GS-14 Shallow unconventional Cretaceous shale gas in southwestern Manitoba: an update (parts of NTS 62C, F, G, H, J, K, N)

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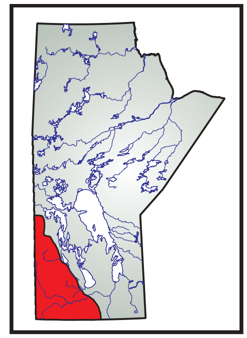

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Summary

Shallow unconventional shale gas plays are seen as the natural gas source of the future. In the last two decades, several shale gas basins have been identified and developed. One of these successful basins is the Antrim Shale in the Michigan Basin. The Antrim Shale is the best analogue for the Cretaceous shale gas prospect in southwestern Manitoba. The two plays have several characteristics in common, including natural fracturing, shallow depths, high total organic carbon (TOC) values, thermal immaturity, thick shale sequences and biogenic gas generation.

In order to further quantify these characteristics in southwestern Manitoba, samples collected during the 2009 field season were sent for organic geochemical analysis (Rock Eval™ and TOC), inorganic geochemical analysis (instrumental neutron activation analysis and inductively coupled plasma–mass spectrometry), and bulk mineralogical analysis (X-ray diffraction). The preliminary organic geochemistry results indicate all the samples were thermally immature and TOC values were highest in the Carlile and Favel formations and the Belle Fourche Member of the Ashville Formation.

The microporosity and mineralogy of the Babcock beds, a 2 m thick siltstone interval in the Boyne Member of the Carlile Formation, were evaluated using scanning electron microscopy and petrography. The Babcock beds were subdivided based on lithology (claystone or siltstone) into the basal, middle and upper units. The interparticle pores range in size from 2 to 12 µm in the claystone laminae and from 10 to 25 µm in the siltstone laminae, and the pores are elongate parallel to bedding. A sample of the basal unit yielded mean porosity values of 4.6 and 9.2% for claystone and siltstone, respectively. A middle unit sample, in comparison, had a slightly higher claystone mean porosity of 6.0 % and a siltstone mean porosity of 12.1%, whereas an upper unit sample of only claystone had a mean porosity of 2.7%. These pore characteristics and porosity values are comparable to those of other shale gas reservoirs, such as the Barnett Shale in Texas.

Introduction

Over the last three years, Manitoba's Cretaceous shale sequences have been studied to evaluate the potential for a shale gas resource. The project, which is focused on southwestern Manitoba (Figure GS-14-1), was introduced in Nicolas (2008), with early fieldwork discussions. Bamburak (2008a) provided the historical background of the gas shows. Nicolas and Bamburak (2009) and Nicolas and Grasby (2009) discussed the organic geochemistry and water and gas chemistry results, respectively, of the shale, with particular focus on the area located south of Twp. 13 to the international border, and west of the Manitoba Escarpment to the provincial border. Fieldwork conducted in the summer of 2009 (Nicolas and Bamburak, 2009) was concentrated in the areas of Riding Mountain, Duck Mountain and Porcupine Hills, essentially including all the Cretaceous shale formations located along the Manitoba Escarpment, westward to the provincial border, and north of Twp. 13; samples were sent for geochemical and mineralogical analysis with some results discussed in this report. Siltstone beds, which are informally referred to as the Babcock beds (Nicolas and Bamburak, 2009) of the Boyne Member within the Carlile Formation, represent a potential shale gas reservoir and as such were evaluated for microporosity.

Geochemistry and mineralogy

A total of 79 samples, consisting of 34 samples collected during the 2009 field season and 45 archive samples collected in 1997 and 1999 (Bamburak, 1999), was sent to the Organic Geochemistry Laboratory of the Geological Survey of Canada in Calgary for Rock Eval™ and TOC analysis under phase 2 of the Shallow Unconventional Shale Gas Project, as described by Nicolas and Bamburak (2009). Of the new samples collected, 22 were sent for inorganic chemistry by instrumental neutron activation analysis and inductively coupled plasma–mass spectrometry analysis to complement the black shale investigations of Bamburak (1999), and to enhance the Manitoba chemostratigraphic database (Bamburak, 2008a, b).

Figure GS-14-2 displays the results of a selective retrieval (Table GS-14-1) from the chemostratigraphic database created during phase 1 of the Shallow Unconventional Shale Gas Project. A relative enrichment of Th, U and several rare earth elements (REE) can be seen for the Gammon Ferruginous Member of the Pierre Shale

