GEOLOGICAL SURVEY OF CANADA
OPEN FILE 7565

Oil and Gas Resource Potential of Eagle Plain Basin, Yukon, Canada

P.K. Hannigan

2014

Natural Resources Canada
Ressources naturelles Canada

Canada

GEOLOGICAL SURVEY OF CANADA
OPEN FILE 7565

Oil and Gas Resource Potential of Eagle Plain Basin, Yukon, Canada

P.K. Hannigan [1]

[1] (Geological Survey of Canada – Calgary, 3303-33rd Street, N.W., Calgary, Alberta)

2014

©Her Majesty the Queen in Right of Canada 2014

doi:10.4095/293952

This publication is available for free download through GEOSCAN (http://geoscan.ess.nrcan.gc.ca/).

Recommended citation
Hannigan, P.K., 2014.Oil and gas resource potential of Eagle Plain Basin, Yukon, Canada; Geological Survey of Canada, Open File 7565, 181 p + 83 PDF files. doi:10.4095/293952

Publications in this series have not been edited; they are released as submitted by the author.

Table of Contents

ABSTRACT **1**

EXECUTIVE SUMMARY **1**

INTRODUCTION **3**

GEOLOGICAL SETTING AND TECTONIC EVOLUTION **4**

PRECAMBRIAN BASEMENT 4
PROTEROZOIC TECTONIC EVOLUTION 5
PHANEROZOIC TECTONIC HISTORY 5

REGIONAL STRATIGRAPHY **7**

PROTEROZOIC SEDIMENTARY SUCCESSION 8
PALEOZOIC-MESOZOIC PASSIVE MARGIN SEDIMENTATION 8
MESOZOIC-TERTIARY FORELAND SEDIMENTATION 20

STRUCTURAL FRAMEWORK **22**

PETROLEUM GEOLOGY-CONVENTIONAL SYSTEMS **23**

EXPLORATION HISTORY/DISCOVERIES TO DATE 23
SOURCE ROCKS 25
RESERVOIR ROCKS 28
TRAPS AND SEALS 29

PETROLEUM RESOURCE ASSESSMENT OF EAGLE PLAIN **29**

INTRODUCTION 29
RESOURCE ASSESSMENT PROCEDURE 31
Basin analysis *31*
Geological play definition *31*
Compilation of play data *32*
Estimating the pool size probability distribution *32*
Estimating number of pools *33*
SCOPE OF ASSESSMENT 34
PURPOSE 35
METHOD AND CONTENT 35
PREVIOUS WORK 35
CURRENT ASSESSMENT 36

INDIVIDUAL EXPLORATION PLAY APPRAISALS **36**

1. LOWER PALEOZOIC CARBONATE PRE-LARAMIDE STRUCTURAL 36
Play definition *36*
Geographic location *36*
Exploration history and shows *37*
Discoveries *37*
Potential reservoir *37*
Source rock maturation, generation and migration *37*
Traps and seals *38*
Risk factors *39*
Play potential *39*
2. LOWER PALEOZOIC CARBONATE LARAMIDE STRUCTURAL 39
Play definition *39*
Geographic location *40*

Exploration history and shows *40*
Discoveries *40*
Potential reservoir *40*
Source rock maturation, generation and migration *40*
Traps and seals *41*
Risk factors *41*
Play potential *41*
3. LOWER PALEOZOIC CARBONATE STRATIGRAPHIC 42
Play definition *42*
Geographic location *42*
Exploration history and shows *42*
Discoveries *42*
Potential reservoir *42*
Source rock maturation, generation and migration *43*
Traps and seals *43*
Risk factors *43*
Play potential *43*
4. IMPERIAL/TUTTLE SANDSTONE STRUCTURAL (ELLESMERIAN DEFORMATION-BELL SUBBASIN) 44
Play definition *44*
Geographic location *44*
Exploration history and shows *44*
Discoveries *44*
Potential reservoir *44*
Source rock maturation, generation and migration *45*
Traps and seals *46*
Risk factors *46*
Play potential *46*
5. IMPERIAL/TUTTLE SANDSTONE STRATIGRAPHIC/COMBINATION 47
Play definition *47*
Geographic location *47*
Exploration history and shows *47*
Discoveries *48*
Potential reservoir *48*
Source rock maturation, generation and migration *48*
Traps and seals *49*
Risk factors *50*
Play potential *50*
6. CANOE RIVER CARBONATE STRUCTURAL 50
Play definition *50*
Geographic location *50*
Exploration history and shows *50*
Discoveries *51*
Potential reservoir *51*
Source rock maturation, generation and migration *51*
Traps and seals *51*
Risk factors *52*
Play potential *52*
7. CANOE RIVER CARBONATE STRATIGRAPHIC 52
Play definition *52*
Geographic location *52*
Exploration history and shows *53*
Discoveries *53*
Potential reservoir *53*

Source rock maturation, generation and migration *53*
Traps and seals *54*
Risk factors *54*
Play potential *54*
8. CHANCE SANDSTONE STRUCTURAL 55
Play definition *55*
Geographic location *55*
Exploration history and shows *55*
Discoveries *55*
Potential reservoir *56*
Source rock maturation, generation and migration *56*
Traps and seals *56*
Risk factors *57*
Play potential *57*
9. CHANCE SANDSTONE STRATIGRAPHIC 57
Play definition *57*
Geographic location *57*
Exploration history and shows *58*
Discoveries *58*
Potential reservoir *59*
Source rock maturation, generation and migration *59*
Traps and seals *59*
Risk factors *60*
Play potential *60*
10. ALDER CARBONATE STRUCTURAL 61
Play definition *61*
Geographic location *61*
Exploration history and shows *61*
Discoveries *61*
Potential reservoir *61*
Source rock maturation, generation and migration *62*
Traps and seals *62*
Risk factors *62*
Play potential *63*
11. ALDER CARBONATE STRATIGRAPHIC 63
Play definition *63*
Geographic location *63*
Exploration history and shows *63*
Discoveries *63*
Potential reservoir *64*
Source rock maturation, generation and migration *64*
Traps and seals *64*
Risk factors *64*
Play potential *65*
12. ETTRAIN CARBONATE STRUCTURAL 65
Play definition *65*
Geographic location *65*
Exploration history and shows *65*
Discoveries *66*
Potential reservoir *66*
Source rock maturation, generation and migration *66*
Traps and seals *66*
Risk factors *66*

Play potential *67*
13. ETTRAIN CARBONATE STRATIGRAPHIC 67
Play definition *67*
Geographic location *67*
Exploration history and shows *67*
Discoveries *67*
Potential reservoir *68*
Source rock maturation, generation and migration *68*
Traps and seals *68*
Risk factors *68*
Play potential *69*
14. JUNGLE CREEK SANDSTONE STRUCTURAL 69
Play definition *69*
Geographic location *69*
Exploration history and shows *69*
Discoveries *69*
Potential reservoir *70*
Source rock maturation, generation and migration *70*
Traps and seals *70*
Risk factors *71*
Play potential *71*
15. JUNGLE CREEK SANDSTONE STRATIGRAPHIC 71
Play definition *71*
Geographic location *72*
Exploration history and shows *72*
Discoveries *72*
Potential reservoir *72*
Source rock maturation, generation and migration *72*
Traps and seals *73*
Risk factors *73*
Play potential *73*
16. JURASSIC-LOWER CRETACEOUS SANDSTONE PRE-ALBIAN STRUCTURAL 74
Play definition *74*
Geographic location *74*
Exploration history and shows *74*
Discoveries *74*
Potential reservoir *74*
Source rock maturation, generation and migration *75*
Traps and seals *76*
Risk factors *76*
Play potential *77*
17. JURASSIC-LOWER CRETACEOUS SANDSTONE STRATIGRAPHIC 77
Play definition *77*
Geographic location *77*
Exploration history and shows *77*
Discoveries *78*
Potential reservoir *78*
Source rock maturation, generation and migration *78*
Traps and seals *79*
Risk factors *79*
Play potential *79*
18. TRIANGLE ZONE STRUCTURAL (BELL SUBBASIN) 79
Play definition *79*

Geographic location ... *80*
Exploration history and shows ... *80*
Discoveries ... *80*
Potential reservoir ... *80*
Source rock maturation, generation and migration ... *81*
Traps and seals ... *82*
Risk factors ... *82*
Play potential ... *82*
19. CRETACEOUS SANDSTONE STRUCTURAL ... 83
Play definition ... *83*
Geographic location ... *83*
Exploration history and shows ... *83*
Discoveries ... *83*
Potential reservoir ... *84*
Source rock maturation, generation and migration ... *85*
Traps and seals ... *86*
Risk factors ... *86*
Play potential ... *86*
20. CRETACEOUS SANDSTONE SHELF STRATIGRAPHIC ... 87
Play definition ... *87*
Geographic location ... *87*
Exploration history and shows ... *87*
Discoveries ... *87*
Potential reservoir ... *88*
Source rock maturation, generation and migration ... *88*
Traps and seals ... *88*
Risk factors ... *89*
Play potential ... *89*
21. CRETACEOUS SANDSTONE SLOPE STRATIGRAPHIC ... 89
Play definition ... *89*
Geographic location ... *89*
Exploration history and shows ... *89*
Discoveries ... *90*
Potential reservoir ... *90*
Source rock maturation, generation and migration ... *90*
Traps and seals ... *90*
Risk factors ... *90*
Play potential ... *91*
DISCUSSION OF ASSESSMENT RESULTS ... 91
Resource potential of the basin ... *91*
Resource distribution ... *91*
Assessment results and exploration history ... *93*
BASIN COMPARISONS ... 93

UNCONVENTIONAL PETROLEUM RESOURCES ... 93

UNCONVENTIONAL OIL POTENTIAL ... 94
UNCONVENTIONAL GAS POTENTIAL ... 94
Tight gas ... *94*
Shale gas ... *95*

CONCLUSIONS ... 98

REFERENCES ... 101

APPENDIX A **118**
APPENDIX B **120**

ABSTRACT

The intermontane Eagle Plain Basin lies within the mountainous and deformed Northern Yukon Fold Complex geological province of the northern mainland of Canada. This Paleozoic-Mesozoic basin forms a petroleum province that is less deformed and less structurally elevated compared to surrounding mountain belts. The Eagle Plain Basin contains the Eagle Fold Belt which consists of bundles of en-échelon folds that have wavelengths of several to tens of kilometres. The folds developed during the Laramide Orogeny and form well-defined structural closures suitable for entrapment of hydrocarbons in the subsurface.

Several assessment studies of petroleum potential have been completed for the Eagle Plain Basin. Recent work associated with the Geomapping for Energy and Minerals Program interpreted petroleum exploration play concepts not previously defined. Evaluations of new petroleum data indicated the need to re-assess the conventional oil and gas potential of the basin. In this study, a total of 21 conventional petroleum exploration plays are defined. Also, the potential for unconventional tight oil and gas, and shale oil and gas accumulations (not previously assessed) are included in the report. Given the fact that some conventional plays and all of the unconventional plays were not quantitatively analyzed because of insufficient data, the total petroleum resource indicated in this study is likely a conservative estimate, as there is evidence for hydrocarbon charge in these non-assessed plays.

The probabilistic assessment of total oil and gas potential (discovered and undiscovered) for all Phanerozoic sedimentary strata in Eagle Plain and its environs is $52.2*10^6$ m^3 (329 MMBO) of oil and $96.7*10^9$ m^3 (3.4 Tcf) of gas (in-place mean volumes). Although there are sizeable discovered reserves ($3.2*10^6$ m^3 (20 MMBO) of oil and $4.6*10^9$ m^3 (165 Bcf) of gas), undiscovered resource potential is significant, as exemplified by the prediction of 2 remaining undiscovered oil pools with mean in-place volumes greater than $4.0*10^6$ m^3 (25.2 MMBO) and 4 gas pool sizes greater than $2.0*10^9$ m^3 (71 Bcf).

EXECUTIVE SUMMARY

The oil and gas resource potential in Phanerozoic strata in the Eagle Plain Basin of northern Yukon is described in this report. The appraisal of petroleum potential of this northern frontier basin constitutes one of a series of reports providing an update of total petroleum resource for all sedimentary basins of Canada. The last Canada-wide assessment was published over a quarter century ago (Procter et al., 1983). Subsequent “updated” reports such as this one contain major revisions and provide new and comprehensive probabilistic exploration play-based estimates of petroleum potential.

A petroleum exploration play is defined as a group of pools or prospects forming a common geological population linked by one or more factors such as stratigraphy,

structure and reservoir-type or source-rock type. For the Eagle Plain Basin of northern Canada, twenty-one immature and conceptual plays were defined on the basis of two major geological controls; potential reservoir strata within which the petroleum accumulations exist or may exist, and trap-type of the petroleum accumulation which includes structural, stratigraphic, or a combination of the two. For each defined play, mapped and compiled data were statistically analyzed to estimate their resource potential. Nineteen of 21 defined plays have sufficient data and/or similar play analogues to perform statistical analyses. All gas plays were analyzed. One of the sixteen oil plays was not analyzed, because no oil pools were predicted due to limited prospect numbers and significant exploration risk. Resource volumes (total potential and pool sizes) in this report are recorded as probability ranges (P95-P5) as well as mean value estimates of in-place oil or gas. Mean and median values of largest pool size volumes are reported.

The volumetric probability distribution model was employed for evaluating the various immature or conceptual plays in the basin. The limited number of discoveries in each established play provides insufficient information for analysis by discovery process, so its model was not utilized in this study. There are three inputs required in the volumetric model; 1) a pool size distribution derived from area of closure, net pay, trap fill, porosity, water saturation and formation volume factor; 2) a play-level or prospect-level risk analysis of geological factors required for petroleum generation and accumulation, such as adequate reservoir, adequate source, proper timing, adequate seal and thermal maturity, and 3) an estimate of the number of prospects in a play derived by counting and extrapolating the number of closures found on seismic structure maps.

The estimated total potential for all plays in the Eagle Plain Basin region is $52.2*10^6$ m^3 (329 MMBO) of oil and $96.7*10^9$ m^3 (3.4 Tcf) of gas (in-place mean volumes). There are sizeable discovered reserves ($3.2*10^6$ m^3 (20 MMBO) of oil and $4.6*10^9$ m^3 (165 Bcf) of gas), but significant potential remains. Ninety-four percent of the oil and 95% of the gas resource remains to be discovered.

The assessment results predict that the Cretaceous sandstone slope stratigraphic and Jungle Creek stratigraphic oil plays encompass about 49% of the total oil potential and seven of the 10 largest undiscovered pools in Eagle Plain Basin. This reflects the relatively large trap sizes and better quality reservoirs in Cretaceous turbiditic and shelf-margin delta sand bodies and Permian thick-bedded sandstone bodies in shoreline and marine shelf environments. Predicted gas pool sizes show a different distribution, with four stratigraphic gas plays having similar undiscovered pool sizes. The ten largest undiscovered gas pools are evenly distributed among these four stratigraphic plays. In Eagle Plain Basin, there are 2 undiscovered oil pools having in-place volumes greater than $4.0*10^6$ m^3 (25.2 MMBO), and four undiscovered gas pool with volumes greater than $2.0*10^9$ m^3 (71 Bcf).

Regions of petroleum prospectivity in Eagle Plain reflect various ranking criteria including potential oil and gas volumes, the overlap and intersection of play polygon areas, the favourability of oil and/or gas generation from potential source rocks, mapped closures, and known accumulations or oil or gas shows. Although the geographic

petroleum resource distributions within the plays themselves are unknown, an assumption of apportionment of total play potential by area may be used. Areas of probable high potential in the basin include southern Eagle Plain where all known accumulations and numerous plays overlap. Moderate potential is expected in western and northern Eagle Plain where the Cretaceous slope stratigraphic and Triangle Zone structural plays occur.

This petroleum resource study provides important new insights into the energy endowment of the Eagle Plain Basin of northern Yukon. Significant petroleum accumulations are predicted to occur in the basin. The resource potential volumes represent a conservative estimate because some conventional and all unconventional plays have not been assessed, because of insufficient data.

INTRODUCTION

Regional petroleum resource assessments have been periodically prepared for various sedimentary basins in Canada by the Geological Survey of Canada. These studies incorporate systematic basin analysis and probabilistic statistical resource evaluations (Procter et al., 1984; Podruski et al., 1988; Wade et al., 1989; Sinclair et al., 1992; Reinson et al., 1993; Bird et al., 1994a; Dixon et al., 1994; Barclay et al., 1997; Hamblin and Lee, 1997; Warters et al., 1997; Hannigan et al., 2001; Lavoie et al., 2009; Hannigan et al., 2011). This report discusses the comprehensive evaluation of oil and gas potential of Eagle Plain Basin in northern Yukon Territory, Canada. Eagle Plain constitutes part of the Northern Yukon Fold Complex which is one of the geological provinces within the Cordillera of the northern mainland of Canada (Fig. 1).

Based on tectonic and geographic considerations, the northern mainland is divisible into four geological provinces, including the Interior Platform and Beaufort-Mackenzie Basin in the relatively undeformed platform terrane, and the Northern Yukon Fold Complex and Northern Foreland Belt within the fold and thrust belt of the eastern Cordillera (Fig. 1). The four geological provinces are informally divided further according to physiographic character into exploration regions or ‘basins’ displaying their unique petroleum geology (Fig. 1).

The Beaufort-Mackenzie Basin, Interior Platform and Northern Foreland Belt provinces of Canada’s northern mainland are not discussed in this report. Petroleum geology and resource potential in these provinces are presented in numerous publications including Lerand (1973) and Dixon et al. (1994) for the Beaufort-Mackenzie region. A comprehensive discussion of petroleum resource potential in the Interior Platform and Northern Foreland Belt provinces, together known as the Mackenzie Corridor, is presented in a Geological Survey of Canada Open File publication (Hannigan et al., 2011). Petroleum resource publications for Northern Yukon Fold Complex basins excluding the Eagle Plain Basin are Hannigan (2000) for Bonnet Plume Basin; Hannigan et al. (1999) for Kandik Basin; and Lawrence (1973), Morrell and Dietrich (1993) and Hannigan (2001) for Old Crow Basin. Specific Eagle Plain petroleum resource

assessment publications include studies completed by the National Energy Board (2000) and the Geological Survey of Canada (Osadetz et al., 2005a).

The most significant discoveries to date in the Eagle Plain Basin are an oil and gas field at Chance and single-well gas discoveries at Blackie M-59 and Birch B-34. All these discoveries are located in southern Eagle Plain.

GEOLOGICAL SETTING AND TECTONIC EVOLUTION

The Northern Yukon Fold Complex extends from the Ogilvie-Wernecke Mountains northward to the Yukon coastal plain (Fig. 1). It is bounded to the east by Peel Plateau in the Interior Platform Province; the Fold Complex extends west into Alaska. Within this mountainous region are five basins or sedimentary depocentres with hydrocarbon potential. They are Eagle Plain, Bonnet Plume, Kandik, and Old Crow basins, and Blow Trough (Fig. 1). The intervening mountain ranges may have limited hydrocarbon potential, but high levels of thermal maturation and exposure of potential reservoirs make these areas less prospective. Thus, any discussion of these mountain ranges (British-Barn Mountains, Keele Range, northern Ogilvie Mountains, and Richardson Mountains) with respect to petroleum potential is limited.

During Late Neoproterozoic time, multi-phase rifting broke up Rodinia and isolated the North American proto-continent (Laurentia) (Meert and Torsvik, 2003). Northern Yukon occupied a continental promontory that was formed at the junction of the Franklinian (Arctic) and paleo-Pacific margins (Lane, 2010). The Late Proterozoic Franklinian margin coinciding with the northwestern margin of Eagle Plain Basin established structural trends that were repeatedly reactivated throughout the Phanerozoic. The Franklinian margin has been inverted and overridden by younger orogenic episodes (Lane, *ibid.*).

Eagle Plain is located within the Cordilleran Orogenic system of northern Canada characterized by marked crustal instability since the beginning of the Proterozoic (Norris, 1997b). Angular unconformities, diverse structural trends, fold bundles, and extension, contraction and transcurrent faults are common features of the region.

Precambrian basement

East of Eagle Plain and the Mackenzie Corridor region, Precambrian rocks of the Canadian Shield craton are exposed. The Shield in this region of northern Canada consists of intensely deformed metamorphic and intrusive rocks of Archean and Proterozoic age overlain in part by weakly deformed Neoproterozoic (Helikian) sedimentary rocks. Various discrete Archean crustal blocks are separated by Proterozoic orogenic rocks. This tectonic collage of Precambrian rock is divided into a series of discrete basement domains differentiated on the basis of geological, geochronological, geochemical and geophysical criteria (Hoffman, 1987, 1989; Ross et al., 1994). These

Precambrian domains are exposed in outcrop on the Shield and extend westward beneath the Interior Platform, Northern Foreland Belt and Northern Yukon Fold Belt where they constitute the basement beneath the supracrustal wedge of sediments. The crystalline igneous and metamorphic complex was affected by the Hudsonian orogeny at 1735 Ma (Norris and Dyke, 1997). There are no exposures of crystalline rocks at the surface in the Eagle Plain region nor have they been penetrated by exploration wells in the basin.

Proterozoic tectonic evolution

Under the Northern Yukon Fold Complex, a very thick succession of deformed Proterozoic sedimentary rocks underlies the Phanerozoic succession. These Proterozoic strata lie unconformably upon the crystalline Precambrian basement. The rocks are low metamorphic grade, which is remarkable considering the number of thermal and orogenic events affecting them. The pattern of sedimentary facies within these rocks and their great thickness suggest that they comprise a curvilinear northwestern continental margin (Delaney, 1985). The earliest Proterozoic sedimentation in the northern Yukon region is represented by the lower Helikian Werneckian (1.7 to 1.2 Ga) succession. This sequence is comprised of slaty argillites, quartzites, dolomites and intrusive breccias of the Wernecke Supergroup that was subsequently deformed by the Racklan Orogeny (1300-1200 Ma) (Norris, 1997b). These rocks appear to underlie most of the region. They are regionally metamorphosed to greenschist facies and are weakly cleaved. It has been speculated that the Wernecke Supergroup in the Wernecke and Ogilvie mountains represents a large-scale displacement northwestward of a distal facies of the Hornby Bay-Dismal Lakes succession occurring in the Interior Platform province of the Mackenzie Corridor region (Bell, 1982; Aitken and McMechan, 1991; Cook and MacLean, 2004). The mid-Proterozoic Wernecke Supergroup directly underlies the Phanerozoic succession of Eagle Plain Basin (Fig. 2).

Unconformably overlying the Wernecke Supergroup in the Taiga-Nahoni Fold Belt and the Richardson Anticlinorium is the upper Helikian Mackenzie Mountain Supergroup-equivalent Pinguicula and lower Tindir groups (Norris and Dyke, 1997) (note: the location of the Anticlinorium and other fold belts are illustrated in Figure 17, and they are discussed in detail in the Structural Geology section). This shelf carbonate and clastic succession was deformed by the Hayhookian Orogeny (900-800 Ma) (Norris, 1997b). The youngest Proterozoic succession is the Windermere Supergroup-equivalent upper Tindir Group in Nahoni Range and Rapitan Group beneath the Richardson Anticlinorium. The dominantly clastic 780 to 570 Ma upper Tindir and Rapitan groups represent the basal succession of the Upper Proterozoic and Paleozoic Cordilleran miogeocline that developed along the rifted western margin of the North American proto-continent (Gabrielse and Campbell, 1991). An unnamed orogenic event (600-560 Ma) deformed these Hadrynian-aged rocks.

Phanerozoic tectonic history

During Early Paleozoic time, much of northern Yukon was a relatively stable cratonic area characterized by shallow water carbonate deposition. The Yukon Stable Block constituted a continental promontory on the margin of Ancestral North America continent. The Richardson Trough, which persisted from Cambrian to Middle Devonian time, separated the Yukon Stable Block from the North American craton (Cecile, 1982, 1986; Lane 1991). Two major Lower Paleozoic positive tectonic elements on Yukon Stable Block are Ogilvie Arch and Dave Lord High (Morrow, 1999). Ogilvie Arch is a long-lived feature bordering the southern margin of the Yukon Stable Block (Figs. 3, 4). There is some evidence that the Arch influenced Early to Middle Cambrian sedimentation (Figs. 3, 5). There are multiple erosional truncations and depositional onlap of Lower Paleozoic strata onto the Arch (Cecile et al., 1997). Although active faulting along the ancestral Knorr Fault bounding Richardson Trough ended by Middle Cambrian time, the trough remained a deep-water depocentre throughout the Lower Paleozoic (Fig. 5). The Dave Lord High, defined by the absence of Silurian to Early Devonian strata beneath the Mount Dewdney Formation (Fig. 2), occurs under western Eagle Plain (Fig. 4; Morrow, *ibid.*). To the east, the present-day Richardson Anticlinorium roughly follows the Richardson Trough. The Anticlinorium is now a structurally inverted and east-verging thrust sheet (Hall, 1996). Western Peel Plateau occupies the eastern portion of the structurally-inverted Richardson Anticlinorium.

During much of the Devonian, the region was relatively quiescent, with eustatic sea-level changes affecting sedimentation patterns on the Stable Block and surrounding troughs. The development and adjustment of areas of carbonate platform deposition accompanied by basinal sedimentation in the troughs characterizes the Devonian paleogeography (Figs. 6, 7, 8, 9).

During Late Devonian time, south-directed Ellesmerian tectonism affected the Eagle Plain region (Lane, 2010). The deformation front widely preserved in outcrop and in the subsurface across northern Eagle Plain defines the southern limit of a northern highland. The highland limit defines the southern boundary of the Bell Subbasin of northeastern Eagle Plain (Lane, *ibid*.). Broad east-west trending Ellesmerian open folds are preserved in the subsurface of Bell Subbasin (Lane, 2007).

Upper Paleozoic (Late Devonian to Permian) facies belts originally trended northwest-southeast along the western margin of the craton, but were re-oriented east-west to northeast-southwest as the ancestral Aklavik Arch became active (Bamber and Waterhouse, 1971). A series of tectonic pulses produced several clastic wedges (Figs. 10, 11, 12). Shallow water clastic and carbonate successions change southward into basinal shales now exposed in the Ogilvie Mountains (Hamblin, 1990).

The various petroleum prospective areas are large-scale tectonic depressions surrounded by highly deformed Proterozoic through Cretaceous strata. The depressions occur in areas where major structural element trends change direction. Deformation within these depressions is generally less intense than in the surrounding mountainous areas. In Eagle Plain Basin, a major northeast-southwest feature called Eagle Arch, a pre-Mesozoic upwarp of Paleozoic strata, marks the northern limit of erosional edges of various Upper

Paleozoic successions. The Arch was active during Late Carboniferous to Early Permian time resulting in erosion of the Carboniferous succession to the north (Richards et al., 1997). Early Permian Arch movement uplifted northern Eagle Plain resulting in bevelling of underlying Paleozoic strata beneath the sub-Mesozoic unconformity (Lane, 2010). The Arch did not directly influence formation of Laramide-related anticlines in Eagle Plain.

Early stages of the Cordilleran orogenesis produced Jurassic and Cretaceous mountain ranges to the south of Eagle Plain region (Beranek, 2009). These ranges were the source areas for clastic debris that shed northward into the foredeep region through Late Cretaceous time (Figs. 13, 14). About two kilometres of clastic strata were deposited unconformably upon Jurassic to Early Cretaceous rocks.

The northern highland created by the Ellesmerian Orogeny broke away from the North American continent during Jurassic-Cretaceous rifting. The rifting reactivated the old Franklinian continental margin and initiated formation of the Arctic Ocean near the present-day Mackenzie Delta (Dietrich et al., 1989). This same extensional rifting episode extended into northern Yukon and culminated in Albian time with the development and infill of the Kugmallit and Blow fault-bounded troughs (Lane, 2010). These troughs are linked to the Sharp Mountain and Kandik basins along the ancestral Franklinian margin. These basins and troughs are contemporaneous and probably kinematically-linked. Pre-Albian faults related to the rifting episode are locally preserved in northern Eagle Plain (Lane, *ibid*.).

Latest Cretaceous-Tertiary deformation led to the development of the Richardson, Ogilvie, Nahoni and Keele mountains and shaped the present-day Eagle Plain Basin. Broad north-trending folds detached by décollements within the Proterozoic succession were formed in Eagle Plain (Lane, 2010). In western Eagle Plain, more intense deformation produced mainly thrust faults, which thickened the late Paleozoic and Cretaceous successions increasing opportunities for deep burial of potential source rocks with accompanying petroleum generation. In northeastern Eagle Plain, the Keele and Richardson mountain fronts exhibit intense Laramide thrusting and folding of Mesozoic strata forming Tertiary triangle zones marginal to the basin (Lane, 1996).

Late Tertiary and Recent deformation in the region indicate northward migration of the Yukon region by means of strike-slip faults in the northern Richardson Mountains, with displacement rates of 1 to 5 millimetres per year (Lane, 2010).

REGIONAL STRATIGRAPHY

Two cross-sections have been prepared to provide a regional framework for the stratigraphic discussion below. Various Phanerozoic stratigraphic relationships are displayed in these cross-sections. An east-west cross-section is located in southern Eagle Plain in the vicinity of the oil and gas discoveries (Fig. 15). A north-south schematic cross-section was also constructed extending from southern Eagle Plain northward to the south flank of Eagle Arch (Fig. 16; see Fig. 14 for section map locations).

Proterozoic sedimentary succession

Proterozoic sedimentary relationships and strata are relatively simple and were previously discussed in the tectonic evolution section.

Paleozoic-Mesozoic passive margin sedimentation

The Phanerozoic stratigraphy varies dramatically between tectonic depressions. Details of stratigraphy have been previously documented both regionally (Mountjoy, 1967a; 1967b; Bamber and Waterhouse, 1971; Pugh, 1983; Norris, 1984, 1985, 1997; Dixon, 1986; 1992; Morrow, 1999) and by individual basin (Eagle Plain, Martin, 1972, 1973; Graham, 1973; Hamblin, 1990; National Energy Board, 2000; Osadetz et al., 2005a; Bonnet Plume Basin, Norris and Hopkins, 1977; Williams, 1988; Hannigan, 2000; Kandik Basin, Indian and Northern Affairs Canada, 1995; Howell, 1996; Hannigan et al., 1999; Old Crow Basin, Lawrence, 1973; Morrell and Dietrich, 1993; Hannigan, 2001b). Other tectonic depressions accumulating Phanerozoic sediments in the northern Yukon region include British-Barn Basin, Blow Trough, Selwyn Basin and Richardson Trough.

Initial Cambrian sedimentation occurred in British-Barn Basin and Selwyn Basin while the intervening Yukon Stable Block and Richardson Trough region accumulated no deposits. During early Early Cambrian time, it was believed that the Stable Block was emergent and Richardson Trough had not yet formed. In British-Barn Basin, an unnamed succession of Cambrian argillites, quartzites and minor limestones were deposited. *Oldhamia* trace fossils provide fundamental constraints in correlating these unnamed rocks to strata in Selwyn Basin to the south (Lane, 1991). In Misty Embayment in northeastern Selwyn Basin, Vampire Formation was deposited on a continental slope (Fig. 3). The Formation contains abundant siltstone and shale interbedded with fine-grained quartzite (Fritz et al., 1991). Vampire strata are characterized by abundant slump folds. Further basinward in northwestern Selwyn Basin, shale and siltstone comprising the Narchilla Formation was deposited as thin planar laminae suggestive of a low-energy environment (Fig. 3; Fritz et al., *ibid*.).

An upper Lower Cambrian assemblage of sediments was deposited throughout northern Yukon. These strata include an unnamed succession of argillite, volcanics and carbonates in British-Barn Basin, a thick succession of Illtyd limestone and massive dolostone deposited on the shallow-water carbonate bank of Yukon Stable Block (future Eagle Plain) and in Richardson Trough, and thin wavy limestone, thick-bedded dolostone and limy siltstone of Sekwi Formation in Misty Embayment of Selwyn Basin (Figs. 2, 3, 15; Fritz et al., 1991; Morrow, 1999). Carbonate buildups have been observed in upper Illtyd strata in northern Richardson Trough. West of Misty Embayment in Selwyn Basin, in the outer slope and basin environment, siltstone and shale of the Gull Lake Formation represent basinal equivalents of Sekwi strata. Illtyd silty limestones and massive dolomites unconformably overlie Precambrian units beneath Bonnet Plume Basin and

Eagle Plain. On the southwestern margin of Yukon Stable Block beneath Kandik Basin, strata equivalent to Illtyd Formation are found within the Lower Jones Ridge Formation of Early Cambrian to Early Ordovician age (Brabb, 1967). This thick-bedded carbonate succession is underlain by the same unconformity that lies beneath the Illtyd Formation to the east (Fritz, 1991). Sekwi strata in northeastern Selwyn Basin and Illtyd rocks in eastern Richardson Trough are diachronously overlain by black shale and dark platy limestone of the Road River Group. In the Yukon Block, most of the Illtyd Formation was removed by Middle Cambrian and post-Cambrian erosion. Negative movement of Richardson Trough during Illtyd deposition led to its preservation in the trough (Figs. 5, 15).

The development of Richardson Trough in northern Yukon between Yukon Stable Block to the west and Mackenzie-Peel Shelf to the east greatly influenced deposition of Lower Paleozoic sediments of Eagle Plain and Bonnet Plume basins (Morrow, 1999). The north- to northwest-trending Trough (Gabrielse, 1967; Pugh, 1983; Norris, 1985) defined an area of deep-water slope and basin sedimentation between two broad regions of shallow-water shelf carbonate deposition (Morrow, *ibid.*). The Richardson Trough persisted as a negative physiographic feature from Early Cambrian to Devonian time.

On the Yukon Stable Block, Middle Cambrian strata are represented by the Slats Creek Formation (Figs. 2, 3, 15). This formation overlies the Illtyd Formation and extends beyond its western limit (Fig. 5; Morrow, 1999). Block faulting in southeastern Yukon Stable Block played an important role in the development and characterization of marine and alluvial Slats Creek strata with variable lithology and rapid thickness changes (Fritz et al., 1991; Fritz, 1997). Sandstone, siltstone, massive conglomerate beds, and dolostone comprise the Formation. Thicknesses vary from 300 to 1570 m. Green (1972) documented Middle Cambrian volcanic activity in Slats Creek rocks by noting the presence of greenstone sills and interbedded volcanics. Slats Creek deposition beneath Bonnet Plume Basin consists of about 1400 m of sandstones, siltstones and conglomerates. In one locality in Richardson Trough, 715 m of Slats Creek sandstone occurs and is probably the product of block faulting. It is juxtaposed against dark shale and platy limestone of the Road River Group. The Road River Group also overlies the Slats Creek sandstone in this area (Figs. 3, 15; Fritz et al., 1991).

Basinal equivalents of Middle Cambrian strata are represented by the Hess River Formation of the Road River Group in northeastern Selwyn Basin and possible basinal facies sediments in British-Barn Basin. No fossils have been found in British-Barn Basin, so Middle Cambrian strata may not be present. The Hess River succession is comprised of dark shale and platy limestone and locally exceeds 2500 m in thickness (Cecile, 1982).

Upper Cambrian strata on Yukon Stable Block includes locally preserved Taiga Formation carbonate strata (Figs. 2, 3). Taiga strata consist of interbedded limestone, dolostone and clastics giving the unit a colour-banded appearance. Maximum thickness of the unit is 600 m. This ‘striped’ appearance contrasts sharply from the monotonous grey of the overlying Bouvette Formation (Fig. 2).

Subsequent to and contemporaneous with deposition of Upper Cambrian Taiga sediments, the prototypical basinal stratal succession of shales and argillaceous limestones of the Road River Group were deposited in Richardson Trough and along its margins (Figs. 2, 3, 15). Maximum thickness of Upper Cambrian Road River Group strata in the Trough is 2000 m. Road River Group deposition also occurred upon eastern Yukon Stable Block interfingering and overlying the Upper Cambrian to Middle Devonian Bouvette Formation carbonate platform (Figs. 2, 15; Morrow, 1999) (formerly, 'unnamed carbonate sequence', Norford, 1997).

Although Late Cambrian fossils have not been found in British-Barn Basin, correlation by lithology with an Upper Cambrian mafic volcanic and carbonate succession in Alaska suggests a basinal assemblage likely occurs in northern Yukon (Reiser et al., 1980). In Selwyn Basin, a slope and basinal dark grey lime mudstone and silty limestone unit called the Rabbitkettle Formation represents the Upper Cambrian portion of the Road River Group (Cecile, 1982; Fritz et al., 1991). This unit is up to 785 m thick in Misty Creek Embayment.

Widespread marine transgression in the Late Cambrian resulted in uniform carbonate deposition during Early to mid-Ordovician time across the entire Yukon Stable Block and the Lac des Bois Platform. Dolostones of the Bouvette Formation were deposited on the Yukon Stable Block and beneath Eagle Plain (Figs. 2, 4, 15, 16; Morrow, 1999). The dolostones pass eastward to equivalent calcareous shales of the Road River Group in Richardson Trough. Equivalent strata are found further east in Lac des Bois Platform where dolostones of the Upper Cambrian to Lower Ordovician Franklin Mountain Formation rest unconformably on Proterozoic sediments (Peel Plain and Plateau column of Fig. 2). The Bouvette carbonate unit in northern Yukon varies in thickness between 500 and 1500 m. The formation unconformably overlies various Proterozoic units to the west. Bouvette carbonates were also deposited on Ogilvie Platform and in the area of Blackstone Trough before it subsided as a depression during the late Early Ordovician (Fig. 4). The formation ranges in age from Late Cambrian to Early Devonian. Lithologies are dominantly dolostone and limestone with limestone tending to occur proximal to the lateral transitions to Road River basinal shales (Morrow, *ibid*.). Depositional settings vary from supratidal during initial transgression to subtidal to intertidal environments during Upper Bouvette sedimentation (Morrow, *ibid*.). The Dave Lord High west of Miner River is defined primarily by the absence of Middle and Upper Silurian and lower Devonian strata (Figs. 2, 4; Morrow, *ibid*.) In this region, lower Bouvette strata are unconformably overlain by Middle Devonian Ogilvie Formation. Jones Ridge limestones and dolostones occurring beneath Kandik Basin west of Eagle Plain are approximately age-equivalent to Cambrian-Silurian Bouvette Formation.

The presence of Lower Paleozoic carbonate rocks under Old Crow Basin is unlikely since the Silurian to Early Devonian transition from shelf carbonate to deep water shale occurs just south of the basin beneath Dave Lord Range. It is believed that a thick succession of basinal shale and argillaceous limestone occurs beneath Old Crow Basin or alternatively, Babbage Basin (Pugh, 1983; Morrow, 1989; Cecile et al., 1997).

An isolated bank of carbonate sediments developed on a Cambrian to Early Ordovician promontory of the Lac des Bois Platform. This White Mountains Platform (Fig. 4) consists of more than 850 m of thickly bedded limestone of the Ordovician to Early Silurian Vunta Formation overlain conformably by thinly bedded Upper Silurian and Devonian carbonate strata (Morrow, 1989; Fritz et al., 1991; Norford, 1997). A trough filled with basinal facies strata lay between the White Mountains platform and Lac des Bois Platform to the east during Late Ordovician to Silurian time.

Subsequent to Late Cambrian to mid-Ordovician marine transgression, the depositional histories of the Stable Block and Lac des Bois Platform diverged. While Middle Ordovician carbonate deposition continued on the Stable Block, the same interval is represented by an unconformity on the Platform that separates the Franklin Mountain Formation from the overlying Upper Ordovician to mid-Silurian Mount Kindle Formation (Figs. 2, 4; Morrow, 1999).

Ronning Group consisting of Franklin Mountain and Mount Kindle formations encompasses the upper Sauk Sequence (Upper Cambrian to Early Ordovician) and Tippecanoe Sequence (Middle Ordovician to Silurian) of Sloss (1963) in the Peel region (Fig. 2). Norford and Macqueen (1975) described Franklin Mountain Formation as comprising three mappable units: a lower cyclic member of fine-crystalline dolostone alternating with argillaceous dolostone; a middle rhythmic member containing finely crystalline and oolitic dolostone regularly alternating with silty dolostone; and an upper cherty member with abundant chert occurring in finely to coarsely crystalline dolostone. There is a pronounced increase of chert content cratonward in the cherty member. Maximum thickness of Franklin Mountain dolomites is near 1000 m. There are reported 15 to 40 m thick stratiform bodies of medium- to coarse-crystalline, vuggy, light grey to white dolomite in the Franklin Mountain Formation in southern Peel Plateau adjacent to northern Mackenzie Mountains (Pyle and Gal, 2007).

The upper cycle of Ronning Group carbonates is represented by Mount Kindle Formation which unconformably overlies Franklin Mountain Formation throughout most of the Lac des Bois Platform (Figs. 2, 4). The cycle began with widespread Late Ordovician transgression resulting in deposition of Upper Ordovician to Lower Silurian thick-bedded, fossiliferous dark grey dolostone of the Mount Kindle Formation (Cecile and Norford, 1993). The end of the cycle is marked by Early and Late Silurian regression and erosion. In outcrop, Mount Kindle Formation is distinguishable from Franklin Mountain Formation as it is more resistant to erosion; it weathers to a darker grey colour and is less silty and more fossiliferous (Norford and Macqueen, 1975). It was deposited in an unrestricted open-marine environment which then transformed into peritidal conditions as indicated by emplacement of stromatoporoidal dololaminites. In the subsurface, Pugh (1983) described Mount Kindle strata as a lithologically uniform, dark brown to buff, finely crystalline dolomite, partly siliceous and locally rich in chert.

In Selwyn Basin and Richardson Trough, Road River Group basinal facies were deposited contemporaneously with Franklin Mountain and Mount Kindle cyclical sedimentation (Figs. 2, 4; Cecile, 1982; Cecile and Norford, 1993; Fritz, 1985; Morrow,

1999). The oldest formation in the Road River Group is the Rabbitkettle Formation in Richardson Trough and western Selwyn Basin (Late Cambrian to Early Ordovician). It consists of dark grey to black argillaceous lime mudstone rhythmically alternating with silty limestone (Cecile et al., 1982). The formation is equivalent to Franklin Mountain Formation and ranges in thickness between 65 to 2000 m in Richardson Trough. Upper Road River strata in Richardson Trough, Selwyn Basin and Misty Creek Embayment range in age from Middle Ordovician to Middle Devonian (Morrow, *ibid*.) making these rocks equivalent to the Mount Kindle to Hume formation platformal successions to the east. Three informal units were recognized by Cecile et al., (*ibid*.) in Upper Road River strata in Richardson Trough; Loucheux, Dempster and Vittrekwa. Loucheux strata consist of black, graptolitic silicified shale, limestone, black chert and resedimented carbonate breccia. Dempster Formation rocks contain argillite and argillaceous dolostone, calcareous shale, argillaceous lime mudstone, silty dolostone and granule conglomerate. Vittrekwa Formation strata consist of rusty, black siliceous shale, conglomerate and lime mudstone (Cecile et al., *ibid.*). Similarly, rocks equivalent to Upper Road River strata are recognized in Selwyn Basin and Misty Creek Embayment. In Misty Creek Embayment they are, in ascending order, Duo Lake and Cloudy formations with interstratified volcanics called Marmot Formation. These strata range in age from Early Ordovician to Early Silurian (Cecile, 1982). In the eastern part of Selwyn Basin, Upper Road River consists of Duo Lake, Steel and Misfortune formations ranging in age from Early Ordovician to Early-Middle Devonian. In western Selwyn Basin, Sekwi, Rabbitkettle and Upper Road River units are equivalent to, in ascending order, Gull Lake (with extensive volcanics), Elmer Creek, Steel and Misfortune formations (Cecile, 2000). During Silurian time, Richardson Trough and Blackstone Trough expanded so that shaly basinal facies spread over much of the Yukon Stable Block (Porcupine and Ogilvie platforms). These Road River basinal sediments were deposited during Middle Ordovician to Silurian time upon Bouvette carbonates (Lenz, 1972; Cecile and Norford, 1992). Road River sediments were not deposited on the Lac des Bois platform because the platform was subaerial at the time.

During Late Silurian time a widespread regression accompanied by uplift, warping and erosion took place. The regressive episode is marked by the major sub-Delorme unconformity which extends across the Devonian continental shelf (Fig. 2). Morrow (1991) and Moore (1993) proposed a subdivision of the Late Silurian-Devonian formational sequence into groups or assemblages that are genetically-related and illustrate marked and abrupt changes of sedimentation patterns. These assemblages represent third-order transgressive-regressive cycles (Moore, *ibid.*). The oldest assemblage or group is the Late Silurian-Early Devonian Delorme assemblage (Fig. 6) which over much of the region corresponds with the Delorme Group of carbonate platformal rocks (Fig. 2). The assemblage records sedimentation associated with transgression onto the subaerially exposed Mount Kindle Formation. Fritz et al. (1991) and Morrow (1999) extended these defined transgressive-regressive cycles throughout the Cordillera, including northern Yukon.

The sub-Delorme unconformity is not evident in Northern Yukon. Basinal deposits of the Road River Group accumulated across Yukon Stable Block (except Dave Lord High

region) at this time as a condensed basal sequence, except for isolated areas of platform carbonate deposition (eg., Royal Mountain platform in Figs. 2, 6). In Richardson Trough, Road River deposition continued, but these strata exhibit more shallow water and oxygenated character than underlying darker shales (Morrow, 1999).

On Peel Platform, Peel Formation argillaceous and silty carbonate and Tatsieta Formation silty dolostones comprise the Delorme Group (Figs. 2, 6). Average thickness of the Peel Formation in the subsurface is 220 m and overall the formation was deposited in intertidal to supratidal environments. Abundant mudcracks and bright yellow to orange colouration indicates subaerial exposure. There are also imbricate breccia deposits of mud clasts suggesting storm or beach ridge depositional environments. The Peel supratidal deposits grade upward into more open-marine grey carbonates in shallow subtidal and intertidal depositional settings (Morrow, 1999). The Tatsieta Formation averages about 58 m in the subsurface and also records intertidal to supratidal deposition. These rocks also contain mudcracks, breccia beds and bright yellow and orange colouration. Coeval Tsetso and Camsell formations constitute the Delorme assemblage on the Norman Wells High (Fig. 6). The Tsetso unit is composed of argillaceous and silty dolostone with minor sandstone near Twitya Uplift (Morrow, 1991). Camsell Formation consists of silty carbonates and evaporites. Anhydrite-bearing subsurface Camsell facies are closely associated with surface exposures of intensely brecciated Camsell strata (Morrow, *ibid.*).

On Dave Lord High in central Eagle Plain, the Early Devonian pre-middle Emsian Mount Dewdney Formation is partly equivalent to the uppermost Delorme Group (Fig. 2). An unconformity separates Mount Dewdney strata from the underlying Bouvette Formation. Mount Dewdney rocks are characterized by a thin distinctive yellow band of orange to yellow silty dolostone that lies between the Bouvette and Ogilvie formations (Morrow, 1999; Figs. 2, 6, 16). There are sand lenses and occasional fine-grained dolomitic sandstone beds as well as a prominent rusty band of silicified chert conglomerate in the Mount Dewdney Formation. This formation was previously included in the Kutchin Formation of Norris (1985, 1997). Thickness of the unit ranges up to 180 m. The depositional setting for the unit is similar to Delorme strata on the Peel Shelf; a package of intertidal to supratidal sediments with mudcracks, flake lithoclasts and laminoid fenestral fabric.

The next major transgressive-regressive cycle in the northern mainland region is the Early to Middle Devonian Bear Rock assemblage which, on the northern continental shelf, includes carbonate shelf rocks of the Arnica and Landry formations (Figs. 2, 7). Road River Group (Misfortune and Prevost formations) sedimentation continued in deeper basinal waters in Selwyn Basin and Richardson Trough to the west. On Peel Platform, the Arnica Formation attains thicknesses of 250 m and consists in the subsurface of brown to buff, locally calcareous dolomites (Tassonyi, 1969). Landry Formation is about 230 m thick in part and consists of light grey occasionally argillaceous limestone with abundant pelletal texture. There are a few intercalated dolomite beds.

In earliest Emsian time, Road River basinal shale deposition east of Porcupine River on the Yukon Stable Block was succeeded by slope-deposited calcareous shales and argillaceous limestones of the Michelle Formation (Figs. 2, 15, 16). It represents a transitional unit to the overlying shallow-water carbonates of the Ogilvie Formation. Thicknesses vary from 60 to 290 m (Morrow, 1999). Rubble breccia beds indicate submarine debris flows caused by seismic or storm activity on the submarine slope. There is an absence, however, of large-scale scour and fill structures which suggest Michelle Formation strata were deposited in a low-angle depositional slope environment (Morrow, *ibid*.)

The Michelle Formation is overlain by the Emsian to early Givetian Ogilvie Formation of the Porcupine carbonate platform extending across much of the Yukon Stable Block underlying Eagle Plain and eastern Kandik Basin (Figs. 2, 7, 15, 16). The Ogilvie Formation is predominantly a thick-bedded fossiliferous limestone sequence, although lower parts of the formation are primarily dolostone. Thicknesses vary generally between 500 and 1000 m. Morrow (1999) observed that thickness changes at the eastern Ogilvie limit are not uniform but occur as a series of discrete steps towards the shelf-to-basin transition at the western margin of Richardson Trough. The various Ogilvie lithofacies (see Morrow (1999) for detailed description of the nine lithofacies) indicate a restricted to open-marine carbonate shelf depositional setting. Laminated fenestral dolomites imply deposition of the lower dolomite member behind a rimmed shelf margin (Read, 1985; Dubord, 1986). Subsequent depositional episodes reveal stable shelf margin shoals and open-marine ramps. Ogilvie carbonate deposition was terminated by sea-level rise in the late Devonian.

Shallow water limestone deposition continued on isolated platforms such as Royal Mountain and White Mountains during the Bear Rock depositional cycle. Bouvette and Ogilvie-equivalent carbonates occur on these platforms. Basinal deposition of Road River shale and slope limestone strata continued in Blackstone and Richardson troughs (Figs. 2, 7).

Major transgression signalled the beginning of deposition of the Middle Devonian Hume assemblage (Figs. 2, 8). The contact of the Hume Formation with the underlying Bear Rock assemblage is transitional or sharp, and conformable. Hume Formation on Peel Platform has a rather uniform thickness of between 100 and 200 m (Moore, 1993). Characteristically, Hume rocks consist of dark grey argillaceous limestones with minor shale interbeds (Morrow, 1991). The formation is divisible into a lower argillaceous member and an upper thick-bedded member with little argillaceous material. The carbonate succession is succeeded everywhere on the platform by a wedge of shale that locally contains reefs. On Peel Platform, the siliciclastic basin fill consists of a unit of dark bituminous highly radioactive shale called the Bluefish Member of the Hare Indian Formation (Fig. 8). Overlying the Bluefish Member is the upper member of Hare Indian Formation, which is also shale-dominated but less bituminous.

In Richardson and Blackstone troughs, dark and siliceous basinal facies shales of the Road River Group accumulated (Figs. 2, 8). In general in northern Yukon, major tectonic

elements and sedimentation patterns of the Hume assemblage are very similar to the previous Bear Rock depositional episode (Figs. 7, 8). Ogilvie carbonate deposition continued on Porcupine and Royal Mountain platforms. Minor changes include the disappearance of the White Mountains Platform and the expansion of the Peel continental platform into the Misty Embayment.

During late Middle Devonian time, sedimentation patterns changed dramatically as turbiditic, chert-rich clastics derived from the north and west flooded the northern Cordillera (Gordey, 1991). Another change was an abrupt transition from shallow water to much deeper water sedimentation which is marked by deposition of the euxinic black siliceous Upper Devonian Canol shale (Morrow and Geldsetzer, 1991) beneath Eagle Plain and Bonnet Plume basins and McCann Hill Chert beneath Kandik Basin as well as Hare Indian siliciclastics on the Peel Platform (Figs. 2, 9, 15, 16). Thicknesses range from 110 to 225 m. The Canol Formation conformably overlies the Road River Group in Richardson and Blackstone troughs and the Ogilvie Formation on the Yukon Stable Block. With the exception of a few isolated carbonate platform remnants from the Porcupine Platform, this 'Lower Fairholme' stratigraphic succession marks the end of carbonate platform deposition across all Lower Paleozoic shelf areas in northern Yukon (Fig. 9; Morrow and Geldsetzer, *ibid*.; Morrow, 1999). This Canol depositional episode generally coincides with the onset of the Taghanic Onlap which eventually covered all Middle Devonian carbonates with siliciclastics in North America (Johnson et al., 1985). On Peel Platform, Hare Indian Formation represents the fill of a shelf interior basin formed during deposition of advancing carbonate platforms (Moore, 1993). It was deposited as a series of clastic lobes derived from the craton, that prograded across the marine shelf. In Peel Plain, Hare Indian Formation ranges in thickness from 24 to 195 m (Gal et al., 2009). In the subsurface, it has a westward and southwestward dip under the plains and structural elevation on frontal thrusts in Peel Plateau.

The youngest complete Devonian sedimentary sequence is the Imperial assemblage (Figs. 10, 15, 16). Early Upper Devonian Imperial deposition consists of siliciclastics dominated by detrital influx from the Ellesmerian Orogeny to the north and east. An Imperial depocentre occurs along the northern periphery of the basin where 2000 m of siliciclastic sediment accumulated during Late Devonian time (Fig. 10). Turbiditic flysch facies dominate beneath Peel Platform. A submarine fan-slope complex prograding southwestward from the eastern basin margin is interpreted as Imperial Formation in Peel Plain and Plateau (Hadlari et al., 2009a). The formation consists of sandstones and shales. Imperial strata underlie Eagle Plain and western Bonnet Plume basins. Beneath Kandik Basin, interbedded chert conglomerates, arenites, siltstones, mudstones, and shales of the Nation River Formation are equivalent in age to Imperial Formation but their provenance is to the west (Gordey, 1991).

A westward thickening wedge of up to 500 m of siliciclastic strata beneath Peel Plain and Plateau consists of much coarser sandstone, rich in chert pebbles and conglomerates. This unit was defined by Pugh (1983) as Tuttle Formation (Figs. 2, 10, 15, 16). The formation ranges in age from Late Devonian to Early Carboniferous. Deposits of Tuttle Formation were derived from a northern or northwestern orogenic source (Pugh, 1983; Norris,

1985). Pugh (*ibid.*) distinguishes Tuttle Formation from Imperial Formation by the presence of kaolinite and quartz infill in pores, thin orthoquartzite beds, vari-coloured chert conglomerates and finer-grained, better sorted and more quartzose sandstones. Tuttle strata also contain brown-black shale, carbonaceous fragments and local coal seams. The Tuttle Formation is much thicker along the eastern and western flanks of the Richardson Anticlinorium where fault-bounded grabens preserve these sediments on their downthrown sides. Maximum preserved thicknesses range up to 1420 m (Norris, 1997a). Lutchman (1977) interpreted the Tuttle Formation as a southward advancing clastic wedge of fluvio-deltaic origin while Hills and Braman (1978) point out that the formation in part shows marine turbiditic character.

Gordey (1991) separated Devono-Mississippian clastic strata according to provenance. Imperial/Tuttle strata have a northern provenance while Earn Group in Selwyn Basin is interpreted to be derived from the west. The Earn Group records the deposition of a marine transgression sequence interrupted by localized regions of uplift and subsidence. Lithologies include siliceous shale, thin-bedded chert, local sandstones and pebbly mudstones and chert-pebble conglomerate. There are minor beds of limestone in part. Richards et al. (1997) divided Upper Devonian and Carboniferous strata of the northern Cordillera into two closely related assemblages. These assemblages were once continuous but are now separated by the Ancestral Aklavik Arch (Fig. 11). The Arch separates the Prophet Trough where southern assemblage units were deposited, from the Yukon Fold Belt where northern assemblage strata onlapped the Fold Belt. Along the Arch, these strata were truncated beneath the sub-Permian disconformity. Both assemblages, northern and southern, comprise a lower terrigenous clastic succession and an upper carbonate-dominated interval. Upper Devonian clastic strata of the lower interval of the southern assemblage have been previously described (Imperial and Tuttle formations).

In the southern assemblage region, during Late Devonian to Viséan time, a major marine transgression deposited Ford Lake Formation shales, up to 975 m thick beneath Eagle Plain and also Kandik Basin (Figs. 2, 11, 15, 16). The formation consists of black shale, orthoquartzite, thinly bedded siliceous siltstone, local chert-rich sandstone and black bedded chert (Gordey, 1991). The lower part of the formation is at least partly equivalent to upper Tuttle Formation and represents the marine transgressive part of the cycle. Upper Ford Lake strata represent marine regression prior to deposition of the overlying shallow-water carbonate of the Hart River Formation (Figs. 2, 11, 15, 16). Deposition of lower Ford Lake strata occurred mainly in a deep-water basinal environment. Upper parts of the Ford Lake Formation contain coarser sandstone and conglomerate units suggesting gradation to shallow-water pro-delta, delta-front and delta-slope environments (Richards et al., 1997). In the northern assemblage region of British Mountains (Fig. 11), the laterally discontinuous nonmarine Lower Mississippian Kekiktuk conglomerate rests with angular unconformity on deformed argillite and quartzite of the Precambrian Neruokpuk Formation or pre-Mississippian Road River shales. The Kekiktuk unit is generally less than 25 m thick and fines upward overall. Localized fining upward units with erosional bases and large-scale trough cross-beds characterize channel fills. Kekiktuk sedimentology reveals texturally immature, locally derived sediments and conglomerate

channel fills which are interpreted as representing a braided stream and/or fan delta depositional setting (Richards et al., *ibid*.). The overlying Kayak succession of shales and minor sandstones and limestones record a transgressive deepening-upward depositional episode in the British Mountains. Coal-bearing siliciclastics deposited in shoreline and coastal plain settings in the basal Kayak are succeeded by shales and carbonates deposited in shallow neritic and intertidal environments (Richards et al., *ibid*.). Thicknesses vary between 220 to 335 m.

East of northern Yukon in Peel Plain and Plateau region, Upper Paleozoic as well as Lower Mesozoic strata are missing as expressed by a major sub-Cretaceous unconformity (Fig. 2). In the Eagle Plain region, Carboniferous and Lower Permian rocks occur with a major sub-Jurassic unconformity defining missing Upper Permian and Triassic strata.

The thickest most extensively preserved Carboniferous carbonate accumulation in northern Yukon conformably overlies the Kayak Formation in the British Mountains and beneath Old Crow Plain. These shelf carbonates forming the Lisburne Group (Alapah and Wahoo formations) are up to 1325 m thick and were deposited in protected to restricted shelf and shelf margin depositional environments (Fig. 11; Bamber et al., 1992). Beneath Eagle Plain and Kandik basins, southern assemblage shelf, slope and basin carbonate deposits of the Hart River Formation include the Canoe River and Alder limestone members. Beneath southern Eagle Plain, a 310 m thick unit called the Chance sandstone member within the Hart River Formation lies between the two limestone members. There are also discontinuous sandstone and conglomerate units within the Hart River Formation. Hart River strata are up to 691 m thick in southern Eagle Plain. The Hart River Formation along with the underlying transgressive Ford Lake Formation jointly constitutes a prominent transgressive/regressive sequence (Richards et al., 1997).

In Prophet Trough in southernmost Eagle Plain, Hart River units are conformably overlain by Blackie Formation basinal spicular shale sequences succeeded by a shallowing-upward succession of slope carbonates (Figs. 2, 11, 16; Bamber et al., 1992). Blackie strata attain thicknesses of more than 700 m. There are also discontinuous bodies of sandy limestone, sandstone and conglomerate in Blackie strata in the region which may represent channel fill deposits. Final Carboniferous carbonate accumulation in the southern assemblage is represented by thick (330-550 m) upper slope to open-shelf limestones of the Ettrain Formation that prograde westward and southward over slope carbonates and shales of the Blackie Formation (Bamber et al., *ibid.*) beneath Eagle Plain and Kandik basins (Figs. 2, 11, 15, 16).

A regional unconformity marks the base of the Permian separating these strata from older Paleozoic units (Fig. 2). During Late Carboniferous to Early Permian time, an upwarp developed in central Eagle Plain called Eagle Arch (also referred to as Ancestral Aklavik Arch). The Arch is in part a rejuvenation of the Lower Paleozoic Dave Lord High. Uplift led to erosion of the Carboniferous and uppermost Devonian strata over the crest of the Arch such that Upper Devonian Imperial Formation subcrops below Mesozoic strata. To the south of the Arch, Upper Paleozoic Carboniferous potential reservoirs subcrop beneath Mesozoic cover and are isolated from those to the north. Permian strata are

absent north of the Arch.

During Late Carboniferous time, the Prophet Trough was exposed to deep subaerial erosion. However, during Early Permian time, the Ishbel Trough developed in much of the area formerly occupied by the Prophet Trough (Fig. 12). The Ishbel Trough developed in a dominantly extensional back-arc basin (Henderson, 1989; Richards, 1989; Henderson et al., 1993).

The Lower Permian Jungle Creek Formation disconformably overlies older Paleozoic units beneath southern Eagle Plain (Hamblin, 1990) and Kandik basins (Hannigan et al., 1999). Beneath Kandik Basin, a varied assemblage of siliciclastics and carbonates constituting the Jungle Creek Formation is disconformably overlain by Upper Permian siliciclastics, carbonates and cherts of the Takhandit Formation (29-410 m thick) (Bamber et al., 1991; Hannigan et al., *ibid.*) deposited on the south flank of the Ancestral Aklavik Arch. The Takhandit Formation grades westward into limey clastics and conglomerates of the Step Formation. Maximum thickness of Jungle Creek Formation is more than 700 m near the Alaska border. In southern Eagle Plain, the Jungle Creek Formation is preserved below the sub-Cretaceous unconformity (Figs. 15, 16). It consists of fine-grained sandstone, siltstone, shale and minor carbonates. The transgressive Jungle Creek unit exhibits deposition in shoreline to offshore settings (Richards et al., 1997). Beneath Old Crow Basin, a relatively thin (~200 m) poorly known Lower Permian succession called the Sadlerochit Formation was deposited north of the Ancestral Aklavik Arch (Fig. 12; Bamber et al., *ibid*.; Richards et al., 1997). Shales, sandstones and minor carbonates of this formation unconformably overlie the Carboniferous Lisburne Group. Permian facies relationships and depositional environments of Sadlerochit strata in this region are unknown.

Triassic strata in the northern Fold Belt are widely, but sparsely preserved. Triassic rocks are found beneath Kandik Basin. In the basin, Middle to Upper Triassic Shublik limestones and coeval Glenn Formation ‘oil shales’ in Alaska unconformably overlie Takhandit strata. The Shublik Formation includes argillaceous limestone, limy mudstone, black shale, calcareous siltstone, fine-grained sandstone and dark grey chert. The formation is also observed in the British Mountains, Richardson Anticlinorium and as erosional remnants in Peel Plateau. It is highly variable in thickness ranging up to more than 120 m. Two distinct facies are recognized; a nearshore depositional environment to the north and deeper-water and organic-rich facies to the south (Norris, 1997c). Triassic strata do not occur beneath Eagle Plain.

Jurassic rocks are widely distributed in northern Yukon and were deposited in a basin that developed subsequent to latest Triassic uplift and erosion. Jurassic strata consist of a series of superimposed clastic wedges that become thicker and more complete to the west and northwest away from the exposed North American craton from which they were derived (Poulton, 1997). There are two major depositional facies successions in Jurassic strata in the region; a western, northwestern and northern argillaceous outer shelf or basinal succession, and a southeastern dominantly arenaceous inner shelf or basin margin succession (Fig. 13).

The outer shelf succession called Kingak Formation consists of shale and siltstone with local thin basal sandstone, conglomerate and ironstone (Figs. 2, 13; Poulton, 1982). The succession encompasses all Jurassic stages and fluctuates in thickness between 600 and 800 m. A narrow belt of strata across central Yukon, containing Middle and Upper Jurassic shale, siltstone and sandstone called the "Lower Schist" division, is likely a southern extension of the same succession.

The southeastern basinal margin succession is comprised of several coarsening-upward progradational sequences. The interdigitation of the arenaceous and argillaceous units in the area records numerous transgressive and regressive episodes in an overall subsiding inner shelf setting (Poulton, 1997). Abundant local faults and a series of uplifts and depressions active at different times during the Jurassic complicate depositional patterns on the basin margin. The inner shelf facies succession is exposed in northern Richardson Mountains and subcrops beneath western Eagle Plain. Three Lower Jurassic formations comprise the Bug Creek Group across the inner shelf region (Fig. 2). The oldest formation is a 30 to 80 m thick shale and siltstone unit of Middle Early Jurassic age called the Murray Ridge Formation. This unit grades upward into the 300 m thick Almstrom Creek sandstone which then is overlain by Middle Jurassic black shales, siltstones and sandstones of the Manuel Creek Formation (100 m). In localized areas of the inner shelf, two additional formations of the Group are present. Overlying Manuel Creek strata, a clastic sequence of mainly sandstone, shale and siltstone of the Richardson Mountains Formation grades upward to sandstone of the Aklavik Formation.

The Bug Creek Group was unconformably overlain and transgressed eastward, southeastward and northeastward by Upper Jurassic Porcupine River Formation sandstone on the inner shelf (Figs. 2, 13) and Husky Formation shales in the outer shelf region. Porcupine River strata consist of very fine-grained to fine-grained sandstone and siltstone ranging in thickness from 60 to 450 m. These marine and non-marine sediments were deposited in nearshore as well as inner shelf settings. Coeval outer shelf Husky rocks consist of dark to brownish-grey shales and siltstones with minor interbeds of coarser clastics. This formation ranges between 250 and 640 m thick.

In northern Yukon, sedimentation was not influenced by Cordilleran uplift until Late Aptian to Early Albian time. Extensional tectonics related to rifting was dominant prior to the Late Aptian. Therefore, pre-Late Aptian sediments were craton- or rift margin-derived (Stott et al., 1991), not sourced from a compressional orogen. The rifting and associated extension on the craton margin led to opening of the Arctic Ocean with concomitant formation of oceanic crust in Canada Basin north of Yukon in the Beaufort Sea. During this phase of tectonic activity, fault-bounded uplifts and depressions were formed in the northern Yukon region. Some of these positive features include Eskimo Lakes Arch, Cache Creek Uplift and Eagle Arch where Berriasian to mid-Aptian sediments are thin or missing (Dixon, 1997).

Recurrent Neocomian clastic wedges overlie Kingak shales beneath northern Eagle Plain, Kandik, Old Crow and Blow Trough basins. These clastic wedges include mid- to outer

shelf Martin Creek sandstones, McGuire bioturbated shales and siltstones, and marine Kamik sandstones. The units comprise the Parsons Group sedimentary succession (Figs. 2, 14). The primary source region for McGuire and Kamik clastics lay to the south and southeast derived from the craton (Stott et al., 1991). Uplift in Middle Hauterivian time led to the development of a regionally extensive unconformity at the base of the Mount Goodenough Formation. This formation consists of about 530 m of marine siltstones, shales and very fine-grained sandstones. Late Barremian to Aptian Rat River sandstones overlie Mount Goodenough strata in northern Eagle Plain (Figs. 2, 14). Neocomian paleogeography shows a southwesterly to westerly-oriented broad shelf area with a shoreline facies on its eastern margin grading into an outer shelf environment to the north and west.

Mesozoic-Tertiary foreland sedimentation

As a consequence of Aptian to Albian tectonic activity, southerly and westerly source areas developed in the northern Cordillera. Sediments were shed into foreland troughs and basins that developed in front of the rising orogen (Stott et al., 1991; Yorath, 1991).

In Peel Plain and Plateau, initial Mesozoic sedimentation began with Upper Aptian-Lower Albian Cretaceous strata (Fig. 2). The 'sub-Cretaceous unconformity' superimposes these strata onto Paleozoic rocks. The lowermost Cretaceous unit in the Peel region directly overlying the unconformity is the Martin House Formation consisting of interbedded sandstones, siltstones and shales. These coarse clastic units represent a major transgressive event during late Aptian/early Albian time. These beds overlap Rat River strata southward on Peel Plateau to rest directly on Upper Devonian beds (Dixon, 1997).

Much of the Interior Platform area during Early Albian time was covered by mud and silt of the Arctic Red Formation (Figs. 2, 14) with local coarse clastic facies such as a basal Arctic Red sandstone unit near Eskimo Lakes Arch and basal glauconitic sandstone beneath Peel Trough (Stott et al., 1993). These siliciclastic lithofacies provide evidence of the transgression of the Albian Clearwater Sea in the Boreal region.

Although the source of Albian strata in northern Yukon is the compressionally-deformed Cordilleran Orogen, thick accumulations were deposited in extensionally-derived rift grabens and half-grabens, such as Kugmallit Trough, Blow Trough, Keele Trough and Kandik Trough in addition to the intervening foreland. In Blow, Keele and Kandik troughs, gravity-flow deposits of conglomerate and sandstone (eg. Sharp Mountain Formation, Fig. 2 and 500 m of Kathul sandstones, shales and conglomerates) accumulated.

South and southeast of these troughs, Albian foreland shelf sedimentation in northern Yukon basins is comprised of up to 1500 m of Whitestone River shales in Eagle Plain and Arctic Red fine clastics in the Peel area (Figs. 2, 14, 15, 16). Under Eagle Plain, there is a northward increase in thickness of Whitestone strata demonstrative of the facies

change from shelf to deeper water sediments (Fig. 16; Dixon, 1992; 1997).

A major tectonostratigraphic boundary marked by a regional unconformity separates Lower Cretaceous from Upper Cretaceous strata. Based on recent foraminiferal biostratigraphy in Peel Plain and Plateau (Hadlari et al., 2009b), initial Upper Cretaceous sedimentation in the region consists of a Cenomanian-Turonian succession comprised of the Slater River and Trevor formations (Figs. 2, 14). The Cenomanian Slater River shale succession consists of soft black shale with bentonite interbeds. In Peel Plain, the overlying 700 m of thick Trevor sands show western-prograding clinoforms opposite in direction to the underlying Albian basin geometry (Hadlari et al., 2009b). The Trevor strata consist of fine-grained to coarse-grained locally conglomeratic sandstone interbedded with shale (Dixon, 1999).

Late phase Lower Cretaceous and early phase Upper Cretaceous sedimentation produced a broad belt of nonmarine to inner shelf coarse clastics deposited in the shallow foreland basin north of the Cordilleran Orogen (Dixon, 1997). The phase is represented throughout much of Eagle Plain basin by the Eagle Plain Group (Figs. 2, 14, 15, 16). These interbedded sandstones and shales are arranged in transgressive-regressive cycles recording the episodic progradation of coarse clastic wedges from the Cordillera (Dixon, 1992). In Kandik Basin, the northward to northeastward progradation of a coastal fan-delta complex is characterized by marine to non-marine conglomeratic sandstones and grit of the Monster Formation (Ricketts, 1988). In Blow Trough, organic-rich shelf muds of the Cenomanian-Turonian Boundary Creek Formation lie unconformably on Albian shales. During Maastrichtian time, a major shift occurred where the locus of sedimentation moved from the Northern Fold Belt region northward to the margin of Canada Basin. Thick latest Cretaceous to Quaternary sediments accumulated on the outer Mackenzie Delta and outer shelf areas as large delta complexes were formed during this phase of sedimentation. At the basin margins, the Tertiary succession consisting of alternating shale and sandstone intervals include the Fish River Group along the northern Yukon coast (Fig. 14; Dixon, 1997).

The Santonian-Campanian Smoking Hills Formation is found in Anderson Plain (Fig. 14). It is a highly organic-rich shale succession resting disconformably on the Lower Cretaceous Horton River shale succession. Black fissile shale of the Smoking Hills succession contains thin interbeds of bentonite. Organic matter can constitute up to 12% (by weight percent) of the rock (Dixon et al., 1992) suggesting the formation in part may be considered an oil shale. Pyrite oxidation, generating sufficient heat for combustion of organic matter, explains the origin of the formation name. An abrupt and disconformable contact separates Smoking Hills rocks from overlying Campanian to Maastrichtian Mason River strata. A distinctive light grey shale unit dominates the Mason River Formation. There are a few horizons rich in rusty ironstone concretions (Dixon, 1999).

In the continental areas, late phase latest Cretaceous to Tertiary strata were deposited as nonmarine sediments. About 2400 m of Maastrichtian to Eocene terrigenous molasse deposits of the Fish River Group overlain by Reindeer delta plain sediments unconformably overlie Boundary Creek strata in Blow Trough. An unnamed sequence of

Oligocene to Miocene coal-bearing and nonmarine sediments unconformably overlies Cretaceous shales and sandstones beneath Old Crow Basin. In Bonnet Plume Basin, a major unconformity separates Upper Cretaceous to Eocene Bonnet Plume nonmarine sediments from underlying Devonian clastic sediments. Two members of the Bonnet Plume Formation have been recognized: a lower member of Late Cretaceous age containing conglomerate, sandstone and coal, and an uppermost Late Cretaceous-Eocene finer-grained member consisting of sandstone, shale and coal (Mountjoy, 1967a; Norris and Hopkins, 1977; Long, 1978, 1987; Dixon, 1986, 1992, 1997). This non-marine alluvial to fluvial succession was deposited during a Late Cretaceous to Early Tertiary compressional tectonic event when considerable quantities of clastics were deposited in the well-defined foreland basin north of the Cordilleran Orogen (Dixon, 1997).

STRUCTURAL FRAMEWORK

There are several generations of structures in the northern Yukon Fold Belt, some of which are reactivated or modified during subsequent periods of deformation. The observable bedrock structures are Laramide contractional features that represent reactivation or modification of previously-established structural elements (Norris, 1984; Morrow, 1999; Osadetz et al., 2005 (a)). Lane (1998) demonstrated that contractional Laramide structures in the Eagle Fold Belt post-date the deposition of the youngest preserved Campanian strata. Lane (*ibid.*) also ascertained that the Eagle Fold Belt, Taiga-Nahoni Belt and Richardson Anticlinorium are linked Laramide structures influenced by the structural fabric of the underlying basement. Faults in the basement controlled distribution of Paleozoic successions on the Porcupine Platform. Laramide bedrock structures where Cretaceous strata are preserved are very well delineated by bedrock mapping (Norris, 1984; Dixon, 1992). Structures formed by earlier deformation events, however, are difficult to identify and separate from Laramide-related structural configurations. There are also multiple detachment surfaces in Phanerozoic strata beneath Eagle Plain complicating the structural picture even further (Lane, 1996).

The Ogilvie Deflection at the southwestern corner of Eagle Plain marks an abrupt trend change of folds and faults in the Taiga-Nahoni fold belt (Fig. 17). The east-west trending arm is truncated to the east by the Richardson Anticlinorium, while the north-trending arm abuts against the Aklavik Arch Complex in the Dave Lord Range (Fig. 17; Gabrielse, 1991). The Eagle Fold Belt lies within the interior angle of the deflection. The total length of the Taiga-Nahoni Fold Belt is 375 km. En-échelon fold trains are observed in the Fold Belt where right- and left-hand patterns occur dependent on their position in the deflection. In the apex of the deflection, both en-échelon fold linkages occur. The axial surfaces of these fold trains are generally steeply-dipping and they verge either towards or away from the interior angle of the deflection. Contraction faults locally disrupt these fold trends (Gabrielse, *ibid*.).

Folding in the Eagle Fold Belt is mapped on surface by means of Cretaceous stratal relationships (Fig. 17). Flexural-slip cylindrical folds that are linked in a right-hand en-

échelon pattern reflect the structural style. Some of these folds can be traced over distances up to 120 km. The folds are cut locally by short-length north-trending contractional faults (Gabrielse, *ibid.*).

In the Richardson Mountains, Phanerozoic rocks were deposited in Richardson Trough, a north-northwest to south-southeast Paleozoic extensional basin separating Mackenzie-Peel shelf from the Yukon Stable Block (Morrow, 1999). Structural inversion of the Trough during the Laramide Orogeny transformed the Trough into the Richardson Anticlinorium, a gently north-plunging structure (Fig. 17). The anticlinorium and northern Richardson Mountains are cut by a family of north-trending curviplanar, near-vertical faults called the Richardson Fault Array (Gabrielse, 1991; Norris, 1997b). The Array extends for nearly 600 km from Mackenzie Mountains in the south to Aklavik Arch Complex and beneath Tuktoyaktuk Peninsula to the north. The Array controlled the development of Richardson Trough and later, the Richardson Anticlinorium. It is believed that fault movement from mid-Proterozoic to Devonian time was dextral strike-slip (Norris and Yorath, 1981). Reactivation of these faults in Late Cretaceous and early Tertiary time was dominantly dip-slip resulting in inversion of the trough to an anticlinorium.

The Aklavik Arch Complex (Norris, 1974; Norris and Yorath, 1981; Norris, 1997b) is a composite tectonic element extending from Keele Range west of Eagle Plain northeastward to Mackenzie Delta and beyond. Its various sub-elements are bounded by northeasterly-trending vertical faults. Where the Arch Complex intersects the northern extension of the Richardson Anticlinorium, a series of small uplifts occur (Rat, Scho, White, Cache Creek; Fig. 17). There are many unconformities in the Complex, indicative of a prolonged tectonic history from mid-Proterozoic to Tertiary time (Norris, 1974). The Complex trends obliquely to the regional structural grain suggesting it is a highly mobile belt that was deformed by four major orogenies. These deformational episodes include the Racklan during mid- to late-Proterozoic time, the Ellesmerian at the end of the Devonian, the Columbian in early Late Cretaceous, and the Laramide during Late Cretaceous to mid-Tertiary time (Norris, 1997b).

PETROLEUM GEOLOGY-CONVENTIONAL SYSTEMS

Twenty-one conventional petroleum exploration plays have been defined in the Eagle Plains basin region. The plays are listed in Table 1, with their major descriptive characteristics. All plays were defined on the basis of reservoir within which the hydrocarbons occur or may occur. The plays were also defined on the basis of trap-type; structural, stratigraphic or combination of the two. In the following section, regional characteristics are discussed with respect to petroleum system elements, followed by a more detailed description for each of the 21 plays.

Exploration history/Discoveries to date

Most petroleum exploration activity in the Northern Yukon Fold Belt has occurred in Eagle Plain Basin. In the basin area, 34 wells have been drilled, five of which discovered oil and/or gas (Fig. 18). Outside Eagle Plain, one well was drilled in Kandik Basin in Alaska, and three other wells were completed in the outcrop belt east of the basin in Yukon. Also, one well was drilled in Blow Trough and another two on its perimeter. Two wells were drilled west of Trevor Fault in western Peel Plateau in the Northern Foreland Belt. Old Crow and Bonnet Plume basins have no petroleum drilling history. Coal occurs in Bonnet Plume Basin and numerous exploration boreholes have delineated the various coal deposits. Gas content in these coals is substantial, and it is expected that there is significant coal-bed methane potential in Bonnet Plume Basin.

Seismic coverage is quite extensive in Eagle Plain with 9952 line kilometres of reflection data covering most of the prospective region (Fig. 18). There is a concentration of seismic coverage in the vicinity of the three discovered fields. Approximately 200 line kilometres of reflection seismic were acquired for exploration drilling on the eastern flank of the basin. Many seismic lines shot in eastern Peel Plateau were extended westward across Trevor Fault into the structurally-inverted eastern portion of the Richardson Anticlinorium of western Peel Plateau.

