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Using Pressure and Volumetric Approaches to Estimate CO₂ Storage Capacity in Deep Saline Aquifers

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Abstract

Various approaches are used to evaluate the capacity of saline aquifers to store CO₂, resulting in a wide range of capacity estimates for a given aquifer. The two approaches most used are the volumetric “open aquifer” and “closed aquifer” approaches. We present four full-scale aquifer cases, where CO₂ storage capacity is evaluated both volumetrically (with “open” and/or “closed” approaches) and through flow modeling. These examples show that the “open aquifer” CO₂ storage capacity estimation can strongly exceed the cumulative CO₂ injection from the flow model, whereas the “closed aquifer” estimates are a closer approximation to the flow-model derived capacity.

An analogy to oil recovery mechanisms is presented, where the primary oil recovery mechanism is compared to CO₂ aquifer storage without producing formation water; and the secondary oil recovery mechanism (water flooding) is compared to CO₂ aquifer storage performed simultaneously with extraction of water for pressure maintenance. This analogy supports the finding that the “closed aquifer” approach produces a better estimate of CO₂ storage without water extraction, and highlights the need for any CO₂ storage estimate to specify whether it is intended to represent CO₂ storage capacity with or without water extraction.

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1. Introduction

Theoretical CO₂ storage capacity estimates for deep saline aquifers at regional and/or basin scales are usually based on volumetric considerations. For “open aquifers”, the method used is to multiply the pore volume by the CO₂ density at in-situ conditions and a storage efficiency coefficient that takes into account aquifer characteristics and displacement efficiency [1-3]. These estimates do not take into account pressure effects that result from injection of CO₂. However, flow simulations of CO₂ injection performed at the aquifer scale typically reveal very significant reservoir pressure build-up for injected volumes much smaller than the theoretical CO₂ storage capacity, limiting the amount of CO₂ that can be injected, hence stored. The main reason for this discrepancy is that the theoretical CO₂ storage capacity derived volumetrically implicitly assumes that pressure will be maintained below some physical or regulatory limit and will be managed during the injection period either through natural processes (e.g., pressure diffusion throughout the aquifer and the confining aquitards, and water movement out of the storage system), or through engineered processes (primarily water production from the storage aquifer). Limiting the pressure build-up is critical to any CO₂ storage operation as excessive overpressure can lead to loss of mechanical integrity of the cap rock, and potentially to induced seismicity and ground heave.

On the other hand, the “closed aquifer” storage capacity estimate that considers the accommodation of the injected CO₂ through water and pore space compressibility does account for pressure build-up, typically with no pressure diffusion through, and water movement across, any (horizontal or vertical) boundary of the aquifer [4-7]. Two additional limitations of this approach are that it does not account for the fraction of dissolved CO₂, which will have a smaller volume than the free dense-phase (undissolved) CO₂ and should take place largely after the cessation of injection; and that it assumes the overpressure to be constant throughout the aquifer compartment.

Volumetric estimations and flow simulations of CO₂ storage in four large-scale aquifers are reviewed: the Mount Simon Sandstone in the United States, the Basal Cambrian Sandstone in the Plains-Prairie region of Canada and the United States, the Bunter Sandstone in the North Sea east of the United Kingdom and the Rotliegend aquifer in The Netherlands. The flow simulations are based on various strategies to place CO₂ injectors, define CO₂ injection rate and duration, and model boundary conditions (between “open” and “closed” aquifers). The injected CO₂ mass and the modeled pressure build up are compared to the volumetric “open” and “closed” CO₂ storage capacity estimates.

The issue of the pressure behavior during CO₂ injection, and its connection with CO₂ storage capacity, is then discussed through a mirror-image analogy with oil production recovery mechanisms, routinely used in the oil industry. Primary oil recovery (also called simple depletion) is performed prior to any fluid injection in the oil pool, and leads to oil reserves limited by pressure constraints. Secondary oil recovery (generally water flooding) is widely performed in order to overcome the pressure constraint. The recovery factors (fraction of the oil to be produced) are largely impacted by the recovery mechanism. Both mechanisms are compared to CO₂ injection into a saline aquifer with or without simultaneous water production.

