ASSESSMENT OF OIL AND GAS POTENTIAL, WINDSOR AND CUMBERLAND BASINS, ONSHORE NOVA SCOTIA

for

NOVA SCOTIA DEPARTMENT OF ENERGY

March 2017

Petrel Robertson Consulting Ltd.

CERTIFICATE OF QUALIFICATION

BRAD J.R. HAYES, Ph.D., P.Geol.

I, Brad J.R. Hayes, Professional Geologist at Petrel Robertson Consulting Ltd., Suite 500, 736 – Eighth Avenue SW, Calgary, Alberta, Canada and author of a report dated March, 2017, do hereby certify that:

I am a professional geologist employed by Petrel Robertson Consulting Ltd., which Company did undertake a study entitled Assessment of Oil and Gas Potential, Windsor and Cumberland Basins, Onshore Nova Scotia for the Nova Scotia Department of Energy.

- I attended the University of Toronto, and that I graduated with a Bachelor of Science (Honours) Degree, Geology Specialist Program (1978), and obtained a Doctor of Philosophy Geology (1982) from the University of Alberta (Edmonton, Alberta); that I am a member of APEGA; that I have in excess of 30 years experience including geological studies relating to both Canadian and international oil and gas properties.

- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, from any associate or affiliate of the Nova Scotia Department of Energy.

- The report was prepared based on information available in the public domain and/or from the Nova Scotia Department of Energy.

PROFESSIONAL GEOLOGIST
DR. BRAD J. HAYES
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Petrel Robertson

CERTIFICATE OF QUALIFICATION

KATHLEEN DOREY, HBSc. P.Geoph.

I, Kathleen Dorey, Professional Geophysicist at Petrel Robertson Consulting Ltd., Suite 500, 736 – Eighth Avenue SW, Calgary, Alberta, Canada and co-author of a report dated March, 2017, do hereby certify that:

- I am a professional geophysicist employed by Petrel Robertson Consulting Ltd., which Company did prepare a report entitled Assessment of Oil and Gas Potential, Windsor and Cumberland Basins, Onshore Nova Scotia for the Nova Scotia Department of Energy.

- I attended the University of Western Ontario at London, Ontario, and that I graduated with a Honours Bachelor of Geophysics Degree, (1983), that I am a member of APEGA; that I have in excess of 28 years experience including geophysical studies relating to both Canadian and International oil and gas properties.

- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, from any associate or affiliate of the Nova Scotia Department of Energy.

- The report was prepared based on information available in the public domain and/or from the Nova Scotia Department of Energy.

Kathleen Dorey, P.Geoph. (Alberta)

CERTIFICATE OF QUALIFICATION

CHRIS LONGSON, BSc., BE., P.Eng.

I, Christopher K. Longson, Consulting Petroleum Engineer, of 710 - 38th Avenue SW, Calgary, Alberta Canada and co-author of a report dated March, 2017, do hereby certify that:

- I am a Petroleum Engineer consulting for Petrel Robertson Consulting Ltd., which Company did prepare a report entitled Assessment of Oil and Gas Potential, Windsor and Cumberland Basins, Onshore Nova Scotia for the Nova Scotia Department of Energy

- I attended the University of Auckland, New Zealand and that I graduated with a Bachelor of Science Degree in Physics in 1973 and a Bachelor of Engineering Degree in Engineering Science in 1975; that I am a registered Professional Engineer in the Province of Alberta; that I have in excess of 35 years' experience in Petroleum Engineering relating to International and Canadian oil and gas properties.

- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, from any associate or affiliate of the Nova Scotia Department of Energy.

- The report was prepared based on information available in the public domain and/or from the Nova Scotia Department of Energy.

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Chris Longson, BSc., BE., P.Eng.

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INTRODUCTION

Petrel Robertson Consulting Ltd. (PRCL) was engaged by the Nova Scotia Department of Energy to provide advice and support on assessing conventional and unconventional oil and gas resources of onshore Nova Scotia. PRCL has completed similar oil and gas resource assessments in other petroleum frontier areas of Canada, and principal Dr. Brad Hayes gained experience in service to the Nova Scotia Expert Panel on Hydraulic Fracturing in 2014.

After consultation with Department of Energy staff on available data and timelines, PRCL agreed to focus on assessing conventional and unconventional oil and gas resources in the Windsor-Kennetcook and Cumberland basins. Ministry staff has compiled available geological and geophysical data to support the assessment, and Dr. D. Fraser Keppie visited PRCL offices during the project to provide support and to become more familiar with the assessment workflow.

The joint goal of the Department of Energy and PRCL for this project is to produce a robust evaluation of resource potential that accurately reflects the quality and availability of data from the Windsor-Kennetcook and Cumberland basins of Nova Scotia – and to enable Department of Energy staff to undertake additional resource assessment work in the future.

Petrel Robertson Consulting Ltd. (PRCL) (www.petrelrob.com) is a fully integrated petroleum geoscience consulting firm, with a wealth of technical and operating experience in mapping and characterizing conventional and unconventional oil and gas play fairways. We have completed both conventional and unconventional resource assessments for industry clients, technical associations, and government agencies and regulators. These projects include:

- Alberta Deep Basin Gas Resource Assessment (2009), for Canadian Association of Petroleum Producers;
- Assessment of Canada's Natural Gas Resource Base (2010), for Canadian Society for Unconventional Gas;
- Petroleum Resource Assessment of Whitehorse Trough, Yukon, Canada – Yukon Geological Survey Miscellaneous Report 6 (2012), for Yukon Geological Survey;
- Assessment of Canada's Light Tight Oil Resources (2014), for Canadian Society for Unconventional Resources.

In addition, we have completed numerous other exploration assessment studies where our goal was to define geological and geophysical characteristics of new or frontier play fairways.

Dr. Brad Hayes (PhD., P.Geo., FGC) has more than 35 years of experience working in the petroleum industry, first with various operating companies, and for the past 20 years with Petrel Robertson Consulting Ltd. He has worked and analyzed a variety of conventional and unconventional plays in Canada and internationally, at all stages of exploration, appraisal, and development. In 2014, Dr. Hayes served on the Nova Scotia Expert Panel on Hydraulic Fracturing, where he was tasked with assessing current knowledge and assessing potential productivity of petroleum reservoirs in onshore Nova Scotia.

PROJECT DEFINITION

Oil and gas resource potential in mature sedimentary basins with long histories of drilling and associated exploration activities can be assessed using a variety of methods building on abundant available datasets. In Canada, the Geological Survey of Canada (GSC) and the National Energy Board (NEB) have completed assessments of specific play fairways and entire petroleum basins, based on geological characterization then statistical analysis of distributions of known discoveries. At the other extreme, in frontier basins with relatively sparse information, little has been done beyond simple volumetric calculations and general assumptions about richness of the petroleum endowment.

During the past decade, the emergence of unconventional reservoirs as primary exploration and development targets has driven re-examination of resource assessment methodology. Both the United States Geological Survey (USGS) and GSC / NEB have published resource assessments for basins and petroleum systems with moderate amounts of data available (e.g., B.C. Ministry of Energy and Mines / National Energy Board, 2011; Charpentier and Cook, 2011). While the focus has been on unconventionals, conventional resource evaluations have been revisited as well. Newer methodologies use drilling and production data to populate play tracts and performance characteristics, upon which stochastic analyses are applied to build resource assessments. Unfortunately, these cannot be applied reasonably in basins where drilling data are very scarce and production data non-existent – as in onshore Nova Scotia.

Resource assessments in data-poor settings must be undertaken by first addressing each key technical parameter – such as porosity, reservoir pressure, organic maturity – to develop the best possible estimates of parameter values and their variations (expressed as statistical distributions). Mapping out these parameters where possible, applying reasonable distributions, and sampling using a Monte Carlo methodology, enables one to develop statistically reasonable ranges of resource endowment. One can also assign levels of confidence, and identify key risks and uncertainties in the assessment. Results are generally expressed as ranges with various levels of confidence – thus P_{90}/P_{50}/P_{10} values (i.e., conservative / most likely / optimistic values).

In undertaking assessment of oil and gas resources in Nova Scotia, PRCL and Department of Energy staff discussed available petroleum datasets for Nova Scotia sedimentary basins, and jointly decided to spend the available time and budget in completing conventional and unconventional oil and gas resource assessments for the Windsor-Kennetcook and Cumberland basins. Sufficient information from wellbores and seismic surveys exist in each basin, in addition to surface mapping and geological characterization, to support “data-limited” assessment methods. It was agreed that such work would serve also to identify data gaps and to provide guidance on assessment work for other Nova Scotia petroleum basins.

PETROLEUM PLAY DEFINITIONS

Conventional Plays

A conventional play is defined as a family of pools (discovered occurrences of oil and/or gas) and prospects (untested exploration targets) that share common geological characteristics and history of petroleum generation, migration, reservoir development, and trap configuration (National Energy Board, 2001). Plays can be subdivided into four categories:

- Established: More than six discoveries exist, and established reserves are assigned;
- Immature: Demonstrated to exist by geological analysis and hydrocarbon shows, but for which there are fewer than six discoveries;
- Conceptual: Geological analysis shows a reasonable certainty of existence, but for which there are no hydrocarbon discoveries or shows;
- Speculative: Geological analysis shows a possibility of existence, but there are no hydrocarbon discoveries or shows, and there is insufficient information to reasonably estimate reservoir and pool parameters.

As there have been no conventional discoveries in Windsor or Cumberland basins, all conventional plays are currently in the range of conceptual or speculative.

Unconventional Plays

Unconventional plays were defined by Law and Curtis (2002), with reference to conventional reservoirs:

> "Conventional [hydrocarbon] resources are buoyancy-driven deposits, occurring as discrete accumulations in structural and/or stratigraphic traps, whereas unconventional [hydrocarbon] resources are generally not buoyancy-driven accumulations. They are regionally pervasive accumulations, most commonly independent of structural and stratigraphic traps."

The regionally pervasive nature of unconventional oil and gas accumulations gives rise to very large in-place resource volumes. Recent advances in horizontal drilling and multi-frac completions technologies have made some of these volumes economically accessible, and are thus radically changing the nature of the oil and gas industry in North America.

Three major categories of unconventional play are recognized: coalbed methane, 'tight' oil and gas, and shale oil and gas. Coalbed methane is, as the name implies, natural gas hosted in seams or beds of coal. Bustin and Clarkson (1998) described it in more detail:

> "Coalbed methane, unlike conventional gas resources, is unique in that gas is retained in a number of ways including: (1) adsorbed molecules within micropores (<2 nm in diameter); (2) trapped gas within matrix porosity; (3) free gas (gas in excess of that which can be adsorbed) in cleats and fractures; and (4) as a solute in ground water within coal fractures."

Tight gas and oil resources are generally found in basin-centred hydrocarbon systems, defined by Law (2002) as:

> "…regionally pervasive accumulations that are gas- [or oil-] saturated, abnormally pressured, commonly lack a downdip water contact, and have low-permeability reservoirs."

In these plays, oil and/or gas occupy a sufficient proportion of reservoir pore volume (generally >75%) to be the fluid that flows preferentially; however, there is almost always some residual water saturation. 'Abnormal pressures' indicate that the hydrocarbon phase is not connected to a regional aquifer – pressures may be relatively high or low compared to a normal hydrostatic gradient (and are commonly both in different regions of a given basin). 'Low permeability' is a term generally taken to mean that natural or artificial fracture stimulation is required for economic hydrocarbon production. These are generally highly-cemented sandstones, siltstones, or carbonates.

Curtis (2002) defined shale reservoirs as:

> "fine-grained, clay- and organic carbon-rich rocks, [which] are both gas source and reservoir rock components of the petroleum system….Gas is of thermogenic or biogenic origin and stored as sorbed hydrocarbons, as free gas in fracture and intergranular porosity, and as gas dissolved in kerogen and bitumen."

Hamblin (2006) noted that 'shale' reservoirs contain a range of lithologies including mud rocks, siltstones, and fine-grained carbonates. He defined them more broadly, in terms of unconventional accumulations:

> "These are unconventional, basin-centred, self-sourced, continuous-type accumulations where the total [hydrocarbon] charge is represented by the sum of free [hydrocarbons] and adsorbed gas….In effect, these shale plays represent discrete, self-enclosed petroleum systems which do not rely on hydrocarbon expulsion/migration/trapping because the premise is

> that the hydrocarbon stays in the original source rock; if they were well-connected to conventional plays, then they wouldn't provide a new play at all."

Hamblin (2006) recognized the Strathlorne / Albert / Cape Rouge group of shales, equivalent to the Horton Bluff shale, as a viable shale gas target in the Maritimes Basin.

METHODOLOGY

Nova Scotia Department of Energy supplied the following data library for both Windsor and Cumberland basins:

- Well logs, data and reports from all petroleum boreholes;
- Images of interpreted seismic lines and gridded seismic surfaces generated from 2D seismic data;
- 3D structural models of each basin in Petrel™ software;
- Literature and reports addressing petroleum systems and source rock information, and existing geological and resource assessments.

