Storage Capacity Enhancement and Reservoir Management Using Water Extraction: Four Site Case Studies

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Abstract

Water extraction from carbon dioxide (CO₂) storage reservoirs may be a method to enhance storage capacity and to actively manage storage reservoirs. Previous investigations into the use of water extraction have utilized homogeneous models to assess the feasibility of this technology. This study addressed water extraction based on four hypothetical CO₂ storage sites, which varied with respect to heterogeneous lithology, variable structure, and complex internal geometry. The simulation results showed the increased CO₂ storage capacity achieved through the use of water extraction varies greatly based on site conditions, ranging from 4% to 1300% in the four cases investigated. In all scenarios, water extraction reduced the maximum reservoir pressures approximately 10% to 20% during injection. In most scenarios, CO₂ plume movement could also be influenced through the use of water extraction. The last two aspects may be very beneficial for risk management and monitoring, verification, and accounting practices for all of the CO₂ storage projects.

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1. Introduction

Carbon capture and storage (CCS) is a technology to reduce carbon dioxide (CO₂) emissions to the atmosphere by storing large quantities of CO₂ in deep geologic reservoirs. Several geological options for CCS have been considered, including coal beds (White et al., 2005; Liu and Smirnov, 2007, 2008), depleted oil/gas reservoirs (Shaw and Bachu, 2002; Kovscek, 2002; Flett et al., 2005), and deep saline formations (DSFs) (Bachu and Adams, 2003; Kumar et al., 2005; Holloway et al., 2004; Liu, 2012). DSFs are the largest potential CO₂ storage resources and have received increased attention in recent years. According to the Intergovernmental Panel on Climate Change (IPCC) report, the lower estimate of storage capacity in DSFs is 1000 Gt of CO₂, which is far greater than estimations for oil and gas fields and unminable coal seams (Metz et al., 2005). Therefore, the utilization of DSFs plays a crucial role in successfully implementing the scale-up of storage from pilot and demonstration projects to commercial operations. Deep saline water extraction from CO₂ storage formations has been proposed as one potential method to enhance CO₂ storage, manage reservoir pressure, and alter CO₂ plume movement (Buscheck et al., 2010; Celia and Bachu, 2003; Hosseini and Nicot, 2012; Eke et al., 2011; Burtin and Bryant, 2009, IEA Greenhouse Gas R&D Programme, 2009, 2014; Saini et al., 2013; Gorecki et al., 2013).

Most publications have demonstrated the basic concept of water extraction from a CO₂ storage

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reservoir based on reservoir simulations of idealized geologic models (Buscheck et al., 2010; Hosseini and Nicot, 2012; Eke et al., 2011; Burtin and Bryant, 2009). For example, Buscheck et al. (2010) modeled the effects of water extraction on CO₂ storage by comparing the results with and without water extraction to an idealized system. Their conclusions indicate that water extraction may be effective for CO₂ plume manipulation and reduction of pressure buildup based on an assumed 1 to 1 ratio of water extraction to CO₂ injection (Buscheck et al., 2010). In addition, the thermal footprint area, thermal drawdown, and cumulative CO₂ storage were investigated based on 5-, 12-, and 16-well patterns over various time periods and well spacings for CO₂ injection and water production (Buscheck et al., 2010). Hosseini and Nicot (2012) developed an analytical system to test the injectivity impacts and pressure reduction gains through brine extraction from CO₂ storage reservoirs and reinjection into shallower reservoirs based on a generic model. Most of the studies do not include any heterogeneity effects or reflect real field structures or conditions, nor do they aim to optimize strategies related to injection and extraction. Therefore, more questions related to the capacity and injectivity of DSFs, especially pressure behavior, CO₂ plume movement, and extraction rates, remain. Additional research is needed that takes into account the real/potential CO₂ storage site structure and geologic properties with various optimization scenarios for injection and production wells (IEA Greenhouse Gas R&D Programme, 2012), ultimately estimating CO₂ storage capacity dynamically with consideration of injectivity and reservoir pressure interference through the use of reservoir simulation. As a result, this study was undertaken to investigate 1) how much CO₂ storage capacity can be increased by implementing water extraction; 2) how reservoir pressure buildup varies under different reservoir conditions, including geologic heterogeneity structures, and fluid properties; 3) the effects on the CO₂ plume movement with water extraction; and 4) how injection and extraction scenarios can be optimized (IEA Greenhouse Gas R&D Programme, 2012; Liu et al., 2012; Klapperich et al., 2012; Saini et al., 2013).

In this study, four CO₂ storage sites were selected: the Ketzin project site in Germany, the Zama oil field in Canada, the Gorgon project site in Australia, and the Teapot Dome oil field in the United States, as shown in Fig. 1 (IEA Greenhouse Gas R&D Programme, 2012). These sites represent offshore and onshore cases with pilot- and commercial-scale plans and differing formation water qualities, injectivities, climates, and beneficial water use opportunities. The following describes the methods employed, case studies by site, and conclusions for the entire investigation.

2. Method

To achieve the goal of understanding reservoir dynamics for CO₂ storage with water extraction, four “idealized” real-world storage sites were selected and modeled. Selected sites were chosen to represent a range of reservoir types that could be used for commercial-scale CO₂ storage targets. Another goal of the study, not discussed in this paper, was to assess the utility of extracted water as a resource at these sites. Therefore, factors such as regional climate and water quality were also taken into consideration when

Fig. 1. Map depicting the location of the selected sites.

identifying possible sites. The selected sites represent a range of geologic and geophysical conditions as well as variations in their climates and regional water demands. The quality of the reservoir water also varied substantially among the four sites. These properties are summarized in Table 1.

