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Defining the Optimal Development Strategy to Maximize Recovery and Production Rate from an Integrated Offshore Water-Flood Project

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Abstract

A reservoir development plan provides the necessary guidance and information for establishing whether or not a project is economically viable considering possible development project options, risks and uncertainties in order to define the most optimal development concept that will increase oil production and reduce production costs. The aim of this project was to determine the optimum way to develop and produce an offshore oil field in a manner that considers risks and uncertainties and values stakeholders' interest. A stochastic multi-tank reservoir model was created using MBAL and it consist of various producers and water injection wells. Sensitivity analysis was carried out on Seven development scenarios with a view to examine effect of maintaining reservoir pressure, sustaining well productivity and injectivity, optimize well counts and improving well delivery- timing, cost and well performance. The economic viability of each of the development scenarios was carried out to determine the net present value, incremental project cash flow, unit technical cost, unit development cost and breakeven price BEP of each of the scenarios. The optimal development strategy was then selected based on the production performance and key economic indicators. The project provided an opportunity to develop an additional 396MMbbls of recoverable oil from 32 new wells both producers and injector wells (P+WI).

INTRODUCTION

Globally, oil consumption is predicted to increase in the near future, hence the oil industry is confronted with the issue of increasing its oil production and reducing production costs to meet future demands. Arguably, this can be achieved by the application of various production optimization techniques (Abbas, et al., 2015; Akpan, et al, 2019; Asadollah, 2012; Layti, 2017; Mai, 2008; Majani, 2018; Rezapour, 2009). The ultimate goal of virtually all effort spent on understanding a petroleum field is to devise an optimal strategy to develop, manage, and operate the field.

In the oil and gas industry, operators often draw up a reservoir development plan (RDP) that may provide the best technical solution and roadmap throughout the development stage of a reservoir. Reservoir development plan studies provide the necessary guidance and information for establishing whether or not a project is economically viable considering all possible development project options, risks and uncertainties in order to define the most optimal development concept that will increase oil production and reduce production costs. But this has been a challenge in the oil and gas industry especially during times of price volatility.

In order to achieve the optimal way to develop a reservoir, a set of integrated multi- disciplinary team is involved during the RDP to achieve a high degree of integration as well as identifying and solving problems that may not be visible to one discipline but seen clearly by others (Rodriguez-Sanchez, et al., 2012). It is clear that an effective field performance review and production optimization services that may provide measurable performance improvements to oil and gas assets is required to support the opportunity of identification of an asset. An integrated study is therefore required to build on the current understanding of the field's performance as an important step towards opportunity identification, evaluation and definition plan.

This research work focused on the development of a shale-induced high offshore water-flood project. The aim of this work was to determine the optimum way to develop and produce from this offshore oil field in a manner that successfully balances risks, uncertainties and values stakeholders' interest. For an effective understanding of the reservoir of interest, analytical simulation is required. This is done to determine the future performance of the reservoir through decline curve analysis, determine the technical limit recovery factor using the Buckley leveret plots and determine the degree of lateral heterogeneities, permeability variation, mobility ration, volumetric sweep efficiency, displacement efficiency and ultimate recovery using the Dykstra Parson's coefficient (Ahmed, 2006).

A numerical analysis was carried out by creating a multi-tank model using MBAL and different developmemt scenerio was considered and an economomic model was built to determine the economic viability of all the production scenerios.

METHODOLOGY

The different steps that were carried out to achieve the overall aim of the research work is shown in Fig 1.

Historical Brief of Ozumba North Reservoir

The field has a production history of a multi-tank reservoir identified as Tank 1 and Tank 2. The multi-tank reservoir production began in 1981 and the field was produced for 10 years. The recovery mechanisms for the multi-tank reservoir was a combination of water drive, expansion drive and water injection mechanism. The shallow reservoir represented as Tank 1 is driven by large aquifer and expanding solution gas while the deeper reservoir represented as Tank 2 is driven by a combination of injected water, limited aquifer and expanding solution gas.

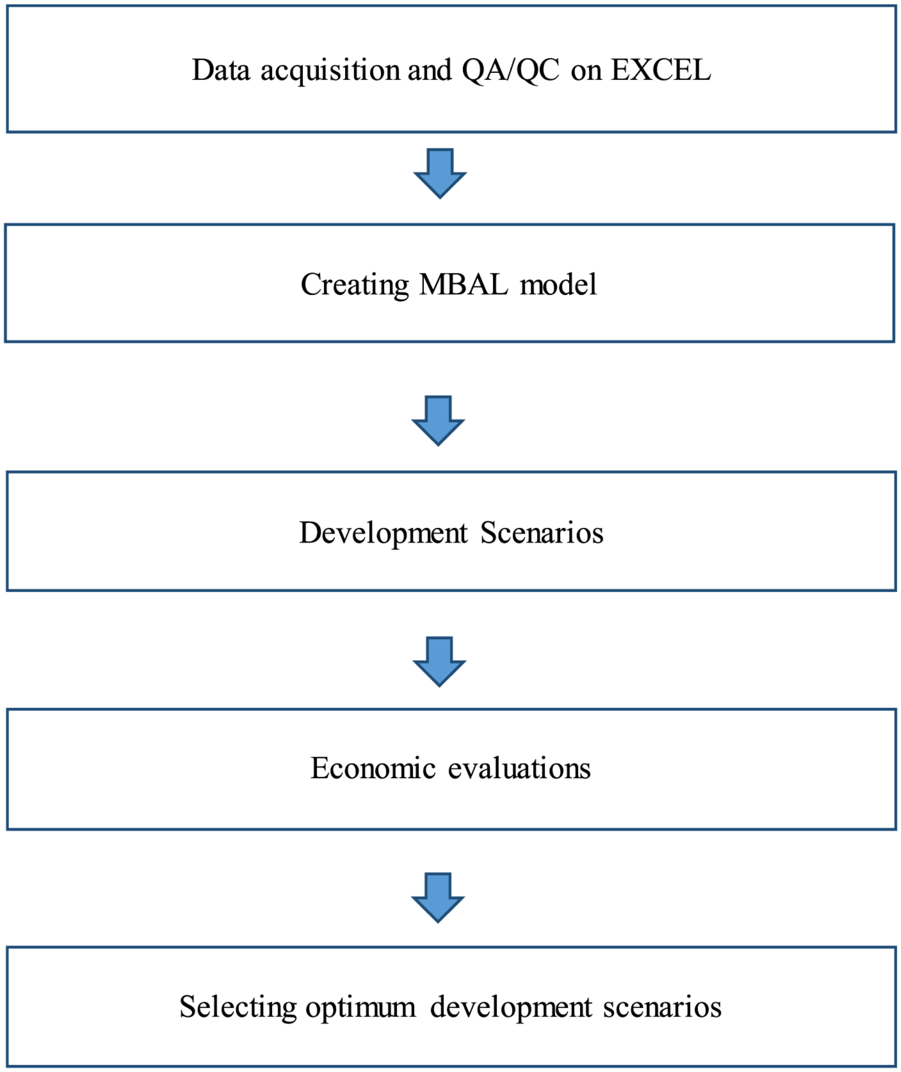


Figure 1—Methodology Flow chart

INPUT DATA PROCESSING AND ANALYSIS

Input Data (QA/QC). A quality assurance/ quality check-QA/QC was carried out on Microsoft excel to verify and detect normal/abnormal trends by plotting pressure verses time, pressure verses cumulative oil, oil rate verses cumulative oil etc to calculate the voidage replacement ratio (VRR) to know how much water to inject to keep the pressure above bubble point. Production and injection profiles (QA/QC) is shown in Fig 2. The plot shows a change in trend in the average oil rate in Tank 2. This is because of an increase in pressure to maintain or increase production as indicated by the green arrow in the plot below. It is seen in Fig 3 that the pressures in tank 1 and tank 2 are steadily depleting as production is achieved. No abnormal trend was detected. He pressure time profile plot is shown in Fig 4.

