Primary recovery factor as a function of production rate: Implications for conventional reservoirs with different drive mechanisms

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Abstract

This study evaluates the dependency of production rate on the recovery of hydrocarbon from conventional reservoirs using MBAL simulator. The results indicated that the recoveries are sensitive to the production rate in almost all hydrocarbon reservoirs. It was also found that the recovery of volumetric gas drive reservoirs is not impacted by the production rate. In fact, any increase in the production rate improves gas recovery in weak and strong water drive reservoirs. Moreover, increasing the production rate in oil reservoirs decreases the recovery with a significant effect observed in the weak water drive reservoirs. The results of this study demonstrate the need for implementing an effective reservoir management in order to obtain a maximum recovery.

Keywords: Recovery factor, production rates, hydrocarbon reservoirs, drive mechanisms

1. Introduction

Hydrocarbon reservoirs are primary produced based on their initial pore pressure (Gong and Rossen 2018). However, due to the interplay of geological, physical and economic limits, it is often very unlikely to recover more than 50% to 60% of hydrocarbon from a reservoir under the primary recovery (Shepherd 2009, Agarwal, Al-Hussainy, and Ramey 1965, Min et al. 2015).

Parameters that may affect the recovery factor can be divided into three categories of: 1) reservoir rock properties (e.g., porosity and permeability), 2) fluid properties (e.g., API gravity and viscosity) and 3) the production methods employed (Kaczmarczyk, Herbas, and Del Castillo 2014). Having known these parameters, it is also recommended to determine the maximum efficient rate at which oil or gas can be produced without reducing the recovery (USLegal 2014).

There have been many studies carried out to determine the effect of the production rate on the recovery factor of certain reservoirs. For instance, Agarwal et al. (1965) carried out an analytical study and concluded that the gas recovery depends on the production rate, residual gas saturation, aquifer strength, aquifer permeability and the volumetric sweep efficiency of the water invaded zone. Gas recovery can be significantly improved by handling the rate and manner of production. As such, the potential and type of aquifer must be evaluated in gas reservoirs to optimize production (Agarwal, Al-Hussainy, and Ramey 1965). Beveridge et al. (1974) investigated the effect of the proudction rate on the utlimate econcomic reocovery in one of the reservoris in Alberta. They found that the ultimate recovery factor was not adversely affected by increasing the production rate as far as the reservoir mechanics were concerned (Beveridge et al. 1974). Connaughton and Crawford (1975) evaluated the effects of the oil producing rate, absolute permeability and well completion intervals on oil recovery in a solution gas drive reservoir by utilizing a radial two-dimensional three-phase numerical reservoir model. The results obtained revealed that the oil recovery is sensitive to the rate, permeability and completion intervals of the reservoir. It appeared that the recovery would be higher with a higher producing rate while a low recovery was observed at a low production rate since gas migration to the top of the reservoir affects the reservoir energy (Connaughton and Crawford 1975). Enhuan (1990) reported that development of the bottom supported reservoirs with a high oil recovery rate does not decrease the ultimate recovery factor in water drive reservoirs (Enhuan 1990). Dake (2001) stated that the production rate only affects the ultimate recovery factor in the solution gas drive and gas cap drive reservoirs, and no effect was observed in the water flooding reservoirs (Dake 2001). According to Ali-Nandalal et al. (1999), (Ali-Nandalal et al. 1999) and Bayley-Haynes and Shen (2003) gas channeling into oil rings has a minor impact on the ultimate recovery of natural gas, but oil production may be hindered with only gas production in the oil production wells. They also stated that if crude oil enters a gas cap, a large amount of oil will be wasted and the oil recovery will be influenced. Fayzullin et al. (2011) introduced the intelligent well completion to improve the cumulative production of gas and oil from a thin oil reservoir with a large gas cap (Fayzullin, Nasibullin, and Yazkov 2011). Studies related to the condensate gas fields revealed that a high gas rate production may result in a low ultimate recovery (Ali 2014). The obtained results also showed that the total oil production and time of water breakthrough are strongly affected by the relative permeability and residual oil saturation (Ediriweera 2015). A series of reservoir simulation studies also highlight that a high oil production rate has no negative effect on the recovery during the contact term (Longxin, Ruifeng, and Xianghong 2015).