Geologically, the sites represent both traditional clastic reservoir environments (Ketzin, Teapot Dome, and Gorgon) and carbonate reservoir systems (Zama). Structurally speaking, domes (Ketzin and Teapot Dome), anticlines (Gorgon), and reef structures (Zama) are represented by the sites. Water quality ranged from nearly fresh at Teapot Dome to concentrated brine (>180,000) at Zama and Ketzin. Additional variability was achieved in terms of climate and regional water stress. Sites ranged in climate from arid (Gorgon) to temperate (Ketzin), with regional water supply ranging from high regional water stress (Teapot Dome and Gorgon) to low regional water stress (Ketzin).

Table 1. Overview of selected case study site characteristics that exhibit ranges of geologic, hydraulic, and surface environment characteristics.

	Ketzin	Gorgon	Teapot Dome	Zama
Location	Central Germany	Offshore western Australia	Wyoming, western USA	Northern Alberta, Canada
Depositional Environment	Fluvial	Clastic slope	Mixed; nearshore marine, eolian, deltaic	Carbonate reef
Geologic Structure	Dome	Plunging anticline	Dome	Pinnacle reef
Porosity, %	7–51	0–31	3–17	3–17
Permeability, mD	0.03–3400	0–272	1–591	0.001–2127
Open/Closed System	Open	Open	Open	Closed
Reservoir Salinity, TDS, ppm	>200,000	7,000–28,000	9500	>180,000
Climate	Temperate	Arid	Semiarid	Semiarid
Regional Water Stress	Low	High	High	Moderate

In addition to testing various behaviors of injected CO₂ in heterogeneous reservoirs within structures in response to injection and extraction designs, different sites enabled specific testing of other operational aspects. Specifically;

- For the Ketzin Model we tested open vs. closed boundary conditions and the effect of adding more injection and production wells.
- The Zama Model tested injection and production rates from a small, closed structure in order to maximize storage.
- The Gorgon model tested injection and production rates for a reservoir with very large capacity, and how water extraction behaves when pressure maintenance is not necessary, and also how the reservoir behaves under a much larger injection.
- The Teapot Dome Model tested different combinations of injectors and producers, and also the use of horizontal wells.

CO₂ storage capacity estimates in this study are based on a dynamic evaluation that takes into account geologic heterogeneity, reservoir pressure interference, well configuration, injectivity/productivity, and boundary condition. The effect of water extraction on dynamic storage capacity was investigated by adding and varying number of water extraction wells and CO₂ injection wells. This is typically accomplished by constructing geocellular models of the injection volume and running numerical simulations. The pressure and CO₂ plume movement are estimated based on the simulation results.

3-D geocellular models were developed for each study site and populated with data related to porosity, permeability, structure, lithology, formation water quality, temperature, and pressure by using a deterministic model populated with geostatistically simulated data to produce one realization per site representing the P₅₀ case (Schlumberger, 2012). Heterogeneities of these sites were assigned according to variogram ranges attributed to depositional environments from GSLIB (Deutsch and Journel, 1998). The lack of input data did not provide enough variation to create multiple realizations without performing detailed petrophysical analysis, which was beyond the scope of this work. Multiple realizations were attempted, however, by only changing the seed number on the geostatistical property simulation. These results did not provide significant change in the geologic model, and results were near identical when ranked in an attempt to reduce geologic uncertainty. The Ketzin and Gorgon sites were modeled following published methodologies for the two sites, which included a combination of object modeling and truncated Gaussian simulation processes (Court et al., 2010; Klapperich et al., 2013; Fleury et al., 2010; Schilling et al., 2009; CO2CRC Technologies Pty Ltd, 2008, 2009). Teapot Dome utilized over 1200 well tops from the field which were used to identify and model the structure of different horizons. The Zama Field pinnacle reefs contain complex internal geometry and variable structure. These systems were modeled using a combination of object modeling and multipoint statistics using an interpreted reef structural diagram as a training image. The facies model was populated with site-specific heterogeneity and properties developed through Plains CO₂ Reduction (PCOR) Partnership characterization activities. It is important to note that two of the selected sites (Zama and Teapot Dome) are depleted oil and gas reservoirs and, as such, are likely to contain varying concentrations of hydrocarbons, which may increase overall treatment costs and/or limit the potential for beneficial use. However, the authors have chosen to use these sites as analogs for similar saline formations in lieu of adequately described formations for the purposes of storage capacity calculations by water extraction.

A compositional reservoir simulator was used for all dynamic modeling and simulations (Computer Modelling Group, 2014a). All scenarios/simulations were run under isothermal conditions with negligible geomechanical behaviors, limited by the maximum cap rock pressure for cap rocks of each respective site. All of the geologic information and modeling parameters, including residual saturations, capillary pressure, relative permeability curves, boundary conditions, and initial reservoir pressure for each site, were derived from published material. If specific data elements were not available from publications, the

parameters were referenced from similar reservoir types within the Average Global Database (IEA Greenhouse Gas R&D Programme, 2009).

Evaluation of fluids and flow was limited to formation water, CO₂, and various compositions of CO₂ dissolved in the formation water. The properties of fluids in models for the four sites were generated by the phase behaviour and fluid property program (Computer Modelling Group, 2014b). The basic pressures and temperatures used in the phase property program were the average values of the specific site. The solubility coefficients were determined and correlated based on the Li–Nghiem Method (Li and Nghiem, 1986). The fluid density and viscosity were correlated by the Rowe–Chou aqueous density correlation (Rowe and Chou, 1970) and Kestin aqueous viscosity correlation (Kestin and Shankland, 1984), respectively, for various pressures and temperatures along with depth of the models.

