COB-2021-2104 Analysis of Water Alternating Gas (WAG) in an Immiscible Reservoir

Vinícius Rafael de Freitas
Eugênio Libório Feitosa Fortaleza
José Oniram De Aquino Limaverde Filho
Universidade de Brasília, Campus Darcy Ribeiro - Brasília (DF), Brasil
vinicius.rafael@aluno.unb.br
efortaleza@unb.br
joseoniram@ieee.org

Fernando Perin Munerato
Repsol Sinopec Brasil - Rio de Janeiro, Rio de Janeiro, Brasil
fernando.perin@repsolsinopec.com

Abstract. *Understand the flow dynamics in the reservoir is extremely important to maximize the net present value (NPV) of oil exploration in any reservoir. Water or gas breakthroughs are the main issue in reservoirs because, after this moment, water or gas production increases progressively reducing the oil production and, therefore, the NPV of the exploration. To mitigate these issues, the water alternating gas injection (WAG) schedule emerged as an interesting solution as it provides the total oil production eventually higher than in the other injection schedule. However, the WAG NPV can be lower when compared to early oil production since the oil production is spaced in time. This study aims to analyze the influence of alternating WAG in an immiscible reservoir, which is, where there is no miscibility of the gas in the oil. In this way, only the interaction due to the differences of viscosity and density between the three fluids (oil, water, and gas) are analyzed under this hypothesis. The findings of this study propose a semi-analytical technique for determining the optimum amount of gas using the SPE5 as the reference scenario with the necessary modifications for gas immiscibility. Numerical simulations were carried out using Open Porous Media Flow (OPM Flow) open-source software to compare the proposed waterflooding followed by gas injection (WFG) with continuous waterflooding (CW) and different WAG ratios. The WFG case, proposed in this paper, shows a slightly higher NPV than WAG and CW in the studied cases, representing the best injection scenario. This is because the initial water injection shows better sweeping efficiency and rapid oil production and, close to the end of the production time, the gas injection helps to maintain the pressure in the reservoir as well as to balance the density of the injected fluids at a considerably lower cost, then increasing the NPV.*

Keywords: *Water Alternating Gas (WAG), Enhanced Oil Recovery (EOR), OPM Flow, Net Present Value (NPV), Oil Production.*

1. INTRODUCTION

In reservoirs that have been waterflooded or gas injected, it is still possible to recover a significant amount of the remaining oil by water-alternating-gas (WAG) injection (Sohrabi *et al.*, 2004). WAG was originally proposed as a method to improve the sweep of gas injection, mainly by using the water to control the mobility of the displacement and to stabilize the front. Since the microscopic displacement of the oil by gas normally is better than by water, WAG injection combines the improved displacement efficiency of the gas flooding with an improved macroscopic sweep by the injection of water (Christensen *et al.*, 2001).

Currently, WAG injection is recognized as a common technology to enhance the total oil recovery through re-injection of produced gas in water injection wells in mature petroleum fields (Hustad *et al.*, 1992). Skauge and Stensen (2003) reviewed 59 WAG fields and their study revealed that the average oil recovery increases up to 10% originally oil in place for all WAG cases.

In Brazil, WAG has been used in the pre-salt fields as the fields of Lula, Sapinhoá, and Búzios (ANP, 2020b) responsible for 87.1% of pre-salt production in May 2020 (ANP, 2020a). In the pre-Salt reservoirs, especially due to its high pressure, the injected gas is miscible with the oil, which enhances the displacement efficiency and the ultimate recovery (ANP, 2020b).

Different variations of WAG are found in the literature based on different attributes (Afzali *et al.*, 2018). Variations may involve process schemes or fluids modifications to improve the sweeping efficiency (see Fig. 1 for more details). Regarding to the process scheme, conventional WAG injection and simultaneous water and gas (SWAG) injection are the most common.. The gas-phase modifications include foam, miscible gas, CO2, and steam. The liquid phase modifications include Low Salinity Water, water-soluble polymer additives, surfactant additives and oil-in-water emulsions (Afzali *et al.*, 2018).

