

Scoping study of unconventional oil and gas potential, Yukon

Yukon Geological Survey Miscellaneous Report 7

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Report prepared by B.J.R. Hayes and H.B. Archibald, Petrel Robertson Consulting Ltd.



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Cover photo: Outcrop of Middle to Upper Devonian Canol Formation along Trail River, east Richardson Mountains, Yukon.

Yukon Unconventional Resources Scoping Study

In September 2011 Yukon Geological Survey awarded a contract to Petrel Robertson Consulting of Calgary, Alberta to assess the petroleum geology of Yukon's basins as it relates to unconventional petroleum. The proponent was directed to examine the characteristics of unconventional hydrocarbon resources, and based on existing Yukon data (field descriptions, well history reports, geological and geophysical reports, journal papers, sample analyses, geophysical well log data, core descriptions, *etc.*) to evaluate whether these characteristics are found within Yukon's Phanerozoic successions.

This assessment is a desk-top study that examines Yukon basin analogs and provides key references for unconventional hydrocarbon resources in other jurisdictions (B.C., Alberta, Alaska). It also provides recommendations for future research should EMR wish to advance knowledge of Yukon's unconventional hydrocarbon resource potential.

Carolyn Relf
Director, Yukon Geological Survey

EXECUTIVE SUMMARY

Unconventional hydrocarbon reservoirs – coals, “tight” sands and carbonates, and shales – are assuming ever-increasing importance in the North American oil and gas supply picture. The industry has used advances in drilling and completions technologies to access hydrocarbons far down the resource triangle – resources that were not even known to exist 20 years ago.

Little is known about the unconventional hydrocarbon potential of Yukon, as there has been a limited amount of petroleum industry activity, and more of a focus on conventional exploration. The success of shale gas drilling in northeast BC and recent land sale activity in the Mackenzie Plain area of Northwest Territories has built industry interest in stepping further afield to investigate unconventional plays in Yukon.

This report represents the first systematic attempt to characterize unconventional hydrocarbon resources in Yukon. A review of the essential elements of unconventional accumulations, and a survey of activity in North America and worldwide, set the stage for understanding prospectivity of Yukon reservoirs. Eight prospective basins are investigated, using stratigraphic, geochemical, and conventional play assessment information generated to guide exploration for conventional resources. Because their geological histories are so varied, the basins offer a wide range of prospectivity for coals, tight reservoirs, and shales. Further work, primarily drilling and focused sampling and testing, is recommended for plays with the highest potential.

Considering current gas market conditions and distance from facilities and markets, Yukon is truly a frontier jurisdiction. However, a number of plays offer liquids potential, which is critical to economic success. As well, opportunities exist to acquire large land positions in highly prospective plays – opportunities that are becoming very scarce in more developed basins of North America.

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UNCONVENTIONAL OIL AND GAS RESOURCES – OVERVIEW

Law and Curtis (2002) defined unconventional gas accumulations as follows:

“Conventional gas resources are buoyancy-driven deposits, occurring as discrete accumulations in structural and/or stratigraphic traps, whereas unconventional gas resources are generally not buoyancy-driven accumulations. They are regionally pervasive accumulations, most commonly independent of structural and stratigraphic traps.”

The regionally pervasive nature of unconventional oil and gas accumulations gives rise to very large resource volumes in most cases, and hence their significance is critical to assess. Unconventional hydrocarbon resources addressed in this study meet the regionally pervasive definition of Law and Curtis (2002).

While much of the analysis of unconventional hydrocarbon plays to date has focused upon gas, current low gas prices and relatively high oil prices in North America have motivated exploration companies to investigate unconventional plays that can generate substantial natural gas liquids (hydrocarbons with short-chain hydrocarbons such as ethane, propane, butane and pentane that exist in a liquid state under reservoir conditions) and even oil, as well as gas. However, the capacity of unconventional reservoirs, particularly shales, to produce liquids is still being tested.

Cander (2010) addressed the geological understanding of unconventional plays, noting:

“...the term ‘resource play’ implies to some that subsurface risks are either minimized or irreducible. As well, the term ‘unconventional gas’ connotes that little is to be gained from application of conventional principles of basin evolution and petroleum generation, migration, and entrapment. Under these circumstances, the value of regional geologic understanding of an entire basin prior to acreage capture can be overlooked.”

According to Cander (2010), it is important to understand a basin from basement to surface in assessing potential for unconventional hydrocarbon resources. For this reason, readers are urged to treat this report only as an initial scoping assessment of unconventional oil and gas potential in Yukon Territory. Much more work – drilling, data gathering, and compilation – is required to accurately identify the existence and economic potential of unconventional hydrocarbon plays.

The Resource Triangle

The Resource Triangle concept (Fig. 1) has been applied in exploration and resource assessment for a number of different commodities, and was popularized in the assessment of gas resources by Masters (1979). It states simply that of the total resource base of a particular commodity, only a small proportion – near the apex of the triangle – is contained in high-quality reservoirs or deposits. Much greater resource volumes occur in poorer-quality deposits, lower in the body of the triangle. For gas and oil, it is recognized that only a very small proportion of the resource has migrated into and can be produced from high-quality “conventional” reservoirs – those that the industry has been drilling throughout most of its history. Much larger hydrocarbon volumes occur in the “unconventional” reservoirs which are described below, many of which have not been recognized as reservoirs until recently.

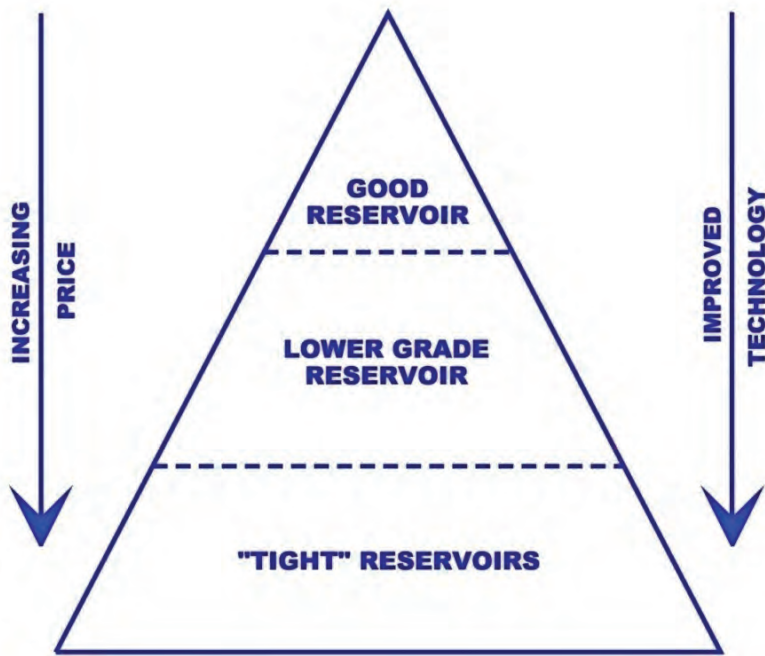


Figure 1. *The Resource Triangle. High-quality reservoirs contain only a small fraction of the overall gas resource. Increased prices and improved drilling and completions technologies are required to access resources in lower-grade reservoirs, further down the triangle (from Masters, 1979).*

Masters (1979) saw that in order to access and produce large, low-grade gas resources, significant increases in gas price as well as advances in drilling and completions technologies would be necessary; this conclusion was echoed by Kuuskraa *et al.* (1998). From 2000 to 2008, the industry saw large gas price increases, and tremendous advances in drilling and completions practices, such as extended-reach horizontal wells and multiple staged hydraulic fracture (frac) stimulations. Unconventional gas production thus increased dramatically in the United States and to a lesser extent in Canada. Since 2008, however, world economic issues and the glut of new gas production on the North American market have depressed gas prices in North America. Industry is now turning more attention to unconventional plays that can produce liquid hydrocarbon resources (natural gas liquids, as defined above, and light oil) from the lower part of the resource triangle.

Types of Unconventional Oil and Gas Reservoirs

Three distinct types of unconventional oil and gas reservoirs are generally recognized:

- coal beds, hosting coalbed methane (CBM), also known as coal seam gas (CSG);
- tight reservoirs, both clastics and carbonates, hosting oil and gas; and
- shale reservoirs.

Methane gas hydrates, which occur as crystalline complexes of water ice and methane under particular pressure-temperature conditions, are sometimes considered unconventional gas resources, but are not addressed in this report. Shallow biogenic gas reservoirs have been considered by some as a distinct unconventional gas resource type (*e.g.*, Shurr and Ridgley, 2002), but are now generally included with shale gas and tight gas resources.

Coalbed Methane

Coalbed methane (CBM) is, as the name implies, natural gas hosted in seams or beds of coal. Bustin and Clarkson (1998) described it in more detail:

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

Coal beds are generally self-sourcing reservoirs – they contain gas evolved either biogenically or thermogenically from organic material within the coals themselves. The key parameters that control gas resource quantities and producibility are:

- thermal maturity – sorption capacity generally increases with maturity;
- maceral composition – sorption capacity increases with vitrinite content, and decreases with inertite content and mineral matter;
- reservoir pressure – generally increases with depth;
- coal thickness;
- fracture (cleat) density;
- permeability, which is a function of burial history, burial depth, and in-situ stresses; and
- hydrologic setting, which dictates how much water is present in coal seams (Ayers, 2002).

Coalbed methane has been produced commercially in the United States from the northern Appalachian Basin since the 1930's and from the San Juan Basin since the 1950's (Ayers, 2002). Exploration and development expanded in the U.S. in the late 1980's and early 1990s, driven partly by an unconventional fuels tax credit. Coalbed methane resources are now recognized in more than 20 U.S. basins (Fig. 2). U.S. CBM reserves peaked at 21.9 TCF in 2007, and declined to 18.6 TCF in 2009, while annual CBM production peaked at 1.97 TCF in 2008, declining to 1.91 TCF in 2009 (U.S. EIA, 2010).

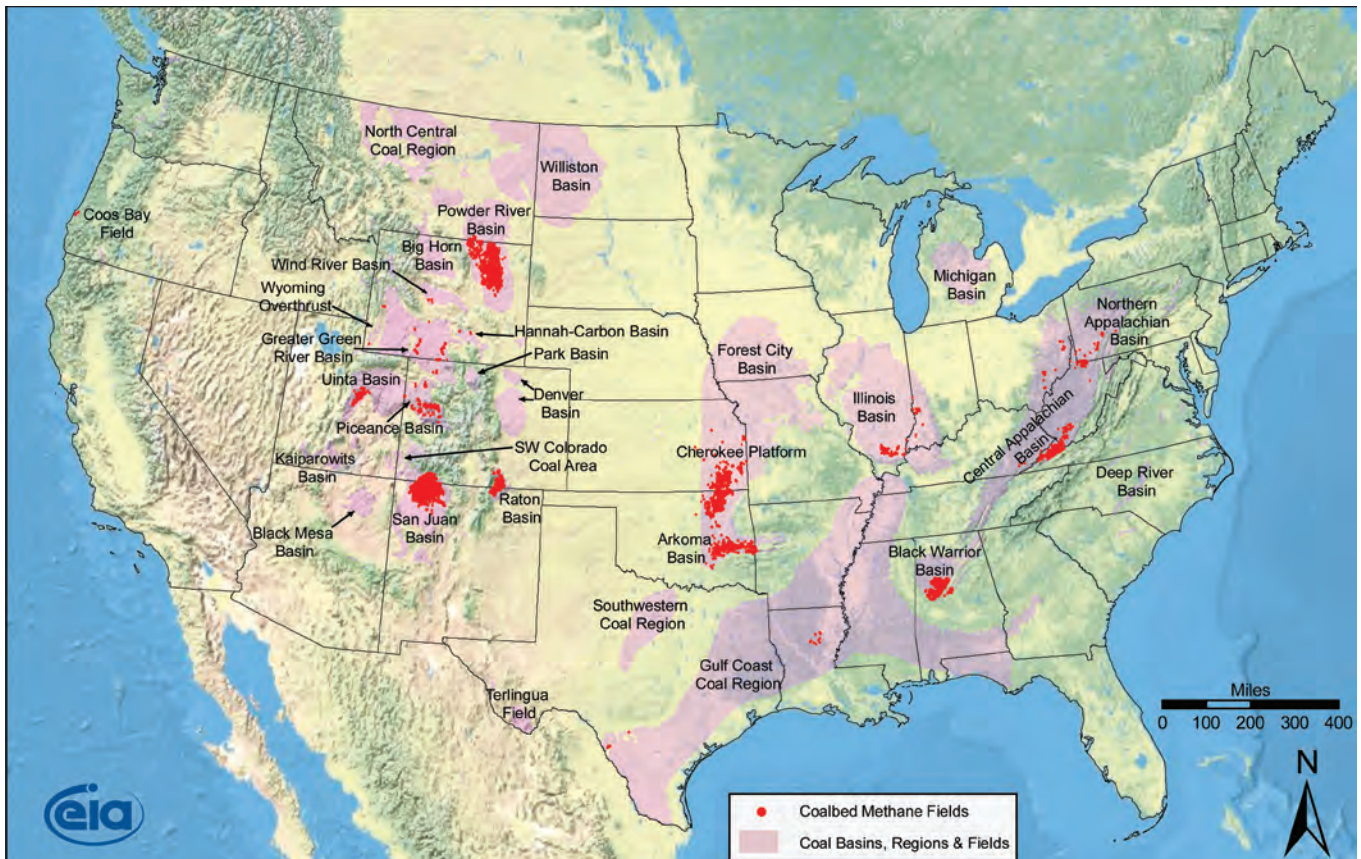


Figure 2. Coalbed methane regions and fields, continental United States (from U.S. Energy Information Administration, 2009).

In Canada, Dawson *et al.* (2000) assessed Canadian coalbed methane projects and exploration, and found most CBM resource potential to occur in the western Canadian foreland basin, with additional potential in smaller basins in British Columbia and Atlantic Canada. Beaton (2003) provided a comprehensive review of Alberta CBM production and potential, and quoted estimates of a total Alberta CBM resource of 100 to 550 TCF (Fig. 3). Extensive information is also available through the Alberta Geological Survey website (www.ags.gov.ab.ca/energy/cbm/index.html), including maps and descriptions of major coal intervals.

Numerous reports on CBM occurrence and potential in British Columbia are available on the Ministry of Energy and Mines website: www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/CoalbedGas/Pages/default.aspx. Their Coalfields and Coalbed Gas Potential map shows a CBM resource potential of 80 TCF in BC, mostly in the Peace River and East Kootenay coalfields (Fig. 4; British Columbia Ministry of Energy, Mines, and Petroleum Resources, 2002).

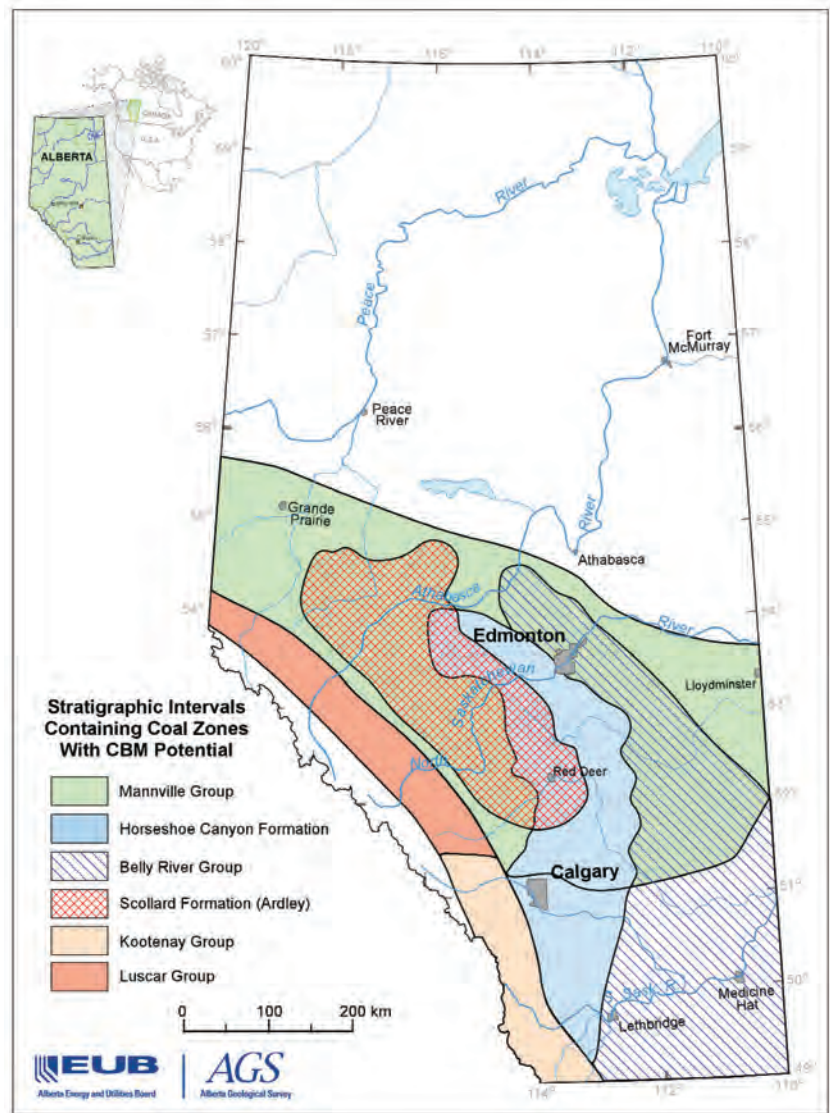


Figure 3. Distribution of strata with significant coalbed methane potential in Alberta (from Beaton, 2003).

Hacquebard (2002) discussed potential CBM resources in Atlantic Canada (Fig. 5). Hayes (2010) concluded that the Northwest Territories holds very little CBM potential, as the few coals that exist are very shallow or exposed at surface. Petrel Robertson Consulting Ltd. (2010a) tabulated estimated CBM gas-in-place resources of about 660 TCF for all of Canada.

Canadian commercial CBM production was restricted to Alberta until recently; CBM accounted for about 3.6% (0.5 BCF/day) of total Alberta gas production in 2006 (Squarek and Dawson, 2006). As of December 31, 2006, there had been 10,723 CBM wells drilled in Alberta, mostly in the Lower Cretaceous Mannville Group and Upper Cretaceous Horseshoe Canyon Formation, in the Alberta Plains region of the Western Canada Sedimentary Basin (www.ags.gov.ab.ca/energy/cbm/coalbed_methane_cbm.html). Hudson’s Hope Gas Ltd. announced in 2009 the first commercial CBM production in British Columbia, tapping the Lower Cretaceous Gething Formation coal measures of the Hudson’s Hope area (Beavers, 2009). Commercial CBM production has not yet been achieved in Atlantic Canada.

Drilling for coalbed methane in Canada and the United States has declined since 2009, as gas prices have

fallen, and most coals produce methane with very low liquids ratios. This is reflected in the declining U.S. CBM reserves and production volumes, and the lack of new information available regarding CBM in Canada.

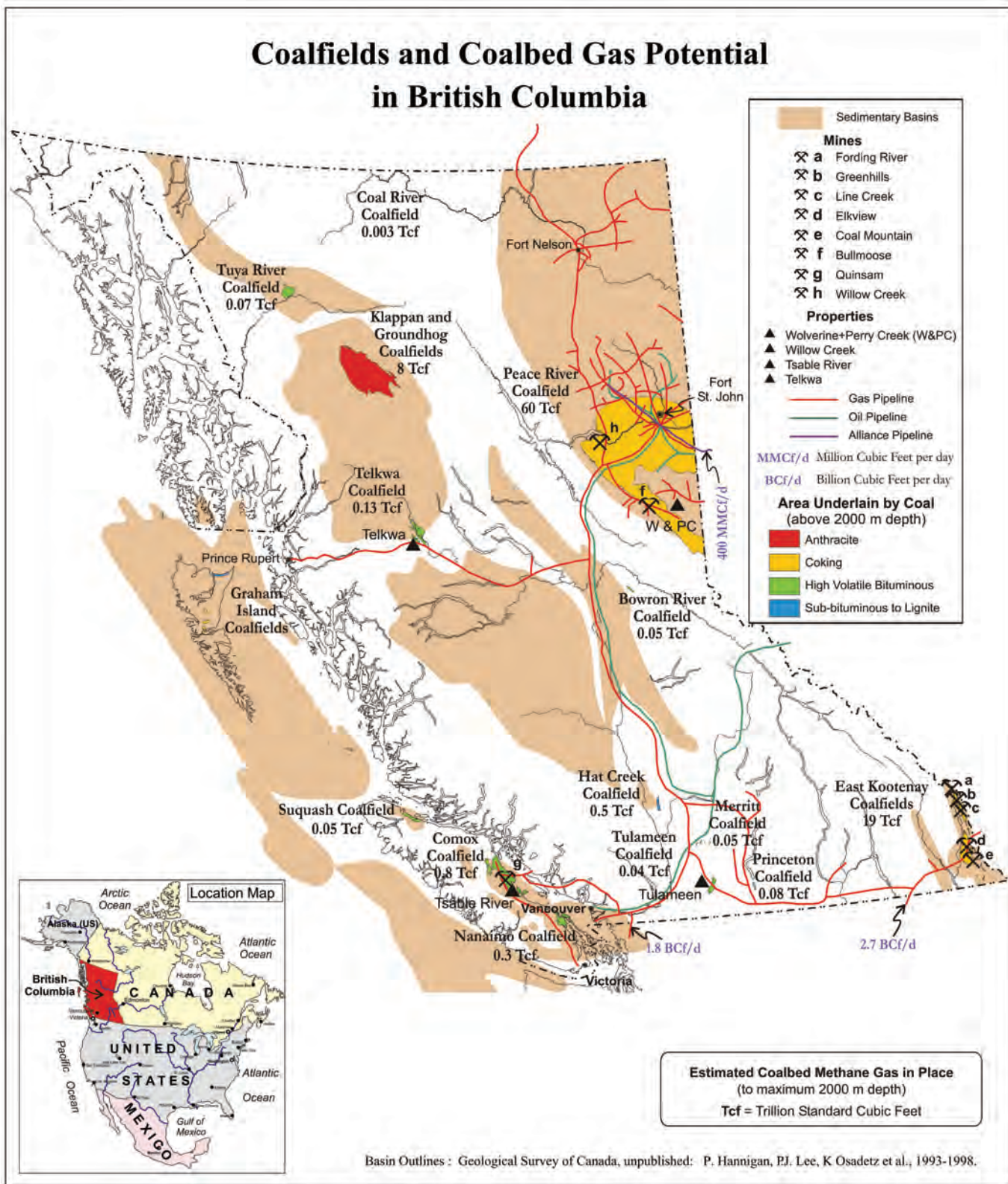


Figure 4. Coalfields and coalbed methane potential in British Columbia (from British Columbia Ministry of Energy, Mines, and Petroleum Resources, 2002).

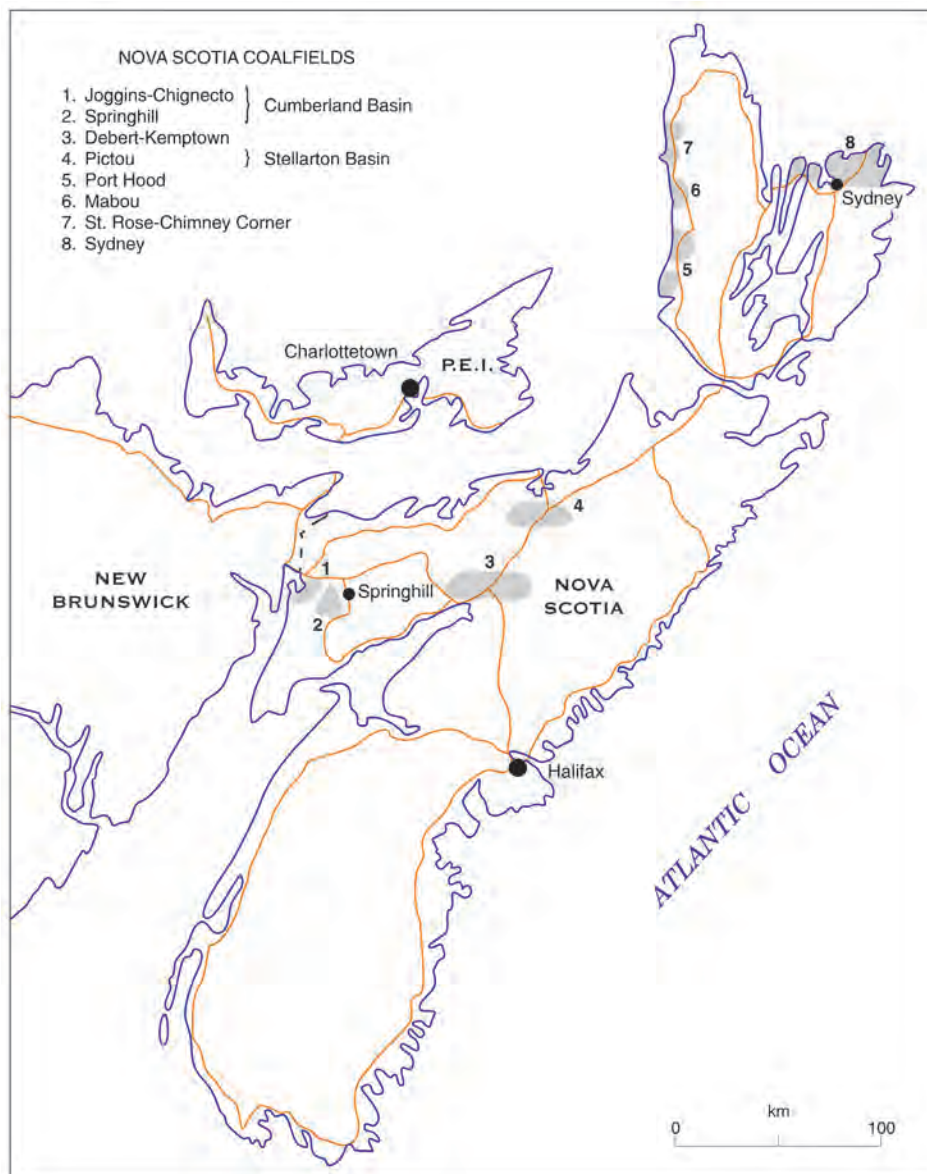


Figure 5. Location map of major Nova Scotia coalfields (from Dawson et al., 2000).

Tight Reservoirs

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

“...regionally pervasive accumulations that are (hydrocarbon) saturated, abnormally pressured, commonly lack a downdip water contact, and have low-permeability reservoirs.”

“Hydrocarbon saturated” means that oil or gas occupies most of the reservoir pore volume (generally >75%), and that one or both of these phases flow from the formation; however, there is almost always some residual water saturation. “Abnormal pressures” indicate that the hydrocarbon phase is not connected to a regional aquifer – pressures may be relatively high or low compared to a normal hydrostatic gradient (and may be both in different regions of a given basin). “Low permeability” is a term that has been used in a variety of ways, but the most commonly accepted definition is that “tight” gas reservoirs have maximum *in situ* permeabilities of <0.1 mD, with the implication that natural or artificial

fracture stimulation is required for economic production. No lower permeability limit has been formally proposed for “tight” oil reservoirs, but it appears that the term “tight oil” has been applied to include reservoirs that have sub-economic permeability for conventional oil production, which may be greater than 0.1 mD.

Source rocks for basin-centred accumulations are commonly found interbedded within or downdip of the tight reservoir section. Hydrocarbons thus charge the system directly, without migration through and exposure to regional aquifer systems (Welte *et al.*, 1984; Law, 2002). Strong aquitards, such as thick, continuous marine shales, also assist in isolating basin-centred accumulations from contact with regional aquifers.

A key feature in the current exploitation of most basin-centred tight gas systems is the presence of a relatively thick (tens to hundreds of metres) column of hydrocarbon-saturated rock. Gas resources in place per unit area (often expressed as BCF/section – billions of cubic feet per one-mile-square section of land) are thus high – up to tens of BCF/section. Alternatively, a tight gas or oil reservoir may be thinner, but very laterally extensive – allowing highly-repeatable drilling strategies over large areas. Using appropriate drilling and completions strategies, each well can access an economic reserves volume, despite low formation permeabilities.

Because of current low gas prices in the North American market, economic returns are difficult to make on tight gas plays. Those plays that produce associated hydrocarbon liquids – generally measured as a ratio of liquids recoverable per unit of gas production (*e.g.*, barrels of liquids / million cubic feet of gas) – are currently favoured.

In general, it appears that as a greater range of low-permeability gas and oil reservoirs are accessed using modern drilling and completions techniques, it is becoming more difficult to draw a definite line between conventional and “tight” reservoirs. This blurring of boundaries between low-quality conventional reservoirs and tight reservoirs has deterred regulators from clearly distinguishing tight reservoir resources and reserves, as noted in the discussions below.

Tight Oil and Gas Reservoirs in the United States

The classic example of a basin-centred gas system is the San Juan Basin of the western United States. Masters (1979) demonstrated the widespread occurrence of gas in low-permeability Cretaceous reservoirs in the centre of the basin, downdip from regional aquifers around the basin margins (Fig. 6). The “tight gas” concept grew in the Rocky Mountain basins of the western U.S. throughout the 1980’s and 1990’s; Hayes (2005) reviewed some of the key advances throughout this time in recognizing the importance and characteristics of tight gas resources.

Law (2002) formalized the definition of basin-centred gas, and tabulated numerous examples of basin-centred gas accumulations (BCGAs) in the U.S. and internationally. Moslow (2005) summarized characteristics of western U.S. Rocky Mountain tight gas reservoirs as follows:

- Thick (tens to hundreds of metres), laterally extensive sandstones;
- Low porosities (8-12%) and permeabilities (<0.1 mD);
- Generally high sand/shale ratios;
- Extensive natural fracturing, arising from the complex tectonic history of most U.S. Rocky Mountain basins; and
- Abnormal reservoir pressures (predominantly overpressured).

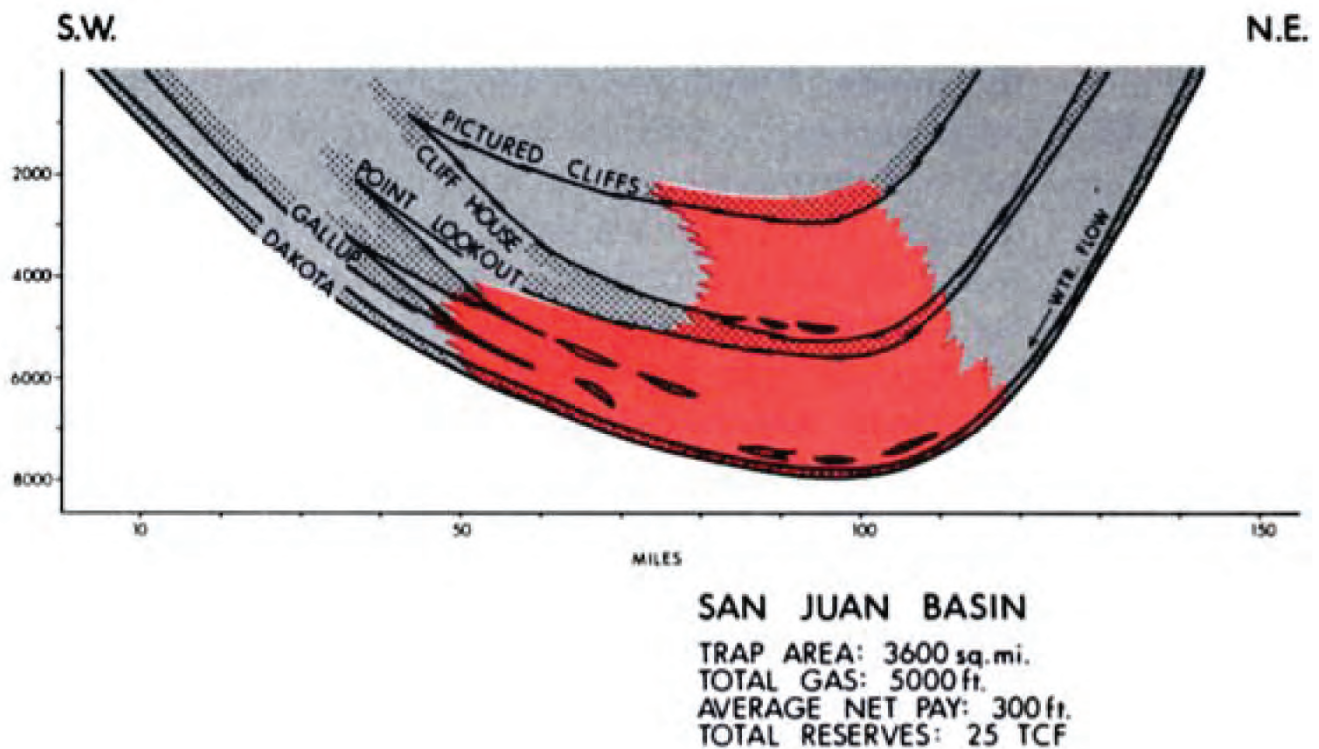


Figure 6. Schematic cross section of San Juan Basin, showing basin-centred gas system (in red; from Masters, 1979). Vertical scale in feet.

Figure 7 shows where tight gas plays are currently important in the United States, and illustrates that tight gas reservoirs are now recognized beyond the Rocky Mountain basins – for example, in midcontinent, Gulf Coast, and Appalachian basins.

The U.S. Energy Information Administration estimated U.S. technically recoverable tight gas (as of January 2009) at 310 TCF, about 17% of the total U.S. technically recoverable gas supply. In its most recent report (effective November 2009, and dated November 2010), the EIA no longer reports tight gas reserves separately from conventional reserves (U.S. EIA, 2010).

There is little formal documentation existing for tight oil reservoirs in the United States, although analyst reports and industry newsletters are abundant. Some tight reservoir plays which produce primarily from low-permeability siltstones, such as the uppermost Devonian Bakken Formation of the Williston Basin, are regarded as shale plays because of the close association of organic-rich shales (see discussion under Shale Reservoir Exploration and Development in the United States).

Tight Gas Reservoirs in Canada

Masters (1979, 1984) proposed that regionally extensive low-permeability gas reservoirs along the western flank of the Western Canada Sedimentary Basin (WCSB) lie within a basin-centred gas system, which he termed the Deep Basin (Figs. 8, 9). The system is sourced from coaly strata interbedded within the tight gas section, and from regional marine source rocks, occurring downsection and downdip in the gas window (Welte *et al.*, 1984). Thick marine shales cap Deep Basin reservoirs, and isolate them from shallow aquifers and meteoric waters. While many geologists were initially reluctant to accept the Deep Basin concept, the success of Canadian Hunter Exploration in discovering widespread subnormally-pressured gas pools, not connected to updip regional aquifers, provided ample evidence that the Deep



Figure 7. Major tight gas plays, lower 48 states (from U.S. Energy Information Administration, 2010).

Basin indeed existed. However, these early discoveries tapped into “stratigraphic sweet spots” within the Deep Basin – relatively small bodies of coarse clastic strata featuring conventional reservoir quality – such as shoreline-deposited conglomerates in the Cadotte and Falher members (Masters, 1984). The enormous gas and liquids resources in the truly low-permeability rocks were not being accessed.

In the early 2000’s, a major advance in Canadian tight gas exploitation began to open up the tight gas potential of the WCSB Deep Basin. EnCana pioneered the “resource play” concept, by acquiring large continuous blocks of tight gas acreage (in this case focused on the Lower Cretaceous Cadomin Formation), and reducing costs with large multi-well drilling programs and strict control of infrastructure costs. Rising gas prices and evolving drilling and completions technologies (large frac stimulations and multi-leg horizontal wells) also played a role in making the Cadomin Formation resource play economically worthwhile. Further advances in drilling and completions technology supported another significant step in accessing Deep Basin tight gas resources by 2005/2006, with the widespread implementation of multi-zone completions and commingling of gas production from several reservoirs. Up to 15 or more tight gas intervals are now produced together routinely in a single wellbore, producing economically from stacked reservoirs that could not otherwise sustain economic flow rates on a standalone basis. Hayes *et al.* (2009) described the regulatory changes that have been made in Alberta to maximize gas resource capture from stacked tight gas reservoirs in the Alberta Deep Basin; similar regulatory initiatives have been completed in British Columbia.

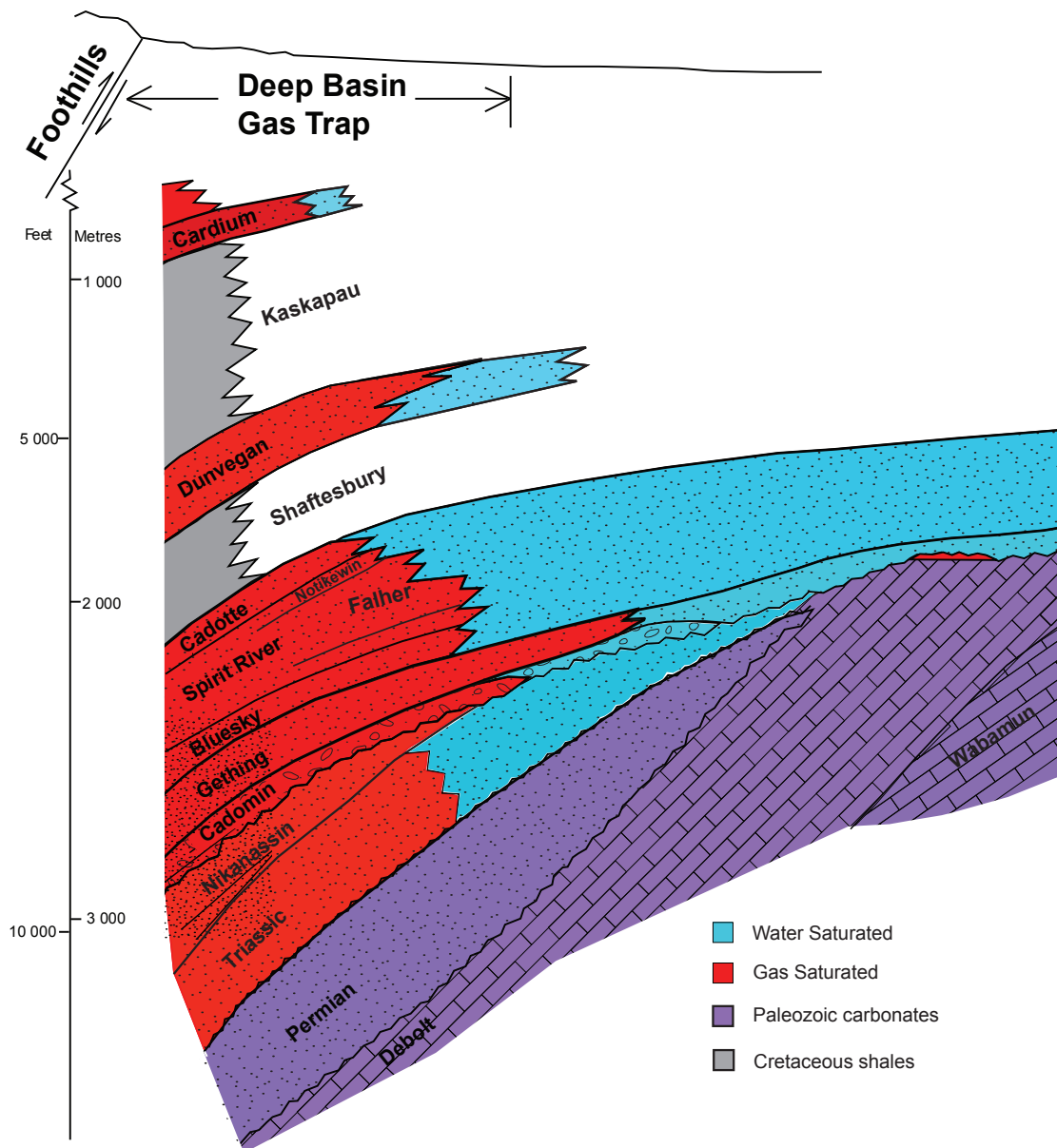


Figure 8. Schematic cross section of Western Canada Deep Basin, showing continuous gas-saturated reservoirs downdip from regional aquifers (after Masters, 1979).

Also since 2004/2005, industry has recognized and pursued Deep Basin tight gas potential over an expanded stratigraphic section in the WCSB. First Energy Capital (2009) and BMO Capital Markets (2010b) provided specific analyses of the Jurassic/Cretaceous Nikanassin Formation Deep Basin tight gas play, found immediately below the Cadomin Formation. Most importantly, overpressured basin-centred gas accumulations have been recognized in siltstones and very fine sandstones of the Triassic Doig and Montney formations (Hayes, 2005, 2009; Walsh *et al.*, 2006). Horizontal wells with multiple frac stimulations have been the key to achieving economic flow rates from the Montney and Doig formations. The Montney Formation play is so significant to British Columbia that land and drilling are actively tracked on the B.C. Ministry of Energy, Mines and Petroleum Resources website at www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/Shalegas/Pages/default.aspx. Although not tracked separately by regulatory authorities in Alberta, the Montney Formation is an increasingly important target in west-central Alberta, and has been written up extensively by industry analysts (*e.g.*, Canaccord Adams, 2008; Peters & Co., 2008; Raymond James, 2008; Tristone Capital, 2008).

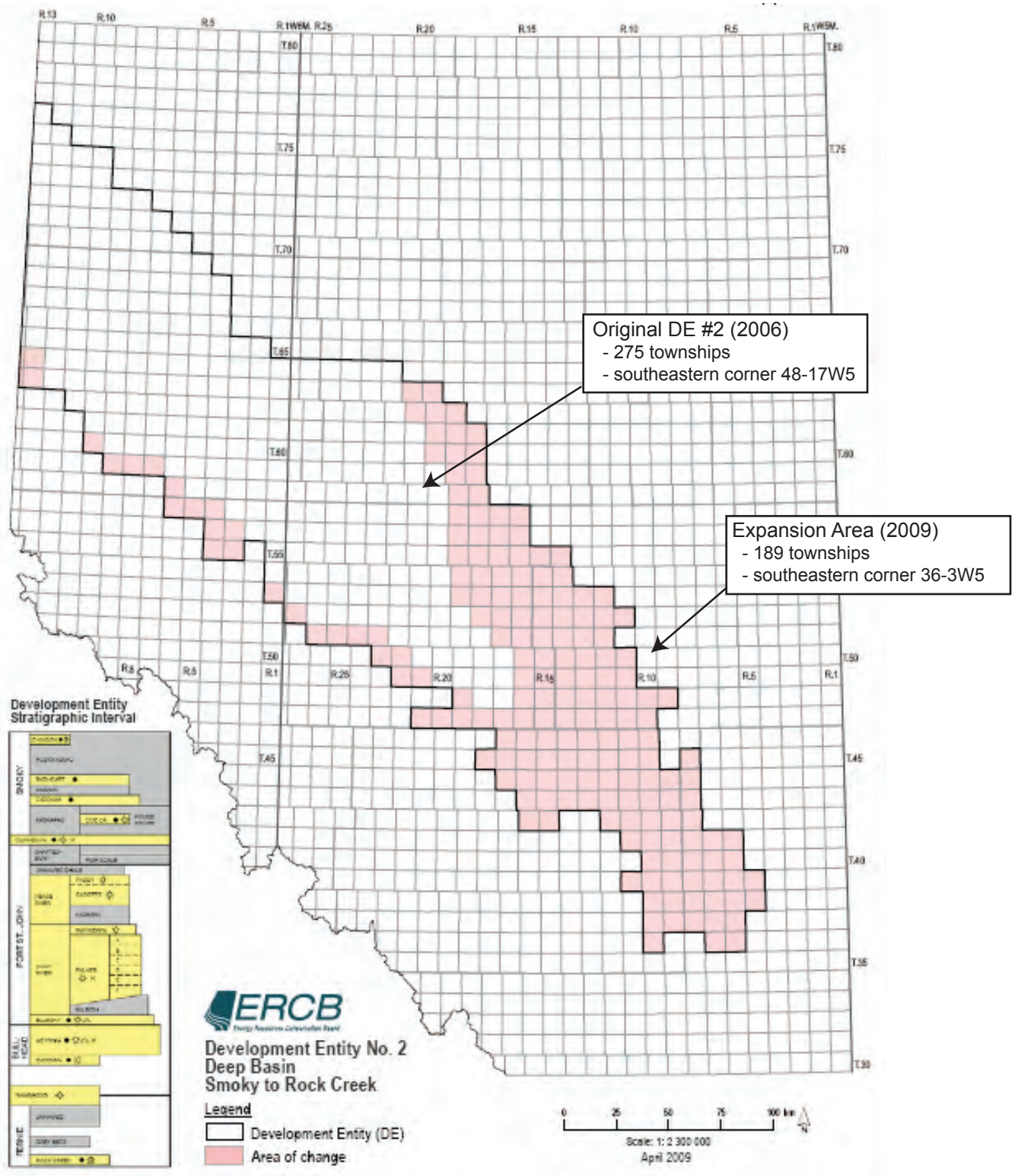


Figure 9. Deep Basin Development Entity, western Alberta. Basin-centred tight gas plays are focused within this area and adjacent northeastern BC (from Energy Resources Conservation Board, 2009).

Deep Basin tight gas reservoirs host huge gas resources in Alberta and British Columbia, and are becoming increasingly important producers. Although consistent, basin-wide statistics have not been developed, some relevant figures are:

- Gas in place, Alberta Deep Basin, Townships 45-75: 430 TCF (Hayes *et al.*, 2009);
- Gas in place, northeast BC Deep Basin: 111-260 TCF (Hayes, 2003; Hayes and Hayes, 2004); and
- Gas in place, Montney Deep Basin: corporate report and analyst figures ranging from 10 to 100's of BCF per section, for a total play potential of hundreds of TCF. No consistent assessment criteria have been developed and accepted to date.

