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## Article

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## Research paper

# A simulation study to enhance the gas production rate by nitrogen replacement in the underground gas storage performance



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## ABSTRACT

Underground gas storage (henceforth; UGS) is considered as a common method which resolves the seasonality problem of transportation and distribution of gas phase in the oil and gas industries. The main objective of this study is to simulate one of Iranian's depleted gas condensate reservoir and compare different injectivity scenarios especially nitrogen injection to enhance the gas production. Based on the anticipated target rate performance of UGS with a different scenario that was analyzed the effect of injection gas, finding optimum original reservoir pressure, an optimum number of wells. Moreover, abandonment pressure is one of the main concerns for UGS process in partially depleted reservoirs especially in the depleted reservoir to decrease the ultimate recovery. It contains insufficient base gas reserves, and if it may not meet the target withdrawal rate, the original reservoir pressure has been estimated at 250 bar. Consequently, it found that this problem can be addressed by injecting a higher volume of gas in the first cycle and due to the existence of new wells, the maximum injection rate was obtained about  $6.1 \times 10^{10} \text{ m}^3$ .

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## 1. Introduction

The ubiquitous use of natural gas storage is to achieve a balance between natural gas supply and its largest demand especially at the coldest months of the year. In natural gas storage reservoirs, methane is considered as the operating gas to provide sufficient energy for producing gas on the storages (Davarpanah, 2018b; DeSantis et al., 2017; Ebadati et al., 2018; Mazarei et al., 2019; Rabbani et al., 2018; Veluswamy et al., 2016). Natural gas is considered as non-renewable energy resources which are continuously produced and demanded to the industrial units (Davarpanah, 2018a; Matos et al., 2016; Pao and Fu, 2013; Zarei et al., 2019; Zhang et al., 2015). This significant energy resource is referred to as a good strategic for many industries and factories, so that consumers try to provide storage facilities and equipment to protect themselves against possible fluctuations and crisis arisen from natural gas shortages (Blanco and Faaij, 2018; Danel et al., 2013; Davarpanah et al., 2018b; Ebadati et al., 2019; Razmjoo et al., 2019). One of the common methods of natural gas storage due to the consumption supplement in cold season referred to the gas storage in depleted gas condensate reservoirs (Bagheri et al., 2019; Davarpanah et al., 2019; Valizadeh and Davarpanah, 2019; Xiao et al., 2006; Ybyraiymkul and Ng, 2016). The composition of the produced gas from a depleted

gas condensate reservoir is different from the injected gas regarding the existence of gas condensates in the reservoir in the depletion processes. Gas storage operation designation depends on the reservoir location and reservoir characteristics (Arfaee and Sola, 2014; Davarpanah et al., 2018a; Ren et al., 2017; Xu et al., 2017).

Underground gas storage (UGS) is considered as one of the principle storage reservoirs to preserve large volumes of gas substances in the world among a wide variety of storage methods in gas fields units. The rapid pace of development and technology in natural gas industries to achieve the maximum sources of gas storages for their daily supplies has risen dramatically (Oldenburg, 2003; Peng et al., 2016; Ren et al., 2017). Furthermore, Natural underground gas storages can be defined as the storing resources for a large volume of natural gas in the porous rocks for different reservoir depths. Underground gas storage facilities could be utilized in some cases such as providing sufficient gas when the irregular reduction occurred, preserving extra gas to provide winter demand for gas, and in emergency circumstances (Juez-Larre et al., 2016; Lawal et al., 2017; Li et al., 2005). These important specifications are utterly depended on climate change, the volume of produced gas, and consumption rate. In the classification of underground storages, some parameters and factors play a significant role. These parameters are porosity, permeability, capillary pressure, and economic considerations of a gas field such as maintenance costs, keeping facilities in a good operational occasion, transferring rates from the reservoir to the surficial

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### Abbreviations

UGS	Underground Gas Storage
PR	Peng–Robinson
PVT	Pressure Volume Temperature
CCE	Constant Composition Expansion
CVD	Constant Volume Depletion
EOS	Equation of State
BHP	Bottom hole pressure

### Nomenclature

FGIP	Field gas in place ( $\text{Sm}^3/\text{day}$ )
FGPT	Field Gas Production Total ( $\text{Sm}^3/\text{day}$ )
FGIT	Field Gas Initial Total ( $\text{Sm}^3/\text{day}$ )
FPR	Field Pressure Rate (bar)
FOPR	Field oil production rate ( $\text{Sm}^3/\text{day}$ )

**Table 1**

Reservoir characteristics.

