CHARACTERIZING POROSITY IN THE HORN RIVER SHALE, NORTHEASTERN BRITISH COLUMBIA

Nicholas B. Harris[1] and Tian Dong[1]

ABSTRACT

Models for controls on porosity and permeability are critical to building robust reservoir models. Relationships between porosity, pore size, total organic carbon and mineralogy can help to identify sites of porosity and possible mechanisms for porosity development. The authors analyze porosity, organic carbon and mineral abundance data from two Horn River shale cores, taken from well files at the British Columbia Ministry of Energy, Mines and Natural Gas, quantitative assessment of pore sizes determined from scanning electron microscope (SEM) images and nitrogen adsorption-desorption and high-pressure mercury injection capillary pressure (MICP) experiments at the University of Alberta.

Porosity is moderately strongly correlated with total organic carbon content in samples from the Evie and Otter Park members of the Horn River Formation, suggesting that porosity dominantly occurs in organic matter, possibly as a function of kerogen cracking, and that porosity can be predicted from models of organic carbon distribution. Data from the Muskwa Formation shows no clear relationship between porosity and organic carbon or any one mineral, indicating a more complicated distribution of porosity.

Estimates of pore size depend on the analytical technique applied. SEM images show pores in the size range of 20 nm to more than 1000 nm; however, MICP data and nitrogen adsorption-desorption experiments indicate that the preponderance of pores are in the size range of 2–10 nm. This demonstrates that most pores are smaller than the resolution of most SEM imaging systems, which accounts for the systematic underestimation of total porosity in SEM images.

Harris, N.B. and Dong, T. (2013): Characterizing porosity in the Horn River shale, northeastern British Columbia; in Geoscience Reports 2013, *British Columbia Ministry of Natural Gas Development,* pages 33–40.

[1]Department of Earth and Atmospheric Sciences, University of Alberta, Edmonton, Alberta; nharris@ualberta.ca Ferri, F., Hickin,

Key Words: Horn River Basin, Horn River Formation, Muskwa Formation, Shale, Porosity, Permeability, Pore size, Mineralogy

INTRODUCTION

The size, distribution and interconnectivity of pores in any reservoir are key to understanding permeability, which in turn substantially dictates flow rates in wells. In most sandstone reservoirs, pores typically occupy the intergranular volume, with a smaller porosity fraction in the interior of grains resulting from dissolution. Pore throats decrease in size and specific surface area increases as grain size decreases, giving rise to the familiar relationship between porosity, permeability and grain size described by the Kozeny-Carman equation (Dvorkin, 2009). In carbonate reservoirs, porosity is commonly the product of recrystallization and dissolution of primary components, but still largely depends on particle size (Lucia, 1995).

The characterization of porosity in shale reservoirs is considerably more challenging than in sandstone or carbonate reservoirs. Complexities arise simply because the pores are so small. Multiple lines of evidence, including mercury injection capillary pressure (MICP) data, adsorption-desorption experiments and high-resolution scanning electron microscope (SEM) analysis, suggest that much of the porosity occurs in pores with diameters of a few nanometres, smaller than can be observed through any optical methods. Pore sizes are smaller than particles in polishing compounds historically used to prepare rock samples; it is now thought that observations of porosity in conventionally polished samples are largely of artifacts induced by the polishing. In a benchmark paper on the Barnett Shale, Loucks et al. (2009) described the application of a wholly different polishing technique taken from the electronics industry, ion milling, to shale samples. Application of this technique, combined with SEM imaging, revealed pore networks not previously imagined. That approach has now expanded to a number of other formations.

A set of key papers now describe basic properties of porosity in shale reservoirs. Pores are most commonly in the range of one to a few hundreds of nanometres (Loucks et al., 2009). Much of the porosity occurs in organic matter, although pores in some formations are also observed between clay particles, in pyrite framboids and in voids in microfossils (Slatt and O'Brien, 2011; Chalmers et al., 2012; Curtis et al., 2012). Researchers have suggested that porosity in organic matter forms as a consequence of thermal maturation, hydrocarbon generation and expulsion (Bernard et al., 2012), although a recent study of the Kimmeridge Clay Formation (Fishman et al., 2012) suggests that interpretation may not apply to all organic-rich shales.

Shale permeability is not simply a function of the volume and size of pores; it also depends on the degree to which pores are interconnected. Establishing the three-dimensional pore networks of shales presents even more challenges. The size distribution of pore throats can be characterized through high-pressure MICP, but such measurements do not identify the location of pores. Sequential ion milling combined with SEM imaging avenues has produced more detailed information. This involves the erosion of successive thin sheets of material from a cube of shale, imaging the surface between each excavation. Images of pores and minerals are stacked and integrated, creating a three-dimensional volume.

Such studies have contributed greatly to the authors' understanding of porosity and permeability in shale reservoirs; however, shale formations have great stratigraphic variability in terms of organic carbon content, mineralogy and trace-metal composition, and rock mechanical properties. It is likely that shale formations also vary stratigraphically in porosity and permeability, but such variation has not been rigorously demonstrated.

