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ABSTRACT

The reservoir characteristics of Carboniferous-Permian sandstones in nine wells in the Maritimes Basin in eastern Canada are evaluated through compilation of core measurements and detailed petrophysical analyses of wireline well logs. The wells include Bradelle L-49, Brion Island No.1, Irishtown No.1, Cablehead E-95 and East Point E-49 in the Magdalen Basin, North Sydney F-24 and Hermine E-94 in the Sydney Basin, and Hare Bay E-21 and Verrazano L-77 in the St. Anthony Basin. Reservoir properties evaluated include lithology, porosity, permeability and water saturation. Although the average porosity and permeability of sandstones in the study wells decrease rapidly with depth, a significant percentage of sandstones have enhanced reservoir quality associated with secondary porosity development. Measured sandstone porosity values in the Magdalen Basin wells are up to 20 % to depths of 2000 m, and up to 15 % to depths of 3500 m. Sandstone porosity values in the Hare Bay well in the St Anthony Basin are up to 15 % to depths of 4500 m.

Possible oil or gas zones in Carboniferous sandstones are identified from porosity and water saturation data, in all nine wells evaluated in this study. Many of the indicated petroleum zones occur in thin shaly sandstones, characterised by very low porosity and permeability. However, possible petroleum zones occur in sandstones with fair to good porosity and permeability. Based on select porosity and water saturation cutoff values (ϕ>7.5% and Sw<55%), possible hydrocarbon reservoirs are identified in sandstones in the Upper Carboniferous Pictou and Mabou groups and Lower Carboniferous Horton Group.

The evaluated well data indicate that sandstone reservoir quality does not appear to be a major limiting factor for petroleum resource potential in many parts of the offshore Maritimes Basin. Due to the complex and varied structural and depositional history in the region, it is uncertain if the reservoir-quality patterns observed in the study data can be extrapolated across all parts of the basin.

INTRODUCTION

The 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.1). The basin encompasses a total area of 250,000 km^2, with about 75 % of the basin area offshore. The Maritimes Basin is a composite basin that includes the Magdalen, Sydney, Deer Lake and St. Anthony basins and numerous local subbasins. Easternmost parts of the Sydney and St. Anthony basins are overlain by Mesozoic-Cenozoic sediments of the Atlantic continental margin.

The petroleum potential of the Maritimes Basin is documented by historic and current oil and natural gas production, and the presence of widespread petroleum seeps and showings. Petroleum exploration in the basin dates back more than 100 years, with most of the offshore activity (seismic surveying and exploration drilling) occurring in the 1970s and early 1980s. A recent quantitative petroleum assessment study identified the Maritimes Basin as highly prospective for conventional natural gas resources, with the potential for discovery of gas fields with in-place volumes in excess of 30 billion cubic metres (1 Tcf) (Lavoie et al. 2009). One of the long-recognised exploration risks in the Maritimes Basin is related to reservoir quality. Exploration wells drilled to date have encountered many petroleum zones or shows in Carboniferous sandstone reservoirs. However, conventional drill-stem tests completed in these reservoirs have commonly resulted in low (sub-economic) oil or gas flow rates.

In this study we present a review of reservoir quality in Upper Paleozoic strata in the offshore areas of Maritimes Basin, based on compilations of core data and new petrophysical analyses of well logs in nine exploration wells. The wells include Bradelle L-49, Brion Island No.1, Irishtown No.1, Cablehead E-95 and East Point E-49 wells in the Magdalen Basin, North Sydney F-24 and Hermine E-94 wells in the Sydney Basin, and Hare Bay E-21 and Verrazano L-77 wells in the St. Anthony Basin (Fig. 1). Eight of the nine wells are located offshore. The onshore Irishtown well, located on the north coast of Prince Edward Island, provides information on Carboniferous reservoir characteristics that can be extrapolated to adjacent offshore areas in the southern Gulf of St. Lawrence.

GEOLOGICAL SETTING

The Maritimes Basin contains up to 12 kilometres of Upper Paleozoic continental and shallow marine strata. Major stratigraphic units include 1) a Lower Carboniferous (Mississippian) succession of lacustrine clastic rocks in fault-bounded subbasins (Horton and Sussex groups and equivalent strata), 2) a widespread Lower Carboniferous succession of marine carbonates and evaporites (Windsor Group and equivalent strata) and nonmarine clastics (Mabou and Deer Lake groups), and 3) a thick Upper Carboniferous (Pennsylvanian) and Lower Permian succession of nonmarine clastics and coal measures (Cumberland and Pictou groups and equivalent strata; Fig. 2). Horton Group strata are up 8000 m thick in the southwestern Magdalen Basin. Cumberland Group strata are up to 3000 m thick in the onshore southern Magdalen Basin, but are thin or absent in other parts of the Maritimes Basin. Pictou Group strata are up to 8000 m thick in the offshore Magdalen Basin. The Pictou group is divided, from base to top, into the Bradelle, Green Gables, Cablehead and Naufrage formations, and an unnamed succession of Lower Permian redbeds (Giles and Utting 1999). The Horton Group (Albert Formation), Cumberland and Mabou groups, and Pictou Group (Bradelle and Cablehead formations) contain thick sandstone successions that are prospective petroleum reservoirs (Fig. 2).

The Maritimes Basin is an intracontinental basin that developed in extensional, strike-slip and foreland basin tectonic settings (Durling and Marillier 1993a; Rehill 1996; Park et al. 2008; Gibling et al. 2008). The early basin evolution included development of fault-bounded Lower Carboniferous basins characterized by complex depositional and structural patterns (Durling and Marillier 1993b; Keighley et al. 2008; St. Peter and Johnson 2009; Fig. 3). Subsequent tectonic phases included transpressional thrust faulting and subbasin inversions (Gibling et al. 2008; Waldron et al. 2010). An important phase of Pennsylvanian basin evolution involved mobilization of Windsor Group evaporites and development of salt-withdrawal minibasins and salt diapir zones (Durling and Marillier 2003a; Waldron and Rygel 2005). Salt diapirs are widespread in the eastern Magdalen Basin, the southeastern Sydney Basin, and the eastern St Anthony Basin (Figs. 1, 2). Syndepositional salt tectonics produced complex depositional and structural patterns in these areas.

Petroleum Plays and Exploration Wells

The Maritimes Basin contains the key petroleum-system elements for a substantial petroleum resource potential, including widespread reservoir rocks, large volumes of thermally mature oil and gas source rocks, and numerous and diverse trap types (Lavoie et al. 2009). The primary petroleum plays in the basin involve Lower Carboniferous (Horton Group) sandstones or conglomerates in fault block or stratigraphic traps, and Upper Carboniferous (Cumberland and Pictou Group) sandstones in salt diapir or fault block traps (Figs. 3, 4). Two of the exploration wells evaluated in this study (Bradelle and Irishtown) tested the Lower Carboniferous play and six wells (Brion Island, Cablehead, East Point, North Sydney, Hermine, and Hare Bay) tested the Upper Carboniferous play (Figs 3, 4). The Verrazano well in the northern St. Anthony Basin was an incomplete test of a Lower Carboniferous prospect, as the well was abandoned at a shallow depth due to drilling problems (Fig. 4). Although not encountered in the wells evaluated in this study, carbonate reservoirs are present in the Lower Carboniferous Windsor Group in parts of the Maritimes Basin (Fig. 2).

Commercial oil and gas production from Carboniferous reservoirs has been established in two fields in the onshore New Brunswick portion of the Magdalen Basin (Stoney Creek and McCully fields; Fig. 1). Both of these fields produce oil and/or gas from Horton Group (Albert Formation) sandstones. The McCully Field produces significant volumes of natural gas, for both local and export markets. There is one significant gas discovery in the Upper Carboniferous Cable Head Formation in the offshore East Point E-49 well (one of the wells evaluated in this study; Fig. 1). The East Point discovery remains undeveloped

RESERVOIR STUDIES

Previous reports on reservoir quality in the Maritimes Basin include the multi-well study of Bibby and Shimeld (2000) and a single-well core study of Chi and others (2003). These studies documented the trends of decreasing sandstone porosity with depth in the western Maritimes Basin, and identified stratigraphic intervals with enhanced porosity. Bibby and Shimeld (2000) also made reservoir-quality comparisons between Magdalen Basin strata and known producing oil and gas fields in Carboniferous basins in the North Sea and US Appalachian regions. The present study advances the observations in these previous reports by deriving a more comprehensive suite of reservoir parameters, identifying potential petroleum-bearing zones, and evaluating both stratigraphic and geographic variations in reservoir quality over a large part of the offshore Maritimes Basin. The reservoir characteristics described here are based on detailed analyses of core data and geophysical logs in nine wells in the Maritimes Basin (Fig. 1). The stratigraphic units encountered in the nine wells are summarized in Table 1. Initial study results for the five Magdalen Basin wells and the North Sydney F-24 well were presented by Hu and Dietrich (2009).

Table 1. Stratigraphic tops and total drill depths (metres below KB) in the nine wells evaluated in this study (adapted from Giles and Utting 1999, 2003, and P. Giles, personal communication 2009). Unnamed Permian strata overlie the Naufrage Formation in the Cablehead and East Point wells.

