Petroleum 9 (2023) 373–389

Contents lists available at ScienceDirect

Petroleum

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Simulation studies on optimizing oil productivity in oil rim reservoirs under gas cap blow down production strategy

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A R T I C L E I N F O

Article history:
Received 25 January 2022
Received in revised form
18 May 2022
Accepted 1 August 2022

Keywords:
Oil rim
Gas cap blow down
Water and gas injection
Oil recovery factor

A B S T R A C T

Gas cap blow down strategy is normally deployed for Ultra-thin oil rim reservoirs with huge gas caps due to extremely high gas oil ratios from wells in such reservoirs. The current state leads to loss of production from the oil reserves due to high initial reservoir pressure thus, reducing its net present value. Data on important factors essential to the productivity of oil rim reservoirs are used to build a heterogeneous ultra-thin reservoir with a time step of 10,000 days using the Eclipse software and its embedded correlations. The reservoir is subjected to a gas cap blowdown via a gas well, then an oil well is initiated into the model at onset and after time periods of 2000 days, 4000 days, 6000 days and 8000 days to estimate the oil recovery. It is expected that due to the large nature of the gas cap, pressure decline will be drastic and leading to a low oil recovery, hence the injection of water and gas at different rates at the periods indicated. The results indicate an oil recovery of 4.3% during gas cap blow down and 10.34% at 6000 days. Peak oil recoveries of 12.64% and 10.80% are estimated under 30,000 Mscf/day at 4000 days and 1000 stb/day at 6000 days respectively. This shows an incremental oil recovery of 8.34% and 6.5% over that recorded during gas cap blow down. The results also indicate that the gas production at those periods was not greatly affected with an estimated increment of 257 Bscf recorded during 30,000 Mscf/day at 4000 days. All secondary injection schemes at the respective time steps had positive impact on the overall oil recoveries. It is recommended that extra production and injection wells be drilled, enhanced oil recovery options and injection patterns be considered to further increase oil recovery.

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1. Introduction

Oil rim reservoirs are vastly situated around the world and with peculiar challenges in exploitation and production due to the nature of the pay thickness ($H_o \leq 100$ feet) and presence of a very large gas cap and active aquifer [1,2]. Kazeem et al. [3] described oil rims as those that forms a pancake or doughnut nature depending on the complexity of the gas cap. Factors that influence the productivity from these reservoirs ranges from operational to reservoir factors. In their studies [4], pareto analysis is utilized to quantify and grade the degree of these uncertainties/factors and their effects on oil and gas recovery in oil rim reservoirs. Variables such as sizes of the gas cap and aquifer [5,6], pay thickness and angle of dip [7], reservoir heterogeneity and fluid properties [8] have all been studied as essential factors that oil rim performances. Olamigoke et al. [9–11] have identified that these factors are essential in determining the accuracy and consistency of production forecasts made on oil rim reservoirs.

As these factors are naturally inherent and unchangeable, more focus has been shifted to operational factors which when optimized reduces the occurrence of coning and maximize oil production [12]. The first main operational factor is the well trajectory and the production rates which have studied extensively in oil rim reservoirs by Refs. [13–20] and general assessment of the importance of horizontal wells over vertical wells by Ref. [21]. The summary of

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Peer review under responsibility of Southwest Petroleum University.

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https://doi.org/10.1016/j.petlm.2022.08.001
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these literatures suggests operational practices such as selecting horizontal wells over vertical ones, optimizing well placement with respect to the sizes of the gas caps and strength of aquifers, and selecting an oil production rate between 1000 stb/day and 2500 stb/day are best options for optimizing production of oil and gas. Due to the nature of oil rims, a realistic approach is required in estimating the critical rates of production to prevent the coning of gas and water into the oil wells [22]. Asides the inherent nature of oil rim reservoirs, practical and economic factors such as water and gas coning, complicated production mechanism, complicated production mechanisms, diverse interest for host country and oil company, slim prospects for developments, dilemma evolving between initial gas development and oil production and an expensive development in a marginal economy have been the main challenging highlights in developing oil rim reservoirs [23,24].

A review of current practices in developing oil rim reservoirs studied by Ref. [25] suggest that proper classification of the oil rim reservoir before implementing a depletion strategy must be outlined before production commences. [26] has highlighted 4 types of oil rim reservoirs based on the size of the gas cap and aquifer strength. The classifications in their report in conjunction with the reservoir fluids contacts has helped in the selection of horizontal well placement strategies in oil rim reservoirs [6,27]. Well placement options and type of oil rim classification must be backed up with good depletion strategies such as concurrent, sequential, swing and gas cap blow down [28,29]. Concurrent and Sequential strategies favorable for oil rims with pay thickness of 70 ft - 100 ft, a steady market for produced gas and where oil production will not affect gas production and vice versa [3]. Swing production strategies may be considered for oil rims between 70 feet to 100 feet but especially for 40 ft–70 ft where reservoir pressure from the gas cap is to be maintained and a gas supply for sales are periodical [23]. [30] prescribed a concurrent development for oil rims with small gas caps and active aquifers. They recommended that for gas cap sies (m < 2) initial gas cap blow down will improve oil recovery else gas cap sizes more than those described will lead to low oil production rates. [31] highlighted that the gas cap and aquifer expansion, pressure depletion, reservoir fluid withdrawal and gravitational forces are major factors that create a force balance in oil rim reservoirs. A good knowledge of these factors enhances careful placement of infill wells and workout a proper secondary or enhanced recovery scheme [32].

Ultra-thin oil rim reservoirs with pay thickness of less than 30 ft as described by Refs. [33,34] still hold considerable reserves if best production optimization practices are put in place. The main objective of oil producers is to get the best recovery from a reservoir, but ultra-thin oil rims present of unique challenges as it relates to controlling gas production from oil wells, reservoir unitization and pressure maintenance. Options for gas cap blow down are normally advised for oil rim reservoirs with pay thickness less than 30 feet. For such reservoirs, only gas production is considered due to huge gas cap sizes meaning the oil reserves will be lost [35].

Simulation studies have been conducted to estimate incremental oil recovery in oil rim reservoirs under secondary and enhanced oil recovery options. [36] concluded in their comparison that higher oil recoveries are experienced when water injection options are considered in oil rims with large gas caps with small aquifer support due to the pressure support from the expanding gas cap making pressure maintenance by gas injection economically unnecessary. Biliter et al. (1999) pioneered options for simultaneous water injection in the gas oil contacts in oil rims with very low dip angles and large gas caps under concurrent oil and gas options while [35] initiated a fencing and peripheral water injection in the attempt to improve the vertical sweep efficiency and curtail gas smearing into the gas cap. The scheme left substantial residual oil which necessitated additional cost of drilling infill well. Simulation results from Ref. [38] showed that wells producing from the flanks of an oil rim with strong aquifer support under gas injection produced longer due to the downward movement of gas oil contact.

It is expected that initiating oil production at the unset (Concurrent oil and gas production) will result almost in an immediate rapid increase in gas oil ratio (especially in oil rims with very large gas caps), low oil recoveries and loss in reservoir pressure which can be maintained by water or gas injection [39–41]. Simulation studies on enhanced oil recovery options such as surfactant flooding as surfactant flooding has been studied by Ref. [42] to optimize oil recovery from oil rim reservoirs with relatively high interfacial tension bonds between oil and water.

The idea of a gas cap blow down is to forego the oil reserves which in most cases is not profitable especially for host countries as oil has a more steady and ready market and has a marginally lower cost in exploitation and processing compared to gas. Thus, it is expected that during this strategy, the reservoir pressure would have dropped to an appreciable level that will accommodate substantial oil production. The pressure decline profile of the reservoir needs to be studied under a gas cap blow down to predict when to initiate oil production. This will enable an operator to know when best during the period of a gas cap blow down to initiate an oil production. Hence, to maximize oil production during gas cap blow down method, this study has used the Eclipse software and its inbuilt correlations to create an heterogenous oil rim model, with a time step of 10000 days and suitable for gas cap blow down (large gas cap, large aquifer and pay thickness of 25 ft) using relevant reservoir data from the Niger-delta region of Nigeria. The time steps are divided into 4 periods for the initiating of oil production (2000, 4000, 6000, and 8000 days) with an onset of oil production with gas production (to depict a concurrent oil and gas production). It is expected that the reservoir pressure would have dropped during these 4 periods hence, water and gas injection schemes at different rates are implemented to balance the reservoir pressure and the oil recoveries are compared under the oil production and secondary injection schemes.

2. Methodology

The first objective of this study is to create a synthetic oil rim model using data from oil rim reservoirs from the Niger delta region of Nigeria. The geological settings of these reservoirs are roll over anticlines at early Miocene age with recorded periods of outbuilding in the subsurface. These data (Table 1) are incorporated in different sections of the Eclipse software to create an oil rim model suitable for a gas cap blow down strategy. The model grid dimension is 20 by 20 by 32 making a total of 12800 cells. The model grid design and configuration used is described by Ref. [26]. Their design has been used to design a model with a datum depth of 7000 feet, pay thickness of 24 feet, a gas cap and aquifer size of 6 and 3 (respectively to the volume of oil) and dip angle of 5°. The design also incorporates the use of widely known Placket Burman on keyword components that are essential to oil rim reservoirs. Doing this will enable a creation of various models of oil rim reservoirs with different properties. The key word EQUALS in the software is used to input the dimensions of each cell as shown in Table A in the Appendix section. The red, green, and blue in the table shows the volume of gas, oil, and water respectively. The porosity values in Table 2 shows different porosity values for every

Table 1
Oil rim properties.

Model	Dip	OGR	K_x, K_y	K_v/K_h	Bore Diam. (ft)	HGOC (ft.)	HWL (ft.)	Qo	K_{rw}	GOR (*Rsi)	BHP (psia)
A	5	0.006	35	0.01	0.33	0.6	1800	1500	0.2	7.5	2000

Table 2
Porosity.

400×0.29	400×0.24	400×0.27	400×0.26	400×0.28	400×0.25	400×0.26	400×0.28	400×0.26	400×0.28	400×0.29
400×0.24	400×0.25	400×0.24	400×0.27	400×0.28	400×0.29	400×0.28	400×0.29	400×0.24	400×0.26	400×0.27
400×0.27	400×0.24	3200×0								

Table 3
Water/Rock PVT properties.

Reference pressure	3600 psia
Water formation volume factor	1.00528 rb/stb
Water compressibility	3×10^{-6} psia^{-1}
Water viscosity at reference pressure	0.5215 cp
Water viscosibility	0 psia^{-1}
Rock reference pressure	3600 psia
Rock compressibility	4×10^{-6} psia^{-1}

400 cells while the last 3200 cells with zero porosity values indicate inactive cells with no reservoir data property while a permeability value of 200 mD is used in the X and Y direction and 20 mD in the Z direction. The values to the depth of the reservoir as its slanting at 5° is in Table B in the Appendix section.

