Research Article

# Application of proxy model to optimize base gas replacement by smart gas in underground gas storage process

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**Abstract**
One way to reduce the costs of investment in underground natural gas storage processes is to replace a portion of the base gas with a cheap gas. Optimizing the replacement amount of the base gas is one of the most attractive issues as mixing between the replaced base gas and the working gas and exceeding the injection pressure above the formation fracturing pressure are the two important phenomena that can occur and limit the amount of base gas replacement. In the present study, the concept of smart gas is applied to alleviate the encountered limitations during base gas replacement. Smart gas is referred to as the gas, the composition of which is adjusted so as to obtain the maximum amount of the base gas replacement. In the present work, dry air is used as the candidate gas to study the base gas replacement process in a depleted gas reservoir. Due to the fact that execution of a large-scale compositional reservoir simulator incorporated with an optimization algorithm is a time-consuming process, in order to calculate the optimum composition of the candidate gases, a proxy model is applied as a computationally inexpensive alternative to full numerical simulation. The results reveal that the composition of $CO_2$ in air is an important parameter in controlling mixing between the candidate base gas and the working gas, while maintaining the injection pressure below the fracturing pressure of the formation. In addition, when the $CO_2$ composition exceeds a specific value (40.95% in the modified air), the pressure that is required for gas production at a target rate cannot be supplied. The optimization of the $CO_2$ composition in the candidate gas employing the proxy model shows that it is possible to replace 28.4% of the base gas and reach an enhanced gas recovery of about 18.55% in the reservoir under study using the optimized $CO_2$ composition of 20.08% in the modified air as the replacing gas.

**Keywords** Base gas · Carbon dioxide · Optimization · Proxy model · Underground gas storage (UGS)

## 1 Introduction

Among energy carriers, natural gas is an abundant resource that has the highest rate in the energy consumption until 2040 and is the first source of electricity generation [1]. Natural gas is considered as a clean fuel and its $CO_2$ emission rate, per unit energy produced, is 60% and 20% less than that of coal and oil, respectively [2]. Hence, it is necessary to provide a stable natural gas supply. Storage is a way to ensure the supply of natural gas in any circumstances. Underground gas reservoirs have been proved as economic and safe locations to storage gas [3]. Depleted oil and gas reservoirs or saline aquifers can be used as underground gas storage complexes [4]. Nonetheless, depleted oil and gas reservoirs are the most appropriate and attractive candidates for underground gas storage [5]. In this process, the extra natural gas is injected into a depleted oil or gas reservoir to response to the high consumption load demand in high consumption seasons [6].

The volumetric categories of the gas contained in underground gas storage reservoirs are as follows [7]:

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- Base gas, referred to as the part of the contained gas that should be remained in the reservoir to maintain the reservoir pressure and the production possibility at the planned target rate during the production cycles.
- Working gas, referred to as the part of reservoir gas that is produced and injected seasonally and becomes available for sale.

Based on the type of underground gas storage reservoir, base gas consists of 15–75% of the total gas contained in the reservoir gas [8]. Due to the large volume of the base gas in the reservoir, it contributes about one-third to half of the investment costs [8]. One way to reduce this cost is to replace a part of the base gas with the less expensive gas such as nitrogen or carbon dioxide [9]. This replacement can affect the produced gas quality due to the mixing between the replaced base gas and the working gas [10]. The mixing amount of the gases should be controlled.

In 1972, for the first time in France, total volume of synthesis working gas and 40% of synthesis base gas were replaced by natural gas [8]. In 1979 in St. Claire aquifer, located in France, nitrogen gas was injected in the southern part of the aquifer as 20% of the base gas [11]. Laille et al. [12] investigated the changing of a low BTU gas in Cerville-Velaine storage aquifer to a high BTU gas and replacement of the base gas with nitrogen. In 1986, in the USA, the possibility of base gas replacement was investigated in Hanson depleted gas field by injecting 400 million cubic feet nitrogen [8]. Labune and Knudsen [13] investigated the replacement of 20% of base gas by nitrogen in Tonder aquifer. In 1989, in St. Illier project, 20% of base gas was replaced by nitrogen in a sandstone reservoir [14]. Kilincer and Gumrah [15] studied the replacement of base gas and mixing problems in a depleted gas reservoir by coupling a 2-D reservoir simulator and the transfer model. Oldenburg [10] investigated the replacement of base gas with carbon dioxide in a part of a depleted gas reservoir. In 1995, the Wierzchowice low-quality reservoir, including 29% nitrogen, 70% methane and 1% $C_2^+$, was changed to a natural gas storage reservoir [16]. Kim et al. [17] compared the replacement of base gas by nitrogen and carbon dioxide in a depleted gas reservoir. Ansari et al. [18] investigated underground natural gas storage in a low-quality reservoir including 85% nitrogen. Juez-Larré et al. [19] investigated the ultimate potential of underground gas storage capacity of the Netherlands. They performed a detailed feasibility study on inflow performances of all onshore natural gas reservoirs. Lawal et al. [20] suggested injecting the associated gas into underground geologic systems for temporary storage, but re-producing same when a viable gas market becomes available. Associated gas is the natural gas found with crude oil either dissolved in the oil or exists as a free gas cap above the oil in the reservoir [21]. Lawal et al. [20] found that underground storage in a virgin gas reservoir is the most attractive solution to address the associated gas in their example field.

Finding a solution for increasing the amount of base gas replacement is one of the most attractive issues in underground natural gas storage process. However, mixing of the replacing base gas and the working gas is one of the limiting factors in achieving the desired amount of the replacement as the quality of the produced gas is inappropriately affected by the mixing phenomenon. Therefore, the composition of the replacing base gas can be optimized so as to obtain the efficient amount of the gas replacement. To achieve this goal, in the present study, a proxy model is used to calculate the optimum composition of the candidate smart gas. The concept of the smart fluid is used where the fluid composition is adjusted to achieve the optimum performance of the studied process. Smart water, for example, is used for enhanced oil recovery by adjusting the ionic composition of the injected water [22]. In this study, air is used as the smart gas, the compositions of which is varied so as to obtain the maximum amount of the base gas replacement in a depleted gas reservoir. The proxy model is used as an alternative to the simulation model as the execution of a large-scale compositional reservoir simulator is a time-consuming process during the optimization procedure. Proxy model is a mathematical relationship, which is capable of replacing the simulator by imitating the relationship between inputs and outputs of the simulation model. Due to its simplicity, the proxy model reduces the number of the simulation runs and hence, the time required to find the optimum case [23].