2. Estimation of CO₂ storage capacity in four large-scale aquifers using flow modeling

The storage capacity of four large-scale aquifers has been modeled using 3D flow models. The four cases have modeled CO₂ injection without water production for pressure control. The objective of this section is to present these various aquifers, and the type of flow modeling that was performed. The next section presents the calculated cumulative injection in comparison with the volumetric “open aquifer” and “closed aquifer” CO₂ storage capacity estimates.

The location of the four aquifers is indicated in Figure 1. Data of the four aquifers in Table 1 were compiled based on the publications on the respective aquifers quoted along the paper. Note that all flow models are based on CO₂ injection only and account for CO₂ dissolution into the formation water.

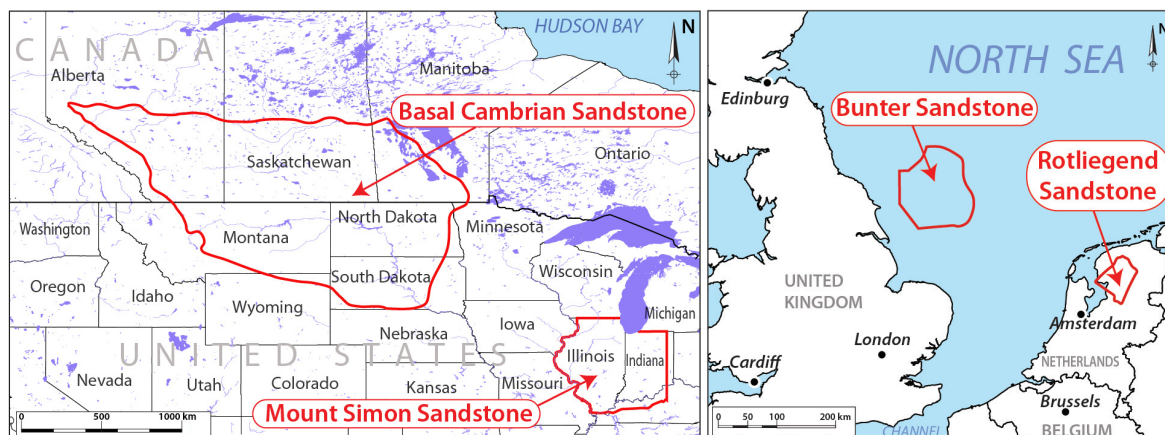


Figure 1. Location of Basal Cambrian and Mount Simon Sandstone aquifers (left) and Bunter and Rotliegend Sandstone aquifers (right)

Table 1. Comparison of the four aquifers, location, geometry and petrophysics

	Mt Simon, Illinois	Basal Cambrian	Bunter	Rotliegend
Country	USA	Canada & USA	UK	Netherlands
Off-shore vs. on-shore	On-shore	On-shore	Off-shore	On-shore
Total area, km ²	241,000	1,297, 000	14,300	3, 500
Net Area, km ²	24,000	511,000	14,300	3,500
Average net thickness, m	450	69	125	100
Average porosity	15%	9.3%	20%	20%
Net water pore volume, km ³	1,620	3,260	350	70

2.1. Mount Simon Sandstone, Illinois Basin, USA

A 3D flow model of the Mount Simon Sandstone, and overlaying formations, was set up in order to model large-scale CO₂ storage into this aquifer [8, 9].

The objective was to model a hypothetical future CO₂ storage scenario in the Illinois Basin, which involves twenty individual CO₂ storage projects (sites) in a core injection area most suitable for long-term storage (Figure 2). Each project is assumed to inject 5 Mt of CO₂ per year for 50 years, hence a cumulative storage of 5 Gt of CO₂. The core injection area was selected to ensure a sufficient depth of the Mount Simon Sandstone, sufficient distance to fresh water areas to the north, and also to avoid the large depth of the Mount Simon Sandstone to the south where petrophysical properties degrade (low porosity and permeability).

In order to limit the impact of the lateral boundary conditions, the model extension is almost twice as large as the Illinois Basin itself, and covers significant portions of the Wisconsin Arch to the North and the Cincinnati Arch to the east. Closed (no flow) versus open (infinite acting aquifer) boundary conditions were compared. Vertically, water flow across the first seal (Eau Claire Formation) was allowed using a permeability of either 1 microDarcy or 0.01 microDarcy.

