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ASSESSMENT OF NATURAL DEPLETION AND WATER INJECTION IN THE DEVELOPMENT OF OIL RESERVOIRS

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Abstract

Field development teams often adopt modalities that would ensure that the production potential of the fields are maximized. This would involve studies, assessment and modelling the reservoir systems that would provide for economically viable petroleum production. This paper presents an evaluation and optimized development plan for a reservoir in UBED field based on the results obtained from a comparative analysis of the two development options examined. The field development plan was designed to ensure an optimum recovery of oil by adopting development strategies that would maximize the total hydrocarbon production at the minimum cost per barrel. As a guide to initial field development, material balance calculations were carried out in order to estimate the production rates, number of wells, Injectivity and other production data necessary to achieve the required targets. The MBE was used for preliminary assessment of the reservoir, to provide insight and as a comparison and benchmark for numerical simulations that was run. Oil recovery for natural depletion was determined by simulation with Eclipse software. The value of the total oil initially in place was found to be 35681991Sm3. Based on the requirement that the plateau rates must be around 15% per year, the estimated ultimate recovery of 25% a rate of 3665m3/d was estimated for natural depletion. Using the reservoir data provided, a black oil model was used and several simulations of the dynamic reservoir model were carried out with the Schlumberger Eclipse® software. The initial reservoir data included two Petrel® grid files, a PVT data file, a schedule file, and an eclipse data file. The first grid file contained data related to the positions of each of the grids while the second grid file contained the upscaled petro-physical properties for each of the grids. Simulation results indicated increase in the oil recovery to 53% compared to 30% obtained from natural depletion case at plateau rate of 7200 Sm3/day for about four years. For the early water injection case, the reservoir was naturally depleted down to a pressure of 350bars, after which water injection was started. Again, results indicated slightly lower recovery of 52.5%. This lower recovery is expected as early water injection increases the mobility of water and also the mobility ratio which would result in decreased sweep efficiency leading to low recovery.

Keywords: : water injection; natural depletion; recovery; efficiency; production; reservoir; sweep; simulation; model; ECLIPSE.

1. Introduction

The dynamism inherent in petroleum reservoir systems demands that any development approach which would be successful would involve sufficient assessment and integration of various uncertainties at conditions of sparse reservoir data, operational feasibility and cost for both the present and future performance of the asset. Sometimes the analysis that would justify the need for pressure maintenance, the appropriate number of injectors and placement are either not done or not properly done. The goal of this study is to analyse the effect of the two development schemes on oil production and development plan for the UBED reservoir, this plan is focused on maximizing the total hydrocarbon production and minimize the development cost in $/bbl.

1.1. Location of the UBED Field

The UBED Field was discovered in 1974 in the South Eastern part of the East Shetland Basin in the UK North sea, about 140 km East of the near most Shetland Island and about 400 km North East of Aberdeen. The water depth is around 130 m. The following map in Fig 1.1 describes the location of the field.

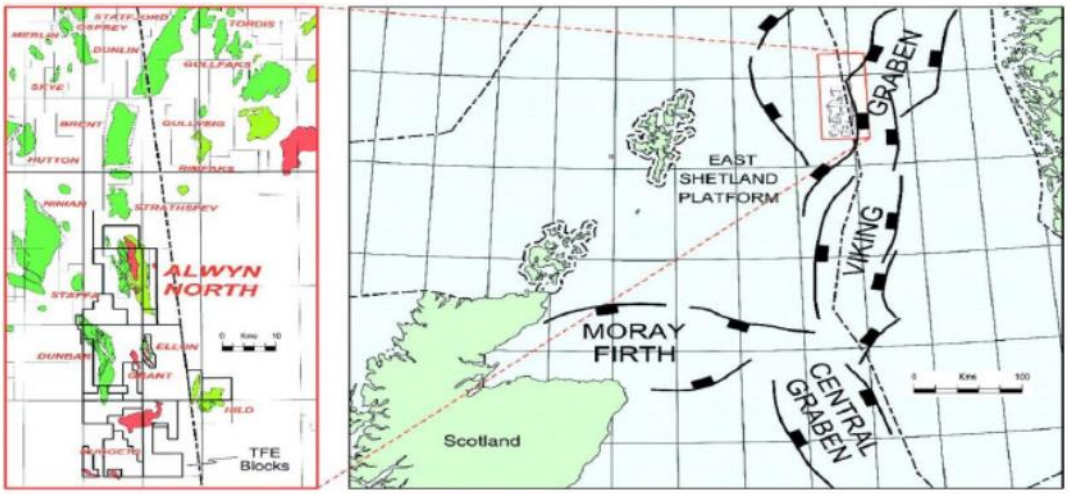

Figure 1.1 UBED field location

1.2. Reservoir model description

A Black Oil model was designed with rectangular cells with 36 cells along the x-direction and 51 cells along the y-direction as shown in Figures 1.2 and 1.3. The reservoir dynamic model was obtained from upscaling the reservoir geological model using Petrel and was used to investigate the production performance of this reservoir and to investigate various development schemes. The geometry definition of the upscaled reservoir dynamic model is given in a Petrel file: **'MODEL_PETREL.GRDECL'.** The petrophysical properties (porosity, permeability's and NTG) are included in the grid in the include file: **'MODEL_ PETREL_PETRO.GRDECL'.** There are three equilibration regions defined in the EQUNUM keyword in the Regions section. The reservoir petrophysical properties (porosity, permeability) were also scaled up. The water salinity in the reservoir is about 17,000 ppm.

