MODEL-BASED OPTIMIZATION OF CYCLES OF CO₂ WATER-ALTERNATING-GAS (CO₂-WAG) INJECTION IN CARBONATE RESERVOIR

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ABSTRACT
Pre-salt reservoirs are among the most important discoveries in recent decades due to the large quantities of oil in them. However, high levels of uncertainties related to its large gas/CO₂ production prompt a more complex gas/CO₂ management, including the use of alternating water and gas/CO₂ injection (WAG) as a recovery mechanism to increase oil recovery from the field. The purpose of this work is to develop a methodology to manage cycle sizes of the WAG/CO₂, and analyze the impact of other variables related to the management of producing wells during the process. The methodology was applied to a benchmark synthetic reservoir model with pre-salt characteristics. We used five approaches to evaluate the optimum cycle size under study, also assessing the impact of the management of producing wells: (A) without closing producers due to gas-oil ratio (GOR) limit; (B) GOR limit fixed at a fixed value (1600 m³/m³) for all wells; (C) GOR limit optimized per well; (D) joint optimization between GOR limit values of producers and WAG cycles; and (E) optimization of the cycle size per injector well with an optimized GOR limit. The results showed that the optimum cycle size depends on the management of the producers. Leaving all production wells open until the end of the field’s life (without closing based on the GOR limit) or controlling the wells in a more restricted manner (with closing based on the GOR limit), led to significant variation of the results (optimal size of the WAG/CO₂ cycles). Our study, therefore, demonstrates that the optimum cycle size depends on other control variables and can change significantly due to these variables. This work presents a study that aimed to manage the WAG-CO₂ injection cycle size by optimizing the life cycle control variables to obtain better economic performance within the premises already established, such as the total reinjection of gas/CO₂ produced, also analyzing the impact of other variables (management of producing wells) along with the WAG-CO₂ cycles.

KEYWORDS
production management; optimization of the WAG-CO₂ cycle size; pre-salt; life-cycle control rules; reservoir simulation

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1. INTRODUCTION

The pre-salt polygon is one of the largest oil provinces in the world; its importance is especially linked to the high productivity of producing wells. According to Beltrão et al. (2009), the main challenges are to build better models, projects, and forecasts with the available data. The author explains that there are three main categories related to these challenges: description and representation of the heterogeneities of rocks and fluids contained in the reservoir, selection of production strategy, and analysis of the future performance of the reservoir.

The process of choosing the production strategy is linked directly to the decision making involved in the development and management of the reservoir because, in these phases where the strategy is defined, the risks are high due to the countless uncertainties associated with the reservoir and with operational and economic conditions (Schiozer et al., 2019).

Gaspar et al. (2016) proposed to hierarchically order three groups of variables for evaluation when selecting a production strategy, according to their nature and importance, which are: project variables (G1), consisting of the development phase, such as the number and location of wells, platform capacity and drilling schedule; control variables (G2) of the management phase that determine the field operation; and the revitalization variables (G3) that are applicable in later phases, such as well completion.

Pre-salt reservoirs have a high gas/CO₂ production, which impacts the technical and economic complexity of the project. The depth, distance from the coast, and presence of contaminants in the gas/CO₂ require different technological solutions. One alternative is the WAG-CO₂ injection.

WAG injection aims to improve the sweep of gas injection, using water to control displacement mobility and maintain stability in the gas front. Some operational problems that are frequently reported include early advancement in producing wells, reduced injectivity, corrosion, and scale deposition. (Christensen et al., 1998). Therefore, the alternating water-gas injection process is used to optimize oil production and offers greater flexibility with the gas produced in many fields. The produced fluids contain some amount of CO₂ contaminant since the beginning of the design of the Tupi Production Pilot (Pizarro & Branco, 2012).

Interest in WAG injection in the pre-salt reservoirs has increased in recent years due to possible recycling and reinjection of the gas produced for oil recovery in these reservoirs. This reinjection of the gas produced in the WAG is a viable alternative for offshore operations due to the limitations in handling, storage, and transportation of the gas (Ligero & Schiozer, 2014).