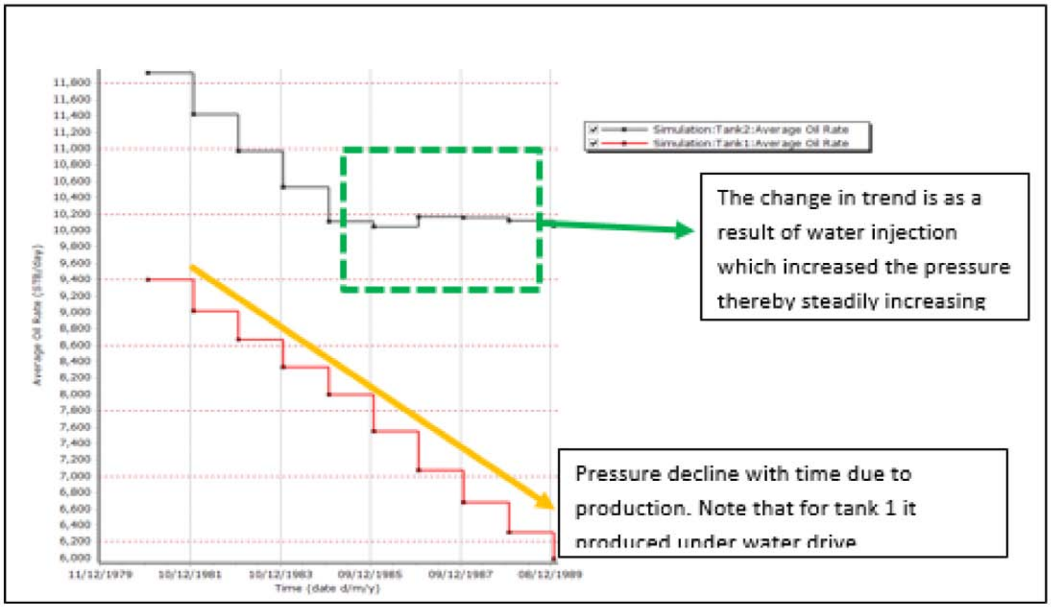


Figure 2—Production and Injection profiles

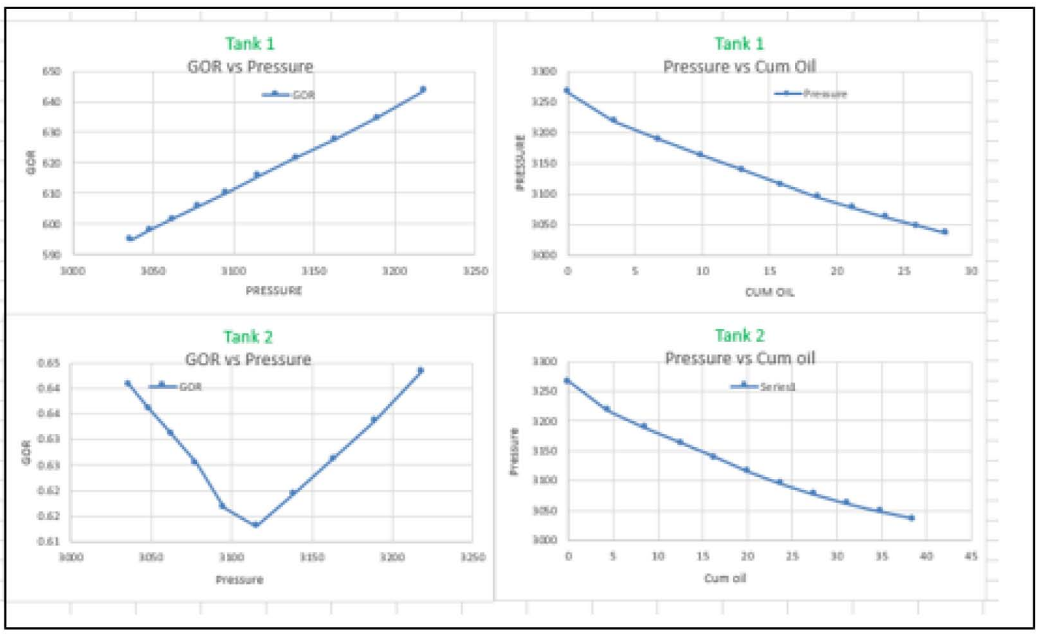


Figure 3—Pressure Profiles

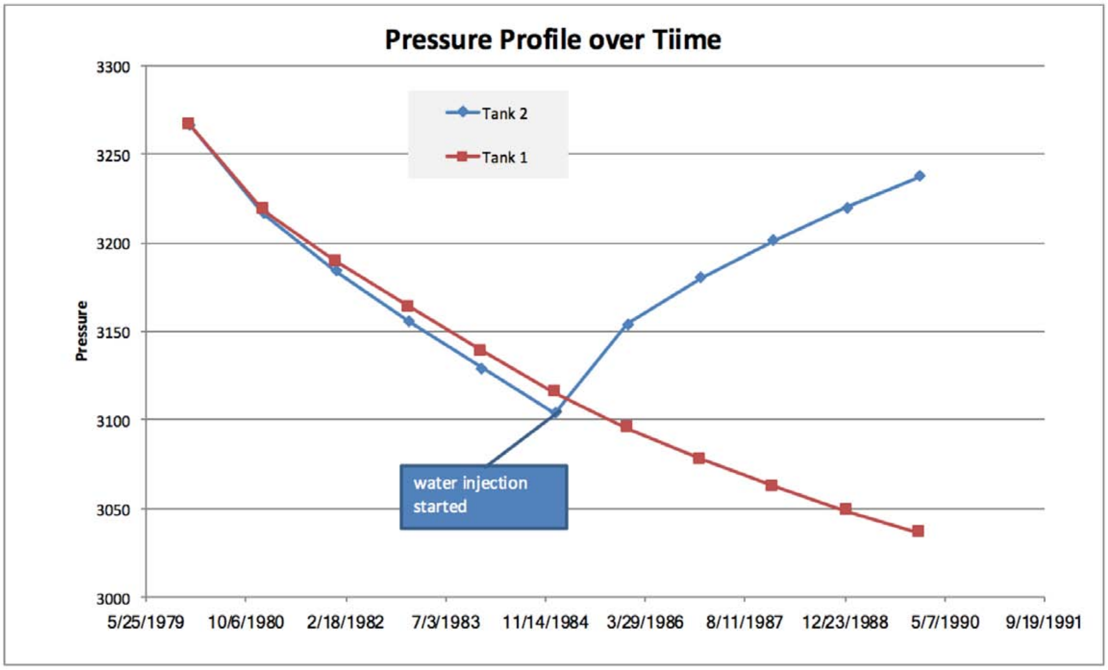


Figure 4—Pressure vs time Profile

PVT data (QA/QC)

The PVT data below shows the plots of the three PVT parameters determined as a function of pressure by routine lab analysis. These parameters relate the surface production to underground withdrawal (reservoir volumes) for an oil reservoir. Fig 5 shows the PVT analysis of Rs, Bo and viscosity of the oil.

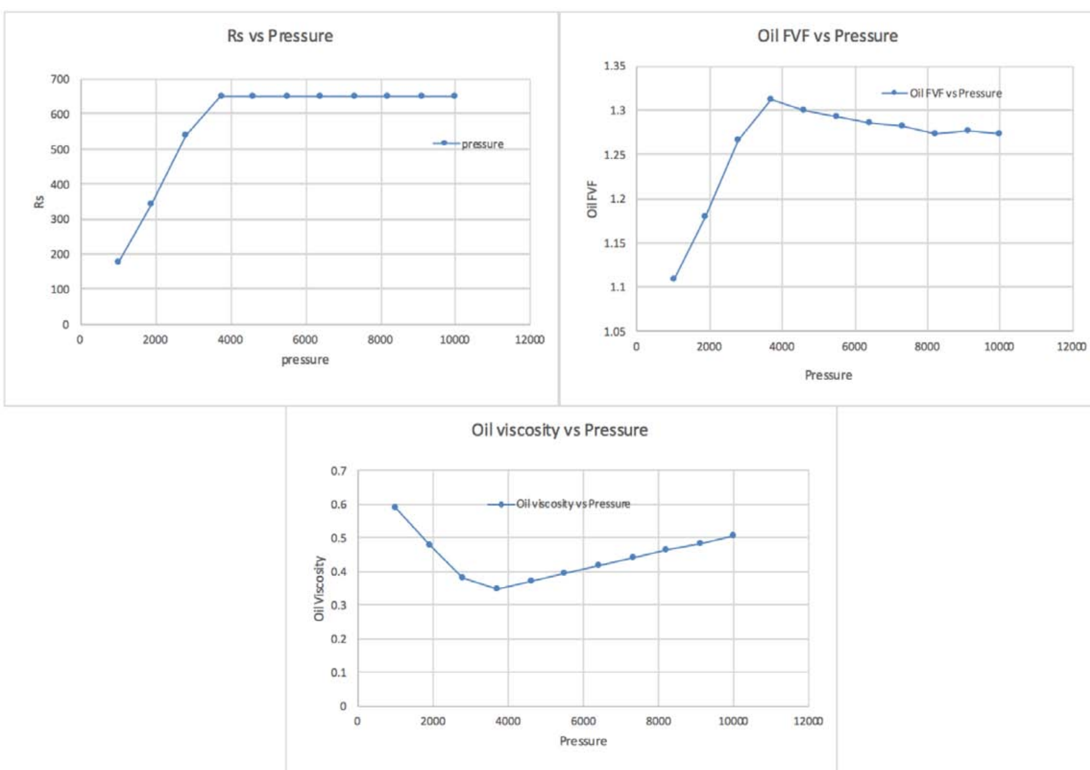


Figure 5—PVT analysis of Rs, Bo and viscosity of the oil

Data Analysis and Modelling.

PVT Characterization and Modelling

To find the best PVT match, PVT matching of lab data with PVT correlations were carried out.

Generally, the good understanding on how to match PVT using the PVT Matching procedures on MBAL were adopted. From the various correlations in figure 6, Glaso and beat et al. correlations was seleced.

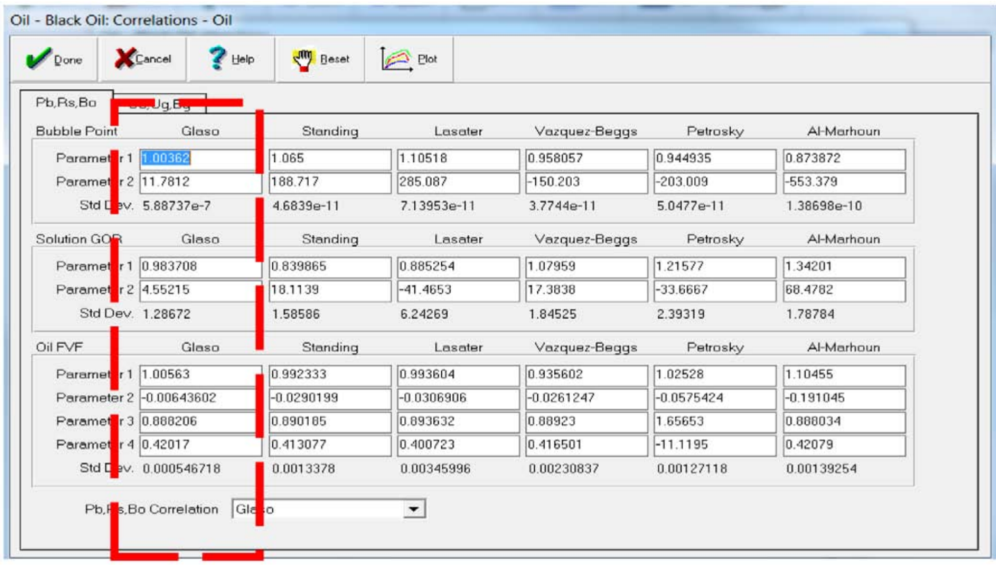


Figure 6—PVT Correlations

Relative Permeability model (normalization, avg)

The averaging of different SCAL representative samples of fluids present in the reservoirs were specified. The relative permeability data is shown in Fig 7 and the data was normalized.

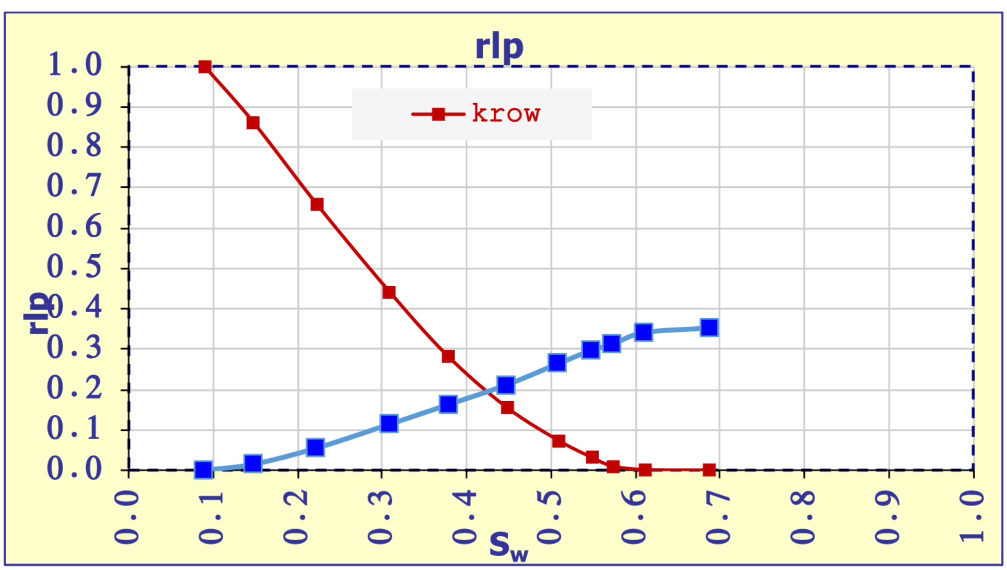


Figure 7—Relative permeability curve

Water influx model

Various aquifer models that best represent the aquifer of interest were critically investigated and the best representation of the aquifer was selected. However, reservoir engineering experts recommends that the Hurst Van Everdingen and Dake Modified or Hurst Van Everdingen modified method should be used for water influx calculation. The aquifer model on MBAL used was the Hurst-van Everdingen-modified model and the qquifer properties is shown in Fig 8. The parameters in these models can be tied to reservoir geology unlike some of the other models. Also, some others are approximations to this models.