Deep Basin production is not consistently reported separately in either Alberta or BC, but Hayes *et al.* (2009) showed Alberta Deep Basin production (Deep Basin Development Entity area only; Fig. 9) to have risen from about 2 BCF/day to about 3 BCF/day between 2003 and 2009. Industry reports place current Montney tight gas production in British Columbia at up to one BCF/day, and increasing rapidly.

Since 2009, industry has placed increased emphasis on Deep Basin plays that produce a high ratio of liquids. Attaining production ratios of more than 20 barrels/MMCF is seen as essential for positive economics on many plays. High liquids ratios are emphasized particularly for plays accessed by horizontal wells, which have high up-front capital expenses.

North of the traditional Deep Basin area on the western flank of the WCSB, the Devonian Jean Marie Member exhibits basin-centred gas characteristics. It is a regional carbonate platform isolated within a thick shale section, and is characterized by regional subnormal pressures, pervasive gas saturation, and a low-permeability reservoir (Letourneau, 1991; McAdam, 1993; Reimer, 1994). The application of horizontal drilling (beginning in the 1990's) to access natural fractures in the Jean Marie Member has demonstrated it to be a tight gas play (National Energy Board (NEB) *et al.*, 2000). A second round of development took place in the early 2000's, as EnCana and others developed the thick westerly platform margin using the resource play approach described above (Hayes, 2005). Although the Jean Marie play is not currently regarded as being as economically attractive as many other unconventional gas plays, considerable exploration potential remains, as the northern, eastern and southern limits of the play have not been completely defined. Exploratory activity is currently focused in the southerly, deeper parts of the Jean Marie Member fairway.

Hayes (2010), in an initial scoping assessment of tight gas potential in the Northwest Territories, concluded that tight gas potential may exist in specific Cambrian depocentres in the Colville Hills area, in the Devonian Imperial Formation of Peel Plain, and in Cretaceous, Triassic, and Devonian Jean Marie tight gas plays mapped northward from Alberta and BC into southern NWT.

Elsewhere in Canada, tight gas potential has generally not been assessed systematically – in part because it is difficult to establish the existence of all the components of a tight gas petroleum system where drilling and testing are sparse. Documentation of complete petroleum systems and conventional petroleum plays in Paleozoic basins of eastern Canada by Lavoie *et al.* (2009) and Dietrich *et al.* (2011) suggests that numerous tight gas and oil plays may exist there. PRCL (2010a) noted poorly-quantified tight gas prospectivity in these basins, based on existing production of gas from low-permeability reservoirs in the McCully Field of New Brunswick.

Tight Oil Reservoirs in Canada

Several oil plays in low-permeability reservoirs are being pursued in western Canada. Although long-term performance has not been documented, sufficient information has been released to support publication of analytical reports by equities research firms (*e.g.*, Macquarie Equities Research, 2010). Geological and play analyses have not yet been published in refereed journals, and it is unclear whether the reservoirs being developed are truly “tight” in the sense of having in situ permeabilities of 0.1 mD or less, or whether they are simply poorer-quality conventional reservoirs. However, it is evident that initial production rates from horizontal wells with multi-frac stimulations are sufficiently encouraging to drive significant capital programs for several plays. From oldest to youngest, these include:

- Swan Hills Formation and equivalents (Devonian): low-permeability reefal facies and platform carbonates in the Swan Hills Formation of west-central Alberta and the Slave Point Formation of Peace River Arch area and northern Alberta, found in association with high-quality conventional reefal reservoirs, host large light oil resources. Horizontal drilling programs have been undertaken by several operators, and initial production rates of hundreds to thousands of barrels of oil per day are being reported from low-permeability units (BMO Capital Markets, 2011b).
- Bakken / Three Forks Formations (Devonian / Mississippian – Williston Basin): the primary reservoir of this play – the middle Bakken tight siltstone – occurs between organic-rich source rocks, the upper and lower Bakken shales. Most wells drill horizontally into the siltstone and are stimulated with multiple fracture treatments. Low-permeability siltstones and carbonates of the Three Forks Formation, immediately underlying the lower Bakken, are being developed in the same areas, although generally using dedicated wells. Mahony (2011) estimated current production at 400,000 BOPD in North Dakota and 70,000 BOPD in the Saskatchewan/Manitoba portion of the Williston Basin.
- Exshaw/Big Valley Formations (Devonian / Mississippian): this rock package, time equivalent to the Bakken Formation and underlying uppermost Devonian units of the Williston Basin, is now being explored in the western part of the WCSB in southwestern Alberta and northwestern Montana. While formal documentation is still scanty, several analyst reports have been written (CIBC World Markets, 2011; Scotia Capital, 2011; BMO Capital Markets, 2010a, 2011a). Mahony (2011) noted that several companies have drilled on the play, and that as of November 2011 the first wells were coming off confidential status in Alberta, showing limited production of light (35-40° API) oil.
- Pekisko Formation (Mississippian): platformal carbonates of various formations making up the Mississippian Rundle Group of the WCSB are locally excellent oil and gas reservoirs where they subcrop beneath younger unconformities, largely as a result of dolomitization and solution. Operators are now developing large oil resources in the oldest of these units, the Pekisko Formation, with horizontal wells and multi-frac completions, where reservoir quality is subeconomic for conventional drilling.
- Montney Formation (Triassic): although the Montney Formation is known primarily as a tight gas play, low-permeability sandstones and coquinas are being developed for oil in west-central Alberta, updip of the primary gas exploration fairway. Conventional-quality reservoirs also occur in these areas, and considerable analysis is required to establish which pools are tapping tight reservoirs, versus conventional pools where development is being accelerated with horizontal wells.

- Charlie Lake Formation (Triassic): outliers and subcrop edges of tight, fine-grained clastics and carbonates in the Charlie Lake Formation of the Peace River Arch area are being developed for oil using horizontal drilling and multi-frac completions.
- Spearfish Formation (Permo-Triassic – Williston Basin): tight siltstones and sandstones are oil-saturated over a relatively restricted area focused in southwestern Manitoba. Several companies are developing these with multi-frac horizontal wells.
- Shaunavon Formation (Jurassic – Williston Basin): tight calcareous sandstones of the upper Shaunavon Formation overlie lower Shaunavon limestones across much of the Saskatchewan Williston Basin. Intensive horizontal multi-frac development is underway across large areas, as a number of companies define prospective plays and refine completion techniques.
- Viking Formation (Cretaceous): heterolithic Viking Formation strata in the Plains of Alberta and Saskatchewan are not economic in conventional wellbores because of abundant interbedded muds, and poor connectivity of individual sandstone beds. Although true “basin-centred” conditions have not been documented, the formation produces oil over broad areas of the eastern Alberta and western Saskatchewan Plains.
- Cardium Formation (Cretaceous): one of the original tight oil plays in the WCSB, horizontal / multi-frac wells produce from sandstones forming low-permeability “halos” surrounding Cardium Formation oil fields with conventional permeability. Numerous analyst reports, such as Peters & Co. (2010) have reviewed drilling strategies and results. Industry is currently testing the economic limits, targeting thinner and tighter Cardium sands as far south as Calgary and as far north as Wapiti.

Shale Reservoirs

Curtis (2002) defined shale reservoirs as:

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

Rokosh *et al.* (2009) pointed out the term “shale” is often used loosely, and that natural gas is hosted:

“not only in shale, but also a wide spectrum of lithology and texture from mudstone to siltstone and fine-grained sandstone, any of which may be of siliceous or carbonate composition.”

Hamblin (2006) also noted the compositional variability of “gas shales”, and defined them more broadly, in terms of unconventional accumulations:

“These are unconventional, basin-centered, self-sourced, continuous-type gas accumulations where the total gas charge is represented by the sum of free gas and adsorbed gas...In effect, these shale gas plays represent discrete, self-enclosed petroleum systems which do not rely on hydrocarbon expulsion/migration/trapping because the premise is that the hydrocarbon stays in the original source rock; if they were well-connected to conventional plays, then they wouldn’t provide a new play at all.”

Numerous parameters have been cited in technical and economic evaluation of shale reservoirs; some of the key ones include:

- Rock volume – thickness and areal extent of the shale;
- Total organic carbon (TOC) content;

- Maturity of organic material;
- Mineralogical composition of the shales and related rocks, particularly as they affect brittleness of the rock, and hence ease of fracturing;
- Presence of natural fractures, and their relationship to stress fields and structural features;
- Water saturation; and
- Pressure, temperature, and depth.

There are no “optimal” values for many of these parameters, but the characteristics of each shale reservoir dictate the most appropriate drilling, completion, and production strategies. As each new shale play unfolds, operators must undertake a period of experimentation in order to refine these strategies. Several workers, such as Curtis (2002), have tabulated selected parameters for various shale plays (Table 1).

Table 1. Geological, geochemical, and reservoir parameters for five shale gas systems in United States (from Curtis, 2002).

Property	Antrim	Ohio	New Albany	Barnett	Lewis
Depth (ft)	600-2400	2000-5000	600-4900	6500-8500	3000-6000
Gross thickness (ft)	160	300-1000	100-400	200-300	500-1900
Net thickness (ft)	70-120	30-100	50-100	50-200	200-300
Bottom-hole temperature (°F)	75	100	80-105	200	130-170
TOC (%)	0.3-24	0-4.7	1-25	4.50	0.45-2.5
Vitrinite reflectance (% R _o)	0.4-0.6	0.4-1.3	0.4-1.0	1.0-1.3	1.6-1.88
Total porosity (%)	9	4.7	10-14	4-5	3-5.5
Gas-filled porosity (%)	4	2.0	5	2.5	1-3.5
Water-filled porosity (%)	4	2.5-3.0	4-8	1.9	1-2
Permeability thickness [Kh (md-ft)]	1-5000	0.15-50	NA	0.01-2	6-400
Gas content (scf/ton)	40-100	60-100	40-80	300-350	15-45
Adsorbed gas (%)	70	50	40-60	20	60-85
Reservoir pressure (psi)	400	500-2000	300-600	3000-4000	1000-1500
Pressure gradient (psi/ft)	0.35	0.15-0.40	0.43	0.43-0.44	0.20-0.25
Well costs (\$1000)	180-250	200-300	125-150	450-600	250-300
Completion costs (\$1000)	25-50	25-50	25	100-150	100-300
Water production (b/day)	5-500	0	5-500	0	0
Gas production (mdcf/day)	40-500	30-500	10-50	100-1000	100-200
Well spacing (ac)	40-160	40-160	80	80-160	80-320
Recovery factor (%)	20-60	10-20	10-20	8-15	5-15
Gas in place (bcf/section)	6-15	5-10	7-10	30-40	8-50
Reserves (mmcf/well)	200-1200	150-600	150-600	500-1500	600-2000
Historic production area basis for data	Otsego Country, Michigan	Pike County, Kentucky	Harrison County, Indiana	Wise County, Texas	San Juan & Rio Arriba Counties, New Mexico

Shale gas has been a “game changer” in the North American natural gas industry. Before 2000, shales were regarded strictly as source rocks, and as seals for conventional or tight gas reservoirs; little productive potential was forecast. Now, in the 2010s, shale gas reserves appear to be enormous and widespread, although with insufficient production history to quantify accurately. Short-term initial production rates of 10 MMCF/D and greater (per well) in many of the plays have produced great

excitement in the industry, and many shale gas wells appear to have the potential to be long-term economic producers. Based on these early results, operators and industry analysts regard many shale gas plays as having better economics than most conventional plays.

As for tight reservoirs, since the decline in North American gas prices in 2009, an increasing emphasis has been placed on the ratio of hydrocarbon liquids that can be recovered from shale gas production, and the most economic and hotly-pursued plays are those from which substantial liquids are produced. Some shale plays are now presented as oil plays, although there appears to be a continuous spectrum of shale reservoir production from liquids-rich gas to oils with a high gas-oil ratio.

Shale Reservoir Exploration and Development in the United States

Many histories of shale development refer to commercial gas production from Devonian shales in the Appalachian Basin, as far back as 1821 (*e.g.*, Curtis, 2002). Production from these shales has been important locally since that time. In 1999, shale gas reservoirs supplied 1.6% of total United States gas production, and contained 2.3% of proved gas reserves (Curtis, 2002). However, only a tiny fraction of the gas-in-place could be accessed – the very richest accumulations (“sweet spots”), in situations where natural fracturing was common, or where conventional wellbore stimulations were economically effective. A relatively small number of shale reservoirs, primarily Devonian and Mississippian organic-rich systems such as the Antrim, Ohio, New Albany, and Barnett shales, were considered viable.

Concerted efforts in the 1980’s and 1990’s by operators working the Barnett Shale in the Fort Worth Basin of Texas, particularly Mitchell Energy, gradually unlocked much greater potential through advances in drilling and completions technology. Key breakthroughs came in the efficient drilling of horizontal wells, and their stimulation with multiple staged frac jobs using fluids optimized to the reservoir. By 2000, the Barnett Newark East Field was the largest producing gas field in Texas, with multi-TCF reserve potential (Montgomery *et al.*, 2005). Mitchell Energy sold out to Devon Energy in 2001 for \$3.5 billion, marking the emergence of shale gas as a major new play type with huge production and economic potential.

Since 2006, shale drilling and production has exploded in the United States, supported by continued advances in technology and rising gas prices. Shale gas plays are producing in numerous basins across the country (Fig. 10), although most of the activity is focused on a few plays such as the Barnett, Haynesville, Fayetteville, Woodford, and Marcellus. Huge efforts are being made to better understand shale reservoirs (*e.g.*, Montgomery *et al.*, 2005; Bowker, 2007; Jarvie *et al.*, 2007; Pollastro, 2007; Pollastro *et al.*, 2007). U.S. shale gas production in 2010 was about 4.8 TCF, approximately 23% of all U.S. production (U.S. EIA, 2011b). U.S. shale gas reserves were 60.64 TCF at year-end 2009, about 21% of overall U.S. natural gas reserves (U.S. EIA, 2010, 2011b). In-place shale gas resources in the lower 48 states have been estimated at 750 TCF, in a report summarizing characteristics of the major U.S. shale plays (Table 2; U.S. EIA, 2011b). Kralovic (2011) reviewed geology, basin metrics, operating companies, and development outlook for established and emerging shale gas plays in the United States.

The U.S. EIA (2011b) report also tabulated U.S. shale oil resources at 24 billion barrels in four plays – the Eagle Ford, Avalon/Bone Springs, Bakken, and Monterey/Santos (Table 2). While the Eagle Ford and Bakken (also considered to be a tight oil play, as discussed above) have attracted the most industry and public attention, the Avalon/Bone Springs play of the New Mexico / west Texas Permian Basin is also being actively developed. The Monterey / Santos play, containing more than 60% of estimated U.S. shale oil resources, is at an earlier stage of development.



Figure 10. Shale gas basins and play trends, continental United States (from U.S. Energy Information Administration, 2011b).

Canadian Shale Reservoir Exploration and Development

Shale plays have been systematically exploited in Canada only since the early 2000's, following the development of horizontal drilling and multi-fracture completion technologies in the United States. However, considerable work has taken place in Canada in refining drilling and completions practices to fit each specific play (e.g., Sanford, 2008).

Hamblin (2006) reviewed 50 shale units in seven major regions of Canada to produce a geographic inventory of significant shale potential across the country (Fig. 11a-d). He concluded that many of these shales have interesting geological characteristics that make them worthy of further investigation. Several have not yet attracted industry interest because of their lack of wellbore data and distance from infrastructure, and so considerable additional work is required to ensure sufficient data have been considered for fair and reasonable assessments. Hamblin (2006) judged the following shale gas units as worthy of concerted geological examination:

- Middle to Upper Ordovician of Appalachian Mountains, St. Lawrence Platform, and Anticosti Island (Utica, Collingwood, Blue Mountain);
- Upper Devonian of St. Lawrence Platform and Michigan Basin (Marcellus, Kettle Point);

- Middle and Upper Devonian of western Alberta, northeastern BC, Liard Basin, and Mackenzie Corridor (Horn River, Muskwa, Imperial, Fort Simpson , Besa River);
- Lower to Middle Triassic of northwestern Alberta and northeastern BC (Montney, Doig);
- Jurassic of western Alberta and northeastern BC (Nordegg, Gordondale, Fernie); and
- Middle-Upper Cretaceous of Alberta, Saskatchewan, and Manitoba (Colorado).

Table 2. Estimates of undeveloped technically recoverable shale gas and oil resources remaining in discovered shale plays in the United States, January 1, 2009 (from U.S. EIA, 2011b).

Play	Technically Recoverable Resource		Area (sq. miles)		Average EUR	
	Gas (Tcf)	Oil (BBO)	Leased	Unleased	Gas (Bcf/well)	Oil (MBO/well)
Marcellus	410.34	...	10,622	84,271	1.18	...
Big Sandy	7.40	...	8,675	1,994	0.33	...
Low Thermal Maturity	13.53	...	45,844		0.30	...
Greater Siltstone	8.46	...	22,914		0.19	...
New Albany	10.95	...	1,600	41,900	1.10	...
Antrim	19.93	...	12,000		0.28	...
Cincinnati Arch*	1.44	...	NA		0.12	...
Total Northeast	472.05	...	101,655	128,272	0.74	...
Haynesville	74.71	...	3,574	5,426	3.57	...
Eagle Ford	20.81	...	1,090		5.00	...
Floyd-Neal & Conasauga	4.37	...	2,429		0.90	...
Total Gulf Coast	99.99	...	7,093	5,426	2.99	...
Fayetteville	31.96	...	9,000		2.07	...
Woodford	22.21	...	4,700		2.98	...
Canawoodford	5.72	...	688		5.20	...
Total Mid-Continent	59.88	...	14,388		2.45	...
Barnett	43.38	...	4,075	2,383	1.42	...
Barnett Woodford	32.15	...	2,691		3.07	...
Total Southwest	75.52	...	6,766	2,383	1.85	...
Hilliard-Baxter-Mancos	3.77	...	16,416		0.18	...
Lewis	11.63	...	7,506		1.30	...
Williston-Shallow Niobraran*	6.61	...	NA		0.45	...
Mancos	21.02	...	6,589		1.00	...
Total Rocky Mountain	43.03	...	30,511		0.69	...
Total Lower 48 U.S.	750.38	...	160,413	136,081	1.02	...

Play	Technically Recoverable Resource		Area (sq. miles)		Average EUR	
	Gas (Tcf)	Oil (BBO)	Leased	Unleased	Gas (Bcf/well)	Oil (MBO/well)
Eagle Ford	...	3.35	3,323		...	300
Total Gulf Coast	...	3.35	3,323		...	300
Avalon & Bone Springs	...	1.58	1,313		...	300
Total Southwest	...	1.58	1,313		...	300
Bakken	...	3.59	6,522		...	550
Total Rocky Mountain	...	3.59	6,522		...	550
Monterey/Santos	...	15.42	1,752		...	550
Total West Coast	...	15.42	1,752		...	550
Total Lower 48 U.S.	...	23.94	12,910		...	460



Figure 11a. Shale gas play areas, Atlantic Canada, Quebec, Ontario, and Hudson Margin (from Hamblin, 2006).

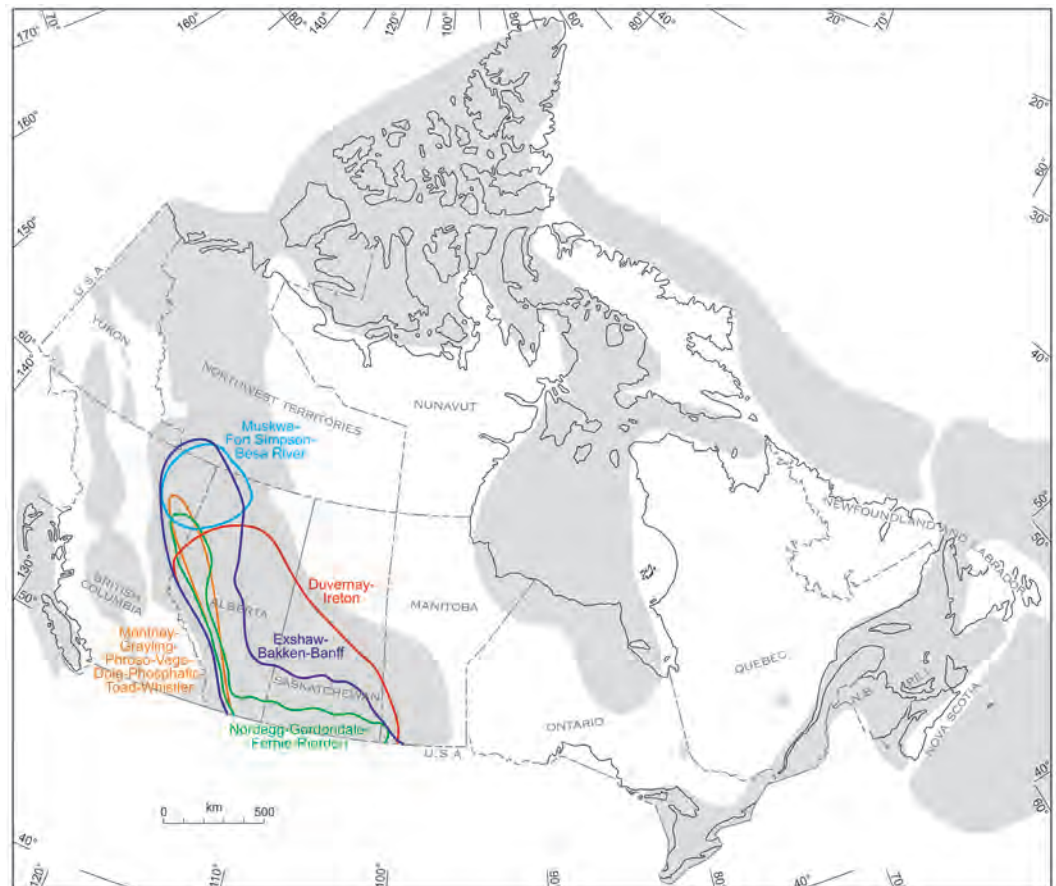


Figure 11b. Shale gas play areas, western Canada Paleozoic and Mesozoic passive margin platform (from Hamblin, 2006).

Figure 11c. Shale gas play areas, western Canada Mesozoic foreland basin (from Hamblin, 2006).

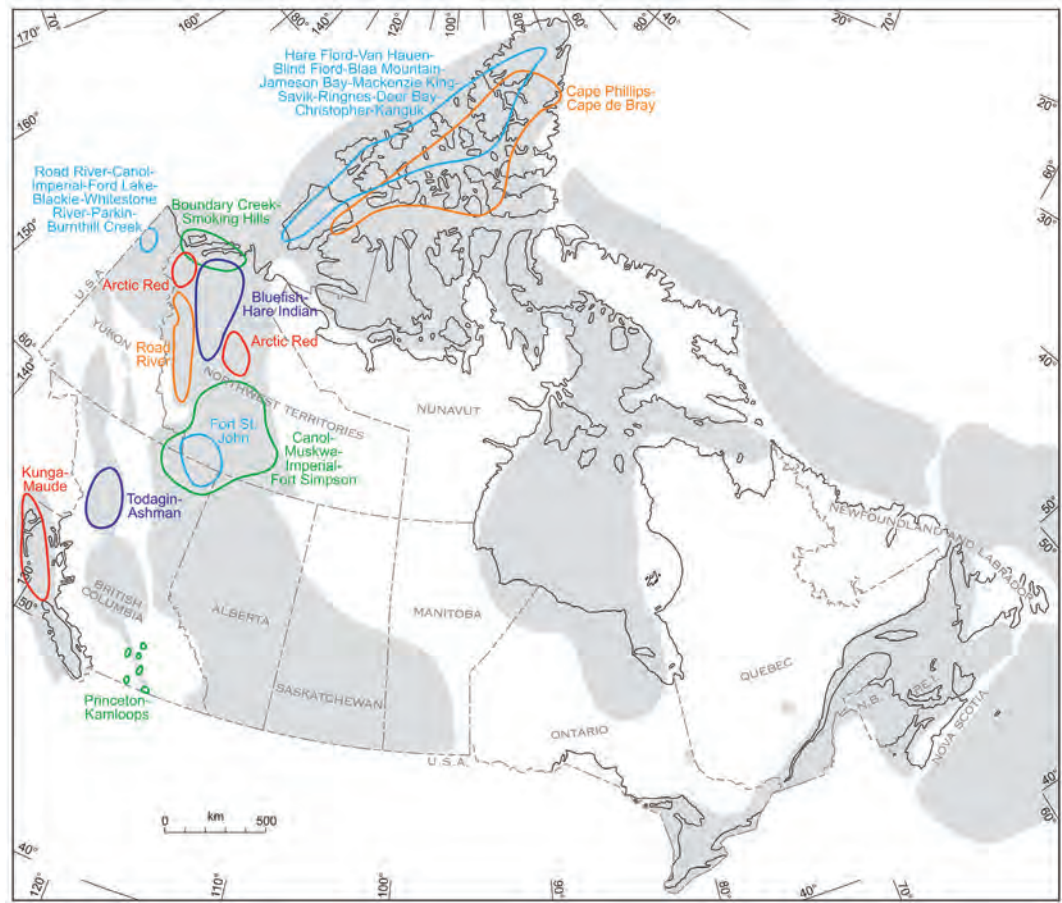
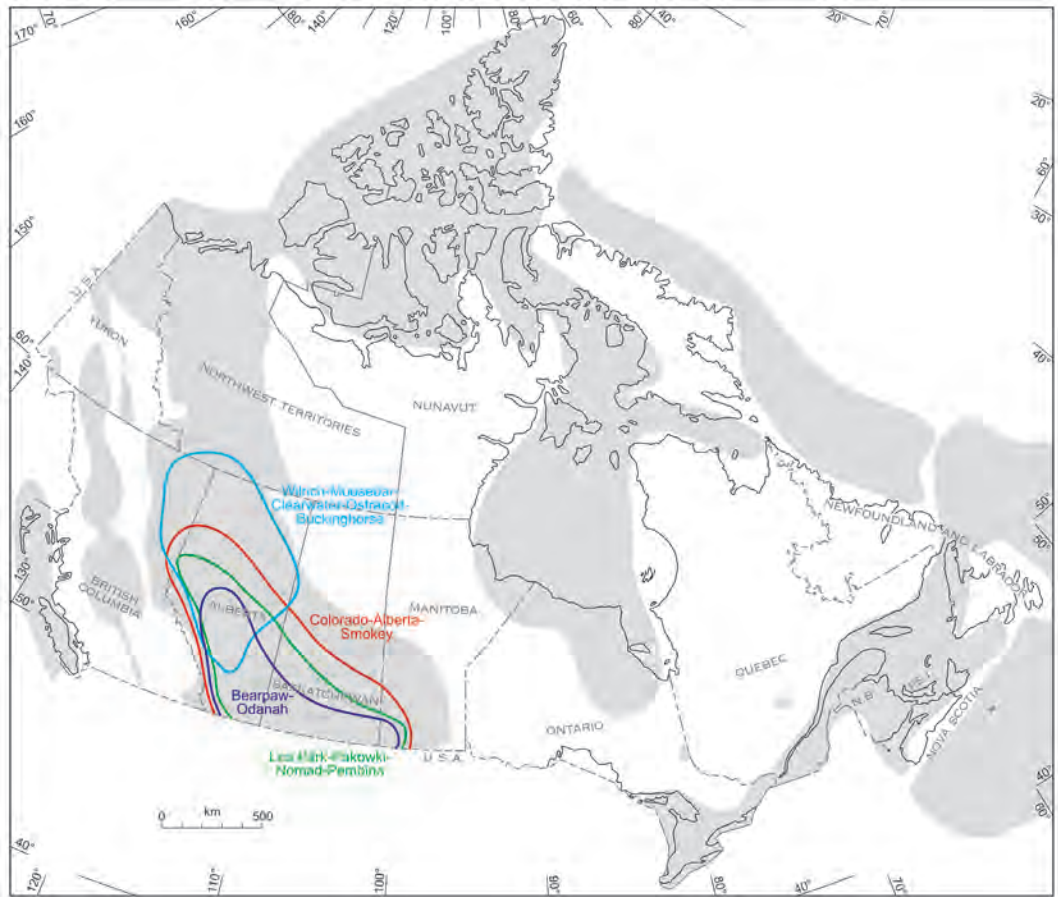


Figure 11d. Shale gas play areas, Northwest Territories, Arctic Islands, and intermontane basins of BC (from Hamblin, 2006).

The NEB (2009) described five Canadian gas shale units currently undergoing evaluation through drilling and flow testing (Table 3). These include:

- Montney Formation, northeastern British Columbia and adjacent Alberta;
- Devonian shales of the Horn River Basin and Cordova Embayment;
- Cretaceous Colorado Group, eastern Alberta and western Saskatchewan;
- Ordovician Utica Group, St. Lawrence River area of Quebec; and
- Carboniferous Horton Bluff Group, Maritimes Basin.

Table 3. Comparison of Canadian gas shales (from National Energy Board, 2009).

Property	Horn River	Montney	Colorado	Utica	Horton Bluff
Depth (m)	2500-3000	1700-4000	300	500-3300	1120-2000+
Thickness (m)	150	up to 300	17-350	90-300	150+
Gas-filled porosity (%)	3.2-6.2	1.0-6.0	<10	2.2-3.7	2
Total organic content (%)	0.5-6.0	1-7	0.5-12	0.3-2.25	10
Maturity (R_o)*	2.2-2.8	0.8-2.5	biogenic	1.1-4	1.53-2.03
Silica (%)	45-65	20-60	sand and silt	5-25	38
Calcite or dolomite (%)	0-14	up to 20%	-	30-70	significant
Clay (%)	20-60	<30	high	8-40	42
Free gas (%)	66	64-80	-	50-65	-
Adsorbed gas (%)	34	20-36	-	35-50	-
CO ₂ (%)	12	1	-	<1	5
GIP/section (million m ³)**	1700-9000+	230-4500	623-1800	710-5950	2000-17000+
GIP/section (Bcf)**	60-318+	8-160	22-62	25-210	72.4-600+
Play area GIP (billion m ³)**	4100-17000	2300-20000	>2800	>3400	>3700
Play area GIP (Tcf)**	144-600+	80-700	>100	>120	>130
Horizontal well cost, including frac (Million \$Cdn)	7-10	5-8	0.35 (vertical only)	5-9	unknown

compiled from various sources
* R_o (vitrinite reflectance) is a measure of the thermal maturity of organic matter; values above 1.2 are in the gas window
**GIP: gas in place; recoverable gas may be on the order of 20 per cent

Studies undertaken by PRCL and current industry activity suggest these lists should be reconsidered and updated in light of shale exploration activity in Canada in 2012, as follows:

- Montney Formation (Fig. 12) – As noted in the *Tight Gas Reservoirs in Canada* section, this is primarily a tight gas play in siltstones and very fine-grained sandstones. Some recent developments – pushing westward into more distal facies (Foothills area of northeastern BC, including Farrell Creek, Altares, and Cypress areas) and increased focus on the overlying Doig Formation phosphatic zone – are addressing intervals with a greater shale component. Kralovic (2011) reviewed geology, basin metrics, operating companies, and development outlook for the Montney play. Toad-Grayling formation siltstones in Liard Basin are equivalent to the Montney Formation (Fig. 12).
- Devonian shales of WCSB (Fig. 12) – The first focus of activity, beginning in 2007, was the Horn River Basin of northeastern BC, where several major operators (EnCana, Apache, Devon, Nexen, EOG, and others) drilled numerous wells to establish high initial gas flow rates and substantial reserves from stacked Middle to Upper Devonian shales. These reservoirs yield relatively dry gas with up to 12% CO₂. A report by BC Ministry of Energy and Mines and the NEB (2011) listed medium-case gas-in place potential for the Horn River Basin play of 448 TCF (12,629x10⁹m³), and medium-case marketable gas resources of 78 TCF (2,198x10⁹m³), based on drilling to the end of 2010. Adams (2011) reviewed recent operator activity in the Horn River Basin play area, and

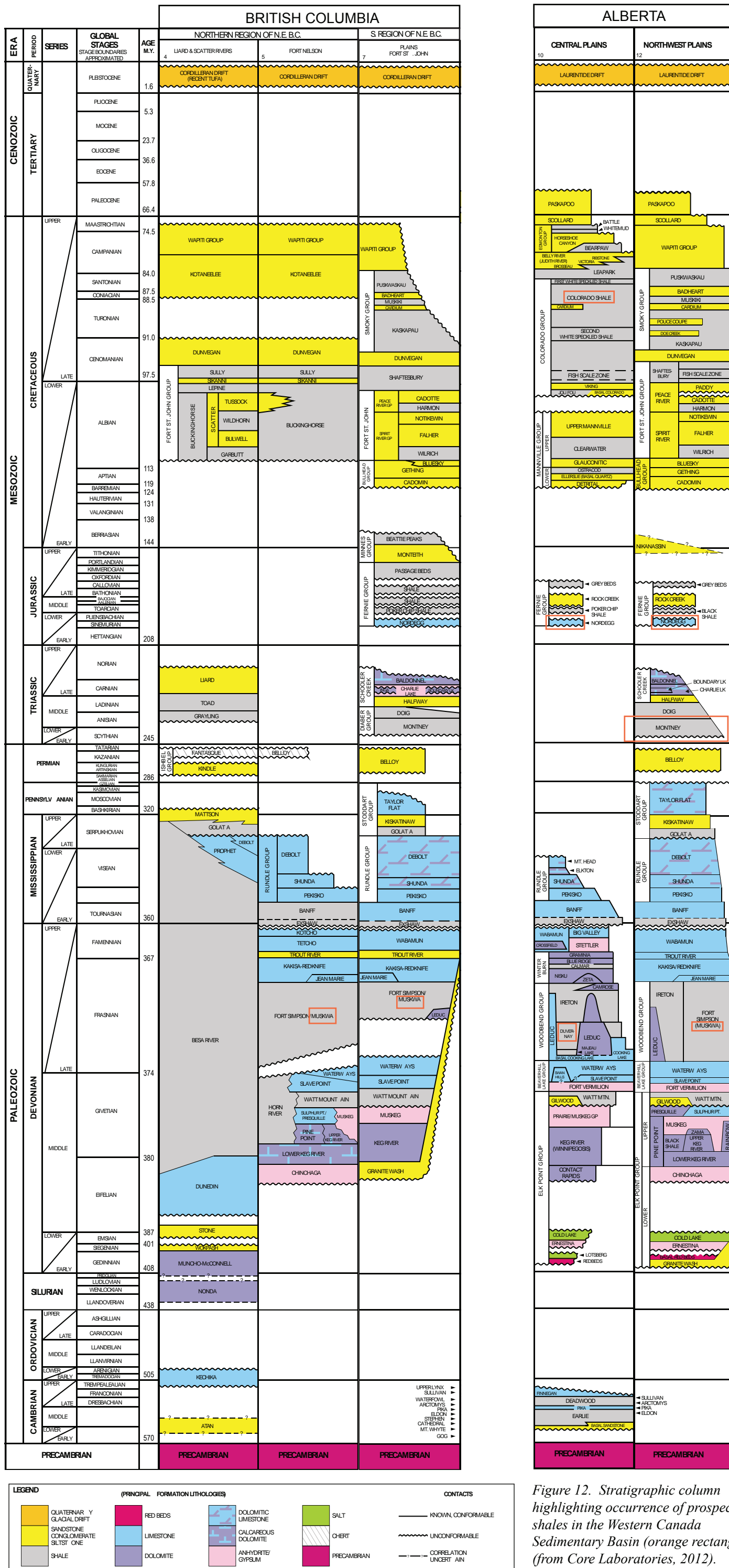


Figure 12. Stratigraphic column highlighting occurrence of prospective shales in the Western Canada Sedimentary Basin (orange rectangles) (from Core Laboratories, 2012).

Kralovic (2011) reviewed geology, basin metrics, operating companies, and development outlook for Horn River Basin Devonian shales.

Some exploratory work is also underway in the adjacent Cordova Embayment and Liard Basin, but these have received far less attention to date (Adams, 2010). Developments in all three areas are tracked on the BC Ministry of Energy, Mines and Petroleum Resources website shale gas page at www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/Shalegas/Pages/default.aspx.

Since late 2009, Devonian Duvernay Formation shales of west-central Alberta have been an active target for liquids-rich gas exploration. While this play was pioneered by junior to intermediate companies, several major companies have announced their participation, and early production results indicate potential for initial gas flows in excess of 10 MMCF/D with high liquids ratios (Macquarie Equities Research, 2011). An Alberta Crown Land auction on June 1, 2011 saw record bids of \$843 million, a large portion of which was attributed to the Duvernay in west-central Alberta (Macedo, 2011a).

Industry has recently expressed interest in the shale gas and oil potential of the Devonian Horn River Group in the Mackenzie Plain area of the Northwest Territories. Responding to the 2010-2011 Call for Bids in the Central Mackenzie Valley, several companies collectively made work commitment bids of \$534.2 million to explore twelve licence blocks, which feature optimal Horn River shale gas and oil prospectivity (www.aadnc-aandc.gc.ca/eng/1311192629194; Hayes, 2011a, 2011b). One operator, ConocoPhillips, stated that their exploration target would be “more from a liquids perspective than from a gas perspective” (Ross, 2011).

A number of technical studies evaluating WCSB Devonian shale gas reservoirs have been published, including CBM Solutions (2005), Ross and Bustin (2008), and Pawlowicz *et al.* (2009a).

Horn River and Canol shales occur in Yukon in Peel Plateau and Plain, Eagle Plain, Bonnet Plume, and Kandik basins (Fig. 15).

- Jurassic Gordondale Member (Ferne Formation), west-central Alberta (Fig. 12) – Oil has been produced from fractured shales of the Gordondale Member (also known as the Nordegg shale) in several wells in west-central Alberta. Industry is now pursuing this play systematically, although at a slower pace than the Duvernay Formation play (Macquarie Equities Research, 2010). As the two plays overlap to some extent geographically, it is difficult to gauge exactly the level of interest in the Gordondale Member play based on land sale activity.

Strata of equivalent age are found in Yukon in Whitehorse Trough, Eagle Plain, Kandik, North Coast and Old Crow Basins, but do not exhibit the high-quality shale reservoir potential of the Gordondale Member.

- Cretaceous shales of WCSB, including the Colorado Group (Fig. 12) – Only one small company, Stealth Ventures Ltd., has actively pursued shale gas potential in the shallow, organic-rich but immature shales of the Alberta and Saskatchewan Plains (Fig. 11c). Most large companies are focusing on thermogenic (mature) plays, found further west in the Alberta Deep Basin and Foothills. Here, operators are pursuing both gas and oil potential in organic-rich Cretaceous shales, particularly the Second White Specks Formation. Pawlowicz *et al.* (2009b) tabulated assessment data for Colorado shale reservoirs in Alberta, and Rokosh *et al.* (2009) listed nine potential shale gas formations in Alberta.

BC Ministry of Energy, Mines and Petroleum Resources (www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/ShaleGas/Pages/default.aspx) notes some Cretaceous shale gas exploration activity in the BC Foothills, where these strata are thicker, more mature, and more deeply buried.

Chalmers and Bustin (2008) evaluated Cretaceous shale gas potential in northeastern BC, and mapped gas-in-place values of up to 25 BCF/section in traditional development areas, increasing to >100 BCF/section in Liard Basin. This work implies significant prospectivity for Cretaceous shales in the Yukon part of Liard Basin, as discussed later in this report.

- Utica Shale – Exploration activity has been conducted by several junior companies and some larger organizations, such as Talisman Energy and Forest Oil (Lavoie *et al.*, 2008). Drilling and completions technologies are still being optimized, but an extended flow test in February 2010 yielding rates up to 6 MMCF/D from a well operated by junior Questerre Energy, has added excitement to the play. Lack of gathering and processing infrastructure and distance from traditional industry areas has restricted the pace of development. Favourable reservoir characteristics and its similarity to other gas shales of the northeastern U.S. support continued activity in the Utica (Lavoie *et al.*, 2008). However, a moratorium on exploratory shale drilling and fracture stimulation in Quebec has brought Utica exploration to a virtual standstill in 2011 (Financial Post, June 30 2011). Kralovic (2011) reviewed geology, basin metrics, operating companies, and development outlook for the Utica Shale play.
- Horton Bluff Group – Onshore Maritimes Basin strata have traditionally been regarded as non-prospective, but recent success by Corridor Resources in tight gas reservoirs in the McCully Field in New Brunswick has attracted industry interest. Construction of the Maritimes & Northeast pipeline through the area, which transports high gas volumes from offshore Sable Island to American and Canadian markets, has provided additional impetus to explore. At the present time, exploration activity is driven primarily by junior companies with small drilling programs, and commercial flow rates have yet to be established (NEB, 2009).

Global Shale Reservoir Exploration and Development

Following upon industry's success in producing hydrocarbons from shale in North America, shales around the world are being explored for their hydrocarbon potential. Shale gas is the primary target, as natural gas is generally more highly valued in world markets than in North America. Exploration is focused in producing hydrocarbon basins, where the search for conventional hydrocarbons has produced sufficient data to underpin shale evaluations, and where production infrastructure is present.

In Europe, domestically-produced shale gas is seen as having potential to reduce or eliminate dependence upon gas imported from Russia. This is particularly the case in Poland, where numerous companies are exploring actively, and Polish regulators are looking to Canada for regulatory models to govern their work. Shale gas potential has been realized in France, but exploration has been slowed by a ban on hydraulic frac stimulations. Fracking concerns are also being expressed in the United Kingdom as early-stage shale exploration takes place.

Elsewhere, Repsol / YPF has announced the discovery of substantial shale gas resources in the Neuquen Basin of southern Argentina. Royal Dutch Shell has produced gas from 11 test wells completed in shales in China, noting a mixed range of outcomes from “pretty poor” to “excellent” (Bergin, 2012). Regulatory and government ownership issues present significant risks to economic development in many areas, however.

The U.S. Energy Information Administration (2011a) produced an initial assessment of shale gas in 14 regions outside the United States, calculating technically recoverable shale gas resources of 6622 trillion cubic feet (Table 4). However, this assessment does not include many regions, including most of Africa, the Middle East, and the former Soviet Union. Given the abundance of shales in sedimentary basins around the world, it is clear that exploration for shale gas and oil is in the very early stages.

Table 4. Estimated technically recoverable shale gas resources for select basins in 32 countries, compared to existing reported reserves, production and consumption during 2009.

	2009 Natural Gas Market ⁽¹⁾ (trillion cubic feet, dry basis)			Proved Natural Gas Reserves ⁽²⁾ (trillion cubic feet)	Technically Recoverable Shale Gas Resources (trillion cubic feet)
	Production	Consumption	Imports (Exports)		
Europe					
France	0.03	1.73	98%	0.2	180
Germany	0.51	3.27	84%	6.2	8
Netherlands	2.79	1.72	(62%)	49.0	17
Norway	3.65	0.16	(2,156%)	72.0	83
U.K.	2.09	3.11	33%	9.0	20
Denmark	0.30	0.16	(91%)	2.1	23
Sweden	-	0.04	100%	-	41
Poland	0.21	0.58	64%	5.8	187
Turkey	0.03	1.24	98%	0.2	15
Ukraine	0.72	1.56	54%	39.0	42
Lithuania	-	0.10	100%	-	4
Others ⁽³⁾	0.48	0.95	50%	2.71	19
North America					
United States ⁽⁴⁾	20.6	22.8	10%	272.5	862
Canada	5.63	3.01	(87%)	62.0	388
Mexico	1.77	2.15	18%	12.0	681
Asia					
China	2.93	3.08	5%	107.0	1,275
India	1.43	1.87	24%	37.9	63
Pakistan	1.36	1.36	-	29.7	51
Australia	1.67	1.09	(52%)	110.0	396
Africa					
South Africa	0.07	0.19	63%	-	485
Libya	0.56	0.21	(165%)	54.7	290
Tunisia	0.13	0.17	26%	2.3	18
Algeria	2.88	1.02	(183%)	159.0	231
Morocco	0.00	0.02	90%	0.1	11
Western Sahara	-	-	-	-	7
Mauritania	-	-	-	1.0	0
South America					
Venezuela	0.65	0.71	9%	178.9	11
Colombia	0.37	0.31	(21%)	4.0	19
Argentina	1.46	1.52	4%	13.4	774
Brazil	0.36	0.66	45%	12.9	226
Chile	0.05	0.10	52%	3.5	64
Uruguay	-	0.00	100%	-	21
Paraguay	-	-	-	-	62
Bolivia	0.45	0.10	(346%)	26.5	48
Total of above areas	53.1	55.0	(3%)	1,001	6,622
Total world	106.5	106.7	0%	6,609	

Sources:

¹ Dry production and consumption: EIA, International Energy Statistics, as of March 8, 2011.

² Proved gas reserves: *Oil and Gas Journal*, Dec., 6, 2010, P. 46-49.

³ Romania, Hungary, Bulgaria.

⁴ U.S. data are from various EIA sources.

UNCONVENTIONAL OIL AND GAS RESOURCES IN YUKON TERRITORY

Introduction

Israel *et al.* (2012) summarized the regional geology of Yukon as follows:

Yukon is located in the northern part of the North American Cordillera, the mountainous backbone of the western part of the continent. Like most of the Cordillera, Yukon is composed of rocks that record more than a billion years of Earth history. These document the evolution of the western margin of Ancestral North America (Laurentia) and of the various displaced terranes that were accreted to it since late Paleozoic.

