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PETROLEUM RESOURCE ASSESSMENT, PALEOZOIC SUCCESSIONS OF THE ST. LAWRENCE PLATFORM AND APPALACHIANS OF EASTERN CANADA

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Petroleum Resource Assessment, Paleozoic successions of the St. Lawrence Platform and Appalachians of eastern Canada

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PETROLEUM RESOURCE ASSESSMENT OF PALEOZOIC BASINS IN EASTERN CANADA

ABSTRACT

The Cambrian-Permian successions in eastern Canada belong to three tectonostratigraphic domains, 1) the autochthonous St. Lawrence Platform, underlain by Cambrian to Devonian (?) rocks which extends from southern Quebec to western Newfoundland, 2) the Appalachians formed by Cambrian to Devonian rocks lying south and east of the St. Lawrence Platform and extending to the Atlantic Ocean, and 3) autochthonous Carboniferous to Permian rocks located offshore in the Gulf of St. Lawrence and in the onshore surrounding areas. Each succession contains unique source rock and reservoir units and specific trap types. Even though all of the basins contain producing or discovered hydrocarbon fields, there has been no recent evaluation of their ultimate oil and gas resource potential.

A total of 15 conventional petroleum plays and 3 unconventional gas plays have been recognized in Paleozoic strata. Two conventional plays are recognized in Quaternary sediments. Of the 15 conventional Paleozoic plays, 6 have sufficient exploration and/or production data or good analogues to formulate a full quantitative assessment. Of these 6 plays, 4 are assessed for oil and gas potential, 1 for oil potential, and 1 for gas potential. Given the fact that a large number of conventional and all of the unconventional plays cannot be quantitatively assessed, the total resource presented herein is a minimum potential as evidence for hydrocarbon charge is compelling in most of the qualitatively assessed plays.

The assessed plays of the eastern Canada Paleozoic basins have a cumulative median (P50%) in-place potential of $1170*10^9$ m^3 (41 Tcf) of natural gas and $403*10^6$ m^3 (2.5 BBO) of oil. The Carboniferous Maritimes Basin accounts for about 95% ($1109*10^9$ m^3 or 39 Tcf) and 60% ($235*10^6$ m^3 or 1.5 BBO) of the total gas and oil resource potential, respectively.

The assessment results provide important new insights into the energy resource endowment of Paleozoic basins in eastern Canada. In particular, the assessment results indicate Carboniferous basins have a large gas resource potential, much higher than previously estimated. Moreover, the preliminary estimates from the industry (not quantitatively evaluated in this report) of the shale gas potential in the Ordovician succession alone, is assumed to be over 40 Tcf.

Our sincere thanks to Jim Dixon who reviewed the initial draft and made very useful comments and suggestions for improvement.

RÉSUMÉ

Les successions du Cambrien-Permien de l'est du Canada appartiennent à trois domaines tectono-stratigraphiques, 1) la Plate-forme autochtone du Saint-Laurent constituée de roches cambriennes à dévoniennes (?), qui s'étend du sud du sud du Québec jusqu'à l'ouest de Terre-Neuve, 2) le domaine des Appalaches formé de roches du Cambrien au Dévonien présent au sud et à l'est de la Plate-forme du Saint-Laurent et s'étendant jusqu'à l'océan Atlantique, et 3) les successions autochtones du Carbonifère et Permien présentes dans le golfe du Saint-Laurent et dans les domaines terrestres adjacents. Chaque succession contient ses assemblagesde roches mères et unités réservoirs à hydrocarbures ainsi que ses types de pièges spécifiques. Malgré que toutes ces zones renferment des champs producteurs ou des découvertes, aucune évaluation récente de la ressource en place n'était disponible.

Un total de 15 systèmes pétroliers conventionnels et 3 systèmes non-conventionnels à gaz ont été reconnus dans les strates du Paléozoïque. Deux systèmes conventionnels sont reconnus dans les sédiments du Quaternaire. Des 15 systèmes conventionnels, 6 ont suffisamment de données d'exploration et/ou de production ou de bons analogues pour mener une évaluation quantitative complète. Des ces 6 systèmes, 4 sont évalués pour leur potentiel en huile et en gaz, 1 pour son potentiel en huile et 1 pour son potentiel gazier. Étant donné que le potentiel d'un bon nombre des systèmes conventionnels et de tous les systèmes non-conventionnels ne peut être quantifiés, l'estimation totale des ressources en place est une valeur minimum puisque des indications de charge en hydrocarbures ont été documentées pour la majorité des systèmes évalués qualitativement.

Les systèmes évalués dans les bassins du Paléozoïque de l'est du Canada ont un potentiel en place médian (P50%) cumulatif de $1170*10^9$ m^3 (41Tpc) de gaz naturel et de $403*10^6$ m^3 (2.5 MBH) d'huile. Le Bassin Carbonifère des Maritimes du Carbonifère compte pour près de 95% ($1109*10^9$ m^3 ou 39Tpc) et 60% ($235*10^6$ m^3 ou 1.5 MBH) de la ressource totale en gaz et en huile, respectivement.

L'évaluation quantitative apporte un éclairage nouveau sur les ressources potentielles des bassins du Paléozoïque de l'est canadien. Les résultats de l'évaluation indiquent que le bassin Carbonifère renferme une grande ressource potentielle de gaz, nettement supérieure à l'estimation précédente. De plus les évaluations préliminaires de l'industrie suggèrent que le potentiel de ressource en place pour les gaz de shale (non évalué par cette étude) est au minimum de 40 Tpc, uniquement pour la succession Ordovicienne.

Merci à Jim Dixon pour ses commentaires et suggestions qui ont amélioré le rapport final.

EXECUTIVE SUMMARY

The Cambrian-Permian successions in eastern Canada belong to three major tectonostratigraphic domains, 1) the autochthonous St. Lawrence Platform, underlain by Cambrian to Devonian (?) rocks which extends from southern Quebec to western Newfoundland, 2) the Appalachians formed by Cambrian to Devonian rocks lying south and east of the St. Lawrence Platform and extending to the Atlantic Ocean, and 3) autochthonous Carboniferous to Permian rocks located offshore in the Gulf of St. Lawrence and in the onshore surrounding areas. Within these three domains, various sedimentary basins of different ages or origin are recognized. In 1984, a preliminary assessment of the hydrocarbon potential of some of these successions was derived from a "minimum of geological data" (Procter et al., 1984). Since 1990, the Geological Survey of Canada (GSC) and provincial partners have generated a wealth of geoscience information and hydrocarbon system data. In 2005, the GSC initiated a new project to prepare a modern quantitative resource evaluation of the Paleozoic successions of eastern Canada.

A total of 15 conventional petroleum plays and 3 unconventional gas plays have been recognized in Paleozoic strata. Two conventional plays are recognized in Quaternary sediments. This report includes detailed descriptions of the plays, a summary of the resource assessment methodology, and assessment results. Of the 15 conventional Paleozoic plays, 6 have sufficient exploration and/or production data or good analogues to formulate a full quantitative assessment. Of these 6 plays, 4 are assessed for oil and gas potential, 1 for oil potential, and 1 for gas potential. Given the fact that a large number of the conventional and all of the unconventional plays cannot be quantitatively assessed, the total resource presented herein is a minimum potential and evidence for hydrocarbon charge is compelling in most of the qualitatively assessed plays.

The assessed plays of the eastern Canada Paleozoic basins have a cumulative median (P50%) in-place potential of $1170*10^9$ m^3 (41 Tcf) of natural gas and $403*10^6$ m^3 (2.5 BBO) of oil. The Carboniferous Maritimes Basin accounts for about 95% and 60% of the total gas and oil resource potential, respectively.

The assessment results provide important new insights into the energy resource endowment of Paleozoic basins in eastern Canada. In particular, the assessment results indicate Carboniferous basins have a large gas resource potential, much higher than previously estimated. The resource potential numbers represent a minimum potential for the region because many of the conventional and all of the unconventional plays were only qualitatively assessed. The conventional resource potential for Cambrian – Devonian strata may be much higher than reported here, because only 4 of 12 plays were quantitatively assessed.

CONVENTIONAL Play	In-place Gas ($10^9 m^3$)			In-place Oil ($10^6 m^3$)		
	P95	P50	P05	P95	P50	P05
Cambrian rift -SLP						
Cambrian-Ord Humber Clastics						
Lower Ordovician HTD - SLP	**1.1**	**7**	**19.3**	**8.4**	**52**	**114**
Lower Ordovician Humber Slices	**1**	**5.6**	**21.3**			
Middle Ordovician HTD - SLP	**4.5**	**28.8**	**88**	**6**	**64**	**152**
Upper Ord. - Dev. Foreland - SLP						
Lower Silurian Clastics - GB						
Lower Silurian HTD - GB						
Upper Silurian Reef/HTD - GB						
Lower Devonian Reef/HTD - GB						
Lower Devonian Fracture/HTD - GB						
Lower Devonian Clastics - GB				**N/A**	**16.2**	**123.3**
Lower Carboniferous Clastics	**127.8**	**452.1**	**731.2**	**35**	**124**	**204**
Lower Carboniferous Reefs						
Upper Carboniferous Clastics	**290.5**	**656.7**	**1135.1**	**38**	**111**	**220**
TOTAL	**656.6**	**1170**	**1736.8**	**236.6**	**402.7**	**589.0**
	23.5 Tcf	**41.3 Tcf**	**61.3 Tcf**	**1488.2 Mbo**	**2533.0 Mbo**	**3704.8Mbo**
UNCONVENTIONAL						
Upper Ordovician Shale gas						
Lower Carboniferous Shale gas						
Upper Carboniferous Coal Bed methane						
Quaternary onshore						
Quaternary offshore						

THE LOWER PALEOZOIC SHALLOW MARINE AND SLOPE SUCCESSION OF THE LAURENTIAN CONTINENTAL MARGIN

INTRODUCTION

The Late Neoproterozoic break-up of the Rodinia supercontinent resulted in the formation of a new continent, Laurentia, characterized by an irregularly-shaped paleo-southern margin with promontories and Reentrants (Thomas, 1977). In eastern Canada, the margin of Laurentia consists of the St. Lawrence Promontory (SLP, mostly western Newfoundland) and the Quebec Reentrant (QR, from Anticosti Island south to the US border; Fig. 1). The large paleogeographic indentation of the margin played a key role in the development of the platform and controlled both facies and evolution of the Cambrian to Upper Ordovician succession (Allen et al., 2009). Lower Paleozoic sediments that accumulated in the shallow and nearshore environments are preserved in the autochthonous St. Lawrence Platform, whereas those deposited along the deeper marine continental slope and toe-of-slope settings have been tectonically displaced and incorporated in the Appalachian Humber Zone (Fig. 2).

The St. Lawrence Platform

The St. Lawrence Platform is classically defined as the autochthonous sedimentary cover of the northeastern-American craton. The St. Lawrence Platform has been divided into western (Michigan and Alleghany basins), central (Ottawa Embayment and southern Quebec) and eastern (Anticosti and western Newfoundland) segments (Sanford, 1993).

The St. Lawrence Platform is limited to the north and northwest by the Neoproterozoic metamorphic – intrusive units of the Grenvillian Orogen; the contact being either faulted or an unconformity. On its southeastern side, the St. Lawrence Platform is in tectonic contact with the Appalachian Humber Zone (Fig. 2; Williams, 1979, 1995).

In southern Quebec, slices of the St. Lawrence Platform units form a spatially restricted frontal deformation zone known as the “parautochthonous” or imbricated fault domain (St-Julien and Hubert, 1975; Comeau et al., 2004). However, reprocessing and reinterpretation of seismic data indicate that the St. Lawrence Platform records significant compressive deformation and is affected by backthrust and blind faults forming triangle zones (Fig. 3; Castonguay et al., 2003; 2006). Taconian deformation along the Quebec foreland is mainly Middle to Late Ordovician in age, based on biostratigraphic ages in mélanges (St-Julien and Hubert, 1975) and K/Ar ages of metamorphic and fault rocks (Glasmacher et

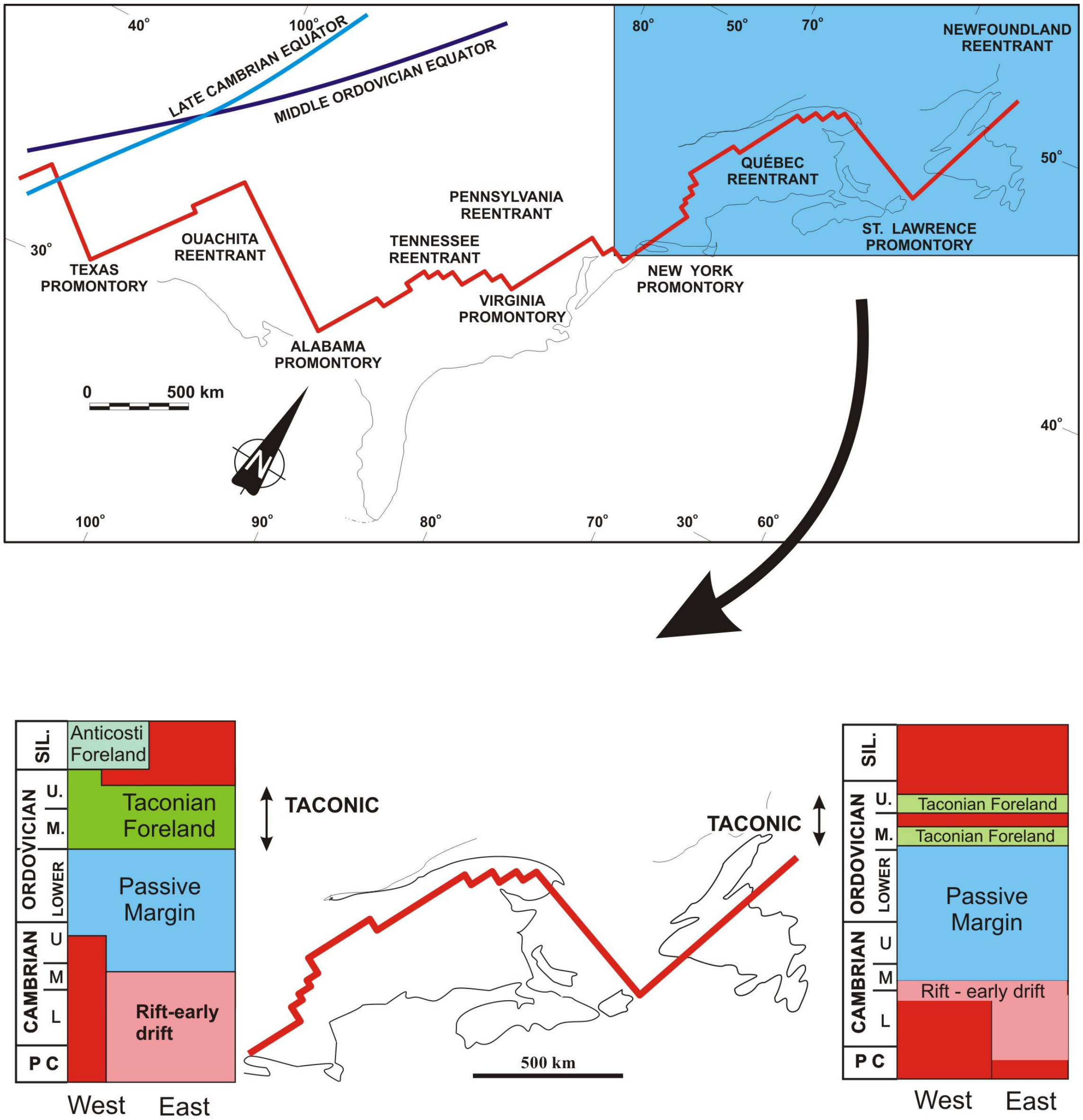


Figure 1: Top: Localisation of the Quebec Reentrant (QR) and St. Lawrence Promontory (SLP) in eastern Canada as well as the other reentrants and promontories in the US (Modified from Thomas, 1977). Bottom: Contrasting large-scale event stratigraphic framework for the QR and SLP.

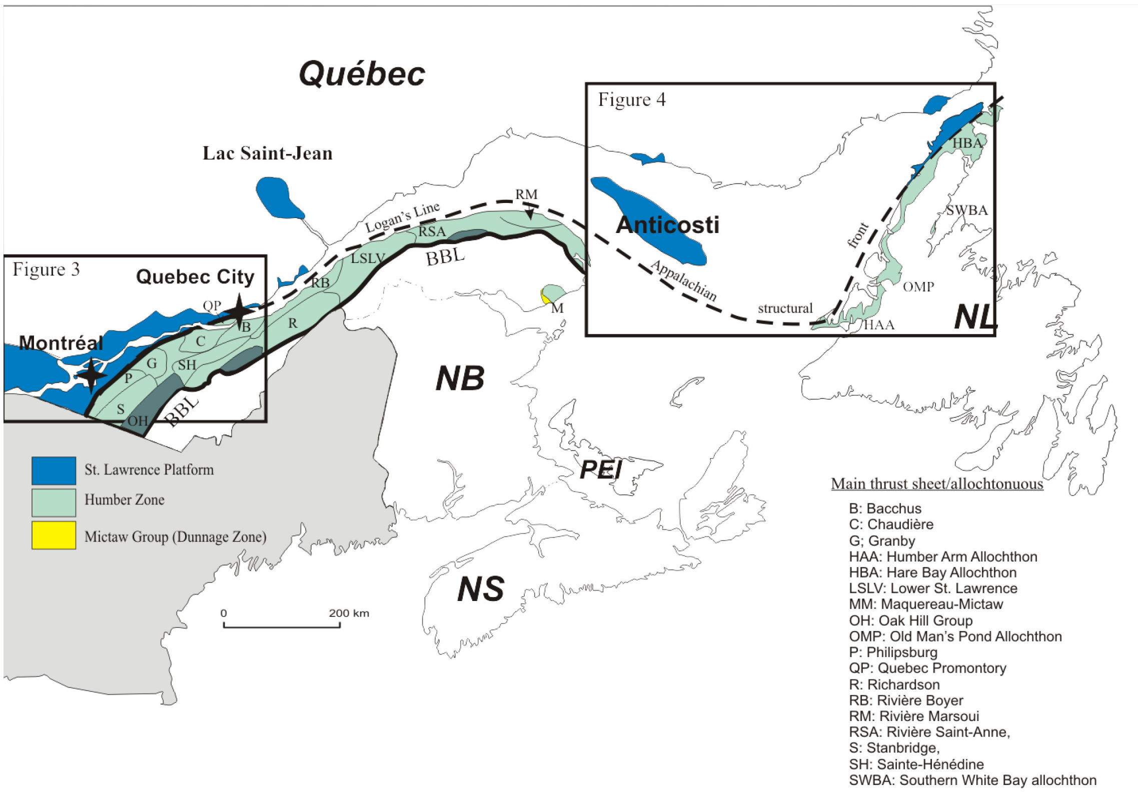


Figure 2: Regional distribution of the St. Lawrence Platform and the Taconian Humber Zone, from southern Quebec to western Newfoundland. A small outlier of the Taconian Dunnage Zone is shown in southern Gaspé (M). BBL is for Baie Verte - Brompton Line. The shallow marine facies of the Oak Hill Group are shown in darker green. Modified from Lavoie et al., (2003)

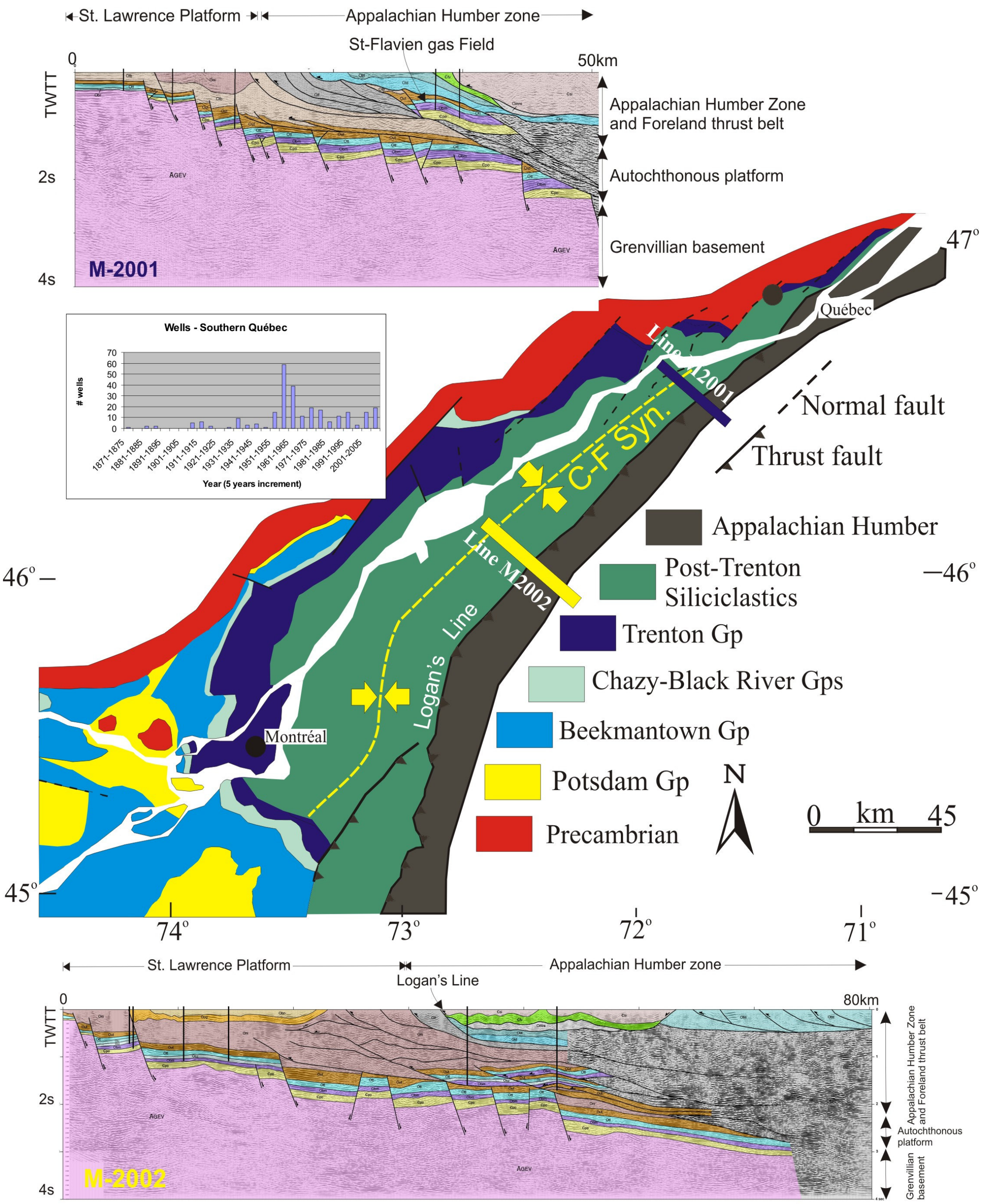


Figure 3. Simplified geological map of the St. Lawrence Platform of southern Quebec; the location of the mapped area is shown on figure 2. Interpretation of the seismic lines M2001 (only NW end of the line) and M2002 are shown (from Castonguay et al., 2006); location on the geological map) . Also, a summary of drilling activities in southern Quebec for both the St. Lawrence Platform and Humber Zone. C-F syn. is Chambly-Fortierville syncline. Map from Globensky (1987).

al., 2003; Sasseville et al., 2008). However, post-Ordovician deformation is increasingly documented on the basis of marine seismic data (Pinet et al., 2008b) and isotopic age constraints (Sasseville et al., 2008).

In western Newfoundland, platform rocks near or at the Appalachian structural front are also deformed (Figs. 4 and 5, Stockmal et al., 1998, 2004). On the Port au Port Peninsula, the platform is cut by Acadian reverse faults, such as the Round Head “Thrust”, interpreted as reactivated Taconian extensional faults. Although these reverse faults do locally involve and displace the Precambrian basement, the platform fault-bounded slices are still rooted in platform stratigraphy and they are not juxtaposed against exotic, transported, deeper marine facies (Cooper et al., 2001).

The Humber Zone

The Humber zone is the northwesternmost Cambro-Ordovician tectonostratigraphic domain of the Canadian Appalachians (Fig. 2; Williams, 1979, 1995). In the Humber zone, Upper Neoproterozoic to Upper Ordovician slope and rise rock units of Laurentian continental affinity and locally Neoproterozoic Grenvillian basement are tectonically thickened and thrust over the St. Lawrence platform in a thin- to locally thick-skinned structural style (St-Julien and Hubert, 1975; Williams, 1979; St-Julien et al., 1983; Cawood and Williams, 1988; Waldron et al., 1998, 2003; Stockmal et al., 1998, 2004; Cooper et al., 2001; Séjourné et al., 2003; Castonguay et al., 2006).

The Humber zone is bordered to the northwest by the autochthonous St. Lawrence Platform; the limit is the westernmost thrust sheet (St-Julien and Hubert, 1975; Williams, 1995). In southern Québec, this limit is commonly referred to as Logan’s line (Figs. 2, 3). In western Newfoundland, the limit is represented by an Acadian triangle zone at the Appalachian structural front (Fig. 5; Stockmal et al., 1998, 2004; Cooper et al., 2001). To the southeast, the Humber zone is in contact with the Dunnage zone, which consists of Ordovician rock units of oceanic affinity (i.e., ophiolites, arc complexes and their sedimentary covers). The surface expression of this limit is defined by a complex and long-lived fault zone marked by mélanges and discontinuous ophiolitic fragments, known as the Baie Verte-Brompton Line (Fig. 2; Williams and St-Julien, 1982). The Humber zone is traditionally divided into a northwestern weakly deformed and faintly metamorphosed external subzone and a southeastern polydeformed and strongly metamorphosed internal subzone (Williams, 1995).These subzones have a similar stratigraphic succession, but exhibit distinctive facies differences.

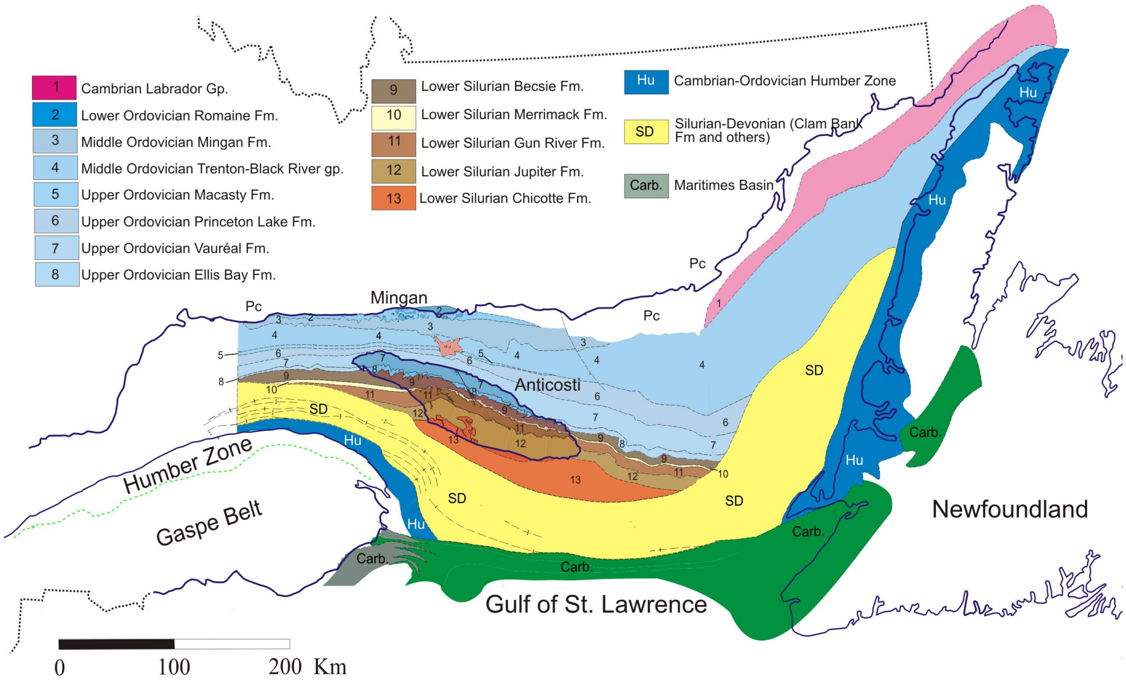


Figure 4: Geological map of the area between Anticosti Island and Western Newfoundland. The map is at the formation level for the Ordovician - Lower Silurian strata of the St. Lawrence Platform. Map location is shown on Figure 2. The St. Lawrence Platform is either unconformably overlain by interpreted Late Silurian-Devonian (SD) units or structurally overlain by Cambrian-Ordovician rocks belonging to the Humber Zone. Map is modified from Okultich and Dietrich (2005).

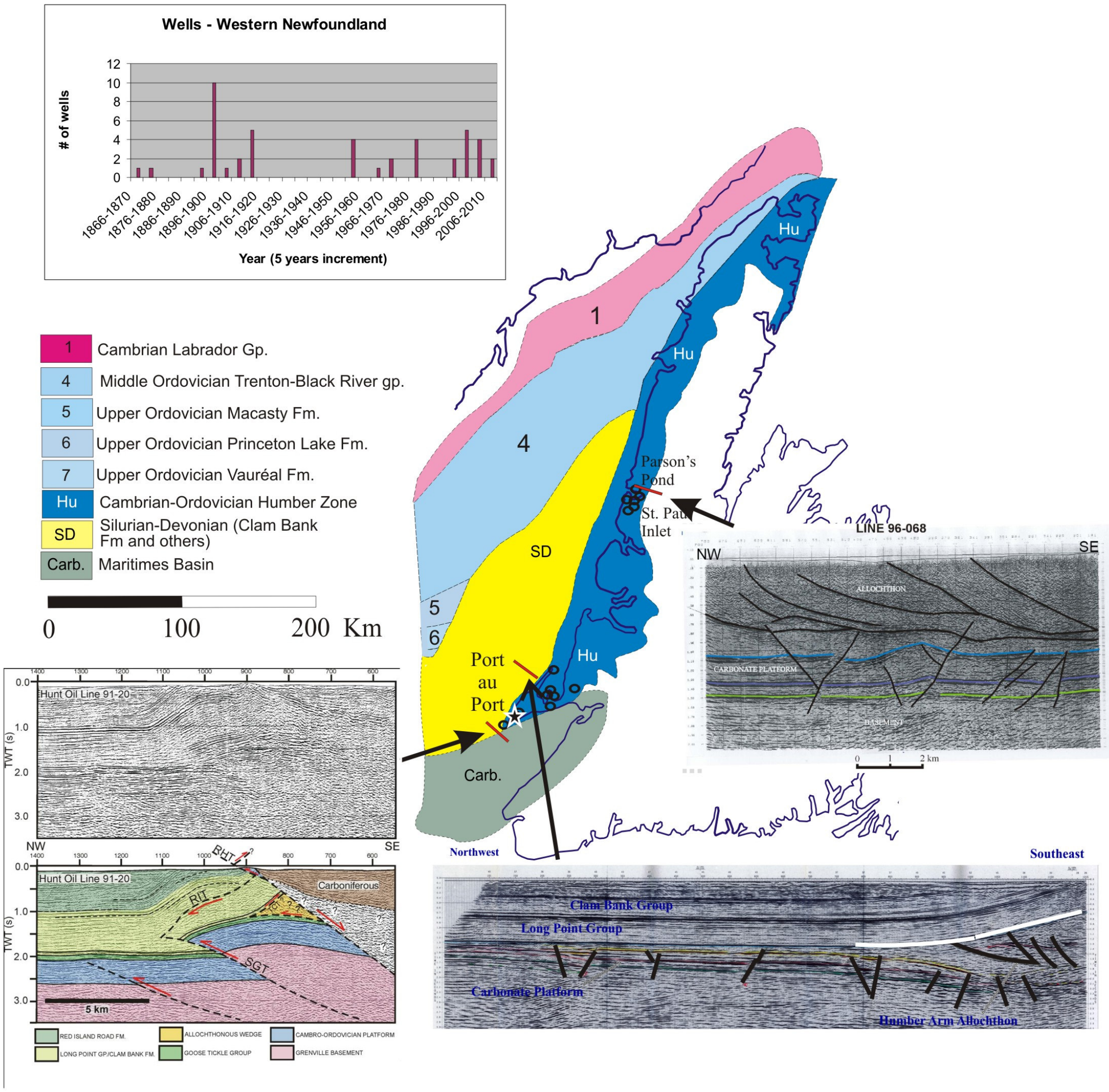


Figure 5: Simplifed geological map of western Newfoundland (at the tectonostratigraphic domains level) to illustrate that most of the onshore surface geology belongs to the deformed Humber Zone whereas the offshore largely belongs to the St. Lawrence Platform. As shown by the three seismic profiles (Stockmal et al., 2004; Enachescu, 2006), the structural style is highly variable (see text). Also shown, the drilling history onshore western Newfoundland and location of some of the drill holes.

Rock units of the Humber zone have mainly been tectonized during the Middle to Late Ordovician Taconian orogeny (St-Julien and Hubert, 1975; Williams, 1979, Pinet and Tremblay, 1995; Pincivy et al., 2003), although Silurian (Salinic) and Devonian (Acadian) structural overprint is also documented locally in the external Humber zone of southern Quebec (Sasseville et al., 2008), along the Appalachian structural front of western Newfoundland (Cawood and Williams, 1988; Waldron et al., 1998; Stockmal et al., 1998, 2004) and throughout the internal Humber (Cawood et al., 1995; Castonguay et al., 2001, 2007).

OVERVIEW OF STRATIGRAPHY AND SEDIMENTARY EVOLUTION

In western Newfoundland, the Lower Paleozoic shallow marine sedimentary succession is preserved in three structural belts: from NW to SE (1) a weakly deformed foreland, a belt also imaged by offshore seismic data; (2) a series of basement-cored thick-skinned structures; and (3) a number of thrust stacks belonging to the Humber Arm allochthon (Cooper et al., 2001). In the Quebec Reentrant, the marine sedimentary succession lies principally northwest of the Appalachian front, occupying the St Lawrence lowlands of southern Quebec (Figs. 2 and 3). The succession is also present on Mingan and Anticosti Islands in the Gulf of St Lawrence (Figs. 4 and 6). Southeast of the Appalachian front, the Lower Paleozoic shallow marine succession occurs at depth underneath the frontal thrust sheets (Fig. 3) and also crops out in the Phillipsburg thrust slice, south of Montréal (Séjourné and Malo, 2007; Salad Hersi et al., 2007), and in the Upton and St. Dominique slices (Lavoie, 1992a; Paradis and Lavoie, 1996; Séjourné and Malo, 2007). Numerous other platform thrust slices are also seismically imaged at depth in southern and eastern Quebec (Fig. 3; Trépanier, 1978; St-Julien et al., 1983; Séjourné et al., 2003; Castonguay et al., 2006).

The St. Lawrence shallow marine platform and deeper slope facies preserved in the Humber zone can be divided into three main assemblages that record the different tectonic and paleoenvironment settings: 1) rift-early drift; 2) late drift (passive margin) and 3) foreland.

The onset of marine conditions

Along the eastern Laurentian margin, the Neoproterozoic breakup of Rodinia is recorded by rift sediments unconformably overlying the Grenville Province and by mafic volcanic rocks and dykes and felsic to mafic intrusions. Rift-related magmatic rocks have been documented from Labrador to Virginia for a distance of *circa* 2500 km. The age of

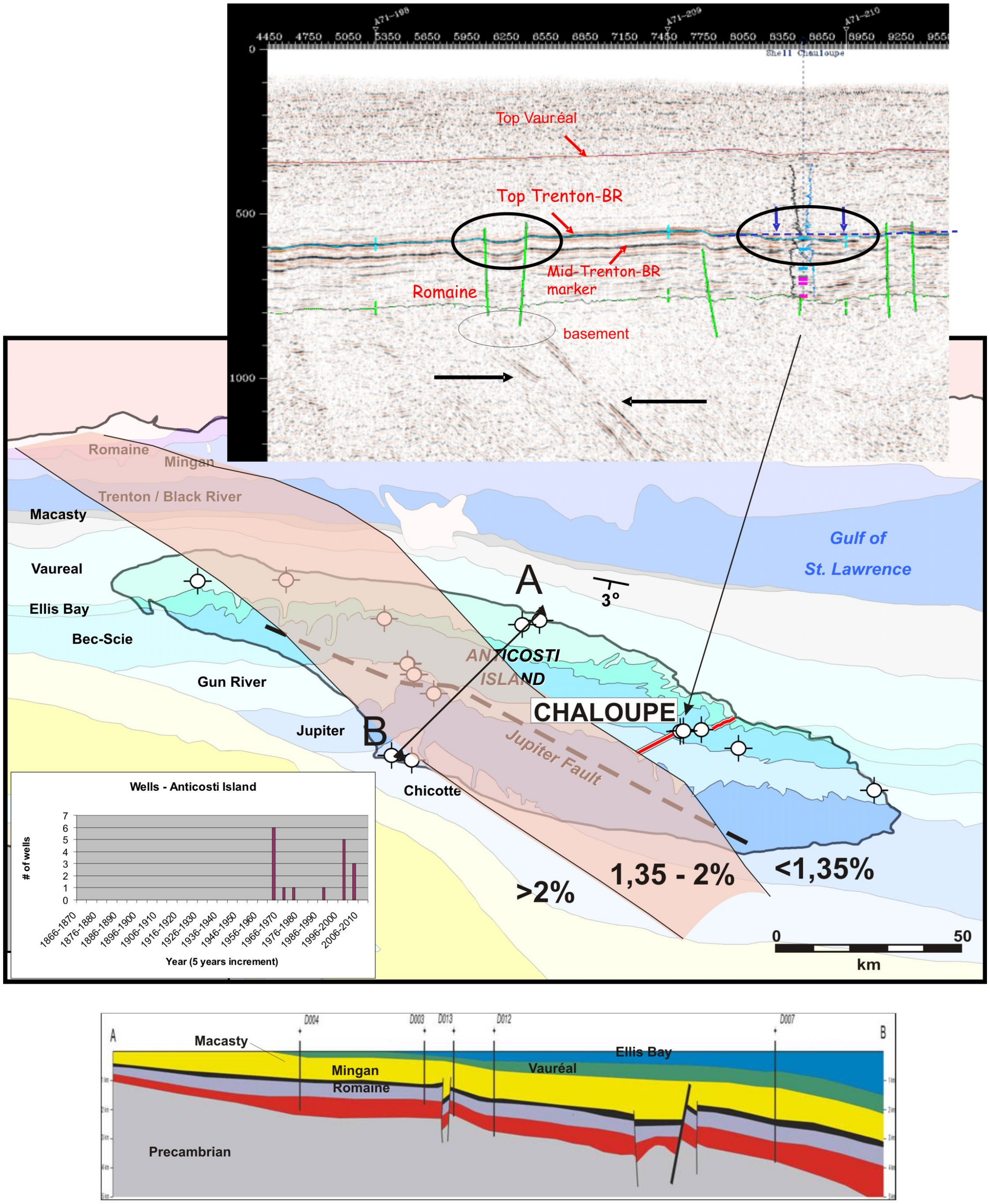


Figure 6: Geological map of Anticosti Island overlain by maturation zones of the Macasty Formation in the sub-surface, data from Bertrand (1987), 1,35% (Ro) is the oil-condensate threshold and 2%(Ro) is the onset of dry gas. The seismic line show one of the many sags on the island; this one was tested by the Chaloupe well. Other sags remain untested, in particular those with fault connections with the basement (producers in New York). Also, the drilling history on the island.

magmatic rocks ranges from 615 Ma to 550 Ma, and seemingly record two distinct rift-related events with the volumetrically most important magmatic suites clustered around 558 +/- 7 Ma (Puffer, 2002).

The St. Lawrence Platform (Fig. 7)

Marine sedimentation was initiated at the St. Lawrence Promontory (SLP) in the Early Cambrian following rapid marine transgression over the thermally subsiding margin (Lavoie et al., 2003; Allen et al., 2009). The uppermost Lower Cambrian Labrador Group is a mixed siliciclastic and carbonate succession that was deposited on a relatively narrow ramp, and which is essentially equivalent to the Sauk I sub-sequence (James et al., 1989). Transgression led to the deposition of shallow marine carbonate and quartz-rich sandstone (Forteau Formation). This was followed by a significant offlap that culminated in the protracted deposition of an extensive, shallow-water, clastic blanket (Hawke Bay Formation) that buried the shelf throughout the late Early Cambrian and early Middle Cambrian.

In the St. Lawrence Platform of southern Quebec, there is no preserved Early to even Middle Cambrian sediments. However, in the Humber internal domain of southernmost Quebec, the base of the thrust imbricated shallow marine Oak Hill Group (Charbonneau, 1980) comprises rift volcanics of the latest Neoproterozoic Tibbit Hill Formation (Kumarapeli et al., 1989). Up-section in the Oak Hill Group, the Cheshire (quartz arenite) and Dunham (dolostone / limestone) formations have yielded Early Cambrian fauna (Clark, 1936; Clark and McGerrigle, 1944). Clasts of micrite, oolitic grainstone and Archaeocyathan-bearing micrite in allochthonous Lower Cambrian clastic conglomerates preserved in the Humber Zone of the Quebec Appalachians are also evidence of the existence of a shallow-water carbonate platform in the Quebec Reentrant (Lavoie, 1997, 2008; Lavoie et al., 2003).

The deeper marine slope facies (Figs. 8 and 9)

Slope and toe-of-slope transported rocks are preserved in various allochthons, such as the Humber Arm Allochthon (Fig. 2), which comprises the Humber Arm Supergroup (Stevens, 1970). The slope and rise sediments of the end-rift episode are recorded in the Curling Group (Lavoie et al., 2003b). The Neoproterozoic to Lower Cambrian Summerside Formation consists of slates with subordinate meta-sandstones and conglomerates (Stevens, 1965, 1970; Waldron and Palmer, 2000; Palmer et al., 2001; Waldron et al., 2003). The overlying Lower Cambrian Irishtown Formation consists of slates with sandstones and limestone conglomerates. (Palmer et al., 2001). The uppermost Lower Cambrian Blow Me Down Brook Formation (Botsford, 1988; Lindholm and Casey, 1990; Burden et al., 2001)

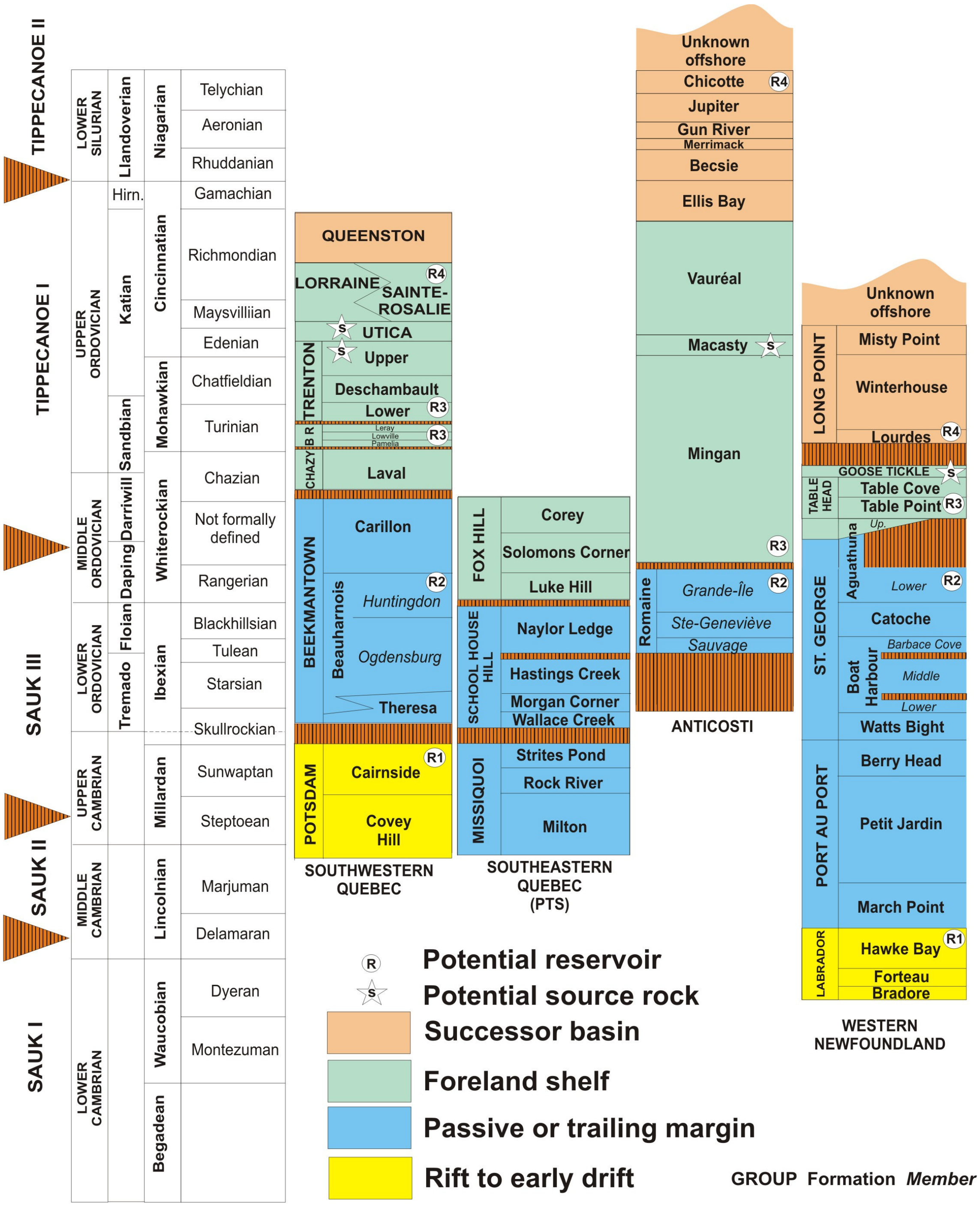


Figure 7: Stratigraphic correlation chart for the St. Lawrence Platform successions in eastern Canada. The successions are divided based on their tectonostratigraphic interpretation . The best potential source rocks (S) and reservoir units (R) are identified and discussed in text. The Sauk and Tippecanoe framework is from Sloss (1963). Modified from Lavoie (2008).

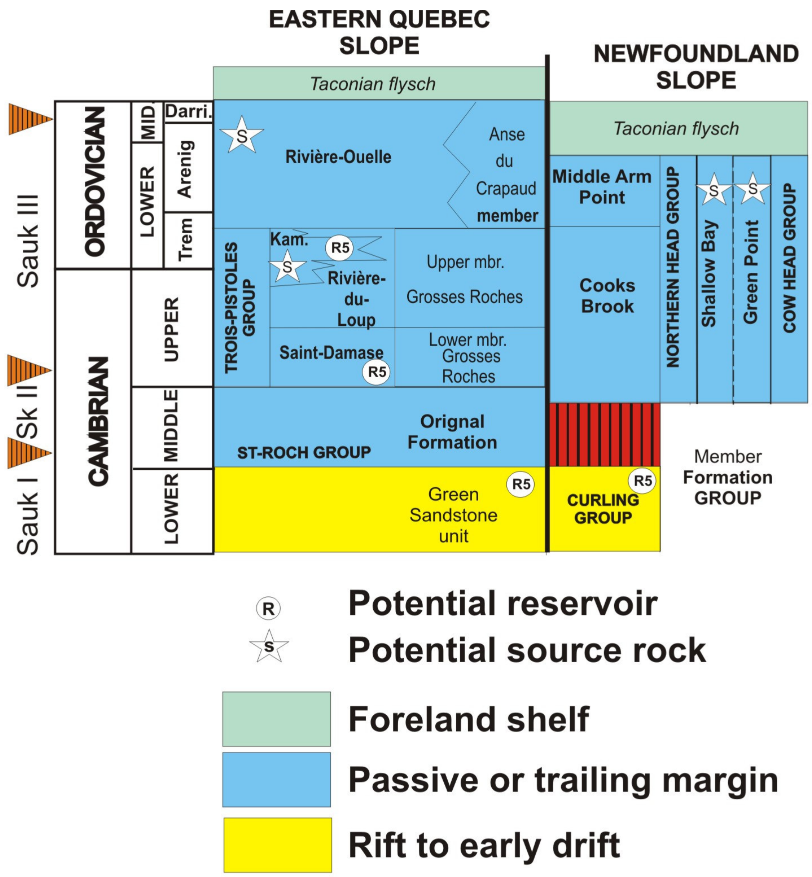


Figure 8: Simplified stratigraphic framework for the Lower Paleozoic rift-early drift and passive margin deep marine successions preserved in various thrusts stacks in the Humber Zone. See text for details. The best potential source rocks (S) and reservoir units (R) are shown; see text for details. The Sauk (SK) framework is from Sloss (1963). Modified from Lavoie (2008).

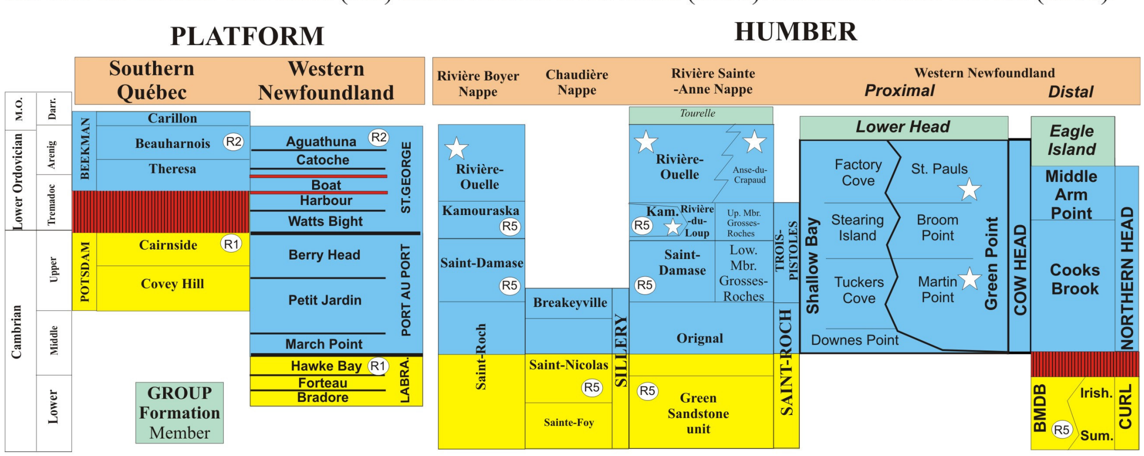


Figure 9. Detailed along strike-correlations of St. Lawrence Platform and Humber zone from southern Quebec to Western Newfoundland, for the rift-early drift and passive margin tectonostratigraphic intervals.The best potential source rocks (S) and reservoir units (R) are shown. See text for details of correlation. Modified from Lavoie (2008).

consists of parallel and cross-laminated, quartz-rich feldspathic sandstone with shale (Waldron and Palmer, 2000; Buchanan et al., 2001; Waldron et al., 2001, 2003).

The Curling Group is time-correlative with the Lower Cambrian shallow marine Labrador Group (Fig. 9; James et al., 1989). Correlations between the Curling Group and the Forteau Formation (Labrador Group) are supported by microfaunal data (Burden et al., 2001; Normore, 2001). The upper unit of the Labrador Group, the Hawke Bay Formation, records a major sea-level lowstand (James et al., 1989). It has been proposed that massive sandstone and conglomerate in the upper part of the Irishtown Formation represents the slope record of that major lowstand (James et al., 1989; Palmer et al., 2001; Lavoie et al., 2003).

The Humber Zone succession in the Quebec Reentrant occurs in a number of imbricated and folded thrust nappes (Fig. 1), for which stratigraphic nomenclatures have been proposed by Lavoie et al. (2003; Fig. 9). At the base of succession, the undated Saint-Roch Group (and correlative Sillery, Armagh and Caldwell groups; Fig. 9) consists of mudstone with subordinate sandstone and rift volcanics (Lavoie, 1997). A distinctive late Lower Cambrian unit of massive, pebbly green sandstone with red and green mudstone (Saint-Nicolas – "green sandstone" and correlative units; Fig. 9) overlies the basal succession and represents a regional marker. This coarse-grained unit is interpreted as the deep-marine expression of a significant late Early Cambrian sea-level lowstand (Lavoie et al., 2003).

A continental-wide passive (trailing) margin

The St. Lawrence Platform (Figs. 7 and 9)

A carbonate platform known as the Great American Bank was first established on the SLP in the late Middle Cambrian (Knight and Boyce, 1987; Lavoie et al., in press). The Middle to Upper Cambrian carbonate-dominated succession comprises the Port au Port Group, which displays sedimentary patterns resulting from long term sea level fluctuations (Chow and James, 1987; Cowan and James, 1993). The facies architecture indicates a narrow shelf of high to low energy preserved in three Cambrian "Grand Cycles". Coeval allochthonous deepwater successions suggest that the platform was rimmed by a high energy oolite shoals (James et al., 1989).

The oldest Paleozoic shallow marine passive margin sediments that crop out in the QR are restricted to fault-controlled late Middle Cambrian oolite-rich facies in eastern Gaspé (Kindle, 1942; Lavoie, 2001) and to a tectonic sliver made up of uppermost Middle to Upper Cambrian thrombolite and oolite-rimmed high-energy platform of the Missisquoi Group in the Phillipsburg Thrust Slice in the Humber Zone of southernmost Quebec (Salad Hersi et al., 2007). Upper Cambrian limestone conglomerates preserved in the Quebec Humber Zone provide other evidence that well-zoned Middle and Upper Cambrian carbonate platforms were present in the QR (Lavoie et al., 2003; Lavoie, 2008). In the St. Lawrence Platform of southern Quebec, a thick succession of Upper Cambrian fluvial to marginal marine clastics (Potsdam Group) marks the base of the Paleozoic succession and overlies Grenvillian basement (Clark, 1972; Globensky, 1987). The lower part of the Potsdam Group is dominated by fluvial to shallow marine interbeds of locally conglomeratic arkose and subarkose (Covey Hill Formation). A thin marine, fossiliferous, dolomitic sandstone unit locally lies at the top of the Covey Hill Formation (Rivière aux Outardes Member, Salad Hersi and Lavoie, 2000a). Occurrence of Medusae in that upper Covey Hill unit supports a Late Cambrian age (Lacelle et al., 2008). The upper part of the group is represented by shallow to marginal marine quartz arenite of the Cairnside Formation (Clark, 1972; Globensky, 1987; Salad Hersi and Lavoie, 2000b).

The platform succession is essentially continuous into the Lower Ordovician on the SLP where it is dominated by peritidal carbonates (St. George Group). In parts of the QR, however, the Cambrian-Ordovician boundary was marked by significant sub-aerial exposure and an unconformity in the inner segment of the margin suggesting an important sea level lowstand at this time (Landing et al., 1992, 2002; Lavoie et al., 2003; Dix et al., 2004; Salad Hersi et al., 2007). Although no direct evidence for similar subaerial exposure is seen in the SLP, the occurrence of widespread peritidal dolostones (part of the 3rd and uppermost "grand cycle") and of exotic limestone clasts derived from the collapse of the shelf margin now preserved in coeval deepwater allochthonous rocks is indicative of such an event (James and Stevens, 1986; James et al., 1989).

The Early Ordovician was marked by a slow sea level rise that progressively onlapped the Laurentian craton. This resulted in the establishment of a regional, wide, low-energy mud-dominated carbonate platform that hosted thrombolite mound complexes. The latter are widely developed as nearshore buildups in Anticosti Island, forming mound barrier complexes on the SLP shelf and possibly a rimmed margin. The base of the Ordovician platform becomes progressively younger towards the west, from an uninterrupted transition into the earliest Ordovician in western Newfoundland (St. George Group; James et al., 1989), to more or less pronounced Cambrian-Ordovician unconformity with a mid Skullrockian base in southeastern Quebec (School House Hill Group; Salad Hersi et al., 2002a, b, 2007). A younger late Skullrockian to Stairsian base occurs for Anticosti, Ontario and southwestern Quebec (Romaine Formation and Beekmantown Group; Lavoie et al., in press; Fig. 7).

The Early Ordovician carbonate platform responded to two major 3rd order sea level fluctuations within which multiple high-order metric cycles are recognized. The first of these 3rd order cycles spans the Tremadocian and is only preserved at the SLP (Watts Bight Formation to the mid-Boat Harbour Formation unconformity; Knight and James, 1987; Knight and Cawood, 1991, Baker and Knight, 1993: Knight et al., 2008). The second cycle, which is mid Ibexian to Whiterockian in age (the former Arenigian), becomes progressively diachronous with time and encompasses the succession from the mid-Boat Harbour unconformity to the Aguathuna Formation in Western Newfoundland (Knight et al., 2007), the Romaine Formation on Anticosti Island (Desrochers et al., in press) and the Beekmantown and School House Hill groups in southern Québec (Dix and Al Rodhan, 2006; Salad Hersi et al., 2007; Lavoie et al., in press). Significant early Middle Ordovician tectonic activity related to the progression of a lithospheric peripheral bulge across the continental margin has influenced facies and chronology of the later stages of the cycle. It culminated in the subaerial exposure and karstification of the platform marked by a regional slightly diachronous unconformity (Jacobi, 1981; Knight et al, 1991; Azmy et al., 2008).

The deeper marine slope facies (Figs. 8 and 9)

Along the SLP, the slope record of the passive margin consists of two laterally correlative rock packages (Fig. 8): the Middle Cambrian-lowermost Middle Ordovician proximal Cow Head Group, and the coeval, but more distal succession of the Northern Head Group. The age of these deep-marine successions is well-constrained; limestone fragments in the conglomerates that punctuate the succession are rich in shallow-marine fauna, whereas the intervening fine-grained sediments are dated by graptolites and acritarchs (Lavoie et al., 2003).

The Cow Head Group has been extensively studied (James and Stevens, 1986; Coniglio, 1986; James et al., 1989) and consists of two laterally correlative formations: The proximal Shallow Bay and the distal Green Point formations (Fig. 8). Seven distinctive rock assemblages (defined as members) of alternating shale, sandstone and fine to coarse-grained limestone are recognized in the Shallow Bay (four members) and Green Point (three members) formations (Fig. 9). Biostratigraphic data allows the correlation of both formations with the shallow-marine platform and with the Cambrian Grand Cycles framework (James and Stevens, 1986; James et al., 1989). The Northern Head Group (Botsford, 1988) consists of the Cooks Brook and Middle Arm Point formations (Figs. 8 and 9). The limestone and shale succession of the upper Middle Cambrian to Lower Ordovician Cooks Brook Formation disconformably overlies the upper Lower Cambrian Irishtown Formation (Fig. 9). The Middle

Arm Point Formation consists of mudstone with subordinate silty dolostone and limestone that carry Tremadocian to Arenigian age graptolites. The detailed work by James and Stevens (1986) and James et al. (1989) correlates the evolution of the Cow Head Group with that of the coeval shallow-marine Port au Port and St. George groups (Fig. 9). Two major T-R cycles (Sauk II and III sub-sequences) are recorded in the Cow Head Group. The correlation of the Cow Head Group with the Northern Head Group is also proposed (Figs. 9; Lavoie et al., 2003; Lavoie et al., in press).

In the QR, the first passive-margin sediments that overlie the upper Lower Cambrian green sandstone unit consist of a thick succession of upper Lower Cambrian to lower Middle Cambrian mudstone with glauconite- and quartz-rich sandstone (Orignal Formation and correlative units; Fig. 8). A distinctive coarse-grained unit (St-Damase Formation and correlative units; Fig. 8) overlies this fine-grained dominated interval. This unit consists of channel-fill carbonate conglomerate, feldspathic and siliceous sandstone and minor mudstone (Lavoie, 1998). The matrix of the conglomerate is Late Cambrian and embedded fragments consist of Early to early Late Cambrian nearshore to shallow marine platform margin limestone facies together with metre-sized sandstone, basalt fragments and basement-derived gneiss and orthoquartzite (Lavoie, 1997, 1998). The coarse-grained interval is overlain by a succession of uppermost Cambrian to lowermost Ordovician mudstone with subordinate sandstone (Rivière-du-Loup Formation and correlative units; Fig. 8) with discontinuous thick channel-fill quartz arenite (Kamouraska Formation; Fig. 8). The youngest passive margin unit (Rivière-Ouelle Formation and correlative units; Fig. 8) consists of variegated mudstone with subordinate sandstone, ribbon limestone, calcarenite and limestone conglomerate of Early Ordovician age (Landing and Benus, 1985; Landing et al., 1986; Bernstein et al., 1992; Maletz, 1992, 2001; Asselin and Achab, 2004). In the southeastern part of the Humber Zone, Upper Cambrian to Lower Ordovician units are correlated with the Rosaire Formation.

The passive-margin slope succession in southern and eastern Quebec also records proximal and distal depositional successions preserved in distinct thrusts Nappes (Fig. 9). The regional synthesis by Cousineau and Longuépée (2003) and Lavoie et al. (2003) offers correlations between the proximal vs distal slope facies in Quebec and with western Newfoundland, as well as with the nearshore successions preserved in southern Quebec.

The Taconian foreland basins (Figs. 7 and 10)

The St. Lawrence Platform (Fig. 7)

Along the eastern seaboard of Laurentia, the migration of a Taconian peripheral bulge was followed by extensional collapse of the continental margin. Sedimentation resumed in largely disconnected, tectonically active foreland basins. Along the SLP, the foreland basin carbonate record is short-lived compared to the foreland carbonate succession preserved in the QR (Lavoie, 1994; Fig. 7); the foreland basin succession starts with the Middle Ordovician Table Head Group (Stenzel et al., 1990) that consists of shallow subtidal carbonate facies (Table Point Formation) and deep marine mixed carbonate and clastic (Table Cove Formation), ultimately giving way to a deep marine black shale unit (Black Cove Formation) and to synsedimentary tectonic breccia (Cap Cormorant Formation). The latter two units form the base of the Taconian deep-marine clastic and flysch of the Goose Tickle Group (Stenzel et al., 1990). The Middle Ordovician Goose Tickle is capped by the Taconian Unconformity and sedimentation resumed in the Late Ordovician with the deposition of the shallow marine carbonates to continental coarse clastic of the Long Point Group (Quinn et al., 1999). The Long Point Group is a Caradocian-Ashgillian tripartite unit (Lourdes, Winterhouse and Misty Point formations) that recorded the third order transgressive-regressive Late Ordovician eustatic cycle (Lavoie, 2008).

Along the QR, the Taconian foreland sedimentation lasted significantly longer than on the SLP (Lavoie, 1994, 2008) (Fig. 7). In southern Quebec, the overall succession also recorded a relative sea level rise and comprises the early Middle Ordovician Chazy Group, the Middle Ordovician Black River Group, the Middle to Upper Ordovician Trenton Group, the Upper Ordovician Utica Shale and the Upper Ordovician Lorraine Group (and equivalents; Lavoie et al., 2008a, 2009a).

The foreland basin succession preserved in the QR and the SLP can be viewed as a classical under-filled peripheral foreland basin and, following Sinclair's (1997) nomenclature, can be divided into three diachronous lithostratigraphic units: I) a lower argillaceous limestone dominated unit, II) a middle mudstone dominated unit and, III) an upper turbidite dominated unit.

I: <u>Lower argillaceous limestone dominated unit</u>.

In southern Quebec, the foreland basin argillaceous carbonates comprise the Chazy, Black River and Trenton groups. Farther north in the Gulf of St. Lawrence domain, these units are correlative to the Mingan Formation (Desrochers, 1988; Lavoie et al., 2005) whereas at the SLP, this unit is expressed by the older Table Head Group (Fig. 7). Salad Hersi and Dix (1997), Lavoie (1994, 1995) and Dix (2003) recognized eustatic marine regressions between the Chazy and Black River groups and between the Black River and Trenton groups, and also noted the development of local unconformities on tectonically-induced paleotopographic highs in the Taconian foreland basin of southern Quebec. Regional facies distribution and thickness variations within the Trenton and Table Head groups and Mingan Formation have been attributed to syn-sedimentary normal faulting (Stenzel et al., 1990; Lavoie, 1994, 1995; Lavoie et al., 2005).

II: <u>Middle mudstone dominated unit</u>

The middle mudstone unit (Fig. 7) consists of the deep water siliciclastic sediments and hemipelagic mud of the Middle Ordovician Black Cove Formation (western Newfoundland), the younger Upper Ordovician Utica Shale (southern Quebec) and Macasty Formation (St. Lawrence Estuary and Gulf). They were deposited over the carbonate units due to rapid subsidence of the foreland basin (Stenzel et al., 1990; Globensky, 1987; Long, 2007). Black shale is characteristic of the early flysch-phase fill along the distal flank of the Middle to Late Ordovician Taconian peripheral foreland basin (Bradley and Kidd, 1991). Diachronous east to west progression of subsidence and age of the deep marine shale are coincident with the progressive westward change from carbonate-dominated to siliciclastic sedimentation within the foreland basin, a phenomenon documented throughout the Appalachian Orogen (Ettensohn, 1991, 2008; Lehmann et al., 1995; Sharma et al., 2003). The mud-rich Black Cove, Utica and Macasty contain little coarse clastic beds compared with the overlying turbidite facies suggesting that the deposition of the former occurred prior to significant input from the advancing Appalachian tectonic wedge (Lavoie et al., 2008a).

III: <u>Upper turbidite unit</u>

The upper turbidite unit consists of synorogenic uppermost Middle to Upper Ordovician sediments accumulated during the emplacement of the external thrust sheets. The siliciclastic source was located to the south-east and debris were derived from the advancing thrust sheets (Globensky, 1987; Stenzel et al., 1990), representing a major reversal in the direction of sediment supply (Hiscott, 1995). The sandstones that accumulate at the toe of, and on top of the thrust wedge are highly immature and rich in lithic fragments with rarer volcanic detritus derived from erosion of the thrust wedge (Beaulieu et al., 1980; Schwab, 1986). The upper turbidite unit is dominated by thick successions of alternating sandstone and mudstone of the Goose Tickle Group in western Newfoundland (Quinn, 1995), the Vauréal Formation (Long, 2007) on Anticosti island and of the laterally correlative flysch-dominated successions of the Sainte-Rosalie and Lorraine groups in southern Quebec (Lavoie et al., 2008a). The Sainte-Rosalie Group conformably overlies the Utica Shale at the Montmorency fall section. Elsewhere in the St-Lawrence lowlands, this flysch sequence is commonly involved in a series of imbricated slices and bounded by major thrust faults near Logan's line

(Castonguay et al., 2006). The Lorraine Group is the thickest (up to 3800 m; Globensky et al., 1993) and the most widespread unit of the St. Lawrence Platform in southern Québec.

The deeper marine slope facies (Fig. 10)

Along the SLP, the transition from the passive margin to a foreland basin is well expressed in the slope and rise environment (Fig. 10). Greenish flyschoid sandstone with subordinate shale of the middle to upper Darriwilian Lower Head Formation (James and Stevens, 1986) conformably overlies the proximal carbonate-rich succession of the Cow Head Group. Flyschoid sandstone with shale of the Arenigian to Darriwilian Eagle Island Formation (Waldron et al., 1998; Waldron and Palmer, 2000) overlies the Middle Arm Point Formation of the Northern Head Group. Taconian flysch are demonstrably slightly older in the successions more distal from the Laurentian continental margin (Fig. 10).

In the QR, the passive-margin slope deposits are overlain by Darriwilian flyschoid sandstone with subordinate mudstone, calcarenite, conglomerate and chert (Tourelle Formation and equivalent units, Fig. 10; Clark and Globensky, 1973; Hiscott, 1978; Slivitzky and St-Julien, 1987; Slivitzky et al., 1991; Prave et al., 2000).

Mélanges are widely distributed in the external Humber zone and are interpreted to be roughly coeval with these Middle Ordovician units (Fig. 10). The best exposed is the Cap Chat Mélange (Cousineau, 1998; Pinet, 2008), which consists of broken units of adjacent formations, such as centimetre to kilometre blocks of the Rivière Ouelle, Tourelle and Des Landes formations (Arenigian to Darriwilian) in a muddy to sandy matrix. In southern Quebec (Fig. 10), chaotic units described as polymictic conglomerate (Citadelle Formation; Osborne, 1956), olistostrome (Drummondville Olistostrome; Slivitzky and St-Julien, 1987) and tectonosome (Pointe-Aubin mélange; Comeau et al., 2004) are exposed. These chaotic units differ from the Cap Chat Mélange; they are composed of small to large-sized blocks of the various lithologies found within the shallow- and deep-marine passive-margin and foreland-basin successions.

Syn-orogenic sedimentation lasted until end-Caradocian and is represented by thick Upper Ordovician coarse and fine-grained flysch of the Cloridorme Formation in the Gaspé Peninsula (Enos, 1969; Prave et al., 2000) and of the Sainte-Rosalie Group in southern Quebec (Les Fonds Formation; Fig. 10; Globensky, 1987; Comeau et al., 2004).

The post-Taconian successor basin (Fig. 7)

Along the SLP, the unexposed contact between the Goose Tickle Group and the overlying Upper Ordovician Long Point Group led to several conflicting interpretations that

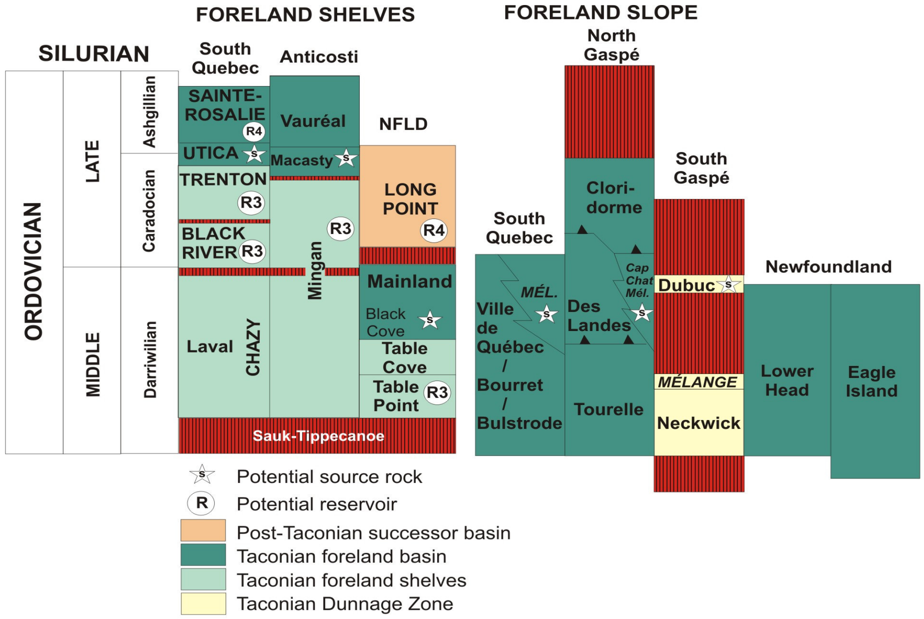


Figure 10. Time-stratigraphic correlation between foreland shelves in the St. Lawrence Platform of eastern Canada and the coeval deep marine sediments in the Taconian foreland basin. The best potential source rocks (S) and reservoir units (R) are shown. See text for details. Modified from Lavoie (2008).

have been the subject of a long lasting controversy (summarized in Lavoie, 2008) between those advocating the presence of an unconformity and those favouring a faulted contact. Recent digging has documented an erosion contact later folded (Batten and Dix, 2004). The Upper Ordovician Long Point Group consists of three formations with a lower transgressive carbonate unit (Lourdes Formation) followed by a middle outer shelf clastic unit (Winterhouse Formation) and capped by regressive nearshore to fluvial coarse clastics (Misty Point Formation; Quinn et al., 1999; Batten and Dix, 2004). The large-scale, 3rd order T-R cycle closely matches the Late Ordovician (Caradocian) eustatic cycle (Lavoie, 2008). The Upper Ordovician Long Point Group is capped by an unconformity that resulted from Salinic deformation (Waldron et al., 1998); the unconformity is overlain by lowermost Devonian sediments of the Clam Bank Formation (Burden et al., 2002; Lavoie, 2008).

A relatively complete and continuous sedimentary record of the Upper Ordovician to the Lower Silurian is preserved on Anticosti Island (Long, 2007). The uppermost Ordovician Ellis Bay Formation consists of shallow marine carbonates that recorded the Late Ordovician global glaciation of Gondwana (Brenchley et al., 1994; Long, 2007). The transition into the Silurian is found in the Becsie Formation which consists of subtidal micrites and calcarenites (Sami and Desrochers, 1992). The Becsie Formation is overlain by a number of other Lower Silurian units (Merrimack, Gun River, Jupiter and Chicotte formations; Long, 2007). The shallow marine to nearshore carbonates of the Telychian Chicotte Formation is the youngest unit preserved on Anticosti Island. However, seismic data from the St. Lawrence Estuary indicates younger sedimentary rocks are present over that coarse-grained carbonate unit (Pinet and Lavoie, 2007). Based on Bertrand’s (1987, 1991) thermal modelling of the Anticosti succession, close to 3-4 km of strata were eroded above the Lower Silurian strata.

Besides a small exposure of Lower Devonian carbonate breccia in the Montréal area (Clark, 1972), there is no preserved record of post-latest Ordovician sedimentation on the St. Lawrence Platform of southern Quebec. However, thermal maturation data (Bertrand, 1991) indicates that the top of the platform succession was buried to a depth of roughly 4-5 km. The exact nature of the burial process is still uncertain, it may have been entirely tectonic (caused by the Taconic allochthons) or the result of combined tectonic and younger (Silurian-Devonian) sedimentary burial.