All of the wells in the models were tied to existing wells whenever possible, including the injection well for the Ketzin site in Germany (Kempka and others, 2010; Martens and others, 2011; Wiese, 2010a), the Zama field in Canada (Burke, 2009), and all proposed injection and production wells in the Gorgon site in Australia (Flett and others, 2008, 2009; CO2CRC Technology Pty Ltd, 2008). If additional wells were required for a given scenario, their locations were suggested based on the hydraulic conductivity and geologic structure of the specific site. Well parameters such as perforation interval, radius, and skin were also referenced to published data whenever possible. If such data were not available, the typical values of the well radius of 0.108 m and a skin of 0 were used for the simulations. Injection wells were perforated in the reservoir interval, while extraction wells were only perforated in the bottom half of the reservoir interval.

For CO₂ injection, a commercial-scale injection rate and period were assumed; that is, 1-million tonne/year injection rate (2 million tonnes or more in the Gorgon and Ketzin study sites based on injectivities), with a 25-year injection period to meet the maximum CO₂ storage and moderate water extraction period. The injection well was controlled by the injection rate and maximum bottomhole pressure (BHP) for all scenarios. If the pressure buildup was less than the maximum BHP constraint, the specified injection rate was used. Otherwise, the injection rate was reduced to match the maximum BHP constraint. The maximum BHP for the specific site was determined by the static pressure at the depth of the well bottomhole with an extra 10% buffer.

Water extraction was carried out based on the minimum BHP and maximum production rate. The reasonable minimum BHP used for most of the scenarios was set based on the specific case study by referring to production operating history and site characterization to avoid any mechanical issues. Water extraction was shut in at each extraction well at the end of the injection period or when CO₂ breakthrough occurred (>1000 m³/day).

All simulation scenarios were developed to compare the effects of different injection and extraction scenarios under several geologic conditions in an attempt to improve CO₂ storage capacity and manage the storage reservoirs. In addition, CO₂ plume and pressure management strategies were investigated to analyze the potential decrease in risk by controlling the CO₂ plume and decreasing reservoir pressure associated with CO₂ storage (IEA Greenhouse Gas R&D Programme, 2012; Liu et al., 2012; Klapperich et al., 2012). More detailed results for the entire study can be found in the published report (IEA Greenhouse Gas R&D Programme, 2012).

3. Case Studies

3.1 Ketzin Case Study

3.1.1 Site Characterization

The Ketzin pilot site, led by the GFZ German Research Centre for Geosciences, is Europe's longest-

operating onshore CO₂ storage site, with the aim of increasing the understanding of geologic storage of CO₂ in saline formations. Located near Berlin, the Ketzin pilot site has been in operation since 2004 and comprises three wells to depths of 750 to 800 m and one shallow observation well. Since June 30, 2008, CO₂ has been injected into a 630- to 650-m-deep sandstone unit on an anticlinal structure in the Northeast German Basin. After 44 months of injection (February 2012), about 59,000 tonnes of CO₂ has been stored successfully. However, the Ketzin project was completed in December 2013.

Ketzin lies on top of the Ketzin–Roskow Anticline, a double plunging structure trending northeast–southwest, approximately 12 × 43 km in size, with a maximum vertical closure of approximately 300 m. The reservoir unit for the site is the Stuttgart Formation, which consists of a series of fluvial channels surrounded by low-reservoir-quality floodplain deposits, shown in Fig. 2 (left) (Norden et al., 2010). The site is relatively shallow, with the reservoir unit being approximately 650 m deep. Several separate modeling efforts have been produced over the course of the project that served as templates, parameters, and data sources for model production (Flett et al., 2009; Forster et al., 2006; Prevedel et al., 2008; Frykman et al., 2006).

The Ketzin simulation results presented in this paper are a theoretical case study and do not reflect the real site operational conditions (this pilot site is a research and development project and limited by legal regulations to a maximum amount of stored CO₂ of <100,000 tonnes).

Fig. 2. Stuttgart Formation structural map (left [Norden et al., 2010]) and modeled surface produced from the data (right).

3.1.2 Modeling

Locations, wireline logs, and Stuttgart Formation structure maps were incorporated for the injection and monitoring wells according to data presented in Norden et al. (2010). Additionally, fluvial analog data collected for the Stuttgart Formation's fluvial system input parameters were integrated into the channel shape and facies-modeling process (Kempka et al., 2010). Most of the properties and parameters for the modeling and simulations, initial reservoir pressure, and well designs were based on publications of the Ketzin project by the GFZ German Research Centre and associated research projects (Court et al., 2010; Frykman et al., 2006; Kopp et al., 2006; Forster et al., 2006; Henniges et al., 2011; Martens et al., 2010; Wiese et al., 2010a, b; Würdemann et al., 2010). The model dimension used in this study was 29,317 × 51,370 × 915 m, which extended the model from 5000 × 5000 × 400 m, as reported by Kempka et al. (2010), to fit a commercial-sized injection without experiencing model edge effects (Fig. 2 [right]). Detailed properties are listed in Table 2.

Table 2. Ketzin Model Properties

Property	Value	Source
Total Porosity	7%–51%, avg: 24%	Norden et al., 2010
Effective Porosity	0%–50%, avg: 12%	Norden et al., 2010
Permeability	0.03–3400 mD, avg: 232 mD	Norden et al., 2010
Thickness	80 m	Würdemann et al., 2010
Depth	~650 m	Würdemann et al., 2010
Pressure, average ¹	9623.7 kPa	Würdemann et al., 2010
Temperature, average	38°C	Prevedel et al., 2008
Average CO ₂ Density	643.91 kg/m ³	Massachusetts Institute of Technology, 2011
Variogram Range, long	398	IEA Greenhouse Gas R&D Programme, 2009
Variogram Range, short	108	IEA Greenhouse Gas R&D Programme, 2009
Total Dissolved Solids (TDS)	228.8–236.5 g/L	Würdemann et al., 2010 ²
Channel Orientation	15°–20°	Forster et al., 2006
Sinuosity Amplitude	100–250 m	Forster et al., 2006
Wavelength	5000–9000 m	Forster et al., 2006
Belt Width	100–1600 m	Forster et al., 2006
Channel Thickness	1–8 m	Forster et al., 2006

¹ Modeled reservoir pressure ranges from 4646 to 13,460 kPa.