## 2 Methodology

In order to study the optimum composition of the smart replacing base gas with the aid of a proxy model, the GEM module of CMG simulator has been used for the simulation of the underground gas storage process. The prediction of the phase behavior of the reservoir fluid and equation of state (EoS) tuning has been made applying the WinProp module of the CMG software. The depleted gas reservoir, explored in 2001 by drilling the first well, has 186 BSCF initial gas in place. The initial pressure and temperature of the reservoir at the datum depth of 5565 feet subsea is 2075 psia and 155 °F, respectively. The reservoir porosity varies in the range of 0.13–0.27 with the average value of 0.21. The permeability of the reservoir is in the range of 14–42 mD, the average value of which is obtained as 23.7 mD. There is no indication of the existence of the water–gas contact and aquifer. Formation fracturing gradient and gas specific gravity of reservoir are 0.68 psi/ft and 0.603, respectively. The reservoir was discretized by the Non-Orthogonal Corner Point grid into $14 \times 100 \times 4$ grid blocks in the *x*, *y* and *z* directions, respectively. The three-dimensional view of the reservoir with the specified locations of the initial wells is shown in Fig. 1.

### 2.1 Building the static model

The static model is a three-dimensional geological model of the reservoir. In order to construct the static model of the reservoir, Builder Module of the CMG software has been used. For this purpose, the underground contour (UGC) map (Fig. 2) is required. The output of the static model is used as the input for building the dynamic model. Therefore, the accuracy of the static model is of great importance in that it affects the accuracy of the dynamic model.

### 2.2 Fluid characterization and building the dynamic model

Due to the difference between the compositions of the injection gas and the reservoir gas, and the occurrence of mixing phenomenon during underground gas storage, GEM compositional simulator has been used. The output of the phase behavior prediction software, i.e., WinProp, is used as the input to the GEM simulator. The three-parameter Peng-Robinson equation of state (1976) has been used for predicting phase behavior of the reservoir fluid. The initial composition of the reservoir fluid and that of the storage gas is given in Table 1. Based on the initial conditions of the reservoir, the reservoir fluid is of dry gas type. Therefore, during the course of production only gas is produced. The outputs of the WinProp software and relative permeability data (Fig. 3) as well as initial temperature and pressure of the reservoir were used as input data to the compositional simulator to construct dynamic model. All the wells along with their production rates and time schedules were also defined in dynamic the model.

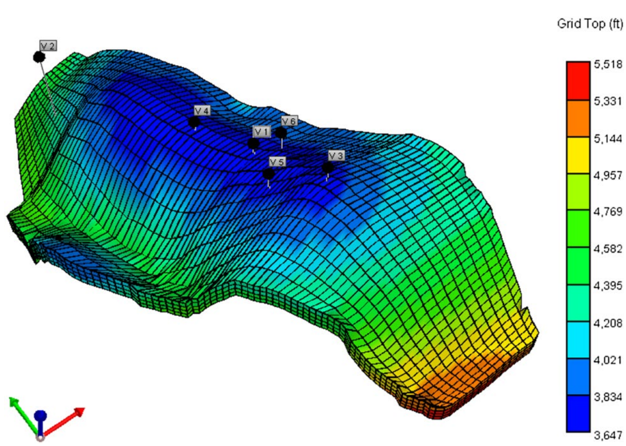


Fig. 1 Three-dimensional view of the reservoir and the location of the initial wells

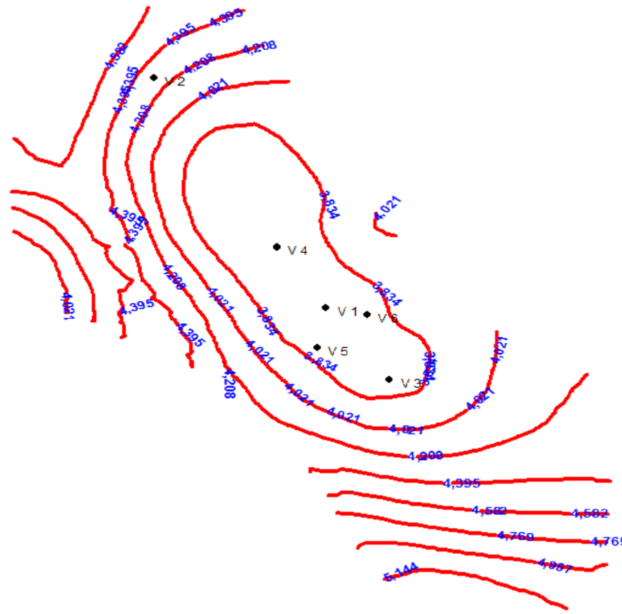


Fig. 2 Underground contour map of the reservoir

### 2.3 History matching initial reservoir depletion phase

Totally, five wells produced until 2008. During the 5-year history of the reservoir, the gas production reached 55235 MMSCF, which is equivalent to 29.7% of the initial gas in place. Due to the undesired production conditions, Well V2 was closed. History matching has been implemented using the observed wellhead pressure and the cumulative production data. In order to get the best match to the

Table 1 Initial composition of the reservoir fluid and the storage gas (injected gas)

| Component | Initial reservoir fluid (mol%) | Storage gas (mol%) |
|---|---|---|
| $N_2$ | 2.28 | 2.00 |
| $CO_2$ | 1.15 | 0.06 |
| $C_1$ | 91.45 | 95.50 |
| $C_2$ | 3.21 | 2.40 |
| $C_3$ | 1.21 | 0.04 |
| $i\text{-}C_4$ | 0.24 | 0 |
| $n\text{-}C_4$ | 0.30 | 0 |
| $i\text{-}C_5$ | 0.09 | 0 |
| $n\text{-}C_5$ | 0.07 | 0 |

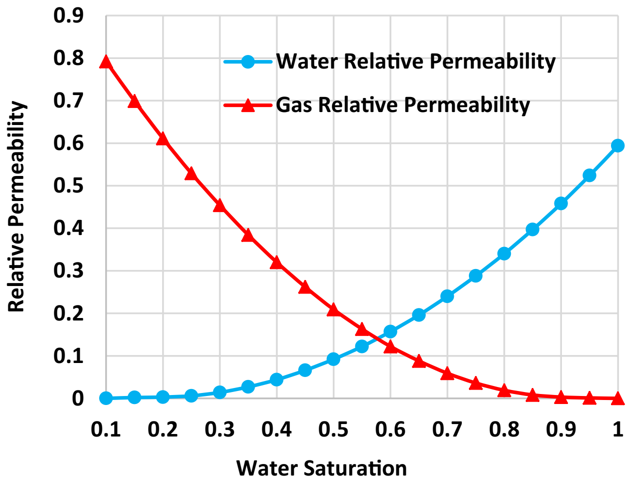


**Fig. 3** Relative permeability curves of gas and water phases

observed data, permeability and porosity of the reservoir have been used as the adjustable parameters. Figure 4 shows a comparison between measured (observed) and simulated data of the cumulative gas production from different wells. A comparison between the observed and simulated data of the wellhead pressure is also given in Fig. 5 for different wells. The history matched model is used to implement different scenarios regarding the gas storage process.

