OLGA Modeling Results for Single Well Reinjection of Non-Condensable Gases (NCGs) and Water

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Keywords

Production technologies, injection well design, NCG injection, CO2 injection, OLGA, injection transient modeling, high temperature reservoir

ABSTRACT

A simultaneous gas and water reinjection system for a high temperature geothermal project has successfully been modeled, which provides critical insight into how to better design and operate a gas and water injection system under various operating conditions. A model of the system was developed using the OLGA simulation software, including two-phase buoyancy and thermal effects, and has been able to accurately model the downhole injection of non-condensable gases (NCGs) (consisting of primarily CO_2) into a water injection stream. The overall results of the modeling analysis have demonstrated that the single-well injection system is a feasible approach to reinject both NCGs and water.

The modeling feasibility study was performed using the OLGA simulator, which is a general transient multi-phase simulator for flow in pipes and wellbores used extensively within the oil industry to model multi-phase flow. The OLGA simulation model developed was able to account for the individual properties and solubility of all seven gas components found in the geothermal fluid (CO_2, H_2S, NH_3, Ar, N_2, CH_4, and H_2). The model was then used to perform sensitivities to investigate the impact mixing depth, injectivity index, and gas mixture solubility would have upon the required gas injection pressure.

The system was modeled through complete operating conditions including start-up, steady-state operation, and shut-down, in order to best understand how the system will perform under both static and dynamic operating conditions.

The results indicate that the optimum gas reinjection depth, which would minimize cost and the injection pressure, is between 300 m and 500 m depth for the system modeled. The model indicates that the NCG-water mixture can be injected under all conditions examined, provided enough injection pressure on the brine and NCG injection line.

In addition to minimizing injection power requirements, the OLGA model has also benefited the project by demonstrating that by reducing the gas

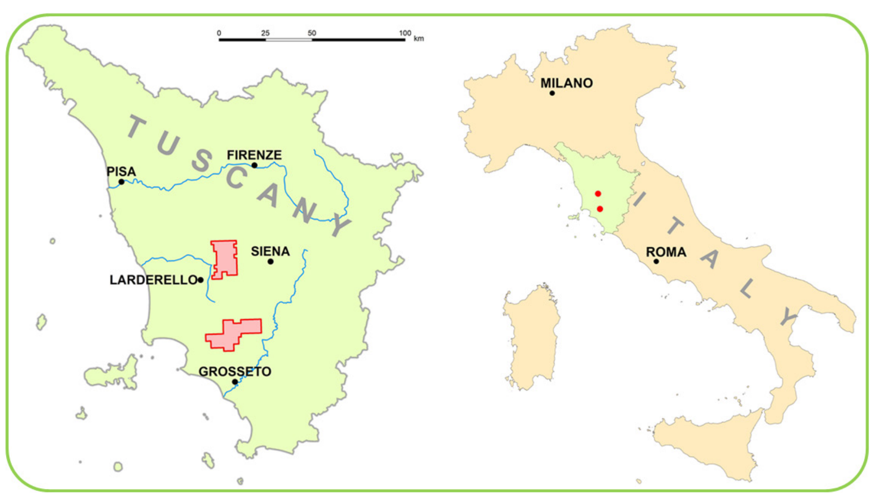

Figure 1. Map of Project Area.

injection depth the difficulty of shutdown and startup operations for the injection well can be reduced by reducing the gas injection pressure.

Overall, the modeling feasibility study has confirmed the concept of using a single well for concurrent NCG and water reinjection, the next step will be to design the well completion to implement this injection system.

1. Introduction

Geothermal energy has been utilized for electrical generation in Italy for more than 100 years. With over 900 MW of electrical geothermal capacity installed and operated by ENEL today. Recently the market of geothermal electric power generation has been liberalized and several players are now actively engaged in the exploration and development of new geothermal projects in Italy.

Magma Energy Italia (MEI) is developing geothermal licenses in Tuscany (Italy), adjacent to the Larderello-Travale geothermal field (Figure 1), for power generation from high enthalpy fluids whose presence is known within deep reservoirs (about 2.5-4 km) in metamorphic rocks, mainly phyllites and micaschists [1, 2, 3].

Recently, extensive exploration programs have been executed by Magma Energy Italia, including a geo-structural survey in partnership with the Universities of Siena and Bari, geophysical surveys (Gravity, Magnetic, MagnetoTelluric) through WesternGeco-Schlumberger (internal reports, unpublished) and a reflection seismic survey, being executed during 2016. As a result of the surveys executed, some drilling projects have been filed.

Part of the unique concept for the geothermal development, will be the system will reinject all produced fluids, including CO_2 and non-condensable gases, back into the reservoir with deep injection wells [4]. In order to prove the feasibility of this reinjection concept a series of multi-phase flow simulations have been performed using the OLGA multi-phase flow simulator to determine the required injection pressures, and the feasibility of mixing multiple injection streams downhole during injection.

The simulation study of the proposed injection system required the evaluation of the system behavior under the following conditions:

1. Steady-state injection with the soluble NCG composition that mainly consists of CO2.
2. Steady-state injection with a highly insoluble NCG composition to understand the impact solubility has upon the feasibility of the injection system.
3. Startup and shutdown of the injection system including the soluble NCG composition mainly consisting of CO2.

2. Methodology

A suite of simulations have been performed using the transient multiphase flow simulator, OLGA. These simulations encompass modeling injection of non-condensable gases (primarily CO2) into the condensed steam injection stream. This study evaluated steady-state injection conditions along with transient conditions that occur during start-up and shut-in. As a result of these simulations, both non-condensable gas, and condensed steam injection pressures were evaluated over a plausible range of reservoir injectivities. In this study, both fluid phase behavior and thermal effects were taken into account.