In Eagle Plain, petroleum exploratory drilling began in 1957 with spudding of the Eagle Plain No. 1 N–49 well in the north-central part of the basin. This well drilled a surface anticline penetrating Cambro-Ordovician shales and carbonates, and encountered abundant gas shows in Ogilvie carbonates. The second well drilled in 1960 was successful. The Western Minerals Chance No. 1 L-08 (M-08) well discovered oil and/or gas in six separate zones. These zones include a gas pool occurring in a 3.6 m brecciated cherty pebbly sandstone in the Upper Devonian-Lower Carboniferous Tuttle Formation, an oil and gas pool in the lower limestone member (Canoe River) of the Hart River Formation, oil and gas pools in three units of the Chance sandstone member of the Hart River Formation, and a gas pool in the Lower Cretaceous Fishing Branch sandstone of the Eagle Plain Group. Since the initial discovery, 32 additional exploratory and delineation wells were drilled and completed resulting in two additional hydrocarbon field discoveries, Blackie M-59 in 1964 and Birch B-34 in 1965. Blackie discovered gas in the Lower Permian Jungle Creek Formation, a poorly sorted conglomeratic sandstone unit. At Birch, gas pools were found in the Tuttle and Chance sandstone units. Five oil and ten gas pools have been discovered in these three fields (Chance, Blackie and Birch) (Osadetz et al, 2005 (a)). In addition to these fields, there is one oil/condensate recovery and twelve gas flows recorded from drill stem tests (DSTs) in 10 wells (Table 1). In addition to the petroleum-bearing stratigraphic units discussed above, oil and gas shows were observed in the Alder limestone member of the Hart River Formation, Parkin, Porcupine River, Ogilvie and Bouvette formations.

There are two surface oil seepages in Eagle Plain located about 35 kilometres northeast of Chance Field (Norris and Hughes, 1997). Upper Devonian shale saturated with natural aromatic hydrocarbons was mapped by Norris (1974). This seepage is located about 6 km northeast of oil-saturated ridge-forming sandstone in the Upper Cretaceous Eagle Plain Group (Norris and Hughes, 1997).

Hydrocarbon shows are few and widespread in other northern Yukon basins. Oil staining was discovered in local porous zones in outcrop in Takhandit limestones, Jungle Creek calcareous sandstones, Ogilvie carbonates and Jones Ridge limestones in the Alaskan portion of Kandik Basin. Subsurface oil staining and several gas kicks were encountered during drilling of the single well in Alaska. Stelck (1944) discovered two bitumen occurrences to the north of Bonnet Plume Basin in Mississippian Ford Lake shales. Petroliferous Upper Devonian shale was also observed around the mapped anticline on the riverbanks adjacent to these occurrences (Stelck, *ibid.*). Gas-cut mud was returned from a DST in the Caribou N–25 well in western Peel Plateau. No significant shows have been reported in Old Crow Basin and Blow Trough.

Source rocks

There are numerous potential hydrocarbon source rocks in the Eagle Plain project area (Fig. 2). Significant source rocks occur in the following successions.

1. The Lower Paleozoic Road River Group basinal shale succession containing up to 19.29% total organic carbon (TOC), and consisting of Type I or II kerogens represents a prominent source rock in the region. The unit is oil-prone but is thermally overmature with potential to generate natural gas (Fig. 19a; Snowdon, 1988). Link and others (1989) indicated that the overall source rock potential of the Road River Group throughout northern Yukon is poor (average S1+S2/TOC near 0.6, average TOC near 1.7%), although occasional high TOC values occur in the Blackstone and Richardson trough regions. Since the kerogen is overmature, the samples fall along the Type III line on the modified van Krevelen plot (Fig. 19a). However, *Tasmanites* algae is present within the Road River Group, indicative of the occurrence of hydrogen-rich Type I and Type II kerogen;
2. a potential source rock may occur in the Lower Paleozoic Bouvette Formation (Osadetz et al., 2005 (a)). Although no specific oil-prone source has been identified as yet in the formation, there is potential for its occurrence due to the global presence of bituminous oil-prone source facies in Upper Cambrian to Ordovician carbonate platforms (Osadetz and Snowdon, 1995);
3. bituminous mudstone intercalations in Ogilvie carbonates represent another potential source with measurements of TOC up to 4.5% in the organic-rich layers (Fig. 19b). Link et al., (1989) indicated that petroleum source potential is generally poor and the strata are overmature. The modified van Krevelen plot (Fig. 19b) show most samples below the Type III line which could indicate Type III kerogen or overmature Type I or II kerogen. There is evidence of petroleum migration; pyrobitumen observed in the South Tuttle N-05 well may be a result of migrated oil. Link et al., (1989) suggested the source of the pyrobitumen may be hydrocarbons generated from oil-prone kerogen that migrated into the Ogilvie carbonate platform and reefs;
4. black bituminous shales of the Upper Paleozoic Canol Formation; these source rocks have TOCs between 0.3 and 20.1% (average: 3.2%), are mixed Type II and III kerogens (Fig. 19c), and are currently mature to overmature (Link et al., 1989; Link and Bustin,

1989). Canol source material has fair to good gas and some oil potential. The hydrogen index (HI) versus oxygen index (OI) plot (Fig. 19c) indicates a large proportion of Type III kerogen in northern Yukon. This contrasts significantly from the Norman Wells area of central Mackenzie Corridor where Type II kerogen predominates. Low HI values resulting in the Type III classification in northern Yukon probably results from the high degree of organic maturity of the Canol strata;

5. the Imperial Formation generally has moderate quantities of Type III organic matter and could generate some gas (Fig. 20a; Link et al., 1989; Link and Bustin, 1989). TOC values range up to 98% in these rocks. However, the 98% value is clearly anomalous and is known to be a solid bitumen sample. Removing this anomalous value from the sample set results in TOC values in Imperial strata ranging from 0.3 to 5.7 %, averaging near 1.0%. About 30% of the samples exhibit source rock generation potential (Peters, 1986). The modified van Krevelen plot reveals a mixture of Type II and III kerogens (Fig. 20a). Link et al., (1989) interpret this pattern as representing a combination of Type III original organic matter and migrated highly biodegraded Type II kerogen from the Canol Formation (Norris and Cameron, 1986);

6. an important identified source rock in southern Eagle Plain area are black and grey bituminous shales of the Carboniferous Ford Lake Formation containing up to 8% TOC; these strata are thermally mature and contain both oil- and gas-prone kerogens (Fig. 20b; Type II and III; Link et al., 1989; Link and Bustin, 1989). Average TOC is 1.6% from well and outcrop and 66% of the samples have source rock generative potential. This interval is the most likely source of oil accumulations in Chance sandstone at the Chance field;

7. carbonate and siliciclastic strata of the Carboniferous Hart River Formation have fair to good gas and some oil potential as illustrated by a mixture of Type II and III kerogens (Fig. 20c). These rocks are thermally immature in central and southeastern Eagle Plain to overmature in the Ogilvie Mountains. TOC values range up to 5.5% and average near 0.9%. Source rock generative potential is found in 27% of analyzed samples. Snowdon (1988) interpreted that organic matter occurring in Hart River strata represent migrated kerogen from underlying Ford River shales. The presence of depleted production index values within Ford River shales underlying known hydrocarbon accumulations in Chance sandstones suggests petroleum expulsion indicative of an efficient petroleum system;

8. basinal shales and organic-rich carbonates in Carboniferous Blackie Formation represent another known source rock in southern Eagle Plain. They contain Type II and III organic matter up to 5.2% TOC and averaging 1.0% (Fig. 20d), and are marginally to fully mature for oil and gas generation;

9. carbonaceous sandstones of the Jurassic Porcupine River Formation in northern Eagle Plain are marginally mature to mature (Link et al., 1989). These Type III gas-prone kerogens represent a fair gas source;

10. another potential gas source in northern Eagle Plain comes from organic-rich marine shales of the Jurassic to Lower Cretaceous Mount Goodenough Formation;

11. Albian shales of the Whitestone River Formation are immature in most of Eagle Plain and become mature in Richardson Mountains and in northwestern Eagle Plain. The HI versus OI plot shows a mixture of Type II and Type III kerogens (Fig. 21a). This marine low-energy organic-rich shelf deposit constitutes a fair to good gas and minor oil source

(Link et al., 1989). TOC content varies up to 12.2% and averages near 1.4%. About 77% of the samples show source rock generative potential; and

12. Lower and Upper Cretaceous carbonaceous siliciclastic deposits of the Eagle Plain Group have fair to excellent gas source potential. Organic-rich fine-grained units such as the Parkin (Fig. 21b) and Burnthill Creek (Fig. 21c) formations are immature and consist dominantly of vitrinite. There are also varying proportions of liptinite and inertinite in some of the samples. Parkin shales have TOCs up to 9.8% and average near 2.1%. The modified van Krevelen plot shows a mixture of Type II and III kerogens indicative of the varying proportions of hydrogen-rich and –poor kerogens (Fig. 21b). The Burnthill Creek plot, however, shows a greater proportion of Type III kerogen (Fig. 21c). Its TOC distribution ranges from 0.8 to 9.1%, averaging near 2.6%. Anomalously high TOC values could represent drilling-mud additive contamination.

The thermal maturity of Phanerozoic sedimentary strata in the Eagle Plain region reflects in part the paleogeothermal gradient as well as the maximum depth of burial. Based on time-temperature models, Link and Bustin (1989) interpret the increase in maturity of all Phanerozoic strata from central to northern and western Eagle Plain as a function of increased burial depth. Also, it was observed that the increase in thermal maturity of Paleozoic strata from central to eastern and southeastern Eagle Plain reflects higher maturation gradients and interpreted paleogeothermal gradients. Additionally, it was discovered that maturation increases with structural complexity, specifically from Eagle Plain to Richardson and Ogilvie Mountains. Lower Paleozoic strata are overmature in all regions. Upper Paleozoic rocks are immature to marginally mature in central Eagle Plain but are mature to overmature elsewhere. Mesozoic strata are immature to marginally mature in Eagle Plain and Ogilvie Mountains, but are mature to overmature in the Richardson Mountains (Link and Bustin, 1989).

Snowdon (1988) investigated petroleum source rock potential and thermal maturation in Eagle Plain. Thermal history modeling by Snowdon (1988) in Eagle Plain Basin suggests that Devonian source rocks reached peak oil generation during Late Carboniferous to Permian time due to sufficient burial. These same rocks exited the oil window and entered the gas generation window during Carboniferous to Early Tertiary time in most of Eagle Plain, but remain in the oil window in northwestern regions. Carboniferous and Permian source rocks entered the oil window from Late Carboniferous to Early Tertiary time throughout most of Eagle Plain. Upper Cretaceous burial caused most of the Carboniferous source rocks in western Eagle Plain to exit the oil window and enter the gas generation window during the Late Cretaceous. In northwestern, eastern and southeastern Eagle Plain, potential Carboniferous source rocks remain in the oil window. In central Eagle Plain, Carboniferous and Permian source rocks remain thermally immature due to shallow burial and low paleogeothermal gradients. Lower Cretaceous source rocks in northwestern Eagle Plain entered the oil window during Late Cretaceous to Early Tertiary time. Throughout the remainder of Eagle Plain, Cretaceous potential source rocks were insufficiently buried to enter the oil window.

Reservoir rocks

Strata containing hydrocarbon accumulations that are classified as petroleum discoveries are termed proven reservoir rocks and there are a number of such reservoirs within Eagle Plain Basin (Fig. 2). They are:

1. Upper Devonian-Carboniferous brecciated and porous chert sandstones of the Tuttle Formation in Eagle Plain as well as western Peel Plateau;
2. lower limestone member (Canoe River) of the Carboniferous Hart River Formation hosts oil and gas in the Chance Field. It consists of thinly bedded micritic crinoidal limestone with porosities up to 13%;
3. middle Chance sandstone member of the Hart River Formation also hosts oil and gas in the Chance Field as well as gas at Birch in Eagle Plain. Thick units of very fine- to very coarse-grained sandstone are moderately to well-sorted and are generally porous and permeable with porosities from 5 to 22% (average 14%) and permeabilities from 100 to 2000 millidarcies (mD);
4. the Lower Permian Jungle Creek Formation hosts gas in the Blackie Field in Eagle Plain Basin. The unit is a medium- to coarse-grained, poorly sorted conglomeratic sandstone with porosities from 5 to 20% and permeabilities from 100 to 22000 mD (Hamblin, 1990); and,
5. Lower Cretaceous Fishing Branch Formation hosts a gas pool at Chance Field in Eagle Plains. This unit is fine-grained, moderately well-sorted cherty marine sandstone with porosities from 15 to 25% (average 22%).

Potential (as opposed to proven) reservoirs beneath Eagle Plain (Fig. 2) include:

1. biostromal or bioclastic layers, oolitic carbonate sandstones and karsted and vuggy limestones and dolostones in the Lower Paleozoic Bouvette Formation;
2. biostromal to biohermal layers, crinoidal wackestones and packstones, and hydrothermally dolomitized Devonian Ogilvie carbonates;
3. upper Alder limestone member of the Hart River Formation from which minor amounts of gas have been recovered. It is a micritic crinoidal unit with poor to fair porosity;
4. skeletal and cherty porous limestone intervals in the shelf margin facies of the Upper Carboniferous Ettrain Formation;
5. fine- to very fine-grained non-marine and nearshore to inner shelf Jurassic sandstones of the Porcupine River Formation in northern Eagle Plain;
6. marine sedimentary gravity flow deposits of the Lower Cretaceous Sharp Mountain Formation. The succession consists of alternating conglomerate and sandstone intervals;
7. marine mass-transport deposits in the basal Upper Cretaceous (Cenomanian) and mid-Parkin sandstone members of the Eagle Plain Group (Jackson et al., 2011); and,
8. fine-grained marine sandstones (with porosities from 15 to 25%) in the Lower Cretaceous Fishing Branch sandstones of the Eagle Plain Group in southern Eagle Plain. In northern Eagle Plain, Fishing Branch strata include upward-coarsening cycles of shale to fine- and medium-grained prodeltaic sandstones. An unconformity above the cyclical unit marks the transition to a channelled fluvial unit (Jackson et al., 2011).

Traps and Seals

Laramide-related parallel northward-striking anticlines and synclines form the principal surface structures in Eagle Plain (Norris, 1985). These anticlines encompass the entire stratigraphic section, with many interbedded reservoir and seal units providing numerous potential stacked traps. Thrust faults paralleling the surface structures occur in the subsurface. Triangle zone structures and associated petroleum traps occur in the Bell Subbasin of northern Eagle Plain. Also, beneath northern Eagle Plain, pre-Albian faults trap hanging wall strata beneath the sub-Cretaceous unconformity.

Stratigraphic and combined traps are also present in Eagle Plain. Important stratigraphic trap configurations include updip basinward facies changes, subcrops of Upper Paleozoic reservoirs beneath the sub-Cretaceous unconformity and carbonate-to-shale facies changes in Lower Paleozoic strata.

PETROLEUM RESOURCE ASSESSMENT OF EAGLE PLAIN

Introduction

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

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

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

There are a number of methods for estimating the quantity of conventional oil and gas that may exist in a play, basin or region. There are additional methods applicable to unconventional hydrocarbon resources occurring as continuous-type accumulations. The most appropriate method depends on the nature and amount of data available. Each method is unique as regards the type of generated information. Descriptions of available methods and their benefits and weaknesses may be found in White and Gehman (1979), Masters (1984a), Rice (1986) and Logan (2005).

Hydrocarbon basin appraisal methods include extrapolation of discovery rates, areal- and volumetric-yield calculations, geochemical material-balance analyses and prospect and

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

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

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

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

Comparisons with estimates made by the geochemical material balance method were discussed by Coustau et al. (1988). Validations by historical data sets were studied by

Lee and Tzeng (1995). Comparisons with other methods were discussed by Lee et al. (1995). Applications for evaluating plays from various basins can be found in Barclay et al. (1997); Bird et al. (1994a, 1994b); Hamblin and Lee (1997); Lee and Singer (1994); Olsen-Heise et al. (1995); Podruski et al. (1988); Reinson and Lee (1993); Reinson et al. (1993); and Warters et al. (1997). Methods related to PRIMES can be found in Kaufman and Lee (1992); Lee et al. (1988); Lee and Price (1991); and Lee and Lee (1994).

The Eagle Plain Basin of northern Yukon represents a frontier hydrocarbon province. In such an area where limited exploration has taken place, the volumetric probability method is appropriate for the evaluation of conceptual or immature plays. In this procedure, the best available geological judgements, appropriately weighted to objective data from existing exploration results, are used to determine pool sizes and number of prospects. Probability distributions of appropriate reservoir parameters and number of prospects are developed. This method also requires the subjective incorporation of exploration risks at a play or prospect level on the basis of the presence or adequacy of necessary geological factors for the generation and preservation of oil and gas accumulations. The underlying assumption in this method is that lognormal approximations of the distributions of various reservoir parameters can be combined by means of statistical summation to obtain pool or field size distributions.

Resource Assessment Procedure

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

Basin analysis

Basin analysis or synthesis needs to be completed in order to understand the underlying geological framework that may affect petroleum generation and accumulation. The goal of basin analysis is the identification of active or potential petroleum systems. To achieve this, one requires a broad knowledge and understanding of the basin. Stratigraphy provides a basic component with its identification of stratal units, their thicknesses, lithologies and facies distributions, together with stratal sequence surfaces, unconformities and depositional environments as do studies of structural framework and tectonic history. Additional important aspects are the understanding of thermal and burial histories of source rocks and reservoirs, their identification and regional distribution, hydrocarbon generation, migration and preservation, diagenetic overprinting and the exploration history of the basin.

Geological play definition

Definitions of play type and play area are essential objectives of the basin analysis that precedes any numerical resource evaluation. The petroleum play is the fundamental unit of assessment and exploration. Traditionally, the petroleum play is defined on the basis of the reservoir strata in which the oil and/or gas accumulations occur or may occur. Therefore, a play map would reflect the subsurface extent of the potential reservoir or reservoirs. However, reservoir does not have to be the basis for play definition. For instance, a play could be defined on the basis of trap-type or timing of structure formation. All plays in this study were defined on the basis of reservoir within which the petroleum accumulation occurs or may occur. In addition, the play definition takes into account basic trap-types such as structural, stratigraphic and combination traps. Most plays have both an oil and gas component requiring two computational runs. Play area boundaries for oil and gas components may not be coincident, depending on the distribution and maturity characteristics of potential source rocks.

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

Compilation of play data

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

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

Estimating the pool size probability distribution

The pool size distribution relies on expressing each variable as a probability distribution in the pool size equation. The probability distribution describes the range of possible values of the variable for each pool or prospect in the play. Probability distributions of reservoir parameters such as prospect area, reservoir thickness or net pay, porosity, trap fill, water saturation and oil or gas formation volume factors are needed for entry into the standard pool-size volumetric equation. A pool is defined as a petroleum accumulation typically within a single stratigraphic interval that is hydrodynamically separate from another accumulation. A field, on the other hand, is a defined area of petroleum accumulation without stratigraphic or hydrodynamic restrictions. Seismic, geophysical well logs and outcrop data prove useful in identifying limits for sizes of prospect area, reservoir thickness and sometimes porosity and water saturation limits. The incorporation of as much objective data as available is essential for each variable, but subjective opinion and analogue data are entered where objective data is missing. Research in similar hydrocarbon-bearing habitats is also important in order to provide reasonable constraints on reservoir parameters as well as to supply additional information that may prove useful in cases where particular reservoir parameters are unknown. All of these probability distributions are combined to create a pool size distribution for the play.

Estimating number of pools

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

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

The second data set needed to determine the number of pools distribution is the number of prospects distribution. There are three inputs needed for this distribution, a minimum,

median and maximum number. The minimum number of prospects can be derived by counting the number of closures or anomalies on seismic time and structural contour maps. The minimum value represents the number of prospects confidently known to exist. Numerous questions or considerations need to be taken into account in order to complete the rest of the distribution. In most instances, in frontier plays, seismic maps do not cover the entire play area. One must consider, therefore, extending over the entire play area the observed density of anomalies present in the mapped areas. This is not the only consideration, however. Small anomalies may be missed due to the density of the seismic grid. Also, as seismic control is improved, some previously mapped structures may become separated into smaller traps, thus increasing the potential number of prospects while reducing their sizes. Seismic data quality may limit the ability to resolve the type of trap under consideration. Subtle stratigraphic traps are often not recognized during the early history of frontier plays when the first seismic datasets are acquired. Areal apportionment takes into account the ratio of coverage of seismic surveys to the total play area but not the density, orientation or quality of seismic data. The areal apportionment result, therefore, represents the median value and the maximum value is reserved for stratigraphic and smaller prospects that may occur in the play.

Probability distributions of oil and gas pool sizes were combined with estimates of the number of prospects and exploration risk to calculate the sizes of individual undiscovered pools and the play potential. The statistical summation of all pool sizes yields the play potential. Play potentials, pool sizes and number of pools are calculated as probability distributions on which all points are valid. Ranges (P95 to P5) and mean values of play potential are reported. In the text, median volumes are given for largest undiscovered pool sizes of individual plays in order to readily compare with their pool-size-by rank plots. Volumes for oil and gas are reported in cubic metres and as in-place values. Billion or million cubic metre volumes are reported dependent on the display of their respective play potential probability curves. Recoverable or marketable oil or gas volumes are not reported in this study.

Scope of Assessment

Regional petroleum resource assessments have been prepared periodically for various sedimentary basins in Canada by the Geological Survey of Canada. These studies incorporate systematic basin analysis with subsequent statistical resource evaluations (Procter et al., 1984; Podruski et al., 1988; Wade et al., 1989; Sinclair et al., 1992; Reinson et al., 1993; Bird et al., 1994a; Dixon et al., 1994; Barclay et al., 1997; Hamblin and Lee, 1997; Warters et al., 1997; Hannigan et al., 2001, 2011; Lavoie et al., 2009). This assessment summarizes the conventional oil and gas potential of the Eagle Plain Basin in the Northern Yukon Fold Complex of Canada (Fig. 1). Potential Upper Cambrian to Upper Cretaceous reservoirs in sedimentary successions in the basin are examined in this study (Fig. 2).

Purpose

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

Method and Content

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

The analysis of oil and gas potential in Eagle Plain entailed the delineation and systematic evaluation of 21 conceptual or immature conventional petroleum plays. These plays are summarized in this report with respect to play definition, geology, exploration history and estimated resource potential. Nineteen of the plays had sufficient data and information to proceed with a quantitative PRIMES analysis. This study is based on reviews of published and unpublished data and reports, interpretations and mapping from seismic reflection data, evaluation of well history records and logs, modelling of thermal maturation histories and probabilistic analyses of the plays.

Previous Work

In 1973, the Canadian Society of Petroleum Geologists prepared a volume discussing the future petroleum provinces of Canada. This work concerned the petroleum potential and related geology of all sedimentary areas of Canada. A chapter discussing the petroleum geology of Eagle Plain Basin (Martin, 1973) and a synthesis chapter reporting assessment results (McCrossan and Porter, 1973), provided estimates of recoverable petroleum resources of $90.6*10^6$ m^3 (0.57 billion bbl) of oil and $68.0*10^9$ m^3 (2.4 Tcf) of gas. Procter et al. (1984) presented petroleum potential estimates (average expectations) of $85*10^6$ m^3 (0.535 billion bbl) and $155*10^9$ m^3 (5.5 Tcf) of recoverable oil and gas, respectively for all northern basins of Canada, including the intermontane basins in northern Yukon such as Eagle Plain, Old Crow, Kandik and Bonnet Plume basins.

Studies of natural gas potential in the Canadian Potential Gas Committee's reports of 2001 and 2005 across Canada gave limited quantitative information on predicted volumes for the study region. The National Energy Board conducted an oil and gas assessment of

Eagle Plain (National Energy Board, 1994; re-released in 2000). The Geological Survey of Canada also examined oil and gas potential in the Eagle Plain area (Osadetz et al., 2005a) and Peel Plain and Plateau (Osadetz et al., 2005b).

Current Assessment

The petroleum assessment of Eagle Plain was undertaken to provide a comprehensive geological study of petroleum potential of the region by supplying quantitative estimates of total oil and gas potential and predictions of sizes of undiscovered pools. The assessment involved quantitative analysis of 19 of 21 regional-scale exploration plays. Based on considerations of source rock types and hydrocarbon shows, most plays were considered to have both oil and gas resource potential. The three Lower Paleozoic carbonate plays were considered to retain natural gas only. One play (Cretaceous sandstone structural) expected to have oil potential had sufficient applied exploration risk that no oil pools were predicted. Natural gas potential was predicted in this play, however. Two plays in the Ettrain Formation had insufficient information for quantitative analysis, but are described qualitatively. All plays are listed in Table 2 with number of discoveries, discovered volumes, expected (mean) number of pools, mean and range of play potential, and mean and median volumes of the largest undiscovered pool size. The PRIMES program requires separate computations for oil and gas components in each play. Appendix B lists all input data used for quantitative statistical analysis of each play (volumetric probability technique). Probability distributions of required reservoir parameters and number of prospects as well as marginal probabilities for prospect and play level risks are tabulated.

INDIVIDUAL EXPLORATION PLAY APPRAISALS

1. Lower Paleozoic carbonate pre-Laramide structural

Play definition

The Lower Paleozoic carbonate pre-Laramide structural exploration play in the Eagle Plain Basin include all pools and prospects within carbonate reservoirs in Cambrian to Middle Devonian Bouvette, Mount Dewdney and Ogilvie formations that have been trapped structurally prior to Late Cretaceous to Tertiary Laramide deformation (Table 1).

Geographic location

The Lower Paleozoic carbonate pre-Laramide structural conceptual natural gas play encompasses a large portion of central and southern Eagle Plain (Fig. 22) and

surrounding mountainous regions. The play covers an area of approximately 2 million hectares.

Exploration history and shows

Lower Paleozoic carbonate strata that were affected by pre-Laramide deformation were tested by two wells. No significant hydrocarbon shows were reported.

Discoveries

There are no discoveries in the play.

Potential reservoir

Biostromal or bioclastic layers, oolitic carbonate sandstones, crinoidal wackstones and packstones, karsted and vuggy limestones and dolostones, and hydrothermally dolomitized carbonates in Lower Paleozoic Bouvette, Mount Dewdney and Ogilvie formations are the potential reservoir units of this play (Morrow, 1999). In core and cuttings, open fractures and pinpoint vugs were observed, with some intervals producing significant water flow in DSTs. Some intercrystalline porosity is plugged with pyrobitumen. Petrophysical well log analyses indicate porosities up to 16% and permeabilities to 276 mD.

Source rock maturation, generation and migration

Possible source rock for Lower Paleozoic carbonates in this play include organic-rich basinal shale strata of Road River Group, bituminous lime mudstone layers within the Ogilvie carbonate succession, and bituminous shales of the Canol Formation.

Ogilvie lime mudstone intercalations exhibit TOC measurements up to 4.5% and HI values to 539 mg HC/g TOC (Fig. 19). Link et al., (1989) indicated that petroleum source potential is generally poor in these overmature strata.

During Early Paleozoic time, the Porcupine carbonate platform was bounded to the north, east and south by basinal depressions that accumulated thick successions of Road River shale with interbedded basinal limestones (Figs. 4, 6 and 7). This potential oil-prone source rock succession is generally of poor quality although occasional anomalous TOC values have been recorded in Richardson and Blackstone trough areas. TOCs range up to 19.3% (Fig. 19a) and HI values up to 712 mg HC/g TOC (note: this anomalous HI value in the North Porcupine F-72 well is not plotted in Fig. 19a because there is no corresponding OI value). These rocks are thermally overmature, indicating gas remains as the only potential hydrocarbon phase.

Link et al. (1989) observed that Type I and II kerogens occur in Road River Group making the source material oil-prone. They did, however, rank the petroleum source potential of these strata as poor, due to high maturity with only potential gas generation based on conodont alteration indices (Link et al., *ibid.*). Another study (Geochem Laboratories and AGAT Consultants, 1977), however, rated Road River Group as a very good and effective light hydrocarbon generating unit.

Link and Bustin (1989) concluded that these once-excellent oil-prone source rocks of Lower Paleozoic graptolitic shale generated hydrocarbons as early as Carboniferous time and are now overmature. Residual bitumen in these rocks are common, suggesting that oil originally held in the reservoir has either escaped, or has thermally cracked to natural gas.

The highest quality organic-rich source rock in the region is the Upper Middle Devonian Canol Formation. In the Eagle Plain area, these rocks attain TOC values of 20.1% and HI values up to 151 mg HC/g TOC (Fig. 19c). Residual kerogen values of 2.4 to 8.6% indicate that sufficient organic carbon was present to generate hydrocarbons when Canol strata became thermally mature during Devonian to Carboniferous time (Link and Bustin, 1989). Canol strata are reported as overmature in Eagle Plain and Richardson and Ogilvie mountains (Link et al., 1989). Morrow (1999) mapped the level of organic maturity at the top of the Ogilvie Formation directly beneath Canol strata. The map revealed that latest Ogilvie strata are overmature in southern, east-central and west-central Eagle Plain. Mature strata are found in northern Eagle Plain (1.08 and 1.30% Ro) and relatively low thermal maturity strata (<1.5% Ro) occur in extreme southwestern Eagle Plain. Strata in northern Eagle Plain are within the oil window and have oil generation potential. No oil shows, however, have been noted in Lower Paleozoic carbonates in the region, suggesting that Canol shales may not be charging these potential reservoirs.

Traps and seals

If Lower Paleozoic source rocks passed through the oil window before the end of Mesozoic time, then the most effective structural traps for hydrocarbon accumulation were formed prior to the Laramide Orogeny, during the period of active oil migration. The pre-Laramide long-wavelength anticlines (Fig. 23) and contractional fault structures represented in this play are potential available sites for entrapping hydrocarbons generated from these Lower Paleozoic source rocks. Sealing formations for the carbonate reservoirs include the laterally-sealing Road River Group and the top-sealing Canol shale (Fig. 23). Hall and Cook (1998) constructed a geological and geophysical transect across the Eagle Plains Fold Belt and Richardson Anticlinorium that included seismic reflection profiles, regional gravity data and drillhole information. This work interpreted Richardson Anticlinorium as a contractional pop-up structure, implying a regional pre-Cretaceous west-to-east contractional deformation episode that also occurred in adjacent Eagle Plains. Deformation commenced subsequent to deposition of the Mississippian Tuttle Formation and before Early Cretaceous time (Hall and Cook, 1998). Link and

Bustin (1989) interpreted the burial history of the North Cathedral B-62 well in western Eagle Plain, one of the two wells penetrating the play (Fig. 22). Their work indicated that Lower Paleozoic source strata entered the oil window in Late Carboniferous time and Devonian strata exited the window during the Permian.

A petroleum event chart for this Lower Paleozoic petroleum system (Road River/Ogilvie/Canol source and Bouvette/Ogilvie reservoir) shows the time spans and relationships of the various elements and processes for this play (Fig. 24). All essential elements and processes are present and the timing is favourable where source rock deposition was contemporaneous with reservoir, seal was either contemporaneous or followed reservoir deposition and overburden rock followed seal. Also, some trap formation took place before hydrocarbon generation, migration and accumulation. The critical moment for the system was chosen at termination of the period of hydrocarbon generation and accumulation. As mentioned previously, the generated oil was cracked to gas after reburial with accompanying elevated thermal stress. Pyrobitumen in the reservoir constitutes a product of this oil-to-gas conversion. Gas remains as the sole petroleum phase in this play.

Risk factors

The risk factors are numerous and exploration risk is high in this Lower Paleozoic play which likely explains the lack of exploration success to date. Significant risk can be assigned to the distribution of adequate reservoir, quality of some of the potential source rocks, and the creation and retention of closure. Seal, timing and maturation with respect to gas generation and preservation are considered as favourable factors.

Play potential

Estimates of the potential for the Lower Paleozoic carbonate pre-Laramide structural gas play range from 0.2 to $3.5*10^9$ m^3 (P95-P5) with a mean in-place volume of $1.5*10^9$ m^3 distributed among 7 pools (mean value) (Figs. 25a, 25b; Table 2). The largest undiscovered pool is expected to contain $472*10^6$ m^3 (median value) (Fig. 25b).

2. Lower Paleozoic carbonate Laramide structural

Play definition

The Lower Paleozoic carbonate Laramide structural play involves all structural prospects occurring in Cambrian to Middle Devonian carbonate reservoirs that have been affected by Laramide deformation (Table 1). These potential reservoirs are Bouvette, Mount Dewdney and Ogilvie formations (Fig. 2).

Geographic location

The Lower Paleozoic carbonate Laramide structural gas play encompasses an area of near 2.4 million hectares of central and southern Eagle Plain Basin (Fig. 26).

Exploration history and shows

The first exploration drillhole penetrating Lower Paleozoic carbonates was also the first borehole drilled in the basin. Eagle Plains YT #1 N-49 was spudded in 1957 and completed in 1958. The well found abundant gas shows and bleeding gas in highly fractured and brecciated cores in the Ogilvie and Bouvette formations. In the seven additional wells testing the play, two gas flows from DSTs were encountered (S. Tuttle YT N-05 and Shaeffer Creek YT O-22), and minor gas shows in the Blackstone YT D-77 well were reported (Fig. 26).

Discoveries

No commercial gas discoveries have been made in the play.

Potential reservoir

As in the previous play, biostromal or bioclastic layers, oolitic carbonate sandstones, crinoidal wackstones and packstones, karsted and vuggy limestones and dolostones, and hydrothermally dolomitized carbonates in Lower Paleozoic Bouvette and Devonian Mount Dewdney and Ogilvie formations represent reservoir (Morrow, 1999). Significant gas and water flows from DSTs, lost circulation zones, as well as observed fractured and brecciated zones in cores and cuttings suggest porous and permeable reservoir zones in the carbonate strata. Intercrystalline, vuggy and fracture porosity was described in the core and cutting geological descriptions. Porosities and permeabilities measured by core analysis and petrophysical evaluation give maximum values of 24% and 8982 mD, respectively.

Source rock maturation, generation and migration

Source rock characteristics are similar to the previous play in that organic shale of the Road River Group and Canol Formation and organic-rich carbonate mudstone layers in the Ogilvie Formation potentially charge the petroleum system. Pyrolysis and organic petrology experiments indicate that these rocks are overmature for oil but still have potential for natural gas.

Traps and seals

Compressional structures associated with Laramide tectonism such as folds and reverse and thrust fault traps represent potential petroleum accumulation configurations in the play (Fig. 27). Seal is provided by Road River shale laterally and top seal is furnished by Canol strata.

Risk factors

In addition to risk factors identified in the previous play of adequate reservoir, adequate source rock and preservation of closure, a most significant additional prospect-level risk in this play is timing of trap formation with respect to hydrocarbon generation, migration and accumulation. Link and Bustin (1989) identified various time intervals for hydrocarbon generation from Devonian source rocks dependent on diverse burial histories and thermal modeling among the wells penetrating these rocks in the basin. They also interpret that thermal maturation values reflect stratigraphic position rather than present-day structural level throughout the basin, indicating maturation pre-dates the Laramide Orogeny. This means that most of the petroleum in the basin was generated and available for migration prior to the formation of Laramide structural traps; an unfavourable sequence of events for this defined play. Link and Bustin (*ibid.*) interpreted Devonian strata entering the oil window in Late Carboniferous to Permian time during deep burial throughout the basin. However, the time these same strata exit the oil window is variable, significantly affecting oil generation and preservation throughout the region. Devonian strata exited the oil window in eastern and western Eagle Plain in Permian to Late Cretaceous time (S. Tuttle YT N-05 and Blackstone YT D-77 wells in eastern and southeastern Eagle Plain, respectively, and N. Cathedral YT B-62 well in western Eagle Plain). In northwestern Eagle Plain (N. Hope YT N-53 well), however, Devonian strata are still within the oil window at the present time.

A petroleum events chart for the play (Fig. 28) show the critical point for thermogenic oil and gas generation, migration and accumulation occurring during late Triassic time (the midway point for oil and gas generation throughout the basin except for northwestern Eagle Plain), well before the formation of trap structures during the Late Cretaceous to Tertiary Laramide orogenic episode. This sequence of events indicates that timing for oil preservation is generally unfavourable. Scattered bitumen throughout cutting samples of reservoir strata indicate that although oil was once present, it has now escaped. Oil shows are unknown in these rocks. There are natural gas shows present however, indicating that some gas potential remains. The occurrence of pyrobitumen in the samples also reveal the thermally overmature state of these rocks, where some of this oil was secondarily cracked to gas.

Play potential

Potential for the Lower Paleozoic carbonate Laramide structural gas play ranges from $1.4*10^9$ to $13.2*10^9$ m^3 with a mean volume of $6.1*10^9$ m^3 (Table 2; Fig. 29a). The estimate assumes a total pool population of 13, with the largest undiscovered pool having an initial in-place volume of $1490*10^6$ m^3 (Fig. 29b).

3. Lower Paleozoic carbonate stratigraphic

Play definition

A third aspect of entrapment of petroleum in Lower Paleozoic carbonate strata are within stratigraphic configurations. Potential reservoir strata are the same as previous plays (Table 1).

Geographic location

The stratigraphic play covers the same play area as the Laramide structural play in central and southern Eagle Plain (Figs. 26, 30). It encompasses 2.4 million hectares.

Exploration history and shows

As in the previous play, the first exploration drillhole penetrating Lower Paleozoic carbonates was also the first drilled in the basin. Eagle Plains YT #1 N-49 was spudded in 1957 and completed in 1958. The well found abundant gas shows and bleeding gas in highly fractured and brecciated cores in the Ogilvie and Bouvette formations. Among seven additional wells in the play, two encountered gas flows from DSTs (S. Tuttle YT N-05 and Shaeffer Creek YT O-22) and one had minor gas shows (Blackstone YT D-77) (Fig. 30). The National Energy Board (2000) specifically identified two of these wells (Eagle Plains YT #1 N-49 and S. Tuttle YT N-05) as testing stratigraphic traps.

Discoveries

No commercial gas discoveries have been made in the play.

Potential reservoir

Reservoir characteristics in the stratigraphic play emulate the descriptions given for the previous structural plays.

Source rock maturation, generation and migration

Source rock characteristics are similar to the structural plays in that organic shale of the Road River Group and Canol Formation and organic-rich carbonate mudstone layers in the Ogilvie Formation potentially charge the petroleum system. Pyrolysis and organic petrology experiments indicate that these rocks are overmature for oil but still have potential for natural gas.

Traps and seals

Various stratigraphic trapping configurations occur in Lower Paleozoic carbonate strata in the region. Entrapment of petroleum may occur at the carbonate platform margins where porous carbonate bounds against basinal shale filling the troughs and depressions encircling the platform (Pugh, 1983; Fig. 31). An example occurs east of Porcupine Platform where a carbonate-shale transition occurs as Road River basinal strata are encountered in Richardson Anticlinorium. Another stratigraphic trap-type involves widespread stratabound porous zones in the carbonate platform interior; the porous zones are associated with transgressive-regressive cycles (Fig. 31; National Energy Board, 2000; Osadetz et al., 2005a). Morrow (1999) describes fractured and totally dolomitized Ogilvie limestone in the Porcupine YT G-31 well that may preserve very porous and permeable reservoir strata.

Combination-type petroleum traps formed by both stratigraphic and structural elements are included in this play. Lane (2010) discusses an example of a stratigraphic and structural combination trap displayed in seismic data, where Road River strata in the hangingwall of the Deception Fault on the eastern margin of Eagle Plain provide seal to potential carbonate reservoir strata in the footwall of the fault.

Sealing formations include the top seal Canol shale as well as lateral seal Road River Group shales across the carbonate-shale transition.

Risk factors

Significant risk was assigned to adequacy of reservoir, closure and source rock quality in the play. Porosity development and preservation are considered as significant risk factors. The play was assessed for natural gas only. The high levels of thermal maturity associated with deep burial suggest oil was not preserved in the succession.

Play potential

The Lower Paleozoic stratigraphic gas play predicts a mean value of 30 pools having a play potential ranging from $3.1*10^9$ to $44.6*10^9$ m^3 with a mean in-place potential of

$21.4*10^9$ m^3 (Fig. 32a; Table 2). The largest estimated pool size is $3103*10^6$ m^3 (Fig. 32b).

4. Imperial/Tuttle sandstone structural (Ellesmerian deformation-Bell Subbasin)

Play definition

The Ellesmerian deformation front delineating Early Carboniferous compressional structures intersects northeastern Eagle Plain and defines the Bell Subbasin in this region. The deformation front outlines the northern highland that developed in present-day northern Yukon and Mackenzie Delta regions. Broad east-west Ellesmerian fold structures are preserved in Bell Subbasin (Lane, 2007) and constitute the principal petroleum prospects in this play.

Geographic location

The play occupies northeastern Eagle Plain Basin which has been subdivided into a subbasin because of its unique tectonic history. The Bell Subbasin encompasses an area of near 620,000 hectares (Fig. 33).

Exploration history and shows

Although three wells have penetrated potential reservoir in the play area (Whitefish YT I-05, Ridge YT F-48 and Crown Bell River YT N-50), it is believed these boreholes were testing Laramide structures, specifically fault prospects. Therefore, this play has not been tested to date. No petroleum shows have been reported within the Ellesmerian structures.

Discoveries

No discoveries have been made in the play.

Potential reservoir

The Ellesmerian Orogeny is defined as a regional deformational event that affected rocks throughout the Canadian Arctic Islands and northern Greenland. It produced a widespread clastic wedge in northern Yukon, derived from the north, comprised of deep water shale interbedded with turbiditic sandstone of the Imperial Formation, overlain conformably in part, by conglomerate, sandstone and shale of the Tuttle Formation. The

coarse clastic intervals in these strata represent potential reservoir. Intergranular porosities and permeabilities in the Tuttle Formation range up to 23% and 99 mD, respectively. Primary porosities and permeabilities in the Imperial Formation are generally poor in this region, but open fractures have been reported in various drill cutting and core descriptions.

Source rock maturation, generation and migration

Potential source rock strata charging these reservoirs include underlying Canol bituminous shales, older Road River Group basinal strata in adjacent troughs, and organic-rich shaly intervals within the Imperial Formation itself.

Black Canol shales in the Eagle Plain region are categorized as good to excellent source rock averaging near 3.0% TOC and attaining a maximum TOC value of 20.1% (Fig. 19c). Hydrogen Index values are generally low (averaging near 8 mg HC/g TOC) but there are occasional anomalous indices ranging up to 151 mg HC/g TOC (Fig. 19c). Link and Bustin (1989) report residual kerogen values ranging from 2.4 to 8.6% in Canol shales characteristic of sufficient organic carbon for the generation of hydrocarbons during Devonian to Carboniferous time of deepest burial. Canol source rocks are for the most part overmature in Eagle Plain and in the surrounding mountain ranges; vitrinite reflectance varies from 0.8 to 3.96 % Ro. Although no thermal maturity data occurs within the play area, surrounding outcrop and drillhole information reveals overmature Canol strata (Link et al., 1989; Fraser et al., 2012). Although Morrow (1999) depicts strata at the top of the Ogilvie Formation immediately underlying Canol strata as occurring in the oil window in northern Eagle Plain (1.08 and 1.30 %Ro), his map does not incorporate any data within the play area itself located to the northeast. Morrow (*ibid.*) does, however, indicate a 2.60 % Ro vitrinite reflectance value beneath Mackenzie Delta suggesting that thermal maturity increases to the northeast. Cutting descriptions among the three wells in the play occasionally describe oil stains with questionable cut fluorescence, suggesting a possible oil residue.

Road River basinal shale and limestone organic-rich strata provide an alternative gas source for the reservoir in the play. Link et al. (1989) classify these strata as poor quality source although occasional anomalous TOC values have been recorded in Richardson Trough to the east of the play area (Fraser et al., 2012). The rocks are thermally overmature indicating some gas potential. Although oil prone Type I and II kerogens dominate in the original source rock, the oil has not been preserved leaving behind scattered residual bitumen. These rocks generated hydrocarbons starting in Carboniferous time but are now overmature (Link and Bustin, 1989).

Marine Imperial turbidite and deltaic deposits have organic-rich intervals in the basin. TOC is highly variable ranging from 0.3 to 98% (Fig. 20a). The highly anomalous 98% value is derived from a solid bitumen sample. Removing this value from the dataset adjusts the average TOC to 1.0% and the maximum value to 5.7% mg HC/g TOC (Fig. 20a). Black shales were observed in Imperial strata in southern Eagle Plain (Pugh, 1983),

which corresponds to higher TOC values. Although a few samples are rated as excellent source rock (Peters et al., 2005), the majority of samples have only fair source rock generative potential (<1.0%). HI values range up to 703 mg HC/g TOC. Average vitrinite reflectance values are near 1.3% Ro which corresponds to near final closing of the oil window, signifying minor oil generative capacity is possible along with greater gas potential. Samples of very high bitumen content with accompanying elevated TOC, such as the solid bitumen sample, are interpreted to represent mobilized, highly biodegraded hydrocarbon that migrated from the oil-prone kerogen of the Canol Formation into Imperial strata (Norris and Cameron, 1986).

Traps and seals

Subsurface Ellesmerian folds detached on a basal décollement above Lower Paleozoic carbonates represent an untested petroleum play in northeastern Eagle Plain (Figs. 33, 34). The folds are detached in the Imperial Formation as expressed by the lack of deformation in the underlying lower Paleozoic rocks. The folded rocks are also overlain by relatively undeformed Mesozoic strata, thereby bracketing the age of deformation as occurring between Early Paleozoic and Jurassic time (Fig. 34). The compressional regime expressed by the folds also suggests that traps formed by thrust faults are possible in the play.

Sealing formations for this play are fine-grained clastic successions (shale and siltstone) of the Jurassic Bug Creek Group and Lower Cretaceous Mount Goodenough and Whitestone River formations (Fig. 2). Interbedded fine clastic strata in the Imperial Formation provide local seal as well.

Risk factors

Significant risk factors affecting the exploration play are the adequacy of reservoir, closure and source rock at the prospect level. Seal is not a significant risk and timing of gas generation with respect to structure formation is interpreted to be favourable. It is believed that Ellesmerian structure formation and hydrocarbon generation occurred contemporaneously providing opportunity for gas entrapment in structures. A greater risk was assigned to oil entrapment due to narrower time constraints for oil generation. Thermal maturation risk was also assigned a greater value for oil because of source rock character; with most source rocks presently overmature.

Play potential

Analysis of the oil potential of the Imperial/Tuttle sandstone Ellesmerian structural exploration play predicts two pools containing a mean volume of $1.3*10^6$ m^3 (Table 2). The play potential ranges from 0.0 to $4.3*10^6$ m^3 (Fig. 35a). The largest predicted pool size encompasses a mean and median volume of $1.1*10^6$ m^3 and $0.8*10^6$ m^3, respectively

(Table 2; Fig. 35b).

Natural gas potential in the Imperial/Tuttle sandstone Ellesmerian structural play is predicted to reside in five pools (Fig. 35d). The expected play potential varies from $0.3*10^9$ m^3 to $8.0*10^9$ m^3 (Fig. 35c, Table 2). Mean play potential is predicted to be $3.2*10^9$ m^3. Mean volume of the largest undiscovered gas pool is $1438*10^6$ m^3 and the median volume is $1143*10^6$ m^3 (Table 2; Fig. 35d).

5. Imperial/Tuttle sandstone stratigraphic/combination

Play definition

The Imperial/Tuttle sandstone stratigraphic/combination oil and gas play is defined by pools and prospects in porous and permeable Upper Devonian/Lower Carboniferous sandstone bodies in various stratigraphic configurations, including subcrop edges, intraformational pinchouts, updip facies changes, and stratigraphic features with structural overprints (Table 1).

Geographic location

The play encompasses a large portion of Eagle Plain Basin and its environs including parts of Richardson Mountains to the east and the Keele Range to the northwest (Fig. 36). These Upper Paleozoic sandstones, however, do not subcrop beneath western and southwestern Eagle Plain Basin. The play area covers near 2.4 million hectares.

Exploration history and shows

Although the first well drilled in the basin (Eagle Plains YT No. 1 N-49) intersected the play reservoir, one can probably surmise that this was a stratigraphic test hole not necessarily targeting the potential reservoir. This hole found no hydrocarbons in these sandstones. The second well drilled in the basin in 1960 (Chance YT No. 1 L-08 (M-08)), however, discovered a significant gas pool in Imperial/Tuttle formations, in addition to constituting the discovery well for the Chance oil and gas field in overlying Carboniferous strata. Fifteen more exploration wells penetrated Imperial and/or Tuttle strata in the play. Among these wells, one additional gas pool was discovered (Birch YT B-34 discovery well), a significant oil and gas show was found (Ellen YT C-24 well; free oil bleeding and gas bubbling from core samples), and minor gas shows were reported from four other wells (Fig. 36; Table 1). The common presence of oil and gas shows confirms the petroleum potential of these rocks.

Discoveries

The Imperial/Tuttle sandstone stratigraphic/combination play became established in 1960 with the discovery of the Chance L-08 (M-08) gas pool in southern Eagle Plain. In the play, two gas discoveries have been made. They are:

1) Chance YT L-08 (M-08) - gas discovery in Tuttle brecciated, cherty and pebbly sandstone; depth-2188 m; pool area-168 ha; net pay-1.8 m (National Energy Board, 2000); porosity-16%; permeability-1 mD; water saturation-0.1; average gas flow rate $99.1*10^3$ m^3/day; maximum gas flow rate $225*10^3$ m^3/day (Indian and Northern Affairs Canada, 1995); gas volume in-place (GIP)-$128*10^6$ m^3; and,
2) Birch YT B-34 – gas discovery in Tuttle sandstone; depth-1600 m; pool area-229 ha; net pay-6.1 m (National Energy Board, 2000); porosity-5%; permeability-1 mD; water saturation-0.28; gas flow rate from 8.7 to 205.5 m^3/day; gas volume in-place (GIP)- $151*10^6$ m^3.

Potential reservoir

Coarse-grained poorly sorted cherty and pebbly fluvio-deltaic sandstones and conglomerates in Upper Devonian Imperial and Upper Devonian/Lower Carboniferous Tuttle formations constitute potential reservoir units in the play. Fine-grained turbiditic sandstones within the shale-dominant Imperial Formation represent potential reservoir. Reservoir porosities range from 5 to 32%, averaging near 16% and permeabilities are up to 740 mD, averaging near 11 mD.

Source rock maturation, generation and migration

Source rock characteristics are identical to the previous play in that organic-rich shale of the Road River Group and Canol and Imperial formations potentially charge the petroleum system. Another potential source for this play lies in the partly coeval and overlying Carboniferous Ford Lake black and grey bituminous shale.

Although Road River strata generally exhibit poor petroleum source potential as measured by the ratio of pre-existing volatilized hydrocarbons and pyrolyzed hydrocarbons to TOC, occasional measurements of high TOC (Fig. 19a), and the identification of Type I or II kerogens indicate that these strata were excellent oil source rocks when they were originally deposited. The thermally overmature character of these rocks indicate that oil generation and expulsion terminated leaving minor natural gas potential. Scattered bitumen and pyrobitumen specks indicate oil was once present in the reservoir but has now escaped.

Black bituminous shales of the Canol Formation have fair to good gas and some oil potential in Eagle Plain. TOCs vary up to 20.1% and average near 3% and HI values range up to 151 mg HC/g TOC (Fig. 19c). The strata are overmature in southeastern and

western Eagle Plain as well as in Richardson Mountains to the east. Mature strata however, (average Ro values of 1.0 and 0.9 % in the Shaeffer Creek YT O-22 and N. Parkin YT D-61 wells, respectively) are located in eastern Eagle Plain. Residual kerogen values ranging from 2.4 to 8.6% in Eagle Plain and Richardson and Ogilvie mountains indicate that there was sufficient organic matter present at the time of thermal maturity during the Devonian and Carboniferous to generate significant hydrocarbons (Link et al., 1989). The pseudo-van Krevelen diagram (Fig. 19c) indicates a large proportion of Type III kerogen. Other studies of the Canol Formation, particularly in the Norman Wells area (Snowdon et al., 1987) show that the kerogen is primarily oil-prone Type II. Link and Bustin (1989) report that Canol strata are more mature in the Eagle Plain area than Norman Wells. The resulting preponderance of Type III kerogen classification in the HI versus OI plots attests to this high degree of thermal maturation.

Although Imperial Formation generally has insufficient organic carbon to be considered a significant source rock (TOC <1%), there are exceptions in the study area (Fig. 20a) including southern Eagle Plain where in some wells average carbon content exceed the 1% threshold. Vitrinite reflectance values vary widely, indicating thermally mature to overmature Imperial strata. Thermally mature conditions tend to occur in wells in south-central and central Eagle Plain. Kerogen type is generally Type III indicative of gas-prone organic matter. All these geochemical characteristics suggest that Imperial organic-rich strata represent a fair to good gas source.

Ford Lake bituminous shales are considered to be the proven source for oil pools found in Carboniferous and Permian reservoirs in southern Eagle Plain (Graham, 1973). TOC and HI vary widely across the entire study area, from 0.3 to 7.9% and 0 to 573 mg HC/g TOC, respectively (Fig. 20b). Average TOC and HI values are 1.6% and 88 mg HC/g TOC. Thermal maturation varies from mature in south-central Eagle Plain to overmature in southeastern and western Eagle Plain. Type II and III kerogens are present (Fig. 20b). Ford Lake has been categorized as a fair to good gas and oil source (Link et al., 1989).

Traps and seals

Various stratigraphic trap configurations which in many cases have a structural overprint resulting in combination stratigraphic-structural traps are present in this play. Possible trap-types include subcrop edge and intraformational porosity pinchouts, updip facies change and unconformity subcrop (Table 1; Fig. 37). Trapping is enhanced by structure but is not necessary for this play.

Some of the previously discussed potential source rock strata also provide seal to many of these traps. Carboniferous Ford Lake shale provides lateral and top seal while interbedded shaly strata within the Imperial Formation can provide intraformational seal to potential reservoir strata.

Risk factors

Significant prospect-level exploration risk factors associated with this play are adequacy of reservoir, closure, and source rock for the oil and gas plays and an additional risk of timing of charge with respect to its preservation in the oil play. Thermal maturation risk was also assigned a greater value for oil because of source rock character and overmaturity.

Play potential

The oil play has an estimated in-place potential range of 0.0 to $1.8*10^6$ m^3, with a mean volume of $0.7*10^6$ m^3 (Fig. 38a, Table 2). The mean value of the number of predicted pools is 3. The largest undiscovered pool is expected to contain $0.3*10^6$ m^3 (median value) (Fig. 38b).

Potential for the Imperial/Tuttle sandstone stratigraphic/combination gas play ranges from $430*10^6$ to $3453*10^6$ m^3 with a mean volume of $1677*10^6$ m^3 (Fig. 38c). The estimate assumes a total pool population of 7, with the largest undiscovered pool having an in-place median volume of $510*10^6$ m^3 (Fig. 38d). The Birch YT B-34 and Chance L-08 (M-08) gas discoveries with total reserves of $279*10^6$ m^3 match with the fourth and fifth largest predicted pool sizes, respectively (Fig. 38d).

6. Canoe River carbonate structural

Play definition

The Canoe River carbonate structural oil and gas exploration play involves all pools and prospects in the lower limestone member of the Carboniferous Hart River Formation in fold and fault traps formed by Laramide compressional deformation (Table 1).

Geographic location

The Canoe River carbonate structural oil and gas play encompasses an area of near 582 thousand hectares of southern Eagle Plain Basin (Fig. 39).

Exploration history and shows

The Chance L-08 (M-08) well completed in 1960 was the first borehole in the basin that penetrated Canoe River strata. Although this well discovered oil and gas in these strata, the petroleum trap has been interpreted to be a combination stratigraphic/structural

configuration (National Energy Board, 2000), here considered part of the Canoe River carbonate stratigraphic exploration play. Among the 13 other wells intersecting Canoe River strata, minor gas shows were encountered in one well (Whitestone YT N-26; gas bleeding from core and cutting samples), and traces of oil were found in four other wells (oil stains with cut fluorescence) (Fig. 39). The presence of these minor oil and gas shows highlights the petroleum potential in these rocks.

Discoveries

There are no discoveries in this conceptual exploration play.

Potential reservoir

The lower limestone member of the Hart River Formation consists of thinly bedded, micritic and crinoidal limestone with chert, dolomite and shale interbeds. Clean carbonate thicknesses range up to 500 m. Core and petrophysical analyses reveal porosities averaging near 10% and permeabilities near 3 mD. Porosities attain maximum values of 33% and permeabilities range up to 57,500 mD in highly fractured intervals. Drill core and cutting geological reports of Canoe River strata indicate numerous potential reservoir intervals by describing intercrystalline, intergranular, pinpoint vug, fossil and fracture porosity. Many of the DSTs in the interval have significant water flows indicative of permeable rocks.

Source rock maturation, generation and migration

The principal source rock charging Carboniferous reservoirs in southern Eagle Plain is the Lower Carboniferous Ford Lake Formation. The formation contains organic-rich black and grey bituminous shales characterized by a mixture of oil-prone Type II and gas-prone Type III kerogens (Fig. 20b). Ford Lake strata are generally mature for oil and likely represent the source for live fluorescent oil stains in drill cuttings from wells in south-central Eagle Plain (Fig. 39). The source rock is overmature in western and southeastern Eagle Plain. Average TOC and HI values are 1.6% and 88 mg HC/g TOC and the rock is considered to have fair to good gas and some oil potential (Link et al., 1989).

Traps and seals

Local seals for Canoe River traps include overlying well-cemented sandstones in the Chance member and intraformational tight lime wackestones. Parallel northward-striking anticlines and synclines are the principal Laramide-aged surface structures. These fold bundles are deflected eastward in southeastern Eagle Plain (Fig. 39). In the subsurface,

various Upper Paleozoic strata including Canoe River limestones have been deformed into stacked folds (trap labelled 6 in Fig. 40) and faulted anticlines.

Risk factors

Significant risk in the play is associated with adequate reservoir, closure and relative timing of structure formation with petroleum generation. Source rock quality and maturity is considered to be favourable and adequate in this petroleum system. The petroleum system events chart (Fig. 41) illustrates the timing issue where peak thermal oil and gas generation and expulsion at the critical moment precedes the deformational episode that formed the structural traps. Consequently, significant risk was assigned to timing in the oil play and was reduced in the gas play to take into account the subsequent episode of minor gas generation. Despite unfavourable timing, the presence of minor oil and gas shows indicate the play has petroleum potential, albeit low.

Play potential

Estimates of the potential for the Canoe River carbonate structural oil play range from $0.2*10^6$ m^3 to $3.6*10^6$ m^3 with a mean in-place volume of $1.5*10^6$ m^3 distributed among 4 pools (mean value) (Figs. 42a, 42b; Table 2). The largest undiscovered oil pool is predicted to contain $0.6*10^6$ m^3 (median value) (Fig. 42b).

The Canoe River gas play predicts a mean value of 6 pools having a play potential ranging from $222*10^6$ to $2591*10^6$ m^3 with a mean in-place potential of $1170*10^6$ m^3 (Fig. 42c; Table 2). The largest estimated pool size is $386*10^6$ m^3 (Fig. 42d).

7. Canoe River carbonate stratigraphic

Play definition

The Canoe River carbonate stratigraphic play is defined by updip facies changes, unconformity subcrop stratigraphic traps and combined structural/stratigraphic traps in the lower limestone member of the Carboniferous Hart River Formation (Fig. 2; Table 1).

Geographic location

The play encompasses the same area (about 582 thousand hectares) as defined by the structural play (Fig. 43).

Exploration history and shows

The first exploration hole penetrating Canoe River strata in Eagle Plain Basin found significant oil and gas (Chance YT L-08 (M-08), completed in 1960). Among the 13 subsequent wells intersecting the reservoir, a single-well gas pool was found in the Chance field (Chance YT J-19), minor gas shows were encountered in Whitestone YT N-26 well in the form of gas bleeding from core and cutting samples, and traces of oil were found in four other wells (oil stains with cut fluorescence) (Fig. 43).

Discoveries

Two oil and/or gas accumulations have been described in the Canoe River stratigraphic exploration play (National Energy Board, 2000). These accumulations are classified as a gas discovery and an oil and gas show in the Chance oil and gas field. They are:

1) Chance YT L-08 (M-08) – oil and gas show hosted in Canoe River thinly bedded micritic and crinoidal limestone; depth-1562 m; area-168 ha; net pay-1.0 m gas; 0.7 m oil (National Energy Board, 2000); porosity-3%; water saturation-0.4; average gas flow rate $14*10^3$ m^3/day; maximum gas flow rate $280*10^3$ m^3/day; recovery of 290 m of oil in DST (Indian and Northern Affairs Canada, 1995); gas volume in-place (GIP)-$7.5*10^6$ m^3; oil volume in-place (OIP)-$0.02*10^6$ m^3; and,
2) Chance YT J-19 – gas discovery hosted in Canoe River thinly bedded limestone, chert and sandstones; depth-1386 m; pool area-229 ha; net pay-2.5 m (National Energy Board, 2000); porosity-13%; maximum permeability-142 mD; water saturation-0.3; average gas flow rate $54*10^3$ m^3/day; maximum gas flow $62*10^3$ m^3/day; gas volume in-place (GIP)-$83*10^6$ m^3.

Potential reservoir

The lower limestone member of the Hart River Formation (Canoe River) is characterized by thinly bedded crinoidal limestone with dolomite, chert and dark shale interbeds. There are also thin interbeds of laminated very fine to coarse-grained sandstone and siltstone (Hamblin, 1990). The unit is described as a clean carbonate attaining a maximum thickness of 500 m (Hamblin, *ibid.*). Fair to poor intercrystalline and intergranular porosity is common in the reservoir. Anomalous porosity and permeability measurements (eg. 33% porosity and 57500 mD) represent fractured intervals. Good flows of gas and salt water from DSTs indicate porous and permeable zones.

Source rock maturation, generation and migration

As in the structural play, the Upper Paleozoic Ford Lake shale succession represents the dominant source rock charging this reservoir. This organic-rich bituminous unit consists of a mixture of Type II and III kerogens (Fig. 20b) that is currently mature for oil in

south-central Eagle Plain. Average TOC and HI values are 1.6% and 88 mg HC/g TOC, respectively and their respective maximums are 7.9% and 573 mg HC/g TOC (Fig. 20b). The rock is considered to have fair to good gas and some oil potential (Link et al., 1989).

Traps and seals

In this exploration play, the Canoe River reservoir petroleum traps include stratigraphic basinward facies change and updip facies change configurations (7 in Fig. 40). Combined stratigraphic/structural configurations beneath the sub-Cretaceous unconformity are also potential petroleum traps. These traps are sealed laterally by Ford Lake shales and top-sealed by Whitestone River shales (Table 1; Fig. 40).

Risk factors

Major exploration risk factors for oil and gas are adequate reservoir and closure, and for oil, maturation. Source rock quality is considered to be favourable and adequate in this petroleum system. Stratigraphic traps usually have the distinction of being formed at the time of deposition, thus, predating the hydrocarbon generation process. In south-central Eagle Plain, however, the Carboniferous succession and its stratigraphic traps have never entered the oil window due to a combination of insufficient burial and low maturation gradients (Link and Bustin, 1989), thus providing, in some instances, an inadequate thermal maturity exploration risk factor at the prospect-level. The fact that significant live oil shows were found in Canoe River reservoirs in some wells indicates that adequate maturation cannot be classified as a play-level exploration risk factor.

Play potential

Mean potential of in-place oil in the Canoe River carbonate stratigraphic play is $0.5*10^6$ m^3 (Table 2). Oil potential estimates range between $0.1*10^6$ m^3 to $0.9*10^6$ m^3 (Fig. 44a) distributed among 7 predicted pools (Fig. 44b). The largest pool is expected to have a mean in-place volume of $0.2*10^6$ m^3 and a median volume of $0.1*10^6$ m^3 (Fig. 44b; Table 2). Although the oil accumulation in the Chance YT M-08 well ($0.02*10^6$ m^3) matches near the lower limit of the smallest predicted pool, an argument could be made that the Chance L-08 oil and gas accumulations may be more correctly classified as significant oil and gas shows (National Energy Board, 2000) rather than as discoveries, principally because of their very small volumes.

The potential for gas ranges from $292*10^6$ m^3 to $1283*10^6$ m^3 (Fig. 44c; Table 2). The in-place mean gas potential is $730*10^6$ m^3. Among 13 predicted pools, the largest size is estimated to be $152*10^6$ m^3 (Fig. 44d; Table 2). The Chance YT J-19 gas pool with a calculated volume of $83*10^6$ m^3 matches most closely with the third largest predicted pool (Fig. 44d). The much smaller gas accumulation in the Chance YT M-08 ($7.5*10^6$ m^3) should be classified as a significant gas show, rather than a pool.

8. Chance sandstone structural

Play definition

The Chance sandstone structural play involves all prospects in structures occurring in Carboniferous sandstone reservoirs within the Hart River Formation that have been affected by Laramide deformation (Table 1). The Chance sandstone member is bounded by the upper and lower carbonate members of the Hart River Formation (Fig. 2). Combination structural/stratigraphic traps where stratigraphic features have been overprinted by structural deformation are included in the Chance sandstone stratigraphic play.

Geographic location

The subcrop area of Chance sandstone is located in southeastern Eagle Plain Basin, occupying 250,000 hectares (Fig. 45).

Exploration history and shows

Although the first well that intersected the Chance sandstone member was likely targeting the Laramide Chance anticlinal culmination (Chance YT L-08 (M-08) completed in 1960), oil and gas was discovered in a combination structural/stratigraphic trap rather than in a trap formed exclusively by deformation (Veezay Geodata Ltd., 1983; National Energy Board, 2000). This discovery established the Chance oil and gas field and the delineation wells testing the extent of the field (Chance YT G-08 and Chance YT J-19) are interpreted to also test stratigraphic/ combination traps (National Energy Board, 2000). The various pools in the Chance sandstone field are, therefore, discussed and included in the Chance stratigraphic play. A total of 10 exploratory wells tested Chance sandstones that have been deformed by orogenic processes. Among these wells, a single-well gas pool was discovered (Birch YT B-34), a gas flow was encountered in a DST (E. Porcupine YT I-13), and minor oil and gas shows were reported in 6 other wells (Fig. 45; Table 1). Both oil and gas are expected to occur in this exploration play.

Discoveries

A gas discovery has been made within a structural trap in Chance sandstones. Its characteristics are:

1) Birch YT B-34- gas pool hosted in fine- to medium-grained, moderately well-sorted Chance Member sandstone; depth-1372.5 m; pool area-177 ha (National Energy Board, 2000); closure area-2400 ha (Veezay Geodata Ltd., 1983); net pay-3.9 m (National Energy Board, *ibid.*); net pay-7.6 m (Veezay Geodata Ltd., *ibid.*); average porosity-18%; average permeability-30 mD; maximum permeability-146 mD; water saturation-0.25; maximum gas flow rate-$14.9*10^3$ m^3/day; gas volume in-place (GIP)-$249*10^6$ m^3.

Potential reservoir

The Chance sandstone member of the Hart River Formation is characterized by thick units of grey to buff, salt-and-pepper, very fine- to coarse-grained sandstones that are fair- to well-sorted, bedded or massive, and contain some floating pebbles (Martin, 1972; Hamblin, 1990). Oil stains and calcite cement are common. In most cases, the sandstone is porous and permeable with porosities ranging from 8 to 28% and permeabilities from 2 to 2675 mD (core and petrophysical analysis). In porous zones, calcite cementation has been replaced by pressure contact and silica sutures. No clays have been noted in these sands. Fair to excellent intergranular porosity is commonly described in cutting and core descriptions. Occasional fracture porosity has been noted. Significant water and occasional gas flows also signify permeable zones in the Chance interval.

Source rock maturation, generation and migration

As in other Hart River plays, the Ford Lake shale formation appears to represent the most significant source rock for oil and gas generation and for charging the reservoir. The source rock is mature to marginally mature in southern Eagle Plain and contains a mixture of Type II and III organic matter (Fig. 20b). In extreme southeastern Eagle Plain in the Blackstone YT D-77 well, Ford Lake shales are overmature. Total organic carbon values range up to 7.9% and hydrogen index values to 573 mg HC/g TOC (Fig. 20b). Link et al. (1989) identified this source rock as having fair to good gas and some oil potential.

Peak generation and migration of thermogenic oil and gas from Ford Lake shale or critical moment is interpreted to occur during the Triassic, the midway point of the petroleum generation/migration event (Fig. 41).

Traps and seals

Anticlinal folds (8 in Fig. 40), faulted anticlines and thrust fault culminations are compressive structures that may contain oil and gas accumulations in this structural play. The traps are sealed by non-porous layers of limestone, shale and siltstone in the overlying Alder Member of the Hart River Formation.

Risk factors

Along with adequate reservoir and to a lesser extent adequate closure, a most significant exploration risk factor is timing. Peak generation and migration of oil and gas occurred prior to structural trap formation in this petroleum system (Fig. 41). Another significant risk is inadequate maturation where in certain regions of the play Ford Lake source material was insufficiently buried and the maturation gradient too low for oil and gas generation (Link and Bustin, 1989). Despite the described significant exploration risk, the occurrences of a gas pool and significant gas flows as well as minor oil shows in the form of oil stains with cut fluorescence and bleeding oil from core samples confirms the existence of this oil and gas play.

Play potential

The oil play has an estimated in-place potential range of $0.4*10^6$ m^3 to $5.3*10^6$ m^3, with a mean volume of $2.4*10^6$ m^3 (Fig. 46a, Table 2). The mean value of the number of predicted pools is 4. The largest undiscovered pool is expected to contain $0.9*10^6$ m^3 (median value) (Fig. 46b).

Potential for the Chance sandstone structural gas play ranges from $0.9*10^9$ m^3 to $5.7*10^9$ m^3 with a mean volume of $2.9*10^9$ m^3 (Fig. 46c). The estimate assumes a total pool population of 7, with the largest undiscovered pool having an initial in-place volume of $821*10^6$ m^3 (Fig. 46d). The Birch YT B-34 gas discovery with a reserve volume of $249*10^6$ m^3 matches with the fifth largest predicted pool size (Fig. 46d).

9. Chance sandstone stratigraphic

Play definition

The Chance sandstone stratigraphic oil and gas exploration play involves all pools and prospects in the middle sandstone member of the Carboniferous Hart River Formation that have been trapped by various stratigraphic and structural/stratigraphic trap configurations (Fig. 2; Table 1).

Geographic location

The stratigraphic play area covers the same territory as outlined by the structural play where the potential Chance reservoir subcrops in southeastern Eagle Plain (Figs. 45, 47). The play area is 250,000 hectares.

Exploration history and shows

The Chance YT L-08 (M-08) well represents the first borehole penetrating the Chance sandstone reservoir. This well, completed in 1960, discovered the Chance oil and gas field in a combination structural/stratigraphic trap. The play was subsequently tested by 12 exploratory and 2 delineation wells. The delineation wells (Chance YT G-08 and Chance YT J-19) tested the extent of the Chance oil and gas field. Among these 12 exploratory boreholes intersecting the reservoir, two wells reported gas flows from DSTs, one well had an oil recovery in a DST, one well reported a gas flare from a DST, another well encountered gas kicks during drilling, two wells encountered bleeding oil from core samples, and 2 other wells were reported as containing oil stains with fluorescent cuts. Oil and gas are expected in the play.

Discoveries

Two oil and gas, two oil and one gas accumulations have been described as discoveries that are trapped by dominantly stratigraphic configurations. They are:

1) Chance YT L-08 (M-08); Chance Sand #1; oil and gas pool hosted in fine- to medium-grained, moderately well-sorted Chance Member sandstone; Oil pool; depth-1333.9 m; pool area-916 ha; net pay-5.0 m; average porosity-8% (National Energy Board, 2000); average permeability-4 mD; water saturation-0.4; DST recovery-610 m oil; oil volume in-place (OIP)-$1.8*10^6$ m^3; Gas pool; depth-1306.5 m; pool area-416 ha; net pay-15.0 m; average porosity-14% (National Energy Board, *ibid.*); average permeability-7 mD; water saturation-0.35; maximum gas flow rate-$283.2*10^3$ m^3/day; gas volume in-place (GIP)-$1330*10^6$ m^3;
2) Chance YT L-08 (M-08); Chance Sand #2; oil and gas pool hosted in fine- to medium-grained, moderately well-sorted Chance Member sandstone; Oil pool; depth-?; pool area-87 ha; net pay-1.4 m; average porosity-5% water saturation-0.4 (National Energy Board, *ibid.*); oil volume in-place (OIP)-$0.03*10^6$ m^3; Gas pool; depth-1427 m; pool area-206 ha; net pay-10.0 m; average porosity-14% (National Energy Board, *ibid.*); water saturation-0.35; maximum gas flow rate-$14.2*10^3$ m^3/day; gas volume in-place (GIP)-$438*10^6$ m^3;
3) Chance YT L-08 (M-08); Chance Sand #3; gas pool hosted in fine- to medium-grained, moderately well-sorted Chance Member sandstone; depth-1477 m; pool area-369 ha; net pay-10.0 m; average porosity-10%; water saturation-0.35 (National Energy Board, *ibid.*); maximum gas flow rate-$14.2*10^3$ m^3/day; gas volume in-place (GIP)-$562*10^6$ m^3;
4) Chance YT J-19; Chance Sand #3; oil pool hosted in fine- to medium-grained, moderately well-sorted Chance Member sandstone; depth-1363.6 m; pool area-97 ha; net pay-6.7 m; average porosity-8%; average permeability-3 mD; water saturation-0.4 (National Energy Board, *ibid.*); DST recovery-500 m gassy oil; oil volume in-place (OIP)-$0.25*10^6$ m^3; and,

5) Chance YT G-08; Chance Sand #1A; oil pool hosted in fine- to medium-grained, moderately well-sorted Chance Member sandstone; depth-1337.8 m; pool area-802 ha; net pay- 5.0 m; average porosity-6%; average permeability-2 mD; water saturation-0.4 (National Energy Board, *ibid.*); DST recovery-360 m oil; oil volume in-place (OIP)-$1.2*10^6$ m^3.

It is also noteworthy that significant gas flows and a gas blowout were also observed in the Chance YT J-19 well suggesting substantial gas potential.

Potential reservoir

Thick units of very fine- to very coarse-grained sandstone constitute the middle clastic member of the Carboniferous Hart River Formation. These sands are moderately to well-sorted and are porous and permeable in part with porosities ranging between 5 and 22% (average 14%) and permeabilities from 1 to 2000 millidarcies. Fair to excellent intergranular porosity and occasional fracture porosity are described in cutting and core descriptions. Numerous water and gas flows from DSTs indicate porous and permeable intervals in the potential reservoir.

Source rock maturation, generation and migration

As in the structural play, the Upper Paleozoic Ford Lake shale succession represents the dominant potential source rock charging this reservoir. This organic-rich bituminous unit consists of a mixture of Type II and III kerogens (Fig. 20b) which is currently mature for oil in south-central Eagle Plain. Average TOC and HI values are 1.6% and 88 mg HC/g TOC, respectively and their maximums are 7.9% and 573 mg HC/g TOC, respectively (Fig. 20b). The rock is considered to have fair to good gas and some oil potential (Link et al., 1989). A hydrocarbon-depleted zone in the upper part of the Ford Lake Formation in the Chance #1 YT L-08 (M-08) well suggests expulsion of generated hydrocarbons indicating a possible source interval for oil accumulations in the Chance petroleum field (Link and Bustin, 1989; Link et al., 1989).

Traps and seals

There are two petroleum trap configurations identified as occurring in this play. An important trap-type is the unconformity subcrop structural/stratigraphic trap in the Chance area of southern Eagle Plain (9 in Fig. 40). This trap configuration which hosts the Chance oil and gas field is sealed by the overlying Albian Whitestone River Formation shale succession. This efficient top seal effectively prevents Whitestone River organic-rich source material from charging the juxtaposed Chance reservoir. The second trap configuration is a purely stratigraphic accumulation where porosity pinchouts are formed as a result of basinward facies changes. The facies change occurs where porous Chance sandstone pinch out against less porous carbonate members of the Hart River

Formation (Fig. 40). The source rocks in this region of facies change at the southern limit of Eagle Plain Basin near the Ogilvie Mountains are overmature, suggesting minor gas potential.

Risk factors

Major exploration risk factors for oil and gas are adequate reservoir and closure, and for oil, thermal maturation. Source rock quality and timing is considered to be favourable and adequate in this petroleum system. Stratigraphic traps usually have the distinction of being formed at the time of deposition, thus, predating the hydrocarbon generation process. In south-central Eagle Plain, however, the Carboniferous succession and its stratigraphic traps never entered the oil window due to a combination of insufficient burial and low maturation gradient (Link and Bustin, 1989), thus indicating an inadequate maturation exploration risk factor at the prospect-level. The fact that significant oil discoveries have been made in Chance sandstones indicates that one cannot imply a play-level risk for thermal maturity.

Play potential

Estimates of the potential for the Chance sandstone stratigraphic oil play range from $1.1*10^6$ m^3 to $11.4*10^6$ m^3 with a mean in-place volume of $5.4*10^6$ m^3 distributed among 7 pools (mean value) (Figs. 48a, 48b; Table 2). The National Energy Board (2000) has listed 4 discoveries in the play. Total oil reserves among these discoveries are $3.2*10^6$ m^3. A matching exercise reveals that the 4 discovered accumulations correlate with the largest predicted pool size (Chance YT L-08 (M-08), Chance Sand #1), the second largest pool size (Chance YT G-08, Chance Sand #1A) and the seventh largest pool size (Chance YT J-19, Chance Sand #3). The remaining 'discovery' (Chance YT L-08 (M-08), Chance Sand #2; volume of $0.03*10^6$ m^3) does not match with the smallest predicted pool size and is considered in this study to be a significant oil show within the Chance petroleum field. All of these oil discoveries represent individual pools in specific sand layers of the Chance sandstone member in the Chance oil and gas field. The largest remaining undiscovered oil pool (ranked as third largest) is predicted to contain $0.8*10^6$ m^3 (in-place median value) (Fig. 48b, Table 2).

The Chance gas play predicts a mean value of 14 pools having a play potential ranging from $3.9*10^9$ to $24.6*10^9$ m^3 with a mean in-place potential of $12.6*10^9$ m^3 (Fig. 48c; Table 2). The largest estimated pool size is $2105*10^6$ m^3 (Fig. 48d). Three gas discoveries within the Chance oil and gas field have been booked for the play and the in-place discovered reserve total is $2.3*10^9$ m^3. The third largest predicted gas pool size matches most closely with the Chance YT L-08 (M-08), Chance Sand #1 discovery. The Chance YT J-19, Chance Sand #3 pool matches with the 12th largest pool size and the Chance YT L-08 (M-08), Chance Sand #2 pool matches with the 14th and smallest predicted pool size (Fig. 48d).

10. Alder carbonate structural

Play definition

The Alder carbonate structural oil and gas exploration play involves all pools and prospects in the upper limestone member of the Carboniferous Hart River Formation that have been deformed by Laramide compressional deformation into fold and fault traps (Table 1; Fig. 2).

Geographic location

The Alder carbonate structural oil and gas play encompasses an area of near 583 thousand hectares of southern Eagle Plain Basin (Fig. 49).

Exploration history and shows

Similar to previous Hart River Formation exploration plays, the first well penetrating the upper Alder limestone member was the Chance YT L-08 (M-08) borehole which was completed in 1960. Although this hole discovered the Chance oil and gas field in the underlying Chance sandstone member, it encountered no oil and gas shows in the Alder member. Seven exploratory wells and a delineation hole subsequently tested the structural play. Most of these wells encountered no oil or gas shows within the reservoir except for the Chance YT G-08 well which found gas bubbles and oil bleeding from core and cutting samples and Blackie YT M-59 well which exhibited oil stains and fluorescent cuts in cuttings and core.

Discoveries

No discoveries have been made in this play.

Potential reservoir

The preserved upper member of the Carboniferous Hart River Formation consists of interbedded micritic limestones and dark calcareous shales. These Alder sediments are burrowed and contain minor thin very fine-grained sandstone beds (Fig. 2; Hamblin, 1990). Reservoir quality has been described as poor to good (Hamblin, 1990) with porosities ranging between 9 and 23% (average-11%) and permeabilities between 1 and 2390 mD (average-27 mD). Open or partially-filled fractures represent the dominant porosity-type in Alder carbonates.

Source rock maturation, generation and migration

Potential source rocks charging Alder reservoirs are Ford Lake, Hart River and Blackie shale successions. The underlying Ford Lake succession consists of black and grey bituminous shales containing significant amounts of TOC (0.1 to 7.9%, average-1.6%). These rocks are marginally mature to overmature, consist of a mixture of Type II and III kerogens, and have fair to good gas and some oil potential (Fig. 20b; Link et al., 1989).