## 3 Results and discussion

### 3.1 Reservoir fast depletion scenario

In this scenario, the fast depletion of the reservoir is implemented. For this purpose, five horizontal wells, in addition to the current vertical wells, are added to the reservoir model. The position of the new wells is determined based on saturation and pressure distributions at the end of the production history, the distance between the neighboring wells and the geological structure of the reservoir (Fig. 6).

The base pressure of the reservoir is 1350 psia. The determination of the minimum base pressure should be the result of a trade-off between the necessity to satisfy the operator requirements and to preserve, on the long term, the performances of the reservoir. As a rough guideline, if it is assumed a minimum pressure of 60 bar (870 psia) at the pipeline input of the gas company, and maximum pressure losses of 10 bar (145 psia) and 20 bar (290 psia), respectively, on the surface and in the wells, the minimum wellhead pressure of 70 bar (1015 psia) and the bottom hole pressure of 90 bar (1305 psia) are required. In this condition, the average reservoir pressure will be 1350 psia at the end of the depletion scenario. According to the determined base pressure, the total production rate of the reservoir is considered as 6.5 MMSCF/D during the fast depletion scenario, which is kept constant for 4 years. Because of the low initial pressure of the reservoir, the gas recovery of the reservoir is low, the value of which is calculated as 34.71% at the end of the fast depletion scenario.

### 3.2 Determination of the optimum injection and production rates

If the deliverability rate of a storage gas reservoir is less than the expected rate, the storage operation will not be profitable. The optimum injection rate is defined as the maximum possible constant injection rate at which the formation and the cap rock do not break down and leakage does not occur through the formation rock. In order to obtain the optimum injection rate, different scenarios are implemented in a manner that the cumulative produced gas during the 5 months of the cold season, from November to March, becomes equal to the cumulative injected gas during the 6 months of the hot season in each cycle. Among many different implemented scenarios, the reservoir injection and production rates of, respectively, 220 MMSCF/D and 268.4 MMSCF/D are selected as the optimum rates during the injection and production periods of the storage process. During the injection cycles, maximum injection rate and maximum injection bottom hole pressure in each well was set to 40 MMSCF/D and 2310 psia, respectively. In addition, maximum production rate and minimum bottom hole pressure in each well was set to 50 MMSCF/D and 1305 psia, respectively, during the production cycles. In order to achieve the determined production rate of 268.4 MMSCF/D, the reservoir pressure should reach at least 1776.79 psia during the injection period of the reservoir. This pressure is the minimum required reservoir pressure to reach the objective production rate in the subsequent implemented scenarios.

### 3.3 Underground gas storage schedule

The beginning of the injection is in the half of April in each year and the beginning of the production is from the November of the same year and this circulation continues to 7 cycles. In each cycle, all the wells are closed for 15 days between the injection and the production periods (totally 1 month).

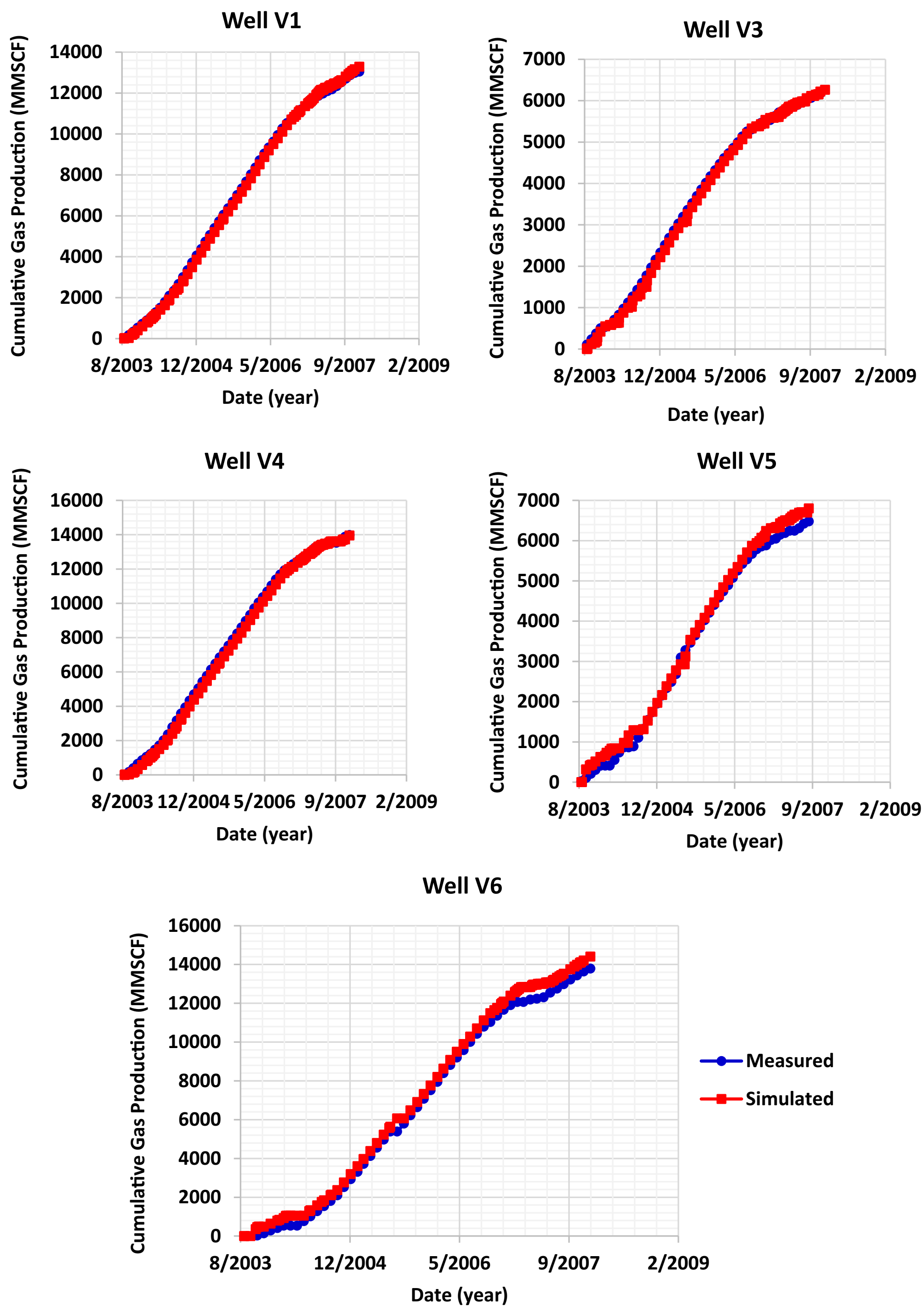


**Fig. 4** Comparison between measured (observed) and simulated data of the cumulative gas production from different wells in the history matched model

### 3.4 Base gas replacement strategy

In order to implement the base gas replacement scenarios, two new horizontal wells (IN-1 and IN-2), in addition to the eleven existing wells, are added in the lowest layer of the reservoir and outmost possible distance from the other wells so as to minimize the mixing of the inert gas and the natural gas (Fig. 6).

