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# Simulation and Sensitivity Analysis of Flare Gas Recovery for Application in Hydrocarbon Reservoirs as Injection Gas

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## ABSTRACT

Flare gas recovery is one of the essential processes in reducing the greenhouse gas emissions caused in the oil and gas industry. On the other hand, due to the reduction of pressure and production rate of hydrocarbon reservoirs especially in Iran, it is necessary to provide solutions for reservoirs pressure maintenance. Therefore, in this paper the potential application of the separated carbon dioxide from the flare gas in Parsian refinery was investigated for injection into a gas condensate reservoir. For this purpose, the flare gas recovery process was simulated using Aspen HYSYS software and operational enhancements were applied. Next, the injection of the separated carbon dioxide into a gas condensate reservoir was simulated in Petrel software, and the best scenario was determined. The obtained results indicated that maximum $CO_2$ recovery is achieved using Diisopropanolamine as solvent with the flow rate 1930 USGPM. The reservoir simulation results revealed that $CO_2$ injection prevents severe pressure drop and causes the reservoir pressure to decline with a lower slope. Thus, the reservoir production rate increases and becomes more stable. The most stable production rate was attained for injection rate of 305 million cubic meters per day.

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## 1. Introduction

As global energy consumption increases, it is essential to prevent the loss of energy resources. Fossil fuels are the most used energy resources and therefore, they should be used in the best possible way. Unfortunately, a significant amount of these resources is wasted daily due to improper utilization and traditional methods. For instance, at least 120 million cubic meters of gas is burned in the flares annually in South Pars refineries. Always a part of the gas produced from oil reservoirs as associated gas is burned in flares, and there is no serious intention for flare gas recovery. In fact, gas flaring provides safety for refineries and well head facilities, and flare gas recovery requires technology development and economic justification.

Although recovery and reduction of flare gas directly led to environmental protection, gas flaring will continue until gas recovery operations have economic justification, suitable capital recovery time, and appropriate technology. A large amount of hydrocarbon and other toxic gases enter the atmosphere from flares, which causes serious air pollution. According to the Canadian Health Association and other published papers in the literature, about 250 known toxins including benzene, mercury, nitrogen oxides, carbon dioxide, methane, acidic gases, and aromatic hydrocarbons are discharged into the air during flaring operations. The effects of flare gas pollution are not only reported in the operational sites including production wells or refineries but also air pollution is observed in places far beyond refineries. Pollutants that are released in the air, cause acid rain which contaminate freshwater and directly affect agricultural crops. In recent decades, optimization of the flare gas amount has been an important topic and extensive research has been done in this field.

Khanipour et al. (2016) carried out a study on nitrogen gas separation from flare gas and return of the recovered gas to the methanol synthesis reactor. Their simulation results showed that the returned gas to the reactor was capable of increasing methanol production. Also, in this study, the simulation and investigation of key factors in membrane gas separation indicated that 98.5% of nitrogen and 92.8% of recovered methane can be separated. Moreover, the emission of 300 tons carbon dioxide to the environment can be prevented daily.

In 2015, a study was conducted to reduce the volume of flare gas. In this study, three approaches for flare gas recovery including gas injection into the feed stream of South Pars gas refineries, gas injection into South Pars reservoir and gas injection into Aghajari oil field through the fifth national gas transmission pipeline were proposed. The appropriate solution from operational point of view was gas compression and injection to the fifth national pipeline. To implement this method, the required outlet pressure of the flare gas recovery unit was about 40 bar, which was much lower than the required pressures of other two solutions (i.e., 80 and 200 bar). Moreover, 10 MMSCMD flare gas recovery can be obtained and gas transmission capacity across the fifth national gas transmission pipeline is increased more than 12%. It should be mentioned that this amount of recovered gas is equivalent to 40% of the gas production capacity of one of the South Pars Refinery (Hashemi Fard and Shafiee, 2020).

Different methods for flare gas recovery in gas refineries and liquefied natural gas companies were examined from exergy point of view. The concept of exergy is derived from the second law of thermodynamics, and the analysis based on this concept usually yields more accurate results than methods based on the first law of thermodynamics. The results of this study indicated that simultaneous generation of electricity and heat using flare gas helps saving gas consumption (about 5793 kg/h) and reducing exergy losses. If there is no demand for generated electricity, the flare gases can be returned to steam generation unit which results in reduction of gas consumption about 5605 kg/h (Kazeruni et al., 2013).

Adeli et.al. investigated an economic approach to the application of flare gas in Nigerian oilfields. Their study was conducted in two parts to identify the existing approaches and the influencing factors. As most of the associated gas loss in the world occurs in Nigeria, the recovery of flare gas is essential in this country. In this study environmental problems of gas flaring were explored and various solutions were proposed (Adewale and Ogunrinde, 2010). Vickers et al studied the recovery of flare for injection into hydrocarbon reservoirs. The most significant part of this research was the design of a new system for more gas storage. Moreover, a mathematical model has been proposed based on experimental data (Vickers et al., 2012).