Oil, water and gas solution and PVT properties such as the reservoir fluid saturations and its relative permeability functions (S_g and K_{rg}, S_o and K_{rog} K_{row}, S_w and K_{rw}), water, gas, and oil viscosities (μ_w, μ_g & μ_o), capillary pressures P_c, Solution gas (R_s), Oil, gas, and water formation volume factors (B_o, B_g & B_w) bubble point pressures (P_b), and oil to gas ratio (OGR), water compressibility factor (C_w) are all inputted into the Eclipse software as inbuilt correlations and relationships between oil rim reservoir variables. The charts to these variables are described in the appendix section as figures (A to E) while water the water property is shown in Table 3. The oil, water and gas densities recorded in lb/ft^3 are 35, 64 and 0.073 respectively. The reservoir is initialized to estimate the initial fluids in place of the model (Table 4). The production concept for gas cap blow down will involve creating a horizontal gas well at the onset to run through to 10,000 days. Then, a horizontal oil well is initiated at 2000 days, 4000 days, 6000 days, and 8000 days. Oil and gas production are estimated and compared at each of this time steps. A gas and oil production rates of 10,000 Mscf/day and 1500 stb/day are respectively subjected on those wells. To support the declining reservoir pressure at each oil production time step interval, water and gas is injected at 3 different rates as shown in Table 5. Figure F in the Appendix section describes the tenary fluid diagram for the model showing the gas (G) and oil (O) wells while figure G shows the Ternary diagram of the model with existence of an injector well (PELU INJ). Keywords such as WELSPEC, COMPDAT, WCONPROD, WCONINJ and WECON are used to create the wells, add locations to the wells as it connects to the reservoir, describe the functionality of the wells as either producer or injector and place economic thresholds on wells.

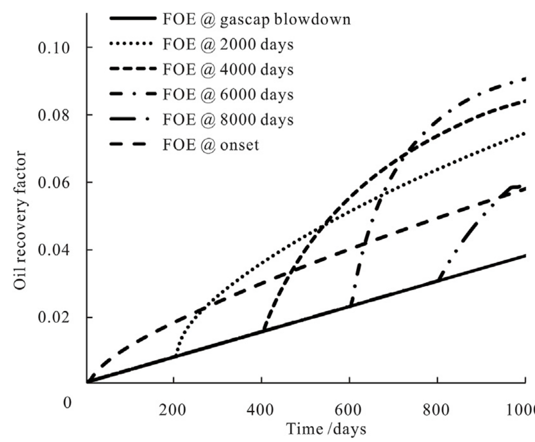


Fig. 1. Oil recovery factor.

The following case studies will be considered in this study:

Table 4
Fluid's in place report.

Oil (stb)		Water (stb)	Gas (Mscf)	
Liquid	Vapour	0	Free	Dissolved
10,415,104	1,209,433	0	241,886,675.	8,717,347
11,624,537		559,407,219	250,604,023	

Table 5
Injection plan.

Water injection (stb/day)			Gas injection (Mscf/day)		
1000	2000	3000	10,000	20,000	30,000

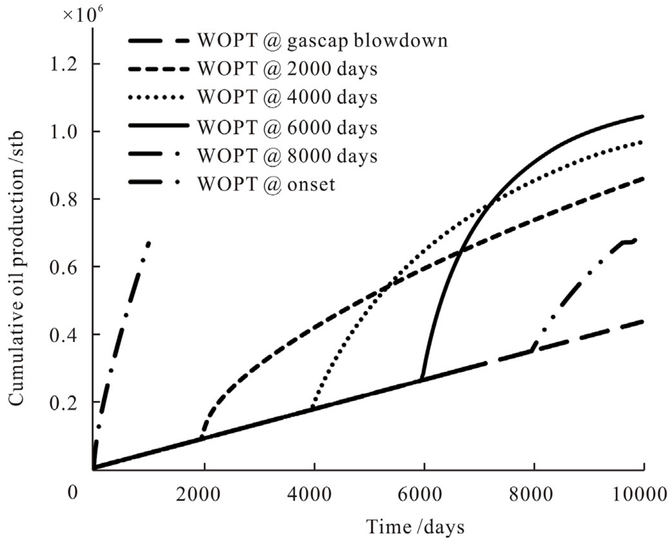


Fig. 2. Cumulative oil production.

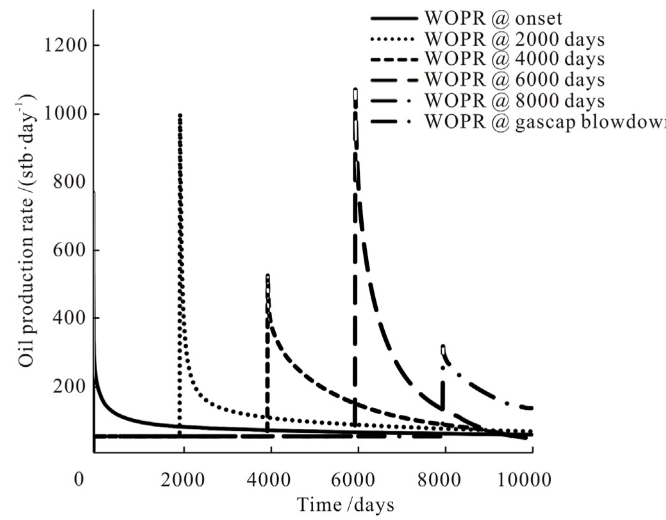


Fig. 5. Well oil production rate.

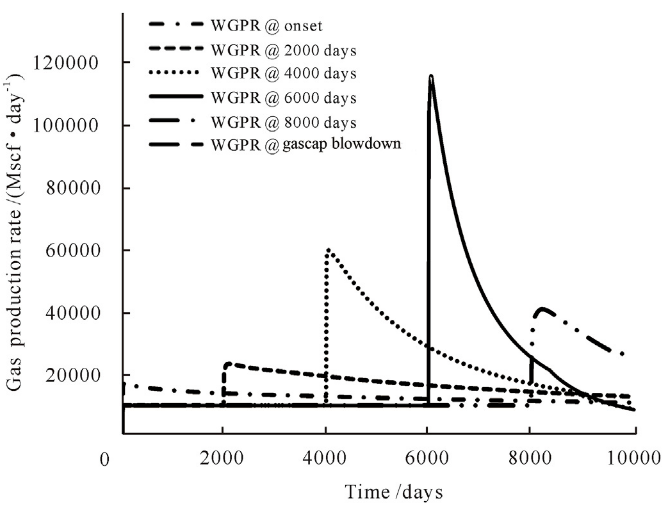


Fig. 3. Well gas production rate.

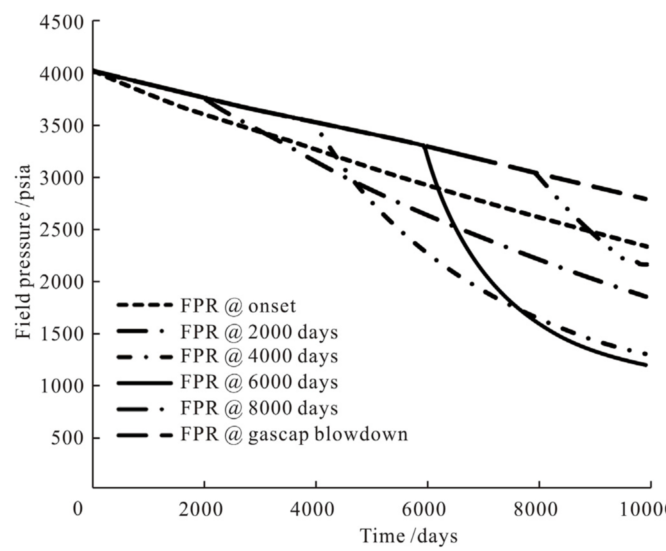


Fig. 6. Field pressure.

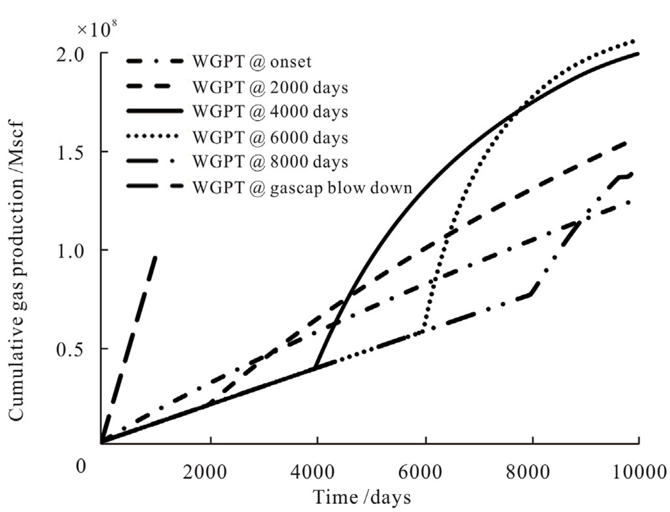


Fig. 4. Well gas cumulative production.

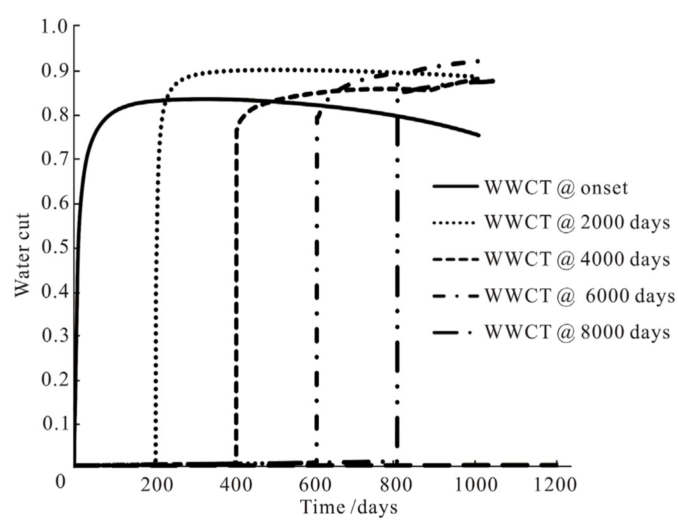


Fig. 7. Well water cut.

Table 6
Production summary for case 1.

	Gas cap blow down	@ Onset	@ 2000 days	@ 4000 days	@ 6000 days	@ 8000 days
Oil recovery factor (%)	4.30	6.61	8.49	9.58	10.34	7.05
Cumulative oil production (stb)	499,910.5	767,817.3	987,372.6	1,112,802	1,200,896	819,417.4
Cumulative gas production (Mscf)	1.0×10^{8}	1.32×10^{8}	1.65×10^{8}	2.11×10^{8}	2.18×10^{8}	1.53×10^{8}
Final pressure (Psia)	2520	1957	1366	691	558	1627
Final water cut (%)	1.4	73.3	92.2	91.6	95.8	91.2

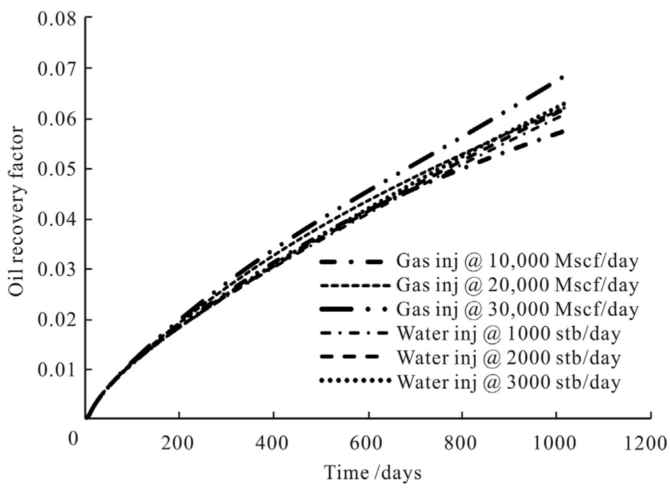


Fig. 8. Oil recovery factor.

