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The "Shale Gas" concept in Canada: a preliminary inventory of possibilities

A.P. Hamblin

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ABSTRACT

The term “Shale Gas” refers to unconventional, continuous-type, self-sourced resources contained in fine grained (ranging from clay to very fine sandstone), organic-rich, low permeability reservoirs in which thermogenic or biogenic methane is stored as free gas in the matrix or fracture porosity, or as adsorbed/dissolved gas on the organics and/or clays. These are self-enclosed petroleum systems, characterized by inefficient “dysfunctional” expulsion and migration, where source, reservoir and trap are all present in the same thick shaly succession. The most prospective shale gas targets will be thick, widespread, gas-saturated, fine grained, organic-rich units with a) significant Type III (terrestrial, gas-prone) organic matter in thermally mature to overmature states, b) significant Type II (marine, oil- and gas-prone) organic matter in a thermally overmature state, and/or c) rich organic matter of any type that is thermally immature and subject to extensive biogenic decomposition. The current economic climate of depleting conventional reserves and rising prices presents an opportunity for the emergence of the shale gas concept in Canada, although significant environmental concerns must be addressed from the beginning. Successful shale gas production has a long history in the USA and each of the four (or more) known play types (Antrim, Ohio/New Albany, Barnett, Lewis) owes its success to different balances of the controlling factors of TOC, thermal maturity, lithology, mineralogy, depth, fracturing, production technique and infrastructure. Entirely new, undescribed, play styles probably still exist. Intensive and detailed, pre-drill, geological study of each potential shale gas play is an inexpensive and efficient method for technical evaluation, to properly assess the economic possibilities, choice of target and recovery of resources. Canada’s sedimentary basins collectively provide numerous (perhaps 50) possible shale gas targets, scattered over at least 7 regions. Of these, seven represent regional-scale units with enough geological prospectivity to justify concerted geological study due to the presence of one or more of excellent geological potential, geographic location, proximity to infrastructure, and/or relation to known conventional and unconventional plays. They are: Upper Ordovician of Appalachian Basin, Upper Devonian of Appalachian/Michigan Basin, Upper Devonian of northwestern WCSB, Triassic of northwestern WCSB, Jurassic of western WCSB, Middle to Upper Cretaceous of WCSB Plains, Middle Devonian of Mackenzie Corridor.

BACKGROUND KNOWLEDGE TO THE SHALE GAS CONCEPT

INTRODUCTION

Unconventional Gas Accumulations

"Unconventional Gas" is natural gas contained in difficult-to-produce reservoirs which require special completion, stimulation and/or production techniques to achieve economic success (Canadian Society of Unconventional Gas). Similarly, it could be defined as any methane not trapped as discrete structural/stratigraphic accumulations in porous, permeable, buoyancy-driven systems (Law and Curtis, 2002; Russum, 2005). These resources are typically of large volumes, dispersed pervasively over wide geographic areas within reservoir rocks of low and/or variable permeability which are closely related to the source rocks, and are characterized by low flow rates, long production life and unusual pressure regimes (Dawson, 2005; Russum, 2005). As much as 32% of current U.S. production is unconventional (Dawson, 2005). Unconventional, continuous accumulations are commonly geographically widespread, with poorly-defined boundaries, may include pockets of conventional accumulations within their borders, and do not rely on gravity segregation of oil/gas/water within the trap (Milici and Ryder, 2004; Ball, 2005b). Exploration and exploitation of unconventional gas resources commonly requires large land positions, greater drilling densities, increased surface infrastructure and greater technological investment (Russum, 2005; Kuuskraa, 2005). Recently, both Canadian and North American conventional natural gas production peaked, and is not expected to resurge in the near future (Russum, 2005), although demand may double in the next two decades (Law and Curtis, 2002). Therefore, only new production from unconventional sources can slow or reverse this trend. Contrary to some opinions, "unconventional" does not mean "non-productive", and misinformation has helped suppress exploration for unconventional resources over time (Law and Curtis, 2002). The most commonly considered unconventional gas types are coal-bed methane, tight gas, and shale gas.

What is "Shale Gas"

Thick, apparently monotonous, basinal sequences of very fine grained sediments are common in the geological record, although they have received little attention among most stratigraphers (Stoakes, 1980). Shale, including all fine grained argillaceous sediment, forms more than 60% of all sedimentary deposits (and a higher proportion of geological time), represent the "normal" sedimentation conditions in basins and should yield much valuable insight into the evolution of many sedimentary basins (Potter et al., 1980; Schieber et al., 1998). Contrary to popular belief, most shales have a subtle, discernible internal stratigraphy defined by organic-content, bedding, biological components and mineralogy, commonly expressed as offlapping clinoform structures related to basin geometry (Potter et al., 1980) and sequences of thinly interbedded coarser lithologies. They are not as inscrutable as many geologists think, but are simply under-studied.

The terms "Shale Gas" or "Gas Shale" refer to the resource contained in a fine grained, organic-rich reservoir (not necessarily only in mudstones, but in a full spectrum of grain sizes from claystones to siltstones and even very fine grained sandstones, and of both siliceous and carbonate-rich compositions) in which much of the methane is stored as free gas in the matrix porosity and fracture porosity, but in which a significant component of the gas is stored in the sorbed state, predominantly on the surface of the organic fraction (Ball, 2005b; Bustin, 2006). These are unconventional, basin-centred, self-sourced, continuous-type gas accumulations where the total gas charge is represented by the sum of free gas and adsorbed gas (Bustin, 2005; Ball, 2005b). In effect, these shale gas plays represent discrete, self-enclosed petroleum systems which do not rely on hydrocarbon expulsion/migration/trapping because the premise is that the hydrocarbon stays in the original source rock: if they were well-connected to conventional plays, then they wouldn't provide a new play at all. This inefficiency of petroleum expulsion and migration makes these plays "dysfunctional" petroleum systems in the conventional sense only: a key factor in understanding the shale gas concept. A significant proportion of the gas storage is by adsorption onto high surface-area clays and dispersed organic matter (Bustin, 2005). The mudstone itself, generally in thick and extensive intervals, is the source, reservoir, seal and trap for the contained methane, and these accumulations are characterized by geographically widespread and pervasive gas saturation, thick pay zones, subtle trapping mechanisms, seals of variable lithologies, and short migration distances (Curtis, 2002). Sub-normal reservoir pressures, or overpressures, are common. Because the matrix permeabilities of mudstones are extremely low, gas is trapped within the source shale itself, and suffers little depletion over geological time frames. In fact, traditional source rocks which were "inefficient" or "dysfunctional" in generating and expelling hydrocarbons may be the best prospects for shale gas potential.

The volume of adsorbed gas increases with the amount of organic matter and with surface area (which also increases with the amount of micro-porous organic matter), and so organic-rich fine grained rocks are the most likely hosts (Bustin, 2005). Gas is stored as a) hydrocarbons adsorbed onto clays and organics, b) free gas in fracture and intergranular porosity, and c) solution gas dissolved in organic matter (Curtis, 2002; Ball, 2005b, Bustin, 2006). The smaller pores typical of shales, with their large surface areas, contain mostly adsorbed, rather than free, gas (Bustin, 2006). Both conventional matrix porosity and permeability, and fracture porosity and permeability, are important. The contained gas may result from any combination of three sources: primary thermogenic decomposition of organic matter, secondary thermogenic cracking of oil, or biogenic bacterial decomposition of organic matter (Schein, 2006). Therefore, both thermogenic and biogenic gas (separately, or combined) may be present in the reservoir.

Initial flows may be high but short-lived (tapping the "free" gas residing in fractures and matrix porosity), followed by a very long history of lower flow rates (slowly accessing the gas adsorbed onto micro-porous clays and organics) (Curtis, 2002; Bustin, 2005). Relatively dry shales will have more sorbed gas because high water saturations will displace adsorbed gas (Bustin, 2006). Fracture stimulation is almost always required to achieve commercial production. Wells have slow decline rates and long production lives (up to 30 years), although the ultimate recovery rate may be rather low (about 20%) (Faraj, 2006). However, the original initial gas-in-place may be enormous: up to 2000 Tcf (Bustin, 2006).

Gas shales are currently one of the most important and active exploration plays in the United States (Kuuskraa, 2005), where these reservoirs have been exploited for over 150 years, and additional plays occur in frontier basins and behind casing in many developed basins throughout North America (Bustin, 2005). In 2002, shale gas accounted for about 4% of total US gas production (Canadian Society for Unconventional Gas), and due to significant recent increases in production from the Barnett Shale, that proportion has certainly increased since. Shale is the most common lithology in many sedimentary basins (Lewis, 2005). Consequently, gas shales represent a potentially large, technically recoverable gas resource which has not yet been exploited anywhere outside the USA. Kuuskraa (2005) estimated that the worldwide gas shale gas-in-place resource may be twice that of either coal-bed methane or tight sandstone gas, especially in the Americas, Middle East and China. Yet, as production from conventional reservoirs in North America continuously declines in the future, gas from unconventional, continuous reservoirs will become increasingly important for energy security. Commercial production likely requires stimulation enhancement to provide economic flow rates (Curtis, 2002; Ball, 2005b), but once initiated, result in long-lived reservoirs (Shirley, 2001a). Active exploration is driven by the powerful economic incentives of moderate exploration costs, low risk/high success rates and slow production declines over long lifespans (Shirley, 2001a). The modern wave of shale gas production in the US was initially stimulated by the "Section 29 non-conventional fuels production tax credit", although that credit expired in 1992. Regardless, operators south of the border have continued to expand their gas shale exploration programs (Shirley, 2001a), suggesting potential and success beyond the confines of that legislation.

Although continuous-type gas plays are often considered as "engineering" or "statistical" plays, the geological complexities and multiple, interrelated controls require detailed scientific analysis and interpretation to maximize results (Shirley, 2004). "Sweet spots" are an intrinsic aspect of the geologic framework of continuous-type plays (Schurr and Ridgley, 2002) and require careful science. As Faraj (2005) stated, now is the time for this new frontier play concept: in these times of high energy prices, if a shale gas play is not economic now, it will never be. At the same time, the maxim that "unconventional plays require unconventional thinking" is patently applicable here.

Relation to Oil Shale

Although there are currently no surveys of gas shale potential in Canada, there have been several studies of oil shale potential in Canada over the years (Macauley, 1984a; Macauley, 1984b; Macauley et al., 1985; Macauley et al., 1990; Dyni, 2003). Lists and characteristics compiled from these reports form the basis of the current gas shale inventory. Proven and potential oil source rocks and oil shales typically display the same general characteristics desirable in potential shale gas targets, and therefore, immediately provide an initial list of potential gas shales. Proven excellent conventional source rocks should be good shale gas candidates (with some qualification). Whereas a good oil source rock requires generation, expulsion and good migration pathways to the ultimate reservoir, a good shale gas or oil shale candidate requires poor migration and therefore retention of the contained hydrocarbons.

Consequently, to the list of known oil shales we would add other mudstone units which are thermally immature or overmature with respect to oil generation: source rocks within the oil window probably have less potential for shale gas. Type I and Type II kerogens have high H/C ratios, low O/C ratios, high hydrogen indices and low oxygen indices and generally generate crude oils at maturity and gas when overmature (Stasiuk, 1999). Type I kerogens are very oil prone in most circumstances (Ramos, 2006). Type III kerogens have low H/C ratios, high O/C ratios, low hydrogen indices and high oxygen indices and generally generate gas at maturity

(Stasiuk, 1999). Type III kerogens also have a greater capacity for gas adsorption (Ramos, 2006). Therefore, whereas dominance of Type I and II kerogen makes for good oil source rocks, potential gas shales should be dominated by more gas-prone Type II and III organic matter. We therefore need to search for thick, fine grained, organic-rich units with 1) significant Type III kerogen which have not yet generated and migrated large amounts of hydrocarbons, or with 2) Type II kerogen which are overmature. Klemme and Ulmishek (1999) noted the gradual universal trend through geological time from the Paleozoic with source rocks with Type I/II kerogens deposited in marine settings at low paleolatitudes toward the Mesozoic/Tertiary dominated by source rocks with Type II/III kerogens deposited in terrestrial and marine settings at higher paleolatitudes.

Objectives of This Study

Because shale gas is a new exploration concept in Canada at this time, the following report is meant only to introduce the subject and review the basic geological factors. Therefore, I have included a) a synthesis of the diverse information available from the successful plays in the USA, b) statements of the conclusions, guidelines and lessons we can learn from these examples and apply in Canada, and c) a brief synthesis of the diverse geological data available for approximately 50 shale units in Canada which could conceivably be prospective. An extensive reference list provides entry into the geological literature of all these stratigraphic units.

Finally, I offer a short list of Canadian shale units which seem to have significant apparent geological potential (ie. possible new conceptual plays?), as a starting point for the serious geological study of this new unconventional play concept. However, this should not be construed as suggesting that these latter examples definitely *do* have economically exploitable resources, or that other units definitely *do not*: this short list simply represents my first impression of the shale units for which the initial published data seems to be geologically most promising. I emphasize that this document is primarily a review of *geological* potential, regardless of economic potential. Some lie in distant frontier areas with little or no infrastructure, and represent thinking for the future.

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PREVIOUS SUCCESSES IN USA

History of shale gas exploration in USA

The first known shale gas production in North America occurred in 1821 when local townsfolk drilled a well 8.3 m deep at Fredonia, New York after the accidental ignition of a gas seepage, making this the oldest hydrocarbon play in North America (Curtis, 2002). The well was completed in the Upper Devonian Dunkirk shale and the gas piped through hollowed logs to light the nearby houses (Curtis, 2002). Shale gas development spread westward along the southern shore of Lake Erie into Ohio, Illinois and Kentucky in the 1860-1880 period, and by the 1880's there was significant production from the upper Devonian shales of the Appalachian Basin for the large nearby markets (Curtis, 2002; Bustin, 2005). Throughout these decades there was no attempt to exploit the correlative rocks across the border in Ontario, and still has not been.

In 1976, the U.S. Department of Energy initiated its "Eastern Gas Shale Project" and in 1980, introduced the "Section 29 Tax Credit" to stimulate development of unconventional hydrocarbon resources (Curtis, 2002; Bustin, 2005). This quickly led to successful exploration and significant production of shale gas from Upper Devonian strata in the Appalachian, Michigan and Illinois basins, from Carboniferous strata in the Fort Worth Basin and from Cretaceous strata of the San Juan Basin (Bustin, 2005). This tax incentive resulted in a quantum leap in understanding of the geology, resource potential and technical challenges to produce shale gas (Ball, 2005b). Although the tax credit expired in 1992, exploitation has continued at a high rate and these three areas still represent the primary shale gas production in North America, supplying 2-4% of the U.S. needs (Shirley, 2001a; Curtis, 2002; Canadian Society for Unconventional Gas; Faraj, 2006). Approximately 36,000 wells have now been drilled in the US for shale gas targets (Lewis, 2005). The successful shale gas plays of the U.S. are each very different, confirming that no one factor or example is paramount and different combinations of parameters can still be successful (Curtis, 2006).

Antrim/Ohio/New Albany/Chattanooga Shale

There is a large, but diverse and widely dispersed, literature which touches on the Devonian black shales of the Appalachian Basin, and only a brief summary is provided here. Part of this complex represents the most active gas play in the United States during the 1990's. Thick dark grey, brown and black shales of Upper Devonian age represent the distal portion of the gigantic Catskill Delta complex of the newly-created Appalachian Foreland Basin, a westward-prograding system that extended from the orogenic highland source in the east into the foreland basin epicontinental sea to the west during and after the Acadian Orogeny (Ettensohn, 1985; de Witt, 1986; Gutschick and Sandberg, 1991a). These strata represent the deposits of the initial foreland subsidence and transgression over the collapsed Middle Devonian carbonate platform. The depositional environment was interpreted as a poorly-oxygenated pro-delta turbidite slope and basin plain striking north-south, located in low paleolatitudes (Broadhead et al., 1982; Klemme and Ulmishek, 1991).

Although areas of occurrence are currently separated by basement arches, deposition was essentially continuous over the entire northeastern US-southeastern Canada region (Matthews, 1983). These organic-rich mudstones are referred to the Antrim Formation in Michigan, the Ohio Formation in Ohio and Pennsylvania, and the New Albany Formation in the Illinois Basin. Their age ranges from early Frasnian to late Fammenian (Gutschick and Sandberg, 1991b). The Antrim, the best-studied, comprises four members, in ascending order: Norwood (black shale), Paxton (interbedded grey shale and limestone), Lachine (black shale) and the "upper member" (black shale to the southeast, greenish shale to the northwest where it is called "Ellsworth Shale") (Gutschick and Sandberg, 1991b; Curtis, 2002). The Kettle Point Formation of southwestern Ontario is the lithologic and time correlative of the Antrim Shale (Gutschick and Sandberg, 1991b). The dark shales represent the extreme distal portions of the deltaic wedge which accumulated in tranquil, anoxic, marine basinal waters during phases of high subsidence rate and transgression (Roen, 1984; Ettensohn, 1985). The high subsidence rate in a distal environment encouraged sediment starvation and the location in a warm subtropical setting with high marine and terrestrial productivity, would allow water column stratification to develop, encouraging utmost preservation of organic matter (Ettensohn, 1992). Thus, Ettensohn (1992) suggested that paleoclimate, paleogeography and tectonism are the major controls on black shale deposition. Conversely, Schieber (2000) identified erosion surfaces, evidence of storm reworking and widespread bioturbation, suggesting that the importance of great depth and bottom water anoxia in the creation of black shales has been over-emphasized in the past. Sedimentation occurred during the Late Devonian time of large-scale changes in vegetative patterns and evolution of land plants into more extensive and upland niches: this increased terrestrial productivity helped generate the high carbon contents of the offshore deposits (Rimmer et al., 2004).

Organic material is of both marine (Type II sapropelic algal, fish and invertebrate) and terrestrial (Type III woody, spores and pollen) origin, with TOC contents ranging up to 37%, and resides in intervals up to 300 m thick (Schmoker, 1980; Broadhead et al., 1982; Matthews, 1983; Roen, 1984; Ettensohn, 1992). In Kentucky, the organic matter comprises (in decreasing order of abundance) alginite, bituminite, vitrinite and inertinite, with minor telalginite (including *Leosphorida* and *Tasmanites*) and sporinite (Robl et al., 1992). Schieber (2000) noted that the black shale successions can be divided into packages (or sequences) by extensive erosion surfaces, and that the lower transgressive and maximum flooding portions of the sequences are dominated by alginite, whereas the upper regressive portions are dominated by bituminite. Thermal maturity varies with local depth but ranges 0.4-1.6 % Ro, and generally increases to the southeast into the Appalachian Basin (Rimmer et al., 1993; Curtis, 2002; Bustin, 2005). In general, the average organic content ranges from less than 2% to about 12% to the northwest and the thickness of organic-rich deposits increases to the west, into the deepest portions of the basin and away from clastic input of the delta (Schmoker, 1980; Rimmer et al., 1993). However, in western Michigan, there is a wedge of greenish mudstone (the Ellsworth shale) in the upper Antrim which records progradation of organic-poor sediment from a mildly-positive northwestern source (Matthews, 1983) (perhaps the foreland bulge?). Mineralogically, the mudstones consist of 30-60% clays (primarily illite, with chlorite and smectite), 10-25% silt-sized detrital quartz, 5-10% feldspar, 5-10% muscovite, minor calcite (commonly as concretions) and ubiquitous pyrite (Broadhead et al., 1982; Roen, 1984; de Witt, 1986). They are typically un-bioturbated and well-laminated with dark organic-rich laminae alternating with thinner, greyer sharp-based quartz silt-rich laminae (Broadhead et al., 1982; de Witt, 1986), which may provide thin zones of permeability enhancement and have been important to gas production along the south shore of Lake Erie in Ohio (Broadhead et al., 1982). Organic-rich mudstone of high gas content has proven to be characterized by a gamma-ray intensity of >230 API units (and generally over 20 API units above the grey shale base line) (Schmoker, 1980).

The Antrim is overlain by (and is truncated to east and west by) a variable thickness of Quaternary glacial drift. Drilling depths for the Antrim generally range only 100-700 m and much of the shale is thermally immature (Broadhead et al., 1982; Martini et al., 1996). Conversely, equivalent shales of the Ohio, Chattanooga and New Albany formations are present in outcrop to the northwest, but dip into the deep subsurface to the southeast. In this large region of the Appalachian Foreland Basin, these same units attain thicknesses up to 600 m, reside at depths up to 1500 m and thermal maturity can range up to the gas window (Bustin, 2005). Currently, the deeper Ohio/New Albany play of Illinois, Kentucky and Ohio is less active or important than the shallow Antrim play. However, these deeper strata appear to harbour enormous gas-in-place resources, in dry thermogenically mature to overmature successions in areas where Appalachian tectonic fracturing trends will be very important (Hamilton-Smith, 1998).

The widespread Middle to Upper Devonian gas shales of the Appalachian Basin have a very long history of exploitation. Gas escaping from fractured shales at Fredonia, New York (south shore of Lake Erie), led to the drilling of the first gas well in North America in 1820, using salt-well drilling equipment (de Witt, 1986; Curtis, 2002). This particular well produced at a modest, low-pressure but commercial, rate for 65 years before finally being abandoned in 1885, and hundreds of others were drilled during these years (de Witt, 1986). Proximity to large urban and industrial markets has always been a significant factor in exploitation of this play. In the 1920's, production was obtained from Upper Devonian shales in Kentucky, where it was first noticed that adjacent wells might produce widely divergent volumes and pressures, from different stratigraphic horizons, and that use of downhole explosives could stimulate flow from apparently dry holes: the first inklings of the concept of fracture control of shale gas production (de Witt, 1986). Today it is accepted that the organic content of the rock, the extent and geometry of the fracture system, and the judicious use of fracture stimulation are the most important factors governing success. Two dominant sets of uncemented, near-vertical stress-relief fractures (northwest-trending and northeast-trending) are present in the main productive trend of the Antrim (Lash et al., 2004), and little success has been achieved outside this fairway (Curtis, 2002). In the 1960's, the famous Niagaran pinnacle reef discoveries of the Michigan Basin commonly recorded gas shows in the uphole Antrim shales, labelled “nuisance gas” by drillers, and eventually led to modern realization of an important bypassed play.

Over 5,000 wells have been completed in the Antrim with a remarkable 95% commercial success rate (Martini et al., 1996), and most production is from depths of 100-700 m, with low drilling costs (Shirley, 2001a). USGS Oil and Gas Fact Sheets provided estimates of undiscovered continuous gas resources in the Antrim and equivalents (see Milici et al., 2003; Swezey et al., 2005; Coleman et al., 2006). Total in-place resource estimates for the Antrim range from 35 to 76 tcf, with an additional 86-160 tcf for the Ohio/New Albany (Shirley, 2001a). Much of the gas generated within the Antrim flat-lying, near-surface shales is of biogenic (bacterial) origin, has been adsorbed onto the organic constituents and has not migrated outward due to very low matrix permeability, but when accessed by fracture systems are capable of producing at modest rates for decades (de Witt, 1986; Martini et al., 1996; Curtis, 2002; Schurr and Ridgley, 2002). Because the gas is biogenic, gas content correlates directly with TOC (Jarvie, 2006). Carbon isotope data and Carbon-14 dating by Martini et al. (1996, 1998) suggest that the dominant source of methane in the Antrim is microbial methanogenesis (mixed with some deeper-derived thermogenic gas) generated in the shallow groundwater environment during the last 22,000 years: the reservoir is continually replenishing itself. Schurr and Ridgley (2002) refer to this system as a "late-generation biogenic system" because there is a long time interval separating deposition of reservoir and source rocks from gas generation, significant water production and it has a ring-like geometry. The near-surface fracture system allows invasion of bacteria-laden meteoric water from overlying Quaternary aquifers: in fact, loading of thick Quaternary ice sheets may have provided hydraulic head that enhanced dilation of pre-existing fractures and influx of meteoric waters (Martini et al., 1998; Curtis, 2002; Schurr and Ridgley, 2002). The initial flush of high production from the open fractures declines, and is followed by a long period of steady-state flow as matrix gas desorbs and migrates into the fracture system (de Witt, 1986). Large volumes of water are typically produced with the gas (Schurr and Ridgley, 2002; Curtis, 2006). At least some of the pervasive fracturing in shallow targets is the result of post-glacial rebound stress release, whereas much of it is due to differential compaction over the underlying thick Niagaran pinnacle reef trend (de Witt, 1986; Ryder, 1996; Curtis, 2006). Additionally, deep-seated basement faults and folds, underlying salt dissolution fairways and other facies changes may create further fracture trends, especially in the deeper Ohio/New Albany play (Ryder, 1996; Hamilton-Smith, 1998). The shallow portions of the Antrim, Ohio and New Albany shales produce significant amounts of saline water during initial dewatering production, which is re-injected into underlying porous Devonian carbonates, whereas deeper, thermogenically mature New Albany and Ohio shale targets are dry (Martini et al., 1996; Hamilton-Smith, 1998; Curtis, 2002).

Barnett Shale

In the 1980's Mitchell Energy (subsequently acquired by Devon) began developing the Lower Carboniferous Barnett Shale in the Newark East field of the Fort Worth Basin of northern Texas, after noticing widespread and unexpected gas shows while drilling other targets (Durham, 2005). The Barnett is up to 150 m thick (thickening to the north), lies at a depth of up to 2600 m and currently produces from over 3500 wells (Curtis, 2002; Bustin, 2005; Montgomery et al., 2005). An estimate of the total in-place gas resource is about 200 tcf, with recoverable reserves assessed as 3-40 tcf (Montgomery et al., 2005): almost 2 tcf have already been produced, although it took 20 years to come to the current understanding (Durham, 2005). Two-thirds of U.S. shale gas production is from the Barnett (Curtis, 2006), and the field may ultimately become the largest in the U.S. (Durham, 2006). Successful exploration involves the important steps of running mudlogs and cutting core with proper analysis for fractures and gas content (Shirley, 2002). Successful production depends on horizontal drilling, modern completion and fracturing techniques (including water fracs) and refracing of existing wells (Shirley, 2001a, 2002; Bustin, 2005). The play is a perfect combination of moderate depth, good pressure, high success rate simple operations and location close to markets and infrastructure (Shirley, 2002). Barnett gas is thermogenic, with hydrocarbons generated in multiple pulses from Late Paleozoic to Cretaceous times, and unlike other shale gas units, is known to have generated and episodically expelled liquid hydrocarbons (Curtis, 2002; Jarvie and Claxton, 2002).

The Barnett Shale is a Lower Carboniferous organic-rich petroliferous mudstone which overlies the Ellenburger platform carbonates and is overlain by grey Marble Falls interbedded shale and limestone. It is approximately correlative to the Bakken/Exshaw units of WCSB. It represents the initial foreland subsidence and transgression deposits over the Upper Devonian collapsed carbonate platform in the Ouachita foreland basin (Shirley, 2002). To the northeast the Barnett thickens, is more calcareous and is divided into upper and lower intervals by the intervening Forestburg limestone tongue (Montgomery et al., 2005). Lithologically, the Barnett comprises siliceous shale and argillaceous limestone with up to 13% TOC (typically 3-5% and highest in clay-rich zones), high radioactivity, porosities of 5-6% and extremely low permeabilities (Montgomery et al., 2005). The organic matter indicates a Type II, oil-prone marine shale (Jarvie and Claxton, 2002). Thermal maturity ranges 1.0-1.4 %Ro (Curtis, 2002; Bustin, 2005). Natural fractures are present, but appear to be sealed with calcite, and are not essential for production: in fact, due to the calcite seals they appear to form barriers to flow (Shirley, 2002, Durham, 2005). Thermal maturation increases into the gas window toward the east where the rocks have generated large volumes of liquid hydrocarbons (Montgomery et al., 2005). Desorption studies of core and cuttings suggest that total gas content is abut 190 standard cubic feet per ton (scf/t), distributed as 55% free gas and 45% sorbed gas (Montgomery et al., 2005): so far, much of the production is of free gas (Durham, 2005). Production is particularly strong from siltier zones in the lower part of the Barnett on the eastern side of the basin. Artificial stimulation (and often re-stimulation) using water and sand fracs is required, and a key factor is the containment of the fracturing to the Barnett interval by the underlying (water-bearing) carbonates and the overlying shales (Shirley, 2002; Durham, 2005). Here, the siliceous, brittle nature of the mudstone appears to be a positive factor (Mullen, 2006). Production from both vertical (older) and horizontal (more recent) wells show an initial high flow rate, then a rapid decline followed by progressive flattening over time: restimulation can bring the rate back to the initial flow (Montgomery et al., 2005). Whereas vertical wells will drain only one long, narrow induced fracture set, a horizontal well drilled perpendicular to the induced fracture direction will drain several parallel sections of reservoir, and achieve 2-3 times the initial flow rate (Durham, 2005; Montgomery et al., 2005). Presently, 80% of Barnett wells are horizontals (Schein, 2006): by November of 2005, 2135 permits for horizontal wells had been issued for the Barnett (Durham, 2006).

Recently, concerted exploration to the east of the productive Barnett play has discovered similar potential in the stratigraphically-equivalent Lower Carboniferous Fayetteville, Caney and Woodford shales of Oklahoma and Arkansas. There, the lower part of the Fayetteville comprises organic-rich mudstone with interbedded siltstone and cherty beds up to 300 m thick, at depths up to 2000 m (Brown, 2006). Discoveries were made, in an area with extensive older well penetrations and infrastructure, as a by-product to exploration in an adjacent tight sandstone play, and long horizontal wells are now producing 2-3 million cubic feet of gas per day (Brown, 2006). This appears to be the next major shale gas play in-the-making.

Lewis Shale

In 1991, Burlington Resources, a dominant CBM producer, began re-completing CBM wells in the Upper Cretaceous Lewis Shale of the San Juan Basin, New Mexico after encountering large flows during air-drilling for deeper targets (Dube et al., 2001; Shirley, 2001b). In the succeeding years, this company and other operators have re-completed hundreds of existing wells and completed the Lewis as a secondary target in hundreds more. The Lewis Shale represents a large, basin-centred, continuous-type gas accumulation containing an estimated 97 tcf of gas-in-place, distributed over a thickness of 400-500 m, where production initially declines and then stabilizes at a low rate due to the presence of a significant desorption component to the gas (Jennings et al., 2001; Shirley, 2001b). The ability to re-complete thousands of shallow wells in the Lewis interval in a basin where extensive infrastructure already exists, is a key economic factor in this play. Co-mingling of production from multiple zones is important. The success of this play implies that many previously-overlooked intervals in well-exploited basins with established infrastructure may have significant commercial potential.

The Lewis Shale is of Campanian age (~74 Ma), lies above the Mesaverde Formation (Belly River equivalent) and below the Pictured Cliffs/Fruitland formations (Horseshoe Canyon equivalent), and so is approximately correlative to the Bearpaw Formation of WCSB, the last major marine incursion in the basin (Jennings et al., 2001; Dube et al., 2001). It represents lower shoreface to offshore open marine deposition during a major transgression-regression cycle during the Laramide Orogeny (Dube et al., 2001; Shirley, 2001b), and is analogous to many Mesozoic mud-rich units of the WCSB. It is more accurately characterized as a sandy siltstone, rather than a true shale, and comprises thinly interbedded shale, siltstone and minor fine grained sandstone (Jennings et al., 2001; Dube et al., 2001; Curtis, 2002). It therefore is intermediate between true "gas shales" and "tight gas sands", a spectrum of reservoirs which is likely more continuous and common than generally appreciated. The presence of sandy/silty lithofacies adds substantial gas storage capacity to the play. The unit comprises 4 shallowing-upward T-R sequences, each capped by a regional flooding surface, with the lower 3 being the main gas productive targets (Dube et al., 2001; Shirley, 2001b). The maximum Lewis transgression occurs in the thick shale at the base of the uppermost sequence (Dube et al., 2001), perhaps forming a regional seal for the underlying gas-charged sandy siltstone units. The production fairway lies at an average depth of about 1370 m (Dube et al., 2001). Average matrix porosity is 1-2%, and permeability is < 1 md, necessitating the pervasive presence of sandy interbeds and natural micro- and macro-fractures and/or fracture stimulation for commercial production (Shirley, 2001b).

