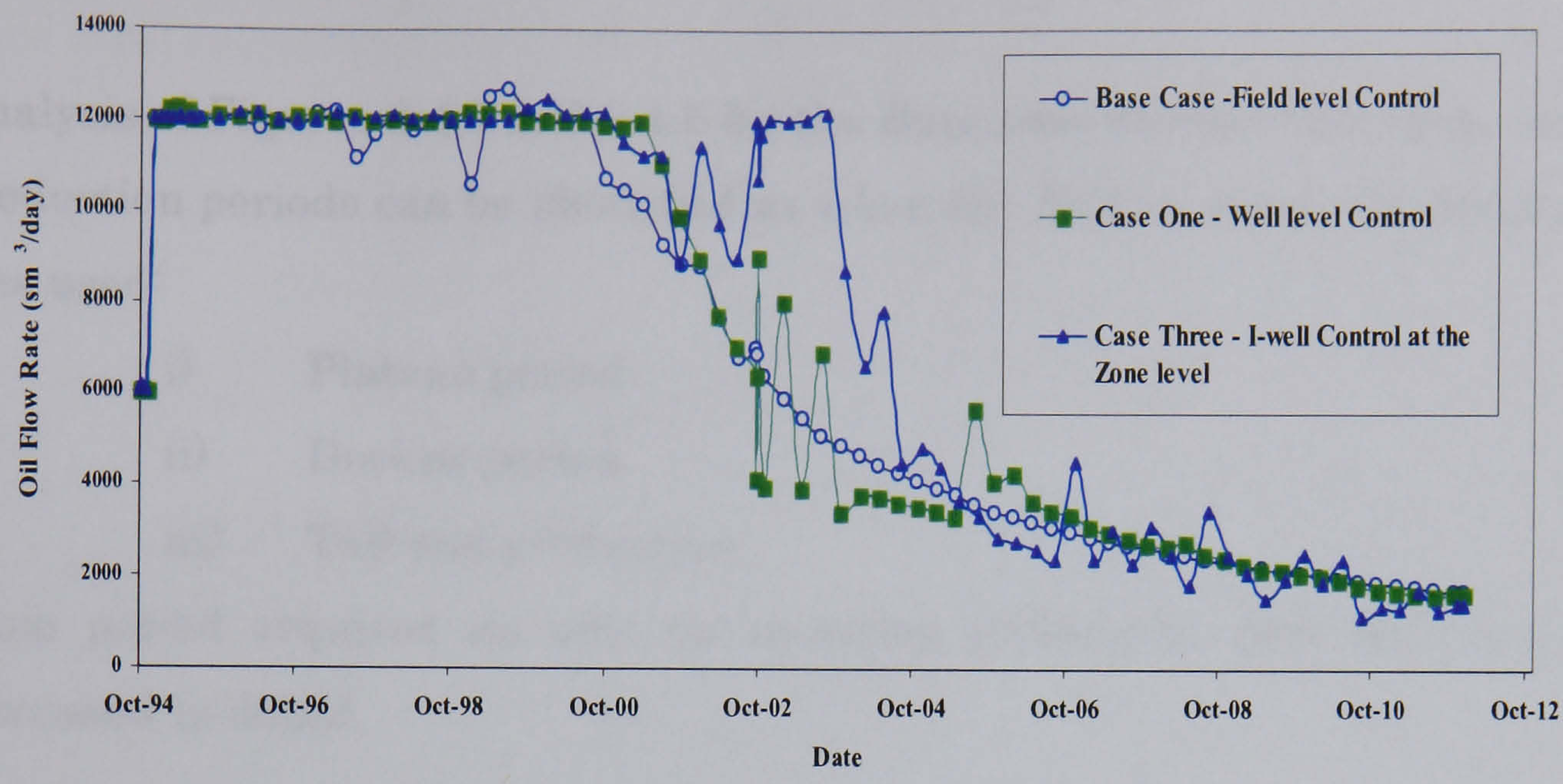


Figure 9.4.6 S-Field oil production rate for the four GAP optimisation cases

Figure 9.4.6 compares the field oil flow rate for three of the cases studied. Figure 9.4.7 shows that the dual control (Case Two) cause more system oscillations compared to field level control (the Base Case), which gives the least oscillations.

Table 9.1 summarises the above results. Downhole control increases the (apparent) recovery factor by 8.6% compared to the base case (Field level control).

Case Name	Cumulative Oil Produced (10^6 sm^3)	Recovery Factor (%)	Increase w.r.t. Base case %
Base Case (Control at Field Level)	43.4	68.5	-
Case One (Control at well level)	44.4	70.1	1.6
Case Two (Well Control during the plateau period & IWT control at zone level during the decline period)	47.6	75.2	6.7
Case Three (IWT control at zone level all times)	48.8	77.1	8.6

Table 9.1 Summary of the results based on GAP

(N.B. We observed that GAP usually gives high values of oil recovery factor compared to the reservoir simulator (REVEAL) – but only looking for relative differences

Analysis of Figures 9.4.5 and 9.4.6 for the Base case showed that three same production periods can be identified as when the Eclipse reservoir simulator was used:

i) Plateau period.

ii) Decline period.

iii) Tail-end production.