The above brief discussion indicates that although many studies have been conducted to evaluate the effect of the production rate on the recovery factor, the interactions between these parameters have not been deeply understood. The aim of this study is to evaluate the impact of the production rate on the ultimate recovery of oil and gas reservoirs considering different drive mechanisms such that production can be improved without imposing any severe effect on the recovery factor.

2. Methodology

In this study, the material balance commercial tool (MBAL) of Petroleum Experts software was used as it provides a better understanding of the reservoir behavior and allows us to model any types of reservoir fluids. The material balance concept is based on the principle of the conservation of mass. The equations of the material balance were developed by Schilthius and equates the cumulative observed production (expressed as the underground withdrawal) to the expansion of the fluid in the reservoir, resulting from the finite pressure drop. This tool consists of an input section where fluid, rock, and reservoir properties can be imported together with a history matching and production prediction section. In the input section, the aquifer type and its properties, relative permeability curves, transmissibility parameters, history of the production and injection of the well and the reservoir can be defined. The data used in this study was chosen such that different drive mechanisms (i.e., solution gas, gas cap, weak water and strong water in oil reservoirs together with the volumetric, weak and strong water in the gas reservoirs (Dake 2001)) could be simulated.

The MBAL program uses traditional black oil correlations for the simulation purposes (Experts 2017). Moreover, the gas oil ratio, water cut and water gas ratio are generally used to generate the gas, water, and oil relative permeability curves using the history matched model. History matching is a trial and error approach to give the best comparison between the actual and the estimated data which helps to identify energy sources, type, and strength of the aquifer as well as the amount of hydrocarbon in place. A non-linear regression is then used to fit the best model in the presence of the reservoir production/injection history to narrow down the difference between the measured and calculated production of the model by adjusting the reservoir model. In this study, history matching and regression analysis were not used since the production history was ignored. Finally, a production simulation is run to check the validity and predict the performance by honoring the history matched aquifer and relative permeability as the basis for predictions. However, history matching was not considered and typical cases were developed to mimic different drive mechanisms for a better production simulation and prediction performance. In the production prediction section, production and constraint schedules were assumed to simulate the reservoir performance. In fact, it was not essential to use reservoir production history in the MBAL tool to run the production prediction since in the presence of history data, reservoir and aquifer related parameters could be tuned.

For a strong and weak water drive in gas and oil reservoirs, the Hurst-van Everdingen-Modified model (Ahmed 2010) was used with the bottom drive system together with an infinite acting boundary having different reservoir radius and vertical permeability. The input data used for the modeling of the gas and oil reservoirs is given in Table 1.

