Innovative Methods for Flow Unit and Pore Structure Analysis in a Tight Gas Reservoir, Montney Formation, NE, BC, Canada*

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Abstract

Tight gas reservoirs are notoriously difficult to characterize using laboratory-based methods because of: the existence of heterogeneity at several scales; fine pore structure that may not correlate to depositional controls and environment due to the impact of diagenesis; stress sensitivity of porosity and permeability; sensitivity of permeability to fluid saturation; and non-Darcy flow effects under laboratory conditions, etc. Porosity, pore size distribution and permeability are correspondingly difficult to measure in the laboratory and upscale to reservoir scale. A promising technique to characterize flow heterogeneity in tight gas reservoirs is to relate permeability to dominant pore throat size; permeability is measured using steady- or non-steady-state techniques and dominant pore size is typically estimated using the mercury intrusion method. Permeability and porosity is measured on full-diameter core or core plugs which may contain heterogeneities that are at a much finer scale than the sample size, resulting in composite estimates of both properties.

We investigate the use of non-routine methods to characterize permeability heterogeneity and pore structure of a tight gas reservoir for use in flow unit identification. Profile permeability is used to characterize fine-scale (< 1 inch) vertical heterogeneity in a tight gas core; over 500 measurements were made. Profile permeability, while useful for characterizing heterogeneity, will not provide in-situ estimates of permeability; further, the scale of measurement is much smaller than log-scale. Pulse-decay permeability measurements collected on core plugs under confining pressure were used to correct the profile permeability measurements to in-situ and point averages of profile permeability were used to relate to log-derived porosity measurements. Finally, a new method (for tight gas) was used to estimate the pore size distribution of several tight gas samples: N2 adsorption. A uni- or bi-modal distribution was observed for the samples, with the larger peak corresponding to the dominant pore throat radius, as inferred from the rp35 calculations. Further, the adsorption-desorption hysteresis loop was
used to interpret the dominant pore shape as slot-shaped pores, which is typical of many tight gas reservoirs. The N2 adsorption method provides for rapid analysis and does not suffer from some of the same limitations of Hg-injection, however the method is limited to fine pore structures (< 1,000 nm).

**Selected References**


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Early Triassic Back-Arc Setting

Pangea

Panthalassic Ocean

Study area

Blakey (2011)

Westward Prograding Clastic Wedge

Modified from: Dan Edwards, 2009
Montney - Pouce Coupe South Pool

Conventional gas pools within turbidite lobe sandstones
New gas plays within shaly intervals
13-12-78-11W6 Cored Well

Distal Glacier turbidite fan sandstones
Leyva, Yazdi and Murdoch (2010)

Montney C
TOC 0.6 - 0.8 Wt %

Montney B
TOC 1.1 - 1.8 Wt %

13-12-78-11W6 Cored Well

17.5m core
Cross-Section – Computed Porosity

Leyva, Yazdi and Murdoch (2010)

Distal Glacier turbidite fan sandstones
Cross-Section – Computed Porosity

~3 km

Distal Glacier turbidite fan sandstones

Leyva, Yazdi and Murdoch (2010)
STOCHASTIC 3D POROSITY MODEL

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Sedimentary Facies – Flow Units

**LOWER FACIES**
- 5-15 cm thick graded beds
- Silt and mudstones
- Distal fan facies

**UPPER FACIES**
- Finely laminated
- Planar and rippled
- 60-70% siltstone
- Middle fan facies

Leyva, Yazdi and Murdoch (2010)
Routine Core Permeability and Porosity

- 37 full diameter core analysis of porosity and permeability ($K_{\text{max}}$, $K_{90}$ and $K_{\text{vertical}}$)
- 24 measurements below 0.01mD lower resolution of instrument
Slip-Corrected Probe Permeability

Upper Facies

Lower Facies

Detection limit

593 probe permeability measurement (2.5 cm spacing)
Slip-Corrected Probe Permeability

K range of 0.001 – 0.03mD at ambient conditions

Upper Facies

Lower Facies

Detection limit

593 probe permeability measurement (2.5 cm spacing)
Reservoir Heterogeneity
Sampling Density

$k = 0.008 \text{ md}$
$SD(k) = 0.005 \text{ md}$
$C_v = 0.6$
$N_0 = 34$
$N = 296$

$k = 0.006 \text{ md}$
$SD(k) = 0.003 \text{ md}$
$C_v = 0.5$
$N_0 = 30$
$N = 297$
Notes by Presenter: Here are a few statistics about these two intervals. Averages are statistically similar but the top is more variable than the bottom. The $C_v = \frac{SD(k)}{avg \ k}$ suggests the top is a little more heterogeneous. No is a ‘rule of thumb’ number of measurements to estimate the average within 20% for 95% of the time. Actual number of measurements taken is about 10 times that needed for the average. Overall impression is that top and bottom perms and variabilities are similar and intervals are well sampled.
Profile Permeability

593 probe permeability measurement (2.5 cm spacing) allow establishment of relationship with microfacies.