Basin	Well	Pictou Group				Cumbe-rland Group	Mabou Group	Windsor Group	Horton Group	Total Depth
		Naufrage Fm.	Cable Head Fm.	Green Gables Fm.	Bradelle Fm.					
Magdalen Basin	Bradelle L-49	0	430	824	1072		2044	2885	2926	4420
	Brion Island No.1	0	335	802	1133		2290	2682		3206
	Irishtown No.1	79	518	800	1300		1597	1740	2545	4108
	Cablehead E-95	503	1070	1387	2384					3243
	East Point E-49	637	1582	1876	2395	2900	2986			3526
Sydney Basin	N. Sydney F-24	73	360	730	1090		1438	1630		1707
	Hermine E-94		1636				1770	2325		3267
St.Anthony Basin	Verrazano L-77						210			460
	Hare Bay E-21		3398							4874

CORE AND LOG ANALYSES (METHODOLOGY)

Analyses of data from 255 sandstone core samples were compiled from well history reports of four wells, Bradelle L-49, Cablehead E-95, East Point E-49 and North Sydney F-24. Porosity-permeability relationships from the core data are illustrated in Figure 5, with data plots grouped by wells, sampled formations/groups, and the youngest stratigraphic interval, the Green Gables Formation.

Evaluations of log data in the nine wells included petrophysical analyses of digital gamma ray, caliper, density, sonic, photoelectric index, spontaneous potential, neutron and resistivity wireline logs, utilizing commercial log-analysis software (Halliburton-GeoGraphix PRIZM™). The well-log derived information included lithology, porosity, permeability, water saturation, and identification of possible petroleum-bearing zones. The log interpretations of sandstone reservoir characteristics in the study wells were complicated by two factors; the poor borehole conditions (enlarged borehole diameters, indicated by caliper logs) in many well intervals, and the presence of thin coal seams in many parts of the sedimentary succession. For lithology determinations, the density logs are adversely affected by poor borehole conditions. Accordingly, the shale contents in the study wells were derived from the gamma ray, spontaneous potential, sonic and neutron logs, with minimum shale-content values selected from the multiple log calculations. The gamma ray log produced the minimum values in most well sections, indicating that shale content (and not variations in sandstone mineralogy) controlled most of the gamma ray log responses. Sandstone porosity was calculated from the sonic and density logs, with shale corrections applied for the shaly-sandstone intervals. The sonic-log porosity was selected in well intervals with poor borehole conditions. The neutron log was not used for porosity calculations in the study wells, due to the abundance of shaly sandstones in the Carboniferous successions. Shaly sandstones may have high apparent porosity on neutron logs due to the effects of bound water. The initial porosity log analyses produced some anomalously high porosity values in coal-bearing intervals. Thin coal seams which are not resolved lithologically can produce log responses of apparent high porosity. Possible erroneous high porosity values in the coal-bearing sections were excluded in the final porosity-depth interpretations.

Water saturation values were derived using two shaly sandstone equations (modified Simandoux and Indonesian equations; Hu and Dietrich, 2009). Water saturation calculations are highly dependent on water resistivity parameters. There are two wells in the study dataset (Brion Island and East Point) with direct water analysis information. Water resistivity values for the other wells were derived from log analyses in clean sandstone intervals. Sandstone permeability values were calculated utilizing the commonly used Timur and Coates equations (Hu and Dietrich 2009). The identification of petroleum-bearing zones was based on lithology, porosity, and water saturation data. Selected criteria used to indentify possible petroleum zones included sandstone porosity values above 7.5 % (the porosity limit of conventional reservoirs in the study wells) combined with water saturation values below 55 % or 45 %. The lower water saturation values (less than 45 %) indicate the most prospective intervals.

The accuracy of the well log interpretations can be evaluated by comparing the log and core measurements. In the four wells with core data, the core and log calculated porosity and permeability values generally matched very closely, providing a high level of confidence for the log-calculated porosity and permeability data derived in this study (Figs. 6, 9). For the permeability and water saturation calculations, the Indonesian equation and Timur equation derived values most closely matched the available core measurements and were utilized for the final log interpretations.

RESERVOIR CHARACTERISATION

The compiled core data outline general trends of increasing permeability with increasing porosity in all wells and most stratigraphic units (Fig. 5). The highest core porosity and permeability values (18 % and 100 millidarcies (mD), respectively) occur in the Upper Carboniferous Green Gables Formation in the Bradelle L-49 well. The Green Gables Formation samples display the best mathematical relationship between permeability and porosity, with a correlation coefficient of 0.88 for a fitted non-linear curve (Fig. 5). With the exception of one fractured core sample in the Horton Group, the bulk of the sampled stratigraphic succession, from the Bradelle Formation to the Horton Group, is characterized by variable porosity and low permeability. The Mabou and Horton group samples display the lowest correlations between core porosity and permeability, with consistently low permeability values associated with a range of porosity values. Sandstones with permeability values less than 0.1 mD (level delineated by dashed black lines in Fig. 5) are commonly referred to as unconventional or tight reservoirs (Law and Curtis 2002). Unconventional petroleum reservoirs generally require special drilling or enhanced recovery techniques (such as formation fracturing) to retrieve the resource. The core data compiled for this study indicate there are approximately equal numbers of sandstones that could be characterised as conventional and unconventional reservoirs. Sandstones with permeability values at or near 0.1 mD have porosity values ranging from 4 to 12 % and averaging 7.5 % (Fig. 5). The permeability-porosity relationship derived from the limited core data can be used as a proxy to describe the distribution of conventional versus unconventional sandstone reservoirs in porosity data plots for the study wells.

Petrophysical evaluations of wireline well logs indicate sandstones are abundant in the Maritimes Basin, with the highest sandstone percentages in the study wells occurring in the Upper Carboniferous Pictou Group and Lower Carboniferous Mabou Group (Fig. 6). The highest log-calculated porosity and permeability values (25 to 35 % and 500 to 800 mD) occur in Pictou Group sandstones in the shallow sections of the Magdalen Basin wells (Figs. 7, 9). Mabou Group sandstones in the shallow Verazzano well (St. Anthony Basin) have porosity of up to 25 % and permeability of up to 100 mD. Pictou and Mabou sandstones in all wells have fair to good reservoir characteristics, with porosity and permeability commonly above 10 % and 1 mD, over a wide range of basin depths. Figure 8 illustrates an example of two sandstone-bearing sections in the Bradelle Formation in the Brion Island well (at depths from 1470 to 1920 m), with log-calculated sandstone porosity between 10 and 20 % (maximum of 25%) and permeability between 0.1 and 10 mD (maximum of 40 mD). Cumberland Group sandstones in the East Point E-49 well have porosity of up to 20 % and permeability of up to 1.0 mD (Fig. 9). Windsor Group sandstones comprise a minor component of the basin fill and in the study wells are characterised by very low porosity and permeability, with little reservoir potential. Sandstones in the Lower Carboniferous Horton Group have fair to good reservoir quality, with porosity and permeability values of 5 to 10 % and 0.1 to 1.0 mD, respectively (e.g., Bradelle well, Fig. 7).

Porosity Trends with Depth

Porosity-depth trends for Upper Paleozoic sandstones in the Maritimes Basin are illustrated for individual wells and stratigraphic units (Fig. 9), basins and basin areas (Fig. 10), and all wells combined (Fig. 11). General trends of decreasing porosity with depth are apparent in all wells/basins. Sandstone porosity is commonly above 20 % at depths above 1000 m, and above 10 % above 2000 m. Sandstones with porosity above 10 % occur to depths of up to 4000 m in the Magdalen Basin (Bradelle and Irishtown wells; Fig. 8) and up to 4500 m in the St. Anthony Basin (Hare Bay well).

Average porosity-depth curves provide general reservoir-quality evaluations and comparisons between basins and areas (Fig. 12). The average sandstone porosity in all basins is below 7.5 % (into the range of unconventional reservoirs) below depths of 1400 to 1800 m. The northern Magdalen Basin wells (Bradelle and Brion Island) appear to have best overall reservoir potential to depths of about 2000 m. At depths below 2000 m, average porosity values in the southern Magdalen Basin wells (Irishtown, Cablehead and East Point) are comparable to the northern Magdalen Basin wells. The Sydney Basin wells (North Sydney and Hermine) are characterised by the poorest reservoir quality, with the lowest average porosity over most depth intervals. There is insufficient data in the St. Anthony Basin wells (Verrazano and Hare Bay) to compare average porosity-depth trends with other study wells in the Maritimes Basin. However, the Hare Bay well in the St Anthony Basin has relatively high porosity values (up to 15 %) in the deepest parts of the penetrated basin succession (4000 to 5000 m; Figs. 9, 10).

DISCUSSION

The core and well log analyses presented here provide an overview of the reservoir characteristics of Carboniferous-Permian sandstones in the offshore Magdalen, Sydney and St. Anthony basins. The well log calculations outline the trends of exponentially-decreasing sandstone porosity with depth. The majority of sandstones in the nine wells evaluated are characterised by relatively low porosity and permeability in the depth range most commonly explored for oil or gas traps (1000 to 4000 m). Carboniferous sandstones in the Maritimes Basin have significantly lower average porosity and permeability than Mesozoic strata in the Atlantic margin basins (e.g., Scotian Shelf and Jeanne D'Arc basins; Wade et al. 1989; Sinclair et al. 1992). The porosity-depth relationships in the Maritimes Basin reflect the basin's history of subsidence, sediment compaction, and exhumation. The maximum paleo-burial depths of Upper

Paleozoic strata in the basin were 600 to 2400 m below present depths, with exhumation/erosion likely occurring during Mesozoic time (Rehill 1996). The average sandstone porosity-depth trends derived from the wells in this study are close or slightly below a model-predicted sandstone compaction curve for paleo-burial depths 1750 m below present depths (Chi et al. 2003; Fig. 12).