Studies that aim to optimize oil production through the WAG process constantly report that WAG is an efficient EOR method. Valeev and Shevellev (2017), for example, provided an express method of assessing the ideal proportion of water and gas injection that results in significant effects, which can also be used to make design decisions during WAG operation planning in a given reservoir. In the work of Chen et al. (2010), NPV is defined as the objective function, while the controlling variables are chosen to be the injection rates, ratios of gas slug size to water slug size (WAG ratio), and cycle time for the injectors and bottom hole pressures (BHPs) for the producers.

Jeong et al. (2014) investigated the effects of the reservoir and the most important operational parameters in the WAG process. In this process, the authors highlighted the WAG ratio, well patterns, and the heterogeneities of the reservoir. In reservoirs with different heterogeneities and correlation lengths, these parameters must be used to find the ideal design of the WAG process since the optimal WAG ratio changes according to the heterogeneity level of the reservoir.

Pal et al. (2018) evaluated the water-alternating-hydrocarbon-gas injection (HC-WAG) production and optimization strategy based on several parameters related to the management (operation) phase. The main parameters of the evaluation were the GOR restriction, size of the WAG cycle, composition of the injected gas, and the overall size of the project concerning its economic performance.

The objective of this work is to develop a methodology to manage the size of the cycle of water-alternating-gas/CO₂ injection based on a production strategy, focusing on the control variables in the reservoir management phase optimization.
2. METHODOLOGY

The proposed methodology aims to optimize the size of the WAG-CO₂ cycle, also verifying the influence of the management of producing wells in the process (in this work, this is done by closing the wells with high GOR content) and analyzing the impact on operational and economic indicators. Gas-Oil Ratio (GOR) is an output variable from the simulator that indicates the amount of gas/CO₂ produced with the oil. The GOR is used as a monitoring variable; once a specified limit is exceeded, the well is closed.

For this, five approaches were studied, each having a different way of managing the production wells. Each approach was divided into two or more stages, according to the discretization of the sizes of the cycles tested, as described below:

A. Without closing producers due to GOR limit
   • Cycles from 2 to 60 months discretized every 2 months
   • Cycles of 60 to 312 months discretized every 1 year

B. GOR limit at a fixed value at 1600 m³ / m³ for all wells
   • Cycles from 2 to 60 months discretized every 2 months
   • Cycles of 60 to 312 months discretized every 1 year

C. Optimization of the GOR limit per well (using WAG cycles of 6 months) and later optimization of the WAG cycles
   • Cycles of 2 to 60 months discretized every 2 months
   • Cycles from 60 to 312 months discretized every 1 year

D. Joint optimization of the GOR limit of producers and WAG cycles
   • Cycles of 3 to 24 months discretized every 3 months
   • Cycles of 24 to 60 months discretized every 6 months
   • Cycles from 60 to 180 months discretized every 1 year

E. Optimization of cycle size per injection well with an optimized GOR limit in approach D
   • Cycles of 3 to 24 months discretized every 3 months
   • Cycles of 24 to 60 months discretized every 6 months
   • Cycles from 60 to 180 months discretized every 1 year

It is noteworthy that, after 156 months (13 years), there were no longer effective "cycles", but only an injection fluid change during the productive life of the field. However, for simplicity, we also refer to these periods as cycles. Thus, the methodology covers a greater number of possibilities to be analyzed (short and long cycles), together with the possibility of closing wells for better field performance.

In approaches C, D, and E, the optimization is done through the IDLHC (Iterative Discrete Latin Hypercube) algorithm. IDLHC is a method that was developed by Maschio and Schiozer (2016) based on an automated probabilistic method to reduce uncertainties and update the probability of uncertain attributes with non-parametric density estimation, being used for data assimilation and historical adjustment. Hohendorff Filho et al. (2016) adapted the same method for the production strategy optimization context, in which the objective is to maximize the objective function. The procedure consists of gradually reducing the search space in each iteration, making the appropriate treatment of the subsequent frequency distributions of levels of discrete variables.

