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Carbon Dioxide Storage in a Natural Gas Reservoir under Strong Bottom Water Drive

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Abstract

Hydrocarbon storage for geologic time frames suggest that depleted hydrocarbon reservoirs offer a safe long-term option for carbon dioxide (CO_2) storage. Recovery efficiency for a conventional natural gas reservoir under strong water drive decreases as water influx traps the gas. This paper considers injecting CO_2 to mitigate water influx, thereby achieving enhanced gas recovery (EGR) and offering an attractive means for permanent storage of the injected CO_2 based on both technical and economic considerations.

Analytical and numerical model simulations explore how best to manage the EGR process to maximize both the natural gas recovery efficiency and the CO_2 storage capacity. In particular, simulations provide insights on where to place injection and production wells, on their geometry (vertical or horizontal) and completion interval locations, and on well operating conditions, to most effectively reduce coning or cresting tendencies, and minimize water production and gas trapping by water influx.

Depleted natural gas reservoirs offer ideal pore space for storage of CO_2 captured and transported from stationary CO_2 emission sources, but strong water drive conditions inhibit pressure depletion while the water influx traps the gas in its path toward producing wells. Aquifer water production following water breakthrough severely impairs continued gas production. Simulations demonstrate that CO_2 injection increases both natural gas recovery and CO_2 storage under these conditions. Interestingly, these reservoirs offer sufficient pore space to store about 50% more CO_2 than will be produced by combustion of the natural gas produced from the same pore space. In effect, CO_2 pressure support renders the produced gas as effectively carbon negative.

The main recommendation from this work is to inject CO_2 while producing natural gas instead of first producing the natural gas and then injecting CO_2, when the reservoir is subject to strong water drive

conditions. This simultaneously achieves significant EGR and enhanced CO_2 storage (ECS) in reservoirs that would otherwise offer low gas recovery.

Introduction

Carbon dioxide (CO_2) storage in conventional gas reservoirs has been proven an effective way of reducing the CO_2 concentration in the atmosphere. However, limited work has been done investigating the possibility of CO_2 storage in conventional gas reservoirs with strong water drive. Conventional gas reservoirs with strong water drive often yield low gas recovery factor, due to strong pressure support and produced water resulting in earlier well abandonment times compared to volumetric natural gas reservoirs.

In natural gas (NG) fields with strong bottom water drive developed using vertical producing wells, reservoir simulation studies by (McMullan and Bassiouni 2000) showed that increasing the gas production rate improves the gas recovery factor. The simulations showed that although higher production rate causes induced water coning and earlier water breakthrough, the high gas mobility results in low water gas ratio after water breakthrough, and that higher production rate is never detrimental to overall production. They also showed that, in contrast to conventional wisdom, increasing the perforation interval length also does not detrimentally impact the ultimate gas recovery, and that completing vertical wells with a reduced perforation interval length far from the gas water contact is detrimental. In contrast, (Sech et al. 2007) modeled horizontal well production in gas fields with confined strong bottom aquifer, and showed that the ultimate gas recovery decreases with increasing production rate because water production after water breakthrough liquid loads the well and stops gas production.

(Hatzignatiou and Ehlig-Economides 2022) coupled CO_2 injection with methane production including reinjection of produced CO_2 after breakthrough and found that this approach achieved both enhanced gas recovery (EGR) and carbon dioxide (CO_2) storage. This work showed that using horizontal CO_2 injection and methane production wells achieved a recovery factor up to 85% can be achieved by continuing until the produced CO_2 more percentage reached 50% in the produced gas stream while maintaining constant gas production rate and reinjecting all produced CO_2 back into the reservoir.

This work offers a new approach for completing and operating vertical and horizontal gas wells in a NG field with a strong bottom water drive, using a similar approach introduced by (Hatzignatiou and Ehlig-Economides 2022) to model gas production in the presence of a strong bottom aquifer, i.e., producing the natural gas while injecting CO_2 into the same formation. Considering the typical reduced recovery factors in this type of gas reservoirs, the proposed approach shows much more significant EGR than the one seen by (Hatzignatiou and Ehlig-Economides 2022) in volumetric reservoirs, again while storing CO_2.

Modeling Methods

This section describes analytical models used to guide well management, completion, and drainage geometries to model with numerical simulation. We then describe new numerical simulation strategies that enable modeling under strong bottom water drive.

Analytical models

“All models are wrong but some are useful (Box 2007). Analytical models enable quick calculations that can provide insight on production well performance. For a well producing a drainage volume with constant thickness and rectangular drainage area without water influx, the behaviors may include the following:

- Time, t_{TBF}, required for a well to reach boundary dominated flow

$$t_{BDF} = \frac{379.2kA}{\emptyset\mu c_t}$$

for k bedding plane permeability in md, A well drainage area in ft^2, μ NG viscosity in cp, and c_t total compressibility (can be approximated by the NG compressibility c_g) in psi^{-1},

- Effective skin imposed by partially completing a vertical well over a limited perforated interval (Wells and Papatzacos 1987)

$$s_c = \left(\frac{1}{h_{wD}} - 1\right) ln\frac{\pi}{2r_{wD}} + \frac{1}{h_{wD}} ln\left[\frac{h_{wD}}{2 + h_{wD}}\left(\frac{A-1}{B-1}\right)^{1/2}\right]$$

where $A = 1/(h_{1D} + h_{wD}/4)$, $B = 1/(h_{1D} + 3h_{wD}/4)$, and $h_{wD} = h_w/h, h_{1D} = h_1/h$, and $r_{wD} = \frac{r_w}{h}\left(\frac{k_v}{k_r}\right)^{1/2}$ with h denoting the gas formation thickness in ft and r_w the wellbore radius in ft.