In this paper, the authors present initial results from a multidisciplinary study of the Horn River Formation in northeastern British Columbia now underway at the University of Alberta. The Horn River shale is a successful shale gas play with documented producible reserves in excess of 100 trillion cubic feet (TCF; 2.8×10^{12} m^3) of gas (Reynolds and Munn, 2010). Operating companies in the play have acquired a large number of cores, many of which now have released datasets. This research applies sedimentology, stratigraphy, geochemistry and petrophysics to develop an integrated model for controls on reservoir quality. This paper summarizes porosity relationships in two Horn River wells, the Nexen Komie D-94-A/94-O-8 and the EOG Maxhamish D-012-L/094-O-15. First, the authors investigate data relating total porosity to gas-filled porosity, total porosity to total organic carbon (TOC) content, and the possible function of mineralogy. Second, porosity in samples is characterized, involving measurements of total porosity and pore dimensions measured by MICP, adsorption-desorption experiments and SEM image analysis on ion-milled samples. The latter work is described in more detail in Dong and Harris (in press).

GEOLOGICAL BACKGROUND

The Horn River Basin in northeastern British Columbia represents a prominent deepwater embayment on the west-facing margin of North America in the Middle and Late Devonian (Fig. 1). The basin was flanked by carbonate platforms of the Hay River bank to the northeast, east and south, and by the Bovie fault to the west, on which there is substantial down-to-the-west displacement (Ross and Bustin, 2008; Ferri et al., 2011).

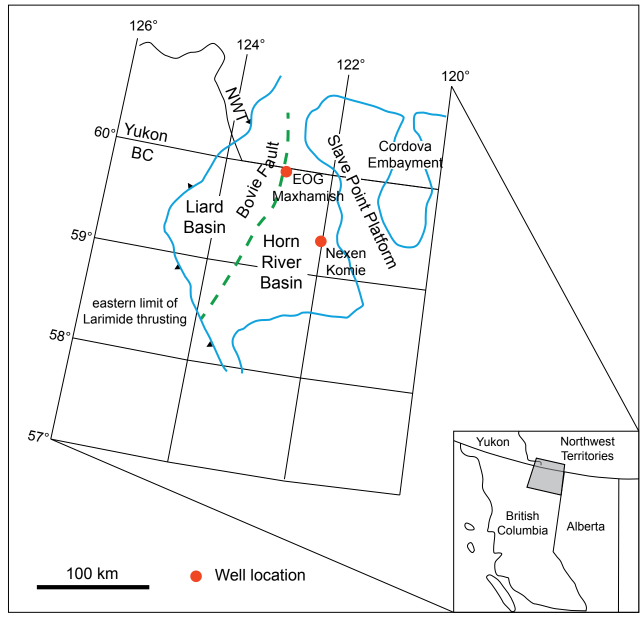


Figure 1. Map of the Horn River Basin, showing the location of wells described in this report (from Dong and Harris, in press; modified after Ross and Bustin, 2008).

Devonian shale stratigraphy in the Horn River Basin consists of the Givetian to lowermost Frasnian (Middle to the base of the Upper Devonian) Evie and Otter Park members of the Horn Fiver Formation (Fig. 2), overlain by the lower Frasnian Muskwa Formation and the Frasnian to Famennian Fort Simpson Formation and Red Knife–Kakisa formations (McPhail et al., 2008; Ferri et al., 2011). This entire sequence rests on Lower Keg River carbonate rocks. Potma et al. (2012) interpret the entire package—from Lower Keg River to Red Knife–Kakisa—to represent two second-order sea level cycles with maximum flooding surfaces in the Evie member and Muskwa Formation.

Of this sequence, the Evie, Otter Park and Muskwa are known to be organic rich; McPhail et al. (2008) report total organic carbon (TOC) contents of 0.3–9.57% in the Evie, 1.6–7.97% in the Otter Park and 0.15–4.99% in the Muskwa. Thermal maturities are considered to be high, between 2.2 and 2.8% Ro according to Reynolds et al. (2010). TOC contents in the overlying Fort Simpson are much lower, averaging 0.25% in data published by Ross and Bustin (2008).

