Petroleum resource assessment of Whitehorse trough, Yukon, Canada

Yukon Geological Survey Miscellaneous Report 6

Report prepared for Yukon Geological Survey
Report prepared by Brad J.R. Hayes, Petrel Robertson Consulting Ltd.

Yukon Geological Survey

Yukon Energy, Mines and Resources

Published under the authority of the Department of Energy, Mines and Resources, Yukon Government
http://www.emr.gov.yk.ca

Published in Whitehorse, Yukon, 2012.

A copy of this report can be obtained by download from: www.geology.gov.yk.ca
or by emailing: Geosales@gov.yk.ca

In referring to this publication, please use the following citation: Hayes, B.J.R., 2012. Petroleum resource assessment of Whitehorse trough, Yukon, Canada. Yukon Geological Survey, Miscellaneous Report 6, 52 p., including appendices.

Cover photo: Limestone hills (Hancock member, Lewes River Group) along Coghlan Lake, northern Whitehorse trough.

Petroleum resource assessment of Whitehorse trough, Yukon, Canada

In September 2011, Yukon Geological Survey tendered a contract for a new assessment of the petroleum resource potential of the Whitehorse trough, a sedimentary basin in south-central Yukon. A new assessment was considered timely in light of the large amount of new geoscientific information about the trough generated since the previous petroleum resource assessment (National Energy Board, 2001). This new information includes new bedrock geological mapping and associated stratigraphic, sedimentological, and geochemical research by the Yukon Geological Survey, as well as 2 seismic lines across the northern part of the trough by the Geological Survey of Canada and Yukon Geological Survey. The contract was tendered to include an upgrade of Government of Yukon's current assessment of conventional petroleum resources as well as a first-time assessment of the trough's potential for unconventional resources, including coal-bed methane. The study was a desk-top synthesis of existing geological, geophysical and thermal maturation data; no new data were collected as part of the project.

The assessment was awarded to Petrel Robertson Consulting Ltd., a Calgary-based consultancy with broad experience in resource assessments for both government agencies and the oil and gas industry. The results of the study will help to support the management of Yukon's energy resources and to identify critical knowledge gaps to inform future research opportunities for the Yukon Geological Survey.

Carolyn Relf
Director, Yukon Geological Survey

EXECUTIVE SUMMARY

Whitehorse trough is a frontier intermontane basin that is prospective for oil and gas from both conventional and unconventional reservoirs. It straddles the Yukon – British Columbia border; the Yukon portion is a triangular-shaped area covering approximately 3.72 million hectares. It features a complexly deformed sedimentary rock section more than 7000 metres thick, with interbedded and capping volcanic rocks.

Yukon Geological Survey directed Petrel Robertson Consulting Ltd. (PRCL) to assess the petroleum resource potential of Whitehorse trough. Since publication of the most recent assessment, by National Energy Board (2001), significant advances have taken place in our understanding of Whitehorse trough, and of petroleum prospectivity of northern Canada in general.

Hydrocarbon prospectivity in Whitehorse trough is assigned to nine plays:

- Cache Creek Assemblage Structural (Speculative)
- Lewes River Structural
- Hancock Stratigraphic
- Tanglefoot Structural
- Tanglefoot Stratigraphic
- Tanglefoot CBM (Speculative Unconventional)
- Richthofen Stratigraphic/Tight Gas/Shale Gas (Speculative Unconventional)
- Tantalus Structural/Stratigraphic
- Tantalus CBM (Speculative Unconventional)

All nine plays are prospective for gas, and three have oil potential as well. Five plays are conceptual, as sufficient information exists to support estimates of play parameters and potential. The other four are speculative, as we do not have sufficient information to support numerical estimates.

Systematic statistical analysis of conceptual conventional plays was undertaken, using a play-based method based on the work of Roadifer (1979) and refined by National Energy Board. Summarized arithmetically and on an unrisked basis, the mean in place assessed hydrocarbon resources of the Whitehorse trough include $82.3x10^9m^3$ (2920 BCF) gas and $17.1x10^6m^3$ (107 MMBO) oil. The range of possible values around these means vary tremendously, however, reflecting our limited knowledge about the basin.