One key innovation has been to intensively study a series of cores taken from specific "Shale Data Wells" to determine fundamental reservoir storage and flow characteristics and investigate optimal drilling, completion and stimulation techniques (Dube et al., 2001). Clay content averages 25% (primarily illite and smectite), porosity ranges 2-8%, permeability is < 0.1 md, water saturation ranges 20-100%, and TOC values range 0.5-2.5% with Type II/III organic matter (Dube et al., 2001; Jennings et al., 2001; Curtis, 2002). Thermal maturity ranges 1.0- 1.9 %Ro (Curtis, 2002; Bustin, 2005). Methane desorption studies suggest that the gas storage capacity ranges 23-38 scf/ton (Jennings et al., 2001). Three sedimentary facies were identified: extensive intervals of mudstone (high TOC, low porosity and permeability), thin but continuous beds of bioturbated siltstone and feldspathic sandstone (coarsest, highest porosity and permeability, lowest TOC, abundant natural fractures), and interlaminated siltstone/mudstone (intermediate characteristics) (Dube et al., 2001). Because the sandstone-rich intervals have the greatest storage capacity and are most fractured, preferentially mapping, perforating and stimulating these primary conduit zones is the most efficient exploration and production method (Jennings et al., 2001; Dube et al., 2001). The presence of swelling clays and high water saturations may indicate that well treatments should avoid introducing water into the reservoir. Burlington Resources has experimented successfully with horizontal drilling during the 1990's, improving vertical drainage by intersecting multiple fracture zones (Jennings et al., 2001).

Alderson Member (Lea Park Formation) - A Canadian Example?

It is possible that we already have an unrecognized, but active and successful, example of a shale gas play in Canada. Long-standing gas production from the shaly Alderson Member of the Lea Park Formation in the enormous southeastern Alberta Milk River Gas Field, which overlies the crest of the Sweetgrass Arch (Hamblin and Lee, 1997), bears some resemblance to the Antrim production of the eastern USA. This is certainly a "continuous" gas accumulation, dominated by fine grained lithologies and producing biogenic gas (Ridgley, 2002).

The Milk River Formation of southeastern Alberta/southwestern Saskatchewan conformably overlies the organic-rich First White Speckled Shale of the Colorado Group, and is sharply overlain by the shaly Lea Park Formation/Pakowki Member (this is contact marked by a widespread, thin chert-pebble bed, which may represent a regional disconformity; see Hamblin and Lee, 1997). Basinward, to the northeast, and with currently poorly understood stratigraphic relationship to the main Milk River Formation is the Alderson Member, which appears to be the trap for most of the gas in the Field. The Campanian-aged Alderson Member of the Lea Park Formation ranges from 70-90 m thick, comprising a vaguely coarsening-upward succession of stacked, distal parasequences of grey to dark grey, bioturbated, silty mudstone, with thin and discontinuous interbeds of porous and permeable siltstone to very fine grained sandstone (Meijer Drees and Mhyr, 1981; Hamblin and Lee, 1997). Deposition occurred in a proximal offshore marine environment (Meijer Drees and Mhyr, 1981; O'Connell, 2004).

Mudstones have porosities of 5-42% and permeabilities of 0-1 md, whereas thin sandy beds have porosities of 17-26% and permeabilities of 3-259 md (Meijer Drees and Mhyr, 1981). The strata are immature and extensive fracturing may be present (Meijer Drees and Mhyr, 1981). Gas is present at very shallow depths (300-400 m), is at very low pressures, produces at low flow rates for very long periods, and includes enormous reserves (Masters, 1982). Updip to the south, water recharge may create a hydrodynamic trap and shallow burial has limited compaction, thus preserving reservoir quality (Masters, 1982; Hankel et al., 1989). Reservoir pressure and general permeability are low, the gas is non-associated and likely originates from biogenic bacterial decomposition, and the underlying First White Specks shale may be the source (Rice and Schurr, 1978; Masters, 1982; Hankel et al., 1989; Ridgley, 2002; Schurr and Ridgley, 2002). Schurr and Ridgley (2002) refer to this system as an "early-generation biogenic system" because gas generation began shortly after deposition of reservoir and source rocks, there is little producible water and it has a blanket-like geometry.

This is a widespread, continuous ("tight gas") accumulation with a large discovered resource, developed over a long period of time. However, the play is very complex, and the controls on trapping and production capability are still poorly understood: the concept of comparing this field to a shale gas play has not previously been suggested, and may open new conceptual possibilities. The production from these strata bears some resemblance to the Antrim (shallow, immature, biogenic, fractured related to groundwater flow) and some resemblance to the Lewis (clastic-dominated, related to foreland basin T-R sequences, modest organic content). If this play actually proves to be another shale gas play, then it suggests that there are even more, unrecognized shale gas play types still to be identified and considered for exploration in Canada.

The Common Themes

From the foregoing, several characteristics common to all the successful examples can be gleaned. Obviously, significant organic content and significant permeability are the two basic factors which must be present for large resources to be created and produced. Most shales retain good natural porosity, even at depth, allowing good storage capacity. Organic content can be as low as the 1% TOC range, but certainly values in the 3-10+ % TOC range are preferable. Fine grained deposits are the most common sedimentary rocks, but thicknesses of 10 m or more are required. Thermal maturity can be low but only in special circumstances where fractured shales exist at surface within the zone of biogenic methanogenesis. For most cases, thermal maturity at or above the oil window, and into the gas window, is preferred, although this may depend partly on kerogen type. Significant gas content must be established, preferably above 40 scf/ton. Significant natural permeability, above that normally offered by the original shales (probably the tightest rocks in the sedimentary record), must be present in the form of fractures or thin siltstone/bioclastic carrier beds, or it must be easily created in brittle rocks through fracture stimulation.

Summary of USA Gas Shale Reservoir Characteristics

The above productive examples from the USA provide a surprisingly variable spectrum of characteristics which typify successful shale gas prospects. Curtis (2002) and Bustin (2005) provided Tables comparing a number of relevant properties for each known shale gas play which also display great variability. This, in itself, is very interesting, in that it implies that a large variety of fine grained units across Canada may have significant unassessed potential, controlled by a wide range of variable reservoir properties. One U.S. research team suggested that “Each individual play has been defined, tested and expanded based on understanding the resource distribution, natural fracture patterns and limitations of the reservoir, and each play has required solutions to problems and issues required for commercial production. Many of these problems and solutions are unique to the play” (Hill et al., 2002). Clearly, each potential shale gas play must be evaluated separately to find the correct balance of all the various factors, appraise the predictability, and properly assess its economic possibilities. Curtis (2006) stated emphatically that “analogues will only take you so far in analysing a shale of interest, and then you must gather more data specific to your particular play”. The most obvious conclusion is that we need to know much more about each Canadian shale unit, through investment in serious geological analysis, before confirming or denying its shale gas potential. The stratigraphical, sedimentological and structural variables of each shale unit need to be fully understood in both the vertical and lateral dimensions in order to properly exploit this concept.

However, from the foregoing discussions and given that each of these analogues illustrates very different circumstances, certain lessons can be gleaned from each example. Although there are several characteristics which are common to all examples, in essence, these three examples represent four different types of shale gas reservoirs with definable characteristics.

Play Style A (Antrim): Upper Devonian black shales of the northeastern USA (Antrim, Ohio, New Albany Shales) represent the initial, maximum-subsidence phase deposits of a major post-orogenic transgression over a foundering carbonate platform in a foreland basin, which accumulated in a quiet, sediment-starved, anoxic marine setting under subtropical conditions. TOC content ranges up to 37%, including both marine Type II and terrestrial Type III organic matter which is mostly thermally immature (0.4-1.6 % Ro), in intervals up to about 100 m thick, at shallow to moderate depths of 100-700 m. Much of the gas originated from microbial methanogenesis in the shallow groundwater environment and may still be being generated. The near-surface open fracture system may relate to the underlying pinnacle reef fairway, or salt dissolution trends and/or may have originally been induced by loading of thick Quaternary ice sheets, and now allows invasion of bacteria-laden meteoric water from the immediately overlying Quaternary aquifers. This close relationship between the Quaternary and bedrock systems in the Antrim is unique, and also likely leads to the common production of significant volumes of saline brines: deeper production of more thermogenic gas from some Ohio and New Albany occurrences is generally dry. This play was discovered over 150 years ago, and this is the region where the concepts of fracture control and downhole artificial stimulation were first established. Proximity to large urban and industrial markets, shallow depths, low drilling costs and a remarkable success rate ensure the commercial success of the play. A clastic variation of this play may be represented by the poorly-understood Alderson Member of the Lea Park Formation of southern Alberta and Saskatchewan in Canada. There, biogenic gas is produced, at shallow depths from a hydrodynamic trap, from immature clay-rich mudstones and sandy siltstones with modest TOC's, representing the offshore deposits of a post-orogenic transgression within a clastic-dominated foreland succession

Play Style B (Ohio/New Albany): Upper Devonian black shales of the northeastern USA (Antrim, Ohio, New Albany Shales) represent the initial, maximum-subsidence phase deposits of a major post-orogenic transgression over a foundering carbonate platform in a foreland basin, which accumulated in a quiet, sediment-starved, anoxic marine setting under subtropical conditions. TOC content ranges up to 37%, including both marine Type II and terrestrial Type III organic matter which is thermally mature to overmature (1.0-1.6 %Ro), in intervals up to about 100 m thick, at moderate to deep depths of 500-1500 m. Most of the gas is thermogenic in origin, fracture patterns relate to Appalachian tectonic stress fields and gas production is generally dry. The presence of thin, interbedded siltier or calcareous zones, with more porosity and permeability is important. New Albany, Ohio and Chattanooga thermogenic gas has been produced in small volumes for decades, and proximity to large urban and industrial markets, modest depths, and large prospective reserves suggest a bright future for this play.

Play Style C (Barnett): Lower Carboniferous black siliceous shales of the Fort Worth Basin (Barnett Shale) represent the initial, maximum-subsidence phase deposits of a major post-orogenic transgression over a foundering carbonate platform in a foreland basin, which accumulated in a quiet, sediment-starved, anoxic marine setting under subtropical conditions. TOC ranges up to 13%, including marine, oil-prone Type II organic matter which is thermogenically mature (1.0-1.4 %Ro) and has generated some hydrocarbons. It occurs in intervals up to about 150 m thick, at moderate to deep depths of 2000-2600 m. The natural fracture system is sealed with calcite, but the siliceous nature and brittleness of the mudstones allow successful artificial stimulation, and therefore containment of the induced fracturing to the Barnett zone is a key factor. The presence of thin, interbedded siltier zones, with more porosity and permeability is important. The play was discovered after noticing widespread and unexpected gas shows while drilling for other targets. Careful desorption studies of cores and cuttings have been important evaluation tools. Modest depth, good pressures, high success rate and location close to markets and pre-existing (under-utilized) infrastructure have helped make the play a success, whereas horizontal drilling, and modern completion and fracturing techniques have improved well performance.

Play Style D (Lewis): Upper Cretaceous clay-rich mudstones and sandy siltstones of the San Juan Basin (Lewis Shale) represent offshore to lower shoreface deposits of a post-orogenic transgression within a clastic-dominated foreland basin succession. TOC content is quite low, ranging only up to 2.5%, including marine Type II/III organic matter in thick intervals up to about 500 m thick, at moderate to deep depths of 1000-1500 m. The organic matter is thermally mature (1.0-1.9 %Ro). A pervasive natural fracture system, successful gel-based artificial fracturing, plus the presence of sandier primary conduit zones have been key factors. The play was discovered after noticing large and unexpected gas shows while drilling for deeper targets in a heavily-drilled area. Intensive study of purpose-cut cores has elucidated fundamental reservoir storage and flow capacity and completion techniques. The ability to re-enter and re-complete existing wells has been a crucial factor in success of the Lewis play. Modest depth, high success rate and location close to markets and pre-existing (under-utilized) infrastructure have helped make the play a success, whereas horizontal drilling, and modern completion and fracturing techniques have improved well performance.

MAJOR GENERIC CONTROLS AND EVALUATION FACTORS

Tectono-Stratigraphic Position and Thickness

Clearly, thick, organic-rich mudstones representing maximum subsidence and maximum flooding phases in tectonic foreland basins (immediately post-orogenic phase: the middle unit of Sinclair's 1997, "underfilled trinity" of depositional realms, overlying both foundered carbonate platforms and regressive clastic wedges) or fault-bounded extensional basins (syn-rift phase) are prime exploration targets. Age itself is not a factor, except in that it may indicate specific post-orogenic subsidence phases which should be investigated in any given basin, and have some influence on the organic matter present. The more widespread the rock unit is, the more potential it has for large in-place gas reserves and successful exploitation. Thicknesses of hundreds of metres of the total shaly unit are preferable, but organic-rich, productive intervals of only tens of metres are necessary to be commercially successful, depending on local depth. However, in general, thicker shales should retain more of their generated hydrocarbons. The generally impermeable nature of the thick shaly unit itself helps to impede primary hydrocarbon migration and to self-seal the reservoir: here, lack of matrix permeability is a positive feature. Depths may be anywhere from surface to several thousand metres, although very shallow plays may require special circumstances and may yield water-wet biogenic gas from thermally-immature shales through inexpensive drilling, while deeper targets yield dry thermogenic gas from mature mudstones through more expensive drilling. Trends of thickness and drilling depth of the target unit across a basin may determine the type and volume of gas-in-place, and are clearly important in economic evaluation.

Organic Matter Content and Lithology

Four obvious detailed geologic factors are necessary prerequisites for a shale gas play: organic-rich shale, porosity- or fracture-related storage capacity, matrix or fracture permeability and the presence of biogenic or thermogenic gas (Faraj, 2006). High TOC content (up to 37%) of either marine or terrestrial organic matter are desirable because these reservoirs are generally self-sourcing, although even 1-2% TOC common in many shaly units is sufficient in the correct circumstances. Faraj (2006) suggested that the search is for organic carbon, not shale per se. Maturity can range from shallow, immature, biogenic generation to deeper, mature thermogenic generation. Trends of thermal maturity across a basin are important in determining gas shale fairways. Total porosity of the shales themselves can range 1-15% which greatly affects the gas storage capacity of the rock. Water saturations are generally very low (5-8%). The ratio of free gas (held in natural fractures and matrix porosity, and easily accessed) to sorbed gas (adsorbed onto high surface-area clays and organic matter in the shale, and only slowly accessed over time) may determine the initial vs. long-term flow rate, and therefore is an important economic parameter of the play. As depth and pressure increase, porosity and adsorbed gas content decrease, although free gas content may increase (Bustin, 2005). At depth, the pore sizes and permeability in shales are both an order of magnitude smaller than in tight gas sands (Bustin, 2006). Units which are known to be good conventional source rock intervals are strong candidates as shale gas producers, although strongly oil-prone source rocks or ones which have already generated prolifically (ie. already “spent”) may be downgraded. Lower Paleozoic organic-rich rocks, with a preponderance of Type I and II kerogen, may need to be either overmature or immature to be prospective, whereas Upper Paleozoic and Mesozoic rocks, with abundant Type III organics, may be prospective in all states of maturity.

Productive lithofacies range from black, clay-rich mudstones to shaly or sandy siltstones to organic-rich marlstones. The presence of interbedded horizons of coarser, more porous and permeable lithologies provides additional storage capacity and contributes prime conduits for gas expulsion and conventional flow into the fracture system, especially in less organic-rich mudstones. Mapping of clusters of these, commonly turbiditic, conduit beds may prove very important in exploration and production in thick marine shale packages. The mineralogy of the shales is very important: for example, a high silica content is a very positive feature, whereas preponderance of swelling clays might be a negative factor (Bustin, 2006).

Fracturing, Stress Field Orientation and Production

A natural fracture system, which can be enhanced by further stimulation, is very helpful in increasing storage capacity and accessible permeability, but can be dispensed with if the rocks have particular properties (brittle, very siliceous, very calcareous) which lend themselves to predictable artificial fracturing. This is particularly true in the absence of thin permeable carrier bed lithologies. Cemented horizons or cemented fractures may actually pose flow barriers. Understanding fracture orientation, spacing and length is vital. Structural trends, both of tectonic origin (deep basement-related or fault/fold-related) and of stratigraphic origin (drape over underlying features or near-surface stress-relief), are important in identifying play fairways. Knowledge of the stress-field orientation and vertical profile is a definite asset, both for initial evaluation of the fracture system and for eventual horizontal drilling/production techniques. Fracture permeability is less compressible, and hence can persist to greater depths, than matrix permeability, and fractures may occur in swarms (Bustin, 2006; Frantz, 2006). Closely-spaced fractures are desirable (Waters, 2006). Artificial fracture stimulation can extensively connect the natural fracture system, but must be carefully controlled to be contained within the target zone, as vertical extension beyond this (into either overlying or underlying horizons) may tap large water zones. By knowing how and under what conditions the reservoir shale rock will fail, fracture "sweet spots" can be created by intersection of natural and synthetically-induced fracturing (Frantz, 2006).

Some shales may not be successfully "fracable" due to their mineralogical content and resulting ductile mechanical properties (Bustin, 2006). Drilling in soft shales can create asymmetrical hole sizes and shapes, and collapse/washout may occur when bending a hole to horizontal (Frantz, 2006). Modern horizontal drilling can access multiple vertical fracture sets by drilling in a direction normal to the principal (natural and induced) fracture systems, and new fracture stimulation techniques (including re-fracing and non-water-based gels) have opened up additional resources in these plays, and are being adopted as standard techniques for these reservoirs. Induced fractures must be held open with abundant proppant (Waters, 2006), and smaller diameter sand may increase production (Schein, 2006). Horizontal drilling may be less effective in interbedded siltstone/shale lithologies. Drilling with under-balanced mud systems may minimize formation damage. Multi-layered models should be used to evaluate gas shale reservoirs because of large differences in lithologies, organic content and fracture orientation/spacing/extent in different stratigraphic zones of the target mudstone unit. Re-evaluating bypassed units in areas of dense previous drilling and under-utilized infrastructure may be a very effective exploration method.

Environmental Concerns

Unconventional gas plays, "basin-centred" or "resource" plays, are fundamentally different from conventional exploration plays in several respects, not least of which is the public concern with environmental issues deriving from the widespread distribution of the resource, the land-use footprint of the exploration/production process, and the possibility of air and surface water pollution and groundwater disturbance (Griffiths, 2006). Shale gas exploration and production also faces these concerns and must address them from the outset.

For an exploration company to have success in shale gas, it likely must assemble a commanding land position, to capture the economies of scale, before knowledge of its intentions becomes public (Ball, 2005a). This can lead to suspicions of intent. Much of the prospective land is likely to reside in regions of well-developed agriculture, relatively close to markets, leading to apprehension for the safety of people, crops and livestock. In fact, recompletion of existing dry holes, or declining wells, within known producing basins with existing infrastructure may present a cost-effective means of developing some shale gas plays with minimal environmental impact (Canadian Society for Unconventional Gas, 2005). Likewise, efficient production may require a greater-than-normal well density, or many directional wells drilled from large well pads (Ball, 2005b), causing noise, transportation disruptions and visual eyesores. This increased pressure on surface land-use could easily create public resistance to exploration/production of this resource. Here, the employment of horizontal wells and multi-lateral horizontals from a single pad may alleviate concerns with drilling density (Durham, 2006). Re-entering and re-completion of old wells with co-mingling of production, where appropriate, may hold great advantages for these plays (Griffiths, 2006).

Due to the gas-charged nature of the shale gas reservoir system, water mitigation/disposal may not be a major factor (Ball, 2005b), but could create problems in some cases (eg. Antrim). The shallower the fracturing and production zone, the more public worries about freshwater aquifer damage there will be; possibly the biggest point of contention (Griffiths, 2006). Sour gas is unlikely to be associated with these plays, but would need to be monitored. Noise associated with drilling of large numbers of wells, and very long production cycles could be an issue in some locations. The employment of well-planned pilot projects may help mitigate problems and improve long-term recoveries. The general lack of understanding in the lay public of shale gas, land and water impacts, the problems of CBM production in the U.S. and a history of poor communication by the industry could create an air of suspicion (Griffiths, 2006).

For all these reasons, industry representatives must engage in informative and honest dialogue with all stakeholders from the beginning, in order to develop an exploration strategy which allows recovery of the resource in an environmentally- and socially-responsible manner (Ball, 2005b; Griffiths, 2006). And, finally, governments need to create the best and safest regulatory environment within which industry will operate, before exploration becomes too far advanced. The importance of this aspect of future shale gas development in Canada cannot be over-estimated.

Specific evaluation methodologies

Once a unit with shale gas possibilities has been identified, the key properties which affect gas-in-place and deliverability must be determined: commercialization of these low pressure/low flow rate plays is very sensitive to drilling and completion costs (Canadian Society for Unconventional Gas, 2005). Full integration of geological characterization, mapping, stratigraphy and sedimentology, paleontology, core analysis, log analysis, organic geochemistry, stress field anisotropy and well testing is required. Actual rock data is key to "ground-truthing" the play, and balancing of many positive and negative factors may be required (Moorman, 2005). Several vertical wells with core may be needed to understand the stratigraphy and rock properties, before proceeding to a horizontal drilling program. Virtually all known shale gas plays in the U.S. have benefited from horizontal drilling, partly because they produce 4x the gas at only 2L the cost, and multilateral drilling from a single pad can reduce the environmental footprint (Gardes, 2006). Horizontal drilling maximizes the wellbore exposure to the reservoir, and the longer the laterals, the better (Durham, 2006). As Moorman (2005) stated, these plays are called "unconventional" for a reason, and require time, detailed study, planning and nontraditional techniques to establish. They also require patience, as early results may be widely variable, until the actual tenets and local controls of the play are confirmed. It is crucial to gather, evaluate and integrate as much real rock data in advance as possible in order to design an exploration/production strategy: these plays will have a "steep learning curve", but a deeper understanding may pay dividends in the end.

"Source rock" attributes, such as kerogen type, TOC and maturity must be evaluated to establish which beds have significant potential (Faraj, 2005; Lewis, 2005). Rock-Eval provides a quick and inexpensive survey method for establishing TOC, thermal maturity and organic matter type, whereas vitrinite reflectance is a more accurate measure of maturity. Isotopic studies and determination of clay mineralogy may be required. Organic-rich mudstones typically have high radioactivity (ie. High U content), high resistivity, high porosity and low density (Lewis, 2005; Taylor, 2005). Issler et al (2002) demonstrated that using core data to calibrate well logs, one can successfully and accurately calculate TOC from sonic-density and sonic-neutron log signatures alone. Their data was from Cretaceous shales in WCSB, but should be transferable to many different ages of strata in many different basins (Issler et al, 2002). The presence of gas, through mudlogs and desorption experiments must be demonstrated. Standard drillstem tests (DST's) may not be reliable indicators of gas because good recovery might require very long test periods (Lewis, 2005). Drilling with under-balanced or managed mud systems may eliminate catastrophic formation damage, and may even eliminate the need for large frac jobs (Gardes, 2006). If gas content correlates strongly with TOC content, then it may mean that the gas is mostly stored in a sorbed state on the organic matter (shallow, low pressure reservoirs, eg. Antrim), whereas if there is a poor correlation, the gas may be stored primarily as free gas in the pores and fracture system (deeper, higher pressure reservoirs, eg. Barnett shale (Jarvie, 2006; Waters, 2006). Pressure analysis may prove to be very important in the evaluation of adsorbed gas volume.

"Reservoir rock" attributes must also be evaluated: abundant clays may bind too much water and make the shale ductile, whereas abundant silica and calcite may make the shale more brittle (Schein, 2006; Waters, 2006). Determination of the diagenetic maturity and mineralogy of the clay species present (eg. swelling *vs.* non-swelling) may be vital. The presence, predictability and effectiveness of permeability (coarser-grained carrier beds, natural fractures, induced fractures) is crucial to making these plays viable (Faraj, 2005; Taylor, 2005). The permeability must be established through mapping of structures and stress-relief zones, lithological description, mineralogical studies and possibly rock mechanical experiments. Detailed seismic is a very valuable tool in evaluation (Durham, 2006). Downhole formation imaging logs are an expensive, newer technology, but can yield crucial information in early exploratory wells: the earlier the fracture style, orientation and spacing is understood, the better the exploration and production programs will be (Frantz, 2006). Simultaneous stimulations of adjacent wells may break up more intervening reservoir rock, and micro-seismic surveys can delineate the extent and coverage achieved by induced fracture programs (Clawson, 2006).

In the Utica shales of Quebec, Aguilera (1978) used a series of standard logging techniques to evaluate the gas potential of fractured shales. These included 1) log-log cross-plots of sonic *vs* resistivity to estimate water saturation, 2) sonic and neutron logs to evaluate porosity, 3) sibilation, temperature and dipmeter logs to identify fracture zones, and 4) sonic and resistivity logs to identify overpressured zones (Aguilera, 1978). A combination of Gamma Ray, Resistivity and Density logs was recommended by Mullen (2006).

To assess gas-in-place, the data which should be collected for each layer in a multi-layered model include a) net pay thickness, matrix gas porosity and water saturation from logs, b) matrix organic content, kerogen type, mineralogy and thermal maturity from core, and c) pressure and gas desorption from lab tests (Frantz, 2001). To assess deliverability, the data which should be collected for each layer in a multi-layered model include a) matrix gas permeability and gas desorption from core, and b) bulk permeability, reservoir pressure, and fracture spacing and half-length from well tests (Frantz, 2001). Once the reservoir is fully understood, programs for horizontal drilling and artificial fracture stimulation (which is almost always required) can be designed which will be controlled and contained, and yield the anticipated results. Micro-seismic may be required to analyse and track hydraulic fracture patterns (Faraj, 2005; Kuuskraa, 2005). A new fracture network with considerable area must be created without causing swelling-clay formation damage, so novel fluids may be necessary (Taylor, 2005). Experience in the US has shown that each potential shale gas unit will likely be somewhat unique in its characteristics, present different stimulation/completion challenges and require new ideas and adaptations to be successful (Canadian Society for Unconventional Gas, 2005). A successful explorer needs to choose a play wisely, then commit to it fully, and finally pursue a creative, aggressive and thorough geological evaluation from the beginning: full data collection in early stages will reap great benefits later on.

General Appraisal Factors for Canadian Setting

Although the modern exploitation of all three USA examples began under federal government tax credits to develop unconventional resources, economically-successful drilling and production has continued long past the end of that regulatory regime. The most important result of that tax setting may simply have been to allow the emergence of the shale gas concept into the exploration mind-set. The ability to re-complete existing wells, in basins close to markets with existing (especially under-utilized) infrastructure and accessible data has been very important in the commercial success of some of these ventures, but is not necessary if the occurrence is sufficiently rich. This factor may prove to be very important in kick-starting exploration in certain Canadian basins (eg. WCSB, N.W.T., southern Ontario). In addition, a basin like WCSB has multiple stacked stratigraphic units with shale gas potential, although each might have somewhat different characteristics. Unconventional gas potential in Canada, exemplified by both coal-bed methane and shale gas concepts, require a new way of thinking in that facies and lithologies previously deemed as “non-reservoir” must now be considered as significant potential reservoirs, thereby opening entirely new play prospects.

More importantly, intensive three-dimensional geological study, including dedicated, purposeful outcrop, core and log work, has proven to be crucial to understanding the true play fairways, reservoir properties, volumes of gas-in-place, best drilling and completion practices and ultimate recovery potential (Faraj, 2005). Stratigraphic, sedimentologic, structural, geochemical and engineering data are all vital to full understanding and technical evaluation of these unconventional reservoirs. These plays are typically discovered after following-up “unexpected” or “nuisance” gas shows with unconventional and open-minded scientific thinking, and frontier exploration approaches. Estimated in-place resources for the commercially successful plays are very large (up to 250 tcf), to be tapped by thousands of wells, making these attractive targets although ultimate recoverable resources in each basin are still unknown. And finally, each of these documented examples has similar and correlative counterparts in onshore areas of Canada which are located close to markets in basins with existing infrastructure and data, which have not yet been seriously evaluated for shale gas potential. In fact, there are wells in Western Canada which already produce gas from fractured shales, but with little fanfare (Ball, 2005b). As one experienced USA operator realized, "we're starting to realize these older basins have a lot of hydrocarbons left", and it can be exciting to discover a large gas field in an old productive basin (Durham, 2006).

In addition, there are numerous candidates in more "frontier" onshore Canadian locations, which may still be rich enough to warrant exploration. The current climate of depleting reserves and high prices may present an opportunity for the emerging shale gas concept. The Canadian Society for Unconventional Gas suggested that the resource estimate for shale gas in Canada could be as high as 860 Tcf, and that silence on the part of Canadian exploration and production companies may signify keen interest and behind-the-scenes activity (Ball, 2005b).

GEOGRAPHIC INVENTORY OF CANADIAN SHALE UNITS

INTRODUCTION

Each of the 50 shale units reviewed here is briefly described geologically and any relevant data from the literature is summarized. These are divided into seven major regions, and presented roughly from east to west to north. These summaries obviously cannot be exhaustive, and draw only on the more obvious sources. More concerted effort on any given shale unit would yield much more information. However, after this initial review, it is clear that many of these units have no serious shale gas potential which could be exploited at this time, but I felt that they should all be fairly evaluated to begin with, in the spirit of conceptual/frontier thinking. Therefore, even units in far-flung frontier areas with no current infrastructure and no likelihood of foreseeable development are reviewed purely for their geological potential.

Conversely, several shale units appear to have serious geological (not necessarily economic) potential which should be further examined. However, it is important to note that the general tendency, in sampling rock for geochemical studies, is to naturally sample the darkest (most organic-rich) intervals, but that these may not be fully representative of the unit as a whole. Therefore, the Rock-Eval data for some units may appear more promising than a systematic and unbiased sampling program would reveal. Over-optimism could be a potential danger in evaluating any given rock unit in this new play concept. Likewise, blanket negativism, without open-minded consideration, is incompatible with the spirit of conceptual play evaluation.

Rock-Eval data quoted in this summary refer only to samples which meet standard cut-offs (eg. TOC > 0.4, S2 > 0.2, T_{max} > 395, HI > 50, etc.), in order to preserve some reliability of results. All Rock-Eval data are quoted in the following units: TOC in weight %, T_{max} in °C, $S_1/S_2/S_3$ in mg hydrocarbon/g of rock, HI in mg hydrocarbon/g TOC and OI in mg hydrocarbon/g TOC.

ATLANTIC CANADA (Figure 1)

Green Point/Curling (Upper Cambrian-Middle Ordovician)

The thick Cambrian and Ordovician sedimentary succession in western Newfoundland includes shallow marine platformal clastic and carbonate facies and coeval deep marine mudstone-dominated facies, which were deposited on the Lower Paleozoic passive margin of North America (Fowler et al., 1995). From Middle Cambrian to Middle Ordovician time, a carbonate platform at the margin of the craton developed (Port au Port and St. George Groups) with coeval deeper water slope facies (Cow Head and Curling Groups) to the east (James and Stevens, 1986; Knight and James, 1987). Taconian, Salinian and Acadian plate convergence and deformation destroyed this platform margin and telescoped and juxtaposed these equivalent deeper marine, mudstone-dominated facies into a structurally-overlying position as a stack of easterly-derived allocthonous thrust slices (Stevens, 1970; Williams, 1979; Waldron and Stockmal, 1991). The hydrocarbon potential of this very complex geological setting has never been fully evaluated. Numerous oil shows have been noted in this area from 1812 to the present, oil was actually produced from these rocks in the early 20th C and spontaneous gas explosions are known from the past at Parson's Pond (Fowler et al., 1995).