The latest deposits – A synopsis of the Quaternary history (Fig. 11)

The unconsolidated Quaternary successions unconformably overlie the main lithotectonic domains (Grenville Province, St. Lawrence Platform and Appalachians). Since at

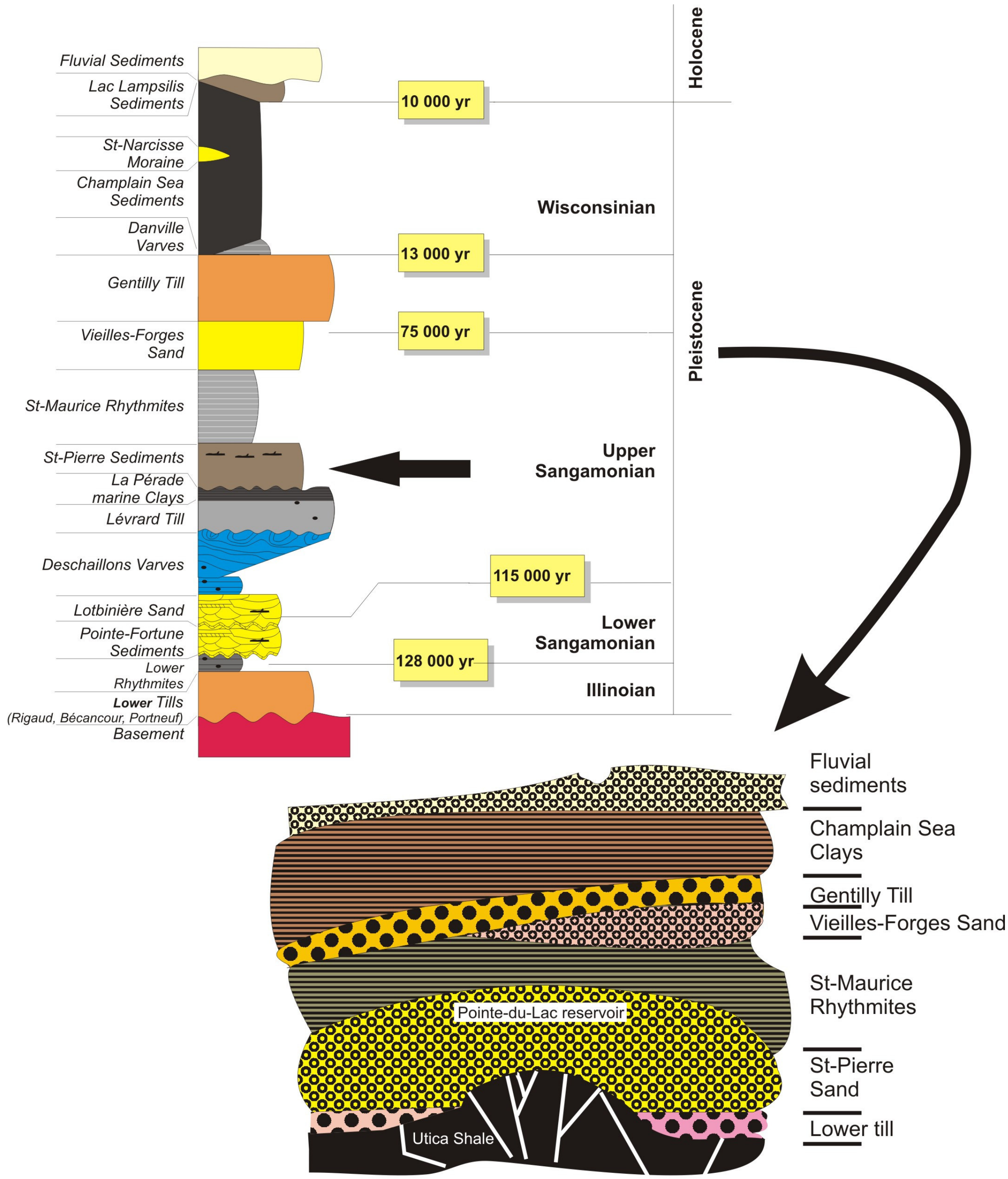


Figure 11 : Stratigraphic setting of the Pointe-du-Lac reservoir. The host sand overlies a high of fractured Utica Shales. In situ biogenic gas and thermogenic gas derived from the Utica Shale sourced the reservoir. The fine-grained rhythmites seal of the gas-bearing sand.

least the Middle Pleistocene, the St. Lawrence lowlands have been periodically invaded by ice sheets and flooded by glacial lakes and seas. These complex glacial retreats and advances resulted in the deposition of sediments that record rapidly evolving and laterally equivalent glacial, deltaic/fluvial, lacustrine and marine environments (Ochietti, 1990; Lamothe, 1989; Ross et al., 2006).

A stratigraphic framework involving three periods of glacial advances and two nonglacial episodes has been put forward to explain the Quaternary sedimentary succession preserved in the St. Lawrence lowlands of southern Quebec. A complex nomenclature is associated with deposits of local extent and only the formal and informal terms corresponding to the Trois-Rivières area will be cited (Lamothe, 1989).

The oldest preserved glacial event (Illinoian, > 135,000 yrs) is represented by a sandy till overlying Paleozoic rocks (Bécancour till). A clay-rich rhythmically-bedded glacio-lacustrine unit overlies the till. Organic bearing sands (Lotbinière Sand) mark the return to 'normal' fluvial conditions. They are overlain by argillaceous and silty lacustrine deposits (Deschaillons Varves) and till (Levrard Till). Organic bearing deposits (St. Pierre Sediments) mark fluvial condition. The last glacial advance is characterized by the deposition of rhythmites (Gray Varves) and till (Gentilly Till). An upper clay unit (Champlain Sea Clay) overlain by the most recently deposited sand completes the succession

STRUCTURAL FRAMEWORK

St. Lawrence Platform

In southern Quebec, most of the St. Lawrence platform exposures are flat-lying with little if any folding at the outcrop scale. Major structural features include normal faults that bound half grabens and broad open folds (such as the Chambly-Fortieville syncline; Fig. 3) that have been traditionally associated with the late increment of the Taconian orogeny. Reprocessing and reinterpretation of regional deep seismic lines in southern Quebec has documented some compressive deformation, including triangle zones and blind thrusts, beyond the surface trace of Logan's line (Fig. 3; Castonguay et al., 2006). Recent studies advocate for a more complex structural evolution than previously thought, including: 1) Middle Ordovician normal faulting that resulted in the formation of sags prior to the deposition of the fine-grained, organic matter rich, clastic unit on top of the foundering carbonate platform; 2) Late Ordovician compressive deformation associated with the Taconian orogeny; 3) post-Ordovician (probably 'Acadian') folding (Pinet et al., 2008b) and faulting (Sasseville et al., 2008).

Structural features of Anticosti Island, which is located farther away from the Appalachian deformation front than the St. Lawrence Platform of southern Quebec, consist predominantly of normal faults, most of which are sealed by the post-Ordovician units (Fig. 6).

In western Newfoundland, detailed studies of platformal units in the Port au Port area have documented a polyphase structural history comprising a Middle Ordovician platform collapse event followed by compressive deformation associated with the Taconian Orogeny, a Late Silurian Salinic thin-skinned event, and a Devonian Acadian thick-skinned event resulting in the formation of a triangle zone close to the Appalachian front (Stockmal et al., 1998, 2004; Cooper et al., 2001; Fig. 5).

Humber Zone

Deformation in the Humber zone was dominantly caused by the attempted subduction of the Laurentian margin and the accretion of ophiolitic and arc complexes associated with the closure of marginal basins and collision of peri-Laurentian microcontinent terranes during the Early to Late Ordovician Taconian Orogeny (Cawood and Surh, 1992; Pinet and Tremblay, 1995; Waldron and van Staal, 2001, van Staal et al., 2007). Rock units of the Humber zone were progressively detached from their basement, principally displaced northwestward (present coordinates), and tectonically thickened and metamorphosed, especially in the hinterland of the Taconian orogen (i.e., internal Humber zone). The external Humber zone mostly forms a northwest-directed, northwest-propagating fold and thrust belt, in which rock units have been deformed into a series of imbricated thrust sheets, termed *nappes* in Quebec (St-Julien and Hubert, 1975) or *allochthons* in western Newfoundland (Williams, 1995), and collectively known as the Taconic allochthons.

In general, the intensity of post-emplacement deformation increases southeastward across the allochthons, mostly caused by the occurrence of hinterland-verging structures approaching the internal Humber zone (Cawood et al., 1995; Pinet et al., 1996a and b). Out of sequence thrust sheet emplacement, normal faulting and reverse-sense fault reactivation, including thick-skinned thrusting are also documented and have complicated the structural architecture of the Humber zone (Waldron et al., 1998, 2003; Stockmal et al., 1998, 2004; Cooper et al., 2001; Palmer et al., 2002; Sasseville et al., 2008).

Western Newfoundland

The external Humber zone of western Newfoundland is separated in four allochthons: the Humber Arm, Old Mans Pond, Southern White Bay and Hare Bay allochthons (Fig. 2).

Typical of the allochthons, the Humber Arm Allochthon was thrust above the platform succession and includes several imbricated thrust slices exhibiting a classical old-over-young thrust sequence, suggesting frontal accretion in a foreland-propagating duplex fashion (Waldron, et al., 1998; Stockmal et al., 1998). Thrust slices are separated by mélanges (Williams and Cawood, 1989). The lower and intermediate thrust slices of the allochthon consist of continental margin units, whereas the upper slices are made of ophiolitic and metamorphic rocks of the Bay of Islands Complex. Although the Humber Arm allochthon has been interpreted as emplaced during thin-skinned Taconian deformation, post-Ordovician thrusting and thick-skinned structures do occur. At Port au Port Peninsula and northeastward offshore, the Humber Arm allochthon occupies the core of a tectonic wedge (Fig. 5). The roof thrust of the triangle zone has earliest Devonian Clam Bank Formation units in its hanging wall, indicating that final emplacement of the allochthon is post-Silurian, and most probably Acadian (Early to Middle Devonian; Stockmal et al., 1998). Moreover, this structure is further reactivated and overridden by thick-skinned thrusting along the Round Head Thrust, which overlies the Garden Hill oil field. The Round Head Thrust is interpreted as a reactivated normal fault, inherited from the Iapetus rifting and or formed in response to foreland loading during the Taconian Orogeny (Stockmal et al., 1998 and references therein). The pattern of thick-skinned faults in the Port au Port Peninsula suggests a history involving transtensional strain (Palmer et al., 2002). In the Parson's Pond area, the structural style of the Humber Arm Allochthon is characteristic of classical fold and thrust belts (Fig. 5). Tectonic overprinting is also present in the Parson's Pond area where triangle zones and thick-skinned deformation are described (Stockmal et al., 1998; Cooper et al., 2001).

Quebec

The external Humber zone of Quebec is separated into numerous thrust nappes: the largest nappes from southern Quebec to Gaspé are: the Stanbridge, Granby, Chaudière River, Richardson, Bacchus/Ste-Hénédine, Lower St. Lawrence and Sainte-Anne River nappes (Fig. 2). Thrust nappes commonly are separated by tectonic and olistostromal mélanges (St-Julien and Hubert, 1975; Lebel and Kirkwood, 1998; Comeau et al., 2004, Pinet, 2008). Severe telescoping by thrusting has caused the juxtaposition of distinct and originally widely separated sedimentary facies (Lebel and Kirkwood, 1998). The structure of these nappes is complex and dominated by northwest verging folding, axial-planar cleavages, locally steeply-dipping and imbrications of thrust slices. Out of sequence faulting and southeast-directed structures are also documented (Pinet et al., 1996a and b; Comeau et al., 2004; Sasseville et al., 2008). Although, the structuration of the external Humber Zone is interpreted as foreland-propagating (St-Julien and Hubert, 1975), the emplacement of a few uppermost nappes, such as the Chaudière River Nappe, is thought to be out of sequence in respect to the underlying thrust nappes (Comeau et al., 2004). Many of these nappes are folded into antiformal culminations, such as the Ste-Hénédine Nappe, or into synformal thrust klippes, such as Chaudière River Nappe.

At the edge of the frontal nappes, across Logan's Line, a series of southeast-dipping thrust fault imbricate the southeastern part of the St. Lawrence platform units into parautochthonous thrust slices, such as the St-Flavien slice, forming a foreland thrust belt (Fig. 3). In southern Quebec, some of these platform slices are now exposed (i.e., Phillipsburg, St-Dominique and Upton slices; Séjourné et al., 2003). Locally, the foreland thrust belt is separated from the autochthonous platform sequence by blind thrusts and back-thrust faults, forming a triangle zone along the southeastern limb of the Chambly-Fortierville syncline (Castonguay et al. 2003, 2006; Fig. 3).

PETROLEUM GEOLOGY – CONVENTIONAL SYSTEMS

Six major plays have been recognized in the Lower Paleozoic sediments of the St. Lawrence Platform and Humber Zone of eastern Canada (Fig. 12); these are, (1) Cambrian rift-drift clastics, (2) Lower Ordovician hydrothermal dolomites, (3) Middle to Upper Ordovician hydrothermal dolomites and (4) Upper Ordovician to Devonian foreland units; and in the Humber zone, we have identified, (5) Cambrian to Ordovician deep-water clastics and (6) Lower Ordovician carbonate platform thrust slices. A seventh play is recognized in southern Quebec and consists of onshore and offshore Quaternary sediments. Finally, shale gas is an important unconventional play that will also be addressed below (U1 on Fig. 12). Of all these plays, the two hydrothermal dolomite plays in the St. Lawrence Platform and the thrust slices of Ordovician platform have enough data for a quantitative assessment of their hydrocarbon resources. In the following pages large-scale considerations on source rocks and maturation and migration are presented and followed by a detailed description of the seven major plays.

Exploration history / discoveries to date

The Lower Paleozoic St. Lawrence carbonate platform in southern Quebec was initially tested for hydrocarbons in the late 1950's and 70's (Fig. 3). Gas shows were reported in many of the wells in both passive margin (Beekmantown Group) and foreland basin (Trenton Group) carbonates. Extensive organic matter studies resulted in detailed maturity map of the St. Lawrence Platform and in the recognition of the Utica Shale as a potential

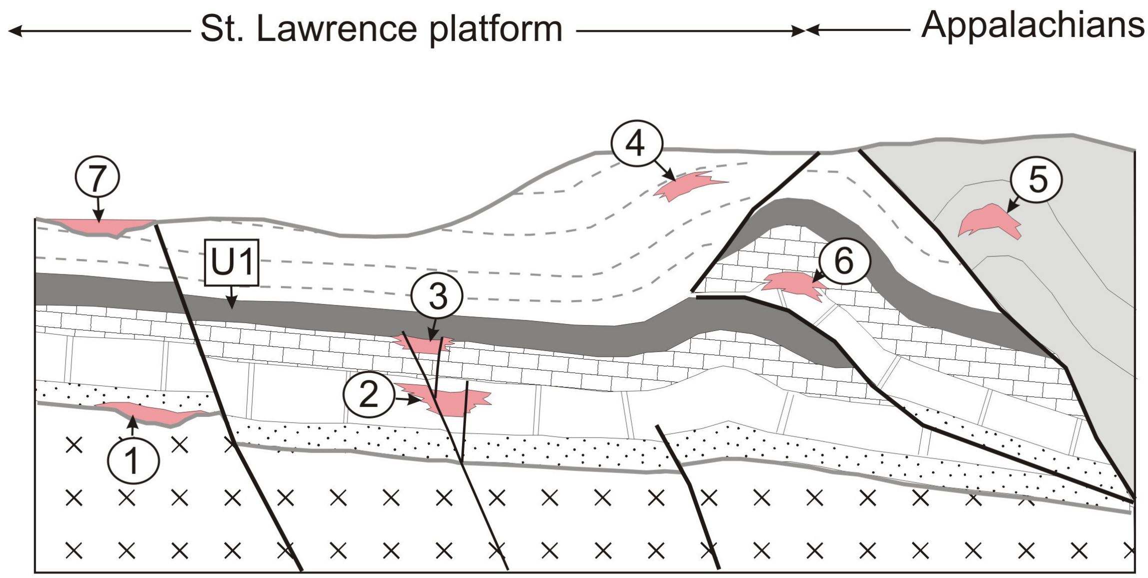


Figure 12. Conceptual tectonostratigraphic setting for the St. Lawrence Platform and largely coeval deep marine sediments preserved in tectonic stacks in the Humber zone. The 7 conventional and one unconventional plays (U1) are located and discussed in text.

source rock (Héroux and Bertrand, 1991; Bertrand, 1991). In the 1990's, following extensive seismic programs (Fig. 13), a new round of exploration targeted the deep autochthonous platform units below the Taconian thrusts. The main exploration targets before the turn of the century were faulted structural highs and unconformity-bounded Lower Ordovician units. Current exploration activities focus on Lower and Middle Ordovician hydrothermal dolostones (Lavoie et al., 2005; Thériault 2007; Lavoie et al., 2009a; Lavoie and Chi, in press). The first significant exploration success for this play occurred in early 2007, when Talisman Energy reported significant (but non-sustained) natural gas flows up to 270 thousand m^3/d (9 mmcf/d; Gentilly well) from hydrothermally-dolomitized intervals of the Trenton-Black River (star #3 on Fig. 13). This was followed by another significant discovery (2 mmcf/d; St. Edouard well) reported in June 2009.

Exploration on Anticosti Island first started in the late 60's (Fig. 6). Initial drilling failed to identify economic accumulation of hydrocarbons, however, the recovered cores and cuttings led to extensive studies that led to a detailed stratigraphic framework, identification of quality source rock, rank of thermal maturation and documentation of potential reservoirs. A second period of exploration started in l997 with over 800 km of new seismic and the drilling of eight new wells. No commercial discoveries were made. However, the program successfully determined the presence of abundant sags with locally thick intervals of porous hydrothermal dolostones in both the Romaine and Mingan formations (Lavoie et al., 2005, 2009a; Lavoie and Chi, in press; Fig. 6).

The first report of oil in Newfoundland goes back to 1812 with the occurrence of floating oil on Parsons Pond in western Newfoundland. It was in 1867 that a shallow (213 m) exploration well encountered some oil at Parsons Pond. Based on the presence of oils seeps in the area, 60 shallow (less than 700 m) wells were drilled in western Newfoundland from 1900 to 1965 (Fig. 5). Reinterpretation of some extensive 1970's seismic (mostly offshore) was published in the early 1990's (Stockmal et al., 1998) (Fig. 5). The new interpretation documented the presence of a Canadian Rocky Mountains Foothills-type triangle zone at the edge of the deformation zone. Extensive seismic and exploration drilling led to the successful Hunt/PanCanadian Port au Port #1 well in 1995 (Fig. 5).

The Lower Ordovician dolostone reservoir is at 3400 m and was flow-tested at an average of 320 m^3/d (2000 b/d) of oil and 39 thousands m^3/d (1.3 mmcf/d) of gas (Cooper et al., 2001). Development drilling consisted of three sidetrack wells from the original well bore, one came up dry, a second one encountered mechanical / production issues after initial flows and the third one after initial production of 64 m^3/d (400 b/d), yielded sub-economic

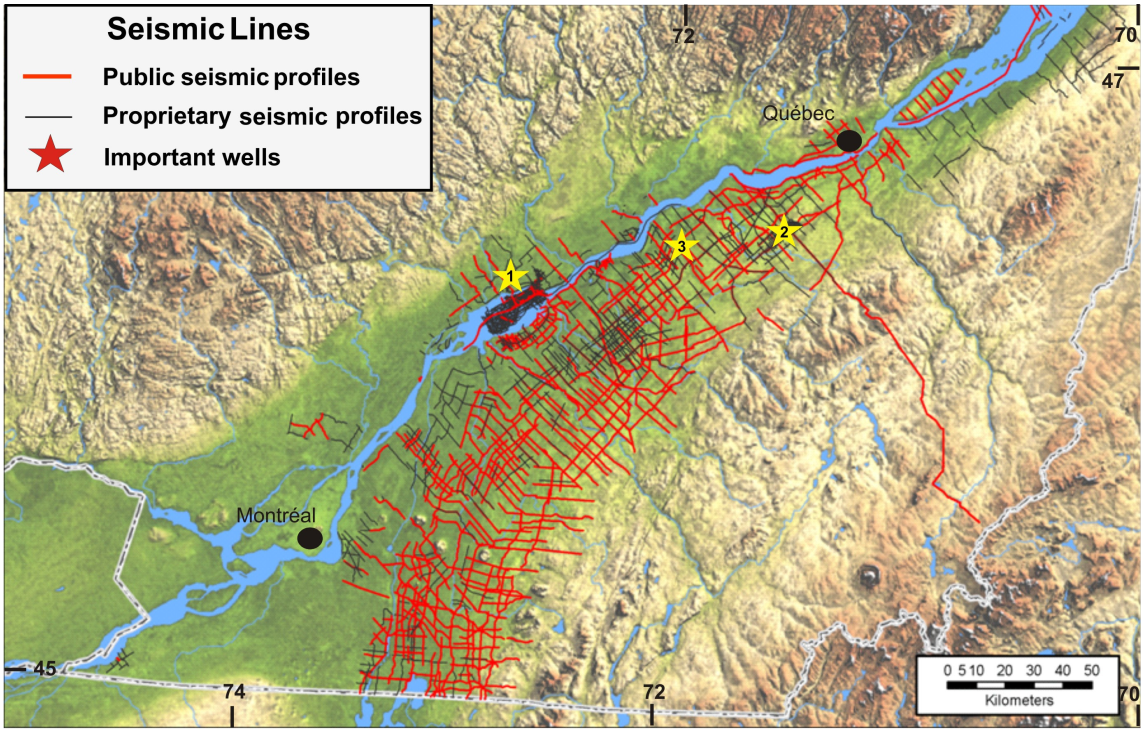


Figure 13. Southern Quebec relief map overlain by all available seismic lines (both public and proprietary) to show the density of information largely concentrated at or near the Appalachian structural front as well as in the Humber zone. The three stars locate the most significant discoveries in southern Quebec. (1) The Pointe-du-Lac Quaternary gas reservoir, (2) the St. Flavien field in a thrust slice of Lower Ordovician Beekmantown dolostones and (3) the Gentilly discovery in Trenton-Black River dolostones.

production volume over prolonged testing. Since initial drilling of the Garden Hill field, over 960 m^3 (6000 barrels) of oil have been produced. Six other deep wells were drilled in the vicinity of the discovery well, testing different structural plays, all came up dry.

The oldest report of surface seeping oil in the Humber Zone of Quebec goes back to 1958 when oil was noticed in a gravel pit in the Montmagny area. Most of the early hydrocarbon exploration in Quebec focussed on the St. Lawrence Platform and on the Gaspé Belt. The Lower Paleozoic Humber Zone of the Quebec Appalachians did not receive significant attention until a late 1960's exploration seismic survey by Shell Canada, using a Foothills-style play concept. This led to the successful drilling of the $210*10^6$ m^3 (7 Bcf) Saint-Flavien gas field (Béland and Morin, 2000; Bertrand et al., 2003a; Fig. 3). A few other exploration wells have been drilled in the Humber Zone of Quebec, most of which did encounter gas shows. Of interest are three holes drilled in the lower St. Lawrence area (Parke wells), which documented a significant porous reservoir unit that was water-filled. Finally, some shallow water wells in the eastern Quebec encountered natural gas in fractured deep marine clastic unit.

Source Rocks

Potential source rocks are found both in the autochthonous platform domain and in the Appalachian allochthonous succession of the Humber Zone. The source rock potential of the Middle Ordovician Mictaw Group, in the Gaspé Belt, will be discussed in the next chapter.

The foreland deep marine autochthonous shale capping the carbonate platform (Fig. 7 and 14) is a regional potential source rock with variable geochemical characteristics. In southern Quebec, detailed organic matter petrography and Rock Eval analysis have shown that the Upper Ordovician Utica Shale has potential for gas (Bertrand, 1991). The formation contains Type II kerogen and a small amount of Type I. The Total Organic Carbon (TOC) values range from 1.0 to 2.7 wt% and the Hydrogen Index (HI) reaches up to 294 (Lavoie et al., 2009b; Fig. 14). In southern Quebec, other potential source rocks with lower potential include the upper part of the Trenton Group and shale intervals at the base of the Lorraine Group (Lavoie et al., 2008a).

The Utica is facies and approximately time equivalent with the Upper Ordovician Macasty Formation on Anticosti Island (Figs. 7 and 14) and the Upper Ordovician Pointe Bleue Formation (TOC: up to 15.5% and HI up to 633) in the Lac Saint-Jean outlier (Fig. 2; Lavoie, 2008). On Anticosti Island, detailed organic matter petrography and Rock Eval analysis have shown that the Macasty Formation has a significant source rock potential (Fig.

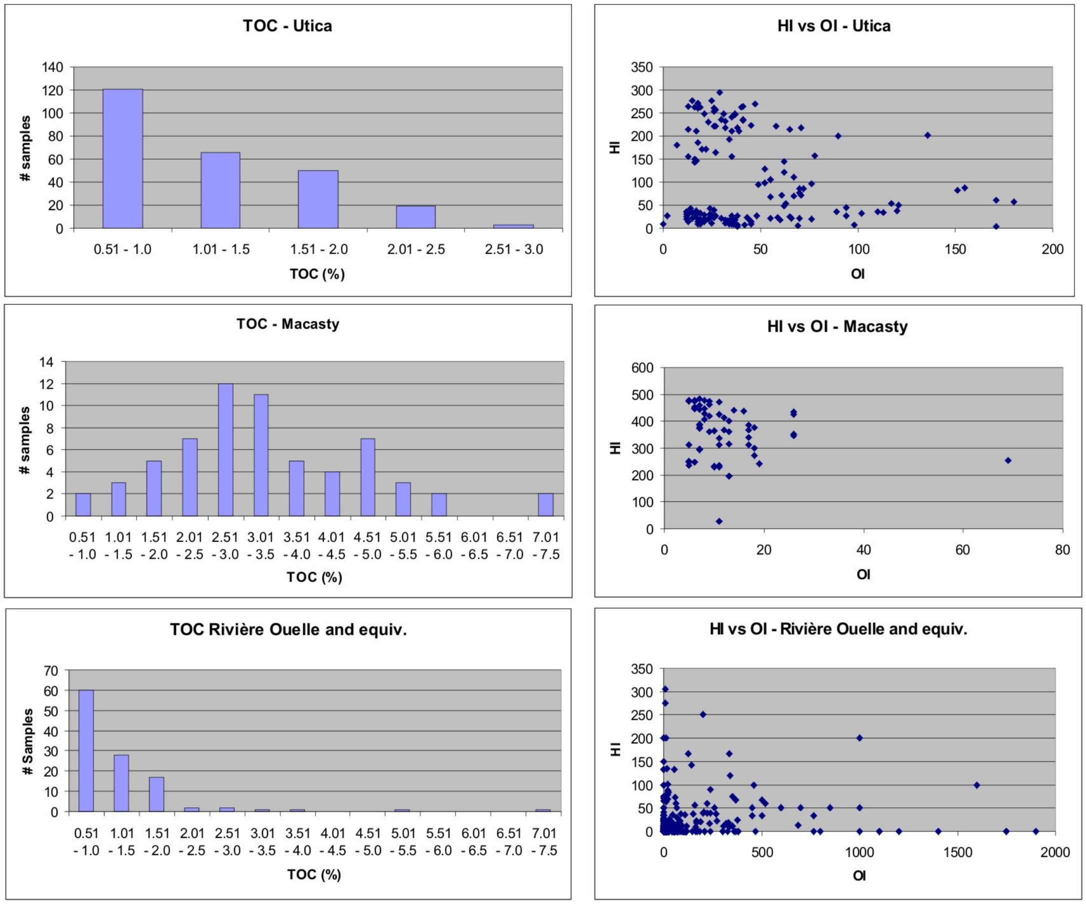


Figure 14. Histograms of frequency distribution of total organic carbon (TOC) for the Upper Ordovician Utica and Macasty shales and for the Lower Ordovician Rivière Ouelle (and equivalent stratigraphic units). Also the Hydrogen Index (HI) versus the Oxygen Index (OI) plots for those three units. Data in Lavoie et al (2009b).

14). The formation contains Type II kerogen and a small amount of Type I. TOC values range from 0.5 to 7.1wt% and the HI is up to 477 (Lavoie et al., 2009b).

In western Newfoundland, the Middle Ordovician Black Cove Formation is facies correlative but older than the Utica Shale (Lavoie, 2008; Fig. 7). The Black Cove Formation has TOC and HI values up to 1.4% and up to 312 respectively (Fowler et al., 1995). The Middle Ordovician Table Cove (0.82%, 340) formations have lower but fair source rock potential (Fowler et al., 1995; Lavoie et al., 2009a)

Over the years, detailed studies of seeping oil and reservoir oil have been carried in western Newfoundland (Fowler et al., 1995). The chemistry of the western Newfoundland oils (51ºAPI) indicates a pre-Devonian clastic source rock of Type I/II organic matter of algal origin. Detailed geochemical studies indicate that the allochthonous Cambrian-Ordovician deep marine Green Point Formation (Cow Head Group, preserved in the Humber Zone; Fig. 8) has the highest TOC and HI values (10.35%, 759) in western Newfoundland and is probably the source for the seeping and produced oil (Fowler et al., 1995). In the Newfoundland Appalachians, unspecified (Cambrian-Ordovician?) Humber Arm Group shale (1.1%, 363) and the Cambrian-Ordovician Shallow Bay Formation (Cow Head Group) shale (2.18%, 382) have lower but fair source rock potential. In the Quebec Appalachians, the latest Cambrian to earliest deep marine highly mature shales (Rivière Ouelle Formation and equivalents, Lavoie et al., 2003; Figs. 8 and 14) has residual TOC and HI values (up to 7.3% and 306, respectively; Lavoie et al., 2009b) that suggest source rock potential (Bertrand et al., 2003b; Lavoie et al., 2009a).

Maturation and generation

In southern Quebec, maturation increases southerly in the St. Lawrence Platform (Fig. 15). In the least mature sector (Quebec City area), the Utica Shale is in the upper part of the condensate zone (Bertrand, 1991; Bertrand and Lavoie, 2006). Elsewhere, the Utica Shale is within the condensate to dry gas zones. Studies of wells show that maturation positively correlates with depth and results from burial of the succession and precedes the formation of the Chambly-Fortierville syncline (Bertrand and Lavoie, 2006).

A significant maturation jump is noted at the Appalachian structural front (Figs. 15 and 16). In the Humber Zone of Quebec, a regional northeasterly increase is noted from the Quebec City area toward the Gaspé Peninsula (oil window to sterile; Fig. 16; Islam et al., 1982; Chi et al., 2000). This regional scenario has been recently detailed (Bertrand and Malo, 2009), significantly lower thermal surface conditions (oil to condensate zones) were noted

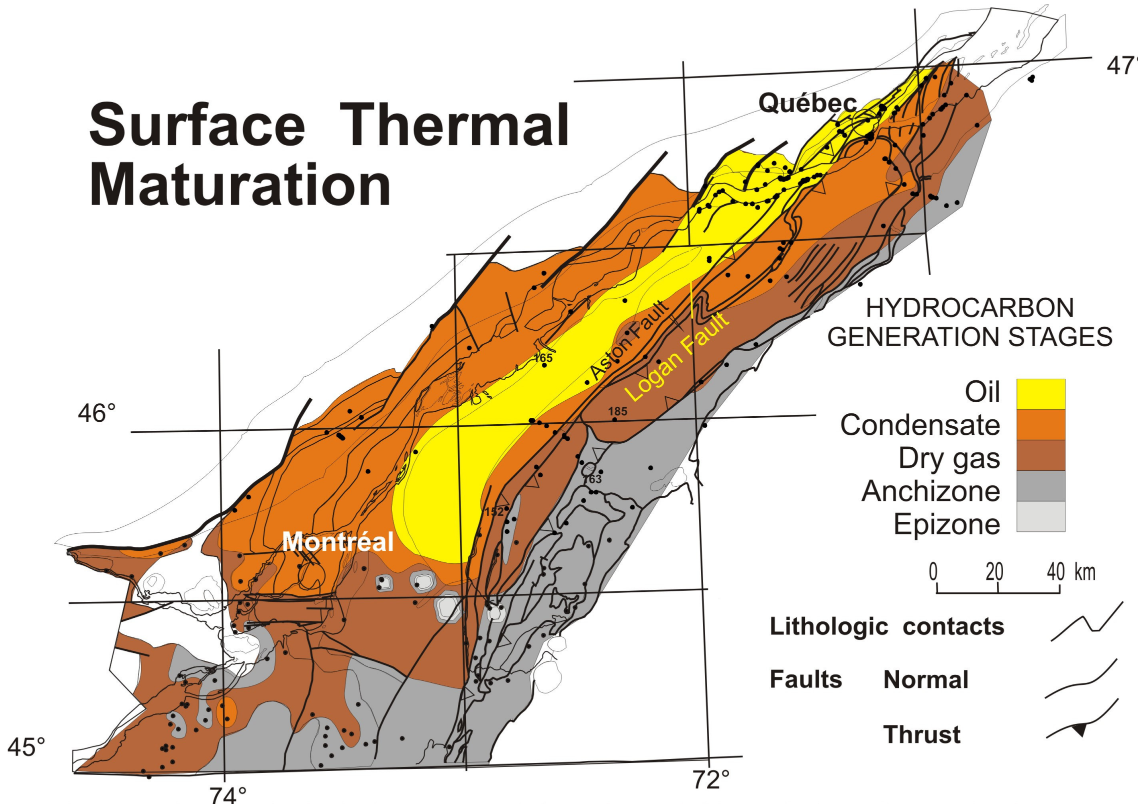


Figure 15. Surface maturation data for the St. Lawrence Platform and west end of the Appalachian Humber zone of southern Quebec. Note the southwesterly increase in thermal conditions for the same stratigraphic interval and the major thermal jump on both sides of the Logan's line. Geology can be seen on Figure 3. Modified from Bertrand and Lavoie (2006). See text for details.

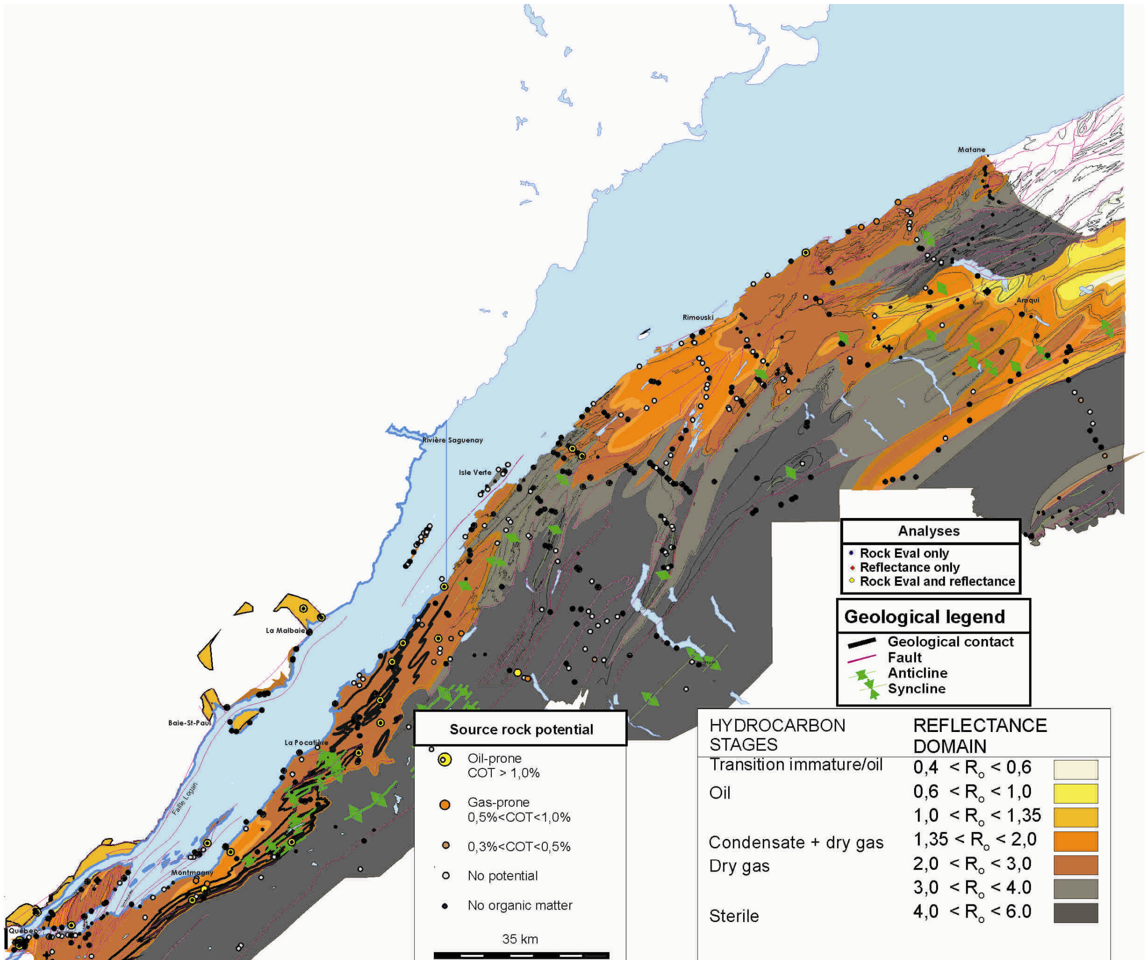


Figure 16. Isocontours of vitrinite equivalent reflectance ($R_{h\text{-}evi}$), in relationships with hydrocarbon stages between Quebec City and Matapédia. Also, samples location together with their TOCvalues. From Bertrand and Malo (2009)

from Quebec City to the La Pocatière area (Fig. 16) and a gradual increase to dry gas and overmature in the Témiscouata region (Fig. 16). Transported burial maturation is indicated by significant maturity jumps from one thrust slice to another, and at the transition between the St. Lawrence Platform and the Appalachian Humber Zone (Héroux and Bertrand, 1991; Bertrand and Lavoie, 2006; Bertrand and Malo, 2009). The Utica Shale has been significantly buried beneath syn-orogenic Taconian flysch and available data on the burial history indicates that the Utica Shale entered the oil window during the Late Ordovician.

Maturation increases southwesterly on Anticosti Island and is also positively correlated with depth (Bertrand, 1987; Lavoie et al., 2009a; Fig. 6). The Macasty source rock is within the oil window in the northeastern half of the island and in the condensate zone in the southwestern part of the island.

Surface samples from western Newfoundland show a south to north increase in maturation with another significant west to east increase on Port au Port Peninsula (Lavoie et al., 2009a; Fig. 17). The Upper Ordovician Long Point Group in Port au Port Peninsula has the lowest maturation levels of all rock units; they are immature to marginally mature. The Cambrian-Ordovician platform rocks at the north end of the belt are mature to overmature. In all areas, maturation decreases upsection. A depth related maturation increase is documented in exploration wells (Cooper et al., 2001). Similar maturation values for units on both sides of the Round Head Thrust suggest that maximum burial was associated with sedimentary loading although tectonic loading may have played a role. In most wells, deeper units (4000+ m) are still in the oil window (Cooper et al., 2001). The available burial history scenarios indicate that the source rocks entered the oil window during the Devonian Acadian Orogeny (Cooper et al., 2001).

Migration and accumulation

Thermal modelling suggests that most of the hydrocarbons from the Utica Shale were generated during the Taconian Orogeny in the Late Ordovician (Bertrand et al., 2003b). Recent gas shows and discoveries in the St. Lawrence Platform of southern Quebec (Dundee, Bécancour, Batiscan and Gentilly wells) argue for an up-dip (southeast to northwest) and vertical (along some of the extensional faults) migration of hydrocarbons of the Upper Ordovician Utica Shale towards Lower and Middle Ordovician carbonate reservoirs.

In the Port au Port Peninsula, a significant migration event occurred after the development of the hydrothermal dolostone reservoir (Cooper et al., 2001; Azmy et al., 2008). In well-exposed sections along the Northern Peninsula, major hydrothermal dolomitization of

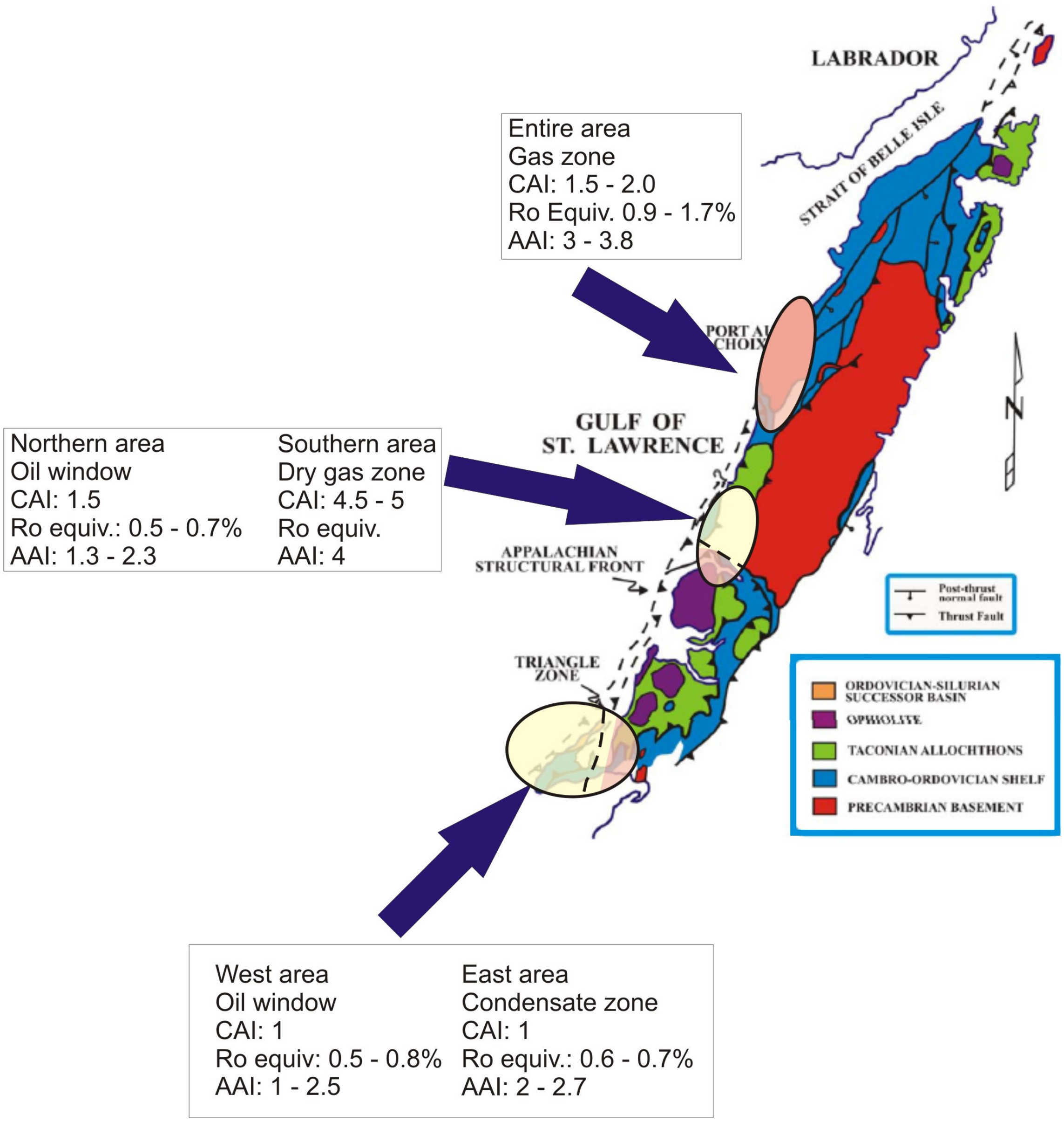


Figure 17. Synthesis of available thermal maturation at three locations in western Newfoundland. Based on multiple datasets presented in Williams et al. (1998).

the carbonate facies (St. George and base of Table Head groups) is associated with extensional faults such as for the Port au Choix exposed oil field (Cooper et al., 2001; Knight et al., 2007, 2008; Azmy et al., 2008, 2009; Conliffe et al., 2009). Hydrothermal fluids and hydrocarbons used these faults as migration pathways. U/Pb dating of base metals associated with the hydrothermal event yielded an Early Devonian age, which is correlative with the Acadian Orogeny and possibly also coeval with oil generation.

Modelling from Anticosti Island suggests that over 75% of generated hydrocarbons have migrated out of the Macasty Formation (Bertrand. 1987). The Macasty Formation on southern Anticosti Island (ARCO well) entered the oil window in the Early Silurian and moved into the gas zone during the Lochkovian, where it still stands (Bertrand, 1987). The Macasty is overlain by shales and flysch sediments of the Vauréal Formation. Fluid flow simulation suggests overpressure in the Macasty by Early Silurian time (Chi et al., 2009). Up-dip northward migration is proposed and vertical migration along some of the major fault planes is assumed. In the Romaine Formation, migration is documented by the presence of pore-coating bitumen and abundant hydrocarbon fluid inclusions in a post-secondary dissolution, late pore-filling calcite cement (Lavoie et al., 2005).

Migration of hydrocarbons is documented in the Humber Zone of Quebec. In the Saint-Flavien gas field, the gas accumulation formed after maximum burial and is assumed to have occurred during the late Taconian Orogeny (Bertrand et al., 2003a). Combined fluid inclusions and organic matter maturation studies show a strong correlation between type of hydrocarbon inclusions (oil, methane), homogenization temperature of aqueous inclusions and Ro of autochthonous organic matter (Chi et al., 2000). This suggests that in most cases, migration occurred during or near maximum burial. Late fractures commonly host hydrocarbon fluid inclusions in diagenetic phases (silica, calcite), solid petroleum residue (impsonite) and gas shows, which support a late tectonic scenario for migration through fractures.

HYDROCARBON PLAYS IN THE ST. LAWRENCE PLATFORM

Four plays have been identified and attributed to the Lower Paleozoic St. Lawrence Platform (Fig. 12): 1) Cambrian rift-drift clastics, 2) Lower Ordovician hydrothermal dolomites, 3) Middle-Upper Ordovician hydrothermal dolomites, and 4) Upper Ordovician – Devonian (?) foreland sandstones and limestones. The two Ordovician hydrothermal plays will be assessed for oil and gas potential. The other two plays will be described qualitatively.

Cambrian rift-drift clastics (R1)

Exploration history and shows

The Upper Cambrian Potsdam Group has been tested by a significant number of wildcat wells in southern Quebec. Seven of these wells yielded positive DST in the Potsdam with gas flows up to 8370 m^3/d (279 mcf/d). In the Port au Port Peninsula of Western Newfoundland, the Lower Cambrian Hawke Bay Sandstone was a secondary target in recent exploration drilling (post-1995).

Discoveries

There are no discoveries.

Potential Reservoir

In southern Québec, the Upper Cambrian Potsdam post-rift sandstone consists of two units (Salad Hersi and Lavoie, 2000a, 2000b and Salad Hersi et al., 2002a). The Covey Hill Formation is largely an impure sand and conglomerate unit. The overlying uppermost Cambrian Cairnside Formation consists of well-sorted, high-energy, medium-grained sized quartzose sandstone deposited in a marginal marine setting. Some bitumen is locally present in the pore space. In the St. Lawrence Lowlands, the basal unit over the Grenvillian basement is time transgressive from the SSW towards the NNE and "Potsdam-like" sandstones occur throughout the platform, with highly variable thickness. Porosity (secondary from leaching of previous carbonate cement) can reach up to 9.2% (Lavoie, 2009).

In western Newfoundland, the Lower Cambrian post-rift nearshore sandstone of the Hawke Bay Formation forms a distinctive sand blanket. The sandstone is locally well-sorted with abundant wave structures and desiccation polygons, which indicate a shallow marine depositional environment. In the Port au Port #1 well, the Hawke Bay sandstone is 64 m thick and has porosity up to 12.2% in the hanging wall of the Round Head thrust. The sandstone still has 5% porosity in the footwall (Cooper et al., 2001).

Geographic distribution

The Cambrian sandstone play is recognized in southern Quebec and Western

Newfoundland (Fig. 18), however, drilling and seismic data argue for its absence on Anticosti Island (Bertrand, 1987; Shell Canada, 2001).

Source rock, maturation, generation and migration

Lower and Upper Ordovician source rocks are the best candidates (see “hydrocarbon geology section”), these type I and II source rocks generated their hydrocarbons during either the Taconian (late Middle Ordovician) or the Acadian (Middle Devonian) orogenies. Based on our understanding of thermal maturation, this play is gas-prone.

Traps and seals

Cambrian rift-drift clastics and unconformity covering clastics are part of complex depositional environments from fluvial to deltaic and marginal marine. As such, traps and seals could include, amongst others, lateral pinchout and channel-fill with various shale and mudstone seals. However, extensional (southern Quebec) and compressional (Western Newfoundland) structural features may significantly modify the trap geometry.

Risk factors

Cambrian clastics are the oldest potential reservoir rocks in the Paleozoic succession and the main risk factor is certainly long term sealing as these sandstones have been affected by a prolonged period of tectonic activity (Taconian, Salinic, Acadian and even Alleghenian in western Newfoundland; Fig. 18).

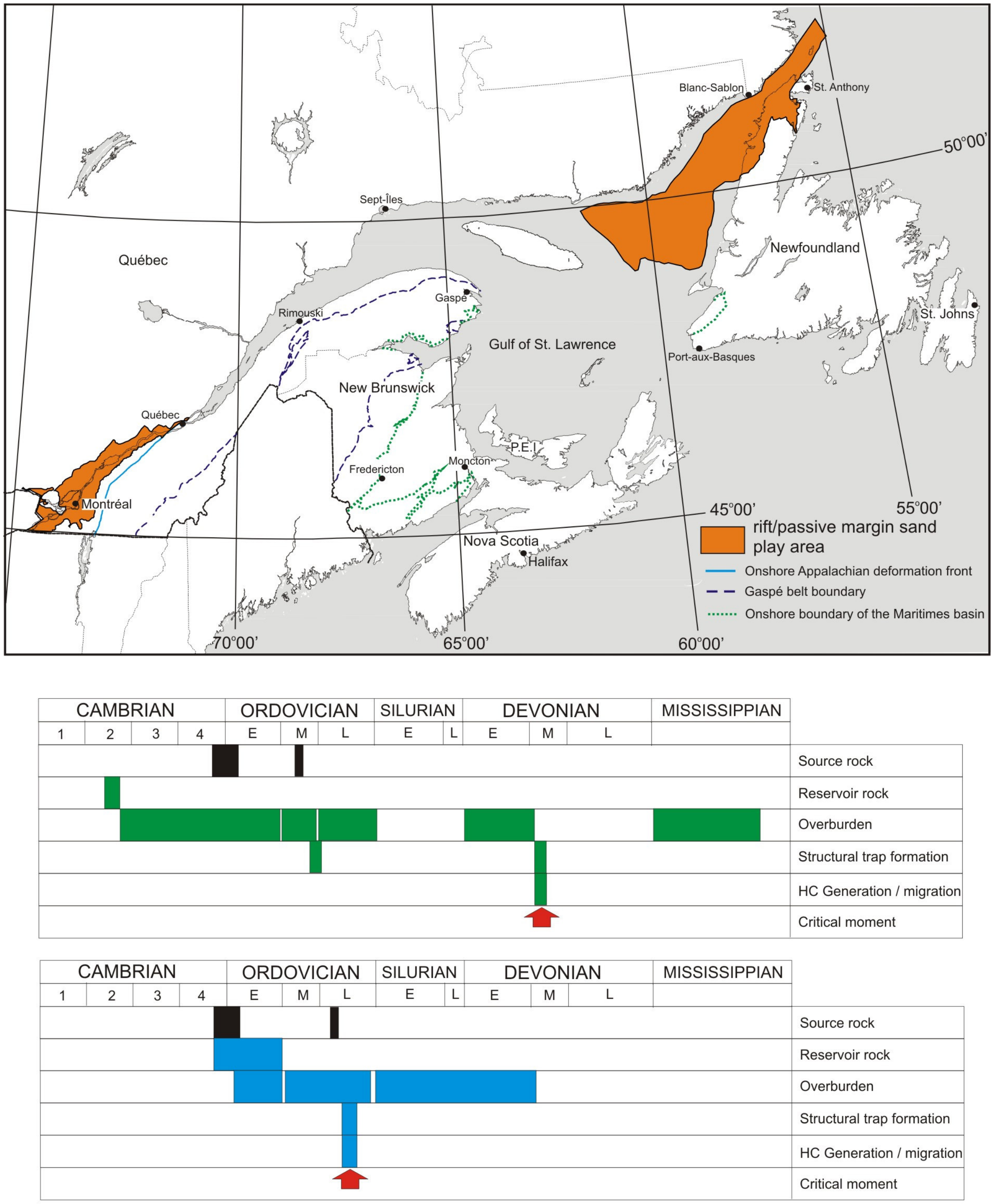


Figure 18: Top, extension of rift to early drift clastic play (orange zone) in eastern Canada, note the absence of this play in the central area. Bottom, hydrocarbon chart for this play with time constraint on hydrocarbon system data. Newfoundland is the green diagram and Quebec is the blue one. See text for details on play zone distribution and risk analysis.

Lower Ordovician HTD (R2)

Exploration history and shows

The Lower Ordovician carbonates in southern Quebec, Anticosti and western Newfoundland have been the primary targets for hydrocarbon exploration drilling in the platform succession since the 19th century. These porous dolostones are the source of positive DSTs in a number of wells in southern Quebec, gas kicks in Anticosti Island and abundant hydrocarbon shows in western Newfoundland. The recent regional-scale recognition of hydrothermal and high temperature dolomitization provides a new exploration model for Lower Ordovician carbonate units.

Discoveries

The Garden Hill oil field was discovered in 1995 in the Port au Port peninsula in western Newfoundland (Cooper et al., 2001). The oil and gas are hosted in hydrothermally-altered dolostones of the Aguathuna Formation (Lower Ordovician St. George Group). The reservoir, at 3460 m deep, is 18.5 m thick and averages 10% porosity with 21 mD permeability. Water saturation is at 25% and the reservoir pressure is 25 MPa. The reservoir produced over 800 m^3 (5000 barrels) of oil during an initial 7 days test. Drilling and testing of three sidetracks resulted in sub-economic flows.

Potential Reservoir

Lower Ordovician carbonates were deposited on a low energy passive margin platform that stretched along the entire eastern margin of Laurentia (Lavoie et al., in press). In eastern Canada, these carbonates correspond to the Beekmantown Group of southern Quebec, the Romaine Formation on Anticosti/Mingan islands and the St. George Group in Newfoundland. The shallow marine platform was laterally well-zoned with a high-energy thrombolite reef or oolite sand shoal rimmed margin (Knight et al., 2007, 2008). Inboard of that margin, a low-energy shallow subtidal domain was the site of accumulation of muddy and bioturbated sediments. These sediments record a large number of high-order, metric-scale shallowing upward hemicycles that are part of longer 3rd order eustatic cycles.

Documented reservoirs formed through dolomitization of the carbonate facies (Cooper et al., 2001; Lavoie et al., 2005; Azmy et al., 2008, 2009; Conliffe et al., 2009). For the Lower Ordovician peritidal carbonates, dolomitization started immediately after sedimentation. This early dolomitization, locally enhanced through meteoric diagenesis (Azmy et al., 2008), created a favourable porosity / permeability system that was used by various fluids (shallow to mid burial, meteoric and hydrothermal) to complexly alter the porosity of the carbonates. Everywhere along the Canadian segment of the margin of Laurentia, a late pulse of hydrothermal fluid is recorded, this event occurred shortly after or during the Taconian foreland basin stage. The stable and radiogenic isotopes and fluid inclusions microthermometry indicate that the late dolomitizing fluids were of high temperature, very saline and significantly enriched in radiogenic isotopes. This pulse was responsible for enhancing the porosity for the carbonates.

Geographic distribution

The play area stretches from southern Quebec to Newfoundland. It has been defined using the limit of surface exposure and a ~3 km depth isocontour (Fig. 19). The play area is located west of the deformation front, except in southwestern Newfoundland (Port-au-Port Peninsula and adjacent areas) where minor but significant compressive deformation is documented. The play is gas-prone except possibly in the offshore domain between Anticosti and western Newfoundland where lower maturation is assumed; this has led to us to quantitatively assess both oil and gas potential.

Source rock, maturation, generation and migration

Lower and Upper Ordovician source rocks are the best candidates (see "hydrocarbon geology section"), these type I and II source rocks have generated their hydrocarbons during either the Taconian (late Middle Ordovician) or the Acadian (Middle Devonian) orogenies. In the Port au Port area, the Lower Ordovician source rock (Green Point Formation) has been identified as the most likely source for the oil. It has recently been proposed that the Lower Ordovician reservoirs of Anticosti Island could have been directly sourced from the Upper Ordovician Macasty, through a significant overpressure regime developed in the Early Silurian (Chi et al., 2009).

Traps and seals

Transition from dolomitized intervals to tight carbonate is expected to be the main trap and seal. However, structural features may significantly modify the trap geometry.

Risk factors

Detailed petrogenetic studies (Cooper et al., 2001; Lavoie et al., 2005; Azmy et al., 2008) indicate that dolomitization started early in the geological history; hydrothermal dolomitization was a later event, after the inception of the Taconian (locally Acadian for western Newfoundland) foreland basin. The main risk factor for the Lower Ordovician HTD play is probably the presence of an adequate long term seal. Fault and fractures that controlled the dolomitizing fluid flow may be reactivated after the hydrocarbon migration (Fig. 19).

Quantitative evaluation

The prospect sizes for the Lower Ordovician hydrothermal play are derived from

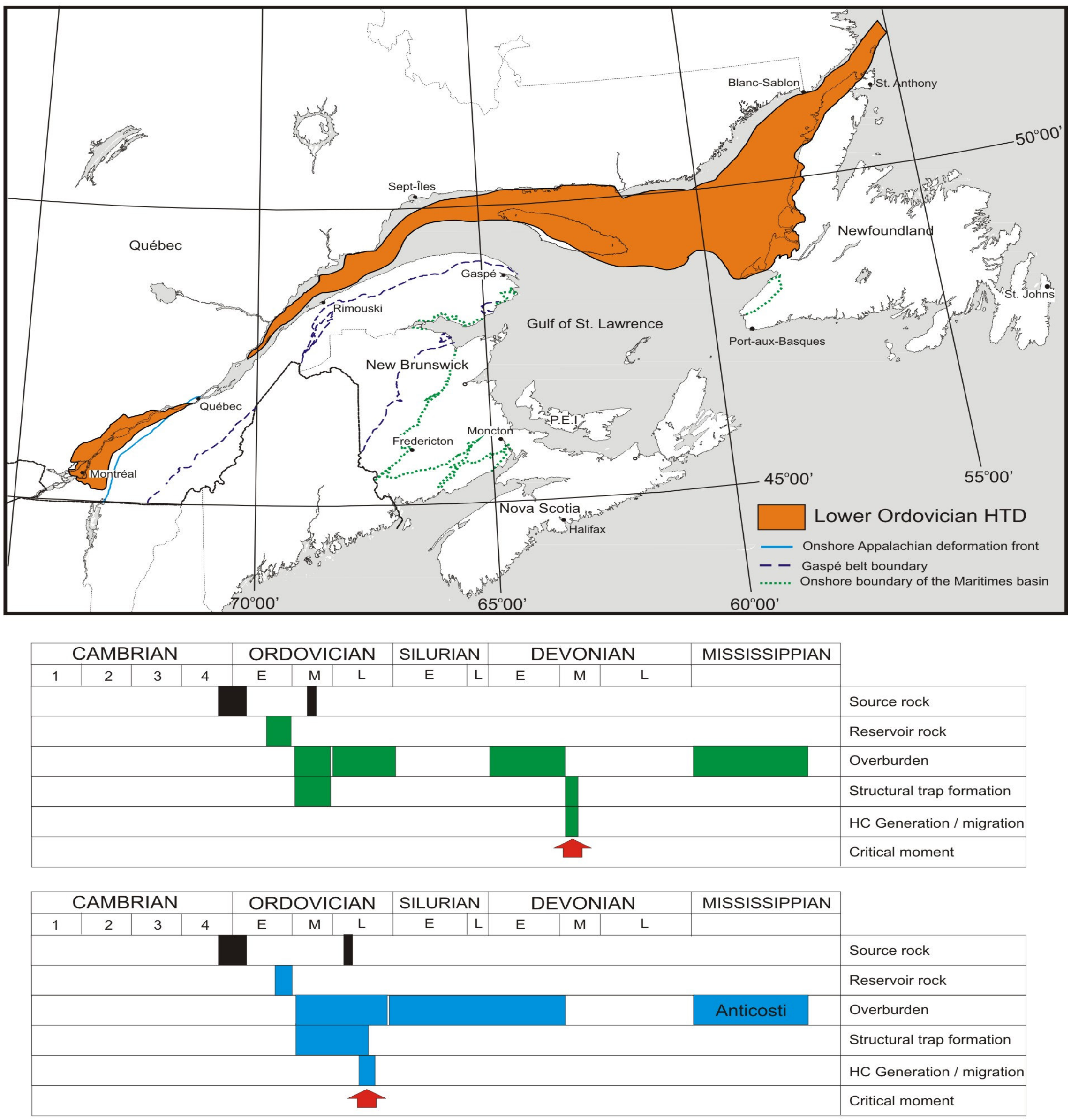


Figure 19: Top, extension of Lower Ordovician HTD play zone (orange zone) in eastern Canada. Bottom, hydrocarbon chart for this play with time constraint on hydrocarbon system data. Newfoundland is the green diagram and Quebec is the blue one. See text for details on construction of play zone and risk analysis.

interpretation of onshore (southern Quebec and Anticosti) and offshore (western Newfoundland) seismic data; the detailed time-structure maps of Thériault and Laliberté (2006) for southern Quebec and Shell Canada (2001) for Anticosti were of critical help. Other parameters such as the thickness of the net pay zone, porosity values and water saturation have been estimated from the petrophysical data from wells on Anticosti Island (Hu and Lavoie, 2008) and from the Garden Hill oil discovery in western Newfoundland (Cooper et al., 2001). These values have been derived for the oil and gas play within that specific unit.

The PRIMES analysis (see further) of the potential gas in place in the Lower Ordovician dolomites in eastern Canada (see also the detailed assessment section) suggests a median potential (P50) of $7 * 10^9$ m^3 (247 Bcf). The potential oil in place in these dolomites has a median potential (P50) of $52 * 10^6$ m^3 (327 Mbo).

Upper Ordovician HTD (R3)

Exploration history and shows

The hydrocarbon reservoir potential of the Upper Ordovician carbonates in southern Quebec and Anticosti has only been recently documented and considered for exploration; this impetus is largely based on significant drilling success in coeval rock units in the US Appalachian and Michigan basins (Smith, 2006). Following the recognition of the hydrothermal dolomitization as the main exploration concept, Upper Ordovician carbonates yielded a few positive DSTs, a discovery in southern Quebec and gas kicks on Anticosti Island.

Discoveries

The 2006 Gentilly #1 well (Talisman et al.) was the second well targeting Upper Ordovician hydrothermal dolomites in southern Quebec. The reservoir is hosted by fractured and dolomitized Black River carbonates at 1875 m deep. The net pay and porosity/permeability data are still confidential; the reservoir is at 20.9 MPa and at 80°C. During initial testing, gas was produced at rates up to $270*10^3$ m^3/d (9 mmcf/d); however, it stabilized at a few thousands cubic feet a day and is currently non-economic. In June 2009, a second significant discovery was announced; the Saint-Edouard #1 well (Talisman et al.) discovered a zone in the TBR that produced gas at a stabilized rate of $60*10^3$ m^3/d (2 mmcf/d). These two wells are vertical, increased production from HTD in coeval rocks in the US is assured through horizontal drilling.

Potential Reservoir

The Upper Ordovician carbonates, commonly designated as the TBR (Trenton-Black River) play were deposited on a tectonically active, high energy, shallow foreland basin carbonate ramp that is distributed along the eastern margin of Laurentia (Lavoie, 1995; Lavoie and Chi, in press; Thériault, 2007). The shallow marine ramp was laterally well-zoned with a subtidal high-energy belt of carbonate sand with adjoining shallower (peritidal) and deeper (offshore) lower energy mud accumulation. These sediments have imperfectly recorded high-order sea-level fluctuations as relatively rapid tectonic foundering of the carbonate ramp occurred. The regional tectonostratigraphic scenario of a westerly-directed diachronous tectonic collapse of the shallow continental margin of Bradley and Kidd (1991) is documented in eastern Canada (Lavoie, 1994).

The reservoir is formed through early dolomitization (Lavoie and Chi, in press; Lavoie et al., 2009a). In several well-studied localities, dolomitization in the Upper Ordovician grainy carbonates, started very shortly after sedimentation (Smith, 2006; Lavoie and Chi, in press). High temperature fluids vertically migrated in brecciated units along active synsedimentary Taconian faults, then migrated laterally in the porous limestones when they reached a preserved impermeable layer (the Upper Ordovician black shales of the Utica or Macasty). The high temperature, saline and radiogenic fluids have generated a complex pattern of limestone leaching, replacement dolomitization, secondary porosity and dolomite cementation. Everywhere along the Canadian segment of the margin of Laurentia, the early pulse of hydrothermal fluids is recorded, this event occurred shortly after or during the Taconian foreland basin stage. Well data from Anticosti Island suggest that porosity can reach up to 20% (Hu and Lavoie, 2008)

Geographic distribution

The play area is roughly similar to the distribution of the Lower Ordovician carbonate play (Fig. 20). It extends from southern Quebec to Newfoundland and has been defined using the limit of surface exposure and the ~3 km depth isocontour. The play is gas-prone except possibly in the offshore domain between Anticosti and western Newfoundland where lower maturation is assumed. This has led to us to quantitatively assess both oil and gas potential.

Source rock, maturation, generation and migration

Lower and Upper Ordovician source rocks are the best candidates (see “hydrocarbon geology section”), these type I and II source rocks have generated their hydrocarbons during either the Taconian (late Middle Ordovician) or the Acadian (Middle Devonian) orogenies. It has recently been proposed that the Middle/Upper Ordovician reservoirs of Anticosti Island could have been directly sourced from the Upper Ordovician Macasty Formation, through a significant overpressure regime developed in the Early Silurian (Chi et al., 2009).

Traps and seals

Transition from dolomitized intervals to tight carbonate is expected to be the main trap and seal. However, structural features may significantly modify the trap geometry.

Risk factors

Detailed studies in the USA (Smith, 2006) and in eastern Canada (Lavoie and Chi, in press) indicate that hydrothermal dolomitization started early in burial history of the TBR and is related to Taconian faulting. The main risk factor for the Upper Ordovician HTD play is probably the presence of an adequate long term seal. Fault and fractures that probably controlled the dolomitizing fluid flow may have been reactivated after the hydrocarbon migration (Fig. 20).

Quantitative evaluation

The prospect sizes for the Middle/Upper Ordovician hydrothermal play are derived from

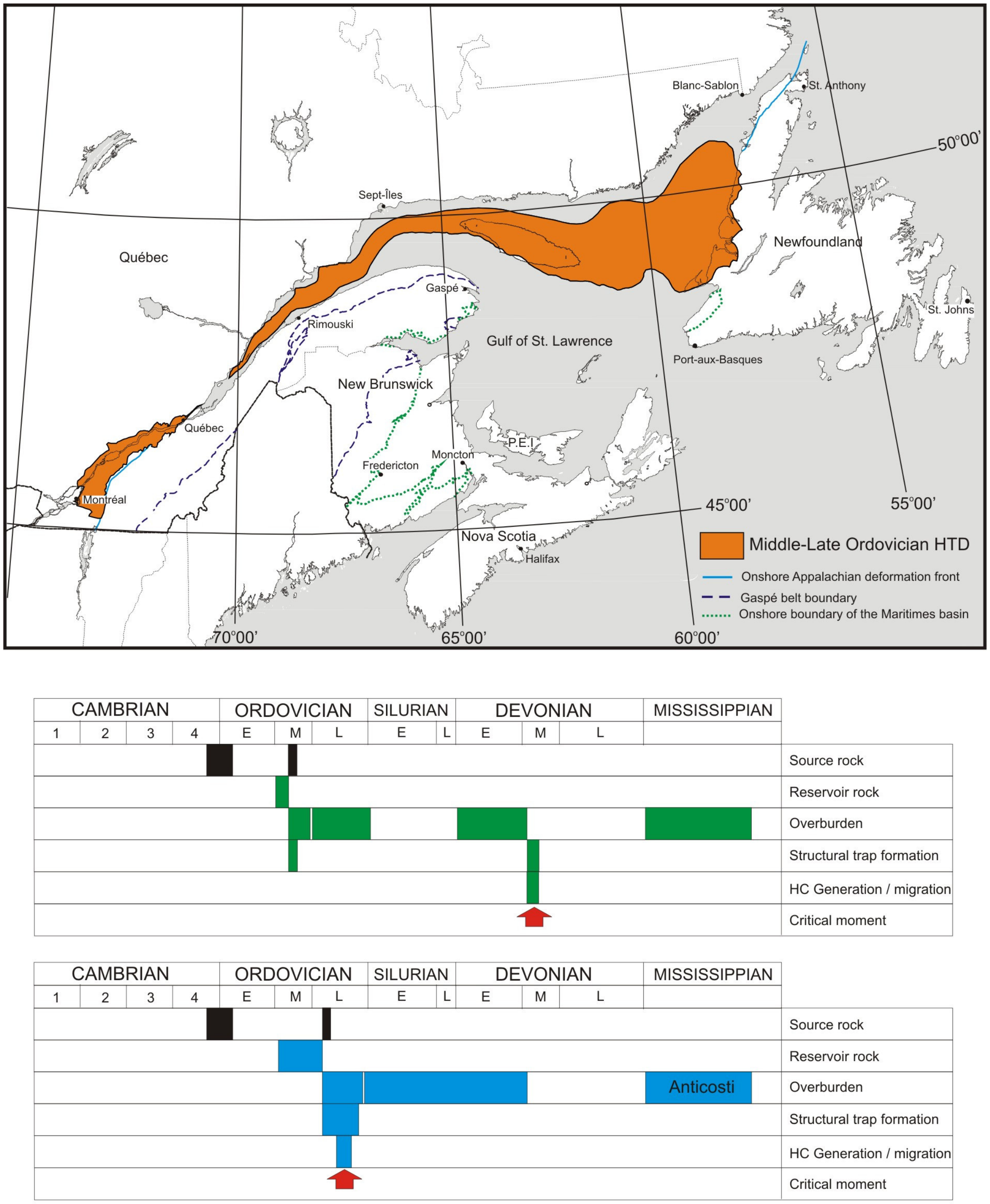


Figure 20: Top, extension of Middle/Upper Ordovician HTD play zone (orange zone) in eastern Canada. Bottom, hydrocarbon chart for this play with time constraint on hydrocarbon system data. Newfoundland is the green diagram and Quebec is the blue one. See text for details on construction of play zone and risk analysis.

interpretation of onshore (southern Quebec and Anticosti) seismic data; the detailed time-structure maps of Thériault and Laliberté (2006) for southern Quebec and Shell Canada (2001) for Anticosti were critical. Other parameters such as the thickness of the net pay zone, porosity values and water saturation have been estimated from the petrophysical data from wells on Anticosti Island (Hu and Lavoie, 2008) and compared with values from the extensively documented similar hydrothermal play in Ontario, and averages of pay zones and porosities were used. These values have been derived for the oil and gas play within that specific unit.

The PRIMES analysis (see further) of the potential gas in place in the Middle to Upper Ordovician dolomites in eastern Canada (see also the detailed assessment section) suggests a median potential (P50) of $28.8 * 10^9 m^3$ (1.02 Tcf). The median potential (P50) oil in place in these dolomites is $64 * 10^6 m^3$ (403 Mbo).

Middle Ordovician to Devonian (?) foreland sandstones and limestones (R4)

Exploration history and shows

Onshore, the foreland flysch sandstones and limestones have never been considered as significant target for exploration for conventional hydrocarbons even though Ordovician flysch sandstones are commonly gas and oil bearing in Quebec and Western Newfoundland, respectively. In Quebec, these sandstones are now considered by exploration companies as targets for unconventional gas.

The offshore part of the Anticosti basin has been the focus of seismic surveys in the 1970s and early 1980s but, due to the presence of strong water-bottom multiples, the imaging of foreland succession has proven unsuccessful.

Discoveries

There are no conventional discoveries so far in this play

Potential Reservoir

A minor but regionally distinctive, although quite variable in thickness, Middle Ordovician sandstone unit overlies the Sauk-Tippecanoe Unconformity. These shallow to near marginal marine sandstones and conglomerates are relatively poorly sorted and mineralogically quite immature. Porosities up to 7.4% have been measured in some outcrop samples (Lavoie, 2009). These sandstones are almost invariably gas-bearing in the subsurface. The most significant facies for the foreland sandstones consists of deep marine flysch derived from the Taconian allochthons and stratigraphically overlying the St. Lawrence platform succession. The Middle to Upper Ordovician flysch comprises the Lorraine and equivalent units in southern Québec (Lavoie et al., 2008a), the Vauréal on Anticosti (Bertrand, 1987) and the Goose Tickle and Long Point in Western Newfoundland (Waldron et al., 1998; Quinn, 1995). They consist of clay and lithic sandstone-siltstone-mudstone succession with significant thickness of coarser grained facies being restricted to western Newfoundland. No data is available for the origin of porosity in these rocks, although dissolution of alumino-silicate is possible in such immature sediments.

Very porous, lower Silurian (Llandoverian) limestones of the Chicotte Formation crop out in a narrow zone along the southwestern shore of Anticosti Island (Desrochers, 2006). These limestones consist of a dominant encrinite facies associated with microbial mud mounds. Multiple sub-aerial exposure surfaces punctuate the unit; nevertheless, the origin of the significant porosity in the encrinites (25 and 30% in two grab samples) remains unknown. In the offshore part of the Anticosti basin, the nature and age of sedimentary units overlying the Chicotte Formation are presently unknown.

Geographic distribution

The western limit of the play area corresponds to the surface exposure of the Utica Shale and correlative units (Fig. 21). In the Gulf of St. Lawrence, the southern play limit corresponds to a 3 km thick Carboniferous cover. As for the Ordovician carbonate plays, the Ordovician foreland sandstone play is gas-prone in southern Quebec, but oil-prone in the northeastern segment of Gulf of St. Lawrence.

Source rock, maturation, generation and migration

Lower and Upper Ordovician source rocks are the best candidates (see “hydrocarbon geology section”), these type I and II source rocks generated their hydrocarbons during either the Taconian (late Middle Ordovician) or the Acadian (Middle Devonian) orogenies.

Traps and seals

The most common trap is structural and consists of various fold closures visible on offshore seismic lines. Faults may have also acted as traps preventing hydrocarbon migration out of the reservoirs. Finally, some stratigraphic pinch-out closures are expected along the sandstone overlying the Sauk Unconformity as well as in channel-fill flysch sands. There are numerous regional mudstone – shale successions that overly the sediments of the play.

Risk factors

The main risk factor for the Middle to Upper Ordovician foreland sand play is probably the presence of an adequate long term seal (Fig. 21) as suggested by the ubiquity of gas seepage features in the St. Lawrence Estuary (Pinet et al., 2008b).

