

An engineering solution for CO₂ injection in saline aquifers

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Author post-print (accepted) deposited by Coventry University's Repository

Original citation & hyperlink:

Shariatipour, SM, Mackay, EJ & Pickup, GE 2016, 'An engineering solution for CO₂ injection in saline aquifers' *International Journal of Greenhouse Gas Control*, vol 53, pp. 98-105. DOI: 10.1016/j.ijggc.2016.06.006

<https://dx.doi.org/10.1016/j.ijggc.2016.06.006>

DOI 10.1016/j.ijggc.2016.06.006

ISSN 1750-5836

Publisher: Elsevier

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54 **Abstract**

55 In this proposed CO₂ injection system, brine is extracted from the target storage aquifer by
56 means of a lateral horizontal completion located near the top of the formation. It should be
57 noted that the brine is not lifted to the surface. An Electrical Submersible Pump (ESP) is used
58 to extract the brine and boost its pressure, before it is mixed with CO₂ that is injected down
59 the vertical section of the well. The mixing takes place in the vertical section of the well
60 below the upper lateral. The CO₂ – brine mix is then injected into the same formation through
61 a lower lateral. A down-hole tool would be used to maximise agitation and contact area
62 between CO₂ and brine in the vertical mixing section of the well, which may be tens to
63 hundreds of metres long, depending on the thickness of the formation.

64 The advantages of this method are that there is little overall pressure increase, because CO₂ is
65 mixed with brine extracted from the formation, and also the extracted brine is already at high
66 pressure when it is mixed with the CO₂, greatly increasing the solubility of CO₂ and reducing
67 the volume of brine required. Energy is not expended lifting the brine to surface nor is there
68 any concern about handling large volumes of acidic brine in the surface equipment. In this
69 study, in addition to the concept of the down-hole mixing (DHM) method which is presented,
70 the application of the DHM method in a hypothetical storage site (Lincolnshire – Smith et al.,
71 2012) is also examined. The calculations are performed to identify the optimum rates of
72 water extraction and injection of dissolved CO₂ in brine.

73 **Introduction:**

74 Since the industrial revolution, the CO₂ concentration in the atmosphere has increased by
75 45% (Celia et al., 2015). At the current time, it is believed that carbon capture and storage
76 (CCS) can play a significant role in reducing the increase in the CO₂ concentration in the
77 atmosphere (Haszeldine, 2009). In the long term, several trapping mechanisms such as
78 structural and stratigraphic trapping, residual trapping, solubility trapping and mineral
79 trapping can be used to sequester supercritical CO₂ into the aquifers or depleted reservoirs
80 (Benson and Cole 2008). Structural trapping to prevent upward migration of CO₂ is provided
81 by a very low permeability layer, which is frequently a clay or shale layer, at the top of the
82 storage formation. Safe long-term CO₂ storage has been one of the most important issues, in

83 terms of environmental damage that could be caused by leakage (Gasda et al., 2004;
84 Nordbotten et al., 2005; Burton and Bryant 2009; Celia et al. 2011; Bachu and Celia 2009).
85 Therefore long-term monitoring needs to be carried out (Mathieson et al., 2011), which
86 increases the total cost of CO₂ storage.

87 Furthermore, due to the complexity of fully understanding the interface between
88 caprock/aquifer, and the risk of CO₂ leakage through caprock as a result of pressure build-up
89 at the interface between aquifer/caprock (Shariatipour et al., 2012, 2014; Newell and
90 Shariatipour 2016), the development of novel methods in which CO₂ injected into aquifers
91 does not migrate toward the interface is desirable. In this paper an engineering method for
92 CO₂ injection in which CO₂ is dissolved in brine down-hole is presented. If we can minimize
93 the vertical migration of CO₂ in the reservoir, then it increases the safety in terms of any
94 possible leakage through existing fractures and faults or fractures arising due to CO₂
95 injection. Injecting dissolved CO₂ could not only prevent buoyant vertical migration of CO₂,
96 but it could also lead to dissolved CO₂ sinking in the reservoir, as brine with dissolved CO₂ is
97 denser (around 1%) than formation brine (Ennis-King and Paterson, 2003, Ennis-King et al.,
98 2005, Riaz et al., 2006).

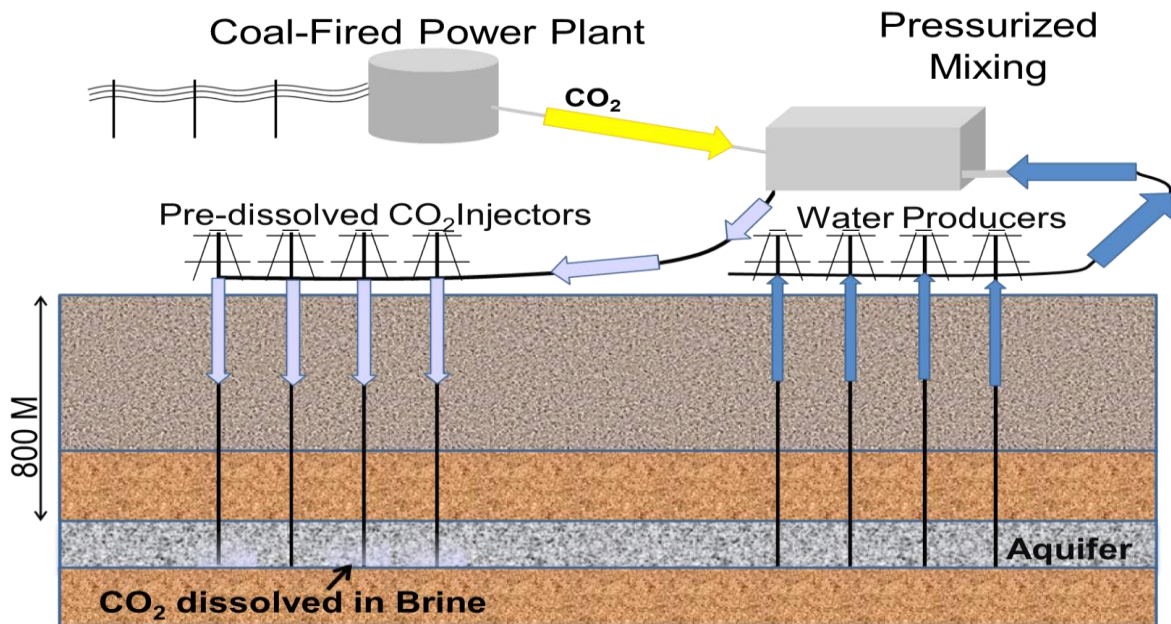
99 In many carbon capture and storage (CCS) research projects that have been published
100 (Kumar et al., 2005; Burton and Bryant 2009; Anchliya et al., 2012 and more), one of the
101 main concerns the authors have addressed is the security of CO₂ storage. Several engineering
102 techniques have been suggested to reduce this risk which can be classified into three
103 categories (Emami-Meybodi et al., 2015): subsurface dissolution, CO₂/brine surface mixing
104 and CO₂/brine wellbore mixing.