Saadawi (2013) introduced a plan to reduce the volume of flare gas to zero within 10 years in UAE. This is done by selecting different types of compressors suitable for the field under study. In this study a comprehensive comparison was performed on the design of different compressor systems and flare gas recovery units. Wallace et al. (2015) studied the Bacon Formation which is the world's largest shale reservoir. In their studies, they concluded that flare gases can be used as drilling rigs fuel supply in drilling and hydraulic fracturing operations. Changing the fuel type from diesel to natural gas can significantly save drilling costs. The aim of all this research is to optimize the recovery of hydrocarbon compounds in flare gas which are industrially and economically valuable.

In 2017, a study was conducted on enhanced gas recovery operations in gas reservoirs and a comprehensive EGR program was proposed. The results of their simulation using black oil and compositional models indicated that $CO_2$ injection is the most effective operation for increasing the gas recovery in gas reservoirs (Iogna, 2017)

Hassan et al. (2017) conducted studies on improving gas recovery in shale and tight gas reservoirs in Saudi Arabia. In this research, different methods such as hydraulic fracturing, application of magnetic nanoparticles, thermal and microbial recovery methods were investigated. Finally, it was concluded that the mixture of $CO_2$ and CH4 as injection gas has the most impact on gas recovery for this type of reservoirs.

Kalar and Wu (2014) conducted studies on carbon dioxide injection to improve gas recovery and proposed various patterns for direction and depth of injection to improve recovery. Bauer et. al. (2012) indicated that separation of high purity carbon dioxide from recovered flare gases is technically and economically feasible in Tunisia. Many researches have been performed on the recovery of flare gas and various applications have been proposed for its optimal use (Salu et al., 2014; Amer et al., 2018; Ding et al., 2019; Wang and Rezaee, 2020; Hamza et al., 2021; Cao et al., 2022; Dai et al., 2022; Guo et al., 2023).

In gas condensate reservoirs, reverse condensation occurs when the reservoir pressure decreases below the dew point pressure. In fact, as the reservoir pressure drops below the dew point, the gas in the reservoir begins to liquefy and appears as liquid droplets in the reservoir rock. The volume of these liquids increases with further decrease in reservoir pressure. The presence of gas condensates inside the reservoir causes problems, the most important of which is the reduction of gas relative permeability. Gas injection is the best solution to maintain the reservoir pressure above the dew point and improve the production of gas condensate reservoirs.

The objective of this study is assessment of the feasibility of flare gas recovery in Parsian refinery for application as injection gas into a gas condensate reservoir. Therefore, the separation of carbon dioxide from the flare gas was first simulated using ASPEN HYSYS software and the best absorbent was selected for maximum separation efficiency. Then, sensitivity analysis was performed on the operational parameters and their effects on gas recovery were investigated and discussed. Moreover, the simulation and feasibility study of the separated carbon dioxide injection into a gas condensate reservoir were carried out in PETREL software.

## 2. Simulation of Flare Gas Separation

There are different ways to separate and recover flare gases. When a mixture contains two or more immiscible phases, physical separation methods based on gravity, centrifugal force, pressure reduction, electrical or magnetic fields can be used to separate the phases. To separate the components in a homogeneous mixture, an insoluble secondary phase should be applied as a solvent which can selectively separate one of the mixture components. In this case, the separation is achieved due to the difference in components mass transfer rate within the solvent. In fact, the driving force for separation is the molecular diffusion (Alcheikhhamdon and Hoorfar, 2016).

The most common method for separation of acidic gases from hydrocarbon mixtures is the physical or chemical absorption using a suitable solvent. Since the efficiency of physical absorption process depends on the amount of carbon dioxide and hydrogen sulfide in the gas mixture and the absorption rate decreases as the concentration of acidic gases reduces, chemical absorption with higher efficiency is often preferred. Different amine solutions can be used as a solvent in chemical absorption; thus, it is first required to identify the best type of amine in order to maximize the absorption of carbon dioxide from the gas mixture sent to the flare. Table 1 shows the characteristics of different types of amine solutions.

**Table 1. Characteristics of different types of amine solutions**

| Amine solution | Molar mass (g/mol) | Boiling point (ºC) |
|---|---|---|
| (DEA) | 105.14 | 280 |
| (MDEA) | 119.16 | 247 |
| (DIPA) | 75.11 | 84 |
| (MEA) | 61.08 | 170 |
| (TEA) | 149.18 | 89 |

The flare gas recovery process was simulated in ASPEN HYSYS software. (Figure 1) illustrates the schematic of process flow diagram. According to the flare gas composition in Parsian refinery, the amount of hydrogen sulfide is very low and therefore the main purpose is to separate carbon dioxide from the hydrocarbon gas mixture.