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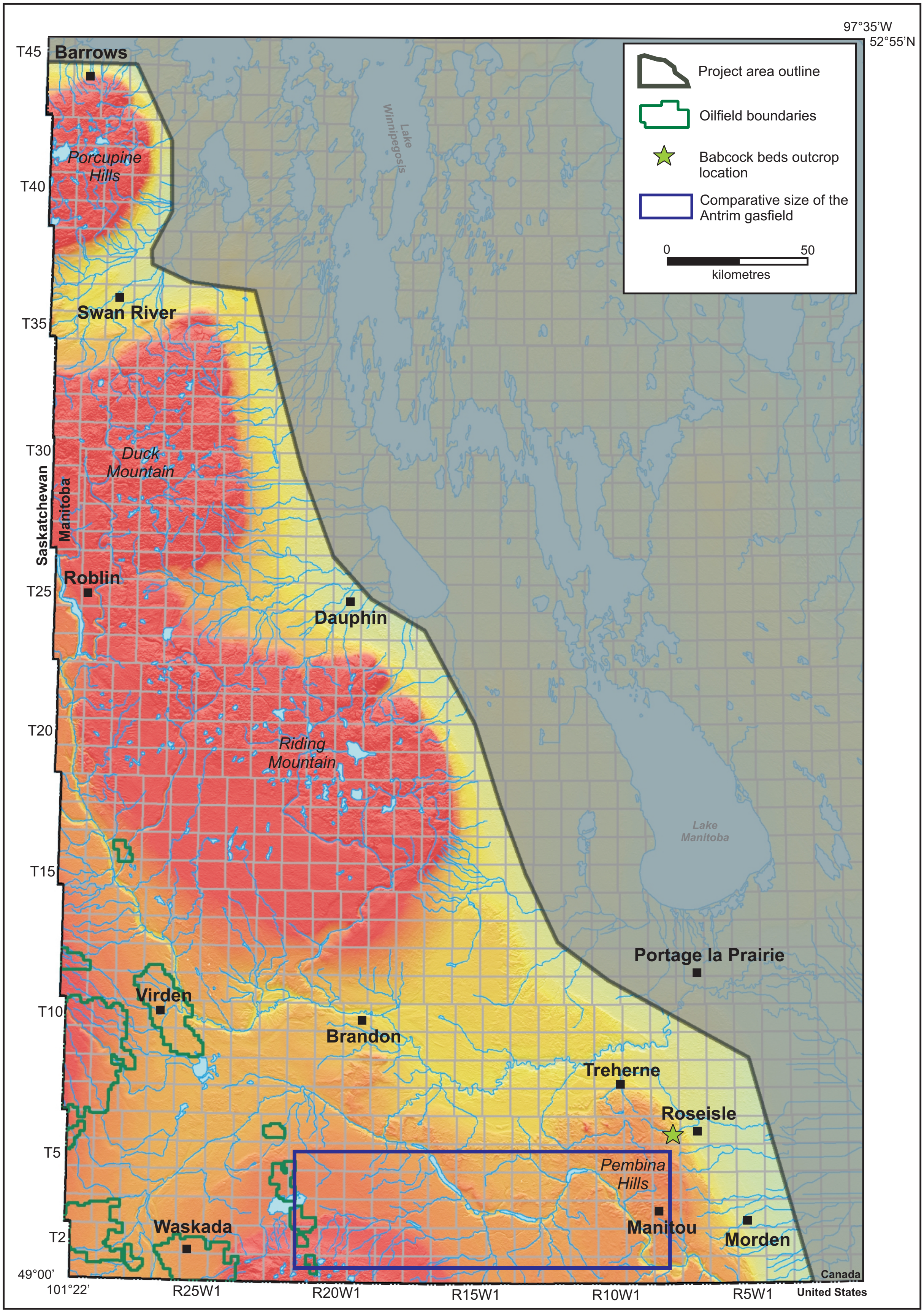

Figure GS-14-1: *Digital elevation map of the project area, southwestern Manitoba, showing the Babcock beds outcrop location and the comparative size of the Antrim gasfield (located in the Michigan Basin).*