Each period required its own optimisation philosophy that will now be discussed in detail.

9.4.2.1 Plateau period (Year 1-6)

During this period the need of downhole control is limited, as well deliverability is in excess of the field plateau rate. However each case has achieved this rate with a different optimisation based philosophy, either for the well as whole or for the downhole valves only. In this period, the downhole control case (IWT) case and the dual control case stay on plateau for longer. The cases employing well level or field level control give the shortest plateau period.

9.4.2.2 Decline period (Year 6-9)

Downhole control yields extra value during this period. Such control allows the field to produce more oil compared to either wellhead control or field level control (i.e. Zone level optimisation worked well in this period).

9.4.2.3 Tail-end production (Year 10-18)

Zone level optimisation increased oil in this period as well as giving the flexibility to shut the high water cut zones (N.B. the tubing performance is such that only limited improvement occurred when the high water cut zones were shut in. The benefit is thus derived for improved reservoir management). In this period dual control (Case Two) optimisation at the zone level causes system oscillation. Figure 9.4.7 shows detailed explanation of the production performance for the dual control optimisation case.

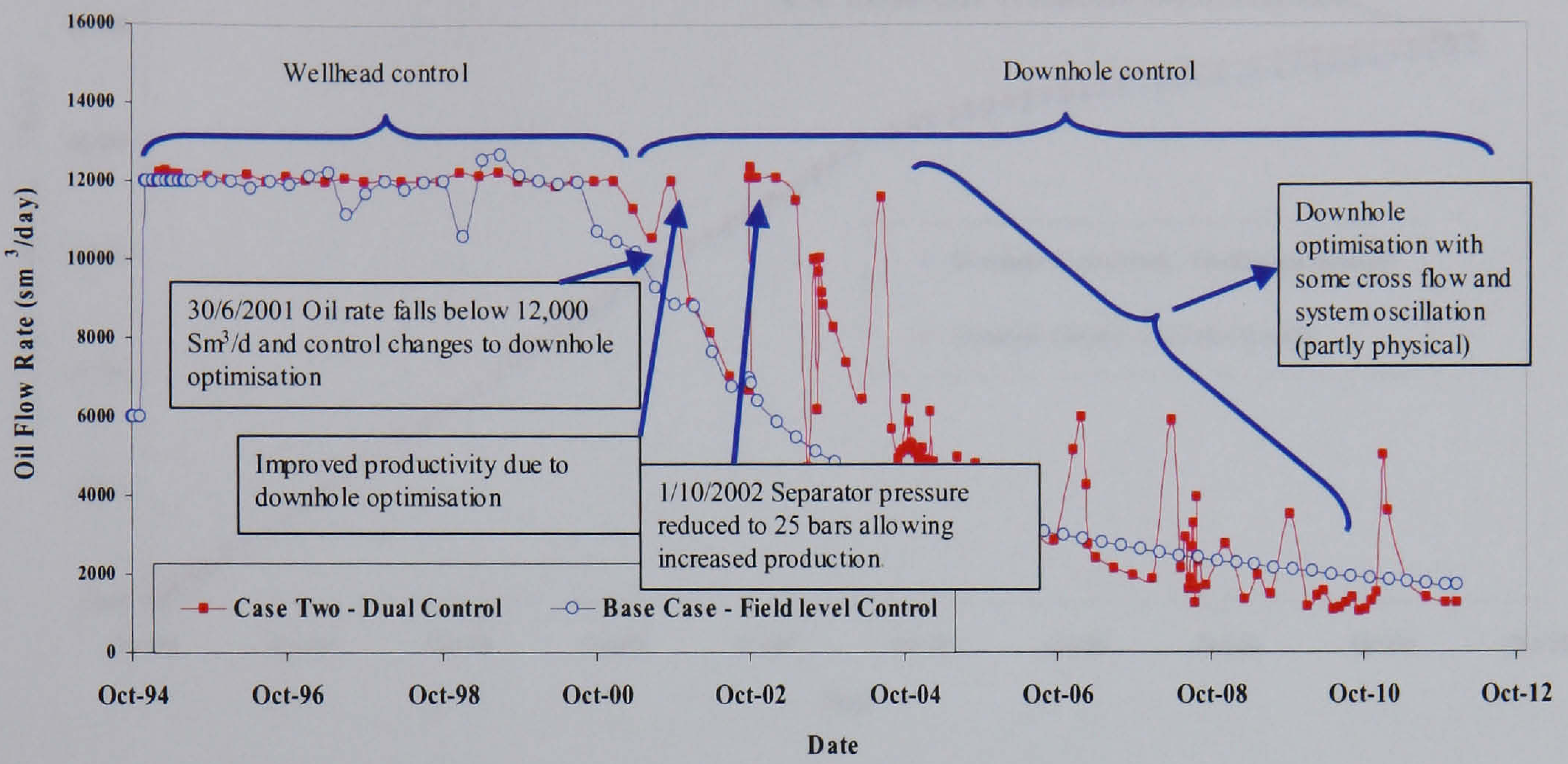


Figure 9.4.7 Annotated S-field performance for the dual control case compared to base case.