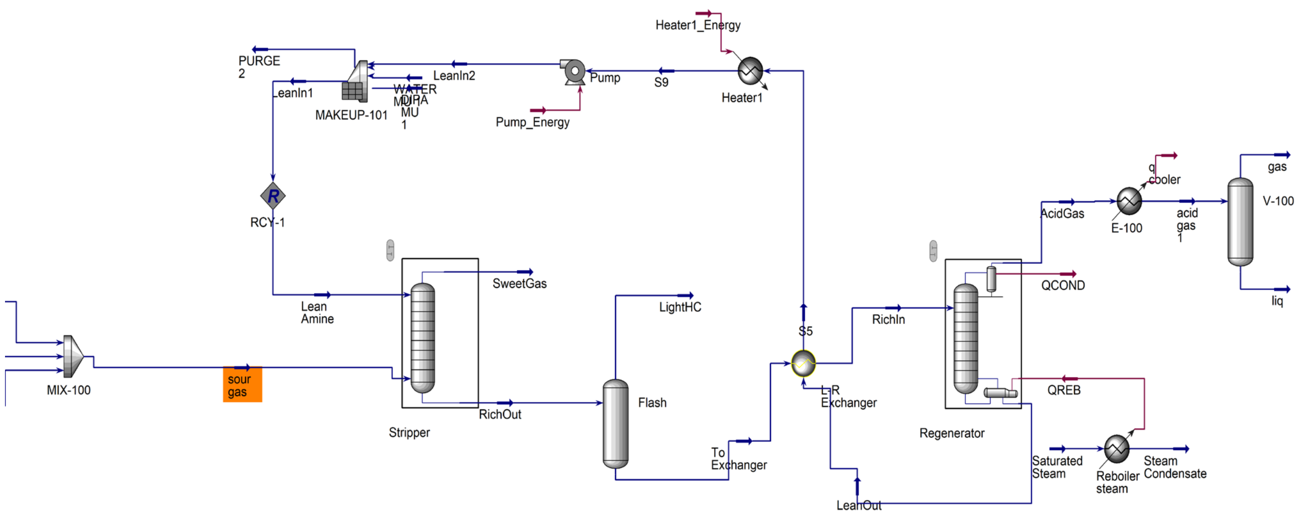



**Figure 1. Schematic of separation process**

The composition of the flare gas in Parsian refinery is reported in Table 2. The temperature and pressure of the gas stream are 32.93 °C and 70 bar, respectively.

**Table 2. Composition of flare gas**

| Component | Mol% |
|---|---|
| $H_2O$ | 0.00 |
| $CO_2$ | 1.08 |
| $H_2S$ | 0.00 |
| $N_2$ | 3.82 |
| Methane | 89.12 |
| Ethane | 3.72 |
| Propane | 1.17 |
| i-Butane | 0.26 |
| n-Butane | 0.35 |
| i-Pentane | 0.16 |
| n-Pentane | 0.11 |
| n-Hexane | 0.22 |

The absorption tower has two outlet streams including sweet gas and solvent flow which contains $CO_2$, $H_2O$, and amine. Sweet gas from the top of the absorption tower can be used for different purposes such as urban or refinery fuel, feed stream to methanol synthesis unit and GTL process. To separate carbon dioxide from the liquid solvent, the outlet stream from the bottom of absorption tower is sent to amine regenerator. The regenerated amine is added to fresh solvent and used in absorption tower.

### 2.1. Selection of Amine Type

First, according to the operating conditions, the best type of amine solution should be selected so that maximum efficiency in carbon dioxide separation can be achieved. To this end, the separation process was simulated using various types of amine solutions and $CO_2$ recovery was calculated. The obtained results are compared in Table 3. It was found that, Diisopropanolamine (DIPA) has the best performance among other amine types.

**Table 3. $CO_2$ recovery using different amine solutions**

| Amine type | $CO_2$ recovery (%) |
|---|---|
| (MEA) | 93.26 |
| (DEA) | 96.86 |
| (TEA) | 96.81 |
| (MDEA) | 96.79 |
| (DIPA) | 97.08 |

### 2.2. Operation Improvement

Since the main objective of this study was to separate carbon dioxide from flare gas for injection into a gas reservoir, some improvements were proposed and performed in separation operation to increase carbon dioxide recovery. Operational improvements were implemented by adding a cooler and a two-phase separator at the outlet of the regenerator.

The separated carbon dioxide in the regenerator contains water vapor. Therefore, it is not suitable for injection into gas reservoirs. To increase the purity of carbon dioxide, the outlet stream from the regenerator was sent to a cooler to convert the water vapor into liquid. After that, a two-phase separator was used to separate liquid water. Thus, carbon dioxide was separated with purity of 97% by choosing the best solvent and performing operational improvements.

