Coupled Wellbore-Reservoir Modeling to Evaluate CO_2 Injection Rate Distribution over Thick Multi-Layer Storage Zones

Mohamed Abdelaal and Mehdi Zeidouni
Craft & Hawkins Department of Petroleum Engineering,
Louisiana State University

SECARB Offshore - GoMCarb Gulf of Mexico Annual Joint Partnership Meeting
April 5 – 7, 2023

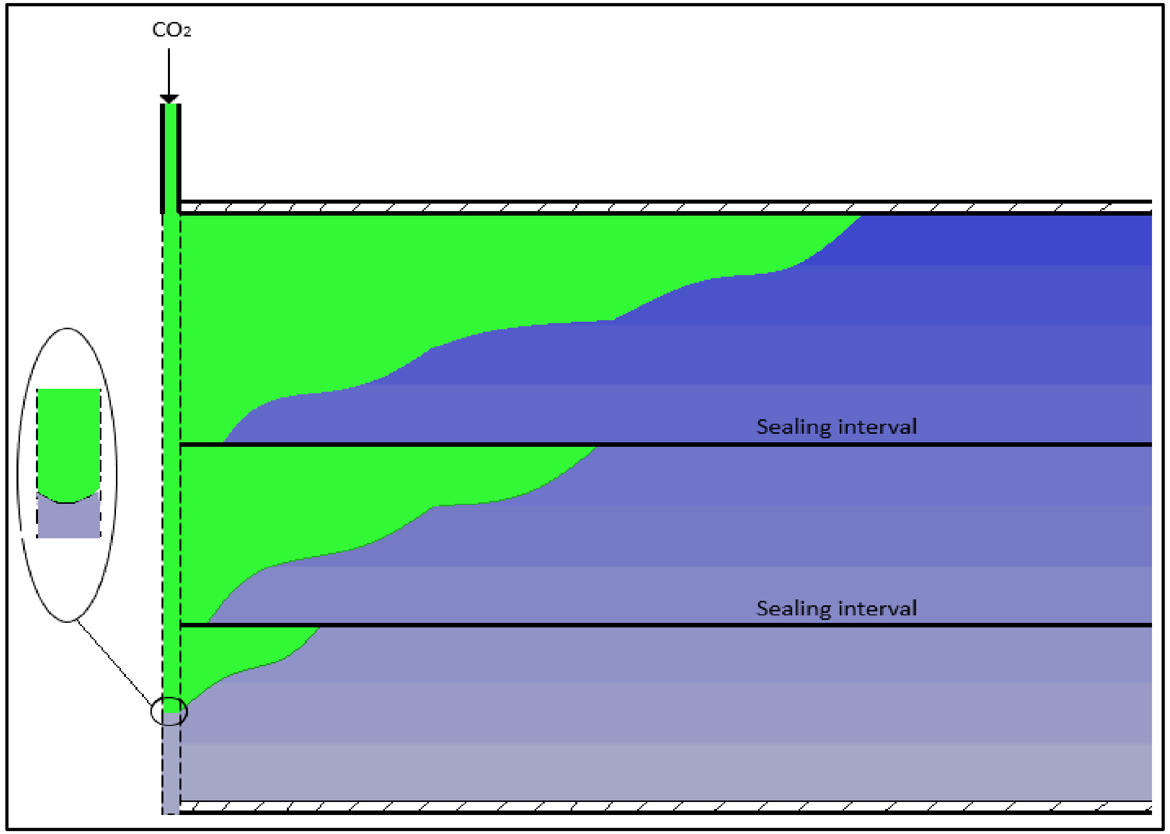
Objectives

Investigation of CO_2 flow rate distribution

- For CO_2 injection through a fully-penetrating vertical well, CO_2 would be unevenly distributed over the aquifer thickness.

- This would underutilize the pore space available to store CO_2.

- In this work, we use coupled wellbore-reservoir modeling to investigate the interplay between the parameters and physical processes and their net effect of the flux distribution.



A schematic illustration (not to scale) of CO_2 injection via a fully-penetrating vertical well in a multi-layer infinite-acting thick aquifer. Dark to light blue colors respectively indicate higher to lower layer flow capacity (Abdelaal and Zeidouni, Under Review)

Background

Physical processes/parameters controlling CO_2 flux distribution

Movement of CO_2/brine interface

CO_2 will not flow through a perforation until the interface level moves below its level.

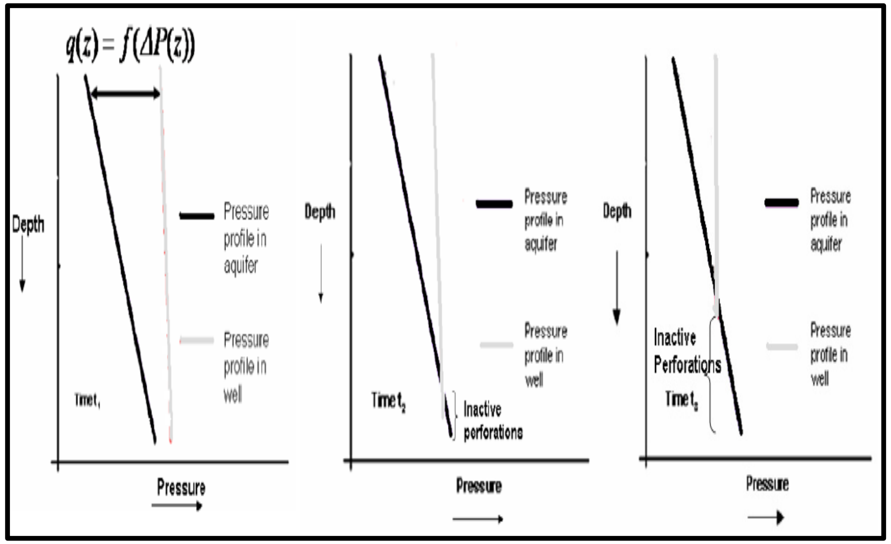
Ennis-king et al., 2018

Heterogeneity in flow capacity

Layers with higher flow capacities take more CO_2

Wen and Benson, 2019;
Boon et al., 2022;
Shao et al., 2022

Pressure difference between the wellbore and the aquifer



A schematic pressure profile in the well and the aquifer along the well length at three different times (Kumar and Bryant., 2009)

Gravity/buoyancy override

$$\Gamma = \frac{2\pi k(\rho_a - \rho_g) g H^2 \cos\alpha}{\mu_g q}$$

Change in the average fluid mobility within layers

$$M_{eff} \propto r_{dry}$$

Model Description and Approach

Simulation Model Setup

- The physical system is simulated using a two-dimensional radial axisymmetric model is generated using CMG-STARS (2021).
- The reservoir model is coupled with FlexWell CMG-STARS wellbore model to simulate the complex wellbore physics which cannot be modelled using sink/source wells.
- Relative permeability data are generated using Corey's equations.
- Pressure-volume-temperature (PVT) properties of CO_2 and brine are generated using Peng-Robinson equation-of-state.
- The capillary pressure curve is generated using van Genutchen formulation.