The Green Point Formation of the Cow Head Group, spanning Upper Cambrian to Middle Ordovician time, includes 400-500 m of interbedded dark grey to black and green ribbon limestone and mudstone with minor resedimented limestone conglomerate (James and Stevens, 1986). Most of the dark shale is present in the lower Martin Point Member, 100-150 m of Late Cambrian, generally unfossiliferous, green and black laminated shale with minor siltstone and limestone beds (James and Stevens, 1986). These strata represent the initial transgressive mudstone deposited on the foundering carbonate platform in a distal basinal position (James and Stevens, 1986). The coeval, and even more basinal, Cook's Brook and Middle Arm Point formations of the Curling Group, include several hundred metres of deep marine black mudstone, turbiditic calcarenite beds and resedimented limestone conglomerates (James and Stevens, 1986). All these strata were derived from the southeast and deposited in tectonically-unstable deeper marine slope and abyssal plain settings. Further to the southwest, some depositional equivalents to these deposits are present in the Utica of Quebec and New York, but are not present in Ontario. These shale units reside in a highly deformed tectonic province and generally occur as components of steeply-dipping thrust slices in an ancient fold and thrust belt (Waldron and Stockmal, 1991).

Shales of the Green Point sampled at surface in western Newfoundland, and probable equivalent shales sampled, include organic-rich (Type I/II) intervals with TOC contents up to 10.4%, HI up to 759 and T_{max} values ranging from 434-443, indicating a thermal maturity below or within the oil window (Nowlan and Barnes, 1987; Weaver and Macko, 1988; Fowler et al., 1995; Bertrand et al., 2003). These researchers also found that the geochemical characteristics of the oil seeps correlate closely to those of the Green Point shales and that maturity increases (at least at surface) from west (immature) to east and from south to north (late mature). Green Point shales present north of Parson's Pond may reside in the gas window. The GSC Rock-Eval Database includes 12 samples of Green Point Formation with the following characteristics: TOC up to 8.37, averaging 5.86; T_{max} up to 444, averaging 440; S_1 up to 1.73, averaging 1.32; S_2 up to 62.06, averaging 34.83; S_3 up to 0.53, averaging 0.29; HI up to 753, averaging 613, OI up to 7, averaging 5 (M. Obermajer, 2006, pers. comm.).

Green Point shales include possibly thick sequences of excellent source rocks (Type I/II organics), which are thermally immature to mature (possibly ranging up to overmature), with good potential for a Style A (Antrim-like) play or a Style B (Ohio/New Albany-like) play, provided structural complications can be dealt with. Further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy of the Green Point would lead to better understanding of the shale gas potential. No samples clearly attributable to the Curling Group have been analysed, although a single sample reported by Fowler et al. (1995) yielded a TOC = 1.2%. We can speculate that these strata could be at least as organic-rich, and likely more mature than, nearby Green Point shales. Because these units were caught up in the Taconian thrust stack, widespread faulting and fracturing are pervasive, and there are no continuous or flat-lying occurrences of these strata. This structural complexity would render these rocks very difficult exploration targets.

Table Cove/Black Cove (Middle Ordovician)

The inception of the Taconian Orogeny caused the initial collapse, subsidence and transgression of the Middle Ordovician shallow marine carbonate platform which had existed at the eastern North American cratonic margin throughout the length of the Appalachian Orogen (Stevens, 1970). The Middle Ordovician Table Head Group and Goose Tickle Group record the collapse and mass-wasting cannibalization of this long-lived platform, the reversal of sediment dispersal from eastward to westward, and the evolution of the resulting Taconian foreland basin (Stevens, 1970; Klappa et al., 1980; Stenzel et al., 1990). The Table Head Group is a fining-upward sequence of bioturbated limestones, interbedded limestone and black shale and slump megabreccias up to 380 m thick, overlain by Goose Tickle Group shales, siltstones and sandstones, which together represent the stratigraphically-highest expression of the cratonic autocthonous succession (Stenzel et al., 1990).

Grey, thick bedded, shallow marine limestones and dolostones of the lowermost Table Point Formation (up to 256 m thick) are overlain by up to 95 m of thinly interbedded grey limestone and black calcareous mudstone with slump folds of the Table Cove Formation, deposited by turbidity currents during subsidence of the carbonate slope (Klappa et al., 1980; Stenzel et al., 1990). These units are overlain by Black Cove Formation black, laminated, pyritiferous and graptolitic, noncalcareous shale with minor green siltstones up to 22 m thick, deposited in a deeper water anoxic setting, as the foreland basin subsided (Klappa et al., 1980; Stenzel et al., 1990). To the west, partly-equivalent black shales with interbedded calcarenites and megabreccias form the Cape Cormorant Formation, up to 180 m thick, representing episodic deposition from debris flows into the deeper water, lower slope environment of the foreland basin (Stenzel, et al., 1990).

There are no published data detailing the organic-content, thermal maturity or fracture systems of these fine grained units. A single sample reported by Fowler et al (1995) yielded TOC < 1%. The Table Cove/Black Cove succession includes a modest thickness of black shales, with coarser beds, which may be organic-rich, but maturity is unknown. We may suppose that there could be a Style A (Antrim-like) play or a Style B (Ohio/New Albany-like) play present, but so little relevant data is available that no definitive statements can be made, and the potential must be listed as modest and speculative. Further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy of the Table Cove/Black Cove would lead to better understanding of the shale gas potential. These strata form part of the vast Middle-Upper Ordovician shale-dominated succession of the Appalachian Basin, which may soon emerge as the next important shale gas province, and could provide a large but as yet unevaluated resource.

Winterhouse (Upper Ordovician)

The inception of the Taconian Orogeny caused the initial collapse, subsidence and transgression of the Middle Ordovician carbonate platform throughout the length of the Appalachian Orogen. The Upper Ordovician Winterhouse Formation, up to 860 m thick, of the eastern Anticosti Basin Platform is essentially continuous with the Vauréal Formation to the west, and includes clastic facies derived from the Taconian Orogen to the southeast (Sanford, 1993; Quinn et al., 1999). But, because of its more proximal position relative to the detrital sources of the Taconian allocthons, the Winterhouse comprises somewhat different lithologies.

The Middle Ordovician Lourdes Formation limestones are gradationally overlain, over a 5 m interval, by lower Winterhouse mudstone-dominated strata (Stait and Barnes, 1991). Grey calcareous, micaceous mudstone and siltstone, with thinly interbedded sandstones which increase in thickness and number upward, and minor fossiliferous limestone conglomerate and calcarenite beds, are typical of the Winterhouse Formation (Sanford, 1993; Quinn et al., 1999). Fine grained grey lithologies, with common burrows, represent 90% of the strata in the lower 50 m, immediately overlying the Lourdes Formation limestone, but are gradually reduced to about 40% upward as a thick prograding succession of storm-dominated shallow marine shelf sandstones dominates in the upper part and is overlain by orogen-derived red sandstones of the Misty Point Formation (previously referred to the Clam Bank Formation) (Quinn et al., 1999). The Winterhouse is of middle to late Caradocian age.

No published data detailing the organic-content, thermal maturity or fracture systems of these fine grained units were found. The Winterhouse includes a great thickness of dark grey shales, with coarser beds, which may have some organic-rich intervals, but maturity is unknown. We may suppose that there could be a Style A (Antrim-like) play or a Style B (Ohio/New Albany-like) play present, but so little relevant data is available that no definitive statements can be made, and the potential must be listed as modest and speculative. Further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy of the Winterhouse might lead to better understanding of the shale gas potential. These strata form part of the vast Upper Ordovician shale-dominated succession of the Appalachian Basin, which may soon emerge as the next important shale gas province, and could provide a large but as yet unevaluated resource.

Strathlorne/Albert/Cape Rouge (Carboniferous)

The Late Devonian-Early Carboniferous Fundy Basin Rift (an early structural configuration of the complex Maritimes Basin), which post-dated Acadian compression and pre-dated Alleghanian transpression, was filled by syn-rift lacustrine and fluvial deposits of the Horton Group, shallow marine evaporites and limestones of the Windsor Group and waning-stage lacustrine and fluvial deposits of the Mabou Group. The Upper Devonian-Lower Carboniferous Horton Group of Nova Scotia comprises the initial nonmarine syn-rift sediments deposited within several fault-bounded, half-graben subbasins of the post-Acadian/pre-Alleghanian intracontinental Fundy Basin Rift of the Maritimes Basin (Hamblin and Rust, 1989). In northern Nova Scotia, Murray (1960) and Kelley (1967) described a regionally-consistent tripartite stratigraphy of a) lower Craignish Formation grey and red sandstone and siltstone up to 1600 m thick, b) middle Strathlorne Formation grey to black organic-rich mudstone, siltstone and fine sandstone up to 600 m thick, and c) upper Ainslie Formation grey and red sandstone, siltstone and conglomerate up to 650 m thick. These units each represent tectonically-controlled, three-dimensional depositional systems with basin-wide occurrence (Hamblin and Rust, 1989), and in each area, the middle, organic-rich mudstone unit has hydrocarbon potential (Hamblin, 1992). The lithologically-similar Horton Bluff Formation dark grey mudstones of the Windsor Subbasin in central Nova Scotia (Martel and Gibling, 1996) and the famous Albert Formation organic-rich mudstones and oil shales in the Moncton Subbasin of southeastern New Brunswick (St. Peter, 1992, 1993), correlate to the Strathlorne (Carter and Pickerill, 1985). In western Newfoundland, parts of the Anguille Group and the Cape Rouge Formation of the White Bay area are organic-rich mudstones which are also correlative (Hamblin et al., 1995). In all subbasins, hydrocarbon indicators are present in these shaly units (Fowler et al., 1993).

The Tournaisian-aged Strathlorne Formation comprises up to 600 m of primarily thinly laminated dark grey mudstone with subordinate grey siltstone or very fine grained sandstone of open lacustrine origin, arranged into coarsening-upward sequences up to about 20 m thick (Hamblin, 1992). At the base of each sequence, claystone is dark grey to black, uniform, laminated and organic-rich, with fish fragments. Minor oolitic and stromatolitic limestones are present at the tops of sequences near subbasin axes. In general, the mudstone-dominated units coarsen-upward into the conformably overlying fluvial/shoreline sandstone-dominated units. The middle Horton, mudstone-dominated units represent open lacustrine, clastic-dominated sedimentation corresponding to the maximum extension/maximum subsidence phase of development of the nonmarine Upper Devonian-Lower Carboniferous Fundy Basin Rift, creating conditions similar to a marine transgression flooding phase which slowly filled with sediment as subsidence waned (Hamblin and Rust, 1989; Hamblin, 1992). Horton Group rocks and equivalents in other subbasins depict similar successions and interpretations: each subbasin underwent similar tectonic evolution, thereby creating similar stratigraphic successions with organic-rich lacustrine mudstones in the middle part of the stratigraphy, but each subbasin was semi-isolated from adjacent ones, creating a string of limited depocentres with somewhat different characteristics.

In the Conche area of western Newfoundland, up to 1200(?) m of Cape Rouge Formation include dark grey laminated mudstone with thin dolomitic siltstone and very fine sandstone beds of open lacustrine origin, partly arranged into coarsening-upward sequences (Hamblin et al., 1995). Some thick bedded, shoreline-related sandstones are present. In the Windsor Subbasin of Nova Scotia, the Horton Bluff Formation includes at least 525 m of lacustrine mudstone, siltstone, sandstone and conglomerate. The middle Blue Beach Member is composed of up to 200 m of thinly interbedded dark grey to grey laminated mudstone, siltstone and minor sandstone, arranged in repeated asymmetric coarsening- and shallowing-upward sequences, deposited in a large wave-dominated, underfilled lake (Martel and Gibling, 1996). In the Moncton Subbasin of New Brunswick, the Albert Formation includes up to 1800 m of fluvial and lacustrine sandstone, mudstone and oil shale which have produced significant volumes of oil and gas from the Stoney Creek field since 1909 (Chowdhury et al., 1991). The middle Frederick Brook Member comprises laminated kerogenous dolomitic mudstones, microlaminated kerogenous shales (oil shales), kerogenous siltstones with minor sandstone interbeds, and varies in thickness from a few tens of metres to more than 200 m (St. Peter, 1992), although there may be fault repeats. The upper Hiram Brook Member comprises up to 700 m of grey partly kerogenous mudstone, siltstone and sandstone (Carter and Pickerill, 1985; Smith and Gibling, 1987).

Strathlorne Formation mudstones have yielded TOC contents ranging 0.1-5.3% with Type I organic matter and thermal maturity ranging from the oil window to the gas window (Hamblin, 1989): recovered oils appear to correlate to these source rocks (Chowdhury et al., 1991). A small number of Cape Rouge Formation samples yielded TOC 0-1.7%, with Type I organic matter at the late stage of oil window maturity (Hamblin et al, 1995). Numerous samples from the Albert Formation yielded Type I organic matter with TOC contents ranging 0-31%, and thermal maturity in the early oil window to beyond the gas window (MacIntosh and St. Peter, 2005). Recovered oils correlate to these source rocks (Smith and Gibling, 1987; Chowdhury et al., 1991). The GSC Rock-Eval Database includes 61 samples of Albert Formation with the following characteristics: TOC up to 31.25, averaging 8.96; T_{max} up to 454, averaging 445; S_1 up to 18.32, averaging 4.69; S_2 up to 209.73, averaging 73.77; S_3 up to 4.36, averaging 1.23; HI up to 1048, averaging 824, OI up to 47, averaging 12 (M. Obermajer, 2006, pers. comm.).

The middle portion of the Horton Group, in the various subbasins of the Fundy Basin Rift and Maritimes Basin, appear to have large thicknesses of organic-rich lacustrine mudstones (Type I organics), with good to excellent source rock intervals (especially the Albert Formation), and abundant silty carrier beds, which could be considered for shale gas potential. A study of several hundred data points in the Albert Formation indicated that the predominant lacustrine Type I organics are oil-prone and reside in the oil window or the gas window through much of the exposed parts of the isolated subbasin areas (MacIntosh and St. Peter, 2005). Correlative strata in deeper, more mature areas should be of greater interest. The presence of a Style D (Lewis-like) play is likely. A considerable amount of stratigraphic and sedimentologic study of these rocks already exists, but further detailed study of organic matter details, maturity variations, depositional details and fracture patterns would lead to better understanding of the shale gas potential in each subbasin.

Hastings/Cape Dauphin/West Bay/ Rocky Brook (Carboniferous)

The Late Devonian-Early Carboniferous Fundy Basin Rift (an early structural configuration of the complex Maritimes Basin), which post-dated Acadian compression and pre-dated Alleghanian transpression, was filled by syn-rift lacustrine and fluvial deposits of the Horton Group, shallow marine evaporites and limestones of the Windsor Group and waning-stage lacustrine and fluvial deposits of the Mabou Group. The upper Viséan to lower Namurian Mabou Group was deposited during the waning stages of tectonic subsidence, into widening, but nearly replete, extensional subbasins as the final fill of that large, intracontinental depocentre throughout New Brunswick, Nova Scotia and Newfoundland (Belt, 1965; Hamblin, 2001). The Mabou Group of Nova Scotia, about 500 m thick, includes the 1) lower Hastings Formation of grey shale with thin sandstone and limestone beds which abruptly but conformably overlies the Windsor Group, deposited in shallow lacustrine environments, and the 2) overlying Pomquet Formation of interbedded red siltstone and sandstone deposited in a subaerial playa-mudflat-floodplain setting (Hamblin, 2001). In central Newfoundland, the Rocky Brook Formation of the Deer Lake Group is approximately coeval with the Hastings Formation: both units, and the locally known Cape Dauphin and West Bay formations in Nova Scotia, are of late Viséan age (Hamblin et al., 1997; Hamblin, 2001). In New Brunswick, the correlative Maringouin, Shepody and Enrage formations comprise a coarsening-upward megasequence of red mudstones, siltstones, sandstones and conglomerates up to 2 km thick, but no organic-rich mudstone is present (St. Peter, 2006, pers. comm.).

The lacustrine Hastings Formation, up to 325 m thick, comprises thinly interbedded dark grey to black, laminated, organic-rich mudstone, grey bioturbated siltstone, dolomitic very fine to fine grained sandstone and minor limestones of oolitic and stromatolitic character (Hamblin, 2001). Near the top of the formation, reddish siltstones and sandstones, deposited in shoreline and fluvial floodplain environments are present in some localities. The Hastings lacustrine system was much more carbonate-rich/saline-rich than the similar Horton Group lacustrine systems, and was interpreted by Hamblin (2001) to represent generally shallower lakes with less clastic input, which may enhance its shale gas potential. In Sydney Basin, Giles (1983) described the late Viséan Cape Dauphin Formation as 78-84 m of dark grey shale with minor fine grained sandstone and limestone, conformably overlying the Windsor Group. Likewise in the Cumberland Basin, Carroll et al. (1972) described 550 m of reddish/greenish shale of the late Viséan West Bay Formation, with lesser dark grey shale, limestone and thin sandstone beds, presumed to overlie the Windsor Group. To the north, the Rocky Brook Formation of the Deer Lake Subbasin of Newfoundland is a deepening-upward, fluvial to lacustrine succession up to 550 m thick with large thicknesses of dark grey to black mudstones and oil shales interbedded with thin sandstone and limestone beds in the Lower Grey Beds and Upper Grey Beds informal units (Hamblin et al., 1997).

A scattering of samples from the Hastings Formation yielded TOC 0.08-0.84%, HI 0-161, OI 0-408 and T_{max} 344-450, suggesting oxidized, rather organic-lean mudstones with Type I/III organic matter of relatively low thermal maturity (Hamblin, 2001). Data suggests that the Hastings has modest amounts of gas-prone organic matter which is currently within the oil window or at the low end of the gas window, but that more organic-rich intervals may lie deeper beneath the surface or beneath the Gulf of St. Lawrence (Hamblin, 2001). In contrast, systematic sampling of the correlative Rocky Brook Formation yielded marginally mature Types I/II/III organic matter with TOC up to 15% in zones of moderate thickness (Hamblin et al., 1997). We may suppose that there could be a Style A (Antrim-like) play or a Style D (Lewis-like) play present in any of these subbasins, but so little data is available that no definitive statements can be made, and the geological potential must be listed as modest and speculative. There have been no studies of the hydrocarbon potential of the Cape Dauphin or West Bay formations, nor is there any published data on fracture patterns for any of these units. Clearly, further study would yield crucial data important in evaluating shale gas potential.

QUÉBEC (Figure 1)

Macasty/Vauréal (Upper Ordovician)

The inception of the Taconian Orogeny, involving collision of the eastern continental margin of North America with a volcanic arc situated above a SE-dipping subduction zone, caused the initial collapse, subsidence and transgression of the Middle Ordovician carbonate platform throughout the length of the Appalachian Orogen (Hiscott et al., 1986). At the cratonic margin of the foreland, which was located near the paleoequator, the carbonate platform succession was covered by a deepening-upward sequence of argillaceous limestone and black organic-rich mudstone, followed by shallowing-upward flysch (Hiscott et al., 1986). The Upper Ordovician Macasty Formation and the lower part of the overlying Vauréal Formation of the Anticosti/Eastern St. Lawrence Platform are organic-rich mudstones, derived from the Taconian Orogen to the southeast (Sanford, 1993).

Platform limestones of the Mingan Formation are succeeded by dark grey to black, bituminous shales up to 175 m thick, with minor limestone interbeds, of the Edenian-aged Macasty Formation, present on Anticosti Island and offshore (Poole et al., 1970; Sanford, 1993; Lavoie et al., 2005). From a subsurface core on Anticosti, Bolton (1970) described 43 m of interbedded black limestone and shale with a fauna time-equivalent to the Lorraine shales of the St. Lawrence Lowlands. Hiscott et al. (1986) interpreted these rocks as the deposits of hemipelagic mud and thin distal turbidites emplaced by flows that periodically reached beyond the axis of the foreland. These strata are succeeded by a sequence exposed on Anticosti and in subsurface cores, up to 720 m thick of grey to dark grey micaceous shale, with interbedded thin limestone and sandstone which increase upward, of the Maysvillian-Richmondian Vauréal Formation (Sanford, 1993). Bolton (1971) described 2 informal members: lower grey shale with thin interbedded limestones up to 150 m thick, and upper grey interbedded limestone and shale up to 200 m thick. Deposits of the Macasty and Vauréal were derived from a southeastern orogenic source (Sanford, 1993). Macasty and lower Vauréal strata resemble, and are approximately equivalent to, the Winterhouse Formation of west Newfoundland and to the Utica-Nicolet River succession of the Québec Basin. These strata are overlain by thick carbonates of the upper Vauréal and Ellis Bay Formation.

Bertrand (1990) and Bertrand et al. (2003) presented data regarding the hydrocarbon potential of the Macasty Formation, the only source rock known in the Anticosti Basin. Organic matter, including primarily Type II with minor Type I organic matter and bitumen, is abundant with TOC values generally above 3.5% (range 1.5-4.9%). These strata have been subjected to a range of thermal maturation, from the early oil window throughout most of the island (Bertrand et al., 2003) to the dry gas zone in the subsurface of the far southwest (Bertrand, 1990). Bertrand (1987) reported early Rock-Eval data for these strata: Macasty (8 samples) yielded TOC contents ranging 0.48-4.11, ranging 440-450, HI ranging 49-259 and OI ranging 2-12; Vauréal (80 samples) yielded TOC ranging 0.03-1.21, T_{max} ranging 397-455, HI ranging 93-542 and OI ranging 0-104. A recent set of 5 samples of Macasty Formation yielded the following characteristics: TOC up to 7.11, averaging 4.24; T_{max} up to 439, averaging 436; S_1 up to 4.09, averaging 2.24; S_2 up to 33.91, averaging 16.97; S_3 up to 1.11, averaging 0.60; HI up to 477, averaging 384, OI up to 26, averaging 16 (D. Lavoie, 2006, pers. comm.). There is no published data from the Vauréal Formation.

The Macasty-Vauréal succession includes a thick sequence with some apparently excellent source rock intervals (Type I/II organics), which are thermally immature to mature (possibly ranging up to overmature), with good potential for a Style A (Antrim-like) play or a Style B (Ohio/New Albany-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, fracture patterns are unknown and relatively few samples have been analysed. These strata form part of the vast Upper Ordovician shale-dominated succession of the Appalachian Basin, which may soon emerge as the next important shale gas province, and could provide a large but as yet unevaluated resource. Within the St. Lawrence Platform-Appalachian region, the Macasty-Vauréal succession (and its correlatives) probably present some of the best prospects for shale gas potential.

Utica/Lorraine (Upper Ordovician)

The inception of the Taconian Orogeny, involving collision of the eastern continental margin of North America with a volcanic arc situated above a SE-dipping subduction zone, caused the initial collapse, subsidence and transgression of the Middle Ordovician carbonate platform throughout the length of the Appalachian Orogen (Hiscott et al., 1986). At the cratonic margin of the foreland, which was located near the paleoequator, the carbonate platform succession was covered by a deepening-upward sequence of argillaceous limestone and black organic-rich mudstone, followed by shallowing-upward flysch (Hiscott et al., 1986; Dykstra and Longman, 1995; Comeau et al., 2004). The Upper Ordovician Utica Group and the overlying Nicolet River Formation of the Québec Basin/Central St. Lawrence Platform are organic-rich mudstones, derived from the Taconian Orogen to the southeast (Sanford, 1993).

In the surface and subsurface along the St. Lawrence River and southward into the U.S., black shales of Edenian age succeed the Trenton limestones and comprise the Utica Group, a rich petroleum source rock, approximately equivalent to the Eastview, Billings, Collingwood and Blue Mountain formations of Ontario (Poole et al., 1970; Belt et al., 1979; Sanford, 1993; Dykstra and Longman, 1995). These include the dark brown and black, laminated and non-bioturbated, calcareous, graptolitic shales up to 100 m thick, which lie disconformably on Trenton limestones to the north (Clark, 1972; Sanford, 1993). The entire Utica Group may reach 300 m in thickness (Aguilera, 1978) and represents the thickest and most widespread of the Lower Paleozoic black shale source rock intervals (Ryder et al., 1998). Lachine rocks are overlain by up to 762 m of grey to dark grey calcareous, bioturbated shale, with upward increase of siltstone and very fine grained sandstone interbeds, of the Nicolet River Formation of the Lorraine Group, approximately equivalent to the Carlsbad and Georgian Bay formations of Ontario (Clark, 1972; Sanford, 1993). The Lorraine Group is conformably overlain by Queenston Group redbeds (Belt et al., 1979). Recuurent tectonism (Taconian, Acadian, Alleghanian) likely created a pervasive fracture network in these rocks which allowed partial upward migration of generated gas through this leaky seal into overlying Lower Silurian sandstone reservoirs in Ontario and New York (Ryder et al., 1998).

In the adjacent U.S., the Utica shales have Type II and III organic matter and TOC contents ranging 0-4.3%, averaging 1.8%, with thermal maturities in the oil window: all geochemical characteristics similar to the Collingwood and Blue Mountain shales of Ontario (Ryder et al., 1998), suggesting possible potential (also see comments by Obermajer et al., 1999).

Utica shales in the St. Lawrence Lowlands have TOC contents increasing from 1.0 in the south to 6.0% in the north and west, and vitrinite reflectance ranging from 1.0% in the north (immediately overlying the Canadian Shield) to 4.0% in the south adjacent to the Taconian overthrust Belt (Bertrand, 1991). The GSC Rock-Eval Database includes 42 samples of Utica Formation with the following characteristics: TOC up to 2.70, averaging 1.72; T_{max} up to 464, averaging 407; S_1 up to 3.69, averaging 1.40; S_2 up to 1.27, averaging 0.39; S_3 up to 2.13, averaging 0.71; HI up to 83, averaging 26, OI up to 132, averaging 44 (M. Obermajer, 2006, pers. comm.). Similarly, the GSC Rock-Eval Database includes 26 samples of Lorraine Formation with the following characteristics: TOC up to 5.10, averaging 1.01; T_{max} up to 454, averaging 411; S_1 up to 9.93, averaging 1.57; S_2 up to 41.14, averaging 3.41; S_3 up to 0.88, averaging 0.47; HI up to 818, averaging 141, OI up to 114, averaging 58 (M. Obermajer, 2006, pers. comm.). Thermal maturity of black Utica shales in allocthonous tectonic blocks ($Ro < 1\%$) is less than that in correlative Utica shales in the autocthonous platform (Ro=1.0-1.2%) in the Quebec City region (Comeau et al., 2004). T_{max} may under-estimate the thermal maturity in these strata due to contamination from allocthonous bitumen (V. Lavoie, 2006, pers. comm.). There are no published data detailing the fracture systems of these potential shale gas units, but faulting is common in the area. St-Antoine and Héroux (1993) cite faulting in the underlying Cambro-Ordovician succession as crucial to the sourcing of thermogenic gas in the Pointe-du-Lac field of Quebec. Recent DST tests suggest that these rocks are gas-saturated, with no water production (V. Lavoie, 2006, pers. comm.).

The Utica-Lorraine succession includes a thick sequence with good source rocks (Type II/III organics), which range from thermally immature to overmature, with good potential for a Style A (Antrim-like) play or a Style B (Ohio/New Albany-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, fracture patterns are unknown and relatively few samples have been analysed. These strata form part of the vast Upper Ordovician shale-dominated succession of the Appalachian Basin, which may soon emerge as the next important shale gas province, and could provide a large but as yet unevaluated resource. Within the St. Lawrence Platform-Appalachian region, the Utica-Lorraine succession (and its correlatives) probably present some of the best prospects for shale gas potential.

Pointe-Bleue (Upper Ordovician)

The inception of the Taconian Orogeny, involving collision of the eastern continental margin of North America with a volcanic arc situated above a SE-dipping subduction zone, caused the initial collapse, subsidence and transgression of the Middle Ordovician carbonate platform throughout the length of the Appalachian Orogen (Hiscott et al., 1986). In the Lac Saint-Jean outlier, a 400 km^2 tract of Ordovician strata at the cratonic margin of the foreland which was located near the paleoequator, the carbonate platform succession was covered by a deepening-upward sequence of dark grey mudstone.

There, the coarse grained and thick bedded bioclastic grainstone and calcarenite of the Galets Formation is abruptly overlain by dark brownish grey, laminated, calcareous shales of the Pointe-Bleue Formation, of Maysvillian (early Ashgill) age (Desbiens and Lespérance, 1989;

Lavoie and Asselin, 1998). These strata, the youngest preserved in the outlier and exposed at surface, are up to 30 m thick, contain an abundant fauna of graptolites and trilobites, and represent rapid drowning of the carbonate platform (Desbiens and Lespérance, 1989; Lavoie and Asselin, 1998). These organic-rich, low maturity shales have TOC up to 15.49%, averaging 6.50%; T_{max} up to 454, averaging 440; HI up to 633, averaging 544; OI up to 15, averaging 10, and $\%R_o$ up to 1.22, averaging 0.97 (only 8 samples) (Bertrand, 1991). These shales outcrop in the Saguenay Graben, a structural complex reactivated numerous times during the Phanerozoic, and fracturing is likely pervasive (D. Lavoie, 2006, pers. comm.).

Pointe-Bleue shales, being very organic-rich (Type I organics), exposed at surface, and of low to moderate maturity, may represent a Style A (Antrim-like) shale gas play in an isolated area on the Canadian Shield. However, they are relatively thin, and present over only a modest area. Further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy could lead to better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, fracture patterns are unknown and relatively few samples have been analysed. These strata form part of the vast Upper Ordovician shale-dominated succession of the Appalachian Basin, which may soon emerge as the next important shale gas province, and could provide a large but as yet unevaluated resource.

ONTARIO/HUDSON BAY (Figure 1)

Eastview/Billings (Upper Ordovician)

In the Ottawa Lowlands of eastern Ontario the Eastview Member of the Lindsay Formation is a thin succession of interbedded limestone and black shale, up to about 6 m thick, which is stratigraphically and lithologically equivalent to the Collingwood (Wilson, 1964; Poole et al., 1970; Williams and Telford, 1986; Hamblin, 1998). It consists of thick bedded dark grey petroliferous limestone grading upward to dark grey or brown calcareous mudstone (Wilson, 1964; Williams and Telford, 1986). The overlying Billings Formation, up to 90 m thick and correlative to the Blue Mountain, comprises noncalcareous, dark brown to black shale with a few thin limestone beds, deposited in a shallow marine shelf setting (Wilson, 1964; Poole et al., 1970; Williams and Telford, 1986; Hamblin, 1998). These strata are overlain by 185 m of dark grey and greenish shale, and minor limestone of the Carlsbad Formation, equivalent to the Georgian Bay Formation (Sanford, 1993).

There are few published data detailing the organic-content, thermal maturity or fracture systems of these two potential shale gas units. Legall et al. (1981) found that the strata were generally mature to overmature. However, there is a well-known active fault system in the Ottawa area (including on the grounds of the Geological Survey of Canada building) which cuts these rocks and may be relevant to their gas shale potential. These strata extend into the adjacent Quebec and New York areas where they are collectively known as the Utica Formation.

The Eastview-Billings succession includes a modest thickness of dark grey shales, with coarser beds, which may have some organic-rich intervals, but maturity is unknown. We may suppose that there could be a Style A (Antrim-like) play or a Style B (Ohio/New Albany-like) play present, but so little relevant data is available that no definitive statements can be made, and the potential must be listed as modest and speculative. Further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy of the Eastview-Billings might lead to better understanding of the shale gas potential. These strata form part of the vast Upper Ordovician shale-dominated succession of the Appalachian Basin, which may soon emerge as the next important shale gas province, and could provide a large but as yet unevaluated resource.

Collingwood/Blue Mountain (Upper Ordovician)

The Upper Ordovician Collingwood Member of the Lindsay Formation and the overlying Blue Mountain Formation of southwestern Ontario are organic-rich mudstones, derived from the Taconian Orogen to the southeast, with long histories of importance in petroleum geology (Hamblin, 1999). As detailed below, these two associated units represent an interval of petroliferous mudstone 30-100 m thick, which are present over a large area of southern Ontario. In the Ottawa Lowlands of eastern Ontario, equivalent strata belong to the Eastview Member and Billings Formation, whereas in the St. Lawrence Lowlands of southern Quebec and northern New York, the correlative Utica Formation is very similar.