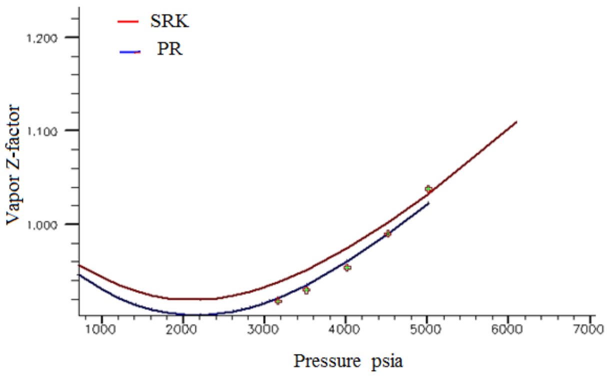
## 3. Reservoir Simulation

The studied reservoir was a gas condensate reservoir with the pressure of 3286 psia and temperature of 180 °F at the datum depth of 1670 m. Compositional model was applied to simulate the gas injection operation in Petrel software. The reservoir grids were determined so that the number of blocks in x, y and z directions were 74, 49 and 17, respectively.

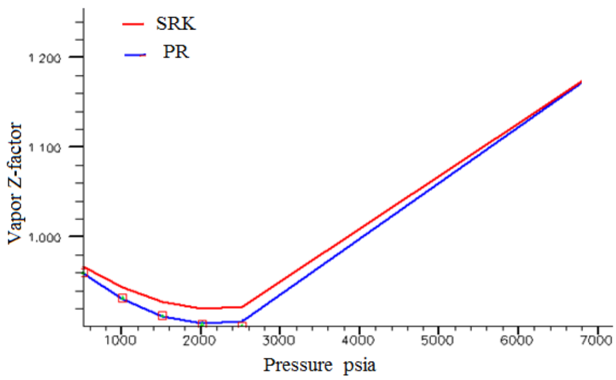
Table 4 shows the reservoir fluid properties used for fluid characterization and developing PVT model. In order to develop the fluid model, experimental data of CCE, CVD, and separator tests were used. As shown in (Figure 2), Peng Robinson equation of state (PR EOS) fits the experimental data better than SRK EOS.

**Table 4. Reservoir fluid data using in PVT model**

| | | |
|---|---|---|
| Reservoir temperature (F) | | 180 |
| Reservoir pressure (psia) | | 3286 |
| Datum depth (m) | | 1670 |
| Average porosity (%) | | 13 |
| Horizontal permeability (md) | | 27 |
| Vertical permeability (md) | | 5.5 |
| Gas Liquid Ratio (SCF/STB) | | 80000 |
| Dew Point Pressure (psia) | | 3163 @ 180 °F |
| Gas formation volume factor | | 0.00525 |
| Separator Liquid Flashed to Ambient Conditions | Oil Density (g/cc) | 0.7564 @ 60 °F |
| | Shrinkage Factor | 0.8397 |
| | Gas Liquid Ratio (SCF/STB) | 296 |
| | Gas specific gravity | 1.055 |




**(A)**




**(B)**

**Figure 2. EOS tuning results (A) CCE test (B) CVD test**

## 4. Results and Discussions

In this study, the simulation of carbon dioxide separation from flare gas in Parsian refinery was carried out after implementation of operational improvements. Then, feasibility of the separated gas injection into a gas condensate reservoir was investigated. To determine the optimum operating conditions, sensitivity analysis was carried out on important parameters affecting both carbon dioxide separation and injection processes.

### 4.1. Regenerator outlet temperature

Since a cooler was added at the top of the regenerator tower, the outlet temperature should be adjusted to achieve the maximum carbon dioxide recovery. The impact of regenerator outlet temperature on carbon dioxide recovery is shown in (Figure 3). It can be seen that, the lower the temperature, the higher the purity of carbon dioxide. The maximum purity of $CO_2$ (i.e., 97.81%) was obtained at the temperature of -28 °C. This can be justified by the fact that as the temperature reduces, more water vapor becomes liquid and therefore, carbon dioxide with higher purity is obtained from regenerator.

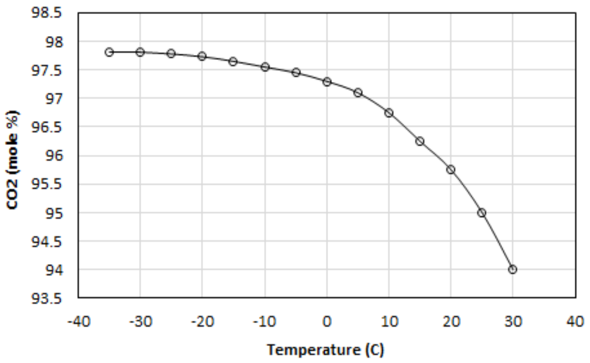



**Figure 3. Impact of regenerator outlet temperature on carbon dioxide recoveryn**

## 4.2. Amine solution concentration

One of the most important and effective parameters in absorption process is the solvent concentration. Therefore, variations in amine solution concentration in absorption tower and its effect on carbon dioxide recovery were evaluated. To investigate the impact of solvent concentration on $CO_2$ separation efficiency, sensitivity analysis was performed on the concentration of the selected type of amine solution, namely diisopropanolamine (DIPA).

