Effect of Gas Injection Rates on the Performance of a Thin Oil Rim: A Simulation Study

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Abstract

Oil recovery from thin oil rims under a strong aquifer and large cap is challenging. Low oil recovery efficiency, water coning, gas cusping and the upward and downward shifts of the oil water contact (OWC) and gas oil contact (GOC) respectively are major issues. However, studies have shown that injecting natural gas at the OWC can significantly improve oil recovery efficiency and reduce water production. But the effect of varying gas injection rates on the performance of such reservoirs needs to be studied, and that is the focus of the simulation conducted in this work.

The model of a thin oil rim with a strong underlying aquifer and large gas cap in the Niger Delta was simulated under six different gas injection rates at the OWC to study the performance of the reservoir. Results show that as gas injection rate increased, the oil recovery efficiency and gas-oil-ratio (GOR) increased almost linearly with the exception of gas injection rate of 2500 Mscf/d which is not strong enough to push back water influx into the reservoir. The highest recovery efficiency was almost 62% at the highest gas injection rate of 15000 Mscf/d which also gave the highest GOR and an insignificant volume of produced water. Every gas injection rate has its merits and demerits but the critical factors are oil recovery efficiency, volume of produced water and GOR. Hence, it is recommended that gas injection rates at the OWC be carefully selected based on goals the operating company wants to achieve.

Introduction

Several techniques that can improve oil recovery efficiency from thin oil rim reservoirs have been suggested and studied. Among the successful techniques are the use of horizontal wells (Akpabio et al. 2013), up dip water injection at the gas oil contact (GOC) and down dip gas injection at the oil water contact (OWC) (Razak et al. 2011; Olabode 2020). Other effective methods that have been reported include simultaneous oil and gas production, water injection at the GOC (Uwaga and Lawal 2006; Billiter et al. 1998 and 1999; and Chan et al. 2011), and the down hole water sink technique (Wojtanowicz 2006). In a particular thin oil rim reservoir study in the Niger Delta, five methods of oil production from a thin oil rim with a strong aquifer and large gas cap were studied by simulation. Results showed that the technique of gas injection at the OWC yielded the highest oil recovery efficiency, lowest volume of produced water and highest gas oil ratio (GOR). Other methods such as water production and disposal, and water production and re-injection as edge water obtained better oil recovery factors than the use of horizontal wells (Ogolo et al. 2017).

In a subsequent study, a combination of two good techniques was explored to find out if combining techniques can further increase oil recovery efficiency. It was observed that alternate water injection at the GOC and gas injection at the OWC resulted in the highest recovery efficiency against the single technique of gas injection at the OWC. But the increase in oil recovery efficiency was not significant enough to justify the cost

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of deploying two techniques in one reservoir. It was therefore recommended that a single effective technique be optimized rather than combining two good methods (Ogolo et al. 2018). Optimizing the single technique of gas injection at the OWC of a thin oil rim by investigating the effect of gas injection rates on oil recovery efficiency, water production and GOR constitute the objectives in this research work.

Statement of Theory and Definitions

Production of oil from thin oil rims with a thickness range between 20 to 50 ft, especially in the presence of a strong underlying aquifer and a large gas cap can be very challenging. Although water encroachment into oil reservoirs is desirable because of its good sweep efficiency, but in thin oil rims it is a dilemma necessitating striking a balance since water coning can constitute a problem. Under a strong water drive from an underlying aquifer, water coning gives rise to early water breakthrough, and an enormous volume of produced water can render oil recovery uneconomical adding to the fact that disposing such large volumes of formation water is expensive. Movement of the fluid contacts can cause oil smearing--pushing oil into the gas and water zones which reduces oil recovery factor. Gas cusping results in large GOR which poses another challenge like in the Niger Delta region of Nigeria where there is no market for the large volumes of produced gas.

The lateral extent of some thin oil rim reservoirs are vast, containing substantial amounts of hydrocarbon resources that efforts are made to exploit them despite the difficulties. A production technique that can enhance oil recovery efficiency, maintain the fluid contacts and minimize oil and gas production will be ideal for oil production in thin oil rims. Previous studies have indicated that the strategy of injecting gas at the oil water contact in a thin oil rim is a good option with the disadvantage of large GOR which can be recycled if gas disposal poses a problem. In this work, a sensitivity analysis on the effect of various gas injection rates at the OWC of a thin oil rim is conducted by simulation.

