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Evaluation of the Development Strategies for a Greenfield Using Integrated Production Modeling

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Abstract

A comparative analysis was conducted in this paper between a standalone and an integrated production model to assess their effectiveness as field development planning tools. Results showed that an Integrated Production Model was more efficient than a standalone model because interaction between different components of a production system were not captured for standalone models, hence less accurate in prediction. An Integrated Production Modeling approach was used in this paper for running sensitivities on optimum well count, production equipment sizing, pressure maintenance dynamics, and in evaluating development strategies for a Greenfield. A case study is presented in this paper in which gas and water production rates were constrained at 100 MMSCF/Day and 80 MSTB/Day respectively on the basis of the capacity of the surface facility network. An Integrated Production Model was developed for each of the four strategies considered in this paper and were simulated. Options 1 and 2 resulted to a recovery factor of 30.25 % and 34.95 % respectively at the end of prediction, and also met the constraints stated in this paper. Options 3 and 4 gave higher recoveries but did not meet the stated constraints and were not selected. Option 2 was selected as a preferred strategy because it resulted respectively to a cumulative oil production and an oil recovery factor of 35.29 MMSTB and 4.7 % higher than that obtained using option 1. Results showed the effectiveness of Integrated Production Modeling in optimal selection of the development strategy for a Greenfield.

Keywords: *Standalone models; Integrated Production Model; Greenfield; Performance evaluation; Development strategies.*

1. Introduction

An integrated production model (IPM) is an approach used to analyze the response resulting from an interaction of a coupled system consisting of reservoirs, wells and surface facilities. With IPM, proper boundary conditions are honored at all times. The concept of this approach used in this paper involves coupling a reservoir model, a wellbore model and a surface facility model with commercial tools that can be used in modeling each of these components as a single production system model. It can be applied to a wide range of field applications since it aids in describing the behavior of an entire production system and how each component of the system interacts with each other.

Surface facility design and field production planning were previously carried out in isolation from each other and this resulted in errors in predicting production and overall field performance. As standalone models, several time consuming iterations were conducted to effectively study the interaction between the components of a production system. In order to accurately predict field production performance and forecast of future production for different development strategies, Integrated Production modeling was implemented during field development planning and management because it eliminated the need to carry out lengthy and time consuming iterations, making accurate decisions on an appropriate development strategy on the basis of forecasted field production and future return on investment. Also, with the aid of IPM, short and long term decisions are made which will take into consideration the simultaneous interaction of all components of the system.

The main objective of this study is to illustrate the application of an integrated production model developed using Petroleum Expert Software (PROSPER, MBAL and GAP) in evaluating development strategies for a Greenfield or a newly discovered reservoir. The data used for this study depicts that of a reservoir with no production history and hence described as a newly discovered reservoir. Also, a workflow for evaluating development strategies for a Greenfield was developed based on the approach of this study and is also presented. This paper is limited to evaluating development strategies during the primary and secondary recovery phases of the reservoir.

According to [1] and [2], integrated production modeling provides an effective multi-disciplinary understanding of an entire production system such that all components are investigated through an integrated analysis, which leads to effective system development, production forecasting, surveillance and optimization of production networks. A similar modeling approach was used by [3] for an onshore field consisting of numerous oil and gas reservoirs located in Bahrain. The model was used in the day to day management of field production, and in long term field development planning. The advantage for this was keeping management about the daily production demands of the operator.

The integrated production modeling workflow developed for Jack Asset in deep water Gulf of Mexico aided in achieving various field development decisions which was beneficial to the success of the project [4]. An IPM approach was implemented in realizing opportunities for Occidental in the Sultanate of Oman [5], and this resulted to an 8% increase in total field production by individual wells optimization, while 25% of gas lift gas was saved since an optimum distribution of lifting gas among producers was attained with the aid of IPM. The accuracy of predicting reservoir deliverability and forecasting field performance on the basis of various production facility schemes was greatly enhanced by application of IPM.

Integrated Production system modeling was used for production system optimization and this aided in accurate prediction of field performance, opportunity identification and validation [6]. An integrated asset modeling approach was applied in selecting an optimal field development strategy for the Vankor oilfield located in a remote and poorly explored area without production wells or surface facilities [7]. The study presented multiple alternatives through which field development could be optimized and as such special efforts needed to be employed in the field development planning.

An integrated production model (IPM) was applied in the development of two complex sour fields comprising three reservoirs in the South of Oman [8]. The model coupled subsurface dynamic 3D models, well models, and surface network models. Interaction of the coupled model was used to optimize the developments of the three reservoirs by assessing the best design of surface network (plant capacity).

Similarly, an integrated asset study on an offshore green field in Angola [9] was carried out and the results obtained were assessed against the results obtained from standalone domain models in the same field. In the study, a reservoir model was coupled to the surface network models via the well models, which were further integrated into the processing facilities models and finally to the asset economics evaluation model.

2. Methodology

An example oil reservoir (Reservoir X) with data shown in Table 1 is presented in this paper. The Reservoir X has an active water drive. It is desired to commence development of reservoir X such that a minimum total oil field production rate of 5000 STB/day, a maximum field gas and water rates of 100 MMSCF/day and 80 MSTB/day are achieved during the life of the reservoir. The initial oil in Place for reservoir X was 750 MMSTB. Using Integrated Production

Modeling, an appropriate development strategy that will meet the desired production specifications and constraints for Reservoir X for the next 20 years was proposed.

Table 1. Rock and fluid properties [10]

Property	Value
Depth of Payzone	9200ft
Reservoir Thickness	200ft
Initial Reservoir Pressure	5000 psig
Bubble Point Pressure	3199.5 psig
Reservoir Temperature	210°F
Permeability	100 md
Porosity	25%
Estimated STOIP	750 MMSTB
Initial Formation Volume Factor	1.475
Formation GOR	820 scf/stb
Oil Gravity	34 API
Gas Gravity	0.833
Water Salinity	140000ppm

In order to meet the objectives of this study, Petroleum Experts Software (PROSPER, MBAL and GAP) was used [10]. PROSPER was used in developing the wellbore models (injection and production wellbore models) which were coupled to the reservoir or tank model. Properties of petroleum fluids such as solution gas-oil ratio, density, formation volume factor, viscosity, and compressibility for oil and gas are important parameters that are considered during design and analyses of petroleum production systems[11]. PVT data were entered into this software and matched to laboratory data. Numerous models are available in the literature for developing Inflow Performance Relationships for oil and gas reservoirs. The focus of this paper involves developing a newly discovered oil reservoir and the Darcy IPR model [12] was used in developing the Inflow performance Relationship (IPR) for the wells. The Darcy IPR model was programmed in PROSPER and is given by

$$J = \frac{q}{\bar{P}_r - P_{wf}} = \frac{2\pi kh}{\mu B_o} \frac{1}{\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + S} \quad 1$$

According to [11] tubing performance relationship (TPR) models also known as Vertical Lift Performance (VLP) models can be described as homogenous and separated flow models, and are used for analyzing multiphase flow in vertical pipes. Homogenous flow models are less accurate because the multiphase fluid is considered as a homogenous mixture, which neglects the effect of liquid holdup. Separated flow models [13-15] are forms of empirical correlations which consider the effect of liquid holdup and flow regime. This makes them more realistic than homogenous models and were considered in this paper in developing the TPR for the wells.

Extensive studies were carried out by [16-17] to compare these models, and their studies recommended the Hagedorn-Brown method for multiphase vertical flow analysis and was adopted for developing TPR's in this paper. The Hagedorn-Brown correlation was reported by [11] in field units as illustrated by equation 2

$$144\frac{dP}{dZ} = \bar{\rho} + \frac{f_F M_t^2}{7.413\ x\ 10^{10} D^5 \bar{\rho}} + \bar{\rho}\frac{\Delta(u_m^2)}{2g_c \Delta Z} \quad 2$$

where $\bar{\rho} = y_L\rho_L + (1 - y_L)\rho_G$ and $u_m = u_{SL} + u_{SG}$.

