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Bayesian inference for heterogeneous caprock permeability based on above zone pressure monitoring

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ABSTRACT

The presence of faults/fractures or highly permeable zones in the primary sealing caprock of a CO_2 storage reservoir can result in leakage of CO_2. Monitoring of leakage requires the capability to detect and resolve the onset, location, and volume of leakage in a systematic and timely manner. Pressure-based monitoring possesses such capabilities. This study demonstrates a basis for monitoring network design based on the characterization of CO_2 leakage scenarios through an assessment of the integrity and permeability of the caprock inferred from above zone pressure measurements. Four representative heterogeneous fractured seal types are characterized to demonstrate seal permeability ranging from highly permeable to impermeable. Based on Bayesian classification theory, the probability of each fractured caprock scenario given above zone pressure measurements with measurement error is inferred. The sensitivity to injection rate and caprock thickness is also evaluated and the probability of proper classification is calculated. The time required to distinguish between above zone pressure outcomes and the associated leakage scenarios is also computed.

1. Introduction

CO_2 capture and storage (CCS) is considered a promising strategy for the reduction of anthropogenic greenhouse gas emissions to the atmosphere (IPCC, 2005). However, injecting large volumes of CO_2 may cause subsurface pressurization over large spatial domains, resulting in leakage that returns the injected CO_2 to the atmosphere and potentially harming natural resources (e.g., groundwater resources) (Birkholzer and Zhou, 2009; Pruess, 2004). To protect the environment and public health, a comprehensive risk profile should be established for each CCS project. To monitor these risks, it is necessary to have the capability to identify and resolve the onset, location, and volume of leakage from the reservoir in a systematic and timely manner. The monitoring of pressure changes, as an indication of leakage, represents one approach to provide this information, and has been explored by a number of investigators (Nogues et al., 2011; Sun and Nicot, 2012; Zeidouni and Pooladi-Darvish, 2012; Benisch and Bauer, 2013; Hovorka et al., 2013; Jung et al., 2013; Strandli and Benson, 2013; Azzolina et al., 2014; Wang and Small, 2014). In many of these studies highly simplified conceptual models have been used for the affected subsurface layers, including an assumption of homogeneous porosity and permeability in each (though in several cases the single values for each zone are treated as uncertain inputs to the model). In this paper, we maintain an idealized geometry for the subsurface system, but incorporate heterogeneity in the fracture pattern of the caprock and its resulting location-specific effective permeability. In addition, we apply a probabilistic approach in which uncertainty in the subsurface may be resolved by successive monitoring results.

Monitoring for leak detection at CO_2 storage sites serves a number of purposes, including ongoing assurance that the site is maintaining its integrity, verification that credited quantities of stored CO_2 do in fact remain underground, and alerting operators when changes are needed to modify or stop operations, including possible initiation of more intensive monitoring and remediation. Subsurface models complement monitoring by allowing interpretation of the observed data to identify the location and size of possible leakage sources (Pawar et al., 2016), and to predict the subsequent costs and risks of alternative response options (see, for example, Gerstenberger and Christophersen, 2016). Models that consider the performance of both the subsurface system and the monitoring network are especially useful in this regard, allowing a pre-construction estimate of the performance of alternative monitoring technologies and network designs under plausible leakage scenarios, including overall false positive and false negative rates

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for system-wide leak detection (Yang et al., 2011, 2012). Once such performance models have been developed and applied, they may be used for optimization of a monitoring network, as previously shown for near-surface groundwater leak detection (e.g., Loaiciga, 1989; Loaiciga et al., 1992; Meyer et al., 1994; Mahar and Datta, 1997; Reed and Minsker, 2004; Dhar and Datta, 2007). Similar optimization approaches have recently been proposed for the design of CO_2 leakage detection networks (Sun et al., 2013; Yonkofski et al., 2016).

Pressure monitoring in the Above Zone Monitoring Interval, or AZMI, has been proposed for early detection of leakage (Hovorka et al., 2013) because of the fast traveling speed of pressure perturbations and the proximity of the AZMI to storage formations (Nordbotten et al., 2004). However, unlike the storage formations, the AZMI will be subjected to less pressure disturbance during injection activities, which will require a monitoring network capable of detecting these smaller signals as well as interpreting potential anomalous pressure signals. From an operations perspective, deep pressure monitoring wells are costly to drill and maintain—drilling and instrumentation costs can easily exceed $ 1 million per well, which is in addition to annual maintenance and operation costs (U.S. Environmental Protection Agency, 2010). Thus, there is strong incentive to optimize the design of pressure-based monitoring networks (Sun et al., 2013).