The evidence for presence of both conventional and unconventional hydrocarbons in Whitehorse trough is compelling, and assessed volumes are sufficiently substantial to support additional exploration and assessment work.

TABLE OF CONTENTS

INTRODUCTION

Whitehorse trough is a frontier intermontane basin that is prospective for oil and gas from both conventional and unconventional reservoirs. It straddles the Yukon – British Columbia border; the Yukon portion is a triangular-shaped area between longitudes 130 to 138°W and latitudes 60 to 62°30'N, covering approximately 3.72 million hectares (Fig. 1). It features a sedimentary rock section more than 7000 metres thick, with interbedded and capping volcanic rocks. Whitehorse trough developed during Jurassic to Cretaceous time, during the formation and deformation of continental margin arcs, producing a structurally-complex, intensely folded and faulted basin cut by numerous intrusive igneous bodies.

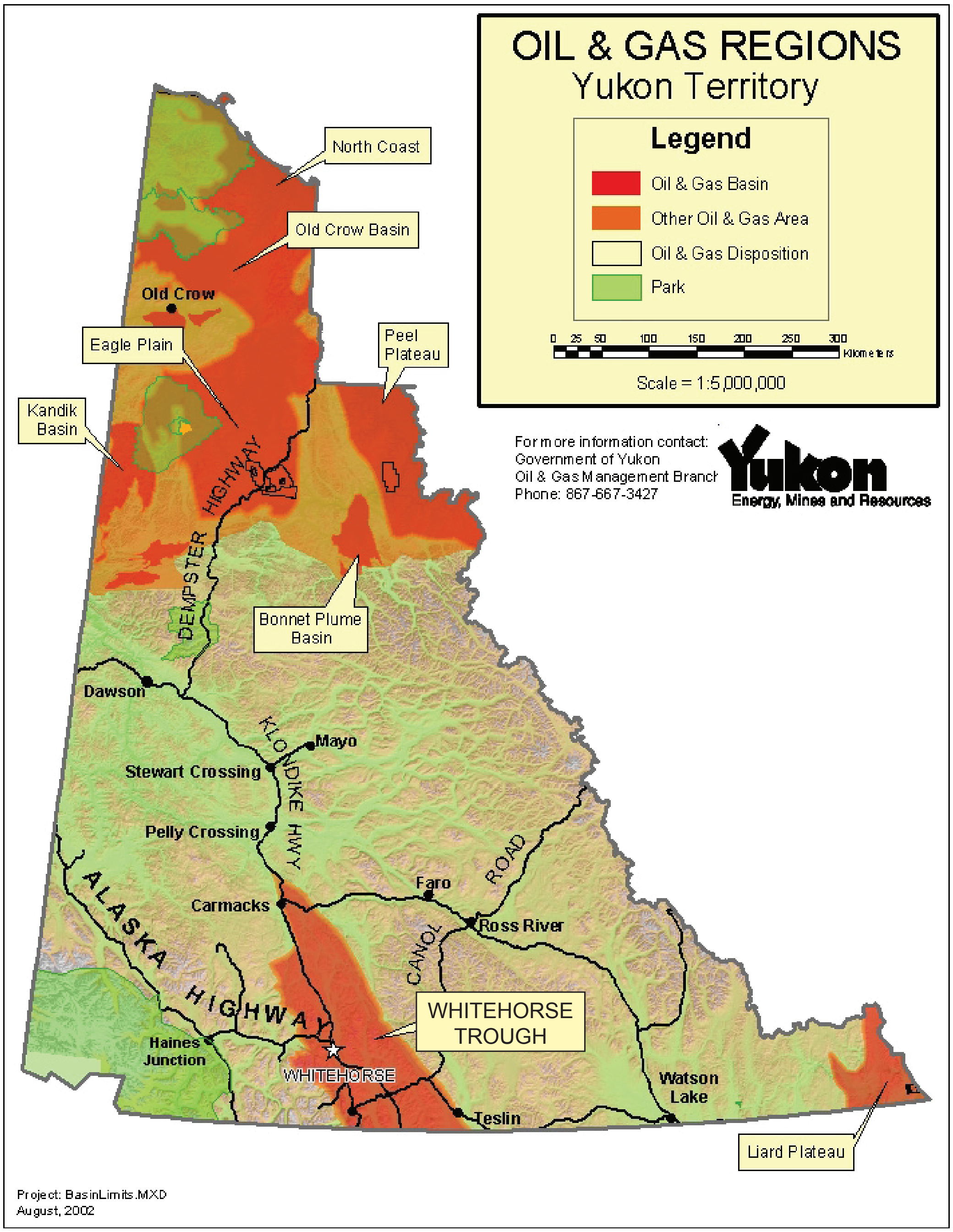


Figure 1. *Whitehorse trough location map.*

Yukon Geological Survey directed Petrel Robertson Consulting Ltd. (PRCL) in late 2011 to assess the petroleum resource potential of Whitehorse trough. Since publication of the most recent assessment, by National Energy Board (2001), significant advances have taken place in our understanding of Whitehorse trough, and of petroleum prospectivity of northern Canada in general. These include:

- regional structural and stratigraphic mapping of the trough and surrounding terranes;
- new data on source rock potential and thermal maturity, and interpretations of their significance;
- two regional seismic sections producing a complete section across the northern part of the trough; and
- increased understanding of unconventional reservoirs – coals, low permeability ('tight') strata, and shales – and their prospectivity in adjacent areas.

A new hydrocarbon resource assessment using this information is timely, as Yukon is in need of oil and gas to develop new electrical generation capacity to support ongoing industrial and population growth in the Territory.

Previous Assessments

Two studies published in the 1973 CSPG Memoir *Future Petroleum Provinces of Canada* listed resource estimates for Whitehorse trough, calculated on a purely volumetric basis: Koch (1973) estimated 25-116x10^9m^3 (0.9-4.1 TCF) gas, while McCrossan and Porter (1973) estimated gas potential of 60-270 MMCF/mi^2. Neither study produced estimates for oil resources.