Description of Applications of Equipment and Processes

This is a simulation study using ECLIPSE software package and is a continuation of previous studies on effective oil production techniques from thin oil rims with strong aquifers and large gas caps (Ogolo et al. 2017 and 2018). The thin oil rim reservoir from the Niger Delta that was modeled and used in previous studies is the same oil rim used in this work. The reservoir model is presented in **Figure 1** while the rock and fluid properties of the reservoir are presented in **Table 1**. The reservoir has a large gas cap and a strong underlying aquifer and the study was projected for more than 30 years.

This simulation involves injecting natural gas into the thin oil rim at the OWC and studying how the change of gas injection rate affects oil recovery efficiency, water production and GOR. The reservoir has several oil producing wells and gas injection wells, and six gas injection rate scenarios were explored. The injection rates are 2500, 5000, 7500, 10000, 12500 and 15000 Mscf/d and total gas injected from the wells are 7500, 15000, 22500, 30000, 37500 and 45000 Mscf/d, respectively.

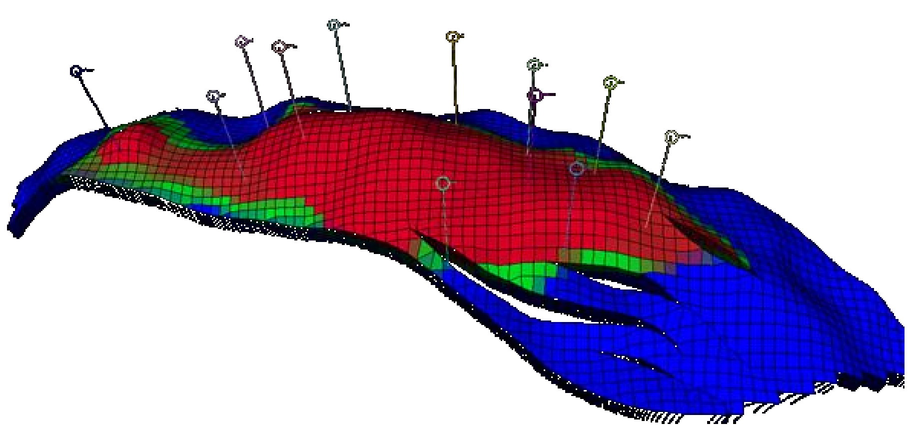

Figure 1—A view of the thin oil rim model.

Table 1—Reservoir rock and fluid properties.

Rock and fluid property	Property	Value
Average reservoir properties	Depth, ft	10421
	Porosity(ϕ)	0.23
	Permeability (k), mD	1292
	Reservoir thickness, ft	45
	Net to gross	0.81
	Initial reservoir pressure (p_i), psia	4540
	Initial water saturation (S_{wi})	0.15
	Formation water compressibility (c_w), psi^{-1}	2.986×10^{-6}
	Rock compressibility (c_f), psi^{-1}	1.1767×10^{-6}
Initial fluid properties	Viscosity (μ_{oi}), cp	0.42110
	Formation volume factor (B_{oi}), rb/stb	1.512
	Saturation pressure (p_b), psia	4540
	Instantaneous GOR, scf/STB	963.5
Average aquifer properties	Porosity (ϕ_a)	0.24
	Permeability (k_a), mD	1292
	Thickness, ft	70
	Inner radius (r_e), ft	5604

Results and Discussion

Results of the simulation study are presented and discussed. **Figure 2** presents gas production from gas wells and subsequent injection into the thin oil rim at the six selected injection rates of 2500, 5000, 7500, 10000, 12500 and 15000 Mscf/d. **Figure 3** is the oil production corresponding to each gas injection rate. The oil production at gas injection rates of 5000 Mscf/d and above were all in close ranges and followed the same pattern--very high at the start of production and then gradually declined over the years. But the oil production at gas injection rate of 2500 Mscf/d did not follow that pattern--oil production was significantly low at the start of production for about six years after which there was a spike which significantly exceeded other cases and fluctuated for about 10 years. After about 20 years of production, the oil production rate fell below other cases and followed the same path as others.