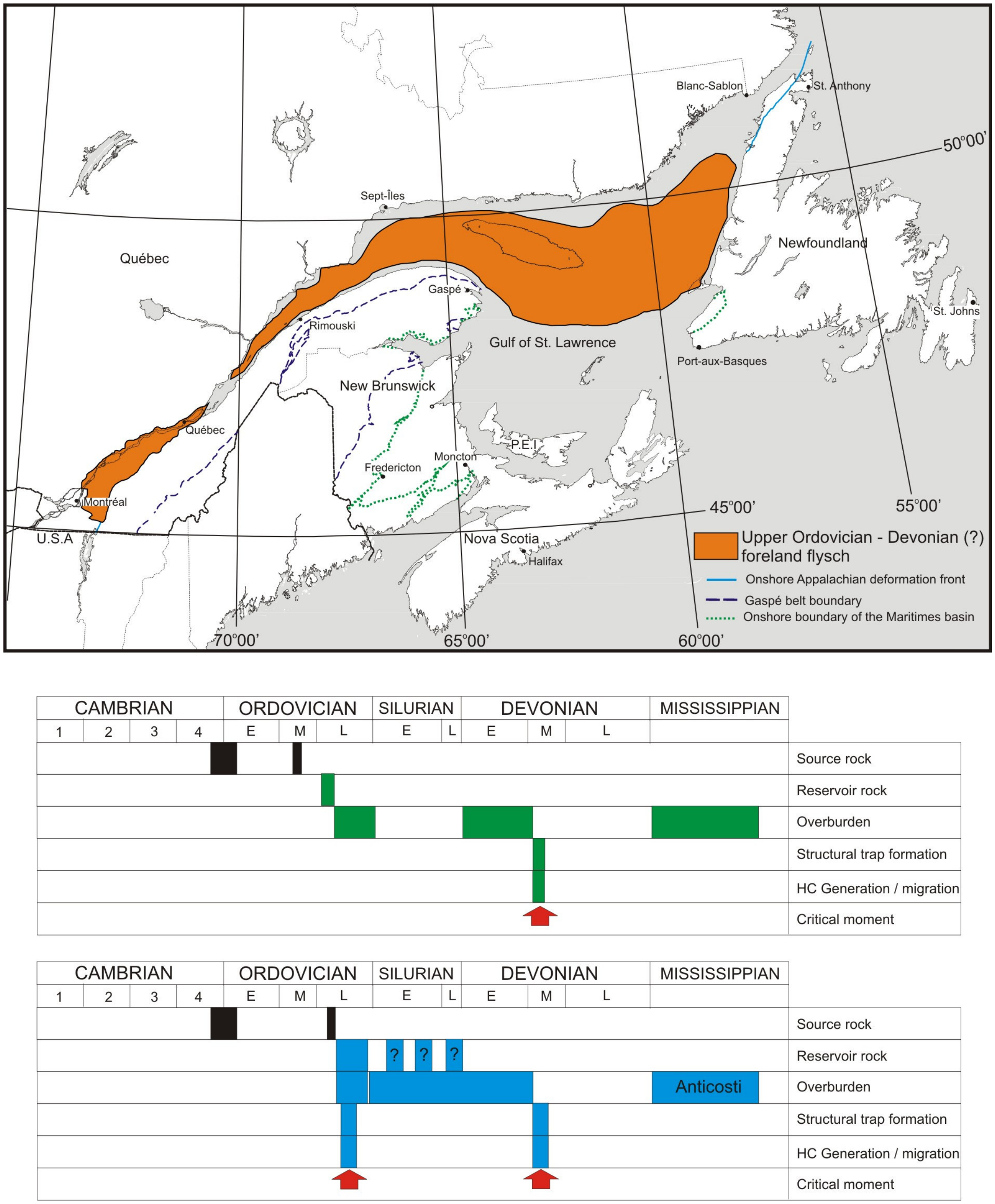


Figure 21: Top, extension of Upper Ordovician -Devonian (?) foreland flysch play zone (orange zone) in eastern Canada. Bottom, hydrocarbon chart for this play with time constraint on hydrocarbon system data. Newfoundland is the green diagram and Quebec is the blue one. See text for details on construction of play zone and risk analysis.

HYDROCARBON PLAYS IN THE HUMBER ZONE

Two gas plays have been identified in the Appalachian Humber Zone (Fig. 12): 5) Cambrian-Ordovician deep-water clastics and 6) Ordovician carbonate platform thrust slices. Only the latter play will be assessed. The deep water clastics play is described qualitatively.

Cambrian-Ordovician deep-water clastics (R5)

Exploration history and shows

In the Humber Zone, continental slope clastics of the passive (Cambrian-Early Ordovician) and convergent (Middle-Late Ordovician) margins of Laurentia are subordinate exploration targets. In the early 1970's, fractured zones with reservoir potential within the Lower Cambrian rift-related deep marine clastics were documented from wells of eastern Quebec (Hu and Lavoie, 2008). Coeval rocks in Newfoundland were documented to carry live oil (Burden et al., 2005). Over the years, drilling for aquifers in eastern Quebec has resulted in the discovery of pockets of natural gas in uppermost Cambrian – lowermost Ordovician quartz arenites. These deep marine clastic accumulations are considered as field analogues to giant Cenozoic offshore fields of western Africa (Lavoie et al., 2008b).

Discoveries

There are no discoveries so far for this play.

Potential Reservoir

The Lower Paleozoic continental slope clastics predominantly consist of background fine-grained hemipelagic sediments and turbidite sands. However, thick accumulations of coarse-grained sandstone and conglomerate are locally found as channel deposits in a deep-marine submarine fan facies association (Lavoie et al., 2003; Lavoie, 2008a). Three intervals have documented or hypothesized reservoir potential, 1) Lower Cambrian rift sandstone (Green Sandstone and Blow Me Down Brook Formation), 2) Upper Cambrian passive margin impure sandstones (Saint-Damase Formation and equivalents) and 3) uppermost Cambrian-lower Ordovician passive margin quartz arenite (Kamouraska Formation).

Porosity is of secondary origin, although little is known about the processes leading to it. Based on petrophysical, petrographic and field data, fractures have contributed to the porosity and permeability and have acted as migration corridors (Chi et al., 2000; Hu and Lavoie, 2008). As suggested from the Park Wells (Lower Cambrian sandstone), some leaching of metastable alumino-silicates has also contributed to enhancing reservoir porosity.

Geographic distribution

This play area (Fig. 22) extends across the entire Humber zone in eastern Canada

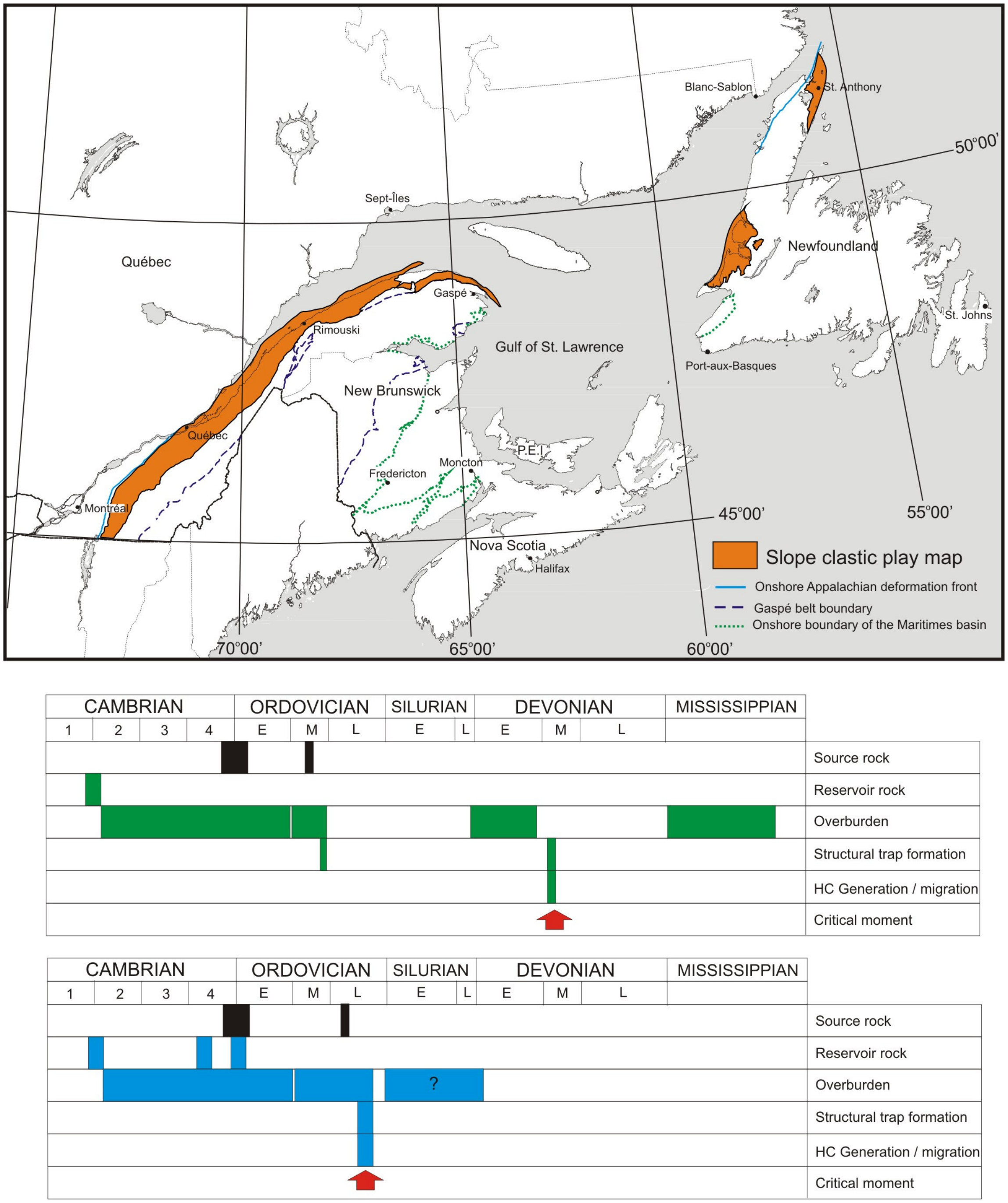


Figure 22: Top, extension of Cambrian-Ordovician deep marine slope clastic play zone (orange zone) in eastern Canada. Bottom, hydrocarbon chart for this play with time constraint on hydrocarbon system data. Newfoundland is the green diagram and Quebec is the blue one. See text for details on construction of play zone and risk analysis.

although for the Upper Cambrian – Lower Ordovician facies, thicker accumulations (and eventual pay zones) are demonstrated to be associated with the Saguenay Graben.

Source rock, maturation, generation and migration

Lower Ordovician source rocks are the best candidates (see "hydrocarbon geology section"), these type I and II source rocks generated their hydrocarbons during either the Taconian (late Middle Ordovician) or the Acadian (Middle Devonian) orogenies. Locally, Middle Cambrian deep marine shales have a fair source rock potential in eastern Quebec. The play is gas-prone.

Traps and seals

The coarse-grained submarine fans are involved in fold and thrust structural traps, deep marine shales (locally potential source rocks) have likely provided impermeable caps.

Risk factors

The main risk factor for the lower Paleozoic deep marine clastic fans is likely the presence of an adequate long term seal as multiple events of faults and fractures have affected these deposits (Fig. 22).

Ordovician carbonate platform thrust slices (R6)

Exploration history and shows

In southern Quebec, a major Foothills-style exploration program was carried out in the late 1960-early 1970 by Shell Canada and partners. The seismic programs identified a large number of thrust slices at the Appalachian structural front, a limited number of which were subsequently drilled. A gas discovery was made and most of the drilled carbonate thrust slices have tested some gas in the Lower Ordovician platform succession. Recently, some of these carbonate slices either have been drilled (Joly) or re-entered (St Simon). Although the Garden Hill oil field of western Newfoundland was discovered by drilling through the Humber Zone unit, it is located in the underlying parautochthonous platform units below a basement-cored tectonic wedge. Plays of detached carbonate platform thrust slices are little explored in Western Newfoundland.

Discoveries

In southern Quebec, the Saint-Flavien gas field was drilled in 1972 by Shell Canada on the seismic recognition of a Foothills-style hanging wall ramp anticline. The field produced $171*10^6$ m^3 (5.7 Bcf) of gas and as of 2009 is still the largest gas discovery in Quebec (Béland and Morin, 2000). The reservoir is hosted by dolostone of the Beauharnois Formation (Lower Ordovician Beekmantown Group), at 1.5 km deep (anticlinal structure) with an average pay zone of 3.5 m (range 1 to 8 m). The St. Flavien reservoir has porosity values ranging from 2.8 to 15% (average of 6%) and permeabilities are between 0.1 and 70 mD (average of 6 mD). Water saturation is less than 15% and original pressure was 13.5 MPa. The reservoir has now been developed into a natural gas storage facility.

Potential Reservoir

The Saint-Flavien gas reservoir consists of Lower Ordovician dolomite of the Beauharnois Formation (Beekmantown Group); this carbonate unit is part of a continental-scale shallow marine platform sequence rimming Laurentia (Salad Hersi et al., 2003; Lavoie et al., in press). The reservoir is hosted in tectonically detached thrust slices of the carbonate platform formed during Taconian thin-skinned deformation. The dolomite reservoir in the Saint-Flavien gas field formed through complex, multi-stage dolomitization events, including some late hydrothermal alteration (Bertrand et al., 2003a). Fractures are an important factor that influences porosity and permeability; it has been shown that thicker dolomite intervals are more brittle and have better reservoir characteristics at St. Flavien (Bertrand et al., 2003a).

Geographic distribution

The play area (Fig. 23) is limited at surface by the first major thrust fault: the Aston

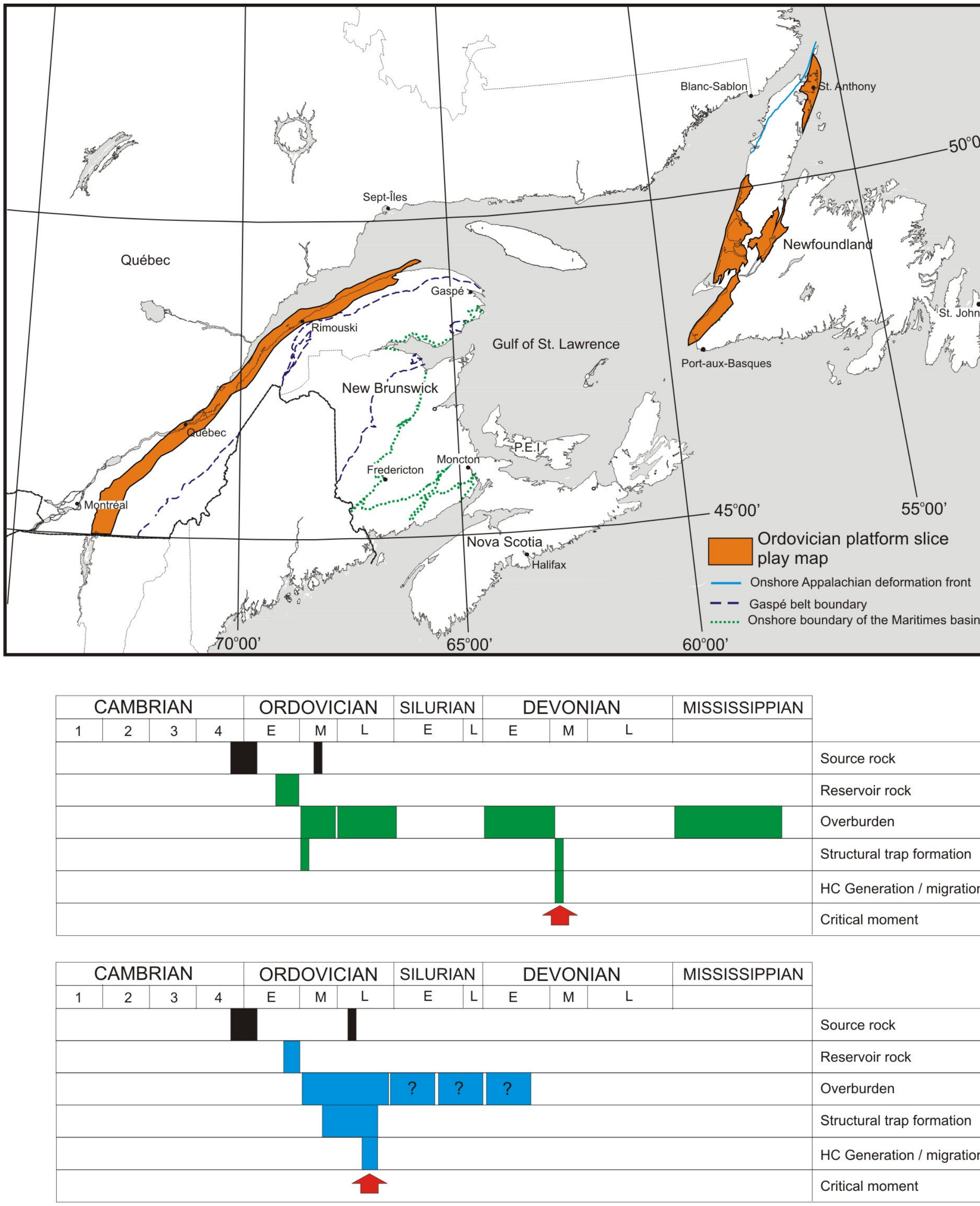


Figure 23: Top, extension of Ordovician platform slices play zone (orange zone) in eastern Canada. Bottom, hydrocarbon chart for this play with time constraint on hydrocarbon system data. Newfoundland is the green diagram and Quebec is the blue one. See text for details on construction of play zone and risk analysis.

fault in southern Quebec, which lies roughly 4 km northwest of Logan's line, and the Round Head Thrust in western Newfoundland. The southeastern limit is defined by a depth limitation (ca. 3.5 km) of prospective platform thrust slices in southern Quebec. These limits outline a ca. 23 km wide play area along the length of the Appalachians (Fig. 23). In southern Québec, the recognition of these platform slices in the subsurface is based on a regional-scale study of seismic data (Trépanier, 1978), coupled with more recent reprocessing and reinterpretation of seismic lines (Castonguay et al., 2006; Séjourné et al., 2003).

Source rock, maturation, generation and migration

Lower and Upper Ordovician source rocks are the best candidates (see "hydrocarbon geology section"), these type I and II source rocks have generated their hydrocarbons during either the Taconian (late Middle Ordovician) or the Acadian (Middle Devonian) orogenies. At St. Flavien, the carbonate thrusts are emplaced over the Upper Ordovician Utica Shale. From our understanding of thermal maturation, the entire play is gas-prone.

Traps and seals

Transition from dolomitized intervals to tight carbonate is expected to be a significant traps and seals mechanism. However, in this tectonically complex domain, structural closures such as the one found at St. Flavien is expected and likely will have compartmentalized potential reservoirs.

Risk factors

The main risk factor for the carbonate slices play is probably the presence of an adequate long term seal because fault and fractures that probably controlled the dolomitizing fluid flow may have been reactivated after the hydrocarbon migration (Fig. 23).

Quantitative evaluation

The prospect sizes for the Lower Ordovician carbonate thrust slices play are derived from interpretation of southern Quebec onshore seismic data at the Appalachian structural front and south-west of it. This evaluation was based on our reinterpretation of the synthesis of Trépanier (1978) and on Castonguay et al. (2006). Other parameters such as the thickness of the net pay zone, porosity values and water saturation have been estimated from the petrophysic data from wells in southern Quebec (in particular from the St. Flavien gas field).

The PRIMES analysis of the potential gas in place in the Lower Ordovician platform thrust slices in eastern Canada (see also the detailed assessment section) suggests a median potential (P50) of $5.6 * 10^9$ m^3 (198 Bcf).

HYDROCARBON PLAYS IN THE QUATERNARY SUCCESSIONS

Two Quaternary plays (Figs. 11 and 12) have been recognized on the basis of past production (onshore sands) and seismic evidence of gas-charged successions (offshore sediments). Both will be described qualitatively.

Onshore Quaternary sands

Exploration history and shows

The unconsolidated Quaternary sands produced the first economic volumes of natural gas in southern Quebec (Trois-Rivières area) at the start of the 20^{th} Century. Since then, a gas field has been exploited and exhausted (Pointe-du-Lac) and over 300 shallow wells have been drilled in southern Quebec targeting these sands. However, besides the early discovery ($96*10^6$ m^3 or 3.2 Bcf), the following gas finds have all been minor and uneconomic.

Discoveries

In 1955, a significant gas accumulation was discovered in unconsolidated Quaternary sediments in the Pointe-du-Lac area. The reservoir is 3 km long by 1 km wide and is 10 m thick (Geonirom, 1995) and has a closure of 6 km^2. The sediment is highly porous (36%) and permeable (up to a few darcys). The shallow (70 m) pay zone is 6 m thick with water saturation ranging from 10-20%, pressure is low (740 kPa).

Potential Reservoir

The onshore Quaternary reservoir at Pointe-du-Lac consists of very porous (up to 36%) sand and gravel deposited during the retreat of the last ice sheets in southern Quebec. The post-glacial deposits include interbedded tills, fluvial-glacial sands and gravels, deltaic / fluvial sands (Occhietti, 1990; Fig. 11). Most of the gas has been found in the lowermost of the three sand intervals in the area (Fig. 11). The clastics unconformably overlie the Paleozoic bedrock and in particular the fractured, organic-rich and gas-prone Utica Shale (Saint-Antoine and Héroux, 1993). The coarse grained clastics are overlain by a thick impermeable layer of clay.

Geographic distribution

The onshore play limit is restricted to southern Quebec and has been drawn where Quaternary deposits overly the Upper Ordovician Utica Shale (Fig. 24).

Source rock, maturation, generation and migration

The Pointe du Lac reservoir and other sub-economic accumulations of gas in unconsolidated sediments are invariably found where the Upper Ordovician Utica Shale is at or near surface. The gas is derived from the thermally mature Utica; isotopic studies of the

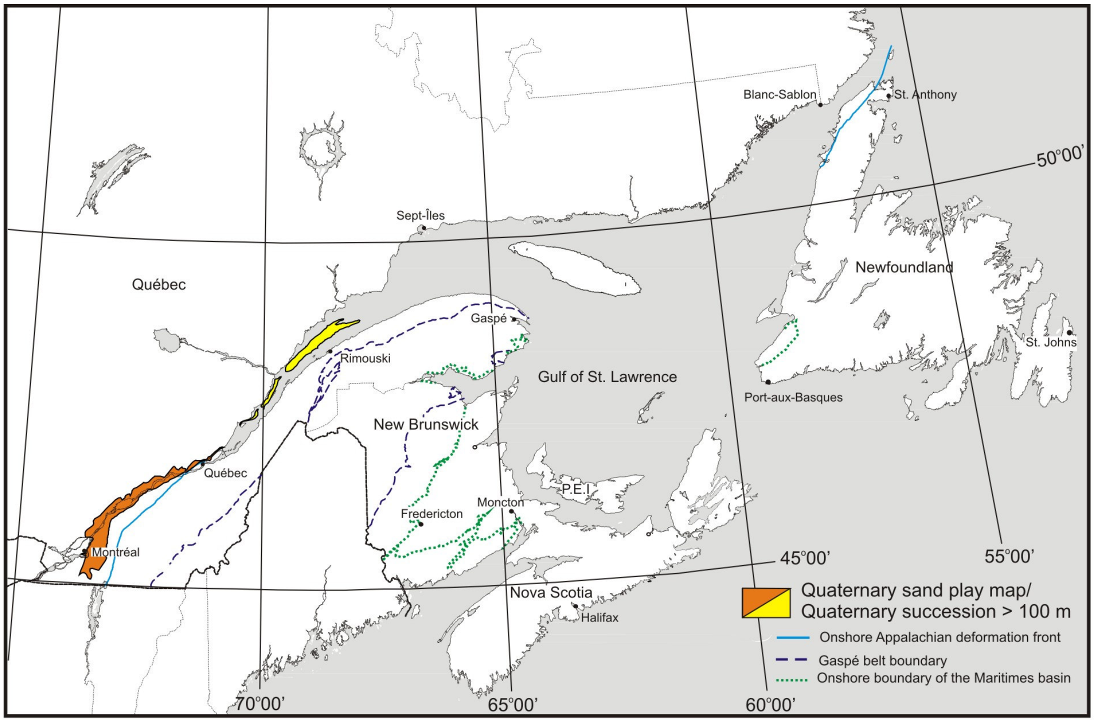


Figure 24: Extension of Quaternary onshore sand play map (orange zone) and offshore thick Quaternary succession (yellow zone) in Québec. See text for details on construction of play zone.

natural gas (St-Antoine and Héroux, 1993) led to the recognition of a locally complex mixture of dominant biogenic- and subordinate thermally-derived gas. The shallow setting of the Utica along the north shore of the St. Lawrence River was favourable to the invasion of glacial melt water in the fractured Utica Shale and the microbial production of biogenic gas (Antrim-type of Hamblin, 2006).

Traps and seals

The fluvial-deltaic sands offer a number of potential stratigraphic traps, including lateral facies changes and pinch outs on basement highs. Regionally, the sand intervals are capped by numerous marine to lacustrine clays and silts that provide efficient seals.

Risk factors

The main risk factor for these recent gas accumulations is an efficient closure of the reservoir.

Offshore Quaternary deposits – St. Lawrence Estuary

Exploration history and shows

In 2003 – 2004, a marine seismic survey (low penetration sparker source) in the St. Lawrence Estuary has documented numerous seismic anomalies in the Quaternary succession; these were later shown to be related to natural gas charge. Following work (multibeam, backscatter, echosounder, video recording) has identified numerous natural gas venting pockmarks on the sea floor.

Discoveries

There are no discoveries so far in this play.

Potential Reservoir

Evidence for gas accumulation in Quaternary sediments in the St. Lawrence Estuary relies on abundant seismic anomalies in the estuary (Pinet et al., 2008b) and spectral decomposition of the seismic traces. The presence of gas in the sediments is also confirmed by the abundant (>1900) active pockmarks or gas escape structures found on the St. Lawrence sea floor (Bolduc et al., 2008; Lavoie et al., in press a). There is little information as to the nature of the gas-charged sedimentary units. Surface to near-surface sediments are predominantly silty mud although possible coarser grained sediments might be present in the lower stratigraphic intervals (Duchesne et al., 2007).

Geographic distribution

The geographic distribution of the play is constrained by our recent seismic and high resolution bathymetric data set. Significant thicknesses of gas-filled Quaternary sediments are currently known between the mouth of the Saguenay River downstream to Les Méchins – Pointe-des-Monts (Fig. 24). A significant number of sea-floor pockmarks have been reported in the Lac St. Pierre area near the town of Trois-Rivières (and the Pointe-du-Lac Quaternary onshore gas field). It is noteworthy that over 90% of these gas escape structures are found in sediments overlying the Lower Paleozoic St. Lawrence platform.

Source rock, maturation, generation and migration

Seismic evidence point out to a dominant Lower Paleozoic source for the gas that charged the Quaternary sediments; seismic chimneys that either reach the seafloor (forming pockmarks) or that die out in the stratigraphic pile are almost invariably rooted in the Paleozoic St. Lawrence Platform (Pinet et al., 2008b). The NE-trending alignments of pockmarks suggest some structural control (fault or fold) for the sourcing of gas. In one case, seismic data has shown that a multi-kilometre long pockmark alignment overlies a bedrock high (Pinet et al., 2008b). Some pockmarks, likely formed through the release of biogenic-gas from organic matter in Quaternary sediments are visible in the northern domain of the St. Lawrence Estuary. These pockmarks overlie the Precambrian basement and are usually concentrated at the mouth of the major rivers on the north shore of the St. Lawrence.

Traps and seals

The exact nature of traps and seals in the offshore quaternary sediments is unknown although, from our knowledge of near-surface sediment types, mud accumulations are likely candidates.

Risk factors

Given the high abundance of gas escape structures on the St. Lawrence seafloor, it becomes quite obvious that the integrity of seal for the unconsolidated reservoir is the main issue.

MIDDLE PALEOZOIC BELTS - THE GASPÉ BELT OF EASTERN QUEBEC AND NORTHERN NEW-BRUNSWICK

INTRODUCTION

The term Gaspé Belt is used to designate the stratigraphic package of sedimentary and volcanic units that were deposited after the Taconian orogenic event (late Early to Late Ordovician) and before the sub-aerial unconformity that relates to the climax of the Acadian Orogeny (Middle Devonian). In eastern Canada, rocks assigned to the Gaspé Belt are recognized from southern Quebec (although they extend into New England) to Gaspé / northern New Brunswick, and in western Newfoundland (Fig. 25).

Uppermost Ordovician to Middle Devonian rocks belonging to the Gaspé Belt unconformably overly, or are in fault contact, with older rocks that have been attributed to the Laurentian margin (Humber Zone), to peri-Laurentian oceanic domain(s) (Dunnage Zone) and peri-Gondwanan units (Gander zone). The relationship between the Lower and Middle Paleozoic rock assemblages is well documented at the northern and southern boundaries of the Gaspé Belt (Bourque et al., 2001; Wilson et al., 2004) but remains poorly documented in the central part of the belt, where older domains are buried under the thick Middle Paleozoic sedimentary cover. In the areas surrounding the Gulf of St. Lawrence, the Gaspé Belt is unconformably overlain by Upper Paleozoic rocks belonging to the Maritimes Basin (Fig. 25; van de Poll et al., 1995).

Early studies have interpreted the Gaspé Belt as characteristic of a ‘successor basin’ developed during a period of tectonic quiescence. Recent studies have advocated for a closer relationship between tectonism, magmatism and sedimentation (Keppie and Dostal, 1994; van Staal and de Roo, 1995; Bradley et al., 1998; Tremblay and Pinet, 2005) and evidence of a significant orogenic pulse (Salinic Orogeny) is increasingly documented (Malo, 2001).

The Silurian-Devonian successions are primarily found in Quebec and New Brunswick, and limited outcrops of Devonian rocks are known in western Newfoundland. Limited maturation data indicate that the Silurian-Devonian successions of southern Quebec and southern New Brunswick are thermally overmature and will not be discussed further. The extent of the Silurian-Devonian rocks beneath the Gulf of St. Lawrence, south of the Appalachian structural front (Fig 25) has been discussed in the St. Lawrence platform section (Anticosti section). The following discussion will be restricted to the successions of eastern Quebec and northern New Brunswick.

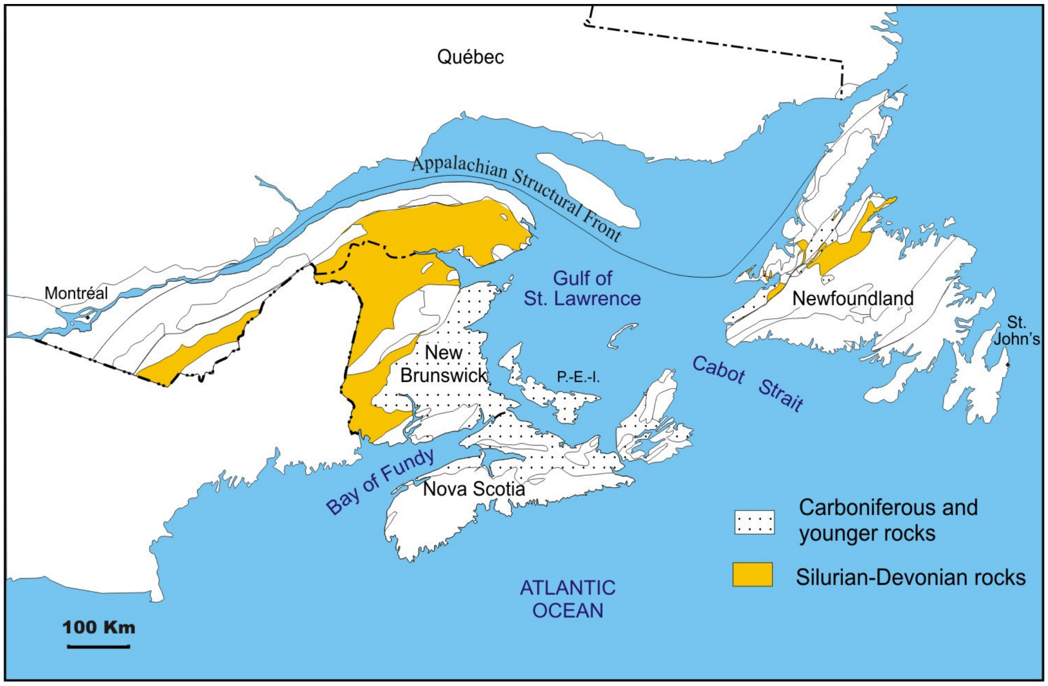


Figure 25: Distribution of Silurian-Devonian rocks in the Canadian Appalachians.

GEOLOGICAL SETTING OF THE GASPÉ BELT

Basement rocks

In the northern part of the Gaspé Peninsula, Edicarian to Upper Ordovician rocks of the Humber Zone (Williams, 1979) form the basement of the Gaspé Belt (Fig. 26B). The contact between the Humber zone and the Gaspé Belt is either faulted (Shickshock-Sud fault) or a regional unconformity (Fig. 26; Brisebois and Nadeau, 2003).

Lower Paleozoic remnants of oceanic and island-arc complexes (Dunnage Zone, Williams, 1979, van Staal et al., 1998) are unconformably overlain by or in fault contact with the Gaspé Belt succession. In the northern Gaspé Peninsula, the Mont-Albert ophiolitic complex structurally overlies the Humber Zone (Fig. 26B). Radiochronologic data (Pincivy et al., 2003) dates the ophiolite accretion as well as the metamorphism of underlying rocks as Late Ordovician (454 - 459 Ma). In the Chaleurs Bay area, Dunnage Zone rocks that form the basement of the Gaspé Belt correspond to Lower Paleozoic ophiolitic remnants (Fournier Group, van Staal et al., 1990; Fig. 26B) and arc-related picritic to andesitic flows (Balmoral Group; Wilson, 2003, Wilson et al., 2004; Fig. 26B). In northern New Brunswick, a narrow belt of Upper Ordovician – Lower Silurian blueschist-facies rocks (Brunswick complex) marks the contact between ophiolitic rocks of the Dunnage Zone and Lower Paleozoic units belonging to the Gander Zone (van Staal et al., 1990).

Stratigraphic framework

The age of the base of the succession varies significantly throughout the Gaspé Belt (Fig. 27). In central/southern Gaspé and in northern New Brunswick, the base of the preserved Gaspé Belt succession is as old as early Late Ordovician (Bourque et al., 1995) and is separated from the underlying Dunnage Zone units by a short hiatus (one or two graptolite zones). In northern Gaspé where the Middle Paleozoic succession overlies the Humber Zone, the composite Taconian and Salinic unconformity is more pronounced and the base of the succession is as young as latest Silurian at some localities (Bourque et al., 1995).

The sedimentary succession of the Gaspé Belt records three distinct regressive phases (R1 to R3) separated by two transgressive events (T1 and T2) (Fig. 27; Bourque et al., 1995, 2000). The succession is divided into four broad temporal and lithological packages, from base to the top these are: 1) the Honorat and Matapédia groups; 2) the Chaleurs Group; 3) the Upper Gaspé Limestones and 4) the Gaspé Sandstones.

Honorat and Matapedia groups

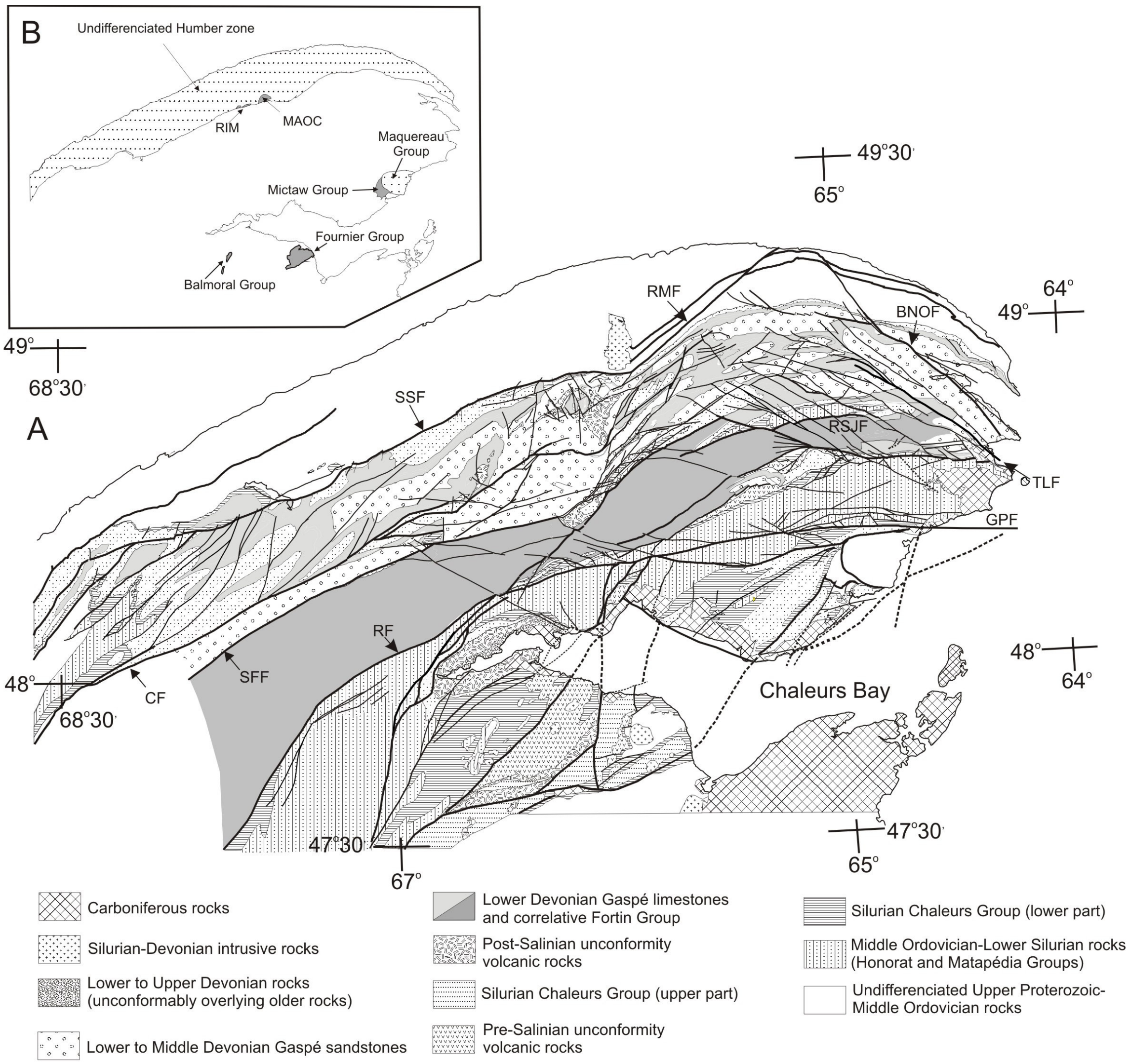


Figure 26: Geological map of the Gaspé Belt in the eastern Québec and northern New Brunswick (modified from Pinet et al., 2008).
Major faults: BNOF, Bras-Nord-Ouest Fault; CF, Causapscal Fault; GPF, Grand-Pabos Fault; RMF, Rivière-Madeleine fault; RF, Ristigouche Fault; RSJF, Rivière-Saint-Jean Fault; SFF, Sainte-Florence Fault; SSF, Schickshock-Sud Fault; TLF, Troisième-Lac Fault.
Inset: Location of rocks units underlying the Gaspé Belt. MAOC, Mont-Albert ophiolitic complex; RIM, Ruisseau Isabelle Mélange.

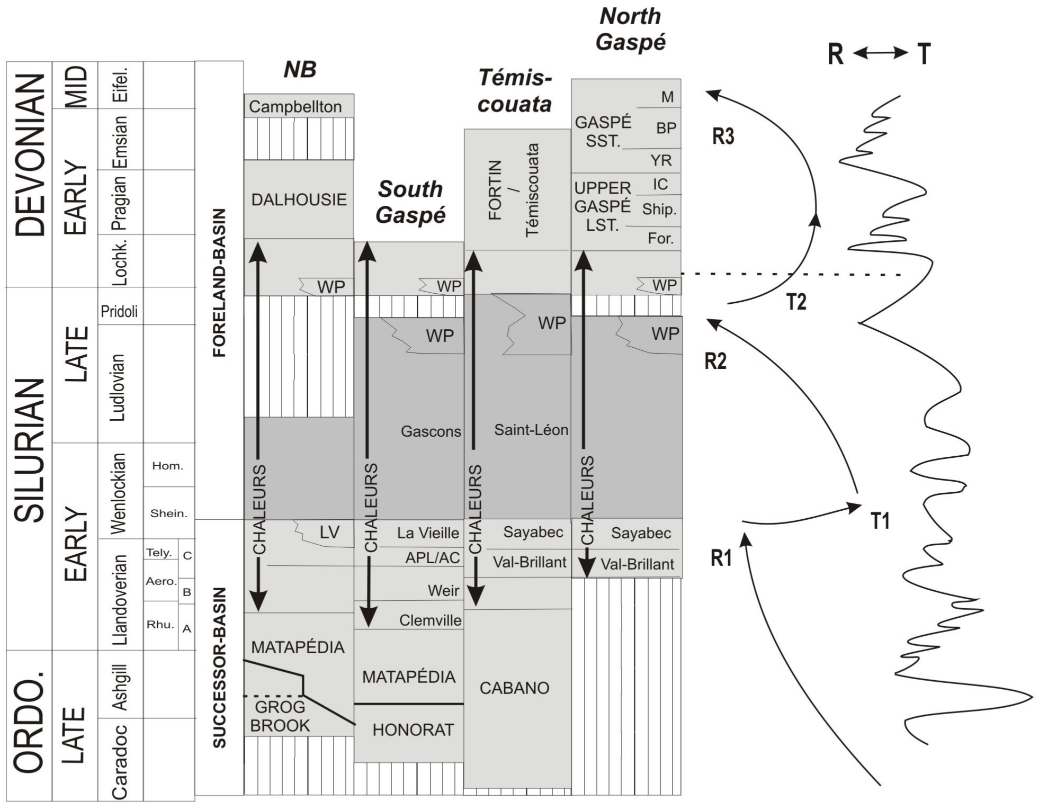


Figure 27: Stratigraphic framework of the Gaspé Belt.
A detailed nomenclature can be found in Bourque et al. (1995, 2001) for Gaspé and Témiscouata, and in Wilson et al. (2004) and Lavoie and Asselin (2004) for New Brunswick.
The major T-R events are shown; the Late Ordovician-Early Silurian R1 event; the Early Silurian-Late Silurian T1-R2 events and the latest Silurian-Middle Devonian T2-R3 events. The Silurian (R1-T1-R2 events) sea-level curve of Ross and Ross (1988, 1996) and the Devonian (T2-R3 events) one of Dennison (1985) are shown for comparative purposes.
Time hiatus are indicated by vertical lines.
Rhu.: Rhuddanian; Aero.: Aeronian; Tely.: Telychian; Shein.: Sheinwoodian; Hom.: Homerian; Lochk.: Lochkovian; LST: Limestones; SST: Sandstones.
Names of formations: APL/AC, Anse à Pierre-Loiselle/Anse Cascon;Bp, Battery-Point; F, Forillon; IC, Indian Cove; LV, La Vieille; M, Malbaie; Ship., Shiphead; WP, West Point; YR, York River;

Where complete, the Upper Ordovician - lowermost Silurian sedimentary package comprises deep marine clastic facies of the Honorat Group (and equivalent Grog Brook Group in New Brunswick and Cabano Group in the Témiscouata region). The conformably overlying Upper Ordovician to lowermost Silurian Matapédia Group is a deep water (below wave base) carbonate-dominated unit, which consists of basal calcareous mudstone to argillaceous limestone (Pabos Formation) overlain by thin-bedded calcilutite (White Head Formation). The Matapédia Group records a progressive shallowing (part of the R1 cycle, Fig. 27) in the depositional environment.

Chaleurs Group

The Chaleurs Group conformably overlies the Matapédia Group from central Gaspé to northern New Brunswick and is unconformable on Early Paleozoic Taconian-deformed Humber Zone in northern Gaspé (Fig. 27). The Chaleurs Group records the upper part of the R1 regressive cycle, the entire T1-R2 transgressive-regressive cycle, and the lowermost part of the T2 cycle (Fig. 27). It consists of three stratigraphic assemblages: a lower clastic assemblage, a middle carbonate assemblage, and an upper clastic assemblage with local reefs and volcanic flows.

In the southern and northern parts of the Gaspé Belt, the lower clastic assemblage is Early Silurian (Llandoverian) in age and corresponds to a coarsening- and shallowing upward succession of basal mudstone or claystone (Clemville Formation), overlain by shallow marine sandstone and pebble conglomerates (Weir, Anse Cascon formations), and by nearshore quartz sandstone (Val Brillant Formation). In the central part of the Gaspé Belt, deep-water claystone and fine-grained sandstone (Burnt Jam Brook Formation) form the base of the Chaleurs Group.

The middle carbonate assemblage is late Early Silurian (latest Llandoverian to Wenlockian) in age and records the establishment of peritidal carbonate ramp sedimentation that marks the maximum sea level fall (R1 regressive event; Fig. 27). It is largely coeval with the La Vieille (southern Gaspé – New Brunswick) and Sayabec (northern Gaspé – Témiscouata) formations. These two formations record sedimentation on a laterally well-zoned carbonate ramp dominated by a wide peritidal flat flanked by a shallow subtidal narrow knob reef belt and a well sorted, above fair-weather wave-base limestone sand belt. Toward the basin, mixed clastic and limy muds mark the transition with slope deposits (e.g., the Limestone Point and Gounamitz Lake formations in New Brunswick and the Laforce Formation in central Gaspé).

The base of the upper clastic interval is marked by a rapid increase in the clastic mud content, interpreted as resulting from a significant increase in tectonic subsidence. The upper clastic assemblage ranges in age from the earliest Late Silurian to the earliest Devonian and is dominated by above storm-wave base mudstones and fine-grained sandstones and subordinate outer-shelf fine-grained limestones (Saint-Léon, Gascons and Indian Point formations). Locally, laterally well-zoned shallow marine reef platform and pinnacle reefs occur above up-thrown walls of paleo-half grabens (Upper Silurian and lowermost Devonian West Point Formation; Bourque, 2001). A major erosional unconformity (Salinic unconformity) cuts trough the Upper Silurian West Point reefs and records the interplay between normal faulting and sea-level changes (Bourque, 2001). Evidence for sub-aerial exposure associated with the Salinic unconformity has been documented in several areas (Bourque et al., 2001; Lavoie and Morin, 2004).

Upper Gaspé Limestones

The Lower Devonian Upper Gaspé Limestones is the uppermost limestone interval in the Gaspé Belt. It records the deepest marine conditions during the Early Devonian (late Lochkovian to earliest Emsian) T2 transgressive event in northern Gaspé (Fig. 27). In northern Gaspé, the Upper Gaspé Limestones are separated into three units: from base to top, the Forillon, Shiphead and Indian Cove formations, all of which represent a 3rd order tectonically-driven transgressive-regressive sequence comprising deep marine basal beds capped by mid to inner shelf facies (Lavoie, 1992b). In eastern Gaspé, facies architecture of the Upper Gaspé Limestones and thickness variations suggest that sedimentation was influenced by extensional faulting (Lavoie, 1992b). Deeper in the basin (i.e., towards the south – southwest), the threefold framework becomes difficult to apply due to facies homogenization and thickening. There the sequence consists of deep siliciclastic marine deposits with significant intra-plate volcanic flows and volcaniclastics (Fortin and Dalhousie groups, and correlative Témiscouata Formation; Bourque et al., 2001; Wilson, 2003).

Gaspé Sandstones

The Gaspé Sandstones correspond to an abrupt shoaling event (R3; Fig. 27) resulting from the building, propagation and erosion of the Acadian orogenic wedge. The overall succession can be very thick (up to 6 km) and accumulated over a short period of time during the late Early Devonian (Emsian). The Gaspé Sandstones is a coarsening-upward succession comprised of fluvial-marginal marine sandstone at the base (York Lake and York River formations), overlain by a succession of conglomeratic sandstone, minor siltstone and mudstone, and a redbed unit (Battery Point Formation) and capped by a thickly-bedded conglomerate with medium to coarse-grained red sandstone interbeds (Malbaie Formation). The Malbaie Formation is unconformably overlain by Carboniferous rocks. In deeper-water facies (i.e., toward the south / southwest), the base of the Gaspé Sandstones is coeval with the upper parts of the Fortin Group/Témiscouata Formation.

The post-Gaspé Sandstones – pre Carboniferous sedimentary record is locally preserved and includes the Middle Devonian Touladi Formation (Témiscouata area) and Upper Devonian Miguasha Group (Chaleurs Bay area). Both are interpreted to have been deposited in marginal marine embayments.

Structural framework

Most of the deformation in the Gaspé Peninsula is generally ascribed to the Middle Devonian Acadian Orogeny. However, a polyphase history has been documented for several structures and pre-Acadian deformation is recorded in several areas. In northern New Brunswick, periods of Late Silurian sinistral transpression and earliest Devonian extensional collapse have preceded the Early to Middle Devonian (Acadian) dextral transpression (van Staal and de Roo, 1995). In the Gaspé Peninsula, field evidence of pre-Acadian deformation is restricted to broad open folds in Upper Ordovician and Lower Silurian rocks (Malo and Béland, 1989) and to sedimentary thickness variations and facies distribution on both sides of syn-sedimentary normal faults (Lavoie, 1992; Bourque, 2001).

The main Acadian deformation style varies along the strike of the Gaspé Belt. Significant thrust faulting is documented in the Témiscouata area, whereas orogen-parallel transcurrent faulting prevails in the eastern Gaspé Peninsula and northern New Brunswick (Malo et al., 1995; Pinet et al., 2008a). A detailed structural study of the Fortin Group in the western Gaspé Peninsula (Kirkwood, 1995) documented distinct periods of strain partitioning, which suggest that a predominantly pure shear regime preceded a dominantly simple shear regime. Kirkwood (1999) applied that model on a regional scale and suggested that Acadian deformation was initially accommodated by folding, flattening and north- and south-directed reverse faulting, followed by further flattening and dominant strike-slip faulting.

In the Gaspé Peninsula and northern New-Brunswick folds are generally open, with typical wavelength of ~ 5 to 15 km. Figure 28 shows a ~ 40 km long seismic transect and illustrates the structural style in the Matapédia area. Near the northwest end of the transect, the Shickshock-Sud fault clearly divides two distinct rock packages. Northwest of the fault, a thin sub-horizontal Silurian-Devonian cover outlines the Matapédia syncline. Southeast of the fault, the sedimentary succession is thicker and is involved in broad open folds. The Taconian unconformity is relatively well-defined in the Gaspé Belt. In seismic sections, the Gaspé Belt succession typically includes four packages: From the base, 1) a lowermost almost transparent seismic unit characterized by few small amplitude reflectors; 2) high amplitude reflectors correlated with the lower part of the Chaleurs Group (e.g., the Val Brillant – Sayabec formations); 3) an almost transparent seismic unit characterized by few small amplitude reflectors overlain by an upper unit with well-defined parallel reflectors that correlate with the upper part of the Chaleurs Group; 4) finally, relatively high amplitude and continuous reflectors attributed to the Upper Gaspé Limestones Group. A slight angular unconformity is locally observed within the upper part of the Chaleurs Group and is interpreted as the Salinic Unconformity. In detail, the geometry of the Siluro-Devonian succession may be locally complex such as in the area of the Amqui anticline, which is affected by both northwest- and southeast-dipping faults (Fig. 28). In other cases, the geometry mimics positive flower structure such as in the area of the Lac Humqui anticline (Fig. 28).

Post-Acadian deformation in the eastern Quebec and northern New Brunswick has traditionally been considered as minor. However, post-Acadian brittle motion along inherited faults is increasingly documented (Jutras et al., 2003; Pinet et al., 2008a).

PETROLEUM GEOLOGY – CONVENTIONAL SYSTEMS

Exploration history/Discoveries to date

Exploration in Gaspé Peninsula started in the mid-19th century following the discovery of seeping oils in eastern Gaspé (Lavoie and Bourque, 2001). Among the 80 scattered seepages mentioned by Parks (1930), most, if not all are located on tight second-order anticlines or in proximity to fault zones prone to extensive fracturing (Sikander, 1975).

Since 1860, 174 wells have been drilled in the Gaspé Belt, the vast majority being located in the Gaspé area (Figs. 29 and 30). Initial drilling targeted Lower Devonian sandstones and limestones with minimal success (1440 barrels of oil produced from one well in Devonian rocks in 1896). In the Gaspé area, early 1980's seismic surveys led to the first geophysical-based drilling campaign. Only a small gas reservoir (Galt field, $21.8*10^6$ m^3 or 728 mmcf gas field) was discovered and led to intermittent production.

Available onshore seismic data are short lines shot in the 1970s and early 1980s and seismic lines acquired in 2001-2002 by the MRNFQ (Quebec Department of Natural Resources) along six 25 to 115 km long transects. The quality of seismic data varies significantly depending on acquisition parameters and location. Along the northern edge of the Gaspé Belt, several seismic units are clearly imaged above the Taconian unconformity.

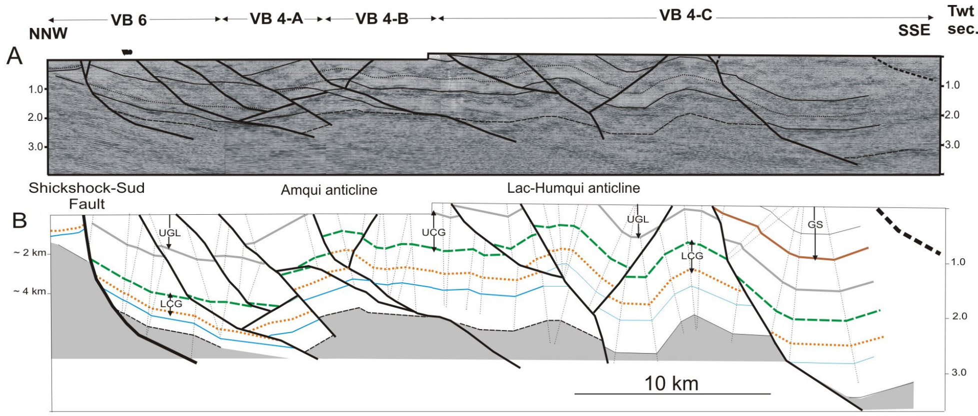


Figure 28Seismic transect in the Matapédia area. Location in Figure 5.
B- Interpretation of the seismic transect shown in A. Horizontal and vertical scale are roughly similar.
However, depths shown on the left side of the cross-section should be considered as approximations .
GS, Gaspé sandstone; LCG, Lower part of the Chaleurs Group; UCG, Upper part of the Chaleurs Group;
UGL, Upper Gaspé Limestone.
The grey pattern corresponds to Neoproterozoic to Upper Ordovician rocks forming the basement of the Gaspé Belt.

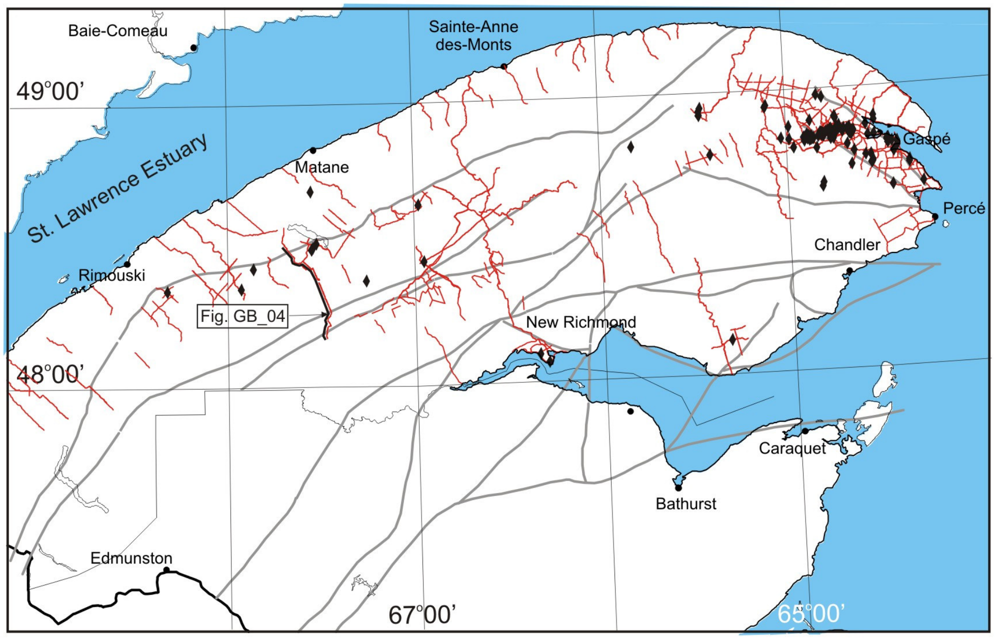


Figure 29: Location of seismic lines (red lines) and hydrocarbon exploration wells (black lozenge) in eastern Quebec and northern New Brunswick.

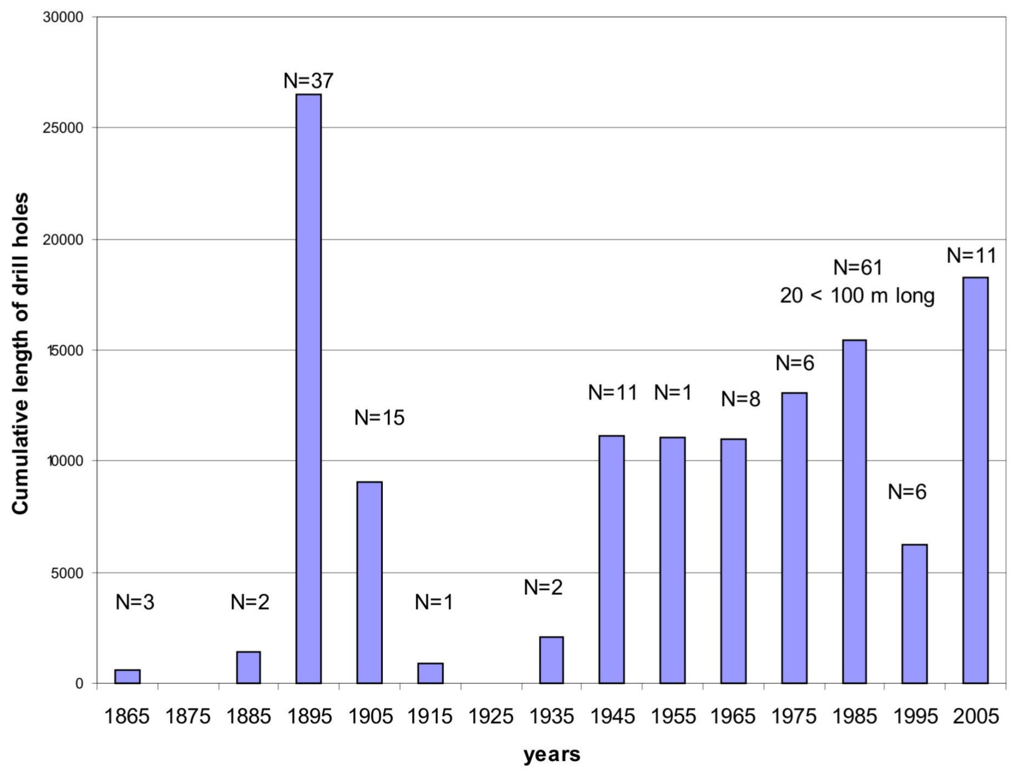


Figure 30: Cumulative length of exploration wells by 10-years period in the Gaspe belt. N refers to the number of wells by 10-years periods.

In a few cases, drill holes allow a direct correlation between these seismic units and geological packages. At the regional scale, the seismic characteristics of the sedimentary pile show an overall coherency and some seismic units (e.g., high amplitude continuous reflectors corresponding to the basal part of the Chaleurs Group) may be identified in most seismic lines. South of the Causapscal (western Gaspé) and Rivière Saint-Jean (eastern Gaspé) faults (Fig. 26), seismic data does not accurately define the geometry of the Gaspé Belt and the correlation between seismic markers and geological packages is more problematic.

Source Rocks

The presence of fair-quality potential hydrocarbon source rocks within the Gaspé Belt succession (Fig. 31) is restricted to the Upper Ordovician Boland Brook Formation in northern New Brunswick (TOC up to 1.4%, Bertrand and Malo, 2005), and to Lower – Middle Devonian rocks corresponding to some limy shale intervals in the Upper Gaspé Limestones (Forillon and Shiphead formations, TOCmax = 1.75 %, HI = 83) and to thin coal seams (York River Formation in easternmost Gaspé; Val D'Amour and Campbellton formations in northern New Brunswick).

High TOC and HI source rocks are found in various outliers of Ordovician deep marine shales belonging to the Dunnage Zone which are present at various localities surrounding the Gaspé Belt (Figs 26 and 31). These rocks include Lower to Upper Ordovician black shales of the Ruisseau Isabelle Mélange (TOC values up to 2.73%; Lavoie et al., 2009c), and the Middle Ordovician Dubuc Formation in Quebec (Mictaw Group; TOC values up to 10,7%; HI up to 257, see Lower Paleozoic chapter, Lavoie et al., 2009a, c) and coeval Popelogan Shales, in northern New Brunswick (TOC values up to 1.8% even if the rocks sit at the end of the dry gas zone; Bertrand and Malo, 2005). High TOC values are also documented in Cambro-Ordovician rocks belonging to the Humber Zone (see Lower Paleozoic chapter) that underlie parts of the Gaspé Belt.

Oil from exploration wells and seeps consists either of dark, slightly biodegraded oil or of light oil-condensate and retrograded condensates with a wide range of API values from 19.6º (seeping oil) to 46.9º (well). Geochemical analyses (GC-MS and GC-IRMS) tend to support a correlation between some oils and Ordovician potential source rocks, even if a (minor?) contribution or contamination by Devonian source rocks cannot be excluded (Roy, 2008).

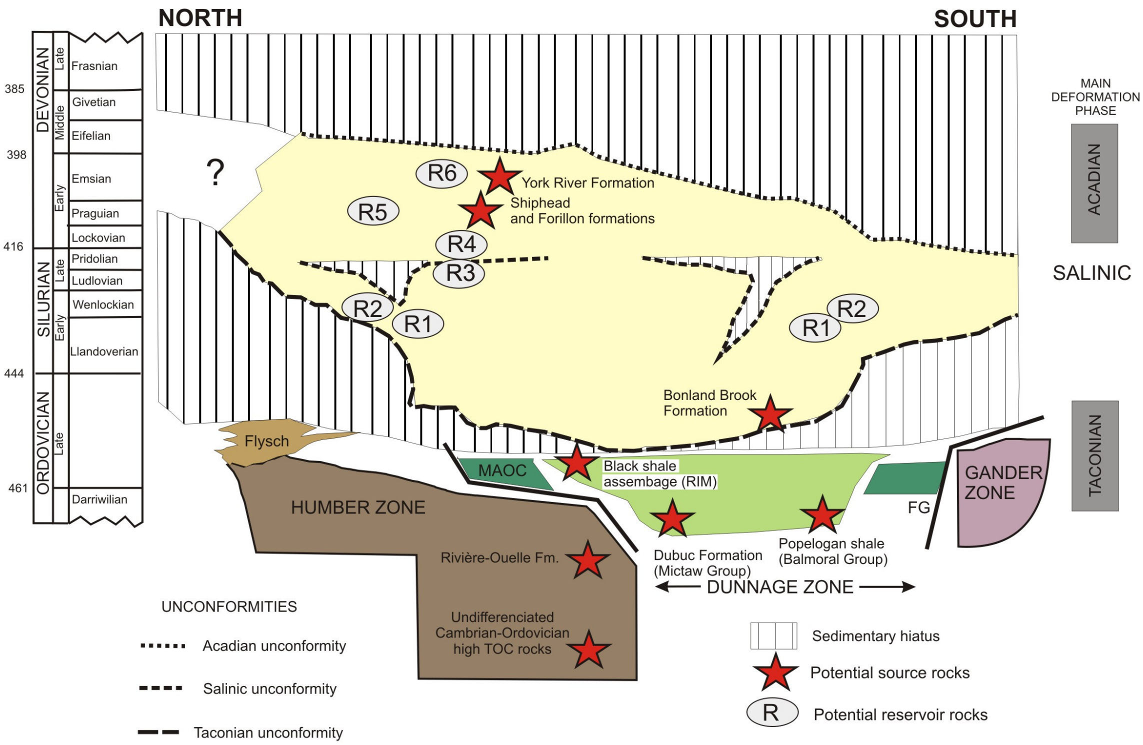


Figure 31: Schematic stratigraphic framework of the Gaspe belt illustrating the position of potential source rocks within the basin and the various basement domains.
The potential reservoir rocks discussed in the text are also illustrated.
The grey pattern indicates the Gaspé Belt sedimentary infill.
The Dunnage Zone comprises ophiolitic (dashed pattern) and sedimentary rocks (stippled pattern).
FG, Fournier Group; MAOC, Mont-Albert ophiolitic complex.

Maturation

Maturation of organic matter is highly variable in eastern Quebec and northern New-Brunswick and ranges from locally immature to the dry gas zone (Fig. 32). Analyses of core samples show that maturation correlates positively with depth (Bertrand and Malo, 2001, 2004; Roy, 2008), and in most cases, isocontours of maturation data are parallel to geological contacts. These characteristics indicate that maturation is primarily related to burial and that maximum burial predates the main Acadian faulting and folding event.

Near the town of Gaspé, the sedimentary succession is amongst the thermally least mature rocks of the Gaspé Belt where some Devonian clastic units in the cores of synclines are only at the threshold of the oil window. In that area, the contact between the Gaspé Belt units and underlying rocks of the Humber Zone is marked either by a maturation jump or by a steady increase of maturation with depth (Bertrand and Malo, 2001). This indicates that the amount of erosion prior to sedimentation is highly variable.

In central Gaspé, Devonian clastic units found in the cores of broad synclines (Lac Huit-Miles and Mont-Berry synclines) span the immature, oil window and condensate conditions. Maturation increases southwesterly and rock units are overmature ($Ro>5\%$) in the Témiscouata area.

South of the Rivière Saint-Jean (eastern Gaspé) and Sainte-Florence (western Gaspé) faults, the Lower Devonian Fortin Group and the Upper Ordovician to Lower Silurian rocks of the Aroostook-Percé Anticlinorium are thermally overmature.

In the Chaleurs-Bay area, maturation varies significantly from one tectonic block to another. The Restigouche syncline and the area to the south of the Maquereau inlier (including surface exposures of the Mictaw Group) are within the oil window. These domains are surrounded by larger zones where surface maturation levels are in the condensate and dry gas zones. Sterile conditions are found to the southeast as in the inlier of the Middle Ordovician Popelogan shales.

Timing of generation of hydrocarbon

1D thermal modelling (Bertrand and Malo, 2003; Roy, 2008) suggests that the potential Devonian source rocks generated hydrocarbons in late Early to Middle Devonian.

Detailed paragenetic studies (see below) suggest that the potential Ordovician source rocks generated hydrocarbons relatively early in the tectono-sedimentary history of the Gaspé Belt, i.e., during the Early Silurian or earliest Late Silurian.

Migration

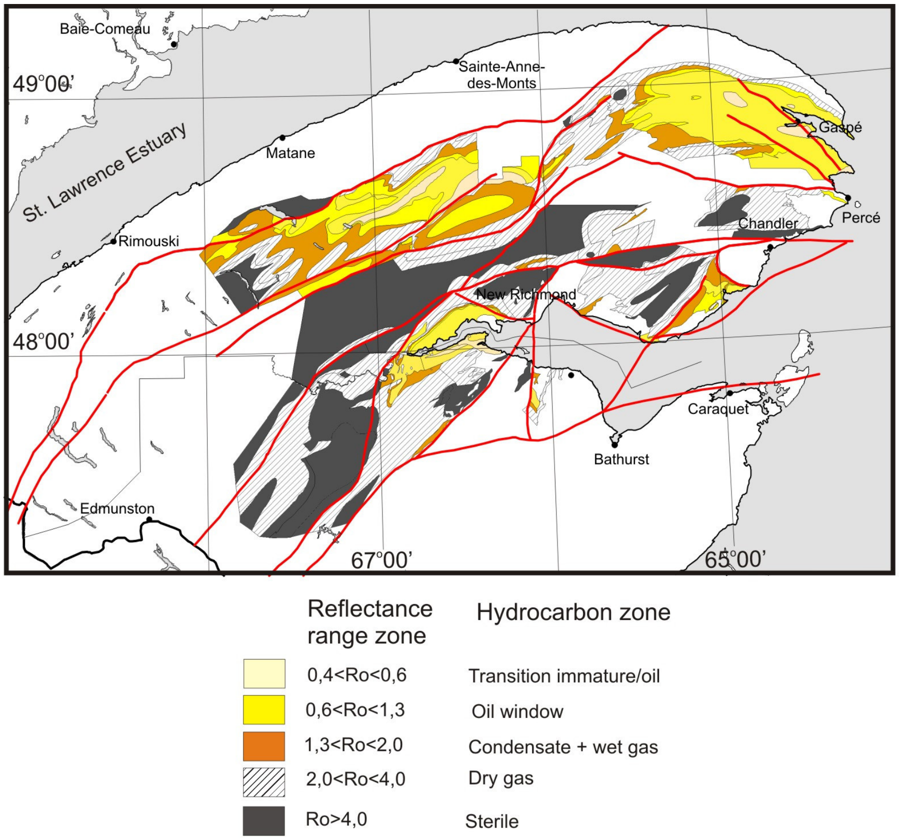


Figure 32: Surface zonation of thermal maturation in eastern Quebec and northern New Brunswick. Modified from Roy (2008). Data taken from Bertrand and Malo (2001, 2004) and Roy (2008).

Evidence for the migration of hydrocarbons comes from the presence of small reservoirs and locally abundant hydrocarbon fluid inclusions and pore-filling bitumen. Detailed petrographic observations suggest that both early and late migrations occurred. Early migration from pre-Lower Silurian source rocks is recognized in Upper Ordovician to Lower Silurian units (Matapédia Group, Val Brillant and Sayabec formations) and supports the potential of Ordovician source rock under the Gaspé Belt. This early migration event occurred before the development of the Upper Silurian Salinic unconformity (Lavoie and Morin, 2004; Lavoie and Chi, in press). Late migration from potential Devonian source rocks or remigration from older reservoirs is recorded in post-Late Silurian units (West Point Formation, Upper Gaspé Limestones and Gaspé Sandstones).

HYDROCARBON PLAYS IN THE SILURIAN-DEVONIAN GASPÉ BELT

Among the potential reservoir units, six have been considered in a specific play. The six conventional plays include Lower Silurian nearshore sandstone (#1 on Fig. 33), Lower Silurian to lowermost Devonian hydrothermal dolomites (HTD) (#2, 3 and 4 on Fig. 33), Lower Devonian fractured and hydrothermally-altered carbonate breccia (#5 on Fig. 33), as well as Lower Devonian fluvial sandstones (#6, Fig. 33).

Given the limited sub-surface information for the Silurian – lowermost Devonian plays (#1 to 4 on Fig. 33) and the unpredictable nature of the fractured carbonate play (#5 on Fig. 33), only the Lower Devonian sandstone play will be quantitatively assessed. The other plays will be evaluated on a qualitative basis.

Lower Silurian clastics (R1)

Exploration history and shows

The Lower Silurian clastic interval has been tested by only three drill holes and the Val-Brillant Formation has been clearly identified in only two. No shows of hydrocarbons have been reported

Discoveries

To date, there are no discoveries for this play.

Potential reservoir

The Lower Silurian nearshore to platform sandstone of the Weir/Anse Cascon formations (southern Gaspé and northern New Brunswick) and the Val Brillant Formation (northern and western Gaspé) are distinctive clastic units that were deposited near the end of the first major regressive event (Fig. 27).

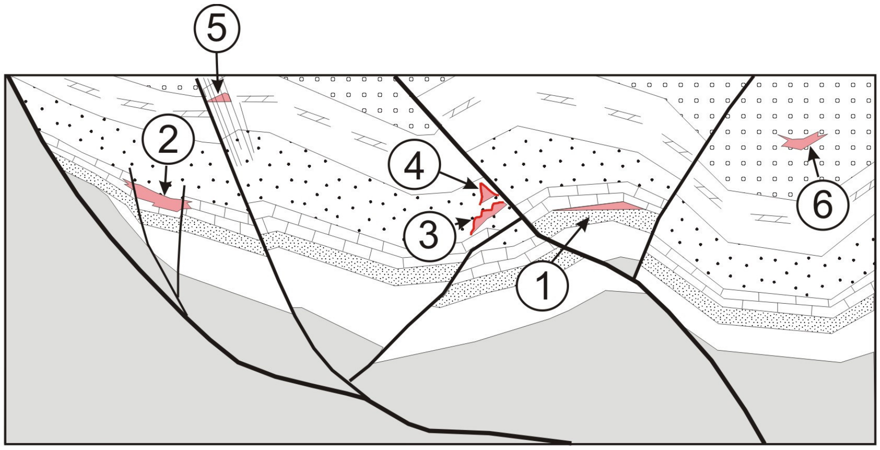


Figure 33: Conceptual sketch showing the Gaspé Belt plays. Numbers refer to the plays discussed in the text.

The Weir/Anse Cascon are shallow subtidal to nearshore sands, locally relatively impure (abundant feldspars and lithic fragments in the Weir sandstones) with only fair granulometric sorting (better in the Anse Cascon). These rocks are characterized by locally significant dissolution of feldspars and even quartz resulting in significant secondary porosity. Average porosity of hand samples ranges between 3.4% (Weir, N=3) and 1.8% (Anse Cascon, N=6; Lavoie, 2009). Permeability is relatively low (0.03md).

The Val Brillant Formation is a nearshore to shoreface, very well rounded and sorted quartz arenite with less than 5% feldspars. At the type locality, the Val Brillant Formation is ~ 30 m thick and unconformably overlies Humber Zone rocks. Southeastward, the thickness increases to 150 m and the Val Brillant Formation conformably overlies the Awantjish Formation. Sandstones of the Val Brillant Formation have 5 to 10% of mm-sized dissolution pores in hand specimens. A few hand samples (N=3; Lavoie, 2009) yielded an average porosity of 2% and an average permeability of 0.02 md. Locally, the Val Brillant is characterized by dead oil and huge amounts of bitumen filling secondary porosity (Lachambre, 1987; Lavoie and Chi, 2002; Lavoie et al., 2009a).

Source rock, maturation, generation and migration

In northern Gaspé, the best potential source rocks are the Middle Ordovician Ruisseau Isabelle shales and to some extent, the Lower Ordovician Rivière Ouelle Formation (see source rock section) both of which underlies the Gaspé Belt. These Type I and II source rocks generated hydrocarbons during and shortly after the Taconian Orogeny (Roy, 2008). An early charge of sandstone reservoirs from Ordovician-derived hydrocarbons is documented by the presence of abundant bitumen and fluorescent oil in primary to secondary pore space (Lavoie and Chi, 2002; Lavoie et al., 2009a)

In southern Gaspé and northern New Brunswick, the Middle Ordovician Dubuc Formation (and the thermally overmature correlative Popelogan shales, see source rock section) is the better potential source rock, along with the Upper Ordovician Boland Brook Formation (Bertrand and Malo, 2005; Lavoie et al., 2009a).