PRCL completed the following assessment steps:

- Summarize regional petroleum geology, including information on basin evolution and tectonics, sedimentation history, structural history, geochemistry, and hydrocarbon occurrences. For this project, we have relied on information supplied by the Department of Energy and published literature.
- Define potential conventional hydrocarbon plays, based upon identification of potential petroleum systems, including reservoir, source, trap, and seal. As there have been no conventional hydrocarbon discoveries in Windsor or Cumberland basins, all plays are conceptual or speculative; none have been proven by drilling and discovery.
- Define potential unconventional hydrocarbon plays, based upon the same petroleum systems, but focusing on factors that could charge unconventional reservoirs on a regional basis, as opposed to discrete conventional traps. Horton Group shales and sandstones are conceptual plays, but Cumberland Group coalbed methane plays in Cumberland Basin have produced some gas, and thus are regarded as immature.
- Map gross rock volumes for each reservoir target, using Petrel™ three-dimensional structural models that incorporate available seismic and well data.
- Execute systematic statistical analysis of each play, using a play-based method based on the work of Roadifer (1979) and refined by National Energy Board and by Petrel Robertson (Hayes, 2012). This analysis is detailed below.

PROBABILISTIC MODELING

We reviewed and assigned values to Play Risk Factors – source rock, charge, migration, reservoir rock, trap/closure, and seal/containment – to reflect the likelihood that each factor actually exists within the prospective play fairway in each basin. This step is described in more detail below under Play Risks and Reservoir Parameter Assignment.

Basic Equations for Gas Volumes

- Free GIIP = $A*H_{net}*por*S_g*E$
- Adsorbed GIIP = $A*H_{net}*D_m*V_L*TOC*S_{ga}*P_{res}/(P_L+P_{res})$ (applies only to shale gas and coal bed methane (CBM) reservoirs)
- Total GIIP = Free GIIP + Adsorbed GIIP
- Recoverable Gas volume = Total GIIP *Rfg
- Marketable Gas volume = Rec. Gas volume *(1 - CO_2 fraction - H_2S fraction)*(1-SL)
- Where
    - GIIP = Gas initially in place
    - A = effective area of undiscovered resources
    - H_{net} = average net pay thickness
    - por = total porosity (matrix + natural fractures)
    - S_g = gas saturation
    - E = Gas expansion factor (conversion to volumes of gas from reservoir conditions to standard conditions)
    - E is a function of pressure, temperature and gas deviation factor (Z)
    - Rfg = gas recovery factor
    - D_m = Rock matrix density (g/cc)
    - TOC = Total Organic content (TOC, % wt)
    - V_L = Ratio Langmuir volume /%TOC (sm3/tonne)
    - P_L= Langmuir Pressure (MPa)
    - P_{res} = reservoir pressure
    - S_{ga} = Adsorbed gas saturation (fraction)
    - SL = surface losses (gas used as fuel in processing plus flared waste gas)
- Recoverable condensate/NGL = Recoverable gas * CGR
- Where CGR = Gas liquids (Condensate + NGL) yield
- NGL = Natural gas liquids (Ethane, Butane, Propane).

Note: Adsorbed gas content is modelled here only as a function of pressure. In reality there are additional variations as a function of gas composition (e.g., CO_2 content) and temperature. These additional factors are overshadowed by uncertainties in the basic capacity of the shale or coal to adsorb gas, as characterised by TOC and V_L. It can be seen from the GIIP formula that the pressure correction only becomes significant in shallow reservoirs.

The model can also calculate recoverable oil but this is not used in this study.

Probabilistic Model Construction

The Monte Carlo modelling program @RISK ™ was used to calculate a probabilistic range of outcomes.

All input variables are entered as Low, 'Best' and High estimates. In Appendix 1 and 2 (Windsor and Cumberland basins, respectively), input variables are listed on a separate worksheet for each play, and are summarized on the "Inputs Control" worksheet. These are fitted to a lognormal probability distribution, assuming the Low, Best and High estimates represent P_{90}, P_{50} and P_{10} confidence levels respectively. The resulting P_{99} and P_{01} confidence levels for each variable are checked for reasonableness before the resource calculation is made. The model truncates all values at the P_{99} and P_{01} confidence levels and confines the variables por, Sg and Rfg to realistic ranges (greater than 0 and less than 1).

The inputs to the recoverable gas and recoverable condensate/NGL equations are all treated as statistically independent variables. Dependencies between these variables are known to exist in specific geological settings, but for the wide ranges of uncertainty applied to undiscovered resources, any likely dependencies between key variables are not considered to significantly affect the calculated outcomes.

The gas expansion factor (E) has a strong dependency on depth, through the pressure and temperature gradients and the strong relationship of gas deviation factor (Z) to pressure and temperature. The model calculates the gas expansion factor as a function of average reservoir depth.

Average reservoir depth can have a wide range of uncertainty where the amount of net reservoir rock is likely to be a small fraction of the gross rock volume in a target formation. The model calculates a statistical range of average reservoir depths using the Low, Best and High estimates of <u>formation</u> depth and the calculated (or estimated) ratio of average net pay to gross interval thickness (NTG). As the NTG increases towards unity, the average reservoir depth range narrows toward the average formation depth. In this model, the Low, Best and High estimates are treated as the Minimum, Average and Maximum reservoir depths, and a triangular probability distribution is applied.

For practical purposes, the minimum conventional reservoir depth is truncated at 50mTVD and the minimum shale gas depth is truncated at 300mTVD.

Gas and oil volumes are reported both as in-place and marketable resources. In-place resources are the total volume of hydrocarbons existing within a reservoir in the subsurface, measured at standard conditions. Marketable resources are hydrocarbon volumes, measured at standard conditions, available for sale after subtracting losses associated with production, including recovery factor from the reservoir, surface losses, and processing to remove non-marketable gases.

REGIONAL GEOLOGY AND PLAY DEFINITION

Regional petroleum geology is well established in the data library information provided by Department of Energy, and also has been discussed thoroughly in the technical literature (e.g., Lavoie *et al*., 2009).

Figure 1 shows Windsor-Kennetcook and Cumberland basin outlines employed for the resource assessment, using digital mapping elements supplied by Department of Energy. Basin boundaries are dictated primarily by our understanding of basin geology, particularly basin-bounding faults. However, subsurface expression of major rock units and faults is not well-known in places, so boundaries were influenced also by the availability of seismic and well data used in mapping and characterization.

STRATIGRAPHIC REVIEW

Figures 2 and 3 summarize the prospective stratigraphic columns in Windsor and Cumberland basins, respectively. Stratigraphic units have been defined primarily in outcrop exposures, and many are not recognized specifically in most wellbores, particularly in the older wells dating back to the 1960's and 1970's. The only unit not on the stratigraphic column but consistently recognized in the subsurface is the Glass Sand, which lies beneath the Tournaisian Cheverie Formation at the top of the Horton Bluff Formation in the Windsor Basin (Fig. 2).

Appendix 3 lists stratigraphic tops in petroleum boreholes completed in and adjacent to the Windsor and Cumberland basins; note that several wells in the Shubenacadie Basin are included on the Windsor Basin spreadsheet. PRCL tops picks are based primarily on sample descriptions and rely heavily on wellsite geological reports and strip logs; we did not attempt to make log picks to refine the tops. Many of these picks have already been documented in the Nova Scotia Onshore Petroleum Atlas, excerpts of which were provided in the data library. We used picks from major units to calibrate selection and mapping of seismic surfaces in the Petrel model for each basin.

PRCL used sample descriptions in wellsite reports and strip logs to understand reservoir parameters, particularly porosity and permeability, thus guiding our designation of reservoir parameter ranges in the assessment process. However, the project scope did not include sufficient time to refine stratigraphic correlations and assessments of reservoir quality – so these represent areas where major improvements to the resource assessment could be made.

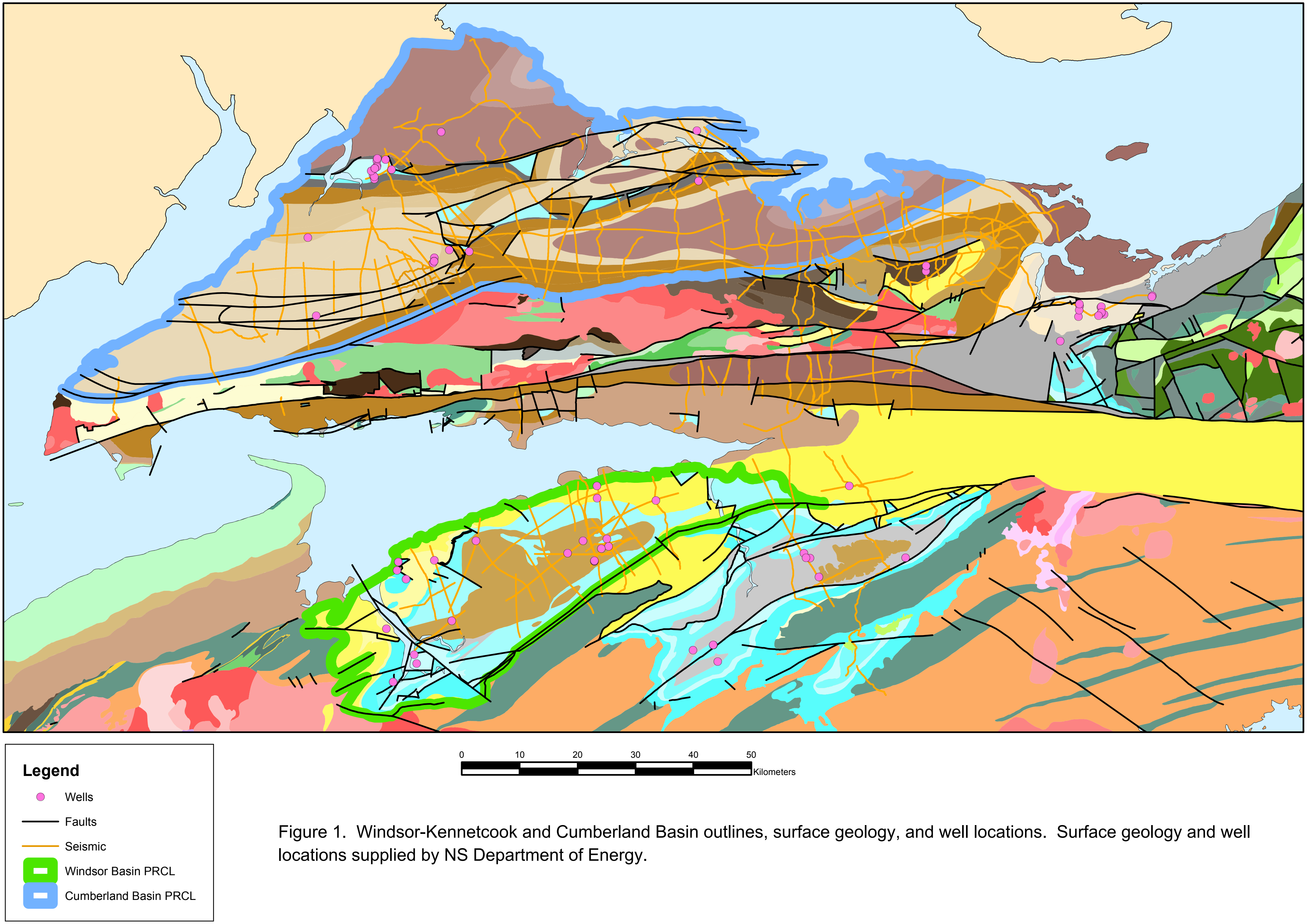


Figure 1. Windsor-Kennetcook and Cumberland Basin outlines, surface geology, and well locations. Surface geology and well locations supplied by NS Department of Energy.