The Hagedorn-Brown correlation was programmed in PROSPER and was used in this paper for developing the TPR's for the production wells of reservoir X. In order to determine the deliverability of the wells, the well inflow performance and wellbore flow performance were combined to predict an achievable production rate from the reservoir [11] based on specific well characteristics (tubing internal diameter and wellhead pressure). The operating point of the well is the point of intersection of the IPR and TPR (VLP) curves which is the well flow rate and bottom-hole flowing pressure.

The reservoir model was developed with IPM MBAL (material balance) using classical material balance principles illustrated by the material balance equation (Equation 4) and respective PVT data for the reservoir [18].

$$N_p\left[B_t + \left(R_p - R_{si}\right)B_g\right] + W_pB_w - G_{inj}B_g - W_{inj}B_w = N\left[\left(B_t - B_{ti}\right) + (1 + m)B_{ti}\left[\frac{S_{wi}C_w + C_f}{1 - S_{wi}}\right]\Delta P + \frac{mB_{ti}}{Bg_i}\left(B_g - B_{gi}\right)\right] + W_e \qquad (3)$$

This made it possible for simulation and prediction studies to be carried out that determined future reservoir variations with time, expected cumulative fluid productions and fluid injections. Since Reservoir X being considered in this paper is a newly discovered reservoir that has only been appraised, no production history data were available. Hence production history matching was not conducted for this study but PVT data was matched to laboratory data. Focus of this study was on prediction of field production, production forecasting and evaluation of reservoir pressure variations with time using rock and fluid properties and pressure data.

The surface network model was developed using General Allocation Program (GAP) and consists of the wellhead, flowlines, compressors and separator as well as the water and gas injection manifolds (for modeling water and gas injection processes). The developed wellbore, reservoir and surface facility models were coupled using GAP to form the integrated production model which mimics the proposed production system of reservoir X. This was used in achieving the goals of this study.

3. Results and discussion

3.1. Wellbore model results

Using the data in Table 1 as input to PROSPER, an Inflow Performance Relationship was developed (Figure 1) with the Darcy IPR model (Equation 1).

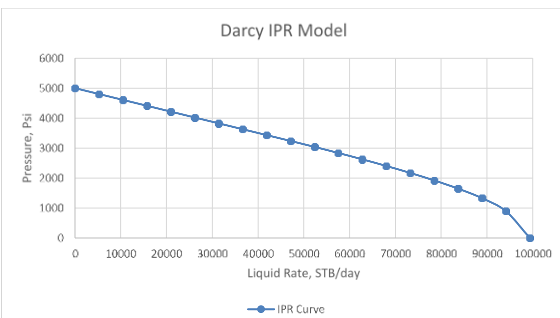


Figure 1. Inflow Performance Relationship for Well A

A tubing sensitivity study (Figure 2) was performed to select a tubing size from 2.375 inch, 3.00 inch and 3.50 inch tubing sizes at wellhead pressures of 100, 300 and 500 psia. Figure 2 shows that the 3.5 inch tubing resulted to a lower pressure drawdown between the bottom hole and the wellhead for the 3.5 inch tubing in comparison with the other tubing sizes, depicted by the higher flow rates and low bottom-hole flowing pressures for all wellhead pressures considered in this paper. The 3.5 inch tubing by virtue of its higher diameter, provided minimal frictional resistance to flow and was selected as the preferred tubing size for the wells.

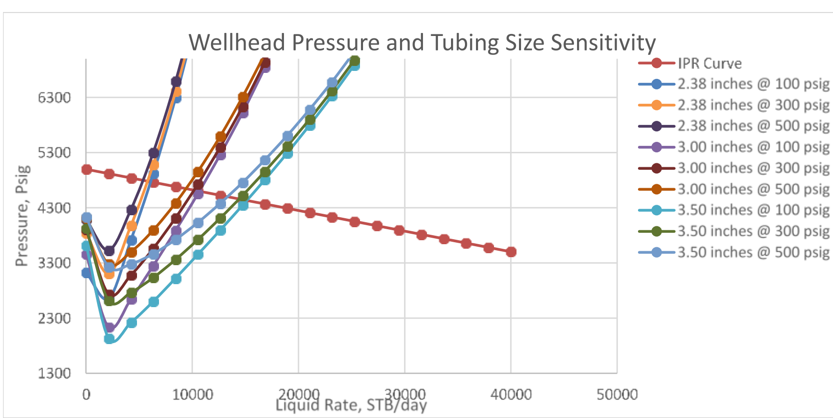


Figure 2. Tubing size and wellhead pressure sensitivity

A comparison of operating flow rates at varying wellhead pressures for the 3.5 inch tubing (Figure 5) indicated a decrease in flow rate with a corresponding increase in wellhead pressure from 100 psia to 500 psia. This implies that as wellhead pressure increases, operating flow rate decreases with a corresponding increase in bottom-hole flowing pressure.

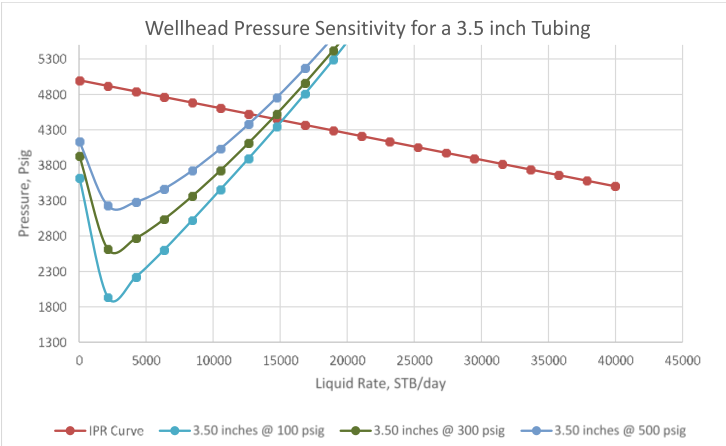


Figure 3. Wellhead Sensitivity for a 3.5 inch tubing

It can be inferred from Figure 3 that a wellhead pressure of 100 psig would be more preferable but a wellhead pressure of 500 psia was selected, because of the need to achieve an allowable pressure drawdown between the wellhead and the separator. Based on these results, the production wells of the integrated production model were designed and completed with a 3.5 inch tubing at a wellhead pressure of 500 psia.

3.2. Reservoir model results

The PVT data (oil formation volume factor, oil viscosity, gas-oil ratio, gas formation volume factor) shown in Table 1 was inputted into MBAL, and matched to data obtained from laboratory studies on reservoir fluid samples. Figure 4, Figure 5, Figure 6 and Figure 7 shows matched laboratory data using respective correlations.