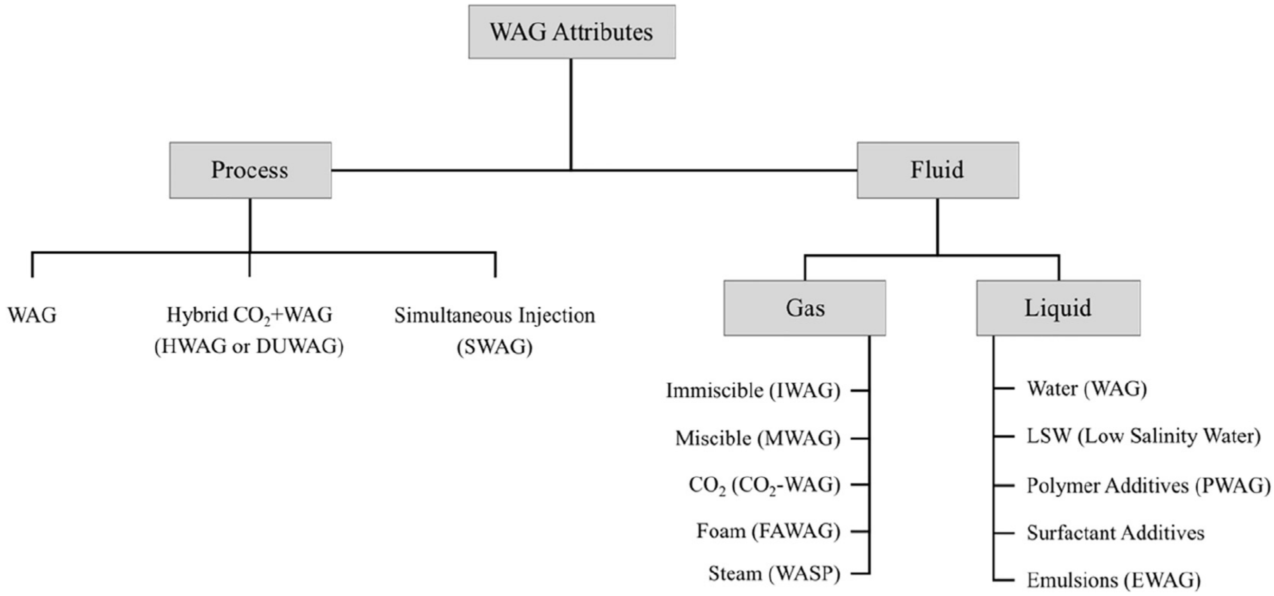


Figure 1. Variations of WAG processes based on different attributes, extracted from Afzali *et al.* (2018).

The most important classification of WAG is based on the miscibility condition in the gas cycles (miscible WAG versus immiscible WAG) (Afzali *et al.*, 2018). For miscible cases, the gas mix with oil decreasing its viscosity and, increasing the oil's mobility. However, in immiscible cases, such mixing does not occur, the interfacial tension between the fluids is non-zero and a capillary pressure difference exists across the interface between gas and oil, increasing the tendency of viscous fingering (Saffman–Taylor instability). Kulkarni and Rao (2005) work indicates a significant increase in oil recovery for a miscible condition over an immiscible condition in the gas phase. Furthermore, there is a delay of oil production with a continuous gas injection when compared to WAG in immiscible cases, which does not occur in miscible cases. The injection of gas increases the chance of gas coning and, according to Fortaleza *et al.* (2019), gas coning can be a limiting factor in the productivity of some oil wells. Also, according to Rodrigues Filho *et al.* (2020) the only gas injection increases the production of undesirables when compared to continuous waterflooding or WAG.

One of the major design issues for WAG is WAG ratio (Kulkarni *et al.*, 2004). The review work of Christensen *et al.* (2001) shows that the most popular WAG ratio in-field experience is 1:1. Survey work of Afzali *et al.* (2018) shows that another popular WAG ratio is 1:4 and 4:1, as used in works of Al-Shuraiqi (2005) and Christie *et al.* (1993).

The main goal of this work is to find an optimal WAG density in the gas immiscibility condition. The semi-analytical analysis of the WAG front was carried out to find the WAG density to stabilize the boundary between injected WAG and reservoir oil. As the density found is a negative value, it is impossible to reach that value through the mixture of the injected fluids. Simulations with different WAG ratios (1:1, 1:4, and 4:1) were carried out and compared with waterflooding and a new injection schedule is proposed to optimize NPV. The new injection schedule had the highest NPV among the simulated cases.

2. BENCHMARK AND ASSUMPTIONS

2.1 SPE5

The fifth comparative solution project of the Society of Petroleum Engineers, known as SPE5, is a benchmark designed to compare different kinds of simulators for three different miscible gas scenarios. SPE5 consists of three layers parallel to the gravitational vector, which allows studying the problem of gravitational segregation. The grid is composed of 147 cells, 7 elements in the x-axis, 7 elements in the y-axis, and 3 elements in the z-axis. The total length of the x-axis and y-axis is 3500 ft and for the z-axis is 100 ft. An injector well was allocated to the cell (1x1x1) and a producer well to the cell (7x7x3), as presented in Fig. 2.

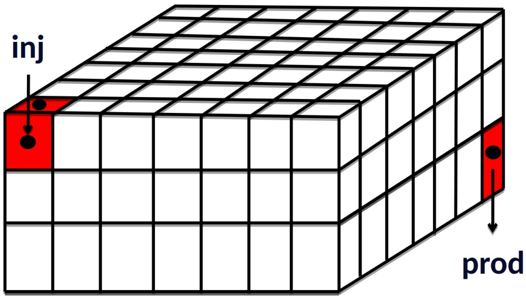


Figure 2. Numerical grid of SPE5 Benchmark.

The SPE5 is an anisotropic reservoir with different cells sizes, as can be seen in Tab. 1.

Table 1. Cell sizes and cell permeabilities of SPE5 Benchmark.

Settings	Layer 1	Layer 2	Layer 3
dx and dy	500 ft	500 ft	500 ft
dz	20 ft	30 ft	50 ft
x-perm and y-perm	500 mD	50 mD	200 mD
z-perm	50 mD	50 mD	25 mD

The original oil, water, and gas density are, respectively, 38.53 lb/ft³, 62.4 lb/ft³, and 0.06864 lb/ ft³. The original oil, water, and gas viscosity are, respectively, 1.14 cP, 0.7 cP, and 0.034 cP. However, the characteristics of the oil were changed to match the pre-salt oil, which will be explained in the next section.