In approach E, we maintained the conditions for the GOR limit of the best solution of approach D, and optimized all the injection wells (one by one) hierarchically. The wells were optimized by order in which they were opened. Still, in approach E, we re-optimized the GOR limit (IDLHC method) to verify the consistency and the possible change in the value for well closure through the GOR limit with the result of different cycles obtained in approach E.

2.1 Assumptions

Premises were considered as a rule of life-cycle control:
   • Total reinjection of the gas/CO₂ produced;
• Maintenance control of the average reservoir pressure at 61,000 kPa through water injection;
• Objective-function: NPV (net present value), calculated using the sharing regime (Marques et al., 2014).

3. APPLICATION

We performed this study on a benchmark synthetic reservoir with characteristics of the pre-salt reservoirs, such as nature of the reservoir (heterogeneous carbonate), type of fluid (light oil with high CO₂ content), and recovery process. The simulations were performed in the GEM (compositional) reservoir simulator from CMG (CMG - Computer Modelling Group Ltd., 2017). Figure 1 shows the grid top of the model.

For comparison purposes, our base-case has a WAG cycle fixed at 6 months and without monitoring the GOR limit in the producing wells. The opening schedule of producers and injectors was established in two waves, the first with the inclusion of six producing wells and seven injection wells; and the second (five years after the first) with the addition of two producing wells and two injection wells. Table 2 shows the attributes being studied, the size of the WAG cycle in the injection wells, the GOR limit in the producing wells, and the respective variability. Table 3 describes the main operational restrictions for the wells. Table 4 shows the conditions of production capacity and injection of the platform. Finally, Table 5 shows the economic data used in the NPV calculations.

Table 1 shows some information about the field model.

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Table 1. Information of model studied.

| Model Data                  | SEC1_2022                      |
|-----------------------------|-------------------------------|
| Grid blocks (I, J, K)       | 63 x 120 x 309                |
| Average depth (m)           | 5,543                         |
| Number of wells             | 8 producers; 9 injectors       |
| Permeability (mD)           | 0 to 7,000 (av.~400)          |
| Porosity (%)                | 0 to 0.3 (av. ~0.1)           |
4. RESULTS AND DISCUSSIONS

The following results are presented in the same order as the approaches introduced in the Methodology section. Figure 2 shows approaches A, B, and C. In approach A (without producer’s shutdown), there is a decrease in the NPV when the size of the cycles is increased because the reservoir tends to saturate more quickly with gas/CO₂, negatively impacting oil production. In approaches B and C, there is an increase in NPV with longer cycles, showing that the control of producing wells by the GOR limit directly influences the choice of the cycle, which is even more significant than the cycle itself.

The GOR limit in approaches B and C showed that the management in producer wells has its specificities because the conditions imposed to one producer (fixed GOR limit for all producers, for example) will not necessarily be the best management for the other. As shown in Figure 2, higher NPVs were obtained when the GOR limit for each producer was monitored and managed with the cycle size. In this optimization process, it is
important to highlight that, especially when optimizing the size of the WAG cycle, it is impossible to optimize isolated parameters without considering factors such as the behavior and the management of the producers. In Figure 3, we show the optimization by the IDLHC method of the GOR limit with the canned cycle in 6 months.

In Figures 4 and 5, there is a clear improvement when optimizing the GOR limit per well along with the cycle size (Figure 4). Unlike approach C, in which the optimization of the GOR limit occurred in a 6-months cycle size for all injectors, the optimization of the cycle-size and the GOR limit in approach D occurred simultaneously. In this case, the best result was the case with the cycle size of 180 months (15 years), which is not a cycle itself, but the management of injectors, with a fluid exchange during the field’s life cycle, as already mentioned. Figure 5 shows the optimization by the IDLHC method of the GOR limit along with the different sizes of the cycle.