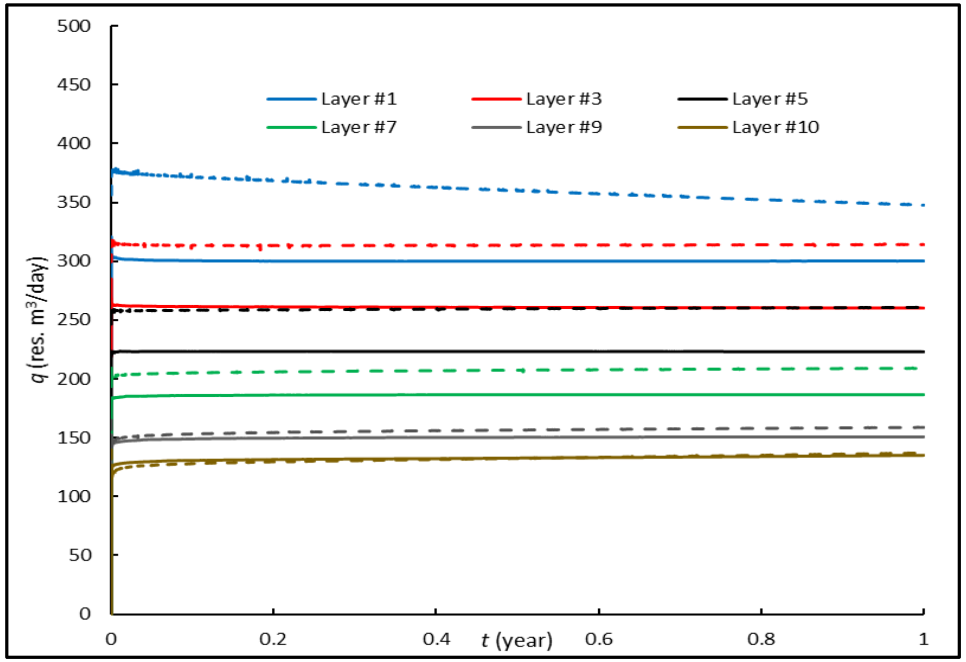
Fluid and rock properties used for the base case

Property	Value
Reservoir properties	
Aquifer radial extent (km)	50
Thickness (m)	100
Depth to top (km)	2.0
Reference depth (km)	2.0
Pressure at reference depth (MPa)	20.1
Number of layers	10
Number of grids (radial × angular × vertical)	500 × 1 × 10
Formation porosity (fraction)	0.2
Horizontal permeability (m^2)	2.5×10^{-13}
Outer boundary	Infinite-acting
Vertical permeability (m^2)	0
Dip angle (^{o})	0
Rock compressibility (1/kPa)	5.0×10^{-7}
FlexWell properties	
Well head injection temperature (^{o}C)	70.0
Well head injection pressure (kPa)	8500
Initial bottomhole pressure (MPa)	20.1
Injection rate (Mton/year)	0.50
Casing internal diameter (m)	0.20
Casing external diameter (m)	0.22
Tubing internal diameter (m)	0.10
Tubing external diameter (m)	0.11

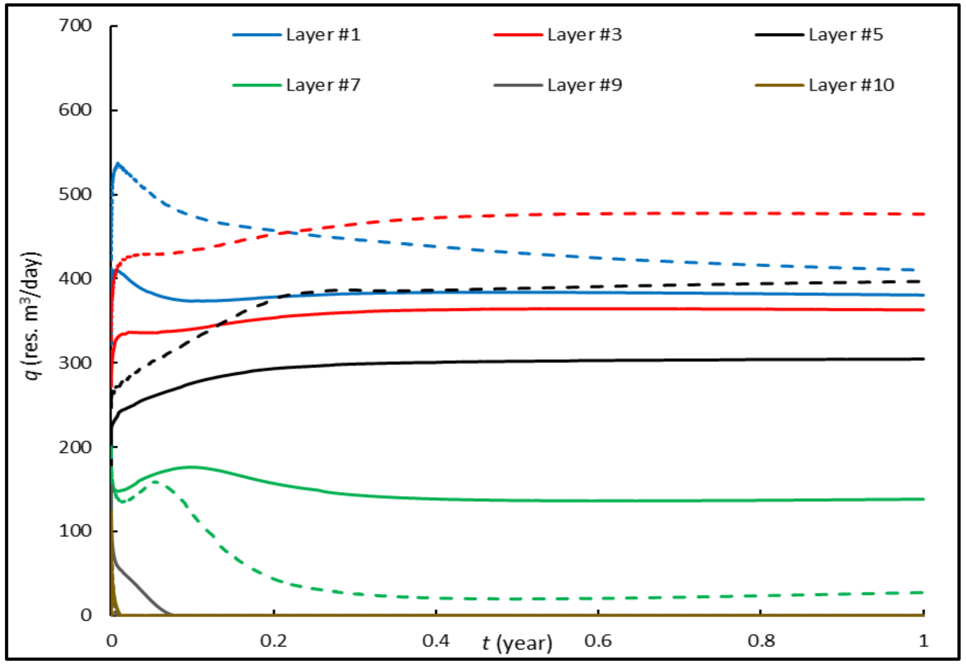
Model Description and Approach

Why coupled wellbore-reservoir modeling vs sink well injection?

- As will be shown later, there are *moderate-to-significant deviations* in the magnitudes of flow rates obtained from the coupled wellbore-reservoir model and the sink-well model.



The flow rate distribution profile for the base case (gravity muted). Solid lines for the coupled wellbore-reservoir model, and dashed lines for the sink well injection (Abdelaal and Zeidouni, under review)



The flow rate distribution profile for case 4 (gravity considered). Solid lines for the coupled wellbore-reservoir model, and dashed lines for the sink well injection (Abdelaal and Zeidouni, under review)