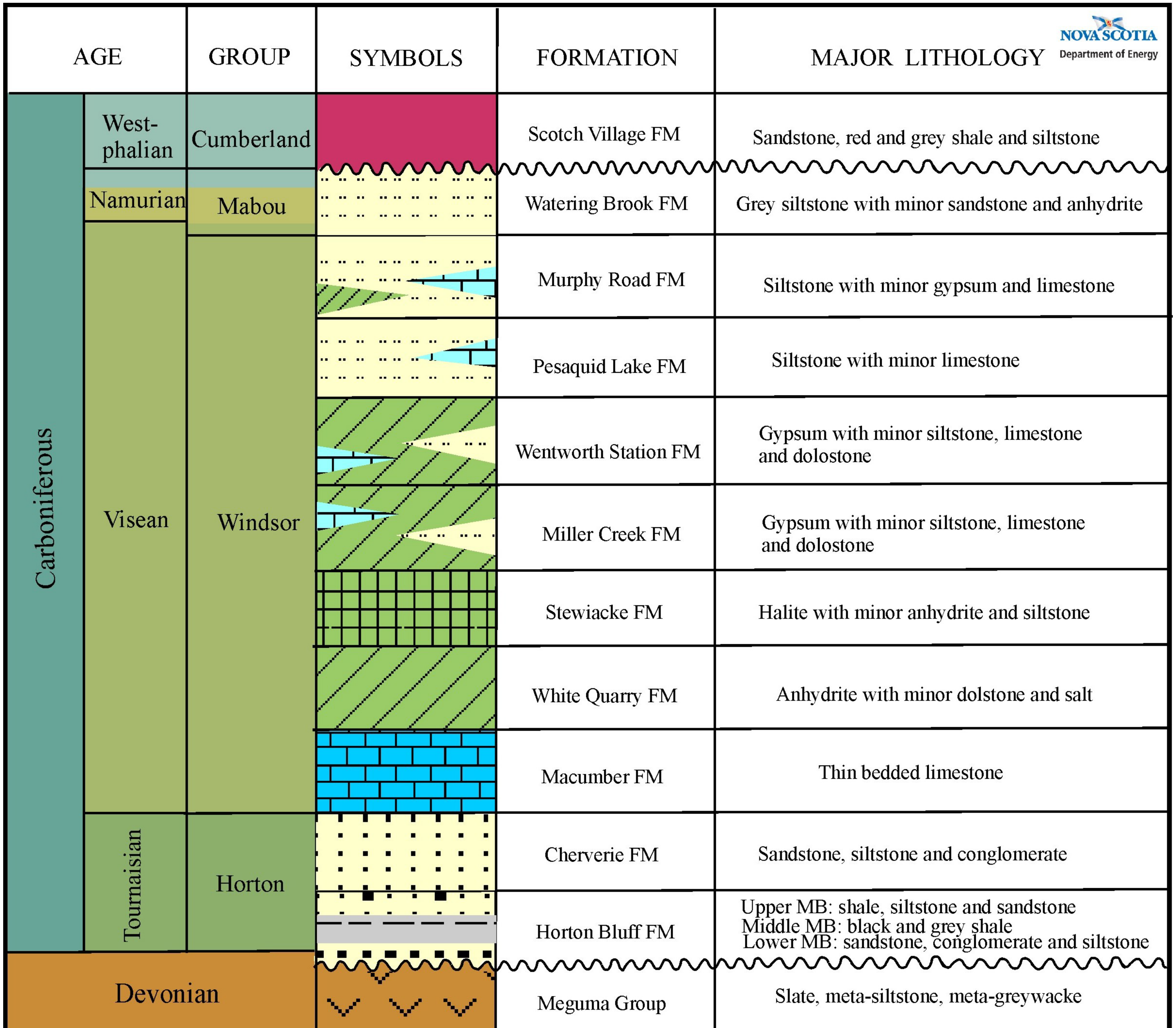
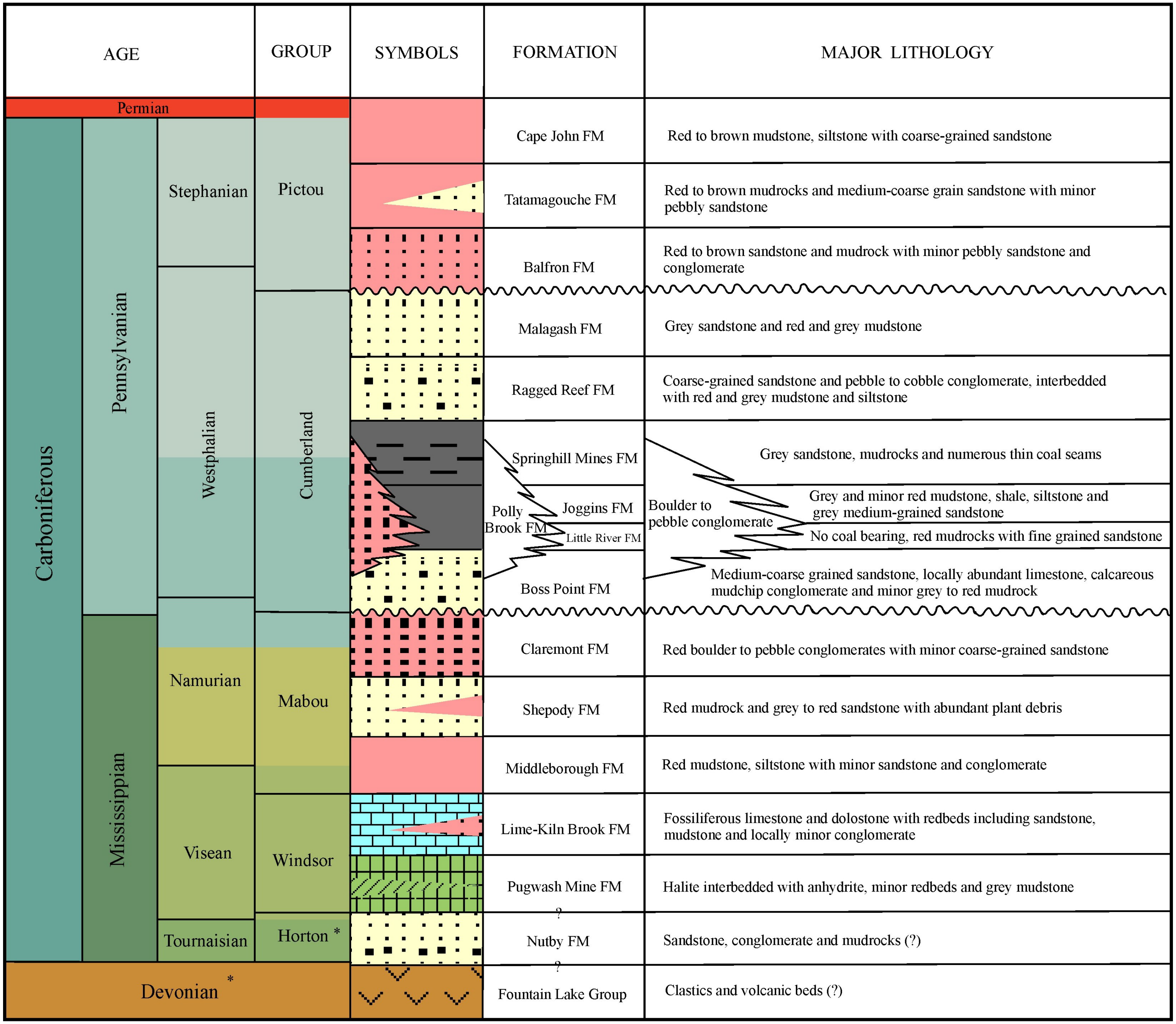


Figure 2. Stratigraphic column, Windsor Basin (from Nova Scotia Department of Energy).



*** Unconfirmed north of Cobequid Highlands**

Figure 3. Stratigraphic column, Cumberland Basin (from Nova Scotia Department of Energy).

PLAY DEFINITION

Results of exploration work to date suggest regional oil and gas potential in the following units, from oldest to youngest:

- Horton Bluff (unconventional);
- Lower Carboniferous clastics (conventional);
- Base Windsor carbonates (conventional);
- Upper Carboniferous clastics (conventional);
- Cumberland coal gas (unconventional).

Review of geological information at the basin scale supports assessment of the following units:

- Windsor Basin
    - Horton Bluff shale (unconventional);
    - Lower Horton Bluff tight sandstone (unconventional);
    - Upper Horton Glass sand (conventional);
    - Cheverie Fm (conventional);
    - Macumber (basal Windsor) carbonates (conventional);
    - Upper Windsor clastics / carbonates (conventional).
- Cumberland Basin
    - Horton Bluff shale (unconventional);
    - Upper Horton clastics (conventional);
    - Windsor Group carbonates (conventional);
    - Mabou Group clastics (conventional);
    - (Lower Cumberland) Boss Point sandstones (conventional);
    - Cumberland Group coalbed methane (unconventional).

SEISMIC / STRUCTURAL MODEL REVIEW

Data Inputs for Petrel™ models consist of parameters and considerations derived from geological and geophysical information. These inputs consist of, but are not limited to:

Geological Inputs

Public literature and data supplied by Department of Energy, as well as PRCL interpretations, including:

- Formation tops
    - PRCL tops picks were based primarily on sample descriptions and relied on wellsite geological reports and strip logs, as described above. Clarification was required to match the seismic surfaces supplied by Department of Energy with PRCL tops.
- Fault information
    - Fault information was derived from the seismic trends of the surfaces supplied, and was added to the model based on fault trends on the seismic and from fault surface information. This was done only for large offset faults corresponding to the seismic information provided. No fault interpretation was supplied with the seismic interpretation.
- Surface geology mapping supplied by the Department of Energy was integrated into the model where required to verify tops assignment and to extend the limits of depth surfaces where seismic was limited.

Seismic Inputs

Windsor Basin

- Seismic surfaces were supplied from the Department of Energy Petrel^{TM} model in depth. Editing of the depth surfaces consisted of:
    - Incorporating fault surface trends and dip angles from 2D seismic data to verify limits of area outlines for each surface used in gross rock volume calculations;
    - Removing spurious depth values due to suspected smoothing within original Petrel model;
    - Extending the existing model surfaces (seismic control limited to only portion of the basin) to the extents of the Windsor Basin outline
        - This process was guided by surface geology map elements supplied by the Department of Energy, and was completed by interpolating seismic surfaces to the extent of the surface outcrop.

Cumberland Basin

- Seismic surfaces were supplied from the Department of Energy Petrel™ model in two-way travel time (negative and positive values).
    - Surfaces were exported to PRCL's Seisware™ seismic interpretation workstation for depth conversion. Culture, wells and appropriate additional information was also imported into the seismic project in order to calculate the time to depth conversion.
- Velocity input information was derived from sonic digital well log data from the control wells, where available.
    - The velocity model was built using a layer down approach, which consisted of up to five layers. Sonic log information for each well penetration for the specific interpreted time layers was integrated into the velocity model.
    - The velocity for each layer was interpolated between well control and gridded using a minimum curvature gridding algorithm for each layer.
- Subsea depth maps were generated for each layer, and residual depth shifts were automatically applied to tie and match the well control depths, where possible.
    - Some interpolated velocities within the upper layer in the Cumberland Basin model were smoothed out for the scope and purpose of this project, as they were too high to be reasonable, creating edge effects.
    - Depth-converted surfaces were re-imported back into Petrel™ from Seisware™ to build a model in depth.

Petrel Model

The Petrel™ model consists of five surfaces for the Cumberland Basin; Base Pictou, Base Cumberland, Base Mabou, Base Anhydrite (proxy for Base Windsor) and Top of Basement. Note the Base Anhydrite was used as a proxy for the Base Windsor but is not exactly the same because there is a thin carbonate formation below the Anhydrite in the Lower Windsor. Likewise there are five surfaces for the Windsor Basin; Upper Windsor, Macumber, Glass Sand, Horton Bluff Sand and Basement. These particular surfaces were chosen based on the seismic interpretation available in the models provided to PRCL.

PRCL loaded seismic depth surfaces, surface geology, well paths, well information and tops into each basin model. In addition, fault planes were added and interpolated using the seismic information combined with the surface geology, particularly in areas where seismic was absent and trends had to be extrapolated to analyze the larger basin outline.

Surfaces were edited where necessary, to ensure well tops matched the seismic surfaces supplied by Department of Energy or converted to depth by PRCL. Surfaces were then gridded, contoured, and relevant sub-sea depth structure maps were generated. Likewise, isopach maps were calculated, gridded and contoured for each of the model surfaces and volumes.

In order to calculate gross rock volumes (GRVs), Petrel™ modelling software incorporated the areas of the surfaces and the thickness of the rock volume for each layer. Depth ranges and average depths from the model helped assess pressure and temperature inputs into the assessment calculations, as well as depth of burial implications for hydrocarbon maturation analysis.

Areas for GRV assessment and calculation were guided by depth cutoffs based on a volume of rock being either too deep to contain reservoir, or too shallow to allow production. For each case, volumes outside the limits were removed from the final GRV prior to resource calculation.

Structural model outputs are illustrated with a structure map and two regional cross-sections for each basin (Fig. 4-9).