One key finding of this study was that the peak overpressure in the core injection area is only marginally affected by the chosen boundary conditions at the end of the injection. However longer-term pressure relaxation will be significantly accelerated by open boundary conditions, primarily due to formation water leakage through the cap rock but also due to a volume of water flowing away through the open lateral boundaries. Finally, a cumulative injection of 5 Gt of CO₂ was modeled, with a peak pressure increase of 3.6 MPa in the core area near the injection wells, i.e. 18% increase over the initial pressure.

In order to estimate the full CO₂ storage capacity of the aquifer, injection could have been modeled up to a 13.1 MPa pressure increase, corresponding to the regulated fractional pressure increase of 65%. Considering a quasi-linear relationship between injection rate and pressure buildup, the total injection mass (i.e., storage capacity) would have increased from 5 to 18.1 Gt of CO₂ [10].

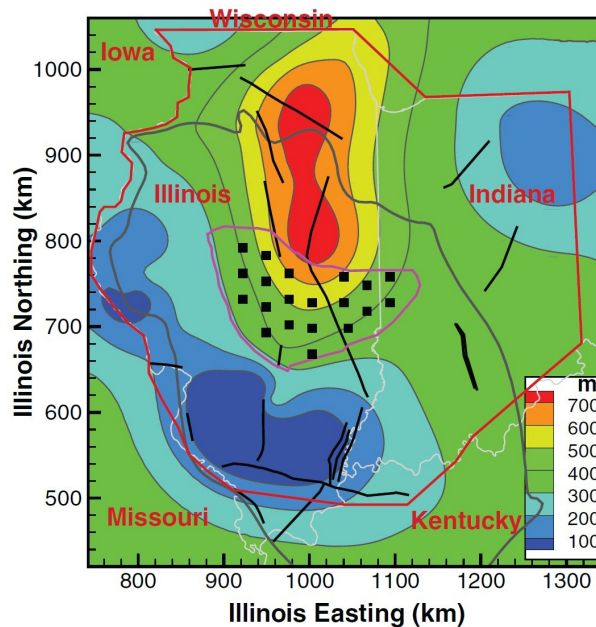


Figure 2. Thickness of the Mount Simon Sandstone (shaded contours in m). Also shown are the boundary of the model domain as a red line, the Illinois Basin boundary as a gray line, the core injection area as a pink line, and 20 hypothetical injection sites as solid squares, from [10]

2.2. Basal Cambrian Sandstone, Plains-Prairie region of Canada and United States

This aquifer is by far the most extensive aquifer of the four cases. It stretches across three provinces (Alberta, Saskatchewan and Manitoba) in Canada and three states (Montana, North Dakota and South Dakota) in the US [11]. However, as displayed in Figure 3, large portions of the aquifer are not suited for CO₂ injection because it is too shallow (in Northern Saskatchewan and most of Manitoba and South Dakota), or aquifer water has low salinity (protected groundwater), or because the transmissivity is too low to inject CO₂ at significant rates. When discounted for water salinity and depth, the area decreases to 718,000 km²; the area reduces further to 511,000 km² for the suitable injection and storage region.

A first flow model was set up where 94 storage sites store 100% of annual CO₂ emissions from current large stationary sources in the region, for a duration of 50 years. The total stored CO₂ is 4.7 Gt. The simulated pressure buildup varies from 1.17 to 6.29 MPa.

A second flow model was set up in order to assess the maximum storage capacity of the Basal Aquifer. A total number of 325 injection wells were placed in suitable storage regions, based on the high maximum layer permeability (> 200 mD) and high transmissivity (>4000 mD×m). The constant injection rate for 50 years at each well was determined based on the maximum allowable pressure buildup calculated using 39% fractional pressure increase from in situ pressure at that well. The maximum allowable pressure gradient is 15.0 kPa/m determined by 90% of the minimum horizontal stress in the Alberta basin. As the initial pressure ranges from 10 to 31 MPa, the average initial pressure is 21 MPa and the average maximum pressure buildup is 8.2 MPa. The maximum dynamic storage capacity obtained through this model is ~25 Gt of CO₂.

Concerning boundary conditions, the models are large enough to avoid interference of injection response with lateral boundaries.