105 The "inject low and let rise" strategy was proposed by Kumar et al., (2005) to enhance the
106 subsurface dissolution. Some authors (Keith et al., 2005; Leonenko et al., 2006; Taku et al.,
107 2007; Leonenko and Keith 2008; Hassanzadeh et al., 2009; Anchliya et al., 2012) have
108 suggested injecting brine above the CO₂ plume to accelerate CO₂ dissolution in the aquifer.
109 They proposed a system where a horizontal brine injection well is placed above a horizontal
110 CO₂ injection well. The water-alternative-gas (CO₂ WAG) has been investigated to increase
111 the solubility trapping by injecting CO₂ chased by brine in the aquifers (Qi et al., 2009;
112 Cameron and Durlofsky, 2012; Zhang and Agarwal 2012, 2013).

113 A CO₂/brine surface mixing strategy (Figure 1) has been investigated by different authors
114 (Burton and Bryant 2009; Eke et al., 2011; Zendeboudi et al., 2011; Cholewinski and

115 Lonenko 2013; Tao and Bryant, 2014). They showed that the surface dissolution facilities
116 enhance CO₂/brine solubility. Hence, the CO₂-saturated brine stream could overcome the
117 buoyancy force. Bergmo et al., (2011) showed that producing water from the aquifer while
118 injecting CO₂ leads to a reduction in pressure both in the near well bore and throughout the
119 field. Therefore, it is considered that a CO₂/brine surface mixing strategy could improve the
120 effectiveness of CO₂ storage. Because injecting dissolved CO₂ eliminates free CO₂ in the
121 aquifer, there is no buoyant rise of CO₂ towards the caprock. However, Burton and Bryant
122 (2009) admitted that the surface dissolution method has some disadvantages in comparison to
123 the standard CO₂ injection method. For example: many more injection wells and extraction
124 wells are needed which raises the storage cost. In addition, as the CO₂ saturated brine is
125 acidic, the surface facilities and injection wells need to be resistant to corrosion. Furthermore,
126 the cost of surface mixing equipment and related operations needs to be considered.

127 A wellbore dissolution technique was proposed (Shafaei et al., 2012; Zirrahi et al., 2013a;
128 Pool et al., 2013; Paterson et al., 2014; Sigfusson et al., 2015) to eliminate some of the
129 disadvantages of the CO₂/brine surface mixing strategy. Shafaei et al., (2012) proposed a
130 reverse gas lift method to inject CO₂ through the annulus and brine through tubing
131 simultaneously. In their proposed method, gas lift valves provide communication for CO₂ to
132 access the tubing where water was injected and consequently CO₂ dissolves in brine in the
133 wellbore. Zirrahi et al., (2013) performed laboratory experiments to assess the feasibility of a
134 static mixing device for CO₂ and brine. They assume that the brine will be produced to the
135 surface from a well some distance away. Then this water will be pumped into the tubing of
136 the injection well while CO₂ is pumped into the annulus. The mixing device will be placed at
137 the bottom of the injection well. Down-hole mixing of CO₂ and brine was performed in one
138 of the tests at the Otway pilot storage site in Australia (Paterson et al., 2013). CO₂ and brine
139 were injected simultaneously down the well, and no special mixing device was used.
140 Sigfusson et al., (2015) demonstrated successful CO₂/brine wellbore dissolution process
141 during its injection into porous basalts rocks at depth of 400-800 m at the Hellisheidi, Iceland
142 CarbFix injection site. In all wellbore dissolution techniques that have been proposed the
143 water is being injected at the wellhead and this means water needs to be extracted and lifted
144 to the surface.



145

146 *Figure 1: CO₂/brine Surface Mixing Strategy.*

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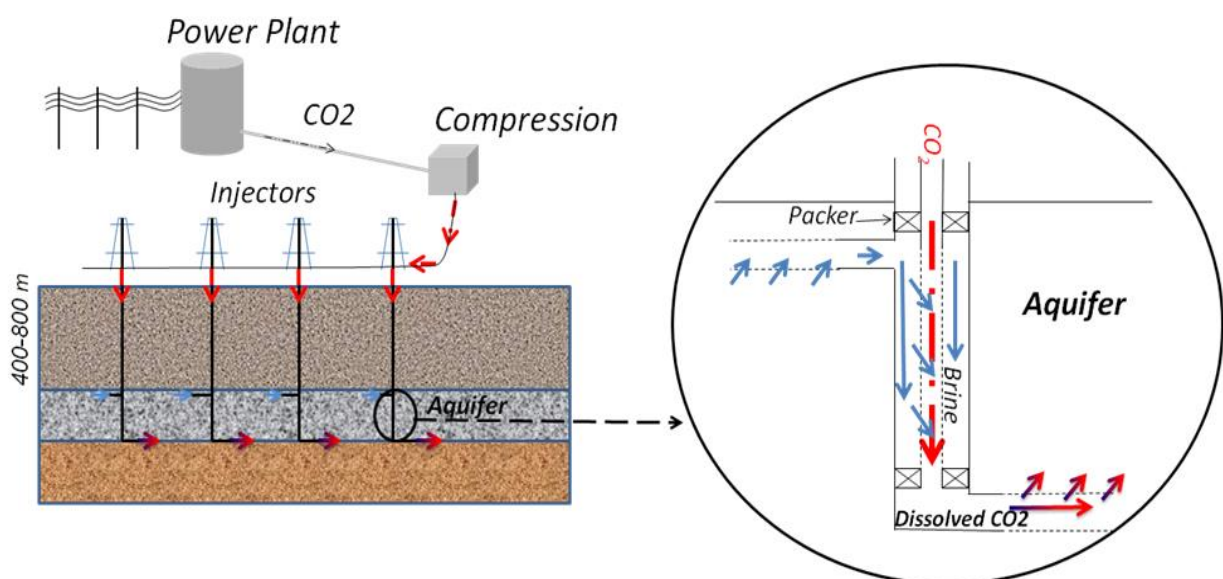
148 **Methodology:**

149 The aim of this work is to investigate the potential to increase storage capacity and security
 150 by use of an engineering method for CO₂ injection in which CO₂ is dissolved in brine down-
 151 hole. The advantage of injecting CO₂ dissolved in brine is that it is denser than unsaturated *in*
 152 *situ* formation brine (approximately 10kg/m³, Ennis-King and Paterson, 2003, Ennis-King et
 153 al., 2005, Riaz et al., 2006), and so will not migrate towards the surface as free phase CO₂
 154 would. Therefore, in this approach, retention of CO₂ within a formation does not rely on the
 155 presence of an impermeable seal. Instead, all CO₂ injected as a dissolved phase will migrate
 156 downwards. This has three consequences. Firstly, a higher percentage of the pore volume
 157 becomes available for storage, and not just that part of the rock that is shallower than the spill
 158 point: this can increase the storage capacity of formations. Secondly, there are no concerns
 159 around the integrity of the caprock. Indeed, there is no requirement for a caprock to prevent
 160 vertical migration of CO₂ due to buoyancy. Thirdly, this means that many additional
 161 formations may become available as potential storage sites.