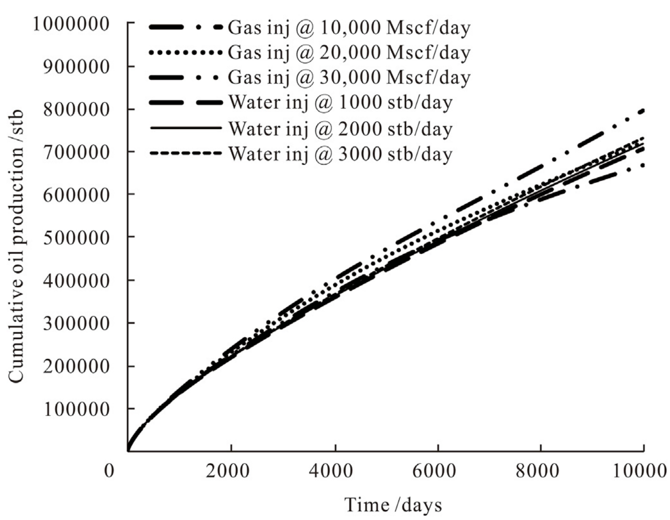


Fig. 9. Cumulative Oil production.

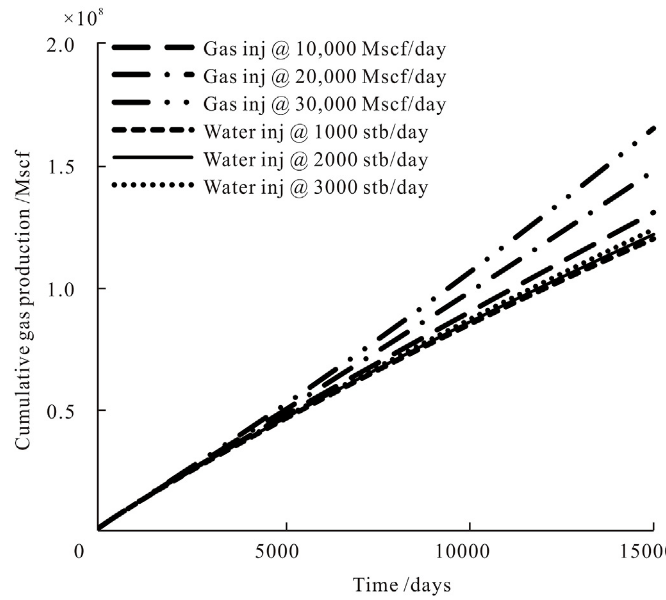


Fig. 10. Cumulative gas production.

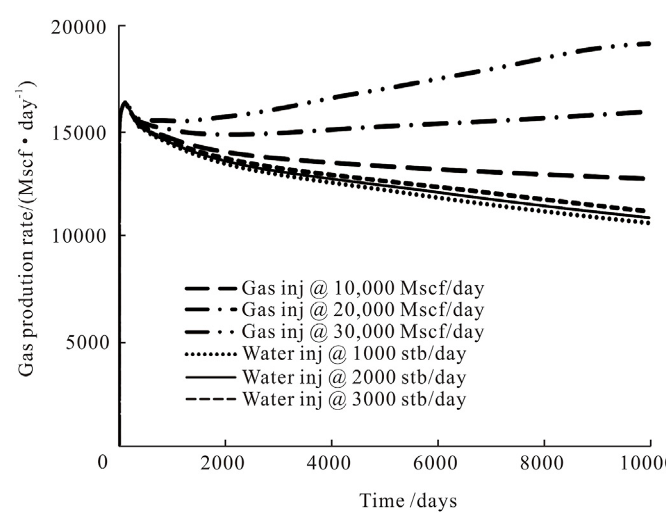


Fig. 11. Gas production rate.

(1) Case 1: gas cap blow down production at onset, then at 2000 days, 4000 days, 6000 days, and 8000 days
(2) Case 2: water downdip and continuous gas up dip injection at rates described in Table 5 at onset and at 2000 days, 4000 days, 6000 days, and 8000 days.

Keywords such as FOE (oil recovery factor), WOPT (well oil production rate), WGPR (well gas production rate), WGPT (well gas production total), FPR (field pressure), WOPR (well oil production rate), and WWCT (well water cut) will be used as variables for comparing the outcomes of the simulated results.

3. Results

3.1. Case 1

During gas cap blowdown strategy an oil recovery of 4.3% is recorded at an estimated oil production of 500,000 stb. As expected, an averagely low oil production rate of 50 stb/day (Fig. 5) is

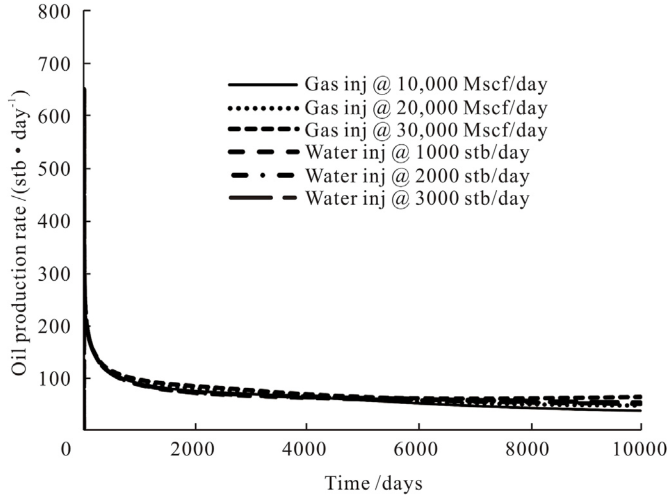


Fig. 12. Oil production rate.

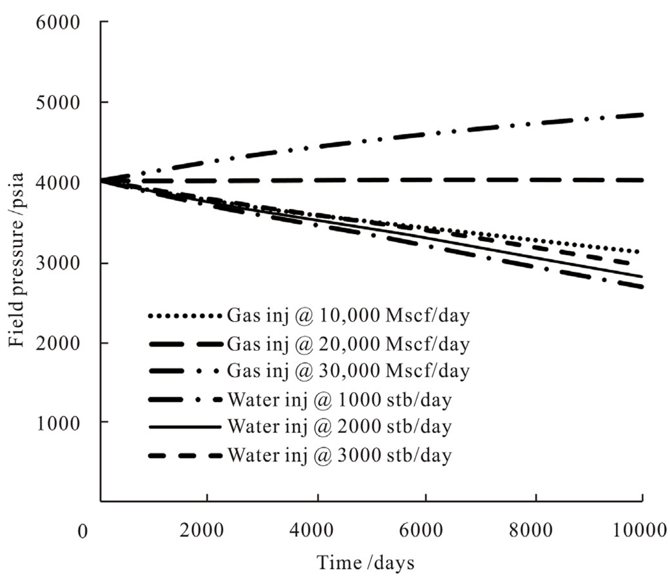


Fig. 13. Field pressure.

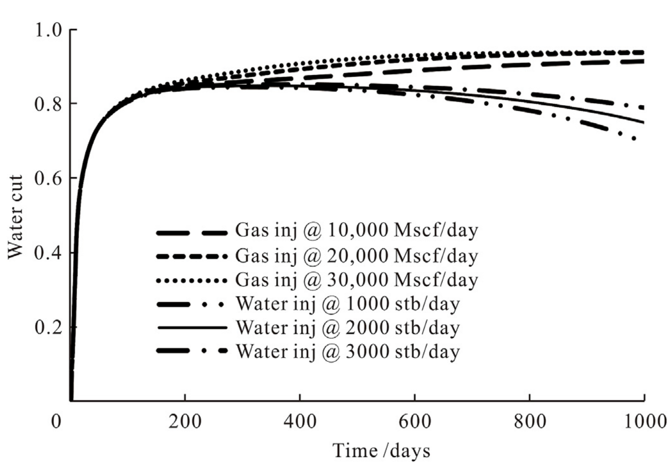


Fig. 14. Water cut.

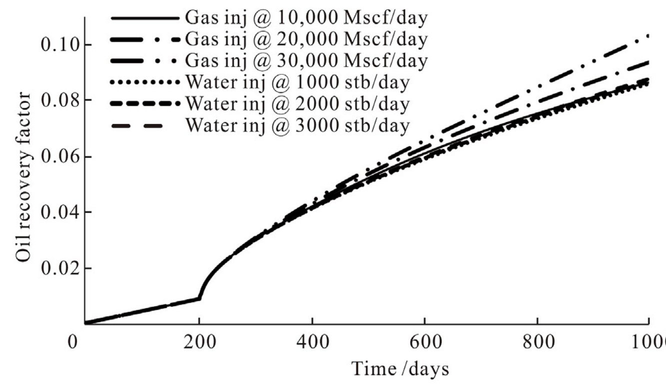


Fig. 15. Oil recovery factor.

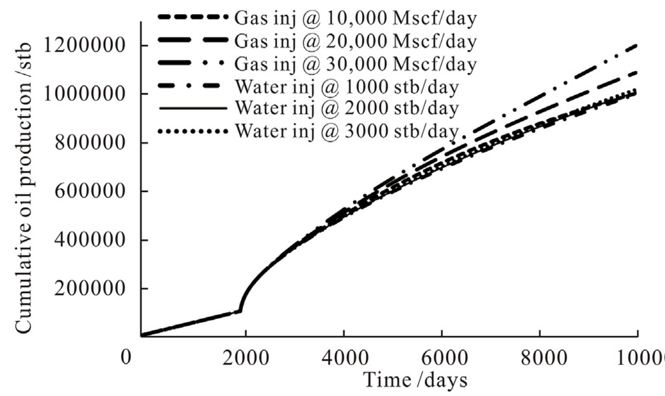


Fig. 16. Cumulative oil production.

