Using pulse testing for leakage detection in carbon storage reservoirs: A field demonstration

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Abstract

Monitoring techniques capable of deep subsurface detection are desirable for early warning and leakage pathway identification in geologic carbon storage formations. This work demonstrates the feasibility of a pulse-testing-based leakage detection procedure, in which the storage reservoir is stimulated using periodic injection or pulsing patterns and the acquired pressure perturbation signals are analyzed in the frequency domain to detect potential deviations in the reservoir's frequency domain response. Unlike the traditional well testing and associated time domain analyses, pulse testing aims to minimize the interference of reservoir operations and other ambient noise by selecting appropriate pulsing frequencies such that reservoir responses to coded injection patterns can be uniquely determined in frequency domain. Field demonstration of this pulse-testing leakage detection technique was carried out at a CO₂ enhanced oil recovery site—the Cranfield site located in Mississippi, USA, which has long been used as a carbon storage research site. During the demonstration, two sets of pulsing experiments (baseline and leak tests) were performed using 90-min and 150-min pulsing periods to demonstrate feasibility of time-lapse leakage

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detection. For leak tests, an artificial leakage source was created through rate-controlled venting of CO₂ from one of the monitoring wells because of the lack of known leakage pathways at the site. Our results show that leakage events caused a significant deviation in the amplitude of the frequency response function, indicating that pulse testing may be deployed as a cost-effective active monitoring technique, with a strong potential for site-wide automated monitoring.

Keywords: Leakage detection, Geological carbon sequestration, Pulse testing, Frequency domain analysis

1. Introduction

Carbon capture and storage (CCS) is being pursued as a large-scale mitigation option for making dramatic reductions in greenhouse gas emissions from power plants and other industrial sources. A recent report by the International Energy Agency points out that CCS is the “only technology available today that has the potential to protect the climate while preserving the value of fossil fuel reserves and existing infrastructure” [18]. For geologic storage, supercritical CO₂ is injected into deep geologic formations that are typically located 1–3 km below surface (e.g., depleted oil and gas reservoirs, unminable coal seams, or saline aquifers). Potential leakage through abandoned wells and geologic faults represent the greatest risk to geologic carbon storage projects. To ensure containment efficiency and public safety, the fate and transport of injected CO₂ plume must be closely monitored during the life cycle of a geological sequestration project. Over the last decade, a wide array of monitoring methods have been developed and demonstrated for leakage detection, including pressure monitoring, soil gas monitoring, groundwater sampling, geophysical surveys, vegetation stress, eddy covariance, and remote sensing [26, 42]. Leakage pathways tend to be more diffused and the leak signals more attenuated as the distance from the source increases. Thus, monitoring methods/instruments

capable of deep subsurface detection are more desirable for early warning and leakage pathway identification. Common methods suitable for deep subsurface monitoring can be roughly classified into surface-based and downhole technologies. The former mainly includes time-lapse seismic surveys, while the latter includes wellbore sensors and tools such as downhole pressure and temperature gauges, fluid samplers, microseismic sensors, and distributed optical sensing cables.

Pressure sensing is one of the most studied and, arguably, most well established leakage detection methods for deep subsurface monitoring. A large number of analytical and numerical modeling works have been performed to quantify pressure anomalies resulting from focused leakage (e.g., from faults and abandoned wells) and diffusive leakage (e.g., from leaky caprocks) [e.g., 32, 8, 37, 40, 23, 10, 13, 6]. Major advantages of pressure sensing over other deep subsurface detection technologies include its (i) early detection potential; (ii) cost effectiveness; (iii) suitability for continuous, automated, long-term deployment; and (iv) suitability for optimal sensing or targeted monitoring [21, 38, 19, 17]. Concerns over pressure sensing include its lack of sensitivity to “small” leaks and its proneness to noise interference, especially when deployed for monitoring CO₂ enhanced oil recovery (CO₂-EOR) reservoirs. Notwithstanding the large number of theoretical studies, relatively few field experiments have been conducted to date to demonstrate the effectiveness and limitations associated with the pressure-based leakage detection for carbon storage reservoirs. Here, a distinction is made between field experiments that are designed to quantify the effect of pressure responses to leakage and those that simply collect pressure data as side products. We refer the former category as active monitoring, while the latter as passive monitoring.

This paper presents results from a series of deep subsurface tests conducted

recently at a CO₂-EOR field near Cranfield, Mississippi, USA. These tests were exclusively designed to investigate the feasibility of deploying pulse testing as a simple and cost-effective leakage detection technique. Pulse testing can be considered a special type of pressure transient testing. During pulse testing, the injection rate is varied periodically while reservoir pressure responses are continuously monitored in observation wells. The pressure data are then analyzed to characterize hydraulic communication between wells and to infer reservoir parameters. Although pulse testing has long been used in reservoir characterization, its use for monitoring the integrity of carbon storage formations is new and, as far as we know, has never been tested in the field. In the following sections, we present the background of our field study site, the experimental design and methodologies, field data interpretation, and discussion. Finally, lessons learned from the field experiment are summarized.

2. Background of study site

The Cranfield site has been used as a demonstration site for geologic carbon storage during the last seven years, under collaboration between the Southeast Regional Carbon Sequestration Partnership (SECARB) and Denbury Onshore LLC (Denbury). Oil and gas production originally started at the site in 1944. Gas recycling was used to maintain reservoir pressure until 1959, when the gas cap was depleted. By 1966, most of the wells had been plugged and abandoned. The reservoir remained idle until Denbury began CO₂ flooding for EOR in July 2008. The source of CO₂ was produced from a nearby natural source in Jackson Dome, Mississippi. The Cranfield site was originally selected by SECARB to develop the practice of “stacked storage,” which would use the EOR operations to support infrastructure setup, characterization, and public acceptance for longer-term saline storage of CO₂ [16].

