Optimized Gas Injection Rate for Underground Gas Storage; Sensitivity Analysis of Reservoir and Well Properties

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Abstract

Increasing demand for natural gas during cold months has forced gas companies to store excess gas into the porous rock formations in summer. This artificial reserves known as underground gas storage (UGS) brings more flexibility to the natural gas provider companies to have enough gas available for peak customer demand. An important parameter that controls the feasibility of any UGS project is the time needed to inject the gas for the storage preparation. This would clearly affect the withdrawal-injection cycles for different gas injection rates which requires an optimum injection rate based on the rock and storage properties especially the maximum pressure for the cap rock stability.

The purpose of this work is to examine a case study to find the optimum injection rate, i.e., the rate by which as much gas as possible is injected into the field with the highest bottom-hole pressure that is secure. Moreover, this optimum injection rate must be constant during the preparation's period. Optimum injection rate is a function of reservoir properties like vertical/horizontal permeability ratio (k_v/k_h), skin factor, horizontal permeability and the well perforation's locations. Sensitivity analysis was performed using fluid flow simulation technique.

The results show that horizontal permeability is the most dominant parameter on the amount of optimum injection rate, while the amount of k_v/k_h has the least effect. The perforation's locations has a linear relationship in a way that the summation of optimum injection rates measured for each perforated layer is approximately equal to the optimum injection rate found for fully perforated case. Skin factor was found to be the intermediate pertinent parameter; however when skin factor is in negative ranges, it leads to higher injection rate. The results show that only one well with negative skin can inject as much gas as several wells that reduces costs of drilling for new wells.

Keywords: *Underground Gas Storage; Optimum Injection Rate; Sensitivity Analysis; Fluid Flow Simulation.*

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1. Introduction

Fossil fuels are still the most important energy source worldwide and their availability during the whole year is vital for many companies. The use of gas storage to satisfy the demand of energy during the whole year is widely used in many industries, especially for countries wherein the seasons vary significantly. Underground gas storage is used for balancing the gas supply and demand over a defined period and it compensates summer/winter periods fluctuations. Besides, it is a clean burning fuel available which makes its role more significant [1]. There are several types of underground gas storage facilities, which differ by storage formation and storage mechanism. Natural gas can be stored in porous rocks such as storage in aquifers, storage in former gas fields, and storage in former oil fields [2]. Besides, it can be stored in caverns such as salt caverns, rock caverns, and abandoned mines [3]. Depleted reservoirs with reliable cap rock which have produced all the recoverable oil or gas are the most common target for underground gas storage [4], [5].

Dealing with gas storage problems, one may face different terminologies. The following terms typically apply to all types of storage:

Total Capacity is the maximum volume of gas that can be stored in an underground storage facility. *Cushion Gas Volume (CGV)* or *Base Gas* is gas volume that must remain in the reservoir to maintain an adequate minimum storage pressure for meeting working gas volume deliverability in any type of reservoir, the cushion gas volume is also required for stability reasons. *Working Gas Volume (WGV)* is volume of gas in the storage which is equal to total capacity minus the cushion gas which can be withdrawn/injected. In fact, it is the gas available to the market. *Deliverability* is the capability of the storage facility to withdraw working gas from the reservoir for delivery into pipelines to serve the marketplace. Various terms used to refer to deliverability are delivery rate, withdrawal rate, or withdrawal capacity [6].

An important parameter controlling the possibility of any UGS project is the time needed to inject the cushion gas. As the injection rate is increased, the field is prepared faster. However, due to cap rock stability, it is not possible to inject the gas with very high rates. As a result, it is required to find an optimum gas injection rate.

The optimum injection rate is achieved when the maximum amount of gas is injected with constant rate and the highest secure bottom hole pressure (BHP).

Nowadays, reservoir simulation is widely used in gas and oil industry. Simulation can be used as the ability to solve problems that are not resolvable by other methods. It can be the best method for describing fluid flow in a non-homogenous reservoir with a time schedule for injection and production. Simulation could predict reservoir performance and is used as an important tool in fields of making decisions and managements. In this work, UGS is simulated by a reservoir simulator (Eclipse).

Ahmadi anticline is a structure placed in south of Iran. It is an appropriate structure for underground gas storage. Khami, Kazeroun and Dehram geological groups are investigated for feasibility of UGS. Khami is nearly filled by water and Kazeroun and Deharm groups contain a non-combustive gas with more than 85 % nitrogen. Kazeroun group seems to be more suitable for UGS. In this study, static model of Kazeroun group was prepared and different dynamic scenarios are simulated by fluid flow simulator (Eclipse).

2. Methodology

In studying an underground gas storage process, one deals with important parameters such as reservoir and well properties, perforation's location, skin factor, horizontal and vertical permeabilites and their ratios. In this study, different status for these parameters is used as input to the simulator and the optimum injection rate for each case is found by sensitivity analysis.