Interbedded and immediate underlying clastic shale and marine limestone strata of the Hart River Formation may in some instances contain sufficient organic carbon to consider the strata as potential source rock. TOCs in these rocks vary from 0.25 to 5.5%, (average 0.9%) and Hydrogen Indices from 14 to 425 mg HC/g TOC, averaging near 172 mg HC/g TOC (Fig. 20c). Similar to Ford Lake strata, Hart River potential source rocks contain a mixture of Type II and III kerogens that are immature to overmature dependent on location in the basin. These rocks have fair to good gas and some oil potential (Link et al., 1989).

The immediate overlying Blackie shale succession provides another potential source for Alder limestones where juxtaposition of source/reservoir units and communication by fracture between the two occur. Blackie strata are characterized by intervals of organic-rich basinal shales containing sufficient organic carbon to be considered as potential source rock (TOC-0.3 to 5.2%, average-1.0%); (Fig. 20d). Type II and III kerogens are mature to marginally mature with some free hydrocarbons occurring in part. HIs are significant (averaging near 170 mg HC/g TOC), but anomalous values (>1000 mg HC/g TOC) are considered to result from contaminants (Link et al., 1989). Again, this is a fair to good gas source with some oil potential.

Traps and seals

A most efficient top seal for trapped hydrocarbon accumulations in the Alder structural play is the immediately overlying Blackie shale succession. This sealing formation traps oil and/or gas in anticlinal fold, faulted anticline and thrust fault compressional structural traps (10 in Fig. 40).

Risk factors

A major risk factor in the play is adequate closure. Lesser risk has been assigned to the adequacy of reservoir and timing. Peak generation and migration of oil and gas occur previous to structural trap formation in the Ford Lake source-Hart River reservoir petroleum system (Fig. 41). Other potential petroleum systems such as Hart River source-Hart River reservoirs and Blackie source-Hart River reservoir have similar unfavourable timing character, as structure and trap formation occurred subsequent to peak generation and migration of hydrocarbon. The occurrence of a minor oil show in one of the exploratory wells confirms the existence of the oil play despite the significant exploration

risk. Natural gas is inferred as a potential resource in the Alder member because of numerous gas shows and pools.

Play potential

Mean potential of in-place oil in the Alder carbonate structural play is predicted to be $0.7*10^6$ m^3 (Table 2). Oil potential volumes range between 0.0 to $2.3*10^6$ m^3 (Fig. 50a), distributed among 2 predicted pools (Fig. 50b). The largest pool is expected to have an in-place volume of $0.4*10^6$ m^3 (Fig. 50b, Table 2).

The potential for gas ranges from 0.0 to $961*10^6$ m^3 (Fig. 50c; Table 2). Its in-place mean potential is $350*10^6$ m^3. Among 3 predicted pools, the largest size is estimated to be $171*10^6$ m^3 (Fig. 50d; Table 2).

11. Alder carbonate stratigraphic

Play definition

The Alder carbonate stratigraphic play involves prospects in the upper limestone member of the Carboniferous Hart River Formation (Fig. 2; Table 1) in stratigraphic traps or combined structural/stratigraphic traps associated with updip facies changes and unconformity subcrops.

Geographic location

The play encompasses the same area (about 582 thousand hectares) as defined by the structural play (Figs. 49, 51).

Exploration history and shows

Among the ten exploratory wells and single delineation well penetrating the Alder limestone member in the Hart River Formation, most encountered no oil or gas shows. Exceptions are the Chance YT G-08 delineation well which found gas bubbles and oil bleeding from core and cutting samples, Blackie YT M-59 well exhibiting oil stains and fluorescent cuts in cuttings and core, and West Parkin YT D-51 borehole showing good scattered oil stain among its cuttings.

Discoveries

There are no discoveries in the play.

Potential reservoir

Alder carbonates consist of interbedded micritic limestones and dark calcareous shales. They are burrowed and contain thin very fine-grained sandstone beds (Fig. 2; Hamblin, 1990). Porosities generally are of poor to fair quality (Hamblin, 1990). However, there are thin intervals of potential reservoir quality with porosities varying between 9 and 23% (average-11%) and permeabilities ranging between 1 and 2390 mD (average-27 mD). Open or partially-filled fractures represent the dominant porous and permeable reservoir-type in Alder carbonates.

Source rock maturation, generation and migration

As in the structural play, potential source rocks likely or possibly charging the reservoir are underlying Ford Lake dark shales, interbedded Hart River organic-rich carbonate and calcareous shale horizons, and juxtaposed overlying Blackie organic-rich shale laminae. These rocks contain sufficient organic carbon content with mixtures of oil-prone Type II and gas-prone Type III kerogens (Figs. 20b, 20c, 20d) to be characterized as potential source material. Thermal maturity parameters indicate that the rocks range from immature to overmature, indicative of their capability for producing both oil and gas dependent on their location within the basin. All of the above potential source rock intervals are considered as fair to good gas sources with some oil potential (Link et al., 1989).

Traps and seals

The unconformity subcrop structural/stratigraphic trap configuration in the Chance area of southern Eagle Plain (11 in Fig. 40) represents an important play type. This trap is efficiently sealed at the unconformity by the overlying Albian Whitestone River Formation shale succession. Whitestone River organic-rich material is not considered a potential source because the intervening effective seal at the unconformity prevents communication between the source and the reservoir. Another expected trap-type is porosity pinchout within the potential reservoir unit itself. The pinchouts occur where the porous or fractured units taper or thin into non-porous more massive Alder limestone (not illustrated in Fig. 40). The non-porous Alder layers also act as lateral seal to the petroleum accumulation.

Risk factors

Sufficient closure has been identified as a principal exploration risk-factor in the play. Secondary risk factors include adequacy of reservoir for oil and gas, and thermal maturity and timing considerations for oil. Stratigraphic traps usually have the distinction of being

formed at the time of deposition, thus, predating the hydrocarbon generation process. In south-central Eagle Plain, however, the Carboniferous succession with its stratigraphic trap prospects never entered the oil window due to a combination of insufficient burial and low maturation gradient (Link and Bustin, 1989), thus providing, in some instances, an unfavourable maturation exploration risk factor at the prospect-level.

Play potential

The oil play has an estimated in-place potential range of $0.2*10^6$ m^3 to $8.8*10^6$ m^3, with a mean volume of $3.6*10^6$ m^3 (Fig. 52a, Table 2). The mean value of the number of predicted pools is 4. The largest undiscovered pool is expected to contain $1.5*10^6$ m^3 (median value) (Fig. 52b).

Potential for the Alder carbonate stratigraphic gas play ranges from $0.5*10^9$ m^3 to $6.7*10^9$ m^3 with a mean volume of $3.0*10^9$ m^3 (Fig. 52c). The estimate assumes a total pool population of 6, with the largest undiscovered pool having an initial in-place volume of $916*10^6$ m^3 (Fig. 52d).

12. Ettrain carbonate structural

Play definition

The Ettrain carbonate structural play involves all structural prospects occurring in Upper Carboniferous-aged carbonate reservoirs that have been affected by Laramide deformation (Table 1; Fig. 2). Combination structural/stratigraphic traps where stratigraphic trap configurations were later overprinted by structural deformation were considered as belonging in the following Ettrain carbonate stratigraphic exploration play.

Geographic location

The subcrop of Ettrain limestone is located in southern Eagle Plain Basin and occupies an area of 500,000 hectares (Fig. 53).

Exploration history and shows

Initial testing of Ettrain carbonate strata was accomplished by the Birch YT B-34 well, which was completed in 1965. This well encountered no oil or gas shows in Ettrain strata, but gas was discovered within the primary deeper target, the Chance sandstone member of the Hart River Formation. The Ettrain Formation was likely a secondary target in the well. Four additional exploratory wells subsequently tested potential reservoir in this

structural play. These wells were dry, except for the South Chance YT D-63 well which encountered a minor gas show in the form of a flare from a DST in the formation.

Discoveries

No oil or gas discoveries have been made in the play.

Potential reservoir

The Carboniferous Ettrain Formation consists of skeletal and cherty limestone with interbeds of chert and dolomite. It is interpreted as a shallow marine shelf margin sandy packstone that occasionally exhibits fair porosity and thus, represents a potential reservoir (Hamblin, 1990). In the reservoir intervals, porosities and permeabilities average near 11% and 25 mD, respectively. Maximum porosity and permeability from petrophysical measurements in the formation are 17% and 641 mD, respectively. Thicknesses are highly variable, averaging near 90 m, with a maximum of 226 m.

Source rock maturation, generation and migration

The most likely potential source rock charging structural traps in the Ettrain Formation is the underlying organic-rich shale succession comprising the Blackie Formation. Blackie shales are characterized by basinal strata containing sufficient organic carbon to be considered potential source rock with TOCs varying between 0.3 to 5.2% and averaging 1.0% (Fig. 20d). Type II and III kerogens are mature to marginally mature with some free hydrocarbons occurring in parts of the unit. HIs are significant (averaging near 170 mg HC/g TOC), but anomalous values (>1000 mg HC/g TOC) are considered to be a result of contaminants (Link et al., 1989). Blackie shales represent a fair to good gas source with some oil potential.

Traps and seals

Local seals for Ettrain traps include overlying well-cemented Jungle Ridge sandstone layers and intraformational tight lime wackestone strata. Parallel northward-striking anticlines and synclines are the principal Laramide-aged surface structures. These fold bundles are deflected eastward in southeastern Eagle Plain (Fig. 53). In the subsurface, various Upper Paleozoic strata including Ettrain limestones have been deformed by compression into stacked folds and faulted anticlines (trap labelled 12 in Fig. 40).

Risk factors

The lack of significant oil or gas shows in the play suggests that exploration risk factors are appreciable. It is expected that considerable risk could be associated with adequate reservoir, seal where overlying Jungle Creek sandstones are not adequately cemented, and timing where Laramide structures were formed subsequent to thermogenic hydrocarbon generation.

Play potential

There is insufficient information available to quantitatively evaluate this oil and gas play.

13. Ettrain carbonate stratigraphic

Play definition

The Ettrain carbonate stratigraphic oil and gas exploration play involves all pools and prospects in the Upper Carboniferous Ettrain Formation in various stratigraphic and structural/stratigraphic trap configurations (Fig. 2; Table 1).

Geographic location

The stratigraphic play encompasses the same area as outlined by the structural play where the potential Ettrain reservoir subcrops in southern Eagle Plain (Figs. 53, 54). The play area is 500,000 hectares.

Exploration history and shows

Similar to the structural play, the first hole penetrating the reservoir was the Birch YT B-34 well, which was completed in 1965. This well encountered no oil or gas shows in the reservoir of interest. The Ettrain Formation was most likely a secondary target in the well. Five additional exploratory wells subsequently tested potential reservoirs in the play. These wells were dry, except for the South Chance YT D-63 well which encountered a minor gas show in the form of a flare from a DST in the formation. This show was also identified in the previous structural play. It is not known what trap-configuration hosts this minor gas accumulation.

Discoveries

No petroleum discoveries occur in the stratigraphic play.

Potential reservoir

Sandy packstone of the Ettrain Formation is interpreted to be deposited in a shallow marine shelf margin depositional setting. The formation is composed of skeletal and cherty limestone with minor interbeds of chert and dolomite. The unit averages near 90 m thick and attains a maximum thickness of 226 m. Hamblin (1990) describes the entire Ettrain interval as clean carbonate. The interval exhibits porosities averaging near 11% and permebilities of 25 mD. Maximum porosity and permeability from petrophysical measurements in the formation are 17% and 641 mD, respectively.

Source rock maturation, generation and migration

As in the structural play, the most likely potential source rock charging these stratigraphic traps is the underlying Blackie organic-rich shale succession. These basinal shale strata generally contain sufficient organic carbon to be considered potential source rocks. Total organic content varies between 0.3 to 5.2% and average about 1.0% (Fig. 20d). Organic matter consists of a mixture of Type II and III kerogens that are mature to marginally mature. Generally, HIs show elevated values (averaging near 170 mg HC/g TOC) suggesting overmaturation is not a significant risk factor, but occasional anomalous values (>1000 mg HC/g TOC) most likely reflect the introduction of contaminants during drilling operations (Link et al., 1989). In general, Blackie shales constitute a fair to good gas source with some oil potential.

Traps and seals

The unconformity subcrop structural/stratigraphic trap configuration in the Chance area of southern Eagle Plain (13 in Fig. 40) represents the most prominent type. The unconformity separates and effectively seals the underlying Ettrain potential reservoir from the overlying Albian Whitestone River shale succession. Intraformational porosity pinchouts are a secondary stratigraphic petroleum trap where the porous or fractured unit tapers out against less porous more massive portions of the Ettrain limestone (not illustrated in Fig. 40). These non-porous layers also act as lateral seal to the petroleum accumulation.

Risk factors

As in the structural play, the lack of significant oil or gas shows in the play implies that exploration risk factors are appreciable. It is expected that considerable risk could be associated with adequate reservoir, seal where overlying Jungle Creek sandstones are not adequately cemented, and adequate closure. Timing risk is not considered to be significant, since traps were formed during sedimentation and contemporaneously with thermogenic hydrocarbon generation and migration.

Play potential

Similar to the structural play, data and information were insufficient to attempt a quantitative resource evaluation in the Ettrain stratigraphic exploration play.

14. Jungle Creek sandstone structural

Play definition

The Jungle Creek sandstone structural oil and gas play is defined by all pools and prospects in Lower Permian sandstone units that occur in traps formed by Laramide deformation (Fig. 2; Table 1). As in previous Upper Paleozoic plays, combination structural/stratigraphic traps are included in the equivalent stratigraphic play.

Geographic location

The exploration play occurs in southern Eagle Plain covering an area of approximately 270,500 hectares (Fig. 55). There are two well locations where Jungle Creek strata occur at surface. These locations are depicted as windows on the play map because any petroleum that may have migrated into the formation was not likely preserved due to lack of top seal.

Exploration history and shows

The first well that intersected the Jungle Creek Formation was the Blackstone D-77 well completed in 1963. This well is not considered part of the play because it was spudded in the Jungle Creek Formation (as noted above). However, the play area encircles the Blackstone well location. The next well penetrating the Jungle Creek succession was completed in 1964. The Blackie YT M-59 well discovered the Blackie gas pool in a Jungle Creek reservoir. Five more wells tested the structural play with one well recording a minor gas flow during a DST, along with minor oil shows in cuttings and cores, and two other wells encountering minor oil and gas shows.

Discoveries

One natural gas discovery occurs in the play. It is:

1) Blackie YT M-59; gas pool hosted in medium- to coarse-grained, poorly sorted conglomeratic Jungle Creek sandstone; depth-656.6 m; pool area-1599 ha; net pay-17.7 m; average porosity-15% (National Energy Board, 2000); average

permeability-24 mD; water saturation-0.3; maximum gas flow rate-79.2*10^3 m^3/day; gas volume in-place (GIP)-1447*10^6 m^3.

Potential reservoir

The Jungle Creek Formation is characterized by thick-bedded sandstones (3-30 m) that are light to dark grey, very fine-grained to conglomeratic units with fine sandstone or siltstone interbeds (Hamblin, 1990). The beds are commonly massive and have variable grain sizes. The sands are poorly- to well-sorted and porosities and permeabilities are fair to excellent. Intergranular porosities range from 8 to 29% and permeabilities from 2 to 22350 mD. Averages are 17% and 93 mD, respectively. There are up to 166 m of clean sandstone in the formation. High-volume water flows and significant gas flows in DSTs testing the formation are indicative of porous and permeable strata.

The sandstone succession is sandwiched between upper and lower dominantly shale units of the Jungle Creek Formation (Fig. 40). No potential reservoir intervals are expected in the shale members.

Source rock maturation, generation and migration

Similar to other Upper Paleozoic reservoirs in southern Eagle Plain, Blackie shales represent the predominant source rock for petroleum accumulations in Jungle Creek strata. Blackie rocks are characterized by intervals of basinal shales containing sufficient organic carbon to be considered potential source rocks (TOC-0.3 to 5.2%, average-1.0%); (Fig. 20d). Type II and III kerogens are mature to marginally mature with some free hydrocarbons occurring in parts of the unit. HIs are significant (averaging near 170 mg HC/g TOC), but anomalous values (>1000 mg HC/g TOC) are considered to be a result of contaminants (Link et al., 1989). Blackie shale represents fair to good gas source with some oil potential.

Carboniferous Blackie Formation entered the oil window during Late Carboniferous time in southwestern Eagle Plain but not until Early Jurassic time in southeastern Eagle Plain (Link and Bustin, 1989). The earlier onset of hydrocarbon generation in western Eagle Plain can be attributed to increased burial in the region during Carboniferous-Permian time. Carboniferous strata exited the oil window during the Late Cretaceous in western Eagle Plain but are presently mature to the east (Link and Bustin, *ibid.*).

No organic-rich beds have been observed within the intraformational Jungle Creek shale members.

Traps and seals

Laramide folds, faulted anticlines and compressive thrust fault structural traps comprise the various trap-types in the play (14 in Fig. 40). As in all Upper Paleozoic successions in southern Eagle Plain, there are numerous interbedded reservoir and seal units that have been affected by Laramide deformation. Seal in the structural play is provided by the upper shale member of the Jungle Creek Formation that can act as both top and lateral seal.

Risk factors

Major exploration risk factors in the Jungle Creek structural play include adequate porosity, source rock quality and unfavourable timing of structure formation with respect to hydrocarbon generation, migration and accumulation. A petroleum events chart of the Blackie source-Jungle Creek reservoir petroleum system illustrates this unfavourable timing relationship between oil and gas generation and structure formation (Fig. 56). Hydrocarbon generation and migration, however, continues to take place in southeastern Eagle Plain providing some potential for gas accumulation after the peak oil generation event at the critical moment. Gas generation, migration and accumulation are proven at the prospect-level with occurrences of the Blackie gas pool and a significant gas flow in another well.

Play potential

The oil play has an estimated in-place potential range of 0.0 to $10.3*10^6$ m^3, with a mean volume of $3.5*10^6$ m^3 (Fig. 57a, Table 2). The mean value of the number of predicted pools is 2. The largest undiscovered pool is expected to contain $2.4*10^6$ m^3 (median value) (Fig. 57b).

Natural gas potential in the Jungle Creek sandstone structural play is predicted to reside among six pools containing a mean potential of $3.6*10^9$ m^3 (Fig. 57c). The expected play potential varies from $0.7*10^9$ m^3 to $7.4*10^9$ m^3 (Fig. 57c, Table 2). The largest undiscovered pool size is the second-ranked predicted gas accumulation having a median volume of $721*10^6$ m^3 (Fig. 57d, Table 2). The Blackie YT M-59 gas pool matches the largest predicted pool size (Fig. 57d).

15. Jungle Creek sandstone stratigraphic

Play definition

The Jungle Creek sandstone stratigraphic play is defined by updip facies changes and unconformity subcrop stratigraphic traps as well as combined structural/stratigraphic traps beneath the sub-Cretaceous unconformity (Table 1).

Geographic location

The stratigraphic play encompasses the same area as the structural play, covering near 270,500 hectares (Fig. 58).

Exploration history and shows

As in the previous structural play, the first well penetrating Jungle Creek strata (Blackstone YT D-77) cannot be considered a diagnostic play test, because the formation occurs at surface and any potential petroleum accumulation would not likely be preserved. The first well that strategically tested the play (Blackie YT M-59) was drilled in 1964 and it discovered a gas pool in a structural trap. Stratigraphic trapping configurations in the same well are possible and minor oil and gas shows may occur in these trap-types. Six subsequent exploratory wells tested the stratigraphic play. Among these exploratory wells, one well encountered a minor gas flow during a DST along with minor oil shows in cuttings and cores, another recovered gas in a DST, and two others have minor oil and gas shows.

Discoveries

There are no commercial discoveries in Jungle Creek stratigraphic traps.

Potential reservoir

The Jungle Creek Formation consists of a middle sandstone-dominant member and upper and lower shale members. Potential reservoir consists of thickly-bedded very fine-grained to conglomeratic units intercalated with minor siltstone layers (Hamblin, 1990). Up to 166 m of clean, poor- to well-sorted sandstone are rated as fair to excellent reservoir quality. Intergranular porosities and permeabilities vary from 8 to 29% and 2 to 22350 mD, respectively. Respective averages are 17% and 93 mD. Numerous gas and water flows in DSTs also indicate permeable strata.

Source rock maturation, generation and migration

Underlying Upper Carboniferous Blackie organic-rich shales represent the principal source rock charging Jungle Creek reservoirs in southern Eagle Plain. These rocks exhibit TOC varying from 0.3 to 5.2%, averaging near 1.0% (Fig. 20d). HIs are also elevated (averaging near 170 mg HC/g TOC), but anomalous values (>1000 mg HC/g TOC) are considered to be contaminants (Link et al., 1989). The mixture of Type II and III kerogens (Fig. 20d) are thermally marginally mature to mature indicating that Blackie shale constitutes a fair to good gas source with some oil potential.

The thermal maturation history of Blackie shale varies across the Eagle Plain region. In the immediate play area, Blackie Formation entered the oil window during Late Carboniferous time in southwestern Eagle Plain but not until Early Jurassic time in southeastern Eagle Plain (Link and Bustin, 1989). The earlier onset of hydrocarbon generation in western Eagle Plain can be attributed to deeper burial in that region. Blackie strata exited the oil window during the Late Cretaceous in western Eagle Plain, but are presently mature to the east (Link and Bustin, *ibid.*).

The adjacent Jungle Creek shale members have not been described as source strata in Eagle Plain, presumably because of the lack of organic carbon.

Traps and seals

Updip stratigraphic facies change (15 in Fig. 40) and unconformity subcrop constitute the major stratigraphic and stratigraphic-dominant combination traps in the Jungle Creek play. These traps are sealed by contiguous upper and lower Jungle Creek members and by overlying Albian Whitestone River shales above the sub-Cretaceous unconformity.

Risk factors

Some of the exploration risk factors identified in the structural play remain significant in the stratigraphic play. These include adequate porosity and source rock quality. Stratigraphic traps usually have the distinction of being formed at the time of deposition, predating the hydrocarbon generation process. Thus, timing issues are not as significant as in the structural play. In south-central Eagle Plain, the Permian succession and its stratigraphic traps never entered the oil window due to a combination of insufficient burial and low maturation gradient (Link and Bustin, 1989), indicating that some prospects in the south-central region have higher risk with respect to thermal maturation.

Play potential

The oil play has an estimated in-place potential range of $1.0*10^6$ m^3 to $33.4*10^6$ m^3, with a mean volume of $13.4*10^6$ m^3 (Fig. 59a, Table 2). The mean value of the number of predicted pools is 6. The largest undiscovered oil pool is expected to contain $4.3*10^6$ m^3 (median value) (Fig. 59b).

Potential for the Jungle Creek sandstone stratigraphic gas play ranges from $3.7*10^9$ m^3 to $33.9*10^9$ m^3 with a mean volume of $15.9*10^9$ m^3 (Fig. 59c). The estimate assumes a total pool population of 17, with the largest undiscovered pool having an initial in-place volume of $2799*10^6$ m^3 (Fig. 59d).

16. Jurassic-Lower Cretaceous sandstone pre-Albian structural

Play definition

In northern Eagle Plain, the extensional rifting event occurring during Jurassic and Lower Cretaceous time produced a series of structures distinct from the compressional Laramide orogenic structures dominating the region (Lane, 2010). The pre-Albian play involves all pools and prospects in these extensional structures that are hosted in various Jurassic and Lower Cretaceous coarse clastic successions occurrences in the region (Fig. 2; Table 1).

Geographic location

The play is restricted to northern Eagle Plain, with the play area aligned with the ancestral Franklinian margin. Various deep-water basins and fault-bounded troughs such as Blow Trough and Sharp Mountain sub-basin are aligned with this margin. The play covers an area near 496,400 hectares encompassing the Sharp Mountain sub-basin of northern Eagle Plain (Fig. 60).

Exploration history and shows

The pre-Albian structural play was initially tested in 1964 by the Molar YT P-34 well which intersected Jurassic Porcupine River coarse clastic strata. This well encountered minor gas shows in the tested reservoirs in the form of bleeding gas from core and cuttings. The single subsequent well testing the play found minor oil and gas shows in their Jurassic and Lower Cretaceous reservoirs.

Discoveries

No discoveries have been made in the play.

Potential reservoir

Coarse clastic sandstone and conglomerate units within the Sharp Mountain sub-basin include the Jurassic Porcupine River Formation and Lower Cretaceous basal sandstone in the Mount Goodenough Formation as well as Cretaceous Rat River and Sharp Mountain formations. Very fine- to fine-grained sandstones dominate the Porcupine River Formation. Massive beds are prevalent and total formation thickness ranges from near 60 m to about 450 m. The overall character of these rocks suggests a nearshore to inner shelf depositional environment (Dixon, 1992). In cores, these rocks are usually well-cemented,

but cutting and core descriptions indicate spotty occurrences of fair to good intergranular, fracture and pinpoint vuggy porosity. Water flows in DSTs also indicate porous and permeable intervals in the Porcupine River unit.

Basal sandstone of the Mount Goodenough Formation is characterized by very fine to fine-grained marine sandstone which has been interpreted as representing sediments deposited during a transgression after a period of major uplift and erosion (Dixon, 1992).

The Rat River potential reservoir consists of very fine to fine-grained sandstones that are commonly argillaceous to silty. Interbedded shales are also present. Coarsening-upward cycles and marine bivalves suggest a prograding or aggrading shelf or shoreline depositional environment.

Sharp Mountain conglomerate and sandstone have no known subsurface occurrences but the succession outcrops within the Keele Range and northern Ogilvie Mountains. The formation is characterized by alternating intervals of sandstone- and conglomerate-rich strata. The conglomerate is clast-supported, predominantly consisting of chert pebbles. The sandstones are fine- to medium-grained and commonly pebbly. Dixon (1986) interprets Sharp Mountain strata as representing sediment-gravity flow deposits.

Petrophysical measurements indicate porosity and permeability varies from 14 to 29% and 5 to 376 mD, respectively in potential reservoir intervals. Average porosity and permeability in these reservoir intervals is 20% and 77 mD.

Source rock maturation, generation and migration

Source rocks that may charge these Jurassic and Lower Cretaceous reservoirs include organic-rich intervals in the Jurassic Porcupine River Formation, Lower Cretaceous Mount Goodenough Formation and Albian Whitestone River Formation. Vertical migration from Upper Paleozoic oil-prone sources, specifically Ford Lake and Blackie shales, is speculated with respect to potential oil accumulations in the play.

Fair gas source potential is expected in carbonaceous shales of the Porcupine River Formation. The terrestrial Type III kerogens in these organic-rich shales are marginally mature to mature in northern Eagle Plain (Link et al., 1989). There are free hydrocarbons present in the Porcupine River Formation pointing to either the onset of hydrocarbon generation or the migration of hydrocarbons into the sandstone. Overmature organic-rich sandstones were observed in part in the Molar YT P-34 well (Link et al., *ibid.*). TOCs vary from 0.4 to 3.1%, averaging near 1.3%. HI values range up to 302 mg HC/g TOC and average near 129 mg HC/g TOC, suggesting thermally mature kerogens.

Fair gas source potential in northern Eagle Plain may occur in organic-rich marine shale facies of the Lower Cretaceous Mount Goodenough Formation. TOCs average near 1.5% and HIs at 103 mg HC/g TOC (Link et al., 1989). Vitrinite reflectance values averaging near 0.5 %Ro indicate thermally immature shales.

Overlying Albian Whitestone River Formation shales may also represent potential source material if structural deformation juxtaposes these strata with potential reservoir intervals. This marine shelf low-energy organic-rich unit constitutes a fair to good gas and minor oil source (Link et al., 1989). TOC content varies up to 12.5% and averages near 1.4%. The HI versus OI pseudo-van Krevelen plot shows a mixture of Type II and Type III kerogens (Fig. 21a). The shales are immature in most of Eagle Plain, but become mature approaching the Richardson Mountains to the east and are also mature in northwestern Eagle Plain.

Underlying Upper Paleozoic (Blackie and Ford Lake) organic-rich oil-prone shales are possible source rock intervals for the oil play. Vertical and/or lateral migration conduits are required to provide communication between source and potential reservoir. These rocks contain sufficient organic carbon content with mixtures of oil-prone Type II and gas-prone Type III kerogens (Figs. 20b, 20d) to be characterized as potential source material. Thermal maturity parameters indicate these source units vary from immature to overmature, indicating the potential for oil and/or gas generation. These potential source rock intervals are considered as fair to good gas sources with some oil potential (Link et al., 1989).

In northwestern Eagle Plain and within the Sharp Mountain Sub-basin, Lower Cretaceous strata are mature. Peak generation of gas from these rocks was attained subsequent to deep burial in Late Cretaceous time (Link and Bustin, 1989). The pre-Albian structures were formed before gas generation and thus were available for gas accumulation (Fig. 61). Therefore, timing with respect to gas retention and preservation is favourable. Carboniferous or Upper Paleozoic strata did not enter the oil window until Late Cretaceous to Early Tertiary time in this region and are presently mature (Link and Bustin, *ibid.*), indicating timing for oil accumulation in pre-Albian structures is also favourable (Fig. 61).

Traps and seals

Extensional structures such as normal faults (Fig. 62) and tilted fault blocks are expected hydrocarbon trap configurations in the play (Table 1). Sealing formations include the overlying and widespread Albian Whitestone River shale succession along with interbedded Mount Goodenough shale intervals. A major regional lateral seal may be the coeval Kingak shale succession occurring to the west of the potential reservoir units (Figs. 2; 13).

Risk factors

Many of the exploration risk factors for this play are interpreted as low. Petrophysical analyses of potential reservoirs among the three wells in the play reveal sufficient porosity and permeability for adequate reservoir and porosity (Fraser, *in press*). As

discussed previously, timing of hydrocarbon generation with trap formation is not problematic for the oil and gas play. Adequacy of seal and source rock maturation are certain. Charging the reservoir from Upper Paleozoic oil-prone source material, however, is considered to be a significant risk factor for the oil play because of substantial intervening and impermeable strata between source and reservoir. Another significant factor in the oil and gas play is sufficient structural closure for trapping of petroleum.

Play potential

Mean potential of in-place oil in the Jurassic-Lower Cretaceous sandstone pre-Albian structural play is predicted to be $0.9*10^6$ m^3 (Table 2). Potential oil volumes range from 0.0 to $2.4*10^6$ m^3 (Fig. 63a) distributed among 2 predicted pools (Fig. 63b). The largest pool is expected to have an in-place median volume of $0.5*10^6$ m^3 (Fig. 63b, Table 2).

The potential for gas ranges from $395*10^6$ m^3 to $3899*10^6$ m^3 (Fig. 63c; Table 2). Its in-place mean potential is $1858*10^6$ m^3. Among 5 predicted pools, the largest size is estimated to be $639*10^6$ m^3 (Fig. 63d; Table 2).

17. Jurassic-Lower Cretaceous sandstone stratigraphic

Play definition

The Jurassic-Lower Cretaceous sandstone stratigraphic oil and gas play is defined to include all pools and prospects in coarse clastic units in northern Eagle Plain which occur in stratigraphic trap-types such as unconformity subcrops and porosity pinchouts (Table 1).

Geographic location

The play is located in northern Eagle Plain encompassing northern Sharp Mountain and the entire Bell Sub-basin (Fig. 64). It covers an area of near 496,500 hectares.

Exploration history and shows

Initial testing of the play took place in 1960 when the Rat River Formation was intersected by the Crown Bell River YT-A No. 1 N-50 well. No hydrocarbons were encountered in the well; therefore, it is dry and abandoned. Scattered bitumen specks were observed throughout, suggesting that oil was once present in these rocks. The second well testing the play (Molar YT P-34; drilled in 1964) encountered hydrocarbons in the form of gas bleeding from core and gas shows in cuttings in Jurassic Porcupine

River sandstones. All three subsequent wells also encountered hydrocarbons in some form. Gassy fresh water was recovered from a DST in the Whitefish YT I-05 well; a gas flare also occurred with the test. The Ridge YT F-48 well produced a gas flow in a DST and also bled oil from a core sample. The Whitefish YT J-70 well showed oil stains with cut and fluorescence as well as a small gas show in a DST.

Discoveries

No commercial discoveries have been made in these rocks to date.

Potential reservoir

Potential reservoirs in the play consist of coarse clastic units of Jurassic and Early Cretaceous age. They are Porcupine River, basal sandstone of Mount Goodenough, Rat River and Sharp Mountain formations. Although these rocks are generally well-cemented, there are potential reservoir intervals with petrophysical measurements of porosities and permeabilities of 14 to 29% and 5 to 376 mD, respectively. Average porosity and permeability in these reservoirs is 20% and 77 mD. Intergranular porosity predominates with lesser amounts of fracture and pinpoint vuggy porosity.

Source rock maturation, generation and migration

As in the pre-Albian structural play, source rocks that may charge these Jurassic and Lower Cretaceous reservoirs include organic-rich intervals in the Jurassic Porcupine River Formation, Lower Cretaceous Mount Goodenough Formation and Albian Whitestone River Formation. These Mesozoic sources are dominantly gas-prone. Vertical migration from Upper Paleozoic oil-prone sources, specifically Ford Lake and Blackie shales, is also possible with respect to potential oil accumulations in the play.

The various source rock characteristics were described in the previous play. In general, the source rock character indicates fair to good gas potential and minor oil potential.

In northwestern Eagle Plain and within the Sharp Mountain Sub-basin, Lower Cretaceous strata are mature. Peak generation of gas from these rocks was attained after deep burial in Late Cretaceous time (Link and Bustin, 1989). Stratigraphic traps are usually formed at the time of deposition, thus, predating the hydrocarbon generation process. Therefore, timing with respect to gas generation and preservation in stratigraphic traps is interpreted as favourable. Carboniferous or Upper Paleozoic strata did not enter the oil window until Late Cretaceous to Early Tertiary time in this region and are presently mature (Link and Bustin, *ibid.*), indicating timing for oil accumulations in these stratigraphic traps is also favourable.

Traps and seals

Possible stratigraphic trap configurations in the play are unconformity subcrops, porosity pinchouts and basinward facies changes. Regional top seal for unconformity subcrop traps is provided by the overlying Whitestone River shale succession. Porosity pinchout traps are sealed by interbedded shales and siltstones updip of the dominantly coarse clastic reservoir strata. The northwest limit of the play delineates the boundary between the inner shelf with interbedded sandstone and fine-grained clastic formations and the outer shelf consisting of the fine-grained Kingak succession (Poulton, 1997). The Kingak shale provides a lateral seal to basinward facies change traps that may occur along the north and west limits of the play area.

Risk factors

Exploration risk factors such as adequate reservoir, seal, source rock maturation and timing of petroleum generation with respect to trap formation are considered insignificant in the play. Fraser (*in press*) found sufficient porosity and permeability from petrophysical analysis to define potential reservoir intervals. Timing of hydrocarbon generation and trap formation is favourable for most stratigraphic oil and gas plays. Adequacy of seal and source rock maturation are certain. Charging the reservoir from Upper Paleozoic oil-prone source material is considered to be a significant risk factor in the oil play because of substantial intervening and impermeable strata between source and reservoir. Trap closure depends on the presence of the unconformity, its geometry, and its sealing integrity.

Play potential

Mean potential of in-place oil in the Jurassic-Lower Cretaceous sandstone stratigraphic play is predicted to be $0.5*10^6$ m^3 (Table 2). Potential oil volumes range from 0.0 to $1.7*10^6$ m^3 (Fig. 65a), contained within one expected pool (Fig. 65b). The largest pool is expected to have an in-place median volume of $0.4*10^6$ m^3 (Fig. 65b, Table 2).

Natural gas potential in the Jurassic-Lower Cretaceous sandstone stratigraphic play is predicted to reside within five pools. The expected play potential varies from $0.4*10^9$ m^3 to $6.7*10^9$ m^3 (Fig. 65c, Table 2). Mean play potential is predicted to be $3.1*10^9$ m^3. The largest undiscovered pool size has a median volume of $1024*10^6$ m^3 (Fig. 65d, Table 2).

18. Triangle Zone structural (Bell Subbasin)

Play definition

The Triangle Zone structural play in Bell Subbasin includes all pools and prospects in Jurassic and Cretaceous coarse clastic strata that have been deformed into structures associated with two intersecting deformation fronts or triangle zones and their hinterlands. The structures formed during Laramide compressional thrust faulting associated with adjacent development of the Richardson and Keele mountain ranges.

Geographic location

The play is located in northeastern Eagle Plain in a sub-basin that formed in the Bell River drainage area called Bell Sub-basin. It covers a play area of about 304,000 hectares (Fig. 66). The triangle zones mark the foreland deformational limits of the nearby mountain ranges.

Exploration history and shows

Exploratory testing is minimal for this play. Two wells penetrate the potential reservoirs but they were drilled prior to interpretation of triangle zone geometry in the region (Lane, 1996). The first well in the region (Crown Bell River YT-A No. 1 N-50 completed in 1960) found a series of vertically-stacked Rat River coarse clastic units indicative of thrust fault repetitions. Although this well was dry, abundant and scattered bitumen specks within Rat River strata indicate oil was once present in these rocks. The second well (Ridge YT F-48) recovered a significant gas flow in a DST in the Porcupine River Formation as well as oil bleeding from vugs in core samples. Oil and gas are expected to be present in this play.

Discoveries

There are no discoveries in the Triangle Zone structural play.

Potential reservoir

As in the previous two plays, Jurassic and Lower Cretaceous coarse clastic formations constitute potential reservoirs in the Triangle Zone play. Sandstones in the Porcupine River, Rat River, Sharp Mountain and basal Mount Goodenough formations are potential reservoirs. Petrophysical analyses from the two wells penetrating these formations reveal intermittent sections with porosities from 14 to 29% and permeabilities from 5 to 376 mD. Average porosity and permeability in these intervals is 20% and 68 mD. Intergranular porosity predominates with lesser amounts of fracture and pinpoint vuggy porosity.

Source rock maturation, generation and migration

Source rocks that may charge these reservoirs include gas-prone organic-rich intervals in the Jurassic Porcupine River Formation, Lower Cretaceous Mount Goodenough Formation and Albian Whitestone River Formation. Potential oil accumulations in the play are likely derived by means of vertical migration from Upper Paleozoic oil-prone sources, specifically Ford Lake and Blackie shales.

Source rock quality has been described as fair to good for gas and fair for oil (Link et al., 1989). Oil potential is also considered to be minor.

Gas-prone Type III kerogens in Porcupine River carbonaceous shales are marginally mature to mature in northern Eagle Plain (Link et al., *ibid.*). Free hydrocarbons in the coarse clastic strata of the formation indicate that hydrocarbon generation and migration has occurred. TOCs vary from 0.4 to 3.1%, averaging near 1.3%. HI values range up to 302 mg HC/g TOC and average near 129 mg HC/g TOC, signifying thermally mature kerogens.

Fair gas source potential in northern Eagle Plain may occur in organic-rich marine shale facies of the Lower Cretaceous Mount Goodenough Formation. In these rocks, TOCs average near 1.5% and HIs average 103 mg HC/g TOC (Link et al., 1989). Vitrinite reflectance values reveal thermally immature shales.

Thrust faulting and duplex formation provide opportunities for reservoir charge where they are juxtaposed with Whitestone River source strata. Whitestone River low-energy marine shelf organic-rich units comprise a fair to good gas and minor oil source (Link et al., 1989). TOC content varies up to 12.5% and averages near 1.4%. The HI versus OI pseudo-van Krevelen plot shows a mixture of Type II and Type III kerogens (Fig. 21a). The shales are immature in most of Eagle Plain, but become mature in the Richardson Mountains and in northwestern Eagle Plain.

Underlying Upper Paleozoic (Blackie and Ford Lake) organic-rich oil-prone shales are possible source rock intervals for oil accumulations in the play. Vertical and lateral migration conduits are required to provide communication between source and potential reservoir. Compressional thrust deformation may provide communication at points of juxtaposition. The Paleozoic rocks contain sufficient organic carbon content with mixtures of oil-prone Type II and gas-prone Type III kerogens (Figs. 20b, 20d) to be characterized as potential source material. Thermal maturity parameters indicate that they range from immature to overmature, suggesting the source rocks may have produced both oil and gas, depending on their burial history within the basin. These potential source rock intervals are considered as fair to good gas sources with some oil potential (Link et al., 1989).

In northern Eagle Plain, Lower Cretaceous strata are immature to mature. The burial history of the nearby Whitefish J-70 well reveals that Lower Cretaceous strata had never entered the oil window and are thus immature (Link and Bustin, 1989). Lower

Cretaceous source strata were never buried sufficiently for thermal generation of gas to occur. Osadetz et al., (2005a) proposed Lower Cretaceous as well as Upper Cretaceous organic-rich strata may constitute a potential source for biogenic gas. Biogenic gas is generated from shallow sources and thus, burial control is not necessary for their formation and accumulation.

Carboniferous or Upper Paleozoic strata did not enter the oil window until Late Cretaceous to Early Tertiary time in this region and are presently mature (Link and Bustin, *ibid.*), indicating timing for oil accumulation is contemporaneous with the Laramide deformational episode. Presumably, some of the generated oil could be trapped in these Laramide structures.

Traps and seals

Compressional structures associated with two intersecting deformation fronts defined by their triangle zones represent the petroleum traps in this structural play. They include thrust-repeated stacked and folded reservoirs, fault propagation folds associated with back-thrusts, subthrust structures (Fig. 67; Table 1), fault-bend folds, drag folds on thrust faults, duplex structures and imbricate thrusts. Combination traps found in fractured and contorted lenses in stratabound deformation zones are also possible.

Regional top seal is provided by the overlying Whitestone River shale succession. Interbedded shales and siltstones provide local top seal within dominantly coarse clastic reservoir strata. The northwest limit of the play delineates the boundary between the inner shelf and the outer shelf consisting of the fine-grained Kingak succession (Poulton, 1997). The Kingak shale provides a lateral seal to traps that may occur along the western limits of the play area.

Risk factors

Significant risk factors in the play are adequacy of reservoir, source rock quality, and closure. Source rock maturity, seal and timing for the gas play are not significant exploration risk factors. There may be an increased risk associated with timing of oil migration and accumulation in available structures because generation and deformation are contemporaneous.

Play potential

The oil play has an estimated in-place potential range of $0.4*10^6$ m^3 to $10.1*10^6$ m^3, with a mean volume of $4.3*10^6$ m^3 (Fig. 68a; Table 2). The mean value of the number of predicted pools is 4. The largest undiscovered pool is expected to contain $1.7*10^6$ m^3 (median value) (Fig. 68b).

Potential for the Triangle Zone structural gas play ranges from $0.4*10^9$ m^3 to $9.1*10^9$ m^3 with a mean volume of $3.9*10^9$ m^3 (Fig. 68c). The estimate assumes a total pool population of 4, with the largest undiscovered pool having an initial in-place volume of $1570*10^6$ m^3 (Fig. 68d).

19. Cretaceous sandstone structural

Play definition

The Cretaceous sandstone structural play consists of all structurally trapped pools and prospects in Lower-Upper Cretaceous Eagle Plain Group coarse clastic successions (Fig. 2). These potential reservoir units are basal and middle sandstone members of the Parkin Formation, and sandstone-dominant Fishing Branch and Cody Creek formations.

Geographic location

The play covers a large portion of north-central and southern Eagle Plains Basin (Fig. 69). It encompasses an area near 1,150,000 hectares.

Exploration history and shows

The first well drilled in Eagle Plain (Eagle Plain YT No. 1 N-49, completed in 1958) was a stratigraphic test hole that recovered small amounts of gas in DSTs within the basal Parkin sandstone member. Subsequent exploration in the play consisted of 19 exploratory and 2 delineation wells. Among these wells, one commercial gas discovery was made in a structural trap in the Fishing Branch Formation (Chance YT L-08 (M-08)), 4 wells had significant gas flows in DSTs (Chance YT G-08; W. Parkin YT C-33; E. Porcupine YT F-18; W. Parkin YT D-54), two of which also had oil shows, and ten other wells encountered oil and/or gas shows. Except for the Chance discovery, insufficient information was available to identify the accumulations as occurring in structural or stratigraphic traps. Oil and gas are expected in all Cretaceous plays in Eagle Plain.

Discoveries

One gas discovery was made in the play. It is:

1) Chance YT L-08 (M-08); gas pool hosted in fine-grained, moderately well-sorted, cherty marine Fishing Branch sandstone; depth-705.2 m; pool area-458 ha; net pay-5.0 m; average porosity-22% (National Energy Board, 2000); average

permeability-22 mD; water saturation-0.35; maximum gas flow rate-23.0*10^3 m^3/day; gas volume in-place (GIP)-197*10^6 m^3.

Potential reservoir

Cretaceous reservoir strata include basal and middle sandstone members in the Parkin Formation, and sandstone-dominant Fishing Branch and Cody Creek formations, all of which occur within the Eagle Plain Group (Fig. 2).

Although the Parkin Formation is a shale-dominant succession, there are two potential reservoir units within the formation; a basal and middle sandstone member. The basal sandstone member is highly variable in thickness, ranging from 6.1 m in the East Porcupine River K-56 well to 204.2 m in the Molar P-34 well. Generally, it thickens to the west and northwest (Dixon, 1992). This sandstone varies from a clean very fine- to coarse-grained locally pebbly unit, to silty or argillaceous very fine-grained sandstone. The clean coarse-grained intervals have the best reservoir potential. Dixon (*ibid.*) interpreted the depositional environment as marine because of extensive bioturbation. Core measurements of the basal sandstone unit reveal average porosity and permeability of 12% and 16 mD, respectively. Petrophysical analysis gives a mean porosity of 20% and permeability of 93 mD. Occasional grit and conglomerate beds exhibit fair to good intergranular porosities.

Subsequent work by Jackson et al. (2011) included identification of an additional middle member in the Parkin Formation (in two wells) consisting of hummocky sandstones and chert conglomerate overlain by clean quartzose shoreface sandstones.

The Fishing Branch Formation consists of thick, very fine- to fine-grained, massive to cross-bedded sandstones and siltstones interstratified with mudstones. Thicknesses vary from 30 to 300 m. The sandstones comprise the uppermost part of 30 m thick upward-coarsening cycles. The sandstones themselves are composed of amalgamated fining-upward depositional units (Dixon, 1992). Hummocky cross-stratification and wave and current ripples suggest deposition on a storm-dominated shelf (Dixon, *ibid.*). Jackson et al. (2011) interpret Fishing Branch strata were deposited in the prodelta of a fluvial-dominated deltaic complex, with a delta front to the east. Sandstone porosities in potential reservoir intervals vary from 8 to 28% and permeabilities from 2 to 3120 mD. Averages are 20% and 76 mD, respectively. Cutting and core descriptions reveal poor to rare good intergranular porosity in part, with occasional gas and water flows in well DSTs indicating permeable layers.

The youngest potential reservoir unit is the Cody Creek Formation. These strata consist of up to 878 m of interbedded planar- and trough-crossbedded sandstone and mudstone (Dixon, 1992; Haggart et al., 2013). Sedimentological features suggest these are marine and fluvial deposits, in northern and southern Eagle Plain, respectively. Porosities and permeabilities in the Cody Creek reservoir sandstones vary from 12 to 27% and 2 to 288

mD, respectively. Averages are 20% and 53 mD. Occasional intervals of fair to good intergranular porosity were noted in well cutting descriptions.

Source rock maturation, generation and migration

Potential source rock units include underlying Whitestone River shales and interbedded Parkin and Burnthill Creek shale-dominant successions in the Eagle Plain Group. The organic-rich units in these formations dominantly consist of terrestrial Type III kerogens indicative of gas-prone organic matter. Oil charging of Cretaceous reservoirs is problematic because of substantial intervening strata between Upper Paleozoic oil-prone organic matter (Blackie and Ford Lake shales) and Cretaceous strata, and unfavourable timing relationships in parts of Eagle Plain with respect to peak oil generation and Laramide structural trap formation. In central Eagle Plain, where much drilling has occurred, Carboniferous to Cretaceous source rock strata have not entered the oil window due to the combined effect of shallow burial depth and low maturation gradient (Link and Bustin, 1989).

Whitestone River low energy marine shelf organic-rich shale units constitute a fair to good gas and minor oil source (Link et al., 1989). TOC varies up to 12.5% and averages near 1.4%. The HI versus OI pseudo-van Krevelen plot shows a mixture of Type II and Type III kerogens (Fig. 21a). The shales are immature beneath southern Eagle Plain, but become mature to the northwest as the Cretaceous section thickens (Dixon, 1992). They are also mature in the Richardson Mountains and in northwestern Eagle Plain (Link et al., *ibid*.).

Carbonaceous strata in Parkin shales have TOC values varying from 0.8 to 9.8% and averaging near 2.1% (Fig. 21b). The van-Krevelen plot indicates that most organic matter is terrestrial Type III kerogen with minor amounts of Type II (Fig. 21b). Vitrinite reflectance values (0.31 to 1.04% Ro) indicate immature to mature strata. HI values range up to 265 mg HC/g TOC and average near 121 mg HC/g TOC. According to this data, fair to excellent gas source potential is present in organic-rich strata in the Parkin Formation.

Burnthill Creek carbonaceous shales also represent a fair to excellent gas source for Cretaceous reservoirs. These rocks contain TOCs ranging from 0.8 to 9.1%, averaging near 2.6% (Fig. 21c; Link et al., 1989). The HI/OI plot shows dominant gas-prone Type III kerogen. Most strata are immature, with few thermally mature samples. Anomalously high TOC values may be the result of drilling-mud additives or, alternatively, may correlate with highly carbonaceous or coaly samples (Link et al., *ibid.*).

Oil accumulations in Cretaceous rocks are expected to be sourced from underlying Upper Paleozoic potential oil strata within Ford Lake and Blackie shales. Vertical migration from Paleozoic source rock to Mesozoic reservoirs is required. Minor oil-flecked drilling mud recoveries, bleeding oil from core, and live oil shows in cutting samples indicates this oil system may be a valid play concept. These potential source rocks contain

sufficient organic carbon content with mixtures of oil-prone Type II and gas-prone Type III kerogens (Figs. 20b, 20d). Thermal maturity parameters indicate that they range from immature to overmature, indicating the strata may have generated both oil and gas, dependent on the source rock's thermal and burial history. These rocks are considered as fair to good gas sources with some oil potential (Link et al., 1989).

Traps and seals

Compressive Laramide folds, faulted anticlines and thrust fault structural traps comprise the various trap-types in the play (Fig. 70). Seals for these various trap configurations are provided by interbedded shale and siltstone successions in the Eagle Plain Group.

Risk factors

Significant exploration risk factors are associated with adequate seal or closure for oil and gas, and adequate thermal maturation and timing for oil. In central Eagle Plain, Lower Cretaceous source strata were never buried sufficiently for thermal generation of gas to occur (Link and Bustin, 1989). Osadetz et al., (2005a) proposed Lower Cretaceous as well as Upper Cretaceous organic-rich strata may constitute a potential source for biogenic gas. Biogenic gas is generated from shallow sources and adequate burial conditions for gas generation are not necessary for their formation.

Carboniferous or Upper Paleozoic strata in western Eagle Plain entered the oil window in Late Carboniferous time and the Early Jurassic in southeastern Eagle Plain. The source strata entered the oil window in Late Cretaceous to Early Tertiary time in northwestern and eastern Eagle Plain and are presently mature (Link and Bustin, *ibid.*), indicating timing for oil generation and accumulation is contemporaneous with the Laramide deformational episode. In western Eagle Plain, Carboniferous strata exited the oil window during the Late Cretaceous. In central Eagle Plain, Carboniferous strata were never buried sufficiently for thermogenic oil and gas to be generated.

Play potential

Exploration risk analysis in combination with the expected number of prospects indicates that no oil pools are predicted in this structural play.

The potential for gas ranges from $1.0*10^9$ m^3 to $3.7*10^9$ m^3 (Fig. 71a; Table 2). Its in-place mean potential is $1.4*10^9$ m^3. Among 7 predicted pools, the largest size is estimated to be $431*10^6$ m^3 (Fig. 71b; Table 2). The second largest predicted gas pool size matches most closely with the Chance YT L-08 (M-08) discovery (Fig. 71b).

20. Cretaceous sandstone shelf stratigraphic

Play definition

Dixon (1992) describes the Cretaceous strata in Eagle Plain as exhibiting low-angle ramp-style morphology. Jackson et al. (2011) identified a shelf-slope break within the Cretaceous basin having a relief of at least 100 m. This added complexity in basin morphology has led to the division of the stratigraphic component of the Cretaceous sandstone play into a marine shelf and a deeper-water slope play with sand-rich slump deposits.

The shelf stratigraphic play includes all pools and prospects trapped in valley-fills, shelf-margin deltas and offshore bars on the shelf of eastern Eagle Plain.

Geographic location

The shelf stratigraphic play occurs in eastern Eagle Plain east of the interpreted prominent shelf-slope break (Fig. 72). It covers an area near 785,000 hectares.

Exploration history and shows

As pointed out in the previous play, insufficient information is available to determine whether the hydrocarbon shows occur within structural or stratigraphic traps, with the exception of the Chance L-08 gas discovery which has been categorized as structural. Thus, history and show information in the stratigraphic plays will be similar to the compiled data for the structural play.

The first borehole drilled into Eagle Plain (Eagle Plain YT No. 1 N-49, completed in 1958) intersected the basal Parkin sandstone member and found minor methane gas in selected DSTs. Subsequent exploration drilling in the shelf play consisted of 17 exploratory and 2 delineation wells. Although a commercial gas discovery occurs in a structural trap in the Fishing Branch Formation in the Chance YT L-08 (M-08) well, an additional gas flow from a DST in a separate stratigraphic interval could indicate a significant gas show in the stratigraphic play. Four other wells found significant gas flows in DSTs (Chance YT G-08; W. Parkin YT C-33; E. Porcupine YT F-18; W. Parkin YT D-54) two of which also had oil shows, oil and gas shows were discovered in another well, minor oil shows were discovered in 5 other wells, and minor gas shows were observed in 4 other wells.

Discoveries

No commercial discoveries have been made in the play.

Potential reservoir

Potential reservoirs in the play consist of coarse clastic units of Early and Late Cretaceous age within the Eagle Plain Group. They are basal and middle sandstones of the Parkin Formation, and Fishing Branch and Cody Creek formations. Potential reservoir intervals show petrophysical measurements of porosities and permeabilities of 8 to 35% and 2 to 3120 mD, respectively. Average porosity in these same reservoir intervals is 20% and permeability averages 72 mD. Intergranular is the main porosity-type in these rocks.

Source rock maturation, generation and migration

Gas-prone Mesozoic source rock include underlying Whitestone River shale as well as interbedded Parkin and Burnthill Creek shale-dominant formations. Oil charge is believed to be derived from underlying Upper Paleozoic strata, specifically Carboniferous Ford Lake and Blackie formations.

The various source rock characteristics were described previously in the structural play. In general, the source rock character suggest fair to excellent gas potential and minor oil potential.

In most parts of Eagle Plain, Mesozoic source rocks are immature. In northwestern Eagle Plain outside of this play area but in the slope play area, Lower Cretaceous strata are mature. Peak generation of gas from these rocks occurred during maximum burial in Late Cretaceous time (Link and Bustin, 1989). Insufficient burial in the remainder of Eagle Plain suggests that thermogenic gas has not yet been generated. Biogenic gas, however, is possible since its formation process does not require deep burial. Stratigraphic traps are usually formed at the time of deposition, thus, predating the hydrocarbon generation process. Therefore, timing with respect to biogenic gas retention and preservation in stratigraphic traps is favourable, while thermogenic gas generation from Mesozoic source rock has not taken place under most of Eagle Plain. Carboniferous or Upper Paleozoic strata maturation timing intervals vary widely throughout the region and are presently mature to overmature (Link and Bustin, *ibid.*), indicating their oil generation potential was dependent on the burial history across the regions.

Traps and seals

Trapping configurations include valley and channel fills, offshore sand bars and shelf-margin deltas. As the name implies, the shelf-margin deltas occur at the shelf-slope break, partly in the shelf play, but also in the slope play. Proximal delta traps are expected in this shelf play. Interbedded shale successions provide local seal.

Risk factors

Important exploration risk factors in the stratigraphic play are adequate seal and/or closure in the oil and gas play as well as adequate thermal maturity in the oil play. Timing is not an issue in stratigraphic plays because traps are formed at the same time as deposition of the reservoir.

Play potential

The oil play has an estimated in-place potential range of 0.0 to $2.0*10^6$ m^3, with a mean volume of $0.7*10^6$ m^3 (Fig. 73a, Table 2). The mean value of the number of predicted pools is 3. The largest undiscovered pool is expected to contain $0.3*10^6$ m^3 (median value) (Fig. 73b).

Potential for the Cretaceous sandstone shelf stratigraphic gas play ranges from $214*10^6$ m^3 to $1618*10^6$ m^3 with a mean volume of $801*10^6$ m^3 (Fig. 73c). The estimate assumes a total pool population of 7, with the largest undiscovered pool having an initial in-place volume of $230*10^6$ m^3 (Fig. 73d).

21. Cretaceous sandstone slope stratigraphic

Play definition

The Cretaceous sandstone slope stratigraphic play includes all oil and gas pools and prospects in stratigraphic trap configurations in the deep-water slope facies of the Cretaceous succession.

Geographic location

The play is located west of the shelf-slope break interpreted and mapped by Jackson et al. (2011) and covers an area of about 327,500 hectares (Fig. 74).

Exploration history and shows

The first well drilled into the basin (Eagle Plain YT No. 1 N-49, completed in 1958) appears to be on the boundary of the shelf and slope play. This well intersected the basal Parkin sandstone member and recovered minor methane gas in DSTs. Subsequent

exploration is very limited in the region, with only two dry exploratory wells occurring in the play (Fig. 74).

Discoveries

No oil or gas discoveries have been made in the slope play.

Potential reservoir

As in previous Cretaceous plays, porous and permeable sandstone layers in the Parkin, Fishing Branch and Cody Creek formations of the Eagle Plain Group represent reservoir in the slope play. These sand bodies or lobes are slump features associated with turbidity currents along the surface of the continental slope. Porosity and permeability measurements have not been completed in the subsurface on these formations within the play area.

Source rock maturation, generation and migration

Source rock characteristics are similar to the previous play in that organic shale of the Whitestone River, Parkin and Burnthill Creek formations potentially charge the natural gas petroleum system. The Upper Paleozoic Ford Lake and Blackie formations are postulated as the source for oil in Cretaceous reservoirs. Pyrolysis and organic petrology experiments indicate that these rocks vary from overmature to immature dependent on location in the basin. Burial and thermal histories vary widely from well to well in the basin and the timing for source rock maturation, generation and migration also varies, suggesting that source rock charge is a prospect-level risk. Biogenic gas generation has also been proposed from Cretaceous sources (Osadetz et al., 2005a).

Traps and seals

Various sand bodies within and associated with turbidites such as submarine fans, channels and lobes that are encased and sealed by interbedded shale-dominant strata represent a principal stratigraphic trap in the play. Similar relationships with sand lobes and channels found in distal parts of shelf-margin deltas provide another stratigraphic trap.

Risk factors

Seal/closure in the oil and gas play and thermal maturity in the oil play are thought to be significant risk factors in this stratigraphic play.

Play potential

Mean potential of in-place oil in the Cretaceous sandstone slope stratigraphic play is predicted to be $12.4*10^6$ m^3 (Table 2). Oil potential volumes range between $0.7*10^6$ m^3 to $30.8*10^6$ m^3 (Fig. 75a) distributed among 4 predicted pools (Fig. 75b). The largest undiscovered pool is expected to have an in-place volume of $4.7*10^6$ m^3 (Fig. 75b; Table 2).

The potential for gas ranges from $2.5*10^9$ m^3 to $23.7*10^9$ m^3 (Fig. 75c; Table 2). Its in-place mean potential is $11.3*10^9$ m^3. Among 8 predicted pools, the largest size is estimated to be $2925*10^6$ m^3 (Fig. 75d; Table 2).

Discussion of Assessment Results

Resource potential of the basin

The total petroleum potential for the Eagle Plain assessment region (from all plays quantitatively analyzed) range from $29.0*10^6$ to $82.4*10^6$ m^3 for oil (Fig. 76a) and $65.8*10^9$ to $131.6*10^9$ m^3 for gas (P95-P5) (Fig. 76b). Their mean potentials are $52.2*10^6$ m^3 and $96.7*10^9$ m^3, respectively (Table 2).

Resource distribution

The greatest oil potential occurs in the Jungle Creek sandstone stratigraphic play and gas potential in the Lower Paleozoic carbonate stratigraphic play (Table 2). The largest individual undiscovered gas pool size is predicted to occur in the Lower Paleozoic stratigraphic play. The largest undiscovered oil pool is expected to occur in the Cretaceous sandstone slope stratigraphic play, with the second largest pool in the Jungle Creek play.

The ranking of oil and gas plays by means of discovered volumes, largest undiscovered pool size and mean play potential reveals interesting comparative trends between plays. The Jungle Creek stratigraphic and Cretaceous slope stratigraphic oil plays have no reported discovered volumes, but significant potential (Fig. 77a). The only play having discovered oil reserves, Chance stratigraphic, has much less potential compared to these two plays, but is still third-ranked among all oil plays. Regarding the gas plays, a similar pattern occurs where certain plays having no discoveries have significant potential (Lower Paleozoic stratigraphic, Jungle Creek stratigraphic, and Cretaceous slope stratigraphic), and one play with substantial discovered gas (Jungle Creek structural) has much less total potential (Fig. 77b). In contrast to the oil plays, the Chance stratigraphic gas play with discoveries has comparable mean potential to the Cretaceous slope stratigraphic play with no discovered pools. It is interesting to note that all oil and gas

plays with significant potential but with no discoveries are stratigraphically-trapped, illustrating a typical exploration history of a frontier basin. In most frontier basins, more obvious structural traps are initially tested, followed later by the examination of more subtle stratigraphic traps as geological knowledge of the basin is improved, stratigraphic relationships are better understood, and seismic survey techniques and strategies are employed to explore for stratigraphic trap features. Many surface structures have been tested in Eagle Plain with some success in initial drilling, but strategies focusing on testing stratigraphic traps are in preliminary stages. Many of the discoveries classified as occurring in combination traps and included in the stratigraphic plays in this study were initially found by testing Laramide surface structures.

Plots of resource potential against largest undiscovered pool sizes reveal plays of greatest upside potential (Fig. 78). The plays showing combinatons of highest potential and largest predicted pool size represent the assessment units of greatest economic significance. The oil play of greatest significance in Eagle Plain Basin is the Cretaceous sandstone slope stratigraphic play (Fig. 78a). The Jungle Creek stratigraphic play also has relatively high potential and a significant largest predicted pool size (Fig. 78a). The gas play of most significance is the Lower Paleozoic stratigraphic play (Fig. 78b), with good potential in the Chance stratigraphic, Jungle Creek stratigraphic and Cretaceous slope stratigraphic gas plays.

This petroleum resource assessment indicates that the Cretaceous slope stratigraphic play and the Permian Jungle Creek stratigraphic play are expected to contain about 49% of the Eagle Plain Basin's total oil volume and seven of the 10 largest undiscovered pools (Table 2; Fig. 79a), reflecting relatively large trap sizes and high-quality reservoirs in Cretaceous turbiditic and shelf-margin delta sand bodies, and Permian thick-bedded shoreline and shallow marine sandstone bodies in pinchout and subcrop traps. In contrast, predicted gas pool sizes in the four most significant stratigraphic plays are similar, suggesting that large future discoveries are anticipated in the previously tested target (Chance sands), and in other untargeted reservoirs, including Lower Paleozoic carbonates, Permian shallow marine sand bodies, and Cretaceous sand bodies deposited in the deep-marine slope depositional environment (Fig. 79b). The ten largest undiscovered gas pools are evenly distributed among the four stratigraphic plays. In Eagle Plain Basin, there are 2 remaining undiscovered oil pools having in-place volumes greater than $4.0*10^6$ m^3 (25 MMBO) and four undiscovered gas pools with its mean volume greater than $2.0*10^9$ m^3 (71 Bcf) (Fig. 79).

Regional ranking of petroleum prospectivity in Eagle Plain reflects various criteria such as potential oil and gas volumes, the overlap and intersection of play polygons, the likelihood of oil and/or gas generation from potential source rocks charging potential reservoir, mapped closures and known accumulations or oil or gas shows. Although the geographic petroleum resource distributions within the plays themselves are unknown, an assumption of equal apportionment of total play potential across the play area may be assumed. Areas of probable high potential in the basin include southern Eagle Plain where all known accumulations and numerous plays overlap. Moderate potential is

expected in western and northern Eagle Plain where the Cretaceous slope stratigraphic and Triangle Zone structural plays are located.

Assessment results and exploration history

The exploration risk factors estimated for Eagle Plain plays (Appendix B) suggest success rates for exploratory drilling in the region should average about 9% for oil and 18% for gas plays. Average historical success rates for exploration wells in the basin to date are 9% for oil and 22% for gas. The past and predicted future oil and gas finding rates are very similar, suggesting that estimated exploration risk factors, at least for structural plays, are reasonable. Evaluation of success rates for stratigraphic plays is not yet possible, as most stratigraphic plays in the basin have not been targeted and have little or no exploration history. Accordingly, the accuracy of the exploration risk factors applied to the stratigraphic plays remains to be validated.

Basin Comparisons

The Richardson Mountains Anticlinorium separates Eagle Plain Basin from Peel Plain and Plateau of the northern mainland of Canada. Strata older than Early Carboniferous are similar in both regions (Fig. 2), as are reservoir types and source rock. Regional structures affecting these strata in Eagle Plain and the Northern Foreland Belt (Peel Plateau) of the northern mainland are also similar.

Total petroleum resources (produced and remaining) in the $0.125*10^6$ km^2 of the Northern Foreland Belt (including Peel Plateau) are $384*10^6$ m^3 of oil and $425.3*10^9$ m^3 of gas (Hannigan et al., 2011). Estimated resource volumes of the Northern Foreland Belt are an order of magnitude larger than total resource estimates for Eagle Plain ($52.2*10^6$ m^3 of oil (Fig. 76a); $96.7*10^9$ m^3 of gas (mean volumes) (Fig. 76b)). Eagle Plain encompasses an area about a fifth the size of the Foreland Belt ($0.024*10^6$ compared to $0.125*10^6$ km^2), accounting for much of the volume differences between the two basins. Other contributing factors for reduced potential in Eagle Plain Basin, relative to the Northern Foreland Belt, may include differences in source rock thickness, richness and maturity, and the number of reservoirs and their quality and thickness.

UNCONVENTIONAL PETROLEUM RESOURCES

Knowledge of unconventional petroleum resources with respect to type as well as their extent and volume is limited in the Eagle Plain region. All exploration activity in the region has been focused on finding conventional accumulations of oil and gas. Therefore, quantitative evaluation is not possible due to the general lack of information over widespread prospective areas containing strata of sufficient organic content and quality to be considered as yielding unconventional petroleum accumulations. However, a qualitative discussion on unconventional petroleum is possible and is presented below.

Conventional oil and gas accumulations are discrete entities with well-defined pool limits commonly bounded by down-dip water contacts and significantly affected by the buoyancy of petroleum in water. Oil and gas occurs in interstitial pores or fractures and have migrated from their point of genesis to the reservoir in a structural or stratigraphic trap (Fig. 80). Unconventional petroleum, on the other hand, occurs in continuous accumulations which are pervasive over large areas, not significantly affected by hydrodynamic influences and lack well-defined down-dip water contacts (Fig. 80). Unconventional accumulations occur in rocks of low porosity and very low permeability making these resources difficult to extract and requiring innovative production techniques other than conventional well-bore methods. The pervasive nature of unconventional accumulations implies, in most cases, the presence of very large in-place oil and gas resource volumes. Producible recoverable resources are dependent on the development of advanced well drilling and completion techniques appropriate for each resource-type and sedimentary formation and basin. Horizontal well-drilling, combined with multi-stage hydraulic fracturing, is one commonly-used innovative exploitation technique used for extraction of tight and shale gas resources.

Unconventional oil potential

Very little information and data are available with respect to unconventional oil resource in the Eagle Plain region. Of the various unconventional oil accumulation-types (oil shales, bituminous sands, bituminous carbonates, extra heavy oils, shale oil), shale oil seems to be the single accumulation-type occurring in the study area. The Carboniferous Ford Lake/Hart River/Blackie unconventional petroleum reservoir has sufficient organic content and favourable thermal maturation properties for shale oil potential. Information on these reservoirs is included in the section on shale gas potential.

Unconventional gas potential

The potential for unconventional gas accumulations is substantially greater in the study area than for unconventional oil. Possible accumulations include tight gas and shale gas. Coal-bed methane and gas hydrates are not expected to occur in the region.

Tight gas

Tight gas found in basin-centred accumulations occurs as pervasive gas-saturated and abnormally pressured low permeability reservoirs which commonly lack a downdip water contact (Fig. 80; Law, 2002). Abnormal pressures imply that the gas phase is not connected hydrodynamically to a regional aquifer. These reservoirs are sourced from interbedded organic-rich strata downdip of the tight gas accumulation.

The tight gas concept in Canada was first proposed by Masters (1979, 1984b) to describe regionally extensive low-permeable deeply buried gas reservoirs on the western flank of the Western Canada Sedimentary Basin, which is termed the Deep Basin. This system is sourced from coaly strata and regional marine source rocks occurring downsection and downdip in the gas window. Thick marine shale aquitards isolate these reservoirs from shallow aquifers and meteoric waters. These low-permeability "resource plays" require horizontal wells with multiple fracture stimulations in order to achieve production.

Hayes and Archibald (2012) recognized three stratigraphic intervals having moderate tight gas potential. They are the Cambrian-Devonian Bouvette-Ogilvie carbonate succession, Upper Devonian Imperial Formation, and Cretaceous Eagle Plain Group succession (Fig. 81).

The Bouvette/Ogilvie carbonate succession is flanked eastward by the equivalent Road River Group and also capped by Canol shales; both potential source rock units (Figs. 19a, 19c). This arrangement of reservoir and source rock allows for the potential expulsion of hydrocarbons from source rock, which consequently migrates into the reservoir, forming a basin-centred tight gas accumulation (Hayes and Archibald, 2012). Investigations of these source rocks indicate they have generated substantial hydrocarbons in the past but are now overmature (Fig. 24). Well coverage in Lower Paleozoic carbonates is extremely limited in Eagle Plain and it has not been determined if an abnormal pressure regime exists to establish and preserve a basin-centred gas accumulation in these rocks.

During late Middle Devonian time, sediment provenance studies indicate that turbiditic, chert-rich clastics derived from the north and west flooded the northern Cordillera (Gordey, 1991). The turbiditic sands of the Imperial Formation are encased by rich source rocks of the underlying Canol Formation and overlying Ford Lake Formation (Fig. 2). Hadlari et al. (2009) described an Imperial Formation play in Peel Plateau and Plain having reservoir, source and seal elements of a possible basin-centred tight gas regime. Hayes and Archibald (2012) suggest that a similar tight gas play concept may exist in Eagle Plain. However, no hydrogeological work has been completed in the basin to confirm the presence of this unconventional petroleum system.

Eagle Plain Group reservoirs have until recently been overlooked as a potential tight gas reservoir because of shallow burial depths. Jackson et al. (2011) identified a shelf-slope break in the Cretaceous succession in Eagle Plain and recognized the presence of sand-rich mass transport deposits in the slope region. These sands are buried to sufficient depth, are isolated and encased by basinal shales, and may contain tight gas accumulations.

Shale gas

The most prospective unconventional gas-type in the Eagle Plain study area is shale gas. Shale gas is natural gas occurring in reservoir rocks consisting of fine-grained sediments ranging from mudstone to siltstone to argillaceous fine-grained sandstone. The shaley

successions form self-enclosed petroleum systems where source and reservoir are within the same stratigraphic unit. The gas may be stored by adsorption onto organic matter or clays, or trapped as free gas in pore spaces or fractures. Fracture stimulation is needed to produce the gas. Shale gas is expected to occur in most of the shale successions in every basin in Canada, and those in Eagle Plain are no exception.

Hamblin (2006) lists eight shale gas formations in the Eagle Plain area. Hayes and Archibald (2012) combined these formations into four shale gas successions or units exhibiting very good to moderate prospectivity. They are Road River, Canol, Ford Lake/Hart River/Blackie, and Mount Goodenough/Whitestone River/Eagle Plain Group shale gas units.

Up to 3000 m of basinal shales of the Road River Group accumulated in Richardson Trough to the east of Eagle Plain, Blackstone Trough to the south, and Babbage Basin to the north; these strata are age-equivalent to the shelfal carbonates deposited on the Porcupine Platform beneath Eagle Plain (Figs. 3, 4, 6, 7 and 8) (Norris, 1997b; Morrow, 1999). The basinal shale successions contain up to 19.29% TOC, and consist of Type I or II kerogens, are oil-prone but thermally overmature, and may have generated oil and natural gas (Fig. 19a; Snowdon, 1988). Link et al., (1989) indicated that the overall source rock potential of the Road River Group throughout northern Yukon is poor (average S1+S2/TOC near 0.6, average TOC near 1.7%), although occasional high TOC values occur in former Blackstone and Richardson trough regions. Link and Bustin (1989) concluded that Road River shales generated liquid hydrocarbons during Devonian to Carboniferous time, and are now overmature.

Allen et al. (2011) and Fraser et al. (2012) completed sampling of shallow diamond drillholes in the Richardson Trough area specifically for shale gas potential. They found residual TOC values ranging from 1.0 to 19.3%, with most below 5%. Type I and II kerogens were identified. Vitrinite reflectance measurements revealed all Road River samples are overmature. Hayes and Archibald (2012) rated Road River shale gas potential as moderate.

The Middle to Upper Devonian Canol Formation is a widespread basinal organic-rich facies with common thicknesses of tens of metres (Fig. 9). Link et al. (1989) and Link and Bustin (1989) identified the foremost Lower Paleozoic organic-rich source rock throughout northern Yukon as black bituminous shale of the Canol Formation with TOCs between 0.3 and 20.1% (average: 3.2%), mixed Type II and III kerogens (Fig. 19c), and are currently mature to overmature. Link and Bustin (1989) report residual kerogen values ranging from 2.4 to 8.6% in Canol shales indicative of sufficiently abundant organic carbon for the generation of hydrocarbons during the Devonian to Carboniferous time of deepest burial. Canol source rocks are for the most part overmature in Eagle Plain and in the surrounding mountain ranges; vitrinite reflectance varies from 0.8 to 3.96% Ro. Although no thermal maturity data occurs within the basin itself, surrounding outcrop and drillhole information indicates overmature strata (Link et al., 1989; Fraser et al., 2012). Good potential is expected for shale gas in the Canol Formation; there may be an

economic risk associated with insufficient thickness of this unit (Hayes and Archibald, 2012).

The Carboniferous stratigraphic package encompassing transgressive fine-grained basinal clastic strata of the Ford Lake Formation overlain conformably by terrigenous clastics and carbonate ramp deposits of the Hart River Formation, in turn overlain by a second transgressive basinal clastic sequence of the Blackie Formation, forms a potential tripartite shale gas succession (Figs. 2, 11). This succession has sufficient thickness (up to 2060 m) for economic shale gas resource potential.

The Ford Lake Formation consists of black and grey bituminous shales containing significant amounts of TOC (0.1 to 7.9%, average-1.6%). These rocks are marginally mature to overmature, consist of a mixture of Type II and III kerogens, and have fair to good gas and some oil potential (Fig. 20b; Link et al., 1989).

Shale and marine limestone strata of the Hart River Formation locally contain sufficient organic carbon to be considered as potential source rocks. TOCs in these rocks vary from 0.25 to 5.5%, (average 0.9%) and Hydrogen Indices from 14 to 425 mg HC/g TOC, averaging near 172 mg HC/g TOC (Fig. 20c). Similar to Ford Lake strata, Hart River potential source rocks contain a mixture of Type II and III kerogens that are immature to overmature dependent on location in the basin. These rocks have fair to good gas and some oil potential (Link et al., 1989).

Blackie strata are characterized by intervals of basinal shales containing sufficient organic carbon to be considered potential source rocks (TOC-0.3 to 5.2%, average-1.0%); (Fig. 20d). Type II and III kerogens are mature to marginally mature with some free hydrocarbons occurring in part. HIs are significant (averaging near 170 mg HC/g TOC), but anomalous values (>1000 mg HC/g TOC) are considered to be a result of contaminants (Link et al., 1989). This is a fair to good gas source with some oil potential.

Hayes and Archibald (2012) conclude that Carboniferous organic-rich strata still retain generative potential and offer substantial shale reservoir potential in Eagle Plain Basin. These strata are interpreted to represent very good unconventional shale petroleum potential for both gas and oil.

Another potential shale gas succession includes the Cretaceous Mount Goodenough/Whitestone River/Eagle Plain Group stratigraphic interval (Figs. 2, 14). The Mount Goodenough Formation is located in northeastern Eagle Plain and represents a basal transgressive sandstone and shale deposit. The Albian Whitestone River Formation covers most of Eagle Plain. This shale-dominated succession has thicknesses ranging up to 1545 m. Stacked transgressive-regressive sandstones and shales, each cycle hundreds of metres thick, constitute the Eagle Plain Group.

Fair gas source potential in northern Eagle Plain occurs in organic-rich marine shale facies of the Lower Cretaceous Mount Goodenough Formation. TOCs average near 1.5%

and HIs at 103 mg HC/g TOC (Link et al., 1989). Vitrinite reflectance values averaging near 0.5 %Ro represent thermally immature shales.

Whitestone River marine low-energy shelf organic-rich shale units constitute a fair to good gas and minor oil source (Link et al., 1989). TOC varies up to 12.5% and averages near 1.4%. The HI versus OI pseudo-van Krevelen plot shows a mixture of Type II and Type III kerogens (Fig. 21a). The shales are immature beneath southern Eagle Plain, but become mature to the northwest as the Cretaceous section thickens (Dixon, 1992) and in the Richardson Mountains and in northwestern Eagle Plain (Link et al., *ibid*.).

Carbonaceous strata in Parkin shales reveal TOC fluctuating between 0.8 to 9.8% and averaging near 2.1% (Fig. 21b). The van-Krevelen plot indicates that most organic matter is terrestrial Type III kerogen with minor amounts of Type II (Fig. 21b). Vitrinite reflectance values (0.31 to 1.04% Ro) indicate immature to mature strata. HI values range up to 265 mg HC/g TOC and average near 121 mg HC/g TOC. According to this data, fair to excellent gas source potential in part is present in organic-rich strata in the Parkin Formation.

Burnthill Creek carbonaceous shales also represent a fair to excellent gas source for Cretaceous reservoir. These rocks contain TOCs ranging between 0.8 and 9.1%, averaging near 2.6% (Fig. 21c; Link et al., 1989). The HI/OI plot shows dominant gas-prone Type III kerogen. Most strata are immature, with very minor thermally mature samples. Anomalously high TOC values may be the result of drilling-mud additives or, alternatively, may correlate with highly carbonaceous or coaly samples (Link et al., *ibid.*).

Hayes and Archibald (2012) conclude that Cretaceous shales have the potential to host substantial shale gas resource in northwestern Eagle Plain Basin where thickness is the greatest and the rocks show sufficient maturity. Shallow burial depth in the remainder of the basin is a significant risk factor. Overall potential is rated as moderate to good.

CONCLUSIONS

The oil and gas resource potential of the Eagle Plain Basin of northern Yukon in Canada have been evaluated through a comprehensive regional petroleum play assessment. Twenty-one conventional petroleum exploration plays were defined in the study area. The assessment includes quantitative analyses of 19 of the 21 immature or conceptual plays, most with both oil and gas components and each incorporating the calculation or estimation of pool size parametric data, numbers of prospects and exploration risks. Oil and gas volumes reported for these conceptual plays are total statistical estimates of the endowment or resource occurring “in the ground”, with no constraints on whether the hydrocarbons are technically or economically producible. Individual undiscovered pool sizes are determined and they are important in identifying and ranking the most attractive plays for exploration programs.