The northwest-striking Tintina fault is one of the most prominent physiographic and geologic feature (*sic*) in Yukon. It is a dextral strike-slip fault with about 430 km of Paleogene displacement. It generally separates rocks of Ancestral North American affinity to the northeast from those of the allochthonous Intermontane terranes to the southwest except in southeast Yukon, where the Tintina fault has shuffled this order and the allochthonous Yukon-Tanana and Slide Mountain terranes lie northeast of the fault, and parautochthonous rocks of Cassiar terrane underlie the Pelly Mountains to the southwest.

The Intermontane terranes are mainly comprised of (*sic*) magmatic arc rocks and related sedimentary deposits that fringed western Laurentia between mid-Paleozoic and early Mesozoic. They envelop more exotic oceanic rocks of Cache Creek terrane in south-central Yukon, which includes elements of Tethyan affinity. The Intermontane terranes are bounded to the southwest by the northwest-striking Denali fault, an active dextral strike-slip fault with more than 400 km of displacement, that separates them from the Insular terranes. The Insular terranes consist of continental fragments and volcanic arc rocks that contain exotic elements of Baltican and Siberian affinities.

In north Yukon, structures along the northeast-striking Porcupine lineament juxtapose rocks of the Ancestral North American margin with those of the Arctic-Alaska terrane to the northwest. Arctic Alaska is a composite terrane which includes Neoproterozoic and Paleozoic elements of Baltican-Siberian affinities, as well as less exotic northern Laurentian rocks.

Cretaceous and younger, mainly post-accretionary plutonic suites intrude part of the Laurentian margin strata and the Intermontane and Insular terranes in southern Yukon. These represent a succession of continental magmatic arcs and related back-arc environments that record the Cretaceous-Paleogene convergence of the various terranes.

The various terranes and plutonic suites that make up Yukon geology are host to a wide range of base and precious metal deposits. Successor basins that developed during Jurassic to Paleogene terrane convergence in the northern Cordillera have hydrocarbon potential.

The map of Yukon geology is displayed in figure 13. Hydrocarbon prospectivity exists in eight distinct exploration areas, where substantial sedimentary rock sections are preserved, and most or all elements of productive petroleum systems have been established (Figs. 14, 15). In general order of unconventional prospectivity, these are:

- Liard Basin
- Eagle Plain Basin
- Peel Plain and Plateau
- Bonnet Plume Basin
- Whitehorse trough
- Kandik Basin
- Yukon North Coast
- Old Crow Basin

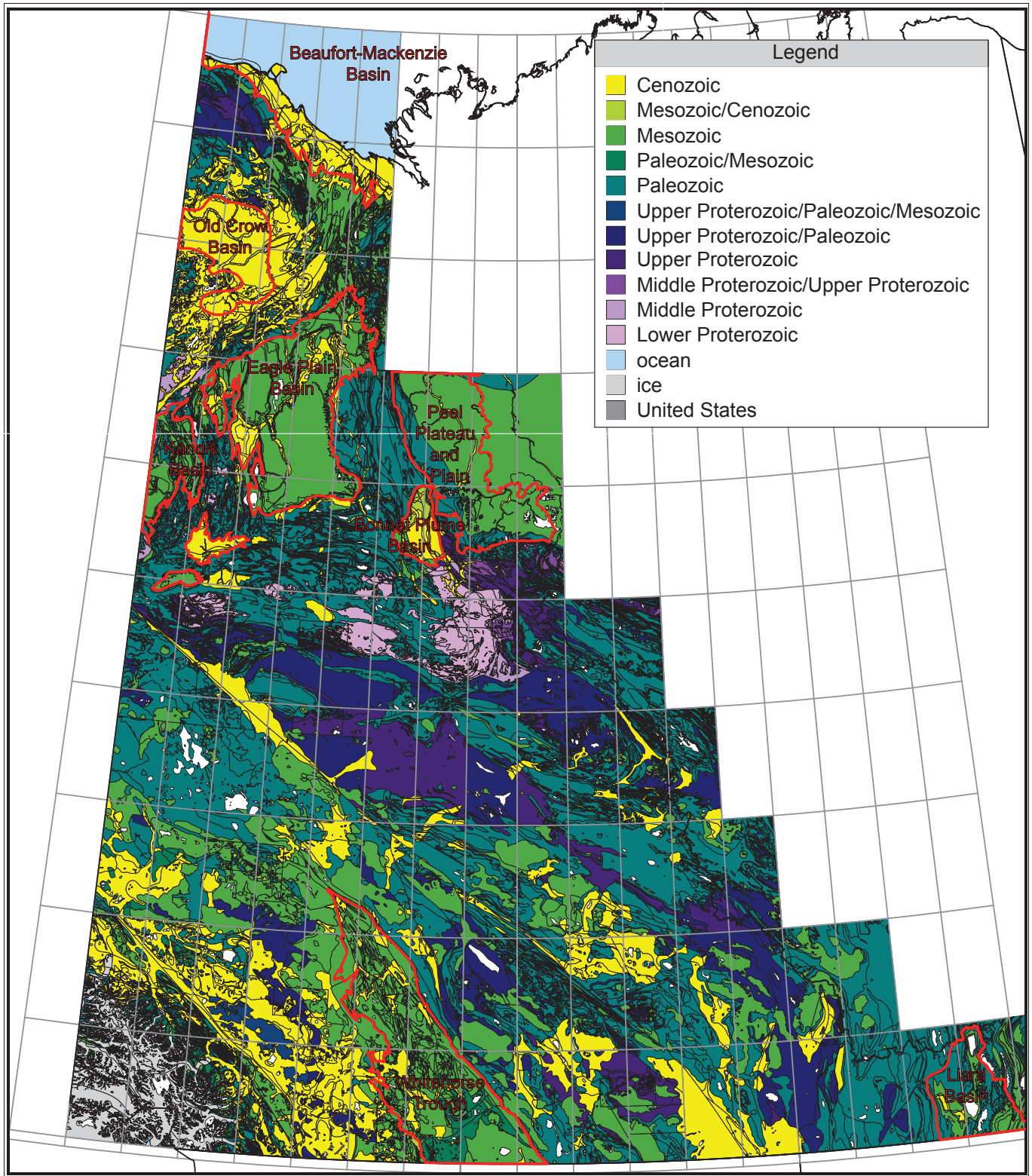


Figure 13. Geological bedrock map, Yukon Territory (from Gordey and Makepeace, 1999). Exploration regions in red (after Oil and Gas Resources, 2012).

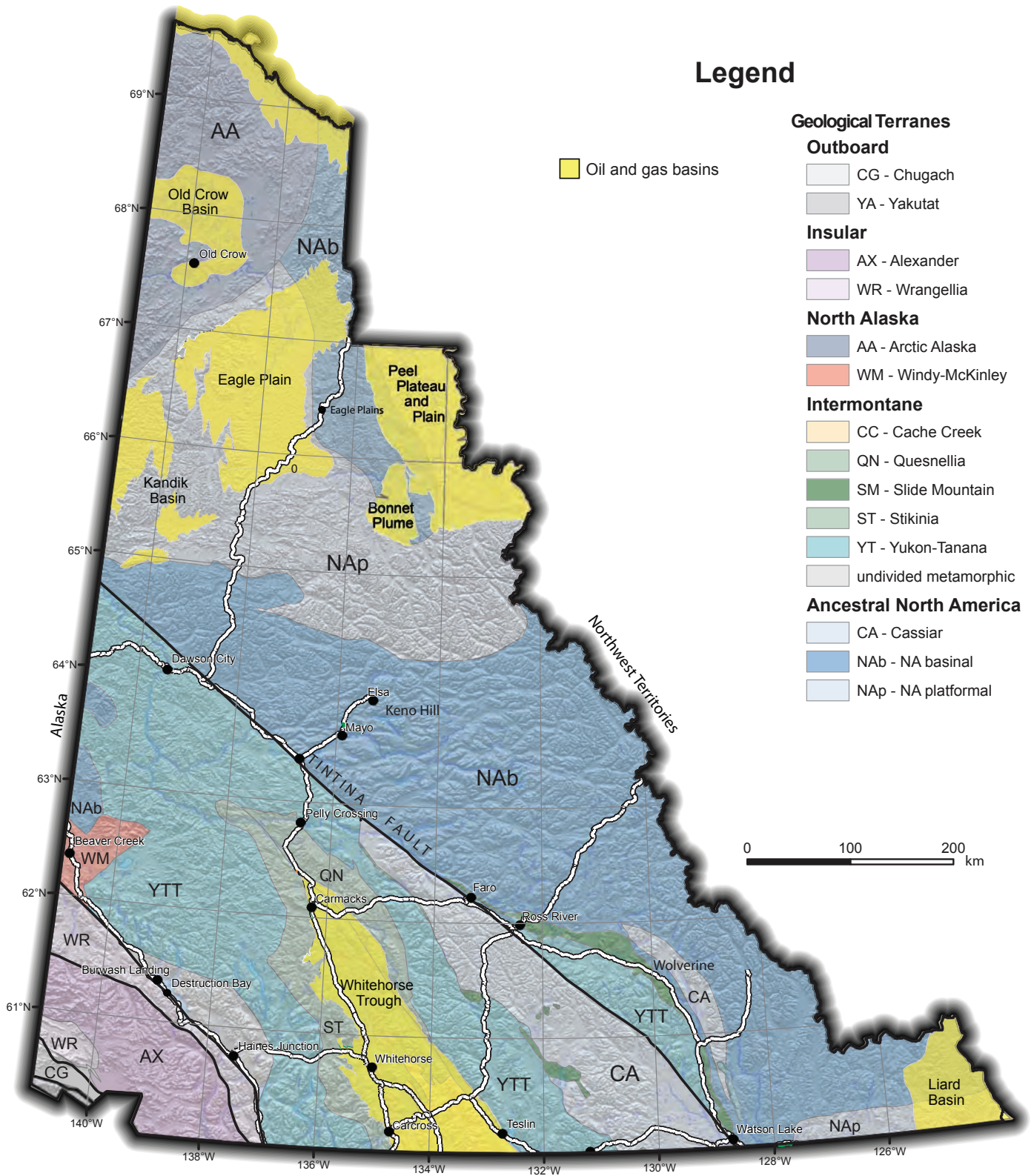


Figure 14. Geological terrane map of Yukon displaying basins prospective for hydrocarbon resources.

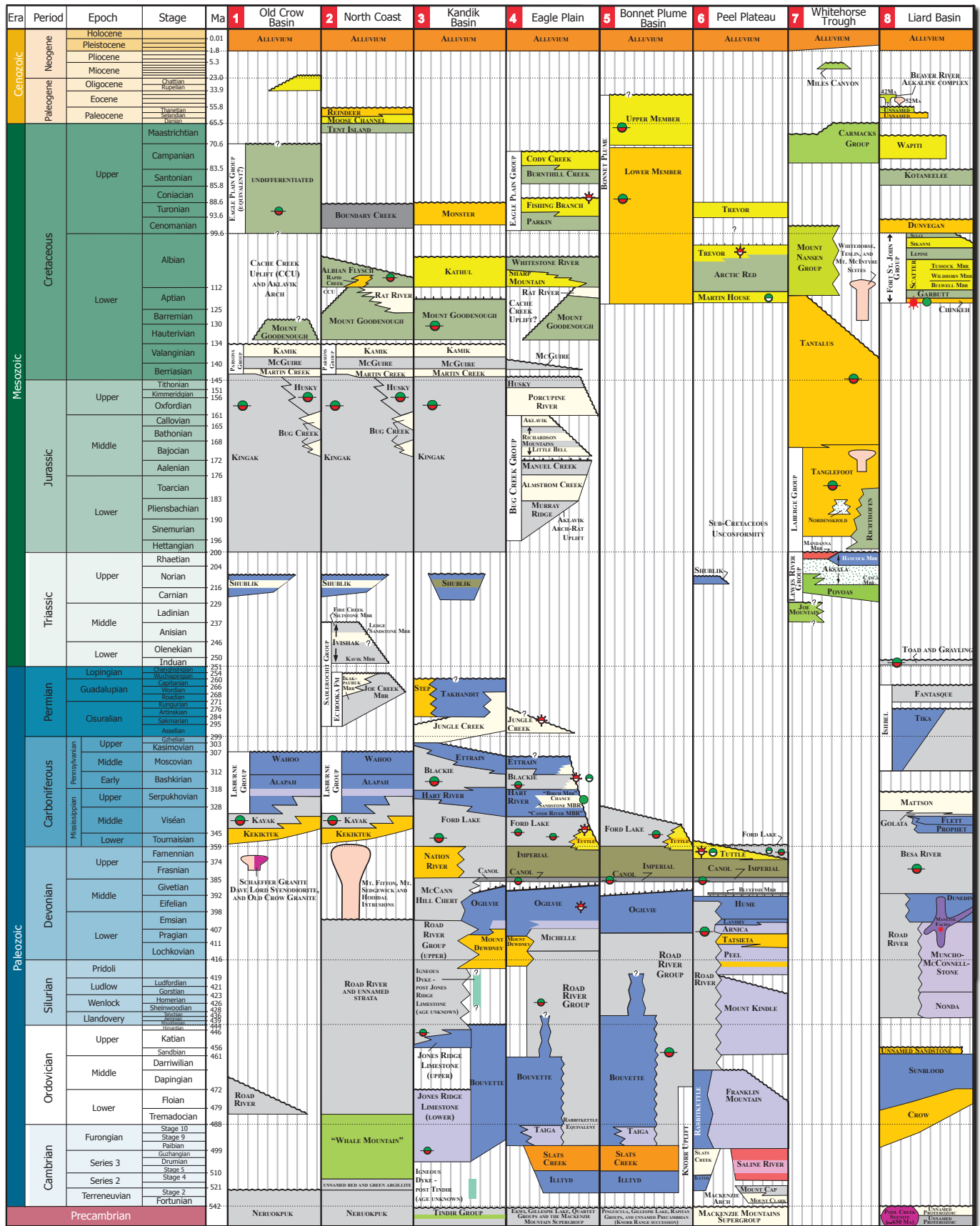


Figure 15. Table of formations, Yukon sedimentary basins (from Pigge, 2009). Oil shows are indicated in green, gas shows in red, and red and green circles denote potential source rocks.

The Liard, Eagle Plain, Peel, Bonnet Plume and Kandik basins lay on the margin of the North American craton through Paleozoic and early Mesozoic time. They share similar depositional histories, and their hydrocarbon prospectivity can be linked to a common regional stratigraphic succession. Yukon North Coast and Old Crow basins are successor basins, containing petroleum systems associated primarily with Mesozoic and younger strata (Department of Energy, Mines and Resources, 2011). Whitehorse trough is an intermontane basin, which evolved from a setting marginal to an active extending and uplifting volcanic arc to an involved foreland basin receiving detritus from oceanic allochthons advancing from the northeast (present coordinates). Thus, its stratigraphy and prospectivity is unlike the other basins.

Elements of petroleum systems exist outside these present-day basins; for example, the Selwyn Basin was a major Paleozoic structural element on the western flank of North America, in which basinal shales (Road River Group) accumulated through much of early Paleozoic time. Road River strata are considered to be prospective in the present-day Liard and Peel Plateau basins, but not in the present-day Mackenzie Mountains. Intense deformation and exposure of most prospective conventional reservoirs has discouraged exploration, and hence limited data are available.

Natural gas is currently produced in Yukon only from the Kotaneelee Field in Liard Basin. While limited hydrocarbon exploration has taken place throughout the territory, there have been only a few discoveries, and some of the basins remain undrilled. Most have been assessed for conventional hydrocarbon resources, but no systematic assessments of unconventional prospectivity have been completed.

Following an overview of Phanerozoic deposition to establish regional context, we will address each basin in turn, outlining the basic elements of petroleum geology, and assessing unconventional prospectivity – coalbed methane, tight reservoirs, and shale reservoirs.

Depositional Overview of the Laurentian Margin

Proterozoic rocks in northern Canada are not generally regarded as prospective for hydrocarbons, as they exhibit poor reservoir quality and lack associated source rocks (Dixon *et al.*, 2007). Our review thus begins with the lower Paleozoic (Cambrian) section.

Early to middle Cambrian transgression caused widespread shallow to restricted marine deposition over much of northern Canada, although few Cambrian rocks are preserved over highlands such as the Peel and Mackenzie arches, which underlie present-day Peel Plain and Plateau (Fig. 16). To the west, however, deeper marine strata were laid down in the Richardson Trough, on the eastern flank of Eagle Plain Basin (Illtyd and Slats Creek formations), and in Selwyn Basin to the south (upper Hyland Group and Gull Lake Formation). Continued marine transgression established a widespread carbonate platform during the Ordovician and Silurian (Franklin Mountain / Mount Kindle carbonates) which extended from Peel Plain and Plateau, into Northwest Territories. Most of Yukon lay south and west of a clearly-defined and long-lived (throughout the lower Paleozoic) platform to basin transition, documented in the uppermost sheets of the Selwyn and Mackenzie fold and thrust belts. These areas therefore experienced coeval deeper-water sedimentation in Richardson Trough (Road River Group) and Selwyn Basin (Rabbitkettle Formation and Road River Group) (Fig. 17). Platform carbonates also accumulated in northwest Yukon (Eagle Plain and Kandik Basins), but are not adequately shown on the figure 17 reconstruction (see discussions below and Fig. 15). Deep-water deposition continued in the west during late Silurian to Devonian time, when regression led to a depositional hiatus on the platform.

Widespread carbonate deposition was re-established during Early Devonian transgression over the eastern platform and western Dave Lord High (Delorme assemblage), while basinal Road River shales and cherts

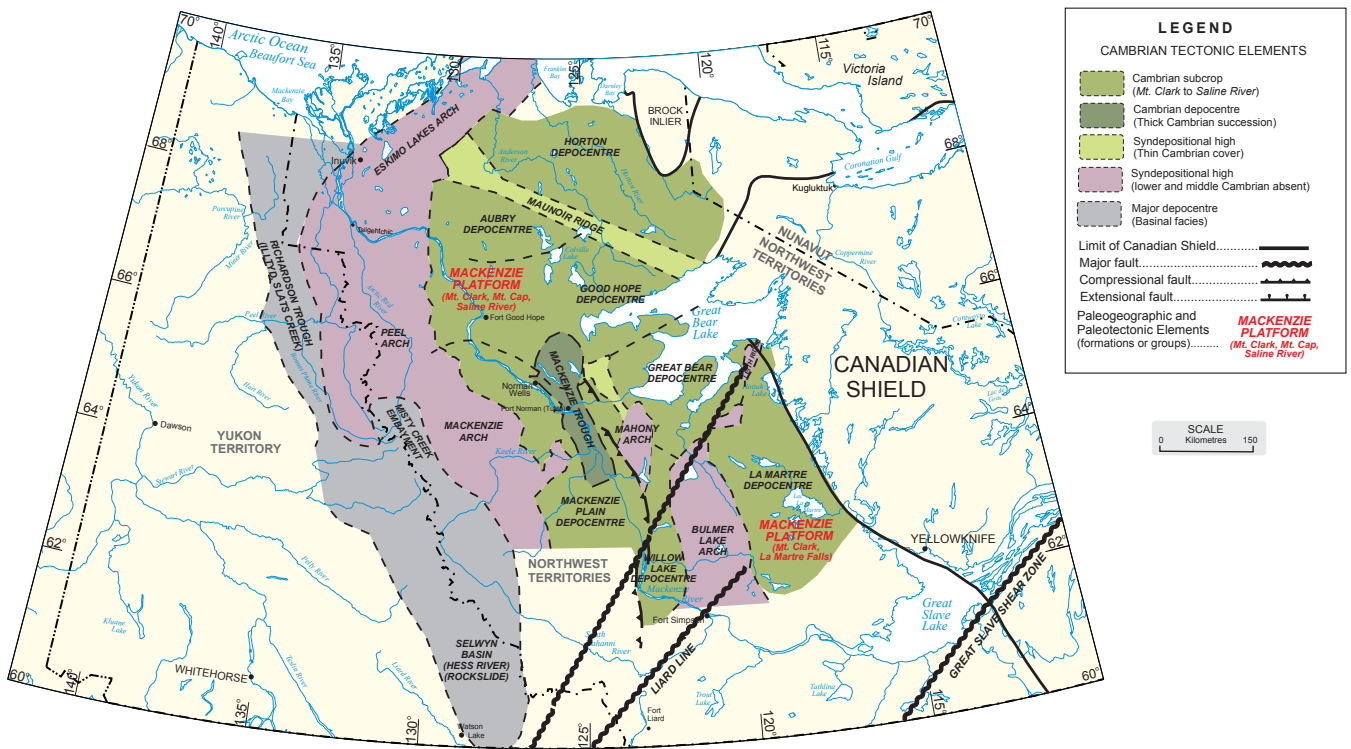


Figure 16. Cambrian paleogeography, northern Canada (from Hannigan et. al., 2011).

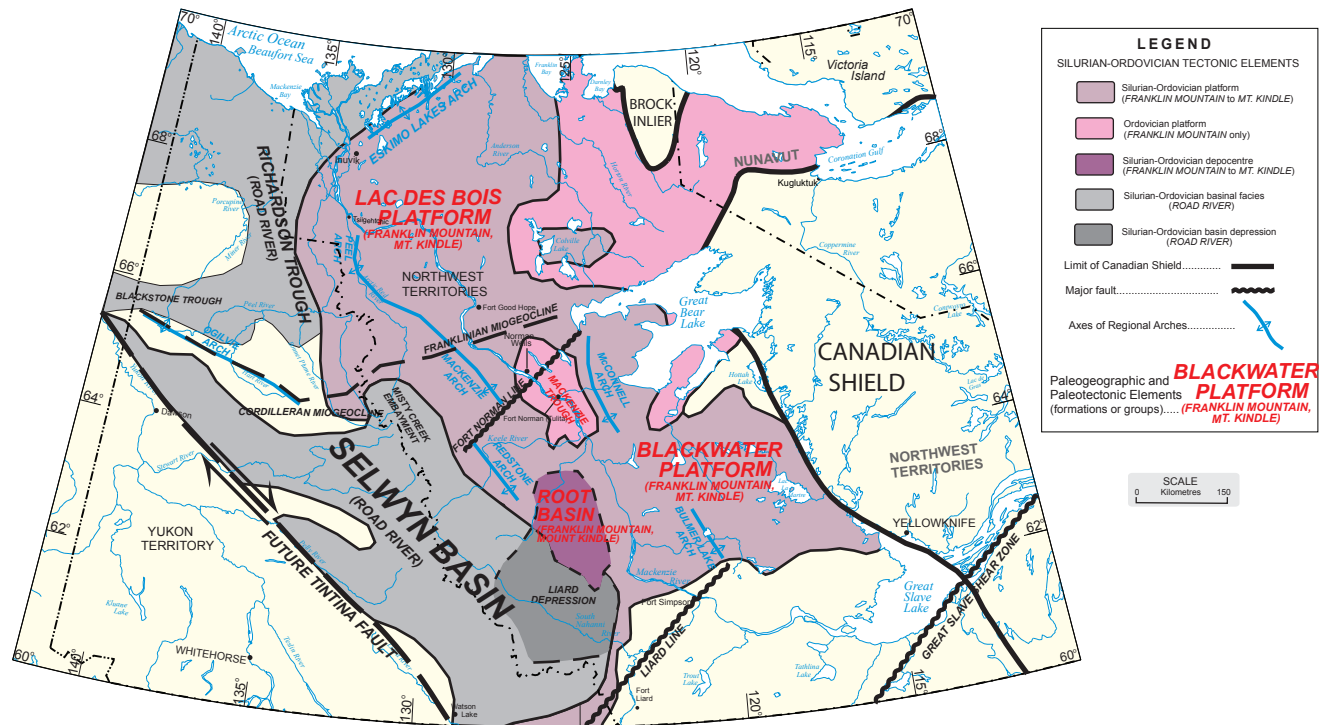


Figure 17. Ordovician / Silurian (Franklin Mountain – Mount Kindle) paleogeography, northern Canada (from Hannigan et. al., 2011).

continued to accumulate in trough areas (Fig. 18). During the next transgressive-regressive cycle (Late Early to Early Middle Devonian), the westerly Porcupine Platform became a major depository, where platform carbonates of the Ogilvie Formation accumulated while the Bear Rock carbonate assemblage was deposited on the eastern craton (Fig. 19). Sedimentation patterns in Yukon were very similar during

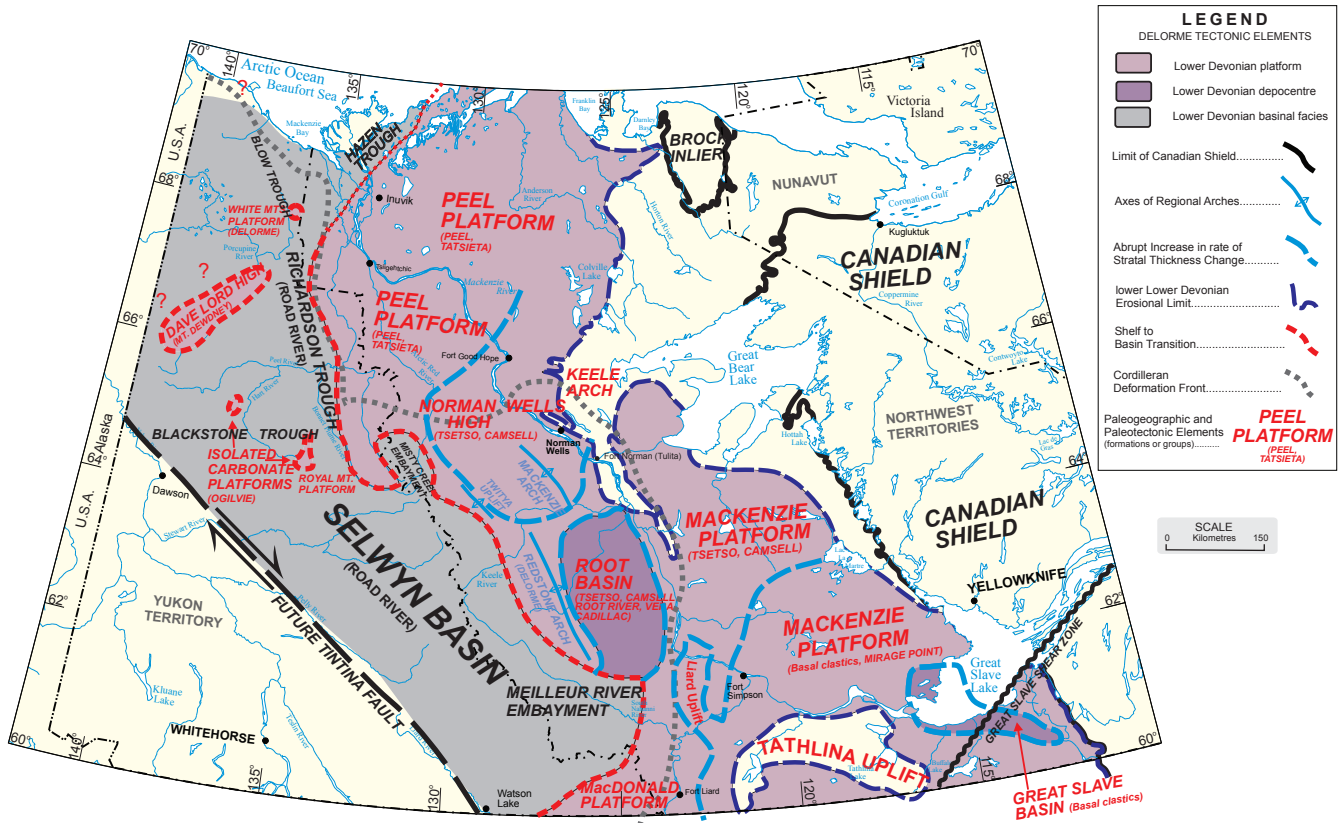


Figure 18. Late Silurian – Early Devonian (Delorme assemblage) paleogeography, northern Canada (from Hannigan et. al., 2011).

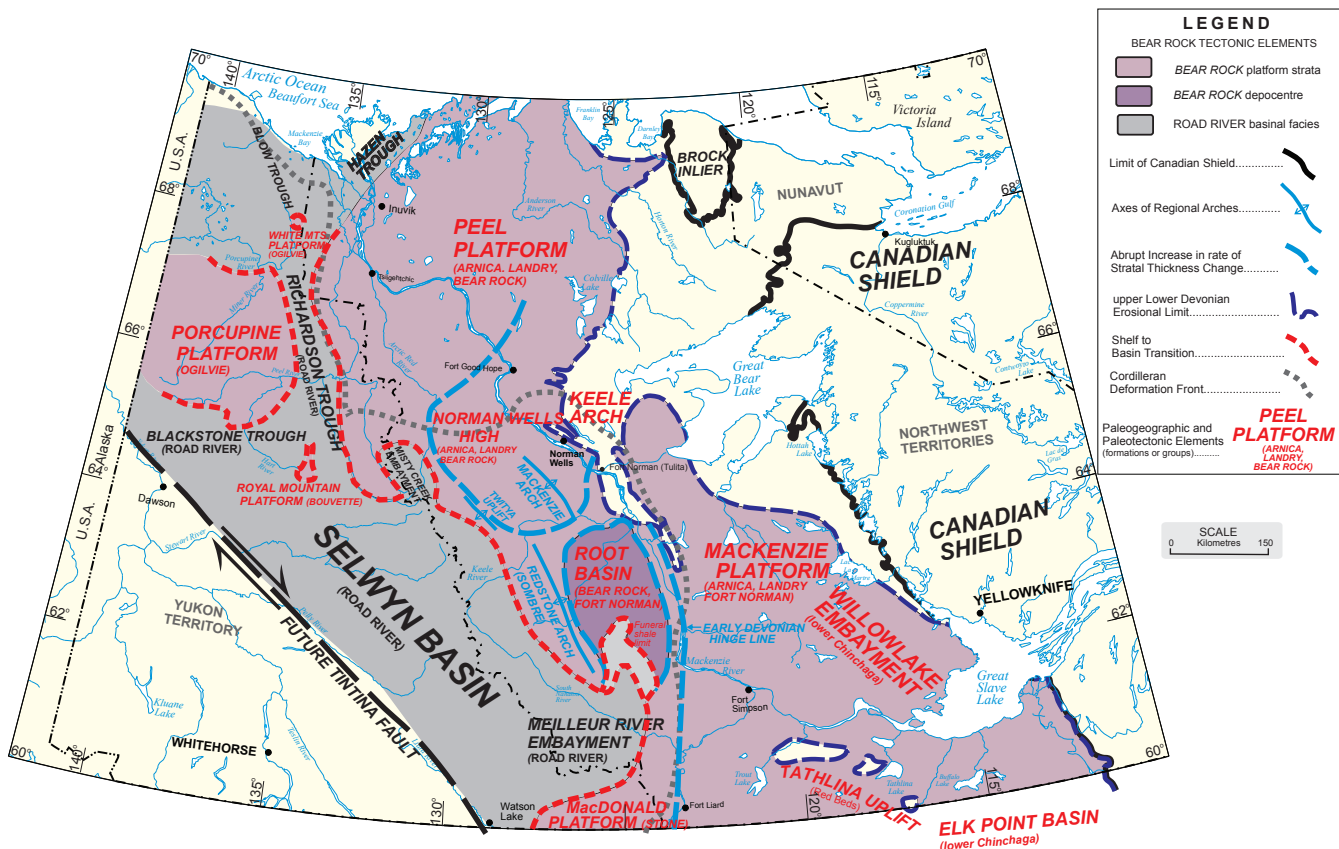


Figure 19. Early Devonian (Bear Rock assemblage) paleogeography, northern Canada (from Hannigan et. al., 2011).

the following depositional cycle, which laid down the Middle Devonian Hume – Lonely Bay assemblage (Fig. 20). During latest Middle to Late Devonian time, however, waters over the platform deepened as the Horn River Group was deposited, capped by Ramparts Formation carbonates to the east (Fig. 21). Over most of Yukon during this time period, distal, organic-rich shales of the Canol Formation and coeval cherts and shales of the Earn Group were deposited in basinal settings, engendered by rifting within the continental margin.

Latest Devonian time saw the progradation of clastic sediments from the north and northwest, sourcing coarsening- and sandier-upwards successions of the Imperial Formation in northern areas (Fig. 22). Progradation continued in the northeast, where sandstones of the Tuttle Formation were laid down in Early Carboniferous time in Peel Plateau and Plain and Eagle Plain regions. Westward and outboard of the Tuttle clastic wedge, a thick section of marine shales and carbonates accumulated throughout most of the rest of Carboniferous time in the craton-margin Prophet Trough, now preserved in Eagle Plain, Kandik and Old Crow basins (Fig. 23). To the south in Liard Basin, basinal shales of the Besa River Formation gave way to platform carbonate deposition in middle Early Carboniferous time. Thick fluvial-deltaic Mattson Formation clastics accumulated at the edge of the Prophet Trough in the late Early Carboniferous (Fig. 23); Richards *et al.* (1993) interpreted a northerly provenance for these sediments, but direct evidence has been removed, as Carboniferous strata have been eroded to the north of Liard Basin. In the Permian, deposition of marine supratidal to basinal, locally cherty siliciclastics and silty to sandy carbonates continued in western areas, where the Ishbel Trough succeeded the Prophet Trough of Carboniferous time.

Evidence of Triassic deposition in Yukon is somewhat fragmental. In the north (Old Crow, Kandik, Peel Plateau, and Beaufort-Mackenzie basins), Norris (1996b) interpreted deposition to have occurred in shoreline to basinal settings which prograded across a low-relief unconformity. Nearshore facies range from basal conglomerates through limestones, sandstones and siltstones, and are generally found in the east. Westward, basinal facies comprise black argillaceous limestones and calcareous shales with dark grey siltstones. In southeastern Yukon, thick marine siltstones and shales of the Toad-Grayling Formation, largely equivalent to the Montney Formation in Alberta and BC, are preserved in Liard Basin.

During Jurassic time, much of the northern North American craton was emergent, but on its northwestern flank in Yukon, a series of southeasterly-sourced clastic wedges prograded northwestward to finer-grained basinal clastic strata (Poulton *et al.*, 1993; Poulton, 1996) (Figs. 24, 25). Proximal clastics are preserved in northernmost Peel Plateau and Eagle Plain Basin, while the shale-dominated Kingak Formation is found in Kandik, Old Crow and North Coast basins. No Jurassic strata are preserved in southern portions of Eagle Plain and Peel Plateau, or in Bonnet Plume and Liard basins.

Lower Cretaceous strata were deposited as shoreline to shelfal sediments, dominated by sandstones along eastern to southeastern source areas, and becoming shalier northwestward (Fig. 26; Dixon, 1996). Shales of the Mount Goodenough Formation dominate the Lower Cretaceous section in Eagle Plain, Kandik, Old Crow, and North Coast basins, while more proximal strata were deposited to the east. A significant regional unconformity separates Lower and Upper Cretaceous strata, reflecting the development of a foreland basin outboard of the Cordilleran Orogen rising to the south. Upper Cretaceous strata were deposited in northerly-prograding transgressive / regressive cycles in the shallow foreland basin (Fig. 27; Dixon, 1996). Coarser clastics characterize southerly basins – *e.g.*, Bonnet Plume Formation in Bonnet Plume Basin, and Monster Formation in Kandik Basin – while finer-grained clastics are found to the north, such as the Eagle Plain Group of Eagle Plain and Old Crow basins. In Liard Basin, Early Cretaceous transgression resulted in deposition of Chinkeh basal sandstones, followed by the shale-dominated marine Fort St. John shale section (Stott, 1982).

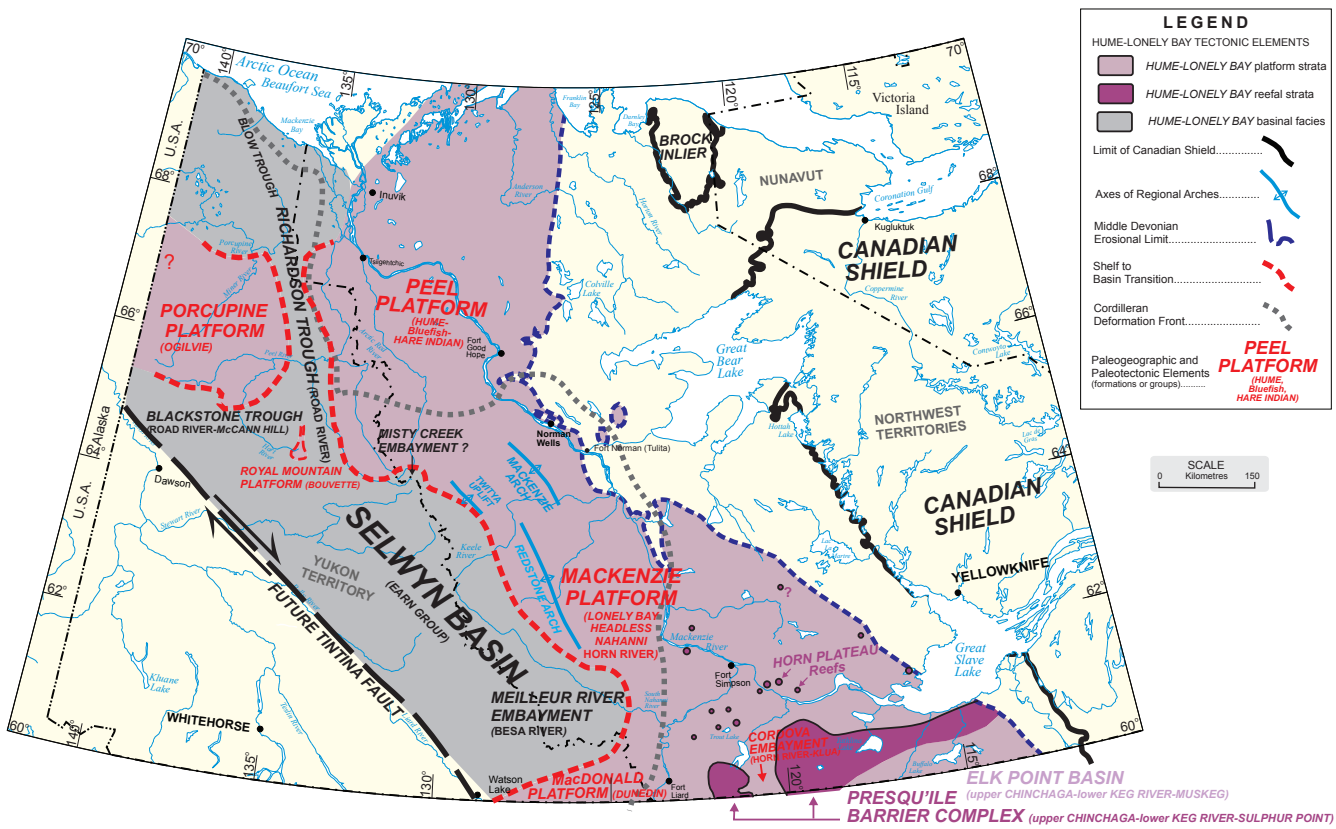


Figure 20. Middle Devonian (Hume – Lonely Bay assemblage) paleogeography, northern Canada (from Hannigan et. al., 2011).

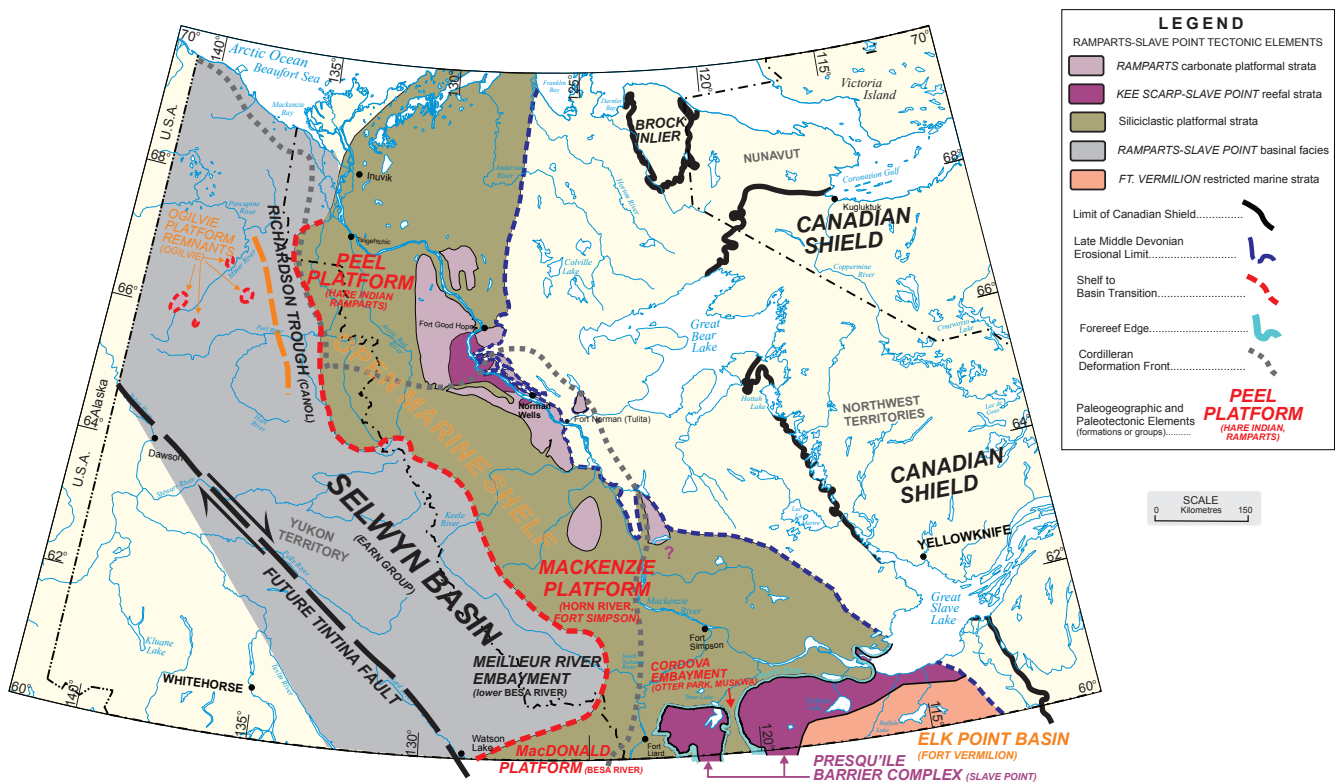


Figure 21. Middle to Late Devonian (Ramparts – Slave Point assemblage) paleogeography, northern Canada (from Hannigan et. al., 2011).

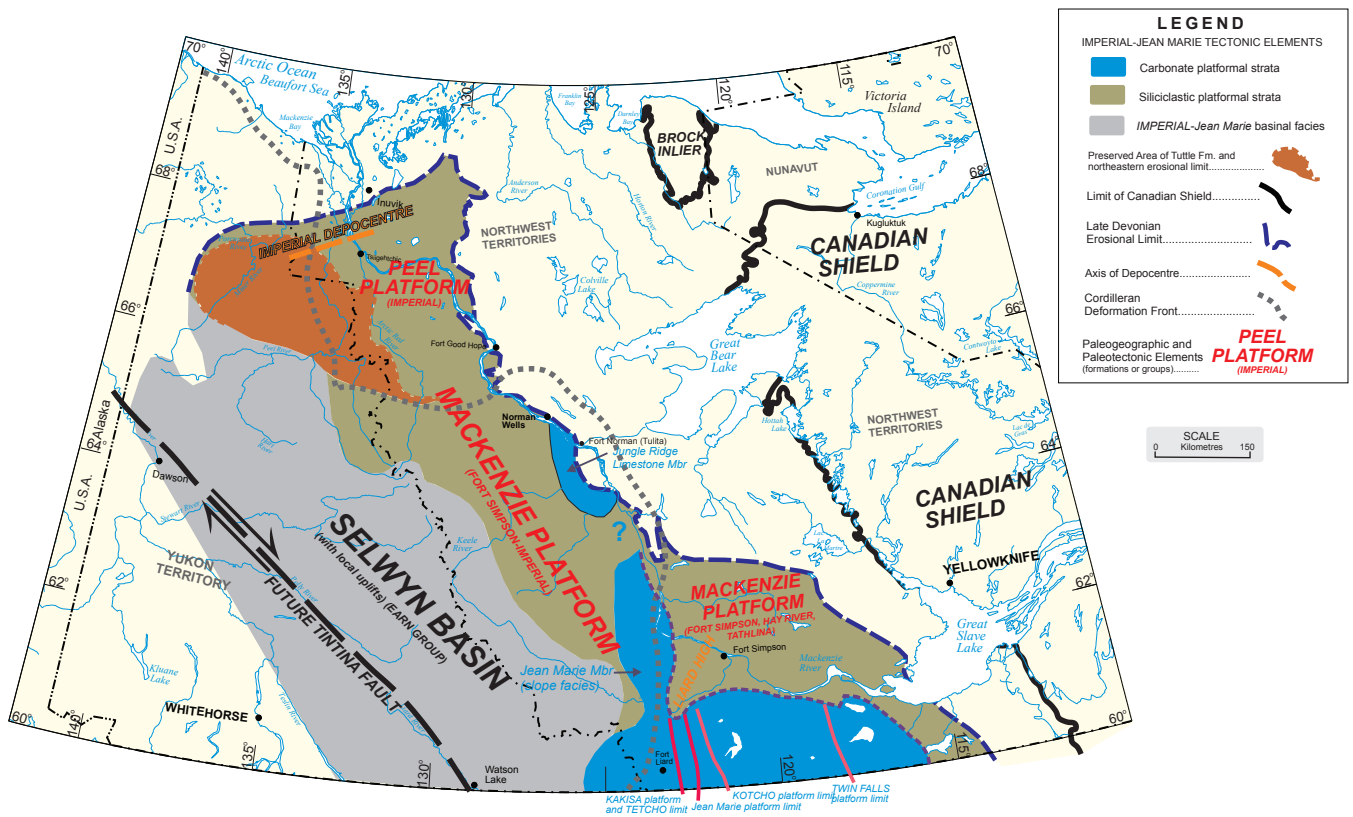


Figure 22. Late Devonian (Imperial assemblage) paleogeography, northern Canada (from Hannigan et. al., 2011).