162 As mentioned above, CO₂ dissolution in brine at the surface prior to injection has been
 163 considered previously (e.g. Burton and Bryant, 2009). However, this postulated method of
 164 injection suffers from some technical limitations. Because the solubility of CO₂ in brine is
 165 limited at standard conditions, energy would be required to pressurise CO₂ and brine at the

166 surface prior to mixing to enhance solubility. The cost of such equipment, which would have
 167 to have an appropriate pressure rating, be made of corrosion resistant material (high
 168 chromium steel) and have capacity for dissolving in the order of thousands of tonnes of CO₂
 169 per day, would be prohibitive. Also, in this method if the brine is not extracted from the
 170 storage formation because of the availability of sea water and to reduce the cost of drilling the
 171 brine extraction wells, then the volume of brine that would have to be injected in addition to
 172 the CO₂ would increase the reservoir pressure much more rapidly than during pure CO₂
 173 injection, very severely restricting storage capacity.

174 In this proposed injection system, brine is extracted from the target aquifer by means of a
 175 lateral horizontal completion located near the top of the formation (Figure 2). It should be
 176 noted that in this method water is not being lifted to the surface. An Electrical Submersible
 177 Pump (ESP) is used to extract the brine and boost its pressure, before it mixes with CO₂ that
 178 is being injected down the vertical section of the well. The mixing takes place in the vertical
 179 section of the well below the upper lateral. However, it should be noted that the entire volume
 180 of CO₂ may not be dissolved throughout the limited section of the wellbore. Blyton and
 181 Bryant (2013) studied the kinetics of CO₂ and brine under a range of conditions. They studied
 182 the dissolution throughout a 2000-ft wellbore for different wellbore radii. A down-hole tool
 183 (e.g. a static mixing device, Zirrahi et al., 2013a) would be used to maximise agitation and
 184 contact area between CO₂ and brine in the mixing section of the well, which may be 10s to
 185 100s of metres long. The CO₂ – brine mix is then injected into the same formation in a lower
 186 lateral. If the CO₂ does not entirely dissolve in the wellbore the dissolution can continue
 187 inside the aquifer.



189 *Figure 2: Schematic process of CO₂/brine down-hole mixing.*

190 **Dissolution of CO₂ in Brine**

191 In this work, the method of Spycher and Pruess (2005) was used to calculate the mole
192 fraction of CO₂ dissolved in brine (assuming that sodium chloride was the only salt present).
193 They studied CO₂-H₂O mixtures in the geological sequestration of CO₂ at temperatures in the
194 range 12–100 °C and at pressures up to 600 bars. CO₂ solubility in brine, at constant
195 temperature and salinity, increases with increasing pressure within these ranges (Spycher and
196 Pruess 2005). With increasing temperature, the solubility of CO₂ decreases even at increasing
197 pressures. Thus the best conditions for having a greater dissolution of CO₂ in brine are higher
198 pressure and lower temperature. Computed data shows that the optimum depth of CO₂
199 storage is just below 800 meters. On the one hand, pressure and temperature conditions meet
200 CO₂ supercritical criteria at that depth. On the other hand, if CO₂ is stored at greater depth,
201 the temperature and salinity will rise, so the amount of dissolution will decrease. It should be
202 noted that storage of CO₂ in deeper saline aquifers with higher pressure and temperature
203 have been of interest to several studies and they have been introduced as favorable candidates
204 for CO₂ storage since storage in them is safer because they are deeper and also their
205 geothermal energy and/or dissolved methane can be used to offset the cost of CCS
206 (Ganjdanesh et al. 2014;2015; Salimi and Wolf, 2012).

207 **Simulations of Down-hole Mixing**

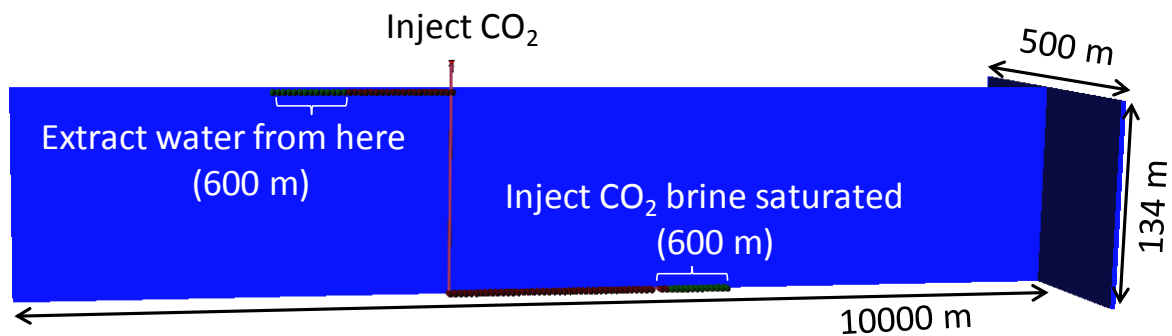
208 A range of numerical simulations using a variety of heterogeneous and homogeneous models
209 was conducted to investigate the impact of the CO₂/brine down-hole mixing injection
210 strategy. Eclipse 300 with the CO2STORE module (Schlumberger, 2012) was used for the
211 simulations.

212 The models all have dimensions of 10000 m × 500 m × 134 m and were discretized into
213 200×50×80 cells. The porosity and the permeability values in the homogeneous models were
214 assigned values of 0.2 and 1000 mD respectively in all directions. For the heterogeneous
215 models the average porosity and average permeability values were the same as the
216 homogeneous one. Sequential Gaussian simulation was used to generate the facies
217 distribution and the permeability and porosity were correlated accordingly. The models
218 represented part of a larger aquifer, and the pore volume of the ten outer cells on each side
219 (left and right of the model) was multiplied by a factor of 1000, to take account of this. In the
220 simulations, the pump for extracting the brine was modelled as a producer in one branch of a

221 well. The down-hole dissolution was not modelled explicitly. Instead, in the simulation, a
222 solution of CO₂ dissolved in brine was injected through the lower branch of the well. In the
223 subsequent description, these branches of the well are referred to as the producer and the
224 injector.