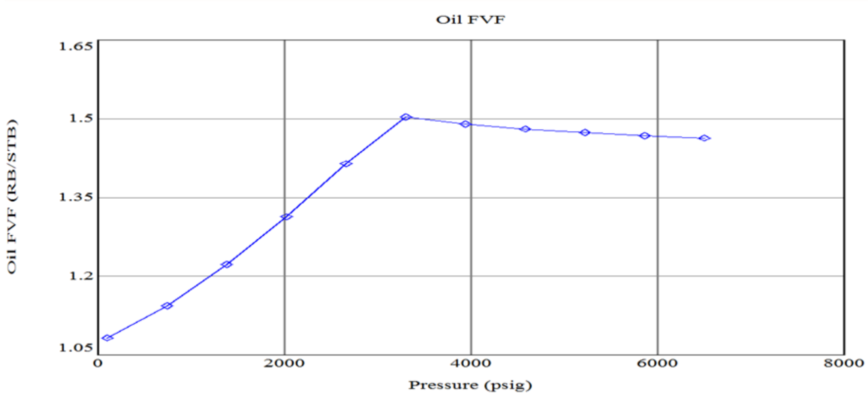


Figure 4. Oil formation volume factor vs pressure

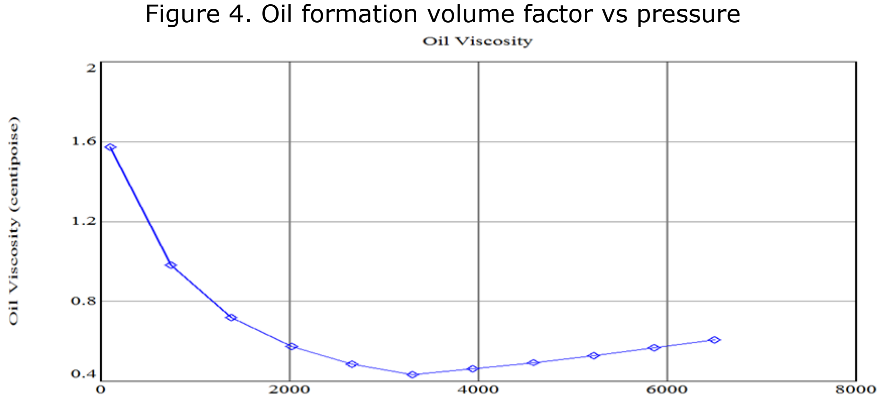


Figure 5. Oil viscosity vs pressure

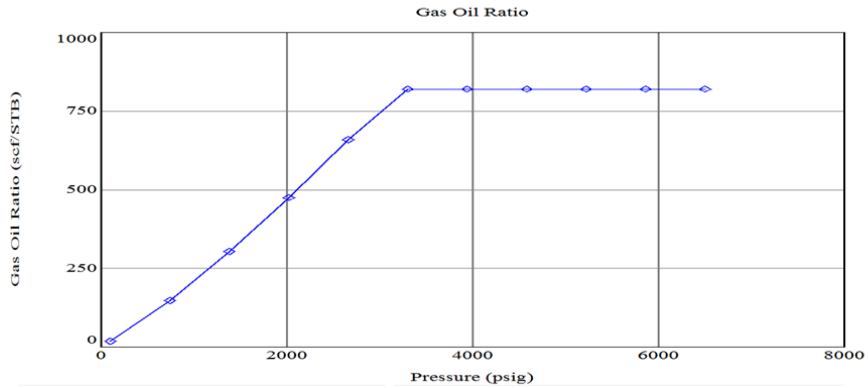


Figure 6. Gas oil ratio vs pressure

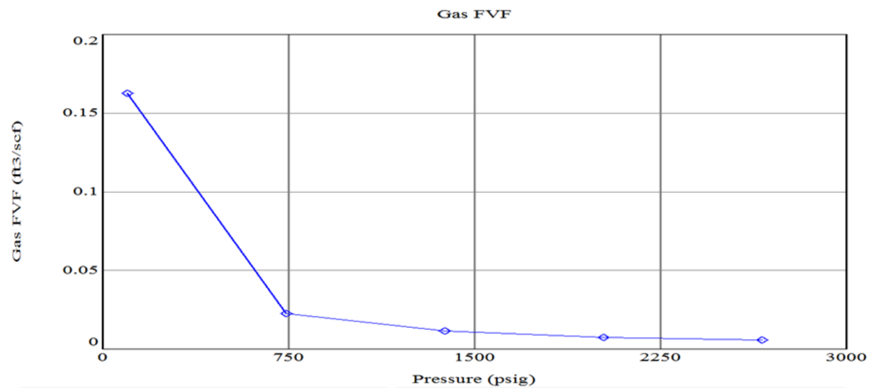


Figure 7. Gas formation volume factor vs pressure

Laboratory data was matched to field data using respective correlations for each fluid property as reported by [11]. The Standing correlation [19] gave a better match between laboratory and field data for bubble point, gas-oil ratio and formation volume factor while Beggs and Robinson [20 correlation matched oil viscosity.

3.3. Comparison between a standalone and an integrated production model

Table 2 shows a comparison of predicted field performance for a standalone (reservoir and well model) and an integrated production model (reservoir, well and surface facility model). The sensitivity was carried out on three well numbering cases (case 1, case 2 and case 3) for both the standalone and integrated production model. The results of the simulation study are shown in Table 2

a. Case 1: 4 production wells at the onset of production and operational throughout the prediction lifespan.
b. Case 2: 4 production wells at the onset of production and an additional 2 infill wells after 10 years of production
c. Case 3: 6 wells at the onset of production and operational throughout the prediction period of 20 years

Table 2. Comparison between Standalone and Integrated Production Models

	Standalones Model			Integrated Production Model		
Parameters	CASE 1	CASE 2	CASE 3	CASE 1	CASE 2	CASE 3
Cumulative oil produced (MMSTB)	274	257.8	258	229	260.85	261.1
Oil recovery factor (%)	36.53	34.37	34.40	30.52	34.78	34.81
Max. produced gas rate (MMSCF/DAY)	49.2	70.88	72.3	64.47	321.7	326.45
Max. produced water rate (MSTB/DAY)	9.52	14.92	15.43	7.36	67.15	68.16

For the standalone model, higher recoveries were obtained the four well scenario (Case 1) than for the two six well scenarios (Cases 2 and 3) which is not realistic because more wells would normally drain more oil from the reservoir. The integrated production model resulted to an increase in field recovery as the number of wells increased from case 1 to case 3 which is more realistic. This shows that results from a standalone model were less accurate than the results from the integrated production model. This justifies the need to carry out well numbering sensitivity and analysis of development strategies using integrated production modeling since accurate results were obtained.

3.4. Well numbering sensitivity

Well numbering sensitivity was also carried out using Integrated Production Modeling to determine the optimum number of production wells during primary recovery phase, required to achieve a minimum oil recovery factor of 30% during a prediction period of 20 years, a maximum gas production rate of 100 MMSCF/Day, and a maximum water production rate 80 MSTB/Day during prediction. A comparison of the results for the 3 well numbering cases are illustrated the integrated production model column of Table 2.

Results show that for cases 2 and 3, cumulative oil produced and oil recovery factor were found to be approximately the same (260.85 MMSTB and 261.1 MMSTB respectively), and higher than the values obtained for case 1 (229 MMSTB). Also, all scenarios (cases 1 to 3) met the water production requirements but the maximum daily gas production rates during prediction for cases 2 and 3 exceeded that for case 1 and that constrained in this paper (100 MMSCF/day).

Based on these results, Case 1 was selected as a more favorable option because the minimum oil recovery factor of 30 % was achieved, the daily gas and water production constrained in this paper were not exceeded during the period of prediction. Hence, cases 2 and 3 were not selected as acceptable number of wells for primary recovery since the daily gas production from both scenarios exceeded that constrained in this paper despite meeting the daily water production requirements.

3.5. Integrated production model results

Based on the results of Table 2, the integrated production model for the base case was selected as an optimal strategy for primary oil recovery, the reason why a four well production scenario was considered. It consists of a tank model, 4 production wells, a network of pipelines, manifolds and a separator (Option1), used as a basis for evaluating other development options. Figure 8, Figure 9, Figure 10 and Figure 11 are Integrated Production Models of the development strategies (Options 1 to 4) considered in this paper and were modeled with GAP.

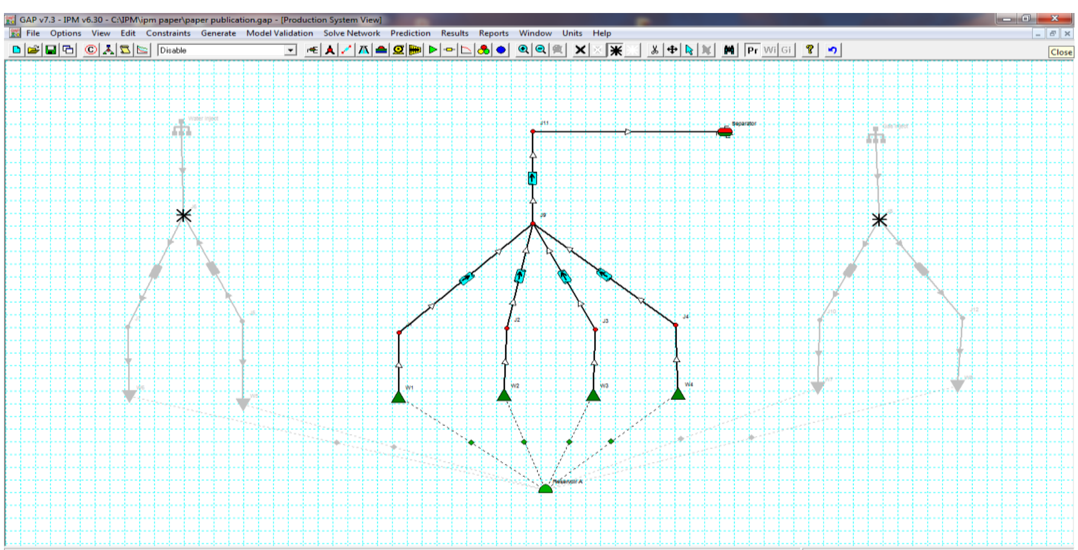


Figure 8. Option 1 – Base case which consists of a single tank, four production wells and a separator