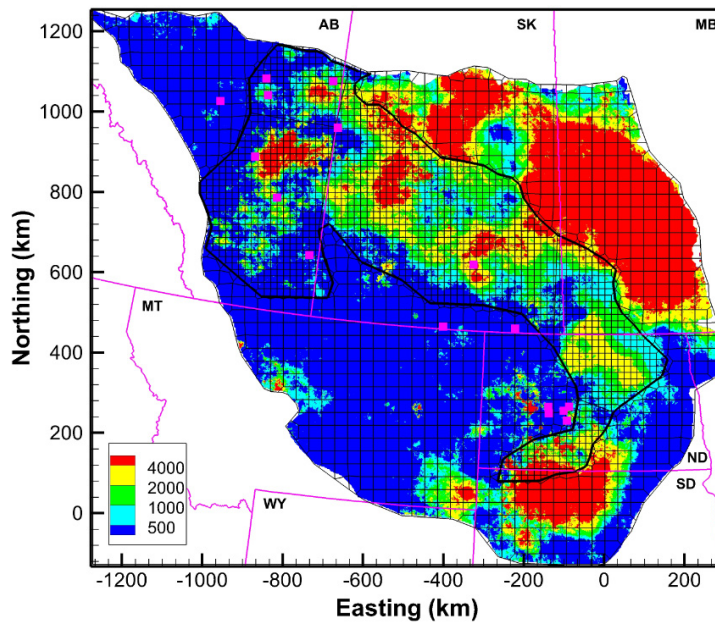


Figure 3. Contour of the Basal Cambrian Sandstone, with a colour code showing the transmissivity (permeability thickness product) in mD×m, the 2D mesh for designing injection wells and the boundary of the suitable storage region (thick black line).

2.3. Bunter Sandstone, offshore United Kingdom

The Lower Triassic Bunter Sandstone aquifer outcrops onshore in eastern England and occurs beneath the UK and Dutch sectors of the southern North Sea, and extends onshore through Netherlands, Germany and Poland. The area noted in Table 1 and shown in Figure 1 is a promising area of the British sector considered for CO₂ storage. The chosen case study area is bounded to the west by the Dowsing Fracture Zone, penetrating salt walls to the south and east, and formation pinch outs to the north and east. Within the study area the Bunter Sandstone ranges from 400 to 3000 m depth, and for modeling purposes has been assigned an average porosity of 20% and a permeability of 100 mD [12].

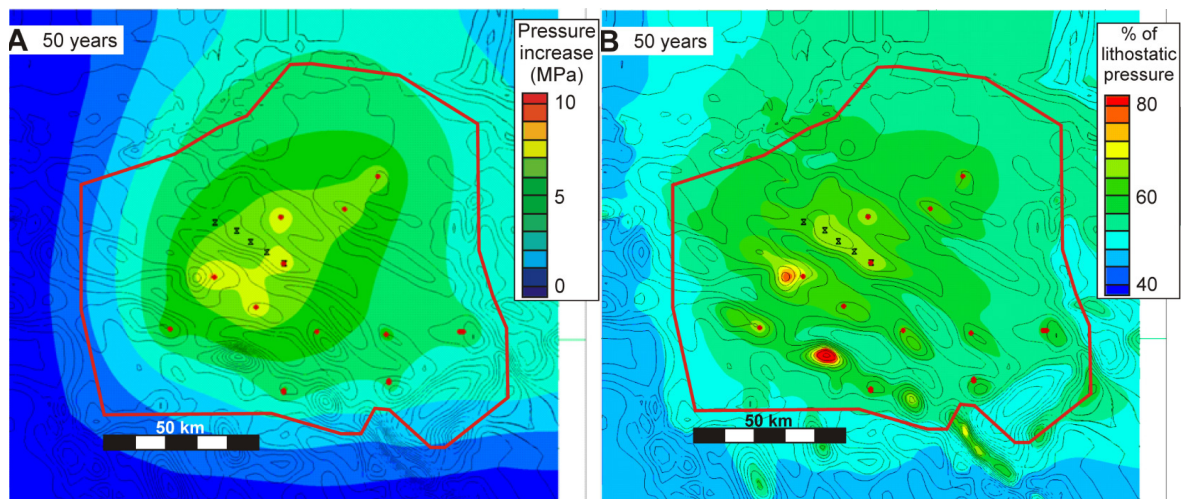


Figure 4. Results of simulations at 50 years (boundary conditions based on an extended grid). Red spots mark injection wells. Red line marks boundary of case study area. (A) Pressure increase in MPa; (B) pressure expressed as percentage of lithostatic [12].

