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MAXIMIZING RECOVERY OF BROWN FIELDS

(A Case Study)

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**SUBMITTED IN PARTIAL FULFILMENT OF THE
REQUIREMENT FOR THE DEGREE OF MASTER OF SCIENCE**

DECLARATION OF ORIGINALITY

This is to certify that the work is entirely my own and not of any other person, unless explicitly acknowledged (including citation of published and unpublished sources). The work has not previously been submitted in any form to the Teesside University or to any other institution for assessment for any other purpose.

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ABSTRACT

In other to meet the rising global consumption of oil, there is serious need to increase its production. With fewer new fields being discovered, brown fields also known as old or mature fields are being worked on to increase their recovery efficiency. This thesis is a case study focused on the study of different methods that can be used to boost primary recovery of a real life field that has produced over time and how much recovery is obtained from each of them. The methods considered include workover or well intervention, gas lift optimization and infill drilling. The main aim of the work is to determine how much extra oil that can be recovered from the field using each of the methods. The result shows that each method has a significant effect on overall recovery. A recovery factor of forty-three percent (43%) was obtained for Cases 2 and 3 with cumulative production of $5.80MMsm^3$ and $5.86MMsm^3$ respectively out of the STOIIP of $13.6MMsm^3$. And Case 4 gives a recovery factor of forty-four percent (44%) and a cumulative production of $6.03MMsm^3$. considering only cumulative production of each of the cases, it is concluded that the method considered most favourable would be Case 4.

ACKNOWLEDGEMENT

I would like to express my heartfelt gratitude to my supervisor, Dr Paul Shelton for his time, support, advice and encouragement all through this research to make it a brilliant success.

My sincere gratitude also goes to my entire family especially my parents, Felix and Bridget Odiki, whose prayers have kept me moving forward in academics and life in general.

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Table of Contents.

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

LIST OF TABLES

List of figures

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

NOMENCLATURE

R_w	Water resistivity
R_t	True formation resistivity
B_o	Oil formation volume factor
B_{oi}	Initial oil formation volume factor
M	Lithology exponent
N	Saturation exponent
S_o	Oil saturation
S_w	Water saturation
S_g	Gas saturation
S_{or}	Residual oil saturation
S_{gc}	Critical gas saturation
S_{wc}	Critical water saturation
S_{wi}	Initial water saturation
P_c	Capillary pressure
ΔP	Change in pressure
C_f	Formation compressibility
V_p	Total pore volume
V_o	Oil volume
q_o	Oil flow rate
q_w	Water flow rate
A	Drainage area

h	Reservoir thickness
N	Stock tank oil initially in place (STOIIP)
N_p	Cumulative oil production
B_w	Water formation volume factor
μ_w	Water viscosity
μ_o	Oil viscosity
Ø	Porosity
C/O	Inelastic gamma ray carbon to oxygen ratio

CHAPTER 1

1.0. INTRODUCTION

Crude oil has maintained its status as a major contributor to the world economy today. The provision of heat, electricity and transport depends on oil and there has not been a single energy source to replace crude oil so far that has broadly integrated. To meet the rising global energy consumption there is dire need to increase production. Over the years the number of new reserves discovered has reduced, hence brown fields are worked on to increase their recovery efficiency with or without enhanced recovery method depending on the size of the field and the cost of EOR.

Brown fields are fields that have reached fifty percent (50%) of its initial proved plus probable reserves or have been in production over ten (10) years. Brown fields are also known as mature fields. Over seventy percent (70%) of the world's oil and gas production are from brown fields with an average recovery factor of seventy percent (70%) recovery for gas fields and thirty-five percent (35%) for oil fields an can be smaller depending on the reservoir characteristics, resource limitations or operational inefficiencies. Maximising recovery has to do with assessing ways that can help increase the life of a field, improve its overall recovery efficiency and delay the cost of abandonment as well as increase the opportunity for third parties to make use of existing infrastructure thereby mitigating the need for developing new fields and offsetting the need for alternative energy sources.

This work is based on the study of a marginal field in Nigeria, West Africa that has produced over a period of time and it would focus on simple methods of maximizing field recovery such as identifying areas containing unproduced oil and determining the best ways to produce them efficiently.

1.1. THESIS STRUCTURE

This thesis comprises of five (5) chapters

Chapter one - gives an introduction of the entire project starting with introduction to brownfields and why they are important. It also addresses the objectives and scope of the research.

Chapter two – will comprise the literature review, explaining ways of determining the amount of oil remaining in the reservoir after a period of time and its location as well as the different methods that can be used to recover them. It also discusses the factors that affect

these methods.

Chapter three – this is basically the beginning of the research work. It starts with a brief description of the case study, the method used and the data needed for the simulation process as well as the simulation process itself. It also contains information of the different fiels development case scenarios that were considered in the process of maximizing oil recovery.

Chapter four – contains the results obtained from the simulation process for the different field development cases and a brief description of the results. And discusses the results in details and compares the results of all the field development cases carried out.

Chapter five – finally discusses the conclusion and further recommendation for this work.

1.2. OBJECTIVE OF WORK
The work will focus on

1. Evaluating current field and well production rates and ultimate recovery of existing reservoir.
2. Evaluating different field development scenarios and carrying out uncertainty analysis to propose optimal complementary field depletion plan to maximise oil production.

1.3. SCOPE OF WORK
1. Review and quality check data.
2. Build a dynamic simulation model using eclipse software
3. Initialize the model to validate the original oil in place obtained from static model
4. Evaluating current well production rates and ultimate recovery of existing producing wells.
5. Evaluating different field development scenarios and carrying out uncertainty analysis to propose optimal complementary field depletion plan to maximise oil production.

CHAPTER 2

2.0. LITERATURE REVIEW

Over 70% of the world's oil and gas production are from brown fields as the possibility of discovering giant fields have greatly decreased over the years (Blaskovich, 2000 as cited in Babadagli, 2007) and in order to meet the increasing demand of oil and its products effective reservoir management practices is needed to increase recovery from oil fields. Generally, field recovery is maximised so as to gain additional production and extend the life of the field. Brown fields' also known as mature fields are fields that have reached a decline in production with time or fields that have produced over a period of ten (10) years (Marshall, 2011). According to Babadagli (2007), a field is said to be in a state of maturity if the field water and gas production has increased with time while the field pressure is decreasing to the field equipment have age over time.

In other to maximise recovery of a field, a good understanding of the formation, fluids and the development procedure of the field is required. Maximising field recovery involves development practices such as recompletion, stimulation, infill drilling, optimization of lift and proper reservoir monitoring which is achievable by having a broad knowledge of the amount of unproduced oil and its location in the reservoir.

2.1. DETERMINING THE AMOUNT OF OIL AND ITS LOCATION

Estimating the amount of oil remaining in the reservoir is a difficult task that requires the use of highly advanced techniques. The amount of the remaining oil in the reservoir is dependent on the reservoir lithology, pore size distribution, permeability, wettability, fluid characteristics, and recovery method and production scheme (Teklu *et al.,* 2013). Estimating the amount of oil in the reservoir is done based on the knowledge of the reservoir remaining oil saturation after the period of active production this helps to assess the technical feasibility and profitability of the project. Babadagli (2007) identified different methods that are used to estimate the amount of remaining oil in the reservoir and they include;

- Core analysis

- Logs

- Volumetric reservoir engineering studies

- Production data analysis

- Well testing

- Chemical tracers

2.1.1. CORE ANALYSIS

Cores are analysed from the reservoir either by conventional core analysis methods or by special core analysis method. Generally, oil saturation in the cores decrease as the core is retrieved to the surface for conventional method but it gives a qualitative idea of the remaining oil saturation in the formation. However, special core analysis is carried out on core samples by simulating realistic reservoir conditions such as pressure, temperature and wettability in order to obtain a result that is as accurate as possible. Teklu *et al.,* (2013) identified core flooding is a method of estimating remaining oil saturation from core samples. They explained that the procedure is a water flood experiment carried out using either reservoir fluids or synthetic fluids on cores under simulated reservoir conditions and the result is a function of the rock wettability.

Teklu *et al* (2013) also identified centrifuge method as another method used to measure remaining oil saturation from cores. They cited Slobod *et al.,* (1951) noting that for best results the experiment must be carried out under approximate reservoir conditions and the result is usually affected by gravity forces, wettability, fluid characteristics at different temperatures as well as capillary end effects.

After analysing the core sample in the laboratory, the remaining oil saturation of the cores is related to the remaining oil saturation at reservoir scale using the equation proposed by Kazemi (1977) as cited by Babadagli (2007) and Teklu *et al* (2013).

$$(S_O)_{res} = (S_O)_{core} \, B_O \, E \, (M/(1-V^2)) \qquad\qquad 1$$

B_O= Oil formation volume factor bbl/STB

E= Bleeding factor

M= Mobility ratio

V= Permeability variation calculated from reservoir core samples

2.1.2. LOGS

Babadagli (2007) explained that different types of logs can be used to estimate remaining oil saturation of a formation and they include

- Resistivity logs

- Nuclear magnetic resonance logs

- Electromagnetic propagation tool

- Dielectric constant log

- Pulsed neutron capture logs

- Carbon/oxygen logs

He noted that in other to obtain the remaining oil saturation using resistivity logs, water saturation is first calculated using Archie's classic water saturation equation

$$\left(\overline{\qquad} \right) \hspace{4cm} 2$$

Where

S_w = Water saturation

n = Saturation exponent

R_w = Water resistivity

R_t = True formation resistivity

m = Lithology exponent

The oil saturation is calculated using the conventional formula

$$S_O = 1 - S_W \qquad\qquad 3$$

He noted that the amount of remaining oil in the reservoir obtained from resistivity logs is greatly affected by the saturation exponent as a small change in saturation exponent will give a significant change in volume of oil calculated. Also, clay content and pore structures are factors that affect the accuracy of remaining oil volume estimation (Worthington and Pallat, 1992 as cited in Babadagli, 2007). Hence the use of resistivity logs to estimate the volume of oil maybe questionable, hence a log-inject-log procedure devised by Murphy (1973) can be used to increase the reliability of resistivity based oil saturation (Al Harbi $et\ al.,$ 2011). For the process of log-inject-log the oil bearing formation is logged to estimate values of formation resistivity (R_t) which is a based resistivity using known water saturation, then solvent is injected to displace the oil followed by the injection of brine in order to measure oil resistivity (R_O), then oil saturation is calculated thus

$$S_O = 1 - (R_O/R_t)^{1/n} \qquad\qquad 4$$

Nuclear magnetic resonance log is also used to determine the amount of oil in the reservoir. It is considered to be the most accurate method used to estimate remaining oil saturation. Its result is not affected by saturation exponent or water salinity (Horkowitz $et\ al.,$ 1997). NMR measures the relaxation times T_1 and T_2 of oil and water signals as well as the diffusion coefficient allowing the quantification of the amount of oil remaining in the reservoir. This is achieved by applying enhanced diffusion method (EDM) (Akkurt $et\ al.,$ 1999). Akkurt $et\ al.,$ (1999) noted that this method uses the differences in diffusion coefficient between oil and water to determine the remaining oil saturation and the diffusion coefficient of the oil is a function of its viscosity.

Another log used to estimate the remaining oil saturation in a field is the electromagnetic propagation tool. It uses the measurement of phase shift and fading rate of an electromagnetic wave transmitted through a formation at a frequency of 1.1GHz to evaluate the remaining oil saturation in the formation (Wharton $et\ al.,$ 1980 as cited in Teklu $et\ al.,$ 2013). They noted that the electromagnetic propagation log is very effective in formations with changes in

salinity. Similar to the electromagnetic propagation tool, the dielectric constant log also measures the remaining oil saturation in formations at a frequency ranging from 16 to 60 MHz (Geng *et al.,* 1980 as cited in Teklu *et al.,* 2013). It investigates a deeper zone than the electromagnetic propagation tool and has a higher accuracy.

The pulse neutron capture (PNC) log is another type of log used to estimate remaining oil saturation in cased holes and open holes using log-inject-log applications. This is achieved by measuring the absorption of thermal neutrons released by the formation fluids. It is very effective in differentiating between gas, oil and water bearing formations (Teklu *et al.,* 2013). Teklu *et al.,* (2013) also noted that when the porosity, formation type, hydrocarbon type and formation salinity are known, PNC log data can be used to estimate saturation. According to Chang et al (1998) and Teklu *et al.,* (2013), PNC log give an excellent accuracy of the remaining oil saturation value.

The carbon oxygen (C/O) log is another type of cased hole log that measures the remaining oil saturation based on the amount of certain elements such as carbon, oxygen, silicon, and calcium present. C/O logs are not affected by chlorine content in the formation water hence it can be used in areas where PNC is not applicable. The formula below proposed by Teklu *et al.,* (2013) is used to estimate the remaining oil saturation using Carbon-Oxygen (C/O) logs.

$$\frac{/\qquad /}{/\qquad\quad /} \qquad\qquad\qquad\qquad 5$$

Where C/O = Inelastic gamma ray carbon to oxygen ratio measurement

Gamma ray logs also use log-inject-log applications to estimate remaining oil saturation. The process involves injecting water containing radioactive tracers into the formation.

2.1.3. VOLUMETRIC AND MATERIAL BALANCE METHOD

Volumetric method can be used to estimate the remaining oil saturation of a reservoir when the initial oil in place and cumulative oil production is known. The formula below is used to calculate the remaining oil saturation;

$$\underline{(\qquad)}$$

Where

N = Stock tank original oil in place STOOIP (STB)

N_p = Cumulative oil produced (STB)

A = Drainage area (Acres)

h = Reservoir thickness (ft)
= Porosity
B_o = Oil formation volume factor

The cumulative oil production (Np) is estimated using material balance method or from production data. The volumetric method gives us a single value of remaining oil saturation.

The remaining oil saturation in the reservoir can be estimated using material balance method. This is achieved when the initial oil in place for the drainage area of each well as well as the cumulative production for each well is known. This gives us an idea of the saturation distribution in the field (Babadagli, 2007).

Babadagli (2007) also identified the use of production data as a method of estimating remaining oil saturation. He explained that this is achieved by using a plot of production history to estimate cumulative (final) production (Np) and using production relative permeability data to estimate saturations. He stated that the formula

$$\underline{\quad}\quad\underline{\qquad}\qquad\underline{\quad}\qquad\qquad\qquad 7$$

Where

q_w = Water flow rate (bbl/day)

q_o = Oil flow rate (bbl/day)

B_w = water formation volume factor (bbl/stb)

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B_O = Oil formation volume factor (bbl/stb)

= Water viscosity (cp)

= Oil viscosity (cp)

WOR = Water oil ratio

Can be used to obtain relative permeability ratio for multiphase flow, and that oil saturation can thus be calculated from production data using the equation below;

$$\underline{\quad} \quad \frac{(\quad)}{_{(\quad)}/_{(\quad)}} \qquad\qquad 8$$

Where

V_o = Oil volume

V_p = Total pore volume

C_f = Formation compressibility (psi^{-1})

S_{wi} = Initial water saturation

B_{oi} = Initial oil formation volume factor (bbl/stb)

= Change in pressure (psi)

He noted that this technique is more reliable than laboratory methods because real production data is used.

2.2. METHODS OF MAXIMISING OIL FIELD RECOVERY

- Recompletion/workover

- Well Stimulation

- Gas lift

- Infill drilling

- Improved oil recovery

- Enhanced oil recovery

2.2.1 RECOMPLETION/ WORKOVER

During the life of a well, problems such as increased water, gas and sand production may be experienced with time. Incompatibility between injected water and formation water results to precipitation of mineral scales as a result of thermodynamic in equilibrium resulting from temperature fluctuations, ionic strength and pressure differences (Zahedzadeh *et al.,* 2014). This decreases oil production and equipment life in completions programs in reservoirs. Other resulting from downhole scale accumulation and corrosion are wear of surface and subsurface facilities. Recompletion and workover is carried out on wells to reduce these effects. Recompletion ranges from squeezing of slurry into perforations to plug back zones producing water and gas and perforating oil zones to well stimulation and acidizing of plugged perforations. It also involves changing of downhole equipment such as tubing and packers.

2.2.2. WELL STIMULATION

Well stimulation is another method of maximizing recovery of a field. Well stimulation is an operation carried out on a well to improve the flow of hydrocarbon from the reservoir into the well (Economides and Nolte 1989). According to Economides and Nolte (1989), there are two methods of well stimulation operations practiced in the industry; Acidizing and fracturing. They explained that acidizing involves the use of acid wash on formations that have precipitated insoluble products such as scale accumulation. They also explained that fracturing is mainly carried out in tight formations and sometimes formations with high permeability, to elude deep formation damage problems which acidizing cannot remove.

2.2.3. GAS LIFT

Artificial lift is used to produce wells that are not flowing sufficiently either from the start of production or later in the life of the well. Ninety percent (90%) of wells worldwide are produced using artificial lift (Perrin, 1999). Artificial lifting of oil can be done mechanically using pumps or by gas lift method.

Gas lifting refers to injecting gas into the lower string of the production tubing in order to move the oil to the surface. Recovery is maximised using gas lift by selecting the most favourable tubing size, lift gas rate and operating valve position with respect to the gas

injection pressure and water cut constraints.

Gas lift optimization is essential in improving production performance. According to Chia and Hussain (1999), this is achieved by applying one or more of the following tools;

- Nodal analysis

- Gas lift optimization model

- Gas lift surveillance data base

- Gas lift monitoring system

Nodal analysis is the analysis of the performance of all the systems in the well from the reservoir sandface across the perforations, completions, tubing, and safety valves to the wellhead and surface facilities (i.e. separators) (Mach *et al.,* 1979 as cited in Chia and Hussain (1999). Nodal analysis is a well performance prediction tool. It can be used to quantify optimum gas lift gas required for a gas lift operation.

Chia and Hussain (1999) explained gas lift optimization model as a detailed computer based production system model that mimic a production system network. It is used in conjunction with nodal analysis to determine optimum gas lift gas allocation. This is done by defining the objective and constraints of the system. It is also used as a sensitivity analysis tool when deciding the best conditions for a field application. They also explained that having a gas lift surveillance database and monitoring system is very important in gas lift optimization. They noted that while gas lift monitoring system measures gas lift flow rate and pressure parameters in real time, the gas lift surveillance data base takes into account the lessons learned and experiences of both successful and failed processes which is used fir the improvement of future gas lift operations in other to achieve success.

Boonmeelapprasert *et al.,* (2011) explained how the application of gas lift process in the Platong field in the Gulf of Thailand increased production from ten percent (10%) in June 2008 to fifty percent (50%) in June 2011. They explained that the Platong field was initially developed in 1985 for the production of gas but commercial volume of oil was within some of the reservoir compartments in 1997. The noted that the first wells drilled into the oil zone were completed without incorporating artificial lift in their completion program, hence production was minimal. With the installation of gas lift mandrels in the completions of the

old wells, an increase in production was recorded. They identified

- Improvement of subsurface completion

- Adequate surface gas lift sources

- Use of fit for purpose monitoring and surveillance tools

- Adequate personnel training

- Good collaboration between office experts and field production

operators, as the major reasons for the accomplishment of results.

2.2.4. INFILL DRILLING

Infill drilling is referred to the process of drilling new wells in between wells. This is done either to produce trapped or bypassed oil, or to reduce the space between injectors and producers so as to have an efficient injection process. Drilling new wells is necessary as fields become mature, this is because production reduces and not all the oil is produced due to reservoir heterogeneity. Shirzadi and Lawal (1993) explained how infill drilling was used to improve recovery in the Prudhoe Bay field. They noted that the process started with having a multidisciplinary knowledge of the field through reservoir surveillance, analysing production data, having a good understanding of the reservoir description and facilities constraints. They explained that in order to drill an infill well, poorly developed areas must be identified and integrated to field measurement results.

Gould and Sarem (1989) also explained that for an infill drilling project to be successful, proper planning which involves analysis of production performance, proper reservoir description and infill drilling project design as well as economic evaluation are essential. They explained that the reservoir description includes reservoir geology, petrophysical information obtained from logs, as well as seismic data. Comparing seismic data acquired originally and seismic data acquired after producing for a period of time is also important. They further noted that acquiring well test information which provides information on the well drainage area is also very important. This helps to determine the area to place the infill well. Furthermore, they explained that having an economic limit and ensuring it's not exceeded while analysing the economic impact of the infill drilling is the most essential aspect of evaluating an infill drilling project. They explained that if these criteria are met, the

result from infill drilling is always favourable whether it is done with intention of carrying out an EOR process or just to produce by-passed or trapped oil. Gould and Sarem (1989) showed some of the successes of infill drilling projects by stating how oil production was increased in the Raja field of south Sumatra from 47.7m^3/day with thirty-six (36) wells to 556m^3/day after additional six (6) infill wells were drilled between 1976 and 1978. The table below also shows how much recovery was increased when infill wells were drilled in different fields.

PROJECT	NUMBER OF WELLS	PROJECT VOLUME (10^6 BBL)	VOLUME PER WELL (10^3 BBL)	INFILL SPACING (ACRES)	VOLUME (BBL/ACRE)
Mean San Andres 20 acre Infill	141	15.4	109	10	5450
Mean San Andres 10 acre Infill	16	1.2	75	20	7500
Fullerton Clearfork	254	24.6	97	18	4850
Robertson Clearfork	138	10.7	78	40	4330
IAB (Menielle Penn)	17	1.7	100	5	2500
Hewitt	15	0.4	27	10	5400
Loudon	50	0.97	19	20	1900
Yates Sand	247	14.6	59	20	5900
Grayburg	17	2.44	144	20	7200
Wasson San Andres (Denver Unit)	293	51.0	174	20	8700
North Riley Clearfork Unit	91	13.2	145	20	7250

Dollarhide Clearfork "AB" Unit	44	5.52	125	20	6250
Total (Well average)	1323	141.7	107.1	17.5	6120

Table 1: Increase in recovery when infill wells were drilled in different fields (Sarem, 1989)

From their study, they concluded that infill drilling would always provide incremental recovery and improve the economic limit of a field as long as the uncertainties in the field are properly analysed.

2.2.5. IMPROVED OIL RECOVERY

Improved oil recovery also known as secondary oil recovery include those methods that are used to increase the recovery of oil and gas from a field after primary depletion methods are no longer profitable. It involves the injection of either water or gas into the reservoir to increase production (Tarek, 2001). According to Thomas, Mahoney and Winter (1989) as cited in Ahmed (2001), factors that determine whether a reservoir is suitable for secondary recovery process include reservoir geometry, reservoir fluid properties, reservoir depth, lithology, rock properties, fluid saturations, reservoir uniformity and pay continuity, and primary reservoir drive mechanism.

Ahmed (2001) noted that water flooding also known as water injection is the most common secondary recovery method. Water flooding is the injection of water into the reservoir either to maintain the reservoir pressure or to increase production. It can be carried out either at the beginning of the life of the field or when the reservoir has been depleted by primary recovery methods and the natural energy in the reservoir is no longer sufficient. It starts with the injection of water through injection wells into the oil zone of the reservoir; the water pushes the oil towards the producing well whence it is produced.

Gas injection is also a secondary recovery method. It involves the injection of gas into the reservoir. The injection is done either through the gas cap or directly into the oil zone (Latil, 1980). Latil (1980) explained that the gas is injected directly into the gas cap if a gas cap already exists in the reservoir either at initial condition or due to segregation of fluids. The injected gas causes the gas cap to expand thereby forcing itself into the oil zone and pushing the oil into the producing well. And if there is no gas cap present, the gas is injected directly

into the oil zone which forces the oil into the producing wells. Generally, the injected gas usually has hydrocarbon base.

2.2.6. ENHANCED OIL RECOVERY

According to Donaldson, Chilingarian and Yen (1985), enhanced oil recovery (EOR) is the final phase of oil production in the life of a field. They explained that after primary and secondary depletion methods have been carried out on a field and there is still sufficient amount of oil left behind, EOR method is considered. They also noted that sometimes EOR can be initiated early enough in the life of the field depending on the fluid properties and reservoir characteristics. Some common EOR methods include chemical flooding, miscible gas injection, and water alternating gas injection (WAG), steam flooding, in-situ combustion and microbial EOR.

2.3. FACTORS THAT AFFECT THE DIFFERENT METHODS OF MAXIMIZING FIELD RECOVERY

- Reservoir drive mechanism
- Fluid type and properties
- Formation properties

2.3.1. RESERVOIR DRIVE MECHANISM

In order to have a good knowledge of a reservoir behaviour and performance, it is necessary to understand its drive mechanism. The reservoir drive mechanism refers to the source or nature of the energy that causes the oil to move into the wellbore (Ahmed, 2001) and is also known as the recovery mechanism of the reservoir. According to Ahmed (2001), there are primarily six (6) reservoir drive mechanisms namely;

- Rock and liquid expansion drive
- Depletion drive
- Gas cap drive
- Water drive
- Gravity drainage drive
- Combination drive

2.3.1.1. ROCK AND LIQUID EXPANSION DRIVE

The energy required for producing this type of reservoir is supplied by the expansion of individual rock grains and compaction of the formation. It is usually dominant in under saturated oil reservoirs with only connate water present. The recovery for this type of reservoir is very low, usually around one to two percent (1-2%) of the original oil in place and pressure decline rate is very high compared to other drive mechanism (Ahmed, 2001).

2.3.1.2. DEPLETION DRIVE MECHANISM

This reservoir drive mechanism is also known as solution gas drive. The energy needed for the recovery of the oil in the reservoir is supplied by the expansion and liberation of gases dissolved in the oil while production is on-going. This type of drive mechanism is found in under saturated oil reservoirs with initial pressure very close to the bubble point pressure (Ahmed, 2001).
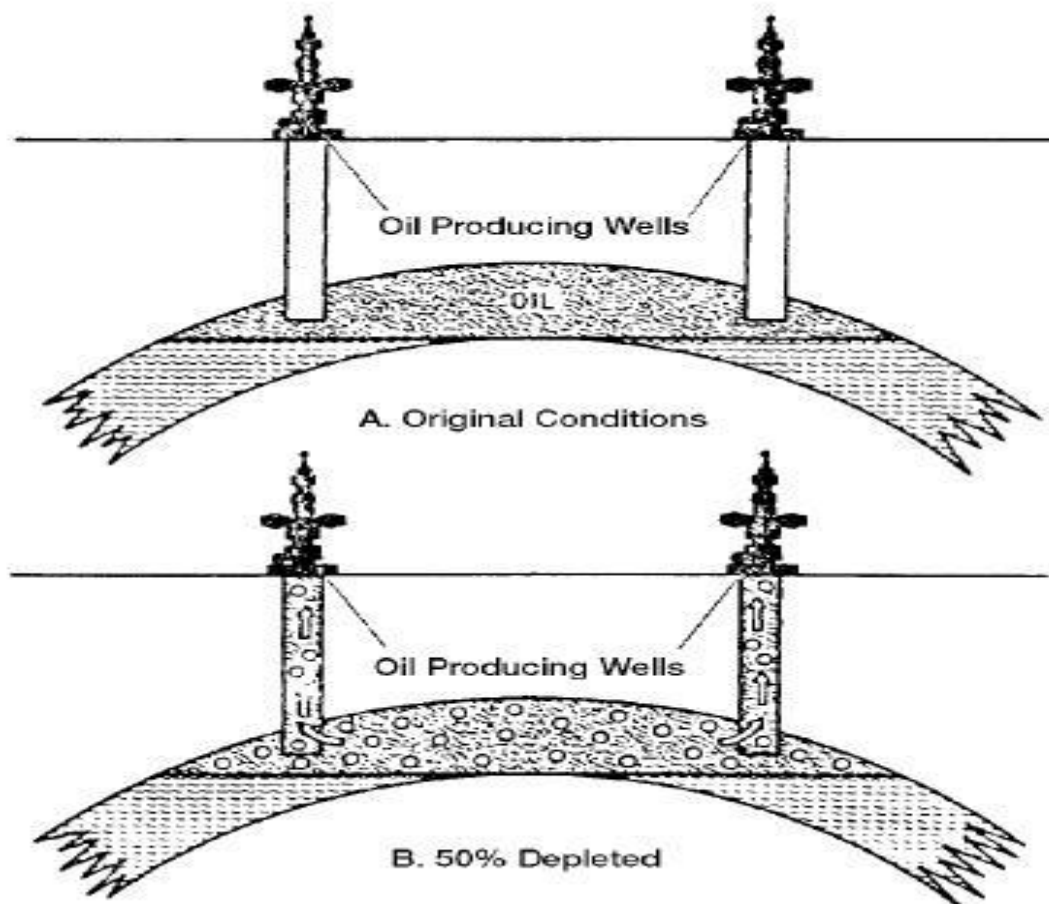
Figure 1: Depletion drive reservoir drive mechanism (Ahmed, 2001)

2.3.1.3. GAS CAP DRIVE

This type of reservoir is characterized by the presence of a gas cap. The energy needed to move the oil into the wellbore is supplied by the expansion of the gas cap as well as the expansion of the gases dissolved in the oil as it is liberated. According to Cole and Clark (1969) as cite in Ahmed (2001), the pressure in this type of reservoir declines slowly and continuously and it is a function of the size of the gas cap. Also, the gas oil ratio (GOR) increases continuously. The overall expected recovery according to Ahmed (2001) is usually between twenty to forty percent (20 – 40%) of the original oil in place.
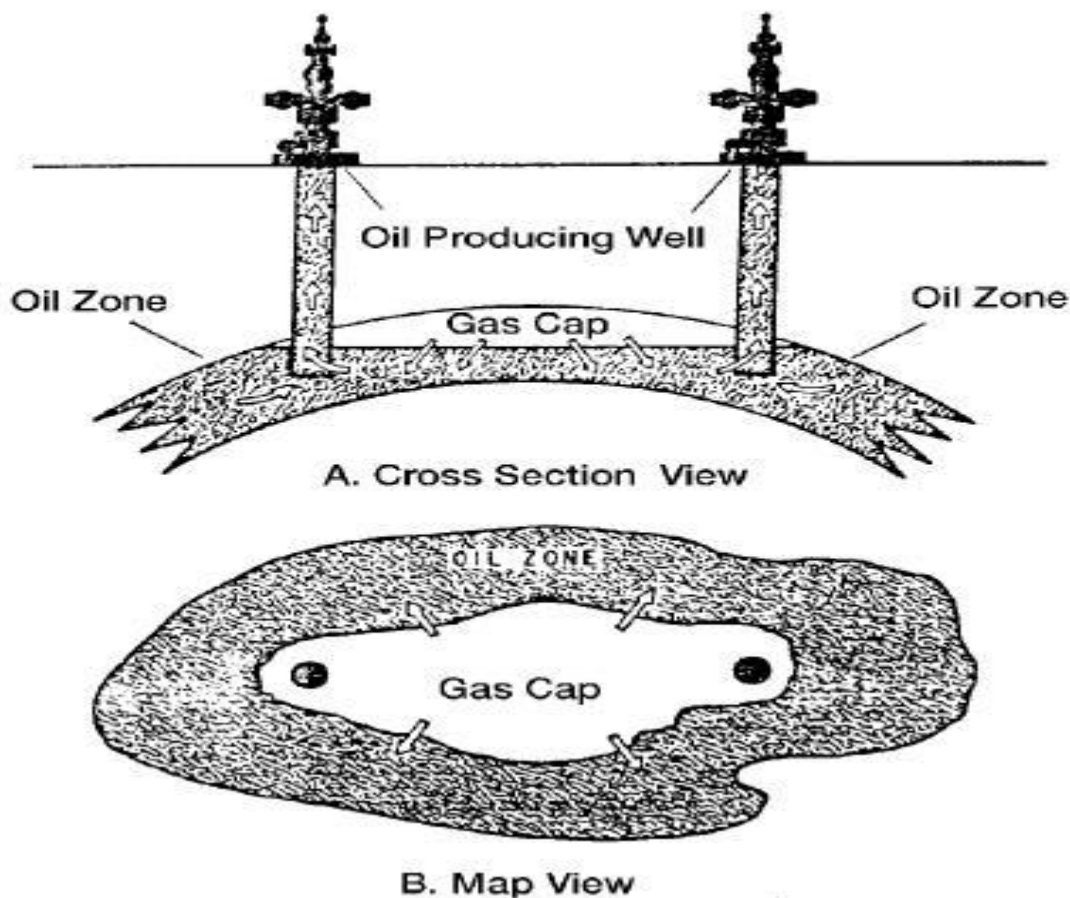
Figure 2: Gas cap drive reservoir drive mechanism (Ahmed, 2001)

2.3.1.4. WATER DRIVE

This type of reservoir is usually connected to an aquifer. The energy required to produce the reservoir fluid I supplied by the partial or complete encroachment of water in to the reservoir as production takes place. A reservoir with water drive have an expected recovery ranging from thirty-five to seventy percent (35 – 70%) of the original oil in place. The reservoir

pressure declines slowly while gas-oil ratio (GOR) is relatively constant and water production occurs early in the life of the field (Ahmed, 2001).