It has not proved possible to distinguish between oscillations due to physical production of extra oil and mathematical oscillations i.e. errors. A (pessimistic) estimate of the extra oil production can be derived from the assumption that all these oscillations are not real. A 2% reduction in cumulative oil produced results (Figures 9.4.8 and 9.4.9).

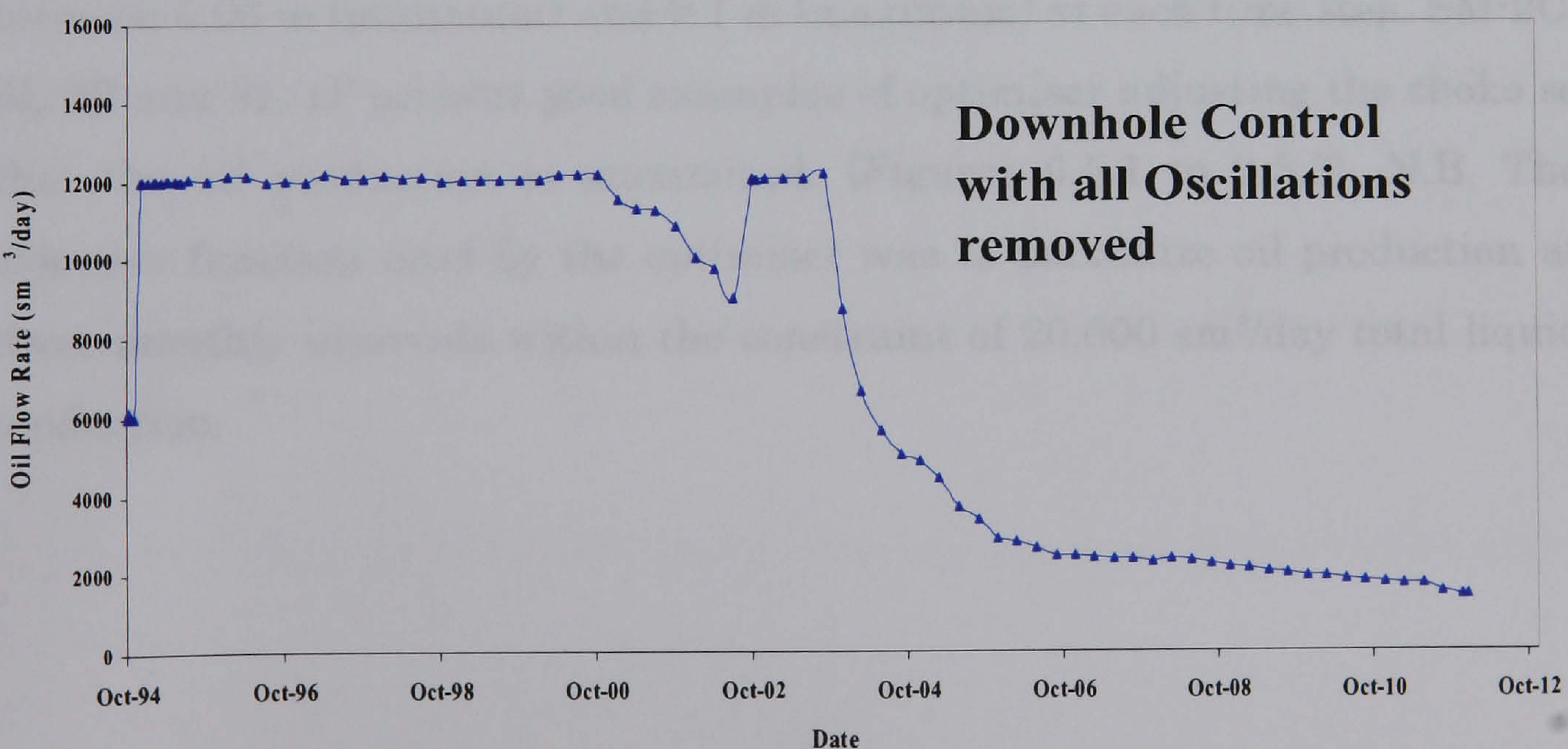


Figure 9.4.8 The Intelligent well Case (Case Three) with all oscillations manually removed