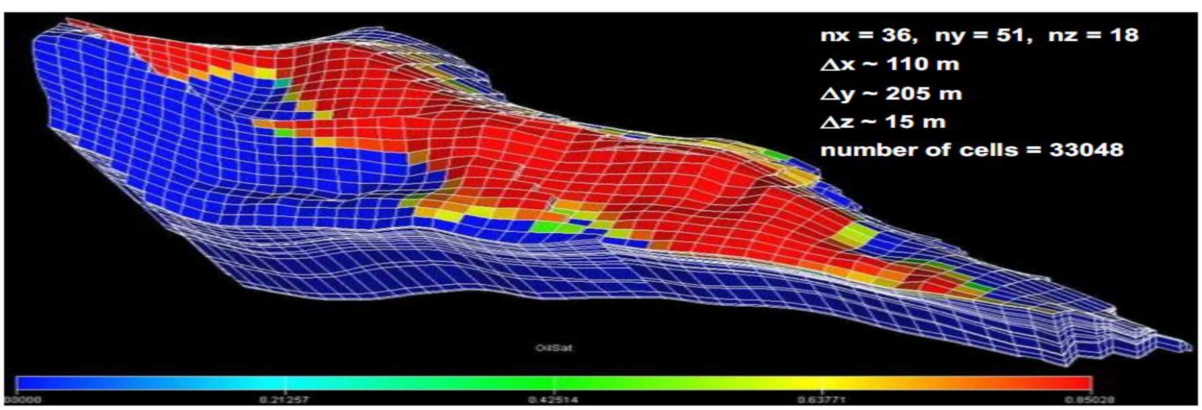

Figure 1.2. Reservoir model showing the grids

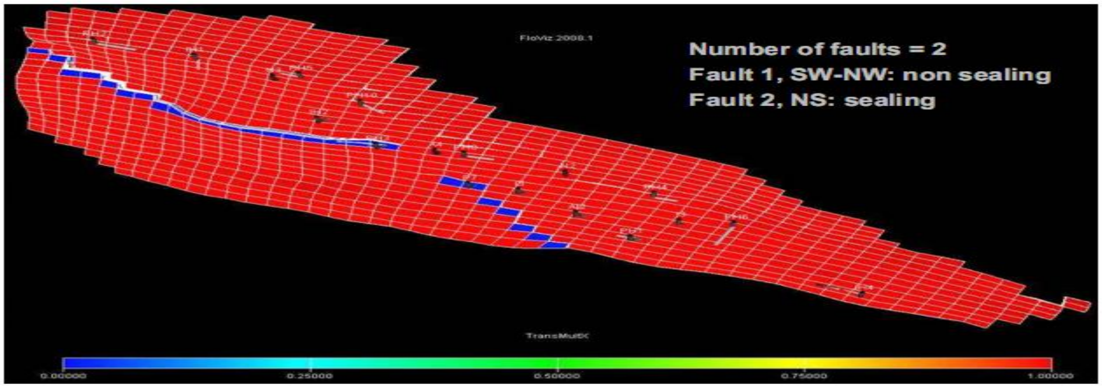

Figure 1.3. Reservoir model showing the faults

2. Methodology

2.1. Reservoir fluid properties

Black Oil PVT representation was used in this study. The PVT data file **'PVTFULL.INC'** contains the relevant composite black oil PVT data which accounts for the field separation conditions. Table 2.1 shows the initial PVT values of the reservoir fluid. The Formation volume factor was gotten by interpolation between pressures of 418.3074bars and 450bars at a solution GOR of 206.8974sm^3/sm^3.

Table 2.1. Initial reservoir properties

Initial reservoir pressure (P_i)	446 bars
Temperature (T)	110ºC
GOR	206.8sm^3/sm^3
Saturation pressure (P_{sat})	258 bars
Oil formation volume factor, Bo @ P_i	1.6038 rb/stb
OOIIP	35681991 m^3

2.2. Fluids in place

The original data file was initialized to obtain the fluid in place values shown in Table 2.2. This was illustrated by adding the ECHO and FIPNUM keywords in the dot DATA simulation.

Table 2.2. Reservoir volumes obtained from FIPNUM report

Currently in place	UBED-1	UBED-2	Entire Field
Oil (sm^3)	31,104,045	4,577,946	35,681,991
Water (sm^3)	125,222,389	188,540,747	313,763,137
Dissolved Gas (sm^3)	6,426,769,976	945,902,886	7,372,672,862

Based on the geological model described, the following deductions can be made.

- There is no initial gas cap; the reservoir is under-saturated
- The structure of the reservoir suggests no gravity drainage

In order to investigate the effect of the two field development schemes on oil production, the two schemes were analysed by:

A. Material balance
B. Model simulation in Eclipse software

Material balance was used to determine the different drive mechanisms providing energy for the reservoir system in order to estimate the oil recovery. Both production schemes were investigated using material balance calculation above saturation pressure (P_{sat}). The two schemes were investigated and their impacts on ultimate recovery were presented in tables 2.1 and 2.2 respectively. Each scenario is reported in detail with all relevant information, assumptions and selected options. The annual production plateau estimate is around 15% of

EUR. The production profiles were evaluated over 15 years. The two scenarios were also implemented in the numerical reservoir model and for each of the scenario studied, production optimization studies was carried out by adjustment of operational parameters. For primary production, the relevant number of producers were calculated to optimize production [1]. The optimal number of wells that would be required to 'sweat the asset' was also investigated.

2.3. Material balance calculations

Material balance was used for preliminary assessment of the reservoir, to provide insight and as a comparison tool for numerical simulations that are run later. PVT parameters from Differential Liberation (DL) and Constant Composition Expansion (CCE) laboratory tests for oil of this reservoir include: P_{bmax}=258.236 bars; R_{smax} =206.897 Sm^3/m^3; Bo =1.6855 @ P_{bmax}.

2.3.1. General assumptions for the MBE calculations [2]

1. The Petro-physical and PVT Properties of both rock types were assumed to be similar.
2. Pressure, temperature, and rock and fluid properties are not space dependent
3. Uniform hydrocarbon saturation and pressure distribution
4. Thermodynamic equilibrium always attained.
5. Isothermal condition apply
6. Production data is reliable
7. Vertical sweep efficiency, E_v is taken to be 0.7 for all regions as neighbouring fields within the area have general E_v close to or equal to 0.7.

2.3.2. Case 1: MBE for only natural depletion

The general material balance equation is given as;

$$N_p\left[B_o + (R_p - R_{si})B_g\right] + W_pB_w = NB_{oi}\left[\frac{\left[(B_o - B_{oi}) + (R_{si} - R_s)B_g\right]}{B_{oi}} + m\left(\frac{B_g}{B_{gi}} - 1\right) + (1+m)\frac{(C_wS_w + C_f)\Delta P}{1 - S_{wc}}\right] + W_eB_w \qquad (2.1)$$

For a reservoir with natural depletion, the following assumptions can be made. Assumptions:

- No initial gas cap, m=0;
- Negligible water influx, W_e = 0, W_p =0;
- Above bubble point, R_s=R_{si}=R_p [3]

Under these assumptions, The MBE equation can be reduced to:

$$N_pB_0 = NB_{oi}\left[\frac{B_o - B_{oi}}{B_{oi}} + \left(\frac{C_wS_{wc} + C_f}{1 - S_{wc}}\right)\Delta P\right] \qquad (2.2)$$