2.3.1.5. GRAVITY DRAINAGE DRIVE

The energy required to produce the fluid in a reservoir with gravity drainage drive is supplied by the differences in the densities of the reservoir fluids. The heavier fluids tend to move downward towards the wellbore as a result of gravitational forces while the lighter fluids move upward. Cole (1969) as cited in Ahmed (2001) stated that a reservoir with gravity drainage drive mechanism would experience a sharp decline in pressure while GOR would be relatively low in low structure wells and high in wells placed up structure of the reservoir. He also noted that overall recovery could be as high as eighty percent (80%) of the initial oil in place depending on the reservoir dip angle, dip direction permeability, oil viscosity, relative permeability and producing rates of the reservoir.
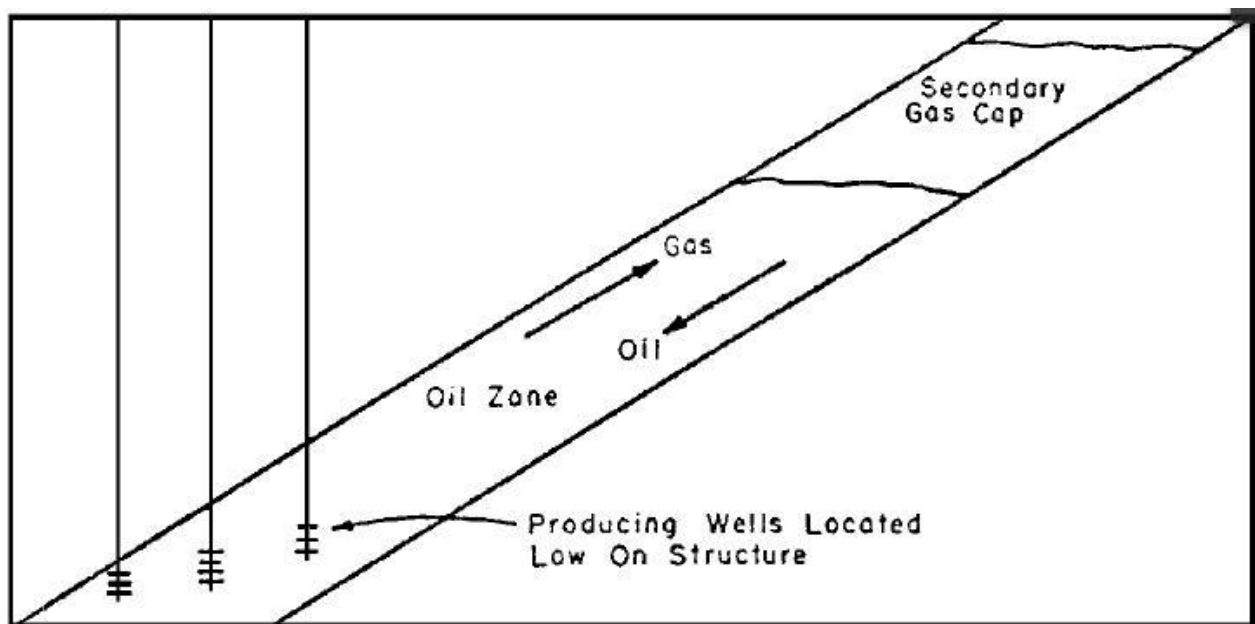
Figure 3: Gravity drainage reservoir drive mechanism (Ahmed, 2001)

2.3.1.6. COMBINATION DRIVE

The energy required to produce this type of reservoir is gotten from a combination of two or more drive mechanisms e.g. gas cap plus water drive or depletion drive plus water drive etc. It is the most common type of reservoir drive mechanism. The behavior of the reservoir is generally a function of all the drive mechanisms present and the dominant drive mechanism in particular (Ahmed, 2001).
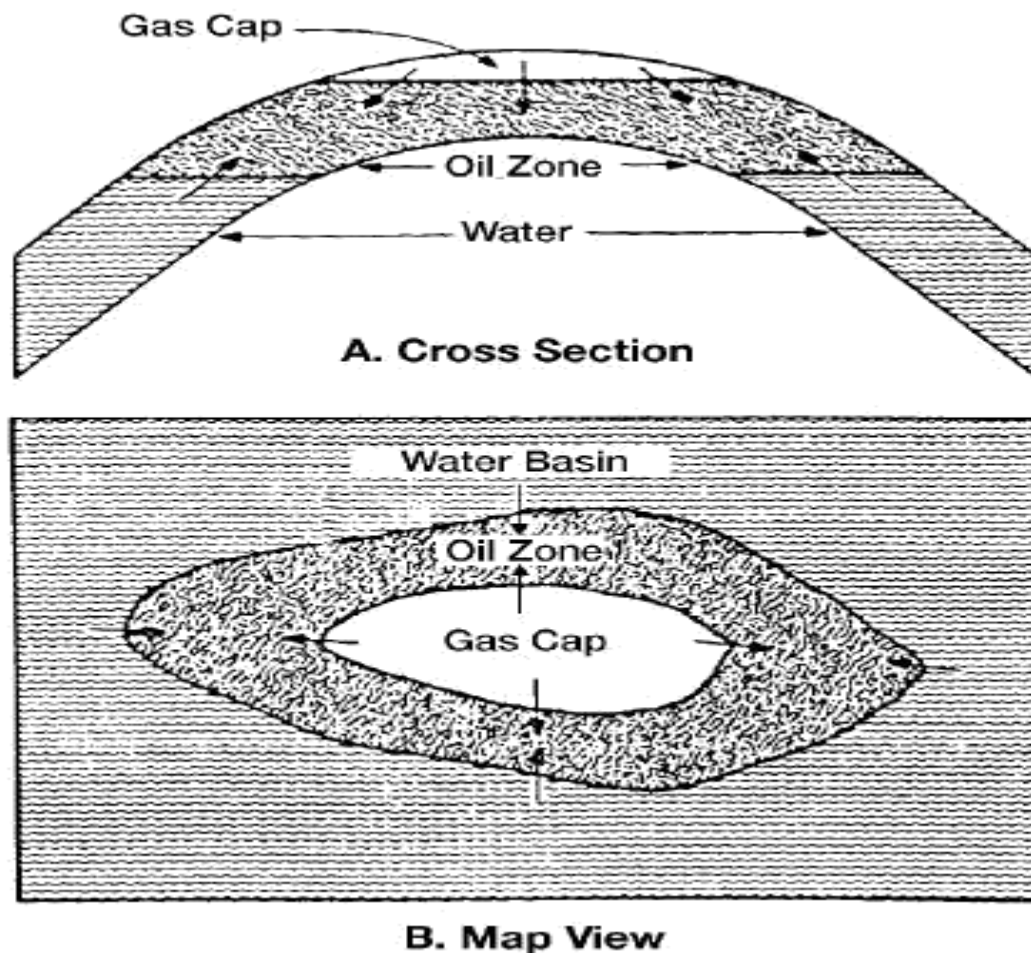
Figure 4: Combination reservoir drive mechanism (Ahmed, 2001)

The reservoir drive mechanism is important when determining the best method for improving recovery because some methods may not have a positive effect on the recovery. For example carrying out water flooding on a reservoir with strong water drive, this would have no effect on the recovery as the reservoir is already effectively supported by the aquifer.

2.3.2. FLUID TYPE AND PROPERTIES

Fluids found in the reservoir ranges from gas, and oil to water. These fluids have different properties and characteristics which are used as criteria to determine their specific type. According to Ahmed (2001), reservoir fluids are classified in to different groups according based on their physical properties, chemical composition, gas oil ratio (GOR), and appearance and pressure-temperature phase diagrams. Oil reservoir fluids are classified into the following groups;

- Ordinary black oil

- Low shrinkage oil

- Volatile oil

- Near critical oil

2.3.2.1. ORDINARY BLACK OIL

Ordinary black oil is an oil reservoir fluid that is characterised by the dissolution of very small amount of gas. At surface conditions, the amount of oil recovered is usually very high because very small amount of gas is evolved. The figure below shows typical pressure-temperature phase behaviour for ordinary black oil.
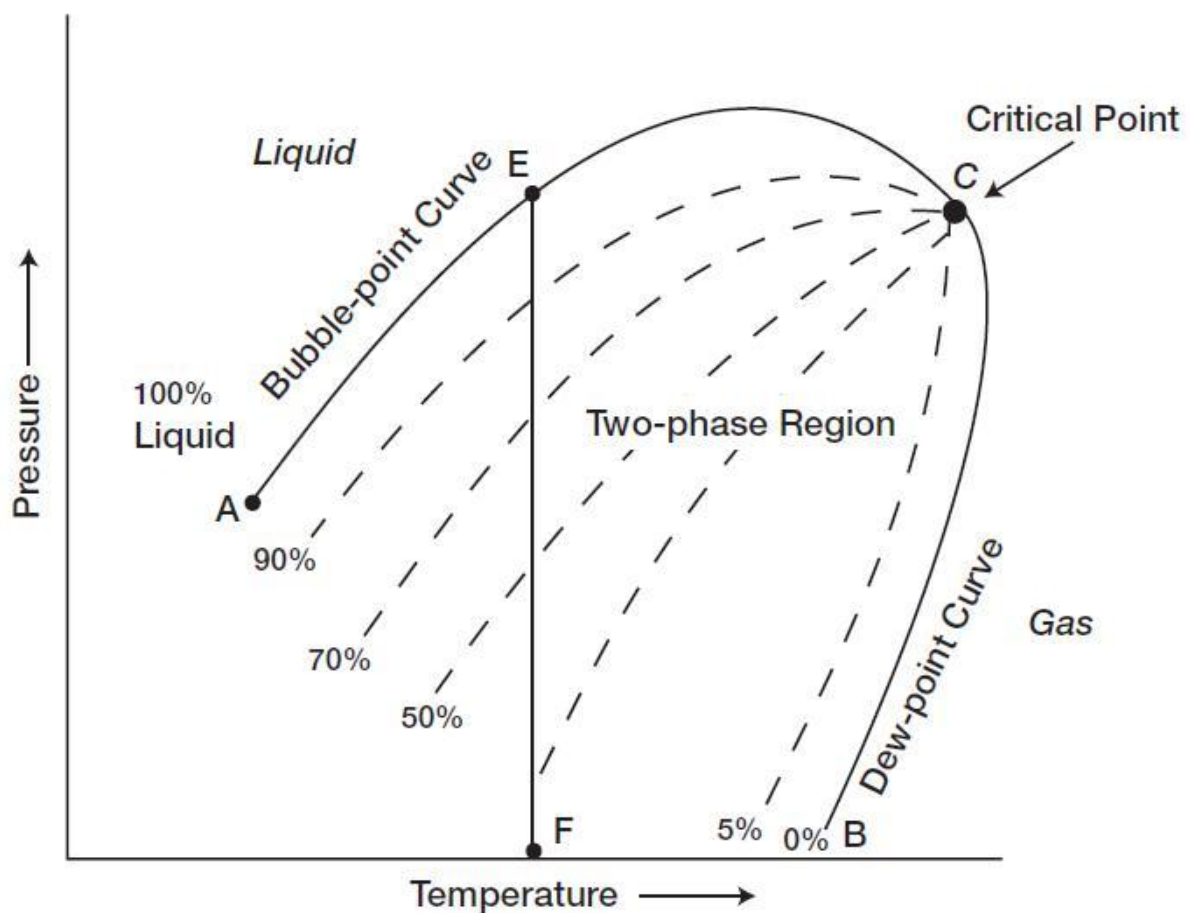
Figure 5: Ordinary black oil pressure-temperature phase behaviour (Ahmed, 2001)

According to Ahmed (2001), ordinary black oils have a gas oil ratio (GOR) between 200-700scf/STB and oil gravity ranging from 15 to 40 ^{0}API.

2.3.2.2. LOW SHRINKAGE OIL

These are reservoir oils that contain dissolved gases less than ordinary black oils. They can also be referred to as heavy oil (Ahmed, 2001). At surface conditions about eighty-five percent (85%) of the oil is recovered because very little amount of gas is dissolved in the oil. Low shrinkage oil is characterised with oil formation volume factor of less than 1.2bbl/STB, gas oil ratio less than 200scf/STB and oil gravity less than 35^0API (Ahmed. 2001).

The figure below show a typical pressure-temperature phase behaviour of a low shrinkage oil.
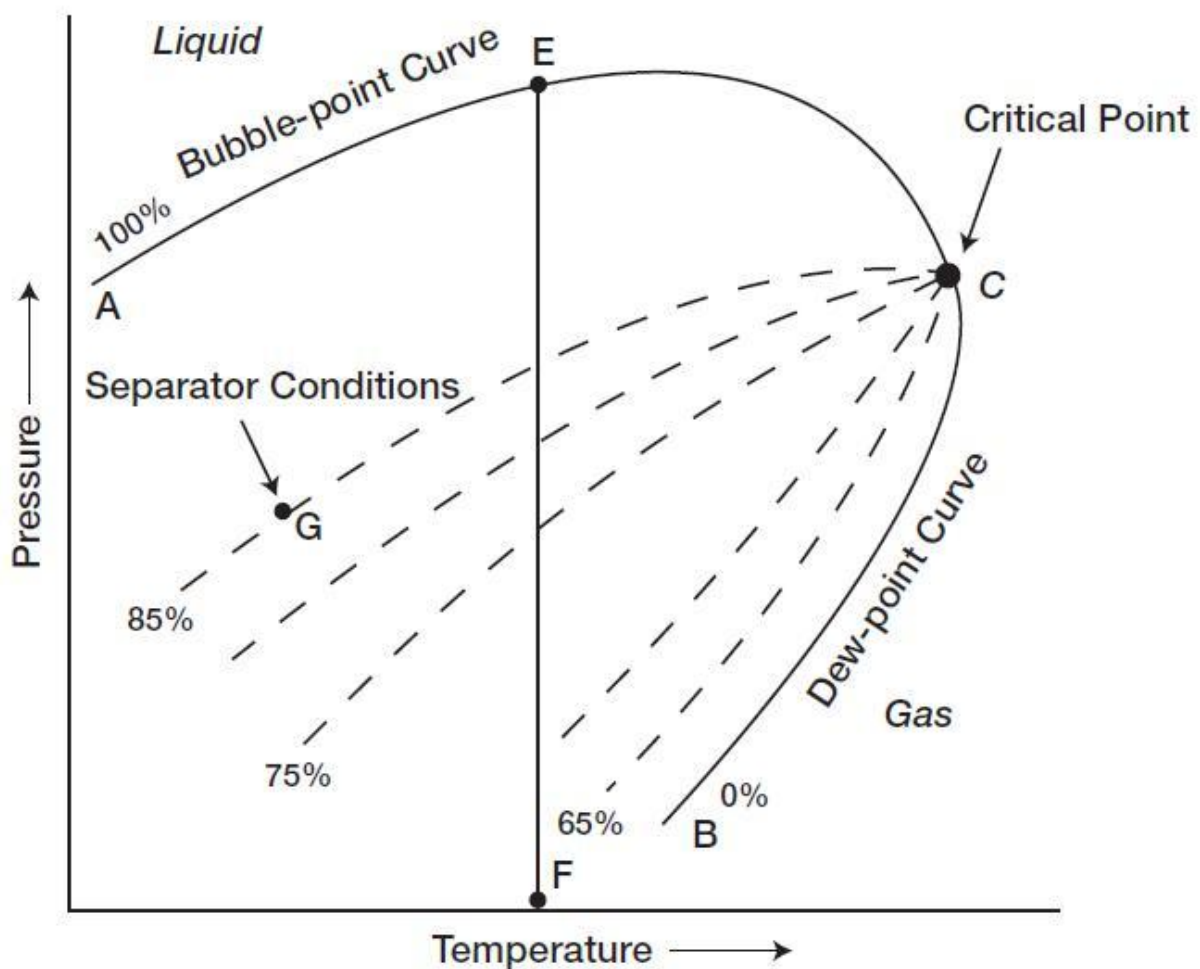
Figure 6: Low shrinkage oil pressure-temperature phase behaviour (Ahmed, 2001)

2.3.2.3. VOLATILE OIL

Volatile oil is also known as high shrinkage oil. It contains very high amount of dissolved gases. At surface conditions, the oil recovered are usually very low because of the

recoverable is dissolved gases that have evolved. Volatile (high shrinkage) oils are characterised with oil formation volume factor of about 2bbl/STB, gas oil ratio between 2000 to 3200 scf/STB and oil gravity between 45 to 55 ^{0}API (Ahmed, 2001). Ahmed (2001) also0 noted that the API gravity of the stock tank fluid increases in the later life of the reservoir. The figure below shows typical pressure-temperature phase behaviour of volatile oils.
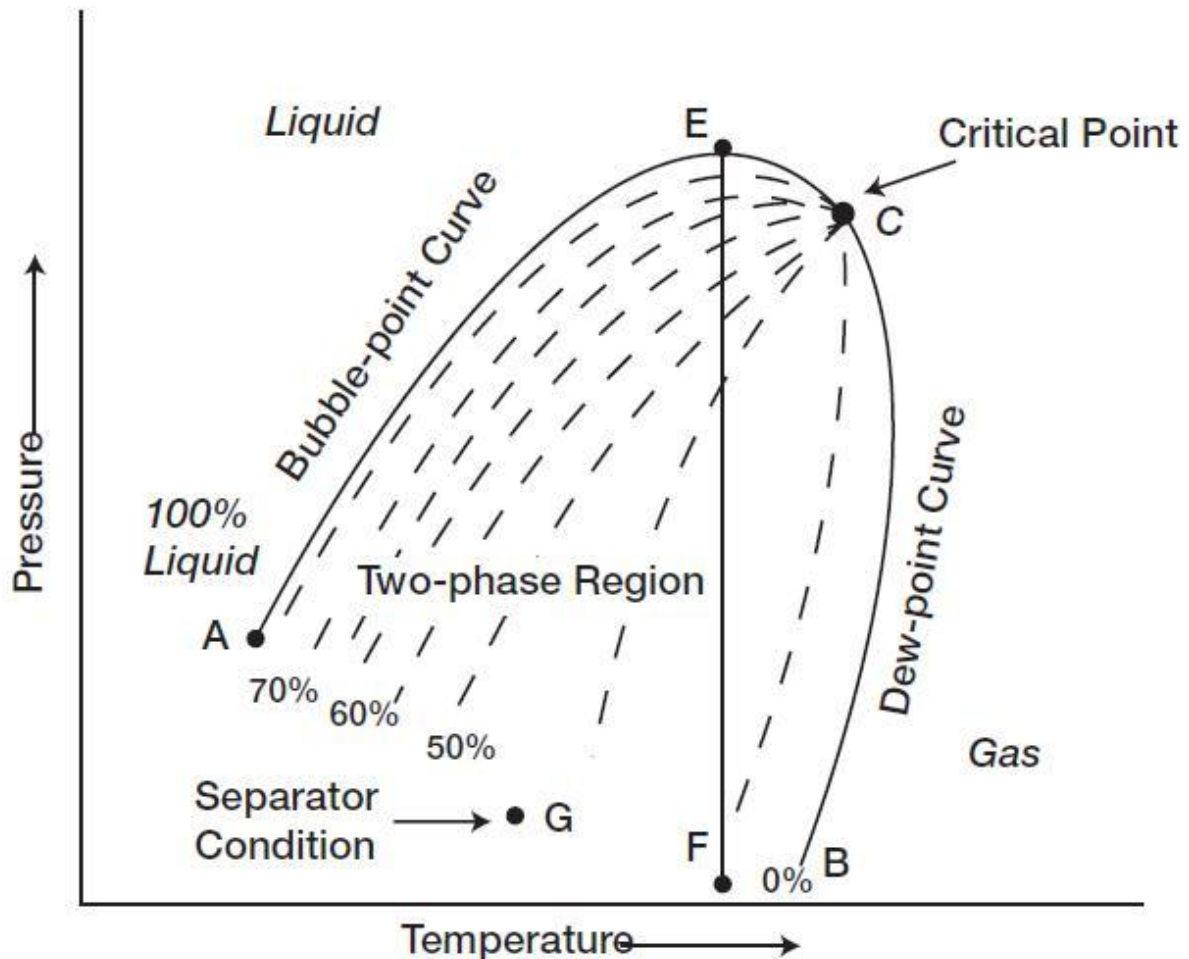
Figure 7: Volatile oil pressure-temperature phase behaviour (Ahmed, 2001)

2.3.2.4. NEAR CRITICAL OIL

These are crude oils whose temperature in the reservoir is very close to the critical temperature. The oil usually contains very large amount of dissolved gases. A very slight drop in pressure can cause the oil to shrink to about fifty-five percent (55%) of its original volume. Near critical oils are characterised by high gas oil ratio (GOR) in excess of 3000scf/STB, oil formation volume factor higher than 2bbl/STB and heptane plus of 12.5 to 20 mole percent and methane of about 50 to 60 mole percent (Ahmed, 2001).

The figure below shows the pressure-temperature phase behaviour of near critical oil.
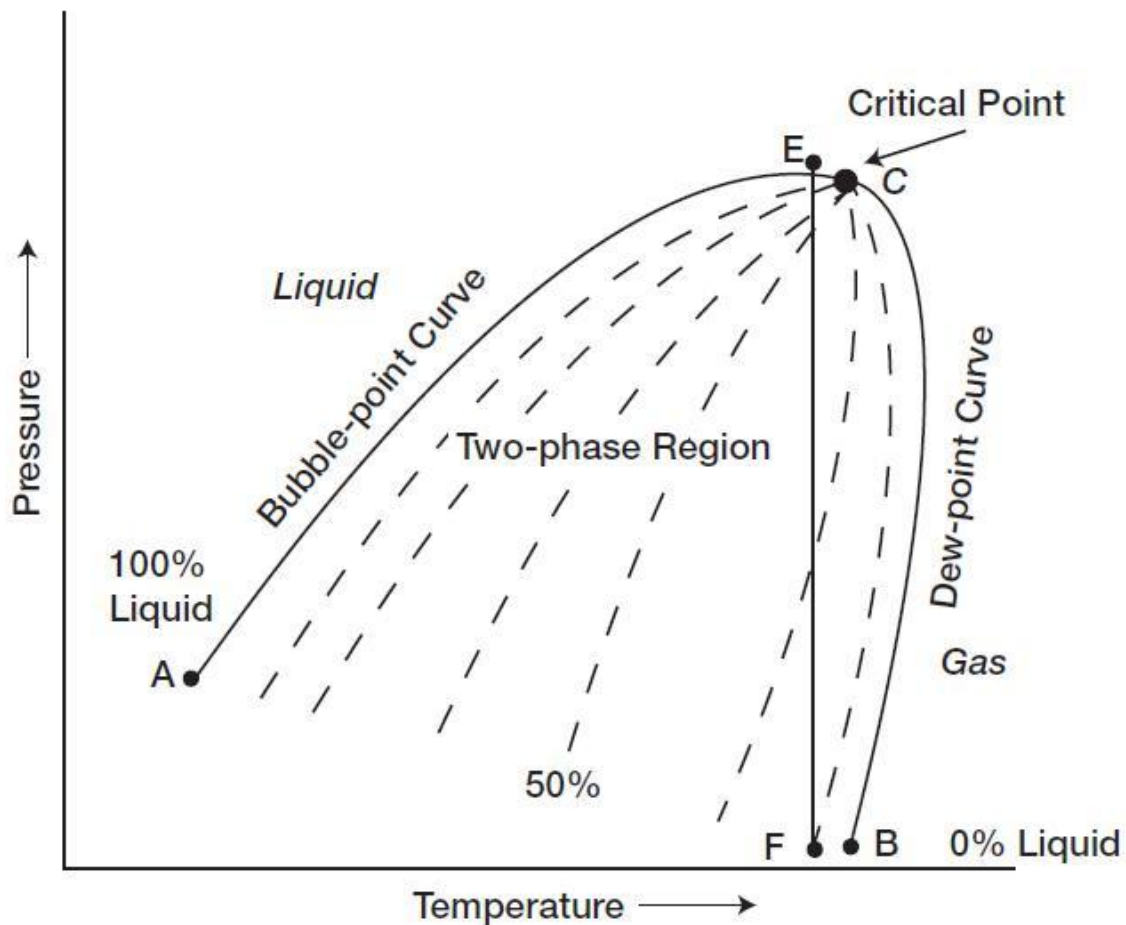
Figure 8: Near critical oil pressure-temperature phase behaviour (Ahmed, 2001)

2.3.3. FORMATION PROPERTIES

Formation properties include porosity, saturation, absolute and relative permeability; capillary pressure, wettability, surface and interfacial tension and overburden pressure (Ahmed, 2001). According to Ahmed (2001), these properties affect the quantity and distribution of the reservoir fluids and regulate the flow of the fluids when combined with the fluid properties. While these properties are used to quantify the amount of hydrocarbon in the reservoir, they also give us an idea of how much hydrocarbon can be produced from a particular section of the reservoir at a particular time. The distribution of these properties within the reservoir also gives an understanding of areas where production is more likely to occur for example, a combination of porosity, relative permeability and saturation (Ahmed, 2001)

CHAPTER 3

3.0. RESEARCH

3.1. ABOUT THE CASE STUDY

The field is located offshore Nigeria about 60km from the coast. The field structure is essentially a large NW-SE oriented monocline. It is bounded by two antithetic faults in the Abgada formation. The reservoir known as IME-D70 was discovered saturated with initial gas cap in 1989. Production started in March 1995 from wells IME-02, IME-04, IME-06, IME-07, IME-10 and IME-12.
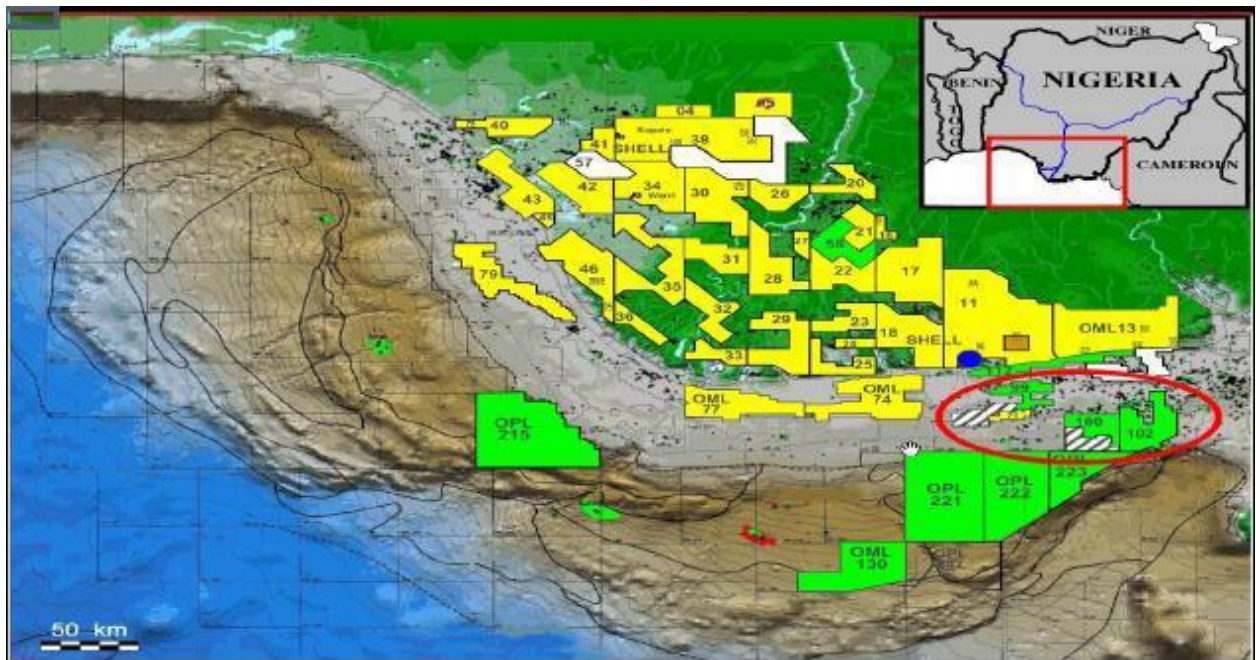
Figure 9: Map view of the location of the field under study

The reservoir was discovered saturated with a gas cap at initial pressure of 142.1Bars, avaerage API gravity of 21.3API, solution gas oil ratio (GOR) of 47.37 sm^3/sm^3, porosity of 27% and water saturation of 29.6%. some of the wells encountered gas cap at depth of 1408m/MSL (Mean Sea Level) but none encountered an oil water contact (OWC). Production started from IME-02 in march 1995 with an average oil rate of 4.61sm^3/day, GOR of 41sm^3/sm^3 and Basic sediments and water (BSW) of 0.6%. shortly after IME-04 was opened to production followed by IME-06 and IME-07. A peak oil production of 2533sm^3/day with GOR of 53sm^3/sm^3 and BSW of 0.01% was attained in the reservoir in

November 1996. Subsequently, the reservoir experienced a production decline with increasing BSW. In december 2000, well IME-10 came onstream with an average oil rate of $16.37 \text{sm}^3/\text{day}$GOR of $52 \text{sm}^3/\text{sm}^3$ and BSW of 4.3%. Well IME-12 was put in to production in november 2011. The relatively minimal pressure decline despite the current oil recovery of thirty-three percent (33%) is owing to its active water drive. Cumulative production as of july 2012 was 4.56MMsm^3 of oil, 364MMsm^3 of gas and 1.35MMsm^3 of water.
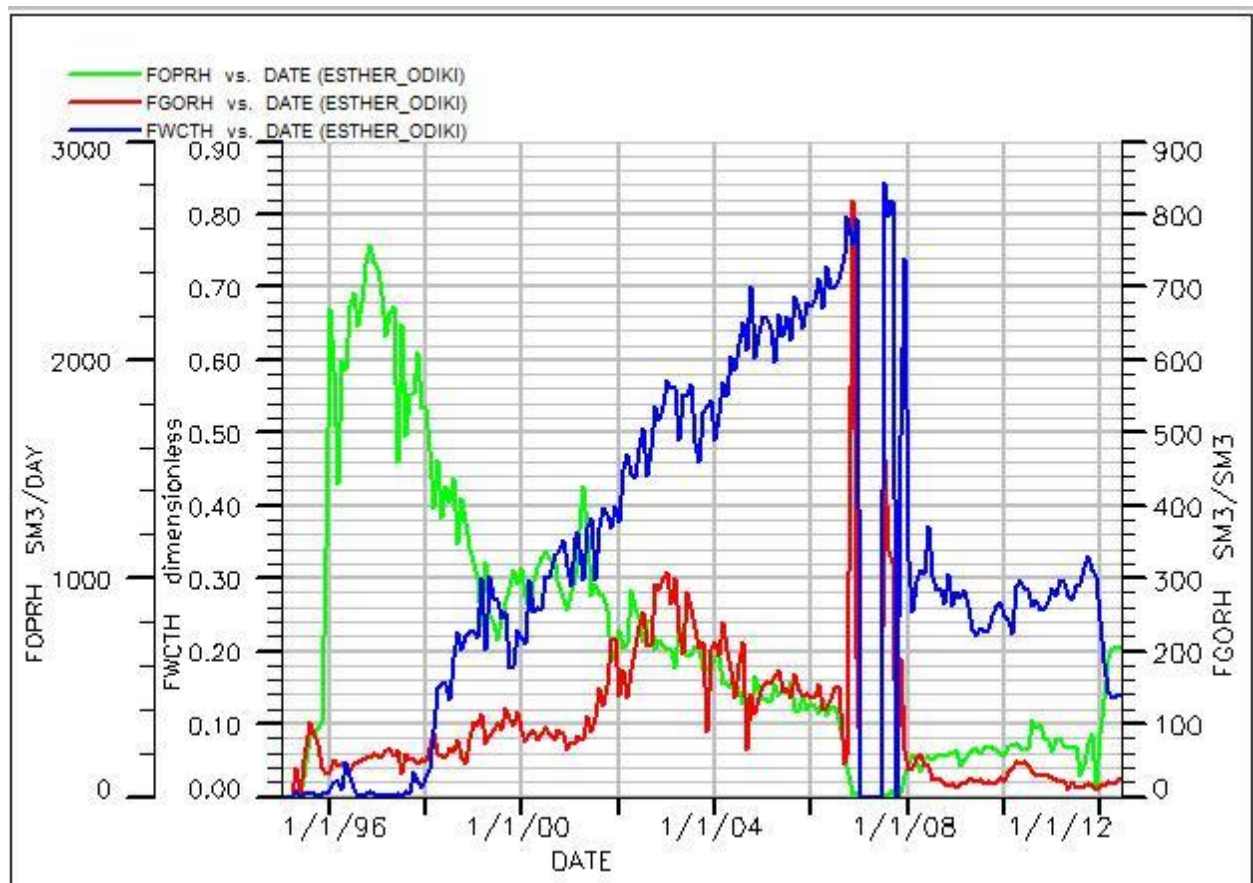
Figure 10: Production performance plot for the reservoir showing Oil rate, GOR and Water cut

3.2. WELL HISTORY

This section explains the performance of all the wells in the field for the period they have been put on production.

