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Petrophysical and geomechanical characteristics of Canadian tight oil and liquid-rich gas reservoirs: I. Pore network and permeability characterization

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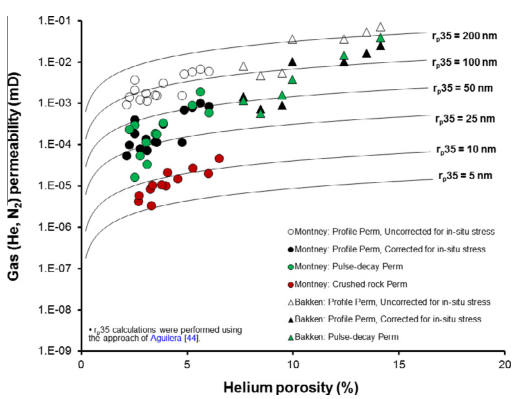
HIGHLIGHTS

- Documentation of geochemical, petrographic and petrophysical characteristics of Montney and Bakken.
- First-time application of profile permeability test to large Montney and Bakken intervals.
- Matrix/fracture permeability measurements under "in-situ" effective stress.
- Comparison of different non-steady-state gas permeability techniques.

GRAPHICAL ABSTRACT



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ABSTRACT

The results from an ongoing laboratory study investigating petrophysical characteristics of the Montney and Bakken formations in Canada are presented. The primary objectives are to (1) characterize the pore network (porosity, pore size distribution) and fluid transport (permeability) properties of these formations in areas with limited datasets and (2) analyze the effects of different geological factors on porosity, pore size distribution and permeability. The techniques used for characterization include: Rock–Eval pyrolysis; bitumen reflectance (BRo); grain size measurement; helium pycnometry; low-pressure gas (N_2) adsorption (surface area, pore size distribution); pressure-decay profile permeability, pulse-decay and crushed-rock gas (N_2, He) permeability and fracture permeability tests.

Rock–Eval analysis and microscopic observations indicate that most samples are organic-lean (average TOC content: 0.3 wt.%), ranging from fine-grained siltstone to very fine-grained sandstone (grain size range: 27–53.7 μm). The measured permeability values on core plugs increase with increasing porosity (2.1–14.1%), ranging between $3.3 \cdot 10^{-6}$ and $7.3 \cdot 10^{-2}$ mD. For the core plugs analyzed ("as-received"), profile (probe) permeability values ($9.2 \cdot 10^{-4}$–$7.3 \cdot 10^{-2}$ mD) are consistently higher than pulse-decay ($1.6 \cdot 10^{-5}$–$3.9 \cdot 10^{-2}$ mD) and crushed-rock ($3.3 \cdot 10^{-6}$–$4.6 \cdot 10^{-5}$ mD) permeability values. Corrected profile (probe) permeability values for "in-situ" effective stress ($5.3 \cdot 10^{-5}$–$2.5 \cdot 10^{-2}$ mD) are, however, comparable with the pulse-decay ($1.6 \cdot 10^{-5}$–$3.9 \cdot 10^{-2}$ mD) permeability values. Unpropped fracture permeability, determined using an innovative procedure in this work, can be significantly (up to eight orders of magnitude) higher than matrix permeability under similar effective stress conditions. The grain size data are correlated to permeability values. The dominant pore throat diameter controlling fluid flow

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is estimated for all samples using Winland-style correlations; these values agree with those obtained from low-pressure N_2 adsorption analysis.

Applying multiple analysis techniques on a large number of samples (26 m of slabbed core, 22 core plugs and their accompanying cuttings), this study provides a comprehensive petrophysical characterization of Montney and Bakken tight oil and liquid-rich gas reservoirs in Canada.

1. Introduction

Tight oil, gas and liquid-rich gas reservoirs are unconventional hydrocarbon plays that are composed of a lithologically diverse group of fine-grained sedimentary rocks including sandstones, mudstones, marlstones, limestones and siltstones [1,2]. Despite significant resource size associated with these unconventional plays, they require innovative exploration and completion strategies to produce hydrocarbon economically [2]. Production forecasting for these unconventional reservoirs is a challenge because of subsurface heterogeneity and complexity of these low-porosity, low-permeability reservoirs.

Economic gas flow rates in these reservoirs, which commonly have matrix permeabilities in the nanodarcy range, can be achieved using completion technologies such as multi-fractured horizontal wells (MFHWs). However, our ability to optimize recovery is hampered by poor understanding of the fluid transport processes in the matrix and fracture systems of these rocks [2–4]. Although hydraulic fracturing contributes critically to the performance of MFHWs, long-term production is necessarily controlled by unstimulated (matrix) permeability, whose laboratory-based measurement is the primary focus of the current work.