In addition, injection of the candidate gas is carried out in the odd cycles simultaneously with the storage gas injection to make its movement slower toward the production wells and reduce the mixing effects. Since the concentration of $CO_2$ and $O_2$ in the salable gas should not be more than 2% [24], and 1% [25], respectively, in the simulation model, the maximum allowable mole percentage of $CO_2$ and $O_2$ in the production gas from the wells is considered as 2% and 1%, respectively. In addition, total mole percentage of $CO_2$ and $N_2$ must be less than 7% [25]. Therefore, maximum allowable mole percentage of $N_2$ in the production gas from the wells

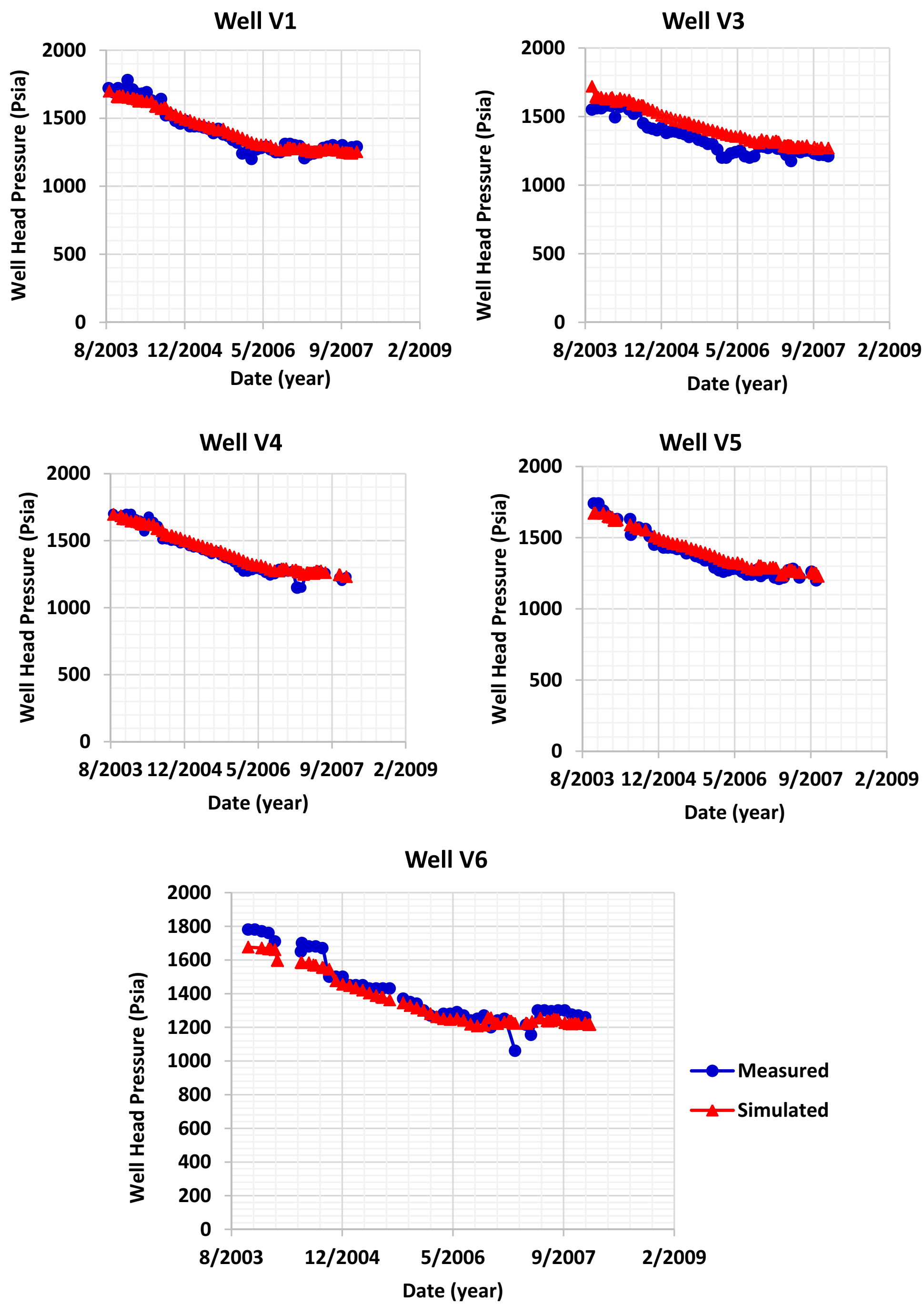


**Fig. 5** Comparison between measured (observed) and simulated data of the wellhead pressure for different wells in the history matched model

should not be more than 5%. Considering the capacities of the compressors in odd cycles, it is possible to replace the base gas with 21.4% of the total injection capacity (220 MMSCF/D), i.e., the air at the rate of 47.08 MMSCF/D. The amount of the replaced base gas is equal to the sum of the differences in the storage gas injected into the reservoir and the natural gas produced from the reservoir in different cycles. If in each of the four odd cycles, the replacement of the base gas is implemented according to the determined strategy, it is possible to replace 28.4% of the base gas and increase the recovery of the reservoir gas by 18.55%.

### 3.5 Replacement of base gas by air

The primary composition considered for air as the replacing base gas consists of 78 mol% $N_2$, 21 mol% $O_2$ and 1 mol% $CO_2$. If this composition is used to replace the base gas, due to very high viscosity of the air, a high injection pressure is required to inject air into the reservoir and the

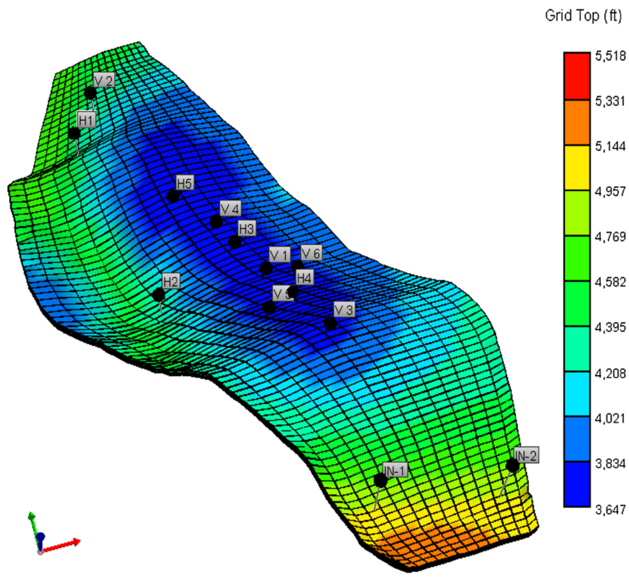


**Fig. 6** Location of the five new horizontal wells (H1–H5) for reservoir fast depletion scenario and two new horizontal wells (IN-1 and IN-2) in the lowest layer of the reservoir for injection of the lower-cost gas