Although the average sandstone porosity and permeability in the study wells is relatively low for any given burial depth, there are many sandstone intervals with higher than average porosity-permeability values (Figs. 12, 13). Most of the enhanced porosity is likely secondary in origin. In a detailed core study of sandstone diagenesis in the Spring Valley No. 1 well in the southern Magdalen Basin (Fig. 1), Chi and others (2003) identified significant secondary porosity development in Upper Carboniferous sandstones and linked the porosity development to dissolution of framework grains (mainly feldspar) and early-formed carbonate cements. The dissolution processes and secondary porosity development in Maritimes Basin strata may be related to intra-formation reactions with fresh meteoric waters or acidic fluids developed during deep burial and maturation of organic-rich strata (Gibling et al. 2000; Chi et al. 2003). The latter factor may account for much of the secondary porosity development in the study wells as enhanced-porosity sandstones occur over a wide range of burial depths, including sections that extend far below the normal depths for meteoric water incursions (e.g., abundance of above-average porosity sandstones at depths from 2500 to 3500 m in the Magdalen Basin wells; Figs 9, 10).

Differences in average reservoir porosity in Upper Carboniferous sandstones in the shallow parts of the northern and southern Magdalen Basin wells (Fig. 12) may also reflect 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).

Petroleum Reservoir Potential

The potential for significant natural gas production from sandstones in the Maritimes Basin is indicated by the production and testing data in the discovered fields and the well-log data evaluated in this study. The magnitude or range of natural gas flow rates relative to reservoir porosity and permeability are documented for the two producing fields and one significant discovery (Fig. 1). In the onshore Stoney Creek Field, 10 wells had initial gas production rates of 10 to18 MMcf/d and 30 wells had initial production rates of 1 to10 MMcf/d (Henderson 1940). The porosity and permeability of the productive sandstone reservoirs in the Stoney Creek Field vary from 8 to 20 % and 0.1 to 100 mD (Chowdbury and Noble 1992; St. Peter 2000). The offshore East Point E-49 well tested gas at a rate of 5.5 MMcf/d from a sandstone reservoir with porosity of 10 to 12 % and permeability of 0.1 to 1.0 mD (Fig. 13). In the onshore McCully gas field, gas well production rates of 0.6 to 13.0 MMcf/d have been established from sandstone reservoirs with porosity of 3 to 10 % and permeability of 0.1 to 4.0 mD (Martel and Durling 2006). Formation fracturing has routinely been applied in the McCully Field to enhance production from low permeability reservoirs (Corridor Resources 2008, 2009).

Well log indications of possible (untested) oil or gas zones are present in all nine wells evaluated in this study. Many of the indicated petroleum zones occur in thin shaly sandstones, characterised by very low porosity and permeability. However, some of the possible petroleum zones occur in sandstones with fair to good porosity and permeability. Examples of possible petroleum-charged sandstones with good reservoir characteristics include intervals in the Horton Group in the Bradelle L-49 well and the Pictou Group in the East Point E-49 and Cablehead E-95 wells (Figs. 13, 14). In the Cablehead well, multiple log-indicated petroleum zones occur in sandstones with calculated porosity of 6 to 12 % and permeability of 0.1 to 2.0 mD (Fig. 14). It is not possible with available data to determine if oil or gas could be produced from any of the log-indicated petroleum zones. However, based on qualitative comparisons with reservoir parameters in the tested gas zone in the East Point well, some sandstone intervals in the Cablehead well appear to have potential for gas recovery. Sandstones with higher porosity and permeability, such as measured in the Brion Island and Bradelle wells, could form high productivity reservoirs if charged with gas or oil.

CONCLUSIONS

The Upper Paleozoic Maritimes Basin contains large volumes of sandstone reservoirs, displaying a wide range of porosity and permeability characteristics. The data compiled and derived in this study indicate there is significant conventional petroleum reservoir potential in the basin, with all wells evaluated containing sandstones with above average porosity over a wide range of burial depths. Measured sandstone porosity values in the Magdalen Basin wells are up to 20 % to depths of 2000 m, and up to 15 % to depths of 3500 m. Sandstone porosity values in the Hare Bay well in the St Anthony Basin are up to 15 % to depths of 4500 m. Most of the enhanced reservoir quality is likely related to secondary porosity development. In terms of overall reservoir quality, Upper Carboniferous sandstones in the northern Magdalen Basin may be the most prospective in the study region.

The Maritimes Basin contains large volumes of low permeability sandstones that are known or prospective unconventional petroleum reservoirs. Although not economically viable at present, unconventional gas reservoirs in the offshore Maritimes Basin may provide opportunities for future resource development.

The Maritimes Basin is characterised by complex and varied structural and depositional elements and it is not certain if the reservoir-quality patterns observed in the study wells can be extrapolated across all parts of the basin. Further evaluations of reservoir potential may benefit from additional studies of wells in onshore basin areas and more detailed analyses of sandstone diagenesis and controls on secondary porosity development.

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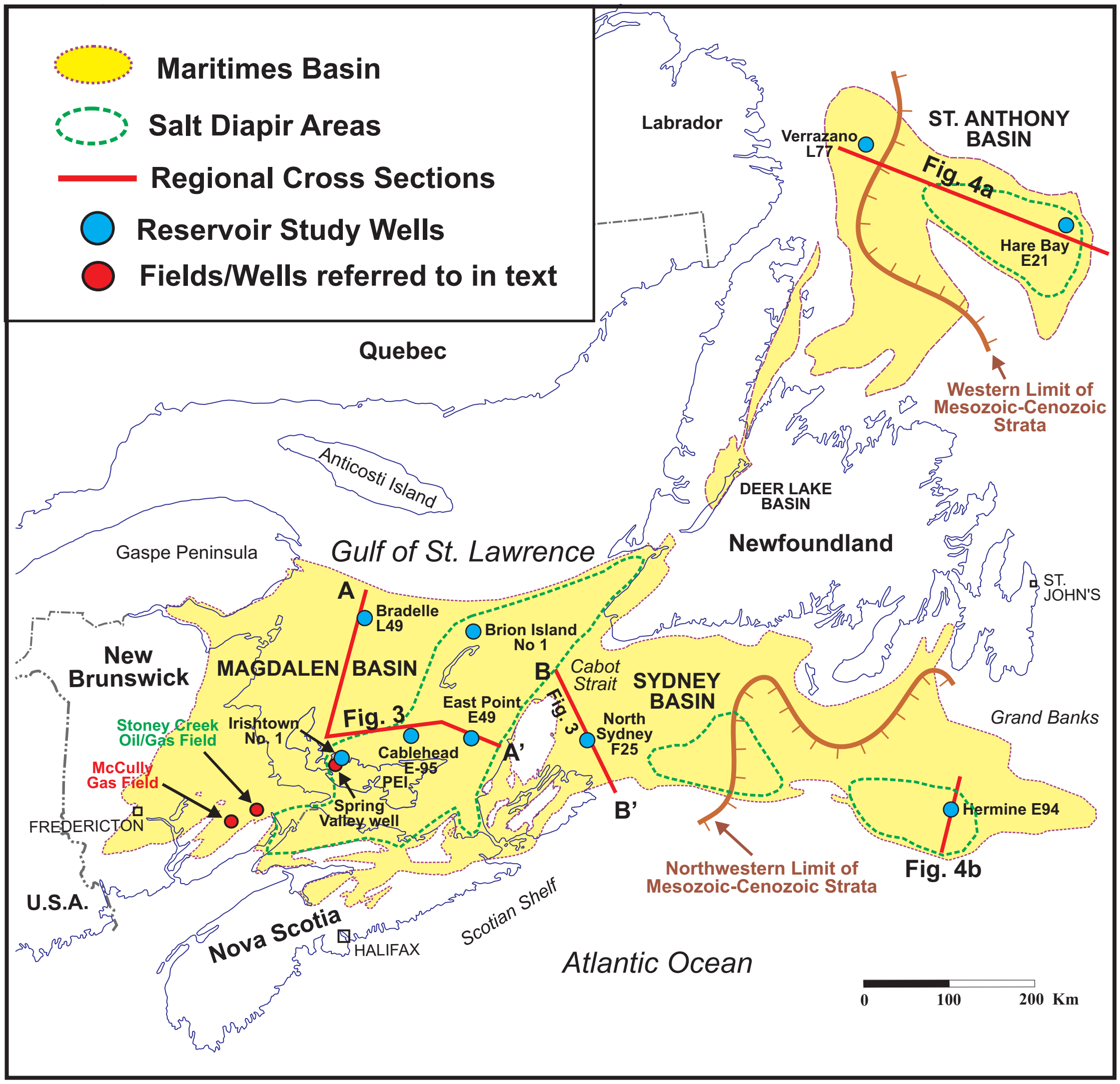

Fig. 1. Regional distribution of Upper Paleozoic strata in the Maritimes Basin in eastern Canada, with locations of the nine wells analysed in this study, regional cross-sections (Figs. 3 and 4), the Stoney Creek and McCully oil/gas fields, and the Spring Valley well. Major Carboniferous basins include the Magdalen, Sydney and St. Anthony basins. Salt diapir zones are present in all three basins. The eastern Sydney and St. Anthony basins are overlain by Mesozoic-Cenozoic strata of the Atlantic continental margin.