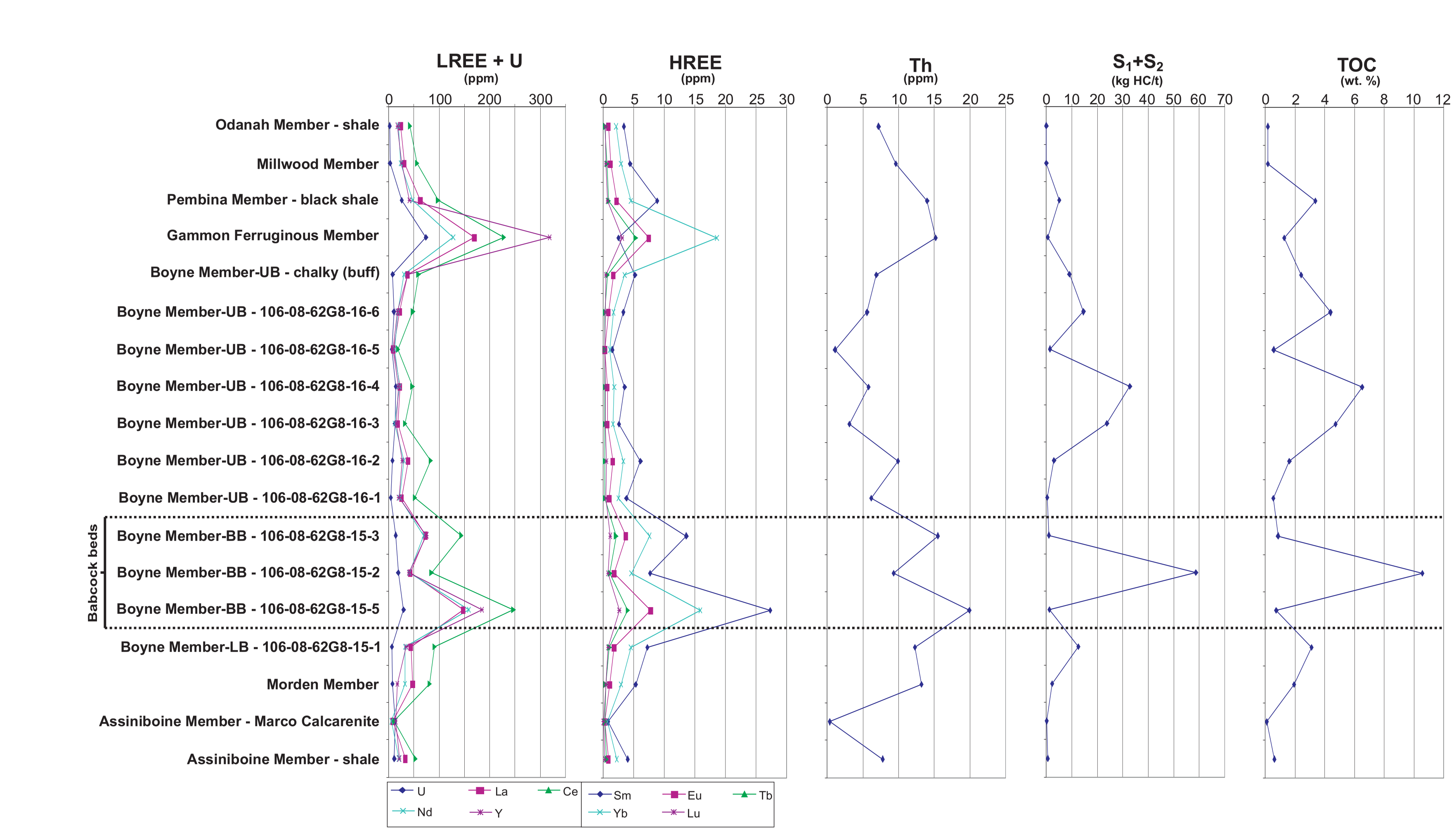

Figure GS-14-2: *Geochemistry profiles of stratigraphic units in this study, including Babcock beds and the Boyne Member upper and lower beds (modified from Bamburak and Nicolas, 2009). Note: each result represents an average value; for total number of samples analyzed see Table GS-14-1. Abbreviations: HC, hydrocarbon; HREE, heavy rare-earth elements; LREE, light rare-earth elements; TOC, total organic carbon; S_1 parameter is a measure of free or adsorbed hydrocarbons volatilized during heating of the sample up to 300°C and S_2 parameter is a measure of the hydrocarbons released during gradual heating from 300 to 550°C at increments of 25°C/min.*

Table GS-14-1: Samples (selectively retrieved from the Cretaceous portion of the Manitoba chemostratigraphic database for the Pembina Hills area [Bamburak, 2008a, b]) used for inorganic chemical analyses, Rock Eval™ and total organic carbon depicted in Figure GS-14-2 (modified from Bamburak and Nicolas, 2009). Note: alphanumeric string refers to sample number.

Sample interval	Lithology	Number of outcrop samples analyzed		
		INAA and ICP-MS	Rock Eval™	TOC
Odanah Member	dark grey shale	16	9	9
Millwood Member	dark grey shale	6	2	2
Pembina Member	black shale	67	9	9
Gammon Ferruginous Member	brown shale	11	3	3
Boyne Member – UB	chalky (buff)	38	28	28
Boyne Member – UB-106-08-62G8-16-6	medium brown shale, just above highest coquina bed	1	1	1
Boyne Member – UB-106-08-62G8-16-5	coquina beds; abundant clam shells	1	1	1
Boyne Member – UB-106-08-62G8-16-4	zebra beds; light grey to beige stripe;chalky	1	1	1
Boyne Member – UB-106-08-62G8-16-3	zebra beds; buff-coloured stripe	1	1	1
Boyne Member – UB-106-08-62G8-16-2	zebra beds; banded beige buff	1	1	1
Boyne Member – UB-106-08-62G8-16-1	greenish medium grey shale	1	1	1
Boyne Member – BB-106-08-62G8-15-3	Upper Babcock beds – siltstone to fine sandstone, resistant, at top of unit	1	1	1
Boyne Member – BB-106-08-62G8-15-2	Middle Babcock beds – brown to buff to grey silty shale to shaly siltstone	1	1	1
Boyne Member – BB-106-08-62G8-15-5	Lower Babcock beds – siltstone beds interbedded black shale laminae	1	1	1
Boyne Member – LB-106-08-62G8-15-1	lower black speckled shale; lowest exposed unit on outcrop	1	1	1
Morden Member	black shale	23	6	6
Assiniboine Member - Marco Calcarenite	calcarenite	5	2	2
Assiniboine Member	shale	13	1	1

Abbreviations: ICP-MS, inductively coupled plasma–mass spectrometry ; INAA, instrumental neutron activation analysis; TOC, total organic carbon; UB, Boyne Member upper beds; BB, Boyne Member Babcock beds; LB, Boyne Member lower beds.

and for the Babcock beds. The Babcock beds also show a corresponding increase in TOC and petroleum potential (S_1+S_2); S_1 parameter is a measure of free or adsorbed hydrocarbons volatilized during heating of the sample up to 300°C and S_2 parameter is a measure of the hydrocarbons released during gradual heating from 300 to 550°C at increments of 25°C/min.

Of the 79 samples (phase 2) sent for organic geochemistry, 67 samples were selected for bulk mineralogical analysis by X-ray diffraction (XRD). The mineralogical samples were still being processed at the time of publication, and no results are available. The organic geochemistry results, although received, have yet to be fully processed and analyzed. A cursory evaluation of the Rock Eval™ results from the 2009 sample suite indicates that all the samples are thermally immature, with T_{max} (temperature measured during sample heating that correlates to the maximum temperature a rock has been subjected to during its burial history) values falling below the oil window. TOC values are highest in the Carlile Formation, Favel Formation and the Belle Fourche Member of the Ashville Formation. The highest TOC values, up to 11.95 wt. %, were measured in samples of the Morden Member of the Carlile Formation collected in 2009.