- Vertical or horizontal well productivity (or injectivity) provided in Table 1, and
- Expected gas recovery factor by pressure depletion to a given production abandonment pressure.

$$\text{RF} = \frac{G_{pa}}{G} = 1 - \frac{p_a/z_a}{p_i/z_i}$$

Table 1: Boundary dominated well productivity index

Flow Geometry	Reservoir Property Multiplier		Dimensionless Productivity Index (Dq for nonDarcy flow mainly for gas only)	Geometric Parameters
	Oil for $\frac{q_o}{\bar{p}-p_{wf}}$	Gas for $\frac{q}{m(\bar{p})-m(p_{wf})}$		
Vertical Well (VW)	$\frac{\sqrt{k_x k_y}h}{141.2B_o\mu_o}$	$\frac{\sqrt{k_x k_y}h}{1424T}$	$\frac{1}{\frac{1}{2}\ln\frac{2.25A}{C_A r_w^2} + s + s_c + Dq}$	max C_A = 31.6 for circle min s_c = 0 for full penetration
Horizontal Well (HW)	$\frac{\sqrt{k_y k_z}b}{141.2B_o\mu_o}$	$\frac{\sqrt{k_y k_z}b}{1424T}$	$\frac{1}{\frac{1}{2}\ln\frac{0.223abC_H}{r_w^2} + s + s_R + Dq}$	min $\ln C_H = 0.523\frac{a}{I_{ani}h} - \frac{1}{2}\ln\frac{a}{I_{ani}h} - 1.088$ for well in vertical and horizontal center min $s_R = 0$ for full penetration (L = b)
Hydraulic Fracture from VW	$\frac{\sqrt{k_x k_y}h}{141.2B_o\mu_o}$	$\frac{\sqrt{k_x k_y}h}{1424T}$	$\frac{1}{\frac{1}{2}\ln\frac{2.25A}{C_A r_w^2} + s_f}$	max C_A = 31.6 for circle $s_f = \ln\left[\frac{r_w}{x_f}\left(\frac{k_{nd}x_f}{\pi k_f w} + 2\right)\right]$
Hydraulic Fracture from HW	$\frac{k_y n_f h}{222B_o\mu_o}$	$\frac{k_y n_f h}{2237T}$	$\frac{x_w}{\frac{L_w}{(n_f-1)} + s_{ch}}$	n_f spacing from one fracture to next, s_{ch} choke skin in fracture near well, $x_f = x_w/2$ for full penetration

While not considered in this work, hydraulic fracturing may be attractive for strong bottom water drive NG reservoirs and will be the subject of future work.

Most natural gas storage facilities use pressure depleted natural gas reservoirs to reinject and produce methane over a working pressure range. Similarly, (Bachu and Shaw 2003) provided a straightforward estimate of the storage capacity from injecting CO_2 into a pressure depleted natural gas reservoir.

Material Balance Implications

Different analytical models apply when an active aquifer underlies the NG reservoir. Drilling the well through the entire gas thickness reveals presence or lack of bottom water and whether the reservoir is dipping. For normally pressured gas reservoirs, a classic material balance graph of pressure divided by the gas deviation factor (p/z) versus cumulative gas production remains at constant negative slope until the reservoir pressure drops to abandonment pressure. In such cases, connate water remains the same and the change in reservoir pressure governs the gas recovery factor. Material balance that fails to remain at a constant slope and instead tends to flatten probably indicates the presence of an active aquifer either directly below a drilled gas-water contact (GWC) or downdip. This study focuses on the presence of bottom water below a natural gas reservoir that is not dipping.

The aquifer below a GWC may be confined (closed) or unconfined (open). Over-pressured NG reservoirs with active water drive must connect to a confined aquifer. Normally pressured NG reservoirs may connect to a closed or open aquifer. The low NG recovery factor results from encroaching water that traps NG and maintains reservoir pressure, thereby limiting production attributed to gas expansion in the reservoir.

Whether due to bottom water or edge water drive, the aquifer volume in place regulates pressure support to the NG reservoir during production. Strong bottom water drive from an open aquifer can maintain the gas reservoir pressure at the initial hydrostatic pressure thereby limiting the recovery factor to the change from initial to residual gas saturation in the water swept volume, provided produced water does not cause liquid loading that stops well production.