73 The Cranfield reservoir is a four-way structural closure (with a northwest-
 74 trending crestal graben) located about 3,010 m below ground surface. The reser-
 75 voir formation comprises fluvial sandstones and conglomerates of the Cretaceous
 76 lower Tuscaloosa Formation, which is underlain by a regional unconformity on
 77 top of shales and sandstones of the Dantzler Formation. The regional confining
 78 zone overlying the reservoir is 60 m of the middle Tuscaloosa marine mudstone.
 79 The CO₂ injection interval at the Cranfield site is locally referred to as the D and
 80 E units, which range from 14 to 24 m in thickness and were deposited as part
 81 of a laterally continuous but internally complex fluvial formation comprised of
 82 fining-upward sandstones and conglomerates. Chlorite coatings appear to have
 83 preserved porosity and inhibited quartz cementation, but occluded permeability.
 84 The stacking facies pattern of point-bar and channel sand bodies as found in the
 85 D-E units can have a significant impact on flow and transport paths, as many
 86 previous studies have shown [24, 39]. The reservoir temperature is about 129
 87 °C, and reservoir pressure before CO₂-EOR started is around 32 MPa, which
 88 is close to the original hydrostatic pressure in place. The dip of the reservoir
 89 interval ranges from 1 to 3 degrees. More detailed descriptions of the regional
 90 and site geology related to Cranfield can be found in Lu et al. [27].

91 Many of the past research and development activities at the Cranfield site
 92 had been conducted at its Detailed Area of Study (DAS) site, which consists of
 93 three colinear wells, including one injector (CFU31-F1) and two monitoring wells
 94 (CFU31-F2 and CFU31-F3) (Fig. 1). These three wells will be referred to as F1,
 95 F2, and F3 in the rest of this paper. The surface separation distance between
 96 F1 and F2 is 69.8 m, and between F2 and F3 it is 29.9 m. The bottom-hole
 97 distance between F1 and F2 is 60 m; between F1 and F3 it is 93 m; and between
 98 F2 and F3 it is 33.5 m. F2 and F3 were completed with fiberglass casing to
 99 facilitate electrical resistance tomography (ERT) measurements and other well

100 loggings during site characterization. Fig. 2 shows the vertical distributions
 101 of permeability and porosity values obtained from core samples, which reflect
 102 the vertically and laterally heterogeneous nature of the lower Tuscaloosa fluvial
 103 formation. All three wells are located just outside the oil field and completed
 104 in the water zone below the oil-water contact.

105 Injection of CO₂ into brine at F1 was initiated on December 1, 2009 with
 106 an initial rate of 175 kg/min, which was increased gradually to 350 kg/min.
 107 Continuous fluid sampling was carried out during the first month of CO₂ injec-
 108 tion, and two subsequent tracer tests using sulfur hexafluoride and noble gases
 109 were conducted at different injection rates to measure flow velocity changes. A
 110 main goal of that experiment was to obtain high-resolution monitoring data as
 111 the reservoir went through phase changes. Experimental results indicated that
 112 the DAS wells were connected through numerous, separate fluid flow pathways
 113 [27]. To confirm storage permanence and track the CO₂ plume pattern, cross-
 114 well seismic tomography was done before injection started and then 10 months
 115 after the initiation of injection [3]. The time-lapse seismic tomography revealed
 116 two spatial zones of significant CO₂ saturation, which corresponds to zones of
 117 elevated permeability in lower Tuscaloosa D-E units (Fig. 2) and are consistent
 118 with results from time-lapse sonic logs and the Reservoir Saturation Tool (RST)
 119 logs.

120 The injection rate at Cranfield has been about 1 million metric tons per
 121 year since 2008 [16]. High-resolution pressure gauges were initially deployed
 122 in both the reservoir and the above-zone monitoring interval in a monitoring
 123 well (EGL-7) located near the center of the Cranfield site to monitor pressure
 124 responses to the initiation of injection. The injection zone gauge showed a pres-
 125 sure increase within days of the start of injection and pressure increased steadily
 126 for 3 months, raising the reservoir pressure to approximately 5.2 MPa (754 psi)

above the initial conditions [31]. Experience gained from EGL-7 suggests that continuous pressure monitoring has merits in capturing high-frequency pressure variations. However, isolating the causes of these variations was challenging using passive monitoring alone because of the ambiguity caused by reservoir operations [16]. In contrast, the time-lapse pulse-testing leakage detection proposed in this study is an appealing, active monitoring technique that is designed to counteract noise interference to pressure signals. In the next section, we describe the main principles underlying pulse testing and provide details on field experimental design and execution.

3. Methodology

3.1. Pulse testing

Pulse testing was originally introduced to reservoir characterization in the 1960s [20]. Since then, the technology has been demonstrated for crosswell pressure transient testing in many reservoir studies [e.g., 30, 4, 11]. The simplest pulse testing involves the use of square or rectangular pulses. If conditions permit, harmonic pulse testing (HPT) may also be done, in which case sinusoidal excitation to the reservoir is introduced through the pulser well and pressure responses are continuously monitored in both the pulser well and the monitoring well(s). Compared to square pulses, HPT data are easier to analyze because only a single sinusoid is involved per test; however, the test itself is more complicated to administer and requires special equipment to generate sinusoidal rates. So far, HPT has been investigated mainly in analytical and numerical reservoir modeling [14, 2, 36], groundwater applications [33, 7, 12, 34], and laboratory core sample characterization [5].