Petrography and microporosity of the Babcock beds

As part of an undergraduate technical project in the Department of Geological Sciences at the University of Manitoba, the evaluation of the microporosity of the siltstone beds, informally referred to as the Babcock beds, was undertaken. Nicolas (2008) reported the discovery of the 2 m thick siltstone beds, within the Boyne Member of the Carlile Formation, outcropping near Roseisle (Figure GS-14-1). The organic geochemistry and mineralogy of these beds were reported in Nicolas and Bamburak (2009). The Babcock beds can be subdivided into three units, referred to here as the basal, middle and upper units (Figure GS-14-3), based on lithology. The basal and middle units are composed of grey shale/claystone with

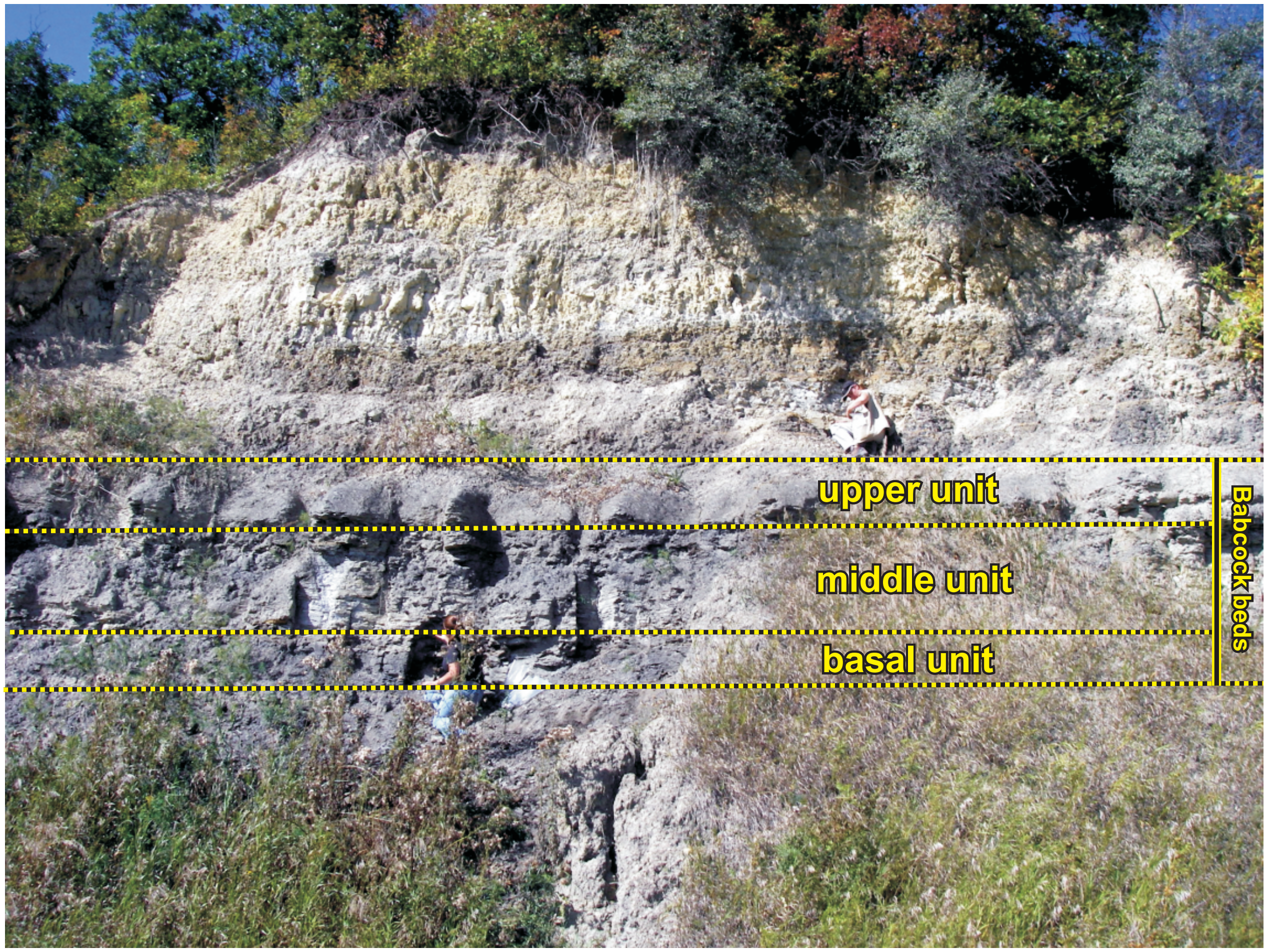

Figure GS-14-3: *Outcrop of the Boyne Member of the Carlile Formation in Snow Valley along Roseisle Creek, southwestern Manitoba, showing internal subdivision of the Babcock beds.*

interbedded siltstone laminae and lenses, and the upper unit is composed of dominantly very fine grained claystone with some siltstone lenses.

Petrography and scanning electron microscopy (SEM) were used to determine the size and shape of the pores and approximate the porosity of the laminated claystone and siltstone units within the Babcock beds. For the creation of the thin sections, a suite of samples, representing the basal, middle and upper units of the Babcock beds, were impregnated with epoxy; the samples were too friable to cut uncemented. In preparation for SEM analysis, small pieces of each sample were coated with gold and mounted with carbon paint onto stubs then oriented parallel to and perpendicular to bedding. Figure GS-14-4 shows SEM images from all three units, viewed parallel and perpendicular to the bedding direction.

Petrography

The Babcock beds are composed of thinly interbedded claystone and siltstone laminae and lenses (Figure GS-14-5), with small-scale crossbedding and ripples (Nicolas and Bamburak, 2009, Figure GS-17-6b). The claystone laminae are 1 to 10 mm thick and siltstone laminae are 2 to 20 mm thick. The siltstone lenses are quartz-dominated with minor feldspar, most common in the middle unit of the beds, and range in thickness from 0.5 to 3.5 mm. Quartz cement infills thin fractures.