Geographic distribution

The geographic distribution of the Lower Silurian clastic play includes two zones (Fig. 34). The northern zone forms a 20 to 30 km wide, nearly continuous band on the northern edge of the Gaspe belt, except to the west of Rimouski and in the Murdochville area where supermature maturation levels are expected. The southern boundary of this zone corresponds to the transition with deeper water rock assemblages (Burnt Jam Brook Formation). The

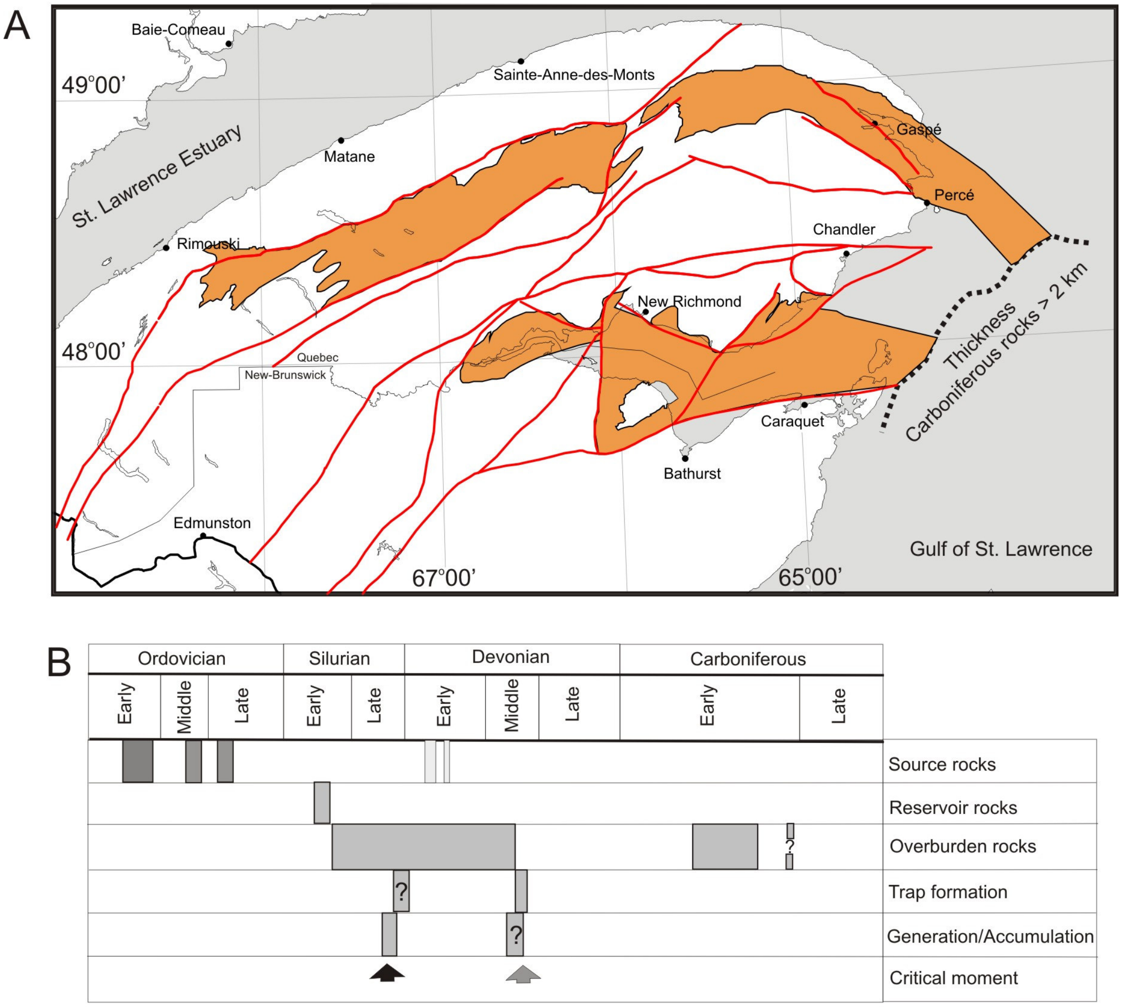


Figure 34: A- Play map for the Lower Silurian clastics (Play # 1).
B- Play # 1 (Lower Silurian clastics) hydrocarbon chart

southern zone is centered in the Chaleurs Bay area and has been defined using maturation data as well as paleogeographic considerations (i.e., transition to deeper waters rocks).

Traps and seals

Structural traps such as open folds associated with Silurian normal faulting or Devonian transpression or mixed structural/stratigraphic traps may offer suitable closures. Where not fractured or hydrothermally altered, the overlying Sayabec (northern zone) and La Vieille (southern zone) formations are tight and may act as seal. The Upper Silurian Salinic unconformity may also provide an adequate seal for Lower Silurian clastic units.

Risk factors

Little is known about the distribution of porous intervals within the lower Silurian clastic units (Hu and Lavoie, 2008). The presence of an adequate long-term seal may be problematic, especially in the hanging wall of Silurian tilted blocks that may have been subaerally exposed during the Salinic event.

Lower Silurian hydrothermal dolomites (R2)

Exploration history and shows

The Lower Silurian limestone interval has been tested by only three drill holes, which were not targeting HTD, and for which the Sayabec Formation has been identified in only one of them (Hu and Lavoie, 2008). Nevertheless, the recognition of highly porous and permeable zones in several localities associated with hydrothermal dolomitization indicates that these rocks have significant reservoir potential. No significant hydrocarbon content was documented through drilling although, a bitumen-rich succession in northern Gaspé is interpreted as representing an exhumed oil field (Lavoie and Morin, 2004; Lavoie and Chi, in press)

Discoveries

There are no discoveries so far in this play.

Potential Reservoir

Lower Silurian carbonates (Sayabec and correlative La Vieille formations) formed in a laterally well-zoned carbonate ramp dominated by a wide peritidal flat flanked by a shallow subtidal narrow knob reef belt and a well sorted, above fair-weather wave-base, belt of limestone sand. These rocks are tight except when secondary porosity associated with hydrothermal dolomitization is present.

Hydrothermal dolomites have been documented in Lower Silurian rocks belonging to the Sayabec and La Vieille formations (Lavoie and Morin, 2004; Lavoie and Chi, 2006; Lavoie and Chi, in press). These rocks exhibit major dissolution cavities and fractures in breccia zones that are irregularly surrounded by massive dolostone. Stable isotopes and fluid inclusions microthermometry indicate that the dolomitizing fluids were of high temperature and very saline. Both the breccia and dolostone units are porous (visible porosity up to 25% in grab samples).

Source rock, maturation, generation and migration

In northern Gaspé, the best potential source rocks are the Middle Ordovician Ruisseau Isabelle Shales and to some extent, the Lower Ordovician Rivière Ouelle Formation (see source rock section) both of which underlies the Gaspé Belt. These Type I and II source rocks have generated hydrocarbons during and shortly after the Taconian Orogeny (Roy, 2008). An early (pre-Late Silurian) hydrocarbon charge of the hydrothermal dolomite reservoir, most likely derived from these Ordovician sources, is documented by the presence of abundant bitumen in secondary pore space (Lavoie and Morin, 2004; Lavoie et al., 2009a; Lavoie and Chi, in press)

In southern Gaspé and northern New Brunswick, the Middle Ordovician Dubuc Formation (see source rock section) is the higher TOC potential source rock, with some potential in the Upper Ordovician Boland Brook Formation (Bertrand and Malo, 2005; Lavoie et al., 2009a). The Dubuc black shales (and the thermally overmature correlative Popelogan shales in northern New Brunswick; Bertrand and Malo, 2005) comprised of Type I and II organic matter are in the oil window in surface exposures of southern Gaspé (Roy, 2008).

Geographic distribution

The play area is roughly similar to the Lower Silurian clastics play (Fig. 35) and it has been drawn using the same criteria (i.e., transition to rocks formed in a deeper water environment and maturation level).

Traps and seals

Transition from dolomitized intervals to tight carbonate is expected to be the main trap- and seal controlling factor. However, deformation may significantly modify the trap geometry. The Late Silurian (Salinic) unconformity may also provide an adequate seal for the Lower Silurian carbonates.

Risk factors

Detailed studies (Lavoie and Morin, 2004; Lavoie and Chi, 2006, in press) indicate that high temperature dolomitization occurred early in the geological history, after the end of carbonate ramp sedimentation (late Early Silurian), but before the sub-aerial exposure in middle Late Silurian (Fig. 35). Moreover, hydrocarbons migrated soon after the dolomitization event as testified by the abundant bitumen filling small (mm-sized) to large (cm-sized) voids. Such an early tectonic-fluid alteration under shallow conditions is generally considered a favourable factor for significant dolomitization and efficient reservoir formation (Davies and Smith, 2006).

The main risk factor for the Lower Silurian HTD play is probably the presence of an adequate long term seal because: 1) sub-aerial exposure during the Late Silurian lowstand (Salinic event) may have breached the reservoir; 2) faults and fractures that probably controlled the dolomitizing fluid flow may have been reactivated after the hydrocarbon migration.

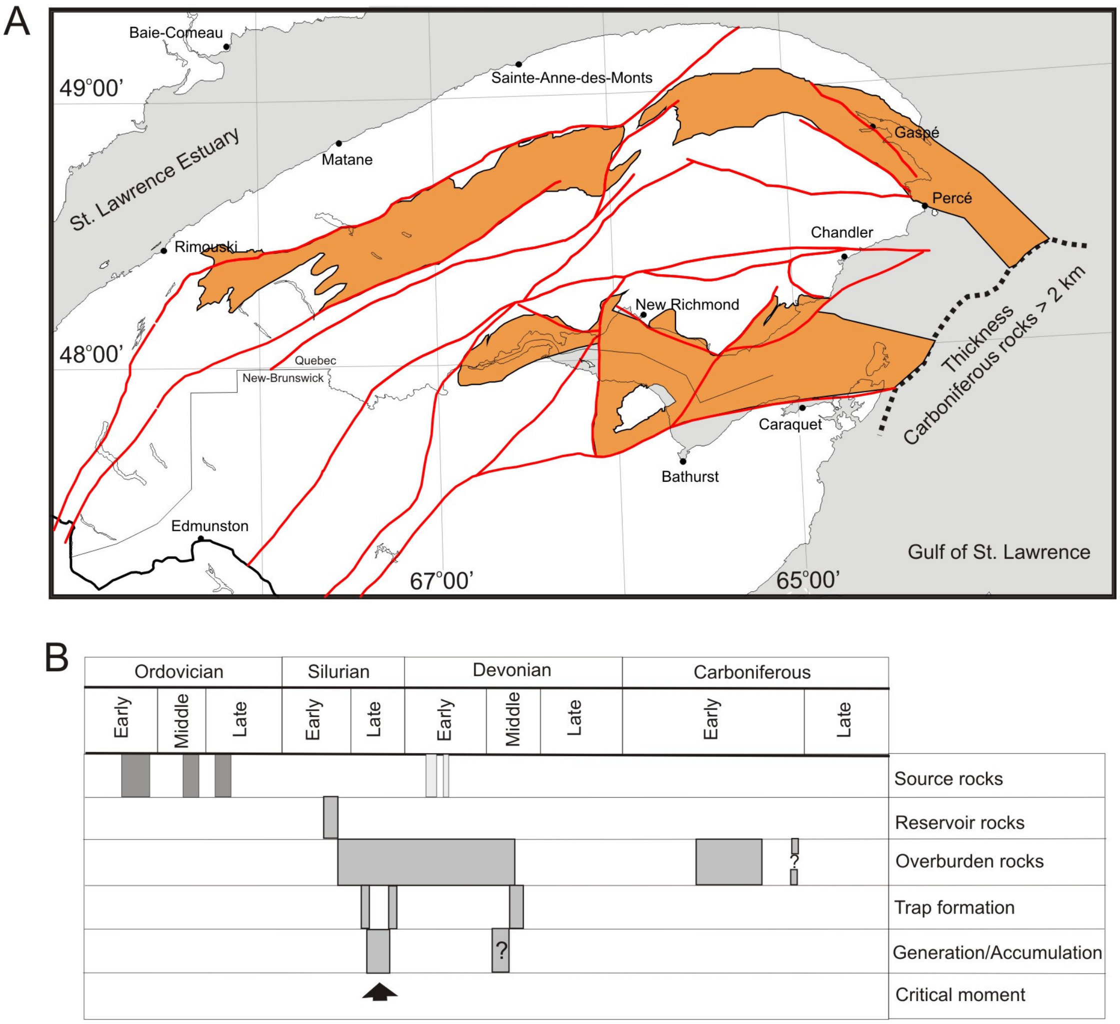


Figure 35: A- Play map for the Lower Silurian HTD;
B- Play # 2 (Lower Silurian HTD) hydrocarbon chart

Upper Silurian limestones and hydrothermal dolomite (R3)

Exploration history and shows

The Upper Silurian West Point Formation has been tested by four drill holes, which were not targeted for HTD: three in the Gaspé area and one in the Chaleurs Bay area (Hu and Lavoie, 2008). There are no reports of hydrocarbon shows.

Discoveries

To date, there are no discoveries in this play.

Potential Reservoir

In the Chaleurs Bay area, the Upper Silurian West Point Formation is well exposed and comprises three superposed reef complexes: a lower complex of deep-water mounds and microbial-algal-bryozoan shallow water reefs; a middle complex of crinoidal sand and gravel banks; and an upper complex of stromatoporoid reef-rimmed platforms (Bourque, 2001). The middle reef complex was formed during a major sea-level lowstand and evidence for episodic and relatively prolonged sub-aerial exposition, which corresponds to the Salinic Unconformity, is found in that interval as well as in the underlying succession. The reef complexes are surrounded by fine-grained clastic facies (included in the Indian Point Formation).

The limestone shows little porosity in outcrop. The average porosity and permeability of recently collected surface hand samples (N=11; Lavoie, 2009) are 1.2% and 0.22 md respectively. However, significant porosity enhancement by hydrothermal dolomitization (and/or fracturing) cannot be excluded even though dolomitic breccia has only been locally observed in the lower reef complex of central Gaspé.

Geographic distribution

The Upper Silurian West Point Formation is well exposed in southern Gaspé. In northern New Brunswick, the Upper Silurian LaPlante Formation consists of a fore-reef facies with some large to small-sized reef margin clasts in a dominant silty matrix. However, although the LaPlante Formation indicates the presence of a nearby reef margin, it correlates lithostratigraphically with the Indian Point Formation (Bourque et al., 2001; Bourque, 2001; Fig. 36). In northern Gaspé, exposures of back reef facies of the upper reef complex, correlative with the Upper Silurian West Point reefal facies, suggest the presence of a reef margin at some short distance from the northern edge of the depositional basin (Bourque, 2001). This model is supported by seismic data. The Upper Silurian Lac Croche Formation in Témiscouata is facies correlative with the West Point Formation (Bourque, 2001).

Source rock, maturation, generation and migration

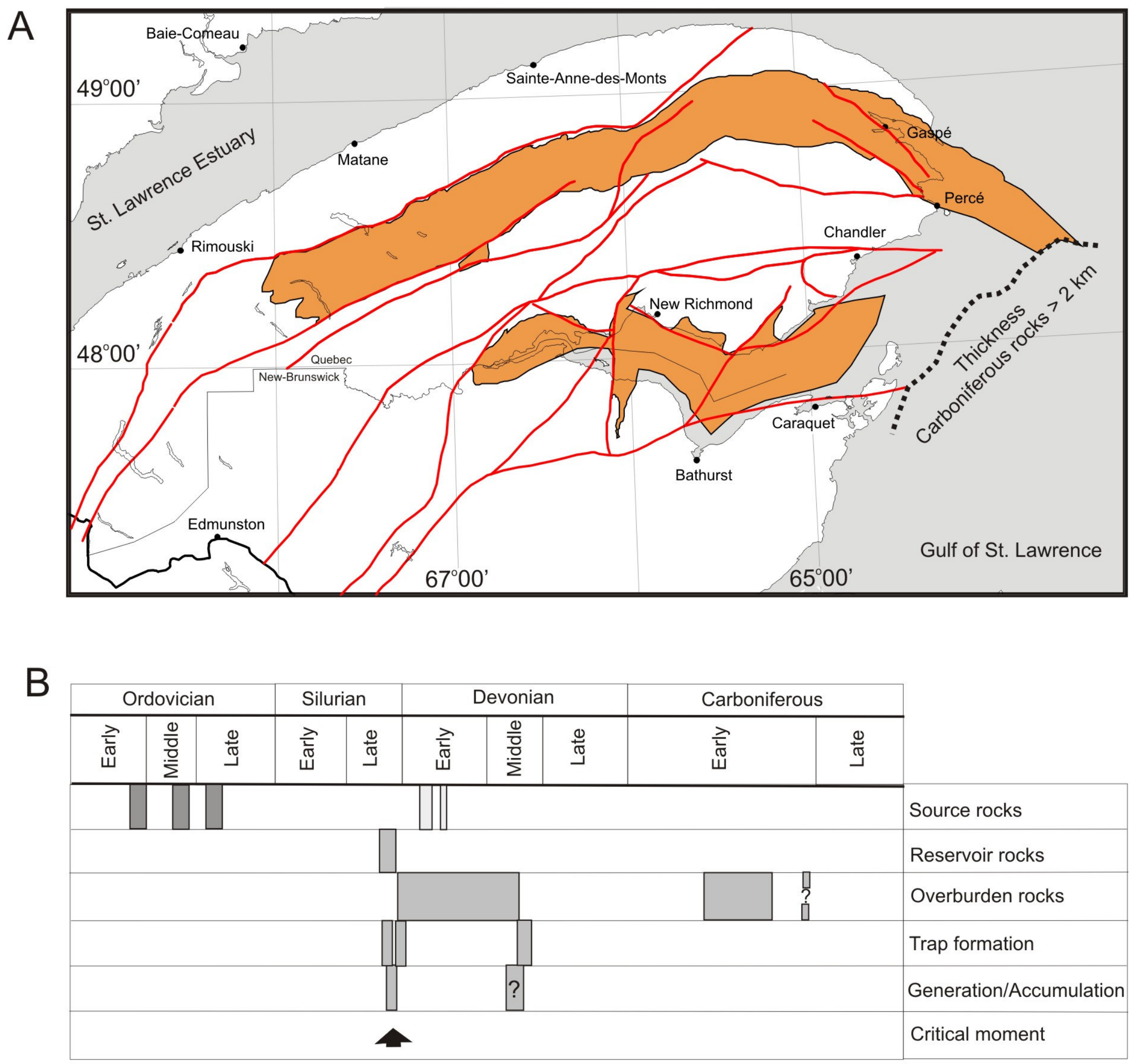


Figure 36: A- Play map for the Upper Silurian HTD (Play #3);
B- Play # 3 (Upper Silurian HTD) hydrocarbon chart

In northern Gaspé, the best potential source rocks are the Middle Ordovician Ruisseau Isabelle Shales and to some extent, the Lower Ordovician Rivière Ouelle Formation (see source rock section), both of which underlie the Gaspé Belt. These Type I and II source rocks generated hydrocarbons during and shortly after the Taconian Orogeny (Roy, 2008).

In southern Gaspé and northern New Brunswick, potential source rocks include the Middle Ordovician Dubuc Formation (and the thermally overmature correlative Popelogan shales) and the Upper Ordovician Boland Brook Formation (Bertrand and Malo, 2004; Lavoie et al., 2009a). The Dubuc black shales contain Type I and II organic matter that are in the oil window at surface in southern Gaspé (Roy, 2008);

Potential trap

Transition from dolomitized intervals to tight carbonate is expected to be the main trap and seal controlling factor. However, deformation may have significantly modified the trap geometry. The Upper Silurian West Point reefs are surrounded by siliciclastic muddy facies of the Indian Point Formation that may act both as a lateral and upper seals.

Risk factor

Detailed, but geographically-restricted diagenetic analyses of the Upper Silurian West Point reef limestone from the Chaleurs Bay area suggest that meteoric water has influenced cementation early in the geological history and occluded pore space in the shallow burial environment (Savard and Bourque, 1989; Bourque et al., 2001). This suggests that the Upper Silurian West Point reefs were potential reservoirs for only a relatively short period of time.

Lower Devonian hydrothermally altered pinnacle reefs (R4)

Exploration history and shows

Lower Devonian pinnacle reefs have never been tested by drilling.

Discoveries

There are no discoveries so far for this play

Potential reservoir

The Lower Devonian West Point Formation consists of largely isolated pinnacle reefs that are up to 300 m thick and a couple of km wide. These show several similarities with the hydrocarbon-bearing Upper Devonian Leduc pinnacles in the Western Canada Sedimentary Basin. The Lower Devonian West Point pinnacles were built on top of paleotopographic highs following Salinic erosion, and overlie Upper Silurian West Point reefs (Bourque, 2001). The internal architecture of pinnacle reefs is complex with stromatopores-corals-microbial bioconstructed zones and irregularly distributed areas made up of reworked bioclastic detritus. A conglomeratic fore-reef detritus belt is generally developed around individual reefs. The pinnacles are surrounded and overlain by relatively deep-water, fine-grained clastics of the Indian Point Formation. Most of these pinnacle reefs are interpreted to have grown at the margin of tectonically active fault blocks (Bourque, 2001) and the presence of extensional (to transtensional?) faults offer the critical pathways for fluid migration leading to hydrothermal alteration of the carbonate facies (Lavoie et al. 2009a).

To date, hydrothermal dolomitization in the pinnacle reefs of the West Point Formation has been locally documented (Lavoie et al., 2009a; in press b). In such cases, the dolomitization seems to be genetically linked with strike slip movement along Acadian faults, and is most likely Middle Devonian in age.

Geographic distribution

The Lower Devonian pinnacle reefs are currently only documented in the northern Gaspé Peninsula (Fig. 37).

Source rock, maturation, generation and migration

In northern Gaspé, the best potential source rocks are the Middle Ordovician Ruisseau Isabelle Shales and to some extent, the Lower Ordovician Rivière Ouelle Formation (see source rock section), both of which underlies the Gaspé Belt. These Type I and II source rocks generated hydrocarbons during and shortly after the Taconian Orogeny (Roy, 2008).

Traps and seals

The presence of transition zones between dolomitized intervals and tight carbonate are expected to be the main trap and seal controlling factor. However, deformation may have

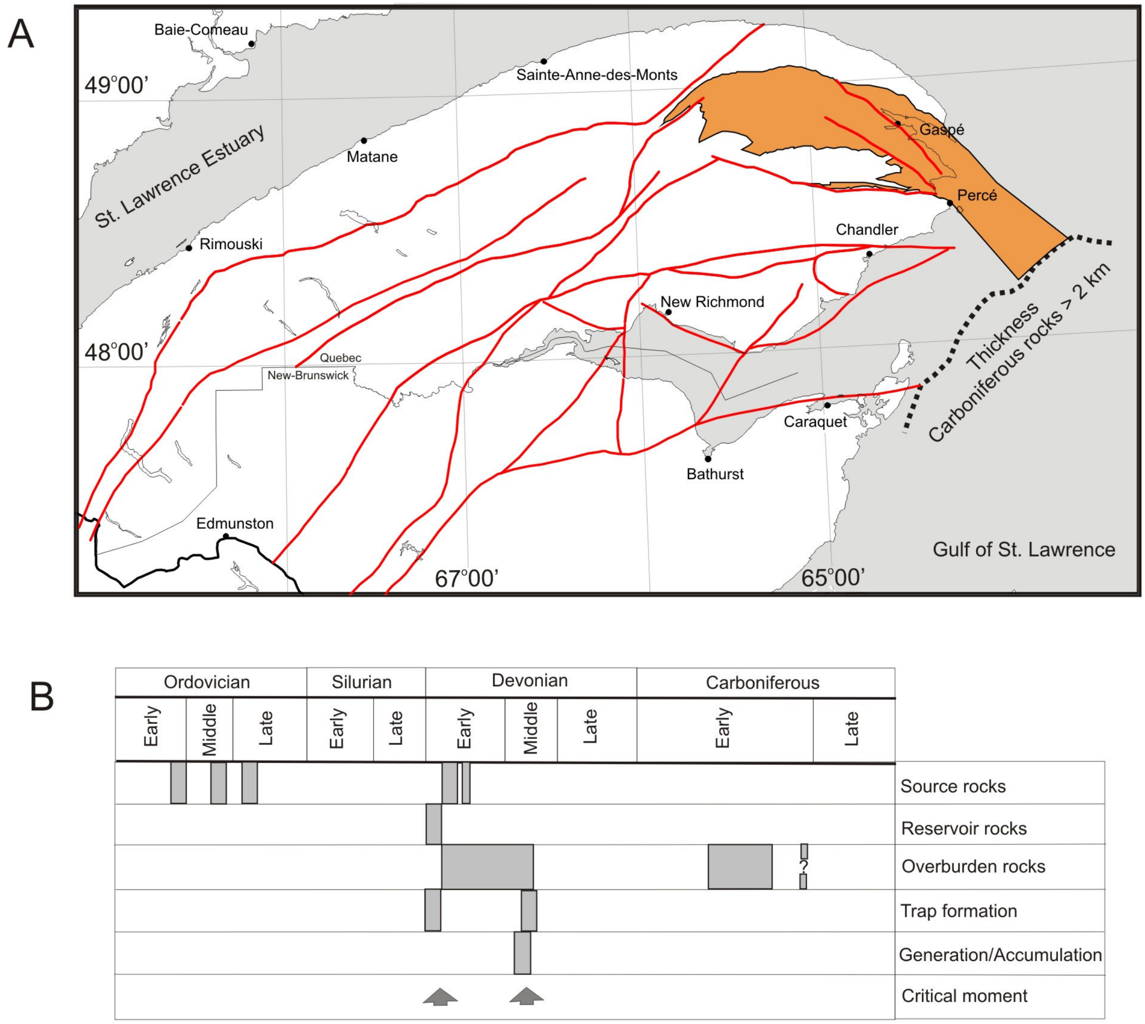


Figure 37: A- Play map Lower Devonian HTD;
B- Play # 4 (Lower Devonian HTD) hydrocarbon chart

significantly modified the trap geometry. The Upper Silurian West Point reefs are surrounded by siliciclastic muddy facies of the Indian Point Formation that may act both as a lateral and upper seals.

Risk factor

In the Gaspé Belt, the Lower Devonian pinnacle reefs are interpreted to have been built at the faulted margin of tilted fault blocks (Bourque, 2001). This has major implications for the potential of hydrothermal dolomitization of these units. These fault zones, and most importantly their subsidiary splays, are likely preferential conduits for high temperature fluids and possibly hydrocarbons (Lavoie et al., 2009a; in press b). Moreover, detailed, but geographically-restricted diagenetic studies (Bourque et al., 2001) suggest that the primary pores of the pinnacle limestone were not completely occluded before reefs were buried to significant depths suggesting that these rocks may have preserved their reservoir potential for a relatively long period of time.

Lower Devonian Upper Gaspé Limestones (R5)

Exploration history and shows

The Lower Devonian limestones of eastern Gaspé attracted the interest of the hydrocarbon industry following the discovery of oil seeps in the late 19^{th} century (McGerrigle, 1950). Since then, most early and recent exploration wells have targeted parts or the entire succession of the Upper Gaspé Limestones (Hu and Lavoie, 2008). Small volumes of oil or gas are almost invariably encountered in either the Indian Cove or Forillon formations (McGerrigle, 1950; Bertrand and Malo, 2001). However, production was never sustained and remained sub-economic.

Discoveries

In eastern Gaspé, in the vicinity of the Troisième Lac Fault (Fig. 38) the oil and gas fields of the Galt property are hosted in fractured Upper Gaspé limestones that have been hydrothermally altered and form carbonate breccia with saddle dolomite cement lining pore space (Kirkwood et al, 2005). The field and its neighbouring extension have been recently tested by four delineation and exploration wells (Galt 1 to 3 and Baillargeon). The field has an $80km^2$ closure; the porosity in the brecciated reservoir averages 6% (not water filled). Two main reservoirs have been identified, the Indian Cove Formation between 400-1200 m (light oil, 38-45 API) and the Forillon Formation between 1500-2500 m (natural gas). The gas reservoir has produced at rates of 1100 m^3/d (37 mcf/d) for a couple of years. A few of hundreds of oil barrels (average 1 m^3 or 5 barrels per day) are produced yearly. The Galt gas field has proven and probable resources of $21*10^6$ and $300*10^6$ m^3 (0.7 and 10 Bcf), respectively. In 2006, the probable oil volume was evaluated at $16*10^3$ m^3 (100 000 barrels).

Potential reservoir

In the northern edge of the Gaspé Belt, the Lower Devonian Upper Gaspé Limestones includes from the base to the top, the Forillon, Shiphead and Indian Cove formations. The group is dominated by fine-grained, shaly and dolomitic calcilutite with significant silica and chert nodules in northern Gaspé (Lavoie, 1992b). Minor sandstone, mudstone and bentonite beds are concentrated in the middle part of the group (Shiphead Formation).

The Upper Gaspé limestones are generally tight, but relatively high fracture porosity is observed close to NW-striking faults that have a polyphase long-lived structural history including syn-sedimentary normal motion and strike-slip motions during the Acadian orogeny and in post-Devonian time (Pinet et al., 2008). Hydrothermal dolomitization has only been observed close to significant fracture networks and may have contributed to permeability enhancement (Lavoie et al., 2009a). Available data for the Galt gas field indicates that the

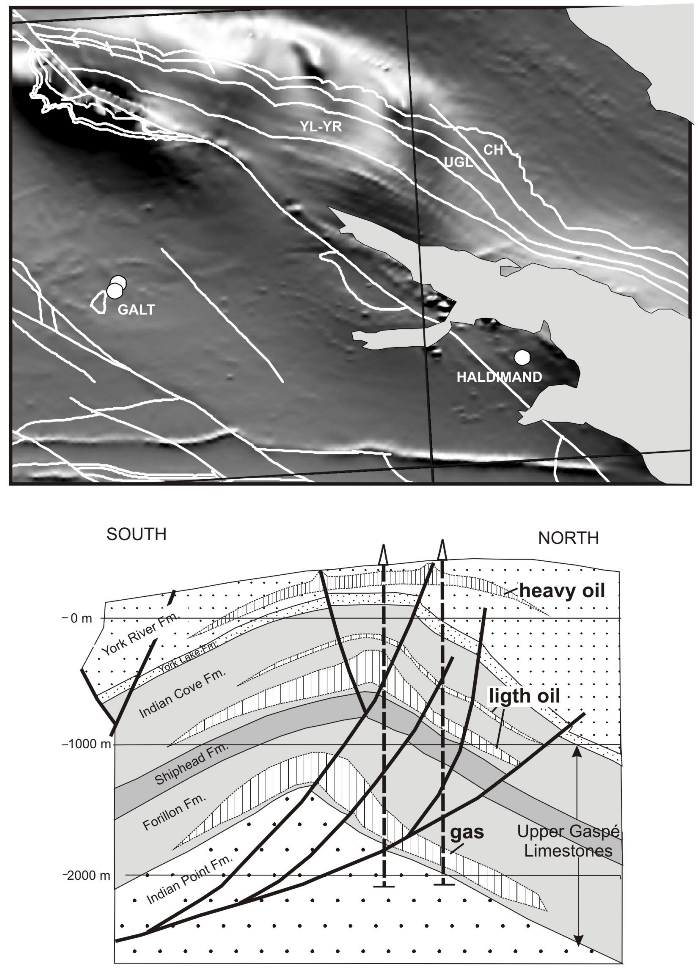


Figure 38 : A- Location of the Galt and Haldimand fields in eastern Gaspé. Geologic contacts (from Brisebois and Nadeau, 2003) have been superimposed on the shaded relief image of the total residual magnetic field. B- Cross section of the Galt field showing the stacked reservoirs in the Upper Gaspé Limestones Group. Modified from Kirkwood et al. (2004).

Lower Devonian Forillon Formation (Fig. 38) has 2.33% of fracture porosity and a permeability of 0.59 md.

Geographic distribution

The prospective area for Lower Devonian fractured Upper Gaspé Limestones is restricted to the northern edge of the Gaspé Belt where it forms a nearly continuous band, except for the area west of Rimouski and around Murdochville where supermature maturation levels are expected (Fig. 39). The southern boundary of this band corresponds either to the transition with the deeper-water Fortin Group or to regional synclines cored with thick clastic succession of the Gaspé Sandstones. Evaluation of prospect distribution is arduous given the critical importance of fracturing for the formation of reservoirs.

Source rock, maturation, generation and migration

In northern Gaspé, the best source rocks are the Middle Ordovician Ruisseau Isabelle Shales (see source rock section) and to some extent, the Lower Ordovician Rivière Ouelle Formation both of which underlie the Gaspé Belt. These Type I and II source rocks generated hydrocarbons during and shortly after the Taconian Orogeny (Roy, 2008). In addition, the Forillon and Indian Cove formations have some fine-grained limy mud facies that have some fair source rock (Type II and III) potential (TOCmax of 2.4% see source rock section and Roy, 2008, Lavoie et al, 2009b). Generation of Devonian hydrocarbons started during the Acadian Orogeny. Comparative geochemistry on extracts and oils suggest a dominant Ordovician source with a locally significant contribution – contamination from Devonian source (Roy, 2008; Fowler et al., 2008; Lavoie et al., 2009a).

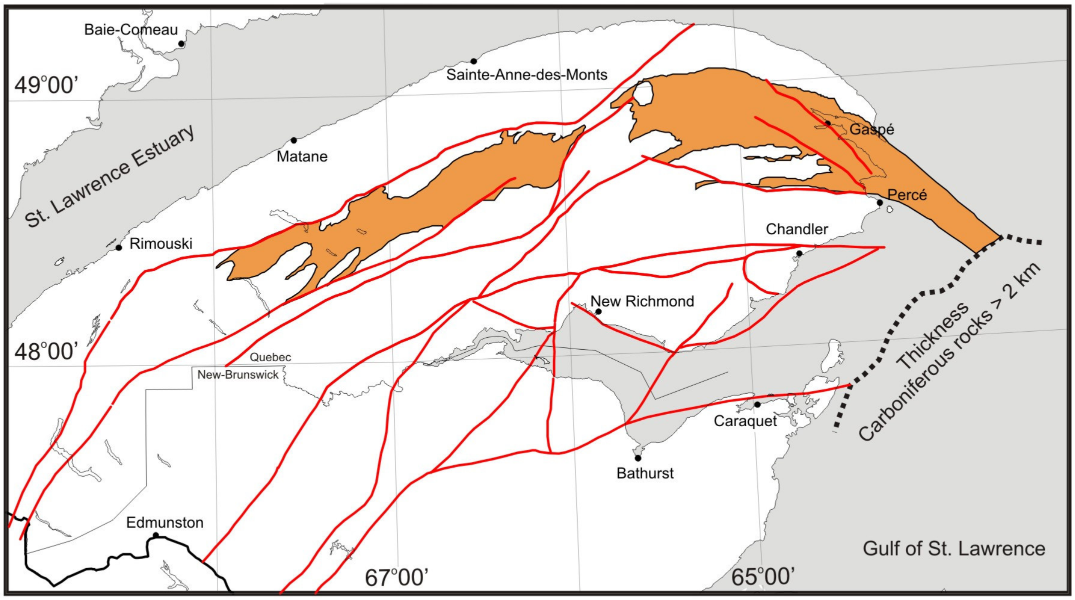
Traps and seals

Anticlinal folds have been a common exploration target in eastern Gaspé and the Galt field is hosted in such a structure (Fig. 39). However, fractures appear as a key parameter for efficient porosity and permeability. Fracture permeability at a specific site is partially dependant on the rheological properties of rocks; its location compared with folds and faults (anticline and damage zone close to second-order faults are expected to be characterize by higher fracture density), and to the presence or lack of fracture-filling gouge material. Massive to weakly fractured rocks are expected to act as a seal.

Risk factor

The long-term sealing capacity of highly fractured zones appears to be the main risk factor especially along polyphase fault zones that have experienced post-Acadian deformation.

A



B

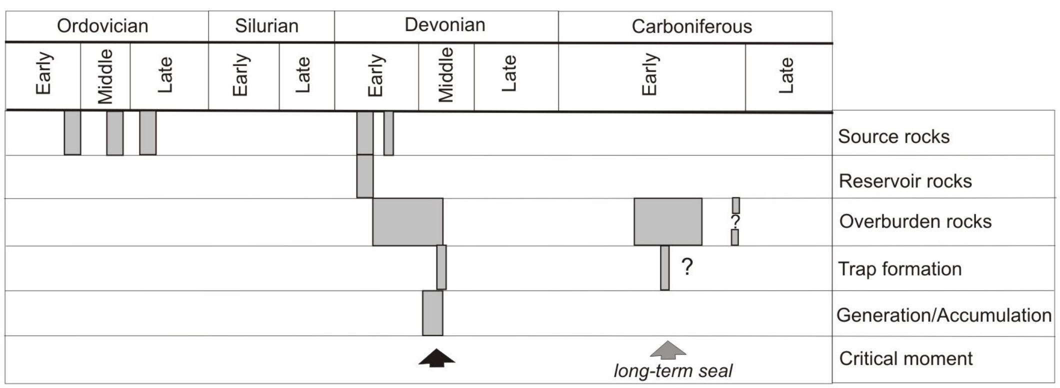


Figure 39: A- Play map Lower Devonian limestone (Play #5);
B- Play # 5 (Lower Devonian limestone) hydrocarbon chart

Lower Devonian Gaspé Sandstones (R6)

Exploration history and shows

The Gaspé Sandstones were the first exploration targets in the eastern Gaspé Peninsula (McGerrigle, 1950; Bertrand and Malo, 2001). The early interest was based on abundant oil seeps associated with fractures in the Gaspé Sandstones and most commonly related to anticlinal crests. Most wells had hydrocarbon shows but gave only minimal production (a few barrels of oil).

Discoveries

The Haldimand Field was discovered in 2006 and is still under evaluation with delineation drilling planned for 2009. The 22 m pay zone in the York River Formation occurs between 950 and 1090 m. Over a 10 days test, the reservoir yielded a stabilized production of 5.4 m^3 (34 barrels) per day of oil (47 API) and some natural gas. The porosity of the reservoir ranges between 5 and 15% and pressure is 12.4 MPa; no water was produced. The pool size is roughly estimated at 30 km^2.

Potential reservoir

The Gaspé Sandstones record an abrupt shoaling event, from shallow marine to terrestrial facies. The transition from the deep water facies of the Upper Gaspé Limestones to the shallow water sands of the Gaspé Sandstones Group is gradational (York Lake Formation), except in the Forillon-Percé area, where it is abrupt (York River Formation). The overlying units (Battery Point and Malbaie formations) contains, at its base, distal braided stream deposits and interbedded marine deposits, overlain by meandering river system and braided plain deposits.

The potential reservoir unit consists of high energy, marginal marine to fluvial sandstone that locally fills channels. Large scale migrating sand bars are locally highly porous. In grab samples, porosity averages 6.3% for York River Formation (N=5) and 9.4% for the coarser grained Battery Point Formation (N=5; Lavoie, 2009). Petrophysical data from wells located in eastern Gaspé (Hu and Lavoie, 2008) indicates similar to slightly higher porosity. The hydrocarbon-charged pay zone of the Haldimand Field is 22 m thick with porosity ranging between 5 to 15%.

Geographic distribution

The map distribution of the Lower Devonian sandstones of the York River Formation is well constrained (Fig. 40)

Source rock, maturation, generation and migration

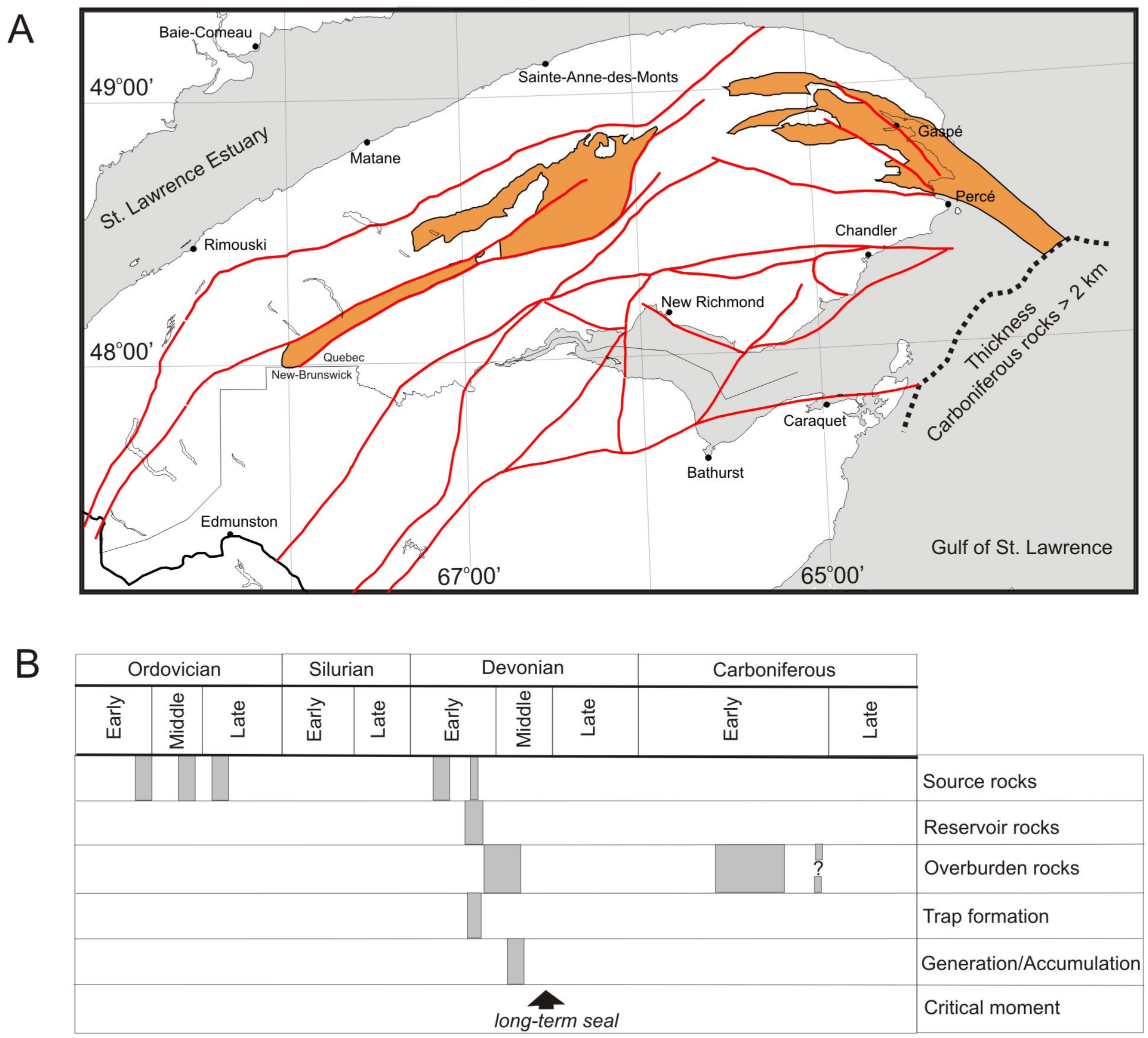


Figure 40: A- Play map Lower Devonian sandstone (Play #5);
B- Play # 6 (Lower Devonian sandstone) hydrocarbon chart

In northern and southern Gaspé, the best source rocks are the Middle Ordovician Ruisseau Isabelle and Dubuc shales (see source rock section) and to some extent, the Lower Ordovician Rivière Ouelle Formation (only in northern Gaspé). These Type I and II source rocks generated hydrocarbons during and shortly after the Taconian Orogeny (Roy, 2008). In addition, the Forillon and Indian Cove formations have some fine-grained limy mud facies that have some fair source rock (Type II and III) potential (TOCmax of 2.4% see source rock section and Roy, 2008, Lavoie et al, 2009b). Generation of Devonian hydrocarbons started during the Acadian Orogeny. In eastern Gaspé, a couple of thin algal-rich coal beds of the York River Formation have high TOC values (64%; Lavoie et al., 2009b) and high generation potential (HI up to 800); their overall abundance and subsurface distribution is unknown. It is noteworthy that coals are abundant in coeval rocks of the Val d'Amour Formation in Northern New Brunswick (Bertrand and Malo, 2005). Comparative geochemistry on extracts and oils suggest a dominant Ordovician source with locally significant contributions by contamination from Devonian sources (Roy, 2008; Fowler et al., 2008; Lavoie et al., 2009a).

Traps and seals

Stratigraphic traps and seals are likely in nearshore coarse-grained clastic units of the Gaspé Sandstones where rapid facies transition from porous channel/deltaic wedges to mud dominated units are documented. However, deformation may significantly modify the trap geometry as in the case of the Haldimand Field, where reservoir units are sealed by a fault.

Risk factors

The most important risk factor for the Lower Devonian clastic play is the presence of a long-term seal as these sandstones are overlain by a coarsening-upward clastic succession. (Fig. 40)

Quantitative evaluation

The prospect sizes for the Lower Devonian clastic play are largely unknown in the Gaspé Belt. For quantitative evaluation purposes, data from the largely time and facies-correlative Lower Devonian Oriskany Sandstone in eastern United States (Milici and Swezey, 2006; C. Swezey, pers. comm. 2009) has been used as an analogue. Other parameters such as the thickness of the net pay zone, its porosity and water saturation have been estimated from petrophysical data from wells in eastern Gaspé.

The PRIMES analysis of the potential oil in place in the Lower Devonian Gaspé Sandstones in Gaspé (see also the detailed assessment section) suggests a median potential (P50) of $16.2 * 10^6$ m^3 (102 Mbo).

THE UPPER PALEOZOIC MARITIMES BASIN

INRODUCTION

The composite Maritimes Basin is a large upper Paleozoic sedimentary basin underlying the southern Gulf of St. Lawrence, Cabot Strait, southwestern Grand Banks and northeastern Newfoundland continental shelves, with onshore extensions in all five eastern Canada provinces (Fig. 41). Upper Paleozoic strata underlie all of Prince Edward Island and the Magdalen Islands (Quebec). Easternmost segments of the Maritimes Basin are overlain by Mesozoic-Cenozoic sediments of the Atlantic continental margin. The Maritimes Basin includes the Magdalen, Sydney, Deer Lake and St. Anthony basins and numerous local subbasins, the largest of which include the Moncton, Cumberland, Antigonish, Bay St. George and White Bay subbasins (Figs. 41, 43). The Maritimes Basin encompasses a total area of 250,000 km^2, with about 75% of the basin area offshore.

The Maritimes Basin unconformably overlies a collage of Appalachian crustal zones of varying age and composition, deformed during the Middle to Late Ordovician Taconian and Early to Mid-Devonian Acadian orogenies (Fig. 41). The basin developed in equatorial latitude, within an oblique collisional zone between the Laurussia and Gondwana cratons, during the final stages of assembly of the Pangea supercontinent (Fig. 42; Calder 1998). Several other large sedimentary basins developed along this plate boundary during the late Paleozoic Alleghenian Orogeny, including the Central Appalachian, Black Warrior and Western European basins. The depositional and structural history for the Maritimes Basin included extensional and strike-slip settings in the Late Devonian to Mississippian and a wrench-foreland basin setting in the Pennsylvanian to early Permian (Bradley, 1982; Durling and Marillier 1993; Rehill, 1996). Regional strike-slip faults were active through most of the basin's development, resulting in local development of pull-apart basins and subsequent basin inversions and deformation. The present day Maritimes Basin is an erosional remnant of a formerly much more extensive cover of Upper Paleozoic strata. Thermochronology studies indicate 1000 to 4000 metres of basin strata were eroded during the Mesozoic (Ryan and Zentilli, 1993).

Geological and Petroleum Exploration History

Geological investigations in the Maritimes Basin date from some of the earliest work of the Geological Survey of Canada more than 150 years ago, when coal was of fundamental

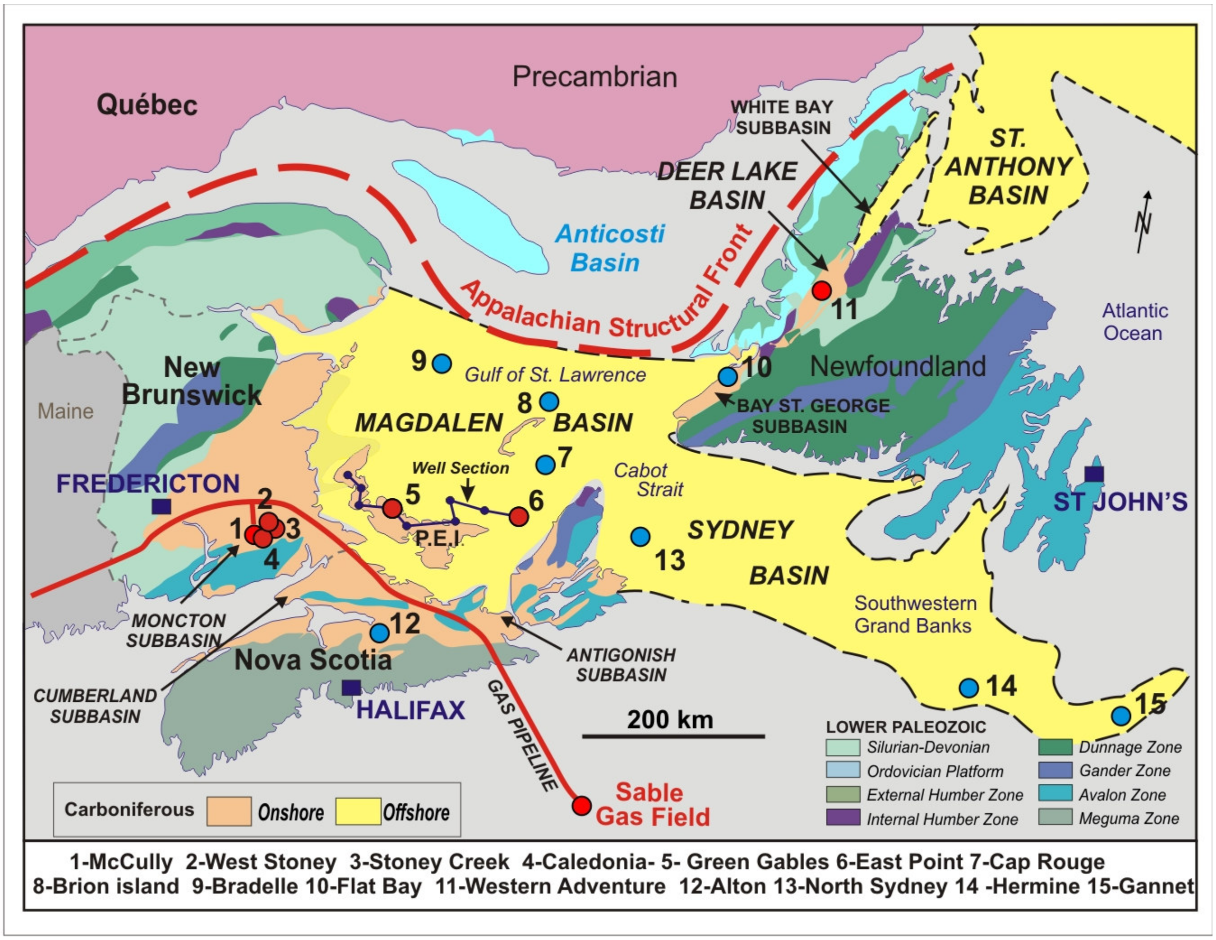


Figure 41. Regional setting of the Maritimes Basin, with indicated hydrocarbon discoveries (red dots), select exploration wells (blue dots) and location of Magdalen basin well cross-section (Figs.46,50).

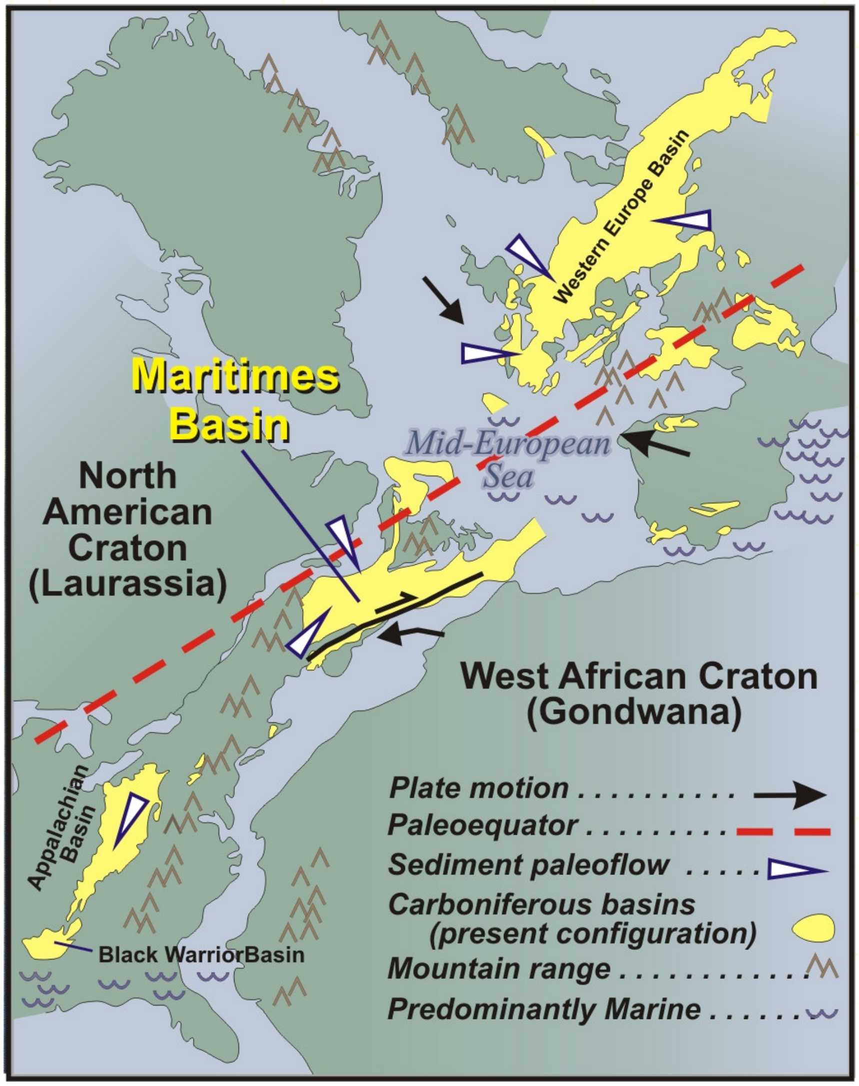


Figure 42. Euramerica Carboniferous paleogeography, illustrating plate tectonic setting of the Maritimes Basin and other major Carboniferous sedimentary basins (modified from Calder, 1998).

importance as an energy resource. Excellent modern summaries of onshore geology are available in St. Peter and Johnston (2009) (New Brunswick); Ryan et al. (1991), Ryan and Boehner (1994), and Calder (1998)(Nova Scotia); and Knight (1983) (southwestern Newfoundland). Regional basin summaries include the works of Bell and Howie (1990), van de Poll et al. (1995), and Gibling et al. (2008).

Petroleum exploration in the Maritimes Basin dates back to the 1800s. Early exploration in the basin was typically driven by oil seeps in outcropping Carboniferous strata. Summaries of historical drilling activity in Nova Scotia and New Brunswick respectively can be found in McMahon et al. (1986) and St. Peter (1987). The earliest drilling activity includes wells in the Dover area in New Brunswick in 1859 and in the Lake Ainslie area in Nova Scotia in 1869 (some of the first wells drilled in North America). The Stoney Creek oil field in New Brunswick (Fig. 41) was discovered in 1909, one of the earliest oil field discoveries in Canada and the first producing oil/gas field in eastern Canada. In its eighty-nine year production history, the Stoney Creek field produced ~28.6 Bcf of gas and ~800,000 barrels of oil, albeit with modest annual production levels (Howie, 1968). The field is currently under redevelopment, with new production of small volumes of oil (Contact Exploration, 2009). Sporadic onshore exploration activity has occurred over the past 100 years, with several hundred wells drilled (most to relatively shallow depths of less than 1000 m). Onshore exploration activity (seismic surveying and drilling) has increased in recent years. The McCully gas field, discovered in 2000 in southeastern New Brunswick, is the largest and most significant discovery in the basin to date. The McCully Field is currently producing 25-35 MMcf/d from 23 gas wells, transported to local and export markets via the Maritimes and Northeast Pipeline (Fig. 41). The field contains an estimated 1+ Tcf gas in-place (Corridor Resources, 2009). Other onshore gas discoveries, as yet undeveloped, include West Stoney and Downey in New Brunswick, Green Gables in Prince Edward Island, and Western Adventure in Newfoundland (Fig. 41). The most recent exploration success was the discovery of oil in the South Branch G-36 well in 2008, near the McCully gas field (Corridor Resources, 2008).

Offshore exploration in the Maritimes Basin dates back to the drilling of Hillsborough No.1 well in 1943 in the southern Magdalen Basin, the first well drilled in an offshore area in Canada. Most offshore exploration activity dates from the 1970's and early 1980's, during which time 14 wells were drilled and over 50,000 line-km of seismic reflection data were acquired. The early offshore exploration resulted in one significant gas discovery in the (1970) East Point E-49 well. A drill-stem test in this well flowed gas at a rate of 5.5 MMcf/d.

The E-49 well site is included in Significant Discovery License No. 082 that was issued by the Government of Canada in February 1987 under the Canada Petroleum Resources Act. Development of the East Point field was deemed uneconomic after a step-out well (East Point E-47) was unsuccessful. Marine portions of the Maritimes Basin have received little attention over the past 25 years, with only a few small seismic surveys undertaken.

REGIONAL STRATIGRAPHY:

The Maritimes Basin contains middle Devonian to Early Permian continental and shallow marine strata, with a maximum known thickness of approximately 12,000 metres in the east-central Magdalen Basin (eastern Gulf of St. Lawrence; Fig. 43). The earliest record of post-Acadian sedimentation is provided by sparsely distributed volcanic and continental sedimentary rocks of middle Devonian age. More typically, early deposition in the Maritimes Basin is marked by coarse-grained redbeds with associated bimodal volcanic rocks of the Late Devonian Fountain Lake Group and Fisset Brook Formation (Fig. 44). Radiometric dates suggest several periods of volcanic activity from Late Devonian to Tournaisian time, in many cases with spatial and genetic links to major fault zones (van de Poll et al., 1995). Regionally, volcanic rocks become progressively less common in younger basin fill sections.

Lower Carboniferous (Tournaisian)

The latest Devonian to Late Tournaisian Horton Group, dominated by alluvial and lacustrine sedimentary rocks, marks the initiation of widespread sedimentation in the Maritimes Basin (Fig. 44). The Horton Group and its western Newfoundland equivalent, the Anguille Group, generally comprises a three-part succession; a basal section of coarse-grained redbeds, a medial interval consisting of black shale and sandstones and conglomerates (Albert Formation in New Brunswick, Strathlorne Formation in Nova Scotia, Snakes Bight Formation in Newfoundland), and an upper succession of redbeds of variable grain size. In the Moncton Subbasin in New Brunswick, the Albert Formation is unconformably overlain by conglomerates and fine grained redbeds of the late Tournaisian Sussex Group (St. Peter and Johnston, 2009). Facies and thickness variations within the Early Carboniferous basin fill indicate deposition in grabens and half-grabens in a rift-related extensional regime. Stratigraphic relationships, particularly in the upper portions of the Horton Group, are often complicated by local unconformities typical of terrestrial settings in local depocentres adjacent to basin-bounding fault systems. The maximum known thickness of the Horton Group in onshore exposures and exploration wells is 3291 metres. Seismic data

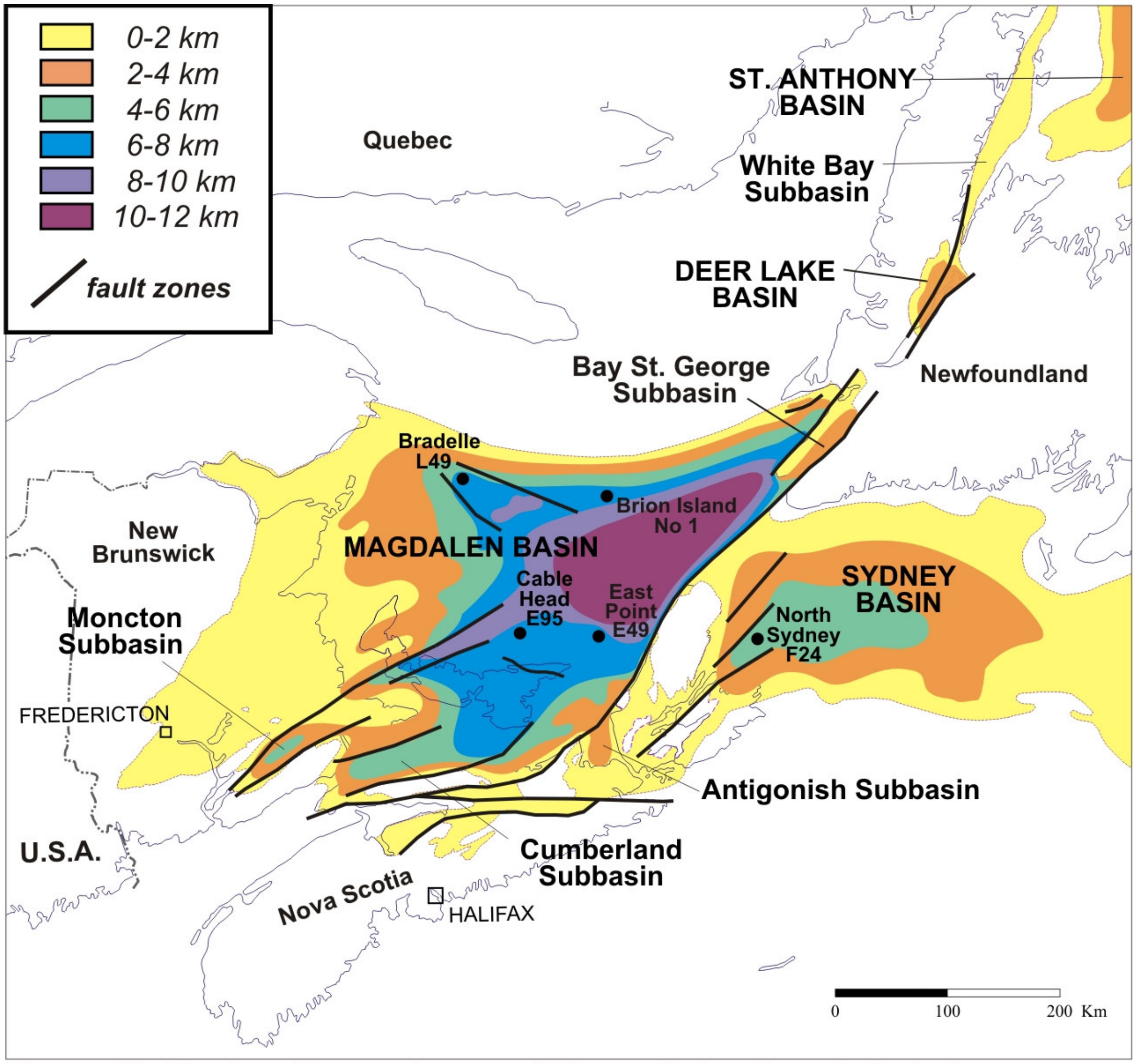


Figure 43. Regional isopach map of Upper Paleozioc strata in the Maritimes Basin, with indicated basin and subbasin names and select offshore wells.

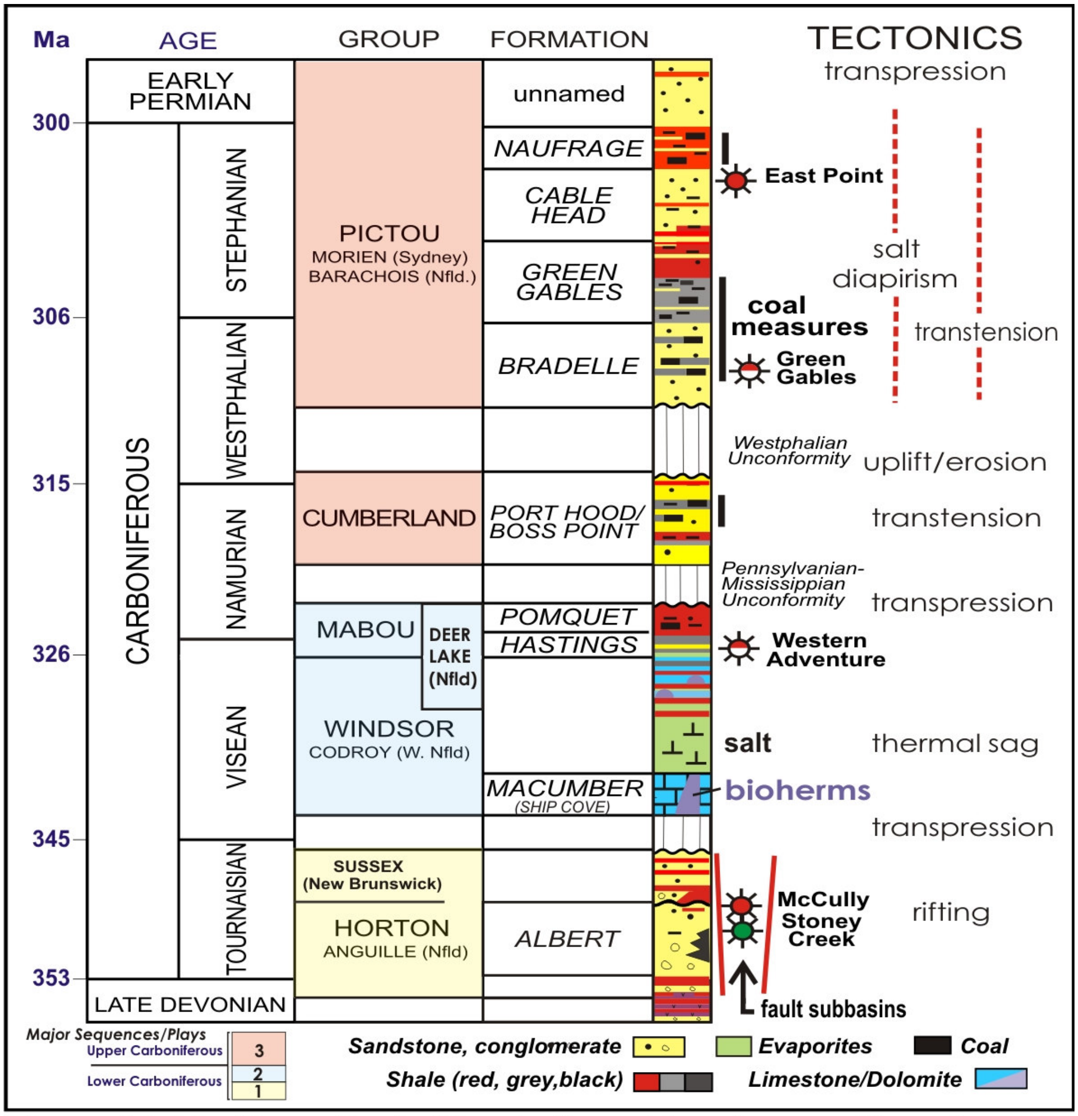


Figure 44. Maritimes Basin lithostratigraphic column, with major tectonic phases and unconformities, key lithologic elements, and stratigraphic position of discovered oil and gas fields.

indicate the Horton Group may be up to 8000 metres thick in fault subbasins in the southwestern Magdalen Basin (Durling and Marillier, 1993).

Lower Carboniferous (Viséan -Early Namurian)

The Viséan Windsor Group and its equivalent in western Newfoundland, the Codroy Group, mark the first fully marine sedimentation in the Maritimes Basin (Fig. 44). The Windsor Group consists of marine fossiliferous carbonate rocks and evaporites, and nonmarine clastics. Carbonate buildups (bioherms) occur locally in the basal Windsor Group (Gays River Formation in Nova Scotia and New Brunswick; Big Cove Formation in western Newfoundland). Windsor Group marine beds provide an important regional marker within the early part of the Maritimes Basin fill. Thirty discrete transgressive-regressive events represented by carbonate rocks are recognized where the Windsor Group is preserved in its entirety in southern and eastern Nova Scotia, on Cape Breton Island and in southwestern Newfoundland. The excellent lateral continuity of the marine carbonate intervals is maintained in spite of local changes in overall thickness, suggesting that both local rifting and regional subsidence characterized the late Viséan.

In southeastern New Brunswick and northwestern Nova Scotia, the marine carbonates which are so characteristic of the Windsor Group become increasingly rare until the marine record comprises only the basal Windsor limestones and associated evaporites. Redbeds ranging from coarse alluvial fan material to fine-grained mudrocks in these areas occupy the stratigraphic position of marine carbonates and evaporites elsewhere in Nova Scotia and western Newfoundland. Windsor-equivalent successions completely lacking in marine strata occur in the western Magdalen Basin (New Brunswick and southern Gaspé Peninsula, Quebec; Jutras et al., 1997) and the Deer Lake Basin in Newfoundland (Hamblin et al. 1997). In the eastern Sydney Basin (southern Grand Banks), evaporites of the lower Windsor Group were intersected in the Hermine E-94 and Gannet O-54 wells (Fig. 41). The Windsor Group is up to 2000 metres thick in onshore areas of Nova Scotia. In the Gulf of St. Lawrence, the Cap Rouge F-52 well (Fig. 41) penetrated nearly 5000 metres of steeply dipping Windsor Group strata, on the flank of a large diapiric structure (Giles and Utting, 2001). Marine seismic data indicate Windsor salt diapirs are widespread in the eastern Magdalen Basin, the northern and eastern Sydney Basin, and the St Anthony Basin. Syndepositional salt diapirism and salt withdrawal produced locally complex depositional and structural patterns in these areas.

. The Windsor Group is gradationally overlain by the Late Viséan -Early Namurian Mabou Group (Fig. 44). In southern and eastern Nova Scotia and on Cape Breton Island, the

Mabou Group comprises two principle rock units, the lowest of which (Hastings Formation) is characterized by grey and dark grey shales with associated thin stromatolitic limestones and interbedded anhydrite and halite. Evaporites near the base indicate that initial deposition was in a saline setting, probably representing the vestiges of the former Viséan marine basin. In northwestern Nova Scotia, the lower Mabou Group contains fluvial sandstones. In western Newfoundland, equivalent strata in the Deer Lake Basin consist of lacustrine-to-fluvial grey shales and sandstones. In southwestern Newfoundland (Bay St. George Subbasin) strata equivalent to the lower Mabou Group are represented by redbeds of the Barachois Group. The upper Mabou Group in Nova Scotia (Pomquet Formation) is characterized by fine-grained red strata with thin intercalated sandstones. Occasional evaporite nodules attest to a seasonally arid climate. Equivalent strata include red sandstones of the Humber Falls Formation in the Deer Lake Basin and fluvial sandstones of the Searston Formation (Barachois Group) in the Bay St. George Subbasin (Utting and Giles, 2008). Sparsely distributed coal-bearing strata occur in these successions.

Upper Carboniferous (Namurian- Early Westphalian)

The Mabou-Cumberland Group contact (unconformity) defines the position of the Mississippian-Pennsylvanian boundary of the American Carboniferous. The Late Namurian - Early Westphalian Cumberland Group marks the first appearance of thick fluviatile sandstones in the New Brunswick and Nova Scotia Carboniferous successions. In western Newfoundland, fluviatile sandstones appear slightly earlier, in latest Mississippian strata of the Barachois Group (Utting and Giles, 2008). Lower Cumberland Group strata, which may exceed 1000 metres in thickness, are represented in Nova Scotia and New Brunswick by the sandstone-dominated Port Hood and Boss Point formations. The Upper Cumberland Group contains coal measures which have historically been of significant economic and geologic importance at Joggins in Nova Scotia and in Cape Breton Island (Calder, 1998). With associated gray to black organic-rich shales, these coal measures are up to 2100 metres thick in the Cumberland Subbasin in Nova Scotia (van de Poll et al. 2005). Accumulation rates for strata within the coal measures were very high, resulting in the preservation of standing tree trunks and fossil forests. In wells drilled on Prince Edward Island and in the southern Gulf of St. Lawrence, strata of the Cumberland Group are only locally represented. They appear to be restricted in distribution in these areas by a second major unconformity at the base of the Pictou Group (termed the Westphalian Unconformity, Fig. 44; Giles and Utting, 1999).

Cumberland Group strata may be present in the Sydney Basin (North Sydney wells and Hermine E-94 well; Fig. 41).

Upper Carboniferous (Westphalian-Early Permian)

All strata above the Westphalian unconformity are assigned to the Pictou Group, essentially following the early stratigraphic model of Bell (1958). Basal Pictou Group strata are marked by thick, coarse-grained fluviatile sandstones of the Bradelle Formation, which interfinger with and pass upwards to coal measures strata (Fig. 44). Onshore equivalents in Nova Scotia include the Malagash Formation in northern mainland Nova Scotia and the Inverness Formation in western Cape Breton Island and the South Bar and Sydney Mines Formation of the Morien Group in the Sydney Basin. The Bradelle Formation passes transitionally upwards into the Green Gables Formation (Westphalian D – Stephanian), characterized by fine-grained grey and red shales and locally well developed fluvial sandstones. Coal seams are common in the lower part of the formation. Unnamed redbeds which overlie the Morien Group coal measures in the onshore Sydney Basin are presumed to be Green Gables Formation equivalents. The Bradelle Formation is overlain by the Stephanian Cable Head Formation, a succession dominated by thick, coarse-grained sandstones. The excellent lateral continuity of the Cable Head sandstones provides an important stratigraphic marker in the younger part of the basin fill. At the top of the Cable Head Formation, a sharp break in the succession marks the appearance of fine-grained variably calcareous red strata which characterize the Stephanian Naufrage Formation. This relatively soft rock unit underlies much of western Prince Edward Island. Channel sandstones occur sporadically throughout the Naufrage. The Naufrage Formation passes upwards into a succession of coarse-grained sandstones and conglomeratic sandstones of Early Permian age. These unnamed sandstones, up to several hundred metres in thickness, are the youngest rocks presently documented in the Maritimes Basin. They may be overlain by undated aeolian redbeds exposed on the Magdalen Islands in the central Gulf of St. Lawrence. The Upper Carboniferous-Early Permian succession may be up to 10,000 metres thick in the central (offshore) Magdalen Basin.

PETROLEUM SYSTEMS

The Maritimes Basin contains the key petroleum-system elements for a substantial petroleum resource potential, including widespread reservoir rocks, thick shale and salt sections (seals), large volumes of thermally mature source rocks, and abundant and diverse trap types (Fig. 45). The main exploration risks in the Maritimes Basin are associated with reservoir quality and trap preservation. Carboniferous sandstones in the basin have generally low porosity and permeability in the depth range most commonly explored for oil or gas traps. The trap preservation risk is related to the timing of hydrocarbon generation relative to basin deformation and erosion.

Reservoir Rocks

Sandstones provide potential reservoirs throughout the stratigraphic succession. These range from lacustrine shoreface and deltaic/fluvial-deltaic sands in the middle part of the Tournaisian Horton Group to thick, multistoried fluviatile sandstones in the Namurian to Permian portion of the basin fill (Fig. 46). Onshore studies have documented lateral continuity of these major fluviatile sandstones of up to two kilometers, with thicknesses ranging to 40 metres or more in onshore exposures. Stacked fluvial sand sections up to several hundred metres thick occur in some wells (Fig. 49). Fluvial sandstones dominate the late Namurian to early Westphalian succession, the Westphalian B to D Bradelle Formation and onshore equivalents in the central Maritimes Basin, as well as the Stephanian Cable Head Formation in the same area. In the Sydney Basin, the upper Carboniferous Morien Group, particularly in its lower part, is volumetrically dominated by thick sand intervals. Throughout the basin fill, the thick fluviatile sand bodies are interbedded with fine-grained mudrock and siltstones and commonly demonstrate abrupt lateral termination within these fine-grained rocks.