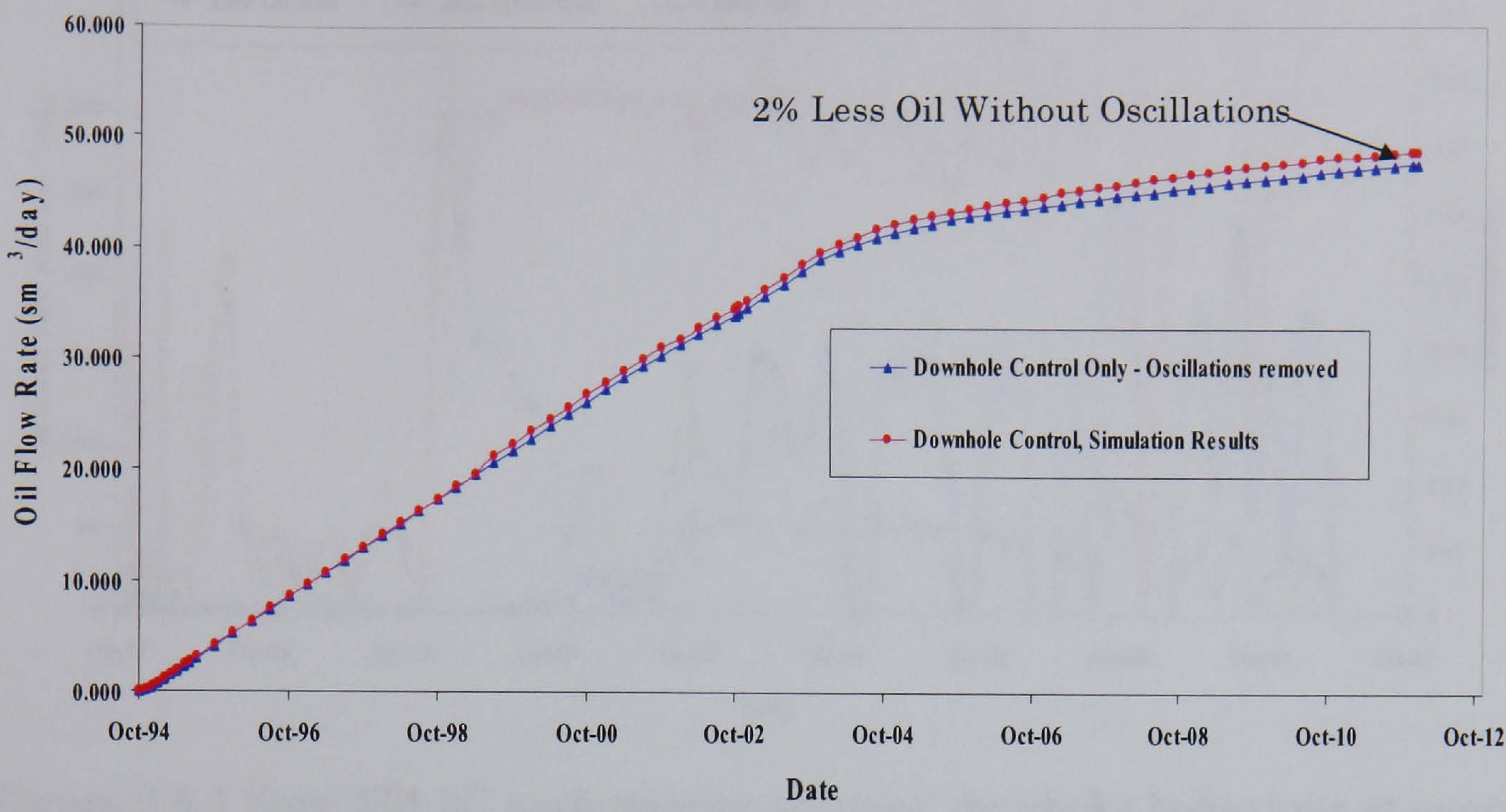


Figure 9.4.9 Cumulative oil produced for the intelligent well case with and without oscillations

9.5 Example of IWT production optimisation by zone level control

In the zone level control case (Case Three) the optimiser has the opportunity to control the well production by changing the downhole chokes to any value between 0.05 m (minimum) and 0.1 m (maximum) at each time step. SM-2C, SL-3B and SL-1F present good examples of optimiser adjusting the choke so that the oil production is maximized. (Figures 9.5.1 to 9.5.3). N.B. The objective function used by the optimiser was to maximize oil production at three-monthly intervals within the constraint of 20,000 sm^3/day total liquid production.