The Collingwood Member comprises black or dark brownish, finely laminated, pyritiferous, calcareous and carbonaceous shale (or marlstone) with thin interbeds of fine grained, organic-rich fossiliferous limestone, especially near the base (Russell and Telford, 1983; Macauley et al., 1990; Churcher et al., 1991). It typically exudes a strong petroliferous odour when broken. Calcite is the principal mineral constituent (50%), followed by quartz (35%) and predominantly illitic clays (15%) (Macauley et al., 1990). Grain size fines-upward through the 1-18 m thickness (average 2-4 m), and the top is marked by a prominent phosphatic lag, decrease in calcareous content and faunal change (Russell and Telford, 1983; Churcher et al., 1991; Hamblin, 2003). The Collingwood is present in outcrop and subsurface over a large area of southwestern Ontario, about 200 km x 200 km and represents an areally-restricted anoxic facies deposited during the transgression of the foundered Trenton carbonate platform during the initial subsidence of the Taconian foreland basin (Liberty, 1969; Russell and Telford, 1983; Hamblin, 2003). The Collingwood-Blue Mountain transition represents the sediment-starved condensed interval marking the maximum transgression point in the conversion of the shallow marine carbonate platform into a siliciclastic-dominated foreland basin, and forms the most distal part of the larger “Utica Black Shale Magnafacies” (Lehmann et al., 1995; Hamblin, 1998).

The Collingwood shales have been known to be petroliferous since the earliest reports of the Geological Survey of Canada and were the object of early attempts to process oil shales. Distillation of oil for illumination and lubrication was established in 1859 from the outcrops in the vicinity of Craigleith, but was overcome by the production of conventional oil in southern Ontario a few years later. An extensive program to evaluate the oil shale potential of the Collingwood was pursued by Ontario Geological Survey in the 1980's (Churcher et al., 1991, and references therein). Powell et al. (1984), Fowler (1992) and Obermajer et al. (1998) found that the Collingwood has Type II organic matter with TOC up to 11%, is thermally marginally mature and has likely sourced oils which are reservoired in Cambrian and Ordovician traps. Barker (1985) found that the unit contains 1-10% TOC, with the upper 2-10 m being the richest at 4-9% TOC, and generally increasing northward. Obermajer (1997) recorded that the normal marine Type II kerogen is dominated by bituminite and alginite and falls into two geographic groupings: a) TOC = 4-7% with T_{max} = 444- 453° (mature) and HI = 500-600 to the north and west, and b) TOC = 0-2.5%, T_{max} = 444- 453° (mature) and HI = 200-400 to the south and east. The GSC

Rock-Eval Database includes 108 samples of Collingwood Member with the following characteristics: TOC up to 11.26, averaging 3.56; T_{max} up to 453, averaging 443; S_1 up to 5.55, averaging 1.85; S_2 up to 59.33, averaging 17.95; S_3 up to 0.80, averaging 0.27; HI up to 623, averaging 416, OI up to 58, averaging 10 (M. Obermajer, 2006, pers. comm.).

The overlying Blue Mountain Formation is dominantly composed of soft, laminated, non-calcareous grey to dark grey shale, up to 75 m thick, and generally thinning to the north (Johnson et al., 1992). However, the lower 2-15 m of the formation are typically dark brownish and more organic-rich, referred to as the Rouge River Member (Barker, 1985; Obermajer, 1997). This lower unit represents a restricted marine facies, marking the maximum transgression point in the Upper Ordovician stratigraphy (Russell and Telford, 1983; Churcher et al., 1991; Hamblin, 2003), and is overlain by about 100 m of more open marine shale deposits. Barker (1985) reported that the lower part of the Blue Mountain generally has TOC content of 1-5%, and Obermajer et al. (1998) found that these strata are thermally mature. Obermajer (1997) analysed a large number of Blue Mountain samples, most of which proved to have normal marine Type II kerogen, dominated by bituminite and alginite, and have good to excellent hydrocarbon potential. Samples from the Rouge River brown/black mudstones of the lower 15 m yielded TOC = 1-3%, T_{max} = 439- 448°, and HI = 200-350. The GSC Rock-Eval Database includes 418 samples of Blue Mountain Formation with the following characteristics: TOC up to 3.05, averaging 1.63; T_{max} up to 458, averaging 444; S_1 up to 2.00, averaging 0.79; S_2 up to 13.76, averaging 4.72; S_3 up to 1.64, averaging 0.24; HI up to 465, averaging 285, OI up to 151, averaging 15 (M. Obermajer, 2006, pers. comm.).

A number of shallow gas wells were drilled in central southern Ontario in the mid-20th C and recovered significant flows of gas from the overlying Georgian Bay and Queenston units (Caley, 1961). Natural gas has been anecdotally reported from water wells in the greater Toronto area for decades, and a number of water wells in central southern Ontario produce water with gas from these strata (Singer et al., 2003; D. Armstrong, pers. comm., 2006). Two well-developed, orthogonal, vertical fracture sets are present in a number of Collingwood-Blue Mountain outcrops, recently measured by myself as oriented about 80-110° (primary set) and 130-140° (secondary set) (75 measurements from 8 outcrops). Regionally-consistent fracture sets may be important in future exploration efforts.

The Collingwood-Blue Mountain succession includes a modest thickness of black to dark grey shales, with coarser beds, which have good to excellent organic-rich source rock intervals (Type II organics), and which are thermally immature to mature. The hydrocarbon potential of these strata is strong and it is likely that there is a Style A (Antrim-like) play and/or a Style B (Ohio/New Albany-like) play present. Further study of the stratigraphy, sedimentology, geochemistry, maturity, mineralogy and fracture patterns of the Collingwood-Blue Mountain is important to pursue and will lead to better understanding of the shale gas potential. These strata form part of the vast Upper Ordovician shale-dominated succession of the Appalachian Basin, which may soon emerge as the next important shale gas province, and could provide a large but as yet unevaluated resource. Within the St. Lawrence Platform-Appalachian region, the Collingwood-Blue Mountain succession (and its correlatives) probably present some of the best prospects for shale gas potential.

Dawson Point (Upper Ordovician)

The inception of the Taconian Orogeny, involving collision of the eastern continental margin of North America with a volcanic arc, caused the initial collapse, subsidence and transgression of the Middle Ordovician carbonate platform throughout the length of the Appalachian Orogen (Hiscott et al., 1986). By Late Ordovician time, that regional transgression arrived in the central part of the Canadian Shield to initiate deposition in the Hudson Bay area. In the Lake Timiskaming outlier (preserved from erosion in a faulted graben), between the St. Lawrence Platform and Moose River Basin at the cratonic margin of the foreland, the carbonate platform succession was covered by a deepening-upward sequence of dark grey mudstone. The entire preserved Paleozoic section is only about 300 m thick (Thomson, 1965).

There, the medium to coarse grained and thin bedded bioclastic grainstone and calcarenite of the Middle Ordovician Farr Formation is sharply overlain by dark calcareous shales of the Dawson Point Formation, of Edenian (Caradocian) age (equivalent to Blue Mountain)(Sanford, 1993). These dark grey shaly strata, the youngest preserved in the outlier (poorly exposed at surface but present in several drillholes), are up to 30 m thick, are calcareous and silty, contain a fauna of trilobites, and represent rapid drowning of the carbonate platform (Thomson, 1965; Sanford, 1993). Deposition occurred near the paleoequator.

Dawson Point shales, may be organic-rich, are exposed at and near surface, and may be of low maturity. They could represent a Style A (Antrim-like) shale gas play in an isolated area on the Canadian Shield. However, they are relatively thin, and present over only a modest area: the outlier covers only about 500 km^2 and the Paleozoic section is condensed. These factors suggest that there is little serious potential here. Further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy could lead to better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, fracture patterns are unknown and no samples have been analysed. These strata form part of the vast Upper Ordovician shale-dominated succession of the Appalachian Basin, which may soon emerge as the next important shale gas province, and could provide a large but as yet unevaluated resource.

Boas River (Upper Ordovician)

On Southampton Island at the northern edge of Hudson Bay Basin, thin oil shales (up to 3.5 m thick) were described from the Upper Ordovician strata, occurring in a poorly-exposed 15 m section of interbedded limestone and dark grey calcareous mudstone at the base of the Churchill River Group (Macauley, 1986; Dewing, et al., 1987). Additional very thin (10 cm) and discontinuous oil shale beds are present at the top of the uppermost Ordovician Red Head Rapids Formation (Macauley, 1986; McCracken and Nowlan, 1989). Dark brownish black to dark brown, finely laminated very organic-rich (TOC =10-20%) argillaceous limestone dominates in the upper few metres and is of Edenian-Maysvillian age (Collingwood equivalent) (Macauley et al., 1990). Similar Middle to Upper Ordovician black mudstones (oil shales) are present as thin intervals in dominantly limestone sequences on Baffin Island and Akpatok Island, suggesting that the extensive offshore areas of Foxe Basin, Hudson Strait and Hudson Bay may harbour significant thicknesses of potential source rocks at depth (Macauley et al., 1990). Indeed, Sanford and Grant (1990) identified Boas River oil shales up to 10 m thick in both onshore and offshore wells in Hudson Bay Basin. In outcrop, these marine sapropelic (Type II organic matter) shales are immature in all areas (Macauley et al., 1990).

Although these reports are intriguing, to date little is known of these poorly exposed rocks or the state of fracturing, and their thicknesses appear to be too small to have realistic shale gas possibilities. Further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to better understanding of the shale gas potential. However, the lack of numerous drill holes is a major barrier to more specific analysis. Data collected by Macauley et al. (1990) suggested thermal immaturity. The detailed stratigraphy and sedimentology of these strata are not well known, there is a lack of data concerning their geochemistry and fracture patterns are unknown. These strata reside in a frontier basin with no active infrastructure, but one which has experienced minor past exploration. The Hudson and Foxe basins are actually only 1000-2000 km directly north of downtown Toronto, and so are less remote than most frontier basins of Canada.

Marcellus (Middle Devonian)

The Marcellus Formation shale, of southwestern Ontario (late Middle Devonian age), is a poorly-known, black bituminous shale which occurs beneath Quaternary deposits along the north shore of Lake Erie and in the subsurface beneath the central portion of the Lake (Winder, 1961; Musial, 1982; Obermajer et al., 1997). It was first described in New York as the basal part of the northwestern extremities of a great Middle Devonian clastic wedge (Hamilton Group) shed from the Appalachian Orogen, and later traced into Ontario through its consistent signature on subsurface well logs (Musial, 1982). The Marcellus Formation grades laterally into the Dundee limestone platform and is up to 25 m thick, averaging 17 m, in Ontario, thickening to over 100 m to the south in New York (Musial, 1982). It conformably but sharply overlies the Dundee carbonates, and is sharply (disconformably?) overlain by glacial drift or the Hamilton Group grey shales in Ontario, New York and Michigan (Musial, 1982; Johnson et al., 1992; Obermajer et al., 1997). The Marcellus represents the most distal facies of the prograding clastic wedge, deposited as a slow rain of organic and siliceous material into a low energy, somewhat deeper inner shelf environment, during the initial phase of the Acadian Orogeny (Obermajer et al., 1997). The depositional basin was located in a subtropical setting.

The formation, which is confined to the area south of the Algonquin Arch, does not actually outcrop anywhere in Ontario, but appears to be present immediately beneath Quaternary cover, and likely exposed on the bottom of the Lake, because fragments wash up on shore regularly (Musial, 1982). Mapping by Musial (1982) and Johnson et al. (1989) indicates the formation occupies a thick, lens-shaped body 170 km long east-west, and 50 km wide north-south, ranging from 0 to 25 m thick, and mostly lying under Lake Erie in 20 m of water depth. The unit dips southward at about 3.5 m/km. The shales are highly siliceous (40-50% silica), with little carbonate content (Johnson et al., 1989). The darkest shale in the Marcellus is found at the base, where there are thin interbeds of limestone, and at the top where the formation displays a general fining-upward trend on logs (Musial, 1982; Johnson et al., 1992). Johnson et al. (1989) divided the formation into 5 units, as follows: 1) lowest brown/black organic-rich shale about 1 m thick with TOC = 4%, 2) thin grey calcareous silty shale with low TOC, 3) thin grey fossiliferous limestone with low TOC, 4) grey silty calcareous shale with low TOC, 5) upper brown/black organic-rich shale about 1 m thick with TOC = 7%.

Samples analysed by Musial (1982) had an average TOC content of 13.5%, whereas those from Johnson et al. (1989) averaged 4.1% from the lower zone and 7.4% from the upper zone. According to Obermajer et al. (1997), most Marcellus samples have 2-4% TOC. The GSC Rock-Eval Database includes 66 samples of Marcellus Formation with the following characteristics: TOC up to 9.62, averaging 2.78; T_{max} up to 447, averaging 440; S_1 up to 6.40, averaging 1.39; S_2 up to 51.94, averaging 15.19; S_3 up to 1.00, averaging 0.54; HI up to 639, averaging 472, OI up to 255, averaging 37 (M. Obermajer, 2006, pers. comm.). Organic matter, which is dominated by amorphous (algal/bacterial) and exinous (spores/pollen) types, represents a combination of marine and minor terrestrial organics and is generally of Type II (Johnson et al., 1989). Obermajer et al. (1997) found that vitrinite is absent, the alginite macerals are dominated by acritarchs, and that hydrocarbon fluid inclusions are common. Chitonozoa have reflectance ranging from 0.62-0.75%, with high S2 yields, and T_{max} averaging 441°, suggesting excellent potential productivity (Obermajer et al., 1997). The organic matter is marginally mature to mature, right at the onset of oil generation, but likely has lost relatively little hydrocarbon through generation and migration (Johnson et al., 1989; Obermajer et al., 1997). Across the Lake, in New York, Lash et al. (2004) found that Marcellus strata have about 10% TOC.

The Marcellus includes a modest thickness of black, siliceous shale, which has good to excellent organic-rich source rock intervals (Type II/III organics), which are thermally immature to mature. The hydrocarbon potential of these strata is strong and it is likely that there is a Style A (Antrim-like) play and/or a Style C (Barnett-like) play present. Drilling for gas targets in Lake Erie has been common, and so there is an existing database and infrastructure. However, the Marcellus is present over a modest area, primarily offshore in Lake Erie, and it has likely already generated and migrated some hydrocarbon. Further study of the stratigraphy, sedimentology, geochemistry, maturity, mineralogy and fracture patterns of the Marcellus, if feasible, would lead to better understanding of the shale gas potential. The siliceous nature of these rocks may make them brittle and subject to fracturing. These strata form part of the vast Middle-Upper Devonian shale-dominated succession of the Appalachian and Michigan Basins, which have been a very successful shale gas province in the US for over a century. Within the St. Lawrence Platform-Appalachian region, the Marcellus and Kettle Point probably present the best prospects for immediate shale gas development.

Kettle Point (Upper Devonian)

The Upper Devonian Kettle Point Formation of southwestern Ontario is an organic-rich black shale which outcrops in only three locations and, excepting the thin and geographically-limited Port Lambton beds, forms the uppermost mappable unit in the Paleozoic stratigraphy in the province. It is stratigraphically and lithologically equivalent to the highly productive Antrim shale of adjacent Michigan, Ohio shale of Ohio and New Albany shale of New York. Caley (1943) refers to the common seepage of natural gas from the thick Quaternary sand and gravel deposits that overlie the Kettle Point Formation. The Kettle Point Formation is famous for the unusual large, spherical calcite concretions (“kettles”) present in the type section. As detailed below, it represents a petroliferous shale up to 100 metres thick, present over a modest portion of southwestern Ontario, within the “Chatham Sag”, between Lakes Huron and Erie (Caley, 1945).

The Kettle Point Formation was first noted by Logan (1863), but was formally defined by

Sanford and Brady (1955) as the black, fissile, petroliferous shales present between the Hamilton Group grey shales below and the Port Lambton Group shale and sandstone above. It apparently spans Frasnian to Late Fammenian ages (Uyeno et al., 1982). It comprises dark brown to black, laminated, bituminous, nonclacareous shale with minor interbeds of green shale, large calcite concretions, pyrite nodules and a profusion of small amber-coloured spore cases of *Tasmanites.* Larger black sac-like spore cases of *Protosalvinia huronensis* (now known as *Foerstia*, Russell, 1985) (Caley, 1943; Sanford and Brady, 1955; Winder, 1961) are confined to certain bedding planes (Coniglio and Cameron, 1990; Armstrong, 1986; Obermajer et al., 1997). Mudstones are composed primarily of illite (22%), chlorite (4%), diagenetic pyrite, mica and bituminous organic matter (Armstrong, 1986). Russell (1985) identified three distinct lithologies, as follows, 1) black, laminated, micaceous, silty shale with *Tasmanites* and concretions, 2) greenish grey, bioturbated mudstone with sharp bases, 3) black, laminated shale with thin white quartz silt beds. Recent outcrop and core description by myself suggest that grey to greenish grey, thin (< 1 cm), sharp-based quartz siltstone beds are ubiquitous throughout the formation, as also mentioned by Armstrong (1986). Burrowing is apparently confined to the green mudstone and grey siltstone beds.

The lower contact of the Kettle Point with the Hamilton Group is sharp, and possibly disconformable. It is overlain over most of its outcrop area by Quaternary drift. Although the maximum known thickness is 105 m, the preserved thickness is generally much less, averaging about 28 m (Caley, 1943; Winder, 1961). Rare fossils include conodonts, plant fragments, lingulid brachiopods, ostracods, sponge spicules, fish fragments and isolated worm burrows (Caley, 1945; MacDonald, 1960; Armstrong, 1986), suggesting deposition in dysoxic marine conditions (Coniglio and Cameron, 1990). The lower 10 m of the formation (well exposed at the famous type section at Kettle Point) displays large spherical concretions of radiating fibrous ferroan calcite up to 1 m in diametre, which grew after deposition (but prior to compaction) at shallow burial depths during early bacterial sulphate reduction, as indicated by the draping curvature of mudstone lamination above and below the concretions (Caley, 1945; MacDonald, 1960; Coniglio and Cameron, 1990).

Russell (1985), citing the well-established relation between organic content and natural radioactivity described by Schmoker (1981), used subsurface gamma-ray curves to identify broad trends in TOC and to correlate stratigraphic sub-units within the Kettle Point: gamma-ray readings for the Kettle point commonly range 500-1000, whereas those for the less organic-rich, under- and over-lying shales average 200 A.P.I. units. Through use of gamma-ray logs, Russell (1985) was able to make direct correlations of the six stratigraphic sub-units identified by Ells (1979) in the Antrim Shale of Michigan across 60 km of distance to Ontario. He, likewise, felt that correlations of individual stratigraphic sub-units between the Ohio Shale on the south side of Lake Erie and the Kettle Point were possible. This analysis allowed Russell (1985) to speculate that the Algonquin Arch had minor submarine relief of 20 m or less at the time of deposition, which was enough to cause thinning/pinch-out of individual sub-units and reduction of TOC.

Kettle Point organic matter (Type II) is typified by abundant bituminite and alginite, minor inertinite and vitrinite in a sub-microfacies usually associated with marine basinal and outer shelf environments (Obermajer et al., 1997). TOC values range from 3.6 to 15.0% in the black shales (<2% in greenish shales), vitrinite reflectance ranges 0.42 - 0.50 %Ro, T_{max} values range 422 - 437°: all data indicates that the Kettle Point is an organic-rich, algal-dominated, marine clastic shale, deposited in anoxic low-energy bottom waters, which is thermally immature in its outcrop and subcrop area of Ontario (Obermajer et al., 1997). The GSC Rock-Eval Database includes 347 samples of Kettle Point Formation with the following characteristics: TOC up to 10.44, averaging 6.32; T_{max} up to 438, averaging 430; S_1 up to 3.45, averaging 1.67; S_2 up to 51.24, averaging 29.39; S_3 up to 4.56, averaging 1.22; HI up to 612, averaging 462, OI up to 107, averaging 21 (M. Obermajer, 2006, pers. comm.). Armstrong (1986) states that the uppermost 3-8 m of the formation is the most organic-rich.

Minor local folds are superimposed on the overall synclinal structure of the Chatham Sag (Caley, 1945; MacDonald, 1960). Structure-contour mapping at the base of the Kettle Point by MacDonald (1960) suggested that local depressions at the base coincide with areas of salt-solution in the underlying Salina Formation, and that local uplifts at the base correspond to oil-producing structural domes in the underlying Dundee Formation. These relations need to be further investigated with modern data sets. Two well-developed, orthogonal, vertical fracture sets are present at the type section and other smaller outcrops, recently measured by myself as oriented about 40-60° (primary set) and 130-140° (secondary set) (26 measurements from 3 outcrops). Regionally-consistent fracture sets may be important in future exploration efforts. In nearby New York, Lash et al. (2004) described dominant ENE and NW fracture patterns in correlative impermeable Devonian black shales which were closely-spaced, planar and continuous, interpreted as having formed under conditions of high differential stress such as in natural hydraulic fracturing. Anecdotal and documented reports suggest the presence of significant gas in the water recovered in dozens of water wells in Kettle Point strata (Singer et al., 2003) (which may be a result of glacial meltwater intrusion and biogenesis; S. Grasby, 2006, pers. comm.).

The Kettle Point includes a modest thickness of black shale, with thin coarser beds, which has good to excellent organic-rich source rock intervals (Type II/III organics), which are thermally immature. The hydrocarbon potential of these strata is strong and it is likely that there is a Style A (Antrim-like) play present, because the Antrim produces in the adjacent area of Michigan. However, the Kettle Point is present over only a modest area, partly in offshore areas of Lakes Huron and Erie. Further study of the stratigraphy, sedimentology, geochemistry, maturity, mineralogy and fracture patterns of the Kettle Point will lead to better understanding of the shale gas potential. These strata form part of the vast Middle-Upper Devonian shale-dominated succession of the Appalachian and Michigan Basins, which have been a very successful shale gas province in the US for over a century. Within the St. Lawrence Platform-Appalachian region, the Kettle Point and Marcellus probably present the best prospects for immediate shale gas development.

Long Rapids (Upper Devonian)

The Upper Devonian Long Rapids Formation of northern Ontario is a poorly-known, black, bituminous shale present at the top of the section in the Moose River Basin, south of Hudson Bay. This is a large, flat-lying intracratonic basin, caused by intracratonic downwarping due to horizontal transmission of plate-margin stresses from the Appalachian collision event, dominated by Devonian strata deposited in a subtropical slope setting (Telford, 1988; Levman and von Bitter, 2002). The Long Rapids Formation represents a period of transgression, overlies a Middle Devonian carbonate/evaporite succession, and is unconformably overlain by Mesozoic sandstones and shales (Telford, 1988; Johnson et al.,1992). The formation contains a well-documented anoxic black shale interval recording the Frasnian-Fammenian extinction event, linked to a major transgressive phase (Levman and von Bitter, 2002). The dark, organic-rich mudstones and minor carbonates of the Long Rapids Formation were deposited in a shallow marine to slope, anoxic setting, at the furthest distal extent of the Upper Devonian Catskill Sea which connected to Michigan and New York (Sanford and Norris, 1975; Bezys and Risk, 1990). They cover an area of about 5400 km^2, are up to 85 m thick, averaging 30 m, and are overlain by a modest thickness of Jurassic and Cretaceous deposits (Bezys and Risk, 1990).

The Long Rapids Formation is divided into three members: lower interbedded greenish mudstone, black shale and limestone up to 36 m thick, middle black fissile shale up to 28 m thick, and upper green and grey shale 15-20 m thick (Telford, 1988; Bezys and Risk, 1990). Fossils suggest that the unit spans most of the Upper Devonian (Telford, 1988). Black laminated shale is concentrated in the lower and middle members where a typical depositional couplet includes beds of organic-rich mudstone which alternate with grey-green mudstones in repetitive, thin, cyclic sedimentary rhythms (Bezys and Risk, 1990). Beds of black shale are up to 1.5 m thick (Bezys and Risk, 1990). A large number of samples (203) were analysed and TOC ranges up to 4.6% and averages 3.2%, primarily derived from terrestrial organic matter (Bezys and Risk, 1990). No maturity data is available. These strata have many characteristics in common with the Kettle Point shales of southwestern Ontario, including the presence of several horizons with large carbonate-rich concretions (Levman and von Bitter, 2002).

The Long Rapids includes a modest thickness of black shale, with thin coarser beds, which has good organic-rich source rock intervals (Type III organics), which may be thermally immature. The hydrocarbon potential of these strata may be significant and present at shallow depths, and may reside in a Style A (Antrim-like) play. However, the Long Rapids is present over only a modest area, located in a frontier area with little infrastructure. Conversely, Moose River Basin lies only 1000 km from downtown Toronto. Further study of the stratigraphy, sedimentology, geochemistry, maturity, mineralogy and fracture patterns of the Long Rapids could lead to better understanding of the shale gas potential. These strata form part of the vast Middle-Upper Devonian shale-dominated succession of the Appalachian and Michigan Basins, which have been a very successful shale gas province in the US for over a century.

WESTERN CANADA SEDIMENTARY BASIN (WCSB) (Figures 2 and 3)

Duvernay/Ireton (Middle-Upper Devonian)

The Duvernay Formation is an Upper Devonian marine, organic-rich unit which is present throughout the central Alberta shallow marine platform, enclosing Leduc reef growth. It overlies the platform carbonates of the Cooking Lake Formation, is approximately coeval with Leduc reefs, and is overlain by the Ireton Formation interbedded mudstones and calcarenites: this suite of related facies represents the Woodbend Group in the central Alberta subsurface (Stoakes, 1980; Glass, 1990). The Duvernay is a thick succession of interbedded dark brown, bituminous mudstone, black shale, greenish calcareous shale and argillaceous limestone (Glass, 1990). The strata are laminated and petroliferous, typically not bioturbated, contain only a sparse pelagic fauna, and include common disseminated pyrite (Stoakes, 1980). These condensed-section deposits represent the initial transgressive, deeper water (65 m), oxygen-starved, euxinic conditions at the toes of depositional clinoforms and adjacent basinal areas in a shallow intracratonic basin (Stoakes, 1980). The Duvernay is divided into three members, from base to top: 1) lower black argillaceous limestone up to 20 m thick, 2) middle black shale with reef-derived skeletal debris, 3) upper brown to black shale with argillaceous limestone up to 60 m thick (Switzer et al., 1994). Thickness ranges 30-120 m (thickest in the "East Shale Basin"), with Type II organic matter and TOC up to 14%, and the Duvernay has been one of the most prolific Devonian oil and gas source rocks in WCSB (Allan and Creaney, 1991). A large amount of the produced oil and gas in WCSB can be correlated to this source rock, suggesting it has already undergone efficient primary generation and migration, which may downgrade its potential as a shale gas target in some areas (Fowler, 2004). Thermal maturity ranges from immature in the eastern East Shale Basin (biogenic gas?) to overmature in the West Shale Basin (thermogenic gas?), and fracturing is present (Faraj, 2002; Fowler, 2004).

Similarly, the overlying Ireton Formation is a closely-related Upper Devonian marine, mudstone unit present throughout the central Alberta shallow marine platform, enclosing and covering (terminating) Leduc reef growth. Broadly sigmoidal clinoform marker surfaces within the succession, which overlap each other and are imbricated westward, reflect the periodic lateral progradation of the original slope and platform depositional topography of the shale basin fill during successive episodes of sea level rise (Stoakes, 1980). The Ireton is divided into three members, from base to top: 1) lower dark coloured, unbioturbated, interbedded calcareous shale and limestone deposited at the toes of the depositional slope, 2) middle green calcareous shale with minor calcarenite beds deposited on the slope, and 3) upper, bioturbated, interbedded calcareous shale and fossiliferous limestone beds deposited in a platformal setting (Stoakes, 1980; Glass, 1990). Leduc reef growth occurred at the same time as adjacent basin-filling by the Duvernay and Ireton mudstones (Stoakes, 1980). The Ireton averages 200 m in thickness, thickening to the west as the conformably underlying Duvernay thins (Stoakes, 1980). This thick mudstone succession includes basal, transgressive deposits, conformably overlain by progradational mudstone with more porous limestone interbeds in a shallowing-upward trend, and may offer shale gas potential in the subsurface of central Alberta.

A large amount of data regarding the organic richness and thermal maturity of Duvernay-Ireton strata have been collected. The GSC Rock-Eval Database includes 356 samples of Duvernay Formation with the following characteristics: TOC up to 13.94, averaging 3.53; T_{max} up to 567, averaging 439; S_1 up to 9.09, averaging 2.05; S_2 up to 71.38, averaging 12.61; S_3 up to 4.90, averaging 0.78; HI up to 692, averaging 273, OI up to 396, averaging 44 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 354 samples of Ireton Formation with the following characteristics: TOC up to 12.09, averaging 0.64; T_{max} up to 516, averaging 431; S_1 up to 16.66, averaging 0.68; S_2 up to 23.44, averaging 0.95; S_3 up to 31.94, averaging 0.48; HI up to 534, averaging 146, OI up to 369, averaging 90 (M. Obermajer, 2006, pers. comm.).

The Middle-Upper Devonian Duvernay-Ireton succession includes a widespread sequence of moderate thickness, present throughout the Plains of Alberta, with good to excellent source rock intervals (Type II organics), with minor coarser grained siltstone and limestone beds, which range from thermally immature to overmature (increasing to the west). There is likely good potential for a Style B (Ohio/New Albany-like) play, and possibly even a Style A (Antrim-like) biogenic play in the shallow East Shale Basin. However, despite extensive knowledge of the source rock characteristics, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy may lead to better understanding of the specific shale gas potential. The detailed stratigraphy and sedimentology are fairly well known and fracture patterns are known to exist. This unit resides in the middle of a mature exploration/production basin, with extensive infrastructure and local markets. The Duvernay-Ireton succession presents strong potential for shale gas, but careful evaluation is necessary because these strata have already acted as efficient oil source rocks in this basin, and so may or may not retain sufficient gas to provide a viable shale gas play.

Muskwa/Fort Simpson/Besa River/Perdrix (Middle Devonian - Lower Carboniferous)

The Muskwa Formation is an Upper Devonian thin, marine, organic-rich unit which is widely-distributed throughout northwestern Alberta and northeast B.C. It overlies the Slave Point/Waterways carbonates and forms the lowermost, transgressive, condensed section of the thick Devonian shale package at the western margin of the North American craton. It is a black, bituminous shale with abundant pyrite and reaches a maximum thickness of 75 m (typically 35-40 m) (Glass, 1990). It has Type II kerogen with a maximum TOC of 6% (av. 3%) in northeastern B.C. (British Columbia Ministry of Energy and Mines, 2005; Ibrahimbas and Riediger, 2005). A consistently high Gamma-Ray signature indicates generally high organic content and correspondingly high adsorbed gas content. Good porosities in the 2-5% range also suggest good free gas potential (British Columbia Ministry of Energy and Mines, 2005).

The Fort Simpson Formation is a very thick, marine unit which is widely-distributed throughout northwestern Alberta and northeastern B.C., north of the Peace River Arch. It is a grey calcareous shale unit, with thin siltstone to sandstone interbeds which passes westward into the Besa River (Glass, 1990). It reaches a maximum thickness of 800 m but has a very low organic content averaging only 0.4% (British Columbia Ministry of Energy and Mines, 2005). Therefore, capacity for adsorbed gas is low. Fracturing is not pervasive, but thin siltstone interbeds are common, supplying potential flow pathways (British Columbia Ministry of Energy and Mines, 2005). The large thickness, lateral extent and high porosity suggest that there may be potential for free gas (British Columbia Ministry of Energy and Mines, 2005).