In the Viséan Windsor Group, the principal reservoirs are marine carbonate rocks (Fig. 46). Up to thirty discrete marine intervals have been documented, typically in cyclic configuration with evaporites and lesser redbeds. Excellent lateral continuity can be demonstrated although thickness is typically less than 8 metres for any single marine carbonate unit. At four stratigraphic levels within the Windsor Group, bioherms comprising abundant bryozoans, brachiopods and mollusks have been documented (Giles et al., 1979; Boehner et. al. 1988). In the middle and upper parts of the Windsor Group, coquinoid carbonate bioherms with mound-like configuration reach 20-25 metres in thickness but pass laterally within ~100 metres or less to dark, bituminous and argillaceous limestones. Deposited in quiet water settings below effective wave base, these mud-mounds occur in basin-margin and more distal basin positions. Their distribution, particularly within the upper parts of the Windsor Group, is unpredictable. At the base of the Windsor Group, biohermal

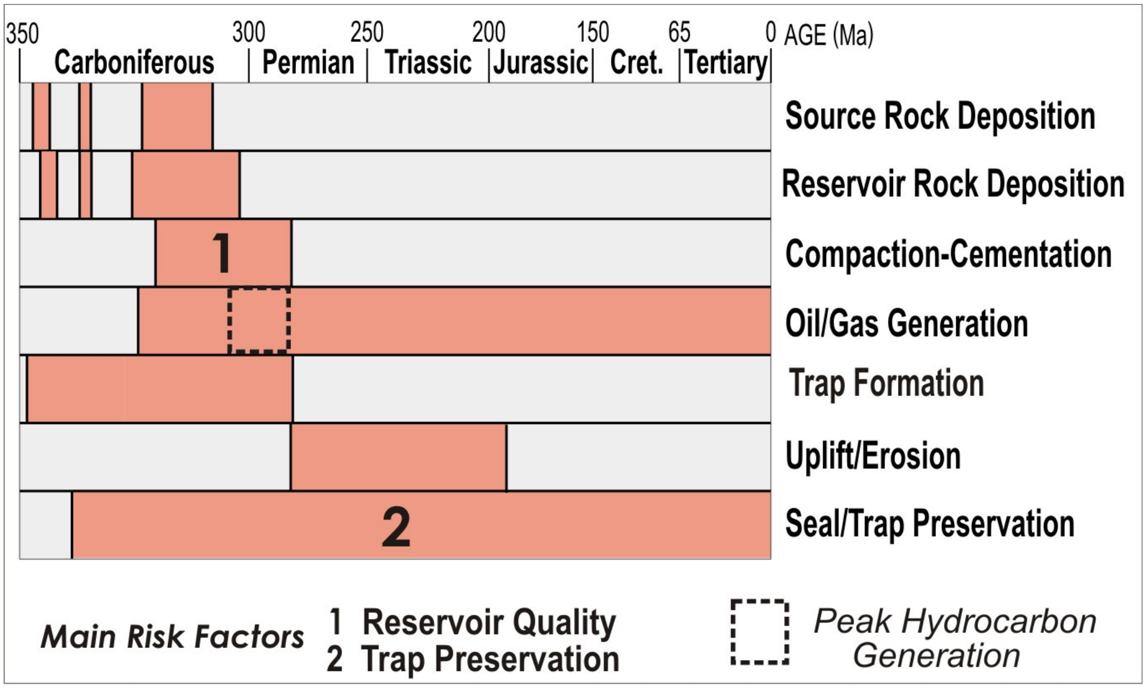


Figure 45. Petroleum systems chart for the Carboniferous Maritimes Basin

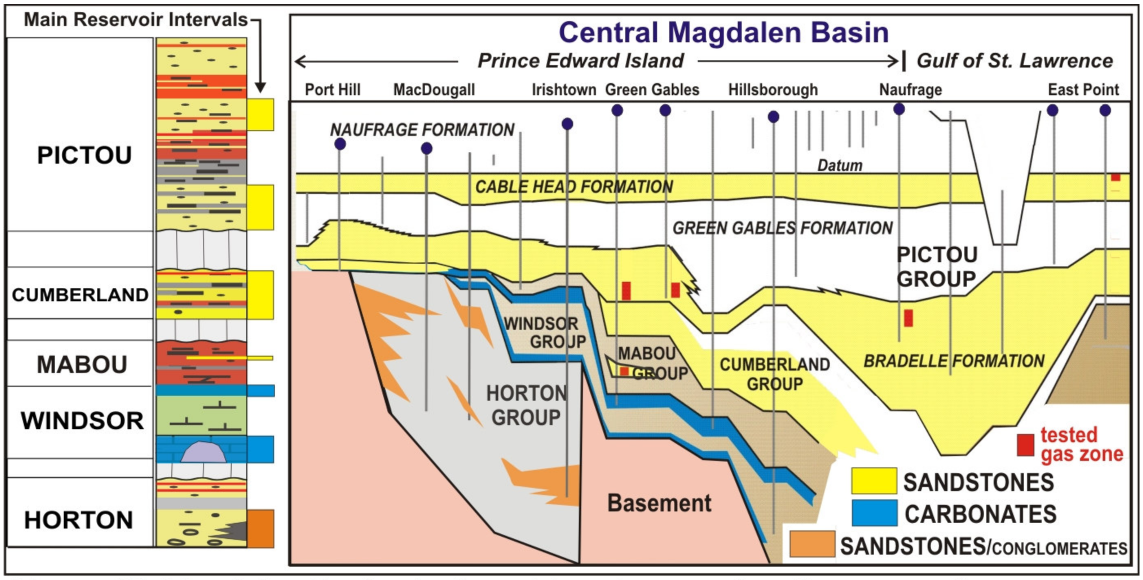


Figure 46. Magdalen Basin stratigraphic column and well cross-section illustrating major reservoir intervals (section location in Fig. 41).

accumulations in the Gays River Formation, deposited at or near the paleo-basin margin adjacent to upland blocks, provide potential reservoir facies of considerably greater volume. The drilled dimensions of the type Gays River biohermal bank complex document a strike length of 10,000 metres and a width of up to 2000 metres, with maximum drill-intersected thickness of ~50 metres (Boehner et. al. 1988). In every case, the carbonate bioherms pass down paleo-basin slope to laminated, sometimes organic-rich rocks of the Macumber or Ship Cove Formations, their laterally equivalent facies.

Reservoir Porosity and Permeability

Reports on Carboniferous reservoir quality include the multi-well studies of Bibby and Shimeld (2000) and Hu and Dietrich (2009), and a single-well core study of Chi and others (2003). These studies documented the general trends of rapidly decreasing porosity and permeability with depth in the Carboniferous basins, and stratigraphic and geographic variations in reservoir quality (Figs. 47, 48). A summary compilation of core-derived measurements outlines the generally pattern of low porosity and permeability for Carboniferous sandstones, with approximately equal percentages of conventional and unconventional (tight) reservoirs (the latter defined by permeability values less than 0.1 md). Well-log derived porosity measurements (Fig. 48a) outline the pattern of decreasing reservoir quality with depth, with average porosity values less than 10% below depths of 1000 to 1500 metres. The porosity-depth trends reflect a basin history of subsidence, sediment compaction, and exhumation. The maximum paleo-burial depths of Carboniferous strata were 1000 to 4000 metres below present depths, with basin exhumation/erosion likely occurring in Mesozoic time (see compaction curve estimated for upper Carboniferous strata in Figure 48b). Accordingly, the best quality reservoirs (porosity of 25 to 30 %, permeability up to 1000 mD) occur at relatively shallow basin depths (above 1000 metres). However, good quality sandstone reservoirs (porosity of 10 to 15%) are present to basin depths of up to 4000 metres. A detailed core study of porosity-depth trends (Fig. 48b) indicates that significant local variations occur in the porosity-depth association due to variations in sandstone diagenesis (Chi et al. 2003). The highest porosity sands are commonly associated with secondary porosity development due to dissolution of (early formed) calcite cements.

The best quality sandstone reservoirs (as measured by well-log derived porosity) occur in the Upper Carboniferous Pictou Group (example in Fig. 49) and locally the Mabou Group. In terms of geographic variations, sandstones in the northern Magdalen Basin (the Brion Island and Bradelle wells) have slightly higher average sandstone porosity values compared to

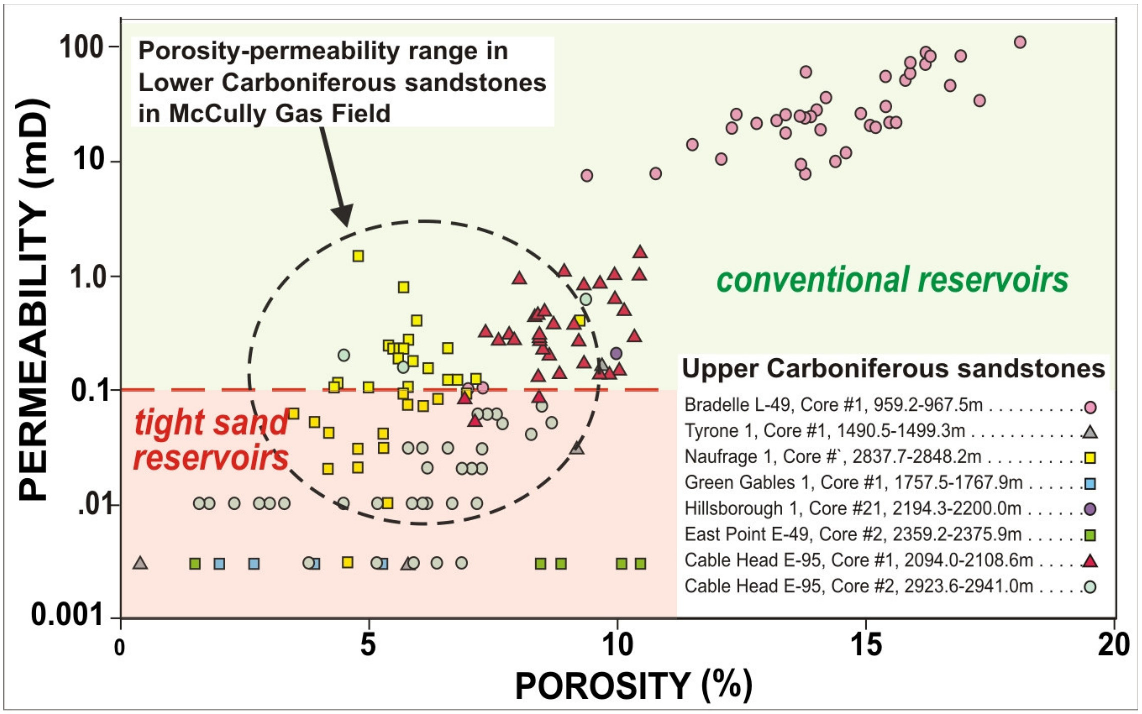


Figure 47. Porosity-permeability cross-plot for sandstone core samples in seven Magdalen Basin wells (adapted from Bibby and Shimeld, 2000). McCully gas field data adapted from Corridor Resources (2005). Differentiation of 'conventional' and 'tight' sand reservoirs based on permeability values above or below 0.1 millidarcies.

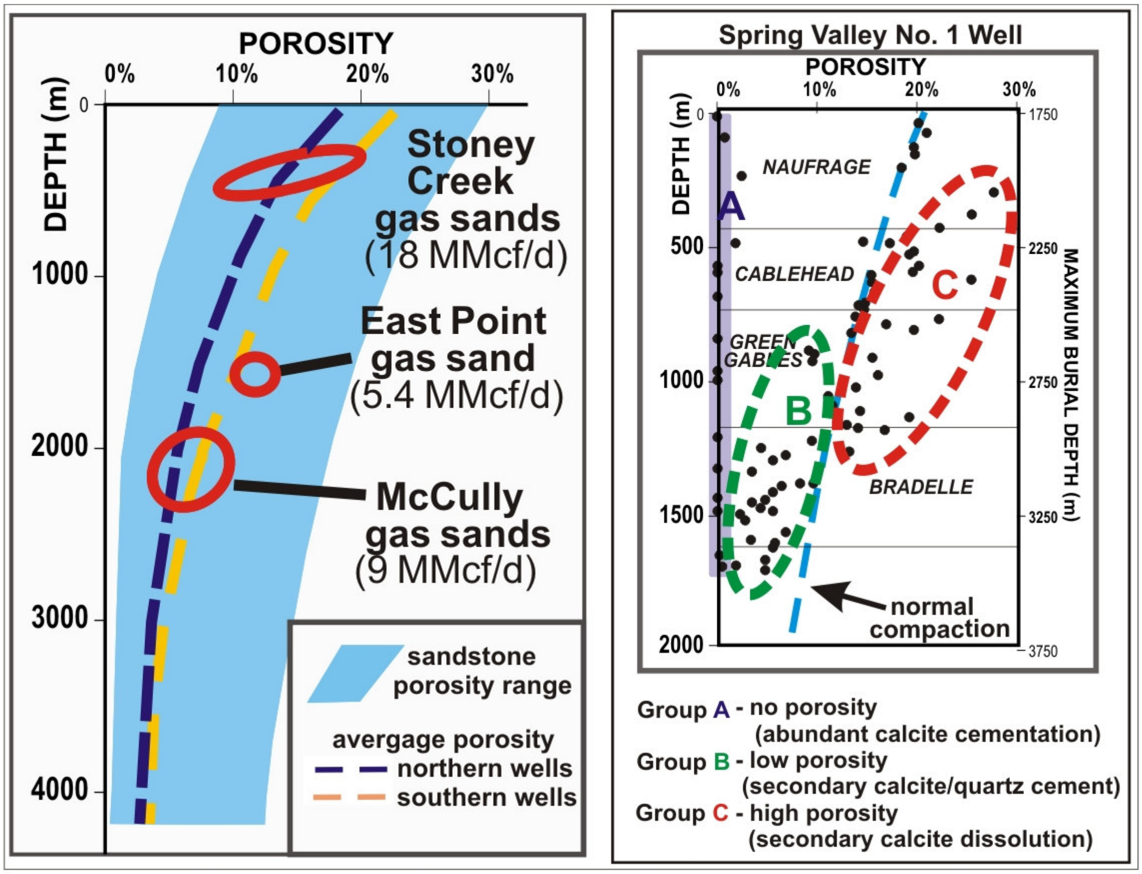


Figure 48. Porosity-depth trends for Carboniferous sandstones in wells in the Magdalen Basin (left panel) and the Spring Valley No. 1 well onshore Prince Edward Island (right panel; adapted from core data study of Chi et al., 2003). Red circles outline range of porosity values in discovered gas reservoirs, with associated maximum tested gas flow rates. Average porosity curves (dashed lines, left panel) adapted from Bradelle L49 and Brion Island No. 1 wells (northern wells) and Cable Head E95, East Point E49 and Irishtown No. 1 wells (southern wells).

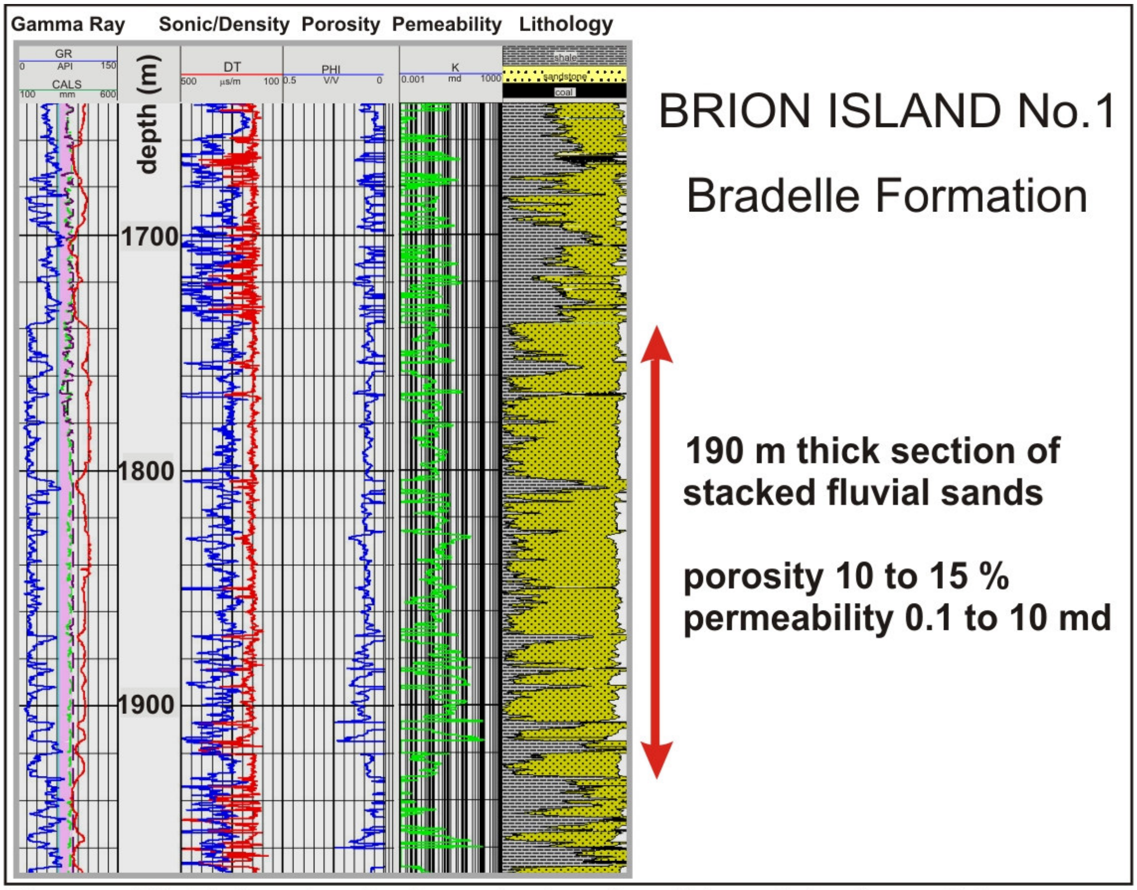


Figure 49. Petrophysical analysis of well log data from Brion Island No. 1 well, illustrating example of a good quality sandstone reservoir section in Upper Carboniferous Bradelle Formation (adapted from Hu and Dietrich, 2008).

equivalent strata in the southern Magdalen and Sydney basins (Fig. 48a). The observation of a northward increase in overall reservoir quality may be related to sediment provenance factors. Previous studies have documented the north to northeast sediment transport directions (from Appalachian source terranes dominated by volcanics and impure clastic sediments) for the southern Magdalen Basin and Sydney Basin (Gibling et al. 1992). In contrast, the quartz-rich metamorphic and intrusive assemblages of the Precambrian Shield may have provided sediment-source terrains for mineralogically more mature sediments for the northern Magdalen Basin, resulting in differences in sandstone petrography and associated reservoir characteristics (Martel and Durling, 2002).

Potential variations in hydrocarbon production relative to reservoir quality are indicated by the known gas recovery volumes in tested or producing reservoirs in the basin (Fig. 48a). Tested maximum gas flow volumes vary from 18 MMcf/d in higher porosity sands (e.g., Stoney Creek Field) to 5.4 to 9 MMcf/d in lower porosity sands (e.g., East Point well and McCully Field). In contrast to these good recovery rates, other wells in the basin have tested log-indicated hydrocarbon zones in low porosity sands with no recovery or very low (sub-economic) gas flow rates. The porosity and permeability of Maritimes Basin sandstone reservoirs compare with other Carboniferous to Permian producing basins such as the southern North Sea and the US Appalachian region. In the North Sea Carboniferous basins, secondary porosity and permeability enhancement is an important factor in overall hydrocarbon potential, and may be of similar significance in the Maritimes Basin (Bibby and Shimeld, 2000).

Source Rocks

Hydrocarbon source rocks are widely distributed in the Maritimes Basin (Fig. 50). Source rocks include Lower Carboniferous lacustrine black shales of the Horton and Mabou groups, marine carbonates of the Windsor Group, and Upper Carboniferous coal measures.

Horton and Anguille Group black shales contain Type I and II organic matter, capable of significant oil and gas generation (Mossman, 1982; Chowdhury et al. 1991). Total organic content (TOC) is commonly above 2% and up to 20% in organic-rich oil shale intervals (Fig. 51). Organic-rich shales are typically 100 to 300 metres thick in Lower Carboniferous subbasins, onshore New Brunswick and Nova Scotia. Rock-Eval pyrolysis and petrographic assessments have shown the presence of both macerated plant matter and algal materials in these shales, as might be anticipated in shallow lacustrine environments. Similar organic-rich

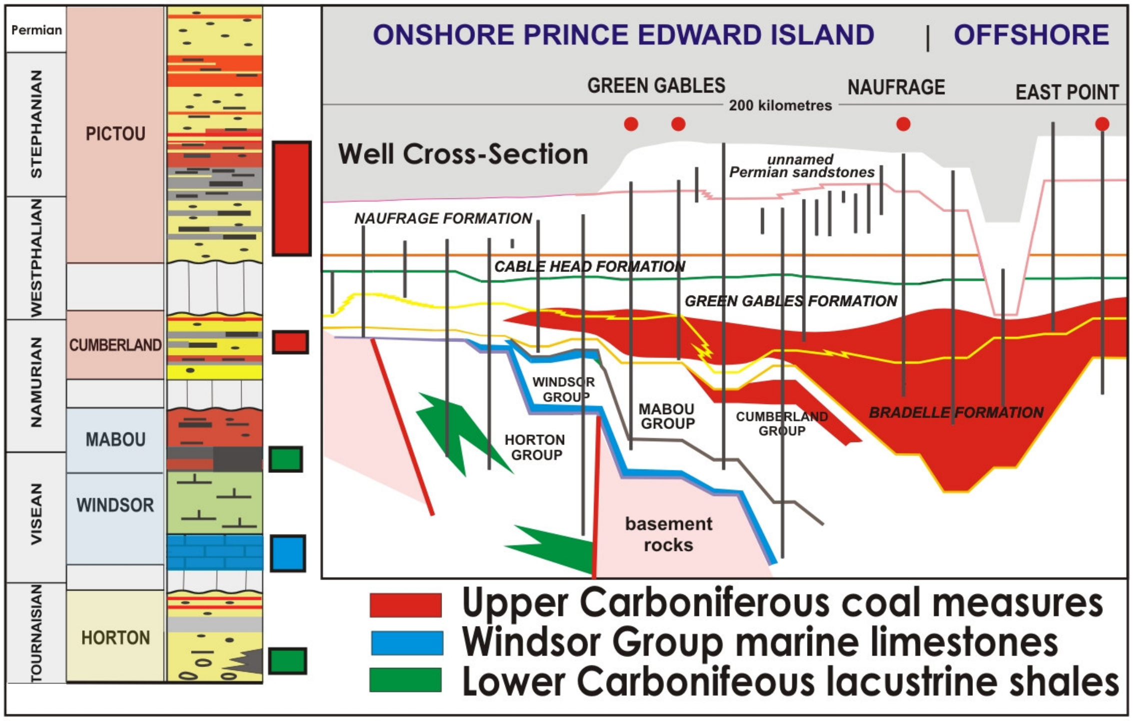


Figure 50. Magdalen Basin stratigraphic column and well cross-section illustrating major hydrocarbon source rock intervals (Visean lacustrine source rocks occur in Deer Lake Basin, Newfoundland).

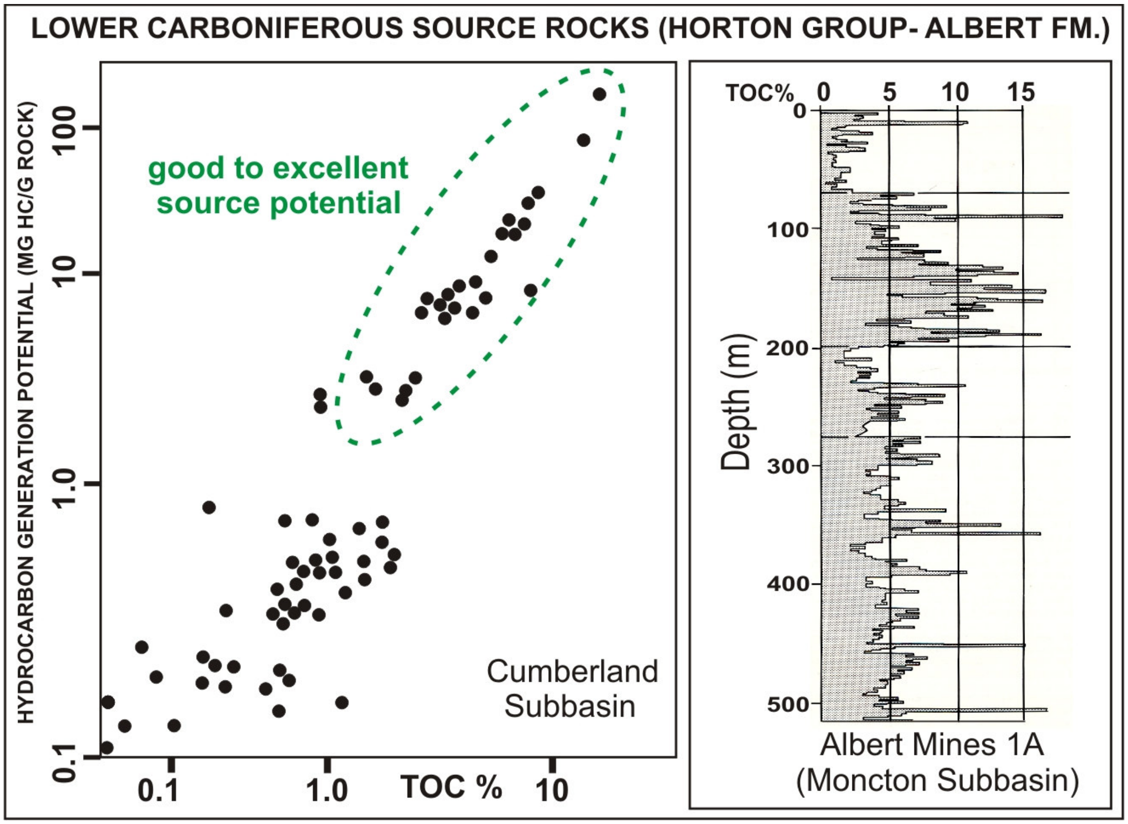


Figure 51. Geochemical data (TOC and hydrocarbon generation potential) for Lower Carboniferous shales in Cumberland Subbasin (left panel; adapted from Mossman, 1992) and Albert Mines 1A well, New Brunswick (right panel; adapted from MacCauley et al. 1985).

lacustrine shales occur in younger Mabou Group strata (Rocky Brook Formation) in the Deer Lake Basin, onshore Newfoundland (Hamblin et al. 1997).

Windsor Group carbonates and calcareous shales contain Type II and III organic matter with up to 5% TOC (Mossman, 1988). Although laterally extensive, Viséan marine limestones are relatively thin and are typically separated by sealing evaporitic strata, possibly limiting hydrocarbon-source capacity.

Thick, widespread coal-bearing successions (coal measures) in the Upper Carboniferous Cumberland and Pictou groups have significant hydrocarbon source potential (Gibling and Kalkreuth, 1991; Macauley and Ball 1984; Mukhopadhyay, 1991; Rehill, 1996). The coal measures consist of organic-rich coal seams and oil shales interbedded with organic-lean grey shales and sandstones. The coals and oil shales contain Type II and III organic matter, with TOC values up to 40% (Fig. 52). The predominance of Type III organic matter in most parts of the succession indicates the coal measures have major natural gas source potential. The coal measures are up to 2000 metres thick in the onshore Cumberland Subbasin and up to 5000 metres thick in the offshore central Magdalen Basin (Fig.53). In terms of thickness and areal distribution, the coal measures are the most abundant source rocks in the Maritimes Basin.

Source Rock Maturation and Hydrocarbon Migration

Regional surface maturation patterns and subsurface depth-maturation trends indicate significant variations in thermal maturation conditions and corresponding hydrocarbon generation potential of Carboniferous source rocks. The highest surface maturation levels occur in strata in onshore and basin margin areas of the Magdalen and Sydney basins (Fig. 54). In local areas, strata in close proximity to major fault systems typically have higher maturation levels than coeval strata located away from the fault zones. Significant lateral maturation changes can occur within a few kilometers. Subsurface depth-maturation trends from well data indicate that present-day oil and gas generation windows occur at depths from about 500 to 5000 metres depth, with the oil window floor (> 1.2 Ro %) at depths from about 1400 to 2000 metres (Fig. 55). These general maturation patterns indicate that natural gas will be the predominant hydrocarbon resource in the Maritimes Basin. However, significant variations occur in some areas/wells. As examples, below average depth-maturation trends occur in sub-salt strata in the Northumberland Strait F-25 well, and above average depth-maturation trends occur in sub-Mesozoic Carboniferous strata in the Hermine E-94 well in the

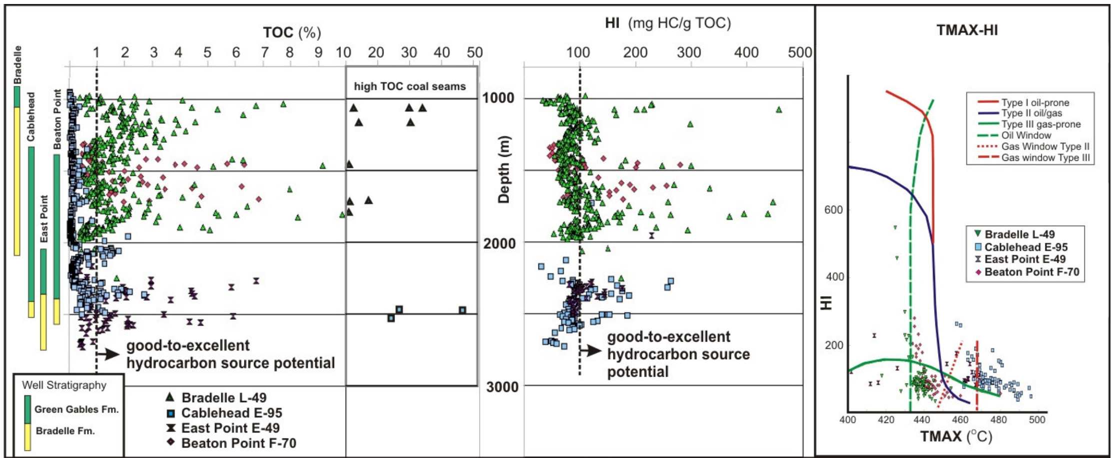


Figure 52. Geochemical Rockeval data (TOC, HI, TMAX) for samples from Upper Carboniferous strata in four Magdalen Basin wells (adapted from GSC Basin database), with annotated stratigraphy and source rock potential

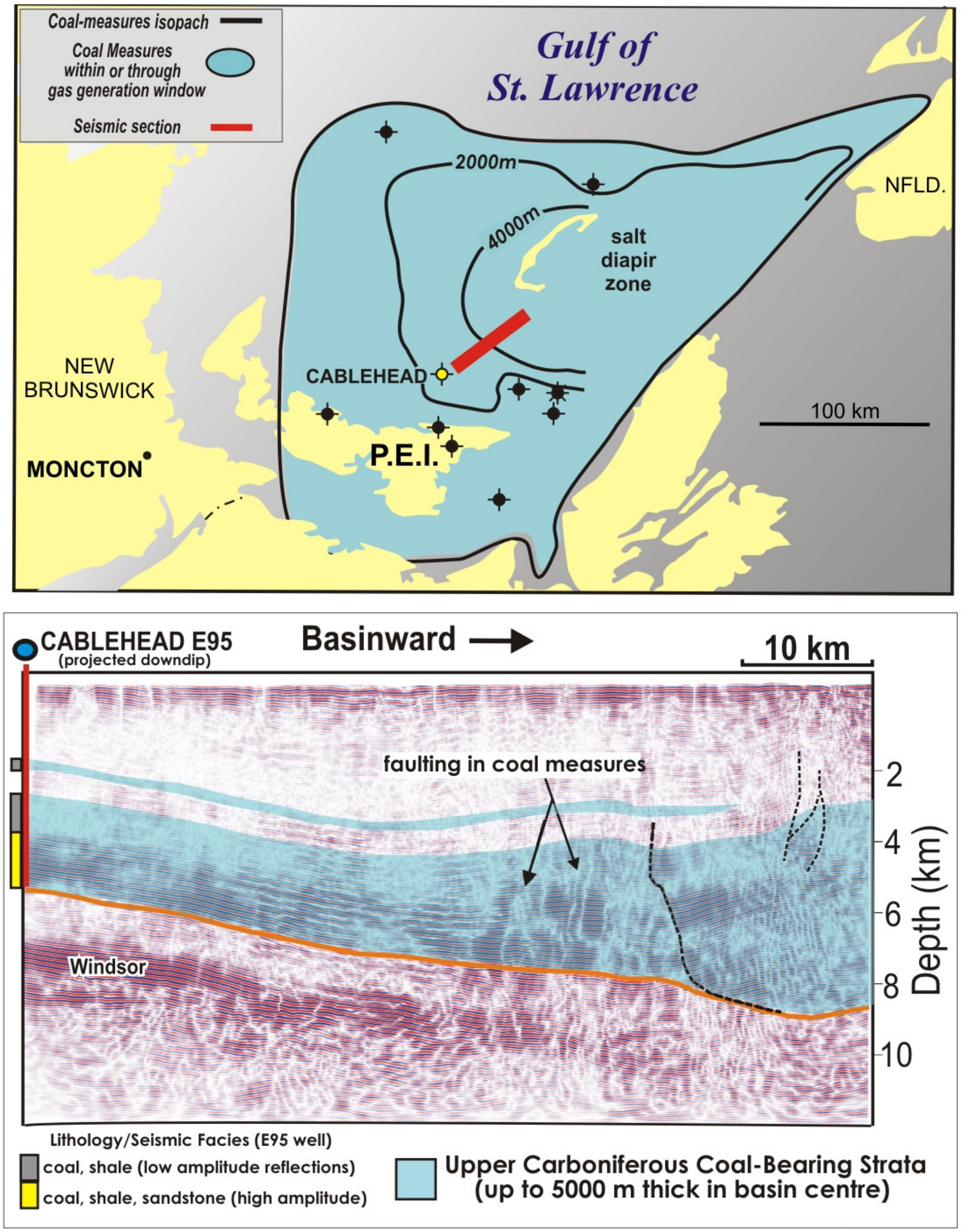


Figure 53. Isopach map and interpreted seismic section (tied to Cable Head E-95 well) illustrating distribution and thickness of Upper Carboniferous coal measures in offshore Magdalen Basin (map modified from Grant and Moir, 1992).

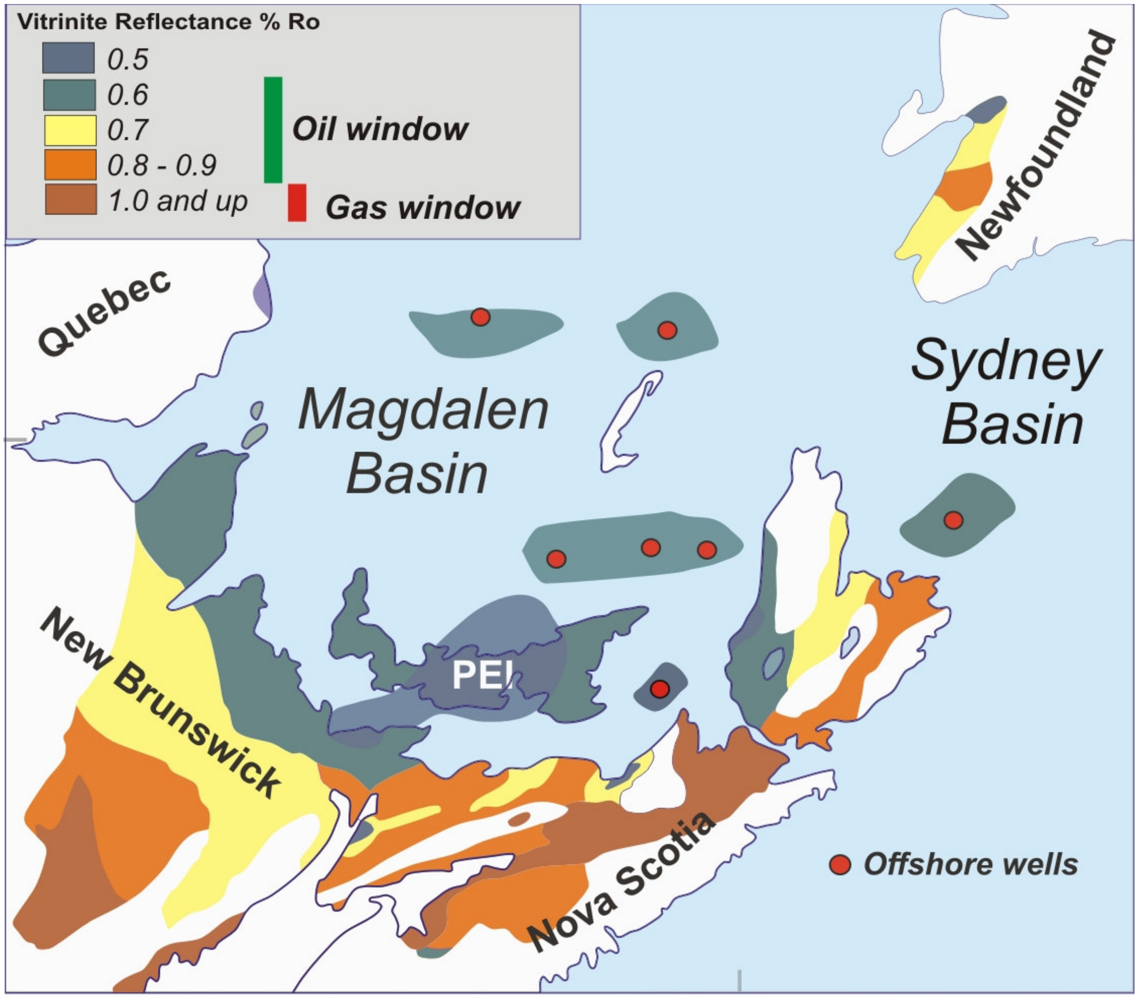


Figure 54. Thermal maturation levels (vitrinite reflectance data) for surface and near-surface Carboniferous strata in Magdalen and Sydney basins (modified from Ryan, 1993).

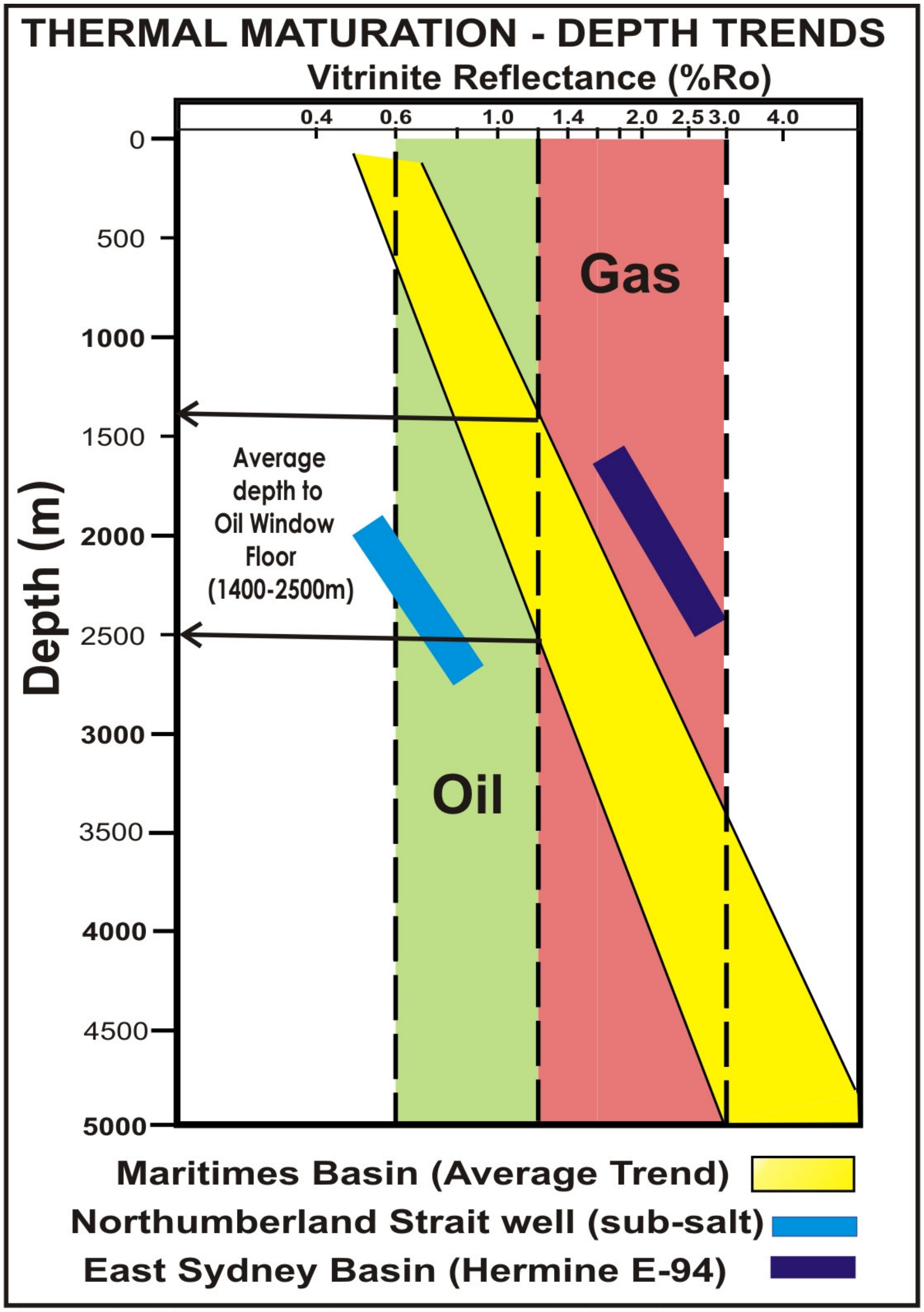


Figure 55. Maturation-depth trends of Carboniferous strata, illustrating ranges of vitrinite reflectance measurements from well samples (adapted from Grant and Moir, 1992, and Rehill,1996), oil and gas generation windows, and average depths to base of the oil window in the Magdalen Basin Anomalous depth-maturation trends include sub-salt strata in the Northumberland Strait F-25 well (adapted from Avery, 2009) and sub-Mesozoic Carboniferous strata in the Hermine E-94 well in eastern Sydney Basin (adapted from Maclean and Wade, 1992).

eastern Sydney Basin (Fig. 55). The below-average maturation in the sub-salt section in the Northumberland Strait well is likely due to the conductive properties of salt (Avery, 2009). Basin areas containing thick salt sections or large salt diapirs may have oil and gas generation windows extending to greater depths than known or inferred from existing data.

Most subsidence and thermal maturation models derived for the Maritimes Basin indicate that source-rock maturation and peak hydrocarbon generation occurred early in the basin's history, during the late Carboniferous to Permian (Fig. 56a; Ryan and Zentilli, 1993; Rehill 1996). One recent study indicates the possibility of a younger onset of hydrocarbon generation in parts of the Maritimes Basin, associated with a mid-Mesozoic heat flow anomaly (Fig. 56b; Wielens and Avery, 2009)). All maturation models indicate a period of post-Early Permian uplift and erosion of 1000 to 4000 metres of Maritimes Basin strata.

The migration of hydrocarbons generated from Maritimes Basin source rocks is poorly understood. The oil and gas accumulations in known discoveries seem to be constrained to reservoirs within or very close to the locally identified source interval, implying short-distance migration. No cases have yet been documented of shallow reservoir intervals containing hydrocarbons from deeply buried or distant source rocks.

Trap and Seals

The exploration risk associated with trap preservation reflects the relative timing of hydrocarbon generation (early) and basin uplift/erosion (late). Long-term preservation or sealing of early-charged hydrocarbon traps may be problematic. However, the known presence of several hydrocarbon accumulations in the basin attests to the local effectiveness of trap sealing. Windsor Group evaporites, including thick halite deposits, may be the most effective regional lithologic seals in the basin. Other regionally extensive seals include the thick shale intervals in the Upper Carboniferous Naufrage and Cable Head formations. In other parts of the succession, lacustrine and fluviatile sandstones are commonly interbedded with or grade laterally into shales that comprise potential seal units. The trap seals in the discovered fields (McCully, Stoney Creek and East Point) are associated with impermeable shales.

Known and Indicated Hydrocarbon Occurrences

Hydrocarbon generation in the Maritimes Basin is well substantiated by the discovered oil and gas fields, including the Horton shale-sourced oil and gas in the Stoney Creek and McCully fields and the coal measures-sourced gas in the East Point E-49 well. Surface and

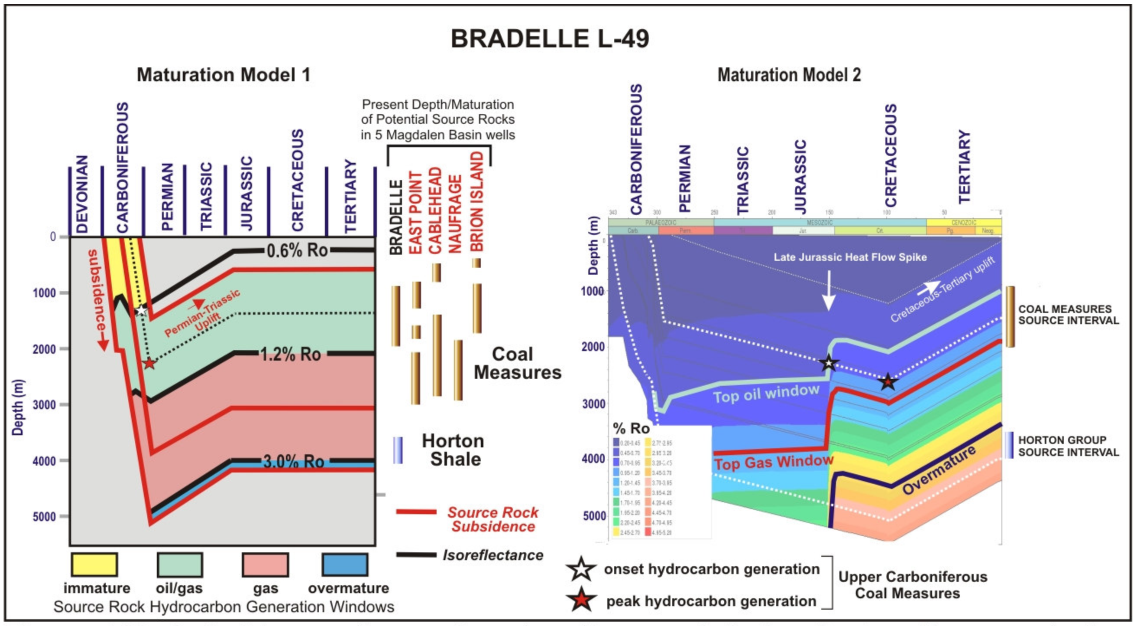


Figure 56. Subsidence-thermal maturation models for Carboniferous strata in the Bradelle L49 well (Model 1(left panel) adapted from Rehill,1996; Model 2 (right panel) adapted from Wielens and Avery, 2009). Peak hydrocarbon generation for coal measures occurs in the early Permian (model 1) or, alternatively, in the Cretaceous (model 2, which incorporates a Mesozoic heat flow anomaly). Both models show late stage uplift/erosion.

subsurface oil and gas shows are common in the basin. Solid bitumen and oil have been encountered in base-metal and salt exploration, both in fractures and rock porosity. Windsor Group carbonate rocks in outcrop, cores and in mine workings are commonly petroliferous. Natural gas has been encountered in many exploration wells drilled through Windsor Group strata, including the Alton 87-1 well in Nova Scotia (Fig. 41) which flowed gas at a rate of 3750 ft^3/day from a 12 metre thick basal anhydrite and/or fractured dolomite unit (Harvey, 2009). The generation of natural gas from coal measures is documented by the numerous mud-log gas shows in exploration wells drilled through coal measures sections (Fig. 57). Most petroleum exploration wells in the Maritimes Basin encountered well-log indications of hydrocarbon zones (see example in Fig. 58). Possible hydrocarbon indicators are apparent in many seismic reflection profiles in the basin. The most common seismic hydrocarbon indictors are reflection bright spots and flat spots (Fig.59).

PETROLEUM EXPLORATION PLAYS

Three major regional petroleum plays are documented by the petroleum-system framework of the Maritimes Basin: a Lower Carboniferous (Tournaisian - Viséan) clastic play, a Lower Carboniferous (Viséan) carbonate play, and an Upper Carboniferous (Namurian - Early Permian) clastic play. The two clastic plays have been mapped in sufficient detail to provide the petroleum data needed for quantitative resource assessments. The carbonate play is the least well known in terms of area and numbers and sizes of prospect, and is only assessed qualitatively in this study. The main exploration risks of reservoir quality and trap-seal preservation are common to all plays.

Lower Carboniferous Clastic Play

The Lower Carboniferous clastic pay includes all Horton, Windsor and Mabou group strata deposited in fault-bounded extensional or strike-slip subbasins (Fig. 44). Most of the play area is represented by the Tournaisian Horton and Anguille groups (and equivalent strata) which contain both source and reservoir rocks. The play locally includes younger clastic strata such as the Viséan Deer Lake Group in the fault-bounded Deer Lake Basin in Newfoundland.

The most extensively explored part of the play is the Moncton Subbasin onshore New Brunswick (Figs. 60, 61). The Moncton Subbasin contains two producing fields (Stoney Creek and McCully) and several oil and gas discoveries. In detail, the Moncton Subbasin consists of a series of linked, fault-bounded depocentres, locally characterized by complex

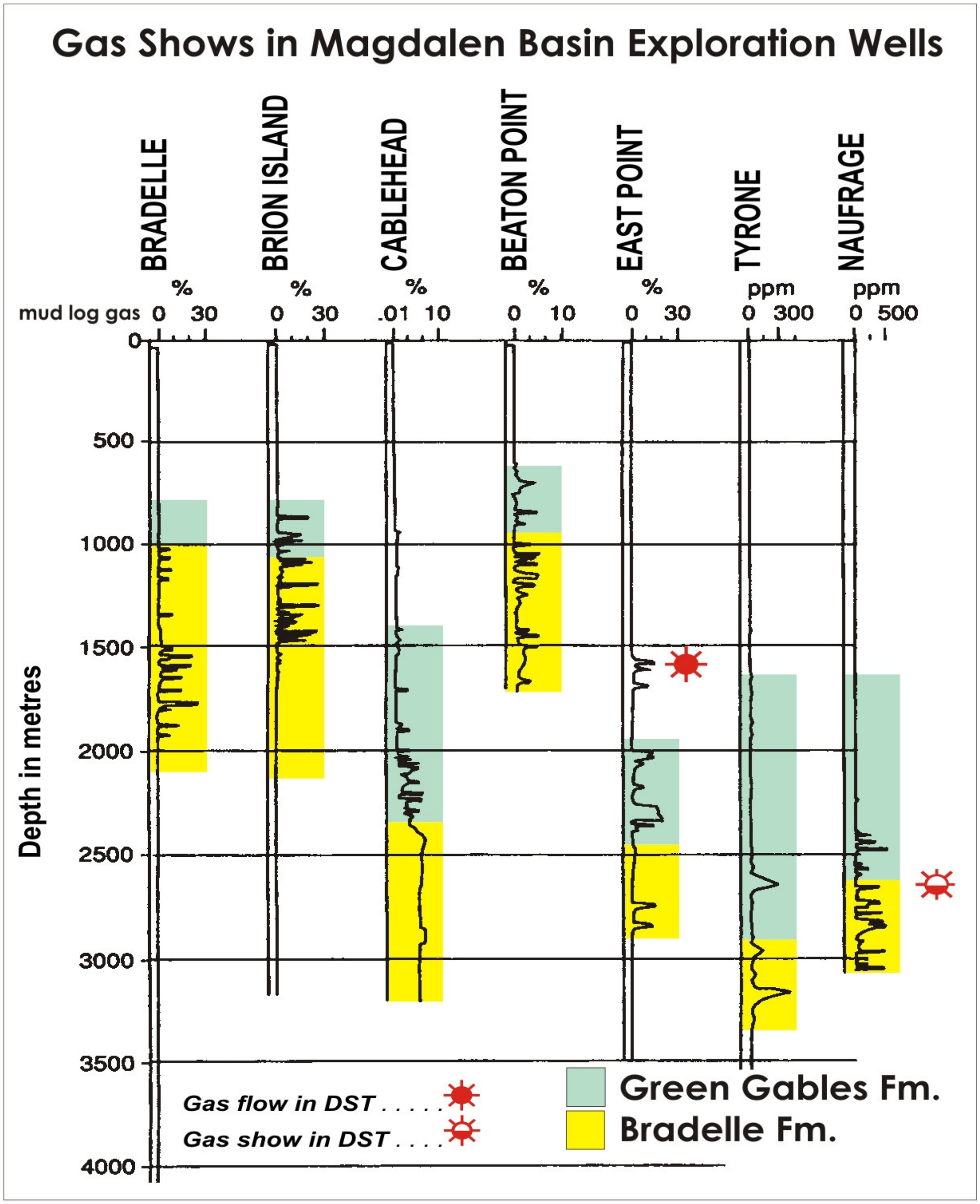


Figure 57. Gas shows (mud-log gas volumes) encountered in Upper Carboniferous strata in 7 Magdalen Basin wells, with annotated stratigraphy and DST gas recoveries (adapted from Grant and Moir, 1992).

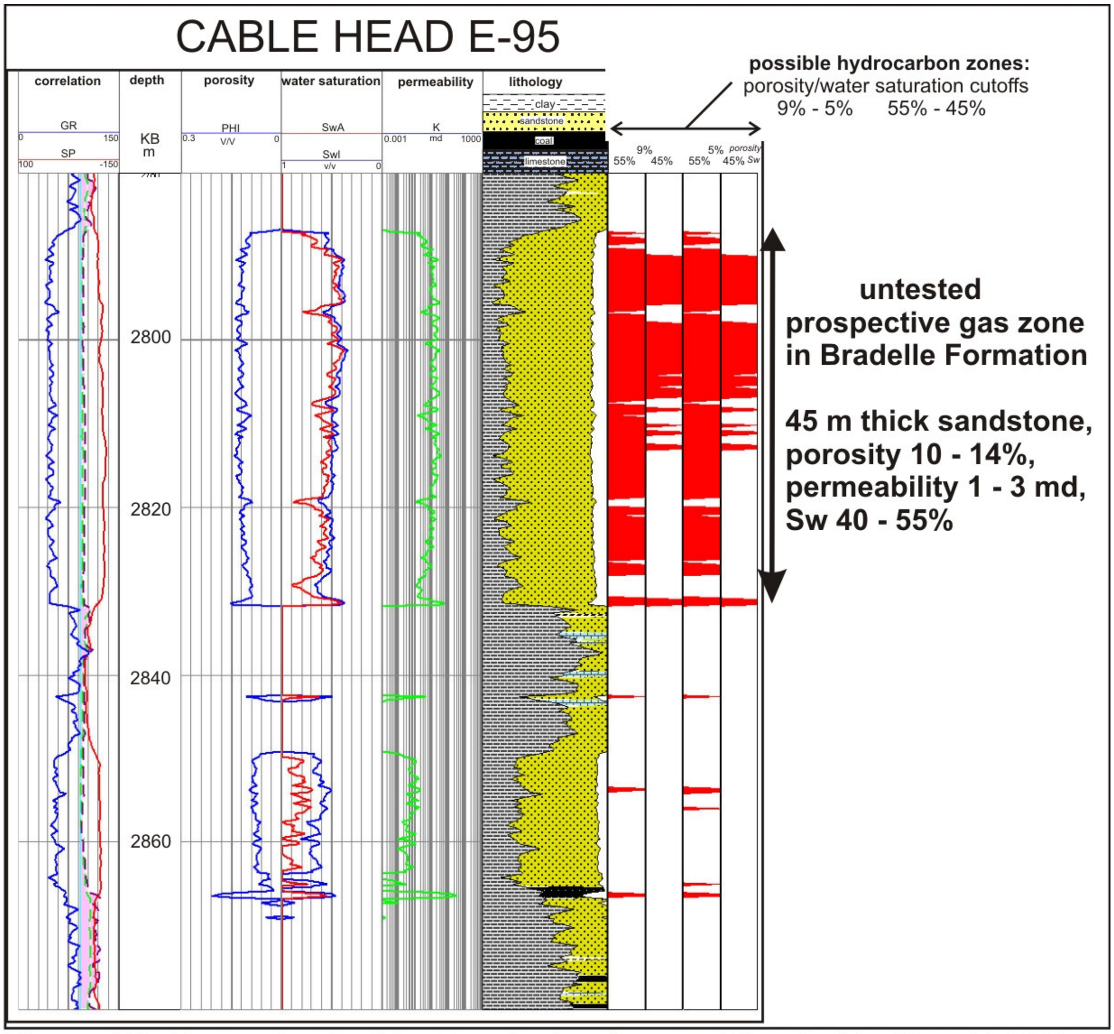


Figure 58. Petrophysical log analysis of part of the Cable Head E-95 well, illustrating a potential (untested) hydrocarbon zone in a 45 metre thick sandstone in the Upper Carboniferous Bradelle Formation (adapted from Hu and Dietrich, 2008).

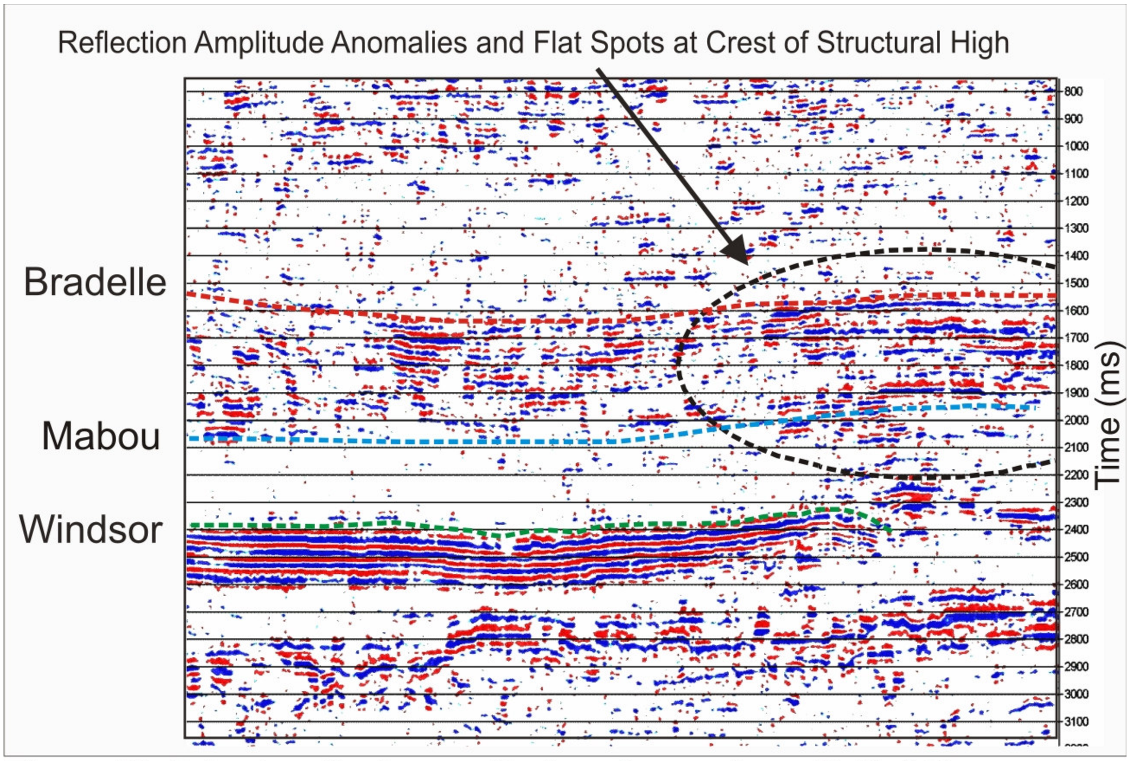


Figure 59. Seismic reflection profile from the southern Gulf of St. Lawrence, illustrating possible seismic hydrocarbon indicators (reflection bright spots and flat spots) in the Upper Carboniferous Bradelle Formation.

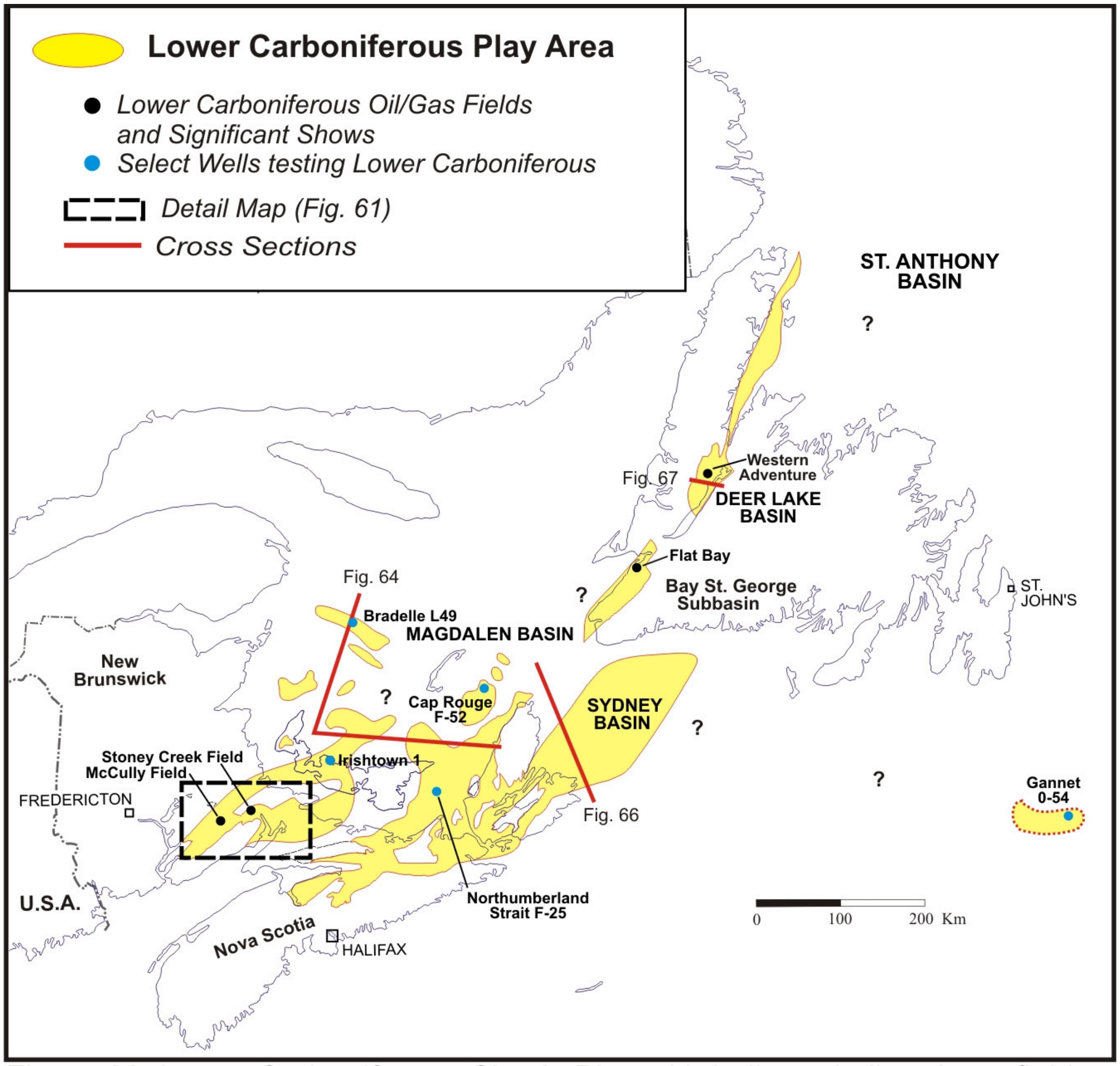


Figure 60. Lower Carboniferous Clastic Play with indicated oil and gas fields and key wells, regional cross-sections (Figs. 64,66,67), and onshore Moncton Subbasin detail map area (Fig. 61).

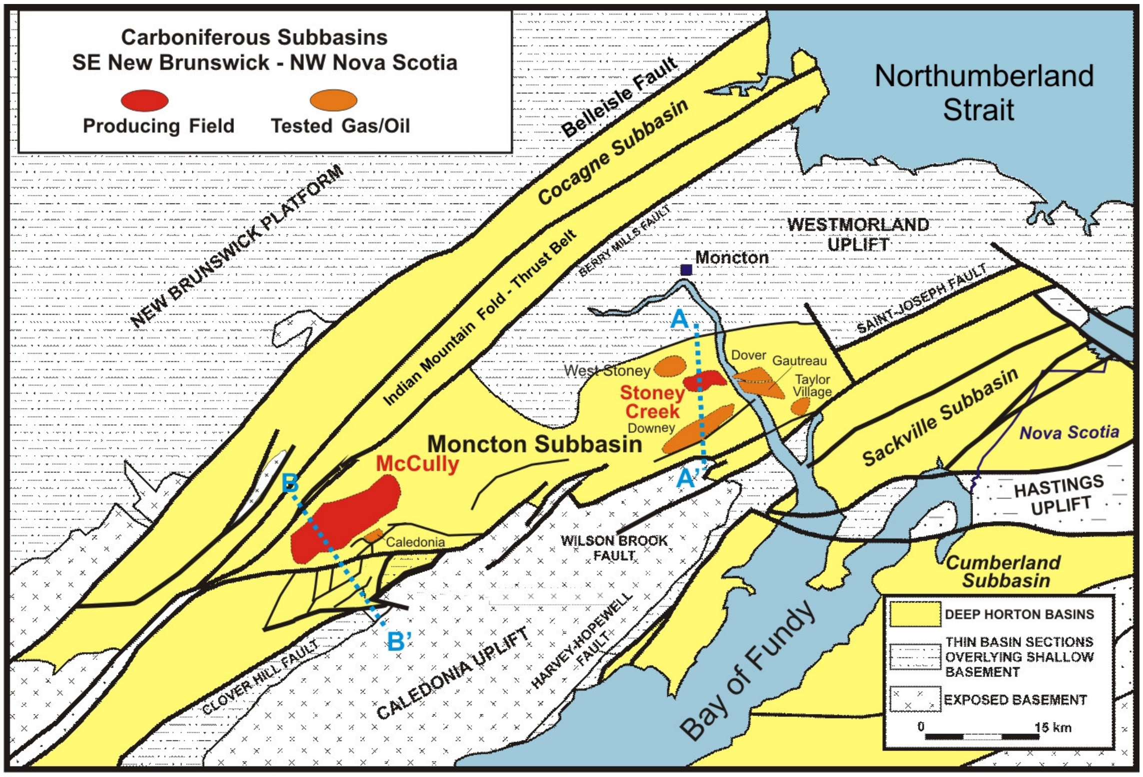


Figure 61. Lower Carboniferous subbasins in southeast New Brunswick and northwest Nova Scotia, with indicated producing oil and gas fields, and structures with tested oil or gas in one or more wells (base map modified from Wilson and White, 2006). Stoney Creek and McCully field cross-sections (A-A' and B-B') illustrated in Figure 62.

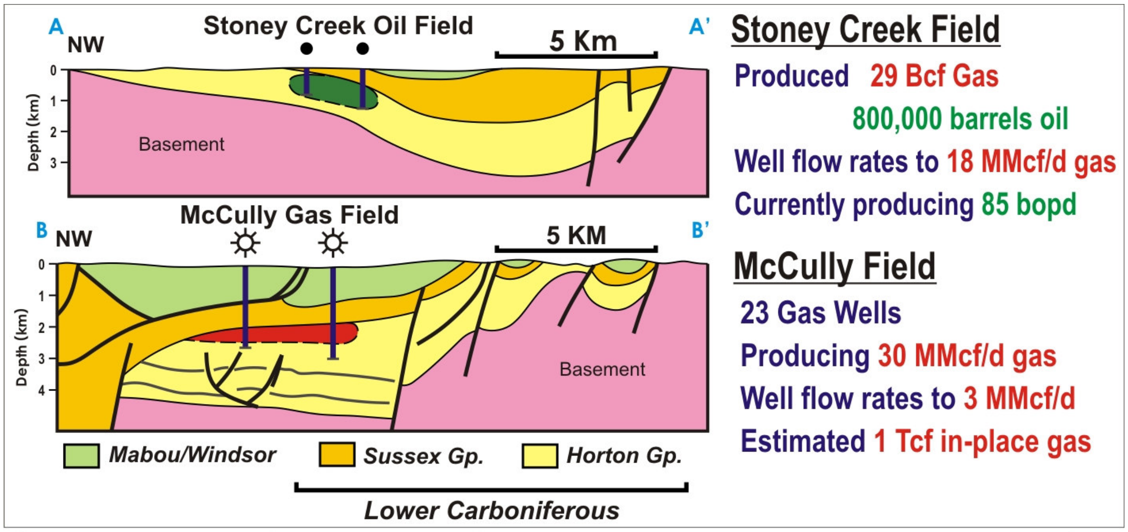


Figure 62. Geological cross-sections across Stoney Creek and McCully oil and gas fields, with indicated field and well production data (section locations in Fig. 61; modified from Fyffe and St. Peter, 2006). Oil and gas reservoirs occur in Lower Carboniferous (Horton Group) sandstones in structural-stratigraphic traps. Detailed reservoir cross-section of the McCully Field illustrated in Figure 63.

depositional and structural patterns. Oil and gas in the Stoney Creek and McCully fields is trapped in upper Horton Group (Albert Formation) sandstones, with source rocks in the underlying (Frederick Brook Formation) shales (Fig 62). Both fields have significant stratigraphic components to hydrocarbon trapping - an updip facies pinchout in the Stoney Creek Field (Fig. 62) and an unconformity in the McCully Field (Figs. 62, 63)

The Lower Carboniferous subbasin play extends over large parts of the Magdalen and Sydney basins (Fig. 60). Common structural prospect types include fold and fault-block traps, often associated with inversion tectonics (Figs. 62, 64, 65). Outside of the Moncton Subbasin, key exploration tests of the Lower Carboniferous Play include the Bradelle well (inversion fold) and the Cap Rouge and Northumberland Strait wells (sub-salt prospects) (Figs. 60, 64). In the offshore Sydney Basin, Lower Carboniferous subbasins have been seismically mapped, but none have yet been tested (Fig. 66; Pascucci et al., 2000). The play extends into the Deer Lake Basin and Bay St. George and White Bay Subbasins in Newfoundland. This part of the play area contains two significant (as yet undeveloped) petroleum accumulations: the Western Adventure Gas Field and the Flat Bay oil show (Figs, 60, 67). Lower Carboniferous fault subbasins have not been identified from seismic data in the offshore St Anthony or eastern Sydney basins (Fig. 60). The only confirmed occurrence of Horton Group strata in these easternmost offshore areas is in the Gannett 0-54 well (Figs. 41, 60). Seismic data studies indicate Carboniferous strata in this well is likely an isolated erosional remnant beneath a thick Mesozoic-Tertiary continental margin basin (Newfoundland Department of Mines and Energy, 2000)

Lower Carboniferous Carbonate Play

The Lower Carboniferous Carbonate Play includes all marine carbonate rocks in the Viséan Windsor Group and equivalent strata (Fig. 44). This play has received little attention from the petroleum industry in spite of proven hydrocarbon reservoir capability for both gas (Alton well) and oil (Malagawatch and Jubilee surface occurrences) in Nova Scotia. Windsor Group platform and basinal carbonates are laterally continuous but typically thin (<10m). More prospective are the biohermal facies (reefs) of the basal Windsor Group. Many Windsor bioherms are known in surface occurrences around the margins of the Magdalen Basin. A type model for the bioherm play has been developed from onshore occurrences in Nova Scotia (Figs. 68, 69). In this area, the Gays River Formation bioherms are flanked by and in some cases overlain by thick evaporites which may provide an effective seal for oil or gas traps. The biohermal facies pass laterally and downslope into thin carbonates (the Macumber

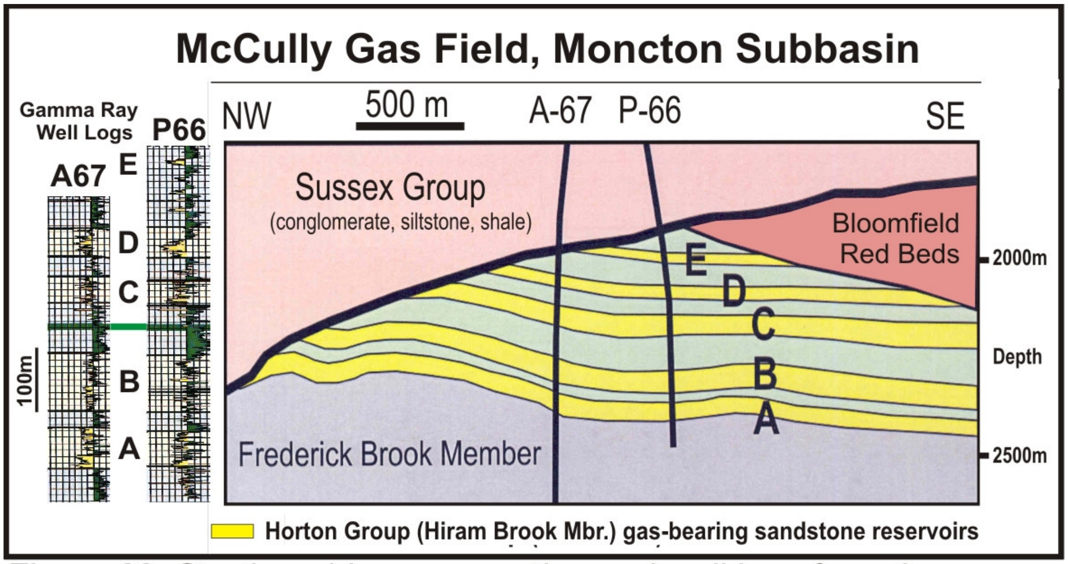


Figure 63. Stratigraphic cross-section and well logs from the McCully Gas Field, illustrating the field's multi-zone reservoirs (sandstone units A to E), and the structural and stratigraphic components of the gas trap (from Corridor Resources, 2009). Hydrocarbon source rocks (lacustrine shales) occur in the Frederick Brook unit.

