

Effects of CO₂ and acid gas injection on enhanced gas recovery and storage

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Abstract Sequestration of CO₂ and other associated waste gases in natural gas reservoirs is an option to mitigate greenhouse gases and enhanced gas recovery. This paper examines strategies to maximize enhanced gas recovery in a natural gas reservoir via subsurface storage of potential associated waste gases such as CO₂ and H₂S. Numerical simulations are performed with a compositional reservoir simulator ‘Tempest’ using experimental data initially produced by Clean Gas Technology Australia (CGTA) at Curtin University in 2009. The simulation results shows that additional gas is recovered by gas-gas displacement after injecting CO₂ and acid gas (CO₂–H₂S) in two separate scenarios. Importantly, when pure CO₂ is injected, CO₂ breakthrough at the production well occurred faster than the breakthrough under mixed CO₂–H₂S injection.

Keywords Gas injection · CO₂ breakthrough · CO₂ storage · Enhanced gas recovery

Introduction

Greenhouse gas injection into geological formations is often considered when attempting to mitigate atmospheric emissions and enhanced hydrocarbon recovery. Sequestering CO₂ to mitigate CO₂ atmospheric emissions is available and technologically feasible because of experience gained in enhanced oil recovery (EOR) by CO₂ injection. The majority of these operations are located in Canada and United States (Bachu et al. 2003). In particular, during the past decade, oil and gas producers in the Alberta basin of western Canada are increasingly being required to reduce atmospheric emissions by injecting acid gas into deep geological formations (Huerta et al. 2012).

The concept of CO₂-EOR, is now considered to be matured, in Canada for conventional oil reservoirs, and has been successfully applied in Zama (Huerta et al. 2012). Additionally, there are several current and planned projects for CO₂-EOR that involve the separation and geological storage of CO₂. The Sleipner gas field in the North Sea (operated by Statoil) is one such pilot project where separated CO₂ is injected into an underground saline aquifer for sequestration purposes. Other commercial projects are based in central Algeria in Salah (operated by BP) (Algharaib and Abu Al-Soof 2008). Similarly, similar processes are under consideration for sour reservoirs being produced in the Arabian Gulf and central Asia. In particular, producers in Iran, Arab Emirates and Kazakhstan are turning to acid gas disposal by deep injection.

However, data on these operations are only available for the CO₂ injection of enhanced oil recovery and storage, mostly in the Permian basin in west Texas (Bennion and Bachu 2008). Experimental data on impure acid gas injection into natural gas reservoirs for enhanced gas recovery and storage are not yet available. While some

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published simulation studies attempt to investigate the CO₂-EGR and storage processes, the focus of these studies is to achieve this task in depleted natural gas reservoirs. In addition, several studies are limited to considering only the economic aspects of CO₂ capture and storage. However, Hussien et al. (2012), Khan et al. (2012) simulate experimental data and outline factors that are favourable to enhanced gas recovery and the storage of CO₂ under supercritical CO₂ injection.

This study intends to examine the effects of pure CO₂ and acid gas injection into known natural gas reservoirs in Western Australia, and the displacement of native gases to better understand the mechanisms involved in enhanced gas recovery regarding geological storage.

Reservoir simulation model

A detailed geological study that examines both upper and lower reservoir layers, and characterizes the reservoir through the study on core plugs experimentally, is produced by CGTA. In particular, the CGTA study was focused on rock characteristics such as porosity, permeability, critical gas and water saturation carried out on core plugs from a known field located in the northwest shelf of Western Australia at a depth of 3,650 m (see Fig. 1). The model reservoir in this study has four layers of different thicknesses and represents alternative geological characterizations of core plugs (see Table 1). The dimensions of the geological model are 1.7 × 2.2 × 0.3 km. In the X direction, 34 cells are used, while in the Y direction 44 cells are employed. The divisions in the Z direction vary by layer, with 8, 10, 12 and 8 cells, formed to represent layers L1, L2, L3 and L4, respectively. In terms of gas-water