Mean estimates for total oil and gas potential for all Eagle Plain plays are $52.2*10^6$ m^3 of in-place oil and $96.7*10^9$ m^3 of in-place gas. The ranges of oil and gas estimates for individual play potential from high to low probability (Table 2) reflect the level of uncertainty in assessing petroleum potential for this region. However, in comparative terms, the estimates from the current assessment are substantially greater than those derived in the Geological Survey of Canada's 1983 assessment (Procter et al., 1984). The greater volumes predicted in this study reflect several factors, including more optimistic evaluations of number of prospects, volume and quality of potential reservoirs, and a better understanding of the richness, maturity and quantity of potential source rock.

The current estimates are also greater than more recent assessment volumes prepared by the National Energy Board (2000); mean volume estimates converted to in-place resources (30% recovery factor for oil; 70% for natural gas) gave oil volumes of $14.9*10^6$ m^3 and $40.7*10^9$ m^3 of gas (National Energy Board, 2000). The greater resource estimates in the current assessment reflect the addition of newly defined plays (eg. Cretaceous sandstone slope stratigraphic) not previously recognized.

A Geological Survey of Canada petroleum resource assessment study (Osadetz et al., 2005a) gave expected volumes of $169*10^9$ m^3 of in-place gas and $67.7*10^6$ m^3 of oil. Differences between the two relatively recent GSC assessments reflect differences in opinions on the subjective categories of numbers of prospects and exploration risk factors of individual plays.

This assessment indicates that the Cretaceous slope stratigraphic oil play and Jungle Creek stratigraphic play are expected to contain about 49% of Eagle Plain Basin's total oil volume and seven of the 10 largest undiscovered pools, reflecting relatively large trap sizes and better quality reservoirs in Cretaceous turbiditic and shelf-margin delta sand bodies as well as Permian thick-bedded shallow marine sandstone bodies trapped by updip pinchouts and subcrops beneath the sub-Mesozoic unconformity. Predicted gas pool sizes show a different distribution, in that four stratigraphic gas plays have very similar undiscovered pool sizes, indicating that future discoveries are anticipated in the targeted reservoir (Chance sands) as well as in other untested reservoirs ranging in age from Lower Paleozoic to Cretaceous. The ten largest undiscovered predicted gas pools are evenly distributed among the four stratigraphic plays. In Eagle Plain Basin, there are 2 remaining undiscovered oil pools having in-place volumes greater than $4.0*10^6$ m^3 (25 MMBO) and four undiscovered gas pools with their mean volume greater than $2.0*10^9$ m^3 (71 Bcf).

Areas of high potential in Eagle Plain Basin include southern Eagle Plain where all known accumulations occur and where numerous plays overlap. Moderate potential is expected in western and northern Eagle Plain where the Cretaceous slope stratigraphic and Triangle Zone structural plays are respectively located.

Unconventional petroleum resources in Eagle Plain Basin occur as tight gas and shale gas or shale oil accumulations. Moderate tight gas potential is expected in the Bouvette-Ogilvie carbonate succession and the Imperial and Eagle Plain Group clastic successions.

Good shale gas and/or shale oil potential is recognized in Road River, Canol, Ford Lake/Hart River/Blackie, and Mount Goodenough/Whitestone River/Eagle Plain Group units.

This assessment study provides a favourable geological basis for further petroleum evaluation and exploration in sedimentary strata of Eagle Plain in northern Yukon. In particular, stratigraphic oil and gas plays in the Lower Paleozoic carbonate succession, the Jungle Creek sandstone formation, and the Cretaceous slope region appear very prospective. The complex geology and predicted high exploration risks associated with all plays suggest that acquisition of a considerable amount of new seismic data and many exploration wells may be required to properly evaluate the region's oil and gas potential. The present assessment indicates substantial petroleum resource remain to be discovered in the Eagle Plain exploration region.

REFERENCES

Aitken, J.D., 1993. Cambrian and Lower Ordovician-Sauk Sequence, Subchapter 4B; in, Sedimentary Cover of the Craton in Canada, D.F. Stott and J.D. Aitken (eds.); Geological Survey of Canada, Geology of Canada, no. 5, p. 96-124.

Aitken, J.D. and McMechan, M.E., 1991. Middle Proterozoic assemblages, Chapter 5; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 97-124.

Allen, T.L., Fraser, T.A., and Lane, L.S., 2011. Preliminary results from a diamond drill hole study to assess shale gas potential of Devonian strata, Eagle Plain, Yukon; in, Yukon Exploration and Geology 2010, K.E. McFarlane, L.H. Weston and C. Relf (eds.); Yukon Geological Survey, p. 1-17.

Arps, J.K. and Roberts, T.G., 1958. Economics for drilling for Cretaceous oil on east flank of Denver-Julesburg Basin; American Association of Petroleum Geologists Bulletin, v. 42, no. 11, p. 2549-2566.

Bamber, E.W. and Waterhouse, J.B., 1971. Carboniferous and Permian stratigraphy and paleontology, northern Yukon Territory, Canada; Bulletin of Canadian Petroleum Geology, v. 19, no. 1, p. 29-250.

Bamber, E.W., Henderson, C.M., Richards, B.C., and McGugan, A., 1991. Carboniferous and Permian stratigraphy of the Foreland Belt; in, Part A. Ancestral North America; Upper Devonian to Middle Jurassic Assemblages, Chapter 8; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 242-265.

Barclay, J.E., Holmstrom, G.D., Lee, P.J., Campbell, R.I., and Reinson, G.E., 1997. Carboniferous and Permian gas resources of the Western Canada Sedimentary Basin, Interior Plains, Part I: Geological play analysis and resource assessment; Geological Survey of Canada, Bulletin 515, p. 1-67.

Bell, R.T., 1982. Comments on the geology and uraniferous mineral occurrences of the Wernecke Mountains, Yukon and District of Mackenzie; in, Current Research, Part B, Geological Survey of Canada, Paper 82-1B, p. 279-284.

Beranek, L.P., 2009. Provenance and paleotectonic setting of North American Triassic strata in Yukon: The sedimentary record of pericratonic terrane accretion in the northern Canadian Cordillera; Unpublished Ph.D. thesis, University of British Columbia, Vancouver, British Columbia.

Bird, T. D., Barclay, J. E., Campbell, R. I., and Lee, P. J., 1994a. Triassic gas resources of the Western Canada Sedimentary Basin, Part I: Geological

play analysis and resource assessment; Geological Survey of Canada, Bulletin 483, p 1-66.

Bird, T. D., Barclay, J. E., Campbell, R. I., and Lee, P. J., 1994b. Triassic gas potential seen high in western Canada plains region; Oil and Gas Journal, v. 92, December, 1994, p. 70-73.

Brabb, E.E., 1967. Stratigraphy of the Cambrian and Ordovician rocks of east-central Alaska; United States Geological Survey, Professional Paper 559-A, 30 p.

Cecile, M.P., 1982. The Lower Paleozoic Misty Creek Embayment, Selwyn Basin, Yukon and Northwest Territories; Geological Survey of Canada, Bulletin 335, 78 p.

Cecile, M.P., 1986. Lower Paleozoic embayments, troughs, and arches, northern Canadian Cordillera (abstract); Geological Survey of Canada, Abstracts for Forum on Oil and Gas Activities in Canada, p. 5-6.

Cecile, M.P., 2000. Geology of the northeastern Niddery Lake map area, east-central Yukon and adjacent Northwest Territories; Geological Survey of Canada, Bulletin 553, 119 p.

Cecile, M.P. and Norford, B.S., 1993. Ordovician and Silurian, Subchapter 4C; in, Sedimentary Cover of the Craton in Canada, D.F. Stott and J.D. Aitken (eds.); Geological Survey of Canada, Geology of Canada, no. 5, p. 125-149.

Cecile, M.P., Hutcheon, I.E., and Gardiner, D., 1982. Geology of the Northern Richardson Anticlinorium; Geological Survey of Canada, Open File 875, 1 map.

Cecile, M.P., Morrow, D.W., and Williams, G.K., 1997. Early Paleozoic (Cambrian to Early Devonian) tectonic framework, Canadian Cordillera; Bulletin of Canadian Petroleum Geology, v. 45, no. 1, p. 54-74.

Conybeare, C.E.B., 1965. Hydrocarbon-generation potential and hydrocarbon-yield capacity of sedimentary basins; Bulletin of Canadian Petroleum Geology, v. 13, no. 4, p. 509-528.

Cook, D.G. and MacLean, B.C., 2004. Subsurface Proterozoic stratigraphy and tectonics of the western plains of the Northwest Territories; Geological Survey of Canada, Bulletin 575, 91 p.

Coustau, H., Lee, P.J., Dupuy, J. and Junca, J., 1988. The Jurassic oil resources of the east Shetland basin, North Sea; Bulletin of Canadian Petroleum Geology, v. 36, no. 2, p. 177-185.

Delaney, G.D., 1985. The middle Proterozoic Wernecke Supergroup, Wernecke Mountains, Yukon Territory; Unpublished Ph.D. thesis, University of Western Ontario, London, Ontario, 373 p.

Dietrich, J.R., Coflin, K.C., Lane, L.S., Dixon, J., and Cook, F.A., 1989. Interpretation of deep seismic reflection data; Geological Survey of Canada, Open File 2106, 15 p.

Dixon, J., 1986. Cretaceous to Pleistocene stratigraphy and paleogeography, northern Yukon and northwest District of Mackenzie; Bulletin of Canadian Petroleum Geology, v. 34, no. 1, p. 49-70.

Dixon, J., 1992. Stratigraphy of Mesozoic strata, Eagle Plain area, northern Yukon; Geological Survey of Canada, Bulletin 408, 58 p.

Dixon, J., 1997. Cretaceous and Tertiary, Chapter 11; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 301-317.

Dixon, J., 1999. Mesozoic-Cenozoic stratigraphy of the northern Interior plains and plateaux, Northwest Territories; Geological Survey of Canada, Bulletin 536, 56 p.

Dixon, J., Dietrich, J.R., and McNeil, D.H., 1992. Upper Cretaceous to Pleistocene sequence stratigraphy of the Beaufort-Mackenzie and Banks Island areas, northwest Canada; Geological Survey of Canada, Bulletin 407, 90 p.

Dixon, J., Morrell, G. R., Dietrich, J. R., Procter, R. M., and Taylor, G. C., 1994. Petroleum resources of the Mackenzie Delta and Beaufort Sea, Part I: Basin analysis, Part II: Resource assessment; Geological Survey of Canada, Bulletin 474, p 1-44.

Dolton, G.L., Carlson, K.H., Charpentier, R.R., Coury, A.B., Crovelli, R.A., Frezon, S.E., Khan, A.S., Lister, J.H., McMullin, R.H., Pike, R.S., Powers, R.B., Scott, E.W., and Varnes, K. L., 1981. Estimates of undiscovered recoverable conventional resources of oil and gas in the United States; U.S. Geological Survey Circular 860, 87 p.

Dolton, G.L., Coury, A.B., Frezon, S.E., Robinson, K., Varnes K.L., Wunder, J.M., and Allen, R.W., 1979. Estimates of undiscovered oil and gas, Permian Basin, west Texas and southeast New Mexico; U.S. Geological Survey Open-File Report 79-838, 72 p.

Drew, L.J., Root, D.H., and Bawiec, W.J., 1979. Estimating future rates of petroleum discoveries in the Permian Basin; in, 8th SPE-AIME Symposium on Economics and Evaluation, Dallas, Texas, Proceedings: American Institute of Mining, Metallurgical and Petroleum Engineers, Inc., Society of Petroleum Engineers, p. 101-106.

Drew, L.J., Schuenemeyer, J.H., and Bawiec, W.J., 1982. Estimation of the future rates of oil and gas discoveries in the western Gulf of Mexico; U.S. Geological Survey Professional Paper 1252, 26 p.

Drew, L.J., Schuenemeyer, J.H., and Root, D.H., 1980. Petroleum-resource appraisal and discovery rate forecasting in partially explored regions, Part A: An application to the Denver Basin; U.S. Geological Survey Professional Paper 1138-A, p. A-1-A-11.

Dubord, M.P., 1986. The stratigraphy and petrology of the Ogilvie Formation (Devonian), northern Yukon Territory; Unpublished M.Sc. thesis, University of Waterloo, Waterloo, Ontario, 189 p.

Fraser, T.A., Allen, T.L., Lane, L.S., and Reyes, J.C., 2012. Shale gas potential of Devonian shale in north Yukon: Results from a diamond drillhole study in western Richardson Mountains; in, Yukon Exploration and Geology 2011, K.E. McFarlane and P.J. Sack (eds.); Yukon Geological Survey, p. 45-74.

Fritz, W.H., 1985. The basal contact of the Road River Group – a proposal for its location in the type area and in other selected areas in the Northern Canadian Cordillera; in, Current Research, Part B, Geological Survey of Canada, Paper 85-1B, p. 205-215.

Fritz, W.H., 1991. Cambrian assemblages; in, Cambrian to Middle Devonian assemblages, Chapter 7; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 155-184.

Fritz, W.H., 1997. Cambrian, Chapter 5; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 84-117.

Fritz, W.H., Cecile, M.P., Norford, B.S., Morrow, D., and Geldsetzer, H.H.J., 1991. Cambrian to Middle Devonian assemblages, Chapter 7; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 151-218.

Gabrielse, H., 1967. Tectonic evolution of the northern Canadian Cordillera; Canadian Journal of Earth Sciences, v. 4, p. 271-298.

Gabrielse, H., 1991. Structural styles, Chapter 17; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 571-675.

Gabrielse, H. and Campbell, R.B., 1991. Upper Proterozoic assemblages, Chapter 6; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 125-150.

Gal, L.P., Pyle, L.J., Hadlari, T., and Allen, T.L., 2009. Chapter 6 – Lower to Upper Devonian strata, Arnica-Landry play, and Kee Scarp play; in, Regional Geoscience Studies and Petroleum Potential, Peel Plateau and Plain: Project Volume, L.J. Pyle and A.L. Jones (eds.); Northwest Territories Geocience Office and Yukon Geological Survey, NWT Open File 2009-02 and YGS Open File 2009-25, p. 477-549.

GeoChem Laboratories (Canada) Ltd. and AGAT Consultants Ltd., 1977. Lower Mackenzie energy corridor study, geochemical component; National Energy Board Report 051-04-06-001.

Gordey, S.P., 1991. Devonian-Mississippian clastics of the Foreland and Omineca Belts; in, Part A. Ancestral North America; Upper Devonian to Middle Jurassic assemblages, Chapter 8; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 230-242.

Graham, A.D., 1973. Carboniferous and Permian stratigraphy, southern Eagle Plain, Yukon Territory, Canada; in, Symposium on the Geology of the Canadian Arctic, Proceedings, J.D. Aitken and D. Glass (eds.); Geological Association of Canada-Canadian Society of Petroleum Geologists, p. 159-180.

Green, L.H., 1972. Geology of Nash Creek, Larsen Creek and Dawson map areas, Yukon Territory (106D, 116A, B, C); Geological Survey of Canada, Memoir 364, 157 p.

Hadlari, T., Gal, L.P., Zantvoort, W.G., Tylosky, S.A., Allen, T.L., Fraser, T.A., Lemieux, Y., and Catuneanu, O., 2009a. Chapter 7 – Upper Devonian to Carboniferous strata I – Imperial Formation play; in, Regional Geoscience Studies and Petroleum Potential, Peel Plateau and Plain: Project Volume, L.J. Pyle and A.L. Jones (eds.); Northwest Territories Geocience Office and Yukon Geological Survey, NWT Open File 2009-02 and YGS Open File 2009-25, p. 290-364.

Hadlari, T., Thomson, D., Schröder-Adams, C.J., Lemieux, Y., MacLean, B.C., and Gal, L.P., 2009b. Chapter 9 – Cretaceous strata and basal Cretaceous sandstone play; in, Regional Geoscience Studies and Petroleum Potential, Peel Plateau and Plain: Project Volume, L.J. Pyle and A.L. Jones (eds.);

Northwest Territories Geocience Office and Yukon Geological Survey, NWT Open File 2009-02 and YGS Open File 2009-25, p. 410-476.

Haggart, J.W., Bell, K.M., Schröder-Adams, C.J., Campbell, J.A., Mahoney, J.B., and Jackson, K., 2013. New biostratigraphic data from Cretaceous strata of the Eagle Plain region, northern Yukon: Reassessment of age, regional stratigraphic relationships, and depositional controls; Bulletin of Canadian Petroleum Geology, v. 61, no. 2, p. 101-132.

Hall, K.W., 1996. Geophysical transect of the Eagle Plains foldbelt and Richardson Mountains anticlinorium, northern Yukon and western Northwest Territories, Canada; Unpublished M.Sc. thesis, University of Calgary, Calgary, Alberta, 67 p.

Hall, K.W. and Cook, F.A., 1998. Geophysical transect of the Eagle Plains foldbelt and Richardson Mountains anticlinorium, northwestern Canada; Geological Society of America Bulletin, v. 110, no. 3, p. 311-325.

Hamblin, A.P., 1990. Upper Paleozoic petroleum geology and potential, southern Eagle Plain, Yukon Territory; Geological Survey of Canada, Open File 2286, 49 p.

Hamblin, A.P., 2006. The “shale gas” concept in Canada: A preliminary inventory of possibilities; Geological Survey of Canada, Open File 5384, 103 p, 1 CD-ROM.

Hamblin, A.P. and Lee, P.J., 1997. Uppermost Cretaceous, post-Colorado Group gas resources of the Western Canada Sedimentary Basin, Interior Plains; Geological play analysis and resource assessment; Geological Survey of Canada, Bulletin 518, 88 p.

Hannigan, P.K., 2000. Petroleum resource assessment of Bonnet Plume Basin, Yukon Territory, Canada; Yukon Economic Development, Whitehorse, Yukon, 59 p.

Hannigan, P.K., 2001. Petroleum resource assessment of Old Crow Basin, Yukon Territory, Canada; Yukon Economic Development, Whitehorse, Yukon, 63 p.

Hannigan, P.K., Dietrich, J.R., Lee, P.J., and Osadetz, K.G., 2001. Petroleum resource potential of sedimentary basins on the Pacific margin of Canada; Geological Survey of Canada, Bulletin 564, 72 p.

Hannigan, P.K., Morrow, D.W., and MacLean, B.C., 2011. Petroleum resource potential of the northern mainland of Canada (Mackenzie Corridor); Geological Survey of Canada, Open File 6757, 260 p.

Hannigan, P.K., Osadetz, K.G., Dixon, J., and Bird, T.D., 1999. Petroleum resource assessment of the Kandik Basin, Yukon Territory, Canada; Yukon Economic Development, Whitehorse, Yukon, 73 p.

Hayes, B.J.R. and Archibald, H.B., 2012. Scoping study of unconventional oil and gas potential, Yukon; Yukon Geological Survey, Miscellaneous Report 7, 100 p.

Henderson, C.M., 1989. The lower Absaroka Sequence: Upper Carboniferous and Permian; in, Western Canada Sedimentary Basin, a Case History, B.D. Ricketts (ed.); Canadian Society of Petroleum Geologists, p. 203-217.

Henderson, C.M., Bamber, E.W., Richards, B.C., Higgins, A.C., and McGugan, A., 1993. Permian, Subchapter 4F; in, Sedimentary Cover of the Craton in Canada, D.F. Stott and J.D. Aitken (eds.); Geological Survey of Canada, Geology of Canada, no. 5, p. 272-293.

Hendricks, T.A., 1965. Resources of oil, gas, and natural gas liquids in the United States and the World; U.S. Geological Survey Circular 522, 20 p.

Hendricks, T.A., 1974. Estimating resources of crude oil and natural gas in inadequately explored areas-Methods of estimating the volume of undiscovered oil and gas resources; American Association of Petroleum Geologists Research Symposium, August 21-23, 1974, Stanford University, p. 47-57.

Hills, L.V. and Braman, D.R., 1978. Sedimentary structures of the Imperial Formation, northwest Canada; in, Display Summaries, Canadian Society of Petroleum Geologists-Core and Field Sample Conference 1978, A.F. Embry (ed.); Canadian Society of Petroleum Geologists, p. 35-37.

Hoffman, P.F., 1987. Continental transform tectonics: Great Slave Shear Zone (ca. 1.9 Ga), northwest Canada; Geology, v. 15, no. 9, p. 785-788.

Hoffman, P.F., 1989. Precambrian geology and tectonic history of North America; in, The Geology of North America – An Overview, A.W. Bally and A.R. Palmer (eds.), Geological Society of America, The Geology of North America, v. A., p. 447-512.

Howell, D.G., 1996. Kandik Basin; in, 1995 National Assessment of United States Oil and Gas Resources-Results, Methodology, and Supporting Data, D.L. Gautier, G.L. Dolton, K.I. Takahashi, and K.L. Varnes (eds.); United States Geological Survey Digital Data Series-30, Release 2, CD-ROM.

Indian and Northern Affairs Canada, 1995. Petroleum exploration in northern Canada: A guide to oil and gas exploration and potential, G.R. Morrell (ed.); Northern Oil and Gas Directorate, Indian and Northern Affairs Canada, 110 p.

Jackson, K., McQuilkin, M., Pederson, P.K., Meyer, R., and Lane, L.S., 2011. Preliminary observations on stratigraphy and hydrocarbon potential of middle to Upper Cretaceous strata, Eagle Plain basin, northern Yukon; in, Yukon Exploration and Geology 2010, K.E. McFarlane, L.H. Weston and C. Relf (eds.); Yukon Geological Survey, p. 125-134.

Johnson, J.G., Klapper, G., and Sandberg, C.A., 1985. Devonian eustatic fluctuations in Euramerica; Geological Society of America, Bulletin, v. 96, p. 567-587.

Kaufman, G.M. and Lee, P.J., 1992. Are wildcat well outcomes dependent or independent? Nonrenewable Resources, v. 1, no. 3, p. 201-213.

Klemme, H.D., 1971. The giants and the supergiants; Oil and Gas Journal, v. 69, no. 9, p. 85-90; no. 10, p. 103-110; no. 11, p. 96-100.

Klemme, H.D., 1975. Giant oil fields related to their geologic setting-A possible guide to exploration; Bulletin of Canadian Petroleum Geology, v. 23, no. 1, p. 30-66.

Lane, L.S., 1991. The pre-Mississippian "Neruokpuk Formation," northeastern Alaska and northwestern Yukon: Review and new regional correlation; Canadian Journal of Earth Sciences, v. 28, p. 1521-1533.

Lane, L.S., 1996. Geometry and tectonics of Early Tertiary triangle zones, northeastern Eagle Plain, Yukon Territory; Bulletin of Canadian Petroleum Geology, v. 44, no. 2, p. 337-348.

Lane, L.S., 1998. Latest Cretaceous-Tertiary tectonic evolution of northern Yukon and adjacent Arctic Alaska; American Association of Petroleum Geologists, Bulletin, v. 82, no. 7, p. 1353-1371.

Lane, L.S., 2007. Devonian-Carboniferous paleogeography and orogenesis, northern Yukon and adjacent Arctic Alaska; Canadian Journal of Earth Sciences, v. 44, p. 679-694.

Lane, L.S., 2010. Phanerozoic structural evolution of Eagle Plain, Yukon; Canadian Society of Petroleum Geologists, Reservoir, no. 2, p. 9.

Lavoie, D., Pinet, N., Dietrich, J., Hannigan, P., Castonguay, S., Hamblin, A.P., and Giles, P., 2009. Petroleum resource assessment, Paleozoic successions of the St. Lawrence Platform and Appalachians of eastern Canada; Geological Survey of Canada, Open File 6174, 273 p.

Law, B.E., 2002. Basin-centred gas systems; American Association of Petroleum Geologists, Bulletin, v. 86, no. 11, p. 1891-1919.

Lawrence, J.R., 1973. Old Crow Basin; in, The Future Petroleum Provinces of Canada-Their Geology and Potential, R.G. McCrossan (ed.); Canadian Society of Petroleum Geologists, Memoir 1, p. 307-315.

Lee, F.C. and Lee, P.J., 1994. Petroleum resource assessments - a fractal approach; in, Current Research, Part E; Geological Survey of Canada, Paper 94-1E, p. 265-270.

Lee, P. J., 1993a. Two decades of Geological Survey of Canada petroleum resource assessments; Canadian Journal of Earth Sciences, v. 30, no. 2, p. 321-332.

Lee, P.J., 1993b. Oil and gas pool size probability distributions - J-shaped, lognormal or Pareto; in, Current Research, Part E; Geological Survey of Canada, Paper 94-1E, p. 93-96.

Lee, P.J., 1998. Oil resources of western Canada; Geological Survey of Canada, Open File 3674, 142 p.

Lee, P.J. and Price, P.R., 1991. Successes in 1980's bode well for western Canada search; Oil and Gas Journal, v. 89, April 22, 1991, p. 94-97.

Lee, P.J. and Singer, D.A., 1994. Using PETRIMES to estimate mercury deposits in California; Nonrenewable Resources; v. 3, no. 3, p. 191-199.

Lee, P. J. and Tzeng, H. P., 1993. The petroleum exploration and resource evaluation system (PETRIMES): Working reference guide, version 3.0 (PC version); Geological Survey of Canada, Open File 2703, 312 p.

Lee, P. J. and Tzeng, H. P., 1995. Effects of appreciation and/or depreciation of gas pools on petroleum resource estimation; in, Proceedings of the Oil and Gas Forum ‘95 - Energy from Sediments, J.S. Bell, T.D. Bird, T.L. Hillier, and P.L. Greener (eds.); Geological Survey of Canada, Open File 3058, p. 341-343.

Lee, P. J. and Wang, P. C. C., 1983a. Probabilistic formulation of a method for the evaluation of petroleum resources; Mathematical Geology, v. 15, no. 1, p. 163-181.

Lee, P. J. and Wang, P. C. C., 1983b. Conditional analysis for petroleum resource evaluations; Mathematical Geology, v. 15, no. 2, p. 353-365.

Lee, P. J. and Wang, P. C. C., 1984. PRIMES: A petroleum resource information management and evaluation system; Oil and Gas Journal, v. 82, October 1, 1984, p. 204-206.

Lee, P. J. and Wang, P. C. C., 1985. Prediction of oil or gas pool sizes when discovery record is available; Mathematical Geology, v. 17, no. 2, p. 95-113.

Lee, P. J. and Wang, P. C. C., 1986. Evaluation of petroleum resources from pool size distribution; in, Oil and Gas Assessment Methods and Applications, D.D. Rice (ed.); American Association of Petroleum Geologists, Studies in Geology, no. 21, p. 33-42.

Lee, P.J. and Wang, P.C.C., 1990. An introduction to petroleum resource evaluation methods; Canadian Society of Petroleum Geologists, 1990 Convention on Basin Perspectives, Short Courses Program: SC-2 Petroleum Resource Evaluation, 108 p.

Lee, P.J., Olsen-Heise, K., and Tzeng, P., 1995. Contrasts between the GSC and CPGC procedures for estimating undiscovered gas resources; in, Proceedings of the Oil and Gas Forum '95 - Energy from Sediments, J.S. Bell, T.D. Bird, T.L. Hillier, and P.L. Greener (eds.); Geological Survey of Canada, Open File 3058, p. 337-340.

Lee, P.J., Quin, R.Z., and Shi, Y.M., 1988. Conditional probability analysis of geological risk factors; in, Statistical Applications in the Earth Sciences, F. Agterberg and G. Bonham-Carter (eds.); Geological Survey of Canada, Paper 89-9, p. 271-276.

Lenz, A.C., 1972. Ordovician to Devonian history of northern Yukon and adjacent District of Mackenzie; Bulletin of Canadian Petroleum Geology, v. 20, no. 2, p. 321-361.

Lerand, M., 1973. Beaufort Sea; in, The Future Petroleum Provinces of Canada-Their Geology and Potential; Canadian Society of Petroleum Geologists, Memoir 1, p. 315-386.

Link, C.M. and Bustin, R.M., 1989. Organic maturation and thermal history of Phanerozoic strata in northern Yukon and northwestern District of Mackenzie; Bulletin of Canadian Petroleum Geology, v. 37, no. 3, p. 266-292.

Link, C.M., Bustin, R.M., and Snowdon, L.R., 1989. Petroleum source potential and depositional setting of Phanerozoic strata in northern Yukon and northwestern District of Mackenzie; Bulletin of Canadian Petroleum Geology, v. 37, no. 3, p. 293-315.

Logan, K.G., 2005. The Truncated Discovery Process Model; Natural Resources Research, v. 14, no. 3, p. 265-281.

Long, D.G.F., 1978. Lignite deposits in the Bonnet Plume Formation, Yukon Territory; in, Current Research, Part A, Geological Survey of Canada, Paper 78-1A, p. 399-401.

Long, D.G.F., 1987. Coal in Yukon; in, Mineral Deposits of Northern Cordillera, J.A. Morin (ed.); Canadian Institute of Mining and Metallurgy, Special Volume 37, p. 311-318.

Lutchman, M., 1977. Mississippian clastic wedge; in, Lower Mackenzie Energy Corridor Study, Geological Component; AGAT Consultants Ltd., p. M1-M10.

Martin, H.L., 1972. Upper Paleozoic stratigraphy of the Eagle Plain Basin, Yukon Territory; Geological Survey of Canada, Paper 71-14, 54 p.

Martin, H.L., 1973. Eagle Plain basin; in, The Future Petroleum Provinces of Canada-Their Geology and Potential; Canadian Society of Petroleum Geologists, Memoir 1, p. 275-306.

Masters, C.D., 1984a. Petroleum resource assessment; International Union of Geological Sciences, Publication No. 17, 157 p.

Masters, J.A., 1979. Deep Basin gas trap, western Canada; American Association of Petroleum Geologists, Bulletin, v. 86, no. 11, p. 1851-1852.

Masters, J.A., (editor) 1984b. Elmworth – Case study of a Deep Basin gas field; American Association of Petroleum Geologists, Memoir 38, 316 p.

McCrossan, R.G. and Porter, J.W., 1973. The geology and petroleum potential of the Canadian sedimentary basins-A synthesis; in, The Future Petroleum Provinces of Canada-Their Geology and Potential; Canadian Society of Petroleum Geologists, Memoir 1, p. 589-720.

McDowell, A.V., 1975. What are the problems in estimating the oil potential of a basin? Oil and Gas Journal, v. 73, June 9, p. 85-90.

Meert, J.G. and Torsvik, T.H., 2003. The making and unmaking of a supercontinent: Rodinia revisited; Tectonophysics, v. 375, no. 1-4, p. 261-288.

Momper, J.A., 1979. Domestic oil reserves forecasting method, regional potential assessment; Oil and Gas Journal, v. 77, no. 33, p. 144-149.

Moore, P.F., 1993. Devonian, Subchapter 4D; in, Sedimentary Cover of the Craton in Canada, D.F. Stott and J.D. Aitken (eds.); Geological Survey of Canada, Geology of Canada, no. 5, p. 150-201.

Morrell, G. and Dietrich, J.R., 1993. Evaluation of the hydrocarbon prospectivity of the Old Crow Flats area of the northern Yukon; Bulletin of Canadian Petroleum Geology, v. 41, no. 1, p. 32-45.

Morrow, D.W., 1989. Lower Paleozoic stratigraphy of the White Mountains, Yukon and Northwest Territories, and sedimentological evidence for a 'White Mountains platform'; in, Current Research, Part G; Geological Survey of Canada, Paper 89-1G, p. 77-84.

Morrow, D.W., 1991. The Silurian-Devonian sequence in the northern part of the Mackenzie shelf, Northwest Territories; Geological Survey of Canada, Bulletin 413, 121 p.

Morrow, D.W., 1999. Lower Paleozoic stratigraphy of northern Yukon Territory and northwestern District of Mackenzie; Geological Survey of Canada, Bulletin 538, 202 p.

Morrow, D.W., 2012. Devonian of the Northern Canadian Mainland Sedimentary Basin (a contribution to the Geological Atlas of the northern Canadian Mainland Sedimentary Basin); Geological Survey of Canada, Open File 6997, 88 p.

Morrow, D.W. and Geldsetzer, H.H.J., 1991. Lower and Middle Devonian assemblages; in, Cambrian to Middle Devonian Assemblages, Chapter 7, W.H. Fritz, M.P. Cecile, B.S. Norford, D. Morrow, and H.H.J. Geldsetzer; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 151-218.

Mountjoy, E.W., 1967a. Upper Cretaceous and Tertiary stratigraphy, northern Yukon Territory and northwestern District of Mackenzie; Geological Survey of Canada, Paper 66-16, 70 p.

Mountjoy, E.W., 1967b. Triassic stratigraphy of northern Yukon Territory; Geological Survey of Canada, Paper 66-19, 44 p.

National Energy Board, 2000. Petroleum resource assessment of the Eagle Plain Basin, Yukon Territory, Canada; Energy Resources Branch, Yukon Economic Development, 74 p.

Norford, B.S., 1997. Ordovician and Silurian, Chapter 6; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 119-162.

Norford, B.S. and Macqueen, R.W., 1975. Lower Paleozoic Franklin Mountain and Mount Kindle formations, District of Mackenzie: Their type sections and regional development; Geological Survey of Canada, Paper 74-34, 37 p.

Norris, A.W., 1997a. Devonian, Chapter 7; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 163-200.

Norris, D.K., 1974. Structural geometry and geological history of the northern Canadian Cordillera; in, Proceedings of the First National Convention, Canadian Society of Exploration Geophysicists, Calgary, April 1973, p. 18-45.

Norris, D.K., 1984. Geology of the northern Yukon and northwestern District of Mackenzie; Geological Survey of Canada, Map 1528A, scale 1:500,000.

Norris, D.K., 1985. Eastern Cordillera foldbelt of northern Canada: Its structural geometry and hydrocarbon potential; American Association of Petroleum Geologists Bulletin, v. 69, no. 5, p. 788-808.

Norris, D.K., 1997b. Geological setting, Chapter 3; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 21-64.

Norris, D.K., 1997c. Triassic, Chapter 9; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 252-269.

Norris, D.K. and Cameron, A.R., 1986. An occurrence of bitumen in the Interior Platform near Rengleng River, District of Mackenzie; in, Current Research, Part A, Geological Survey of Canada, Paper 86-1A, p. 645-648.

Norris, D.K. and Dyke, L.D., 1997. Proterozoic, Chapter 4; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 65-83.

Norris, D.K. and Hopkins, W.S., Jr., 1977. The geology of the Bonnet Plume Basin, Yukon Territory; Geological Survey of Canada, Paper 76-8, 20 p.

Norris, D.K. and Hughes, O.L., 1997. Mineral and hydrocarbon potential, Chapter 15; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 369-396.

Norris, D.K. and Yorath, C.J., 1981. The North American Plate from the Arctic Archipelago to the Romanzof Mountains; in, The Arctic Ocean, E.M. Nairn, M. Churkin Jr., and F.G. Stehli (eds.); The Ocean Basins and Margins, Plenum Press, New York and London, v. 5, Chapter 3, p. 37-103.

Olsen-Heise, K., Lee, P. J., and Reinson, G.E., 1995. Resource assessment of the Cadotte Plains and Deep Basin gas; in, Proceedings of the Oil and Gas Forum '95 - Energy from Sediments, J.S. Bell, T.D. Bird, T.L. Hillier, and P.L. Greener (eds.); Geological Survey of Canada, Open File 3058, p. 361.

Osadetz, K.G. and Snowdon, L.R., 1995. Significant Paleozoic petroleum source rocks in the Canadian Williston Basin: Their distribution, richness and thermal maturity (southeastern Saskatchewan and southwestern Manitoba); Geological Survey of Canada, Bulletin 487, 60 p.

Osadetz, K.G., Chen, Z., and Bird, T.D., 2005a. Petroleum resource assessment, Eagle Plain Basin and environs, Yukon Territory, Canada; Geological Survey of Canada, Open File 4922, 88 p., 1 CD-ROM.

Osadetz, K.G., MacLean, B.C., Morrow, D.W., Dixon, J., and Hannigan, P.K., 2005b. Petroleum resource assessment, Peel Plateau and Plain, Yukon Territory, Canada; Geological Survey of Canada, Open File 4841, 76 p, 1 CD-ROM.

Peters, K.E., 1986. Guidelines for evaluating petroleum source rock using programmed pyrolysis; American Association of Petroleum Geologists, Bulletin, v. 70, no. 3, p. 318-329.

Peters, K.E., Walters, C.C., and Moldowan, J.M., 2005. The Biomarker Guide, Volume I. Biomarkers and Isotopes in the Environment and Human History; Cambridge University Press, New York, 471 p.

Podruski, J. A., Barclay, J. E., Hamblin, A. P., Lee, P. J., Osadetz, K. G., Procter, R. M., and Taylor, G. C., 1988. Conventional oil resources of Western Canada (light and medium), Part I: Resource endowment; Geological Survey of Canada, Paper 87-26, p. 1-125.

Poulton, T.P., 1982. Paleogeographic and tectonic implications of the Lower and Middle Jurassic facies patterns in northern Yukon Territory and adjacent Northwest Territories; in, Proceedings of the 3rd International Symposium on the Geology of the Arctic, A.F. Embry and R.L. Christie (eds.); Canadian Society of Petroleum Geologists, p. 13-17.

Poulton, T.P., 1997. Jurassic, Chapter 10; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.); Geological Survey of Canada, Bulletin 422, p. 266-299.

Procter, R. M., Taylor, G. C., and Wade, J. A., 1984. Oil and natural gas resources of Canada 1983; Geological Survey of Canada, Paper 83-31, 59 p.

Pugh, D.C., 1983. Pre-Mesozoic geology in the subsurface of Peel River map area, Yukon Territory and District of Mackenzie; Geological Survey of Canada, Memoir 401, 61 p.

Pyle, L.J. and Gal, L. P., 2007. Lower to Middle Paleozoic stratigraphy and measured sections, NTS 106F, G, H, I, Northwest Territories; Northwest Territories Geoscience Office, NWT Open Report 2007-004, 95 p.

Read, J.F., 1985. Carbonate platform facies models; American Association of Petroleum Geologists, Bulletin, v. 69, p. 1-21.

Reinson, G.E. and Lee, P.J., 1993. Study finds Devonian gas resources of western Canada attractive target; Oil and Gas Journal, v. 91, September 13, 1993, p. 80-85.

Reinson, G. E., Lee, P. J., Warters, W., Osadetz, K. G., Bell, L. L., Price, P. R., Trollope, F., Campbell, R. I., and Barclay, J. E., 1993. Devonian gas resources of the Western Canada Sedimentary Basin; Part I: Geological play analysis and resource assessment; Geological Survey of Canada, Bulletin 452, p. 1- 127.

Reiser, H.N., Brosge, W.P., Dutro, J.T., and Detterman, R.L., 1980. Geologic map of the Demarcation Point quadrangle, Alaska; U.S. Geological Survey, Miscellaneous Investigations Series, Map I-1133.

Rice, D. D., 1986. Oil and gas assessment - methods and applications; American Association of Petroleum Geology, Studies in Geology, no. 21, 267 p.

Richards, B.C., 1989. Upper Kaskaskia Sequence: uppermost Devonian and Lower Carboniferous; in, Western Canada Sedimentary Basin, a Case History, B.D. Ricketts (ed.); Canadian Society of Petroleum Geologists, p. 165-201.

Richards, B.C., Bamber, E.W., and Utting, J., 1997. Upper Devonian to Permian; in, Geology and Mineral and Hydrocarbon Potential of Northern Yukon Territory and Northwestern District of Mackenzie, D.K. Norris (ed.), Geological Survey of Canada, Bulletin 422, p. 201-251.

Ricketts, B.D., 1988. The Monster Formation: A coastal fan system of Late Cretaceous age, Yukon Territory; Geological Survey of Canada, Paper 86-14, 27 p.

Root, D.H. and Schuenemeyer, J.H., 1980. Petroleum-resource appraisal and discovery rate forecasting in partially explored regions, part B: Mathematical foundations; U.S. Geological Survey Professional Paper 1138-B, p. B1-B9.

Ross, G.M., Broome, J., and Miles, W., 1994. Potential fields and basement structure –

Western Canada Sedimentary Basin; in, Geological Atlas of the Western Canada Sedimentary Basin, G.D. Mossop and I. Shetsen (comps.); Canadian Society of Petroleum Geologists and Alberta Research Council, p. 41-47.

Schenk, C.J. and Pollastro, R.M., 2002. Natural gas production in the United States; U.S. Geological Survey, Fact Sheet, FS 0113-01, 2 p.

Sinclair, I. K., McAlpine, K.D., Sherwin, D. F., and McMillan, N. J., 1992. Petroleum resources of the Jeanne D'Arc Basin and environs; Part I: Geological framework; Geological Survey of Canada, Paper 92-8 p. 1-38.

Sloss, L.L., 1963. Sequences in the cratonic interior of North America; Geological Society of America, Bulletin, v. 74, no. 2, p. 93-114.

Snowdon, L.R., 1988. Petroleum source rock potential and thermal maturation reconnaissance in Eagle Plain, Yukon Territory; Geological Survey of Canada, Open File 1720, 115 p.

Snowdon, L.R., Brooks, P.W., Williams, G.K., and Goodarzi, F., 1987. Correlation of the Canol Formation source rock with oil from Norman Wells; Organic Geochemistry, v. 11, no. 6, p. 529-548.

Stelck, C.R., 1944. Final geological report on "The Upper Peel River Area", Yukon Territory (Canada); Imperial Oil Limited, Canol Project Assignment No. 23.

Stott, D.F., Yorath, C.J., and Dixon, J., 1991. The Foreland Belt; in, Upper Jurassic to Paleogene Assemblages, Chapter 9; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 335-344.

Stott, D.F., Caldwell, W.G.E., Cant, D.J., Christopher, J.E., Dixon, J., Koster, E.H., McNeil, D.H., and Simpson, F., 1993. Cretaceous, Subchapter 4I; in, Sedimentary Cover of the Craton in Canada, D.F. Stott and J.D. Aitken (eds.); Geological Survey of Canada, Geology of Canada, no. 5, p. 358-438.

Tassonyi, E.J., 1969. Subsurface geology, lower Mackenzie River and Anderson River areas, District of Mackenzie; Geological Survey of Canada, Paper 68-25, 207 p.

Veezay Geodata Ltd. (1977) Limited Partnership, 1983. Geologic report, 1982 Mackenzie Basin Canada Lands exploration program, COGLA Project Number 9230-V2-1P.

Wade, J. A., Campbell, G. R., Procter, R. M., and Taylor, G. C., 1989: Petroleum resources of the Scotian Shelf; Geological Survey of Canada, Paper 88-19, 26 p.

Warters, W.J., Cant, D.J., Tzeng, H.P., and Lee, P.J., 1997. Mannville gas resources of the Western Canada Sedimentary Basin; Geological Survey of Canada, Bulletin 517, 101 p.

Weeks, L.G., 1949. Highlights on 1948 developments in foreign petroleum fields; American Association of Petroleum Geologists, Bulletin, v. 33, no. 6, p. 1029-1124.

Weeks, L.G., 1950. Concerning estimates of potential oil reserves; American Association of Petroleum Geologists, Bulletin, v. 34, no. 10, p. 1947-1953.

Wheeler, J. O. and McFeeley, P., 1991. Tectonic assemblage map of the Canadian Cordillera and adjacent parts of the United States of America; Geological Survey of Canada, Map 1712A, scale 1:2,000,000.

White, D. A. and Gehman, H. M., 1979. Methods of estimating oil and gas resources; American Association of Petroleum Geologists, Bulletin, v. 63, no. 12, p. 2183-2192.

Williams, G. K., 1988. A review of the Bonnet Plume area, east-central Yukon Territory (including Snake River, Solo Creek, Noisy Creek and Royal Creek areas); Geological Survey of Canada, Open File 1742, 70 p.

Yorath, C.J., 1991. Upper Jurassic to Paleogene assemblages, Chapter 9; in, Geology of the Cordilleran Orogen in Canada, H. Gabrielse and C.J. Yorath (eds.); Geological Survey of Canada, Geology of Canada, no. 4, p. 329-371.

APPENDIX A

TERMINOLOGY

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

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

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

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

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

Various statistical terms are specified in this report. A *population* is a set of entities. *Probability* is the likelihood of occurrence while a *probability distribution* describes the range of possible values that a *random variable* can attain and the probability that the value of the random variable is within that range. A *random variable* is a variable whose value results from a measurement of on a random process. A *lognormal probability*

distribution is a distribution of a random variable whose logarithm is normally distributed. The *mean* is the average of a population while the *median* is the measure of the central tendency of a population (P50). *Percentiles* are values dividing a rank-ordered set into 100 equal parts. *P95-P5*, for example, represents a range of percentiles representing the 95% and 5% cumulative probabilities. *Cumulative probability* or *frequency* represents the total number of scores less than or greater than a percentile. *Probability in upper percentiles* denotes percentile values using the cumulative 'greater than' distribution convention. Unlike classical statistics where the cumulative 'less than' percentile distributions are traditionally employed, the 'greater than' convention is used in petroleum assessments because explorationists are particularly interested in the upside potential of prospects. Percentiles are thus expressed as *upper percentiles*. A *marginal probability* is the probability of one variable taking a specific value irrespective of the values of others in a multivariate distribution. *Pool-size-by-rank* indicates the size of the largest pool, the second largest pool, and so on.

APPENDIX B

INPUT DATA FOR PETROLEUM ASSESSMENTS

The following tables present the probability distributions of reservoir parameters and number of prospects and marginal probabilities of geological risk factors used as input for the various volumetric statistical analyses discussed in this paper. These estimates are based on subjective opinion, partly constrained by reservoir data and information from analogous petroleum-bearing basins. Numbering of tables corresponds to play numerations in Table 1 and the text.

EAGLE PLAIN BASIN

1-G. LOWER PALEOZOIC CARBONATE PRE-LARAMIDE STRUCTURAL GAS PLAY

TABLE B-1-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	40	450	5035	5110
Net pay	m	1	15	60	150
Porosity	decimal fraction	0.05	0.1	0.155	0.16
Trap fill	decimal fraction	0.05	0.2	0.5	0.95
Water saturation	decimal fraction	0.05	0.12	0.39	0.45
Formation volume factor		0.004	0.006	0.0069	0.007

TABLE B-1-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.75		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.5		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.5		√
Adequate maturation	1.0	√	

TABLE B-1-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	17	30	60

2-G. LOWER PALEOZOIC CARBONATE LARAMIDE STRUCTURAL GAS PLAY

TABLE B-2-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	40	480	10925	13240
Net pay	m	1	25	190	200
Porosity	decimal fraction	0.05	0.11	0.21	0.24
Trap fill	decimal fraction	0.05	0.2	0.5	0.95
Water saturation	decimal fraction	0.04	0.23	0.47	0.5
Formation volume factor		0.004	0.006	0.0069	0.007

TABLE B-2-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.75		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.875		√
Adequate seal	1.0	√	
Adequate timing	0.25		√
Adequate source	0.5		√
Adequate maturation	0.875		√

TABLE B-2-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	88	165	310

3-G. LOWER PALEOZOIC CARBONATE STRATIGRAPHIC GAS PLAY

TABLE B-3-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	40	600	9065	9075
Net pay	m	1	25	190	200
Porosity	decimal fraction	0.05	0.11	0.21	0.24
Trap fill	decimal fraction	0.1	0.3	0.7	0.95
Water saturation	decimal fraction	0.04	0.23	0.47	0.5
Formation volume factor		0.004	0.006	0.0069	0.007

TABLE B-3-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.88		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.5		√
Adequate maturation	0.88		√

TABLE B-3-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	20	150	300

4-O. IMPERIAL/TUTTLE SANDSTONE STRUCTURAL (ELLESMERIAN DEFORMATION-BELL SUBBASIN) OIL PLAY

TABLE B-4-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1160	13500	14000
Net pay	m	1	6	35	36
Porosity	decimal fraction	0.08	0.17	0.23	0.24
Trap fill	decimal fraction	0.05	0.1	0.12	0.15
Water saturation	decimal fraction	0.25	0.38	0.48	0.481
Formation volume factor		1.05	1.12	1.28	1.3

TABLE B-4-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.75		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.5		√
Adequate seal	1.0	√	
Adequate timing	0.75		√
Adequate source	0.5		√
Adequate maturation	0.5		√

TABLE B-4-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	12	20	40

4-G. IMPERIAL/TUTTLE SANDSTONE STRUCTURAL (ELLESMERIAN DEFORMATION-BELL SUBBASIN) GAS PLAY

TABLE B-4-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1160	13500	14000
Net pay	m	1	6	35	36
Porosity	decimal fraction	0.08	0.17	0.23	0.24
Trap fill	decimal fraction	0.05	0.4	0.7	0.9
Water saturation	decimal fraction	0.25	0.38	0.48	0.481
Formation volume factor		0.005	0.0055	0.012	0.013

TABLE B-4-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.75		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.5		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.5		√
Adequate maturation	1.0	√	

TABLE B-4-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	12	20	40

5-O. IMPERIAL/TUTTLE SANDSTONE STRATIGRAPHIC/COMBINATION OIL PLAY

TABLE B-5-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	595	12065	13240
Net pay	m	1	4.3	6.24	6.25
Porosity	decimal fraction	0.08	0.16	0.31	0.32
Trap fill	decimal fraction	0.05	0.1	0.12	0.15
Water saturation	decimal fraction	0.17	0.42	0.4989	0.4997
Formation volume factor		1.15	1.3	1.349	1.35

TABLE B-5-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.55		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.55		√
Adequate seal	0.82		√
Adequate timing	0.73		√
Adequate source	0.36		√
Adequate maturation	0.55		√

TABLE B-5-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	60	75	105

5-G. IMPERIAL/TUTTLE SANDSTONE STRATIGRAPHIC/COMBINATION GAS PLAY

TABLE B-5-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	595	12065	13240
Net pay	m	1	4.3	6.24	6.25
Porosity	decimal fraction	0.08	0.16	0.31	0.32
Trap fill	decimal fraction	0.05	0.4	0.7	0.9
Water saturation	decimal fraction	0.17	0.42	0.4989	0.4997
Formation volume factor		0.0046	0.0053	0.011	0.012

TABLE B-5-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.55		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.55		√
Adequate seal	0.82		√
Adequate timing	1.0	√	
Adequate source	0.36		√
Adequate maturation	1.0	√	

TABLE B-5-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	60	75	105

6-O. CANOE RIVER CARBONATE STRUCTURAL OIL PLAY

TABLE B-6-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	40	410	4160	4220
Net pay	m	1	12	123	124
Porosity	decimal fraction	0.05	0.1	0.21	0.33
Trap fill	decimal fraction	0.05	0.1	0.12	0.2
Water saturation	decimal fraction	0.08	0.23	0.43	0.49
Formation volume factor		1.19	1.27	1.2994	1.3

TABLE B-6-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.75		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.67		√
Adequate seal	1.0	√	
Adequate timing	0.33		√
Adequate source	1.0	√	
Adequate maturation	0.89		√

TABLE B-6-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	17	26	40

6-G. CANOE RIVER CARBONATE STRUCTURAL GAS PLAY

TABLE B-6-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	40	410	4160	4220
Net pay	m	1	12	123	124
Porosity	decimal fraction	0.05	0.1	0.21	0.33
Trap fill	decimal fraction	0.1	0.4	0.6	0.8
Water saturation	decimal fraction	0.08	0.23	0.43	0.49
Formation volume factor		0.0074	0.0094	0.011	0.012

TABLE B-6-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.75		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.67		√
Adequate seal	1.0	√	
Adequate timing	0.44		√
Adequate source	1.0	√	
Adequate maturation	1.0	√	

TABLE B-6-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	17	26	40

7-O. CANOE RIVER CARBONATE STRATIGRAPHIC OIL PLAY

TABLE B-7-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	20	90	415	420
Net pay	m	0.5	12	123	124
Porosity	decimal fraction	0.02	0.1	0.21	0.33
Trap fill	decimal fraction	0.05	0.1	0.15	0.2
Water saturation	decimal fraction	0.08	0.23	0.43	0.49
Formation volume factor		1.19	1.27	1.2994	1.3

TABLE B-7-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.67		√
Adequate seal	1.0	√	
Adequate timing	1.0		√
Adequate source	1.0	√	
Adequate maturation	0.5		√

TABLE B-7-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	25	37	55

7-G. CANOE RIVER CARBONATE STRATIGRAPHIC GAS PLAY

TABLE B-7-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	20	90	415	420
Net pay	m	0.5	12	123	124
Porosity	decimal fraction	0.02	0.1	0.21	0.33
Trap fill	decimal fraction	0.2	0.6	0.75	1.0
Water saturation	decimal fraction	0.08	0.23	0.43	0.49
Formation volume factor		0.0074	0.0094	0.011	0.012

TABLE B-7-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.67		√
Adequate seal	1.0	√	
Adequate timing	1.0		√
Adequate source	1.0	√	
Adequate maturation	1.0	√	

TABLE B-7-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	25	37	55

8-O. CHANCE SANDSTONE STRUCTURAL OIL PLAY

TABLE B-8-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1500	4140	4225
Net pay	m	1	5	43	44
Porosity	decimal fraction	0.08	0.13	0.24	0.28
Trap fill	decimal fraction	0.05	0.1	0.12	0.2
Water saturation	decimal fraction	0.01	0.22	0.45	0.49
Formation volume factor		1.17	1.25	1.345	1.35

TABLE B-8-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.8		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.5		√
Adequate seal	1.0	√	
Adequate timing	0.5		√
Adequate source	1.0	√	
Adequate maturation	0.9		√

TABLE B-8-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	14	22	35

8-G. CHANCE SANDSTONE STRUCTURAL GAS PLAY

TABLE B-8-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1500	4140	4225
Net pay	m	1	5	43	44
Porosity	decimal fraction	0.08	0.13	0.24	0.28
Trap fill	decimal fraction	0.1	0.4	0.6	0.8
Water saturation	decimal fraction	0.01	0.22	0.45	0.49
Formation volume factor		0.003	0.0065	0.009	0.0091

TABLE B-8-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.8		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.7		√
Adequate seal	1.0	√	
Adequate timing	0.5		√
Adequate source	1.0	√	
Adequate maturation	1.0		√

TABLE B-8-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	14	22	35

9-O. CHANCE SANDSTONE STRATIGRAPHIC OIL PLAY

TABLE B-9-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1500	3400	3500
Net pay	m	1	7	52	55
Porosity	decimal fraction	0.08	0.13	0.24	0.28
Trap fill	decimal fraction	0.05	0.1	0.15	0.2
Water saturation	decimal fraction	0.01	0.22	0.45	0.49
Formation volume factor		1.17	1.25	1.345	1.35

TABLE B-9-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.55		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.73		√
Adequate seal	1.0	√	
Adequate timing	1.0		√
Adequate source	1.0	√	
Adequate maturation	0.5		√

TABLE B-9-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	14	30	65

9-G. CHANCE SANDSTONE STRATIGRAPHIC GAS PLAY

TABLE B-9-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1500	3400	3500
Net pay	m	1	7	52	55
Porosity	decimal fraction	0.08	0.13	0.24	0.28
Trap fill	decimal fraction	0.2	0.6	0.75	1.0
Water saturation	decimal fraction	0.01	0.22	0.45	0.49
Formation volume factor		0.003	0.0064	0.009	0.0091

TABLE B-9-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.55		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.73		√
Adequate seal	1.0	√	
Adequate timing	1.0		√
Adequate source	1.0	√	
Adequate maturation	1.0		√

TABLE B-9-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	14	30	65

10-O. ALDER CARBONATE STRUCTURAL OIL PLAY

TABLE B-10-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	500	4160	4220
Net pay	m	1	11	76	80
Porosity	decimal fraction	0.06	0.1	0.21	0.33
Trap fill	decimal fraction	0.05	0.1	0.12	0.2
Water saturation	decimal fraction	0.015	0.22	0.41	0.48
Formation volume factor		1.19	1.24	1.289	1.29

TABLE B-10-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.25		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.75		√
Adequate seal	1.0	√	
Adequate timing	0.75		√
Adequate source	1.0	√	
Adequate maturation	0.75		√

TABLE B-10-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	12	17	25

10-G. ALDER CARBONATE STRUCTURAL GAS PLAY

TABLE B-10-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	500	4160	4220
Net pay	m	1	11	76	80
Porosity	decimal fraction	0.06	0.1	0.21	0.33
Trap fill	decimal fraction	0.1	0.4	0.6	0.8
Water saturation	decimal fraction	0.015	0.22	0.41	0.48
Formation volume factor		0.0082	0.014	0.0159	0.016

TABLE B-10-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.25		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.75		√
Adequate seal	1.0	√	
Adequate timing	0.75		√
Adequate source	1.0	√	
Adequate maturation	1.0		√

TABLE B-10-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	12	17	25

11-O. ALDER CARBONATE STRATIGRAPHIC OIL PLAY

TABLE B-11-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1500	3400	3500
Net pay	m	1	11	76	80
Porosity	decimal fraction	0.06	0.1	0.21	0.33
Trap fill	decimal fraction	0.05	0.1	0.15	0.2
Water saturation	decimal fraction	0.015	0.22	0.41	0.48
Formation volume factor		1.19	1.24	1.289	1.29

TABLE B-11-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.2		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.8		√
Adequate seal	1.0	√	
Adequate timing	0.8		√
Adequate source	1.0	√	
Adequate maturation	0.8		√

TABLE B-11-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	14	30	65

11-G. ALDER CARBONATE STRATIGRAPHIC GAS PLAY

TABLE B-11-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1500	3400	3500
Net pay	m	1	11	76	80
Porosity	decimal fraction	0.06	0.1	0.21	0.33
Trap fill	decimal fraction	0.2	0.6	0.75	1.0
Water saturation	decimal fraction	0.015	0.22	0.41	0.48
Formation volume factor		0.0082	0.014	0.0159	0.016

TABLE B-11-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.2		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.8		√
Adequate seal	1.0	√	
Adequate timing	1.0		√
Adequate source	1.0	√	
Adequate maturation	1.0		√

TABLE B-11-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	14	30	65

14-O. JUNGLE CREEK SANDSTONE STRUCTURAL OIL PLAY

TABLE B-14-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	500	2900	3000
Net pay	m	1	48	100	101
Porosity	decimal fraction	0.08	0.16	0.27	0.29
Trap fill	decimal fraction	0.05	0.1	0.15	0.2
Water saturation	decimal fraction	0.06	0.24	0.48	0.5
Formation volume factor		1.07	1.11	1.34	1.35

TABLE B-14-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	1.0		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.8		√
Adequate seal	1.0	√	
Adequate timing	0.2		√
Adequate source	0.6		√
Adequate maturation	0.8		√

TABLE B-14-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	7	20	35

14-G. JUNGLE CREEK SANDSTONE STRUCTURAL GAS PLAY

TABLE B-14-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	500	2900	3000
Net pay	m	1	48	100	101
Porosity	decimal fraction	0.08	0.16	0.27	0.29
Trap fill	decimal fraction	0.1	0.4	0.6	0.8
Water saturation	decimal fraction	0.06	0.24	0.48	0.5
Formation volume factor		0.0066	0.016	0.025	0.026

TABLE B-14-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	1.0		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.8		√
Adequate seal	1.0	√	
Adequate timing	0.6		√
Adequate source	0.6		√
Adequate maturation	1.0	√	

TABLE B-14-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	7	20	35

15-O. JUNGLE CREEK SANDSTONE STRATIGRAPHIC OIL PLAY

TABLE B-15-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	150	1400	10000	16000
Net pay	m	1	15	100	101
Porosity	decimal fraction	0.08	0.16	0.27	0.29
Trap fill	decimal fraction	0.05	0.1	0.15	0.2
Water saturation	decimal fraction	0.06	0.24	0.48	0.5
Formation volume factor		1.07	1.11	1.34	1.35

TABLE B-15-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.83		√
Adequate seal	1.0	√	
Adequate timing	1.0		√
Adequate source	0.67		√
Adequate maturation	0.34		√

TABLE B-15-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	20	50	125

15-G. JUNGLE CREEK SANDSTONE STRATIGRAPHIC GAS PLAY

TABLE B-15-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	150	1400	10000	16000
Net pay	m	1	15	100	101
Porosity	decimal fraction	0.08	0.16	0.27	0.29
Trap fill	decimal fraction	0.25	0.65	0.8	1.0
Water saturation	decimal fraction	0.06	0.24	0.48	0.5
Formation volume factor		0.0066	0.018	0.025	0.026

TABLE B-15-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.83		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.67		√
Adequate maturation	1.0	√	

TABLE B-15-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	20	50	125

16-O. JURASSIC/LOWER CRETACEOUS SANDSTONE PRE-ALBIAN STRUCTURAL OIL PLAY

TABLE B-16-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	40	270	1700	1800
Net pay	m	1	15	45	50
Porosity	decimal fraction	0.08	0.2	0.28	0.29
Trap fill	decimal fraction	0.05	0.1	0.15	0.2
Water saturation	decimal fraction	0.24	0.41	0.499	0.5
Formation volume factor		1.2	1.27	1.379	1.38

TABLE B-16-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	1.0		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.5		√
Adequate maturation	1.0		√

TABLE B-16-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	4	8	15

16-G. JURASSIC/LOWER CRETACEOUS SANDSTONE PRE-ALBIAN STRUCTURAL GAS PLAY

TABLE B-16-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	40	270	1700	1800
Net pay	m	1	15	45	50
Porosity	decimal fraction	0.08	0.2	0.28	0.29
Trap fill	decimal fraction	0.1	0.4	0.6	0.8
Water saturation	decimal fraction	0.24	0.41	0.499	0.5
Formation volume factor		0.0045	0.005	0.0059	0.006

TABLE B-16-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	1.0		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	1.0	√	
Adequate maturation	1.0		√

TABLE B-16-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	4	8	15

17-O. JURASSIC/LOWER CRETACEOUS SANDSTONE STRATIGRAPHIC OIL PLAY

TABLE B-17-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	20	240	2900	3000
Net pay	m	1	15	20	50
Porosity	decimal fraction	0.08	0.2	0.28	0.29
Trap fill	decimal fraction	0.05	0.1	0.15	0.2
Water saturation	decimal fraction	0.24	0.41	0.499	0.5
Formation volume factor		1.27	1.33	1.379	1.38

TABLE B-17-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.6		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.8		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.2		√
Adequate maturation	1.0		√

TABLE B-17-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	4	15	20

17-G. JURASSIC/LOWER CRETACEOUS SANDSTONE STRATIGRAPHIC GAS PLAY

TABLE B-17-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	20	240	2900	3000
Net pay	m	1	15	20	50
Porosity	decimal fraction	0.08	0.2	0.28	0.29
Trap fill	decimal fraction	0.25	0.65	0.8	1.0
Water saturation	decimal fraction	0.24	0.41	0.499	0.5
Formation volume factor		0.0047	0.0055	0.0065	0.0066

TABLE B-17-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.6		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.8		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.8		√
Adequate maturation	1.0		√

TABLE B-17-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	4	15	20

18-O. TRIANGLE ZONE STRUCTURAL (BELL SUBBASIN) OIL PLAY

TABLE B-18-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	2400	8000	8100
Net pay	m	1	5	35	40
Porosity	decimal fraction	0.08	0.19	0.28	0.29
Trap fill	decimal fraction	0.05	0.1	0.15	0.2
Water saturation	decimal fraction	0.24	0.41	0.499	0.5
Formation volume factor		1.0	1.25	1.49	1.5

TABLE B-18-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.5		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.5		√
Adequate maturation	1.0		√

TABLE B-18-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	13	30	45

18-G. TRIANGLE ZONE STRUCTURAL (BELL SUBBASIN) GAS PLAY

TABLE B-18-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	2400	8000	8100
Net pay	m	1	5	35	40
Porosity	decimal fraction	0.08	0.19	0.28	0.29
Trap fill	decimal fraction	0.1	0.4	0.6	0.8
Water saturation	decimal fraction	0.24	0.41	0.499	0.5
Formation volume factor		0.0049	0.0055	0.0065	0.0066

TABLE B-18-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.5		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.5		√
Adequate maturation	1.0	√	

TABLE B-18-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	13	30	45

19-G. CRETACEOUS SANDSTONE STRUCTURAL GAS PLAY

TABLE B-19-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	45	650	18900	21150
Net pay	m	1	5	38	40
Porosity	decimal fraction	0.08	0.2	0.28	0.35
Trap fill	decimal fraction	0.1	0.5	0.7	1.0
Water saturation	decimal fraction	0.1	0.44	0.499	0.5
Formation volume factor		0.013	0.015	0.0159	0.016

TABLE B-19-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.47		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.71		√
Adequate seal	0.88		√
Adequate timing	0.82		√
Adequate source	0.71		√
Adequate maturation	0.88		√

TABLE B-19-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	13	35	95

20-O. CRETACEOUS SANDSTONE SHELF STRATIGRAPHIC OIL PLAY

TABLE B-20-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	20	500	2000	3000
Net pay	m	1	5	38	40
Porosity	decimal fraction	0.08	0.2	0.28	0.35
Trap fill	decimal fraction	0.05	0.08	0.1	0.3
Water saturation	decimal fraction	0.1	0.44	0.499	0.5
Formation volume factor		1.05	1.15	1.219	1.22

TABLE B-20-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.47		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.8		√
Adequate seal	0.87		√
Adequate timing	1.0	√	
Adequate source	0.8		√
Adequate maturation	0.33		√

TABLE B-20-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	23	29	52

20-G. CRETACEOUS SANDSTONE SHELF STRATIGRAPHIC GAS PLAY

TABLE B-20-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	20	500	2000	3000
Net pay	m	1	5	38	40
Porosity	decimal fraction	0.08	0.2	0.28	0.35
Trap fill	decimal fraction	0.1	0.5	0.7	1.0
Water saturation	decimal fraction	0.1	0.44	0.499	0.5
Formation volume factor		0.013	0.015	0.0159	0.016

TABLE B-20-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.47		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.8		√
Adequate seal	0.87		√
Adequate timing	1.0	√	
Adequate source	0.73		√
Adequate maturation	0.87		√

TABLE B-20-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	23	29	52

21-O. CRETACEOUS SANDSTONE SLOPE STRATIGRAPHIC OIL PLAY

TABLE B-21-O(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1100	12100	12140
Net pay	m	6	30	118	120
Porosity	decimal fraction	0.08	0.18	0.29	0.3
Trap fill	decimal fraction	0.05	0.08	0.1	0.3
Water saturation	decimal fraction	0.1	0.33	0.499	0.5
Formation volume factor		1.05	1.15	1.219	1.22

TABLE B-21-O(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.4		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.5		√
Adequate maturation	0.5		√

TABLE B-21-O(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	34	80	135

21-G. CRETACEOUS SANDSTONE SLOPE STRATIGRAPHIC GAS PLAY

TABLE B-21-G(a) – Pool size probability distributions

Geological variable	Unit of measurement	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
		1.0	**0.5**	**0.01**	**0.0**
Area of closure	ha	100	1100	12100	12140
Net pay	m	6	30	118	120
Porosity	decimal fraction	0.08	0.18	0.29	0.3
Trap fill	decimal fraction	0.1	0.5	0.7	1.0
Water saturation	decimal fraction	0.1	0.33	0.499	0.5
Formation volume factor		0.013	0.015	0.0159	0.016

TABLE B-21-G(b) - Marginal probabilities of geological risk factors

Geological factors	Marginal probability	Play level	Prospect level
Adequate closure	0.5		√
Presence of reservoir facies	1.0	√	
Adequate porosity	0.4		√
Adequate seal	1.0	√	
Adequate timing	1.0	√	
Adequate source	0.5		√
Adequate maturation	1.0		√

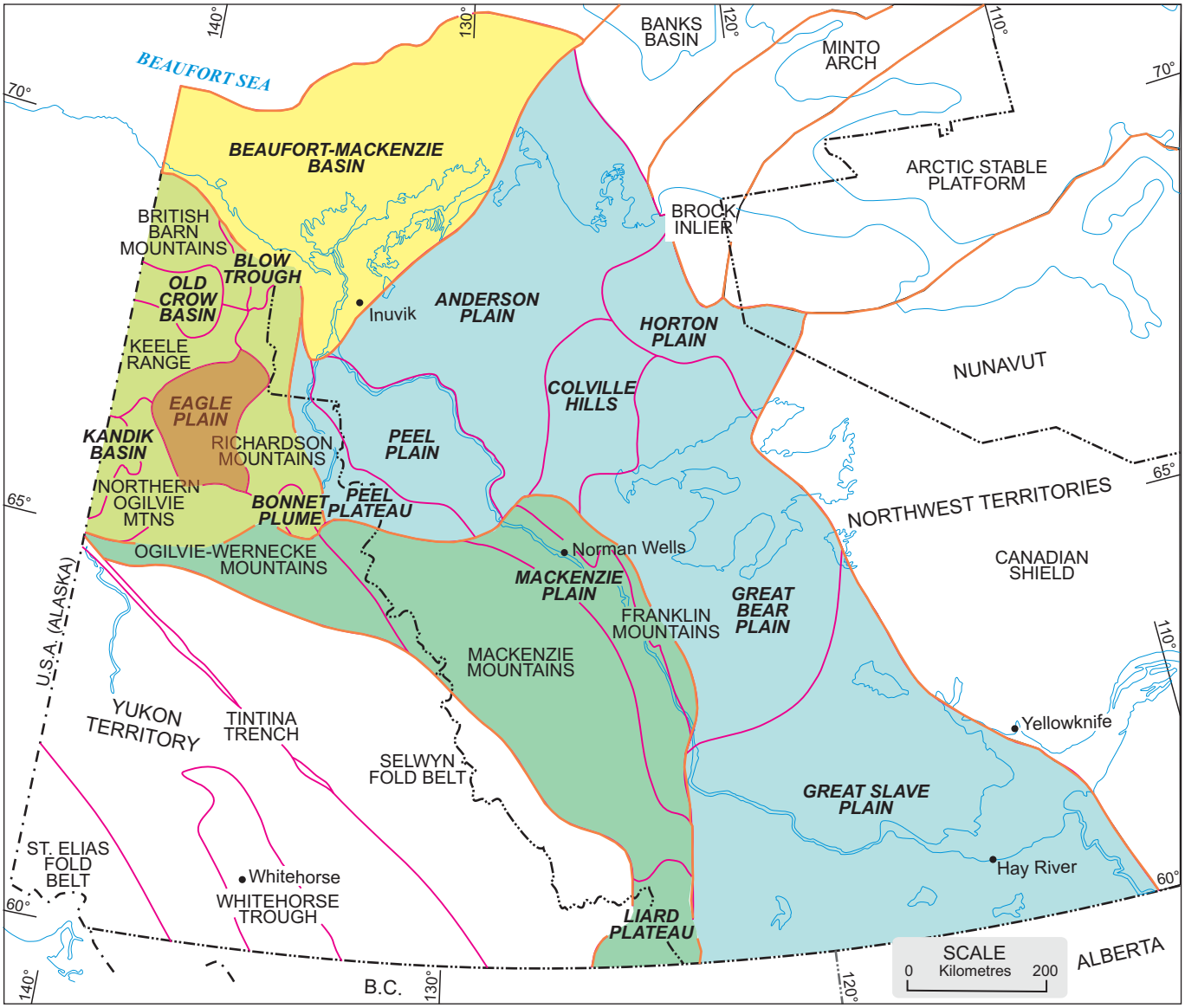
TABLE B-21-G(c) – Number of prospects probability distribution

Geological variable	Probability in upper percentiles	Probability in upper percentiles	Probability in upper percentiles
	0.99	**0.5**	**0.0**
Number of prospects	34	80	135

Table 1: Summary of petroleum exploration plays in the Eagle Plains Basin area

Play Name	Gas/Oil	Play type	Reservoir	Source	Seal	Trap style	Discoveries/shows
1) Lower Paleozoic carbonate pre-Laramide structural	gas	Conceptual	Bouvette, Ogilvie, Mt. Dewdney carbonates	Road River shales, organic-rich layers in Ogilvie carbonates, Canol shales	Road River & Canol shales	anticlinal folds, thrust fault traps, duplex structures	no discoveries or significant shows
2) Lower Paleozoic carbonate Laramide structural	gas	Conceptual	Bouvette, Ogilvie, Mt. Dewdney carbonates	Road River shales, organic-rich layers in Ogilvie carbonates, Canol shales	Road River & Canol shales	anticlinal folds, thrust fault traps	2 gas flows in DSTs, Ogilvie Formation in S. Tuttle N-05 well and Shaeffer Creek O-22 well; traces of gas in 2 other wells
3) Lower Paleozoic carbonate stratigraphic	gas	Conceptual	Bouvette, Ogilvie, Mt. Dewdney carbonates	Road River shales, organic-rich layers in Ogilvie carbonates, Canol shales	Road River & Canol shales	basinward and updip facies changes; dolomitized and fractured carbonate bodies; stratabound interior platform porous zones; combination structural/stratigraphic	1 gas flow in DST, Ogilvie Formation in S. Tuttle N-05 well; traces of gas in 1 other well
4) Imperial/Tuttle sandstone structural (Ellesmerian deformation-Bell Subbasin)	gas/oil	Conceptual	Imperial, Tuttle sandstones & conglomerates	Canol, Ford Lake, Road River and Imperial shales	Bug Creek, Whitestone River & Mount Goodenough shales interbedded shales in Imperial Fm	anticlinal folds, thrust fault traps	no discoveries or significant shows
5) Imperial/Tuttle sandstone stratigraphic/combination	gas/oil	Immature (gas); conceptual (oil)	Imperial, Tuttle sandstones & conglomerates	Canol, Ford Lake, Road River and Imperial shales	Ford Lake shales (both lateral and top seal); interbedded shales in Imperial Fm	subcrop edge pinchouts, intraformational stratigraphic pinchouts, updip facies changes, unconformity subcrop; combination structural/stratigraphic	2 gas pools; Birch B-34, Chance L-08 (M-08) traces of gas in 4 other wells, significant show of oil & gas in 1 other well
6) Canoe River carbonate structural	gas/oil	Conceptual	Canoe River carbonates	Ford Lake shales	well-cemented Chance sandstone; interbedded lime wackestones	anticlinal folds; faulted anticlines, thrust fault traps	minor gas show in 1 well; traces of oil in 4 other wells
7) Canoe River carbonate stratigraphic	gas/oil	Immature	Canoe River carbonates	Ford Lake shales	Ford Lake shales (lateral); Whitestone River shales (top)	updip facies changes, unconformity subcrop; basinward facies changes; combined structural/stratigraphic traps beneath sub-Cretaceous unconformity	1 gas pool, Chance J-19 1 significant oil & gas show; Chance L-08 (M-08) minor gas show in 1 well; traces of oil in 4 other wells
8) Chance sandstone structural	gas/oil	Immature (gas); conceptual (oil)	Chance sandstones	Ford Lake shales	tight limestone, shale and siltstone of Alder Member	anticlinal folds; faulted anticlines, thrust fault traps	1 gas pool, Birch B-34 1 gas flow in DST; E. Porcupine YT I-13 minor gas shows in 2 other wells; traces of oil in 4 other wells
9) Chance sandstone stratigraphic	gas/oil	Immature	Chance sandstones	Ford Lake shales	Whitestone River shales (top); well-cemented Hart River limestone members (lateral)	updip facies changes, unconformity subcrop; combined structural/stratigraphic traps beneath sub-Cretaceous unconformity	2 oil & gas pools; Chance L-08 (M-08) 2 oil pools; Chance G-08, Chance J-19 1 gas pool; Chance L-08 (M-08) 1 oil recovery in DST, W. Parkin D-51 3 gas flows in DST, 2 in East Chance C-18 well, E. Porcupine I-13 minor gas shows in 2 other wells; traces of oil in 4 other wells
10) Alder carbonate structural	gas/oil	Conceptual	Alder carbonates	Ford Lake and Blackie shales, Hart River organic-rich strata	Blackie shales (top)	anticlinal folds; faulted anticlines, thrust fault traps	no discoveries or significant shows
11) Alder carbonate stratigraphic	gas/oil	Conceptual	Alder carbonates	Ford Lake and Blackie shales, Hart River organic-rich strata	Whitestone River shales (top); well-cemented Alder limestone layers (lateral)	porosity pinchouts, unconformity subcrop; combined structural/stratigraphic traps beneath sub-Cretaceous unconformity	no discoveries or significant shows
12) Ettrain carbonate structural	gas/oil	Conceptual	Ettrain carbonates	Blackie shales	well-cemented Jungle Ridge sandstone; interbedded lime wackestones	anticlinal folds; faulted anticlines, thrust fault traps	no discoveries or significant shows
13) Ettrain carbonate stratigraphic	gas/oil	Conceptual	Ettrain carbonates	Blackie shales	Whitestone River shales	porosity pinchouts, unconformity subcrop; combined structural/stratigraphic traps beneath sub-Cretaceous unconformity	no discoveries or significant shows
14) Jungle Creek sandstone structural	gas/oil	Immature (gas); conceptual (oil)	Jungle Creek sandstones	Blackie shales	Jungle Creek shale members	anticlinal folds; faulted anticlines, thrust fault traps	1 gas pool; Blackie M-59; also minor oil shows 1 gas flow in DST with minor oil shows; E. Porcupine I-13 minor oil and gas shows in 2 other wells
15) Jungle Creek sandstone stratigraphic	gas/oil	Conceptual	Jungle Creek sandstones	Blackie shales	Whitestone River shales; contiguous Jungle Creek shale members	updip facies changes, unconformity subcrop; combined structural/stratigraphic traps beneath sub-Cretaceous unconformity	2 gas flows in DST; E. Porcupine I-13; S. Chance D-63 1 gas recovery in DST; S. Chance D-63 minor oil and gas shows in 2 other wells
16) Jurassic-Lower Cretaceous sandstone pre-Albian structural	gas/oil	Conceptual	Porcupine River, Mount Goodenough, Rat River, and Sharp Mountain coarse clastics	Whitestone River, Mount Goodenough and Porcupine River shales (gas only); Ford Lake and Blackie shales (oil and/or gas)	Whitestone River shales (top); interbedded Mount Goodenough shales; Kingak shales (lateral)	normal faults; tilted fault blocks	no discoveries or significant shows
17) Jurassic-Lower Cretaceous sandstone stratigraphic	gas/oil	Conceptual	Porcupine River, Mount Goodenough, Rat River, and Sharp Mountain coarse clastics	Whitestone River, Mount Goodenough and Porcupine River shales (gas only); Ford Lake and Blackie shales (oil and/or gas)	Whitestone River shales (top); interbedded shales & siltstones; Kingak shales (lateral)	unconformity subcrop; stratigraphic pinchouts; basinward facies changes	1 gas flow in DST; Ridge F-48; traces of oil in same well minor oil and gas in 1 other well minor gas shows in 2 other wells
18) Triangle Zone structural (Bell Subbasin)	gas/oil	Conceptual	Porcupine River, Mount Goodenough, Rat River, and Sharp Mountain coarse clastics	Whitestone River, Mount Goodenough and Porcupine River shales (gas only); Ford Lake and Blackie shales (oil and/or gas)	Whitestone River shales (top); interbedded shales & siltstones; Kingak shales (lateral)	thrust-repeated stacked reservoirs; fault propagation folds; fault bend folds; drag folds on thrust faults, duplex structures; imbricate thrusts; subthrust structures	no discoveries or significant shows
19) Cretaceous sandstone structural	gas/oil	Immature (gas); conceptual (oil)	Eagle Plain Group (Parkin Fm basal and middle ss, Fishing Branch and Cody Creek sandstones	Whitestone River, Parkin and Burnthill Creek shales (gas only) Ford Lake and Blackie shales (oil and/or gas)	interbedded Eagle Plain Group shales	anticlinal folds; faulted anticlines, thrust fault traps	1 gas pool; Chance L-08 (M-08) 4 gas flows in DSTs; Chance G-08, W. Parkin C-33; E. Porcupine F-18, W. Parkin D-54 traces of oil in 2 of the above wells; minor oil and gas show in 1 other well minor oil shows in 5 other wells; minor gas shows in 4 other wells
20) Cretaceous sandstone shelf stratigraphic	gas/oil	Conceptual	Eagle Plain Group (Parkin Fm basal and middle sandstones, Fishing Branch and Cody Creek sandstones)	Whitestone River, Parkin and Burnthill Creek shales (gas only) Ford Lake and Blackie shales (oil and/or gas)	interbedded Eagle Plain Group shales	valley & channel fills; shelf-margin deltas; offshore bars	5 gas flows in DSTs; Chance L-08 (M-08), Chance G-08, W. Parkin C-33; E. Porcupine F-18, W. Parkin D-54 traces of oil in 2 of the above wells; minor oil and gas show in 1 other well minor oil shows in 5 other wells; minor gas shows in 4 other wells
21) Cretaceous sandstone slope stratigraphic	gas/oil	Conceptual	Eagle Plain Group (Parkin Fm basal and middle sandstones, Fishing Branch and Cody Creek sandstones)	Whitestone River, Parkin and Burnthill Creek shales (gas only) Ford Lake and Blackie shales (oil and/or gas)	interbedded Eagle Plain Group shales	turbidite sands (channels,fans and lobes); shelf-margin deltas	no discoveries or significant shows

Table 2: Conventional oil and gas potential of Eagle Plain Basin							
Play name	No. of	Discovered	Expected no.	Range of play	Mean play	Mean of largest	Median of largest
All volumes initial in place (E6 m3)	discoveries	volumes	of pools	potential	potential	undiscovered	undiscovered
						pool size	pool size
Lower Paleozoic carbonate pre-Laramide structural (gas)	0	0	7	222-3471	1483	616	472
Lower Paleozoic carbonate Laramide structural (gas)	0	0	13	1402-13222	6050	1996	1490
Lower Paleozoic carbonate stratigraphic (gas)	0	0	30	3050-44567	21403	3705	3103
Imperial/Tuttle sandstone structural (Ellesmerian deformation-Bell Subbasin) (oil)	0	0	2	0-4.3	1.3	1.1	0.8
Imperial/Tuttle sandstone structural (Ellesmerian deformation-Bell Subbasin) (gas)	0	0	5	289-8024	3203	1438	1143
Imperial/Tuttle sandstone stratigraphic/combination (oil)	0	0	3	0-1.8	0.7	0.4	0.3
Imperial/Tuttle sandstone stratigraphic/combination (gas)	2	279	7	430-3453	1677	633	510
Canoe River carbonate structural (oil)	0	0	4	0.2-3.6	1.5	0.7	0.6
Canoe River carbonate structural (gas)	0	0	6	222-2591	1170	495	386
Canoe River carbonate stratigraphic (oil)	0	0	7	0.1-0.9	0.5	0.2	0.1
Canoe River carbonate stratigraphic (gas)	1	83	13	292-1283	730	178	152
Chance sandstone structural (oil)	0	0	4	0.4-5.3	2.4	1	0.9
Chance sandstone structural (gas)	1	249	7	855-5735	2858	940	821
Chance sandstone stratigraphic (oil)	3	3.2	7	1.1-11.4	5.4	0.8	0.8
Chance sandstone stratigraphic (gas)	3	2330	14	3883-24648	12590	2321	2105
Alder carbonate structural (oil)	0	0	2	0-2.3	0.7	0.6	0.4
Alder carbonate structural (gas)	0	0	3	0-961	350	224	171
Alder carbonate stratigraphic (oil)	0	0	4	0.2-8.8	3.6	1.7	1.5
Alder carbonate stratigraphic (gas)	0	0	6	481-6664	3013	1039	916
Ettrain carbonate structural (oil & gas)							
Ettrain carbonate stratigraphic (oil & gas)							
Jungle Creek structural (oil)	0	0	2	0-10.3	3.5	2.7	2.4
Jungle Creek structural (gas)	1	1447	6	717-7442	3629	756	721
Jungle Creek stratigraphic (oil)	0	0	6	1.0-33.4	13.4	5.3	4.3
Jungle Creek stratigraphic (gas)	0	0	17	3670-33896	15917	3272	2799
Jurassic-Lower Cretaceous sandstone pre-Albian structural (oil)	0	0	2	0-2.4	0.9	0.6	0.5
Jurassic-Lower Cretaceous sandstone pre-Albian structural (gas)	0	0	5	395-3899	1858	720	639
Jurassic-Lower Cretaceous sandstone stratigraphic (oil)	0	0	1	0-1.7	0.5	0.5	0.4
Jurassic-Lower Cretaceous sandstone stratigraphic (gas)	0	0	5	447-6652	3086	1203	1024
Triangle Zone structural (Bell Subbasin) (oil)	0	0	4	0.4-10.1	4.3	2	1.7
Triangle Zone structural (Bell Subbasin) (gas)	0	0	4	357-9143	3948	1812	1570
Cretaceous sandstone structural (oil)							
Cretaceous sandstone structural (gas)	1	193	7	95-3704	1382	605	431
Cretaceous sandstone shelf stratigraphic (oil)	0	0	3	0-2	0.7	0.4	0.3
Cretaceous sandstone shelf stratigraphic (gas)	0	0	7	214-1618	801	270	230
Cretaceous sandstone slope stratigraphic (oil)	0	0	4	0.7-30.8	12.4	5.9	4.7
Cretaceous sandstone slope stratigraphic (gas)	0	0	8	2464-23746	11281	3406	2925
Total	3 (oil); 9 (gas)	3.2 (oil); 4581 (gas)	55 (oil); 170 (gas)		52.2 (oil); 96741 (gas)		



GEOLOGICAL PROVINCES

- Beaufort-Mackenzie Basin
- Northern Yukon Fold Complex
- Interior Platform
- Northern Foreland Belt
- Exploration regions

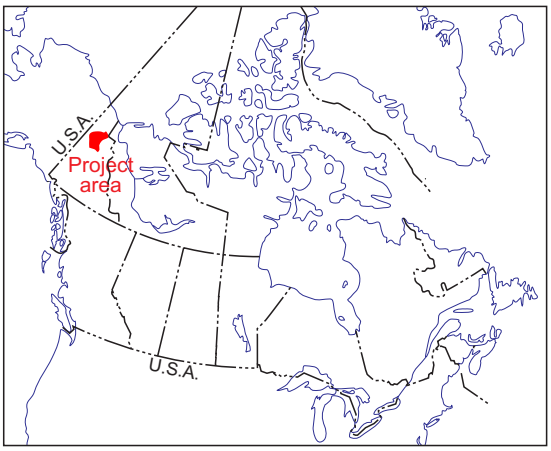


Figure 1. Geological provinces of the northern mainland of Canada. The Eagle Plain project area is found within the Northern Yukon Fold Complex province.