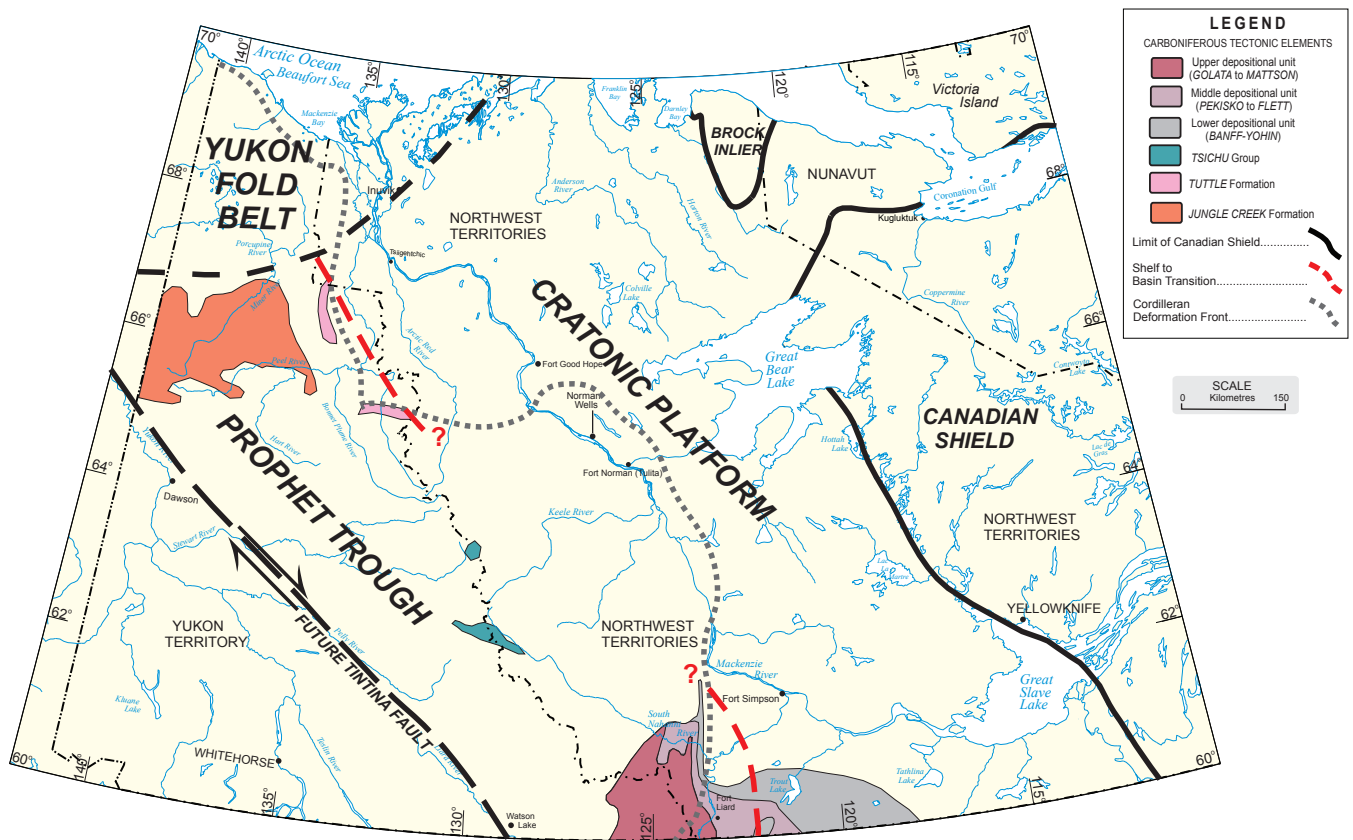
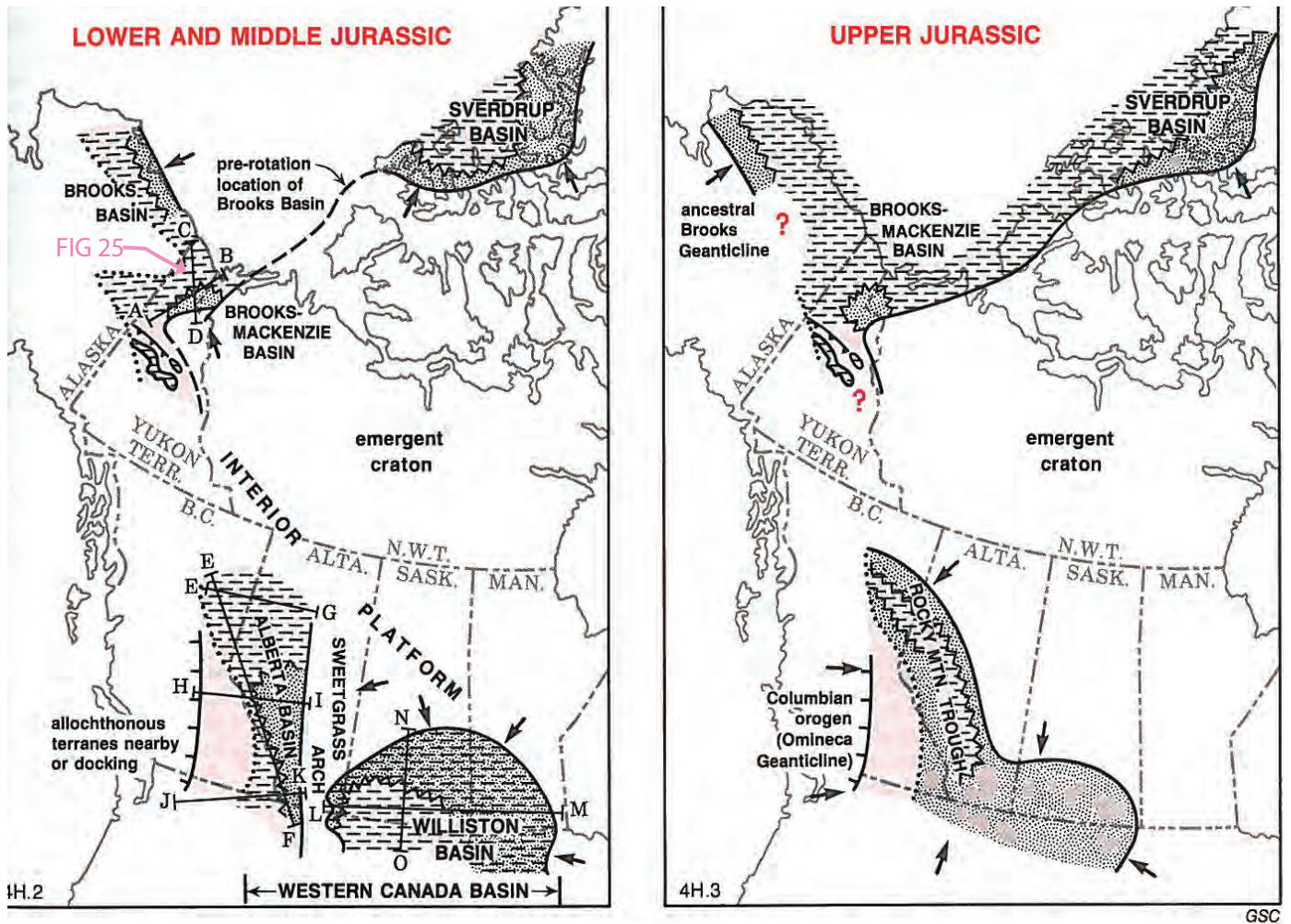


Figure 23. Subcrop map of Carboniferous units with major tectonic elements, northern Canada (from Hannigan et. al., 2011).



LEGEND











-  Mainly arenaceous facies
-  Mixed facies
-  Mainly argillaceous facies
- Facies change 
- Direction of sediment transport 
- Lines of cross-sections 
- Shorelines (approximate, assumed) 
- Palinspastically restored western limit of epicratonic Jurassic rocks 
- Present western limit of epicratonic Jurassic rocks 
- Dawson Thrust Fault 

Figure 24. Jurassic paleogeography, northern Canada (from Poulton et. al., 1993). C-D is Figure 25 line of section.

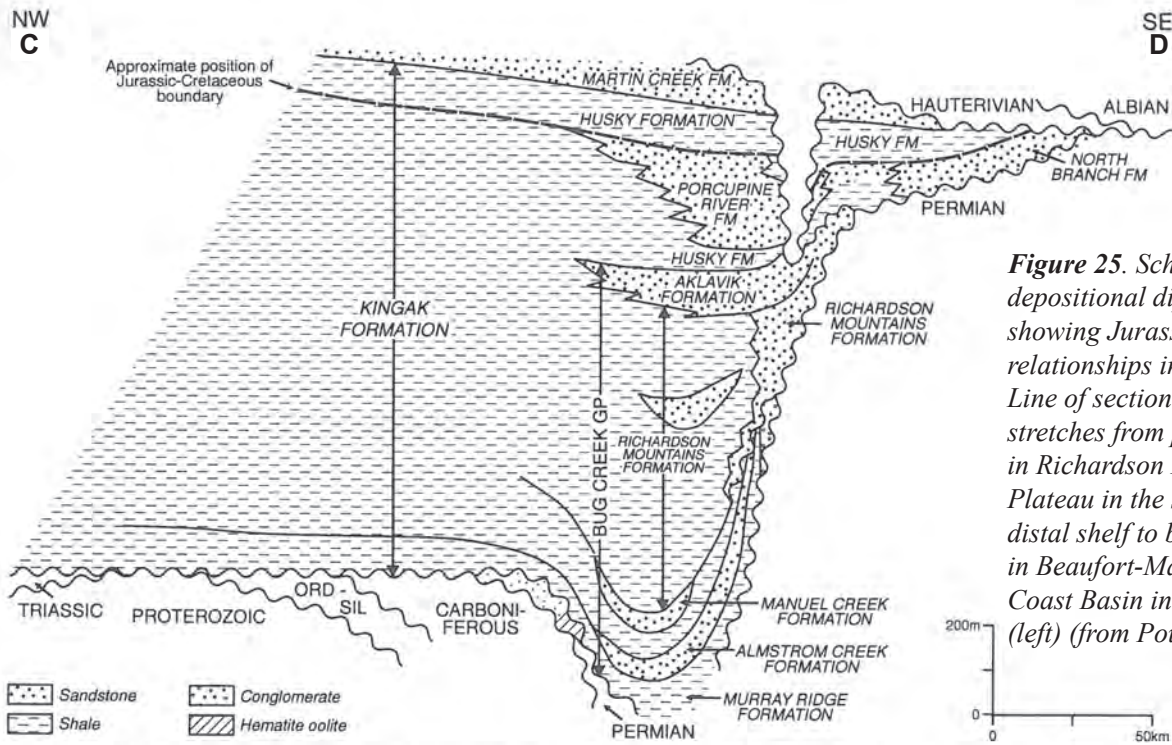


Figure 25. Schematic depositional dip cross section showing Jurassic facies relationships in northern Yukon. Line of section (shown in Fig. 24) stretches from proximal settings in Richardson Mountains / Peel Plateau in the southeast (right) to distal shelf to basin environments in Beaufort-Mackenzie/North Coast Basin in the northwest (left) (from Poulton et al., 1993).

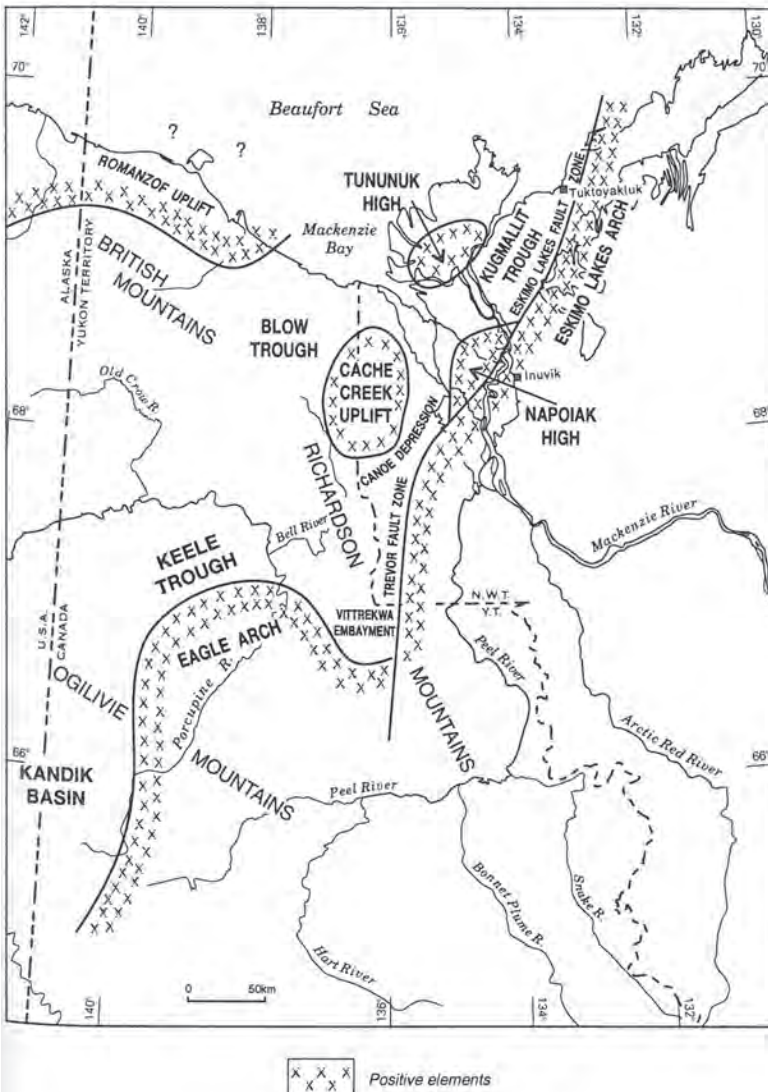


Figure 26. Early Cretaceous tectonic elements (from Dixon, 1996).

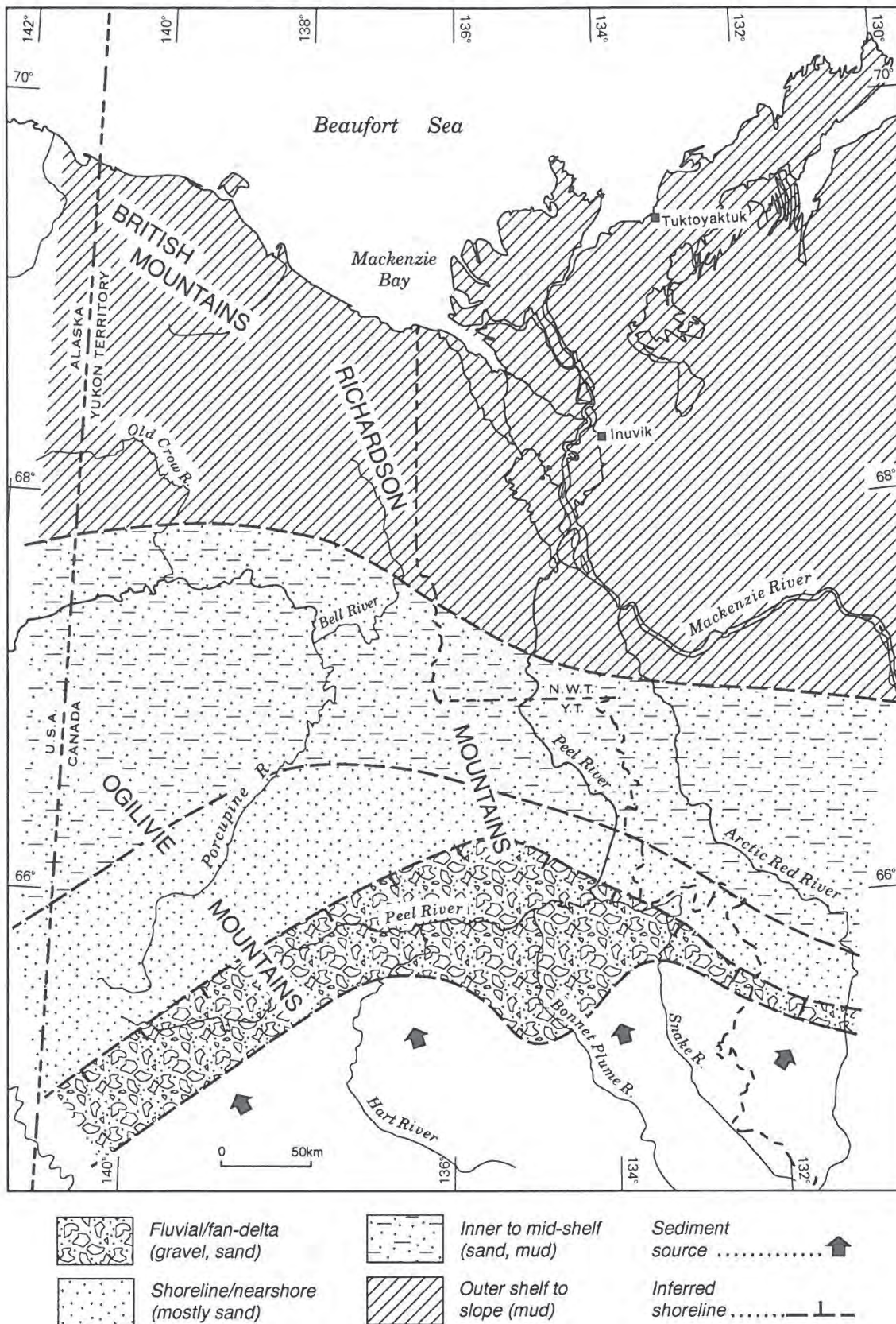


Figure 27. Late Cretaceous tectonic elements (from Dixon, 1996).

Liard Basin

Liard Basin lies in southeastern-most Yukon, and is a northern extension of the Western Canada Sedimentary Basin, straddling the British Columbia and Northwest Territories borders (Fig. 14). It includes the physiographic Liard Plateau and portions of the southern Mackenzie and Franklin Mountains, and thus is characterized by north-south trending thin-skinned folds and thrust faults (Fig. 28). It is bounded to the east (in NWT) by the Bovie Fault Zone, and to the northwest, west, and southwest by large thrust faults bringing early Paleozoic or older strata to surface.

The sedimentary section thickens markedly from east to west in Liard Basin, to several thousand metres, reflecting passage from limited accommodation space on the craton to the east, to much greater accommodation space in westerly depositional troughs (during Paleozoic time) and the Cordilleran foredeep (during Jurassic / Cretaceous time; Fig. 29).

Exploration History and Conventional Hydrocarbon Resources

Exploration of Liard Basin began in 1955 with reconnaissance field work by California Standard (later Chevron). Several large anticlines were recognized as prospective traps, and lands were permitted in BC, NWT and Yukon. Drilling began in BC in 1957, and the first well was a multizone gas discovery on the Beaver River structure. The first well in Yukon, SOBC Shell Beavercrow YT K-02 (Unique Well Identifier (UWI) 300K026010125000), was drilled in 1963. To date, 13 wells have been completed in the Yukon portion of Liard Basin (the most recent in 2005), and 570 km of 2D seismic data have been acquired. Portions of three fields – Beaver River, Kotaneelee, and La Biche – lie within Yukon, and Kotaneelee is still producing gas (Fig. 28; NEB, 2001a; Department of Energy, Mines and Resources, 2011). Although there has been little activity in Liard Basin in Yukon recently, substantial acreage was purchased at Crown land sales during 2008 to 2010 in the British Columbia portion of the Liard Basin (www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/ShaleGas/Pages/default.aspx), and Lone Pine Resources has promoted Muskwa shale gas prospectivity in the NWT Liard Basin, immediately east of the Yukon border (Daily Oil Bulletin, 2011; <http://phx.corporate-ir.net/phoenix.zhtml?c=242054&p=irol-presentations>).

Discovered hydrocarbon resources have been estimated for only one play in Yukon Liard Basin – the Manetoe facies dolomite. Totals for this play are $44.1 \times 10^9 \text{m}^3$ (1.56 TCF) gas in place, and $14.0 \times 10^9 \text{m}^3$ (0.495 TCF) initial marketable gas, while in Yukon alone, estimates are $14.2 \times 10^9 \text{m}^3$ (0.503 TCF) gas in place, and $5.18 \times 10^9 \text{m}^3$ (0.184 TCF) initial marketable gas (NEB, 2001a).

NEB (2001a) assessed six conventional petroleum plays in the Yukon Liard Basin; all are immature (*i.e.*, proven to exist, but with no established discoveries) except the Manetoe play noted above. The mean total resource potential for all plays, calculated on a probabilistic basis, are $56.3 \times 10^9 \text{m}^3$ (1.99 TCF) initial marketable gas and $0.002 \times 10^6 \text{m}^3$ (0.015 million barrels) initial marketable oil.

Unconventional Hydrocarbon Resource Potential

Very limited well control and complex structure make it difficult to assess unconventional hydrocarbon resource potential in Liard Basin. Unconventional reservoir characteristics can be extrapolated from areas to the south and east with better well control, but reservoir continuity and integrity cannot be mapped with certainty, and thus present major risks to resource potential and exploitation.

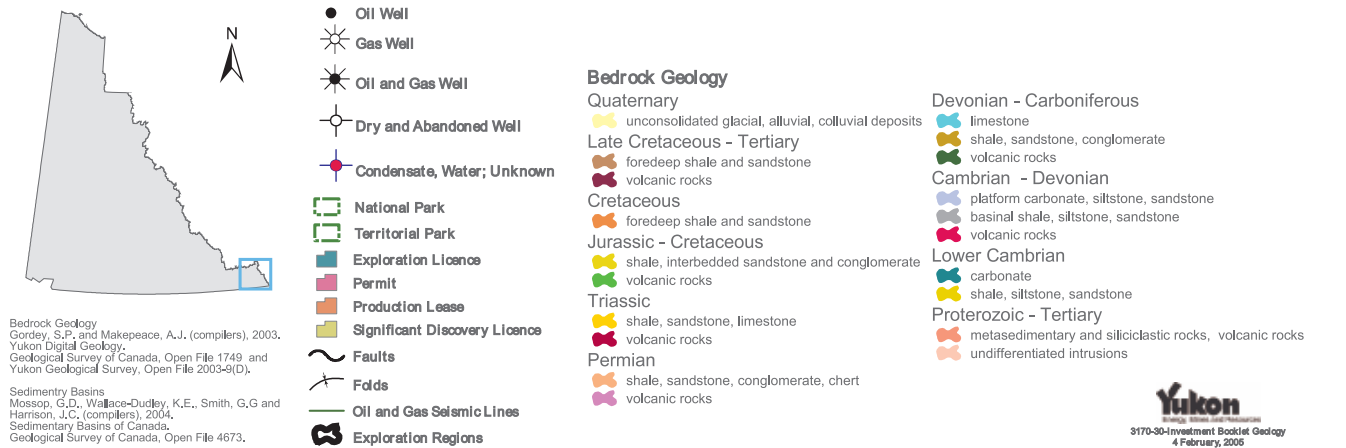
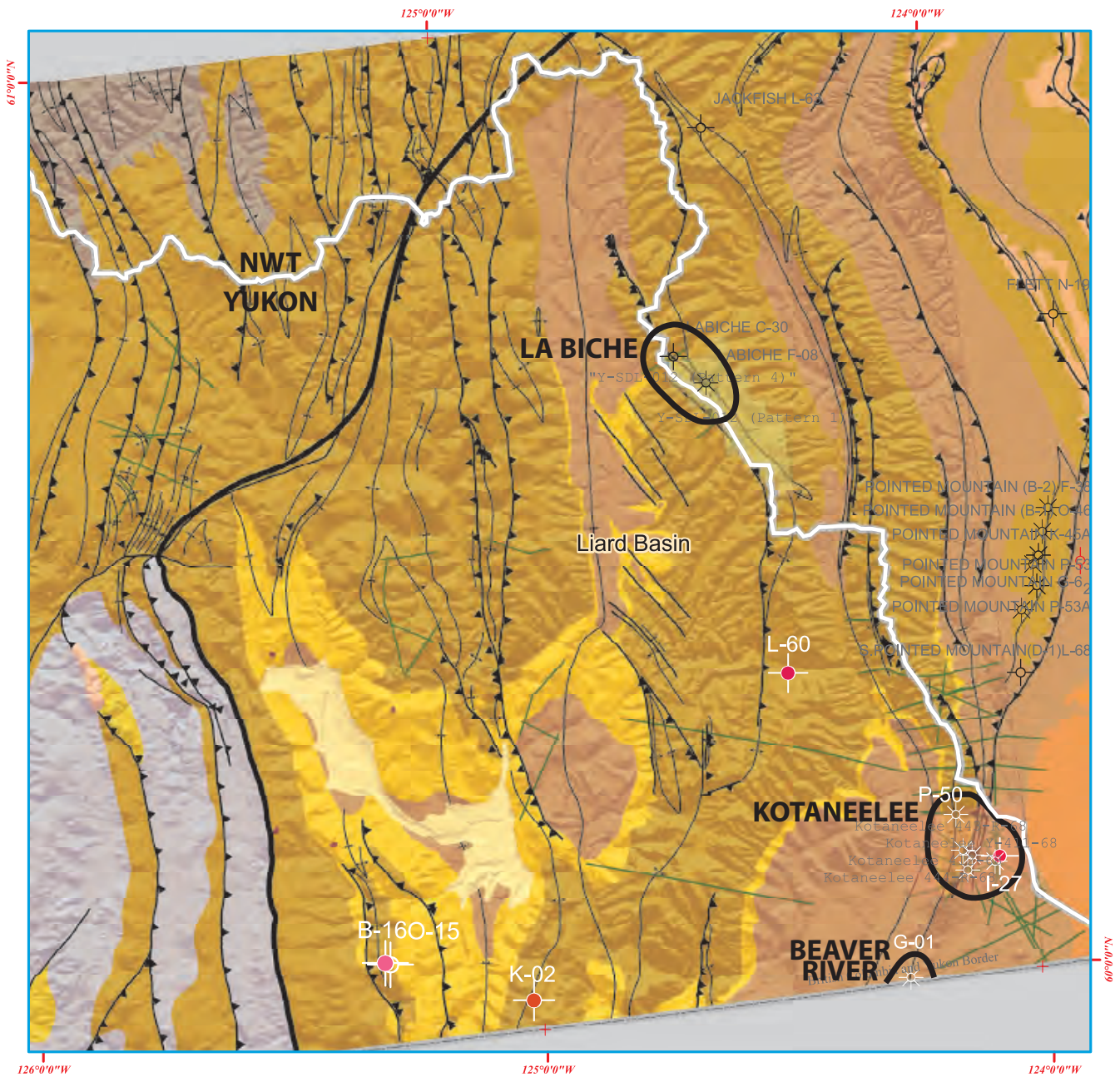


Figure 28. Simplified geological map of Liard Basin, showing well locations and some 2D seismic data (from Department of Energy, Mines and Resources, 2011).

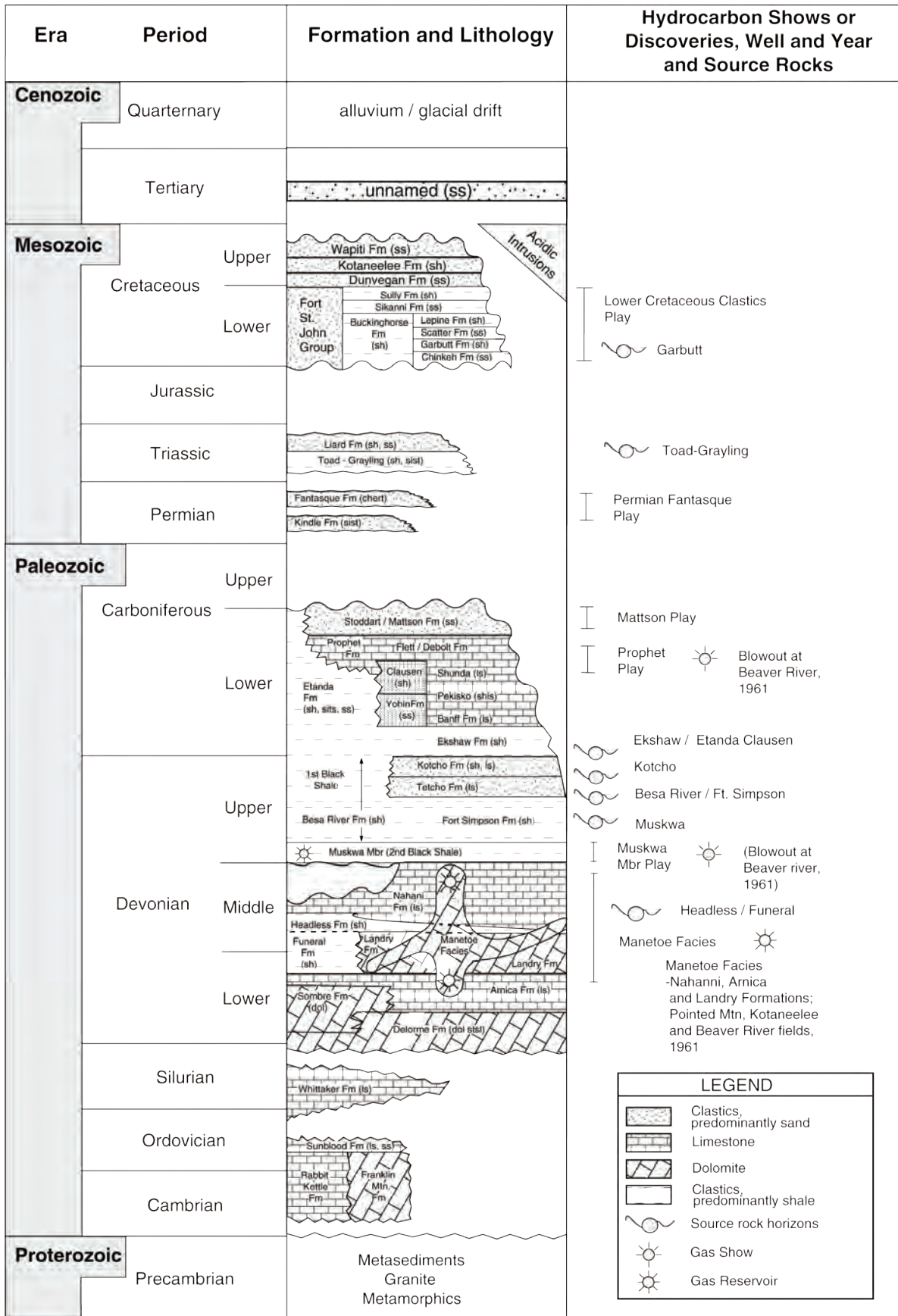


Figure 29. Stratigraphic column, Liard Basin (from NEB, 2001a).

Coalbed Methane

Coal occurs in both the Upper Cretaceous Wapiti Group and in the Lower Carboniferous Mattson Formation at and adjacent to the northern Rocky Mountains – Mackenzie Mountains deformation front in Liard Basin (Fig. 29).

Wapiti coals are sub-bituminous, and occur in thin seams up to 0.4 m thick at surface and shallow depths (Cameron, 1993). Mattson coals are high-volatile bituminous B rank, with low ash and moisture contents (Potter *et al.*, 1993). Deltaic to marginal marine Mattson Formation strata are up to 1410 m thick, and crop out extensively through the area. Coals range from 0.3 m to 1.5 m thick, and occur primarily in the middle to upper Mattson; lateral continuity and systematic mapping of these coals has not been documented.

Thick Mattson Formation sections occur as deep as 2000 m in the subsurface of the Liard Basin, immediately east of the thrust belt in southeasternmost Yukon, southwesternmost Northwest Territories, and adjacent British Columbia (Monahan, 1999). Coal has been noted to occur in core, but no efforts to map thickness or continuity have been documented.

CBM resource potential may exist in Mattson coals of the Liard Basin, which exhibit appropriate composition and maturity in outcrop to the west. In order to quantify this potential, mapping work must be done to establish sufficient thicknesses and continuity at suitable depths in the subsurface.

Tight Reservoirs

Tight reservoir prospectivity in Yukon Liard Basin may occur in the Triassic and Cretaceous sections.

Triassic Montney siltstones in British Columbia and adjacent Alberta host one of the most active tight gas plays in North America today (Walsh *et al.*, 2006; Hayes, 2009). The Montney is preserved only in the WCSB foredeep, and pinches out to a subcrop edge well south of the NWT border. However, equivalent strata of the Toad and Grayling formations are preserved in Liard Basin, and thicken abruptly westward from the Bovie Fault Zone (Monahan, 1999). Utting *et al.* (2005) and Beranek *et al.* (2010) showed the Toad and Grayling Formations to extend northward into the Liard Plateau of southwestern Northwest Territories and adjacent Yukon, but their thickness and distribution are not well defined.

No work has been done to date to evaluate tight gas potential of the Toad-Grayling formations in Liard Basin. However, Toad-Grayling strata are comparable to the Montney in terms of depositional environment and lithological characteristics, and in parts of Liard Basin, they are buried beneath a thick section of Cretaceous shales, which would provide an effective top seal for a basin-centred gas accumulation. Utting *et al.* (2005) noted thermal alteration indices indicative of oil generation in samples from the Toad-Grayling within Liard Basin, and higher (gas-generative) values from outcrops 80 km to the west.

We conclude that the Triassic Toad-Grayling holds considerable tight gas potential within Liard Basin. Using the BC Montney play as a template, it should be possible to do considerable work on characterizing this potential, based on existing well control and outcrop work.

Cretaceous strata are buried up to 2000 metres or more in eastern Liard Basin, and are capped by a thick marine shale package, which provides both source and seal potential. Quartz arenites of the basal fluvial to marine Lower Cretaceous Chinkeh Formation can be mapped continuously throughout Liard Basin,

and in more isolated pods to the east and northeast (Leckie *et al.*, 1991). In B.C., the Chinkeh Formation hosts the Maxhamish Lake gas pool, which contained 327 BCF original gas in place, and has produced 188 BCF since 1991 (Fig. 30). Modest reservoir quality, relatively low formation pressures, and no evidence of formation water production, suggest that this may be a basin-centred gas accumulation. Strategic Oil & Gas Ltd. has drilled two horizontal multi-frac oil wells on the western flank of the pool, and mapped an extensive oil fairway (>500 million barrels of oil in place), which fits well into the basin-centred concept (www.sogoil.com/en/investor/sog_corporate_20110214.pdf). PRCL (2009), reviewing formation test data in the NWT, mapped a regional aquifer in Chinkeh strata east of Liard Basin, but noted a subnormally pressured gas test at Fort Liard A-01, which may be linked to the Maxhamish Lake accumulation.

Further up section in the Cretaceous of Liard Basin, Scatter Formation sandstones form a westerly thickening wedge, encased within marine shales of the Garbutt and Lepine formations (Fig. 31).

Leckie and Potocki (1998) interpreted a shallow marine shelf to shoreface setting, in which moderately to poorly porous, glauconitic, lithic-rich sandstones with abundant clay matrix were deposited. The Scatter Formation crops out around the margins of Liard Basin, and thus is prospective only within the basin proper. Although Leckie and Potocki (1998) noted several gas shows on drillstem test, Hayes (2005) found no evidence of actual gas flows.

Tight gas and oil potential in Cretaceous strata of Liard Basin thus appears limited primarily to the Chinkeh Formation, in which a productive fairway may extend north from proven production at Maxhamish Lake. All the necessary components – low-permeability reservoir, source rocks, proven production, and regional seals – are present. Additional mapping and hydrogeological work can be

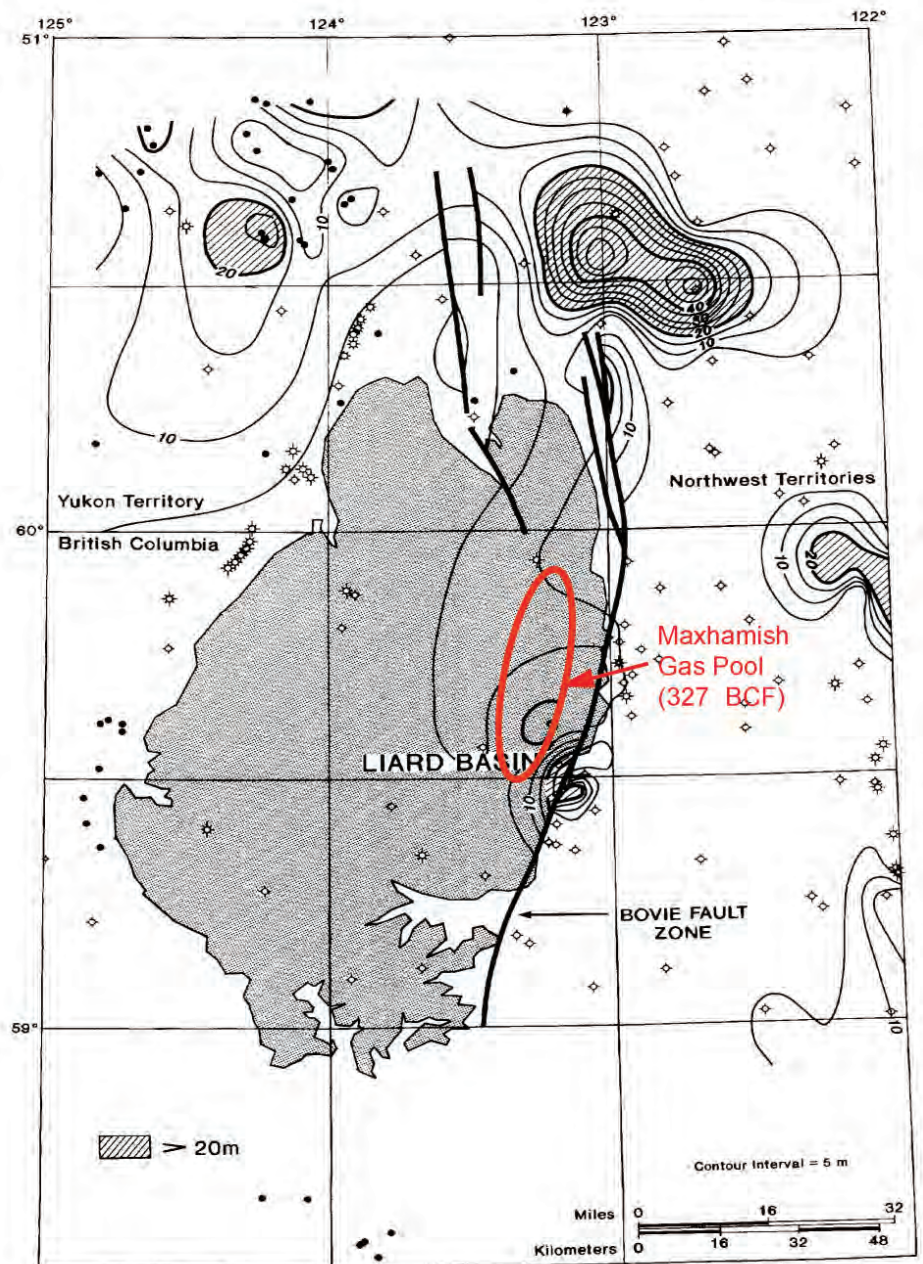


Figure 30. Isopach map of the Chinkeh Formation, incorporating both outcrop and well data. Red outline indicates approximate position of Maxhamish Lake Chinkeh gas pool (after Leckie *et al.*, 1991).

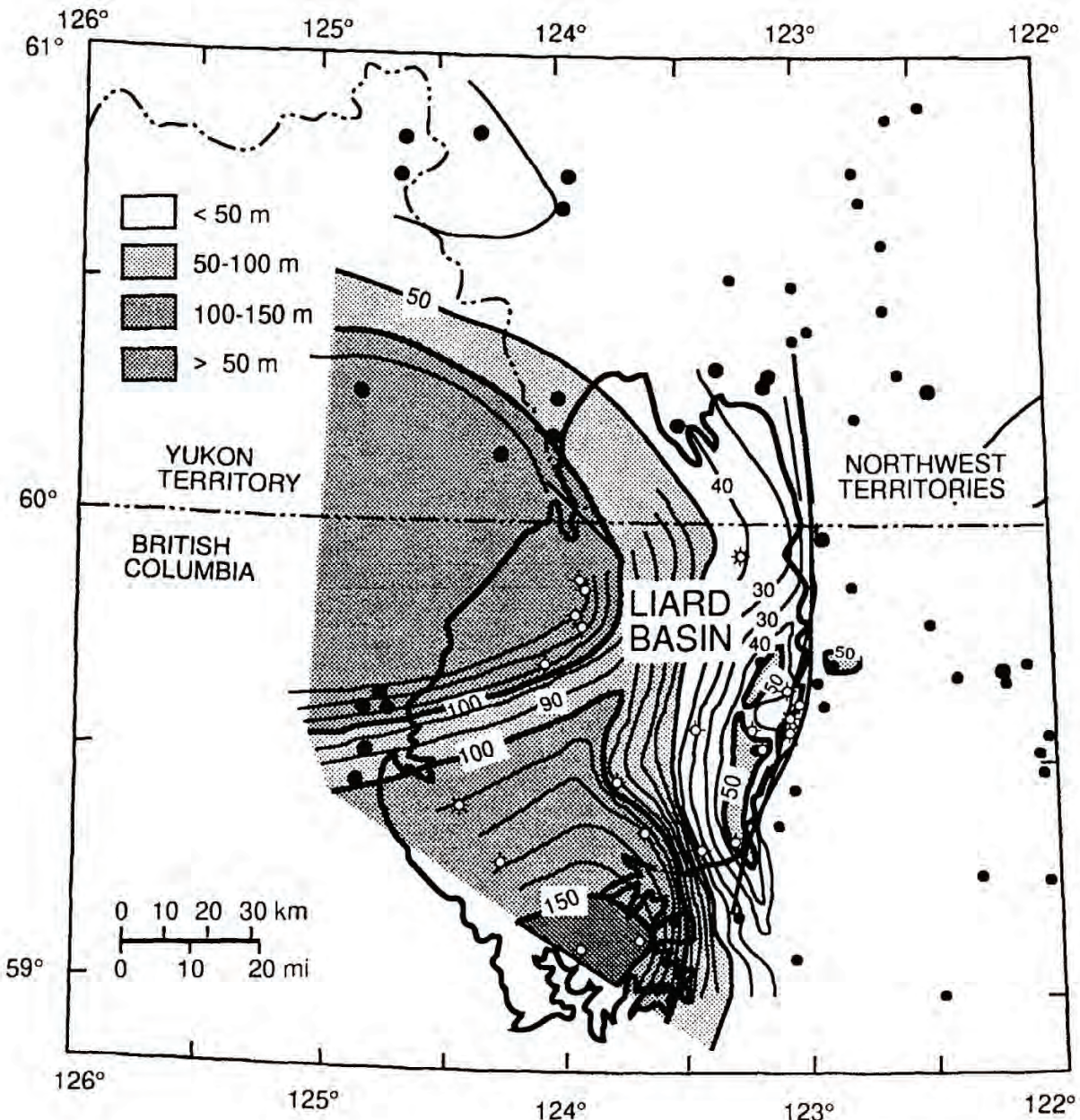


Figure 31. Net sandstone isopach map of the Scatter Formation. Open circles indicate subsurface (well) data, and filled circles outcrop data (from Leckie and Potocki, 1998).

undertaken on existing wells to better quantify this potential. Upsection, the Scatter Formation may also hold tight gas potential, but is limited by a small prospective area and shallow burial depths. Lithic, clay-rich sands would be less brittle than the Chinkeh quartz arenites, and may respond poorly to conventional stimulation techniques. A major risk in Yukon Liard Basin is the possibility of structural complexity and unroofing/exposure of the prospective sandstones.

Shale Reservoirs

Although well control is sparse in the Yukon Liard Basin, work in the BC and Northwest Territories portions of the basin has shed considerable light on shale prospectivity on the Yukon side. Potential exists in three units (from oldest to youngest):

- Funeral / Headless formations (Lower to Middle Devonian): these basinal shales are known primarily from outcrop, and were deposited in the Selwyn Basin outboard of Landry platform

carbonates of the Bear Rock Assemblage (Figs. 19, 29). Hayes (2011a) did not attempt to map them in Northwest Territories, as they were found difficult to correlate consistently on well logs. Little work has been done to characterize their geochemistry or maturity, although where they can be recognized on logs, high gamma log values suggest high total organic carbon content.

- Besa River / Muskwa / Exshaw formations (Upper Devonian through Carboniferous; Fig 32): the Upper Devonian Klua/Evie/Muskwa/Horn River shales are established gas producers in Horn River Basin of northeastern BC, southeast of Yukon Liard Basin (Fig. 12). Several companies have drilled horizontal wells with multi-frac stimulations to obtain high flow rates of dry gas with significant CO₂ content, as noted earlier in this report. These results are consistent with the work of Ross and Bustin (2008), who found the shale package to be organic-rich, mature for gas generation, and brittle (rich in silica).

Uphole, the uppermost Devonian/Lower Carboniferous Exshaw Formation tested high-liquids gas in 2011 from a BC Horn River Basin horizontal well drilled by Quicksilver Resources, although it had been expected that oil would be produced, based on mapping of thermal maturity values (Macedo, 2011b). Based on core samples from four wells in northeastern BC considerably south of the NWT border, CBM Solutions (2005) reported high TOC values, favourable geochemistry, and maturation levels in the dry gas generation window for the Exshaw Formation. Because of its thinness, however, Exshaw gas in place capacity was calculated at only 2-10 BCF/Section.

