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EFFECT OF INITIAL GAS OIL RATIO, PRODUCED GAS RE-INJECTION AND FORMATION COMPRESSIBILITY ON PREDICTED PRODUCTION PERFORMANCE OF A DEPLETION DRIVE RESERVOIR

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Abstract

Production from depletion drive reservoirs is mainly driven by the expansion of oil and gas originally dissolved in it. When the reservoir pressure drops below the bubble point, free gas evolves from solution and gradually begins to build up within the reservoir. When the critical gas saturation is reached, the free gas becomes mobile and starts flowing towards producing wells. The basic problem with such reservoirs is therefore low oil recoveries obtained since energy is lost as GOR rises. In this paper, a theoretical behaviour of depletion drive reservoirs was modelled with particular emphasis on early production performance, a stage at which reservoir pressure is above bubble point pressure and oil recovery is typically very low. This was achieved by examining the effects of initial gas oil ratio, formation compressibility and produced gas re-injection through the modification of the general material balance equation using PVT data obtained with correlations developed by Vasquez and Beggs and Petrosky and Farshad. The PVT data generation and material balance were carried out by a combination of PROSper software and Microsoft Excel. From the results obtained, this study proposed produced gas re-injection above the bubble point pressure at low initial gas oil ratio and high formation compressibility conditions as improved strategies that can be used to obtain higher oil recoveries from the early stages of production of depletion drive reservoirs.

Keywords: *Depletion drive reservoirs; Solution gas oil ratio; formation compressibility; Production performance of depletion drive reservoirs; Material balance equation; Vasquez and Beggs; Petrosky and Farshad; Production modelling using PROSPER.*

1. Introduction

A depletion drive reservoir is one in which the principal production mechanism is the expansion of oil and gas originally dissolved in it [1]. It is usually initially undersaturated (i.e. a situation in which the initial reservoir pressure is much higher than the bubble point pressure) and at such conditions, there is no free gas saturation in the reservoir. The pressure drop during this stage is always rapid because of the low compressibility of oil, rock and connate water.

When the reservoir pressure falls below the bubble point, dissolved gas begins to come out of solution, causing the oil to shrink slightly. The gas bubbles formed expand, occupying the volume of the produced oil thus ensuring less rapid pressure decline. The absence of water drive indicates little or no water production during the entire production life of such reservoirs unless the reservoir pressure drops to such an extent that there is sufficient expansion of the connate water to ensure mobility. But even at such conditions, water production is small [2].

As the gas continues to accumulate in the reservoir, a point is reached when the critical gas saturation, is reached at which the gas becomes mobile. This trend often leads to an increase in the permeability of the formation to gas and a reduction in the permeability of the formation to oil leading to low oil recoveries and rapidly increasing gas to oil ratios (GOR). Oil production by depletion drive is usually the least efficient recovery method. This is a direct result of the formation of gas saturation throughout the reservoir. Ultimate oil recovery from depletion-drive reservoirs may vary from less than 5% to about 30%. The low recovery from this type of reservoirs suggests that large quantities of oil remain in the reservoir and, therefore, depletion-drive reservoirs are considered the best candidates for secondary recovery applications. This makes secondary recovery schemes such as gas injection or water flooding an alternative field development solution for such reservoirs [3]

Secondary recovery is the result of human intervention in the reservoir to improve recovery when the natural drives have diminished to unreasonably low efficiencies [2]. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise there is a risk that the substantial capital investment required for a secondary recovery project may be wasted (Ahmed 2006). In many cases, reservoir pressure is maintained by gas injection and oil is displaced by injected gas, thus making it an external gas drive mechanism [4].

1.1. Statement of problem

Oil recovery for depletion drive reservoir is typically between 20% and 30% of original oil in place (i.e. low). Of this only 0% to 5% of oil is recovered above the bubble point [2]. There is usually no production of water during oil recovery unless the reservoir pressure drops sufficiently for the connate water to expand sufficiently to be mobile. Even in this scenario little water is produced [2].

Early production of depletion drive reservoirs refers to the production stage above the bubble point, the stage at which oil recovery is primarily due to expansion of oil and rock. This is often a few percentages of oil initially in place, typically ranging from 0% to 5% [2].

Ultimate recovery of depletion drive seldom exceeds 30%, this low oil recovery suggests that large quantities of oil remain in the reservoir and, therefore, solution gas drive reservoirs are usually considered the best candidates for secondary recovery such as gas injection to ensure continuous production of the reservoir and make maximum returns on investment.

1.2. Objective of the study

This study seeks to investigate the effects of Initial Gas Oil Ratio, Produced Gas Re-Injection and Formation Compressibility on Production Performance in a depletion drive reservoir.

1.3. Significance of the study

The economic limit of production for depletion reservoirs is typically reached at low ultimate oil recovery efficiencies which seldom exceed 30%. The rapid loss of gas (the expansion of which provides the main drive mechanism) from the reservoir is the reason for such poor recoveries. Improved depletion strategies are thus essential to make maximum returns on investment.

2. Literature review

Reservoirs can be classified on the basis of the boundary type, which determines the drive mechanisms [5]. To really understand reservoir behaviour and predict future performance, it is of a necessity to have knowledge of the drive mechanisms that control the behaviour of fluids within the reservoirs [3]. In performance prediction of a hydrocarbon reservoir under different drive mechanisms, different conditions arise during the exploitation of the reservoirs. With internal gas drive mechanism, volumetric undersaturated reservoirs are produced by liquid expansion and rock compressibility. As the reservoir pressure declines, oil phase contracts due to release of solution-gas and production is due to gas expansion. As gas saturation reaches the critical value, free gas begins to flow, resulting in high gas-oil ratios and low recoveries.

Bondino *et al.* [6] in their work on heavy oil systems identified three different regimes of bubble growth, depending upon capillary number and depletion rate. The three regimes are (a) the conventional capillary-controlled growth pattern at low capillary numbers, (b) viscous biased growth at intermediate capillary numbers, and (c) bubble mobilization and breakup leading to foamy behaviour at the highest capillary numbers and depletion rates.

With external gas drive mechanism, saturated reservoirs are produced by depletion drive mechanism. In many cases, reservoir pressure is maintained by gas injection and oil is displaced by injected gas, thus making it an external gas drive mechanism. With the gravity segregation, high relief reservoirs with good along-dip permeability give favourable conditions for gravity segregation of injected gas or gas released from solution [4].

2.1. Depletion drive mechanism

In depletion drive mechanism, the principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced [3]. It is also called solution gas or dissolved gas drive or internal gas drive. Depletion drive reservoirs may be initially undersaturated or saturated depending on the pressure [2]. If initially undersaturated, there will be no free gas present in the reservoir and production under such conditions is largely due to the expansion of oil, rock and connate water. The initial reservoir pressure in such conditions is above the bubble point pressure. Both black and volatile oils are amenable to solution gas drive [8].

While focusing on heavy oil reservoirs, Alshmakhy and Maini [9] evaluated the contribution of gravitational forces under foamy flow conditions. Foamy Oil was observed to be the major reason for unusually high primary recovery factors (RFs) observed in numerous heavy-oil reservoirs. Foamy oils are non-Darcy flow involving formation and flow of gas-in-oil dispersion. It occurs when the wells are produced aggressively at high drawdown pressures that led to conditions in which the viscous forces become sufficiently strong to overcome the capillary forces in pushing dispersed bubbles through pore throats.

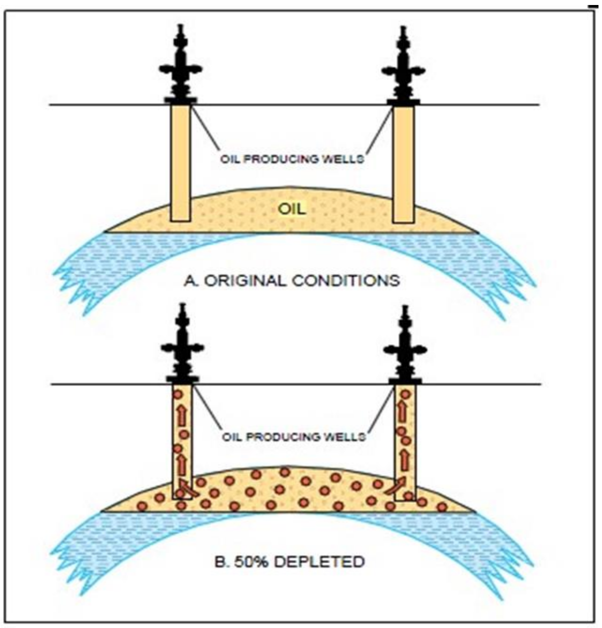

Fig 1 Depletion drive reservoir [11]

Depletion drive reservoirs usually undergo four stages of idealized production as illustrated in Fig. 1:
Stage 1- Production while initially undersaturated.
Stage 2- Production while saturated but the free gas in the reservoir is immobile.
Stage 3- Production while saturated and the free gas is mobile and the producing gas oil ratio is increasing.
Stage 4- Production while saturated and free gas is mobile and the producing gas oil ratio, (GOR) is decreasing [8].