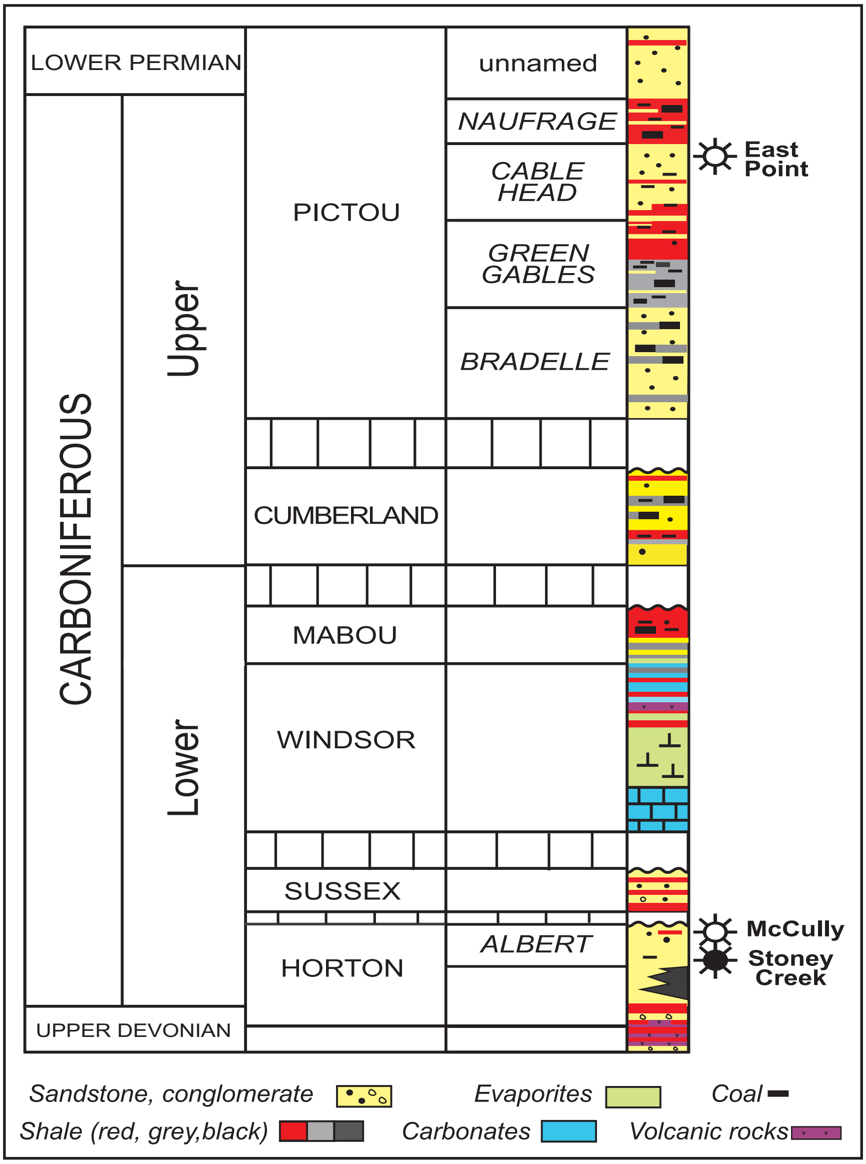

Fig. 2. Generalized lithostratigraphy for the Maritimes Basin (adapted from Giles and Utting 1999, and St. Peter and Johnston 2009). Prospective petroleum reservoirs occur in sandstones in the Lower Carboniferous Horton Group (Albert Formation) and Mabou Group, and the Upper Carboniferous Cumberland and Pictou groups (mainly the Bradelle and Cablehead formations in the latter). Producing or tested oil and gas reservoirs occur in sandstones in the Albert and Cablehead formations.

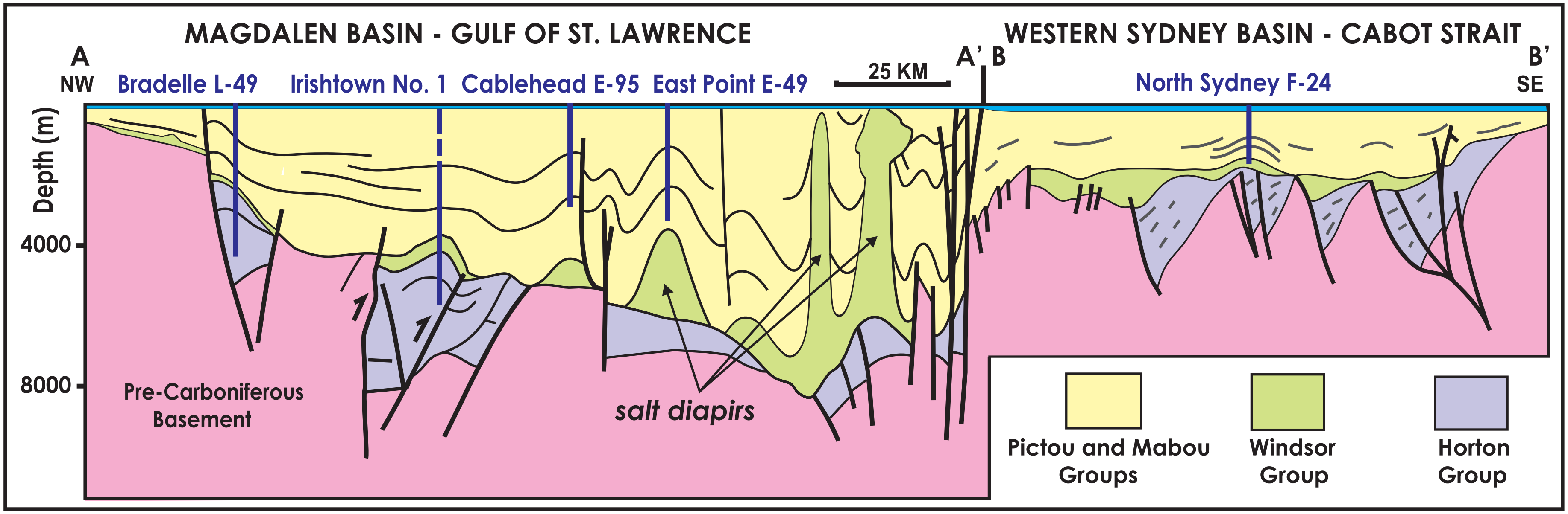

Fig. 3. Regional composite cross-section of the offshore Magdalen Basin (A-A') and western Sydney Basin (B-B'), illustrating geological setting of the Bradelle, Irishtown, Cablehead, East Point and North Sydney wells (location in Fig. 1; Irishtown well projected into line of section; Sydney Basin section modified from Pascucci et al. 2000). The Brion Island well (Fig.1) tested a salt-cored anticline similar to the East Point structure.