2.1 OLGA Modeling

In this study, the computer program OLGA was used. OLGA is a general transient multiphase simulator for flow in pipes and wellbores. The latest commercial OLGA version, 7.3.5, was used. In order to determine the phase behavior of mixing near-single-component non-condensable gas (NCG) and condensed steam (Brine) streams, the compositional tracking feature of OLGA was employed. In this feature, all fluid properties are calculated using the local, instantaneous, chemical composition of the flowing mixture. General characterization of the fluid properties of the constituent chemical components of the flowing mixture was accomplished using the equation-of-state program Multiflash, version 4.3.1.

2.2 Well Description

The schematic of the injection well simulated is shown in Figure 2.

Figure 2 shows the borehole geometry of the injection well and the expected geology. The NCG mixture is injected through a 2⅞″ tubing string, while the brine is injected through the annulus between the 2⅞″ tubing string and a 7″ tubing string. The depth of the NCG mixture injection is the primary design variable of concern and will be established according to simulation results.

Below the mixing point it was assumed that the mixed fluid would exit the well and enter the reservoir at a single fracture at a depth of 3,000 m TVD. At this fracture entrance, the reservoir temperature was assumed to be 250°C, and the reservoir static pressure was assumed to be 85 bar, which represents a reasonable estimate for the reservoir pressure based on nearby data and the reservoir pressure estimated in the geothermal reservoir model prepared by GeothermEx and Magma Energy (unpublished). Surroundings temperature were assumed to increase linearly from 20°C at 0.0 m TVD to 250°C at 3,000 m, which is in good agreement with the local geothermal gradient.

In order to inject the fluid, the injection pressure at the fracture entrance must be higher than the static reservoir pressure encountered at the fracture entrance. The fractures resistance to injection is accounted for through reservoir injectivity. Two reservoir injectivity values were considered as shown in Table 1.

The NCG stream was assumed to have the composition shown in Table 2, which shows that the injection gas stream is overwhelmingly composed of CO_2

For the purposes of this study, the injected Brine was assumed to be composed solely of water with the exception of 0.01 weight % of each of the components CO_2 and H_2S. The exact concentrations of these acid gases make some, although not crucial, differences in the amount of gas flashed from the Brine stream above the mixing point. Below the mixing point, however, the large amount of NCGs in the mixed stream overwhelms the impact of any acid gases originating in the Brine stream.

Heat transfer between the injection streams and the surroundings was accounted for in a rigorous fashion. Radial heat flow between the streams and the casing strings and between the casing strings was determined through conduction through the appropriate media. Multiple radial layers were considered, including seven rock layers cumulatively about 128" thick. The rock was assumed to have a specific heat capacity of 0.25 btu/lbm-F, a thermal conductivity of 1.00 btu/ft-h-R, and a density of 62lb/ft3.

The heat transfer between the NCG and Brine streams was treated as occurring in a co-current heat exchanger.

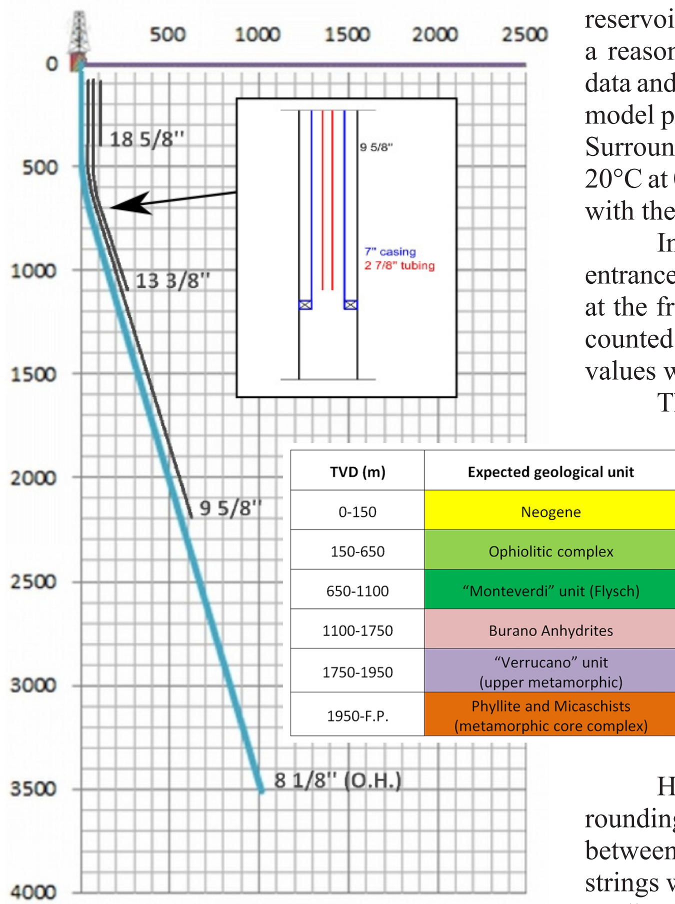

Figure 2. Schematic of proposed injection well and completion design.

Table 1. Summary of Injectivity range evaluated in study.

	Injectivity Index (t/hr/bar)
Low estimate Injectivity (t/hr/bar)	1.78
High Estimate for injectivity (t/hr/bar)	8.90

3. Results

Nine different injection sensitivities were evaluated to fully understand how the system could behave under various design scenarios. Table 3 summarizes the scenarios evaluated and included within the study. The primary design variable investigated was the depth at which the non-condensable gas (NCG) could be injected into the down flowing brine stream. The depths investigated ranged from 0 m measured depth (m-MD) to 1250 m-MD. The secondary variable investigated was injectivity, in order to understand what impact the injectivity would have upon selecting the NCG injection depth. The low injectivity assigned was 1.78 ton/hr/bar, based on the lowest injectivity measured in a nearby well. From this measured value a high estimate of 5 times the low value was used (8.9 ton/hr/bar). This range from 1.78 to 8.9 ton/hr/bar was used to adequately capture the range of well injectivity with the highest likelihood of being encountered when the well has been completed.

