Periodic CO$_2$ Injection for Improved Storage Capacity and Pressure Management under Intermittent CO$_2$ Supply

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Abstract: Storing CO$_2$ in geological formations is an important component of reducing greenhouse gases emissions. The Carbon Capture and Storage (CCS) industry is now in its establishing phase, and if successful, massive storage volumes would be needed. It will hence be important to utilize each storage site to its maximum, without challenging the formation integrity. For different reasons, supply of CO$_2$ to the injection sites may be periodical or unstable, often considered as a risk element reducing the overall efficiency and economics of CCS projects. In this paper we present outcomes of investigations focusing on a variety of positive aspects of periodic CO$_2$ injection, including pressure management and storage capacity, also highlighting reservoir monitoring opportunities. A feasibility study of periodic injection into an infinite saline aquifer using a mechanistic reservoir model has indicated significant improvement in storage capacity compared to continuous injection. The reservoir pressure and CO$_2$ plume behavior were further studied revealing a 'CO$_2$ expansion squeeze' effect that governs the improved storage capacity observed in the feasibility study. Finally, the improved pressure measurement and storage capacity by periodic injection was confirmed by field-scale simulations based on a real geological set-up. The field-scale simulations have confirmed that 'CO$_2$ expansion squeeze' governs the positive effect, which is also influenced by well location in the geological structure and aquifer size, while CO$_2$ dissolution in water showed minor influence. Additional reservoir effects and risks not covered in this paper are then highlighted as a scope for further studies. The value of the periodic injection with intermittent CO$_2$ supply is finally discussed in the context of deployment and integration of this technology in the establishing CCS industry.

Keywords: CO$_2$; carbon capture and storage; storage capacity; pressure management; cyclic and periodic injection; intermittent supply; saline aquifer

1. Introduction

Storing CO$_2$ in geological formations, such as saline aquifers or depleted petroleum reservoirs, is an important component of reducing greenhouse gas emissions. Geological storage of CO$_2$ is, currently, the only technology available that can safely store volumes produced by emitting industries such as steel and cement as well as power production. As the Carbon Capture and Storage (CCS) industry continues to grow around the world, massive storage volumes would be needed [1–3]. It will hence be important to utilize each storage site to its maximum, complying with safety and environmental constraints. At the same time, different injection and storage scenarios may be needed to fit the emitters requirements.

The aim of a CCS project is to make the best use of the available space in the reservoir by flooding it with the largest possible volume of CO$_2$ while ensuring safety and maintaining proper resource management during injection operations and after. Appropriate reservoir

pressure and storage capacity management is critical to ensure the long-term functionality of such projects.

Underground CO_2 storage in a CCS project always depends on CO_2 supply or volumes available to be injected into a storage site. Beyond seasonal variations, there could be many reasons for periodic or intermittent CO_2 supply, such as scheduled or un-scheduled maintenance of CCS infrastructure, intermittent transport such as shiploads to offshore injection facilities etc. Even with increase in renewals there may still be need for disposal of CO_2 generated by power plants in periods with shortages of renewable electricity supply or high demand peaks [4]. Operational reasons such as well tests, workovers and treatments as well as maintenance of injection facilities always exist, also causing periodic injection [5].

CO_2 storage capacity and pressure management are widely discussed in the literature [1], whereas we concentrate exclusively on a historical review of cyclic or periodic CO_2 injection as the scope of this paper. Cyclic injection of CO_2 has been used in the oil industry for many decades as a means to enhance oil recovery (EOR), mainly through two alternative processes. Huff 'n' puff includes the cyclic injection of CO_2 into the reservoir, which after a "soaking" period is put back into production. This low cost technique was widely investigated and showed great potential for EOR both in laboratory and field tests [6–10]. The other approach, called CO_2-WAG (Water Alternating Gas), uses periods of CO_2 injection followed by water, displacing remaining oil and supporting reservoir pressure. There are several publications available covering CO_2-WAG, ranging from the following general to more specific aspects: gas cap contamination [11]; combination of CO_2-WAG with Soft Micro Gel (SMG) [12]; and rock wettability under CO_2 flooding [13]. Nevertheless, neither of these processes are designed for maximizing permanent storage of CO_2.

In this work, we focus on CO_2 storage in saline aquifers, considering risks and advantages of periodic injection, which will be the target for larger-scale projects [14]. Several authors have proposed solutions for this scenario, e.g., Buscheck et al. [15] developed the Active CO_2 Reservoir Management (ACRM) process that aimed to control pressure buildup and brine migration. This was achieved by using brine-producing wells in a CO_2 injection reservoir, as it was identified that such production in EOR processes helped to increase the volume of CO_2 injected and to control pressure buildups [15]. Agarwal and Zhang [16] developed a genetic-algorithm optimization (GA-TOUGH2) which among many benefits, aimed to optimize the injection pressure management and reduce CO_2 accumulation under the caprock. Jazayeri Noushabadi et al. [17] used the ACRM [15] approach but combined WAG-CO_2 injectors and brine producing wells (two wells for each type) in the same reservoir. The study proposed that alternating injection between two wells (not constant injection) increased the overall storage efficiency. Other scenarios presented in this study showed that combining CO_2-WAG injection wells with continuous water extraction from the brine producers led to acceleration of solubility trapping, thus reducing the risk of leakage due to mechanical trapping failure, which is particularly relevant in the early years of a CO_2 injection project. Edlmann et al. [18] presented an interesting development showing that, during cyclic injection of water and supercritical CO_2, the water cycle rendered a steady pressure increase while during CO_2 cycles it remained almost unchanged. Nazarian et al. [19,20] introduced another approach using Composition Swing Injection (CSI) technology [21]. CSI uses two CO_2-rich fluids (with different CO_2 mole percentages) which are injected cyclically into the reservoir; one has gas-like properties and the other behaves as a liquid. This is done to manage the CO_2 plume and counteract pressure buildup [17–20]. Singh [22] investigated the spatial and temporal pressure and CO_2 saturation distributions under four different injection schemes: constant; stepwise incremental; stepwise decremental; and cyclic. The study concluded that a cyclic injection scheme, due to CO_2 compressibility, tends to reduce the pressure build up. At the same time, it is not clear from the CO_2 saturation perspective whether the results show any benefit from this approach as the final plume saturation seems similar in all cases.

Even though some of the mentioned WAG studies showed that the reservoir pressure increases more slowly during CO_2 injection than when injecting water [18–20,22], a

comprehensive research of this effect was not found in the literature. This study aims to cover the periodic (a generalized form of cyclic) injection from the reservoir pressure management and storage capacity points of view by focusing on positive effects of such periodic injection including both pressure and CO_2 plume dynamics.

Although many studies indicated positive effects from cyclic CO_2 injection, certain risks may also be associated with introducing the cycles. Thus, geochemistry may play a role during periodic injection inducing changes in the compositions and properties of fluids and reservoir rocks. This can give reduction in permeability, e.g., due to precipitation of salts and minerals, hydrate formation, and growth of bacteria [5,23–25]. The risk and extent of these formation damages will depend on original conditions, how much the temperature and pressure vary during the CO_2-injection periods and the amount of CO_2 injected in each period. Variation in temperature and pressure may also affect the integrity of wells [26]. In the presented study it is assumed that the properties of the reservoir rocks are not changed during the periodical CO_2-injection, however the risks associated with their possible changes described above may be addressed in further studies.

The study starts from analyzing an actual CO_2 injection case [5] highlighting reasons for occasional periods of injection and well shut-ins and typical constraints applied in any CO_2 injection process. Then, we introduce the periodic injection concept defined in the context of current CO_2-injection common practices. Since one of the limiting factors during any CCS project is the maximum reservoir pressure governed by formation integrity constraints, we continue with studying the effects of periodic injection in both mechanistic and full-field reservoir simulations assuming injection at this maximum pressure. The paper concludes with analysing overall effect from the periodic injection studied in the context of a real field-case environment including other benefits from periods in injection like improved permanent reservoir monitoring.