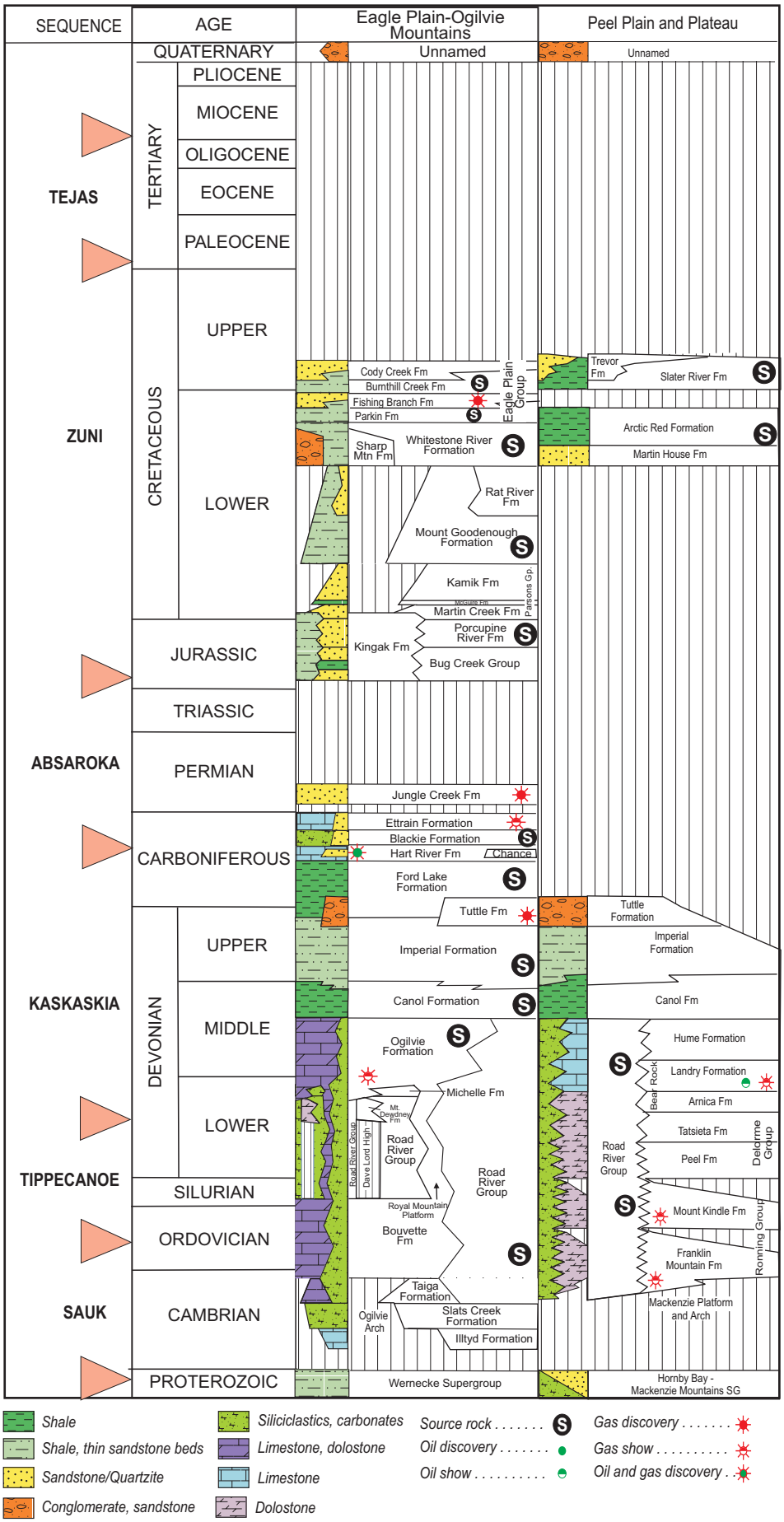


Figure 2. Correlation chart of sedimentary strata in Eagle Plain basin and Peel Plateau and Plain. Petroleum discoveries, shows and known and potential source rocks are indicated. From Morrow (1999), Dixon (1999), Pugh (1993), Hadlari et al. (2009a, 2009b) and Haggart et al. (2013).

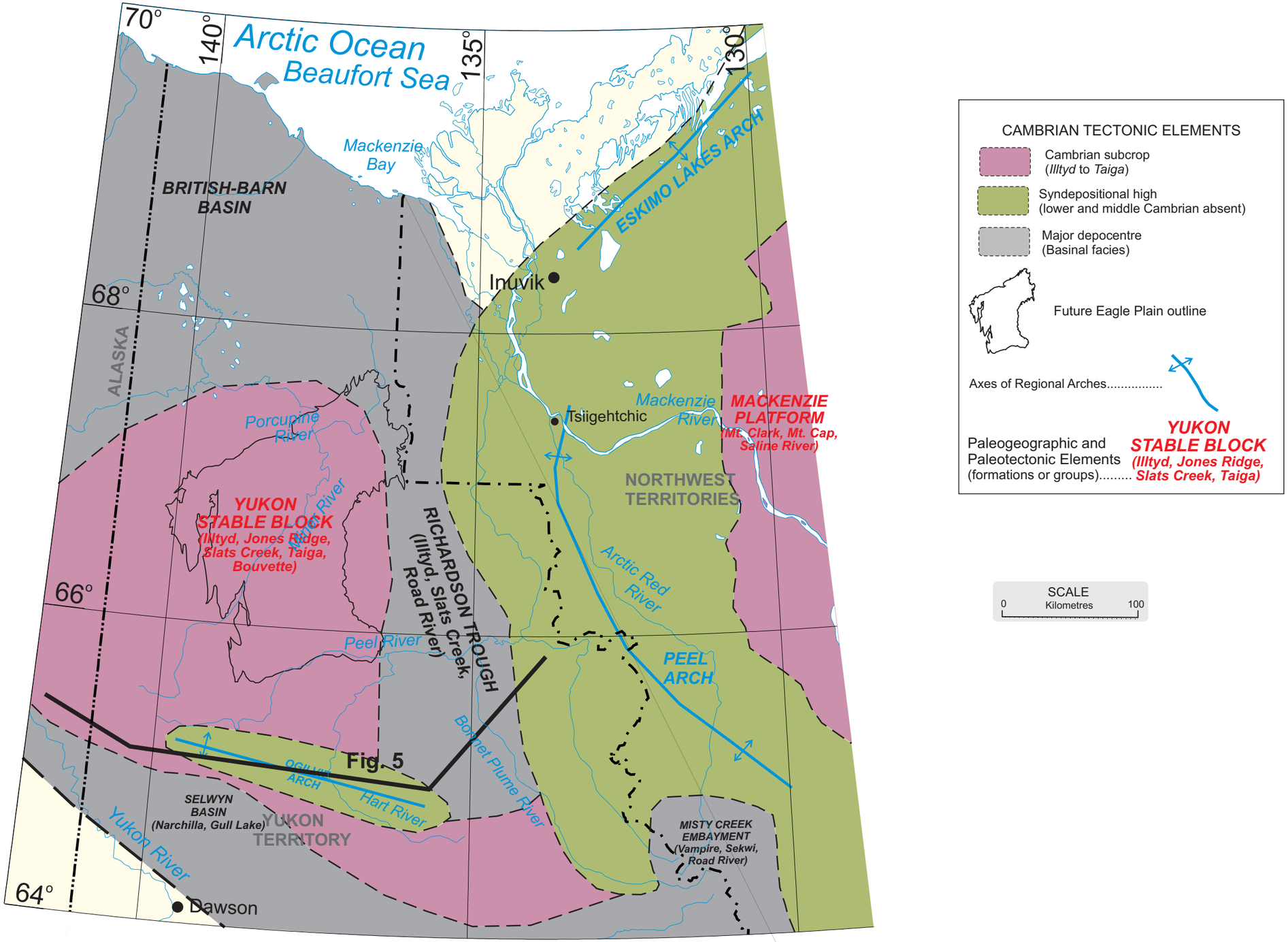


Figure 3. Paleogeographic map of Cambrian strata (Illtyd to Taiga interval) with major tectonic elements. From Fritz et al. (1991); Lane (1991); Aitken (1993); Cecile et al. (1997); Morrow (1999). Section line of Figure 5 is depicted.

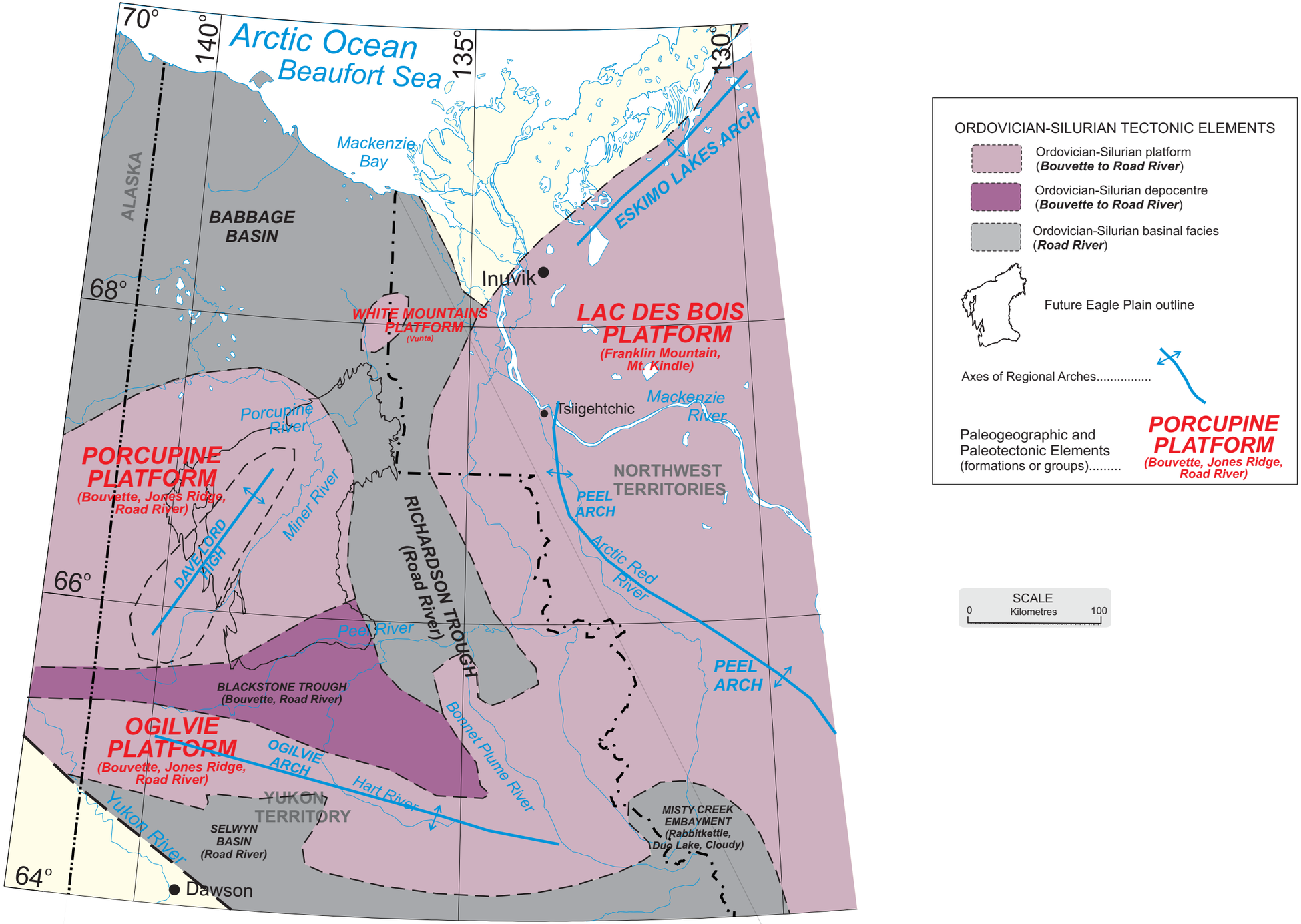


Figure 4. Paleogeographic-facies map of Ordovician and Silurian strata (Bouvette to Road River interval) with major tectonic elements. From Wheeler and McFeeley (1991); Lane (1991); Cecile et al. (1997); Norford (1997); Morrow (1989; 1999).

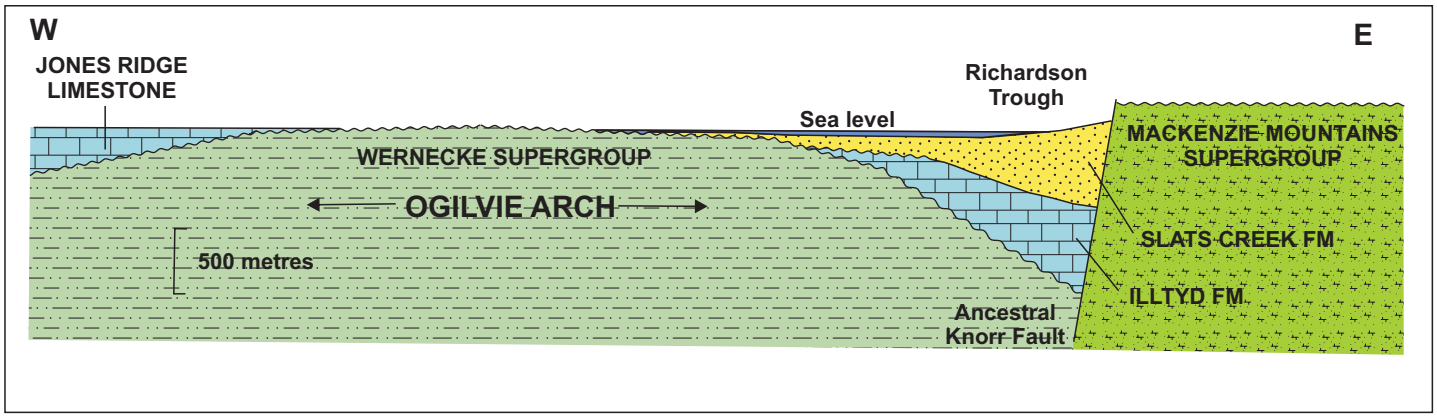


Figure 5. Schematic reconstruction of the Cambrian depositional setting across the Ogilvie Arch and Richardson Trough. Section line is displayed on Fig. 3. Same legend as in Fig. 2.

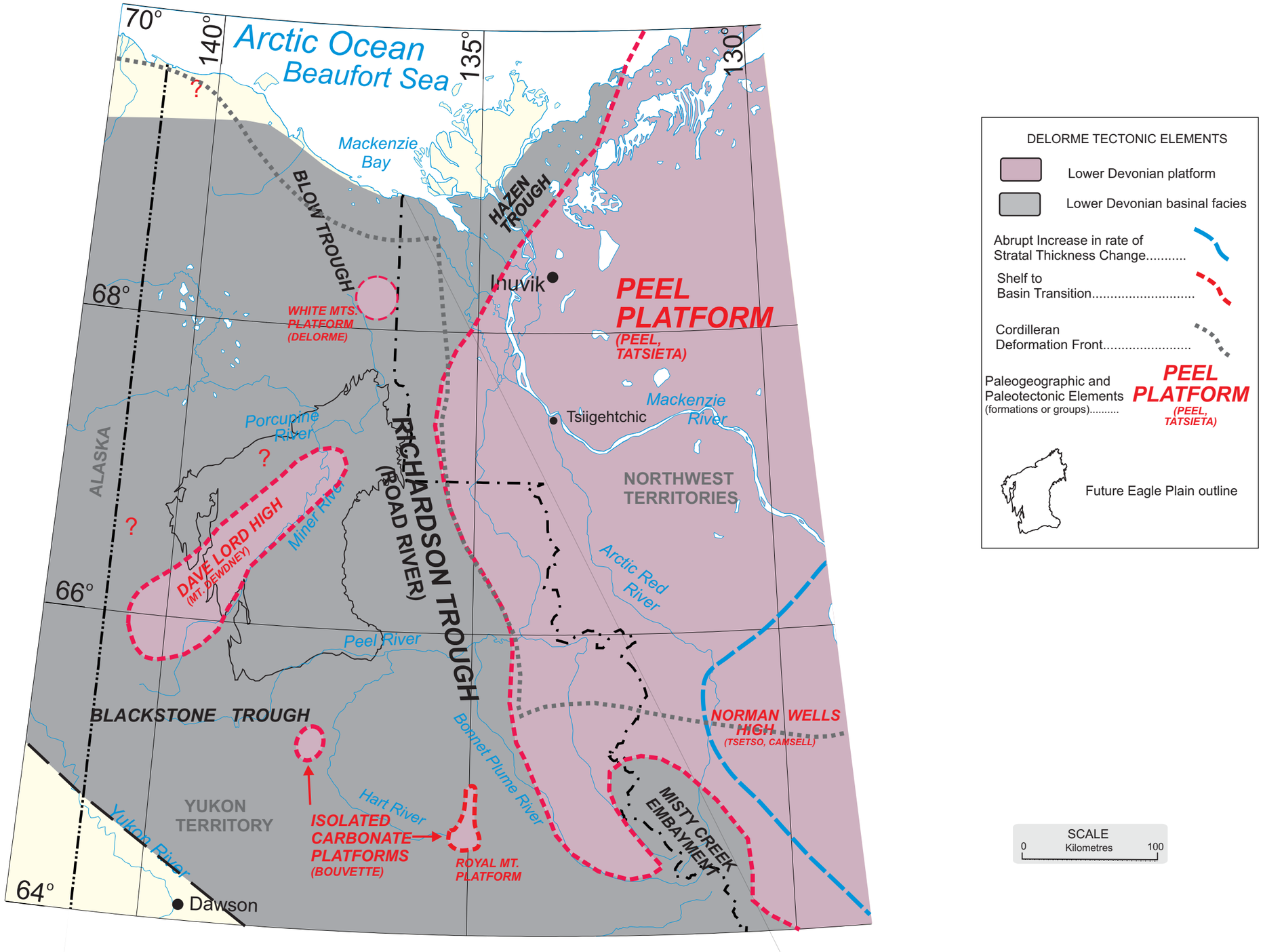


Figure 6. Paleogeographic-facies map of Late Silurian-Early Devonian Delorme assemblage with major tectonic elements. From Fritz et al., (1991); Norford (1997); Norris (1997); Morrow (1999).

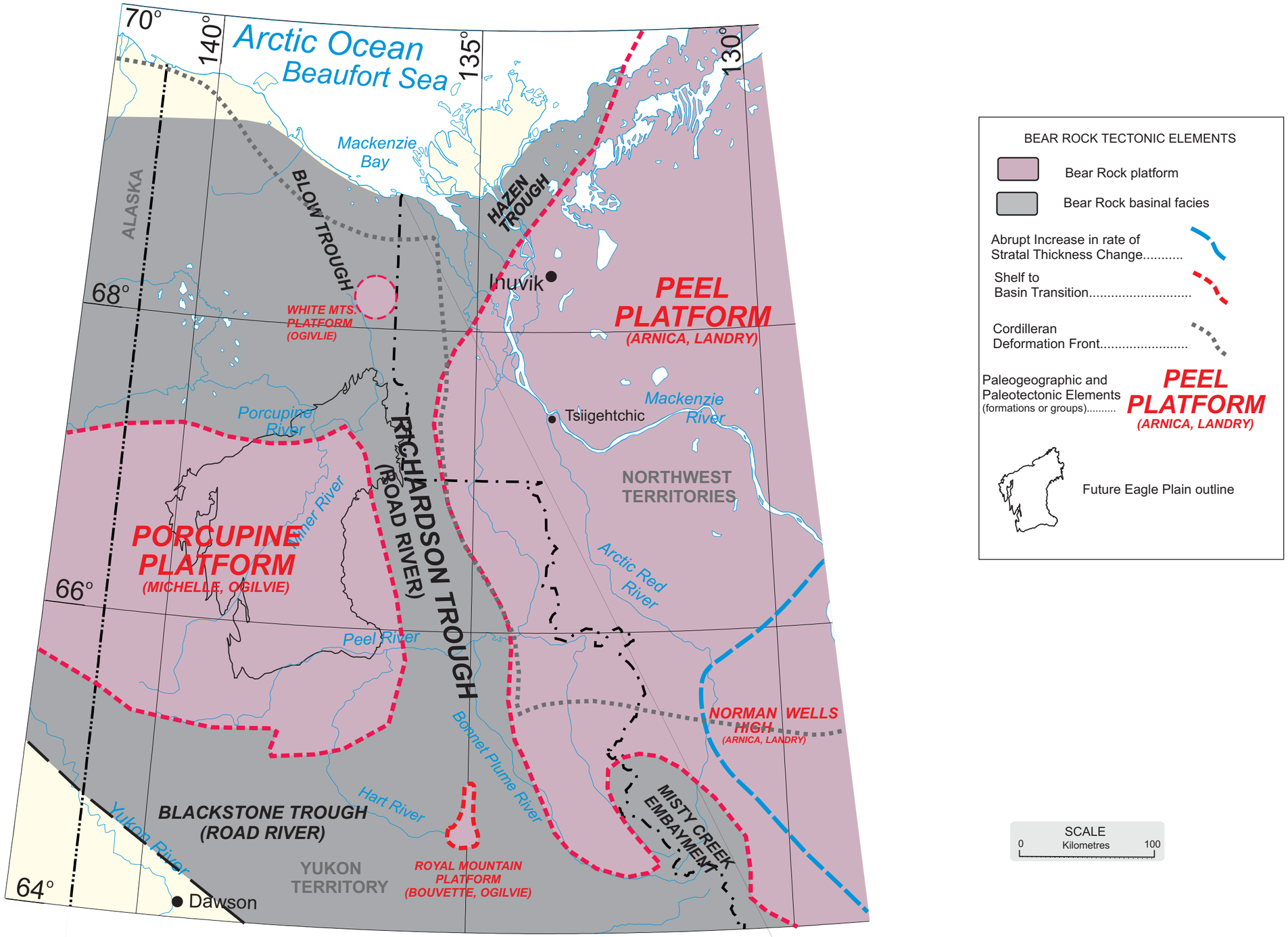


Figure 7. Paleogeographic-facies map of Early to Middle Devonian Bear Rock assemblage with major tectonic elements. From Fritz et al., (1991); Norris (1997); Morrow (1999).

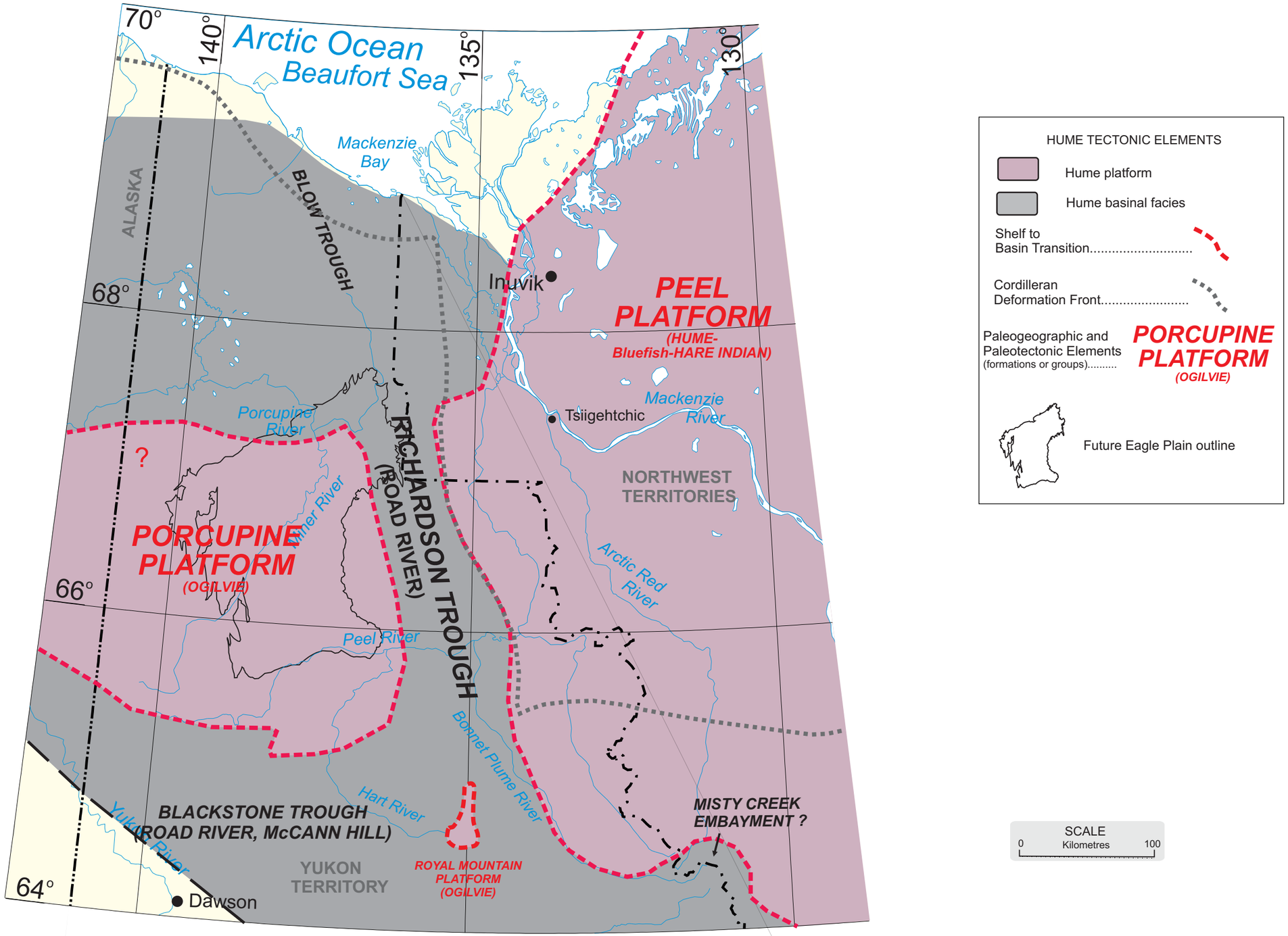


Figure 8. Paleogeographic-facies map of Middle Devonian Hume assemblage with major tectonic elements. From Fritz et al., (1991); Norris (1997); Morrow (1999).

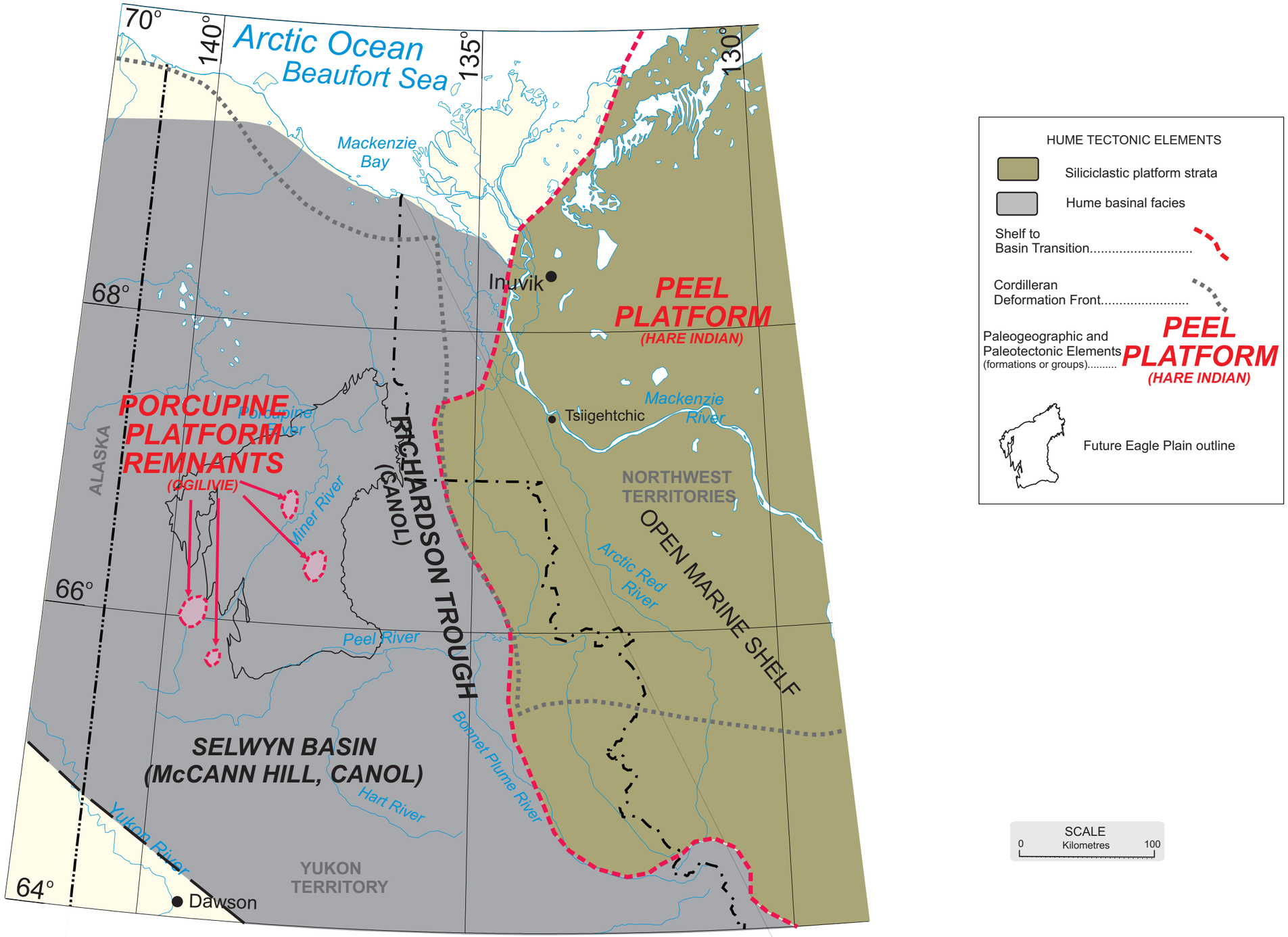


Figure 9. Paleogeographic-facies map of Middle and Upper Devonian Lower Fairholme assemblage with major tectonic elements. From Fritz et al., (1991); Norris (1997); Morrow (1999).

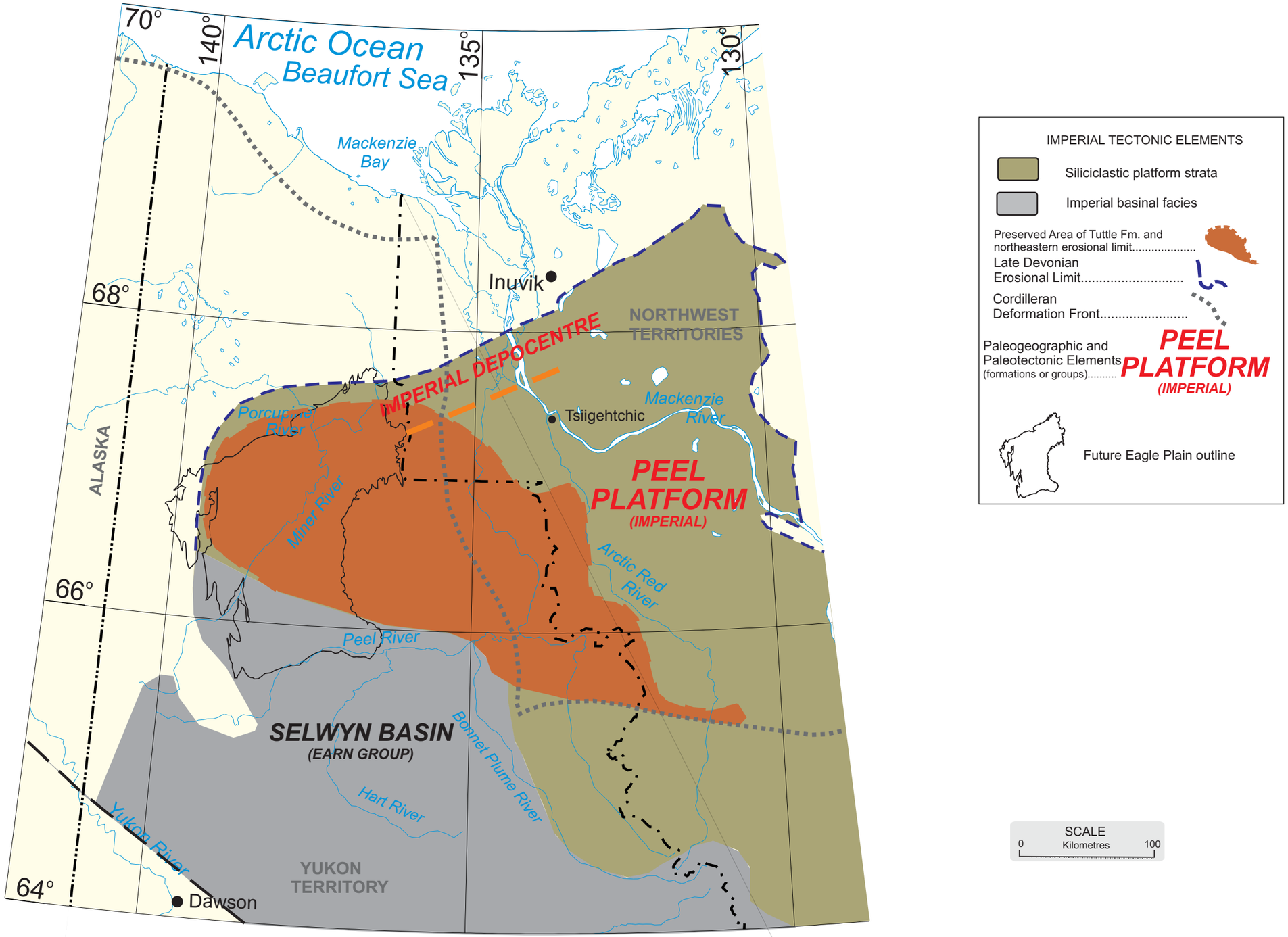


Figure 10. Paleogeographic-facies map of Upper Devonian Imperial assemblage with major tectonic elements. From Gordey et al., (1991); Moore (1993); Norris (1997).

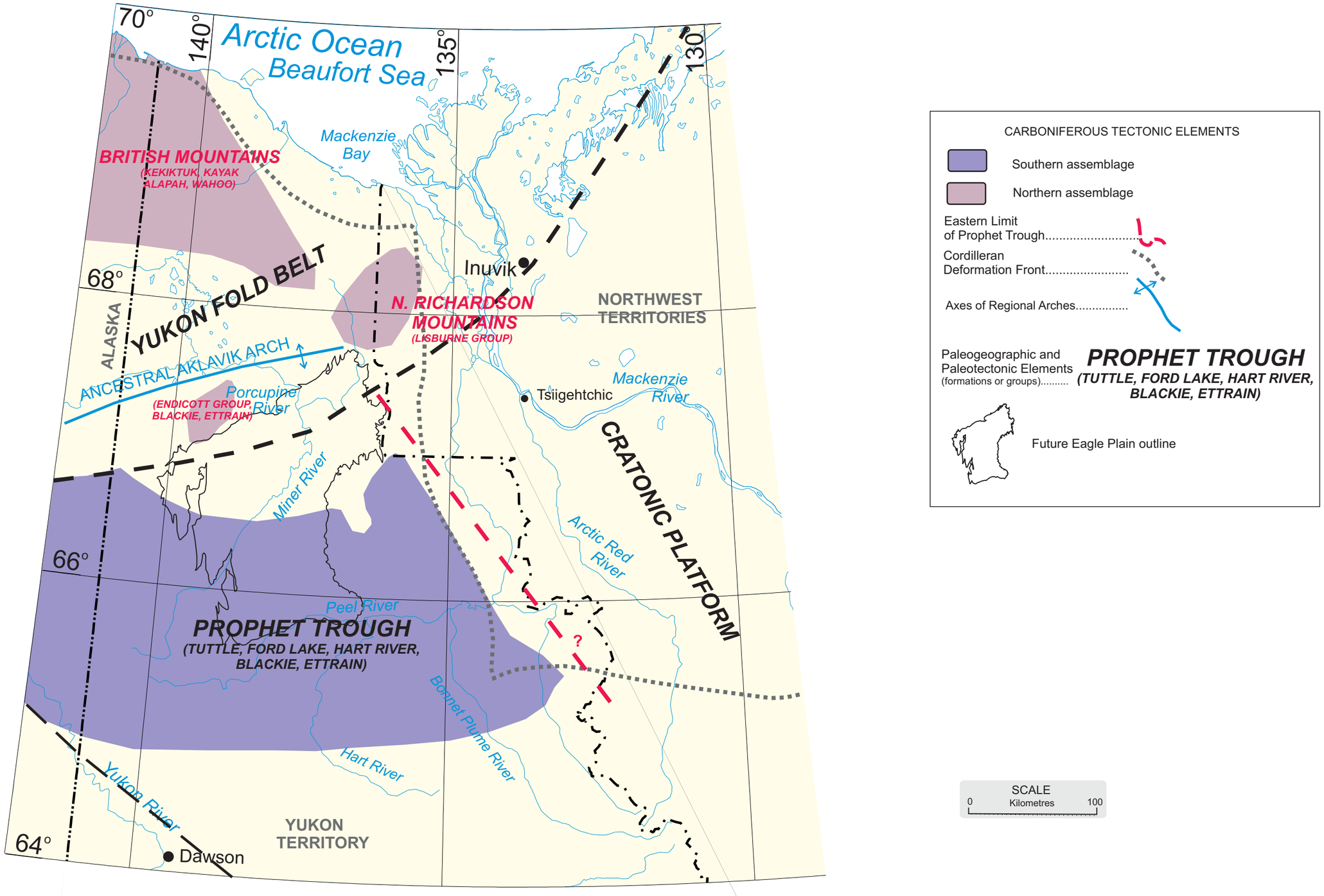


Figure 11. Assemblage map of Carboniferous sedimentary units with major tectonic elements. From Gordey et al., (1991); Richards et al., (1997).

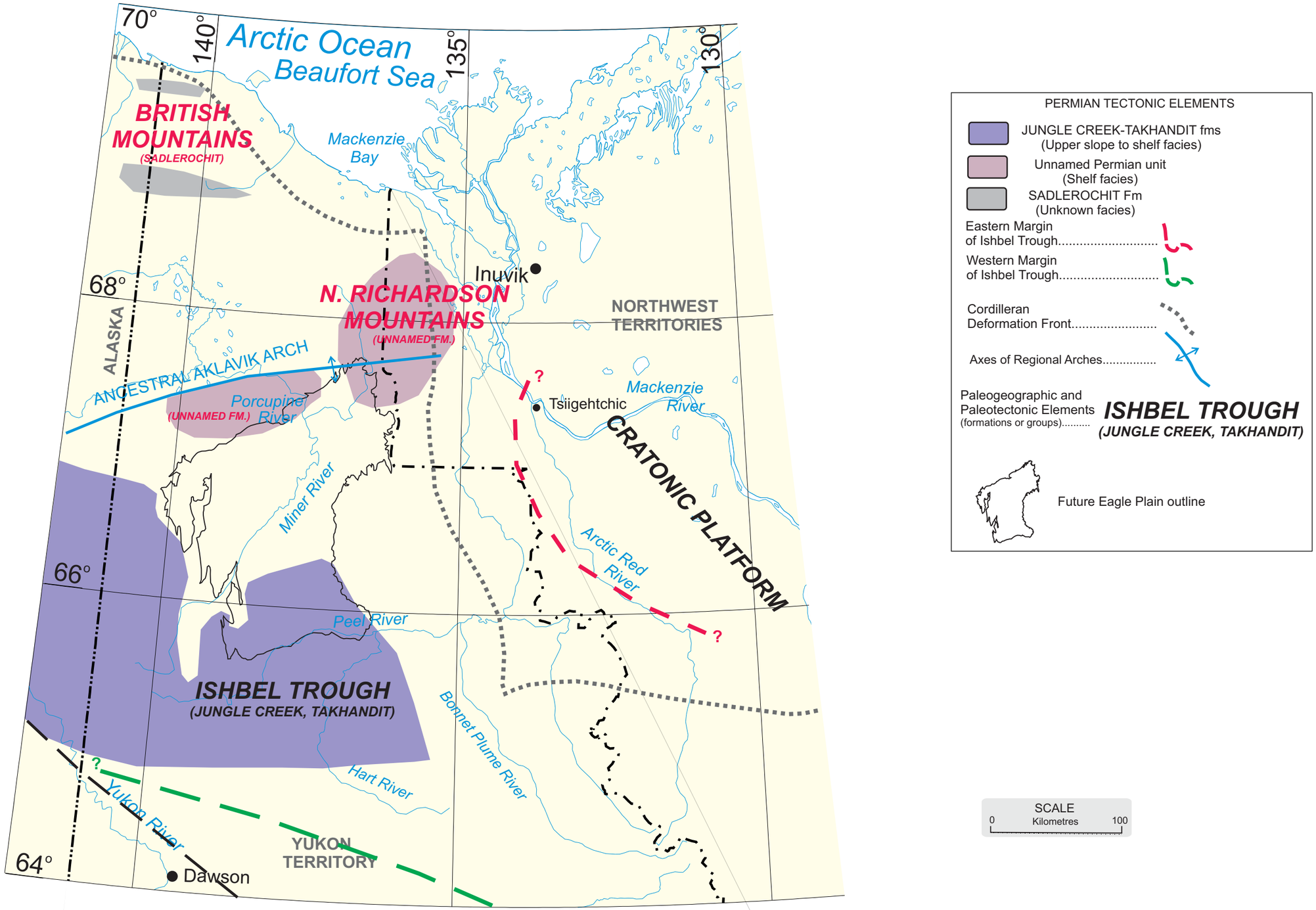


Figure 12. Facies distribution map of Permian units with major tectonic elements. From Gordey et al., (1991); Richards et al., (1997).

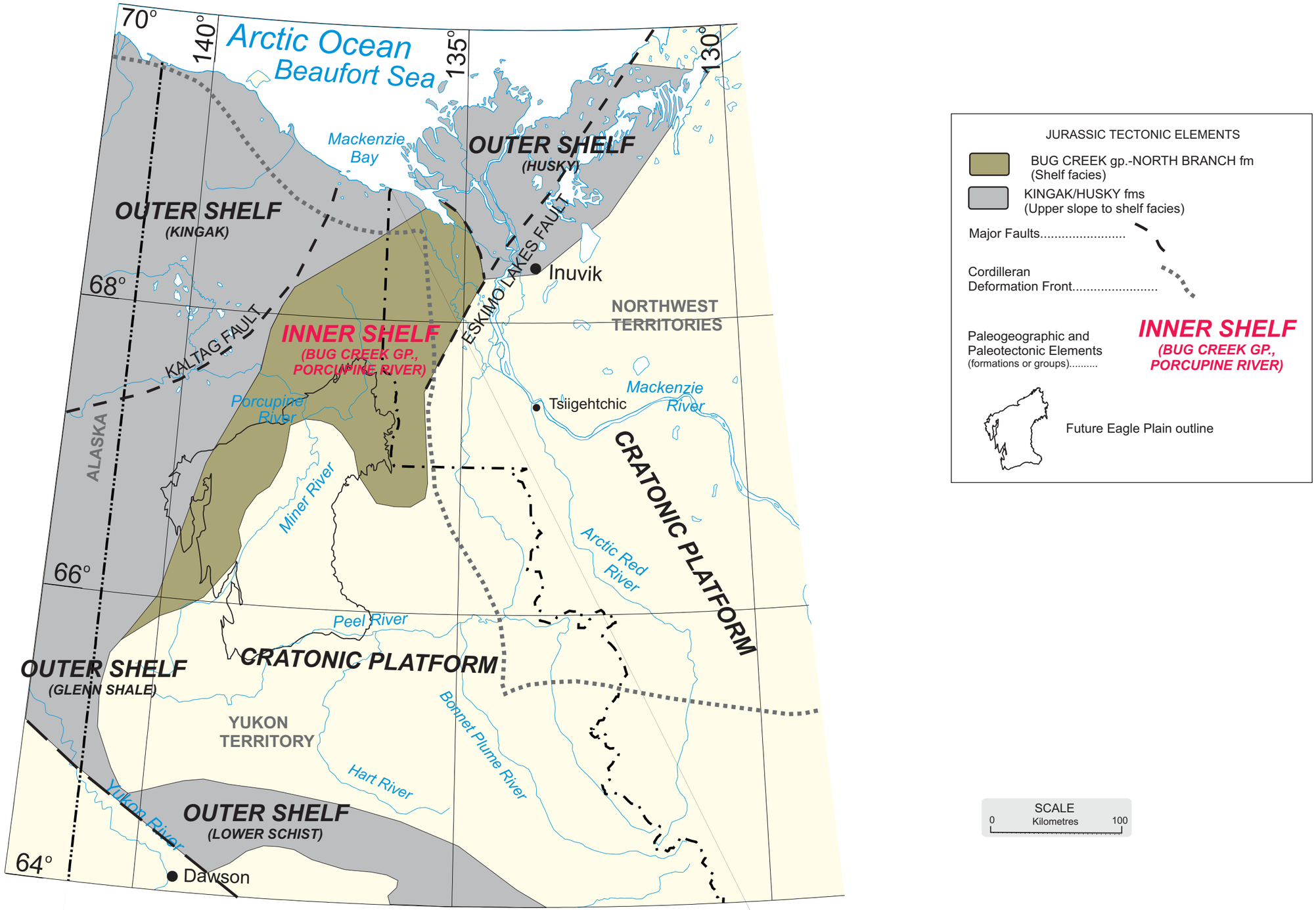


Figure 13. Facies distribution map of Jurassic units with major tectonic elements. From Gordey et al., (1991); Poulton (1997).

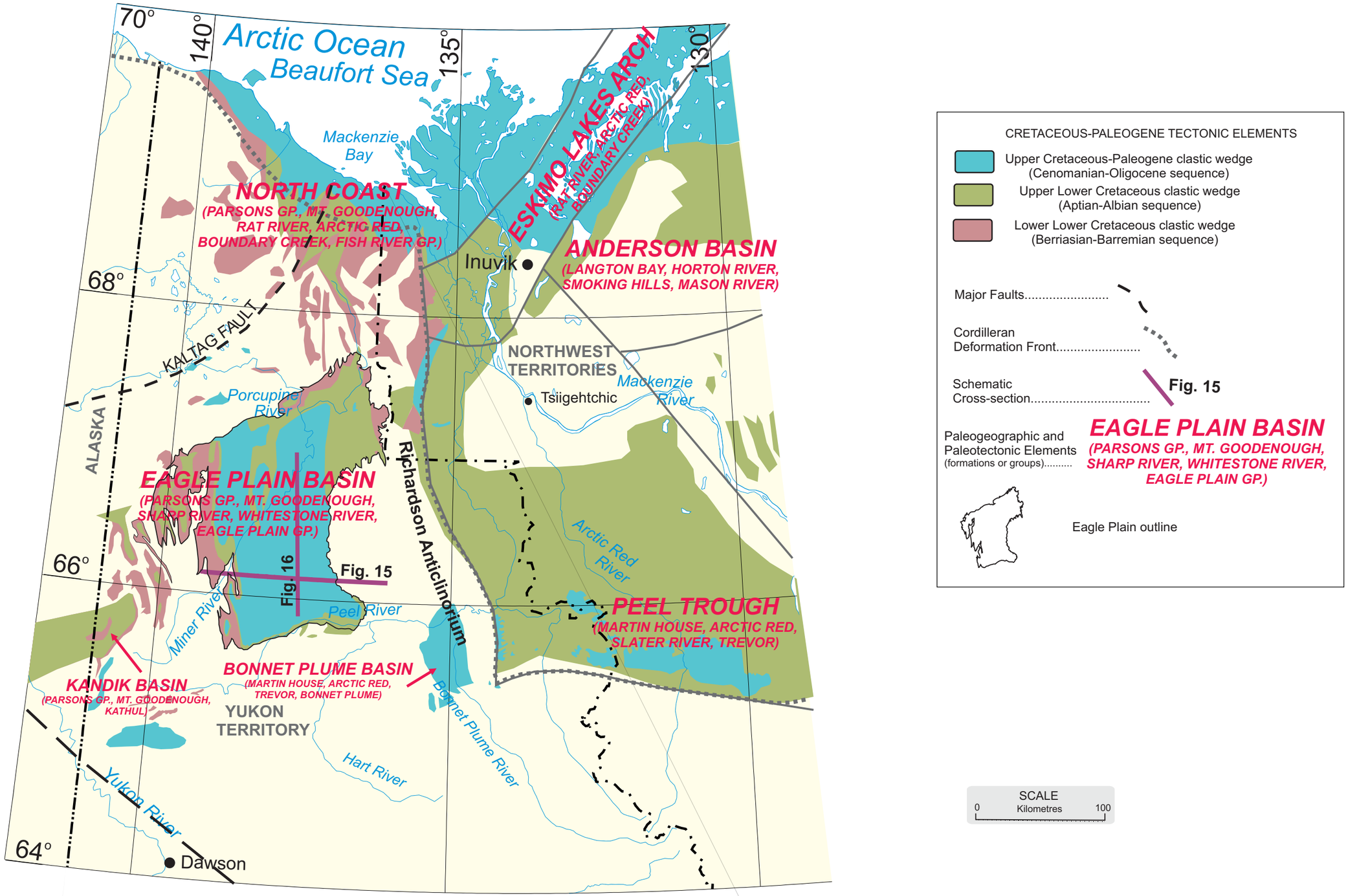


Figure 14. Geologic bedrock and subcrop map of Cretaceous-Paleogene units with major tectonic elements. From Yorath (1991); Dixon (1992; 1997). Lines of schematic cross-sections are shown.

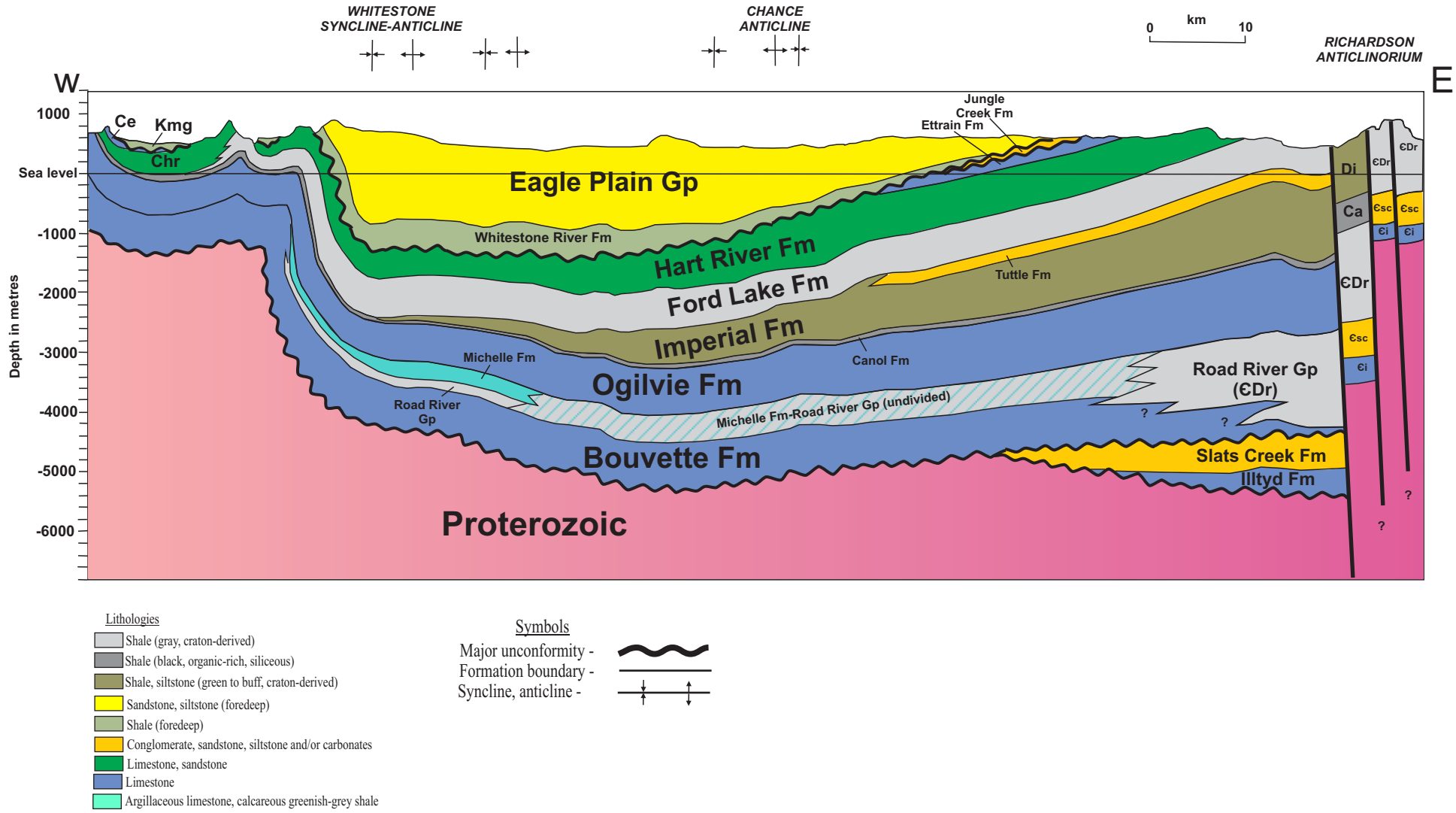


Figure 15. An east-west schematic structual cross-section across Eagle Plain basin. Section line depicted on Fig. 14. From Morrow (1999).

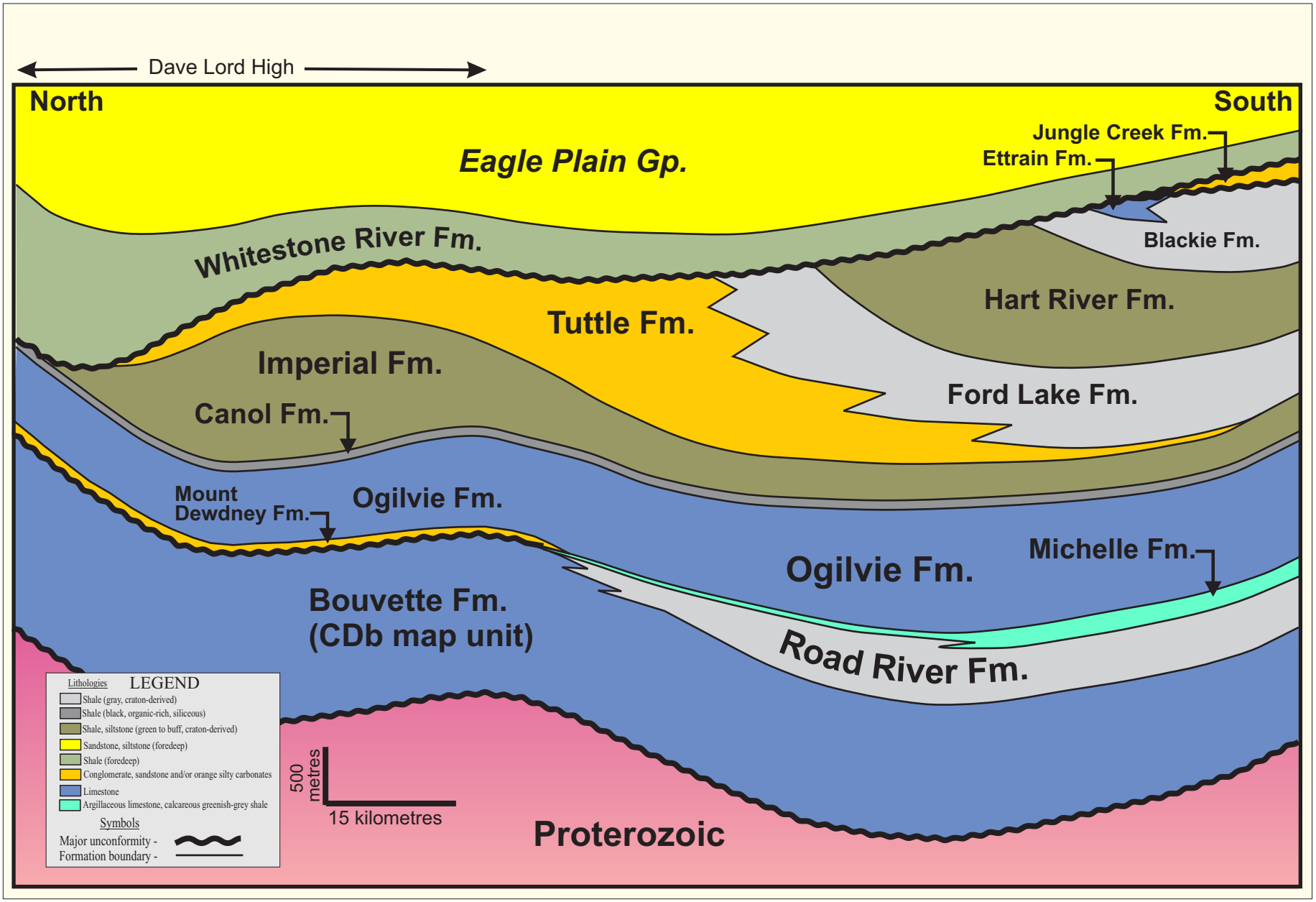


Figure 16. A north-south schematic cross-section across Eagle Plain basin and the south flank of Eagle Arch. Section line depicted on Fig. 14.

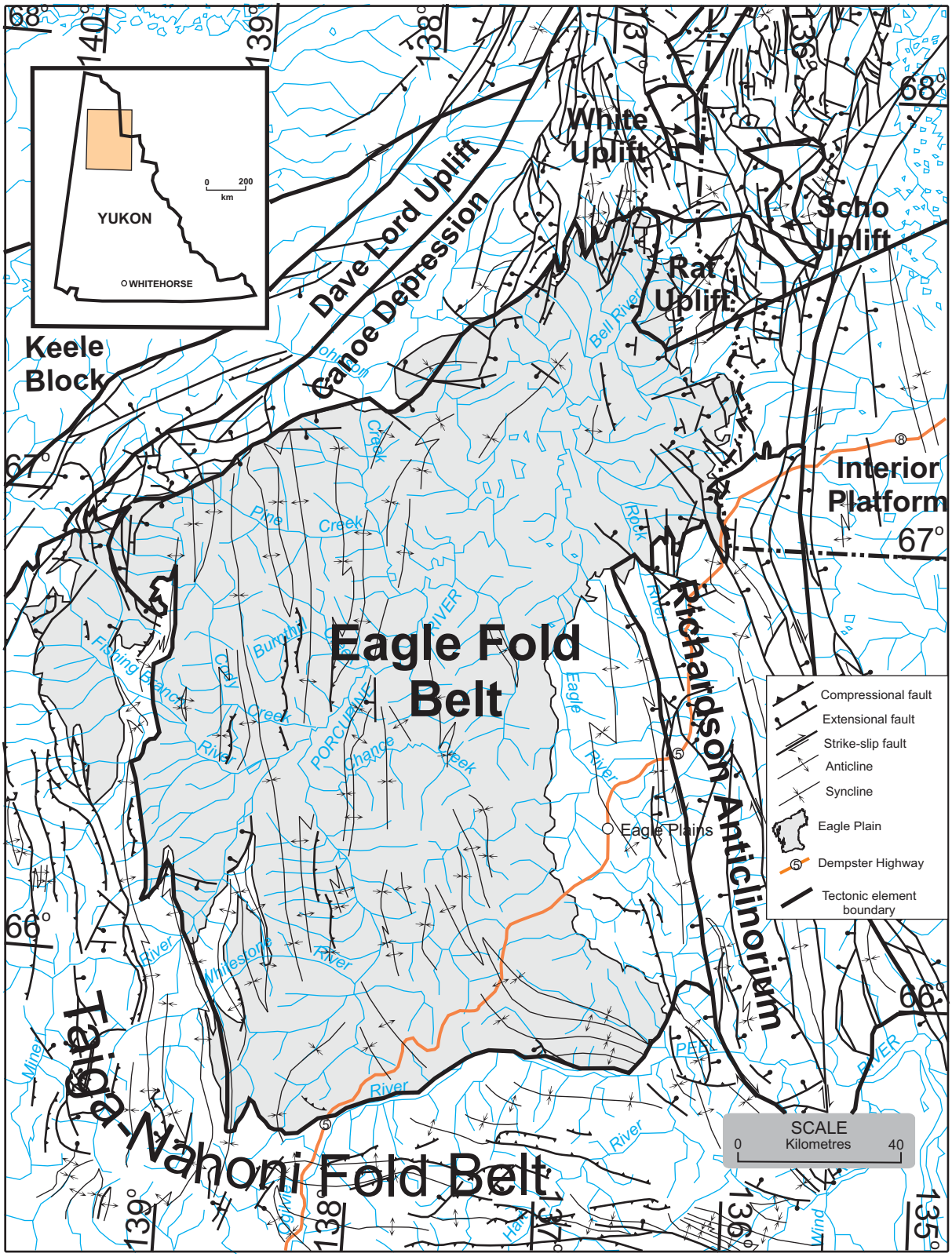


Figure 17. Compilation of major structural features and tectonic elements in the Eagle Plain Basin region. Keele Block, Dave Lord Uplift, Canoe Depression, Rat Uplift, White Uplift, and Scho Uplift are sub-elements of the Aklavik Arch Complex. From Norris (1984; 1997).

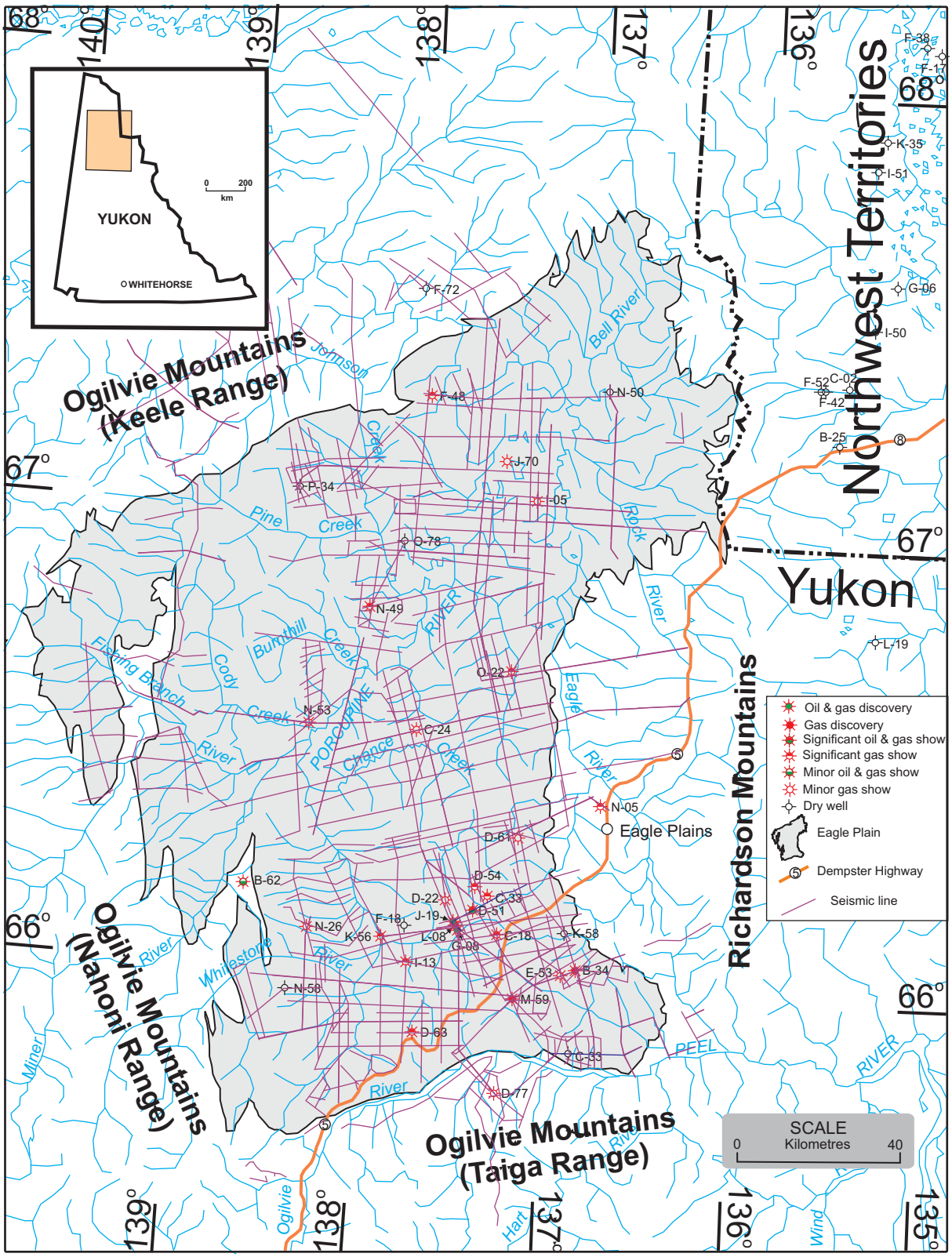


Figure 18. Petroleum wells completed in the Eagle Plain basin. Major discovery locations are illustrated. Publicly available reflection seismic lines of all vintages are also depicted.

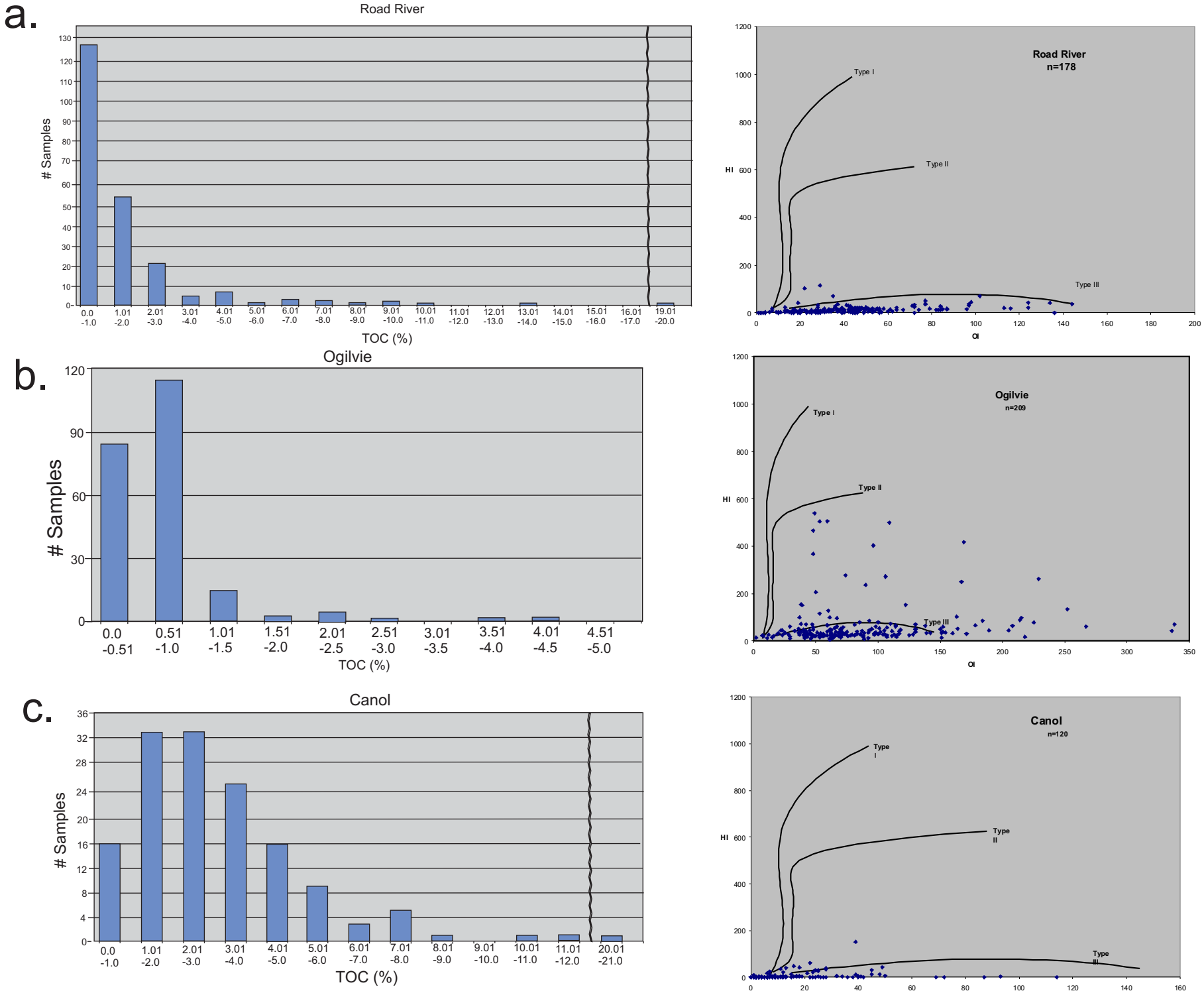


Figure 19. Histograms of frequency distribution of total organic carbon (TOC) and HI vs OI (pseudo-van Krevelen) plots for selected Lower Paleozoic source rocks (a. Road River Gp., b. Ogilvie, and c. Canol fms.).

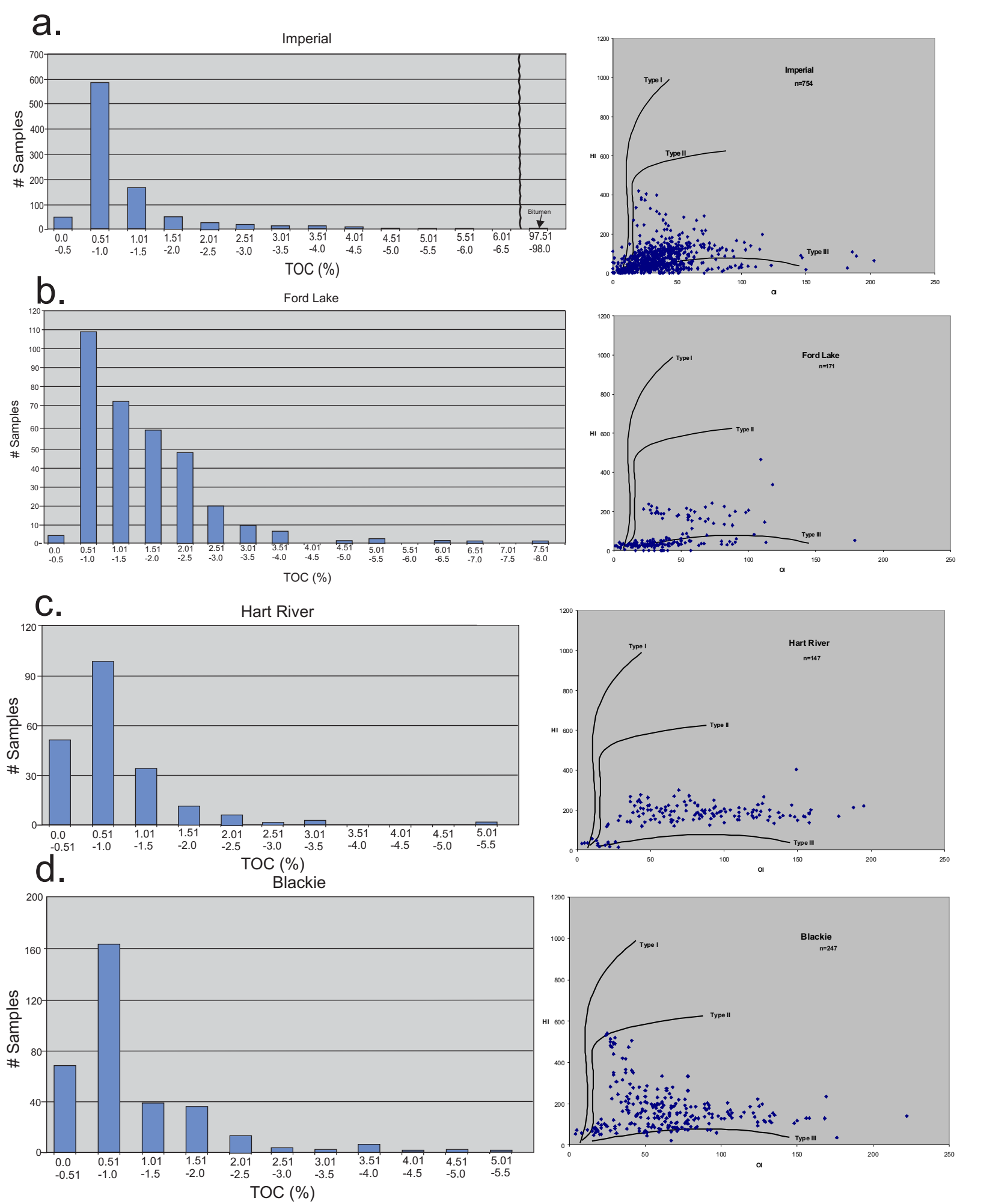


Figure 20. Histograms of frequency distribution of total organic carbon (TOC) and HI vs OI (pseudo-van Krevelen) plots for selected Upper Paleozoic source rocks (a. Imperial, b. Ford Lake, c. Hart River, and d. Blackie fms.).