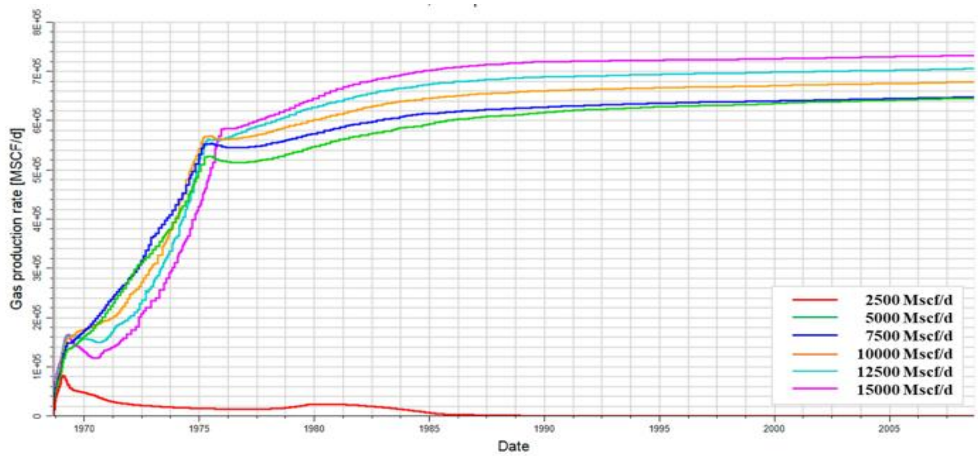

Figure 2—Simulated gas production and injection rates into the thin oil rim.

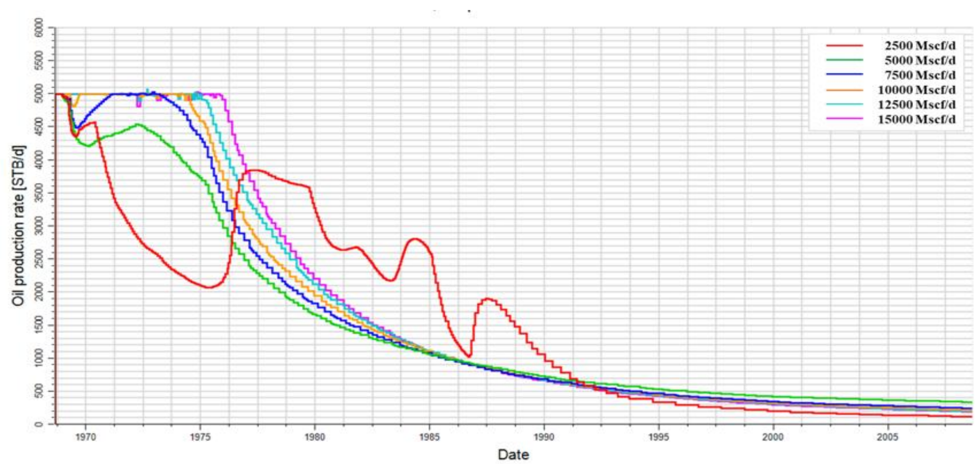

Figure 3—Field oil production rate.

The water production presented in **Figures 4** and **5** show that the gas injection rate of 2500 Mscf/d gave the highest water production rate. This is because the gas injection rate was not strong enough to minimize water encroachment into the reservoir. Hence to control water influx into a reservoir by injecting gas at the OWC, a simulation study should first be conducted to determine the rate of gas injection that can significantly push back invading water. The rates of water influx for gas injection rate of 5000 Mscf/d and above are minimal and within the range of 500 to 950 STB/d (**Figure 5**). But the rate of water influx for the gas injection rate of 2500 Mscf/d is very enormous, about 160000 STB/d as shown in Figure 4. **Figure 6** is a semi log plot of the results showing all the cases on one graph.