2. Periodic Injection in Previous CCS Projects

Analysis of actual CCS projects with CO_2 injection in saline aquifers shows that well injection history is always a combination of sequential injection and shut-in periods related to well tests, treatments, workovers and stimulations. The Snøhvit CO_2 injection may be considered as an example [5,27]. In this CCS project, CO_2 produced together with hydrocarbon gas from the offshore Snøhvit gas field is separated on-shore and injected in a saline aquifer adjacent to the gas field reservoirs. Although stable CO_2 supply is provided in this case, periodic injection is taking place by operational reasons as described below.

The three-year history of CO_2 injection into the Tubåen formation (Figure 1) contains a series of injection and shut-in periods. The major well shut-ins (Figure 1) were related to the well treatment in October 2008 and the major plant maintenance during autumn 2009 [5]. At the same time, a variety of well shut-ins and rate variations are observed over time. The injection timeline is therefore actually represented by irregular periodic injections of different duration. Fracturing pressure for the Tubåen formation was estimated to approximately 390 bar [5] which stopped the CO_2 injection as the pressure build-up reached the threshold value as may be seen in Figure 1.

This short overview demonstrates that even with stable CO_2 supply, operational conditions may dictate periodicity of injection. This provides additional argumentation for investigating the impact of periodic injection on efficiency of underground storage.
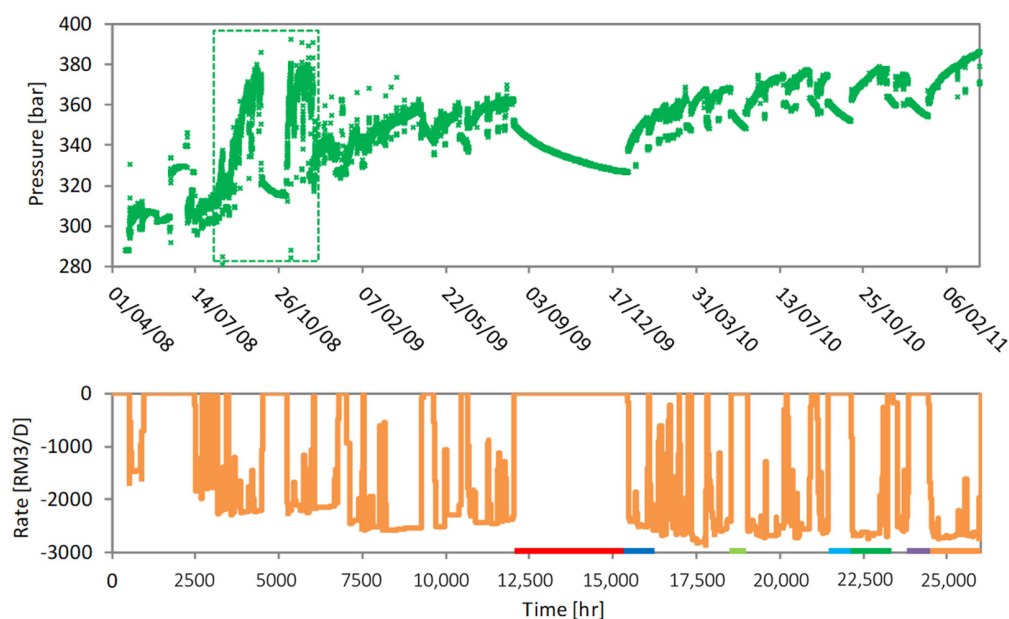
Figure 1. History of CO_2 injection into the Tubåen formation of the Snøhvit field containing many injections and shut-in periods [27]. The area highlighted by the square indicates period of well injectivity losses with following treatment to recover the injectivity.

3. Concept of Periodic Injection

Intermittency of CO_2 supply may happen due to different reasons such as:

- Transport with ships, tank-trucks, trains.
- Seasonal variations of summer and winter electricity demands and production.
- Sources with variable rates like coal- or gas-fired power plants.
- Planned and accidental shutdown of different facilities.

The concept of periodic injection considered in this paper is similar to the concept of cyclic injection, with regular, scheduled and repeated cycles, widely used in IOR/EOR applications discussed above, but it has several distinctive features:

- Injection may happen with alternating well shut-in and injection periods, but also with variable injection rate without shut-ins.
- Shut-in and injection durations and rate changes may vary on a irregular basis due to intermittent supply and operational reasons.

In this paper we denote all the cases as periodic injection in comparison with continuous injection for consistency, while these 'periodic' cases also include cyclic injection as a particular case.

The main effects to play a role in periodic CO_2 injection are assumed to be: fluid compressibility, gravity and fluid segregation, and CO_2 dissolution in water. In this paper we study all these effects, step by step. The main focus in mechanistic simulations was on fluid compressibility, while gravity and dissolution were studies in the field scale simulations. Other CO_2 trapping mechanisms such as rock-fluid interactions and microbial reactions are beyond the scope of the study.

4. Feasibility Study of Periodic CO_2 Injection

As a first step, a feasibility study was carried out on a 2D model of one-well CO_2 injection in a saline aquifer assembled in the Saphir simulator, following the study and the reservoir and fluid parameters discussed in [28,29] and previous studies of petroleum reservoirs [30]. The reservoir segment simulated in this study has a size of 10 km with 25% porosity and 19 mD permeability, with PEBI-type simulation grid and grid-block sizes varying from 0.05 m near the wellbore to a 400 m distance from the reservoir. In this paper, we concentrate on pressure management and injection capacity evaluations using this

model, while CO_2 injection combining injection and shut-in periods was also studied with similar models in the context of permanent reservoir monitoring as discussed in [27,31].

Figure 2 shows a 2D square-shape saline aquifer reservoir simulation model with no-flow outer boundaries used for the initial investigations. The size of the model was, however, set large enough to avoid impact of the boundaries, thus making the aquifer close to infinite acting (within the time frame of the simulations). Single-phase flow was simulated for water injection, while two-phase water-CO_2 flow without CO_2 dissolution in brine was simulated for the CO_2 injection scenarios.
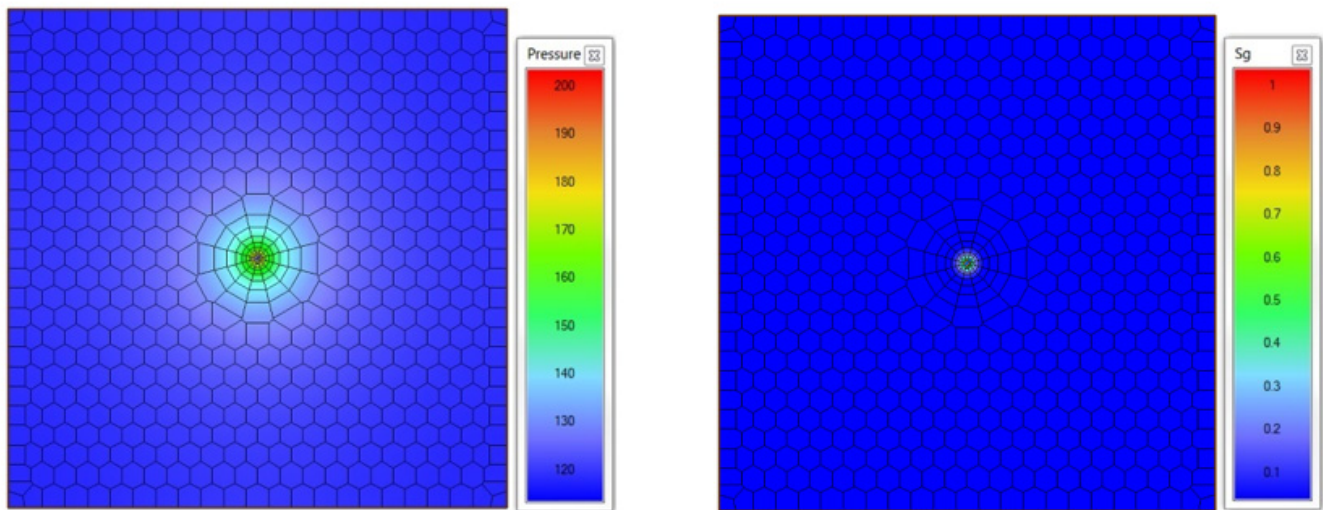
Figure 2. Pressure (**left**) and CO_2 saturation (**right**) distributions in 2D numerical simulations in Saphir.