As a result, a base case is considered and the simulation analysis is performed on this model. The base case has the following characteristics:

Table 1 The base case

Horizontal Permeability(Kx)	0.05 mD
Horizontal Permeability(Ky)	0.05 mD
Vertical Permeability(Kz)	0.025 mD
Porosity	From Real Field Data
Well Bore ID	0.5 ft.
Control mode on BHP	8000 psi (Layer to define BHP: Layer1)
Skin Factor	0
Depth	16726' -18214'
Pressure at Datum Depth(16736')	4737.7 psia
Preparation's Due	During 1800-2000 days

As it can be seen in Figure 1, the static model consists of 32 grids in x-direction, 24 grids in y-direction, and 7 grids in z-direction. In this study local grid refinement is also used around the well as it is shown in Figure 2, and the blocks around the well are divided into 3 Blocks in x-direction, 4 Blocks in y-direction, and 1 Block in z-direction.

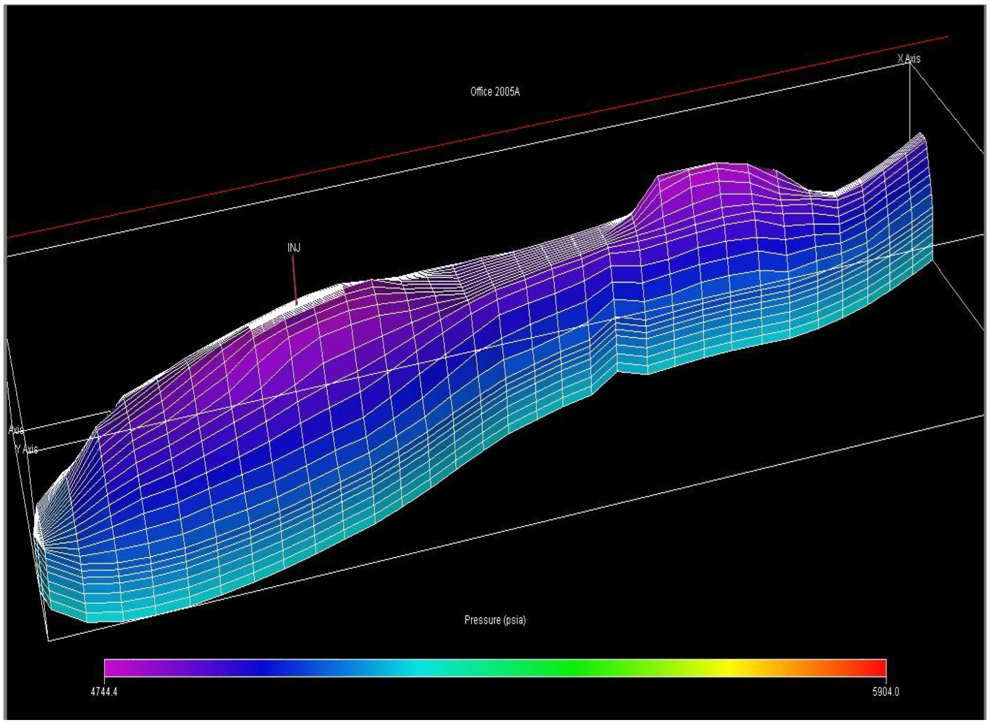

Figure 1 The static model structure

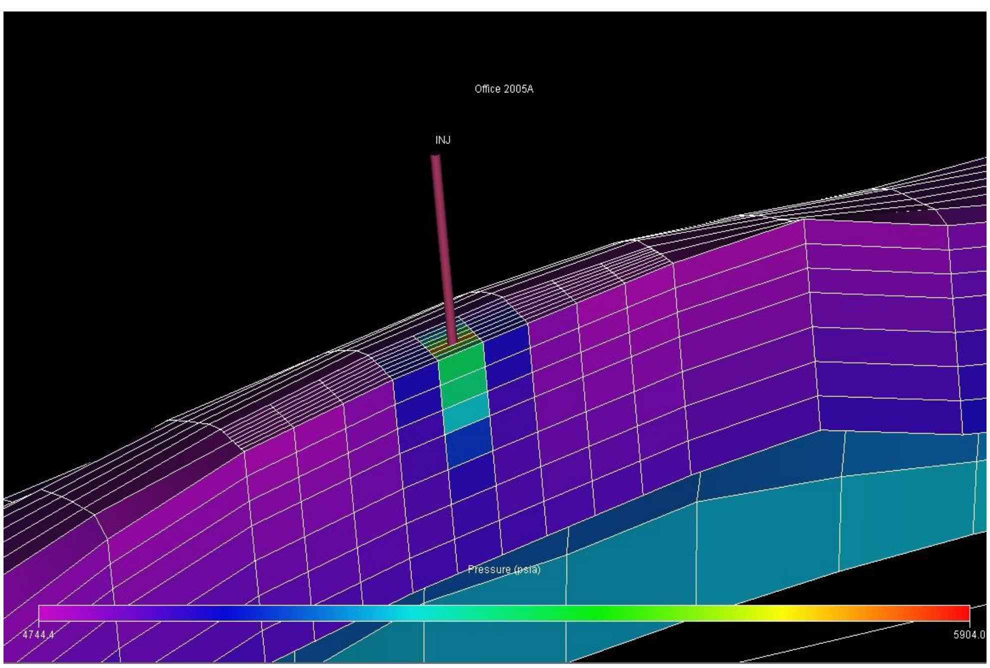

Figure 2 Local grid refinement used around the well

This model is then simulated and different scenarios are considered for this structure to investigate the significance of each parameter and figure out which one has the most vital effect on preparing the field faster for starting underground gas storage cycles.

3. Results and Discussion

3.1. Investigating the Effect of Locations of Well’s Perforations

The static model has 7 layers in z-direction, therefore different cases in which different well’s locations are perforated are simulated and the effect of the location of perforations on optimum injection rate is investigated. Figures 3-6 show the well gas injection rate (WGIR) vs. time for the following cases:

- Case 1: Layers 5-7 perforated
- Case 2: Layers 3-5 perforated
- Case 3: Layers 1-3 perforated
- Case 4: Layers 1-7 perforated (fully perforated)