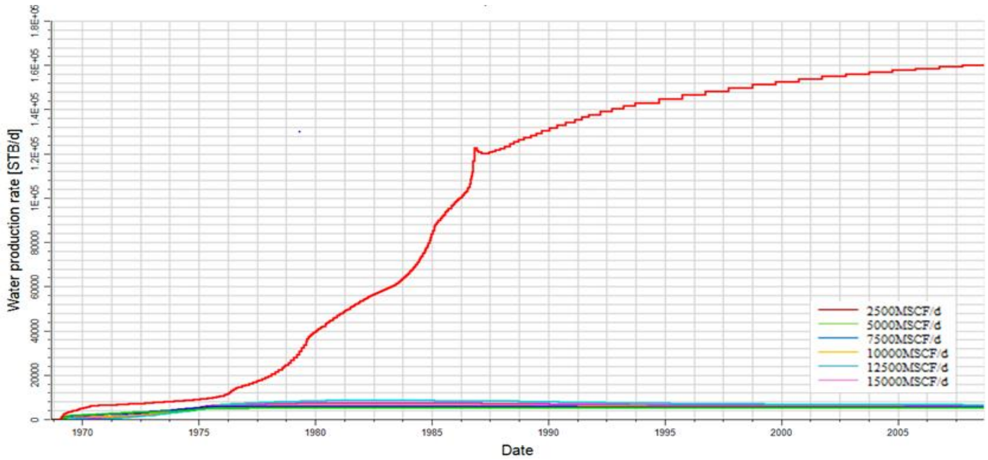

Figure 4—Field water production rate for 2500 Mscf/d gas injection rate.

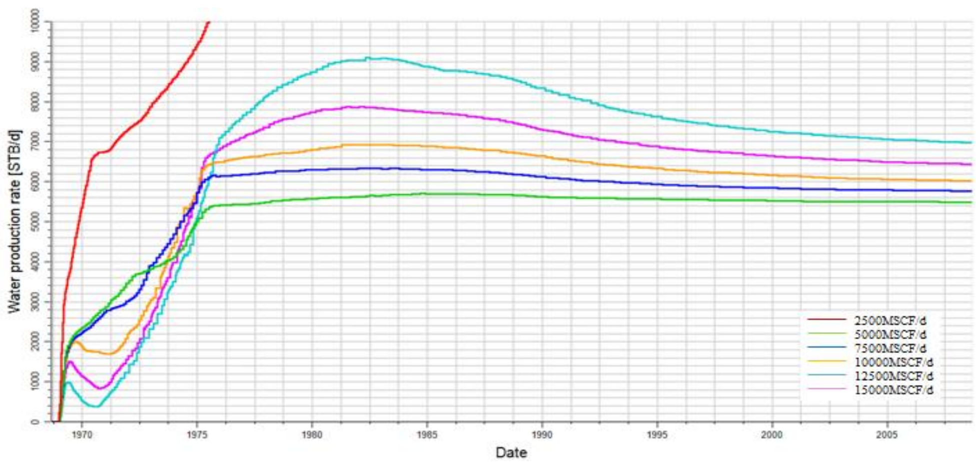

Figure 5—Field water production rate for higher gas injection rates.

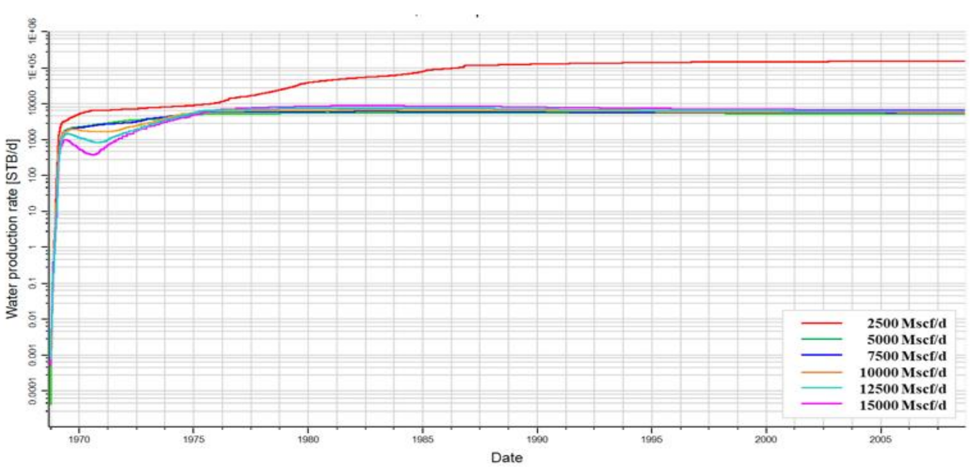

Figure 6—A semi log plot of water production rate for the six cases.

Figures 7 to **9** show the cumulative volume of produced water for more than 35 years of production from the thin oil rim which reiterate observations made in Figures 4 to 6. It is observed in Figures 7 and 8 that the cumulative volume of produced water from a gas injection rate of 2500 Mscf/d is outrageous compared to that of gas injection rates of 5000 Mscf/d and above. Note that the highest gas injection rates did not give the lowest volume of produced water after 35 years of production as observed from Figure 8. This means that the relationship between gas injection rate and volume of produced water may not be linear. However, this was not the trend from the beginning of production in 1970 which appeared to be linear, the trend changed inversely at the tenth years of production in 1980. The reason for this change in trend requires further research work. Figure 9 is a semi log plot of the results showing all the cases on one graph.

