A model to estimate CO_2 injectivity and storage capacity for geological sequestration in shale gas wells

Subsurface Hydrology RESEARCH GROUP

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CMI CARBON MITIGATION INITIATIVE

Introduction

- Recent studies have suggested the possibility of CO_2 sequestration and/or enhanced gas recovery in depleted shale gas formations [1-4].
- Favorable characteristics include preferential adsorption of CO_2 over CH_4 in the rocks and potentially large accessible pore space through shale gas wells.
- Storage capacity estimates include: 10 – 18 Gt in the Marcellus Shale by 2030 [2]; 55 Gt total technically accessible capacity in the Marcellus [3]; 28 Gt in the Devonian shales underlying Kentucky [4].
- Questions remain regarding the dynamics and practicality of injecting such large amounts of CO_2 into shale gas wells.
- **This work**: Developed a well-scale model of gas flow in a shale reservoir capturing the most important physical processes for CO_2 injection. Investigated transient injection rates and capacity for individual wells and their implications.

Shale Reservoir Model

- Barnett Shale natural gas production data from 8,284 wells has been shown to fit very well to the solution of a one-dimensional diffusion equation in a finite domain [5]. The implied model system geometry is shown in Figure 1.

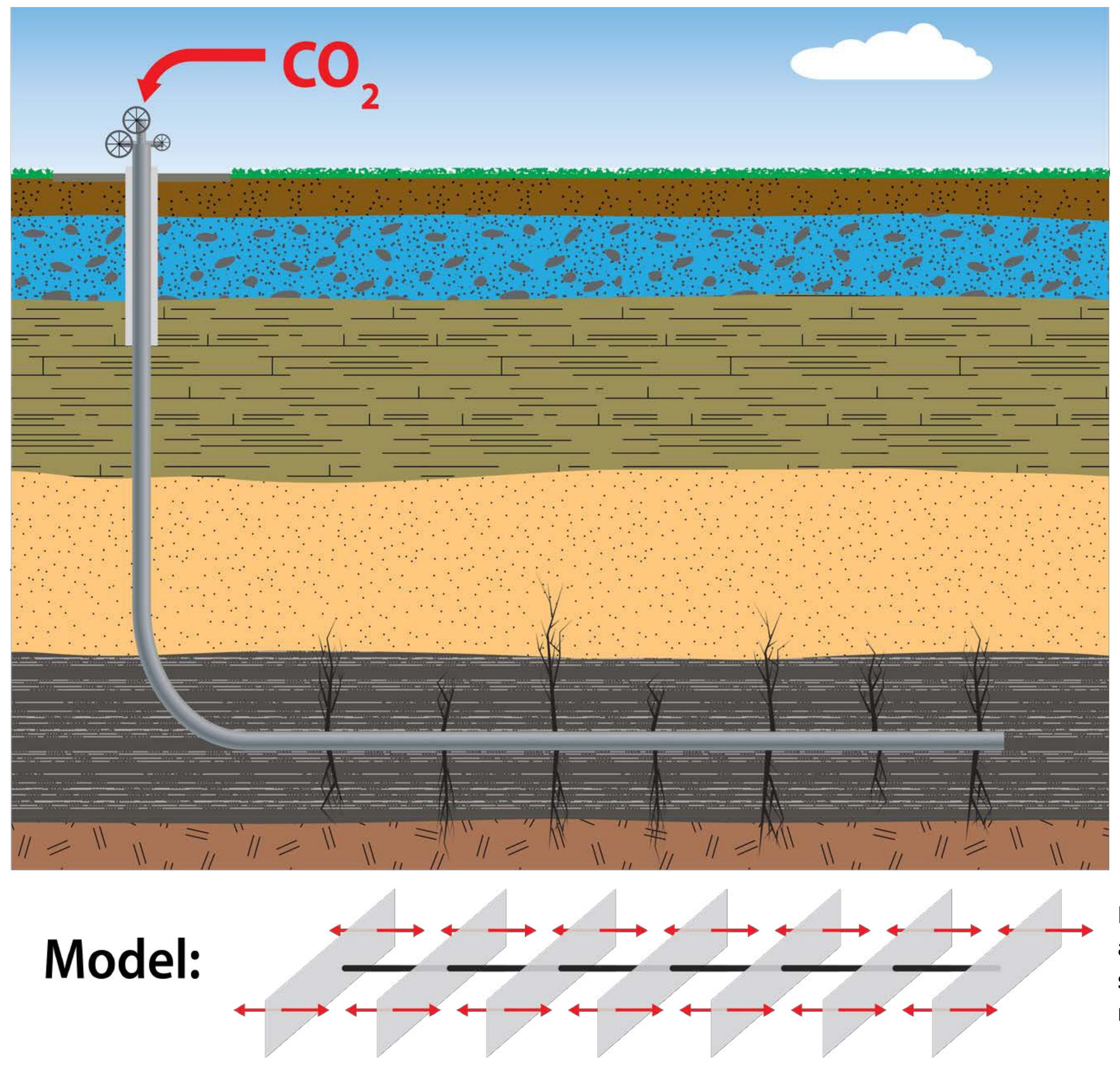

Figure 1 – Illustration of a typical horizontal shale well and model representation.

- We extend the model to a two-component model (CO_2 and CH_4) to represent CO_2 injection into a depleted well:

$$\frac{\partial}{\partial t}\left[\phi S_g \rho^b(\omega_c,p) + \rho_c^a(\omega_c,p) + \rho_m^a(\omega_c,p)\right] - \frac{\partial}{\partial x}\left[\frac{\kappa\rho^b(\omega_c,p)}{\mu^b(\omega_c,p)}\frac{\partial p}{\partial x}\right] = 0$$

$$\frac{\partial}{\partial t}\left[\phi S_g \rho^b(\omega_c,p)\omega_c + \rho_c^a(\omega_c,p)\right] + \frac{\partial}{\partial x}\left[\rho^b(\omega_c,p)u^b\omega_c\right] - \frac{\partial}{\partial x}\left[\phi S_g \rho^b(\omega_c,p) D_c \frac{\partial \omega_c}{\partial x}\right] = 0$$

- Adsorption of CO_2 and CH_4 in shales is described well by Langmuir model [6,7]. Modeled adsorption using a modified two-component Langmuir equation:

$$\rho_c^a = \rho_c^{max}\frac{K_c p_c}{1 + K_c p_c + K_m p_m}\left(1 - \frac{\omega_c \rho^b(\omega_c,p)}{\omega_c^a(\omega_c,p)\rho_a}\right)$$

Parameter Selection & History Matching

- In order to determine appropriate reservoir parameters for CO_2 injection scenarios, the model was history-matched to natural gas production data.
- History-matched model to three separate shale gas regions: the Barnett Shale, southwest Pennsylvania (PA) Marcellus Shale, and northeast PA Marcellus Shale.
- Most parameters were either set to typical parameters obtained from literature or known from well data. Remaining parameters calibrated in history-match.
- Matched to averaged production data from 8,951 wells in the Barnett, 1,449 wells in southwest PA, and 2,516 wells in northeast PA [8].

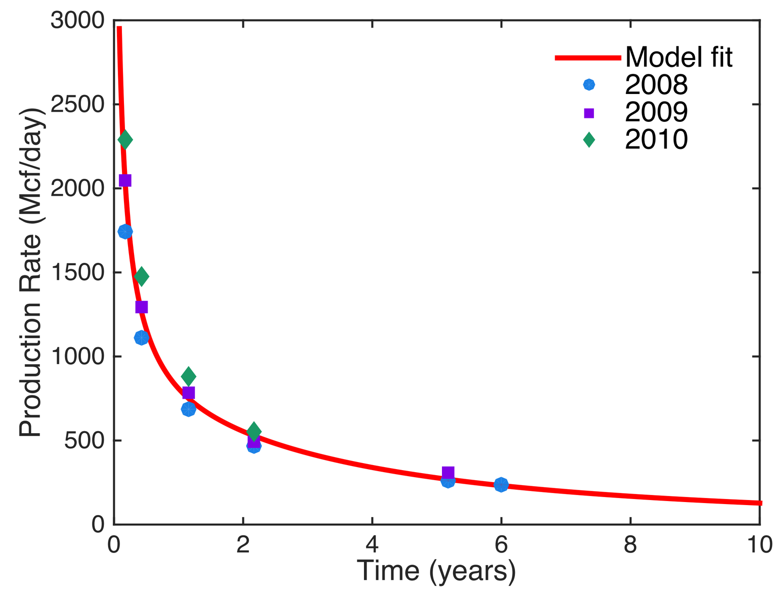

Figure 2 – Barnett Shale production rate model fit compared with averaged data for wells drilled in 2008-10