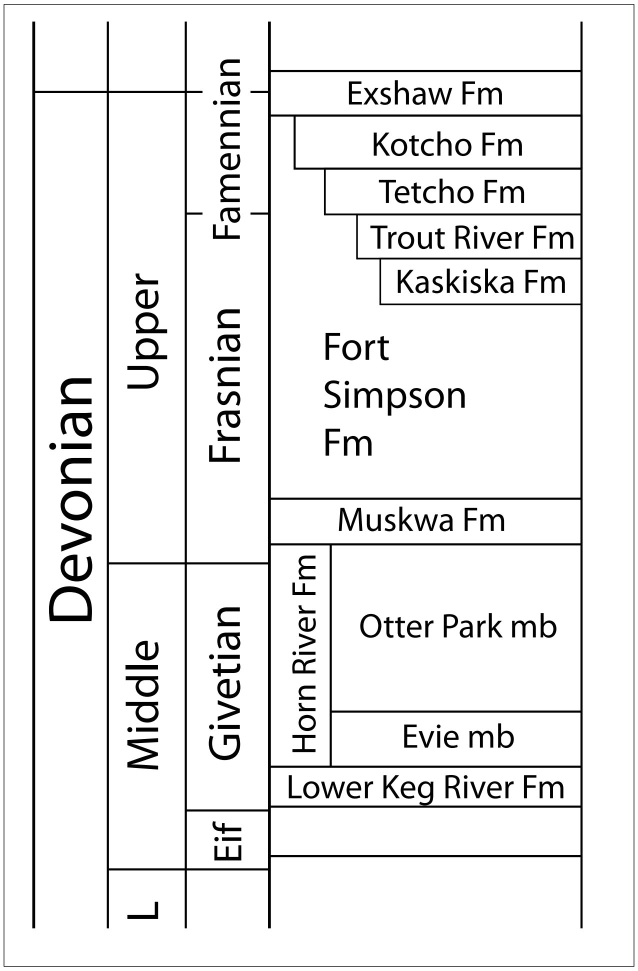


Figure 2. Middle and Upper Devonian stratigraphy of the Horn River Basin (modified after McPhail et al. 2008 and Ferri et al., 2011).

DATA AND SAMPLES

Samples and data from two wells are analyzed: the Nexen Komie D-94-A/94-O-8 well is located near the margin of the eastern Horn River Basin and the EOG Maxhamish D-012-L/094-O-15 is located in the northern part of the basin, somewhat farther from the carbonate platform edge. Porosity and data are taken from files at the British Columbia Ministry of Energy, Mines and Natural Gas. Analysis of the Maxhamish core was carried out by TerraTek and analysis of the Komie core was carried out by CBM Solutions. Work at the University of Alberta included quantitative analysis of SEM images using Image-Pro Plus software to outline and measure all the individual pores and fractures in the area of interest, nitrogen adsorption-desorption experiments (also called BET analysis) on an Autosorb-1 instrument produced by Quantachrome and high-pressure MICP measurements using an Autopore IV 9500 by Micromeritics Instrument Corp., using a maximum pressure of 413.3 MPa (59 944 psi). Additional details on image analysis and the adsorption-desorption experiments are found in Dong and Harris (in press).

RESULTS

Shale composition

The Horn River shales show a range of compositions in the Maxhamish and Komie wells. The major mineral components are quartz, clay and carbonate, with subsidiary pyrite and feldspar. When plotted on a ternary diagram representing quartz, total carbonate and total clay (Fig. 3), compositions in most samples are dominated by quartz with subsidiary clay. Evie samples and a small fraction of the Otter Park samples contain significant carbonate. Muskwa samples generally contain very little carbonate. The range of Muskwa compositions in the Maxhamish and Komie wells are very similar.

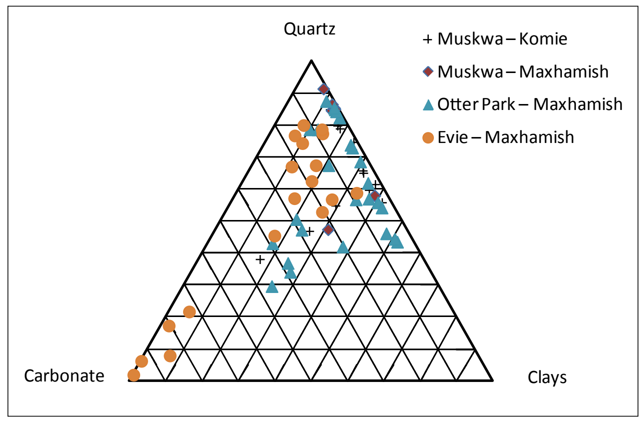


Figure 3. Composition of Horn River shale units in the EOG Maxhamish and Nexen Komie wells, based on data from well files; see text for details.

Organic carbon content

The Muskwa, Otter Park and Evie all contain elevated organic carbon content, summarized in Table 1. Data obtained by TerraTek from the Maxhamish well indicate that the Muskwa is somewhat enriched relative to the other two units, with an average of 4.8% TOC compared to a 3.3% average TOC in the Otter Park and a 3.8% average TOC in the Evie.

The average TOC content of the Muskwa Formation is significantly lower in the Komie well than in the Maxhamish well. The reason for this is not clear. TOC content was obtained through a combustion technique for the Komie well (Leco or equivalent). Well files do not indicate the method used by TerraTek for the Maxhamish core. Different methods (for example, TOC from Leco versus TOC from Rock Eval) yield somewhat different results; nonetheless, these data represent an almost 100% difference, probably more than can be accounted for by a difference in analytical method.

TABLE 1. SUMMARY OF TOTAL ORGANIC CARBON CONTENT (TOC) IN THE MAXHAMISH AND KOMIE WELLS.