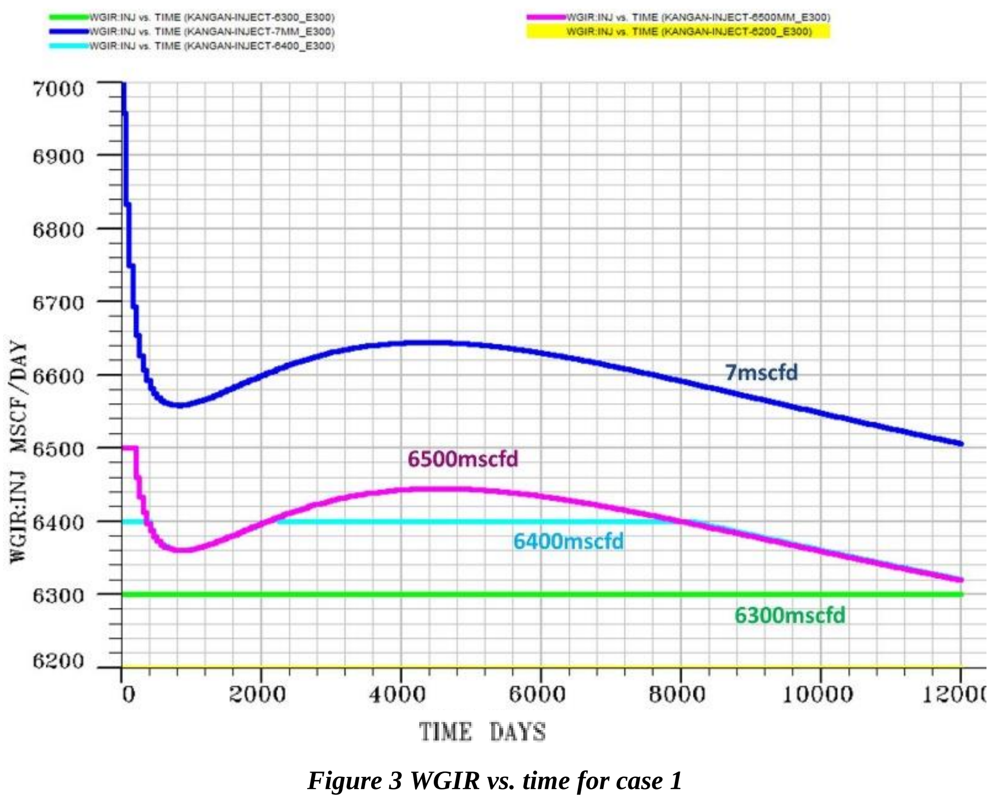

Figure 3 WGIR vs. time for case 1

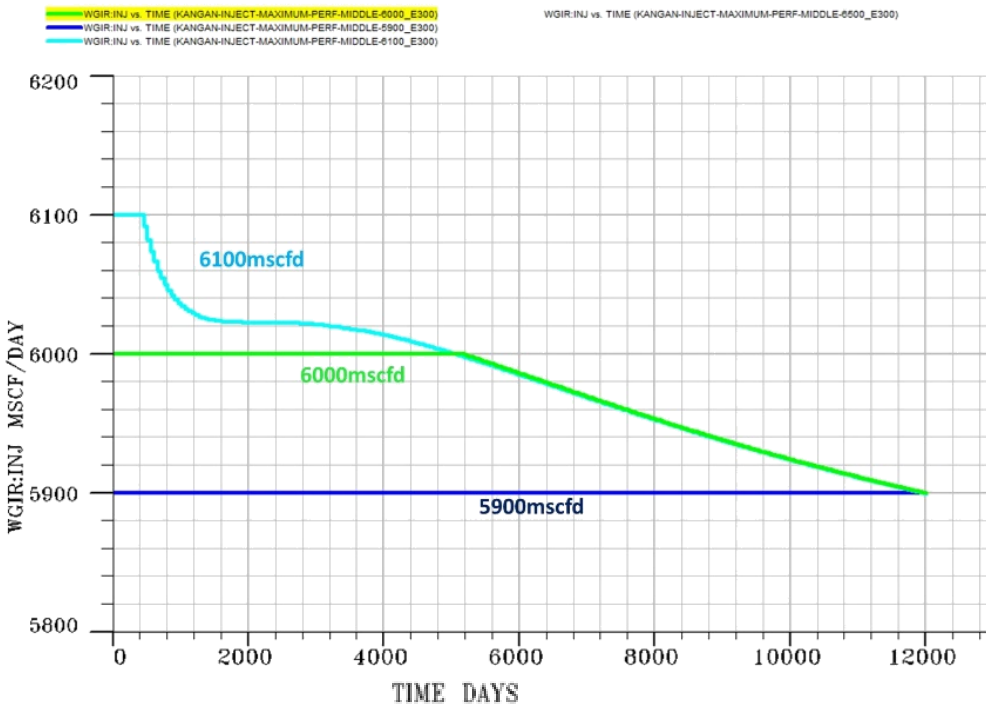

Figure 4 WGIR vs. time for case 2

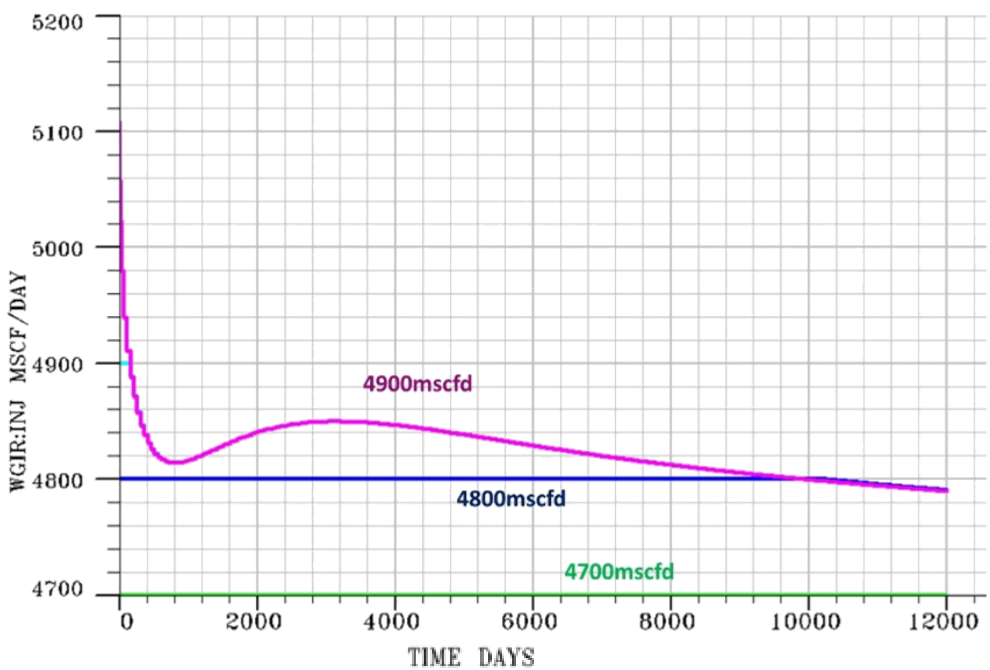

Figure 5 WGIR vs. time for case 3

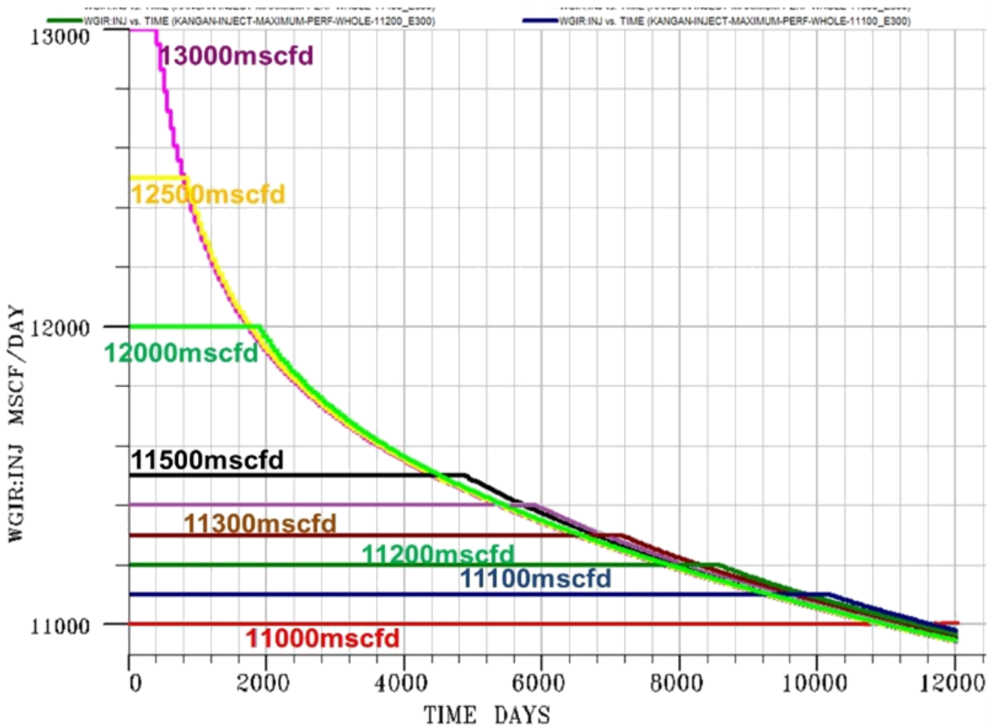

Figure 6 WGIR vs. time for case 4

Figure 3 is the case in which the well is perforated in layers 5 to 7. The results show that the optimum injection rate, which is constant during preparation time, for this case is 6300 MSCFD. This is the rate at which the maximum possible gas is injected into the reservoir without any sudden decrease in the injection rate due to caprock's pressure equality to BHP. In Figure 5, the same procedure is carried out while the perforation's location is at the highest point and close to the caprock; In this case, the injection rate is lower than other cases as the gas front reaches the caprock in a short time. The optimum injection rate for other cases are summarized in Table 2. It can be concluded that the optimum injection rate has linear relationship with perforation's locations as it is approximately the summation of each case's optimum injection rate.