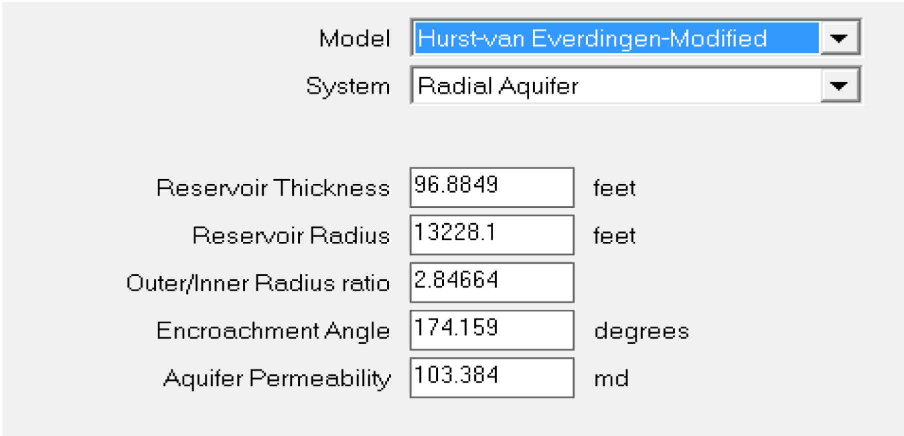


Figure 8—MBAL Aquifer model

Analytical Methods

DCA (Predict wells performance and UR). Decline curve analysis (DCA), during the QA/QC was first done using Microsoft excel to predict the future performance of the wells (Fig 9). The 3 types of DCAs were analyzed and tested based on the conditions each gives and the one that best describes the future performance of the well was used. DCA models are applicable to both oil and gas production, however, gas production requires special consideration of other factors such as water influx. However, using MBAL, DCA was carried out using the model provided by the software. Production and injection wells were created on the existing multi-tank model to calculate inflow and outflow performance. This provided information for outflow to maximize production rate and have an idea of the STOIIP and Recovery factor RF.

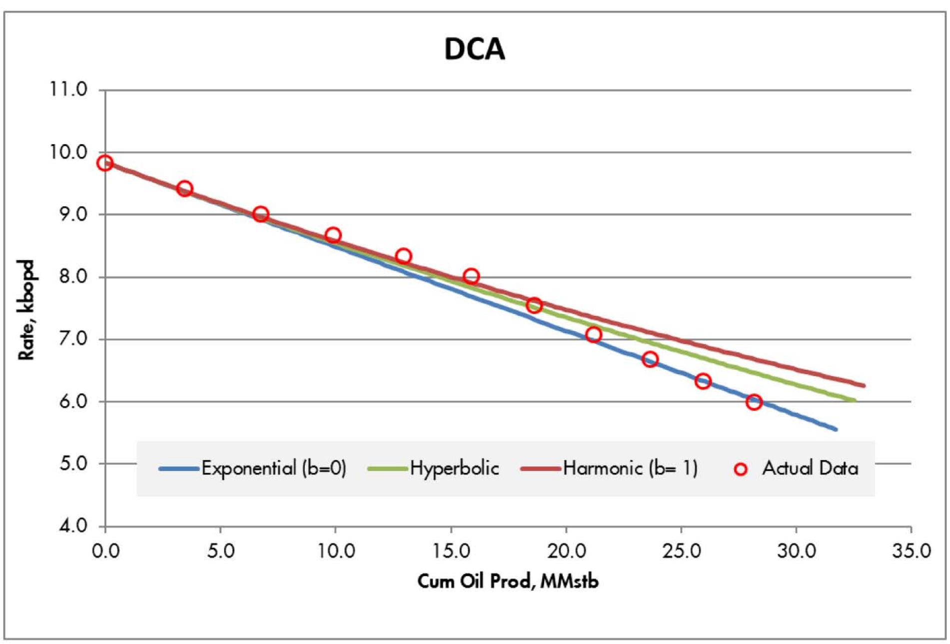


Figure 9—Decline curve analysis plot

Dykstra-Parson. Dykstra-Parson explains the concept of permeability variation which is designed to describe the degree of heterogeneity within the reservoir usually the lateral heterogeneity. Fig 10 shows the Dykstra Parson plot.

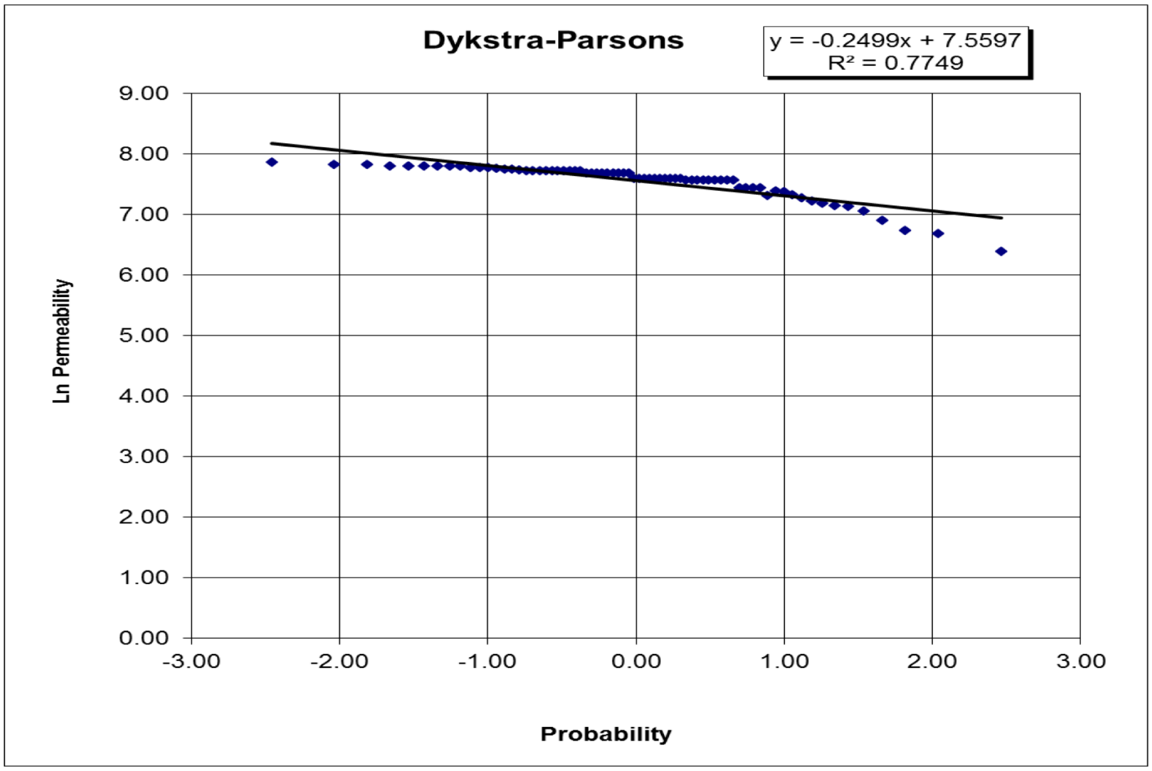


Figure 10—Dykstra Parson Plot

Craig-Geffen-Morse (CGM method). The parameters obtained from the CGM as shown in Table 1 were used to calculate the start of flood, first response, peak response and the end of project.

Table 1—Craig-Geffen-Morse (CGM method)

Craig-Geffen-Morse (CGM method)	
Lorenz Coeff	**0.12**
Swc	**0.090**
Residual Oil Saturation @ end life	**0.312**
Floodable Pore Volumes, MMbbls (Vp)	**76,440**
Economic WOR	**25.0**
Oil Production Rate @ Flood Start, Mstb/d	**50**
Primary Decline Rate	**5.0**
Oil Formation Volume Factor @ abond. Press.	**1.31**
STOIIP, Mstb	**100,000**
Cum Prod, Mstb	**10,000.0**
Remaining STOIIP, Mstb	**68,800**
Movable STOIIP, Mbbls	**76,440**
Boi @ WF start (from day-1), bbl/stb	**1.30**
Swi	**0.09**
water Injection rate, Mstb/d	**65**
Residual Oil Saturation @ flood start	**0.598**

Creating MBAL model

The steps taken to build the MBAL model are discussed in the following sections.

Input data for creating MBAL model. The input data for the MBAL is shown in Fig 11.

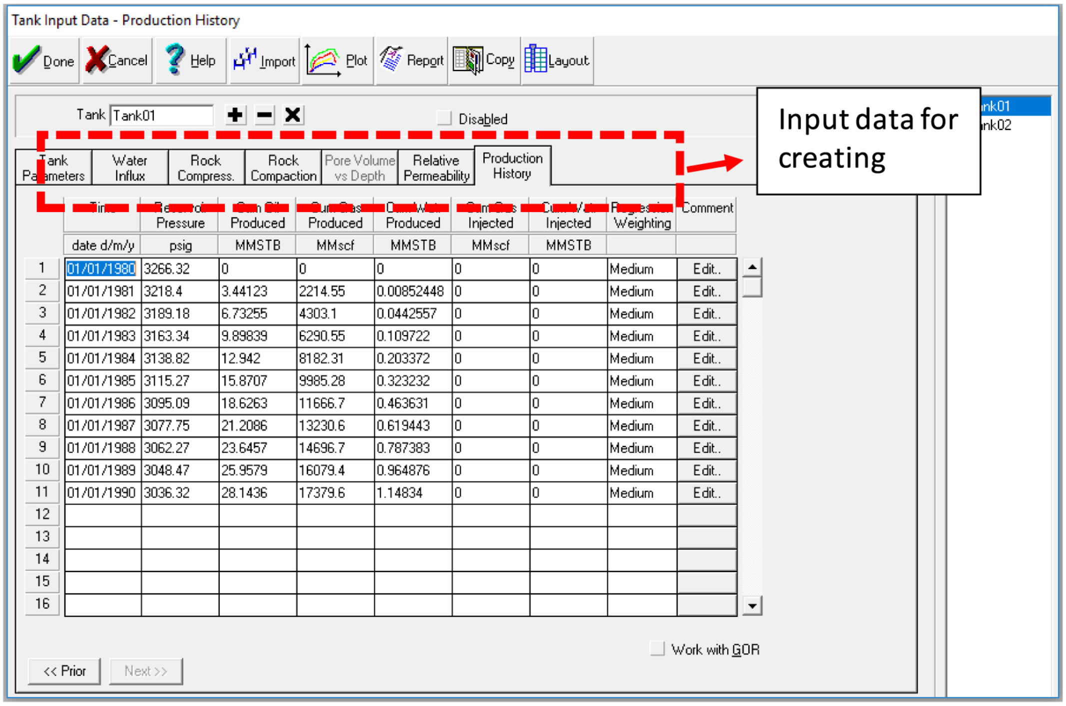


Figure 11—MBAL Input data

History Match. The production history data and PVT data were used to model the reservoir by matching the history, the production data was constrained, and the pressures were calculated. The simulated pressures were then matched with the actual pressures and the volumetric were estimated (Fig 12 and Fig 13). The 10 years production history of both Tanks 1 and 2 was used for the history match. The future performance of the two tanks, the recovery factor (RF), the volumetric, and the pressures were then estimated.