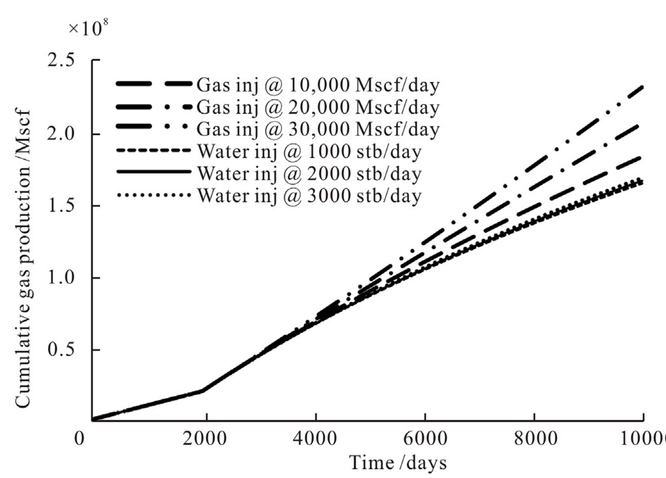


Fig. 17. Cumulative gas production.

estimated as much of the produced oil came from the dissolved oil in gas. A plateau gas production rate of 10,000 Mscf/day (Fig. 3) resulted in a cumulative 100 Bscf (Fig. 4). This case scenario involves gas production from onset till 10,000 days. It is expected that some oil will be produced from the gas well due to the volume of dissolved oil in gas. The oil recovery factor shown in Fig. 1 indicates peak and lowest recovery of 10.3% and 6.6% (Fig. 1) at 6000 days and at onset resulting in a cumulative oil production of 1,200,896 stb and 767,817 stb respectively. High oil production rates are experience at 6000 days resulting from a pressure declined that

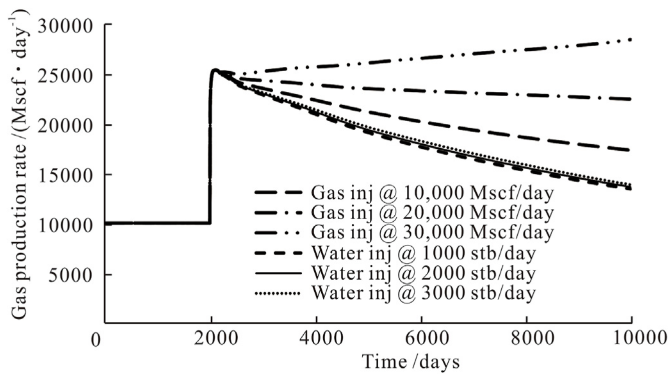


Fig. 18. Gas production rate.

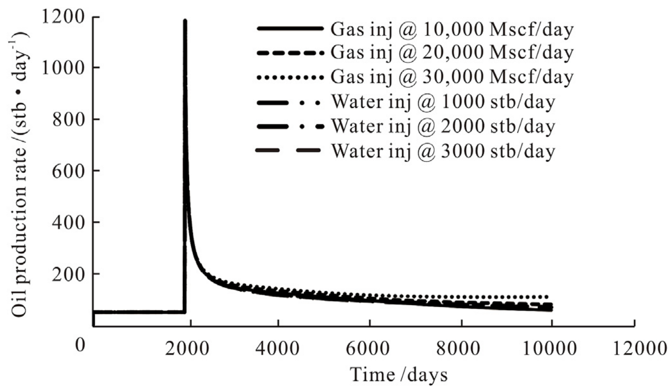


Fig. 19. Oil production rate.

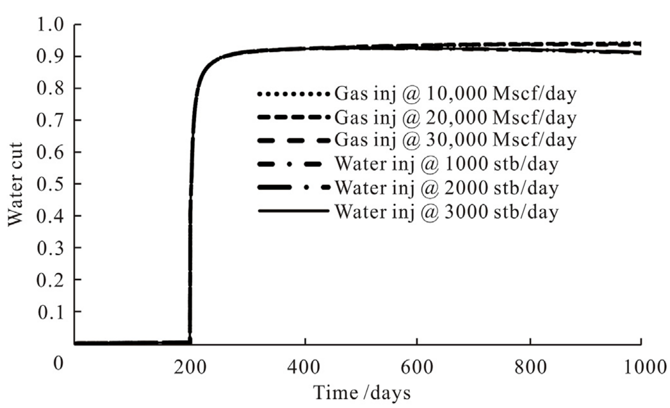


Fig. 20. Water cut.

supported additional oil production (Fig. 3) while peak gas production rates recorded in (Fig. 4) are a result of gas dissolved in oil accompanied by high gas production rates (see Fig. 2).

Due to initial oil production from an oil well at higher reservoir pressure (at 2000 days) and no oil production from an oil well (gas cap blowdown), a less rapid pressure decline is observed (Fig. 5) while the remaining time steps observed drastic pressure drops at their respective points of oil production (from 4000 psia to 560 psia at 6000 days). All the time steps experienced a water cut of 75% and above (Fig. 7) except during gas cap blowdown that recorded a water cut of 1.4% (due to no oil production). The production summary is shown in Table 6.

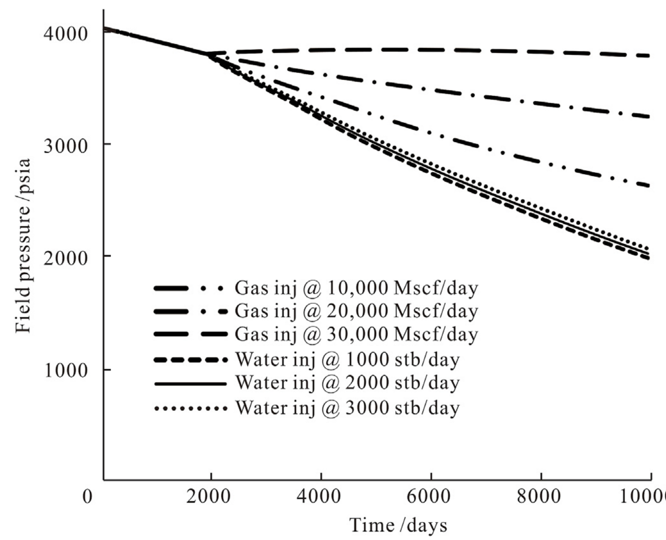


Fig. 21. Field pressure.

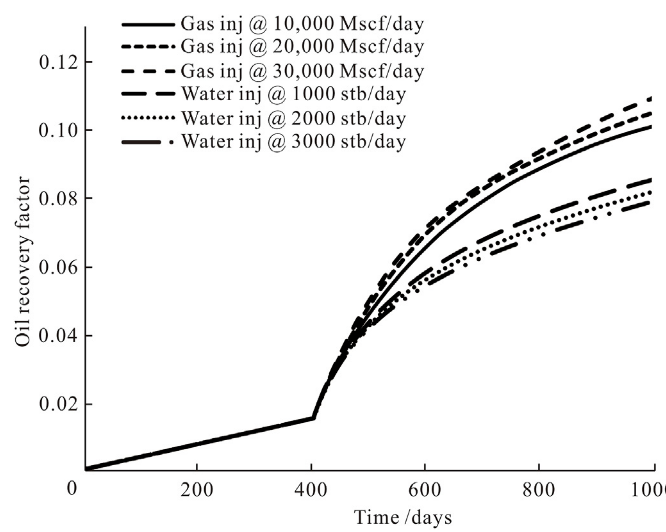


Fig. 22. Oil recovery factor.

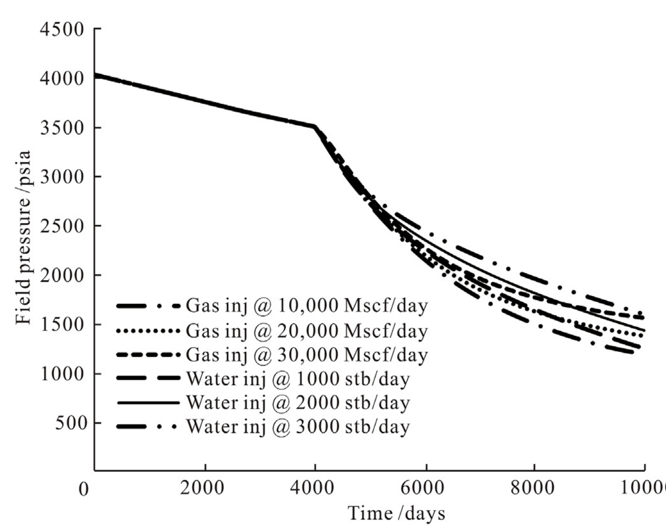


Fig. 23. Field pressure.

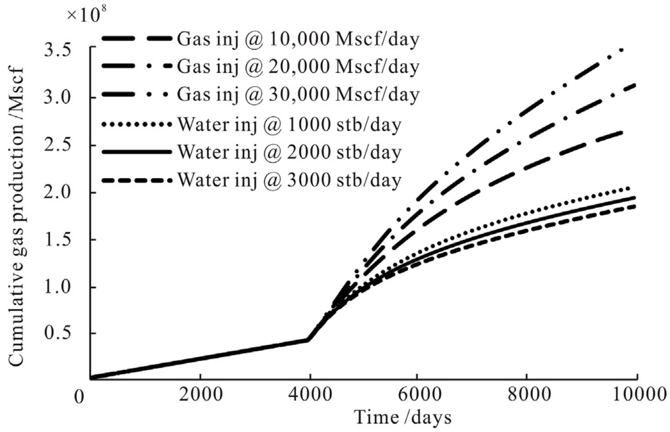


Fig. 24. Cumulative gas production.

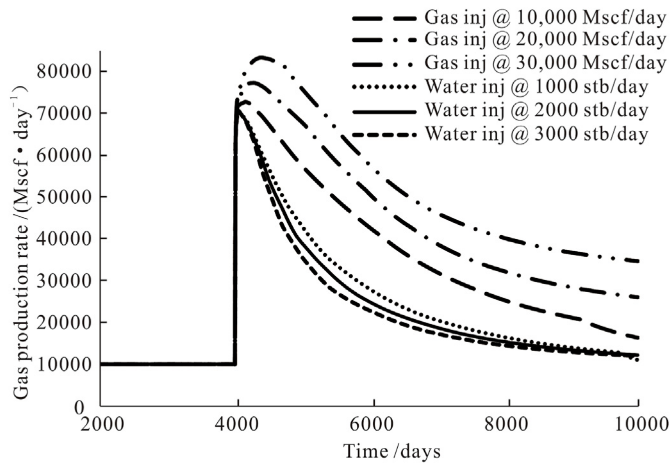


Fig. 27. Gas Production rate.

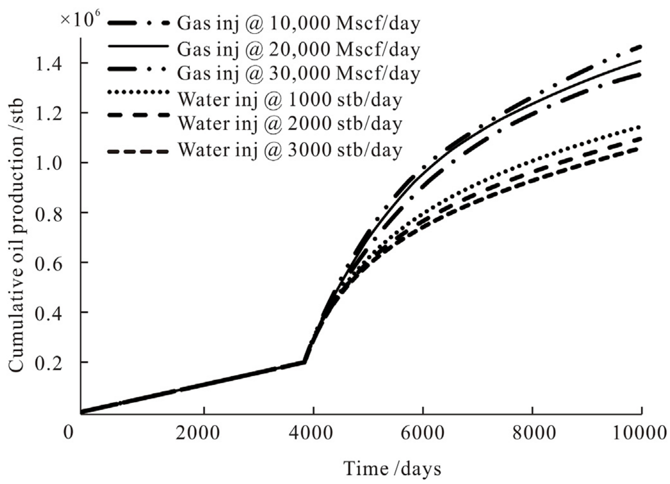


Fig. 25. Cumulative oil production.

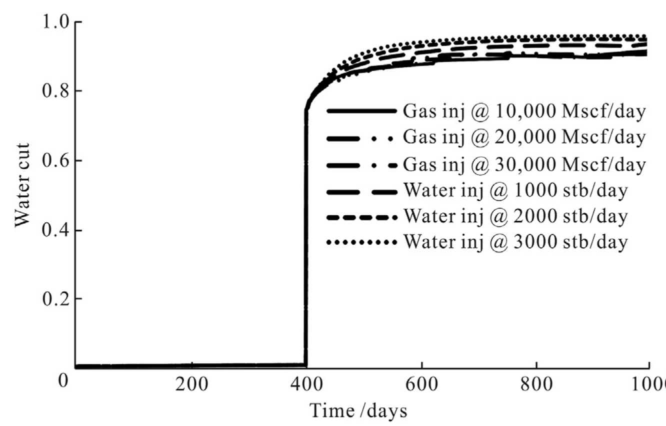


Fig. 28. Water cut.

