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Injected CO_2 Arrival At Newell County Field Research Station's Geochemistry Observation Well: Characteristics and Initial Reactive Transport Analysis

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Summary

CO_2 gas phase injection into Campanian Foremost Fm. at Carbon Management Canada's Newell County Field Research Station (50.450° N; 112.120° W) began 2017/08/07. Periodic injection zone water sampling indicates bicarbonate concentrations began increasing 30 m up dip of the injector 2022/11/13, ~2000 days after injection began, when 64.0 tCO_2 was injected. Dissolved CO_2 concentrations began increasing prior to 2024/04/24, when 89.7 tCO_2 was injected, but not before 2023/12/06, when 83.3 tCO_2 was injected. During 2024 dissolved CO_2 came to exhibit carbon isotopic ratio characteristics like the injected CO_2 confirming that dissolved species concentration increases are attributable to dissolution in, and reaction with, injected CO_2 and formation water. Most injected CO_2 remains in the pore space gas plume at saturation ~35%, consistent with geophysical and pressure transient data and analysis. Over time the proportion of injected CO_2 dissolved in formation water increases. By the end of 2025, about 100 tCO_2 were injected, about 22% of which had dissolved in formation water. The sequential arrival of bicarbonate followed by dissolved CO_2 indicates reactive transport and molecular diffusion in formation water, ahead of the, now slowly expanding, gas plume. The model predicted gas plume arrival at the observation well before April 2024, after the observed arrival of dissolved injected CO_2. In late December 2025 the gas plume had not arrived, nor were its pressure effects observed at the observation well. This suggests that other processes or reactions must be considered to account for the delayed arrival of the injected gas plume, including migration into higher strata, consistent geophysical and pressure transient data analyses, but perhaps not excluding other processes.

Setting and Previous Work

Carbon Management Canada (CMC) Inc. operates a shallow gas-phase CO_2 pore space storage pilot in southeastern Alberta (50.450° N; 112.120° W), described as the Newell County Field Research Station (Lawton et al., 2019; Macquet et al., 2022). The Campanian Belly River Gp. bedrock storage complex, predominantly sandstone, coal and mudstone, crops out below Pleistocene glacial till ~25 m thick. Three deeper wells, each with a surface casing vent (SCV; Wigston et al., 2020) include an Injector (~550 m deep), a geochemical observation well (Well #2, ~350 m deep) and a geophysical observation well (Well #3, ~350 m deep). The site has a protracted and diverse baseline geochemical and hydrological characterization at the three deep

wells that is augmented by samples from water wells (Utley et al., 2023; Utting et al., 2023; 2025). Gaseous CO_2 injection began August 2017 into the basal shoreface sandstones (291-298 m deep). The injection program simulates a leak from a deeper and larger underlying supercritical CO_2 storage site into depths near, but below, the groundwater protection zone. The pilot demonstrates how well integrity monitoring contributes to subsurface containment monitoring at a CO_2 storage complex.

Currently, but not initially, all three SCVs emit 'sweet', biogenic CH_4-rich natural gas at very low rates or intermittently. At Well #2, the casing interior and exterior sand pack completion are sampled, respectively, from well headspace (Utting et al., 2023; 2025) or a U-tube (Freifeld et al., 2005; Utting et al., 2023; 2025) on the exterior of the well casing that is positioned in the well annulus sand pack between the injection zone and screened casing intervals. Gas sampling began July 2017 (Utley et al., 2023) and became quarterly after May 2018 (Utting et al., 2023; 2025).

Observations

Over time, CO_2, none of which resembled the injected CO_2 isotopically, became less abundant in samples at all SCV sources (Utting et al., 2023; Osadetz et al., 2024; Utting et al., 2025). This was initially mimicked by a decline in CH_4 from Well #2 SCV and its interior into mid-2020 (ibid.). In contrast, the CH_4 richness emitted from the Injector and Well #3 SCVs remained higher and are generally similar. Well #2 SCV CH_4 richness became similar to the other wells in early 2022, although Well #2 casing interior samples remained CH_4 poor and contaminated by air due to well interventions to perform geophysical experiments. Well #3 SCV could not be sampled due to reduced rate in early and mid-2020, but in late 2020 samples were again obtained from all sources and the Well #2 SCV CH_4 richness was higher than that observed prior to 2020. Headspace gas sampling was suspended temporarily at Well #2 in early 2021 to facilitate injection zone pressure measurements and to repair a monitoring device. Well #2 head space.