	Muskwa–Maxhamish	Muskwa–Komie	Otter Park–Maxhamish	Evie–Maxhamish
Average TOC	4.80%	2.50%	3.30%	3.80%
Maximum TOC	6.40%	3.60%	7.00%	6.50%
Minimum TOC	3.66%	1.40%	1.16%	0.38%

Porosity

ASSOCIATIONS WITH MINERALS AND ORGANIC CARBON

Porosity data measured by TerraTek from the Muskwa, Otter Park and Evie in the Maxhamish well show similar ranges, each unit averaging between 5.1% and 5.6% porosity (Fig. 4). The range of porosities is somewhat smaller for the Muskwa dataset than for the Otter Park and Evie, but few Muskwa samples were analyzed, which may account for the difference in the range of values. Porosities measured in the Komie well by CBM Solutions are considerably higher; they report an average total porosity of 10.9% in 14 Muskwa samples (range from 6.7 to 14.4%). The range of values reported for effective porosities by CBM Solutions (total porosity × (1–Sw)) is in fact similar to the total porosity reported by TerraTek for the same formation.

The underlying reason for the difference between the two datasets in measured porosity is not immediately apparent. It is generally recognized that different labs produce measurements for important reservoir properties such as porosity and permeability, and the two datasets may simply reflect that. Alternatively, real differences in porosity between the two wells are perhaps due to differences in rock compositions.

Possible controls on porosity can be assessed by comparing porosity to compositional parameters. Porosity has been associated in particular with organic matter in other shale formations, for example, the Barnett Shale (Loucks et al., 2009); if porosity is present in organic matter and results from the cracking of kerogen to hydrocarbons, then a correlation might exist between porosity and TOC content. In the Maxhamish dataset, relatively strong associations exist between TOC and porosity for the Evie and Otter Park members (Fig. 4; correlation coefficients of +0.61 and +0.71, respectively), No such relationship exists between TOC and porosity for the Muskwa Formation (correlation of –0.33).

If, on the other hand, porosity is largely associated with specific minerals such as clays or pyrite, this could be recognized through high positive correlation coefficients between porosity and these minerals. No such correlations exist between porosity and any reasonable mineral phase in the Maxhamish dataset for any stratigraphic unit, although it is appropriate to note the difficulty of obtaining accurate

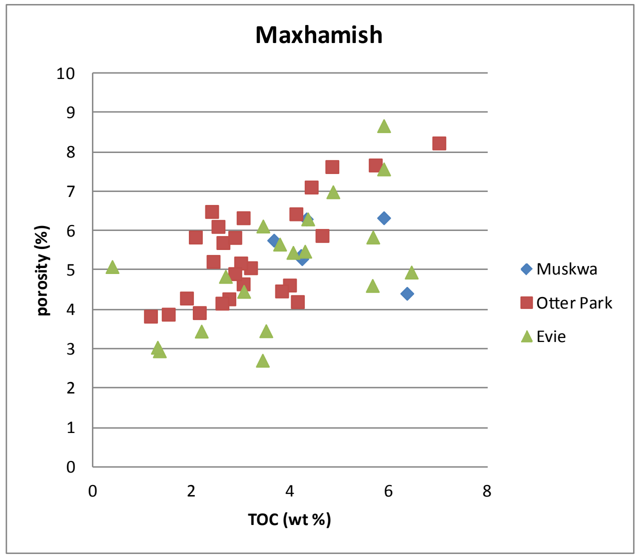


Figure 4. Total porosity versus total organic carbon (TOC) in samples from the EOG Maxhamish well, based on data from well files.

quantitative mineralogical compositions from X-ray diffraction analysis.

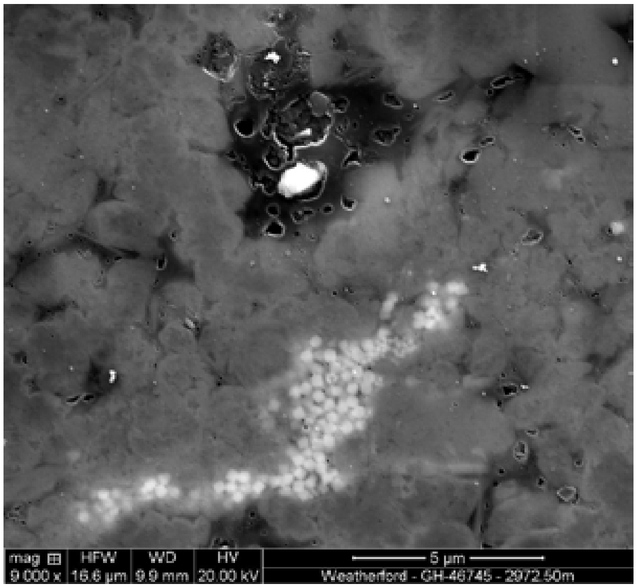
Based on these relationships in the Maxhamish data, it can be concluded that porosity is primarily associated with organic matter in the Evie and Otter Park members. The mode of porosity development in the Muskwa is apparently very different than in the deeper shale reservoir units. The lack of any strong associations in this unit suggests that porosity is dispersed among a number of hosts.