Table 2. NCG Injection Stream.

	% of NCG Stream	
CO_2	97.50%	
H_2S	2%	
Other	0.50%	% of "Other"
NH_3	0.0451%	9.03%
Ar	0.0003%	0.06%
N_2	0.0340%	6.79%
CH_4	0.1925%	38.50%
H_2	0.2281%	45.62%

Table 3. Steady-State Injection Scenarios Evaluated.

		Scenarios Evaluated					
		Mixing Depth (m-MD)					
		0	250	500	750	990	1250
Nearby Measured Injectivity (ton/hr/bar)	1.78	Completed	Completed	Completed	Completed	Completed	Completed
High Estimate for injectivity (ton/hr/bar)	8.90	---	---	---	Completed	Completed	Completed

3.1 Steady-State Cases Considered With Soluble NCG

The first condition analyzed was for when the system operates under steady-state conditions. For all steady-state simulations considered, the total mass injection rate in the well was assumed to be 20 kg/s. This rate was composed of a bine stream injection rate of 18.4 kg/s, and a NCG rate of 1.6 kg/s. The Brine stream was assumed to be injected at the casing head at a temperature of 85°C, while the NCG stream was assumed to be injected at a temperature of 50°C. In these simulations, both Brine and NCG injection rates were assumed to be time invariant. No pump head curves were assumed, and wellhead injection rates were assumed to be insensitive to wellhead pressures.

The critical results from all 9 simulation scenarios have been replotted and presented in Figures 3 thru 11. The pressure profile are plotted for each injection string with respect to measured depth. The purple line represents the pressure profile of the water-NCG mixture in the well below the NCG injection point, while the red and blue line represent the NCG injection string and the liquid brine injection string respectively (Note: the red and blue line are not present in Figure 3 as mixing occurs just before entering the wellhead and no separate injection strings do not exist).

In Figure 2 the base design is shown in which mixing of the NCG and Brine stream occurs at 990 m TVD, additional cases were simulated for mixing depths (TVD) of 750, and 1,250 m. In addition shallow mixing points involving 2 7/8” tubing strings to each of 250 m, and 500 m were simulated. Finally, a simulation was performed for which no 2 7/8” string was included, and the NCG and Brine streams were mixed at the casing head.

The primary simulation matrix consisted of nine simulations including mixing depths (TVD) of 750 m, 990 m, and 1,250 m. For each of these mixing depths reservoir injectivity of 1.78 t/bar-hr, and 8.90 t/bar-hr were simulated. All simulations were run long enough to permit steady-state conditions to be reached.

In addition to this primary simulation matrix, two cases were run to investigate the impact of injecting at shallow mixing depths (TVD) of 250 m and 500 m, using short sections of 2⅞″ tubing. Finally, in taking the shallow injection sensitivity to the limit, a simulation was run where no 2⅞″ tubing string was used. For this case the Brine and NCG streams were mixed at the casing head.

Tables 4 and 5 present a summary of the wellhead pressure for both the liquid and NCG injection strings in each scenario plotted in Figures 3 - 11. Table 4 presents the NCG injection pressure required to inject the NCG into the down flowing brine stream. Where the yellow and red cells indicate less favorable wellhead pressure (around 60 bara), while green cells indicate lower, more favorable injection conditions. Table 5 presents the wellhead pressure on the brine injection line, where injection pressures above the plant discharge pressure of 9.6 bara are unfavorable (due to the necessity of a booster injection pump) and colored red, while lower more preferred injection pressure below 9.6 bara are colored green. In examining the Figures 3 through 11 and Tables 4 and 5, the following conclusions may be drawn from the scenarios evaluated;

- A well with injectivity lower than 1.78 ton/hr-bar would begin to require substantial injection pressure on both the brine and NCG injection side. With very low injectivity (<1.0 ton/hr-bar) the NCG injection pressure would likely be unfavorably high along with the brine injection pressure, leading to the conclusion that a low injectivity well cannot be considered appropriate for the purpose of operations.

- The benefits of a high injectivity well are significant. The increase in injectivity reduces the wellhead pressure on the NCG line slightly, but due to the injected fluid being a gas, the wellhead pressure does not decrease as significantly as would occur when injecting a liquid. On the brine line no added benefit is realized with higher injectivity, the wellhead pressure remains below atmospheric pressure at 0.4 bara (when the NCG injection string is installed below 500m).

- As the NCG injection mixing depth is decreased the required NCG injection pressure decreases as well. At the extreme with mixing at the surface the NCG injection pressure can be reduced down to 22 bara.

Table 4. NCG injection Pressure required at the wellhead for each scenario evaluated.

		NCG Line Injection Pressure (Bar-a)					
		Mixing Depth (m-MD)					
		0	250	500	750	990	1250
Nearby Measured Injectivity (ton/hr/bar)	1.78	22.0	33.1	42.7	52.4	58.4	63.3
High Estimate for injectivity (ton/hr/bar)	8.90	---	---	---	47.4	52.9	53.7

Table 5. Brine injection pressure required at the wellhead for each scenario evaluated.