(Agarwal et al. 1965) employed a numerical simulation model for NG production under edge water drive that observed increased gas recovery factor with increasing well production rate particularly for lower reservoir permeability and noted that curtailing production was detrimental to the recovery factor. Their model stopped production at water breakthrough. They provided the following simple material balance equation estimate for the NG recovery factor (RF):

$$\mathrm{RF} = \frac{G_{pa}}{G} = 1 - E_w\left(\frac{S_{gr}}{S_{gi}} + \frac{1-E_w}{E_w}\right)\frac{p_a/z_a}{p_i/z_i}$$

for G initial gas in place, G_{pa} gas produced at abandonment pressure, E_w reservoir fraction under water influx, p_i and p_a initial and abandonment reservoir pressures, and z_i and z_a initial and abandonment gas compressibility factors, S_{gr} gas residual factor, and S_{gi} initial gas saturation.

Well Completion Implications

Primary consideration relates to the well geometry, e.g. whether to produce from a vertical or a horizontal well. The productivity index equations in Table 1 help to explain when a horizontal well can outperform a vertical well. Because NG reservoirs tend to be deeper than crude oil reservoirs, reservoir depth may favor horizontal wells to achieve deliverability rates at lower development cost. However, remarks in the introduction section encourage elaboration.

As mentioned previously, (McMullan and Bassiouni 2000) showed advantages to fully completing the gas thickness and to producing the well at high rate for a NG reservoir with strong bottom water drive. Both this paper and a previous one by (Armenta and Wojtanowicz 2002) address the reverse coning phenomenon that occurs in gas wells but not in oil wells. Neither paper was able to show reverse coning with a reservoir simulation model, but the latter paper provided an analytical model showing the behavior. Like most analytical coning models, this model addresses steady state conditions induced by a constant pressure drainage boundary, which has no relationship with likely reality. Nonetheless, these papers encourage attention to the potential for high gas recovery factor under bottom water drive using vertical wells.

A way to understand reverse coning in gas wells is to consider a well that is fully completed through the entire gas thickness and below the GWC. The much greater mobility thickness along the portion of the well completed opposite the flowing gas than the completed opposite the water has the flow advantage and even induces downward gas flow below the original GWC. As more gas is produced, the GWC contacted as water influx traps gas, but low lateral pressure gradient above the contact ensures the rising GWC remains flat. As such, production can continue as long as the gas rate is sufficient to keep the well unloaded or as long as produced water handling does not overcome gas production revenue. Higher production rate increases recovery factor because it prolongs well unloading. Under strong bottom water drive with effectively a constant pressure boundary from below in the aquifer, the well must be completed through most or all of the gas column to ensure a high recovery factor.

In contrast, a horizontal well drilled near the reservoir top will induce cresting. Close horizontal well spacing minimizes excessive bypassed gas outside the water swept volume (Ehlig-Economides et al. 1996). A key difference between horizontal and vertical well is that water breaks through along much or all of the productive horizontal completion length unlike a small fraction of the productive completion length in a vertical well completion. A slanted well would serve to reduce high water production to a level the gas production rate can unload.

Further investigation may reveal that hydraulic fracturing is an effective strategy for lower permeability gas reservoirs to achieve reverse gas cresting along the fracture face.

The simulations in the next section use a well spacing designed to recover the gas in a reasonable time frame. Lower permeability results in lower well productivity and injectivity, thereby requiring smaller well spacing to achieve overall similar field rates.

Reservoir simulation model

A Cartesian, compositional, commercial reservoir simulator (CMG 2023) is used in this study to simulate natural gas production with simultaneous CO_2 injection under a constant pressure bottom aquifer. The simulation model considers injection and production well pairs in a square reservoir drainage that represents a quarter five-spot pattern when using vertical wells or a direct line drive when using horizontal well pairs to produce the entire pattern. The base case gas reservoir pattern considered in this work is a 5280 ft × 5280 ft square-base (640 acres) with 100 ft net reservoir thickness underlain by a constant pressure aquifer boundary 1000 ft below the gas water contact (GWC) modeled with an additional 5 ft aquifer layer with permeability of 100 Darcy containing wells that maintain constant hydrostatic pressure. Horizontal wells that produce (or inject) water maintain the constant pressure at the aquifer bottom when pressure increases (or increases) in the well vicinity. The formation is considered to be homogeneous and anisotropic with 100 mD horizontal effective gas permeability in the gas zone and the 1000 ft aquifer zone, with a 0.1 vertical-to-horizontal permeability ratio, 15% porosity, 25% initial interstitial water saturation, average initial reservoir pressure of 3040 psi, and initial reservoir temperature of 211°F. The specific gravity of the natural gas is 0.602, consisting of 90% methane and 10% ethane. Capillary pressure and relative permeability hysteresis are considered negligible. The gas/water relative permeability curves are the same ones used by (McMullan and Bassiouni 2000).

For the vertical well pair, A cartesian model is used consisting of 30 × 30 × 110 grid-blocks in the gas formation with refined grids near the injection and production wellbore regions. The production well and the CO_2 injection well are located at diametrically opposite sides of the square reservoir sector, with the top 90 ft of the simulated reservoir thickness completed.