The dataset from the Komie well includes only Muskwa samples, and mineralogical analysis was carried out on a sample adjacent to the porosity-TOC sample, not the same sample, which introduces a potential source of error in attempting to identify relationships between porosity and rock composition. In this dataset, no strong correlation exists between either total or effective porosity and TOC, or between porosity and any specific mineral, which is essentially the same finding as for the Maxhamish well.

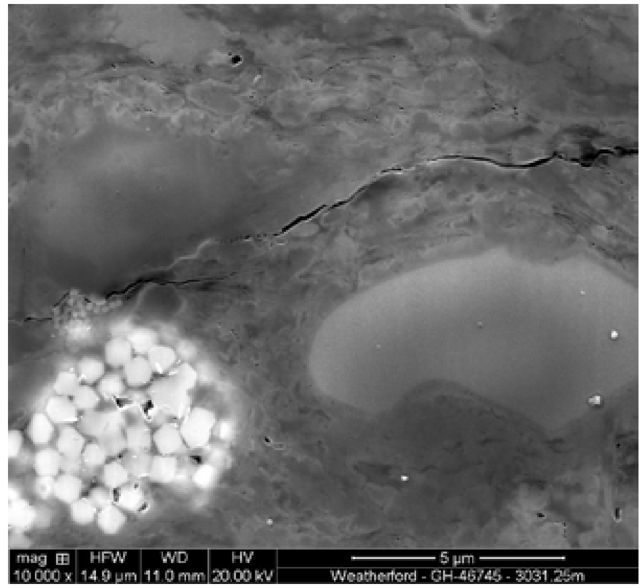
PORE CHARACTERISTICS AND DIMENSIONS

Pore dimensions and the location of pore spaces are important because of their influence on water saturation, gas storage capacity, permeability and adsorption effects. As noted above, however, characterizing shale porosity is remarkably challenging because of the small pore sizes, thus requiring analytical techniques not needed for coarser-grained reservoirs.

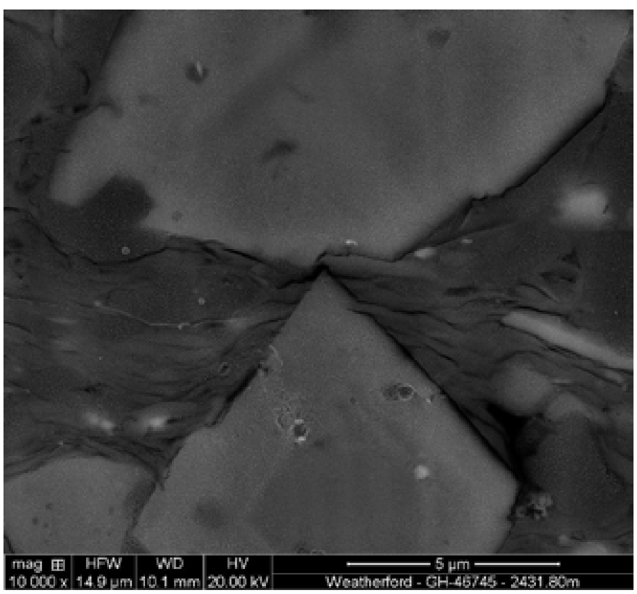
Scanning electron microscrope (SEM) images can be used to characterize pore shapes and sizes. Under some circumstances it is possible to image 20 nm pores, but in many cases the resolution of SEM images is coarser. Figure 5 illustrates different modes of porosity occurrence: in organic matter (Fig. 5a), in the interstices between pyrite crystals in framboids (Fig. 5b), between clay flakes (Fig. 5c) and in dolomite crystals (Fig. 5d). Pores are resolved down to approximately 20 nm in these images. Pores vary in shape depending on the mode of occurrence, notably flattened in pores between clay flakes and rounded in the other settings. Three-dimensional aspect ratios cannot be determined from these photos, but it is reasonable to expect that pore networks associated with framboids are isolated and roughly spherical because of the shape of the framboids.