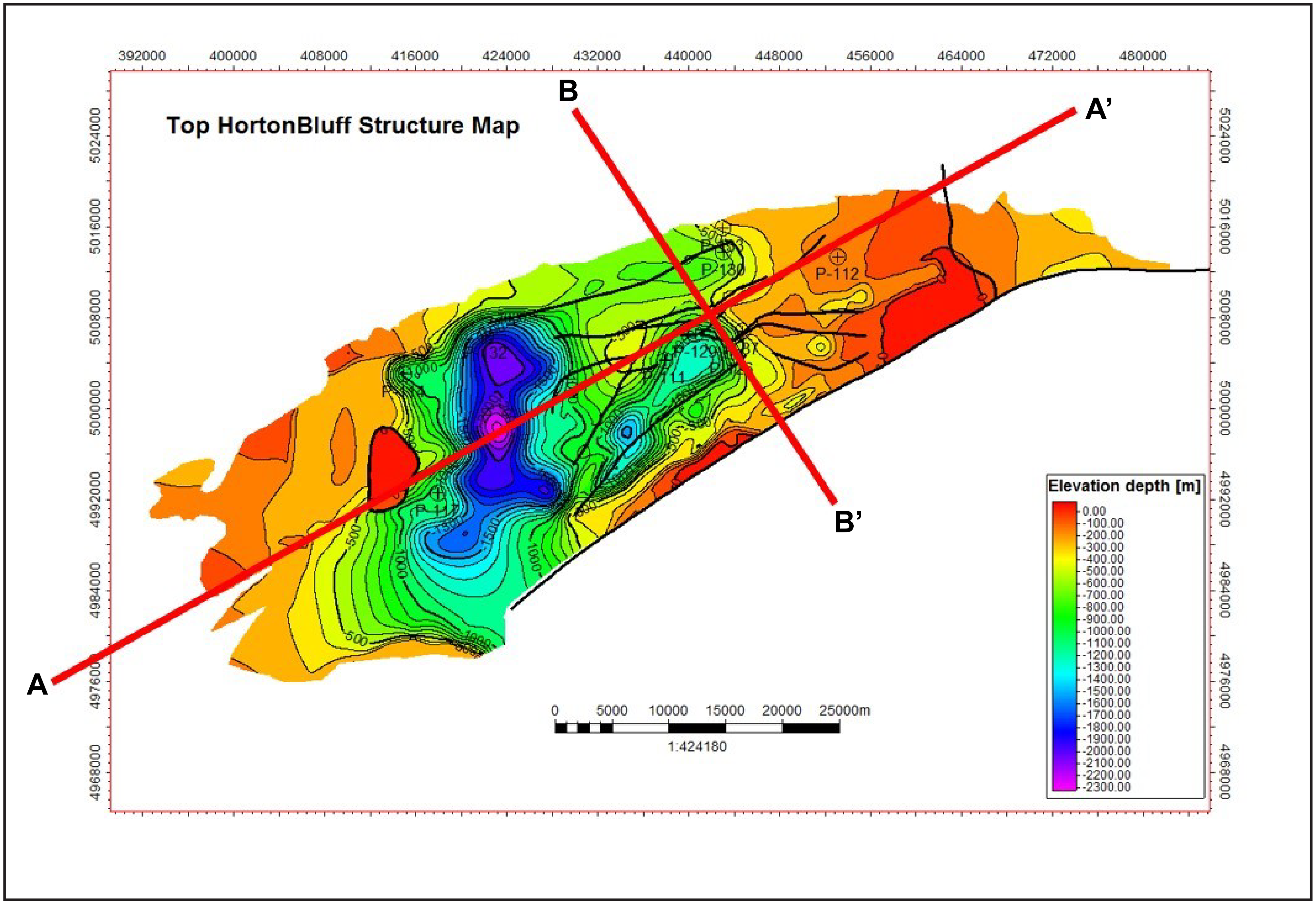


Figure 4. Top Horton Bluff structure map, Windsor Basin.

Windsor cross section 1

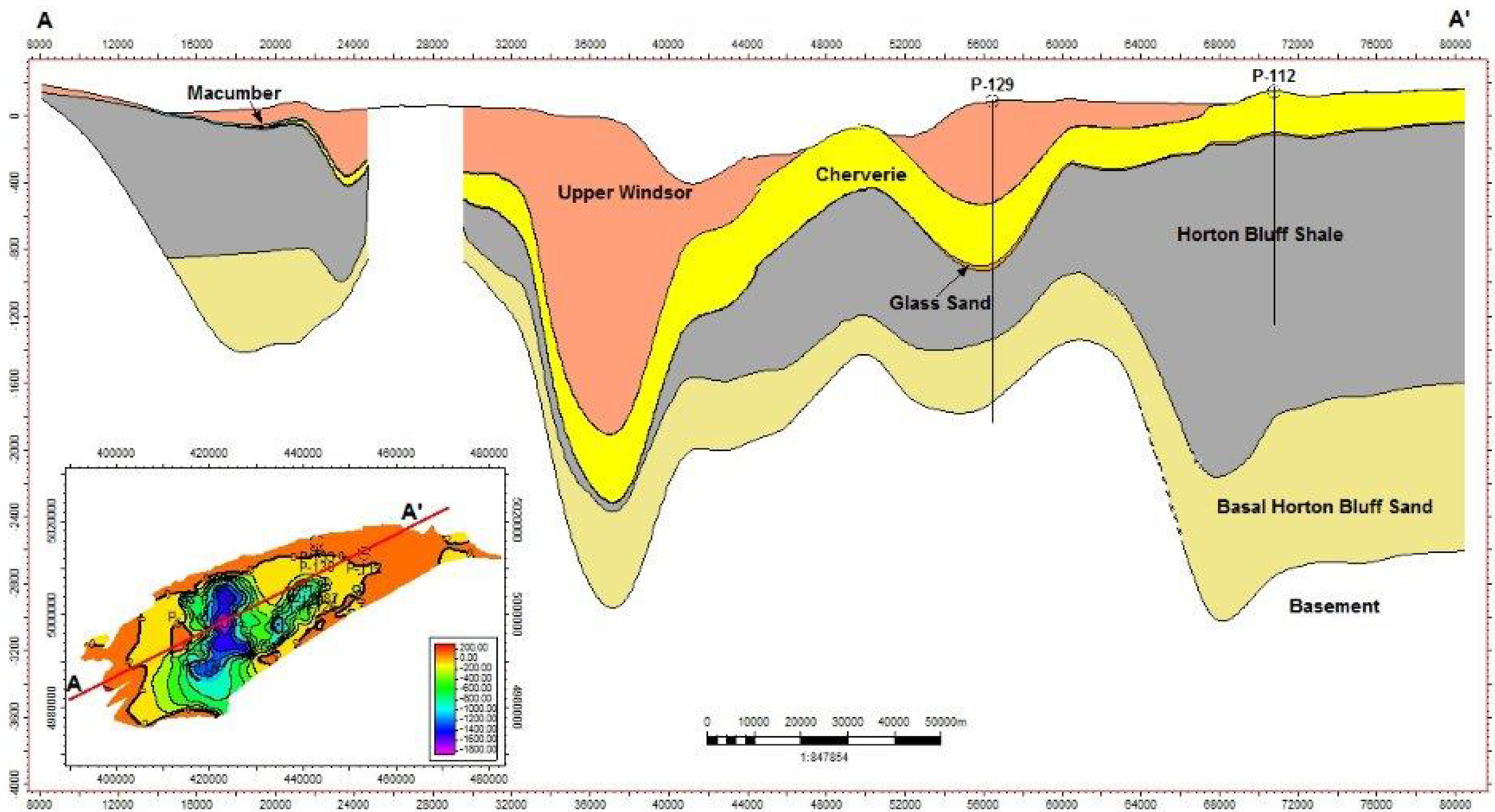


Figure 5. West-East cross-section, Windsor Basin.

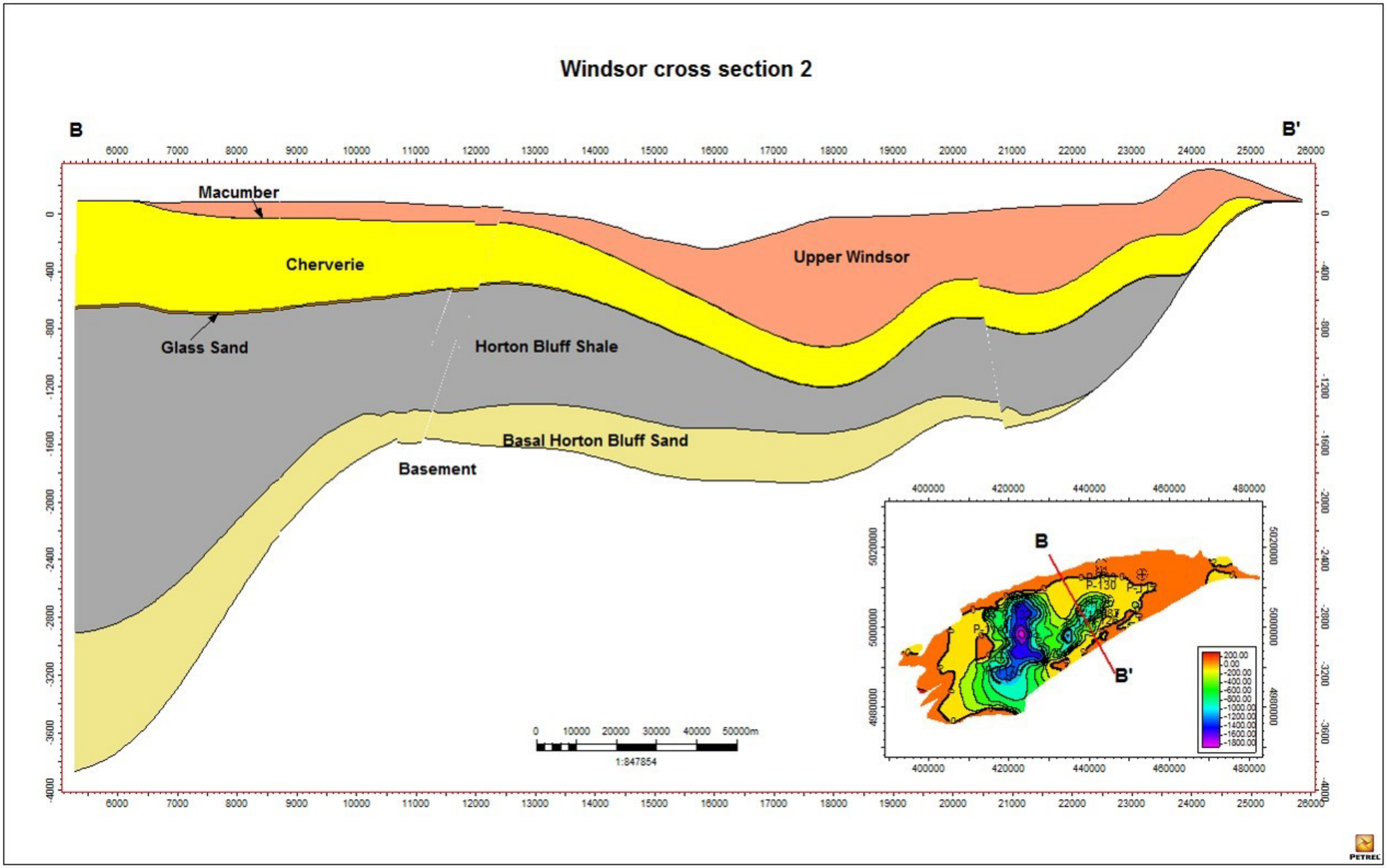


Figure 6. North-south cross-section, Windsor Basin.

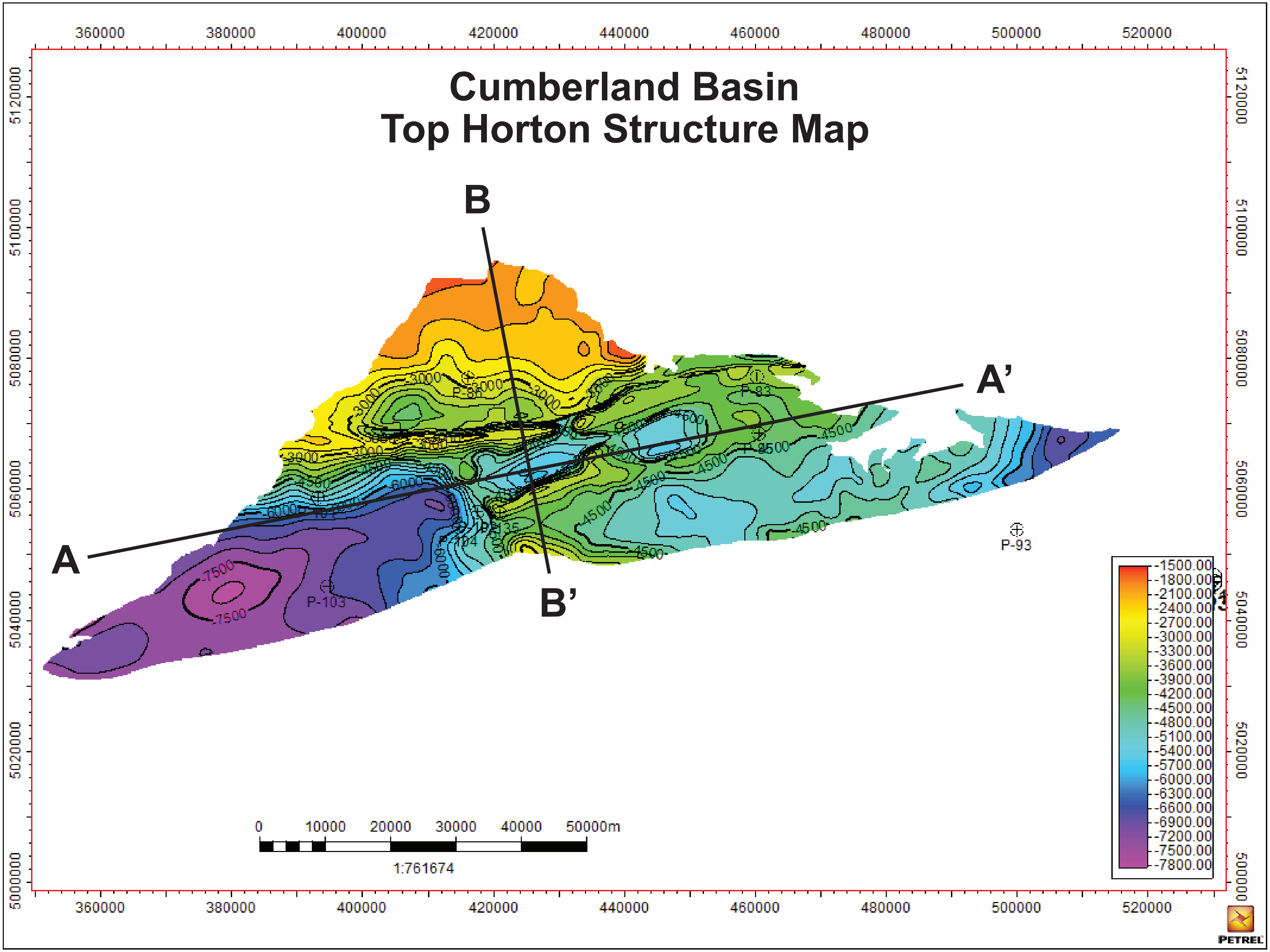


Figure 7. Top Horton Bluff structure map, Cumberland Basin.