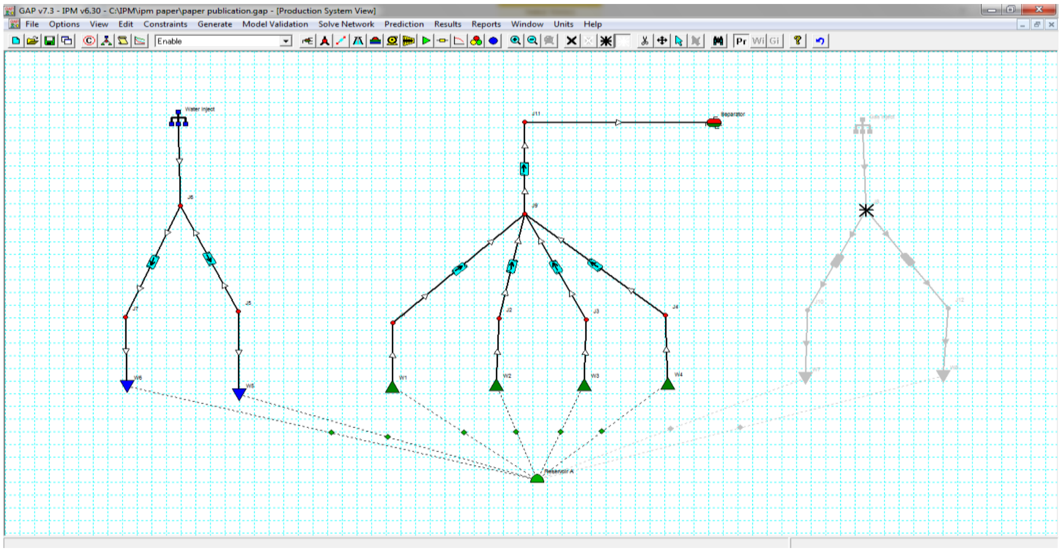


Figure 9. Option 2 – Base case and two water injection wells that commence injection 10 years into the life of the field

For all the scenarios (Figures 8 to 11), the blurred and highlighted components of the production system are respectively inactive and active. The active components are considered during production prediction while the inactive components are not considered for a specific option. A description of the symbols on the integrated production model are presented by SYMBOLS at the end of this paper. A simulation study was conducted for each strategy for a period of 20 years and a comparison of predicted oil, gas and water production rates, cumulative oil and gas produced, recovery factor and variation of reservoir pressure were conducted and results presented in Figures 12 to 18.

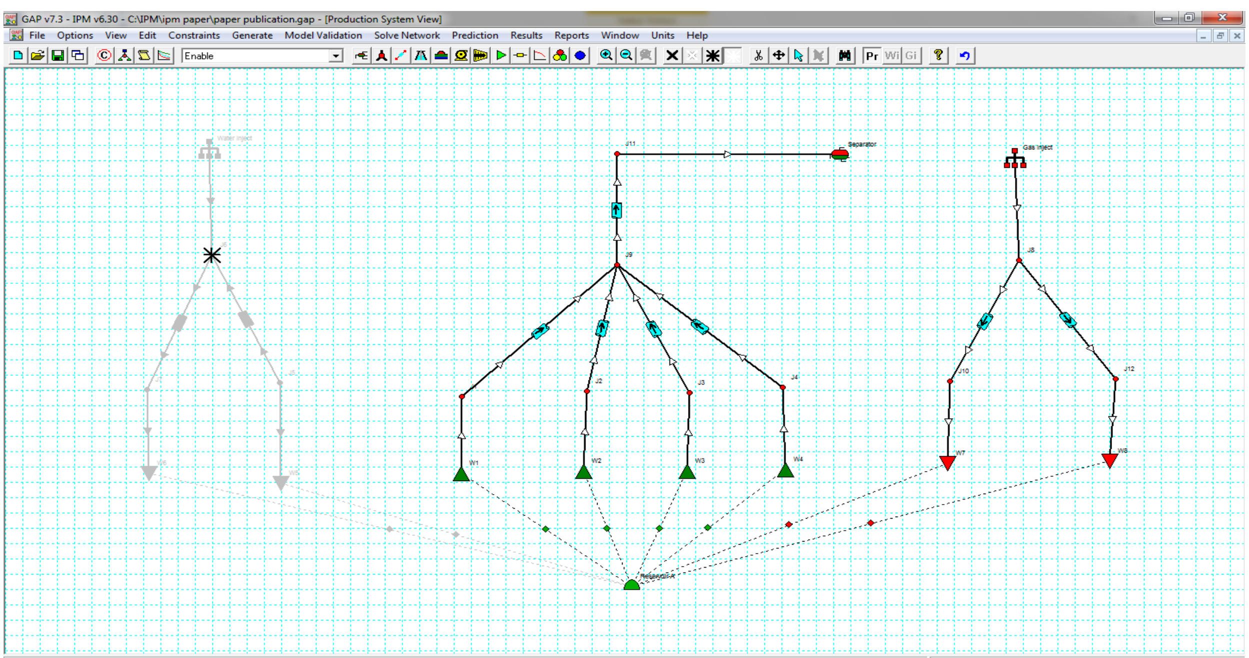


Figure 10. Option 3 – Base case and two gas injection wells such that injection commences 10 years into the life of the field

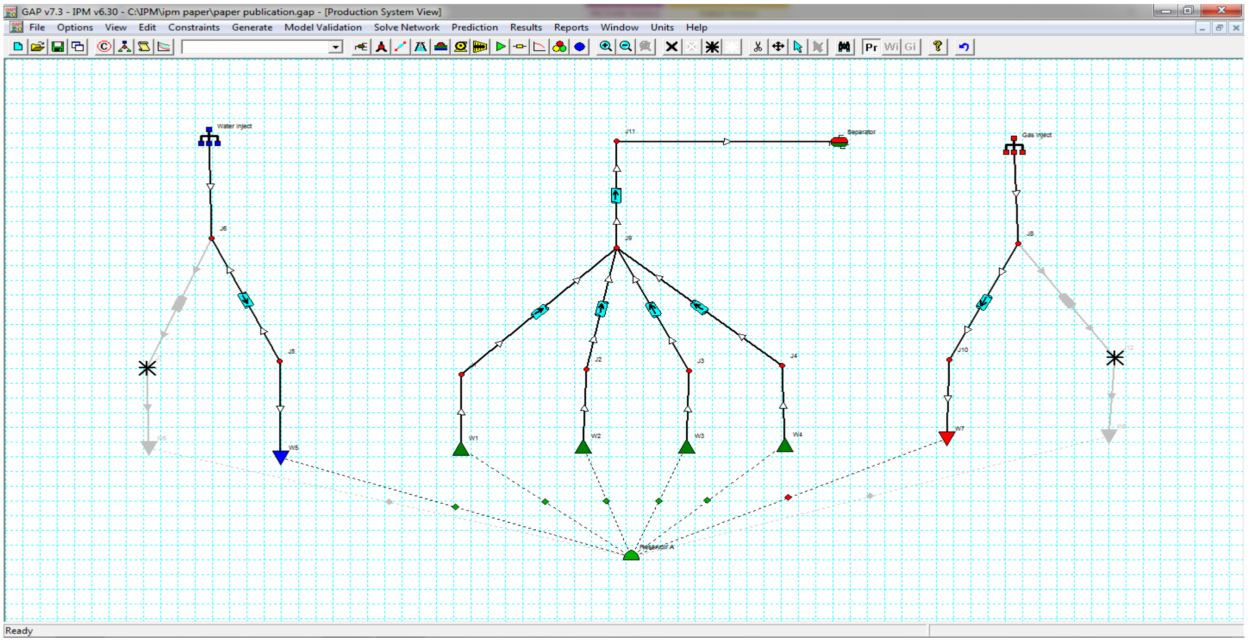


Figure 11. Option 4 – Base case with one water and one gas injector well that commence injection 10 years into the life of the field