The horizontal wells are assumed to penetrate the entire square drainage area length of 5280 ft. The CO_2 injection well is located at the bottom side of the sector 10 ft above the water gas contact, and the production well at the top of the opposite side. A two-dimensional (xz) Cartesian grid model (50 × 1× 110) with refined grids near the wellbore regions and the gas water contact) to reduce the numerical dispersion and improve the accuracy of CO_2 breakthrough times, is used to model the reservoir for the case of horizontal wells. The production wells for both vertical and horizontal well pairs are operated at constant surface natural gas production rate to accommodate consistent gas feed to facilities such as hydrogen plants and power plants. Since the simulator well operational conditions enable only constant total gas (natural gas prior to CO_2 breakthrough and natural gas plus CO_2 afterwards) production, a Python script is used to adjust the natural gas production rate and CO_2 injection rate at each time step. When the production well cannot sustain the required rate, the well operating condition switches to a constant wellhead pressure (100 psi) production mode.

We monitor the production well and record the CO_2 breakthrough time at a specified CO_2 mole fraction in the production stream. After CO_2 breakthrough, the simulation continues until the CO_2 mole fraction in the production stream reaches 0.5. Beyond this CO_2 mole fraction, it would require continuous extraction of decreasing natural gas concentrations in the production stream and compression of increasing CO_2 injection volumes, which results in a decreasingly economically attractive process over time.

The Peng-Robinson equation of state (EOS) is used in the compositional model, the CO_2 solubility in the water phase, as well as convectional mixing of the natural gas and CO_2 due to mechanical and hydrodynamic dispersion (Ren et al. 2005).

Results

Table 2 provides a summary of 4 simulation case studies discussed in this paper. All of the cases employ the strong water drive condition described in the previous subsection. This section starts with 2 case studies, one for a vertical well (Case 1), the other for a horizontal well (Case 2), that include NG production to deplete the natural gas bearing formation and then convert the production well to injector to inject and sequester CO_2.

A second subsection considers 2 more case studies, each with simultaneous CO_2 injection and NG production. Case 3 considers vertical injection and production wells, with the injection surface well rate 50% higher than the production well surface rate to compensate for its greater density than NG and thereby achieve near fluid displacement volumetric balance. Case 4 is like Case 3 but with horizontal injection and production wells. (Hatzignatiou and Ehlig-Economides 2022) simulated simultaneous injection and production at the same surface rate that provides justification for this approach by demonstrating that equal surface injection and production rates results in loss of average reservoir pressure. Maintaining reservoir pressure helps to minimize water influx.

Table 2: Summary of simulation cases and results

Case ID	Well orientation	Description	Gas production rate (MMSCF/d)	CO2 injection rate (MMSCF/d)	CO2 BT time (days)	RF at CO2 BT (%)	Water BT time (days)	Max water rate (STB/day)	Max water rate time (days)	Cumulative water end of production (MMSTB)
1	Vertical	NG PROD then CO2 INJ	20	20	N/A	N/A	30	15713	1451	10.29
2	Horizontal	NG PROD then CO2INJ	20	20	N/A	N/A	1121	47445	1384	8.46
3	Vertical	Simultaneous INJ+PROD	20	30	712	25.74	52	1752	2302	0.77
4	Horizontal	Simultaneous INJ+PROD	20	30	846	31.43	2214	6645	2331	0.39
Case ID	**Time switching to WHP constraint (days)**	**RF end of production (%)**	**Amount of Stored CO2 (BSCF)**	**Amount of recirculated CO2 (BSCF)**	**Amount of produced NG (BSCF)**	**Injector BHP at process end (psi)**	**Pavg end of production (psi)**	**End of production time (days)**	**Pavg end of injection (psi)**	**Process end (days)**
1	1350	56.83	58.41	N/A	30.60	3216.38	2986.94	1920	3078	4840
2	1384	53.49	58.41	N/A	28.80	3057.55	2853.76	1482	3083	4402
3	-	83.17	69.06	6.04	46.04	3088.32	3036.22	-	-	2302
4	-	86.59	69.93	4.02	46.61	3085.81	3011.99	-	-	2331

Sequential natural gas recovery and CO_2 storage under strong water drive

Up to now most applications for CO_2 storage in a depleted hydrocarbon reservoir have focused on injecting CO_2 after natural gas pressure depletion to an economic limit. Pressure depletion may achieve high recovery factor strictly by gas expansion to terminate production at an abandonment pressure without need for produced water handling. The cases in this section consider depletion under strong bottom water drive terminated when liquid loading causes the well to shut down or when the cost of produced water handling exceeds production revenue with reservoir pressure at or near the initial reservoir pressure. Economic constraints used in this study are natural gas price of $3.5/MSCF $0.5/STB cost for water handling.

Vertical well Case

For Case 1 the vertical well is centered in the drainage area, completed over the upper 90% of the NG reservoir thickness and producing at a rate of 20 MMSCF/D of natural gas. After the end of the production period, CO_2 injection is initiated at rate of 20 MMSCF/D via the same well with the CO_2 mole fraction in the reservoir, the well bottomhole injection pressure and the reservoir average pressure monitored throughout the injection period. Initial control on simulated injection rate switches to constant pressure if or when injection bottomhole pressure reaches the formation fracture pressure (4850 psi).