The resulting equation becomes:

$$N_pB_o = NB_{oi}C_e\Delta P \quad \text{where} \quad C_e = \frac{1}{1 - S_{wc}}\left(C_oS_o + C_wS_{wc} + C_f\right) \qquad (2.3)$$

The fractional recovery, N_p/N is given as Recovery efficiency

$$\frac{N_p}{N} = \frac{B_{oi}}{B_o}C_e\Delta P \qquad (2.4)$$

Estimation of the above parameters and final EUR for natural depletion case are presented table 2.1:

$$Average\ Oil\ Withdrawal = \frac{OOIP.EUR.(\%\ reserves)}{365\ day} \qquad (2.5)$$

PI (@ 446bar and 290bar respectively)

$$PI = \frac{Q_{surface}}{(P - BHP)} = \frac{\alpha.Kh.k_{ro}}{(Bo\mu o\ [ln(rd/rw)] + S - 0.75} \qquad (2.6)$$

α=0.0086.2Π=0.0536→metric unit; α= 0.001127.2Π=0.00708→field unit)

$$Production\ plateau = PI_{mean}x\ DD \qquad (2.7)$$

$$Number\ of\ wells = \frac{average\ oil\ withdrawal}{Production\ plateau} \quad (2.8)$$

$$Recovery = \frac{N_p}{OOIP} \quad (2.9)$$

2.3.3. Case 2: MBE for water injection scheme

For this case a combination of natural depletion and pressure maintenance through water injection. The water injection scheme involves natural depletion to a pressure just above bubble point pressure, P_b (290 bar), followed by water injection for pressure maintenance.
Assumptions: $W_i = 0$, $G_i = 0$, $m = 0$, $C_f \neq 0$, $C_w \neq 0$ and $B_t = B_o$ [4]
Therefore equation 1 becomes:

$$N = \frac{NpBo + WpBw - We}{BoCe\Delta P} \quad (2.10)$$

$$R = Ea * Ev * Ed \quad (2.11)$$

2.4. Numerical simulation in Eclipse

The reservoir performance analysis done using the material balance identified the major driving force for the reservoir Based on the results of the analytical calculation, the production schemes were defined: Natural depletion and water injection.

Each scenario was implemented in the numerical simulator and reported in detail with relevant information, assumption and selected option.

2.4.1. Scenario one: natural depletion

Under natural depletion, the reservoir was simulated by depletion from the initial reservoir pressure of 446bars down to 100bars (below the bubble point). Two cases were examined with the four (4) initial wells under different condition:

a. Depletion from 446bar – 100bar and sgc =0%;
b. Depletion from 446bar – 100 bar and sgc =10%.

Geometry of the grid block in 3D showing the well locations is as shown in Fig 2.1.

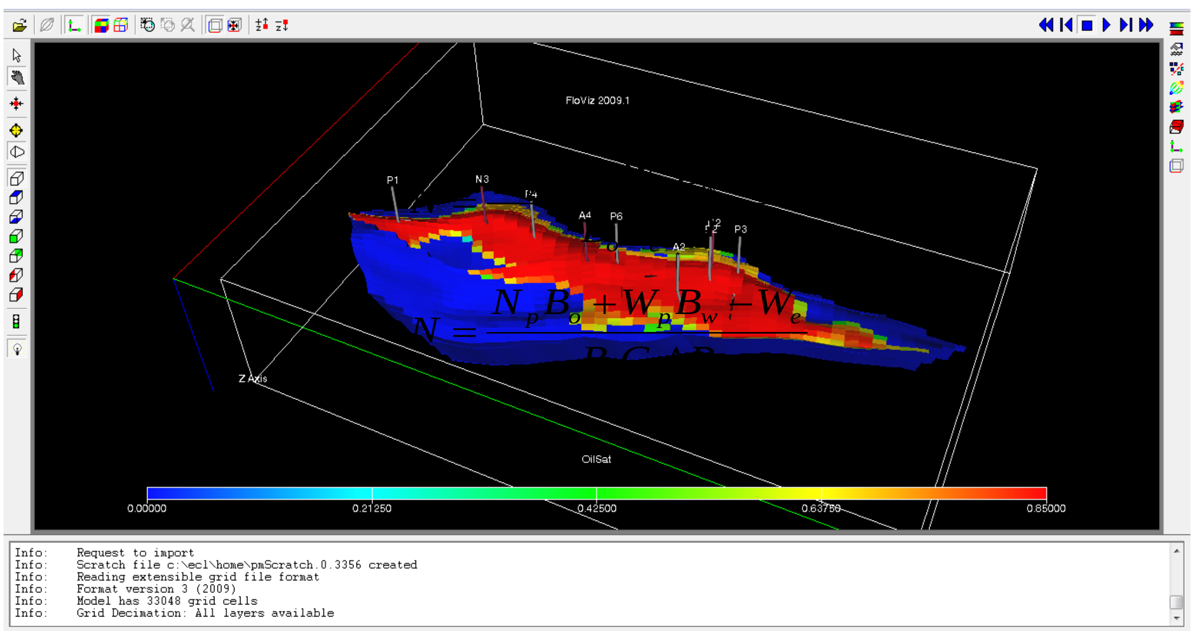

Figure 2.1. Geometry of the Grid Block In 3D Showing the Well Locations (8 wells)

2.4.2. Scenario two: water injection

Water injection is a secondary oil recovery mechanism [2]. Traditionally water injection is used by the oil industry to maintain the pressure above the bubble-point pressure or alternatively to pressurize the reservoir to the bubble-point pressure. In such types of reservoirs, as the reservoir pressure drops below the bubble-point pressure, some volume of the liberated gas will remain in the reservoir as a free gas.

In this scenario, ECLIPSE was used to simulate the behaviour of the reservoir under water injection drive and the expected recovery [5]. A schematic of the grid block showing the placement of the injection wells is as shown in Fig 2.2. Two cases for this scenario were examined:

1. In the first, the model was run by depleting the reservoir from the initial reservoir pressure (446 bars) to a flowing bottom hole pressure of 290 bars after which we initiated the water injection scheme.
2. Pressure maintenance scheme was initiated earlier when the pressure declined to 350 bars.