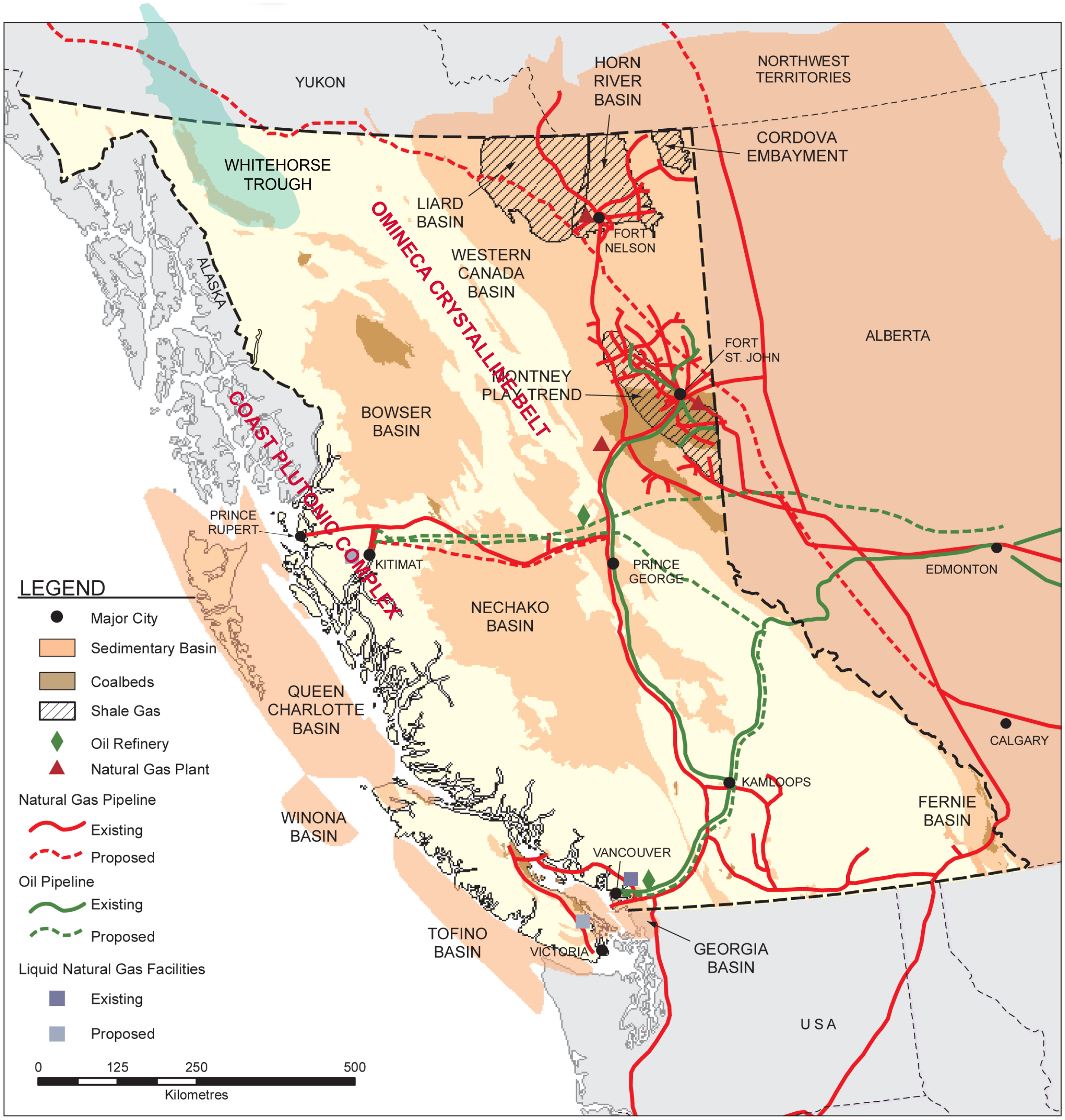
Only one comprehensive assessment of Whitehorse trough hydrocarbon resources has been published – by National Energy Board (2001). Eight conceptual plays were identified – five pure gas plays, and three gas plays with minor oil potential. The authors concluded that Whitehorse trough is "an immature, mainly gas-prone basin". They calculated a 65% chance that gas exists in the basin, and a 52% chance that liquid hydrocarbons exist. Mean marketable gas was tabulated at 5.52x10^9m^3 (196 BCF), with mean recoverable oil of 1.29x10^6m^3 (8.12 MMBO).

Kirk Osadetz of the Geological Survey of Canada undertook assessment of Whitehorse trough hydrocarbon resources subsequent to the NEB report, but results of his study were not published. However, he has made them available for consideration in the preparation of the current report.

REGIONAL GEOLOGICAL SETTING

Yukon and British Columbia west of the Rocky Mountain fold and thrust belt originated as a collage of tectonostratigraphic assemblages with varying affinities to the North American craton (Price, 1994). Beginning in Early Triassic time, smaller terranes amalgamated into two composite superterranes – the Intermontane and Insular superterranes - which collided with and accreted to the western margin of the North American craton. Two broad orogenic belts are built across the sutures between the terranes and the evolving continental margin – the Omineca Crystalline Belt to the east and the Coast Plutonic Complex to the west. These are characterized by granitic magmatism, crustal thickening, and uplift and exposure of igneous and metamorphic rocks (Price, 1994).