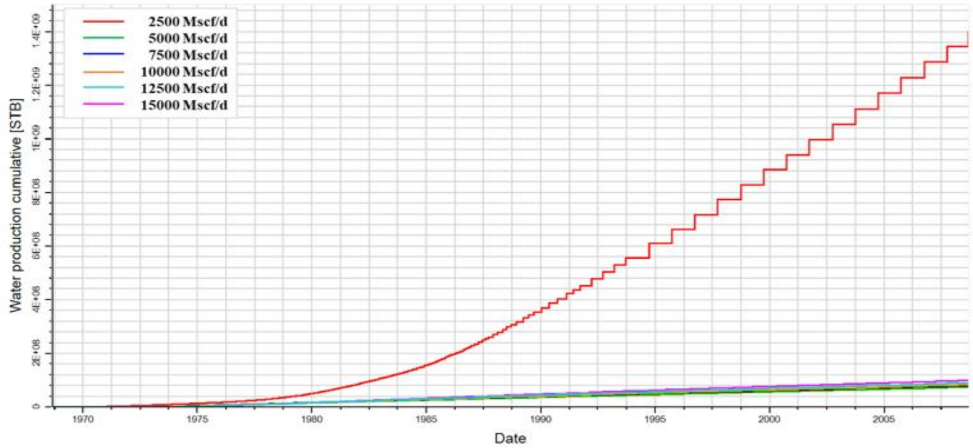

Figure 7—Cumulative volume of produced water especially for 2500 Mscf/d gas injection rate.

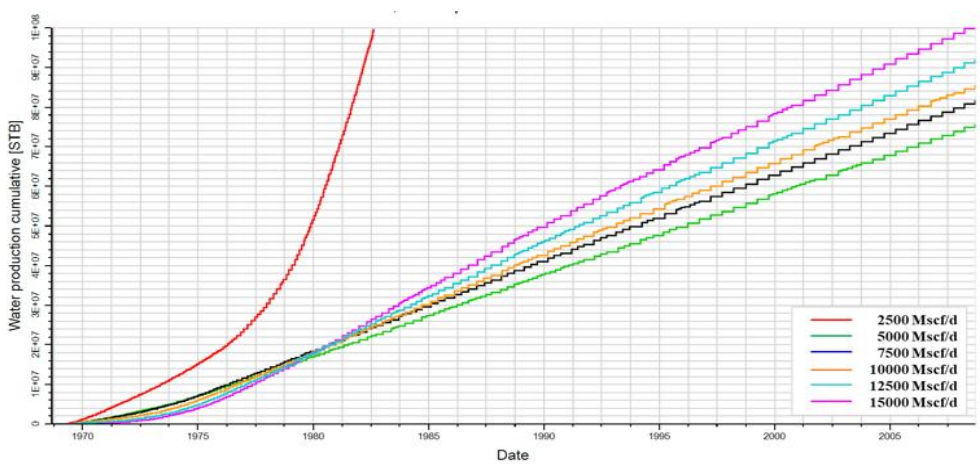

Figure 8—Cumulative Volume of Produced Water at Different Gas Injection Rates.