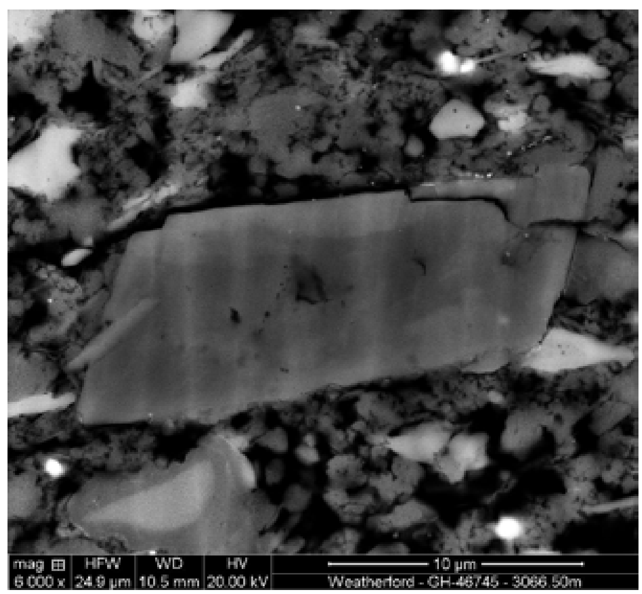
5a



5b



5c



5d

Figure 5. The SEM images of Horn River shale samples from the Nexen Komie and EOG Maxhamish wells, illustrating various modes of porosity occurrence. Images from reports by Weatherford in well files at the British Columbia Ministry of Energy, Mines and Natural Gas: a) Pores developed in organic matter (dark pore filling material in the upper part of the photo), Otter Park member, EOG Maxhamish well, 2972.49 m; b) Porosity developed in pyrite framboid (white minerals in the lower-left part of the photo), Otter Park member, EOG Maxhamish well, 3031.23 m; c) Porosity between clay flakes (especially in the middle-right part of the photo), Muskwa Formation, Nexen Komie well, 2431.83 m; d) Porosity in dolomite crystal (the middle of the photo), Evie member, EOG Maxhamish well, 3066.51 m.

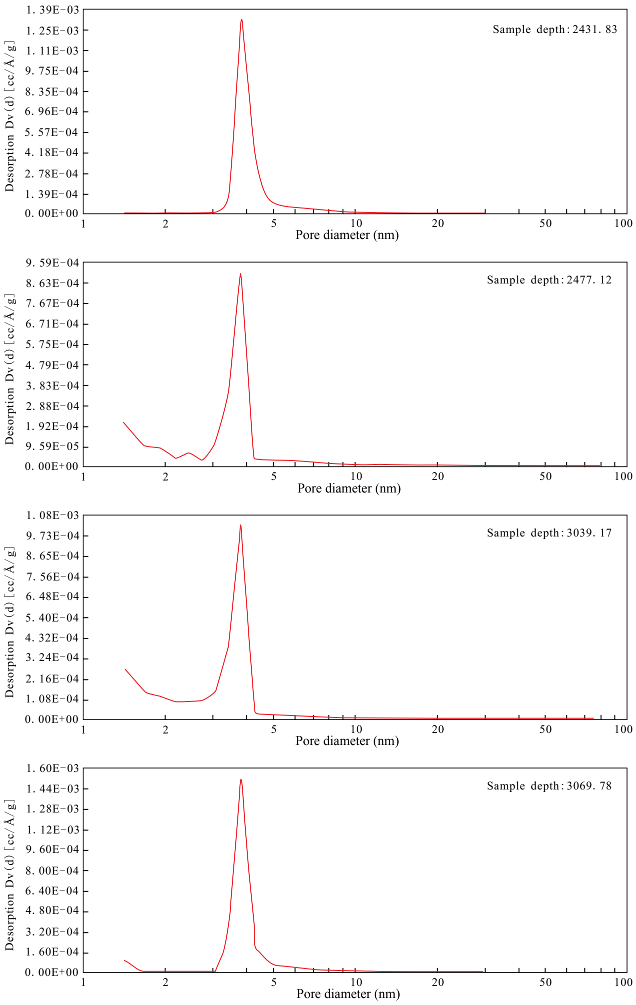


Figure 6. Representative pore-size distributions from nitrogen adsorption-desorption experiments. Height of curve is a measure of relative frequency of pore diameters. Modified after Dong and Harris (in press). Methods are described in detail in Dong and Harris (in press): a) Muskwa Formation, Nexen Komie well, 2431.83 m; b) Muskwa Formation, Nexen Komie well, 2477.12 m; c) Otter Park member, EOG Maxhamish well, 3039.17 m; d) Evie member, EOG Maxhamish well, 3069.78 m.

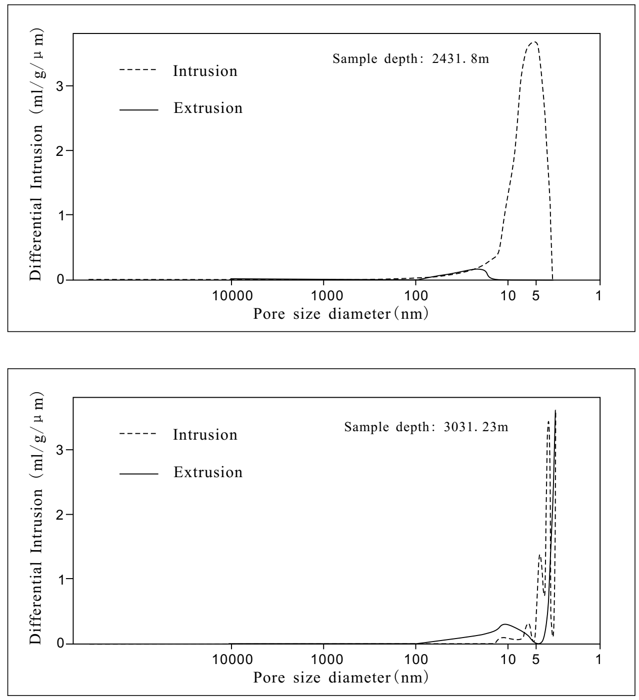


Figure 7. Pore throat sizes calculated from high-pressure MICP experiments: a) Muskwa Formation, Nexen Komie well, 2431.83 m. b) Otter Park member, EOG Maxhamish well, 3031.23 m.