A flow model was set up in order to evaluate the full CO₂ storage capacity of the aquifer. Twelve wells inject a total rate of 33 Mt per year for 50 years, for a total of 1,650 Mt CO₂ stored. No injector was located in the shallowest structures (~400 m depth), where stress is expected to be the smallest in the cap rock.

Various boundary conditions were compared. Laterally four scenarios were evaluated: an optimistic scenario with constant pressure at the boundaries of the area (assuming infinite dissipation of pressure); an intermediate scenario where a larger area, with closed boundaries, was modeled; a pessimistic scenario with closed (no flow) boundary conditions; and a fourth scenario where the larger area is modeled but geological features (sealing faults, penetrating salt walls) are added, impeding horizontal pressure dissipation. Vertically, a scenario was set up using a permeability value as high as 10^{-17} m² (0.01 mD) in the cap rock, allowing for water migration through the cap rock (no CO₂ flow is expected to flow through the caprock due to capillary containment).

For all these scenarios, the overpressure reached an unacceptable level within the shallowest structure (pressure exceeded 75% of the vertical stress or lithostatic pressure): see Figure 4 for one of the scenarios using an extended domain to model lateral boundary conditions.

2.4. Rotliegend Sandstone, Netherland

A geological model was built with an extent of 50 x 70 km around a possible CO₂ aquifer storage location in the Friesland Platform. The lateral limits of the model correspond to structural elements. The model includes the Rotliegend Slochteren Formation reservoir, as well as the overburden, based on the available 3D and 2D seismic data and well data. The Rotliegend Sandstone has good reservoir properties, with an average porosity of 20% and an average permeability of 1000 mD.

A flow model was built for the Rotliegend formation only. A single horizontal well was located towards the northern border of the platform, and CO₂ injection was simulated with a constant rate of 8.5 Mt/year (after an initial pilot test with much lower injection rates). Even at this high injection rate the reservoir appears to dissipate the increased pore-pressures very well. After 7 years of injection (and a cumulative injection of 60 Mt), a rather homogeneous overpressure develops, reaching 7 MPa at the injector and a far-field response of 2 MPa.

Concerning boundary conditions, no vertical flow through the cap rock was allowed, as the Zechstein (Werra) anhydrite is the primary sealing rock for the Rotliegend aquifer. A detailed study was performed on the possible geomechanical failures modes of the cap rock. The value of 6.8 MPa is 70% of the maximum pressure increase before pressure reaches the minimum horizontal stress and is considered as the maximum admissible overpressure; however risks of shearing existing fractures occur at a significantly lower overpressure, estimated at ~3 MPa of pressure increase in the aquifer.

3. Comparison of CO₂ storage capacity using various estimates

3.1. Setting up a “closed aquifer” estimate

Based on the pore and water compressibility values used in the various storage flow models, and the overpressure reached at the injectors, it is possible to derive a “closed aquifer” storage efficiency coefficient assuming that the aquifer is closed, and that the overpressure is homogeneous in the net water volume of the aquifer (Table 2). The Mount Simon data uses the extrapolated capacity for a 13 MPa pressure buildup, and the Basal Cambrian data are based on the second flow model results, aiming at deriving the full capacity of the aquifer. Note that instead of using an average overpressure in Table 2, numerical static models can easily implement a maximum overpressure as a function of depth to calculate a “closed aquifer” maximum storage capacity where different overpressures are expected in different areas corresponding to different depths of the aquifer.

A first interesting observation is that the storage efficiency calculated from the closed aquifer assumption is less than 1%, even for the Bunter Sandstone where the maximum injection pressure is derived from the lithostatic pressure (vertical stress) and not the minimum horizontal stress. For the Rotliegend case, deriving the maximum overpressure from the risk of cap rock fracture reactivation would have further decreased the “closed aquifer” efficiency.