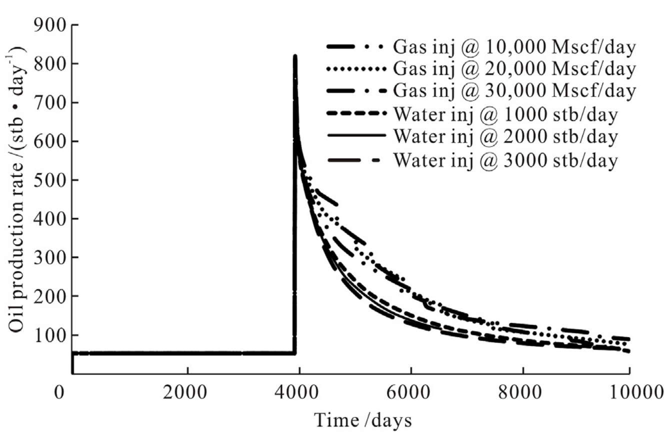


Fig. 26. Oil production rate.

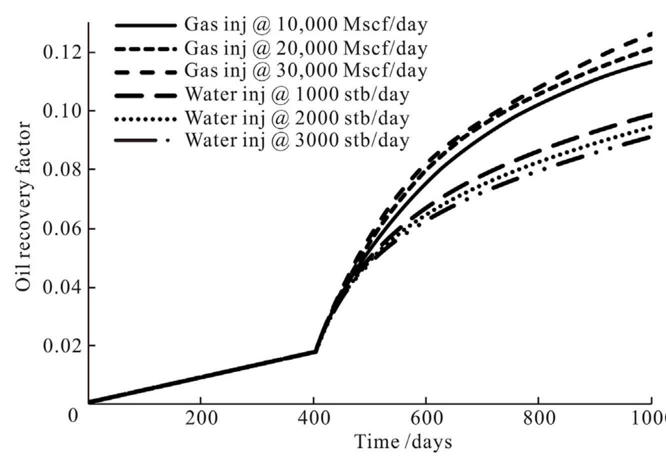


Fig. 29. Oil recovery factor.

3.2. Case 2

Due to low oil recovery from the gas cap blow down strategy, it would be unnecessary to perform an injection scheme during gas cap blow down period. Peak and low oil recoveries of 7.1% and 5.9% are recorded during gas injection at 30,000 and 10,000 Mscf/day (Fig. 8). This resulted in an incremental oil recovery of 2.8% and 0.49% over gas cap blow down and onset production. The pressure

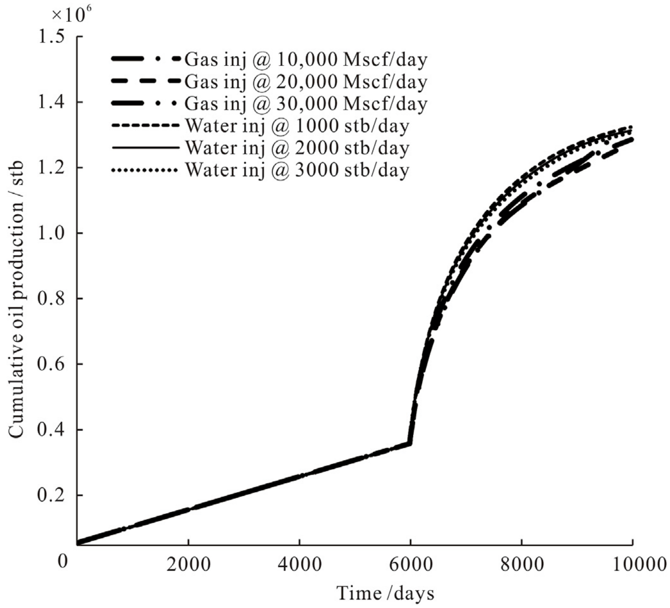


Fig. 30. Cumulative oil production.

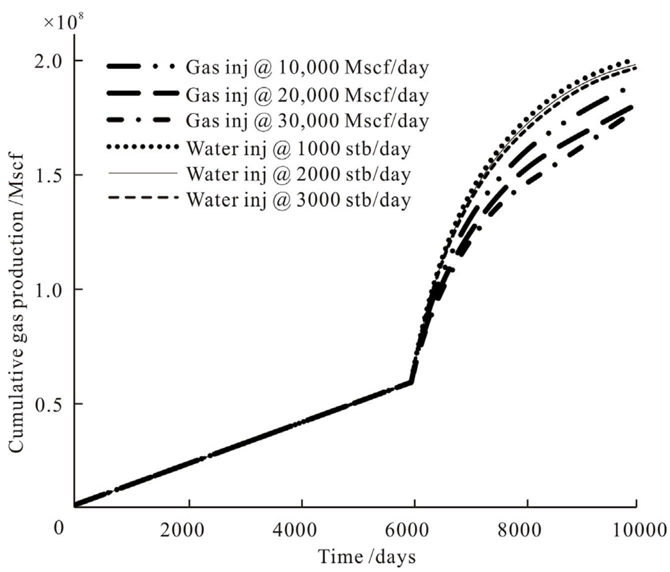


Fig. 31. Cumulative gas production.

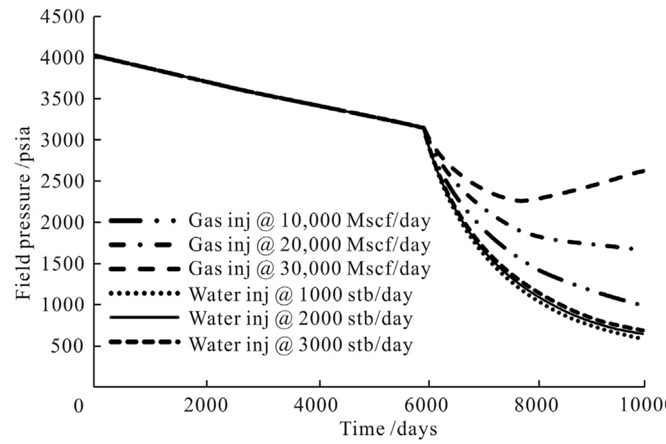


Fig. 32. Field pressure.

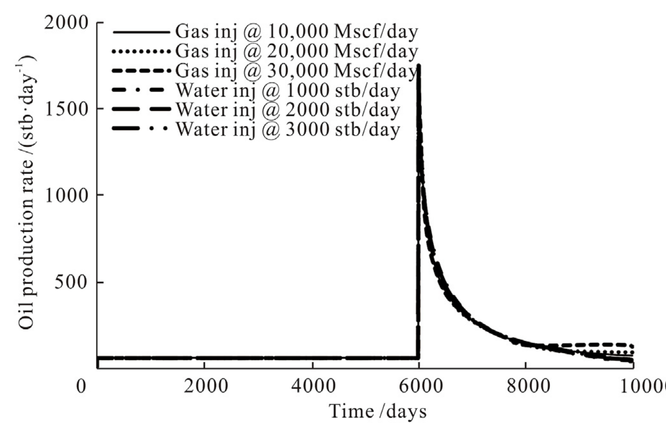


Fig. 33. Oil production rate.

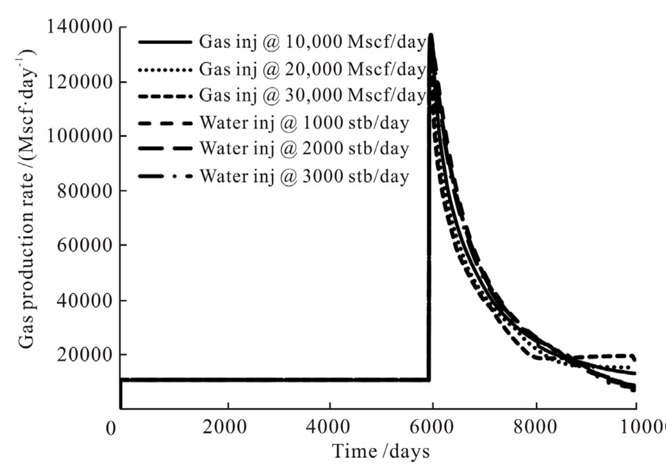


Fig. 34. Gas production rate.

decline reported in Fig. 13 is not as drastic as those recorded in Fig. 6. Not withstanding, a rapid reduction in oil production rates are expereinced till around 120 stb/day few days after commencement of production (Fig. 12). The increase in reservoir pressure above 4000 psia during gas injection at 30,000 Mscf/day is expected as it occurred during onset of production, and this resulted in a 7.1% recovery and cumulative of 818,385 stb (Fig. 9). This spike increases in reservoir pressure due to gas injection is also observed in an increase in the gas production rate (Fig. 11) from 10,000 to 19, 350 Mscf/day (under gas injection at 30,000 Mscf/day). The advent of oil production at this period and gas injection (at all rates) increased the cumulative gas produced (Fig. 10), i.e., by 41,000 Mscf at 30,000 Mscf/day. Lower water cuts are experienced for water injection schemes (Fig. 14) compared to the gas injection schemes.

3.3. Water and gas injection at 2000 days

The gas wells are still opened for production as they account for part of the cumulative oil produced. The producer well and all its properties is moved to 2000 days and the results observed in terms

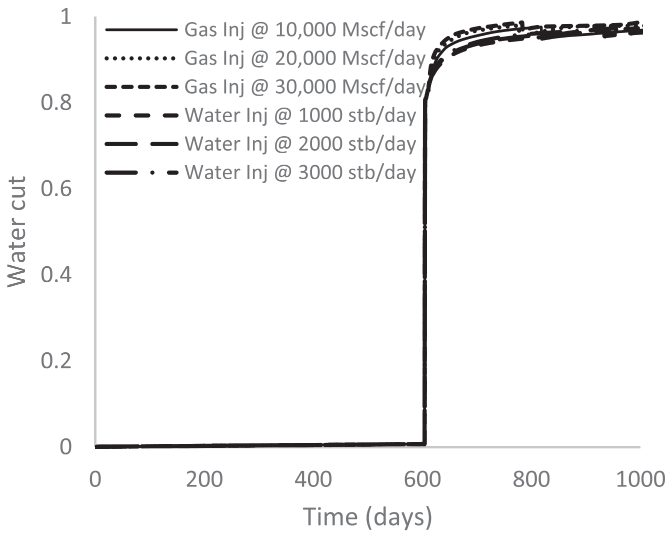


Fig. 35. Water cut.

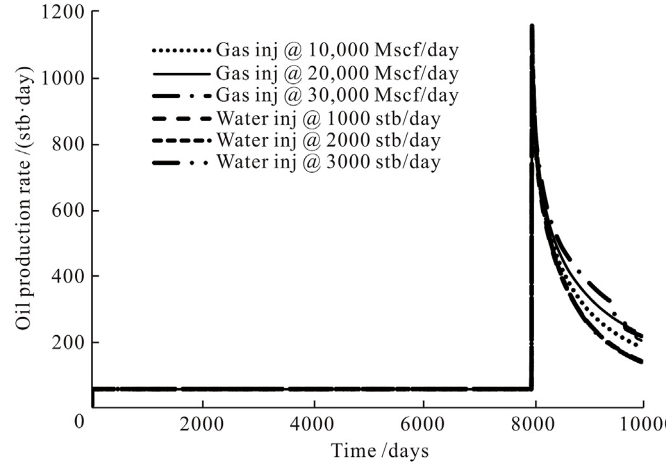


Fig. 37. Oil production rate.