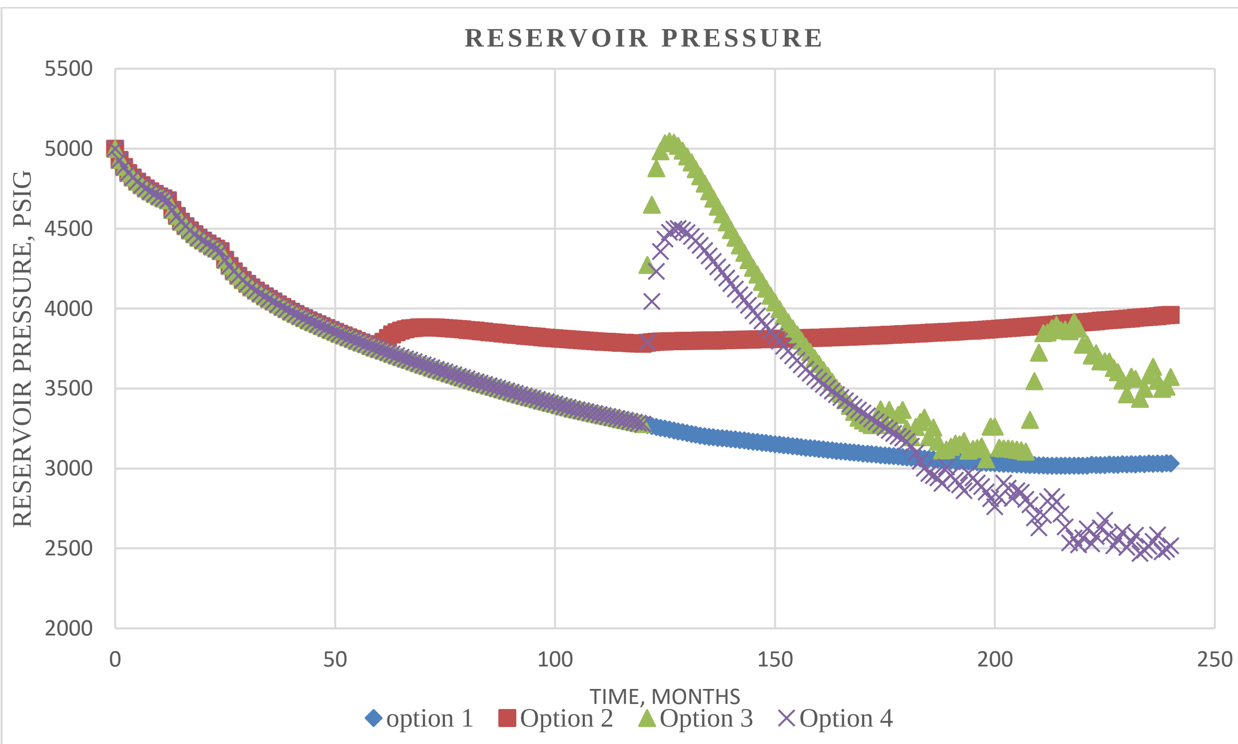


Figure 12. Comparison of predicted variation of reservoir pressure for all strategies

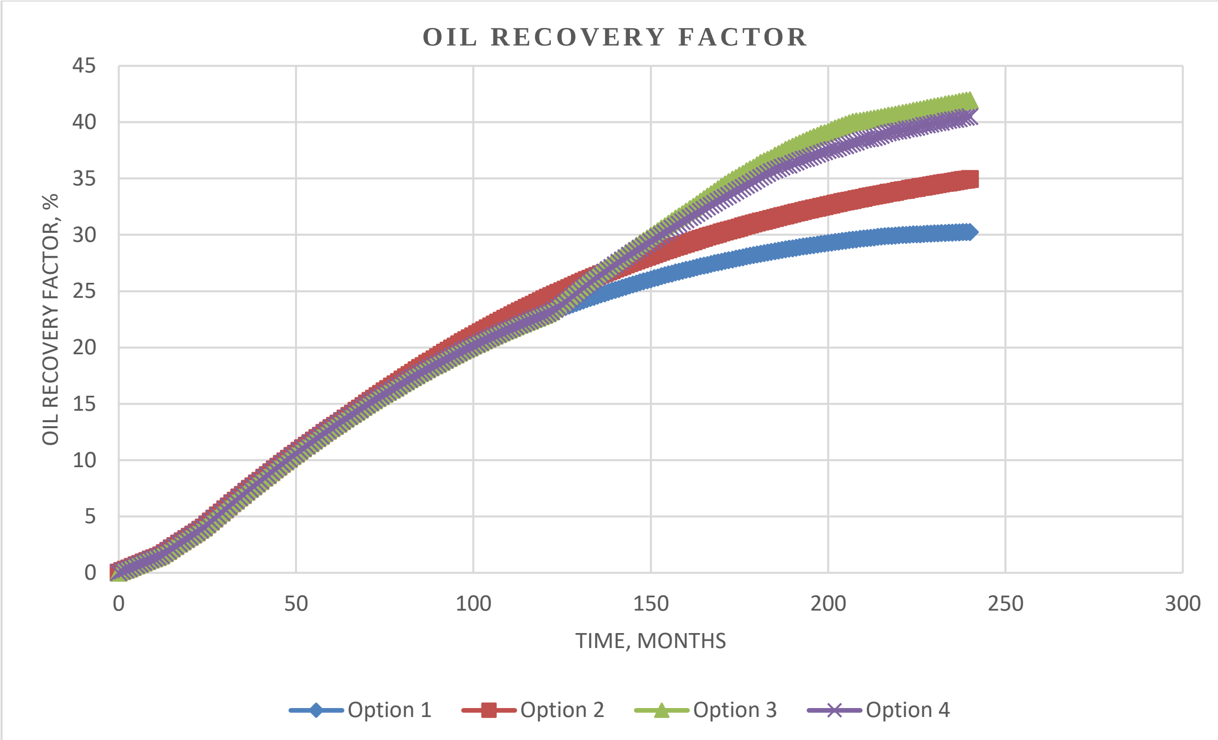


Figure 13. Comparison of predicted oil recovery factor for all strategies

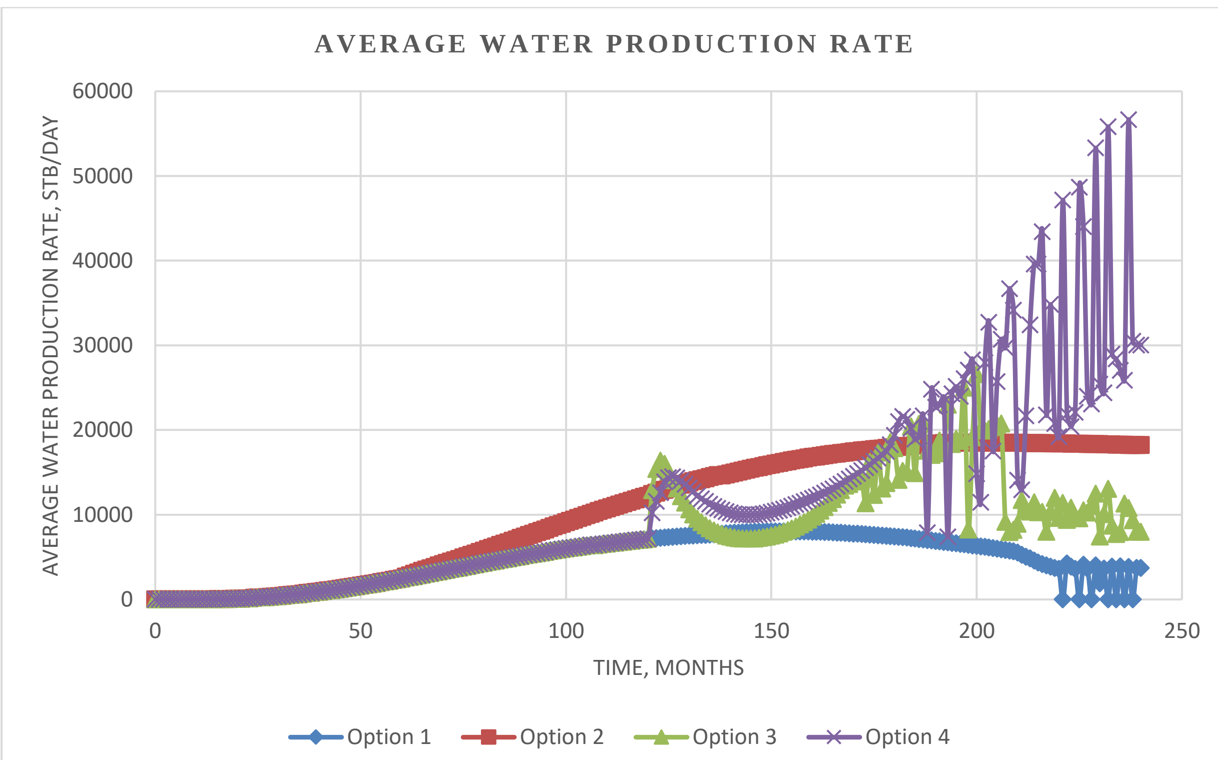


Figure 14. Comparison of predicted average water production rates for all strategies

