Geological reservoir characterization and modelling of a CO$_2$ storage aquifer: A case study of the Nagaoka site, Japan

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Abstract

Site characterization is critical for safe and effective geological storage of CO$_2$ because geological heterogeneity affects reservoir quality, plume migration, and trapping. This study shows geological characterization and modeling of a CO$_2$ storage aquifer near Nagaoka, Japan. Core and well-logging analysis show that the target aquifer consists of deltaic deposits, which are characterized by a fining-upward to coarsening-upward succession that has developed on a ravinement surface. The target aquifer is attributed to prodelta and deltafront deposits. A geostatistical method known as sequential Gaussian simulation with collocated cokriging was applied to generate a spatial distribution of petrological and physical properties including shale volume, porosity, and permeability. The simulation was performed using well-log data as a primary variable and seismic-derived porosity data as a secondary variable under the constraints of correlation coefficient between variables. Simulated models showed that impermeable fine-grained deposits are distributed toward the east. This trend can explain the fact that breakthrough has not been observed at an observation well located farthest to the west from the injection well, IW-1. This result is consistent with previously proposed paleogeographic interpretations that show that detrital particles are transported from east to west at the Nagaoka site.

Keywords: Reservoir characterization; core-well-seismic data integration; Sequential Gaussian simulation with collocated cokriging

1. Introduction

Geological storage of CO$_2$, injection of captured atmospheric CO$_2$ in subsurface strata, is a prospective approach being considered to mitigate carbon emissions generated by fossil fuel combustion [1, 2]. Deep saline aquifers with...
no economic resources are suitable for geological storage. A robust site characterization of a deep saline aquifer is important to evaluate its safety and durability for successful geological storage. Site characterization techniques such as core analysis, well-logging analysis, and geological modeling provide the basis for evaluation. However, data are often sparse and limited at the early stage of a CO\textsubscript{2} injection project [3]. To overcome this deficiency, it is important to integrate and utilize available sediment core, borehole logging, and seismic geological and geophysical data. On the basis of those data, reservoir characterization and geostatistical approaches can be used to describe reservoir architecture and properties between and beyond well controls [4, 5].

Detailed sediment core analysis and well-log data interpretation provide useful information about vertical and lateral heterogeneity due to depositional environmental changes in a framework of sequence stratigraphy. However, those data only depict geology and petrology near wells. Effective utilization of seismic data strongly supports constructing a geological model that describes reservoir architecture away from wells, thus reducing uncertainty in the site characterization. In this paper, we present as a case study, an example of reservoir characterization and development of a reservoir model for a saline aquifer near Nagaoka, Japan.

2. Nagaoka project

The Nagaoka site is located near Nagaoka, Niigata Prefecture, in the Niigata Basin of central Japan (Fig. 1a). The target reservoir rock utilized for storage is correlated with the Pleistocene Haizume Formation (Fig. 1b). During 2001 and 2002, one injection well (IW-1) and three observation wells (OB-2, -3 and -4) were drilled (Fig. 1c). The permeable horizon with a 12 m thickness between 1093 and 1105 m depth at the IW-1 was selected as the target reservoir rock.

From 7 July 2003 to 11 January 2005, 10400 tons of CO\textsubscript{2} was injected into the target reservoir rock at IW-1 [6]. Pressure and temperature monitoring at the reservoir showed that the injected CO\textsubscript{2} was in a supercritical state (48 °C and 10.8 MPa). During and after injection, CO\textsubscript{2} breakthrough at the observation wells and behaviors of the CO\textsubscript{2} plume in the target reservoir rock were monitored using geophysical methods such as time-lapse well loggings [7, 8] and cross-well seismic tomography [9]. The post-monitoring results using P-wave velocity showed that the CO\textsubscript{2} distribution was not uniform in the reservoir rock (Fig. 1d). Significant decreases in P-wave velocity indicated CO\textsubscript{2} breakthrough at OB-2 240 days after injection start and OB-4 330 days after injection start; however, no CO\textsubscript{2} breakthrough has been observed at OB-3 (Fig. 1d). These monitoring results indicate geological heterogeneity. Lithological characterization of reservoir rock will be a key issue for understanding heterogeneity.

![Fig. 1. General geology and monitoring results at the Nagaoka site. (a) Index map; (b) illustration of geology; (c) configuration of wells; (d) time-lapse well logging using P-wave velocity after injection of CO\textsubscript{2}. P-wave velocity decreased significantly with the breakthrough of injected CO\textsubscript{2} in the observation wells.](image-url)
3. Geological, petrophysical, and geophysical data

We focused on a sediment core taken from target reservoir rock at IW-1, at the depth between 1080 and 1100 m, and describe its lithology and physical properties. We measured mud content, porosity, and permeability using core samples or core plugs, and measured grain size distribution using laser diffraction. Mud content was defined as the proportion of grains < 64 μm. Core plugs were retrieved and dried in a temperature-controlled oven at 100 °C until constant weight was achieved. We calculated core porosity using measured grain volume and bulk volume. We measured permeability was measured by a N₂ permeameter using the core plugs and used the Klinkenberg correction to correct for gas-slippage effects. Brine permeability was obtained by using the conversion relationship of gas and brine permeability.