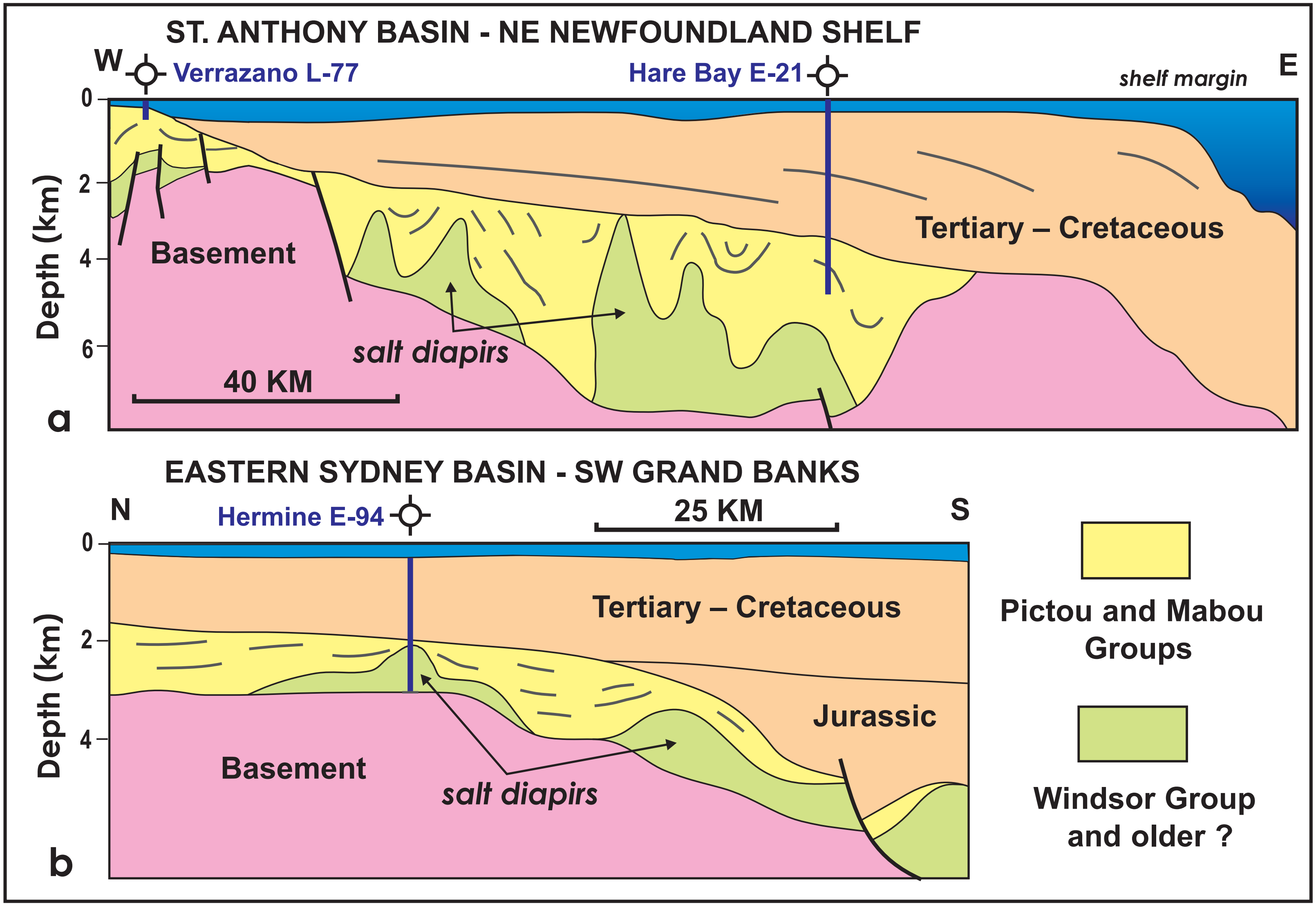

Fig. 4. Regional cross-sections of the St. Anthony Basin (a) and eastern Sydney Basin (b), illustrating geological setting of the Verrazano, Hare Bay and Hermine wells evaluated in this study (locations in Fig. 1; St Anthony Basin section based on data from Grant and McAlpine 1990 and McWhae et al. 1980; eastern Sydney Basin section modified from MacLean and Wade 1992). The Verrazano well was abandoned at a shallow depth after penetrating a thin section of Mabou Group strata.

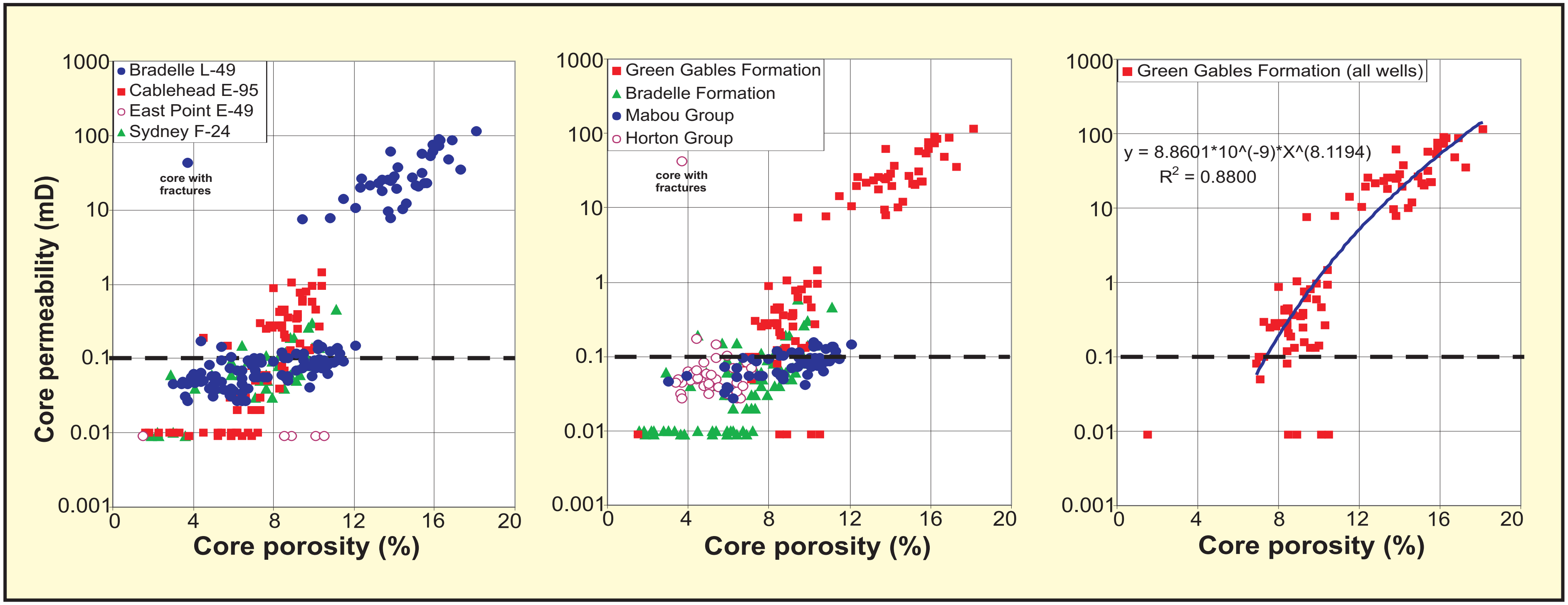

Fig. 5. Cross plots of sandstone core permeability and porosity from four Maritimes Basin wells, illustrating trends and variations within wells (top panel), stratigraphic units (middle panel) and the Upper Carboniferous Green Gables Formation (bottom panel). General trends of increasing porosity with permeability are evident in all plots, with the exceptions of the lowest permeability sandstones (≤0.01 mD). Sandstones with permeability values less than 0.1 millidarcies (level delineated by dashed black lines) are commonly referred to as unconventional reservoirs.

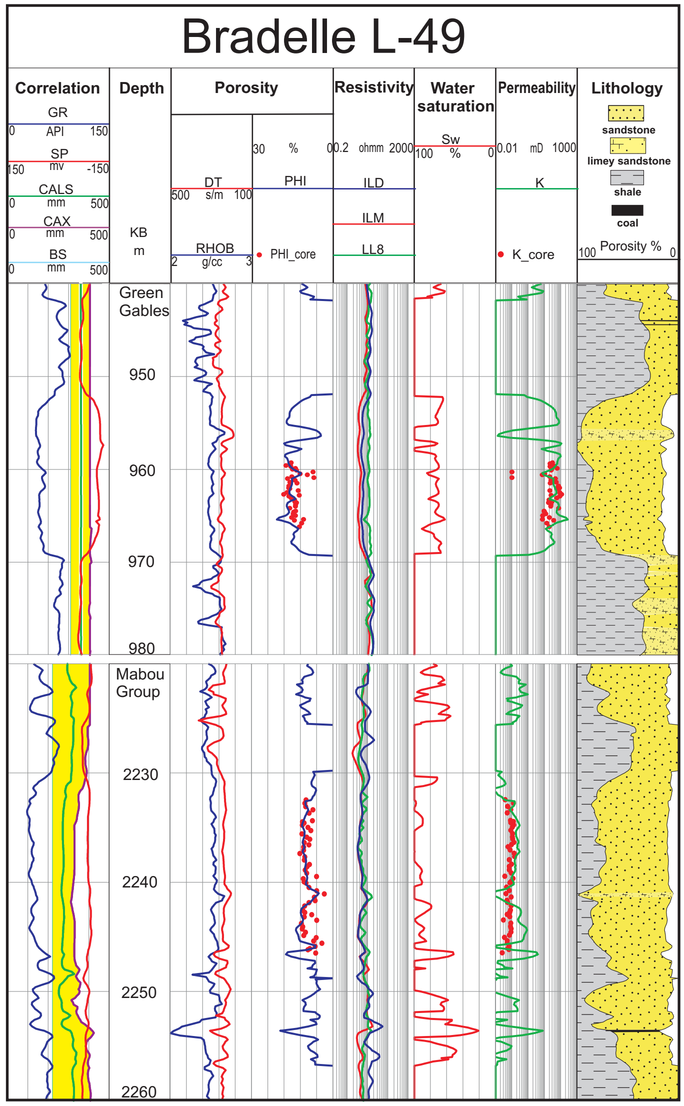

Fig. 6. Comparison of well-log derived petrophysical properties with core data (red dots) for sandstones in the Green Gables Formation (top segment) and Mabou Group (bottom segment) in the Bradelle L-49 well. The log-derived sandstone porosity and permeability values closely match the core measurements.