Cumberland Basin
West-East Cross-Section

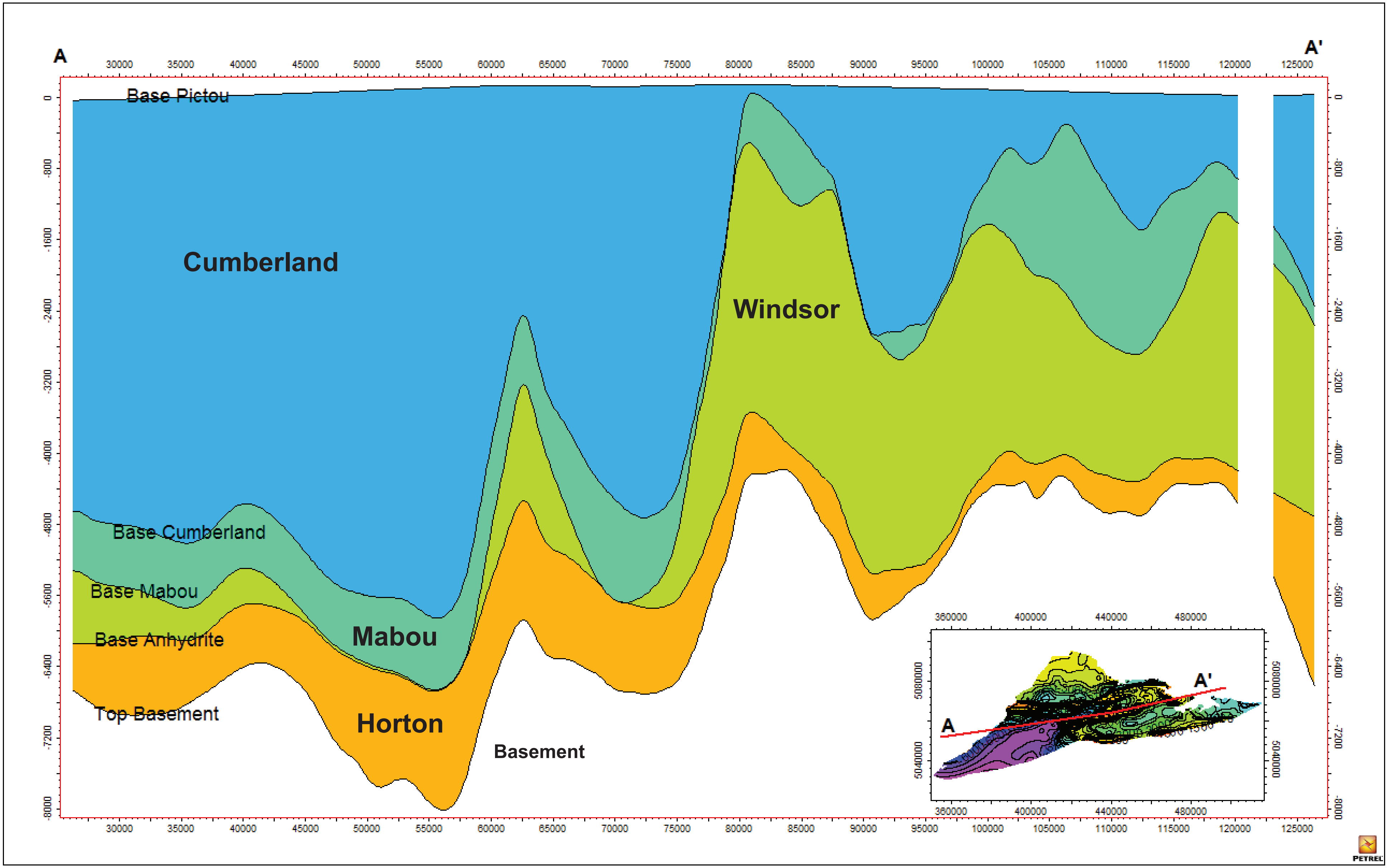


Figure 8. West-east cross-section, Cumberland Basin.

Cumberland Basin
South-North Cross-Section

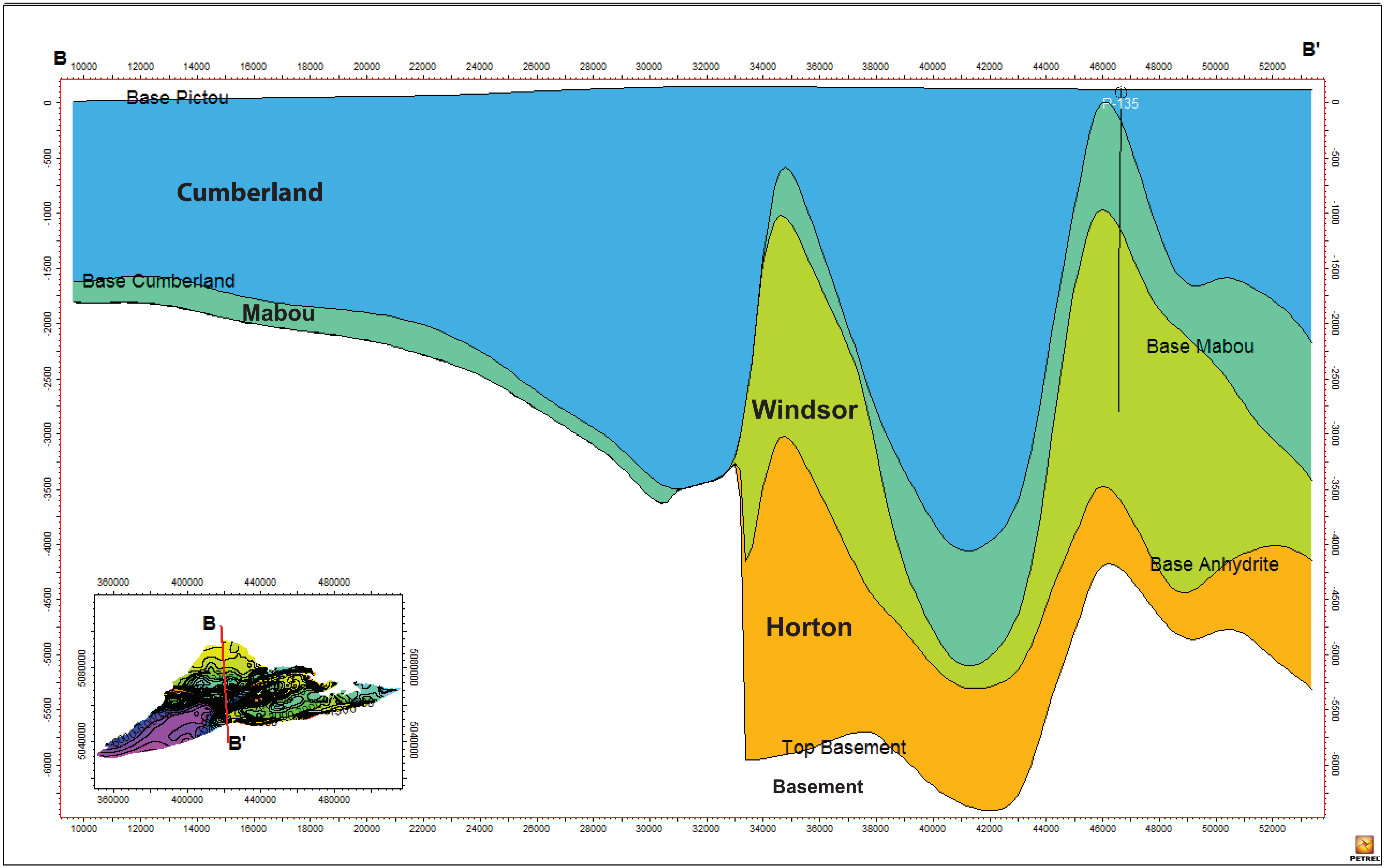


Figure 9. South-north cross-section, Cumberland Basin.

PLAY RISKS AND RESERVOIR PARAMETER ASSIGNMENTS

The "inputs control" worksheet in each of Appendix 1 and 2 lists Play Risk Factors and Hydrocarbon Volume Component / Reservoir Parameter ranges for each play in the Windsor and Cumberland basins. Individual worksheets for each play list parameter ranges in more detail and summarize calculations.

Play Risk Factors – source rock, charge, migration, reservoir rock, trap/closure, and seal/containment – reflect the likelihood that each factor actually exists within the prospective play fairway in each basin. For a conventional play to exist and a discovery to be made, each factor must be present. Multiplying all play risk factors together gives us the Probability of Geological Success – that is, the chance that the play exists somewhere in the basin. Play Risk Factors are estimated based on our general geological knowledge of each play.

- Source rock – presence of a petroleum source rock of sufficient maturity and volume to evolve sufficient hydrocarbon volumes;
- Charge – certainty that hydrocarbons generated by source rocks have found a pathway to charge the reservoirs in question;
- Migration – appropriate timing of hydrocarbon generation and migration, such that traps are in place at the time hydrocarbons migrate;
- Reservoir rock – certainty that reservoir rock of appropriate quality exists;
- Trap / closure – certainty that structural and/or stratigraphic trapping configurations exist;
- Seal / containment – certainty that traps are sufficiently sealed to preserve hydrocarbons in the traps over geological time.

For unconventional plays – self-sourced or basin-centred reservoirs – risk factors generally are set at 1.0, reflecting our certainty that the play exists. The only exception in this study is for the Horton Bluff shale play in Cumberland Basin, where we have set the Reservoir Rock risk factor at 0.5, reflecting our uncertainty that the play even exists because Horton Bluff shales have not yet been drilled in the basin, although based on regional knowledge we believe that they should exist.

Hydrocarbon Volume Components / Reservoir Parameters are ranges of possible values assigned to each parameter required to calculate in-place and marketable hydrocarbon volumes for each play. Gross reservoir rock volumes are input from the Petrel structural models. Most other parameters are estimated based on our knowledge of specific plays where applicable; some values (e.g., hydrocarbon saturation in matrix) are assigned reasonable industry norms where there are no specific data. Appendix 4 summarizes assumptions around reservoir parameters from an engineering perspective; we expand upon these from a geological perspective in the following discussion.

WINDSOR BASIN

Horton Bluff Shale (Unconventional)

Play Description

- Restricted / lacustrine shale-dominated unit, hundreds of metres thick, prospective throughout the basin. Organic-rich, good potential source rock.
    - Regionally extensive, analogous to the Frederick Brook shale play in adjacent New Brunswick
    - Significant interbedded sandstone content, may contain more coarse clastics approaching adjacent highlands
- Tested in the Windsor Basin with a five-well program by Elmworth Energy / Triangle Petroleum in 2007 / 2008
    - Extensive coring and sampling; used to support Ryder Scott (2008) resource evaluation report for Elmworth properties
    - No operational (horizontal drilling / multiple fracturing) evaluation completed, and so the play is deemed not to have been formally tested
- Stratigraphy poorly understood – Elmworth noted significantly different Horton Bluff sections in each deep penetration
    - Shale stratigraphy and continuity of organic-rich beds not well established
    - Relationships with sand-dominated Horton Bluff facies not well understood
- The Horton Bluff is buried very deeply in parts of the basin. Rock volumes >4500m are excluded from the assessment, as porosities are very low at such depths, and hydraulic fracturing very difficult and expensive.

Play Risk Factors

- All are set to 1.0, reflecting certainty that the unconventional play exists.

Hydrocarbon Volume Components / Reservoir Parameters

- **Reservoir overpressuring** – assigned a very small range around normal hydrostatic pressure, as we observed no significant variations in drilling mud density that would reflect abnormal gradients. This treatment is the same for all plays. However, Macquarie Tristone (2013) indicated the possibility for significant overpressuring in the deep Horton Bluff shale section in the Elgin area of New Brunswick.

- **H_2S content** – none noted in the basin, so set to zero. This assumption needs to be reviewed in light of potential for sulphur-rich rocks in the basement section.

- **CO_2 content** – assumed to be substantial based on relatively high maturity of Horton shales. Range of values is based upon gas analyses from the Horton Bluff in Kennetcook-1 well. This treatment is the same for all plays potentially sourced from the Horton.

- **Gross Rock Volume / Total play area** – reflects exclusion of rock volume >4500m deep

- **Tested play area** – Set at zero, because even though the play has been drilled, it has not been tested by an effective horizontal / multi-frac well.

- **Fraction of untested play filled / Developable fraction of total play** – the shale play exists everywhere, but reservoir parameters (geochemistry, organic richness, geomechanical properties) are sufficient to merit economic development over only a part of the area. The range was chosen on general knowledge, and requires careful review as more is learned about the play.

- **Fraction of play volume oil bearing** – set at zero, shales are seen as sufficiently mature to yield gas only.

- **Net to gross** – most of the shale section is seen as prospective.

- **Matrix porosity** – typical range for older, well-compacted shale; subject to revision with more extensive analytical work.