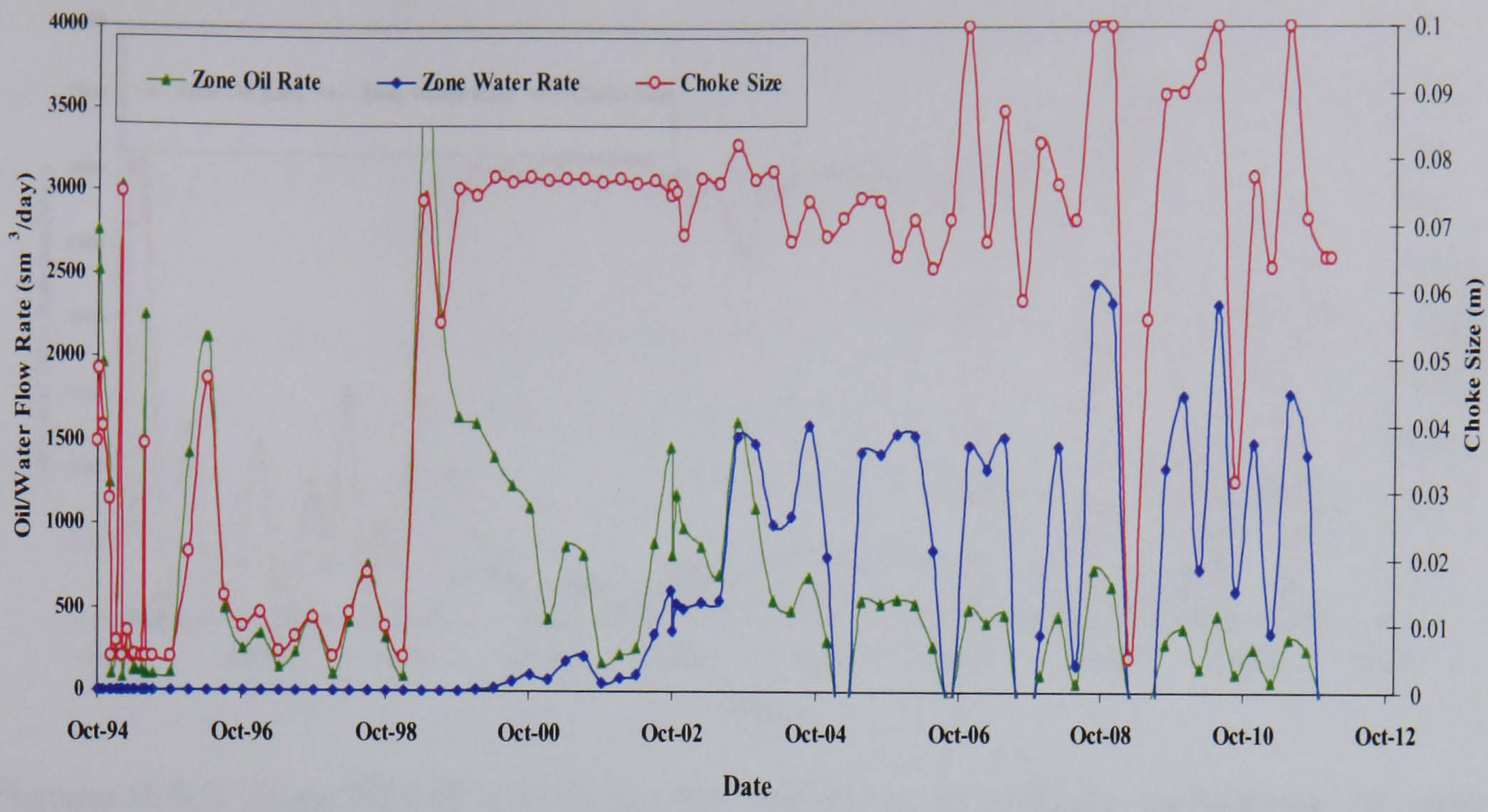


Figure 9.5.1 Zone SM-2C performance showing the choke behaviour at every time step