² Water chemistry is the variation in four time-lapse samples, not absolute range.

3.1.3 Key Results

A total of 12 cases (Table 3) were designed to analyze different scenarios of injection and water extraction in order to assess differences in storage capacity and efficiency while defining potential volumes of produced water for treatment or disposal. The cases were compared based on how water extraction influences storage capacity and reservoir management through adding extraction wells, varying the number of injection/extraction wells, and converting the same number of injection wells to extraction wells. An injection program was selected that maximized injectivity and, ultimately, storage capacity for an injection of 2 megatonnes a year as a well constraint over a period of 25 years per single vertical injection well. The results of injected CO₂ and extracted water for all cases are plotted in Fig. 3 and indicate that the boundary conditions have significant effects on the storage capacity and pressure buildup, especially the case with closed boundaries. The effects between semiclosed (Case 2) and open conditions (Case 3) show less pressure buildup than the case with closed boundaries (Case 1), especially after adding water extraction in Cases 4 and 5. This is due to the strong influence of the dome structure that restricts the CO₂ movement laterally. For similar reasons, the storage capacity using two CO₂ injectors (Case 6) is better than one CO₂ injector and one water extractor in Case 5. In Case 4, which added one extraction well, the storage capacity was increased 98% to 25.7 Mt from 13.0 Mt in Case 2 with only one injection well. This is an example that water extraction could enhance the CO₂ storage in the reservoir.

For the multiple extraction well patterns in Cases 7 through 12, the storage capacity increases with additional extraction wells. The percentage increase of CO₂ storage with extraction wells is much larger than the cases where the same number of injection wells was utilized. It is likely that in these scenarios, with the utilized well spacing, the pressure interference of injection becomes the dominant factor.

The use of extraction wells assists in reducing the overall reservoir pressure. As an example, Fig. 4 shows that the reservoir pressure reductions are approximately 12% in the central area of the injection plume as a result of water extraction in Case 4 by comparing the results in Case 2 without water extraction. Along with a pressure reduction, the plume area increased by 32% as CO₂ was drawn south toward the downdip extraction well, as shown in Fig. 5. The reason is that approximately 98% more CO₂ storage space was created by water extraction. Similar results of structurally dominated migration were

observed in Case 5, where open model boundary conditions allowed for a greater injection rate (IEA Greenhouse Gas R&D Programme, 2012; Liu et al., 2013).

Table 3. Case Scenarios and Resulting Storage Capacities for the Ketzin Site

Scenario	Well Configuration	Averaged Actual Gas Injection, ¹ kg/(day*well)	Water Production, kg/(day*well)	Boundary Conditions	Storage Capacity, Mt
Case 1	1 injector	451,000	NA ²	Closed	4.12
Case 2 (base case)	1 injector	1,430,000	NA	Semiclosed	13.0
Case 3	1 injector	1,980,000	NA	Open	18.1
Case 4	1 injector	2,810,000	12,752	Semiclosed	25.7
Case 5	1 extractor				
	1 injector	3,000,000	13,580	Open	27.4
	1 extractor				
Case 6	2 injectors	3,550,000	NA	Semiclosed	32.4
Case 7	4 injectors	6,954,760	NA	Semiclosed	63.3
Case 8	4 injectors	7,170,000	12,700	Semiclosed	65.4
	4 extractors				
Case 9	8 injectors	9,500,000	NA	Semiclosed	86.7
Case 10	12 injectors	14,500,000	NA	Semiclosed	132.0
Case 11	12 injectors	24,877,000	65,753	Semiclosed	226.7
	13 extractors				
Case 12	25 injectors	20,100,000	NA	Semiclosed	183.8

¹ Standard conditions (15.5°C, 101.25 kPa).

² Not applicable.

Fig. 3. Comparison of injected CO₂ utilizing multiple combinations of injection and extraction wells.

Fig. 4. Average reservoir pressure after 25 years of injection for Cases 2 and 4.

Fig. 5. Outline of plume extent after 25 years of injection for Cases 2 and 4 overlain grid to top.

3.2 Zama Case Study

3.2.1 Site Characterization

The Zama F pool is one of over 700 hydrocarbon-bearing geologic structures in the Zama Subbasin located in extreme northwestern Alberta, Canada, and the site of a combined enhanced oil recovery (EOR) and storage project operated by Apache Canada, with the Energy & Environmental Research Center (EERC) through the PCOR Partnership Program. Since December 2006, Apache Canada has been injecting acid gas (approximately 70% CO₂ + 30% H₂S) for the simultaneous purpose of EOR, H₂S disposal, and CO₂ storage. The Keg River pinnacle reefs typically consist of variably dolomitized carbonate and are surrounded and overlain by the very tight anhydrite Muskeg Formation that acts as a cap rock, effectively forming a closed system. A large variation in both porosity and permeability is observed with a decrease in both properties toward the reef tops. The principal rock types include various carbonate lithologies, including wackestone, packstone, floatstone, and rudstone with varying degrees of alteration due to secondary leaching and dolomitization. Porosity type varies from intercrystalline to microfractures in Table 4 (Burke, 2009).