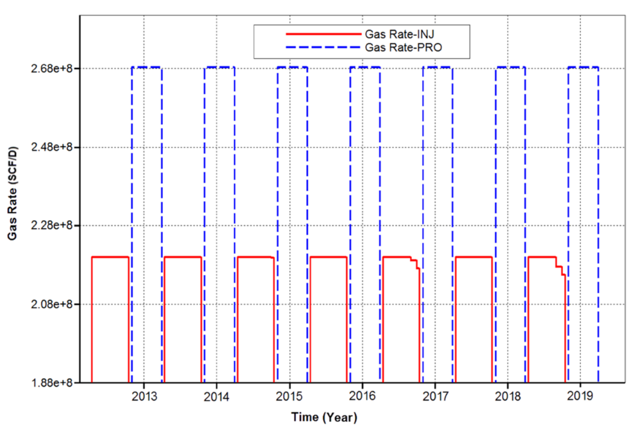


**Fig. 7** Injection and production rates of the gases during different cycles of gas storage process using air with the composition of 78% $N_2$, 21% $O_2$ and 1% $CO_2$

injection pressure exceeds the formation fracturing pressure. As Fig. 7 shows, when air is injected into the reservoir with the above-mentioned composition, the injection rate is reduced in Cycles 5 and 7, which is a result of the injection pressure increase above the formation fracturing pressure. Therefore, it is not possible to replace base gas in Cycles 3, 5 and 7. In this case, only 14.2% of the base is replaced by air in the first cycle. The gas recovery increases by 9.28% with respect to reservoir depletion scenario and the ultimate recovery reaches 43.99%.

To alleviate this problem and reduce the viscosity of the injection air, the composition of the injection air is adjusted so as to satisfy the pressure and composition constraints of the simulation model. The composition of the air should be adjusted by putting the flowing criteria:

1. The reservoir pressure should not fall below the minimum pressure of 1776.79 psia that is required to keep the production rate at the target value.
2. The composition of $CO_2$, $N_2$ and $O_2$ in the produced streams from the wells should not exceed its standard limitation.
3. The injection pressure should not exceed the formation fracturing pressure. Given the formation fracture gradient of 0.68 psi/ft and the reservoir top of 3773 ft, the estimated formation fracturing pressure is 2566 psia. However, it is more appropriate to consider safety margins to reflect uncertainties in the formation fracture gradient. Hence, it is typical to limit the allowable fracturing pressure to 90% of its estimated value. For this reason, the cap rock fracturing pressure is set to 2310 psia.

In order to optimize the composition of the air, the constructed compositional simulation model should be applied. However, due to the large number of grid blocks and the compositional nature of the simulation model, the optimization in this way is a time-consuming process as the simulator should be executed many times to find the optimum composition. To alleviate this problem, a proxy model is used in the present study. The proxy model creates a mathematical relationship between inputs and outputs of the simulation model, which has the capability of being used instead of the simulator. In this way, the number of executions of the simulation is reduced efficiently and hence, the optimum composition can be found in the fastest and simplest way. The proposed proxy model for the reservoir under study is as follows:

$$Y = a + bX + cX^2 + d\ln(X+1) + eX^{0.9} + f\exp\left(X^{0.5}\right) \quad (1)$$

where $X$ and $Y$ are inputs and outputs, respectively.

At the first stage, the reservoir pressure constraint required to maintain the target production rate is investigated. Assuming that the $CO_2$ molar composition in the air is constant at 1%, due to the drying effects of both $N_2$ and $O_2$, in different composition ranges of these gases, the reservoir pressure always remains above the minimum required pressure to keep the production rate at the target value. It should be mentioned that the minimum required pressure of the reservoir is sufficient to satisfy the reservoir pressure constraint during gas injection process. However, the high viscosity of oxygen in air with different compositions does not allow to inject air at the constant predetermined value as it requires higher injection pressure than the formation fracturing pressure. In this condition, the injection rate

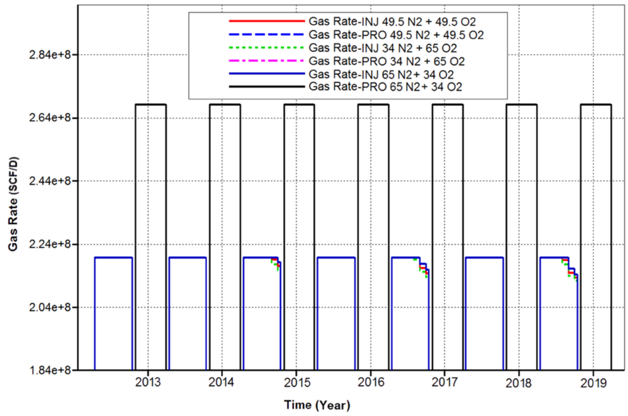


**Fig. 8** Injection and production rates of the gases during different cycles of gas storage process using air with three different compositions of $N_2$ and $O_2$, keeping the $CO_2$ composition constant at 1%

decreases automatically by the software to keep the injection pressure constant somewhat below the formation fracturing pressure. As a result, variation of the air composition while keeping carbon dioxide composition constant in the air does not provide appropriate conditions for substitution of the base gas in each of the four air injection cycles (Fig. 8).

Therefore, the appropriate conditions of the gas storage process can be achieved by variation of the $CO_2$ composition in air as carbon dioxide has different viscosity and density behavior from $O_2$ and $N_2$. Due to the low viscosity of $CO_2$ and its wetting effect, in order to reduce the viscosity of air and maintain the reservoir pressure at the constraint value (i.e., the minimum pressure required for gas production at the target rate), the composition of carbon dioxide in air is varied by keeping the oxygen composition constant. In this way, the maximum possible carbon dioxide composition can be obtained so as to transfer the maximum amount of $CO_2$ to underground while assuring that the main criteria of the gas storage are met. For this purpose, and due to the time-consuming nature of the compositional simulation, again the proxy model is applied, in this case, using the data of $CO_2$ composition in the replacing gas as inputs and the reservoir pressure as outputs of the simulation model. These data, which are given in Table 2, are used to obtain the parameters of the proxy model.