- **Natural fracture porosity** – assumed that in a basin with abundant faulting and deformation that some part of shale volume will be naturally fractured.

- **Hydrocarbon saturation in matrix** – industry standard range; some bound water expected in shales.

- **Free gas and adsorbed gas parameters** – industry standard values, and ranges informed by Elmworth / Triangle testing programs; requires careful review as more samples are gathered and more is learned about the play.

- **Recovery factors** – industry standard values.

Yield Components

- Industry standard values for all plays.

Lower Horton Bluff sandstone (Unconventional)

Play Description

- Tight (low porosity / permeability) basin-centred gas sandstones, deposited in shallow lacustrine / deltaic (?) settings.
- Geographic / stratigraphic relationship with Horton Bluff shales not well-established.
  - Limited well and outcrop control, structural complications in deep wells – we assume a basal sandstone play beneath the shales based on regional stratigraphy; potentially hundreds of metres thick.

Play Risk Factors

- All are 1.0, reflecting certainty that the unconventional play exists.

Hydrocarbon Volume Components / Reservoir Parameters

- **Reservoir overpressuring** / **H_2S content** / **CO_2 content** / **Gross Rock Volume / Total play area / Tested play area / Fraction of untested play filled / Developable fraction of total play** / **Fraction of play volume oil bearing** – all same as Horton Bluff shale play.
- **Net to gross** – a relatively small percentage of the sandstone section is likely sufficiently thick and continuous to be prospective; subject to revision with more mapping.
- **Matrix porosity** – typical range for older, well-cemented tight sandstone; subject to revision with more extensive analytical work
- **Natural fracture porosity** – assumed that in a basin with abundant faulting and deformation that some part of tight sandstone volume will be naturally fractured; values are somewhat higher than for the Horton Bluff shale because sandstone is likely to be more brittle.
- **Hydrocarbon saturation in matrix** – industry standard range; some bound water expected in shales.

- **GOR / FVF / Recovery factors** – industry standard values

Upper Horton Glass Sand (Conventional)

Play Description

- Tight, quartzose sandstone capping Horton Bluff Formation, below Cheverie.
  - Not clearly distinguished in geological reports or sample logs for many wells.
  - High net/gross, extensively silica cemented.
- Recognized historically as a conventional reservoir target, commonly cited as a secondary objective in exploratory boreholes.

Play Risk Factors

- **Source rock / Charge / Migration-timing** – all very high, reflecting close proximity to underlying Horton Bluff shale source rocks.
- **Reservoir rock** – clean sandstones described, good chance of sufficient porosity development.
- **Trap / Seal** – Abundant structural trapping opportunities, good seal potential in overlying tight clastics in Cheverie and Windsor evaporites above.

Hydrocarbon Volume Components / Reservoir Parameters

- **Reservoir overpressuring** / **H_2S content** / **CO_2 content** – basinwide values.
- **Tested play area** – very little drilling, not systematically tested in existing wellbores (same logic for all conventional plays).
- **Fraction of total play in trap** – assume existence of substantial structural traps; stratigraphic trapping potential unknown.
- **Fractional fill of untested play traps** – good source rock and migration fairways indicate existing traps will be largely filled.
- **Fraction of pore volume oil bearing** – assume some oil generated, migrated and preserved in early phases of source rock maturation; low values overall reflect gas-prone source rock.
- **Net to gross** – sample descriptions indicate a clean sandstone with little interbedded non-reservoir rock.

- **Matrix porosity** – typical range for older, well-cemented tight sandstone; subject to revision with more extensive analytical work.

- **Natural fracture porosity** – assumed not to be significant for a conventional play.

- **Hydrocarbon saturation in matrix** – industry standard range; some bound water expected.

- **GOR / FVF / Recovery factors** – industry standard values.

Cheverie Formation (Conventional)

Play Description

- Thick (up to 600m) continental / red bed succession; we have no systematic information about internal stratigraphy.

- Sandstones are lithic / feldspathic, coarse-grained; clay-rich and poorly sorted.

  - Stratigraphic and structural trap potential in fan / floodplain / fluvial / deltaic facies, but we have no map information to support assessment of prospectivity.

Play Risk Factors

- All factors comparable to the Glass sand, except that chance for effective seal is higher because the unit is capped by lower Windsor tight carbonates and evaporates.

Hydrocarbon Volume Components / Reservoir Parameters

- **Reservoir overpressuring** / **H_2S content** / **CO_2 content** / **Tested play area / Fraction of total play in trap** / **Fractional fill of untested play traps / Fraction of pore volume oil bearing** – all same as Glass sand parameters.

- **Net to gross** – abundant sandstone in samples, but also abundant red beds and clays, which likely degrade reservoir quality in sandstones.

- **Matrix porosity / Natural fracture porosity / Hydrocarbon saturation in matrix** – all same as Glass sand parameters.

- **GOR / FVF / Recovery factors** – industry standard values.

Basal Windsor Macumber Formation (Conventional)

Play Description

- Carbonate shoals / banks / buildups with good reservoir quality, sealed by overlying evaporates.
    - Buildups mapped in outcrop in several locations, mean thickness ~50m.
- Viewed as being most prospective in Alton Block (Shubenacadie Basin), across which Forent Resources has mapped a play fairway (Gays River Fm).
    - Buildups interpreted to occur preferentially over basement highs.
- Buildups not developed in wells drilled to date in Windsor Basin, so presence of the play is conjectural.

Play Risk Factors

- **Source rock / Charge / Migration-timing** – all very high, reflecting close proximity to underlying Horton Bluff shale source rocks, and potential self-sourcing.
- **Reservoir rock** – carbonate buildups should contain good reservoir rock, but their presence in the basin is uncertain, so this risk is substantial.
- **Trap** – Buildups provide excellent stratigraphic trap potential.
- **Seal** – overlying evaporites provide excellent seals.

Hydrocarbon Volume Components / Reservoir Parameters

- **Reservoir overpressuring** / **H_2S content** / **CO_2 content** – basinwide values.
- **Tested play area** – play not yet established in the Windsor Basin.
- **Fraction of total play in trap** – good stratigraphic trap potential makes this factor higher than in other conventional plays.
- **Fractional fill of untested play traps** – good source rock and migration fairways indicate existing traps will be largely filled.
- **Fraction of pore volume oil bearing** – assume some oil generated, migrated and preserved in early phases of source rock maturation; low values overall reflect gas-prone source rock.

- **Net to gross** – outcrop descriptions indicate substantial reservoir-quality rock in buildups.
- **Matrix porosity** – typical range for reefal carbonate facies; 9% mean porosity value noted in outcrop. Subject to revision with more extensive analytical work (e.g., extent of dolomitization).
- **Natural fracture porosity** – assumed not to be significant for a conventional play.
- **Hydrocarbon saturation in matrix** – industry standard range; some bound water expected.
- **GOR / FVF / Recovery factors** – industry standard values.

Upper Windsor Clastics and Carbonates (Conventional)

Play Description

- Formations identified in outcrop are not broken out in the subsurface, so we regard the entire upper Windsor (Miller Creek up to Murphy Road formations) as one unit comprising interbedded clastics, evaporites and carbonates.
- No effective information regarding stratigraphic play trends.
- Prospective only where Cumberland Group crops out in the middle of the basin, and even here there is considerable risk for adequate seal.

Play Risk Factors

- **Source rock / Charge / Migration-timing** – charge factor is downgraded compared to other conventional plays, as we question whether underlying upper Windsor evaporites isolate the section from Horton Bluff source rocks.
- **Reservoir rock** – the thick section must contain a variety of reservoirs, but we know very little about them.
- **Trap** – Abundant structural, unknown stratigraphic trapping opportunities.
- **Seal** – seal integrity is a major risk – play lies above Windsor evaporites.

Hydrocarbon Volume Components / Reservoir Parameters

- **Reservoir overpressuring** / **H_2S content** / **CO_2 content** – basinwide values.
- **Tested play area** – play not yet established in the Windsor Basin.

- **Fraction of total play in trap** – assume substantial structural trapping potential; stratigraphic trap potential unknown.
- **Fractional fill of untested play traps** – downgraded compared to other plays – do source rocks have sufficient access to effectively charge existing traps?
- **Fraction of pore volume oil bearing** – assume some oil generated, migrated and preserved in early phases of source rock maturation; low values overall reflect gas-prone source rock.
- **Net to gross** – geological reports and lithological logs do not provide clear evidence of substantial good-quality reservoir.
- **Matrix porosity** – typical range for well-cemented sandstones; subject to revision with more extensive analytical work.
- **Natural fracture porosity** – assumed not to be significant for a conventional play.
- **Hydrocarbon saturation in matrix** – industry standard range; some bound water expected.
- **GOR / FVF / Recovery factors** – industry standard values.

CUMBERLAND BASIN

Horton Bluff Shale (Unconventional)

Play Description

- Same play as in Windsor Basin; not penetrated within Cumberland Basin boundaries, but prospective organic-rich lacustrine shales assumed to exist over some part of the basin.
- Larger proportion of volcanics / coarse clastics toward basin margins – Fountain Lake Group in Chevron Scotsburn #2 (P-93) interpreted to be proximal equivalent.
- Buried very deeply in many parts of the basin. Rock volumes >4500m are excluded from the assessment, as porosities are very low at such depths, and hydraulic fracturing very difficult and expensive.

Play Risk Factors

- **Source Rock** – set at 0.5, reflecting our uncertainty that the play exists in the Cumberland Basin.

- All other Play Risk Factors are 1.0, reflecting certainty that if the reservoir is present, there are no other substantial play risks.

Hydrocarbon Volume Components / Reservoir Parameters

- **Reservoir overpressuring / H_2S content** / **CO_2 content / Gross Rock Volume / Total play area / Tested play area / Fraction of untested play filled / Developable fraction of total play / Fraction of play volume oil bearing** – same logic as for Horton Bluff shale play in Windsor Basin.

- **Net to gross** – much lower than in Windsor Basin; reflects presence of non-reservoir facies (i.e., Fountain Lake Group equivalents) over an unknown portion of the basin.

- **Matrix porosity / Natural fracture porosity** / **Hydrocarbon saturation in matrix / Free gas and adsorbed gas parameters / Recovery factors** – same as for Horton Bluff shale play in Windsor Basin.

Yield Components

- Industry standard values for all plays.

Upper Horton Clastics (Conventional)

Play Description

- We have no well information to support the presence of this play – we assume there is a play analogous to the Glass sand in the Windsor Basin, with similar reservoir parameters.

Play Risk Factors

- **Source rock / Charge / Migration-timing** – all very high, reflecting close proximity to underlying Horton Bluff shale source rocks.

- **Reservoir rock** – lower than Windsor Basin Glass sand – we have no direct evidence the reservoir exists in Cumberland Basin.

- **Trap / Seal** – Abundant structural trapping opportunities, excellent seal potential in overlying Windsor evaporates.

Hydrocarbon Volume Components / Reservoir Parameters

- All very similar to Windsor Basin / Glass sand parameters.

Windsor Group Carbonates (Conventional)

Play Description

- We have no substantial well information on this play – the Lime-Kiln Brook Formation (Fig. 3) lies above basal Windsor evaporites, but the section has not been definitively drilled / logged in the Cumberland Basin.

- We are unclear whether the Gays River carbonate buildup play model applies in Cumberland Basin, so we have not used it.

Play Risk Factors

- **Source rock / Charge / Migration-timing** – all very high, reflecting close proximity to underlying Horton Bluff shale source rocks, and potential self-sourcing. Lower charge value reflects underlying evaporites isolating reservoir from the Horton Bluff, plus uncertainty that overlying Cumberland coals could charge this reservoir.

- **Reservoir rock** – high likelihood of some reservoir, but nature and distribution unknown.

- **Trap** – abundant structural trap situations; stratigraphic potential unknown.

- **Seal** – higher risk – overlying clastic / coal section.

Hydrocarbon Volume Components / Reservoir Parameters

- **Reservoir overpressuring** / **H_2S content** / **CO_2 content** – basinwide values.

- **Tested play area** – play not yet established in the Cumberland Basin.

- **Fraction of total play in trap** – assume substantial structural trapping potential; stratigraphic trap potential unknown.

- **Fractional fill of untested play traps** – good source rock and migration fairways indicate existing traps will be largely filled.

- **Fraction of pore volume oil bearing** – gas-prone source rock, little chance for oil.

- **Net to gross** – geological reports and lithological logs do not provide clear evidence of substantial good-quality reservoir.

- **Matrix porosity** – typical range for well-cemented reservoirs; subject to revision with more extensive analytical work.

- **Natural fracture porosity** – assumed not to be significant for a conventional play.

- **Hydrocarbon saturation in matrix** – industry standard range; some bound water expected.

- **GOR / FVF / Recovery factors** – industry standard values.

Mabou Group / Claremont Fm (Conventional)

Play Description

- Claremont coarse-grained clastics are the only unit noted in wellsite lithological logs.

- Sandstone reservoir quality generally poor.

- We have no specific insights on stratigraphic play potential.

Play Risk Factors / Hydrocarbon Volume Components / Reservoir Parameters

- Industry-standard values chosen for the most part; we have very little information about reservoir quality or stratigraphic trapping potential in this unit.

(Lower Cumberland) Boss Point Sandstones (Conventional)

Play Description

- Medium- to coarse-grained sandstones; limited wellsite descriptions indicate relatively low net/gross and poor reservoir quality.