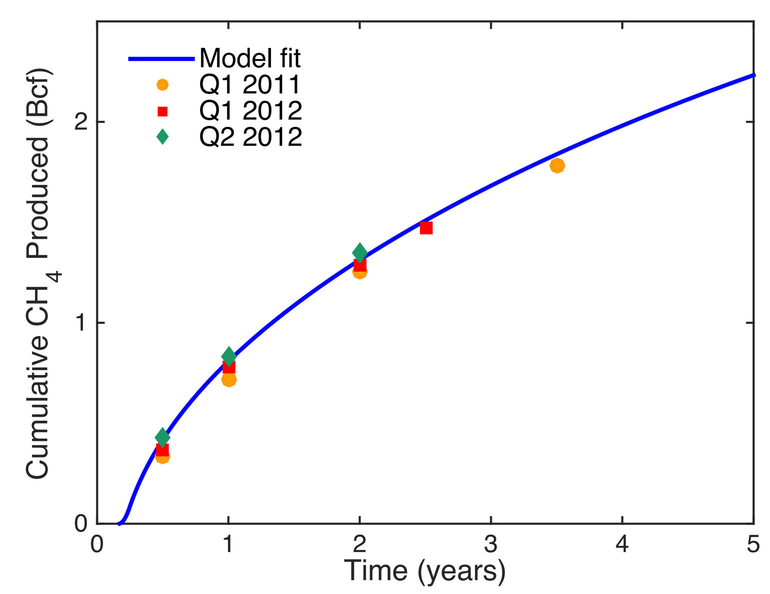

Figure 3 – Marcellus SW PA cumulative production model fit compared with averaged data for wells drilled 2011-12

Table 1 – Selected history-matched parameters for an average well in each region, used in CO_2 injection simulations

Region	Porosity (%)	Effective Permeability (nD)	Lateral Well Length (m)	Fracture Spacing (m)	Max. Injection Pressure (MPa)	Depleted Reservoir Pressure (MPa)
Barnett	6	45	872	30	25	3.5
Marcellus SW PA	6	25	1,556	30	35	3.5
Marcellus NE PA	6	20	1,675	30	35	3.5

Simulated CO_2 Injection Rates

- CO_2 injection simulations were performed using the history-matched reservoir parameters in constant-pressure and constant-rate injection scenarios.
- Maximum allowable injection pressure assumed to be equal to initial reservoir pressure to minimize risk of re-fracturing the rock.

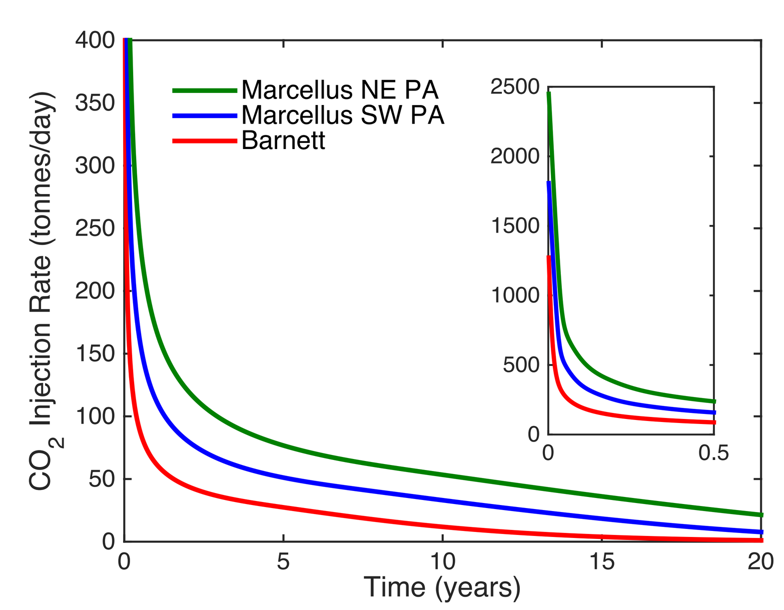

Figure 4 – Constant-pressure injection rate with time for an average well in each region.