The well bottom hole pressure results of two initial cases are as follows: continuous injection of water and CO_2, respectively, are shown in Figure 3, demonstrating monotonic pressure buildup in both cases (we should note that injection volumes were not the same in these cases). Introducing cycles into the injection schedule changes the picture significantly (Figure 4). While the pressure in each next injection period builds up to a higher level compared to the previous one (as expected) for water injection, the maximum buildup for the similar CO_2 case actually declines from period to period. This effect may be useful for pressure management and for increasing injection capacity under maximum injection pressure limitations as shown further in this section. Understanding of the mechanics behind this effect is also important, that is elaborated in 1D radial simulations presented later in the article.

In CCS projects, maximum well injection pressure is always limited, most often by formation integrity constraints ensuring safe injection and storage as discussed above, therefore governing maximum storage capacity. A representative injection case with the well operating at maximum bottom hole pressure, that was assumed to be 200 bar, was studied on the same model (Figure 5) to see potential of periodic injection for increasing storage capacity. The declining pressure drop observed at periodic injection of similar CO_2 volumes in each injection period (Figure 4) argued for the possibility to increase injected volume at each next cycle, keeping well pressure below the maximum pressure limit. Simulations of continuous and periodic CO_2 injection (Figure 5) showed that an additional amount of CO_2 may be injected at each next injection period, and this amount increases from period to period (Figure 6). Comparison of cumulative volumes injected for these two cases gives increase of CO_2 injected by 22% for the same 'effective injection time'.
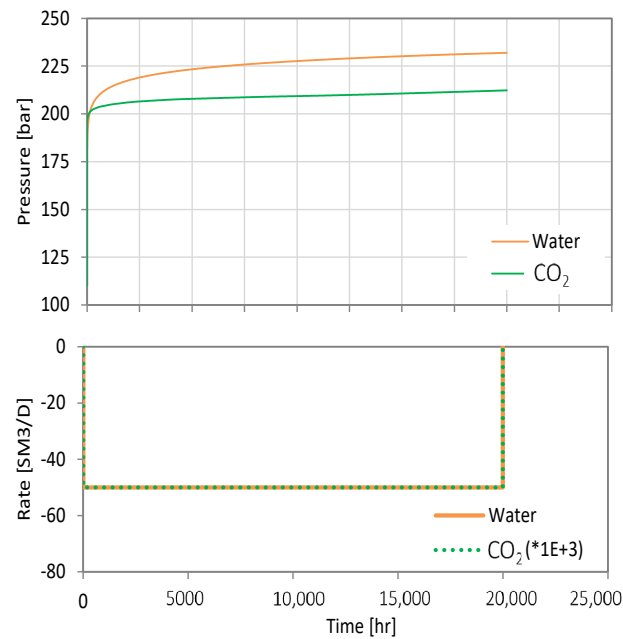
Figure 3. Pressure buildup as a response to continuous injection of water and CO_2 into infinite saline aquifer, 2D numerical simulations in Saphir. Injection rates are negative in contrast to positive production rates used by reservoir simulators.
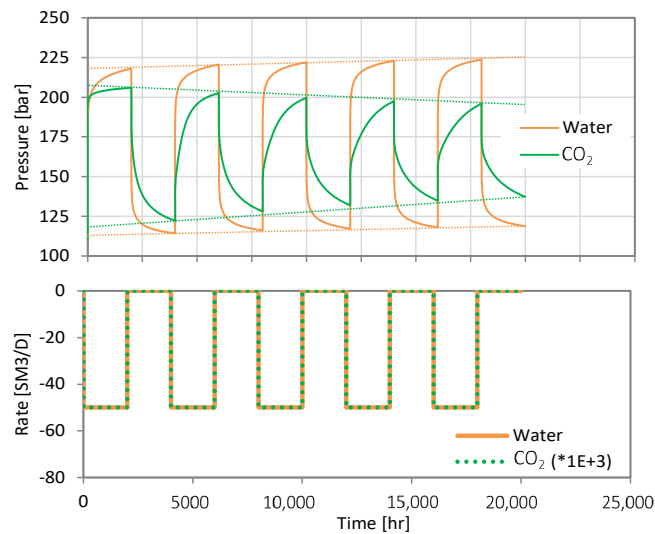

Figure 4. Well bottom hole pressure as a response to five sequential injection and shut-in periods (with cycle half-length of 83 days). The same reservoir model (Figure 2) was used following the simulations presented in Figure 3.
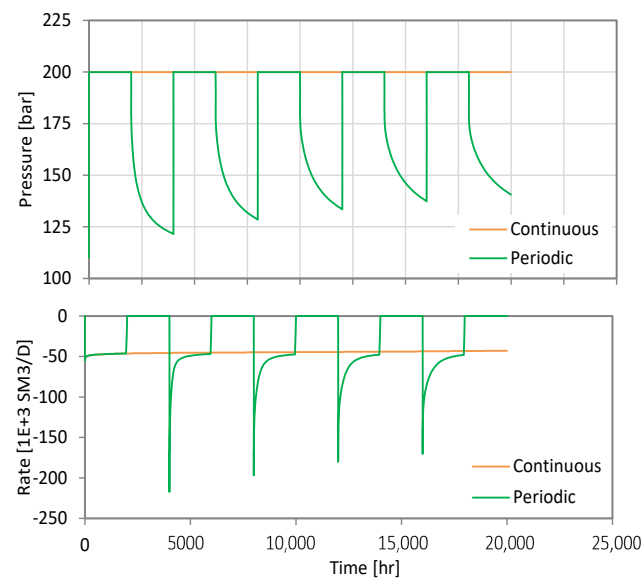
Figure 5. Comparison of continuous and periodic injections of CO_2 into saline aquifer at constant bottom hole pressure condition at the well, 2D numerical simulations in Saphir.
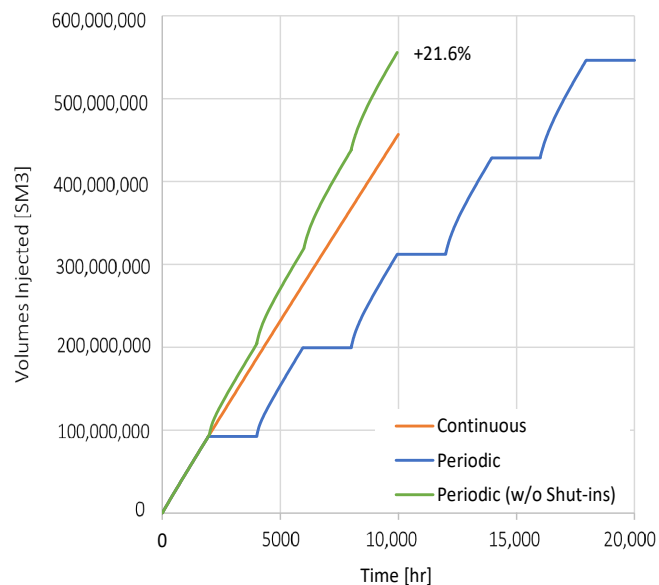

Figure 6. Comparison of CO_2 volumes injected at continuous and periodic injections with cycle half-length of 83 days (Figure 5).