Play Risk Factors / Hydrocarbon Volume Components / Reservoir Parameters

- Industry-standard values chosen for the most part; we have very little information about reservoir quality or stratigraphic trapping potential in this unit.

- **Matrix porosity** – assigned a higher range than other plays based on descriptions of coarse grain size and better sorting / less clay.

Cumberland Group Coalbed Methane (Unconventional)

Play Description

- Relatively thin bituminous coal beds concentrated in fine-grained floodplain facies, in a dominantly fluvial sandstone succession. The succession is extensively structurally deformed, and the coals have been mined in specific areas with sufficient resource density and access.

- Considerable drilling has been done to test the play, so we have some play parameters to work with. Existing engineering resource reports (e.g., Amvest, 1999; Sproule, 2006) provide additional guidance.

- The coal-bearing succession is buried deeply in parts of the basin; reservoir volumes >3500m deep have been excluded from calculations, as they are not practically accessible for CBM extraction.

Play Risk Factors

- All are 1.0, reflecting certainty that the unconventional play exists.

Hydrocarbon Volume Components / Reservoir Parameters

- **Gross Rock Volume / Total play area** – reflects exclusion of rock volume >3500m deep.

- **Tested play area** – Set at zero, because even though the play has been drilled, it has not been fully tested in a commercial operation.

- **Fraction of untested play filled / Developable fraction of total play** – the play is widespread, but reservoir parameters and structural complexities restrict potential economic development to only a part of the area. The range was chosen on general knowledge, and requires careful review as more is learned about the play.

- **Fraction of play volume oil bearing** – set at zero, coals generally contain only methane.

- **Net to gross** – only a small percentage of the mapped rock volume consists of coal seams.

- **Matrix porosity** – typical range for coals; subject to revision with more extensive analytical work.

- **Natural fracture porosity** – fracture (cleat) porosity is a normal component of coal reservoirs.

- **Hydrocarbon saturation in matrix** – many coals are completely filled with methane; but impurities or small amounts of water may exist.

- **Free gas and adsorbed gas parameters** – industry standard values, and ranges informed by corporate testing programs; requires careful review as more samples are gathered and more is learned about the play.

- **Recovery factors** – industry standard values.

DISCUSSION – CALCULATED RESOURCE VOLUMES

Tables 1 and 2 summarize resource volumes calculated for Windsor and Cumberland Basins, respectively; they are taken from the summary worksheets in Appendix 1 and 2.

- Oil and liquids volumes are very small, as we have assumed that mature, non-marine source rocks have generated primarily gas.
- Resource volumes are listed in both metric and Imperial units, and as both in-place and recoverable values.
- For each play, resource volumes are listed with and without consideration of Play Risks:
    - **Risked liquids / gas volumes** are mean volumes of resource calculated to be present, including application of Play Risk factors;
    - **Gas and liquids volumes "given success"** are $P_{90}/P_{50}/P_{10}$ (conservative, expected, optimistic) resource volumes we expect to find, after having established that the play actually exists.

In the Windsor Basin (Appendix 1), the Horton Bluff unconventional shale play contains most of the gas resource; the lower Horton Bluff tight sandstone play lags far behind but still has almost 2 TCF of gas in place in the mean Risked case. The Cheverie play also hosts substantial volumes, largely because the reservoir is thick and widespread. Projected volumes in the other plays are relatively small; note that the risked volumes for the Upper Windsor are impacted most significantly by the low Play Risk value.

In the Cumberland Basin (Appendix 2), the unconventional plays (Horton Bluff shale and Cumberland CBM) also host the largest resources, but the Horton Bluff potential is much smaller than in the Windsor Basin, reflecting uncertainty around its areal extent, and also extremely deep burial depths over much of the basin.

Overall, these gas volumes represent substantial and potentially very economically valuable exploration and development targets, particularly in a market where there is some existing transportation infrastructure, a growing dependence on imported gas to supply domestic needs, and potential for LNG exports (Corridor Resources, 2016).

When considering the viability of any of the plays, one must consider exploration, appraisal and development strategies, in addition to the resource volume prize. For example, the lower Windsor Macumber / Gays River reef play features a distinct reservoir model supported by outcrop analogues. Exploratory seismic and geological mapping strategies are readily executed – in contrast to less-defined plays like the

	Play Risk	Risked Liquids volume	OIP+CIIP given success			Risked Gas Volume	GIIP given success			Risked Gas Volume	GIIP given success		
			P90	P50	P10		P90	P50	P10		P90	P50	P10
		e6stm3	e6stm3	e6stm3	e6stm3	e9sm3	e9sm3	e9sm3	e9sm3	Bscf	Bscf	Bscf	Bscf
Horton Bluff Shale	1.00	8.89	1.62	5.57	18.55	781.4	190.9	551.6	1,556.0	27,734	6,777	19,579	55,229
Lower Horton Bluff Sandstone	1.00	1.03	0.13	0.53	2.20	51.6	7.5	29.2	107.3	1,831	266	1,036	3,810
Upper Windsor Group – clastics and carbonate	0.07	0.00	0.01	0.03	0.14	0.1	0.3	1.1	4.2	5	9	38	150
Macumber Fm (Gays River equiv.) – basal Windsor	0.42	0.07	0.02	0.08	0.40	2.2	0.5	2.6	12.2	78	18	91	435
Upper Horton Cheverie Fm	0.42	0.35	0.07	0.37	1.90	10.6	2.4	12.1	57.7	378	86	429	2,047
Glass sand (top of Horton Bluff Fm)	0.32	0.01	0.01	0.03	0.10	0.4	0.2	0.9	2.9	16	8	30	103

							Recoverable Gas given success				Recoverable Gas given success		
			P90	P50	P10		P90	P50	P10		P90	P50	P10
		e6stm3	e6stm3	e6stm3	e6stm3	e9sm3	e9sm3	e9sm3	e9sm3	Bscf	Bscf	Bscf	Bscf
Horton Bluff Shale	1.00	1.33	0.17	0.70	2.90	101.7	16.4	60.4	219.6	3,608	581	2,143	7,794
Lower Horton Bluff Sandstone	1.00	0.31	0.03	0.15	0.65	13.4	1.7	7.0	28.5	476	59	248	1,011
Upper Windsor Group – clastics and carbonate	0.07	0.00	0.00	0.02	0.07	0.1	0.1	0.5	1.9	2	4	17	69
Macumber Fm (Gays River equiv.) – basal Windsor	0.42	0.04	0.01	0.04	0.21	1.0	0.2	1.1	5.7	36	8	41	201
Upper Horton Cheverie Fm	0.42	0.18	0.04	0.19	1.00	4.9	1.1	5.4	26.5	174	37	193	941
Glass sand (top of Horton Bluff Fm)	0.32	0.01	0.00	0.01	0.05	0.2	0.1	0.4	1.4	7	3	13	48

Table 1. Resource volume outputs, Windsor Basin plays.

	Play Risk	Risked Liquids volume	OIP+CIIP given success P90	P50	P10	Risked Gas Volume	GIIP given success P90	P50	P10		Risked Gas Volume	GIIP given success P90	P50	P10	
		e6stm3	e6stm3	e6stm3	e6stm3	e9sm3	e9sm3	e9sm3	e9sm3		Bscf	Bscf	Bscf	Bscf	
Horton Bluff Shale	0.50	0.69	0.08	0.50	3.14	65.1	9.2	52.7	306.0		2,311	327	1,872	10,862	
Cumberland Coal Bed Methane (CBM)	1.00	0.39	0.03	0.15	0.84	76.2	8.7	39.1	169.9	**	2,705	309	1,387	6,032	**
Cumberland Group Boss Point sandstone, Ragged Reef fm	0.29	0.35	0.14	0.59	2.46	10.7	4.7	19.2	74.0		381	168	682	2,625	
Mabou Group Upper Claremont Fm	0.37	0.34	0.06	0.34	1.90	10.3	2.0	11.1	58.7		366	72	395	2,085	
Windsor Group – carbonates with interbedded evaporites	0.38	0.18	0.02	0.14	1.12	5.5	0.5	4.3	34.6		196	19	154	1,229	
Horton Fm clastics	0.36	0.09	0.03	0.12	0.55	2.8	1.0	4.0	16.8		100	34	141	595	

			P90	P50	P10		Recoverable Gas given success P90	P50	P10			Recoverable Gas given success P90	P50	P10	
		e6stm3	e6stm3	e6stm3	e6stm3	e9sm3	e9sm3	e9sm3	e9sm3		Bscf	Bscf	Bscf	Bscf	
Horton Bluff Shale	0.50	0.10	0.01	0.06	0.46	8.5	0.9	5.7	39.0		301	31	204	1,385	
Cumberland Coal Bed Methane (CBM)	1.00	0.23	0.02	0.09	0.51	39.8	4.4	20.1	88.9	**	1,411	158	714	3,155	**
Cumberland Group Boss Point sandstone, Ragged Reef fm	0.29	0.19	0.07	0.31	1.31	4.9	2.0	8.4	33.4		172	71	299	1,185	
Mabou Group Upper Claremont Fm	0.37	0.18	0.03	0.18	1.02	4.7	0.9	4.9	26.6		165	31	173	943	
Windsor Group – carbonates with interbedded evaporites	0.38	0.10	0.01	0.07	0.58	2.5	0.2	1.9	15.8		90	8	69	560	
Horton Fm clastics	0.36	0.05	0.01	0.06	0.29	1.3	0.4	1.8	7.7		46	15	63	273	

Note **
Undiscovered CBM resource only
Discovered CBM resource is extra

Table 2. Resource volume outputs, Cumberland Basin plays.

upper Horton Cheverie or upper Windsor clastics/carbonates, where we have no clear model of reservoir geometries or settings. Operators can also envision that a Macumber reef discovery could be appraised and developed with a small number of wells and put on stream quickly. Appraisal and development of a fluvial sandstone discovery in one of the other plays would proceed more tentatively as the operator worked to build a reservoir model to understand the potential scope and quality of the discovery.

Larger operators would be encouraged by the scope of a successful Horton Bluff shale play, knowing that economies of scale could be applied to develop its extensive resource base once economic productivity is established – assuming the appropriate regulatory framework is in place to allow such development.

It is thus no surprise that exploration/appraisal programs have been undertaken for the unconventional plays and for the Macumber / Gays River, but not for the other conventional plays. Companies are pursuing opportunities where they can quantify risks and execute strategies, but are less willing to undertake exploration expenditures on plays with poorly-defined parameters.

We suggest that in the future, assuming that the regulatory regime allows the full scope of exploratory practices including hydraulic fracturing, exploration for unconventional plays will lead the way, and exploration for conventional plays will follow later as data generated by unconventional operations provide better knowledge of conventional plays.

DATA GAPS AND RECOMMENDED FUTURE WORK

DATA GAPS AND UNCERTAINTIES

Scarcity of data lends considerable uncertainty to all facets of resource identification and assessment. This situation is not unique to Nova Scotia onshore basins – but is particularly important because of the complexity of petroleum reservoirs and systems.

Basin / Reservoir Geology

- Basin stratigraphy is defined primarily in outcrop, and recognition of stratigraphic units in the subsurface is not consistent. We don't understand subsurface stratigraphy in sufficient detail, in part because of scant well control.

- Basin structure – internal and basin boundaries – is complex, and we don't have a good understanding of local and regional fault patterns, and their influence on hydrocarbon traps. Salt diapirism, particularly in the Cumberland Basin, further complicates the structural picture.

- Conventional reservoirs are defined only in very broad terms, on a formation scale. We lack mapping of specific trends – e.g., fluvial sandstone reservoir fairways, or basin-edge alluvial fan deposits – that could be used to define hydrocarbon traps and drilling targets.

    - Net to gross ratios assigned in the resource assessment have little concrete basis, and represent major uncertainties that would be addressed with better stratigraphic knowledge

- Horton Bluff shale and tight sandstone reservoirs are poorly understood

    - In the Cumberland Basin, lack of well control makes us uncertain as to whether the plays actually exist, and if they do, over what areas.

    - In the Windsor Basin, stratigraphic and reservoir characterization work is limited largely to several wells in the Elmworth / Triangle drilling program.

Seismic

- Seismic data for the Cumberland Basin were available in time only, and information to support a robust depth conversion was not complete. Past assumptions and procedures in interpretation were not well documented.

- As well control to support depth conversion is very sparse, particularly for deeper units, it would be useful to have access to stacking velocities used in seismic processing.

- Information on faults is scarce – there were no faults in the Petrel models, and so we worked from surface fault traces only. Mapping of fault planes and angles from seismic could substantially impact reservoir volumes in the models, and might also provide insights on migration pathways and specific trapping situations.

- Seismic information provided was not sufficient to support reservoir characterization work, which could be hugely valuable, particularly for the unconventional plays

Assessment Procedures

PRCL's resource assessment work was completed in a short period of time, with limited budget. Some specific observations, and some suggestions for additional work to be undertaken to improve quality of the assessment follow.