By design, the interference of instrumentation noise and reservoir operations can be significantly suppressed or even completely eliminated in pulse testing

by selecting a priori the pulsing periods and, thereby, frequencies of signals. Such is the main advantage of active pressure monitoring over passive pressure monitoring. Moreover, repeating pulse testing at multiple pulsing periods may extract additional information on reservoir properties and improve reservoir parameter estimation, as shown in previous studies [7, 11].

Using Fourier expansion, the pulse function applied at an injector can be approximated using superposition of sinusoids, each having a frequency that is a multiple of the fundamental frequency. The corresponding pressure response at a monitoring well can then be approximated as

$$P(r, t) = \sum_{n=1}^N A_n \sin(n\omega t + \phi_n), \quad (1)$$

where P is pressure, r is distance from the pulser, t is elapsed time, $\omega = 2\pi/T$ is the fundamental frequency determined by the pulsing period T , and A_n and ϕ_n represent the amplitude and phase associated with the n -th sinusoid, respectively. It can be shown through integration that the square pulse contains only odd multiples of ω . According to the Nyquist sampling theorem, the highest frequency that can be resolved is determined by $1/(2\Delta t)$, where Δt is the sampling interval. Eq. (1) implies that pressure responses acquired from pulse testing can be analyzed using similar frequency-domain techniques developed for HPT [2, 11, 36].

Let P_{inj} and P_{obj} denote the pressure responses obtained from the injector and a monitoring well, the excitation-response relationship of the reservoir is given by the convolution integral

$$P_{obs} = \int_0^t P_{inj}(t - \tau)g(\tau)d\tau, \quad (2)$$

where $g(\cdot)$ is the transfer or kernel function. Let $\tilde{P}_{inj}$ and $\tilde{P}_{obs}$ represent the

175 Fourier transform of P_{inj} and P_{obj} , the system frequency response function
 176 $\mathcal{H}(\omega)$ (i.e., the Fourier transform of $g(\cdot)$) is defined as the ratio between $\tilde{P}_{obs}$
 177 and $\tilde{P}_{inj}$, namely, $\mathcal{H}(\omega) = \tilde{P}_{obs}/\tilde{P}_{inj}$. The frequency response function depends
 178 on mobility, porosity, and total compressibility of the reservoir under study,
 179 and thus it provides a characterization of the reservoir's excitation-response be-
 180 havior in frequency domain. For homogeneous isotropic reservoirs, pulse test-
 181 ing determines the value of mobility-thickness product (kb/μ) and porosity-
 182 compressibility-thickness product $(\phi c_t b)$, where k , b , μ , ϕ , and c_t represent
 183 permeability, effective reservoir thickness, viscosity, porosity, and total com-
 184 pressibility, respectively [22]. In this work, the frequency-domain data are used
 185 to estimate parameters through an analytical forward model. Each data point
 186 in frequency domain represents system responses to a particular frequency em-
 187 bedded in the pulsing signal (see Eq. (1)). By focusing only on those frequencies
 188 with meaningful data, the ambiguities related to time domain analyses, espe-
 189 cially those caused by noise, can be lessened.

190 The main idea behind pulse-testing-based leakage detection procedure is
 191 that if one or more new leaks occur within the detectable range of an observer,
 192 the observer's pressure responses to pulser will be modified, which then leads to
 193 an observable deviation in $\mathcal{H}(\omega)$ from its baseline shape. Thus, this technique is
 194 similar to time-lapse seismic methods in principle. When deployed as a routine
 195 monitoring method, each pulse test without anomaly can in turn serve as the
 196 baseline for the next test. The requirement of a baseline is common among time-
 197 lapse monitoring methods. Alternatively, a forward model can be developed to
 198 predict the nominal system behavior (i.e., in absence of leakage) in lieu of the
 199 baseline. The latter aspect is examined in the following analyses in Section 4.3.

200 In a multiphase fluid setting, it is commonly assumed that the injected fluid
 201 displaces the ambient fluid in a piston-like fashion such that two fluid banks are

202 formed and the saturation gradient within each fluid zone is approximately zero
 203 [1]. Theoretical and numerical validation of the time-lapse HPT leakage detec-
 204 tion concept have been provided in Sun et al. [35] and Sun et al. [36] for single-
 205 and multiphase flows. In general, the amplitude of $\mathcal{H}(\omega)$ decreases monotoni-
 206 cally with increasing pulse frequency. Longer pulsing periods may help probe
 207 leaks located farther away (provided that the observation well is still sensitive
 208 to both the pulser and leaks), but at the expense of longer experiment time.
 209 For carbon storage reservoirs, the authors suggested that the fluid condition at
 210 observation locations should not change significantly between two HPTs for the
 211 time-lapse method to give meaningful results.

212 The purpose of our Cranfield DAS experiment is to provide a field-scale vali-
 213 dation of the pulse-testing leakage detection concept. CO₂ flooding at the injec-
 214 tor F1 has been ongoing since December 2009. At Cranfield site, the operator
 215 injects CO₂ continuously rather than using the conventional water-alternating
 216 gas EOR strategy. For those reasons, it was expected that the injection interval
 217 underneath the DAS site is mostly saturated with supercritical CO₂ and the
 218 nonlinear effect related to multiphase flows is minimal. Also, fluid conditions
 219 between different sets of pulse tests were not expected to change significantly.

