

# Impact of Shale Heterogeneity upon Gas Storage Potential and Deliverability: Examples from Jurassic and Devonian–Mississippian Shale Gas Reservoirs

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## Summary

An investigation of shale pore structure and compositional/geochemical heterogeneities has been undertaken to elucidate the controls upon gas capacities of potential shale gas reservoirs in northeastern British Columbia. Methane sorption isotherms, pore structure and surface area data indicate a complex interrelationship of total organic carbon (TOC) content, mineral matter and thermal maturity affect gas sorption characteristics of Devonian–Mississippian (D–M) and Jurassic strata.

Methane and carbon dioxide sorption capacities of D–M shales increase with TOC content, due to the microporous nature of the organic matter. Clay mineral phases are also capable of sorbing gas to their internal structure; hence D–M shales which are both TOC- and clay-rich have the largest micropore volumes and sorption capacities on a dry basis. Jurassic shales, which are invariably less thermally mature than D–M shales, do not have micropore volumes which correlate with TOC. The covariance of methane sorption capacity with TOC, independent of micropore volume, indicates a solute gas contribution (within matrix bituminite) to the total gas capacity. On a wt% TOC basis, D–M shales sorb more gas than Jurassic shales: a result of greater thermal-maturation induced, structural transformation of the D–M organic fraction.

Organic-rich D–M strata are considered to be excellent candidates for gas shales in Western Canada. In the sub-surface, thermally mature strata of the Besa River, Horn River, Muskwa and Fort Simpson formations attain thicknesses of over 1 km (3300 ft), encompassing an area of approximately 125,000 km<sup>2</sup> (48,300 mi<sup>2</sup>) and represent an enormous potential gas resource. These strata have TOC contents ranging between 1–6 wt%, thermal maturities into the dry-gas region, and thicknesses in places of over 1000 m. Total gas capacity estimates range between 60 and 600 bcf/section where a substantial percentage of the gas capacity is free gas, due to high reservoir temperatures and pressures. Muskwa shales have adsorbed gas capacities ranging between 0.3 and 0.5 cm<sup>3</sup>/g (9.6–16 scf/t) at reservoir temperatures of 60–80°C (140–176°F), whereas Besa River mudrocks and shales have low adsorbed gas capacities <0.01 cm<sup>3</sup>/g (0.32 scf/t; Liard Basin region) because reservoir temperatures exceed 130°C (266°F).

Inorganic material influences modal pore size, total porosity and sorption characteristics of D–M shales. Carbonate-rich samples, adjacent carbonate platform and embayment successions, often have lower organic carbon contents (oxic deposition) and lower porosity, hence potentially lower sorbed and free-gas capacities. Seaward of the carbonate Slave Point edge, Muskwa and lower Besa River mudrocks can be both silica- (biogenic) and TOC-rich (up to 92% quartz and 5 wt% TOC), and most favorable for shale gas reservoir exploration due to possible fracture enhancement of the brittle organic- and siliceous-rich facies. However, quartz-rich Devonian shales display tight-rock characteristics, with poorly developed fabric, small median pore diameters and low permeabilities. Hence potential ‘frac-zones’ will require an increased density of hydraulic fracture networks for optimum gas production.