The solution gas drive process depends largely to an extent on fluid properties of the oil and gas [10]. However, the factor that exhibits the greatest influence on recovery is gas/oil relative permeability ratio as well as the critical gas saturation, S_g up to which the liberated gas is trapped within each pore in discrete bubbles. Ultimately, as the reservoir pressure declines to the abandonment pressure, the change in the gas formation volume factor offsets the increasing gas to oil mobility ratio and gas to oil ratio trend is reversed. The loss of gas from the reservoir increases the oil viscosity and decreases the oil formation volume factor [11].

The economic limit of production for depletion reservoirs is reached at low ultimate oil recovery efficiencies. This typically ranges from 0 to 5% above the bubble point and 20 to

30% of the oil initially in place below the bubble point [2]. There is usually no water production during oil recovery unless the reservoir pressure drops sufficiently for the connate water saturation to expand sufficiently to be mobile. Even in such conditions, water production remains negligible. Other producing mechanisms may often augment the depletion drive mechanism. Its production performance is used as a benchmark to compare other producing mechanisms [8].

Early production of depletion drive reservoirs refers to production above the bubble point, the stage at which oil recovery is primarily by the expansion of oil and rock. This is often a few percentage of the oil initially in place, typically ranging from 0 to 5% [2]. Improved depletion strategies are thus required in order to make maximum returns on investment on such reservoirs.

Almost all reservoirs experience an element of pore compressibility C_f as a result of pressure depletion. In most reservoirs, pore compressibility is small and remains almost constant during depletion. Typical values of ranges from 3×10^{-6} psi^{-1} to 6×10^{-6} psi^{-1}. Under these conditions, pore compressibility has only a marginal effect in enhancing oil recovery however; reduction in fluid pressure due to oil production causes a significant reduction in pore volume. This mechanism has been recognized as an important drive mechanism in Alberta and Venezuela heavy oils and oil sands [12].

An increase of pore compressibility values on depletion drive had a great impact on the oil fractional recovery. This was further supported with reference to the Bachaquero field in Venezuela, and the Ekofisk field in the Norwegian sector of the North Sea. The Bachaquero field is one of the largest heavy oil fields in the Bolivar coast in Venezuela. The contributions of pore compressibility towards oil recovery were 45% and 48% respectively. This large reservoir dips between 1000–4000 ft. and has uniaxial compressibility in excess of 100×10^{-6} psi^{-1}. The pore compressibility provided more than 50% of the total drive mechanism for the field. Since most of the production was done by primary recovery, there was considerable surface subsidence which indicated the significance of this compressibility [13].

The most significant effect of pore compressibility was in the Ekofisk field in the Norwegian sector of the North Sea. Ekofisk is one of the largest fields in the entire North Sea with a STOIIP of 6000 MMSTB [10]. The field had an abnormal degree of pore compressibility increasing from 6×10^{-6} psi^{-1} to a maximum of 100×10^{-6} psi^{-1}). The pore compressibility provided more than 30% of the total drive mechanism for the field. The undesirable effects of pore compressibility which caused subsidence of the sea bed cost the operator huge sum of money and created awareness for compaction studies for offshore fields produced primarily by pressure depletion [10].

2.2. Fluid properties

Solution gas drive mechanisms depend to a large extent on PVT properties [10]. Onolemhemhen *et al.* [14] carried out a study to develop a correlation model that can estimate recovery factor under both primary and secondary recovery from oil reservoirs in the Niger Delta having water and depletion drive mechanisms. The results show that for both water and solution gas drive reservoirs; oil viscosity and residual oil saturation do have a strong correlation with recovery factor, while pressure, API gravity and gas oil ratio do have a strong correlation with recovery factor only in solution gas drive reservoirs.

These fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids. In the absence of experimentally measured properties, it is necessary for the petroleum engineer to determine the properties from empirically derived correlations [3]. Determination of PVT properties can also be achieved by Equation of state with appropriate calibrations and Artificial Neural Networks models [15]. The basic properties required to estimate a reservoir's performance includes solution gas oil ratio, oil formation volume factor and gas formation volume factor. Other properties such as density and compressibility are interrelated through the solution GOR [5].

2.3. Fluid property correlations

The most accurate method for determining the behaviour of petroleum fluids is a laboratory PVT analysis. Several authors have done a lot of work on Pressure-Volume-Temperature (PVT) correlations. While some have fine-tuned older correlations others have propounded new ones altogether. PVT parameters are extremely critical input items into the material balance equation for performance prediction, as such the accuracy of such PVT parameters, or better still, the accuracy of the correlations by which they are predicted is very vital.

There have been a lot of correlations developed for crude oils from various geographic locations around the world. These include Standing, Vasquez and Begg's, Glaso, Petrosky and Farshad, Al-Marhoun etc. The accuracy of these correlations is often limited because reservoir fluids consist of varied and complex multicomponent systems with parameters such as gas gravity, oil gravity and GOR which depend entirely on the process by which the oil and gas are separated [16].

The development of neural networks for the modelling of PVT data indicates promising improvements over numerical modelling. Neural networks are mathematical models that acquires artificial intelligence; acquiring knowledge through a learning process [15]. They are information processing systems with similar performance characteristics with the biological networks [17]. They have the advantage of learning behaviour by self-tuning parameters, ability to discover patterns, fast response and confident prediction of PVT data [15]. []

2.3.1. Vasquez and Beggs Correlation– Worldwide Oil System

Vasquez and Beggs published correlations for gas oil ratio and oil formation volume factor in 1976. They were the first to categorize oil mixtures into two; above 30°API gravity and below 30°API gravity [18]. The correlation was developed with a wide variety of data points from over 600 laboratory measurements. An interesting feature of their study was the strong dependence on gas gravity. Realizing that the value of the specific gravity of the gas depends on the conditions under which it is separated from the oil, Vasquez and Beggs proposed that the value of the gas specific gravity as obtained from a separator pressure of 100 psig be used in the equation given below. This reference pressure was chosen because it represents the average field separator conditions [7]. The correlations are given as follows:

i. Bubble point pressure Correlation

$$P_b = \left[\frac{R_{sb}}{C_1 \gamma_{gs} exp\left(\frac{C_3 \gamma_{API}}{T_R}\right)}\right]^{\frac{1}{C_2}} \quad (1)$$

ii. Solution gas - oil ratio Correlation

The Vasquez and Begg's Correlations for solution gas oil ratio is given as follows

$$R_s = C_1 \gamma_{gs} P^{C_2} exp\left(\frac{C_3 \gamma_{API}}{T_R}\right) \quad (2)$$

Where: T_R = Temperature, °R; P = Pressure, psia; γ_{API} = Stock tank gravity, °API; γ_{gs} = Gas gravity.

The values of the dimensionless constants are given in Table 1.

Table 1. Values of the dimensionless constants for solution gas oil ratio (Vasquez and Begg's Correlations)

Coefficient	γAPI ≤ 30	γAPI ≥ 30
C1	0.0362	0.0178
C2	1.0937	1.187
C3	25.724	23.931

iii. Oil Formation Volume Factor Correlation for saturated oils

The correlation for saturated oils is given as follows

$$B_o = 1 + C_1 R_s + (T_F - 60)\frac{\gamma_{API}}{\gamma_{gs}}(C_2 + C_3 R_s) \quad (3)$$

Where: B_o = FVF of oil conditions P, T rb/stb; R_s = Solution GOR at conditions P, T scf/stb; T_F = Temperature of the system, ºF.

The values of the dimensionless constants are given in Table 2.

Table 2. Values of the dimensionless constants for Oil Formation Volume Factor Correlation for saturated oils (Vasquez and Begg's Correlations)

Coefficient	γAPI ≤ 30	γAPI ≥ 30
C1	4.677 × 10-4	4.670 × 10-4
C2	1.751 × 10-5	1.100 × 10-5
C3	-1.811 × 10-8	1.337 × 10-9

Oil Formation Volume factor correlation for undersaturated oil ($P > P_b$)

$$B_o = B_{ob}\, exp[C_o(P_b - P)] \quad (4)$$

where: B_{ob} = oil formation volume factor at the bubble-point pressure, bbl/STB; B_o = oil formation volume factor at the pressure of interest, bbl/STB; P = pressure of interest, psia; P_b = bubble-point pressure, psia; C_o = Isothermal compressibility.

$$C_o = \frac{5R_{sb} + 17.2T_F - 1180\gamma_{gs} + 12.61\gamma_{API} - 1433}{P \times 10^5} \quad (5)$$

where: R_{sb} = Dissolved gas oil ratio at P_b, scf/stb; T_F = Temperature, °F.