For Case 1, Table 2 shows that the water breakthrough occurs within a month from the production onset due to the close proximity of the well completion to the original GWC. By the end of the gas production cycle, the gas recovery is 56.83% with the well having produced 10.29 MMSTB of water. The maximum water production rate is 14713 STB/D occurred at 1451 days. Figure 1 shows the water saturation distribution along a vertical cross-section that includes the well after 1440 days on production and at the end of natural gas production along a vertical cross-section that includes the well. This figure shows that gas (reverse water) coning occurs opposite to traditional water coning. Although not shown, but in agreement with previously reported results by (McMullan and Bassiouni 2000), completing the well only 5 ft near not shown, but in agreement with previously reported results by (McMullan and Bassiouni 2000), completing the well only 5 ft near the formation top yielded a lower recovery factor of 51.5% with cumulative water production of 0.318 MMSTB. The phenomenon of water reverse coning enables effective gas production, but the cumulative water for this case is the highest of all cases.

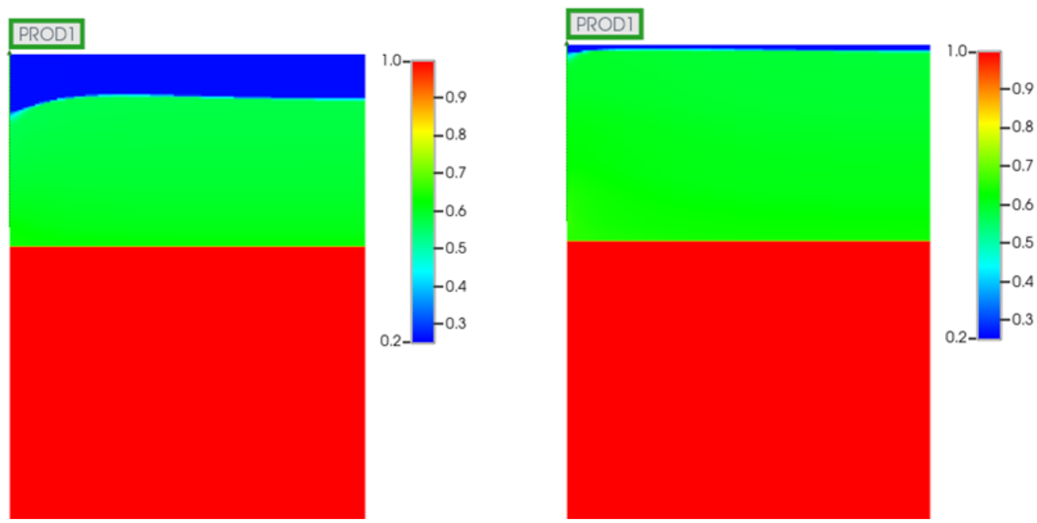

Figure 1: Reverse coning observed during NG production from a vertical well fully completed in the gas reservoir; left picture: water saturation at 1440 days; right picture: water saturation at end of NG production (1920 days).

During the CO_2 injection period, although the open aquifer maintains constant pressure below the reservoir, the reservoir pressure increases with injection to enable downward displacement of the reservoir fluids. However, instead of reservoir pressure continuing to increase with continued compression of the reservoir fluids, as expected in a closed aquifer, the constant pressure in the open aquifer slows the reservoir pressure rise.

Figure 2 shows the water saturation profile after injecting CO_2 for 8 years on the left. On the right this figure shows the CO_2 mole fraction dissolved in the water phase. The maximum CO_2 mole fraction in the water phase is the CO_2 solubility in water, or 2%. The right-hand figure illustrates how the CO_2 concentration diffuses into the water phase during injection.

By imposing constant pressure at the base of the model, the geometry applies for a single development well surrounded by equally spaced development wells. This accounts for the square drainage shape and induces plume interference in the lateral direction while CO_2 also flows downward below the GWC. This results contrasts with claims by (Bachu and Shaw 2003) that rising pressure will limit CO_2 injection into a reservoir depleted by water influx. Water influx driven by an open aquifer during production will allow injection of more CO_2 than the produced NG because the open aquifer pressure is vented to the atmosphere at some distance from the injection, provided brine flowing toward the outcrop does not contaminate fresh water

(Nicot 2008; Mukhtar et al. 2023) Note that produced NG after 5.3 years on production is 30.6 BCF followed by injection of 8 years for a total of 13.3 years including production followed by injection.

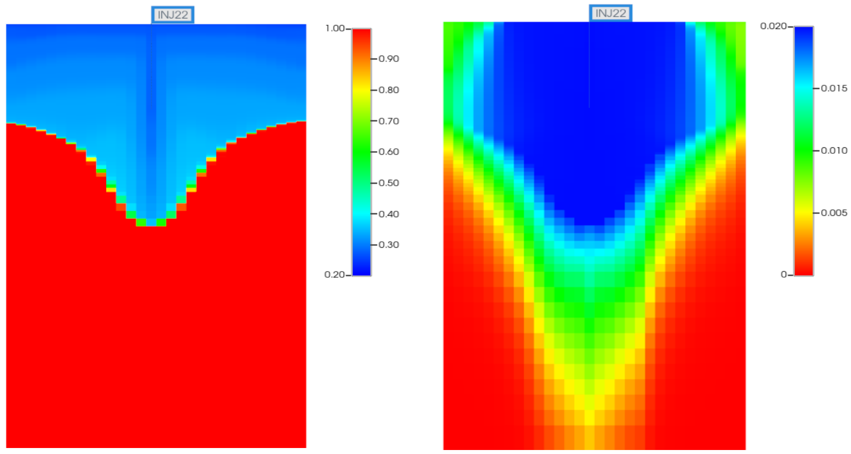

Figure 2: CO_2 injection after NG depletion at the end of CO_2 injection for fully completed vertical well; left figure: water saturation; right figure: CO_2 mole fraction dissolved in water.