(Figure 4) indicates the variations of carbon dioxide recovery against amine concentration. It can be seen that the maximum carbon dioxide recovery is achieved using 25% amine solution. In previous published studies available in the literature, it has been reported that the best concentration of amine solution in absorption process is between 20% and 40%. In fact, at concentrations less than 20%, the absorption rate is significantly low and at concentrations more than 40%, corrosion and foaming occur in the absorber.

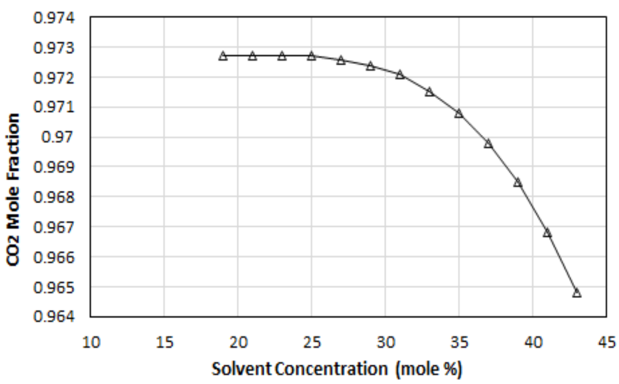



**Figure 4. Effect of amine concentration on carbon dioxide recovery**

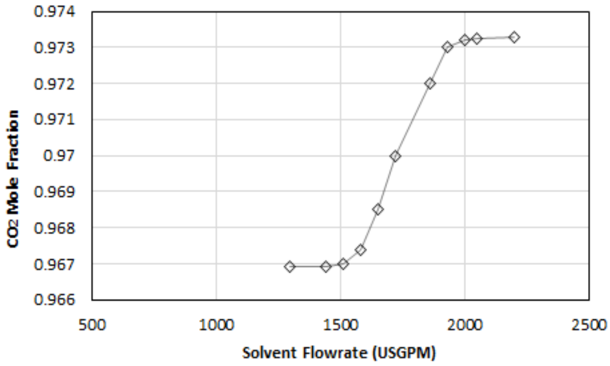



**Figure 5. Effect of amine flow rate on carbon dioxide recovery**

## 4.3. Solvent Flow Rate

In addition to the appropriate concentration for the solvent, the solvent flow rate has also a significant effect on the separation efficiency. The optimum solvent flow rate is determined according to economic considerations so that minimum solvent loss and maximum $CO_2$ absorption are achieved. The impact of solvent flow rate on carbon dioxide separation efficiency was explored while amine type and concentration were constant at values obtained from previous analysis. As shown in (Figure 5), the optimum solvent flow rate is 1930 USGPM.

## 4.4. Gas injection simulation results

In this section, the simulation results of the separated carbon dioxide injection into a gas condensate reservoir are presented. First, history matching was performed on the reservoir model from 2007 to 2017, and then the model was applied for the prediction of gas production from 2017 to 2026. It should be mentioned that the reservoir production rate was 15 million cubic meters per day. Moreover, the minimum bottom hole pressure was assigned 140 bar.

(Figure 6) shows reservoir production history from 2007 to 2017 as well as production rate prediction from 2017 to 2027. As can be seen in this figure, the model matches well the production history. It is observed that after about 5 years of production, i.e., in 2023, a significant drop in production rate occurs and the reducing trend continues until 2027.

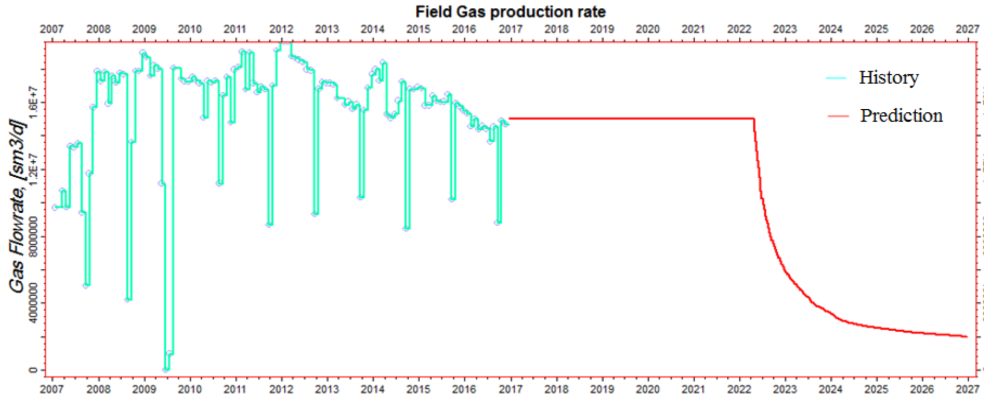



**Figure 6. History match and prediction of gas production rate**

The reservoir pressure variations from 2007 to 2017 and the model prediction from the end of 2017 to 2027 is illustrated in (Figure 7). It can be seen that if the reservoir pressure drop continues due to natural depletion, the reservoir pressure declines to a minimum and gas production decreases greatly until 2023.