Permeability is one of the most difficult/challenging parameters to be accurately and reliably measured, mainly due to factors such as reservoir heterogeneity, measurement scale, different fluids used for measurement, and reproduction of "in-situ" fluid saturations, pore pressure and effective stress conditions [5]. The routine steady-state gas flow technique, which is sufficient for high-permeability rocks, is usually difficult to establish in a reasonable testing time. Therefore, non-steady-state gas flow techniques are commonly preferred in the laboratory for measuring permeability in tight oil/gas reservoirs. The most common non-steady-state gas permeability methodologies to analyze matrix permeability of tight oil/gas reservoirs include either pulse-decay or crushed-rock permeability techniques. Excellent discussions on pulse-decay [6,7] and crushed-rock [6,8–11] permeability techniques have already been provided. The pulse-decay permeability technique has some advantages, such as sampling a much larger rock volume (core plug) relative to cuttings, and further, the measurements are performed on core plugs that are subject to confining stress ("in-situ" stress conditions). However, one concern about using core plugs for pulse-decay measurements is that stress-induced fractures may influence the measurements [9]. Because shale samples are likely to part along micro-fractures and bedding planes during crushing, it is generally assumed that individual cuttings contain few to no micro-fractures compared to core plugs. Therefore, the crushed-rock technique (GRI method) is considered as a favorable technique which might be capable of providing a better estimation of matrix permeability compared to other techniques. Nevertheless, both of these permeability techniques are unable to differentiate and quantify the permeability of small-scale heterogeneities in rocks. Profile (probe) permeability measurement is, in turn, a favorable laboratory-based technique for characterizing the permeability of sedimentary rocks. It is a fast, non-destructive method which is capable of differentiating and quantifying the permeability of small-scale heterogeneities in rocks. This technique is of particular interest for highly-heterogeneous reservoirs such as the Montney, where lithological heterogeneities are abundant vertically (and even visually detectable) along the drill cores on a cm-scale basis. The lower limit of the profile permeability technique is about one microdarcy, and in an absolute sense, is of limited value for low-permeability shales which commonly have permeabilities down to the nanodarcy range. This technique can be useful, however, as a fast "screening" tool for comparison of the permeability of small-scale (lower than 2.5 cm) heterogeneities (e.g., laminations) in tight gas reservoirs, as demonstrated recently [12–14]. A practical approach that can be followed to partly overcome the shortcomings of this technique, and make it useful for quantitative permeability evaluation in low-permeability shales, is to combine it with pulse-decay permeability tests performed under "in-situ" stress conditions. Pulse-decay permeability tests are conducted under "in-situ" effective stress conditions on core plugs sampled at the same location as profile permeability testes conducted on the core slab. These measurements can be then used to correct profiles permeability values for the "in-situ" stress conditions. This technique is particularly useful when only core slabs are available as sample material other than plugs/cuttings [12,14].

It has recently been suggested that secondary fractures, which may consist of natural fractures that were once healed but reactivated during the hydraulic fracturing process, may also be an important pathway for fluids to be transported from the matrix to propped hydraulic fractures [15]. Unlike matrix permeability, measurement of unpropped (induced) fracture permeability is not routinely performed in the laboratory, but could be of great importance. Flow mechanisms in these unpropped fractures may vary from Darcy to turbulent flow depending on the fracture aperture size, and rate and pressure conditions. Steady-state measurements performed on a core plug with artificially-induced fracture are used to estimate fracture permeability in the present study.

This study presents results from an ongoing laboratory study investigating petrophysical characteristics of Montney and Bakken formations in Canada. The primary objectives are to (1) characterize the pore network (porosity, pore size distribution) and fluid transport (permeability) properties of these formations in areas with limited datasets and (2) analyze the effects of different geological factors on porosity, pore size distribution and permeability. The techniques used for characterization include: Rock–Eval pyrolysis; bitumen reflectance; grain size measurement; helium pycnometry; low-pressure gas (N_2) adsorption (surface area, pore size distribution); pressure-decay profile permeability, pulse-decay and crushed-rock gas (N_2, He) permeability and fracture permeability tests.

Using a suite of instruments/techniques, we have characterized the matrix permeability of Montney and Bakken formations at different sample scales and experimental conditions. One of the advancements of the present study is that these different gas permeability measurements (profile, pulse-decay and crushed-rock) were conducted on "identical" sample materials and compared. Therefore, the effect of heterogeneity on measured permeability values could be mitigated. To the best of our