Horizontal well Case

As for the vertical well, the horizontal well for Case 2 is located at the center of the reservoir drainage and is converted to a CO_2 injection well after the end of production terminated by the high cost of produced water. As shown in Table 1Table 2, water breakthrough occurs after about 3 years of production (~1120 days). The recovery factor of the horizontal well producing until reaching the economic limit is 53.49%. We can see that in this case, the horizontal well does not outperform the fully completed vertical well in Case 1. Although water breakthrough occurs much later than the vertical well case, the cumulative water production is nearly equal to that of the vertical well case.

Figure 3 shows the water saturation profile after injecting CO_2 for 8 years on the left. On the right this figure shows the CO_2 mole fraction dissolved in the water phase. As previously, the maximum CO_2 mole fraction in the water phase is 2%. The right-hand figure illustrates how the CO_2 concentration diffuses into the water phase during injection. Note that produced NG after 4.1 years on production is 28.8 BCF followed by injection of 8 years for a total of 12.1 years including production followed by injection.

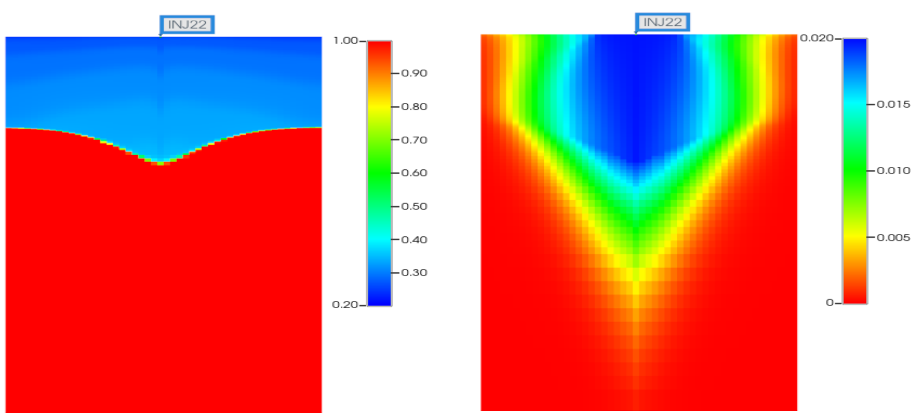

Figure 3: CO_2 injection after NG depletion at the end of CO_2 injection for fully completed horizontal well; left figure: water saturation; right figure: CO_2 mole fraction dissolved in water

Figure 4 shows the pressure behavior for Cases 1 and 2. For both cases the well control changes from constant gas production rate to constant wellhead pressure (WHP) of 100 psi once the well is unable to meet the required production gas rate schedule. The change in well control dramatically impacts both bottomhole and average reservoir pressure behaviors. Similarly, dramatic pressure behavior changes occur when the wells change from production to injection. Since the injection of CO_2 was initiated right at the end of the natural gas production, the pressure at and near wellbore is lower than the average reservoir pressure. For the horizontal well, Case 2, this results to a sharp increase of the injection BHP in a rather short time period due to the change of the well operating condition followed by a much slower rate of BHP increase over time until the end of the process period. For the case of vertical well, Case 1, the injection BHP increases much more sharply compared to the horizontal well one (Case 2) based on the same physical factors, but also because the injectivity of the vertical well is lower than the horizontal well one for placing comparable volumes of CO_2 in the pore space. After reaching boundary dominated injection conditions, the average reservoir pressure slowly increases over the time frame as shown in Figure 4.

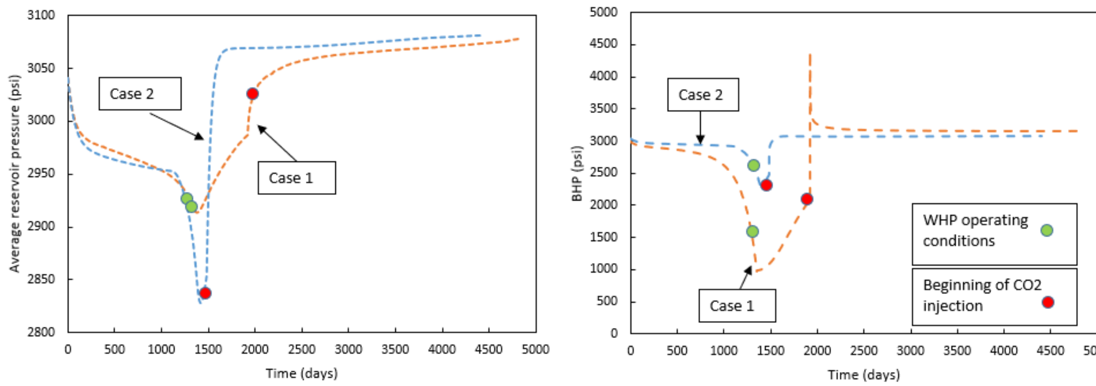

Figure 4. Pressure behaviors for Case 1 and Case 2: left showing average reservoir pressure, right showing natural gas production well/CO_2 injection well bottomhole pressure