2.2 OPEN POROUS MEDIA FLOW AND MODEL ASSUMPTIONS

The Open Porous Media Flow (OPM Flow) is a fully-implicit, black-oil simulator capable of running industry-standard simulation models (Baxendale, 2020). OPM Flow aims to represent a reservoir geology, fluid behavior, and description of wells and production facilities as in commercial simulators and hence offer support industry-standard input and output formats (Rasmussen *et al.*, 2021). In the Rasmussen *et al.* (2021) work, the numerical results obtained by the OPM flow for the SPE5 are compared with the results obtained by the ECLIPSE and, except for some minor discrepancies in the gas production rate and the bottom-hole injector pressure, there is general agreement between the well responses computed by OPM Flow and ECLIPSE.

According to with (Christensen *et al.*, 2001), sometimes the first gas slug dissolves to some degree into the oil, so to avoid that, the model has been adapted to ensure that the immiscibility condition is maintained. The model code has been changed to exclude the words that describe how the gas dissolves in the oil. In this way, regardless of the pressure in the reservoir, the fluids do not mix ensuring that injection and production rates do not alter the miscibility conditions.

The original characteristics of oil in SPE5 were changed to be similar to those found in the Brazilian pre-salt. According to Nakano *et al.* (2009), the pre-salt oil API grade is around 28 and live oil viscosity is 1.14 cP ($1.14 \times 10^{-3}\mathrm{Pa} \cdot \mathrm{s}$). For simplicity, the API grade used in this work was 30 resulting in a density of 54.70 lb/ft3 or 876.21 kg/m3.

Different from the work of de Aquino Limaverde Filho *et al.* (2016) that propose control techniques in the production well, this work keeps the injection and production rate unchanged, both worth 12000 Mcf/d or bbl/d. The changes were made only to the injection schedule.

2.3 NET PRESENT VALUE SETTINGS

The most used technique to assess the economic factors linked to a given engineering project is the NPV approach. It consists of discounting all future cash flows (both in- and out-flow) resulting from the innovation project with a given discount rate and then summing them together (Žižlavskỳ, 2014). Fonseca *et al.* (2017) and Fortaleza *et al.* (2020) uses the NPV approach from equation (1).

$$NPV = \sum_{n=1}^{N_t} \left\{ \frac{\Delta t_n}{(1+b)^{\frac{t_n}{365}}} \left[\sum_{j=1}^{N_P} \left(r_o \cdot \overline{q_{o,j}^n} - c_w \cdot \overline{q_{w,j}^n} \right) - \sum_{k=1}^{N_I} \left(c_{wi} \cdot \overline{q_{wi,k}^n} - c_{gi} \cdot \overline{q_{gi,k}^n} \right) \right] \right\} \tag{1}$$

where $i = 1, 2, ..., N_e$; N_e is the number of random geological models; n denotes the n^{th} time step of the reservoir simulator; N_t is the total number of time steps; the time at the end of n^{th} time step is denoted by t_n; Δt_n is the n^{th} time step size; b is the annual discount rate; N_P and N_I denote the number of producers and injectors, respectively; r_o is the oil revenue; c_w, c_{wi} and c_{gi}, respectively, denote the disposal cost of produced water, and the cost of water injection and the cost of gas injection; $\overline{q^n_{o,j}}$ and $\overline{q^n_{w,j}}$, respectively, denote the average oil production rate and average water production rate at the j^{th} producer for the n^{th} time step; $\overline{q^n_{wi,k}}$ and $\overline{q^n_{gi,k}}$, respectively, denote the average water injection rate and the average gas injection rate at the k^{th} injector for the n^{th} time step (Fonseca *et al.*, 2017) .

The values used in the NPV calculations of this work come from the works of Fonseca *et al.* (2018) and Chen *et al.* (2016) and are: oil revenue of 45 USD/bbl (r_o); water production cost of 6 USD/bbl (c_w); gas production cost of 0 USD/bbl; water injection cost of 2 USD/bbl (c_{wi}); gas injection cost 1.5 USD/Mscf (c_{gi}) and the annual discount rate of 0.08.

3. SEMI-ANALYTICAL ANALYSIS OF WAG FRONT

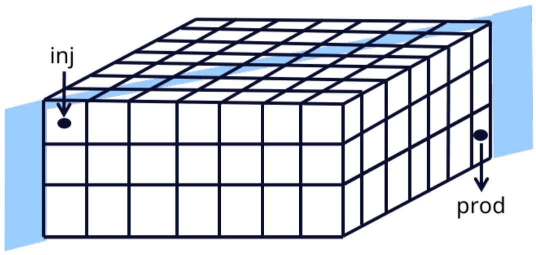
SPE5 is an anisotropic reservoir, so to facilitate calculations, an isotropic equivalent was found with new dimensions and permeability (see Rosa *et al.* (2006) for more details), which are:

$$x_{eq} = 287.37 \text{ m} \quad ; \quad z_{eq} = 113.15\text{m} \quad ; \quad L_{wells} = 421.86 \text{ m} \quad ; \quad \beta = 74.99^\circ \quad ; \quad \overline{k} = 8.3545 \times 10^{-14} m^2 \quad (2)$$

