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CO_2 Plume Tracking and History Matching Using Multilevel Pressure Monitoring at the Illinois Basin – Decatur Project

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Abstract

The incorporation of multilevel pressure monitoring at the Illinois Basin – Decatur Project (IBDP) has provided a unique opportunity to validate methods for tracking buoyant migration of CO_2 using multilevel pressure transient data. Additionally, by history matching pressure transient data it is possible to develop a highly resolved hydrogeological model that can be used to forecast future plume migration. At the IBDP, the multilevel pressure transient alone indicate that the CO_2 remains largely confined to the depth interval into which it was injected, and there is no indication of buoyancy flow towards the shallower portions of the storage reservoir. By incorporating multilevel pressure monitoring into the monitoring program, additional information is available that can be used to minimize and manage potential risk associated with CO_2 and displaced brine migration to shallower depths.

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Keywords: CO_2 sequestration; multilevel pressure monitoring; pressure transients; vertical pressure gradients; demonstration project

1. Introduction

The Illinois Basin – Decatur Project (IBDP) is a carbon capture and sequestration (CCS) pilot project in Decatur, Illinois, USA, aimed to demonstrate the ability of the Cambrian-age Mt. Simon Sandstone to accept and store one million metric tons of CO_2 over three years. The CO_2 is captured from an ethanol plant owned by the Archer Daniels Midland Company, and injection started in November 2011 at a rate of approximately 1,000 metric tons per day. As

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part of an extensive Monitoring, Verification, and Accounting program, the Westbay* multilevel groundwater characterization and monitoring system was installed in a deep in-zone verification well (2,000 m) to record the pressure before, during, and after CO_2 injection [1]. The geographic location, a site map showing the relative locations of the injection well, CCS1, and the verification well, VW1, and a description of the implementation of the Westbay system at the IBDP are provided in Locke II et al. [1]. A more detailed description of the Westbay system can be found in Black et al. [2].

Multilevel pressure monitoring has been employed in groundwater hydrology and contamination studies [e.g., 3, 4, 5, 6, 7, 8], where the importance of high-resolution head monitoring has been emphasized. It was found that whereas core log information was often insufficient for identifying depths of highest head differentials, major head differentials almost always corresponded to low permeability sediment layers [5, 8].

In the context of CCS, the pressure monitoring at the IBDP is unique in that multiple monitoring zones are placed within the storage reservoir itself. Single-depth pressure measurements, on the other hand, have been commonly employed for site characterization and monitoring [e.g., 9, 10], and several studies have investigated above-zone pressure monitoring [11] for detection and characterization of leakage of CO_2 or displaced brine through the caprock [e.g., 12, 13, 14, 15]. Simulation studies by Chabora [13] suggested that multilevel pressure monitoring in the storage reservoir itself might have potential for tracking the CO_2 plume. Simulation studies by Birkholzer et al. [16] on the pressure response in idealized, stratified systems showed horizontal flows ahead of the CO_2 plume, with slight upward flows directly in front of the plume, and gravity segregated flow within the CO_2 plume. Benisch and Bauer [17] modeled a geologic anticline structure representative for anticline structures identified as potential CO_2 storage sites in the North German Basin, and examined the pressure response in both vertical and horizontal directions, but at much greater horizontal distances to the monitoring wells than at the IBDP, and only one monitoring depth per formation per well.

Strandli and Benson [18] conducted a synthetic study with a setup similar to that at the IBDP, and used simulated multilevel pressure transients in the storage reservoir, seal, and overlying aquifer to identify diagnostics for reservoir structure (layering and anisotropy) and CO_2 plume migration during injection. Pressure buildups were normalized to the pressure buildup at the depth of injection and vertical pressure gradients were normalized to the initial, hydrostatic pressure gradient. Soon after the start of the CO_2 injection, normalized pressure transients and vertical pressure gradients were diagnostic of reservoir structure. With time, normalized pressure transients and vertical pressure gradients became diagnostic of the height of the CO_2 plume, as buoyancy-induced migration of CO_2 within the storage reservoir gave rise to larger pressure buildups at shallower depths, with upward flow of displaced brine above the CO_2 plume and downward flow of displaced brine below the plume.

In this study, the identified diagnostics [18] are applied to the multilevel pressure transient data at the IBDP. In addition, a multilayered, radially symmetric model with TOUGH2-MP/ECO2N [19, 20] is used to history match the change in bottomhole pressure (BHP) at injection well CCS1 and the change in pressure at three monitoring zones at verification well VW1 during CO_2 injection.

2. Configuration at the Illinois Basin - Decatur Project

Verification well VW1 is located 305 m from injection well CCS1. Eight monitoring zones are located within the Mt. Simon, one monitoring zone is located in the pre-Mt. Simon (close to the Precambrian granite basement), and two monitoring zones are placed in the Ironton-Galesville Sandstone directly above the Eau Claire Formation (primary seal).

The Westbay system installed in verification well VW1 consists of a casing system and portable probes and tools to allow for continuous data acquisition [21]. In-situ fluid pressures are obtained using an electronic probe that is lowered inside the tubing to access each monitoring zone via valved couplings [22]. Measurement ports allow direct connection with the formation fluid (the practical resolution of the pressure transducers is about 1,000 Pa), and water inflated Westbay packers are placed between the monitoring zones to preserve the natural distribution of fluid pressures and prevent artificial vertical flow [21, 22].