Table 4. Reservoir Properties for the Zama F Pool Pinnacle Reef

Property	Value	Source
Effective Porosity	0.03% – 17%	Log derived
Permeability	0.001 to 2127 mD	Log derived
Thickness	240 m	Burke, 2009
Depth, structure top	1427 m	Burke, 2009
Temperature	71.1 °C	Operator communication
Initial Reservoir Pressure	14,450 kPa	Operator communication
Average CO ₂ Density	653.43 kg/m ³	Massachusetts Institute of Technology, 2011
TDS*	180,000 ppm	Operator communication

* Total dissolved solids.

3.2.2 Modeling

The Zama model was a special case where an advanced workflow was followed because of available information. Core-calibrated multiminerale petrophysical analysis was performed on wireline logs. Borehole image logs were used to more accurately identify the different facies and determine each facies' properties along the wellbores. Seismic attribute data interpretations were used to identify the reef versus nonreef facies to aid in the distribution of the facies in the reservoir model. Properties were then spatially distributed throughout the model using a combination of multiple-point statistics and object-modeling workflows to produce equiprobable reef facies, structure, and volumetric realizations (Fig. 6). P₁₀, P₅₀, and P₉₀ geologic models were constructed for Zama, based on the above workflow; however, only the P₅₀ was used for numerical simulation.

Fig. 6. 3-D view of porosity attributes with internal reef heterogeneity.

3.2.3 Key Results

Seven different cases of simultaneous CO₂ injection and formation water extraction were tested (Table 5 and Fig. 7). In Case 1, acid gas was injected at a base rate (0.113 Mt/year) without the extraction of formation water. In Cases 2–6, a water extraction well was placed in the bottom (water) zone of the reef structure. The results of Cases 1 and 2 show that the storage capacity increased from 0.05 Mt to 0.62 Mt with water extraction. The storage capacity also increased when the water extraction rate was decreased in Cases 3–5 because of a delay in gas breakthrough at the extraction well. Injection rates were doubled in Case 6, but this resulted in earlier CO₂ breakthrough and lower capacity than Cases 3–5. With two water extractors in Case 7, early breakthrough was again observed, limiting total capacity. Overall, a pair of injection–extraction wells shows the best storage capacity for the Zama Site (IEA Greenhouse Gas R&D Programme, 2012; Saini et al., 2013, Liu et al., 2014, Gao et al., 2014).

Table 5. Cases Tested in Predictive Simulations for the Zama Site

Scenario	Well Configuration	Averaged Actual Gas Injection, ¹ kg/day*well	Water Production, m ³ /day*well	Boundary Conditions	Storage Capacity, Mt
Base 1	1 injector	311,800	NA ²	Closed	0.045
Case 2	1 injector 1 extractor	311,800	516	Closed	0.47
Case 3	1 injector 1 extractor	311,800	516	Closed	0.62
Case 4	1 injector 1 extractor	311,800	429	Closed	0.68
Case 5	1 injector 1 extractor	310,680	397	Closed	0.69
Case 6	1 injector 1 extractor	621,359	1144	Closed	0.49
Case 7	1 injector 2 extractors	621,359	572	Closed	0.60

¹ Standard conditions (15.5°C, 101.25 kPa).² Not applicable. Fig. 7. Comparison of injected CO₂ utilizing multiple combinations of injection and extraction wells.

3.3 Gorgon Case Study

3.3.1 Site Characterization

The Gorgon project is a joint venture to inject and store produced CO₂ and is managed by oil companies Chevron, ExxonMobil, and Royal Dutch Shell, with partners Tokyo Gas, Osaka Gas, and Chubu Electric (Massachusetts Institute of Technology, 2011). The injection target is the Dupuy Formation, a clastic turbidite sequence 2500 m below the surface infrastructure on Barrow Island off the western coast of Australia. The project aims to inject approximately 3.8 Mt/year through eight injection wells, with four water production wells located to the west of the site; injection is expected to begin in 2015 (Massachusetts Institute of Technology, 2011; Flett et al., 2008).

The island is located atop a large (25 × 38 km), north–south-trending, double-plunging anticline. The injection target is 200–500 meters thick, comprising sandstones and siltstones deposited as turbidite and debris flows, which discharged onto the Australian slope and were later uplifted to their present position.

Four major subunits have been defined with lithology presented in Table 6. Data were scarce for the site for both modeling workflow and reservoir data, with basic results from modeling efforts reported by Flett et al. (2008). In order to develop the hypothetical injection plan for this study, additional data, including wireline logs from an exploratory well, were incorporated from Brantjes (2008).

Table 6. Unit Descriptions and Thicknesses from the Gorgon Site

Subunit	Lithology (from Brantjes [2008])	Thickness, m
Upper Dupuy	Bioturbated siltstone; poor quality	111
Upper Massive Sand	Medium-grained sandstone; high quality	140
Lower Dupuy	Fine-grained sandstone/siltstone to shale; fair quality	190
Basal Dupuy	Siderite-cemented fine-grained sandstone; poor quality	95

3.3.2 Modeling

Well locations and the structure on top of the Upper Massive Sand unit of the Dupuy Formation were used as baseline data according to Flett et al. (2008). As sufficient well logs or structure maps for additional subunits were not present, constant unit thickness was defined from unit boundaries on well logs from Brantjes (2008) (Table 7). The model size used by Flett et al. (2008) was found to be sufficient to contain the 3.3–3.8-million-tonnes/year injection without reaching the model boundaries. Since poor reservoir quality was encountered in wireline logs, facies were not assigned for the Basal Dupuy, and the unit is considered to behave as a lower seal. The Lower Dupuy was assigned facies using truncated Gaussian simulation, using parameters and techniques suggested by Flett et al. (2008), who stated that reservoir quality degrades from high on the north end to silty then shaley moving south. The Upper Massive Sand and Upper Dupuy zones were modeled using object modeling processes for fan-type deposits with thicknesses and prevalence by following the suggestions of Flett and others (2008) and Brantjes (2008). Facies were populated with porosity and permeability properties according to variograms from GSLIB (Deutsch and Journel, 1998); clastic slope/basin environments and porosity, effective porosity, and permeability values were from Brantjes (2008). Most of the properties and parameters, including saturations, relative permeability curves, boundary conditions, and initial reservoir pressure for modeling and simulations, were based on publications (Table 7, Fig. 8) (Brantjes, 2008), and notably, the proposed location of the injection and production wells followed the study of Flett et al. (2008).

