Carbonated Brine Injection as a Low-Risk CO_2 Storage Strategy: A Case Study for Inyan Kara Sandstone Reservoir

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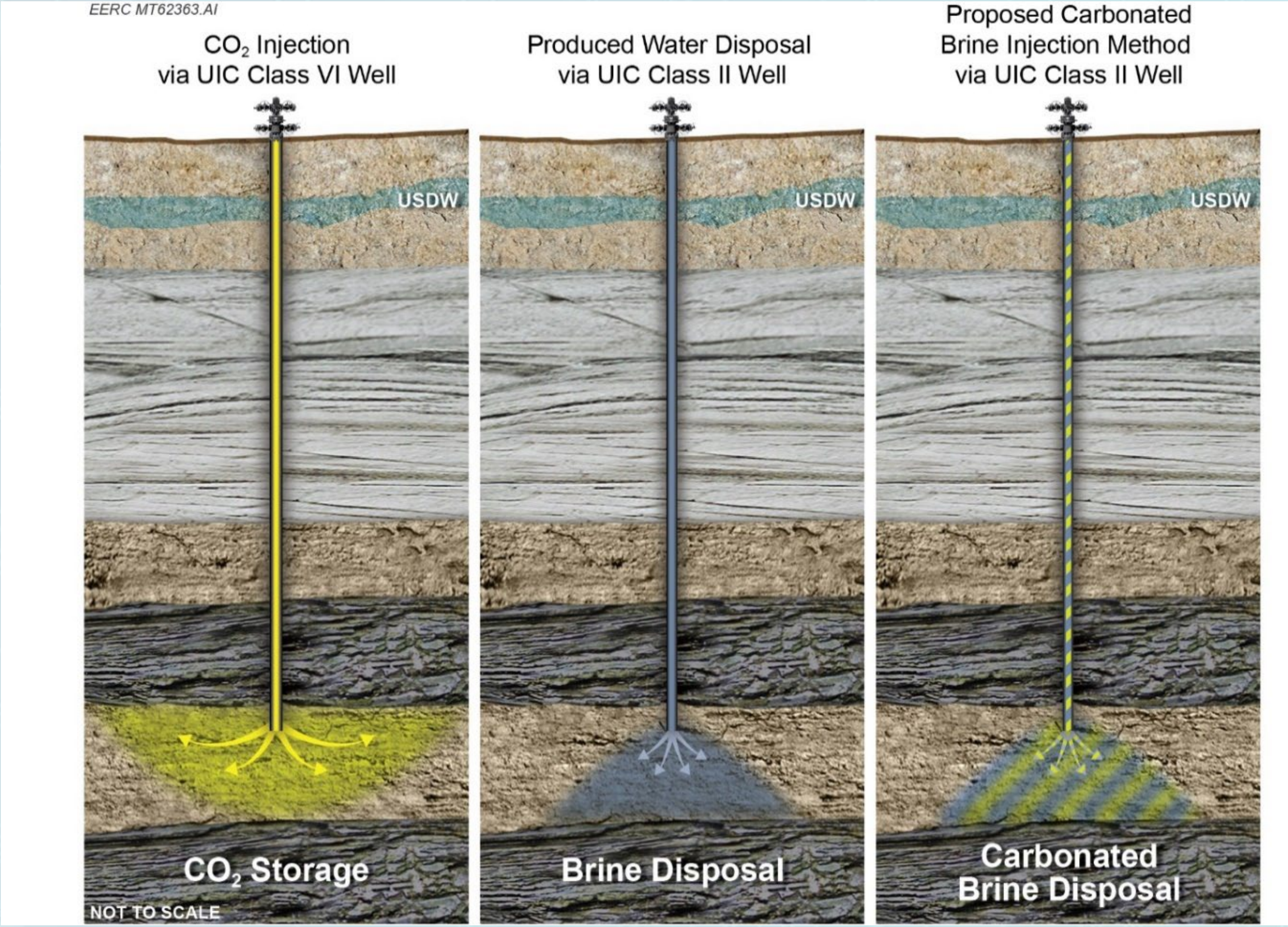
Overview



Carbonated brine injection (CBI) has the potential for large-scale carbon sequestration throughout the oil and gas industry through its network of already existing Class II saltwater disposal (SWD) wells. For CBI, CO_2 is first dissolved into produced waters being injected. Since the CO_2 is mixed with the produced water prior to injection, the benefits are predicted to include no migration of free-phase CO_2 and negligible pressure increase when compared to standard SWD injection.