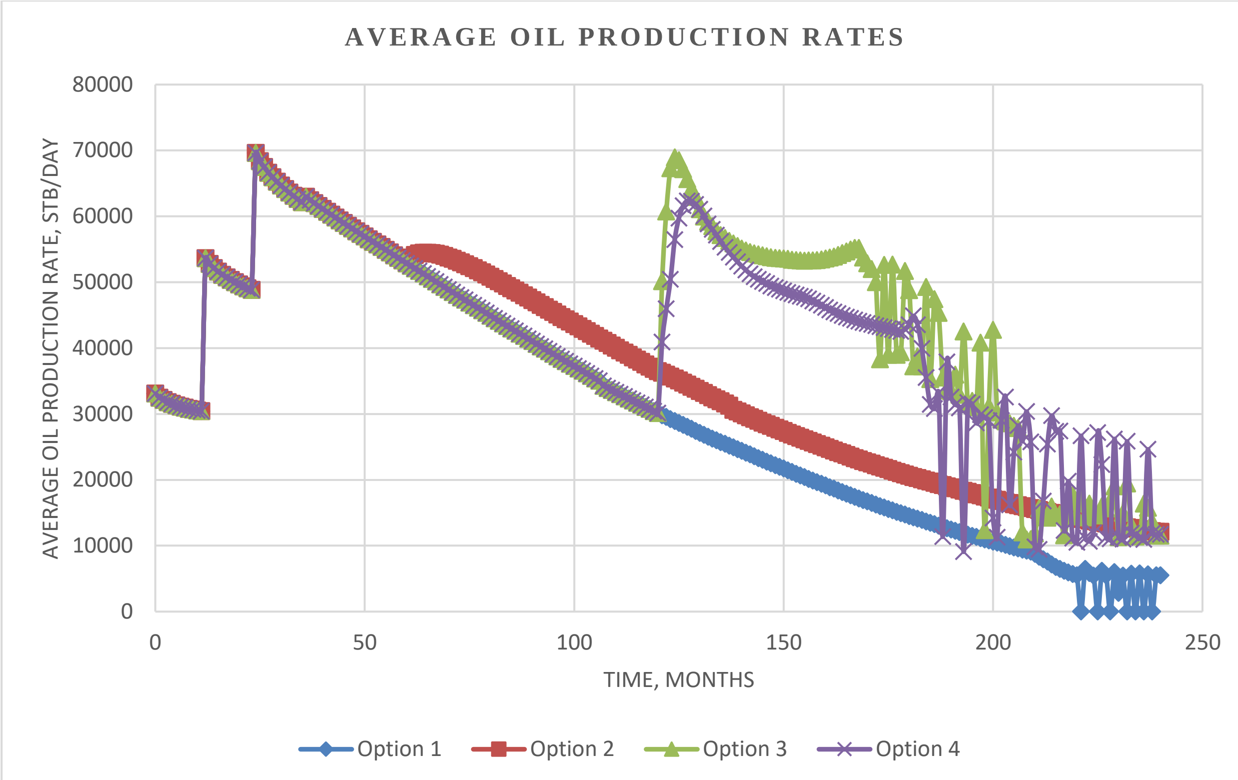


Figure 15 Comparison of predicted average oil production rate for all strategies

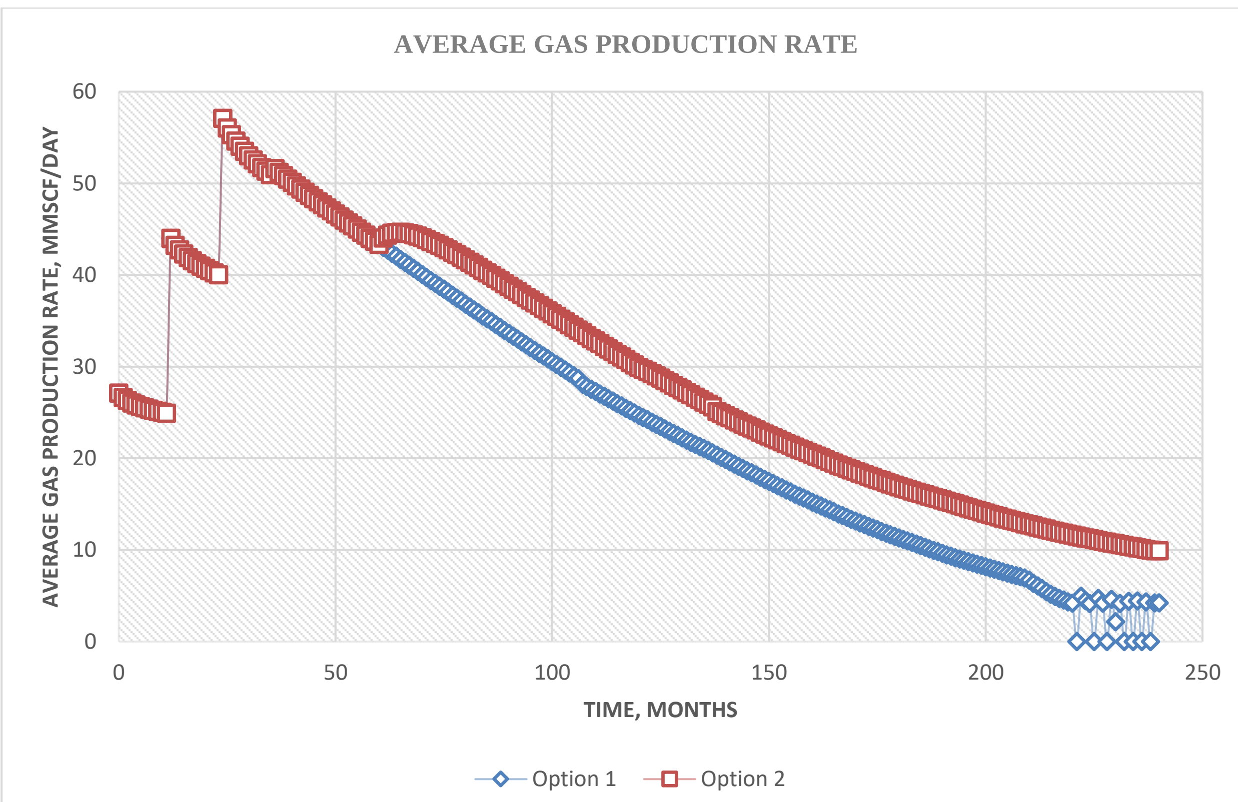


Figure 16. Comparison of predicted average gas production rates for options 1 and 2