Whitehorse trough lies at the northern end of the Intermontane Belt. It is the northernmost of three major intermontane basins, lying to the north of Bowser and Nechako basins (Fig. 2). Each is regarded as prospective for hydrocarbons, although no discoveries have been made in any of them.



from: British Columbia Natural Gas and Petroleum -- Yours to Explore 2010

Figure 2. *Map of Western Canada Cordillera, showing location of Whitehorse trough relative to Nechako and Bowser basins in the Intermontane Belt of the Canadian Cordillera.*

Various interpretations of the tectonic history of Whitehorse trough have been advanced (*e.g.*, Dickie and Hein, 1995; National Energy Board, 2001; Lowey *et al.*, 2009), and some elements continue to be discussed (Colpron, pers. comm., 2012). Clearly, however, it existed as a basin by the Early to Middle Jurassic, at which time sediments of the Laberge Group were deposited. The basement to these rocks comprises volcanic and sedimentary rocks of Stikinia and Quesnellia terranes, which accumulated in part coevally in volcanic arc settings. Cache Creek terrane volcanic rocks and carbonates are in fault contact with Stikinia and Quesnellia to the south (Fig. 3). Colpron (pers. comm., 2012) suggested that Cache Creek rocks may be thrust over younger rocks to the north, but there are no subsurface data to test this proposal.