Table 2 Results of optimum injection rate for each case

Layers Perforated	Optimum Injection Rate(MSCFD)
1-3	4800
3-5	6000
5-7	6300
Fully Perforated	12000

3.2. Investigating the Effect of Skin Factor

Another parameter which has an important effect in preparing the field for gas storage is skin factor. Positive skin can be appeared due to damage caused at different times and places in reservoir. For instance, fine migration, mud solids invasion, phase trapping, wettability alteration and surface adsorption effects near wellbore, and mechanical action of the bit near wellbore are different reasons that lead to positive skin factor and create large drops in production [7].

While positive skin leads to lower production or injection rate, negative skin has great impact on enhancing the injection or production rate in a field. There are several techniques for stimulating reservoir which can be chemical, thermal or hydraulic techniques. By injecting fluids into the formation, the available reservoir's volume will be enhanced and this leads to having more volume in the reservoir to be used for injection [8].

A simulation is performed on the model to investigate the effect of skin factor on the optimum injection rate. The range of skin factor varies from -5 to +5 in order to figure out which skin has more significant effect on reducing or improving the injection rate and consequently preparing the field for gas storage faster. As a typical example the results for cases in which skins were +2 and -2 are presented in Figures 7 and 8 respectively.

Figures 9 and 10 show the optimum injection rate for each value of skin factor. In positive ranges of skin factor, there is slight change in slope of figure. This shows formation damage does not cause a sudden decrease in optimum injection rate. On the other hand, in negative ranges of skin factor, there is sudden increase in optimum injection rate as skin factor increases. This shows a negative skin, which can be achieved by stimulation methods such as acidizing or hydraulic fracturing, increases the optimum rate for injecting cushion gas while reduces the preparation time of the field for gas storage; Indeed, it can be concluded that using stimulation methods lead to high injection rate while it saves costs of drilling another wells.