3. Results and Discussion

After simulating the behavior of drive mechanisms using MBAL, the results obtained were presented separately. For instance, in the gas reservoirs, the predicted results of the pressure and water gas ratio (WGR) at different levels of production rates for various drive mechanisms (i.e., volumetric gas drive (VDG), weak water drive (WWDG), and strong water drive (SWDG)) are shown in Figures 1 and 2. Figure 1 is a so-called Cole and Campbell plot which is an accurate approach to detecting and characterize aquifers and water drive strengths. In MBAL, the model without/with aquifers were modeled as VDG, WWDG, and SWDG. In the WWDG and SWDG, different aquifers were characterized as clearly shown with the gas in place of 50 BScf (billion of standard cubic feet). Figure 2 displays the trends of the pressure and water gas ratio (WGR) at different levels of production rates for various gas drive mechanisms. For instance, in the VDG case, the reservoir pressure declines sharply as a function of time depending on the production rate which reduces to 600 psig which is aligned with the results presented in the earlier studies (Dake 2001, Ahmed 2010). At 5 MMScf/D, the reservoir pressure declines from 4000 psig to 1000 psig within 1984 to 2004 while in the case of 15 MMScf/D and 30 MMScf/D, the pressure declines to 800 psig within only 10 years from 1985 to 1995. The trend of WGR at different production rates was very similar but a smaller amount of water was produced compared to gas till the end of the production period. This smaller production of water is always associated with the volumetric gas drive as reported earlier (Dake 2001, Ahmed 2010). In the case of the WWDG for the gas reservoirs, the trends of the pressure and water gas ratio were also sensitive to the production rates. The pressure starts to decline from the initial reservoir pressure slowly due to the water aquifer support. The WGR cut off of 100 STB/MMSCF was considered and achieved at different time periods based on various production rates. This pressure decline and the WGR trends are evident of the weak water drive. For the SWDG case, it was found that the rates and the WGR ratio are affected by the production rate similar to the VD and WWD cases but the results were quantitatively different. The trend of the pressure decline is similar to the values reported in the previous studies (Dake 2001, Ahmed 2010), which shows minor reduction of the pressure till the end of the production due to the strong water aquifer support. The WGR cut off of 100 STB/ MMSCF was also considered and achieved early due to the high water production. This high water production and small reduction of the pressure indicate the presence of a strong water drive. The effect of the production rate on the gas recovery is aligned with the statement that the gas recovery depends on the production rate, residual gas saturation, aquifer strength, aquifer permeability and the volumetric sweep efficiency of the water invaded zone (Min et al. 2015, Agarwal, Al-Hussainy, and Ramey 1965). Comparatively, all cases (i.e., VD, WWD, and SWD) are simulating the actual conditions of the gas drive mechanisms if the trends of the pressure and water production are considered. It appears that the pressure behavior and the water production are sensitive to the production rates as well as the gas drive mechanisms which could affect the ultimate recovery.

Like the pressure and the WGR trends, the recovery factor varies as the drive mechanisms changes (see Table 2) and are within the range of the typical gas reservoir recovery (Bassiouni 1990) if the WGR of 50 STB/MMSCF is considered. Having said that, it was found that there is no relationship between the production rate and the recovery in the VDG case while the recovery increased from 79.6% to 86.3% with the production rate in in the WWDG. A similar observation was made for the SWDG when the recovery was improved from 67% to 71% by the production. This increase in the recovery of the water drive reservoirs could be attributed to the high relative permeability of gas compared to water (Dake 2001, Ahmed 2010). It could also be linked to the loss of the residual gas trapped at the initial reservoir pressure (Agarwal, Al-Hussainy, and Ramey 1965, Ali 2014). Comparatively, the recovery is higher in the VDG and WWDG for the gas reservoirs due to the effect of the multiphase flow in porous media once production is initiated.

The predicted results of the pressure and production of the gas-oil ratio (GOR) at different levels of production rates for different gas drive mechanisms in oil reservoirs (i.e., solution gas drive oil (SGDO), gas cap drive oil (GCDO), weak water drive oil (WWDO), strong water drive oil (SWDO), and combination drive oil (CDO)) are shown in Figure 3.

As it can be seen in Figure 3, for the SGDO case, the trend of the pressure and the production of GOR is affected by the production rates. For instance, the decline in the reservoir pressure is very sharp and continuous while the rate of decline falls at the bubble point pressure of 2300 psi. Production of GOR was found to be low up until the bubble point pressure, and then increases to a maximum value and declines. These trends can be seen in Figure 3 and are aligned with the ones discussed earlier (Dake 2001, Ahmed 2010, Karikari 2010) which clearly indicate the absent of water influx. These trends are similar at two different production levels but quantitatively different as the effect of the high production rate is significant on the pressure and production of GOR compared to the low production rate.