3.2.1. WELL IME-2

IME-2 was the first well to start production in the D70 reservoir in March 1995 at an initial oil rate of $4.61 \text{sm}^3/\text{day}$ with GOR of $41 \text{sm}^3/\text{sm}^3$ and BSW of 0.6%. The well experienced a

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water breakthrough in August 1999. As shown in Figure below, the peak oil production of 260.42sm^3/day with an associated BSW of 13% and GOR of 82sm^3/sm^3 was in June 2000. Production declined to about 5sm^3/day in April 2003, when it was shut in from high BSW and mechanical problems (based on asset records). Cumulative production from this well is 0.13MMsm^3 of oil, 8.70MMsm^3 of gas and 0.08MMsm^3 of water.
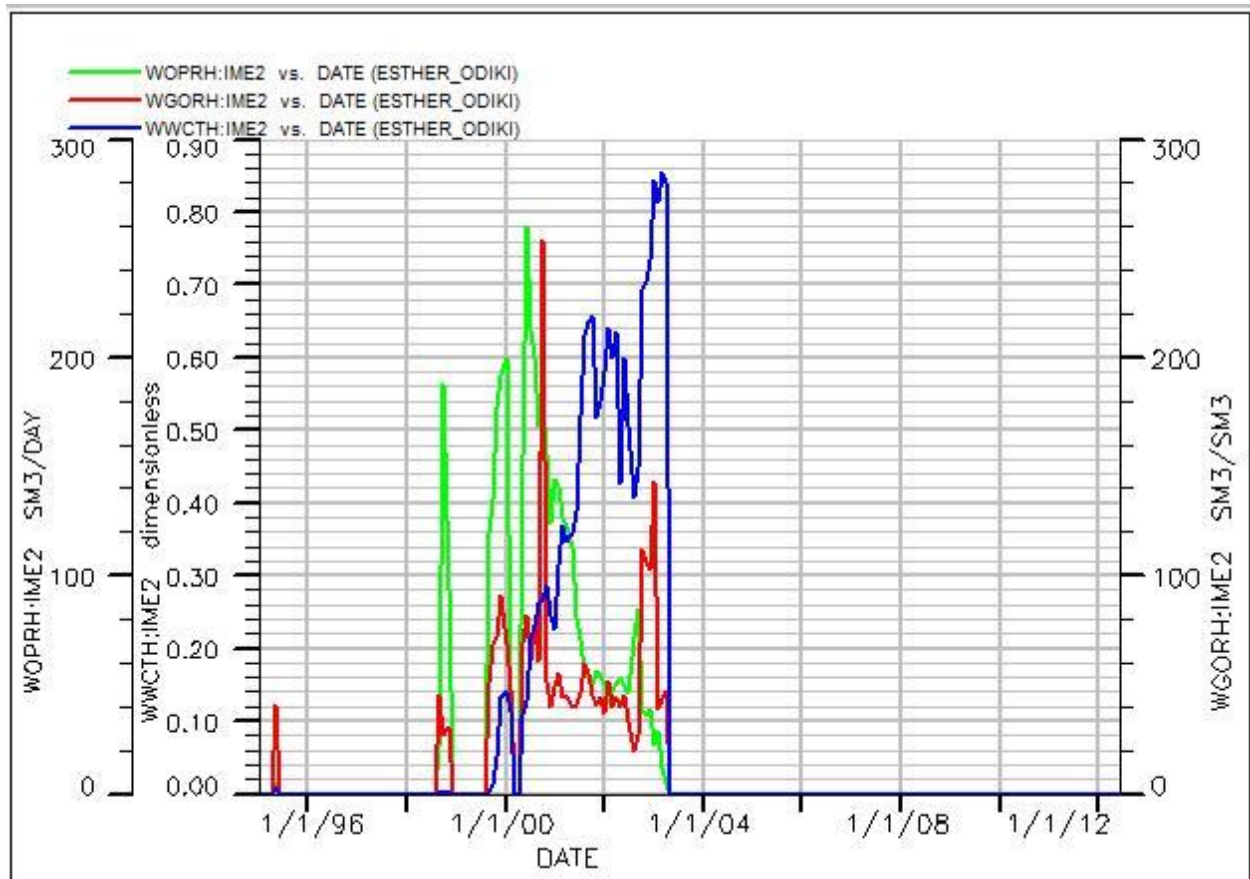
Figure 11: Production performance for well IME-2 showing oil rate, GOR and water cut

3.2.2. WELL IME-4

The IME-4 well was brought on stream in May 1995 and attained a peak production of 275.36sm^3/day, at a BSW of 0.05% and GOR of 102sm^3/sm^3. A month later the well was zone switched to an overlaying reservoir because the well was initially tested to see how much oil can be produced from D70 reservoir, it produced till August 2007 when it was zone switched back to the D70 reservoir. An oil production rate increase with decrease in water

production was observed with a peak oil rate of 220sm^3/day in July 2010. It is currently flowing through tubing at an average rate of 80sm3/d, BSW of 18% and a GOR of 45sm^3/sm^3. Cumulative production from this well is 0.25MMsm^3 of oil, 9.82MMsm^3 of gas and 0.04MMsm^3 of water.
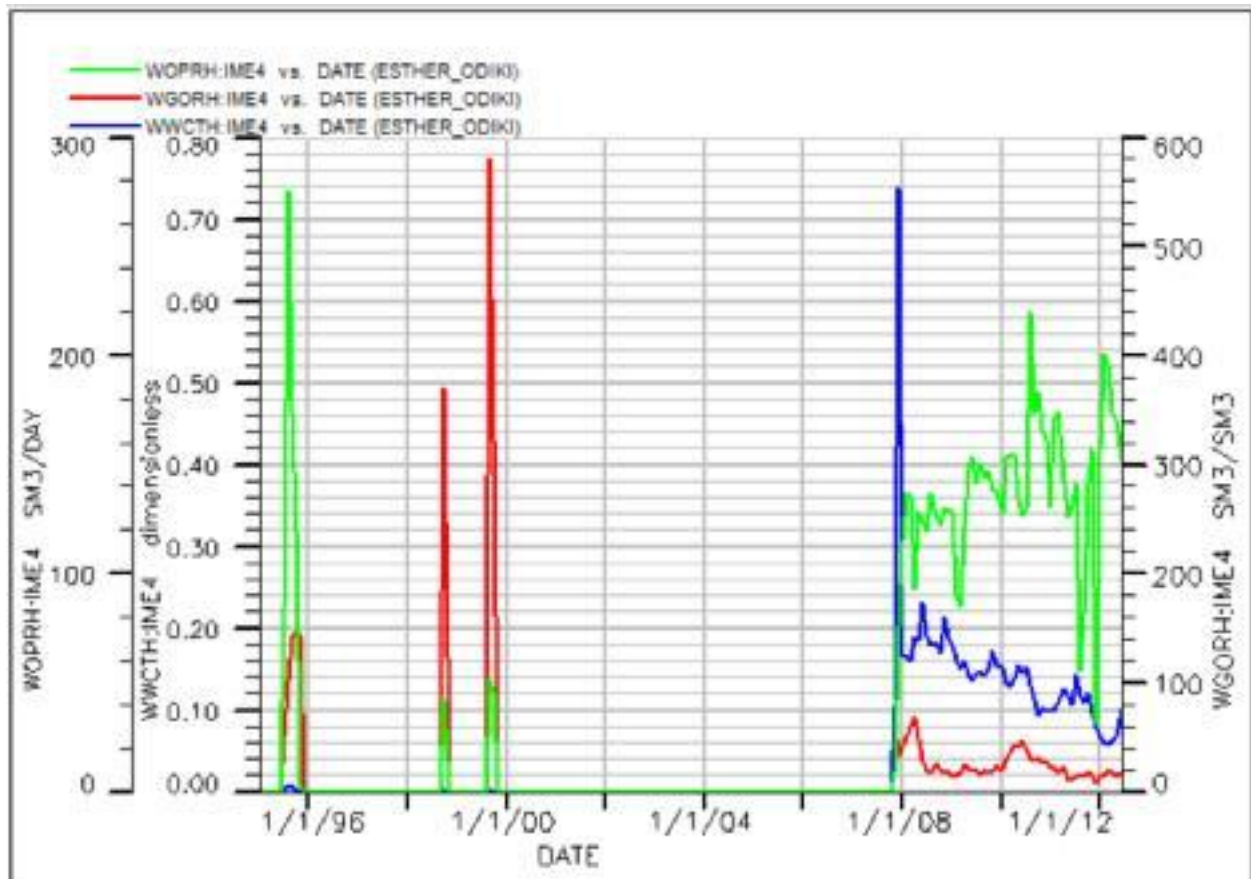
Figure 12: Production performance plot for well IME 4 showing oil rate, GOR and water cut

3.3.3. WELL IME-6

The IME-6 well was drilled as a horizontal drain with pre-packed screens and was put on production in August 1995. Well IME-6 initial production was at a relatively low oil rate of 107.15sm^3/day which rose to about 1442.45sm^3/day in three months as a result of beaning up the choke. A year later, the oil production peaked at about 1535.34sm^3/day with minimal BSW and initial solution GOR in August 1996. The well experienced a decline in oil rate with increasing GOR and eventually water broke through in December 1997. The GOR increased to an average of 135sm^3/sm^3 in August 1999 and kept declining thereafter. The oil and water production trends continued until the well was shut in for high BS&W (80%) in August 2006 as shown in the figure below. Cumulative production from IME-06 is

2.30MMsm^3 of oil, 148.30MMsm^3 of gas and 1.17MMsm^3 of water.
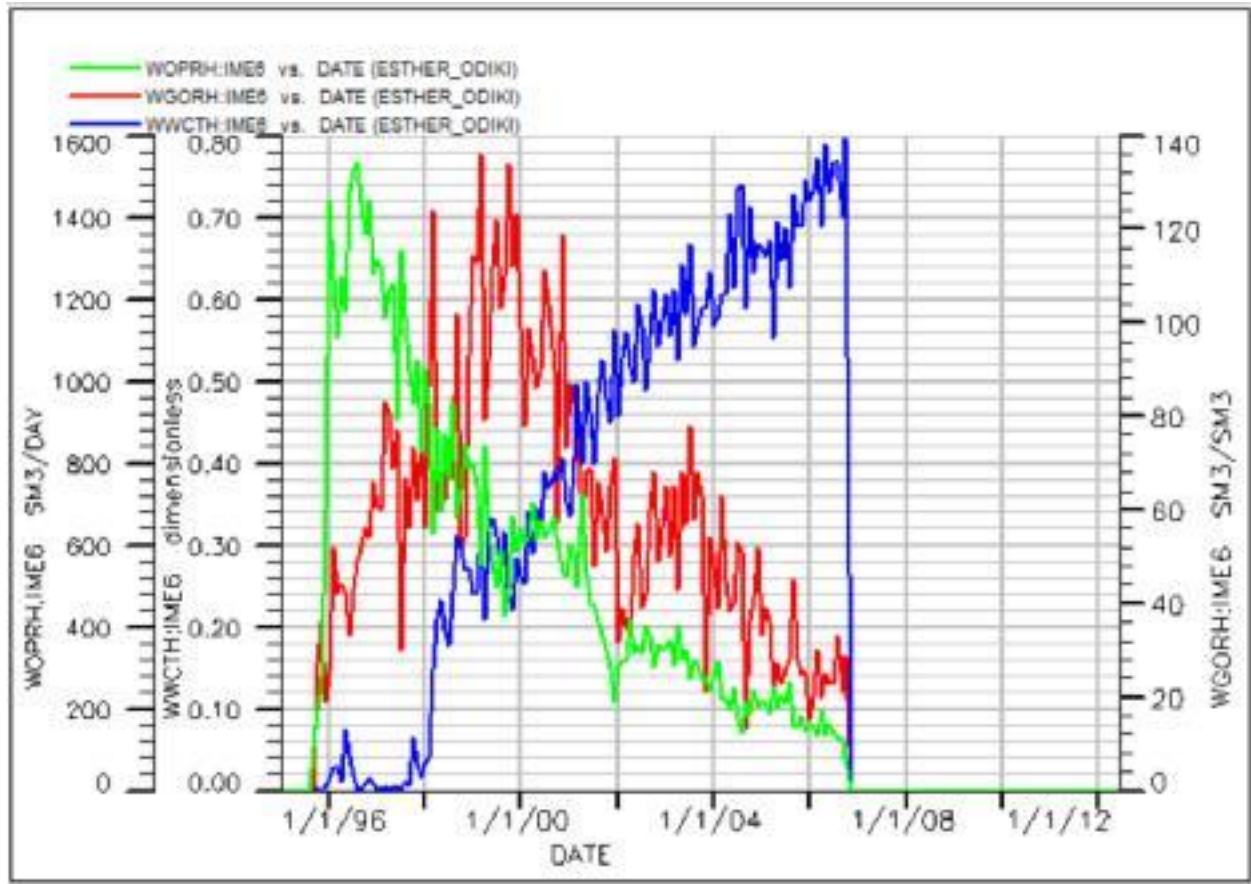
Figure 13: Production performance plot for well IME-6 showing oil rate, GOR and water cut

3.2.4. WELL IME-7

This well was drilled as a horizontal well with pre-packed screens due to the unconsolidated nature of the sand. IME-7 came on stream in August 1995 and after a few months it was producing at an average oil rate of 794.91sm^3/day, a BSW of 0.1% and a GOR of 48sm^3/sm^3. The oil production in IME-7 increased at minimal BSW until it peaked at about 1192.37sm^3/day in September 1996. A year later, water breakthrough occurred resulting in a rapid decline in oil production from a high of about 969.79sm^3/day to 217.81sm^3/day. The choke size was regulated to maintain oil production volumes and minimise the water production. This was achieved for about two years between January 1999 to August 2001, as an average BSW of 20% and oil rate of 286.17sm^3/day was observed. Subsequently, BSW rose to about eighty percent (80%) with decreasing oil production leading to a shut-in of the well in August 2006. Cumulative production from this well is 13.98MMsm^3 of oil,

76.57MMsm^3 of gas and 0.58MMsm^3 of water.
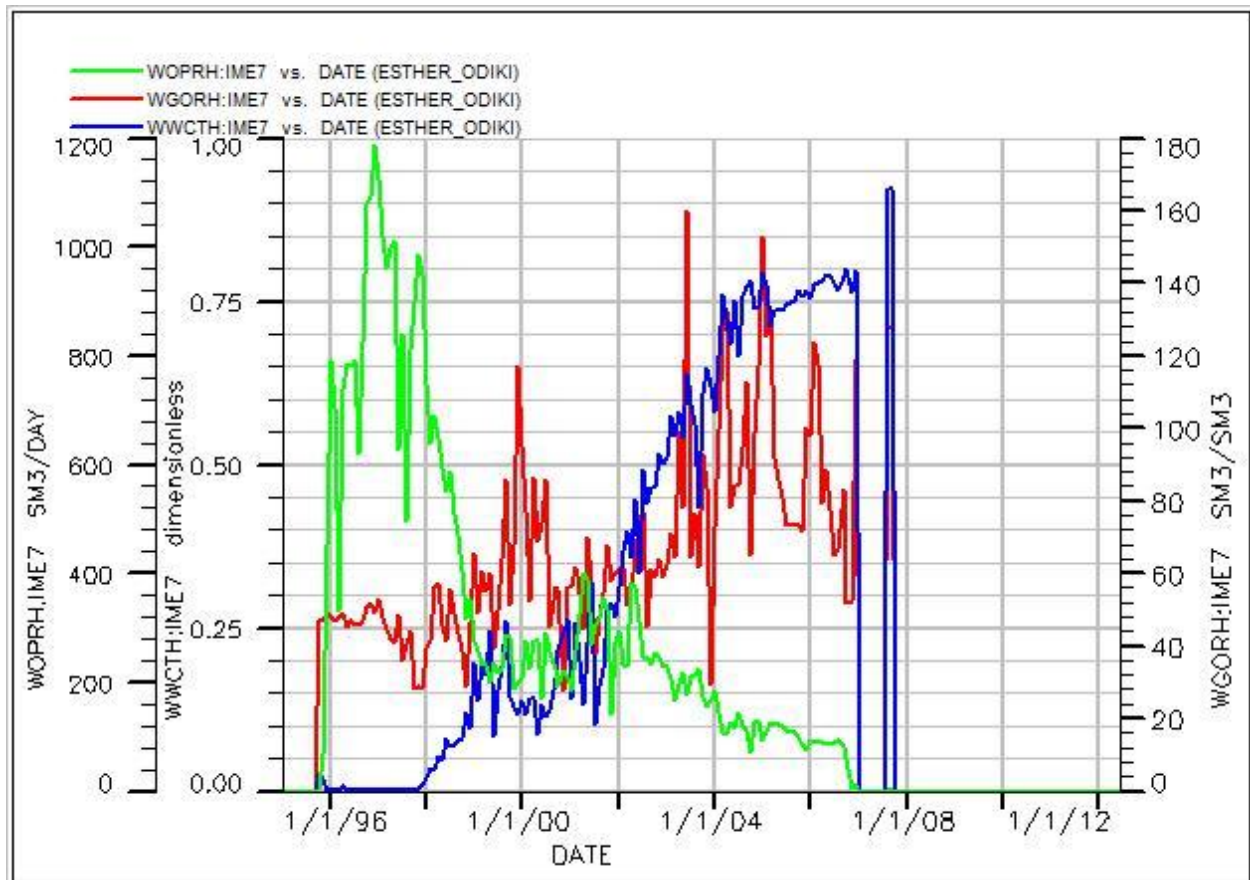
Figure 14: Production performance plot of well IME-7 showing oil rate,GOR and water cut

3.2.5. WELL IME-10

Well IME-10 is a sidetracked well, completed as a horizontal oil producer in the D70 reservoir. The well came on stream in December 2000 with an average oil rate of 16.37sm^3/day, GOR of 52sm^3/sm^3 and a BSW of 4.3%. The GOR increased sharply to peak at 2257sm^3/sm^3 as observed in the figure below. This high gas production can be attributed to the fact that the well's completion is very close to the gas cap and there are high permeability streaks surrounding the drainage area. Upon depletion of the gas cap gas within its drainage area there was a decline in the GOR and associated increase in the oil production. Water eventually broke through in March 2004 and it increased rapidly until the well was shut in due to a faulty well head in September 2006. The well was reopened about a year later and it experienced a drop in water production with an increase in oil production. As of July 2012, the GOR is 51sm^3/sm^3, oil rate is 47sm^3/day and BSW is 63%. Cumulative production from this well is 0.41MMsm^3 of oil, 170.11MMsm^3 of gas and 0.21MMsm^3 of water.
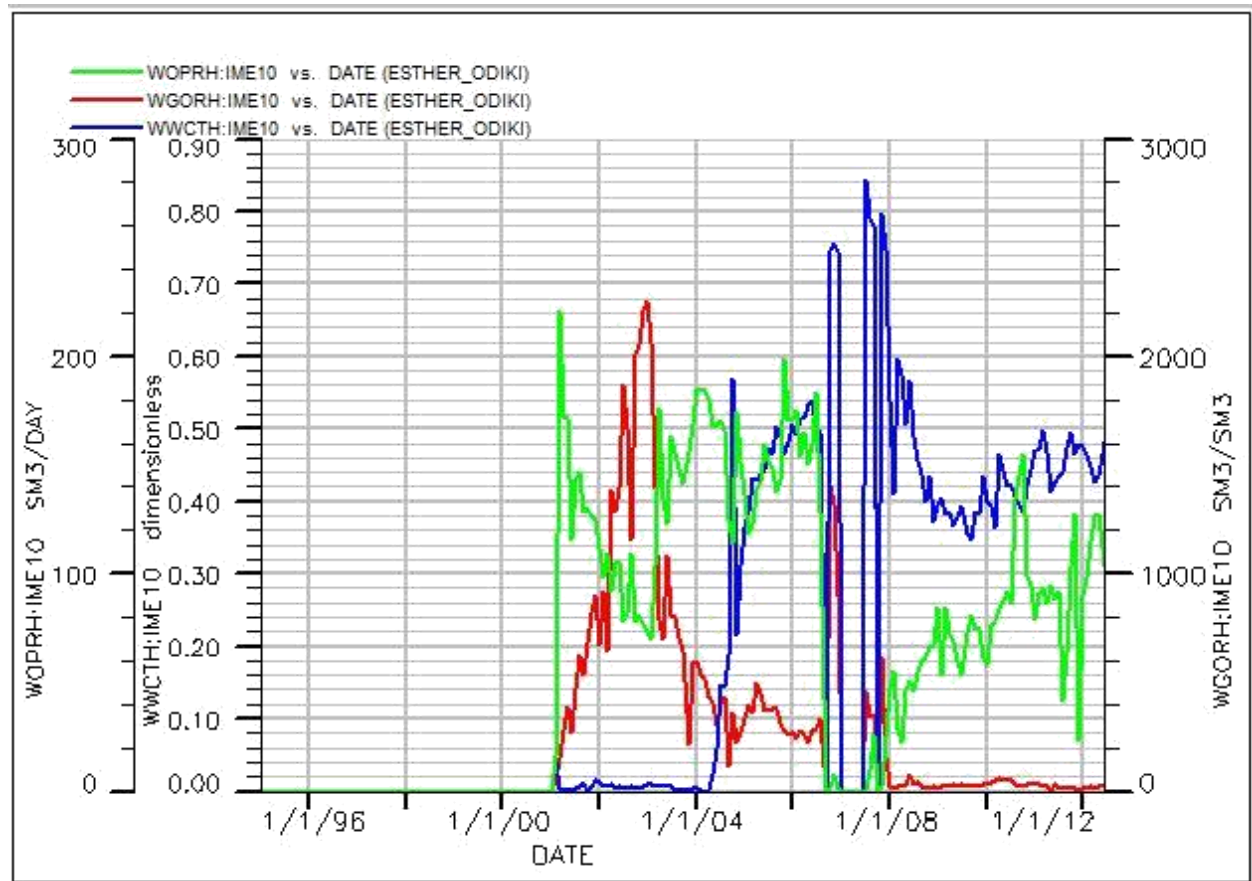
Figure 15: Production performance plot of well IME-10 showing oil rate, GOR and water cut

3.2.6. WELL IME-12

The IME-12 well was drilled as a horizontal drain in the crestal part of the reservoir. It commenced production in December 2011 and is currently flowing at an average rate of about $200sm^3$/day, at a low BSW of 2% and GOR of $45sm^3$/sm^3 as shown in the figure below. Cumulative production from this well is $0.052MMsm3^3$ of oil, $1.13MMsm^3$ of gas and $0.15Msm^3$ of water.
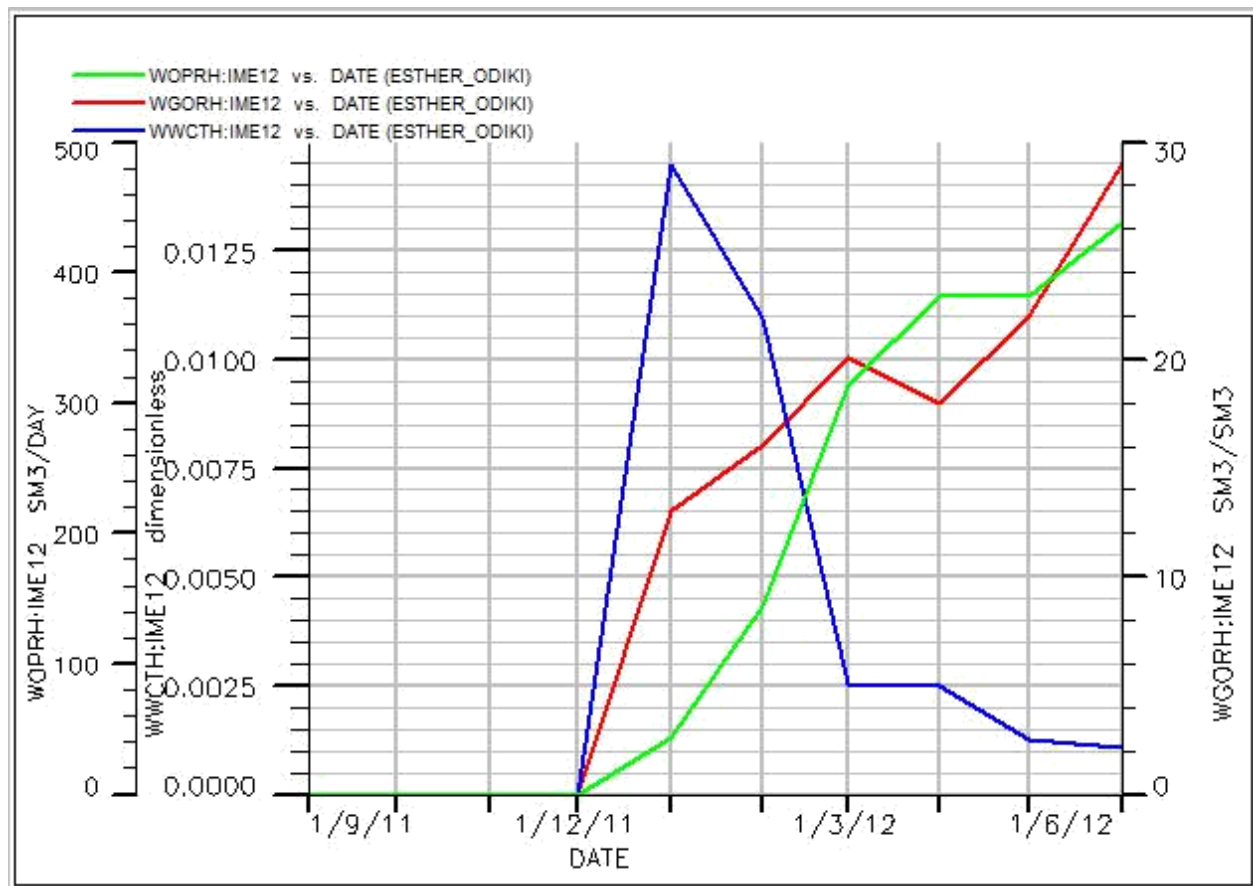
Figure 16: Production performance plot of well IME-12 showing oil rate, GOR and water cut

3.3. DATA USED

Dynamic simulation model is created by the integration of different input data. These data include poduction data, pressure-volume- temperature (PVT) data, as well as rock data and information on reservoir drive mechanisms and aquifer data.

3.3.1. PRODUCTION PERFORMANCE DATA

This comprises of oil rate, pressure and well test data for the field from the start of production. They are used to validate the model when carrying out history matching.

3.3.2. PVT DATA

These are data obtained from the analysis of the reservoir fluids in the laboratory. They include fluid gravity, gas oil ratio (GOR), fluid formation volume factor, fluid compresibility as well as saturation pressure, bubble point pressure, viscosity, fluid density, gas solubility and surface tension. They give an understanding of the type of fluid in the reservoir, as they change with respect to changes in the reservoir temperature and pressure thus affecting the recoverable reservoir volume. The PVTdata was used to generate a PVT model for the study.

3.3.3. ROCK PROPERTIES

Thus comprises of information about the rock tpe such as porosity, permeability,wettability, compressibility etc.

3.3.4. RELATIVE PERMEABILITY DATA

Relative permeability is the ability of a rock to transmit a fluid when the rock is saturated with more than one fluids (Ahmed, 2001).

Mathematically, relative permeability for gas is

$$\left(\underline{\hspace{1cm}} \right) \frac{\int \hspace{1cm} /}{\int \hspace{1cm} /} \hspace{4cm} 9$$

Relative permeability to oil is

$$\left(\underline{\hspace{1cm}} \right) \frac{\int \hspace{1cm} /}{\int \hspace{1cm} /} \hspace{4cm} 10$$

Relative permeability to water is

$$\left(\underline{\hspace{1cm}} \right) \frac{\int \hspace{1cm} /}{\int \hspace{1cm} /} \hspace{4cm} 11$$

Where

S_o = Oil saturation

S_g = Gas saturation

S_w = Water saturation

S_{or} = Residual oil saturation

S_{gc} = Critical gas saturation

S_{wc} = Critical water saturation

P_c = Capillary pressure

Relative permeability data are generated from special core analysis (SCAL) and are used to generate relative permeability curves which represent the drainage and imbibition processes

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for the rock type.

3.3.5. WELL COMPLETION DATA
This is information containing the completion/perforation interval of all the wells in the field.

3.3.6. RESERVOIR DRIVE MECHANISM
The drive mechanism of a reservoir refers to the dominant energy that controls fluid behaviour within the reservoir and aides the recovery of fluids (Ahmed, 2001). The drive mechanism of the reservoir is obtained from the analysis of production data using material balance method.

For the field in study, the reservoir energy is majorly a combination the gas cap expansion and water influx from the aquifer. Initially the gas cap expansion is predominant energy source, but as it is depleted water influx from the aquifer becomes the more significant drive mechanism. The expected recovery from these reservoir drive mechanisms is between 40-50%. With the pressure behavior, it indicates a strong active aquifer and there might be no need for secondary recovery methods like water injection for pressure maintenance.

3.3.7. AQUIFER INFORMATION
The response of the aquifer to the production of fluids can be determined using material balance analysis method. To obtain this information, a software known as Mbal is used. It is used to determine the aquifer size as well as the reaction time of the aquifer to the voidage caused by fluid production.

From information given about the aquifer, the ratio of the aquifer radius to the reservoir radius also known as aquifer size is estimated to be 12.85; it indicates a large aquifer and is likely to react fast to voidage caused by oil, water and gas production. As a result of the monoclinal structure of the reservoir in study, the water influx is from the edge. Owing to the heterogeneity of the reservoir, the water tends to push the hydrocarbons through the high permeability streaks. This preferential sweep causes some oil volumes to be bypassed in regions with relatively low permeability in the reservoir.

Also from material balance analysis, the aquifer behaviour is consistent with carter tracy model (given information).

3.4. SIMULATION MODEL

The reservoir fluid flow simulation model was constructed using the data obtained from the static model, material balance analysis and rock and fluid properties, SCAL, well completions and production data provided. A description of the simulation model is presented in the following sections.

3.4.1. MODEL DIMENSIONS

The model dimensions in the X-, Y- and Z-direction are 74, 69 and 21, respectively. This amounts to 107226 active cells. Hence there was no need to upscale the model and it properties because the simulator can handle the number of cells and also there was need to preserve certain geologic features like thin shale streaks captured in certain layers of the static model.

3.4.2 MODEL PROPERTIES

Properties used to build the dynamic model are as follows:

- Permeability in the X and Y direction for all the cells (PERMX, PERMY).

- Permeability in the Z direction (PERMZ) was derived based on Kv/Kh values assigned to each rock type. **See the table** for the Kv/Kh used to calculate PERMZ for each rock type.