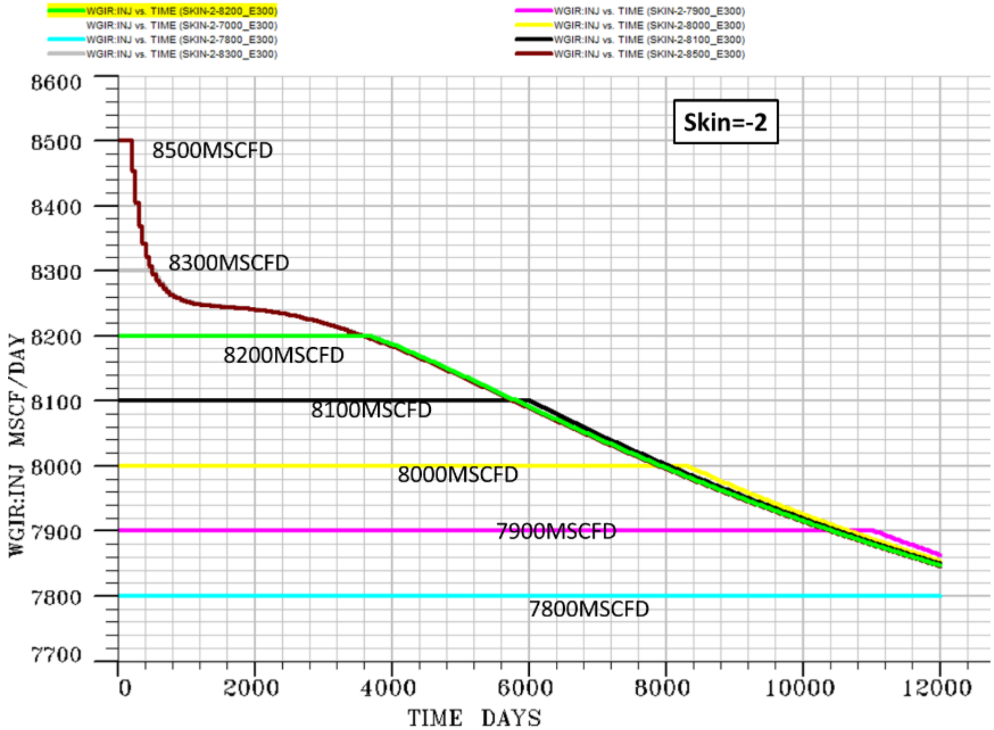

Figure 7 WGIR vs. Time for skin = -2

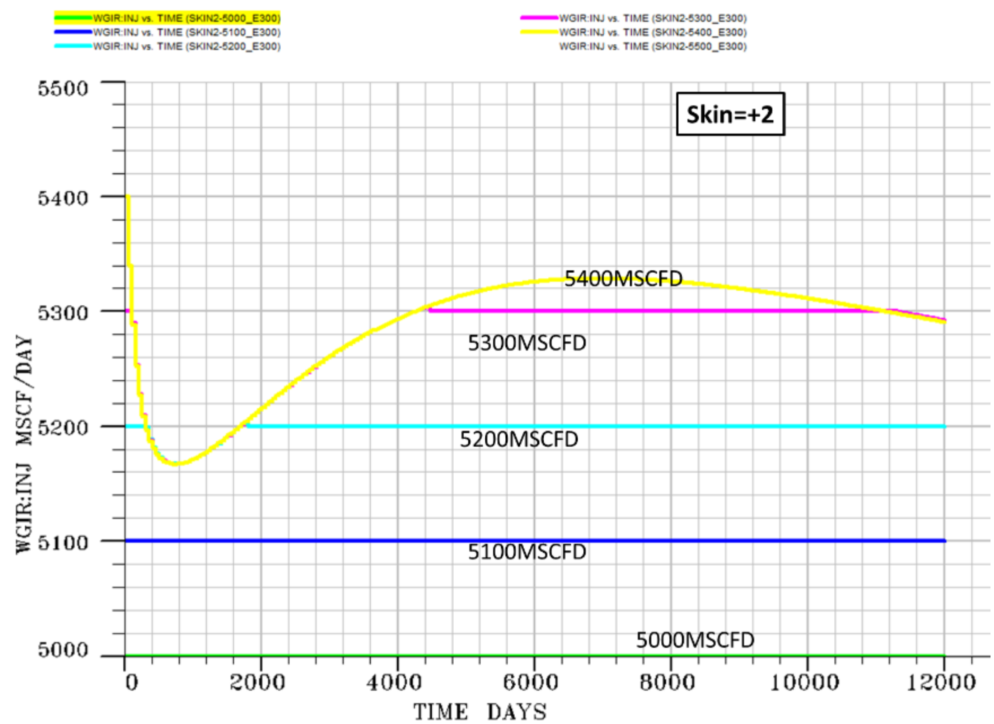

Figure 8 WGIR vs. Time for skin=+2

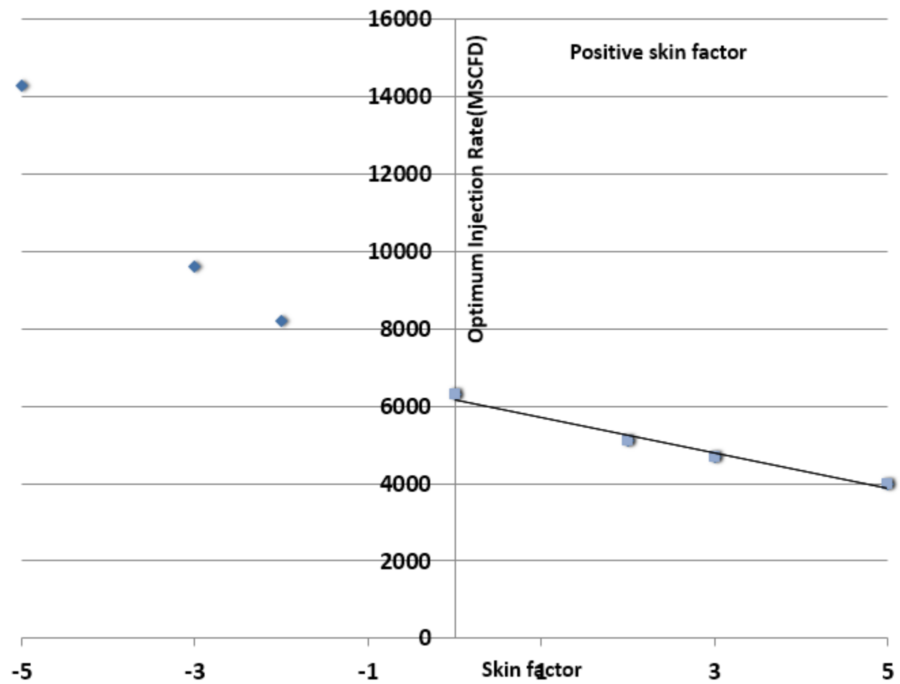

Figure 9 Effect of skin factor (positive ranges) on optimum injection rate

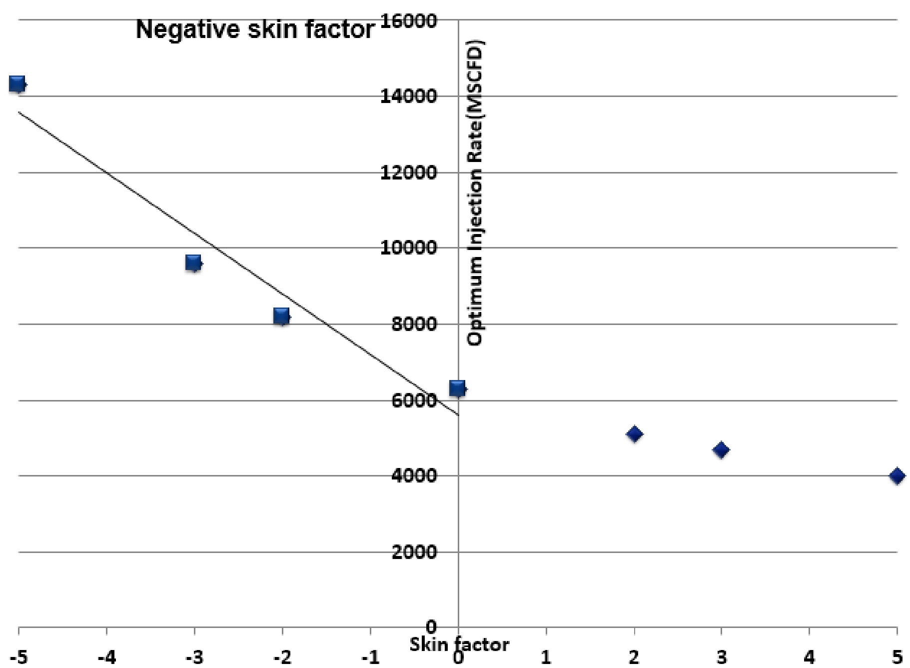

Figure 10 Effect of skin factor (negative ranges) on optimum injection rate

3.3. Investigating the Effect of Vertical over Horizontal Permeabilities (k_V/k_h)

Most of the reservoirs are not homogenous and the vertical over horizontal permeability ratio varies within the reservoir which is known as anisotropy. In this section, the effect of this parameter is studied in order to investigate the importance of reservoir anisotropy on the final optimum injection rate. Different scenarios are simulated for different values of k_v/k_h changing from 1 to 0.1 and the results are compared with the base case (ratio of k_v/k_h=0.5). A typical example generated for the case in which k_v/k_h is equal to 0.1 is presented in Figure 11. All optimum injection rates measured for different cases are summarized in Table 3. The results show the ratio of vertical to horizontal permeabilities has minor effect on the optimum injection rate and the injection rate decreases slightly as the permeability ratio decreases.