The siltstone has framework grains consisting of 40 to 50% subangular quartz (20 to 60 µm in size), 10 to 15% elongate chitinous shell fragments (10 to 80 µm in size), 5 to 10% subangular biotite (20 to 40 µm in size), and 2 to 5% subrounded opaque minerals (10 to 30 µm in size). The matrix comprises 30% subrounded quartz (1 to 3 µm in size) and 70% organic matter and clay minerals. Figure GS-14-6 shows these framework grains in thin section.

The claystone laminae are composed of framework grains comprising 20 to 25% subangular quartz (1 to 3 µm in size), 10 to 15% elongate chitinous shell fragments (2 to 4 µm in size), 5 to 7% subangular biotite (1 to 2 µm in size), and 2 to 5% subrounded opaque minerals (1 to 3 µm in size). The matrix is mostly dark brown and opaque, and consists of very fine grained material, dominantly clay minerals, quartz and organic matter.

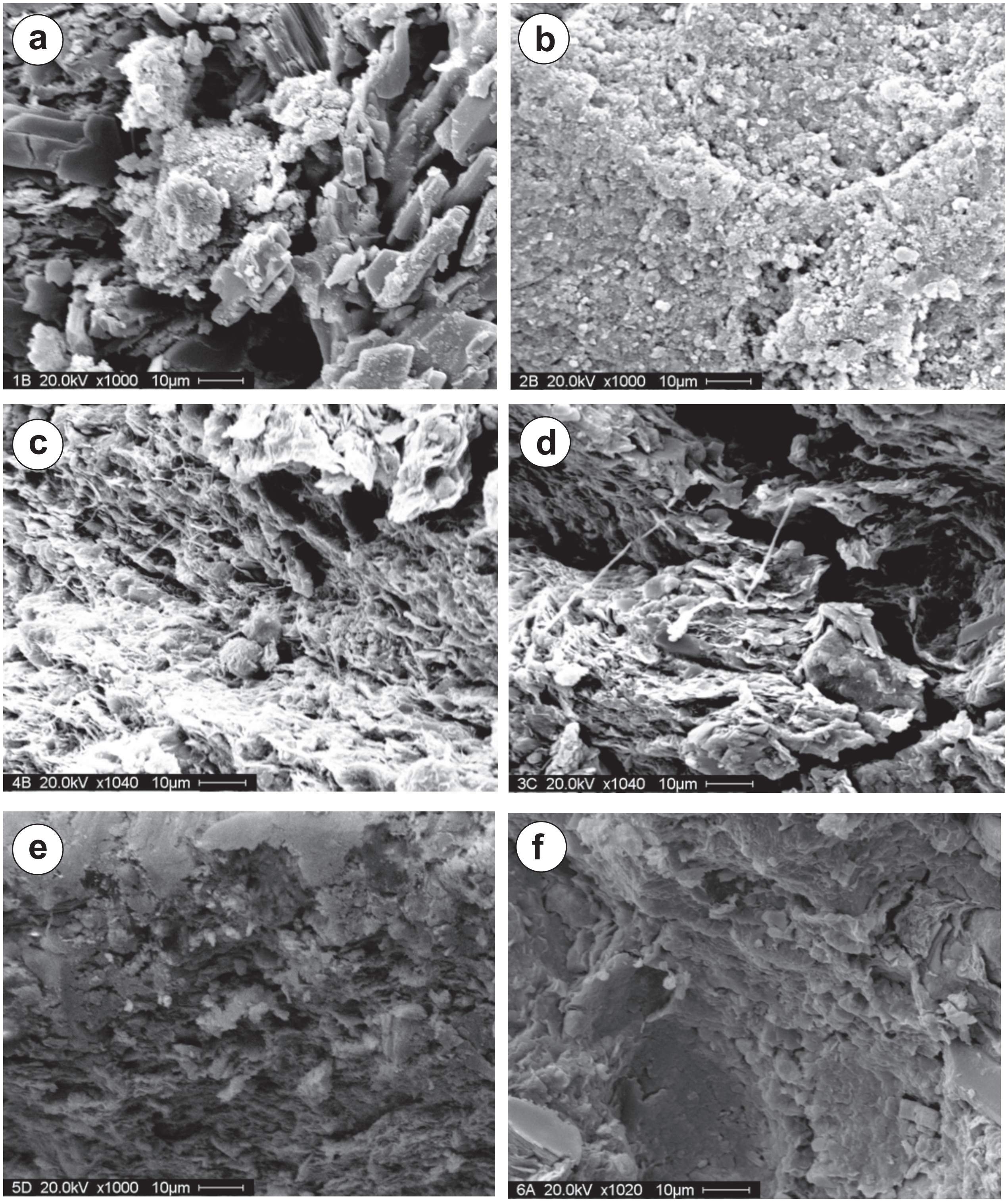

Figure GS-14-4: *Scanning electron microscopy images of samples from the three units in the Babcock beds, southwestern Manitoba:* ***a)*** *basal unit, view parallel to bedding;* ***b)*** *basal unit, view perpendicular to bedding;* ***c)*** *middle unit, view parallel to bedding;* ***d)*** *middle unit, view perpendicular to bedding;* ***e)*** *upper unit, view parallel to bedding; and* ***f)*** *upper unit, view perpendicular to bedding.*