The Besa River Formation is a very thick, marine shale unit which is widely-distributed throughout northeastern B.C. It reaches a maximum thickness of 1600 m and individual carbonaceous units up to 30 m thick occur throughout the formation, especially in the lower part (British Columbia Ministry of Energy and Mines, 2005). Lithological variations within the unit lead to variations in TOC. Dark grey to black, calcareous to siliceous shale contains bedded chert, sponge spicules and radiolarians which may form brittle fracture-prone beds (Glass, 1990). In addition, thin siltstone and sandstone beds are common in certain zones. Eastward, it passes into the Fort Simpson, Imperial, Exshaw and Banff formations (Glass, 1990). It has Type II kerogen with a maximum TOC of 9% (av. 4.3%) (British Columbia Ministry of Energy and Mines, 2005; Ibrahimbas and Riediger, 2005). High TOC in some intervals and significant porosities of 2-7% suggest significant potential for both adsorbed and free gas (British Columbia

Ministry of Energy and Mines, 2005).

A fairly large amount of data regarding the organic richness and thermal maturity of the Muskwa/Fort Simpson/Besa River succession have been collected. The GSC Rock-Eval Database includes 253 samples of Muskwa Formation (primarily in Alberta) with the following characteristics: TOC up to 13.61, averaging 1.93; T_{max} up to 583, averaging 461; S_1 up to 8.78, averaging 0.77; S_2 up to 66.11, averaging 3.64; S_3 up to 1.99, averaging 0.31; HI up to 721, averaging 158, OI up to 191, averaging 25 (M. Obermajer, 2006, pers. comm.). Similarly, the GSC Rock-Eval Database includes 68 samples of Fort Simpson Formation (primarily in Alberta, with some from northeast B.C.) with the following characteristics: TOC up to 6.98, averaging 0.88; T_{max} up to 588, averaging 410; S_1 up to 12.44, averaging 0.59; S_2 up to 18.46, averaging 1.56; S_3 up to 8.47, averaging 0.66; HI up to 528, averaging 138, OI up to 340, averaging 95 (M. Obermajer, 2006, pers. comm.). And finally, the GSC Rock-Eval Database includes 108 samples of Besa River Formation (primarily in NE B.C., with some from Yukon) with the following characteristics: TOC up to 6.39, averaging 1.22; T_{max} up to 544, averaging 405; S_1 up to 4.19, averaging 0.64; S_2 up to 14.04, averaging 1.04; S_3 up to 5.14, averaging 0.47; HI up to 830, averaging 126, OI up to 387, averaging 45 (M. Obermajer, 2006, pers. comm.).

The Muskwa/Fort Simpson/Besa River succession includes a very thick and widespread sequence, present throughout northwestern Alberta and northeastern B.C., with fair to excellent source rock intervals (Type II/III organics) and abundant coarser grained beds, which range from thermally immature to overmature. Good porosities, high siliceous content and fracturing are present in the Besa River. There is likely very good potential for a Style C (Barnett-like) play or a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy, sedimentology and fracture patterns are not well known. The Muskwa/Fort Simpson/Besa River succession provides good potential for shale gas, but much more detailed geological research is required to properly evaluate this potential. This unit resides in a mature exploration/production basin, with extensive infrastructure and local markets.

Exshaw/Bakken/Banff (Upper Devonian/Lower Carboniferous)

The uppermost Devonian and Lower Carboniferous of southern and central Western Canada is a thick succession of shelf, ramp and basinal strata deposited on the downwarped western convergent margin of the ancestral North American craton (Richards, 1989). These deposits are preserved in an arcuate belt from northeast B.C. to southern Manitoba, thinning eastward onto the platform, and thickening markedly westward into the deep, linear Prophet Trough (Richards, 1989). At the base of this second-order transgressive-regressive succession are the carbonaceous shales of the Exshaw and Bakken formations, disconformably overlying platform/ramp carbonates of the Palliser and Wabamun formations, and overlain by the interbedded shale, siltstone and limestone of the Banff Formation,(Richards, 1989). The Bakken and Exshaw formations comprise fine grained siliciclastics deposited in deeper euxinic-basin to shallow-neritic environments at the culmination of rapid regional transgression over the subsiding Upper Devonian carbonate platform (Richards et al., 1994; Caplan and Bustin, 1998). Siliciclastic input was dominantly derived from the east and northeast (Richards, 1989).

The Exshaw Formation is a thin, marine, organic-rich unit which is widely-distributed throughout western Alberta and northeast B.C. It typically comprises a lower member of radioactive black shale up to 10 m thick (which includes the Devonian-Carboniferous boundary) and an upper member of brownish bioturbated calcareous siltstone (Glass, 1990; Caplan and Bustin, 1998). The upper member comprises grey to greenish silty mudstones with minor thin siltstone beds (Caplan and Bustin, 1998). It reaches a maximum thickness of 86 m (although the organic-rich interval is generally 10 m or less) and has Type II kerogen with a maximum TOC of 6% in northeastern B.C., and a maximum TOC of 14% in Alberta, and consequent potential for high sorbed gas capacity (Fowler, 2004; British Columbia Ministry of Energy and Mines, 2005; Ibrahimbas and Riediger, 2005). In addition, porosities of 2-6%, localized fracturing and silty beds suggest significant additional potential for free gas (British Columbia Ministry of Energy and Mines, 2005). The upper member of the Exshaw is also overlain by a black shale member of the lower Banff Formation up to 8 m thick with TOC up to 14% (Smith and Bustin, 2000). The Banff Formation generally consists of a coarsening-upward succession of grey mudstone with interbedded siltstone, and minor sandstone up to about 400 m thick (Richards, 1989). The Exshaw Formation has been a prolific oil source rock in the WCSB, sourcing hydrocarbons in the tar sands, heavy oil trend and conventional pools (Fowler, 2004). Thermal maturities range from immature to overmature (Fowler, 2004). The modest thickness and the fact that the Exshaw has already generated and migrated significant hydrocarbons are negative factors for shale gas potential (Faraj, 2002).

The near-coeval Bakken Formation is a thin, marine, organic-rich unit which is widely distributed throughout southern Saskatchewan and Manitoba. It reaches a maximum thickness of 20 m and is divided into a lower member of black noncalcareous radioactive shale up to 13 m thick (TOC up to 20%), a middle member of interbedded grey very fine sandstone, limestone and mudstone up to 6 m thick, and an upper member of black noncalcareous shale up to 5 m thick (TOC up to 35%) (Fox and Martiniuk, 1994; Smith and Bustin, 2000; Toews, 2005). These members correspond to the lower and upper members of the Exshaw, and the lower member of the Banff in Alberta (Smith and Bustin, 2000). Transgression was followed by shallowing, recorded by siltstone and calcarenite deposits of the upper Bakken, upper Exshaw and regressive Banff Formation (Richards, 1989). The Bakken Formation may have sourced oils which are reservoired in Lower Carboniferous rocks of the Williston Basin (Fowler, 2004), but its thermal maturity is below the oil generation window over much of its distribution area (Faraj, 2002). Clearly, further study of this thin interval is required to determine the gas shale potential.

A very large amount of data regarding the organic richness and thermal maturity of the Exshaw/Bakken/Banff succession have been collected. The GSC Rock-Eval Database includes 325 samples of Exshaw Formation (primarily in Alberta and B.C.) with the following characteristics: TOC up to 18.06, averaging 2.52; T_{max} up to 578, averaging 408; S_1 up to 10.08, averaging 1.45; S_2 up to 96.42, averaging 8.45; S_3 up to 4.44, averaging 0.43; HI up to 653, averaging 221, OI up to 337, averaging 50 (M. Obermajer, 2006, pers. comm.). Similarly, the GSC Rock-Eval Database includes 200 samples of Bakken Formation (primarily in Saskatchewan and Alberta) with the following characteristics: TOC up to 24.26, averaging 4.71; T_{max} up to 457, averaging 425; S_1 up to 24.24, averaging 1.67; S_2 up to 113.68, averaging 17.81; S_3 up to 7.34, averaging 1.67; HI up to 1123, averaging 271, OI up to 236, averaging 55 (M. Obermajer, 2006, pers. comm.). And finally, the GSC Rock-Eval Database includes 1441 samples of Banff Formation (primarily in Alberta, with some from NE B.C.) with the following characteristics: TOC up to 11.93, averaging 0.86; T_{max} up to 563, averaging 432; S_1 up to 11.26, averaging 0.38; S_2 up to 40.45, averaging 1.39; S_3 up to 13.73, averaging 0.40; HI up to 693, averaging 150, OI up to 400, averaging 57 (M. Obermajer, 2006, pers. comm.).

The Exshaw/Bakken/Banff succession includes a very widespread sequence of moderate thickness, present throughout the Plains of WCSB and the southern Foothills, with good to excellent source rock intervals (Type II/III organics), with abundant coarser grained beds in the Banff, which range from thermally immature to overmature (increasing to the west). There is likely very good potential for a Style A (Antrim-like) play or a Style B (Ohio/New Albany-like) play, although thickness of organic-rich intervals may be a concern. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are fairly well known, although fracture patterns are not. As is true of all of WCSB, this unit resides in a mature exploration/production basin, with extensive infrastructure and local markets. The Exshaw/Bakken/Banff succession presents good potential for shale gas, but careful evaluation is necessary in each area of the Basin because these strata have already acted as efficient oil source rocks in this basin, and so may or may not retain sufficient gas to provide a viable shale gas play.

Montney/Grayling/Phroso/Vega (Lower - Middle Triassic)

The Triassic succession of western Alberta and northeastern B.C. was deposited on a broad marine shelf and slope along the western margin of the North American craton as the plate drifted northward into temperate paleolatitudes (Podruski et al., 1988). Triassic rocks represent the final deposits on the passive craton edge before Jurassic conversion to an active convergent margin. Their distribution is limited by pre-Jurassic erosional removal. Three major transgressive-regressive, coarsening-upward sequences, which were easterly-derived and westerly-thickening, are present: Montney (Lower Triassic), Doig-Halfway-Charlie Lake (Middle Triassic), and Baldonnel-Pardonet (Upper Triassic) (Podruski et al., 1988; Gibson and Barclay, 1989).

The Lower to Middle Triassic Montney Formation of the subsurface of northwestern Alberta and northeastern B.C. comprises dark grey shale and siltstone up to 280 m thick, and thinning to an erosional edge to the east (Glass, 1990). It rests unconformably on the underlying Paleozoic rocks, and the lowest deposits represent a basin-scale maximum flooding surface associated with an easterly to southeasterly marine transgression (Gibson, 1975; Gibson and Barclay, 1989; Dixon, in press). The Montney is overlain unconformably by the basal phosphatic zone of the Doig Formation. The lower Montney transgressive unit consists of thinly interbedded dark grey shale and dolomitic siltstone, whereas the upper Montney regressive unit is brownish siltstone with thin interbeds of fine grained sandstone and coquina (Gibson and Barclay, 1989). It is approximately equivalent to the Grayling-lower Toad formations in outcrops to the west and the Phroso and Vega members of the Sulphur Mountain Formation in outcrops to the south (Glass, 1990). The Grayling Formation of the northwestern Foothills is dark grey interbedded dolomitic siltstone, shale, limestone and minor very fine grained sandstone up to 457 m thick (Gibson, 1975; Glass, 1990). The Phroso Member is dark grey, carbonaceous, pyritiferous siltstone and shale with minor sandstone at the base, up to 242 m thick, and the conformably overlying Vega Member is grey to brown dolomitic siltstone, shale, limestone and minor sandstone, up to 363 m thick (Gibson, 1974; Glass, 1990). These two units are present throughout the southern Front Ranges and Foothills (Gibson, 1974).

Montney rocks in the subsurface are generally mature with respect to oil in Alberta and overmature in B.C., and may have generated significant hydrocarbons earlier in their history, although no direct correlations to known oils has been made (Riediger et al., 1990). Utting et al. (2005) suggested that lower Triassic samples from subsurface oil fields in northwestern Alberta indicate relatively low thermal maturity. Because coeval rocks are past the peak oil generation point in NE B.C. there may be shale gas potential (Dixon, in press). Both Fowler (2004) and Ibrahimbas and Riediger (2005) suggested that the Montney, with TOC up to 4%, Type II/III organic matter and thicknesses up to 250 m, presents a good source rock and a good shale gas possibility. The Phroso/Vega siltstones are also very thick and have good source rock potential, with TOC up to 7% and HI values up to 450 (Riediger et al., 1989), although they lie in more difficult terrain. The presence of thin siltstone/sandstone beds may provide conduits for gas flow. The presence and abundance of fracturing is currently unknown but may be significant in the Foothills. Obviously, further study, in both surface and subsurface, is required to address the potential of this interval.

A fairly large amount of data regarding the organic richness and thermal maturity of the Montney/Grayling/Phroso/Vega succession have been collected. The GSC Rock-Eval Database includes 490 samples of Montney Formation (primarily in Alberta and some in B.C.) with the following characteristics: TOC up to 7.55, averaging 0.97; T_{max} up to 486, averaging 439; S_1 up to 8.30, averaging 0.69; S_2 up to 45.57, averaging 1.92; S_3 up to 5.56, averaging 0.37; HI up to 642, averaging 195, OI up to 343, averaging 43 (M. Obermajer, 2006, pers. comm.). Similarly, the GSC Rock-Eval Database includes 63 samples of Grayling Formation (primarily in B.C. with some in Alberta) with the following characteristics: TOC up to 3.27, averaging 0.99; T_{max} up to 456, averaging 387; S_1 up to 1.08, averaging 0.43; S_2 up to 7.42, averaging 0.75; S_3 up to 1.37, averaging 0.25; HI up to 460, averaging 76, OI up to 331, averaging 34 (M. Obermajer, 2006, pers. comm.).

The Lower - Middle Triassic Montney/Grayling/Phroso/Vega succession includes a thick and widespread sequence, present throughout northwestern Alberta and northeastern B.C. and southward in the Foothills, with fair to good source rock (Type II/III organics) intervals and abundant coarser grained beds, which range from thermally immature to overmature (increasing westward). There is likely fair to good potential for a Style A (Antrim-like) play or a Style D (Lewis-like) play. Development of this play might proceed if other shale gas plays in northwestern Alberta, northeastern B.C. and N.W.T. proved successful. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy, sedimentology and fracture patterns are not well known. This unit resides on the edge of a mature exploration/production basin, with numerous well penetrations, nearby extensive infrastructure and local markets. These strata may have already acted as oil source rocks in this basin, and so may or may not retain sufficient gas to provide a viable shale gas play.

Doig/Phosphatic/Toad/Whistler (Middle Triassic)

The Doig succession represents the second of the Triassic major transgressive-regressive, coarsening-upward sequences deposited on the western trailing margin of the North American craton, which were easterly-derived and westerly-thickening (Podruski et al., 1988). Following the development of an erosional unconformity after Montney/Grayling/Phroso/Vega deposition, a second marine transgression in Middle Triassic time led to deposition of the Doig/Toad interval (Gibson and Barclay, 1989).

The basal transgressive strata of the Doig Formation are represented by dark phosphatic shale and silty carbonate (the "phosphatic zone") with a conspicuous, thin, radioactive phosphatic pellet bed up to 10 m thick at the base (Gibson and Barclay, 1989; Riediger et al., 1990). The Doig is up to 364 m thick, thinning to the east to an erosional edge (Glass, 1990) and is identified on subsurface logs by its high gamma-ray response (Riediger et al., 1990). It is approximately equivalent to the Toad Formation, exposed in outcrops of the Foothills of NE B.C. which comprises thinly interbedded, fossiliferous dark grey calcareous siltstone, limestone and shale up to 800 m thick, with phosphate nodules at the base (Gibson, 1975; Glass, 1990). In the outcrops of the southwestern Foothills and Front Ranges, the equivalent Whistler Member of the Sulphur Mountain Formation, consists of dark grey to black carbonaceous, pyritiferous, dolomitic siltstone, up to 85 m thick, with thin grey silty laminations and phosphatic conglomerate at the base (Gibson, 1974; Glass, 1990).

The distinctive, and laterally-extensive organic-rich phosphatic zone shale of the Doig/Toad/Whistler interval is a proven excellent source rock (Riediger et al., 1989; Ibrahimbas and Riediger, 2005) which is known to correlate with produced oils from Doig and Halfway formation reservoirs (Riediger et al., 1990). It has Type II organic matter, TOC up to 10% (generally > 4%), HI values in excess of 300 and moderate to high maturity (Riediger et al., 1989; Ibrahimbas and Riediger, 2005). Optical analyses show yellow to orange fluorescing algal and amorphous material (Riediger et al., 1990). The Whistler Member has Type II organic matter with TOC up to 15% (generally >2%), and is thermally mature, suggesting excellent source rock characteristics (Riediger et al., 1989; Riediger et al., 1990). The GSC Rock-Eval Database includes 305 samples of Doig Formation (primarily in Alberta and some in B.C.) with the following characteristics: TOC up to 11.63, averaging 2.79; T_{max} up to 579, averaging 448; S_1 up to 4.15, averaging 1.67; S_2 up to 31.65, averaging 5.41; S_3 up to 4.66, averaging 0.64; HI up to 490, averaging 31, OI up to 306, averaging 31 (M. Obermajer, 2006, pers. comm.). Similarly, the GSC Rock-Eval Database includes 85 samples of Toad Formation (all in B.C.) with the following characteristics: TOC up to 2.57, averaging 0.61; T_{max} up to 492, averaging 419; S_1 up to 6.38, averaging 0.81; S_2 up to 6.03, averaging 0.81; S_3 up to 1.77, averaging 0.37; HI up to 709, averaging 159, OI up to 228, averaging 82 (M. Obermajer, 2006, pers. comm.).

The Middle Triassic Doig/Phosphatic/Toad/Whistler succession includes a sequence of moderate thickness, present throughout the Plains and Foothills of northeastern B.C. and southward in the Alberta Foothills, with thin intervals of good to excellent source rock (Type II organics) and abundant coarser grained beds, which range from thermally mature to overmature (increasing westward). There is likely good potential for a Style B (Ohio/New Albany-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy, sedimentology and fracture patterns are not well known. The presence and abundance of fracturing is currently unknown but may be common in these more brittle lithologies with Foothills deformation. As with all of WCSB, this unit resides in a mature exploration/production basin, with extensive infrastructure and local markets. Careful evaluation is necessary because these strata are known to have already acted as oil source rocks in this basin, and so may or may not retain sufficient gas capacity to provide a viable shale gas play.

Nordegg/Gordondale/Fernie/Rierdon (Lower - Upper Jurassic)

The Jurassic succession of western Alberta, Saskatchewan and northeastern B.C. was deposited in marine shelf conditions along the western margin of the North American craton as the plate drifted further northward into temperate paleolatitudes and Columbian Foreland Basin tectonism began to affect the region (Podruski et al., 1988). The Jurassic section records the transformation from a depositional regime of stable platform carbonates and shales to one with stacked wedges of molassic clastics characteristic of the Foreland Basin succession (Podruski et al., 1988; Poulton, 1989). The Fernie Group is characterized by generally shaly lithologies, with some sandstone and limestone units, and multiple unconformities (Frebold, 1957). Sediments group into five shallowing-upward cycles, each with organic-rich mudstone facies at the base (Stronach, 1984).

The Lower to Upper Jurassic Fernie Group comprises dark brownish to black, laminated, recessive mudstones with some interbedded sandstones and cherty limestones present in the Foothills and Front Ranges and western subsurface of the Plains, thinning to an erosional zero edge near Calgary (Glass, 1990). The lower portion of the Fernie (?equivalent to Cycle I of Stronach, 1984) includes dark cherty limestones of the Nordegg Member and the organic-rich mudstones of the recently-defined Gordondale Member (previously referred to as “Nordegg Member” in the literature; see Asgar-Deen et al., 2003, 2004). The Gordondale Member consists of dark brown, organic-rich, finely laminated, fossiliferous, calcitic mudstones with high radioactivity and high resistivity, which thins westward from a maximum of 50 m to the West Alberta Arch, then thickens westward again, and is of Lower to Middle Jurassic age (Asgar-Deen et al., 2004; Asgar-Deen, 2005). In the subsurface, it can be divided into a lower radioactive unit up to 25 m thick, a middle silty unit up to 5 m thick, and an upper radioactive unit up to 25 m thick (Asgar-Deen et al., 2004). These mudstones, which represent basinal equivalents to the Nordegg carbonate ramp cherty limestones, are very organic-rich, with TOC contents up to 28% in the lower unit and up to 19% in the upper unit, making them the richest potential source rocks in WCSB (Asgar-Deen et al., 2003, 2004; Ibrahimbas and Riediger, 2005). Organic matter is of Type I/II, and the thermal maturity ranges from immature in the east to overmature in the deformed belt where fracturing and shale gas potential may be greatest (Fowler, 2004; Asgar-Deen, 2005). This depositional system records the initial syn-orogenic marine transgression over the craton margin and carbonate ramp as the Columbian Orogeny began (Poulton, 1989; Asgar-Deen, 2005). Other, stratigraphically higher, portions of the Fernie Group (Poker Chip shale, Grey Beds, Passage Beds) have relatively low TOC contents, but are thicker, include interbedded siltstone/sandstone beds and may provide shale gas potential if natural fracture systems and silty conduit beds are well developed.

A large amount of data regarding the organic richness and thermal maturity of Nordegg/Gordondale/Fernie strata have been collected. The GSC Rock-Eval Database includes

819 samples of Fernie Formation (primarily in Alberta and some in B.C.) with the following characteristics: TOC up to 20.87, averaging 1.11; T_{max} up to 555, averaging 409; S_1 up to 45.40, averaging 0.56; S_2 up to 85.94, averaging 2.27; S_3 up to 22.93, averaging 0.36; HI up to 852, averaging 162, OI up to 396, averaging 34 (M. Obermajer, 2006, pers. comm.). Similarly, the GSC Rock-Eval Database includes 678 samples of "Nordegg Member" (primarily in Alberta and some in B.C.) with the following characteristics: TOC up to 28.73, averaging 6.85; T_{max} up to 575, averaging 454; S_1 up to 9.81, averaging 2.05; S_2 up to 244.80, averaging 33.47; S_3 up to 6.69, averaging 1.24; HI up to 870, averaging 349, OI up to 309, averaging 22 (M. Obermajer, 2006, pers. comm.).

The Lower-Upper Jurassic Nordegg/Gordondale/Fernie/Rierdon succession includes a sequence of moderate thickness, present through the western Plains and Foothills of B.C. and Alberta, with good to excellent source rock (Type I/II organics) intervals and some coarser grained beds, which range from thermally immature to overmature (increasing westward). There is likely very good potential for a Style D (Lewis-like) play, although thickness varies significantly over short lateral distances. In addition, a Style C (Barnett-like) play is possible in the brittle, chert-rich intervals of the Nordegg. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy, sedimentology and fracture patterns are not well known, although abundant fracturing may be present in the deformed belt. As with all of WCSB, this unit resides in a mature exploration/production basin, with numerous well penetrations, extensive infrastructure and local markets.

Wilrich/Moosebar/Clearwater/Ostracod/Buckinghorse (Lower Cretaceous)

The Lower Cretaceous Mannville/Blairmore/Bullhead/Fort St. John groups of western Alberta and northeastern B.C. represent the second vast transgressive-regressive clastic wedge which filled the Columbian Foreland Basin following tectonic accretion of allocthonous terranes (Cant, 1989). It comprises interbedded marine and nonmarine sandstones and shales shed from the west and is generally divided into a lower nonmarine-dominated transgressive succession, a middle marine mudstone-dominated unit, and an upper regressive nonmarine-dominated succession (Glass, 1990). The Lower Mannville transgressive phase culminated with the Middle Mannville marine transgression which proceeded from north to south and extended nearly to the U.S. border, forming a southward-thinning wedge of thick marine shale and associated marginal estuarine and lacustrine deposits (Podruski et al., 1988; Cant, 1989; Hayes et al., 1994) that encompass a number of stratigraphic units of Albian age. These deposits extend over northern Alberta and northeast B.C.

At the most southerly reaches of this wedge in central Alberta, the dark, calcareous shales, siltstones shelly coquinas and minor sandstones of the (primarily lacustrine) Ostracod/Calcareous members zone represent the furthest extent of the transgression where it filled low points in the basinal topography (Hayes et al., 1994). These deposits range up to 40 m thick (although generally much thinner), are richly fossiliferous, and are typically unconformity-bound (Glass, 1990). North of Edmonton, this interval is represented by a northward/westward-thickening wedge of marine shale which is referred to as Clearwater Formation in the northeast, Wilrich Member (of the Spirit River Formation) in the central Plains subsurface and Moosebar

Formation in the northwestern Foothills. The Clearwater consists of black to grey shale with minor interbedded sandstone and sideritic concretions up to 85 m thick (Glass, 1990). The Wilrich is dark grey shale with interbedded thin sandstone beds up to 154 m thick (Glass, 1990). The Moosebar comprises dark grey shale with minor siltstone up to 289 m thick, and with sideritic concretions at the base (Glass, 1990). All three units are characterized by increasing siltstone/sandstone content upward. To the far northwest, in northeastern B.C., these units meld into the very thick, dark grey to black marine mudstone, with sideritic concretions at the base, of the Buckinghorse Formation, up to 1000 m thick (Glass, 1990).

The Ostracod Zone (now defined as the Nanton Formation, see Akpulat 2003), although not very thick in most locations, is known to include thin, organic-rich intervals of lacustrine origin with Type I and III kerogen. However, these are separated by coarser, organic-poor units, and these thin intervals probably have minimal shale gas potential (Fowler, 2004). The Wilrich/Moosebar/Clearwater shales are all quite thick and include thin sandy interbeds, although they are generally of modest organic content, making them similar to the Lewis Shale play of the U.S. (Faraj, 2002). In NE B.C., TOC=1-5%, the organic matter is dominated by Type III, the shales are up to 200 m thick, and the thermal maturity is good (Faraj, 2002; Ibrahimbas and Riediger, 2005). It is notable that all these units in the Middle Mannville interval have the darkest (most organic-rich?) shales with concretions (sediment-starved condensed intervals) at their bases. The presence or extent of fracturing in this interval is currently unknown.

The GSC Rock-Eval Database includes only 12 samples of Clearwater Formation with the following characteristics: TOC up to 1.44, averaging 1.05; T_{max} up to 443, averaging 430; S_1 up to 0.10, averaging 0.07; S_2 up to 0.48, averaging 0.35; S_3 up to 1.91, averaging 1.56; HI up to 80, averaging 36, OI up to 216, averaging 152 (M. Obermajer, 2006, pers. comm.). On the other hand, the GSC Rock-Eval Database includes 139 samples of Ostracod Member with the following characteristics: TOC up to 8.93, averaging 2.21; T_{max} up to 478, averaging 444; S_1 up to 3.18, averaging 0.65; S_2 up to 44.21, averaging 7.33; S_3 up to 3.26, averaging 0.49; HI up to 879, averaging 272, OI up to 87, averaging 27 (M. Obermajer, 2006, pers. comm.). In northeast B.C., the GSC Rock-Eval Database includes 74 samples of Buckinghorse Formation with the following characteristics: TOC up to 1.91, averaging 0.99; T_{max} up to 454, averaging 437; S_1 up to 3.12, averaging 1.21; S_2 up to 7.27, averaging 2.56; S_3 up to 0.77, averaging 0.45; HI up to 473, averaging 253, OI up to 95, averaging 45 (M. Obermajer, 2006, pers. comm.).

The Lower Cretaceous Wilrich/Moosebar/Clearwater/Ostracod/Buckinghorse succession includes a geographically-diverse sequence of moderate to large thickness, present throughout the Plains and Foothills of B.C. and Alberta, with fair to good source rock (Type III organics) intervals and abundant coarser grained beds, which are thermally mature. There is likely fair to good potential for a Style D (Lewis-like) play, with prospects increasing northward as the unit thickens. Potential probably varies significantly with stratigraphic position and across the region. Development of this play might proceed if other shale gas plays in northwestern Alberta, northeastern B.C. and N.W.T. proved successful. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy, sedimentology and fracture patterns of most of this large clastic wedge are not well known, and much of this succession has not been extensively sampled for organic and maturity analyses. Fracturing may be present in the deformed belt. This unit resides in a mature exploration/production basin, with numerous well penetrations, extensive infrastructure and local markets.

Colorado/Alberta/Smoky Groups (Fish Scale, Second Specks, First Specks) (Middle - Upper Cretaceous)

General Geology

The Middle to Upper Cretaceous mudstone-dominated strata of the Western Canada Sedimentary Basin are included in intervals referred to as Colorado Group over much of the Plains, Alberta Group in the southern and central Foothills and Smoky Group in the northern Foothills. These rocks, totalling up to 1200 m in thickness, were deposited over a span of about 25-30 million years from Albian to Santonian time and rest on a regional basal unconformity (Leckie et al., 1994). A combination of global high sea level and active tectonic downflexure yielded a succession dominated by mudstone, with a series of distinctive transgression/regression-related organic-rich units deposited in stratified anoxic water, alternating with sandstone units. The organic-rich nature of these strata has been known since the earliest geological studies along the Manitoba Escarpment by Tyrrell. The following paragraphs attempt to organize and synthesize the enormous, but scattered literature pertinent to this thick stratigraphic interval. A plethora of stratigraphic nomenclature (some informal) attends this interval, confusing and masking the regional relationships and correlations, but several organic-rich units have great lateral extent and are highlighted here. As Leckie et al. (1994) stated, "Within the Colorado Group, the First and Second White Speckled Shales, the Fish Scale Zone, and the shale at the base of the Shaftesbury Formation are more radioactive than overlying and underlying shales, have high total organic carbon contents, and have high hydrocarbon generating potential. An interval such as the Second White Speckled Shale is potentially both a source and a reservoir rock for hydrocarbons". Clearly, these rocks have potential for shale gas plays.

The Colorado Group comprises a westward-thickening wedge, up to 1000 m thick, of dark grey mudstone with minor, but important, sandstone, siltstone and chalky limestone units, and is divided (at the base of the Second White Speckled Shale) into lower noncalcareous and upper calcareous units (Glass, 1990; Nielsen et al., 2003). Likewise, in the Foothills the Alberta Group comprises dark grey silty marine mudstone with thin sandstone and limestone interbeds and sideritic concretions, up to 1200 m thick (Stott, 1963). The group is divided into the lower Blackstone shale, middle Cardium sandstone and upper Wapiabi shale (Stott, 1963). The Smoky Group, which lies conformably on the closely-related Shaftesbury shale and Dunvegan sandstone successions, consists of up to 1100 m of dark thinly bedded silty shale divided into the lower Kaskapau shale, the middle Bad Heart sandstone and the upper Puskwaskau shale (Stott, 1967).

An enormous amount of data regarding the organic richness and thermal maturity of the strata within the Colorado/Alberta/Smoky Groups throughout the surface and subsurface of WCSB have been collected. Addressing the Group-level unit as a whole, the GSC Rock-Eval Database includes 1141 samples of Colorado Group (primarily in Alberta, with some in Saskatchewan) with the following characteristics: TOC up to 11.99, averaging 1.69; T_{max} up to 477, averaging 433; S_1 up to 4.67, averaging 0.37; S_2 up to 50.04, averaging 2.74; S_3 up to 8.93, averaging 0.84; HI up to 533, averaging 139; OI up to 373, averaging 49 (M. Obermajer, 2006, pers. comm.). Likewise, the GSC Rock-Eval Database includes 155 samples of Alberta Group (all in Alberta) with the following characteristics: TOC up to 9.34, averaging 1.09; T_{max} up to 487, averaging 458; S_1 up to 1.52, averaging 0.27; S_2 up to 54.22, averaging 1.93; S_3 up to 1.74, averaging 0.22; HI up to 581, averaging 111; OI up to 82, averaging 21 (M. Obermajer, 2006, pers. comm.). These data suggest that the Group as a whole has fair to good background levels of organic carbon, and is mature in the Plains, and mature to overmature in the Foothills.