Depths of measurement ports and perforations, including the depths of the two perforated injection intervals and the depth of the BHP gauge at the injection well, are listed in Table 1, along with the corresponding formations.

Table 1. Depths of the bottomhole pressure (BHP) gauge and perforated injection intervals at injection well CCS1, and depths of ports and perforations at verification well VW1. All depths are reported as depths below Mean Sea Level (MSL). MSL is 205.7 m below ground level at CCS1 and 203.9 m below ground level at VW1.

Injection well CCS1		Verification well VW1			
		Measurement port	Depth (m)	Perforated interval (m)	Formation
		Zone 11	1290.2	1290.4 – 1291.3	Ironton - Galesville
		Zone 10	1315.9	1315.7 – 1316.6	Ironton - Galesville
		Zone 9	1514.6	1514.8 – 1515.9	Mt. Simon
		Zone 8	1571.5	1571.7 – 1572.7	Mt. Simon
		Zone 7	1747.0	1747.2 – 1748.2	Mt. Simon
	Depth (m)	Zone 6	1812.9	1813.0 – 1814.1	Mt. Simon
BHP gauge	1717.5	Zone 5	1839.7	1839.9 – 1840.9	Mt. Simon
Perforated injection intervals		Zone 4	1875.5	1875.5 – 1876.5	Mt. Simon
Upper	1917.8 – 1926.9	Zone 3	1908.4	1908.5 – 1909.6	Mt. Simon
Lower	1930.9 – 1938.5	Zone 2	1919.8	1919.9 – 1921.0	Mt. Simon
		Zone 1	1943.6	1943.8 – 1944.7	Pre-Mt. Simon

3. Approach

First, the multilevel pressure transients are analyzed according to the diagnostic tools provided by Strandli and Benson [18]. Second, the multilevel and injection well pressure transient data are history matched to develop a hydrogeological model that in turn can be used to predict CO_2 migration.

The change in pressure from the initial pressure at each monitoring zone and the change in BHP at the injection well (hourly averages) are shown in Fig. 1 over an injection period of two years. Zones 2 and 3 have nearly identical responses and respond almost instantaneously to changes in the highly varying injection rate. Zone 4 experiences a much smaller change in pressure, and is not very sensitive to the highly varying injection rate. At shallower monitoring zones in the Mt. Simon, slight increases in pressure can be observed, originating from displaced brine gradually migrating upward. In Zones 10 and 11 (above the Eau Claire seal), no increase in pressure is observed. Data from Zone 1 are not considered further due to uncertainty about whether these measurements are reliable. Zones 3 and 4 experienced a slight drift in the pressure prior to injection, which is corrected for at early time (~ 10 days of injection).

3.1. Hydrogeological description of the Mt. Simon

The relative locations of the injection intervals at CCS1 and monitoring zones at VW1 are also shown in Fig. 2a, where “crossplots” of normalized gamma ray (GR) and porosity logs are used as a means to obtain a preliminary, qualitative facies identification. Relatively higher GR values in combination with relatively lower porosity values indicate the presence of “shaley” (tighter) rock, whereas relatively lower GR values in combination with relatively higher porosity values indicate more porous sand. Note that the term “shaley” as employed here does not necessarily mean shale but simply refers to layers of lower permeability and porosity rock. This may be granite (such as the underlying Precambrian basement rock), shale, siltstone, or other tight sands.

Comparison of the crossplot logs from the two wells indicates a high degree of lateral continuity between the two well locations and intervals of tighter rock (intermediate seals) within the Mt. Simon itself (especially above Zone 7). Zones 2 and 3 at VW1 appear to correspond to the injection zone, and indications of tighter rock between Zones 3 and 4 suggest that upward flow between the injection zone and Zone 4 may be limited. The Mt. Simon Sandstone is underlain by the Pre-Mt. Simon, which is low-porosity, fractured rock that overlies the Precambrian basement rock.