In the case of GCDO, the trends of the pressure and production of GOR indicated that the gas cap drive mechanism and it was found that they are sensitive to the production rate. The rate of decline in the pressure was sharp and continuous at a high production rate which could be due to the high production of gas (Jia et al. 2014). The production of GOR increased and then decreased with time. Although, for a gas cap drive reservoir, the production of GOR typically increases continuously as reported by (Dake 2001, Ahmed 2010), the decrease in the production of the GOR indicates the continuous production of gas and reduction in its volume with time.

For the WWDO, the production rate affects the pressure and production of GOR. It seems that at a low production rate, the rate of pressure decline was smooth while the production of GOR remained constant till 2042 but sharply declined after reaching the bubble point pressure. This pressure decline was rapid in a few years at a high gas production rate with a significant impact on the production of GOR.

The results obtained from the SWDO case were almost aligned with the one presented earlier for the WWDO. The impact of the high production rate was significant on the pressure decline rate and GOR. However, there is a smooth decline in the reservoir pressure at the low production rate which also helps to have a low production of GOR (Dake 2001, Ahmed 2010). The magnitude of reservoir energy, under these circummures may have a significant influence on the primary recovery factors. A major source of energy is supplied by a large water aquifer in the direct contact with an oil zone (Shepherd 2009).

The results obtained for the CDO indicated that the pressure and the solution GOR may decline with a very slow rate due to the dual support of gas cap and water aquifer. Thus, a high pressure of almost 3700psig is the final pressure at the WOR cut off value of 100 STB/STB. Like other cases, the pressure and GOR trends revealed the relationship with the production rate.

Comparatively, all cases are simulating the actual condition of the oil drive mechanisms if the trends of the pressure and gas production are considered. The pressure behavior and gas production seems to be sensitive to the production rates and gas drive mechanisms which could affect the ultimate recovery. Table 3 presents the results of all cases simulated in this study.

As it can be seen in this Table, recovery decreases with the increase of the production rate in different drive mechanisms with a significant effect in the WWDO reservoir. Likewise, the pressure and the WGR trends which are sensitive to the drive mechanisms and production rates, the recovery factor varies in different drive mechanisms, as give in Table 3. These results are within the range of the values reported earlier by (Satter and Iqbal 2016). The decrease in the oil recovery with the production rate can be attributed to the high relative permeability of oil compared to water. Comparatively, the recovery factor of oil reservoirs are smaller than gas reservoirs (Shepherd 2009) as the gas phase has a high mobility, non-wetting phase, and high compressibility.

4. Conclusion

This study was carried out to evaluate the sensitivity of the recovery factor to the production rate in conventional reservoirs with different drive mechanisms. It was concluded that the pressure decline rate, water-gas ratio, gas-oil ratio and recovery are all sensitive to the production rate in almost all hydrocarbon reservoirs. Particularly in the gas reservoirs, the effect of the production rate on the recovery is dominant in the weak and strong water drive cases. On the other hand, in all cases, the recovery decreases with the increase of the production rate in various drive mechanisms with a significant effect observed in the WWDO case. It was recommended to consider a high production rate in the gas reservoirs and an optimum rate in the oil reservoirs.

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Table 1: Input data used for modeling of oil and gas reservoirs

Gas Reservoirs		Oil Reservoirs	
Gas gravity	0.7 sp. gravity	Formation GOR	500 scf/STB
		Oil Gravity	39 API
Water salinity	50000 ppm	Gas gravity	0.8 sp. gravity
Mole percent H_2S	5 percent	Water salinity	50000 ppm
Gas Viscosity	Lee correlation	Pb, Rs, Bo	Glaso correlation
Temperature	212 ^{O}F	Oil Viscosity	Beggs correlation
		Temperature	250 ^{O}F
Initial pressure	4000 psig	Initial pressure	4000 psig
Porosity	20%	Porosity	20%
Connate water saturation	0.3	Connate water saturation	0.3
Water compressibility	3e-6	Water compressibility	3e-6
Original gas in place	50.85 BScf	Original oil in place	210.867 MMSTB
Krw@residual	0.3	Krw@residual	0.15
Krg@residual	0.1	Krg@residual	0.02
Krw@endpoint	0.5	Krw@endpoint	0.75
Krg@endpoint	0.9	Krg@endpoint	0.9
		Kro@residual	0.15
		Kro@endpoint	0.8