		Brine Line Injection Pressure (Bar-a)					
		Mixing Depth (m-MD)					
		0	250	500	750	990	1250
Nearby Measured Injectivity (ton/hr/bar)	1.78	22.0	6.3	0.4	0.4	0.4	0.4
High Estimate for injectivity (ton/hr/bar)	8.90	---	---	---	0.4	0.4	0.4

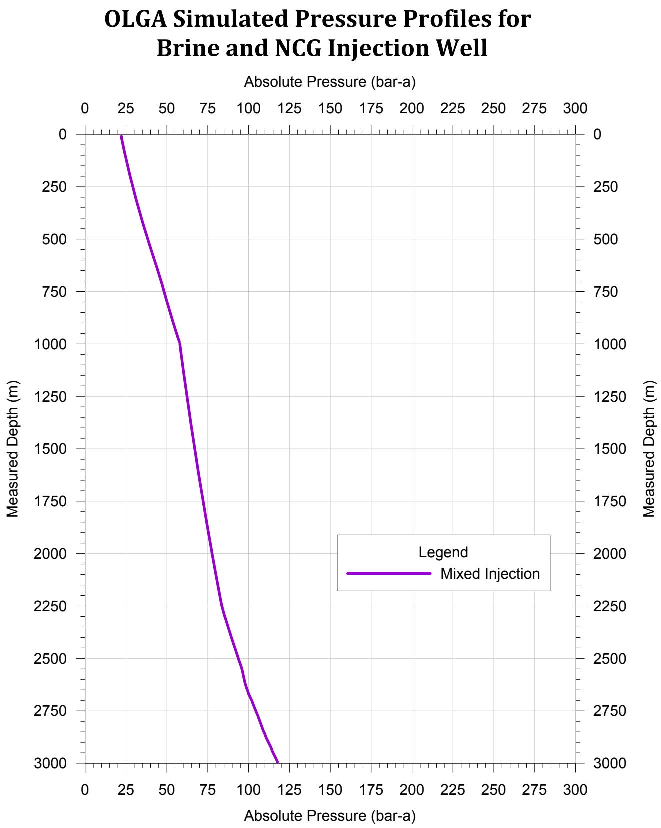

Figure 3. Brine and gas injection with mixing occurring at 0 m depth and an Injectivity Index equal to 1.78 ton/h/bar.

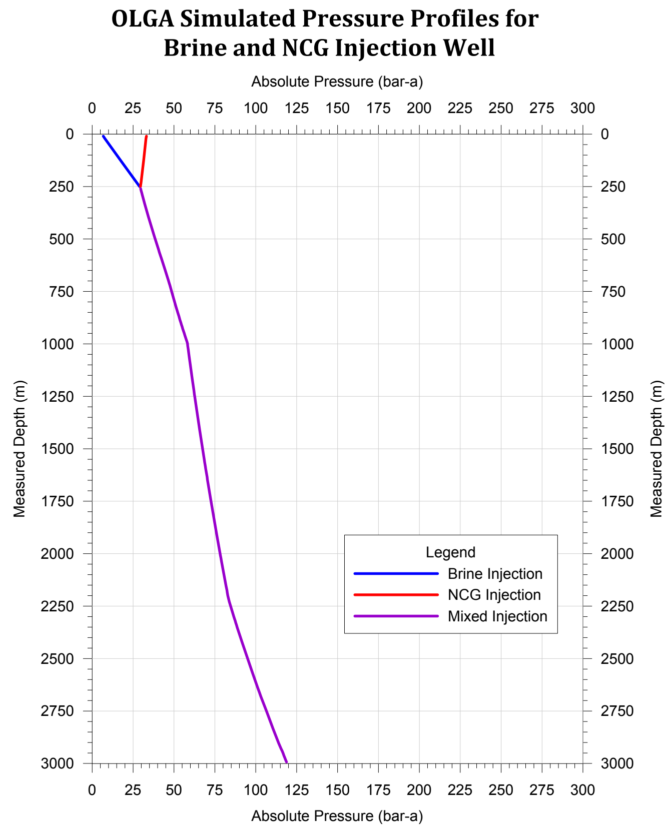

Figure 4. Brine and gas injection with mixing occurring at 250 m depth and an Injectivity Index equal to 1.78 ton/h/bar.

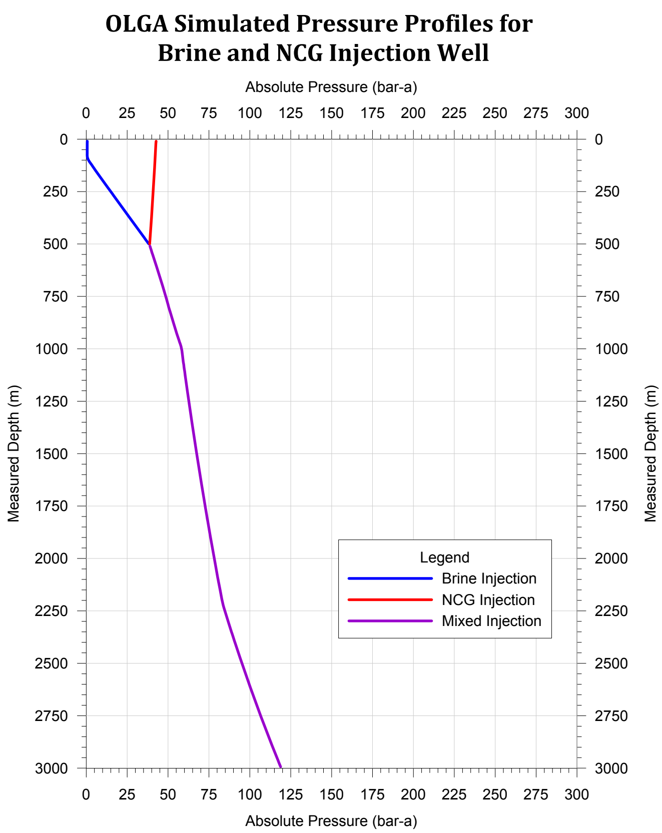

Figure 5. Brine and gas injection with mixing occurring at 500 m depth and an Injectivity Index equal to 1.78 ton/h/bar.