Three prominent organic-rich marker units are present in the Colorado Group and equivalents throughout WCSB, and represent major maximum transgression/condensed section periods: in ascending order, Fish Scale Zone, Second White Speckled Shale and First White Speckled Shale. These are separated by a variety of shale, siltstone and sandy units.

Lower Colorado

The lower part of the Colorado Group across WCSB has been divided into 4 regionally mappable shale units, from base to top: 1) the Late Albian Westgate Formation (20-120 m thick, thickening to the northwest) regressive noncalcareous mudstone with Type III organic matter and TOC < 2%, deposited at high sedimentation rates in a cool Boreal-connected sea, 2) the Early Cenomanian Fish Scales Formation (2-20 m thick, thickening westward) transgressive/condensed section laminated radioactive mudstone and fish fragment coquina with Type II/III organic matter and TOC up to 8%, deposited at low sedimentation rates in anoxic Boreal bottom waters, 3) the middle to Late Cenomanian Belle Fourche Formation (20-150 m thick, thickening northwestward) regressive noncalcareous mudstone with Type III organic matter and TOC < 2%, deposited at high sedimentation rates in mixed Boreal/Tethyan waters, and 4) the latest Cenomanian to Middle Turonian Second White Specks Formation (25-90 m thick, thickening northwestward) transgressive/condensed section laminated calcareous radioactive mudstone (with abundant coccolithic fecal pellets) with Type I and II organic matter and TOC contents up to 12%, deposited at low sedimentation rates in anoxic Tethyan bottom waters (Leckie et al., 1994; Bloch et al., 1999; Schröder-Adams et al., 2001; Yurkowski, 2005).

In northwestern Alberta strata equivalent to the Second Specks are included in the Shaftesbury Formation and in the Blackstone Formation of the Foothills, whereas the Second White Specks are equivalent to the Favel Formation of Manitoba and the Greenhorn Formation of the U.S. (Glass, 1990). These shales are immature with respect to oil east of the Fifth Meridian and mature adjacent to the Fold and Thrust Belt, transgressive shales are oil prone whereas regressive shales are gas-prone, and localized natural fracture formation occurred at the time of maximum burial (Bloch et al., 1999). Traditionally, due to its much higher carbonate content, the Second White Speckled Shale is included in the Upper Colorado Group.

Following is a summary of the geochemical data for the component parts of the lower Colorado. The GSC Rock-Eval Database includes 118 samples of Westgate Formation (most in Alberta, some in Saskatchewan) with the following characteristics: TOC up to 10.01, averaging 2.06; T_{max} up to 477, averaging 434; S_1 up to 2.99, averaging 0.48; S_2 up to 30.51, averaging 2.71; S_3 up to 1.74, averaging 0.47; HI up to 305, averaging 100; OI up to 78, averaging 24 (M. Obermajer, 2006, pers. comm.). For the equivalent Shaftesbury Formation, the GSC Rock-Eval Database includes 237 samples (in Alberta and B.C.) with the following characteristics: TOC up to 3.44, averaging 1.19; T_{max} up to 471, averaging 440; S_1 up to 6.30, averaging 0.42; S_2 up to 9.31, averaging 1.51; S_3 up to 4.88, averaging 0.69; HI up to 400, averaging 119; OI up to 392 averaging 55 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 427 samples of Fish Scales Formation (most in Alberta, some in B.C.) with the following characteristics: TOC up to 7.96, averaging 1.65; T_{max} up to 469, averaging 434; S_1 up to 4.46, averaging 0.38; S_2 up to 33.04, averaging 3.13; S_3 up to 10.34, averaging 0.73; HI up to 487, averaging 166; OI up to 266, averaging 44 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 152 samples of Belle Fourche Formation (in Alberta and Saskatchewan) with the following characteristics: TOC up to 8.99, averaging 1.98; T_{max} up to 457, averaging 432; S_1 up to 3.27, averaging 0.51; S_2 up to 37.54, averaging 3.73; S_3 up to 2.96, averaging 0.67; HI up to 421, averaging 150; OI up to 277, averaging 41 (M. Obermajer, 2006, pers. comm.). At the top of the lower Colorado is the Second White Specks Formation, and equivalents, for which there is a great deal of geochemical data, as follows. The GSC Rock-Eval Database includes 914 samples of Second White Specks Formation (most in Alberta, some in Manitoba and Saskatchewan) with the following characteristics: TOC up to 12.62, averaging 2.18; T_{max} up to 470, averaging 436; S_1 up to 18.76, averaging 0.71; S_2 up to 53.99, averaging 5.83; S_3 up to 7.78, averaging 0.85; HI up to 1158, averaging 231; OI up to 243, averaging 40 (M. Obermajer, 2006, pers. comm.). In the Plains of Saskatchewan and Manitoba, the equivalent strata of the Favel Formation include 104 samples with the following characteristics: TOC up to 11.90, averaging 3.60; T_{max} up to 463, averaging 422; S_1 up to 8.10, averaging 0.65; S_2 up to 65.34, averaging 9.02; S_3 up to 6.69, averaging 2.77; HI up to 549, averaging 200; OI up to 262, averaging 92 (M. Obermajer, 2006, pers. comm.).

In the Foothills of Alberta, the Blackstone Formation includes 1273 samples with the following characteristics: TOC up to 16.33, averaging 0.79; T_{max} up to 523, averaging 452; S_1 up to 49.04, averaging 0.85; S_2 up to 77.26, averaging 1.51; S_3 up to 12.87, averaging 0.37; HI up to 794, averaging 158; OI up to 414, averaging 34 (M. Obermajer, 2006, pers. comm.), and the Kaskapau Formation includes 214 samples with the following characteristics: TOC up to 3.04, averaging 1.11; T_{max} up to 498, averaging 447; S_1 up to 8.76, averaging 1.57; S_2 up to 14.03, averaging 2.32; S_3 up to 2.32, averaging 0.37; HI up to 462, averaging 183; OI up to 385, averaging 36 (M. Obermajer, 2006, pers. comm.).

Upper Colorado

The upper part of the Colorado Group across WCSB has received less study, but has been divided into 2 regionally mappable units: 1) the Late Turonian Morden or Carlile Formation shale (or upper undifferentiated Colorado shale) of dark grey to black, non-calcareous, poorly fossiliferous mudstone with siltstone laminations up to 160 m thick (thickening to the west) with Type III organic matter and TOC up to 3%, (informally subdivided into lower grey shale, middle dark grey shale and upper siltier members) unconformably overlain by 2) the Coniacian-Santonian Niobrara Formation, up to 240 m (thickening to the southwest) of fossiliferous, partly calcareous mudstone and siltstone which includes the lower Verger Member dark shale with white foraminifer and coccolith speckles, the middle sandy Medicine Hat Member, and the upper First White Specks Member (Niobrara Formation of Manitoba, the Thistle Member within the Wapiabi Formation of the Foothills) of dark grey, very calcareous and radioactive mudstone with calcarenite, 10-75 m thick, with Type I and II organic matter and TOC up to 15%, and micro-fractures in core (Glass, 1990; Leckie et al., 1994; Schröder-Adams et al., 2001; Nielsen, 2003;

Yurkowski, 2005). Thermal maturities are within the oil window for the Carlile, and below the oil window for the Niobrara (Nielsen, 2003). Over a large area of central Saskatchewan, the Morden/Carlile shale appears to be missing due to lack of deposition plus erosion, and there the Niobrara organic-rich shale lies directly on the Second White Specks organic-rich shale (Macauley, 1984b; Schröder-Adams et al., 2001).

Following is a summary of the geochemical data for the component parts of the upper Colorado. The GSC Rock-Eval Database includes 98 samples of Morden Formation (most in Saskatchewan, some in Manitoba) with the following characteristics: TOC up to 10.23, averaging 3.39; T_{max} up to 467, averaging 421; S_1 up to 2.55, averaging 0.45; S_2 up to 33.03, averaging 5.49; S_3 up to 6.21, averaging 2.68; HI up to 695, averaging 137; OI up to 378, averaging 95 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 158 samples of Niobrara Formation (in Saskatchewan and Manitoba) with the following characteristics: TOC up to 14.76, averaging 2.26; T_{max} up to 517, averaging 426; S_1 up to 2.80, averaging 0.33; S_2 up to 58.03, averaging 4.35; S_3 up to 6.87, averaging 1.95; HI up to 506, averaging 121; OI up to 321, averaging 101 (M. Obermajer, 2006, pers. comm.). The equivalent strata of the First White Specks Member include 158 samples (only in Saskatchewan and Manitoba) with the following characteristics: TOC up to 12.17, averaging 5.45; T_{max} up to 427, averaging 416; S_1 up to 3.85, averaging 1.08; S_2 up to 45.04, averaging 18.23; S_3 up to 9.67, averaging 3.42; HI up to 585, averaging 310; OI up to 190, averaging 73 (M. Obermajer, 2006, pers. comm.). In the Foothills of Alberta, the upper Colorado is referred to the Wapiabi Formation, for which the GSC Rock-Eval Database includes 773 samples with the following characteristics: TOC up to 23.44, averaging 0.85; T_{max} up to 491, averaging 450; S_1 up to 3.42, averaging 0.31; S_2 up to 48.47, averaging 1.33; S_3 up to 4.33, averaging 0.27; HI up to 481, averaging 139; OI up to 292, averaging 35 (M. Obermajer, 2006, pers. comm.).

Summary of Characteristics

Rocks of the Lower Colorado have been extensively sampled (totalling more than 3400 samples) in certain areas and allow the following conclusions regarding their shale gas potential. They include a) good to excellent source rock intervals (Type II/III organics) and abundant coarser grained beds which are thermally mature in the Westgate-Shaftesbury section, b) good to excellent source rock intervals (Type II organics) which are very calcareous and brittle and which are mature to overmature (increasing to the west) in the Fish Scale section, c) good to excellent source rock intervals (Type II/III organics) and abundant coarser grained beds which are thermally mature in the Belle Fourche section, d) good to excellent source rock intervals (Type II organics) which are very calcareous and brittle and which are mature to overmature (increasing to the west) in the Second White Specks-Favel section, and e) fair to excellent source rock intervals (Type II/III organics) and abundant coarser grained beds which are thermally mature to overmature in the Blackstone-Kaskapau section of the Foothills.

Rocks of the Upper Colorado have been extensively sampled (totalling more than 1185 samples) in certain areas and allow the following conclusions regarding their shale gas potential. They include a) good to excellent source rock intervals (Type III organics) and abundant coarser grained beds which are thermally immature to mature in the Morden-Carlile section, b) good to excellent source rock intervals (Type I/II organics) which are very calcareous and brittle and which are immature to overmature in the Niobrara-First White Specks section, and c) good to excellent source rock intervals (Type II/III organics) and abundant coarser grained beds which are thermally mature to overmature in the Wapiabi section of the Foothills.

Comments on Shale Gas Potential

The Upper Cretaceous Colorado Group (and equivalents) succession includes a very thick succession, present throughout the Plains and Foothills of WCSB, with fair to excellent source rock (Type II/III organics) intervals and abundant coarser grained beds, which are thermally immature to overmature (generally increasing westward). There is likely good potential for Style A (Antrim-like) plays or Style D (Lewis-like) plays, and possibilities for Style C (Barnett-like) plays, as detailed below.

The Colorado Group is the main source of previously-discovered Upper Cretaceous oils and biogenic gas (ie. it has already generated and expelled large amounts of HC in western Alberta, but likely retains a significant proportion), and has several thick organic-rich units, particularly the First White Specks, Second White Specks and the Fish Scales Zone (Fowler, 2004). Much of the rest of the shale of the Colorado Group is of modest organic content, gas-prone Type II and III organic matter in the 1-4% range, resides in the immature to mature zone, includes numerous thin siltstone/sandstone interbeds, and occurs in thick units between the main sandy formations. These conditions are similar to the Style D (Lewis-like) shale play of the U.S., and suggest that the Colorado in general should be more seriously investigated over most of the WCSB for shale gas potential.

Conversely, the main transgressive/condensed section shales (Fish Scales, Second Specks, First Specks) are characterized by high organic contents, oil-prone Type II organic matter in the 8-12% range, reside in the immature to overmature zones, in intervals of modest thickness (2-90 m), but subject to natural fracturing. These conditions are similar to the Style A (Antrim-like) shale play of the U.S., and suggest that these parts of the Colorado also should be seriously investigated over most of the WCSB for shale gas potential. Anecdotal reports suggest the presence of gas in outcropping and subcropping Colorado Group strata (Favel and Niobrara formations) in water wells around the Manitoba Escarpment (J. Bamburak and M. Nichols, 2006, pers. comm.) (which may be a result of glacial meltwater intrusion and biogenesis; S. Grasby, 2006, pers. comm.). Thermal maturity increases from east to west across the Basin. Apparently random gas shows are known across the Prairies.

Alternatively, toward the Foothills, and overlying areas of salt dissolution in Saskatchewan, fracturing is certainly present, increasing the potential. Podruski et al.(1988), Leckie et al. (1994) and Bloch et al. (1999) all described the significant oil plays in fractured organic-rich shales of the First and Second White Speckled Shales in the Foothills (which were primarily discovered by chance in the past), where diagenetic alteration (calcareous and siliceous cements) and tectonic position enhance the possibilities of fracturing. The conditions in the Foothills may be similar to those of the Style C (Barnett-like) shale play of the U.S., and suggest that these parts of the Colorado should be seriously investigated for shale gas potential throughout the deformed belt.

Unquestionably, parts of the Colorado Group (and equivalents) present excellent, perhaps the best, prospects for multiple shale gas plays across WCSB. However, further focussed study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy of the Colorado throughout the Basin would lead to much better understanding of the shale gas potential. The detailed stratigraphy, sedimentology and fracture patterns of most of this clastic wedge are not well known, and advanced geological research would enhance the outlook in these very prospective rocks. Fracturing may be present in certain regions and in the deformed belt. Clay mineral content, characteristics and diagenesis studies may prove to be crucial in evaluation of the potential. Importantly, the Colorado Group is one of the shallowest potential shale gas intervals. This unit covers much of the WCSB mature exploration/production basin, with numerous well penetrations, extensive infrastructure and local markets, and resides at shallow depths through most of its area of occurrence.

Lea Park/Pakowki/Nomad/Pembina (Upper Cretaceous)

At the base of the Uppermost Cretaceous-Tertiary stratigraphic interval, there is a regionally-persistent contact between the Milk River-Chungo sandstone-dominated strata below and the Pakowki-Lea Park mudstone-dominated strata above, marked by a thin chert pebble lag in outcrop and a distinctive geophysical marker ("Milk River Shoulder") in the subsurface (Dawson et al., 1994; Hamblin and Abrahamson, 1996). This represents a major sequence boundary and the succeeding transgression ushered in the final Laramide orogeny foreland basin fill succession following docking of the oceanic Insular Superterrane, foreland subsidence and creation of accommodation space (Hamblin and Abrahamson, 1996). Fine grained sediment was deposited into the broad north-south seaway, especially in southern Alberta, from the developing Cordillera 300-400 km to the west.

The Lea Park Formation consists of a westward-thinning wedge of dark grey, bioturbated, marine shale up to about 250 m in thickness, with ironstone concretions and an upward increase of thin siltstone and very fine grained sandstone beds (Glass, 1990; Hamblin and Abrahamson, 1996). It rests disconformably on the First White Speckled Shale and the "Milk River Shoulder" and interfingers with the overlying Belly River Group shoreline and nonmarine sandstones (Dawson et al., 1994). In the Plains of southern Alberta, eastward into Saskatchewan and in the southern Foothills, this interval is expressed as the similar dark grey mudstones of the Pakowki Formation (up to 200 m thick) and Nomad Member (up to 52 m thick), respectively (Glass, 1990). It also includes the Alderson Member, the productive facies of the enormous Southeastern Alberta Milk River Gas Field (described above in an Introductory section), which may represent a previously-unrecognized, productive Canadian shale gas play. Far to the east, in Manitoba, correlative strata comprise the unconformity-bounded, dark grey mudstones with thin bentonite beds of the Pembina Member of the Pierre Formation, which rest on the Niobrara Formation or Gammon Member of the Pierre (Glass, 1990).

A fairly large amount of data regarding the organic richness and thermal maturity of Lea Park/Pakowki/Nomad/Pembina strata have been collected. The GSC Rock-Eval Database includes 227 samples of Lea Park Formation (most in Alberta) with the following characteristics: TOC up to 8.89, averaging 1.75; T_{max} up to 471, averaging 436; S_1 up to 1.73, averaging 0.14; S_2 up to 12.37, averaging 1.23; S_3 up to 17.33, averaging 1.25; HI up to 289, averaging 71, OI up to 321, averaging 73 (M. Obermajer, 2006, pers. comm.). Likewise, the GSC Rock-Eval Database includes 83 samples of Pakowki Formation (all in Alberta) with the following characteristics:

TOC up to 8.64, averaging 1.87; T_{max} up to 503, averaging 440; S_1 up to 1.28, averaging 0.16; S_2 up to 12.09, averaging 1.22; S_3 up to 4.77, averaging 1.32; HI up to 224, averaging 65, OI up to 307, averaging 93 (M. Obermajer, 2006, pers. comm.).

The Upper Cretaceous Lea Park/Pakowki/Nomad/Pembina succession includes a sequence of moderate thickness, present throughout the Plains of Alberta and Saskatchewan, with fair to good source rock (likely Type III organics) intervals and abundant coarser grained beds, which are thermally mature. These strata may be immature in Saskatchewan. There is likely good potential for a Style D (Lewis-like) play, and in northeastern Alberta and Saskatchewan, there may be good potential for a Style A (Antrim-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy, sedimentology and fracture patterns of most of this clastic wedge are not well known, and large prospective areas have been poorly sampled for organic and maturity analyses. There is no current information on the stress regime of the Lea Park, but in the Crowsnest Pass area of the southern Foothills, the equivalent strata are heavily fractured. In spite of the moderate thickness, additional advanced geological research would significantly clarify the shale gas prospects. This unit resides in a mature exploration/production basin, with numerous well penetrations, extensive infrastructure and local markets, and is very shallow or exposed at surface through most of its area of occurrence.

Bearpaw/Odanah (Upper Cretaceous)

During the Late Campanian a major, north-south, broad inland marine seaway existed between the Canadian Shield and the active Cordilleran belt, stretching from the Arctic to the Gulf of Mexico. Initial rapid Bearpaw marine transgression over the Belly River nonmarine clastic wedge was synchronous with, and related to, tectonically induced subsidence due to movement on major thrusts and tectonic loading. In central Alberta, the marine deposits interfinger with equivalent and overlying Horseshoe Canyon Formation nonmarine strata (Hamblin, 2004). The Bearpaw Formation, dominated by marine shale, thins to the west and north, but thickens to the east and south (Link and Childerhose, 1931) at the expense of the under-and overlying nonmarine prisms to become part of the very thick Riding Mountain and Pierre formations of Manitoba and the U.S. (Caldwell, 1968). After isostatic relaxation and uplift, the subsequent rapid increase in sediment supply allowed progradation of the partly-equivalent Horseshoe Canyon nonmarine clastic wedge and concomitant rapid eastward withdrawal of the Bearpaw Sea (Hamblin, 2004).

The Campanian-Maastrichtian Bearpaw Formation comprises up to 350 m (typically 150-200 m), thinning to pinchout to the north and west as it merges with the sandy Horseshoe Canyon and St. Mary river clastic wedges) of dark grey montmorillonitic mudstone, with subordinate siltstone and very fine sandstone beds (generally increasing upward), numerous concretionary beds and thin bentonites (Glass, 1990; Dawson et al., 1994). It thins to a pinchout to the north and west in Alberta as it merges with the sandy Horseshoe Canyon and St. Mary river clastic wedges (Hamblin, 2004). To the south and east in Saskatchewan, it is represented, in ascending order, by the 1) Manyberries Member, up to 260 m of dark grey shale with horizons of concretions and bentonites with an upward increase of thin silty beds, 2) Oxarart, Belanger and Thelma sandstone members totalling up to about 40 m in thickness of greenish to greyish very fine to fine grained sandstone, 3) Medicine Lodge Member, up to 25 m of dark grey silty mudstone with an upward increase of thin sandy beds, overlain by the sandstones of the Eastend Formation (Furnival, 1950; Lines, 1963). In the far east, in Manitoba, the correlative Odanah Member of the uppermost Pierre Formation consists of grey siliceous shale, with minor soft greenish shale beds and iron-manganese concretions, up to 150 m thick (Glass, 1990). There is no current information on the stress regime of the Bearpaw, but in Saskatchewan, the Odanah shale is highly siliceous and heavily fractured (Yurkowski, 2005).

The GSC Rock-Eval Database includes 178 samples of Bearpaw Formation (most in Alberta) with the following characteristics: TOC up to 3.61, averaging 1.87; T_{max} up to 582 (but generally lower), averaging 441; S_1 up to 2.37, averaging 0.35; S_2 up to 10.71, averaging 0.75; S_3 up to 2.89, averaging 0.82; HI up to 355, averaging 72, OI up to 388, averaging 103 (M. Obermajer, 2006, pers. comm.).

The Upper Cretaceous Bearpaw/Odanah succession includes a sequence of moderate thickness, present at very shallow depth across much of the southern WCSB, with fair source rock (likely Type III organics) intervals and abundant coarser grained beds, which are thermally mature in Alberta. These strata may be immature in Saskatchewan and Manitoba. There could be some potential for a Style D (Lewis-like) play, and in southern Saskatchewan and Manitoba, there may be potential for a Style A (Antrim-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. Shales of the Bearpaw are generally bentonitic, and the ability to fracture-stimulate these rocks may be questionable. The detailed stratigraphy and sedimentology are known to some extent, and fracture patterns exist but are not well understood. This unit resides in a mature exploration/production basin, with numerous well penetrations, extensive infrastructure and local markets, and is very shallow or exposed at surface through most of its area of occurrence.

CORDILLERA (Figure 4)

Road River (Cambrian-Devonian)

Eagle Plain Basin is a large intermontane basin, 170 x 80 km in size and traversed by the Dempster Highway, in northern Yukon which is underlain by up to 4000 m of Paleozoic strata. Oil and gas exploration began in 1957 and 33 wells have been drilled to date with several discoveries and multiple minor shows (Hamblin, 1990; Dixon, 1992). Thick Middle Ordovician to Middle Devonian carbonate platform limestones and dolostones pass westward into the thick basinal shale succession of the Road River Formation of the Richardson Trough, present in Liard and Peel Plateau areas (Pugh, 1983). The Road River is a widely distributed, thick sequence of deeper marine dark grey to black, graptolitic mudstones with subordinate interbedded argillaceous limestone, siltstone and fine sandstone turbidite beds, possibly up to 2000 m thick (Pugh, 1983; Morrow, 1999). The Road River was deposited in a variety of basin and slope pelagic settings below normal wave-base, representing the initial deepening of the Richardson Trough and thicknesses of 500 m are more normal (Morrow, 1999). A lower member of limestone and argillaceous limestone is Late Cambrian to Early Ordovician age, whereas the upper, recessive, shale-dominated member is of Ordovician, Silurian and Early Devonian age (Cecile, 1982). Later work in Yukon subdivided the Road River Group into three formations, in ascending order: 1) Rabbitkettle dark grey to black, rhythmically-bedded argillaceous lime mudstone up to 2000 m thick, 2) Loucheux black graptolitic shale with limestones and resedimented carbonate breccias up to 450 m thick, and 3) Dempster grey argillite and dolostone up to 150 m thick (Cecile et al., 1982; Morrow, 1999).

The Road River has Type I and II organic matter with TOC up to 10%, particularly in the lower and upper graptolite-bearing and siliceous shale units of deepwater origin (Link et al., 1989).The GSC Rock-Eval Database includes 20 samples of Road River Formation (all in N.W.T.) with the following characteristics: TOC up to 3.07, averaging 1.41; T_{max} up to 530, averaging 436; S_1 up to 0.88, averaging 0.37; S_2 up to 1.84, averaging 0.77; S_3 up to 2.05, averaging 0.59; HI up to 126, averaging 62; OI up to 151, averaging 43 (M. Obermajer, 2006, pers. comm.). It is not clear whether this data from N.W.T. is relevant to the Yukon region. Link and Bustin (1989) suggest that these strata are generally overmature with respect to oil, residing in the gas window.

The Road River succession includes a very thick sequence with apparently good to excellent source rocks intervals (Type I/II organics), which are thermally mature to overmature, and some coarser interbeds. There may be good geological potential for a Style C (Barnett-like) play or a Style B (Ohio/New Albany-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, fracture patterns are unknown and relatively few samples have been analysed. Most Road River outcrop areas are in structurally complex belts around the edges of the basin, but these strata are present in the subsurface as well. These strata reside in a distant frontier basin, but one which has experienced some past successful exploration and has some infrastructure. Any shale gas exploitation that might occur likely lies far in the future.

Canol/Imperial (Middle - Upper Devonian)

Eagle Plain Basin is a large intermontane basin, 170 x 80 km in size and traversed by the Dempster Highway, in northern Yukon which is underlain by up to 4000 m of Paleozoic strata. Oil and gas exploration began in 1957 and 33 wells have been drilled to date with several discoveries and multiple minor shows (Hamblin, 1990; Dixon, 1992). The Middle to Upper Devonian Canol and Imperial formations represent a thick wedge of dark-coloured fine-grained clastics which thin to the south and southwestward, and pass upward, and northeastward toward the Richardson Mountains, into a coarse grained, shallow marine/shoreline clastic facies known as the Tuttle Formation (Pugh, 1983). These strata denote a major transgression over the underlying Ogilvie carbonate platform, creating an initial deep-water, anoxic environment, followed by regression, and they generally coarsen-upward. The Canol (Frasnian age) is a highly radioactive, dark grey to black bituminous shale, commonly siliceous and pyritic, up to about 100 m thick, which is gradationally overlain by the Imperial Formation (Pugh, 1983). In the region to the east (and likely here too), it was deposited under uniform anoxic conditions (Al-Aasm et al., 1996). The Imperial (Frasnian to Fammenian age) comprises up to about 600 m of grey to dark grey marine mudstone, siltstone and minor very fine sandstone and limestone, in a generally coarsening-upward sequence, which was derived primarily from the north (Martin, 1972; Pugh, 1983). In the region to the east (and likely here too), it was deposited in relatively deep to shallow, more oxygenated, marine conditions.

Black bituminous shale of the Canol Formation has significant amounts of Type II and III organic matter (TOC up to 9%) and is mature to overmature with respect to oil (Link and Bustin, 1989; Link et al., 1989). The GSC Rock-Eval Database includes 292 samples of Canol Formation (most from the Norman Wells area in N.W.T., only a few from Yukon) with the following characteristics: TOC up to 27.14, averaging 4.59; T_{max} up to 580, averaging 445; S_1 up to 20.13, averaging 2.07; S_2 up to 90.88, averaging 12.88; S_3 up to 4.79, averaging 0.85; HI up to 625, averaging 223; OI up to 242, averaging 23 (M. Obermajer, 2006, pers. comm.). The Imperial Formation has moderate amounts of Type III organic matter, TOC averaging about 1%, and is within the gas window (Link and Bustin, 1989; Link et al., 1989). The GSC Rock-Eval Database includes 1015 samples of Imperial Formation (most from the Norman Wells area in N.W.T., only a few from Yukon) with the following characteristics: TOC up to 7.49, averaging 1.09; T_{max} up to 559, averaging 441; S_1 up to 11.14, averaging 0.42; S_2 up to 32.73, averaging 1.32; S_3 up to 7.61, averaging 0.39; HI up to 869, averaging 93; OI up to 381, averaging 51 (M. Obermajer, 2006, pers. comm.). It is not clear whether this data is relevant to the Eagle Plains.

The Canol-Imperial succession includes a very thick sequence with good to excellent source rock intervals (Type II/III organics), which range from thermally mature to overmature, with abundant coarser interbeds. There appears to be good potential for a Style C (Barnett-like) play or a Style B (Ohio/New Albany-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and fracture patterns are unknown. Most Canol-Imperial outcrop areas are in structurally complex belts around the edges of the basin, but these strata are present in the subsurface as well. These strata reside in a distant frontier basin, but one which has experienced some past successful exploration and has some infrastructure. Within Eagle Plain Basin, the Canol-Imperial and Ford Lake successions probably present the best prospects for shale gas potential.

Ford Lake (Upper Devonian-Lower Carboniferous)

Eagle Plain Basin is a large intermontane basin, 170 x 80 km in size and traversed by the Dempster Highway, in northern Yukon which is underlain by up to 4000 m of Paleozoic strata. Oil and gas exploration began in 1957 and 33 wells have been drilled to date with several discoveries and multiple minor shows (Hamblin, 1990; Dixon, 1992). Nearby Kandik Basin (primarily in adjacent Alaska) also has a thick Paleozoic section, but very few well penetrations. The upper Devonian-Lower Carboniferous Ford Lake Formation is a thick wedge of dark shale which passes upward and northeastward into the Hart River Formation shallow shelf carbonates and clastics of Eagle Plain (Pugh, 1983). The Ford Lake is 300-1000 m (thickening northwestward) of brown to black, radioactive, bituminous and pyritic, noncalcareous shale with minor siltstone, and cherty sandstone which sharply overlies the grey shale of the Imperial (Martin, 1972; Pugh, 1983). There is a general upward increase in thin sandy (and even conglomeratic) interbeds as the unit passes upward into the Hart River sandy limestone (Martin, 1972; Pugh, 1983). The Ford Lake is of Fammenian to Viséan age (Graham, 1973). These strata denote a major re-transgression over the underlying Imperial-Tuttle depositional system, followed by regression, and they generally coarsen-upward.

The Ford Lake appears to be a significant potential source rock with a mixture of Type II and III organic matter and TOC up to 4% and may have supplied the oil discovered for the Chance Sandstone play (Link and Bustin, 1989). Analysis of palynomorphs and organics from the Ford Lake in outcrop indicate low to moderate thermal maturity, within the oil window (TAI = 2-3+, CAI = 2-2.5, Ro = 0.88-1.69%) (Utting, 1989; Link et al., 1989), but these strata may be more mature in deeper portions of the basin. The GSC Rock-Eval Database includes 137 samples of Ford Lake Formation with the following characteristics: TOC up to 14.54, averaging 1.22; T_{max} up to 512, averaging 409; S_1 up to 17.77, averaging 0.97; S_2 up to 33.25, averaging 1.04; S_3 up to 29.73, averaging 0.76; HI up to 475, averaging 68; OI up to 325, averaging 48 (M. Obermajer, 2006, pers. comm.). Snowdon and Price (1994) noted that the Ford Lake has some intervals with TOC greater than 1% and high thermal maturity in one well in Kandik Basin, immediately west of Eagle Plain.

The Ford Lake succession includes a very thick sequence with good to excellent source rock intervals (Type II/III organics), which range from thermally immature to mature, with abundant coarser interbeds. There appears to be good potential for a Style A (Antrim-like) play or a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and fracture patterns are unknown. Most Ford Lake outcrop areas are in structurally complex belts around the edges of the basin, but these strata are present in the subsurface as well. These strata reside in a distant frontier basin, but one which has experienced some past successful exploration and has some infrastructure. Within Eagle Plain Basin, the Ford Lake and the Canol-Imperial successions probably present the best prospects for shale gas potential.

Blackie (Upper Carboniferous)

Eagle Plain Basin is a large intermontane basin, 170 x 80 km in size and traversed by the Dempster Highway, in northern Yukon which is underlain by up to 4000 m of Paleozoic strata. Oil and gas exploration began in 1957 and 33 wells have been drilled to date with several discoveries and multiple minor shows (Hamblin, 1990; Dixon, 1992). The upper middle Carboniferous Blackie Formation is a thick wedge of dark spicular shale which passes upward and northeastward into the Ettrain Formation shallow shelf carbonates of Eagle Plain (Bamber and Waterhouse, 1971). The Blackie sharply overlies the Hart River carbonate platform and is of Upper Carboniferous age (Graham, 1973; Pugh, 1983). It comprises a thick sequence of black, bituminous shale with thin beds of dolomitic siltstone and argillaceous limestone, 200-700 m thick (Pugh, 1983). These strata denote a major re-transgression over the underlying Hart River depositional system, followed by regression, and generally coarsen-upward.

