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Outcrop-based reservoir modeling of a naturally fractured siliciclastic CO_2 sequestration site, Svalbard, Arctic Norway

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SUMMARY

We present a geological model of an unconventional siliciclastic reservoir projected for CO_2 sequestration near Longyearbyen, Svalbard. The reservoir is characterized by a substantial sub-hydrostatic pressure regime, very low matrix porosity and –permeability values, extensive natural fracturing and the presence of igneous dykes and sills. Due to the poor reservoir properties of the matrix, flow in the reservoir is largely governed by fracture properties. Input data to the model includes four boreholes, partly or completely penetrating the reservoir section, offshore and onshore 2D seismic profiles and structural and sedimentological data collected from nearby outcrops of the target formation. Combined, these datasets provide firm modeling constraints with respect to the regional geometry, sedimentology and fracture patterns. Previous work has shown that the observed fractures can be grouped into five distinct litho-structural units (LSUs), each exhibiting a characteristic set of properties (fracture density, orientation etc.). The spatial distribution of these LSUs is incorporated into the model. Initial first-order water injection tests using a commercial streamline simulator validate the applicability of this model for further fluid injection tests, including the long-term monitoring of injected CO_2.

Introduction

The Longyearbyen CO_2 laboratory investigates the feasibility of subsurface sequestration of carbon dioxide from the coal-fuelled power plant of this high-Arctic settlement. Since 2007, eight slim-hole boreholes have been drilled and fully cored to verify reservoir injectivity and cap rock integrity of the Upper Triassic-Middle Jurassic shallow marine succession forming the intended storage formation (Braathen et al., 2012). Water injection tests have demonstrated a total flow capacity of 45 mD·m in the lowermost section of the Dh4 borehole, although laboratory permeability measurements on drill cores do not exceed 1 mD (Braathen et al., 2012). The presence of natural fractures, identified both in boreholes and in the outcropping reservoir section approximately 15 km north-east of the planned injection site is critical for injectivity in the otherwise tight unconventional aquifer (Ogata et al., 2012).

Fracture characterization is based on a combination of detailed structural logging of well cores, televiewer logs in the upper part of the reservoir and extensive outcrop data outlined by Ogata et al. (this conference). This paper focuses on the application of these datasets towards constructing a geological model of the target reservoir, suitable for flow simulations.

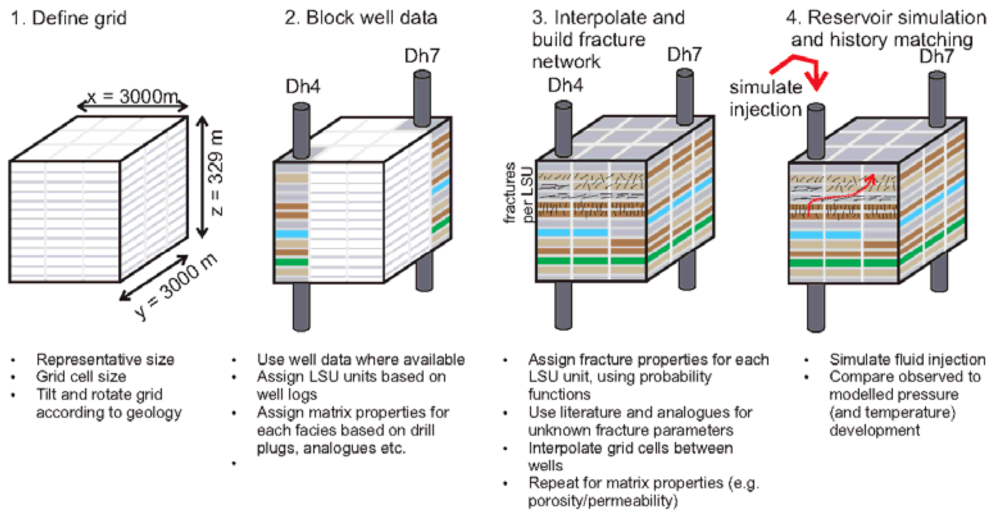

Figure 1 *Stochastic modeling workflow utilized in the present study. Input data include facies logs, litho-structural unit (LSU) logs and petrophysical measurements from the drilled wells as well as fracture and sedimentary facies data from outcrops. Note that the natural fracture network is incorporated using the LSUs, with each LSU containing a specific set of fracture network properties.*