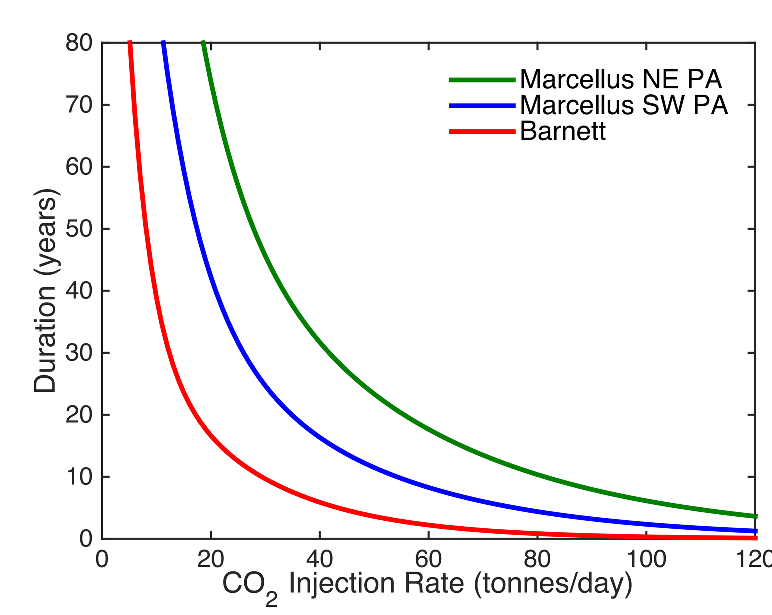

Figure 5 – Duration of constant-rate injection until max. injection pressure is exceeded, versus injection rate.

- Injection rates are very low compared with large industrial CO_2 sources (≈8,200 tonnes/day for a typical 500 MW coal power plant).
- Sequestration of example coal plant emissions for a 40-year period would require approx. 670 wells in the Barnett, 320 wells in SW PA, or 200 wells in NE PA.

CO_2 Storage Capacity Estimates

- Using model simulation results for CO_2 storage capacity of average individual wells in each region (Fig. 6), estimated total capacity of all existing and planned wells in each region (Table 2), and performed a case study of storage capacity for major emission sources in PA (Fig. 7).

Table 2 – Estimated total CO_2 storage capacity for each region and for current and future well inventories

Region	Barnett	SW PA	NE PA	Marcellus Total
Existing capacity (Gt) *(no. wells)*	1.9 – 2.9 *(15,279)*	0.5 – 0.7 *(1,731)*	1.3 – 1.8 *(2,801)*	1.9 – 2.6 *(4,845)*
Exist. & permitted capacity (Gt) *(no. wells)*	2.1 – 3.1 *(16,663)*	1.6 – 2.2 *(5,623)*	5.0 – 6.6 *(10,449)*	7.2 – 9.6 *(18,273)*
Godec Marcellus capacity (Gt) [3] (no. wells)				*55* (115,000)

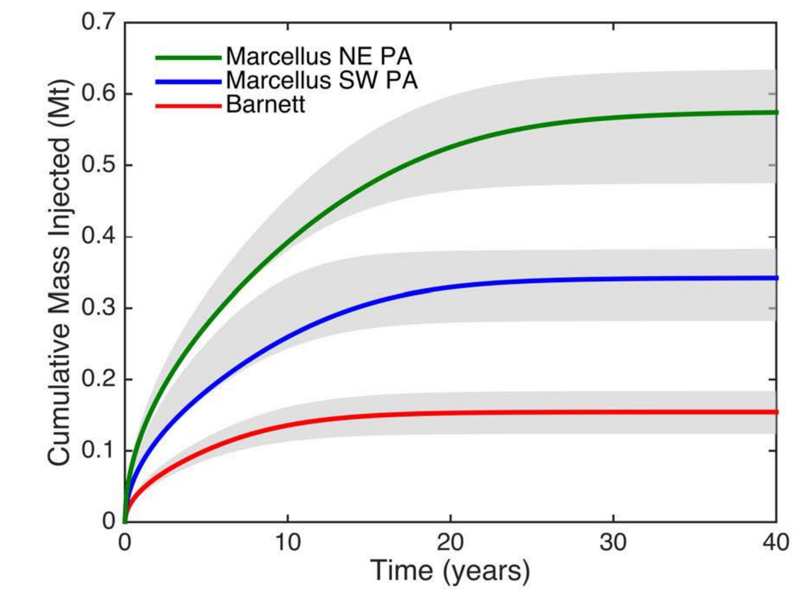

Figure 6 – Cumulative injected CO_2 with time for constant-pressure injection in an avg. well in each region