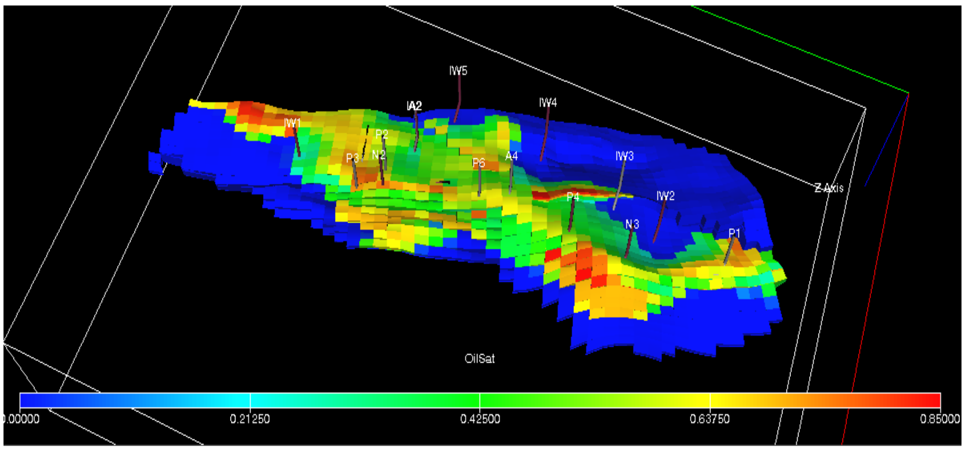

Figure 2.2. Representation of the injection wells for oil sweep by water injection

3. Results and discussion

3.1. Material balance calculations

3.1.1. Natural depletion

The solutions for recovery by natural depletion is as shown in Table 3.1. The development parameters for the reservoir are shown in Table 3.2.

Table 3.1 Analytical solution for recovery by natural depletion drive

	NATURAL DEPLETION	
Data	UBED-1	UBED-2
B_{oi}	1.6038	1.6038
B_o	1.6683	1.6683
B_w	1.047	1.047
$C_w(Psi^{-1})$	0.00005	0.00005
$C_o(Psi^{-1})$	0.000258	0.000258
C_f (Psi^{-1})	0.00005	0.00005
C_e (Psi^{-1})	0.000325	0.000334
S_{wc}	0.15	0.3
S_o	0.85	0.7
ΔP(bar)	156	156
OOIIP (bbls)	31104045	4577946
P_i(bar)	446	446
P_f (bar)	290	290
N_p (bbls)	1517877.4	240740.45
Recovery (%)	24	26
FIELD OOIIP	35681991	
FIELD RECOVERY	1758617.85	
GLOBAL EUR (%)	25	

Table 3.2 Development parameters for a natural depletion reservoir

Parameter	Estimate
OOIP	35681991 m^3
Using 25% EUR	8920497.75 m^3
15% of 25% EUR	1338.074 m^3
Qo field	3665.95 m^3/day
PI @446	65.14 m^3/d/bar
PI @290	84.73
PI mean	74.94 m^3/d/bar
Plateau production	2248.09 m^3/d
Number of wells	3

The maximum well production for any of the vertical wells is 1800m^3/d. The PI_{mean} for natural depletion exceed this value. This is an indication that the number of wells present is insufficient. More were needed. The fractional flow curves for the two regions of the UBED reservoir are as shown in Figures 3.1 and 3.2 respectively.

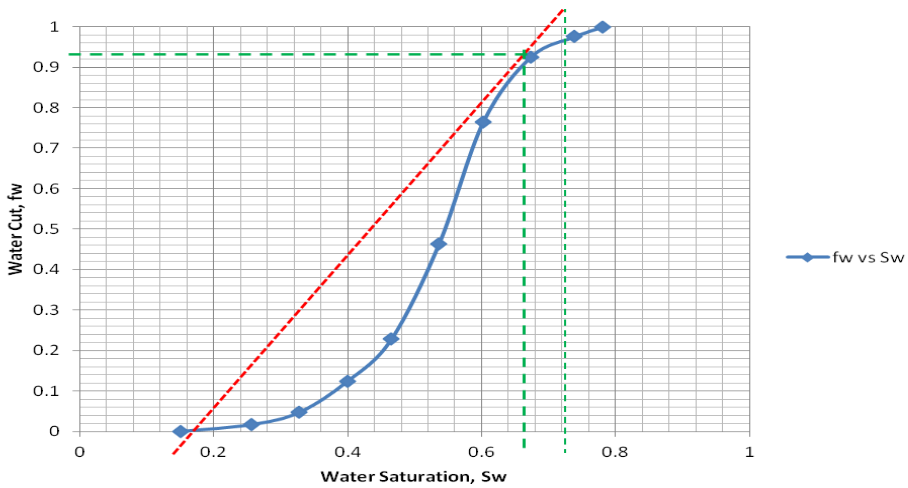

Figure 3.1. Fractional flow curve for the UBED-1 Region

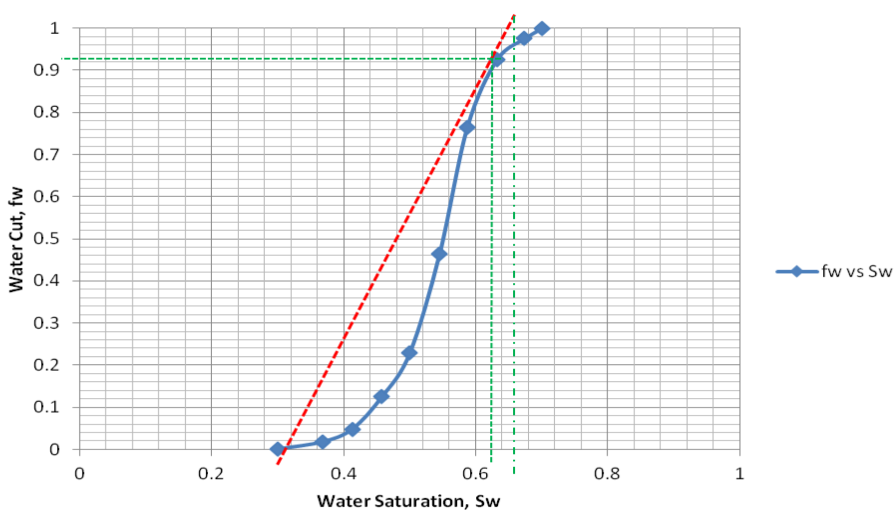

Figure 3.2. Fractional flow curve or the UBED-2 region

3.1.2. Water Injection

Table 3.3 shows a summary of results obtained by calculation for the total oil that can be produced by water injection while the estimates for water injection are outlined in Table 3.4.