The objective of this study was to evaluate the feasibility and long-term safety associated with combined produced water and CO_2 storage in the North Dakota portion of the Williston Basin.

Methods

Assessment of CBI as Low-Risk Strategy for Geologic Carbon Storage

Reservoir Modeling

- Investigate CO_2 molality
- Phase changes over time
- Pressure changes at different salinity
- Computer Modeling Group (CMG)

Corrosion Modeling

- Wellbore compatibility with dissolved CO_2
- Scale tendency of injected water
- OLI Software

Reactive Transport Modeling

- Rock-fluid interactions during injection
- Long-term CO_2 fate in reservoir
- Geochemist's Workbench

Theme 4. 3:40 PM. Belarbi et al. Investigation of Scale Deposition and Wellbore Corrosion in Carbonated Brine Injection: A Simulation Study

Reservoir Model Parameters

- Reservoir thickness: 300 ft
- Simulation block widths in the I and J direction: 101*101
- Simulation cell size: 10*10-ft (I*J) with a cell thickness of 10 ft (K)
- Number of layers: 40
  - Mowry Formation, 5 layers
  - Inyan Kara Formation, 30 layers
  - Swift Formation, 5 layers
- The reservoir was assumed to be 100% brine saturated
- Porosity and permeability data extracted from a larger geological model
  - Porosity 0.23
  - Permeability in I and J direction is 284 md; permeability in K direction is 10% of the horizontal permeability

Constant Parameters	Value
Injection Rate, bbl/day	8,000
Years of Injection	20
• Pre-injection	1
• Post-injection	100
Reservoir Pressure, psi	2,255 or 1,500
Reservoir Depth, ft	4,700
Reservoir Temperature, °F	165
Wellhead Temperature, °F	60

Preliminary simulation findings revealed that within the molality range of 0.75 to 0.65 mol/kg, approximately 99.99% of CO_2 would be successfully dissolved into the reservoir fluid with 10,000 ppm injection fluid salinity and reservoir fluid salinity. **To minimize the leakage risk, 0.2, 0.4, and 0.6 mol/kg CO_2 molality were chosen to study salinity scenarios.**

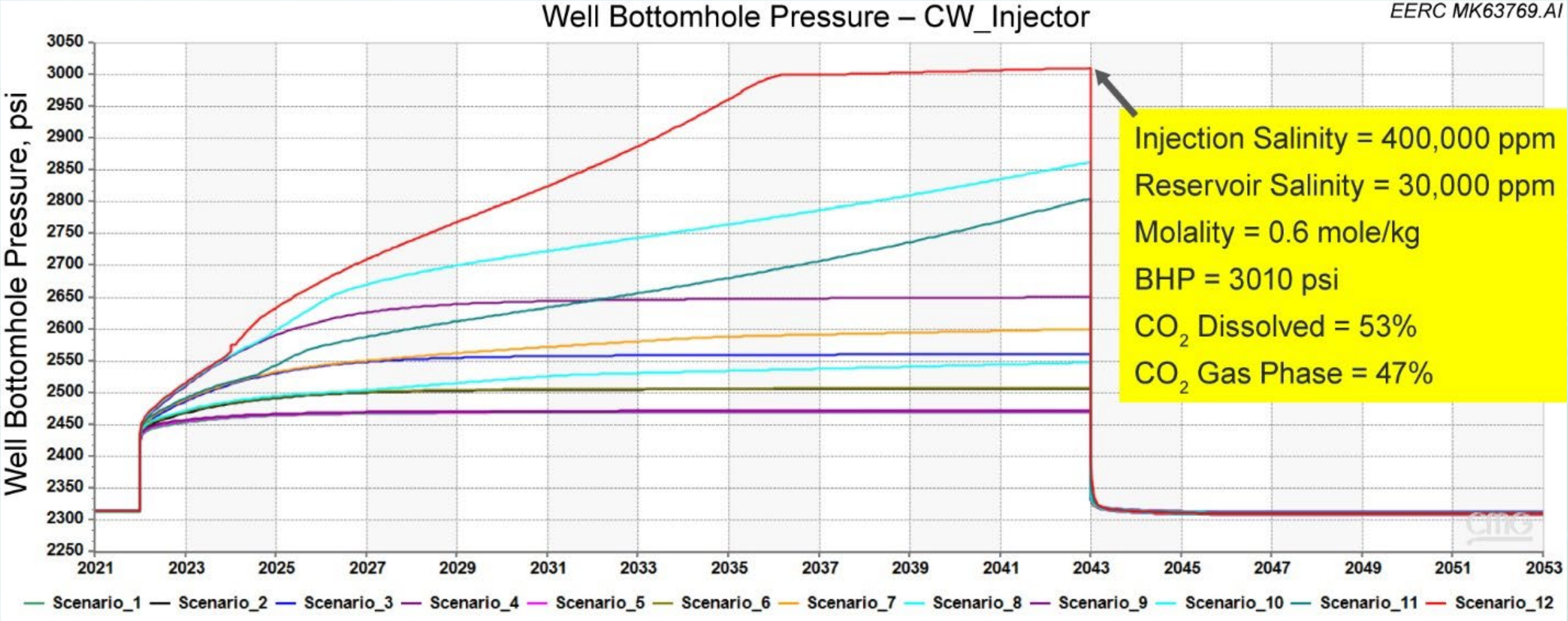
Reservoir Injection Scenarios and Results