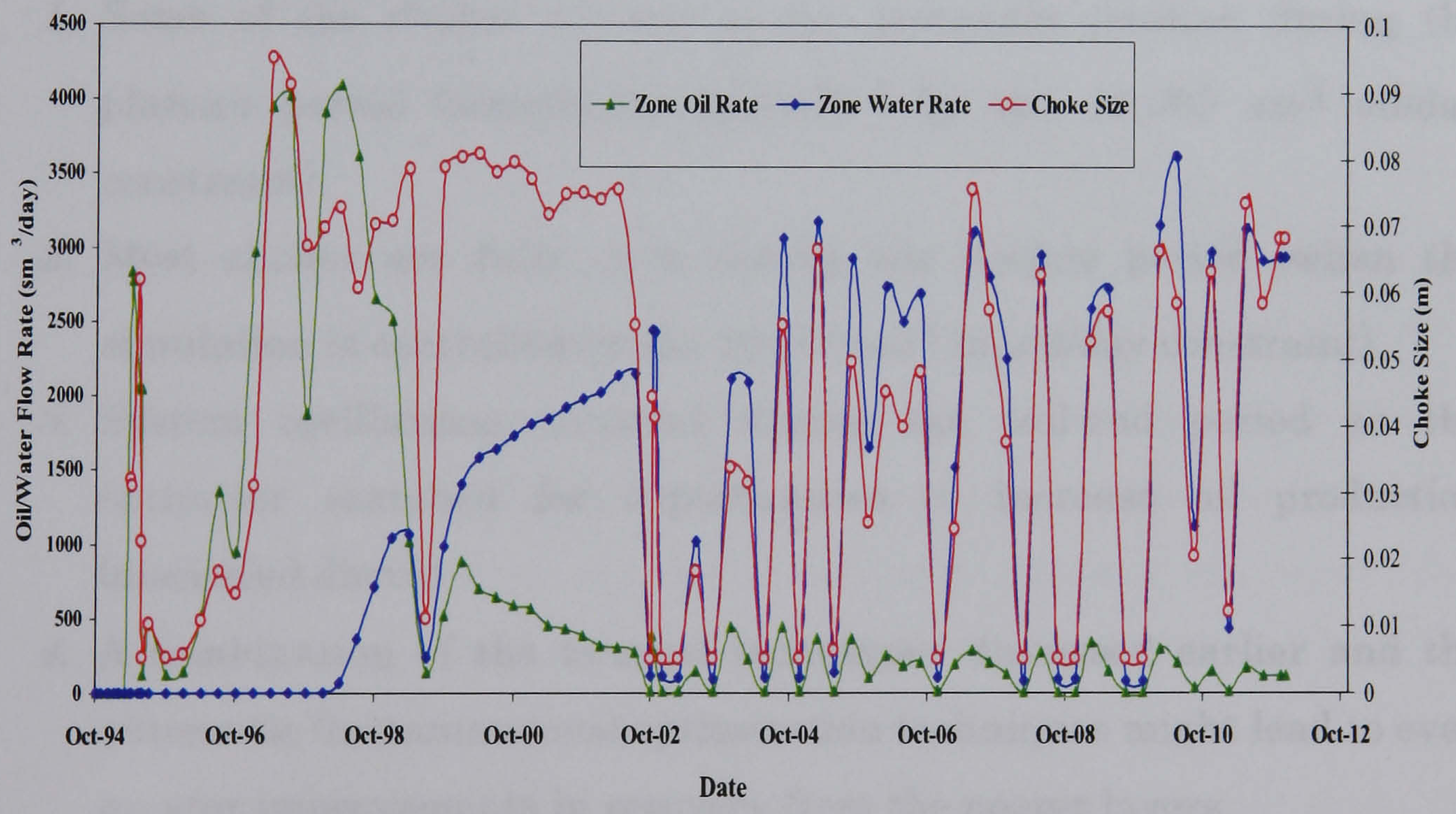


Figure 9.5.2 Zone SL-3B performance showing the choke behaviour at every time step

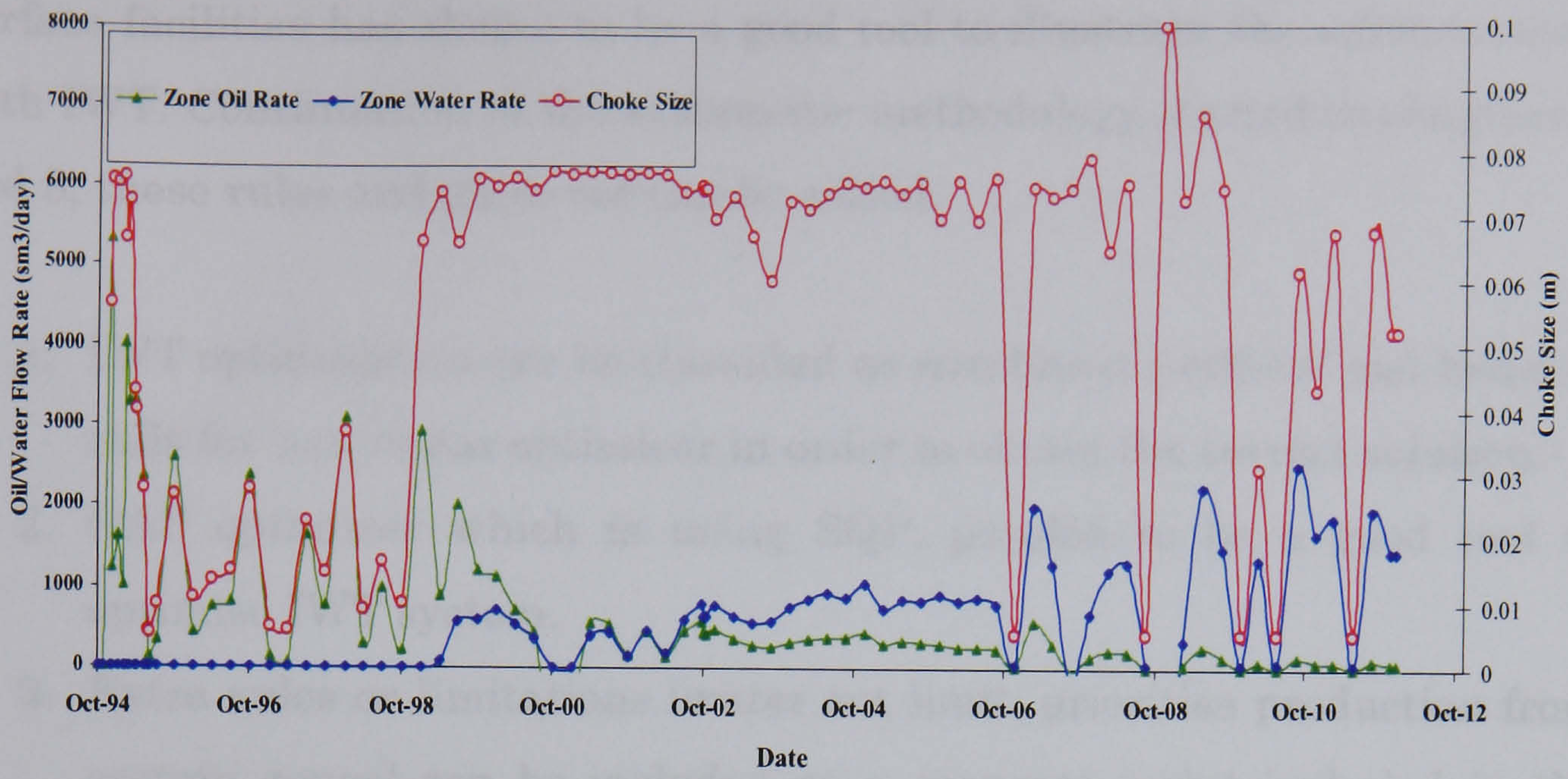


Figure 9.5.3 Zone SL-1F performance showing the choke behaviour at every time step

9.6 General observation concerning the GAP optimiser 's performance

1. Some of the chokes are set to the minimum position during the plateau period (simulation controlled by the 12,000 sm^3 oil/day constraint).
2. Most chokes are fully open during the decline period (when the simulation is controlled by the 20,000 sm^3 liquid/day constraint).
3. System oscillations occurred during the tail-end period as the optimiser searched for opportunities to increase oil production (discussed above).
4. A combination of the manual techniques discussed earlier and the automatic (instantaneous) optimisation techniques might lead to even greater improvements in recovery from the poorer layers.