To the north of Horn River Basin, in southwestern Northwest Territories, Hayes (2011a) mapped favourable TOC and T_{max} parameters in the Klua/Muskwa/Horn River shale package. However, low S₂ values from Rock-Eval data are found in the west, toward Liard Basin, indicating the

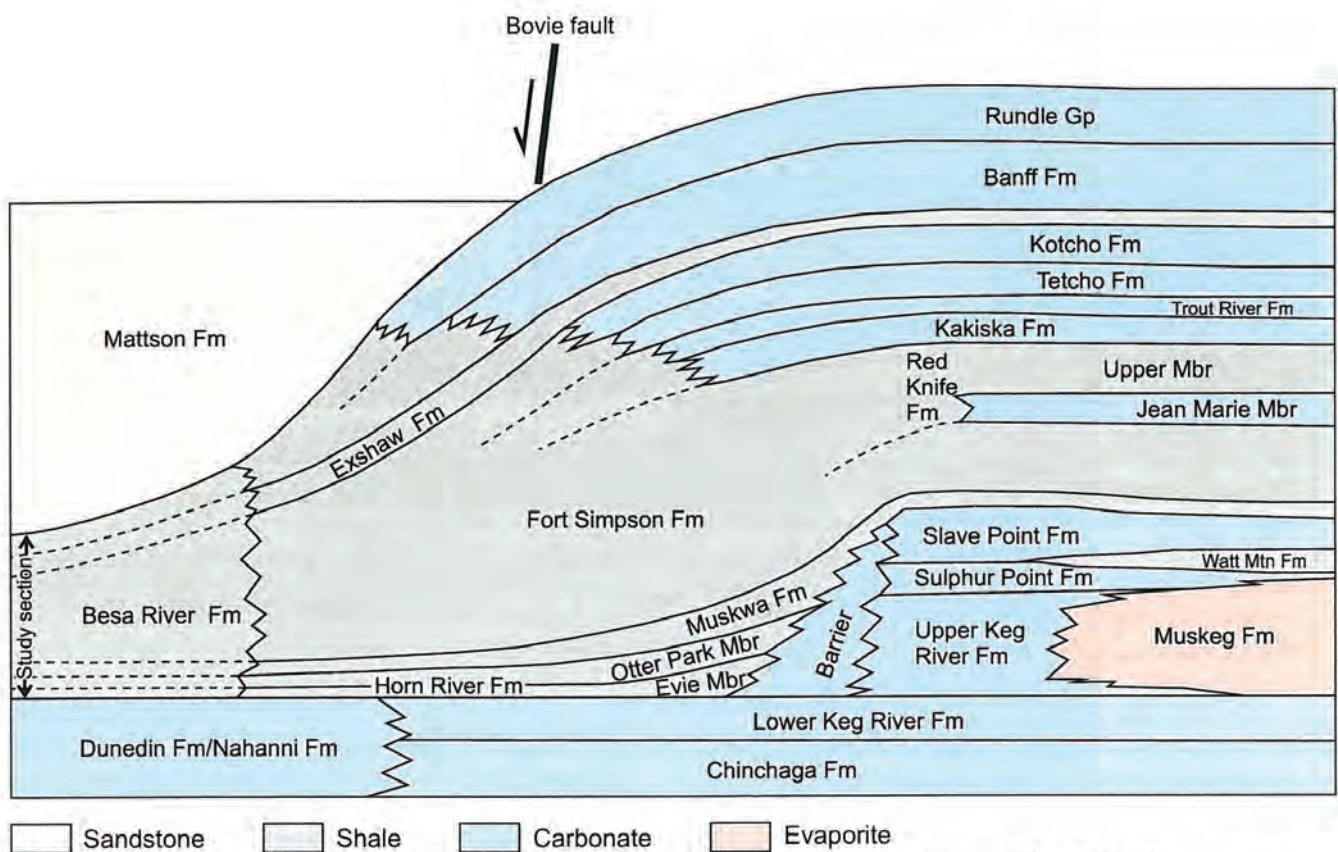


Figure 32. Schematic diagram showing shelf to basin middle to upper Paleozoic stratigraphic relationships between Liard Basin (west of Bovie Fault) and areas to the east (from Ferri et. al., 2011a).

rocks may be over-mature, and thus would have little remaining gas-generative capacity. Very limited data are available for the Exshaw in Northwest Territories, but it is organic-rich and mature for oil generation east of Liard Basin (Hayes, 2011a). Devonian shales have not been tested by horizontal wells in Northwest Territories to date, although Lone Pine Resources has plans to re-enter the Pointed Mountain L-68 well, just east of the Yukon border, to test the Muskwa, as noted above.

Moving westward into Liard Basin, the Devonian-Carboniferous carbonate shelf and shale succession passes into Besa River Formation shales (Figs. 20, 21, 22, 32). Ross and Bustin (2008) mapped very good shale gas potential in the Besa River, although their interpretations were extrapolated northward from well control in northeastern BC, and included only the southeasterly, undeformed portion of the basin (Fig. 33). They noted that adsorbed gas capacity generally

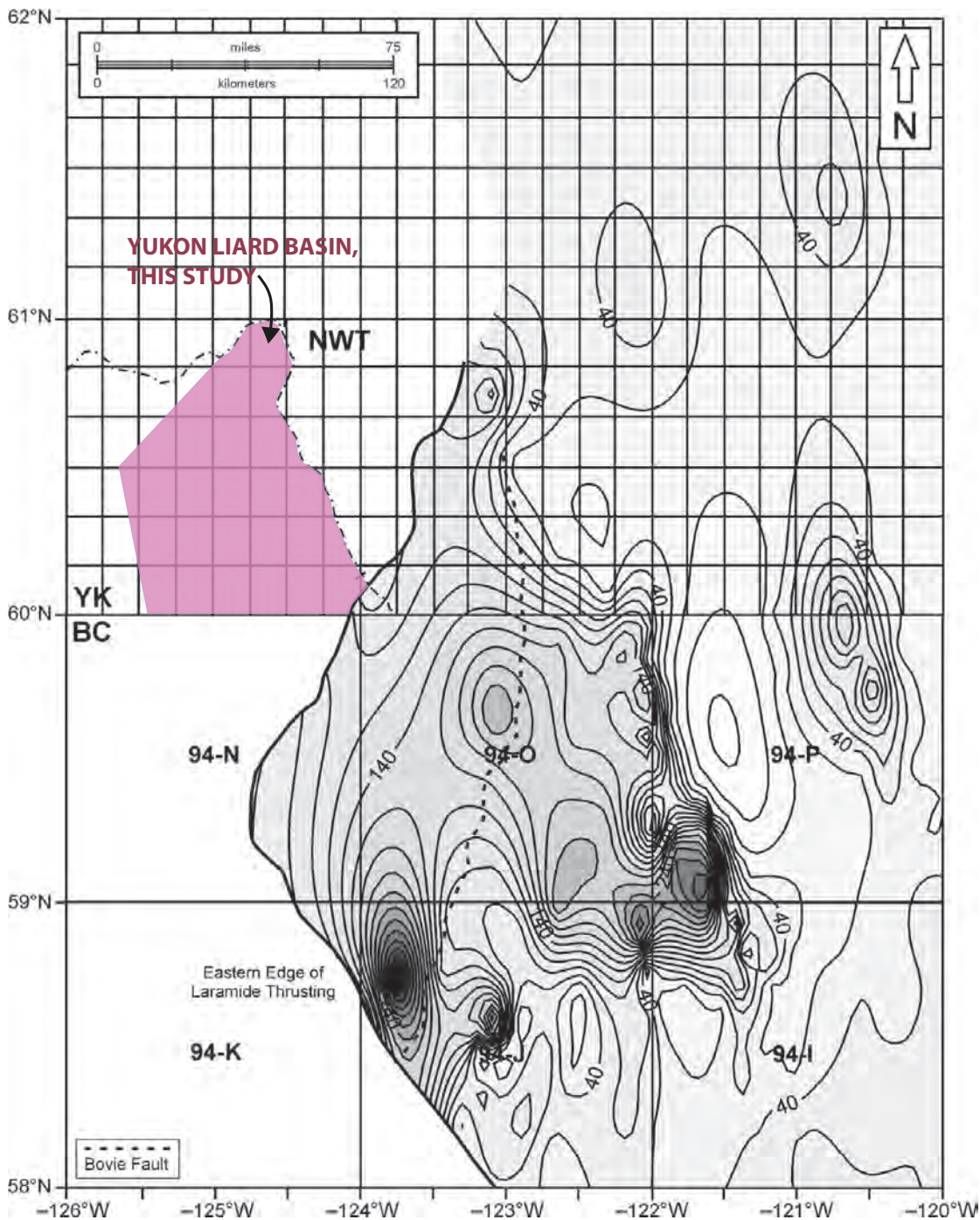


Figure 33. Total gas capacity map (adsorbed gas plus free gas, BCF/section) for Horn River and Muskwa formations (contour interval=20 BCF/section) (from Ross and Bustin, 2008).

decreases westward with increasing reservoir temperature. Ferri *et al.* (2011a) sampled a 285 m Besa River section in outcrop in western Liard Basin of northeastern BC, and found that they could correlate organic-rich shale sections to the Muskwa and Exshaw in the subsurface. They measured TOC values as high as 6%, although the organic material was generally mature to over-mature.

We conclude that there is a thick, organic-rich section of Devonian-Carboniferous shales in Yukon Liard Basin that may be prospective for shale gas. Major risks include high maturity levels, leaving little gas-generative capacity, and Cordilleran structural deformation, disrupting shale reservoir continuity and integrity.

- Fort St. John Group / Buckinghamhorse / Garbutt (Cretaceous): Chalmers and Bustin (2008) undertook a detailed study of Lower Cretaceous Buckinghamhorse shales of northeastern BC, and mapped large gas in place potential in the basal organic-rich section (ORB unit), as well as in the leaner overlying Garbutt / Moosebar / Wilrich section (Fig. 34). Ferri *et al.* (2011b) described shales of the Garbutt Formation, the lowest Fort St. John Group shale package, in outcrop on the western flank of Liard Basin in northeastern BC. They found that TOC levels ranged up to 1.67%, with an average value of 1.12%; Rock-Eval work suggested the kerogen to be Type III in nature. T_{max} values increased with depth from about 452 °C to 476 °C, indicative of dry gas generation. These results appear to be consistent with the regional patterns documented by Chalmers and Bustin (2008). However, drilling to date in northeastern BC for Cretaceous shale gas has taken place only in the Beatton-Sikanni River areas to the south (www.empr.gov.bc.ca/OG/OILANDGAS/PETROLEUMGEOLOGY/UNCONVENTIONALGAS/Documents/CretaceousShaleNEBC.pdf).

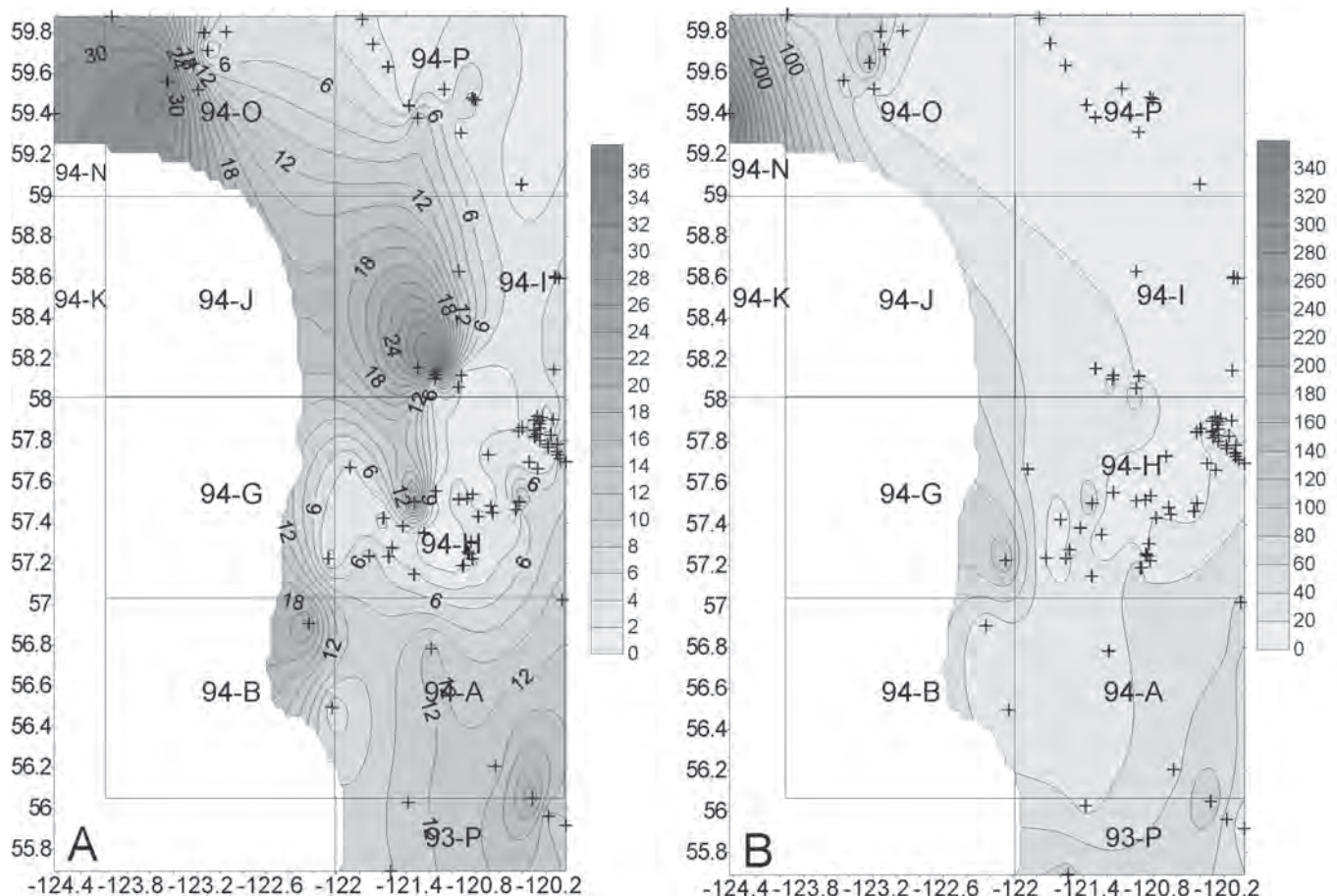


Figure 34. Total gas in place map for Lower Cretaceous Buckinghamhorse Formation, northeastern BC – A. organic-rich basal shales (ORB unit), and B. Garbutt / Moosebar / Wilrich shales (from Chalmers and Bustin, 2008).

Hayes (2011a) tabulated modest TOC values (1-2%) through most of the equivalent Fort St. John shale section in Northwest Territories, although organic-rich intervals equivalent to radioactive markers on gamma logs showed values ranging up to 5.8%. Maturation levels in Northwest Territories east of Liard Basin indicate oil-generative capacity, but higher maturity levels would be expected with greater burial depths in Liard Basin.

We conclude that Cretaceous shales may be prospective for shale gas and oil in Liard Basin. The major risk and limiting factor is Cordilleran structural deformation, which has disrupted shale reservoir continuity and integrity, and has resulted in exposure and erosion of the Cretaceous in many areas (Fig. 28).

Eagle Plain Basin

Eagle Plain Basin is an outlier of the Mesozoic of the western North America foreland basin in north-central Yukon, covering an area of approximately 20,600 km². It is defined by a central area of flat-lying Cretaceous bedrock, flanked by uplifts of folded and faulted Paleozoic bedrock (Figs. 35, 36). Eagle Plain Basin is bounded by the Richardson Mountains to the east, and the Ogilvie Mountains to the south and west (Osadetz *et al.*, 2005a).

Phanerozoic sedimentary rocks range up to 5800 m in thickness, and lie unconformably on Proterozoic successions of various ages and tectonic origins (Figs. 15, 36). Much of our knowledge of the stratigraphic section derives from outcrop studies, and limited well and seismic data.

Exploration History and Conventional Hydrocarbon Resources

The first well was spudded in the Eagle Plain Basin in 1957, and a total of 33 exploratory and outpost wells were drilled between 1957 and 1985. Only one well has been drilled since then, in 2005, a shallow test of the Chance sandstone in the far southeast. 9952 km of 2D seismic data have been acquired, most in the 1970's, and there are a number of active exploration dispositions, mostly in the east-central part of the basin (Fig. 35). A high-resolution airborne magnetic survey of the Eagle Plain Basin, flown with an 800 m line spacing, and totalling more than 62,000 line km, was released in 2009 (Yukon Energy, Mines and Resources, 2011). Osadetz *et al.* (2005a) reviewed drilling details and testing results for each well (except the most recent test in 2005). Drilling has focused on conventional targets, particularly large structures apparent on surface mapping, and/or imaged by regional 2D seismic. Only eight wells penetrate deeper than the Devonian Canol Formation, and none are deep enough to test the Cambrian.

Active petroleum systems in Eagle Plain Basin are evident in the presence of surface seeps, oil and bitumen staining, and oil and gas recoveries from wells. NEB (2000) considered three wells to have discovered conventional oil and gas fields, and two additional wells were drilled into these accumulations. Proven hydrocarbon resources were calculated at 1.76x10⁶m³ (11 million barrels) oil, and 2.38x10⁹m³ (84 BCF) gas (NEB, 2000). Osadetz *et al.* (2005a) noted gas flows to surface on tests in five other wells not considered to be significant discoveries, and also listed 25 wells where gas or oil shows occurred on tests.

Osadetz *et al.* (2005a) assessed fifteen conventional petroleum plays (nine gas and six oil) in Eagle Plain Basin, and calculated a probabilistic mean resource endowment of 171x10⁹m³ (6.06 TCF) of gas, and 69.5x10⁶m³ (437 million barrels) of oil, distributed amongst 114 pools.

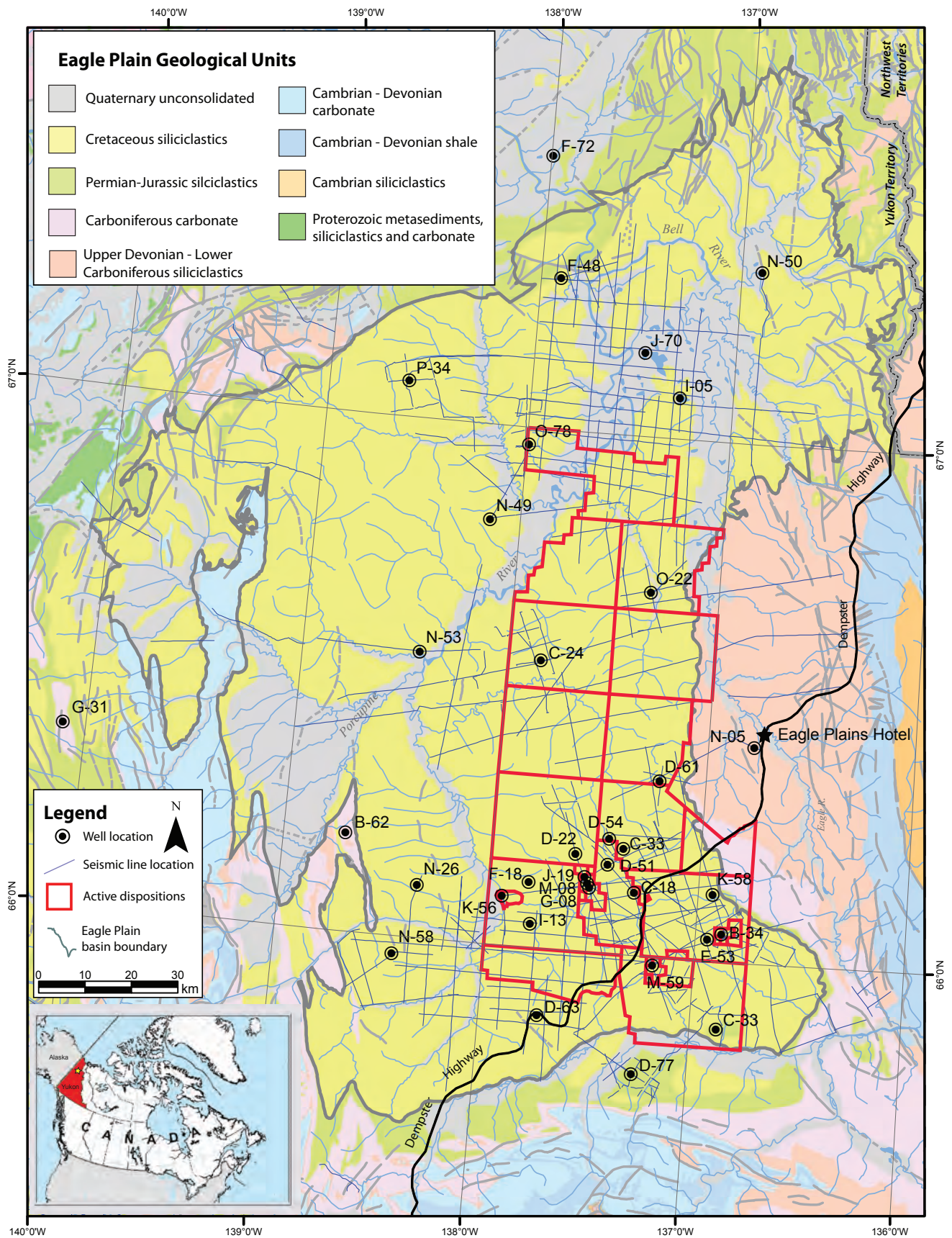


Figure 35. Simplified geological map of Eagle Plain Basin, showing all well locations and 2D seismic data (from Department of Energy, Mines and Resources, 2011).

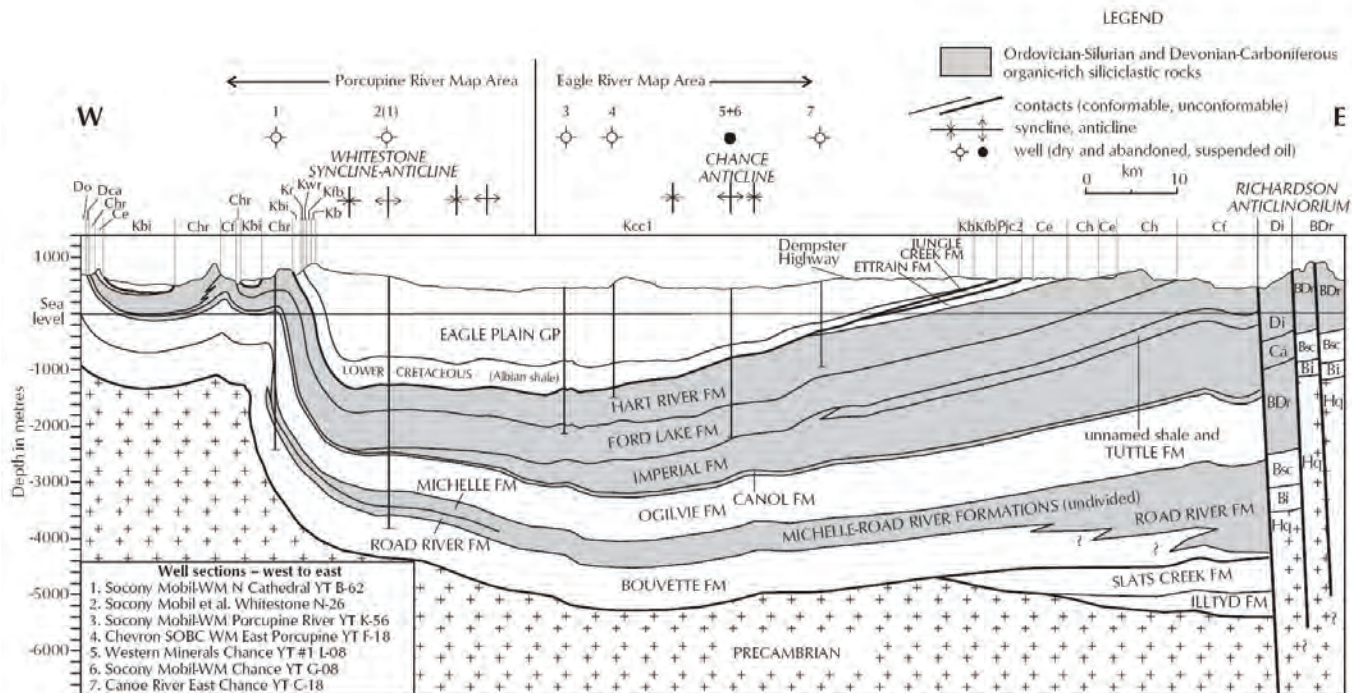


Figure 36. Schematic west-east cross section across Eagle Plain Basin. Note outcrop of Paleozoic strata flanking Cretaceous strata (Eagle Plains Group and Lower Cretaceous) on both the eastern and western basin margins, and the Richardson Mountains overthrust belt at the eastern basin boundary (from Osadetz et al., 2005a).

Unconventional Hydrocarbon Resource Potential

Coalbed Methane

Coals have not been mapped in the predominantly marine strata of Eagle Plain Basin, and thus there is no coalbed methane potential.

Tight Reservoirs

Cambrian strata were deposited in Richardson Trough, but have not been penetrated by any wells to date in Eagle Plain Basin, and thus cannot be assessed. Tight reservoir potential may exist in the thick overlying Paleozoic carbonate succession and Imperial Formation clastics. Carboniferous Tuttle and Cretaceous sands crop out or lie at relatively shallow depths, and are less likely to be isolated from meteoric recharge, particularly where deformed, and thus are unlikely to host basin-centred hydrocarbon accumulations.

- Bouvette / Ogilvie carbonate (Cambrian through Middle Devonian): these strata are flanked regionally by equivalent Road River shales, and are capped by Canol shales, both potential source rock units (Figs. 15, 37). This configuration sets up the potential for hydrocarbons to be expelled from the Road River and Canol, and to migrate into the carbonates, where they may be trapped in a basin-centred petroleum system. Source rock investigations (summarized in the shale reservoir discussion below) indicate that both units have generated substantial hydrocarbon volumes in the past and are now over-mature.

In the Mackenzie Corridor and Eagle Plain Basin, numerous drillstem tests in Paleozoic carbonates have recovered formation water, from which PRCL (2005) interpreted the presence of widespread regional aquifers, recharged with meteoric waters in the Mackenzie Mountains, and exhibiting regional cross-formational flow. However, well control is so sparse in Eagle Plain Basin that the presence or absence of abnormally-pressured basin-centred hydrocarbons cannot be established.

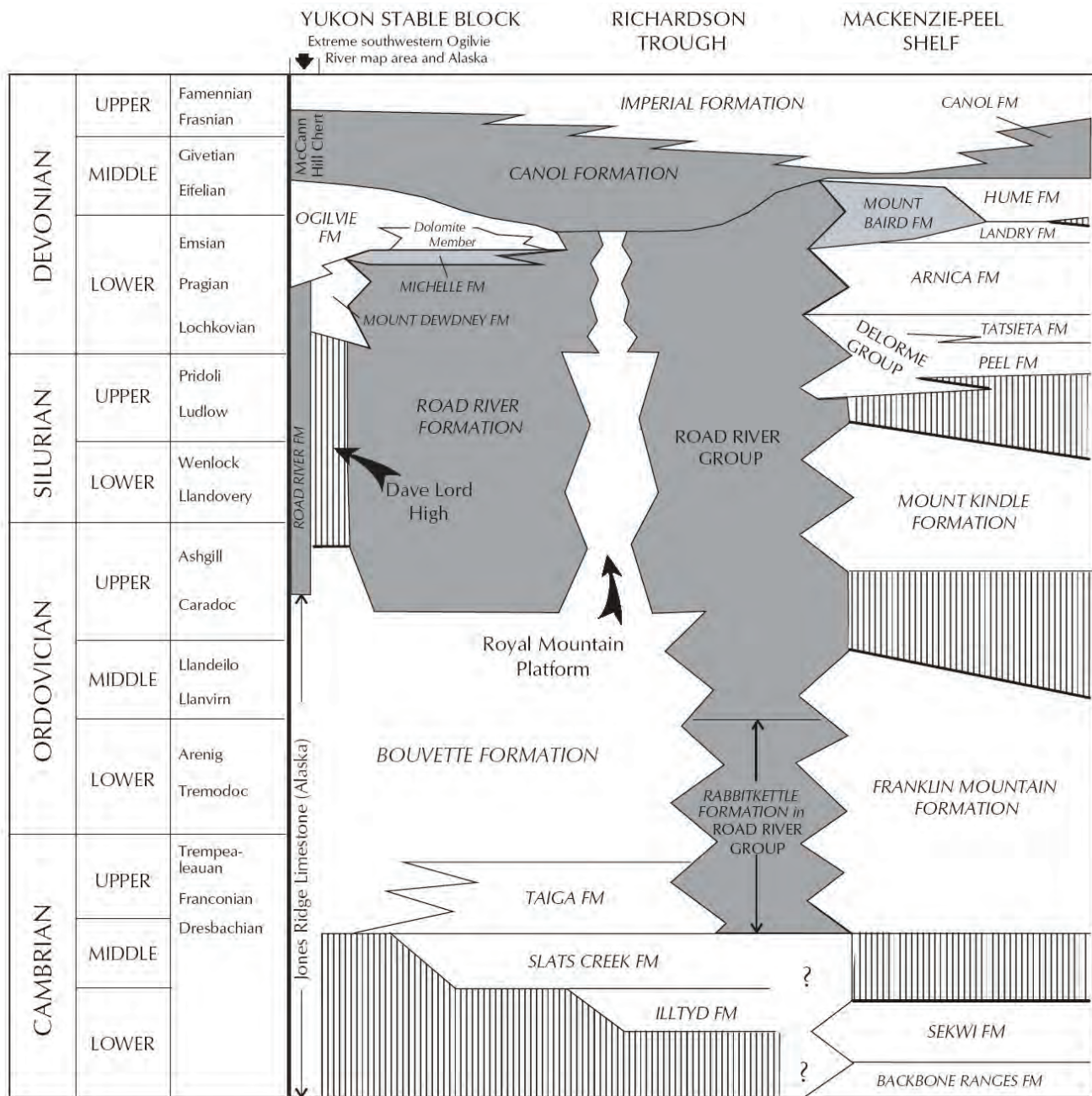


Figure 37. East-west stratigraphic relationships in lower Paleozoic strata from the Yukon Stable Block, through the Richardson Trough to the Mackenzie-Peel Shelf. The Eagle Plain Basin is underlain by lower Paleozoic successions of the Yukon Stable Block. Hydrocarbons generated in Road River Group and Canol shales may have migrated into the Bouvette and Ogilvie carbonates, becoming trapped in a basin-centred petroleum system (from Osadetz et al., 2005a).

Osadetz et al. (2005a) envisioned significant potential for conventional gas accumulations, both structurally- and stratigraphically-trapped, in the Paleozoic carbonate section. Little is known about the distribution of reservoir quality in these rocks, but it is reasonable to assume that conventional reservoir quality exists where solution, dolomitization, or fracturing has taken place, and that the remaining rock volume is in unenhanced “tight” facies. Large gas accumulations could therefore occur in low-permeability platform and reefal settings like those now being developed in Swan Hills, Slave Point and Jean Marie carbonates in the Western Canada Sedimentary Basin.

In summary, regional conditions support the potential for basin-centred tight petroleum systems to have evolved in Paleozoic carbonates of Eagle Plain Basin. Intensive analysis of existing well test and well log data are required to help quantify this potential, and to guide future exploration.

- Imperial Formation (Upper Devonian): as exposed on the flank of the Mackenzie Mountains and northward, turbiditic sands of the Imperial Formation were deposited within a thick shale package, in a fan-slope complex that prograded southwestward from an eastern basin margin (Hadlari *et al.*, 2009a, b). The Imperial succession reaches up to 2000 m thick in Eagle Plain Basin, and is encased by rich, gas-prone source rocks of the Canol Formation below and Ford Lake Shale above (Osadetz *et al.*, 2005a).

Very fine-grained turbiditic facies, with poor to modest reservoir quality, were described by Hadlari *et al.* (2009b) in Mackenzie Mountains outcrops. These facies strongly resemble Montney tight gas reservoirs in northeastern BC. Hadlari *et al.* (2009a) included them in a conceptual Imperial Formation play in the Peel Plateau and Plain, with all the reservoir, source, and seal elements of a possible basin-centred tight gas play. A very similar petroleum system can be envisioned to exist in Eagle Plain Basin. Osadetz *et al.* (2005a) did not assess the potential for a conventional Imperial Formation play, however, specifically because little conventional reservoir quality has been tested in wells drilled to date.

We conclude that the Imperial Formation offers conceptual potential for a significant tight gas system in Eagle Plain Basin. Targeted mapping and hydrogeological assessment is required to better quantify this potential.

- Upper Cretaceous: although Cretaceous sands have been discounted as tight/basin-centred gas targets because of shallow burial depths, recent work on the Parkin Formation has highlighted a potential target. From outcrop work in the Parkin Formation in southern Eagle Plain Basin, Jackson *et al.* (2011) interpreted substantial shelf to basin floor topography and the presence of sand-rich mass transport deposits on the basin floor. Isolated by the enclosing basinal shales, such sands could provide attractive tight gas targets in the deeper northwestern part of the basin, particularly if similar depositional scenarios exist in other Cretaceous progradational cycles.

Hydrocarbon charge of Cretaceous sandstones has been demonstrated by a gas flow of 3300 MCF/D from Fishing Branch Formation sandstones at Chance G-08, and the recovery of gas- and oil-cut mud from Cretaceous sandstones elsewhere in the basin (Jackson *et al.*, 2011). Gas may have been generated from Cretaceous shales where they are mature in the northwestern part of the basin, or biogenically where the shales are immature. Osadetz *et al.* (2005a) postulated the existence of conventional gas and oil plays in Cretaceous sands over much of the basin.

To summarize, tight gas potential may exist in Cretaceous sandstones in northwestern Eagle Plain Basin, where isolated basin-floor sandstones are buried to sufficient depths, and where enclosing shales are sufficiently mature to have generated a gas charge. Additional stratigraphic work using the depositional model of Jackson *et al.* (2011) should be undertaken to better quantify this potential.

Shale Reservoirs

Shale reservoir potential exists at several stratigraphic levels in the Paleozoic succession of Eagle Plain basin, particularly in the Richardson Trough depocentre to the east. Jurassic strata are penetrated by only a few wells in the northern part of the basin, and are generally in proximal sandy facies. Cretaceous shales are widespread, and may offer limited shale potential at shallow burial depths.

- Road River Group (Upper Cambrian through Middle Devonian): up to 1000 m of basinal shales accumulated in Richardson Trough on the eastern flank of Eagle Plain Basin through much of the early Paleozoic, equivalent to shelfal carbonates deposited on platform areas to the west and east (Norris, 1996a; Figs. 16-20). As will be noted in the discussion for Peel Plain and Plateau, regional sampling programs from outcrop have established the Road River as a potential source rock, although there are few reliable data points from the Eagle Plain Basin subsurface (Snowdon, 1988; Link *et al.*, 1989; Lane *et al.*, 2010). Osadetz *et al.* (2005a) concluded that the Road River Group in Eagle Plain Basin exhibits TOC values up to 2%, and thermal maturity in the gas generation window. Link *et al.* (1989) noted TOC levels up to 9.6%, and the presence of Type I/II (oil-prone) kerogen in the most basinal facies, but concluded that the Road River Group generated hydrocarbons during Devonian to Carboniferous time, and is now post-mature.

Fraser *et al.* (2012), building on preliminary work by Allen *et al.* (2011), analyzed shallow diamond drill core samples of the Road River Group from Richardson Mountains on the eastern flank of the basin. They found residual TOC values of 1.0-19.3%, with most values less than 5%. Type I and II organic macerals were identified, suggesting they may have been richer source rocks in the past. Vitrinite reflectance measurements showed all samples to be overmature. XRD data show variable silica (62-96%), carbonate (up to 37%), and clay mineral contents. Fraser *et al.* (2012) concluded that the Road River would have the potential to host unconventional hydrocarbons, under favourable burial conditions.

Further work is required to map out the most prospective fairways in terms of thickness, burial depth, organic richness and maturity. The potential for over-maturity in the subsurface is a major risk.

- Canol Formation (Middle to Upper Devonian): Middle Devonian transgression resulted in widespread deposition of basinal, organic-rich Canol shales in Eagle Plain Basin, generally tens of metres thick. As noted in the forthcoming discussion for Peel Plain and Plateau, regional sampling programs from outcrop and subsurface have established the Canol Formation as an organic-rich source rock, and the probable source for the Norman Wells oil field (Link *et al.*, 1989). There are, however, only a few reliable data from the Eagle Plain Basin subsurface (Snowdon, 1988; Link *et al.*, 1989; Lane *et al.*, 2010). Link *et al.* (1989) noted the presence of residual kerogen with TOC levels of 2.4-8.6%, but concluded that the Canol Formation generated hydrocarbons during Devonian to Carboniferous time, and is now post-mature in Eagle Plain Basin.

Fraser *et al.* (2012), building on preliminary work by Allen *et al.* (2011) analyzed shallow diamond drill core samples of the Canol Formation from Richardson Mountains on the eastern flank of the basin. They found residual TOC values of 0.3-20.1%, with most values in the range of 2-5%. All samples were overmature with respect to oil generation according to vitrinite reflectance measurements, although values systematically decrease southward to the upper limit of the wet/dry gas window. XRD data show the Canol to be rich in silica (quartz values of 91-100%), and thus is likely to be quite brittle and amenable to frac stimulation.

In conclusion, Canol shales offer good potential as shale reservoirs throughout Eagle Plain Basin. Further work is required to map out the most prospective fairways in terms of thickness, burial depth, organic richness and maturity. Limited thickness and the potential for over-maturity in the subsurface are significant risks.

- Ford Lake / Hart River / Blackie (Carboniferous): fine-grained basinal clastic rocks of the Ford Lake Formation, up to 975 m thick, were deposited in Eagle Plain Basin after Early Carboniferous transgression over the northerly-derived Imperial / Tuttle clastic wedge. The Ford Lake passes

conformably upward into terrigenous clastics and carbonate ramp deposits of the Hart River Formation, up to 790 m thick. Blackie Formation lime muds, up to 294 m thick, were deposited in a basinal setting during a subsequent Upper Carboniferous transgression (Richards *et al.*, 1996). Link *et al.* (1989) found TOC values ranging up to 7.9% with Type II/III kerogen in the Ford Lake, TOC up to 4.9% with Type II/III kerogen in the Hart River, and TOC ranging only to 1.2% in the Blackie. They considered the kerogen types to reflect terrestrial input into the marine basin, and to have the potential to generate both oil and gas. These strata were likely the source for hydrocarbon shows in conventional Carboniferous reservoirs, and may still retain generative capacity in the Eagle Plain subsurface.

We conclude that Carboniferous shales offer substantial reservoir potential in Eagle Plain Basin. Further work is required to map out the most prospective fairways in terms of thickness, burial depth, organic richness and maturity. The most apparent risk is loss of reservoir pressure and integrity approaching outcrop on the eastern flank of the basin.

- Mount Goodenough / Whitestone River / Eagle Plain Group (Cretaceous): Berremian to Early Aptian transgression created accommodation space for deposition of a basal transgressive sandstone and overlying shales of the Mount Goodenough Formation in the far northeast. Over most of the basin, the Albian Whitestone River Formation is the basal Cretaceous unit; it consists of up to 1545 m of shale-dominated strata (in the far northwest Molar P-34 well; Fig. 35), thinning to the east and southeast (Dixon, 1992). Upper Cretaceous Eagle Plain Group strata comprise stacked transgressive-regressive sandstones and shales, each hundreds of metres thick, reflecting episodic progradation of coarse clastic wedges from the Cordillera.

Link *et al.* (1989) identified gas-generative potential in organic-rich intervals of the Mount Goodenough in northern Eagle Plain Basin. They also saw fair to excellent gas source potential from type III kerogen in Upper Cretaceous strata, but judged these rocks to be immature except at Molar P-34 in the far northwest, where the Cretaceous is thicker and more deeply buried (Fig. 35). Osadetz *et al.* (2005a) agreed with this assessment, although pointed out potential for biogenic gas generation from these rocks.

In summary, Cretaceous shales have the potential to host substantial gas resources, in the northwestern part of Eagle Plain Basin, where they are thickest, and exhibit sufficient maturity.

Peel Plain and Plateau

Peel Plain and Plateau is a physiographic region lying west of the Mackenzie River, in northeastern Yukon and adjacent NWT (Fig. 14). Although a common Phanerozoic stratigraphic succession underlies the entire region, three geologically distinct settings were identified by Osadetz *et al.* (2005b):

- Peel Plateau west of Trevor Fault (Fig. 38): on the eastern edge of the Richardson Mountains, this area features Paleozoic bedrock, deposited primarily as basinal facies in the Richardson Trough (*e.g.*, Fig. 20), and deformed by Cretaceous and Tertiary Cordilleran structures;
- Peel Plateau east of Trevor Fault: Cretaceous bedrock is preserved above a thick Paleozoic platformal succession, all deformed during the most recent Tertiary episodes of folding and thrusting (Fig. 39); and
- Peel Plain: Cretaceous and Paleozoic strata are relatively undeformed, east of the Cordilleran fold and thrust belt (Fig. 39). Peel Plain lies primarily in Northwest Territories, and occupies only a small northeastern corner of Yukon (Fig. 38).

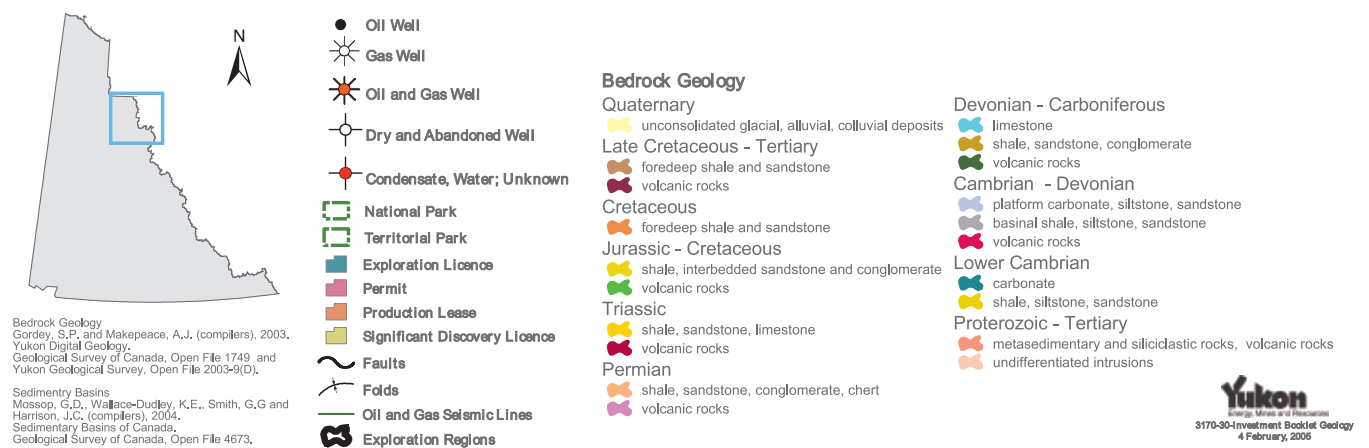
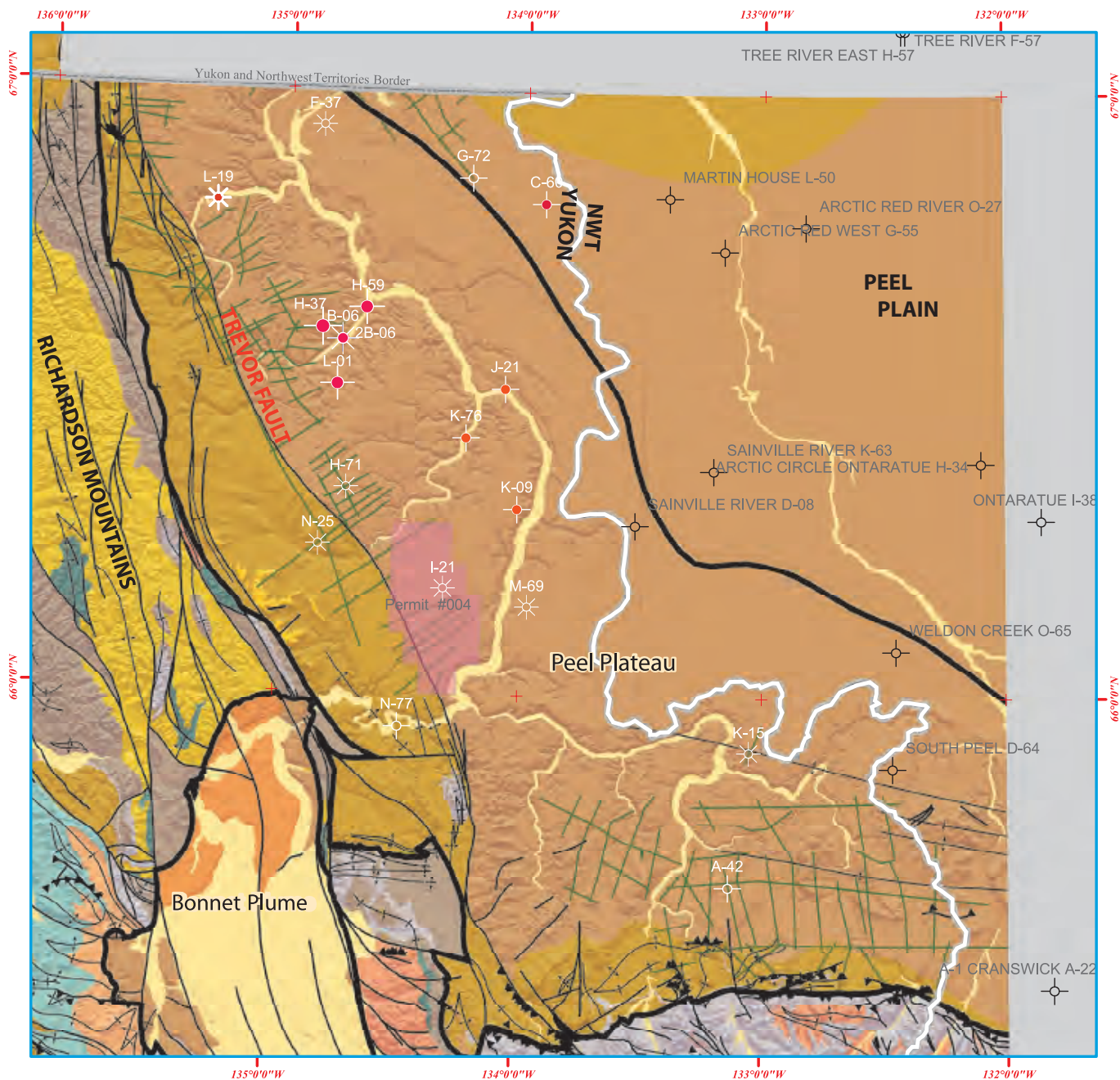


Figure 38. Simplified geological map of Peel Plain and Plateau, showing well locations and some 2D seismic data (from Energy, Mines and Resources, 2011).

