Case study on combined CO₂ sequestration and low-salinity water-production potential in a shallow saline aquifer in Qatar

Tausif Khizar Ahmed⁵, Hadi Nasrabadi⁶,⁎

⁵Texas A&M University at Qatar. Email: tausif.ahmed@qatar.tamu.edu
⁶Texas A&M University at Qatar
PO Box 23874, Education City, Doha, Qatar

⁎Corresponding author. Email: hadi.nasrabadi@qatar.tamu.edu
Phone: +974.4423.0206; Fax: +974.4423.0011;
ABSTRACT

CO$_2$ is one of the byproducts of the natural gas production in Qatar. The high rate of natural gas production from Qatar’s North Field (world’s largest non-associated gas field) has led to the production of a significant amount of CO$_2$. The release of CO$_2$ into the atmosphere may be harmful from the perspective of global warming. In this work, we study the CO$_2$ sequestration potential in Qatar’s Aruma aquifer. The Aruma aquifer is a saline aquifer in the southwest of Qatar. It occupies an area of approximately 1985 km$^2$ on land (16% of Qatar’s total area). We have developed a compositional model for the CO$_2$ sequestration in the Aruma aquifer on the basis of the available log and flow test data. We suggest water production at some distance from the CO$_2$ injection wells as a possible way to control the pore pressure. This method increases the potential for the safe sequestration of CO$_2$ in the aquifer without losing the caprock integrity and without any CO$_2$ leakage. The water produced from this aquifer is considerably less saline than seawater and can be a good water source in the desalination process. The main source of Qatar’s current water usage is desalinated seawater. The outcome of the desalination process is water with higher salinity than the seawater that is currently discharged into the sea. This discharge can have negative long-term environmental effects. The water produced from the Aruma aquifer is considerably less saline than seawater and can be a partial solution to this problem.

Keywords: CO$_2$ aquifer storage; Aruma aquifer; pressure control; water production; seawater desalination; environmental impact

1. Introduction

The combustion and flaring of fossil fuels produces large quantities of CO$_2$. The Intergovernmental Panel on Climate Change (IPCC, 2007) has stressed upon the need to control anthropogenic greenhouse gases in order to mitigate the climate change that is adversely affecting the planet.

In 2009, Qatar produced 3,154 billion ft$^3$ (89 billion m$^3$) of natural gas, which is approximately 8.6 billion ft$^3$/day (243 million m$^3$/day). Discovered in 1971, Qatar’s North Field is the largest non-associated gas field in the world with estimated reserves exceeding 900 trillion standard cubic feet (SCF) (25.5 trillion m$^3$). The natural gas produced from the North Field has an average density of 0.8 kg/m$^3$ (0.05 lb/ft$^3$) consisting of 3.5-wt% CO$_2$ (Whitson and Kuntadi, 2005). This translates into an annual production of 2.54 million metric ton (tonne) of CO$_2$.

Real estate development in Qatar during the recent years has also led to an increase in cement production. The production of 1 ton of cement generates 0.83 ton of CO$_2$. 
However, fossil fuel combustion still remains the largest source of CO$_2$ emission. According to the Carbon Dioxide Information Analysis Center (CDIAC), Qatar produced 17.1 million ton of CO$_2$ in 2007 (Fig. 1), out of which 10 million ton were produced from the combustion of gas fuels. Cement production emitted 340,000 ton of CO$_2$. Qatar has the highest per capita emission of CO$_2$ in the world (14.02 ton). Comparatively, the US ranks as the 11th highest CO$_2$ emitter per capita (5.2 ton). Hence, there is a need for CO$_2$ mitigation in Qatar.