9.7 Systematic methodology for IWT derived from applying automatic optimisation in S-Field

Using of automatic optimisation to control the downhole valves installed in S-Field along with including the vertical lift parameters and the effect of surface facilities has shown to be a good tool to illustrate the value created with IWT. Continuation of the systematic methodology started in chapters 7 and 8, these rules and guidance can be added.

1. IWT optimisation can be classified as non-linear problem and hence it calls for non-linear optimiser in order to obtain the correct solution.
2. GAP optimiser which is using SQP, proofed to be a good tool to optimise IWT system.
3. Extra rules or limitations (water cut limit, prioritise production from certain zones) can be included as a separate script included in the optimisation system.

9.8 Summary and conclusions:

This chapter presents first time application of GAP's SQP optimiser to optimise IWT system including surface facilities and applied it to a real field example. Previous publications were used synthetic cases and it uses linear programming to optimise the system.

This chapter can be summarized in the following points:

1. The value of automatic optimisation at in S-Field has been shown. Automatic optimisation with the control at the zone level indicated an increase between 6.6 % and 8.6% (depend on the level of control - well or downhole) in recovery compared to the field level control.

2. Automatic optimisation will provide a quicker answer than the manual techniques discussed earlier. However the "automatic answer" can only be properly analysed once the reservoir / field production process is fully understood.

3. The use of automatic optimisation is valuable when building a "value statement" for the implementation of IWT in a particular field study, as it justify the use or not-to-use this technology in a reasonable time.

4. GAP optimiser using SQP technique is applied to IWT for this field worked efficiently with acceptable increase in the computing time compared with similar model but without this complexity.

5. Previous experience with manual optimisation shows that the flexibly of the IWT require a good optimiser to identify the maximum value statement when justifying or when using this technology. A combination of both techniques may well give the greatest predicted recovery especially from the poorer zones where is chance to increase recovery is still available.

6. The large number of variables and potential valid solutions place a great demand on the optimiser calculations routine.

7. The need to simplify the problem (minimum and maximum choke setting allowed) and mathematical oscillations (solution errors) were two manifestations of problems with the software.

N.B. The providers of the GAP/REVEAL software program are actively working to solve the oscillations problem identified in this study.

Chapter 10

10.Conclusions and Future work

Insights gained into a range of IWT application examples drawn from a number of real reservoir development and management cases. This leads to a systematic guide for a reservoir engineer when designing or managing a reservoir project employing IWT.

10.1 Summary of Systematic Methodology for IWT application

Systematic Methodology to capture all the generic aspects of this study can be drawn to provide future students and practicing engineers with clear guidance. These rules and guidance can be summarised as follows:

1. Showed the importance of geological barriers within the completion section when considering using IWT to control production in long horizontal well producing from thin oil rim reservoir with a large, rich gas cap.

2. Illustrated the application of IWT in a compacting reservoir and the challenges presented by this kind of reservoir.

3. Studied the value of IWT to improve reservoir management as a whole.

4. Developed a methodology for managing ICVs in order to:
    a. Extend the plateau period
    b. Delay unwanted fluid breakthrough and
    c. Encourage production from poorer reservoir zones.

5. Applied GAP's SQP automatic optimiser to operate ICVs in order to maximise the objective function (Cumulative Oil) taking into account all system elements (reservoir, vertical flow and surface facilities).

6. Lessons learned from Single & "Multi-Well" Field Cases are:
    a. Single Well Cases:
        i. Well design and location are key when applying IWT.
        ii. IWT is able (in some cases) to correct any mistakes done in designing the well or/and handle any associated geological uncertainty.

    b. "Multi-Well" Field Case:
        i. Field constraints, number of isolated zones and are key points when designing & optimising the ICVs.
        ii. Managing the reservoir as a whole requires a more powerful & flexible optimiser than currently available.

10.2 Conclusions

The main conclusions of this thesis are:

1. Justification of the installation of an Intelligent Completions has to be based on a Case-by-Case basis. Each field has it is own characteristics and constraints which will not be relevant to other cases. However there are some cases where the use of IWT is

essential to achieve high recovery (e.g. one well completed in more than one separate sand with different pressures)

2. An accurate reservoir simulation model can be used to identify the value of IWT. This will be more efficient if the performance of the model is understood.

3. "Engineering judgment" is needed even if a smart optimisation tool is available.