Limited data from the Blackie suggests mature to marginally mature Type II and III organic matter, with TOC up to 5% (Link et al., 1989), but these strata may be more mature in deeper portions of the basin. The GSC Rock-Eval Database includes 76 samples of Blackie Formation with the following characteristics: TOC up to 3.92, averaging 1.09; T_{max} up to 469, averaging 424; S_1 up to 2.92, averaging 1.10; S_2 up to 3.08, averaging 0.93; S_3 up to 1.16, averaging 0.45; HI up to 220, averaging 87; OI up to 169, averaging 54 (M. Obermajer, 2006, pers. comm.).

The Blackie Formation includes a thick sequence with good source rock intervals (Type II/III organics), which range from thermally immature to mature, with abundant coarser interbeds. There appears to be fair potential for a Style B (Ohio/New Albany-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and fracture patterns are unknown. The Blackie outcrops rarely around the southeast edge of the basin, but these strata are present in the subsurface as well, and could be developed if Canol-Imperial and Ford Lake plays were successful. These strata reside in a distant frontier basin, but one which has experienced some past successful exploration and has some infrastructure.

Todagin/Ashman (Middle -Upper Jurassic)

Bowser Basin, is a clastic basin located in the Intermontane Belt on the Stikine Terrane of northwestern B.C., formed in Middle Jurassic time, and was deformed during the Cretaceous as a result of amalgamation of more outboard terranes during assemblage of the Cordillera (Evenchick et al., 2001). The basin was filled by a westerly-prograding succession of marine and nonmarine clastic facies from Middle Jurassic to Early Cretaceous time (Evenchick and Thorkelson, 2005). The basin is underexplored (most activity has focussed on the Groundhog Coalfield), but houses some currently unassessed hydrocarbon potential (Evenchick et al., 2006). The Bowser Lake Group is subdivided into a complex of interfingering, and poorly dated, units representing deep marine to nonmarine environments (Evenchick et al., 2001). Gradationally overlying the siliceous tuffs of the Hazelton Group, the Middle to Upper Jurassic Todagin assemblage is dominated by dark grey to black siltstone and silty mudstone with thin interbeds of medium to coarse grained sandstone and rare thick pebble conglomerate lenses (Evenchick and Thorkelson, 2005). Similar rocks were originally mapped as the Ashman Formation. These strata are up to 2500 m thick, recessive-weathering, and synsedimentary deformation and slump folding is present in some areas. These deposits are interpreted to represent sedimentation in a slope setting with subordinate submarine fan and channel facies (Evenchick and Thorkelson, 2005).

The Todagin-Ashman succession of Bowser Basin includes a thick sequence with possible organic-rich intervals (possibly Type II/III organics), with abundant coarser interbeds. Some vitrinite reflectance data suggest that much of the basin may be thermally mature to overmature and oil staining has been identified (Evenchick and Thorkelson, 2005). Although little is known about these rocks, there could be potential for a Style D (Lewis-like) shale gas play. However, much further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and fracture patterns are unknown. These strata reside in a distant frontier basin, but one which is of increasing exploration interest, and further work is currently ongoing.

Kunga/Maude (Jurassic)

The Queen Charlotte Islands lie on the western margin of the Wrangellia allocthonous terrane, which has been translated northward about 2500 km since deposition (Thompson et al., 1991; Cameron and Tipper, 1985). Jurassic rocks were deposited into a northwesterly-trending, deep-water, back-arc basin behind a volcanic arc positioned offshore from the craton. The Jurassic rocks (approximately time-correlative to similar Wrangellia rocks on Vancouver Island) are mainly clastic facies encompassing five major transgressive-regressive cycles and deposited in deep to shallow marine settings (Cameron and Tipper, 1985). These rocks, which likely extend into the offshore (Hamilton and Cameron, 1989), were later affected by multiple regional fold and fault events and magmatic thermal anomalies (Thompson et al., 1991; Lyatsky and Haggart, 1993). Onshore and offshore exploration occurred in the 1950-1970 period, and the prime source rocks for many hydrocarbon shows are considered to lie within the Kunga and Maude Groups (Fowler et al., 1988; Hamilton and Cameron, 1989; Lyatsky and Haggart, 1993).

The Late Triassic-Early Jurassic Kunga Group comprises the lower Sadler Formation grey limestone, the middle Peril Formation black limestone and the upper Sandilands Formation which consists of up to 500 m of Hettangian-Sinemurian-aged mudstones which correlate with the Harbledown Formation of Vancouver Island (Cameron and Tipper, 1985). These upper strata are typically dark grey to black, thin-bedded, pyritic, fossiliferous mudstone (with a prominent fetid odour and oil staining), with thin interbeds of grey siltstone, limestone, tuff and graded lithic sandstone deposited in a deep euxinic marine environment (Cameron and Tipper, 1985; Hamilton and Cameron, 1989). The unit tends to fine-upward, is brittle with common fracturing, and it grades up into the overlying Maude Group. The GSC Rock-Eval Database includes 64 samples of Kunga Formation with the following characteristics: TOC up to 8.70, averaging 3.09; T_{max} up to 508, averaging 453; S_1 up to 12.36, averaging 2.77; S_2 up to 87.67, averaging 18.60; S_3 up to 1.10, averaging 0.35; HI up to (?)1150, averaging 472; OI up to 51, averaging 14 (M. Obermajer, 2006, pers. comm.).

The Lower to Middle Jurassic Maude Group comprises five formations, in ascending order: 1) Ghost Creek, dark grey bituminous shale up to 68 m thick with fetid odour and oil staining and with thin interbeds of grey limestone, deposited in a deep euxinic environment, 2) Rennell Junction fine grained sandstone, siltstone and grey shale, 3) Fanin tuffaceous sandstones, 4) Whiteaves greenish shale, and 5) Phantom Creek fine to coarse sandstones (Cameron and Tipper, 1985; Hamilton and Cameron, 1989). In some areas, Ghost Creek shales are tuffaceous, hard and brittle. The Sandilands and Ghost Creek formations contain Type I and II organic matter, TOC ranging 1-10% (average 1-4%) in individual beds up to 10 m thick, and thermal maturity generally in the mature to overmature range (increasing from north to south), suggesting very good petroleum generative potential (Vellutini and Bustin, 1991a, b). They were previously evaluated as sub-economic oil shales (Hamilton and Cameron, 1989).

The Kunga-Maude succession includes a thick sequence with good to excellent source rock intervals (likely Type II/III organics), which range from thermally mature to overmature, with abundant coarser interbeds. These rocks are siliceous, brittle and fractured. There appears to be potential for a Style C (Barnett-like) play or a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and fracture patterns are unknown. These strata reside in a distant tectonically-disturbed frontier basin, but one which has experienced some past successful exploration. The presence of a thick, organic-rich succession of thermally-mature mudstones with significant fracturing over a significant area indicates the possibilities for shale gas potential. However, these rocks may have already sourced significant volumes of hydrocarbon, and therefore may have less potential. In any case, and very importantly, the remote and environmentally-sensitive location, and the current exploration moratorium in the west coast offshore, precludes any further analysis for the present.

Whitestone River (Lower Cretaceous)

Eagle Plain Basin is a large intermontane basin, 170 x 80 km in size and traversed by the Dempster Highway, in northern Yukon which is underlain by up to 2500 m of Mesozoic strata. Oil and gas exploration began in 1957 and 33 wells have been drilled to date with several discoveries and multiple minor shows (Hamblin, 1990; Dixon, 1992). The Whitestone River Formation, defined by Dixon (1992) and of Albian age, rests unconformably on Paleozoic rocks, is poorly exposed but is present in subsurface wells and 10 cores, at depths of greater than 1000 m. The Whitestone River comprises up to 1545 m (thinning to the southeast) of dark grey to grey, marine, fossiliferous mudstone with very thin laminations of siltstone, very fine sandstone and ironstone concretions, generally in a coarsening-upward succession (Dixon, 1992). Dixon (1992) reported Rock-Eval data from 8 wells and concluded that all Mesozoic shales in Eagle Plain Basin have Type III gas-prone organic matter, but low TOC values (generally <2%) and low thermal maturities (T_{max} = 425-450). However, one 20 m horizon in the upper part of the Whitestone River in one well yielded more positive source rock characteristics. At this time, the shale gas potential of the Whitestone River is poorly understood, but could be significant.

The Whitestone River Formation includes a very thick sequence with fair source rock intervals (Type III organics), which range from thermally immature to mature, with abundant coarser interbeds. There is little data currently available on the geochemistry or maturity of these rocks. There appears to be fair potential for a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and fracture patterns are unknown. These strata reside in the shallow portions of a distant frontier basin, but one which has experienced some past successful exploration and has some infrastructure.

Parkin/Burnthill Creek (Upper Cretaceous)

Eagle Plain Basin is a large intermontane basin, 170 x 80 km in size and traversed by the Dempster Highway, in northern Yukon which is underlain by up to 2500 m of Mesozoic strata. Oil and gas exploration began in 1957 and 33 wells have been drilled to date with several discoveries and multiple minor shows (Hamblin, 1990; Dixon, 1992). The Parkin and Burnthill Creek formations of the Eagle Plain Group, defined by Dixon (1992) and of Cenomanian-Turonian ages, rest unconformably on the Lower Cretaceous Whitestone River Formation at depths greater than 500 m. The Shale Member of the Parkin Formation comprises up to 317 m (thinning to the southeast) of transgressive dark grey to black marine shale with minor thin interbeds of burrowed siltstone and very fine sandstone, in a generally regressive coarsening-upward sequence which passes gradationally into the overlying Fishing Branch Formation sandstones (Dixon, 1992). Abruptly overlying the Fishing Branch is the shale-dominant Burnthill Creek Formation, up to 430 m thick, which passes gradationally upward into the Cody Creek

Formation sandstones. The Burnthill Creek consists primarily of dark grey to black, marine to marginal marine shale with thin to thick interbeds of siltstone and fine sandstone (Dixon, 1992). Dixon (1992) reported Rock-Eval data from 8 wells and concluded that all Mesozoic shales in Eagle Plain Basin have Type III gas-prone organic matter, but low TOC values (generally <2%) and low thermal maturities (T_{max} = 425-450). At this time, the shale gas potential of the Parkin and Burnthill Creek formations is poorly understood.

The Parkin and Burnthill Creek formations include thick sequences with fair source rock intervals (Type III organics), which range from thermally immature to mature, with abundant coarser interbeds. There is little data currently available on the geochemistry or maturity of these rocks. There appears to be fair potential for a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and fracture patterns are unknown. These strata reside in the shallow portions of a distant frontier basin, but one which has experienced some past successful exploration and has some infrastructure.

Princeton/Kamloops (Eocene)

Within the interior of British Columbia are a number of fault-bounded basins, of Tertiary age, which contain nonmarine sedimentary and volcanic rocks. They are generally geographically small, geologically complex and have received very little detailed study: hence, their hydrocarbon potential is currently very poorly understood. Enclosed coal seams have been mined in the past, and may provide coal-bed methane prospects in the future. Most of these basins formed as extensional grabens during a phase of regional right-lateral shear as the Pacific Plate moved northward past the Cordillera (Parrish et al., 1988; Gabrielse and Yorath, 1991; Constenius, 1996) and their sedimentary successions have distinct similarities. In the western Intermontane Belt, the basins are, from south to north: Princeton, Tulameen, Quilchena, Merrit, and Hat Creek (White, 1947; Williams and Ross, 1979; McMechan, 1983). Similarly, in the eastern Intermontane Belt they are White Lake, Summerland, Kelowna, Vernon, Kamloops, Chu Chua, Horsefly, Bowron River and Quesnel (Jones, 1969; Church, 1973; Graham and Long, 1979; Ewing, 1981). Sedimentary fill sequences (Princeton Group, Kamloops Group) are of Early Eocene-Early Oligocene ages, can be hundreds to thousands of metres thick due to rapid subsidence rates, and typically include a basal fluvial coarse grained unit, a thick medial lacustrine mudstone and coal unit (Allenby, Coldwater, White Lake, Tranquille and Kishenehn formations), and an upper fluvial sandstone/mudstone unit. Mudstones are of lacustrine origin, may be very thick and of basin-wide distributions, and may be organic-rich as is common in lacustrine successions worldwide. In the U.S. portion of the Kishenehn Basin, thick accumulations of algal-rich oil shales and sapropelic coals with TOC up to 35% are present (with individual oil shale beds attaining thicknesses of 10 m): where sampled at surface these Type I organics are immature, but the presence of oil and gas shows suggests that deeper in the basin the maturity increases (Curiale et al., 1988).

Geological understanding of the Tertiary Intermontane Basins of the southern Cordillera is among the lowest of all basins in Canada, and the complex combination of potential thermogenic, biogenic and coal-bed gas makes petroleum systems analysis extremely difficult until more information is available. However, experience on the U.S. side of Kishenehn Basin suggests a positive outlook is warranted. These basins may include thick sequences with fair to good source rock intervals (Type I and/or Type III organics) and abundant coarser interbeds, which range from thermally immature to overmature. There is little data currently available on the geochemistry and maturity of these rocks, or the abundant structural/fracture complications. There appears to be fair, but purely speculative, potential for Style D (Lewis-like) plays. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and fracture patterns are unknown. Outcrops are scarce and the basins are geographically limited, and it would be necessary to synthesize whatever subsurface data is present. These strata reside in multiple small frontier basins, located in southern Canada in an area with well-developed infrastructure, which are gaining importance due to emerging CBM, water, agricultural and land use questions.

NORTHWEST TERRITORIES (N.W.T.) (Figure 4)

Road River (Ordovician-Devonian)

Thick Middle Ordovician to Middle Devonian carbonate platform limestones and dolostones pass westward into the thick basinal shale succession of the Road River Formation of the Richardson Trough, present in Liard and Peel Plateau areas (Pugh, 1983). The Road River is a widely distributed, thick sequence of deeper marine dark grey to black, graptolitic mudstones with subordinate interbedded argillaceous limestone, siltstone and fine sandstone turbidite beds, possibly up to 2000 m thick (Pugh, 1983; Morrow, 1999). The Road River was deposited in a variety of basin and slope pelagic settings below normal wave-base, representing the initial deepening of the Richardson Trough and thicknesses of 500 m are more normal (Morrow, 1999). A lower member of limestone and argillaceous limestone is Late Cambrian to Early Ordovician age, whereas the upper, recessive, shale-dominated member is of Ordovician, Silurian and Early Devonian age (Cecile, 1982). Later work in Yukon subdivided the Road River Group into three formations, in ascending order: 1) Rabbitkettle dark grey to black, rhythmically-bedded argillaceous lime mudstone up to 2000 m thick, 2) Loucheux black graptolitic shale with limestones and resedimented carbonate breccias up to 450 m thick, and 3) Dempster grey argillite and dolostone up to 150 m thick (Cecile et al., 1982; Morrow, 1999).

The Road River has Type I and II organic matter with TOC up to 10%, particularly in the lower and upper graptolite-bearing and siliceous shale units of deepwater origin (Link et al., 1989). The GSC Rock-Eval Database includes 20 samples of Road River Formation with the following characteristics: TOC up to 3.07, averaging 1.41; T_{max} up to 530, averaging 436; S_1 up to 0.88, averaging 0.37; S_2 up to 1.84, averaging 0.77; S_3 up to 2.05, averaging 0.59; HI up to 126, averaging 62; OI up to 151, averaging 43 (M. Obermajer, 2006, pers. comm.). These strata are generally overmature with respect to oil, residing in the gas window (Link and Bustin, 1989).

The Road River succession includes a very thick sequence with apparently good to excellent source rocks intervals (Type I/II organics), which are thermally mature to overmature, and some coarser interbeds. There may be potential for a Style C (Barnett-like) play or a Style B (Ohio/New Albany-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, fracture patterns are unknown and very few samples have been analysed. These strata reside in a frontier basin, but one which has experienced past and present successful exploration and has active infrastructure. Recent and future development in the adjacent Mackenzie Corridor are important positive factors in the gas shale potential of the Road River.

Bluefish/Hare Indian (Middle Devonian)

In Peel Plateau area of N.W.T., the Middle to Upper Devonian Hare Indian Formation represents a thick, fine grained transgressive succession which abruptly overlies the Hume carbonate platform (Kunst, 1973). The initial, anoxic, transgressive shale is represented by the basal, thin but widespread, Bluefish Member (formerly called "spore-bearing member") dark grey to brown to black, bituminous and pyritiferous mudstone. The Bluefish is typically calcareous at the base, grading up into noncalcareous laminated shale, is fossiliferous, 15-30 m thick and is of Givetian age (Pugh, 1983). The sequence becomes more fissile, recessive, less calcareous and higher in clay toward the top (Al-Aasm et al., 1996). The overlying Upper Member of the Hare Indian comprises up to about 250 m (thinning to the west) of dark brownish to greenish grey, calcareous, silty marine shale with thin argillaceous limestone and siltstone beds in an overall coarsening-upward sequence (Kunst, 1973; Pugh, 1983). This member is typically organized into at least three 10-25 m thick cycles (Al-Aasm et al., 1996). These strata were deposited in a shallow marine to slope environment which grades upward into the Kee Scarp Formation (Kunst, 1973; Pugh, 1983).

For the Bluefish Member, TOC ranges up to 10.4%, whereas that of the Upper Member ranges 1-3% (Al-Aasm et al., 1996). The GSC Rock-Eval Database includes 88 samples of Bluefish Member with the following characteristics: TOC up to 9.27, averaging 3.31; T_{max} up to 585, averaging 440; S_1 up to 4.58, averaging 1.23; S_2 up to 37.44, averaging 7.49; S_3 up to 3.02, averaging 0.89; HI up to 878, averaging 209; OI up to 149, averaging 33 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 51 samples of Hare Indian Formation with the following characteristics: TOC up to 7.47, averaging 1.52; T_{max} up to 506, averaging 447; S_1 up to 4.67, averaging 0.76; S_2 up to 37.90, averaging 3.13; S_3 up to 1.20, averaging 0.37; HI up to 621, averaging 160; OI up to 324, averaging 60 (M. Obermajer, 2006, pers. comm.).

The Bluefish/Hare Indian succession is clearly an organic-rich shale section of significant thickness with apparently good to excellent source rocks intervals (Type II/III organics) and some coarser interbeds, which are thermally mature to overmature. There may be good geological potential for a Style C (Barnett-like) play or a Style B (Ohio/New Albany-like) play. However, further integrated study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The fracture patterns are unknown. These strata reside in a frontier basin, but one which has experienced past and present successful exploration and has active infrastructure. Recent and future development in the adjacent Mackenzie Corridor are important positive factors in the gas shale potential of this unit. Within the Mackenzie Corridor, this unit may present some of the best prospects for shale gas potential.

Canol/Muskwa/Imperial/Fort Simpson (Middle - Upper Devonian)

In southern N.W.T., in Liard and Cameron Hills, the Upper Devonian Muskwa-Fort Simpson succession comprises a thick, fine grained transgressive-regressive succession deposited on gently sloping ramps (Hadley and Jones, 1990). These strata denote a major transgression over the underlying Slave Point (Presqu'ile) carbonate platform, creating an initial deep-water, anoxic environment, followed by regression, and they generally coarsen-upward. The Muskwa Formation (Frasnian age) is a dark brown to black, bituminous, pyritic, siliceous to calcareous mudstone up to 37 m thick, which is gradationally overlain by the Fort Simpson Formation (Hadley and Jones, 1990). The Fort Simpson comprises up to 1000 m (generally about 300 m) of greenish grey, calcareous, fossiliferous shale with thin bioclastic limestone and calcareous siltstone beds, occurring in a general coarsening-upward trend (Hadley and Jones, 1990). Farther west, equivalent strata are part of the Besa River Formation.

To the north, in Peel Plateau, the Middle to Upper Devonian Canol and Imperial formations represent a thick wedge of dark-coloured fine grained clastics which thin to the south and southwestward (Pugh, 1983). These strata denote a major transgression over the underlying Kee Scarp carbonate platform, creating an initial deep-water, anoxic environment, followed by regression, and they generally coarsen-upward. The Canol (Frasnian age) is a highly radioactive, dark grey to black bituminous shale, commonly siliceous and pyritic, up to about 100 m thick, which is gradationally overlain by the Imperial Formation (Pugh, 1983). In this region, it was deposited under uniform anoxic conditions (Al-Aasm et al., 1996). The Imperial (Frasnian to Fammenian age) comprises up to about 600 m of grey to dark grey marine mudstone, siltstone and minor very fine sandstone and limestone, in a generally coarsening-upward sequence, which was derived primarily from the north (Martin, 1972; Pugh, 1983). In this region, it was deposited in relatively deep to shallow, more oxygenated, marine conditions.

The Muskwa of northeast B.C. commonly has TOC greater than 2% and is thermally mature to overmature, whereas the Fort Simpson is leaner, with TOC of 1-2% (Fowler et al., 2001). The GSC Rock-Eval Database includes 253 samples of Muskwa Formation (most in N.W.T., some in Alta. and B.C.) with the following characteristics: TOC up to 13.61, averaging 1.93; T_{max} up to 583, averaging 461; S_1 up to 8.78, averaging 0.77; S_2 up to 66.11, averaging 3.64; S_3 up to 1.99, averaging 0.31; HI up to 721, averaging 158; OI up to 191, averaging 25 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 68 samples of Fort Simpson Formation (most in Alta. and B.C.) with the following characteristics: TOC up to 6.98, averaging 0.88; T_{max} up to 588, averaging 410; S_1 up to 12.44, averaging 0.59; S_2 up to 18.46, averaging 1.56; S_3 up to 8.47, averaging 0.66; HI up to 528, averaging 138; OI up to 340, averaging 95 (M. Obermajer, 2006, pers. comm.).

Black bituminous shale of the Canol Formation has significant amounts of Type II and III organic matter (TOC up to 9%) and is mature to overmature with respect to oil (Link and Bustin, 1989; Link et al., 1989). The GSC Rock-Eval Database includes 292 samples of Canol Formation (most in N.W.T., some in Yukon) with the following characteristics: TOC up to 27.14, averaging 4.59; T_{max} up to 580, averaging 445; S_1 up to 20.13, averaging 2.07; S_2 up to 90.88, averaging 12.88; S_3 up to 4.79, averaging 0.85; HI up to 625, averaging 223; OI up to 242, averaging 23 (M. Obermajer, 2006, pers. comm.). The Imperial Formation has moderate amounts of Type III organic matter, TOC averaging about 1%, and is within the gas window (Link and

Bustin, 1989; Link et al., 1989). The GSC Rock-Eval Database includes 1015 samples of Imperial Formation (most in N.W.T., some in Yukon) with the following characteristics: TOC up to 7.49, averaging 1.09; T_{max} up to 559, averaging 441; S_1 up to 11.14, averaging 0.42; S_2 up to 32.73, averaging 1.32; S_3 up to 7.61, averaging 0.39; HI up to 869, averaging 93; OI up to 381, averaging 51 (M. Obermajer, 2006, pers. comm.).

The Canol/Muskwa/Imperial/Fort Simpson succession in N.W.T. and NE B.C. is clearly a very thick organic-rich shale section with apparently fair to excellent source rock intervals (Type II/III organics) and abundant coarser interbeds, which are thermally mature to overmature. Although much of the stratigraphic thickness of these units include rocks which are relatively lean, their great thickness and widespread distribution are positive factors. In addition, there are significant organic-rich intervals of excellent source rocks. There may be good geological potential for a Style C (Barnett-like) play or a Style B (Ohio/New Albany-like) play. However, further integrated study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and the fracture patterns are unknown. These strata reside in a frontier basin, but one which has experienced past and present successful exploration and has active infrastructure. Recent and future development in the adjacent Mackenzie Corridor are important positive factors in the gas shale potential of this unit. Within the Mackenzie Corridor, this unit may present some of the best prospects for shale gas potential.

Arctic Red/Fort St. John (Middle Cretaceous)

Middle Cretaceous (Albian) strata, primarily thick shaly units, are widely distributed through the northern Interior Plains and have significant shale gas potential. In Peel Plain, Mackenzie Plain and Great Bear Plain the Arctic Red Formation is a shale-dominated succession 350-400 m thick (locally up to 1500 m), composed of dark grey to black, fissile, silty to sandy mudstone with ironstone concretions and thin bentonite beds, and thin silty beds arranged into an overall coarsening-upward, progradational succession (Dixon, 1999). The Arctic Red is characterized by faunas of Early to late Albian age and prograding deltaic clinoforms, suggesting deposition in a low-energy marine shelf setting (Dixon, 1999). In one area along Mackenzie River the Arctic Red is unconformably overlain by 400-800 m of Slater River Formation (Turonian age, partly equivalent to the Boundary Creek formation) soft, black, radioactive shales with thin bentonite beds and minor thin siltstone laminae, deposited in a low-energy, reducing marine environment (Dixon, 1999). The presence of these strata considerably increases the thickness of organic-rich mudstone in that area.

In Great Slave Plain of southwestern N.W.T. and adjacent northeast B.C., the Albian-Cenomanian Fort St. John Group is a marine shale-dominated succession up to 600 m thick (thinning eastward), with several sandy units (Dixon, 1999). In northeastern B.C., these units meld into the very thick, dark grey to black marine mudstone, with sideritic concretions at the base, of the Buckinghorse Formation, up to 1000 m thick (Glass, 1990). These strata partly represent the distal equivalents of the Lower Cretaceous Wilrich/Moosebar/Clearwater/Ostracod and Middle to Upper Cretaceous Colorado/Alberta/Smoky shale successions of the WCSB. Several prominent radioactive shale intervals are present at specific stratigraphic levels within the Fort St. John (at the base of the Garbutt shale, the base of the Lepine shale, and a third near the top of the Group at a point approximately equivalent to the Fish Scale Marker of WCSB), interpreted as resulting from major basin-wide transgressions, followed by progradational, coarsening-upward sequences (Dixon, 1999). This stratigraphic arrangement of distinct radioactive, organic-rich shale intervals separated by shale-rich progradational sequences is reminiscent of that of the Colorado Group of WCSB.

Arctic Red strata generally contain Type II and III organic matter and have moderate organic contents between 1 and 2%, ranging from mature to overmature conditions (Dixon, 1999). The GSC Rock-Eval Database includes 734 samples of Arctic Red Formation with the following characteristics: TOC up to 15.76, averaging 1.49; T_{max} up to 519, averaging 438; S_1 up to 32.35, averaging 0.45; S_2 up to 17.68, averaging 1.54; S_3 up to 5.05, averaging 0.61; HI up to 358, averaging 95; OI up to 261, averaging 41 (M. Obermajer, 2006, pers. comm.). Slater River shales range up to 8% TOC, with Type I and II organic matter in an immature to marginally mature state. The GSC Rock-Eval Database includes 169 samples of Slater River Formation with the following characteristics: TOC up to 8.02, averaging 1.63; T_{max} up to 448, averaging 431; S_1 up to 3.94, averaging 0.33; S_2 up to 25.44, averaging 2.63; S_3 up to 4.51, averaging 0.90; HI up to 477, averaging 113; OI up to 393, averaging 69 (M. Obermajer, 2006, pers. comm.).

Within the Fort St. John Group, the radioactive shales at the base of the Garbutt and the base of the Lepine have TOC up to 3% and are marginally mature to mature (Dixon, 1999). The GSC Rock-Eval Database includes 303 samples of Fort St. John Group (in northwest Alberta and northeast B.C.) with the following characteristics: TOC up to 6.25, averaging 1.33; T_{max} up to 462, averaging 432; S_1 up to 9.12, averaging 0.34; S_2 up to 33.01, averaging 3.07; S_3 up to 14.01, averaging 0.63; HI up to 737, averaging 180; OI up to 338, averaging 48 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 23 samples of Garbutt shale (in northwest Alberta and northeast B.C.) with the following characteristics: TOC up to 1.84, averaging 1.20; T_{max} up to 447, averaging 439; S_1 up to 1.39, averaging 0.51; S_2 up to 3.98, averaging 2.49; S_3 up to 0.97, averaging 0.49; HI up to 353, averaging 216; OI up to 144, averaging 52 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 95 samples of Lepine shale (all in northeast B.C.) with the following characteristics: TOC up to 2.41, averaging 0.90; T_{max} up to 447, averaging 437; S_1 up to 1.07, averaging 0.19; S_2 up to 8.43, averaging 1.90; S_3 up to 1.30, averaging 0.42; HI up to 517, averaging 200; OI up to 126, averaging 48 (M. Obermajer, 2006, pers. comm.).

The Arctic Red-Fort St. John succession in N.W.T. and NE B.C. is clearly a thick shale section with apparently fair source rocks intervals (Type II/III organics, TOC=1-2%) and abundant coarser interbeds, which are thermally mature. Although the rocks are relatively lean, their considerable thickness and widespread, shallow distribution are positive factors. In general, these strata should have significant shale gas potential, of both shallow biogenic and deeper thermogenic styles, and there may be good potential for a Style I (Antrim-like) play or a Style D (Lewis-like) play. However, further integrated study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and the fracture patterns are unknown. Development of this play might proceed if other shale gas plays in N.W.T. proved successful. These strata reside in a frontier basin, but one which has experienced past and present successful exploration and has active infrastructure. Recent and future development in the adjacent Mackenzie Corridor are important positive factors in the gas shale potential of this unit.

Boundary Creek/Smoking Hills (Upper Cretaceous)

Upper Cretaceous strata are preserved as an unconformity-bounded succession in various parts of the N.W.T., primarily as thin outliers in Anderson, Horton and Great Slave Plains, and as thicker strata beneath Mackenzie Delta and in Liard Basin (Young, 1975; Dixon, 1999). The Boundary Creek Formation of the Mackenzie delta area comprises dark grey to black, bituminous and pyritic, recessive shale up to 240 m thick, with minor argillaceous calcarenite limestones and thin bentonitic beds which was deposited in a quiet, stagnant reducing marine setting (Young, 1975). These strata, of Cenomanian-Campanian age, are soft and plastic, displaying disharmonic folds in outcrop, rather than fractures (Young, 1975). In one area along Mackenzie River there is 400-800 m of Slater River Formation (Turonian age, partly equivalent to the Boundary Creek formation) comprising soft, black, radioactive shales with thin bentonite beds and minor thin siltstone laminae, deposited in a low-energy, reducing marine environment (Dixon, 1999). The partly-correlative Smoking Hills Formation (Santonian-Campanian age) of Anderson Plain derives its name from the exposed hills at Franklin Bay where the shales “burn” continuously due to pyrite oxidation (Dixon, 1999). Smoking Hills shale, deposited in a low energy, reducing environment below wave-base, is black, fissile pyritic and radioactive, with thin bentonite beds, and up to 500 m thick in subsurface (Dixon, 1999).

Snowdon (1980) mentioned the reputation of the Boundary Creek as “one of the richest known source rocks in Canada” and suggested that the mixture of Type II and III organic matter and TOC ranging from 1-7% make these rocks excellent potential source rocks, but that the immature to marginally mature state render that potential unrealized. However, its stratigraphic position between thick shaly packages may have inhibited previous hydrocarbon migration (Snowdon, 1980). Smoking Hills strata have TOC ranging 2-12%, with moderate HI and high OI indicating Type II and III organic matter in an immature to marginally mature state. The GSC Rock-Eval Database includes 40 samples of Boundary Creek Formation with the following characteristics: TOC up to 7.49, averaging 3.88; T_{max} up to 562, averaging 420; S_1 up to 4.97, averaging 0.86; S_2 up to 10.56, averaging 4.67; S_3 up to 5.68, averaging 2.98; HI up to 218, averaging 118; OI up to 228, averaging 83 (M. Obermajer, 2006, pers. comm.). Similarly, the GSC Rock-Eval Database includes 236 samples of Smoking Hills Formation with the following characteristics: TOC up to (coal?)50.04, averaging 3.57; T_{max} up to 493, averaging 425; S_1 up to 7.02, averaging 0.48; S_2 up to 59.20, averaging 4.80; S_3 up to 9.95, averaging 1.48; HI up to 524, averaging 115; OI up to 374, averaging 70 (M. Obermajer, 2006, pers. comm.).