![Fig. 1 – Fossil-fuel CO$_2$ emission for Qatar from 1949 to 2007 (CDIAC, 2007).](image)

There are various long-term and short-term methods for reducing the concentration of CO$_2$ in the atmosphere. Among the long-term solutions are biodiversity and afforestation (Caldwell et al., 2007; Huston and Marland, 2003) Further, geological CO$_2$ sequestration is an effective short-term mitigation strategy. Geologic storage of CO$_2$ is possible by sequestering the CO$_2$ captured from anthropogenic sources such as power plants, oil and gas refineries, and chemical plants in an underground geological formation.
The largest, but least defined, sources of geologic storage possibilities lie in saline aquifers (Beecy and Kuuskraa, 2001). When injected in saline aquifers, CO\textsubscript{2} can be trapped through a combination of one or more chemical and/or physical processes. Orr et al. (2005) studied the time and length scales that characterize the sequestration of CO\textsubscript{2} and introduced two time periods: injection period and post-injection period. During the injection period, advection and gravity segregation are the dominant transport mechanisms. The structural trapping of CO\textsubscript{2} and the trapping of CO\textsubscript{2} as a residual gas (hysteresis) are the main sequestration mechanisms during this phase (Nghiem et al., 2004). In the post-injection period (100 to 10000 years), the dissolution of CO\textsubscript{2} in brine, downward buoyancy-driven fingering, and mineralization of CO\textsubscript{2} have become more important with the passage of time (Ennis-King and Paterson, 2005; Ukaegbu et al., 2009; Zhang et al., 2009).

The Sleipner project in offshore Norway is the world’s first commercial-scale CO\textsubscript{2} storage project injecting CO\textsubscript{2} in the sands of the Utsira formation at 1 million ton/year (Gale et al., 2001). The experience from CO\textsubscript{2} injection at other commercial operations (Snohvit, In Salah) and pilots projects (Frio, Ketzin, Nagaoka) has shown that CO\textsubscript{2} sequestration in saline aquifers is technologically feasible. By the end of 2008, approximately 20 million ton of CO\textsubscript{2} was successfully injected in saline aquifers by the existing operations (Michael et al., 2010).

More recently, storage in shallow saline aquifers has also been investigated (Tiamiyu et al., 2010). The motivation behind this study was the fact that deep saline aquifers may not always be present near the CO\textsubscript{2} source. They found that the potential of CO\textsubscript{2} storage in shallow saline aquifers could be greatly enhanced using water production.

Water production can effectively alleviate a major concern related to the CO\textsubscript{2} sequestration in saline aquifers. This concern is the rapid increase in the aquifer pressure owing to the CO\textsubscript{2} injection in a closed system with low compressibility that can cause fractures in the caprock and the leakage of CO\textsubscript{2} (Economides and Ehlig-Economides, 2009). This method has been investigated in several studies (Bergmo et al., 2011; Flett et al., 2008; Lindeberg et al., 2009; Yang, 2008).

Low-salinity water production can also have a positive environmental and economical impact on Qatar and the surrounding region. The water scarcity in the Middle East, especially in the Persian Gulf region, has reached unprecedented crisis levels. Desalinated seawater is the most important water source in these countries. In fact, desalinated seawater is the major source of water supply for Qatar (Amer and Al Rahman, 2005), Kuwait (Darwish and Al-Najem, 2005), and the United Arab Emirates (Sommariva and Syambabu, 2001).

The largest number of desalination plants can be found along the shores of the Gulf with a total seawater desalination capacity of approximately 45% of the worldwide daily production (Lattmann and Höpner, 2008). These desalination plants use continuous
discharge into the Gulf as a practical method to dispose of a brine waste stream (Areiqt and Mohamed, 2005). The total dissolved solids (TDS) in the Gulf is 45 g/l (approx. 44 parts per thousand or ppt) as compared to the typical seawater salinity of approximately 34.5 g/l (Cotrugo, 2005).