Whitehorse trough is preserved in a northwest-trending structural depression characterized by complex internal structure, including southwest-verging fold and thrust belts (Lowey *et al.,* 2009).

Whitehorse Trough Boundaries

Major faults define the limits of Jurassic Laberge Group deposition, and thus also define the boundaries of Whitehorse trough. These relationships are clear along the eastern (Teslin fault), far northeastern (Tatchun fault) and far northwestern (Braeburn fault) margins. However, deep-seated intrusions, shallow volcanic flows, and Quaternary cover have obscured these faults over many areas, leaving considerable uncertainty regarding the precise outline of the structural basin.

As this assessment is designed to address all petroleum prospectivity in the geographic area, boundaries for the Whitehorse trough assessment have been selected to most completely capture all prospective reservoirs. Figure 3 illustrates a number of these choices:

- Tadru fault bounds much of the eastern and northeastern margin, in order to include potential reservoirs in the Semenof Formation (Triassic, Quesnellia);
- The boundary along part of the west side follows the outer map limit of Upper Cretaceous Carmacks Group volcanics, with the assumption that Laberge and/or Tantalus strata underlie much of this area; and
- The southwestern boundary is drawn to encompass as many occurrences as possible of potential reservoir rocks in upper Lewes River, Laberge, and Tantalus strata outcrop areas.

Regional Stratigraphy

Figure 4 summarizes Whitehorse trough stratigraphy; interpretations have evolved considerably since original regional descriptions were made by Wheeler (1961). The complex tectonic history of the basin produced sedimentary bodies derived from a variety of source areas, interbedded locally with coeval volcanic deposits. Depositional patterns have been disrupted by normal, thrust, and strike-slip faulting, as well as widespread igneous intrusions. Disconformities and unconformities are numerous, particularly on the basin margins. Combined with a lack of petroleum wells to provide subsurface control, these factors have made it difficult to produce a consistent, basin-wide stratigraphic scheme. Even today, Colpron (pers. comm., 2012) has noted widely-varying thickness estimates for the major stratigraphic units.

Upper Triassic Lewes River Group of the Stikinia terrane comprises the Povoas Formation and overlying Aksala Formation (Fig. 4). The Povoas is dominated by volcanic rocks, and is not considered as a potential petroleum reservoir. The Aksala, up to 2000 m thick, can be subdivided into informal Casca (mudstone, sandstone and limestone with minor conglomerate), Hancock (limestone, including reefal buildups), and Mandanna (sandstone, limestone, volcaniclastics, and minor conglomerate) members (Lowey *et al.,* 2009). Equivalent strata associated with Quesnellia terrane, the Semenof Formation, have not been subdivided in comparable detail, but appear to contain up to 40% potential reservoir rock in outcrop along the eastern margin of the basin (Colpron, pers. comm., 2012).

Laberge Group strata range up to 3000 metres thick, and were deposited during Early to Middle Jurassic time in the newly-formed Whitehorse trough depositional basin. Lowey (2008) interpreted fluvial/floodplain and deltaic sandstones, fine-grained clastic rocks, coal, and minor conglomerates to have prograded north to south across the northern part of the basin as the Tanglefoot Formation. To the south, coeval fine-grained basinal clastic rocks with isolated coarser grained submarine channel and fan deposits are assigned to the Richthofen Formation (Fig. 5). A lithic tuff unit, the Nordenskiold Formation, occurs at multiple stratigraphic levels equivalent to both the Tanglefoot and Richthofen on the western flank of the basin (Colpron, pers. comm., 2012). This interpretation of Laberge stratigraphy has been developed since the NEB (2001) assessment, and is responsible for some of the differences in play definition between NEB (2001) and the current study.