Table 7. Gorgon Model Properties

Total Porosity	Value	Source
Effective Porosity	0%–25.3%	Brantjes, 2008
Permeability	0–272 mD	Brantjes, 2008
Depth, top of Upper Dupuy	2245 m	Flett et al., 2008
Pressure, average	25,165 kPa	Flett et al., 2008
Temperature, average	161°C	Colombo et al., 2010
Average CO ₂ Density	528.1 kg/m ³	Massachusetts Institute of Technology, 2011
Variogram Range, long	1346	IEA Greenhouse Gas R&D Programme, 2009
Variogram Range, short	367	IEA Greenhouse Gas R&D Programme, 2009
TDS	7096–28,615 ppm	Trupp, 2011

Fig. 8. 3-D representation of the Gorgon reservoir model with location of injection and extraction wells.

3.3.3 Key Results

Seven hypothetical cases were simulated by using the planned eight injection wells and four extraction wells (Table 8 and Fig. 9). The base scenario injected 0.5 Mt/year (base rate) through each well for investigational periods of 25 and 50 years, for a total of 100- and 200-Mt CO₂ injections. The effects of extraction on capacity were minimal in Cases 1–5, as the reservoir has excellent injectivity and capacity, meaning that the upper limit of injection was not achieved through these simulations. For this reason, the total storage in Cases 1–5 is quite linear with regard to injection rate and period. Cases 6 and 7 sought to maximize the injection rate, beginning with 7.5 times the base yearly injection rate, or 3.75 Mt/year per well for 25 years. Because of the higher injection rates, pressure increases near the injection wells were expected to cause issues that may be alleviated by water extraction. Simulations under this scenario resulted in storage capacities of 551 Mt without water extraction, which increased to 637 Mt with water extraction, an increase of 16% (IEA Greenhouse Gas R&D Programme, 2012; Liu et al., 2013).

Pressure management through water extraction proved very consistent, with pressures reduced by approximately 10% from Case 1 to Case 2 (Fig. 10) after 13 years of injection. Over the injection and extraction period, the pressure differences increased because of the effect from water extraction. However, with more CO₂ being injected, reservoir pressure started increasing slightly. The difference in plume size was relatively small between Cases 1 and 2, differing by a negligible percentage. The size difference between Cases 6 and 7 was a notable 10.1% with maximum injection scenarios (Fig. 11) (Liu et al., 2013).

Table 8. Case Scenarios and Resulting Storage Capacities for Gorgon

Scenario	Well Configuration	Target Injection Rate/Well, Mt/year	Averaged Actual Gas Injection Rate/Well, kg/day	Water Production Rate/Well, m ³ /day	Injection Period, yr	Storage Capacity, megatonnes
Case 1 (base case)	8 injectors	0.5	10,661,700	NA	25	97.3
Case 2	8 injectors 4 extractors	0.5	10,661,700	215,120,000	25	97.5
Case 3	8 injectors	0.5	10,661,700	NA	50	195
Case 4	8 injectors 4 extractors	0.5	10,661,700	334,919,000	50	196
Case 5	8 injectors 4 extractors	0.25	5,330,830	396,606,000	50	97.5
Case 6	8 injectors	3.75	60,400,000	NA	25	551
Case 7	8 injectors 4 extractors	3.75	69,900,000	261,802,000	25	637

Fig. 9. Comparison of injected CO₂ utilizing multiple combinations of injection and extraction wells.

Fig. 10. Average reservoir pressure after 25 years of injection for Cases 1 and 2.

EERC GL49289.AI

Fig. 11. Map of injection and extraction wells on Barrow Island with plume outlines of cases.

3.4 Teapot Dome Case Study

3.4.1 Site Characterization

Teapot Dome, also known as Naval Petroleum Reserve 3 or the Rocky Mountain Oilfield Testing Center (RMOTC), is a demonstration site near Casper, Wyoming. Teapot Dome is a stacked sedimentary sequence on the western flank of the Powder River Basin present as an elongated anticline and is adjacent to the Salt Creek Anticline, a commercial oil field currently undergoing CO₂ EOR. Over 1300 wells penetrate the structure at the Teapot Dome, which has historic production within the Tensleep and Frontier sandstones and reserves in the Muddy sandstone. Additionally, saline aquifers are located in both clastic and carbonate beds, including the Dakota/Lakota and Madison Formations (Table 9). Produced water from oil field activities at Teapot Dome is of extremely high quality and has many uses in the semiarid Powder River Basin.