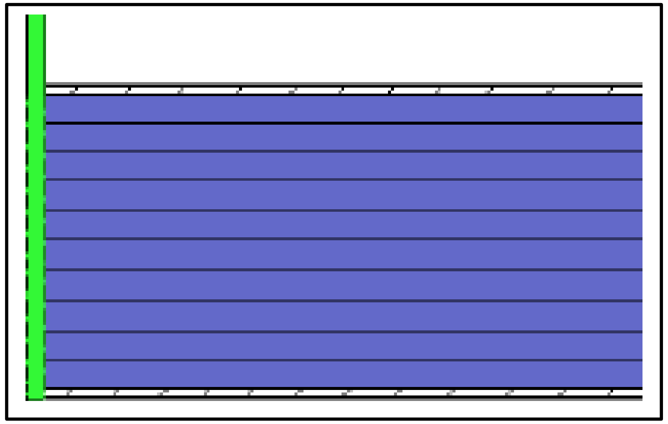
LSU

Results

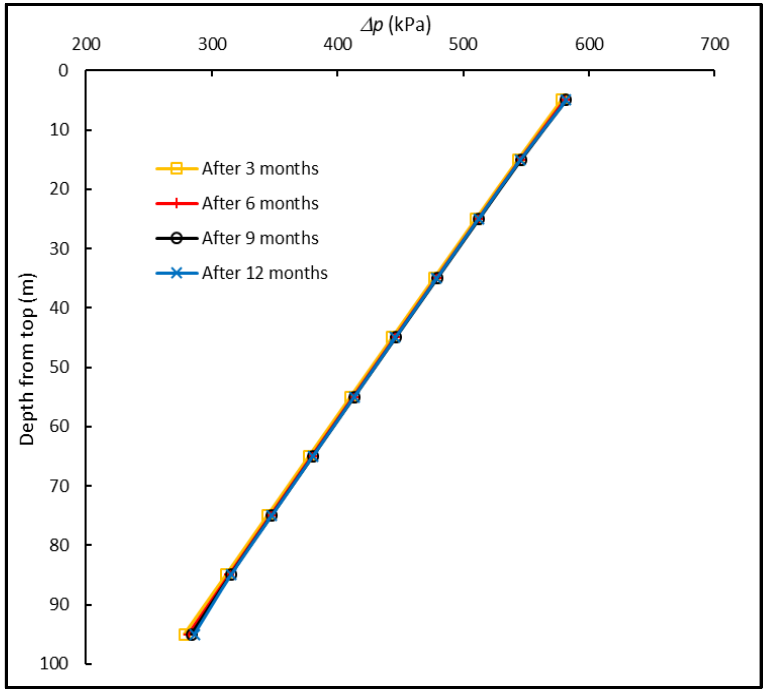
Effect of the difference in hydrostatic pressure gradients and change in average fluid mobility (Base case)

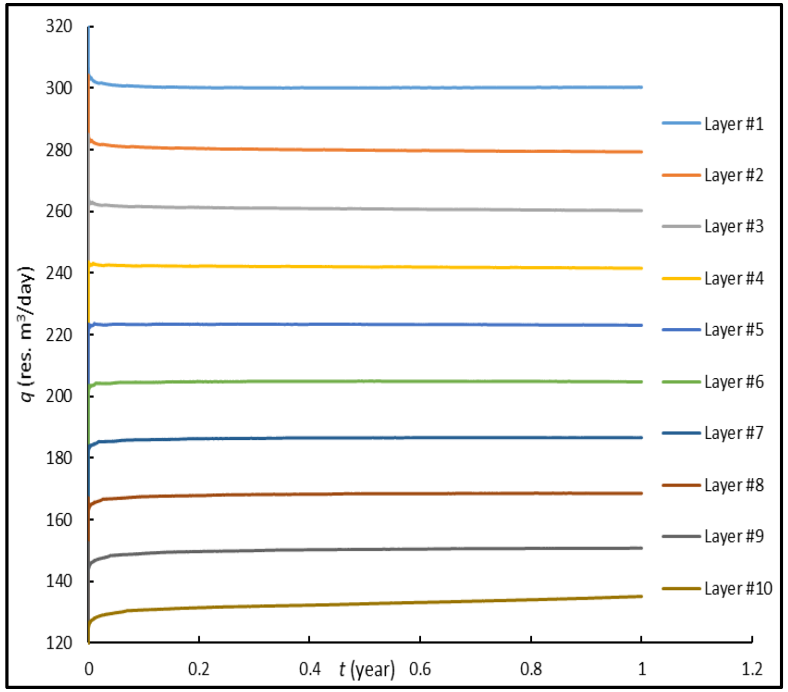
Model Setup

- Homogeneous reservoir.
- The vertical-to-horizontal permeability ratio is zero.
- The wellbore is initially filled with CO_2.



Schematic illustration of the simulation model (base case)





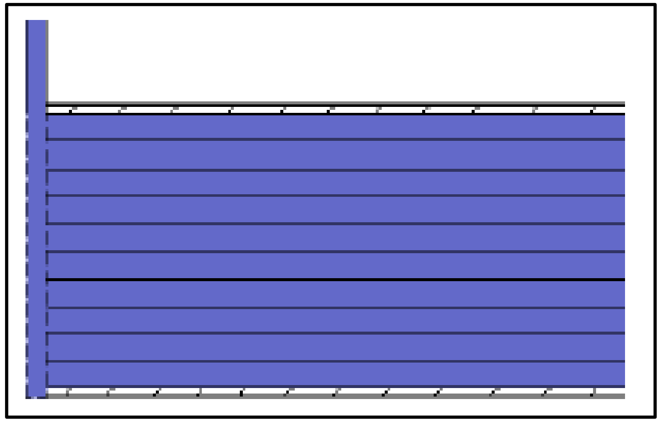
The profiles of pressure difference between the wellbore and the aquifer at different times (left) and the flow rate distribution profile along the injection interval (right) (Abdelaal and Zeidouni, under review)

Results

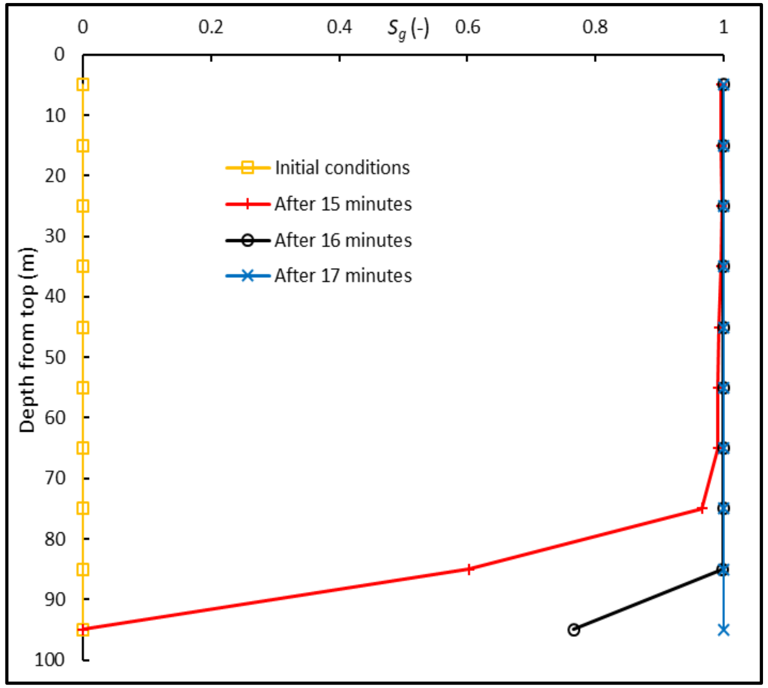
Effect of moving CO_2/brine interface within the wellbore (Case 2)