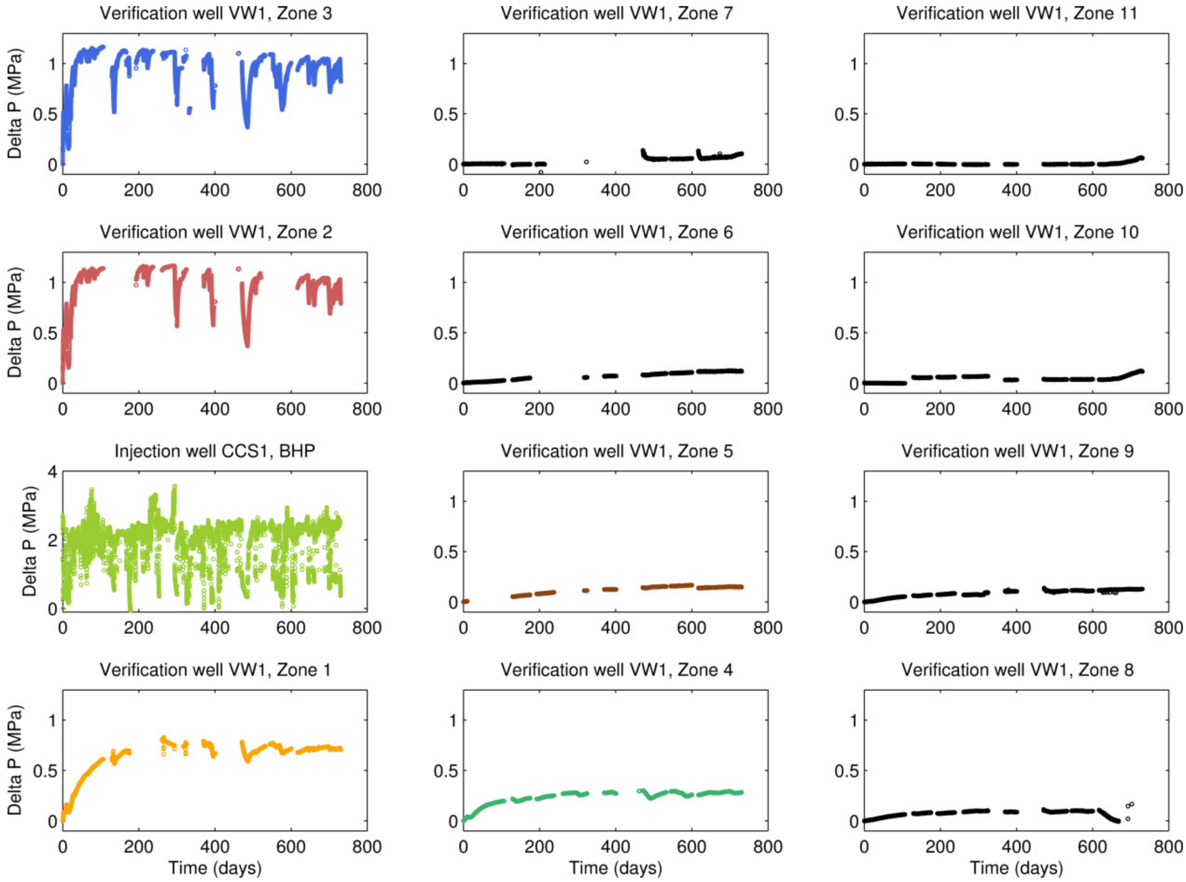

Fig. 1. Change in pressure from the initial pressure at monitoring Zones 1-11 at verification well VW1 and change in BHP at injection well CCS1 (uncorrected for the brine/CO_2 column between the pressure gauge and perforations). Obvious outliers/aberrant segments in the pressures (few) have been manually removed. Other gaps in the pressure transients are due to sampling and individual pressure sensors being offline. The IBDP data are all hourly averages.

3.2. Diagnostics

The diagnostics identified by Strandli and Benson [18] provide a relatively simple means for assessing reservoir structure (heterogeneity in form of layering and anisotropy) and approximate height of the CO_2 plume in the absence of formal inversion of the multilevel pressure transient data.

In order to allow for easy comparison of the pressure buildups at different depths, the pressure buildup in each monitoring zone is normalized to the pressure buildup in the monitoring zone at the depth of injection. At early time, the depth of injection is where the pressure buildup will be the highest. If the reservoir is highly heterogeneous and/or anisotropic, the shallower monitoring zones will experience less pressure buildup and the normalized pressure buildups will be much less than unity. With time, normalized pressure transients are diagnostic of the height of the CO_2 plume, as buoyancy-induced migration of CO_2 will give rise to larger pressure buildups at shallower depths, with upward flow of displaced brine above the CO_2 plume and downward flow of displaced brine below the plume. At the IBDP, Zones 2 and 3 both appear correspond to the injection zone (recall Section 3.1 and Fig. 2a). In fact, Zones 2 and 3 have nearly identical responses, however Zone 2 is chosen as the reference zone to normalize to because it initially has the highest pressure buildup and because relatively soon after the start of injection, the pressure buildup in Zone 2 is exceeded slightly in magnitude by the pressure buildup in Zone 3. If there is any buoyancy effect due to rising CO_2 between Zones 2 and 3, we would like to observe it.

Multilevel pressure monitoring devices also permit vertical pressure gradients to be calculated between adjacent monitoring zones. This provides information on vertical flow and intervals of low vertical permeability. In order to separate out the effects of the hydrostatic pressure, the vertical pressure gradients are normalized to the initial, hydrostatic pressure gradient. Normalized, vertical pressure gradients equal to unity indicate no change from initial conditions. At early time, large gradients are diagnostic of low permeability layers. With time, normalized gradients greater than unity indicate upward flow of displaced brine above/ahead of the CO_2 plume and normalized gradients less than unity indicate downward flow of displaced brine below/ahead of the CO_2 plume.

Added knowledge of reservoir structure and CO_2 plume migration path is valuable for complementing formal inversion and for model validation.

3.3. Model setup for history matching

By history matching the pressure transient data it is possible to develop a hydrogeological model that can be used to predict future migration pathways. To demonstrate this, a multilayered, radially symmetric model with TOUGH2-MP/ECO2N is used to history match the pressure buildup at injection well CCS1 and verification well VW1 (see Appendix A for details on mesh and well implementation).

A schematic of the geologic model is provided in Fig. 2b. The model consists of the Mt. Simon storage reservoir, the underlying Pre-Mt. Simon, and the lower portion of the overlying Eau Claire Formation (primary seal). The total thickness is 554 m, and no-flow conditions are imposed at the top and bottom. In order to accommodate a layer-cake model, the VW1 logs were shifted down 13.1 m after detailed comparison of logs from the two wells. The porosity and initial permeability values that were input into the model (as averages across each grid cell layer) were based on a combination of well log values from CCS1 and VW1 (the lower injection interval and below were mainly constructed from CCS1 logs and shallower depths were mainly constructed from VW1 logs). Over the course of multiple forward simulations, horizontal and vertical permeabilities were altered in the depth interval between Zones 1 and 4 in order to achieve a good match between the simulated pressure buildup and the pressure buildup observed at Zones 2 through 4 at the IBDP.