4. The cases studied presented illustrate the importance of the reservoir's geology with respect to the design of the Intelligent Completion and the management of the production. However the value delivered from managing geological uncertainty was omitted in this study. The simulation model was always assumed to be "The Truth". In practice IWT could be used to also handle flexibility in face of geological uncertainty.

There are also specific conclusions for each of the areas studied

A. Modelling of intelligent completion

A.1) This thesis highlighted the importance of the friction pressure loss calculation when modelling flow in a (horizontal) well with long completion interval. This is particularly important for IWT completions where reduced tubing diameter is installed.

A.2) The Eclipse simulator's multi-segment option can be used to model two-phase flow through the ICVs during the numerical reservoir simulation. It also calculates the pressure profile of flow through the annulus and tubing by splitting the completion zone into a number of segments.

B. Thin oil column reservoir – NH Field Case

B.1) Frictional pressure loss across the completion section is an important factor when high permeability reservoirs are developed by high rate wells. This was emphasised by the improved well performance achieved on changing the well azimuth by 180°.

B.2) The NH Field Case presented a difficult case for "Added Value" justification of intelligent wells. Cross-flow nature of the formation makes it difficult to control each zone independently. In fact, for this thin oil column case, the presence of a high permeability streak connecting the heel of the well to the gas cap resulted in the acceleration of the tendency of the gas to breakthrough tendencies at the heel of the well i.e. breakthrough at the heel of the well was observed earlier than would have been expected on the basis of homogenous geology.

B.3) All three-control techniques tested in NH Field Case lead to an increase in the total oil production in the early production period (the first three years). This is the only period during which choking the free gas leads to a greater increase in the free oil production compared to the resulting loss of vaporized oil production.

C. Compaction reservoir – CT Field Case

C.1) The CT field is a good example of compartmentalised compacting reservoir. The study illustrates the value of well design. All the studied redevelopment options gave a greater oil recovery from the lower sand compared to the existing well design. Also, sidetracking the existing well to include all the lower sand compartments could dramatically increase the total oil produced. The value derived from the water injection to maintain the reservoir pressure reduced effect of the rock compaction, hence leading to further improvement in recovery.

C.2) The capabilities of the manual valve setting technique was limited to managing the water production and hence improving the lift performance. A powerful optimisation tool could have worked better as to optimise the drawdown (as an objective function) around the wellbore and to reduce the permeability damage caused by the compaction.

D. Oil water reservoir system – S-Field Case

D.1) This thesis describes the development of a systematic methodology to understand the recovery process within the S-Field. It also develops control policies useable by reservoir simulators employing manual control keywords. This helped to quantify the extra oil achievable through the use of an intelligent completion compared to a conventional well development employing a greater number of production and injection wells.

D.2) The manual optimisation procedure developed in this thesis helped to improve management of the reservoir as a whole rather than improved tubing performance or co-production of different reservoirs, as was done in many previously reported, case histories.

D.3) Inclusion of smart injection technology gives the flexibility to control injection into each zone. This ability that was not available in the real conventional development, even when more injection wells were in place.

D.4) Utilizing ICVs for scale management i.e. shutting-in only the scaling zone by choking back the scaling valve while producing from the other zones, results in a reduced oil production loss compared to the conventional procedure of shutting the whole well.

D.5) The ICVs may also be used to control the placement of inhibitor in a more effective and economic manner.

E. Automatic optimisation

E.1) The value of automatic compared to manual optimisation has been shown using the S-Field and the GAP optimiser. Automatic optimisation with zone level control indicated an increase in oil production between 6.6 % and 8.6% in recovery compared to the field level control. This is valuable when building a complete "value statement" for the implementation of IWT in a particular field study.

E.2) Comparison of the experience gained with manual and automatic optimisation routines indicates that the inherent flexibility of IWT requires a good optimiser to quantify the maximum value statement in a reasonable period of time when justifying or when using this technology.

E.3) The large number of variables and potential valid solutions place a great demand on the optimiser calculations routine and increase the program's execution time.

10.3 Future work

There are many areas need more research to be done such as:

a. This study covers number of field cases illustrating different reservoir management challenges. There are still further types of reservoirs where

IWT can deliver value from different sources e.g. fractured reservoirs and stacked reservoirs. Similar studies as to those discussed here can be carried out in order to show that value using real or synthetic field examples.

b. This study was concentrated on applying Intelligent Wells in either vertical or horizontal wells. Multi-lateral wells are now becoming a favored technology that can be used in conjunction with IWT. It should be studied whether the lessons leaned from this study can be directly applied to multilateral wells.

c. Geological uncertainty was ignored in this study, even though it is recognised that it can play a key role on designing and operating the ICVs. A parallel study to evaluate the value of including geological uncertainty into some of these examples will help to build a comprehensive understating of its effect on the recommended operating procedure.

d. This thesis uses a simple economic analysis of the field study results. A full economic and risk analysis of one of these case studies could be used as a template for building the IWT value statement.

e. Development of improved optimisation techniques holds the key to quicker completion of studies of the type reported here and to the development of operational optimisation tools based on real-time data. In particular, the GAP optimisation tool needs to be improved in order to reduce the number of system oscillations and to reduce the simulation time.

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