CO_2 enhanced gas recovery under strong water drive

For gas reservoirs with strong water drive, injecting CO_2 and producing natural gas at the same time enables enhanced gas recovery, and impacts the early water encroachment into the reservoir. This section shows the advantages and limitations of this method. Simulation well controls ensure that injection well bottomhole pressure never exceeds the formation fracture pressure. All produced CO_2 is reinjected.

Vertical wells

Case 3 considers a vertical well pair consisting of a natural gas production well and a CO_2 injection well with well location and completion intervals specified in the reservoir simulation mole section. The NG production is at a rate of 20 MMSCF/d, and the CO_2 injection rate is 30 MMSCF/d. Table 2 shows that water breakthrough occurs after only 52 days on production, well before the CO_2 breakthrough occurring after 712 days. The NG recovery factor for this case is 83%, much higher than the 57% recovery factor for production in Case 1, and the total water production for Case 3 is less than 10% of the water production for Case 1. Clearly, the CO_2 injection offers significant EGR while storing significant CO_2.

The authors are not able to show a cross section through the vertical injection and production wells to illustrate water saturation and CO_2 mole fraction behaviors.

Horizontal wells

Case 4 considers a horizontal well pair consisting of a natural gas production well and a CO_2 injection well with well location and completion intervals specified in the reservoir simulation model section. As for Case 3, the NG production is at a rate of 20 MMSCF/d, and the CO_2 injection rate is 30 MMSCF/d. Table 2 shows that water breakthrough occurs after 2214 days (6 years) on production, well before the CO_2 breakthrough occurring after 846 days (2.3 years). The NG recovery factor for this case is 86.6%, much higher than the 53.5% recovery factor for production in Case 2, and the total water production for Case 3 is less than 5% of the water production for Case 2, and less than 4% of the water production for Case 1, showing a clear advantage for using horizontal wells.

Figure 5 shows the water saturation profile after conducting CO_2 EGR until the mole percent of CO_2 reaches 50%. On the right this figure shows the CO_2 mole fraction dissolved in the water phase. As previously, the maximum CO_2 mole fraction in the water phase is 2%. As before, the right-hand figure illustrates how the CO_2 concentration diffuses into the water phase during injection. The left figure shows that water crests to the horizontal production well while injected CO_2 cones downward below the GWC while miscibly displacing NG toward the production well.

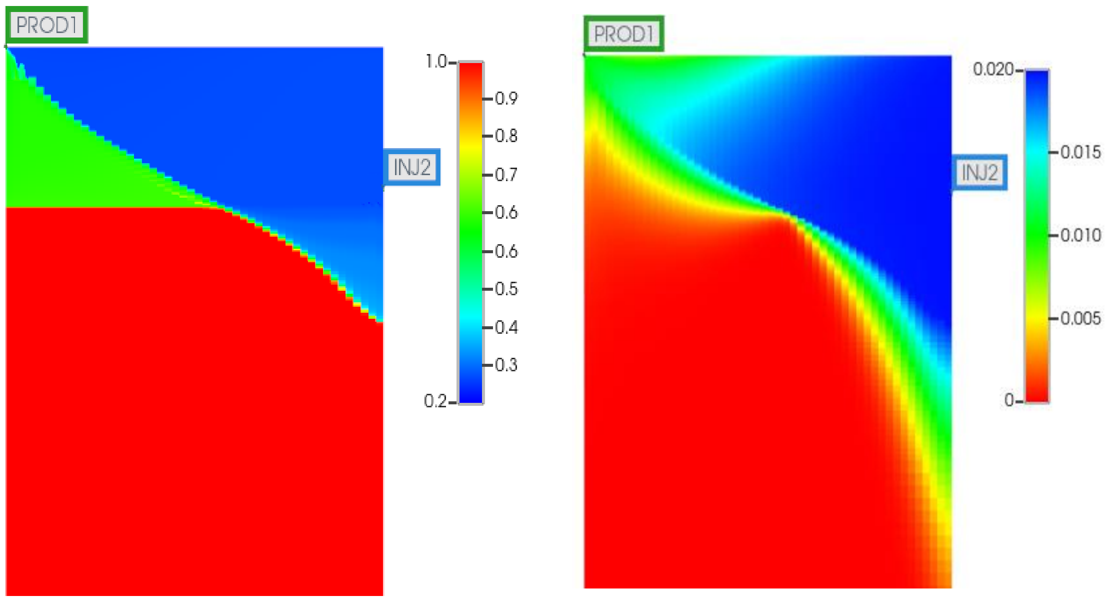

Figure 5: End of Simultaneous NG production (20 MMSCF/d) and CO_2 injection (30 MMSCF/d) for fully completed horizontal wells: left showing water saturation, right showing CO_2 mole fraction dissolved in water.