Methods and data

The dual porosity-permeability geological model was constructed using a standard reservoir modeling workflow (Fig. 1). Seismic profiles, both newly acquired and pre-existing onshore and offshore 2D seismic lines were utilized to construct a regional "Near Top Reservoir" surface. Sub-seismic features were identified using borehole data (stratigraphic and structural logging, wireline logging) and extensive fieldwork in the exposed reservoir interval. As described in the contribution by Ogata et al. (this conference), the natural fractures of the reservoir can be subdivided into five characteristic litho-structural units (LSUs). Sedimentological logging of the fully cored Dh4 borehole also identified 21 individual sedimentary facies. Both LSU and facies classifications are assigned a range of probable matrix porosity-permeability values which serve as input to stochastic petrophysical modeling (Fig. 2). The LSU classification was also used to generate an implicit fracture network for each LSU zone.

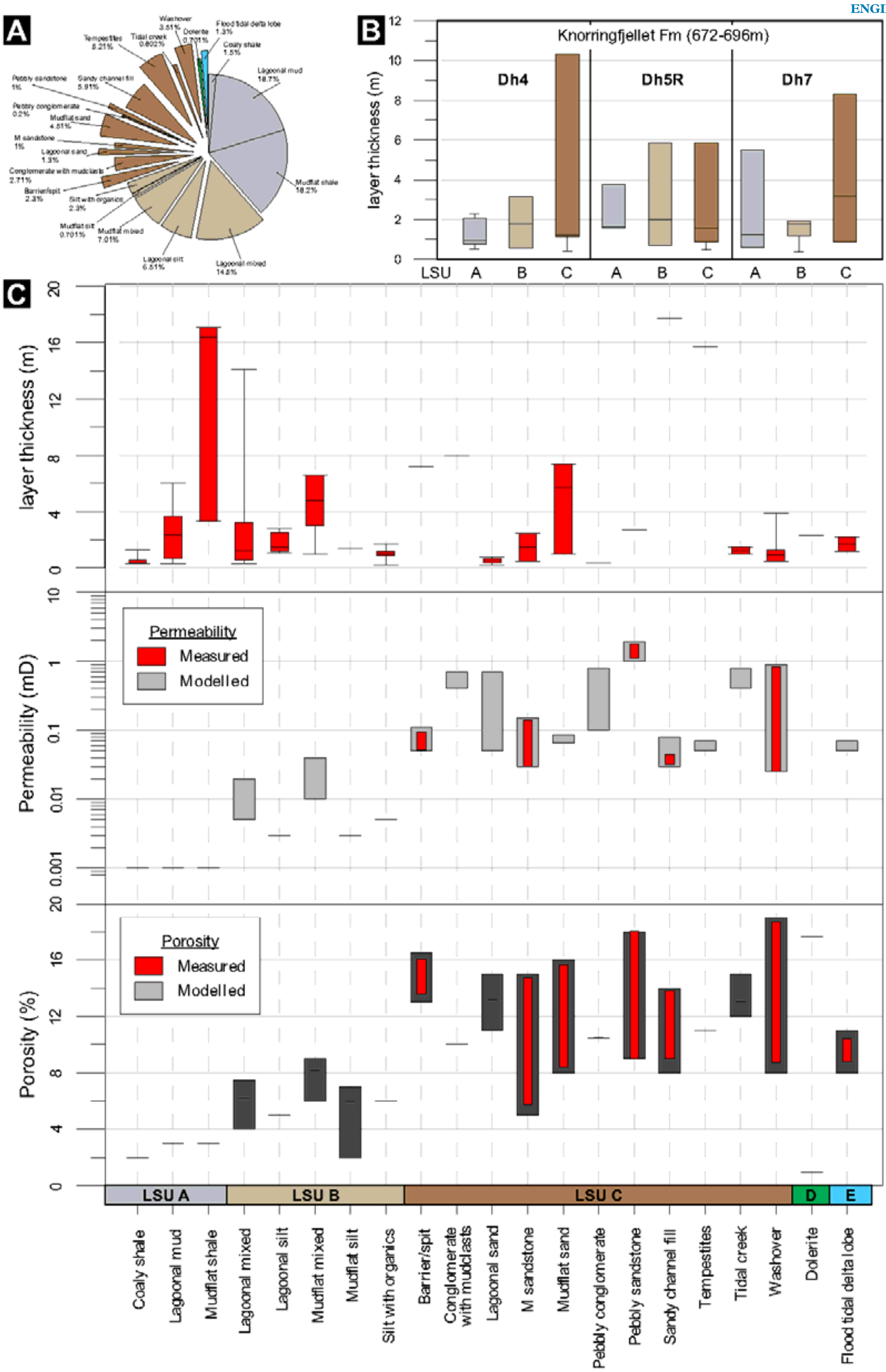

Figure 2 *Summary of input data used to populate the geological model. A) pie-chart illustrating the 21 defined sedimentary facies in the reservoir interval of well Dh4. The facies' colour-codes in the chart indicate which LSU unit they belong to (cf. colour legend at the bottom of the figure). B) Box-whisker plots (min, max, mean, upper and lower quartile) of the layer thicknesses within the Knorringfjellet Formation as drilled by the three boreholes, Dh4, Dh5R and Dh7. The wells are located within 100 m of each other. C) Summary of layer thicknesses and matrix properties within the*

full aquifer section in Dh4, from 672 to 972 m depth. For permeability and porosity, the laboratory-measured data reported by Braathen et al. (2012) and references therein are highlighted in red.

As a compromise between the computational requirements and the need for an accurate representation of the subsurface, a 3000*3000*329 m grid with 20*20*1 m cells was implemented. The grid was rotated 50 degrees east to align with the regional dip, and tilted to the regional dip of ca. 3°. The interpreted LSU log in Dh4 was blocked into 1 m thick grid cells, and the blocked data used to populate the entire reservoir model using a mix of deterministic and stochastic techniques (i.e. indicator kriging, sequential indicator simulation and assigning laterally constant values). Natural fractures are represented implicitly, with field-based orientations and fracture frequencies used as input to represent the fracture network. Dolerite dykes are considered as poorly permeable to cross-flow and thus represented in the model as baffling faults. Permeable fracture corridors, on the other hand, are represented as highly transmissible faults acting as permeability pathways. Some sub-seismic faults identified in outcrops are also implemented in the model to test their impact on fluid flow and reservoir compartmentalization.