Table 9. Unit Descriptions for the Teapot Dome Site

Formation	Interpreted Lithology
Frontier	Interbedded sandstones and shales, deltaic
Muddy	Sandstone body, nearshore marine
Dakota	Sandstone bodies, nearshore marine
Lakota	Sandstone bodies, nearshore marine
Tensleep	Interbedded sandstone and dolomite, sandstones primarily eolian
Madison	Variable reservoir quality, shallow shelf

Study efforts were focused on the Dakota and Lakota Formations for this site, although it is recognized that utilizing several formations in the stratigraphic section is optimal for storing large volumes of CO₂. Because of historic hydrocarbon production, characterization of the site has resulted in large volumes of data, and the field continues to operate as a demonstration and experimental site, as oil production has declined to unprofitable levels. Interest in CO₂ EOR is present because of successful CO₂ EOR ongoing in the adjacent Salt Creek Field since 2003, where 6583 tonnes of CO₂ a day is injected, totaling 6.6 million tonnes as of February 2010 (Forster, 2006).

3.4.2 Modeling

A data set of Teapot Dome information, including well locations, picked formation tops, and well logs, was available in CD format from RMOTC (Rocky Mountain Oilfield Testing Center, 2007). Formation tops were used to form a high-resolution structural model of each horizon. Unfortunately, characterization information gleaned from literature review was not conducive to direct application in modeling, and full-scale petrophysical interpretation of the site is beyond the scope of this study. A limited amount of data collection has been processed by Milliken (2007) regarding geothermal resources and water quality, and a historical perspective and field overview were performed by Curry (1977). Because of the lack of petrophysical data at Teapot Dome, a deterministic model was developed to include reported or derived rock properties collected through core analysis, including porosity and permeability. Only one realization was modeled because of a lack of input data. The geologic model was developed (Fig. 12) based on published data (Table 10) (Milliken, 2007; Curry, 1977; Rocky Mountain Oilfield Testing Center, 2011).

The injection and production wells used in the models were a combination of existing wells in the field and hypothetical wells based on the geologic structure and geology for these investigations.

Fig. 12. 3-D view of the Teapot Dome Dakota model showing the porosity attribute.

Table 10. Reservoir Properties of the Dakota and Lakota Formations

Property	Value	Source
Effective Porosity	0%–25.3%	IEA Greenhouse Gas R&D Programme, 2009
Permeability	0.4–319 mD	IEA Greenhouse Gas R&D Programme, 2009
Thickness	40 m	Rocky Mountain Oilfield Testing Center, 2007
Depth, structure top	1450 m	Rocky Mountain Oilfield Testing Center, 2007
Temperature	65.5°C	Milliken, M., 2007*
Pressure	~11,000 kPa	Milliken, M., 2007*
Average CO ₂ Density	163.23 kg/m ³	Massachusetts Institute of Technology, 2011
Variogram Range, long	6792	IEA Greenhouse Gas R&D Programme, 2009
Variogram Range, short	1852	IEA Greenhouse Gas R&D Programme, 2009
TDS	9500 ppm	Rocky Mountain Oilfield Testing Center, 2011

* From gradients based on data from Milliken (2007).

3.4.3 Key Results

Injection/extraction analysis of the Dakota/Lakota Formation at Teapot Dome was investigated through a total of five simulations (Table 11 and Fig. 13). The boundary of the domain was set as semi-closed to reflect the geology with partial aquifer support from surroundings. The base injection target rate used for the site was 1 Mt/year. The baseline simulation (Case 1) without extracted water resulted in a total storage capacity of 5.2 Mt for the site over 25 years, which is significantly lower than the injection target. In Case 3, one water extractor was added; this scenario resulted in a storage capacity of 11.1 Mt, more than doubling the single injection well results. Further, these results indicate that utilizing an injection–extraction well pair is a more efficient situation than utilizing two injection wells alone (Case 2).

Table 11. Case Scenarios and Resulting Storage Capacities for Teapot Dome

Scenario	Well Configuration	Averaged Actual Gas Injection Rate/Well, kg/day	Water Production Rate/Well, m ³ /day	Storage Capacity, megatonnes
Case 1 (base case)	1 injector	565,128	NA	5.2
Case 2	2 injectors	836,848	NA	7.6
Case 3	1 injector 1 extractor	1,212,810	1657	11.1
Case 4	1 horiz. injector 1 horiz. extractor	2,090,498	6701	19.1
Case 5	2 horiz. injectors	1,953,238	N/A	17.8

Fig. 13. Comparison of injected CO₂ utilizing multiple combinations of injection and extraction wells.

An alternative method of increasing storage capacity is using horizontal wells in place of vertical wells. In Case 4, two 1-km-long horizontal wells were utilized: one for injection and one for water extraction. This case resulted in 19.1 Mt of storage capacity, nearly doubling the capacity of using a vertical well pair. In addition to the increase in storage capacity, the plume size increased by 44% from Case 3 to Case 4 (IEA Greenhouse Gas R&D Programme, 2012; Liu et al., 2013), with an associated drop in overall reservoir pressure, which means that horizontal wells play a significant role in enhancing CO₂ storage through lateral injection and extraction performance. For comparison, Case 5 was run with two 1-km-long horizontal injection wells instead of an injector–extractor pair; this scenario resulted in 17.8 Mt of storage capacity over the 25-year injection period, which was about 7% less storage than the injector–extractor pair (Fig 14). Hence, storage capacity was enhanced 7% by using water extraction instead of horizontal injection in comparing Cases 4 and 5. The results from these five cases indicate that storage capacity can be further improved in certain scenarios by utilizing injection–extraction pairs rather than by adding more injectors.

Fig. 14. Plume distribution of Teapot Dome Cases 4 and 5 illustrating the effects on plume size from the utilization of horizontal and vertical extraction wells.

4. Conclusions and Future Works

Extracting water from a CO₂ storage reservoir was observed to have variable effects based on the specific nature of reservoir rock and reservoir boundary conditions as well as operational factors such as injection/extraction management and placement of wells. The assumption of achieving a 1:1 ratio of injected CO₂ to extracted water was generally appropriate for increasing CO₂ storage capacity. However, in order to perform pressure or plume management tasks, the volume of water that must be removed from the reservoir was found to be four or more times greater in some cases.