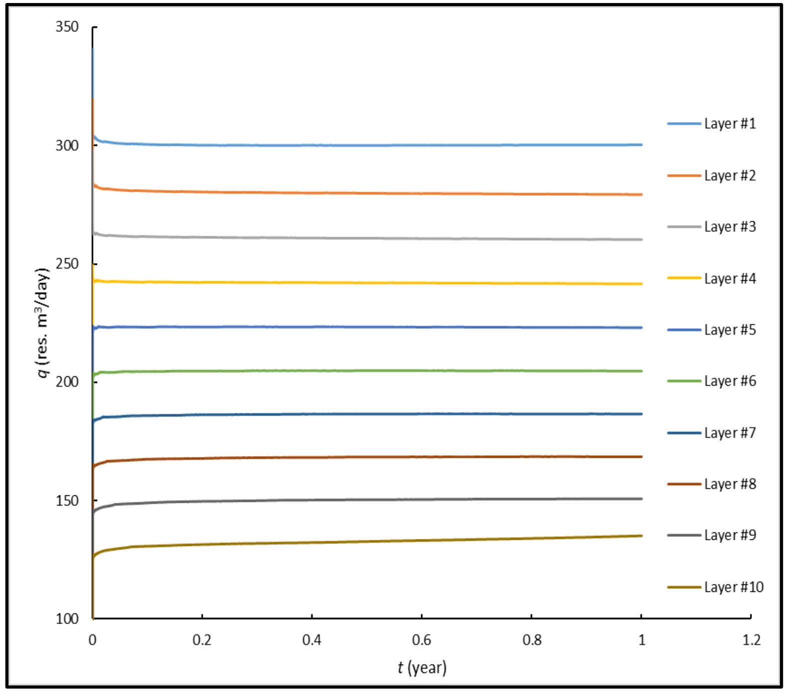
Model Setup

- Homogeneous reservoir.
- The vertical-to-horizontal permeability ratio is zero.
- The wellbore is initially filled with brine.



Schematic illustration of the simulation model (case 2)





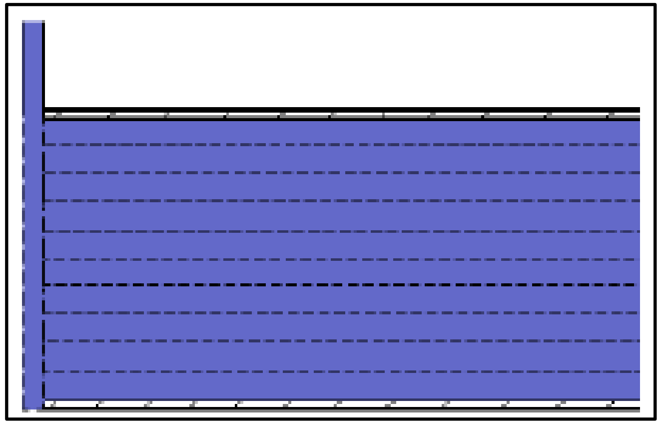
The profiles of saturation of CO_2 at different times within the wellbore (left) and the flow rate distribution profile along the injection interval (right) (Abdelaal and Zeidouni, under review)

Results

Effect of gravity/buoyancy override (Case 3)

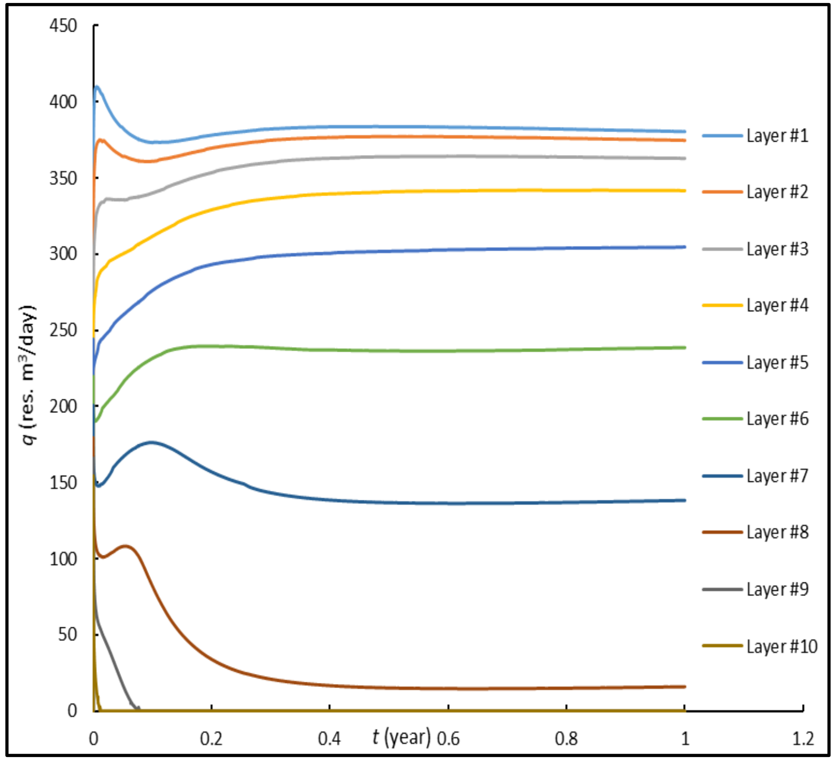
Model Setup

- Homogeneous reservoir.
- The vertical-to-horizontal permeability ratio is 1.0.
- The wellbore is initially filled with brine.



Schematic illustration of the simulation model (case 3)

- The flow is initially viscous driven controlled by the pressure difference behavior.
- Therefore, the flow is highest at top layers and lowest at bottom (like previous case).
- However, unlike the previous cases, differences between the rates are higher, and the rates eventually decline to 0 for layers #9 and #10 within 4 and 28 days.
- This is due to the gravity-driven displacement which follows the initial viscous-driven period.



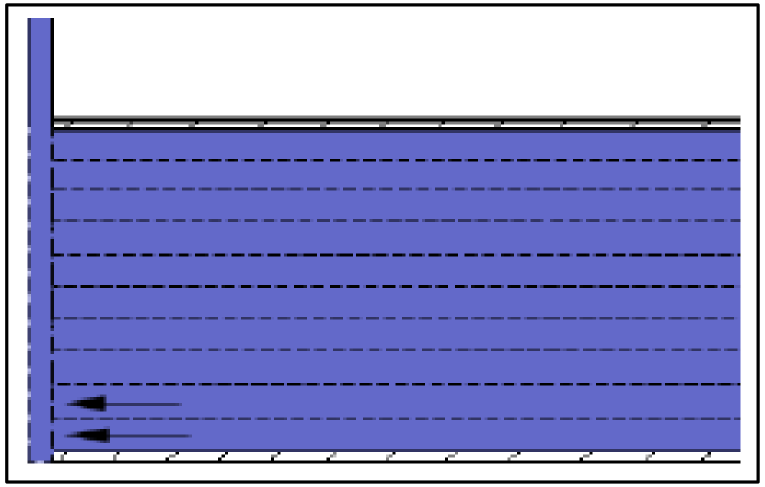
The flow rate distribution profile along the injection interval for case 3 (Abdelaal and Zeidouni, under review)