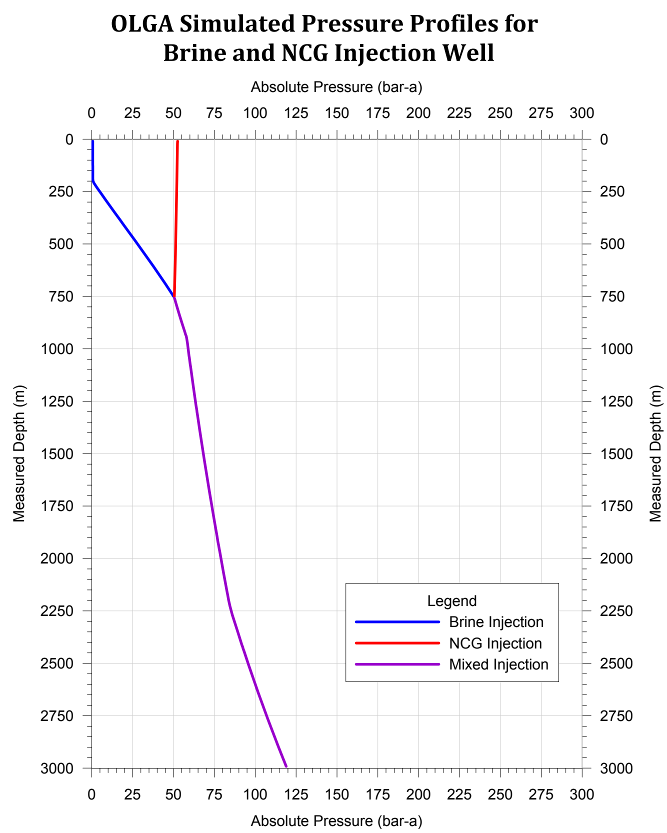

Figure 6. Brine and gas injection with mixing occurring at 750 m depth and an Injectivity Index equal to 1.78 ton/h/bar.

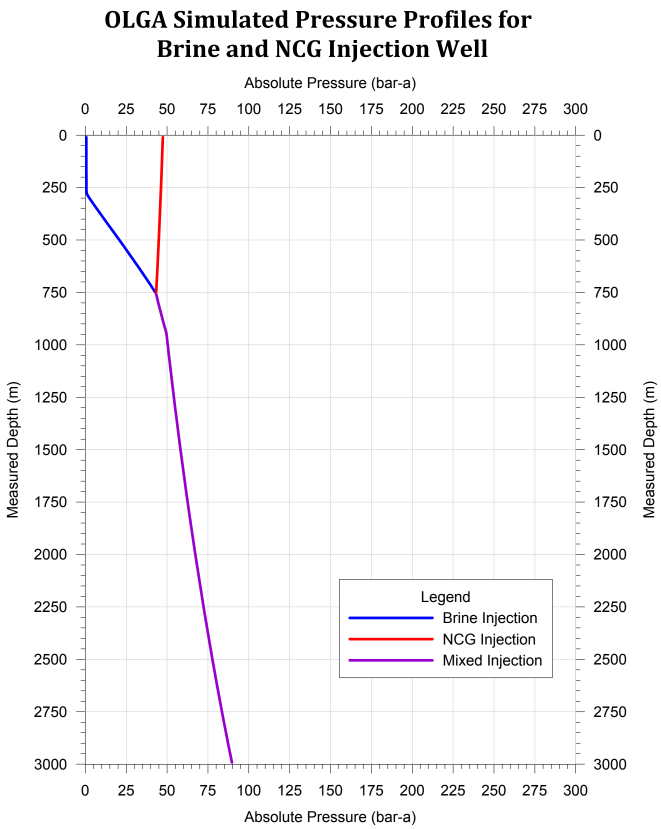

Figure 7. Brine and gas injection with mixing occurring at 750 m depth and an Injectivity Index equal to 8.90 ton/h/bar.

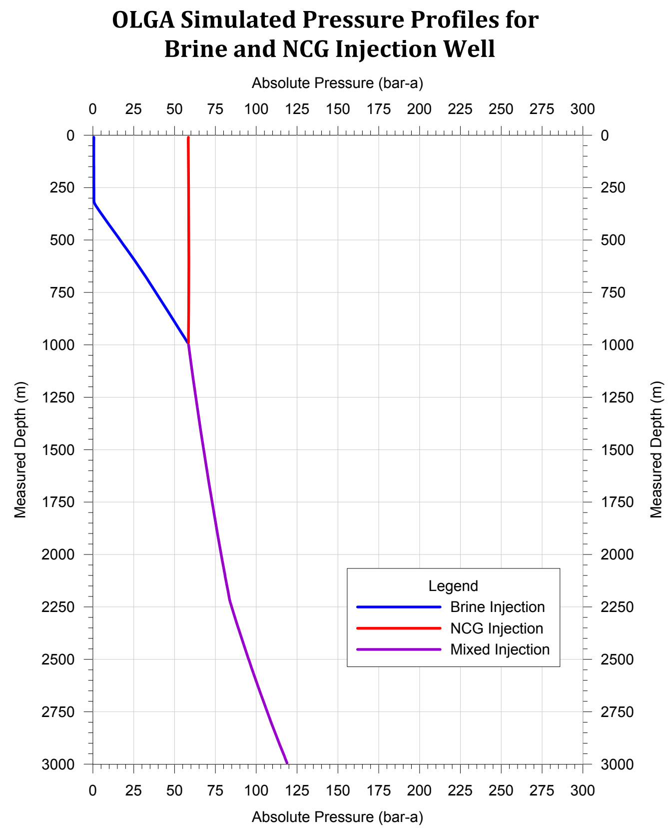

Figure 8. Brine and gas injection with mixing occurring at 990 m depth and an Injectivity Index equal to 1.78 ton/h/bar.