2.3.2. Petrosky and Farshad's Correlation – Gulf Of Mexico Oil System

Petrosky and Farshad developed new correlations for Gulf of Mexico crudes in 1993 based on the modification of the Standing's correlations for bubble point pressure, solution gas oil ratio and oil formation volume factor [18]. They proposed a new expression for estimating B_o. The proposed relationship is similar to the equation developed by Standing; however, the equation introduces three additional fitting parameters in order to increase the accuracy of the correlation [7]. They also used Vasquez and Beggs oil compressibility correlation as a basis for developing the oil compressibility model. Their approach was to give the original correlation model a wide range of flexibility through nonlinear regression. This allowed each variable to have a multiplier and an exponent. Over 90 data sets from Gulf of Mexico was used to develop these correlations [18].

The Petrosky and Farshad correlations are presented below

i. Bubble point pressure Correlation

$$P_b = 112.727\left[\frac{R_s^{0.5774}}{\gamma_g^{0.8439}10^X} - 12.340\right] \quad (6)$$

where $X = 7.916 \times 10^{-4}\gamma_{API}^{1.5410} - 4.561 \times 10^{-5} T_F^{\ 1.3911}$ (7)

ii. Solution gas - oil ratio Correlation

$$R_s = \left[\left(\frac{P_b}{112.727} + 12.340\right)\left(\gamma_g^{\ 0.8439}\right)10^X\right]^{1.73184} \quad (8)$$

where: $X = 7.916 \times 10^{-4}\gamma_{API}^{1.5410} - 4.561 \times 10^{-5} T_F^{\ 1.3911}$

2.3.2.3 Isothermal Oil Compressibility correlation

$$C_o = (1.705 \times 10^{-7}) \times R_s^{\ 0.69357} \times \gamma_g^{\ 0.1885} \times \gamma_{API}^{\ 0.3272} \times T_F^{\ 0.6729} \times P^{-0.5906} \quad (9)$$

iii. Oil Formation Volume Factor Correlation

$$B_o = \left[a_1 + a_2 R_s^{\ a_3}\left(\frac{\gamma_g^{\ a_4}}{\gamma_o^{\ a_5}}\right) + a_6 T^{a_7}\right]^{a_8} \quad (10)$$

a_1 = 1.0113; a_2 = 7.2046e^{-5}; a_3 = 0.3738; a_4 = 0.2914; a_5 = 0.6265; a_6 = 0.24626; a_7 = 0.5371; a_8 = 3.0936; R_s = solution GOR, scf/stb; B_o = Oil formation volume factor, rb/stb; P_b = Bubble point pressure, psia; P = Pressure, psia; γ_g = Gas specific gravity; γ_o = Oil specific gravity; T_F = Temperature, ºF.

2.4. Material balance calculations

The material balance equation (MBE) has long been recognized as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance [3]. The complete MBE is given by equation 11:

$$N_p\left[B_o+\left(R_p-R_{si}\right)B_g\right]+W_pB_w=NB_{oi}\left[\frac{\left[(B_o-B_{oi})+(R_{si}-R_s)B_g\right]}{B_{oi}}+m\left(\frac{B_g}{B_{gi}}-1\right)+(1+m)\frac{\left(C_wS_w+C_f\right)\Delta P}{1-S_{wc}}\right]+W_eB_w \quad (11)$$

where: N_p = total Oil produced in STB; B_o = Oil Formation Volume Factor, RB/STB; R_p = Cumulative Produced Gas-Oil-Ratio (GOR), SCF/STB; B_g = Gas Formation Volume Factor, RB/SCF; W_p= Cumulative Water Produced STB; m = ratio of gas cap pore volume to oil leg pore volume; B_{oi} = Initial Oil Formation Volume Factor; R_s = Solution Gas-Oil ratio, SCF/STB; N = Initial oil-in-place, STB; S_{wc}= Initial Average Water Saturation; W_e = Cumulative Water Encroachment.

For a depletion drive or solution gas oil drive reservoir at initial pressure conditions, there is no initial gas cap, thus m = 0 and no water influx. Also, above the bubble point, $R_p = R_{si} = R_s$

The general material balance equation now reduces to

$$\frac{N_p}{N}=\frac{\left[(B_o-B_{oi})+\frac{B_{oi}\left(C_wS_w+C_f\right)\Delta P}{1-S_{wc}}\right]}{B_o} \quad (12)$$

Also,

$$S_o=\frac{Oil\ volume}{pore\ volume}=\frac{\left(N-N_p\right)B_o}{\left(\frac{NB_{oi}}{1-S_{wi}}\right)}=\left(1-S_{wi}\right)\left(1-\frac{N_p}{N}\right)\frac{B_o}{B_{oi}} \quad (13)$$

As the solution gas evolves from the oil with declining reservoir pressure, the gas saturation (assuming constant water saturation, S_{wi}) is simply given as

$$S_g=1-S_o-S_{wi} \quad (14)$$

Below the bubble point, $R_p \neq R_{si} \neq R_s$

The general material balance equation now reduces to

$$\frac{N_p}{N}=\frac{\left[(B_o-B_{oi})+(R_{si}-R_s)B_g+\frac{B_{oi}\left(C_wS_w+C_f\right)\Delta P}{1-S_{wc}}\right]}{B_o+\left(R_p-R_{si}\right)B_g} \quad (15)$$

For the effect of gas injection in depletion drive reservoir, Above the bubble point, the equation becomes

$$N_pB_o=NB_{oi}C_{eff}\Delta P+G_iB_{gI} \quad (16)$$

$$C_{eff}=\left[\frac{C_oS_o+C_wS_w+C_f}{1-S_{wc}}\right] \quad (17)$$

Since $G_i=N_pR_{si}$ then the above equation now becomes

$$N_pB_o=NB_{oi}C_{eff}\Delta P+FN_pR_{si}B_{gI} \quad (18)$$

where F is the fraction of gas to be injected

Now re-arranging the above equation, we have that:

$$\frac{N_p}{N}=\frac{B_{oi}C_{eff}\Delta P}{B_o-FR_{si}B_{gI}} \quad (19)$$

Below the bubble point pressure, the general material balance equation is modified as follows

$$\frac{N_p}{N}=\frac{(B_o-B_{oi})+(R_{si}-R_s)B_g+\frac{B_{oi}\left(C_wS_w+C_f\right)\Delta P}{1-S_{wc}}}{B_o+\left(R_p-R_{si}\right)B_g-FR_{si}B_{gI}} \quad (20)$$

$$R_p=\frac{\Sigma\left(\Delta N_p\right)R}{N_p}=\frac{\Sigma\left(\Delta N_p/\mathrm{N}\right)R}{N_p/\mathrm{N}}=\frac{N_{pb}R_{si}+\left(N_p-N_{pb}\right)R_{avg}}{N_p} \quad (21)$$

where $R_{avg}=\frac{R_{si}+R_s}{2}$ (22)

G_i = Cumulative gas injected, scf; B_{gI} = injected gas formation volume factor, bbl/scf.

3. PVT Data

The solution gas oil ratio, R_s and oil formation volume factor, B_o used for this work were generated using two correlations already given in section 2 of this work: Vasquez & Beggs and Petrosky & Farshad. The use of these PVT correlations requires the following initial conditions specified as shown in Table 3.

Table 3. PVT properties used for the analysis

Properties	Values
Initially dissolved Solution gas oil ratio, R_{si}	1200scf/stb to 300scf/stb
Specific gravity of Gas, γ_g	0.75
API gravity of Oil, γ_{API}	40
Temperature of reservoir, T	660ºR

Bubble Point pressures P_b, estimated using Vasquez & Beggs and Petrosky & Farshad correlation are presented in Table 4.

Table 4. Showing comparison of bubble point pressures predicted by the two correlations

R_{si} (scf/stb)	P_b (psia) Vasquez & Beggs	P_b (psia) Petrosky & Farshad
1200	4393	4563
1000	3767	3969
700	2789	2971
400	1741	1767
300	1366	1283

4. Results

For an initially under-saturated reservoir, R_{SI} values are expected to remain constant until the reservoir becomes saturated, at which stage a gradual decline in R_s values should occur. The point at which this decline occurs is strongly dependent on the bubble point (P_b) of the reservoir as a result of solution gas released at this pressure. Fig. 2 shows the variation of solution gas oil ratio with pressure for a reservoir temperature of 200°F.