Lower injection salinity allows more CO_2 to be safely stored through dissolution. Among all the tested scenarios, 0.2 mol/kg dissolved CO_2 presents minimal leakage risk.

Sc.	Injection Fluid Salinity (ppm)	Reservoir Fluid Salinity (ppm)	Molality (mole/kg)	CO_2 Dissolved, %	CO_2 Gas Phase, %
1	100,000	10,000	0.2	99.99%	0.01%
2	200,000	10,000	0.2	99.99%	0.01%
3	300,000	10,000	0.2	99.97%	0.02%
4	400,000	10,000	0.2	99.94%	0.04%
5	100,000	20,000	0.4	99.99%	0.01%
6	200,000	20,000	0.4	99.98%	0.02%
7	300,000	20,000	0.4	93.06%	6.93%
8	400,000	20,000	0.4	63.92%	36.07%
9	100,000	30,000	0.6	99.99%	0.01%
10	200,000	30,000	0.6	92.19%	7.80%
11	300,000	30,000	0.6	65.35%	34.64%
12	400,000	30,000	0.6	53.19%	46.79%

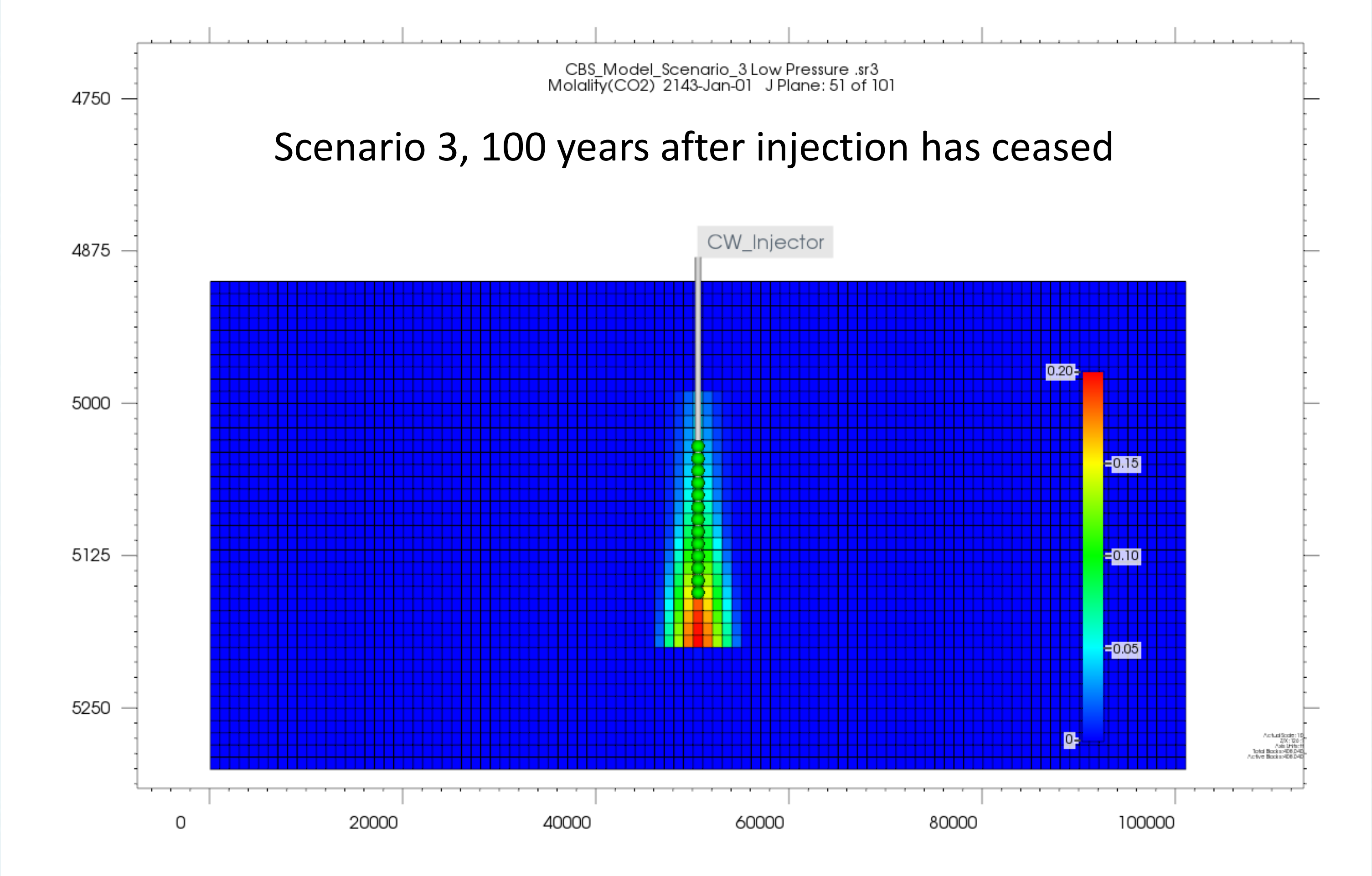
Bottomhole Pressure

Bottomhole pressure (BHP) built steadily throughout the simulation period while still remaining well below the maximum BHP for a typical SWD well in the Williston Basin (~3,000–3,300 psi). The highest BHP observed in these tests came from Scenario 12 which reached 3,010 psi at the end of the injection phase. Scenario 12 represents the case with the highest tested salinity and dissolved CO_2 molality of 0.6. A rise in BHP was observed in Scenarios 8, 11, 12 due to excessive gas phase CO_2.



Dissolved CO_2 Migration

Dissolved CO_2 migrates downwards over long-term storage, further lowering the leakage risk.



Reactive Transport Model Setup

Sandstone is mostly composed of quartz, with a porosity of 23%. There was 0.2 molal dissolved CO_2 in the injected produced water. The injection period was set at 20 years with the injection fluid rate (1,280 m^3/day). After 20 years, the injection fluid rate was set at 0 for 100 years as the shut-in period. All kinetic rates for primary and secondary minerals are from literature.