- Porosity (PHIE).

- Saturation number (SATNUM) for assigning drainage saturation function tables to different cells based on their rock types.

- Imbibition number (IMBNUM) for assigning imbibition saturation function tables to different cells based on their rock types.

- Net to gross (NTG) file.

- FAULT file.

- SCAL data comprising the relative permeabilities for oil/water and gas/oil systems for both the drainage and imbibition processes for the four rock types. The capillary pressures were also incorporating which formed the basis for the simulator to generate saturation distribution.

- PVT data.

- Aquifer Model: The aquifer model properties are shown in Table below.

3.4.3. AQUIFER PROPERTIES FOR THE SIMULATED RESERVOIR MODEL

Parameters	Reservoir Model
Datum depth (meters)	1430
Permeability (md)	1000
Compressibility (1/bars)	4.0E-4
Porosity (fraction)	0.27
Reservoir outer radius (meters)	1000
Aquifer thickness (meters)	45
Encroachment Angle (degrees)	125
Re/Ri (Fraction)	8

Table 2: Aquifer properties for the simulated reservoir

3.4.4. SCHEDULE

The production history data as well as the deviation survey data for the wells were loaded into the simulation model using ECLIPSE schedule. The program calculates the well connection factors using the reservoir properties. In addition, this program outputs the production data in a format suitable to be included directly into an ECLIPSE model.

3.4.5. VERTICAL FLOW PERFORMANCE (VFP)

The hydraulic tables for IME-04, IME-10 and IME-12 used to estimate the flow performace of the wells is given in the appendix. The data covered the necessary ranges of GOR, water cut, tubing head pressure required to calculate the vertical lift performance in the simulations. They are generated using PROSPER software and considering the capacity of surface facilities.

3.5. HISTORY MATCHING

This is an essential part of dynamic modelling. History match is done by comparing the data from the simulated model and the data obtained from the field. The process validates the dynamic model based on matching historical pressures and saturations.

For this reservoir study, history match was done for both pressure and saturation

3.5.1. PRESSURE MATCH

This is the first phase of the history match process and it is meant to properly calibrate the energy in the system by closely matching simulated model pressures with the historical static bottomhole pressure for all the wells throughout the life of the reservoir. This was achieved by carrying out the following tasks:

- Constrained the model to produce the entire fluid (oil, gas and water) production volume/total voidage from 1995 to 2012 and then the model estimated the corresponding reservoir pressure. This was initially done without an aquifer model to determine the reservoir response. It was observed that there was a steep drop in reservoir pressures.

- The Carter Tracy aquifer model generated from MBAL was then used to match the reservoir pressure. After a number of modifications to the aquifer properties, the pressure match was achieved on reservoir and well-by-well basis.
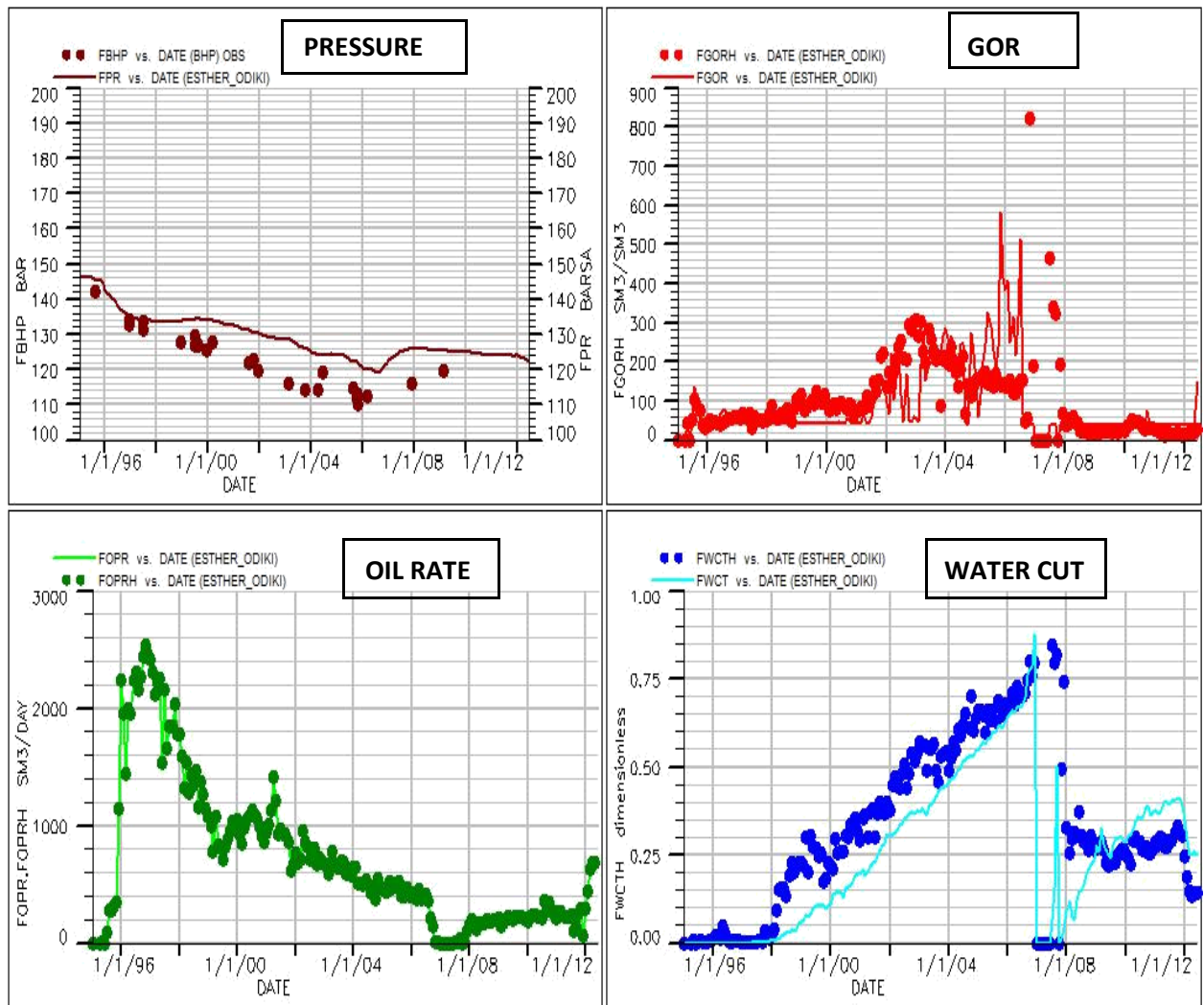
Figure 17: Field History matched plots showing reservoir pressure, GOR, Oil rate and Water cut.
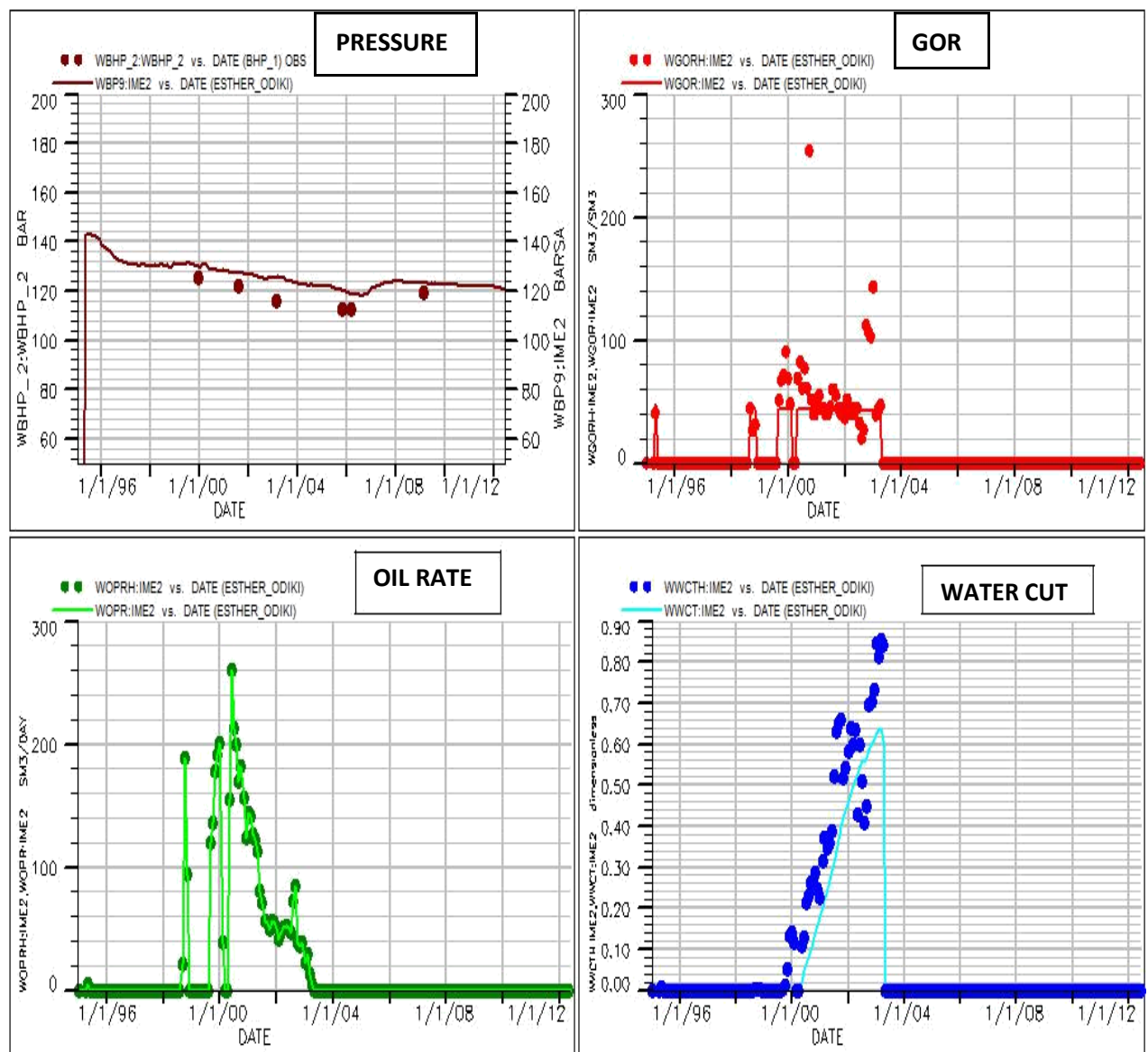
Figure 18: Well IME-2 history matched plots showing Well pressure, GOR, Oil rate and Water cut
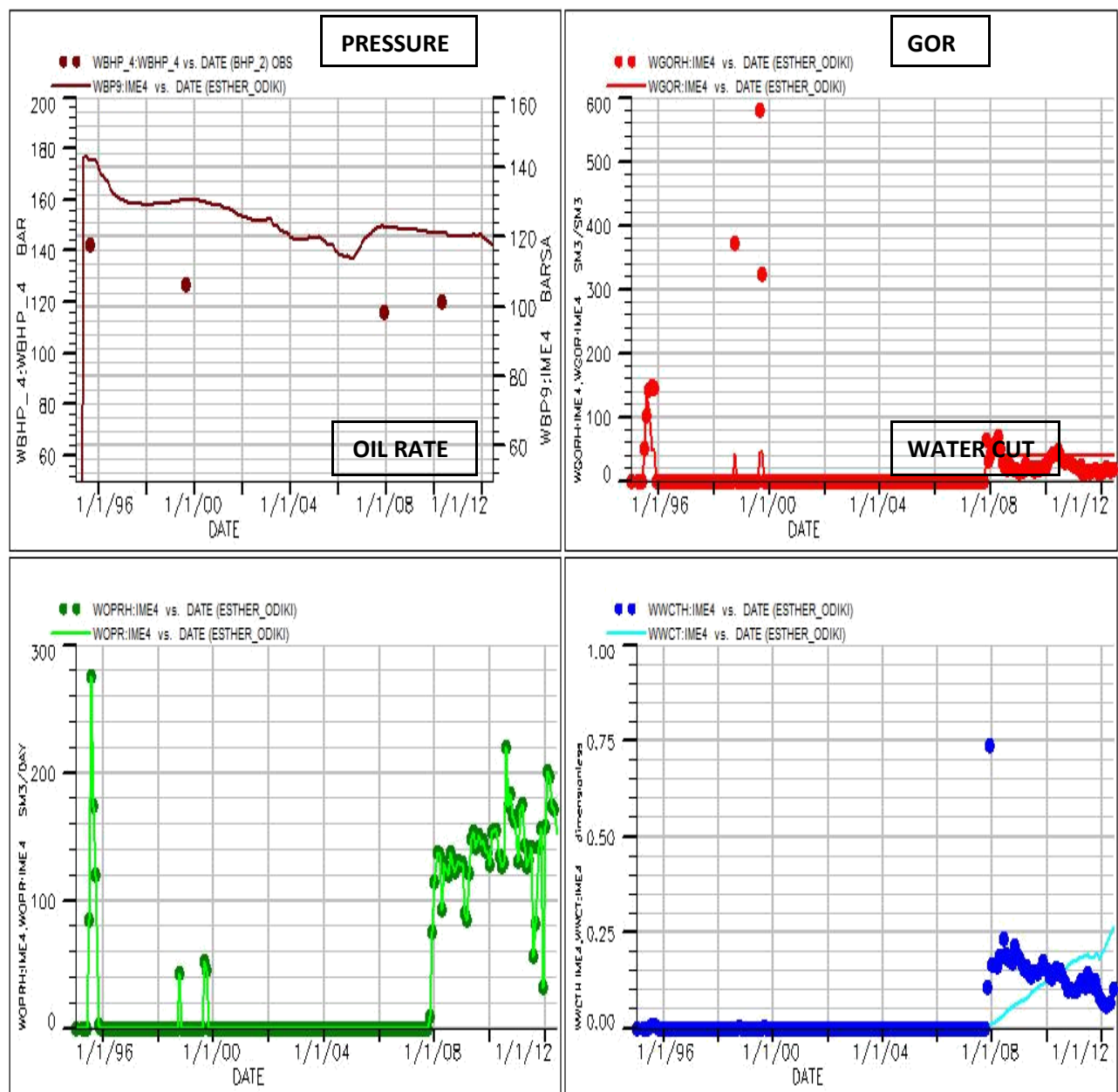
Figure 19: Well IME-4 History matched plots showing Well pressure, GOR, Oil rate and Water cut
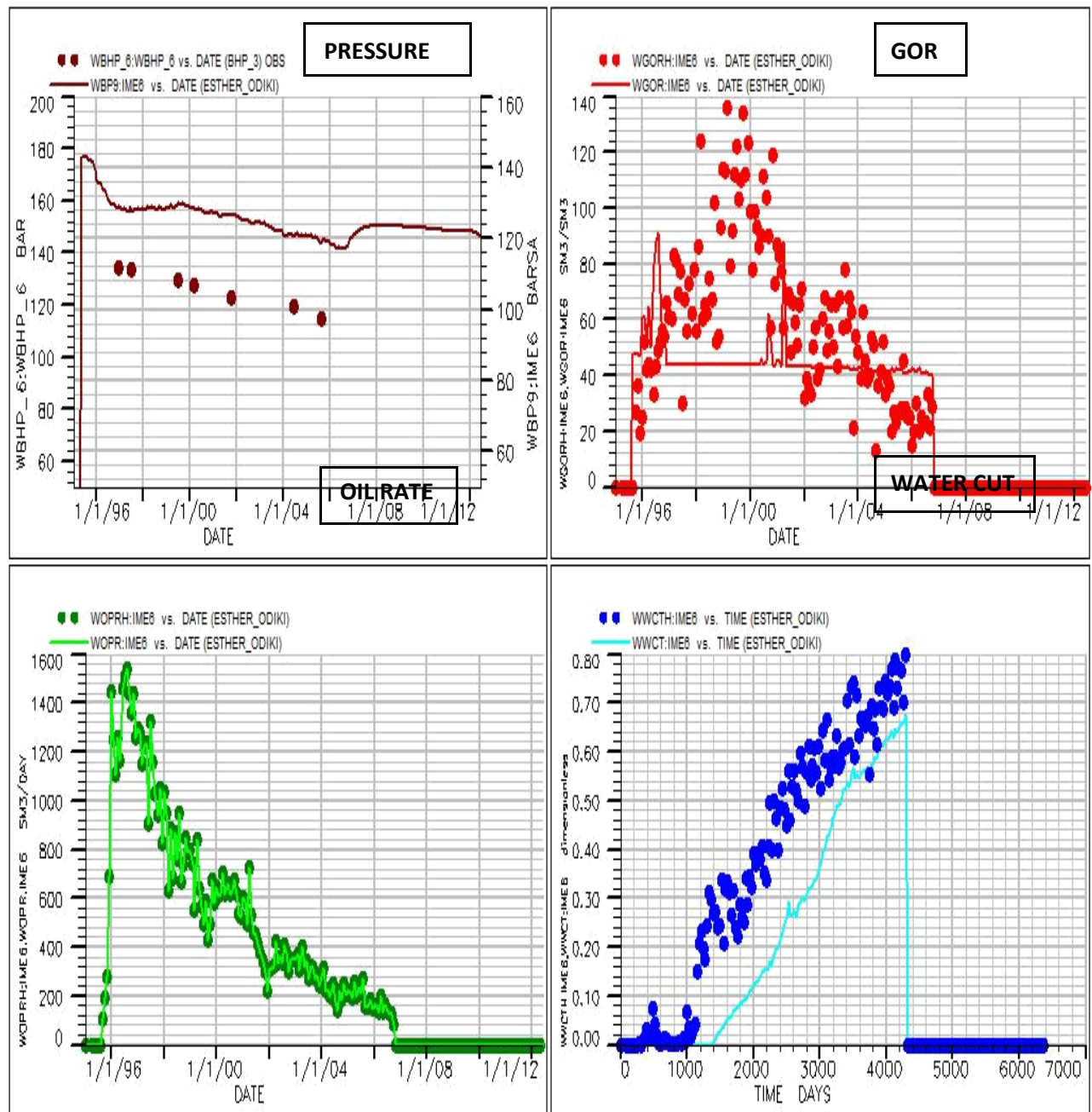
Figure 20: Well IME-6 History matched plots showing Well pressure, GOR, Oil rate and Water cut
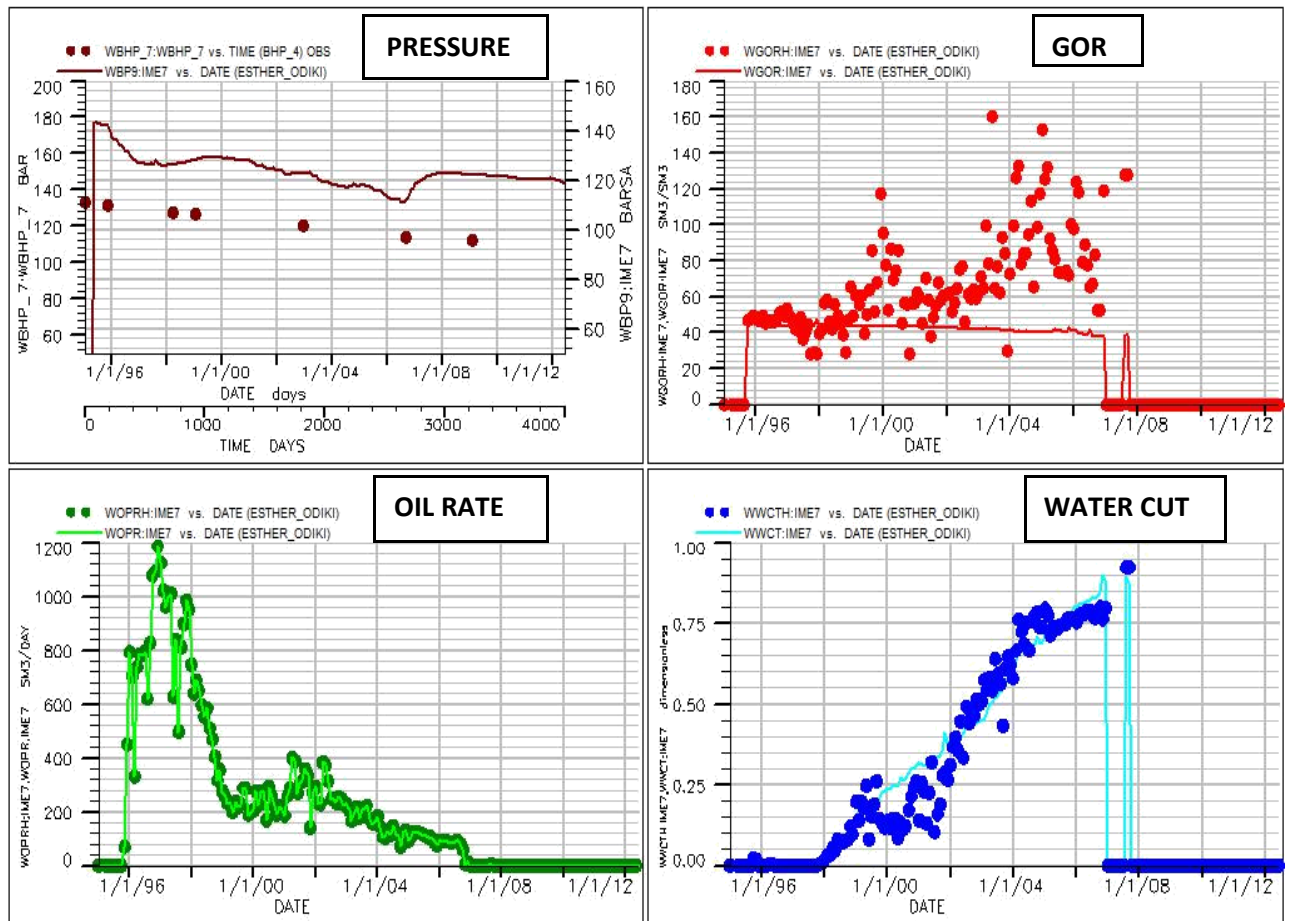
Figure 21: Well IME-7 history matched plots showing Well pressure, GOR, Oil rate and Water cut
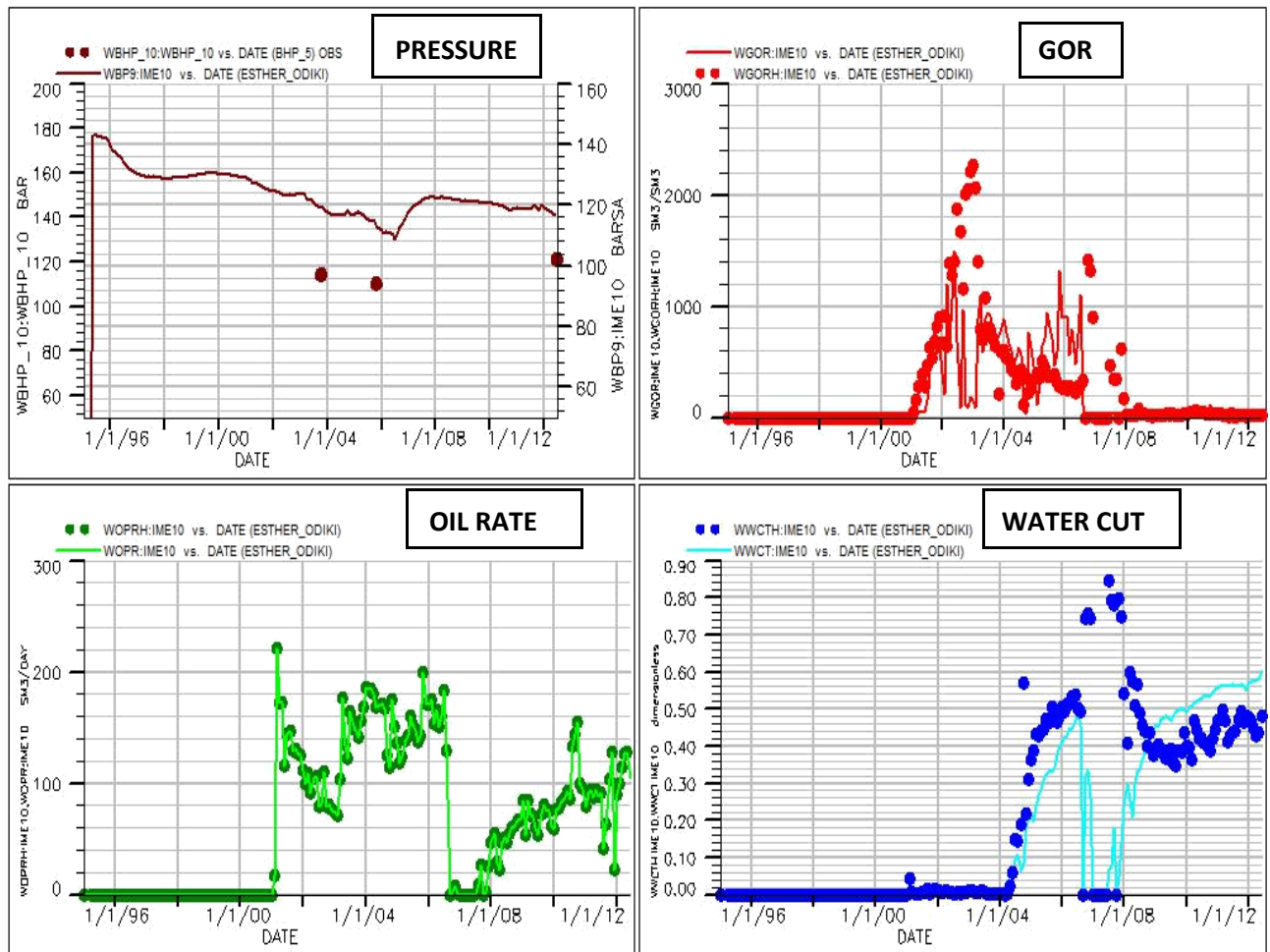
Figure 22: Well IME-10 history matched plots showing Well pressure, GOR, Oil rate and Water cut

3.5.2. SATURATION MATCH

In this phase, the simulator was constrained to produce the historical oil production rates and then the water cut, GOR and reservoir pressure were estimated. These were then compared to historical data to validate the dynamic model. The following changes were made to the simulation model to obtain a good history match of the pressure and production profiles:

- The transmissibility of the fault towards the crest of the reservoir was reduced by 20% (multiplied by a factor of 0.8) as a result of the excessive gas being produced in the model by IME-10.

- PERMZ was reduced globally by a factor of 0.5. This improved the water production in IME-02 and IME-06 by enhancing the lateral flow of water in those areas, hence

more water was produced.

- Critical water saturation was increased by a factor of 1.5 globally to match the water breakthrough time in the IME-10 and IME-12. This was done because the connate water saturations obtained from the static model was relatively low.