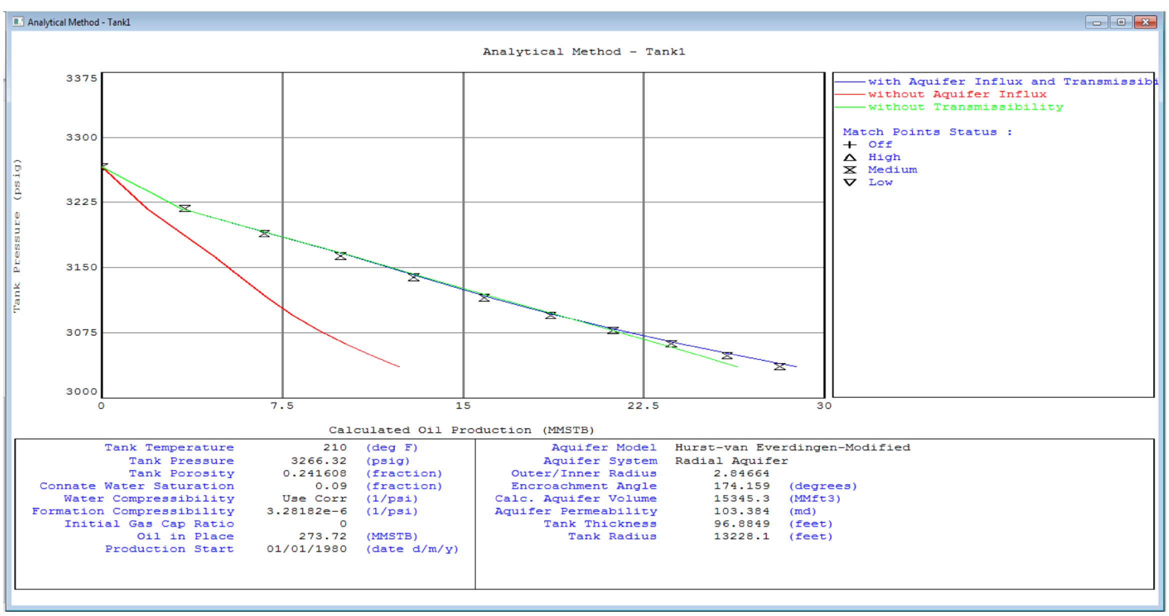


Figure 12—History match for Tank 1

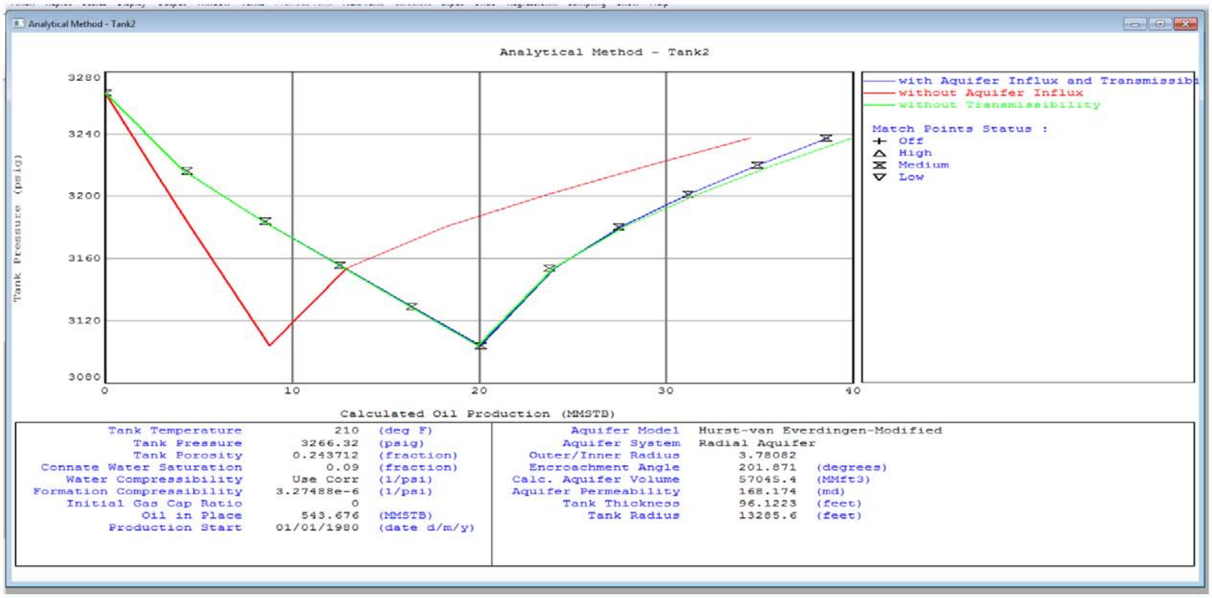


Figure 13—History match for Tank 2

Energy Plot (Drive Mechanism). Analysis of the drive mechanism of the reservoir using MBAL was carried out. It was observed tha Tank 1 produced under water drive as indicated by the large water influx in figure 14 while Tank 2 produced under water injection as well as via water influx in figure 15.

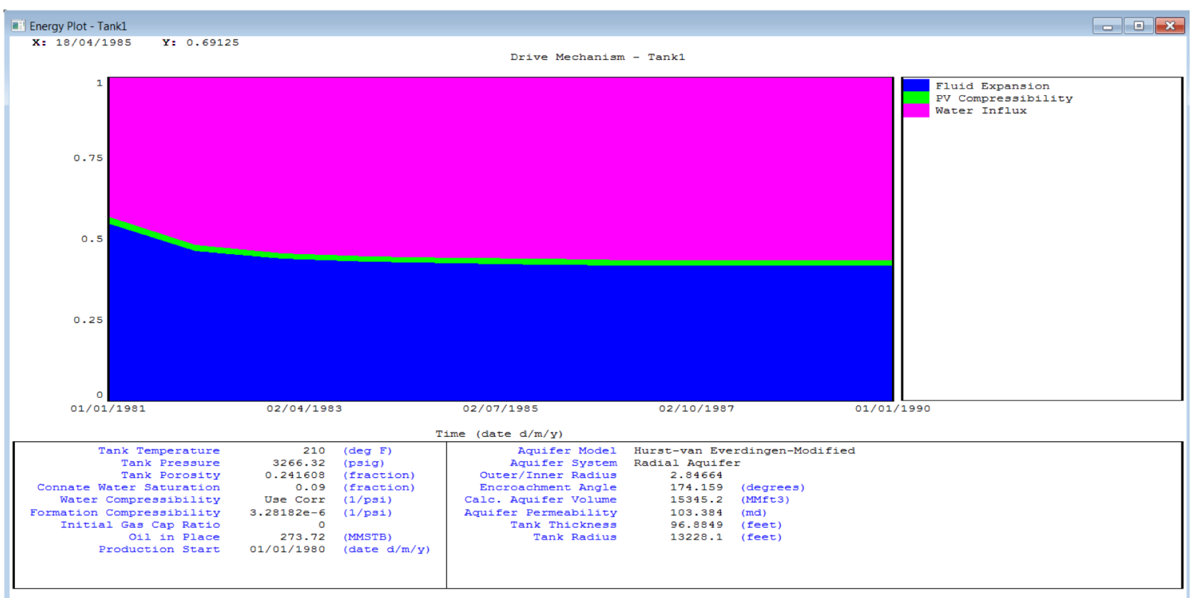


Figure 14—Depletion drive

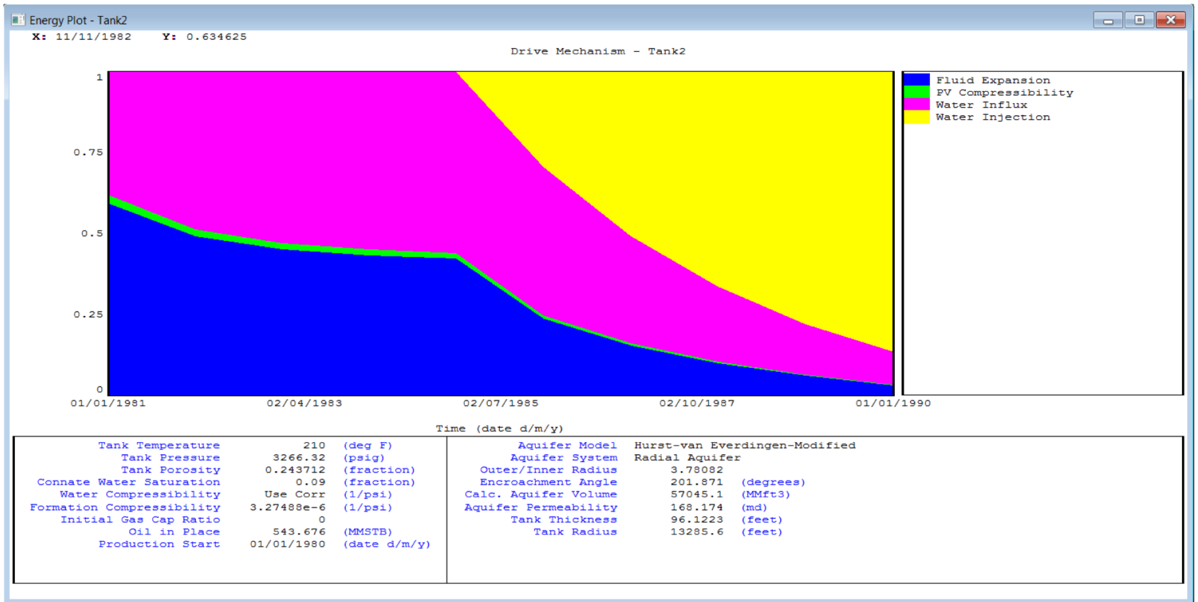


Figure 15—Water injection drive

Production Forecast. Production prediction was carried out by first of all predicting production profile through well models with water injection and voidage replacement with water and specifying prediction start date. Well type was defined by selecting the fraction model, corrected the productivity index for mobility with relative permeability, well inflow/outflow performance and IPR.

Various scenarios with a view of optimizing well count and maximizing recovery through drilling of NFA (No Further Activity) wells, water injection wells, vertical and horizontal infill wells in Tank 1 and Tank 2 were then carried out and analyzed. Results from the prediction were compared with the simulation results and history match results.