The initial pressure is hydrostatic. For simplicity, the system is isothermal at 49°C and the salinity of the Mt. Simon is neglected. As the Mt. Simon is in fact very saline, with total dissolved solids of up to more than 200,000 ppm, the permeabilities that were input into the model were scaled according to the ratio between the H_2O viscosity used in the TOUGH2-MP simulations (0.56×10^{-4} Pa-s) and the brine viscosity of the Mt. Simon (believed to be roughly 0.8×10^{-4} Pa-s [23]) (and scaled back for analyses). A relatively low pore compressibility c_R of 1×10^{-10} Pa^{-1} was needed to match the pressure responses. Relative permeability curves were constructed using the Corey's Curves Model [24], with residual liquid saturation $S_{lr} = 0.65$ (to match the observed CO_2 breakthrough time at verification well VW1 [25]) and residual gas saturation $S_{gr} = 0$. Capillary pressure curves were constructed using the van Genuchten function [26] and scaled to each material according to the Leverett J-function [27] according to Eq. 1,

$$P_C(S_l)=\frac{\sqrt{k_{ref}/\varphi_{ref}}}{\sqrt{k/\varphi}}P_{C,ref}(S_l) \tag{1}$$

where P_c is the capillary pressure as a function of liquid saturation S_l, and permeability k and porosity ϕ are specific to the given material. Because the flow in the injection zone is largely horizontal and the CO_2 flow above the injection zone is likely to be vertical, the horizontal permeability was used to scale the capillary pressure below 1915 m and the vertical permeability was used to scale the capillary pressure above 1915 m. The reference capillary pressure curve, $P_{C,ref}(S_l)$, and reference values k_{ref} and ϕ_{ref} stem from measurements on a Berea Sandstone core. The capillary pressure curves were input into TOUGH2-MP with $S_{lr} = 0.60$, saturated liquid content $S_{ls} = 0.999$, fitting parameter $\lambda = 0.5$, and maximum capillary pressure $P_{max} = 2.4\times10^7$ Pa.

A mechanical skin factor, s, of -0.85807 [22] that will result in a smaller pressure drop than for a well where no skin effect is present, is incorporated as a modified, higher permeability k_s in the grid cells immediately outside the well column (see Appendix A for details on well implementation) according to Eq. 2 [28],

$$s = \left(\frac{k}{k_s} - 1 \right) \ln \frac{r_s}{r_w} \tag{2}$$

where r_w is the well radius (r_w = 0.12 m) and r_s is the outer radius of the adjacent grid cell (r_s = 0.29 m).