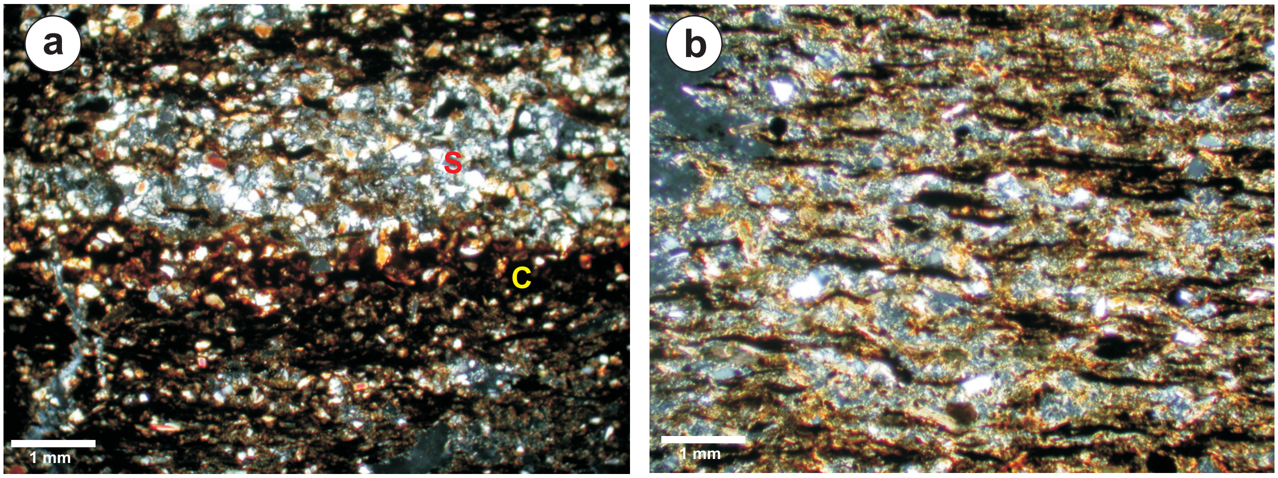

Figure GS-14-5: *Thin-section photomicrograph of **a)** quartz-rich siltstone (S) laminae within a claystone (C) bed and **b)** siltstone with interbedded clay and organic matter; analyzed using cross-polarized light. Both samples from the middle unit of the Babcock beds, southwestern Manitoba.*

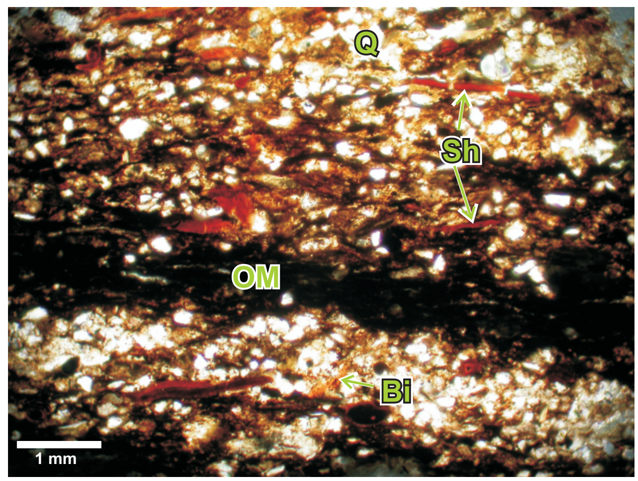

Figure GS-14-6: *Thin-section photomicrograph of a siltstone laminae from the basal unit of the Babcock beds, southwestern Manitoba. Components include quartz (Q), chitinous shell fragments (Sh), biotite (Bi) and organic matter (OM); analyzed using plane-polarized light.*

Scanning electron microscopy

Two samples were analyzed from each of the basal, middle and upper units of the Babcock beds. SEM images were taken from mounted samples oriented parallel to and perpendicular to bedding, in order to see the porosity differences between the two orientations. Each sample was viewed at magnifications of 100, 500, 1000 and 2000x. The results were grouped by the dominant lithology of the lamina in view, being either claystone or siltstone.

Pore geometry

Pore size and shape varies between the three sample sets. The basal samples have pore sizes that range from 2 to 6 µm in the claystone laminae, and from 10 to 25 µm in the siltstone laminae. The majority of the interparticle pores are elongate parallel to bedding, with some interparticle porosity around larger mineral grains. Samples from the middle unit have pore sizes that vary from 2 to 3 µm in the claystone, and 6 to13 µm in the siltstone laminae. The pores are elongate parallel to bedding (Figure GS-14-7). In the upper unit, the claystone has interparticle pores ranging in size from 2 to 12 µm.

Porosity

Porosity was determined for each sample using the Scion Imaging® software on SEM images captured at a magnification of 1000x, and by applying various filters to minimize errors due to beam shadows, artificial fractures and plucked grains resulting from sample preparation and mounting.

Mean porosity values for the basal unit of the Babcock beds were 4.6 and 9.2% for claystone and siltstone, respectively. In comparison, the middle unit sample returned slightly higher mean porosity values with a claystone mean porosity of 6.0 % and a siltstone mean porosity of 12.1%. The upper unit sample returned a much lower value of 2.7% for claystone and no return on siltstone as it was not present in the sample. Table GS-14-2 summarizes the mean porosity values of the claystone and siltstone laminae in each of the three units, viewed

