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Permeability Thickness as a Primary Control on Injectivity and Storage Performance in the Western Canada Sedimentary Basin

Jonathan C. White, P. Geol.
Sproule ERCE

Summary and Objectives

Subsurface geologic storage studies conducted under the Society of Petroleum Engineers' Storage Resources Management System (SRMS) framework have historically focused on estimating in-place storage capacity during early-stage screening. When project-specific injectivity or pressure-performance data are unavailable, these studies rely on generic storage efficiency assumptions based on depositional environment, such as the basin-scale saline aquifer efficiency ranges published by the U.S. Department of Energy through its National Energy Technology Laboratory. While suitable for regional or preliminary assessments, these volumetric approaches do not explicitly capture the dynamic controls governing injection performance, pressure behavior, and the achievable portion of storage capacity for a defined project.

Mapping for SRMS assessments typically applies volumetric calculations derived from porosity and gross or net reservoir thickness, effectively defining the “size of the tank”. While this approach is appropriate for estimating static storage volumes, it does not directly address a fundamental control on storage performance: injectivity. For carbon dioxide (CO_2) storage and subsurface fluid disposal projects, injectivity governs injection rates, controls pressure buildup in the reservoir and pressure propagation, and ultimately constrains realizable storage capacity.

Permeability thickness (kh), defined as the product of permeability and effective thickness, is the key parameter controlling fluid flow capacity in subsurface reservoirs. High kh values are indicative of superior rock quality, enhanced connectivity, and favorable flow pathways. As such, permeability thickness provides a more direct and operationally relevant measure of reservoir performance than porosity or thickness alone. Despite its importance, kh has not been routinely mapped or incorporated into early-stage regional screening workflows for geologic storage, particularly within SRMS-aligned evaluations where injectivity confidence underpins project maturity and resource classification.

In this study, Sproule ERCE developed regional-scale permeability thickness maps for several regionally extensive Cambrian and Ordovician reservoirs within the Western Canada Sedimentary Basin (WCSB), including the Basal Cambrian Sand (BCS), Deadwood Formation, Winnipeg Formation, and Red River Formation. These maps were generated for specific application to deep saline CO_2 storage, fluid disposal, and other subsurface fluid injection activities. The objective was to identify regional trends in injectivity, delineate injectivity “sweet spots,” and highlight areas where reservoir compartmentalization or reduced flow capacity may pose challenges for injection and pressure management.

The resulting kh maps demonstrate that permeability thickness mapping is a practical screening and characterization tool that complements traditional capacity-focused assessments. When integrated into project planning, kh mapping improves site selection, informs well placement strategies, and reduces uncertainty related to long-term pressure propagation and containment risk supporting progression from regional screening toward SRMS project definition.

Geological Context

Regional geologic storage evaluations have historically been rooted in volumetric concepts, with workflows centered on petrophysical interpretation of well logs to estimate porosity, followed by integration with net thickness to generate porosity-thickness maps and ultimately reservoir volume. These maps are effective representations of storage volume but do not adequately capture the dynamic behavior of injected fluids.

In contrast, injectivity is the ability of the reservoir to transmit fluids, which is a function of permeability, effective thickness, and lateral continuity. kh integrates both rock quality and vertical reservoir development into a single parameter that directly correlates with well productivity and injectivity. In the context of CO_2 storage, kh directly governs achievable injection rates, the spatial extent of pressure perturbations, and the number of wells required to meet storage targets within allowable pressure constraints.

From a geologic perspective, permeability is strongly influenced by depositional environment, grain size distribution, sorting, cementation, and diagenetic processes. Thickness reflects both accommodation space and preservation of quality reservoir facies within the stratigraphic framework. As a result, kh inherently captures the effects of depositional processes, paleotopography, and post-depositional modification.

Recognizing these controls, this study emphasizes kh as a basin-scale diagnostic parameter that attempts to bridge static reservoir description and dynamic performance expectations.

Data, Methods, and Workflow

The workflow implemented in this study integrates geological, petrophysical, and core-derived data to calculate and map permeability thickness across the WCSB. Core-derived permeability measurements were compiled from publicly available datasets and were evaluated within the mapped stratigraphic framework for each formation. These data were used to constrain the high, low and mid-range permeabilities at a given porosity. Permeability was estimated using these calibrated relationships, ensuring consistency across the basin.