Porosity and pore size can be estimated by quantitative analysis of the images. These data show a range of pore diameters from 20 nm to more than 1000 nm, with modes ranging from 20 to 40 nm (Dong and Harris, in press). Image analysis also consistently underestimates He-porosity measurements reported by TerraTek and CBM solutions. This discrepancy is most likely the result of pores occurring in sizes below the resolution of the SEM.

Both nitrogen adsorption-desorption and high-pressure MICP experiments indicate substantial populations of much smaller pores. Adsorption-desorption experiments reveal a substantial population of pores with a dominant size range between 3 and 5 nm (Fig. 6). The shapes of the hysteresis loops (a comparison between the adsorption and desorption curves) suggests the pores are largely slit-shaped (Dong and Harris, in press).

The MICP data from two samples (one Muskwa and one Otter Park) provide similar information, indicating dominant pore throat sizes of 6 and 4 nm, respectively (Fig. 7). It should be noted that MICP and adsorption-desorption experiments provide somewhat different information: the former represents the size of pore throats, whereas the latter indicates the size of pore diameters. It is possible for large diameter pores to be connected by small pore throats, but the combined information from adsorption-desorption and MICP experiments indicates that in this case, pore diameters and pore throats are of similar size.

DISCUSSION

In this report, the authors have mined data contained in released reports from Horn River well files at the British Columbia Ministry of Energy, Mines and Natural Gas and combined that with the authors' analytical work on porosity systems in the Horn River shale reservoirs. The results highlight both the complexity of pore systems in these shales and the challenges of analyzing these rocks.

Pores in shale reservoirs are known to have different size characteristics, modes of occurrence, and—presumably—different controls. Good models for predicting reservoir behaviour depend on understanding these relationships. Research on the Horn River shale reveals complexities in the size, distribution and interconnectivity of pores.

Two lines of evidence suggest that a considerable fraction of porosity occurs as small pores: 1) He-porosity data is consistently higher than porosity measured by analysis of SEM images from the same sample and 2) SEM images show larger pores than are indicated by adsorption-desorption and MICP experiments. These datasets together indicate that the SEM images fail to record a significant fraction of total porosity. Similar observations have been recorded by Curtis et al. (2012) for a number of other shale reservoirs.

If SEM images are used as the primary source of information for porosity characterization, controls on some reservoir properties may be misinterpreted. Large pores undoubtedly contribute more to permeability than small pores (Dewhurst et al., 1999), so a misunderstanding of pore sizes may not affect interpretations of controls on permeability. Gas storage volume, however, does depend on total porosity, so misunderstanding where the significant volume of porosity occurs can affect models for gas storage. Moreover, gas desorption effects are surface-area dependent, which in turn depend on pore size. This affects models for gas flow during the production life of the reservoir.

The authors' Horn River database, although currently small, points to significant stratigraphic differences in reservoir properties. Data taken from TerraTek reports suggest that total porosity in the Evie and Otter Park members is associated with organic matter, based on moderately strong correlations between TOC and porosity. That relationship is not present in the Muskwa data, suggesting that there is a different mode of porosity occurrence in that unit. This topic will be a major focus in the authors' research group during the next three years.

Porosity differences in the same stratigraphic unit are also evident in a comparison between wells at different distances from the basin edge. Measured total porosity from He-pycnometry in a set of Muskwa measurements averaged 10.9% in a well near the basin margin (Nexen Komie), total porosity measurements in a set of Muskwa data averaged 5.6% in a well farther from the margin (Maxhamish) whereas average Muskwa TOC content was higher in the Maxhamish well than in the Komie well (5.8% versus 2.5%). Geographic position within a shale basin can lead to different rock compositions, either because of decreasing coarse sediment composition toward the basin margin or because of variable biogenic contributions. Interpretations here are complicated by possible interlaboratory variation in analytical results, which is suspected to be particularly problematic in porosity data.

CONCLUSIONS

Data taken from publically available well files have been combined with the experimental results to shed light on porosity controls in the Horn River shale reservoir. Three findings are highlighted:

- Significant differences in the modes of porosity occurrence are evident in the different reservoir units. Total porosity correlates moderately well with TOC in the Evie and Otter Park samples, suggesting that porosity is largely associated with organic carbon in these units. No correlation exists between total porosity and either TOC or any mineral in Muskwa data. This suggests that porosity in that unit is distributed among several phases.
- Geographic differences exist in TOC and porosity in Muskwa data, although these differences in porosity may be an artifact of different laboratories and analytical procedures. Nonetheless, differences are likely between wells in different parts of the basin due to varying contributions from sediments shed from platforms and to varying biogenic production of organic matter and silica.
- Scanning electron microscope images, while visually appealing, may fail to capture a large fraction of porosity occurring as pores less than 10 nm in diameter. The large pores readily apparent in SEM images are probably the major contributor to reservoir permeability, but small pores contribute significantly to the total gas storage of the reservoir. It is suspected that the small pores also need to be taken into account for gas desorption effects during production, given their high surface area, but such relationships have yet to be documented.