Results

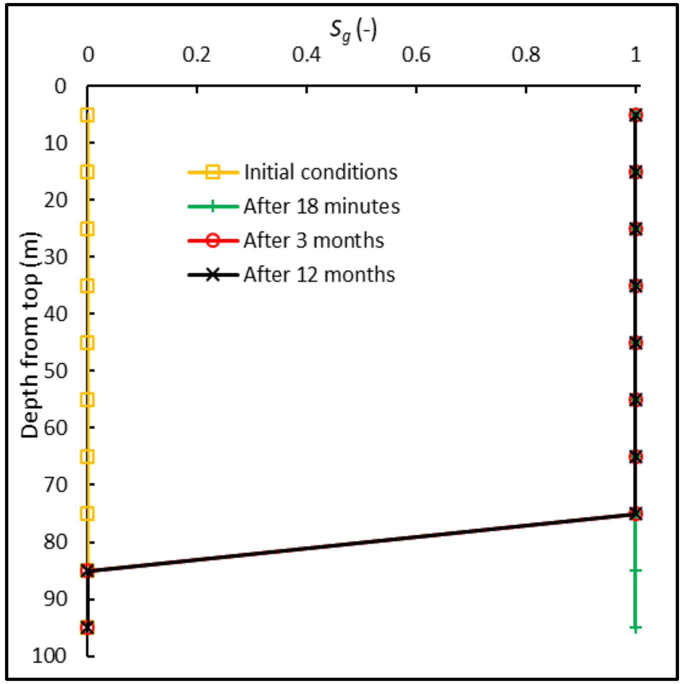
Effect of backflow of brine to the wellbore (Case 4)

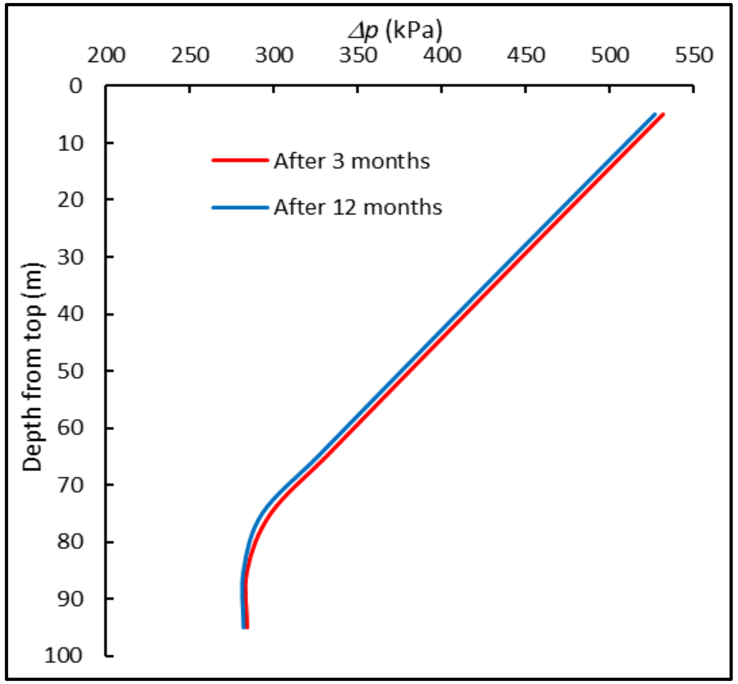
Model Setup

- Homogeneous reservoir.
- The vertical-to-horizontal permeability ratio is 1.0.
- The wellbore is initially filled with brine.
- Backflow of brine is included.



Schematic illustration of the simulation model (case 4)



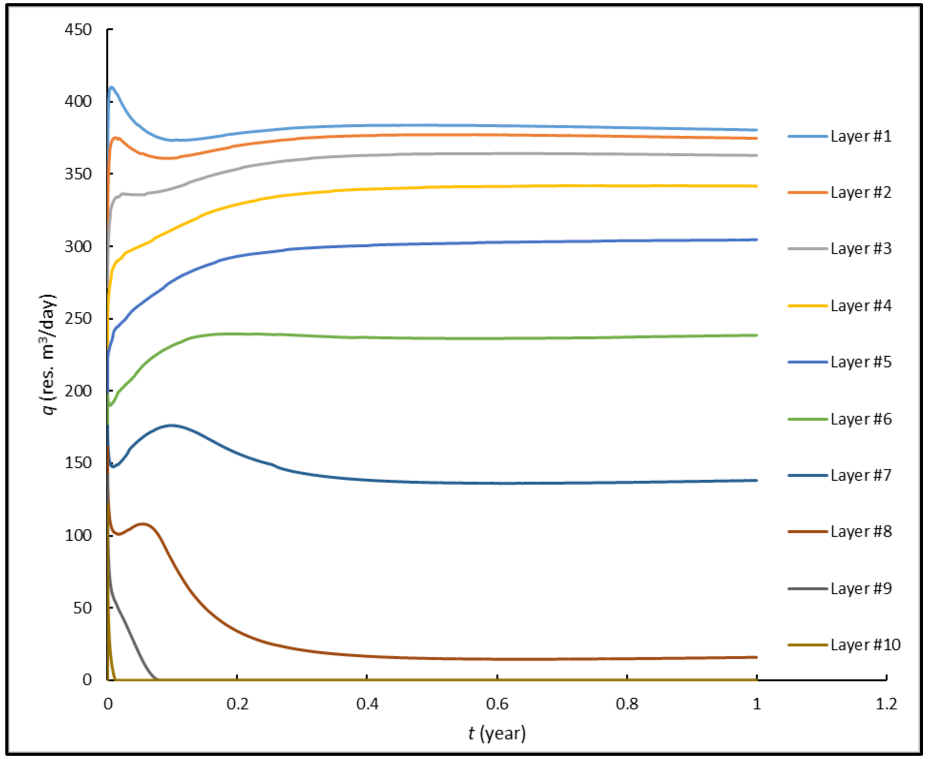


The profiles for case 4 of the pressure difference between the wellbore and the aquifer at different times (left) and CO_2 saturation at different times within the wellbore (right) (Abdelaal and Zeidouni, under review)

Results

Effect of backflow of brine to the wellbore (Case 4) – Cont’d

- By comparison with the results of case 3, backflow of brine has insignificant effect on the flow rate distribution.
- In reality, brine backflow increases the salinity around the wellbore because it redissolves the already precipitated salt next to the wellbore.
- Consequently, the drying out process following shut-in will increase amount of salt precipitation which further lowers the permeability in the near wellbore region, and negatively affects the flow rates into the layers experienced backflow.
- Proper modeling of this process requires further investigation of how salinity varies around the wellbore which warrants separate study.