An increase in the brine discharge significantly increases the salt concentration in the recipients, as shown by Bashitialshaaer et al. (2011). Bashitialshaaer et al. show that as a result of the brine discharge, the peak salinity of the Gulf increased by 0.42 ppt in 1996 and 0.93 ppt in 2008; it is predicted to increase by 2.24 ppt in 2050. This increase can pose serious threats to the already fragile environment of the Gulf (Lattemann and Höpner, 2008). This effect is also important from an economical and technical point of view. A relatively high salinity of the seawater intake will reduce the efficiency of the desalination plant (Abdul Azis et al., 2000) and hence, increase the cost of producing desalinated seawater (Dore, 2005). This can already be partly observed in the Gulf region (Bashitialshaaer et al., 2011).

In this study, we investigate the potential of combined CO$_2$ sequestration and low-salinity water production in Qatar’s Aruma aquifer. First, the aquifer is described. Next, we provide the details of the simulation model for the CO$_2$ sequestration study. The results of the simulation studies on the sequestration and water production potential are presented in the next section followed by the discussion and concluding remarks.

2. Aquifer Description and Hydrogeology
The Aruma aquifer is located in southwest Qatar. It occupies an area of approximately 1985 km$^2$ on land, which is approximately 16% of Qatar’s total area. Qatar’s Department of Agricultural and Water Research has drilled four deep wells in this aquifer in order to characterize it better. Regional monitoring of the groundwater levels, comprehensive logging, and water quality analysis was performed to better understand the aquifer (ATS, 2004).

The Aruma aquifer consists of approximately 130 m (426 ft) of granular limestone belonging to the Aruma Formation. The top of the aquifer ranges from 380 to 550 m within southwest Qatar. The aquifer is overlain by relatively thick impermeable deposits of the lower Umm Er Radhuma (UER) aquifer and is underlain by a sequence of shales having a thickness of up to 100 m and belonging to the relatively low Aruma Formation. These strata bind the aquifer and serve to isolate it from the groundwater movement between layers. There was no evidence of leakage or drainage while testing. The overall thickness of the Aruma formation decreases northwards from approximately 265 m in the south to less than 240 m in the north. Within the formation, the upper limestone becomes thicker moving northwards whereas the shales at the base become thinner.

3. Data Processing
The approximate limits of the project area are shown in Fig. 2. There are 11 pre-existing deep wells in the project area numbered DW-1 to DW-11. The new deep wells drilled in 2003 were numbered DW-12, DW-13, DW-14, and DW-15. DW-12 and DW-13 are located adjacent to the existing wells DW-03 and DW-11 in order to perform aquifer tests while observing the water levels of the nearby deep wells. The new wells are located around the flanks of the Dukhan anticline, which has a dip that exceeds 0.5°. DW-14 and DW-15 are located in the neighboring syncline, whereas DW-12 and DW-13 are located on the anticlinal crest.
Detailed logging was performed at each new deep well location. These data, along with the limited log data of the existing deep wells, were used for mapping the top and the bottom of the Aruma aquifer. Table 1 provides a summary of the aquifer properties measured from the log data and the flow tests. It is important to note that the Aruma aquifer is highly permeable (Table 1). Firoozabadi and Cheng (2010) emphasized the
selection of high-permeability aquifers to store CO\textsubscript{2} because these aquifers aid in the rapid dissolution of CO\textsubscript{2} in brine. Another important aquifer property is the water salinity. The water salinity in the Aruma aquifer (5 ppt) is approximately an order of magnitude less than the Gulf water salinity (currently used in the desalination process). The salinity of the discharge water of a desalination plant is very high and usually ranges from 50 to 85 g/l, depending on the type of desalination plant (Lattemann and Höpner, 2008). Therefore, by using the Aruma water, we can not only reduce the cost and improve the efficiency of the desalination process, but we can also discharge water with considerably less salinity than seawater and help to avoid or mitigate another serious environmental problem for Qatar and the surrounding region.

Using the log data and the flow test results, we created maps for illustrating porosity, permeability, formation depth, and thickness. Geographix™ software was used for log analysis and map creation. These maps were then exported to a commercial reservoir simulator (CMG-GEM) to create the static reservoir model.