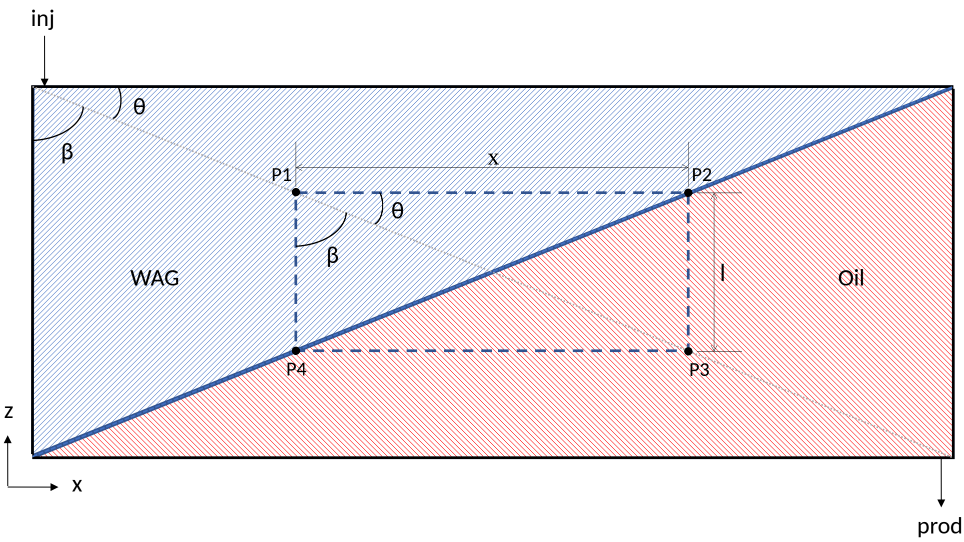
where x_{eq} and z_{eq} are the distance on the isotropic equivalents x-axis and z-axis, respectively, L_{wells} is the isotropic equivalent distance between the injector and producer wells, β is the isotropic equivalent angle between the diagonal connecting the injector and producer wells and the vertical, and $\overline{k}$ is the isotropic equivalent average permeability of the porous media. All subsequent calculations of this section were performed with the characteristics of this equivalent reservoir and the equivalent subindex eq was omitted for a better readability.

3.1 WAG Density Analysis

With the equivalent isotropic reservoir, the analytical development will begin to find a correlation for the density of the WAG mixture. For this purpose, we made a cross section in the equivalent isotropic reservoir, as can be seen in Fig. 3(a).



(a) Reservoir view.



(b) Cross section view.

Figure 3. Cross section in the SPE5 equivalent isotropic reservoir.

Four points were chosen to form a rectangle: Points 1 and 3 are on the diagonal that connects the injector and producer wells, and points 2 and 4 are on the opposite diagonal and coincide with the boundary between WAG and oil. The rectangle formed by the points must be seen as an infinitesimal rectangle, that is, a differential element. Figure 3(b) outlines the cross section of the reservoir with the aforementioned points.

Note that the distance between the points is related to:

$$x = l \times \tan(\beta) \tag{3}$$

The pressure drop in the horizontal component between any two points is due to the pressure gradient between them, on the other hand, the pressure drop in the vertical component between any two points is given by the fluid column between such points.

$$\frac{p_1 - p_4}{l} = \rho_{wag} \times g \tag{4}$$

$$\frac{p_2 - p_3}{l} = \rho_{oil} \times g \tag{5}$$

$$\frac{p_1 - p_2}{l \times \tan(\beta)} = \nabla \rho_{wag} \tag{6}$$

$$\frac{p_4 - p_3}{l \times \tan(\beta)} = \nabla \rho_{oil} \tag{7}$$

Taking p_3 as a reference, that is, equaling zero, equations (5) and (7) become, respectively:

$$\frac{p_2}{l} = \rho_{oil} \times g \tag{8}$$

$$\frac{p_4}{l \times \tan(\beta)} = \nabla \rho_{oil} \tag{9}$$

Adding equations (4) to (9),

$$\frac{p_1 - p_4}{l} + \frac{p_4}{l} = \rho_{wag} \times g + \nabla p_{oil} \times \tan(\beta) \tag{10}$$

$$\frac{p_1}{l} = \rho_{wag} \times g + \nabla p_{oil} \times \tan(\beta) \tag{11}$$

Isolating l in equation (8) and replacing it in equation (11),

$$p_1 = \frac{p_2}{\rho_{oil} \times g} \left[\rho_{wag} \times g + \nabla p_{oil} \times \tan(\beta)\right] \tag{12}$$

Isolating p_1 in equation (6), and replacing l from equation (8),

$$p_1 = \frac{p_2}{\rho_{oil} \times g} \nabla p_{wag} \times \tan(\beta) + p2 \tag{13}$$

$$p_1 = \frac{p_2}{\rho_{oil} \times g} \left[\nabla p_{wag} \times \tan(\beta) + \rho_{oil} \times g\right] \tag{14}$$

Substituting (14) in (12),

$$\frac{p_2}{\rho_{oil} \times g} \left[\nabla p_{wag} \times \tan(\beta) + \rho_{oil} \times g\right] = \frac{p_2}{\rho_{oil} \times g} \left[\rho_{wag} \times g + \nabla p_{oil} \times \tan(\beta)\right] \tag{15}$$

$$\nabla p_{wag} \times \tan(\beta) + \rho_{oil} \times g = \rho_{wag} \times g + \nabla p_{oil} \times \tan(\beta) \tag{16}$$

where the density of the WAG mixture is given by:

$$\boxed{\rho_{wag} = \frac{1}{g} \left[\nabla p_{wag} \times \tan(\beta) + \rho_{oil} \times g - \nabla p_{oil} \times \tan(\beta)\right]} \tag{17}$$