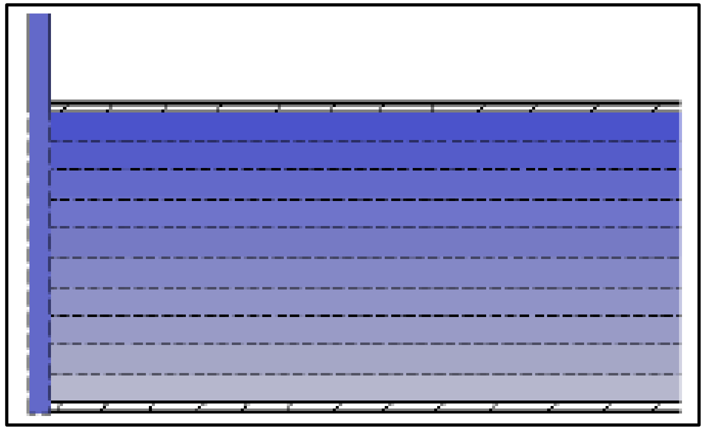
The flow rate distribution profile along the injection interval for case 4 (Abdelaal and Zeidouni, under review)

Results

Effect of individual layer flow capacity (Case 5)

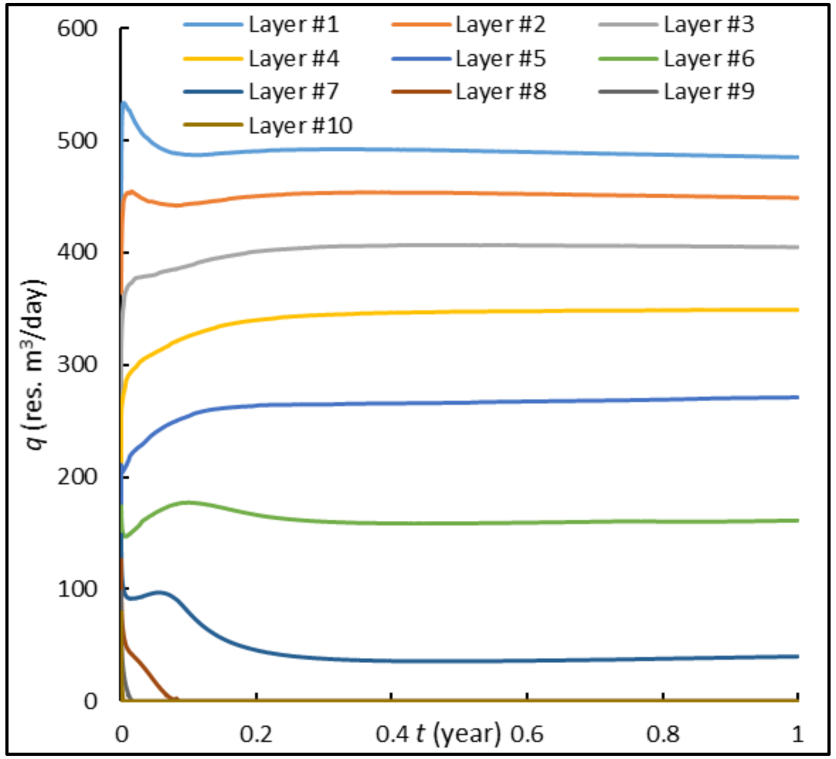
Model Setup

- Vertically heterogeneous reservoir.
- The vertical-to-horizontal permeability ratio is 1.0.
- The wellbore is initially filled with brine.



Schematic illustration of the simulation model (case 5)

- The rate behavior is similar to that of case 3 except that the span of flow rates is higher.
- This is because of the descending flow capacities which amplifies the gravity effect.
- More importantly, the flow through the bottommost two perforations successively declines to 0 faster.



The flow rate distribution profile along the injection interval for case 5, descending-order flow capacities (Abdelaal and Zeidouni, under review)

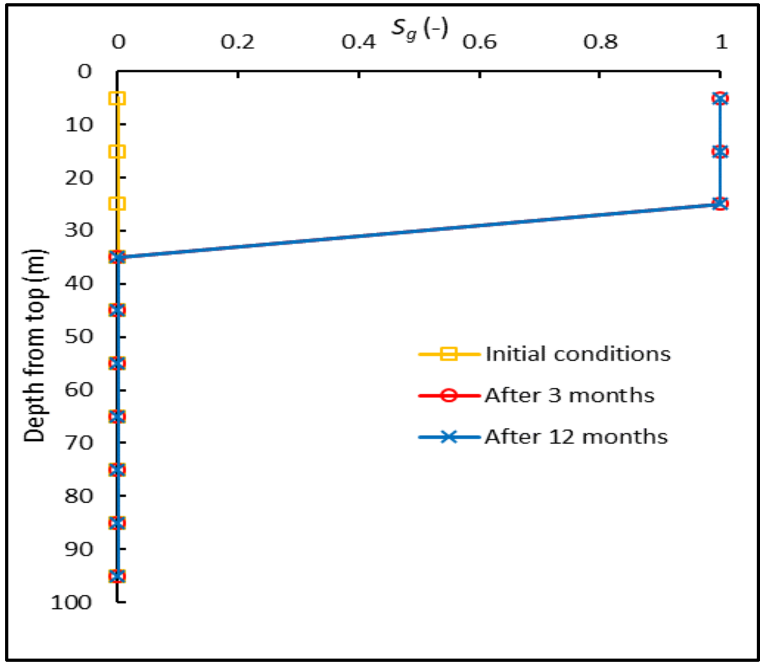
Additional Investigations

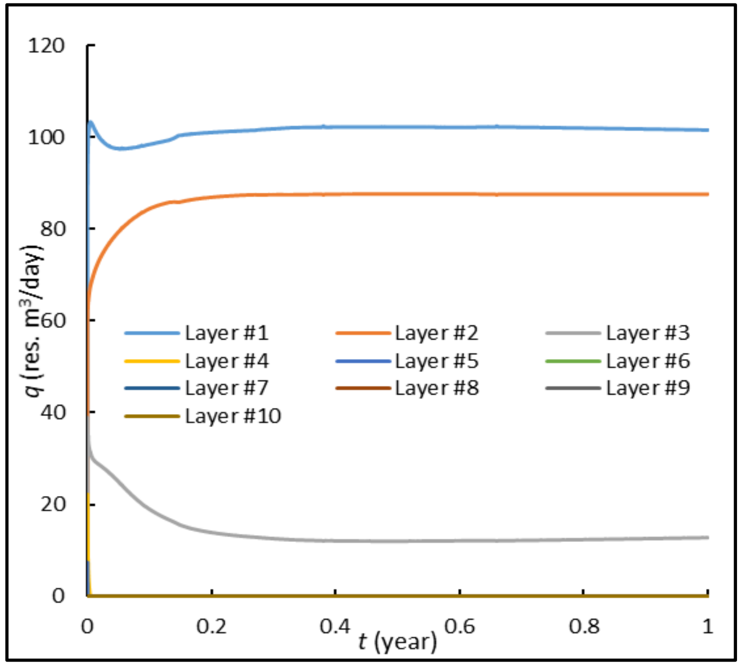
Effect of CO_2 injection rate

Model Setup

- Case 4 except that the injection rate is reduced by 10 times (i.e. to 0.05 Mton/year).

- Due to the low injection rate, CO_2/brine interface stabilizes at 35-m level within the wellbore as compared to the 85-m level for case 4.
- Consequently, only the upper 4 perforations contribute to injection over the whole injection period.