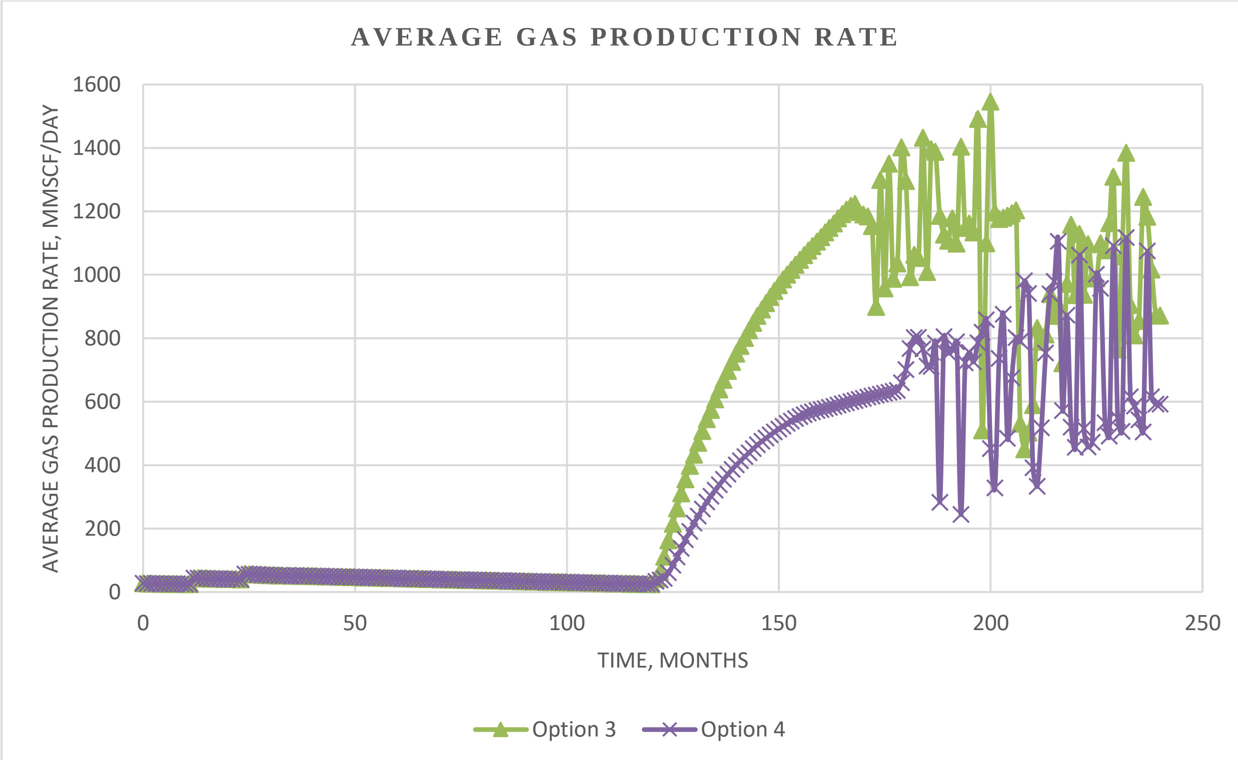


Figure 17. Comparison of predicted average gas production rates for option 3 and 4

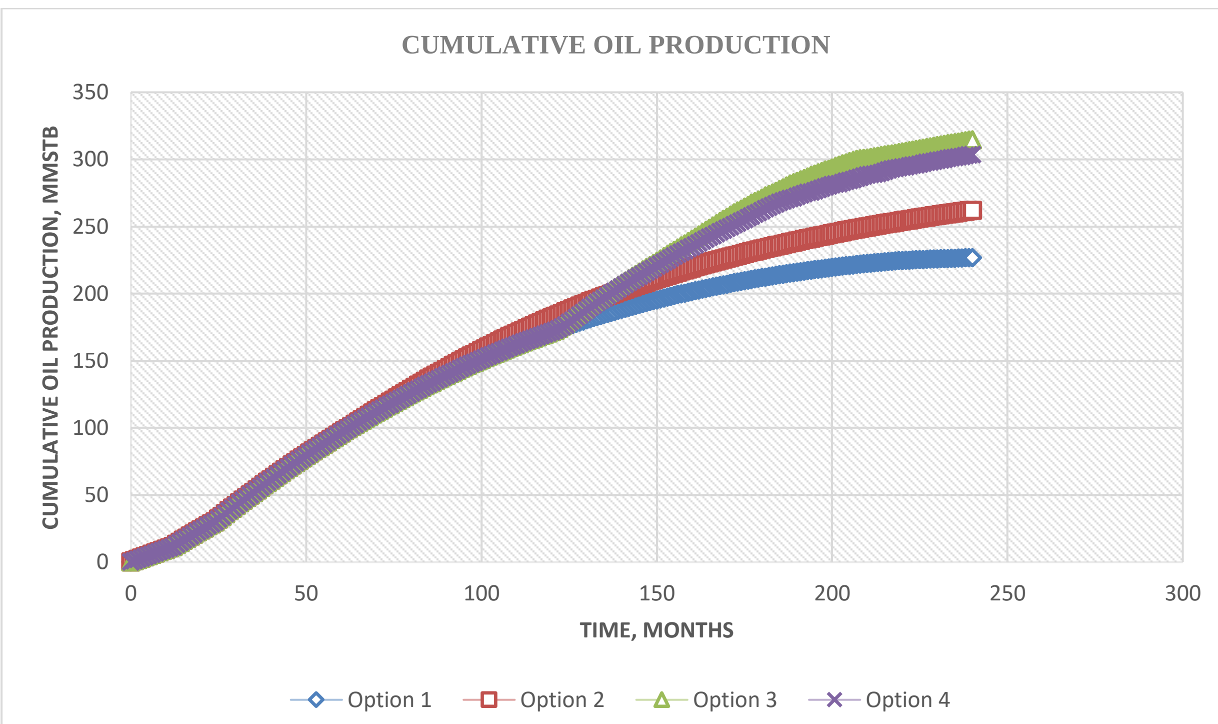


Figure 18. Comparison of predicted cumulative oil produced for all strategies

4. Discussion of results

Table 3 shows a summary of the results illustrated by Figures 12 to 18 which is a comparison of cumulative oil production, oil recovery factor and reservoir pressure at end of production prediction. Also, maximum water and gas production rates obtained during production prediction for each development strategy are also presented in Table 3. This aided in the selection of an optimum development strategy for the reservoir while taking into consideration the constraints stated in this paper.

Table 3. Comparison of field performance and constraints for different production strategies

Options	Cumulative oil production (MMSTB)	Cumulative gas production MMSCF	Cumulative water production MMSTB	Oil recovery Factor (%)	Reservoir pressure @ end of prediction (psig)	Maximum average Water rate (STB/Day)	Maximum average gas rate (MMSCF/Day)
Option 1	226.868	184795	33.517	30.25	3030.66	8049.5	57.09
Option 2	262.16	214970.8	76.868	34.95	3960.67	18478	57.09
Option 3	314.581	3574198	50	41.94	3572.47	26588	1545.55
Option 4	303.633	2202026	127.44	40.48	2516.7	56654	1117.39

The initial reservoir pressure for all scenarios dropped gradually as shown in Figure 12 with option 2 having the highest reservoir pressure of about 4000 psia and option 4 the lowest of about 2500 psia at the end of prediction.

Figure 18 shows that all strategies considered in this paper resulted to an oil recovery factor of not less than 30 % at the end of prediction with option 3 resulting to the highest recovery factor (41.94%), and option 1 the lowest (30.25%) because it did not receive any support from a water or gas injector during prediction (Figure *8*). Since a recovery factor of not less than 30% was achieved for all strategies at the end of prediction, it implies they would all be suitable for developing the reservoir under consideration.

Figure 14 shows a comparison of average water production rates for all strategies, and results show that during the period of prediction, the average water production rates achieved for all strategies did not exceed the water production rate of 80 MSTB/day constrained in this paper. This implies that the surface facility network considered can handle the daily water production if any of the development options considered in this paper were implemented. Water production from Options 1 and 3 resulted from aquifer influx while water production from options 2 and 4 resulted from water influx and injected water. Option 4 resulted to the highest water production rate during prediction while option 1 resulted to the lowest (Figure 14).

However, results from Figure 16 and Figure 17, which shows a comparison of average gas production rates respectively for options 1 and 2, and options 3 and 4, indicates clearly that the during the period of prediction, average gas production rates for options 3 and 4 exceeded that constrained in this paper (100 MMSCF/Day), but was not exceeded for options 1 and 2. Hence, options 3 and 4 were not considered for development of reservoir X because the maximum daily gas production exceeds the daily gas capacity of the surface facility. High gas production rates were caused by wide differences in density and viscosity between the injected gas and the displaced oil. This led to viscous fingering, gravity override and gas segregation, all of which resulted to early gas breakthrough indicated by an increase in gas production rate.