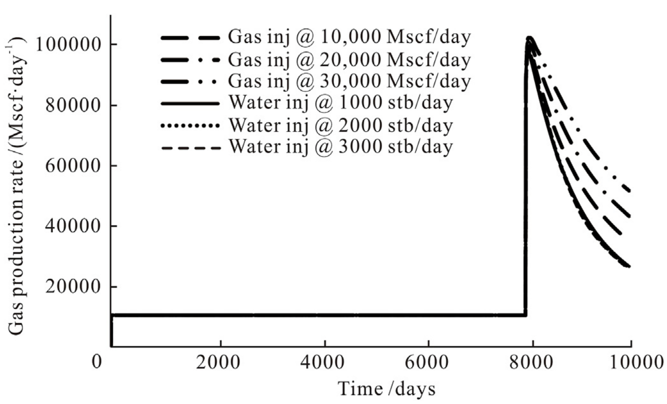


Fig. 36. Gas production rate.

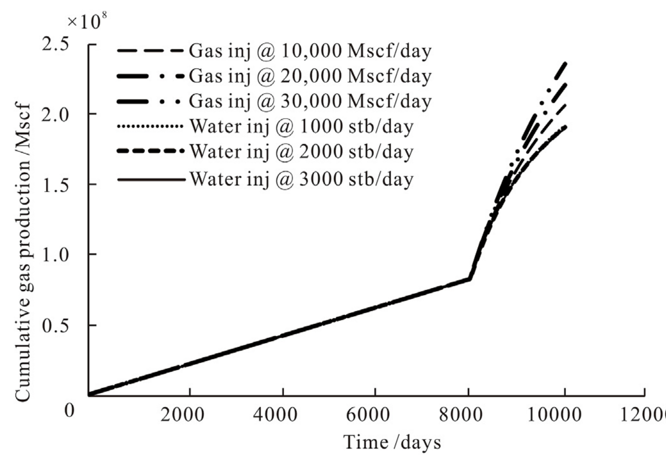


Fig. 38. Cumulative gas production.

of oil produced. The estimated recoveries from this period were better compared to onset production. Peak oil recovery and cumulative oil and gas production of 10.3%, 1.2 MMstb, and 235 Bscf are respectively experienced under gas injection at 30,000 Mscf/day (Figs. 15–17), which is a 3.2% increase over onset production (at the same injection rate) and 6.02% over gas cap blow down strategy. A reason for this is due to the initial pressure depletion for 2000 days before the commencement of oil production and the pressure balance/maintenance from water and gas injection schemes and a view is from the plateau pressure profile experienced in the first curve of Fig. 21. The oil production rates during these schemes all peaked to around 1150 stb/day before they dropped drastically within a year before they all plateaued (Fig. 19) and this is expected as respective gas production rates increased (the first 2 curves in Fig. 18). The results from gas production shows that its production didn't jeopardize that of oil as the estimates recorded are 135 Bscf and 103 Bscf more than those recorded during Gas cap blow down and onset production. Average estimated high water cuts of 95% are experienced due to rapid pressure decline (Fig. 20) and high injection rates.

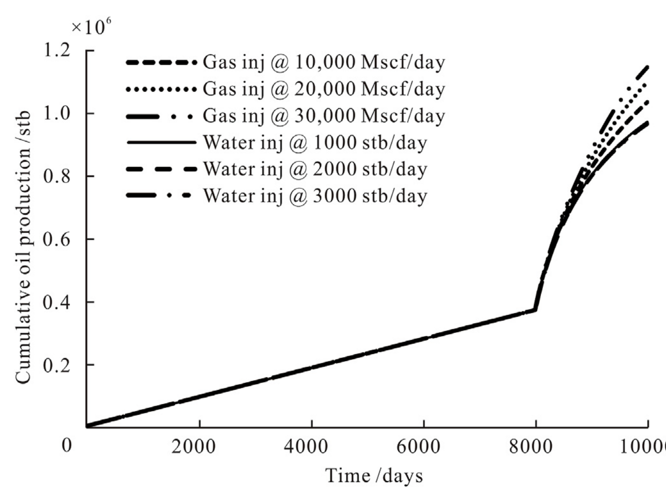


Fig. 39. Cumulative oil production.

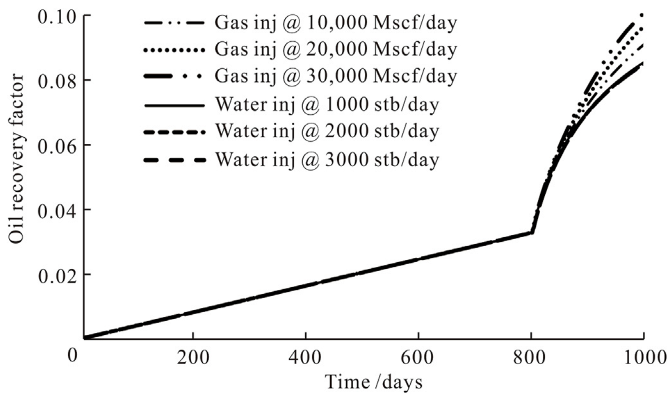


Fig. 40. Oil recovery factor.

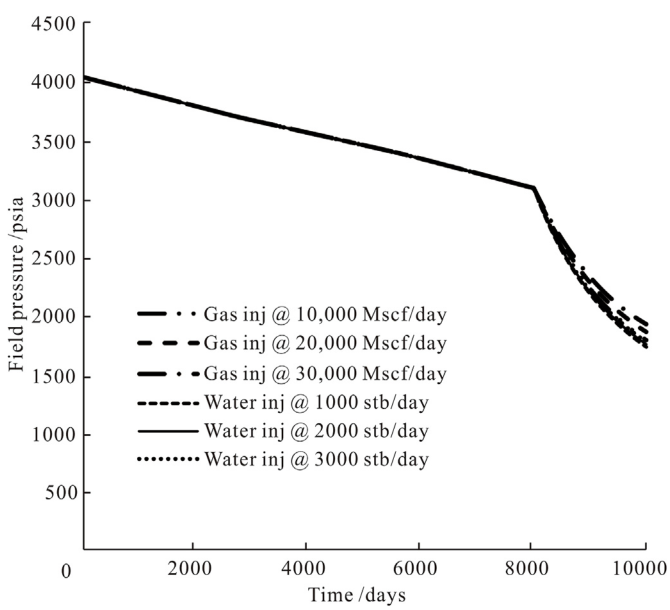


Fig. 41. Field pressure.

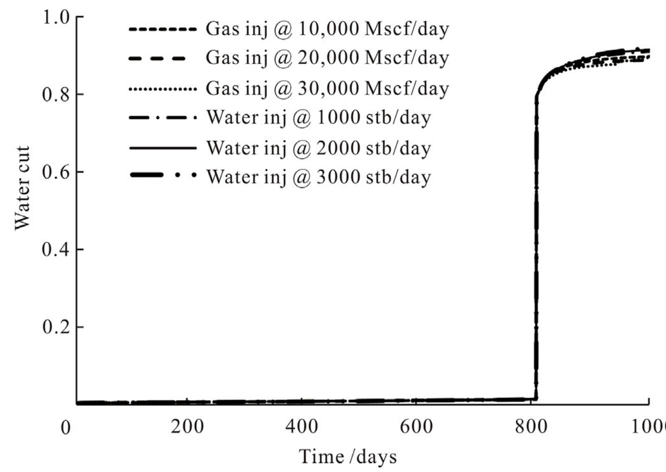


Fig. 42. Water cut.

3.4. Water and gas injection at 4000 days

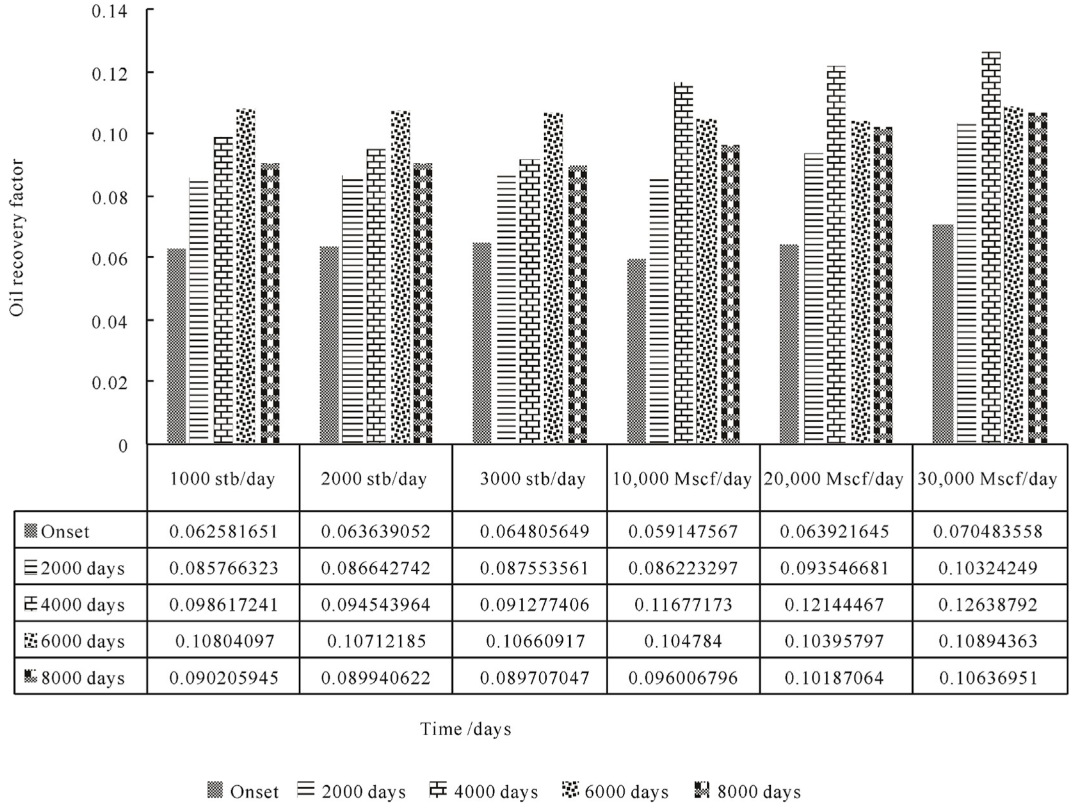
Once again, the producer wells and its properties (described in the methodology) are moved to the time step 4000 days. Oil recoveries under gas injection schemes all improved over those at 2000 days and the same scenario is noticed for water injection schemes. Oil recoveries of 12.2% (incremental recovery of 1.9% over that at 2000 days) and 12.6% (incremental recovery of 2.3% over that at 2000 days) are recorded under gas injection at 20,000 Mscf/day and 30,000 Mscf/day (Fig. 22) resulting in a cumulative oil production of 1.41 MMstb and 1.46 MMstb respectively (Fig. 25) and cumulative gas production of 311 Bscf and 357 Bscf (Fig. 24). A slight steep drop in pressure is experienced after 4000 days and with similar trends for all the schemes (Fig. 23). The indication is that the pressure is dropping but not at a fast rate like what would have been observed between 4000 days and 5400 days. It is assumed that the effect of pressure maintenance via injection is felt after 5400 days hence the steep in different paths for each scheme. The effect of this is experienced in the oil production rates (Fig. 26) as a spreading out/away of the rates from the 4000 days stand point compared to the closeness of the rates to the 2000 days in Fig. 19. Water cuts experienced are high with an average of 85% for each scheme (Fig. 28). Peak gas production rates of 80,000 Mscf/day is recorded during gas injection at 30,000 Mscf/day (Fig. 27) and at these rates the oil recovered is substantially higher those at 2000 days. This is an indication that implementing production and pressure maintenance at later stages enhances oil production during gas cap blow down strategy.