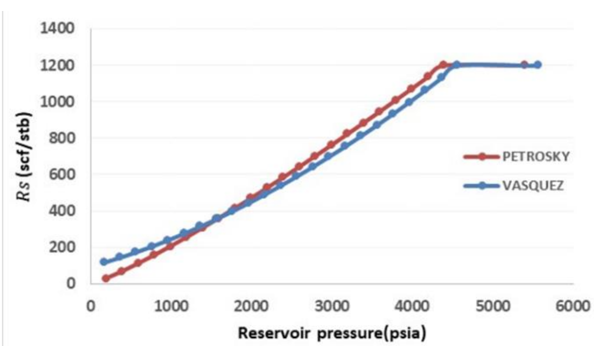

Fig. 2. Plot of Rs vs Pressure for Rsi=1200scf/stb

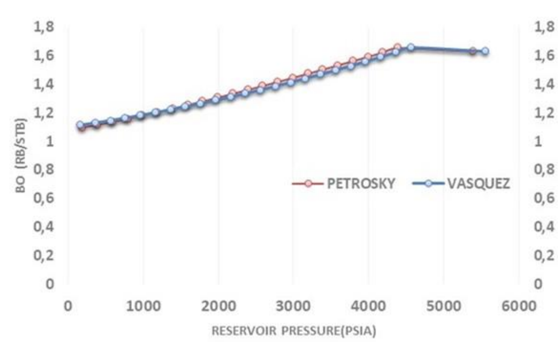

Fig. 3 Plot of Bo vs Pressure for Rsi=1200scf/stb

At an initial reservoir pressure of 5393psia, the Vasquez and Beggs correlation predicts 1200scf/stb of solution gas dissolved in the oil while the Petrosky and Farshad predicts 1200scf/stb of dissolved gas at 5563psia. The graphical plot shows that there is no evolution of solution gas at this point until the bubble point pressure is reached at 4393psia for the Vasquez and Beggs and 4563psia for the Petrosky and Farshad correlation. At these pressures, the first bubbles of free gas begin to appear. At 1593psia, the solution gas is 360.078scf/stb for the Vasquez and Beggs correlation and the average solubility is calculated as follows

Average solubility = $\frac{1200-360.078}{5393-1593}$ = 0.221scf/stb/psi

The prediction of gas solubility for the Petrosky and Farshad correlation for R_{si} = 1200scf/stb compare closely to that by Vasquez and Beggs as shown below

Average solubility = $\frac{1200-356.29}{5563-1563}$ = 0.211scf/stb/psi.

On the other hand, B_o values are expected to increase slightly for an initially under-saturated reservoir, before a gradual decline below the bubble point pressure of the reservoir. The initial increase in B_o values are due to the slight compressibility of oil, which expands as reservoir pressure decline above the bubble point. Below the bubble point, oil expansion continues but is over-shadowed by a decrease in oil volume due to evolving dissolved gas coming out of solution as shown in Fig. 3.

4.1. Effect of Initial Gas Oil Ratio (R_{si}) on Predicted Production Performance

From the results obtained from the material balance calculations using the Vasquez and Beggs and Petrosky and Farshad correlations, it is observed that R_{si} does not have significant effect on oil recovery above the bubble point. This is illustrated by the fact that recovery above the bubble point for C_f = 6 × 10^{-6} psi^{-1} was always low, varying between 1.89 to 2.43% for all values considered and always higher for C_f= 30 × 10^{-6} psi^{-1} varying between 5.86 to 5.38% as seen in Fig. 4 and Fig. 5. For gas re-injection, recovery above the bubble point was essentially the same for all R_{si} values considered, varying between 3.08 to 3.73% for all values considered with the two correlations.

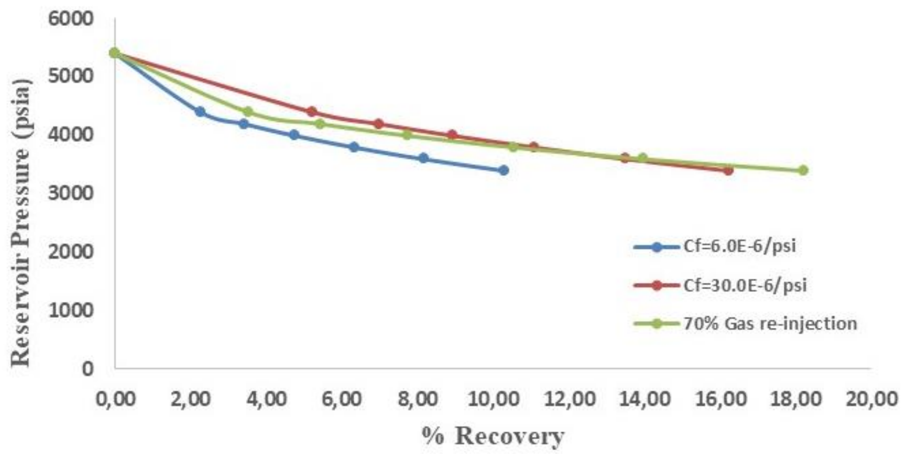

Fig. 4. Plot of % Recovery vs Pressure for Rsi = 1200 scf/stb (Vasquez and Beggs)

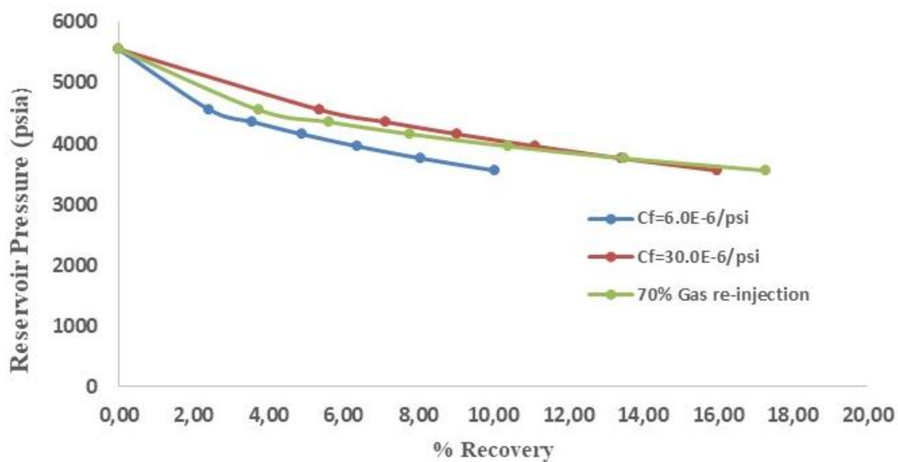

Fig. 5. Plot of % Recovery vs Pressure for Rsi = 1200 scf/stb (Petrosky and Farshad)

However, below the bubble point, the effects of R_{si} becomes more significant with higher cumulative recoveries obtained at lower values for gas re-injection and C_f =30 × 10^{-6} psi^{-1} by the two correlations used. The oil cumulative recovery was observed to have increased with reducing R_{si} values and vice versa. R_{si} strongly influences the cumulative produced gas-oil ratio (R_p), such that increases in R_{si} values correspond to an increase in R_p. Fractional recovery varies inversely with R_p, such that an increase in R_p corresponds to reduced fractional recovery.

4.2. Effect of Produced Gas Re-Injection on Predicted Production Performance

From the results presented in the earlier sections, it could be observed that re-injection of 70% produced gas provided an average recovery of 3.44 % down to the bubble point pressure for all R_{si} values considered with both the Vasquez and Beggs and the Petrosky and Farshad correlations. This is a very small recovery fraction given that this is a percentage of the oil initially in place. At higher R_{si} values, cumulative recovery obtained is low whereas at very low R_{si} values i.e. 300 scf/stb, higher recoveries were obtained (See Fig A.1 and A.16). This behaviour is explained by the fact that at low R_{si} values, reservoir pressure is low and according to Boyles law, gas expands significantly, this is reflected by the increase in the gas formation volume factor, B_g values obtained at such low R_{si} values but at higher pressures encountered with higher R_{si} values, gas volume is greatly reduced i.e. compression of gas occurs at high pressures.

It is the expansion of this gas that forms the secondary gas cap which provides energy or drive for increased oil recovery as observed in Fig. 6.