Parameter	Value	Unit
Initial reservoir pressure	360.4	bar
Initial temperature	130	Celsius
Basis depth	2610	meter
Initial gas in place	37.2	$10^9 \text{m}^3$
Gas cumulative production	14.32	$10^9 \text{m}^3$
$D_x$	$17.6 < D_x < 200$	meter
$D_y$	$450 < D_y < 510$	meter
$D_z$	$4.5 < D_z < 5.1$	meter
Porosity	$0.028 < \phi < 0.132$	%
Permeability in the i and j direction	$0.187 < k < 51.2$	mD
Permeability in the k direction	$0.032 < k < 20.13$	mD
Water compressibility	$5.34 \times 10^{-5}$	$1/\text{bar}$
Gas compressibility	0.0051	$\text{m}^3/\text{m}^3$
Water density	180.35	$\text{kg}/\text{m}^3$
Gas density	1000	$\text{kg}/\text{m}^3$
Simulation time	1980–2045	Years

**Table 2**

Properties of reservoir fluid.

Row	Composition	Mole percent	Unit
1	$\text{N}_2$	1.430	%
2	$\text{CO}_2$	0	%
3	$\text{C}_1$	94.470	%
4	$\text{C}_2$	2.170	%
5	$\text{C}_3$	0.390	%
6	$\text{C}_4$	0.320	%
7	$\text{C}_5$	0.220	%
8	$\text{C}_6$	0.210	%
9	$\text{C}_{7+}$	0.790	%
10	Sp.Gr $\text{C}_{7+}$	0.786	–
11	MWC $_{7+}$	143.800	

wellbore facilities and the capability of gas to cycle throughout the well (Arfaee and Sola, 2014; Davarpanah et al., 2018b; Xu et al., 2017).

There are four types of natural gas preservation in underground storage places such as maintaining of gas in the depleted hydrocarbon reservoirs, preservation in underground aquifers, preservation in salt domes, and preservation of gas in underground reservoirs. Depleted gas reservoirs are used for gas maintenance in porous media, and the other three types are used for preserving of gas in the artificial underground pores. Thereby, the reservoir model should be a good representative of the reservoir behavior, and it should be capable of exact prediction of reservoir deliverability. Due to the contact of injected light gas with initial pure gas (by considering vaporized condensate), initial condensate and formation water, several phenomena could occur. The affordability and ubiquity use of nitrogen gas in a wide variety range of petroleum and chemical engineering operations such as gas lift design and its applied performances, recycle of the produced gas, pressure maintenance, and enhanced oil recovery techniques are commonly administered. Proper estimation of interfacial tension (IFT) between nitrogen and hydrocarbon plays a substantial role in several operations of petroleum and chemical (Ha-Duong and Keith, 2004; Hemmati-Sarapardeh and Mohagheghian, 2017).

Although, there are numerous simulation analysis and experimental investigation have widely reported in the literature to consider the importance of underground gas storages, in this comprehensive study, different injectivity scenarios such as nitrogen replacement injection instead of main reservoir gas were simulated to provide the original reservoir pressure. Furthermore, the effect of nitrogen injection on the reservoir pressure and its characteristics, the amount of gas which is contaminated by a mixture of the injected gas and the number of condensate extractions were studied, and the optimum conditions are simulated. Therefore, the comparison between nitrogen injection and the utilization of natural gas to enhanced recovery was simulated and compared together.

## 2. Simulation procedure

The geological model of the studied reservoir has consisted of  $50 \times 15 \times 50$  blocks in the X, Y, Z directions. The reservoir characteristics are illustrated in more detail in Table 1. The gas layer is a sandstone layer with high permeability and porosity that it is restricted with upper and lower non-permeable layers. Furthermore, reservoir gas does not have any  $\text{H}_2\text{S}$  and considered

as sweet gas. The volume of produced gas in this reservoir up to the year 2007 was  $14.584 \times 10^9 \text{m}^3$  and the pressure drop was about 225 bar. Due to the lack of information about the aquifer, gas and water contact level is not being accurately estimated.