Cross sectional views of the model saturations at the initial (start of production for the wells) and end of production (July 2012) are shown in Figures below. The results show the changes in fluid saturations during the period of the history match.
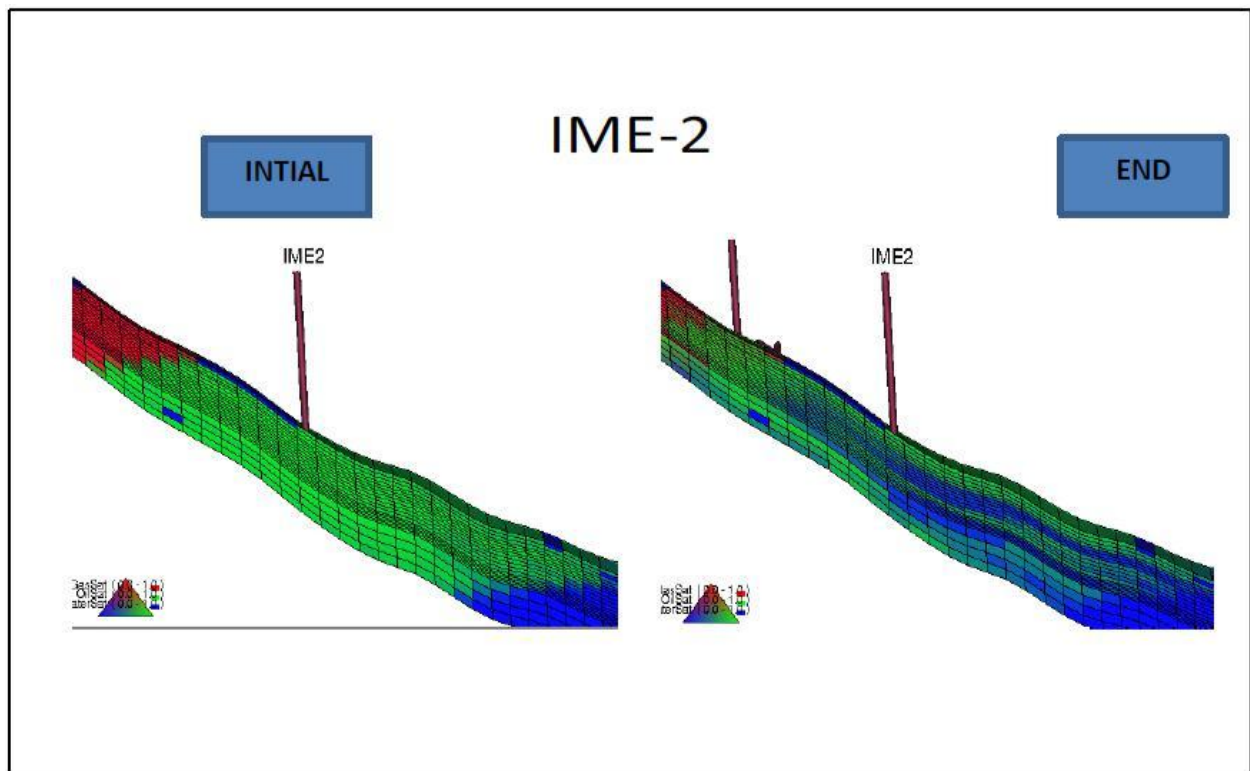
Figure 23: Oil saturation around well IME-2 at initial condition and end of history matching period.
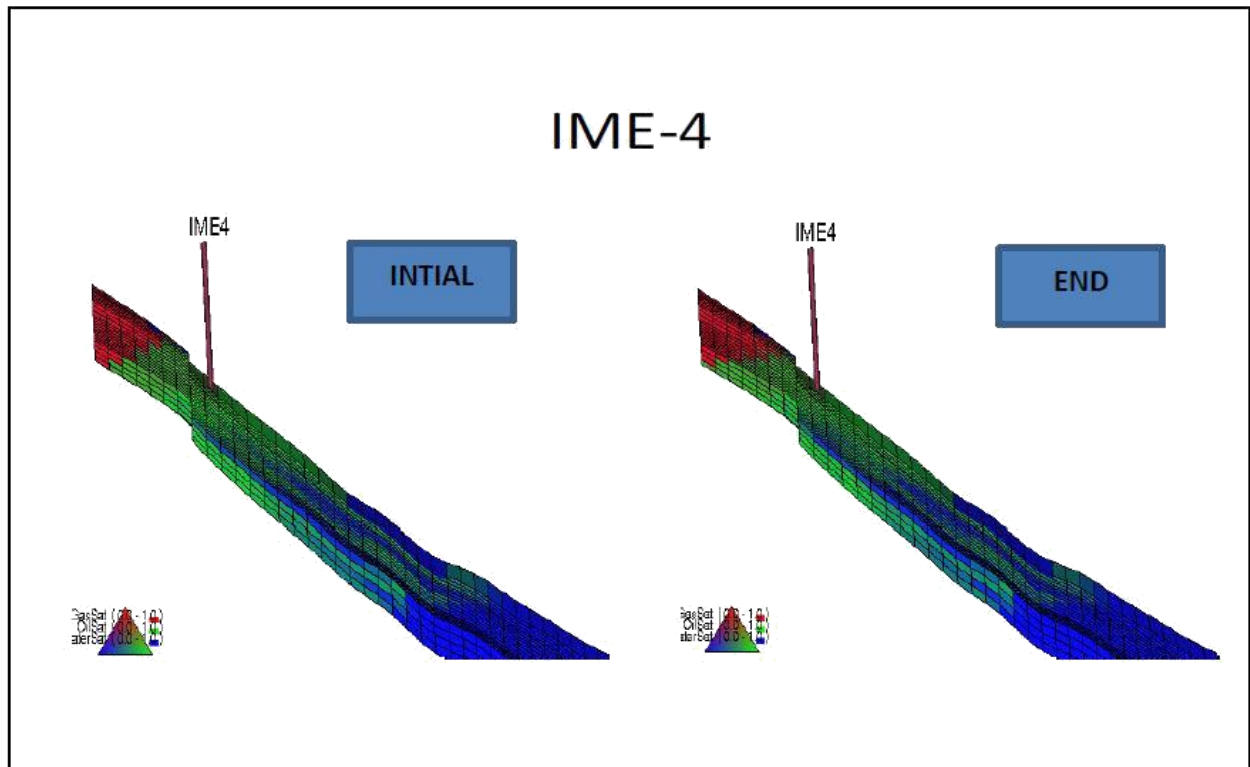
Figure 24: Oil saturation around well IME-4 at initial condition and end of history matching period.
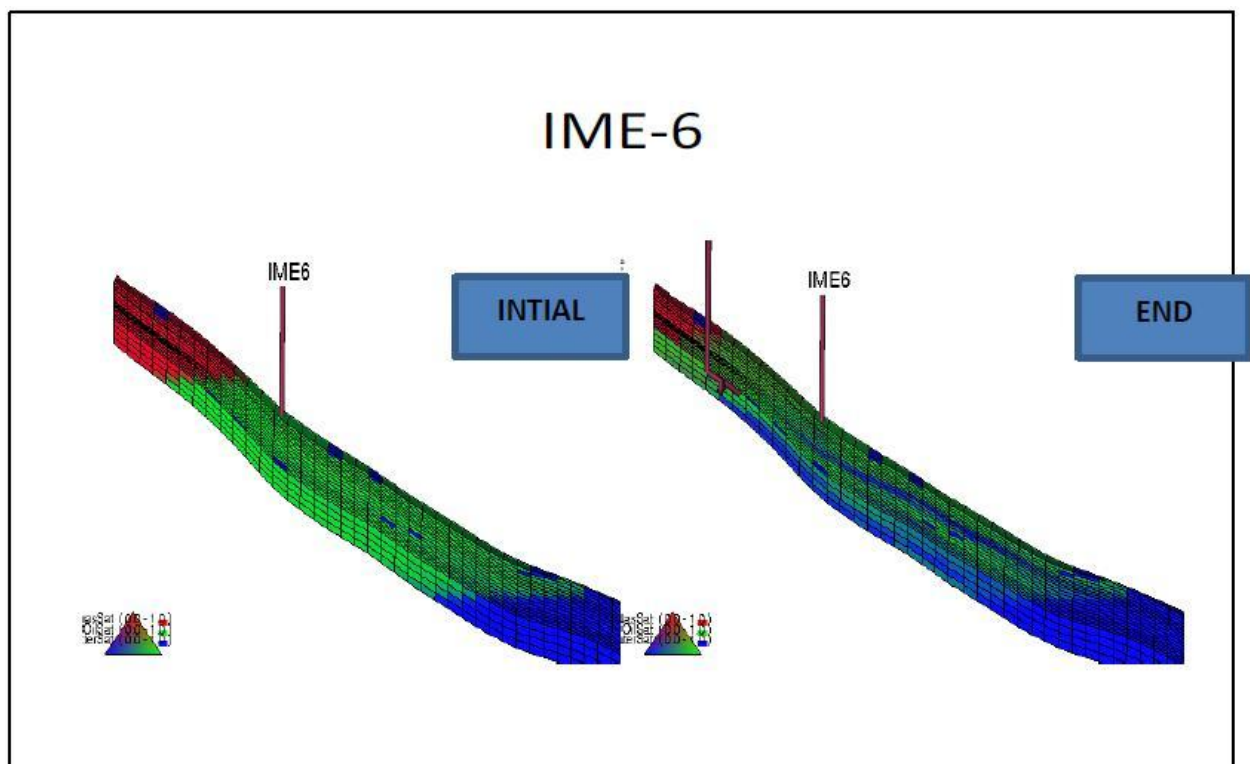
Figure 25: Oil saturation around well IME-6 at initial condition and end of history matching period.
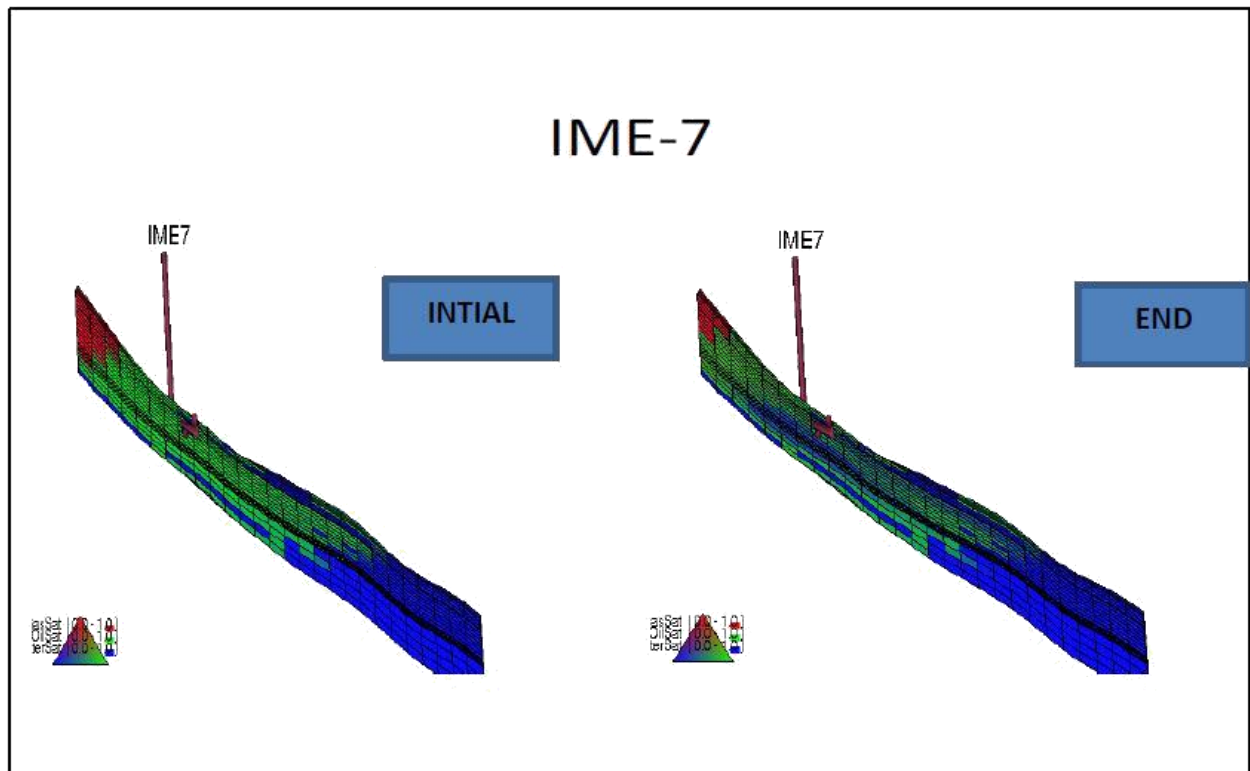
Figure 26: Oil saturation around well IME-7 at initial condition and end of history matching period.
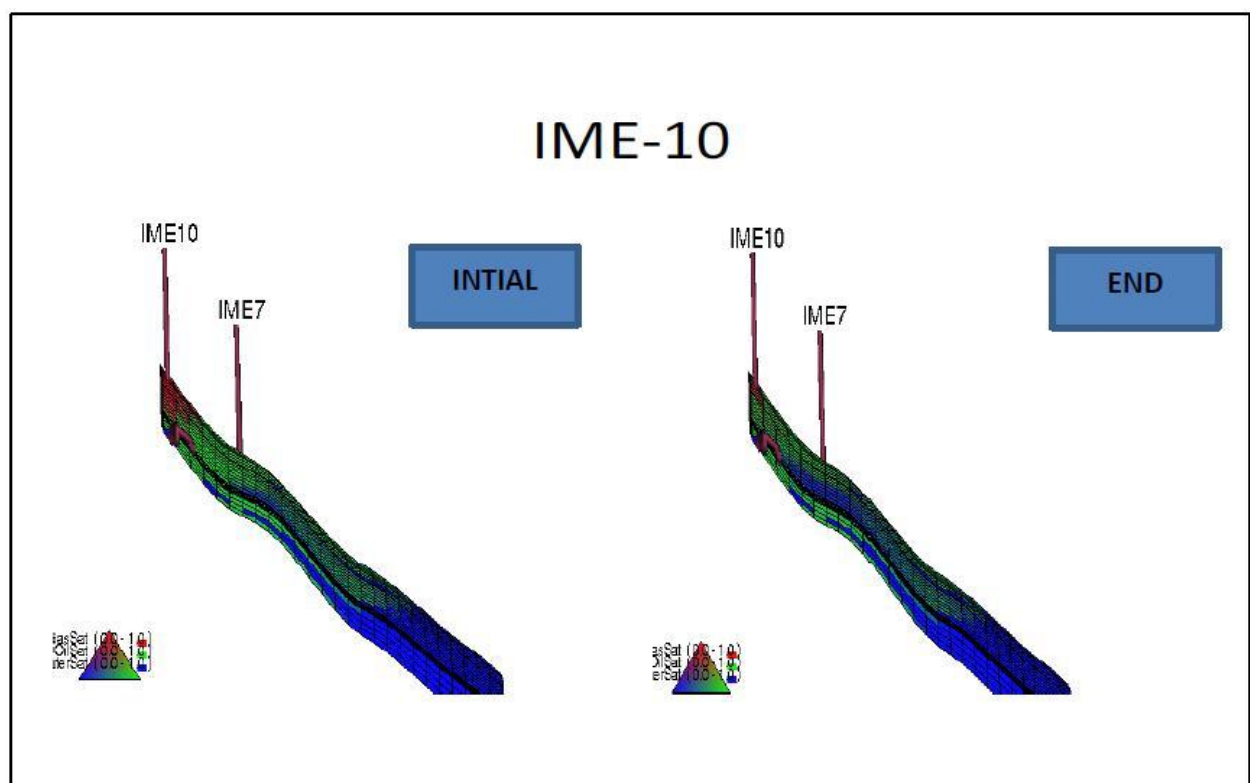
Figure 27: Oil saturation around well IME-10 at initial condition and end of history matching period.
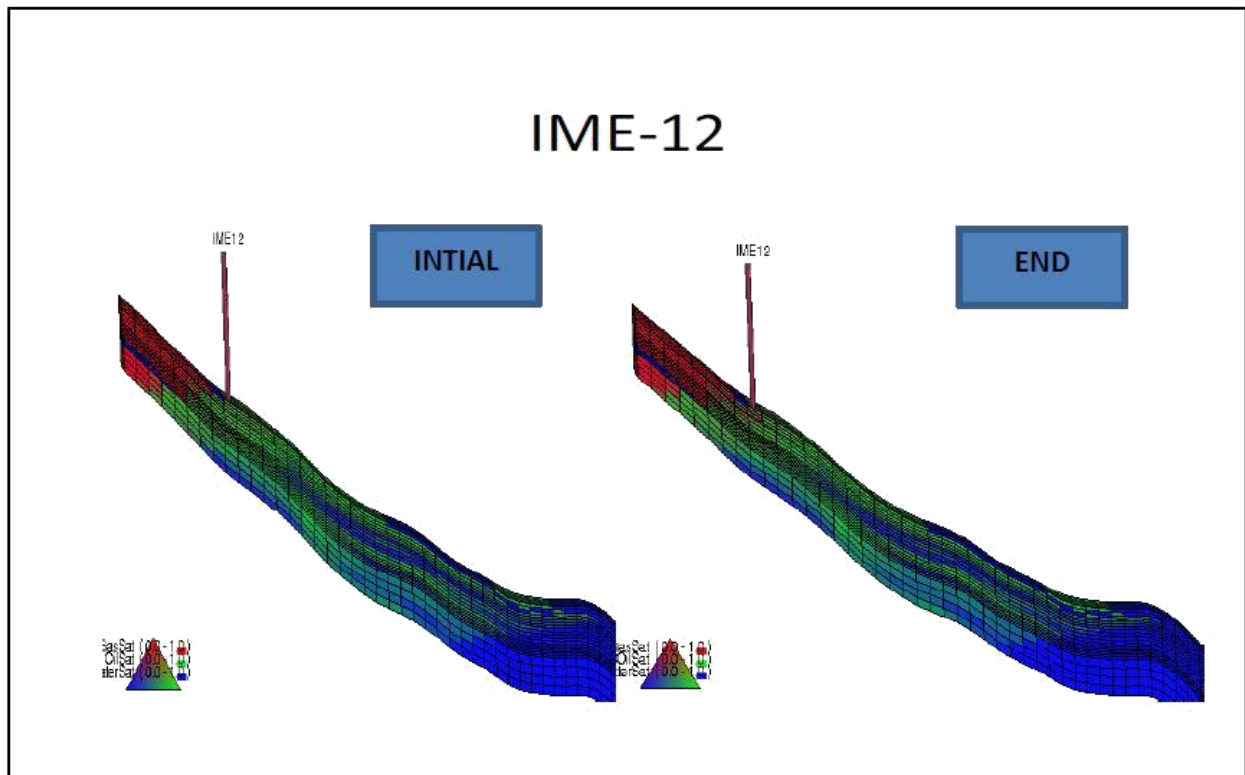
Figure 28: Oil saturation around well IME-12 at initial condition and end of history matching period.

3.7. MODEL TUBING HEAD PRESSURE (THP) CALIBRATION

After completing the history match, the model was calibrated using the VFP tables to match the tubing head pressure recorded during production. Three wells are currently flowing through tubing, namely: IME-04, IME-10 and IME-12; hence three VFP tables were used for the THP calibration. The period of the THP calibration was from December 2011 to June 2012. After assigning the VFP tables to the corresponding producing wells, the first calibration run was performed and the results showed that the simulated THP values were higher than the observed. The simulated THP was then adjusted to align with observed Tubing head pressure (THP) so that prediction can be as accurate as possible. The VFP shift in pressure for the three wells is shown in Table 2 below. It is noted that no VFP pressure shift was required in IME-10.

Well	VFP shift (Bars)
IME-04	+16
IME-10	0
IME-12	+8

Table 3: Vertical lift performance shift

3.8. PREDICTION

The main objectives of the prediction runs were to estimate reserves and generate production forecasts for the base case and other field development cases in order to optimize oil recovery from the D70 reservoir. Several reservoir development cases were considered and sensitivity runs were carried out to identify the optimal field development plan.

3.8.1. PREDICTION RUNS

In the prediction runs, the current potential of the wells was evaluated and this formed the basis for defining the individual well production rate constraints. Prediction run was carried out to find out the expected life span of the field. The table below shows the operational and economic constraints applied to the producing wells during the prediction runs.

Constraints	Well IME-04	Well IME-10	Well IME-12
Minimum oil rate (sm^3/day)	15.9	15.9	15.9
Minimum THP (bars)	3.1	3.1	3.1
Maximum GOR(sm^3/ sm^3)	150	400	400
Maximum BS&W	95%	95%	95%
Maximum oil rate (sm^3/day)	80	60	200

Table 4: Production constraints for the simulation production forecast.

The field development cases considered in this study are listed below

Case	Description
1	Base Case (Do nothing scenario)
2	Well intervention (i.e. workover of existing wells by shutting completions when water cut is exceeded)
3	Implementing gas lift in well IME-04
4	Side track from well IME-04 with gas lift

Table 5: List of field development case scenarios

To evaluate various field development options, a set of sensitivity runs were carried out for the four cases listed earlier. Sensitivity runs included:

- Variation of maximum oil rate target in the base case
- Gas-lift sensitivity runs to find optimal lift gas volumes
- Orientation of the IME-04 side track to target by-passed oil

CHAPTER 4

4.0. RESULTS AND DISCUSSIONS

This chapter contains the results obtained from the prediction runs/production forecasts carried out in the simulation for the different field development cases as well as the discussions of the results. The stock tank oil initially in place (STOIIP) is 13.6MMsm^3 and at the end of history about 4.4MMsm^3 of oil has been produced. The results obtained are explained thus;

4.1. CASE 1 (BASE CASE)

In the base case (Case 1—do nothing case), the simulations were carried out assuming that the existing wells IME-04, IME-10 and IME-12 will continue to produce without gas-lift. It was observed that the wells stopped production as a result of low tubing head pressure as they reached the threshold THP of 3bars. The base case production performance plots for the reservoir and the three producing wells are shown below.
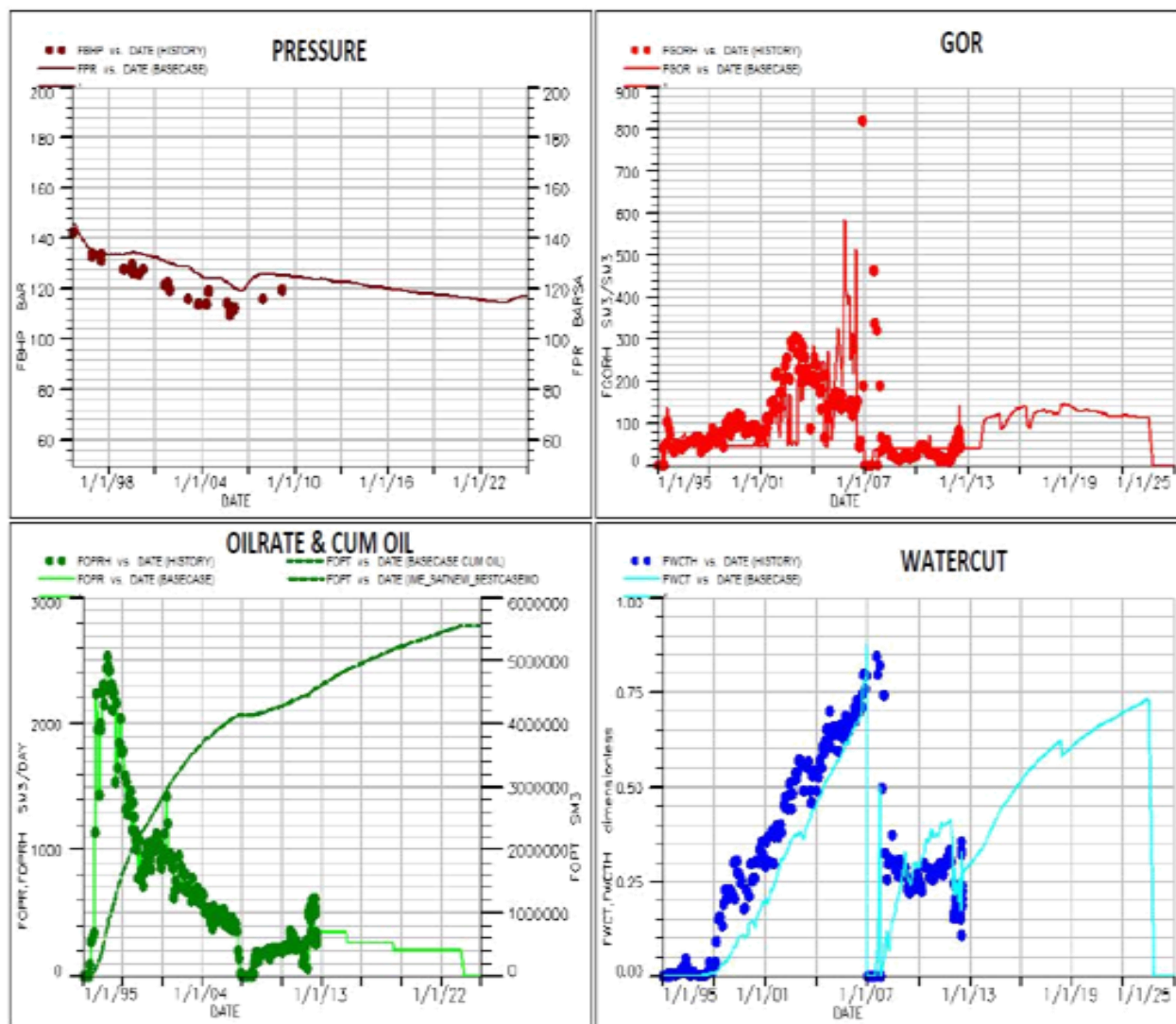
Figure 29: Field performance plots for base case prediction showing pressure, GOR, oil rate, cumulative oil production and water cut
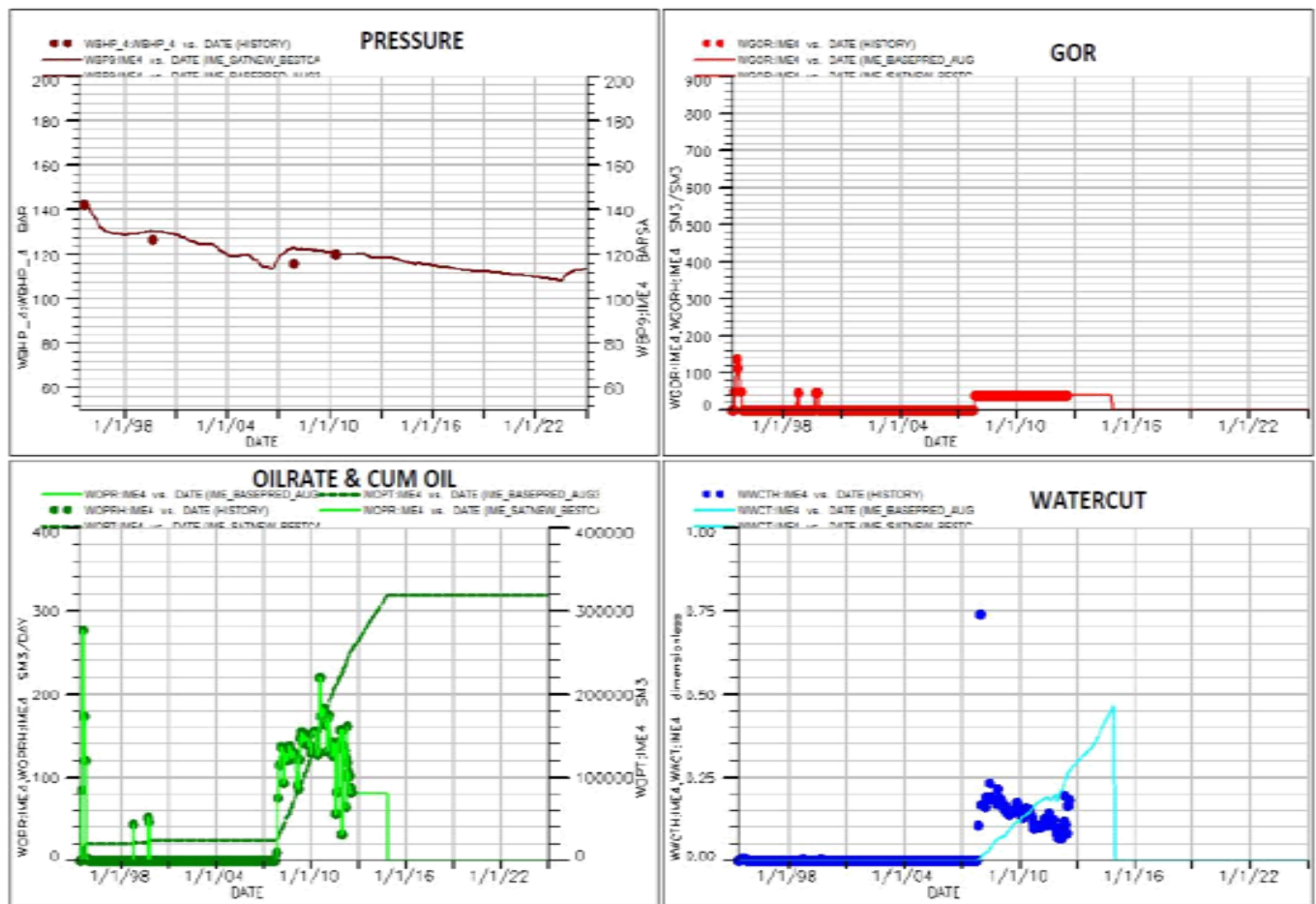
Figure 30: Well IME-4 performance plots for base case prediction showing pressure, GOR,
oil rate, cumulative oil production and water cut.
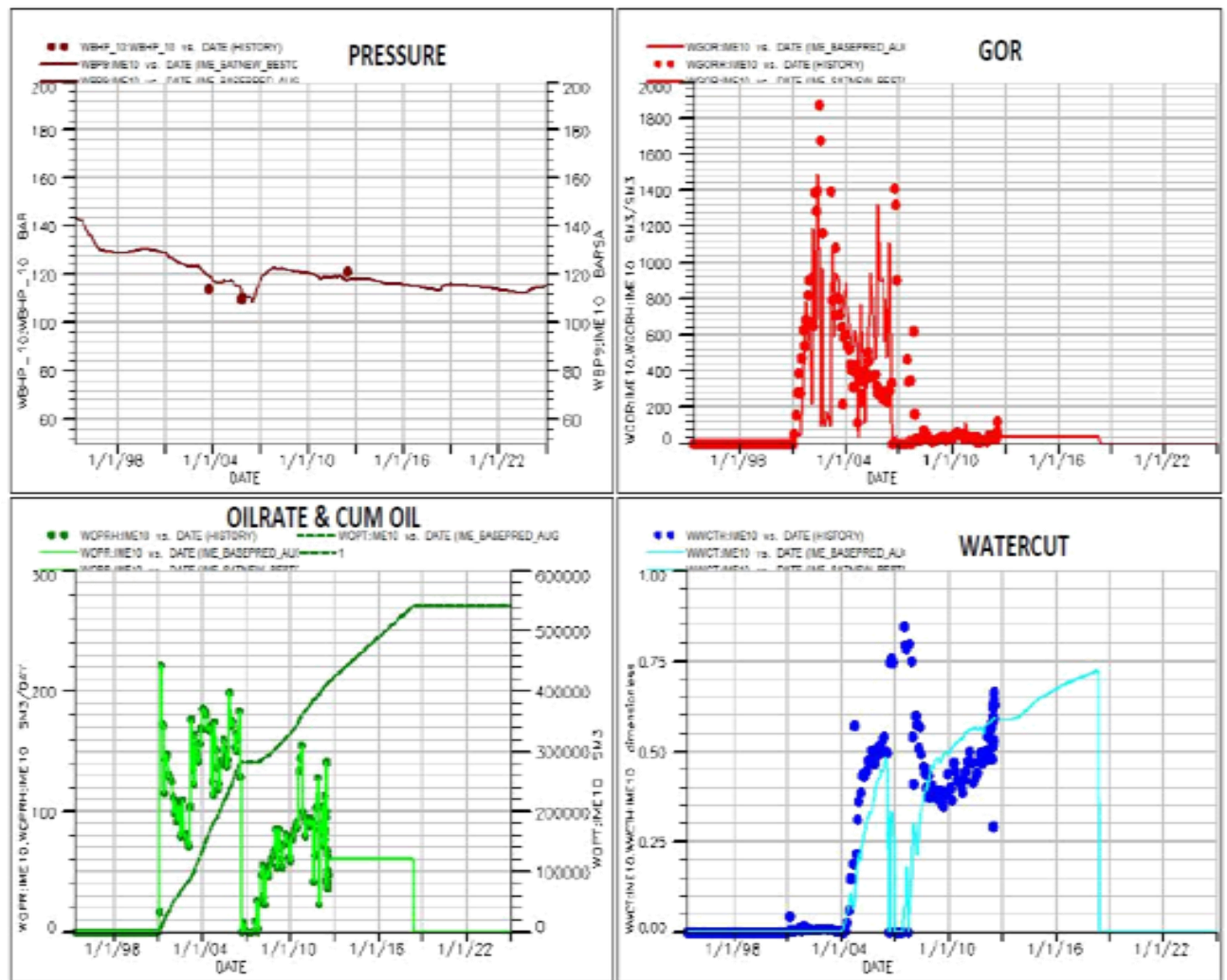
Figure 31: Well IME-10 performance plots for base case prediction showing pressure, GOR, oil rate, cumulative oil production and water cut
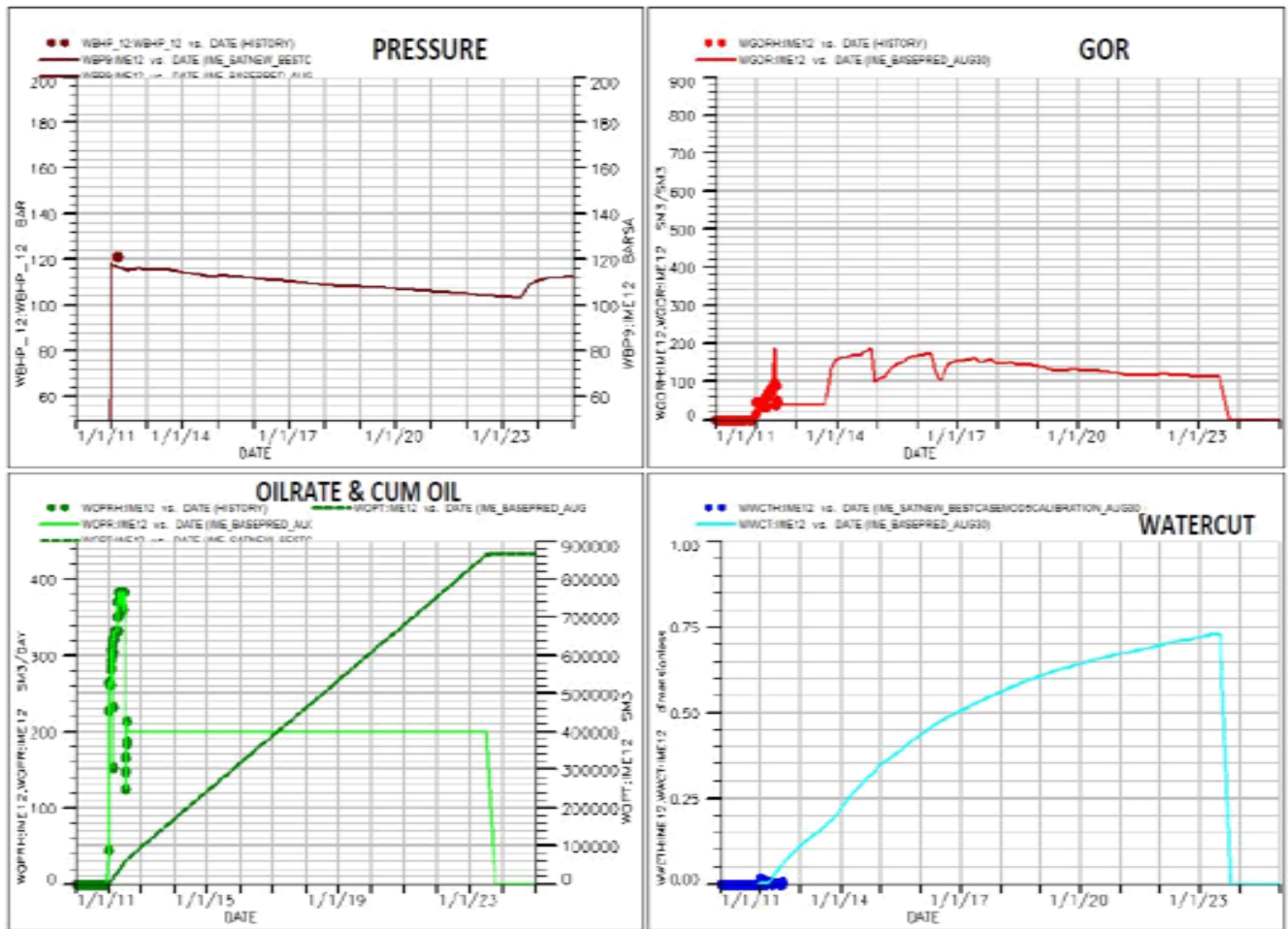
Figure 32: Well IME-12 performance plots for base case prediction showing pressure, GOR, oil rate, cumulative oil production and water cut

An estimated cumulative oil recovery of 5.56MMsm^3 (i.e., 41% recovery factor) was obtained from the base case prediction run. Thus, the reservoir can still produce additional 1.0MMsm^3 of oil from 2012 (end of history) until 2023. The maximum oil production rates used for the base case prediction run were 80, 60, and 200sm^3/day for IME-04, IME-10 and IME-12, respectively. The runs terminated before 2024 because of low THP.