CO_2 injection began 2017/08/07, 424 days prior to the beginning of the generally quarterly geochemical sampling program on 2018/10/05 (day 0 QGSP) from the U-Tube at Well #2. U-tube samples showed systematic increases in bicarbonate concentrations by 2023/07/25, after 75.4 tCO_2 were injected. Bicarbonate concentrations have increased progressively since that time until at least the end of 2025. An empirical fit to bicarbonate concentration over time suggests that increased bicarbonate was present at the U-tube only slightly before 2022/11/13, when 64.0 tCO_2 were injected. Dissolved CO_2 began increasing in U-Tube samples prior to 2024/04/24, when 89.7 tCO_2 were injected, but not before 2023/12/06 when 83.3 tCO_2 were injected). The progressive increase in dissolved CO_2 was accompanied by a progressive change in U-tube sample dissolved CO_2 carbon isotopic ratio and by mid-2024 it was isotopically like injected CO_2. This confirms that changes in dissolved CO_2 concentration were attributable to the injected CO_2 gas phase injection. Pressure and temperature gauges co-located with the U-

Tube in the sand packed completion of Well #2 still do not record changes in pressure or temperature associated with the periodic injection of gaseous CO_2. This indicates that the primary transport mechanism for the plume-derived dissolved CO_2 and bicarbonate appearing at the U-Tube is molecular diffusion.