The interpolating function and the parameters of the model are shown in Fig. 9 and Table 3, respectively. The accuracy of fitting is investigated using the revised correlation factor ($R^2$adj) and sum of squared errors (SSE). The revised correlation factor shows the correlation of the output variables using the proxy model and the simulation model [26]:

$$R^2\text{adj} = 1 - \frac{\text{SSE}(n-1)}{\text{SST}(n-m)} \tag{2}$$

**Table 2** Reservoir pressure in the gas storage process for the specified values of the $CO_2$ molar composition in the replacing injection gas using the simulation model

| $CO_2$ mole percent in the replacing gas (input) | Reservoir pressure (psia) (output) |
|---|---|
| 0 | 1790.46 |
| 15 | 1786.24 |
| 30 | 1781.34 |
| 45 | 1775.61 |
| 60 | 1768.85 |
| 75 | 1760.62 |
| 79 | 1758.09 |

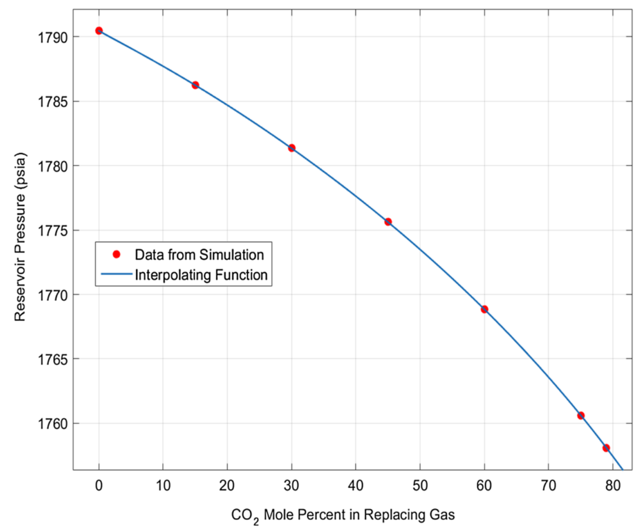


**Fig. 9** Interpolating function based on the proposed proxy model using the data given in Table 2

**Table 3** Proxy model constants and interpolation error for the simulation data of Table 2

| Constants of the proxy model | |
|---|---|
| *a* | 1790 |
| *b* | −0.3374 |
| *c* | $-1.39\times10^{-3}$ |
| *d* | $-9.43\times10^{-2}$ |
| *e* | 0.1255 |
| *f* | $-4.14\times10^{-4}$ |
| Error | |
| SSE | $9.307\times10^{-6}$ |
| Adjusted $R^2$ | 0.99999994 |

where $n$ is the number of response values and $m$ is the number of fitted coefficients estimated from the response values. SSE is sum of squared errors and defined as the following [26]:

$$SSE = \sum_{i=1}^{n} w_i \left( y_i - \hat{y}_i \right)^2 \quad (3)$$

where $n$ is the number of data points, $y_i$ is the $i$th output variable of the simulation model, $\hat{y}_i$ is the $i$th output variable of the proxy model. $w_i$ is the $i$th weighting factor applied to each data point and is set to unity. SST is total sum of squares, defined as follows [26]:

$$SST = \sum_{i=1}^{n} w_i \left( y_i - \bar{y}_i \right)^2 \quad (4)$$

where $y_i$ is the value of the $i$th output variable, $\bar{y}_i$ is the mean value of the output variables. The values of the $R^2$adj and SSE, obtained using interpolation of the simulation data of Table 2 applying the proposed proxy model, are shown in Table 3.

After determining the constants of the proposed proxy model, excel solver optimization tool is applied [27] to obtain the molar composition of $CO_2$ in the injection air so that the reservoir pressure reaches the constraint value of 1776.79 psia. According to the results, the optimum composition of the replacing injection gas contains 38.05% $N_2$, 21% $O_2$ and 40.95% $CO_2$. Due to the fact that the composition of air is significantly changed with respect to its original composition, from now on, "replacing gas" is used instead of "air" to represent the base gas replacement process. Implementing the simulator using this composition, the reservoir pressure is obtained as 1777.25 psia, which indicates a relative error of 0.025% in predicting the reservoir pressure applying the proxy model. In this case, the injection and production rates of the gases during different cycles of the gas storage are depicted in Fig. 10.

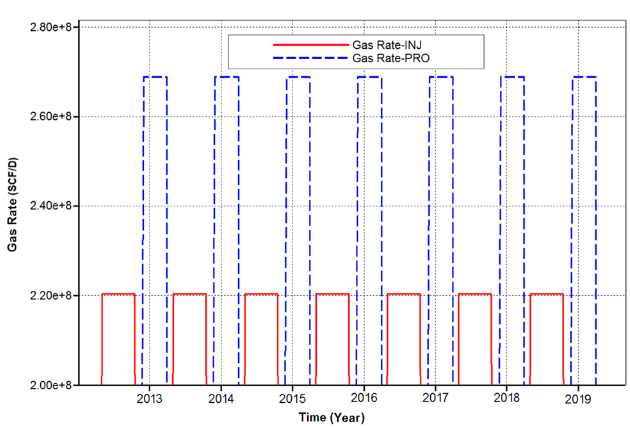


**Fig. 10** Injection and production rates of the gases during different cycles of gas storage process using the replacing gas with the composition of 38.05% $N_2$, 21% $O_2$ and 40.95% $CO_2$

As the figure shows, the reservoir pressure reaches the minimum pressure that is required to keep the production rate and production rate is maintained at a constant rate. When the carbon dioxide concentration in the replacing gas increases above 40.95 mol%, the wetting effect of $CO_2$ in the injected gas becomes dominant which along with its higher density, the injected gas is not able to maintain the reservoir pressure at the minimum required pressure for gas production at the target rate. Therefore, composition of $CO_2$ in the replacing gas should be at most 40.95%.

The simulation results using the replacing gas with molar composition of 38.05% $N_2$, 21% $O_2$ and 40.95% $CO_2$, also indicates that the molar composition of $CO_2$ in the produced gas streams from all the wells in the model, except Well V3, always remains below the standard criterion of 2%. In the case of Well V3, the molar composition of $CO_2$ in Cycle 7 exceeds 2% (Fig. 11). Figures 12 and 13

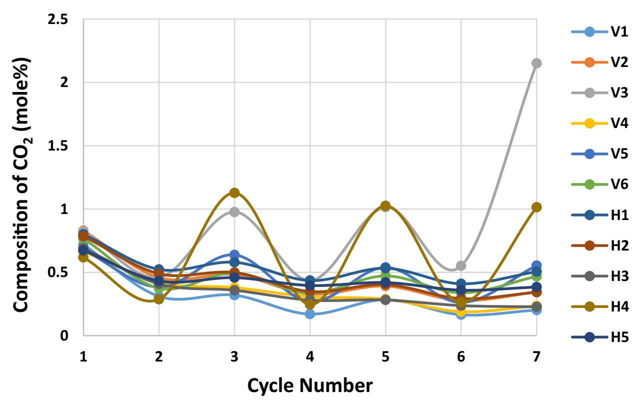


**Fig. 11** Composition of carbon dioxide in the produced gas streams from different wells during the gas storage cycles for the replacing gas with the composition of 38.05% $N_2$, 21% $O_2$ and 40.95% $CO_2$