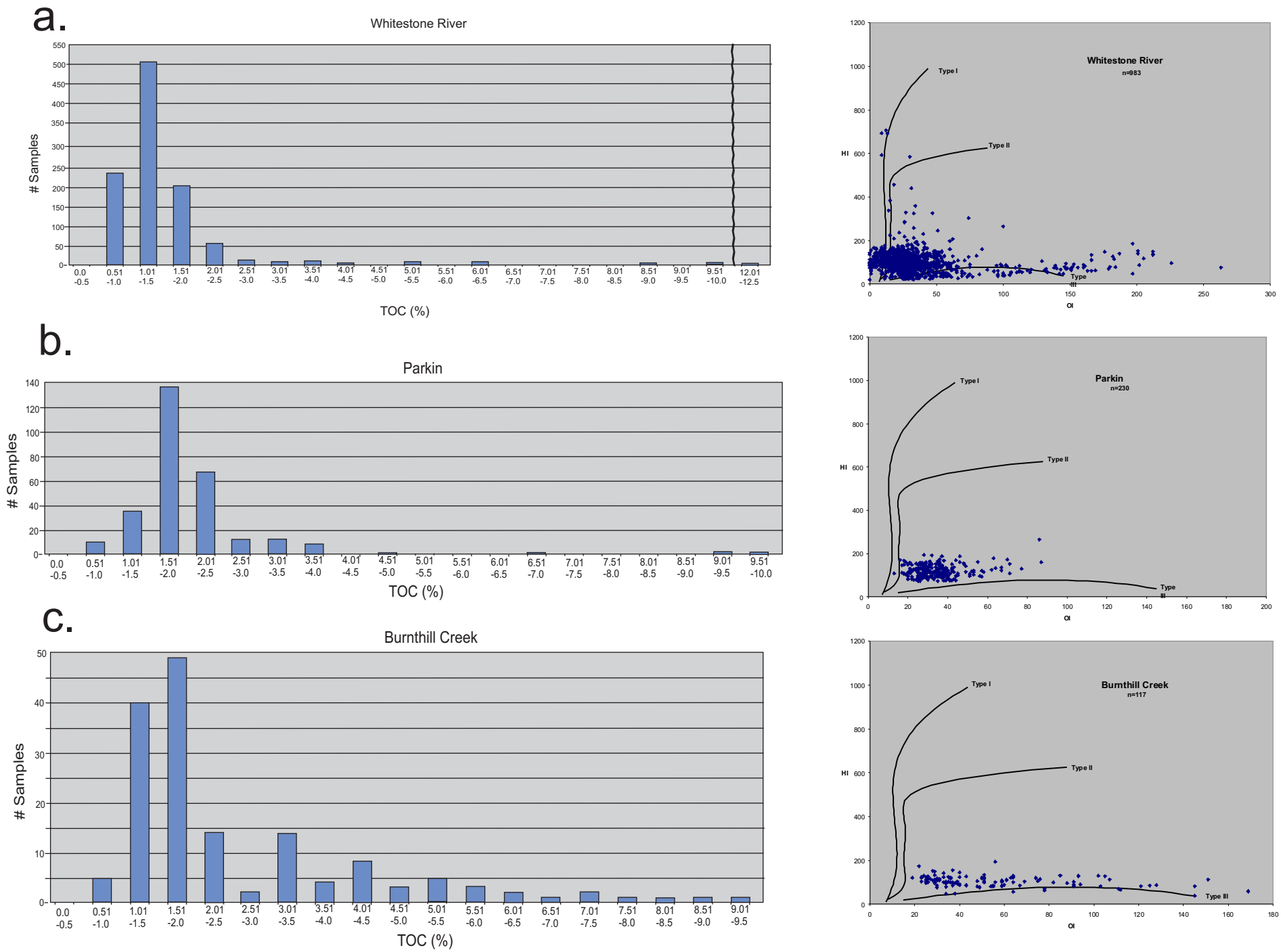


Figure 21. Histograms of frequency distribution of total organic carbon (TOC) and HI vs OI (pseudo-van Krevelen) plots for selected Cretaceous source rocks (a. Whitestone River, b. Parkin, and c. Burnthill Creek fms.).

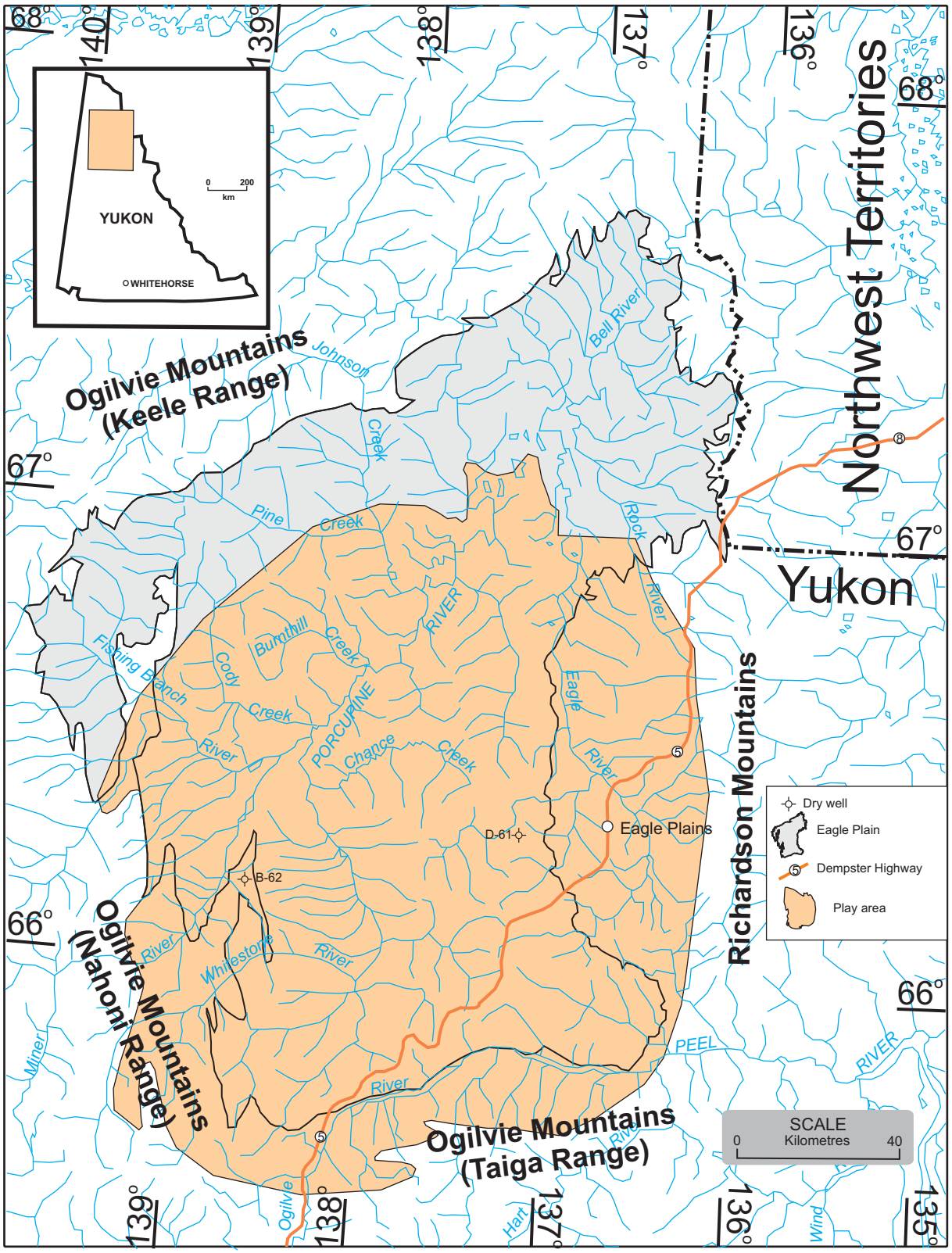


Figure 22. Lower Paleozoic carbonate pre-Laramide structural gas play.

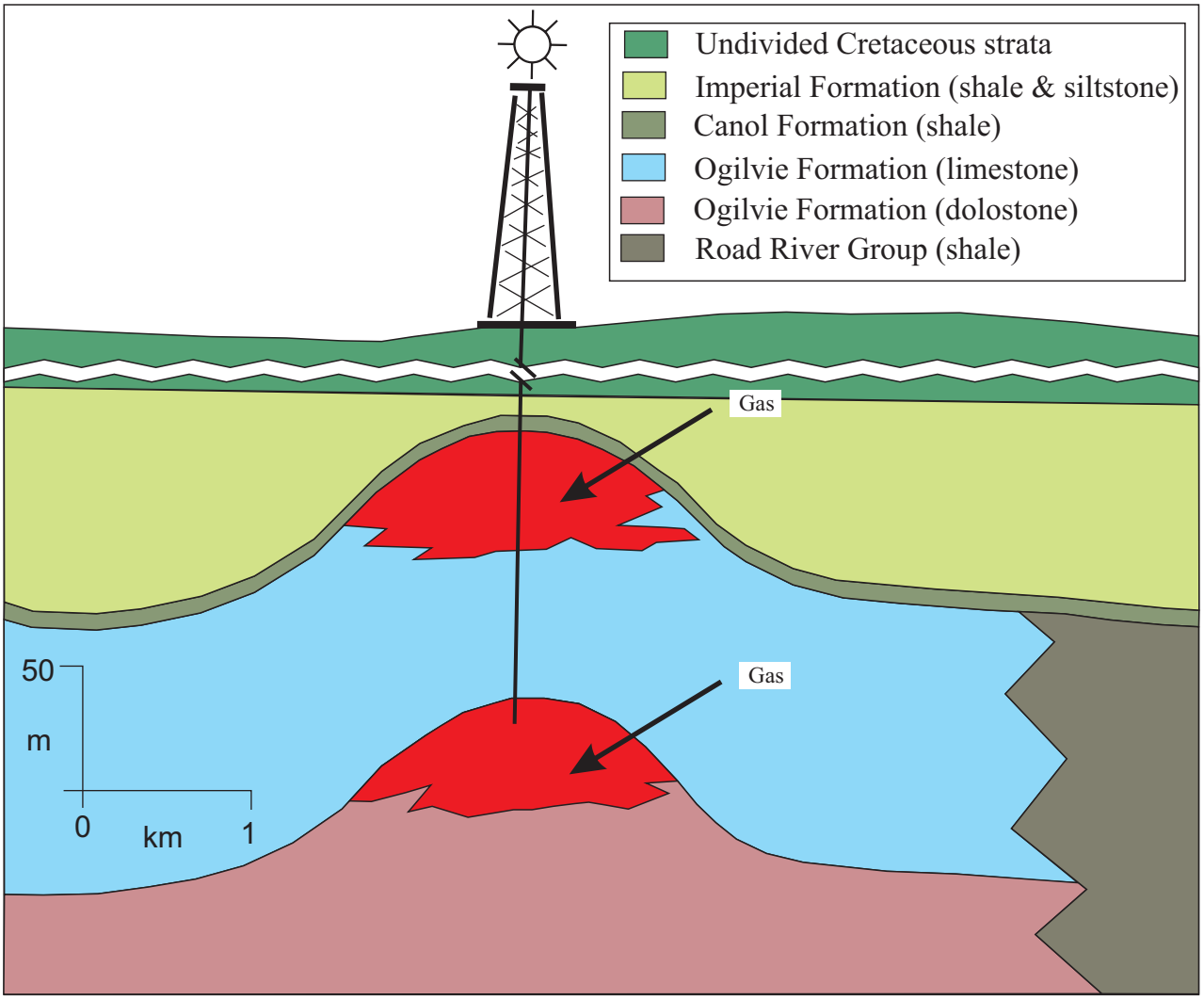


Figure 23. Schematic cross-section illustrating potential trap configurations in the Lower Paleozoic pre-Laramide structural gas play. Illustrated traps include anticlinal traps. From National Energy Board, 2000.

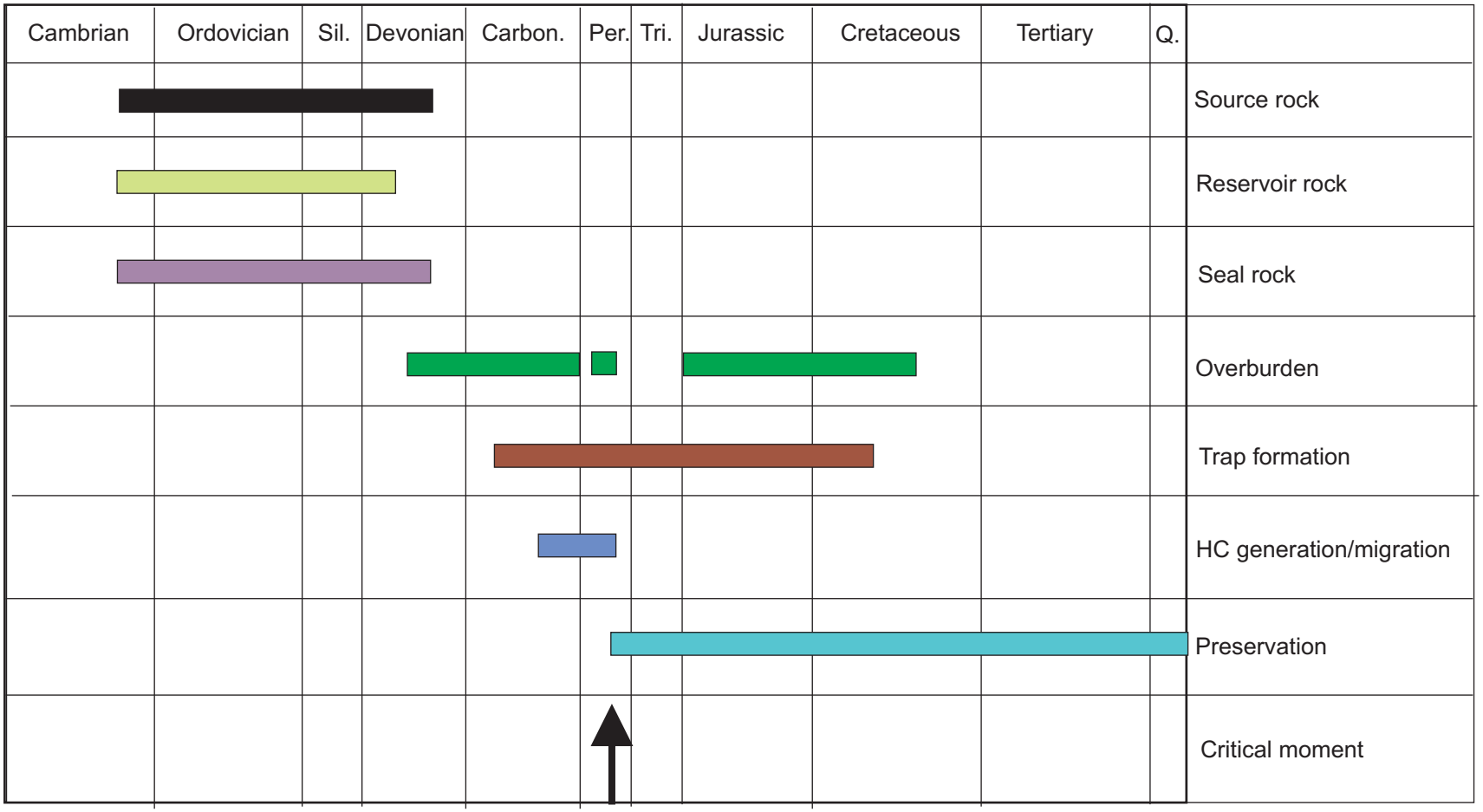


Figure 24. Petroleum event chart for a Lower Paleozoic petroleum system (Road River/Ogilvie/Canol source-Bouvette/Ogilvie reservoir). The critical moment for oil and gas generation (arrow) occurred during Early Permian time as a result of uplift of the Richardson Mountains anticlinorium and associated tectonic development of contractional fold and fault structures in Eagle Plains to the west (Link and Bustin, 1989; Hall and Cook, 1998). Sil.-Silurian, Carbon.-Carboniferous, Per.-Permian, Tri.-Triassic, Q.-Quaternary.

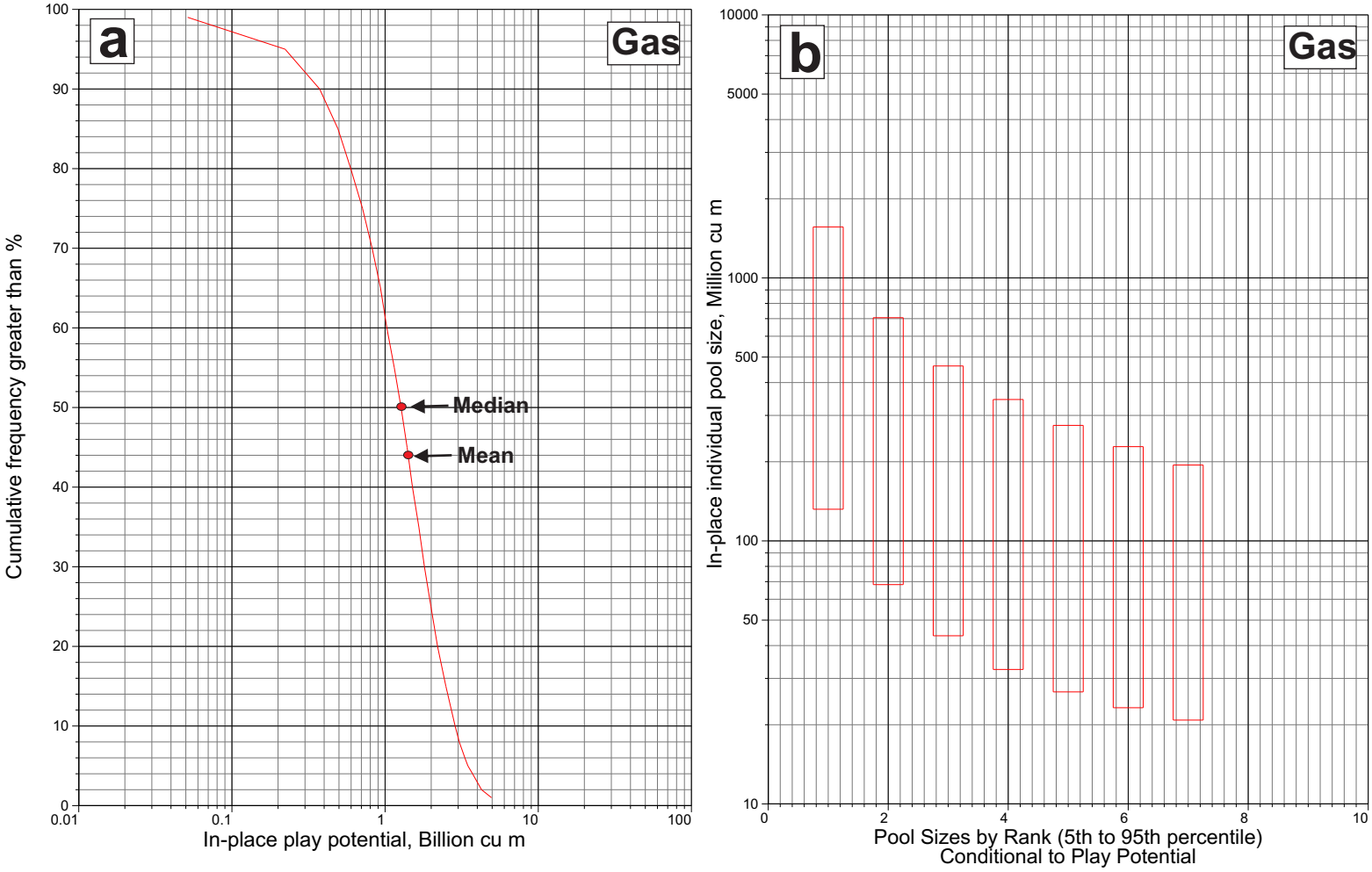


Figure 25. Estimate of in-place gas (a) potential of the Lower Paleozoic carbonate pre-Laramide structural play.. Pool-size-by-rank plot (b) of the play is also displayed.

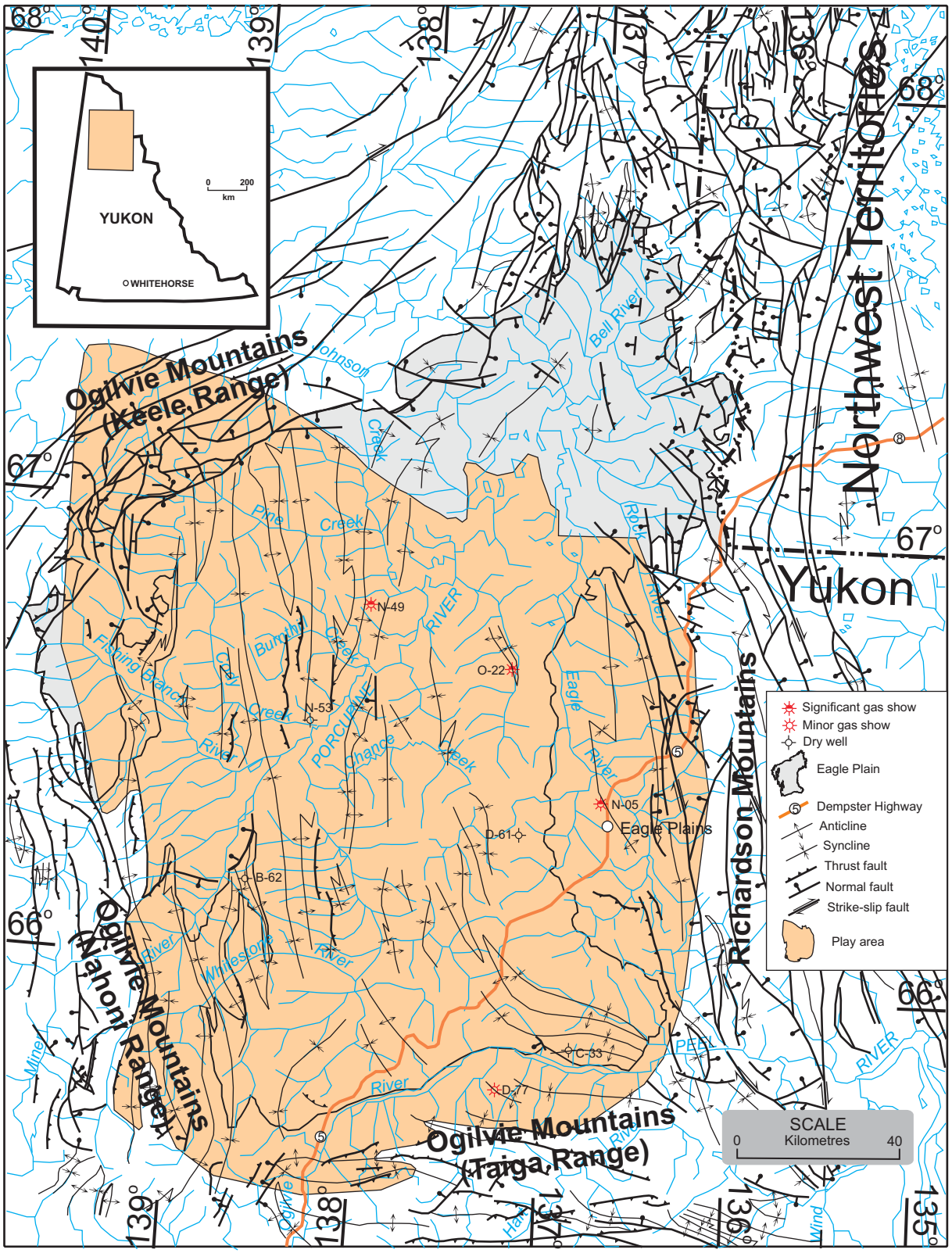


Figure 26. Lower Paleozoic carbonate Laramide structural gas play. Laramide surface structures are depicted.

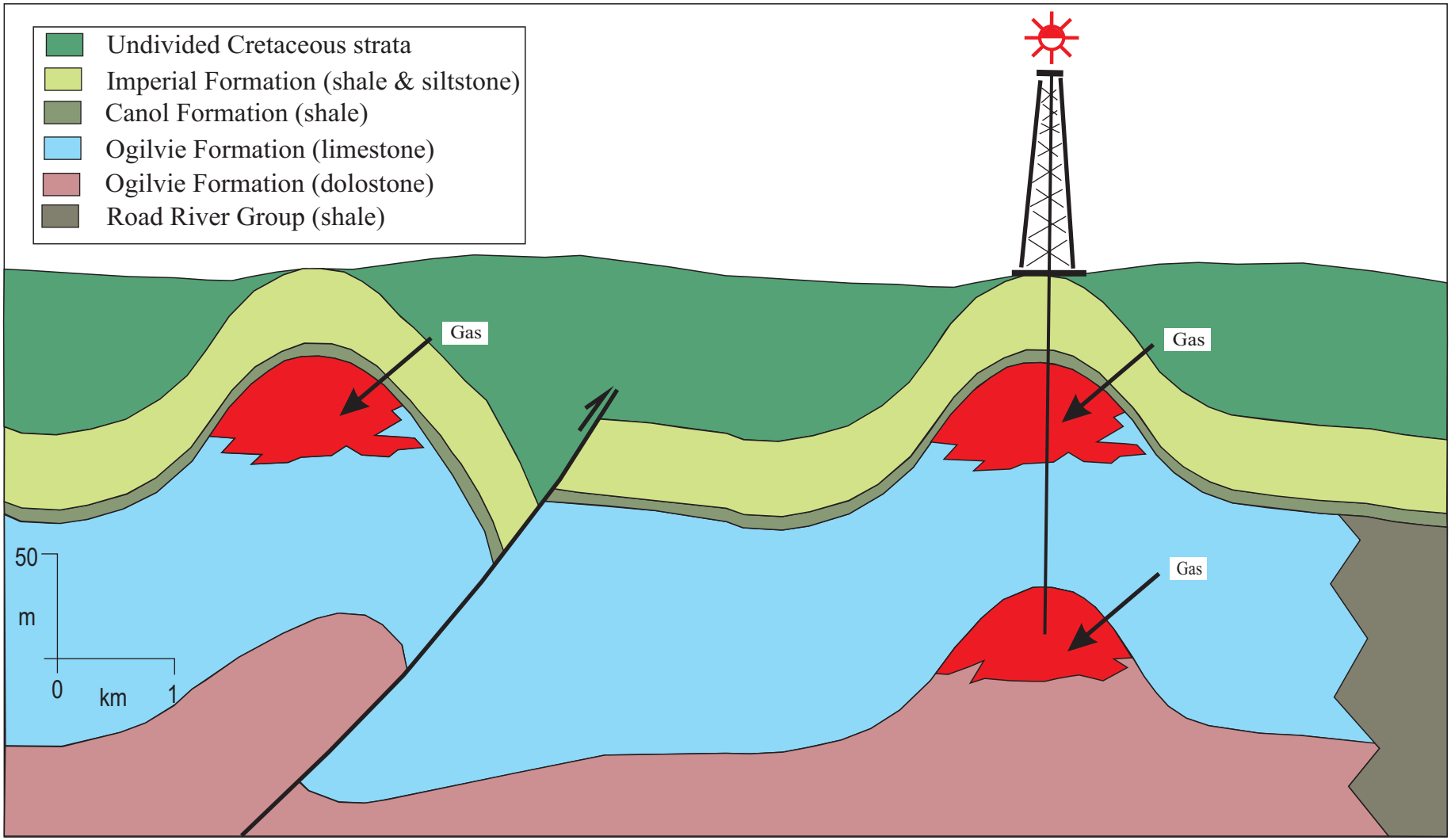


Figure 27. Schematic cross-section illustrating potential trap configurations in the Lower Paleozoic Laramide structural gas play. Illustrated traps include antiformal structures..

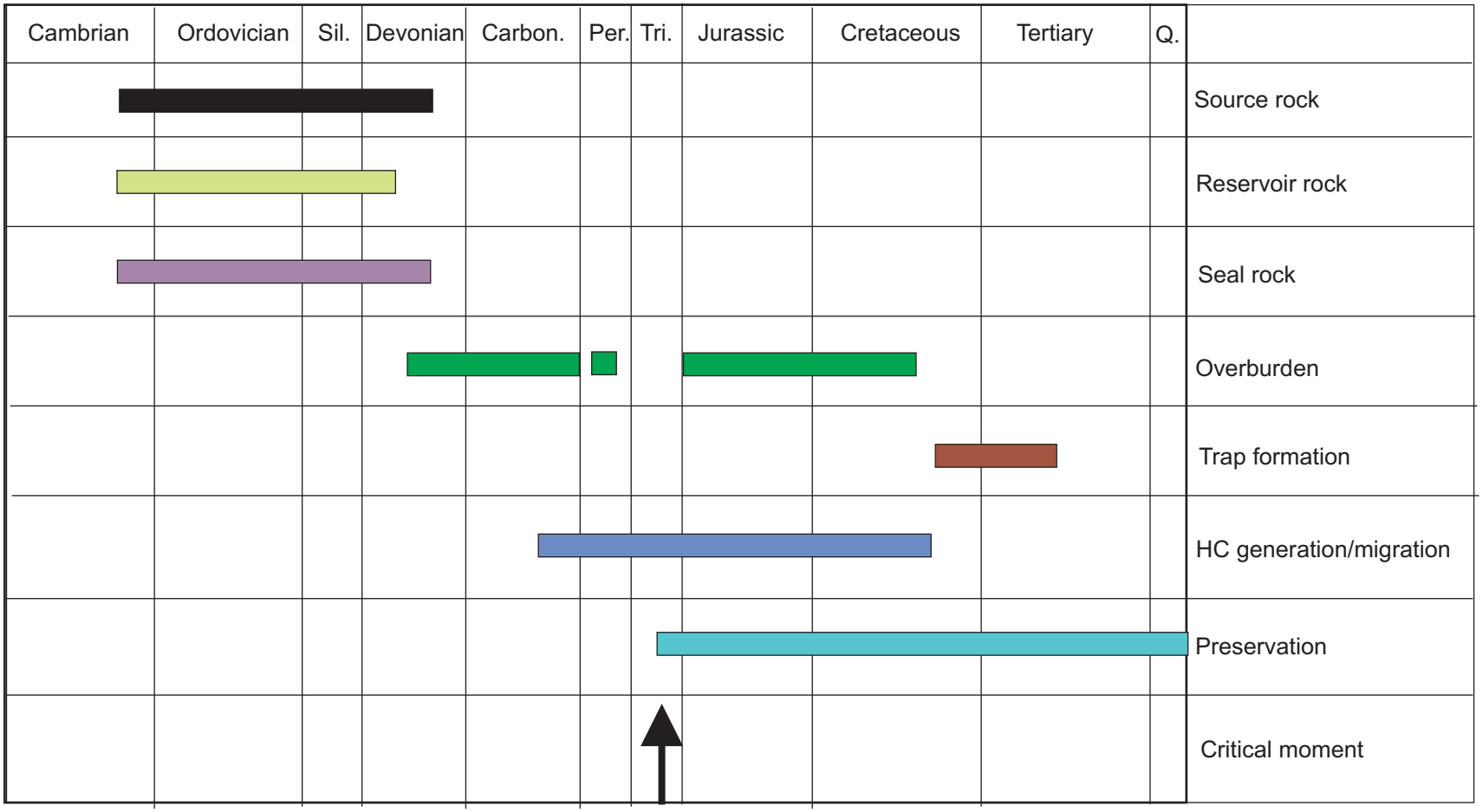


Figure 28. Petroleum event chart for a Lower Paleozoic petroleum system (Road River/Ogilvie/Canol source-Bouvette/Ogilvie reservoir). The critical moment for oil and gas generation (arrow) in most of Eagle Plain occurred during Late Triassic time, the midway point of thermal oil and gas generation from burial history diagrams of Link and Bustin (1989). Sil.-Silurian, Carbon.-Carboniferous, Per.-Permian, Tri.-Triassic, Q.-Quaternary.

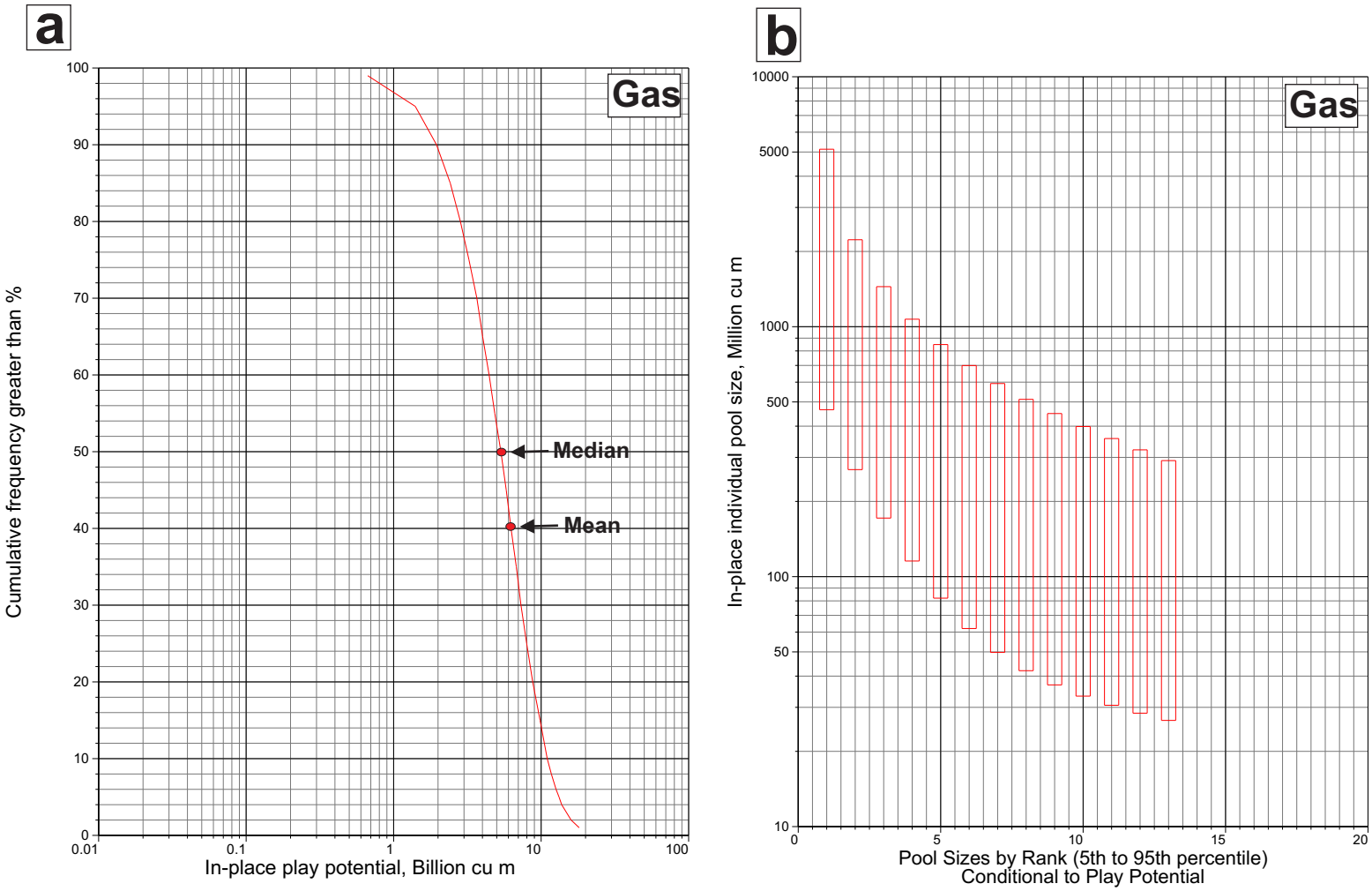


Figure 29. Estimate of in-place gas (a) potential of the Lower Paleozoic carbonate Laramide structural play. Pool-size-by-rank plot (b) of the play is also displayed.

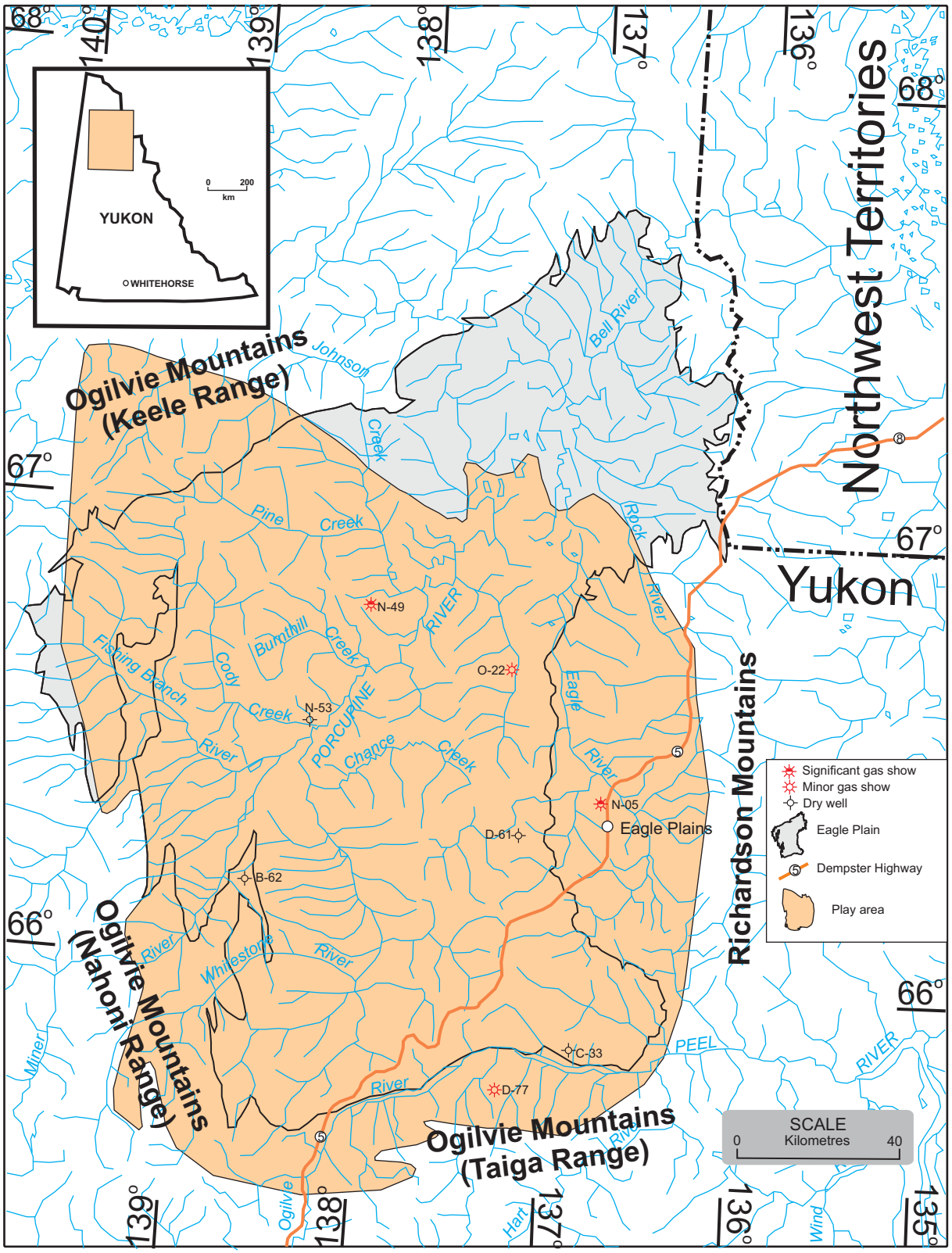


Figure 30. Lower Paleozoic carbonate stratigraphic gas play.

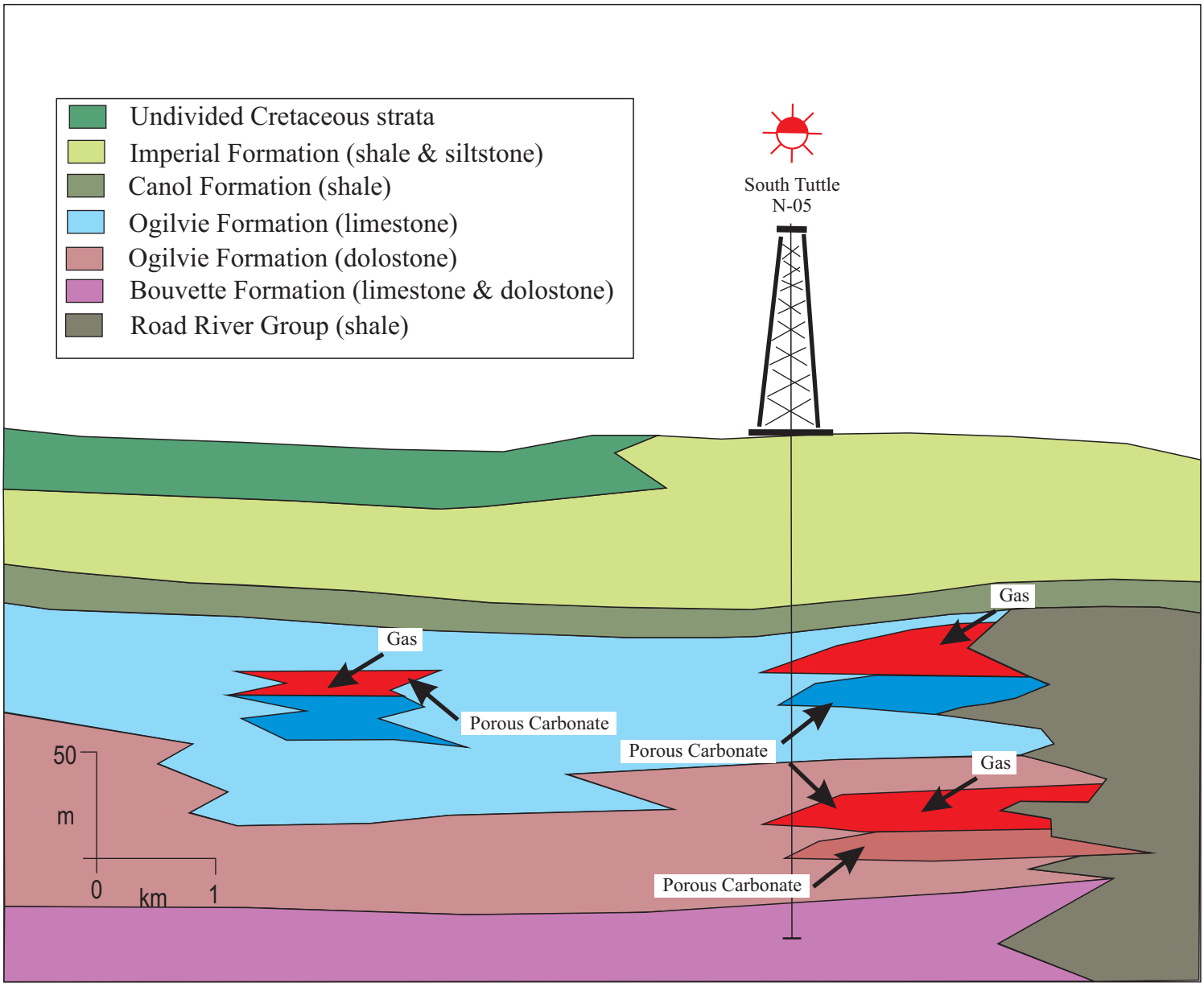


Figure 31. Schematic cross-section illustrating potential trap configurations in the Lower Paleozoic stratigraphic gas play. Illustrated traps include facies change traps where porous carbonates abut against tight basinal shale or non-porous carbonate within the formation. From National Energy Board, 2000.

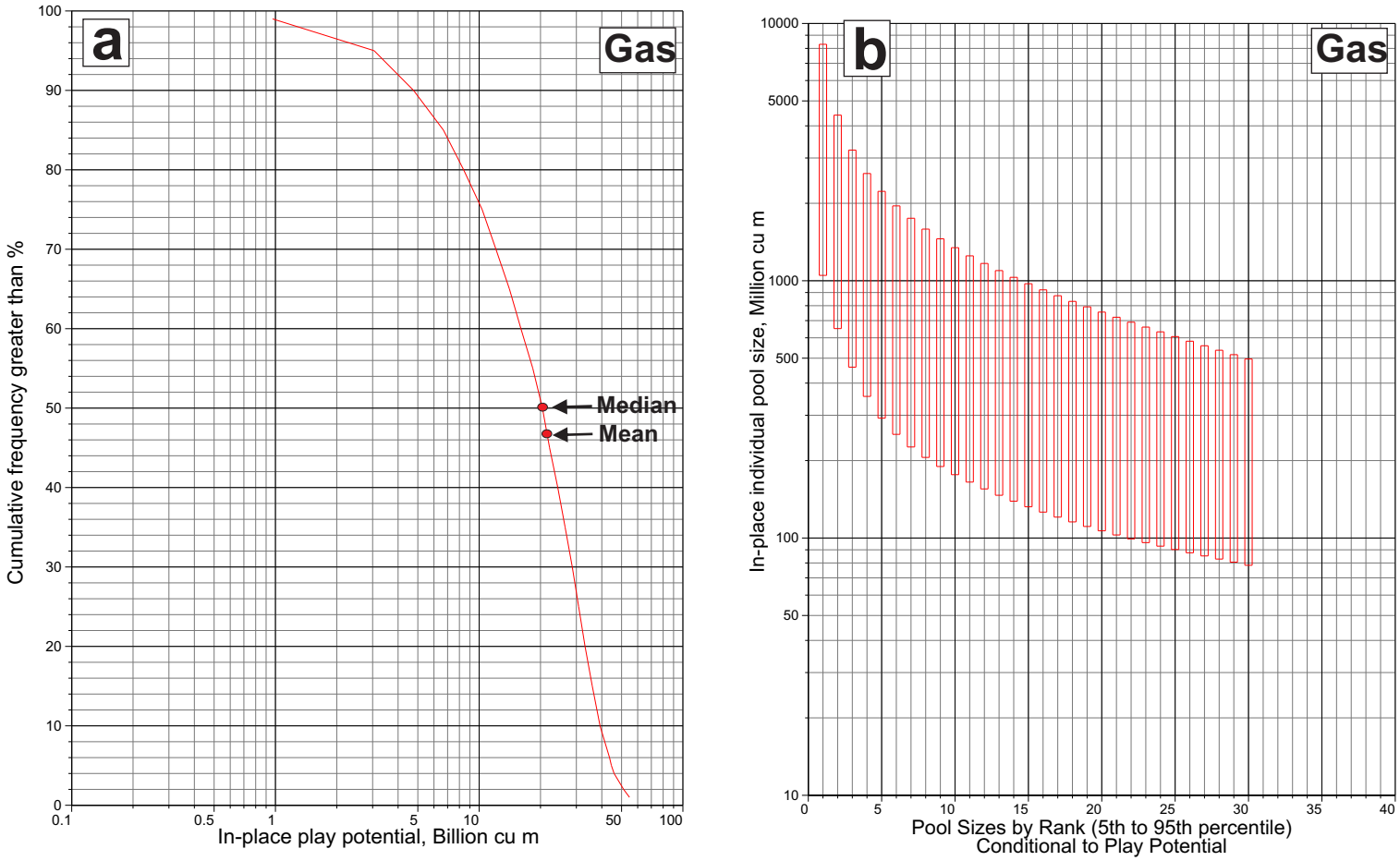


Figure 32. Estimate of in-place gas (a) potential of the Lower Paleozoic carbonate stratigraphic play. Pool-size-by-rank plot (b) of the play is also displayed.

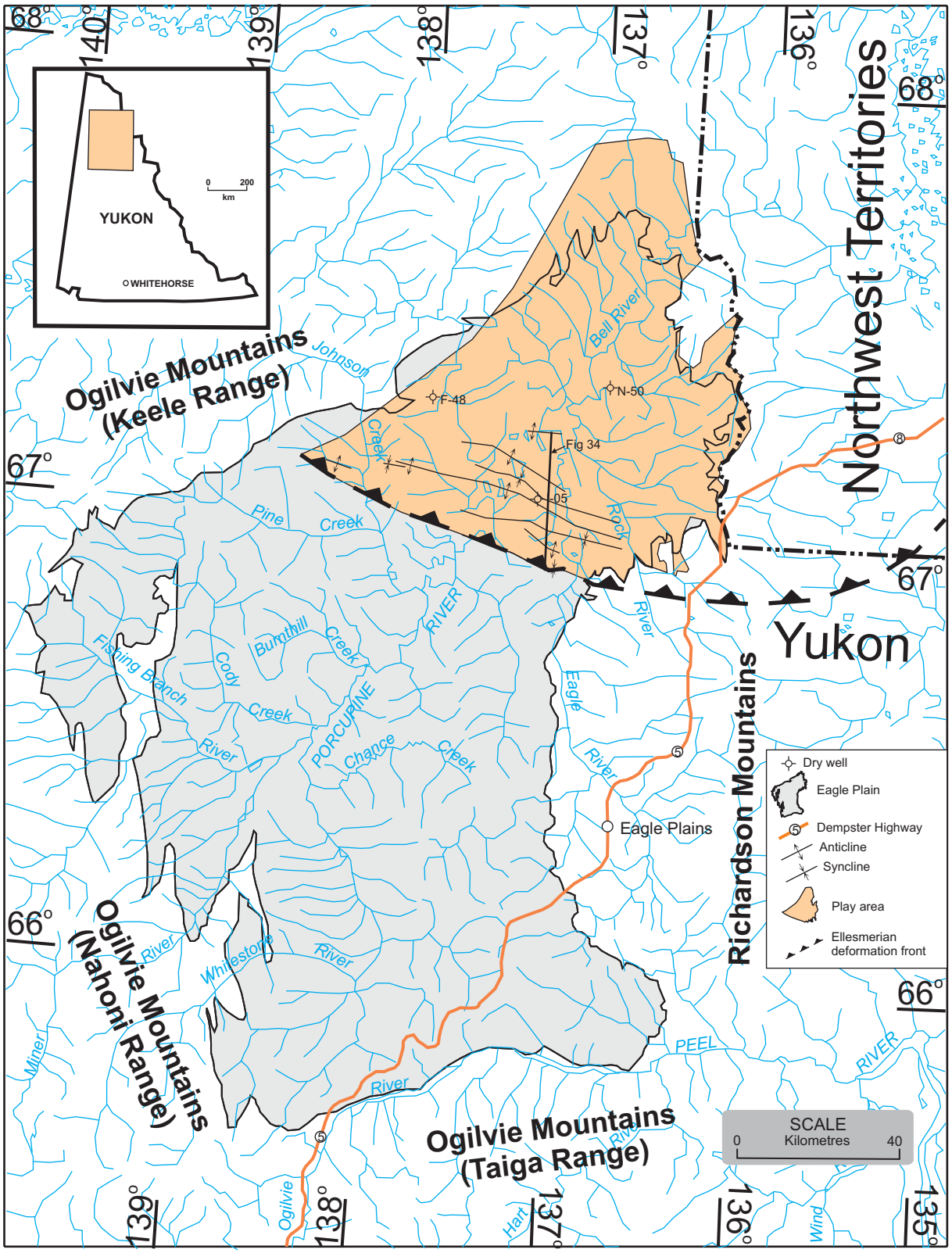


Figure 33. Imperial/Tuttle sandstone structural (Ellesmerian deformation-Bell Subbasin) oil and gas play. Interpreted Ellesmerian compressional structures (anticlines and synclines) and deformation front are depicted (from Lane (2007)). Seismic line location of Fig. 34 is shown.

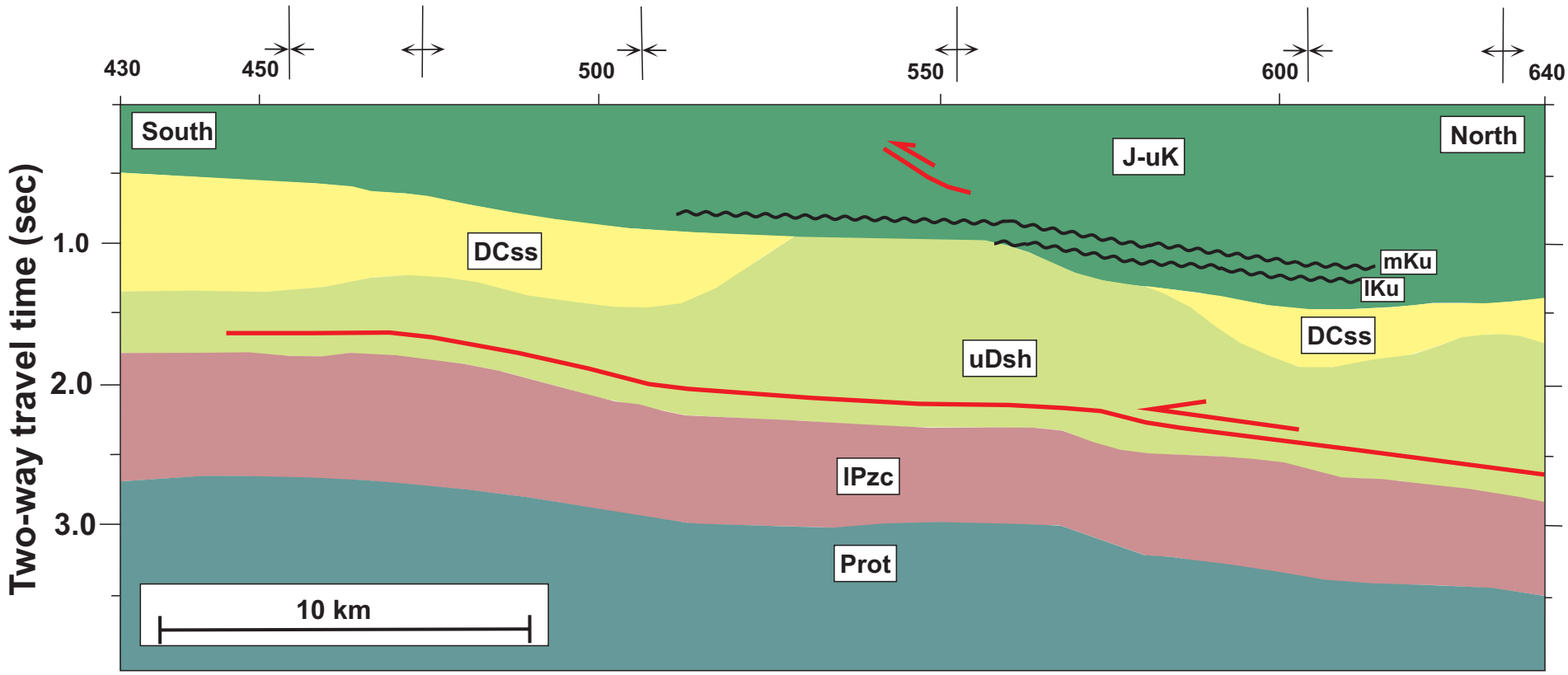


Figure 34. Schematic seismic section illustrating Ellesmerian structures and potential trap configurations in northeastern Bell Subbasin (see Fig. 33 for location). Folds are outlined by high-amplitude reflections within the interbedded sandstone and shale succession (Imperial/Tuttle formations; Dcss). From Lane (2007). Part of Chevron Canada Resources seismic reflection line 11. J-uK, Jurassic to Upper Cretaceous clastic succession; uDsh, Upper Devonian Imperial Formation, shale dominant succession; lPzc, lower Paleozoic carbonate shelf to offshelf shale facies; Prot, Proterozoic; mKu, mid-Cretaceous unconformity; lKu, lower Cretaceous unconformity..

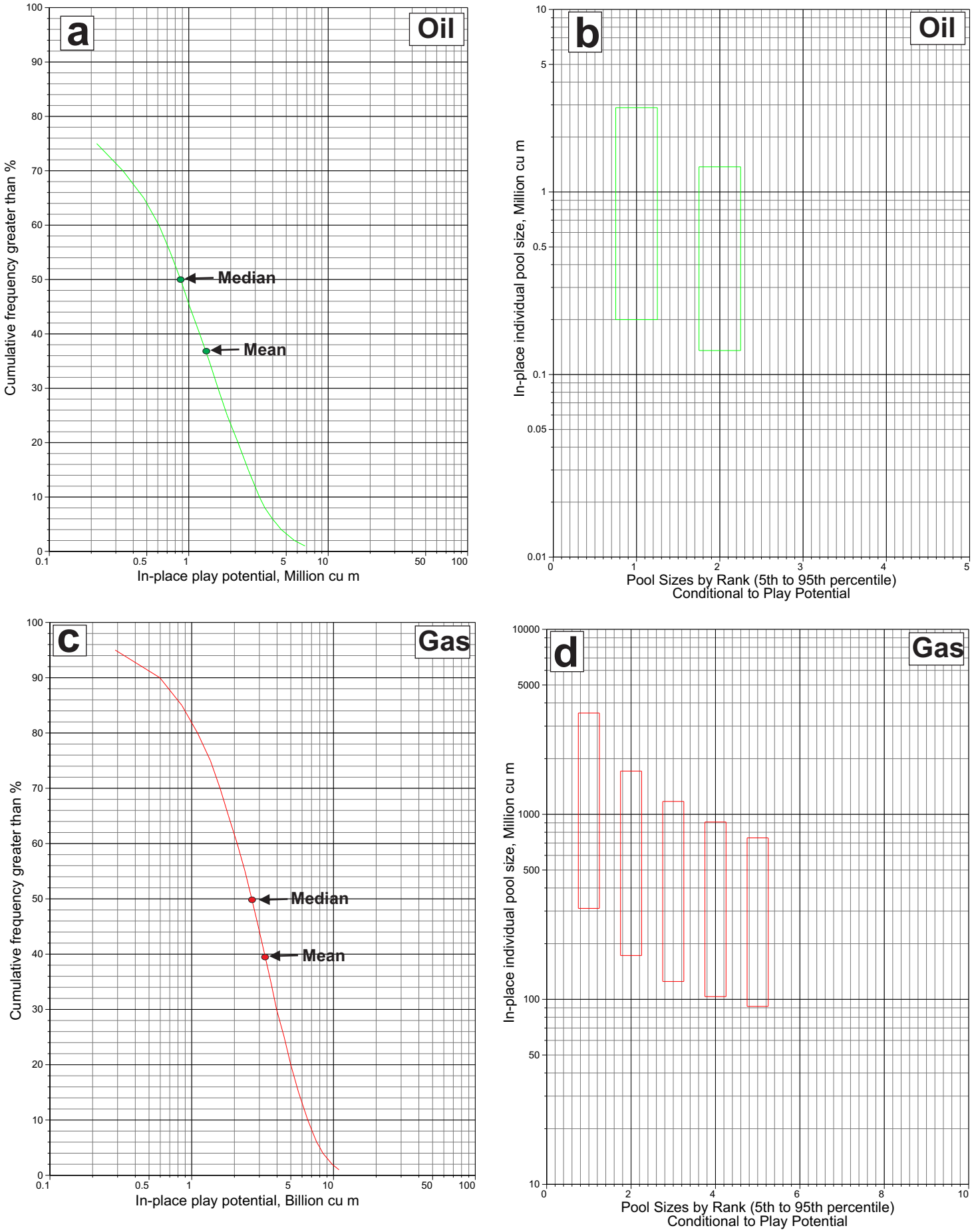


Figure 35. Estimates of in-place oil (a) and gas (c) potential of the Imperial/Tuttle sandstone structural (Ellesmerian deformation-Bell Subbasin) play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

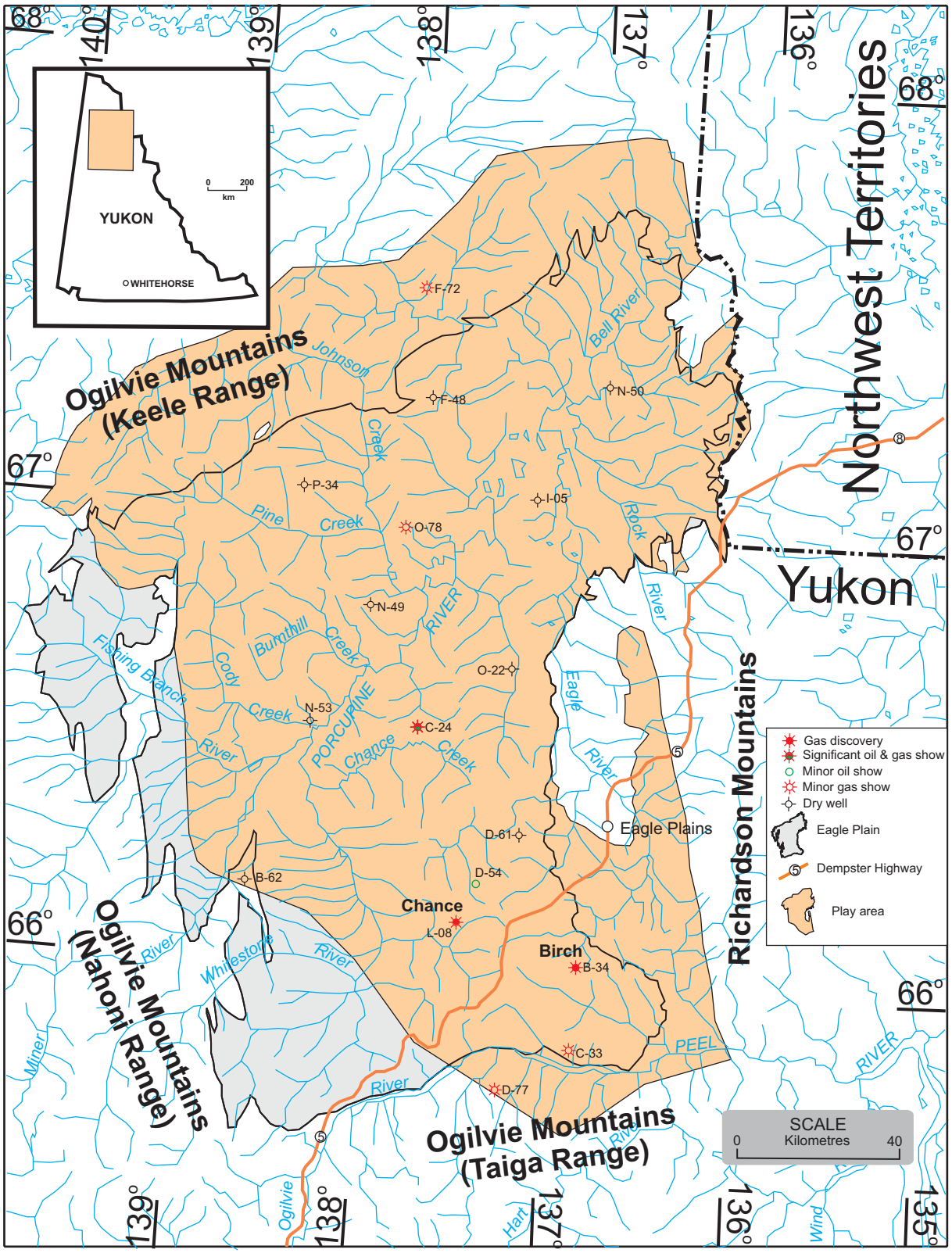


Figure 36. Imperial/Tuttle sandstone stratigraphic/combination oil and gas play.

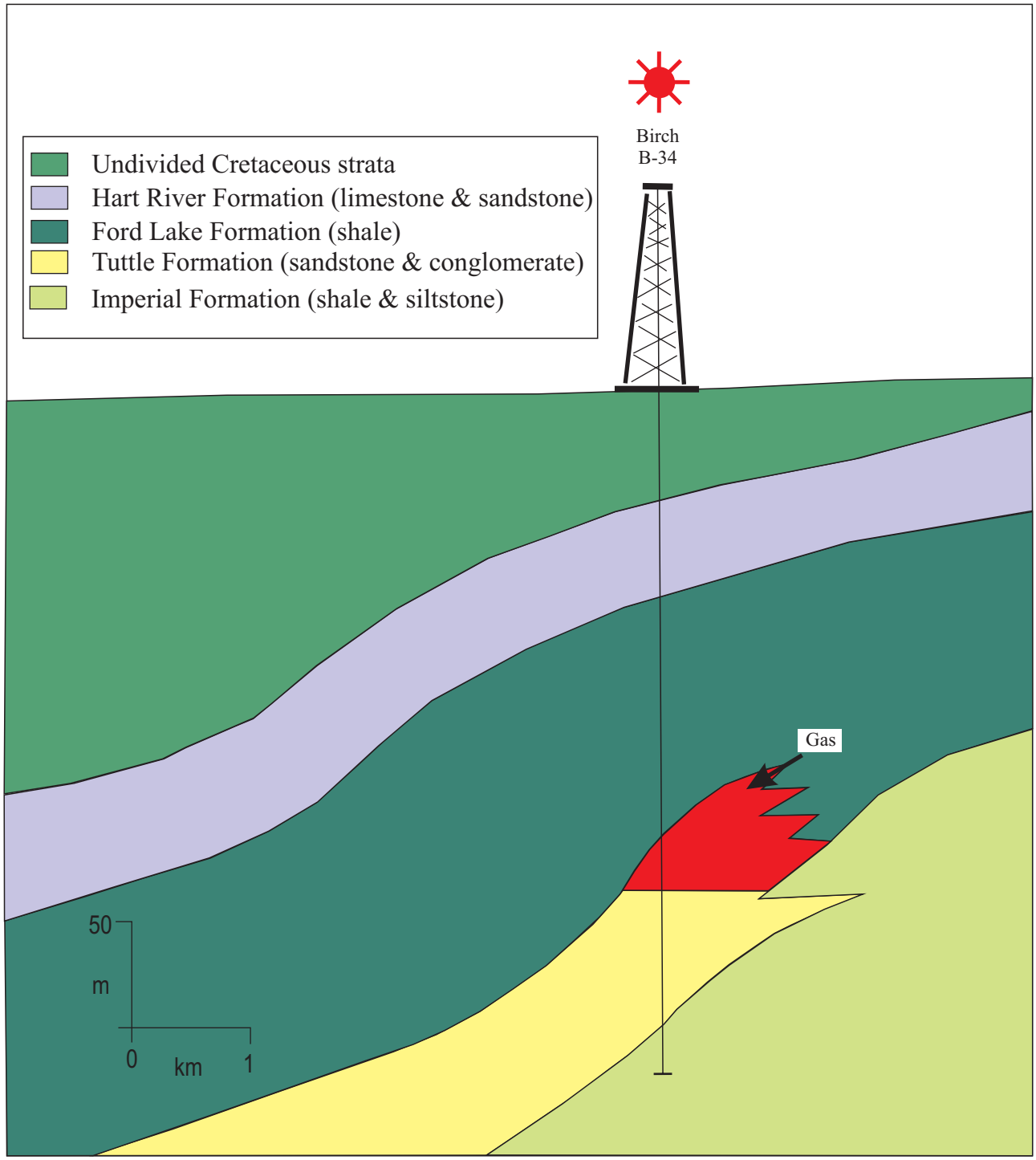


Figure 37. Schematic cross-section illustrating potential trap configurations in the Imperial/Tuttle sandstone stratigraphic/combination oil and gas play. Illustrated trap is an updip facies change where Tuttle porous sandstones abut against shale formations.. From National Energy Board, 2000.

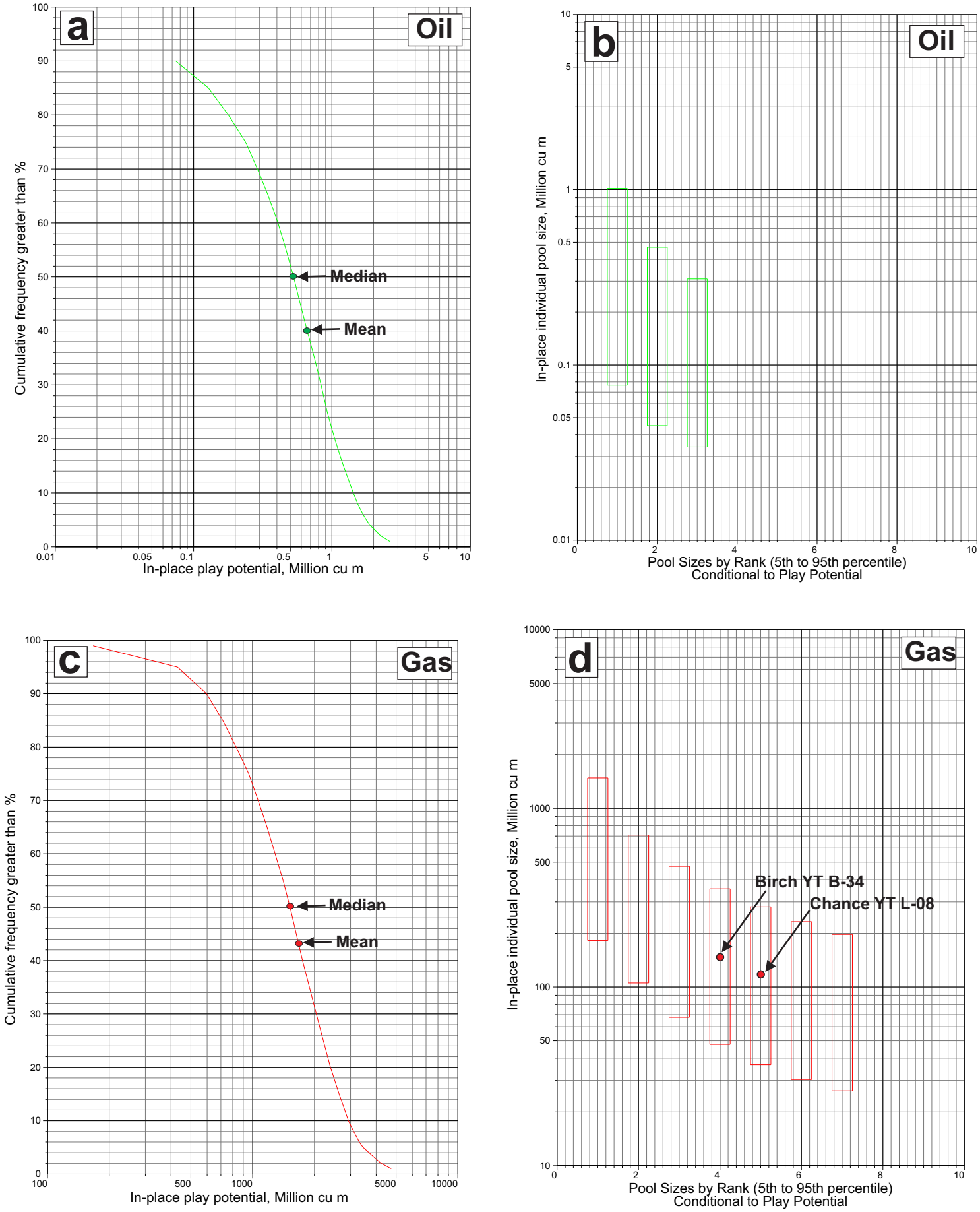


Figure 38. Estimates of in-place oil (a) and gas (c) potential of the Imperial/Tuttle sandstone stratigraphic/combination play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

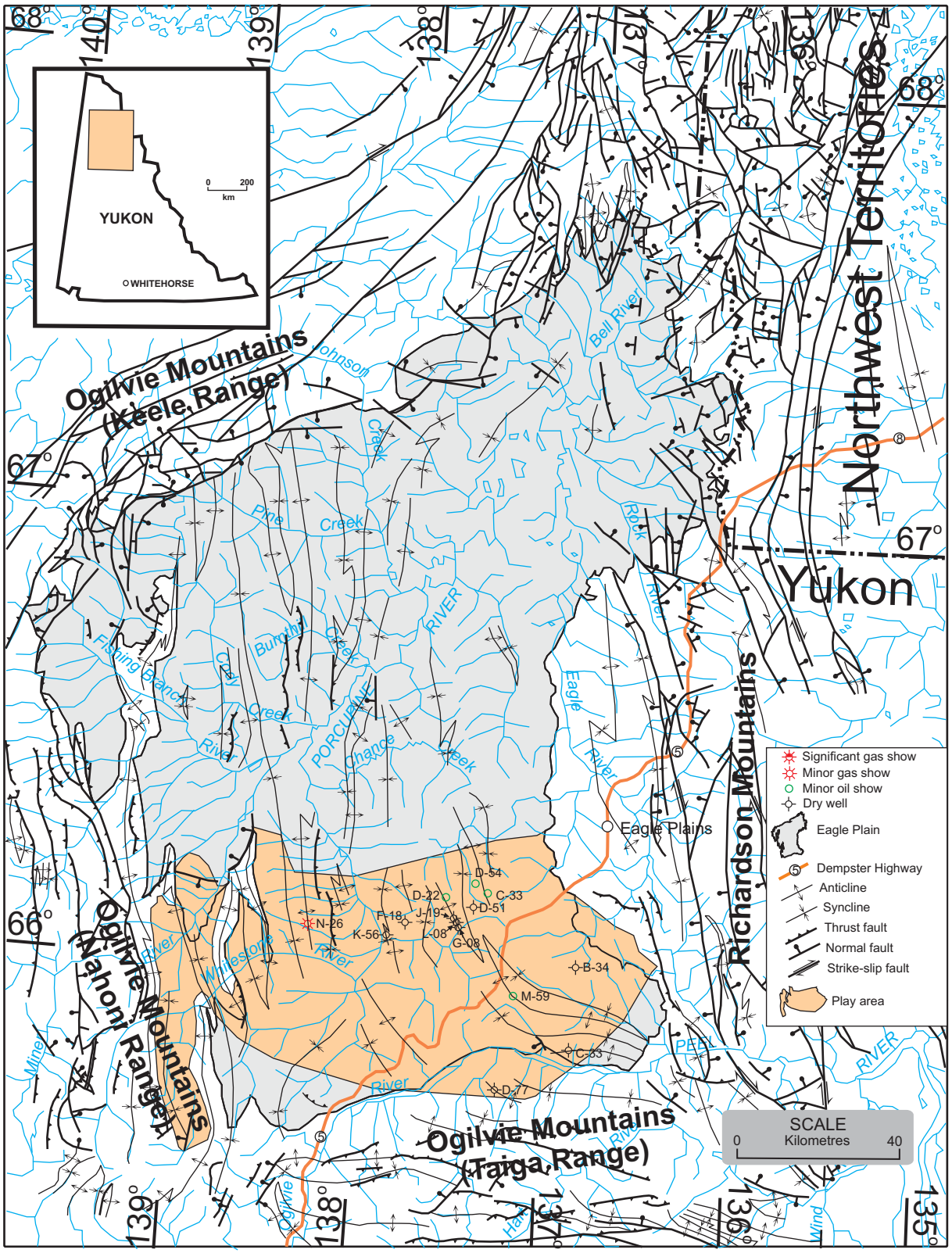


Figure 39. Canoe River carbonate structural oil and gas play.

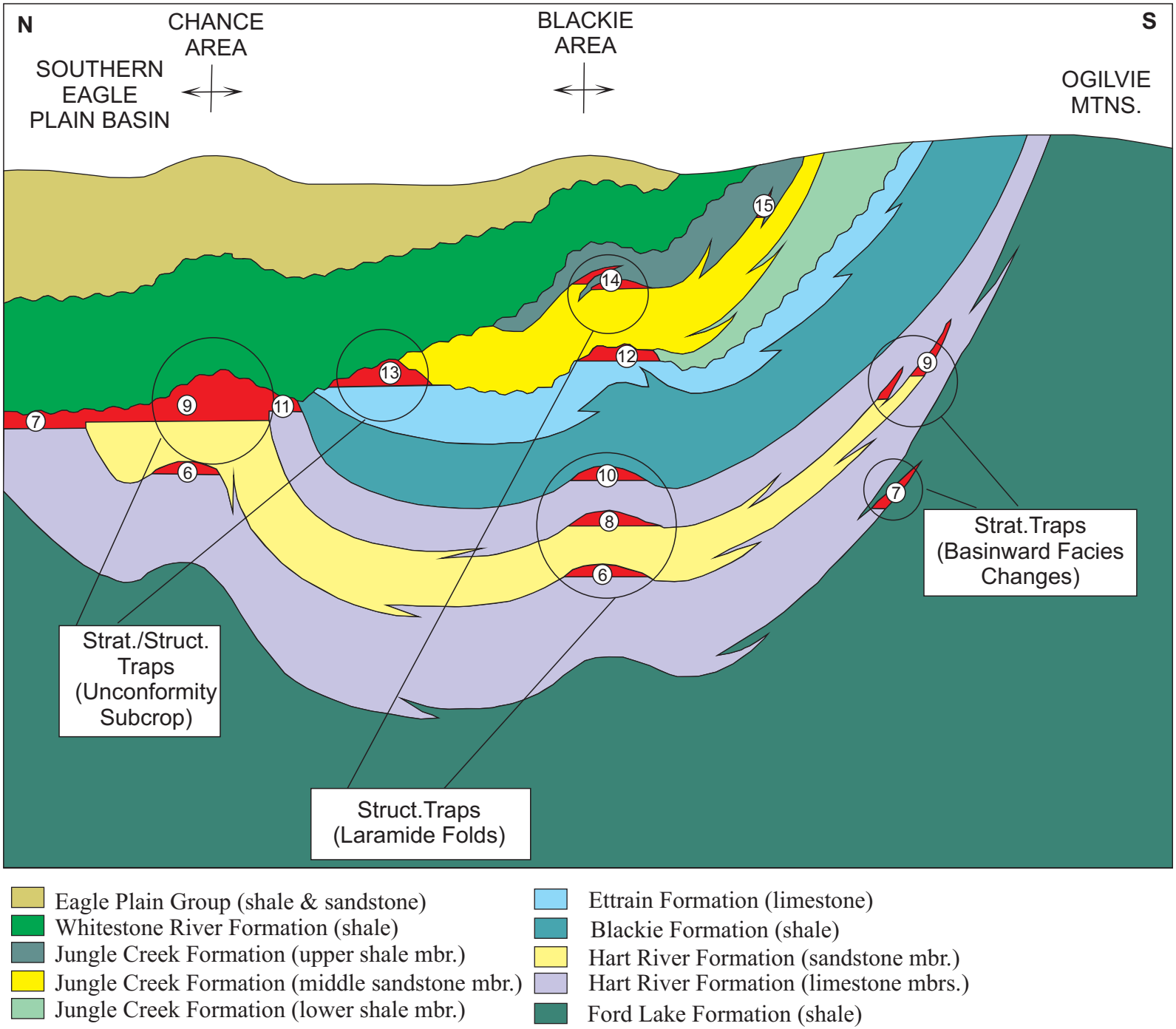


Figure 40. Schematic cross-section illustrating potential trap configurations in southern Eagle Plain Basin. Numbering of petroleum accumulations directly correlates with the numeration of petroleum plays in Table 1 and the text. From Hamblin, 1990.