Creaming Curve. To determine well count, the creaming curve was used to optimize the number of well to be drilled in the field (Fig 15).

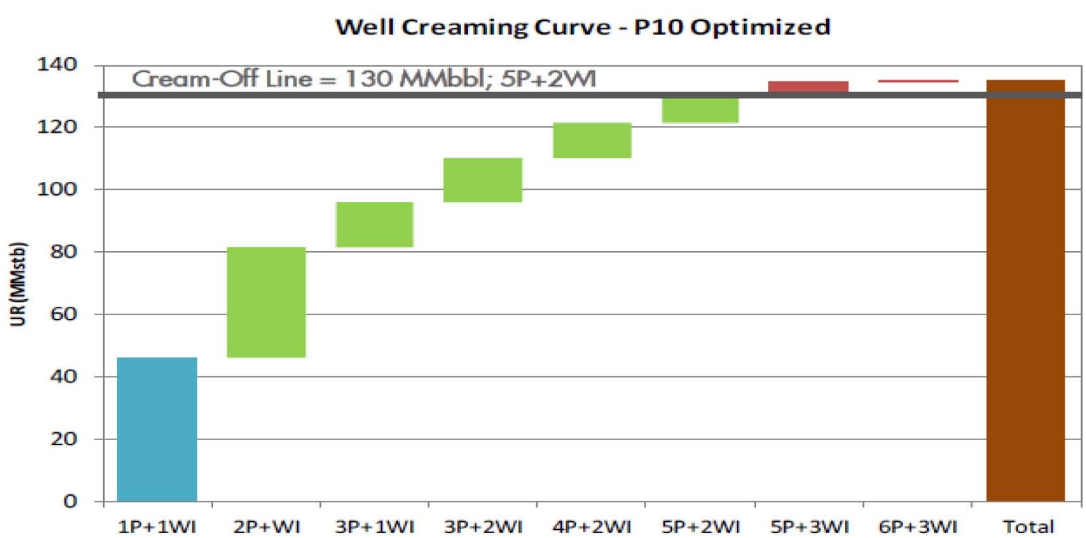


Figure 15—Creaming curve to optimize well count

Development Scenarios

Scenarios that focus on several iterations with a view of optimizing well count, well type and the drilling sequence to maximize recovery during field maturity processes. There were 7 scenarios that were considered which include;

- No further activity, NFA (Vertical wells)
- Infill Drilling (Vertical wells)
- Infill Drilling (Horizontal wells)
- Infill Drilling + Water Injection (WI) in Tank1
- Infill Drilling + Water Injection (WI) in Tank1 horizontal
- Infill Drilling + Water Injection (WI) in Tank2 + infill in Tank2
- Infill Drilling + Water Injection (WI) I in Tank2 + infill in Tank2 horizontal

Project Economics

Production Sharing Contract (PSC). The project was evaluated under the 1993 Nigeria Deepwater Production Sharing Contract (PSC) and the Petroleum Profit Tax Act of 1959.

Economic Indicators. The project profitability indicators evaluated includes: Net present value (NPV), unit technical cost (UTC), unit development cost (UDC), break-even price (BEP).

Net Present Value (NPV)

Net present value (NPV) is the difference between the present value of cash inflows and the present value of cash outflows over a period of time. NPV is used in capital budgeting and investment planning to analyze the profitability of a projected investment or project. The equation below is used to calculate NPV.

Unit Technical Cost (UTC)

The sum of the capital costs and operating costs can be divided by the number of barrels produced to give a unit cost. This is given mathematically as

$$UTC\left(\frac{\$}{bbl}\right) = \frac{\text{Total costs}(CAPEX + OPEX)}{\text{Total Production}} \quad 1$$

Unit Development Cost (UDC)

The sum of the capital costs divided by the number of barrels produced gives the unit development cost This is given mathematically as:

$$UDC(\$/bbl) = \frac{\text{Total CAPEX}}{\text{Total Production}} \quad 2$$

Break-even price (BEP)

The Breakeven Price (BEP) is the point at which total cost and total revenue are equal in a project. It's a point in a project where there is neither profit nor loss. The main purpose of break-even analysis is to determine the minimum price that must be exceeded for a business to be profitable.

RESULTS AND DISCUSSIONS

This section presents the results obtained from this study and the discussion of these results.

MBAL Model

The MBAL multi-tank model; Tank 1 and Tank 2 comprises of both producer and injector wells as shown in figure 16 below. Various development scenarios for water flooding scheme including infill drilling of vertical and horizontal wells in both Tank 1 and Tank 2 were conducted. Various sensitivity analysis was conducted to examine effect of maintaining reservoir pressure, sustaining well productivity and injectivity, optimize well counts and improving well delivery- timing, cost and well performance. For each development scenario, a simple economic evaluation was conducted in order to meet the objective of the project.

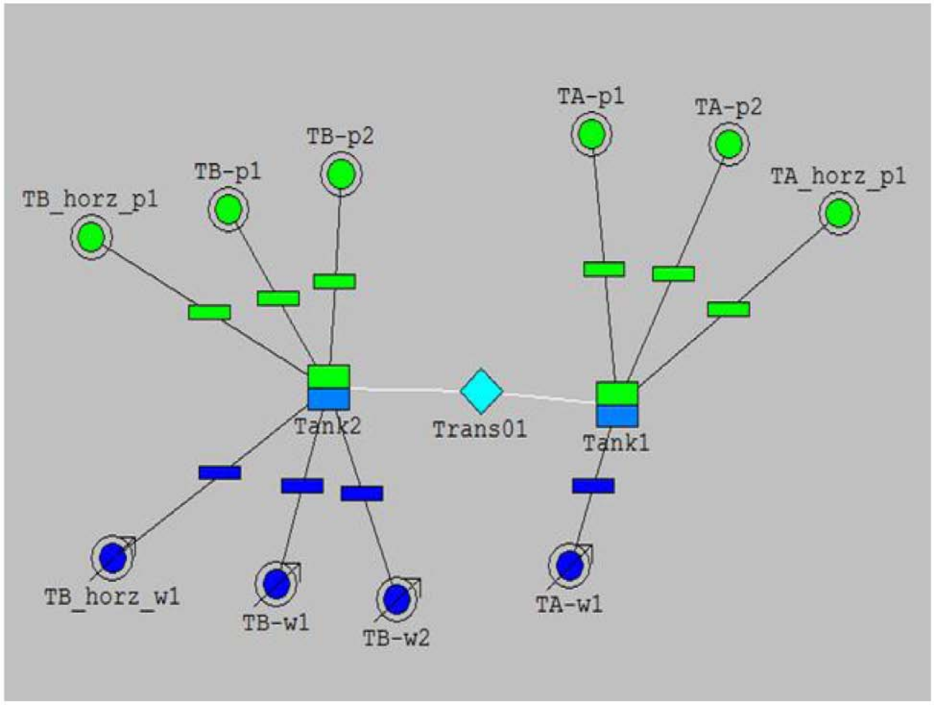


Figure 16—MBAL Multi-Tank Model

Results of Development Scenarios

Scenario 1: No further activity, NFA (Vertical wells). NFA prediction was based on the study and observation (forecast) carried out without new capital expenditure (CAPEX) invested. A total of 6 vertical wells were drilled, 2 producers in Tank 1 and 2 producers, 2 injectors in Tank 2. The reservoir produced a total ultimate recovery, UR of 115MMbbls with a recovery factor, RF of 27.3% in tank 1 and 19.6% in tank 2.

The oil and gas production streams (Fig 17) presents the trend of oil rate, gas rate, water injection rate, water cut and cumulative oil and gas production. The oil production rate was about 136 kbopd; the gas was produced at a rate of about 15-17 MMscf/day with an initial water injection rate of 24.7 STB/day. Cumulative oil produced was about 181.5 MMstb and the corresponding cumulative gas was produced at about 131.9 k/MMscf. There was a steady pressure decline in the reservoir.

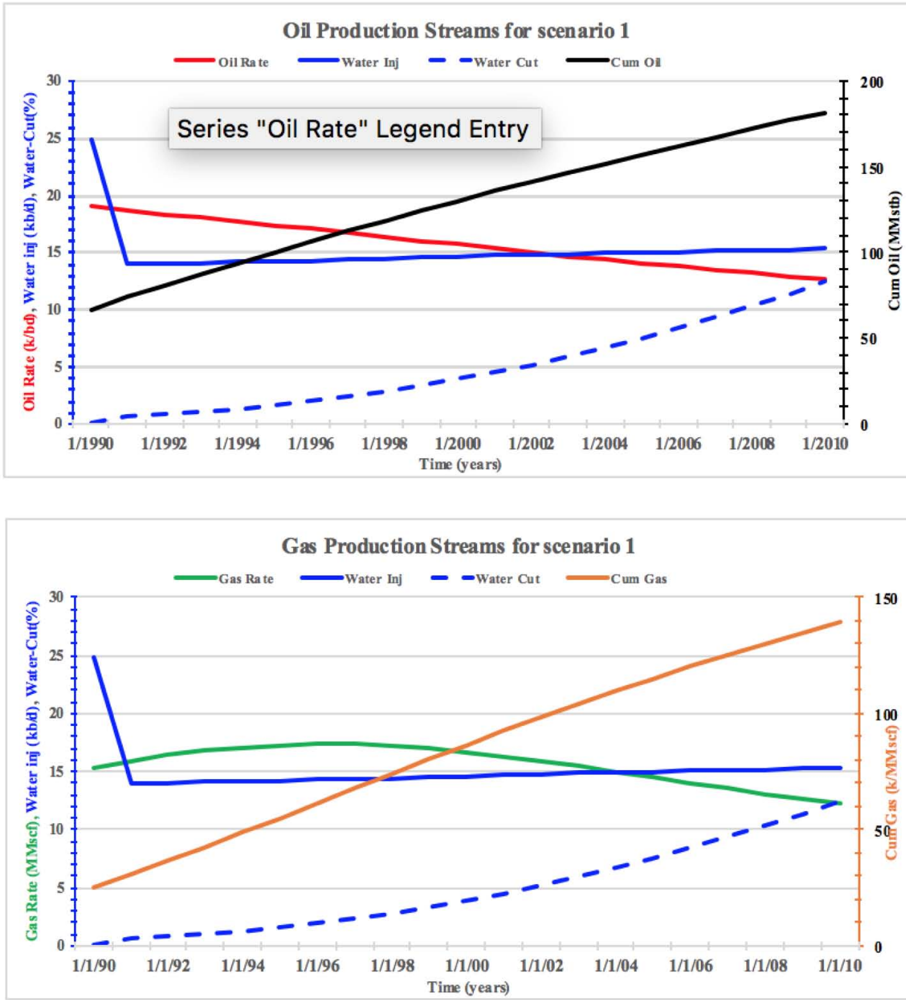
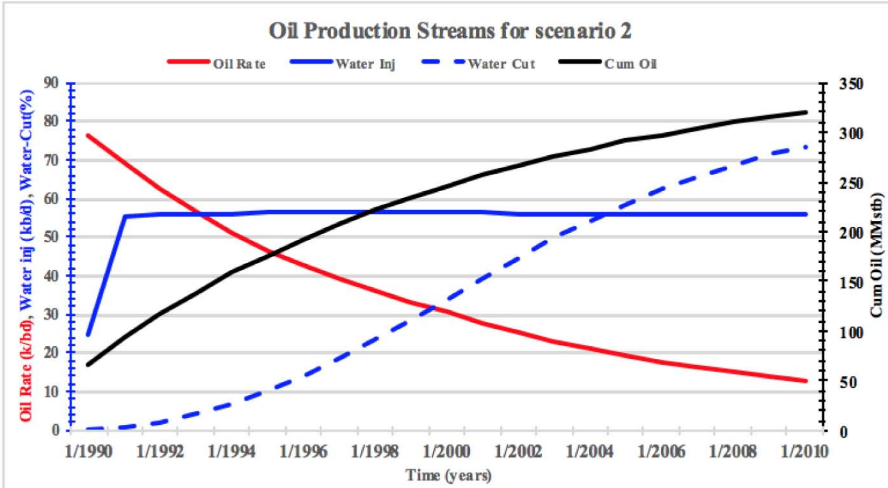