- More time is required for the assessors to get familiar with local geology. There is abundant outcrop literature and some good information in well files. Discussions with John Waldron regarding basin structure were very informative and useful. All of this takes time to absorb, work, and understand. Better decisions on play definition, risking and parameters could likely be made with more familiarity with the reservoir section, which could be achieved with existing information, even before undertaking new work recommended below.
    - In particular, there are a number of reports regarding local and regional source rock / maturity trends, and we did not have sufficient time to fully understand these.
    - Department of Energy staff may be able to modify and upgrade assessment parameters using their better-established local knowledge.

- Similarly, while the seismic information provided was useful, we were limited by use of seismic interpretations only. Access to the original seismic data would have enabled us to address specific issues – such as detection and mapping of specific fault planes, or potential for seismic mapping of reservoir characteristics.

- Provision of Petrel™ models to map and quantify reservoir volumes is an excellent idea, and enabled us to provide reasonable GRV's in the time available. As noted below, however, we had to do considerable work with the models to generate reasonable outputs, and much more fine-tuning could be done with additional time and resources.

RECOMMENDED FUTURE WORK

- The most obvious need toward better understanding resource endowment and prospectivity is additional subsurface data – both seismic and well information. While acquiring such information is obviously not within the mandate of the Department of Energy, consideration should be given towards incenting industry activity to generate new data.
    - In PRCL's opinion, it is highly unlikely that operators will undertake significant new work while regulatory restrictions on hydraulic fracturing are in place.
- Targeted surface geology studies, focused on better understanding key stratigraphic relationships and reservoir distributions, would be very useful – and should include specific efforts to tie back to subsurface sections. Selected outcrop sampling and analytical work for petrographic, geochemical, maturity and geomechanical properties is also recommended.
    - Additional structural work could also be very useful, particularly if applied toward better understanding of subsurface structure.
- Systematically review cores and drill cuttings to better characterize petroleum stratigraphy and reservoir quality and distribution in the subsurface.
    - PRCL recommends drill cuttings evaluation by specialists trained specifically to estimate reservoir quality from cuttings samples.
- Calibrate and display well logs in a consistent fashion to support:
    - Systematic and consistent stratigraphic correlations in the subsurface;
    - Systematic quantitative petrophysical analysis of reservoir characteristics, where log data are sufficient to do so.
- Undertake basin modelling work to better understand petroleum systems, and thus make more informed decisions around source rock, charge and migration issues.
    - Compile existing geochemical / maturity data, and determine where additional sampling and analytical work would have the maximum impact on improving our understanding of petroleum systems.
    - Incorporating petrographic analysis in basin modeling would also better define diagenetic trends, and potentially enable us to better understand reservoir quality distribution, and to assign depth limits to each conventional play.

- Undertake geochemical and geomechanical sampling and characterization of unconventional plays, particularly the Horton Bluff shale.
    - Quantify stratigraphic trends to optimize drilling targets in this very thick section.
    - Assess “frackability” of the rock, and support design of optimal stimulation programs.
- Undertake a systematic and unified interpretation of all available seismic data in each basin, in order to provide best outputs – well ties, velocities / depth conversions, and surfaces to populate models.
    - Examine how seismic can provide additional reservoir and fluid information.
        - Map direct hydrocarbon indicators (DHI’s) – fluid contacts, gas chimneys.
        - Map conventional reservoir fairways – e.g., channel trends.
        - Map porosity / geomechanics / stratigraphic trends in unconventional reservoirs.
    - Forward modelling could be undertaken in the Horton Bluff, to identify seismic characteristics associated with lateral changes to more sand-rich sections, and to non-prospective proximal (Fountain Lake) facies. Modelling success would support regional facies mapping using existing seismic lines.
    - A robust seismic inversion might also better delineate targets within the entire seismic dataset.
- Continue to develop Petrel™ models of the basins, incorporating best available information from consistent and unified geological and geophysical interpretations.
    - We likely don’t have sufficient well / log control and stratigraphic knowledge to enable useful population of Petrel property models for reservoir characterization, but we should aspire to continue improving our datasets so that this objective might become possible.
    - Improving structural representation in the models can substantially inform assignment of the “percentage of play in trap” parameter for resource modeling, which is a significant uncertainty.

- Expand resource assessment analysis by undertaking a sensitivity analysis of variables used in the assessment (commonly plotted as "tornado diagrams"). This would show the key uncertainties to address in order to improve the assessment, or might reveal that the information required to make meaningful improvement is simply not available.

- Undertake a rigorous and quantitative analysis of analogue plays and basins in order to refine estimates of input variables.

- Review data on discovered resources (Cumberland CBM and Kennetcook Horton Bluff shale gas), with the goal of refining estimates of discovered resources in a manner consistent with the regional assessment of undiscovered resources.

RESERVOIR ANALOGUES

Where our knowledge of prospective petroleum reservoirs is limited by scant subsurface data, as in Nova Scotia onshore basins, identifying and reviewing analogue reservoirs can provide insights into productive potential. Analogues are most useful in analyzing unconventional reservoirs, as we are still developing our understanding of reservoir quality and productivity controls in these settings, and comparisons can be made usefully on a basin-wide scale. Conventional fluvial sandstone and shallow marine carbonate reservoirs in stratigraphic and structural traps are hugely variable but reasonably well understood, and analogue studies are not likely to add much value at this level of assessment.

We therefore focus our attention on analogues for the Horton Bluff shale and Horton Bluff tight sandstones in the Windsor and Cumberland basins.

The U.S. Energy Information Administration (2013) reviewed the Horton Bluff shale play in the Windsor Basin, but it appears they simply reviewed the Ryder Scott (2008) evaluation of the Elmworth / Triangle activity, and brought no new insights. Hamblin (2006) emphasized shale gas prospectivity in Horton Bluff and equivalent shales in the various sub-basins of the larger Maritimes Basin, but provided no insights on quantitative assessment. Similarly, Lavoie *et al.* (2009) specifically discussed unconventional gas potential in the Horton Bluff shales and Cumberland CBM units throughout the Maritimes Basin, but could not quantify the resource endowment using their discovery-based method.

CANADIAN ANALOGUES

In Canada, established producing shale, "tight" and CBM plays occur in the Western Canada Sedimentary Basin. Most productive reservoirs are situated in relatively undeformed areas, well east of the Rocky Mountain fold and thrust belt. Strata are subjected to a reasonably simple and consistent stress regime associated with formation of the Rockies; the principal stress is directed northeastward, although it varies locally around basement features like the Peace River Arch. Thus, the structural setting and stress regime hosting these plays is much different than in the highly structured, complexly-stressed setting of onshore Nova Scotia.

Duvernay and Horn River Shale Plays

Shale reservoirs of the Middle to Upper Devonian Duvernay and Horn River formations consist of open marine, organic-rich shales, deposited in quiet cratonic to craton-margin settings flanking carbonate platforms and reef build-ups, far away from major sources of coarse clastic supply (BC Ministry of Natural Gas / NEB, 2011; BCOGC, 2014). Authigenic carbonate and silica mineralization imparts geomechanical properties (“brittleness”) that enable these reservoirs to be fractured effectively; interbedded coarse clastics play no significant role in reservoir quality. They are structurally undeformed in the areas where commercial development has taken place.

Duvernay and Horn River shales are regionally extensive, and exhibit a range of thermal maturity levels. Where they have been deeply buried, as in the Horn River Basin and western reaches of the Alberta Deep Basin, contained organics are highly mature to overmature, and dry gas is produced. In shallower, less thermally-mature settings, lying further east in Alberta and in the Northwest Territories, gas liquids make up a significant fraction of the production.

Extensive reservoir characterization work has been completed on the Duvernay and Horn River, focused in two areas:

- Investigation of stratigraphic architecture to characterize stratigraphic controls on reservoir quality and distribution;

- Sampling and analytical work to determine geochemical, maturity, and geomechanical properties.

While there are significant differences between the western Canada Devonian shale plays and the younger Horton Bluff shales of Nova Scotia, approaches to reservoir characterization in the Duvernay and Horn River suggest the scope and magnitude of work that must be undertaken to truly understand the potential of the Horton Bluff.

Montney Tight Sandstone / Siltstone Play

Triassic Montney Formation siltstones and fine-grained sandstones host one of the largest tight / unconventional oil and gas accumulations in the world (B.C. OGC, 2012). The National Energy Board *et al*. (2013) have assigned in-place resources of 4,274 TCF of gas, 127 billion barrels of natural gas liquids, and 141 billion barrels of oil.

Montney reservoirs were deposited in shallow, open to restricted marine settings on the western flank of the North American craton – much different than any environments envisioned for onshore Nova Scotia reservoirs. However, we speculate that comparisons could be made with the poorly-understood Horton Bluff tight sandstone play:

- Both are thick (up to 300m) sections of clastics containing significant organic material, and grading to shalier distal deposits;

- Complex grain mineralogies reflect provenance from a variety of terranes and source lithologies;

- Where prospective, sections are deeply buried and effectively sealed from shallower, normally-pressured systems.

As we noted for the Duvernay and Horn River, a great deal of work has been done to understand Montney reservoir stratigraphy, and to characterize geochemical and geomechanical properties. An additional focus area in the Montney that may be particularly important to evaluation of Horton Bluff sandstones is detailed petrophysical analysis, to accurately measure effective porosities and thus resource capacity.

An additional point of comparison to be considered is that the northwestern-most reaches of the Montney fairway lie in the outer Foothills of northeastern B.C., and operators (Progress Energy, Canbriam, Painted Pony) have developed strategies to optimize development and production in a more structurally-complex and variably-stressed setting. While structure and tectonics are not directly comparable to onshore Nova Scotia, there may be lessons from the Montney to be applied.

Second White Specks Shale Play

There is a long history of oil and gas production from brittle, fractured, organic-rich shales of the Upper Cretaceous Second White Specks Formation in the structurally-deformed Alberta Foothills (Clarkson and Pedersen, 2011). Tens of thousands of wells have been drilled through the unit in pursuit of deeper targets, and several hundred have tested and produced oil and gas; the best wells have produced more than one millions barrels of light oil. Many were tested in response to pressure anomalies ("kicks") encountered while drilling, indicative of intersecting open fractures.

More recently, some operators have undertaken intensive, seismically-based mapping to reconstruct structural deformation in detail, identifying specific locations where fracturing could be best developed. Directional or horizontal wells to intersect interpreted fracture trends have been drilled, with varying degrees of success. While much of the organic-rich Second White Specks is clay rich and ductile, there are specific intervals containing interbedded clastics and abundant calcite cements that are sufficiently brittle to fracture well and serve as productive "channels".

There may be potential to apply this style of prospecting to shale and tight clastic reservoirs in the Horton Bluff section of onshore Nova Scotia. There is evidence of abundant natural fracturing associated with the complex structure of the Windsor and Cumberland basins. While focusing exploration and appraisal on naturally-fractured fairways inherently limits the resource available to be produced, there may be sufficiently widespread fracturing in thick Horton Bluff shales and coarser clastics to provide an economic resource target.

Moncton Sub-Basin Plays

Gas and oil discoveries in tight sandstones of the upper Horton Hiram Brook Formation at McCully and Stoney Creek fields are obvious analogues to Horton Group prospects in onshore Nova Scotia, because of similar structural settings and regional depositional histories (Lavoie *et al*., 2009; Corridor Resources, 2016).

Perhaps more critically, Corridor's work to date in evaluating the unconventional Frederick Brook shale reservoir should provide guidance to evaluation and appraisal of approximately equivalent Horton Bluff shales (Corridor Resources, 2016; Macquarie Tristone, 2013).

Hiram Brook and Frederick Brook stratigraphic relationships and geochemical / maturity / geomechanical properties should all be considered for their applicability to better understanding the Horton Bluff section in onshore Nova Scotia.

U.S. ANALOGUES

While there are many productive shale reservoirs in the United States, most of the best-known – the Barnett, Eagle Ford, Haynesville, Antrim, Marcellus – are open marine, organic-rich shales like the Duvernay and Horn River. They were deposited in broad open basins, and are exploited in relatively undeformed settings.

Better comparisons for the Horton Bluff shale and tight sandstone plays can be made to shales and tight sandstones in Rocky Mountain basins of the western United States. There are two major points of comparison:

- Rocky Mountain basins, while much larger than onshore Nova Scotia sub-basins, have experienced multiple tectonic episodes producing complex stress patterns and structures having profound effects on reservoir development and production. The San Juan Basin of northwestern New Mexico is an excellent example (e.g., Lorenz and Cooper, 2003).

- Cretaceous shales of the Rocky Mountain region contain both organic-rich intervals and interbedded clastics. Original deposition took place in marine to marginal marine settings in the broad Late Cretaceous intracratonic seaway, but clastic content varies according to proximity to various source terranes.

The Lewis and Mancos shales of the San Juan Basin are good examples of possible Horton Bluff analogues, and should be investigated. Gas production from naturally-fractured Lewis reservoirs dates back to the 1950's, and USGS (2002) identified significant gas resources in the Lewis Shale Total Petroleum System, which includes both shales and interbedded siltstones and sandstones. Bereskin (2003) pointed out large productive potential in Lewis shale/sandstone gas reservoirs – but the play is not currently a major producer. Both its potential and its failure to become a major producer may hold important lessons toward our understanding of the Horton Bluff unconventional petroleum system. Similarly, interbedded sandstones and shales of the Mancos Formation hold widespread oil and gas prospectivity in the San Juan Basin, but drilling and evaluations to date have been focused more to the north in the Piceance Basin (Broadhead, 2014).

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