225 In all cases, a single production/injection well was placed in the centre of the model. The
226 composition of the injected fluid, in terms of mole fractions was 0.015, 0.9556 and 0.0294 for
227 dissolved CO₂, water and NaCl respectively. These values correspond to thermodynamic
228 equilibrium at down-hole conditions in the simulations, at 100 bars and 35 °C using Spycher
229 and Pruess (2005). The control mode for both production and injection was reservoir fluid
230 volume rate and the rates were 1000 m³/day and 940 m³/day for the injector (solution of
231 CO₂ dissolved in brine) and the producer (brine) respectively. Both producer and injector
232 were shut after 20 years and the simulation was continued for 100 years. It should be noted
233 that the mineral trapping is not been considered in this modelling.

234 Figure 3 illustrates the well location and connections. Water is extracted from the top of the
235 reservoir and pumped into the bottom hole while the supercritical CO₂ is injected into the
236 well. Supercritical CO₂ is dissolved in the extracted brine in the well. It is assumed that this
237 process can be managed by a specific CO₂/brine down-hole mixing tool.



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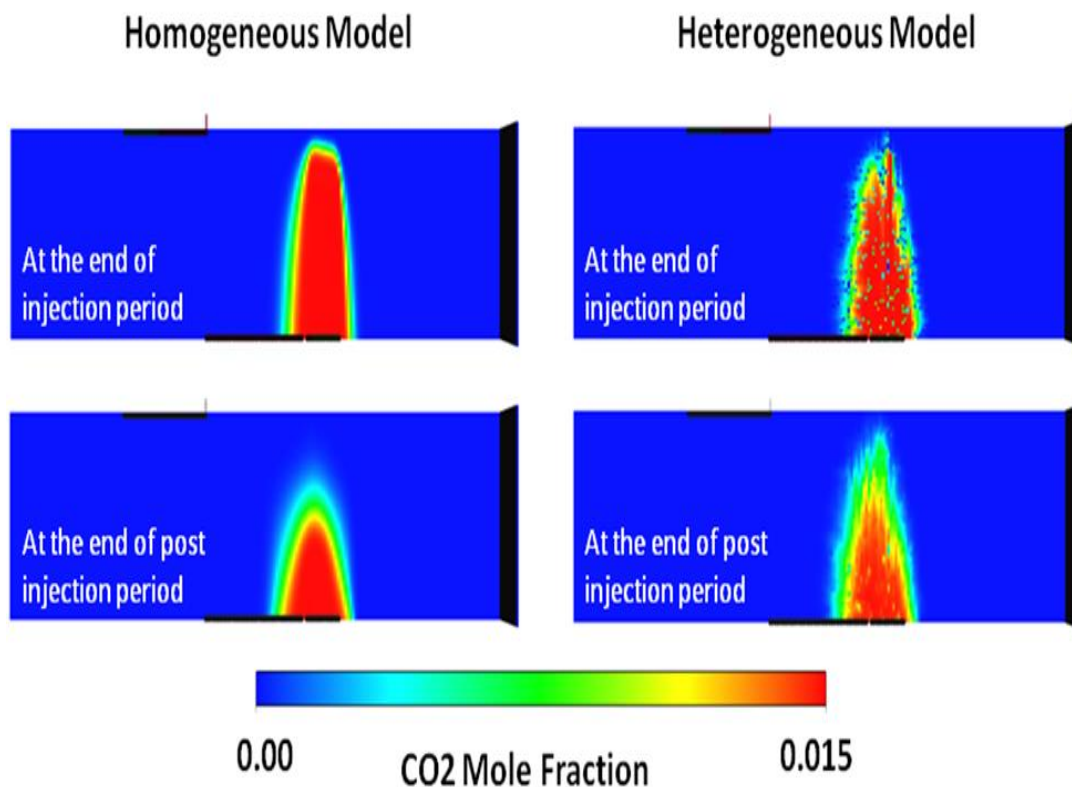
240 *Figure 3: Well location and Connections.*

241 This work does not consider the design of such a tool, but is purely concerned with the
242 question of whether such a tool, if it could be appropriately designed, would provide a benefit
243 for CCS. Zirrahi et al., (2013b) proposed the application of a back flow cell model for the
244 simulation of the supercritical CO₂ dissolution. In the Otway Pilot Test (Paterson, 2013), it
245 was estimated that down-hole mixing would occur without the use of a specific tool.

246 Sigfusson et al., (2015) successfully demonstrated the complete dissolution of CO₂ into water
247 during its injection into a storage formation. In our study we assume the CO₂ is dissolved in
248 brine prior to its injection into the saline aquifer.

249 **Results and Discussion:**

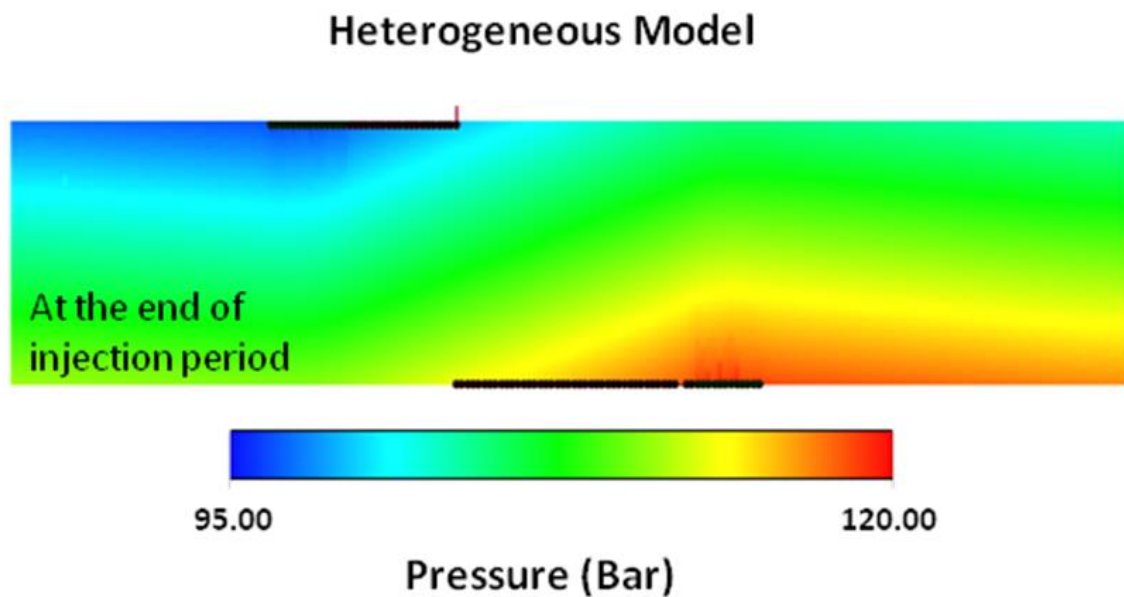
250 Figure 4 shows the CO₂ mole fraction at the end of the 20 year injection period and 100 years
251 after shut-in, for the 3-D homogeneous and heterogeneous models. Note that, because CO₂
252 was dissolved in brine in the well, there was no free injected CO₂ in the model, nor did any
253 exsolve from solution during the period of the calculation. As the dissolved CO₂ is injected
254 into the aquifer it moves in all directions. This migration is governed by the injection rate,
255 heterogeneity, production rate and gravity forces during the injection period. When both
256 producer and injector are shut, gravity is dominant. The CO₂-saturated region tends to be
257 skewed towards the producer where the pressure is lower, but the dissolved CO₂ does not
258 reach the extraction region.