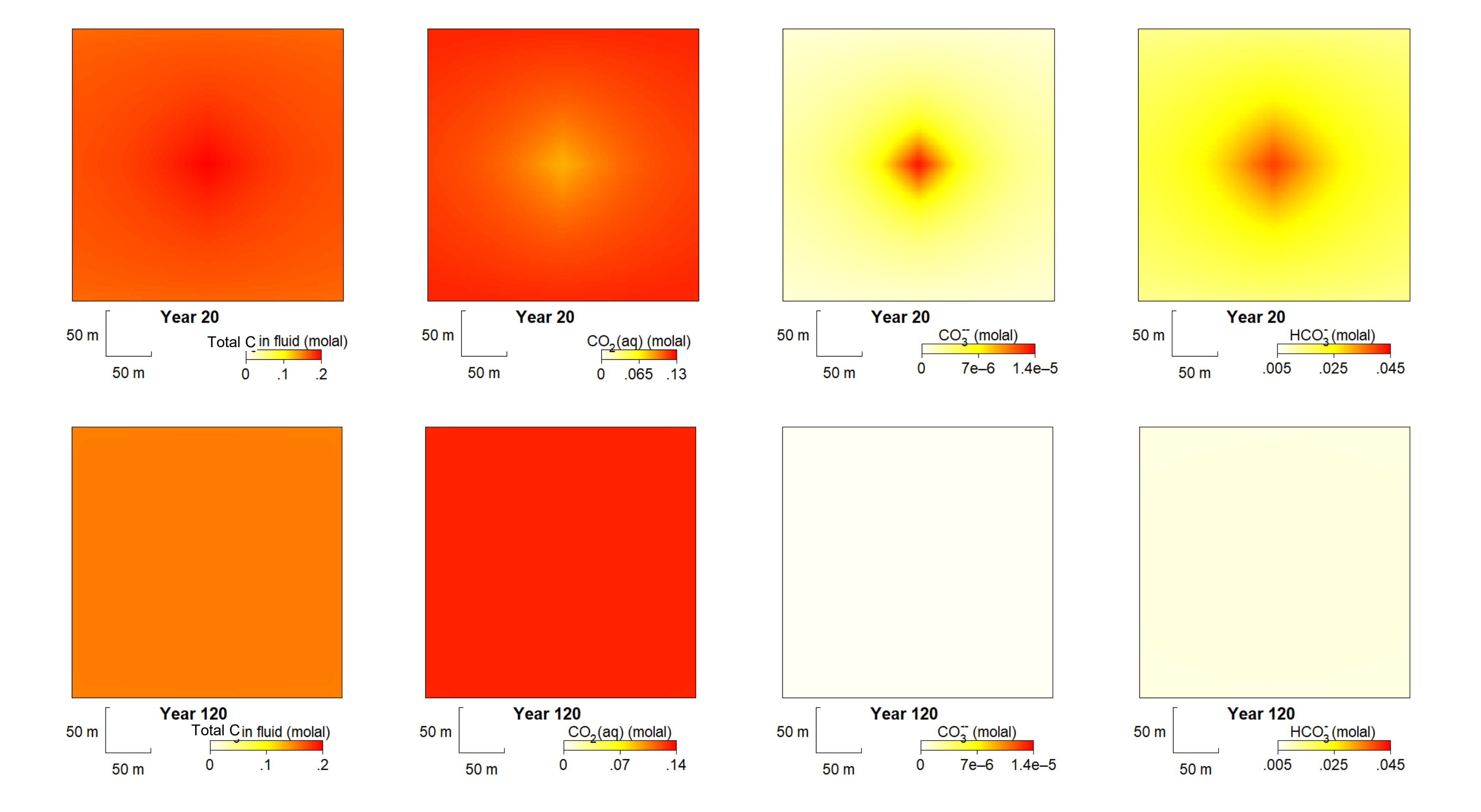
Formation	Concentration	Injection Water	Concentration
Quartz	70.5 volume %	SiO_2(aq)	
Muscovite	2.7 volume %	Al^{+++}	
Siderite	3.8 volume %	Fe^{++}	124.71 mg/L
Mg^{++}	57 mg/L	Mg^{++}	1,091.15 mg/L
pH	6.1	pH	5.94
Ca^{++}	259 mg/L	Ca^{++}	16,674.76 mg/L
Na^{+}	7,114 mg/L	Na^{+}	75,341.45 mg/L
K^{+}	408 mg/L	K^{+}	4,483.17 mg/L
Cl^{-}	10,600 mg/L	Cl^{-}	152,006.21 mg/L
$SO4^{--}$	1,000 mg/L	SO_4^{--}	613.46 mg/L
$HCO3^{-}$	1,086 mg/L	HCO_3^{-} as C	0.2 molal
Ba^{++}		Ba^{++}	34.40 mg/L
NO_3^{-}		NO_3^{-}	151.96 mg/L