The Boundary Creek-Smoking Hills succession in northern N.W.T. is clearly a thick organic-rich shale section with apparently good to excellent, organic-rich source rocks intervals (Type II/III organics) and some coarser interbeds, which are thermally immature to marginally mature. The considerable thickness, richness and widespread, shallow distribution are positive factors which may make this unit very prospective. In general, these strata should have significant shale gas potential, of both shallow biogenic and deeper thermogenic styles, and there may be good potential for a Style A (Antrim-like) play or a Style D (Lewis-like) play. However, further integrated study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology are not well known, and the rocks may be too soft for extensive fracturing to be significant. These strata reside in a frontier basin, but one which has experienced past and present successful exploration and has active infrastructure. Recent and future development in the adjacent Mackenzie Delta and Corridor are important positive factors in the gas shale potential of this unit.

NUNAVUT (Figure 4)

Cape Phillips (Upper Ordovician-Lower Devonian)

The Lower Paleozoic of Ellesmere, Cornwallis, Bathurst and Melville islands (Franklinian Basin/Arctic Fold Belt) includes a thick carbonate platform deposited along the southeastern margin of Hazen Trough, represented by the shallow marine limestones and dolostones of the Allen Bay Formation and Read Bay Group (Trettin, 1979). Adjacent and basinward of this development are the coeval thick dark shales of the Cape Phillips Formation (and equivalents), deposited in a slope to basin setting (Trettin, 1979). The Cape Phillips, of Late Ordovician to Early Devonian age, comprises up to 3000 m (thinning to the northwest) of dark grey, recessive, laminated calcareous siltstone, mudstone and argillaceous limestone (Kerr, 1976; Mayr, 1980). It is divided into a thin lower member of dolomite and limestone (70-100 m thick), a thin middle member of argillaceous limestone and cherty mudstone (100-125 m thick), and a thick upper member of uniform, laminated, graptolitic and pyritic, calcareous and noncalcareous mudstone with interbedded thin argillaceous limestone (300-800+ m thick) (Trettin, 1979; Mayr, 1980).

Data regarding the organic richness, thermal maturity and natural fractures are not common, but analysis of two samples yielded TOC of 0.78-6.86% (Trettin, 1979). According to Powell (1978), 24 samples of shales of the Cape Phillips were characterized by relatively high TOC (2-5%) and ranged from thermally mature to overmature. Stasiuk and Fowler (1994) found the Cape Phillips to have good source rock potential, with thermally-mature Type I-II kerogen and TOC contents ranging from 0.2 to 5.6%. The GSC Rock-Eval Database includes 437 samples of Cape Phillips Formation with the following characteristics: TOC up to 6.70, averaging 1.81; T_{max} up to 586, averaging 444; S_1 up to 4.40, averaging 0.66; S_2 up to 18.82, averaging 1.74; S_3 up to 3.79, averaging 0.30; HI up to 620, averaging 97; OI up to 642, averaging 21 (M. Obermajer, 2006, pers. comm.).

The Cape Phillips succession includes a very thick and widespread sequence with apparently good source rock intervals (likely Type II organics), and some coarser interbeds, which are thermally mature to overmature . The hydrocarbon potential of these strata may be significant and there may be good geological potential for a Style C (Barnett-like) play or a Style B (Ohio/New Albany-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology of the Cape Phillips are not well known and fracture patterns are unknown. These strata reside in a remote frontier basin with no active infrastructure, but one which has experienced some past successful exploration.

Cape de Bray (Middle Devonian)

From the earliest Middle Devonian to the Early Carboniferous clastic sedimentation dominated in the Franklinian Basin (Arctic Fold Belt) and a thick and widespread clastic wedge prograded southwestward (over the areas of Bathurst, Melville, Prince Patrick and Banks islands), heralding the advance of Ellesmerian deformation (Embry, 1991a). The lower portion of this enormous wedge includes a progradational succession (resting on the Cape Phillips Formation) ranging from deep marine to fluvial floodplain with the marine slope to basinal deposits represented by the Eifelian-Givetian-aged Cape de Bray Formation (Embry and Klovan, 1976; Mayr, 1980; Embry, 1991a). The Cape de Bray Formation comprises 100-1025 m of grey to dark grey, recessive, noncalcareous, micaceous silty shale with thin, sharp-based interbeds of fossiliferous and burrowed siltstone to fine sandstone arranged in coarsening-upward bundles (Embry and Klovan, 1976; Goodbody, 1993). Clinoforms, corresponding to the original depositional slope have been identified on seismic, and the unit grades upward into marine shelf strata of the Weatherall Formation (Embry, 1991a).

There are currently few data available regarding organic richness or thermal maturity, although Powell (1978) and Embry et al. (1991) suggested that TOC from 19 samples was low (~0.5%) and that the shales are mature. The GSC Rock-Eval Database includes 31 samples of Cape de Bray Formation with the following characteristics: TOC up to 1.47, averaging 0.29; T_{max} up to 473, averaging 439; S_1 up to 0.42, averaging 0.13; S_2 up to 2.61, averaging 0.42; S_3 up to 1.47, averaging 0.40; HI up to 321, averaging 144; OI up to 334, averaging 136 (M. Obermajer, 2006, pers. comm.). The Cape de Bray is deformed by folds, thrusts and ductile flow in the Canrobert Fold Belt of Melville Island (Harrison et al., 1991).

The Cape de Bray succession includes a thick and widespread sequence with apparently poor to fair source rocks intervals (Type II/III organics), and some coarser interbeds, which are thermally mature. The hydrocarbon potential of these strata probably is not significant, but there may be some potential for a Style D (Lewis-like) play. Further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy could lead to better understanding of the shale gas potential. The detailed stratigraphy and sedimentology of the Cape de Bray are not well known and fracture patterns are unknown, although modest deformation is documented. These strata reside in a remote frontier basin with no active infrastructure, but one which has experienced some past successful exploration.

Hare Fiord/Van Hauen (Carboniferous-Permian)

Upper Carboniferous to Permian rocks of the Arctic Archipelago define a 5-part set of facies belts roughly parallelling the NE-SW depositional axis of the Sverdrup Basin (Davies and Nassichuk, 1991). The marginal Clastic, Marginal Clastic and Carbonate and the Southeastern Carbonate belts define the southeast margin of that basin, whereas the Northwestern Carbonate Belt defines the northwest margin: between these is the Central Basinal Clastic and Evaporite Belt with deeper-water, axial slope deposits (Thorsteinsson, 1974; Davies and Nassichuk, 1991). Within this latter belt, the Upper Carboniferous-Lower Permian Hare Fiord Formation mudstones and the disconformably-overlying Lower Permian Van Hauen Formation mudstones and cherts were deposited.

The Hare Fiord comprises 300-1250 m of dark grey to brown, hard, noncalcareous, quartzose siltstone, micaceous shale, argillaceous limestone (primarily in the lower part) and minor fine sandstone, with a slight petroliferous odour (Thorsteinsson, 1974). These strata are coeval with the adjacent shallow marine carbonates of the Nansen Formation, and massive, lens-shaped vuggy limestone "Waulsortian mound" reefs occur in the lower Hare Fiord near the facies change (Thorsteinsson, 1974; Beauchamp et al., 2001). Large-scale, concave-upward, intraforrmational, slump scar discontinuities due to catastrophic slope failure and gravity sliding are present (Davies and Nassichuk, 1975). The disconformably-overlying Van Hauen Formation comprises up to 800 m of dark grey to black, fissile, siliceous, noncalcareous shale, siltstone with minor chert and sandstone overlain by black, resistant, pyritic, chert and siliceous siltstone which is very brittle (Thorsteinsson, 1974; Beauchamp et al., 2001). These strata are coeval, and pass gradationally upward and laterally into shallow marine sandstone of the Trold Fiord Formation as the basinal facies of a transgressive-regressive sequence (Beauchamp et al., 2001). These strata may have been affected by salt tectonics of the underlying Otto Fiord Formation.

Data regarding the organic richness, thermal maturity and natural fractures are generally lacking. Powell (1978) found relatively lean organic content in 30 samples (about 1%) and Embry et al. (1991) stated that shales of the Hare Fiord and Van Hauen are mature to overmature. The GSC Rock-Eval Database includes 16 samples of Van Hauen Formation with the following characteristics: TOC up to 1.29, averaging 0.97; T_{max} up to 503, averaging 453; S_1 up to 0.42, averaging 0.24; S_2 up to 1.26, averaging 0.53; S_3 up to 1.00, averaging 0.43; HI up to 98, averaging 53; OI up to 90, averaging 42 (M. Obermajer, 2006, pers. comm.).

The Hare Fiord/Van Hauen succession includes a very thick and widespread sequence with apparently fair source rock intervals (likely Type II/III organics), and some coarser interbeds, which are thermally mature to overmature. The hydrocarbon potential of these strata could conceivably be significant and, if so, there may be potential for a Style C (Barnett-like) play or a Style D (Lewis-like) play. However, the lack of relevant information is acute, and further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology of the Hare Fiord/Van Hauen formations are not well known and fracture patterns are unknown, although the presence of salt tectonics suggests significant structural complexity. These strata reside in a remote frontier basin with no active infrastructure, but one which has experienced some past successful exploration.

Blind Fiord/Blaa Mountain (Lower-Upper Triassic)

From Early Triassic to Cretaceous time, the NE-SW elongate Sverdrup Basin was the main depocentre in the Arctic Islands region (accumulating up to 9000 m of thickness) and was dominated by clastic sedimentation, with shallow marine to shoreline deposits occurring along the basin margins, and mudstone units predominating in the basin centre (Embry, 1991b). The Basin extended from northwestern Ellesmere Island to Banks Island. Identification of 31 regional transgressions has allowed subdivision of Mesozoic rocks into a series of Transgressive-Regressive (T-R) sequences, each representing a distinct depositional interval characterized by thin basal transgressive deposits and thicker regressive deposits, typically basin-centre mudstone coarsening-upward to basin-margin sandstone (Embry, 1991b).

Triassic basin-centre facies are represented by the thick conformable shaly packages of the Blind Fiord Formation and Blaa Mountain Group which represent the offshore slope and shelf deposits of several T-R sequences, and pass upward and laterally into marginal shoreline and fluvial facies (Embry, 1991b). The Blind Fiord comprises 330-1210 m of grey to greenish, micaceous, interbedded siltstone and shale, arranged in three coarsening-upward cycles (Embry, 1991b). In the basin centre, the Blind Fiord is overlain conformably by 1500-2500 m of shaly strata including the Middle Triassic Murray Harbour, Middle to Upper Triassic Hoyle Bay and Upper Triassic Barrow formations (all of the Blaa Mountain Group), each of which similarly represents the basinal facies of several T-R sequences and is characterized by multiple coarsening-upward cycles (Embry, 1991). The Murray Harbour Formation consists of black, bituminous shale with abundant phosphate nodules, with increasing silty beds upward; the Hoyle Bay Formation comprises interbedded dark grey bituminous shale and siltstone; the Barrow Formation consists of grey interbedded silty shale and siltstone (Embry, 1991).

A large amount of data regarding the organic richness and thermal maturity of the Blind Fiord, and especially the Blaa Mountain, strata have been collected. Shales of the Murray Harbour and Hoyle Bay contain abundant Type II kerogen (TOC up to 10%) and are thermally mature over much of the western Sverdrup (Embry et al., 1991). Powell (1978) analysed 33 samples from these units and found that TOC ranged 0.2-3.0%. The GSC Rock-Eval Database includes 18 samples of Blind Fiord Formation with the following characteristics: TOC up to 1.29, averaging 0.57; T_{max} up to 445, averaging 430; S_1 up to 0.78, averaging 0.27; S_2 up to 2.12, averaging 0.67; S_3 up to 1.18, averaging 0.42; HI up to 218, averaging 104; OI up to 196, averaging 75 (M. Obermajer, 2006, pers. comm.). Gentzis et al. (1996) lists the following characteristics for 97 samples of the Murray Harbour: TOC up to 3.97, averaging 0.70-3.08; HI up to 563, averaging 103-525; T_{max} up to 455, averaging 438-455; %Ro 0.81-1.10. In the same study, the Hoyle Bay yielded the following from 16 samples: TOC up to 1.89, averaging 0.61-1.57; HI up to 200, averaging 118-133; T_{max} up to 446, averaging 440-446; %Ro 0.73-0.94 (Gentzis et al., 1996). Similarly, 147 samples of Barrow yielded TOC up to 2.04, averaging 0.39-1.07; HI up to 255, averaging 58-226; T_{max} up to 453, averaging 437-444; %Ro 0.68-0.89 (Gentzis et al., 1996). The GSC Rock-Eval Database includes 20 samples of Murray Harbour Formation with the following characteristics: TOC up to 3.01, averaging 1.28; T_{max} up to 494, averaging 442; S_1 up to 1.35, averaging 0.68; S_2 up to 10.02, averaging 2.90; S_3 up to 1.17, averaging 0.46; HI up to 462, averaging 208; OI up to 165, averaging 52 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 24 samples of Hoyle Bay Formation with the following characteristics: TOC up to 2.15, averaging 1.08; T_{max} up to 492, averaging 441; S_1 up to 0.59, averaging 0.24; S_2 up to 7.76, averaging 1.29; S_3 up to 0.89, averaging 0.47; HI up to 361, averaging 104; OI up to 80, averaging 46 (M. Obermajer, 2006, pers. comm.). The GSC Rock-Eval Database includes 103 samples of Barrow Formation with the following characteristics: TOC up to 2.10, averaging 0.82; T_{max} up to 462, averaging 442; S_1 up to 0.51, averaging 0.12; S_2 up to 8.86, averaging 0.74; S_3 up to 3.11, averaging 0.58; HI up to 422, averaging 82; OI up to 331 averaging 77 (M. Obermajer, 2006, pers. comm.).

The Blind Fiord/Blaa Mountain succession includes a very thick and widespread sequence with apparently fair to good source rock intervals (Type II/III organics), and some coarser interbeds, which are thermally mature to overmature. The hydrocarbon potential of these strata may be significant and there may be potential for a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology of these strata are not well known and fracture patterns are unknown. These strata reside in a remote frontier basin with no active infrastructure, but one which has experienced some past successful exploration.

Jameson Bay/Mackenzie King/Savik/Ringnes/Deer Bay (Lower Jurassic-Lower Cretaceous)

From Early Triassic to Cretaceous time, the NE-SW elongate Sverdrup Basin was the main depocentre in the Arctic Islands region, with shallow marine to shoreline deposits occurring along the basin margins, and mudstone units predominating in the basin centre (Embry, 1991b). Identification of 31 regional transgressions has allowed subdivision of Mesozoic rocks into a series of Transgressive-Regressive (T-R) sequences, each representing a distinct depositional interval characterized by thin basal transgressive deposits and thicker regressive deposits, typically basin-centre mudstone coarsening-upward to basin-margin sandstone (Embry, 1991b).

Regional transgression occurred in the Early Jurassic, and as shorelines retreated, offshore mudstones and siltstones of the Jameson Bay Formation were deposited, heralding the very thick, long-lived development of the central basinal facies of the Middle Jurassic to Lower Cretaceous Mackenzie King Formation and various more marginal shale tongue equivalents (Embry, 1991b). The Lower to Middle Jurassic Jameson Bay consists mainly of grey shale and siltstone with minor sandstone representing at least two coarsening-upward T-R sequences (Embry, 1991). In basin centre locations, these shales are overlain by grey to dark grey shale and siltstone with minor ironstone and sandstone beds of the Middle Jurassic McConnell Island Formation, with two or three coarsening-upward T-R sequences (Embry, 1991). The McConnell Island is overlain conformably by Ringnes Formation dark grey to black, bituminous shale with thin siltstone beds which increase upward and large dolostone concretions, deposited in an offshore shelf setting below wave base (Embry, 1991). Higher in the stratigraphy, the Deer Bay Formation is outer shelf dark grey silty shale with thin siltstone and minor sandstone beds, whereas the equivalent Mackenzie King Formation dark grey to black, organic-rich shales with thin siltstone beds were deposited in the basin centre (Embry, 1991). This entire complex of mudstone-dominated deposition is approximately 2000 m thick.

A large amount of data regarding the organic richness and thermal maturity of the Lower Jurassic-Lower Cretaceous strata have been collected. Powell (1978) analysed 81 samples of Mackenzie King and equivalents and found TOC contents ranging up to 5.5% and generally 1-4%. The Jameson Bay Formation contains Type II and Type III kerogen, and is marginally mature to mature (Embry et al., 1991). Gentzis et al. (1996) lists the following characteristics for 221 samples of the Jameson Bay: TOC up to 2.77, averaging 0.59-2.22; HI up to 389, averaging 68-322; T_{max} up to 446, averaging 432-443; %Ro 0.60-0.79. In the same study, the McConnell Island yielded the following from 80 samples: TOC up to 5.46, averaging 2.03-3.23; HI up to 298, averaging 55-167; T_{max} up to 446, averaging 434-443; %Ro 0.57-0.72 (Gentzis et al., 1996). Similarly, 108 samples of Ringnes yielded TOC up to 8.65, averaging 3.38-5.71; HI up to 293, averaging 66-216; T_{max} up to 451, averaging 443-447; %Ro 0.57-0.71 (Gentzis et al., 1996). Stewart et al. (1992) determined that the Ringnes contains immature to overmature, dominantly terrestrial organic matter, with TOC contents up to 11%. In addition, 281 samples of Deer Bay yielded TOC up to 4.66, averaging 1.29-2.85; HI up to 290, averaging 38-140; T_{max} up to 447, averaging 434-440; %Ro 0.52-0.67 (Gentzis et al., 1996).

The GSC Rock-Eval Database includes 146 samples of Jameson Bay Formation with the following characteristics: TOC up to 9.60, averaging 1.22; T_{max} up to 448, averaging 436; S_1 up to 44.72, averaging 0.86; S_2 up to 22.13, averaging 1.83; S_3 up to 4.92, averaging 0.72; HI up to 476, averaging 135; OI up to 252 averaging 63 (M. Obermajer, 2006, pers. comm.). Likewise, the GSC Rock-Eval Database includes 184 samples of Ringnes Formation with the following characteristics: TOC up to 11.00, averaging 4.32; T_{max} up to 454, averaging 436; S_1 up to 2.78, averaging 0.65; S_2 up to 18.60, averaging 6.27; S_3 up to 4.71, averaging 1.19; HI up to 444, averaging 150; OI up to 136 averaging 29 (M. Obermajer, 2006, pers. comm.). And finally, the GSC Rock-Eval Database includes 278 samples of Deer Bay Formation with the following characteristics: TOC up to 13.06, averaging 1.86; T_{max} up to 474, averaging 437; S_1 up to 5.82, averaging 0.26; S_2 up to 29.02, averaging 1.45; S_3 up to 7.40, averaging 1.37; HI up to 222, averaging 77; OI up to 279 averaging 79 (M. Obermajer, 2006, pers. comm.).

The Jameson Bay/Mackenzie King/Savik/Ringnes/Deer Bay succession includes a very thick and widespread sequence with apparently excellent source rock intervals (Type II/III organics), and some coarser interbeds, which are thermally mature. The hydrocarbon potential of these strata is probably very significant and there is likely very good potential for a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology of these strata are not well known and fracture patterns are unknown. These strata reside in a remote frontier basin with no active infrastructure, but one which has experienced some past successful exploration. Within the Arctic Islands, this unit harbours some of the best shale gas potential, based solely on geological characteristics.

Christopher (Lower Cretaceous)

From Early Triassic to Cretaceous time, the NE-SW elongate Sverdrup Basin was the main depocentre in the Arctic Islands region, with shallow marine to shoreline deposits occurring along the basin margins, and mudstone units predominating in the basin centre (Embry, 1991b). Identification of 31 regional transgressions has allowed subdivision of Mesozoic rocks into a series of Transgressive-Regressive (T-R) sequences, each representing a distinct depositional interval characterized by thin basal transgressive deposits and thicker regressive deposits, typically basin-centre mudstone coarsening-upward to basin-margin sandstone (Embry, 1991b). Lower Cretaceous sedimentation was dominated by the sandy Isachsen, shaly Christopher and sandy Hassel successions.

In late Aptian time, a regional transgression covered the Sverdrup Basin and allowed deposition of 100-1400 m of the argillaceous Christopher Formation conformably over the Isachsen sandstones. The Christopher is predominantly dark grey, silty marine shale and interbedded siltstone, with minor thin beds of fine sandstone which increase upward and delineate at least two coarsening-upward T-R sequences (Embry, 1991). These strata, deposited in the axial part of the basin, are gradationally overlain by the Hassel Formation shallow marine and deltaic sandstones with coal (Embry, 1991).

A fairly large amount of data regarding the organic richness and thermal maturity of the Lower Cretaceous Christopher strata have been collected. Powell (1978) analysed 7 samples of

Christopher and found TOC contents of 1-3%. Gentzis et al. (1996) lists the following characteristics for 292 samples of the Christopher: TOC up to 3.97, averaging 1.80-2.98; HI up to 109, averaging 29-51; T_{max} up to 442, averaging 433-435; %Ro 0.37-0.50. The GSC Rock-Eval Database includes 266 samples of Christopher Formation with the following characteristics: TOC up to 5.78, averaging 2.75; T_{max} up to 450, averaging 434; S_1 up to 6.01, averaging 0.28; S_2 up to 6.34, averaging 1.23; S_3 up to 13.21, averaging 2.82; HI up to 143, averaging 43; OI up to 337, averaging 106 (M. Obermajer, 2006, pers. comm.).

The Christopher Formation includes a thick and widespread sequence in the shallow subsurface, with apparently fair to good source rock intervals (likely Type III organics), and some coarser interbeds, which are thermally mature. The hydrocarbon potential of these strata could be significant with potential for a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology of these strata are not well known and fracture patterns are unknown. These strata reside in a remote frontier basin with no active infrastructure, but one which has experienced some past successful exploration.

Kanguk (Upper Cretaceous)

From Early Triassic to Cretaceous time, the NE-SW elongate Sverdrup Basin was the main depocentre in the Arctic Islands region, with shallow marine to shoreline deposits occurring along the basin margins, and mudstone units predominating in the basin centre (Embry, 1991b). Identification of 31 regional transgressions has allowed subdivision of Mesozoic rocks into a series of Transgressive-Regressive (T-R) sequences, each representing a distinct depositional interval characterized by thin basal transgressive deposits and thicker regressive deposits, typically basin-centre mudstone coarsening-upward to basin-margin sandstone (Embry, 1991b). The late history of the Sverdrup Basin is dominated by the thick shaly deposits of the Kanguk Formation.

In late Cenomanian time, a regional transgression covered the Sverdrup Basin and allowed deposition of 150-365 m of the argillaceous Kanguk Formation conformably over the Hassel sandstones. The Kanguk comprises black, bituminous, papery shales, deposited in a starved offshore setting, overlain by dark grey, siltier mudstone with minor siltstone and fine sandstone beds, arranged in an overall coarsening-upward succession (Embry, 1991). These strata, deposited in the axial part of the basin, are gradationally overlain by the Expedition Formation shallow marine and deltaic sandstones with coal (Embry, 1991).

A large amount of data regarding the organic richness and thermal maturity of the Upper Cretaceous Kanguk strata have been collected. The GSC Rock-Eval Database includes 930 samples of Kanguk Formation with the following characteristics: TOC up to 11.64, averaging 2.71; T_{max} up to 570, averaging 424; S_1 up to 2.22, averaging 0.13; S_2 up to 47.16, averaging 3.47; S_3 up to 135.00, averaging 1.57; HI up to 491, averaging 155; OI up to 184, averaging 62 (M. Obermajer, 2006, pers. comm.).

The Kanguk Formation includes a widespread sequence of moderate thickness, in outcrop or shallow subsurface, with apparently good to excellent source rock intervals (likely Type II/III organics), and some coarser interbeds, which are thermally immature to overmature. The hydrocarbon potential of these strata is probably significant and there may be good geological potential for a Style A (Antrim-like) play or a Style D (Lewis-like) play. However, further study of the stratigraphy, sedimentology, geochemistry, maturity and mineralogy would lead to much better understanding of the shale gas potential. The detailed stratigraphy and sedimentology of these strata are not well known and fracture patterns are unknown. These strata reside in a remote frontier basin with no active infrastructure, but one which has experienced some past successful exploration.

CANADIAN SHALE GAS PROSPECTS MOST LIKELY TO JUSTIFY/BENEFIT FROM CONCERTED GEOLOGICAL EXAMINATION

(those with a * justify immediate serious study as possible new conceptual plays)

EASTERN CANADA

* Middle-Upper Ordovician of Appalachians/St. Lawrence Platform/Anticosti
(Winterhouse, Macasty/Vauréal, Utica/Lorraine, Pointe Bleu, Eastview/Billings, Dawson Point, Collingwood/Blue Mountain)

Lower Carboniferous of Fundy Basin Rift
(Strathlorne, Albert, Cape Rouge, Hastings, Cape Dauphin, West Bay, Rocky Brook)

* Upper Devonian of St. Lawrence Platform/Michigan Basin
(Marcellus, Kettle Point)

WCSB/NORTHERN INTERIOR PLATFORM

* Upper Devonian of western Alberta/northeast B.C./southern Mackenzie/Liard Corridor
(Canol, Muskwa, Imperial, Besa River, Fort Simpson)

Lower Carboniferous of Alta., Sask., Man.
(Exshaw, Bakken, Banff)

* Lower-Middle Triassic of northwest Alta./northeast B.C.
(Montney, Grayling, Phroso, Vega, Doig, Phosphatic, Toad, Whistler)

* Jurassic of western Alberta/northeast B.C.
(Nordegg, Gordondale, Fernie)

Lower Cretaceous of northern Alta./northeast B.C.
(Wilrich, Moosebar, Clearwater, Ostracod, Buckinghorse)

* Middle-Upper Cretaceous of Alta., Sask., Man.
(Colorado/Alberta/Smoky Groups and numerous contained formations, Lea Park, Pakowki, Nomad, Pembina)

NORTHERN MAINLAND

Cambrian-Devonian of Eagle Plain/Mackenzie Corridor
(Road River)

* Middle Devonian of Mackenzie Corridor
(Bluefish, Hare Indian)

Upper Devonian-Upper Carboniferous of Eagle Plain

(Canol, Imperial, Ford Lake, Blackie)

Middle-Upper Cretaceous of Mackenzie/Liard Corridor
(Arctic Red, Fort St. John, Boundary Creek, Smoking Hills)

ARCTIC ISLANDS
Upper Ordovician-Lower Devonian of Franklinian Basin
(Cape Phillips and equivalents)

Lower-Upper Triassic of Sverdrup Basin
(Blind Fiord, Murray Harbour, Hoyle Bay, Barrow)

Lower Jurassic-Lower Cretaceous of Sverdrup Basin
(Jameson Bay, Mackenzie King, Savik, Ringnes, Deer Bay, Christopher)

CONCLUSIONS

1.The term “Shale Gas” refers to unconventional, continuous-type, self-sourced resources contained in fine grained (ranging from clay to very fine sandstone), organic-rich, low permeability reservoirs in which the methane is stored as a) free gas in the matrix porosity, b) free gas in the fracture porosity, and c) adsorbed or dissolved gas on the organics and/or clays. These are self-enclosed petroleum systems where source, reservoir and trap are all present in the same thick shaly succession, and the gas may be generated by thermogenic or biogenic means.

2. The most prospective shale gas targets will be thick, widespread, gas-saturated, fine grained, organic-rich units with a) significant Type III (terrestrial, gas-prone) organic matter in thermally mature to overmature states, b) significant Type II (marine, oil- and gas-prone) organic matter in a thermally overmature state, and/or c) rich organic matter of any type that is thermally immature and subject to extensive biogenic decomposition. Known hydrocarbon source rocks and oil shales which had inefficient (“dysfunctional”) expulsion and migration pathways, or which are not yet “spent” are two examples of prospective targets.

3. Shale gas production has a surprisingly long and successful history in the USA (dating from 1821), emerged as a viable modern play concept after major tax incentives in the 1980's, and now represents 2-4% of that nation’s supply from thousands of wells in several major producing plays in mature basins. Each of these examples reflect very different controlling factors, can be considered as different play types with unique characteristics, and can provide guidance for Canadian explorationists.

4. Play Style A (Antrim) involves very organic-rich, fractured mudstones deposited at the maximum subsidence phase over a foundering carbonate platform, now present at shallow depths, which are thermally immature and produce biogenic gas and water. A clastic variation of this type may be represented by the poorly-understood Alderson Member of southern Alberta and Saskatchewan (an additional, yet-to-be-defined Play Style?). Shallow depth and proximity to large markets have been key to success.

5. Play Style B (Ohio/New Albany) involves very organic-rich, fractured mudstones, with thin clastic and carbonate carrier beds, deposited at the maximum subsidence phase over a foundering carbonate platform, now present at modest to large depths, which are thermally mature to overmature and produce dry thermogenic gas. Proximity to large markets has been key to success.

6. Play Style C (Barnett) involves very organic-rich, siliceous mudstones, with thin clastic and carbonate carrier beds, deposited at the maximum subsidence phase over a foundering carbonate platform, now present at modest to large depths, which are thermally mature to overmature and are very brittle (which allows successful artificial fracturing). The play emerged in an area close to large markets with pre-existing (under-utilized) infrastructure, and extensive horizontal drilling has contributed to success.

7. Play Style D (Lewis) involves modestly organic-rich, fractured mudstones, with abundant thin clastic carrier beds, deposited at the maximum subsidence phase over a regressive clastic wedge, now present at modest depths, which are thermally mature to overmature. Proximity to large markets, re-completion of existing wells, horizontal drilling and pre-existing (under-utilized) infrastructure have been keys to success.

8. Potential shale gas plays must be evaluated separately and in great detail (without relying too much on these USA examples as strict “recipes”) to properly assess the economic possibilities. The precise controlling factors present will require imaginitive use of the known examples, combined with a healthy dose of unconventional thinking. It is likely that entirely new, undescribed, play styles still exist, waiting to be found in Canada by creative thinkers.

9. Because continuous, basin-centred, unconventional plays are fundamentally different from conventional plays, environmental concerns revolving around the large land-use footprint, surface- and ground-water disturbance, large-scale fracturing and noise and visual/aesthetic worries may create public resistance to exploration/production of this resource. Recovery of shale gas in a fully environmentally-responsible manner should be a paramount goal from the beginning.

10. One of the prime lessons from the known examples is that intensive (pre-drill) geological study is an inexpensive and efficient method for technical evaluation, and for maximizing the choice of target and recovery of resources from this new play concept. The current economic climate of depleting conventional reserves and rising prices presents an opportunity for the emergence of the shale gas concept in Canada.

11. Canada’s mature conventional, immature conventional and frontier basins collectively provide numerous (perhaps 50) individual units, in localized areas scattered over at least 7 regions, which could be considered as potential shale gas targets. The geology of each is briefly reviewed here with relevant data and some comments on their prospectivity.

12. Of the shale units reviewed, 16 are considered to represent regional-scale units with enough geological prospectivity to justify further geological study to flesh out their geological (not necessarily economic) potential. Furthermore, because of excellent geological potential and additional factors of geographic location, proximity to infrastructure, and/or relation to known conventional and unconventional plays, I have designated 7 potential regional shale gas plays which require immediate and intense geological study. I believe that the first successful shale gas plays in Canada will emerge from this list. They are: Upper Ordovician of Appalachian Basin, Upper Devonian of Appalachian/Michigan Basin, Upper Devonian of northwestern WCSB, Triassic of northwestern WCSB, Jurassic of western WCSB, Middle to Upper Cretaceous of WCSB Plains, Middle Devonian of Mackenzie Corridor.

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