<table>
<thead>
<tr>
<th>Table 1 – Properties of Aruma Aquifer</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Well</strong></td>
</tr>
<tr>
<td>DW-12</td>
</tr>
<tr>
<td>DW-13</td>
</tr>
<tr>
<td>DW-14</td>
</tr>
<tr>
<td>DW-15</td>
</tr>
<tr>
<td>Total Dissolved Solids, ppt</td>
</tr>
<tr>
<td>(k_v/k_h)</td>
</tr>
</tbody>
</table>

4. Model Description

A three-dimensional corner point grid was used for modeling the project area. The model consisted of 212 grids in the \(x\)-direction, 298 grids in the \(y\)-direction (width), and 6 grids in the \(z\)-direction (Fig. 3a). The Aruma aquifer was modeled with five layers in the \(z\)-direction (Fig. 3b). The layer above the aquifer represented the seal. Each grid block was 250 m in the \(x\)-and \(y\)-directions. The isopachs generated from the log analysis were used for assigning the thickness for each layer in the \(z\)-direction. The permeability of the seal was assumed to be 0.01 mD. A \(k_v/k_h\) value of 0.1, which is a typical value for consolidated sediments, was used. The well locations in the reservoir model are shown in Fig. 3a.
(a) Reservoir model showing formation depth (in m) and well locations;
(b) description of layers for well DW14, which is considered as a sample well.

The Peng-Robinson equation of state (Peng and Robinson, 1976) was used for modeling the phase behavior. The aqueous phase density was calculated using the Rowe and Chou correlation (Rowe and Chou, 1970), whereas the aqueous viscosity was calculated using the Kestin correlation (Kestin and Shankland, 1984). The Peng-Robinson EOS accurately predicted the CO₂ gas density within the pressure range of this study when a volume shift parameter of zero was used. The Pedersen correlation was used for calculating the viscosity of the components. The values of the five coefficients used in this study were those obtained by Kumar (2004) (Table 2).
Henry’s Law was used for modeling the CO₂ solubility in brine. Henry’s constant calculated at the reservoir temperature was also dependent on salinity (Nghiem et al., 2004). The Harvey model (1996) was used for calculating Henry’s constant of CO₂.

### Table 2 – Parameter values for Pedersén et al.’s (1984) viscosity correlation for CO₂–brine system obtained by Kumar (2004)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW mixing rule coefficient</td>
<td>0.291</td>
</tr>
<tr>
<td>MW mixing rule exponent</td>
<td>1.4</td>
</tr>
<tr>
<td>Coupling factor correlation coefficient</td>
<td>0.0005747</td>
</tr>
<tr>
<td>Coupling factor correlation density exponent</td>
<td>4.265</td>
</tr>
<tr>
<td>Coupling factor correlation MW exponent</td>
<td>1.0579</td>
</tr>
</tbody>
</table>

The relative permeability data were obtained on the basis of the equations and parameters presented by Kumar (2004) and Anchliya (2009). The capillary pressure profiles for the seal and aquifer were taken from Alexander and Bryant (2009). The initial reservoir pressure at 500 m (1640 ft) was 721 psi, which was calculated using a hydrostatic gradient of 0.44 psi/ft. The effect of diffusion was also included in the model. On the basis of the experimental data (Frank et al., 1996; Tamimi et al., 1994), a CO₂ diffusion coefficient of $3 \times 10^{-5}$ cm²/s was used in this study.

### 5. Results and Discussion

In this study, we estimated a realistic CO₂ injection rate taking into account the existing sequestration projects. The Sleipner project was chosen as the facilities design analog. CO₂ was injected into the Utsira Formation at a rate of 1 million ton/year. This translated to an average daily injection rate of 52 million SCF (standard cubic feet) (1,472,476 m³). For the Aruma aquifer, we chose a similar daily injection rate. From our calculations, we found that this amount was approximately 40% of the daily production of CO₂ in Qatar.