To develop a condensate gas reservoir model to present the accurate reservoir fluid characteristics, pressure-volume-temperature (PVT) tests like CCE (constant composition expansion) test and CVD (constant volume depletion) test should be considered in the commercial simulator. In this study, the modified Peng–Robinson (PR) equation of state (EOS) for estimating the real properties of reservoir fluid. To reduce the time of simulation, Whitson equation is utilized to separate and combine fluid parts, and fluid compositions are decreased to 8 different compositions. The reservoir fluid characteristics are statistically shown in Table 2.

One of the major factors in the injection procedures is the injection pressure which poses special challenges in the operations. Moreover, the reservoir rock persistence capability and cementing quality beyond casing wells should be considered. Due to the existence of current wells with the injection rate of  $12 \times 10^6 \text{m}^3/\text{day}$ , the injection rate would be determined only on the two primary injection periods. However, by continuing the injection and reaching the bottom hole pressure to 360.4 bar, the wells are being shut. Therefore, regarding existed wells it could not be possible to organize the injection scenarios in the specific time to remain the injection rate constantly and subsequently after two period of injection, the injection rate would be decreased. As a result, it is necessary for this reservoir to drill more wells to achieve a balance between supply and demand.

In this part of the simulation, different mole percentages of nitrogen gas were applied in the simulation and reservoir characteristics were analyzed accurately. Due to the fact that, by injection of gas into the reservoir, the condensate around the wellbore is being leached regarding the pressure increase, and

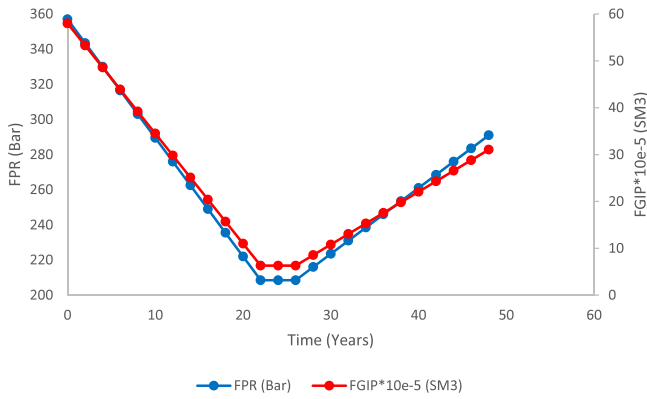


Fig. 1. Gas reserve and reservoir pressure drop by the consideration of constant injection rate.

it has contacted with the injected dry gas. Owing to the combination of injected gas with initial gas in place and vaporized condensate, the gas would be enriched. Therefore, this enriched gas is mobilized to the further distances due to the continuing of dry gas injection and new injected gas has been contacted with less condensate and less initial gas in place, and as a result, it would be enriched lower than the previous scenario. Before the commencing of the production period, regions around the wellbore have contained lighter gas rather than further regions. So, at the initial time of production regarding the presence of gases near the wellbore and their production, condensate recovery was low and next to further gases have been produced. Subsequently, the obtained recovery in primary stages was low, and it has been gradually increased. On the other hand, as it is observed from the simulation results, the liquid oil ratio in the nitrogen injection scenario had higher volumes than natural gas injection scenario. To elaborate this phenomenon clearly, it is evident that nitrogen has less capability to vaporize the remained condensate than methane gas and subsequently, in the injection procedures, there are more volumes of condensate around the production/injection wells.

### 3. Results and discussion

#### 3.1. Reservoir pressure and gas production for primary wells

As it is observed in Fig. 1, reservoir pressure has been increased gradually and subsequently the total volume of produces gas has increased. Furthermore, as can be seen in Fig. 2, the cumulative rate of the injection and production of the reservoir was observed. During the injection and production operation, a total volume of  $3.125 \times 10^{10} \text{ m}^3$  gas had been injected and  $2.1590 \times 10^{10} \text{ m}^3$  gas were produced. Therefore, 70% of the total reserve gas were produced.