Effective reservoir thickness was determined through formation-specific net-to-gross criteria, incorporating GR (Vshale) and total porosity cutoffs. The resulting permeability and thickness datasets were then integrated to calculate kh over the entire WCSB at depths over 1000 m. This data was used to produce continuous regional kh maps for each formation. This approach allows for direct comparison of injectivity potential across formations and regions, providing a consistent basis for screening and evaluation at both regional and project scales.

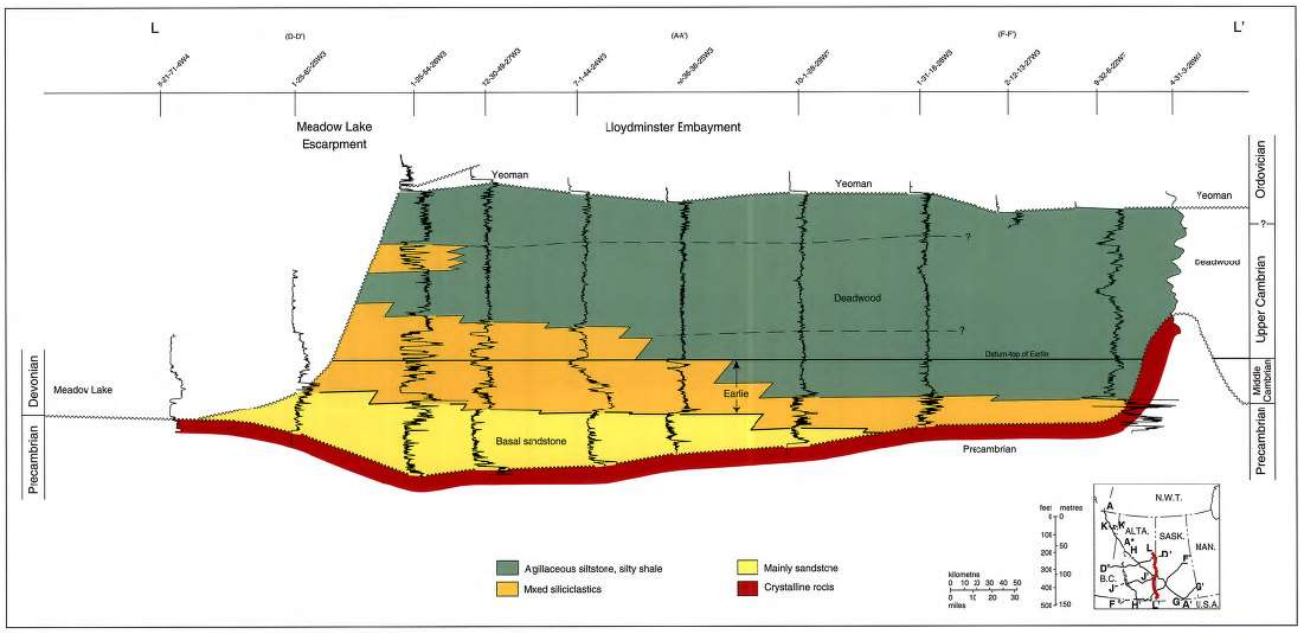


Figure 1 – Cambrian North-South Stratigraphic Cross Section at Saskatchewan/Manitoba Border showing decreasing sand thickness in the BCS and Deadwood from North to South (Figure 8.13, Slind ET AL, 1994)