To evaluate physical properties, we obtained continuous well logging data at all wells using nuclear magnetic resonance (NMR) and natural gamma-ray (GR) logging tools. Porosity and permeability of the target strata were obtained from the NMR data. We employed the Schulmberger-Doll Research (SDR) method to obtain permeability from NMR logging data. The GR logging tool was used for measuring natural gamma ray intensity to obtain shale volume \( V_{\text{shale}} \) from the following formula [10]:

\[
V_{\text{shale}} = \frac{\text{GR} - \text{GR}_{\text{sand}}}{\text{GR}_{\text{shale}} - \text{GR}_{\text{sand}}},
\]

where GR is measured gamma-ray (API), \( \text{GR}_{\text{sand}} \) is sand baseline gamma-ray (API), and \( \text{GR}_{\text{shale}} \) is shale baseline gamma-ray (API). \( \text{GR}_{\text{sand}} \) and \( \text{GR}_{\text{shale}} \) are set as the minimum and maximum GR values of the target strata at each well.

We acquired 3-D seismic data to construct a geological framework model. The vertical resolution of tuning thickness is about 23 m. The data were converted from time to depth domain using a 3D velocity model constructed from seismic velocity, check-shot, and sonic data. Well-logging and seismic data were then imported into Schlumberger Petrel software to reconstruct geological modeling at the Nagaoka site.

4. Results and discussion

4.1. Lithological features and physical properties at IW-1

Figure 2 shows GR-based shale volume, porosity, and permeability profiles with core analysis at IW-1. The major lithologies are bioturbated siltstone to fine-grained sandstone, laminated fine-grained to coarse-grained sandstone, and conglomerate (Fig. 2a). Lithological and grain-size features indicate generally coarsening-upward sequences. A previous study illustrated that the sediment core is mainly composed of shallow marine siliciclastic deposits and has a coarsening-upward sequence, which is attributed to a prodelta to deltafront sequence [11]. The prodelta deposits are found above 1091.5 m and below 1102.3 m, while the deltafront deposit is found between 1092.5 to 1102.4 m. According to the depth profile of mud content, the prodelta deposits show higher mud content than deltafront deposits (Fig. 2b). We can distinguish the depositional environments by setting a mud content of 30 % as a threshold value. The depth profile of core porosity varies from 0.24 to 0.43 (Fig. 2c); however, no significant changes are recognized between prodelta and deltafront deposits. On the other hand, the depth profile of core permeability varies from 0.2 to 99.8 md (Fig. 2d) and deltafront deposits show higher core permeability than prodelta deposits. Lithological features and physical properties suggest that deltafront deposits are suitable as a reservoir rock, which is also supported by the spinner test at IW-1 [6].

The depth profile of GR-based shale volume shows agreement with that of core mud content (Fig. 2a). The depth profiles of log-based porosity and permeability also show agreement with core-based values (Fig. 2c, d). Thus an integration of core-analysis data and well-logging data was successfully established, and these data were used to reconstruct a geological model.
4.2. Well log correlation and identification of sequence boundary

Well-log data correlations are useful for investigating spatial distribution of the strata. We used the depth profile of shale volume at each well as a correlation tool because shale volume reflects lithological features at this site. The depth profile of shale volume at each well has two depositional cycles (Fig. 3), each of which is characterized by a fining-upward to coarsening-upward sequence and is thought to be associated with transgressive-regressive cycle [12]. In general, the transgressive-regressive sequence is enveloped by subaerial unconformities or ravinement surfaces and their correlated maximum regressive surfaces [12, 13]. In this study, the recognized transgressive-regressive sequence is regarded as a depositional sequence bounded at its top and base by sequence boundaries [14]. The sequence boundaries identified at each well are used as controls to construct a framework model, which visualizes the geological structure and architecture of target strata (Fig. 3).
The 3-D seismic data largely support construction of a stratigraphic framework model between and beyond well controls. To construct a stratigraphic framework, we picked sequence boundaries spatially by multiple seismic slices, and then made a surface model with an isochore interpolation algorithm using the Petrel software (Fig. 4). The surface model was divided into seven layers by a proportional method, and was divided into 5×5 m cells in the horizontal direction. The grid model had a total of 579600 cells [14]. In this study, we applied the geostatistical method described below to integrate well-logging data as hard data and 3-D seismic data as soft data to construct the spatial distribution of petrological and physical properties such as shale volume, porosity, and permeability.