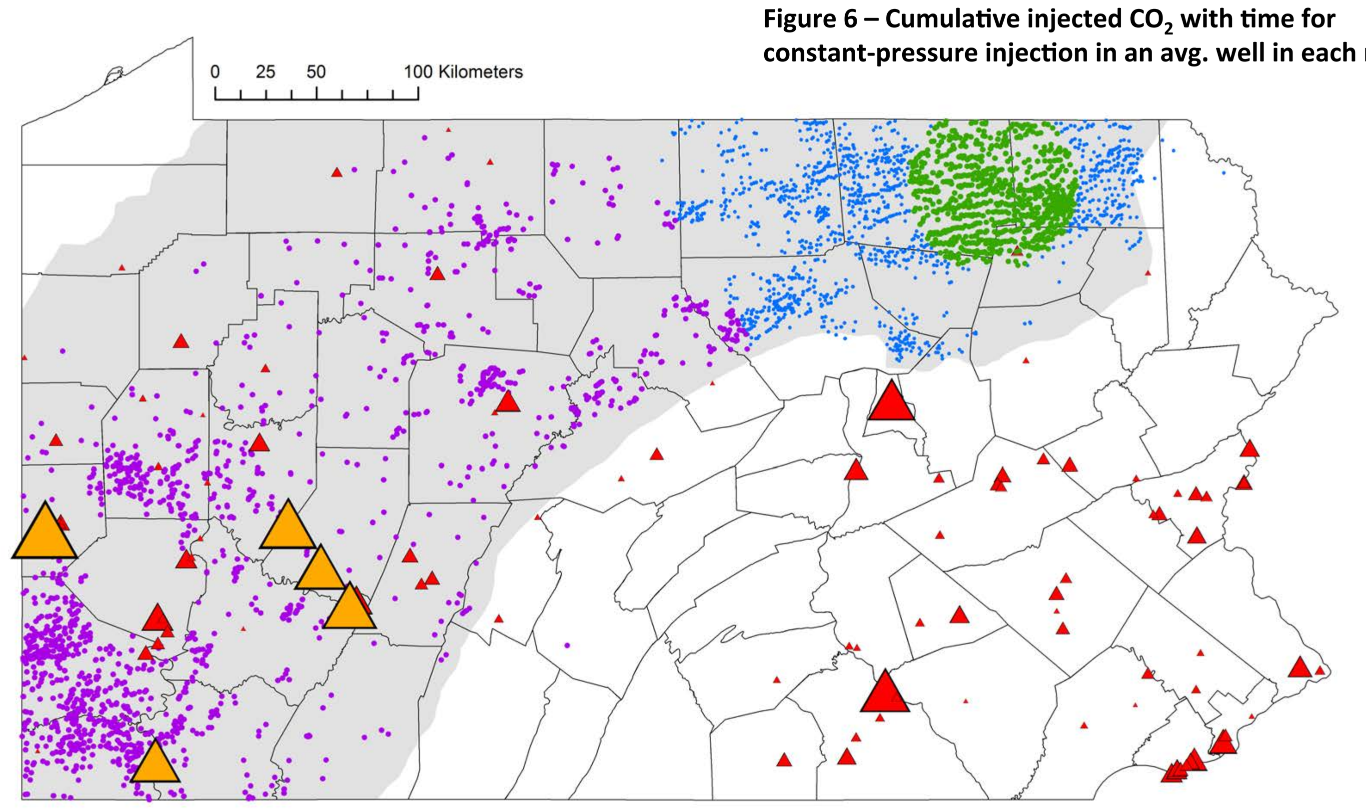

Figure 7 – Marcellus Shale wells required in SW PA (5,600: purple) or NE PA (3,500: green) to store 40 years of emissions from top 5 stationary CO_2 sources overlying Marcellus in PA (≈53 Mt/a: orange triangles, scaled to emissions)

Model Limitations

- Parameter uncertainty: adsorption parameters in particular have significant uncertainty, and future evolution of well design is uncertain.
- CO_2 adsorption-induced swelling may possibly cause a decrease in permeability, which is a significant issue in coals [9]. Not considered in the model as effect likely to be far smaller in shales due to lower organic content, although yet to be shown.

Implications & Further Issues

- Practical issues: wells not designed for CO_2 injection; 3-9% of wells already reported to have integrity issues [10,11]; leakage concerns due to hydraulic fracturing; wells required to be plugged after production completed.
- Although there may be substantial capacity, it will be practically difficult to access. Many wells would be required for sequestration from large industrial sources. Shale gas formations may be better suited for smaller, more local CO_2 sources.

References

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