Table 3.3 Summary of analytical solution for recovery by water injection

Summary of analytical solution for the two regions			
UBED-1		UBED-2	
Fwf	90%	Fwf	90%
Swc	0.15	Swc	0.3
Swf	0.66	Swf	0.62
Avg. Sw@BT	0.71	avg. Sw@BT	0.66
Ed@BT	0.65	Ed@BT	0.51
Mobility Ratio	0.33495	Mobility Ratio	0.334
Recriprocal MR	2.985520227	Recriprocal MR	2.985
Ea@90%Fwf	0.98	Ea@90%Fwf	0.98
Ev	0.7	Ev	0.7
Recovery, R	0.48423	Recovery, R	0.378
OOIP	31104045 Sm^3	OOIP	4577946 Sm^3
Np	1517877.4Sm^3	Np	240740.4Sm^3
Nw	13757567.9Sm^3	Nw	1544045.2Sm^3
Cummulative volumes			
Total Np	1754363.412		Sm^3
Total Nw	15301613,48		Sm^3
Np + Nw	17722498.9		Sm^3
OOIP	35681991		Sm^3
EUR field	49.6%		

3.1.2.1. Calculation of Producers and Injectors Parameters

Similarly, estimates of the productivity index (PI), daily production rate and the minimum number of producer and injector wells made

$$Injectivity\ index\ II = \frac{\alpha.Kh.k_{rw}}{B_w \mu_w [\ln(r_d/r_w)] + S - 0.75} \quad (2.19)$$

$$Injection\ per\ day = production\ plateau \times \left(\frac{B_o}{B_w}\right) \quad (2.20)$$

Table 3.4. Estimates for water injection scheme

Producers		
Relevant parameters	Value	Unit
ro @S_{wc}	0.8	
B_{oi}	1.6038	Rm^3/Sm^3
B_o @ 290bar =	1.6683	Rm^3/Sm^3
μo @446bar=	0.3916	Cp
μo @ 290bar =	0.2894	Cp
Skin, *s*	5	
Drainage radius, r_d	400	M
Wellbore radius, r_w	0.0889 (hole ID = 7")	M
Average Permeability, *K*	186.62	Md
Anisotropy, I	1.0	
Average NTG	0.96883	
Average Thickness, Dz	64.72	M
Productivity Index @ 446	65.39218	Sm^3/day/bar
Productivity Index @ 290	82.09	Sm^3/day/bar
Average PI , PI_{mean}	73	Sm^3/day/bar
Drawdown, *DD*	30	Bar
Well production max. allowable, q_{max}	1800	Sm^3/day
Field production min. allowable,	200	Sm^3/day

Producers, *continue*		
Relevant parameters	Value	Unit
Actual field daily production, Q_p	7011.054	Sm^3/day
Annual field production, Q_p per year	2559035	Sm^3/yr
Number of producers@ 1800 Sm3/day (constraint)	4	
Injectors		
Relevant parameters	Value	Unit
K_{rw} (S_{wc} =1)	1.0	
B_w	1.047	Rm^3/Sm^3
μ_w	0.27	Cp
Skin, *s*	-4	
Drainage radius,r_d	400	M
Wellbore radius, r_w	0.0889 (hole ID = 7”)	M
Average Permeability, *K*	186.62	Md
Anisotropy, I	1.0	
Average NTG	0.96883	
Injectivity Index, *I*	606	$Sm^3/day/bar$
Drawdown, *DD*	30	Bar
Initial estimate of rate, q_i	18180	Sm^3/day
Well production max. allowable, q_{imax}	3000	Sm^3/day
Well Injection actual rate, q_i	3000	Sm^3/day
Field Injection rate, Q_i	11171.5	Sm^3/day
Field Injection max. allowable, Q_{imax}	15000	Sm^3/day
Vol. of water to be injected per day	11171.5	Sm^3/day
Annual field Injection, Q_i per year	4077591	Sm^3/yr
Number of Injectors @ 3000 Sm^3/day (constraint)	4	

The calculation implies an EUR of 49.6% for a combined natural depletion with pressure maintenance by water injection. This value represents approximately 50% which is quite significant. At least four (4) producer wells and four (4) injector well are to be drilled to achieve this at a plateau of 7283 m^3/d

3.2. Numerical simulation results in Eclipse

a. Depletion from 446bar – 100bar and sgc =0%
b. Depletion from 446bar – 100 bar and sgc =10%

The effect of Sgc on the recovery efficiency of the field is illustrated in Fig 3.3.

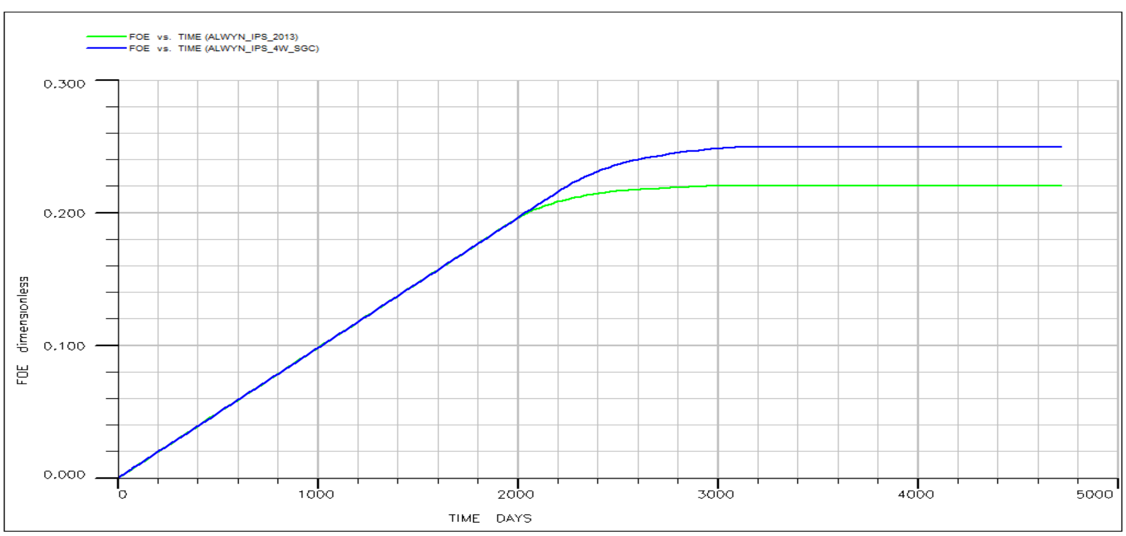

Figure 3.3. Effect of Sgc on the field oil efficiency for natural depletion

It can be seen that the recovery from the 0% sgc case (22%) is smaller compared to the case of 10% sgc (25%) as shown in figure 3.3.