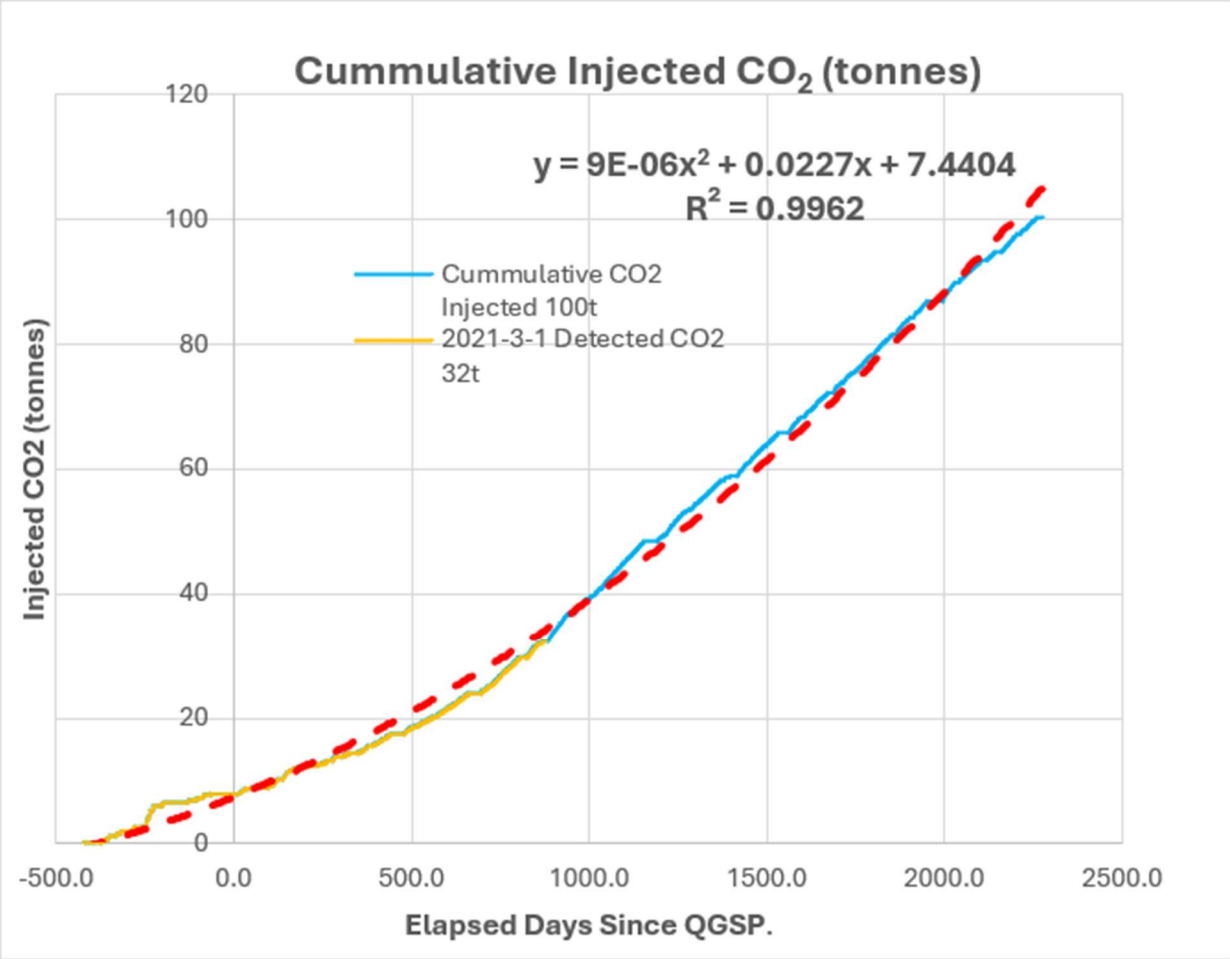


Figure 1: Cumulative injected CO_2 mass (t), measured at surface, as a function of the number of elapsed days since the beginning of the QGSP. The cumulative injected mass is distinguished both prior to (orange) and after the date, when 32.2 t CO2 were injected and the edge of the plume was inferred from repeat seismic surveys (Kolkman-Quinn et al., 2023a).

Analysis and Discussion

The inference that U-Tube sample compositional and isotopic ratio changes are attributable to transport by molecular diffusion is consistent with the observation that bicarbonate concentrations increase ~13 months, 390 days, before the dissolved CO_2 begins to increase in

U-tube samples, if one considers the diffusion constants and material characteristics of the two molecules (i.e. CO_2 should arrive first if diffusing without reaction with the formation water to produce bicarbonate). Yet, we know from combinations of electrical resistivity tomography (Macquet et al., 2023; Kolkman-Quinn et al 2023a; 2023b) and reflection seismic geophysical data, as well as the analysis of pressure transient data associated with the episodic injection operations that a persistent gas-phase plume extends away from the injection well.

We produced a simple, analytical gas plume evolution model that is a function of cumulative injected CO_2 mass to estimate the plume arrival date at Well #2. Despite the widespread use of CO_2 in industrial processes the solubility CO_2 and the reaction rates for both CO_2 dissolution in formation waters and bicarbonate formation from CO_2 in water are uncertain on geological time scales (Leslie et al., 2021). Using judiciously chosen and widely accepted solubility relationships (e.g. Preuss and Spycher, 2007; Preuss and Nordbotten, 2011; Kempke et al., 2014) we locally infer dissolution and reaction constants using a geophysically-inferred plume edge on a given date, based on the interpretation of repeated seismic surveys (Kolkman-Quinn et al., 2023a) In particular we employ the geophysically-inferred plume margin on 2021/03/01 (878 days QGSP, when 32.2 tCO_2 were injected) to defined reaction co-efficients used to predict gas plume size as a function of cumulative CO_2 mass injected over ~3000 days.

Injected CO_2 mass is measured at surface and in these models, it is assumed to be injected into and contained within, the 6 m thick basal Foremost Formation, Belly River Group sandstone injection zone with porosity 11%, an initial water saturation 100%. Injected CO_2 gas density is 105 kg/m^3, (NIST materials database) using observed reservoir temperature, 12.5^oC, and injection zone pre-injection pore fluid pressure, 2.54 MPa. The pre-injection pore fluid pressure reflects the natural under pressure in the succession at the FRS (Osadetz et al., 2024).