220 3.2. Field experiment design and procedure

221 The field campaign consists of baseline and leak experiments, which were
 222 conducted sequentially. Before the field experiments, high-resolution permanent
 223 downhole gauges (Ranger Permanent Hybrid Digital Addressable Surface Read
 224 Out Gauge, Ranger Gauge Systems, Sugar Land, Texas, USA) were installed
 225 in well F2 and F3 on December 16–17, 2014. The control lines in each well
 226 consist of hybrid fiber-optic electrical cables encapsulated in 0.635-cm (¹/₄-in)
 227 stainless steel tubing and were installed using a capillary injection unit through
 228 a lubricator and packoff. Resolution of the pressure gauge is 68.9 Pa (0.01 psi)

and its data polling frequency is set to every 2 sec. As discussed below, these highly sensitive pressure gauges are necessary to detect small pressure anomalies. Records kept by our well management subcontractor (Sandia Technologies, LLC, Houston, Texas, USA) show that the depth of the downhole gauge assembly is 3,221.1 m (10,568 ft) in F2 and 3,222.0 m (10,571 ft) in F3. Ideally, the bottom-hole pressure (BHP) at F1 should also be monitored during the experiment to normalize the frequency response function, $\mathcal{H}(\omega)$. However, it was not an option for this project. Thus, we mainly used the monitoring well data during analyses.

For the baseline, two sets of pulse testing experiments were performed on January 19 and January 20, 2015, one using a 90-min period and the other using a 150-min period. Each period starts with a shutin half cycle (50% of the time), followed by a constant-rate injection half cycle. These pulses were introduced to F1 by manually turning on/off the wellhead choke valve. F2 was used as the monitoring well in all experiments.

The actual pulse testing does not require additional equipment other than pressure gauges. However, because there is no known leakage pathway at the DAS site, for demonstration F3 was used to create an artificial leak by venting CO₂ from its wellhead. For this purpose, a surface venting plumbing system was set up while the baseline experiments were being conducted. The venting system was used to control the leak rate and to connect to a flowback tank for properly disposing of reservoir fluids that flow out with the gas. Fig. 3 shows a schematic design of the venting system. After rising to the wellhead, the CO₂ stream goes from the F3 wing valve into a 2.54-cm (1-in) iron pipe, which is equipped with a filter, a Coriolis flow/density meter (Micro Motion, Emerson Process Management, Boulder, Colorado, USA), and a flow control valve. Finally, the stream discharges into a 5.08-cm (2-in) pipe connected to the flowback tank that is located more than 15 m from the wellhead. Pressure

256 and temperature sensors are installed at various locations of the venting system
257 to monitor the flow condition. The filter is used to remove solid particles (e.g.,
258 drilling mud residues) that rise to the wellhead. To prevent safety hazards, all
259 sensors and the flow meter are wired to an onsite trailer for remote monitoring
260 and data recording, and the flow control valve can also be regulated remotely
261 through an air compressor connected to the valve.

262 The leak experiments were repeated using the same pulsing periods as those
263 used in the baseline tests, but with the controlled “leak” on all the time. The
264 first leak experiment was started on January 23. Unfortunately, data com-
265 munication with the downhole gauge in F2 was lost soon after the experiment
266 started. A slickline service company was called in to replace the downhole gauge
267 with a wireline memory gauge. Experiments then resumed one week later. A
268 90-min leak experiment was performed on January 30 and a 150-min leak ex-
269 periment was performed the second day. Venting rate from F3 was fixed at 60
270 kg/min during two leak experiments, but sensitivity to smaller leak rates was
271 also studied.

272 A number of incidents happened during the leak experiments, caused by
273 natural and human factors. First, after a couple of cycles in each leak ex-
274 periment, formation water somehow got into the F3 wellbore, causing surface
275 venting pipelines to freeze. The experiment had to be stopped to de-ice the
276 pipelines. Second, the filter was briefly clogged on several occasions and needed
277 to be “backwashed” to clean out residues. Third, the first experiment was cut
278 short because of a shortage of field personnel (only Denbury personnel could
279 control F1 valve). The impact of all these interruptions on the pulse testing
280 results will be discussed in Section 4.

3.3. Data processing and parameter estimation

Pressure data acquired during pulse testing are first detrended before they are transformed to frequency domain using fast Fourier transform (FFT). Also, to mitigate the impact of initial pressure transients, data from the first half-cycle of all experiments are discarded. The baseline experiments are used for two purposes: (a) time-lapse comparison with the subsequent leak experiments and (b) characterization of reservoir parameters in a baseline model. The latter is developed from pressure diffusivity equation given in radial coordinates

$$\frac{\partial^2 P}{\partial^2 r} + \frac{1}{r} \frac{\partial P}{\partial r} = \frac{\phi \mu c_t}{k} \frac{\partial P}{\partial t} \quad (3)$$

subject to initial and boundary conditions

$$\begin{aligned} P(r, t = 0) &= P_{init}, \\ \lim_{r \rightarrow \infty} P(r, t) &= P_{init}, \\ \frac{2\pi k b}{\mu} r \frac{\partial P}{\partial r} \Big|_{r=r_w} &= q_{inj} B, \end{aligned} \quad (4)$$

where P_{init} is initial pressure, q_{inj} is constant injection rate, B is volumetric formation factor, and the ratio $k/(\phi \mu c_t)$ is diffusivity. Eq. (5) assumes homogeneous formation properties and infinite boundary conditions, which is a simplified representation of the physical system under study. Nevertheless, the simplified model provides a reasonable first-order approximation of the local system immediately surrounding the pulser well. In this case, the nearby oil producers are located much farther away than the distances between DAS wells. Thus, the imposed boundary conditions are deemed appropriate. The steady periodic solution can be obtained by solving Eq. (3) in frequency domain [36]