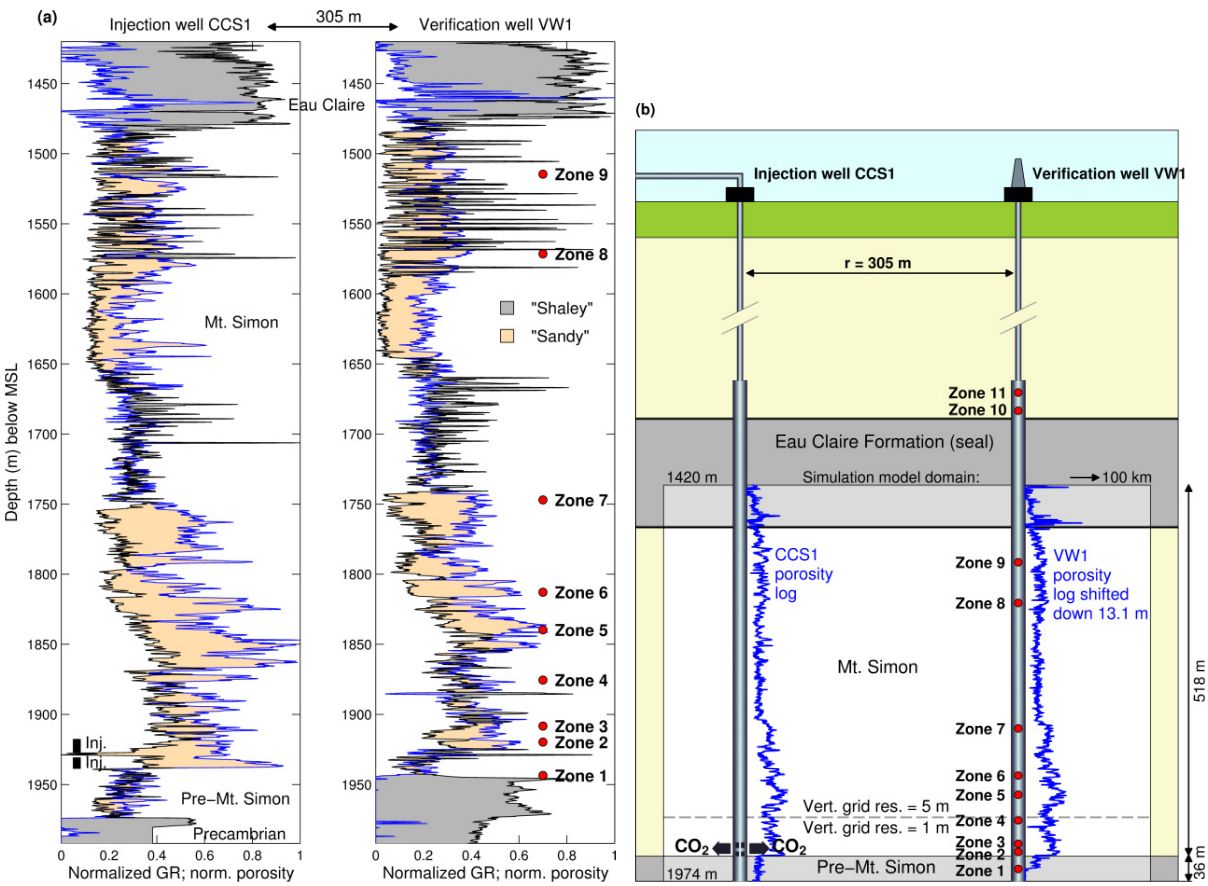

Fig. 2. (a) "Crossplots" of normalized gamma ray (GR; black) and normalized porosity (blue) for injection well CCS1 and verification well VW1. Combinations of relatively lower GR and higher porosity values indicate sandy rock, whereas combinations of relatively higher GR and lower porosity values indicate tighter rock. The logs from CCS1 were normalized to minimum and maximum GR values of 26 and 227 API, and minimum and maximum porosity of 0.01 and 26.6%, respectively. The logs from VW1 were normalized to minimum and maximum GR values of 12 and 188 API, and minimum and maximum porosity of 0.01 and 37.0%, respectively. (b) Schematic of the geologic model used for simulations. The model is symmetric about injection well CCS1 and perfectly layered, and the logs from verification well VW1 are shifted down 13.1 m in order to accommodate the perfectly layered system. Supercritical CO_2 is injected at the bottom of the Mt. Simon (into two separate intervals), and the simulation grid has a vertical resolution of 1 m below and 5 m above 1,885 m.

4. Results and discussion

First, the multilevel pressure transients at IBDP are analyzed according to the diagnostic tools provided by Strandli and Benson [18]. Pressure buildups normalized to the pressure buildup at the depth of injection and vertical pressure gradients normalized to the initial, hydrostatic pressure gradient are diagnostic of reservoir structure and height of the CO_2 plume. Second, we demonstrate that by history matching the multilevel pressure transient data, it is possible to develop a hydrogeological model that can be used to predict future CO_2 migration pathways.

4.1. Diagnostic analysis – normalized pressure transients

Normalized pressure changes for Zones 2 through 6 (normalized to the pressure change in Zone 2) are shown in Fig. 3, next to the regular changes in pressure from the initial pressure. The normalized pressure buildups in Zones 4 through 6 (and shallower zones) stay well below unity, indicating a heterogeneous/anisotropic reservoir and that the CO_2 plume is confined to the depth of injection and never reaches Zone 4. (The spikes in the normalized pressure changes are caused by the variable injection rate. Whereas Zones 2 and 3 respond quickly to injection rate changes, the other zones do not, hence the normalized pressure buildups in Zones 4-6 in particular spike during periods when the injection well is shut-in.)

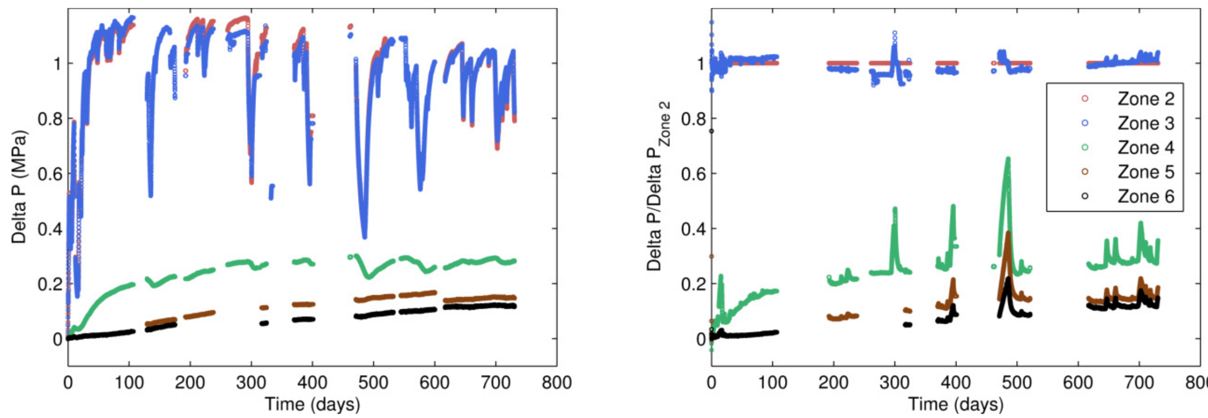

Fig. 3. Change in pressure from the initial pressure (left) and pressure buildups normalized to the pressure buildup in Zone 2 (right) for Zones 2 through 6 at verification well VW1. (Note that the spikes are caused by the variable injection rate.)

4.2. Diagnostic analysis – normalized, vertical pressure gradients

Vertical pressure gradients for selected monitoring zones and times and the corresponding vertical pressure gradients normalized to the initial, hydrostatic pressure gradient are shown in Fig. 4. Normalized, vertical pressure gradients equal to unity indicate no change from initial conditions. Before the CO_2 plume intersects the verification well, normalized gradients greater than unity indicate upward flow of displaced brine above/ahead of the plume, whereas normalized gradients less than unity indicate downward flow beneath the plume.