The CO_2 injection well bottomhole pressure (BHP), the natural gas production well BHP and the average reservoir pressure for Cases 3 and 4 are presented in Figure 6 and Figure 7, respectively. For Cases 3 and 4 the injection BHP pressure follows practically the same path with its values increasing mildly above the average reservoir pressure for the duration of the CO_2 injection with a relative higher rise rate at the early injection times.

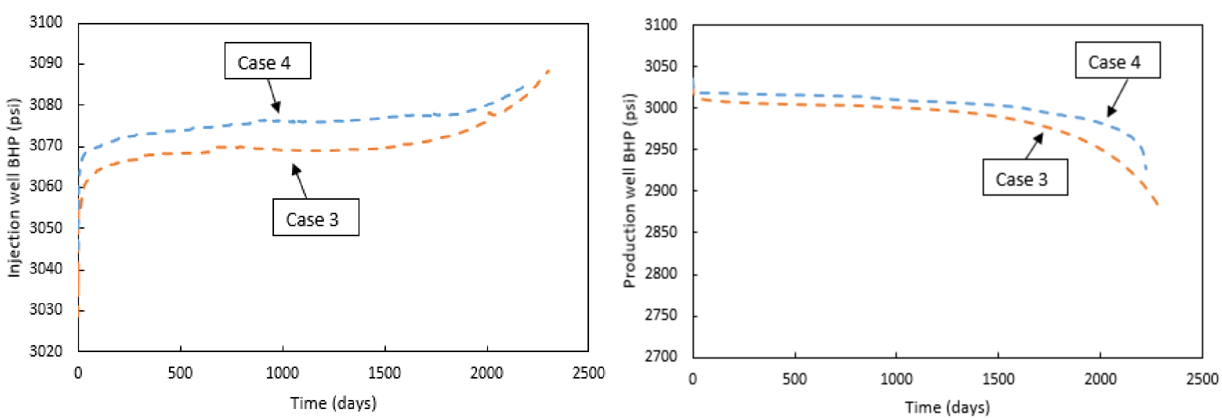

Figure 6. CO_2 injection and production well bottomhole pressures for Cases 3 and 4.

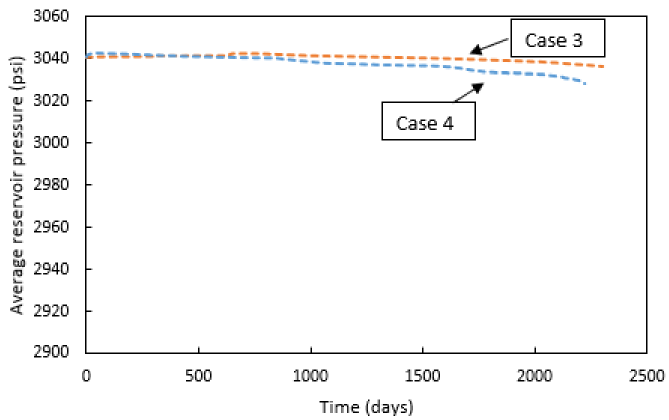

Figure 7. Average reservoir pressure for Cases 3 and 4.

Discussion

Not shown in this paper, but clearly evident from Cases 1 and 2 is the observation that CO_2 injection can continue after recovery of the NG for even greater CO_2 storage for either the vertical or horizontal well EGR Cases 3 and 4.

This paper introduces novel simulation approaches to NG production under strong bottom water drive. Previous simulation models for bottom water drive have used a limited aquifer volume that extends beyond the lateral extent of the gas reservoir. Such approaches effectively limit reservoir production to only one well and fail to represent the behavior of bottom water drive from an open aquifer. Analytical models for coning and cresting have used constant pressure lateral boundaries that do not reflect the behavior of multiple pattern production well producing with strong bottom water drive.

Injection of CO_2 while producing natural gas will not only yield higher gas recovery factors but also "shield" to a large degree the production well from the advancement of water from the underlying aquifer, thus leading to reduced water production rates and cumulative volumes. This itself will reduce the amount of trapped (residual) natural gas in the water-invaded gas occupied pore space and decrease the possibilities for the producing well to water-load; both of which would otherwise reduce the gas recovery factor. The newly proposed process results also in higher volumes of sequestered CO_2 compared to the corresponding sequential natural gas and CO_2 storage cases.

The authors are continuing this work to consider more common gas reservoir permeability values. The previous work by (Hatzignatiou and Ehlig-Economides 2022) suggests that the recovery factor advantage for horizontal wells will be even more apparent for lower permeability. Further, we plan more work on coupling NG production and hydrogen generation with CO_2 capture and injection into the same NG reservoir, as was done in the previous paper, in order to convert NG to blue hydrogen, a higher value product.

Conclusions

This paper significantly extends previous work related to NG production under strong bottom water drive conditions. The strategies we illustrate can turn disappointing NG reservoirs into high priority prospects.

The single well radial geometry with strong bottom water drive successfully illustrates reverse coning of gas into water swept reservoir volume.

Simultaneous CO_2 injection and NG production significantly outperforms sequential injection followed by production, and horizontal wells outperform vertical wells.

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