Dissolved CO_2 Species

Total C | CO_2(aq) | CO_3^{2-} | HCO_3^-

End of injection

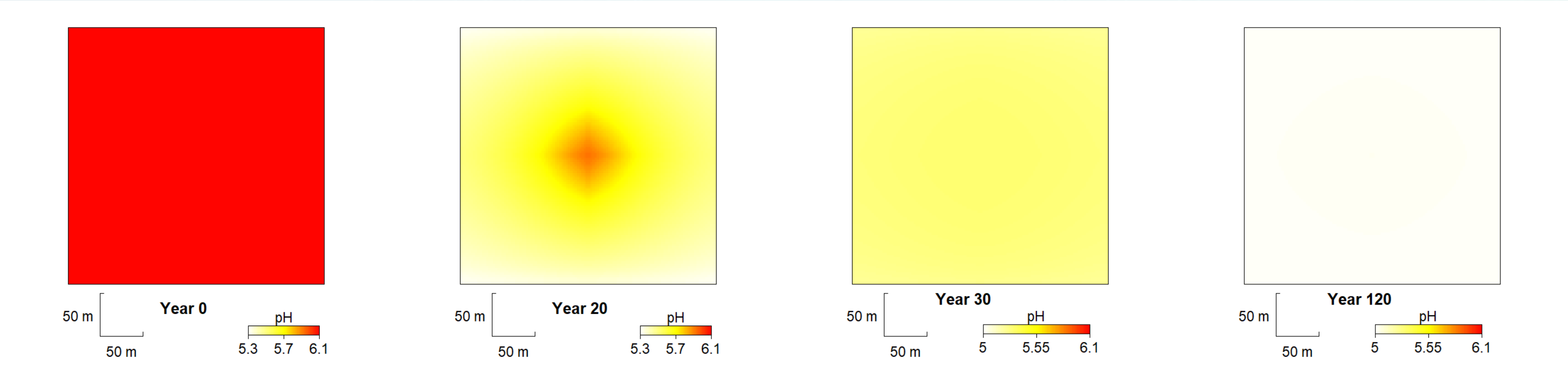
100 years of shut-in



CO_2(aq) remains the predominant form. Total C decreases slightly over time. Carbonate and bicarbonate participates in rock-fluid interactions.