5. Reservoir Pressure and CO_2 Plume Dynamics

The feasibility study described above called for a need to understand CO_2 plume and reservoir pressure dynamics under periodic injection. This helps in optimizing injection schedule and well locations in field-scale studies. A simplified 1D radial model, similar to the 2D model described above, was assembled in the Eclipse reservoir simulator to study these dynamics (Figure 7). Two sequential periods of injection and shut-in were simulated, with CO_2 rate specified in reservoir volumes (in contrast to volumes at standard conditions and specified bottom hole pressure used as the well control in the Saphir runs above). The same effect of declining pressure buildup in each next injection period were observed in the Eclipse runs (Figure 8).
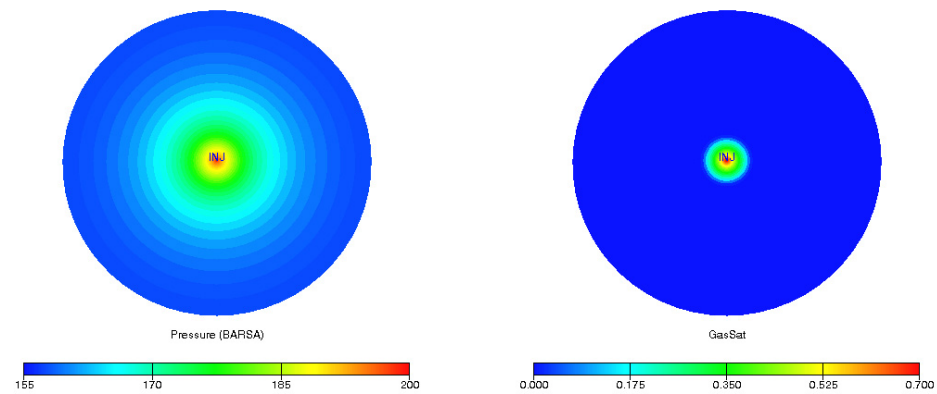
Figure 7. Pressure (**left**) and CO_2 saturation (**right**) distributions in 1D radial simulations in Eclipse (the radius of the simulated area is 1000 m). Pressure scale adjusted to highlight the buildup area, all values below 155 bar marked with blue.
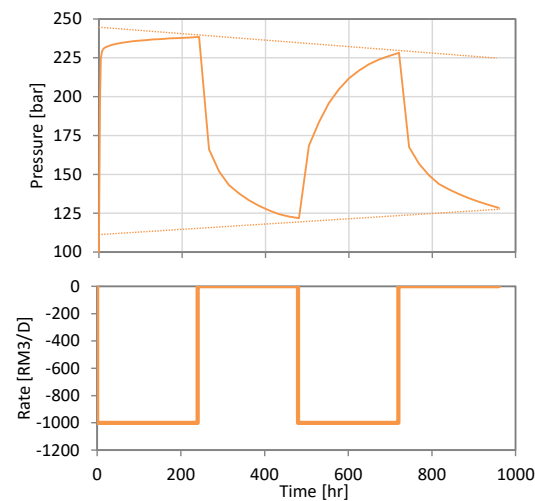

Figure 8. Two cycles of CO_2 injection into saline aquifer with cycle half-length of 10 days, 1D radial simulation in Eclipse.

Radial pressure distributions after the sequential injection periods illustrate the decline in pressure buildups (Figure 9) caused by a growing CO_2 plume (Figure 10). Inside the plume, viscosity of the fluid system (brine and CO_2) is lower than brine viscosity, while compressibility of the system is higher than brine compressibility. The growing plume resulted in the pressure buildup decline (Figures 8 and 9).

The radial saturation distributions (Figure 10) shed light on the complementary effect: CO_2 saturation front moves not only during injection, but also during well shut-in periods. This growth of plume volume is governed by CO_2 expansion due to pressure equilibration during shut-in periods. The growth becomes more visible, when the saturation profile is transformed into pore volumes occupied by CO_2 (Figure 11). The observed initial increase of the pore volumes is governed by radial grid with growing grid block volume with radius. The plume volume grows at about 10% during the first shut-in and more than 20% at the second one.

The simulations above have shown that the plume was growing during well shut-in periods, that will be called 'CO_2 expansion squeeze' further in the paper. In order words, pressure cycles can govern CO_2 plume growth even during well shut-ins without active viscous water displacement, improving injection potential. This effect may give an advantage when planning injection schedule and can be employed to increase injected volumes at given maximum injection pressure constraints as illustrated in the next section.
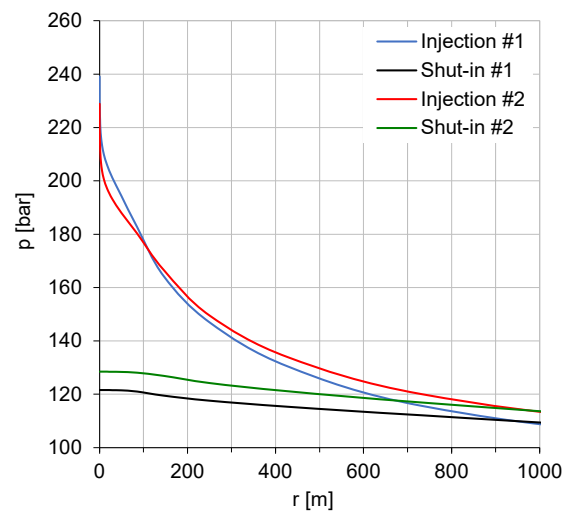
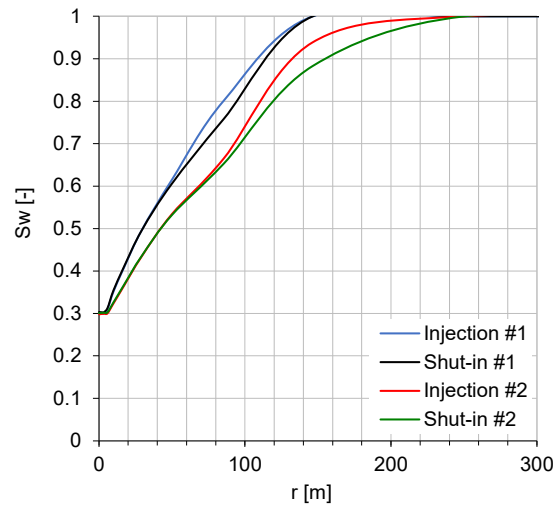**Figure 9.** Pressure profiles at end of injection and shut-in periods for the run in Figure 8.

Figure 10. Water saturation profiles in the cases described in Figure 8.
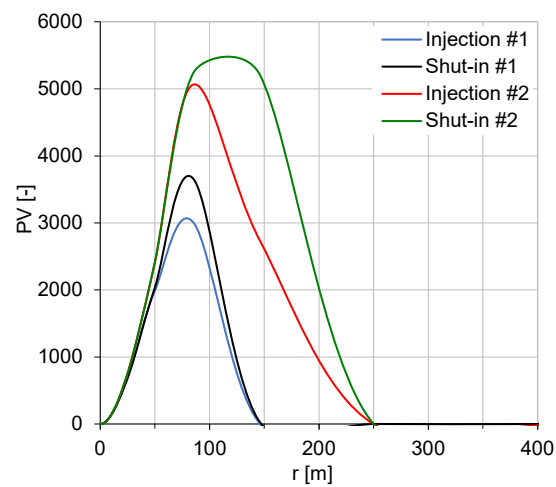

Figure 11. Pore volume (PV) occupied by CO_2 at end of the periods calculated from the saturation profile (Figure 10).

6. Actual Field Case Simulations

Reservoir model. Based on the inspiring results from the feasibility and detailed CO_2 plume studies above, it was decided to investigate the effects of periodic CO_2 injection in an actual geological setting. For this purpose we used the model of the LBr-1 reservoir (in the Czech Republic), available from earlier studies [28,29]. This reservoir consists of four zones with limited communication between zones, pinching out in the east, and connected to a significant aquifer to the west. The aquifer is believed to be closed, with an active volume in the order of 1 to 2 Gm^3. The model reservoir pore volume is around 40 Mm^3. The reservoir rock is sandstone with approximately 20% porosity and permeability in the 100 to 500 mD range. Reservoir depth is around 1100 m below ground level, with temperature of 43 °C and current pressure estimated to be about 115 bars.