Table 2: Recovery factors in different drive mechanisms and production rates in gas reservoir

Gas drive and production rate	Abandoned year	Final Pressure, psig	Recovery factor, %
VDG-5MMScf/D	2017	632	84
VDG-15MMScf/D	2006	632	84
VDG-30MMScf/D	2005	632	84
WWDG-5MMScf/D*	2007	2158	79.6
WWDG-15MMScf/D*	1994	1390	86.0
WWDG-30MMScf/D*	1993	1411	86.3
SWDG-5MMScf/D*	2004	3866	67
SWDG-15MMScf/D*	1991	3764	70
SWDG-30MMScf/D*	1989	3698	74

*At cutoff value of WGR=100 STB/MMSCF

TABLE 3. Recovery factors in different drive mechanisms and production rates in oil reservoir

Gas drive and production rate	Abandoned year	Final Pressure, psig	Recovery factor, %
SGDO- 5000STB/D	2023	6.34	19.38
SGDO-30000STB/D	2006	9.00	19.20
GCDO-5000STB/D	2035	5.5	29.85
GCDO-30000STB/D	2006	9.4	29.14
WWOD-5000STB/D	2052	7.42	45
WWDO-30000STB/D	2006	11.67	27
SWDO-5000STB/D	2080	29.3771	68
SWDO-30000STB/D	2012	66.356	61
CDO-5000STB/D	2029	3738	49.69
CDO-30000STB/D	2010	3738	49.62