This is due to the fact that in a depletion-drive reservoir is characterized by a rapidly increasing gas-oil ratio from all wells, regardless of their structural position. After the reser-voir pressure is reduced below the bubble-point pressure, gas evolves from solution throughout the reservoir. Gas saturation increases as reservoir pressure declines rapidly [7]. Once the gas saturation exceeds the critical gas saturation, free gas begins to flow toward the wellbore and the gas-oil ratio increases. This vertical movement of gas into the wellbore due to gravitational forces results in secondary gas cap formation and reduces the oil relative permeability and thus decreases recovery. The higher the critical gas saturation, the harder it is for gas to start flowing into the wellbore and thus oil recovery is not reduced.

The performance (FPR, FWCT, FGOR, FOPR and FOE vs Time) curve for this field under natural depletion is shown in Figure 3.4

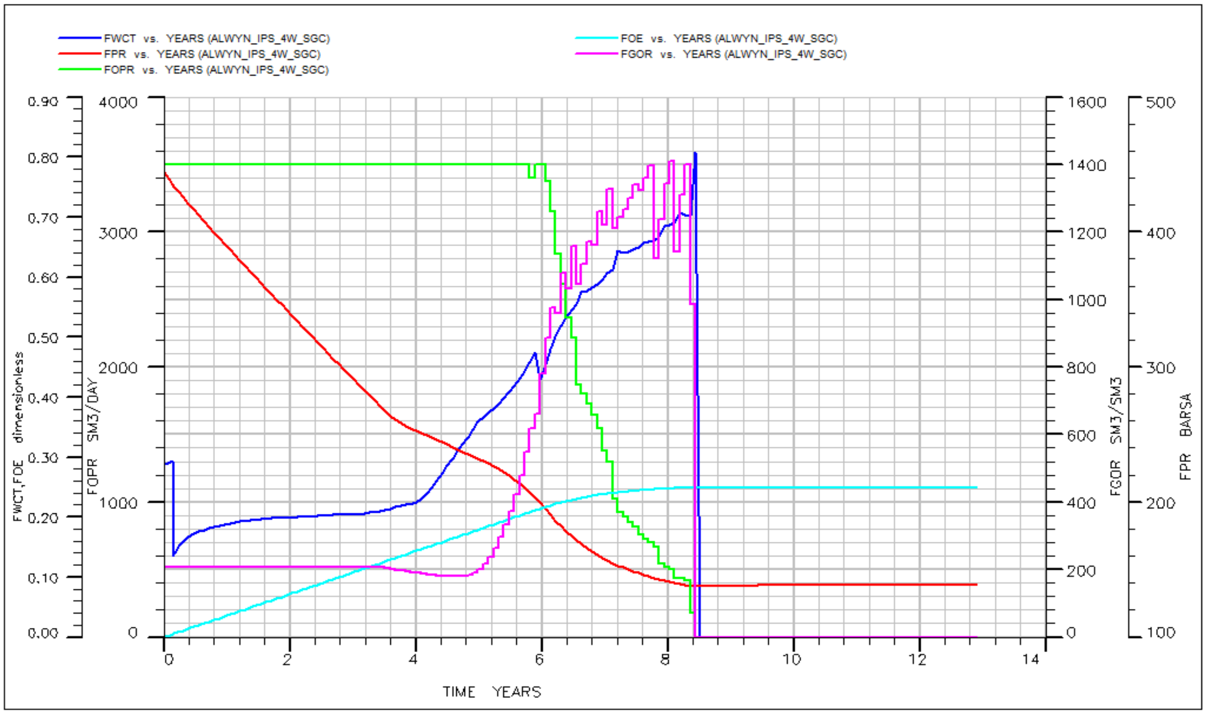

Figure 3.4. Field performance for natural depletion for sgc=10%

From the field performance plots, oil production was maintained at a relatively high rate of 3500Sm^3 at a plateaux period for about 6years. GOR was also relatively constant for the plateau period at about 200 Sm^3/Sm^3. There was early water production at about 29% which dropped to 14% after 2months. For the next first 4years remained fairly constant at 20% and rose rapidly in the next 4 years to about 80%. And GOR increased to over 1400 Sm^3/Sm^3 within the same period. This resulted in shutting down production.

3.3. Production optimization - natural depletion

Optimization of production from this asset for natural depletion would involve: optimum number of wells and location based on prevailing geological structure (fault, Kv, Kh, dip etc.) and maximizing drainage by drilling appropriate well configuration [1]. Based on above criterion; different cases were simulated by adding extra producer wells and examining how much impact they have on the total the production. The comparison of FOE and FPR for 4 wells (sgc =10%) and for five wells is illustrated in Figure 3.5.

The recovery obtained by adding additional three wells was 29.5% which is above the recovery for four wells 25%.

Table 3.5 shows that all the five wells are producing well (>900,000 Sm3/day) and maintained an average plateau of 5.5 years. Also, from the FPR vs Time the lowest reservoir pressure attained was above 120bars. This value is quite high, greater than 100bar (abandonment pressure). This again suggests that the five wells drilled are not adequate to get maximum recovery from the field. The reservoir still has sufficient energy to produce more oil. Therefore additional three wells were added making a total of eight (8) well, the plots of FOE, FPR and FOPR at this new condition are as shown in Fig 3.6.