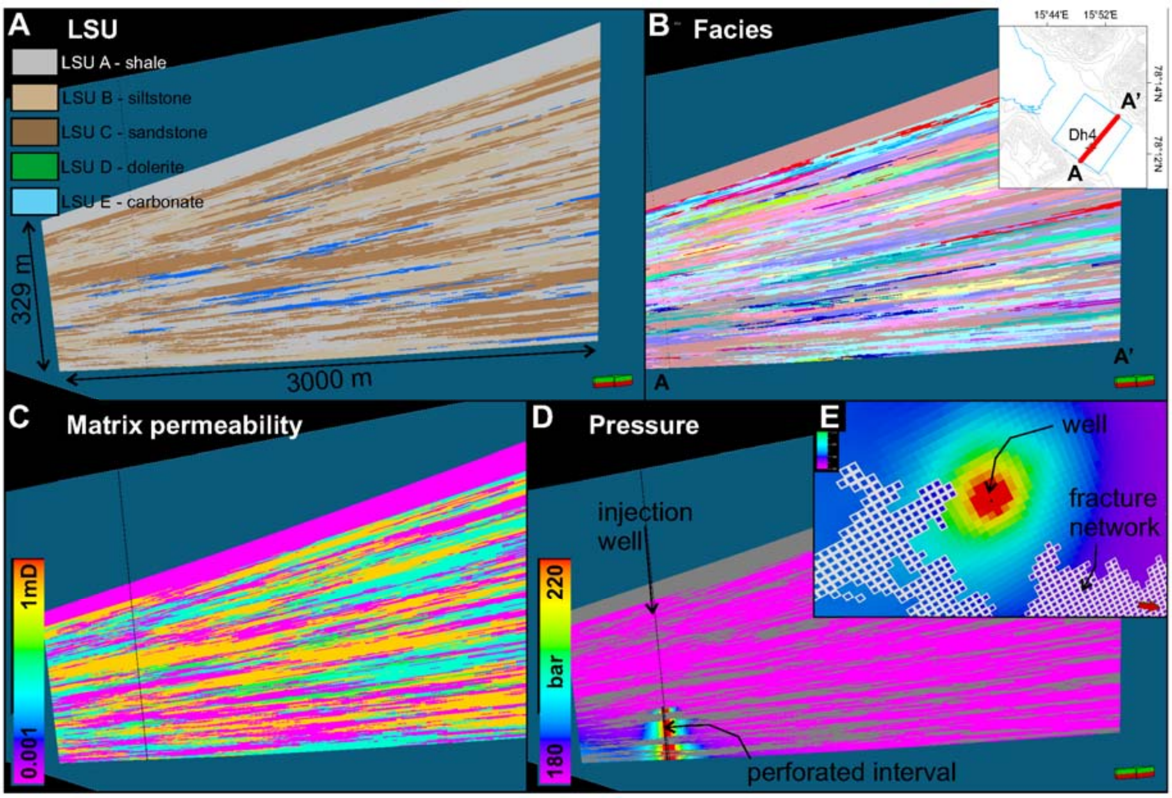

***Figure 3** Sample cross-section from a random realization of the stochastic geological model. All profiles are shown with 3X vertical exaggeration. The profiles run from the injection well up-dip towards the north-east, where the aquifer section crops out ca. 15 km from the planned injection site. The inset map shows the location of the cross-section (red line) and the extent of the 3*3 km grid with respect to the Dh4 water injection well. A) LSU-based subdivision of the aquifer. Note particularly the 30 m of LSU A (shale) cap rock at the top and the intra-formational shales. B) Subdivision of the aquifer into 21 sedimentary facies, as logged in the Dh4 borehole. C) Matrix permeability assigned on the LSU zonation, with correspondingly low permeability within LSU A. D) First-order water injection test using the FrontSim streamline simulator, showing the pressure build-up in the near-well area following water injection in the 870-970 m interval. E) View from below highlighting the pressure increase around the injection well. Where present, the fracture network properties are illustrated along with the matrix properties in a sugar cube display.*

Results and discussion

The geological model combines both the borehole-derived stratigraphic subdivision as well as extensive fracture data collected from reservoir outcrops. Much uncertainty remains, particularly related to the extrapolation of well data from one borehole across the whole model. Nevertheless, the model highlights the potential geological heterogeneity of the target aquifer. The heterogeneity set-up by LSUs A, the low-permeability shale-dominated intervals (Fig. 3a), appears to have a major impact on the permeability field (Fig. 3c). This is confirmed by differential pre-injection initial pressure regimes in the upper and lower part of the target aquifer and corresponding need for laterally extensive impermeable barriers. The sand-dominated LSU C, on the other hand, enhances vertical fluid flow through the fracture system. Interfaces at the boundaries between different LSU units furthermore act as fluid pathways, as do the fractured chilled margins of the igneous intrusions. This is highlighted by water injection simulation using the FrontSim streamline simulator (Fig. 3d, e). The internal flow barriers channel the fluid flow within the more permeable and fractured LSU B and LSU C units. The presence of igneous intrusions in the lower part of the aquifer, notably discordant dykes, is modeled on the basis of a conceptual model developed using field exposures, but additional flow simulation are required to constrain the impact of intrusions on regional fluid flow.

Conclusions

We here present a dual-porosity, dual-permeability geological model for a CO_2 target aquifer on Svalbard. The model is based on borehole and outcrop data, with special emphasis on capturing the natural fracture network. Initial examination of the model, including first-order streamline-based water injection simulation, suggests that internal heterogeneities related to the presence of shale-dominated low-permeable layers will act as internal flow barriers steering the fluids laterally. The resulting model provides a robust framework for conducting full-field simulation studies of CO_2 injection into the target aquifer.

Acknowledgements

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