The resulting analytical reactive transport model considers only CO_2, partitioned among the gas phase plume, the CO_2 dissolved in formation water and the injected CO_2 that reacted to produce dissolved HCO_3^-. The model evaluates the gas phase plume evolution. It permits dissolution of injected CO2 at the gas water contact and its reaction to form dissolved bicarbonate, but it does not incorporate molecular diffusion of these species in the water phase, which from above, occurs in the injection zone. A mass conservation check was performed to ensure that injected CO_2 matches the species in the model after partition among the three components illustrated in Figure 2.

Models were made for both fresh water and seawater, although the shallow formation waters are much less saline than seawater. The model shows that the CO_2 gas phase plume is the dominant feature of the injected program and the pore space gas plume. This is consistent with both geophysical observations and pressure transient analysis during long shut in periods in the injection program. The model average pore space CO_2 gas saturation is 0.35 for freshwater and 0.37 for seawater, consistent with the reduction of CO_2 solubility with increasing pore water salinity and indicative of the brackish formation water composition. Most dissolved CO_2 reacted

to form dissolved bicarbonate, again consistent with observation that dissolved bicarbonate arrives before dissolved CO_2 does at Well #2. With time and increased injected mass proportionally more of the injected CO_2 enters the dissolved phases. The proportion of injected CO_2 dissolved reaches ~22% on 2025/12/18 ~3000 days after injection commenced.