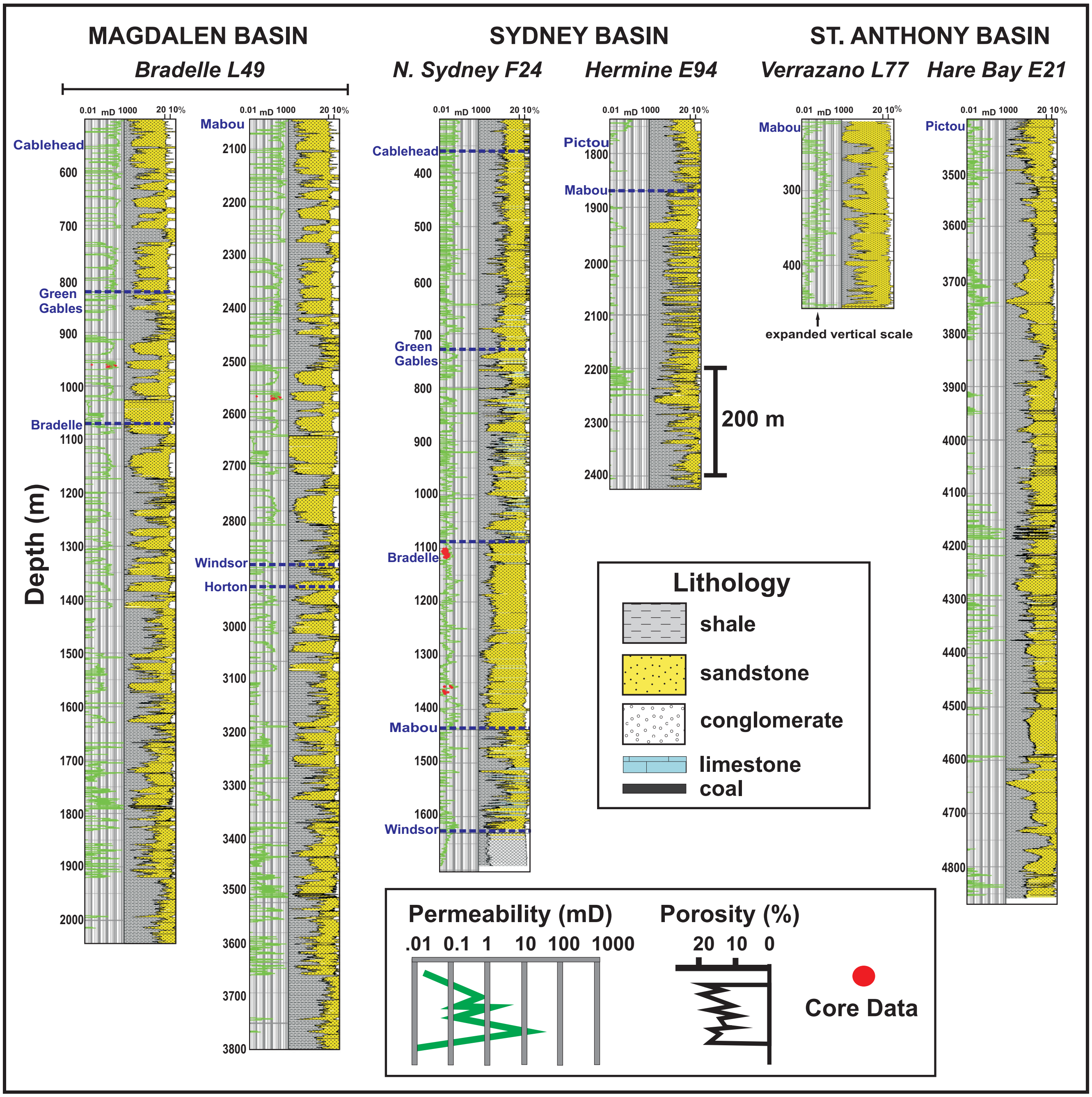

Fig. 7. Stratigraphy, lithology and porosity-permeability data for five wells in the Maritimes Basin.

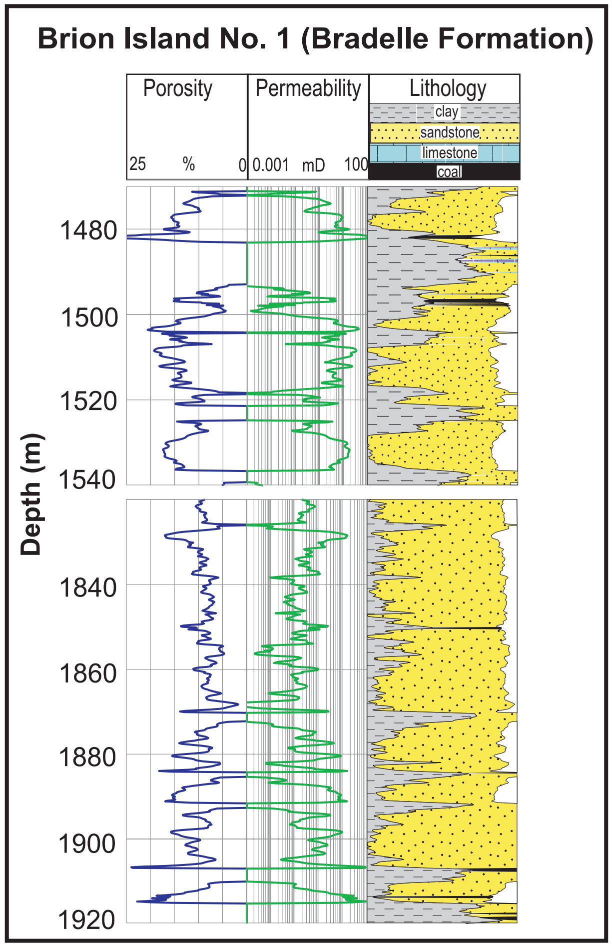

Fig. 8. Detailed lithology and porosity-permeability data for two sections in the Upper Carboniferous Bradelle Formation in the Brion Island No.1 well, northern Magdalen Basin.

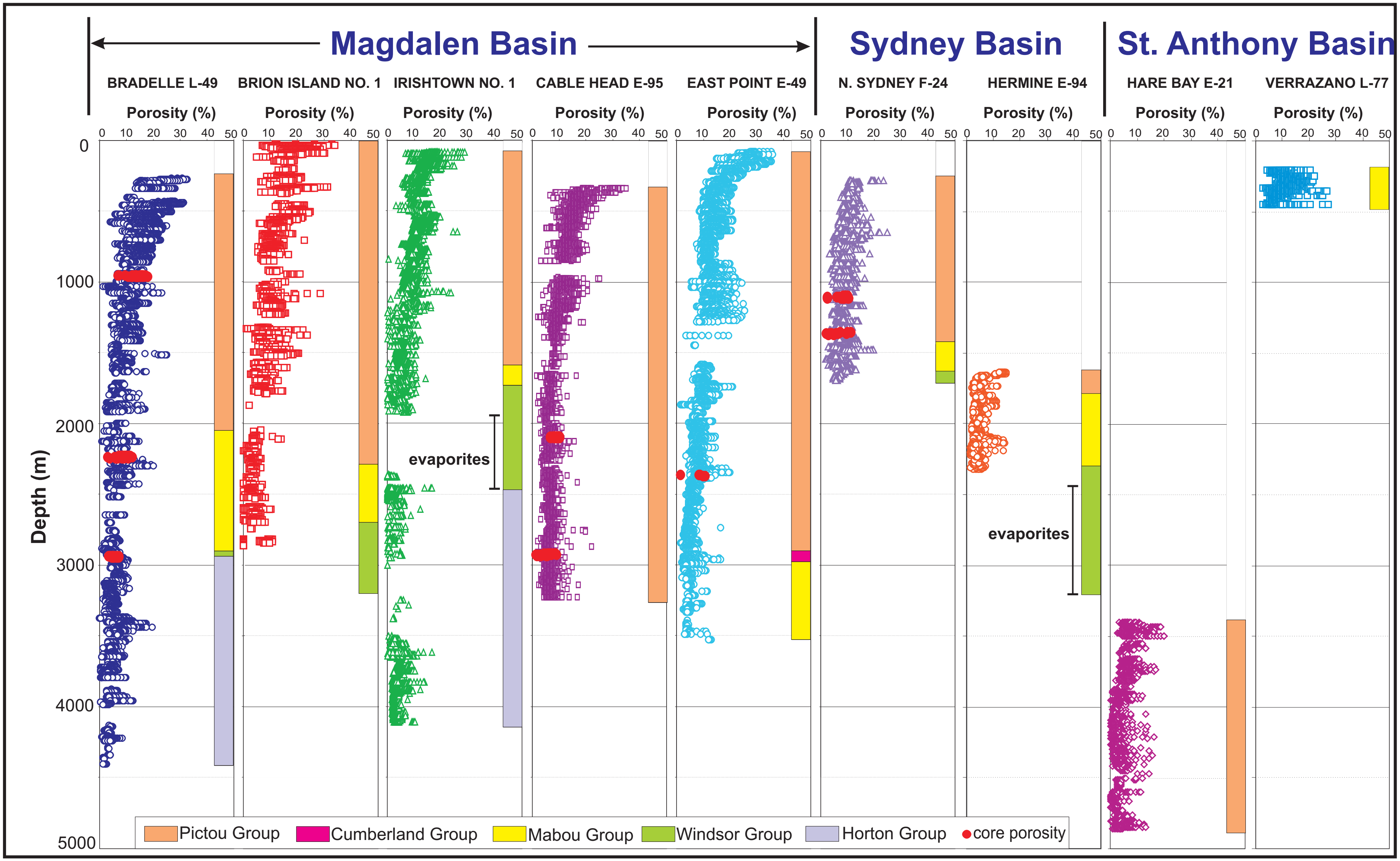

Fig. 9. Well-log derived sandstone porosity-depth trends for individual wells with indicated well stratigraphy and core porosity data.