4.1.1. BASE CASE SENSITIVITY ANALYSIS

Using the base case, sensitivity runs were carried out by reducing the maximum oil production rate constraints for the three producing wells in an attempt to extend the life of the wells—extend the time the well will shut-in due to low tubing head pressure. The rates used are given below;

Number	Flow rate (sm^3/day)
Rate 01	Well-4 60 Well-10 40 Well-12 150
Rate 02	Well-4 50 Well-10 50 Well-12 120
Rate 03	Well-4 40 Well-10 30 Well- 12 180

Table 6: Oil rates used for base case sensitivity analysis

It was observed that some wells produced for a longer time but, there was no significant increase in the ultimate recovery (cumulative oil production) from the reservoir. The results for the sensitivity runs are shown below comparing pressure, GOR, production rate and cumulative production as well as water cut using the different flow rates for the field and wells.
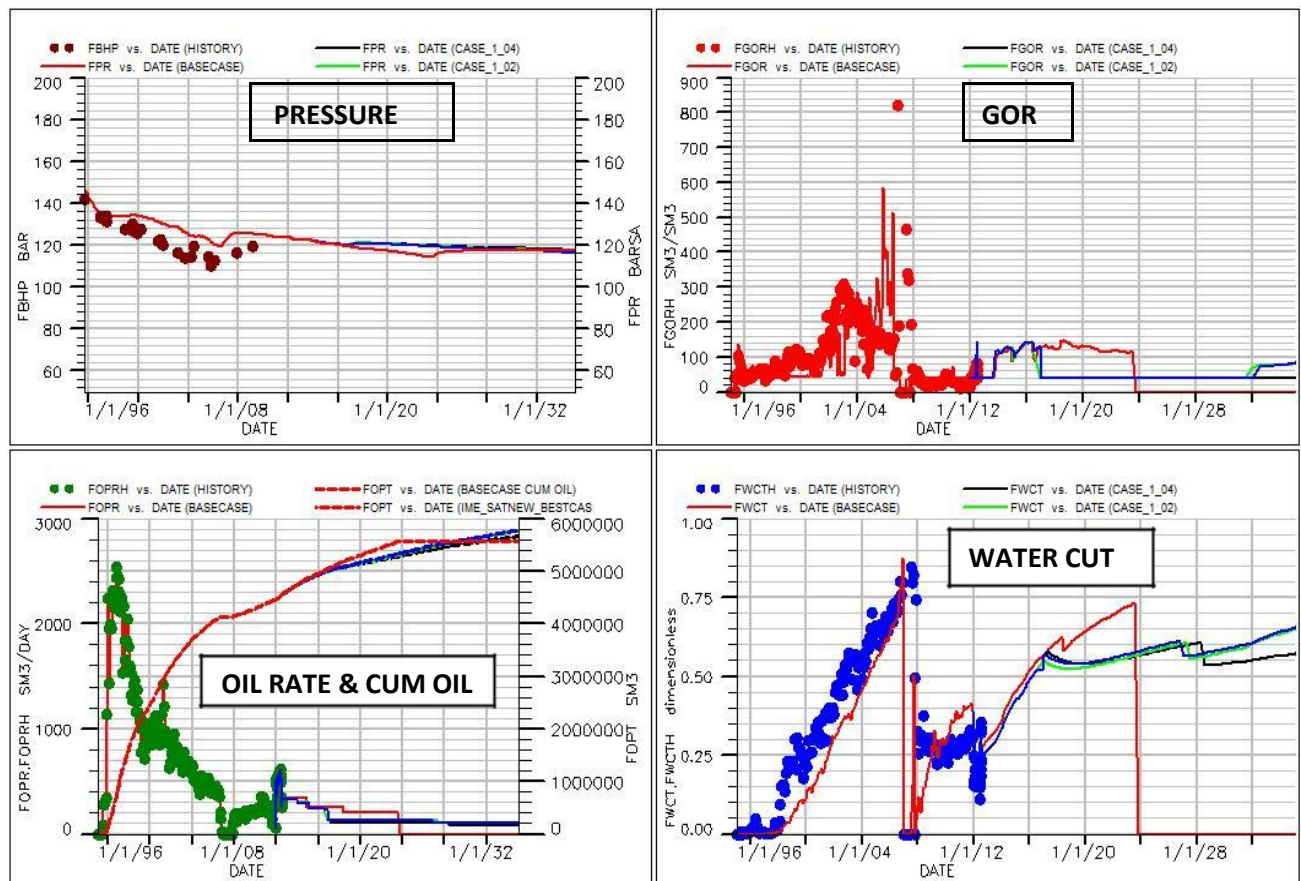
Figure 33: Field performance plots for base case sensitivity analysis for the different rates.
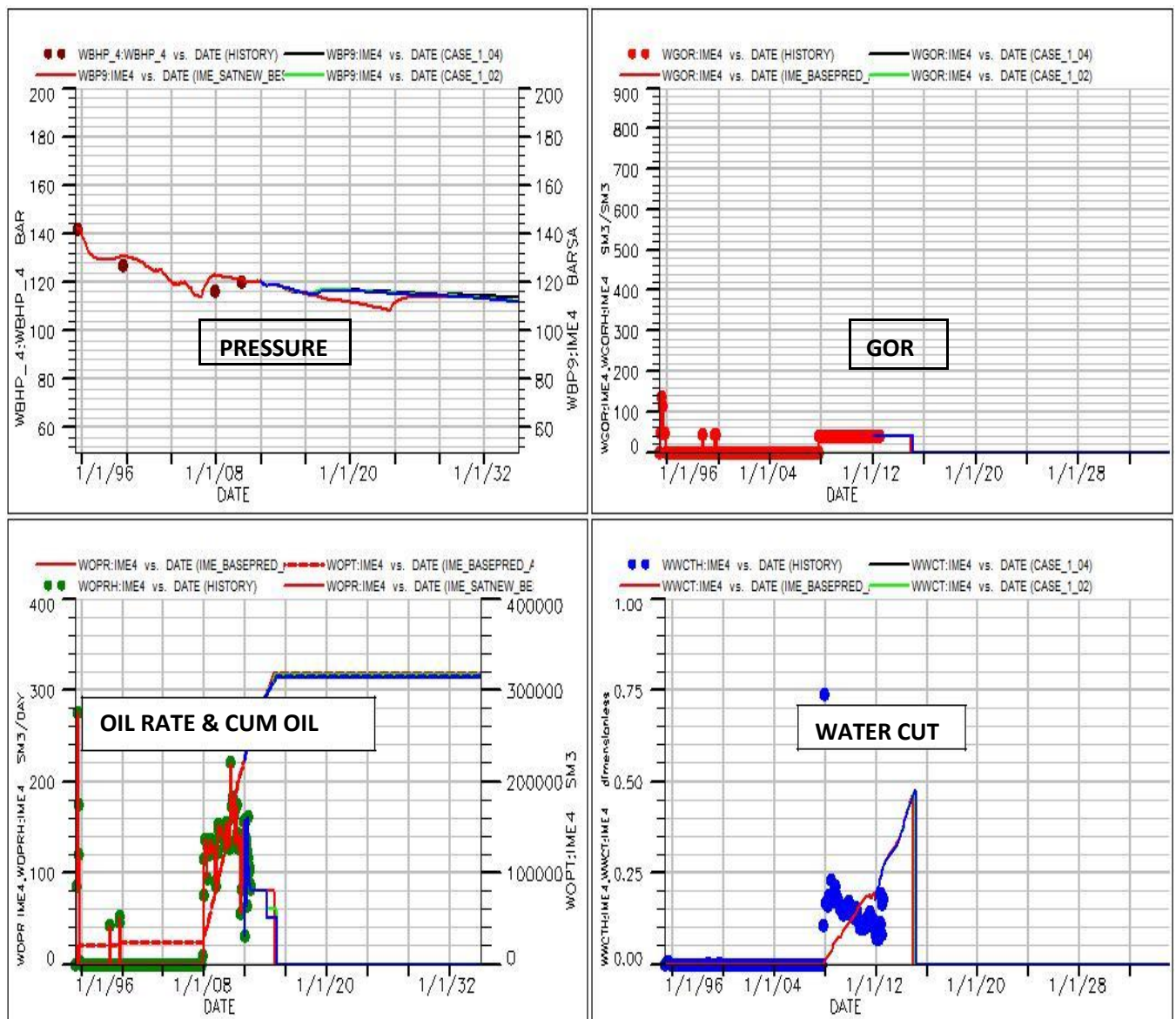
Figure 34: Well IME-4 performance plots for base case sensitivity analysis for the different
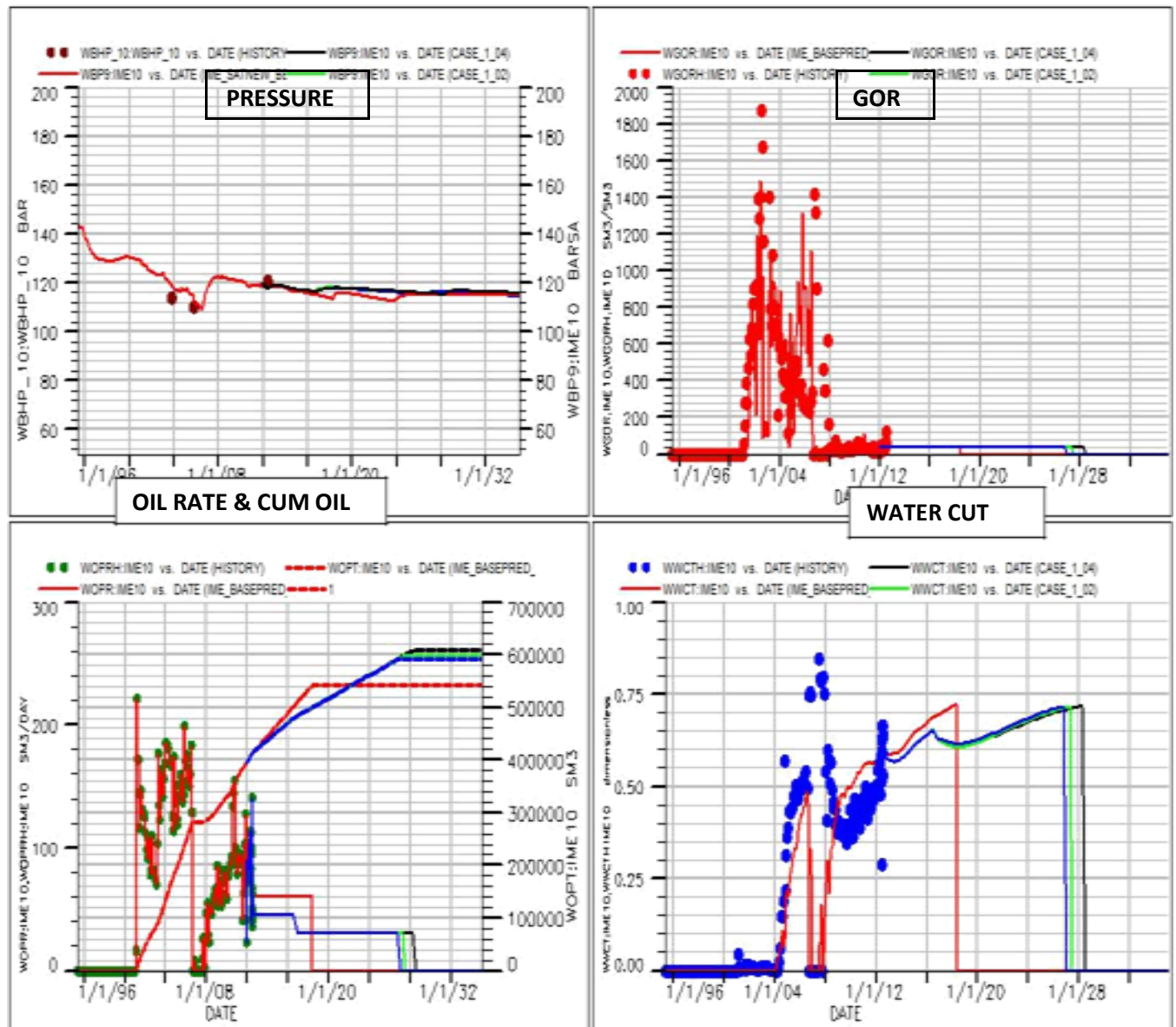
rates

Figure 35: Well IME-10 performance plots for base case sensitivity analysis for the different rates
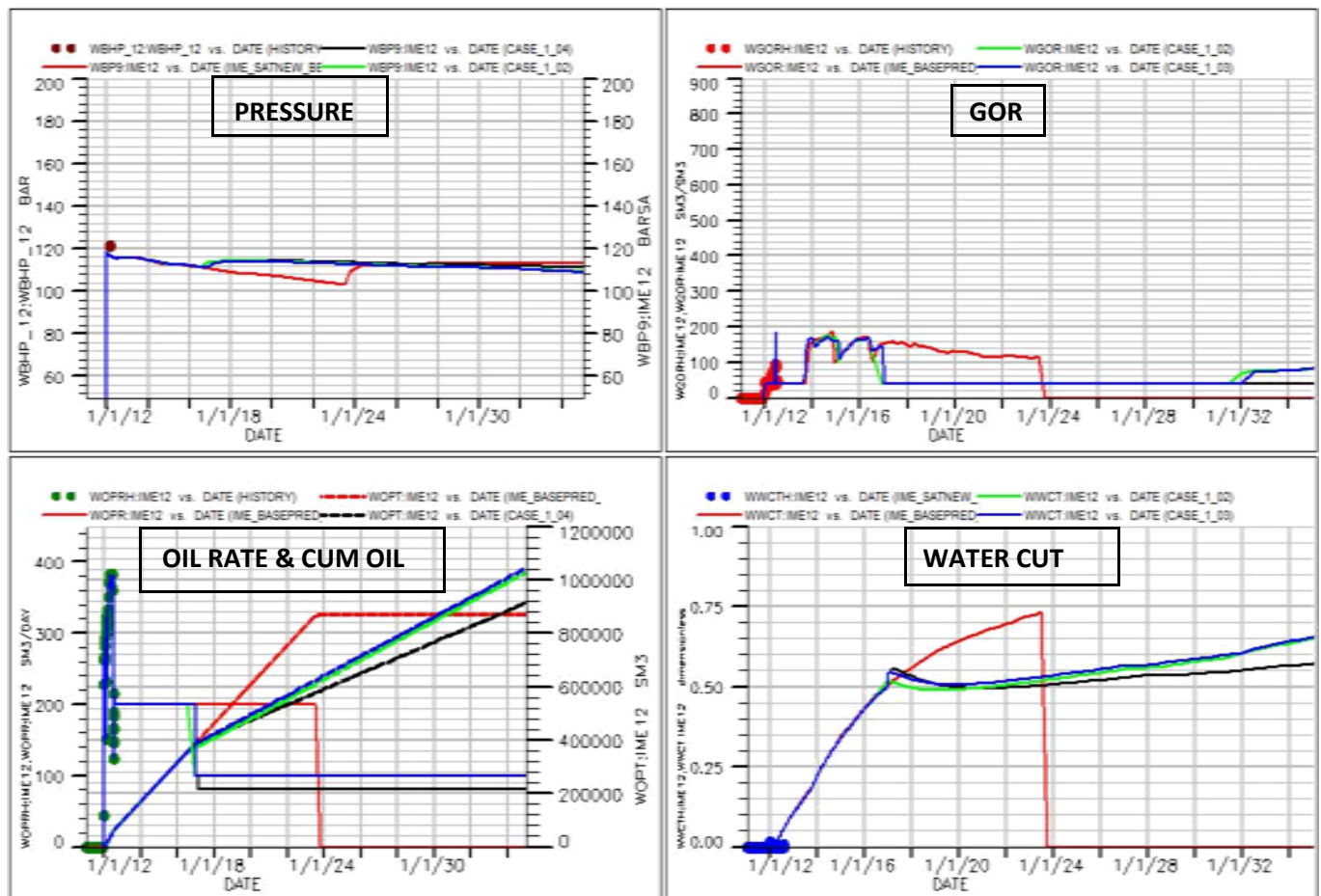
Figure 36: Well IME-12 performance plots for base case sensitivity analysis for the different oil rates

4.2. CASE 2 (WORKOVER CASE)

The development case (Case 2) involved carrying out workover operations on wells based on their completion's water production exceeding specified water cut limits. The essence of this case was to reduce the hydrostatic column in the well by reducing the water produced which will in turn decrease the rate of decline of the tubing head pressure. Each well's perforations, comprising of a group of layer connections, were grouped into lumped completions on the basis of their water cut prior to the prediction. The high water producing connections were lumped into one connection and shut-in while the relatively low water cut producing connections were grouped into another. The results for the prediction runs showing field pressure, GOR, oil production rate, cumulative production and water cut for the field are shown below.
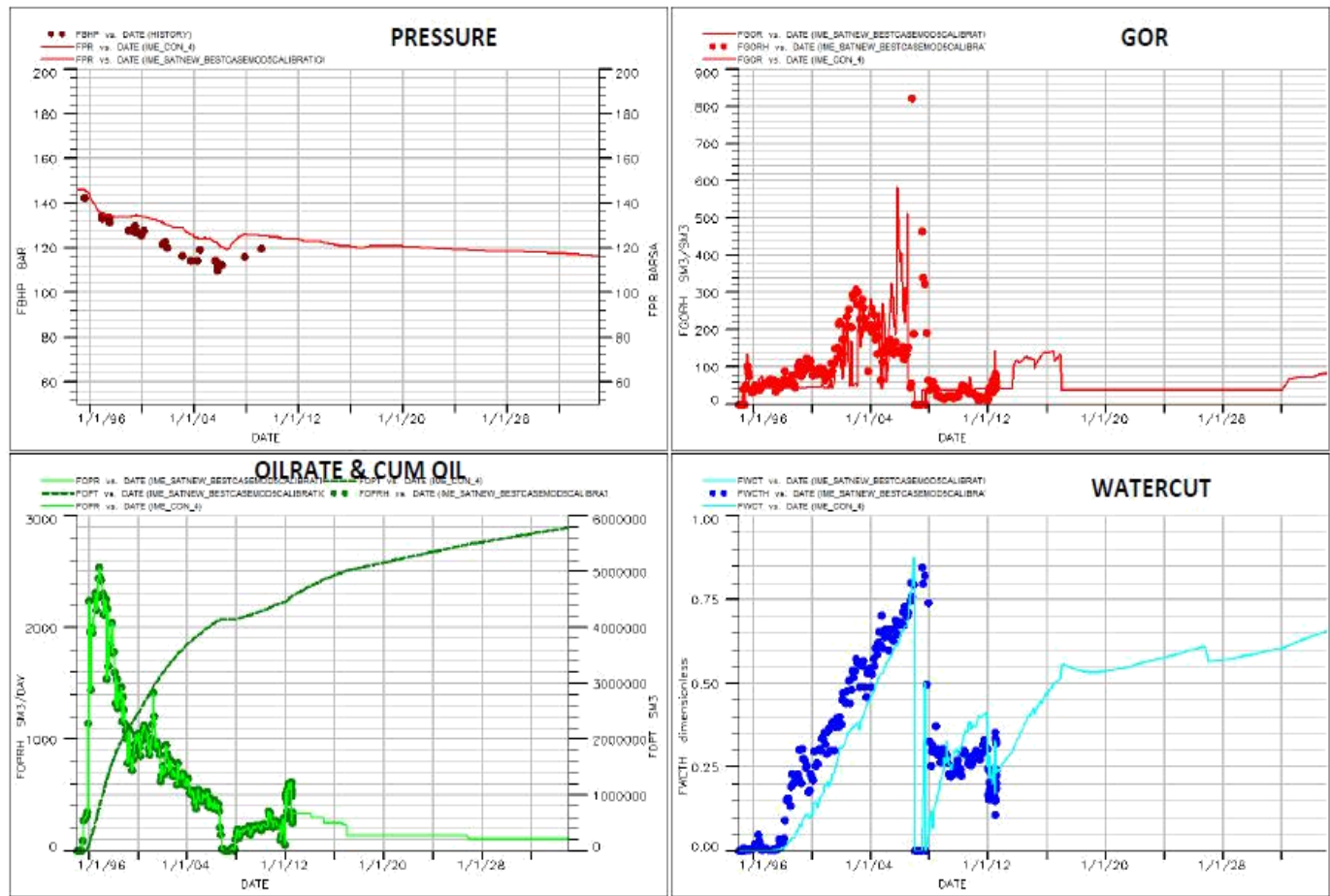
Figure 37: Field performance plots for Case 2 (Workover Case) showing pressure, GOR, oil rate, cumulative oil production and water cut

4.3. CASE 3 (WELL IME-4 GAS LIFT)

In field development Case 3, IME-04 well was produced with gas-lift at an optimal gas injection rate of 8500sm^3/day. This optimal gas lift injection rate was derived from sensitivity runs using injection rates of 3000sm^3/day, 5000sm^3/day, 8500sm^3/day and 11000sm^3/day. The result for the simulation runs showing the pressure, GOR, production rate, cumulative production and water cut for the field and wells are shown below.
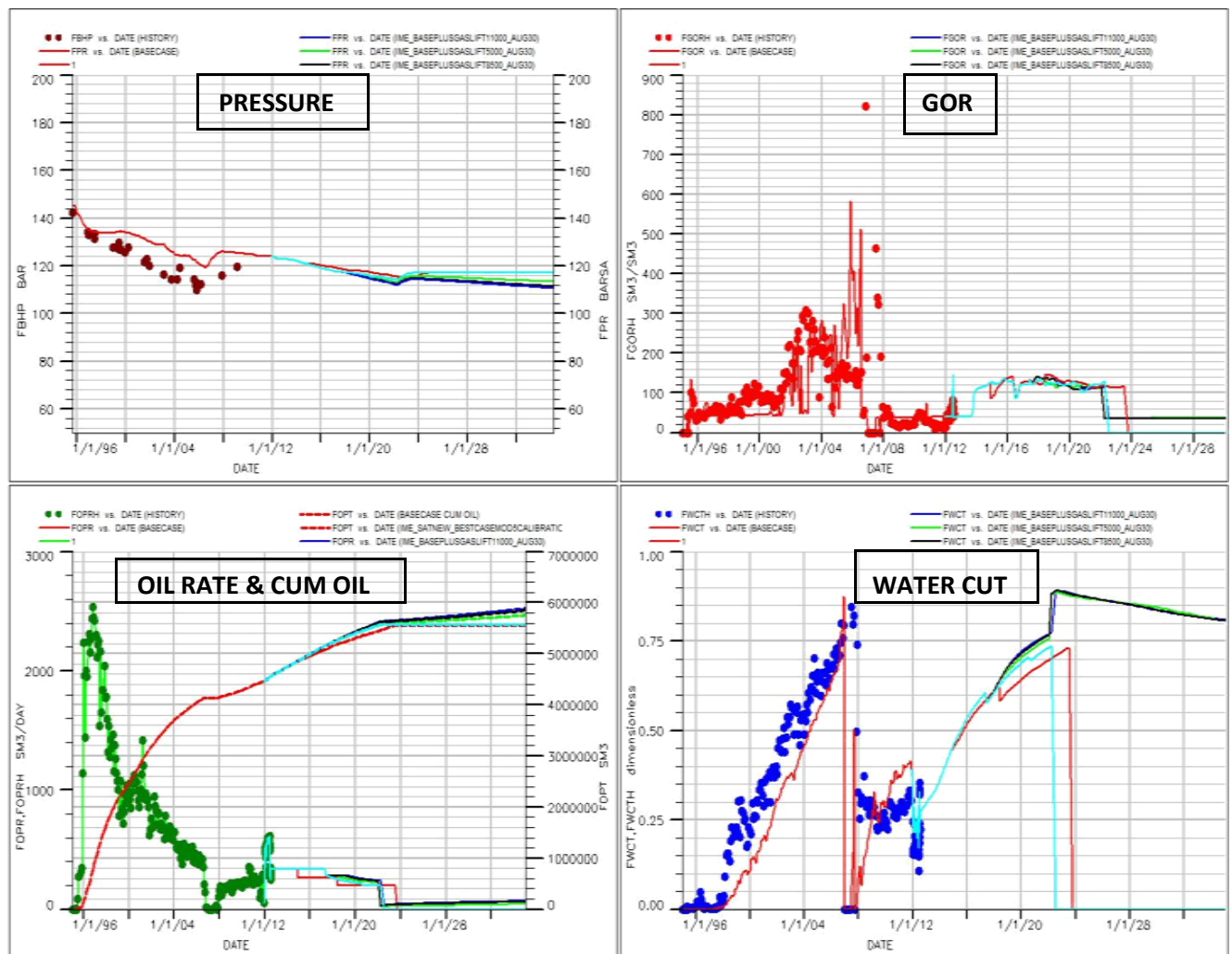
Figure 38: Field performance plots comparing different gas lift rates for well IME-4 (Case 3)
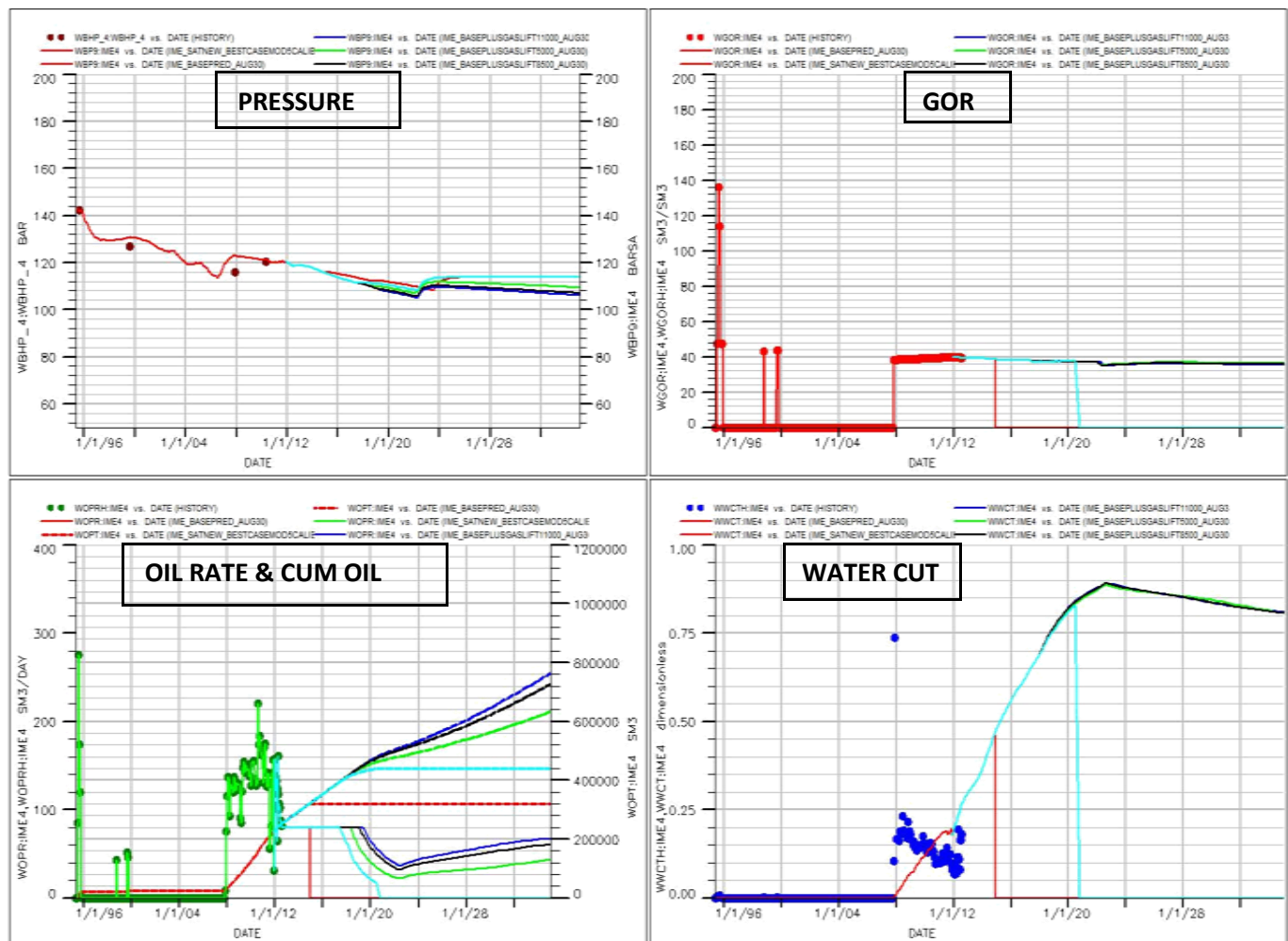
Figure 39: Well IME-4 performance plots showing the effect of the different gas lift rates (Case 3)
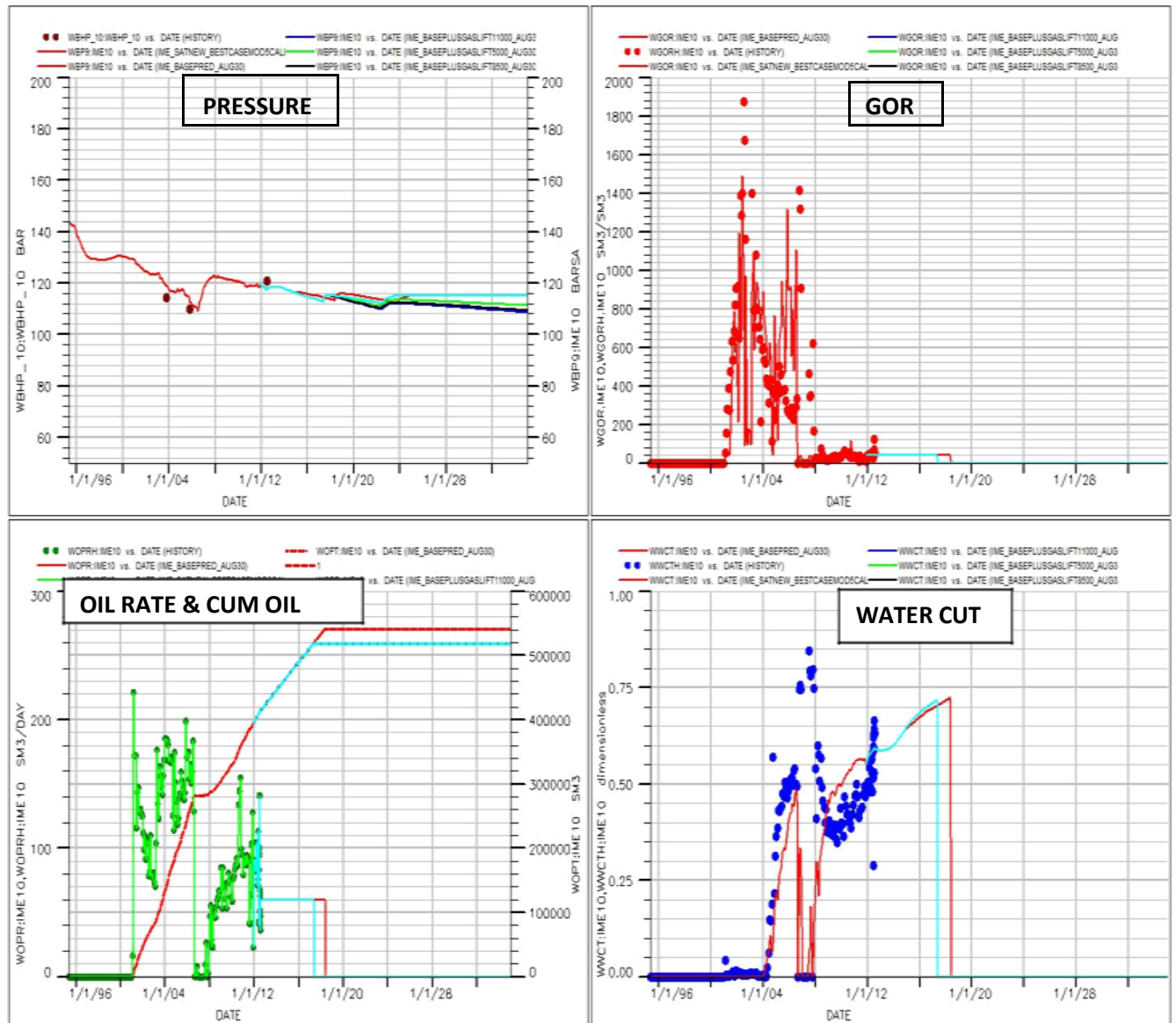
Figure 40: Well IME-10 performance plots showing the effect of the different gas lift rates on well IME-4 (Case 3)
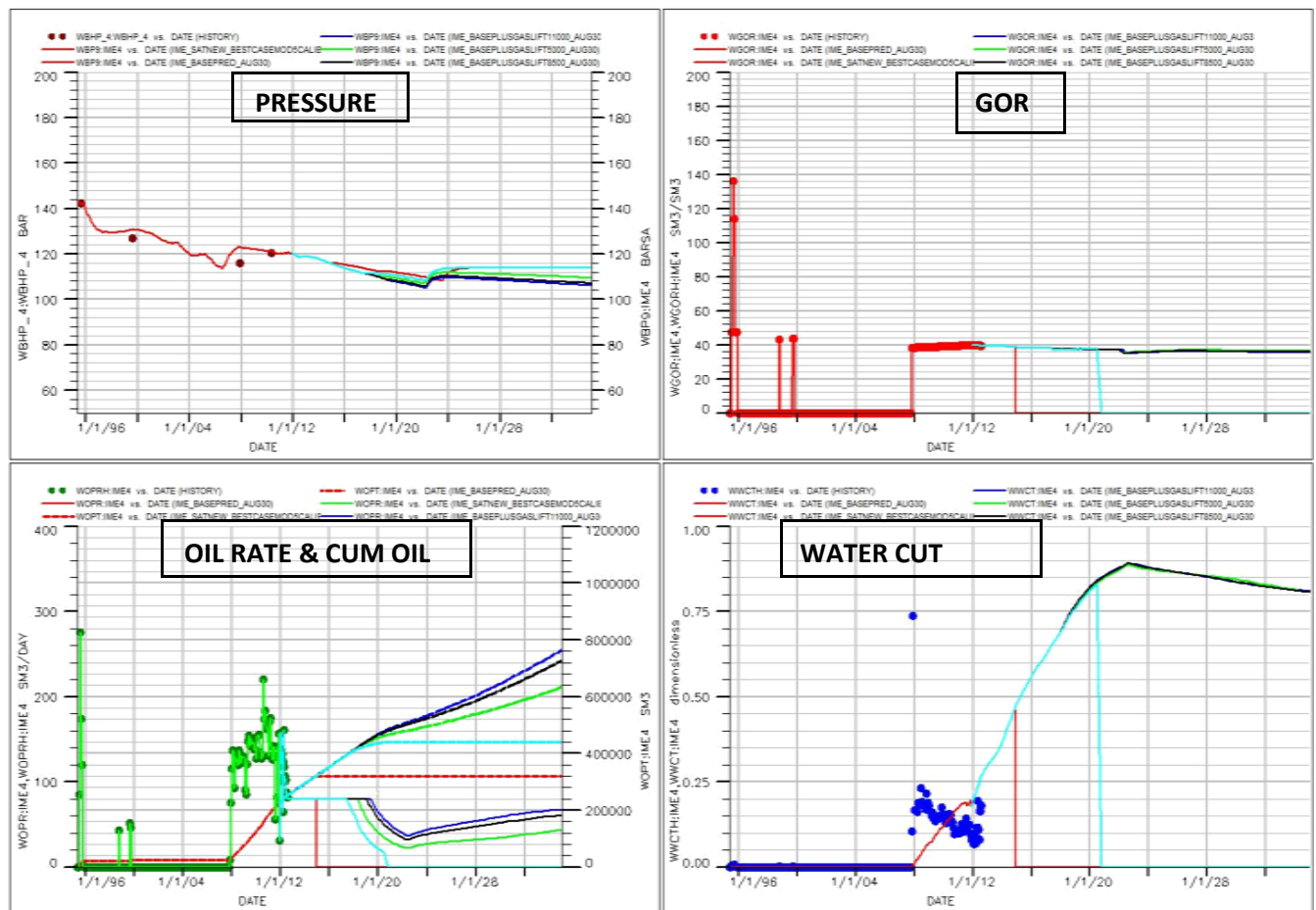
Figure 41: Well IME-12 performance plots showing the effect of the different gas lift rates on well IME-4 (Case 3)