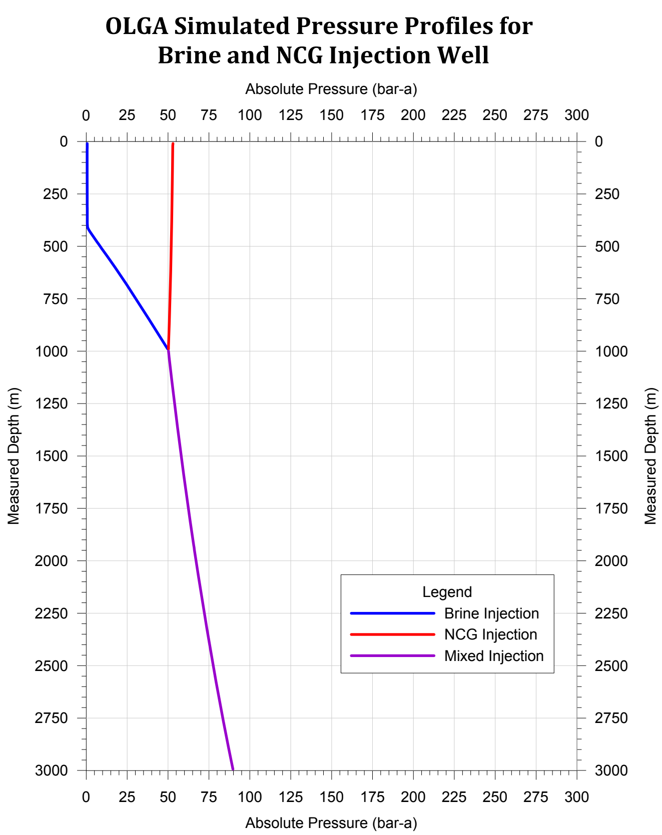

Figure 9. Brine and gas injection with mixing occurring at 990 m depth and an Injectivity Index equal to 8.90 ton/h/bar.

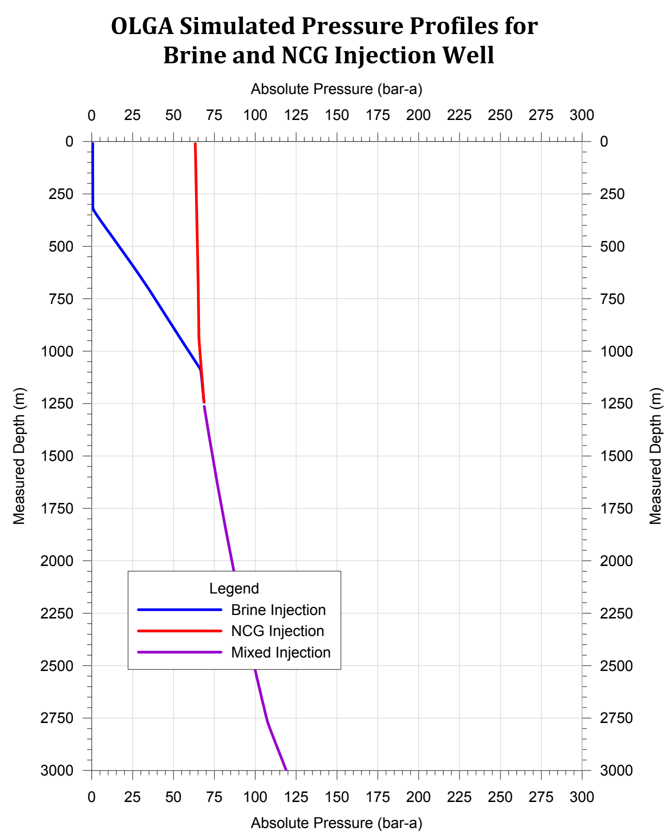

Figure 10. Brine and gas injection with mixing occurring at 1,250 m depth and an Injectivity Index equal to 1.78 ton/h/bar.

- On the brine line, as the NCG injection mixing depth is decreased, eventually the reduced density of the upper section of the mixed fluid column results in the observation of surface wellhead pressure. This results in the brine line injection pressure becoming greater than atmospheric pressure, and would require the use of a brine injection pump. Therefore, reducing the NCG injection depth too much would result in an increase in brine line injection pressure.
- The modeling results indicate that the maximum pressure stress at the fracture during the continuous reinjection operation would remain less than the pressure imposed by the drilling fluid during drilling operations. The value of the overpressure at the fracture at 3000 m varies between about 30 bara, for low injectivity, and about 5 bara for high injectivity. In the case with the highest injection pressure, the overpressure generated is an order of magnitude lower than the overpressure applied during the drilling operation by fluid circulation. .

3.2 Steady-State Injection With Insoluble NCG

In order to understand the impact the solubility of the gas has upon the injection design a sensitivity cases was run to evaluate the impact. Figure 12 illustrates the impact solubility has on the effectiveness on the injection system. For this case the injection depth was set to 500 m, Injectivity Index = 1.78 t/h/bar and the NCG injection stream used was 100% nitrogen which is highly insoluble in water.