In this paper, we focus on leakage of CO_2 through the primary caprock and resulting pressure changes in the AZMI. The primary aim of this work is to characterize the time required to distinguish AZMI pressure outcomes and associated leakage scenarios through a probabilistic assessment of the integrity and permeability of the caprock and also the amount of CO_2 injected into the reservoir. We present a method for integrating monitoring and modeling results to draw inferences regarding the integrity of the caprock, including how quickly these inferences can be made for different representative caprock types and conditions. These scenarios represent effective caprock permeability from almost impermeable to highly permeable cases. We then model the probability distributions of pressure build-up in the AZMI for each of these scenarios, with the modeled pressure fields assumed to be observed with measurement errors. These distributions serve as the likelihood function for a Bayesian classification model, in which the posterior probabilities are computed for each of the four caprock fracture scenarios. We also evaluate the influence of the thickness of the caprock and the CO_2 injection rate on the modeled pressure build-up and the subsequent performance of the Bayesian classification procedure. The modeling approach used in this study is based on the systematic framework shown in Fig. 1. The results from this work can in the future form the basis for more refined evaluation and optimization of monitoring technologies and networks.

2. Model setup

The CO_2 storage system is modeled as a three-layer system with two aquifers separated by a sealing caprock of thickness 50 m (Fig. 2(a)). The lower aquifer is the storage reservoir where CO_2 is injected at a base rate of 1 MT per year for a period of 30 years. Higher and lower injection rates are also considered in a sensitivity analysis. The base case thickness of the reservoir is assumed to be 100 m. The reservoir is located at a depth of 1000 m. The areal extent of the subsurface storage system is defined as 10 km × 10 km. The assumed reservoir features are summarized in Table 1. Reservoir simulations (Fig. 3) are conducted using TOUGH2. CO_2 and brine flux from the seal are then simulated for a period of 30 years of injection and 170 years of post-injection using the seal model, NSealR (Lindner, 2015). NSealR is a reduced order model (ROM) developed by the U.S. Department of Energy's National Risk Assessment Partnership (NRAP) program (NETL, 2011). NSealR uses a two-phase, relative permeability approach with Darcy's law for one dimensional (1-D) flow computations of CO_2 through the horizon in the vertical direction. The above zone thickness used in this study is 50 m. It is assumed that the AZMI layer has a porosity of 0.1 and a permeability of 10.5 mD. The residual CO_2 and brine saturations were set at 0.01 and 0.02 respectively and the bubbling pressure was set to equal 0.01 MPa. Three base case observation wells screened at 900 m depth are also considered. The locations of the wells are shown in Fig. 2(b). The locations are chosen to be representative of a possible spatial layout, primarily for demonstration purposes.

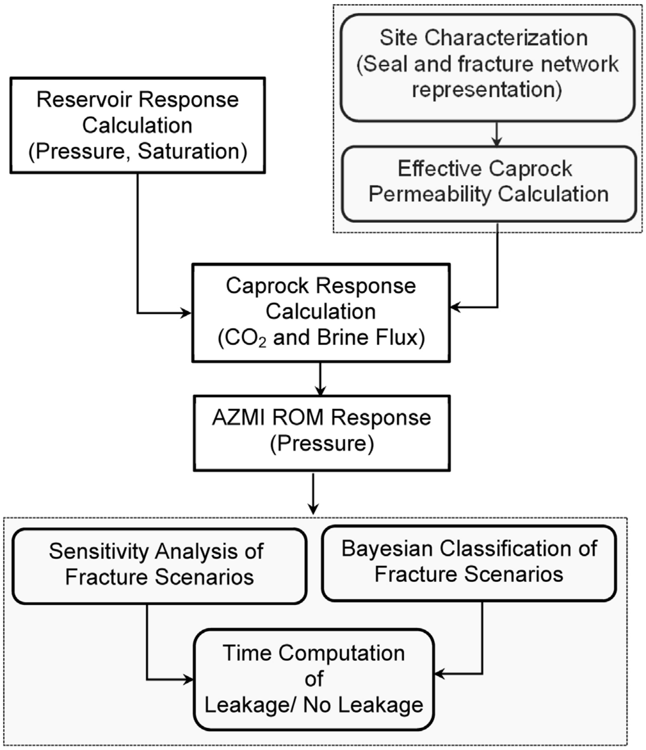

Fig. 1. Schematic framework of Bayesian design for above zone pressure monitoring.

Table 1
Storage reservoir and caprock features.

Parameters	Value
Density of rock	2600 kg/m^3
Initial pressure at depth = 1000 m	10 MPa
Pressure gradient	10^4 Pa/m
Average temperature at caprock	50 °C
Horizontal permeability (storage formation)	10^{-13} m^2 (0.1 D)
Vertical permeability (storage formation)	10^{-14} m^2 (0.01 D)
Salt (NaCl) mass fraction in brine	0.08
Porosity (storage formation)	0.1
Porosity (caprock)	0.05
CO_2 residual saturation	0.1
CO_2 injection period	30 years
Maximum simulation time	200 years
Domain size	10 × 10 km
Boundary condition	Open boundary

The sealing caprock is modeled for four different fractured network scenarios: (I) fractured network with low aperture; (II) randomly distributed clusters of fractures with high apertures; (III) fractured network zone with high aperture near the injection well and; (IV) densely fractured network with high aperture. These four scenarios are assumed to be representative of the range of possible storage seal scenarios with an impermeable seal layer with