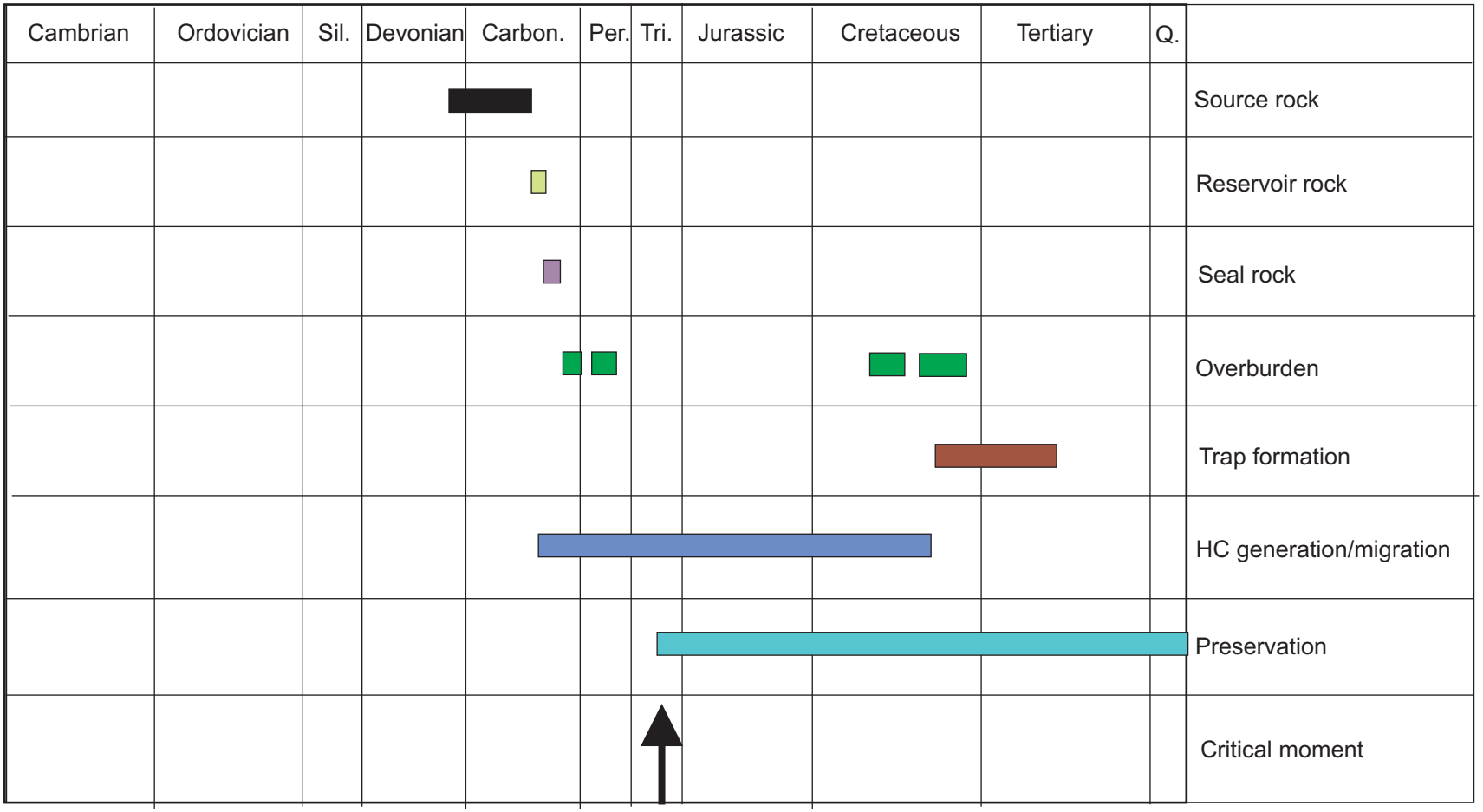


Figure 41. Petroleum event chart for a Carboniferous petroleum system (Ford Lake source-Hart River reservoir). The critical moment for oil and gas generation (arrow) in southern Eagle Plain occurred during Late Triassic time, the midway point of thermal oil and gas generation derived from burial history diagrams of Link and Bustin (1989). Sil.-Silurian, Carbon.-Carboniferous, Per.-Permian, Tri.-Triassic, Q.-Quaternary.

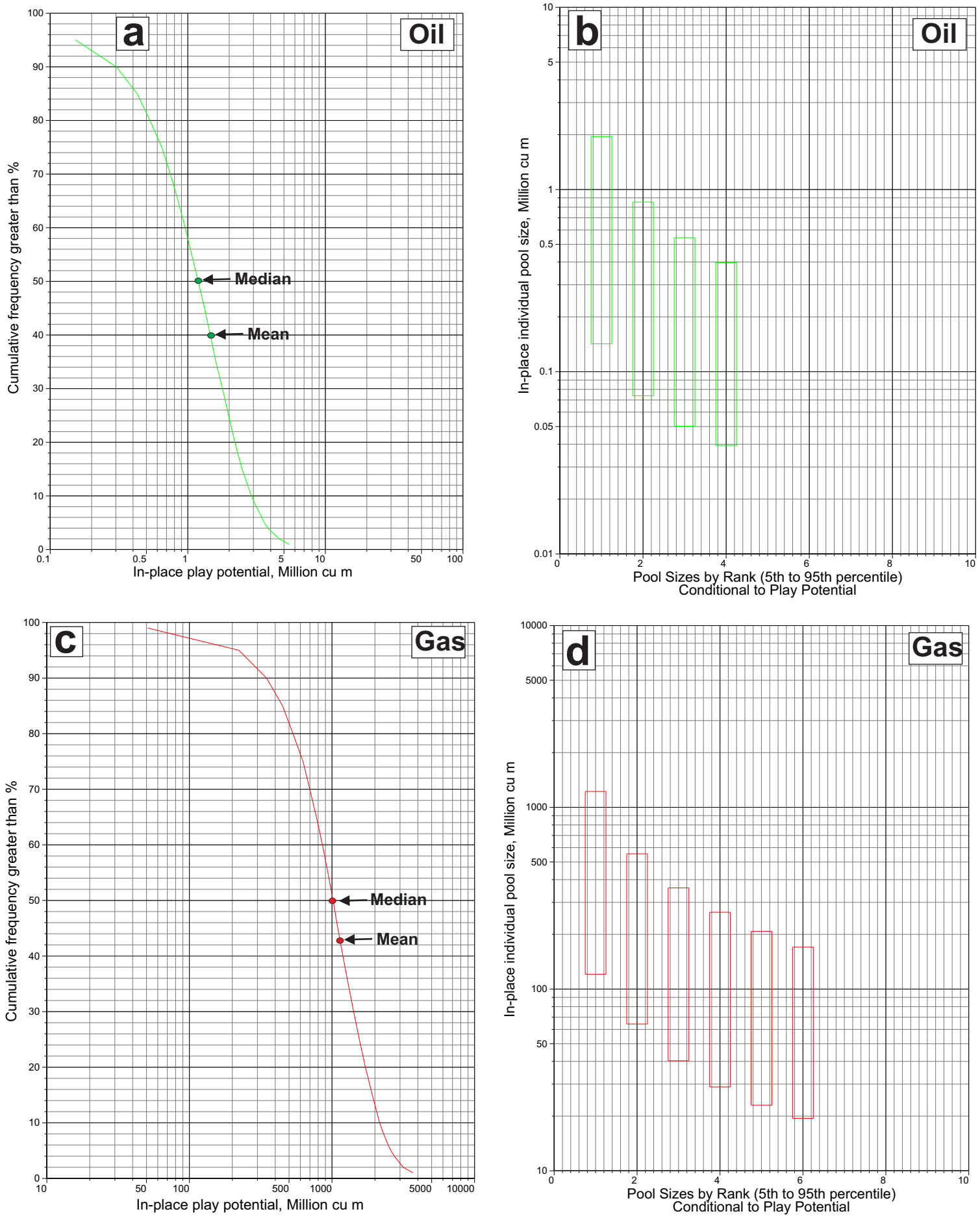


Figure 42. Estimates of in-place oil (a) and gas (c) potential of the Canoe River carbonate structural play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

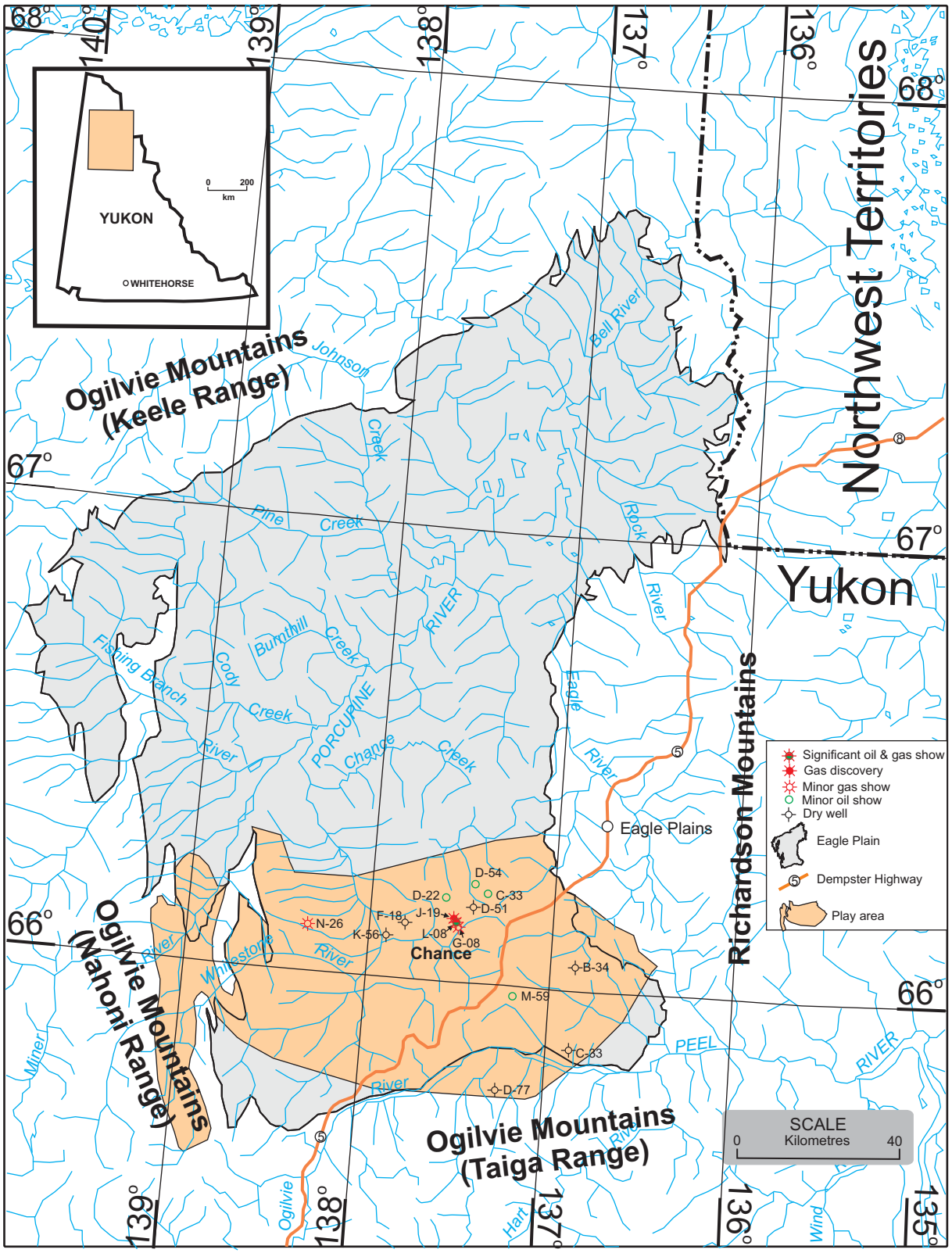


Figure 43. Canoe River carbonate stratigraphic oil and gas play.

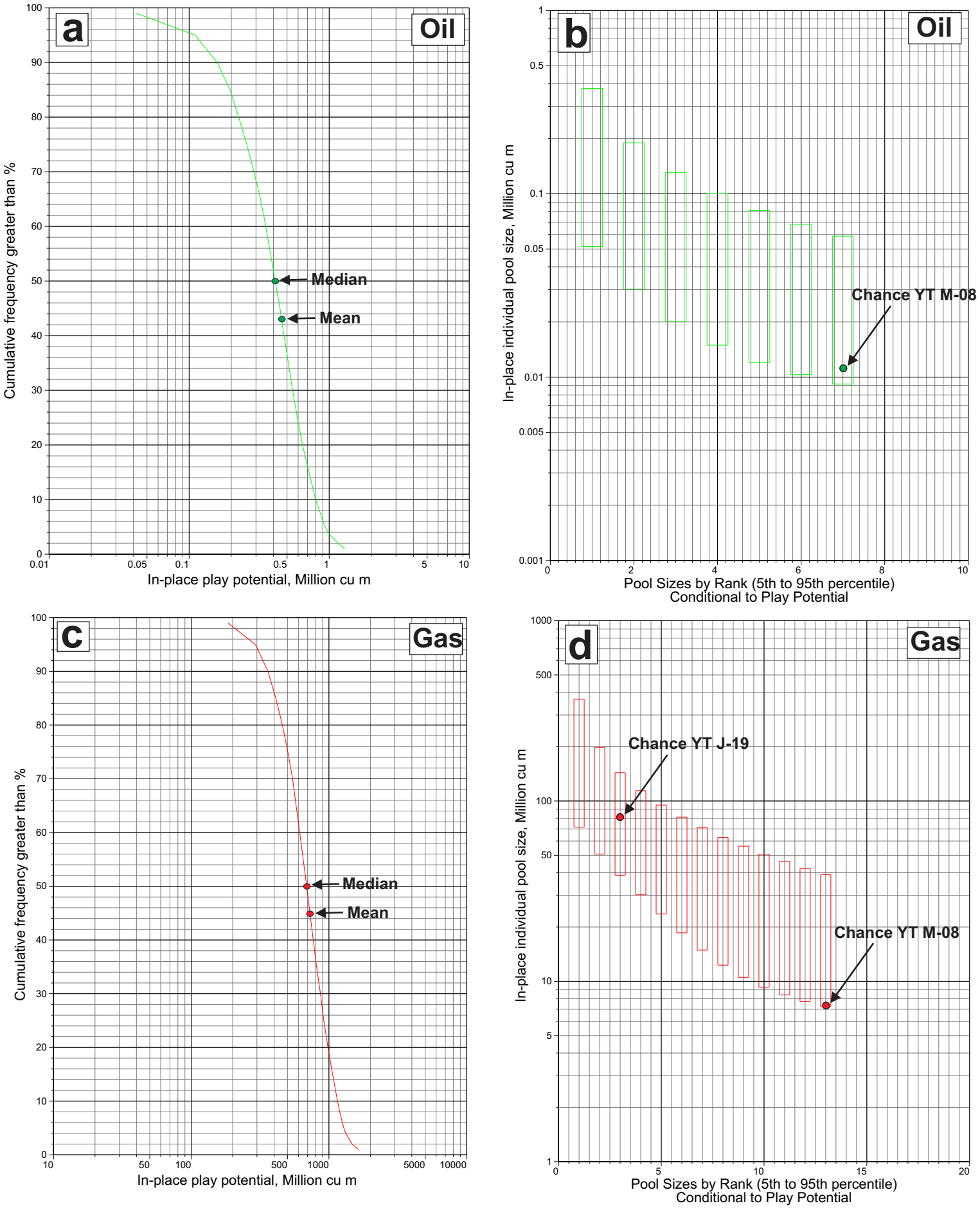


Figure 44. Estimates of in-place oil (a) and gas (c) potential of the Canoe River carbonate stratigraphic play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

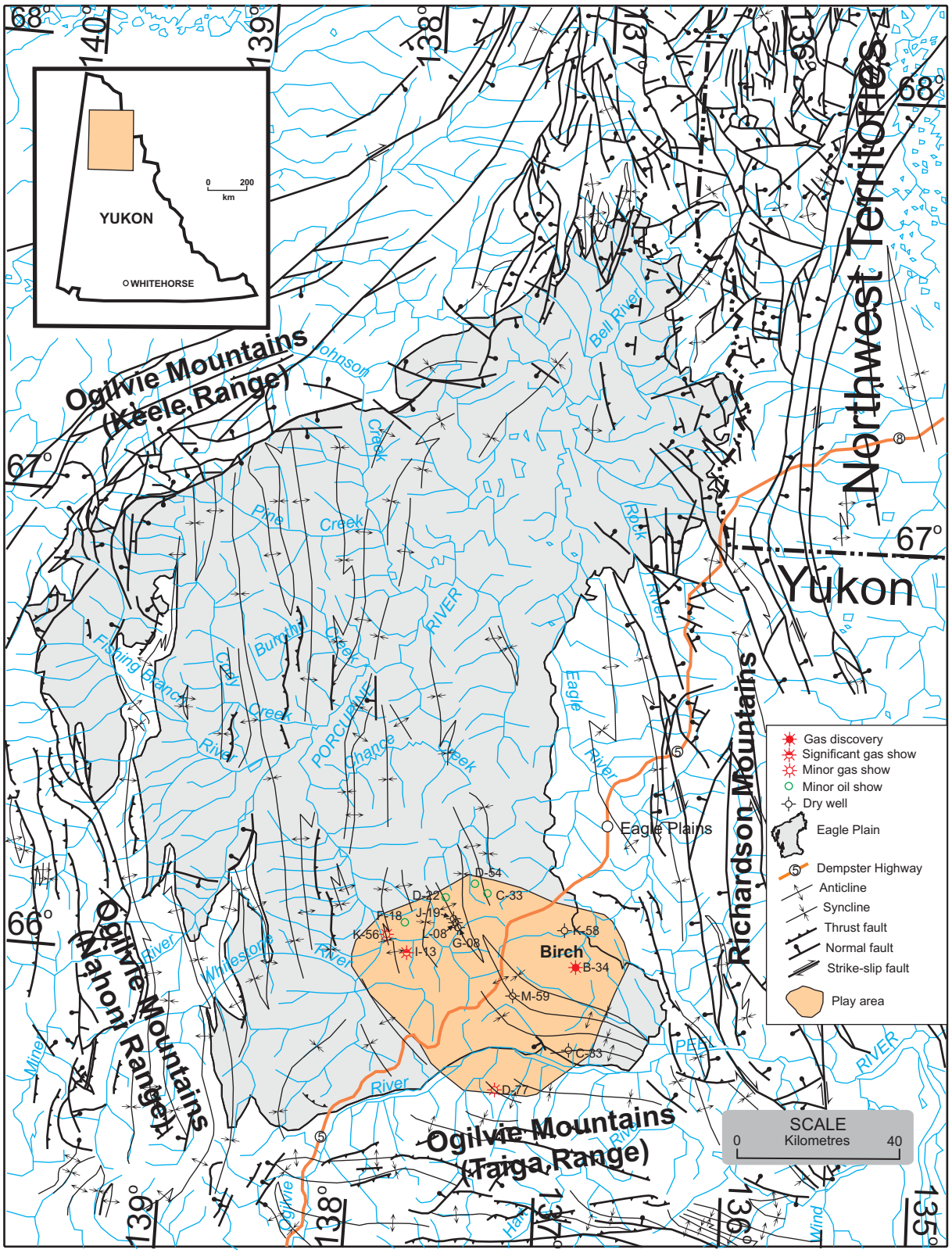


Figure 45. Chance sandstone structural oil and gas play.

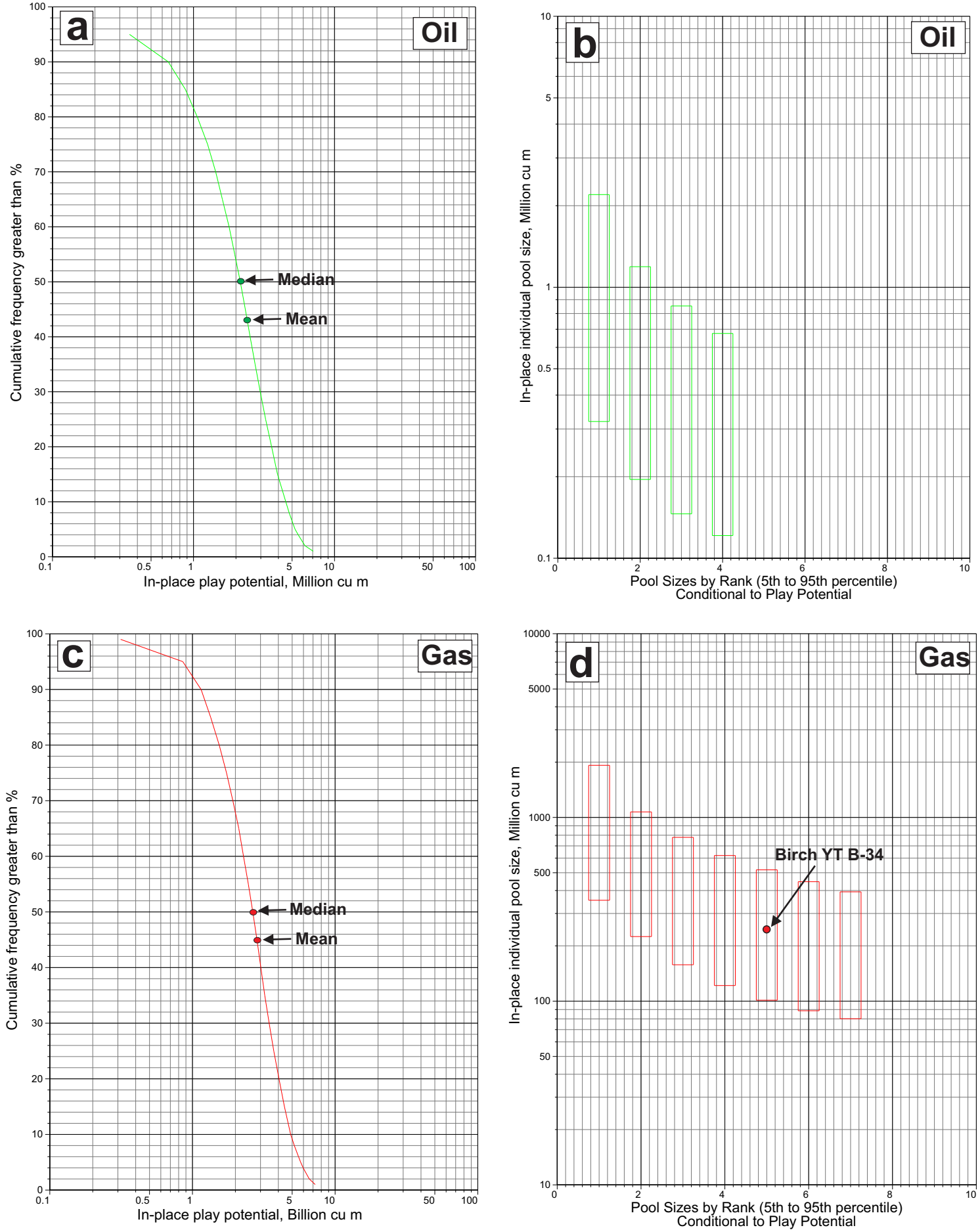


Figure 46. Estimates of in-place oil (a) and gas (c) potential of the Chance sandstone structural play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

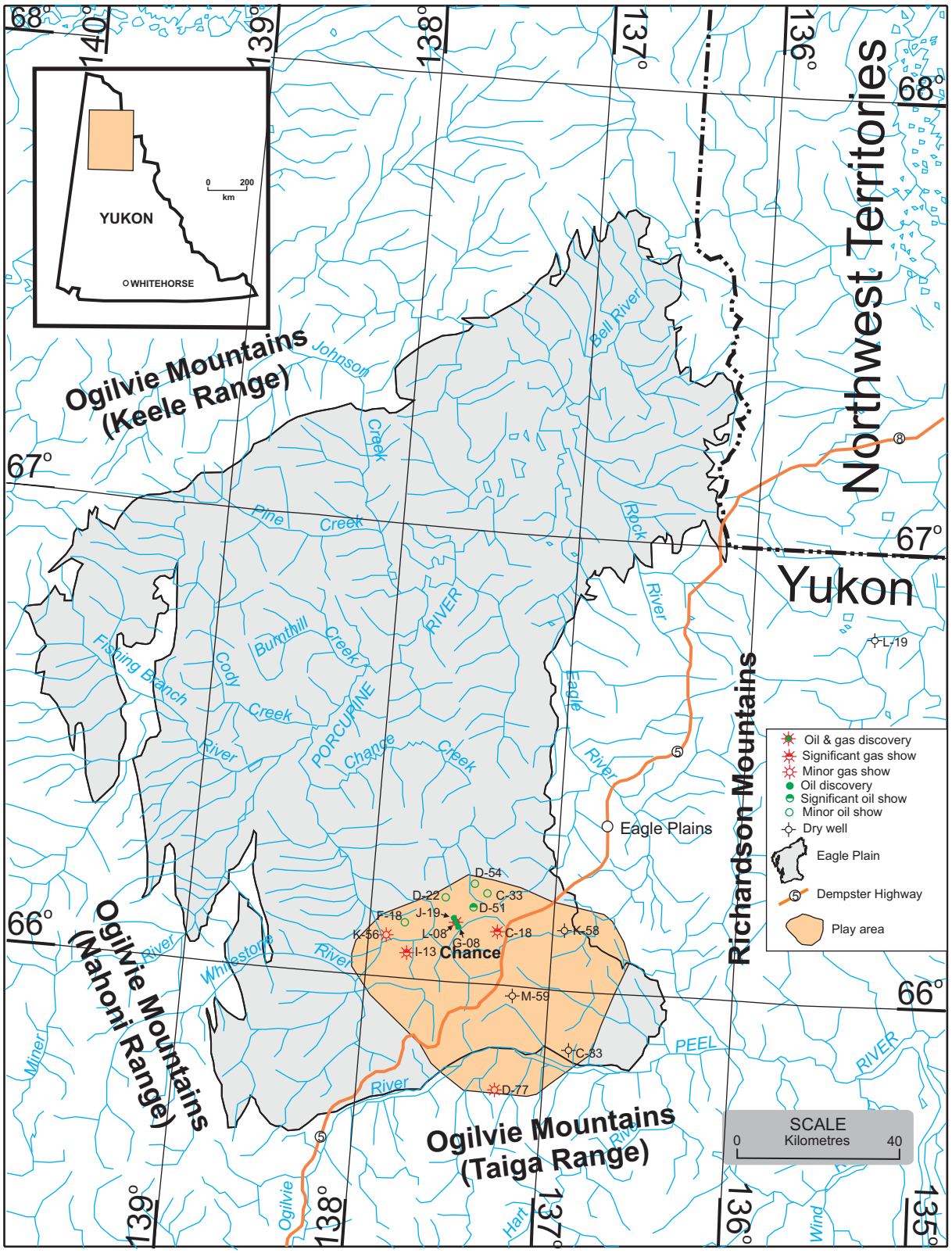


Figure 47. Chance sandstone stratigraphic oil and gas play.

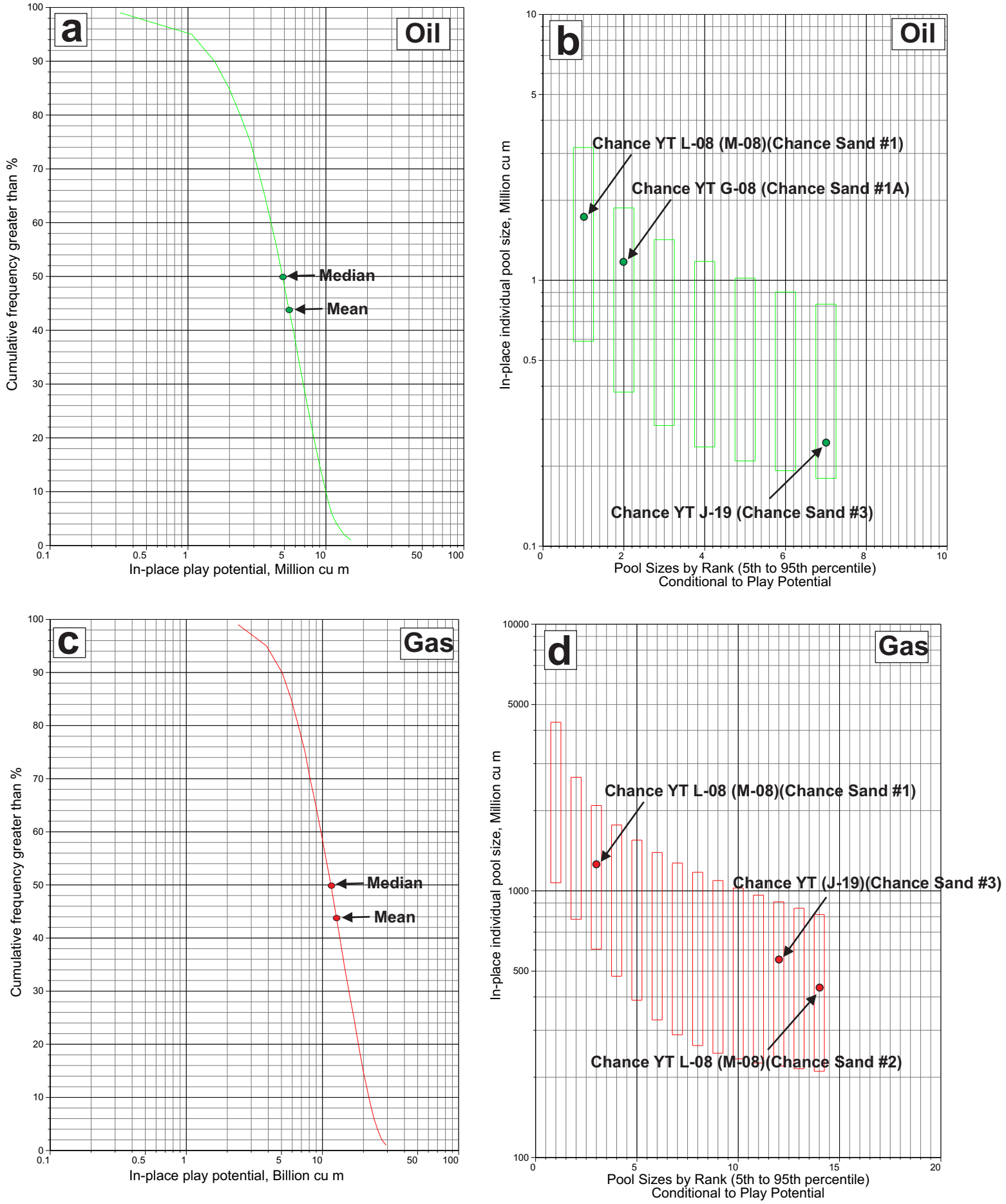


Figure 48. Estimates of in-place oil (a) and gas (c) potential of the Chance sandstone stratigraphic play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

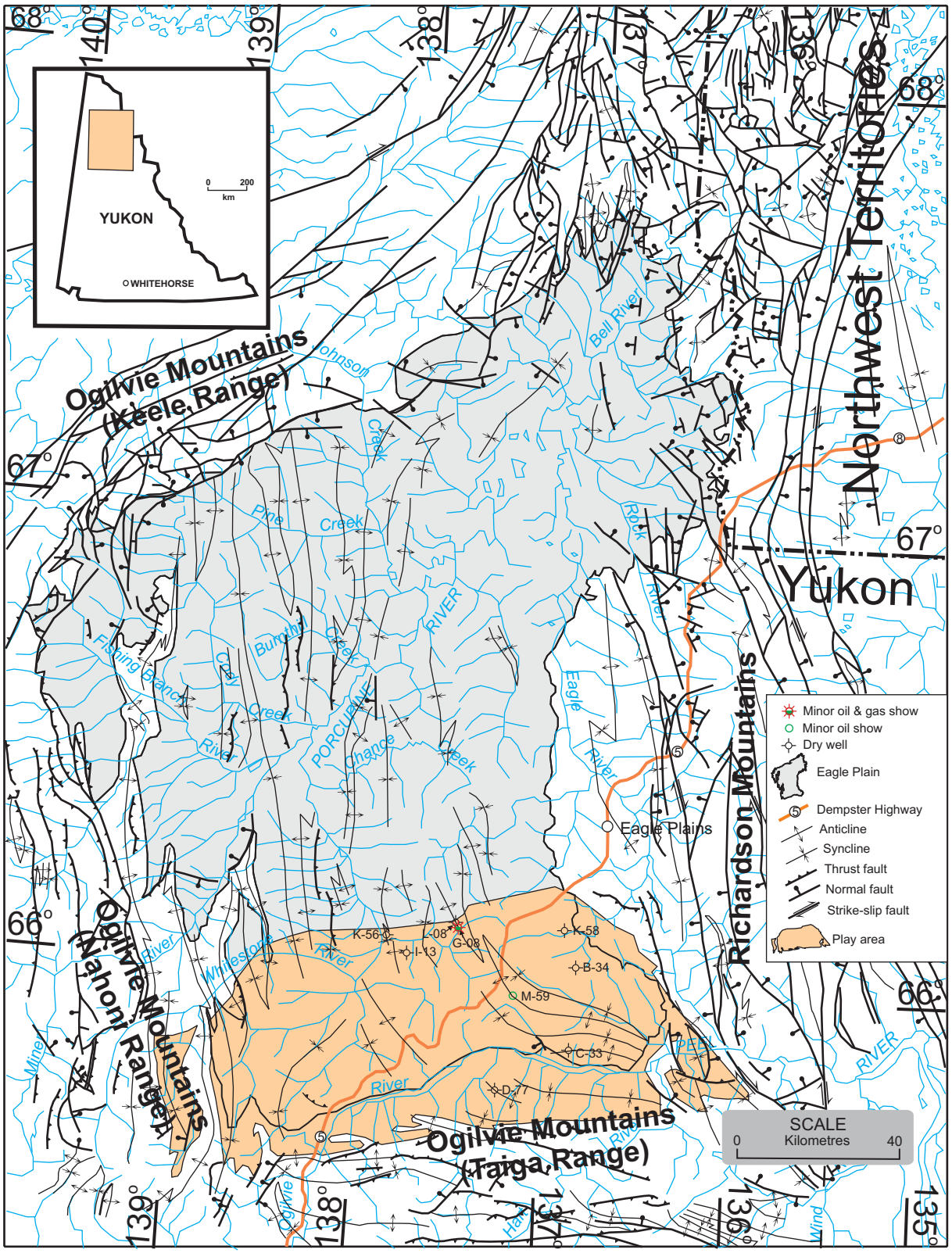


Figure 49. Alder carbonate structural oil and gas play.

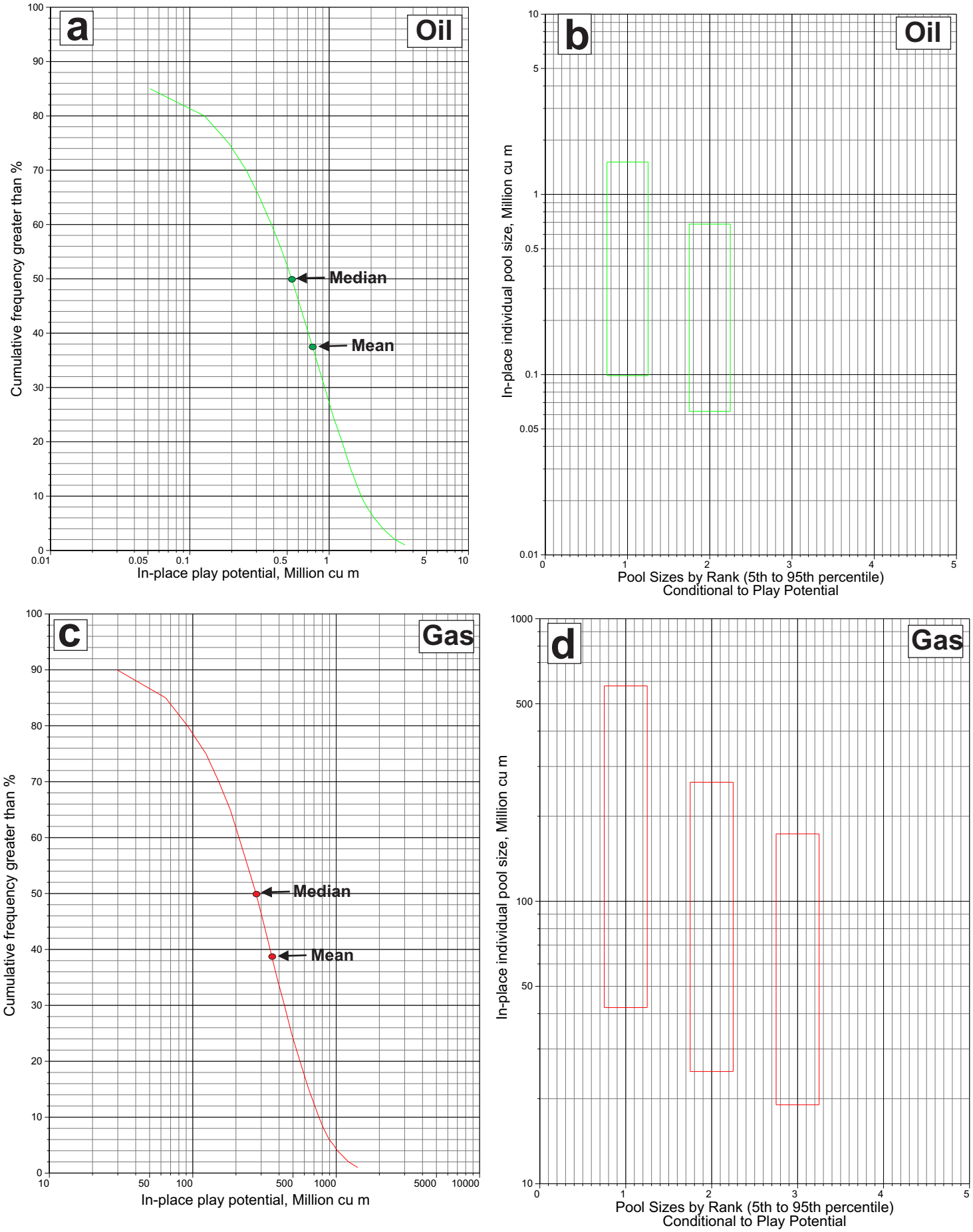


Figure 50. Estimates of in-place oil (a) and gas (c) potential of the Alder carbonate structural play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

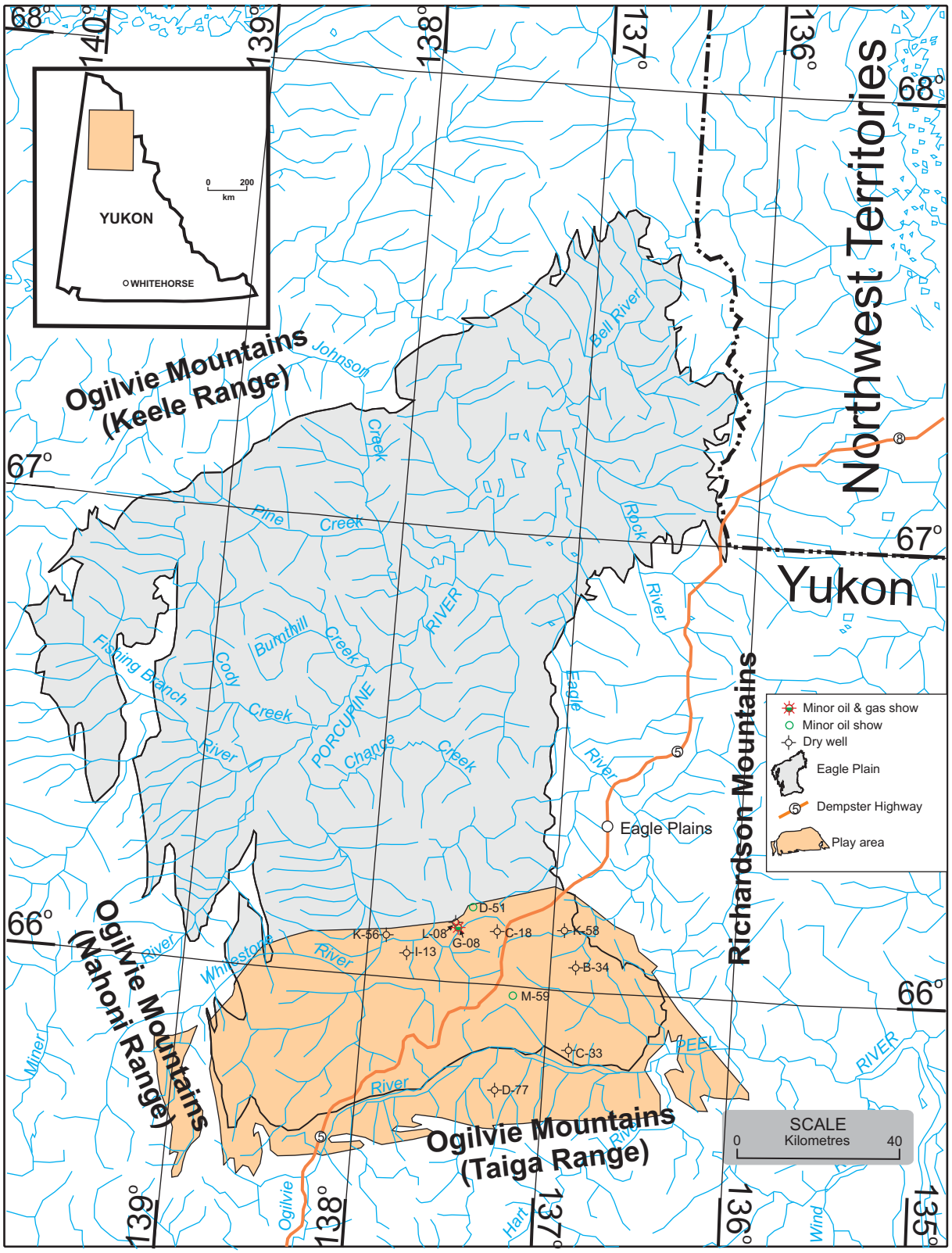


Figure 51. Alder carbonate stratigraphic oil and gas play.

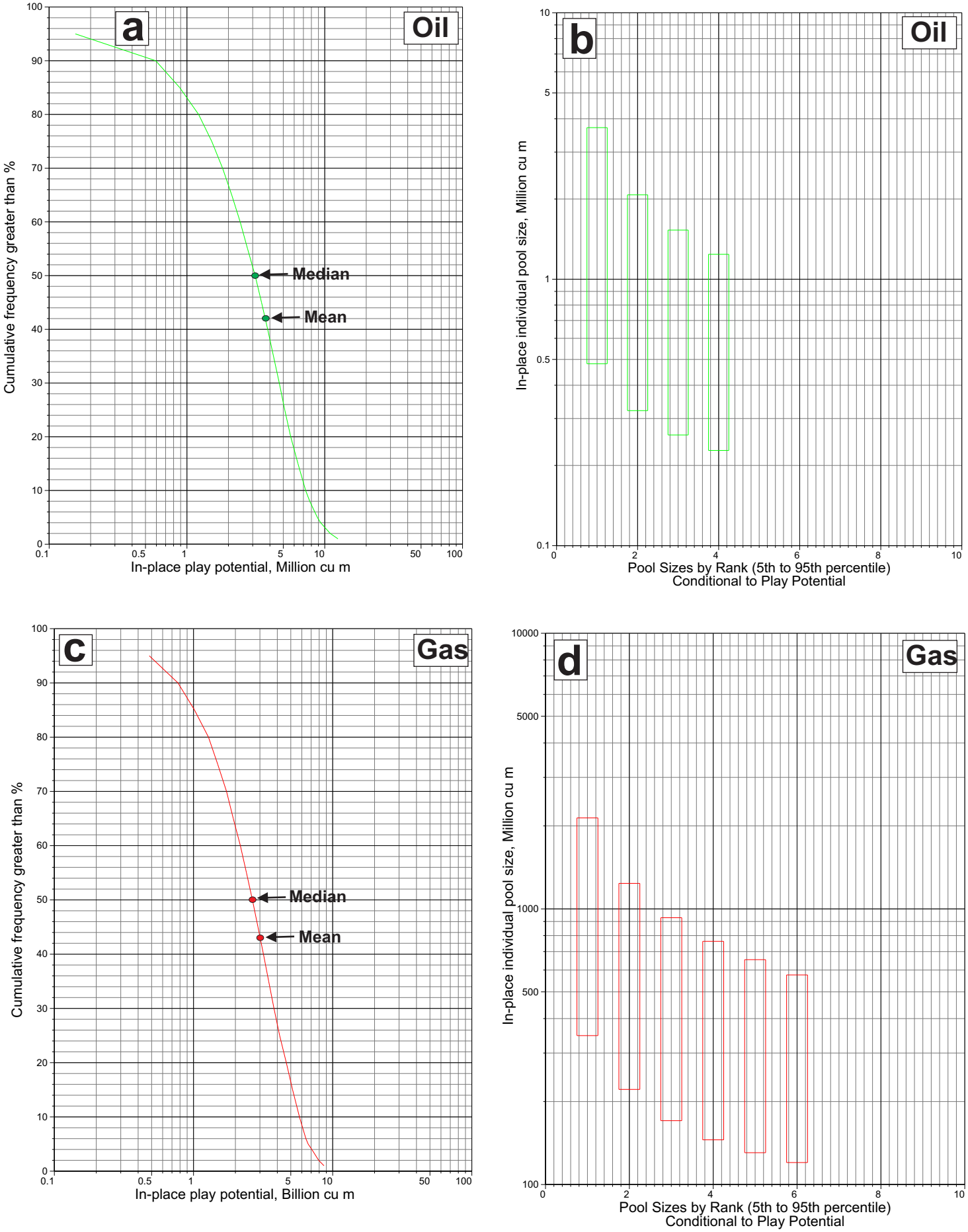


Figure 52. Estimates of in-place oil (a) and gas (c) potential of the Alder carbonate stratigraphic play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

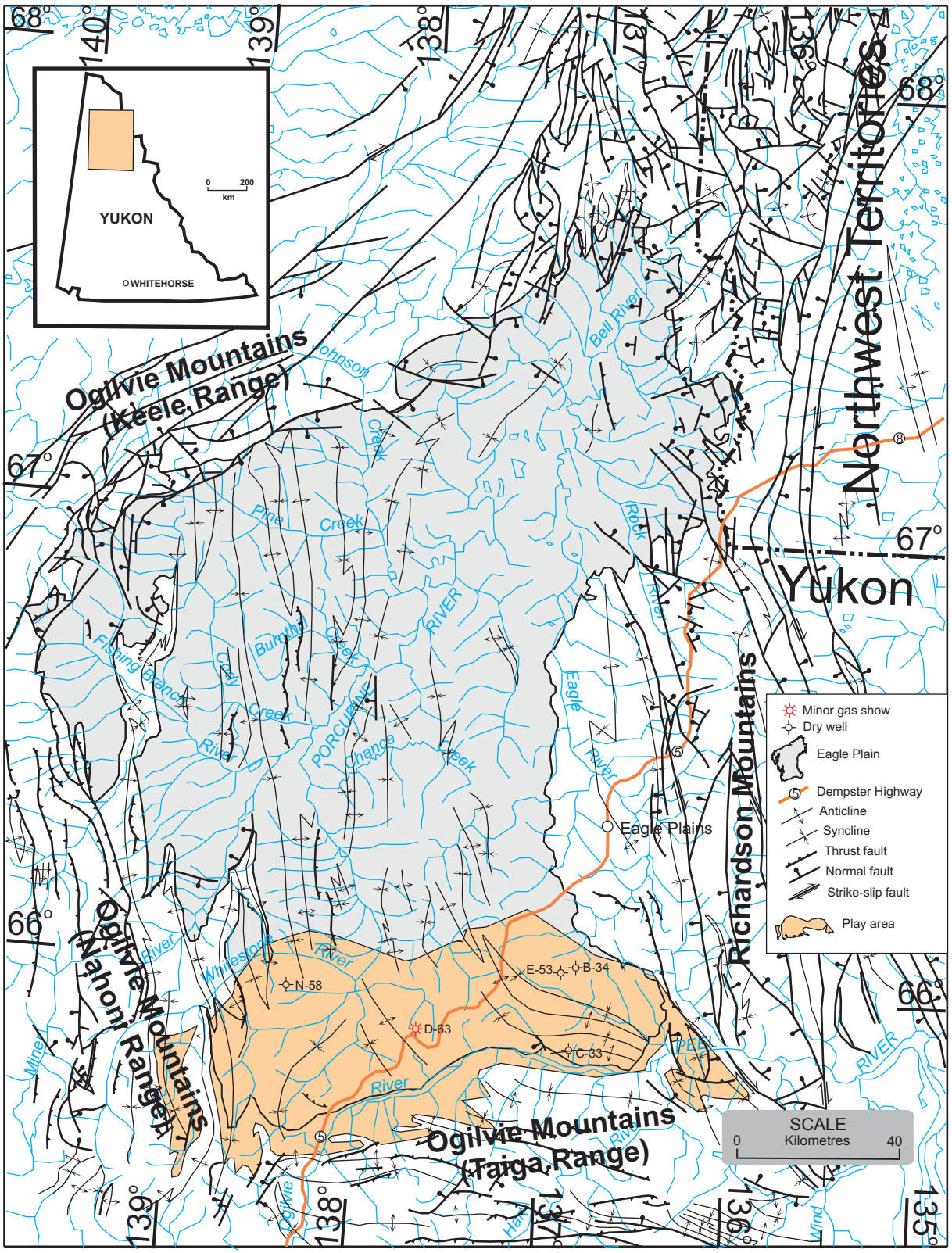


Figure 53. Ettrain carbonate structural oil and gas play.

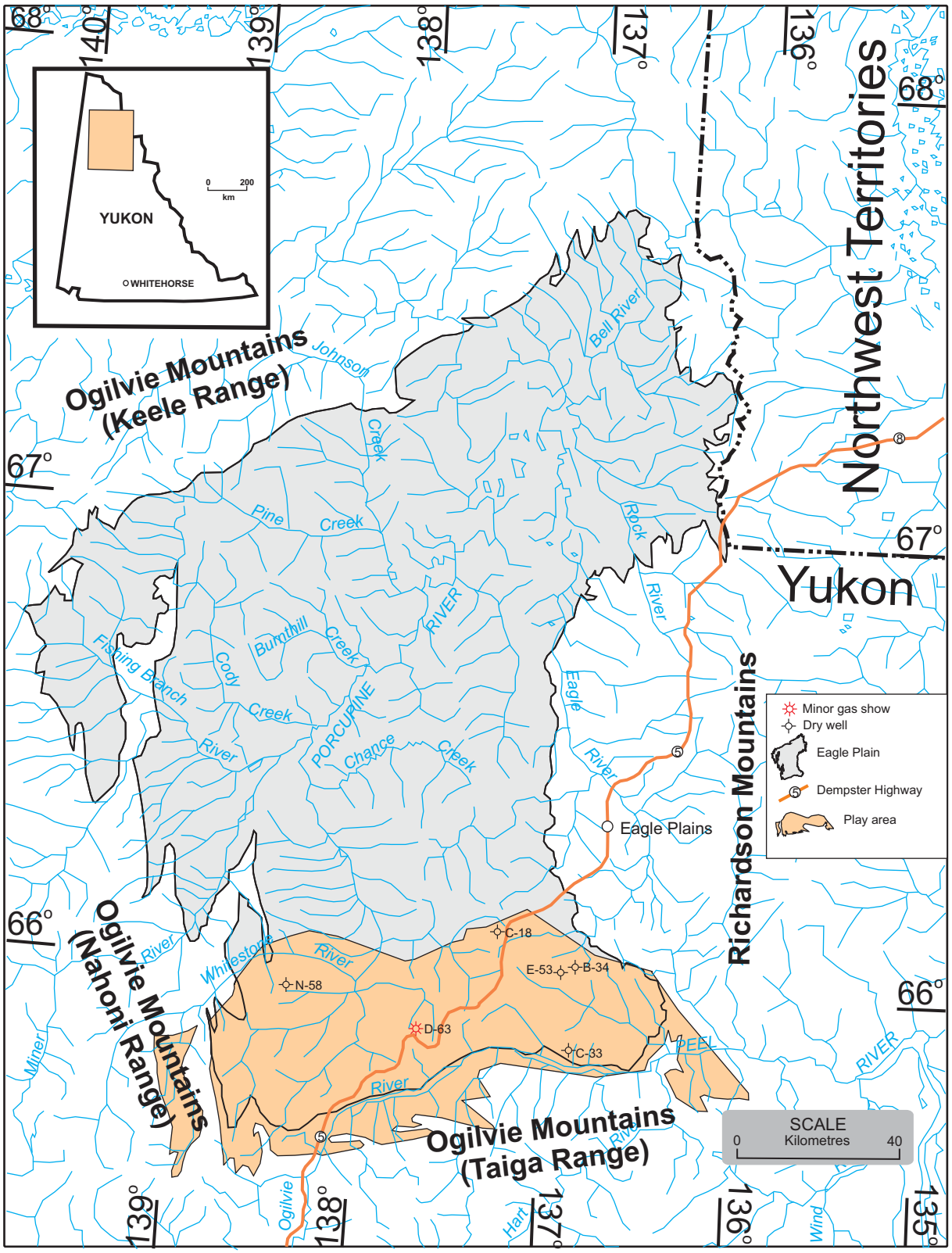


Figure 54. Ettrain carbonate stratigraphic oil and gas play.

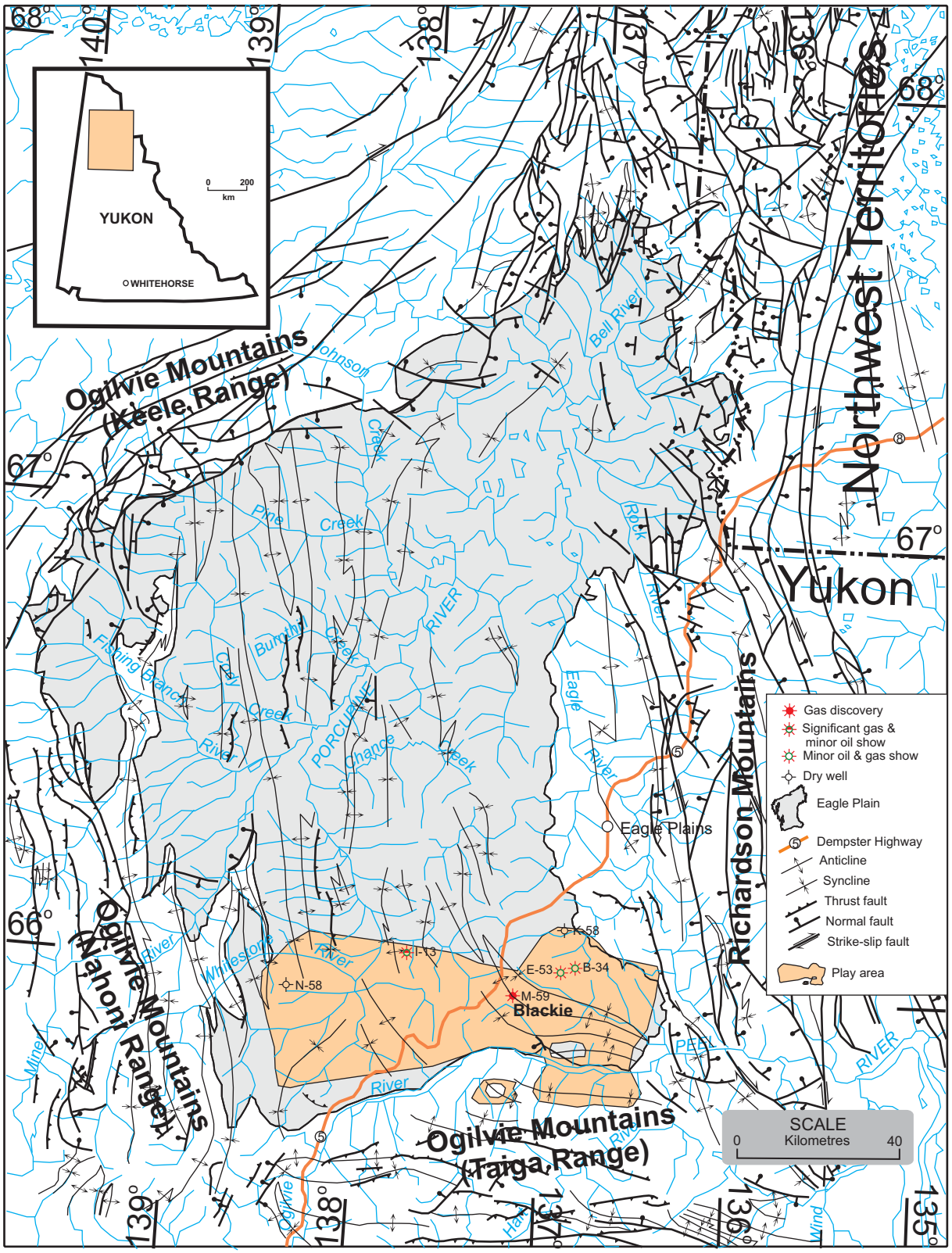


Figure 55. Jungle Creek sandstone structural oil and gas play.

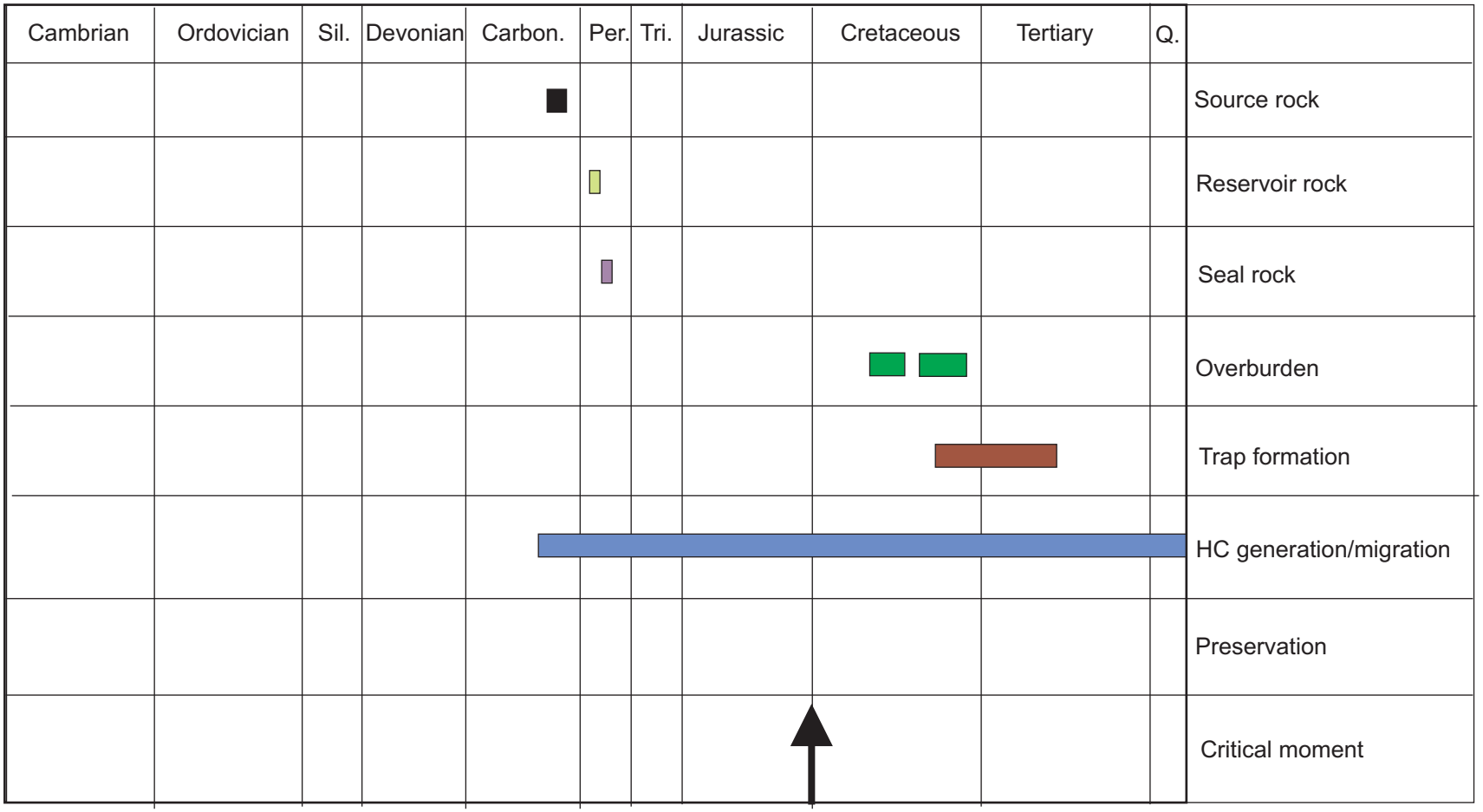


Figure 56. Petroleum event chart for a Carboniferous-Permian petroleum system (Blackie source-Jungle Creek reservoir). The critical moment for oil and gas generation (arrow) in southern Eagle Plain occurred during Late Jurassic/Early Cretaceous time, the midway point of thermal oil and gas generation derived from the burial history diagrams of Link and Bustin (1989). Sil.-Silurian, Carbon.-Carboniferous, Per.-Permian, Tri.-Triassic, Q.-Quaternary.

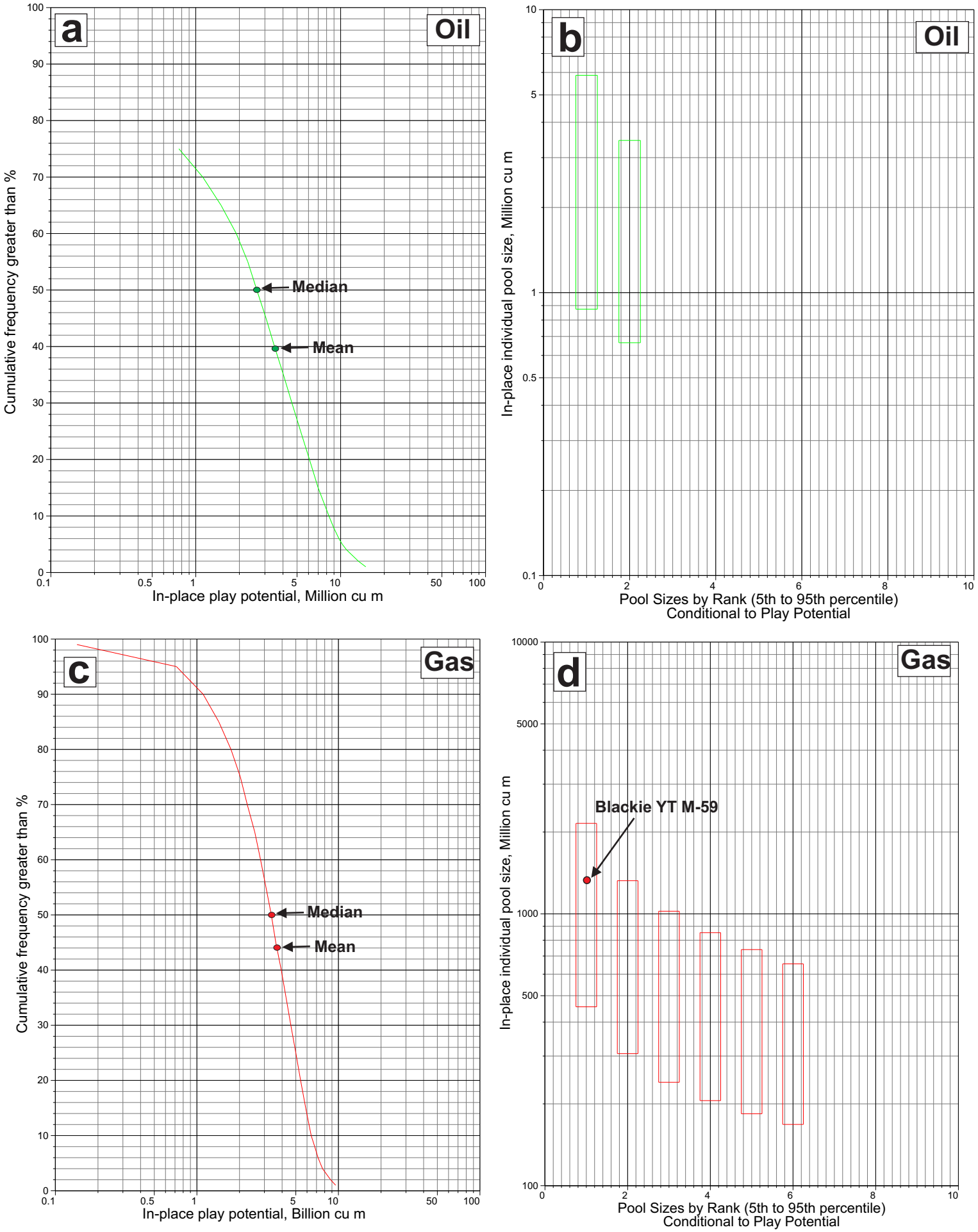


Figure 57. Estimates of in-place oil (a) and gas (c) potential of the Jungle Creek sandstone structural play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

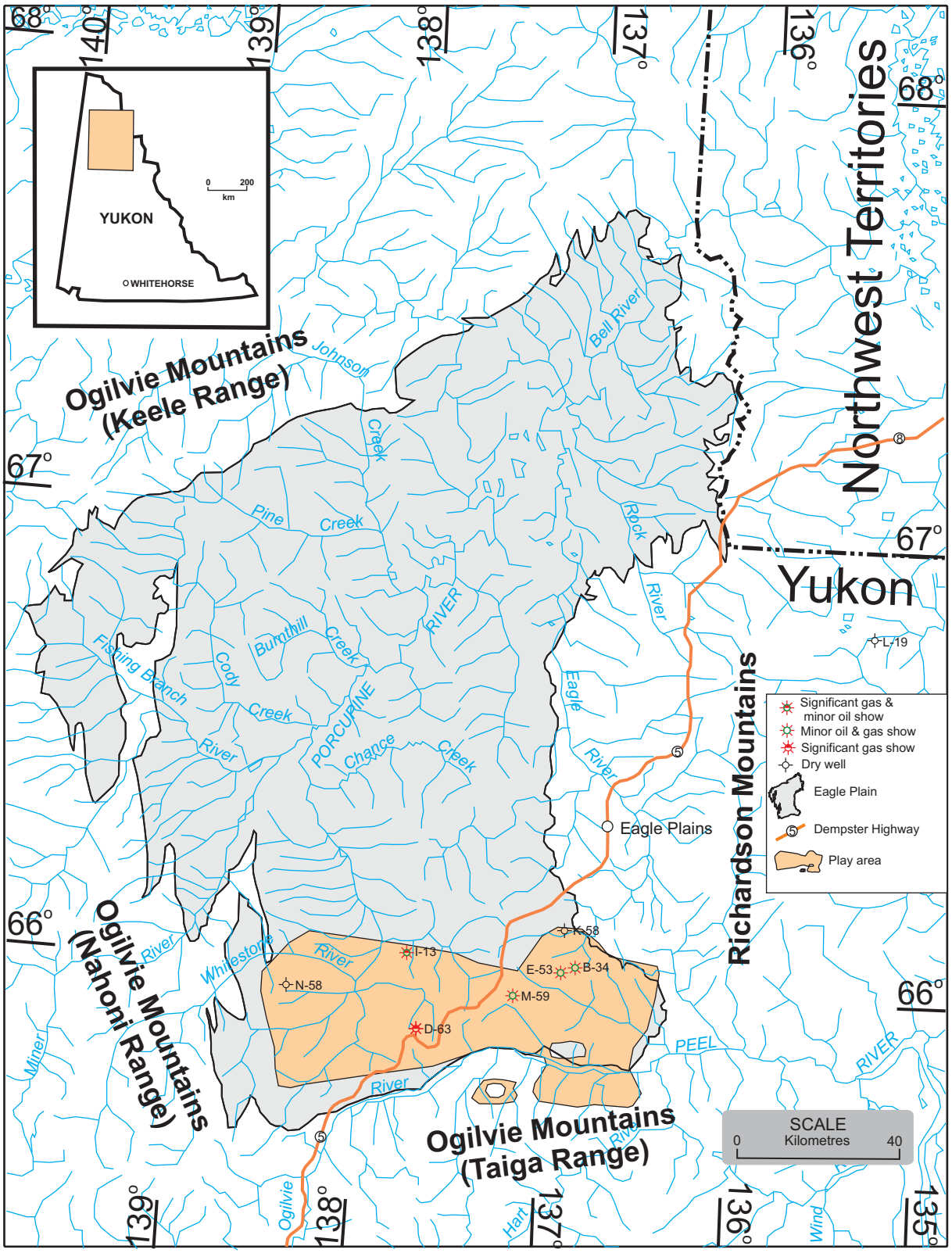


Figure 58. Jungle Creek sandstone stratigraphic oil and gas play.

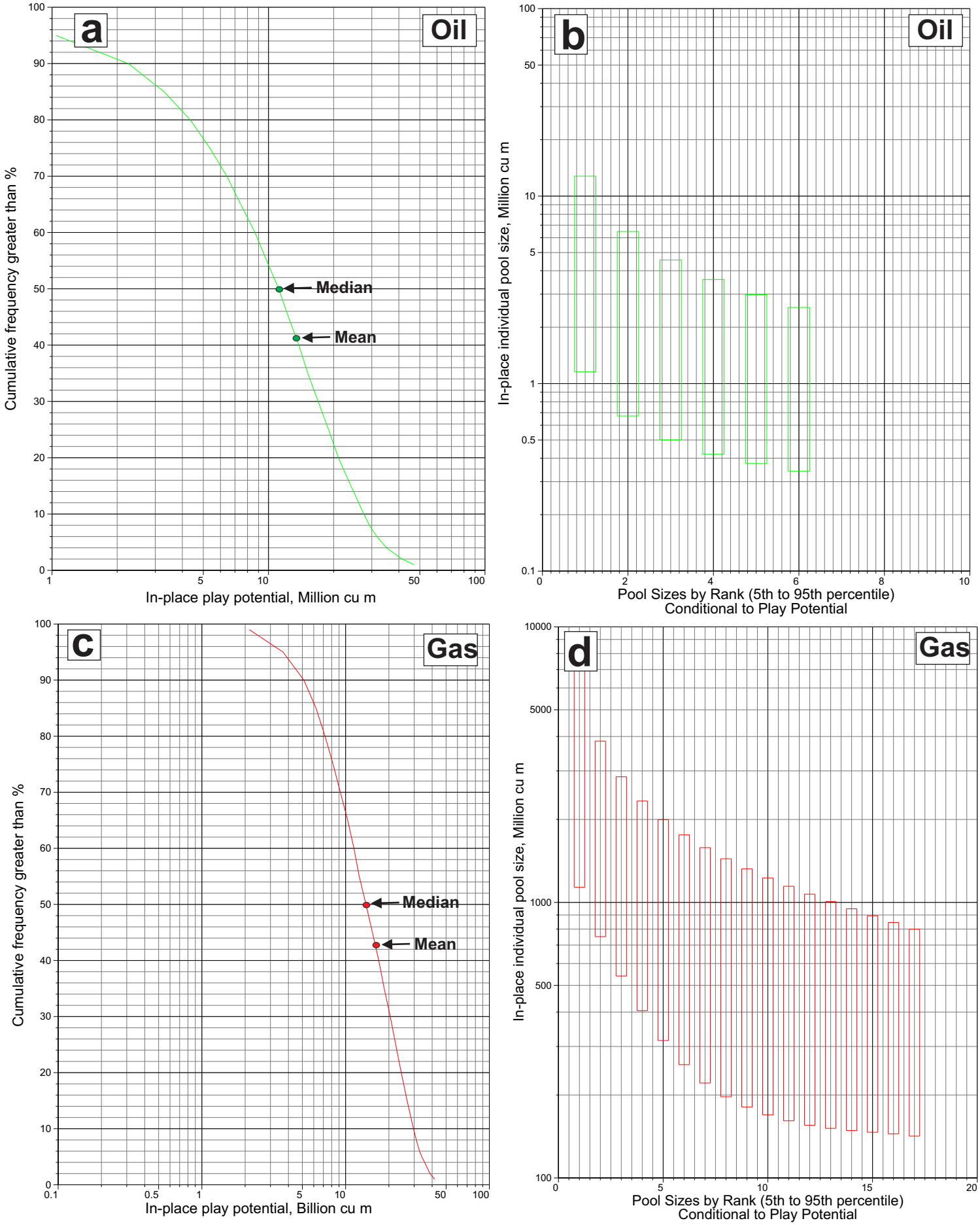


Figure 59. Estimates of in-place oil (a) and gas (c) potential of the Jungle Creek sandstone stratigraphic play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

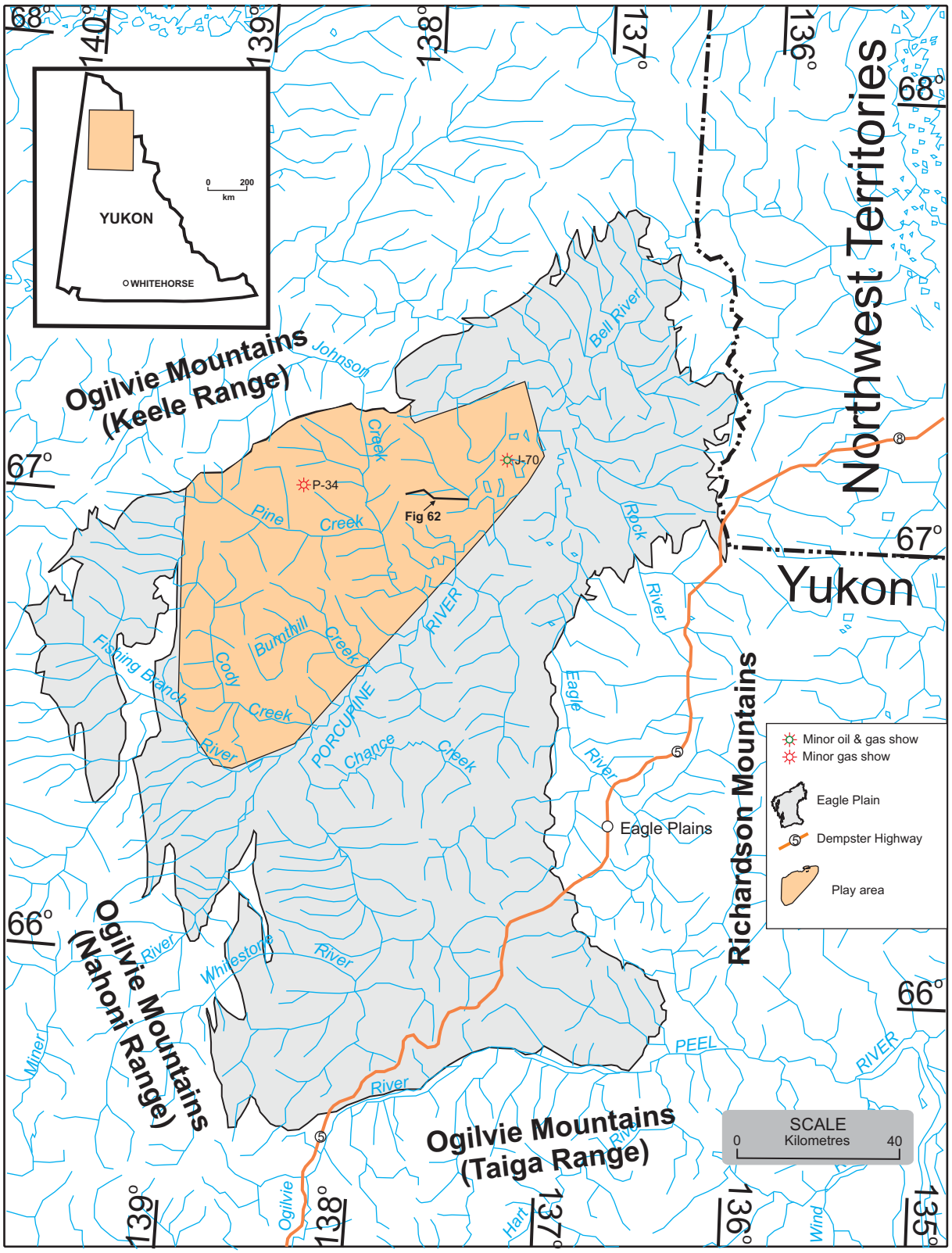


Figure 60. Jurassic/Lower Cretaceous sandstone pre-Albian structural oil and gas play. Seismic line location of Fig. 62 is shown.

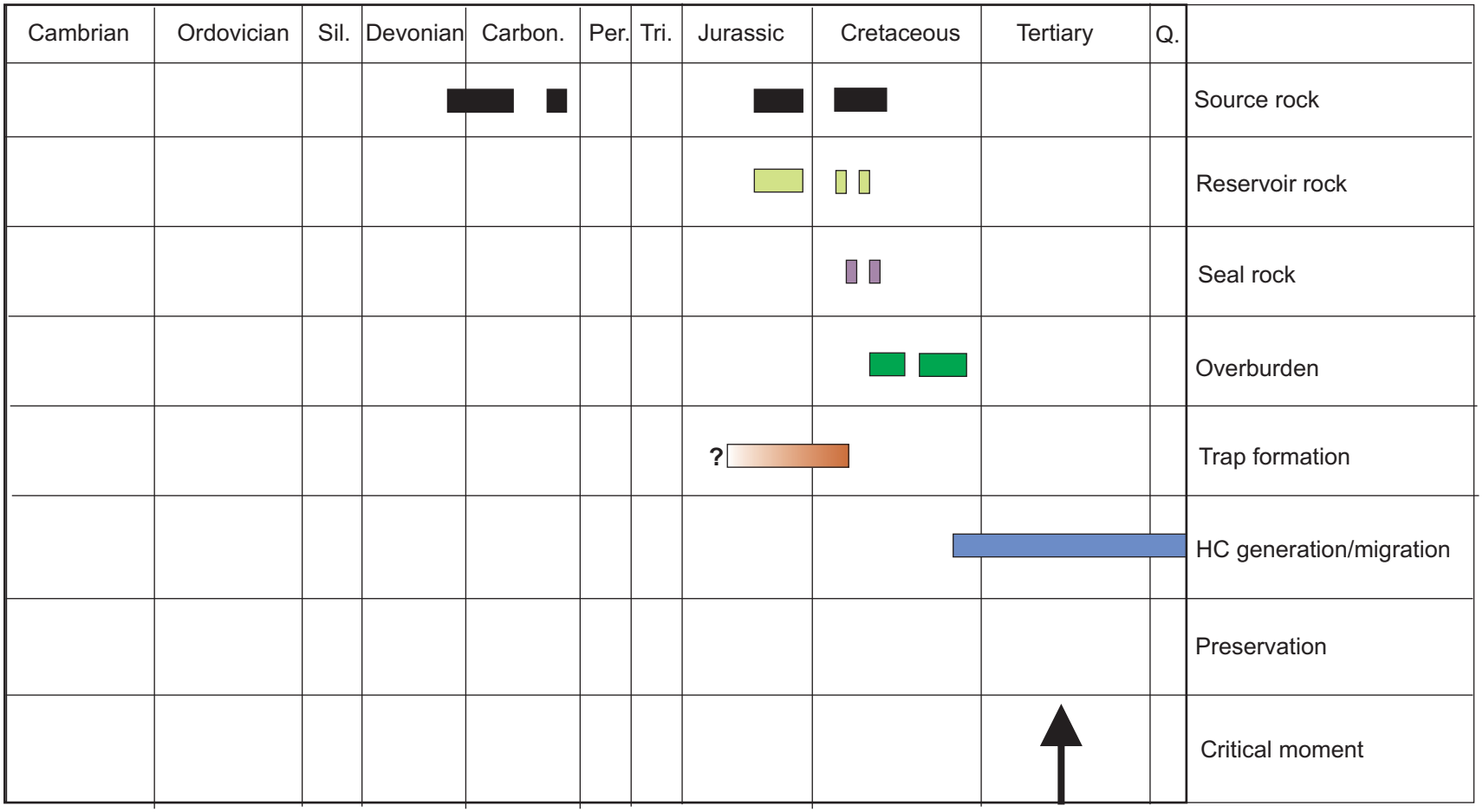


Figure 61. Petroleum event chart for a Carboniferous-Jurassic/Lower Cretaceous petroleum system (Blackie/Ford Lake source-Porcupine River/Mount Goodenough/Rat River/Sharp Mountain reservoir) and a Jurassic/Lower Cretaceous system (Porcupine River/Mount Goodenough/Whitestone River source-Porcupine River/Mount Goodenough/Rat River/Sharp Mountain reservoir). Structural trap formation is described as pre-Albian (Lane, 2010) in the play, so the timing of initiation of trap formation is unknown. The critical moment for oil and gas generation (arrow) in the Sharp Mountain sub-basin occurred during mid-Tertiary time, the midway point of thermal oil and gas generation derived from the burial history diagrams of Link and Bustin (1989). Sil.-Silurian, Carbon.-Carboniferous, Per.-Permian, Tri.-Triassic, Q.-Quaternary.