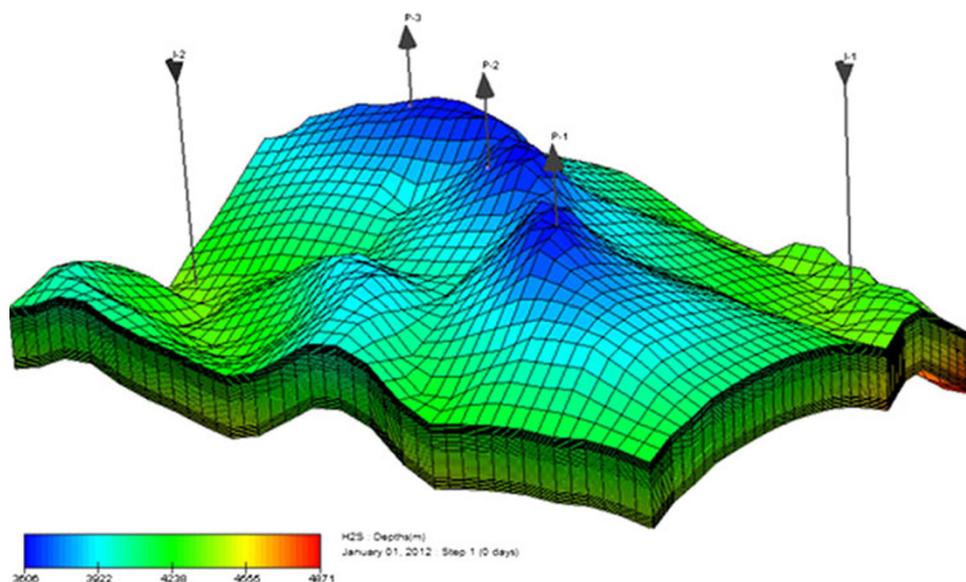
contact, reference depth of the reservoir, pressure and temperature at the reference depth and depth specifying the water-gas contact is calibrated to achieve equilibrium initialisation. This approach provides an indication of the transition zone between gas and water. The simulator employs these values to stabilize the initial aquifer zone, which is allocated within depths of the bottom cells in the gas reservoir model. Beneath of this aquifer zones lays the target for drilling and completion of the injector wells, and is where the injection strategies are proposed.

The initial pressure of the reservoir model is set at 406 bar, with temperature of 160 °C (see Table 2). PVT-Software is used to generate the necessary PVT data for this simulation. Relative permeability curves are generated for the core plugs using modified Darcy's Law to achieve required displacement between the gases. The gas reservoir model typically contains 0.09 of carbon dioxide, 0.9 of methane, 0.005 of butane and 0.005 of propane on a volumetric or molar basis. The base-case development plan calls for three vertical production wells, allocated and perforated in the upper layers of the reservoir. In addition, two injection wells are perforated in the bottom layer of the reservoir to allow for gravitational forces. These production wells are expected to produce natural gas at same rate of 320 × 1,000 m³/day. In general, the production wells are controlled as a function of the maximum gas production rate per day and a minimum producing bottom-hole pressure for each well.

Enhance gas production

Hussien et al. (2012) and Khan et al. (2012) investigated the CO₂ injection process for enhanced gas recovery and storage to predict optimal trade-offs between maximum

Fig. 1 Hypothetical gas reservoir model



methane production and CO₂ storage. In this study, the layers of the reservoir model are arranged from top to bottom as very low, high medium and low quality of rock, respectively. The investigation assesses the effects of reservoir re-pressurization on the injectivity of CO₂ and distribution of the injected CO₂ as a function of permeability. Other operating parameters considered are the solubility factor of the injected gas mixture, vertical injection well pattern, higher injection pressure compared to the initial reservoir pressure. The objective of this study is to compare the effects of pure CO₂ injection and acid gas on enhanced methane recovery and storage, in addition to illustrating the mixing of injected gas with native gases in the reservoir. To examine the effect of CO₂ injection on gas production, natural gas production is simulated without injection as a base-case under normal production for 15 years. Consequently, proposed development cases are optimized for different level of reservoir uncertainty to illustrate the sweep efficiency of gas injection. For this scenario, cumulative methane and CO₂ production ‘lb-mole’ and

bottom-hole pressure ‘bar’ are estimated for select periods (see Fig. 2). This scenario is intended as the base for comparison, so as to illustrate the acceleration of methane production, and lower CO₂ production under a case of injection as a function of a given gas injection rate.