Gas lift rate of 8500sm^3/day was used as the optimum injection rate. This is because the difference in cumulative recovery between 8500sm^3/day and 11000sm^3/day was very small. The result for the simulation runs using the gas lift rate of 8500sm^3/day showing pressure, GOR, oil production rate, cumulative production and water cut for the field is shown below.
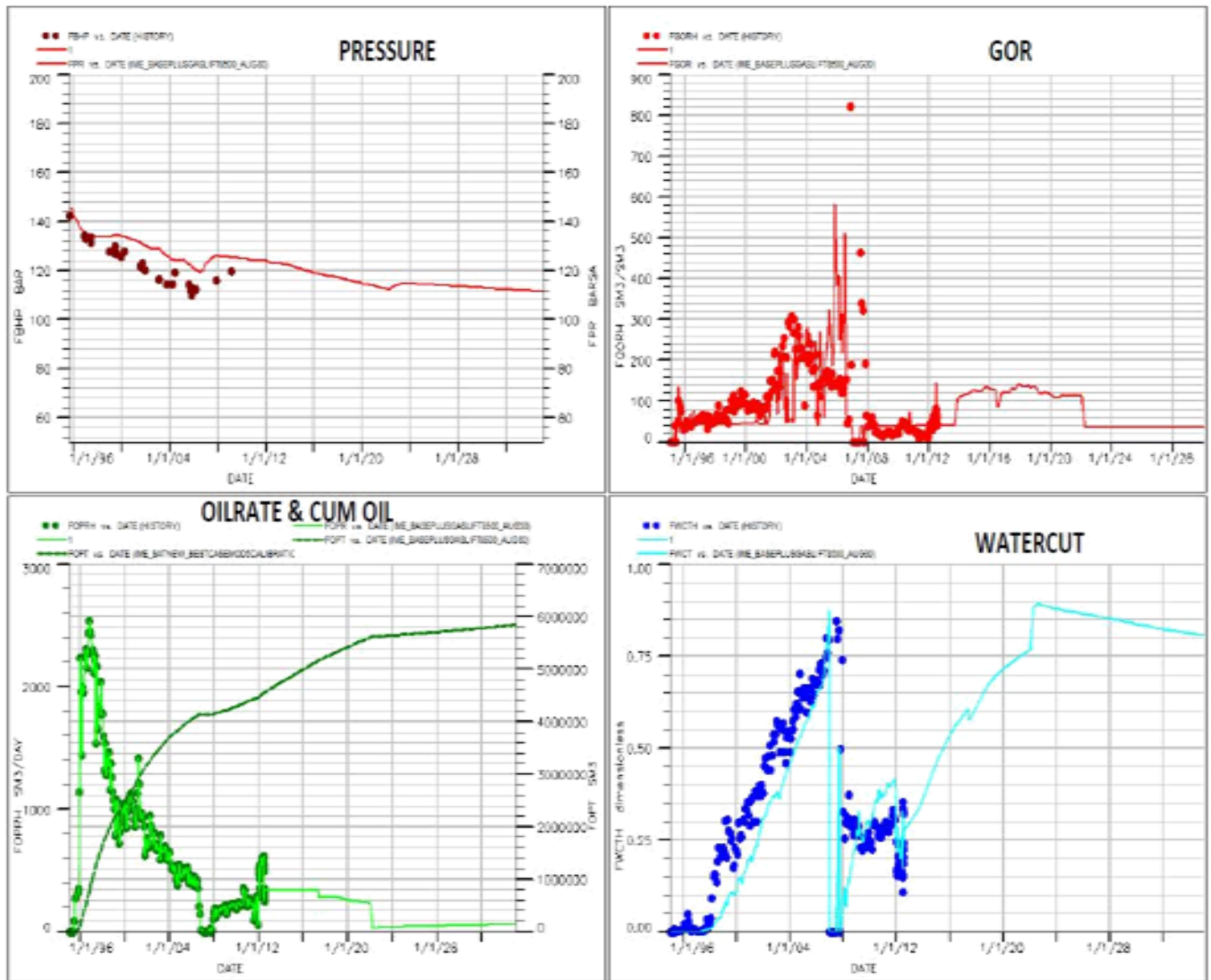
Figure 42: Field performance plots using the optimum gas lift rate of 8500sm^3/day for well IME-4 (Case 3)

The plots above shows that using a gas lift rate of 8500sm^3/day, a cumulative oil of about 5.86MMsm^3 will be recovered from the start of history to the end of prediction (2035) and more oil can still be recovered with time as the reservoir pressure is still high and oil rate is fairly constant but low. Water cut gradually increased during the early phase of prediction and gradually drops this is possible because of the reduction in flow rate in other to increase oil production.

4.4. CASE 4 (WELL IME-4 SIDE TRACK + GAS LIFT)

The results of the Base Case show that the IME-4 well shuts barely two years into the prediction phase. A review of the oil saturation maps (Hu*PHI*So) indicated that the area surrounding the IME-04 well has some by-passed oil; it is not fully drained after two years of

oil production past the end of the history match. A side track from IME-04 to target the un-drained pool of oil around the original well was considered as the field development Case 4. Different well orientations of the IME-04 side track were evaluated in this study to optimize the well placement as shown in the figure 43 below.
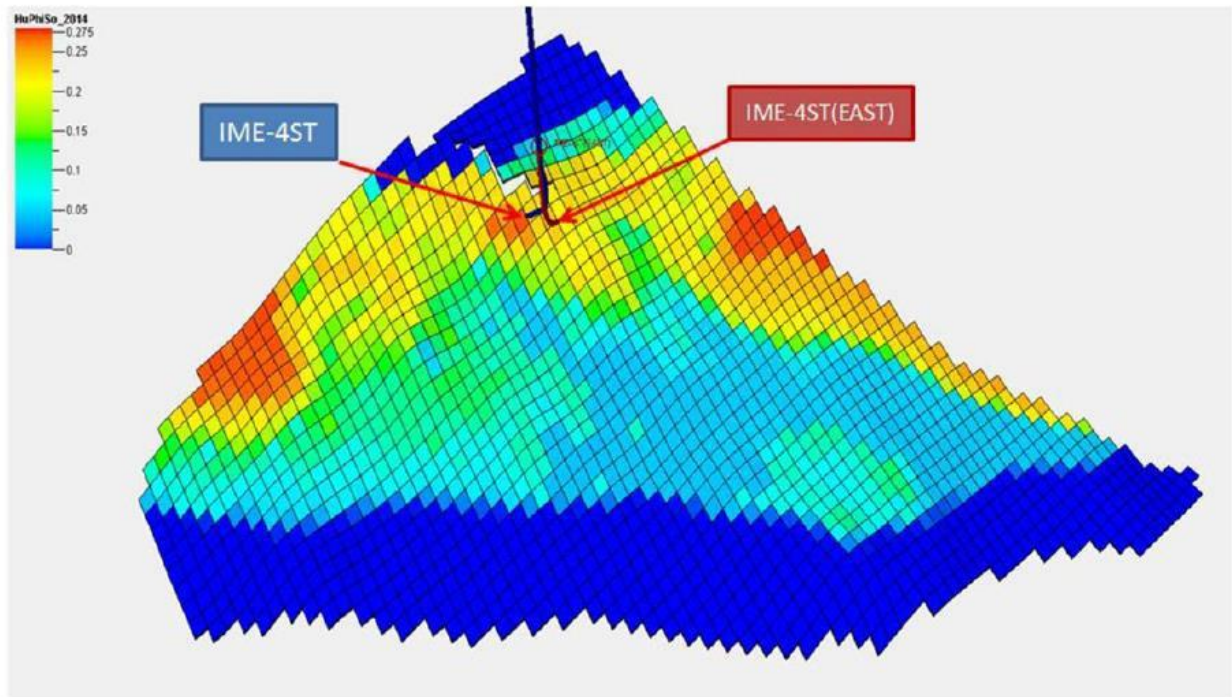
Figure 43: Saturation map showing saturations and different likely orientation of the side track.
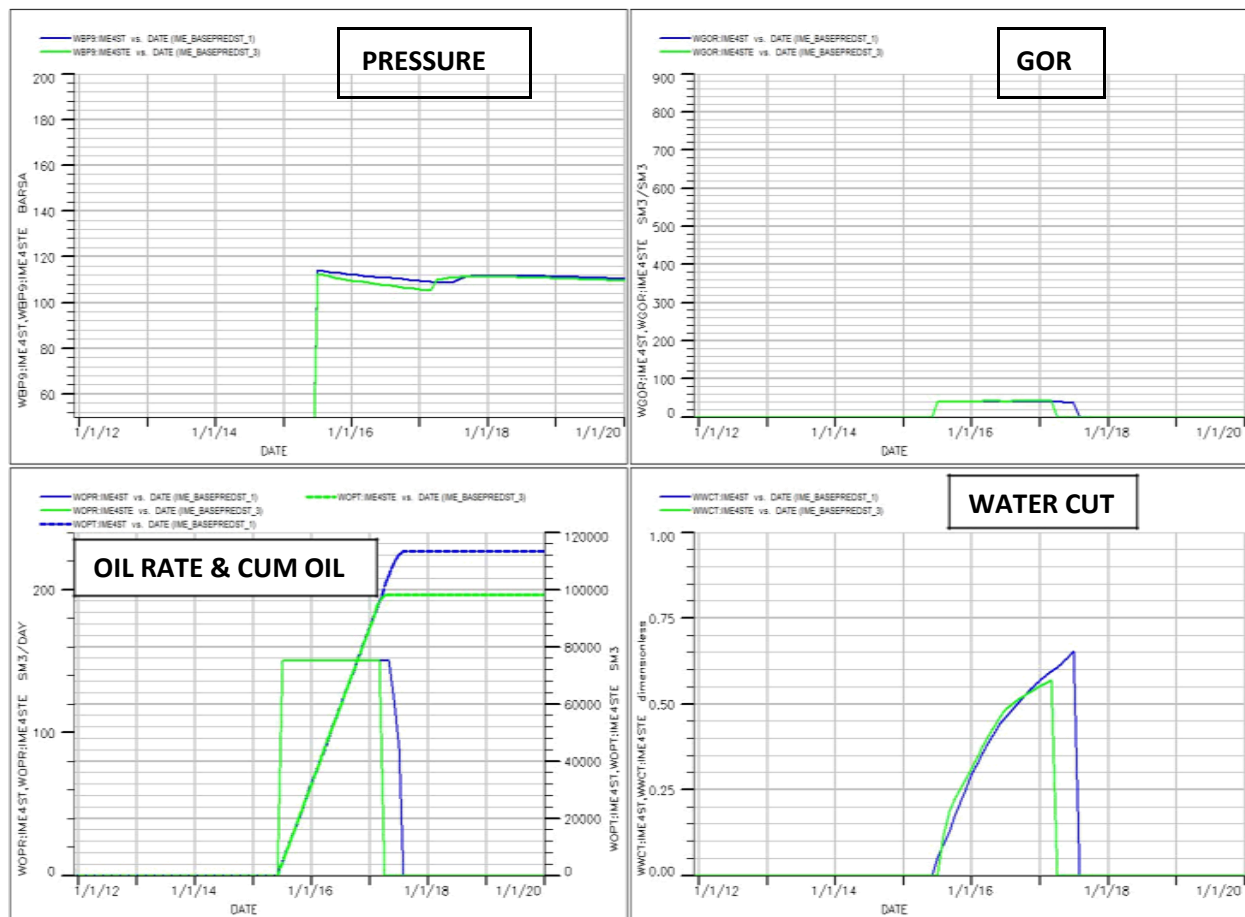
Figure 44: Performance plots of the different Well IME-4 side track orientations + gas lift

From the figures 43 and 44 above, the best orientation is IME-4ST. The placement of the side track was as a result of the location of the sweet spot which was captured in the saturation map. The side track was then equipped with gas lift to assist production. The results for the prediction runs showed that recovery was higher for side track IME-4ST than IME-4ST (EAST) for the same period of time which confirms what is shown on the saturation map that IME-4ST has an approximate saturation of 0.25 while IME-4ST (EAST) has an approximate saturation of 0.2.
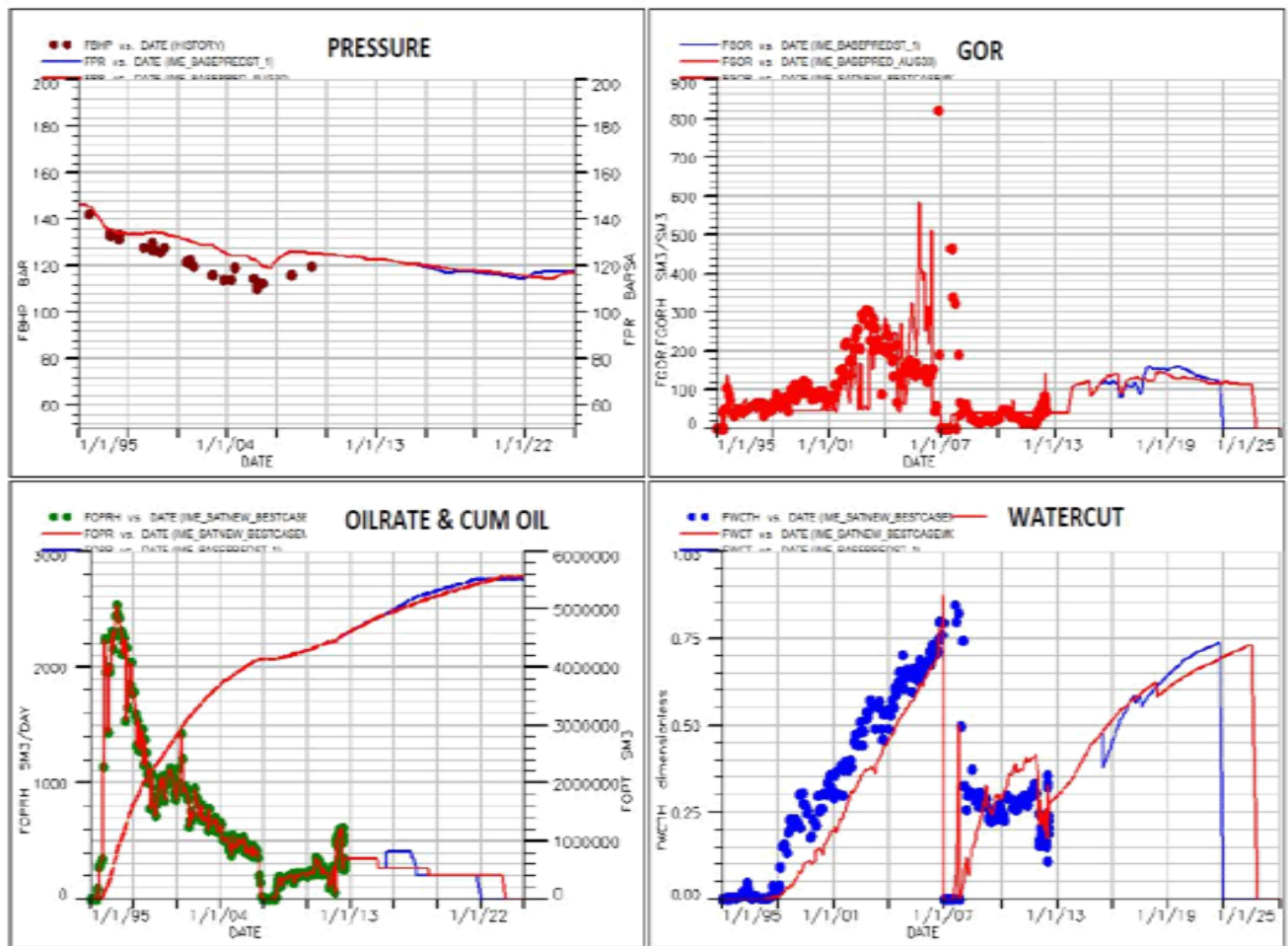
Figure 45: Field performance plots using the optimum side track orientation (IME-4ST) for Case 4

4.5. DISCUSSIONS

From the prediction runs for all the cases (Case 1 to Case 4), it is observed that the reservoir stopped producing earlier for case one (1) than for any other case. Cases two (2) to four (4) shows that the field was still producing as at 2035 which was the end of simulation time. Installation of gas lift on well IME-4 with side track (Case 3) gave the highest recovery of forty-four percent (44%) with cumulative oil produced to be $6.03MMsm^3$ while the gas lift of well IME-4 (Case 3) and carrying out work over operations on all wells (Case 2) both gave a recovery of forty-three percent (43%) with cumulative production of $5.86MMsm^3$ and $5.80MMsm^3$ respectively within the simulation period.

In other to select the best method to produce the field, different factors are considered. These factors include the overall recovery efficiency and the cost of carrying out each operation.

In the study, Case 2 which is work over of three producing wells is the recommended reservoir development case. This case provided $0.24MMsm^3$ of incremental oil recovery

(reserves) from the reservoir with the field producing longer than 2035. It is noted that all the wells get shut-in by 2023 for the Base Case. Although equipping IME-04 well with gas lift or drilling IME-04 side track yielded slightly higher incremental recovery than Case 2 (workover existing wells), the costs of installing gas lift equipment or drilling a side track are too high to justify these two reservoir development plans. The table below shows a summary of the results obtained from the prediction forecast for all the cases.

Cases	Prediction	Cumulative oil recovery (MMsm^3)	Incremental recovery over base case (MMsm^3)	Recovery factor (%)	Comments
Case 1	Base case (Do nothing case)	5.56	-	41	Production stops in 2023
Case 2	Work over Case	5.80	0.24	43	Still producing as at 2035
Case 3	Well IME-4 Gas lift	5.86	0.30	43	Still producing as at 2035
Case 4	Well IME-4 Side track + Gas lift	6.03	0.47	44	Still producing as at 2035

Table 7: Summary of results

CHAPTER 5

5.0. CONCLUSION AND RECOMMENDATIONS

5.1. CONCLUSION

There are different methods of maximizing field recovery. The methods range from operations that can boost primary recovery to secondary and tertiary recovery operations. This work focused on those field development scenarios that can be used to boost primary recovery which include carrying out workover operations, gas lifting producing wells or drilling infill wells to help recover by-passed oil.

From results obtained, it can be concluded that all the field development scenarios carried out in this study can be used to improve (maximise) recovery of an old field. And in other to determine the best case scenario in real life operation, the economics and profitability of each scenario has to be taken in to consideration.

5.2. RECOMMENDATIONS

Further study to determine the best secondary or tertiary recovery method that can be used to recover more oil from the field with time, it is noted that the field has a strong water drive which will always be very active. Therefore, water injection cannot be used as a method to increase oil recovery. Hence other enhanced oil recovery methods would have to be considered; knowing that after a period of time because of changes in reservoir conditions and properties those operations used to boost primary recovery would no longer be favourable.

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APPENDICES

APPENDIX A
HISTORY MATCH DATA

IME_SATNEW_BESTCASEMOD5CALIBRATION_AUG14_4.data

RUNSPEC

TITLE

--IME FIELD

METRIC

OIL

GAS

WATER

DISGAS

METRIC

SAVE

/

--MEMORY

--500 500 /

DIMENS

74 69 21/

EQLDIMS

--nregs #d Pnodes #d RVnodes

   1 4* /

ENDSCALE

/

SMRYDIMS

50000000 /

FAULTDIM

         250 /

SATOPTS

HYSTER /

TABDIMS

--ntsfun ntpvt nssfun nppvt ntfip nrpvt nrpvt ntendp   pmaint

 8   1   200   50 9 50   50   1   /

REGDIMS

--ntfip #sets

1 1 3*   /

WELLDIMS

--maxw conW grup wlG stg strm

  35   100   100   100 /

VFPPDIMS

 20 10 10 10 1 3 /

ACTDIMS

  10 /

AQUDIMS

0 0 15 100 6 1000000

/

NSTACK

 100 /

UNIFIN

```
UNIFOUT


--OPTIONS

--73* 1/



--NOSIM

--NOWARN



START

 1 'JAN' 1995 /



------------------------------------------------------------------------

GRID

--      THIS SECTION SPECIFIES THE GEOMETRY OF THE i X j X k GRID, AND

--      SETS THE ROCK POROSITIES AND PERMEABILITIES.

------------------------------------------------------------------------

INIT

--
NOECHO



--

--

GRIDFILE

 2 1 /
```

--MINPORV

--200 /

PINCH

/

INCLUDE

D70GRID.grdecl /

INCLUDE

PHIE.grdecl /

INCLUDE

PERMX.grdecl /

INCLUDE

PERMY.grdecl /

INCLUDE

PERMZ.GRDECL /

/

INCLUDE

FAULT_MOD6.GRDECL /

/

MULTFLT

FAULT2 0.8 /

FAULT3 0.07 /

/

INCLUDE

NTG.GRDECL /

/

MULTIPLY

PERMZ 0.5 /

/

RPTGRID

PORV ROCKVOL /

EDIT

INCLUDE

TRANX.GRDECL /

/

INCLUDE

TRANY.GRDECL /

/

INCLUDE

TRANZ_6.GRDECL /

/

PROPS

--   THE PVT PROPERTIES AND ROCK-FLUID DATA.

INCLUDE

JULY242012_RUN1.INC   /

INCLUDE

SWCR.GRDECL /

/

MULTIPLY

SWCR 1.5 /

/

MAXVALUE

SWCR 0.99999 /

/

INCLUDE

IME_PVT_D70.txt /

INCLUDE

INFLUENCE_TABLES.INC /

EHYSTR

1* 2   /

FILLEPS

REGIONS

-- THERE ARE SEVEN FLUIDS-IN-PLACE REGIONS, SEPARATED BY VERTICAL IMPERMEABLE BARRIERS

--   ARRAY   VALUE   ------ BOX ------

EQUALS

   'FIPNUM'   1   1 74 1 69 1 21 /

/

EQUALS

   'EQLNUM'   1   1 74 1 69 1 21 /

/

EQUALS

   'PVTNUM'   1   1 74 1 69 1 21 /

/

INCLUDE

SATNUM.GRDECL /

COPY

SATNUM IMBNUM/

/

ADD

IMBNUM 4   /

/

SOLUTION

RESTART

IME_SATNEW_BESTCASEMODAUG2NEW_5 200 /

/

RPTSOL

 'FIP=3' 'RESTART=1' 'FIPRESV' AQUANCON=2 /

RPTRST

 BASIC=3 FIP=1 PCOW PORV 'CONV=50' /

SUMMARY

RPTONLY

RPTSMRY

  0 /

COPR

'*' /

/

COPT

'*' /

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/

COPP

'*' /

/

CWFR

'*' /

/

CWPR

'*' /

/

CWPT

'*' /

/

CWPP

'*' /

/

CGPR

'*' /

/

CGPT

'*' /

/

CLFR

'*' /

/

CWCT

'*' /

/

CGOR

'*' /

/

CPR

'*' /

/

CPI

'*' /

/

FOE

FPR

FOPR

FOPRH

FGPR

FWPR

FWPH

FWCT

FWCTH

FGOR

FGORH

FWIT

FWITH

FOPT

FOPTH

FWPT

FWPTH

FVPR

FLPT

FLPTH

FLPR

FGPT

FGPTH

TCPU

ROIP

/

RPR

/

ROPR

/

RGPR

/

RWIR

/

ROIR

/

ROIT

/

RWIT

/

RWFT

/

FMWIV

FAQR

FAQT

FPPC

FRPV

FWPV

FVPT

FVIT

ROE

/

WOPR

/

WOPRH

/

WGOR

/

WGORH

/

WWCT

/

WWCTH

/

WOPT

/

WOPTH

/

WGPT

/

WGPTH

/

WWPR

/

WWPRH

/

WWPT

/

WWPTH

/

WWIT

/

WWIR

/

WOIR

/

WOIRH

/

WOIT

/

WOITH

/

WWIRH

/

WBHP

/

WBP

/

WBP4

/

WBP9

/

WTHP

/

GOPR

/

GOPRH

/

GGPR

/

GGPRH

/

GGOR

/

GGORH

/

GWPR

/

GWCT

/

GWCTH

/

GOPT

/

GOPTH

/

GGPT

/

GGPTH

/

GWPT

/

GWPTH

/

GWIT

/

CVPT

/

CVFR

/

CVIT

/

WLPR

/

WTHPH

/

SCHEDULE

SKIPREST

MESSAGES

2* 10000 10000 4* 10000 10000 /

TUNING

/

/

2* 100 /

DRSDT

0.001

/

WHISTCTL

ORAT/

MATCORR

/

RPTSCHED

'MULT' 'WOC' 'GOC' 'VFPPROD' /

INCLUDE

IME_04_5_250412.ECL /

/

INCLUDE

IME_10_5_260412.ECL /

/

INCLUDE

IME_12_D70_180512.ECL /

/

INCLUDE

IME_AUG5_2.SCH /

END

PREDICTION DATA

CASE 1 (BASE CASE) PREDICTION DATA

RUNSPEC

TITLE

--IME FIELD

METRIC

OIL

GAS

WATER

DISGAS

METRIC

SAVE

/

--MEMORY

--500 500 /

DIMENS

74 69 21/

EQLDIMS

--nregs #d Pnodes #d RVnodes

  1 4* /

ENDSCALE

/

SMRYDIMS

50000000 /

FAULTDIM

          250 /

SATOPTS

HYSTER /

TABDIMS

--ntsfun ntpvt nssfun nppvt ntfip nrpvt nrpvt ntendp   pmaint

 8   1   200 50 9 50   50 1   /

REGDIMS

--ntfip #sets

1 1 3*   /

WELLDIMS

--maxw conW grup wlG stg strm

 35   100   100   100 /

VFPPDIMS

 20 10 10 10 10 3 /

ACTDIMS

  10 /

AQUDIMS

0 0 15 100 6 1000000

/

NSTACK

 100 /

UNIFIN

UNIFOUT

--OPTIONS

--73* 1/

--NOSIM

--NOWARN

START

 1 'JAN' 1995 /

GRID

--   THIS SECTION SPECIFIES THE GEOMETRY OF THE i X j X k GRID, AND

--   SETS THE ROCK POROSITIES AND PERMEABILITIES.

INIT

--
NOECHO

--

--

GRIDFILE

 2 1 /

--MINPORV

--200 /

PINCH

/

INCLUDE

D70GRID.grdecl /

INCLUDE

PHIE.grdecl /

INCLUDE

PERMX.grdecl /

INCLUDE

PERMY.grdecl /

INCLUDE

PERMZ.GRDECL /

/

INCLUDE

FAULT_MOD6.GRDECL /

/

MULTFLT

FAULT2 0.8 /

FAULT3 0.07 /

/

INCLUDE

NTG.GRDECL /

/

MULTIPLY

PERMZ 0.5 /

/

RPTGRID

PORV ROCKVOL /

EDIT

INCLUDE

TRANX.GRDECL /

/

INCLUDE

TRANY.GRDECL /

/

INCLUDE

TRANZ_6.GRDECL /

/

PROPS

--   THE PVT PROPERTIES AND ROCK-FLUID DATA.