3.2 WAG Density Calculation

To calculate the WAG mixture density, it remains to calculate the ∇p_{wag} and ∇p_{oil}. Both gradients can be obtained by the Darcy equation, which governs the movement of fluids in a porous medium (Rosa *et al.*, 2006):

$$v_s = \frac{k}{\mu}\nabla p \tag{18}$$

Rearranging the terms, we arrive at:

$$\nabla p = \frac{\mu}{k}v_s \tag{19}$$

where v_s is the speed in any direction and can be defined as a distance by time. Numerical simulations of constant water injection show that the water took approximately 2400 days to reach the producing well:

$$v_s = \frac{L_{wells}}{time} = \frac{421.86}{2400}\frac{\mathrm{m}}{\mathrm{d}} = \frac{421.86}{2400 \times 24 \times 60 \times 60}\frac{\mathrm{m}}{\mathrm{s}} = 2.034 \times 10^{-6}\frac{\mathrm{m}}{\mathrm{s}} \tag{20}$$

The velocity x-componentis given by:

$$v_x = v_s \times \cos(\theta) = 2.034 \times 10^{-6} \times \cos(15.01) = 1.97 \times 10^{-6}\frac{\mathrm{m}}{\mathrm{s}} \tag{21}$$

According to Nakano *et al.* (2009), the pre-salt oil viscosity is approximately $1.14\mathrm{cP}$ or $1.14 \times 10^{-3}\mathrm{Pa.s}$. Therefore:

$$\nabla p_{oil} = \frac{\mu_{oil}}{k}v_x = \frac{1.14 \times 10^{-3}}{8.3545 \times 10^{-14}} \times 1.97 \times 10^{-6} = 26881.32\frac{\mathrm{Pa}}{\mathrm{m}} \tag{22}$$

Similarly, for the WAG pressure gradient,

$$\nabla p_{wag} = \frac{\mu_{wag}}{k}v_x \tag{23}$$

However, the WAG viscosity is unknown. Works by Kendall and Monroe (1917) and Arrhenius (1887) define the relationship of dynamic viscosity when there is a mixture of fluids. Kendall and Monroe (1917) correlation is given by:

$$\mu_{mix}^{\left(\frac{1}{3}\right)} = x_1\mu_1^{\left(\frac{1}{3}\right)} + x_2\mu_2^{\left(\frac{1}{3}\right)} \tag{24}$$

where x_1 and x_2 are the molar fractions of components 1 and 2. Similarly, the Arrhenius (1887) correlation is:

$$\log(\mu_{mix}) = x_1\log(\mu_1) + x_2\log(\mu_2) \tag{25}$$

Based on the Killough *et al.* (1987) tables and the appropriate conversions, equation (24) becomes:

$$\mu_{mix1}^{\left(\frac{1}{3}\right)} = 0.11 \times 0.000034^{\left(\frac{1}{3}\right)} + 0.89 \times 0.0007^{\left(\frac{1}{3}\right)} \tag{26}$$

$$\mu_{mix1} = 0.000563 \tag{27}$$

and equation (25) becomes:

$$\log(\mu_{mix2}) = 0.11\log(0.000034) + 0.89\log(0.0007) \tag{28}$$

$$\mu_{mix2} = 0.000502 \tag{29}$$

The WAG viscosity is given by the average of both methods:

$$\mu_{mix} = \frac{\mu_{mix1} + \mu_{mix2}}{2} = 0.0005325\text{Pa.s} \tag{30}$$

Substituting the WAG viscosity obtained in (30) into WAG pressure gradient (see (23)):

$$\nabla p_{wag} = \frac{0.0005325}{8.3545 \times 10^{-14}} \cdot 1.97 \times 10^{-6} = 12524.66\frac{\text{Pa}}{\text{m}} \tag{31}$$

Using the values obtained in (22) and (31), the WAG density is given as follows:

$$\rho_{wag} = \frac{1}{g}\left[\nabla p_{wag} \times \tan(\beta) + \rho_{oil} \times g - \nabla p_{oil} \times \tan(\beta)\right] \tag{32}$$

$$\rho_{wag} = \frac{1}{9.81}\left[12524.66 \times \tan(74.99) + 876.21 \times 9.81 - 26881.32 \times \tan(74.99)\right] = -4581.73\frac{\text{kg}}{\text{m}^3} \tag{33}$$

As the value found for the density of the WAG mixture is negative, it is not possible to find a mixture of water and gas that keeps the balance of forces in steady-state flow.

For the boundary to be stable, the pressure drop between p_1 and p_3 (see Fig. 3(a)) by both paths must be the same. In other words, the vertical pressure drop in the WAG due to the gravitational force between the points p_1 and p_4, governed by density, added to the horizontal pressure drop in the oil resulting from the pressure gradient between the points p_4 and p_3, governed by viscosity, must be equal to the horizontal pressure drop in the WAG due to the pressure gradient between the points p_1 and p_2, governed by viscosity, plus the vertical pressure drop in the oil due to the gravitational force between the points p_2 and p_3, governed by density. However, due to the difference in density and viscosity between oil and other fluids, to balance the forces, the WAG density value must be negative, which is physically impossible.

As it is not possible to find an optimal mixture of water and immiscible gas that stabilizes the oil boundary in the studied reservoir, a new injection schedule (WFG) is proposed to maximize exploration profit: continuous water injection and before the breakthrough takes place, continuous gas injection until reaching the maximum NPV.