The selected gradients in Fig. 4 indicate presence of low permeability rock between Zones 3 and 4 and that the CO_2 plume is confined to Zones 2 and 3, with upward flow of brine above Zone 3. The normalized, vertical gradient between Zones 2 and 3 first goes above unity but then decreases below unity, suggesting that over time, a bigger portion of the CO_2 plume is flowing through Zone 3. This pattern is diagnostic of buoyancy driven flow between Zones 2 and 3 and consistent with CO_2 first being detected in VW1 in Zone 3 (March 2012) and later in Zone 2 (July 2012) [25].

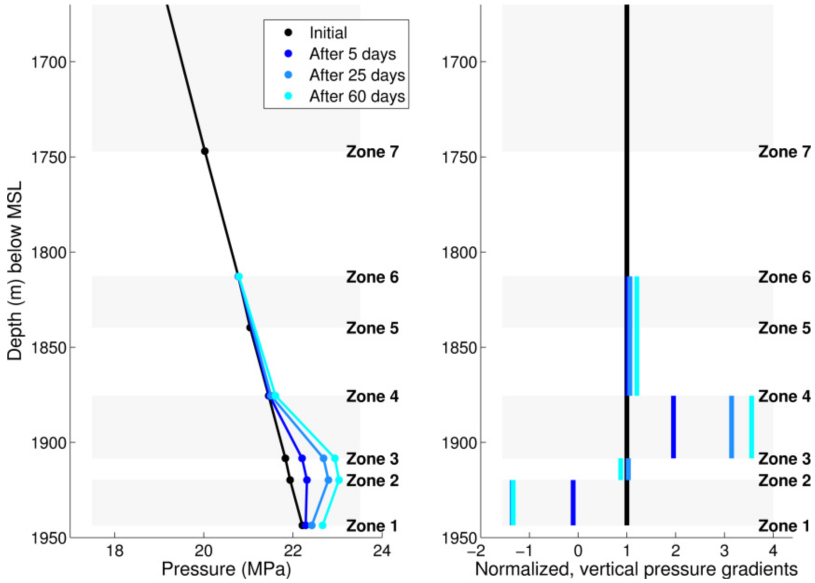

Fig. 4. Selected vertical pressure gradients (left) and the same vertical pressure gradients normalized to the initial, hydrostatic pressure gradient (right). A normalized gradient equal to 1 indicates no change from initial conditions, a normalized gradient greater than 1 indicates upward flow, and a normalized gradient less than 1 indicates downward flow. Zone 5 has been left out and the gradient between Zones 4 and 6 calculated instead, as the pressure gauge in Zone 5 was offline for much of this early time. Zone 1 is shown here for completeness but is otherwise left out due to uncertainty about whether the measurements from Zone 1 are reliable.

4.3. History matched multilevel pressure data

The permeability values that were found to give a match between the TOUGH2-MP simulated pressure and the pressure buildup observed at the IBDP are shown in Fig. 5. The average permeability over the 23-24 m thick injection zone in the model is approximately 150 mD.

The pressure transient data were history matched over 40 days of injection and is predicted over two years of injection, shown in Fig. 6. The increasing gap between the simulated and observed pressure data over time requires further investigation, still, the overall good match suggests that a multilayered, radially symmetric model may be sufficient for describing and predicting CO_2 migration at the IBDP. In particular, the multilevel pressure data show that the CO_2 plume is confined below Zone 4 by low permeability layers that provide capillary barriers to the buoyant flow of CO_2. Without the presence of low permeability rock between Zones 3 and 4, the pressure buildup in Zone 4 would be much higher. This major influence on the buoyant flow of CO_2 is well captured by a perfectly layered model. Our model predicts (so far correctly) that the CO_2 will continue to migrate mainly laterally within the zone of injection.

Fig. 7 shows the corresponding, simulated CO_2 plume after four months and eight months of injection (March and July 2012, respectively). The CO_2 plume migrates along two high permeability layers, arrives first at Zone 3 and then at Zone 2 but never reaches Zone 4, which corresponds with the information obtained from RSTPro* reservoir saturation tool logs [25].