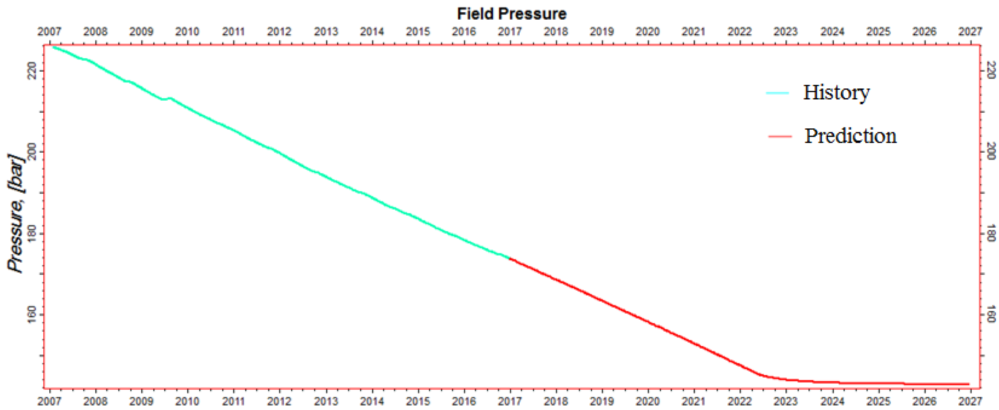



**Figure 7. Reservoir pressure variations**

(Figure 8) compares the reservoir production rate for two scenarios, i.e., natural depletion and $CO_2$ injection with the rate of 305,000 m3/day. It can be seen that the production rate reaches a constant value after $CO_2$ injection into the reservoir.

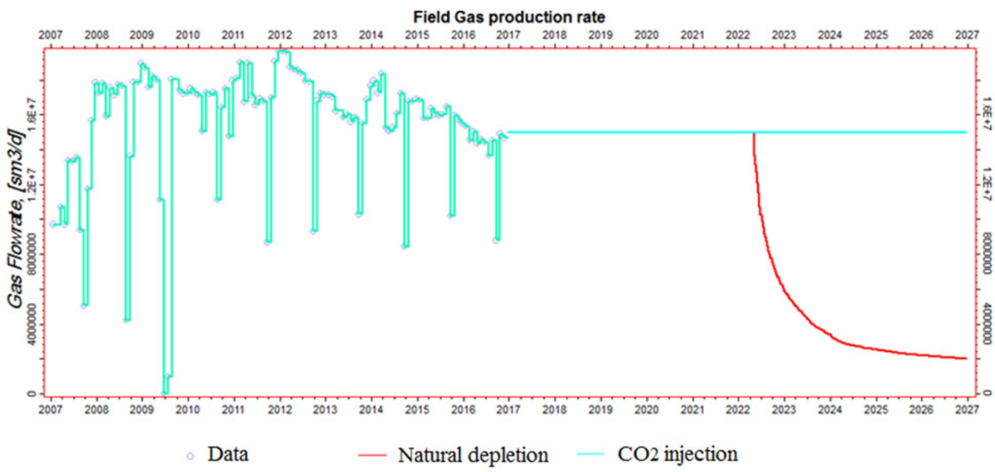



**Figure 8. Production rate for natural depletion and gas injection scenarios**

(Figure 9) indicates a comparison of the reservoir pressure for natural depletion and gas injection scenarios. It is shown that $CO_2$ injection prevents severe pressure drop, and pressure decline occurs with a lower slope. Thus, the reservoir production rate increases and becomes more stable.