$$\tilde{P}_{obs} = \frac{\mu B q}{2\pi k b} \frac{K_0(\sqrt{j\omega_D})}{r_D \sqrt{j\omega_D} K_1(r_D \sqrt{j\omega_D})}, \quad r_D = \frac{r_w}{r_O}, \quad \omega_D = \frac{\omega r_O^2 \phi \mu c_t}{k} \quad (5)$$

in which j is the imaginary unit, r_w is well radius, r_O is the distance between
 pulser and monitoring well, and K_0 and K_1 are the zero-th and first-order mod-
 ified Bessel function of the second kind. Eq. (5) involves four main parameters,
 namely, k, b, c_t , and ϕ . The unknown parameters are estimated by minimizing
 the following objective function

$$\min_{\boldsymbol{\theta}} \sum_i \{ (\Lambda_i - |\tilde{P}(\omega_i, \boldsymbol{\theta})|)^2 + \lambda (\Phi_i - \angle \tilde{P}(\omega_i, \boldsymbol{\theta}))^2 \} \quad (6)$$

where $\boldsymbol{\theta}$ is a vector of unknowns; Λ_i and Φ_i are amplitude and phase data ob-
 tained from actual experiments for frequency ω_i ; $|\tilde{P}(\omega_i, \boldsymbol{\theta})|$ and $\angle \tilde{P}(\omega_i, \boldsymbol{\theta})$ denote
 the amplitude and phase shift of the frequency domain model given in Eq. (5);
 and λ is a weight factor used to scale the two terms in the objective function.
 The summation is over all amplitude and phase shift data pairs. In this work,
 the unknown parameters include permeability and the product of porosity and
 total compressibility (i.e., $\boldsymbol{\theta} = [k, \phi c_t]^T$), as is commonly done in type curve
 analyses [25]. The resulting sum of squares problem is solved by using `lsqnonlin`
 function in Matlab[29].

4. Results and discussion

4.1. Baseline experiments

The 90-min baseline pulse testing was initiated at 11:10 on January 19 and
 lasted for 5 cycles. Each cycle consisted of a 45-min shutin period, followed by
 a 45-min period of constant-rate injection at 3,621 bbl/d (2.83×10^5 standard
 m³/d), which is about twice the nominal injection rate (1,800 bbl/d) that had
 been used continuously at F1 for at least one month prior to our experiment.
 After the last shutin period of the experiment, the injection rate was set back
 to the nominal rate for the night. Before the experiment, the initial reservoir
 pressure was 4,718 psi (32.53 MPa). The formation factor corresponding to

the reservoir pressure and temperature is 0.00317 reservoir bbl/bbl. Figs. 4a and 4c show the raw pressure time series (1 psi = 6,894.7Pa) acquired from F2 and F3 for the duration of the experiment. Both plots show a sinusoidal pattern with a mild upward trend. Figs. 4b and 4d show the pressure anomalies obtained after detrending the raw data. The figures suggest that pressure anomalies resulting from pulsing are less than 0.5 psi in both wells, indicating relatively small effective permeability. Nevertheless, the signal-to-noise ratio is strong and instrumentation noise mainly manifests as small oscillations around the sinusoidal waves.

The baseline was repeated for the 150-min cycle on the second day (January 20) using the same injection rates. The test started at 8:25 and lasted for 4 cycles. Figs. 5a and 5c show the raw pressure time series obtained from the second pulse test, and Figs. 5b and 5d show the corresponding pressure anomalies. The raw signals show patterns similar to those seen in the 90-min case: a sinusoidal wave with a mild upward trend. In this case, the magnitudes of pressure anomalies are greater because of longer pulsing periods.

Overall, the baseline experiments went smoothly, although the magnitude of reservoir pressure anomalies resulting from pulsing was lower than expected, indicating a relatively low effective permeability. Thus, the high-resolution pressure gauges turned out to be instrumental for picking up the small pressure changes. During the experiments, the monitoring well temperature was rather insensitive to the pulses and is not shown here.

4.2. Leak experiments

The 90-min leak experiment started at 8:30 on January 30 and venting of CO₂ started at the same time. Fig. 6 shows a typical scene from the leak experiment. The expansion of CO₂ from liquid to gas phase absorbs heat. Thus, the pipeline to flowback tank is covered with frost under normal conditions, as

shown in the picture. However, when CO₂ stream also has water and other impurities in it, ice forms inside the pipeline, eventually clogging the CO₂ flow.

Fig. 7a shows the raw pressure signals obtained from the 90-min experiment. Fig. 7b shows the BHP at F3 and leak history. Density log measured by the flow meter is shown in Fig. 7c. During the experiment, the venting pipeline was stopped briefly (several minutes) for backwashing and de-icing, which show up as three spikes in Fig. 7b. Between 11:00 and 11:30, the density log shows two slight increases that signal the inflow of heavier formation water into the well column. Because of the personnel issue mentioned in Section 3, the experiment was terminated earlier than planned at 12:15. Fig. 7d shows the pressure anomalies after removing a linear trend from the raw pressure signals. For comparison, pressure anomaly time series from the corresponding baseline experiment is superposed. The leak profile is more subdued than that of the no-leak case. The low pressure near 10:55 coincided with the first shutdown for backwash, which caused the pressure to rise earlier than planned.

The 150-min leak experiment started at 8:30 on January 31. Venting was started at 8:10. The experiment went smoothly from the start until about 13:05 when the pipeline became frozen, causing the experiment to shut down for 20 min. The water influx issue became more severe from that point on, as shown in Figs. 8a and 8b and the density log in Fig. 8c. As a result, the analysis was restricted to data collected before 13:00. In this case, Fig. 8d suggests that the deviation from the no-leak counterpart becomes more pronounced after the second full cycle starts. Comparison of Figs. 8a and 8b indicates that F2 is very responsive to BHP changes in F3, indicating good pressure communication between the two wells.