* At a cutoff value of WOR = 100 STB/STB

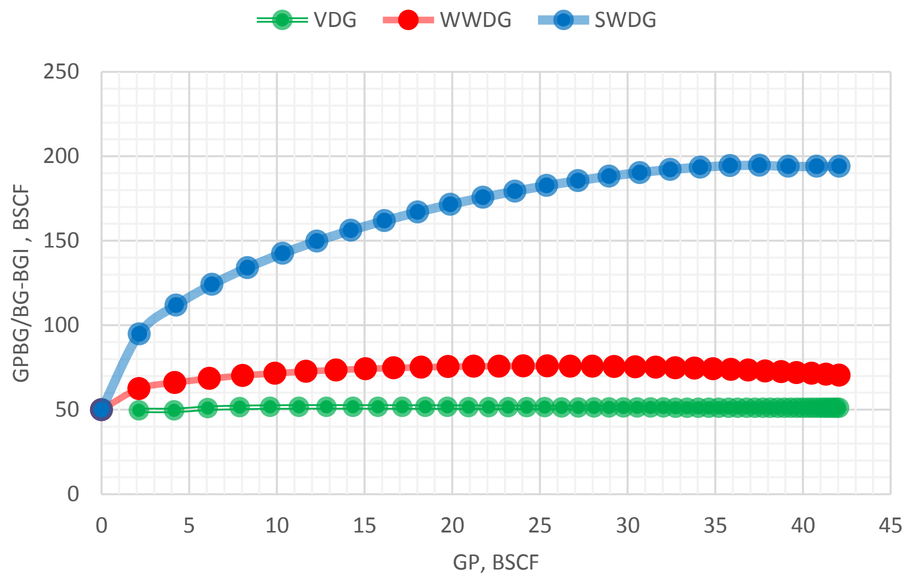

Figure 1: Cole and Cambell plots showing the classification of gas reservoirs

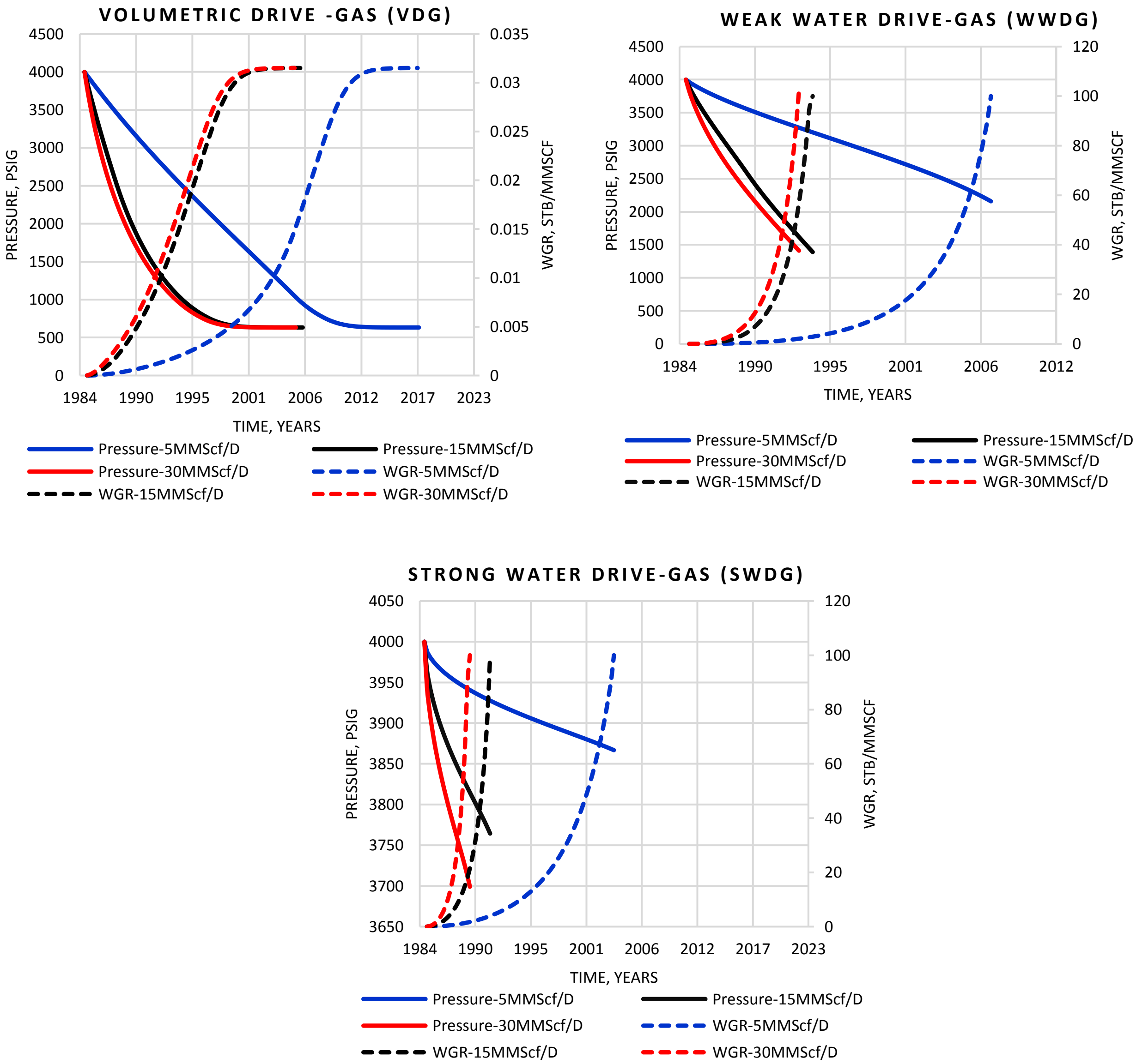

Figure 2. Pressure and Water-Gas Ratio profile at different production rates in gas reservoirs with different drive mechanisms