259

260 *Figure 4: CO₂ mole fractions dissolved in brine in the X-Z plane for the homogeneous model*
261 *(left) and heterogeneous model (right).*

262 Figure 5 shows pressure changes across the aquifer in a cross section of the heterogeneous
263 model. As can be seen the range in pressure in the model is only 25 bar. The time to establish
264 a steady state pressure field is determined by the magnitude of the diffusivity constant. Once
265 the transient period is completed, the subsequent pressure trends are determined by mass
266 balance in the field, which depends on the difference between the down-hole injection and
267 production rate.



268

269 *Figure 5: Pressure distributions in the X-Z plane at the end of injection period in the*
270 *heterogeneous model.*

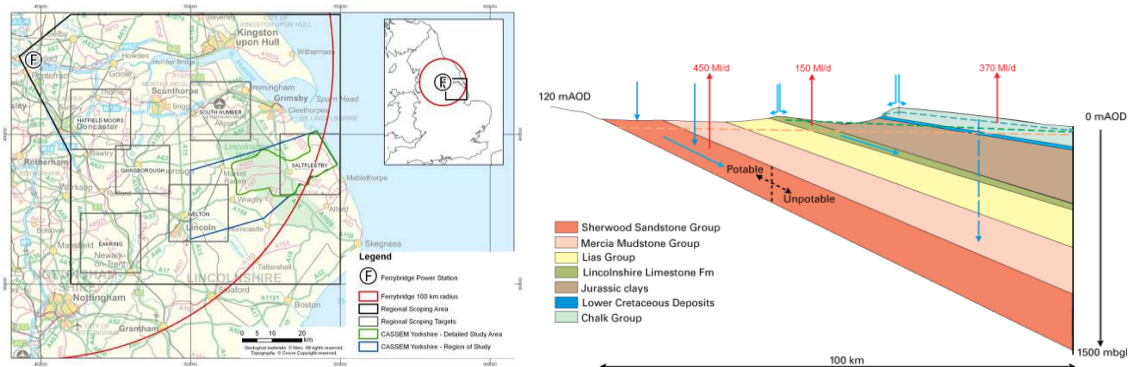
271 **The advantages of this method include**

- 272 ▪ Because the CO₂ is mixed with brine from the same formation, any overall pressure
273 increase is due exclusively to injection of the CO₂ and is not due to brine.
- 274 ▪ The extracted brine is already at high pressure when it mixes with the CO₂, greatly
275 increasing the solubility of CO₂ and reducing the volume of brine required. Energy is
276 not expended lifting the brine to surface. Nor is there any concern about handling
277 large volumes of acidic brine in the surface equipment.
- 278 ▪ The extent of monitoring of migration of free CO₂, which is costly, is decreased
279 because all the CO₂ is dissolved.
- 280 ▪ The injected CO₂ – brine mix will ultimately migrate downwards, increasing storage
281 capacity and security.

282

283 Application of DHM Method to a Real Field

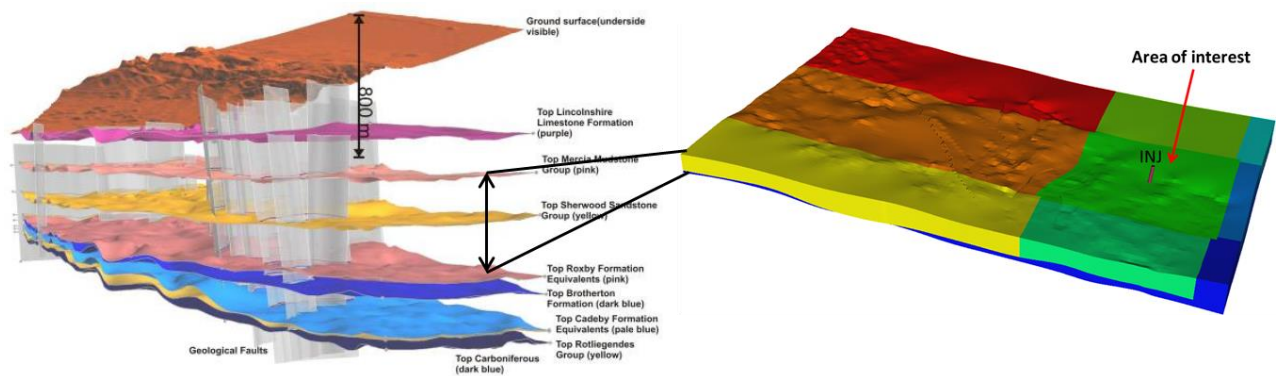
284 The British Geological Survey (BGS) highlighted a near shore formation in Lincolnshire as
285 an analogue of a hypothetical large offshore storage site for captured CO₂ from potential
286 onshore capture projects (i.e. Ferrybridge Power Station). A West to East schematic
287 geological cross-section of the Lincolnshire study area is presented in the Figure (right
288 picture).