Next, CO₂ is injected at the rate of 1,250 × 100 m³/day for reservoir re-pressurization, thus enhancing gas recovery and storage of the injected CO₂. Similarly, for this scenario, simulations are conducted using impure CO₂ containing 30 % of H₂S as an acid injection gas. For both cases under gas injection, acid gas and CO₂ breakthrough occurs at the production wells as expected. Figure 2 compares the injection scenarios as a function of enhanced gas recovery. Comparison of the injections indicates that the gas recovery factor under the CO₂ injection rate is greater than that for both the acid gas CO₂–H₂S injection case, and the base-case. Accordingly, the bottom-hole pressure decline is less gentle than under CO₂ injection. Conversely, Fig. 3 CO₂ breakthrough under alternative injection rates, and shows that the CO₂ injection rate results in earlier breakthroughs compared to gas acid injection. As a result, the simulation suggests that although gas injection involves excessive gas mixing; it does have potential to increase incremental gas recovery.

Table 1 General reservoir characteristics by layer

Layers (1–4)	Very low	High	Medium	Low
Core plugs	S_A_4	S_A_1	S_A_2	S_A_3
Swcr	0.120	0.175	0.145	0.100
Sgcr	0.05	0.03	0.04	0.05
Porosity (%)	0.04	0.17	0.14	0.09
K _z (md)	4	370	100	6
K _y (md)	6	390	115	8.5
K _x (md)	6	390	115	8.5
Z direction (cells)	8	10	12	8
Z thickness (m)	50	70	120	60

Table 2 Reservoir model parameters

Property	Value
Reservoir type	Sandstone
Reservoir depth	3,650 m
Area (X–Y direction)	1,700 m X, 2,300 m Y
Thickness (Z direction)	300 m
Grids in X direction	32
Grids in Y direction	44
Grids in Z direction	8, 10, 12 and 8 for L1, L2, L3 and L4
Relative permeability	JBN method and Darcy’s law
Initial reservoir temperature	160 °C
Initial reservoir pressure	406 bar
Well injector pressure (maximum)	450 bar
Well producer pressure (minimum)	50 bar
Injection rate	1,250 × 1,000 m ³ /day
Maximum gas production rate	9,600 × 1,000 m ³ /day

Storage of gas injection

Storage volumes of CO₂ and acid gas are documented by mass balance methods developed through reservoir simulation results. This method quantifies the initial CO₂ volume and maps any changes in producible volumes as a reservoir management technique, when CO₂ injection is applied over the field life. CO₂ storage estimates are based on the notion that CO₂ and acid gas breakthrough for production wells. Further, it is assumed that 9 and 0 % of CO₂ and H₂S respectively are present in the reservoir, along with 90 % for methane. Figure 3 also depicts the total CO₂ produced and the acid gas fraction in the reservoir, when different CO₂ and acid gases are used for injection. The scenario illustrates that the produced fraction of CO₂ and acid gas increase with the produced fraction of injected gases. During injection process, the fraction of produced CO₂ and acid gas exceed the CO₂ and H₂S fractions initially in the reservoir. These excess amounts represent the produced fraction of the injected CO₂ and acid gas and are shown in Fig. 4.

The simulation results indicate that the production of the injected gas under the acid gas injection scenario is low as compared to that under pure CO₂ injection. Thus, the greater is the produced fraction of the injected gases the lower is the stored volume of the injected gas. Figure 5 shows alternative gas injections rates for both cases, and also illustrates gradual increases in the injection rates until