The profiles of CO_2 saturation at different times within the wellbore (left) and flow rate distribution between layers applied to case 4 with reduced injection rate of 0.05 Mton/year rate (right) (Abdelaal and Zeidouni, under review)

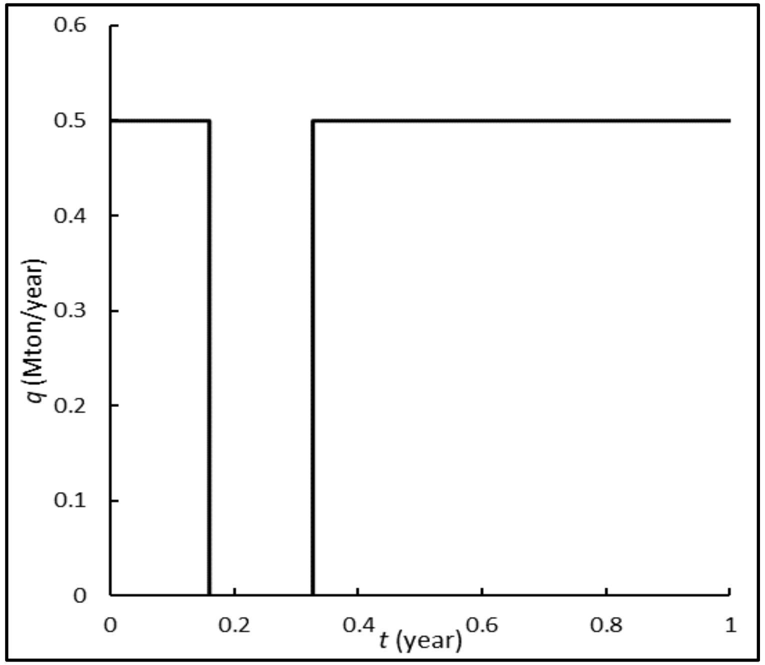
Additional Investigations

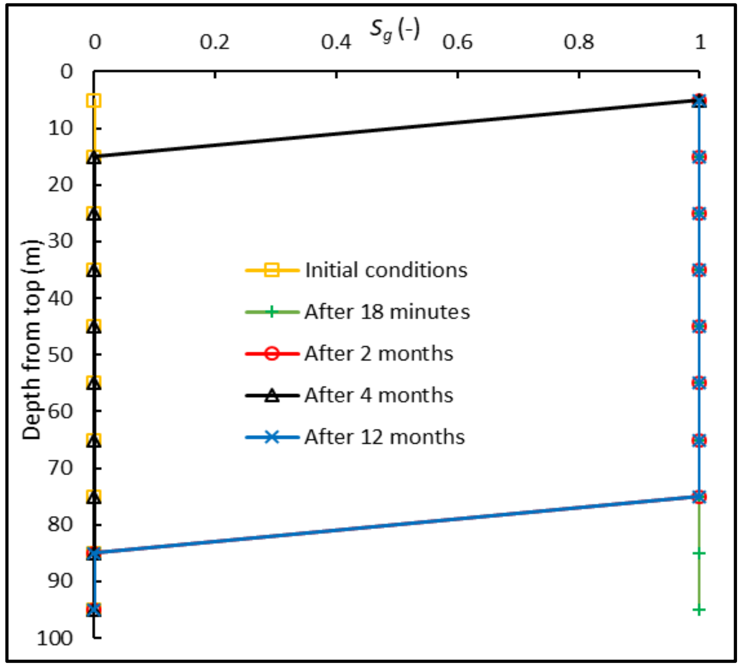
Effect of intermittent CO_2 injection

Model Setup

- Case 4 except that a shut-in for 2 months follows an initial flow period of the same duration.

- CO_2 completely saturates the wellbore within 18 minutes.
- Then, due to backflow, CO_2/brine interface rises up to the 85-m level by end of the initial flow period.
- The interface rises up-to the 15-m level by end of the shut-in period.
- Then, it stabilizes again at the 85-m level during the latter flow period.





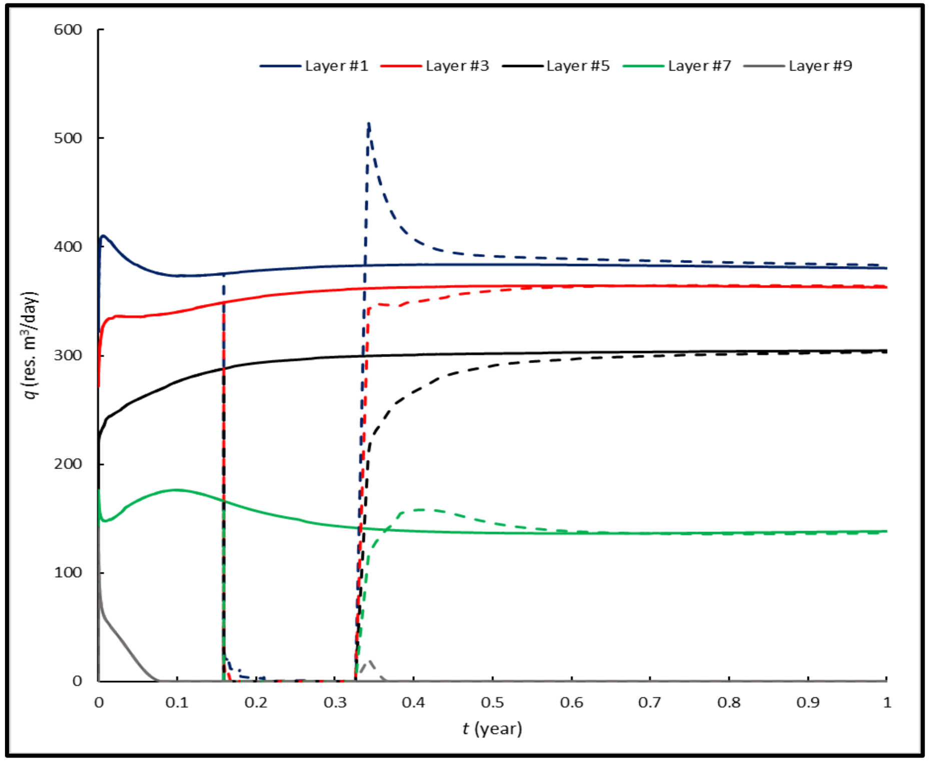
The profiles for case 4 with shut-in of injection rate history (left) and CO2 saturation at different times within the wellbore (right) (Abdelaal and Zeidouni, under review)

LSU

Additional Investigations

Effect of intermittent injection – Cont'd

- The interface stabilization during the latter flow period occurs within few minutes.
- This means that despite the noticeable effect of backflow on wellbore filling with brine during shut-in, it should have insignificant effect on the flow rate distribution.
- Beyond the transient period which last for few days, both profiles overlap each other.