To appreciate the impact solubility has Figure 12 can be compared to the results shown in Figure 5, where the normal soluble NCG composition was used. In comparing the two it can be seen that the fluid column is significantly less dense below the mixing point when the injected NCG cannot dissolve. This results in an increase in the injection pressure required to dispose of the fluid. The brine injection pressure increases from 0.4 bar to 25 bar, while the NCG injection pressure increases from 43 bara to 75 bara, due to the reduction in solubility of the NCG injection stream. Therefore, the solubility of CO_2 and H_2S is quite beneficial for this injection design and must be properly accounted for when modeling the system.

Despite the lower permeability considered in this case, there is no substantial difference in the overpressure needed at the fracture entrance to inject the fluid into the reservoir: the use of an insoluble NCG would increase the pressure in the fracture of less than 5 bar, which represents a minor increase.

3.3 Startup and Shutdown Transients

To better understanding how the injection system would perform under real operation conditions, the dynamic capabilities of OLGA were utilized to model the systems behavior during start-up and shut-down. The modeling results of the system being shut-in is shown in Figure 13. In the shut-in operation, the brine stream was closed 15 min after

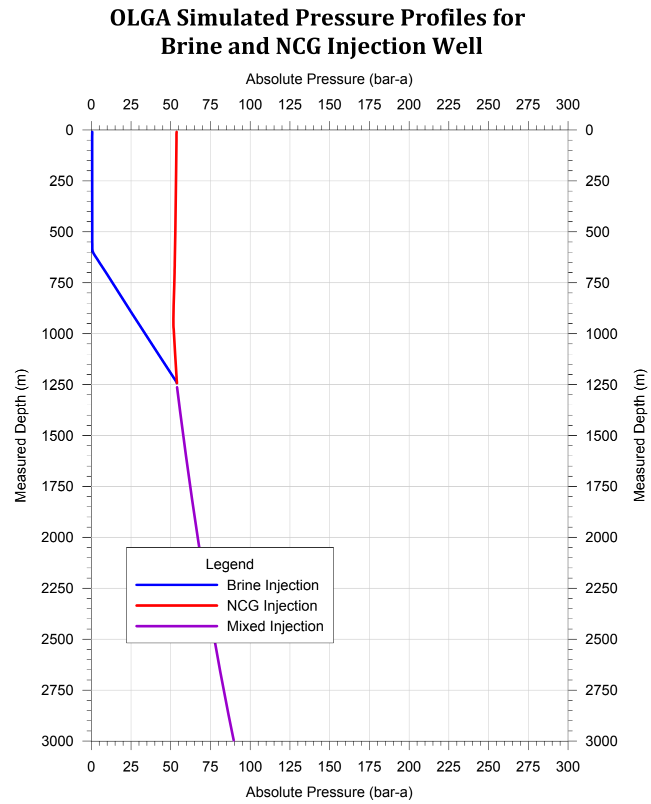

Figure 11. Brine and gas injection with mixing occurring at 1,250 m depth and an Injectivity Index equal to 8.90 ton/h/bar.

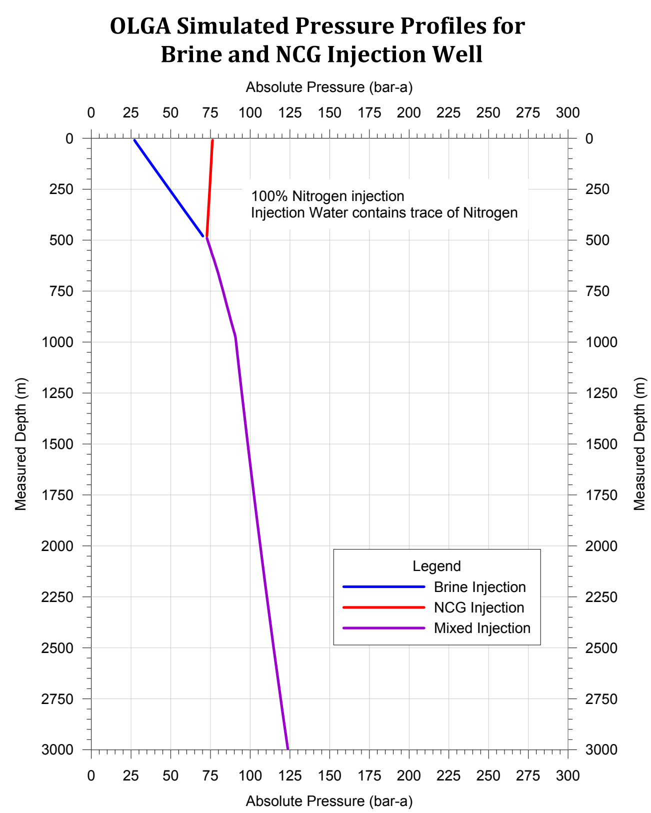

Figure 12. Injection of insoluble gas (N2) with mixing occurring at 500 m depth and an Injectivity Index equal to 8.90 ton/h/bar.

the NCG injection was stopped. During this initial 15 minutes the NCG injection pressure declines as there is less NCG in the mixed fluid column deeper in the well. Then when the brine injection stops both the brine and NCG wellhead pressure increase back to static conditions.

Following this sudden shut-in of the injection well, a follow on investigation was performed to understand what would be required to restart injection, without venting the gas in the well to the atmosphere in order to maintain the operator's objective of protecting the environment. Figure 14 presents this scenario where the system is restarted after proceeding through the above shut-in operations without releasing the accumulated gas in the well. To overcome this pressure buildup the brine injection pump would need to initially inject fluid at high pressures approaching 50 bar to enter the well and displace the NCG accumulated at the wellhead. However, after 15 min the brine wellhead pressure would collapse and return to vacuum as observed during steady-state operations. The NCG injection stream was then restarted after 2 hours and the injection pressure was shown to quickly reach steady state. Under conditions where the gas within the well is vented, the brine injection could resume under vacuum wellhead pressure conditions, and the brine injection would not need to overcome the initial 50 bar wellhead pressure caused by the trapped gas.