Fig. 2 Cumulative gas production and average bottom-hole

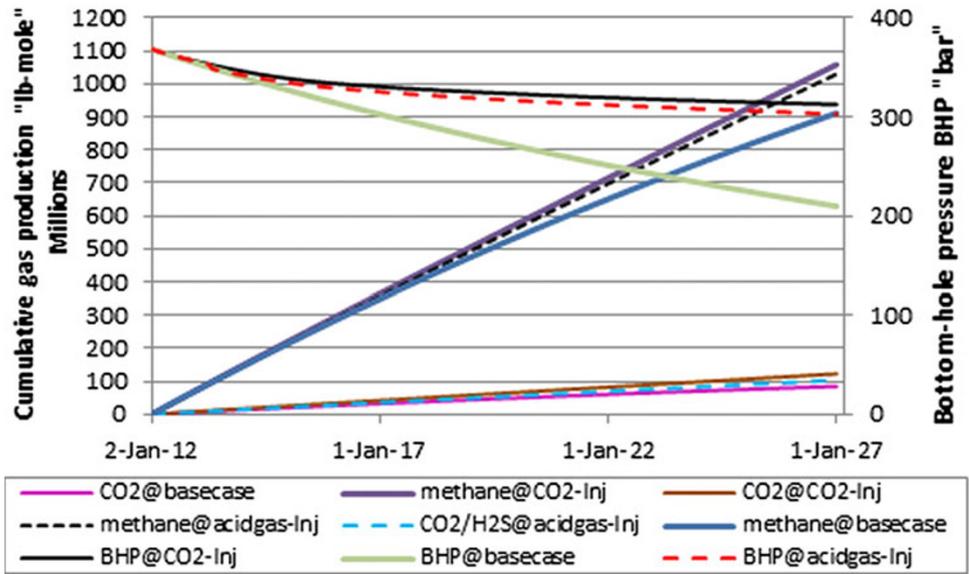
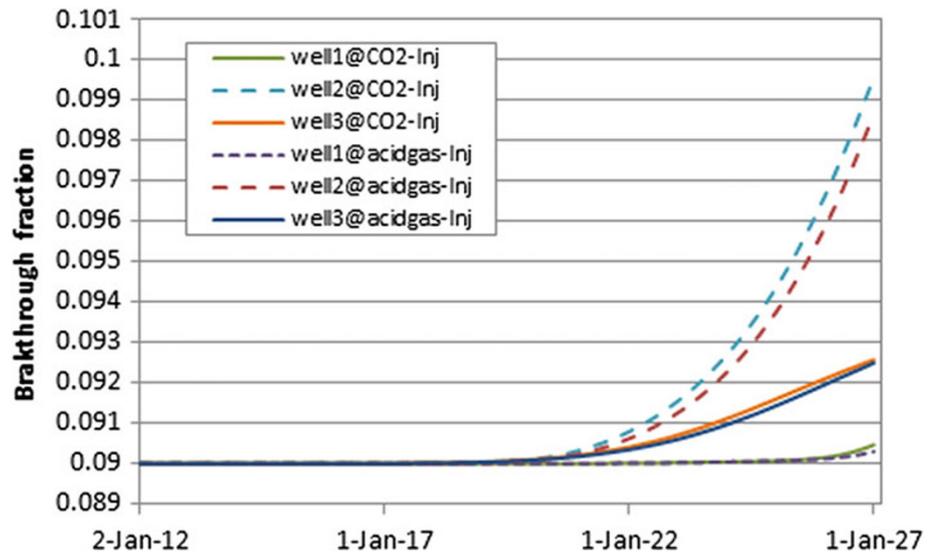


Fig. 3 CO₂ and acid gas breakthrough



they reach the required injection rate. Under the acid gas injection scenario, the injected acid gas due to higher injectivity, reaches to the required rate of injection fastest. The reason this speed could be due to the physical properties of H₂S. For instance, the solubility of H₂S is almost double that of CO₂ (Pooladi-Darvish et al. 2009).

Furthermore, CO₂ and CO₂–H₂S storage is evaluated after breakthrough is illustrated for both scenarios in terms of the produced fraction of injected CO₂ and H₂S–CO₂ after allowing for the initial gas reservoir conditions. After estimating the produced fraction of the injected gas for both cases, production rates of the injected gas are calculated by multiplying the produced fraction of the injected gas from each well by production rate of CO₂ or H₂S–CO₂ (at the same time during the injection). Additionally, the total production rates of injected CO₂ or H₂S–CO₂ are

compared, after allowing for the injection rate under alternative storage scenarios. Figure 5 shows that pure CO₂ injection leads to greater production rates of injected gas when compared to acid gas injection scenario. In addition, during the CO₂ injection process some of the injected CO₂ dissolves in the formation of water. Finally, acid gas injection because of favourable H₂S solubility requires smaller volumes of injected gas to be available in the gas reservoir to mix. This will lead to delay breakthrough and results in more storage.