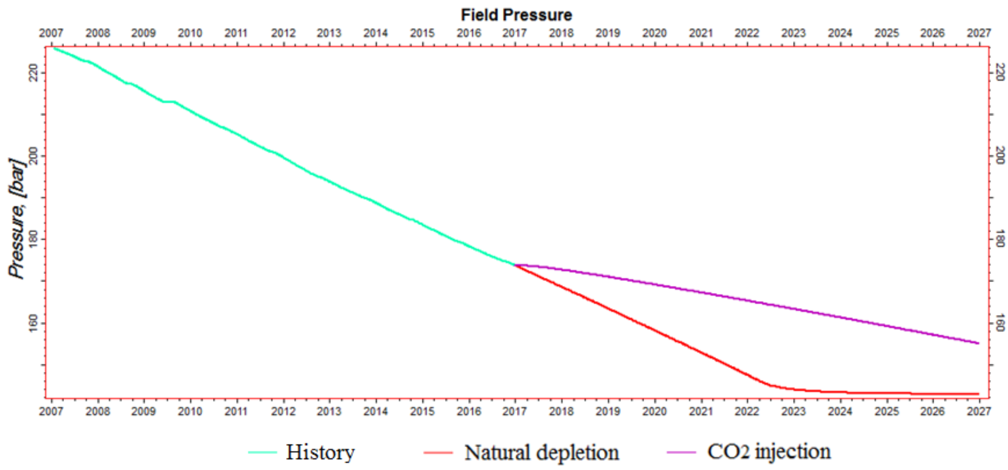



**Figure 9. Reservoir pressure for $CO_2$ injection and natural depletion scenarios**

The reservoir pressure drop in different scenarios of daily production from 15 to 25 million cubic meters is shown in (Figure 10). The maximum pressure drop in the reservoir occurs for production rate of 25 million cubic meters per day. In fact, the reservoir pressure is reached to the minimum value in 2022. Therefore, carbon dioxide injection is required to maintain the reservoir pressure.

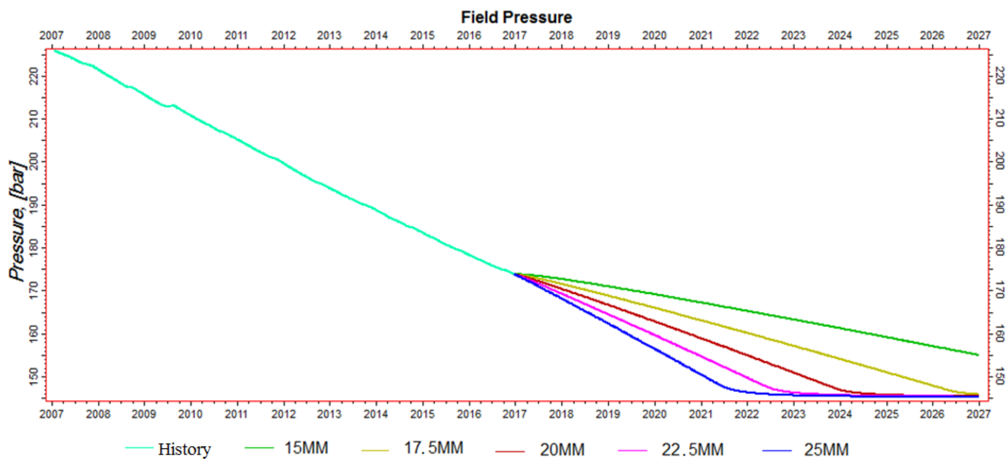



**Figure 10. Reservoir pressure for different production rates in natural depletion scenario before gas injection**

(Figure 11) illustrates daily gas production rates in different scenarios. As can be seen, stable production and longer production time are obtained at lower production rates. When the production rate is 25 million cubic meters per day, despite the higher cumulative production, the duration of stable production is lower compared to other scenarios.

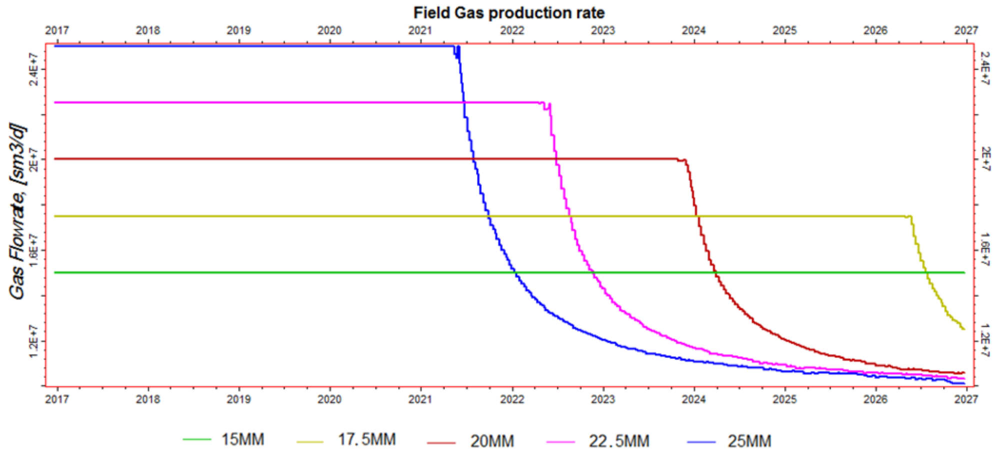



**Figure11. Gas production rates for different production scenarios before gas injection**

Sensitivity analysis on carbon dioxide injection rate is presented in (Figure 12). In this analysis, the model results were compared for gas injection flow rates from 200 to 595 million cubic meters per day. It can be seen that the most stable production rate is achieved for injection rate of 305 million cubic meters per day.