Figure 6 shows the results of the optimization of the cycle size per well (approach E – optimal solution). We observe that three injectors had their cycle size reduced when compared to approach D (all injectors with the same cycle). After obtaining these results, we re-optimized the GOR limit of the producers, since the conditions reached from the previous optimization have changed. We observed a 2.2% increase in NPV compared to approach D and a 9.5% increase relative to the base case.

This is the result of a set of factors that impacted the production of the producing wells. The first is the proximity that these injection wells have to producer wells with a low GOR limit for closure; the second is the increase in the volume of water injected in these injectors with smaller cycles, providing more efficiency in the maintenance of the pressure in the reservoir; and the third is the decrease in the volume of injected gas/CO₂ in these injection wells, causing the reservoir to be gradually saturated with gas/CO₂.
It is common to adopt relatively short WAG cycles (3, 6, and 12 months) (Mello et al., 2013; Diniz, 2015; Pal et al., 2018; Rodrigues et al., 2019), in contrast to the optimal solution of this work, which resulted in longer cycles. Thus, it is important to test alternatives to avoid sub-optimal solutions.

Figure 7 shows an improvement in oil production from the base case to the optimum solution, in which the oil production was hastened/accelerated over the productive life of the field.

Figure 8 shows that the optimal solution does not necessarily have to use all the gas/CO$_2$ storage capacity to reach the best NPV, unlike the base case, which was considered during the entire production, but with a lower NPV. This shows that good gas/CO$_2$ management is the best way to achieve better economic performance.

The production and injection of water from the reservoir increased considerably (Figures 9 and 10) in the optimal solution, reflecting in the maintenance of the average pressure of the reservoir and also in the increase in oil production.

This is due to the configuration of the injection wells that enter the WAG period. The first configuration occurs with the entry of 3 water injector wells with cycles of 180 months (15 years of injection) and 4 gas injector wells (1 well with 180 months and the others with short cycles 3, 6, and 12 months of injection). When the duration of these long cycles end, the injection fluid alternates. The high volume of water injected at the beginning of the WAG makes a better sweep of the reservoir (4000 to 8000 is when the largest oil production occurs in the field in the optimal case) compared to the base case.
Figure 8. Gas production rate of the field: Base case and optimal solution.

Figure 9. Oil production rate of the field: Base case and optimal solution.

Figure 10. Water injection rate of the field: Base case and optimal solution.
Water injection was important to reach the optimal solution, as already mentioned. In Figure 11, we show a subtle upward trend in NPV with the increase in the volume of injected water.

What explains this trend is the better sweeping in the center of the reservoir, since most of the injectors are found at the edges, mainly impacting the increase in oil production of two producing wells (P16 and P17).

5. CONCLUSIONS

The main objective of this work was to optimize the size of the WAG cycles, verifying the influence of the management of the producing wells through the closure of the wells. We used the GOR limit as a monitoring variable, while analyzing the impact on operational and economic indicators.

The reservoir, without a GOR limit for producing wells, tends to saturate more quickly with gas/CO₂ injection, while wells that have a GOR limit experience a maximized production and a higher projected revenue (NPV). This effect has an influence on the management of the cycles, as shown in the results.

We demonstrated through the study that the optimum cycle is dependent on other control variables, and can change significantly due to them. Therefore, we recommend the application of an optimization process that considers the cycle size along with other control variables to achieve the best field performance possible.

For the case studied, the optimal solution was based on the control of gas production optimized for each well, resulting in very different cycles depending on the well, unlike what is practiced in many cases reported by the industry, where 6-month cycles are used. Three wells resulted in shorter cycles, while the others presented very long cycles (only one fluid change during the field life cycle), showing that there is no general rule to determine the ideal cycle size, and, hence, we need to optimize each case.

Most authors adopted a relatively short WAG cycle size (3, 6, and 12 months) and with the same duration for all injection wells. In these cases, we recommend an evaluation of other possibilities to avoid working with suboptimal solutions. We have shown that each case requires a different study, possibly resulting in different cycle sizes to optimize each case.

The complexity of the reservoir must be considered and a number of studies must be performed before deciding on new forms of management throughout the productive life of the field, clearly defining the objective function of the study.

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