Water extraction was found to be imperative to control pressure and increase storage space in closed systems and likely will provide benefit to most semiclosed, bounded reservoirs if water disposal or use is not highly prohibitive.

The Ketzin-based model provided a stage on which to test boundary conditions and the impact of increasing injectors and/or producers across a geologic structure. More injectors accessed more of the fluvial reservoir, and extractors were beneficial in storage capacity increases, on the order of 98% more storage space and a 32% smaller plume area.

The most dramatic results were found in closed reservoir simulations from the Zama site, where storage capacity could be increased by nearly 1300% in a single pinnacle reef structure with proper well placement. Although individually small, capable of holding approximately 690,000 tonnes of CO₂, the Zama Field has hundreds of similar structures, which could be developed in the same way to meet the 1-million-tonne/yr injection goal. A key observation in storage scenarios such as the Zama F pool was that higher injection rates led to faster breakthrough and, therefore, limited lower storage capacity.

The Gorgon-based model tested various strategies of the proposed injection design of eight injectors and four water extraction wells. Water production at the site was found to have little impact because of the site's capacity, injectivity, and reservoir quality being much greater than the injection scheme; therefore, alleviation of reservoir pressure to aid in pressure management was not necessary. Only when injection rates were increased by 7.5 times did water extraction impact the site. Although water extraction had essentially no impact on potential storage capacity, it was still found to influence plume behavior and pressure propagation in such a way as to be useful for plume management.

The opposite of the Gorgon-based model was encountered in the case of the Teapot Dome-based model, where injection design quickly approached reservoir limits. For sites such as this, water extraction is beneficial, and designs incorporating pressure management were found to produce significant gains in storage capacity. The impact of horizontal wells was tested in the Teapot Dome model, in which lateral wells accessed the reservoir better and provided enhanced performance from vertical injector–producer pairs.

Simulations of hypothetical injections at the Ketzin and Teapot Dome sites showed potential CO₂ storage capacity increases of approximately double (197% and 204%, respectively) from formation water extraction. In each of these cases, capacity and the relative influence on plume behavior could be enhanced by modifying the injection scheme. The Ketzin simulations initially showed that two CO₂ injection wells outperformed an injection extraction pair. However, it was found that if the number of wells was substantially increased to a 25-spot well pattern, the combination of 12 injection and 13 extraction wells outperformed 25 injection wells by 123% and did so while removing approximately half as much water (by volume) as CO₂ injected. At the Teapot Dome site, it was found that the use of horizontal well pairs could further increase the impact of water extraction and increase the CO₂ storage capacity. Overall capacity was increased by 367% over the base case single vertical injection well and thus represents an additional 163% increase over the injection–extraction pair. In both these cases, optimizing simulations to achieve pressure maintenance or plume management generally resulted in decreased reservoir storage capacity, with a significant increase in the volume of extracted water.

The characterizations of four sites diverge from geologic structure and heterogeneity that resulted in different effects on the CO₂ storage capacity. Sites were chosen to reflect differences in reservoir behavior (open vs. closed boundaries), geologic properties and heterogeneity, structure, modern climate, and data availability. It was observed that variation of temperature and pressure due to the geology and depth of the sites directly influenced the CO₂ storage capacity estimation because the CO₂ density is highly sensitive to these factors. This is the primary reason that the CO₂ density in the four cases changed from 163 kg/m³ (Teapot Dome site) to 528 kg/m³ (Gorgon site) and about 650 kg/m³ (Zama and Ketzin sites). However, these four case studies illustrate the wide range of results that may be possible and that geologic and reservoir engineering factors may both have a large influence on the final results. It can also be said that if it is feasible to utilize a large number of injection and extraction wells, overall storage may be increased by a large margin, even in high-quality storage reservoirs.

The influence of water extraction on the migration of pressure and free-phase CO₂ plumes was observed in each of the open-system sites. However, this influence was moderated by other factors such as geologic structure and local reservoir heterogeneities. The utilization of water extraction for the purpose of reservoir management is best applied to reservoirs with low structural control. In the case of the Ketzin site (a dome-shaped structure), water extraction did not appear to have a strong effect on the structure-dominated CO₂ movement. However, in the case of a relatively flat-structured reservoir (the

Gorgon and Teapot Dome sites), CO₂ plume and pressure management results were significantly affected by water extraction. At the Gorgon and Teapot Dome sites, CO₂ injection with fluid extraction increased storage capacity by 50%, with only a 10% increase in plume size in several scenarios. In other scenarios, fluid extraction resulted in a 10% to 20% pressure reduction, with only a 5% increase in plume size. Therefore, the CO₂ plume movement trended in the direction of fluid extraction during this process, especially by the geologic structure and local reservoir heterogeneities. In all cases, CO₂ storage capacity was increased with a reduction in the overall reservoir pressure, suggesting that water extraction can play a role in maximizing the utility of large-scale CO₂ storage facilities in the future as more projects are developed.

Extracted water treatment, utilization, and regulation need to be much investigated based on the variation of the salinities by following the recommendations in the detailed report (IEA Greenhouse Gas R&D Programme, 2012). Developing formulaic methodology to estimate CO₂ storage capacity specific to the use of formation water extraction as a reservoir management strategy based on the more depositional environments and reservoir types are highly encouraged for the future study. This would allow for rapid assessment of the benefits of extraction on known and future CO₂ storage targets.

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Figure

Zama CO₂ Storage and Water Extraction

EERC GL45548.CDR

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EERC GL50505.AI

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