The model was assembled in an oil-industry standard reservoir simulation tool (Eclipse100) with three phases, respectively, representing water (brine), CO_2 (in supercritical state), and CO_2 dissolved in water. CO_2 solubility in brine for the different temperature and pressure was taken from [32], while the corresponding variation in brine density was obtained from [33]. Relative permeabilities were based on actual measurements done in connection with the earlier studies. Capillary pressure between brine and CO_2 as well as capillary trapping of CO_2 were set to zero in this study. Hysteresis effects were therefore not included. These issues should probably be a subject for further investigations. As the sole purpose of this study was CO_2 storage, the reservoir was assumed 100% brine filled initially. Figure 12 pictures the structural framework of the model.
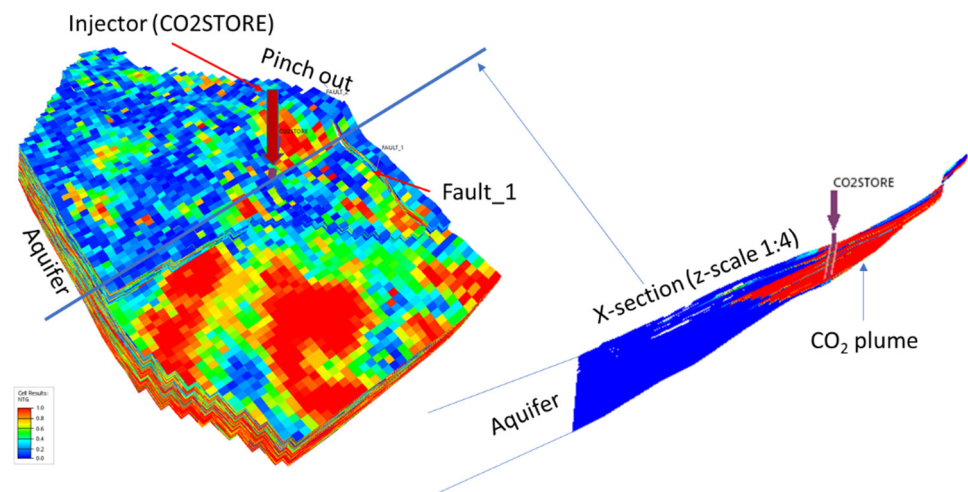

Figure 12. Simulation of CO_2 injection at LBr-1 geological setting (Eclipse reservoir simulator): perspective view with effective pore volume distribution and cross-section showing the mid-reservoir well position with color indicating CO_2 saturation after end of injection.

The CO_2 injection was set to be controlled by a fixed bottom hole pressure (Figure 13), thus accounting for injectivity variation related to CO_2 saturation in the wellbore area.

Four principal sensitivities were investigated:

1. Period (cycle) half-length: 1-month (i.e., 1 month injection and 1 month shut-in) vs. 3-months.
2. Placement of injection well: up-flank vs. mid-reservoir.
3. CO_2 dissolution in water: dissolution vs. no dissolution.
4. Aquifer size: limited (but large) vs. unlimited.
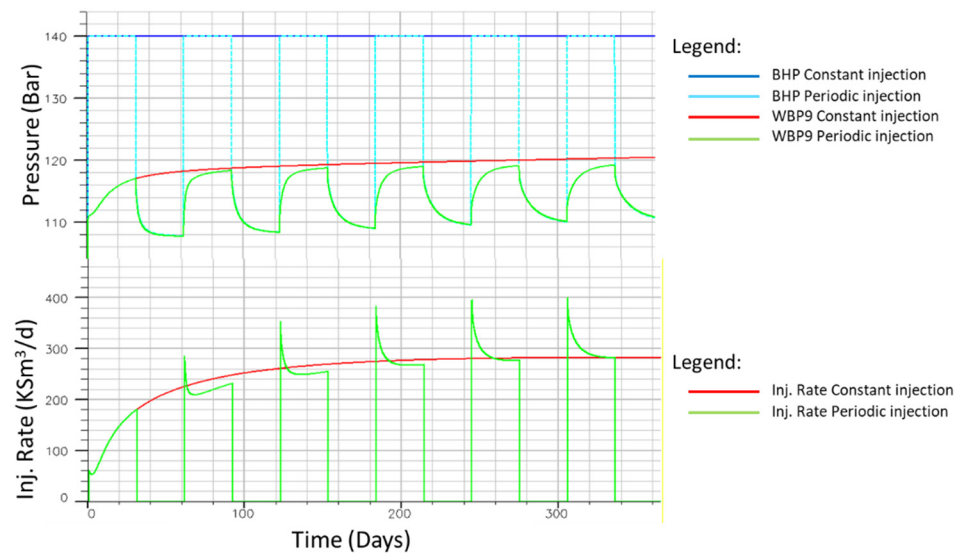5. Random variation in injection/shut-in periods length (between 1 and 3 months).

Figure 13. Bottom hole (BHP) and average near-well (WBP9) pressures and injection rates in the cases of continuous and periodic injection.

Up-flank injection. Sensitivities 1 and 2 were run in combination, comparing 10 years of periodic injection with 5 years continuous (equal net injection time). The complete results for the up-flank injection with 1-month cycles are shown in Figure 14.
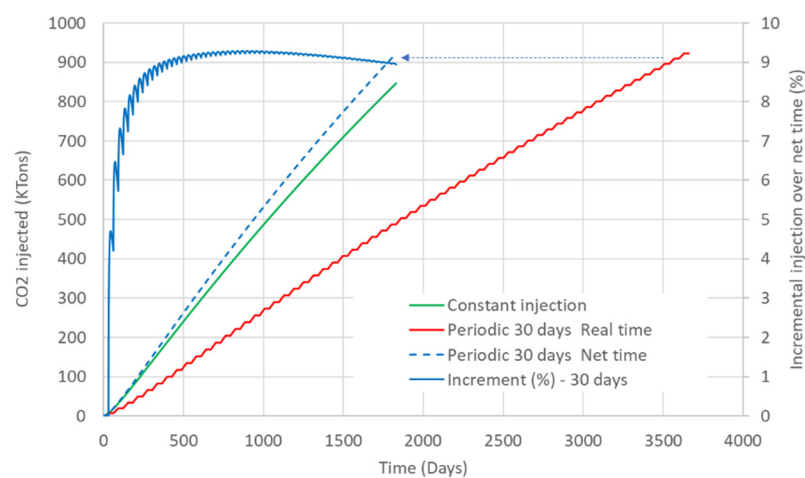

Figure 14. Up-flank injection with one month period half-length. The periodic injection shows around 9% more CO_2 injected after 2 years net injection time compared to continuous injection.

Figure 15 illustrates spatial distribution of CO_2 plume for the cases of continuous and periodic CO_2 injection with half-period of 1 month discussed above. The plume form and size are different in these cases: periodic injection governs large plume extent due to the CO_2 expansion squeeze effect revealed in the mechanistic simulations described above.