Peel Plain and Plateau are bounded by zones of Cordilleran and younger deformation, including thrust exposures of sub-Carboniferous rocks in the Richardson Mountains to the west and Mackenzie Mountains to the south. To the east, the gentle epeirogenic Mackenzie-Peel Arch is a subtle boundary (Osadetz *et al.*, 2005b). Total basin area in Yukon is 10,300 km².

The stratigraphic column beneath Peel Plain and Plateau is up to 4000 m thick, and tapers gently eastward (Figs. 15, 39).

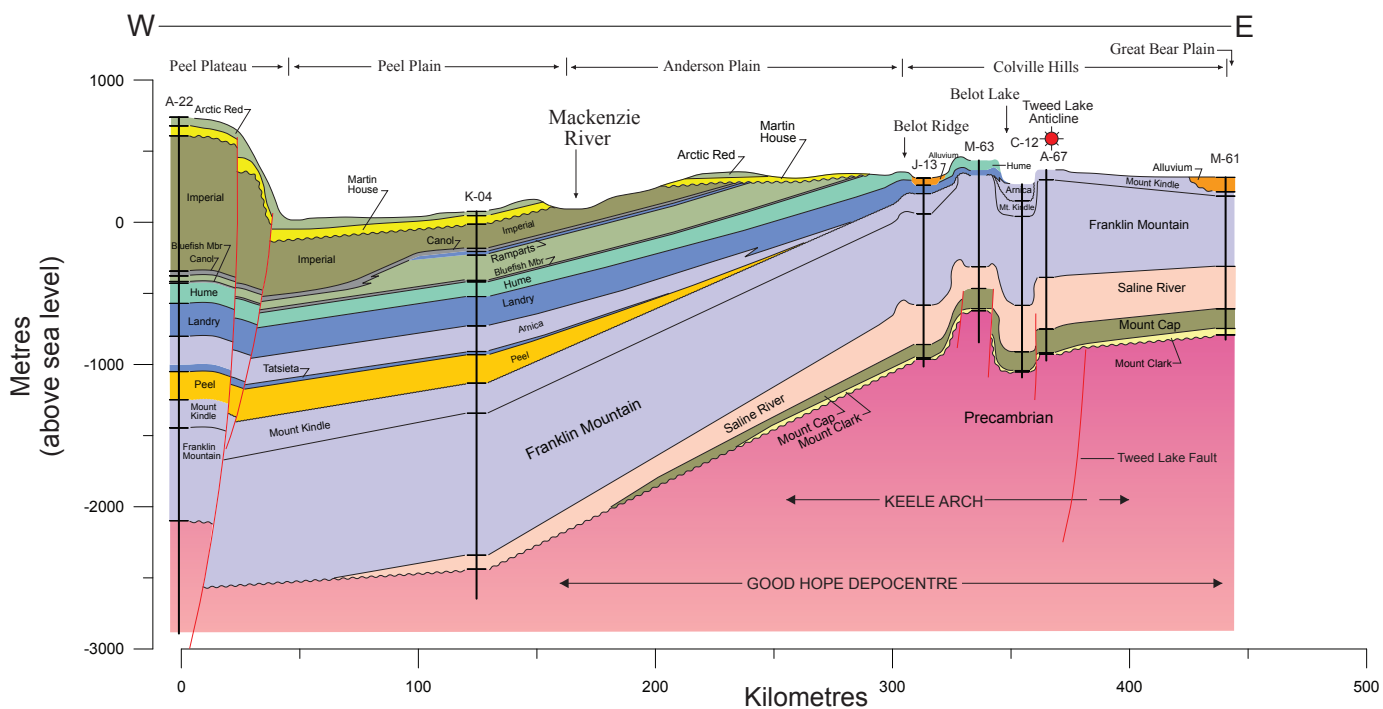


Figure 39. Regional cross section illustrating stratigraphic succession in eastern Peel Plateau, Peel Plain, and areas to the east (from Hannigan *et al.*, 2011).

Exploration History and Conventional Hydrocarbon Resources

The first exploration well was drilled on the NWT side of Peel Plain and Plateau in 1960; the first well in Yukon was Shell Peel River YT J-21, which commenced drilling in 1965. Osadetz *et al.* (2005b) tabulated all wells in an assessment area that extends beyond the Peel region boundaries, and produced a brief drilling and testing history of each. Thirty-nine wells were drilled in their assessment region between 1964 and 1977, 19 in Yukon. More than 3000 km of regional 2D seismic data have been acquired in Yukon, some of which are shown on figure 35. Drilling has focused on conventional targets, particularly large structures apparent on surface mapping, and/or imaged by regional 2D seismic. Osadetz *et al.* (2005b) concluded that this exploration effort yielded only a “few modest favourable gas shows”, and thus there are no proven hydrocarbon resources attributed to the area. However, Gal *et al.* (2009) listed numerous observations of oil-stained outcrops, bitumen occurrences, surface oil and gas seeps, reported gas in seismic shotholes, gas kicks in exploration wells, mud gas log anomalies, and shows on drillstem tests and flow tests in the general Peel region (Fig. 40).

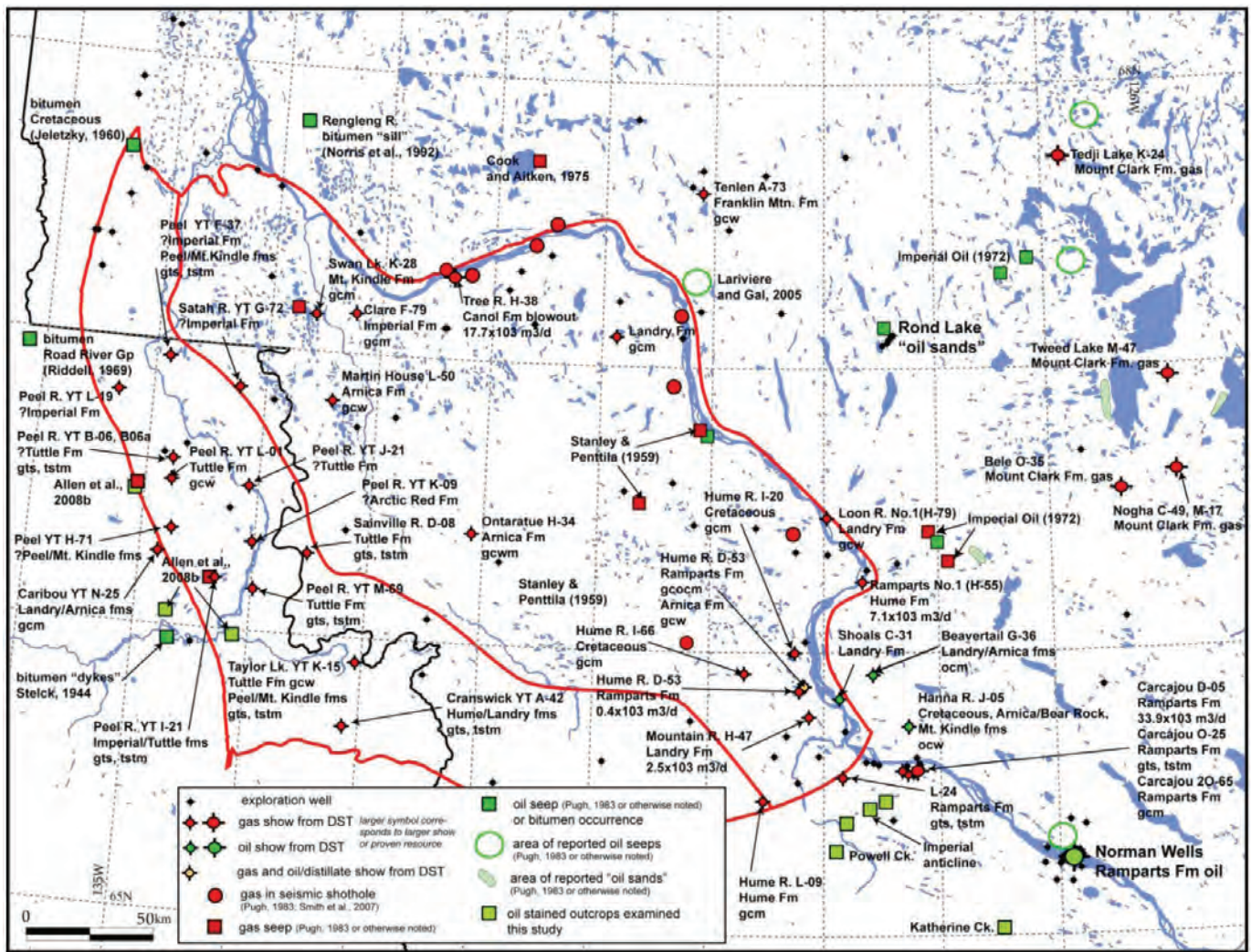


Figure 40. Summary map of hydrocarbon indications in wells and outcrop, Peel region (from Gal *et al.*, 2009).

Osadetz *et al.* (2005b) assessed conventional petroleum potential separately in three areas: Peel Plateau (west of Trevor Fault), Peel Plateau, and Peel Plain. They calculated a probabilistic mean resource endowment of $83.4 \times 10^9 \text{ m}^3$ (2.95 TCF) of gas in place, distributed amongst 88 pools. No oil resource was assessed, as the authors judged the area to be gas-prone due to high maturity levels in the associated source rocks. Addressing the entire Peel Plain and Plateau region, Gal *et al.* (2009) identified seven conceptual plays, two of which are limited to NWT. Although oil is predicted to occur in several of these plays, the Yukon area is seen to be primarily gas-prone, as potential source rocks generally become overmature to the west. Gal *et al.* (2009) did not make quantitative predictions of gas resources.

A call for work commitment bids on eleven parcels in the northern Mackenzie Plain exploration region, Northwest Territories, immediately southeast of Peel Plain, yielded more than \$534 million in June 2011. Liquids-rich gas or oil from the Devonian Horn River Group (Canol Shale) was likely a strong driver for these bids (Hayes, 2011b; Ross, 2011).

Unconventional Hydrocarbon Resource Potential

Coalbed Methane

Pre-Cretaceous strata in Peel Plain and Plateau region were deposited in marine settings, and hence have no coal and no CBM potential. Although Cretaceous strata crop out extensively east of the Trevor Fault (Fig. 38), at most locations only basal Martin House sandstones and marine Arctic Red shales and siltstones are preserved, and younger, coal-bearing Cretaceous strata have been eroded.

Tight Reservoirs

Cambrian clastic units in Northwest Territories may hold tight gas potential, but pinch out southwestward toward the Mackenzie Arch, and are unlikely to be present beneath Yukon Peel Plateau (Hayes, 2010). Tight reservoir potential may exist in the thick Paleozoic carbonate succession, and possibly in the overlying Imperial Formation clastics as well. Overlying Tuttle and Cretaceous sands crop out or lie at relatively shallow depths, and are unlikely to host basin-centred accumulations isolated from meteoric recharge.

- Upper Cambrian through Middle Devonian carbonate platform: conventional reservoir quality is present throughout this succession in the Mackenzie Corridor, including Peel Plain. Hydrogeologically, numerous tests have recovered formation water, and PRCL (2005, 2009) interpreted the presence of widespread regional aquifers, recharged with meteoric waters in the Mackenzie Mountains, and exhibiting regional cross-formational flow. More locally, however, Gal *et al.* (2009) noted a dominance of tight carbonate rocks in Peel Plain and Plateau, and suggested that hydrocarbon migration from western Road River or Horn River source rocks may have been hindered by lack of migration pathways. It may be possible that a westerly “Deep Basin”, as in the Western Canada Sedimentary Basin, exists west of the western platform margin.

While a Peel region “Deep Basin” is only conceptual, systematic mapping, hydrogeological evaluation, and petrophysical interpretation in the region may provide supporting evidence.

- Imperial Formation (Upper Devonian): on the flank of the Mackenzie Mountains and northward into the Peel Plain and Plateau regions, turbiditic sands of the Imperial Formation were deposited within a thick shale package, in a fan-slope complex that prograded southwestward from an eastern basin margin (Hadlari *et al.*, 2009a, b). Pyle *et al.* (2008) noted that more than 200 wells have penetrated the Imperial in the Mackenzie Corridor, several with oil and gas shows, although it is unclear how many of these have tested the sandy part of the section. Very fine-grained turbiditic facies, with poor to modest reservoir quality, described by Hadlari *et al.* (2009b), strongly resemble Montney tight gas reservoirs in northeastern BC. Hadlari *et al.* (2009a) included these strata in a conceptual Imperial Formation play in the Peel Plateau and Plain, with all the reservoir, source, and seal elements of a possible basin-centred tight gas play.

Shale Reservoirs

Four stratigraphic intervals are prospective shale reservoirs in Peel Plain and Plateau. Numerous studies of source rock potential and conventional prospectivity have been undertaken, focused primarily in Northwest Territories (*e.g.*, Link and Bustin, 1989; Osadetz *et al.*, 2005; Gal *et al.*, 2007; Pyle *et al.*, 2008; Gal *et al.*, 2009; Pyle *et al.*, 2011). For this report, we have relied primarily upon Gal *et al.* (2009), which includes information summarized from earlier studies.

- Road River (Ordovician through Middle Devonian): this is a thick basinal shale succession in westernmost Peel Plateau, deposited in the Richardson Trough seaward of carbonate strata laid down on the Peel Shelf (Figs. 16-20). Figure 41 shows the approximate eastern limit of Road

River shales, although considerable interfingering likely occurs, and stratigraphic control is poor. Road River shales have high organic content in many samples, but are generally regarded as post-mature because of their long history and deep burial. Thus, although they may have generated substantial hydrocarbon volumes in the past, they are now “inactive” in terms of generating new hydrocarbons; however, they may retain some gas that has been unable to migrate out of the thick shale section.

Deep burial and structural complexity impose significant logistical and economic risks to the play.

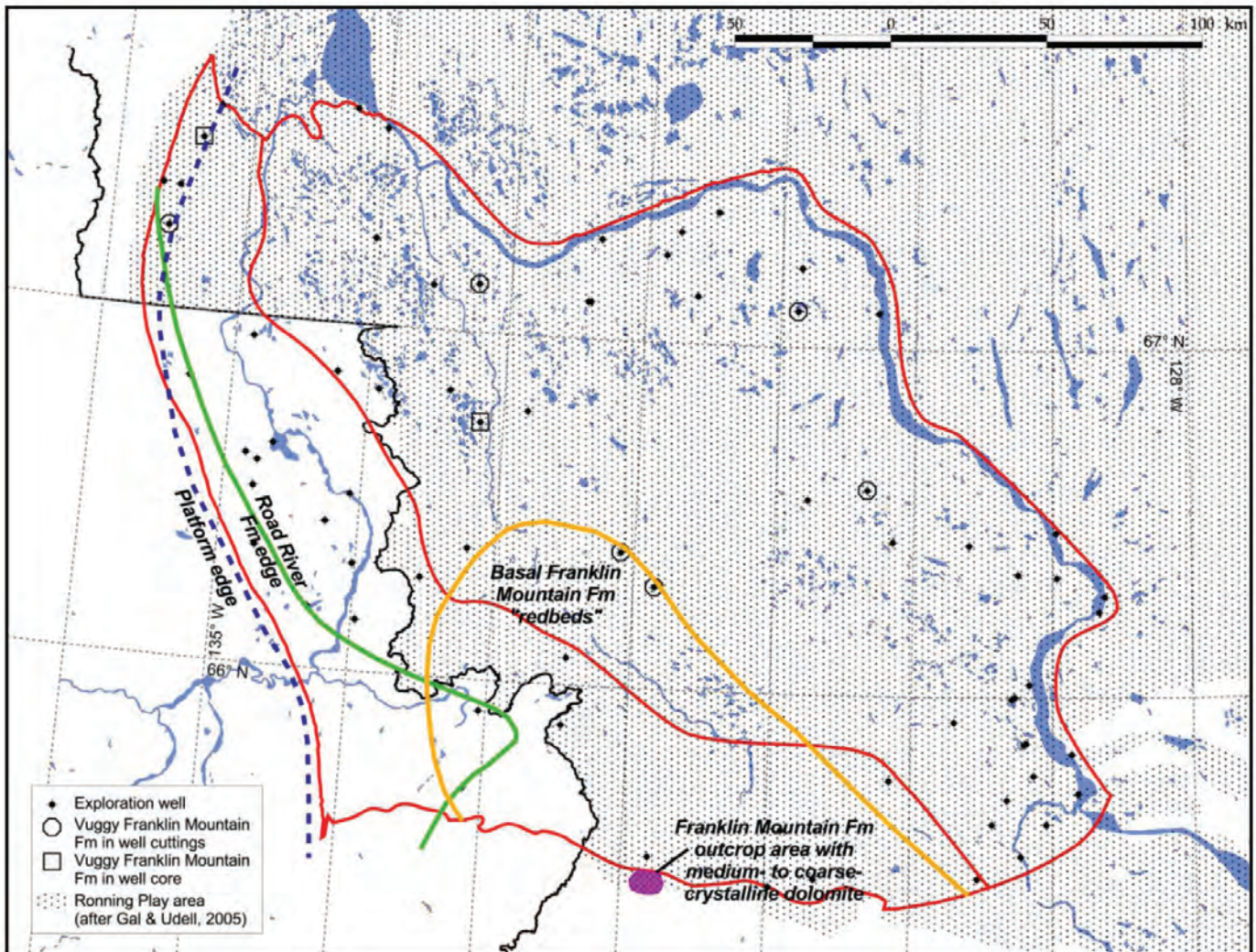


Figure 41. Lower Paleozoic play map, Peel Plain and Plateau. Road River shale gas play lies west of limit of Road River shales (green line) (from Gal *et al.*, 2009).

- Horn River Group (Upper Devonian): Horn River (Bluefish/Hare Indian/Canol) shales are viewed as perhaps the most important source rock interval in northern mainland Canada. Numerous studies have demonstrated TOC values of greater than 5% in organic-rich facies across large areas. Gal *et al.* (2009) compiled outcrop and subsurface data showing that the Canol and Bluefish are generally mature in the east, but over-mature to post-mature on the Yukon side of Peel Plateau (Fig. 42). They also noted the Canol to be siliceous and cherty, with a tendency to be highly fractured in outcrop. Pyle *et al.* (2011) summarized an extensive sampling program on four Mackenzie Mountains outcrop locations by noting excellent TOC's, predominantly Type II kerogens, and abundant silica in Horn River shales.

Hayes (2011a) mapped favourable TOC and T_{max} values in Horn River shales across Mackenzie Plain and northward into southern Peel Plain and Plateau, and demonstrated continuity of the map unit with prospective Horn River shales in southern Northwest Territories and producing Muskwa shales in Horn River Basin of northeastern BC. As noted above, large work commitment bids at the June 2011 Call for Bids in the northern Mackenzie Plain reflect industry's positive view of Horn River shale potential.

We conclude that the Horn River Group (Bluefish/Hare Indian/Canol) may be a highly prospective shale reservoir in Peel Plain and Plateau. Structural complexity, poor stratigraphic control, and increasing maturity values impart more risk to the play in the Yukon part of the region.

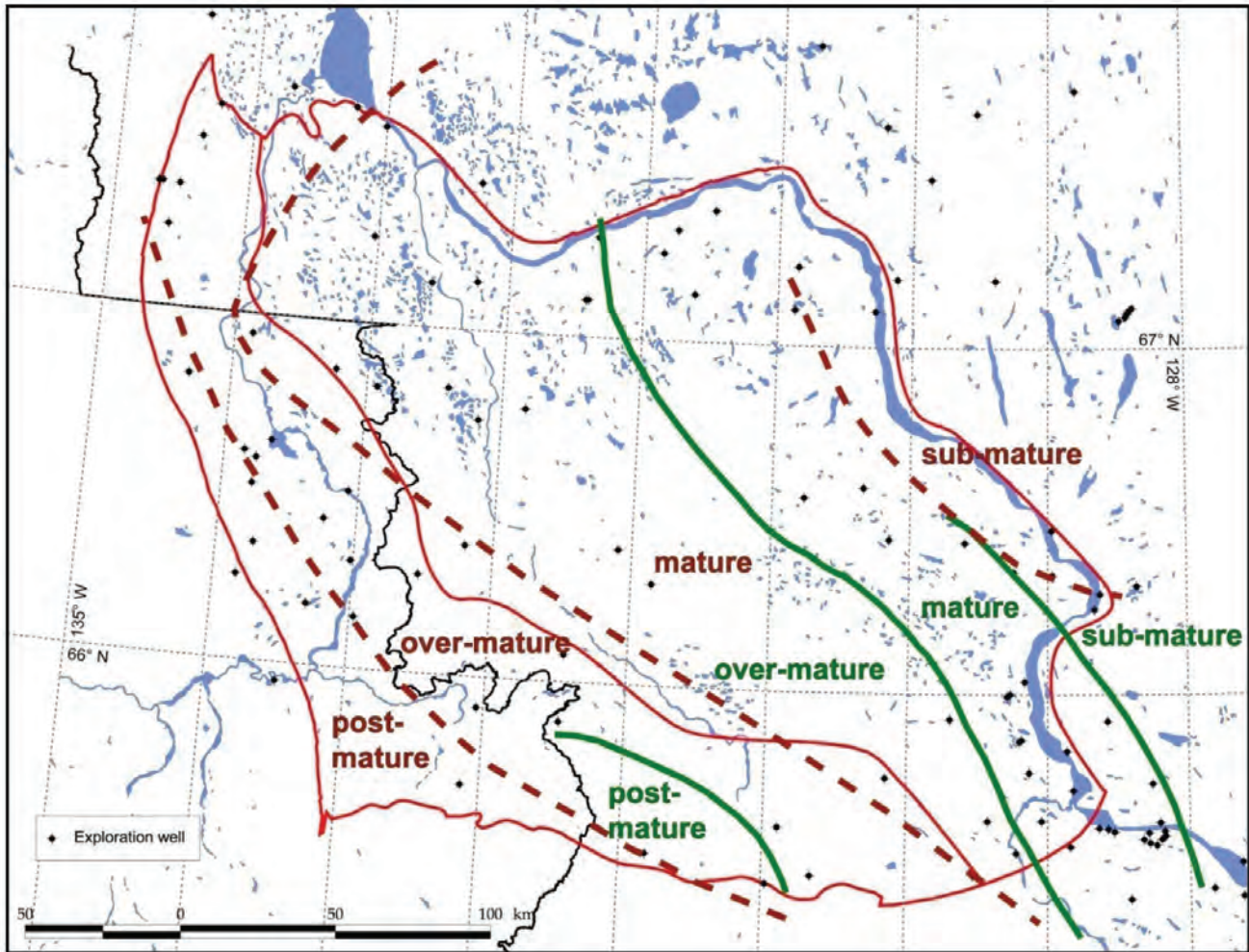


Figure 42. Zones of organic matter maturity for Canol Formation (brown dashed lines) and Hare Indian Formation (Bluefish Member; green lines), Peel Plain and Plateau (from Gal *et al.*, 2009).

- Ford Lake Shale (Devonian to Carboniferous): Ford Lake shale is known primarily from Eagle Plain Basin to the west, but has been mapped in northern Mackenzie Mountains and Richardson Mountains west of the Trevor Fault (Richards *et al.*, 1996). Allen *et al.* (2009) proposed that equivalent strata were likely present in the subsurface in Peel Plateau, but such a relationship has not been conclusively established. Gal *et al.* (2009) reported that TOC values average 4.65% in outcrop samples of the Ford Lake, and showed the underlying Tuttle Formation to be mature for oil over most of Yukon Peel Plateau, with maturity values increasing westward (Fig. 43).

Thus, the Ford Lake Formation may represent an attractive shale target in central to western

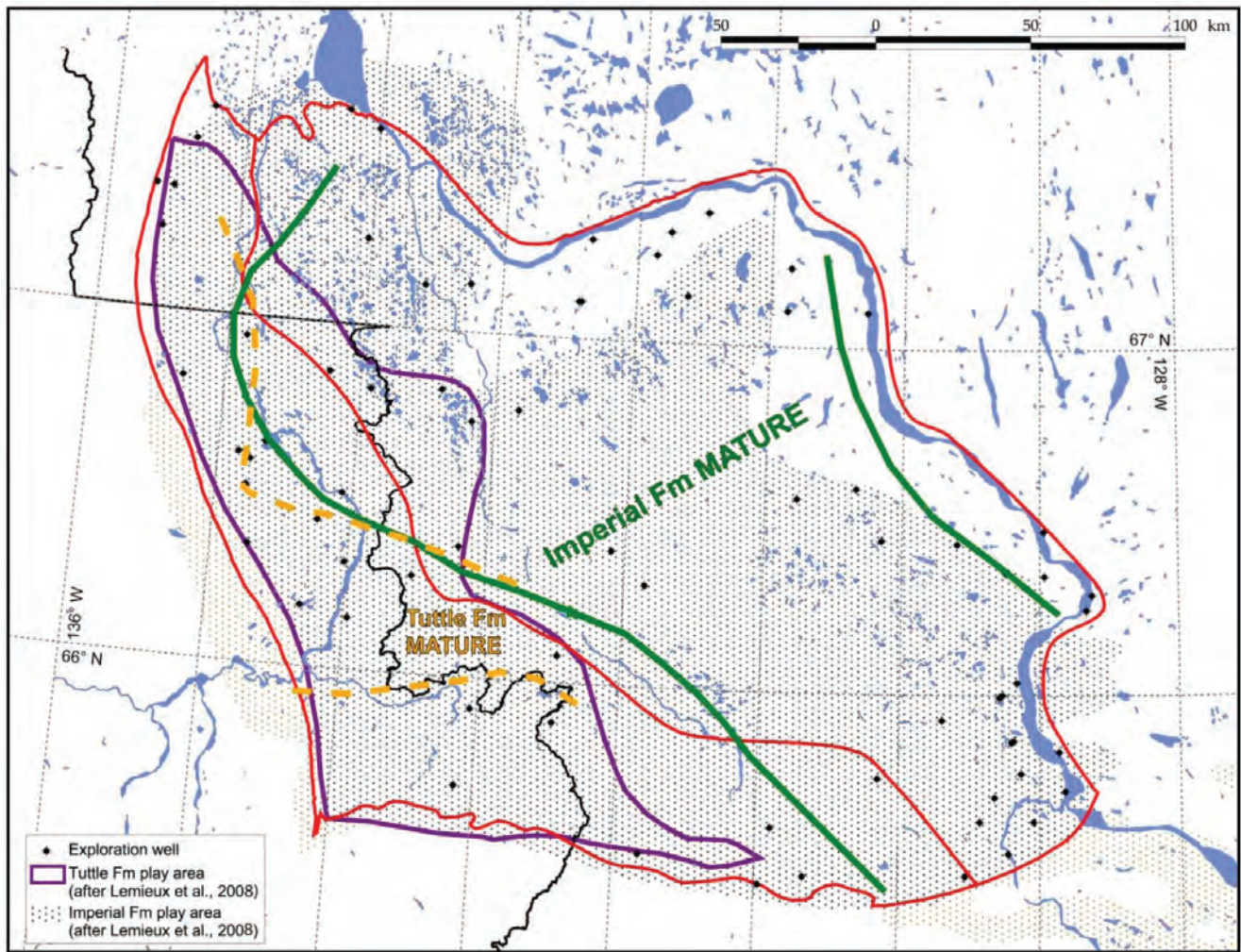


Figure 43. Imperial and Tuttle (including Ford Lake Shale) play areas, Peel Plain and Plateau (from Gal *et al.*, 2009).

Yukon Peel Plateau, but mapping of its subsurface distribution and characteristics is required to quantify this potential.

- Arctic Red Formation (Cretaceous): marine Arctic Red shale and siltstone crop out over much of Peel Plain and Plateau. On the Northwest Territories side, Hayes (2011a) mapped the Arctic Red, but logged younger Cretaceous strata (and therefore a complete Arctic Red section) in only one wellbore. He noted moderate (1.0-2.5%) TOC values, and a lack of significant high-organic intervals. Sparse data indicate maturity in the oil window in Mackenzie Plain subsurface. Gal *et al.* (2009) incorporated outcrop data in calculating an average TOC value of 1.64% for the Arctic Red, and showed it to be mature for oil through much of Yukon Peel Plateau (Fig. 44). They also noted shale reservoir parameters for the younger Slater River Formation, but Hayes (2011a) mapped this unit to occur only south of Peel Plain and Plateau.

Detailed geochemical analyses have not been published for the Arctic Red Formation. It may be more amenable to fracturing where there are abundant interbedded siltstones.

Arctic Red strata reach a maximum thickness of up to 1500 m at well F-47(UWI F476540130450) in NWT, and the base of the formation may occur as deep as 1700-2100 m where measured in wellbores (Hayes, 2011a). Despite this considerable thickness, however, shallow burial depths, modest organic content, and relatively low maturity limit Arctic Red Formation potential as a shale reservoir.

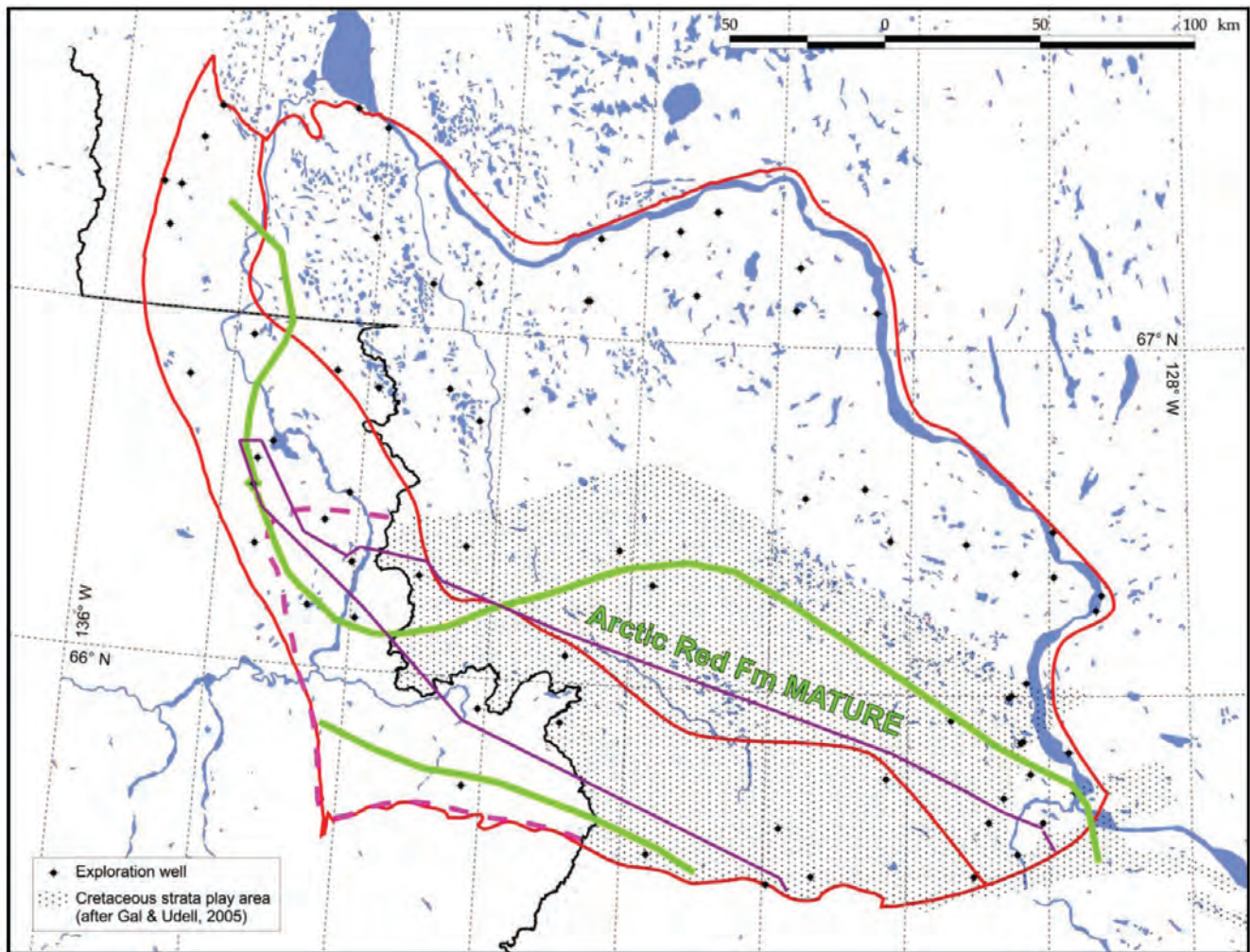


Figure 44. Cretaceous clastic play area, Peel Plain and Plateau. Note green outline enclosing area where Arctic Red shales are mature (from Gal et al., 2009).

Bonnet Plume Basin

Bonnet Plume Basin is a fault-bounded basin, lying a short distance southwest of Peel Plateau (Figs. 14, 45). During Paleozoic time, the Bonnet Plume area was within the depositional regime of southern Richardson Trough. Strike- and dip-slip faulting associated with Cordilleran compression and subsequent inversion during Cretaceous time formed a discrete structural depression and successor basin, in which a thick Cretaceous-Tertiary clastic section accumulated (Figs. 15, 46, 47; Hannigan, 2000).

Exploration History and Conventional Hydrocarbon Resources

No wells have been drilled within the basin, and no seismic data have been acquired. An east-west gravity profile was completed across the basin in 1979 (Department of Energy, Mines and Resources, 2011). The nearest well is Toltec Peel River YT N-77, drilled 20 km to the northeast (Fig. 45). The only hydrocarbon shows are two bitumen “intrusions” located north of the basin (Fig. 45; Department of Energy, Mines and Resources, 2011).

Hannigan (2000) identified three conceptual conventional gas plays in Bonnet Plume Basin, with a total median estimated gas in place of $25 \times 10^9 \text{ m}^3$ (0.9 TCF). Little conventional oil potential was identified by Hannigan, but Lowey (2009, 2010) proposed that liptinite-bearing coals and siliceous oil shales in the Cretaceous Bonnet Plume Formation may have oil-generating potential.

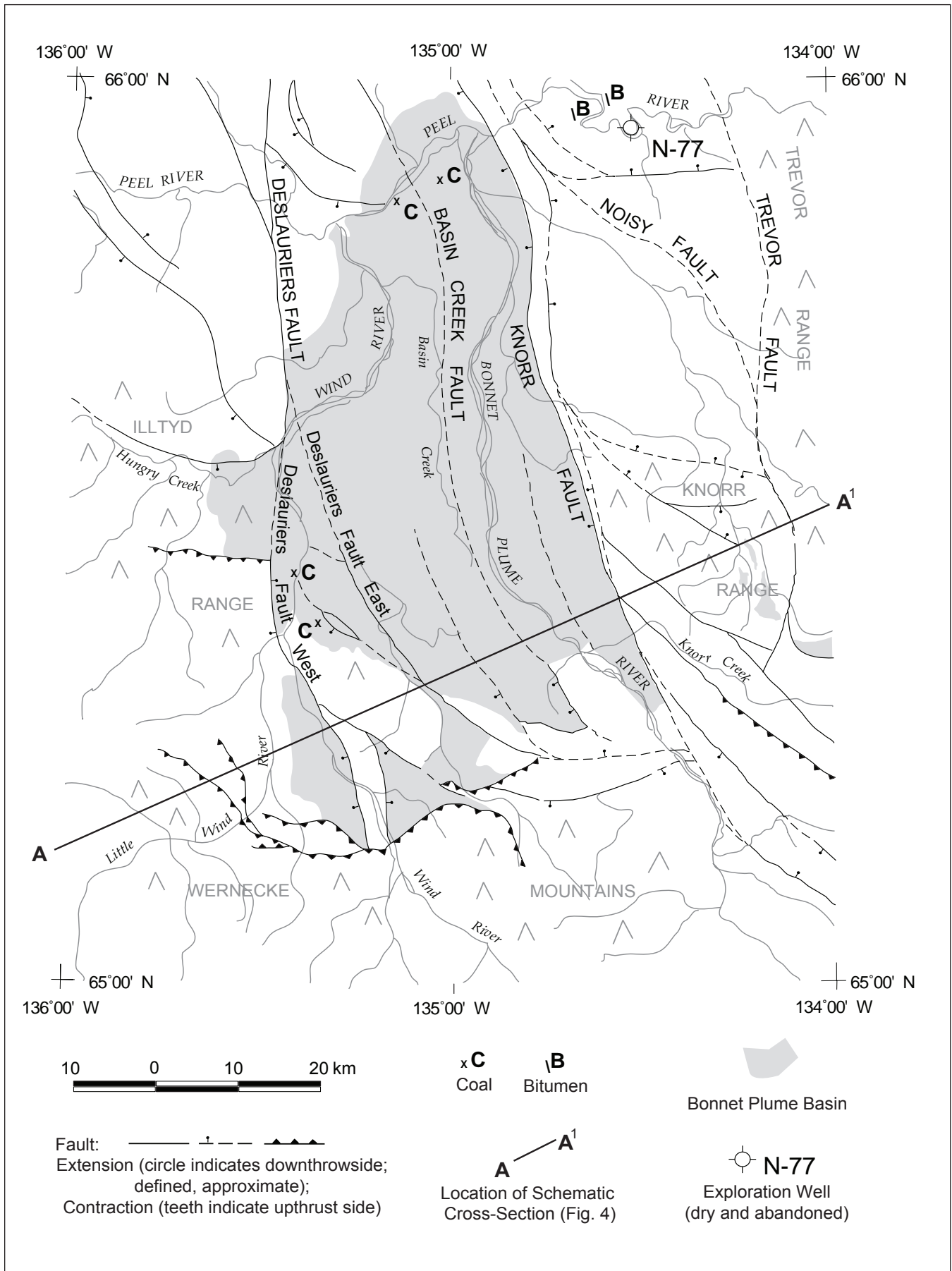


Figure 45. Base map of Bonnet Plume Basin (from Hannigan, 2000).

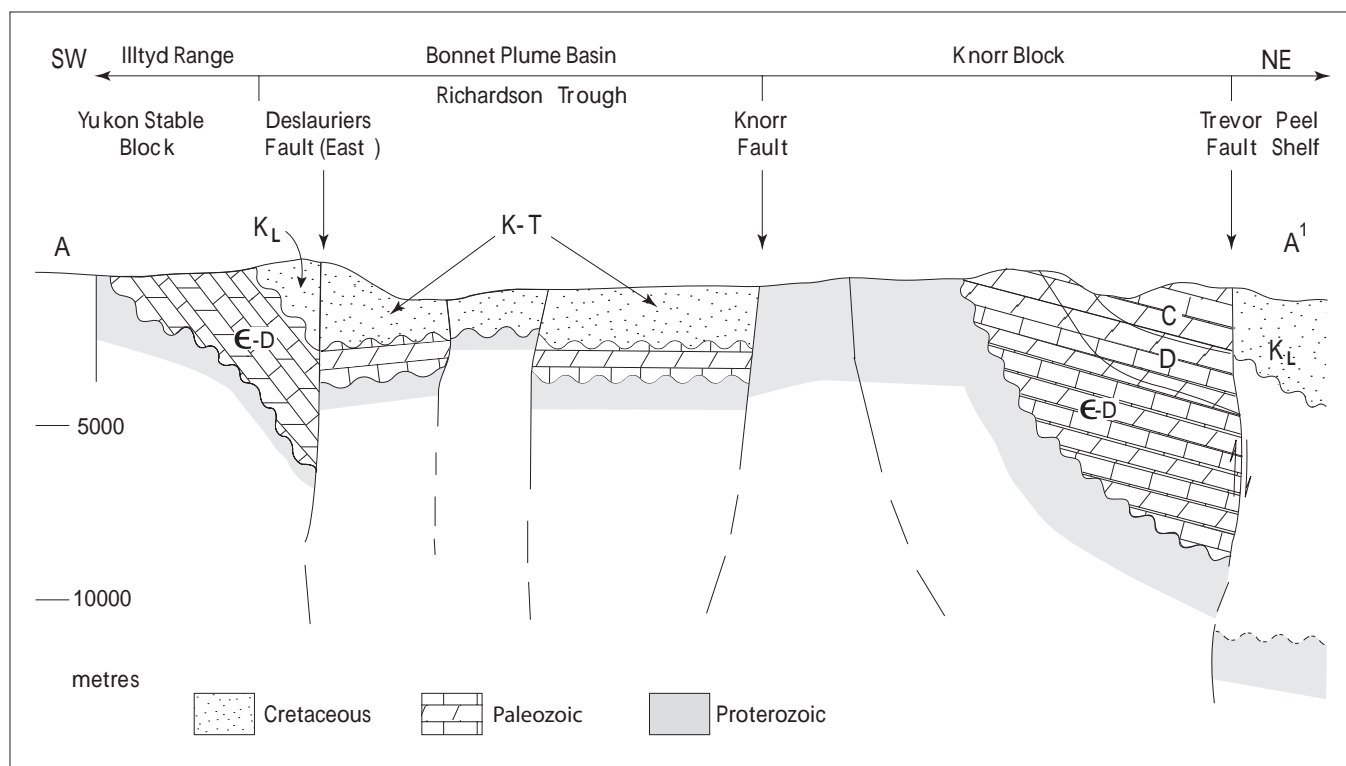


Figure 46. Schematic cross section of Bonnet Plume Basin (from Hannigan, 2000). Line of section shown on Figure 45.

Unconventional Hydrocarbon Resource Potential

Lack of well control and the limited amount of analytical work on petroleum prospectivity in Bonnet Plume Basin limits our understanding of unconventional hydrocarbon potential. Coalbed methane potential can be discussed with reference to documentation on coals in Bonnet Plume Basin, but tight reservoir and shale reservoir prospectivity is summarized only briefly, based on our knowledge of these units in Eagle Plain and Peel Plain and Plateau to the north.

Coalbed Methane

Norris and Hopkins (1977) reported the Bonnet Plume Formation in outcrop in northern Bonnet Plume Basin to comprise up to 1500 m of coarse clastic rocks lying unconformably on Paleozoic strata. Dixon (1996) showed these strata to be deposited in proximal non-marine environments at the front of the rising Cordillera to the south. Middle to Upper Albian conglomerates dominate the basal part of the formation, while sandstones, shales and lignites form an upper subdivision of uppermost Cretaceous to Paleocene age. With added information from exploratory drilling for coal, Cameron and Beaton (2000) showed an area of up to 3000 km² to be underlain by coal-bearing Bonnet Plume strata. The lower Bonnet Plume contains at least six coal zones, one of which has a maximum thickness of 9 m; the rank is sub-bituminous to high-volatile C bituminous, with low sulphur. Upper Bonnet Plume coals are less explored, but there are at least two lignite zones, one up to 17 m thick. Government of Yukon, Department of Energy, Mines and Resources (www.geology.gov.yk.ca/pdf/coal.pdf) tabulated 660 Mt of high-volatile bituminous C coal in seams of mineable thickness in Bonnet Plume Basin.