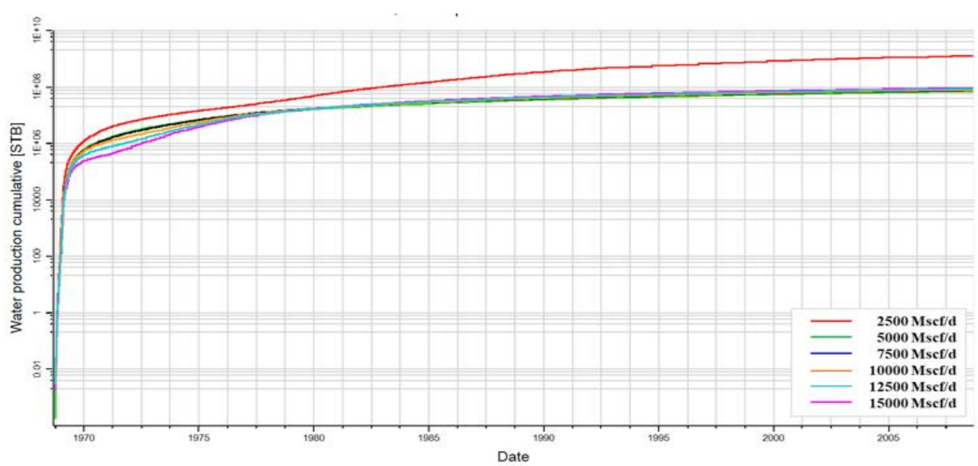

Figure 9—Cumulative volume of produced water on a semi log plot.

Figures 10 and **11** are results of the GOR as gas injection rates vary, and as expected the GOR increased as gas injection rate increased from 5000 to 15000 Mscf/d. However, at gas injection rate of 2500 Mscf/d, the GOR is insignificant compared to higher gas injection rates because of the large volume of encroaching water in the reservoir. It is observed from **Figure 12** that the relationship between gas injection rate and GOR is approximately linear as expected. But this was not the pattern from the beginning in 1970 as observed from Figure 10, the pattern which was inverse changed in the twelfth and half year (1982) after production started. This is also an area for further research which might have a relationship with results of cumulative volume of produced water presented in Figure 8.

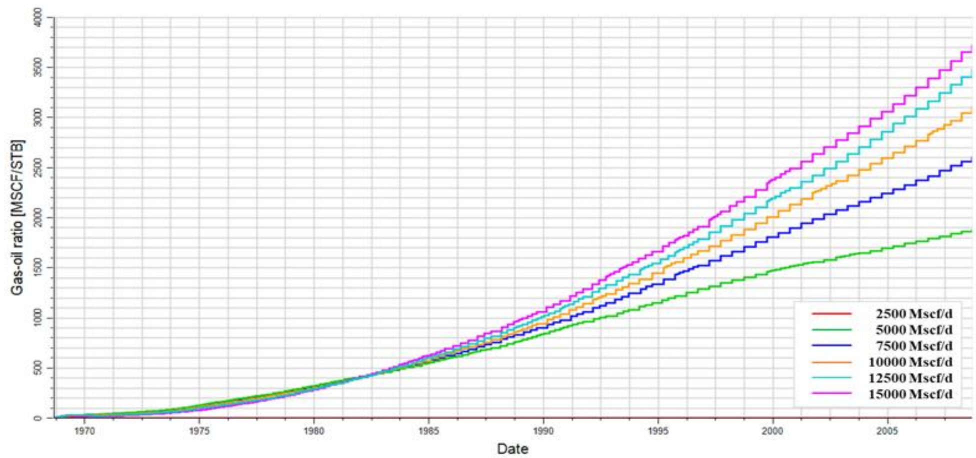

Figure 10—Field gas-oil-ratio.

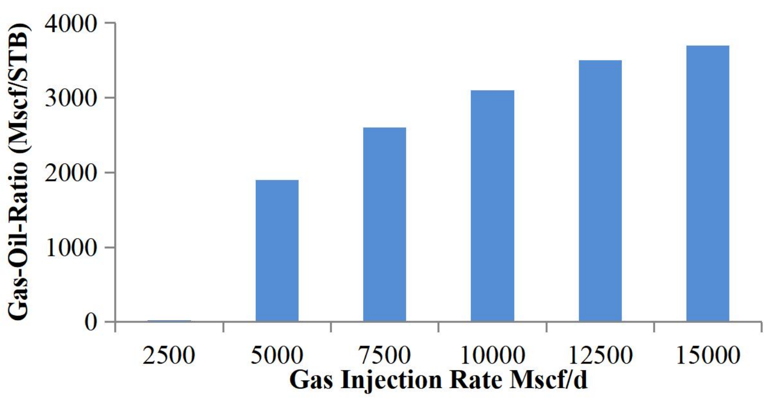

Figure 11—Gas-oil-ratio with gas injection rates.