ACKNOWLEDGMENTS

The authors thank the British Columbia Ministry of Natural Gas Development for providing access to Horn River well files and for initial funding of the Horn River research study. Warren Walsh and Fil Ferri of the British Columbia Ministry of Natural Gas Development were particularly instrumental in facilitating these studies.

The authors also thank Drs. Nancy Zhang and Eric Flaim of the Integrated Nanosystems Research Facility at the University of Alberta for training and guidance in the use of the Autosorb-1 instrument and Randy Kofman for carrying out high-pressure MICP measurements in the lab of Dr. Doug Schmitt at the University of Alberta.

REFERENCES

Bernard, S., Horsfield, B., Schulz, H.-M., Wirth, R., Schreiber, A. and Sherwood, N. (2012):Geochemical evolution of organic-rich shales with increasing maturity: A STXM and TEM study of the Posidonia Shale (Lower Toarcian, northern Germany); *Marine and Petroleum Geology*, Volume 31, pages 70–89.

Chalmers, G.D., Bustin, R.M. and Power, I.M. (2012): Characterization of gas shale pore systems by porosimetry, pycnometry, surface area, and field emission scanning electron microscopy/transmission electron microscopy image analyses: examples from the Barnett, Woodford, Haynesville, Marcellus, and Doig units; *AAPG Bulletin*, Volume 96, pages 1099–1119.

Curtis, M.E., Sondergeld, C.H., Ambrose, R.J. and Rai, C.S. (2012): Microstructural investigation of gas shales in two and three dimensions using nanometer-scale resolution imaging; *AAPG Bulletin*, Volume 96, pages 665–677.

Dewhurst, D.N., Yang, Y. and Aplin, A.C. (1999): Permeability and fluid flow in natural mudstones, in Muds and Mudstones: Physical and Fluid Flow Properties, Aplin, A.C., Fleet, A.J. and Macquaker, J.H.S., Editors, *Geological Society of London,* Special Publication 158, pages 23–43.

Dong, T. and Harris, N.B. (in press): Size distribution and morphology of pores in the Horn River Shale, Middle and Upper Devonian, northeastern British Columbia; in Electron Microscopy of Hydrocarbon Shale Reservoirs, Camp, W., Diaz, E. and Wawak, B., Editors, AAPG, Memoir 102.

Dvorkin, J. (2009): The Kozeny-Carman equation revisited; unpublished paper, URL <http://pangea.stanford.edu/~jack/KC_2009_JD.pdf> [February 2013].

Ferri, F., Hickin, A.S. and Huntley, D.H. (2011): Besa River Formation, western Liard Basin, British Columbia (NTS 094N): geochemistry and regional correlations; in Geoscience Reports 2011, *British Columbia Ministry of Energy, Mines and Natural Gas*, pages 1–18.

Fishman, N.S., Lowers, H.A., Hackley, P.C., Hill, R.J. and Egenhoff, S.O. (2012): Porosity in shales of the organic-rich Kimmeridge Clay Formation (Upper Jurassic), offshore United Kingdom; *Search and Discovery* Article #50620, 56 pages.

Loucks, R.G., Reed, R.M., Ruppel, S.C. and Jarvie, D.M. (2009): Morphology, genesis, and distribution of nanometer-scale pores in siliceous mudstones of the Mississippian Barnett Shale; *Journal of Sedimentary Research*, Volume 79, pages 848–861.

Lucia, F.J. (1995): Rock fabric/petrophysical classification of carbonate pore space for reservoir characterization; *AAPG Bulletin*, Volume 79, pages 1275–1300.

McPhail, S., Walsh, W., Lee, C. and Monahan, P.A. (2008): Shale units of the Horn River Formation, Horn River Basin and Cordova Embayment, northeastern British Columbia; *British Columbia Ministry of Energy, Mines and Natural Gas*, Petroleum Geology Open File Report No. 2008-1, 14 pages.

Potma, K., Jonk, R., Davie, M. and Austin, N. (2012): A mudstone lithofacies classification of the Horn River Group: integrated stratigraphic analysis and inversion from wireline log and seismic data; Presented at the 6th BC Unconventional Gas Technical Forum, *British Columbia Ministry of Energy, Mines and Natural Gas*, URL <http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/K%20Potma.pdf>.

Reynolds, M.M. and Munn, D.L. (2010): Development update for an emerging shale gas giant field—Horn River Basin, British Columbia, Canada; SPE Unconventional Gas Conference, *Society of Petroleum Engineers*, paper no. 130103-MS, 17 pages.

Ross, D.J.K. and Bustin, R.M. (2008): Characterizing the shale gas resource potential of Devonian-Mississippian strata in the Western Canada sedimentary basin: application of an integrated formation evaluation; *AAPG Bulletin*, Volume 92, pages 87–125.

Slatt, R.M. and O'Brien, N.R. (2011): Pore types in the Barnett and Woodford gas shales: contribution to understanding gas storage and migration pathways in fine-grained rocks; *Search and Discovery* Article #80166, 18 pages.