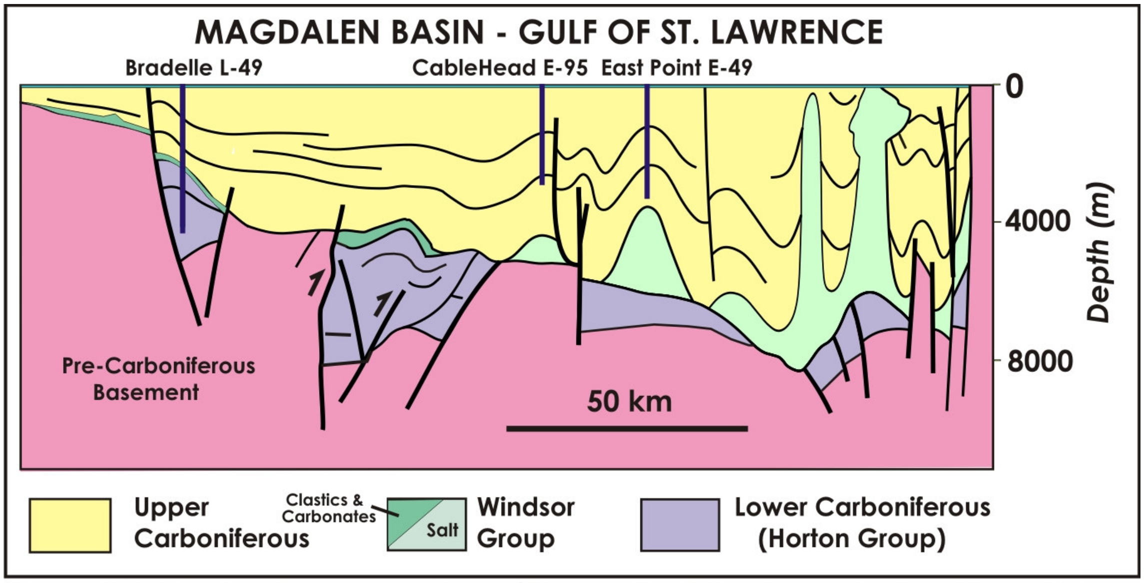


Figure 64. Regional cross-section of the central Magdalen Basin with well ties, illustrating major stratigraphic packages and structure types, including inverted Lower Carboniferous subbasins, salt diapirs and basin-margin fault zones (section location in Fig. 60)

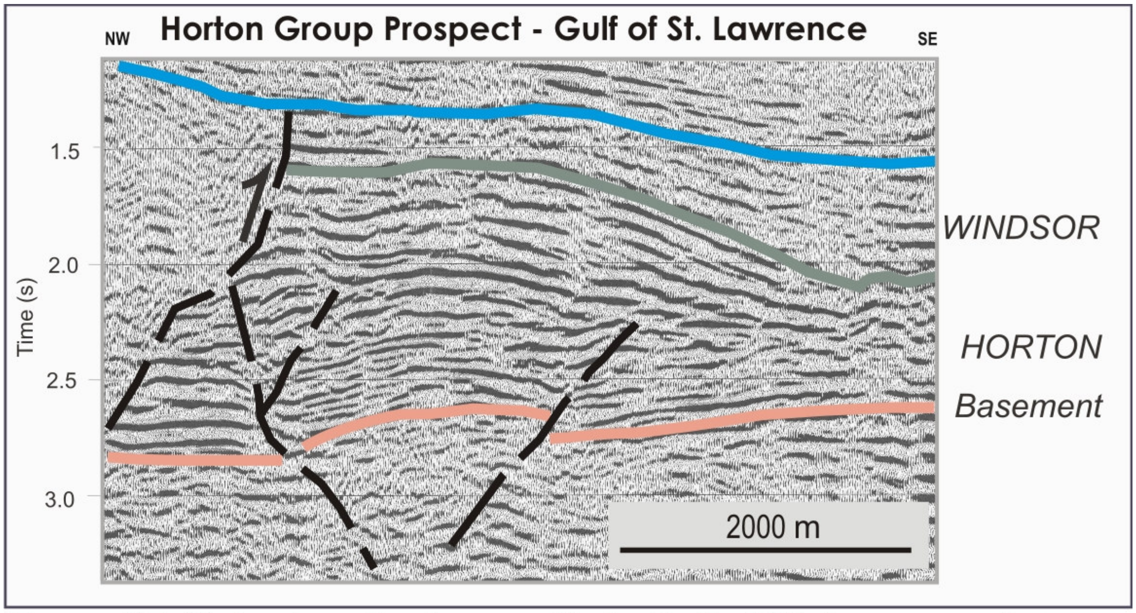


Figure 65. Seismic reflection profile in Gulf of St. Lawrence (near section in Fig. 64) illustrating undrilled faulted anticline prospect in Lower Carboniferous strata.

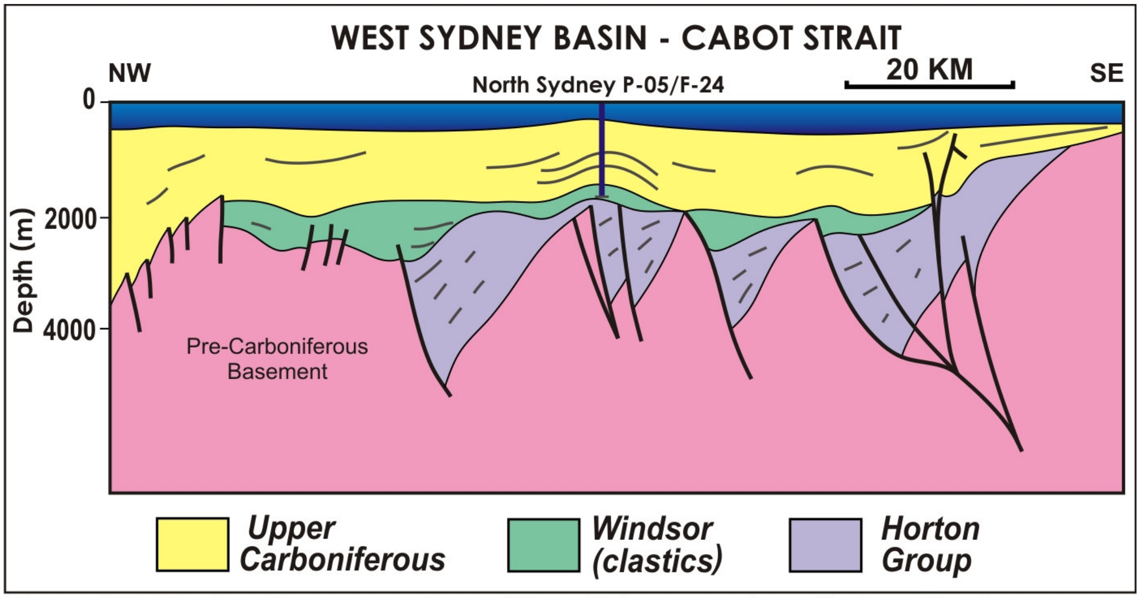


Figure 66. Regional cross-section of the offshore western Sydney Basin, illustrating undrilled Lower Carboniferous subbasins and the Upper Carboniferous anticlinal structure tested by the North Sydney wells (section location in Fig. 60) (modified from Pascucci et al. 2000).

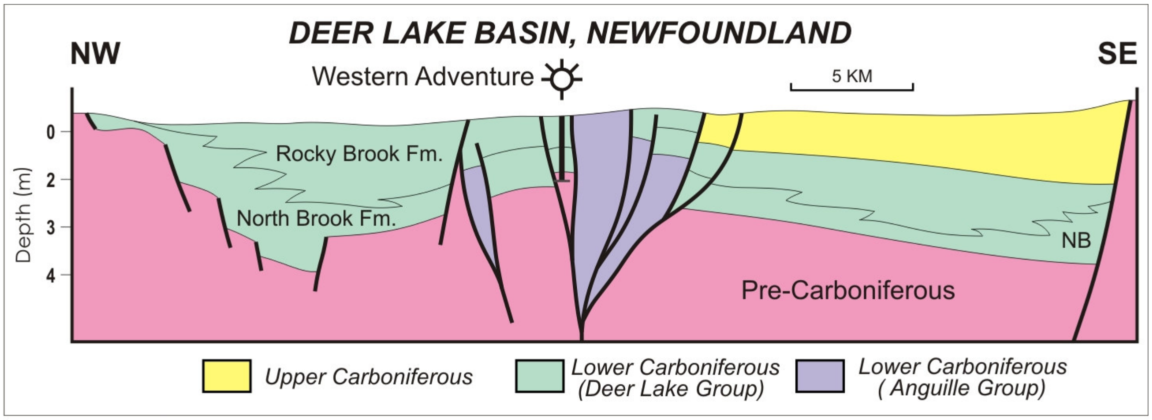


Figure 67. Cross-section of the Deer Lake Basin (Newfoundland), illustrating major stratigraphic units and structures, including a central fault-inversion high (section location in Fig. 60). The Western Adventure well encountered gas in sandstones in the Lower Carboniferous Deer Lake Group (North Brook formation) in a fault-block trap within the central uplift (modified from Hamblin et al. 1997).

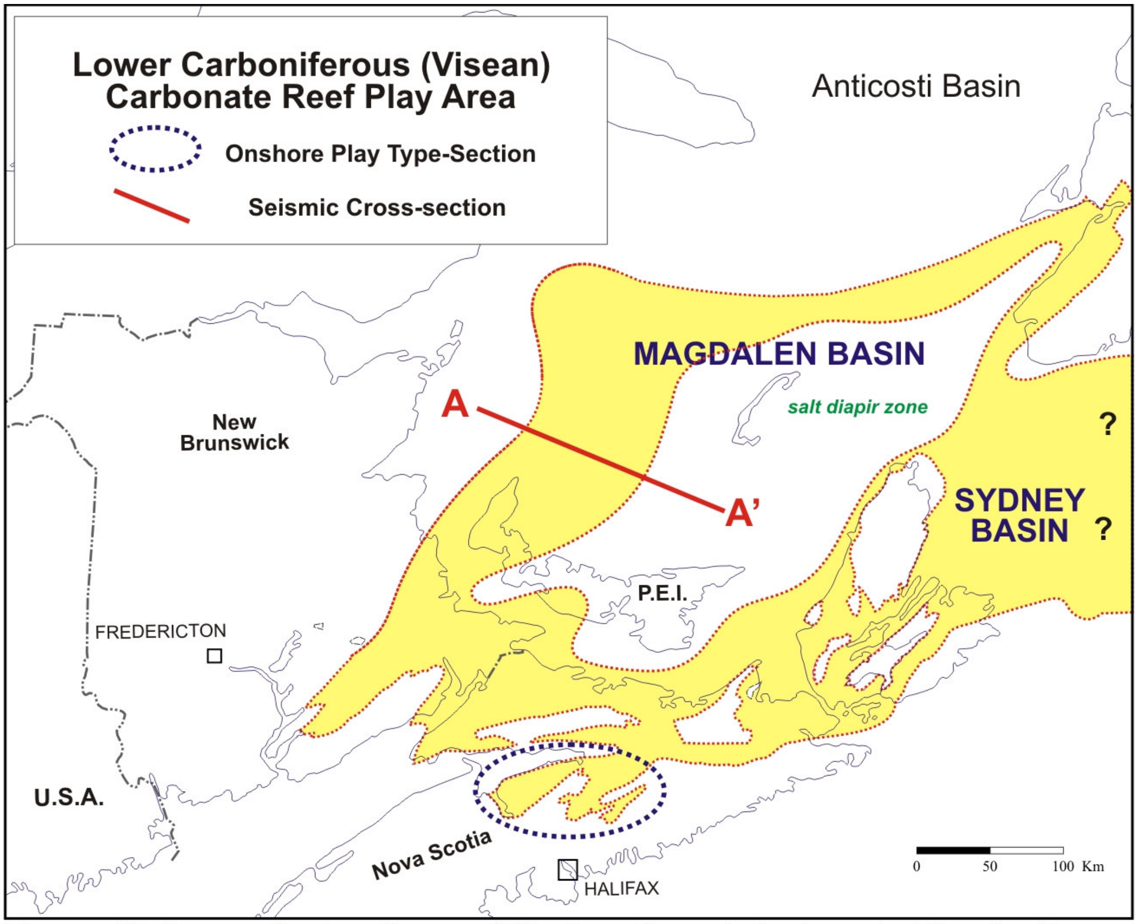


Figure 68. Lower Carboniferous (Windsor Group) Carbonate Play for the Magdalen and Sydney basins, with indicated locations of onshore play type-section (Fig. 69) and offshore seismic cross-section (Fig. 70)

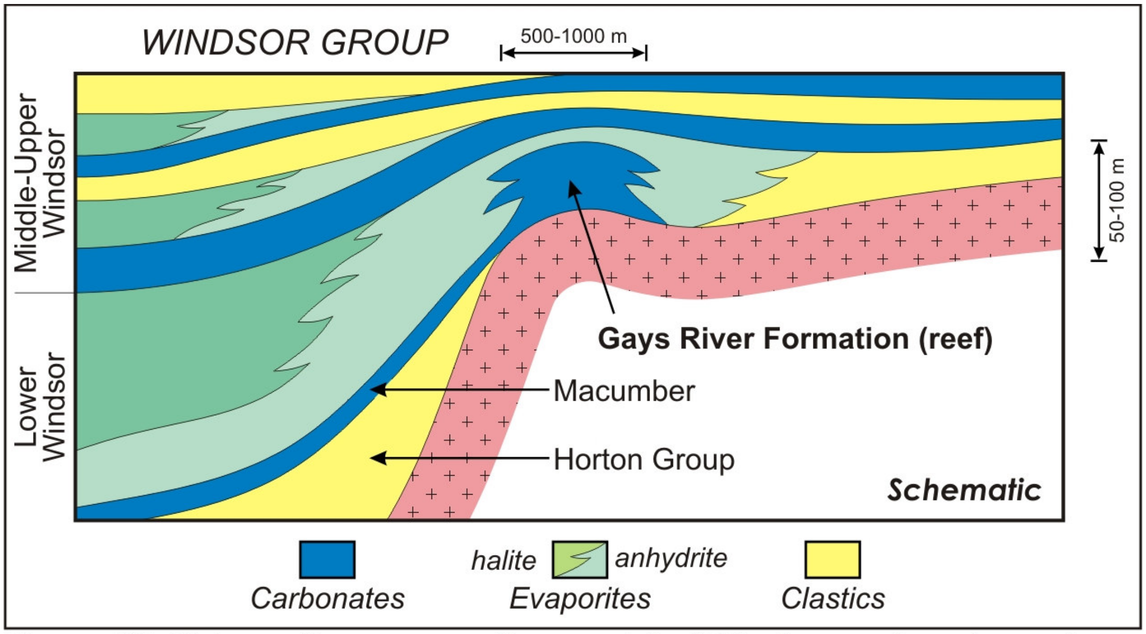


Figure 69. Schematic cross-section model of Windsor carbonate reef play (Gays River Formation) onshore Nova Scotia (modified from Savard and Chi,1998).

Formation) and overlying evaporites. Potential source rocks include organic-rich basinal Windsor carbonates or underlying Horton Group shales. Known surface bioherms are typically several hundreds of meters in diameter and tens of meters in thickness. Exploration drilling has outlined subsurface biohermal complexes of up to 5 km strike-length and 2 km width.

Based on paleogeographic models and seismic reflection data interpretations, the western side of the Magdalen Basin in the Gulf of St. Lawrence should contain a significant band of Windsor Group carbonate rocks, extending from New Brunswick to southwestern Newfoundland (Figs. 68, 70). The distribution of these carbonate rocks will follow the paleogeographic shallow-water limits of the earliest portion of the marine basin fill. The reef trend in plan view may be quite complex. The exploration challenge will be to recognize the 'reef belt' with seismic data, between its updip limits where continental clastics replace the carbonate-evaporite succession, and the deeper water setting where biohermal facies pass downslope to basinal carbonate and evaporite facies. The biohermal play may extend into the offshore Sydney Basin.

Upper Carboniferous Clastic Play

The Upper Carboniferous Play includes all clastic reservoirs in the Namurian to early Permian Cumberland and Pictou groups (Fig. 44). The play extends across most of the Maritimes Basin, encompassing an area that is the largest of the three Carboniferous plays (Fig. 71). Primary reservoir intervals include thick, multi-storied fluvial sandstones in the Bradelle and Cable Head formations and equivalent strata in onshore mainland basin areas. Source rocks include coal measures (primary) and underlying Windsor carbonates or Horton Group shales (secondary). Shales both above and adjacent to the reservoir sections provide the seals. Windsor Group evaporites may provide seals in salt-structure play areas.

The primary trap types in the Upper Carboniferous Play are associated with salt structures, including salt-withdrawal anticlines, salt pillows and diapirs (drape and onlap prospects) and salt overhangs (sub-salt prospects) (Figs. 72 to 74). The eastern Magdalen Basin contains hundreds of salt structures, of varying sizes and shapes. The largest single salt structure mapped in detail is the 200 km^2 Old Harry prospect in the northern part of the Magdalen Basin (Figs. 72, 74). Salt structures are also widespread in the northern and eastern Sydney basins and the St. Anthony Basin (Figs. 72, 75). Salt-structure prospects in the eastern parts of the Sydney and St. Anthony basins are overlain by thick sections of Mesozoic-Cenozoic sedimentary strata of the Atlantic continental margin (Figs. 72, 76). Other structural

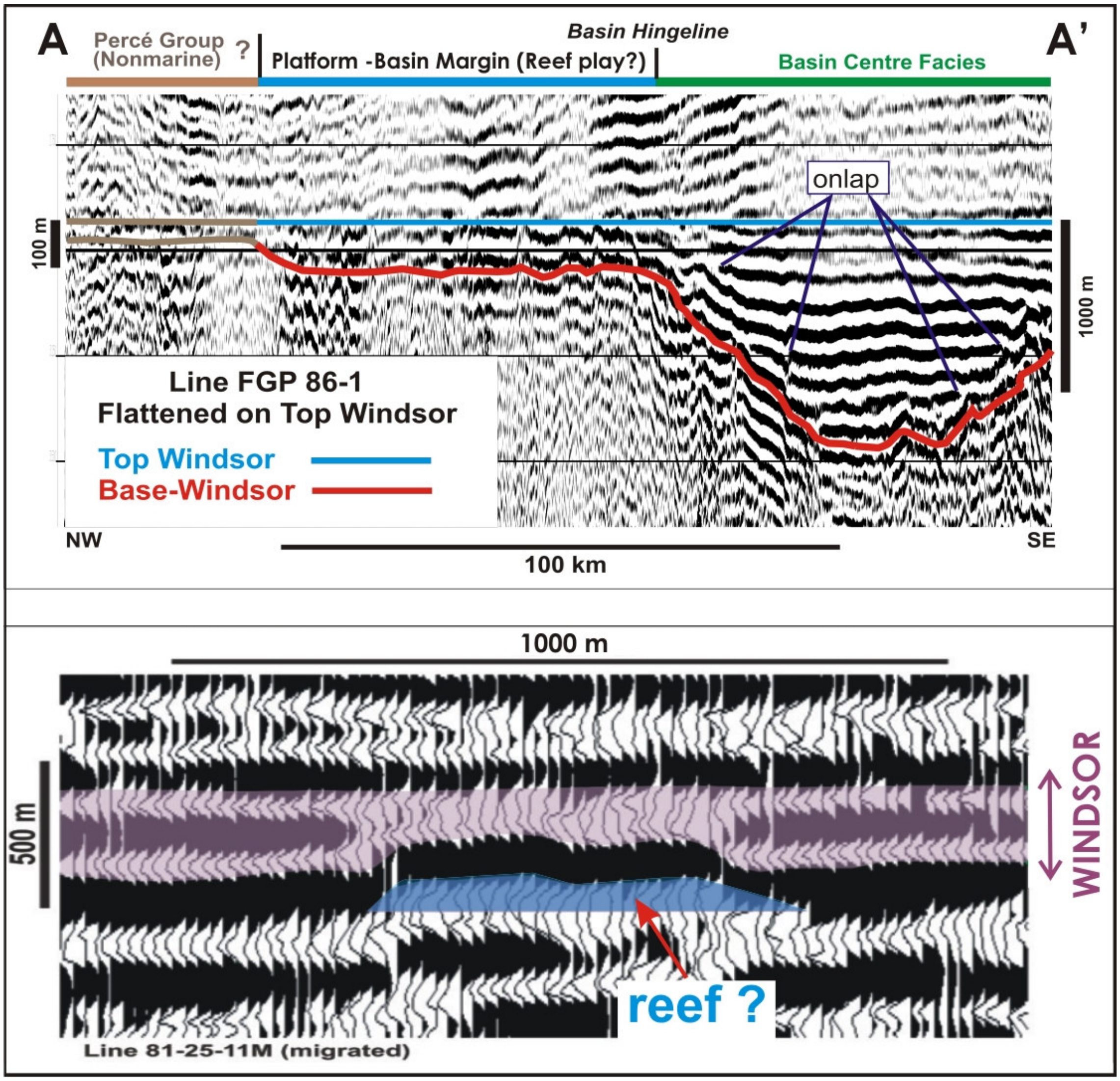


Figure 70. Regional seismic reflection profile (top panel) flattened on top Windsor Group, illustrating interpreted depositional facies belts in Visean Windsor Group, including prospective reef fairway in platform-basin margin (section location A-A' in Fig. 68). Detailed seismic section (bottom panel) from same area illustrates an intra-Windsor seismic anomaly interpreted as a possible reef.

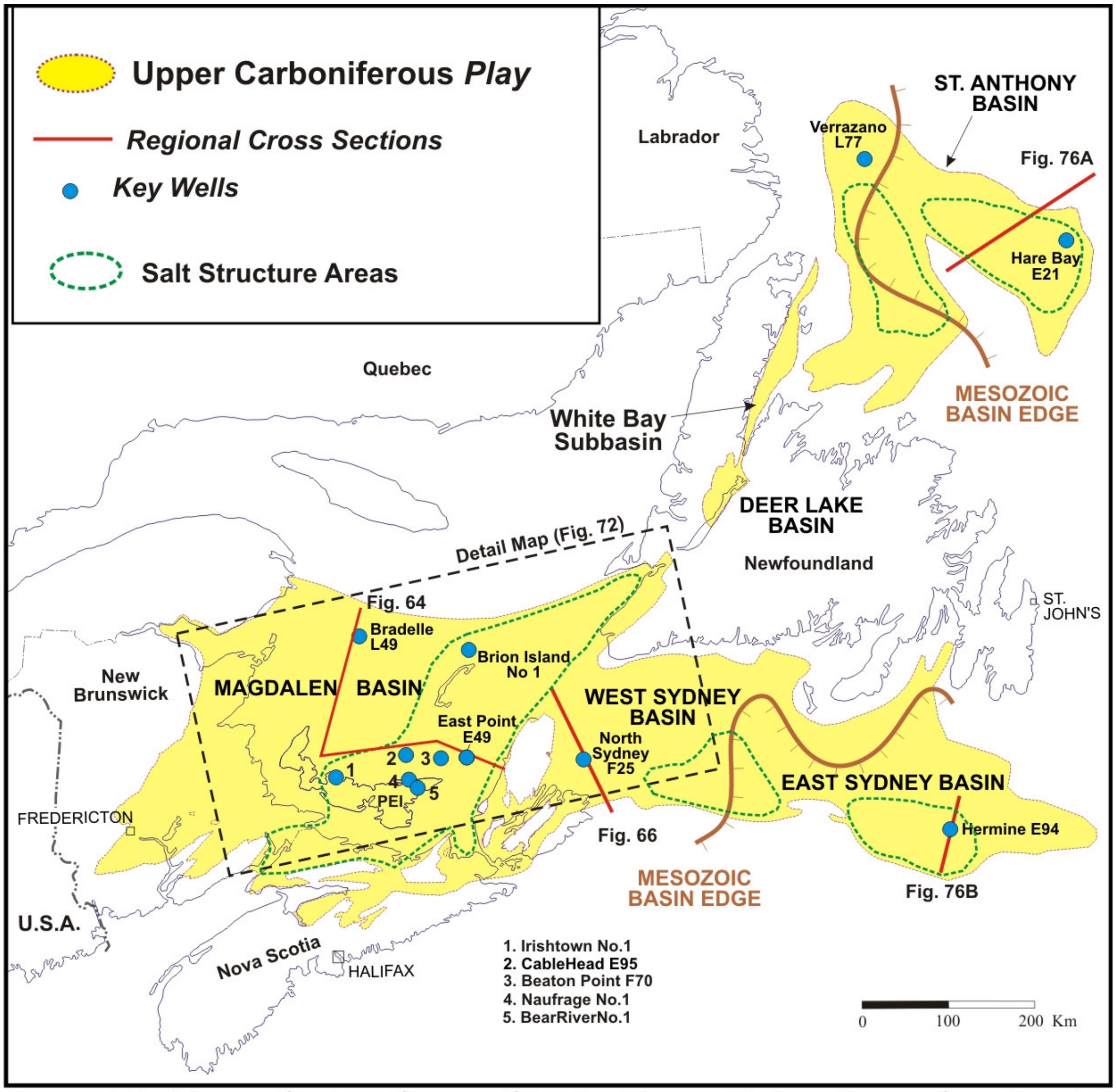


Figure 71. Upper Carboniferous Clastic Play, with locations of regional cross-sections (Figs 64, 66, 76a,b), select wells, detail map (Fig. 72), salt structure areas, and western limits of Mesozoic-Cenozoic sedimentary basins.

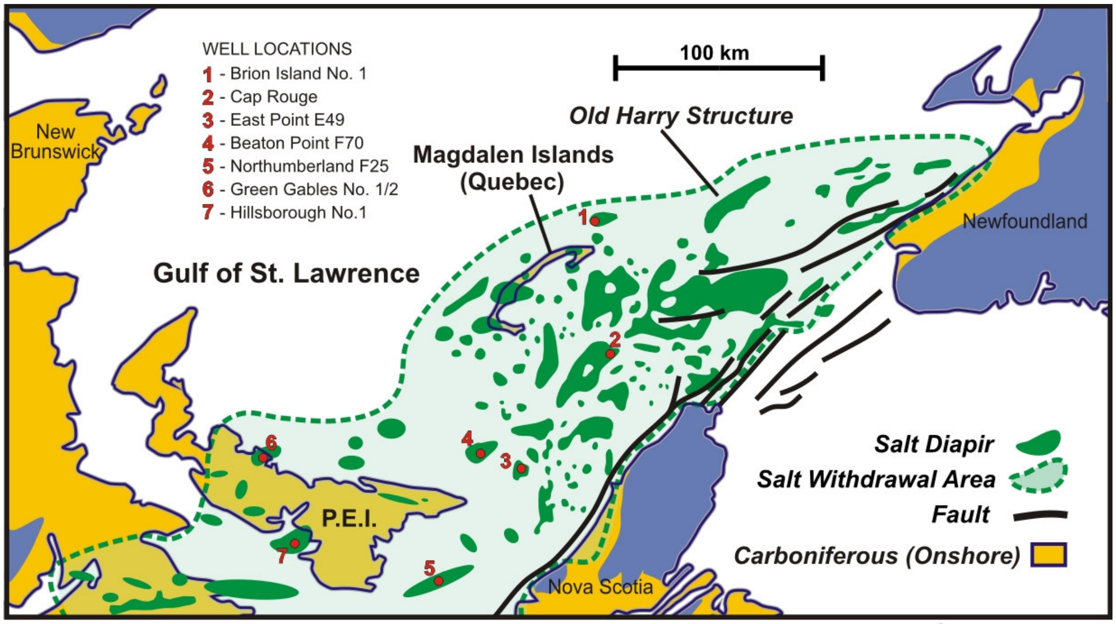


Figure 72. Magdalen Basin salt-diapir zone, with locations of mapped salt structures, salt-withdrawal area, and key wells that tested salt structures (compiled from Hayward et al., 2005, Durling and Martel, 2004, and Langdan and Hall, 1994). A salt basin cross-section and seismically-imaged salt structure examples are shown in Figures 73 and 74.

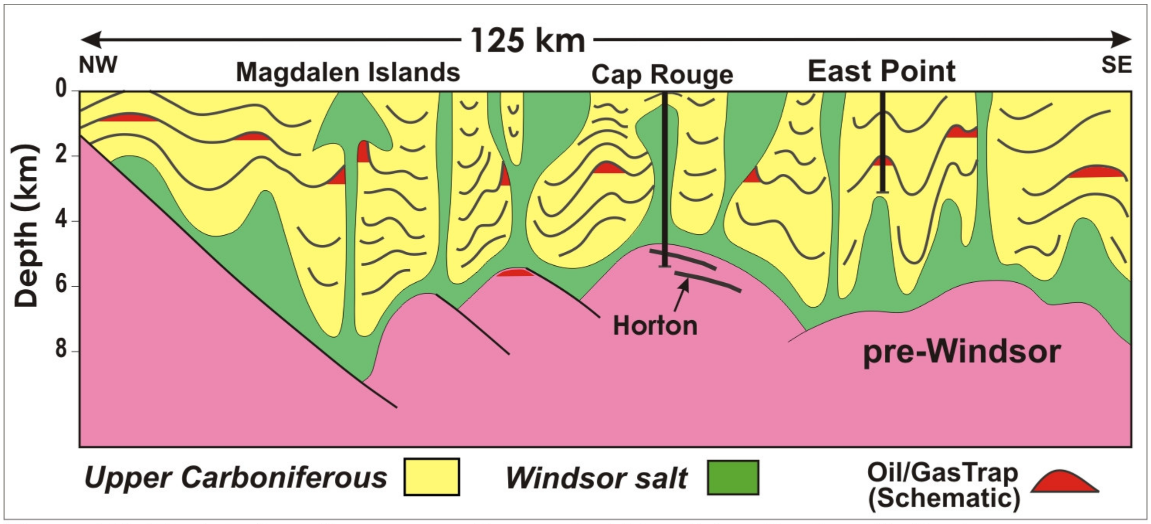


Figure 73. Regional section across the central Magdalen Basin salt-diapir zone, illustrating varied salt-structure sizes and shapes and highly irregular sub-Windsor basement topography. Potential hydrocarbon traps include salt-withdrawal anticlines, drape over salt pillows and diapirs, onlap onto salt-structure flanks, minibasin turtle structures, and shallow and deep subsalt features (modified from Durling and Martel, 2005).

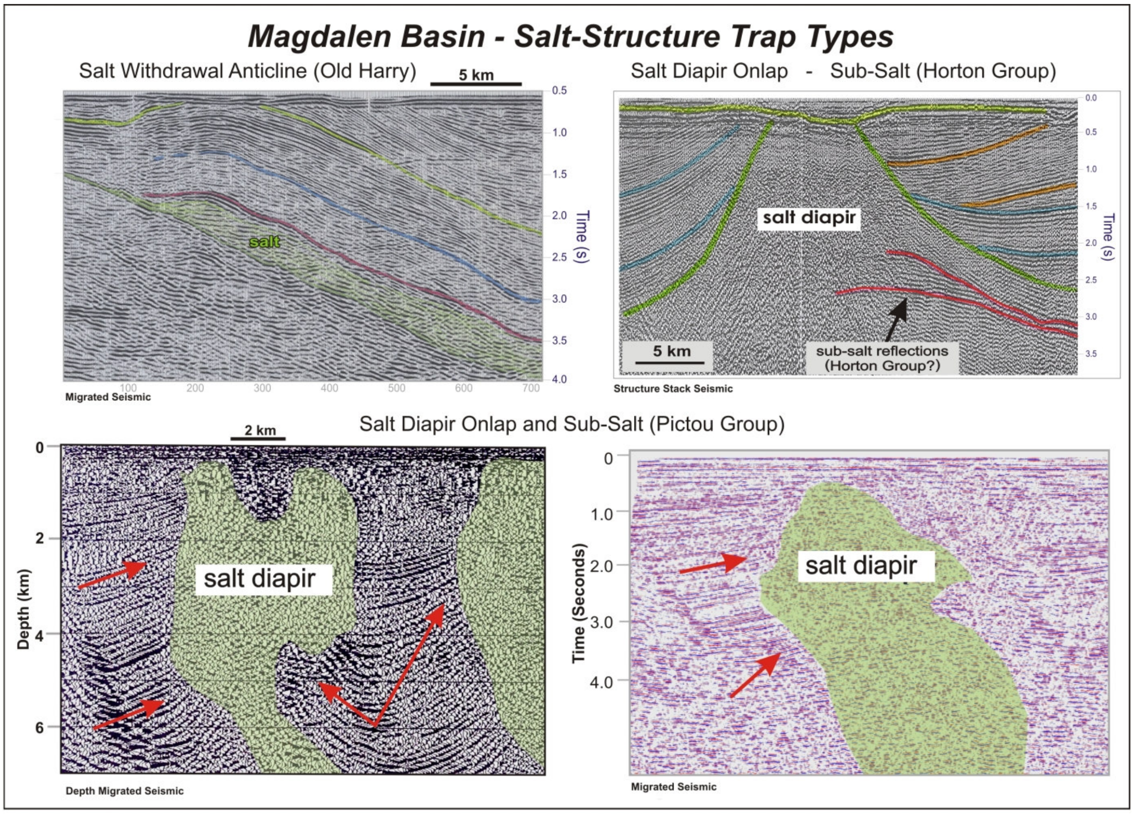


Figure 74. Seismic reflection profiles illustrating examples of salt structures and prospect types in the offshore Magdalen Basin. Top left panel illustrates the Old Harry Structure, a large salt-withdrawal anticline. Top right panel illustrates a large piercement salt diapir with onlap and deep subsalt (Horton) prospects. Two bottom panels are migrated sections illustrating potential for salt flank and sub-salt prospects in Upper Carboniferous strata (bottom left figure adapted from Lines et. al. 1995)

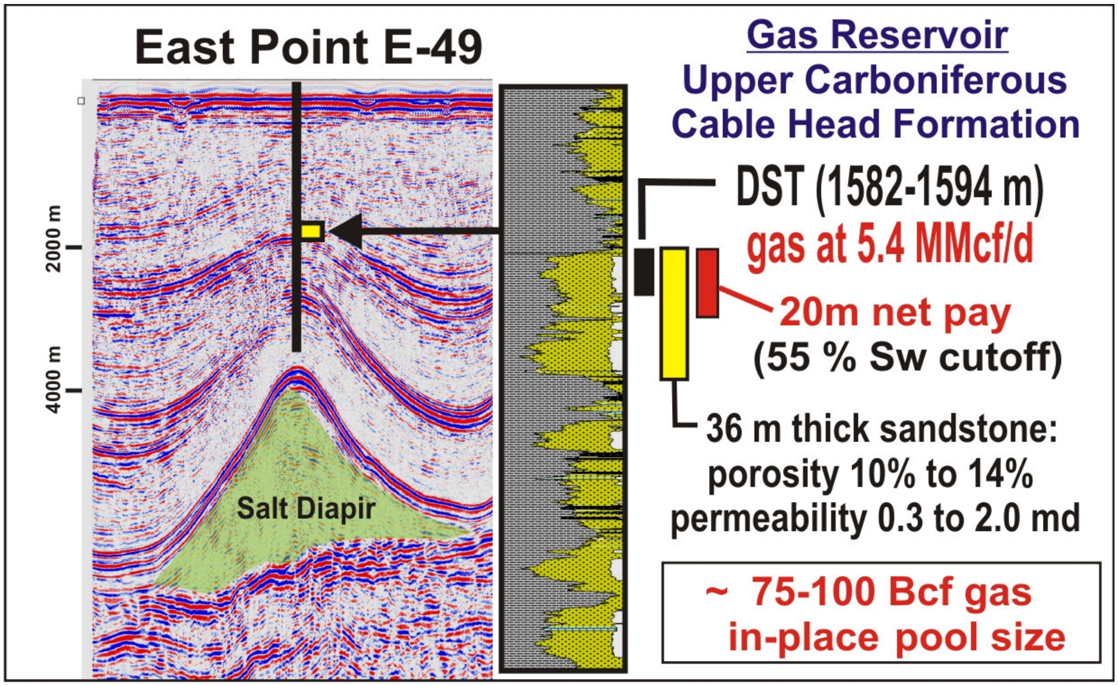


Figure 75. Migrated seismic section (left panel) across the East Point E-49 gas discovery well, illustrating deep-seated (detached) salt diapir and position of gas-bearing sands. Gas zone is detailed in log-derived lithology plot (centre panel), with reservoir parameters and estimates.

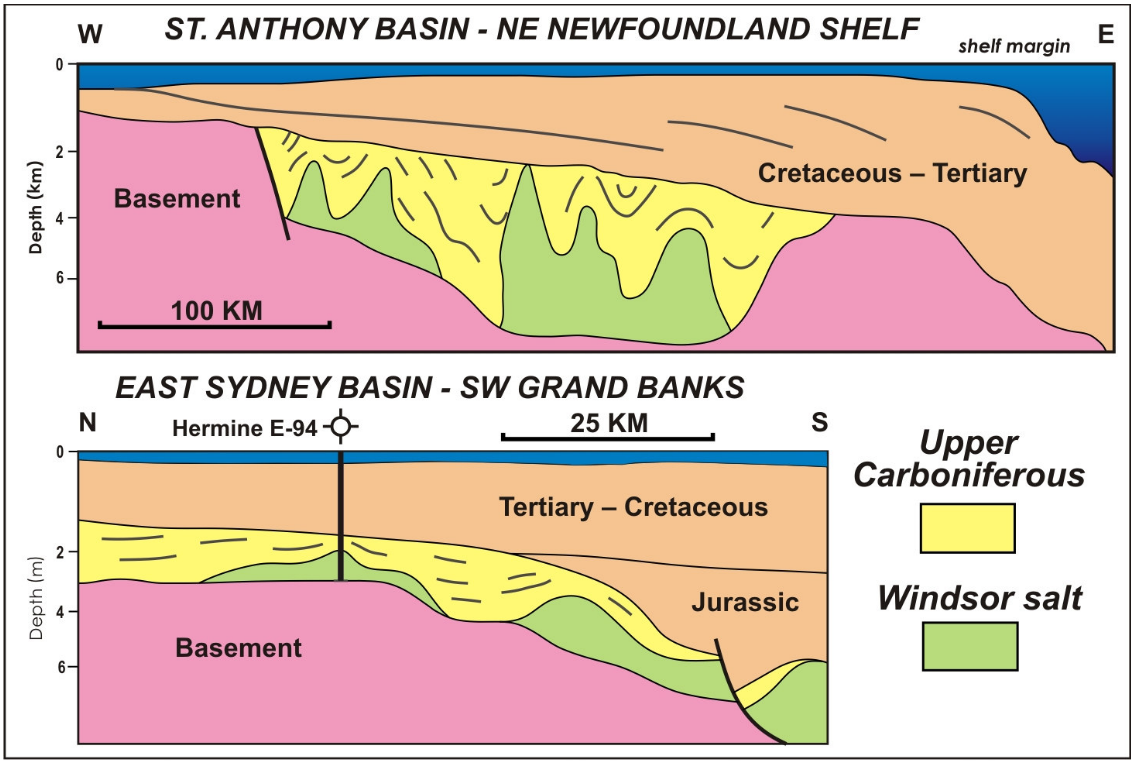


Figure 76. Regional cross-sections of the St. Anthony Basin (top panel - 76A) and eastern Sydney Basin (bottom panel - 76B)(locations in Fig. 71). These sections illustrate the easternmost parts of the Maritimes Basin, with both areas characterised by similar Carboniferous stratigraphy and salt structures, and overlying Mesozoic-Cenozoic sedimentary wedges (adapted from Grant and McAlpine, 1990, and Maclean and Wade, 1992).

trap types in the Upper Carboniferous include inversion folds and fault blocks within and adjacent to major fault zones (Figs. 64, 66).

The gas discovery in the East Point E-49 well is part of the Upper Carboniferous play. The E-49 well encountered a 20 metre thick gas zone in a sandstone within the upper Cable Head Formation, above a large detached salt diapir. Although deemed uneconomic for offshore development, the East Point discovery provides a template for the effectiveness of petroleum systems in the play. Other key exploration tests in the Upper Carboniferous Play include the Brion Island, Beaton Point, Cable Head, Irishtown, Hermine and Hare Bay wells (all tests of salt structures), the Naufrage and Bear River wells (tests of fault structures and rollover anticlines) and the North Sydney well (a fold-structure test). All of these wells encountered gas shows in Upper Carboniferous sandstones, and two wells (Irishtown No. 1 and Naufrage No. 1) recovered small volumes of gas in drill-stem tests.

In terms of total petroleum resource potential, the Upper Carboniferous Play is considered the most prospective of the three Maritimes Basin plays. This reflects the combination of a large play area, large numbers and sizes of prospects, and thick and widespread source rocks in the Upper Carboniferous

UNCONVENTIONAL GAS RESOURCES OF GULF OF ST. LAWRENCE REGION

Introduction to unconventional gas resources

Unconventional gas resources are defined as those natural gas resources contained in "difficult-to-produce" geological units that require special completion, stimulation and/or production techniques to achieve economic production (CSUG, 2009). Typically, unconventional gas resources do not flow freely at commercial rates without artificial stimulation, because either the fluid or the reservoir properties impede that free flow: these are low porosity-low permeability reservoirs. A large percentage of the gas resources are adsorbed onto the surface area of contained organic material or present as free gas in fractures. Unconventional resources are typically of large volumes, dispersed pervasively over wide geographic areas within reservoir rocks of low and/or variable permeability that are closely related to their source rocks. Geological variability and apparent unpredictability are common. They are characterized by low flow rates, long production life, and unusual pressure regimes. Exploration and exploitation of unconventional gas resources commonly require large land positions, greater drilling densities, increased surface infrastructure and greater technological investment (Hamblin, 2006). By this definition, resources such as tight gas, coal-bed methane, organic shales (either oil or gas) and gas hydrates are considered to be unconventional.

In Canada, reservoirs designated as tight gas, coal-bed methane and shale gas are thought to contain as much as 2000 Tcf of natural gas, with potential producible reserves in excess of 190 Tcf (CSUG, 2009) significant resources indeed. Although the volume of gas in-place is likely to be large and widely dispersed, well productivity tends to be low, production costs are high and pre-production extensive pilot projects are required to assess feasibility. In addition, the density of drilling sites required to efficiently "harvest" these resources is often higher than is typical of conventional, permeable reservoirs. It must be recognized that unconventional plays may produce at low volumes and low pressures for decades: producers must be ready to accept steep learning curves, uncertainty at the beginning, the crucial need for specialist teamwork, long economic payouts, and have the ability to re-think project designs as abundant data is recovered over many years. In the past, technical and financial challenges in locating, stimulating and producing unconventional gas resources have deterred concerted exploration. However, as conventional gas resources are rapidly depleted, conversion from oil to cleaner-burning natural Gas becomes widespread, energy costs increase, and energy demands increase, these alternative possibilities will become more mainstream. Going forward, much of the new exploration, drilling and production in the future will involve these kinds of resources: unconventional gas may represent the most important energy source in North America over coming decades. But, can exploration and exploitation of unconventional resources progress rapidly enough to replace dwindling conventional resources and keep up with growing demand?

In the past 5 years a focus of the Canadian exploration industry has been on coal-bed methane development in the Alberta Plains (with nearly 7000 wells drilled into the Horseshoe Canyon Formation alone (CSUG, 2009) (see Hamblin, 2004, for geological background). Gas shales in the WCSB (see Hamblin, 2006, for geological background), especially in NE-BC, have attracted much attention in the past 3 years (CSUG, 2009). Both coal-bed methane and shale gas are now being actively explored for in Quebec, New Brunswick and Nova Scotia. The large areal extent, and under-explored state, of the Gulf of St. Lawrence region strongly suggest that significant unconventional gas resources await further exploration and that a positive outlook for success is justified.

Coal-Bed methane concept

Coal-bed methane (CBM, or “natural gas from coal”, NGC) production has become an important energy resource in the U.S., and Canada over the past few decades. Methane is generated during the coalification process as a function of the temperature to which the coal is heated during burial (CSUG, 2009). The gas content increases with maturity and peaks in coals of high-volatile bituminous rank (CSUG, 2009). The coal seams form self-enclosed petroleum systems where source, reservoir, seal and trap are all present in the same thick, coaly succession. Coal seams act as “dual-porosity” reservoirs because they include both matrix porosity-permeability and fracture network porosity-permeability. The gas may be stored by adsorption onto coal itself, or trapped as free gas in fractures (“cleats”) in the coal, or trapped as free gas in pore spaces in the associated interbeds of coarser-grained (more porous) sediments (Dawson et al., 2000). The successful generation, storage and producibility of coal gas from coal seams is dependant on: 1) the rank, composition, ash content and thickness of the coal seams, 2) the depth and thermal history, and especially 3) the micro-and macro-permeability within the seams, which is primarily a function of the complexity of the fracture (cleat) systems (Dawson et al., 2000; CSUG, 2009). The fracture system is commonly anisotropic, with the primary fracture set (referred to as the “face cleats”) contributing greater effective permeability, than the secondary fracture set (called the “butt cleats"). Coal-bed methane is produced by drilling into the seam, usually inducing fractures, then reducing the natural pressure within the seam, which allows the gas to escape along natural or induced fractures through the seam to the well. If formation waters are present, then the seam must first be de-watered before the gas will flow. The development of horizontal drilling (to access more of the reservoir) and large-scale fracturing technology (to create and retain larger surface areas and conduits to flow) have revolutionized the possibilities for production. The volume and nature of produced waters, and their disposal/reclamation at surface are also clearly of great environmental importance.

One clear lesson from the plays developed to date is that each potential coal-bed methane gas play must be evaluated separately to discern the correct balance of all the various factors, appraise the predictability of the coal seams, and properly assess its economic possibilities. Further detailed mapping of coal seam/zone distribution in the near-surface setting, stratigraphy/sedimentology of the enclosing sediments, desorption testing of these coals and study of subtle structural drape/fracturing should elucidate greater potential for coalbed methane resources in the strata of the Upper Carboniferous. However, important environmental questions associated with the production of this gas must also be addressed.

Coal-Bed methane immature/conceptual play

Play Definition

This immature/conceptual play is defined to include all potential gas-bearing coal seams and coal zones in Upper Carboniferous non-marine successions (Fig. 71). The primary targets are the Joggins, Springhill Mines (Cumberland Basin), Stellarton (Stellarton Basin) and Sydney Mines (Sydney Basin) formations, but minor seams occur in several other units as well. The play occurs wherever Upper Carboniferous rocks are present over a large area, principally in northern and eastern Nova Scotia, adjacent areas of eastern New Brunswick, Prince Edward Island and southwestern Newfoundland, as well as closely adjacent offshore portions of the Gulf of St. Lawrence/Cabot Strait.

Geology

Coals of the Upper Carboniferous of Atlantic Canada probably formed primarily in deltaic and alluvial environments near, and landward of, marine shorelines (Fig. 44). Strata of the Cumberland Group (see Ryan et al., 1991) in Cumberland, Sydney, Mabou and Stellarton Basins enclose thick coal measures of primarily Westphalian age (Naylor et al., 1989; Ryan et al., 1991; Masson and Rust, 1990). Although some older literature suggested Westphalian C/D ages, more recent re-appraisal has concluded these units are likely of Westphalian A/B ages (Utting et al., 2009). Major coal-bearing formations include Joggins and Springhill Mines (Cumberland Basin), Inverness (Mabou Basin), Stellarton (Stellarton Basin) and Sydney Mines (Sydney Basin). These units typically comprise thick successions of grey fluvial floodplain, distributary channel and splay sandstone, overbank siltstone, lacustrine shale and minor lacustrine to marine-influenced limestone. Strata are commonly arranged in coarsening-upward cyclothems, with multiple coal seams ranging from very thin to 18 m in thickness. Coal is generally of high volatile bituminous A rank (Hacquebard and Donaldson, 1969). Peat accumulation was most prominent in coastal mires remote from clastic input from fluvial channels and in backshore depressions.

In Cumberland Basin, the very thick Joggins Formation comprises interbedded mudstone, siltstone and sandstone with thin (< 1 m) coal seams, whereas the overlying Springhill Mines Formation is composed of medium grained sandstones, mudstones, minor limestones and numerous coal seams (> 20) up to 4 m thick, which have a long history of mining (Ryan et al., 1991). The Inverness Formation of the Mabou Mines Coalfield was deposited in an upper delta plain setting wherein coal seams up to 4 m thick are interbedded with thick medium grained trough cross bedded braided fluvial sandstones and minor mudstones (Gibling et al., 1994). In addition, these thick coal measures apparently continue into the extensive offshore Magdalen Basin between Cape Breton Island and Prince Edward Island, and beneath the latter island itself (Grant and Moir, 1992) where Hacquebard (2002) suggested large CBM resources exist. The Stellarton Formation of the Pictou Coalfield was deposited in a small, rapidly-subsiding fault-bounded basin (10 x 25 km x 3 km deep) wherein up to 35 coal seams of the Westville Member and the Albion Member (up to 13 m thick) are interbedded with oil shales, mudstones and fine grained sandstones and are best-developed toward the basin centre (Naylor et al., 1989). The Sydney Mines Formation of the Sydney Coalfield was deposited on a distal alluvial plain near a marine shoreline, and comprises abundant green and red floodplain mudstones, cross bedded fluvial sandstones, and laterally-extensive coal seams up to 4 m thick (Masson and Rust, 1990). In addition, these same coal measures extend many kilometres offshore into Cabot Strait where Hacquebard (2002) suggested large CBM resources exist.

Exploration History

Recent coalbed methane activity by a small number of companies has focused on the Cumberland and Stellarton basins. There is currently no actual production of gas from coals in eastern Canada. In Cumberland Basin, Amvest and Contact Exploration acquired a 178,000 acre block and drilled two vertical wells on this Cumberland Exploration Permit to delineate the high-volatile A to medium-volatile bituminous seams in the Springhill and Joggins formations. In recent years, Stealth Ventures has become the operator and has drilled and tested three long-reach horizontal wells, and has obtained an onshore production permit for the Basin. Current corporate estimates suggest gas content of 100-510 scf/ton and $36 * 10^6$ m^3 (1.2 Tcf) in-place resource, primarily in the Springhill Formation. In Stellarton Basin, Amvest began exploration in the early part of this decade by assembling 24,000 acres of contiguous land as a Coal Gas Production Lease, which was later acquired by Stealth Ventures. Stealth built a drilling pad, and drilled several vertical wells (technical difficulties have hampered drilling of the horizontal legs) over the past 4 years, and contemplated drilling of further horizontals and re-completion of several other wellbores. Current corporate estimates suggest gas content of 130-330 scf/ton and $13 * 10^6$ m^3 (426 Bcf) in-place resources, primarily in the Albion Member. However, in February, 2009, Stealth Ventures sold its entire Stellarton Basin Coal Bed Methane assets to East Coast Energy, as part of its non-core assets divestment program.

Play Potential

Fully constrained estimates of the potential for this very immature play are not possible because of the limited data available at this time. However, Hacquebard (2002) reviewed the geology and CBM potential of all of Atlantic Canada and suggested that Upper Carboniferous strata may harbour an estimated $2.4 * 10^9$ m^3 (79 Tcf) of *in situ* resource, primarily remaining in the offshore regime. Currently, exploration is continuing in several parts of Nova Scotia and western Newfoundland (St. George's coal field), and further discoveries are likely.

Shale gas concept

Shale gas actually has a long, but poorly-known, history. The first known shale gas production occurred in 1821, when local townsfolk drilled a well 8.3 m deep at Fredonia, NY, making this the oldest hydrocarbon play in North America (Hamblin, 2006). It now represents about 10% of US gas production. "Shale gas" is natural gas produced from reservoir rocks composed dominantly of fine-grained sediments (ranging from mudstone to siltstone to argillaceous fine-grained sandstone). Shale is the most common lithology in many sedimentary basins, and consequently, shale gas represents a potentially large gas resource. The "shales" form self-enclosed petroleum systems where source, reservoir, seal and trap are all present in the same thick, shaley succession: the gas may be stored by adsorption onto insoluble organic matter, or high-surface-area clays in the shale itself, trapped as free gas in fractures in the shale, or trapped as free gas in pore spaces in the shale or in associated interbeds of coarser-grained (more porous) sediments (Hamblin, 2006). The volume of adsorbed gas generally increases with the amount of organic matter and surface area and, therefore, organic-rich, fine-grained rocks are the most likely hosts. The contained gas may result from any combination of the following processes: primary thermogenic decomposition of organic matter at depth, secondary thermogenic cracking of existing oil at depth, or biogenic microbial decomposition of organic matter in shallow, water-wet settings (Hamblin, 2006; CSUG, 2009). Because most shales retain good natural porosity and good storage capacity, even at depth, significant organic content, thickness and permeability are the three most important factors that must be present to create a potential play. However, the presence of conduits for gas flow to the well bore through these low-permeability rocks is crucial. Therefore, networks of natural fractures, or the ability of the shale to hold induced fracturing, or the presence of thin permeable carrier beds within the strata are major positive features. Many shale gas reservoirs are represented by thick successions of black, very organic-rich mudstone where natural fractures occur, or calcareous/siliceous cements lend brittleness (for induced fractures). Others are typified by thick interbedded successions of moderately organic-rich mudstone and thin coarser-grained beds which act as additional gas reservoirs and more permeable gas conduits: these latter are referred to as “hybrid” shale gas plays. The development of horizontal drilling (to access more of the reservoir) and large-scale fracturing technology (to create and retain larger surface areas and conduits to flow) have revolutionized the possibilities for production.

One clear lesson from the plays developed to date is that each potential shale gas play must be evaluated separately to discern the correct balance of all the various factors, appraise the predictability, and properly assess its economic possibilities. Further detailed mapping of shale thickness and distribution in both the near-surface (biogenic) setting and the deep, dry (thermogenic) setting, study of the stratigraphy/sedimentology/mineralogy, desorption testing of these rocks and study of subtle structural drape/fracturing should elucidate greater potential for shale gas resources in these strata. However, important environmental questions associated with the production of this gas must also be addressed.

Shale gas immature/conceptual play

Play Definition

This immature/conceptual play is a composite of the shale gas potential of numerous different stratigraphic units scattered over the greater Gulf of St. Lawrence region. It is defined to include all potential gas-bearing, mudstone-dominated units in Paleozoic-Mesozoic marine and nonmarine successions. The primary targets are the Upper Cambrian to Middle Ordovician Green Point Formation and equivalents (western Newfoundland and adjacent Gulf), Middle to Upper Ordovician Utica Formation and equivalents (western Newfoundland and adjacent Gulf, Anticosti Island and adjacent Gulf, St. Lawrence River/Estuary and adjacent onshore area; Figs. 8 to 10), Lower Carboniferous Albert, Strathlorne, Rocky Brook and Hastings formations and equivalents (western Newfoundland, northern Nova Scotia, eastern New Brunswick; Fig. 44), but unknown potential may also occur in the offshore equivalents of the Late Triassic Wolfville and Blomidon formations (Bay of Fundy). The play occurs wherever these strata are present over a large area, principally in southern Quebec along the St. Lawrence River/Estuary, western Newfoundland, northern Nova Scotia, adjacent areas of eastern New Brunswick, as well as closely adjacent offshore portions of the Gulf of St. Lawrence/Cabot Strait/Anticosti/St. George's Bay/White Bay.

Geology

Shales of the Upper Cambrian to Lower Ordovician in western Newfoundland (Green Point Formation, especially the Martin Point Member, of the Cow Head Group, and the coeval Cook's Brook and Middle Arm Point formations of the Curling Group) are dark grey to black marine mudstones with interbedded thin limestones and sandstones, deposited adjacent to a thick carbonate platform (Fowler et al., 1995). Successions are thick, total organic content ranges up to 10.4%, with thermal maturities up to mature or overmature, although structural complications are common (Hamblin, 2006). Coeval passive margin shales are preserved in structural thrust slices in the Humber Zone of eastern Quebec (Rivière Ouelle Formation and equivalents), although these thick successions are thermally more mature with lower residual TOC (Lavoie et al. 2003).

Shales of Middle to Late Ordovician age occur throughout eastern Canada and were deposited in relatively deep marine settings within the newly-created, subsiding Taconian Foreland Basin, after collapse of the North American marginal carbonate platform. These strata belong to the Table Cove/Black Cove/Winterhouse (western Newfoundland), Macasty/Vauréal (Anticosti Island) and Utica/Lorraine/Pointe-Bleue (Quebec) units, which constitute thick units of dark grey to black, organic-rich mudstones (Lavoie et al., 2008). These successions are up to 1000 m thick, with total organic contents up to 15%, and thermally immature to overmature (Hamblin, 2006). Some of these units are not yet well-understood, and structural complications may be present (although less complex than adjacent shales of the Humber Zone).

The Utica shales and overlying Lorraine siltstones of the St. Lawrence Lowlands in Quebec are in the active exploration phase and have the following characteristics: 700-1800 m depth, 150-300 m thickness, TOC 1-3%, thermal maturity 1.3-2.0 % Ro (CSUG, 2009). Extensive new seismic, drilling and geotechnical study has documented three exploration fairways: 1) thermally mature, relatively undeformed shales between the Yamaska Fault and Logan's Line, where current exploration and testing is focused, 2) deeper, tectonically-thickened shales in the dry gas zone, east of Logan's Line, and 3) thinner, shallower, less deformed shales west of Yamaska Fault which may include thermogenic and biogenic possibilities (Junex, 2008).

Shales of the Lower Carboniferous mid-Horton Group (Strathlorne, Albert, Horton Bluff/Cape Rouge formations; eg., Hamblin, 1992) and mid-Mabou Group (Hastings/Cape Dauphin/West Bay/Rocky Brook formations; e.g., Hamblin et al., 1997) of Atlantic Canada formed primarily in lacustrine settings within extensional half-graben tectonically-controlled sub-basins. These units consist of grey to black, variably organic-rich mudstones, with interbedded fine-grained sandstone and minor limestone, up to 1800 m thick. Stacked, shallowing-upward sequences are characteristic, with the most organic-rich shales at their bases. Total organic content ranges up to 15%, with thermal maturities of mature (oil window) or overmature (gas window), although structural complications within the sub-basins are common (Hamblin, 2006).

In addition, it is possible that the Triassic-Jurassic rift basin of the Bay of Fundy may contain a thick undrilled succession of organic-rich shales in the offshore area (primarily of Late Triassic age), comparable to those of the nearby, coeval rift basins of the northeastern US (Wade et al., 1996). The potential of this basin is, as yet, unknown.

Exploration History

Recent shale gas activity in eastern Canada has focused on Quebec, Nova Scotia, New Brunswick and Newfoundland. There is not yet any actual commercial production of gas from shales in eastern Canada. In the St. Lawrence Lowlands of southern Quebec, shale gas activity has greatly increased over the past several years. Junex, a Quebec-based junior with major joint-venture partners, has been actively exploring for Utica shale gas on 1.36 million acres in southern Quebec for several years. Several wells with cores have yielded encouraging results, and further drilling is proceeding. The company is testing both thermogenic play possibilities and biogenic potential in the Utica, and estimates a potential of about $150 * 10^6$ m^3 (5 Tcf) recoverable resources on their acreage (Junex, 2008). Forest Oil acquired 269,000 acres and drilled two vertical wells in 2007 to test Utica potential, with production tests recovering flows up to 30 * 10^3 m^3/d (1 MMcf/d), and suggesting resource potential of 120 * 10^6 m^6 (4 Tcf). The company has followed-up with three horizontal wells and massive fracturing; long-term flow testing of diverse stratigraphic intervals yielded low flows. In 2008, Talisman Energy announced a successful test from Utica shale in its vertical Gentilly well, which flowed at 24 * 10^3 m^3/d (800 mcf/d), and further tests are expected for the overlying Lorraine siltstone. The rocks were announced to be thick, porous, brittle and over-pressured, all of which are conducive to artificial fracture stimulation. Talisman and its partner Questerre Energy have recently announced the casing of three successful vertical wells; test results from one fractured interval in the mid Utica yielded flows between 9 and 27 * $10^3 m^3$/d (300 and 900 mcf/d). An independent technical report announced a best estimate recoverable value of 4.2 Tcf on their acreage. Talisman Energy and Questerre Energy have started a multi horizontal well program in September 2009. Gastem Inc., which also explores for Utica shale gas in adjacent New York, and its new partner Canbriam Resources are (September 2009) drilling three vertical shale gas well in southern Quebec.

In Nova Scotia and New Brunswick, shale gas exploration has only been active for a few years and has been confined to the Lower Carboniferous strata. Triangle Petroleum, in partnership with Elmworth Energy and Contact Exploration, has shot 2-D and 3-D seismic and drilled, cored and fractured two vertical test wells on 516,000 acres near Windsor in Nova Scotia. There, Horton Bluff Formation rocks have yielded samples with high maturity, high saturations of dry gas from shales with TOC averaging 11%. They also have 68,000 acres in New Brunswick with the same partners, yet to be tested. In New Brunswick, Corridor Resources has acquired 2-D seismic and drilled and cored several horizontal wells for Horton Bluff shale gas potential on 118,150 acres in the Moncton Basin. An additional two coreholes are planned. Petroworth has also recently drilled several wells intersecting thick, gas-bearing shales of the Frederick Brook Member (Horton Group) and plans further testing. In the Deer Lake Basin of Newfoundland, Deer Lake Oil and Gas has been exploring on 226,000 acres for shale gas in the lacustrine mudstones of the Rocky Brook Formation, with up to 15 % TOC and both thermogenic and biogenic potential.

Play Potential

Estimates of the potential for this very immature play are not possible because of the limited data available at this time. However, exploration is continuing in Quebec, New Brunswick, Nova Scotia, and Newfoundland, and further discoveries are likely.

PETROLEUM RESOURCE ASSESSMENT OF PALEOZOIC BASINS IN EASTERN CANADA

INTRODUCTION

A comprehensive petroleum resource assessment needs to satisfactorily resolve the following questions:

1) How much pooled hydrocarbon exists in a play?
2) What is the geographic and stratigraphic distribution of these oil and gas resources?
3) How much is oil and how much is natural gas?
4) What size accumulations are expected? and
5) How certain are these estimates?

The best way to answer these questions is by providing a range of estimated values and their probability of occurrence.

There are a number of methods for estimating the quantity of conventional oil and gas that may exist in a play, basin or region. There are other methods for determining non-conventional hydrocarbon resource occurring as continuous-type accumulations. The method employed depends on the nature and amount of data available. Each method is unique in the type of generated information. White and Gehman (1979), Masters (1984), Rice (1986) and Logan (2005) describe various methods in use.

Some hydrocarbon basin appraisal methods include extrapolation of discovery rates, areal- and volumetric-yield calculations, geochemical material-balance analyses, and prospect and play analyses. The discovery trend method statistically determines future oil and gas discoveries by extrapolating past exploration performance (Arps and Roberts, 1958; Dolton et al., 1979, 1981; Drew et al., 1979, 1980, 1982; Root and Schuenemeyer, 1980). This method is most applicable in well-explored or mature basins. The most commonly used historical statistic in this method are finding rates which relate the discovered volume of hydrocarbons to exploratory metres drilled, the number of exploratory wells, or to time. In the areal and volumetric-yield methods, the quantities of discovered hydrocarbons per unit area or volume in rock in mature basins are calculated and applied to areas or volumes of rocks in less well-explored areas (Weeks, 1949, 1950; Hendricks, 1965, 1974; Klemme, 1971, 1975; McCrossan and Porter, 1973). The analogues that are used in this yield method can be based on geologic character, tectonic framework, stratigraphy or other geological factors. The geochemical material balance method calculates the amount of hydrocarbon generated, migrated and trapped by examining the character and volume of source rock, its thermal maturity and burial history, and the quantities of hydrocarbon generated, extracted, trapped and preserved in reservoirs (Conybeare, 1965; McDowell, 1975; Momper, 1979).

The National Energy Board uses an Excel add-in program called '@RISK' developed by Palisade Corporation which estimates petroleum resource by multiplying hydrocarbon volume by yield by risk. These parameters are expressed as probability distributions determined by geological analyses of individual plays.

The statistical methods used in the hydrocarbon resource assessment in this study were developed by the Geological Survey of Canada (Lee, 1993a, 1993b; Lee and Lee, 1994; Lee and Tzeng, 1993, 1995; Lee and Wang, 1983a, 1983b, 1984, 1985, 1986, 1990). These methods have been incorporated in the computer program system now known as **PRIMES** (**Pet**roleum **R**esource **I**nformation **M**anagement and **E**valuation **S**ystem). Since the early 1980s, this system has been applied to evaluate plays from various worldwide basins. Some of the assessment results have been verified by subsequent discoveries.

The Geological Survey of Canada utilizes two methods, both operating at the exploration play level. These two approaches are called the discovery process model and the volumetric probability method. Both models require information or estimates of the pool or field sizes and the number of pools or prospects in the play in order to obtain the resource potential of the play. For established plays, with as few as eight discoveries, the discovery process model has been found to be the more powerful analytical tool. The basic assumption of the discovery process model is that discoveries made in the course of an exploration program represent a biased sample of the underlying population of a play. The sample is biased in the sense that the largest prospects in a play tend to be tested first. The result of this biased testing process is that largest pools tend to be found early in the play's exploration history. The discovery process model of Lee and Wang (1984, 1985, 1986), employs the sizes of discoveries that have already been made and their sequence of discovery to produce estimates of play potential and individual pool size. This model uses two of the most reliable data sets, in-place pool size and their discovery date.

Comparisons with the output from the geochemical material balance method were discussed by Coustau et al. (1988). Validations by historical data sets were studied by Lee and Tzeng (1995). Comparisons with other methods were discussed by Lee et al. (1995). Applications for evaluating plays from various basins can be found in Barclay et al. (1997); Bird et al. (1994a, 1994b); Hamblin and Lee (1997); Lee and Singer (1994); Olsen-Heise et al. (1995); Podruski et al. (1988); Reinson and Lee (1993); Reinson et al. (1993); and Warters et al. (1997). Methods related to PETRIMES can be found in Kaufman and Lee (1992); Lee et al. (1988); Lee and Price (1991); and Lee and Lee (1994).

The Paleozoic basins in eastern Canada represent frontier hydrocarbon provinces. All defined exploration plays in these basins have very few discoveries or in some cases no discoveries. The discovery process procedure cannot be applied to this exploration region.

The volumetric probability method is used mainly for conceptual or very immature plays, often occurring in frontier areas where limited exploration has taken place. In this procedure, subjective opinions combined with data from existing exploration results are used to determine the sizes and number of prospects. Probability distributions of appropriate reservoir parameters and number of prospects are employed in this technique. This method also requires the subjective incorporation of exploration risks at a play or prospect level on the basis of the presence or adequacy of necessary geological factors for the generation and preservation of oil and gas accumulations. The underlying assumption in this method is that lognormal approximations of the distributions of various reservoir parameters are combined by summation to obtain pool or field size distributions.

RESOURCE ASSESSMENT PROCEDURE

Before a petroleum assessment can take place, there are three important steps or procedures that need to be completed: basin analysis, play definition and mapping, and compilation of relevant data in the play.

Basin analysis

The basin analysis or synthesis needs to be completed in order to understand the underlying geological framework that may affect petroleum generation and accumulation. The main achievement of the analysis is the identification of an active or potential petroleum system or systems. One aspect of basin analysis is stratigraphy which includes the identification of stratal units, their thicknesses, lithologies, and facies distributions, together with stratal sequence surfaces, unconformities, and depositional environments. Structural framework and tectonic history are another important aspect of basin analysis. Other aspects are thermal and burial histories, source rock and reservoir rock identification and their regional distribution, hydrocarbon generation, migration and preservation, diagenetic overprinting, as well as the exploration history of the basin.

Geological play definition

The definitions of play type and play area are essential objectives of the basin analysis that precedes any numerical resource evaluation. The petroleum play is the fundamental unit of assessment or exploration. Traditionally, the petroleum play is defined on the basis of reservoir in which the oil and/or gas accumulations occur or may occur. Therefore, the play map would reflect the subsurface extent of the potential reservoir or reservoirs. Reservoir does not have to be the basis for play definition. A play could be defined on the basis of trap-type or timing of structure formation. All plays for the eastern Canada Paleozoic basins were defined on the basis of reservoir. Most plays have both an oil and gas component requiring separate computational runs for each hydrocarbon type. Play area boundaries for oil and gas components may not be coincident, depending on the distribution and maturity characteristics of potential source rocks.

A properly defined play will possess a single population of pools and/or prospects that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration. Pools and/or prospects in a play form a natural geological population characterized by one or more of the following: age, depositional model, structural style, trapping mechanism, geometry and diagenesis. The pools and prospects in a properly defined play form a population limited to a specific area and are homogeneous in terms of geology and risk characteristics. Play definitions can be very broad or quite restricted. However, it is important to properly define the play so that it corresponds to a single statistical population. A mixed population, derived from an improperly defined play will not satisfy the statistical assumptions required for the application of the evaluation models and will adversely impact on the quality of the resource estimate. Usually, as geological knowledge increases as a result of exploration, plays become more subdivided into better defined units, thus, making more specific and reliable estimates.

Compilation of play data

Once a play has been properly defined, then pertinent petroleum data can be compiled. In mature plays with an appropriate number of discoveries, a pool list is compiled with discovery dates and in-place play volumes for direct entry into the discovery process model. The pool lists are examined to ensure that they are consistent with the play definition and within the play boundaries.

With respect to immature and conceptual plays where applying the volumetric probability distribution method is required, compilation of play data is the most labor- and time-consuming part of the procedure. Two sets of information are required to evaluate immature and conceptual plays: pool size and number of pools probability distributions.

Estimating the 'pool' size probability distribution

The pool size distribution relies on describing each variable as a probability distribution in the pool size equation. The probability distribution describes the range of possible values of the variable for each pool or prospect in the play. Probability distributions of reservoir parameters such as prospect area, reservoir thickness or net pay, porosity, trap fill, water saturation, and oil or gas formation volume factors are needed for entry into the standard 'pool'-size volumetric equation. A pool is defined as a petroleum accumulation typically within a single stratigraphic interval that is hydrodynamically separate from another accumulation. A field, on the other hand, is a defined area with petroleum without stratigraphic or hydrodynamic restrictions. Field size distributions are commonly estimated for frontier basins where there are limited numbers of petroleum accumulations and few if any detailed reservoir engineering studies. The Paleozoic plays in eastern Canada were all assessed using field size estimates. Seismic, geophysical well logs and outcrop data prove useful in identifying limits for sizes of prospect area, reservoir thickness and sometimes porosity and water saturation limits. The incorporation of as much objective data as available is essential for each variable, but subjective opinion and analogue data is entered where objective data is missing. Research in similar hydrocarbon-bearing habitats is also important in order to provide reasonable constraints on reservoir parameters as well as provide additional information that may prove useful in case particular reservoir parameters are unknown in the basin under consideration. All of these probability distributions are combined to create a field size distribution for the play.

Estimating number of 'pools'

Another essential parameter to be determined is the probability distribution of the number of 'pools' or fields in the defined play. Two sets of data are needed; the exploration risk of the play and the number of prospects distribution.

Regarding exploration risk, it is always possible that a prospect may not contain hydrocarbons. Thus, associated with each prospect is an exploration risk that measures the probability of the prospect containing an oil or gas field. Geological risk factors that determine accumulation and preservation of hydrocarbons are the presence of adequate closure, porosity, seal, timing, source, maturation and charge. These risk factors can be assigned at either a play-level or prospect-level, but not both. Play-level risk measures the marginal probability that a geological risk factor affects all prospects in a play equally. Prospect-level risk measures the risk factor according to a prospect-by-prospect basis. All of the assessed plays for the eastern Canada Paleozoic basins were risked at the prospect level only, as each play contains at least one proven discovery. The geological risk factor presence or absence is represented by a marginal probability ranging from 0.0 to 1.0. Higher risk is represented by lower marginal probability. For the prospect to be a field, simultaneous presence of all the critical geological factors in the prospect is necessary. The exploration risk for the play is the product of all the critical marginal probabilities of risk factors in the play. The determination of risk is usually derived by subjective opinion with respect to the combined knowledge of experts most familiar with the geology of the basin. Appropriate play analogues reporting risk factor probabilities can be utilized. Examining all exploratory wells targeting the play and determining their reason or reasons for failure can provide information on geological risk factor probabilities.

The second data set needed to determine the number of fields distribution is the number of prospects distribution. There are three input entries needed for this distribution, a minimum, median and maximum number. The minimum number of prospects can be derived by counting the number of closures or anomalies derived from seismic time and structural contour mapping. The minimum value represents the number of prospects known to exist with confidence. Numerous questions or considerations need to be taken into account in order to complete the rest of the distribution. In most instances, in frontier plays as well as in all plays in the Gulf of St. Lawrence region, seismic maps do not cover the entire play area. One must consider, therefore, extending over the entire play area the observed density of anomalies present in the mapped areas. This is not the only consideration, however. Small anomalies may be missed by the density of the seismic grid. Also, when seismic control is improved in the play, there is a distinct possibility that some larger structures or anomalies previously mapped are separated into smaller traps, thus increasing the potential number of prospects. The quality of the seismic data may limit the ability to resolve the type of trap under consideration. Subtle stratigraphic traps are often not recognized in the early history of frontier plays when the first seismic datasets are acquired. Areal apportionment takes into account the ratio of coverage of seismic surveys to the total play area but not the density, orientation or quality of seismic data. The areal apportionment result, therefore, has been added to the 0.5 column and the maximum value determined by extrapolation on lognormal graph paper is reserved to represent the stratigraphic and smaller prospects that may occur in the play.

The probability distributions of oil and gas field sizes were combined with estimates of the number of prospects and exploration risk to calculate the sizes of individual undiscovered fields and the play potential. The statistical summation of all field sizes yields the play potential. Play potentials, field sizes and number of fields are calculated as probability distributions on which all points are valid. Ranges (P90 to P10), means and median values are reported. Volumes for oil and gas are reported in cubic metres and as in-place values. Detailed engineering and economic studies are not available in this frontier basin, so it is not feasible to assign appropriate recovery factors to estimate recoverable or marketable oil or gas volumes.

EASTERN CANADA PALEOZOIC BASINS PETROLEUM ASSESSMENT

Scope

Regional petroleum resource assessments have been prepared periodically for various sedimentary basins in Canada by the Geological Survey of Canada. These studies incorporate systematic basin analysis with subsequent statistical resource evaluations (Procter et al., 1984; Podruski et al., 1988; Wade et al., 1989; Sinclair et al., 1992; Reinson et al., 1993; Bird et al., 1994a; Dixon et al., 1994; Barclay et al., 1997; Hamblin and Lee, 1997; Warters et al., 1997; Hannigan et al., 2001). This report summarizes the assessment of oil and gas potential of Paleozoic basins in eastern Canada including offshore and onshore components of the autochthonous St. Lawrence Platform encompassing Anticosti and West Newfoundland basins and southern Quebec (Figs. 2, 3 and 4), the Appalachian Humber Zone (Figs. 2, 3 and 4), the Middle Paleozoic belt in the Gaspé region (Fig. 26), and the Carboniferous Maritimes Basin (Fig. 41). These basins constitute the principal hydrocarbon-prospective pre-Mesozoic sedimentary accumulations in the Gulf of St. Lawrence region of eastern Canada.

Based on geologic, geographic and tectonic considerations, the basins and sub-basins in the region were grouped into four general assessment regions; St. Lawrence Platform, Humber Zone, Gaspé Belt and Maritimes Basin. The St. Lawrence Platform assessment region includes the autochthonous sedimentary cover on the northeastern American craton along the St. Lawrence River (Figs. 2, 3 and 4). It encompasses Lower Paleozoic sedimentary successions in southern Quebec, Anticosti Basin and Western Newfoundland Basin. The Humber Zone assessment region includes the deformed and allochthonous Cambro-Ordovician rocks of the Canadian Appalachians in southern Quebec and western

Newfoundland (Figs. 2, 3 and 4). The Gaspé Belt assessment region includes the Paleozoic stratigraphic package deposited after the Late Ordovician Taconic Orogeny and before the Middle Devonian Acadian Orogeny (Fig. 26). The Maritimes basin assessment region includes Upper Paleozoic sedimentary successions in the onshore-offshore Magdalen and Sydney basins in the Gulf of St. Lawrence, Cabot Strait, and southern Grand Banks regions, the offshore St. Anthony basin north of Newfoundland, and the small onshore Deer Lake sub-basin in western Newfoundland (Fig. 41).