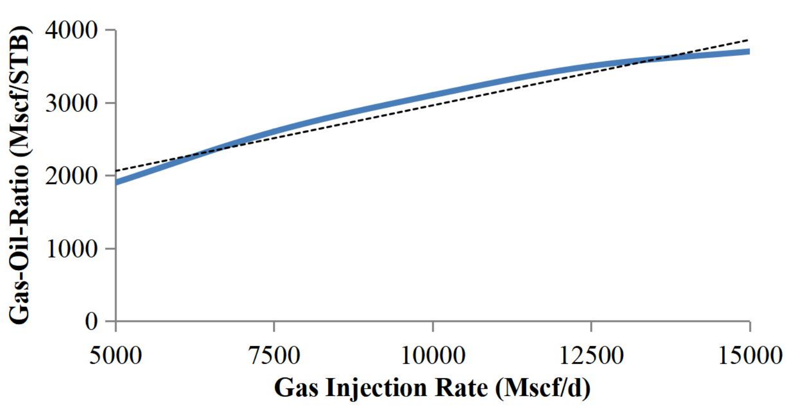

Figure 12—Gas-oil-ratio with gas injection rates: blue line is gas-oil-ratio, dash is the trend curve.

Results of oil recovery efficiency are presented in **Figures 13** to **15**. The highest oil recovery efficiency which is one of the most important factors to consider during production is about 62% and was attained at the highest gas injection rate of 15000 Mscf/d. It is observed that oil recovery efficiency increased as gas injection rate increased, noting the exceptional and interesting case of the lowest gas injection rate of 2500 Mscf/d. The oil recovery efficiency of this case was almost 58% despite the fact that the gas injection rate was low. This is because water encroachment from the underlying aquifer improved sweep efficiency which supported oil production.

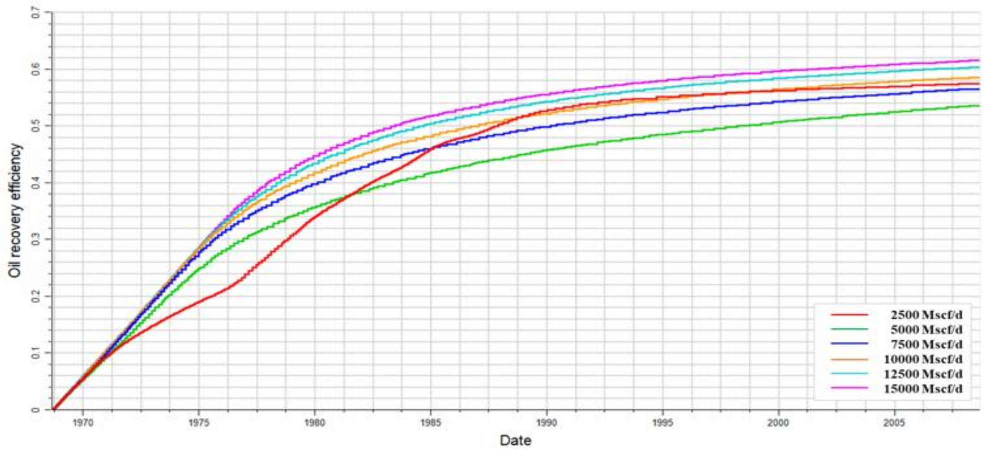

Figure 13—Field oil recovery efficiency.

Figure 14 is plotted for the sake of clarity and it shows that the oil recovery efficiency at 2500 Mscf/d gas injection is good, even better than cases of gas injection rates at 5000 and 7500 Mscf/d but the main disadvantage is the large volume of produced water as presented in Figures 4 to 9 which will involve high cost of disposal. Starting from gas injection rate of 5000 Mscf/d where the rate of water production is significantly reduced, (excluding the case of gas injection rate of 2500 Mscf/d) it is observed that oil recovery efficiency has almost a linear relationship with gas injection rate as presented in Figures 14 and 15.