Table 2. Evaluation of storage efficiency coefficient (E) and CO₂ storage capacity based on volumetric assumptions, and comparison with cumulative injected CO₂ from the flow models

	Mount Simon	Basal Cambrian	Bunter	Rotliegend
Injection average depth, m	2000	2000	1400	2200
Initial pressure at injection depth, MPa	20	20	15	22
Average overpressure at injectors, MPa	13.0	7.8	8.4	6.8
Total (pore & water) compressibility, 1/MPa	7.09×10^{-4}	8.00×10^{-4}	9.50×10^{-4}	$10. \times 10^{-4}$
Closed storage efficiency coefficient (E)	0.92%	0.62%	0.80%	0.68%
CO ₂ volume, km ³	14.9	20.2	2.8	0.48
CO ₂ density, kg/m ³	890	800	800	700
CO ₂ storage cap. (closed aquifer assumption), Gt	13.3	16.2	2.23	0.33
CO ₂ storage cap. (open aquifer assumption), Gt	11 - 150	57-193	4.2	
Cumulative CO ₂ storage from flow model, Gt	18.1	25	1.65	0.06

The second result is that the “closed aquifer” CO₂ storage capacity may be higher or lower than the storage calculated from the flow model, but represents a fair first order match:

- It is significantly higher in the Rotliegend case as the injection is performed through only one well, leading to an average overpressure in the aquifer significantly lower than the overpressure at the well;
- For Basal Cambrian and Mount Simon aquifers, water volumes outside the injection area are partially pressurized due to the CO₂ injection, compensating the overpressure heterogeneity and leading to a higher capacity from the flow models. Concerning the Mount Simon aquifer, the projected storage efficiency relative to the pore volume of the core injection area (see Table 1) is 1.26%.

3.2. Comparison with “open aquifer” CO₂ capacity estimates

For the Bunter Sandstone case, using an “open aquifer” storage efficiency of 2% leads to a CO₂ storage capacity of 4.2 Gt, almost 3 times as high as the capacity obtained from various flow modeling scenarios, all being overoptimistic as maximum pressure reaches a too high value in the shallow areas of the aquifer [12].

For the Mount Simon Sandstone, two main sources are available for “open aquifer” CO₂ storage estimates: the US Department of Energy (DOE) Atlas 2012 edition and the 2013 US Geological Survey (USGS) National Assessment of Geologic Carbon Dioxide Storage Resources, which use different methodologies to estimate the CO₂ storage capacities:

- The estimate from the DOE Atlas 2012 edition [13, page 46] indicates a CO₂ storage capacity between 11 and 150 Gt (for storage coefficients of 0.4% and 5.5% respectively);
- Looking at the published numbers from the USGS National Assessment of Geological CO₂ Storage [14], the Mount Simon Sandstone in the Illinois Basin is defined as unit C50640101. Its CO₂ storage capacity ranges from 62 to 130 Gt, with larger values but varying in a narrower range than that of the DOE estimate. One explanation is that the storage efficiency coefficients (for class 2, the largest class for this basin in the USGS formalism) range from 2.9% to 6.9%.

For the Basal Cambrian Case, the storage capacity from the DOE Atlas 2012 edition [13, page 66] ranges from 57 to 193 Gt of CO₂.

No “open aquifer” storage capacity estimate is available for the Rotliegend aquifer.

3.3. Discussion on the differences

The comparison between “closed aquifer”, “open aquifer” estimates and reservoir flow model results clearly highlights the fact that “open aquifer” estimates are significantly larger than the estimates obtained using the other two methods, the only exception being the DOE low estimate of the Mount Simon Sandstone.

A key factor is that both USGS and DOE methodologies assume that the “open” aquifer estimate can be reached without exceeding any critical pressure (either damaging the cap rock integrity or creating other unwanted effects as induced seismicity or ground heave) [15, page 24]

This is stated for the DOE approach in an appendix document to the Atlas itself [16, page 6]: for open systems, “... the primary constraints on the percentage of pore space that can be filled with CO₂ in open systems are due to displacement efficiencies, rather than pressure increases...”

As the storage is controlled by displacement processes, the storage efficiency coefficient is defined as the product of various efficiency coefficients [16, eq.5]:

$$E = E_{An / At} \times E_{hn / hg} \times E_{\phi_a / \phi_{tot}} \times E_A \times E_L \times E_g \times E_d \quad (1)$$

The various coefficients on the right-hand of the equations are fractions of pore space available or fractions of displacement efficiency (either macroscopic or microscopic) quantifying how CO₂ can replace water (without considering that some pressure limit would be reached at some point). Some sweeping coefficients are derived from flow models [17]; however these flow models assume generally an isolated CO₂ injection well in a large aquifer bounded by open boundary conditions. This modeling assumption may be not representative for large-scale injection of CO₂ in an aquifer (where pressure due to multiple injection wells will interfere and hence where a pattern approach with closed boundary conditions may be more appropriate as there is no rationale to allow flow migration from one pattern to the next), nor for large-scale CO₂ injection combined with water production (where a pattern approach coupling injection wells and water production wells could be set up, leading to a complex problem of pressure maintenance and avoidance of CO₂ recycling to the water producers).