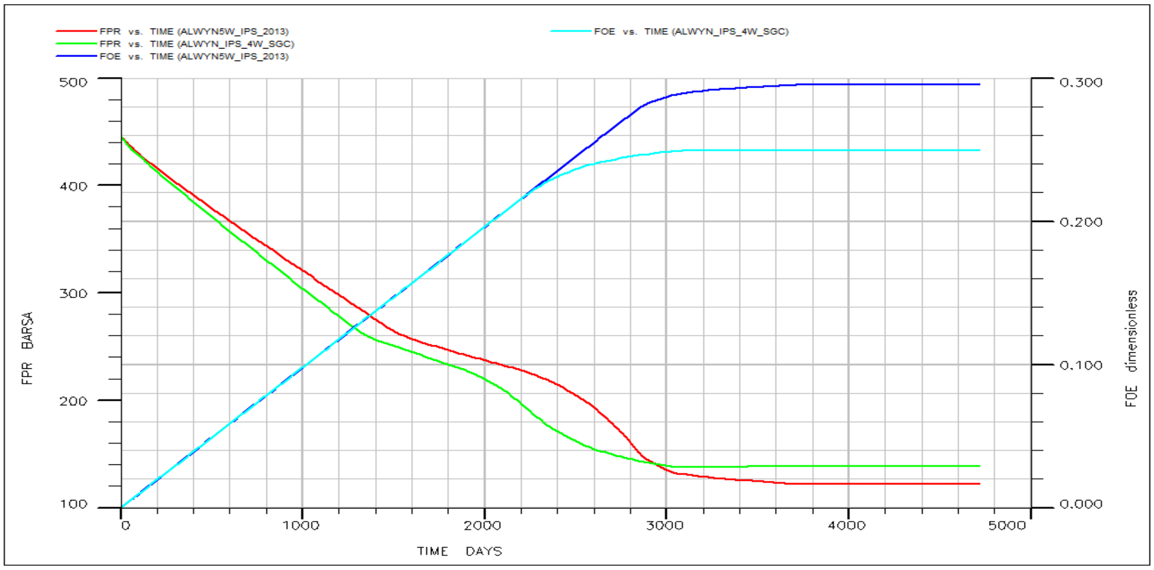

Figure 3.5. Comparing FOE and FPR for 4 wells (sgc =10%) and for five wells

Table 3.5. Individual well Performance for the first 5.5 years of production

Well	WOPT	WOPR	WGOR	WWCUT
N2	1610000	>600	<200	<10%
N3	1400000	>600	<200	<10%
A4	2620000	>1100	<200	<10%
P2	2500000	>800	<200	<10%
P4	2350000	>700	<200	<10%

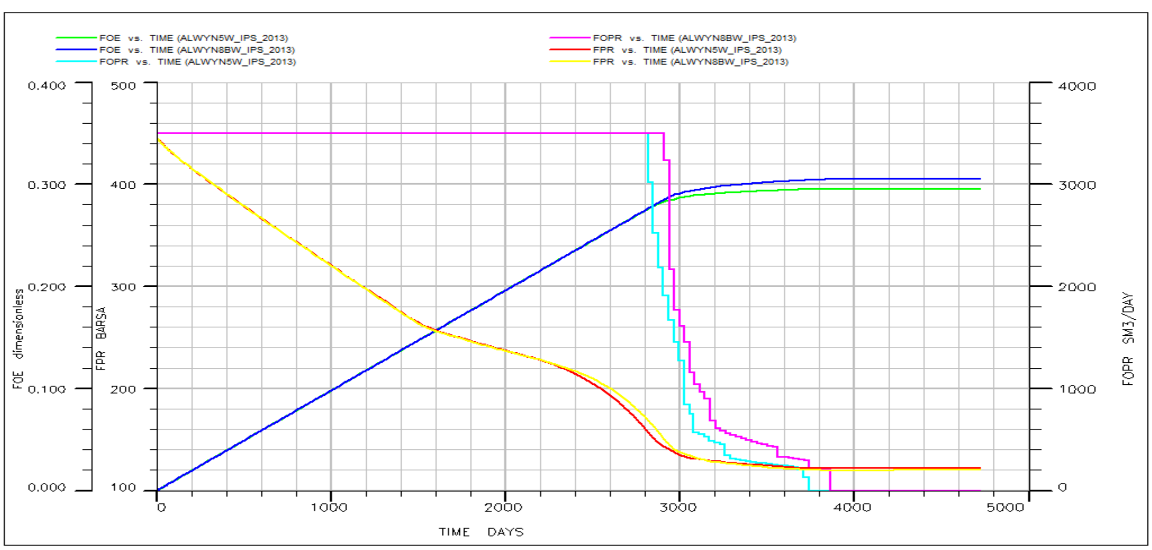

Figure 3.6. FOE, FPR and FOPR vs. Time for the 5 wells and 8 wells cases compared

Figure 3.6 indicates an increased oil recovery of 30.9% in the case of natural depletion with eight wells. This is a significant improvement over the 25% obtained from using only four wells and 29.5% obtained from using five wells respectively. It can also be seen from the FPR curve that the pressure declined slightly below 120bars.

All the eight wells produced optimally for the period of over 8 years and 2months at approximately above 500m^3/day. In addition the field maintained a plateau rate of 3500 bopd for over 8-year period. Most of the wells were shut after 8years of production. An investigation for this was done by checking the WGOR, WWCUT for the wells. The perfor-mances of the various cases of Sgc and number of wells are shown in Table 3.6.

3.4. Summary of natural depletion and optimization

Table 3.6 presents comparison of the performance of the reservoir for the various cases.

Table 3.6. Comparison of the performance for the various cases

Well definition	Recovery (%)	Lowest BHP (bars)	Field oil rate (Sm^3/d)	Plateau period (yrs)	Max. water cut
Sgc(0%)- 4wells	22	135	3500	6	79
Sgc(10%)- 4wells	25	140	3500	6	75
Sgc(10%)-5wells	29.6	122	3500	7.7	56
Sgc(10%)-8wells	30.9	119.5	3500	8.2	62

3.5. Scenario two: water injection results

3.5.1. Late water injection

This involves depleting the reservoir from the initial reservoir pressure (446 bars) to a flowing bottom hole pressure of 290bars and then starting water injection. Figure 3.7 gives details of the results obtained from the late water injection situation.

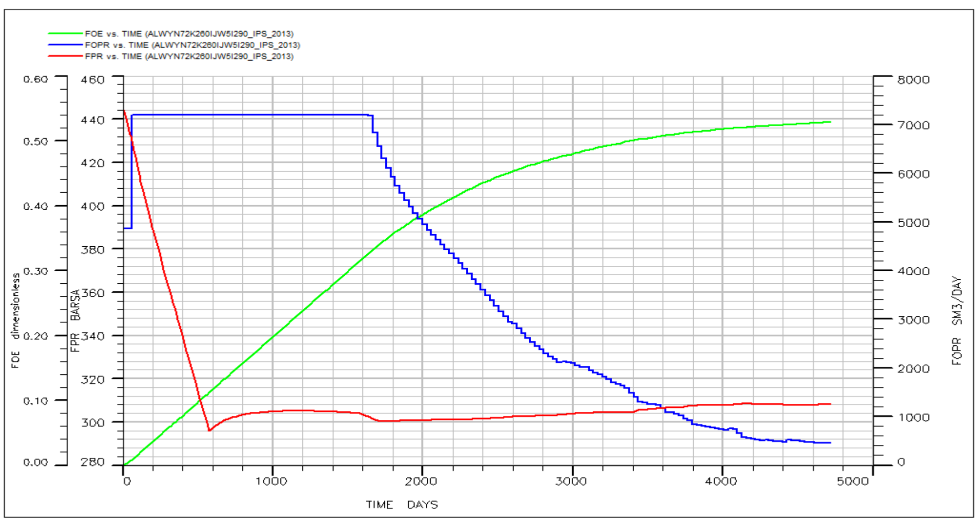

Figure 3.7 FOE, FOPR and FPR for the Llate water injection

3.5.2. Early water injection scenario

This involves depleting the reservoir from the initial reservoir pressure (446 bars) to a flowing bottom hole pressure of 350bars and then starting water injection. Figure 3.8 gives details of the results obtained from the early water injection scenario.