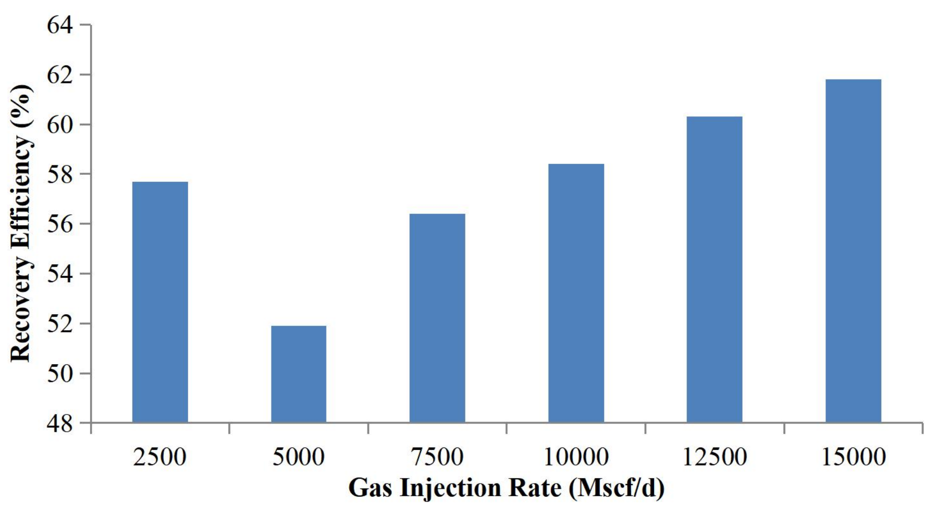

Figure 14—Recovery efficiency of different gas injection rate.

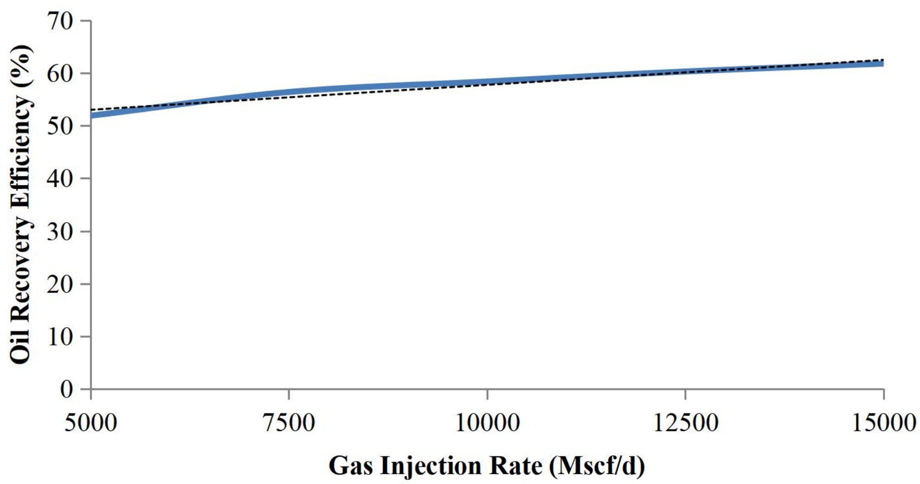

Figure 15—An almost linear trend of recovery efficiency with gas injection rate.

This study shows that each gas injection rate has its merits and demerits and the objectives of the operating company should determine the gas injection rate that will be selected. If the goal is to maximize oil recovery efficiency with minimal water production, then the highest gas injection rate can be selected with the disadvantage of a very high volume of produced gas (high GOR) which can be recycled (Ogolo et al 2017) if managing the gas poses a challenge. If the target is to minimize the volume of produced gas (low GOR) with fairly good oil recovery efficiency, then a low gas injection rate could be selected, but a very large volume of produced water should be expected. This stresses the importance of conducting a gas injection rate sensitivity analysis by simulation when the technique of gas injection at the OWC in a thin oil rim is proposed.

Conclusions

The conclusions drawn from this work are as follows:

1. In gas injection technique at the OWC for optimizing oil recovery from a thin oil rim with a strong aquifer and large gas cap, gas injection rate is a sensitive factor that can determine oil recovery efficiency, volume of produced water and GOR.
2. It is important to conduct a simulation sensitivity analysis on gas injection rate at the OWC of a thin oil rim reservoir if gas injection technique is considered to be deployed. This is in order to carefully select the injection rate that will aid the operating company achieve its objectives.
3. The rate of gas injection at the OWC should be strong enough to push back water influx and significantly improve oil recovery efficiency if part of the objective is to drastically reduce water production from the reservoir.
4. Gas injection rate at the OWC in a thin oil rim tends to exhibit a linear relation with oil recovery efficiency.

Recommendation

Before embarking on gas injection at the OWC as a technique to optimally improve oil recovery efficiency and minimize water production from thin oil rims with a strong aquifer and large gas cap, a simulation sensitivity analysis on the gas injection rate should be conducted. The gas injection rate should be strong enough to push back invading water in order to prevent the fluid contacts from shifting if this constitutes part of the company's goal.

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Conflict of Interest

The authors do not have any conflict of interest to disclose.

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