Comparison of the flow rate distribution between layers between cases 4 and 4 with shut-in (Abdelaal and Zeidouni, under review)

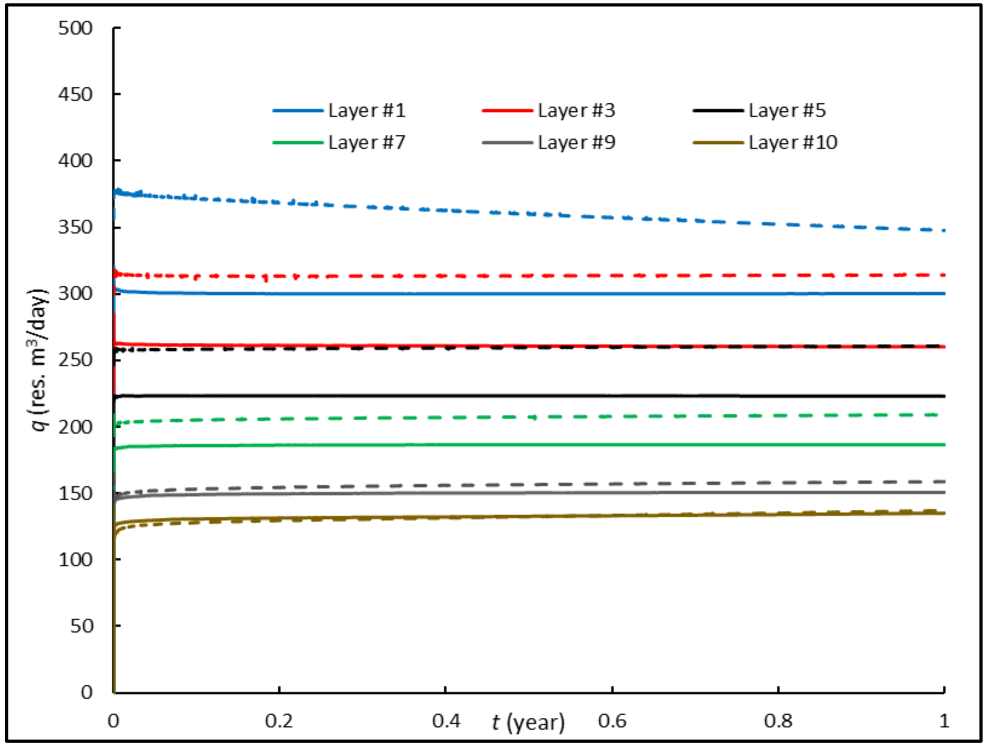
Additional Investigations

Effect of decoupled wellbore-reservoir modeling

- The deviation is slight-to-moderate in situations where gravity force is negligible (e.g. due to very low kvh) and viscous force is very strong (e.g. due to very high injection rate).

- Such conditions would allow for the rate distributions, obtained using coupled and decoupled models, to agree or slightly deviate due to:

  - the faster establishment of the steady-state flow behavior within the wellbore, and
  - the minimal effect of phase segregation.

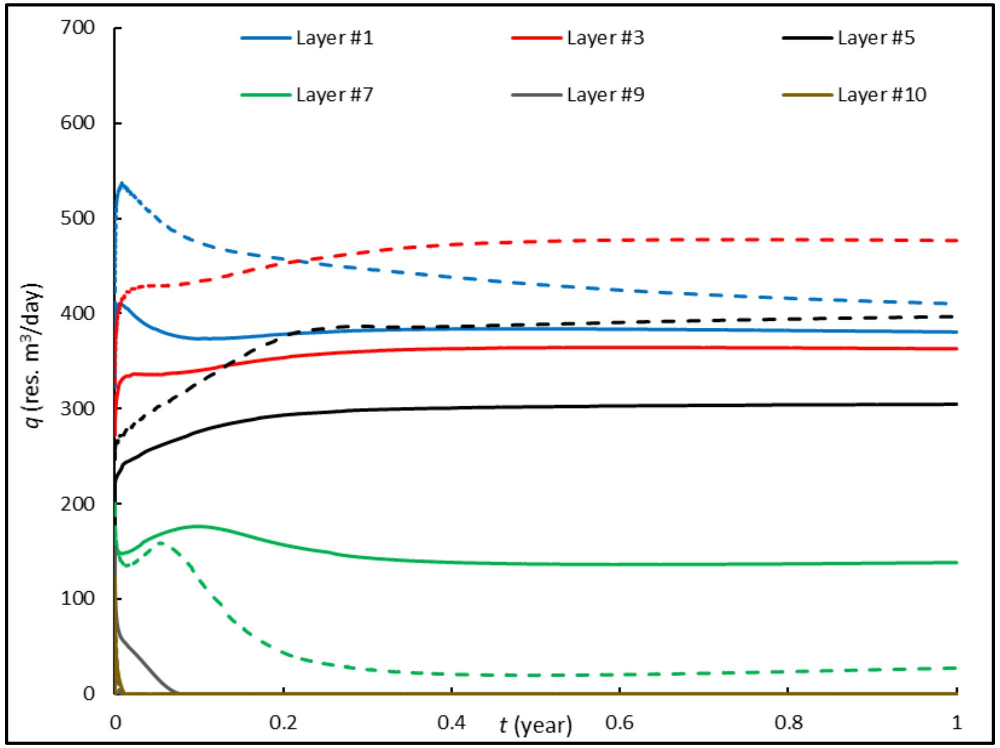


The flow rate distribution profile for the base case. Solid lines for the coupled wellbore-reservoir model, and dashed lines for the sink well injection (Abdelaal and Zeidouni, under review)

Additional Investigations

Effect of decoupled wellbore-reservoir modeling – Cont'd

- Conversely, the deviations could be significant when more complex cases - that involve more physical processes - are modeled using sink/source wells.
- For instance, deviations arising from neglecting some wellbore physics (e.g. wellbore storativity, mass accumulation, and phase segregation) can be exaggerated in conditions where gravity force is dominating that the transient flow behavior within the wellbore plays a important role.



The flow rate distribution profile for case 4. Solid lines for the coupled wellbore-reservoir model, and dashed lines for the sink well injection (Abdelaal and Zeidouni, under review)

Conclusions

- Movement of CO_2/brine interface is found to have insignificant effect on flow rate distribution.
- When buoyancy is insignificant, the flow rate distribution is controlled by (a) the pressure difference and (b) flow capacity.
- The pressure difference generally permits higher rates into the shallower layers as compared to the deeper ones. Nevertheless, its effect can be muted if higher flow capacity layers are at shallower depths.
- When buoyancy is significant, the early-time viscous-dominant flow quickly turns into gravity-dominant flow making preferential CO_2 flow into the upper layers.
- Strong buoyancy can result in underutilizing the bottom layers while possibly completely shutting off some bottom perforations.
- For elongated shut-in periods, brine backflow can introduce higher salinities around the wellbore, and therefore, cause higher permeability reductions due to additional salt dry-out.
- Decoupled wellbore-reservoir modelling can cause deviations in reproducing the results of the coupled model.

Questions?