4. NUMERICAL RESULTS AND DISCUSSIONS

Numerical simulations were carried out using OPM Flow with the proposed WFG. Water was continuously injected for 2562 days and, after that, continuous gas injection until the end of exploration. For comparative purposes, results obtained by different injection schedules were used: continuous waterflooding (CW) and WAG injection in three different ratios (1:1, 1:4, and 4:1). For WAG cases, the injection starts with water and has one-year cycles in all cases. In summary, WAG 1:1 alternates injections of 1 year of water followed by 1 year of gas injection, WAG 1:4 alternates injections of 1 year of water followed by 4 years of gas injection, and WAG 4:1 alternates 4 years of water injections followed by 1 year of gas injection. Figure 4 compares the NPV reached by the different injection schedules mentioned: WFG, CW, and WAG ratio of 1:1, 1:4, and 4:1.

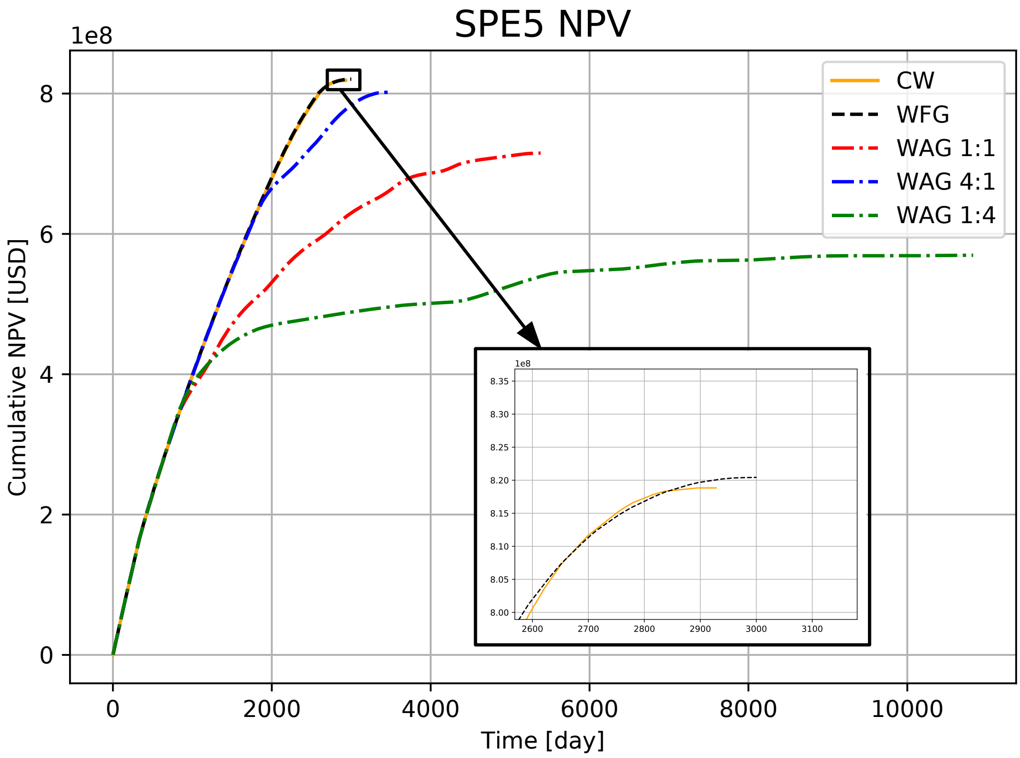
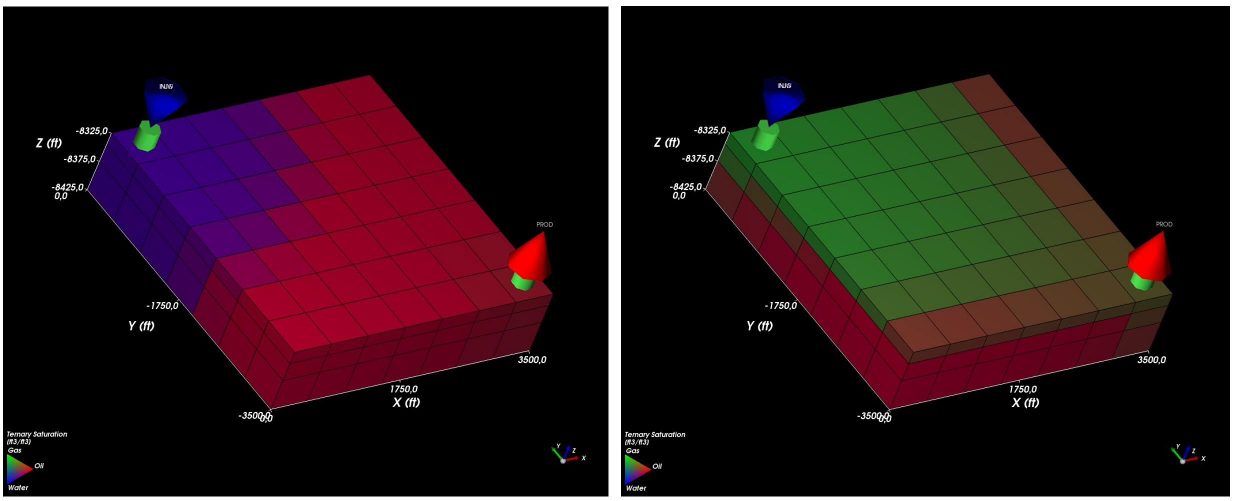


Figure 4. SPE5 NPV for different injection schedules.