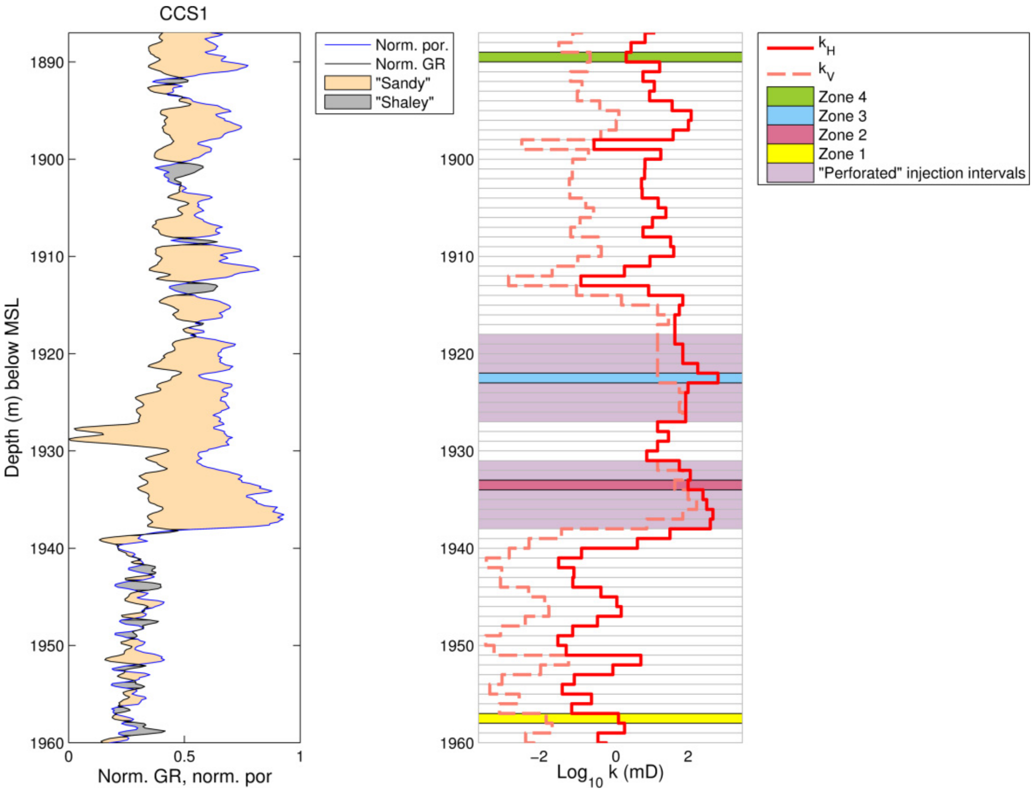

Fig. 5. "Crossplot" of normalized gamma ray (GR) and porosity logs for injection well CCS1 (left) and "best case" permeability values that were input into the simulation model in TOUGH2-MP (right) for the depth interval between Zones 1 and 4. The initial horizontal permeabilities k_H were based on SDR (Schlumberger-Doll Research) Model computed permeability logs from CCS1 and verification well VW1 and subsequently modified. The initial vertical permeabilities k_V were taken as $0.01 \times k_H$ and also subsequently modified. The depths of monitoring Zones 1 through 4 in the simulation model are indicated, as are the depths of the "perforated" injection intervals. The grid lines correspond to the horizontal grid lines in the simulation model; at this depth the grid cells are 1 m thick in the vertical direction. In order to achieve a match with the CO_2 breakthrough time at VW1, individual layers of k_H in the injection intervals were adjusted subsequent to the history match of the pressure transient data, maintaining the average k_H across the injection intervals obtained from the history match. Note that Zone 1 has not been matched with this input.

5. Conclusions

This work demonstrates that multilevel pressure monitoring inside a geological storage reservoir offers valuable information on reservoir structure and CO_2 migration. In particular, multilevel pressure transients can be used to determine the height of the CO_2 plume within the storage reservoir, and multilevel pressure transients are also excellent for history matching to help constrain hydrogeological models used to predict future CO_2 migration.

The application of multilevel pressure monitoring at the IBDP, where the Westbay System is installed in verification well VW1, has provided a unique opportunity to test and evaluate the potential for tracking CO_2 plume migration using multilevel pressure transient data. Diagnostic analyses of the multilevel pressure data from the IBDP show that the CO_2 plume is confined below Zone 4, which is consistent with sampling data and RSTPro reservoir saturation tool logs. In addition, a multilayered, radially symmetric model with TOUGH2-MP/ECO2N has been used to history match the pressure buildup at injection well CCS1 and verification well VW1. Though the increasing gap over time between the simulated and observed pressure data requires further investigation, this work shows one possible hydrogeological model that gives an overall good match with the change in BHP at injection well CCS1 and three monitoring zones at verification well VW over two years of injection, as well as the CO_2 breakthrough time at VW1. This demonstrates that by history matching multilevel pressure transient data, a hydrogeological model can be developed that in turn can be used to predict future CO_2 plume migration. As the history match is non-unique, inverse modeling with rigorous sensitivity studies will need to be addressed in future work.