Overall, the two leak experiments turned out to be quite eventful. The original downhole pressure gauges lost communication to surface unit because

reservoir fluids got inside the stainless steel tubing used for housing the electrical cable. Indeed, several cracks were found on the tubing after the downhole gauge unit was retrieved from F2. The cracks might have been introduced during the installation process or caused by corrosion. Thus, for long-term monitoring, careful considerations must be given not only to the downhole gauge selection, but also to all its accessories, including tubing materials. The unexpected frozen pipe issue caused several mishaps. Apparently, formation water exists in isolated compartments that are outside the established CO₂ sweeping zones, five years after the initial CO₂ injection. When the pressure at F3 was reduced locally, either vertical or lateral water flux was activated, leading to influx into the wellbore. Although this issue pertains mainly to the needs of creating an artificial leak in our experiments and not to real-life pulse testing, for future experiments of this kind it is suggested that a separator be used to avoid ice formation in the venting pipe.

4.3. Time-lapse analyses

In this subsection, we compare data obtained from baseline and leak experiments. Signal processing is done by first removing a linear trend from the time series and then performing FFT. The resulting residual or pressure anomalies are already shown in Figs. 4, 5 and 7, 8. Because a simple square wave pattern is used in our experiments, amplitudes are dominated by those corresponding to the pulsing frequency, as can be seen from Fig. 9. Thus, only the dominating amplitudes are extracted for parameter estimation. Although other non-zero frequency responses (e.g., multiples of the pulsing frequency) can also be utilized for parameter estimation, [11], they are not pursued here because our main focus is on comparing time-lapse changes in frequency response function at the fundamental pulsing frequencies.

For the baseline experiments, the average phase shifts for each observation

well are identified from the time series plots shown in Figs.4 and 5 (vertical dotted lines) by using start time of injection and start time of pressure rise. The phase shift data are then normalized by respective pulsing periods. The effective reservoir thickness is set to 25 m in accordance with previous studies [15]. The scaling factor λ is set to 0.01 to scale amplitudes and phase shifts in the objective function because of their magnitude differences, Eq. (6). Using baseline data, the best estimates of k and ϕc_t are found to be 1.5 mD (1 mD= 1×10^{-15} m²) and 9×10^{-12} Pa⁻¹. To facilitate the demonstration of model-based leakage detection, uncertainty analyses is performed using Monte Carlo simulation by sampling from distributions listed in Table 1. Note that both k and ϕc_t are assumed to follow log-normal distributions. Their bounds are set on the basis of prior knowledge. Parameter variance values are chosen in such a way that the amplitude deviations are just outside the confidence bounds of the baseline model (see discussion below). A large number of realizations (20,000) are used in lieu of more delicate sampling schemes because the analytical model is fast to run.

The estimated effective permeability is relatively low but not unreasonable. Previously, Ajo-Franklin et al. [2013] estimated the permeability and porosity values to be 64 mD and 0.25 on the basis of F2 core samples. It is well known that crosswell testing reflects the effective formation properties of the reservoir volume between the pulser and observation well pair, whereas core sample analysis mainly provides point property estimates and may not be extrapolated to large distances beyond the logged well, especially for heterogeneous formations. On the basis of their U-tube sampling studies, Lu et al. [2012] noted that at the DAS site multiple flow pathways exist over a distance of tens of meters. Hosseini et al. [2013] could not identify a good linear correlation between porosity and log permeability using core sample data from six wells at Cranfield site.

Thus, because of the highly complex nature of the fluvial D-E units, it is not surprising that effective permeability estimated using pulse testing data differs from the core sample estimates. However, a key difference between our experiments and the 2009 tracer studies is that the effective reservoir flow paths are saturated with CO₂ in our case and thus, we mainly deal with single-phase CO₂ flows. The 2009 experiment largely dealt with CO₂ invasion in a depleted oil reservoir. The flow path characteristics and travel times are different in the two cases. Indeed, Lu et al. [27] observed that fluid flow velocity between F1 and F2 decreased after 5 months of continuous CO₂ flooding because of increased CO₂ saturation in the flow pathways or enlarged sweeping paths, or both.

Figs. 10a,b plot the amplitudes of transformed signals as a function of distances from the pulser, as predicted by the calibrated baseline model. For each subplot, the solid line is generated by using the estimated parameters and the shaded area is generated by using the 95% confidence interval derived from Monte Carlo simulations. Open circles correspond to the baseline data from F2 and F3. Fig. 10 suggests that amplitude decreases with increasing distance from the pulser and longer pulsing periods (i.e., 150-min) tends to boost the amplitude.

Fig. 11 plots the amplitude data obtained from all four pulse testing series acquired from observation well F2. Open symbols correspond to the no-leak experiments, while filled symbols are from the leak experiments. A plot like Fig. 11 provides the essential information required for time-lapse diagnosis of leakage. In this case, the chart shows a clear drop in the amplitude of leak data, as predicted by the analytical models given in [36]. The percentages of amplitude attenuation are 29% and 20% in the 150-min and 90-min experiments. The trend of amplitude attenuation as a function of pulsing frequency (ω) is also consistent with the analytical solutions presented in Sun et al. [2015], particu-

larly longer pulsing frequencies reveal larger amplitude attenuation. Thus, Fig. 11 graphically validates the concept of time-lapse leakage detection using DAS data.