289
290 *Figure 6 Location Map of Lincolnshire area (left picture), schematic geological cross-section*
291 *(west to east) of the Lincolnshire study area (Smith et al., 2012).*

292 The model has dimensions of 43 km × 33 km × 600 m and was discretized into 96×67×15
293 cells. An isotropic range of 2000m in the horizontal was used for the correlation in the
294 distribution of properties. The geometric average for the permeabilities was 500 mD for the
295 storage formation (Sherwood Sandstone) and 0.005 mD for the low permeable layers (Mercia
296 Mudstone) (Smith et al., 2012). The ratio of vertical permeability to horizontal permeability
297 (K_v/K_h) was assumed to be 0.1 due the layered types of sediments which were deposited in
298 this region. The layer just beneath the caprock has been divided in 10 layers and modified to
299 consist of 60% mudstone and 40% sandstone to represent the transition zone between the
300 Sherwood Sandstone and the Mercia Mudstone, which was observed at outcrop (Shariatipour
301 et al., 2014).

302 The base case model is large, covering an area of 1419 km² (top surface) and also has a large
303 cell size 0.2 km² (450m×450m, in the X and Y directions). In order to improve the accuracy
304 of the simulations, a sector of this model was used with a finer resolution. Figure
305 demonstrates the area of interest for further study in this model.

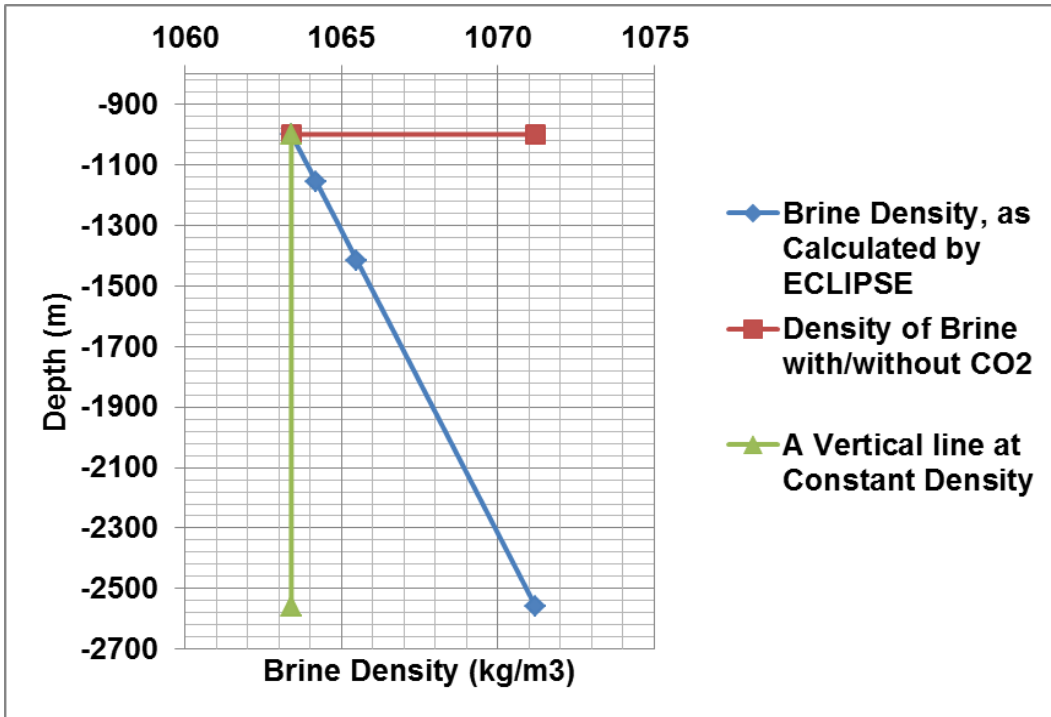


306

307 *Figure 7 The geological framework of the Lincolnshire Model (10X vertical exaggeration)*
 308 *(left picture, Smith et al., 2012), area of interest (green section) in the middle (right picture).*

309 In all cases, a single production/injection well was placed in the centre of the model (to
 310 represent a down-hole mixing system, as described above). The control mode for both
 311 production and injection was reservoir fluid volume rate and the rates were 6500 m³/day and
 312 6175 m³/day for the injector and the producer, respectively. Both producer and injector were
 313 shut after 100 years and the simulation was continued for 1000 years.

314 Figure 8 shows brine density verses depth used in the Lincolnshire Model for this study. As a
 315 result of dissolving CO₂ in brine the density of brine increases (Duan and Sun 2003, Spycher
 316 et al., 2005). This increase for the extracted brine at the depth of 1000 m in this model equals
 317 7.8 kg/m³ which is equal to the density of fresh brine at the depth of 2557 m. The difference
 318 in density of brine with and without CO₂, for most suitable storage aquifers is similar.
 319 However, the salinity gradient may vary and therefore the blue line may move upwards or
 320 downwards.



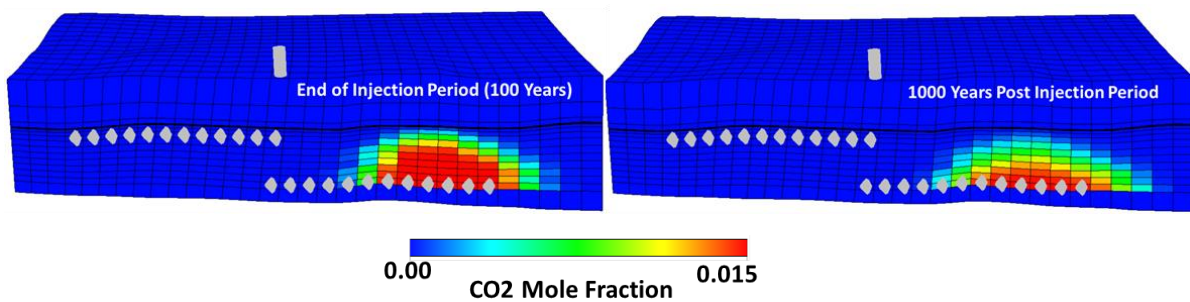
321

322 *Figure 8 Brine density versus depth, red dots show density of brine without CO₂ (1063.4 kg/m³) and*
 323 *with CO₂ (1071.2 kg/m³) at the depth of 1000 m. The blue line refers to the brine density extracted*
 324 *from the simulator for the Lincolnshire Model. Geothermal gradient is set at 20 C/km.*

325 **Results**

326 Figure 9 demonstrates the CO₂ mole fraction at the end of the 100 year injection period and
 327 1000 years after well is shut-in. Note that, because CO₂ was dissolved in brine in the well,
 328 there was no free injected CO₂ phase in the model, nor did any exsolve from solution during
 329 the period of the calculation. CO₂ saturated brine is denser than *in situ* brine. Therefore, it
 330 should go downwards. Upwards migration of CO₂ occurs initially due to the applied
 331 pressure gradient, but it then subsequently sinks down again due to gravity.