The USGS approach is based on a methodology [18] that does not model explicitly the pressure buildup at injection wells:

- It assumes that the fluids are incompressible (flow is instantaneously transmitted to the boundary conditions);
- Due to the incompressibility equation, the mass conservation equation no longer involves the resolution of the pressure field;
- The pressure buildup at injection wells is not modeled by a radial flow assumption, which leads to an exponential decrease of pressure with the increasing distance from the wellbore, but by a linear flow assumption perpendicular to a continuous injection line

The result from the flow models of the large-scale aquifers presented above is that even though the aquifers have open flow boundaries, the CO₂ capacity is constrained primarily by the admissible pressure buildup. This is certainly related to the fact that the injection rates are high and the injection period relatively short. As the rates are very high, the pressure buildup cannot easily be mitigated through open boundary conditions (water migration through cap rocks or lateral boundary conditions). However, in order to consider CCS as a reasonable solution to mitigate climate change, significant volumes of CO₂ should be captured, transported and stored in the next 50 or 100 years, and not over much longer periods of time. So, high CO₂ injection rates should indeed be considered.

These results indicate that most likely the results of “closed aquifer” estimates apply in fact to any CO₂ storage system when pressure buildup is not mitigated by water production. The results of “open aquifer” estimates could then be applicable for CO₂ storage systems that include water production for pressure buildup mitigation.

4. Analogy to oil production

The oil industry faces a similar issue to the CO₂ storage industry, only in reverse (oil production as opposed to CO₂ injection). The industry has to define/estimate what fraction of the oil in place, in a given oil reservoir, will be ultimately produced with a given technological/business context. A coefficient called recovery factor is multiplied to the original oil in place (OOIP) to calculate the oil to be produced (recovered).

The oil industry uses the concept of oil recovery mechanism in order to estimate the recovery factor. Three key recovery mechanisms are commonly used:

- Primary recovery or primary depletion: oil can be produced under its own pressure drive without injecting any other fluid in the reservoir, until some low pressure limit is reached and production is no longer possible;
- Secondary recovery, or water flooding: to mitigate the pressure decrease in the reservoir, water is injected, enabling to increase the oil ultimate production; and
- Tertiary recovery or enhanced oil recovery (EOR) methods: the injected fluid (e.g., solvents) is designed in order to improve the sweep that would have been obtained from water flooding.

The key element is that the oil recovery factor increases by switching from primary to secondary recovery. A large range of recovery factors can be obtained by primary recovery (from 5 to 60% for the best cases), while recovery factors of up to 70% are obtained with water flooding [19, Fig. 2].

4.1. Analogy of CO₂ injection without water production with primary recovery

In oil primary production (without water flooding to maintain pressure), the oil production will cease when some low natural pressure limit is reached: the reservoir pressure (or energy) is too low to lift the reservoir fluids (oil, gas, and water) in the wells.

The major types of energy (pressure maintenance) in an oil reservoir are [20]:

- The energy of decompression of the water, rock, oil and gas within the reservoir;
- The energy of decompression of water contiguous to and in communication with the petroleum reservoir (e.g., from underlying aquifers); and
- The gravitational energy that causes the oil and gas to segregate within the reservoir.

In CO₂ injection (with no water production), we can define the same types of energy (only in reverse):

- The energy of compression of the water and rock within the area of the aquifer suitable for CO₂ injection;
- The energy of dissolution of CO₂ within the formation water (the fact that when CO₂ dissolves, the free-phase CO₂ occupies a smaller volume than prior to dissolution, and hence it leads to a smaller pressure increase); and
- The energy of compression of water contiguous to and in communication with the area suitable for CO₂ injection, when the aquifer boundaries are open

Unfortunately, the system we start with in CO₂ aquifer storage comprises only water and rock, which both have low compressibility, and hence has a much lower total compressibility than an oil and/or gas reservoir.