As can be seen in Fig. 3, the rate of produced condensates in the higher gas production rates is lower than these condensate volumes in natural gas depletion drive mechanisms. The reason for this is that the initial injected gas is usually dry and when it was mixed with the main reservoir fluid during the production operation, the gas is lighter than the primary fluid in the reservoir. Hence, this condensate volume has been increased over each period and the volume of lighter reservoir fluid during successive periods will be decreased gradually.

#### 3.2. Optimization of new wells number

Since existed wells are inefficient for the obtained volume of produced gas, it is necessary to drill new wells to provide

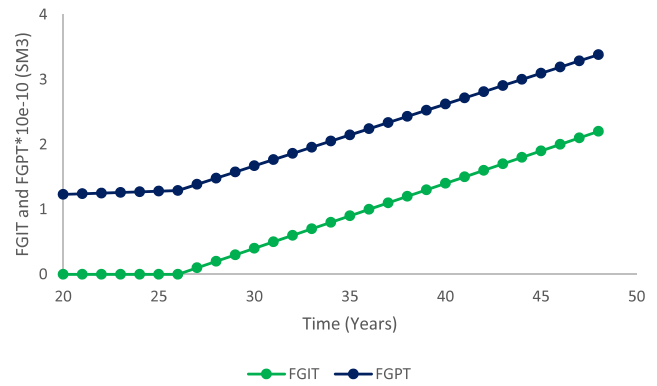


Fig. 2. Cumulative production and injection rate by primary wells.

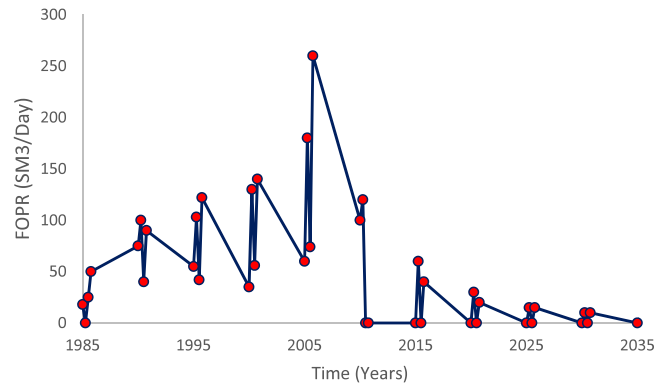


Fig. 3. Reservoir condensate rate (produced and injected by existed wells).

sufficient production rate to reach the optimum amount of gas production. In this part of the study, if the reservoir pressure had been reduced less than original reservoir pressure during the production procedure to supply sufficient energy to maintain obtained flow rate stabilized during the production. To address this problem, it would be enhanced the length of the injection period in the first stage or increasing the injection rate to provide optimum gas for necessary processes. Furthermore, due to the obtained information from experimental production tests, abandoned reservoir pressure was less than the original reservoir pressure. Thereby, by obtaining a sufficient volume of gas to achieve this optimum pressure, injecting  $1.1 \times 10^{10} \text{ m}^3/\text{day}$  of gas from March of 2012 to achieve this pressure. By adding nine new wells, the production rate at the initial day of the procedure was  $2.31 \times 10^{10} \text{ m}^3$  and it was gradually decreased. Hence, the production rate would be increased at the successive periods. One of the major reason for this discrepancy might be the production from the reservoir and subsequently the pressure drop near the wellbore and in some occasions reduced under the dew point. Moreover, the condensates were being trapped near the wellbore and consequently a reduction in the gas relative permeability which led to reduce of gas production. In the next steps of gas continuous injection, the production rate would be increased slightly to lighten the reservoir fluid by injecting dry gas and produce the remained condensate in the reservoir. Therefore, the damages which are caused by performing of condensates near the wellbore are reduced and by passing 20 years of production, it could be achieved to the determined flow rate. Consequently, to optimize the flow rate, it is highly recommended to drill 10 new wells to eliminate the flow rate production and reach to stabilized flow rate by minimum pressure of 250 bar. Moreover, the volume of total gas storage at several periods are being shown in Fig. 4 which is constant after drilling of 10 new wells.