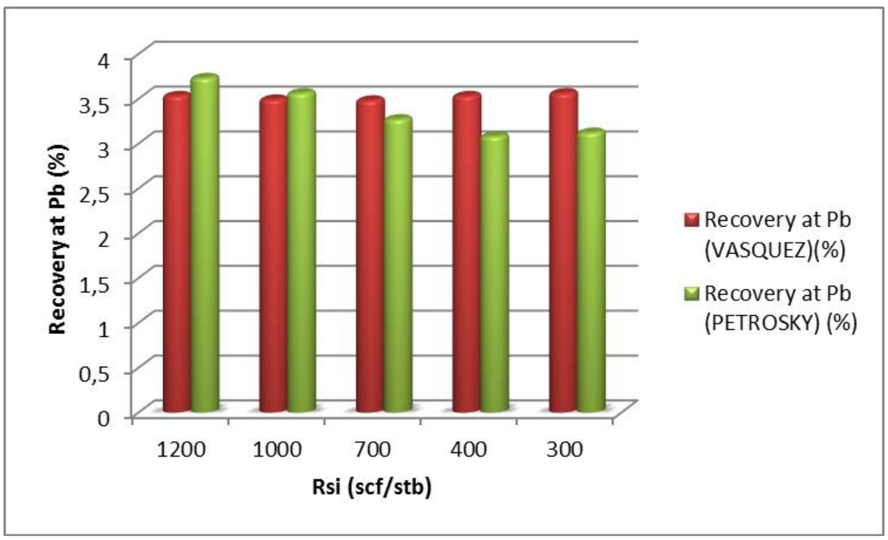

Figure 6. Showing recovery rates at bubble point as result of produced gas re-injection

4.3. Effects of formation compressibility on Predicted Production Performance

The effects of formation compressibility were investigated because at high values, it contributes to oil recovery by compaction drive mechanism. Values of C_f used in this study were 6×10^{-6} psi^{-1}, typical in most reservoirs and 30×10^{-6} psi^{-1}, which is high and can be obtained in chalky reservoirs with high porosities. With $C_f = 6 \times 10^{-6}$ psi^{-1}, it provided an average recovery of 2.22% above the bubble point for all R_{si} values considered with the two correlations but with 30×10^{-6} psi^{-1}, recovery rates obtained above the bubble point doubled to an average of 5.18% for all values of R_{si} considered. However, in all cases, these recovery rates were lesser than those obtained with 70% gas re-injection considered. It is thus established that the higher the value of formation compressibility, the higher the oil recovery above the bubble point but the lower the cumulative recovery as compared to 70% gas re-injection considered. This is illustrated in Fig. 7 and Fig. 8. The increase in recovery obtained with high formation compressibility value of 30×10^{-6} psi^{-1} above the bubble point is a result of increase in grain pressure as a result of withdrawal of fluids and subsequent production.

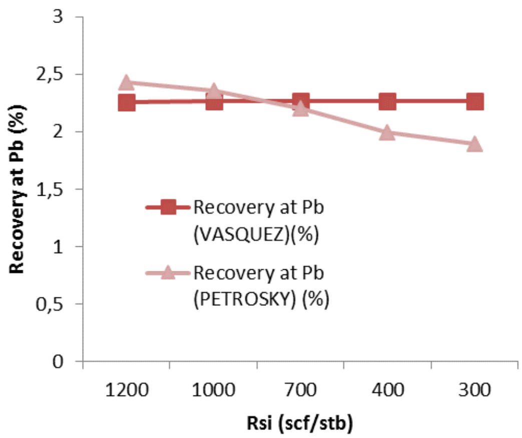

Figure 7. Showing recovery rates at the bubble point with C_f = 10^{-6} psi^{-1} by the two correlations

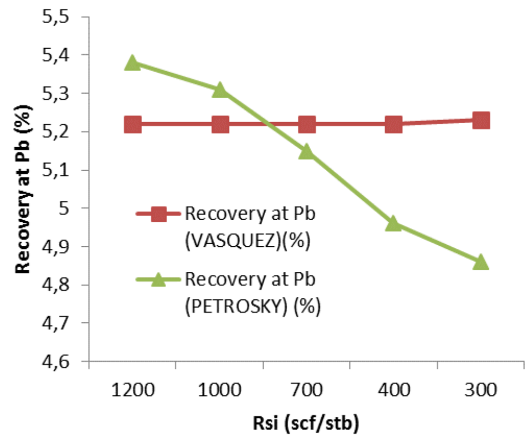

Figure 8. Showing recovery rates at the bubble point with C_f = 30 × 10^{-6} psi^{-1} by the two correlations

4.4. Improved strategies for early production of depletion drive reservoirs

Early production of depletion drive reservoirs refers to the production stage above the bubble point. This is desirable for the following reasons

1. Maintaining production above the bubble point delays the evolution of free gas from the reservoir when gas treatment and or handling facilities are yet to be put in place. In view of the increasing ban on gas flaring, this is an alternative way of production without incurring prohibitive sanctions.
2. To monitor reservoir performance (well flow rates, etc.) under depletion conditions before selecting an optimum secondary recovery strategy. This has the advantage of justifying the need to postpone artificial lift methods.

The investigation of the effects of formation compressibility and gas injection earlier discussed offer valuable insights to the development of improved strategies for increasing oil recovery at early stages of a depletion drive reservoir. The strategies are enumerated below.

4.4.1. Produced gas Re-Injection

Gas injection will give increased oil recovery above the bubble point for depletion drive reservoirs where initial solution gas oil ratio value is low and formation compressibility value is high. Where the R_{si} value is high, the effect of gas injection makes only small improvements on recovery.

High pressure associated with high R_{si} values will put a high economic premium on the gas compression facilities that is required for injection making it more unsuitable as an alternative secondary recovery method. There are a number of practical issues that may arise as a result of this strategy. In the first instance, high values of formation compressibility are closely associated with reservoir compaction. For this reason, geo mechanical analysis must be conducted as early as possible during field development of depletion drive reservoirs to screen, assess and engineer for compaction so as to utilize it a useful drive mechanism.

Another practical difficulty that may arise with this strategy is fingering. This occurs as a result of the downward displacement of oil due to the lower viscosity of gas. However, this effect can be minimized by keeping production rates as low as possible.

4.4.2. Water injection

At some point after gas injection is commenced at the upper section of the reservoir, water injection can also be used to increase oil recovery by helping the movement of fluids from upswept zones at the lower sections of the reservoir. The delay in starting water injection provides an opportunity to determine the dynamic characteristics of the aquifer. It is important to note that with water injection, water cut will increase with time and as such, top side facilities must be designed or able to handle excess water production.

However, the combination of the two schemes could be carried out either as WAG (water alternating gas) or SWAG (simultaneous water and gas injection). In each case, there has to be provision of gas compression and injection facilities as well as water injection facilities. This has the capacity of substantially increasing the field economics.

4.4.3. Thermal recovery

At low R_{si} values there is a less amount of gas in solution, this however does not necessarily imply that the oil in the reservoir will have high viscosity. However, if the oil is highly viscous, then hot water flooding operations will provide a useful means of improving recovery by reduction of oil viscosity, enhancing interfacial tension and thus mobility.

Steam soaking or cyclic steam injection is another useful method of recovery for such viscous reservoirs. This method involves the injection of steam into the reservoir for several days before bringing the well on stream. However, the increase in carbon foot print associated with these operations alongside insulation and corrosion control requirements must be carefully considered before this strategy can be adopted.

5. Conclusion

Using the PVT data generated from the two empirical correlations, an increase in oil fractional recovery was observed with a decrease in dissolved solution gas-oil ratio (R_{SI}). Reasons for this trend can be attributed to two major factors:

i. R_{SI} strongly influences the cumulative produced gas-oil ratio (R_P), such that increases in R_{SI} values correspond to an increase in R_P.
ii. Fractional recovery varies inversely with R_P, such that an increase in R_P corresponds to reduced fractional recovery.

Cumulative oil recovery of Vasquez and Beggs was higher than that of Petrosky and Farshad for all case scenarios ($C_f = 6 \times 10^{-6}$ psi^{-1}, $C_f = 30 \times 10^{-6}$ psi^{-1} and 70% gas re-injection). Also, cumulative oil recovery of $C_f = 30 \times 10^{-6}$ psi^{-1} was highest above bubble point and begins to drop below bubble point. For cumulative recovery of 70% gas re-injection, it is higher above bubble point but overtakes $C_f = 30 \times 10^{-6}$ below bubble point and has the highest cumulative oil recovery for both correlations.

From the results of the material balance calculations carried out with the two correlation

i. Formation compressibility is a significant factor that contributes to oil recovery at both undersaturated and saturated conditions in depletion drive reservoirs.
ii. Initial gas oil ratio has no significant effect on the extent of oil recovery above the bubble point pressure for depletion drive reservoirs.
iii. Produced gas re-injection is the most beneficial technique for improving oil recovery at low initial gas oil ratio conditions for depletion drive reservoirs.

5.1. Further work

This study had a primary focus on the effects of the initial gas oil ratio in depletion drive reservoirs. There are a number of other factors that may affect oil recovery. As part of recommendations for further study, the effects of viscosity, reservoir porosity and permeability and critical gas saturation can be further investigated and results validated by computational simulation. An understanding of the interactions of these various parameters will determine the success of secondary recovery methods to be adopted.

Also, fractional oil recovery at values of R_{SI} < 300 scf/stb should be investigated to further highlight the importance of this term to overall fractional recovery at pressure above and below bubble point.