We considered two possible scenarios in our simulations: 1) we used all the eight wells as injectors and divided the total injection rate equally among the eight wells, giving each an injection rate of 6.5 million SCF/day (184,060 m³/day) and 2) we considered six injectors and two producers where the injection rate in each injector was 8.67 million SCF/day (245,413 m³/day). This rate was divided equally among the eight wells, giving each an injection rate of 6.5 MMSCF/day (184,060 m³/day). CO₂ was injected through the perforations made in the bottom layer of the Aruma aquifer.

The change in pressure at the well impacted the pressure at the caprock, which affected the seal integrity. Using the formula proposed by Eaton (1969) for predicting the fracture gradient, we obtained a fracture gradient of 15.7 kPa/m (0.69 psi/ft). This implied that at
an average depth of 500 m (1640 ft), the fracture pressure of the rock was 76904 kPa (1115 psi).

The injectors in both scenarios were set to inject equal amounts of CO₂ in the bottom layer for 200 years. During the injection period, the radial spread of CO₂ around the injection point was limited (Fig. 4a). A majority of CO₂ accumulated beneath the seal and started migrating up-dip along the anticline (Fig. 4b).

**Fig. 4 – CO₂ global mole fraction after 200 years in (a) layer below caprock (layer 1) at end of simulation and (b) lowest layer of Aruma aquifer (layer 5).**

In the first scenario (no producers), the average reservoir pressure increased by approximately 320 psi. In this scenario, the reservoir pressure in some parts of the reservoir increased to above the formation fracture pressure, and the seal integrity was lost. In the second scenario, when DW-07 and DW-12 were converted to producers with a total brine withdrawal rate of 3300 m³/day (22% of the injected CO₂ as shown in Fig. 5), the average reservoir pressure increased by only 240 psi (Fig. 6), and the pressure remained below the fracturing pressure owing to water production. At the current water withdrawal rate, there was no CO₂ breakthrough observed at the brine producers, and only water was produced. Therefore, brine withdrawal was found to be an effective method for controlling the increase in the reservoir pressure. As shown in Fig. 5, upon the injection of a significant volume of CO₂ (approx. 1100 million m³ at the reservoir condition), we will produce more than 200 million m³ of low-salinity water that can replace seawater in Qatar’s desalination plants. Fig. 7 shows the reservoir pressure right below the seal at the end of the simulation run time (200 years). The pressure did not exceed the fracture pressure of the formation.
Fig. 5 – Comparison of reservoir volumes of injected CO₂ and withdrawn brine.
Fig. 6 – Effect of withdrawal brine on average reservoir pressure.
**Fig. 7** – Reservoir pressure (in kPa) at end of 200 years. Brine producers DW-07 and DW-12 are located in the north of the field.

### 6. Conclusions

In this work, we presented a case study of the combined CO$_2$ sequestration and low-salinity water production from Qatar’s Aruma aquifer. We included the effects of CO$_2$ dissolution in brine, CO$_2$ diffusion, and capillary pressure in our model. Our results show that the Aruma aquifer, despite being a shallow saline aquifer, can have a significant potential in CO$_2$ sequestration. The aquifer can store approximately 40% of Qatar’s CO$_2$ production from natural gas for 200 years, if CO$_2$ injection is combined with water production. We monitored the underground flow of CO$_2$ in the aquifer. Our results show that at least for 200 years, the CO$_2$ is not going to leak from the aquifer and the caprock integrity will be conserved. Brine withdrawal was found to be an effective method for controlling the increase in reservoir pressure. In addition to alleviating reservoir pressure, brine withdrawal could help reduce the dependence on desalinated seawater for domestic use and reduce the negative environmental impact of the discharge of high-salinity water to the sea. The inclusion of geochemistry in the aquifer model and its effect on CO$_2$ injectivity would be the next step in our study.
Acknowledgements
This study was made possible by NPRP grant # 29-6-7-30 from the Qatar National Research Fund (a member of Qatar Foundation). We also would like to thank Computer Modeling Group for providing us with a license for the GEM reservoir simulator to perform the CO$_2$ sequestration studies. The statements made herein are solely the responsibility of the authors.

References