When comparing the NPV of the different WAG ratios, it is noted that the higher the water to gas ratio in the WAG, the higher the NPV. Figure 5 shows the SPE5 Ternary Saturation at day 731, it is possible to verify that the water flow in the reservoir does not present great gravitational segregation, flowing similarly in the three layers of the reservoir. The same does not happen with the gas, which flows mostly in the first layer of the reservoir and advances more quickly to the producing well, thus culminating in the unwanted precocious gas conning.



(a) Continuos Waterflooding.

(b) Continuos Gas Injection.

Figure 5. SPE5 Ternary saturation plot[1] at day 731.

Such behaviors can be better understood in the analysis of layer permeabilities and fluid properties such as density and viscosity. Table 1 shows that the second layer has the lowest permeability, thus justifying the advance of the majority gas in the upper layer of the reservoir. By the law of conservation of mass, so that the flow is kept the same, the velocity increases to keep the flow constant. Furthermore, the low viscosity of the gas also contributes to the increase in advance

[1] Saturation plot performed with Kraken - Reservoir data management and analysis.

speed. However, in the case of CW, water has viscosity and densities relatively closer to that of oil, resulting in a more homogeneous distribution of water in the 3 layers so that there is a balance of viscous and gravitational forces.

Lastly, it is noted that the case with the highest NPV is the one proposed in this paper with an increase of $1,597,216.11 (0.19%) to the second-placed CW. Such NPV gain is justified by financial issues linked to the injection and production cost. The final injection of gas does not cause an increase in oil production, but it does reduce costs linked to exploration. The gas is capable of maintaining the pressure in the reservoir, however, at a considerably lower cost, thus justifying the higher NPV of this injection schedule.

5. CONCLUSIONS

The present work conducted a semi-analytical of WAG front analysis to determine an optimal mix of the injected fluids to maintain a stable boundary with the oil and thus maximize the production NPV. The results of the analysis indicate that it is not possible to find such a proportion of the mixture with the ideal density for the immiscible gas case. Also, an injection schedule was proposed and simulations were carried out to determine the best injection schedule to maximize the exploration NPV. The proposed WFG in this paper resulted in the highest NPV among the studied cases.

The injection of immiscible gas in the upper layer becomes more attractive if there is an intention to sweep the reservoir from above due to strong heterogeneity, for example. However, in general, each case has its peculiarities and the study of the reservoir must be done individually, according to its characteristics such as permeability, porosity, inclination, shape, as well as positions of the injector and producer wells and their completions.

The miscibility feature proved to be extremely relevant for the injection calendar design. In the miscible case, the mixture of oil and gas decreases the viscosity of the oil and, therefore, increases its mobility and can reduce residual oil saturation to a very low number (Bahagio, 2013). However, in the immiscible case, such an increase in sweeping efficiency does not occur and the non-mixing of the fluids results in a greater tendency to form viscous fingers due to the lower viscosity of the gas and the non-zero interfacial tension and the capillary pressure difference exists across the interface between fluids (Al-Shuraiqi, 2005). Therefore, the injection of immiscible gas is not justified in most cases, especially when the cost of construction of wells is taken into account.

The constant search for oil has made offshore exploration in ultra-deep waters increasingly common, so that such reservoirs are more likely to present increasingly higher pressures and, therefore, the miscibility condition is met. The result of this work is relevant for the immiscible WAG, however, the consideration is a first semi-analytical approximation that can be useful for miscible cases near the end of the exploration.

6. ACKNOWLEDGEMENTS

The authors would like to acknowledge the company Repsol Sinopec Brasil (ANP Project No. 21363-7) for supporting the present study.

7. REFERENCES

Afzali, S., Rezaei, N. and Zendehboudi, S., 2018. "A comprehensive review on enhanced oil recovery by water alternating gas (wag) injection". *Fuel*, Vol. 227, pp. 218–246.

Al-Shuraiqi, H.S., 2005. "Mechanisms of oil recovery via first contact miscible wag injection".

ANP, 2020a. "Búzios, lula e sapinhoá produzem 87,1 percent do pré-sal". Agência Nacional do Petróleo, Gás Natural e Biocombustíveis Publication - 7/09/2020. Available in https://www.presalpetroleo.gov.br/ppsa/noticias/buzios-lula-e-sapinhoa-produzem-871-do-pre-sal, access on June 1, 2021.

ANP, 2020b. "Study on the use of the pre-salt natural gas". Agência Nacional do Petróleo, Gás Natural e Biocombustíveis Publication - 7/29/2020. Available in http://www.anp.gov.br/arquivos/estudos/ingles-aproveitamento-gn-pre-sal.pdf, access on June 1, 2021.

Arrhenius, S., 1887. "Über die dissociation der in wasser gelösten stoffe". *Zeitschrift für physikalische Chemie*, Vol. 1, No. 1, pp. 631–648.

Bahagio, D., 2013. "Ensemble optimization of co2 wag eor".

Baxendale, D., 2020. "Open porous media flow documentation manual". Equinor ASA - Heyerdahlsvei 12b, 0777 Oslo, Norway.