Comparison of one-month vs. three-month periods is shown in Figure 16, with the up-flank injector position. The periodic injection allows for pressure decline after each cycle and partial fluid equilibration in the area of CO_2 plume, leading to repetitive improvement of the injection performance with increased rate in each injection following a shut-in period. This effect is illustrated in Figure 17 where the rates for the three injection scenarios are shown vs. net injection time. Related to the quality of this reservoir, the equilibration seems to be completed within the one-month shut-in, giving the full opportunity of this improvement. Longer shut-in, therefore, does not lead to any further injection enhancement.
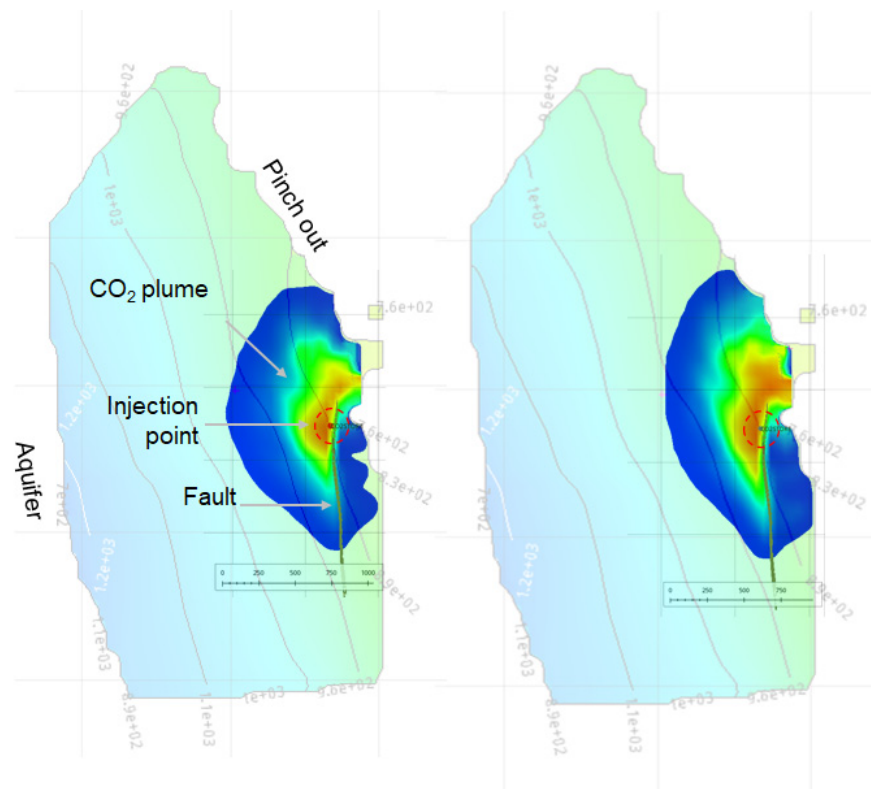
Figure 15. CO_2 plume extensions after one year of net-time injection for the cases of continuous (**left**) and periodic (**right**) injection.
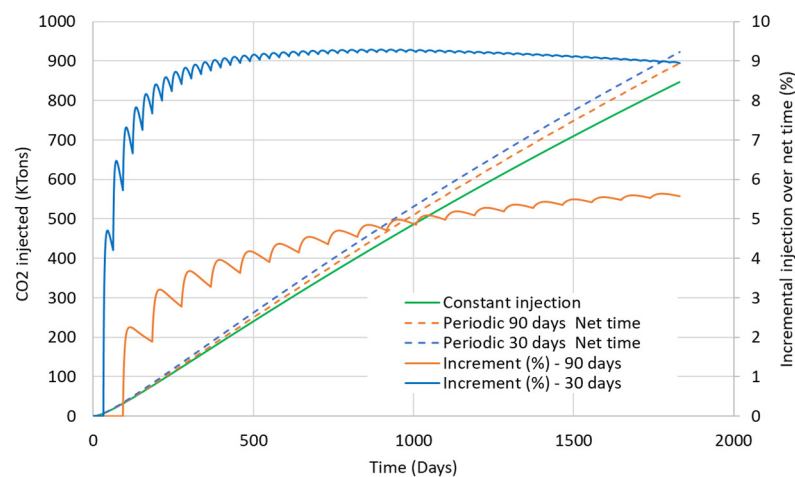

Figure 16. Up-flank injection, comparing one-month vs. three-month half-cycles. Longer cycles appear to reduce the benefit of periodic injection.

Mid-reservoir injection. Figures 18 and 19 exhibit the equivalent results, indicating lesser rate benefits of periodic injection in this case, particularly for the three-month half-cycles. The reason seems to be the gravitational effects, stimulated by the formation dip and thicker reservoir zones. While the up-flank injection rapidly establishes a stable CO_2 cap around the injector, the mid-reservoir injection allows for CO_2 to migrate vertically within each layer as well as up-dip during shut-ins due to density differences, leaving water to re-occupy the well surroundings.
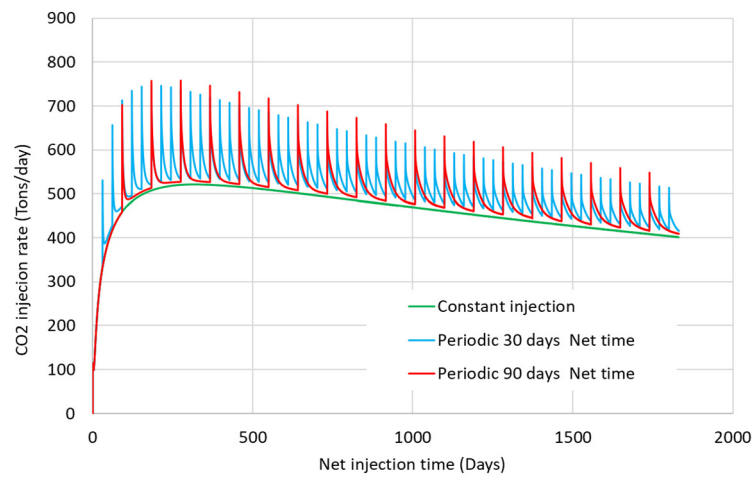
Figure 17. Net time rates of periodic injection vs. continuous injection rates for up-flank injection—clearly indicating rate improvements after each shut-in period.
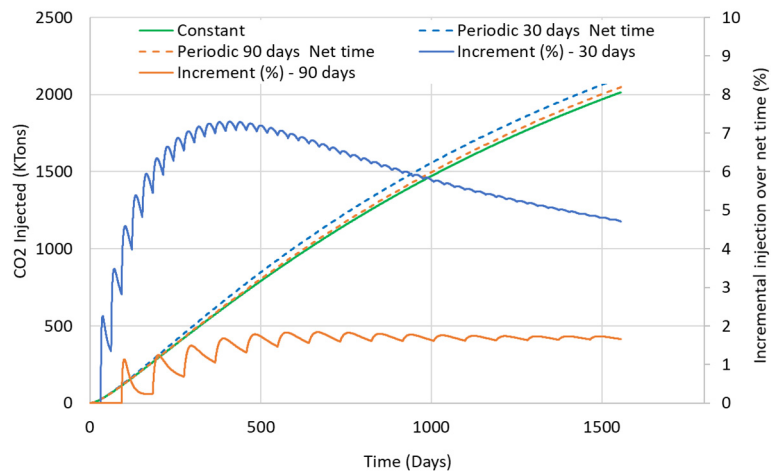

Figure 18. Mid-reservoir injection, comparing one-month vs. three-month cycles. Benefit of cycling appear much lower for this injector position. Longer cycles further reduce the benefit of periodic injection.
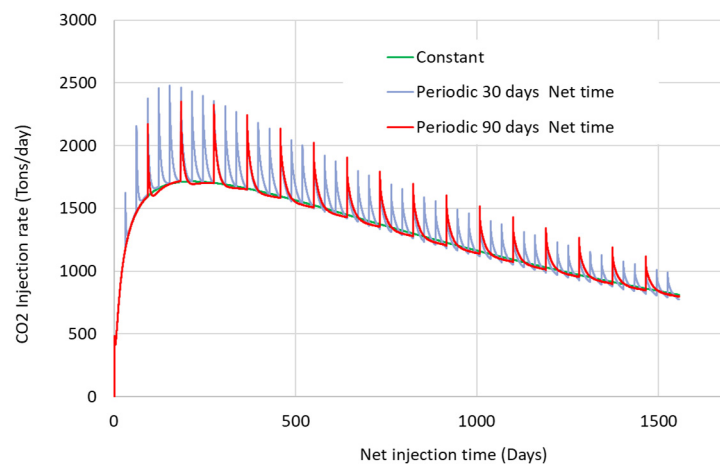

Figure 19. Net time rates of periodic injection vs. continuous injection rates for mid-reservoir injection—signaling lesser rate effects after each shut-in period.