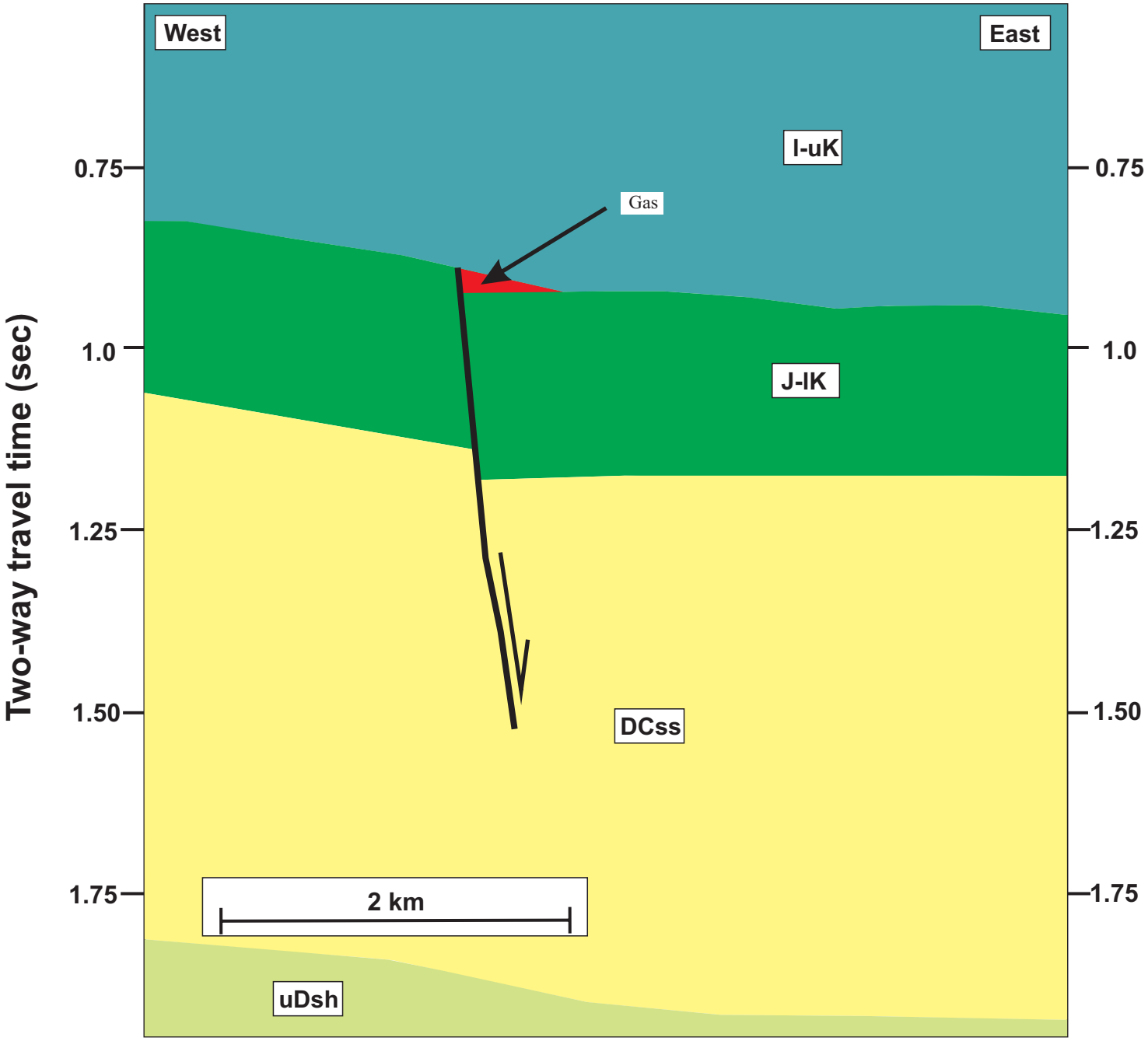


Figure 62. Schematic seismic section illustrating a pre-Albian normal fault structure and potential trap configuration in Sharp Mountain Subbasin (see Fig. 60 for location). Local preservation of hanging-wall strata within interbedded sandstone and shale succession (Jurassic-Lower Cretaceous; J-lK). From Lane (2010). Part of Chevron Canada Resources seismic reflection line 12bb. l-uK, Lower to Upper Cretaceous clastic succession; J-lK, Jurassic to Lower Cretaceous clastic succession; Dcss , Imperial/Tuttle formations;Dsh, Upper Devonian Imperial Formation, shale dominant succession.

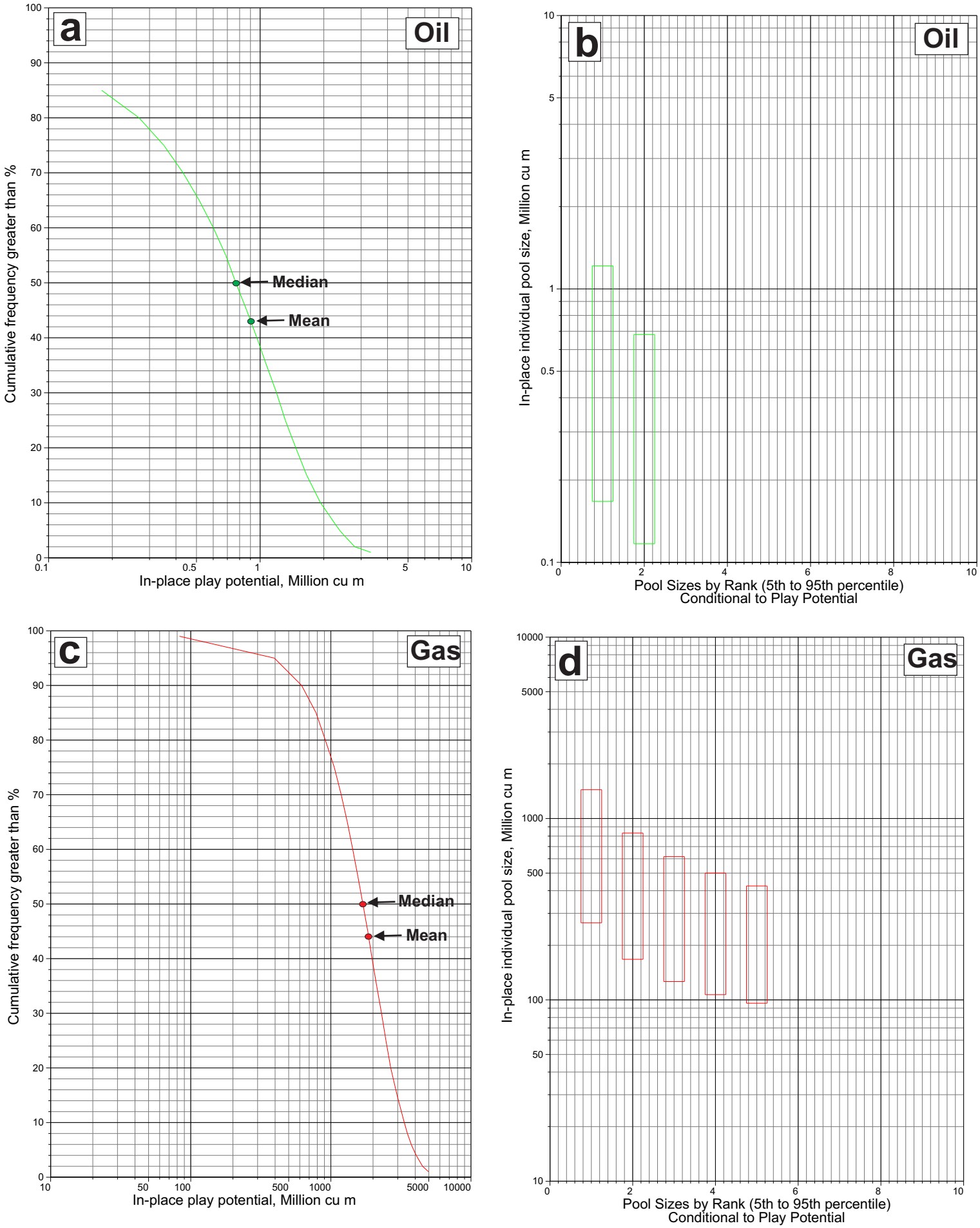


Figure 63. Estimates of in-place oil (a) and gas (c) potential of the Jurassic-Lower Cretaceous sandstone pre-Albian structural play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

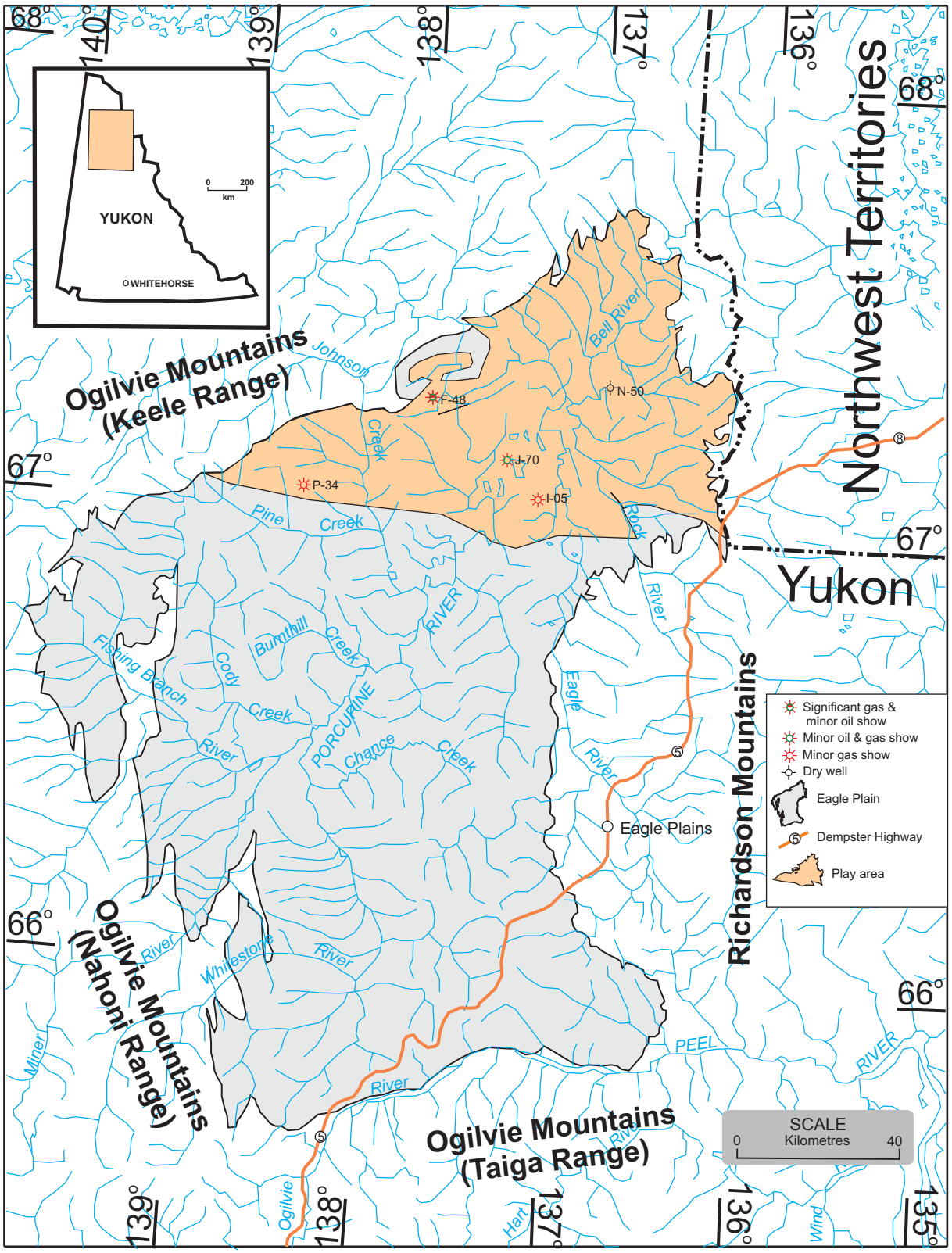


Figure 64. Jurassic/Lower Cretaceous sandstone stratigraphic oil and gas play.

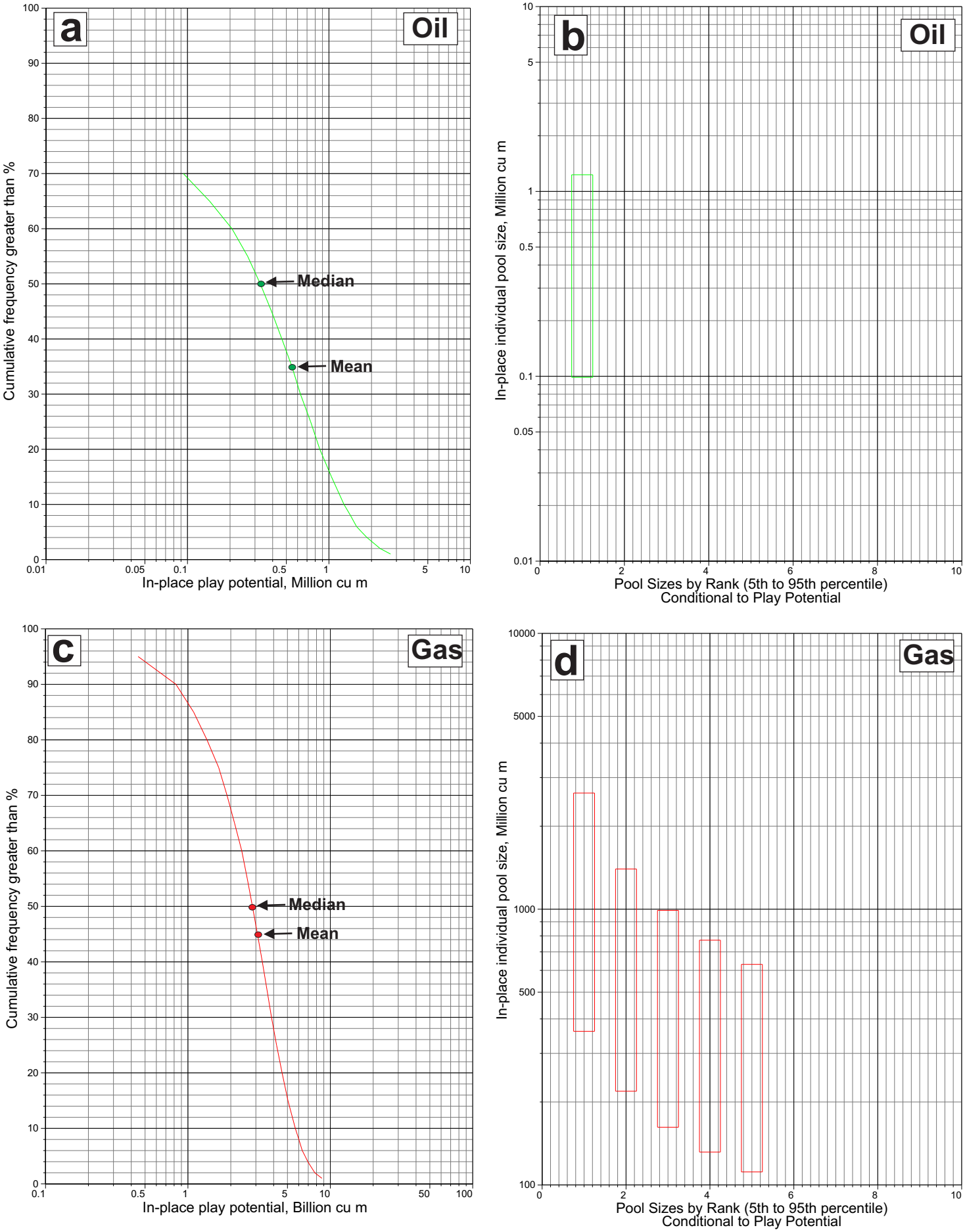


Figure 65. Estimates of in-place oil (a) and gas (c) potential of the Jurassic-Lower Cretaceous sandstone stratigraphic play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

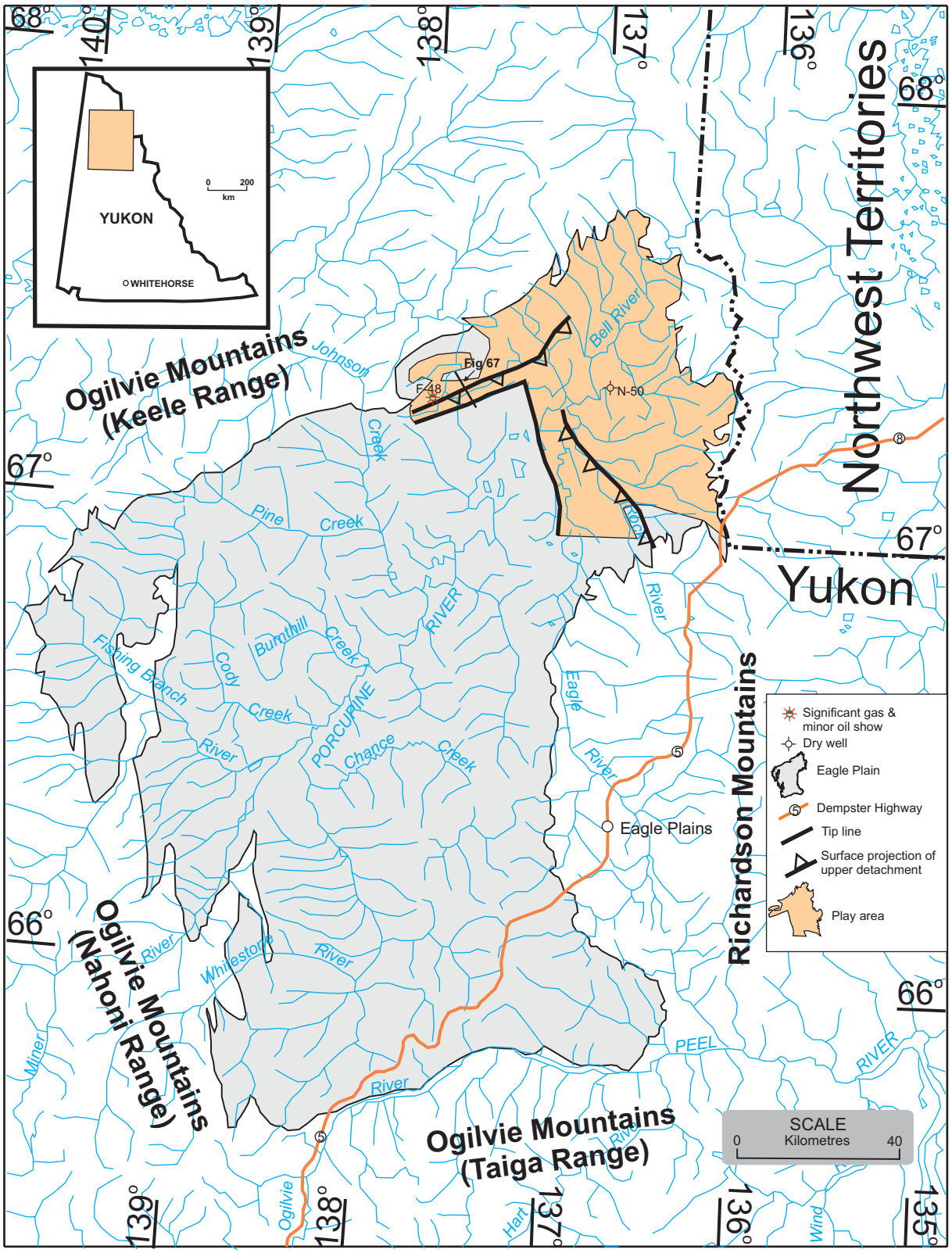


Figure 66. Triangle zone structural (Bell Subbasin) oil and gas play. Tip lines and upper detachment surface projections of triangle zones are from Lane (1996). Seismic line location of Fig. 67 is shown.

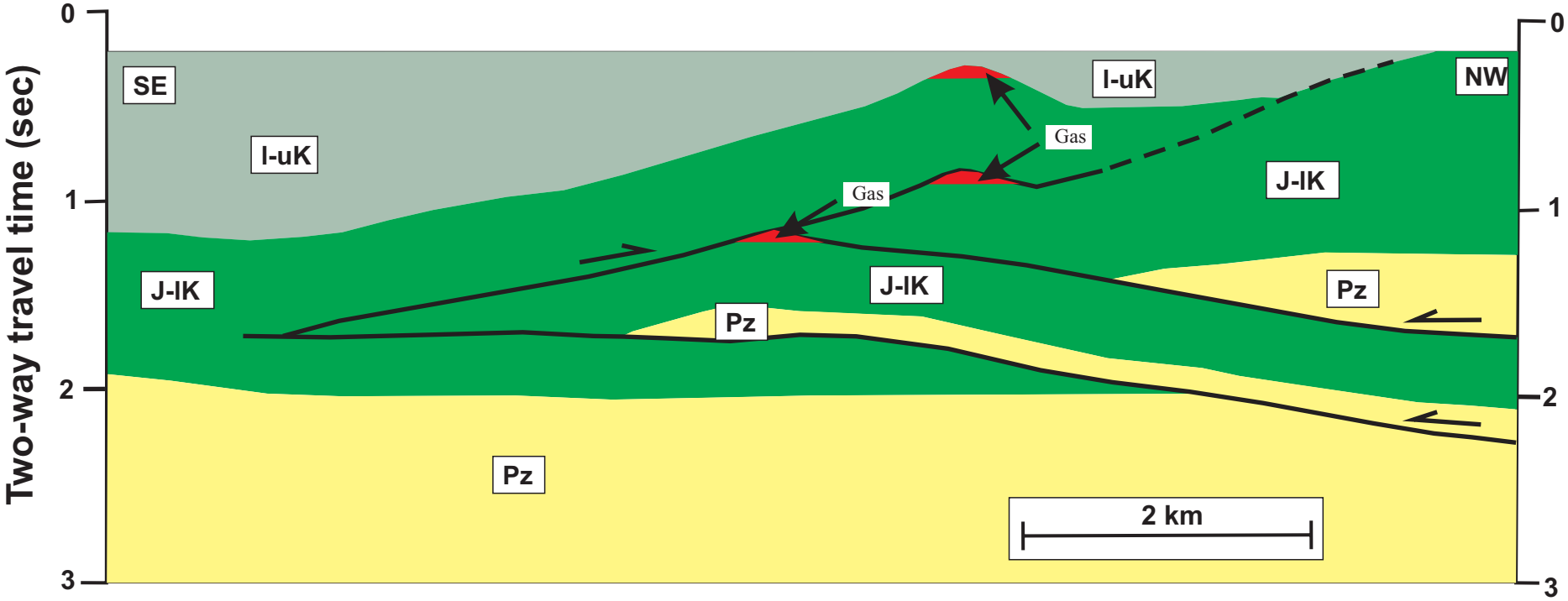


Figure 67. Schematic seismic section illustrating thrust-repeated stacked reservoirs, fault-propagation folds and subthrust structures associated with backthrusts in a triangle zone adjacent to Dave Lord Mountains in the Keele Range (see Fig. 66 for location). From Lane (1996). Chevron Canada Resources seismic reflection line 39X. l-uK, Lower to Upper Cretaceous clastic succession; J-lK, Jurassic to Lower Cretaceous clastic succession; Pz, Paleozoic succession. Faults are dashed when inferred.

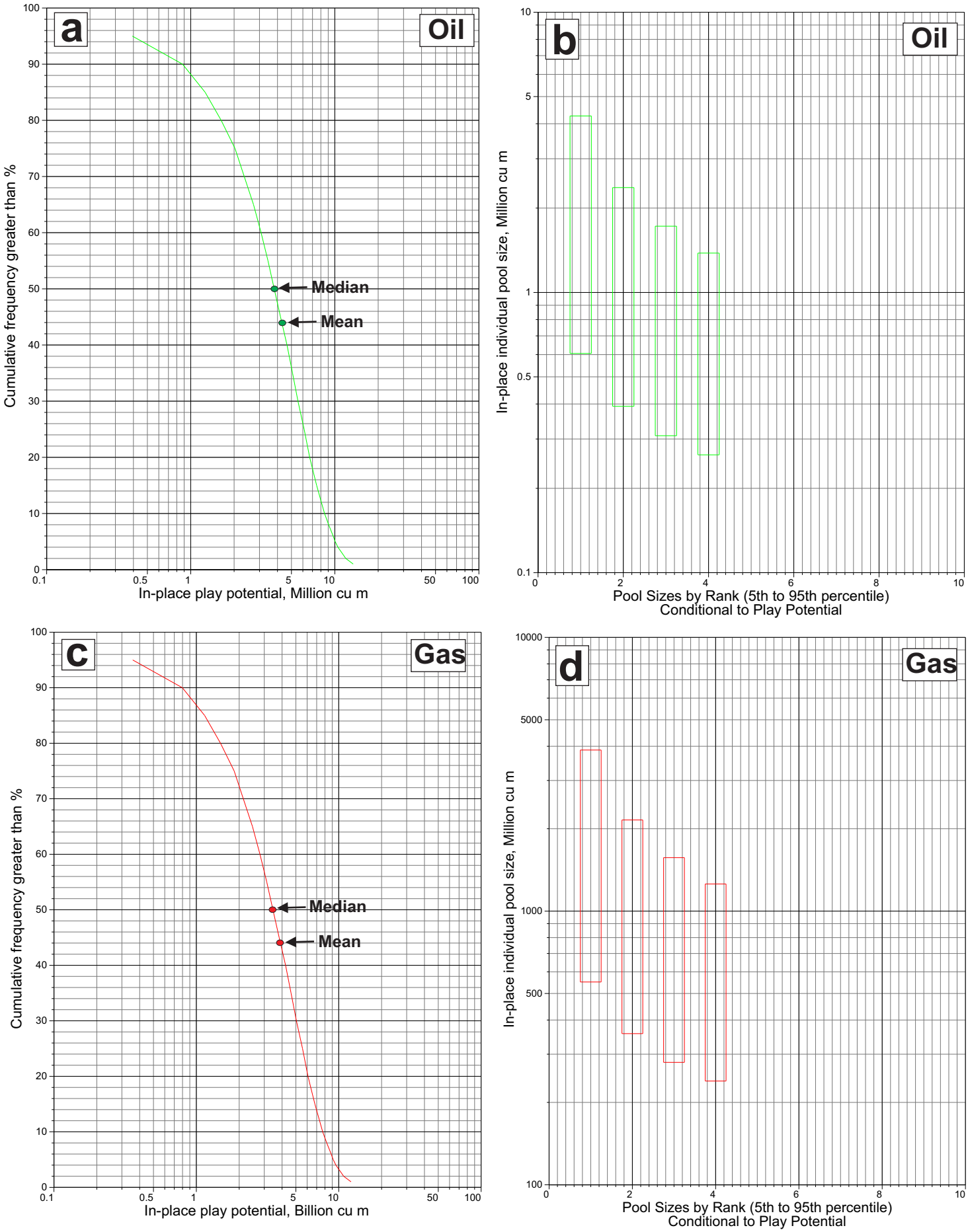


Figure 68. Estimates of in-place oil (a) and gas (c) potential of the Triangle Zone structural (Bell Subbasin) play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

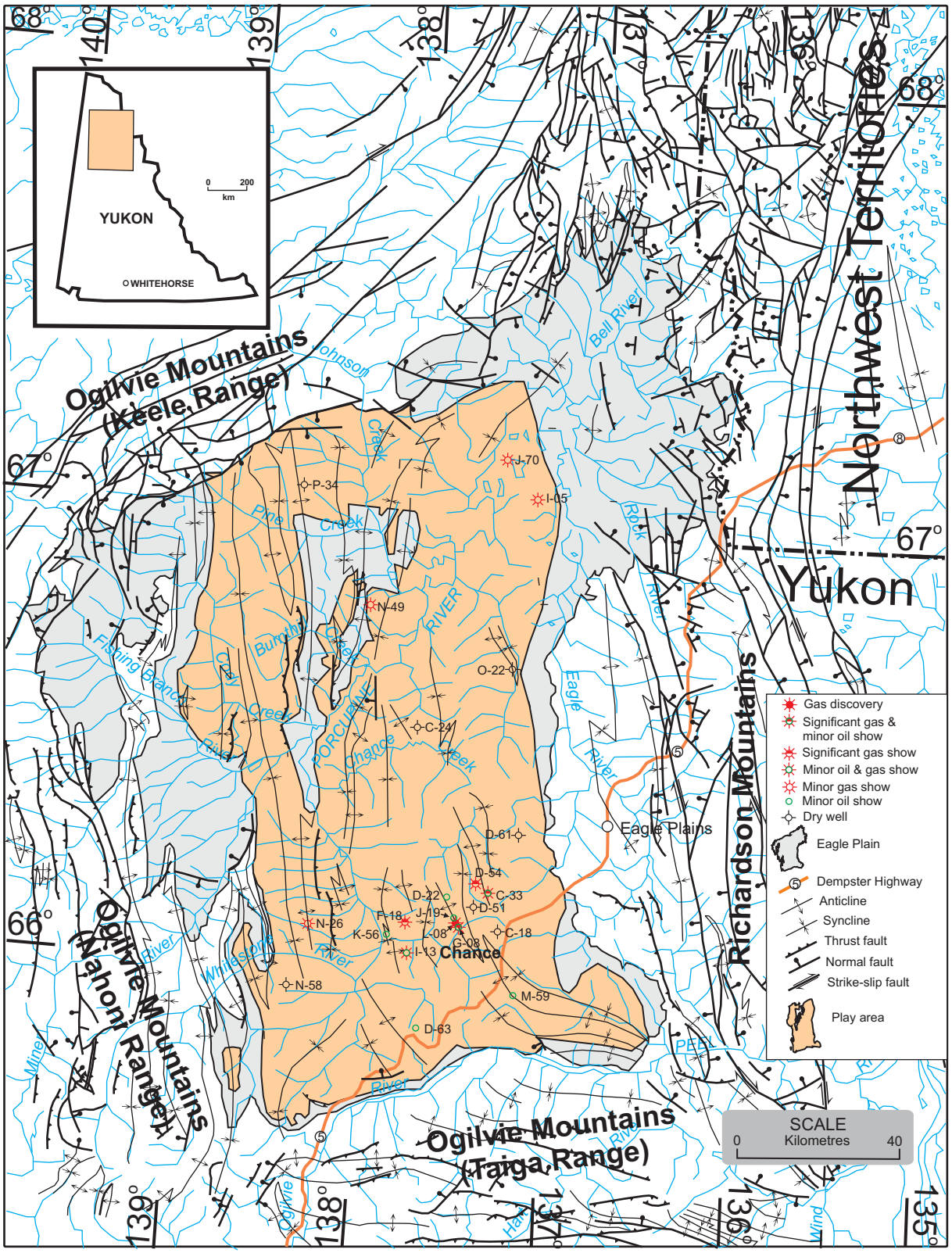


Figure 69. Cretaceous sandstone structural oil and gas play.

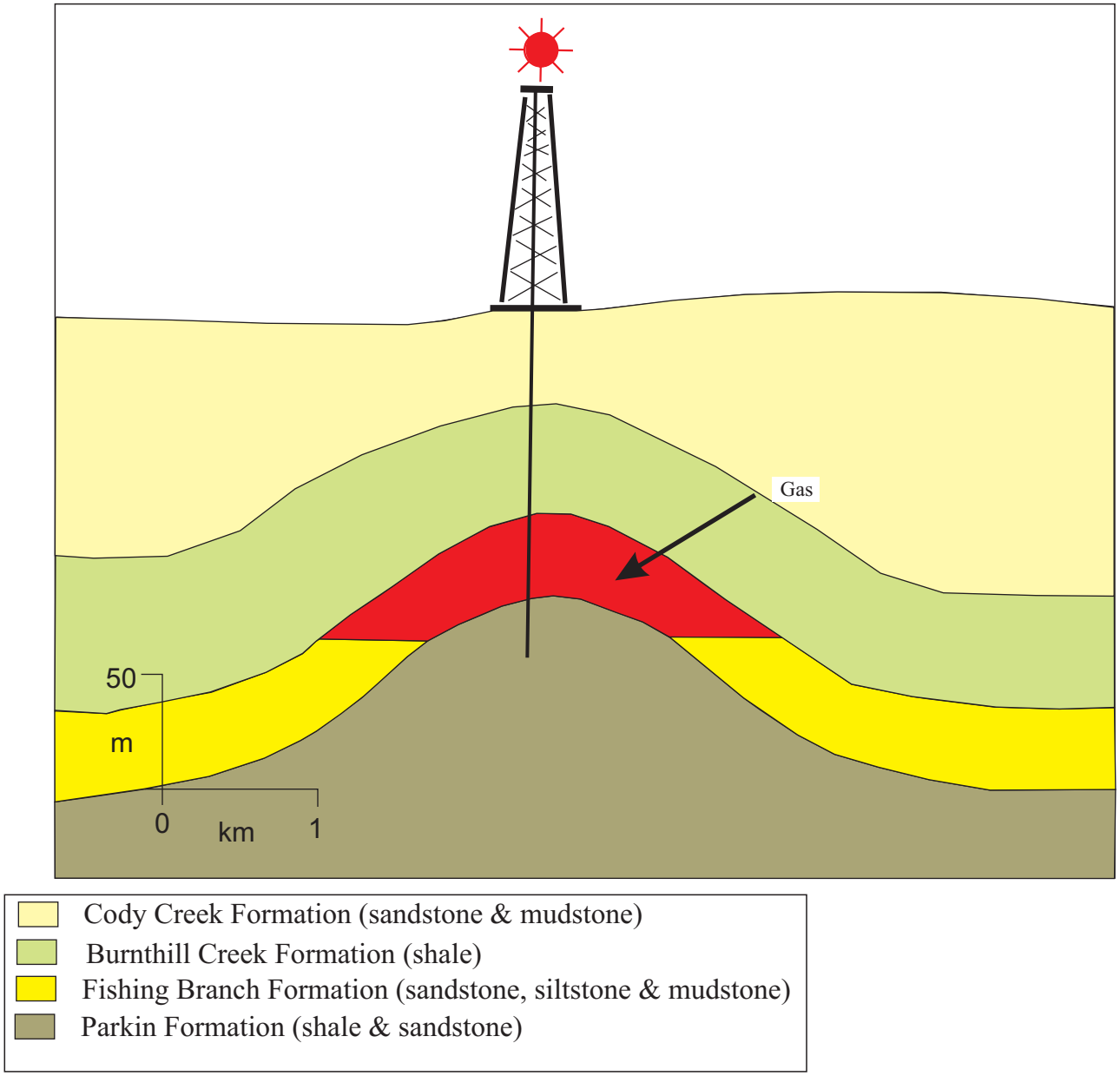


Figure 70. Schematic cross-section illustrating potential trap configurations in the Cretaceous sandstone structural oil and gas play. Illustrated trap is an anticlinal fold. From National Energy Board, 2000.

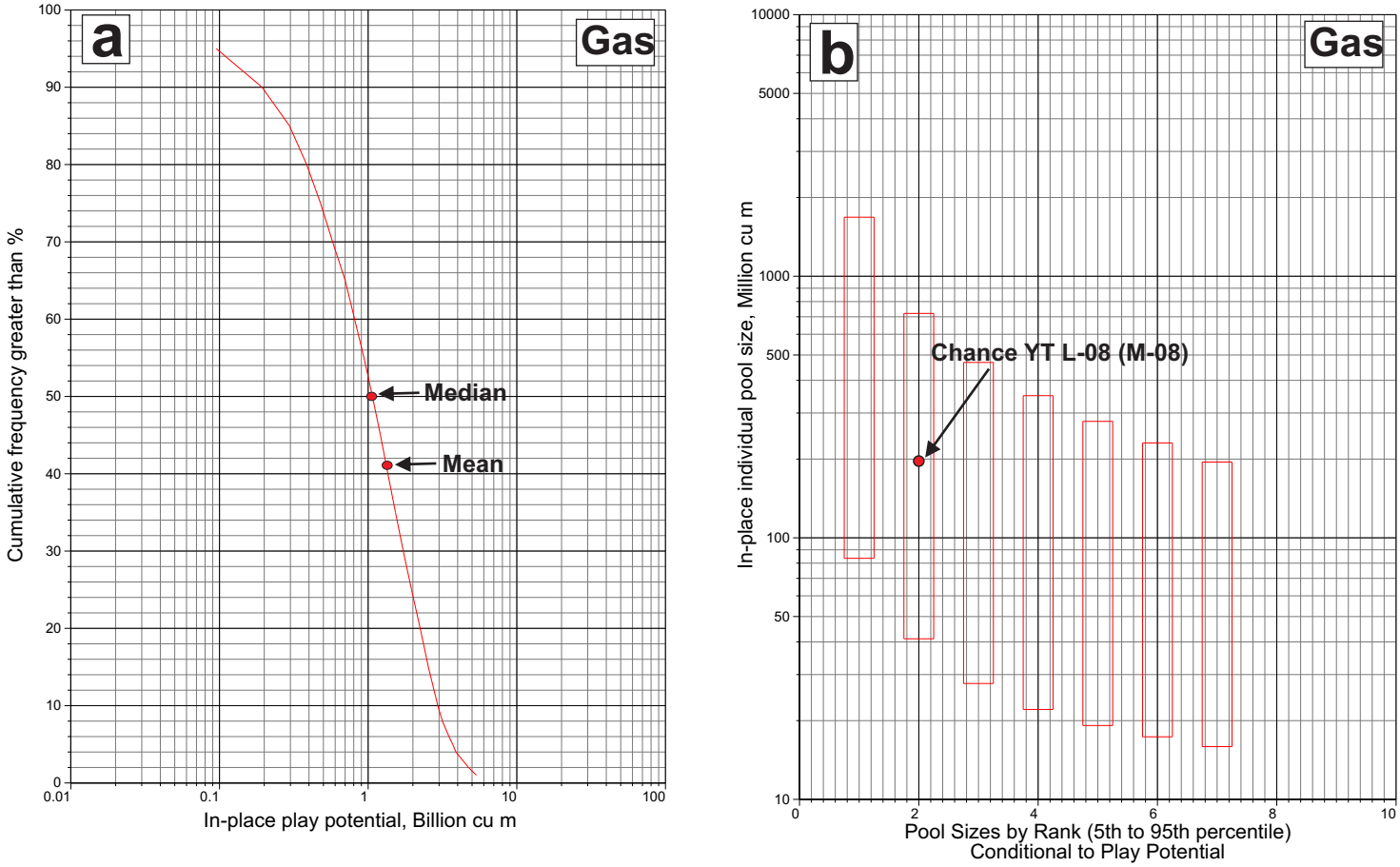


Figure 71. Estimate of in-place gas (a) potential of the Cretaceous sandstone structural play. Pool-size-by-rank plot of the gas (b) play is also displayed.

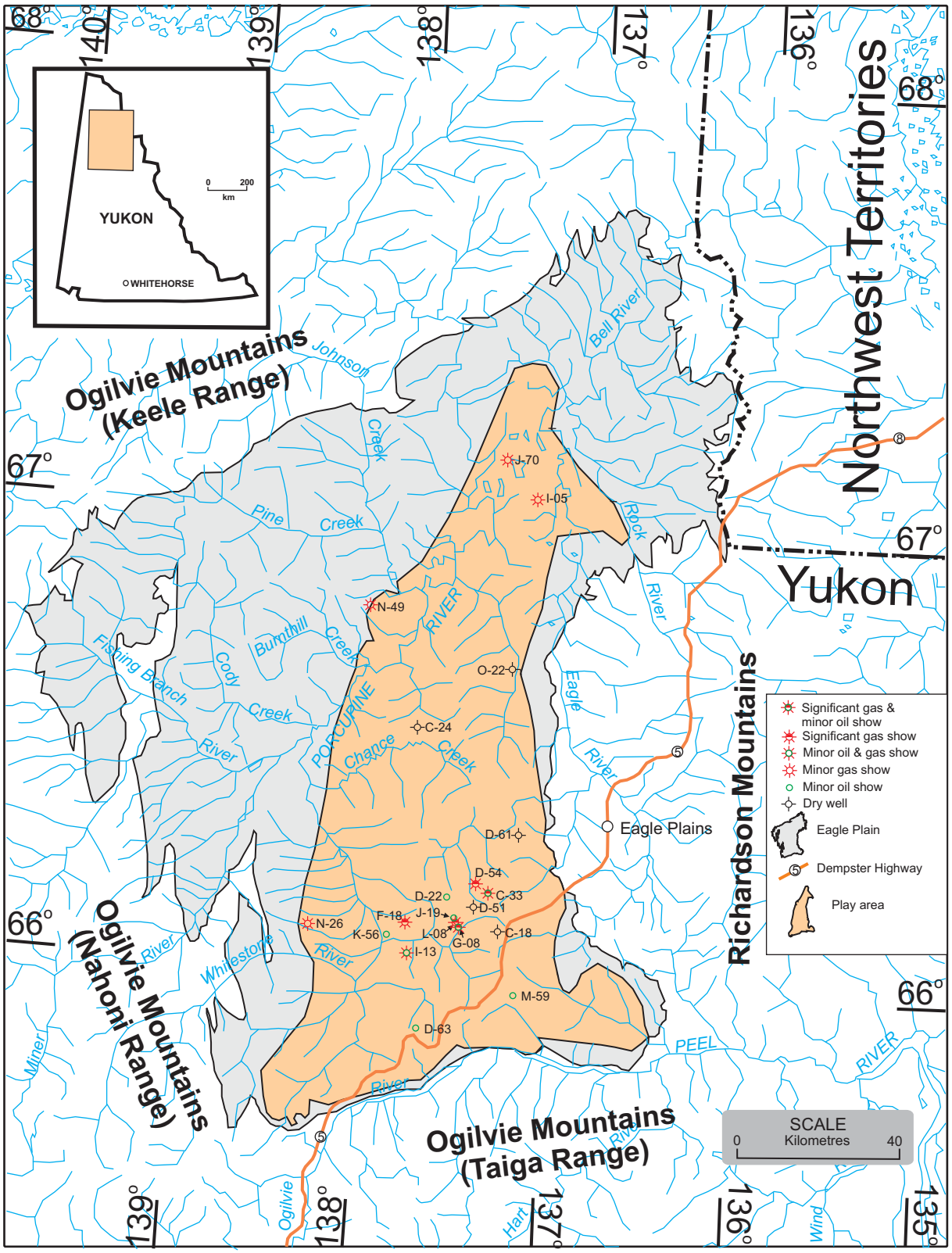


Figure 72. Cretaceous sandstone shelf stratigraphic oil and gas play.

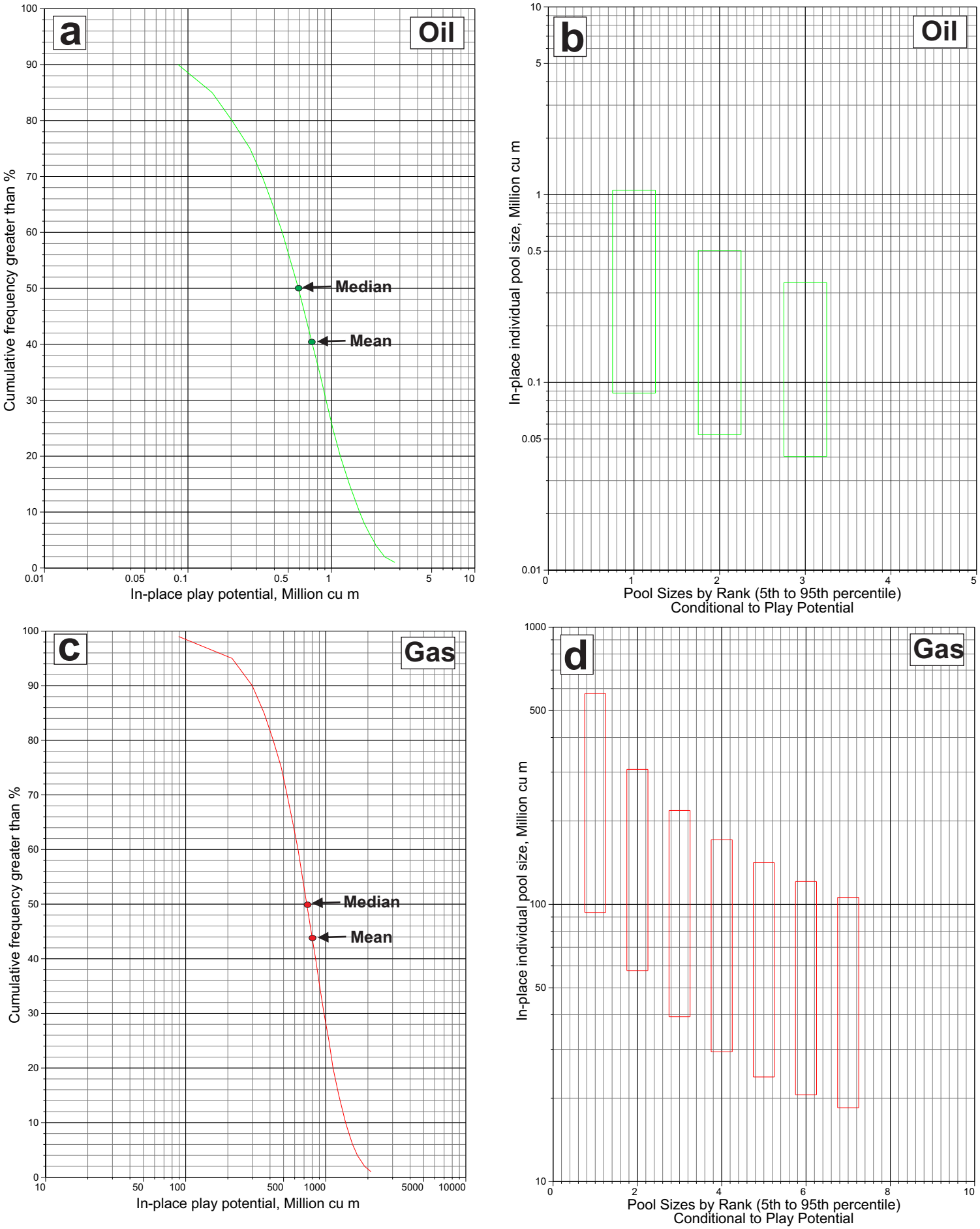


Figure 73. Estimates of in-place oil (a) and gas (c) potential of the Cretaceous sandstone shelf stratigraphic play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

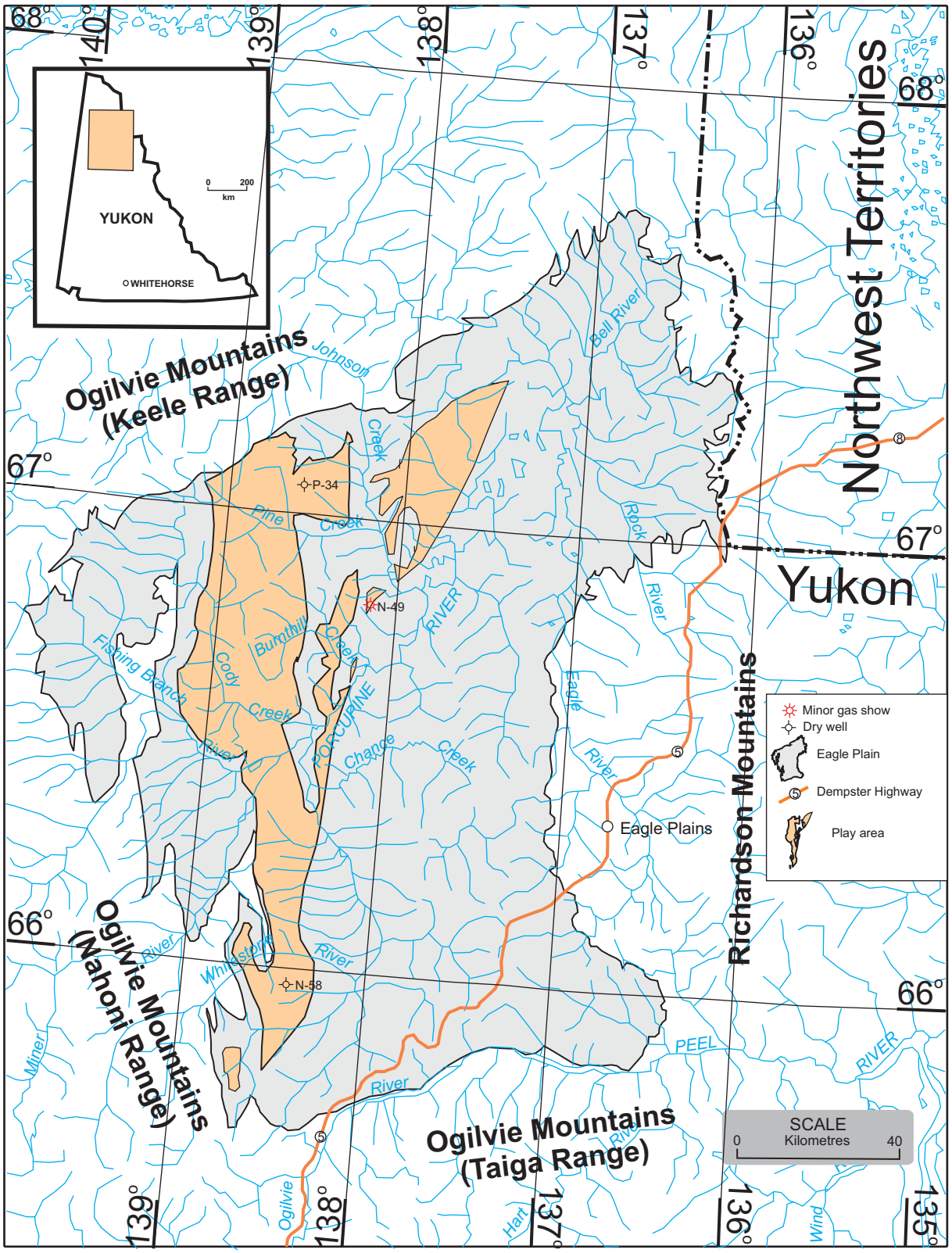


Figure 74. Cretaceous sandstone slope stratigraphic oil and gas play.

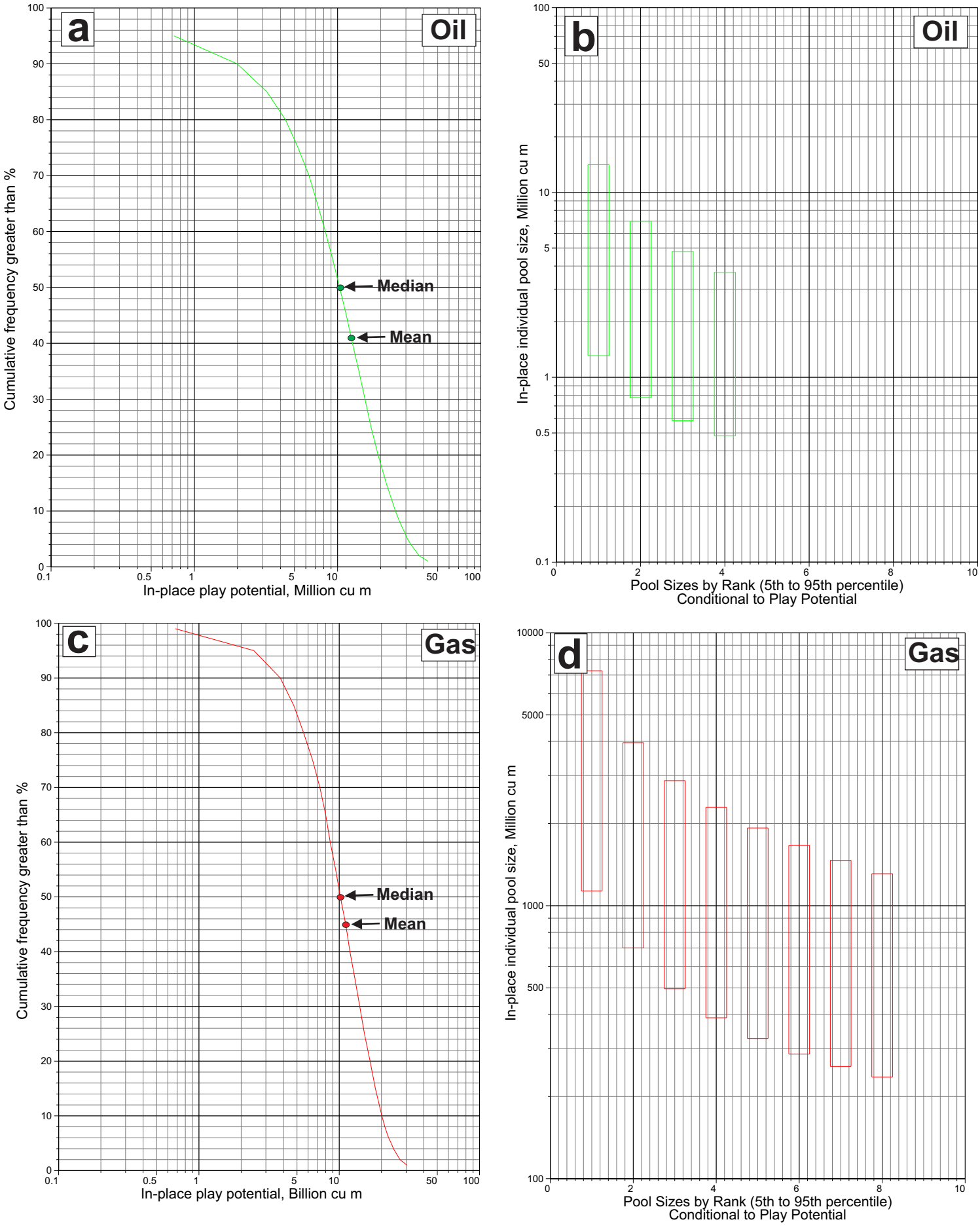


Figure 75. Estimates of in-place oil (a) and gas (c) potential of the Cretaceous sandstone slope stratigraphic play. Pool-size-by-rank plots of the oil (b) and gas (d) plays are also displayed.

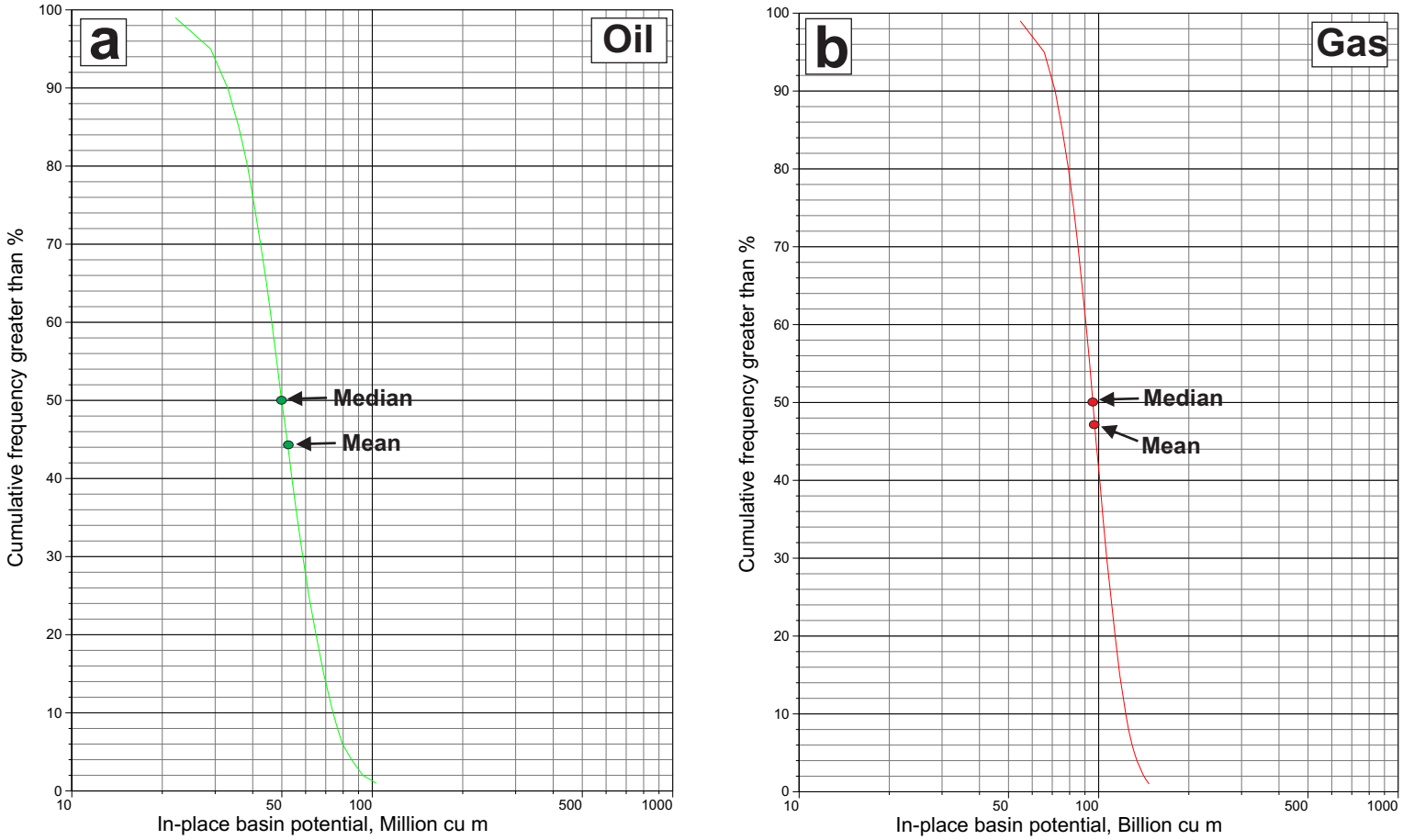
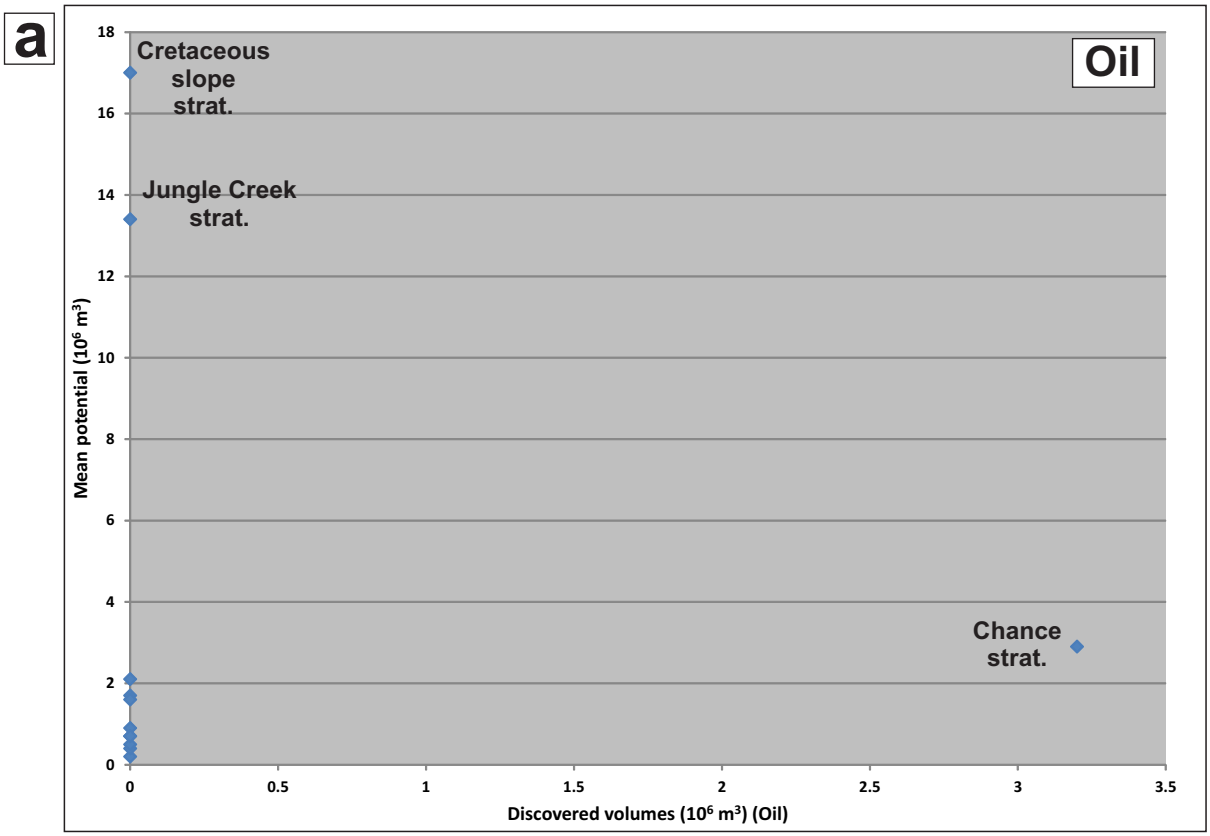


Figure 76. Estimate of in-place oil (a) and gas (b) potential of the Eagle Plain Basin.



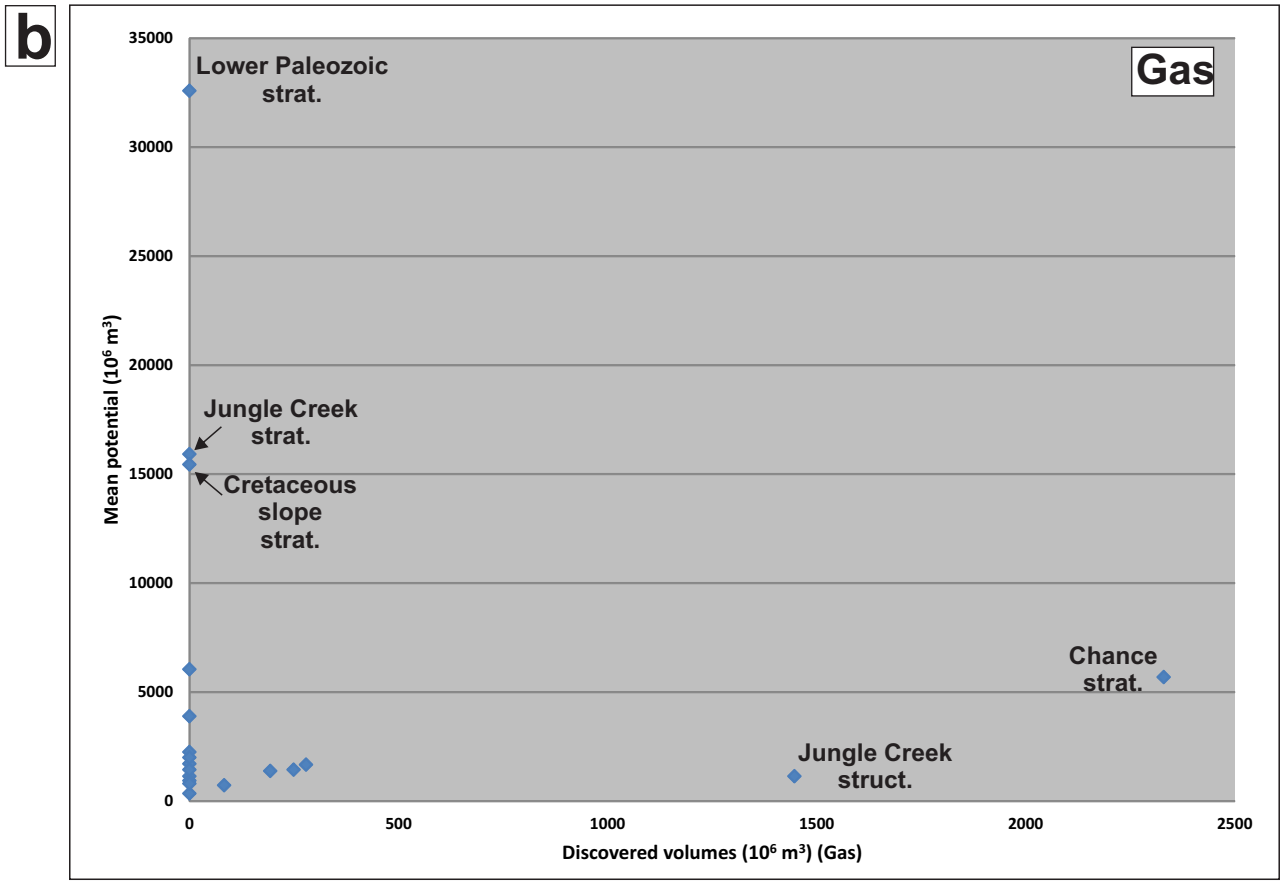


Figure 77. Plots showing the relation of mean play potential to discovered in-place volumes of all oil plays (a) and all gas plays (b) in Eagle Plain Basin.

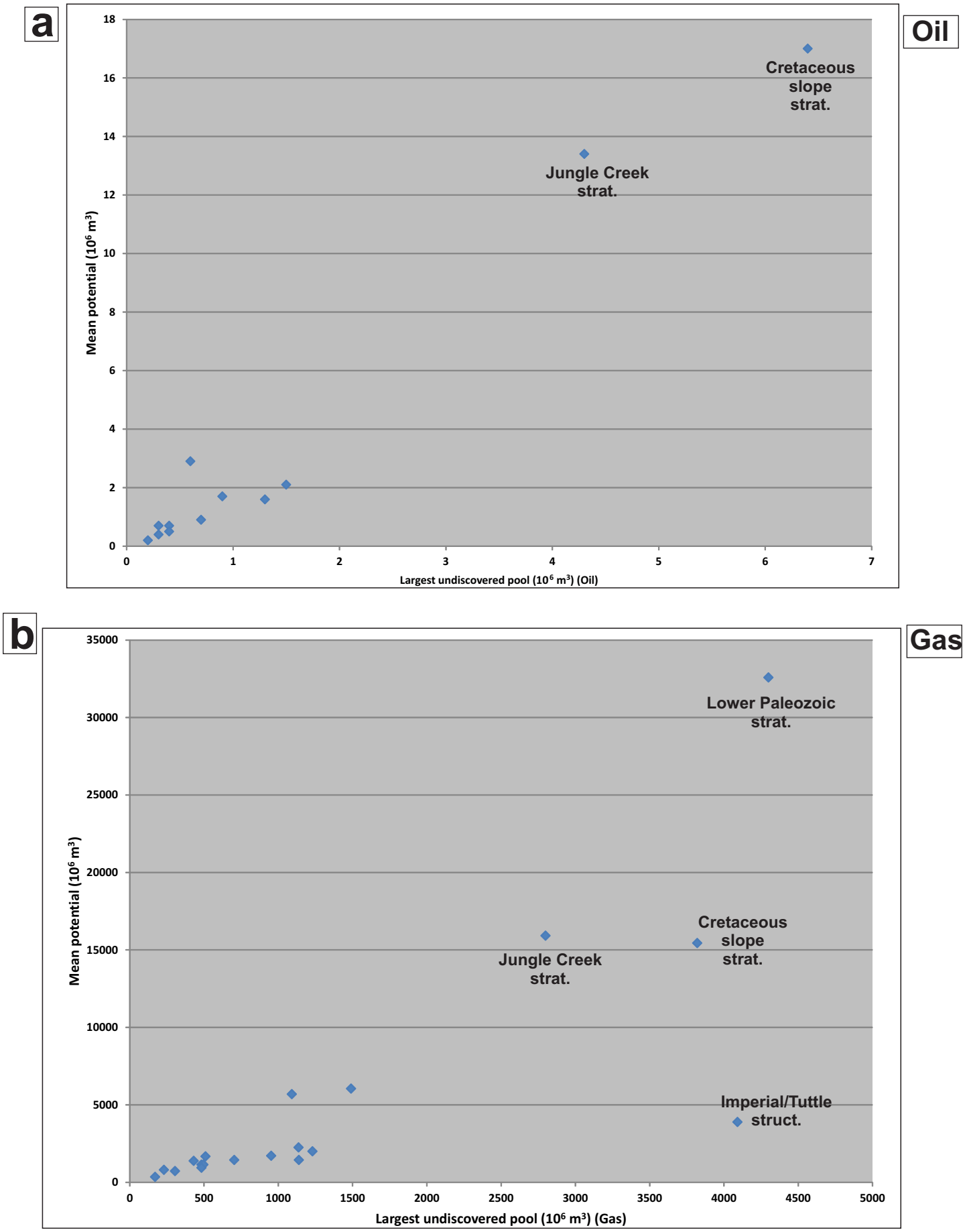


Figure 78. Plots showing the relation of mean play potential to undiscovered pool sizes of all oil plays (a) and all gas plays (b) in Eagle Plain Basin.

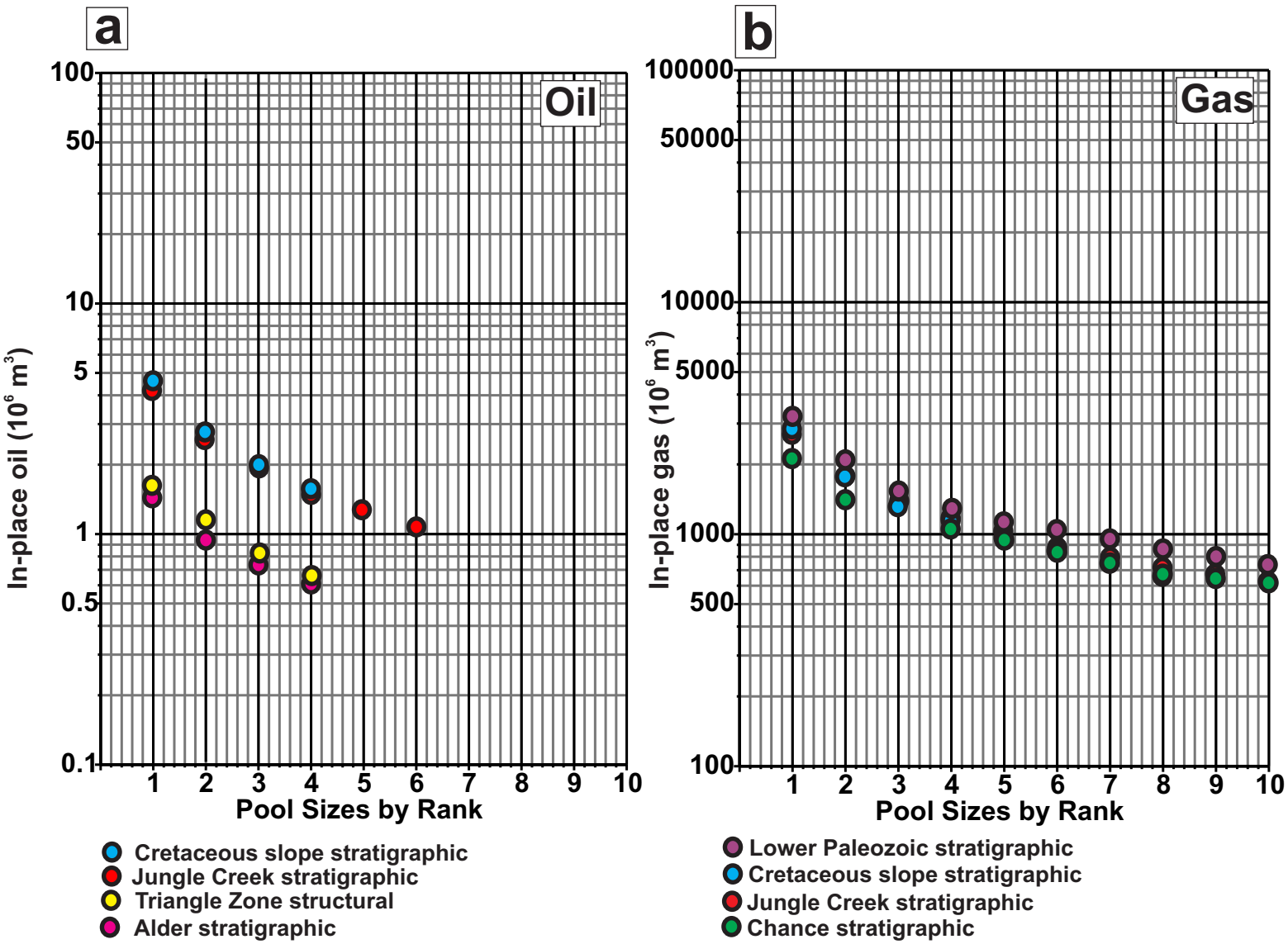


Figure 79. Pool-size-by-rank plots of largest undiscovered oil (a) and gas (b) pools showing relationships between significant plays, Eagle Plain Basin. Median pool sizes are plotted.

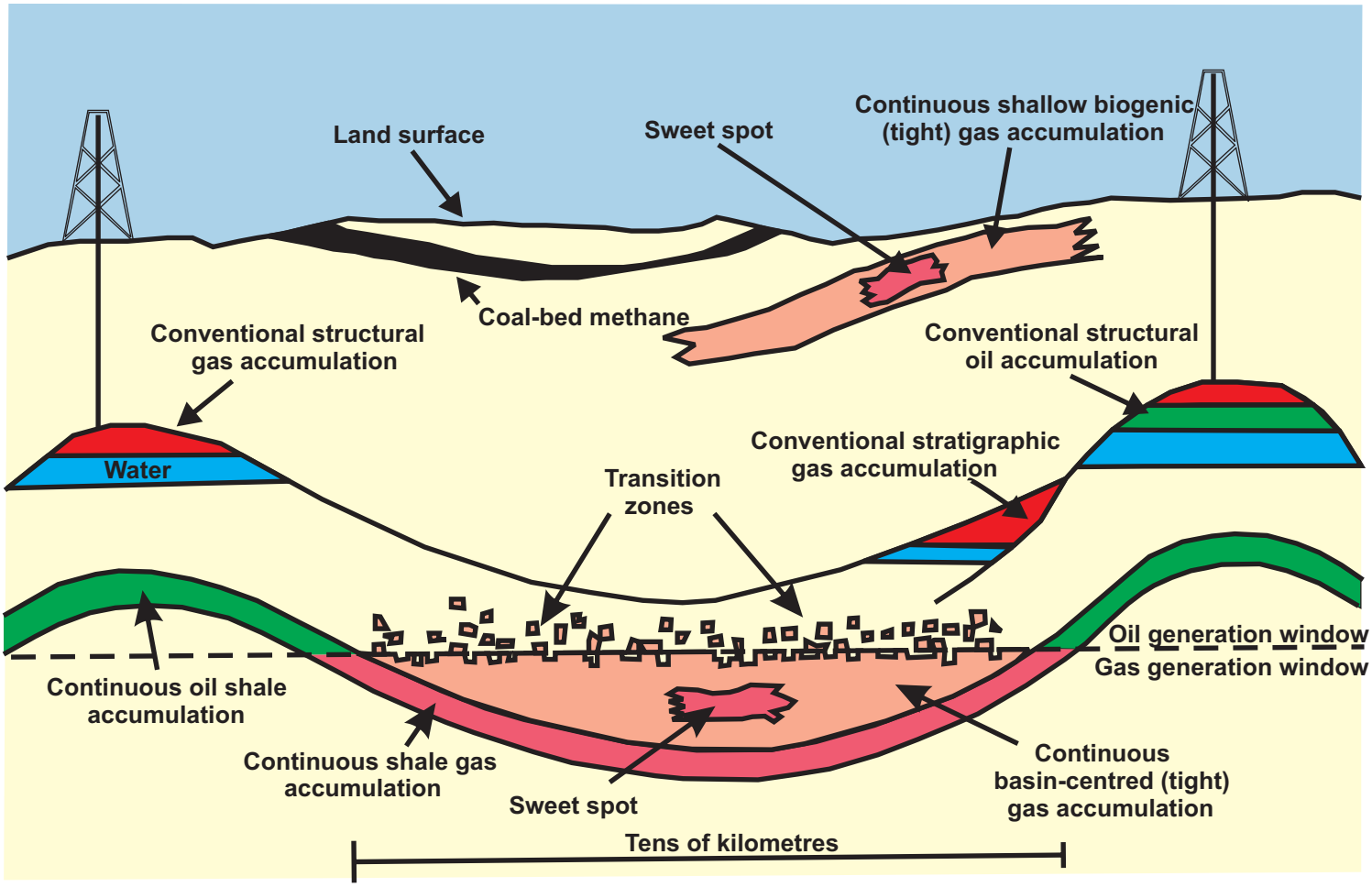


Figure 80. Schematic diagram illustrating conventional and unconventional petroleum accumulations. Modified from Schenk and Pollastro, 2002.

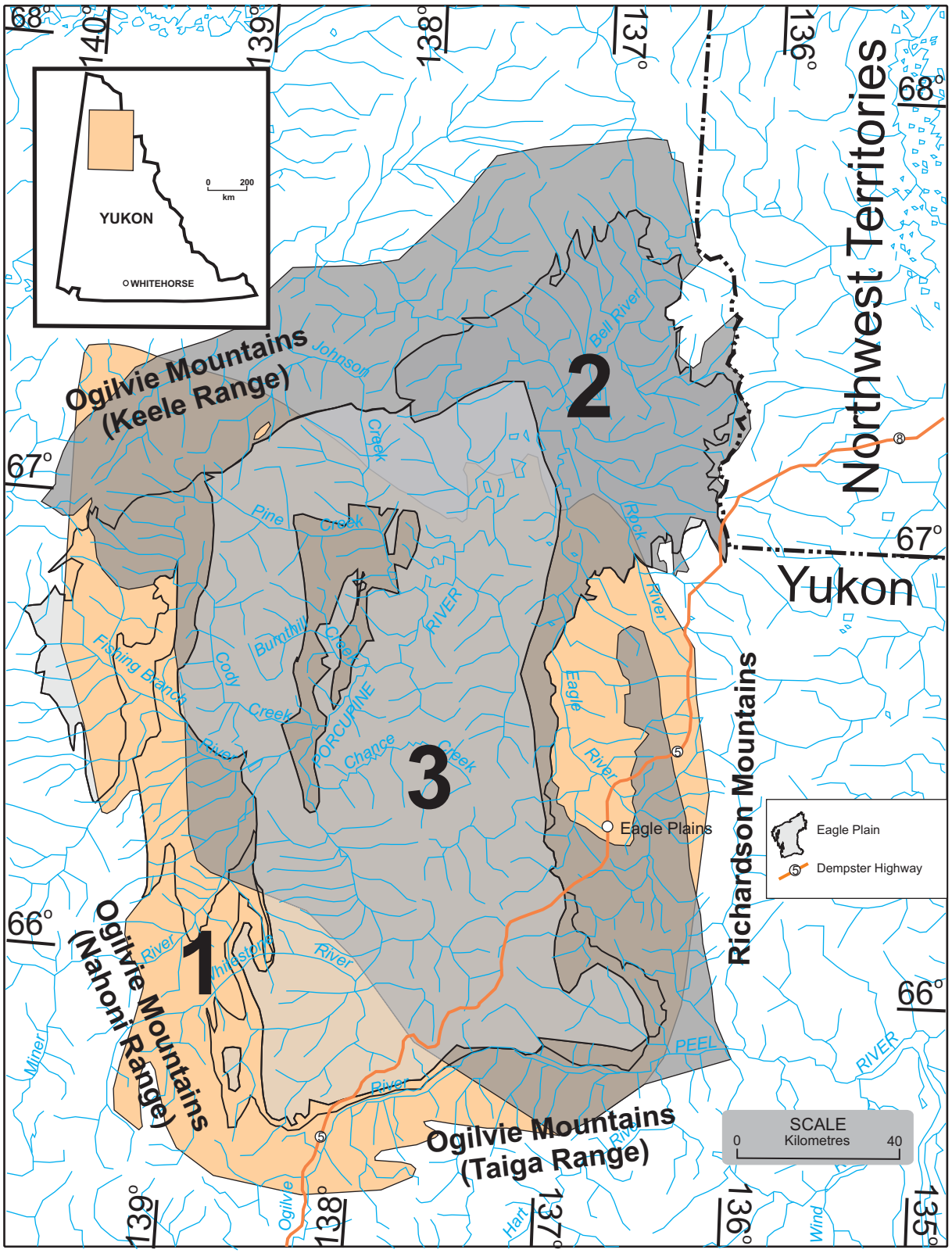


Figure 81. Map showing extent of moderately to poor to moderately prospective tight gas reservoirs in the Eagle Plain Basin. These reservoirs include Bouvette/Ogilvie (1), Imperial (2) and Eagle Plain Group (3).