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335 *Figure 9 CO₂ mole fraction at the end of injection period (100 years) (left picture), and 1000*
 336 *years post injection period (right picture).*

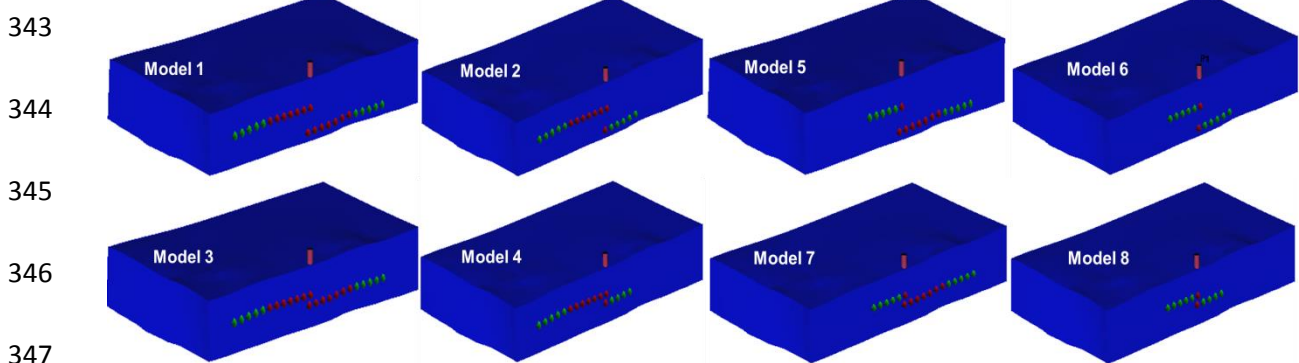
337 **Optimization**

338 In this section we investigate the position of the laterals in terms of depths and lengths. *Table*
 339 *1* and Figure 10 shows all scenarios studied here. The area around the injection lateral into
 340 which the dissolved CO₂ is injected was refined by factor of 9×9×9 in X, Y, and Z directions.

341 Table 1 Model properties

	Brine Extractor Lateral		CO ₂ Saturated Brine Lateral	
Model	Location of the lateral	Distance from the wellbore	Location of the lateral	Distance from the wellbore
1	Top of the aquifer	2.7 km away from the wellbore	Bottom of the aquifer	2.7 km away from the wellbore
2	Top of the aquifer	2.7 km away from the wellbore	Bottom of the aquifer	Adjacent to the wellbore
3	Top of the aquifer	2.7 km away from the wellbore	Middle of the aquifer	2.7 km away from the wellbore
4	Top of the aquifer	2.7 km away from the wellbore	Middle of the aquifer	Adjacent to the wellbore
5	Top of the aquifer	Adjacent to the wellbore	Bottom of the aquifer	2.7 km away from the wellbore
6	Top of the aquifer	Adjacent to the wellbore	Bottom of the aquifer	Adjacent to the wellbore
7	Top of the aquifer	Adjacent to the wellbore	Middle of the aquifer	2.7 km away from the wellbore
8	Top of the aquifer	Adjacent to the wellbore	Middle of the aquifer	Adjacent to the wellbore

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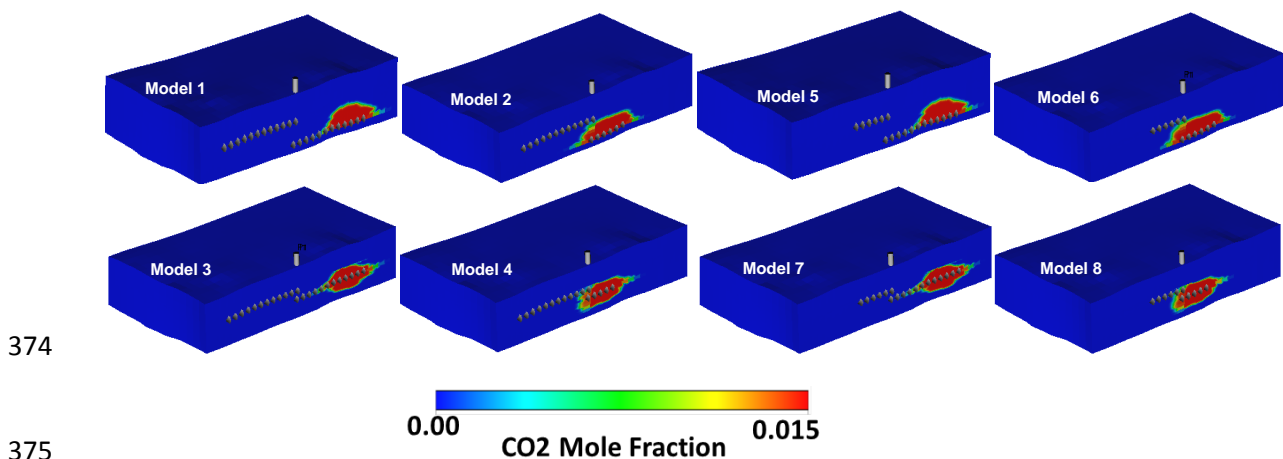


348 *Figure 10* Cross sections of Models 1 to 8 show the brine extractor laterals at the top of the
 349 storage formation and the injector laterals at the either bottom of the aquifer (Models 1,2,5,
 350 and 6) or at the Middle of the aquifer (Models 3,4,7, and 8). Brine is extracted 2.7 km away
 351 from the well bore in the four left Models (1, 2, 3 and 4) whereas is extracted at adjacent
 352 to the well bore in Model 5, 6, 7, and 8 (four right models). Dissolved CO₂ in brine is injected
 353 into the storage formation 2.7 km away from the well bore in the four left Models (1, 3, 5, and
 354 7) and at adjacent to the well bore in the four right Models (2, 4, 6, and 8) respectively.

355 The viscous force is the main driving force when dissolved CO₂ is injected into the aquifer.
 356 The injected fluid tends to migrate towards the brine extractor lateral where the pressure is
 357 lower. However, even after 100 years of dissolved CO₂ injection into the storage formation,
 358 the dissolved CO₂ does not reach the brine extractor perforations, except in Models 6 and 8
 359 due to shorter distance between injection and producer points than in other models (Figure
 360 11). All the free phase CO₂ was dissolved prior to injection into the storage formation.
 361 Dissolved CO₂ in brine is heavier than fresh brine and thus the CO₂ saturated brine tends to
 362 sink in the aquifer under gravity.