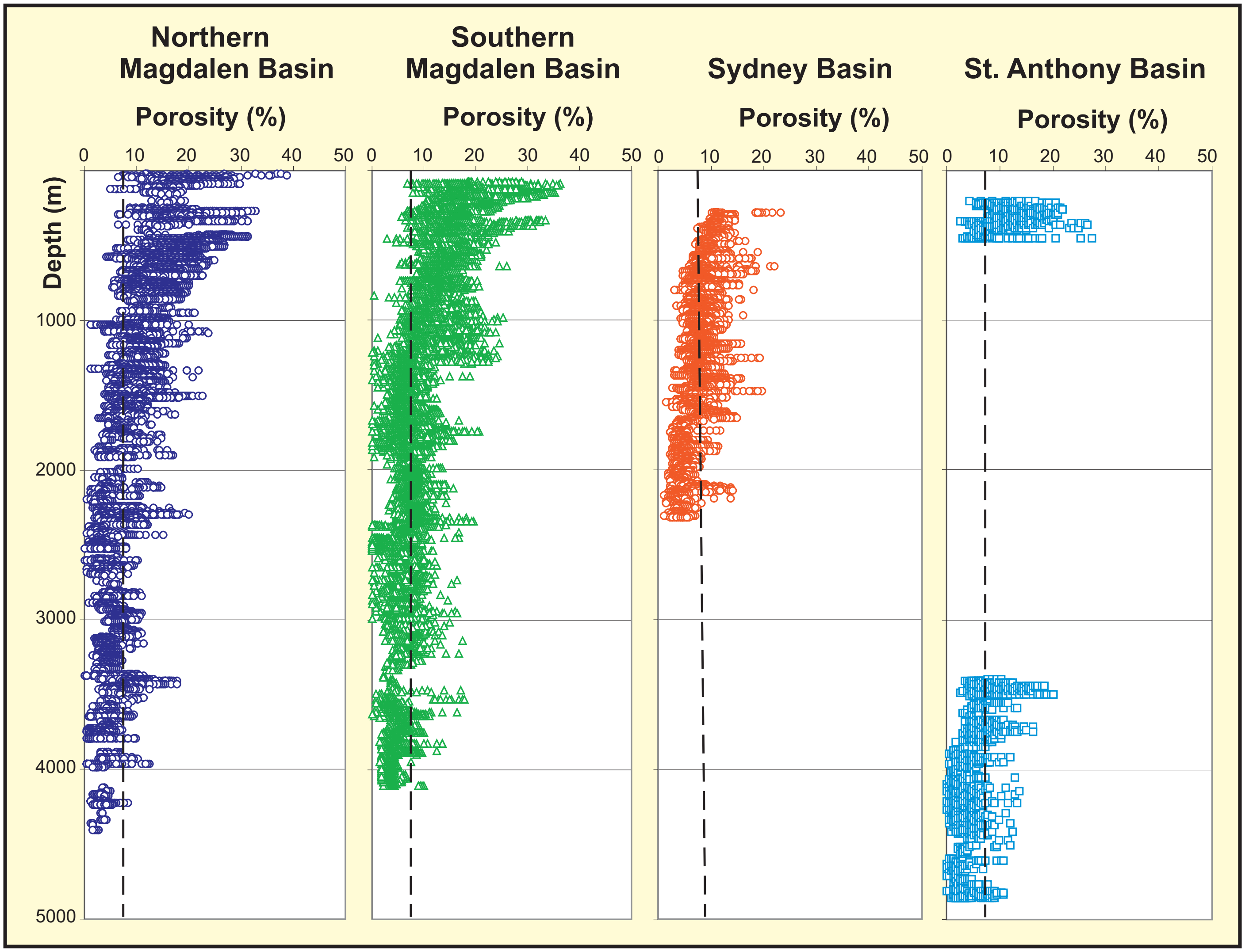

Fig. 10. Composite sandstone porosity-depth plots for the northern Magdalen Basin (Bradelle and Brion Island wells), southern Magdalen Basin (Irishtown, Cablehead and East Point wells), Sydney Basin (North Sydney and Hermine wells) and St. Anthony Basin (Verrazano and Hare Bay wells). Vertical dashed lines provide approximate boundaries between conventional and unconventional sandstone reservoirs (above and below 7.5 % porosity).

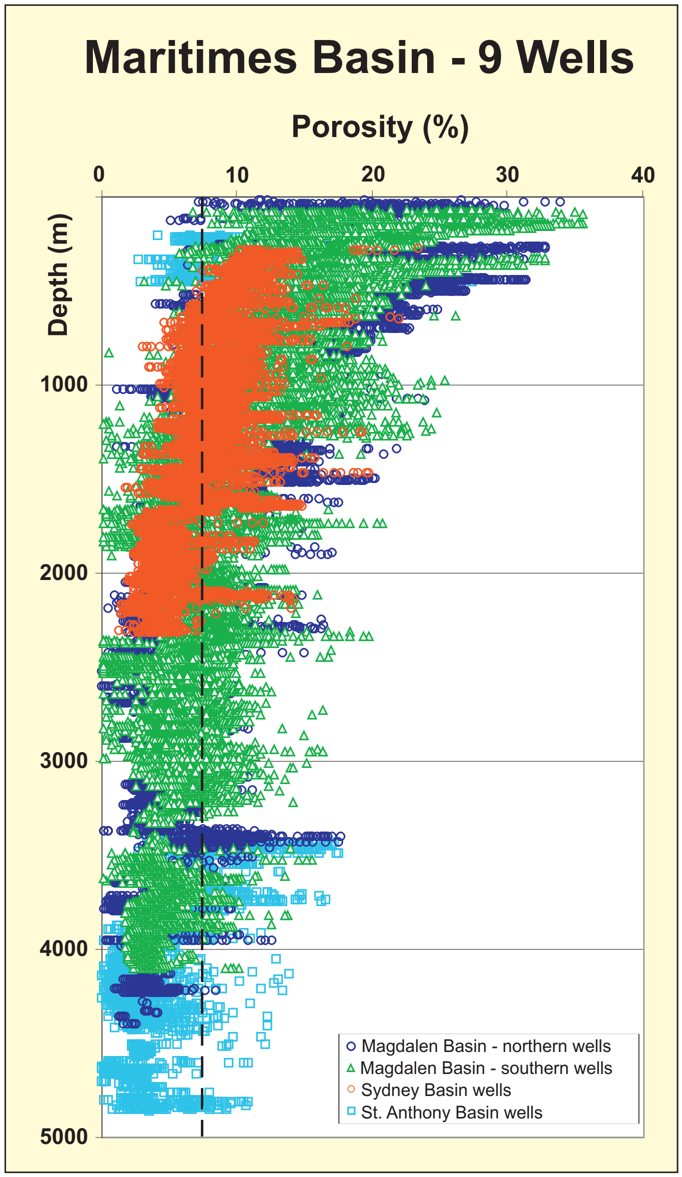

Fig. 11. Composite sandstone porosity-depth plot for all nine wells in the Maritimes Basin. Vertical dashed line provides approximate boundary between conventional and unconventional sandstone reservoirs (above and below 7.5 % porosity).