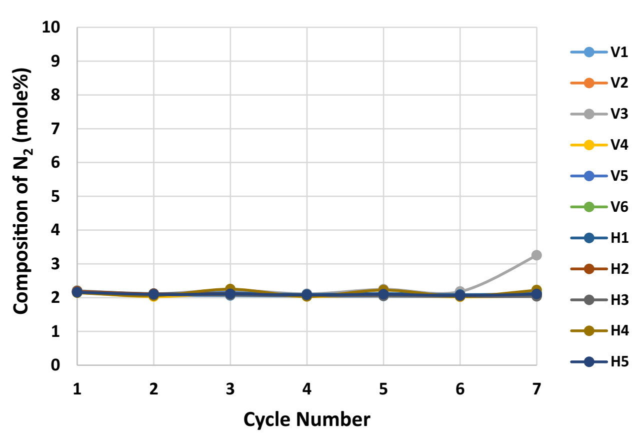


**Fig. 12** Composition of nitrogen in the produced gas streams from different wells during the gas storage cycles for the replacing gas with the composition of 38.05% $N_2$, 21% $O_2$ and 40.95% $CO_2$

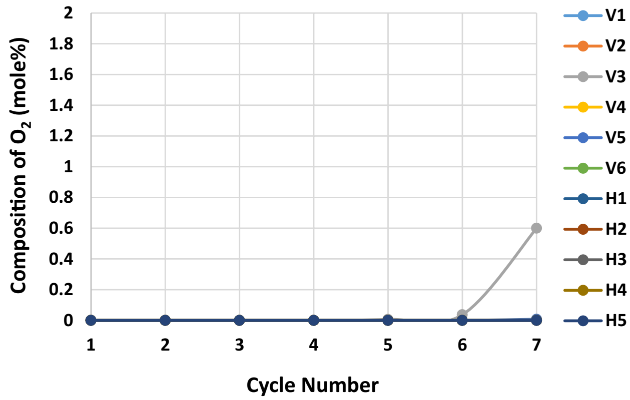


**Fig. 13** Composition of oxygen in the produced gas streams from different wells during the gas storage cycles for the replacing gas with the composition of 38.05% $N_2$, 21% $O_2$ and 40.95% $CO_2$

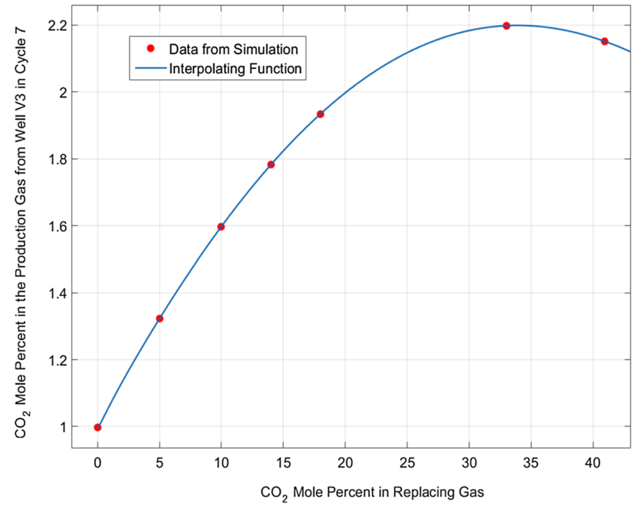


**Fig. 14** Interpolating function based on the proposed proxy model using the data given in Table 4

**Table 4** Molar composition of $CO_2$ in the produced gas stream from Well V3 in Cycle 7 for the specified values of the $CO_2$ molar composition in the replacing gas

| $CO_2$ mole percent in the replacing gas (input) | $CO_2$ mole percent in the produced gas from well V3 in cycle 7 (output) |
|---|---|
| 0 | 0.9968 |
| 5 | 1.3221 |
| 10 | 1.5967 |
| 14 | 1.7825 |
| 18 | 1.9337 |
| 33 | 2.1978 |
| 40.95 | 2.1507 |

**Table 5** Proxy model constants and interpolation error for the simulation data of Table 4

| Constants of the proxy model | |
|---|---|
| *a* | 0.9965 |
| *b* | 0.2501 |
| *c* | $-1.52\times10^{-3}$ |
| *d* | 0.1007 |
| *e* | $-0.2514$ |
| *f* | $3.23\times10^{-4}$ |
| Error | |
| SSE | $3.835\times10^{-7}$ |
| Adjusted $R^2$ | 0.999998 |

depict, respectively, the molar composition of $N_2$ and $O_2$ in the produced gas streams from different wells in the model. According to the figures, the molar composition of $N_2$ and $O_2$ in the produced streams always remains below their allowable values of 5% and 1%, respectively. Therefore, the composition of $CO_2$ in the replacing gas is adjusted in the range below 40.95 mol% to ensure that the constraint for the $CO_2$ composition in the produced gas stream from Well V3 is satisfied. This is accomplished using the proposed proxy model with the aid of the simulation model.

The simulation results of the $CO_2$ molar composition in the produced gas stream from Well V3 in Cycle 7 for the specified values of the $CO_2$ composition in the replacing gas are given in Table 4. The interpolating function and the parameters of the proposed model are shown in Fig. 14 and Table 5, respectively. As it can be seen from the results, the proposed proxy model accurately fits the simulation data (Fig. 14 and Table 5).

The proposed proxy model with the constants given in Table 5 is then used to calculate the optimum $CO_2$ composition in the replacing gas so that its composition in the produced gas from Well V3 does not exceed 2 mol% in Cycle 7 and the constraint for the injection pressure is satisfied. According to the results, the optimum composition of the replacing gas consists of 58.92 mol% $N_2$, 21 mol% $O_2$ and 20.08 mol% $CO_2$. In the $CO_2$ composition range below 20.08 mol%, whereas the constraints for the reservoir pressure and the produced gas stream composition are always met, the injection pressure increases above the formation fracturing pressure. In addition, the molar composition of oxygen and nitrogen in the production stream from Well V3 may exceed 1% and 5%, respectively.