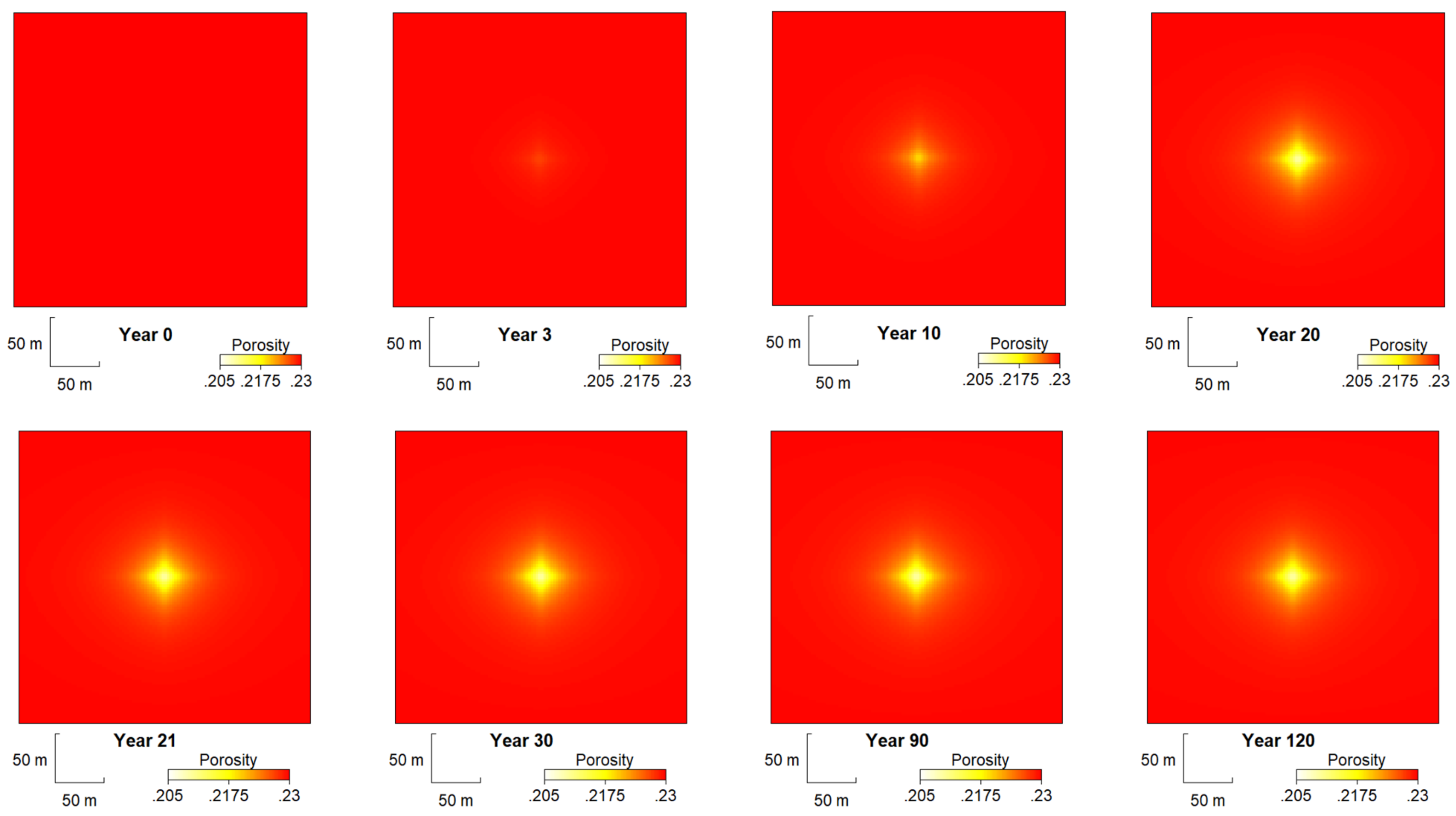
pH

pH decreases from 6.1 before injection to 5 over long-term storage.



Porosity Change

Porosity decreases from 23% to 21% due to carbonate mineral precipitation close to the injection point.



Summary

- Carbonated brine storage is a low-risk geologic CO_2 sequestration strategy. Simulations of CBI at small CO_2 molality (0.2 mol/kg) were found to show no perceivable increases in reservoir pressure or impacts to brine viscosity or density due to the dissolved CO_2.

- Dissolving CO_2 into produced water disposal streams creates a cash incentive through IRS Section 45Q tax credits. For permanent storage, the tax credit is currently $85/ton of CO_2 sequestered.

- CBI may be applied relatively quickly because no new wells need to be drilled. Regulatory considerations for CBI include the regulations surrounding above ground storage of the produced water on location and creating a path to approval under Class II injection wells.