Figure 20 shows the fluctuation of CO_2 saturation in a simulation grid cell close to the injector, with further illustration in Figure 21—underpinning this assumption. This adverse injectivity impact appears to largely outweigh the positive effect of pressure equilibration. Beware that the mid-reservoir well generally has higher injection rates due to better reservoir exposure.
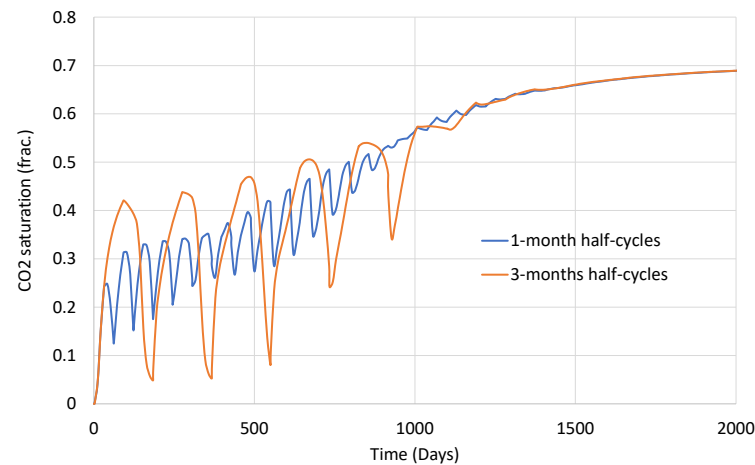

Figure 20. Fluctuation in CO_2 saturation in a near-well cell for the mid-reservoir injection scenario.
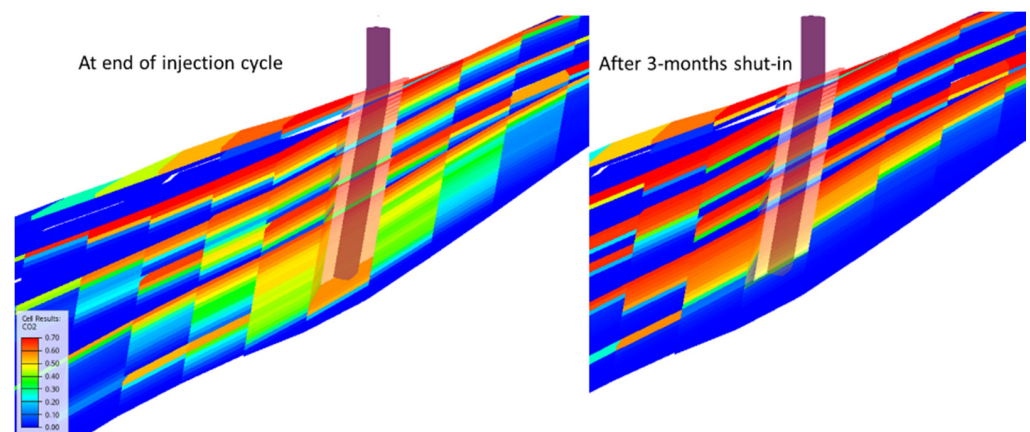

Figure 21. CO_2 saturation near-well-bore at end of injection cycle and after following three-month shut-in.

This repeated flow-back of brine into the near-well region may also have other adverse effects, such as augmented precipitation of salt. This and other potential negative effects are discussed in the 'Discussion' section below.

CO_2 dissolution in brine. The effect of letting CO_2 dissolve in water, depicted in Figure 22, is based on the optimum scenario of up-flank injection and one-month half-cycles. As expected, the cumulative injected volumes are lifted both for continuous and intermittent injection (CO_2 dissolved in water occupies less reservoir volume than supercritical CO_2 in free form), however, the impact relative to periodic injection seem inconsequential.

Aquifer size. The aquifer of the LBr-1 reservoir is believed to be closed. However, the initial pressure was very close to hydrostatic, so the possibility of an open aquifer may not be ruled out. In order to investigate the consequences of an open (infinite acting) aquifer, the up-flank, one-month half-cycle case was re-run with a down-flank relief well, set to limit reservoir pressure to a few bars above the original. Figure 23 presents the result of this case, suggesting that the size and dynamic response of the aquifer can be an important parameter as to the benefit of periodic injection.
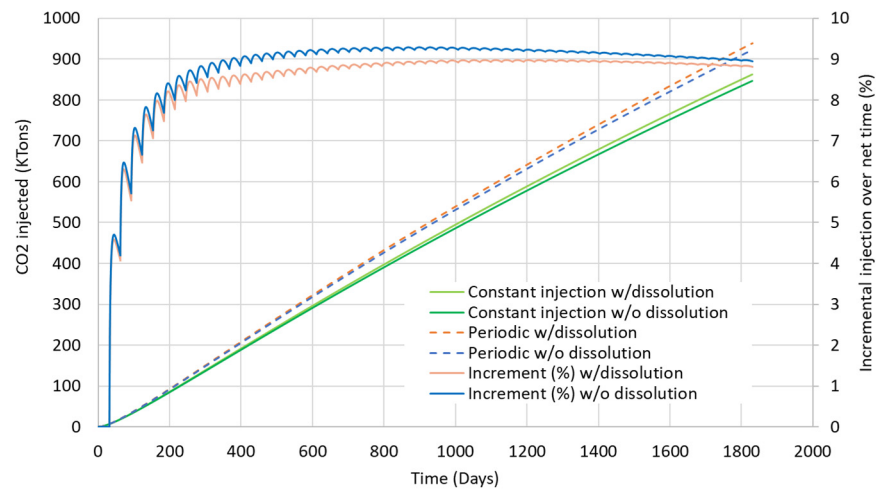
Figure 22. Effect of CO_2 dissolution in water. As seen the effect is insignificant in this case and context.
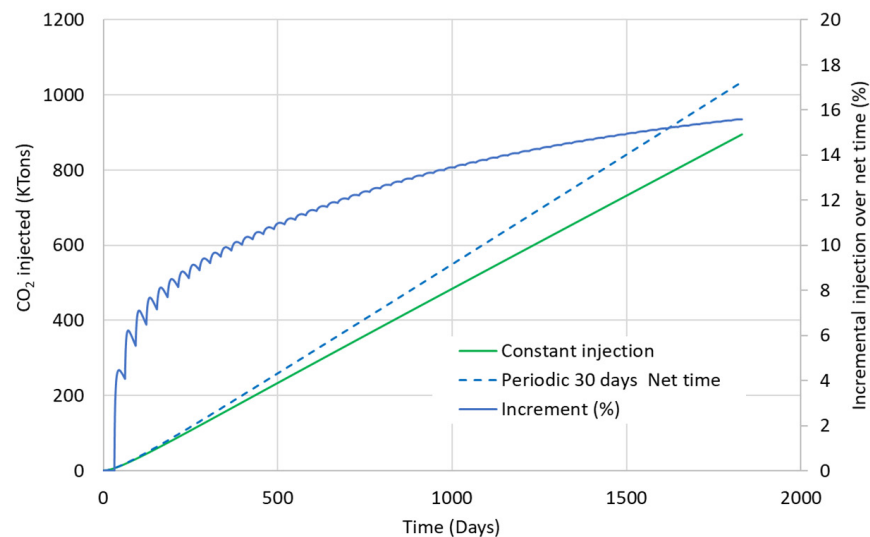

Figure 23. Results of periodic injection with a huge (unlimited) aquifer.

In this study, the simplest case of periodic injection with equal flowing and shut-in durations and the same well operating condition (specified bottom hole pressure) was mainly used, since it provides clear understanding of the positive effect counted in additional volume or in mass stored. In reality, a periodic injection may include injection and shut-in periods of different lengths and injection at different rates or simply periods of varying injection rates. The case of the different lengths may be studied using the same criterion of efficiency (additional volume stored), while evaluating effects from varying injection rates requires different criteria also accounting for pressure management. The latter case is a subject for separate study, while the effect of different lengths was evaluated in this study.