Chen, B., Reynolds, A.C. *et al.*, 2016. "Ensemble-based optimization of the water-alternating-gas-injection process". *SPE Journal*, Vol. 21, No. 03, pp. 786–798.

Christensen, J.R., Stenby, E.H. and Skauge, A., 2001. "Review of wag field experience". *SPE Reservoir Evaluation & Engineering*, Vol. 4, No. 02, pp. 97–106.

Christie, M., Muggeridge, A., Barley, J. *et al.*, 1993. "3d simulation of viscous fingering and wag schemes". *SPE reservoir engineering*, Vol. 8, No. 01, pp. 19–26.

de Aquino Limaverde Filho, J.O., Cordoba, L.M.I. and Fortaleza, E., 2016. "Identification and nonlinear control strategy for two-dimensional gas coning problem". *IFAC-PapersOnLine*, Vol. 49, No. 18, pp. 909 – 914. ISSN 2405-8963. doi:https://doi.org/10.1016/j.ifacol.2016.10.282. URL `http://www.sciencedirect.com/science/article/pii/S2405896316318626`. 10th IFAC Symposium on Nonlinear Control Systems NOLCOS 2016.

Fonseca, R.R.M., Chen, B., Jansen, J.D. and Reynolds, A., 2017. "A stochastic simplex approximate gradient (stosag) for optimization under uncertainty". *International Journal for Numerical Methods in Engineering*, Vol. 109, No. 13, pp. 1756–1776.

Fonseca, R., Della Rossa, E., Emerick, A., Hanea, R. and Jansen, J., 2018. "Overview of the olympus field development optimization challenge". In *ECMOR XVI-16th European Conference on the Mathematics of Oil Recovery*. European Association of Geoscientists & Engineers, Vol. 2018, pp. 1–10.

Fortaleza, E.L., Limaverde Filho, J.O., Gontijo, G.S., Albuquerque, É.L., Simões, R.D., Soares, M.M., Miranda, M.E. and Abade, G.C., 2019. "Analytical, numerical and experimental study of gas coning on horizontal wells". *Journal of the Brazilian Society of Mechanical Sciences and Engineering*, Vol. 41, No. 3, pp. 1–16.

Fortaleza, E.L.F., Neto, E.P.B. and Miranda, M.E.R., 2020. "Production optimization using a modified net present value". *Computational Geosciences*, Vol. 24, No. 3, pp. 1087–1100.

Hustad, O.S., Holt, T. *et al.*, 1992. "Gravity stable displacement of oil by hydrocarbon gas after waterflooding". In *SPE/DOE enhanced oil recovery symposium*. Society of Petroleum Engineers.

Kendall, J. and Monroe, K.P., 1917. "The viscosity of liquids. ii. the viscosity-composition curve for ideal liquid mixtures." *Journal of the American Chemical Society*, Vol. 39, No. 9, pp. 1787–1802.

Killough, J., Kossack, C. *et al.*, 1987. "Fifth comparative solution project: evaluation of miscible flood simulators". In *SPE Symposium on Reservoir Simulation*. Society of Petroleum Engineers.

Kulkarni, M.M. and Rao, D.N., 2005. "Experimental investigation of miscible and immiscible water-alternating-gas (wag) process performance". *Journal of Petroleum Science and Engineering*, Vol. 48, No. 1-2, pp. 1–20.

Kulkarni, M., Rao, D. *et al.*, 2004. "Experimental investigation of various methods of tertiary gas injection". In *SPE annual technical conference and exhibition*. Society of Petroleum Engineers.

Nakano, C.M.F., Capeleiro Pinto, A.C., Marcusso, J.L., Minami, K. *et al.*, 2009. "Pre-salt santos basin-extended well test and production pilot in the tupi area-the planning phase". In *Offshore technology conference*. Offshore Technology Conference.

Rasmussen, A.F., Sandve, T.H., Bao, K., Lauser, A., Hove, J., Skaflestad, B., Klöfkorn, R., Blatt, M., Rustad, A.B., Sævareid, O. *et al.*, 2021. "The open porous media flow reservoir simulator". *Computers & Mathematics with Applications*, Vol. 81, pp. 159–185.

Rodrigues Filho, R.W.C., Fortaleza, E. and Rosa, A., 2020. "Análise da injeção alternada água-gás em malha de 5 pontos utilizando o OPM flow". In *XXVII Congresso Nacional de Estudantes de Engenharia Mecânica*. ABCM. doi:10.26678/abcm.creem2020.cre2020-0082. URL `https://doi.org/10.26678/abcm.creem2020.cre2020-0082`.

Rosa, A.J., de Souza Carvalho, R. and Xavier, J.A.D., 2006. *Engenharia de reservatórios de petróleo*. Interciência.

Skauge, A. and Stensen, J., 2003. "Review of wag field experience". In *Oil Recovery–2003, 1st International Conference and Exhibition, Modern Challenges in Oil Recovery*. pp. 19–23.

Sohrabi, M., Tehrani, D., Danesh, A. and Henderson, G.D., 2004. "Visualization of oil recovery by water-alternating-gas injection using high-pressure micromodels". *Spe Journal*, Vol. 9, No. 03, pp. 290–301.

Žižlavskỳ, O., 2014. "Net present value approach: method for economic assessment of innovation projects". *Procedia-Social and Behavioral Sciences*, Vol. 156, pp. 506–512.

8. RESPONSIBILITY NOTICE

The authors are solely responsible for the printed material included in this paper.