Results and discussion

While injected solvent and extant gases mix and contaminate production, the best strategy to employ depends on

Fig. 4 Produced fraction of different injected gas

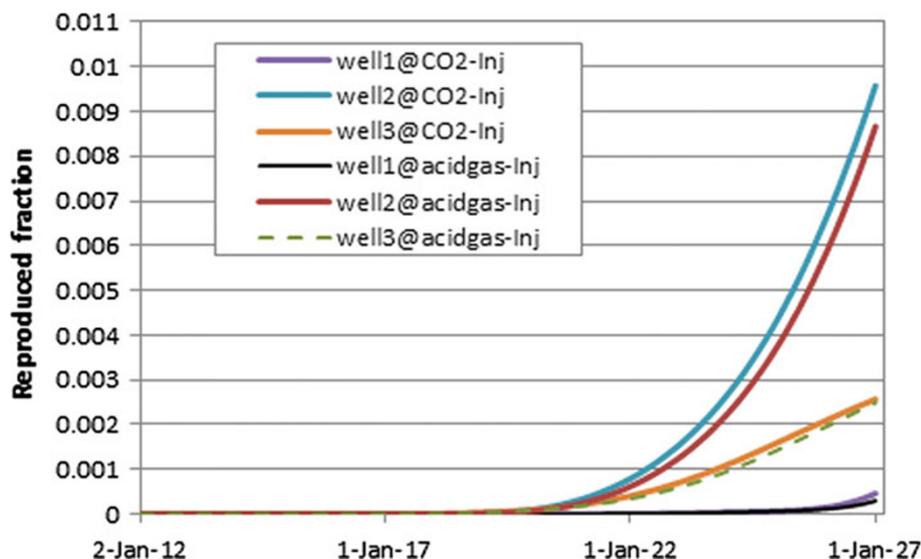
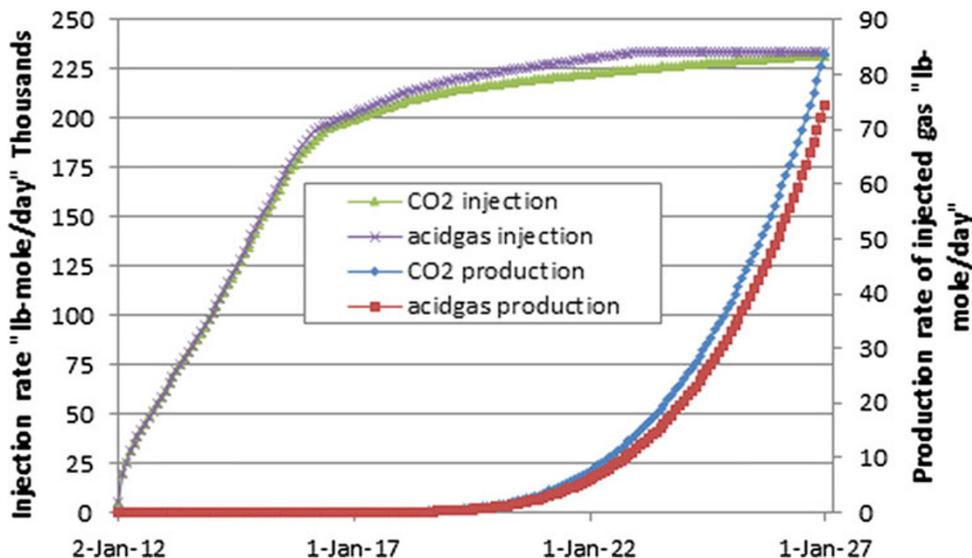


Fig. 5 Injection rate and production rate of the injected gas



the physical properties of solvents when compare to those of methane, the natural gas in the reservoir. In this study, the physical properties of methane, H₂S and CO₂ are studied at different pressures and temperatures using HYSYS software. The simulation results indicate that H₂S has higher viscosity and density compared to CO₂ and methane. Another physical property is the solubility factor. Al-Hashami et al. (2005) claim carbon dioxide is potentially more soluble than methane. The current simulation study and other laboratory experiments (Pooladi-Darvish et al. 2009) confirm that the solubility of H₂S is higher than CO₂ solubility.