363 Models 6 and 8 are not of further interest due to the small distance between the perforation at
 364 the injector lateral and extractor lateral that could allow dissolved CO₂ to reach the extraction
 365 region. In all other models (1, 2, 3, 4, 5, 7) dissolved CO₂ does not reach the perforations at
 366 the extractor lateral. Therefore, all these models are acceptable for further study. However,
 367 further screening was performed based on the length of the laterals (which determines the
 368 cost), and the pressure loss. Model 1 provides the biggest distance between the extraction
 369 region and the injection region among all models, therefore it can be considered as the safest
 370 scenario. On the other hand, Model 4 could be the best option because of:

- 371 1. The lowest frictional pressure loss in the wellbore.
- 372 2. The minimum length of high chromium steel needed.
- 373



374
 375
 376 *Figure 11 CO₂ mole fractions dissolved at the end of injection period (100 years). Models 1*
 377 *to 8 show the brine extractor lateral at the top of the storage formation and the injector*
 378 *lateral at either the bottom of the aquifer (Models 1,2,5, and 6) or at the middle of the aquifer*
 379 *(Models 3,4,7, and 8). Brine is extracted 2.7 km away from the well bore in the four left*
 380 *Models (1, 2, 3 and 4) whereas it is extracted adjacent to the well bore in Models 5, 6, 7, and*
 381 *8 (four right models). Dissolved CO₂ in brine is injected into the storage formation 2.7 km*
 382 *away in the four left Models (1, 3, 5, and 7) and adjacent to the well bore in the four right*
 383 *Models (2, 4, 6, and 8) respectively.*

384 **CO₂ Storage Capacity**

385 Table 2 shows the amount of CO₂ can be dissolved in water with 3 different salinities (35000
386 mg/l, 100000 mg/l and 200000 mg/l) at depths of 1000 m. This analytical calculation is made
387 based on Spycher and Pruess (2005).

388 *Table 2: Amount of CO₂ which can be dissolved in brine at different conditions*

Depth (m)	Pressure (bar)	Temperature (C)	Salinity (mg/l)	CO ₂ dissolved (kg/m ³)
1000	100	35	35000	50.583
			100000	39.34
			200000	29.067

389

390 The density of CO₂ at 100 bars and 35 C equals 713.68 kg/m³ and at standard conditions (15
391 C and 1 bar) equals 1.85 kg/m³. In our calculation 39.34 kg CO₂ can be dissolved in 1 m³
392 brine (NaCl, 100,000mg/l). Thus, the amount of CO₂ that can be dissolved at this reservoir
393 condition in 6175 m³ brine equals 242924.5 kg.

394 Assuming mass conservation, then 0.088 Mt CO₂/year per well can be dissolved down-hole
395 and injected into the aquifer at the aforementioned condition. The target of injecting 1 MT
396 CO₂/year can be achieved by drilling 11 wells. This calculation depends on the P, T, salinity,
397 and the reservoir volume injection rate. For a reservoir with lower salinity (e.g. 35,000 ppm
398 at the brine extractor points) with the same T, P, and reservoir volume injection rate just 8
399 wells are needed to inject 1 MT dissolved CO₂ in brine/year. Drilling engineering enables us
400 to use dual completion and multi-lateral well techniques so more laterals could be used for
401 brine extraction and CO₂ saturated brine injection. This results in reducing the number of
402 required wells for CO₂ injection. The model indicates the amount of dissolved CO₂ which
403 could be injected per well per year. However, at this stage, no detailed modelling of the
404 mixing process in the well has been carried out.

405 The impact of injection of carbonated water would also be to stimulate the near wellbore,
406 akin to acid stimulation (Fredd and Fogler, 1998), but on a continuous rather than batch basis.
407 This would be different from any stimulation arising from pure CO₂ injection with
408 subsequent dissolution in the brine phase, since such dissolution would, in the main, take

409 place away from the sand face. In this latter case, CO₂ would dissolve in the formation brine,
410 and this acid brine will quickly be displaced from the near well zone, with less than one local
411 pore volume of acid brine contacting the near wellbore rock. Any residual water would also
412 be acidified, but any dissolution of rock would buffer this brine, and no further dissolution
413 would take place. However, continuous injection of carbonated water will result in many
414 multiple pore volumes of unbuffered acid brine flowing through the near wellbore zone, and
415 this is the part of the system where rock dissolution and increase of local permeability will
416 have the greatest impact.

417 **Conclusions and Recommendations:**

418 The results indicate that CO₂/brine down-hole mixing could improve CO₂ sequestration. This
419 reservoir simulation study demonstrates that the upward migration of CO₂ in the reservoir can
420 be limited to viscous effects during the injection period, and that during the subsequent shut-
421 in period gravity segregation displaces the CO₂ saturated brine downwards, thereby
422 increasing the storage safety. The limitation of the proposed method is that the amount of
423 CO₂ that can be injected in one well is restricted. Injecting at a much higher total volume rate
424 will increase the bottom hole pressure (BHP). On the other hand, it will be single rather than
425 two-phase injection, and the acid brine may additionally stimulate the formation. The BHP
426 will be higher for this method than if the CO₂ were injected without brine, but the increase
427 will be somewhat mitigated by these two factors (single phase injection and acidic fluid
428 stimulation). Also, the overall field average pressure will be the same as if the CO₂ were
429 injected without brine, as the overall material balance is the same.

430 Calculations were performed to identify the optimum level and length of water extraction and
431 injection of dissolved CO₂ in brine. In terms of the minimum length of corrosion-resistant
432 tools and frictional pressure loss, the most efficient model is the one where the brine
433 extraction lateral is completed away from the borehole whereas the CO₂ saturated injection
434 lateral is close to the borehole. The former is to maximize the distance between extraction
435 and injection and the latter is to minimize the need for having high chromium steel. This
436 technique provides the opportunity for much more secure storage of CO₂ than is currently
437 envisaged by conventional injection of CO₂ alone. Less attention needs to be paid to caprock
438 integrity using this method of storage, and appraisal and monitoring costs may be vastly
439 reduced. More secure storage of CO₂ will be of interest to organisations involved in CCS

440 projects, regulators, and other stakeholders, such as environmental organisations and the
441 general public.

442 Having demonstrated that the concept can be used to maximise storage capacity and security,
443 recommendations for future work include a full economic calculation to evaluate the use of a
444 dual completion, instead of a new well, and also to compare economically this method with
445 all other proposed methods for CO₂ injection.

446 **Acknowledgements**

447
448 We thank Schlumberger for the use of ECLIPSE 300 and Petrel. The authors wish to thank
449 the Scottish Carbon Capture and Storage (SCCS) Consortium and Foundation CMG for
450 funding this work.

451

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