As mentioned before, a more challenging situation is when baseline data are not readily available (e.g., at a site with pre-existing leak wells). For these situations, we propose that a statistical hypothesis testing approach be used, which involves a calibrated forward model that also incorporates model uncertainty. The performance of pulse-testing-based leakage detection is then dependent on the model’s prediction capability, at least for diagnosing the initial testing results. As an illustration, the variance of k and ϕc_t in Table 1 are manually selected such that the leaks can be identified using the baseline model with reasonable confidence. The resulting one-way lower confidence bound, 95% in this case, is obtained from Monte Carlo simulation and plotted in Fig. 11. For the present case, results suggest that parameter uncertainties should be relatively mild to be able to isolate the presence of leaks. When model uncertainty increases, the difference between deviations caused by model uncertainty and that by leakage becomes blurred. Such difficulty, however, is pertinent to all monitoring technologies requiring the use of predictive models and can only be tackled through acquiring additional site characterization information which, preferably, is acquired through a goal-oriented experimental design approach developed for leakage monitoring [41]. A model that is originally developed for capacity estimation may not possess the sensitivity or accuracy needed for leakage detection uses. It is worthwhile to point out that the shaded area in Fig. 11 is related to model prediction uncertainty, but not sample variance. The latter quantity can only be obtained by repeating the same pulse test configuration several times, and is expected to be much smaller than the range of model prediction uncertainty because it is mainly affected by random fluctuations in

485 experimental conditions (e.g., in injection rates), not by model uncertainties.

486 To simulate the worst-case scenario, the venting rate was fixed at 60 kg/min
487 throughout the leak experiments, which is about 20% of the injection rate.
488 Several sensitivity studies were performed on January 30 after the first leak
489 experiment was terminated. In these experiments, the leak rate at F3 was
490 pulsed while F1 was injecting at a constant nominal rate. The purpose was to
491 observe sensitivity of F2 to different leak rates. Fig. 12 shows an example from
492 the smallest leak rate we tested, which is 10 kg/min or 3% of the injection rate.
493 In this case, the magnitude of filtered signal is less than 0.05 psi (345 Pa), but
494 the effect of sinusoidal variations can be still observed in F2, indicating that F2
495 is sensitive to smaller leak rates at F3.

496 In general, several criteria need to be satisfied for pulsing testing to be used
497 as a detection procedure. First, observation wells need to be sensitive to puls-
498 ing. Typical distances between injectors and producers in oil and gas reservoirs
499 range from 100 to 500 m [28]. The distances between DAS wells fall on the low
500 side of the range, implying longer pulsing periods are probably needed for reser-
501 voirs having similar properties as Cranfield. However, we deal with a reservoir
502 with relatively low effective permeability. For more permeable reservoirs, the
503 area of coverage is expected to be larger. Second, observation wells need to be
504 sensitive to leaks. It is important to place monitoring wells at positions that
505 can enhance anomaly discovery through (adaptive) monitoring network design
506 [38]. In a benchmark study, Class et al. [2009] showed that a leak located
507 100 m from the injector can reach a maximum leak rate of about 1.2 kg/min
508 when the injection rate is 532 kg/min, which is on the same order of magnitude
509 as the smallest leak rate we tested at DAS. Thus, we expect that the pulsing
510 testing procedure demonstrated here has the potential to be deployed at the
511 well-pattern scale. Finally and probably more importantly, the cause of fre-

quency response deviation can be attributed to leakage. Although pulse testing is designed to avoid most commonly seen reservoir noise, site-specific conditions need to be considered during the triage phase. The last criterion requires the emplacement of a comprehensive data management such that anomalies can be analyzed and verified through multiple sources of information.

5. Summary and conclusions

A series of field experiments were performed at Cranfield’s DAS site to demonstrate the concept of time-lapse leakage detection. Results suggest that leakage introduced significant deviations in the reservoir’s frequency response function. Thus, pulse testing has the potential to be deployed as a cost-effective leakage detection procedure. Because it is an active monitoring technique, pulse testing can avoid much of the interference caused by reservoir noise. The wide availability of smart sensing technologies and the relatively straightforward testing procedure imply that pulse testing is suitable for long-term monitoring without significant additional investment from field operators. Cranfield’s DAS site offers several conditions that favor this particular demonstration, such as the proximity of the three wells, the relatively stable flow conditions after 5 years of CO₂ flooding, and the small impact of nearby production activities. The low permeability of the reservoir may have smoothed the pressure perturbations and made them appear more sinusoidal, but it also dampened the observed responses. In our case, the limited field access time prevented a more comprehensive set of leakage experiments from being done. In the future, we hope this simple technique can be tested by more researchers and reservoir operators.

535 **Acknowledgments**

536 This work was supported by the U.S. Department of Energy, National Energy
 537 Technology Laboratory under grant DE-FE0012231. The authors are grateful to
 538 the following individuals for their help during the field experiments: Denbury
 539 field technicians; Mr. Ramon Trevino, the SECARB project manager at the
 540 Bureau of Economic Geology; Mr. Paul Cook and Alex Morales at Lawrence
 541 Berkeley National Lab; Mr. Kirk Delaune at Sandia Technologies, LLC; and
 542 NETL project manager Mr. Brian Dressel. The authors are thankful to the
 543 two reviewers (Drs. Michael Cardiff and Peter Fokker) for their constructive
 544 comments during the review of the original manuscript.