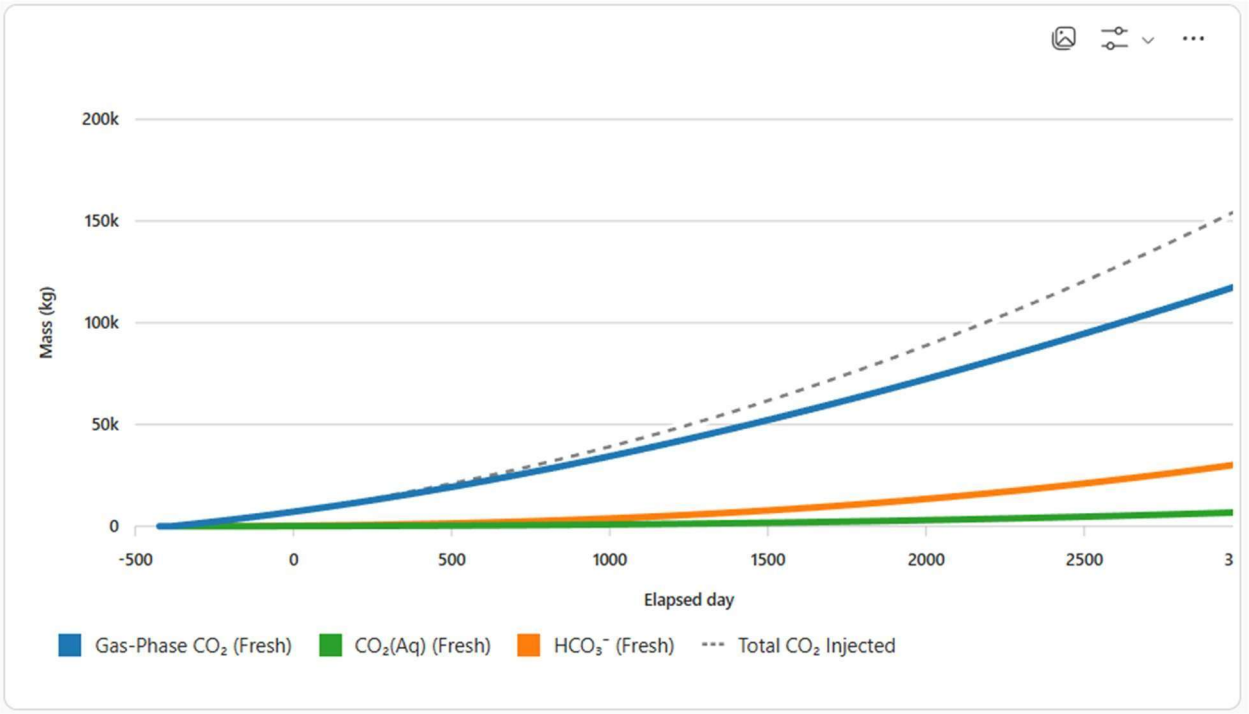


Figure 2: Model partition of injected CO_2 mass among: the gas phase plume, CO_2 dissolved in formation water (freshwater model) and CO_2 reacted with formation water to produce dissolved HCO_3^-, as a function of days since QGSP.

The model also predicts the location of the gas phase plume edge relative to the injection well, discounted for CO_2 dissolution, as a function of time since injection began. Using the locally derived dissolution parameters the model predicted that the gas plume would arrive at Well #2 at the end of March 2024 slightly after when 2024/02/06 sample data suggests that dissolved CO_2 concentrations began to increase. In a sequential manner, the reactive transport model correctly predicts the sequence of species arriving at the observation well. However, as of mid-December 2025, ~3000 days after injection began, the gas plume had not arrived at the observation well, nor were its pressure effects recorded a gauge co-located with the U-Tube at Well #2. There are several potential independent or co-dependent explanations for this inconsistency as to when the gas plume arrives at the observation well:

1. Geophysical models suggest some injected gas migrated above the injection zone into superior Foremost Fm. strata (Macquet et al., 2023). This is not accommodated in the reactive transport model, nor is there an estimate of the mass of gas that might have left the

confines of the model. The injection zone is overlain by shales and coals. Some injected CO_2 might be adsorbed into overlying coal beds or migrated higher in the succession. Pressure communication between the injection zone and overlying coals resulted in gas production from these coals at Well #2 when it was evacuated for a geophysical survey in 2018.

2. Repeat seismic experiments (Kolkman-Quinn et al., 2023a) may have overestimated the extent of the gas phase plume. At Sleipner a full wave form inversion model gives gas plumes volumes suggesting no dissolution or reaction with formation water (Martinez-Guzman et al., 2025), which is inconsistent with previous Sleipner studies (Alnes et al., 2008; 2011) and observations both elsewhere (Leslie et al., 2021) and at the FRS.

3. The effects of dissolved species diffusion, if included in the model, could increase concentration gradients at the gas water interface, resulting in additional CO_2 dissolution.

4. Other factors, or combinations of factors, such as microbial consumption of injected CO_2 to produce CH_4, as observed elsewhere (Tyne et al., 2021), may be active.

We await gas plume arrival and pore-fluid pressure effect indications at Well #2. We continue to collect and characterize U-Tube fluid samples. We also wait for noble gas sample results, including Argon, that may provide independent constraints on transport phenomena. Exploration and improvement of the analytical reactive transport model will lead to numerical reactive transport simulations, using models like TOUGH2MP/ECO2N.

Conclusions

1. Injected CO_2 began arriving as dissolved and reacted phases, both bicarbonate and later CO_2 at the Geochemistry Observation well (Well #2) ~1924 days after injection began in mid-November 2022, after 64.0 tCO_2 were injected at the surface.

2. Most of the injected CO_2 is inferred to remain in the gas plume, consistent with other, largely geophysical studies that suggest the persistence of a gas phase plume at the FRS. By the end of 2025, ~100 tCO_2 was injected, about 22% of which has dissolved in pore space formation water, predominantly as bicarbonate, but also, to a lesser extent as CO_2, which has isotopic characteristics of the injected CO_2 gas.

3. The sequential arrival of bicarbonate, inferred derived from injected CO_2, followed by dissolved CO_2 is consistent with other indications that reactive molecular diffusion occurs in pore water.

4. A simple analytical reactive transport model predicted the arrival of the gas plume at the Well #2 by the end of March 2024, after dissolved and reacted CO_2 had arrived at that well. Yet,

as of December 2025 the gas plume has not arrived, suggesting that other processes or reactions account for its delayed arrival at that well.

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