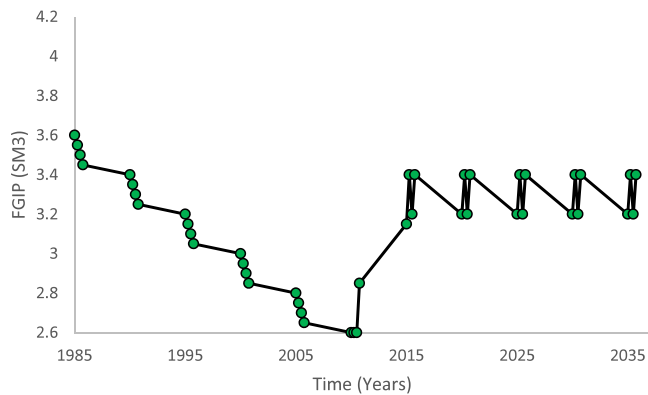


Fig. 4. Volume of total gas storage.

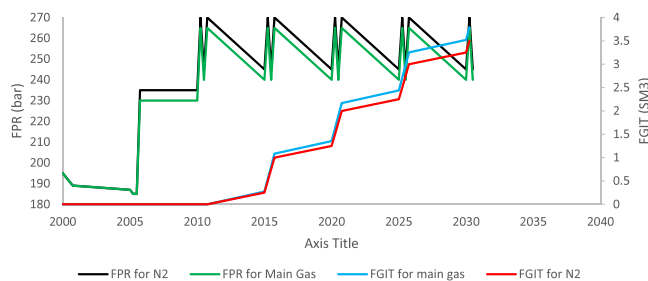


Fig. 5. Comparison of natural gas and nitrogen injection.

### 3.3. Nitrogen replacement to provide original reservoir pressure

The simulation of nitrogen injection with a combination of different nitrogen percent to achieve the optimal composition of the injection has been considered in the simulation procedures to provide sufficient original reservoir pressure.  $0.5 \times 10^{10} \text{ m}^3$  of nitrogen gas were injected for a continuous injection period from March 2012 until June 2013. On the contrary, natural gas injection in the period of 18 month from March 2012 until November 2013 to reach the original reservoir pressure was  $6.1 \times 10^{10} \text{ m}^3$ . Another major reason to utilize nitrogen instead of natural gas is that nitrogen has occupied more spaces in the reservoir rock and therefore it needs lower volumes of gas for injection. The result of cumulative condensate production for both scenarios are potted in Fig. 5.

Due to the thermodynamic properties of nitrogen, regarding the nitrogen injection the dew point pressure of reservoir fluid was being increased more than the natural gas injection because at the production stage and regarding pressure drop, the dew point is achievable and heavy compounds were trapped in the reservoir. Hence, the production of heavy compounds in other conditions was low except  $C_6$ .

## 4. Conclusion

One of the chief aims of depleted gas reservoirs is to store gas in the underground gas storages. By simulating and modeling the approximate sample of the realistic model of reservoir characteristics to optimize the efficiency of previously applied methodologies and provide holistic solutions and consider optimum ways to enhance the recovery of fluid productions. The results of this comprehensive study have shown that to achieve the targeted injection and production program by the existed wells; it is necessary to drill ten new wells to provide the original reservoir pressure of 250 bar. Another solution for this phenomenon is to

increase the volume of gas injection on the primary stages of injection scenarios.

Furthermore, it would have mutual benefits; solving the problem of making condensate near the wellbore and reaching to the original reservoir pressure. The main purpose of this paper is to substitute nitrogen instead of natural gas for increasing the original reservoir pressure which significantly reduces the volume of injected gas in the injection processes. As can be seen in the simulated results the volume of injected nitrogen gas is about 1/12 of natural gas injection, and it would major a breakthrough in the petroleum industries. Moreover, the volume of heavy compounds in the produced gas when we assumed nitrogen as a substitution gas for natural gas is lower, and it is utterly depended to the dew point pressure of the nitrogen which increases the injection and production periods and decreases the concentration of nitrogen in the reservoir fluid composition in both scenarios. The maximum concentration of nitrogen gas in the composition of the injection gas to reach the original reservoir pressure can be up to 15% of the national gas company standard.

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