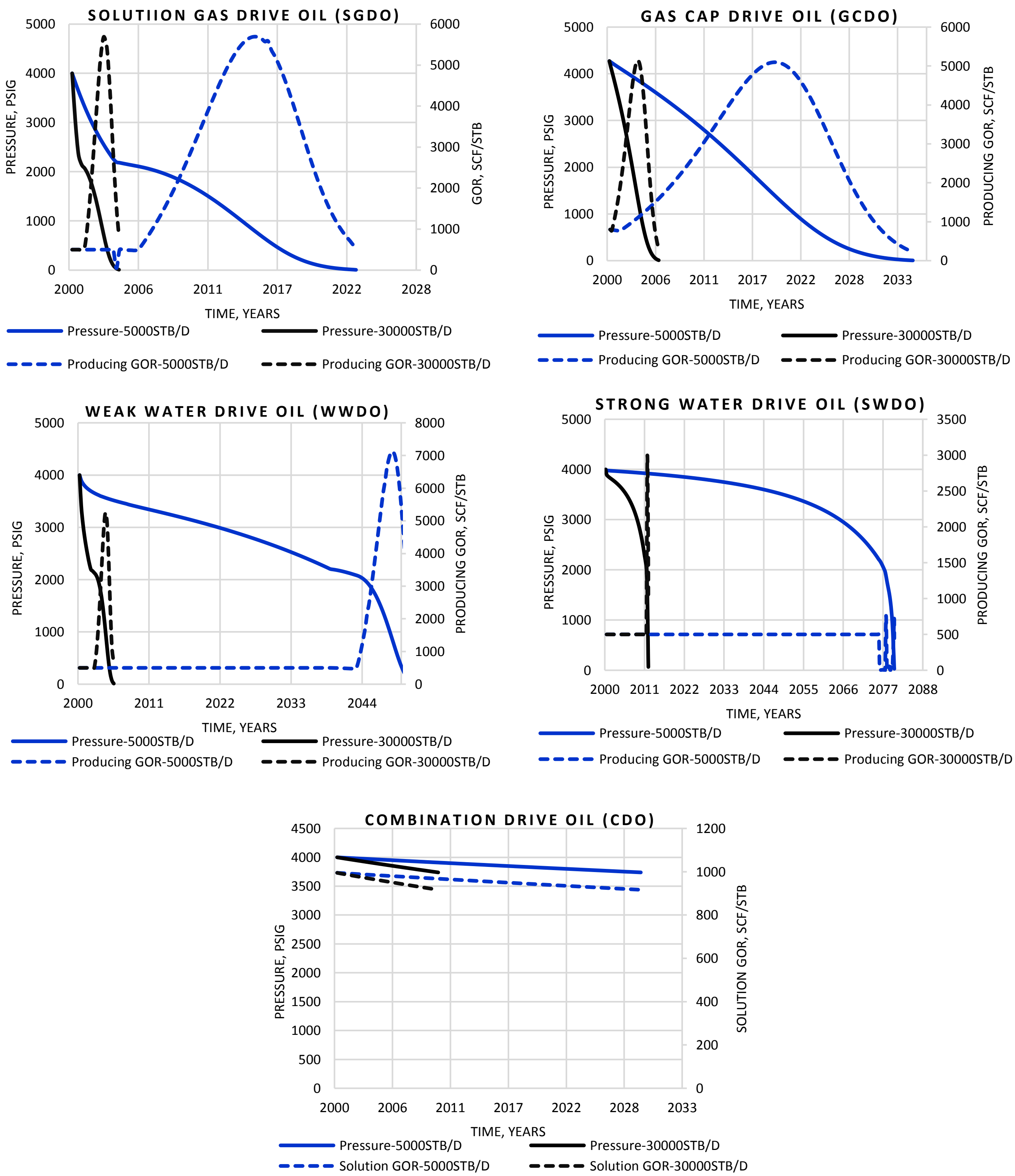

Figure 3. Pressure and Gas Oil Ratio trends at different production rates in oil reservoirs with different drive mechanisms