INCLUDE

JULY242012_RUN1.INC   /

INCLUDE

SWCR.GRDECL /

/

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

MULTIPLY

SWCR 1.5 /

/

MAXVALUE

SWCR 0.99999 /

/

INCLUDE

IME_PVT_D70.txt /

INCLUDE

INFLUENCE_TABLES.INC /

EHYSTR

1* 2   /

History

FILLEPS

REGIONS

-- THERE ARE SEVEN FLUIDS-IN-PLACE REGIONS, SEPARATED BY VERTICAL IMPERMEABLE BARRIERS

--   ARRAY   VALUE   ------ BOX ------

EQUALS

   'FIPNUM'   1   1 74 1 69   1   21 /

/

EQUALS

   'EQLNUM'   1   1 74 1 69   1 21 /

/

EQUALS

   'PVTNUM'   1   1 74 1 69   1   21 /

/

INCLUDE

SATNUM.GRDECL /

COPY

SATNUM IMBNUM/

/

ADD

IMBNUM 4   /

/

SOLUTION

RESTART

Esther_Odiki_Calibration 200 /

/

RPTSOL

  'FIP=3' 'RESTART=1' 'FIPRESV' AQUANCON=2 /

RPTRST

 BASIC=3 FIP=1 PCOW PORV 'CONV=50' /

SUMMARY

RPTONLY

RPTSMRY

  0 /

COPR

'*' /

/

COPT

'*' /

/

COPP

'*' /

/

CWFR

'*' /

/

CWPR

'*' /

/

CWPT

'*' /

/

CWPP

'*' /

/

CGPR

'*' /

/

CGPT

 '*' /

/

CLFR

'*' /

/

CWCT

'*' /

/

CGOR

'*' /

/

CPR

'*' /

/

CPI

'*' /

/

FOE

FPR

FOPR

FOPRH

FGPR

FWPR

FWPH

FWCT

FWCTH

FGOR

FGORH

FWIT

FWITH

FOPT

FOPTH

FWPT

FWPTH

FVPR

FLPT

FLPTH

FLPR

FGPT

FGPTH

TCPU

ROIP

/

RPR

/

ROPR

/

RGPR

/

RWIR

/

ROIR

/

ROIT

/

RWIT

/

RWFT

/

FMWIV

FAQR

FAQT

FPPC

FRPV

FWPV

FVPT

FVIT

ROE

/

WOPR

/

WOPRH

/

WGOR

/

WGORH

/

WWCT

/

WWCTH

/

WOPT

/

WOPTH

/

WGPT

/

WGPTH

/

WWPR

/

WWPRH

/

WWPT

/

WWPTH

/

WWIT

/

WWIR

/

WOIR

/

WOIRH

/

WOIT

/

WOITH

/

WWIRH

/

WBHP

/

WBP

/

WBP4

/

WBP9

/

WTHP

/

GOPR

/

GOPRH

/

GGPR

/

GGPRH

/

GGOR

/

GGORH

/

GWPR

/

GWCT

/

GWCTH

/

GOPT

/

GOPTH

/

GGPT

/

GGPTH

/

GWPT

/

GWPTH

/

GWIT

/

CVPT

/

CVFR

/

CVIT

/

WLPR

/

WTHPH

/

SCHEDULE

SKIPREST

MESSAGES

 2* 10000 10000 4* 10000 10000 /

TUNING

 /

 /

 2* 100 /

DRSDT

 0.001

/

WHISTCTL

ORAT/

MATCORR

/

RPTSCHED

'MULT' 'WOC' 'GOC' 'VFPPROD' /

INCLUDE

IME_04_5_25041201.ECL /

/

INCLUDE

IME_10_5_260412.ECL /

/

INCLUDE

IME_12_D70_180512.ECL /

/

INCLUDE

Esther_Odiki_Pred.SCH /

--GCONPROD

--GRUP0001   ORAT   340   /

--/

WCONPROD

 'IME4' 'OPEN' 'THP' 80 5* 3 1   /

 'IME10' 'OPEN' 'THP' 60 5* 3 2 /

 'IME12' 'OPEN' 'THP' 200 5* 3 3 /

/

WECON

 'IME4' 15.9 1* 0.9 150 1* /

'IME10' 15.9 1* 0.9 400 1*   /

'IME12' 15.9 1* 0.9 400 1* /

/

WVFPEXP

IME4 EXP 1* YES1 /

/

DATES

1   AUG   2012   /

1   SEP   2012   /

1   OCT   2012   /

1   NOV 2012   /

1   DEC   2012   /

 1   JAN   2013 /

 1   FEB   2013 /

 1   MAR   2013 /

 1   APR   2013 /

 1   MAY   2013 /

 1   JUN   2013 /

 1   JUL   2013 /

 1   AUG   2013 /

 1   SEP   2013 /

1   OCT   2013   /

1   NOV 2013   /

1   DEC   2013   /

1	JAN	2014	/
1	FEB	2014	/
1	MAR	2014	/
1	APR	2014	/
1	MAY	2014	/
1	JUN	2014	/
1	JUL	2014	/
1	AUG	2014	/
1	SEP	2014	/
1	OCT	2014	/
1	NOV	2014	/
1	DEC	2014	/
1	JAN	2015	/
1	FEB	2015	/
1	MAR	2015	/
1	APR	2015	/
1	MAY	2015	/
1	JUN	2015	/
1	JUL	2015	/
1	AUG	2015	/
1	SEP	2015	/
1	OCT	2015	/
1	NOV	2015	/
1	DEC	2015	/

1   JAN   2016 /

1   FEB   2016 /

1   MAR   2016 /

1   APR   2016 /

1   MAY   2016 /

1   JUN   2016 /

1   JUL   2016 /

1   AUG   2016 /

1   SEP   2016 /

1   OCT 2016 /

1   NOV 2016 /

1   DEC 2016 /

1   JAN   2017 /

1   FEB   2017 /

1   MAR   2017 /

1   APR   2017 /

1   MAY   2017 /

1   JUN   2017 /

1   JUL   2017 /

1   AUG   2017 /

1   SEP   2017 /

1   OCT 2017 /

1   NOV 2017 /

1   DEC 2017 /

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

1	JAN	2018	/
1	FEB	2018	/
1	MAR	2018	/
1	APR	2018	/
1	MAY	2018	/
1	JUN	2018	/
1	JUL	2018	/
1	AUG	2018	/
1	SEP	2018	/
1	OCT	2018	/
1	NOV	2018	/
1	DEC	2018	/
1	JAN	2019	/
1	FEB	2019	/
1	MAR	2019	/
1	APR	2019	/
1	MAY	2019	/
1	JUN	2019	/
1	JUL	2019	/
1	AUG	2019	/
1	SEP	2019	/
1	OCT	2019	/
1	NOV	2019	/
1	DEC	2019	/

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

1	JAN	2020	/
1	APR	2020	/
1	JUL	2020	/
1	OCT	2020	/
1	JAN	2021	/
1	APR	2021	/
1	JUL	2021	/
1	OCT	2021	/
1	JAN	2022	/
1	APR	2022	/
1	JUL	2022	/
1	OCT	2022	/
1	JAN	2023	/
1	APR	2023	/
1	JUL	2023	/
1	OCT	2023	/
1	JAN	2024	/
1	APR	2024	/
1	JUL	2024	/
1	OCT	2024	/
1	JAN	2025	/
1	APR	2025	/
1	JUL	2025	/
1	OCT	2025	/

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

1	JAN	2026	/
1	APR	2026	/
1	JUL	2026	/
1	OCT	2026	/
1	JAN	2027	/
1	APR	2027	/
1	JUL	2027	/
1	OCT	2027	/
1	JAN	2028	/
1	APR	2028	/
1	JUL	2028	/
1	OCT	2028	/
1	JAN	2029	/
1	APR	2029	/
1	JUL	2029	/
1	OCT	2029	/
1	JAN	2030	/
1	APR	2030	/
1	JUL	2030	/
1	OCT	2030	/
1	JAN	2031	/
1	JUL	2031	/
1	JAN	2032	/
1	JUL	2032	/

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

1   JAN   2033 /

1   JUL   2033 /

1   JAN   2034 /

1   JUL   2034 /

1   JAN   2035 /

1   JUL   2035 /

/

END

CASE 2 WELL INTERVENTION SIMULATION DATA

RUNSPEC

TITLE
--IME FIELD

METRIC

OIL

GAS

WATER

DISGAS

METRIC

SAVE

/

--MEMORY

--500 500 /

DIMENS

74 69 21/

EQLDIMS

--nregs #d Pnodes #d RVnodes

  1 4* /

ENDSCALE

/

SMRYDIMS

50000000 /

FAULTDIM

    250 /

SATOPTS

HYSTER /

TABDIMS

--ntsfun ntpvt nssfun nppvt ntfip nrpvt nrpvt ntendp   pmaint

 8   1   200   50 9 50   50   1   /

REGDIMS

--ntfip #sets

  1 1 3*   /

WELLDIMS

--maxw conW grup wlG stg strm

  35   100   100   100 /

VFPPDIMS

 20 10 10 10 10 3 /

ACTDIMS

  10 /

AQUDIMS

0 0 15 100 6 1000000

/

NSTACK

 100 /

UNIFIN

UNIFOUT

--OPTIONS

--73* 1/

--NOSIM

--NOWARN

START

 1 'JAN' 1995 /

GRID

--   THIS SECTION SPECIFIES THE GEOMETRY OF THE i X j X k GRID, AND

--   SETS THE ROCK POROSITIES AND PERMEABILITIES.

INIT

--
NOECHO

--

--

GRIDFILE

 2 1 /

--MINPORV

--200 /

PINCH

/

INCLUDE

D70GRID.grdecl /

INCLUDE

PHIE.grdecl /

INCLUDE

PERMX.grdecl /

INCLUDE

PERMY.grdecl /

INCLUDE

PERMZ.GRDECL /

/

INCLUDE

FAULT_MOD6.GRDECL /

/

MULTFLT

FAULT2   0.8   /

FAULT3   0.07   /

/

INCLUDE

NTG.GRDECL /

/

MULTIPLY

PERMZ 0.5 /

/

RPTGRID

PORV ROCKVOL /

EDIT

INCLUDE

TRANX.GRDECL /

/

INCLUDE

TRANY.GRDECL /

/

INCLUDE

TRANZ_6.GRDECL /

/

PROPS

--   THE PVT PROPERTIES AND ROCK-FLUID DATA.

INCLUDE

JULY242012_RUN1.INC   /

INCLUDE

SWCR.GRDECL /

/

MULTIPLY

SWCR 1.5 /

/

MAXVALUE

SWCR 0.99999 /

/

INCLUDE

IME_PVT_D70.txt /

INCLUDE

INFLUENCE_TABLES.INC /

EHYSTR

1* 2   /

FILLEPS

REGIONS

-- THERE ARE SEVEN FLUIDS-IN-PLACE REGIONS, SEPARATED BY
VERTICAL IMPERMEABLE BARRIERS

--   ARRAY   VALUE   ------ BOX ------

EQUALS

   'FIPNUM'   1   1 74 1 69   1   21 /

/

EQUALS

   'EQLNUM'   1   1 74 1 69   1   21 /

/

EQUALS

   'PVTNUM'   1   1 74 1 69   1   21 /

/

INCLUDE

SATNUM.GRDECL /

COPY

SATNUM IMBNUM/

/

ADD

IMBNUM 4   /

/

SOLUTION

RESTART

Esther_Odiki_Calibration 200 /

/

RPTSOL

 'FIP=3' 'RESTART=1' 'FIPRESV' AQUANCON=2 /

RPTRST

 BASIC=3 FIP=1 PCOW PORV 'CONV=50' /

SUMMARY

RPTONLY

RPTSMRY

  0 /

COPR

'*' /

/

COPT

'*' /

/

COPP

'*' /

/

CWFR

'*' /

/

CWPR

'*' /

/

CWPT

'*' /

/

CWPP

'*' /

/

CGPR

'*' /

/

CGPT

 '*' /

/

CLFR

'*' /

/

CWCT

'*' /

/

CGOR

'*' /

/

CPR

'*' /

/

CPI

'*' /

/

FOE

FPR

FOPR

FOPRH

FGPR

FWPR

FWPH

FWCT

FWCTH

FGOR

FGORH

FWIT

FWITH

FOPT

FOPTH

FWPT

FWPTH

FVPR

FLPT

FLPTH

FLPR

FGPT

FGPTH

TCPU

ROIP

/

RPR

/

ROPR

/

RGPR

/

RWIR

/

ROIR

/

ROIT

/

RWIT

/

RWFT

/

FMWIV

FAQR

FAQT

FPPC

FRPV

FWPV

FVPT

FVIT

ROE

/

WOPR

/

WOPRH

/

WGOR

/

WGORH

/

WWCT

/

WWCTH

/

WOPT

/

WOPTH

/

WGPT

/

WGPTH

/

WWPR

/

WWPRH

/

WWPT

/

WWPTH

/

WWIT

/

WWIR

/

WOIR

/

WOIRH

/

WOIT

/

WOITH

/

WWIRH

/

WBHP

/

WBP

/

WBP4

/

WBP9

/

WTHP

/

GOPR

/

GOPRH

/

GGPR

/

GGPRH

/

GGOR

/

GGORH

/

GWPR

/

GWCT

/

GWCTH

/

GOPT

/

GOPTH

/

GGPT

/

GGPTH

/

GWPT

/

GWPTH

/

GWIT

/

CVPT

/

CVFR

/

CVIT

/

WLPR

/

WTHPH

/

SCHEDULE

SKIPREST

MESSAGES

 2* 10000 10000 4* 10000 10000 /

TUNING

 /

 /

 2* 100 /

DRSDT

 0.001

/

WHISTCTL

ORAT/

MATCORR

/

RPTSCHED

'MULT' 'WOC' 'GOC' 'VFPPROD' /

INCLUDE

IME_04_5_25041201.ECL /

/

INCLUDE

IME_10_5_260412.ECL /

/

INCLUDE

IME_12_D70_180512.ECL /

/

INCLUDE

IME_PREDbase.SCH /

--GCONPROD

--GRUP0001 ORAT   340   /

--/

WCONPROD

 'IME4' 'OPEN' 'THP' 80 5* 3 1   /

 'IME10' 'OPEN' 'THP' 60 5* 3 2 /

 'IME12' 'OPEN' 'THP' 200 5* 3 3 /

/

WECON

 'IME4' 15.9 1* 0.5 890 1* CON /

 'IME10' 15.9 1* 0.6 890 1* CON   /

 'IME12' 15.9 1* 0.5 890 1* CON   /

/

WVFPEXP

IME4 EXP 1* YES1 /

/

DATES

1   AUG   2012   /

/

WCONPROD

 'IME4' 'OPEN' 'THP' 80 5* 3 1   /

 'IME10' 'OPEN' 'THP' 45 5* 3 2 /

 'IME12' 'OPEN' 'THP' 200 5* 3 3 /

/

WECON

  'IME4' 15.9 1* 0.5 890 1* CON /

  'IME10' 15.9 1* 0.6 890 1* CON   /

  'IME12' 15.9 1* 0.5 890 1* CON   /

/

DATES

1   SEP   2012 /

1   OCT   2012 /

1   NOV 2012 /

1   DEC 2012 /

 1   JAN   2013 /

 1   FEB   2013 /

 1   MAR   2013 /

 1   APR   2013 /

 1   MAY   2013 /

 1   JUN   2013 /

 1   JUL   2013 /

 1   AUG   2013 /

 1   SEP   2013 /

1   OCT   2013 /

1   NOV 2013   /

1   DEC   2013 /

/

DATES

1   JAN   2014 /

/

WCONPROD

 'IME4' 'OPEN' 'THP' 50 5* 3 1 /

 'IME10' 'OPEN' 'THP' 45 5* 3 2 /

 'IME12' 'OPEN' 'THP' 200 5* 3 3 /

/

WECON

 'IME4' 15.9 1* 0.5 890 1* CON /

 'IME10' 15.9 1* 0.6 890 1* CON /

 'IME12' 15.9 1* 0.5 890 1* CON /

/

DATES

 1   FEB   2014 /

 1   MAR   2014 /

 1   APR   2014 /

 1   MAY   2014 /

 1   JUN   2014 /

 1   JUL   2014 /

1   AUG 2014 /

1   SEP 2014 /

1   OCT   2014   /

1   NOV 2014   /

1   DEC   2014   /

1   JAN   2015 /

1   FEB   2015 /

1   MAR   2015 /

1   APR   2015 /

1   MAY   2015 /

1   JUN   2015 /

1   JUL   2015 /

1   AUG   2015 /

1   SEP   2015 /

1   OCT   2015   /

1   NOV 2015   /

1   DEC   2015   /

1   JAN   2016 /

1   FEB   2016 /

1   MAR   2016 /

1   APR   2016 /

1   MAY   2016 /

1   JUN   2016 /

/

DATES

1   JUL   2016 /

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

/

WCONPROD

 'IME4' 'OPEN' 'THP' 50 5* 3 1   /

 'IME10' 'OPEN' 'THP' 30 5* 3 2 /

 'IME12' 'OPEN' 'THP' 200 5* 3 3 /

/

WECON

 'IME4' 15.9 1* 0.5 890 1* CON /

 'IME10' 15.9 1* 0.9 890 1* CON   /

 'IME12' 15.9 1* 0.5 890 1* CON   /

/

1   AUG   2016 /

1   SEP   2016 /

1   OCT   2016 /

1   NOV   2016 /

/

DATES

1   DEC   2016 /

/

WCONPROD

 'IME4' 'OPEN' 'THP' 50 5* 3 1   /

 'IME10' 'OPEN' 'THP' 30 5* 3 2 /

'IME12' 'OPEN' 'THP' 100 5* 3 3 /

/

WECON

 'IME4' 15.9 1* 0.5 890 1* CON /

 'IME10' 15.9 1* 0.9 890 1* CON   /

 'IME12' 15.9 1* 0.9 890 1* CON   /

/

DATES

1   JAN   2017 /

/

DATES

1   FEB   2017 /

/

WCONPROD

 'IME4' 'OPEN' 'THP' 50 5* 3 1   /

 'IME10' 'OPEN' 'THP' 30 5* 3 2 /

 'IME12' 'OPEN' 'THP' 100 5* 3 3 /

/

WECON

 'IME4' 15.9 1* 0.5 890 1* CON /

 'IME10' 15.9 1* 0.9 890 1* CON   /

 'IME12' 15.9 1* 0.9 890 1* CON   /

/

DATES

1   MAR   2017 /

1   APR   2017 /

1   MAY   2017 /

1   JUN   2017 /

1   JUL   2017 /

1   AUG   2017 /

1   SEP   2017 /

1   OCT   2017 /

1   NOV 2017 /

1   DEC   2017 /

1   JAN   2018 /

1   FEB   2018 /

1   MAR   2018 /

1   APR   2018 /

1   MAY   2018 /

1   JUN   2018 /

1   JUL   2018 /

1   AUG   2018 /

1   SEP   2018 /

1   OCT   2018 /

1   NOV 2018 /

1   DEC   2018 /

ESTHER, ODIKI - MSc Petroleum Engineering, Middlesbrough, 2014.

1 JAN 2019 /

1 FEB 2019 /

1 MAR 2019 /

1 APR 2019 /

1 MAY 2019 /

1 JUN 2019 /

1 JUL 2019 /

1 AUG 2019 /

1 SEP 2019 /

1 OCT 2019 /

1 NOV 2019 /

1 DEC 2019 /

1 JAN 2020 /

1 APR 2020 /

1 JUL 2020 /

1 OCT 2020 /

1 JAN 2021 /

1 APR 2021 /

1 JUL 2021 /

1 OCT 2021 /

1 JAN 2022 /

1 APR 2022 /

1 JUL 2022 /

1 OCT 2022 /

1 JAN 2023 /

1 APR 2023 /

1 JUL 2023 /

1 OCT 2023 /

1 JAN 2024 /

1 APR 2024 /

1 JUL 2024 /

1 OCT 2024 /

1 JAN 2025 /

1 APR 2025 /

1 JUL 2025 /

1 OCT 2025 /

1 JAN 2026 /

1 APR 2026 /

1 JUL 2026 /

1 OCT 2026 /

1 JAN 2027 /

1 APR 2027 /

1 JUL 2027 /

1 OCT 2027 /

1 JAN 2028 /

1 APR 2028 /

1 JUL 2028 /

1 OCT 2028 /

```
1      JAN    2029 /

1      APR    2029 /

1      JUL    2029 /

1      OCT    2029 /

1      JAN    2030 /

1      APR    2030 /

1      JUL    2030 /

1      OCT    2030 /

1      JAN    2031 /

1      JUL    2031 /

1      JAN    2032 /

1      JUL    2032 /

1      JAN    2033 /

1      JUL    2033 /

1      JAN    2034 /

1      JUL    2034 /

1      JAN    2035 /

1      JUL    2035 /

/
```

END

CASE 3 (WELL IME-4 GAS LIFT) PREDICTION DATA

RUNSPEC

TITLE

--IME FIELD

METRIC

OIL

GAS

WATER

DISGAS

METRIC

SAVE

/

--MEMORY

--500 500 /

DIMENS

74 69 21/

EQLDIMS

--nregs #d Pnodes #d RVnodes

  1 4* /

ENDSCALE

/

SMRYDIMS

50000000 /

FAULTDIM

     250 /

SATOPTS

HYSTER /

TABDIMS

--ntsfun ntpvt nssfun nppvt ntfip nrpvt nrpvt ntendp   pmaint

 8   1   200 50 9 50 50 1 /

REGDIMS

--ntfip #sets

  1 1 3*   /

WELLDIMS

--maxw conW grup wlG stg strm

  35 100   100   100 /

VFPPDIMS

 20 10 10 10 10 3 /

ACTDIMS

  10 /

AQUDIMS

0 0 15 100 6 1000000

/

NSTACK

 100 /

UNIFIN

UNIFOUT

--OPTIONS

--73* 1/

--NOSIM

--NOWARN

START

 1 'JAN' 1995 /

GRID

--   THIS SECTION SPECIFIES THE GEOMETRY OF THE i X j X k GRID, AND

--   SETS THE ROCK POROSITIES AND PERMEABILITIES.

INIT

--
NOECHO

--

--

GRIDFILE

 2 1 /

--MINPORV

--200 /

PINCH

/

INCLUDE

D70GRID.grdecl /

INCLUDE

PHIE.grdecl /

INCLUDE

PERMX.grdecl /

INCLUDE

PERMY.grdecl /

INCLUDE

PERMZ.GRDECL /

/

INCLUDE

FAULT_MOD6.GRDECL /

/

MULTFLT

FAULT2   0.8   /

FAULT3   0.07   /

/

INCLUDE

NTG.GRDECL /

/

MULTIPLY

PERMZ 0.5 /

/

RPTGRID

PORV ROCKVOL /

EDIT

INCLUDE

TRANX.GRDECL /

/

INCLUDE

TRANY.GRDECL /

/

INCLUDE

TRANZ_6.GRDECL /

/

PROPS

--   THE PVT PROPERTIES AND ROCK-FLUID DATA.

INCLUDE

JULY242012_RUN1.INC   /

INCLUDE

SWCR.GRDECL /

/

MULTIPLY

SWCR 1.5 /

/

MAXVALUE

SWCR 0.99999 /

/

INCLUDE

IME_PVT_D70.txt /

INCLUDE

INFLUENCE_TABLES.INC /

EHYSTR

1* 2   /

                                                                    History

FILLEPS

REGIONS

-- THERE ARE SEVEN FLUIDS-IN-PLACE REGIONS, SEPARATED BY
VERTICAL IMPERMEABLE BARRIERS

--   ARRAY   VALUE   ------ BOX ------

EQUALS

```
   'FIPNUM'    1     1 74 1 69   1   21   /
```

```
/
```

```
EQUALS
```

```
   'EQLNUM'     1     1 74 1 69   1   21 /
```

```
/
```

```
EQUALS
```

```
   'PVTNUM'    1     1 74 1 69   1   21   /
```

```
/
```

```
INCLUDE
```

```
SATNUM.GRDECL /
```

```
COPY
```

```
SATNUM  IMBNUM/
```

```
/
```

```
ADD
```

```
IMBNUM 4          /
```

```
/
```

```
-----------------------------------------------------------------
```

```
SOLUTION
```

```
-----------------------------------------------------------------
```

RESTART

Esther_Odiki 200 /

/

RPTSOL

  'FIP=3' 'RESTART=1' 'FIPRESV' AQUANCON=2 /

RPTRST

 BASIC=3 FIP=1 PCOW PORV 'CONV=50' /

SUMMARY

RPTONLY

RPTSMRY

  0 /

COPR

'*' /

/

COPT

'*' /

/

COPP

'*' /

/

CWFR

'*' /

/

CWPR

'*' /

/

CWPT

'*' /

/

CWPP

'*' /

/

CGPR

'*' /

/

CGPT

 '*' /

/

CLFR

'*' /

/

CWCT

'*' /

/

CGOR

'*' /

/

CPR

'*' /

/

CPI

'*' /

/

FOE

FPR

FOPR

FOPRH

FGPR

FWPR

FWPH

FWCT

FWCTH

FGOR

FGORH

FWIT

FWITH

FOPT

FOPTH

FWPT

FWPTH

FVPR

FLPT

FLPTH

FLPR

FGPT

FGPTH

TCPU

ROIP

/

RPR

/

ROPR

/

RGPR

/

RWIR

/

ROIR

/

ROIT

/

RWIT

/

RWFT

/

FMWIV

FAQR

FAQT

FPPC

FRPV

FWPV

FVPT

FVIT

ROE

/

WOPR

/

WOPRH

/

WGOR

/

WGORH

/

WWCT

/

WWCTH

/

WOPT

/

WOPTH

/

WGPT

/

WGPTH

/

WWPR

/

WWPRH

/

WWPT

/

WWPTH

/

WWIT

/

WWIR

/

WOIR

/

WOIRH

/

WOIT

/

WOITH

/

WWIRH

/

WBHP

/

WBP

/

WBP4

/

WBP9

/

WTHP

/

GOPR

/

GOPRH

/

GGPR

/

GGPRH

/

GGOR

/

GGORH

/

GWPR

/

GWCT

/

GWCTH

/

GOPT

/

GOPTH

/

GGPT

/

GGPTH

/

GWPT

/

GWPTH

/

GWIT

/

CVPT

/

CVFR

/

CVIT

/

WLPR

/

WTHPH

/

SCHEDULE

SKIPREST

MESSAGES

2* 10000 10000 4* 10000 10000 /

TUNING

/

/

2* 100 /

DRSDT

0.001

/

WHISTCTL

ORAT/

MATCORR

/

RPTSCHED

'MULT' 'WOC' 'GOC' 'VFPPROD' /

INCLUDE

IME_04_5_25041201.ECL /

/

INCLUDE

IME_10_5_260412.ECL /

/

INCLUDE

IME_12_D70_180512.ECL /

/

INCLUDE

Esther_Odiki_Pred.SCH /

--GCONPROD

--GRUP0001   ORAT   340   /

--/

END

CASE 4 (WELL IME-4 SIDETRACK PLUS GAS LIFT) PREDICTION DATA

RUNSPEC

TITLE

--IME FIELD

METRIC

OIL

GAS

WATER

DISGAS

METRIC

SAVE

/

--MEMORY

--500 500 /

DIMENS

74 69 21/

EQLDIMS

--nregs #d Pnodes #d RVnodes

 1 4* /

ENDSCALE

/

SMRYDIMS

50000000 /

FAULTDIM

250 /

SATOPTS

HYSTER /

TABDIMS

--ntsfun ntpvt nssfun nppvt ntfip nrpvt nrpvt ntendp   pmaint

 8   1   200 50 9 50 50 1 /

REGDIMS

--ntfip #sets

  1 1 3*   /

WELLDIMS

--maxw conW grup wlG stg strm

  35 100 100 100 /

VFPPDIMS

 20 10 10 10 1 3 /

ACTDIMS

  10 /

AQUDIMS

0 0 15 100 6 1000000

/

NSTACK

 100 /

UNIFIN

UNIFOUT

--OPTIONS

--73* 1/

--NOSIM

--NOWARN

START

 1 'JAN' 1995 /

GRID

--   THIS SECTION SPECIFIES THE GEOMETRY OF THE i X j X k GRID, AND

--   SETS THE ROCK POROSITIES AND PERMEABILITIES.

INIT

--
NOECHO

--

--

GRIDFILE

 2 1 /

--MINPORV

--200 /

PINCH

/

INCLUDE

D70GRID.grdecl /

INCLUDE

PHIE.grdecl /

INCLUDE

PERMX.grdecl /

INCLUDE

PERMY.grdecl /

INCLUDE

PERMZ.GRDECL /

/

INCLUDE

FAULT_MOD6.GRDECL /

/

MULTFLT

FAULT2   0.8   /

FAULT3 0.07 /

/

INCLUDE

NTG.GRDECL /

/

MULTIPLY

PERMZ 0.5 /

/

RPTGRID

PORV ROCKVOL /

EDIT

INCLUDE

TRANX.GRDECL /

/

INCLUDE

TRANY.GRDECL /

/

INCLUDE

TRANZ_6.GRDECL /

/

PROPS

--   THE PVT PROPERTIES AND ROCK-FLUID DATA.

INCLUDE

JULY242012_RUN1.INC   /

INCLUDE

SWCR.GRDECL /

/

MULTIPLY

SWCR 1.5 /

/

MAXVALUE

SWCR 0.99999 /

/

INCLUDE

IME_PVT_D70.txt /

INCLUDE

INFLUENCE_TABLES.INC /

EHYSTR

1* 2   /

FILLEPS

REGIONS

-- THERE ARE SEVEN FLUIDS-IN-PLACE REGIONS, SEPARATED BY
VERTICAL IMPERMEABLE BARRIERS

-- ARRAY   VALUE   ------ BOX ------

EQUALS

   'FIPNUM'   1   1 74 1 69 1 21 /

/

EQUALS

   'EQLNUM'   1   1 74 1 69 1 21 /

/

EQUALS

  'PVTNUM'   1   1 74 1 69 1 21 /

/

INCLUDE

SATNUM.GRDECL /

COPY

SATNUM IMBNUM/

/

ADD

IMBNUM 4   /

/

SOLUTION

RESTART

IME_SATNEW_BESTCASEMODAUG2NEW_5 200 /

/

RPTSOL

 'FIP=3' 'RESTART=1' 'FIPRESV' AQUANCON=2 /

RPTRST

 BASIC=3 FIP=1 PCOW PORV 'CONV=50' /

SUMMARY

RPTONLY

RPTSMRY

   0 /

COPR

'*' /

/

COPT

'*' /

/

COPP

'*' /

/

CWFR

'*' /

/

CWPR

'*' /

/

CWPT

'*' /

/

CWPP

'*' /

/

CGPR

'*' /

/

CGPT

 '*' /

/

CLFR

'*' /

/

CWCT

'*' /

/

CGOR

'*' /

/

CPR

'*' /

/

CPI

'*' /

/

FOE

FPR

FOPR

FOPRH

FGPR

FWPR

FWPH

FWCT

FWCTH

FGOR

FGORH

FWIT

FWITH

FOPT

FOPTH

FWPT

FWPTH

FVPR

FLPT

FLPTH

FLPR

FGPT

FGPTH

TCPU

ROIP

/

RPR

/

ROPR

/

RGPR

/

RWIR

/

ROIR

/

ROIT

/

RWIT

/

RWFT

/

FMWIV

FAQR

FAQT

FPPC

FRPV

FWPV

FVPT

FVIT

ROE

/

WOPR

/

WOPRH

/

WGOR

/

WGORH

/

WWCT

/

WWCTH

/

WOPT

/

WOPTH

/

WGPT

/

WGPTH

/

WWPR

/

WWPRH

/

WWPT

/

WWPTH

/

WWIT

/

WWIR

/

WOIR

/

WOIRH

/

WOIT

/

WOITH

/

WWIRH

/

WBHP

/

WBP

/

WBP4

/

WBP9

/

WTHP

/

GOPR

/

GOPRH

/

GGPR

/

GGPRH

/

GGOR

/

GGORH

/

GWPR

/

GWCT

/

GWCTH

/

GOPT

/

GOPTH

/

GGPT

/

GGPTH

/

GWPT

/

GWPTH

/

GWIT

/

CVPT

/

CVFR

/

CVIT

/

WLPR

/

WTHPH

/

SCHEDULE

SKIPREST

MESSAGES

 2* 10000 10000 4* 10000 10000 /

TUNING

 /

/

2* 100 /

DRSDT

 0.001

/

WHISTCTL

ORAT/

MATCORR

/

RPTSCHED

'MULT' 'WOC' 'GOC' 'VFPPROD' /

INCLUDE

IME_04_5_250412.ECL /

/

INCLUDE

IME_10_5_260412.ECL /

/

INCLUDE

IME_12_D70_180512.ECL /

/

INCLUDE

IME_AUG5_2.SCH /

END