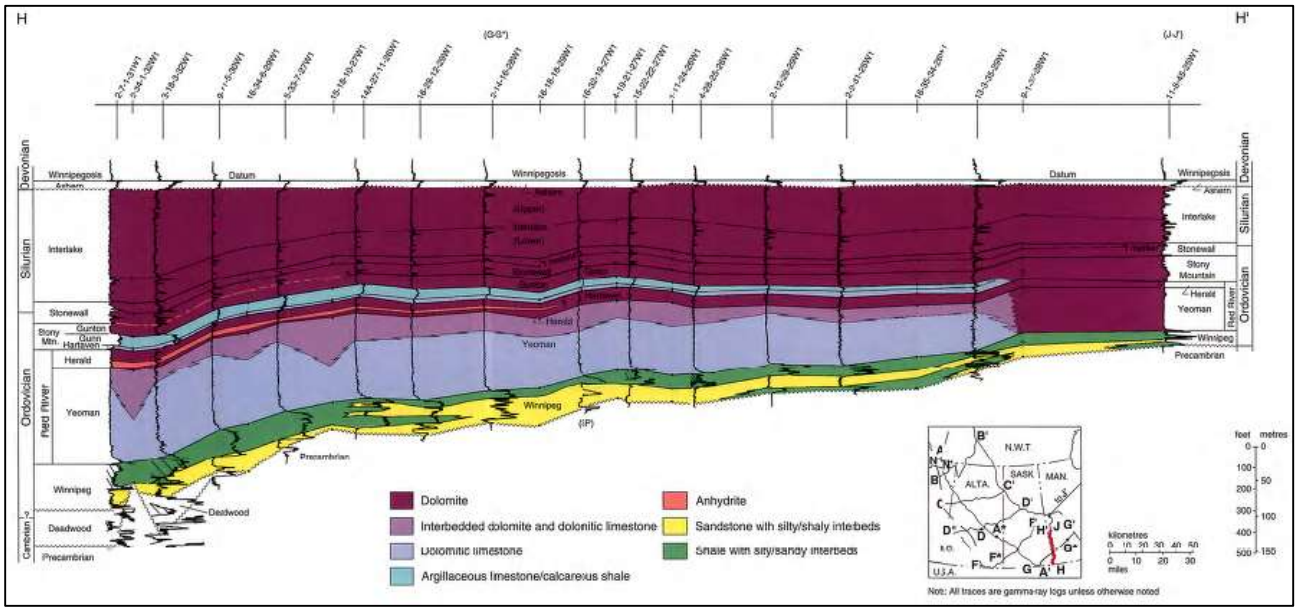


Figure 2 – Lower Ordovician North-South Stratigraphic Cross Section at Saskatchewan/Manitoba Border showing Winnipeg sand and Red River Carbonate stratigraphic relationships (Figure 9.18, Norford ET AL, 1994)

Results and Geological Interpretation

The resulting permeability thickness maps reveal pronounced regional-scale trends within each formation that are directly relevant to injectivity and pressure behavior.

Sandstone reservoirs in the BCS, Deadwood and Winnipeg formations display kh patterns that are strongly controlled by pre-Cambrian paleotopography and sediment supply. Areas characterized by thicker sand accumulations and higher permeability generally correspond to paleotopographic lows and zones of enhanced sediment transport and deposition. These regions exhibit excellent injectivity potential and are well suited for high-rate injection. Conversely, areas overlying paleo highs or dominated by finer-grained or cemented facies show reduced kh values, indicating lower injectivity and increased compartmentalization.

As a carbonate reservoir, the Ordovician Red River formation exhibits permeability thickness distributions that are more closely linked to facies development, dolomitization, and possible fracturing in some areas. Quality reservoir distribution is more heterogeneous, with kh values showing higher variability spatially. This variability creates a larger number of localized injectivity sweet spots and results in more variable pressure propagation and storage efficiency compared to the sandstone reservoirs of the BCS, Deadwood and Winnipeg.