Purpose

The objective of this assessment report is to provide an overview of the petroleum geology of the Paleozoic basins in eastern Canada and to present quantitative estimates of the oil and gas resources contained therein. New drilling and geoscience data may eventually generate information that affects these estimates by providing improved constraints on reservoir parameter inputs used in the evaluation. This geological and resource framework will assist government agencies in evaluating land-use and moratorium issues, and petroleum industry companies in pursuing future exploration opportunities. Terminologies used in the remainder of this report are summarized in Appendix B.

Method and Content

This report incorporates two essential components; geological basin analysis and statistical assessment. Basin analysis fundamentally describes and characterizes the exploration play. Fields and prospects in a play form a natural geological population that can be delimited in any given area. Once a play is defined, a numerical and statistical resource assessment is undertaken using field or prospect data from that specific play.

The analysis of oil and gas potential in the Paleozoic basins in eastern Canada entailed the delineation and systematic evaluation of 15 conceptual or immature conventional petroleum plays and 5 non-conventional natural gas plays. These plays are summarized in this report with respect to play definition, geology, exploration history and estimated resource potential. Six of the plays had sufficient data and information to proceed with a quantitative PRIMES analysis. This study is based on reviews of published and unpublished data and reports, interpretations and mapping from marine and onshore seismic reflection data, evaluation of well history records and logs, modelling of thermal maturation histories, and probabilistic analyses of the plays.

Previous Assessments

In 1973, the Canadian Society of Petroleum Geologists prepared a volume discussing the future petroleum provinces of Canada. This work concerned the petroleum potential and the geology related to its determination for all sedimentary areas of Canada. A chapter on the Quebec and Maritimes basins discussing the petroleum geology (Williams, 1973) and a synthesis chapter reporting assessment results (McCrossan and Porter, 1973), produced estimates of in-place petroleum resource of 680 * 10^6 m^3 (4.28 billion bbl) of oil and 62.3 * 10^9 m^3 (34 Tcf) of gas. Procter et al. (1984) presented petroleum potential estimates (average expectations) of 37 * 10^6 m^3 (233 MMbbl) and 100 * 10^9 m^3 (3.5 Tcf) of recoverable oil and gas, respectively. Subsequent studies of gas potential in the Canadian Potential Gas Committee's reports of 2001 and 2005 for Canada revealed no quantitative assessments of predicted volumes for the region. Since publication of the quantitative assessments in 1973 and 1984, numerous studies have been undertaken in the region and considerable amounts of new geological data collected.

Petroleum Assessment

The petroleum assessment of Paleozoic basins in eastern Canada was undertaken in order to provide quantitative estimates of total oil and gas potential and possible sizes of undiscovered fields in the region. The Paleozoic basins assessment involved quantitative analysis of six, regional-scale conceptual and immature plays. The remainder of the plays had insufficient information for quantitative analysis. All plays are listed in Table 1 with expected number of fields, median and range of play potential and the median volume of the largest undiscovered field size. Based on considerations of source rock types and hydrocarbon shows, all of the Paleozoic basin plays, except the carbonate platform slice play in the Humber Zone, were considered to have both oil and gas resource components. The Humber Zone play is likely gas-prone only because of thermal maturation considerations. Appendix A lists all input data used for quantitative statistical analysis of the play. Probability distributions of reservoir parameters and number of prospects and marginal probabilities for prospect and play level risks are tabulated.

Petroleum Plays

St. Lawrence Platform

Lower Ordovician HTD (hydrothermal dolomite) oil and gas play

Play definition. This oil and gas play involves all prospects associated with hydrothermal dolomitization within Lower Ordovician carbonate strata within the St. Lawrence Platform sedimentary succession in southern Quebec (Beekmantown Group), Anticosti Basin (Romaine Formation), and offshore and onshore western Newfoundland, including platform strata (St. George Group) beneath allochthons in the outer Humber Zone (Fig. 19). The Lower Ordovician Platform has also been explored in the Humber Zone of southern Quebec targeting large structural domes and block faulted strata of autochthonous Beekmantown carbonates under complexly thrusted allochthonous rocks. The Garden Hill oil discovery in western Newfoundland occurs in the relatively undeformed platform succession beneath easterly-derived allochthonous strata. Prospects in the Lower Ordovician play include small fault-bounded platform sags and rotated fault blocks, some occurring beneath complexly thrusted allochthonous rocks.

Play potential. This play has an estimated in-place oil potential range of 13.6 * 10^6 to 102.8 * 10^6 m^3 (P90-P10), with a median volume of 52 * 10^6 m^3 (Fig. 77; Table 1). The mean value of the number of predicted fields is 40. The largest undiscovered field is expected to contain 6.5 * 10^6 m^3 of oil (median value) (Fig. 78). Potential for the Lower Ordovician gas play ranges from 1.7 to 17.5 * 10^9 m^3 in-place with a median volume of 7 * 10^9 m^3 (Fig. 79). The estimate assumes a total field population of 98 (mean value), with the largest undiscovered field having an initial in-place volume of 764 * 10^6 m^3 of natural gas (Fig. 80). A porous Beekmantown dolomite section in the deep authochthon below the Humber thrust stack of southern Quebec contains mostly carbon dioxide. This reservoir in the St.-Simon well is calculated to contain 230 * 10^6 m^3 of CO_2-rich natural gas which matches with the seventh-largest predicted field size (Fig. 80).

Upper Ordovician HTD (hydrothermal dolomite) oil and gas play

Play definition. The HTD oil and gas play involves all prospects associated with hydrothermal dolomitization within Upper Ordovician carbonate strata within the St. Lawrence Platform sedimentary succession in southern Quebec (Black River and Trenton groups), Anticosti Basin (Mingan Formation), and offshore and onshore western Newfoundland, including platform strata (Table Head Group) beneath Humber Zone allochthons (Fig. 20). The Gentilly # 1 well completed in southern Quebec in 2006, was a sub-commercial gas discovery in Upper Ordovician carbonates. Prospect types are similar to the Lower Ordovician play.

Play potential. Estimates of the potential for the Upper Ordovician HTD oil play range from 12.5-137.6 * 10^6 m^3 with a median in-place volume of 63.8 * 10^6 m^3 distributed in

Table 1: Oil and gas potential in Maritimes Basin, St. Lawrence Platform, Humber Zone and Gaspe Belt (O=oil; G=gas)

Play name	Expected no. of fields (mean)	Range of play potential (in-place) (million m^3)	Median play potential (in-place) (million m^3)	Median of largest field size (in-place) (million m^3)
Maritimes Basin				
Lower Carboniferous clastic (g)	73	171630-672430	452070	49769
Lower Carboniferous clastic (o)	32	47.8-188.4	124	14,5
Visean Windsor reefs (o & g)				
Upper Carboniferous clastic (g)	56	342760-1042000	656730	74095
Upper Carboniferous clastic (o)	16	50.5-195.5	111	22,5
Total	**129 (G); 48 (O)**	**712220-1564900 (G); 143-345 (O)**	**1116500 (G); 239 (O)**	
St. Lawrence Platform				
Cambrian rift-drift clastics (g)				
Lower Ordovician HTD (g)	98	1688-17467	7009	764
Lower Ordovician HTD (o)	40	13.6-102.8	52,3	6,5
Upper Ordovician HTD (g)	119	6875-78656	28804	2426
Upper Ordovician HTD (o)	91	12.5-137.6	63,8	4,6
Upper Ordovician/Devonian foreland (o & g)				
Onshore Quaternary sands (g)				
Quaternary offshore -St. Lawrence estuary (g)				
Total	**217 (G); 131 (O)**	**14972-88158 (G); 54.5-207.3 (O)**	**39797 (G); 126.8 (O)**	
Humber Zone				
Cambrian-Ordovician deep water clastics (g)				
Ordovician carbonate platform slices (g)	42	1431-19026	5631	776,5
Total	**42 (G)**	**1431-19026 (G)**	**5631 (G)**	
Gaspe Belt				
Lower Silurian clastics (o & g)				
Lower Silurian HTD (o & g)				
Upper Silurian limestones & HTD (o & g)				
Lower Devonian pinnacle reefs HTD (o & g)				
Lower Devonian Upper Gaspe limestone (o & g)				
Lower Devonian Gaspe sandstone (o)	11	n/a-103.8	16,2	7,5
Lower Devonian Gaspe sandstone (g)				
Total	11 (O)	n/a-103.8 (O)	16.2 (O)	
Gulf of St. Lawrence Region (Total)		**765930-1617500 (G) 274.9-543.7 (O)**	**1170000(G) 402.7 (O)**	

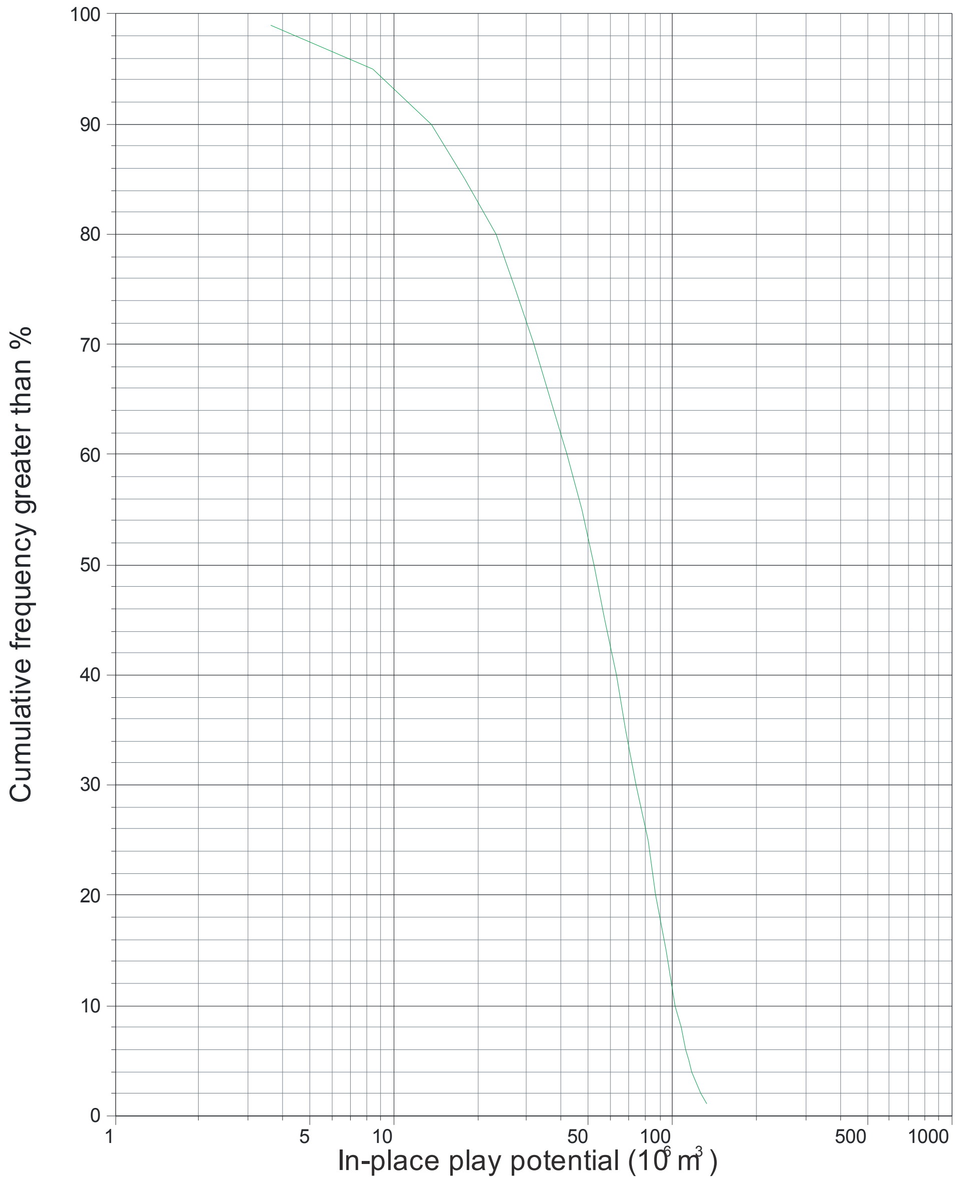


Figure 77. Estimate of in-place oil potential of the Lower Ordovician HTD play in St. Lawrence Platform. Median value of probabilistic assessment is 52 million m^3 of in-place oil distributed in 40 fields.

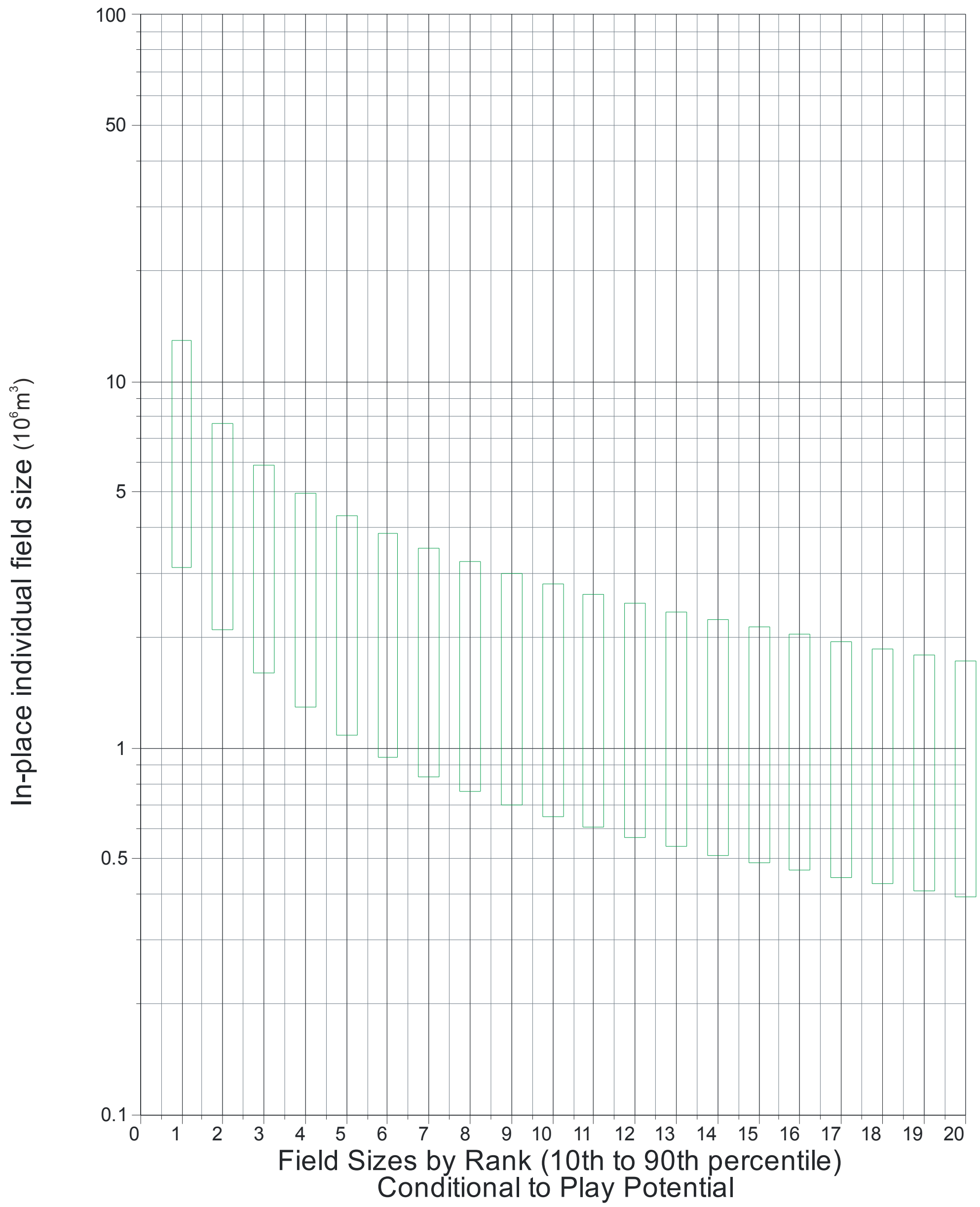


Figure 78. Field size-by-rank plot of the 20 largest predicted field sizes of the Lower Ordovician HTD play in the St. Lawrence Platform. Median value of largest field size is 6.5 million m^3 of in-place oil.

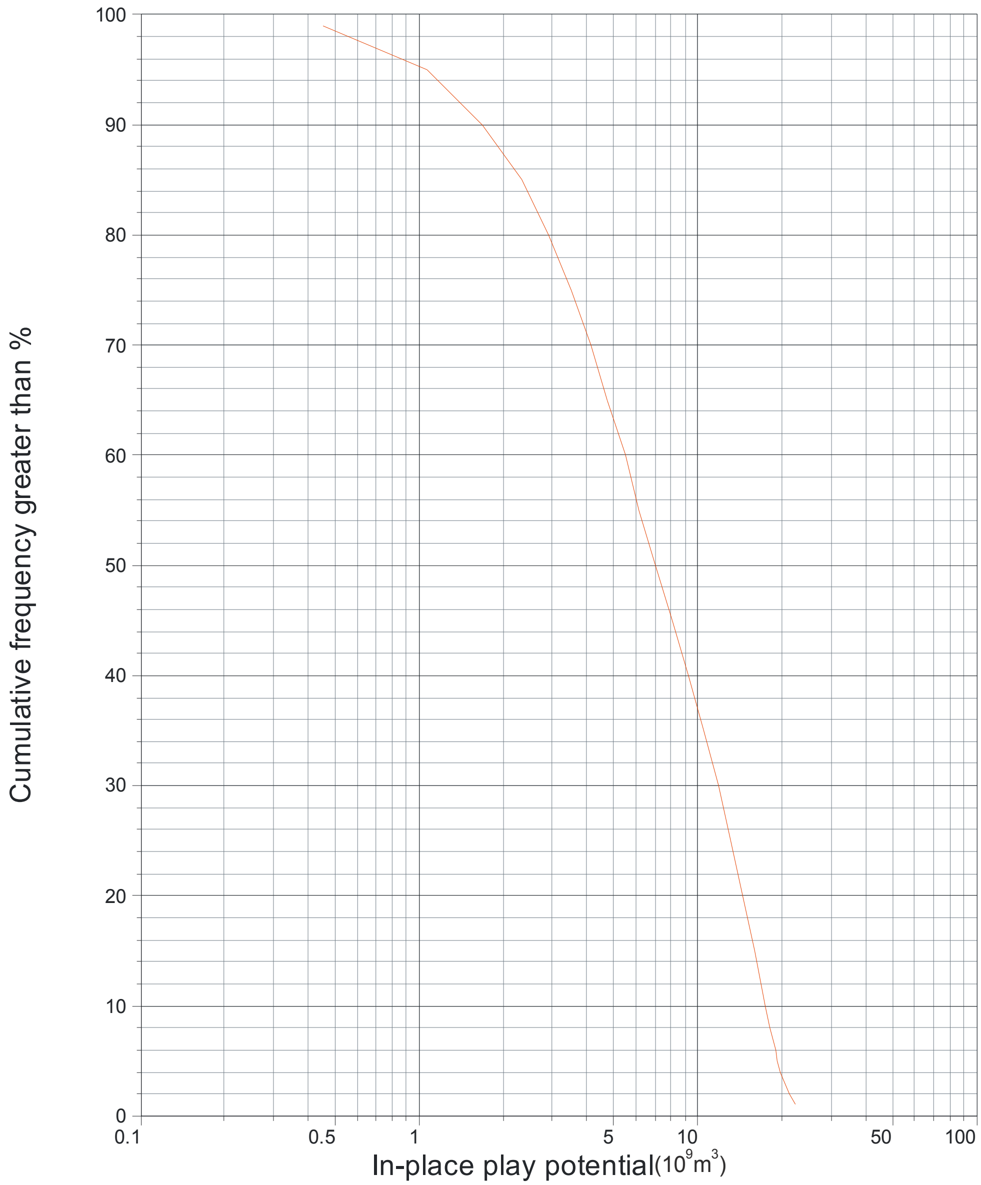


Figure 79. Estimate of in-place gas potential of the Lower Ordovician HTD play in the St. Lawrence Platform. Median value of probabilistic assessment is 7 billion m^3 of in-place gas distributed in 98 fields.

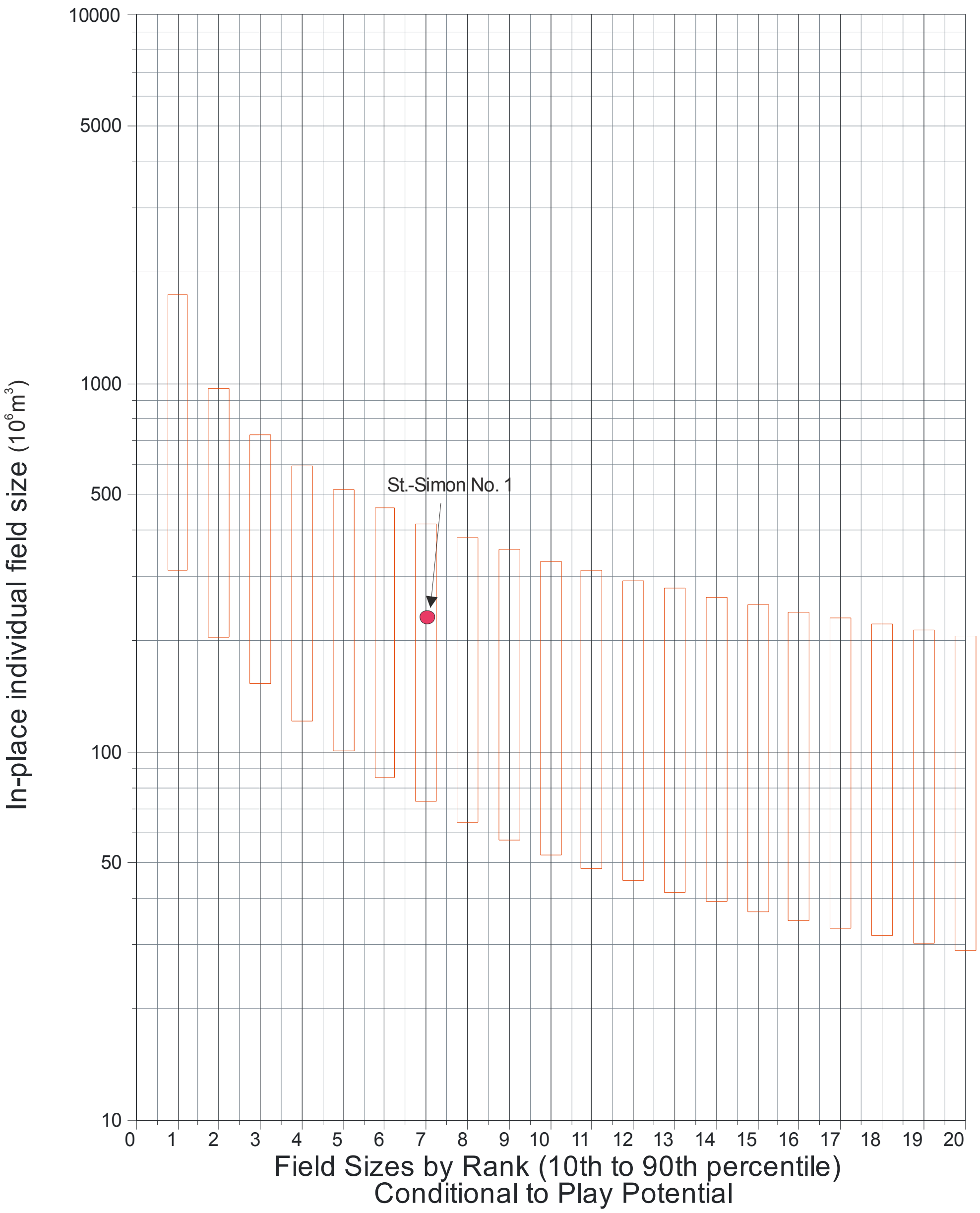


Figure 80. Field size-by-rank plot of the 20 largest predicted field sizes of the Lower Ordovician HTD gas play in the St. Lawrence Platform. Median value of largest field size is 764 million m^3 of in-place gas.

91 fields (mean value) (Fig. 81, Table 1). The largest undiscovered oil field is predicted to contain 4.6 * 10^6 m^3 (median value) (Fig. 82). The Upper Ordovician gas play predicts a mean value of 119 fields having a play potential ranging from 6.9 to 78.7 * 10^9 m^3 with a median in-place potential of 28.8 * 10^9 m^3 (Fig. 83, Table 1). The largest estimated gas field is 24.3 * 10^9 m^3 (median in-place volume) (Fig. 84, Table 1). There are no reports as yet of the size of the gas discovery at Gentilly #1.

Discussion of Assessment Results

Resource potential. Median estimates of total petroleum potential for the St. Lawrence platform assessment region (from all plays quantitatively analyzed) are 126.8 * 10^6 m^3 (798 MMbbl) of in-place oil and 39.8 * 10^9 m^3 (1.4 Tcf) of in-place gas (Table 1; Figs. 85, 86) (Note that the total median estimates for assessment regions are not derived arithmetically by adding together the median hydrocarbon potentials of individual plays. These numbers are derived by statistical summing techniques). High confidence (90% probability) and speculative (10% probability) estimates of total oil potential are 54.5 and 207.3 * 10^6 m^3 (343 and 1303 MMbbl), respectively. High confidence and speculative estimates of gas potential are 15 and 88.1 * 10^9 m^3 (0.5 and 3.1 Tcf), respectively (Table 1; Figs. 85, 86). The wide range of estimates of total potential is typical of frontier region assessments and reflects the geological uncertainties in quantifying lightly explored or conceptual exploration plays.

Resource distribution. The greater oil and gas potential occur in the Upper Ordovician play (Table 1). The largest individual oil and gas field sizes, however, vary between plays. The largest oil field is predicted to occur in the Lower Ordovician play, with a median size estimate of 6.5 * 10^6 m^3 (40.9 MMbbl) of in-place oil. This oil is distributed among 40 predicted fields in the Lower Ordovician play compared to 91 in the Upper Ordovician play. With respect to natural gas, the largest predicted field occurs in the Upper Ordovician HTD play (24.3 * 10^9 m^3 median volume; 85.7 Bcf). The Upper Ordovician gas play also predicts a greater number of fields. Field size rankings for all plays suggest that about 25 to 40% of the region's total petroleum resource is expected to occur in the five largest oil and gas fields. This resource distribution indicates a poorly to moderately concentrated hydrocarbon habitat, typical of large composite cratonic margin basins (Klemme, 1984).

The assessment results indicate the Upper Ordovician HTD play is expected to contain about 70% of the region's total natural gas resource volume in carbonate reservoirs and 9 of the 10 largest pools, a concentration reflecting the greater abundance and quality of reservoirs

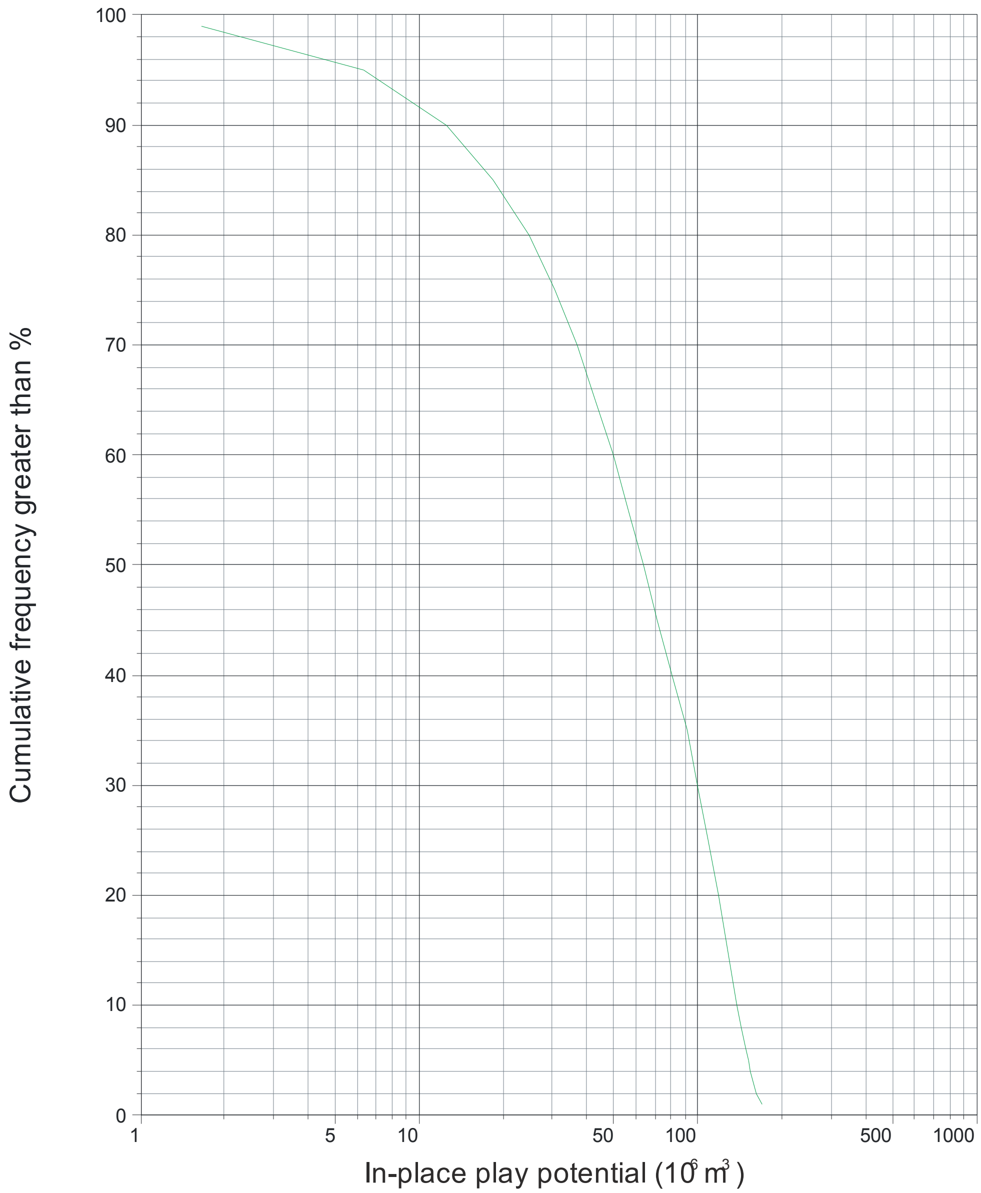


Figure 81. Estimate of in-place oil potential of the Upper Ordovician HTD play in the St. Lawrence Platform. Median value of probabilistic assessment is 63.8 million m^3 of in-place oil distributed in 91 fields.

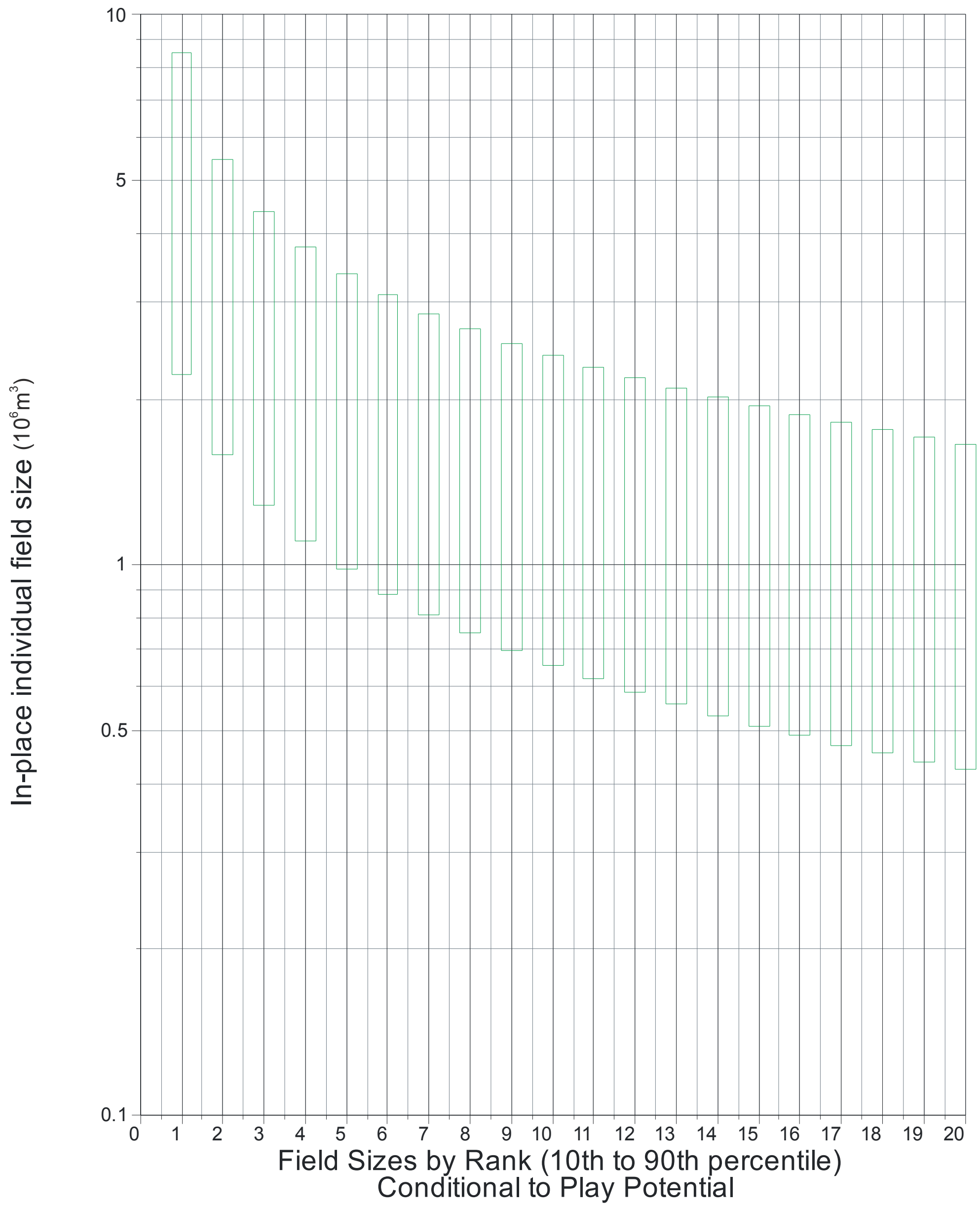


Figure 82. Field size-by-rank plot of the 20 largest predicted field sizes of the Upper Ordovician HTD play in the St. Lawrence Platform. Median value of largest field size is 4.6 million m^3 of in-place oil.

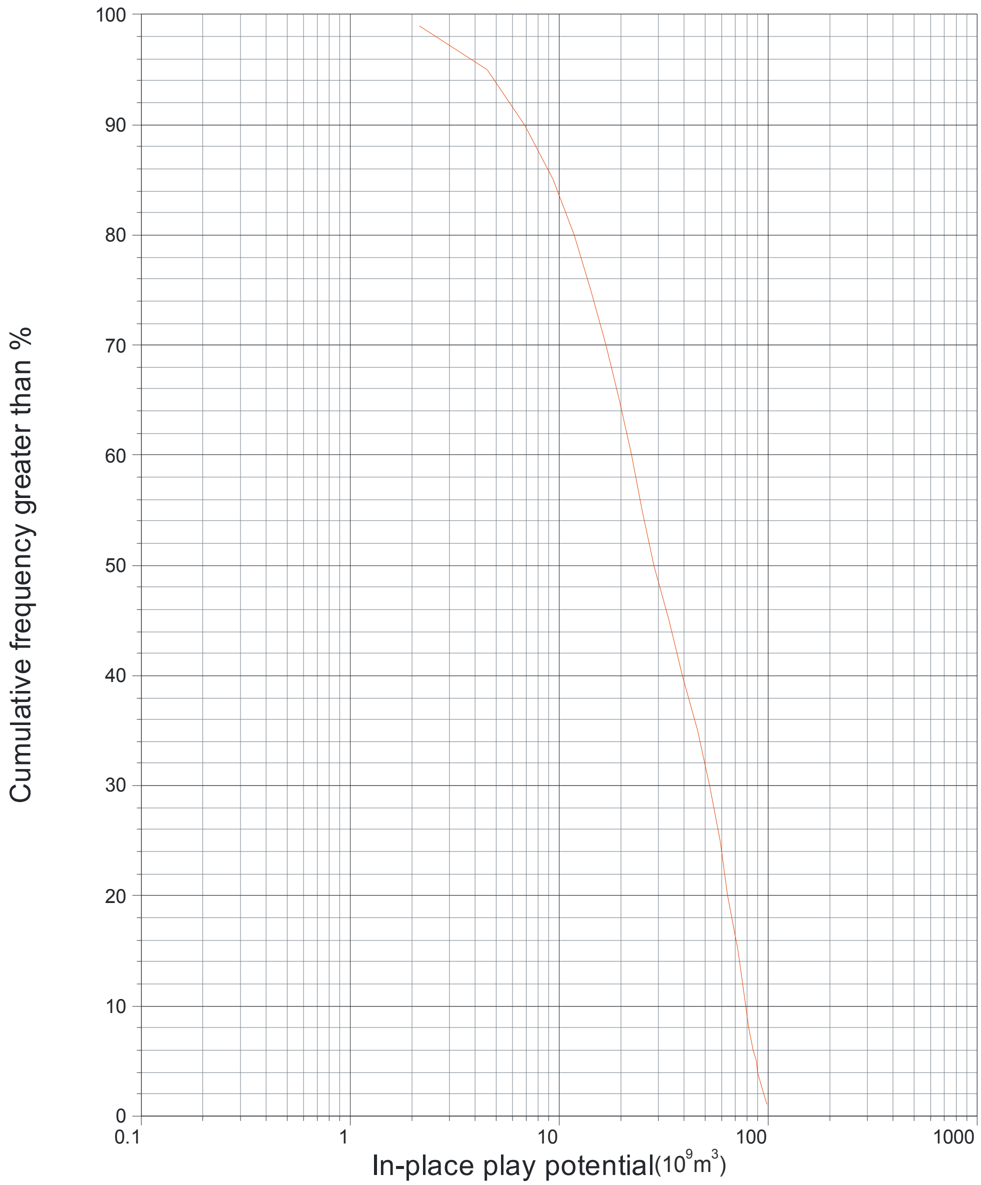


Figure 83. Estimate of in-place gas potential of the Upper Ordovician HTD play in the St. Lawrence Platform. Median value of probabilistic assessment is 28.8 billion m^3 of in-place gas distributed in 119 fields.

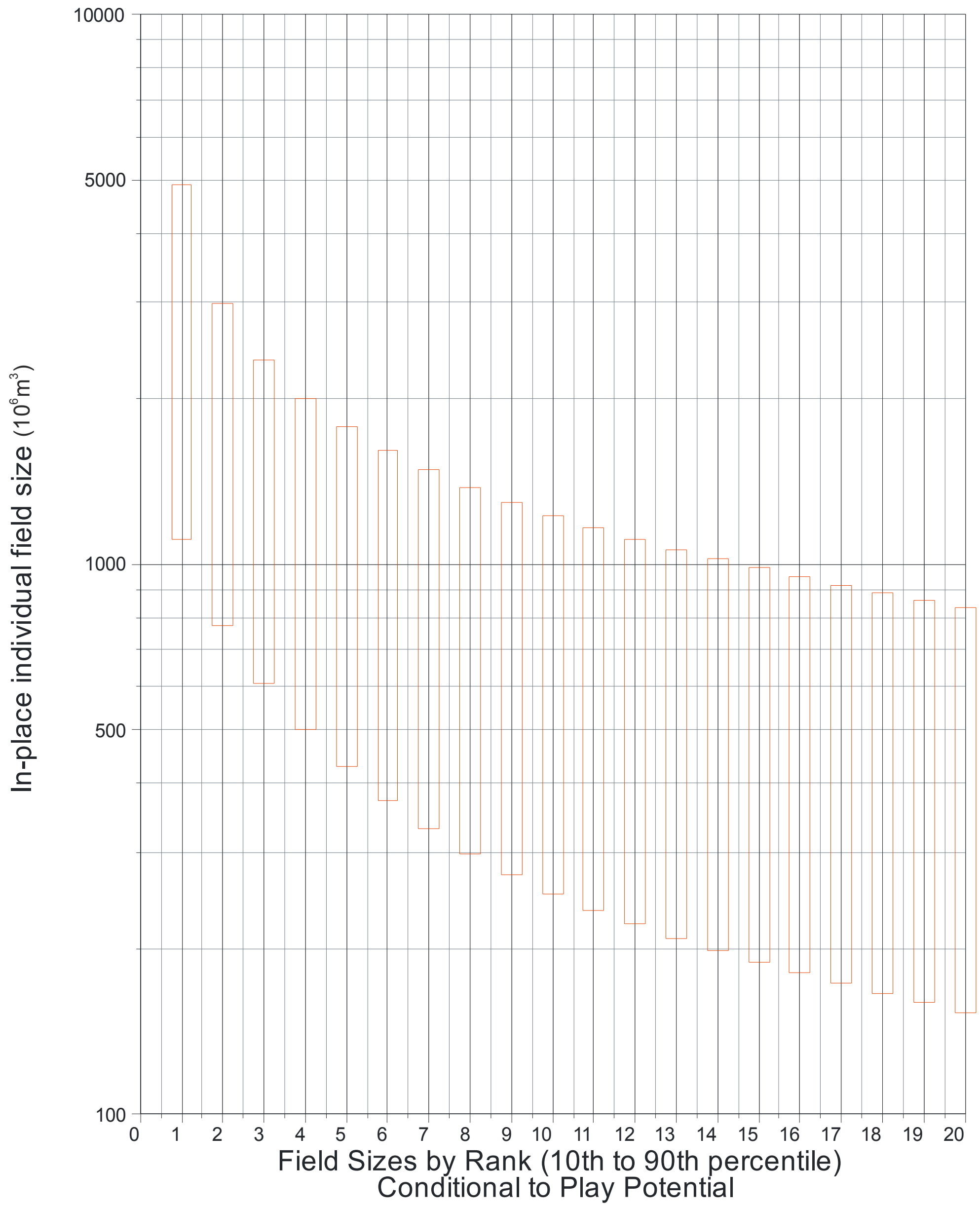


Figure 84. Field size-by-rank plot of the 20 largest predicted field sizes of the Upper Ordovician HTD gas play in the St. Lawrence Platform. Median value of largest field size is 2426 million m^3 of in-place gas.

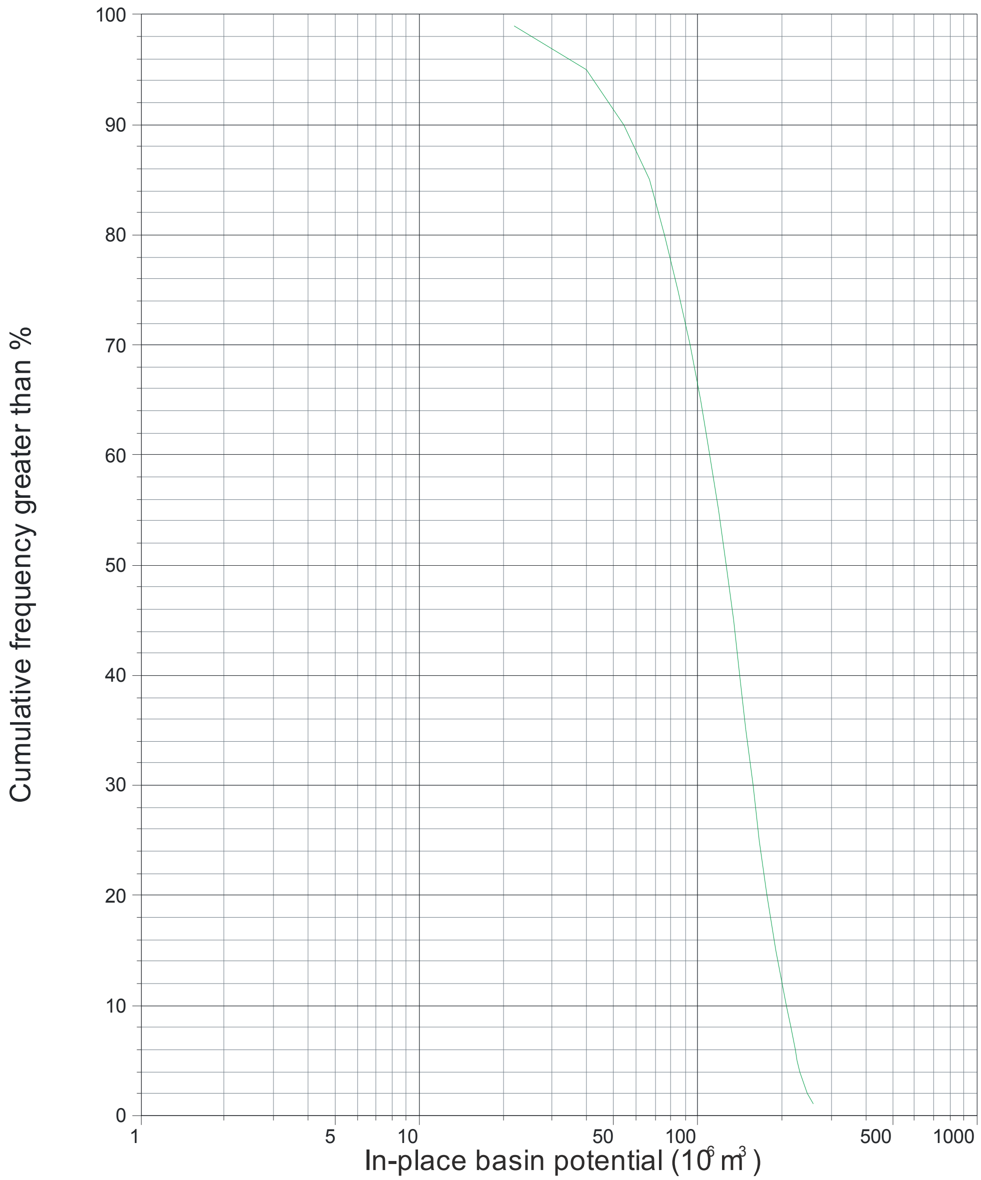


Figure 85. Estimate of total oil potential for the St. Lawrence Platform region. Median value of probabilistic assessment is 126.8 million m^3 of in-place oil.

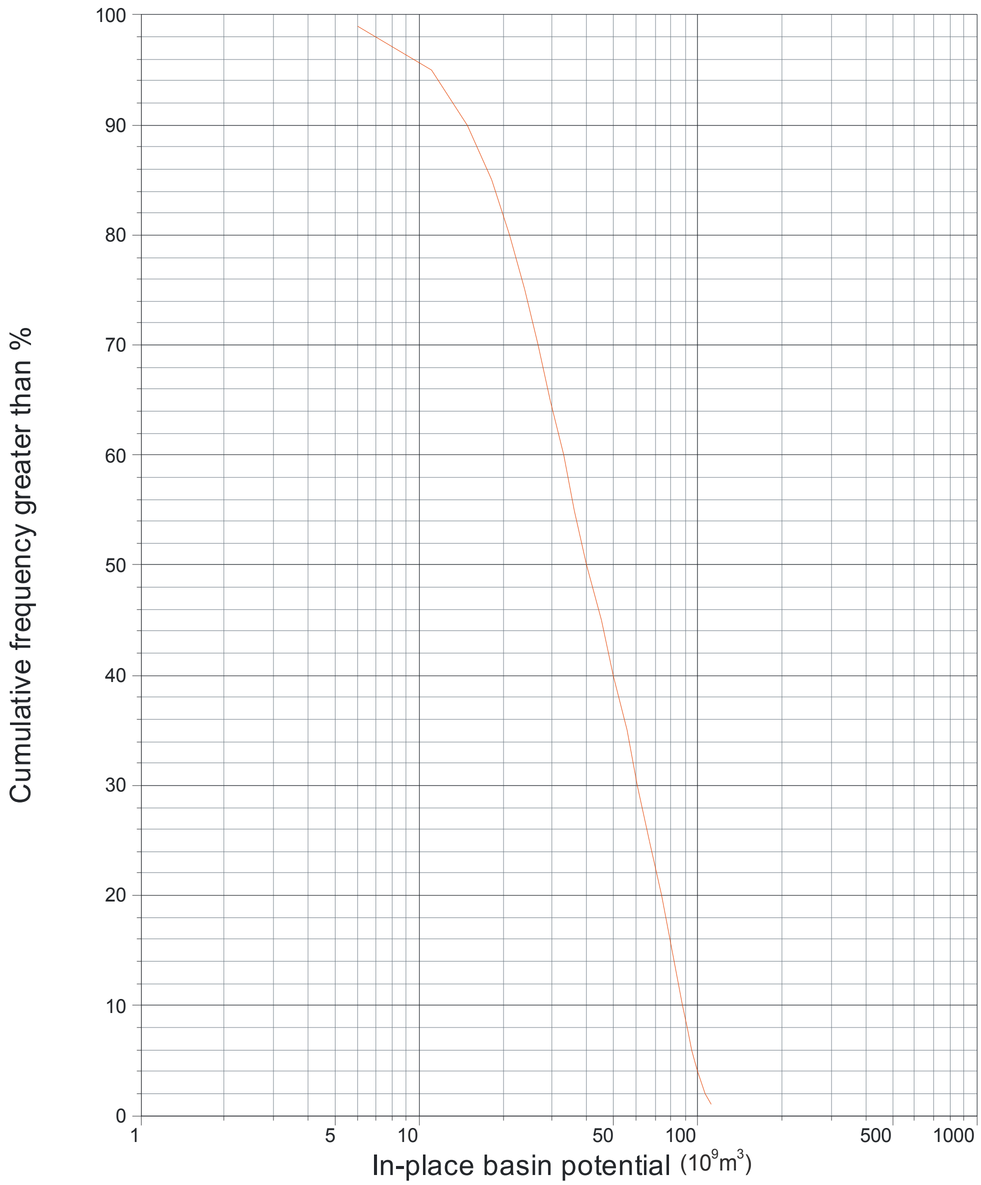


Figure 86. Estimate of in-place gas potential for the St. Lawrence Platform region. Median value of probabilistic assessment is 39.8 billion m^3 of in-place gas.

within the Middle and Upper Ordovician foreland shelf succession. On the other hand, predicted oil field sizes show a dissimilar distribution. The Lower and Upper Ordovician HTD oil resource volumes are about equal and 6 of 10 of the largest fields are predicted to occur in the Lower Ordovician play representing the passive margin tectonic setting. In terms of general geographic area within the region, the oil plays are restricted to the northeastern segments of the St. Lawrence Platform between Anticosti Island and western Newfoundland. The most prospective portion of the play area also correspond to the oil-prone region in both plays reflecting the optimum combination of oil and gas with their respective oil-equivalent energy contents, excellent source rock in western Newfoundland, minor but significant compressive deformation beneath the allochthon, the allochthon itself providing a long-term seal, and the occurrence of the only discovery, the Garden Hill oil and gas accumulation. Southern Quebec, Anticosti Basin west of Anticosti Island and northwestern onshore and offshore Newfoundland are less prospective partly due to the probable lack of effective seals and the higher maturation levels of potential source rocks.

The preceding discussion does not reflect the complete distribution of potential oil and gas resource in the St. Lawrence platform region because insufficient data were available to quantitatively assess the oil and gas expected to occur in the Cambrian rift-drift clastic or Upper Ordovician/Devonian (?) foreland sediment play.

Assessment results and exploration history. The exploration risks estimated for the St. Lawrence platform plays suggest success rates for exploratory drilling in the region should average about 0.14. The occurrence of one gas discovery and numerous gas flows from drill-stem tests in the 183 exploratory wells drilled in the region reveal a historical success rate near 0.12 corresponding closely with the exploration risk. One oil discovery and 3 oil flows recorded in three other wells from 20 exploratory wells in the oil plays indicate a historical success rate near 0.18 again suggesting relatively close correlation with the estimated exploration risk.

Although historical success rates and exploration risk are similar, the small differences may reflect inadequate or partially diagnostic exploration tests of the reservoirs under consideration. Initial exploration programs tested faulted structural highs and unconformity-bounded Lower Ordovician units. These early tests resulted in numerous consequent and extensive studies that identified source rocks such as Upper Ordovician Utica Shale, their rank of thermal maturation as well as potential reservoirs.

Current exploration strategies for conventional resource are focused on hydrothermal dolomites and the critical roles that strike-slip or extensional faulting plays in creating conduits for high pressure and high temperature dolomitizing fluids. The historical success rate already achieved is somewhat remarkable in that the hydrothermal dolomite play concept was not recognized in the region until recently, so the fact that many wells in the historical record in southern Quebec and Anticosti Island encounter numerous sub-commercial oil and gas shows and flows bode well for future success. Some wells are undoubtedly drilled in less than optimum locations. Historically, the first significant hydrocarbon discovery in a frontier region is often preceded by many unsuccessful exploration wells. It is noteworthy that the Gentilly #1 discovery was the second well specifically drilled to test a seismic-defined sag anomaly indicative of the hydrothermal dolomite reservoir model.

Comparison with play analogue. Coeval rocks in eastern United States, the prolific Trenton-Black River fairway including the Albion-Scipio petroleum field in Michigan Basin and the Finger Lakes gas fields in upper New York state, extend into southern Ontario and Quebec and along the St. Lawrence River and provide an acceptable exploration analogue for hydrocarbon exploration in the Gulf. The Ordovician Trenton-Black River hydrothermal dolomite play in southern Ontario is an appropriate regional analogue for the Upper Ordovician HTD play in the St. Lawrence Platform. Over $1.3 * 10^6$ m^3 of oil and $991 * 10^6$ m^3 of natural gas have been produced from the Trenton-Black River hydrothermal dolomite play in southern Ontario over the past 100 years (Trevail et al., 2004, Golder Associates Ltd, 2005). Individual linear hydrothermal dolomite bodies reach up to 14 kilometres in length and 1200 metres in width. In-place mean play potentials are predicted to be $8844 * 10^6$ m^3 gas in 1201 pools and $39 * 10^6$ m^3 oil in 106 pools (Trevail et al., 2004). There are numerous discoveries in the southern Ontario play, so a truncated discovery process model (TDPM) analysis can be utilized (Logan, 2005). The TDPM forecast of the ultimate number of pools contrasts with PRIMES' discovery process model that under-estimates the number due to economic truncation. Economic truncation occurs when provincial governmental agencies apply a lower limit for the size of pools that will be booked as reserves, thereby excluding many small pools. The estimated resource with respect to individual pool size range up to $5.9 * 10^6$ m^3 oil and $656 * 10^6$ m^3 gas (mean in-place volumes). Comparing with the Upper Ordovician HTD play in St. Lawrence Platform, (mean largest field size, oil $5.7 * 10^6$ m^3, gas $2829 * 10^6$ m^3), oil volumes are remarkably similar but gas volumes are substantially larger in the St. Lawrence platform play. The disparity in gas volumes reflect differences in prospect area and net pay derived from interpretation of onshore seismic data in southern Quebec and Anticosti (Thériault and Laliberté, 2006; Shell Canada, 2001), and petrophysical log analysis

(Hu and Lavoie, 2008) on Anticosti Island compared to listed pool size parameters in southern Ontario.

Humber Zone

Ordovician carbonate platform thrust slices gas play

Play definition. One defined play in the Humber Zone had sufficient information for quantitative analysis. The Lower Ordovician carbonate platform thrust slice gas play includes structural and structural-stratigraphic traps in the Humber Zone adjacent to the Appalachian structural front in southern Quebec (Beekmantown Group) and western Newfoundland (St. George Group) (Fig. 23). The Saint-Flavien gas field, discovered in 1976, is the largest gas discovery in Quebec.

Play potential. The total in-place median play potential is 5.6 * 10^9 m^3 of gas (Fig. 87; Table 1). Play potential ranges from 1.4 to 19 * 10^9 m^3 (Fig. 87; Table 1). The predicted median of the largest field is 776.5 * 10^6 m^3 in-place (Fig. 88; Table 1). The mean number of fields expected in the play is 42. The Saint-Flavien reservoir (Beauharnois Formation pool) has a reported in-place volume of 252 * 10^6 m^3 of natural gas. This volume matches most closely with the ninth largest predicted field size (median in-place volume of 257.4 * 10^6 m^3; Fig. 88).

Discussion of Assessment Results

Resource distribution. One exploration play in the Humber Zone, the Ordovician carbonate thrust slice play, had sufficient information for quantitative analysis. The predicted gas volume is 5.6 * 10^9 m^3 (199 Bcf) distributed in 42 fields (Fig. 87). Approximately 45% of the region's total petroleum resource is concentrated in the 5 largest pools. This distribution indicates a moderate concentration of gas resource consistent with a moderately-sized composite cratonic margin basin (Klemme, 1984).

The area near the Saint-Flavien discovery is considered the most prospective due to presence of Utica source rock occurring directly beneath potential carbonate reservoir thrust slices, the occurrence of thicker more brittle dolomite intervals in the region allowing for enhanced fracture development (potential reservoir facies), and known positive DST tests in nearby wells. About 50 thrust slices have been mapped in southern Quebec. However, the detached carbonate platform slice play in western Newfoundland is little explored indicating prospectivity in that area may be underestimated.

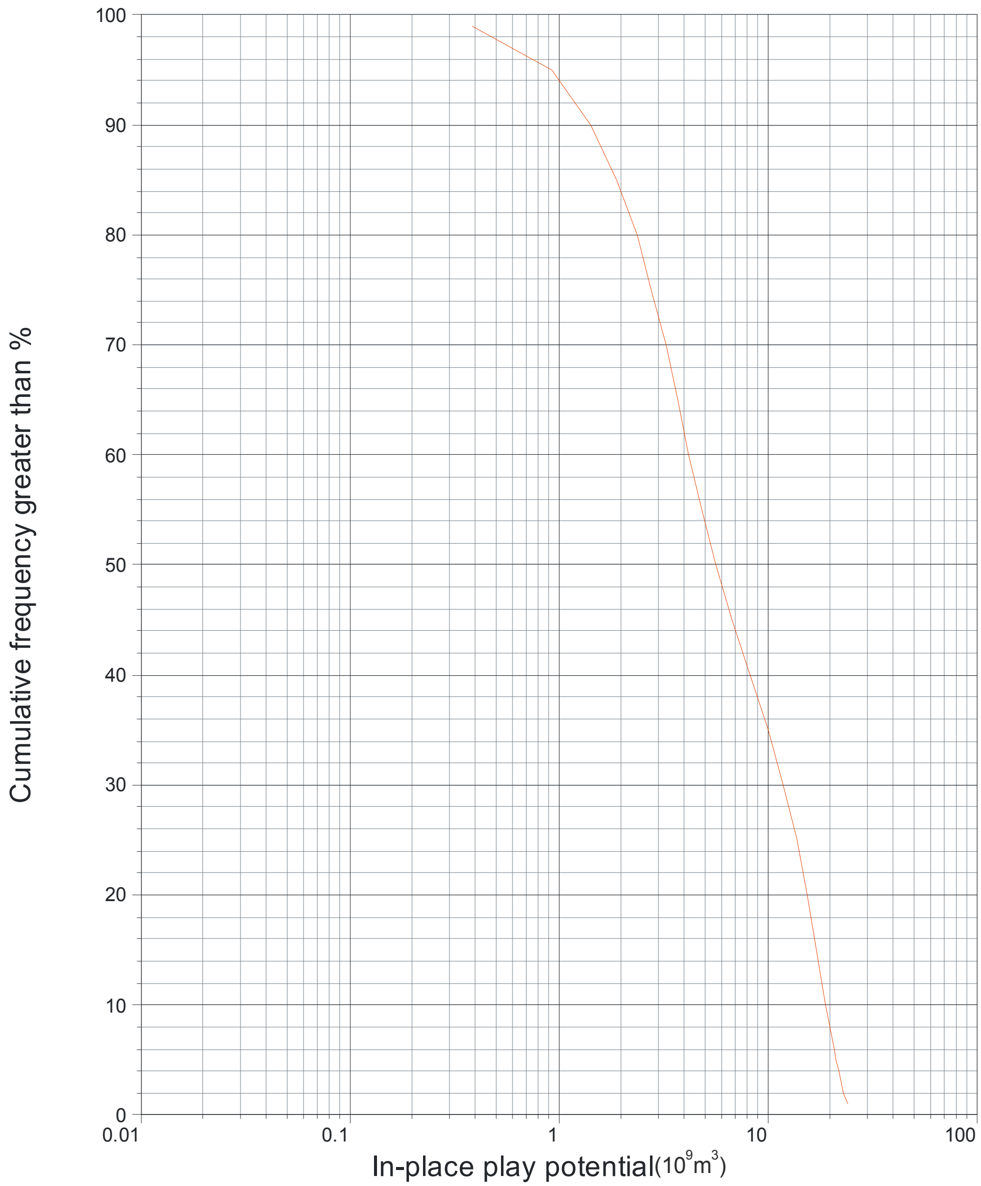


Figure 87. Estimate of in-place gas potential of the Ordovician carbonate platform slices play in the Humber Zone. Median value of probabilistic assessment is 5.6 billion m^3 of in-place gas distributed in 42 fields.

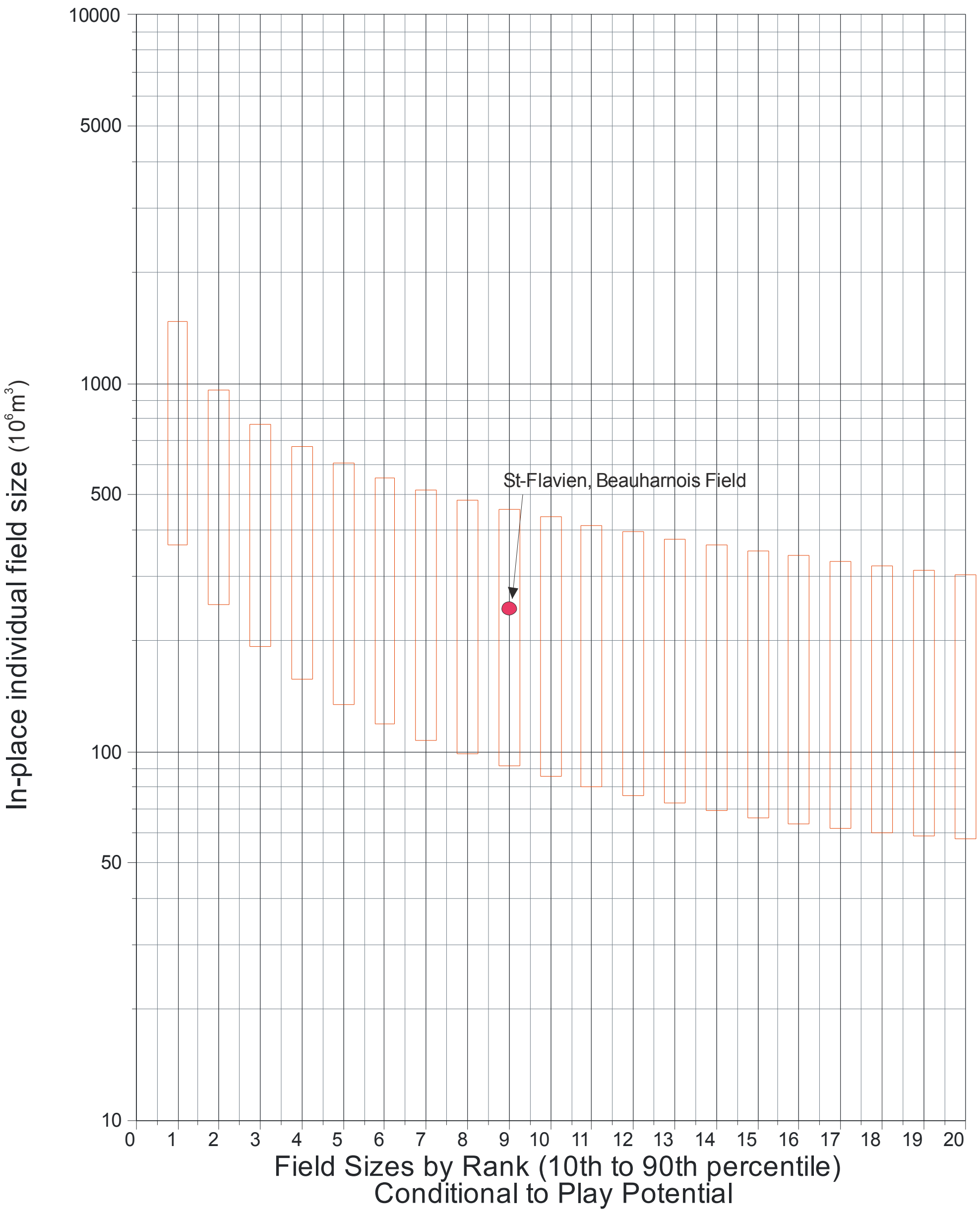


Figure 88. Field size-by-rank plot of the 20 largest predicted field sizes of the Ordovician carbonate platform slices gas play in the Humber Zone. Median value of largest field size is 776.5 million m^3 of in-place gas.

The preceding discussion does not reflect the complete distribution of potential resource in the Humber Zone region because insufficient data were available to quantitatively assess the oil and gas expected to occur in the Cambrian-Ordovician deep water clastic gas play.

Assessment results and exploration history. The exploration risk estimated in the play assessment suggests success rates for exploratory drilling in the region should average about 0.08. The presence of one commercial discovery in 26 exploratory wells drilled to date as well as 9 other wells exhibiting gas flows in DSTs represents a success ratio of 0.38 indicating significant success was achieved in previous exploration attempts. Many of the successful wells, however, are SOQUIP Saint-Flavien wells located in very close proximity and drilled subsequent to the St-Flavien field discovery, suggesting that these wells should not be considered as rank wildcat exploratory tests, but as delineation wells. The removal of these wells from the historical success rate calculation reduces the success ratio by half which is more indicative of the assumed exploration risk.

The Lower Paleozoic Appalachians in southern Quebec did not receive significant exploration attention until the late 1960s when seismic surveys revealed a foothills-type exploration model. This understanding directly led to the St-Flavien gas discovery. Despite the successful exploration history, the Humber Zone remains the least explored region in southern Quebec and western Newfoundland. Early drilling tested structural closures, such as faulted anticlines. Later recognition of fractured and hydrothermal dolomite occurrences in the tectonic slices provides additional trapping mechanisms for accumulation and preservation of hydrocarbons. In previous exploration activity at the Appalachian structural front, drilling was focused on the Beekmantown interval in the thrust slices. However, given the recognition of reservoir potential in the Trenton-Black River interval elsewhere in the region, significant attention is likely in the latter and proper testing of the units is expected.

Gaspé Belt

Lower Devonian Gaspé sandstone oil play

Play definition. The Gaspé sandstone oil play is defined by stratigraphic and stratigraphic-structural traps in nearshore coarse-grained clastic units of the Lower Devonian Gaspé Sandstones in eastern Gaspé Peninsula (Fig. 27, 40). The Haldimand oil field discovered in 2006 in York River Formation fluvial sands is still under evaluation (40 BOE/d over prolonged testing).

Play potential. Median potential for in-place oil in the Lower Devonian Gaspé sandstone play is predicted to be 16.2 * 10^6 m^3 (Fig. 89; Table 1) distributed among 13 fields. The largest field is expected to have an in-place volume of 7.5 * 10^6 m^3 (Fig. 90; Table 1)

Discussion of Assessment Results.

Resource distributions. One of six hydrocarbon plays in Gaspé Belt was quantitatively assessed for resource potential. Approximately 80% of the region's total petroleum resource is concentrated in the 5 largest pools. This distribution indicates a high concentration of oil resource which seems to be inconsistent with a foreland basin formed by continued convergent plate margin tectonics (Malo, 2001). According to Klemme (1984), the total resource should be more evenly distributed among all field sizes in convergent plate margin basins. The preceding discussion does not reflect the complete distribution of potential resource in the Gaspé Belt region because insufficient data were available to quantitatively assess the oil and gas expected to occur in the Lower Silurian clastic, Lower Silurian hydrothermal dolomite, Upper Silurian hydrothermal dolomite and limestone, Lower Devonian hydrothermally altered pinnacle reef, and the Lower Devonian Upper Gaspé Limestone oil and gas plays. A proper resource distribution discussion with respect to field size should include all defined plays in a region. The numerous unassessed plays may have quite different pool resource distributions than the single assessed play. The inconsistent field size distribution with respect to convergent plate margin basins may be attributable to these missing potential resource volumes.

Assessment results and exploration history. The Gaspé Sandstone oil play has a long exploration history with initial wells drilled in 1860 testing nearby oil seep occurrences. A spatial relationship between seeps and major Acadian faults such as Bassin Nord-Ouest and Troisième Lac (Lavoie and Bourque, 2001) was long recognized in the region. Early wells tested oil seeps associated with fractured anticlinal crests. The recent discovery of the Haldimand oil field where the accumulation is trapped in a stratigraphic/structural configuration indicates that traps with stratigraphic components are a significant target for future exploration programs. Exploration risk estimated in the assessment of the Lower Devonian Gaspé Sandstone oil play suggest success rates for exploration drilling in the region should be 0.13. The presence of one commercial discovery in 66 exploratory wells drilled to date penetrating the target in the play area as well as 7 other wells exhibiting oil flows in DSTs or showing histories of producing small quantities of oil (minimum production of 3.0

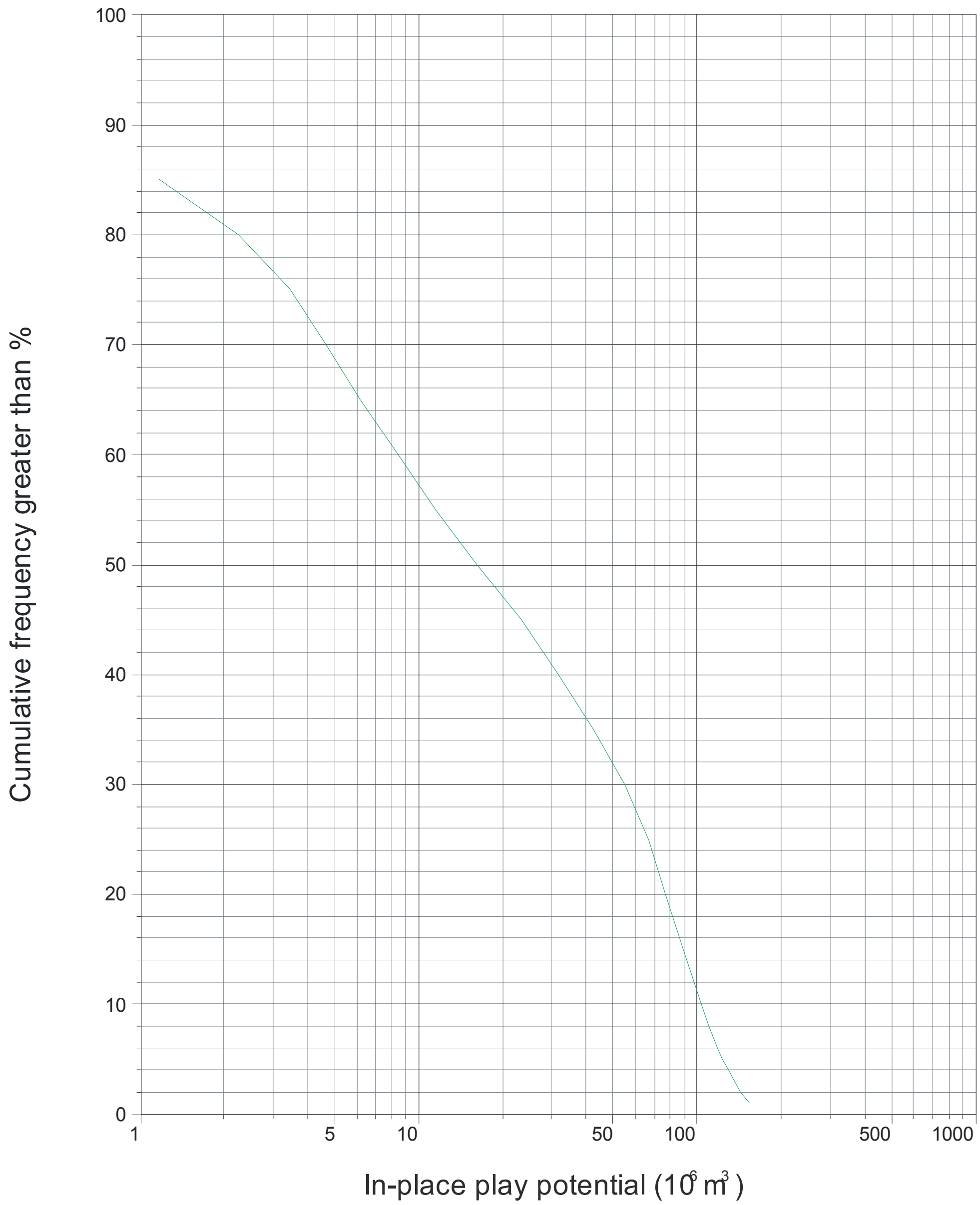


Figure 89. Estimate of in-place oil potential of the Lower Devonian Gaspe sandstone play in the Gaspe Belt. Median value of probabilistic assessment is 16.2 million m^3 of in-place oil distributed in 11 fields.