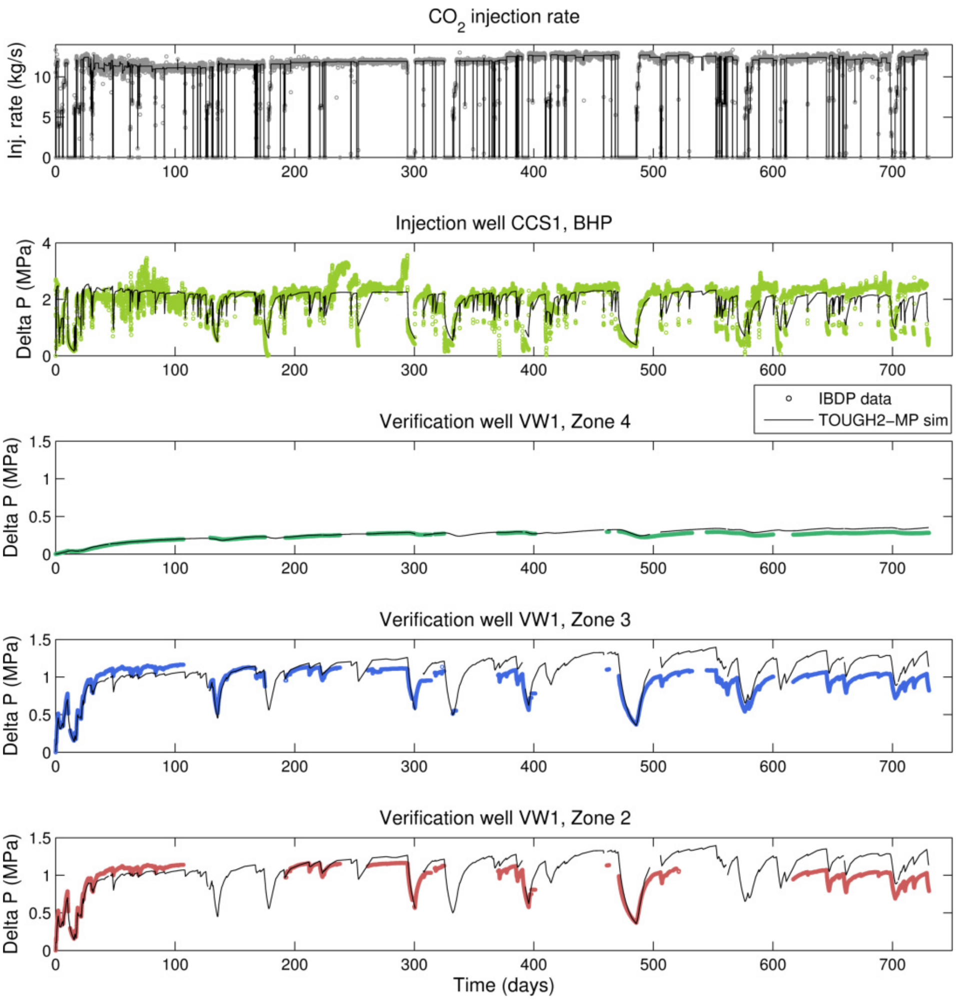

Fig. 6. History matched and TOUGH2-MP predicted change in BHP (injection well CCS1) and pressure changes at Zones 2 through 4 (verification well VW1), along with the pressure changes (hourly averages) observed at the IBDP. The varying CO_2 injection rate at the IBDP (hourly averages) and the step rates that were input into TOUGH2-MP are is also shown (top).

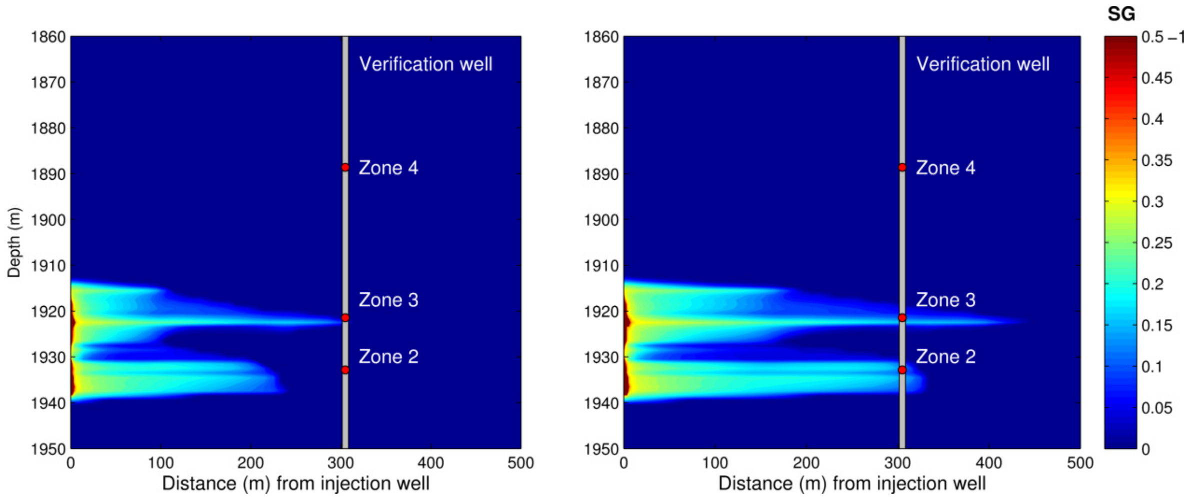

Fig. 7. TOUGH2-MP simulated CO_2 plume (gas saturation SG) after (left) four months of injection and (right) eight months of injection.

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Appendix A. Mesh and well implementation used for simulations in TOUGH2-MP

A radially symmetric grid with 12,194 grid cells is used for simulations in TOUGH2-MP. Details on the mesh are provided in Table 2.

A well is implemented in the center column by letting 20 grid cells from the top of the upper "perforated" interval to the bottom of the lower "perforated" interval have very high porosity (0.98) and permeability (1×10^{-6} m^2) and no capillary pressure. Connections are removed above and below the well column, as well as between four well grid cells and the adjacent reservoir grid cells between the two "perforated" intervals. At the "perforated" intervals, the nodal points in the well grid cells are moved almost to the grid cell interfaces (less 1×10^{-10} m). All injection is into the uppermost well grid cell.

Table 2. Mesh used for simulations in TOUGH2-MP.

Radial direction (center to outer end)										Sum
Number of grid cells	1	2	3	5	10	30	6	5	5	67
Grid cell thickness (m)	0.12	0.17	0.18	1.8	9	10	100	1,800	18,000	100,000 m
Vertical direction (bottom to top)										Sum
Number of grid cells	89	93								182
Grid cell thickness (m)	1	5								554 m