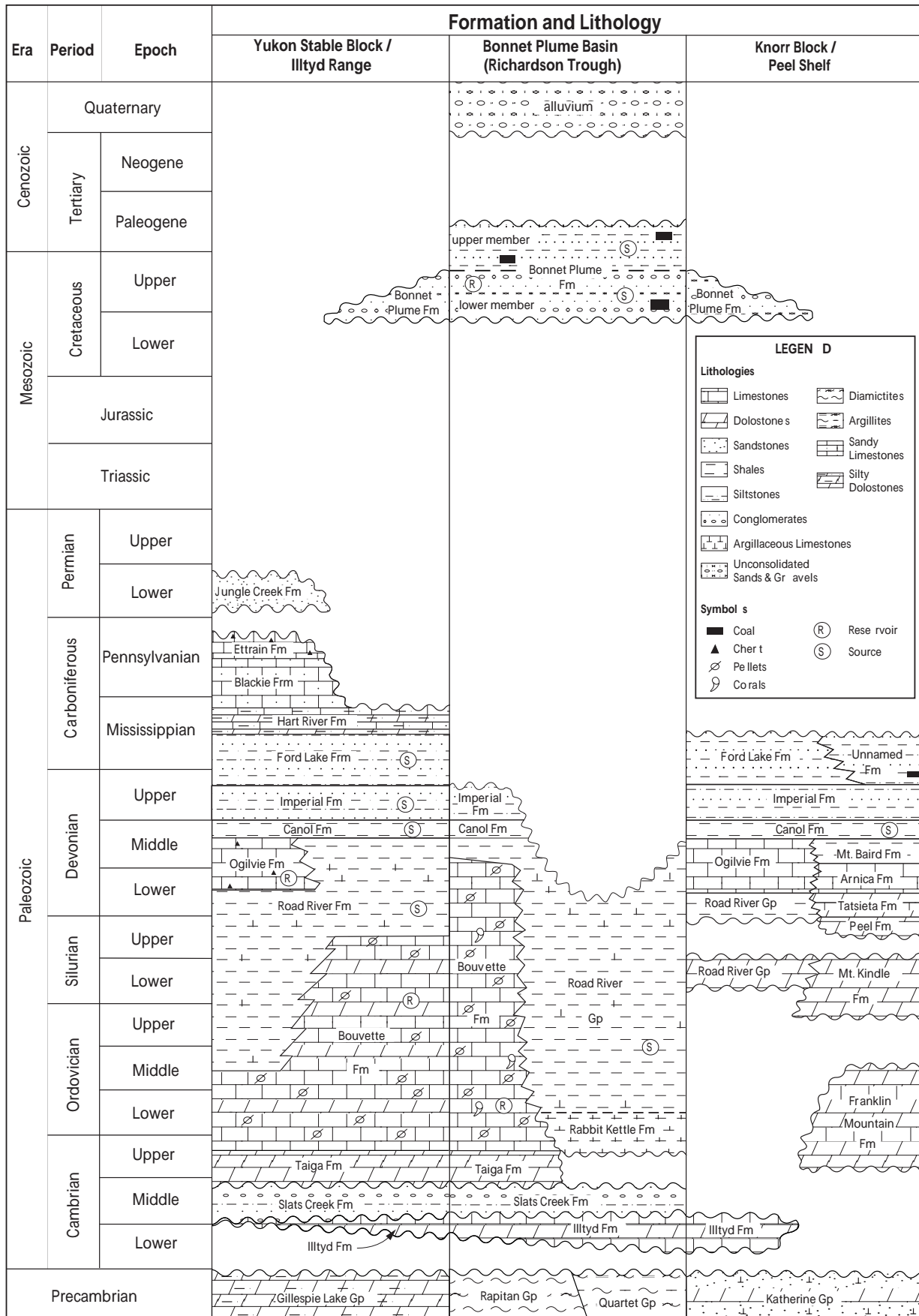


Figure 47. Stratigraphic column, Bonnet Plume Basin and surrounding areas (from Hannigan, 2000).

Lowey (2009, 2010) reported that Rock-Eval 6 evaluation shows good source potential in both lower and upper Bonnet Plume coals, with the potential for oil generation from liptinite-bearing sections. However, there has been no work reported on evaluations specific to CBM prospectivity, such as adsorbed gas capacity, hydrogeology, or detailed coal composition and cleat characteristics.

Very good coalbed methane potential may therefore exist in Bonnet Plume Basin. Substantial work is required to quantify it, including detailed structural and stratigraphic mapping, characterization of coal qualities, and a hydrogeological assessment. Such a program will require substantial financial commitment, as drilling of test holes in areas of interest will be required to gather sufficient data. Should coalbed methane be prospective in Bonnet Plume Basin, the potential for hydrocarbon liquids production from the liptinite-rich coals may be of economic interest.

Tight Reservoirs

Gas may be trapped in basin-centred hydrocarbon systems in Paleozoic carbonates of Bonnet Plume Basin, in a scenario very similar to that envisioned in Eagle Plain Basin. The same play elements are present, but no well data exist with which to assess the play. Backing up this concept, Hannigan (2000) described a conceptual conventional hydrocarbon play in Bonnet Plume Paleozoic carbonates, very similar to that described by Osadetz (2005a) in Eagle Plain Basin. However, overall prospectivity is reduced by over-mature to post-mature source rocks, and because pervasive and intense structural deformation in the basin has likely disrupted reservoir integrity and continuity.

Thick coarse clastic rocks of the Cretaceous to Tertiary Bonnet Plume Formation offer abundant conventional reservoir potential, and likely contain large mappable volumes of low-permeability rock with tight reservoir potential. Interbedded coals have been documented as good source rocks for gas and possibly oil (Lowey, 2009, 2010). However, it appears unlikely that substantial basin-centred hydrocarbon accumulations could occur within these strata, given their shallow burial depths and widespread outcrop exposure. As well, regional shales that could provide lateral and top seals to a tight hydrocarbon system have not been identified.

Shale Reservoirs

Paleozoic Road River and Canol shales are preserved in parts of Bonnet Plume Basin (Figs. 46, 47). They were deposited in southern Richardson Trough, and thus should exhibit stratigraphic and sedimentologic aspects similar to those described in Peel Plateau and Eagle Plain Basin. They are expected to have relatively low prospectivity as shale reservoirs, however, as they are likely over-mature to post-mature, and because intense structural deformation in the basin has likely disrupted reservoir integrity and continuity. Lowey (2009) reported poor to fair TOC values, and probable post-mature conditions for Road River samples in and adjacent to Bonnet Plume Basin.

Carboniferous and Cretaceous shales with shale prospectivity in Peel Plateau and Eagle Plain are not preserved in Bonnet Plume Basin. "Oil shales" in the Cretaceous section reported by Lowey (2009, 2010) have not been described in detail, but likely occur at shallow depths, unsuitable for exploitation by horizontal drilling.

Whitehorse Trough

Whitehorse trough is a structurally-complex basin, which is interpreted to have formed within the assemblage of exotic terranes accreting to the western margin of the North American craton in Mesozoic time (Long, 2005). It forms part of Stikine terrane, and extends about 650 km from Carmacks in south-central Yukon, southward to Dease Lake in BC (Figs. 14, 48). It is bounded in Yukon by deformed and metamorphosed Paleozoic rocks of Yukon-Tanana terrane.

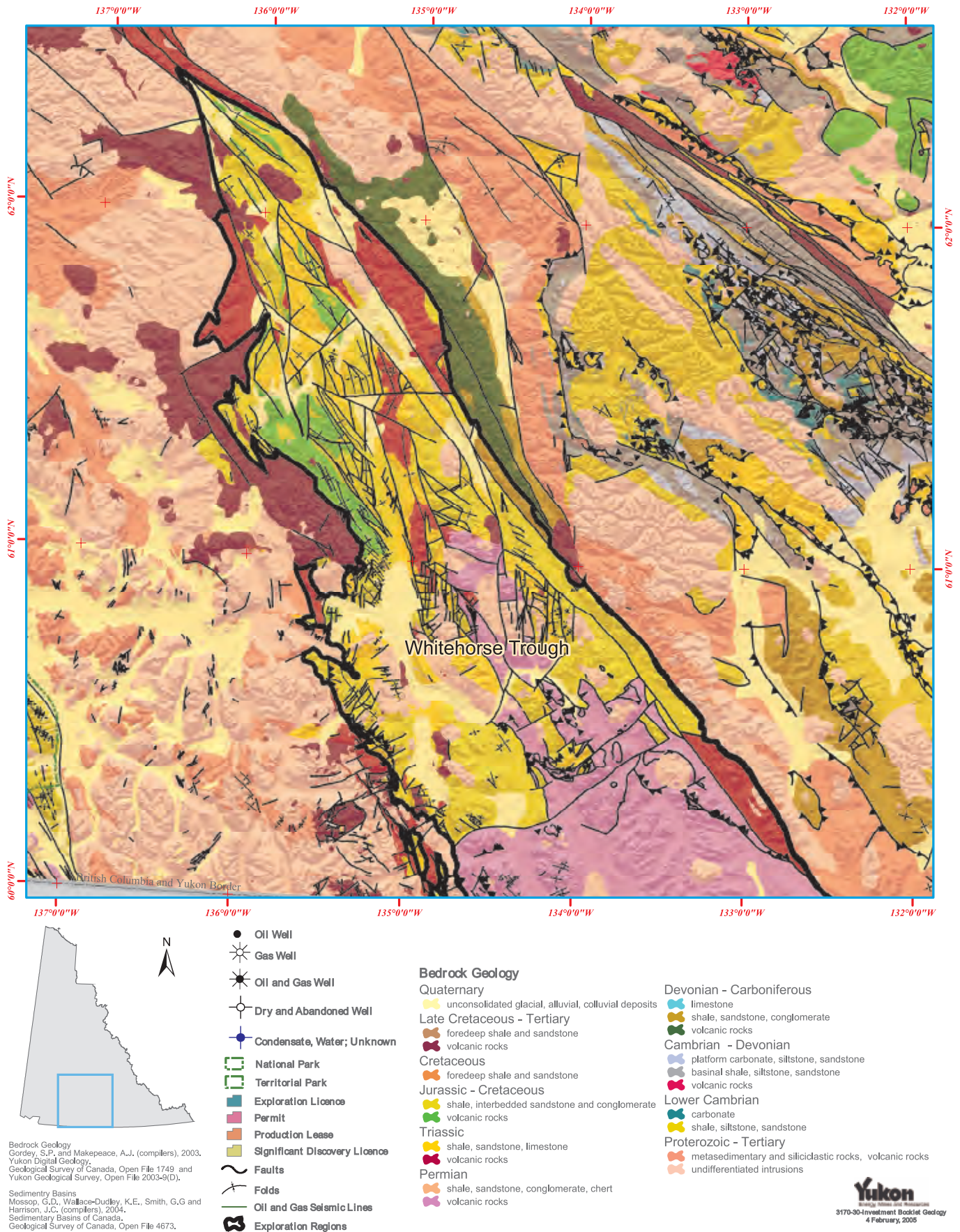


Figure 48. Geological base map of Whitehorse trough, highlighting structural complexity and sharp bounding faults (from Department of Energy, Mines and Resources, 2011).

Sedimentary fill of Whitehorse trough dates from Late Triassic time, when alluvial to marginal marine coarse clastics and shallow marine carbonates were deposited in association with volcanic rocks in a magmatic arc setting. This entire assemblage is included in the Lewes River Group (Fig. 49; English *et al.*, 2005). Basin-margin coarse clastics and basin-axial deepwater mudstones of the Laberge Group accumulated during the Jurassic, in a complex arc-basin setting with continued active volcanic input. Whitehorse trough took its present form during Late Jurassic to Early Cretaceous deformation. Thick, coal-bearing non-marine conglomeratic sediments of the Tantalus Formation were shed from newly-uplifted terranes and deposited unconformably on older strata in smaller, fault-bounded sub-basins.

White *et al.* (2006) undertook a preliminary interpretation of a west-east regional seismic transect of the basin, and concluded that the Mesozoic section reached a total thickness of up to 7000 m. Broad antiformal and synformal structures were noted, truncated by relatively steep faults with up to 4000 m of vertical relief (Fig. 50).

Exploration History and Conventional Hydrocarbon Resources

NEB (2001b) reviewed the issuance of a number of exploration permits between 1953 and 1980, upon which numerous geological mapping and reconnaissance programs were undertaken. PetroCanada undertook fieldwork in 1985, with geochemical sampling and reservoir analysis, but no permitting has taken place since that time. No exploratory wells have been drilled, nor has any seismic data been acquired by exploration companies. Yukon Geological Survey and Geological Survey of Canada jointly acquired 170 km of 2D seismic data in 2004, in a west-east transect across northern Whitehorse trough (White *et al.*, 2006).

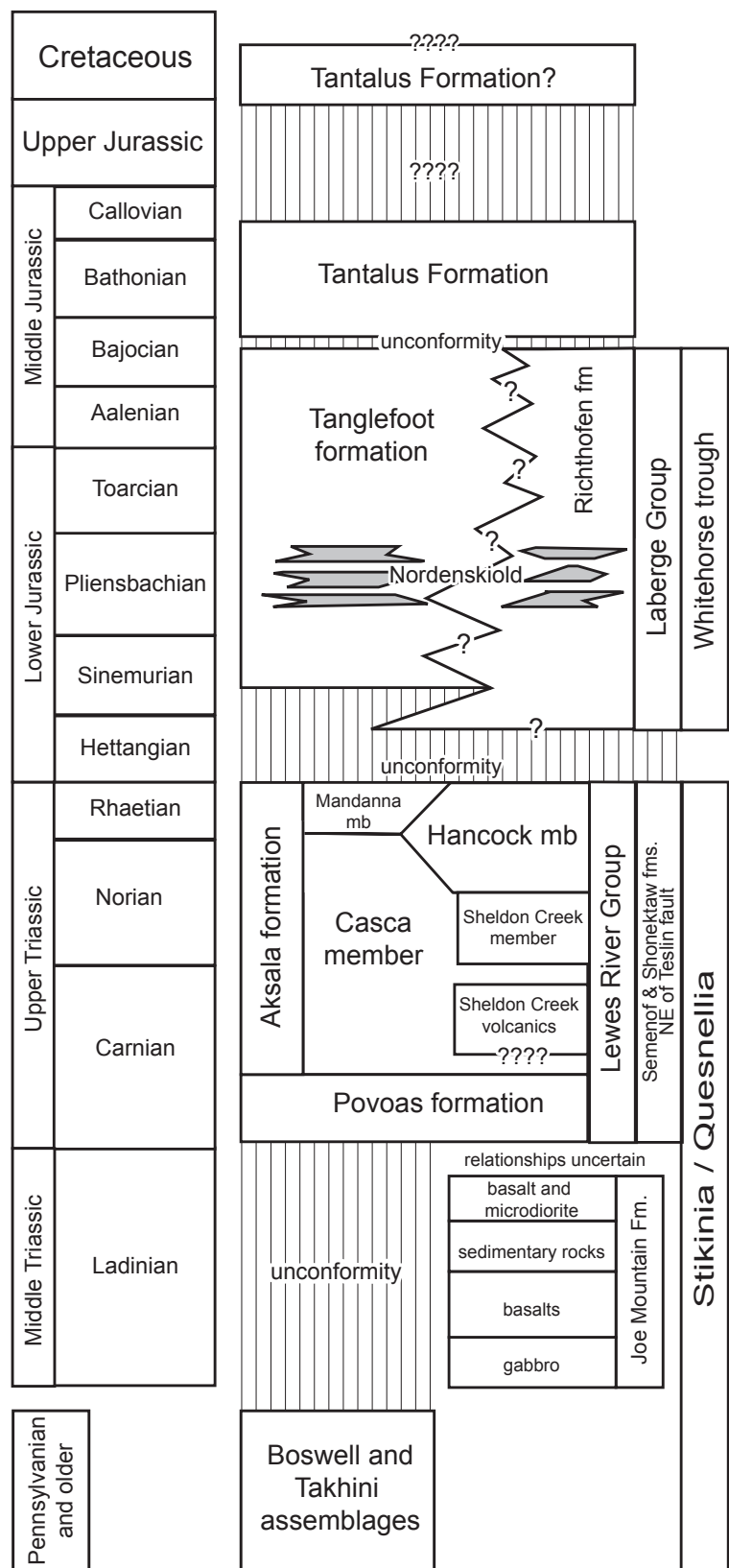


Figure 49. Stratigraphic column, Whitehorse trough (from Colpron, 2010).

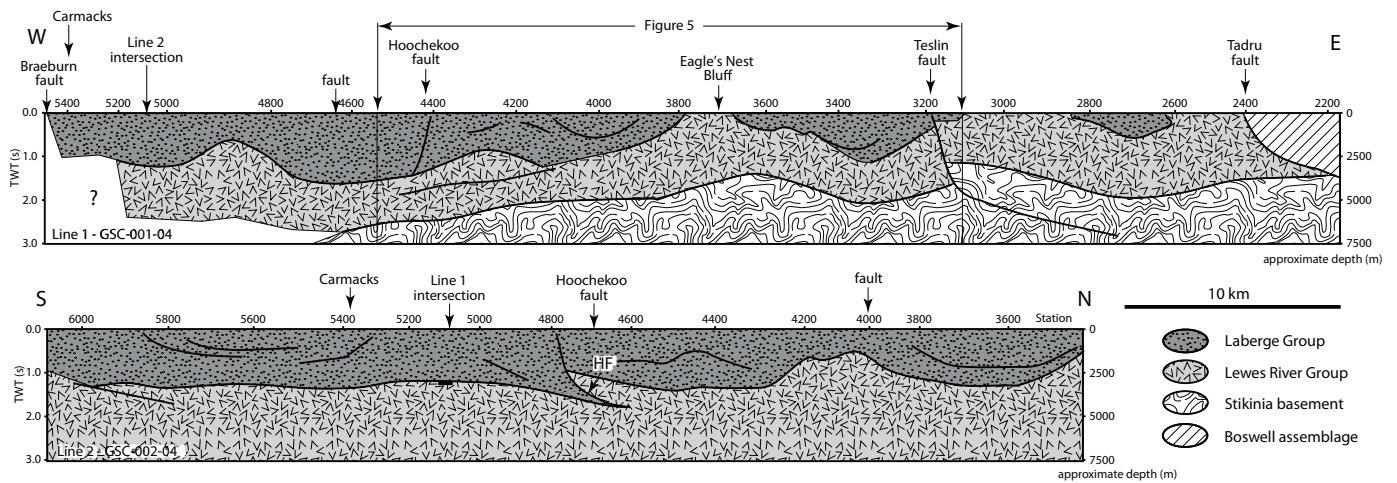


Figure 50. Schematic interpretation of west-east seismic transect across northern Whitehorse trough (from White *et al.*, 2006).

Oil and gas seeps have been reported in Whitehorse trough, but none have been verified as naturally-occurring. Lewes River Group carbonates were noted to be locally bituminous in outcrop (NEB, 2001b), and Lowey and Long (2006) noted the occurrence of pyrobitumen in these rocks as well.

NEB (2001b) identified eight conceptual plays, two structural and six stratigraphic, prospective primarily for gas. Their statistical summary showed mean total play potential of $1.29 \times 10^6 \text{ m}^3$ (8.1 million barrels) recoverable oil, and $5.5 \times 10^9 \text{ m}^3$ (0.2 TCF) marketable gas for the entire basin. Long (2005) and Lowey *et al.* (2009) expressed doubt about the definition of some of these plays, based upon ongoing stratigraphic analysis of the basin. Government of Yukon, Department of Energy, Mines and Resources (2011) reported a somewhat different list of plays, with total mean play potential of $6.3 \times 10^6 \text{ m}^3$ (39.6 million barrels) oil, and $12.0 \times 10^9 \text{ m}^3$ (0.42 TCF) gas. English *et al.* (2005) identified three conceptual gas plays in the central Whitehorse trough in British Columbia, south of the Yukon border, but did not undertake a quantitative analysis of play potential.

Hayes (2012) has recently completed a new petroleum resource assessment of Whitehorse trough, based upon recent advances in knowledge of Whitehorse trough petroleum systems and prospectivity. Hydrocarbon prospectivity was assigned to nine plays, including three unconventional plays (Tanglefoot CBM, Tantalus CBM, and Richthofen Tight Gas / Shale Gas). Systematic statistical analysis of conceptual conventional plays yielded an arithmetic unrisksed mean of $82.3 \times 10^9 \text{ m}^3$ (2920 BCF) gas in-place and $17.1 \times 10^6 \text{ m}^3$ (107 MMstb) oil in-place. Data available were not sufficient to quantitatively assess unconventional plays.

Unconventional Hydrocarbon Resource Potential

Coalbed Methane

Whitehorse trough contains large quantities of coal in the Jurassic Tanglefoot Formation and Upper Jurassic-Cretaceous Tantalus Formation (Fig. 60). Ricketts (1984) catalogued at least 15 locations throughout the Yukon portion of the basin. Cameron and Beaton (2000) identified three areas where exploration and/or mining have taken place – the northerly Tantalus/Carmacks (up to 3 zones with a maximum thickness of 2.5 m), central Division Mountain (15 seams grouped into two zones, of which one has a maximum thickness of 15 m), and southerly Mount Granger (8 coal zones with a maximum thickness of 13 m) areas. Allen (2000) placed the coals at Division Mountain in the upper Tanglefoot

Formation, where she found 14 major coal seams ranging 1.7-17.3 m thick, and numerous subordinate seams, aggregating between 10 and 32 m thick across the area. A number of field reports and earlier studies are referenced and/or summarized in these papers.

Whitehorse trough coals are generally classified as high-volatile bituminous, although higher ranks have been noted locally where contact metamorphism has taken place. Several workers have evaluated them in terms of source rock potential – for example, Lowey *et al.* (2009) concluded:

“Tanglefoot Formation is a good source rock that is immature to early mature and gas-prone. The Tantalus Formation is also a good source rock that is immature to early mature and gas-prone”.

Lowey and Long (2006) and Lowey *et al.* (2009) also suggested that these coals may be capable of generating liquid hydrocarbons, although substantial liptinite-rich coals have not been mapped in the basin.

Coal evaluations to date have been undertaken primarily to assess mineable resources, with a secondary focus on hydrocarbon-generative and CBM potential. As well, data have come only from outcrop exposures and local shallow drilling programs. Thus, the distribution of coals throughout the subsurface and their hydrogeological regimes are essentially unknown.

Hayes (2012) identified CBM prospectivity in both the Tanglefoot and Tantalus formations, but regarded both plays as speculative because sufficient data to support numerical estimates of resource potential are lacking. Overall, it appears that Whitehorse trough is highly prospective for CBM, perhaps with associated liquids. However, a great deal of subsurface work is required to identify the most prospective areas and their productive characteristics.

Tight and Shale Reservoirs

Hayes (2012) envisioned fine-grained sandstones, siltstones and shales of the basinal Jurassic Richthofen Formation as possible unconventional reservoirs in a basin-centred tight gas / shale gas setting. Clear definition and regional mapping of Jurassic Laberge Group stratigraphic relationships make it possible to define this potential (Lowey *et al.*, 2009; Colpron, 2011). The presence of a basin-centred petroleum system is entirely speculative in the absence of firm evidence such as hydrocarbon shows and subsurface tests demonstrating anomalous pressure conditions attributable to isolation from hydrostatic gradients associated with regional aquifers.

Source rock richness and maturity is a significant risk for the Richthofen basin-centred play. Lowey *et al.* (2009) reviewed Rock-Eval results from 70 samples and concluded that the Richthofen contains generally low TOC (mean 0.45% and maximum 3.02%) and is postmature for oil generation. Very low S_2 values make T_{max} values obtained from Rock-Eval analysis unreliable, but vitrinite reflectance of 1.41 % R_o and the presence of black and degraded palynomorphs (thermal alteration index > 4) confirm high thermal maturity. English *et al.* (2005) documented more favourable source rocks in the equivalent Inklin Formation on the northeastern B.C. side of the basin, providing encouragement that better source rock remains to be found in Yukon.

The Richthofen Formation is prospective beneath younger rocks, and where it crops out throughout the south-central part of the basin (Fig. 49). The chance for a basin-centred petroleum system to occur is best where the Richthofen is thick, such that impermeable strata in the upper part of the formation can isolate hydrocarbon-bearing sections deeper within the basin. Areas with lesser degrees of structural

deformation, particularly faulting, are likely to be more prospective, as faulting may breach the basin-centred regime. If the play does exist, it could be very large, given the widespread presence of thick Richthofen strata in the southern part of the basin.

Kandik Basin

Kandik Basin is a structural depression, elongated southwest-northeast, straddling the Yukon/Alaska border southwest of Eagle Plain Basin (Figs. 14, 51). It formed as a structurally-controlled depositional site in Albian time, and was complexly deformed during subsequent Laramide tectonic events (Norris, 1997; Hannigan *et al.*, 2000). It comprises three separate areas, bounded to the southwest by the Tintina Fault, which separates it from crystalline rock complexes, to the east by the Ogilvie Mountains, and to the northwest by the Yukon Thrust (Figs. 51, 52).

Phanerozoic sedimentary rocks range in excess of 11 km thick. Much of our knowledge of the stratigraphic section derives from outcrop and regional studies, as the basin is structurally complex and only lightly explored (Figs. 14, 53, 54).

Exploration History and Conventional Hydrocarbon Resources

Three wells have been drilled on the Canadian side of the Kandik Basin, all between 1970 and 1972, based upon surface structure mapping and a total of 180 km of 2D seismic data (Fig. 52). On the Alaska side, one well was drilled in 1976, followed in 1977 by two wells to the northwest in the Yukon Flats Basin (Hannigan *et al.*, 2000).

Petroleum systems in Kandik Basin are inferred to exist because of the presence of viable source rocks and reservoirs, and abundant structural traps. However, no hydrocarbon shows were encountered in any of the Canadian wells. Hite (1997) reported the presence of “live oil seeps”, and of bitumen at more than 20 locations, but did not map the distribution of these shows (although they are presumably in Alaska).

Hannigan *et al.* (2000) identified three conceptual play types, each prospective for oil and gas in different areas. Their statistical summary showed mean total play potential of $54 \times 10^6 \text{m}^3$ (340 million barrels) oil in place, and $38 \times 10^9 \text{m}^3$ (1.3 TCF) gas in place for the entire basin. If one assumes the largest discoveries of oil and gas are made on the Yukon side of the border, then Yukon mean total play potential is $25.5 \times 10^6 \text{m}^3$ (160 million barrels) oil in place, and $24 \times 10^9 \text{m}^3$ (0.85 TCF) gas in place. Howell (1995) discussed two hypothetical plays on the Alaska side of the basin, emphasizing the rich source rock potential.

Unconventional Hydrocarbon Resource Potential

Coalbed Methane

The Upper Cretaceous Monster Formation is a thick (up to 2000 m) package of coarse-grained non-marine sediments deposited in front of the rising Cordillera, in a setting very similar to the Bonnet Plume Formation in Bonnet Plume Basin (Dixon, 1996). Hannigan *et al.* (2000) reported the presence of thin coals, based on field work by Ricketts (1988). Cameron and Beaton (2000) noted “substantial resources” of low-rank coal, mainly lignite, along the Tintina Fault Zone in this geographic area; these were noted in the regional coal inventory produced by Ricketts (1984). Government of Yukon, Department of Energy, Mines and Resources coal brochure (www.geology.gov.yk.ca/pdf/coal.pdf) does not highlight these coals as a significant resource.

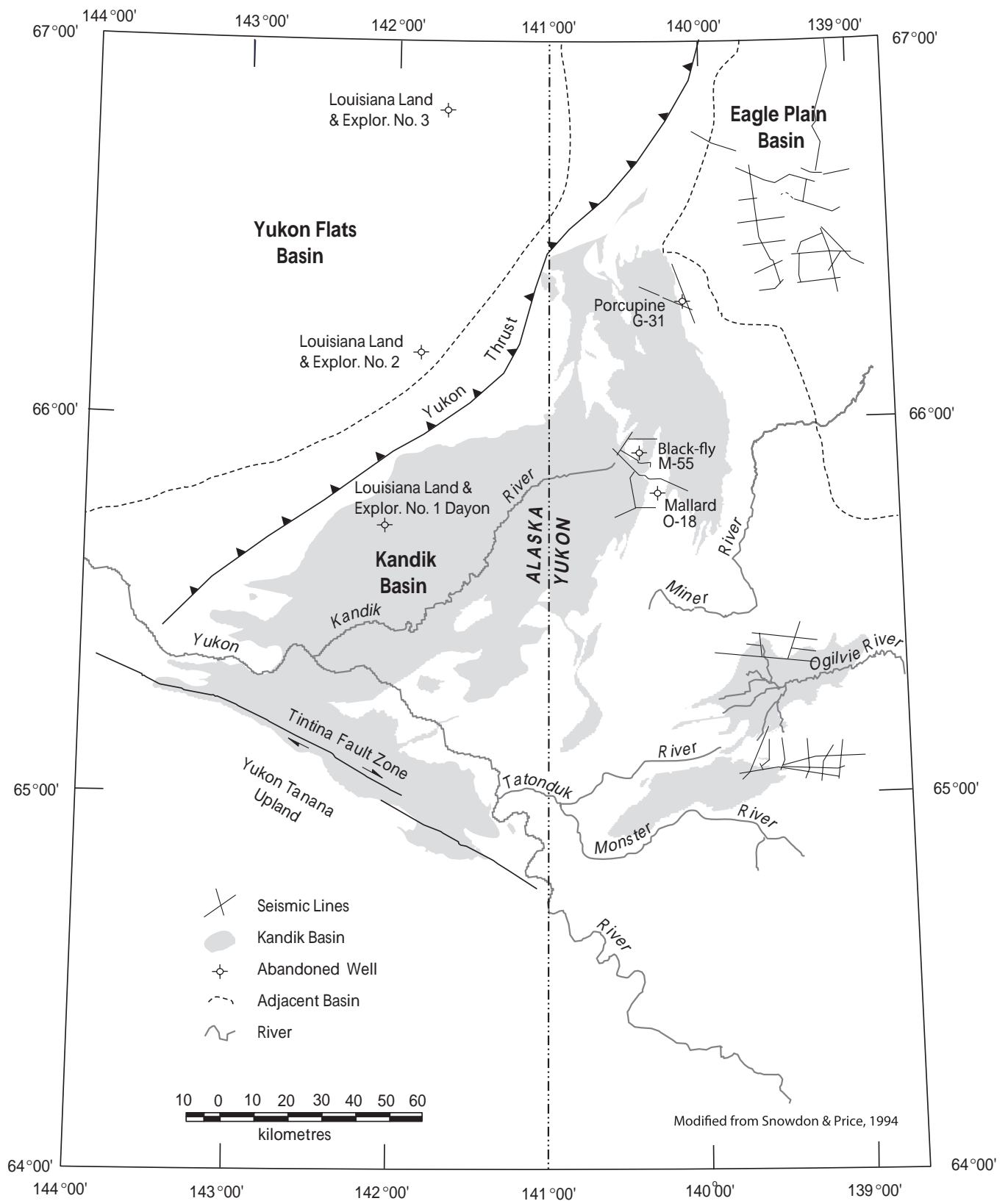
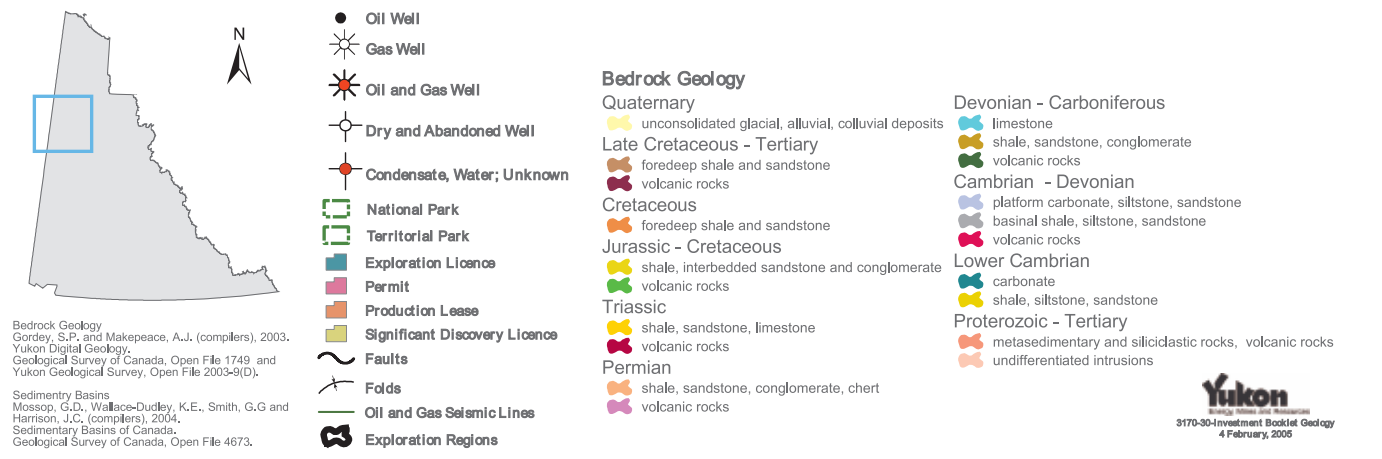
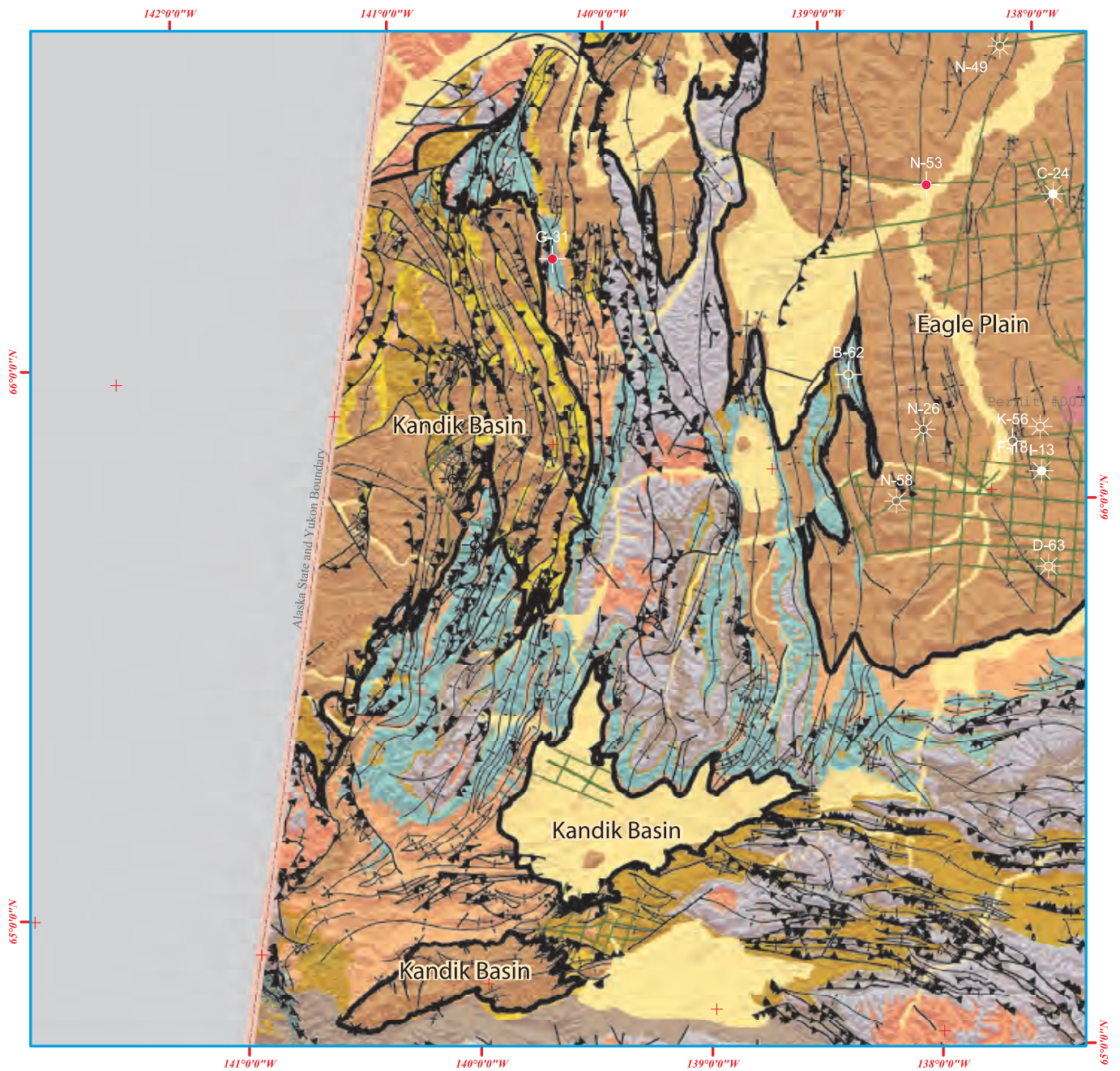


Figure 51. Base map of Kandik Basin, showing well locations in Yukon and Alaska, 2D seismic data, and adjacent basins (from Hannigan et al., 2000).



Bedrock Geology
Gordy, S.P. and Makepeace, A.J. (compilers), 2003.
Yukon Digital Geology,
Geological Survey of Canada, Open File 1749, and
Yukon Geological Survey, Open File 2003-9(D).

Sedimentary Basins
Mossop, G.D., Wallace-Dudley, K.E., Smith, G.G and
Harrison, J.C. (compilers), 2004,
Sedimentary Basins of Canada,
Geological Survey of Canada, Open File 4673.



Figure 52. Geological map, Kandik Basin area (from Department of Energy, Mines and Resources, 2011).

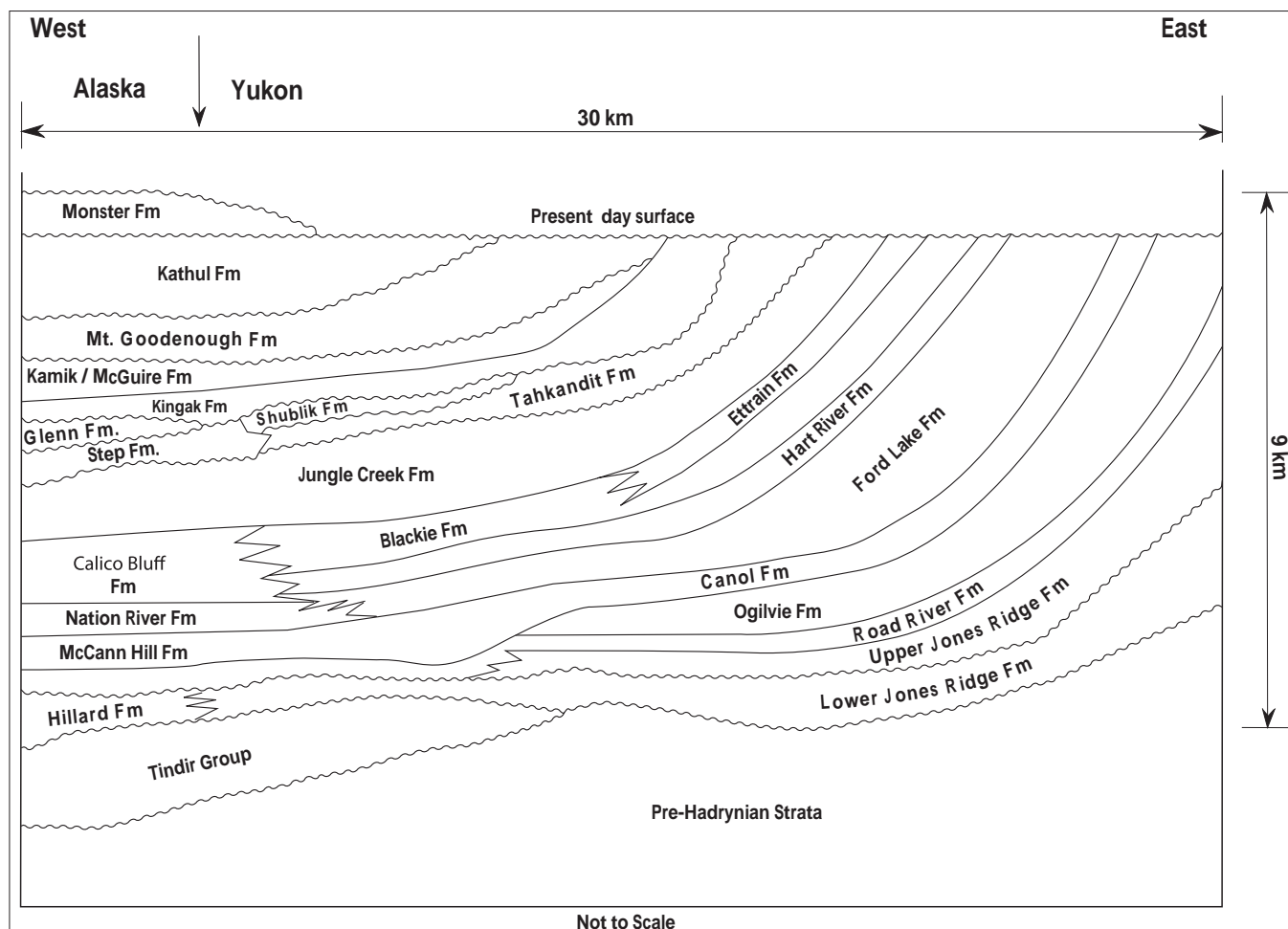


Figure 53. Schematic stratigraphic cross section, Kandik Basin (from Hannigan et. al., 2000).

Coalbed methane potential in Kandik Basin must be regarded as low, based upon the description of thin coal seams of low rank, exposed at surface or buried at shallow depths. As the depositional history of the Monster Formation is similar to the Bonnet Plume, it may be possible that additional field work and drilling may reveal more prospective coal seams in lower, more deeply-buried parts of the Monster.

Tight Reservoirs

As noted in other basins where Paleozoic carbonate shelf facies pass to basinal shales, potential exists for the development of a basin-centred hydrocarbon system, where conventional and tight carbonate reservoirs are sealed by shales that serve also as source rocks. In Kandik Basin, prospectivity for this play type must be regarded as relatively low, as the encasing shales are over-mature (Snowdon and Price, 1994), and pervasive and intensive structural deformation reduces potential for integrity and continuity of the carbonate reservoirs – a situation similar to Bonnet Plume Basin.

Jurassic and Cretaceous sandstones may offer tight reservoir potential, with hydrocarbon charge provided by deeper source rocks or Monster Formation coals. However, as in Bonnet Plume Basin, shallow burial depths, lack of regional seals, and structural complexity greatly reduce the chances for regional basin-centred accumulations to be preserved.

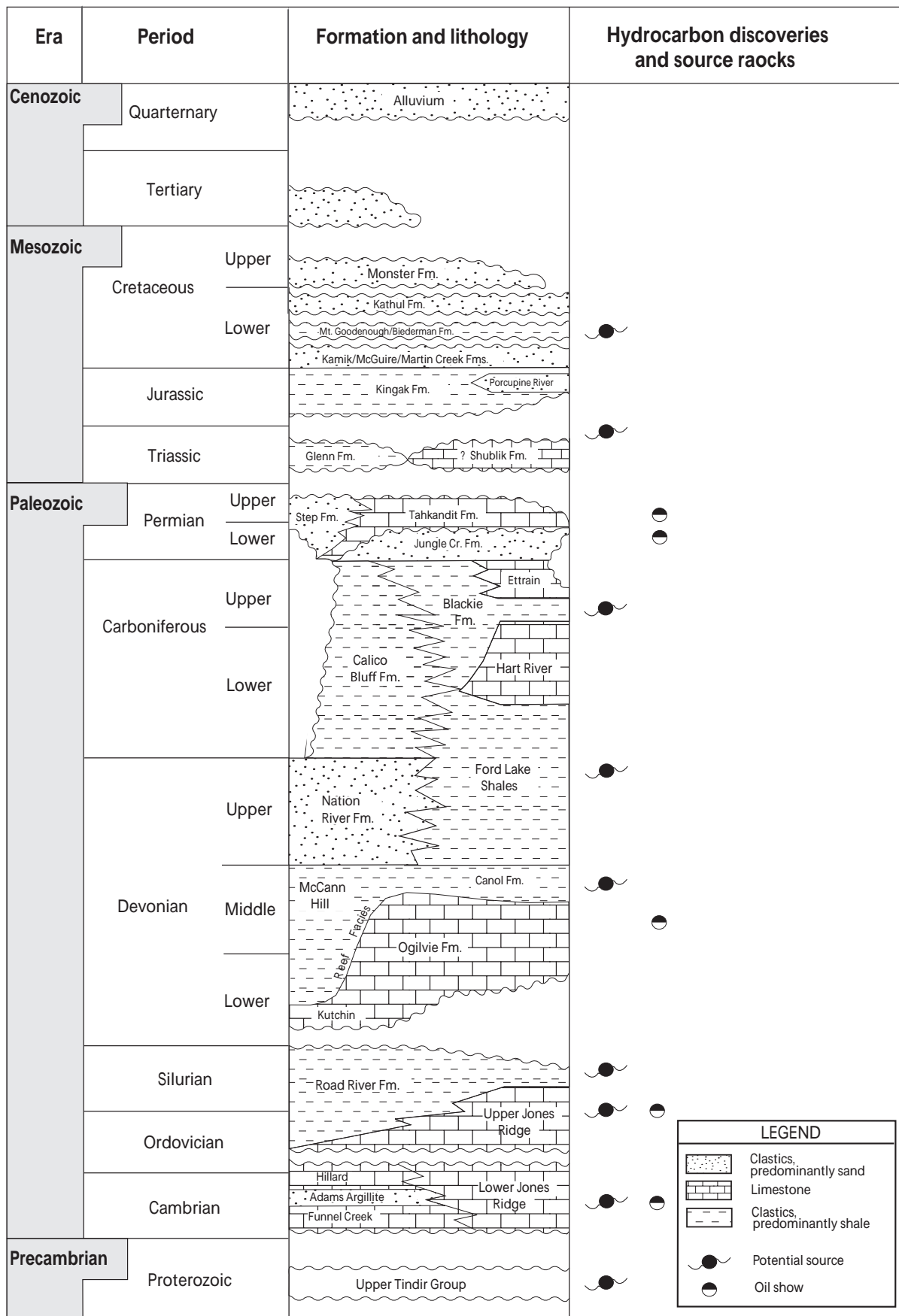


Figure 54. Stratigraphic column, Kandik Basin (from Hannigan et al., 2000).