APPENDIX

Ikpeka Princewill Maduabuchi, Mbagwu Chinedu: Effect of Initial Gas Oil Ratio, Produced Gas Re-Injection and Formation Compressibility on Predicted Production Performance of a depletion drive reservoir, Pet Coal, 2019; 61(1): 31-49

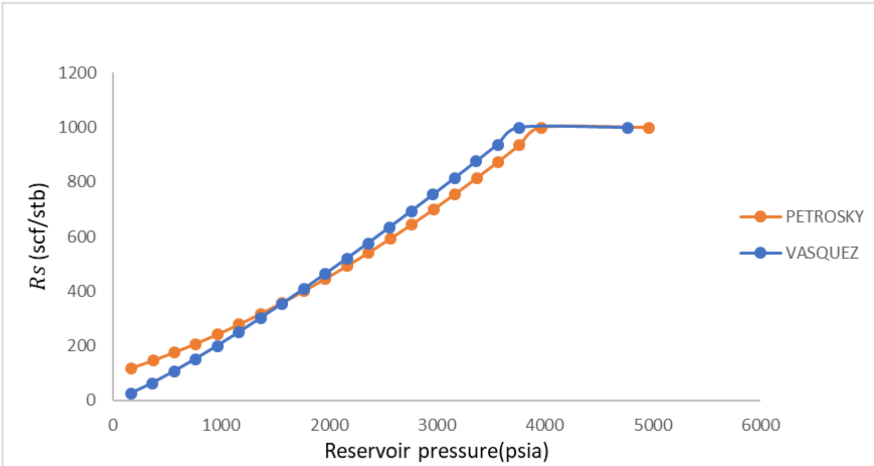

Fig. A.1 Plot of Rs vs Pressure for Rsi = 1000 scf/stb

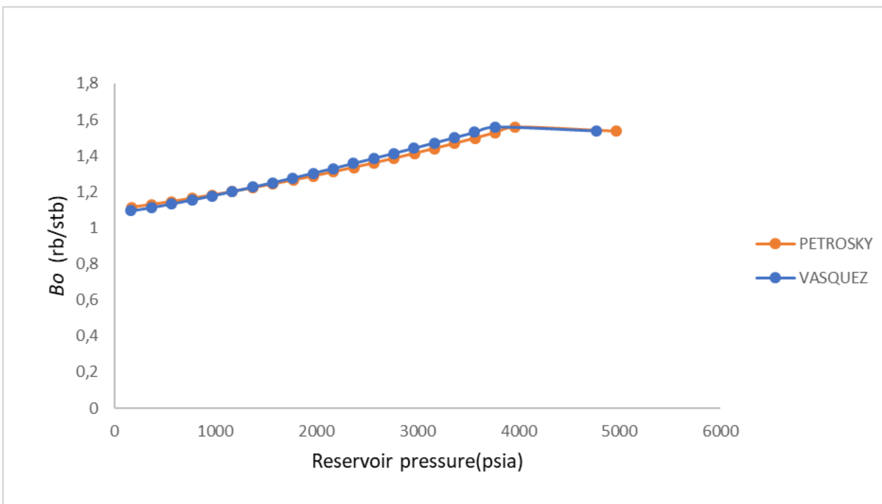

Fig. A.2 Plot of Bo vs Pressure for Rsi = 1000 scf/stb

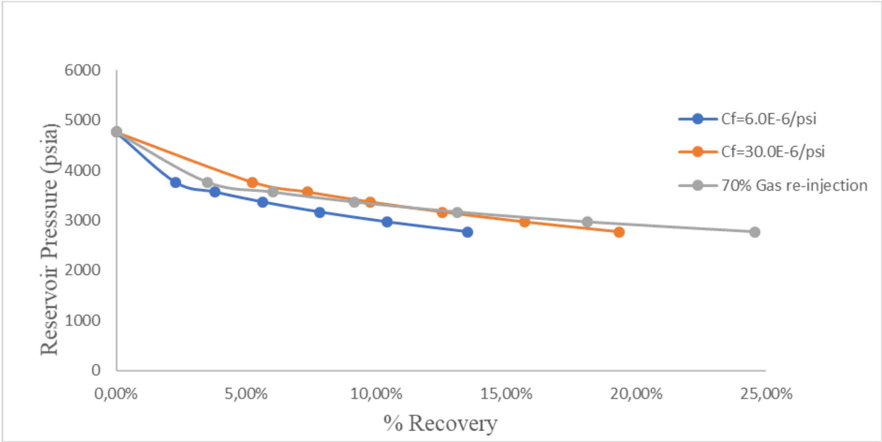

Fig. A.3 Plot of % Recovery vs Pressure for Rsi = 1000 scf/stb (Vasquez)

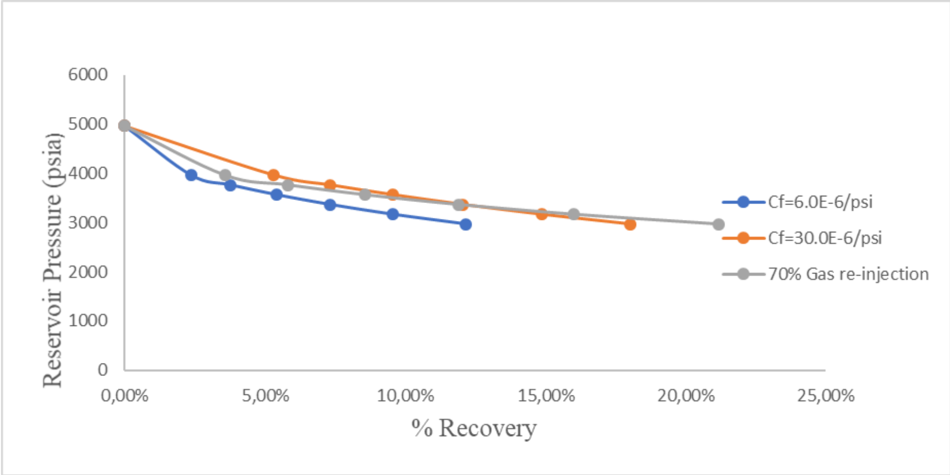

Fig. A.4 Plot of % Recovery vs Pressure for Rsi = 1000 scf/stb (Petrosky)