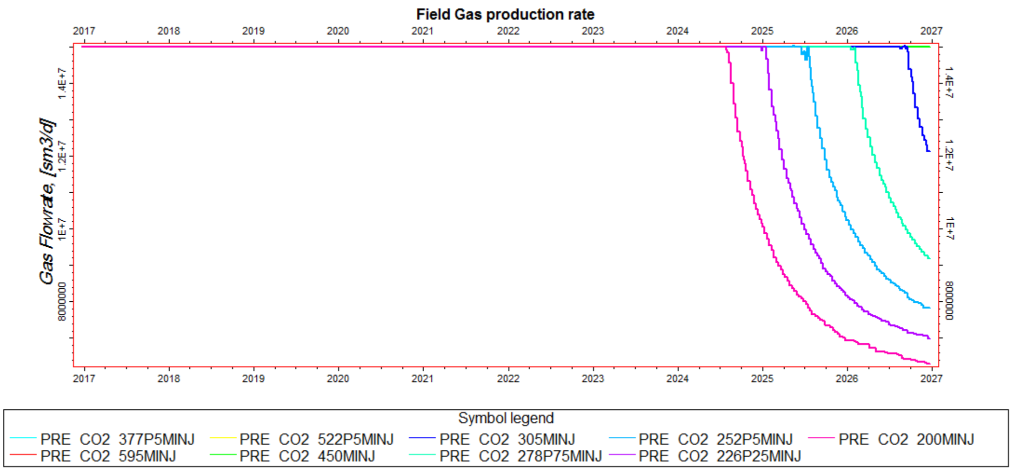



**Figure 12. Production rate for various gas injection flow rate**

Based on the composition of flare gas in Parsian refinery, the injection of recovered carbon dioxide leads to 2.52% increase in the reservoir recovery factor. It should be noted that the amount of $CO_2$ that can be recovered from flare gas in South Pars field is much higher than the amount obtained in Parsian refinery and can result in further increase in reservoir recovery factor.

## 5. Conclusions

In this paper, the separation of carbon dioxide from flare gas in Parsian refinery was simulated and the feasibility of the recovered gas injection into a gas condensate reservoir was studied. The carbon dioxide separation process was simulated using ASPEN HYSYS software and sensitivity analysis was carried out on important operating parameters. The gas injection operation was simulated in Petrel software and the variations of reservoir pressure and production rate were investigated at different conditions. Based on the performed analysis, the main findings are as follows:

- In the process of carbon dioxide separation from the flare gas, diisopropanolamine (DIPA) was selected as the solvent with maximum efficiency.
- Sensitivity analysis on the operating parameters in the gas separation process showed that the optimum separator temperature is -28 °C, optimum solvent concentration and flow rate are 25% and 1930 USGPM, respectively.
- Based on the simulation results, in the optimum scenario, the production rate is 25 million cubic meters per day with 305,000 cubic meters per day carbon dioxide injection.
- After separation of carbon dioxide from the flare gas, the remaining sweet gas can be used in GTL process to produce high value-added liquid hydrocarbons such as naphtha, kerosene, diesel fuel, gasoline, LPG, and chemicals with higher added value.

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# شبیه‌سازی و آنالیز حساسیت بازیابی گاز مشعل جهت کاربرد در مخازن هیدروکربنی به‌عنوان گاز تزریقی

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## چکیـــــده

بازیابی گاز مشعل یکی از فرآیندهای ضروری در کاهش انتشار گازهای گلخانه‌ای در صنایع نفت و گاز است. از طرفی با توجه به کاهش فشار و میزان تولید مخازن هیدروکربنی به‌ویژه در ایران، ارائه راهکارهایی برای نگهداری فشار مخازن ضروری است، بنابراین در این مطالعه پتانسیل استفاده از دی‌اکسید کربن جدا شده از گاز فلر در پالایشگاه پارسیان برای تزریق به یک مخزن گاز میعانی بررسی شد. برای این منظور، فرآیند بازیابی گاز مشعل با استفاده از نرم‌افزار Aspen HYSYS شبیه‌سازی و بهبودهای عملیاتی اعمال شد. سپس تزریق گاز دی‌اکسید کربن جدا شده به یک مخزن گاز میعانی در نرم‌افزار Petrel شبیه‌سازی شده و بهترین سناریو تعیین شد. نتایج به دست آمده نشان داد که بیشترین بازیابی $CO_2$ با استفاده از دی ایزوپروپانول آمین به‌عنوان حلال با دبی ۱۹۳۰USGPM حاصل می‌شود. نتایج شبیه‌سازی مخزن نشان داد که تزریق $CO_2$ از افت فشار شدید جلوگیری کرده و موجب می‌شود که فشار مخزن با شیب کمتری کاهش یابد، بنابراین، نرخ تولید مخزن افزایش یافته و پایدارتر خواهد بود. پایدارترین نرخ تولید از مخزن برای نرخ تزریق ۳۰۵ میلیون مترمکعب در روز به‌دست آمد.

**واژگان کلیدی:** گاز فلر، تزریق گاز، مخزن گاز میعانی، شبیه‌سازی