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680 **Tables**

Table 1: Prior statistics used for Monte Carlo simulation

Parameter	Distribution	Mean	Std Dev	Lower Bound	Upper Bound
$\log(k)$	Normal	0.37	0.55	-4.61	4.61
$\log[(\phi c_t)10^{10}]$	Normal	-2.43	0.25	-6.91	1.61

681 **Figure Captions**

682 Fig. 1. Areal view of the Detailed Area of Study at Cranfield site (Lon: -91.141° ,
 683 Lat: 31.564°), which consists of an injector (F1) and two monitoring wells (F2
 684 and F3). During leak experiments, F3 was used as a “leaky” well. Locations of
 685 the flowback tank and trailer area are also labeled.

686 Fig. 2. Porosity and permeability profiles obtained from core sample analyses
 687 for (a, b) F2 and (c, d) F3.

688 Fig. 3. Schematic drawing of leak experiment setup: CO_2 vents from F3 well-
 689 head into the surface plumbing system consisted of a filter, a flow meter, a leak
 690 valve, and multiple pressure and temperature sensors. A flowback tank (see
 691 Figure 1) is used to collect formation fluids that may rise to the surface during
 692 venting.

693 Fig. 4. Results of 90-min baseline experiment: (a) the square wave injection
 694 pattern imposed at F1 (right axis) and raw pressure data observed in F2 (left
 695 axis); (b) filtered pressure anomalies in F2; (c) raw pressure data acquired from
 696 F3; and (d) filtered pressure anomalies in F3. Vertical dotted lines in (a) and
 697 (c) indicate lags between injection starts and observed pressure rises. The time
 698 axis corresponding to actual experimental time.

699 Fig. 5. Results of 150-min baseline experiment: (a) square injection pattern
 700 (right axis) and resulting raw pressure data observed in F2 (left axis) ; (b)
 701 filtered pressure anomalies in F2; (c) raw pressure data in F3; and (d) filtered

702 pressure anomalies in F3. Vertical dotted lines indicate lags between injection
 703 start times and observed pressure rises.

704 Fig. 6. Scene from leak experiment in session, in which the venting pipeline
 705 is covered with frost, liquid flowback tank is in the far back, and a slickline
 706 pressure gauge is used to monitor downhole pressure.

707 Fig. 7. Results from 90-min leak experiment: (a) raw data observed in F2
 708 (left axis) and imposed square pulses (right axis); (b) BHP in F3 (left axis) and
 709 surface leak rate (right axis); (c) density log measured by flow meter; and (d)
 710 filtered pressure anomalies in F2 for both leak and baseline experiments.

711 Fig. 8. Results from 150-min leak experiment: (a) raw data collected in F2
 712 (left axis) and square pulses (right axis); (b) BHP in F3 (left axis) and surface
 713 leak rate (right axis); (c) density log obtained by flow meter; and (d) filtered
 714 pressure anomalies in F2.

715 Fig. 9. Amplitude vs. frequency for the 90-min pulse experiment for F2 and
 716 F3, which show the dominating amplitudes occur at the base pulsing frequency.

717 Fig. 10. Amplitude of observed pulsing signals as a function of distance from
 718 F1 for (a) 90-min and (b) 150-min pulsing period. Open symbols on each plot
 719 correspond to data obtained from F2 and F3. Shaded areas represent confidence
 720 intervals estimated from Monte Carlo simulation, solid line corresponds to model
 721 values calculated using estimated parameters.

722 Fig. 11. Leak (filled symbols) caused significant deviation in amplitudes of
 723 frequency response function as compared to the no-leak case (open symbols).
 724 Solid line is calculated using estimated reservoir parameter values and shaded
 725 area is formed by using lower 95% confidence bound.

726 Fig. 12. A test used to test sensitivity of F2 to lower venting rates in F3: (a)
 727 filtered pressure response, and (b) BHP at F3 (left axis) and leak rate (right
 728 axis). A pulse like leak rate was imposed at F3.

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Figure 3: Fig. 3. Schematic drawing of leak experiment setup: CO₂ vents from F3 wellhead into the surface plumbing system consisted of a filter, a flow meter, a leak valve, and multiple pressure and temperature sensors. A flowback tank (see Figure 1) is used to collect formation fluids that may rise to the surface during venting.

Figure 4: Results of 90-min baseline experiment: (a) the square wave injection pattern imposed at F1 (right axis) and raw pressure data observed in F2 (left axis) ; (b) filtered pressure anomalies in F2; (c) raw pressure data acquired from F3; and (d) filtered pressure anomalies in F3. Vertical dotted lines in (a) and (c) indicate lags between injection starts and observed pressure rises. The time axis corresponding to actual experimental time.

Figure 5: Results of 150-min baseline experiment: (a) square injection pattern (right axis) and resulting raw pressure data observed in F2 (left axis); (b) filtered pressure anomalies in F2; (c) raw pressure data in F3; and (d) filtered pressure anomalies in F3. Vertical dotted lines indicate lags between injection start times and observed pressure rises.

Figure 6: Scene from leak experiment in session, in which the venting pipeline is covered with frost, liquid flowback tank is in the far back, and a slickline pressure gauge is used to monitor downhole pressure.

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Figure 8: Results from 150-min leak experiment: (a) raw data collected in F2 (left axis) and square pulses (right axis); (b) BHP in F3 (left axis) and surface leak rate (right axis); (c) density log obtained by flow meter; and (d) filtered pressure anomalies in F2.

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Figure 10: Amplitude of observed pulsing signals as a function of distance from F1 for (a) 90-min and (b) 150-min pulsing period. Open symbols on each plot correspond to data obtained from F2 and F3. Shaded areas represent confidence intervals estimated from Monte Carlo simulation, solid line corresponds to model values calculated using estimated parameters.

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