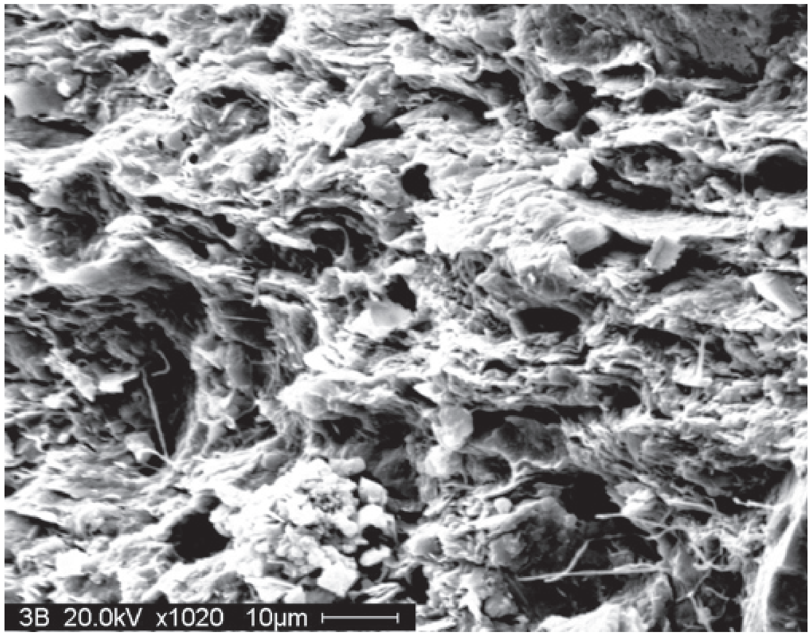

Figure GS-14-7: Scanning electron microscopy image of elongate pores parallel to bedding in claystone laminae of the middle unit of the Babcock beds, southwestern Manitoba.

Table GS-14-2: Summary of mean porosity for each of the units within the Babcock beds, southwestern Manitoba.

Babcock beds unit	Laminae lithology	Mean porosity	
		View parallel to bedding	View perpendicular to bedding
Upper	Claystone	2.7%	2.0%
	Siltstone	NA	NA
Middle	Claystone	6.5%	5.8%
	Siltstone	12.7%	11.2%
Basal	Claystone	7.5%	2.8%
	Siltstone	9.2%	NA

NA, not available

parallel and perpendicular to bedding. Some samples did not contain sufficient siltstone laminae for accurate porosity determination.

Shale basin analogues and exploration

Definitions and challenges

The definition of 'shale' and 'shale gas' varies greatly (Spencer et al., 2010) between authors, organizations and regulatory bodies. The Canadian Society for Unconventional Gas (Canadian Society for Unconventional Gas, 2010) defines shale gas as a natural gas that is stored in organic-rich and very fine grained rock; the term shale is loosely applied, and really represents any fine-grained rock including pure shale, mudstone, laminated siltstone and very fine grained sandstone. The shale acts as both the source and the reservoir, where the gas is derived from and adsorbed onto the organic matter and clay within the rock, and can be generated by either biogenic or thermogenic processes (Canadian Society for Unconventional Gas, 2010). While not all shale beds are prospective for shale gas (Rokosh et al., 2009), it is a combination of different factors that can lead to potential gas production. Each shale gas play has a unique stratigraphy with a distinctive geochemical and mineralogical composition, and requires a customized exploration and development approach, which is unconventional and can be challenging since many of the commonly used approaches to exploration, such as seismic surveys and detailed well log analysis, do not provide reliable results. With these challenges upfront, and in an inadequately explored area like southwestern Manitoba, particularly east of the traditional oil production region towards the Manitoba Escarpment, there is minimal well data and few stratigraphic controls over a large area to assist in understanding the shale gas potential of the province. These challenges currently make a resource assessment of Manitoba's shale gas very difficult, if not impossible.

Assessment of a potential shale gas play in southwestern Manitoba requires basic information including, but not limited to, the presence of organic matter (TOC content), maturity of the organic matter, type of gas in the reservoir, and permeability of the reservoir (Rokosh et al., 2009). In an attempt to address some of this basic information, during the course of this project, information on organic matter, both TOC and maturity, and gas chemistry have been collected and analyzed (Nicolas and Bamburak, 2009; Nicolas and Grasby, 2009). The data collected so far indicates that southwestern Manitoba has an aerially extensive, thick sequence of fine-grained, organic-rich shale. Gas chemistry indicates a 100% biogenic methane resource in the Pembina Hills region, with good probability to extend west and northward along and into the Manitoba Escarpment. Evidence for shale gas potential farther north along the escarpment are reported gas shows in two water wells that were drilled and immediately abandoned due to gas; these wells are located north of the town of Swan River, just off the southeast slope of the Porcupine Hills, in Twp. 39, Rge. 26 to 27, W 1st Mer.

Analogues

There are many shale gas basins in North America promising large resources. Some of the most popular include the Barnett Shale in the Fort Worth Basin (Texas, USA), Ohio Shale and Marcellus Formation in the Appalachian Basin (New York and Pennsylvania, USA), the Antrim Shale in the Michigan Basin (Michigan, USA), the Lewis Shale in the San Juan Basin (New Mexico and Colorado, USA), the Muskwa Formation in the Horn River Basin (Alberta and British Columbia, Canada), and the Montney and Milk River formations and Colorado Group shale sequence in the Western Canadian Sedimentary Basin (Alberta and Saskatchewan, Canada). The shale gas plays in all these basins are unique, each requiring specific exploration and development techniques to achieve economic production of gas. Of all these basins, the Antrim Shale in the Michigan Basin represents the closest analogue to the potential shale gas play that exists in southwestern Manitoba.

Antrim Shale

The Antrim Shale is an organic, gas-bearing Devonian shale and siltstone sequence located in the Michigan Basin. The Antrim gasfield is outlined by the green box in Figure GS-14-1 and is displayed to show its relative size compared to the Cretaceous shale occurrences in Manitoba. The Antrim Shale gas pools are located along the northern rim of the basin, where the shale sequences subcrop at shallow depths below a thin glacial drift cover (Curtis, 2002; Rokosh et al., 2009). Early gas production in these pools was from unstimulated, vertical wells. The most productive wells occurred along natural fractures (Curtis, 2002). The natural fracturing in the Antrim Shale is a result of sediment and ice loading and unloading, glacial isostatic rebound (Ryder, 1995) and continental basement tectonic shifting (Curtis, 2002). The influx of fresh meteoric water and methane-producing bacteria into the formation has produced a gas that is dominantly biogenically derived; a minor thermogenic component is present and is likely derived from gas seepage from deeper formations (Curtis, 2002; Rokosh et al., 2009). The thick shale sequence of the Antrim Shale has high TOC values and is thermally immature. With the exception of the age of the rocks, the details of the Antrim Shale mentioned above could easily be substituted for what is known about the Cretaceous shale sequence in southwestern Manitoba; Table GS-14-3 shows the comparison of the Antrim Shale gas play properties with two potential plays in Manitoba. The Antrim Shale has had commercial production for decades and has been extensively drilled, and is thus well understood.