3.5. Water and gas injection at 6000 days

At this period (6000 days) in the reservoir the pressure has been depleted to around 3000 psia before the commencement of water and gas injection schemes (Fig. 32). This influenced the pressure profile especially for the first 3 plots as they seem to rise and then plateau after 6000 days. This didn't affect the oil recoveries as initial oil production and injection of water and gas commenced after 6000 days. Peak oil recoveries of 10.89% and 10.8% are estimated under gas injection at 30,000 Mscf/day and water injection at 1000 stb/day respectively (Fig. 29). Gas produced at these rates were 193 Bscf and 218 Bscf (Fig. 31) while a cumulative of 1.27 MMstb and 1.26 MMstb (Fig. 30) are respectively produced. The peak oil recovery estimated during this period is lower than that experienced at 4000 days. This is related to a shortened period to pressure decline (3400 days) compared to the elongated periods (3000 psia at 6000 days). An incremental oil recovery of 0.55% is recorded over a case scenario of no injection resulting an additional 65,433 stb of oil produced. the rates of oil production decline A plateau oil production rate trend seen in Fig. 33 at 8200 days for the injection schemes resulted in the very low oil recovery factors experienced. The average water cuts recorded for the schemes is as high as 97% (Fig. 35). High gas production rates (Fig. 34) are estimated due to the higher prospects of evolution of high volumes of dissolved gas in oil during oil production accompanied by gas production from the gas cap.

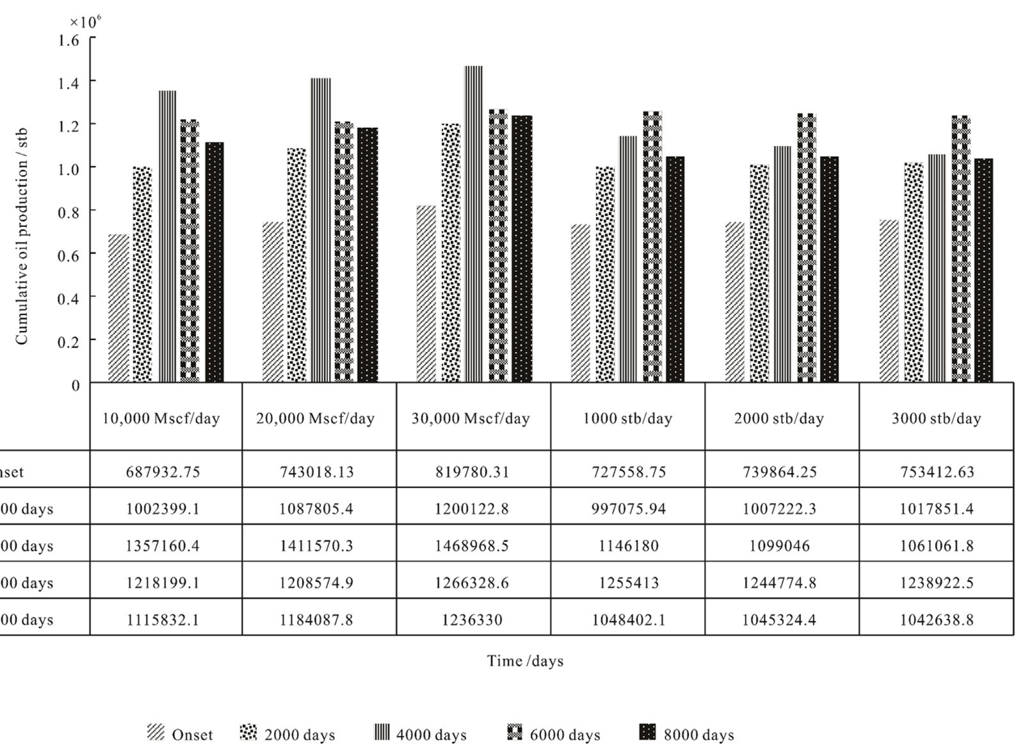
3.6. Water and gas injection at 8000 days

A short period of gas and oil production rates is expected



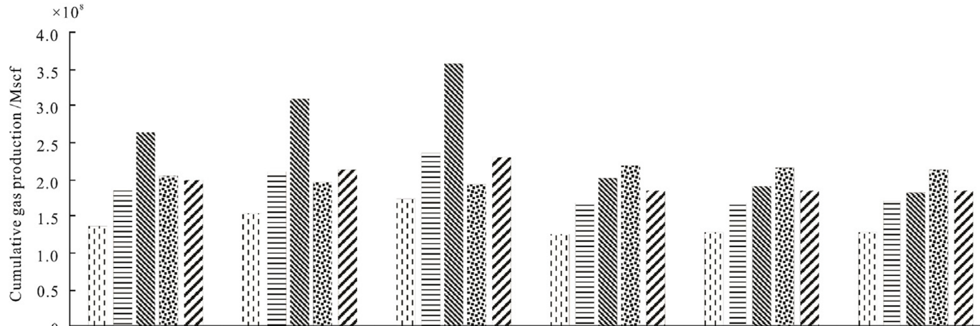
	1000 stb/day	2000 stb/day	3000 stb/day	10,000 Mscf/day	20,000 Mscf/day	30,000 Mscf/day
Onset	0.062581651	0.063639052	0.064805649	0.059147567	0.063921645	0.070483558
2000 days	0.085766323	0.086642742	0.087553561	0.086223297	0.093546681	0.10324249
4000 days	0.098617241	0.094543964	0.091277406	0.11677173	0.12144467	0.12638792
6000 days	0.10804097	0.10712185	0.10660917	0.104784	0.10395797	0.10894363
8000 days	0.090205945	0.089940622	0.089707047	0.096006796	0.10187064	0.10636951

Fig. 43. Summary of oil recovery.



	10,000 Mscf/day	20,000 Mscf/day	30,000 Mscf/day	1000 stb/day	2000 stb/day	3000 stb/day
Onset	687932.75	743018.13	819780.31	727558.75	739864.25	753412.63
2000 days	1002399.1	1087805.4	1200122.8	997075.94	1007222.3	1017851.4
4000 days	1357160.4	1411570.3	1468968.5	1146180	1099046	1061061.8
6000 days	1218199.1	1208574.9	1266328.6	1255413	1244774.8	1238922.5
8000 days	1115832.1	1184087.8	1236330	1048402.1	1045324.4	1042638.8

Fig. 44. Summary of Cumulative Oil production.



	10,000 Mscf/day	20,000 Mscf/day	30,000 Mscf/day	1000 stb/day	2000 stb/day	3000 stb/day
Onset	1.36×10^8	1.54×10^8	1.73×10^8	1.25×10^8	1.27×10^8	1.29×10^8
2000 days	1.86×10^8	2.10×10^8	2.35×10^8	1.67×10^8	1.69×10^8	1.71×10^8
4000 days	2.65×10^8	3.11×10^8	3.57×10^8	2.02×10^8	1.91×10^8	1.82×10^8
6000 days	2.06×10^8	1.96×10^8	1.93×10^8	2.18×10^8	2.15×10^8	2.14×10^8
8000 days	2.00×10^8	2.14×10^8	2.29×10^8	1.86×10^8	1.85×10^8	1.85×10^8

Time /days

Onset 2000 days 4000 days 6000 days 8000 days

Fig. 45. Summary of Cumulative Gas production.

between 8000 days and 10,000 days. The final average rates were 34,000 Mscf/day and 160 stb/day (Figs. 36 and 37). This short period resulted in a short production of oil and gas which is expected to result in low oil recoveries and production totals. Peak oil recovery of 10.64% (Fig. 40) at a cumulative of 1.24 MMstb (Fig. 39) is estimated under gas injection rate of 30,000 Mscf/day. This result only performed better at an incremental rate of 0.32%, 3.54%, and 3.58% over peak result at 2000 days, at onset and during gas cap blow down respectively. Due to the short time span of production the average pressure decline trend is fast and steep (Fig. 41). A peak gas production of 229 Bscf (Fig. 38) is estimated at this injection rate giving an indication that the gas production didn't jeopardize that of oil at the short period. Figs. 43–45 shows describes the bar charts summarizing the oil recoveries, cumulative oil, and gas production of the secondary injection schemes at the time steps. Figs. 43 and 45 shows peak oil recovery and gas production of 12.64% and 357 Bscf at 4000 days during gas injection at a rate of 30,000 Mscf/day. Comparing these figures to those during gas cap blow down method, it is discovered that gas production didn't jeopardize that of oil and vice versa. Water cuts experienced are high with an average of 55% for each scheme (Fig. 42).

4. Conclusions

For oil rim reservoirs with large gas caps subjected to a Gas cap blow down strategy, optimal oil recoveries can be achieved by producing oil at different time intervals during the exploitation of such reservoirs. Implementing water and gas injection schemes during these time steps enhances oil recovery. From the results, the oil production from these schemes did not affect gas production (and vice versa) and in some cases an increased is experienced (at 4000 days and 6000 days). Increasing the number of producer and injector wells is recommended else options for normal and inverted injection patterns as described by Ref. [40] can be deployed. This is important as the comparative analysis of the oil recovered during water and gas injection strategies are close considering the fact that optimal injection rates were considered. Consideration can be made for other enhanced oil recovery options such as low salinity flooding as studied by Ref. [43]. Due to high water cuts, water handling issues will be experienced and high volumes water in oil emulsions leading to additional costs. To reduce the inherent cost of high water cuts and increase oil recovery, a downhole water sink assisted gravity drainage with gas injection at the gas cap can be considered [44,45].

Acknowledgements

The authors sincerely appreciate the management of Covenant University for creating a serene atmosphere for academic research.