Random variation in injection/shut-in periods length. One additional case was simulated to study this effect. We ran the up-flank injection case controlled by maximum BHP (140 bar) described above (Figures 16–18), but with injection and shut-in periods varying between 30 and 90 days. As anticipated, the results showed addition injection potential somewhere between the 30-day and 90-day half-cycles presented above. The findings are shown in Figures 24 and 25 below.
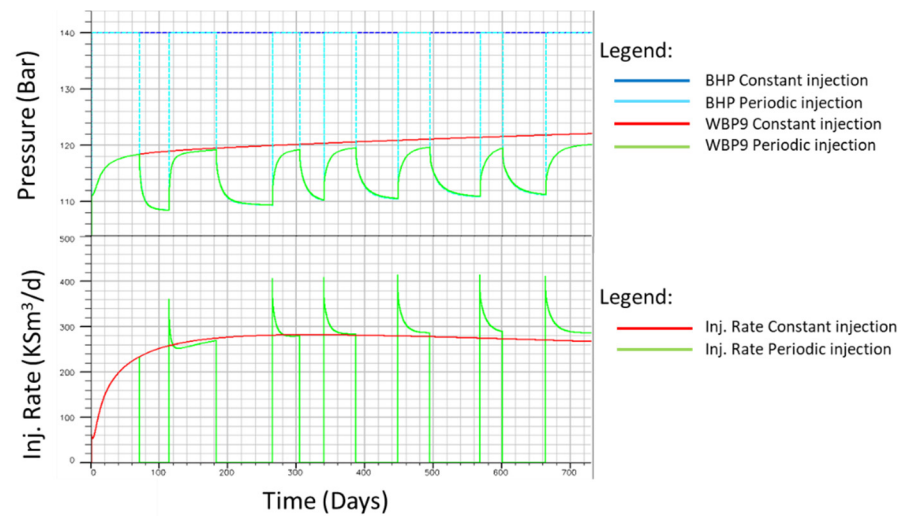
Figure 24. Bottom hole (BHP) and average near-well (WBP9) pressures and injection rates in the cases of continuous and periodic injection with varying injection and shut-in lengths.
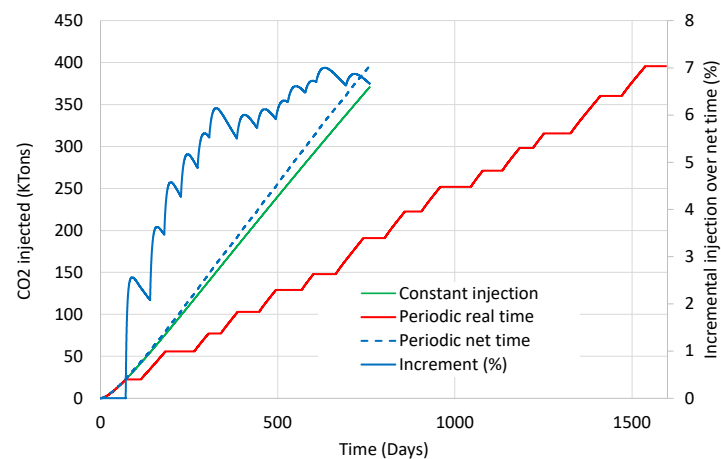

Figure 25. Up-flank injection with varying period lengths. The periodic injection shows around 6.5% more CO_2 injected after two years net injection time compared to continuous injection.

7. Discussion

In this paper, we concentrated only on the case of injection at a specified bottom hole pressure, since it may be easily linked to maximum injection pressure restriction and it allows for simple criteria of efficiency—additional CO_2 volume or mass stored. The case of periodic injection with variable rate is a matter for future studies, since evaluation of efficiency of such a process requires more complicated criteria including pressure management efficiency.

The cases simulated in this study have shown strong potential of periodic CO_2 injection to improve pressure management and storage capacity. However, the simulations did not account for potential geochemistry effects such as salt precipitation, mineral dissolution and formation, and hydrate formation. These effects may create risks for field applications of the periodic CO_2 injection and should be evaluated specifically for each reservoir in focus.

Reduction of the permeability of the rock in the near-well region during CO_2-injection can be a showstopper for CO_2-storage. Pressure buildup and uncontrolled fracturing in the near-well region can cause severe injectivity problems. If dry CO_2 is injected to the reservoir, the water around the injector will evaporate into the gas phase and this can give salt precipitation [23]. Periodical injection of CO_2 can cause back-flow of the brine phase

during shut-in periods which can affect the salt accumulation in the near-well region as shown by the case of mid-reservoir injection studied in this paper. The salt precipitation will depend on several parameters, e.g., water-phase composition, residual water saturation, flow rate, pressure and temperature. Dissolution of injected CO_2 into the water-phase in the near-well region will vary with temperature and pressure and will therefore affect the solubility of minerals in the reservoir rock [34]. The solubility of carbonate minerals is rather fast and especially sensitive to temperature and pressure. High pressure and low temperature during CO_2-injection will give high solubility of carbonate minerals, and this may increase the permeability and porosity of the rock. During the shut-in period with pressure reduction and temperature increase, precipitation of carbonate minerals may cause permeability reduction. Geochemical reactions can also change rock mechanic properties [35].

When cold CO_2 is mixed with the water in the near-well region, cooling of the near-well region at high injection pressure can cause hydrate formation and thereby permeability reduction. The potential for hydrate formation will depend on the ionic composition of the water [36] and thereby on the brine composition in the near-well region. During the shut-in period, the hydrate can dissociate depending on temperature and pressure during this period. Variation in the conditions can also affect the well integrity [26].

The risk for formation damage during periodical CO_2 injection will depend on the composition of the reservoir fluids and the reservoir conditions, i.e., it will be field-specific. In addition, it will depend on the injection procedure that is used, e.g., variation in reservoir pressure and temperature. For a specific reservoir, the procedure for periodic injection should be optimized to reduce the risk for formation damage and maintain well and reservoir integrity. Procedure for mitigations should also be established.

The paper did not consider reservoir monitoring capabilities provided by periodic injection. This is another important aspect making periodic injection a very attractive option to improve underground CO_2 storage. Shchipanov et al. [27] have studied application of reservoir monitoring technology based on time-lapse pressure transient analysis to the Snøhvit CO_2 injection case early discussed in the Section 2. It was shown that the periodic injection provides favorable conditions for improved reservoir monitoring including early detection of leakage out of the formation as it was particularly shown in [31] for the geological formation studied in this paper. Here the sequence of injection and shut-in periods populates the time-lapse survey of pressure transients. Therefore, a combination of improved storage capacity, pressure management and reservoir monitoring makes periodic injection a very attractive option to apply in CO_2 storage projects.

8. Conclusions

Results and conclusions from these studies may be separated in two different groups: first, addressing the CO_2 expansion squeeze effect; and second, studying this effect in the context of field-scale simulations, including gravity, dissolution and reservoir size effects.

The CO_2 expansion squeeze effect governed by fluid compressibility has been studied in the mechanistic reservoir simulations resulting in the following conclusions:

- During a well shut-in after an injection period, CO_2 plume continues to grow, displacing water due to reservoir pressure equilibration and CO_2 expansion.
- This effect, in a combination with pressure decline inside the plume during the shut-in period, leads to forming a high compressibility and low viscosity area near the well.
- As a result, following injection of the same mass of CO_2 will provide a lower pressure buildup than in the previous injection period.

This effect may be employed for improving efficiency of CO_2 injection via increasing volume injected with pressure management utilizing periodic injection.

The field-scale reservoir simulations have confirmed increased storage capacity and ability to manage reservoir pressure under periodic injection revealed by the mechanistic simulations with the following, particular conclusions:

- The CO_2 expansion squeeze effect play a dominant role in the positive effect of periodic injection, increasing injection capacity up to 9% for the same net-time up-flank injection for formation in focus.
- Gravity and vertical migration of CO_2 plume may significantly reduce the positive effect as it was shown on the comparison of the up-flank and mid-reservoir injection with reduction of the effect to 2% in the latter case.
- Random variation of the length of injection/shut-in periods may lead to a minor decline in the effect from periodic injection, but keeping similar overall efficiency if compared to the same length of injection/shut-in periods.
- CO_2 dissolution in water provided three to four percent of additional CO_2 stored in our runs, but this increase was the same in both cases on continuous and periodic injection. This argued that the dissolution does not play an important role in the effect of periodic injection.
- In contrast, aquifer size seems to play a major role in increasing storage capacity. Thus, sensitivity of periodic injection to the aquifer size has shown almost double the increase of the capacity in the case of the larger aquifer.

Summarizing the conclusions on field-scale simulations, we can conclude that the periodic injection has significant potential for improving pressure measurement and storage capacity. Analysis of the risks described in the discussion section above and mitigating measures should also be integrated in injection site evaluations.

We therefore suggest to include assessments of periodic injection in storage site evaluations. Such assessments should address structure of the formation in focus and different well locations, while understanding boundary conditions for the site (e.g., size of the aquifer and faults) may play a major role in the assessments.

Further development of the presented technology of periodic CO_2 injection into saline aquifers may include studies of the geochemistry and thermal effects highlighted in the discussion section above.

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