Table 3 The optimum injection rate measured for different k_v/k_h

Kv/Kh	Optimum Injection Rate (MSCFD)
1	6500
0.8	6400
0.5	6300
0.25	5900
0.1	5700

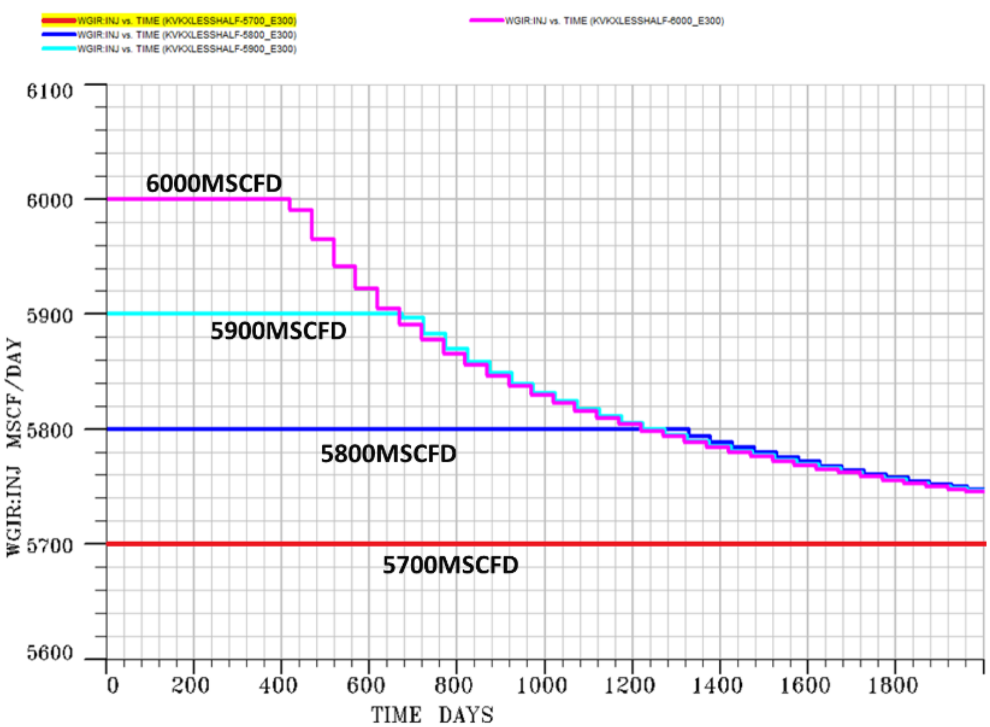

Figure 11 WGIR vs time for kv/kh=0.1

3.4. Investigating the effect of Different Horizontal Permeabilities

To study the effect of horizontal permeability on optimum injection rate, the k_v/k_h ratio is assumed to be constant, and different scenarios for different values of horizontal permeabilites are simulated. Figure 12 is a plot of the values of optimum injection rates versus horizontal permeability. The results show that there is a linear relationship between k_h and optimum injection rate which makes this parameter the most effective one. It can also be justified by Darcy's law which indicates the linear relationship between flow rate and formation permeability.

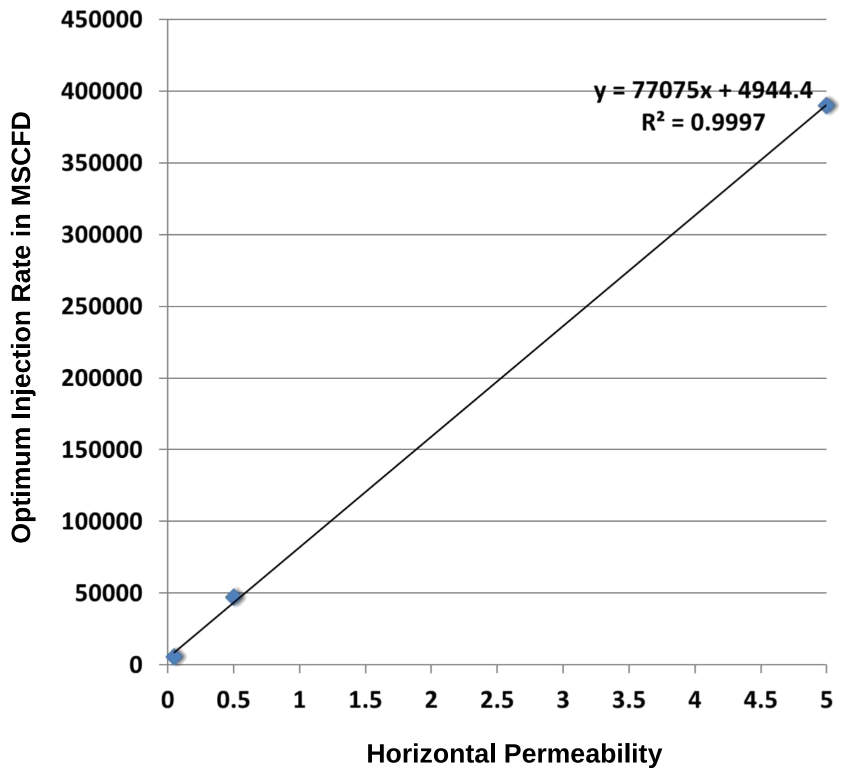

Figure 12 Effect of horizontal permeability on optimum injection rate

4. Conclusions

The purpose of this work was to examine a case study to find the optimum injection rate, i.e., the rate by which as much gas as possible is injected into the field with the highest bottom-hole pressure that is secure for gas storage. Moreover, this optimum injection rate must be constant during the preparation's period. Optimum injection rate is a function of reservoir properties like vertical/horizontal permeability ratio (kv/kh), skin factor, horizontal permeability and the well perforation's locations. Sensitivity analysis was performed using fluid flow simulation technique to investigate the importance of these parameters.

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