3. Discussion

The scenarios investigated included: natural depletion, late water injection and early water injection. Simulation results were obtained from natural depletion of the reservoir to 100bar with 8 wells (5 vertical and 3 deviated), a recovery of 30.9% was achieved with a production plateau rate of about 3500Sm3/day for about eight (8) years. This is a significant increase compared to the field efficiency of 25% and 22% obtained when using only 5wells and 4 wells respectively to drain the reservoir. For the water injection case, simulation was done by integrating pressure maintenance through water injection scheme. Five injection wells were placed adopting peripheral pattern to the (8) production wells. The reservoir was initially depleted to a bottom-hole flowing pressure of 290bars, after which water injection was started.

Ultimate Oil Recovery: from the chart presented, the maximum oil recovery was (30.9%) achieved with 8 wells. The same accounted for maximum pressure depletion with minimal water production and relatively low GOR. The low recovery from this type of reservoirs suggests that large quantities of oil remain in the reservoir and, therefore, this reservoir will be considered a good candidate for secondary recovery applications.

Reservoir pressure: The reservoir pressure declined rapidly and continuously. This reservoir pressure behaviour is attributed to the fact that no extraneous fluids or gas caps are available to provide a replacement of the gas and oil withdrawals.

Water production: There was considerable water production with the oil during the entire producing life of the reservoir. This is due to the presence of an active water drive.

Gas-oil ratio: This natural depletion is characterized by a rapidly increasing gas-oil ratio from all the wells, regardless of their structural position [8]. After the reservoir pressure has been reduced below the bubble-point pressure, gas evolves from solution throughout the reservoir.

Optimum Injectors: Four injection wells were initially drilled including well A2 which was converted to an injector. But, a quick pressure decline was experienced indicating that more injectors are required. Also placing four injectors, total rate achievable is a maximum of 1200Sm^3/d due to the constraint of 3000Sm^3/d.

Therefore, a total of five water injectors and 8 producers were used. This number of injectors was above the estimate from the MBE calculations. The five injectors were observed to maintain the pressure above 300bars and higher recovery compared to the four injectors which was barley about 288bar.

Recovery: Oil recovery from the late and early water injection scenarios are shown. The maximum FOE recorded was 53%. Production plateau rate of 7200m^3 was also maintained for over 4 years.

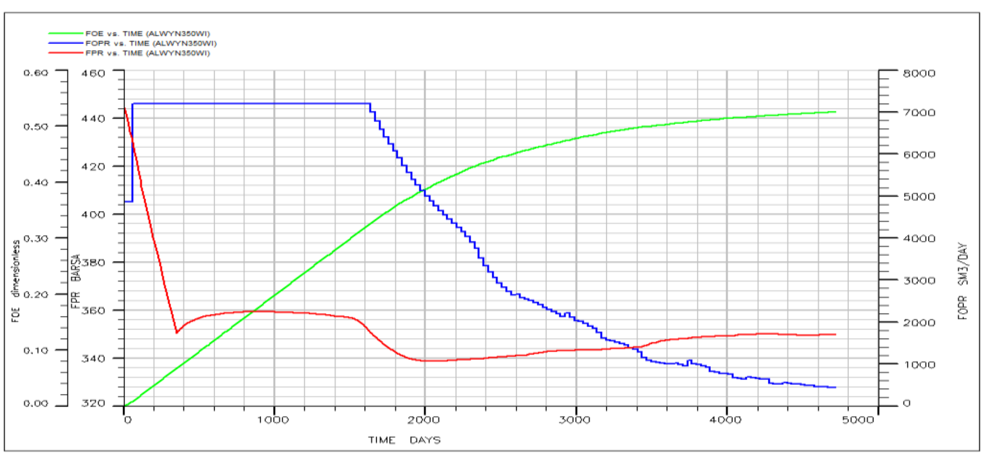

Figure 3.8. FOE, FOPR and FPR for the early water injection scenario

4. Conclusion

Natural depletion and water injection options were evaluated in this work for the development of UBED field. For the natural depletion case, the ultimate recoveries were examined at sgc of 0% and 10% respectively and the results were presented. Similarly, for the water injection scenario, the UBED field was assessed for late water injection (pressure depleted to 290bars) and the early water injection (pressure depleted naturally to 350 bars). For both cases, the results were presented. For each of the two cases examined, it can be clearly seen that the water injection significantly increased the amount of oil recovered. In the early water injection cumulative recovery was 52.5% compared to the 53% recovery realized from the late water injection case.

Based on the results of the various simulation scenarios, the water injection scenario after natural depletion to 290 bars process was found to be the most economically profitable and technically efficient scenario considering total recovery, total profit of the project and operational techniques that would be employed.

Nomenclature

EUR	*Estimated ultimate recovery*
DD	*Drawdown*
PI	*Productivity index*
Ea	*Areal sweep efficiency*
Ev	*vertical sweep efficiency*
FGOR	*Field Gas-Oil Ratio*
FOE	*Field Oil Recovery Factor (%)*
FOIP	*Field Oil in Place*
FORFE	*Field fraction total oil produced by expansion*
FORFF	*Field fraction total oil produced by free gas influx*
FORFG	*Field fraction total oil produced by gas influx*
FORFR	*Field fraction total oil produced by rock expansion*
FORFS	*Field fraction total oil produced by solution gas*
FORFW	*Field fraction total oil produced by water influx*
FOPT	*Cumulative Field Oil Production cumulative total*
FOPR	*Field Oil Production*
FPR	*Field Pressure*
FWCT	*Field Water-Cut*
FWPR	*Field Water production rate*
FWPT	*Field Water Production cumulative total*
ROIP	*Regional Oil in Place*
WBHP	*Well Bottom Hole Pressure*
WGOR	*Well Gas-Oil Ratio*
WOPR	*Well Oil Production Rate*
WWCT	*Well Water-Cut*

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