As a result of these calculations, and due to the environmental benefits, the optimized molar composition of 58.92 mol% $N_2$, 21 mol% $O_2$ and 20.08 mol% $CO_2$ is the appropriate composition of the replacing gas in the gas storage process. Figure 15 shows the injection and production rates during gas storage cycles using the optimized composition. The molar compositions of $CO_2$, $N_2$ and $O_2$ in the produced gas streams from different wells in the

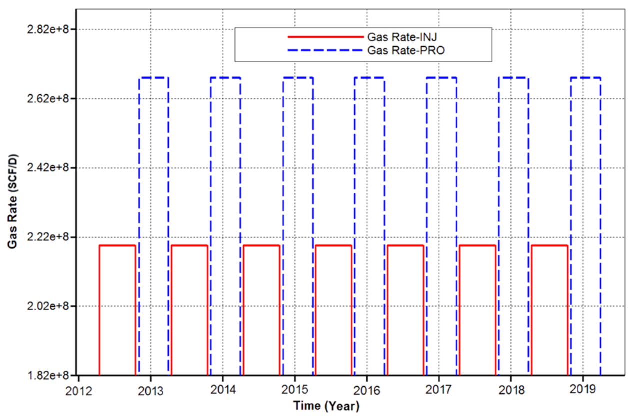


**Fig. 15** Injection and production rates of the gases during different cycles of gas storage process using the replacing gas with the composition of 58.92% $N_2$, 21% $O_2$ and 20.08% $CO_2$

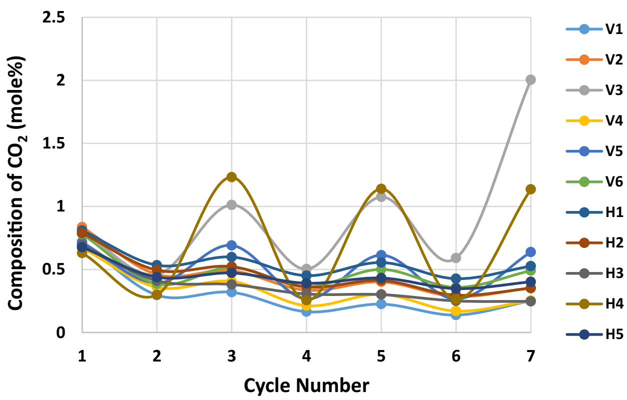


**Fig. 16** Composition of carbon dioxide in the produced gas streams from different wells during gas storage cycles for the replacing gas with the composition of 58.92% $N_2$, 21% $O_2$ and 20.08% $CO_2$

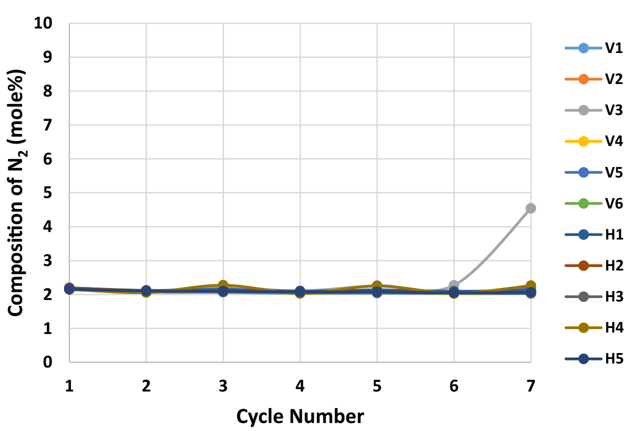


**Fig. 17** Composition of nitrogen in the produced gas streams from different wells during gas storage cycles for the replacing gas with the composition of 58.92% $N_2$, 21% $O_2$ and 20.08% $CO_2$

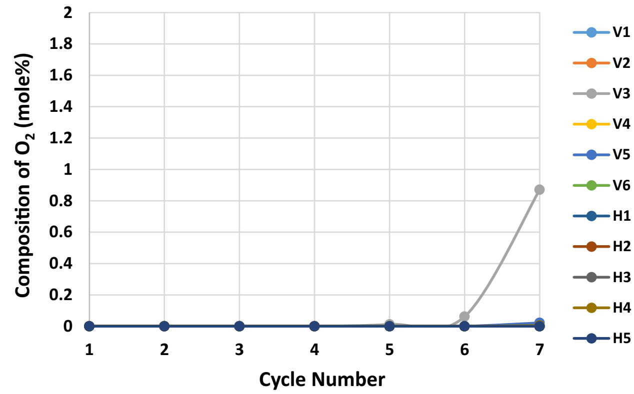


**Fig. 18** Composition of oxygen in the produced gas streams from different wells during gas storage cycles for the replacing gas with the composition of 58.92% $N_2$, 21% $O_2$ and 20.08% $CO_2$

simulation model are depicted in Figs. 16, 17 and 18, respectively. According to the simulation model results, the molar composition of $CO_2$ in the produced gas from Well V3 is 2.004%, which again confirms the high accuracy of the proposed proxy model with a relative error of 0.2% with respect to simulation result. As the figures show, all the constraints that were defined in the gas storage process are satisfied when the optimized composition of the replacing gas is used as input to the simulation model (Figs. 15, 16, 17, 18). In this case, 28.4% of the base gas is replaced by the injection gas and the gas recovery increases by 18.55% with respect to reservoir depletion scenario. Using the optimized composition of the replacing gas, the ultimate recovery reaches 53.26%.

At present, diverse methods are available to manufacture gas mixtures and smart gas with specified and controlled composition. Static and dynamic systems to produce gas mixtures using other gases are presented in Ref. [28]. Static systems are usually used when relatively small volumes of the gas mixtures are needed. Gas blending is one of the static system methods. Mixing can be carried out using the partial pressure method in which proportion of gases depends on the partial pressure of each gas. In addition, mixing can be performed by delivering known volumes of gases to a gas tank. Gas mixtures can also be produced through mixing applying the weigh method. In this method, the weight of each added gaseous component is assumed to be known. In dynamic method, the component parts of the gas mixtures must be continuously blended at some specified periods of time. The dynamic method is especially useful in generating reactive gas mixtures. Gas stream mixing is one of the dynamic system methods [28].

## 4 Conclusions

Based on the simulation results of the gas storage process and the proposed proxy model results obtained in this study, we arrive at the following conclusions:

1. When using air containing 78 mol% $N_2$, 21 mol% $O_2$ and 1 mol% $CO_2$, the injection pressure constrain is not met. As a result, the composition of air as the replacing gas should be adjusted to satisfy the criteria of the gas storage. In the $CO_2$ molar composition range above 40.95%, the wetting effect of $CO_2$ is dominant. Therefore, in order to satisfy the reservoir pressure constraint, the composition of $CO_2$ should be less than 40.95 mol%.
2. In the case of using modified air with the composition of 58.92 mol% $N_2$, 21 mol% $O_2$ and 20.08 mol% $CO_2$, all the criteria for the storage gas are satisfied. Applying this composition as input to the simulation model, gas recovery increases by 18.55% with respect to reservoir depletion scenario and the ultimate recovery reaches 53.26%. In this case, 28.4% of the base gas is replaced by the modified air.
3. According to the results, the proposed proxy model can accurately imitate the reservoir behavior, which allows one to determine the optimum composition of the replacing gas so as to satisfy all the constraints for the base gas replacement process. Implementing the simulator using the optimum compositions of the air indicated that the reservoir pressure remains above the minimum required pressure to maintain the production rate at the target value while keeping the injection pressure below the formation fracture pressure. In this way, the maximum possible $CO_2$ composition in the replacing gas is obtained so that the composition of the non-hydrocarbon gases in the produced gas streams remains below the maximum limited values. As a result, the mixing phenomenon which occurs between the replacing base gas and the working gas is controlled as well.

### Compliance with ethical standards

**Conflict of interest** The authors declare that they have no conflict of interest.

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