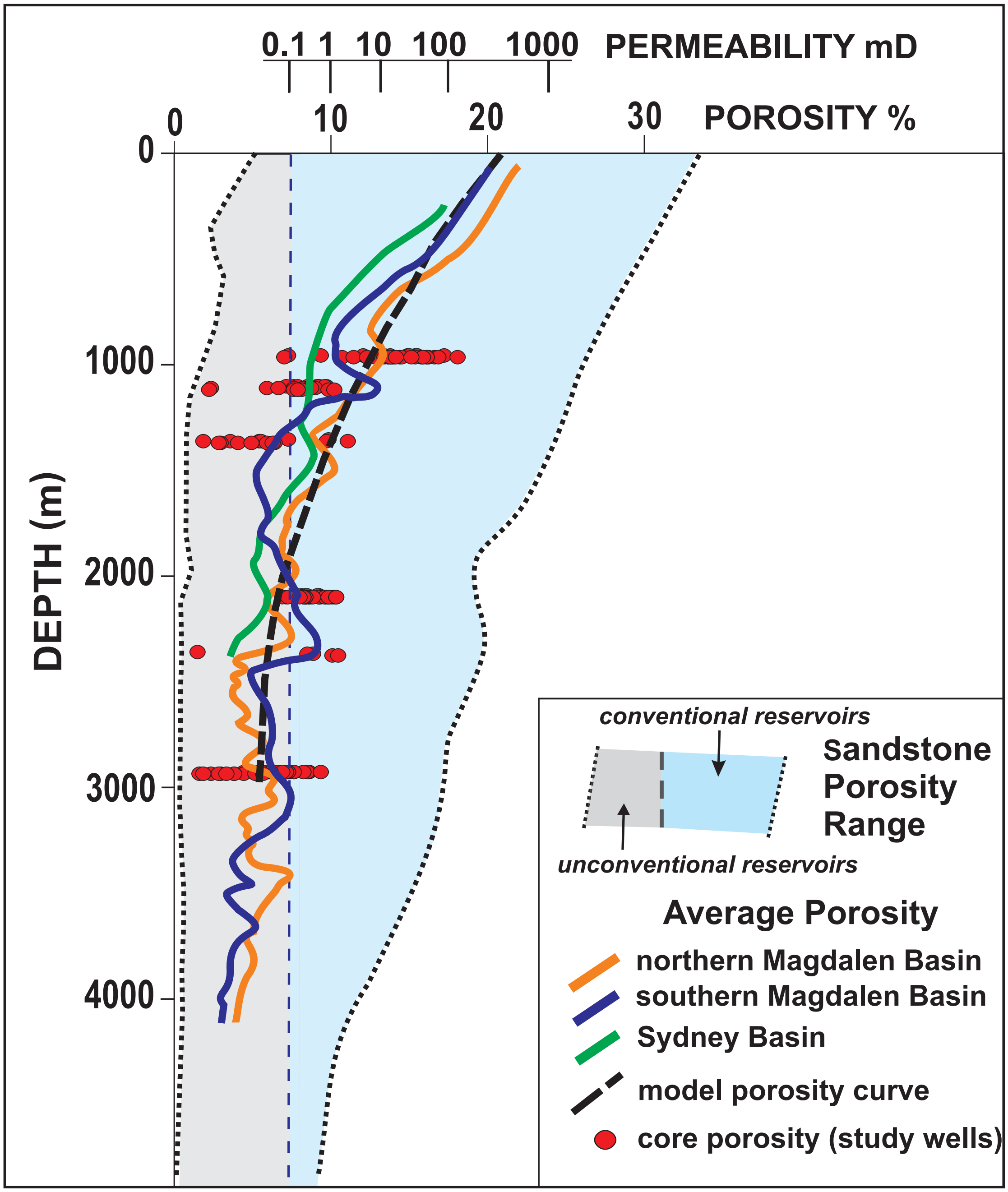

Fig. 12. Summary of porosity-permeability depth trends for Upper Paleozoic sandstones in the Maritimes Basin, including porosity range with depth, average porosity-depth curves (statistically derived 11 point moving averages) for wells in the northern Magdalen Basin (Brion Island and Bradelle), southern Magdalen Basin (Irishtown, Cablehead, and East Point) and Sydney Basin (North Sydney and Hermine), and core porosity measurements for the study wells. Model porosity curve denotes a theoretical sandstone compaction curve for paleo-burial depths of 1750 m below present depths (adapted from Chi et al. 2003). Permeability scale based on statistical correlations between porosity and permeability core data (Fig. 5). Vertical dashed line at 7.5 % porosity (0.1 mD permeability) provides an approximate boundary between conventional and unconventional reservoirs.

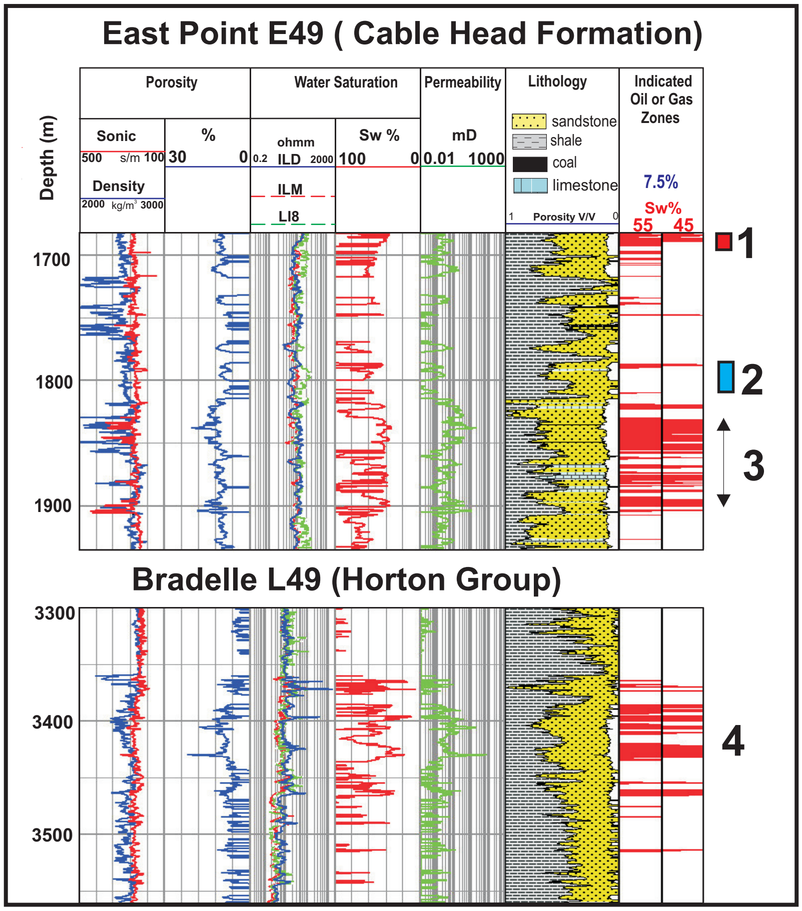

Fig.13. Petrophysical log analyses of parts of two Magdalen Basin wells, illustrating known and possible petroleum zones in Carboniferous strata, based on porosity and water saturation cutoff values (right columns): 1. tested gas zone in the Cablehead Formation in the East Point well (gas recovery at 5.5 MMcf/d); 2. tested zone in the East Point well with no oil or gas recovery; 3. untested log-indicated petroleum zone; 4. untested log-indicated petroleum zone in the Horton Group in the Bradelle well.

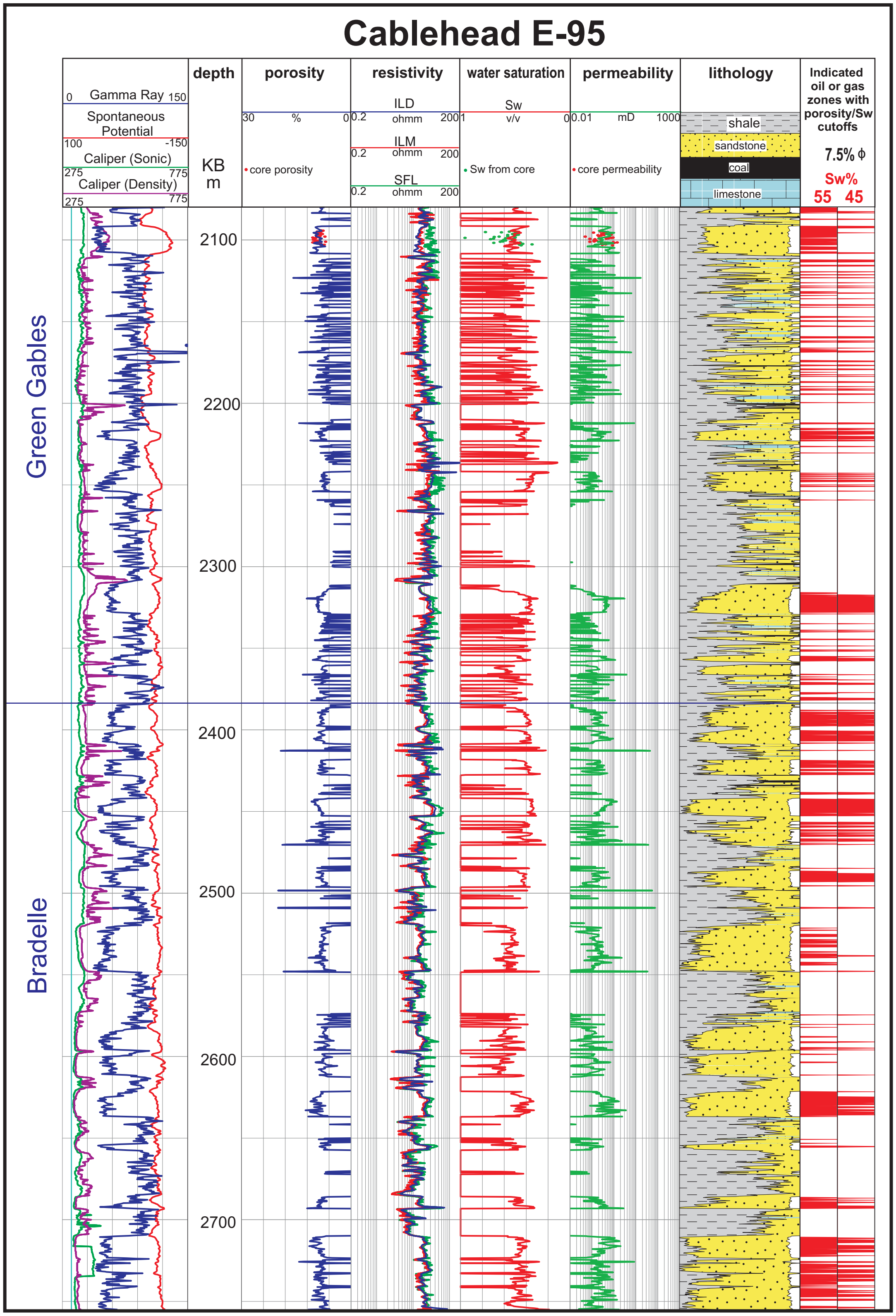

Fig. 14. Detailed petrophysical plot of parts of the Upper Carboniferous Green Gables and Bradelle formations in the Cablehead E-95 well. This well section contains multiple sandstone intervals with many log-indicated petroleum zones (based on the noted porosity and water saturation cut-offs). The log analysis indicates sandstones in this well section have porosity of 6 to 10 % and permeability of 0.1 to 10 mD. Core measurements of porosity, permeability and water saturation from one sandstone interval (~2100 m) are comparable to the log calculations.