Moreover, the boundary configuration (water contiguous to the storage area or oil pool) is also not in favor to CO₂ storage. An oil reservoir can be in contact to water both vertically (through an oil-water contact) and horizontally, with volumes of water potentially several orders of magnitude higher than that of the oil pool. Through this size effect, the water compressibility multiplied by the water volume can ultimately be larger than the oil compressibility multiplied by its volume. In the case of CO₂ storage in an aquifer, as large portions of the aquifer are considered for storage (and for compression when water is not produced), the benefit from adjacent waters (waters in shallow or low-salinity areas) can be significantly less than in the case of water contiguous to an oil pool.

4.2. Analogy of CO₂ injection with water production with secondary recovery or water flooding

The principal reason for water flooding an oil reservoir is to increase the oil-production rate and, ultimately, the oil recovery. This is accomplished by “voidage replacement”—injection of water to increase the reservoir pressure to its initial level and maintain it near that pressure [21]. Water flooding is the most common production mechanism used for conventional oil reservoirs.

Displacement efficiency (or waterflood oil-recovery efficiency) is calculated as the product of three independent terms [21]:

$$E_R = E_A \times E_I \times E_D \quad (2)$$

where E_A , E_I , E_D are respectively the areal displacement (flooding) efficiency; the vertical displacement efficiency and the unit (or microscopic) flooding efficiency. Equation 2 is clearly analogous to Equation 1, as both equations describe a fluid replacement process without accounting for any specific pressure issue.

Hence, we see a direct analogy between the “open aquifer” approach for CO₂ storage in aquifers with water production and water flooding in the oil industry.

Reservoir geology has to be accounted for to evaluate water flooding in an oil reservoir [21], as heterogeneities may accelerate water cycling and facilities have to be designed to account for additional water production and treatment prior to reinjection. By analogy, this may have important consequences when designing CO₂ storage with water production to mitigate pressure increase. Firstly, heterogeneities may drive CO₂ to the water producers and hence it may be required to account for CO₂ separation, compression and reinjection. Secondly, saline formation water will be produced, and will have to be dealt with somehow (disposed of into another saline aquifer or into the sea in off-shore cases, or desalinized and used).

4.3. Summary of the analogy of saline aquifers CO₂ storage efficiency factors with oil recovery mechanisms

As a consequence of this analogy, clearly different CO₂ storage efficiency coefficients should be defined based on the selected CO₂ storage mechanism.

For saline aquifer CO₂ storage without water production, the storage efficiency should be primarily derived using the “closed aquifer” approach, where the energy of the system comes mainly from the pore and water compressibility. Care should be taken to evaluate pore compressibility and maximum acceptable overpressure (either through a single value or a map), reviewing various possible mechanical failure modes, as discussed previously.

For saline aquifer CO₂ storage with water production, the “open aquifer” approach as defined by the DOE methodology could definitively be used, keeping in mind that the produced volumes of water should be similar to the injected volumes of CO₂ (at storage conditions) to allow pressure maintenance. However, sweeping efficiency (areal, vertical) should be based on pattern flow modeling representing both injection and water production to evaluate the volumes of water to be produced and the risk of CO₂ cycling to the water producers.

5. Conclusions

We have reviewed four hypothetical examples of full scale CO₂ storage into saline aquifers, without water production. For these four cases, the injected volumes lead to a rapid pressure increase, which is only marginally compensated by water migration across open boundaries and leakage through confining seals.

In two of the four cases, an independent “open aquifer” estimate of the CO₂ storage capacity is available, either from the DOE Atlas or from the USGS storage assessments. The flow modeling clearly demonstrates that these estimates, which do not account for the pressure build up in the aquifers, are too high, unless water production would maintain pressure at or below an acceptable level.

Hence, the “closed aquifer” CO₂ storage capacity estimate appears to be closer to the cumulative CO₂ injection that can be modeled honoring a given maximum pressure increase, if no water is produced.

The analogy with oil recovery or oil production mechanisms leads to the same conclusion. CO₂ aquifer storage without water production is analogous to primary recovery, whereas CO₂ aquifer storage with water production is analogous to secondary recovery based on water flooding.

As a recommendation, two distinct sets of capacity estimates or efficiency coefficients (or probabilistic distributions of these) should be established, differentiating clearly cases with or without water production. This has implications not only for CO₂ storage capacity estimates, but also for the technologies required to store CO₂. Producing formation water to manage pressure requires drilling water production wells; handling the brine (potentially complicated for on-shore scenarios) and also separating, compressing and reinjecting CO₂ that may be produced in the water production wells, just as water is treated in water flooding oil developments.

Acknowledgment

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