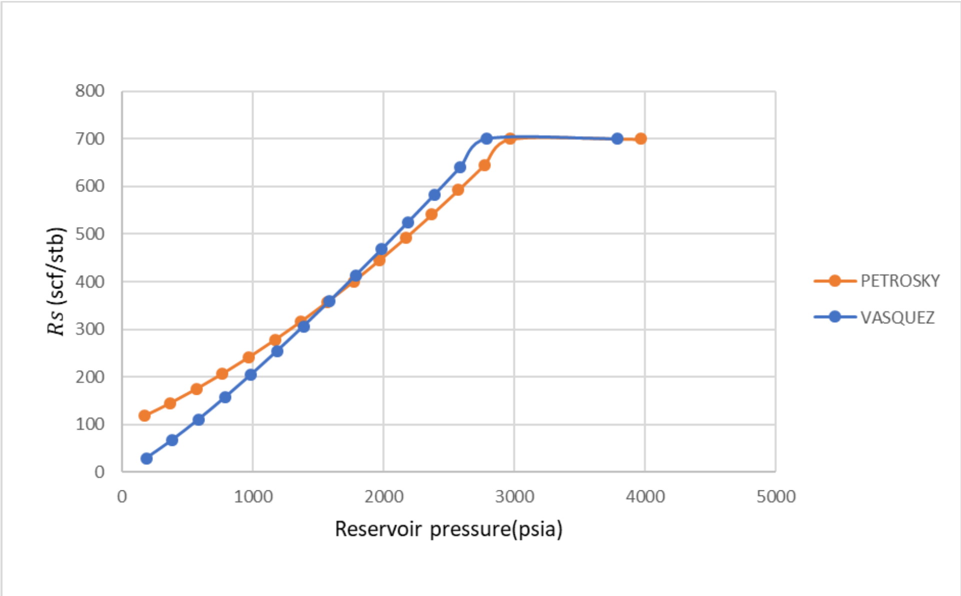

Fig. A.5 Plot of Rs vs Pressure for Rsi = 700 scf/stb

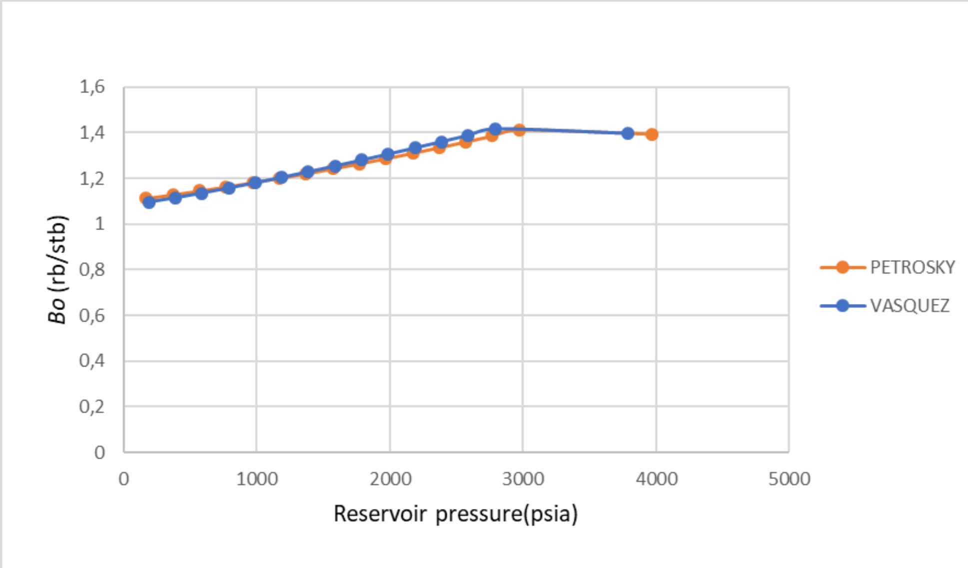

Fig. A.6 Plot of *Bo* vs Pressure for *Rsi* = 700 scf/stb

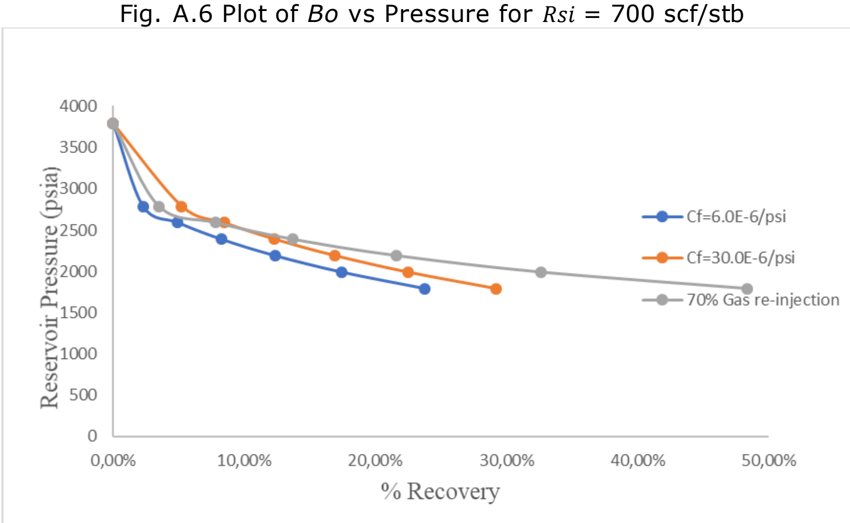

Fig. A.7 Plot of % Recovery vs Pressure for *Rsi* = 700 scf/stb (Vasquez)

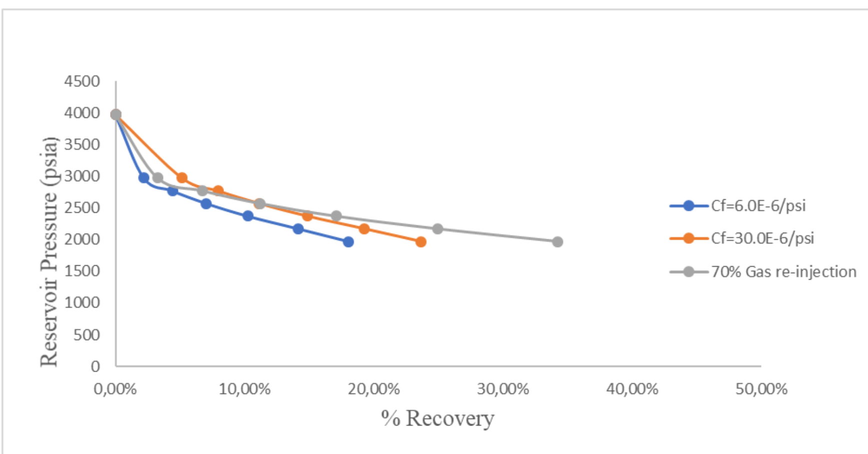

Fig. A.8 Plot of % Recovery vs Pressure for Rsi = 700 scf/stb (Petrosky)

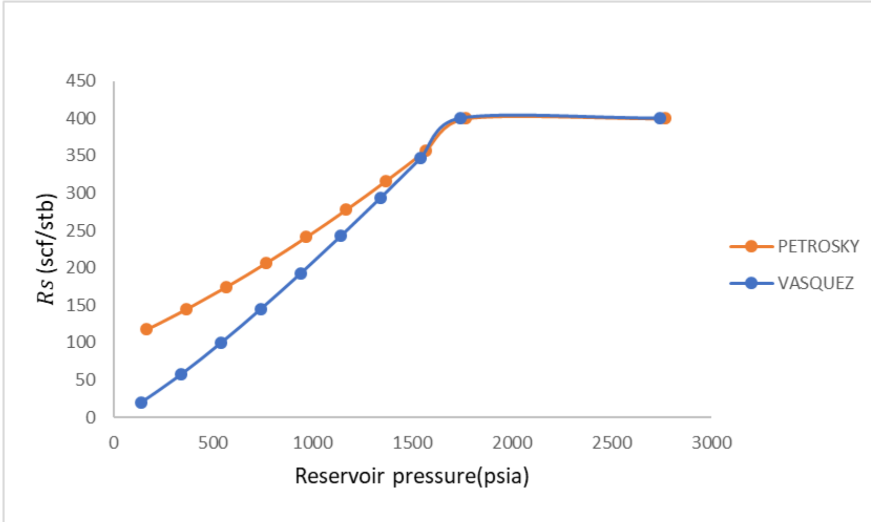

Fig. A.9 Plot of Rs vs Pressure for Rsi = 400 scf/stb

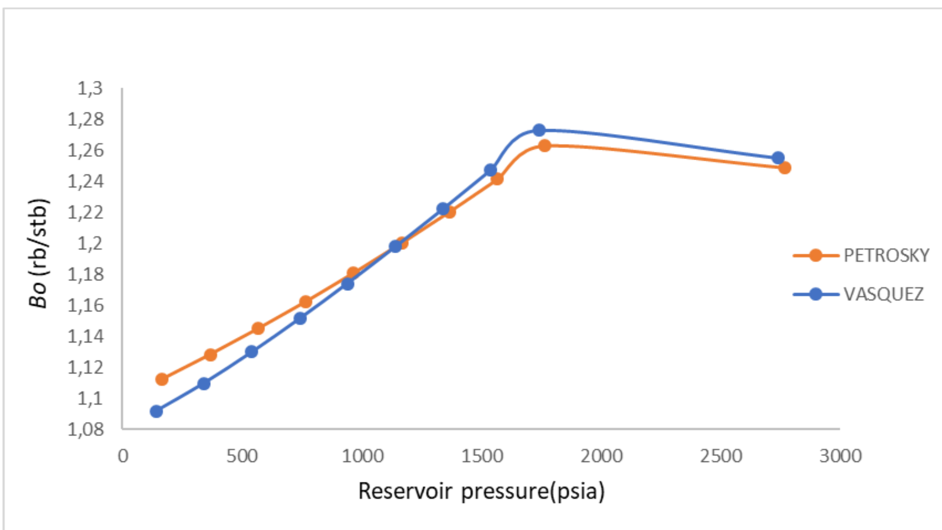

Fig. A.10 Plot of *Bo* vs Pressure for Rsi = 400 scf/stb

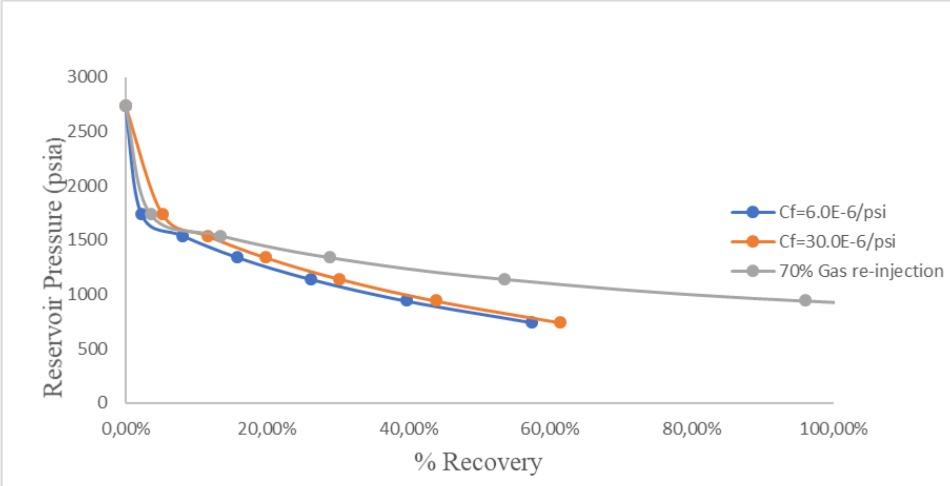

Fig. A.11 Plot of % Recovery vs Pressure for Rsi = 400 scf/stb (Vasquez)