Figure 17—Production Stream for Scenario 1

Scenario 2: Infill Drilling (Vertical wells). In order to improve sweep efficiency, drilling of wells in spaces between existing wells in the reservoir to accelerate recovery was carried out. This was done by increasing the number of wells in the reservoir through Infill drilling of vertical wells. A total of 24 infill vertical wells were drilled, 8 of which were producers in Tank 1, 8 producers and 8 injectors in Tank 2. The reservoir produced a total ultimate recovery, UR of 253MMbbls with a recovery factor, RF of 32.8% in Tank 1 and 42.2% in Tank 2.

The production stream for scenario 2 is shown in figure 18 and it shows an initial oil production rate of 269.1 kbpod and a gas rate of 61 MMscf/d at an average water injection of 55 STB/d. The cummulative oil and gas production yielded about 66.6 MMstb and 24.8 k/MMscf respectively. The average reservoir pressure was maintained below bubble point pressure to prevent formation of secondary gas cap in this production streams.



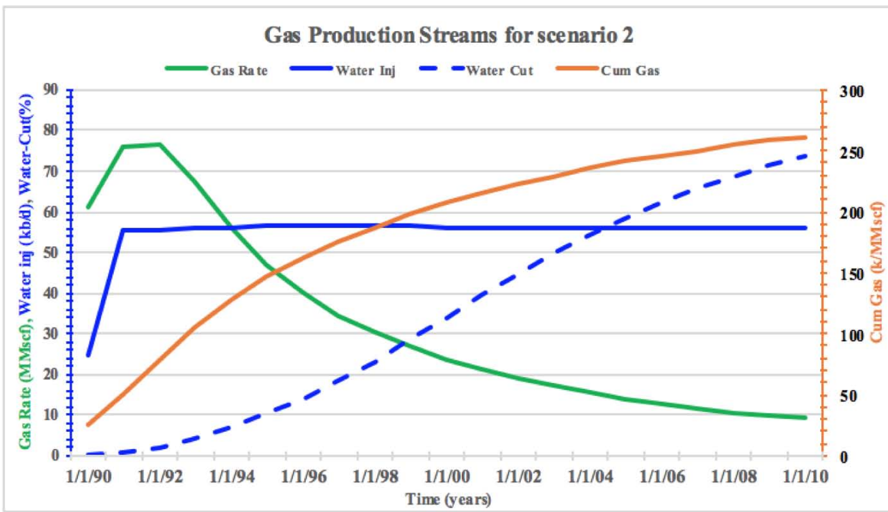
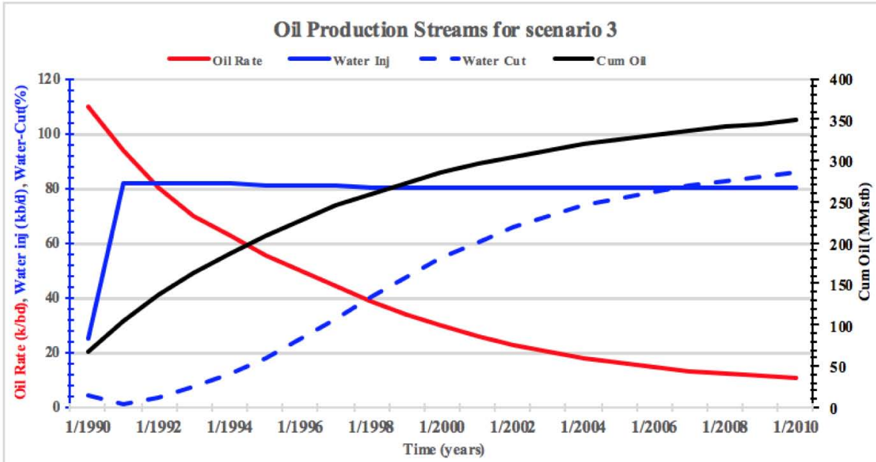


Figure 18—Production stream for scenario 2

Scenario 3: Infill Drilling (Horizontal wells). In this scenario, infill drilling of horizontal wells in spaces between existing wells was carried out in order to further improve sweep efficiency in the reservoir. The reservoir produced a total ultimate recovery (UR) of 283 MMbbls with a recovery factor (RF) of 32.6 % in Tank 1 and 47.8 % in Tank 2. The total number of wells drilled were 24 horizontal wells, 8 of which were producers in Tank 1, while there are 8 producers and 8 injectors in Tank 2.

However, figure 19 shows the trend in oil rate with an initial production of 242.2 kbpod that steadily declined as a result of pressure maintenance. There was a sudden spike in the gas production rate initially but due to an increase in the water injection rate, it declined steadily over time. Total cumulative oil and gas produced was about 349.4 MMstb and 284.2 k/MMscf.



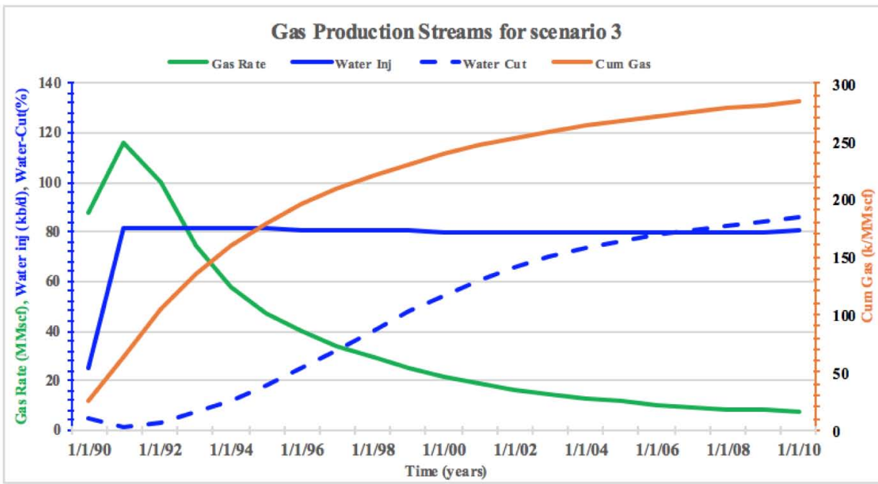


Figure 19—Production stream for scenario 3

Scenario 4: Infill Drilling + Water Injection (WI) in Tank1 Vertical well. Infill drilling of vertical wells resulted in an ultimate recovery, UR of 329 MMbbl with a recovery factor of 55.8 % in Tank 1 and 44.8 % in Tank 2. This was achieved from a total number of 32 horizontal wells with 8 producers, 8 injectors in Tank1 and 8 producers, 8 injectors in Tank 2.

As water injection rate increases from an initial rate of 24.7 kbod to 119.3 kbod, there was an increase in the oil production rate compared to scenario 3 as indicated by value of 345.7 kbpod (Fig 20). Due to pressure maintenance activities, the cumulative oil and gas produced were 395.9 MMstb and 244.3 k/MMscf respectively.

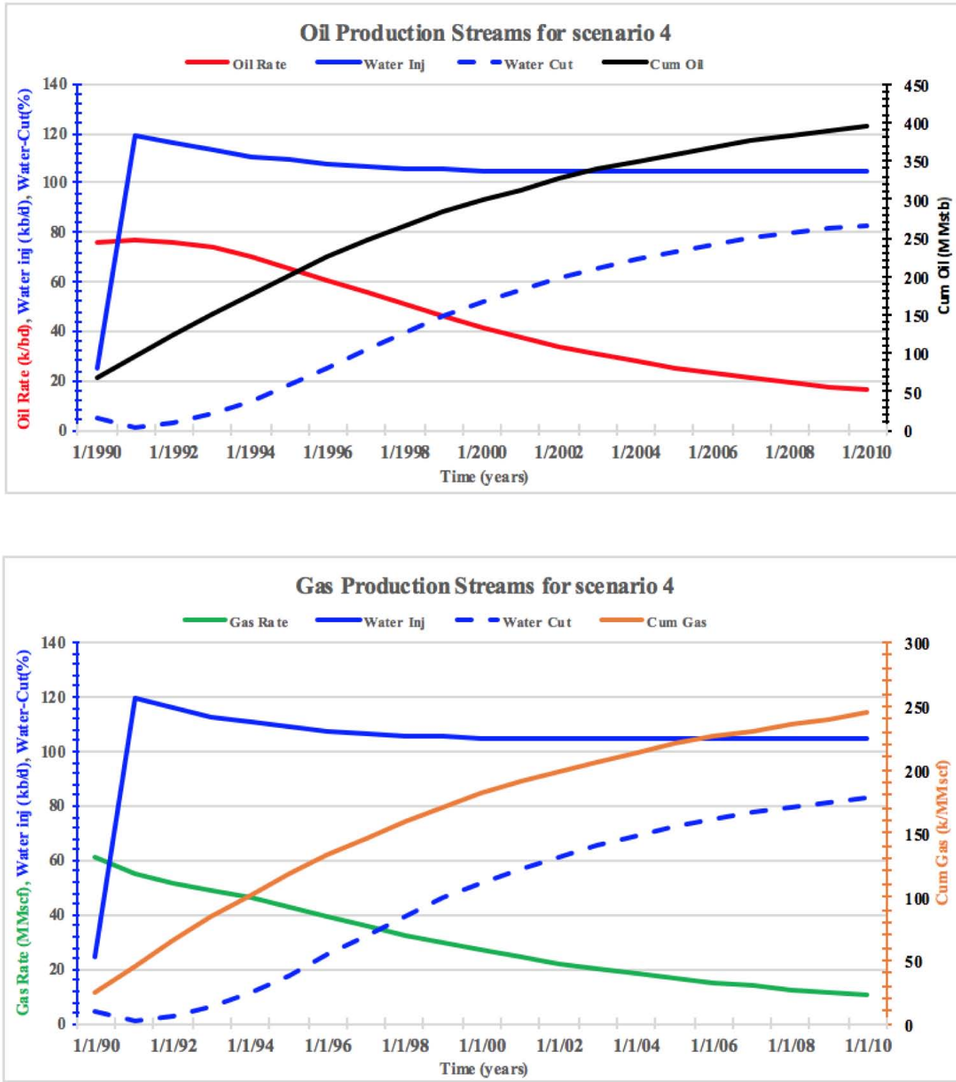
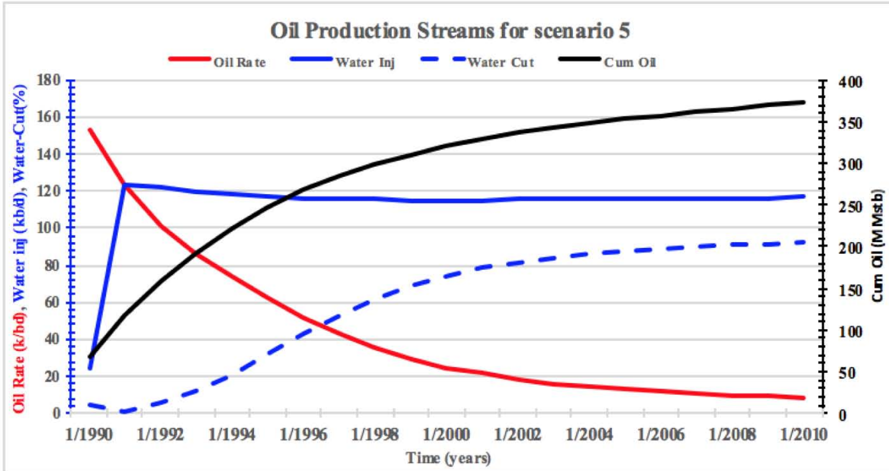