Nomenclature

FOE	Field oil efficiency (oil recovery factor)
WGPR	Well gas production rate
WGPT	Well gas production total
FPR	Field pressure
WWCT	Well water cut
WOPT	Well oil production total
SCF	Standard cubic feet
STB	Stock tank barrel

Appendix

Table A
EQUALS

'DX' 300/
'DY' 300/
'DZ' 30 1 20 1 20 1 1/
'DZ' 30 1 20 1 20 2 2/
'DZ' 30 1 20 1 20 3 3/
'DZ' 30 1 20 1 20 4 4/
'DZ' 30 1 20 1 20 5 5/
'DZ' 30 1 20 1 20 6 6/
'DZ' 30 1 20 1 20 7 7/
'DZ' 30 1 20 1 20 8 8/
'DZ' 30 1 20 1 20 9 9/
'DZ' 30 1 20 1 20 10 10/
'DZ' 30 1 20 1 20 11 11/
'DZ' 30 1 20 1 20 12 12/
'DZ' 30 1 20 1 20 13 13/
'DZ' 30 1 20 1 20 14 14/
'DZ' 30 1 20 1 20 15 15/
'DZ' 3 1 20 1 20 16 16/
'DZ' 3 1 20 1 20 17 17/
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'DZ' 3 1 20 1 20 19 19/
'DZ' 3 1 20 1 20 20 20/
'DZ' 3 1 20 1 20 21 21/
'DZ' 3 1 20 1 20 22 22/
'DZ' 3 1 20 1 20 23 23/
'DZ' 1.2 1 20 1 20 24 24/
'DZ' 22 1 20 1 20 25 25/
'DZ' 22 1 20 1 20 26 26/
'DZ' 22 1 20 1 20 27 27/
'DZ' 22 1 20 1 20 28 28/
'DZ' 22 1 20 1 20 29 29/
'DZ' 22 1 20 1 20 30 30/
'DZ' 22 1 20 1 20 31 31/
'DZ' 0.5 1 20 1 20 32 32/

Table B
Reservoir TOPS (approximated values)

7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
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7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
7000	7039	7079	7118	7157	7197	7236	7276	7315	7354	7394	7433	7472	7512	7551	7591	7630	7669	7709	7748
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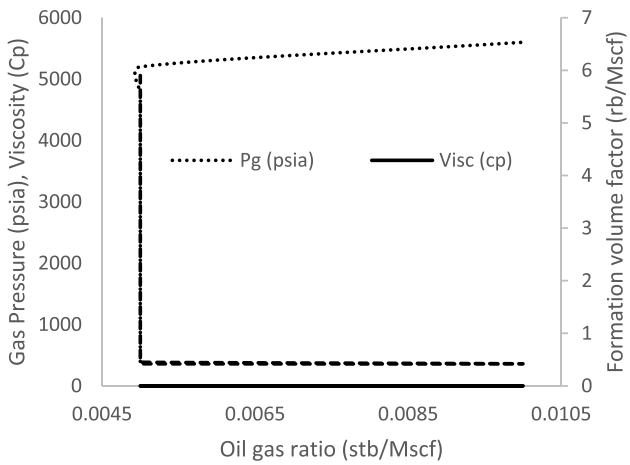

Fig. A. PVTG Wet gas property (with dissolved oil)

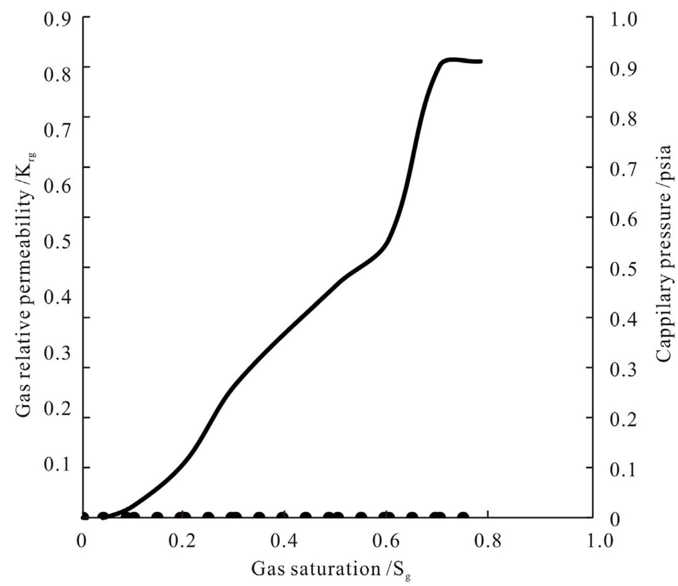

Fig. C. Gas saturation function

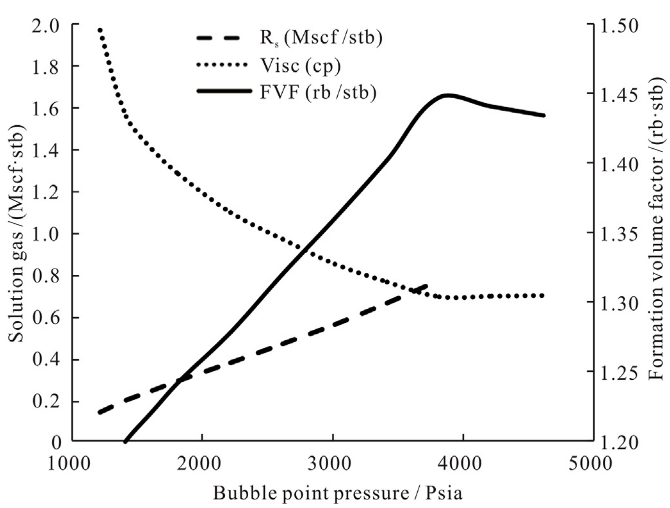

Fig. B. Live oil property (with dissolved gas)

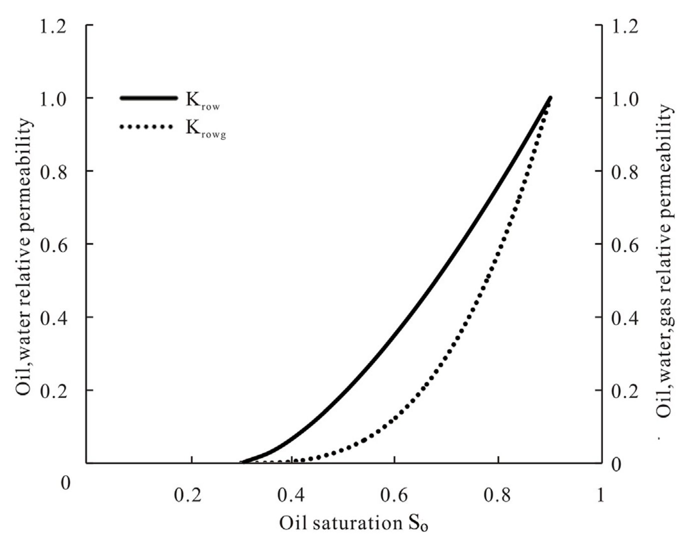

Fig. D. Oil saturation function

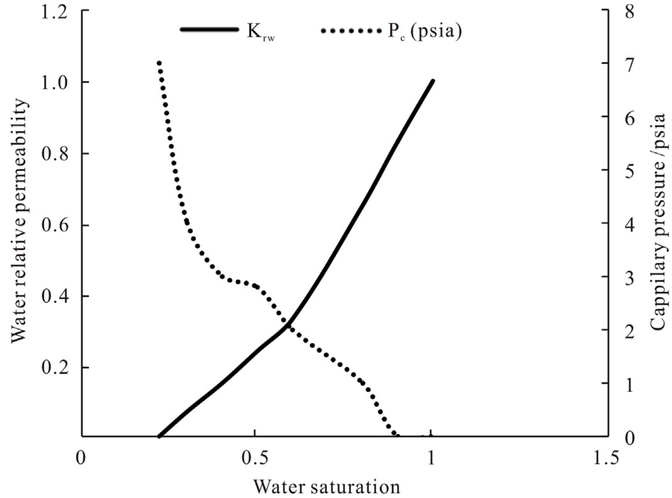

Fig. E. Water saturation function

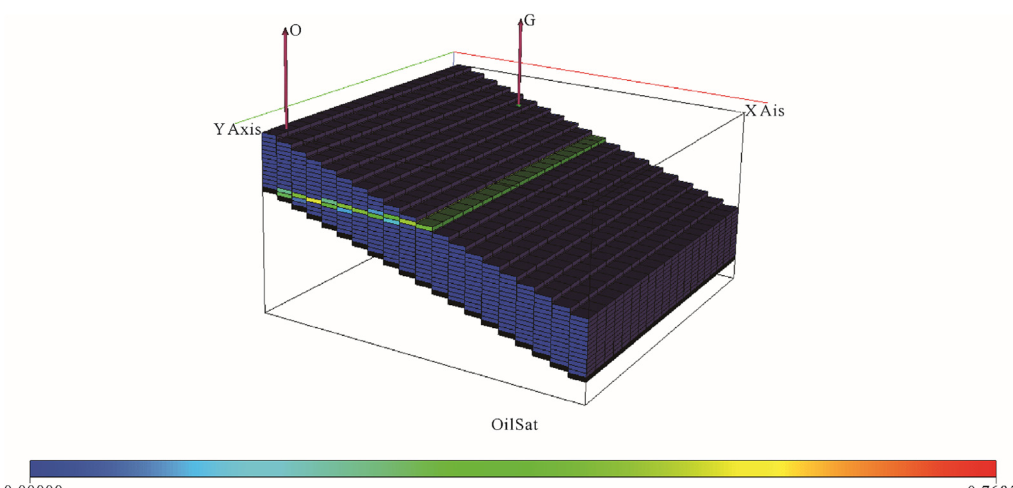

Fig. F. Model A with oil saturation

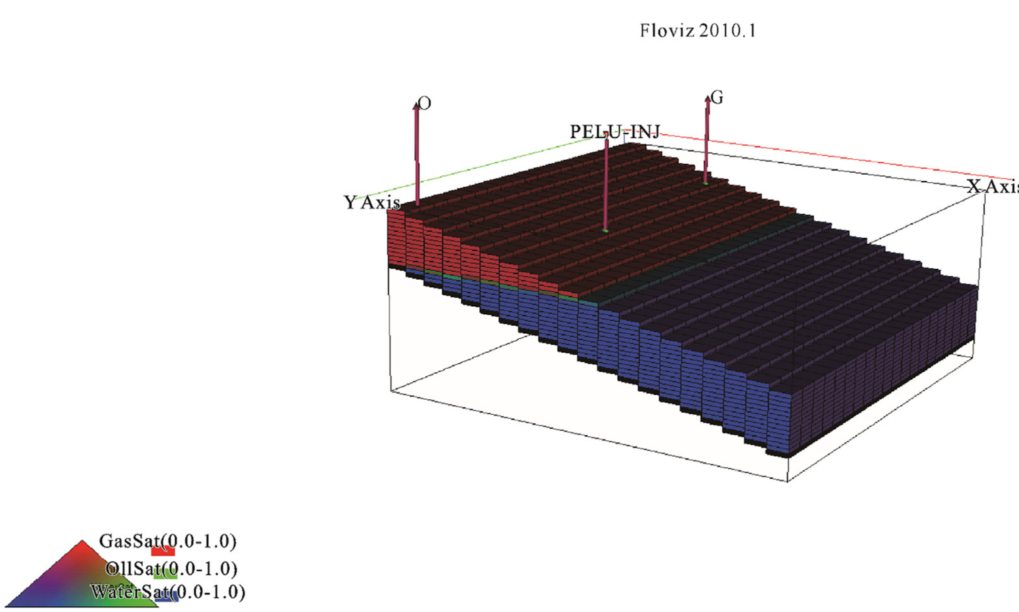

Fig. G. Ternary diagram showing the producer wells (O and G) and Injector well (PELU INJ)

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