Since the predicted cumulative oil production (262.16 MMSTB) and oil recovery factor (34.95 %) for option 2 was greater than that of option 1 (226.868 MMSTB and 30.25 %) by 35.29 MMSTB and 4.7 % respectively, option 2 was selected for developing this reservoir.

5. Conclusion

An integrated production model was developed for evaluating multiple development scenarios for Reservoir X. Simulation results showed that a four-well production scenario with pressure support from two water injection wells (Option 2) was optimal because field constraints stated in this study were honored at all times during prediction. Also, a cumulative oil production and recovery factor of 262.16 MMSTB and 34.95 % respectively were obtained from prediction, which met the production requirements for primary and secondary phases of production of the reservoir (Minimum Recovery factor of 30%). Either of Option 3 or Option 4 would have been a better option but since field constraints were exceeded, they were not selected in this paper as a strategy for developing the reservoir. However, an upgrade of the capacity of the surface facility network would result in a change in the strategy for developing the reservoir and would incur extra cost for the oil and gas operator in improving the capacity of the surface facility.

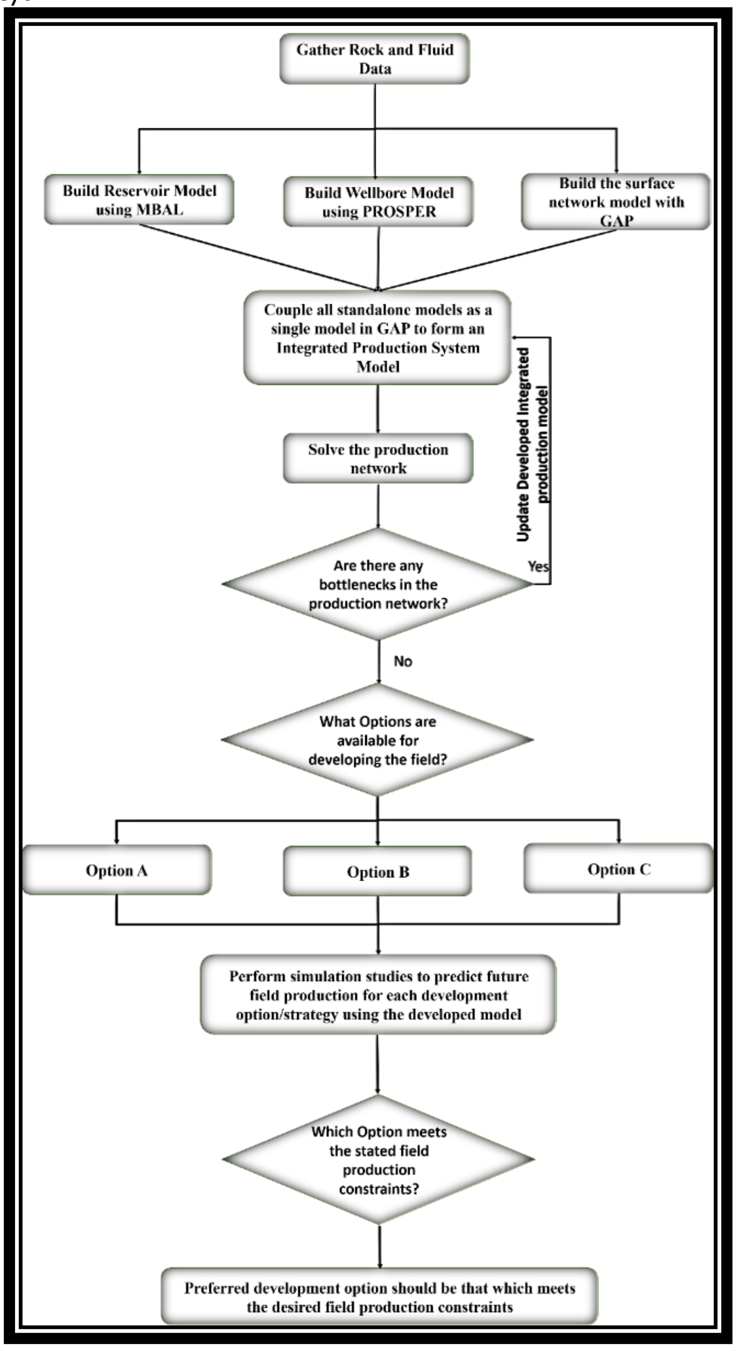
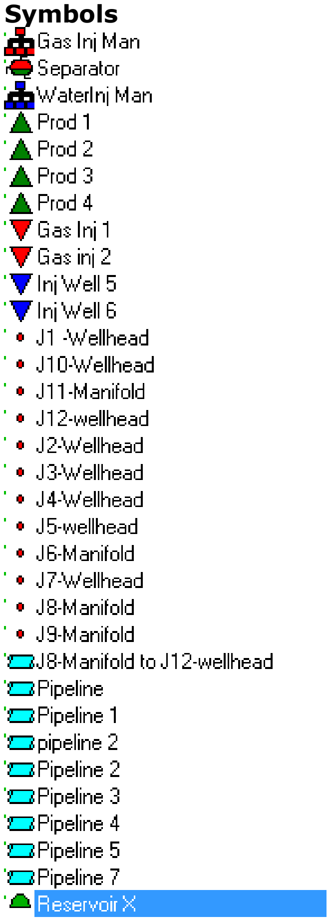


Figure 19. An integrated production modeling workflow for evaluating development strategies for a greenfield

This paper highlighted the fact that, with an integrated production model in place, there is room for optimization of the production of an entire asset by conducting studies for different development scenarios which captures the interactions of the different components of a Petroleum Production System. The Integrated production modeling approach discussed in this paper proved to be an effective and robust tool in the evaluation of various development strategies for the Greenfield (Reservoir X), since it was able to select an optimum development strategy for the reservoir through prediction of field performance using rock and fluid properties, fluid in place volumes, and reservoir pressure data.

Based on the approach used in this study, a workflow for evaluating development strategies for a Greenfield using Integrated Production Modeling was developed and is presented in this paper (Figure 19). It can be used as a guide for proposing development strategies for newly discovered reservoirs using IPM.

Symbols



Nomenclature

IPM	Integrated Production Modeling
MBAL	Material Balance
PROSPER	Production System Optimization and Performance
Q	Liquid rate, stb/day
Q_{max}	Absolute Open Flow (AOF), STB/day
J	Productivity index, stb/day/psi
$\bar{P_r}$	Average reservoir pressure, psi
P_{wf}	Downhole flowing pressure, psi
r_w:	Wellbore radius, ft.
r_e:	External drainage radius, ft.
S:	Skin factor, dimensionless
h:	Reservoir thickness, ft.
μ:	Viscosity, cp
B_o:	Formation volume factor, bbl/stb
θ:	Angle
Np	Cumulative oil produced, MMSTB
B_t	Two Phase Formation Volume Factor, BBL/STB
R_p	Producing Gas oil Ratio, SCF/STB
R_{si}	Initial Gas Oil Ratio, SCF/STB
B_g	Gas Formation Volume Factor, ft3/stb
B_w	Water Formation Volume Factor, SCF/STB
W_p	Water Production, MMSTB
G_{inj}	Gas Injection, MMSCF
W_{inj}	Water Injection, MMSTB
S_{wi}	Initial water saturation
C_w	Water Compressibility, 1/psi
C_f	Rock compressibility, 1/psi
ΔP	Differential pressure, psi
W_e	Water influx, MMSTB
$\frac{dP}{dZ}$	Pressure Gradient, psi/ft
$\frac{g}{g_c}$	
$\bar{\rho}$	Average Mixture Density, Ib/ft3
f_F	Friction Factor
y_L	Liquid Fraction, fraction
ρ_L	Liquid Density, Ib/ft3
ρ_G	Gas Density, Ib/ft3
u_{SL}	Liquid Superficial velocity, ft/s
u_{SG}	Gas Superficial Velocity, ft/s
u_m	Mixture Velocity, ft/s

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