Figure 20—Production stream for scenario 4

Scenario 5: Infill Drilling + Water Injection (WI) in Tank1 horizontal well. Again, scenario 5 took the same lead as in scenario 4 but infill drilling of horizontal wells from a total number of 32 horizontal wells with 8 producers, 8 injectors in Tank1 and 8 producers, 8 injectors in Tank 2 resulted in an ultimate recovery of 296 MMbbl with a recovery factor, RF of 32.5 % in Tank 1 and 52.2 % in Tank 2. A reduction in ultimate recovery, UR was observed when horizontal wells were drilled in this scenario.

From the production streams in Figure 21, the initial oil production rate was 353.3 kbpod, the initial water injection rate was 24.7 kbod which was increased to 123.4 kbod as a result of decrease in average reservoir pressure. For the same reason, the initial gas rate was increased from 122.1 k/MMscf to 165.6 k/MMscf with an initial oil rate of 153.6 kbod. the cumulative oil and gas produced was 372.7 MMstb and 301 k/MMscf.



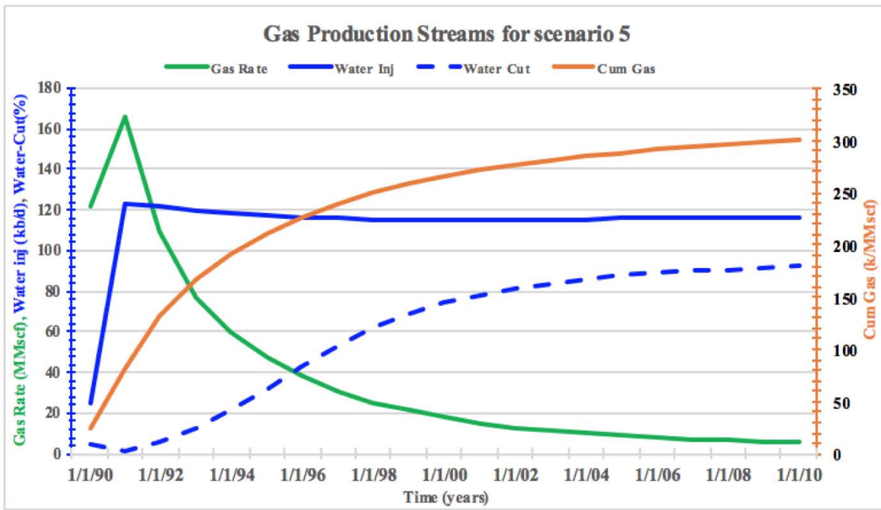


Figure 21—Production stream for scenario 5

Scenario 6: Infill Drilling + Water Injection (WI) in Tank2 + infill in Tank2 vertical wells. Infill drilling of vertical wells in Tank 2 where there was an active water injection and good transmissibility resulted in an ultimate recovery of 362 MMbbls with a recovery factor of 55.8% in Tank 1 and 50.8 % in Tank 2. This was achieved from a total number of 40 wells with 8 producers, 8 injectors in Tank 1and 12 producers, 12 injectors in Tank 2.

From the production stream for scenario 6 (Fig 22), a great amount of water was injected into Tank 2 in order to increase the pressure in the reservoir for a better sweep efficiency. The pressure was however maintained which resulted in an oil rate of 381.2 kbpod and an initial gas rate of 73.8 MMscf/d. About 89 % water cut was maintained with a cumulative oil production of 428.6 MMstb and cumulative gas production of 265.3 k/MMscf.

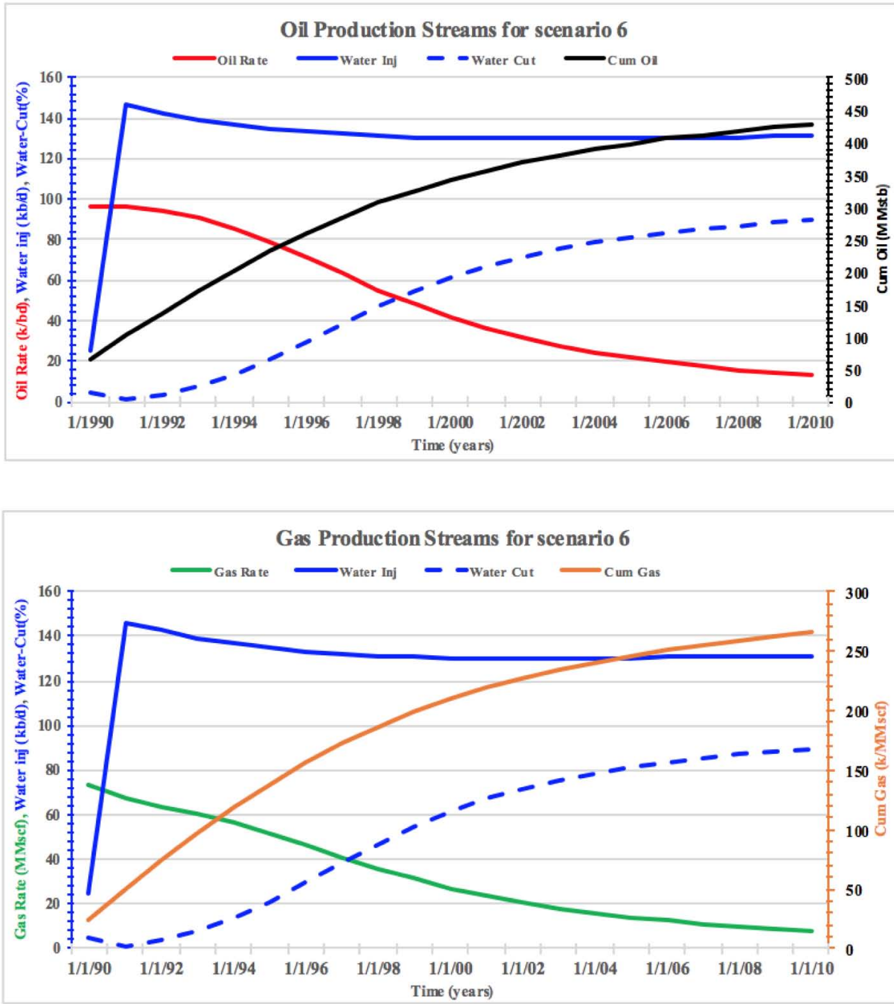


Figure 22—Production stream for scenario 6

Scenario 7: Infill Drilling + Water Injection (WI) in Tank 2 + infill in Tank 2 horizontal well. In this scenario, infill drilling of horizontal wells in spaces between existing wells to accelerate the recovery was carried out. A total ultimate recovery, UR of 429 MMbbls from 40 new horizontal wells in both tank 1 and tank 2 was recorded. The recovery factor, RF in Tank 1 was 55.8 % and 50.8 % in Tank 2.

From Figure 23 above, water was injected at an initial rate of 24.7 kbod to 146.1 kbod where the reservoir pressure was maintained at an average injection of 133kbod. The oil production rate was about 344.5 kbpod with an initial gas production rate of 128.5 MMscf/d. The cumulative oil and gas production from this scenario was 380 MMstb and 305 k/MMscf respectively.

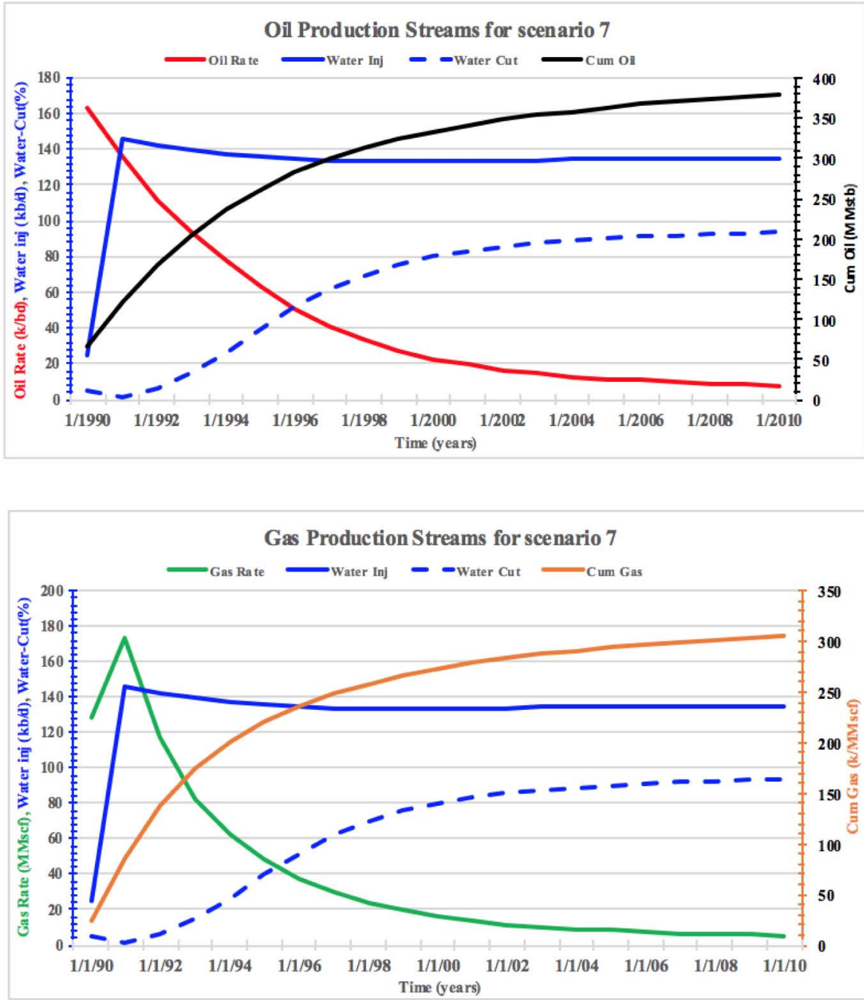


Figure 23—Production stream for scenario 7

Economic Analysis/Evaluations

An Economic analysis was carried out to determine the economic viability the project under the 1993 Deepwater Production Sharing Contract (PSC) under the Petroleum Profit Tax Act of 1959. The economic evaluation process began by looking at the objective, scope, project maturity, risks and strategies involved in the project. A quality assurance/quality check (QA/QC) analysis was carried out to ensure data set was okay. The economic model was built based on the economic assumptions established in table 4.1 and the economic indicators of interest in the project were calculated; Net Present Value (NPV), Internal Rate of Return (IRR), Unit Technical Cost (UTC), Unit Development Cost (UDC) and Breakeven Price (BEP). Results from the calculations were computed and analyzed and the project was concluded by choosing a scenario that agrees with most of the economic indicators of interest.