Boyne Sand near Kamsack, Saskatchewan

In the Kamsack area of southeastern Saskatchewan, commercial production of gas from the Boyne Member of the Carlile Formation was achieved in the early to mid 1900s. The gas was produced from a shallow reservoir called the Boyne Sand Pool (Simpson, 1970), and is stratigraphically equivalent to sand beds in southwestern Manitoba (Nicolas and Bamburak, 2009). Production values collected from this pool can serve as a potential analogue to the gas possibilities of the Boyne Member in Manitoba, and are included for comparison with the Antrim Shale and Manitoba prospects in Table GS-14-3.

Discussion

Relative to other shale gas reservoirs, the pore characteristics and porosity of the Babcock beds are comparable to the Barnett Shale in Texas (Loucks et al., 2009) and the Buckinghorse Formation in northeastern British Columbia (Chalmers and Bustin, 2008), and are at least comparable to, and in some cases superior to, those in the Duvernay and Muskwa formations in Alberta (Anderson et al., 2010) and the Lewis Shale in the San Juan Basin in New Mexico and Colorado (Rokosh et al., 2009). The characteristics of the Babcock beds are also comparable to sequences that host shale gas plays in southwestern Saskatchewan and Montana, such as the Greenhorn Formation, Carlile/Bowdoin Sandstone and Niobrara/Medicine Hat Sandstone (Shurr and Ridgley, 2002).

Fedikow et al. (2009) conducted a soil geochemistry survey around one of the historical gas wells near the village of Manitou in Twp. 2, Rge. 9, W 1st Mer., and the results suggest seepage gas sites exist, and that soil surveys may be one way to find them. Given the natural fracturing present in the shale outcrops along the Manitoba

Table GS-14-3: Properties of shale gas plays and prospects (modified from Faraj et al., 2004; Rokosh et al., 2009).

Characteristic	Antrium Shale	Boyne Sand Pool	Favel Formation	Boyne Member, Carlile Formation
Reference	Faraj et al. (2004), Rokosh et al. (2009)	Simpson (1970)	Nicolas and Bamburak (2009), Nicolas and Grasby (2009)	Nicolas and Bamburak (2009), Nicolas and Grasby (2009)
Basin	Michigan	WCSB[1]	WCSB[1]	WCSB[1]
Location	Michigan, USA	Kamsack, SK	Manitou, MB	Notre Dame de Lourdes, MB
Age	Devonian	Cretaceous	Cretaceous	Cretaceous
Depth (m)	183–610	~60	~180	66–74
Thermal maturity	immature (R_o=0.4–1.6)	immature	immature (T_{max}=403–431°C)	immature (T_{max}=408–427°C)
Total organic carbon (wt. %)	0.5–20		0.29–11.17	0.74–10.55
Gas production (mcf/day/well)	40–500	151		
Water production (bbl/day)	20–100			
Well spacing (ha)	16–64			
Recovery factor	20–60			
Gas-in-place (bcf/section)	8–16			
Resources (tcf)	12–20			
Total gas production	35–76 tcf[2]	168 mmcf[3]		

[1] Western Canadian Sedimentary Basin
[2] as of 2005 (Canadian Society for Unconventional Gas, 2010)
[3] as of approximately 1950 (Saskatchwan Ministry of Energy and Resources and National Energy Board, 2008)

Escarpment, and following the example of the Antrim Shale, these seepage sites likely occur along natural fracture systems, providing a natural permeability to the shale gas units and a conduit for the gas to concentrate and vent to the surface. During the two field seasons, regular fracture patterns were observed and orientations measured in some outcrops along the Manitoba Escarpment. If the gas seepage is related to the natural fracture systems, structural mapping of these fractures in both the horizontal and vertical directions could be used as an early exploration tool to find shale gas, particularly where dominant fracture sets and intersections of orthogonal fractures may provide sweet pockets of gas (Curtis, 2002). An example of a fracture pattern study for shallow gas applications is described in Shurr (1998); such studies have also been done for the Antrim Shale (Goodman and Manness, 2008).

This type of shale gas has been known to be extractable from simple, unstimulated vertical wells, as was the case in the wells drilled prior to 1950 with cable tool rigs in the Pembina Hills, near the village of Manitou, but stimulation increases gas recovery significantly. Drilling, stimulation and completion techniques in shale gas plays have improved significantly over the years, particularly in the last decade. Horizontal wells with multistage fracs are commonly used in many shale gas plays with advantages and disadvantages, but the Antrim Shale gas play responds best to stimulated vertical wells. Several gas-bearing horizontal beds can be accessed in a single stimulated vertical well, and the shallow depths make vertical drilling less expensive and thus more economic.

Economic considerations

The economic potential for shale gas production from the Cretaceous shale sequences in southwestern Manitoba is considerable. As its closest analogue, the success of the Devonian Antrim Shale in the Michigan basin is proof that such a shale gas play can be profitable and sustainable. To date, the Shallow Unconventional Shale Gas Project has provided some of the basic information needed to evaluate Manitoba's shale gas prospect. Initial results are more than encouraging and have already attracted the energy industry's attention, finally putting Manitoba on the 'potential shale gas play' map.

Acknowledgments

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