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For more information, please see the published report:

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Appendix - Kinetic Rates

Minerals	k (mol/cm^2·s)	E (J/mol)	Reference
Quartz	1.00E-16	87,500	(Rimstidt and Barnes, 1980)
Muscovite	2.00E-16	64,000	(Nagy, 1995)
Siderite	2.00E-11	55,000	Set to dolomite
Barite	1.26E-12	30,800	(Palandri and Kharaka, 2004)
Calcite	1.58E-10	63,000	(Plummer et al., 1978)
Dolomite	2.00E-11	55,000	(Busenberg and Plummer, 1982)
Witherite	4.47E-12	41,900	Set to strontianite (Sonderegger et al., 1976)
Kaolinite	3.98E-16	64,000	(Sverdrup, 1990)
Dawsonite	1.00E-11	62,800	(Palandri and Kharaka, 2004)
Magnesite	4.57E-14	23,500	(Palandri and Kharaka, 2004)
Aragonite	1.58E-10	63,000	Set to calcite
Huntite	2.00E-11	55,000	Set to dolomite
Monohydrocalcite	1.58E-10	63,000	Set to calcite
Maximum Microcline	1.26E-15	58,000	Set to K-feldspar
K-feldspar	1.26E-15	58,000	(Helgeson et al., 1984)