Furthermore, injected gas whether CO₂ or/and H₂S–CO₂ is migrated downward due to gravity, and these forces will stabilize the displacement between the injected gas and methane initially in place because of low mobility ratio of CO₂ and acid gas, respectively. Additionally, higher acid

gas solubility in forming water compared to that for pure CO₂ injection delays breakthrough. Any of these gases as injection considered could potentially provide favourable reservoir re-pressurization without extensive gas-gas mixing, and benefit the enhanced gas recovery (EGR) and storage process. Therefore, gas-gas mixing technically could be supervised via good reservoir management and production control measures, because these physical properties of the solvents undergo large changes as the pressure increases.

Figure 6 displays efficient acid gas injection downward flows that stabilize the displacement of native gas caused by the pressure gradient and gravitational forces. Clearly, after some injection period, the grids around the production wells are covered with the initial natural gas while the reservoir lower portion is partially filled with injected CO₂–H₂S. The heterogeneity of reservoir flows of CO₂ and

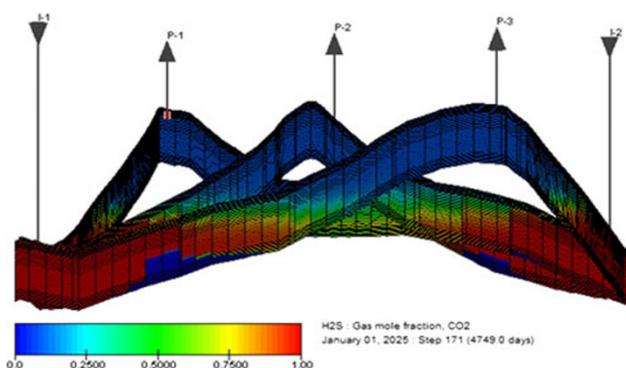


Fig. 6 Injection sweep efficiency

H₂S from the bottom layer toward the production wells depends on permeability of the layers, especially the second and third layers from bottom of the reservoir (high permeable). This preferential flow can be favourable for CO₂–H₂S injection and allows greater amounts of CO₂–H₂S to be injected. Eventually, breakthrough will be caused based on the physical properties of the layers and enhanced gas recovery effects through time.

Under H₂S–CO₂ and pure CO₂ mixing in the injection stream, the potential for EGR and storage are investigated at an injection rate of $1,250 \times 100 \text{ m}^3/\text{day}$. Under CO₂ injection, slightly higher methane production is recovered because CO₂ is more mobile (less viscous) compared to H₂S in forming water. Therefore, pure CO₂ injection is expected to rise to the upper layers more quickly than impure CO₂ injection. In this instance, the injected gases are expected to overrun native gases in the production wells faster. Although, this scenario will affect sweep efficiency at some time, to that stage reservoir re-pressurization will occur faster.

Conclusion

This paper develops a true gas reservoir model using the reservoir simulation software Tempest and true reservoir experimental data produced by CGTA. The simulation indicates that gas injection for enhanced gas recovery and storage is technically feasible for this particular reservoir. Even though, reservoir heterogeneity can cause increase in CO₂ or/H₂S–CO₂ breakthrough, reservoir re-pressurization

can be considered a support against the concept of breakthrough. A benefit of re-pressurization is that it can occur prior to CO₂ and acid gas breakthrough. Accordingly, an optimal strategy is to benefit from the high viscosity, density and solubility of injected gases, reservoir re-pressurization by injecting gas into the lower portions of the reservoir to drive out the out natural gas from the bottom reservoir layers, while minimizing mixing and contamination in the upper parts of the reservoir.

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