![Figure 4. Grid model of the reservoir at the Nagaoka site [14].](image)

### 4.3. Modeling the spatial distribution of petrological and physical properties

For modeling we used a geostatistical method known as a sequential Gaussian simulation (SGS) algorithm [15]. The SGS algorithm is widely used in a petrophysical modeling for the stochastic characterization of continuous variables. It is a kriging-based method—which requires a variogram related to the spatial correlation—and a sequential conditional simulation method [15]. However, it is often difficult to make a variogram because well-logging data are sparse and well data at the early stage of the project are limited. Under such constraints, 3-D seismic data are useful as a guide for accurate prediction of the spatial distribution of reservoir properties, if there are correlations between well-log and seismic data. In a previous study of reservoir characterization at the Nagaoka site, we confirmed a significant correlation between seismic amplitude and porosity, thus obtaining an inversion-derived spatial porosity distribution analyzed by the Geology-Driven Integration (GDI) tool developed by de Groot-Bril Earth Science in the Netherlands [16]. The GDI tool uses a Monte Carlo simulation and artificial neural network to create pseudo wells and detect the relationship between reservoir characteristics and seismic attributes based on well data and regional geological constraints.

In this paper, we applied the SGS algorithm with collocated cokriging to the 3-D grid model using upscaled shale volume and permeability logs as the primary variable and downscaled GDI-based porosity distribution as the secondary variable. The collocated cokriging approach requires a linear relationship between the two variables and needs the correlation coefficient between two variables [15]. On the basis of the well-log analysis at the Nagaoka site, porosity has a close relation to both shale volume and reservoir rock permeability. Therefore, we used their correlation coefficients and used the GDI-based porosity distribution as a secondary variable for predicting the spatial distributions of shale volume and permeability as primary variables. Prior to modeling, we conducted a variogram analysis to describe the spatial continuity of the variable. An experimental variogram was calculated from the sample data and fitted using a variogram model to determine range, sill, and nugget, which were used as
constraints in the simulation. In the Petrel software, the variogram and its parameters were normalized to a sill of 1. An exponential function was used to model the experimental variogram in this study. The vertical range and sill were calculated using the well-logging data variogram. We set a vertical range of 10 m and a nugget of 0.2 m. Horizontal range and sill were determined using the variogram of the seismic data because it had more spatial information than the well-logging data. The anisotropy of the variogram was observed for the major and minor directions. Thus, a horizontal variogram was estimated for each direction. The major and minor ranges were set at 600 m and 200 m, respectively, and nugget was set at 0.2 m for both ranges.

Figure 5 illustrates GDI-based porosity (Fig. 5a), and one realization of shale volume (Fig. 5b) and permeability distributions (Fig. 5c). Simulated realizations of both shale volume and permeability distributions exhibit a similar trend to the GDI-based porosity distribution. In particular, the trend of porosity distribution shows lower to the western part of the reservoir rock (Fig. 5a). In association with this trend, shale volume distribution has higher value and permeability distribution becomes lower to the western part of the reservoir rock (Fig. 5b, c). According to the core analysis, we can interpret that prodelta and deltafront deposits appear toward the west and east, respectively.

![Fig. 5. Modeling results. (a) GDI-based porosity distribution used as a secondary variable, (b) shale volume, and (c) permeability distributions.](image)

As stated earlier, time-lapse well-logging during and after CO₂ injection suggests that CO₂ migration in the reservoir rock is not uniform. For example, CO₂ breakthrough has never been observed at the observation well OB-3, although other two wells, OB-2 and OB-4, indicate the breakthrough shown by time-lapse P-wave velocity logging (Fig. 1d). The heterogeneous nature of flow behavior can be explained by the distribution trend of muddy deposits with low permeability. The shale volume distribution trend is also supported by paleogeographic studies that show that detrital particles are transported from east to west at the Nagaoka site [17, 18]. Therefore, modeling using a SGS algorithm with collocated cokriging can be valuable constraint for geostatistical reservoir characterization and predicting the distribution of injected CO₂ in a reservoir.

5. Conclusion

Densely-sampled grain-size distribution analyses of the recovered core and well-log analysis indicated that the target aquifer is composed of prodelta to deltafront deposits. The depth profile of GR-based shale volume, porosity, and permeability agree with the grain-size distribution in the core. This indicates a successful integration between core analysis and well-logging data. The logging and 3-D seismic data are used for geostatistical modeling. An SGS algorithm with collocated cokriging was used to map petrological and physical properties in the reservoir. We estimated the spatial distribution of shale volume and permeability using log data as a primary variable and GDI-based porosity distribution as the secondary variable under the constraints of correlation coefficient between the primary and secondary variables. We performed a variogram analysis to evaluate the spatial correlation in the reservoir, using well-log and 3-D seismic data. The simulated model showed that the western and eastern parts of the reservoir consist of impermeable muddy deposits and permeable sandy deposits, respectively. This trend is
concordant with the paleogeographic map proposed by most of previous studies. Furthermore, simulated models can reasonably explain the monitoring results in which no breakthrough was occurred at OB-3, the westernmost observation well. These results demonstrate that a geostatistical approach that integrates core and well-log data using 3-D seismic data is promising for reservoir characterization.

Acknowledgements

The authors would like to thank Osamu Nishizawa for his thoughtful support. We are grateful to the INPEX, GSC, and JGI for providing logging and seismic data. This work is part of an R&D project “the Development of Safety Management Technology for Large-Scale CO2 Geological Storage, commissioned to the Geological Carbon Dioxide Storage Technology Research Association by the Ministry of Economy, Trade and Industry (METI) of Japan.

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