Upper Facies

Depth: 2200.7m

Lower Facies

Depth: 2205.9m
Microfacies:  
1: >5mm thick coarse siltstone beds/lamina  
2: <5mm thick coarse siltstone lamina  
3: Finely laminated, fine to medium siltstone  
4: Thick bedded, fine to medium siltstone  
5: Mudstone
Microfacies:
1: >5mm thick coarse siltstone beds/lamina
2: <5mm thick coarse siltstone lamina
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Microfacies Probe Permeability

10 core plugs for analysis at reservoir conditions
Ambient vs. Reservoir Net Overburden Pressure Porosity and Permeability

Porosity and Pulse-Decay permeability from core plugs
Ambient vs. Reservoir Net Overburden Pressure Porosity and Permeability

Porosity and Pulse-Decay permeability from core plugs
Up to 71% loss in permeability
Facies controlled?

Porosity and Pulse-Decay permeability from core plugs
The two different measurements of permeability are weakly correlated. They differ substantially in absolute value due to differences in measurement conditions and volumes of rock sampled.
Facies Control on Loss of Porosity and Permeability

![Graph showing the relationship between Net Overburden Pressure (kPa) and Porosity (Fraction) and Permeability (mD)]
Slight loss in porosity but significant decrease in permeability indicates slot type porosity.
N$_2$ Adsorption Isotherm Analysis

N$_2$ adsorption isotherms

hysteresis loops suggest slit-shaped pores

BJH pore size distributions

Mercury (Hq) pore size analysis

from nearby Montney core
N$_2$ Adsorption Isotherm Analysis

**N$_2$ adsorption isotherms**

Hysteresis loops suggest slit-shaped pores.

**BJH pore size distributions**

Uni- and Bi-modual pore size distribution from nearby Montney core.

**BJH desorption cumulative pore volume**

Mercury (Hq) pore size analysis from nearby Montney core.
**N₂ Adsorption Isotherm Analysis**

**N₂ adsorption isotherms**

- Hysteresis loops suggest slit-shaped pores

**BJH pore size distributions**

- Uni- and Bi-modual pore size distribution

- 80-100nm pore sizes

**Mercury (Hq) pore size analysis**

- From nearby Montney core

**BJH desorption cumulative pore volume**

- Sample 4, Sample 5, Sample 24
N$_2$ Adsorption Isotherm Analysis

N$_2$ adsorption isotherms

BJH pore size distributions

Mercury (Hq) pore size analysis

hysteresis loops suggest slit-shaped pores

Uni- and Bi-modal pore size distribution

80-100nm pore sizes

50-100nm pore sizes

from nearby Montney core
Flow Unit Identification

Core Plug Pulse-Decay Permeability vs. Porosity Data at Reservoir NOB

Pulse-Decay k at NOB 25468kPa

rp35 lines based on

\[ r_{p35} = 2.665 \left( \frac{k}{100\phi} \right)^{0.45} \]

Porosity (%)
Averaged Probe Permeabilities (13-point) vs. Well Log Density Porosity
Averaged Probe Permeability (13-point) vs. Well Log Density Porosity
Flow Unit Identification

Uncorrected probe permeability data versus well log density porosity

Probe k vs. Density Porosity

 rp35 lines based on  
\[ r_{p35} = 2.665 \left( \frac{k}{100\phi} \right)^{0.45} \]  
Porosity (%)
Corrected to in-situ reservoir stress probe permeability data vs. density porosity

probe \( k \) corrected to in-situ vs. Density Porosity

\[ r_{p35} = 2.665 \left( \frac{k}{100\phi} \right)^{0.45} \]

porosity from N2 ads

rp35 lines based on

0.2 \( \mu m \)

0.1 \( \mu m \)

0.05 \( \mu m \)
Corrected to in-situ reservoir stress probe permeability data vs. density porosity

\[ r_{p35} = 2.665 \left( \frac{k}{100\phi} \right)^{0.45} \]

rp35 lines based on

\[ y = 0.3272x^{0.5849} \]

\[ R^2 = 0.7672 \]
Corrected to in-situ reservoir stress probe permeability data vs. density porosity

\[ r_{p35} = 2.665 \left( \frac{k}{100\phi} \right)^{0.45} \]

One flow unit

pore size from N2 ads

0.05 μm

0.1 μm

0.2 μm
Core Plug Pulse-Decay $k$ and Porosity

- Probe data can be used to identify dominant hydrological flow unit or units, given that lithology dependent compressibility has been taken into account.
- Slip flow is likely dominant, i.e. modified Darcy model or diffusion-based model needed to characterize gas flow.

Javadvour et al. (2007)
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35MPa reservoir pressure

Javadpour et al. (2007)
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Javadvour et al. (2007)
Conclusions

• Routine core analysis performed on full diameter core is not useful for characterizing the subject tight gas siltstone reservoir due to:
  – the highly heterogeneous character of the reservoir
  – measurements are not performed under reservoir conditions

• Profile permeability data are very useful for quantifying fine scale heterogeneity (laminations)
  – Although more data still need to characterize it

• Profile permeability measurements require correction to in-situ stress conditions for use in flow unit identification.
  – Pulse-decay measurements on core plugs under reservoir conditions, appear to be useful for correcting the profile measurements

• N2 adsorption measurements can be applied to fine-grained tight gas reservoirs to identify dominant pore sizes
  – consistent with rp35 calculations and mercury intrusion measurements

• The dataset studied appears to correspond to a single flow unit, with a fairly narrow range of permeability for each porosity
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• References
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