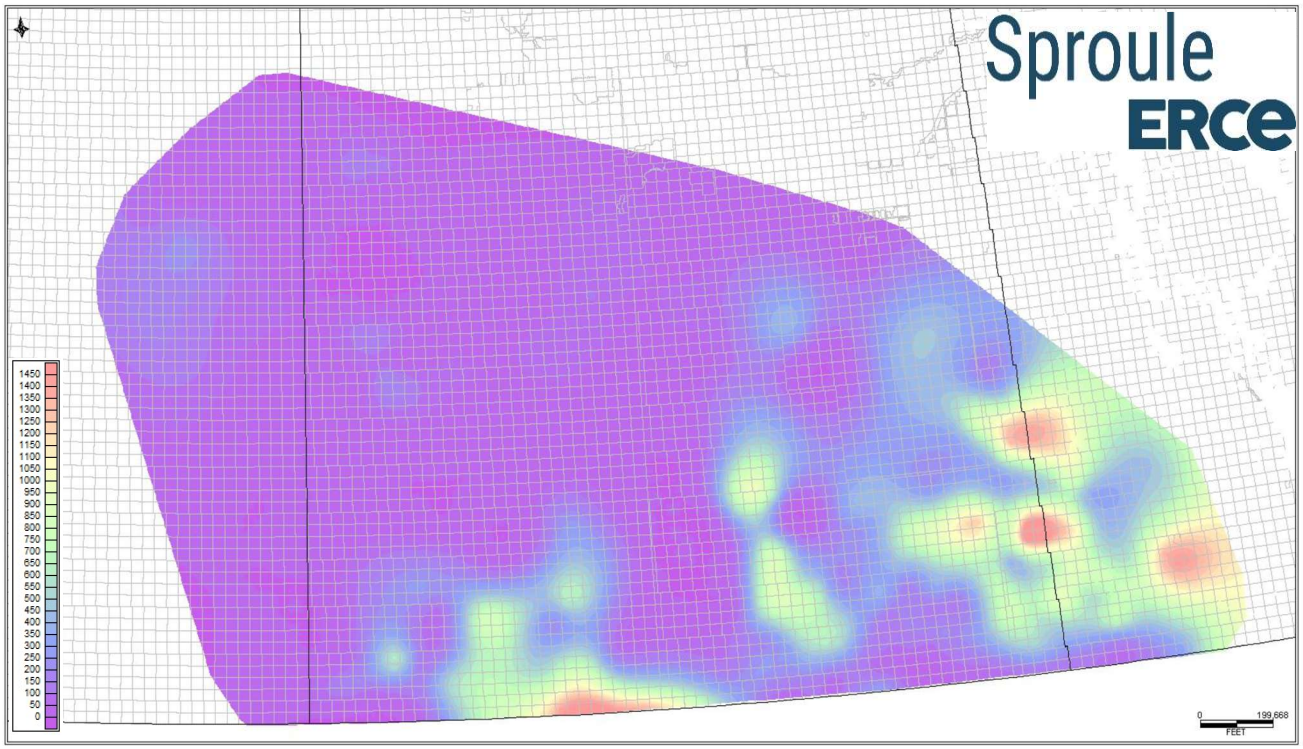


Figure 3 – Red River Porosity Thickness Map (mD*m)

Implications for CO_2 Storage and Subsurface Disposal

The results of this study support the integration of permeability thickness mapping as a component of geologic storage screening and characterization workflows. Unlike maps of net thickness, porosity, or average permeability considered in isolation, kh provides a direct indication of flow capacity and reservoir performance tied to the rocks.

The kh maps presented identify multiple injectivity sweet spots within Cambrian and Ordovician reservoirs of the WCSB. The scale, continuity, and quality of these reservoirs represent a significant and strategic storage resource for CO_2 sequestration and other subsurface injection applications in western Canada when evaluated within defined development concepts and pressure constraints.

As competition for pore space increases with expanded carbon management and disposal activities, understanding regional trends in injectivity by formation is another tool for project planning and regulatory engagement and for informing well count, spacing, and pressure management strategies.

Importantly, the workflow developed in this study is transferable and can be applied to other sedimentary basins where similar data are available. By integrating the geologic assessment of injectivity, permeability thickness mapping enhances decision-making and reduces uncertainty associated with injectivity confidence, pressure propagation, and realizable storage capacity.

Conclusions

Permeability thickness is a fundamental control on injectivity, pressure behavior, and storage efficiency in subsurface geologic storage systems. Regional kh mapping provides valuable insights into reservoir performance that can be used to inform storage efficiency factors used in capacity estimates.

Integration of core-derived permeability data, petrophysical interpretation, and stratigraphic frameworks enables robust basin-scale assessment of injectivity potential and supports early-stage project screening and maturation.

In the Western Canada Sedimentary Basin, kh mapping of the Basal Cambrian Sand, Deadwood, Winnipeg, and Red River formations reveals distinct reservoir quality trends and highlights injectivity sweet spots for future CO_2 storage and subsurface disposal projects. Incorporating permeability thickness into early-stage screening and characterization represents a practical tool for geologic storage evaluation. By directly linking regional geologic variability to injectivity and pressure-limited performance, kh mapping reduces reliance on generic storage efficiency assumptions and provides a performance-based bridge between volumetric capacity screening and project-defined, realizable storage under SRMS.

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