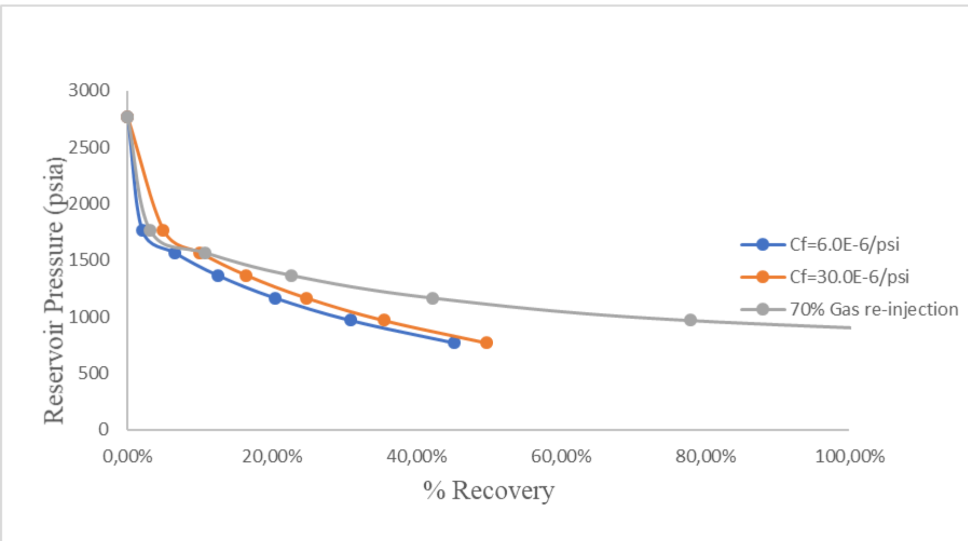

Fig. A. 12. Plot of % Recovery Vs Pressure (Petrosky)

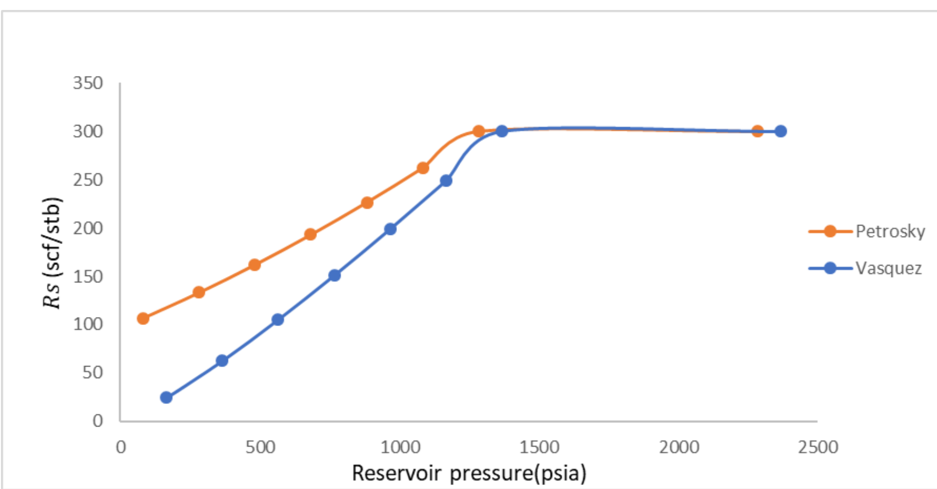

Fig. A.13 Plot of Rs vs Pressure for Rsi = 300 scf/stb

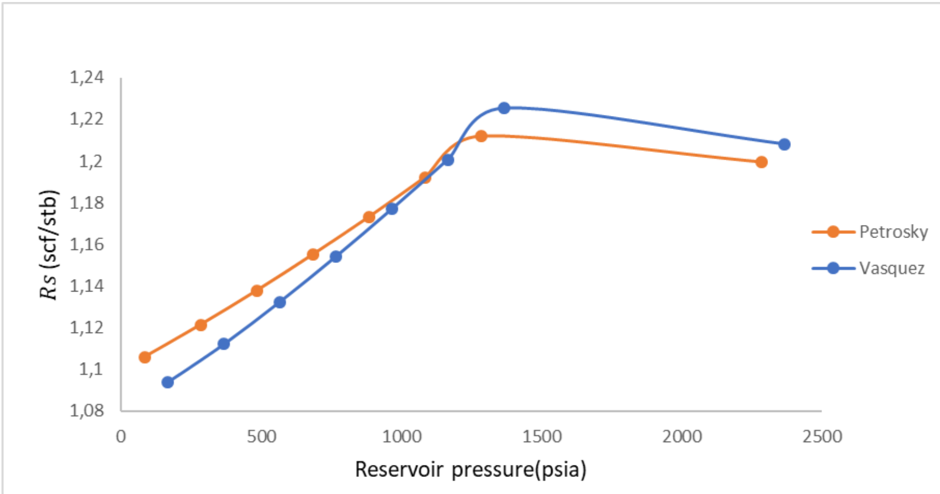

Fig. A.14 Plot of *Bo* vs Pressure for Rsi = 300 scf/stb

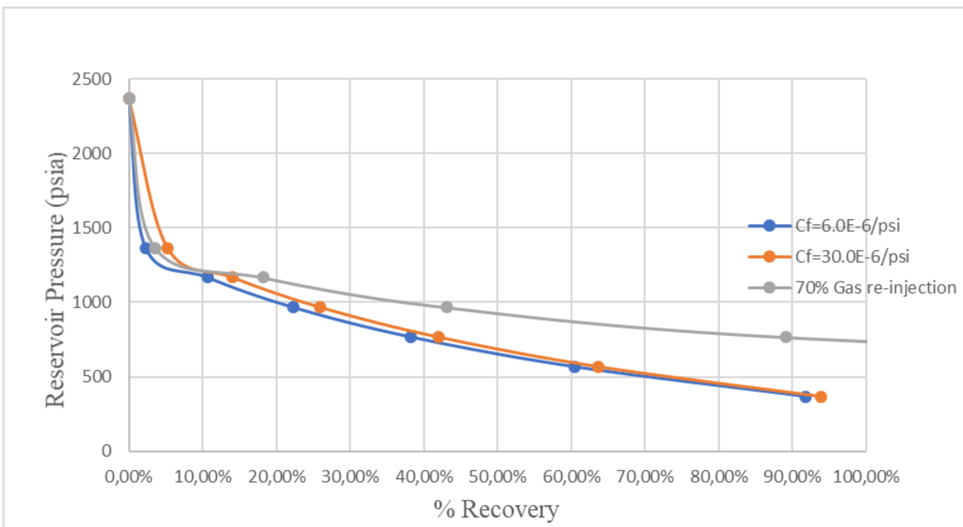

Fig. A.15 Plot of % Recovery vs Pressure for Rsi = 300 scf/stb (Vasquez)

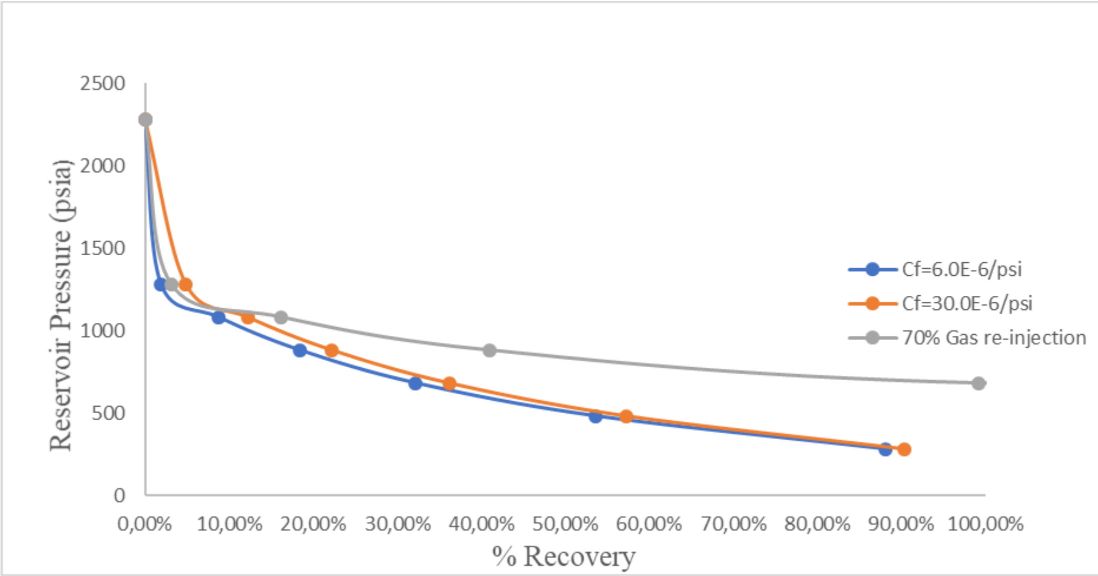

Fig. A.16 Plot of % Recovery vs Pressure for Rsi = 300 scf/stb (Petrosky)

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