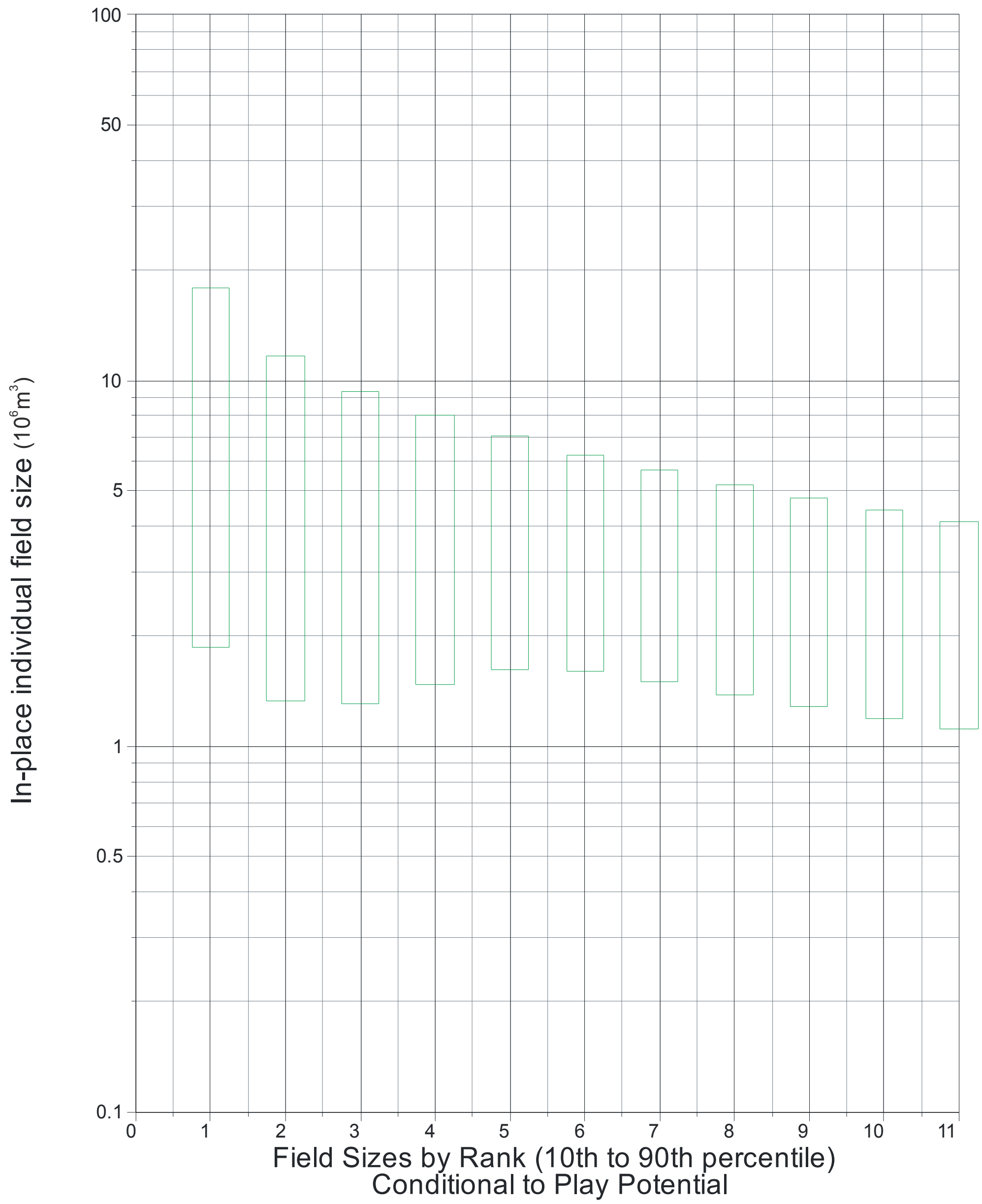


Figure 90. Field size-by-rank plot of all predicted field sizes of the Lower Devonian Gaspe sandstone oil play in the Gaspe Belt. Median value of largest field size is 7.5 million m^3 of in-place oil.

m^3), represents a success ratio of 0.12, indicating some success was achieved in previous exploration attempts.

Comparison with play analogue. An appropriate play analogue for the Lower Devonian Gaspé Sandstone oil play is the Oriskany sandstone structural/stratigraphic play in the Appalachian Basin of eastern United States. Similarities between the two regions include the general ages and types of reservoir strata, source rocks, regional unconformities and structures, and common occurrences of surface hydrocarbon shows. The Drake well drilled in 1859 at Titusville in northwestern Pennsylvania was located near surface oil seeps. The well produced oil from a Devonian sandstone and it was the foremost discovery for the United States Geological Survey's Devonian Shale-Middle and Upper Paleozoic Total Petroleum System Unit (Milici and Swezey, 2006) which includes the Oriskany petroleum plays. Gaspé and Oriskany sandstones are largely time- and facies-correlative in each of the foreland basins. The main difference between the two regions is the depositional setting of the sandstones; the Gaspé sandstones are a typical syn-orogenic molasse sequence coarsening upward from marine to terrestrial deposits brought about by an abrupt shoaling event. On the other hand, the Oriskany succession was deposited in a pre-orogenic shallow marine stable shelf setting. The Oriskany plays show regional maturation data indicating the play is gas-prone, rather than oil-prone in Gaspe Peninsula. This difference in hydrocarbon-type prevents a direct comparison of field-size results.

Maritimes Basin

Lower Carboniferous clastic play

Play definition. The Lower Carboniferous clastic oil and gas play includes all prospects in Tournaisian Horton Group and equivalent sedimentary clastic strata in structural-stratigraphic traps in the onshore-offshore Magdalen, Sydney, and St. Anthony basins (Fig. 60). The Stoney Creek oil and gas field discovered in 1909 and the McCully gas field discovered in 2000 in southeastern New Brunswick, occur in this play.

Play potential. The Lower Carboniferous play is characterized by numerous faulted anticlinal structures within the Horton Group. This play has an estimated in-place oil potential range of $47.8 * 10^6$ to $188.4 * 10^6$ m^3 (P90-P10), with a median volume of $124 * 10^6$ m^3 (Fig. 91; Table 1). The mean value of the number of predicted fields is 32. The largest undiscovered field is expected to contain $14.5 * 10^6$ m^3 of oil (median value) (Fig. 92). The Stoney Creek oil discovery is reported to contain $2.8 * 10^6$ m^3 (Contact Exploration, 2008) which matches with the 17th largest predicted field (Fig. 92).

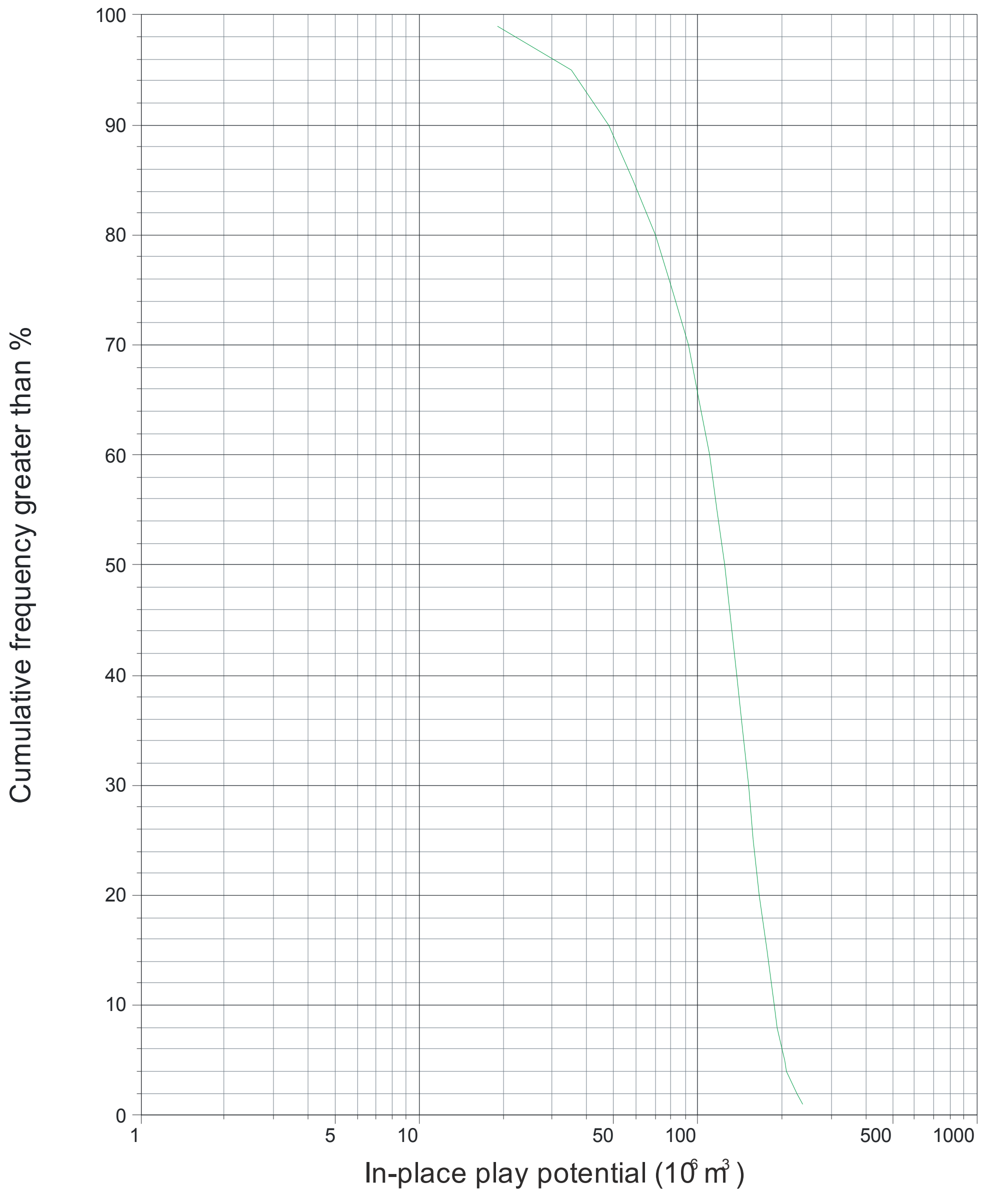


Figure 91 . Estimate of in-place oil potential of the Lower Carboniferous clastic play in the Maritimes Basin. Median value of probabilistic assessment is 124 million m^3 of in-place oil distributed in 32 fields.

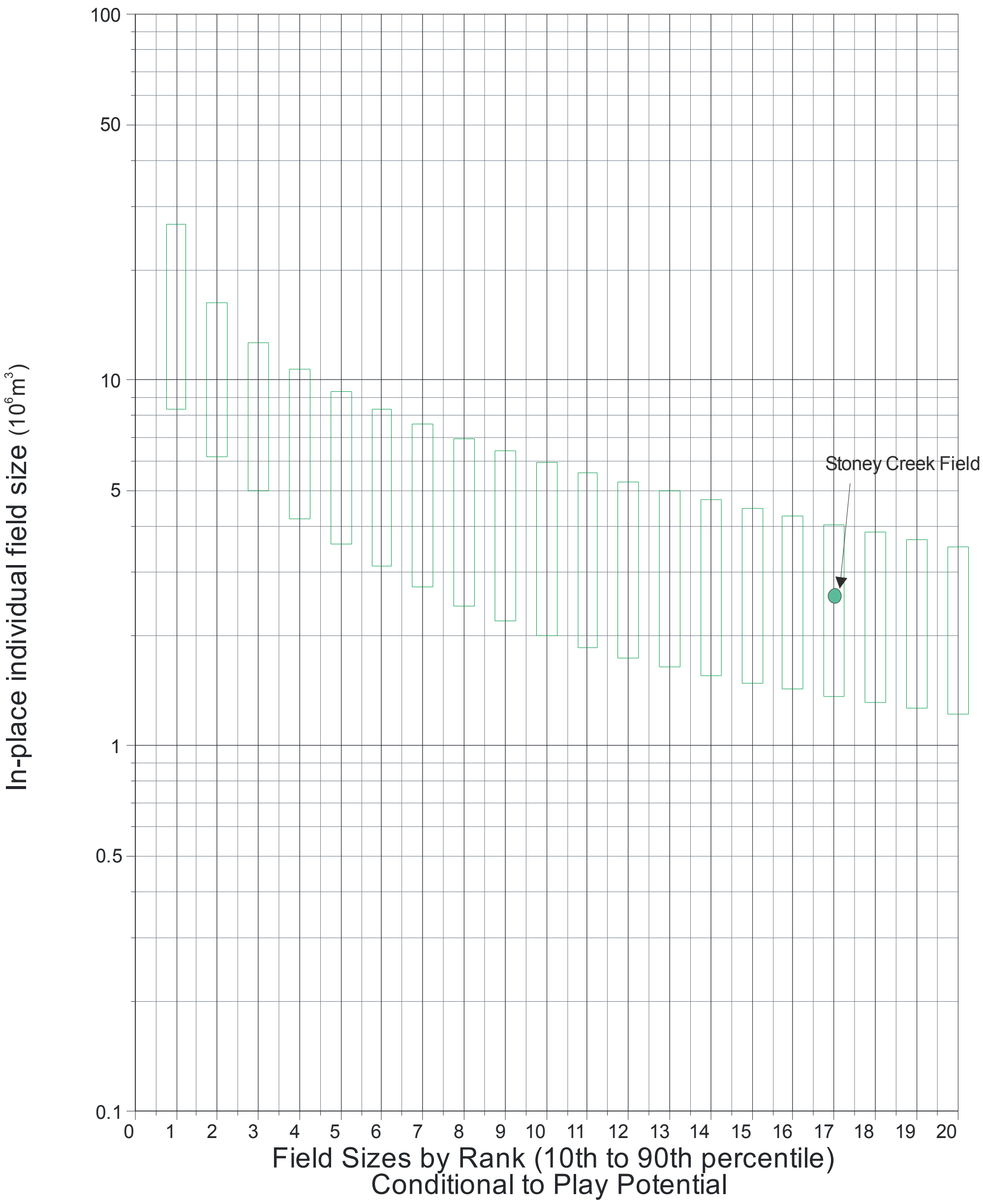


Figure 92. Field size-by-rank plot of the 20 largest predicted field sizes of the Lower Carboniferous clastic play in the Maritimes Basin. Median value of largest field size is 14.5 million m^3 of in-place oil.

Potential for the Lower Carboniferous gas play ranges from 171.6 to 672.4 * 10^9 m^3 in-place with a median volume of 452.1 * 10^9 m^3 (Fig. 93). The estimate assumes a total field population of 73 (mean value), with the largest undiscovered field having an initial in-place volume of 49.8 * 10^9 m^3 of natural gas (Fig. 94). The McCully gas field is reported as having an in-place median volume of 28320 * 10^6 m^3 (1 Tcf) (Keighley, 2008). This volume matches most closely with the third largest predicted pool size (Fig. 94).

Upper Carboniferous clastic play

Play definition. This oil and gas play involves all prospects occurring in the Upper Carboniferous-Lower Permian Cumberland and Pictou group sedimentary successions in the Magdalen, Sydney, and St. Anthony basins (the composite Maritimes Basin) (Fig. 71). A sub-commercial gas discovery at East Point E-49 in offshore eastern Magdalen Basin occurs in this play in uppermost sands of the Cable Head Formation.

Play potential. Estimates of the potential for the Upper Carboniferous clastic oil play ranges from 50.5-195.5 * 10^6 m^3 with a median in-place volume of 111 * 10^6 m^3 distributed in 16 fields (mean value) (Fig. 95, Table 1). The largest undiscovered oil field is predicted to contain 22.5 * 10^6 m^3 (median value) (Fig. 96). The Upper Carboniferous gas play predicts a mean value of 56 fields having a play potential ranging from 342.8 to 1042 * 10^9 m^3 with a median in-place potential of 656.7 * 10^9 m^3 (Fig. 97, Table 1). The largest gas field is estimated to contain 74.1 * 10^9 m^3 (median in-place volume) (Fig. 98, Table 1). The East Point E-49 field is reported to contain an in-place gas volume of 2180 * 10^6 m^3. This size does not satisfactorily match with any of the 56 predicted field sizes. The authors believe that the reported East Point gas volume relates to only one sand horizon (a gas pool) in the East Point structure. Net pay estimates for this assessment were derived by measuring all potential sandy reservoir horizons in the thick Cumberland and Pictou groups according to pre-defined net pay cutoffs including porosity, permeability, water saturation and thickness criteria (Hu and Dietrich, 2008). The greater net pay values derived from the petrophysical well-log analyses in Upper Carboniferous strata in the basin (including the succession in the East Point well) may have produced the apparent poor match of known and predicted field sizes in the play.

Discussion of Assessment Results

Resource potential. Median estimates of total petroleum potential for the Maritimes Basin assessment region (from all plays quantitatively analyzed) are 239 * 10^6 m^3 (1503 MMbbl) of in-place oil and 1116.5 * 10^9 m^3 (39.4 Tcf) of in-place gas (Table 1; Figs. 99

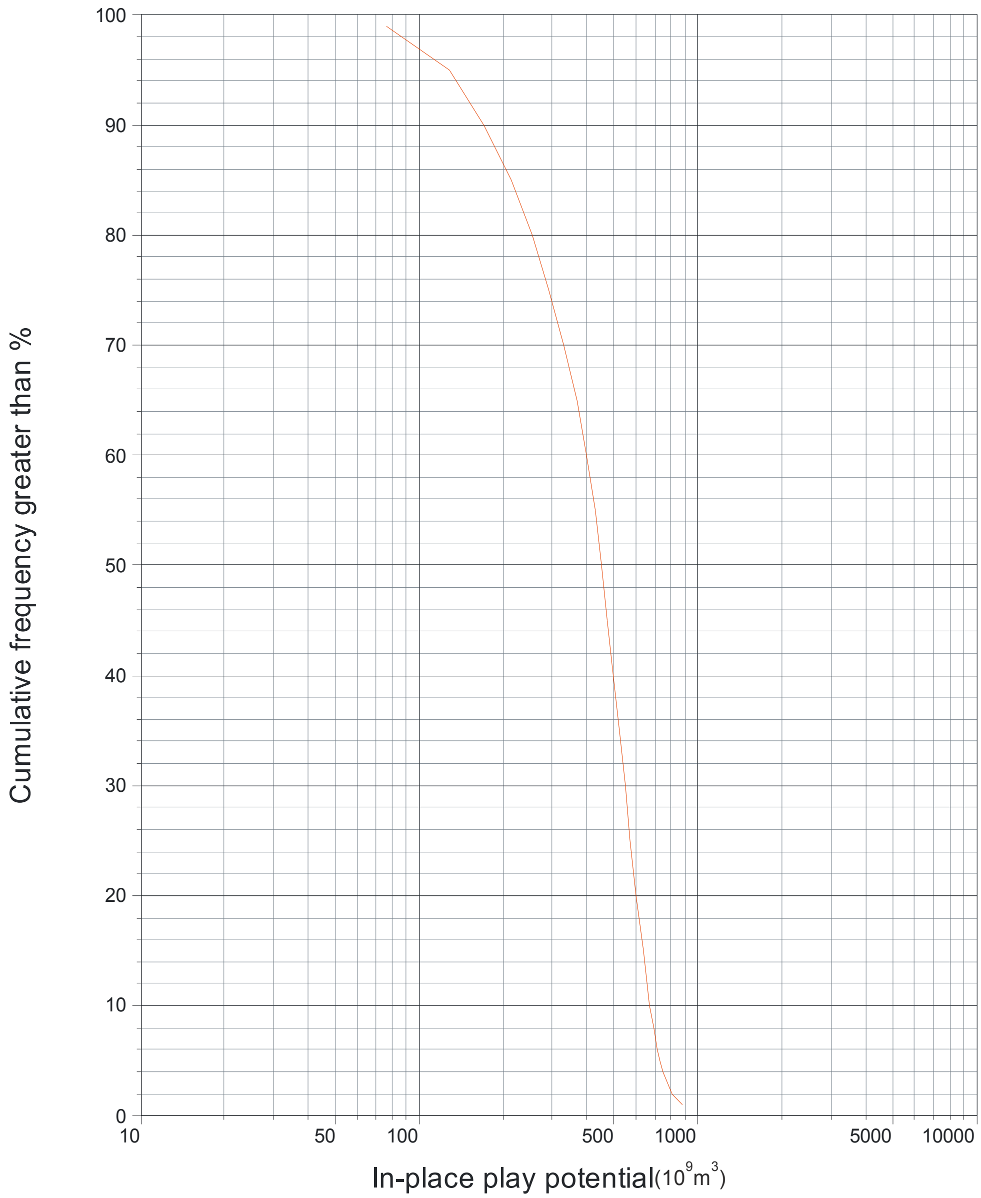


Figure 93. Estimate of in-place gas potential of the Lower Carboniferous clastic play in the Maritimes Basin. Median value of probabilistic assessment is 452.1 billion m^3 of in-place gas distributed in 73 fields.

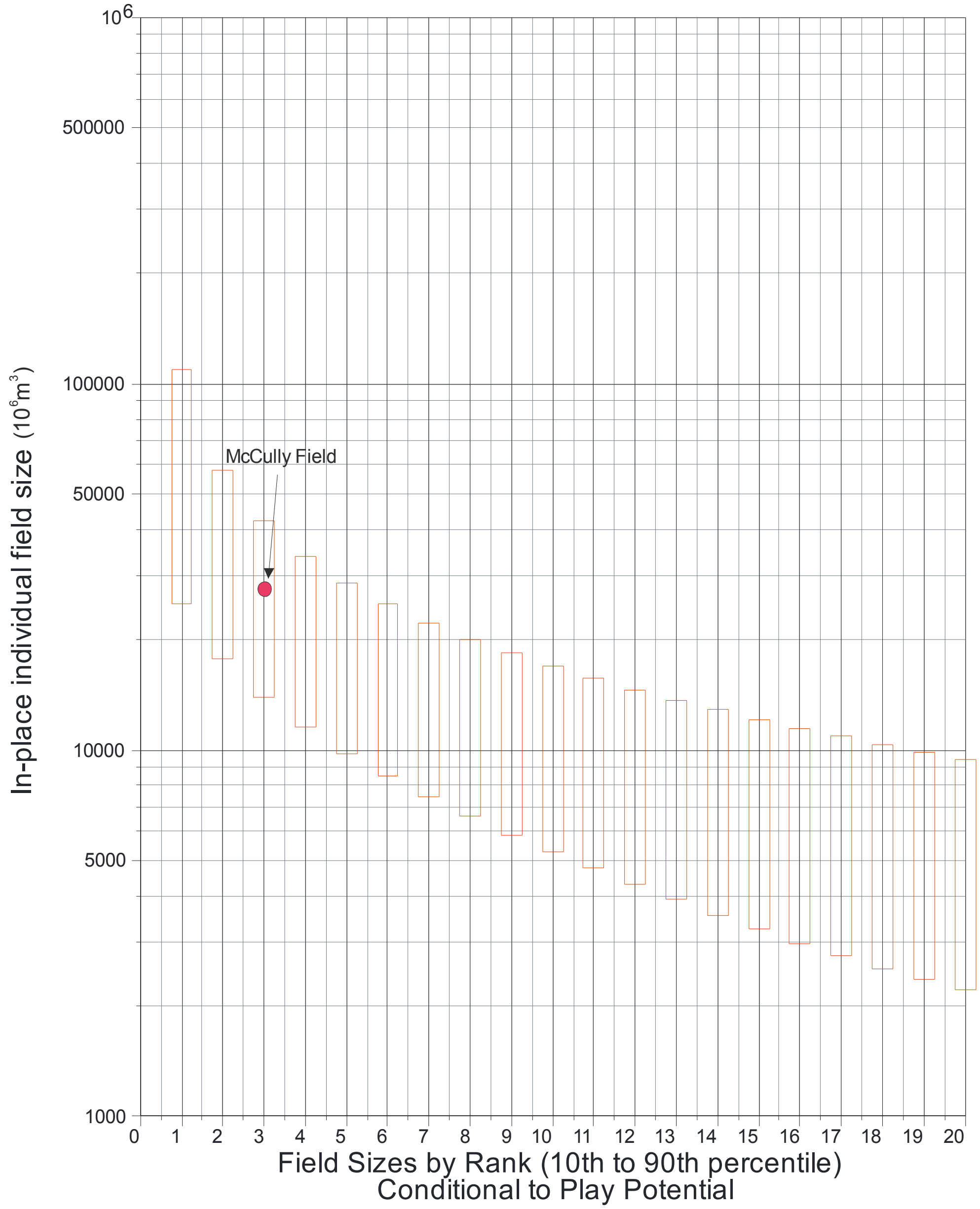


Figure 94. Field size-by-rank plot of the 20 largest predicted field sizes of the Lower Carboniferous clastic gas play in the Maritimes Basin. Median value of largest field size is 49769 million m^3 of in-place gas.

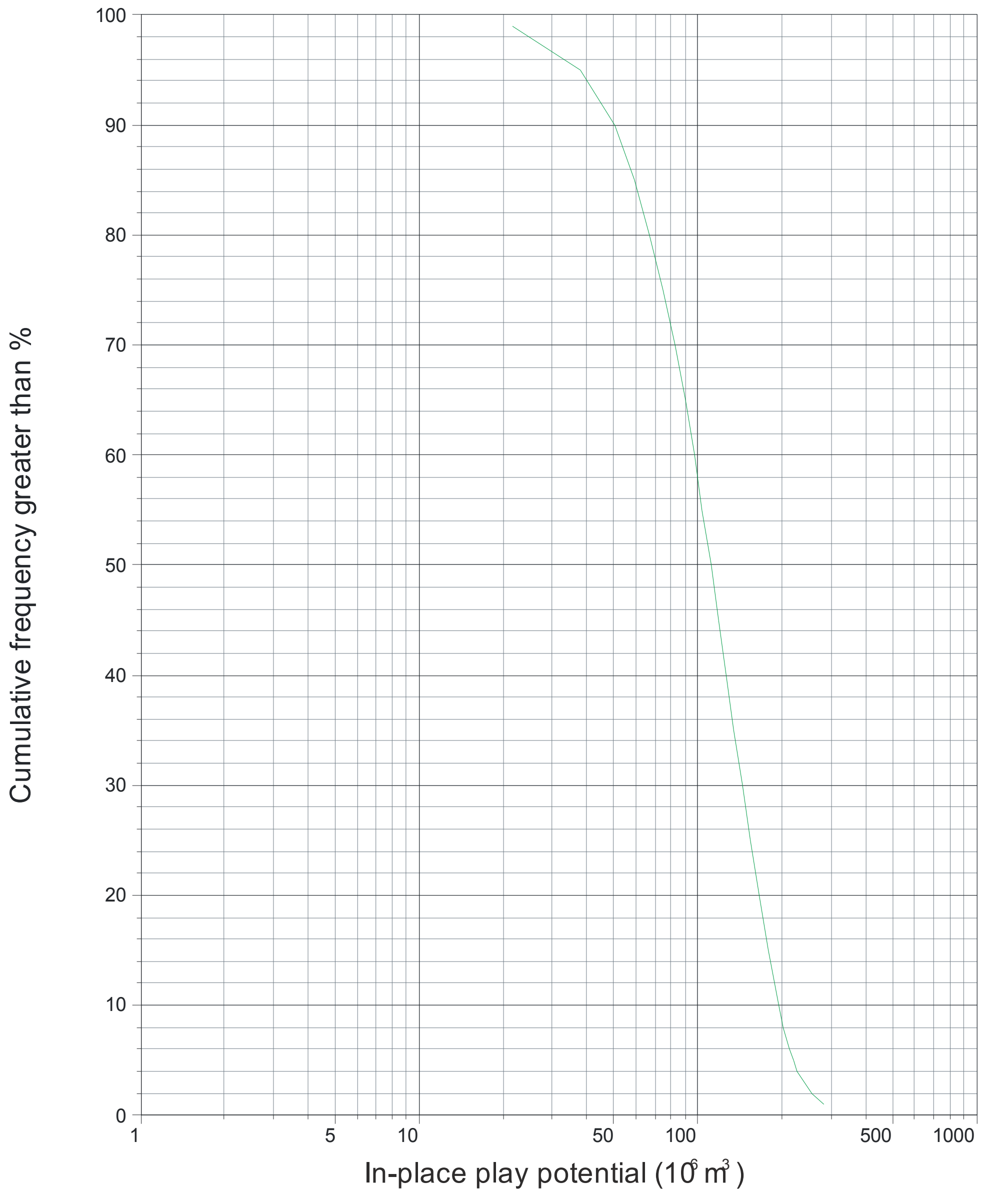


Figure 95 . Estimate of in-place oil potential of the Upper Carboniferous clastic play in the Maritimes Basin. Median value of probabilistic assessment is 111 million m^3 of in-place oil distributed in 16 fields.

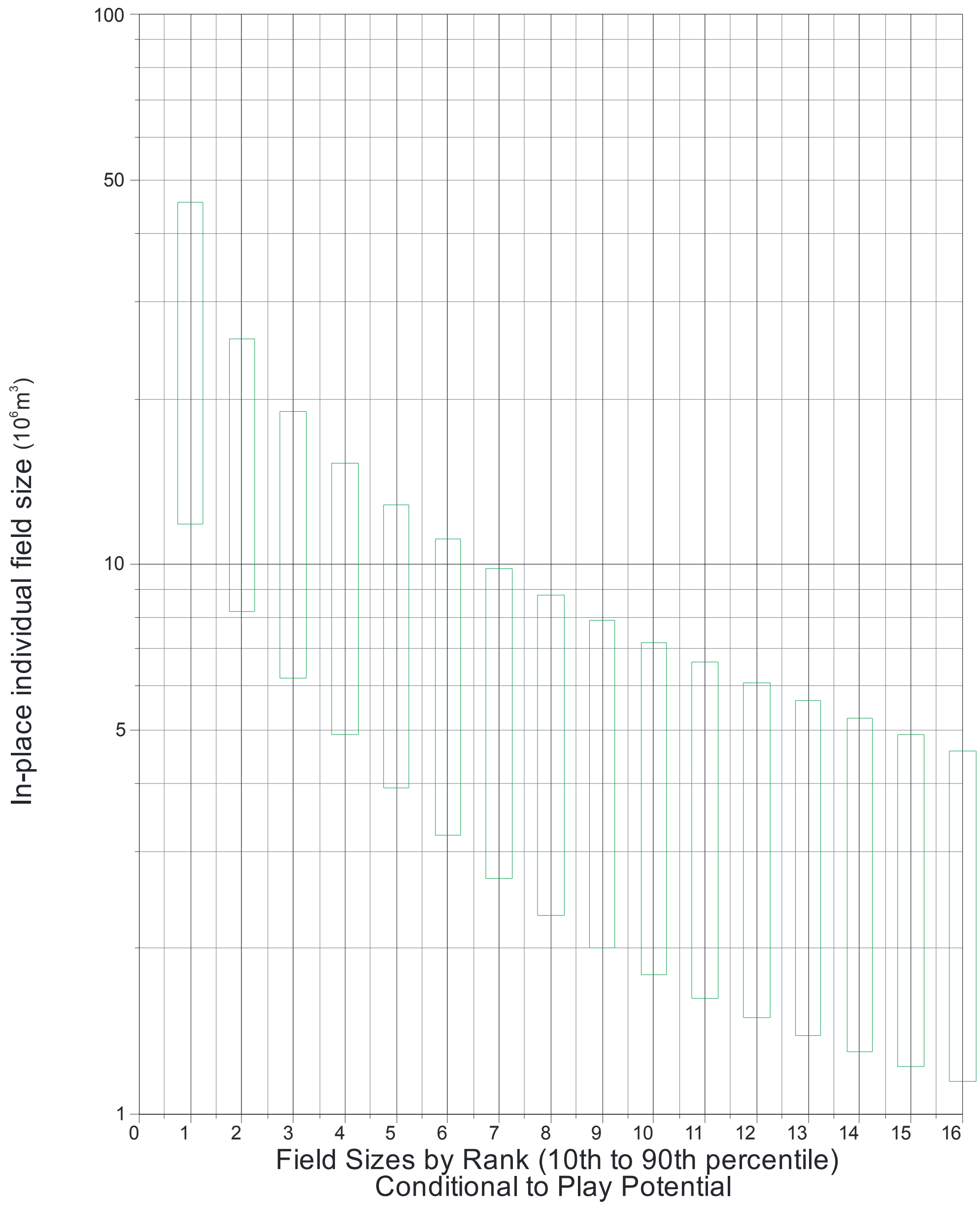


Figure 96. Field size-by-rank plot of all predicted field sizes of the Upper Carboniferous clastic play in the Maritimes Basin. Median value of largest field size is 22.5 million m^3 of in-place oil.

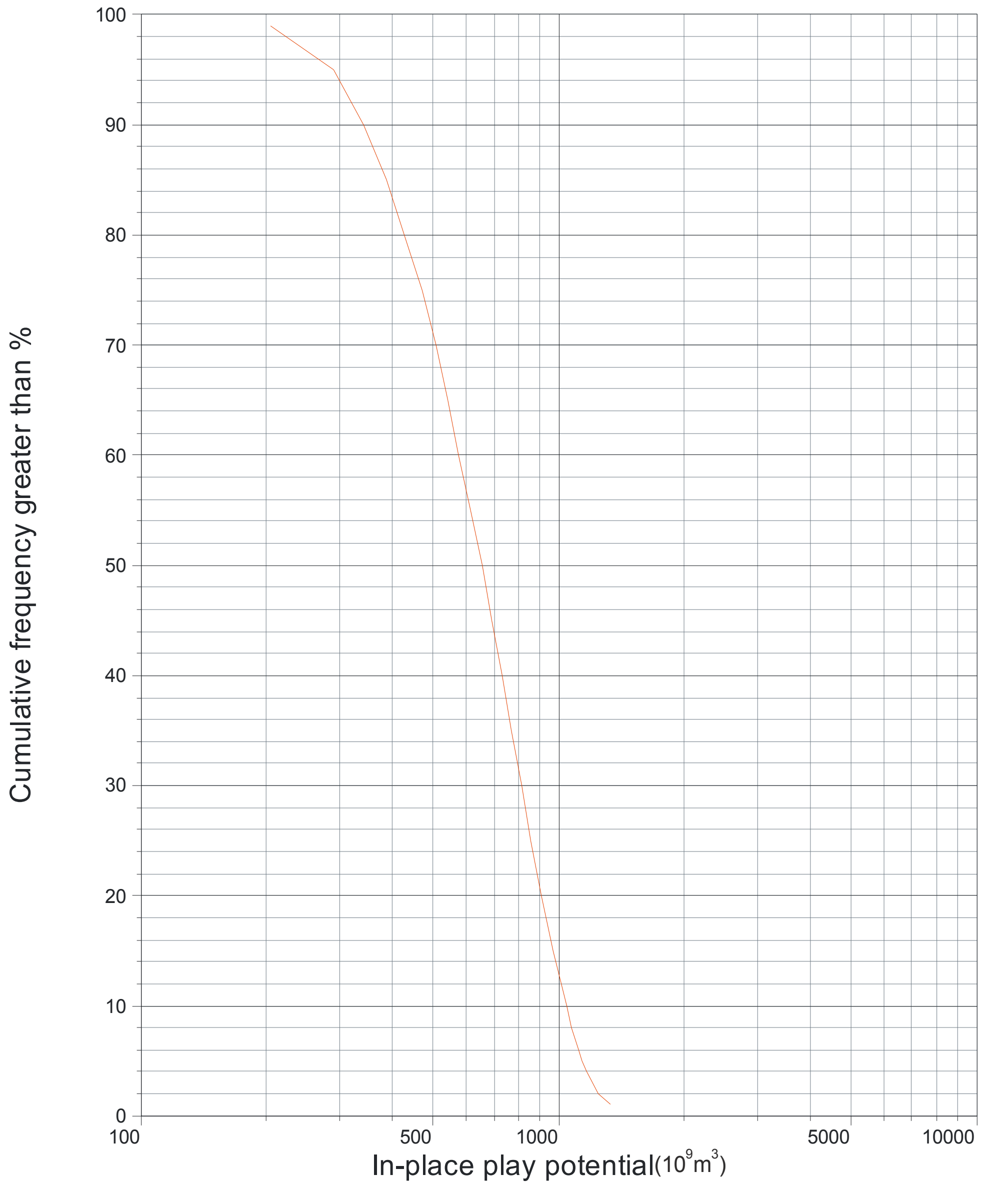


Figure 97. Estimate of in-place gas potential of the Upper Carboniferous clastic play in the Maritimes Basin. Median value of probabilistic assessment is 656.7 billion m^3 of in-place gas distributed in 56 fields.

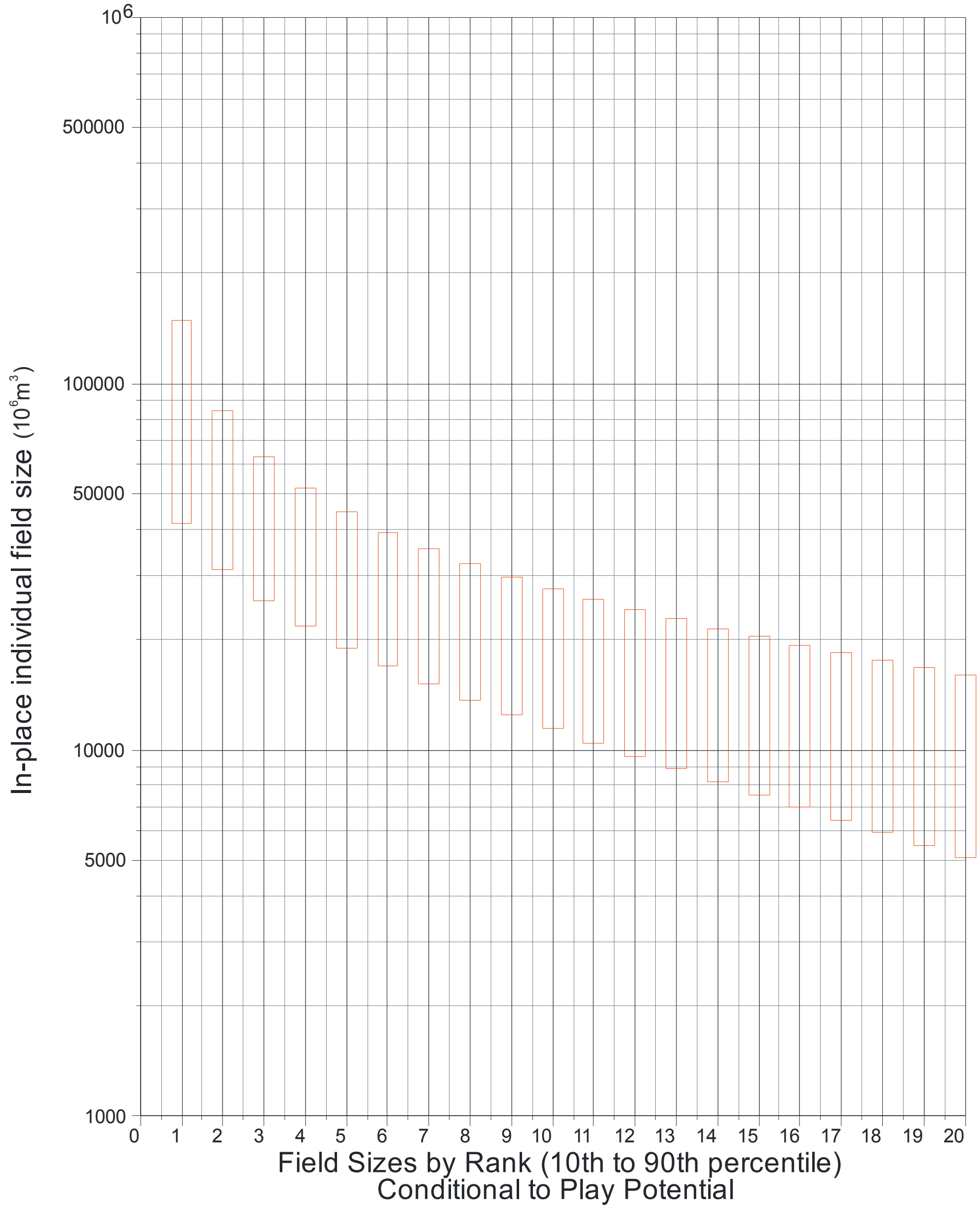


Figure 98. Field size-by-rank plot of the 20 largest predicted field sizes of the Upper Carboniferous clastic gas play in the Maritimes Basin. Median value of largest field size is 74095 million m^3 of in-place gas.

100). High confidence (90% probability) and speculative (10% probability) estimates of total oil potential are 143 and 345 * 10^6 m^3 (899 and 2170 MMbbl), respectively. High confidence and speculative estimates of gas potential are 712.2 and 1564.9 * 10^9 m^3 (25.2 and 55.3 Tcf), respectively (Table 1; Figs. 99, 100).

Resource distribution. Comparing the Lower and Upper Carboniferous play results, the greater gas potential occurs in the Upper Carboniferous play (about 30% greater) but oil potential is slightly less (Table 1). Even though seal is expected to significantly enhance hydrocarbon preservation in the sub-salt Lower Carboniferous play, the significantly greater gas potential in the Upper Carboniferous play reflects its larger play size with larger numbers and sizes of prospects. This prospect number and size difference overrides the differences in seal risk for the two plays – the Lower Carboniferous play having lower seal risk due to enhanced seal potential associated with sub-salt prospects (Fig. 72 Appendix A; Table A-8a; Table A-10a). The slightly lower oil potential in the Upper Carboniferous play is attributed to the higher risk attributed to source rock quality charging the Upper Carboniferous potential reservoirs (Appendix A; Table A-7b, Table A-9b). The largest individual oil and gas fields are predicted to occur in the Upper Carboniferous play (Table 1). The oil and gas resources in the Upper Carboniferous play are concentrated in fewer large fields compared to the Lower Carboniferous play. The higher risk associated with seal, source and timing assigned to the Upper Carboniferous play reduced the number of predicted fields, even though there are more prospects in the play. Field size rankings for all plays suggest that about 35 to 60% of the regions's total petroleum resource is expected to occur in the five largest oil and gas fields. This resource distribution indicates a moderately to highly concentrated hydrocarbon habitat, typical of rifted passive margin basins (Klemme, 1984).

The assessment results indicate the Upper Carboniferous clastic play is expected to contain about 60% of the region's total natural gas resource volume in clastic reservoirs and 7 of the 10 largest fields, a concentration reflecting the greater abundance and quality of reservoirs within the Upper Carboniferous foreland succession. Conversely, predicted oil field sizes show a different distribution with about equal Lower and Upper Carboniferous oil resource volumes. Six of the 10 largest oil fields are predicted to occur in the Upper Carboniferous play. In terms of general geographic area within the Maritimes Basin region, one of the most prospective areas likely occurs in northeastern Magdalen Basin coincident with the salt basin (Fig. 72). This area contains a thick succession of Upper Carboniferous strata, abundant good quality source and reservoir rocks, and a multitude of

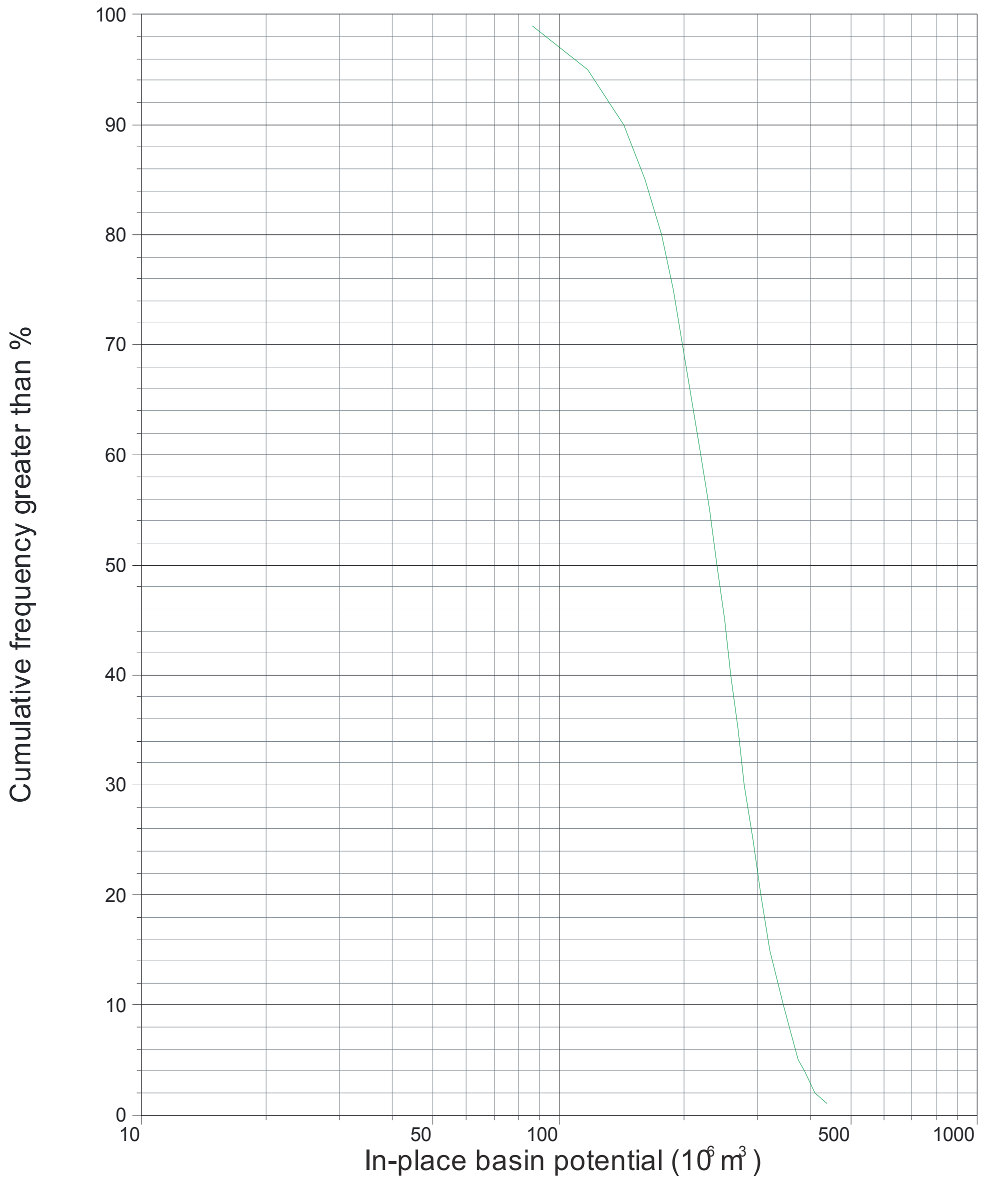


Figure 99. Estimate of total oil potential for the Maritimes Basin region. Median value of probabilistic assessment is 239 million m^3 of in-place oil.

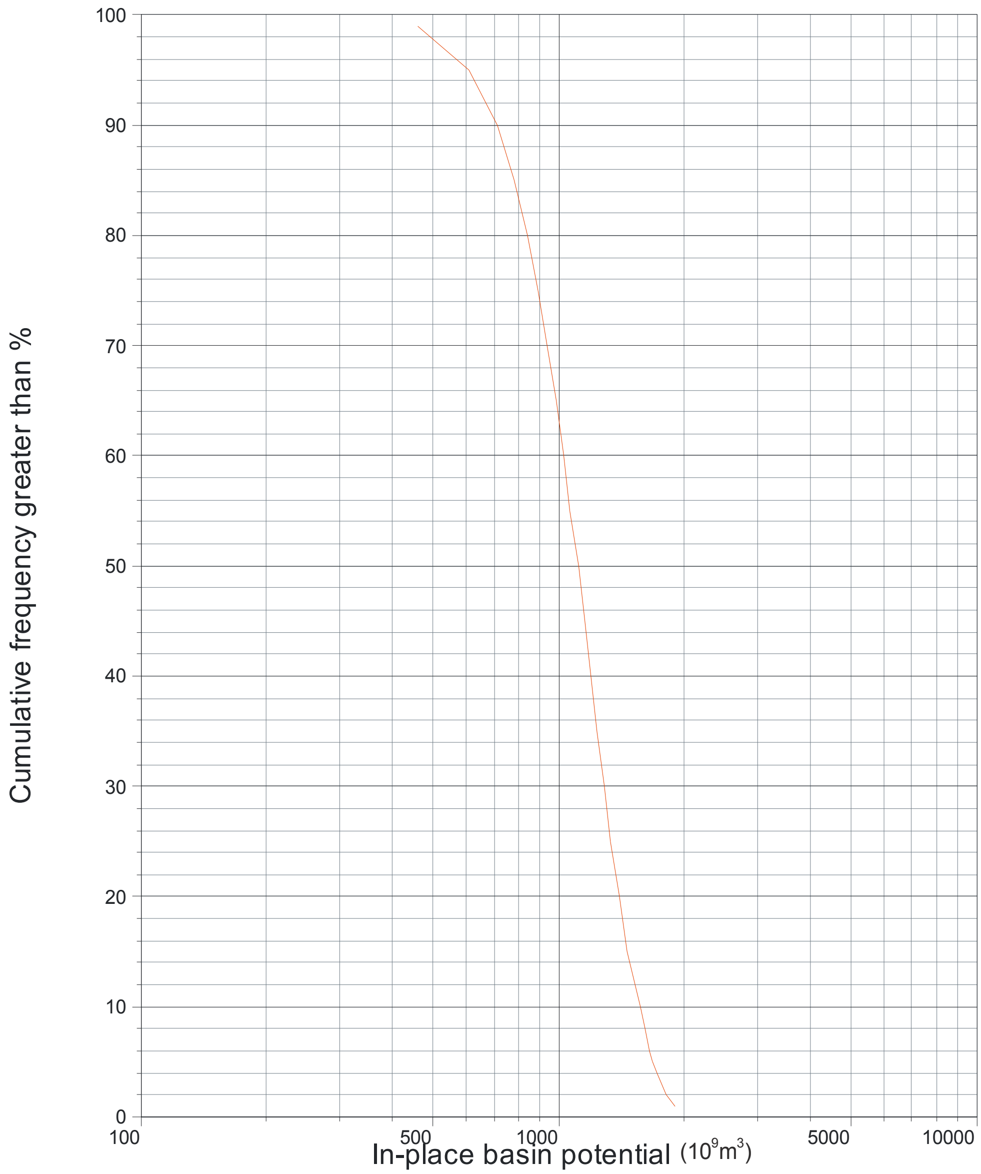


Figure 100. Estimate of in-place gas potential for the Maritimes Basin region. Median value of probabilistic assessment is 1116.5 billion m^3 of in-place gas.

large salt structures. Those, in turn, supply numerous trapping opportunities. Subsalt and salt-flank traps are important trap-types in this area. The area also includes a large portion of the underlying Lower Carboniferous oil and gas play in onshore southeastern New Brunswick, eastern Prince Edward Island and northwestern Nova Scotia as well as inter-offshore areas (Fig. 60). The fact that all three hydrocarbon discoveries to date in the Maritimes Basin occur in this same area (McCully, Stoney Creek, East Point E-49) confirms the higher prospectivity rating. Most previous exploration in the region targeted traps associated with strata above salt diapirs in the salt basin and structural traps associated with half-grabens such as at Stoney Creek. The recent discovery of McCully indicate that gas can occur in low permeability fluvial sands where faulting has produced sufficient fracturing for gas production.

The preceding discussion does not reflect the complete distribution of potential resource in the Maritimes Basin region because insufficient data were available to quantitatively assess the oil and gas expected to occur in the Viséan Windsor carbonate play.

Assessment results and exploration history. The exploration risks estimated in the play assessments suggest success rates for exploratory drilling in the region should average near 0.16 for the Lower Carboniferous gas play and 0.11 for the Upper Carboniferous play. The occurrence of 2 gas discoveries and four gas flows from drill-stem tests in the 37 exploratory wells drilled in the Lower Carboniferous play in the Magdalen Basin provide a historical success rate of 0.16, equal to the estimated exploration risk. Similarly, the Upper Carboniferous play has one gas discovery at East Point E-49 and 3 gas flows in DSTs suggesting a historical success rate of 0.11, equal again to the estimated exploration risk. With respect to oil, one oil discovery (Stoney Creek) and one oil flow in a DST (Caledonia) were reported and numerous oil shows were recorded among the wells in the Lower Carboniferous play. The historical success rate is 0.05 close to the 0.08 exploration risk estimate. No oil flows were recorded from DSTs in any of the exploratory wells in the Upper Carboniferous oil play, in contrast to the predicted 0.03 success rate from exploration risk estimates. The difference in historical success and exploration risk in the Upper Carboniferous oil play may reflect inadequate or partially diagnostic exploration tests of the reservoir under consideration. Some wells were undoubtedly drilled in less than optimum locations.

Initial onshore exploration programs in the Maritimes Basin were focused on areas near surface seeps and oil shale deposits (resulting in the discovery of the Stoney Creek oil and gas field). One early exploration model involved hydrocarbons sourced from organic-rich shales in the Horton Group, trapped in Lower Carboniferous reservoirs with Windsor Group evaporite seals. Notably, however, all of the significant discoveries to date, including the Stoney Creek and McCully fields, occur in traps with no associated evaporite seal.

The first offshore discovery occurred in 1970 at East Point E-49, where gas was found in Upper Carboniferous sandstone. This gas was most likely sourced from Upper Carboniferous coal measures, known to be thick and widespread in the Magdalen Basin. The recognition of a natural gas play associated with Carboniferous coal measures suggests that play analogues from Carboniferous basins in northwest Europe, specifically in the southern North Sea, and the Appalachian Basin and Black Warrior Basin in eastern United States are appropriate. Reconstruction of Late Carboniferous paleogeography shows that, during collision of Euramerica with Gondwana, numerous cyclothemic coal-bearing strata were deposited in tropical to sub-tropical basins in present day northwest Europe, eastern Canada and southeastern United States. The repeated transgressive and regressive events caused by Gondwanan glacial cycles led to the development of the cyclothems that contain extensive coal deposits in each of these Upper Carboniferous basins.

The extensive faulting and salt tectonism in the Maritimes Basin were important components in hydrocarbon play development. Source rock maturation and hydrocarbon migration histories and their variations with respect to faulting and salt movements are not completely understood and challenges remain in understanding the accumulation and preservation of oil and gas in the region.

Comparison with play analogue. The Carboniferous Black Warrior Basin in northern Alabama and Mississippi in the United States is an appropriate petroleum system analogue to the Upper Carboniferous play in the Maritimes Basin. The 45,000 km^2 Black Warrior Basin contains 220 discovered oil and gas fields (Pawlewicz and Hatch, 2007). The largest gas field has recoverable reserves of $220*10^9$ ft^3 of natural gas ($6230*10^6$ m^3). The largest oil field at Black Warrior has recoverable reserves of greater than 6.3 MMBO or $40*10^6$ m^3. Over $1.7 * 10^6$ m^3 of oil and $29 * 10^9$ m^3 of natural gas have been produced over the past 100 years from the Carboniferous sandstones assessment unit in the Black Warrior Basin (U.S. Geological Survey Black Warrior Basin Province Assessment Team, 2007). Recoverable undiscovered mean play potential is predicted to be $10.4 * 10^9$ m^3 gas and $0.94 * 10^6$ m^3 oil (U.S. Geological Survey Black Warrior Basin Province Assessment Team, 2007). A “Seventh Approximation” model (Schmoker and Klett, 2005) was applied in the Black Warrior conventional petroleum assessment. This model defines undiscovered petroleum as that which exists outside of known accumulations but resides in accumulations larger than a stated minimum value. The model underestimates the ultimate number of pools due to economic truncation. After applying a recovery factor of 0.3 for oil and 0.7 for gas, the estimated in-place resource with respect to individual field size range up to 130 * 10^6 m^3 oil and 8900 * 10^6 m^3 gas (mean volumes). Comparing with the Carboniferous plays in Maritimes Basin, (mean largest field size, oil 16.5 * 10^6 m^3 and 22.5 * 10^6 m^3, gas 62034 * 10^6 m^3 and 88208* 10^6 m^3 for the Lower and Upper Carboniferous plays, respectively), the Maritimes Basin is estimated to contain less oil, but substantially more gas than the Black Warrior Basin. The difference in gas volumes reflects the larger field areas and net pay derived from interpretation of onshore and offshore seismic data in Gulf of St. Lawrence and New Brunswick and Prince Edward Island, and petrophysical log analysis (Hu and Dietrich, 2008) in the Maritimes Basin compared to listed field sizes in the Black Warrior Basin. Also, the Maritimes Basin encompasses a substantially larger play area with a greater number of prospects and larger volumes of gas source rocks.

CONCLUSIONS

The oil and gas resource potential of Paleozoic basins in eastern Canada have been evaluated through regional petroleum play assessments. The quantitative assessments were derived using the Geological Survey of Canada's (PRIMES) assessment methodology system. The assessments included analyses of 6 immature or conceptual plays most with both oil and gas components, each of which incorporated the calculation or estimation of field size parametric data, numbers of prospects and exploration risks. Oil and gas volumes reported for these conceptual plays are total statistical estimates of the endowment or resource occurring "in the ground", with no constraints on whether the hydrocarbons are technically or economically producible. Individual field size determinations are important in identifying and ranking the most attractive plays for exploration programs.

Median estimates for total oil and gas potential for all eastern Canada Paleozoic basins are 403 * 10^6 m^3 of in-place oil and 1170 * 10^9 m^3 of in-place gas (Figs. 101 and 102). The ranges of oil and gas estimates from high to low probability reflect the level of uncertainty in assessing petroleum potential for this region. However, in comparative terms, the estimates from the current assessment are substantially greater than those derived in the Geological Survey of Canada's 1983 assessment (Procter et al., 1984). The greater resource predictions in this current assessment reflect several factors, including more optimistic evaluations of number of prospects and volume and quality of potential reservoirs.

The recent recognition of hydrothermal dolomite plays in the St. Lawrence Platform intimately associated with a proven source rock for gas has opened up the area to a new phase

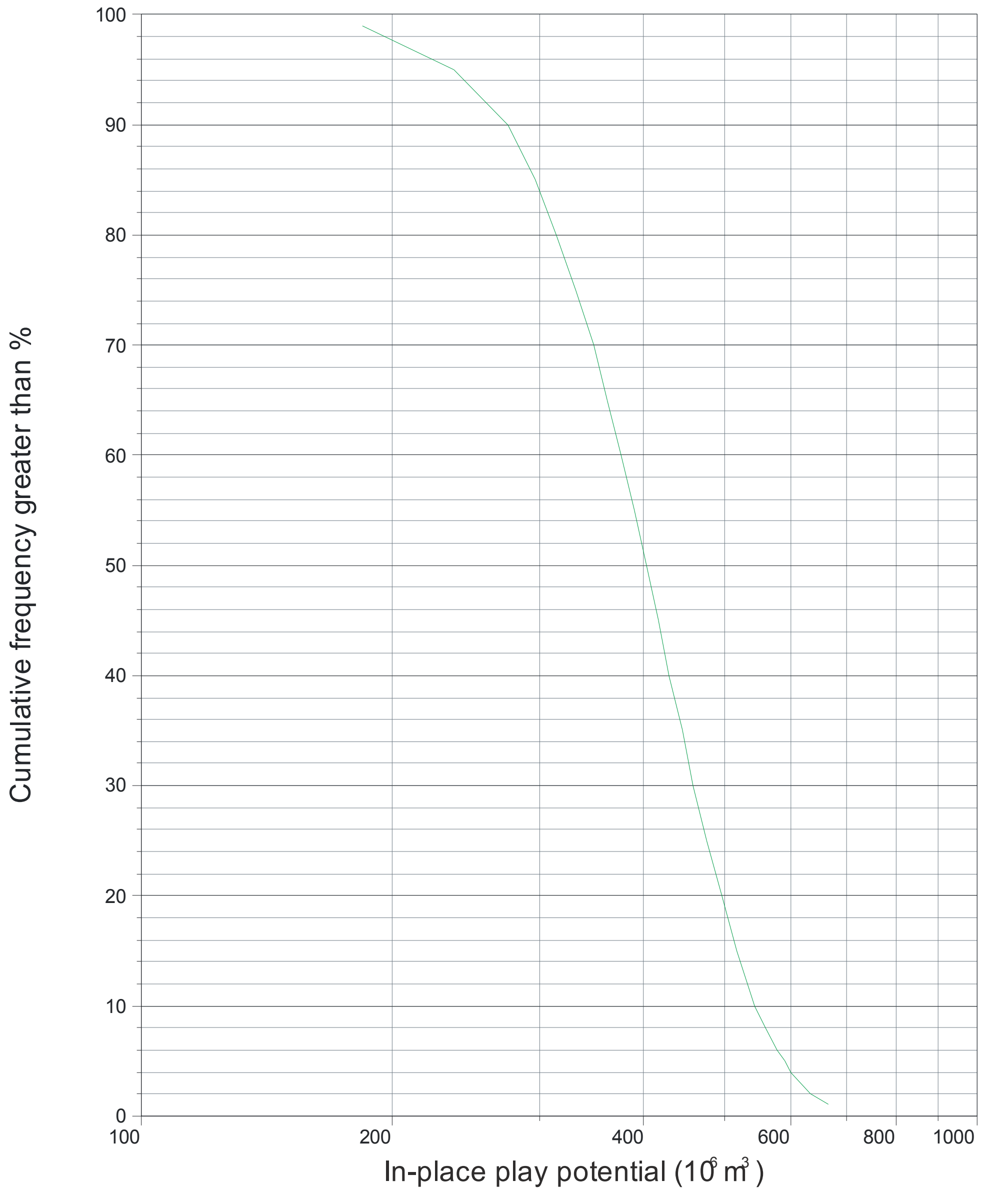


Figure 101. Estimate of total oil potential for the Gulf of St. Lawrence assessment region. Median value of probabilistic assessment is 402.7 million m^3 of in-place oil.

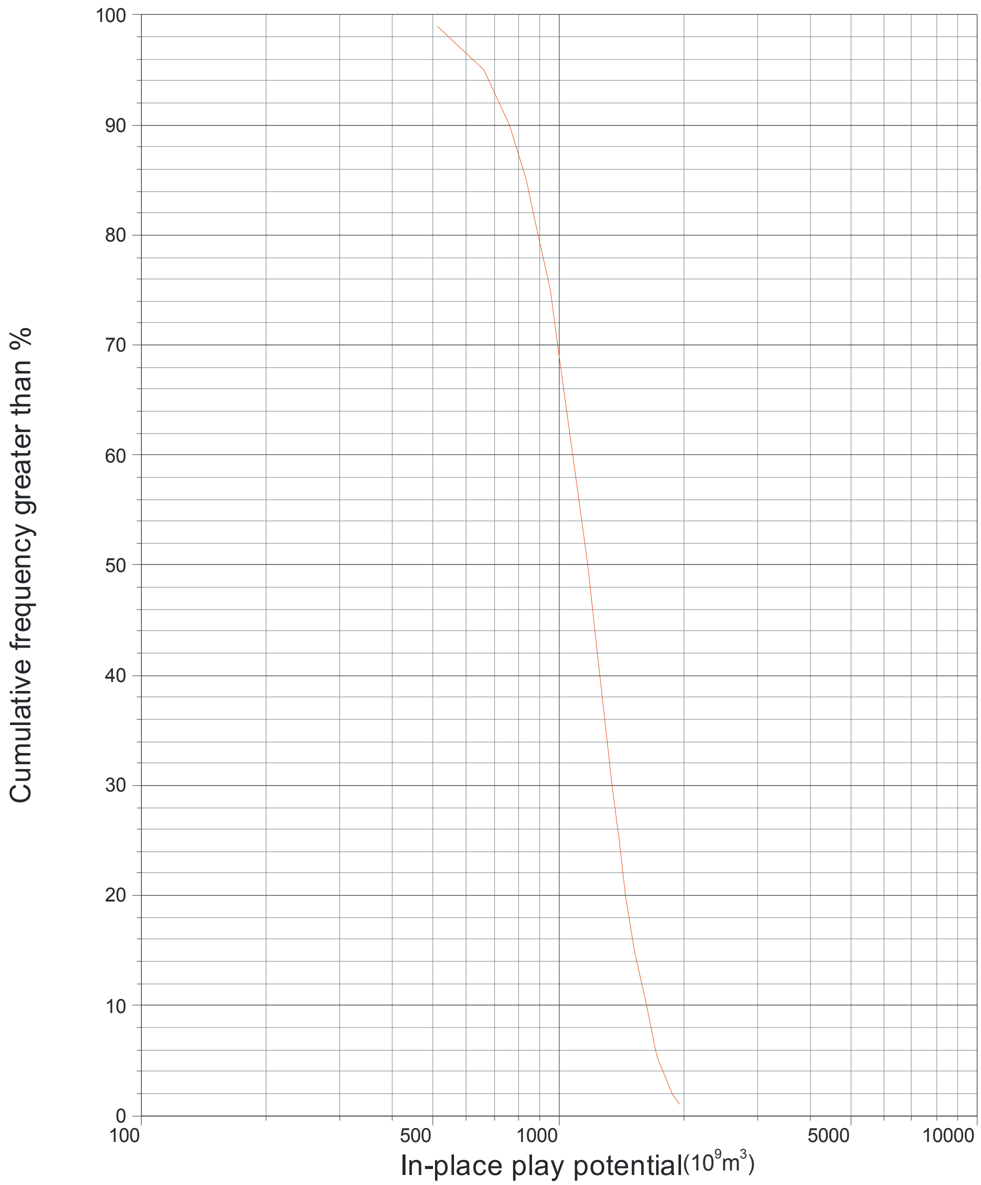


Figure 102. Estimate of in-place gas potential for the Gulf of St.. Lawrence assessment region. Median value of probabilistic assessment is 1170 billion m^3 of in-place gas.

of exploration investigating conventional petroleum potential as well as non-conventional shale gas opportunities. Stratigraphic traps formed by transitional boundaries between porous dolomitized intervals and tight carbonate is expected to be a significant target in future exploration programs.

In the Humber Zone in southern Quebec, previous exploration efforts revealed the presence of a foothills style exploration play along the Appalachian structural front. The Saint-Flavien gas field structure, a hanging wall ramp anticline, is part of this structural play. Seismic surveys have identified numerous potential traps in other detached carbonate thrust slices.

In the Gaspé Belt, the Gaspé sandstones represented one of the earliest exploration targets with proven, albeit modest, oil production. A new discovery at Haldimand in 2006 indicates that potential still exists in the play.

In the Maritimes Basin, significant potential is indicated by the combined presence of abundant reservoir strata, good petroleum source rocks, numerous and diverse structural and stratigraphic traps, and common occurrence of oil and gas shows. In terms of number of predicted fields and oil-equivalent volumes, estimated gas resources are more abundant than oil. The discovery and production of large volumes of gas in low permeability sandstones at McCully provides a modern example of the type and magnitude of gas resource in the basin.

This assessment study provides a favourable geological basis for further petroleum evaluation and exploration in Paleozoic strata in eastern Canada. In particular, the Carboniferous basins in the Gulf of St. Lawrence and environs appear very prospective. The complex geology and anticipated high exploration risks associated with all of the plays suggest that considerable amounts of new seismic data and many exploration wells may be required to properly evaluate the region's oil and gas potential. The present assessment suggests substantial petroleum resource remain to be discovered in these sedimentary basins on the eastern coast of Canada.

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APPENDIX A
INPUT DATA FOR PETROLEUM ASSESSMENTS

The following tables present the probability distributions of reservoir parameters and number of prospects and marginal probabilities of geological risk factors used as input for the various conceptual statistical analyses discussed in this paper. These estimates are based on subjective opinion, partly constrained by reservoir data and information from analogous petroleum-bearing basins.

1. LOWER ORDOVICIAN HTD (HYDROTHERMAL DOLOMITE) OIL PLAY

TABLE A-1a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	4.5	72.4	80
Net pay	m	1	10.3	44	45
Porosity	decimal fraction	0.02	0.05	0.12	0.2
Water saturation	decimal fraction	0.11	0.36	0.54	0.55
Formation volume factor		1.1	1.2	1.29	1.3

TABLE A-1b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		√
Presence of reservoir facies	0.8		√
Adequate seal	0.5		√
Adequate timing	0.6		√
Adequate source	0.9		√
Adequate maturation	0.8		√

TABLE A-1c – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	43	305	665

2. LOWER ORDOVICIAN HTD (HYDROTHERMAL DOLOMITE) GAS PLAY

TABLE A-2a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**

Area of closure	km^2	1	4.5	72.4	80
Net pay	m	1	5.2	89	94
Porosity	decimal fraction	0.02	0.03	0.11	0.2
Water saturation	decimal fraction	0.09	0.39	0.54	0.55
Formation volume factor	decimal fraction	0.0029	0.008	0.012	0.013

TABLE A-2b - Marginal probabilities of geological risk factors

Geological factors	**Marginal probability**	**Play level**	**Prospect level**
Presence of closure	0.7		√
Presence of reservoir facies	0.8		√
Adequate seal	0.5		√
Adequate timing	0.6		√
Adequate source	0.9		√
Adequate maturation	0.8		√

TABLE A-2c – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	73	645	1080

3. UPPER ORDOVICIAN HTD (HYDROTHERMAL DOLOMITE) OIL PLAY

TABLE A-3a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	3.5	39	40
Net pay	m	1	7.6	44	45
Porosity	decimal fraction	0.02	0.052	0.21	0.25
Water saturation	decimal fraction	0.06	0.49	0.5496	0.55
Formation volume factor		1.1	1.2	1.29	1.3

TABLE A-3b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		√
Presence of reservoir facies	0.7		√
Adequate seal	0.6		√

Adequate timing	0.7		√
Adequate source	0.9		√
Adequate maturation	0.8		√

TABLE A-3c – Number of prospects probability distribution

Geological variable	**Probability in upper percentiles**	**Probability in upper percentiles**	**Probability in upper percentiles**
	0.99	**0.5**	**0.0**
Number of prospects	19	544	1350

4. LOWER ORDOVICIAN HTD (HYDROTHERMAL DOLOMITE) GAS PLAY

TABLE A-4a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	3.5	39	40
Net pay	m	1	13.6	66	68
Porosity	decimal fraction	0.02	0.04	0.12	0.19
Water saturation	decimal fraction	0.06	0.44	0.548	0.55
Formation volume factor	decimal fraction	0.0039	0.0047	0.02	0.034

TABLE A-4b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		√
Presence of reservoir facies	0.7		√
Adequate seal	0.6		√

Adequate timing	0.7		√
Adequate source	0.9		√
Adequate maturation	0.8		√

TABLE A-4c – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	58	606	1950

5. ORDOVICIAN CARBONATE PLATFORM THRUST SLICES GAS PLAY

TABLE A-5a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	6	40	50
Net pay	m	1	4.5	18.4	18.5
Porosity	decimal fraction	0.02	0.075	0.28	0.3
Water saturation	decimal fraction	0.15	0.23	0.54	0.55
Formation volume factor	decimal fraction	0.0024	0.0066	0.013	0.018

TABLE A-5b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.6		√
Presence of reservoir facies	0.7		√

Adequate seal	0.5		√
Adequate timing	0.6		√
Adequate source	0.9		√
Adequate maturation	0.7		√

TABLE A-5c – Number of prospects probability distribution

Geological variable	**Probability in upper percentiles**	**Probability in upper percentiles**	**Probability in upper percentiles**
	0.99	**0.5**	**0.0**
Number of prospects	54	325	1400

6. LOWER DEVONIAN GASPE SANDSTONE OIL PLAY

TABLE A-6a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	7	100	110
Net pay	m	1	22	48	50
Porosity	decimal fraction	0.01	0.04	0.11	0.15
Water saturation	decimal fraction	0.21	0.47	0.547	0.55
Formation volume factor	decimal fraction	1.1	1.2	1.29	1.3

TABLE A-6b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.7		√
Presence of reservoir facies	0.9		√

Adequate seal	0.4		√
Adequate timing	0.8		√
Adequate source	0.9		√
Adequate maturation	0.7		√

TABLE A-6c – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	4	21	300

7. LOWER CARBONIFEROUS CLASTIC OIL PLAY

TABLE A-7a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	10	80	100
Net pay	m	1	10	20	25
Porosity	decimal fraction	0.05	0.07	0.22	0.43
Water saturation	decimal fraction	0.01	0.47	0.548	0.55
Formation volume factor	decimal fraction	1.1	1.2	1.29	1.3

TABLE A-7b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.6		√
Presence of reservoir facies	0.8		√

Adequate seal	0.5		√
Adequate timing	0.6		√
Adequate source	0.9		√
Adequate maturation	0.6		√

TABLE A-7c – Number of prospects probability distribution

Geological variable	**Probability in upper percentiles**	**Probability in upper percentiles**	**Probability in upper percentiles**
	0.99	**0.5**	**0.0**
Number of prospects	115	475	600

8. LOWER CARBONIFEROUS CLASTIC GAS PLAY

TABLE A-8a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	10	100	300
Net pay	m	1	33.5	100	170
Porosity	decimal fraction	0.05	0.07	0.22	0.43
Water saturation	decimal fraction	0.01	0.47	0.548	0.55
Formation volume factor	decimal fraction	0.0025	0.0036	0.016	0.017

TABLE A-8b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.6		√
Presence of reservoir facies	0.8		√

Adequate seal	0.5		√
Adequate timing	0.8		√
Adequate source	0.9		√
Adequate maturation	0.9		√

TABLE A-8c – Number of prospects probability distribution

Geological variable	**Probability in upper percentiles**	**Probability in upper percentiles**	**Probability in upper percentiles**
	0.99	**0.5**	**0.0**
Number of prospects	115	475	600

9. UPPER CARBONIFEROUS CLASTIC OIL PLAY

TABLE A-9a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	20	271.5	300
Net pay	m	1	8	15	17
Porosity	decimal fraction	0.05	0.08	0.27	0.43
Water saturation	decimal fraction	0.02	0.43	0.548	0.55
Formation volume factor	decimal fraction	1.1	1.2	1.29	1.3

TABLE A-9b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.6		√
Presence of reservoir facies	0.9		√

Adequate seal	0.4		√
Adequate timing	0.7		√
Adequate source	0.3		√
Adequate maturation	0.7		√

TABLE A-9c – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	250	500	800

10. UPPER CARBONIFEROUS CLASTIC GAS PLAY

TABLE A-10a – Field size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	km^2	1	20	271.5	300
Net pay	m	1	50	150	270
Porosity	decimal fraction	0.05	0.08	0.27	0.43
Water saturation	decimal fraction	0.02	0.43	0.548	0.55
Formation volume factor	decimal fraction	0.0025	0.005	0.016	0.017

TABLE A-10b - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Presence of closure	0.6		√
Presence of reservoir facies	0.9		√

Adequate seal	0.4		√
Adequate timing	0.7		√
Adequate source	0.8		√
Adequate maturation	0.9		√

TABLE A-10c – Number of prospects probability distribution

Geological variable	**Probability in upper percentiles**	**Probability in upper percentiles**	**Probability in upper percentiles**
	0.99	**0.5**	**0.0**
Number of prospects	250	500	800

APPENDIX B
TERMINOLOGY

The terminology used in this report follows those outlined in Reinson et al. (1993) and are summarized below.

Resource indicates all hydrocarbon accumulations known or inferred to exist. *Resource, resource endowment* and *endowment* are synonymous and can be used interchangeably. *Reserves* are that portion of the resource that has been discovered, while *potential* represent the portion of the resource that is not discovered but is inferred to exist. The terms *potential* and *undiscovered resources* are synonymous and may be used interchangeably.

Gas-in-place indicates the gas volume found in the ground, regardless of what portion is recoverable. *Initial in-place volume* is the gross volume of raw gas, before production. *Recoverable in-place volume* represents the volume expected to be recovered with current technology and costs. These definitions are applicable to oil volumes as well. All volumes are reported as in-place in this report.

A *prospect* is defined as an untested exploration target within a single stratigraphic interval; it may or may not contain hydrocarbons. A prospect is not synonymous with an undiscovered pool. An undiscovered pool is a prospect that contains hydrocarbons but has not been tested as yet. A *pool* is defined as a discovered accumulation of oil or gas typically within a single stratigraphic interval that is separated, hydrodynamically or otherwise, from another hydrocarbon accumulation. A *field* consists of one or more oil and/or gas pools within a single structure or trap. Similar to most frontier regions, the assessment of Gulf petroleum resource is based on estimates of field rather than pool sizes. A *play* is defined as a family of pools and/or prospects that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration.

Plays are grouped into two categories; *established* and *conceptual* plays. *Established plays* are demonstrated to exist due to the discovery of pools with established reserves. *Conceptual plays* are those that have no discoveries or reserves, but which geological analyses indicate may exist. Established plays are categorized further into *mature* and *immature* plays depending on the adequacy of play data for statistical analysis. Mature plays are those plays that have sufficient numbers of discoveries within the discovery sequence so that the *discovery process model* of the PRIMES assessment procedure is of practical use (Lee and Tzeng, 1993; Lee and Wang, 1990; Lee, 1993a). Immature plays do not have a sufficient number of discoveries with established reserves to properly apply the model. Conceptual and immature play analysis was applied exclusively in this study due to the lack of a sufficient number of discovered pools with established reserves.