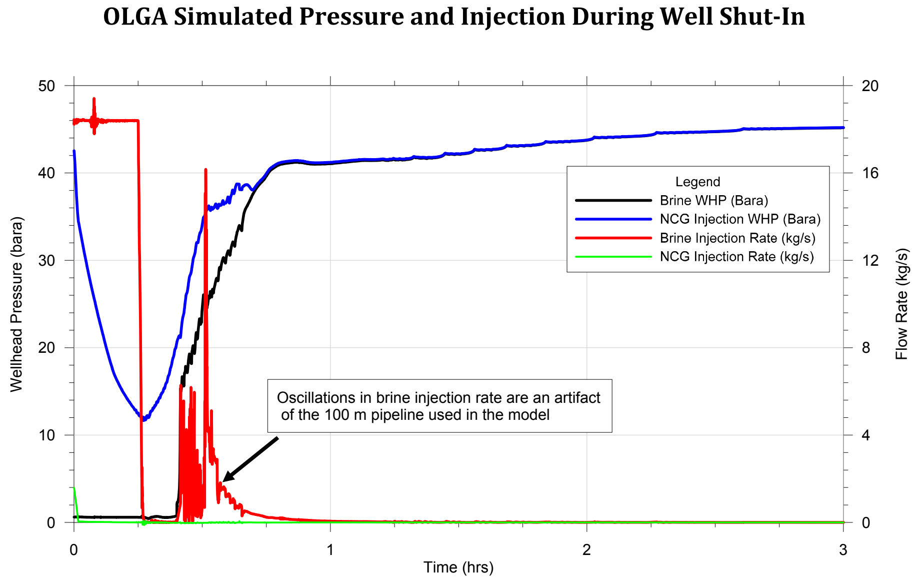

Figure 13. Shut-in transient model results.

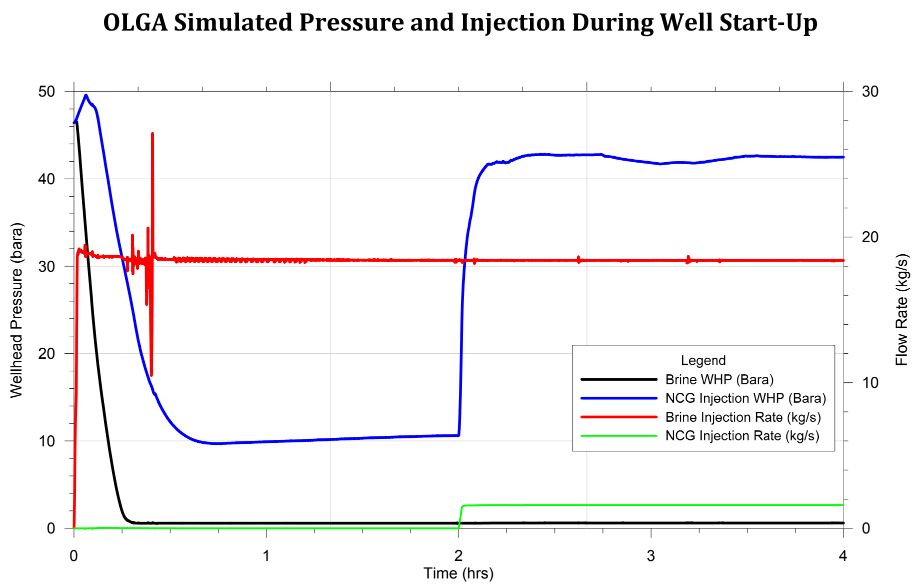

Figure 14. Start-up Transient Results.

Based on these modeling results indicating high pressure injection pumps would be required to restart injection if the gas is not vented to the atmosphere, current efforts are being performed to evaluate the feasibility of reducing the startup pressure by releasing the gas pressure back into surface equipment. This would allow the operator to maintain their objective of 100% reinjection of all produced fluids.

4. Conclusions

Following the completion of this study in which we examined the feasibility of using a single-well Injection system to dispose of a NCG-water mixture, we have arrived at the following conclusions and recommendations.

- The OLGA simulation model indicates that the proposed single-well injection system to dispose of NCG and water is a feasible design.
- The modeling results have shown that with sufficient injection pressure on both the brine injection line and the NCG injection line that counter-current flow will not occur during steady-state injection operations.

- The NCG injection string depth can be placed at relatively shallow and still adequately dispose of the NCGs. By reducing the depth of the NCG injection string the injection pressure can be reduced, thereby reducing the cost of injection operations. In order to reduce the amount of power required for injection, an injection depth between 300 m and 500 m would be the most favorable injection depth, based on the current well design configuration, assumed reservoir conditions, and desired injection pressures. Under these conditions, the brine can be injected at atmospheric pressure at the wellhead, even in case of low permeability. As more data becomes available for each of these parameters this estimate can be further refined.
- The solubility of CO_2 and H_2S is critical for this injection design and must be properly accounted for when modeling the system.

The OLGA simulation model developed here can be used in further studies to understand how the injection system would perform under other real operating conditions, to test various operating strategies, and to allow the design team to further optimize the design of the injection tubing string.

Acknowledgments

The Authors would like to thank: Sekhar Nagarakanti and the Schlumberger OLGA modeling team for their modeling expertise and insights, Vera Trinciarelli at Magma Energy Italia for the useful comments and Fausto Batini, Managing Director at Magma Energy Italia, for allowing the publication of the results.

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