Various economic assumptions were made as shown in table 4.1 below. The date in the project was converted to present value PV (2019). Also, this is in order to quantify the value of the project in present time.

Table 2—Generic PSC Model Assumptions

Generic PSC Model Assumptions	
PV Reference Date	**2019**
Discount Date Year_Shift	0
Inflation Rate	2.5%
Oil Price	55.0
Oil_Price_Type	MOD
CA_Uplift	0%
ITC_Rate	50%
Oil PPTax Rate	50%
Oil Royalty Rate	4%
EduTax_Rate	2%
EduTax_Deductible	Yes
NDDC_Rate	3%
NDDC_Applicable	Yes
RT Discount Rate	10%
Company Equity Percentage	100%

The cost of drilling a well in this project was estimated to be \$30 million per well. The capital expenditure of the well (CAPEX) is the total sum of all the wells drilled (producers and injectors) as indicated in Table 3 below. The facilities CAPEX include Manifolds, flowlines, etc and was estimated at a cost of \$50million. The operating expenditure (OPEX) and abandonment Expenditure (ABEX) were estimated to be \$20 million per well.

Table 3—Deepwater Oil Projects- Data Series

Project Description	Total UR	Well Capex	Facilities Capex	Opex + Abex	Total Cost	No of Wells
	MMbbl	$mln	$mln	$mln	$mln	@30mln/well
Scenario 1	115			300	300	0
Scenario 2	253	720	300	980	2000	24
Scenario 3	283	720	300	980	2000	24
Scenario 4	329	960	400	1140	2500	32
Scenario 5	396	960	400	1140	2500	32
Scenario 6	362	1200	500	1300	3000	40
Scenario 7	429	1200	500	1300	3000	40

Table 4 shows the oil rates produced for each scenario. In choosing the optimal scenario, the highest oil rate was considered as highlighted in red (381.2 kbopd). However, the scenario following the highest oil rate as highlighted in yellow (353.3 kbopd) was also considered alongside other economic evaluators.

Table 4—Oil Production Rates

Project Description	Oil Rate (kbopd)
Scenario1 - NFA (Vertical Wells)	136
Scenario 2 - Infill Drilling (Vertical Wells)	269.1
Scenario 3 - Infill Drilling (Horizontal Wells)	242.2
Scenario 4 - Infill Drilling + WI in Tank1 (Vertical Wells)	345.7
Scenario 5 - Infill Drilling + WI in Tank1 (Horizontal Wells)	353.3
Scenario 6 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Vertical Wells)	381.2
Scenario 7 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Horizontal Wells)	344.5

Net Present Value (NPV). The Net present value (NPV), shows the difference between the present value of cash inflows and the present value of cash outflows over a period of time by putting into consideration the discount rate i.e 10% in this case. After discounting, the NPV from each of the scenarios was considered. This is because the higher the NPV, the more valuable the project. Scenario 5 presents the highest NPV for both RT and MOD as indicated by these values of $2356.8MM and $6064.2MM respectively (Table 5).

Table 5—Net present value (NPV)

Result Summary Table	NPV10 RT2019 $mln, RT	CS - MOD $MM, MOD
Scenario1 - NFA (Vertical Wells)	704.6	1852.5
Scenario 2 - Infill Drilling (Vertical Wells)	1799.2	5227.6
Scenario 3 - Infill Drilling (Horizontal Wells)	1153.2	4844.1
Scenario 4 - Infill Drilling + WI in Tank1 (Vertical Wells)	2024.2	6211.8
Scenario 5 - Infill Drilling + WI in Tank1 (Horizontal Wells)	**2356.8**	6064.2
Scenario 6 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Vertical Wells)	2204.4	6611.4
Scenario 7 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Horizontal Wells)	2339.8	6089.1

Incremental project Cash flow

The incremental cash flow of a project is the additional operating cash flow that an organization receives from taking on a new project. The incremental cash flows are estimated by comparing the company's net cash flows if the project is accepted and its cash flows if the project is not accepted. In this project, the highest incremental cash flow is considered as indicated by the RT value of $1652.2MM. However, at a constant oil price of $55 (MOD), the highest value is $4758.9MM. Thus, the value on a PV basis lead to choosing scenario 6 that presented the highest incremental cash flow for this project as shown in Table 6.

Table 6—Incremental Project cash flow

Incremental Project Cashflow	RT	MOD
Scenario1 - NFA (Vertical Wells)	704.6	1852.5
Scenario 2 - Infill Drilling (Vertical Wells)	1094.6	3375.0
Scenario 3 - Infill Drilling (Horizontal Wells)	448.6	2991.5
Scenario 4 - Infill Drilling + WI in Tank1 (Vertical Wells)	1319.6	4359.3
Scenario 5 - Infill Drilling + WI in Tank1 (Horizontal Wells)	**1652.2**	**4211.6**
Scenario 6 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Vertical Wells)	1499.8	4758.9
Scenario 7 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Horizontal Wells)	1635.1	4236.6

Unit Development Cost (UDC) and Unit Technical Cost (UTC). However, considering other economic indicators, scenario 3 yielded the lowest UDC but looking at other factors, it will not be economically viable to consider it as it may have a low oil rate, lower NPV, low IRR and perhaps the lowest incremental cash flow. However, most of the economic indicators seemed to agree with scenario 5 and thus the UDC in this scenario is $4.59/bbl which is on the high side how considering the robustness of the project it can be considered.

Table 7—UDC and UTC of the Different Scenarios

Project Description	UDC	UTC
	$/bbl	$/bbl
Scenario1 - NFA (Vertical Wells)	0.00	2.61
Scenario 2 - Infill Drilling (Vertical Wells)	4.03	7.91
Scenario 3 - Infill Drilling (Horizontal Wells)	3.60	7.07
Scenario 4 - Infill Drilling + WI in Tank1 (Vertical Wells)	4.13	7.60
Scenario 5 - Infill Drilling + WI in Tank1 (Horizontal Wells)	4.59	8.45
Scenario 6 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Vertical Wells)	4.70	8.29
Project 7 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Horizontal Wells)	3.96	6.99

The Unit Technical Cost (UTC) is very similar to UDC only that in this case the it considers how much it will cost per barrel to develop and operate from the project of interest. The lower the UTC the more cost effect the project is. However, for the same reasons as UDC, the UTC in scenario 5 was considered although it is the highest value, other economic indicators will economically justify for choosing the final selection of the best development scenerio.

Breakeven Price (BEP). The Breakeven Price (BEP) is the point at which total cost and total revenue are equal in a project. It's a point in a project where there is neither profit nor loss. Meaning that it is the oil and/or gas price at which the NPV is zero. The lower the BEP the better the value of the project and scenario 5 is presented with the least BEP at $12/bbl as shown in Table 8.

Table 8—Breakeven Price

Project Description	BEP ($/bbl)
Scenario1 - NFA (Vertical Wells)	2.37
Scenario 2 - Infill Drilling (Vertical Wells)	12.82
Scenario 3 - Infill Drilling (Horizontal Wells)	18.03
Scenario 4 - Infill Drilling + WI in Tank1 (Vertical Wells)	14.44
Scenario 5 - Infill Drilling + WI in Tank1 (Horizontal Wells)	**12.68**
Scenario 6 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Vertical Wells)	15.77
Scenario 7 - Infill Drilling + WI in Tank2 + Infill in Tank2 (Horizontal Wells)	14.85

Assessment of Scenarios

The assessment of the development scenerios were based on the production philosophy of producing above bubble point via water injection with some aquifer support where available was maintained in the project. The development scenarios were thus based on water-flooding by drilling producer/injectors well pairs, using only producer wells where there was significant aquifer support like in Tank 1 and producers and injectors where support was need as in tank 2. A study has been initiated to evaluate any potential gains by producing any of the reservoirs below bubble point using both Tank 1 and Tank 2 reservoirs as pilot for further investigation.

Selecting the Optimum Development Scenario

The optimum development scenario for this project was chosen based on the key value drivers: Maximize production, minimize cost and Maximize profit and keep facility full. From the seven development scenarios generated, the optimal scenario is one with highest Ultimate Recovery, highest Oil production rate, highest NPV, highest incremental Project Cashflow, lowest UDC, lowest UTC, and lowest Breakeven Price.

Based on Engineering and Economic judgment, Scenario 5-Infill Drilling + WI in Tank1 (Horizontal Wells) was chosen to be the optimal development strategy to produce from the multi-tank reservoir. Although, the scenario was not compliant with some of the economic indicators but it appears to agree with most, of the factors.

Conclusion

- An extensive literature review was done reservoir development planning and waterflooding, so as to aid in understanding their mechanisms, methods and their application.

- The objective of this thesis is to determine the optimal development scenario to maximize recovery and production rate from an integrated offshore waterflood project was carried out.
- The study showed that reservoir development options of a field development plan can be achieved using a stochastic multitank material balance model.
- Seven (7) development scenarios were developed from the model and sensitivity analysis was carried out on each scenario.
- Economic analysis was done through a differential cash flow analysis of the field and an evaluation of the corresponding net present value and other economic indicators.

Conclusively, the optimal development scenario for this project was chosen to be Scenario 5- Infill Drilling + WI in Tank1 (Horizontal Wells). It met the value driver criteria for the project

Recommendation

The strategies for managing the Reservoir development of this project for the rest of its remaining life are strongly predicated on an ability to maintain voidage replacement and optimize sweep and efficiency by maximizing recovery in all the reservoirs. Therefore, all future activities in the field should be geared towards optimizing production. This will involve consistent reservoir management practices and activities.

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