Shale Reservoirs

Paleozoic shales with source rock characteristics – Road River Group, Canol, Blackie, and Ford Lake formations – better-known from basins to the east are present in Kandik Basin. Snowdon and Price (1994) presented Rock-Eval/TOC data from the three Canadian wells, demonstrating that these shales are generally over-mature, with low to moderate residual TOC values. On the Alaskan side, shales of the Triassic Glenn Formation are regarded as rich, oil-prone source rocks (Howell, 1995; Hite, 1997). Unfortunately, it appears that this unit is not widely-distributed on the Yukon side (Fig. 53). Hannigan *et al.* (2000) did not mention any work done to characterize source rock potential in Jurassic Kingak or Cretaceous Mount Goodenough shales; it appears likely that they are relatively lean and immature, based upon their characteristics in adjacent basins.

There appears to be little shale reservoir potential in Kandik Basin. Scant reservoir data are not encouraging, and the highly-faulted nature of the basin is not favourable for preservation of laterally-extensive shale reservoirs. The best situation to be hoped for is that future seismic and geological mapping can identify prospective Glenn shales on the Yukon side of the basin.

Yukon North Coast

Beaufort-Mackenzie Basin is a major frontier hydrocarbon province, the southwestern margin of which lies onshore in Yukon (Fig. 14). It is sharply fault-bounded on its landward margins – in Yukon by uplifted Proterozoic and Lower Paleozoic strata of the British and Richardson Mountains (Fig. 55). The basin is underlain by complexly deformed Proterozoic through Tertiary strata, which can be subdivided into four tectonostratigraphic assemblages separated by regional unconformities described by Dixon *et al.* (1994) and Hannigan (2001b; Fig. 56). The basin fill thins sharply landward, and comprises primarily Upper Cretaceous to Holocene sediments (Figs. 57, 58).

Exploration History and Conventional Hydrocarbon Resources

Tens of thousands of line-kilometres of 2D seismic data have been acquired offshore and onshore in Beaufort-Mackenzie Basin since the early 1960's. The first wells were drilled in 1962 and since then, 247 wells have been completed, with 53 oil and gas discoveries (Hannigan, 2001b). Dixon *et al.* (1994) estimated that 10.4 to 12.6 TCF of gas and 1.5 to 2.0 billion barrels of oil have been discovered to date; estimates are based only upon test data and volumetric calculations, as production infrastructure is not in place.

On the Yukon North Coast, a widely-spaced grid of seismic data have been acquired, and only three exploratory wells have been drilled, all dry and abandoned (Fig. 55).

Hannigan (2001b) assessed hydrocarbon potential on the Yukon North Coast, but in considering geologically-based play fairways, his assessment included areas in Northwest Territories as well. Six immature and conceptual exploration plays were identified – two oil plays with a median play potential of $39.8 \times 10^6 \text{ m}^3$ (250 million barrels) oil in place, and four gas plays with a median play potential of $38.6 \times 10^9 \text{ m}^3$ (1.4 TCF) gas in place. Median play potential in Yukon alone is considerably smaller, depending upon whether one assumes the largest undiscovered pool on any play lies within or outside Yukon borders.

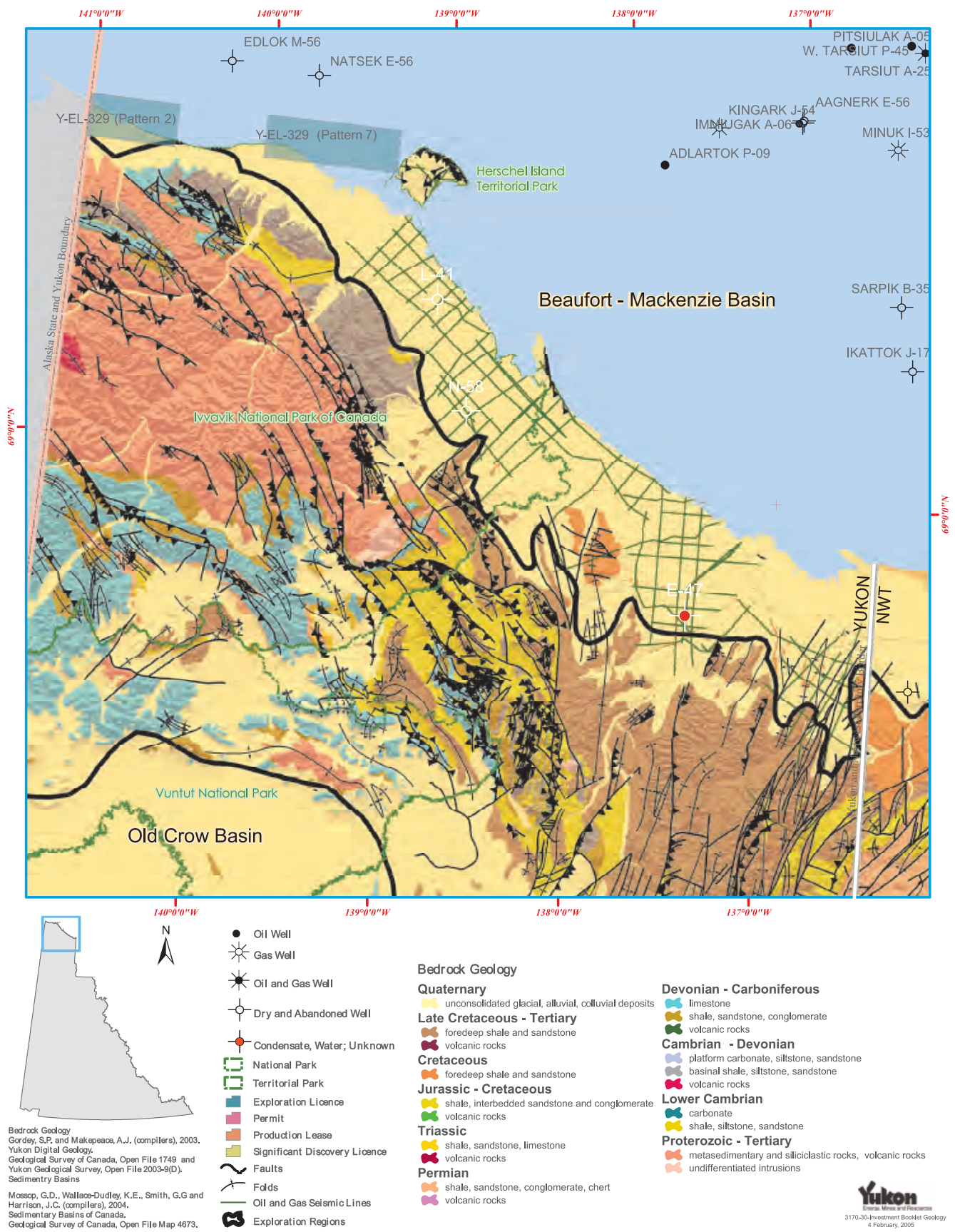


Figure 55. Geological base map of Beaufort-Mackenzie Basin / Yukon North Coast, highlighting exploratory wells and 2D seismic data (from Department of Energy, Mines and Resources, 2011).

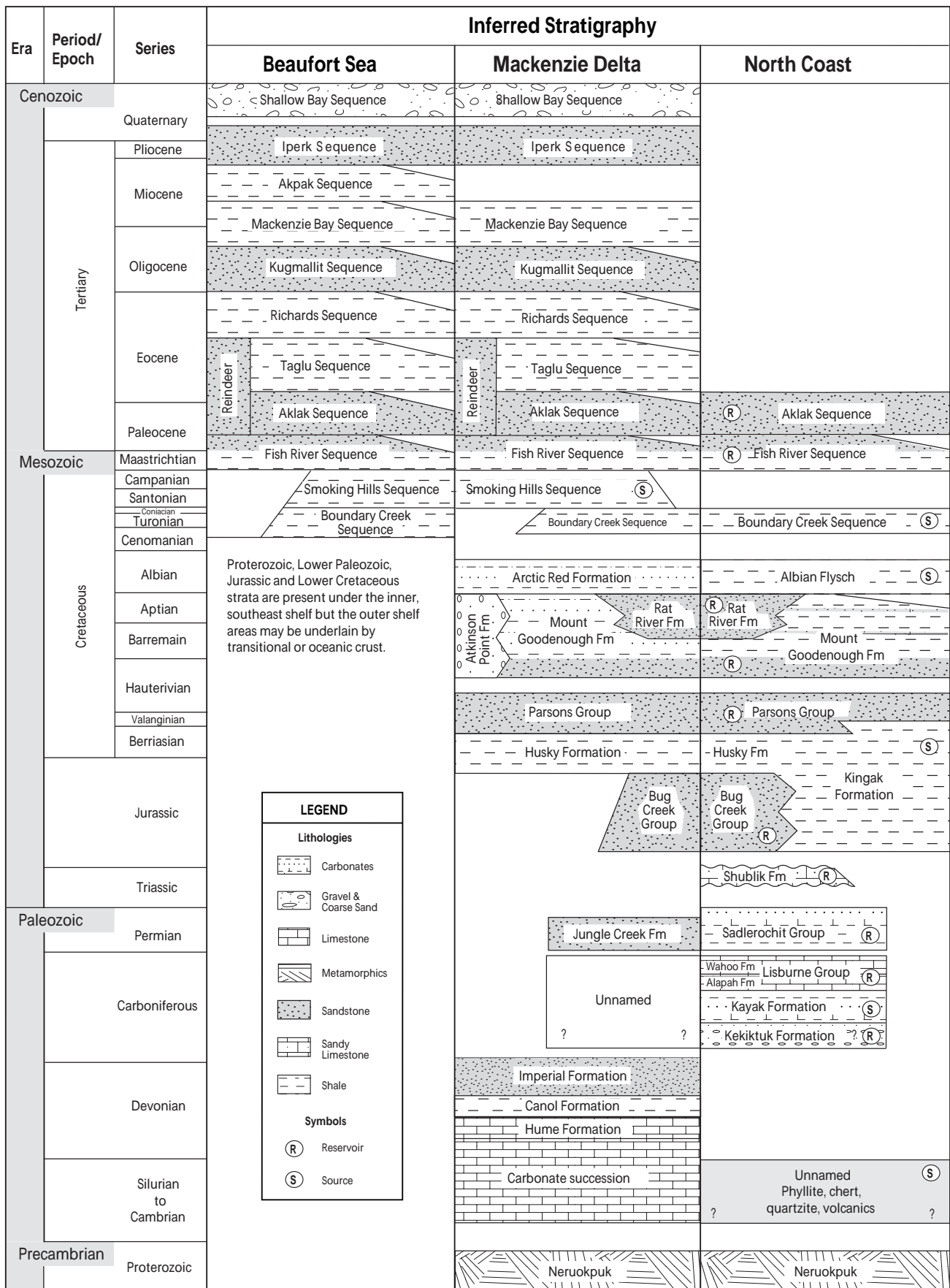


Figure 56. Stratigraphic column, Beaufort-Mackenzie Basin and Yukon North Coast (from Hannigan, 2001b).

Unconventional Hydrocarbon Resource Potential

Coalbed Methane

Coals are interbedded with sandstones in the basal part of the Carboniferous Kayak Formation in outcrops in the British Mountains. Cameron *et al.* (1994) described the coal as semi-anthracite to anthracite, and noted the presence of at least one seam greater than 5 m thick that can be traced laterally up to 4 km. Ricketts (1984) mapped three occurrences of thin bituminous coal seams in Cretaceous outcrop in the northeastern North Coast area, immediately west of the NWT border, and another outcrop with thicker seams immediately east of the border.

Kayak Formation coals present little CBM prospectivity, as their extent and characteristics in the subsurface have not been established. Cretaceous coals, while potentially representing relatively continuous and extensive coastal plain / deltaic deposits, have limited prospectivity because of shallow burial depths. Conceptually, coals may have been deposited in proximal facies in several Cretaceous sequences in the North Coast region, but further drilling and stratigraphic work must be undertaken to establish their presence, extent, and characteristics.

Tight Reservoirs

Little tight reservoir prospectivity can realistically be ascribed to pre-Mesozoic strata in the North Coast area, as equivalent strata are known only from highly-deformed outcrop sections in the British and Richardson Mountains to the south, and from outcrop and well control in Alaska to the west. With the presence of several unconformities, and rapid thinning of the sedimentary section landward (Fig. 57), it is not clear whether pre-Mesozoic strata are even preserved at the landward edge of the basin. Paleogeographic reconstructions by Richards *et al.* (1996) suggest that the North Coast area was emergent during much of the Carboniferous and Permian.

Proximal to distal marine sandstones are conventional reservoir targets in the

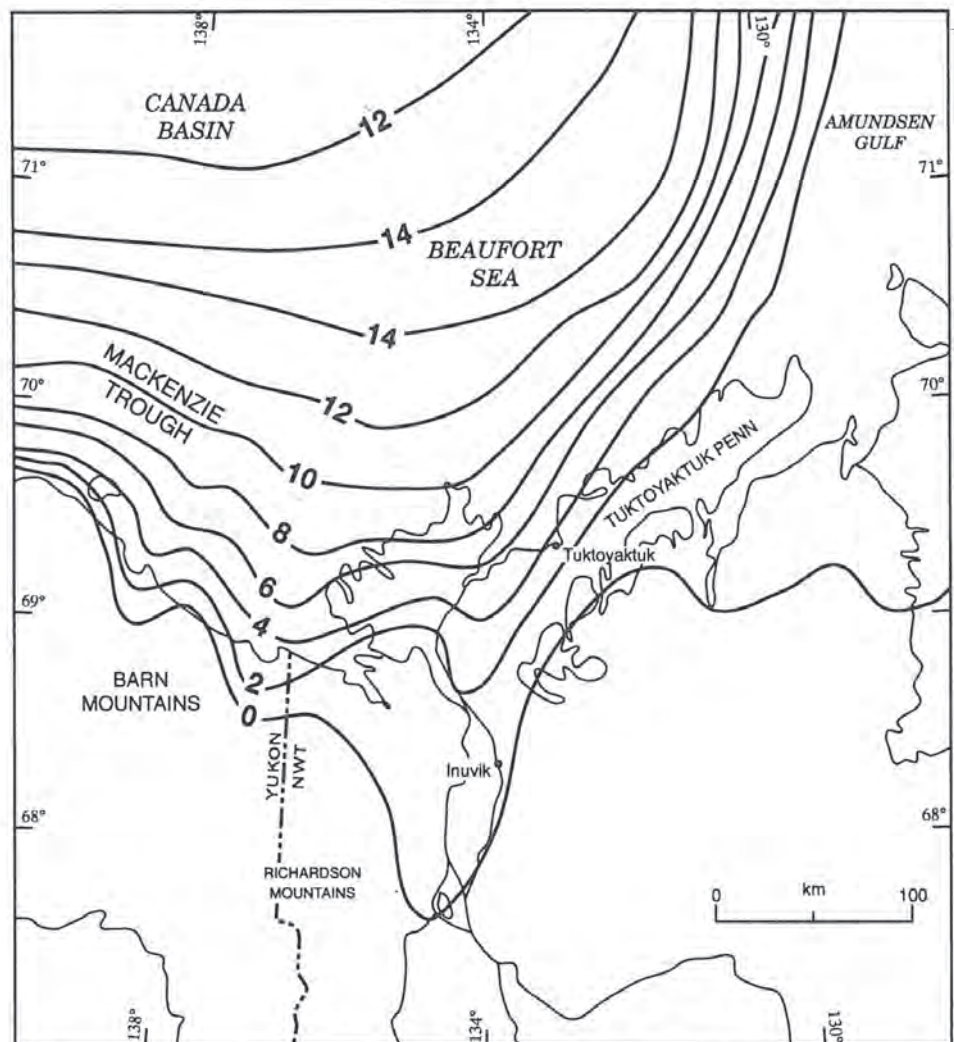


Figure 57. Isopach of Beaufort-Mackenzie basin fill (contour interval 1000 m), made up primarily of Upper Cretaceous to Holocene sediments. Note limited distribution of basin fill onshore Yukon (from Dietrich and Dixon, 1996).

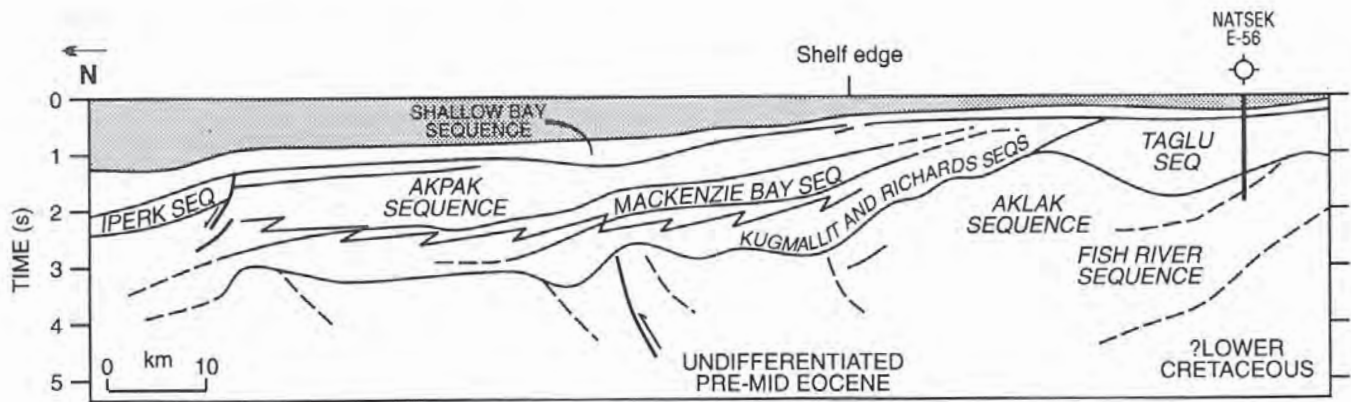


Figure 58. Schematic structural-stratigraphic cross section, western Beaufort Sea (note location of well Natsek E-56, shown on Figure 55) (from Dietrich and Dixon, 1996).

Jurassic-Cretaceous succession of stacked progradational clastic wedges (Fig. 56; Hannigan, 2001b). Relatively distal sandy facies may be encased in basinal shales, and would present considerable potential for extensive basin-centred hydrocarbon accumulations. Additional well and seismic control in the North Coast area will be required to define potentially prospective trends, and to acquire reservoir characterization data.

Shale Reservoirs

Lower Paleozoic basinal shales, equivalent to the Road River Group, were deposited across Northern Yukon and into the current North Coast and offshore areas (Norford, 1996). Subsequently, however, these rocks have been complexly deformed and mildly metamorphosed. It thus appears unlikely that they would retain shale reservoir prospectivity, even if preserved in the onshore part of the basin. Carboniferous through Permian shales and carbonates described in outcrop by Richards *et al.* (1996) may also present some shale reservoir prospectivity, but their distribution and reservoir characteristics are essentially unknown in the North Coast area, as noted above.

Distal fine clastic facies dominate the Jurassic-Cretaceous succession in the North Coast area, and are prospective as shale reservoirs. Jurassic Kingak and Husky shales and Lower Cretaceous Mount Goodenough shales are rich in terrestrial (Type III) organic material, and thus are prospective for gas (Poulton, 1996). Younger Cretaceous shales such as the Boundary Creek sequence are more prospective for liquids (Hannigan, 2001b). On a regional basis, these strata are relatively thick, widely distributed, and undeformed – but are not well known locally in the North Coast area because of lack of stratigraphic control. As well, no work on shale reservoir characterization has been reported.

Future shale reservoir exploration on the North Coast should focus on delineation and characterization of Jurassic and Cretaceous to lowest Tertiary shales. Exploration for deeper shales is a much lower priority, and should wait on additional information from deep conventional exploration wells.

Old Crow Basin

Our knowledge of structure and sedimentation in Old Crow Basin is based upon regional geological relationships and interpretations of reconnaissance seismic, as there are no petroleum boreholes, and outcrop within the basin is mantled by Quaternary alluvium. A Tertiary structural depocentre defines the basin proper, and overlies regional Mesozoic, Paleozoic, and Proterozoic strata above a major Eocene unconformity (Figs. 59, 60; Hannigan, 2001a). It is flanked by intensely deformed and uplifted Proterozoic to Mesozoic strata of the British Mountains, Richardson Mountains, Old Crow Range, and Keele Range.

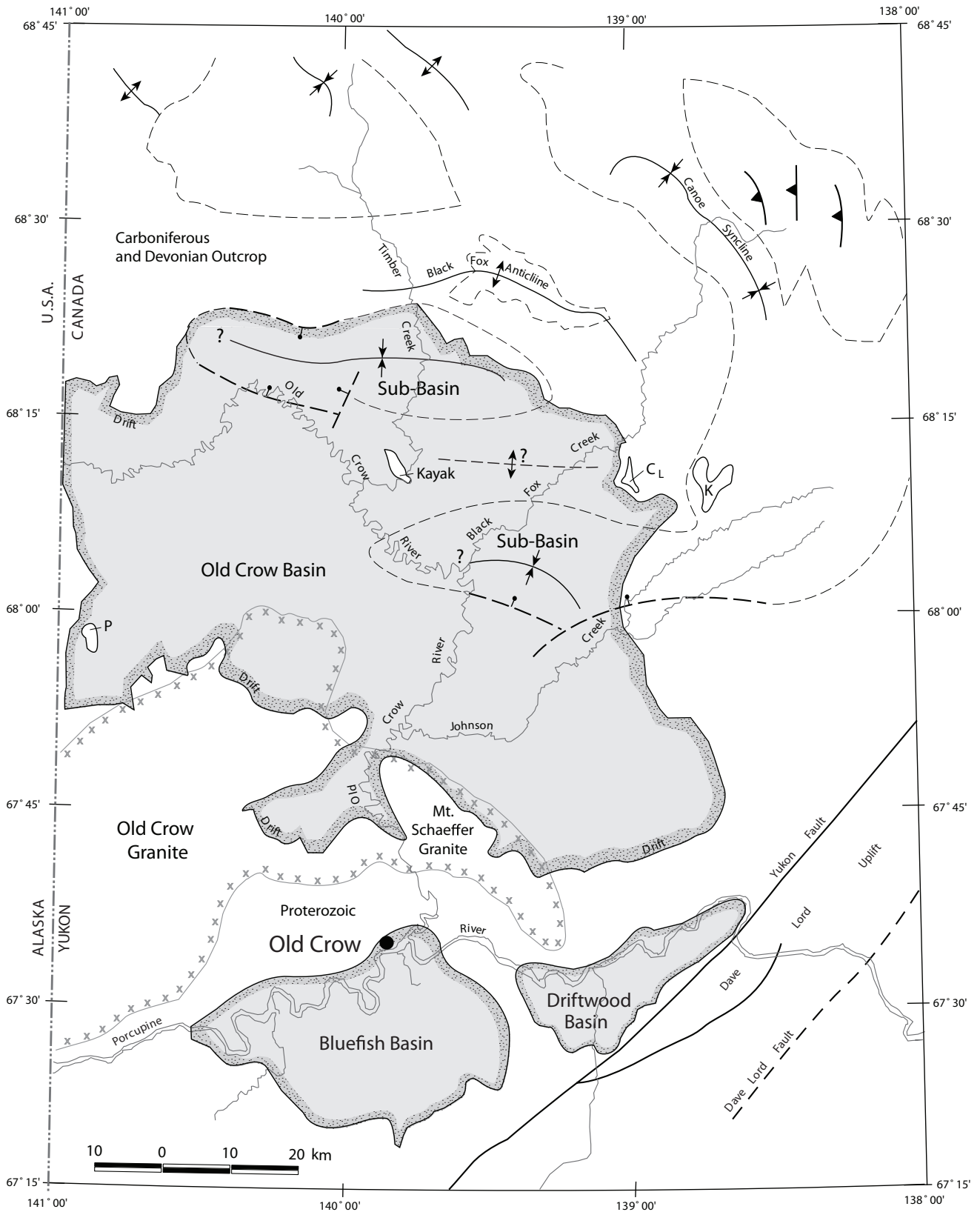


Figure 59. Base map of Old Crow Basin (from Hannigan, 2001a).

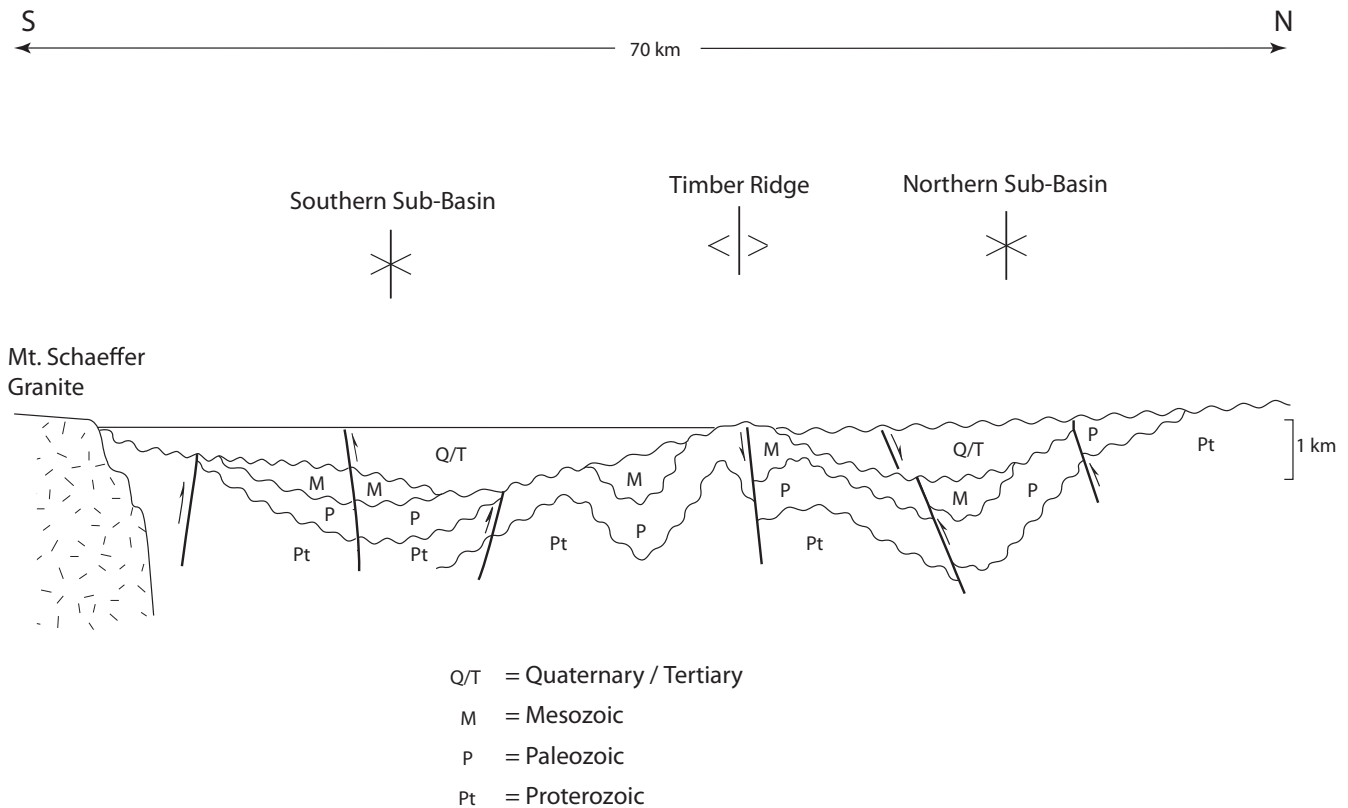


Figure 60. Schematic south to north cross section across Old Crow Basin (from Hannigan, 2001a).

Gravity and seismic data define a variable basement topography with fault-bounded sub-basins containing up to 4000 m of post-Paleozoic strata (Morrell and Dietrich, 1993; Fig. 60). Paleozoic through Tertiary stratigraphic fill of the basin has been reconstructed by Morrell and Dietrich (1993) and Hannigan (2001a), based upon regional reconstructions and outcrops of equivalent strata in surrounding uplifts (Figs. 15, 61).

Exploration History and Conventional Hydrocarbon Resources

No wells have been drilled in Old Crow Basin. Approximately 200 km of regional seismic were acquired between 1969 and 1972, and an extensive gravity survey was completed in 1972 (Department of Energy, Mines and Resources, 2011). The nearest well is Socony Mobil Western Minerals Molar YT P-34 (UWI 300P346710138300), drilled 50 km to the southeast in Eagle Plain Basin. Much of the basin, within Vuntut National Park and Old Crow Flats Special Management Area, has not been available for petroleum exploration since 1972.

Hannigan (2001a) identified three conceptual gas plays, with a mean total play potential of $29 \times 10^9 \text{ m}^3$ (1.0 TCF) gas in place. Three speculative gas plays, with insufficient information to determine hydrocarbon resource potential, were also discussed. No substantial oil potential was assessed.

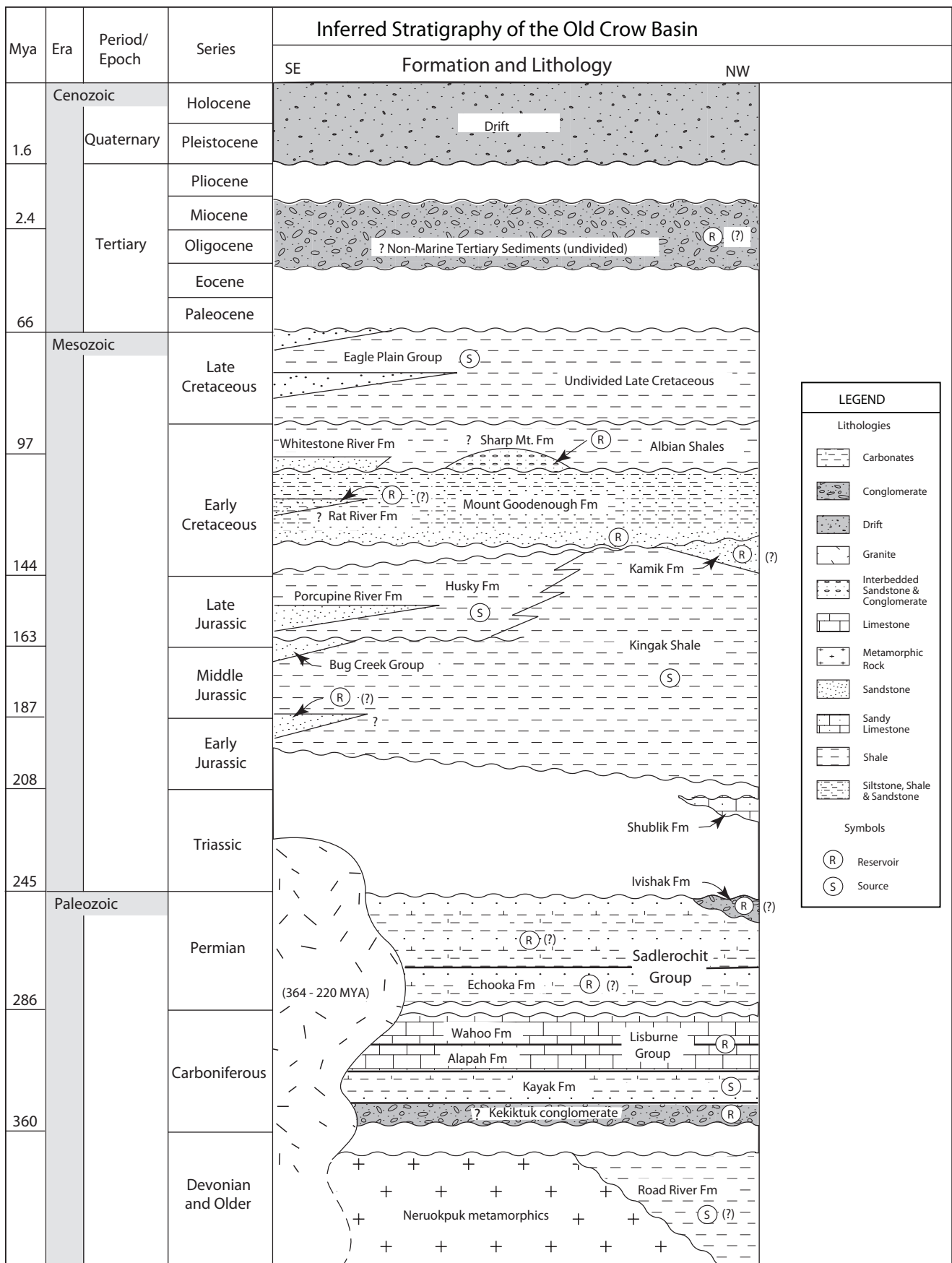


Figure 61. Stratigraphic column, Old Crow Basin (from Hannigan, 2001a).

Unconventional Hydrocarbon Resource Potential

Coalbed Methane

Ricketts (1984) noted the presence of “occasional” lignite seams within the largely unconsolidated Tertiary succession exposed for about 65 km along Porcupine River in Old Crow Basin. Morrell and Dietrich (1993) inferred the presence of “coals interbedded with poorly-consolidated clastic sediments” from seismic amplitudes at shallow depths. Neither Cameron and Beaton (2000) nor the Government of Yukon, Department of Energy, Mines and Resources coal brochure (www.geology.gov.yk.ca/pdf/coal.pdf) highlighted these coals as a significant resource.

Because of their low rank, uncertain thickness and continuity, and shallow burial depth, Tertiary coals in Old Crow Basin are not regarded as being prospective for coalbed methane production.

Tight Reservoirs

Considerable uncertainty exists about the nature of the lower Paleozoic section beneath Old Crow Basin – is it in carbonate platform or basinal shale facies, or does the transition between the two occur in the basin? Morrell and Dietrich (1993) and Hannigan (2001a) judged it more likely that Road River shale deposition was continuous across the area, thus eliminating potential for the tight / basin-centred gas play in Paleozoic carbonates that has been discussed in other basins.

The inferred stratigraphic column of Old Crow Basin shows the possible presence of a number of several clastic reservoirs of Carboniferous through Cretaceous age (Fig. 61). Only regional inferences can be made about distribution and reservoir quality, so it is difficult to rank them in terms of tight reservoir prospectivity. However, deeper Carboniferous through Triassic units can be regarded as somewhat more prospective, as they would be encased in thick shales, which would provide hydrocarbon source and assist in preserving reservoir continuity and integrity.

Shale Reservoirs

If Road River deposition dominated Old Crow area during the lower Paleozoic, as discussed above, there may be deep shale reservoir potential across the basin, although high maturity levels would reduce the potential of this play, if present. Carboniferous Kayak shales, equivalent to the Ford Lake shales of Eagle Plain and Kandik Basins and to source rocks on the Alaskan North Slope, may offer shale reservoir prospectivity, but are expected to be over-mature to post-mature (Hannigan, 2001a). If Jurassic strata are present, they are likely dominated by basinal shales of the Kingak Formation, which are significant source rocks on the Alaska North Slope and in the Beaufort Sea. Again, maturity levels pose a risk to their prospectivity, based on outcrop sampling in the western Richardson Mountains (Hannigan, 2001a). Cretaceous shales (Mount Goodenough Formation, Eagle Plain Group) may be prospective as gas reservoirs, although there is considerable uncertainty about their depositional facies and maturity levels.

In summary, a number of shale units may be reservoirs in Old Crow Basin, but there are three major sources of uncertainty regarding their prospectivity:

- Facies and thickness of each unit is highly uncertain because of lack of stratigraphic control;
- Regional relationships suggest that maturity levels for most units are high, with no remaining generative capacity for oil, and perhaps little for gas; and
- Structural complexity within the basin, suggested by the little seismic available, may have reduced reservoir continuity and integrity.

Additional mapping work and drilling will be required to address these risks – and drilling cannot take place while regulatory prohibitions exist.

SUMMARY

This report represents the first systematic attempt to characterize unconventional oil and gas resources of Yukon. Although it is only lightly explored, abundant stratigraphic, geochemical and play assessment data (primarily by the Geological Survey of Canada, Yukon Geological Survey, and NEB), combined with analogue information from producing and prospective reservoirs elsewhere, have enabled the identification of unconventional hydrocarbon prospectivity, and recommendations for additional work.

Tables 5, 6, and 7 summarize the unconventional prospectivity discussed in this report. Highlights include:

- Coalbed methane is prospective only in Bonnet Plume Basin and Whitehorse trough, which contain large coal resources of bituminous rank in thick, non-marine Cretaceous sections;
- Tight gas prospectivity is conceptual, as drilling and test data are not sufficient to establish or discount the existence of areally-extensive basin-centred hydrocarbon accumulations. Several situations do exist, such as in the deep Paleozoic carbonates of Peel Plateau and Eagle Plain basins, and in the basinal clastics of the Richthofen Formation in Whitehorse trough, where potential source rocks, low-permeability reservoirs, and seals are arranged in a configuration that could support such accumulations; and
- Numerous shale units have reservoir characteristics capable of hosting large hydrocarbon resources. Thermal maturity is a common risk factor, as much of the existing data indicates over-maturity. However, outcrop sampling in orogenic uplifts may not fairly represent maturity levels in the subsurface, where there is relatively little sampling. Several basins lack sufficient deep stratigraphic control to accurately assess potential, and intensive structural deformation poses risks to reservoir integrity and continuity in some basins.

Table 5. Coalbed methane prospectivity, Yukon basins.

BASIN	AGE	FORMATION	PROSPECTIVITY	COMMENTS
Liard	Cretaceous	Wapiti	Very poor	Thin seams, limited area, shallow burial
	Carboniferous	Mattson	Poor	Thin seams, questionable continuity
Peel Plain and Plateau			None	No coal-bearing strata preserved
Eagle Plain			None	No coal-bearing strata preserved
Bonnet Plume	Cretaceous	Bonnet Plume	Very good	Large coal resources; liquids possible?; needs subsurface mapping work
Kandik	Cretaceous	Monster	Poor	Low-rank coal, shallow burial depth; deeper coals in basin??
Old Crow	Tertiary	Undifferentiated	Very poor	Low-rank coal, shallow burial depth
North Coast	Carboniferous	Kayak	Poor	Subsurface distribution and characteristics unknown; structural deformation a risk
	Cretaceous	Moose Channel	Poor	Shallow burial depths
Whitehorse Trough	Jurassic-Cretaceous	Tanglefoot / Tantalus	Very good	Large coal resources, good rank; liquids possible?; needs subsurface mapping work

Table 6. Tight reservoir prospectivity, Yukon basins.

BASIN	AGE	FORMATION	PROSPECTIVITY	COMMENTS
Liard	Cretaceous	Scatter	Poor	Burial depth and preservation questionable in Yukon
	Cretaceous	Chinkeh	Moderate	Limited potential area; possible oil leg
	Triassic	Toad-Grayling	Moderate	Analogous to B.C. Montney; not tested
Peel Plain and Plateau	Cambrian-Devonian	Carbonate platform	Moderate (?)	“Deep Basin” configuration is possible; deep data are lacking; no regional hydrogeology to support the concept
	Devonian	Imperial	Moderate	Reservoir, source and seal are present; few tests, and no regional hydrogeology to support
Eagle Plain	Cambrian-Devonian	Bouvette / Ogilvie	Moderate	“Deep Basin” configuration is possible; deep data are scattered; no regional hydrogeology to support the concept
	Devonian	Imperial	Moderate	Reservoir, source and seal are present; few tests, and no regional hydrogeology to support
	Cretaceous	Eagle Plain Grp	Poor-moderate	Offshore sands encased in shales; shallow burial depth
Bonnet Plume	Cambrian-Devonian	Carbonate platform	Moderate (?)	“Deep Basin” configuration is possible; deep data are lacking; no regional hydrogeology to support the concept, intense structural deformation
Kandik			Very poor	Geology does not favour regional concepts; intense structural deformation
Old Crow	Carboniferous-Cretaceous	several	Poor (?)	Poorly-known section; thick shales would assist in basin-centred configuration
North Coast	Jurassic-Cretaceous	several	Moderate (?)	Distal sands may be encased in shales; poor stratigraphic control; no supporting hydrogeology
Whitehorse trough	Jurassic	Richthofen	Moderate (?)	“Deep Basin” configuration is possible; deep data are lacking; no regional hydrogeology to support the concept

RECOMMENDATIONS

Geoscientific work to be undertaken to advance unconventional oil and gas exploration in Yukon should focus on plays with large potential resources and economic rewards. Other key factors include:

- Location – proximity to existing facilities and infrastructure allows production to begin in the shortest possible time, thus maximizing short-term return on investment;
- Plays that compare closely to known producing unconventional plays will attract the most industry interest; and
- Potential for liquids production is of key importance, at least in the near future.

We recommend the following plays be given highest priority in future geoscientific work:

- Liard Basin shale plays (Besa River, Muskwa, Exshaw and Fort St. John) and Montney / Chinkeh (tight) plays. Producing infrastructure exists in or on the margins of Yukon Liard Basin. Oil or liquids-rich gas may occur, at least in the Cretaceous. Existing well and seismic control should support a fairly quick mapping effort to determine where any or all of these units are prospective, versus areas where structural deformation significantly impacts the potential for preservation of regional hydrocarbon accumulations;
- Peel Plain and Plateau shale (and tight) plays. Stacked reservoir potential exists in both shale and tight reservoirs, several of which could be tested in individual wellbores. If liquids potential can be established in any of these plays, proximity to the existing Norman Wells pipeline would be valuable in terms of tying in the liquids production; and

- Eagle Plain Basin shale (and tight) plays: stacked reservoir potential exists in both shale and tight reservoirs, several of which could be tested in individual wellbores.

Table 7. Shale reservoir prospectivity, Yukon basins.

BASIN	AGE	FORMATION	PROSPECTIVITY	COMMENTS
Liard	Cretaceous	Fort St. John	Good	Thick, large resource in place; structural deformation a major risk
	Devonian-Carboniferous	Muskwa / Exshaw / Besa River	Good	Good reservoir parameters, gas; structural deformation a risk
	Devonian	Funeral / Headless	Moderate (?)	Little data, but appears organic rich; mappability in subsurface and structure are risks
Peel Plain and Plateau	Ordovician-Devonian	Road River	Moderate (?)	Thick, regionally extensive; maturity levels, burial depth, structural complexity are risks
	Devonian	Horn River	Very good	Excellent shale reservoir parameters; structural complexity and high maturity are risks
	Carboniferous	Ford Lake	Good (?)	Good characteristics in outcrop and Eagle Plain; not mapped in Peel Plateau
	Cretaceous	Arctic Red	Moderate	Thick shales, moderate organic content; shallow burial a risk
Eagle Plain	Cambrian-Devonian	Road River	Moderate	Thick, regionally extensive; no stratigraphic control; maturity level a risk
	Devonian	Canol	Good	Excellent shale reservoir parameters; maturity level and thickness (?) are risks
	Carboniferous	Ford Lake / Hart River / Blackie	Very good	Very good shale reservoir parameters, good thickness; needs mapping work; subcrop to east threatens reservoir integrity
	Cretaceous	Mount Goodenough / Whitestone River / Eagle Plain	Moderate - good	Good shale reservoir parameters; type III kerogen (gas); shallow burial depths
Bonnet Plume	Cambrian-Devonian	Road River / Canol	Poor	Good shale reservoir parameters originally; overmature, intense structural deformation
Kandik	Cambrian-Carboniferous	Road River / Canol / Ford Lake	Poor	Good regional shales, but over-mature; intense structural deformation
	Triassic	Glenn	Moderate (?)	Rich oil-prone rock in Alaska; distribution in Yukon doubtful
Old Crow	Cambrian-Devonian	Road River	Poor (?)	Thick, regionally extensive; no stratigraphic control; maturity level a risk
	Carboniferous	Kayak	Poor (?)	Equivalent to shale reservoirs elsewhere; no stratigraphic control; maturity level a risk
	Jurassic-Cretaceous	Kingak / Mount Goodenough	Moderate (?)	Regionally promising reservoir parameters; no stratigraphic control
North Coast	Cambrian-Devonian	Road River	Poor	Intense deformation; overmature to metamorphosed
	Jurassic-Cretaceous	Kingak / Mount Goodenough / Boundary Creek?	Moderate - good(?)	Thick, some good shale reservoir parameters; abundant type III in lower units, but Boundary Creek may be oil-prone if preserved; poor stratigraphic control
Whitehorse trough	Jurassic	Richthofen	Moderate (?)	“Deep Basin” configuration is possible; deep data are lacking; no regional hydrogeology to support the concept

For each area, a geoscientific work program can be designed to best build on existing control. Specific studies that have the best potential to stimulate industry interest include:

- Systematic sampling and characterization of potential shale reservoirs to better define key parameters such as organic content, maturity, mineralogy, and rock properties. Outcrop studies (e.g., Gal *et al.*, 2007 and Pyle *et al.*, 2011) or sampling of shallow borehole cores (e.g., Allen *et al.*, 2011 and Fraser *et al.*, 2012) are most useful, as industry is generally not equipped to do this work;
- Analysis and characterization of resources to support unconventional reservoir exploitation, such as:
 - Water source and disposal zones. Such studies have been completed for the Central Mackenzie Valley of Northwest Territories (Hayes and Dunn, 2012) and the Horn River Basin and Montney Formation play fairway of northeastern British Columbia (Petrel Robertson, 2010b; www.geosciencebc.com/s/Montney.asp);
 - Sources of frac sand. Studies have been completed by Hickin *et al.* (2010) for the Horn River Basin, and by Levson (in press) for the Central Mackenzie Valley;
 - Sources of industrial materials such as sand and gravel for road building; and
- Specialized mapping studies, such as structural analyses, which would support assessing factors such as reservoir continuity and degree of natural fracturing.

While such studies will be important in guiding regional assessments of prospectivity and economic value, acquisition of new seismic data and drilling of new wells (with appropriate sampling and testing regimens) will be essential to create major gains in basin and play evaluation.

Geoscientific work in Bonnet Plume, Kandik, Old Crow, North Coast, and Whitehorse trough basins should assume a lower priority. These basins are generally less prospective for unconventional hydrocarbons, have relatively little liquids potential, have little or no existing subsurface control, and are distant from currently-existing infrastructure.

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