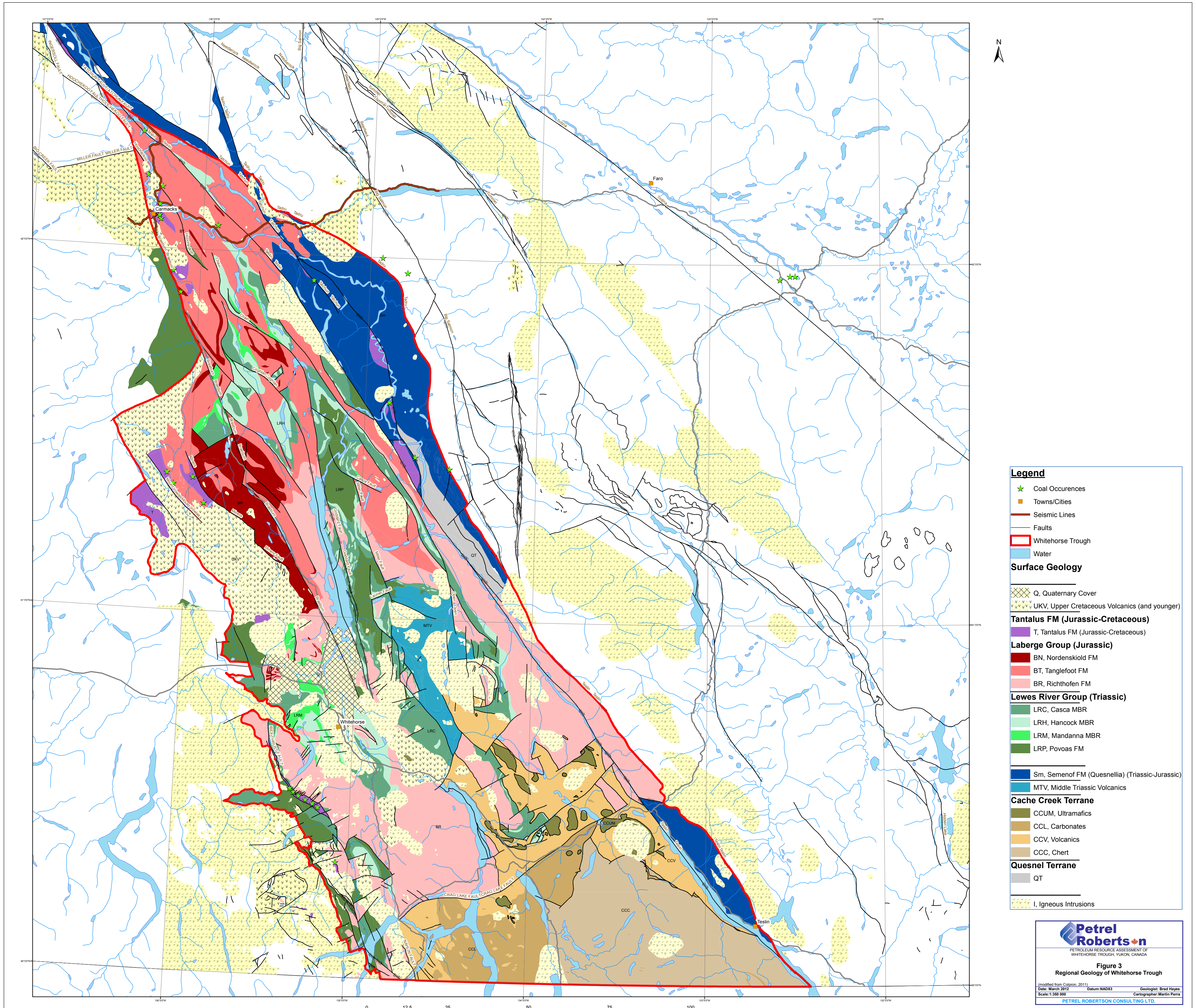


Figure 3. *Regional geology of Whitehorse trough, showing basin boundaries and major faults and rock units (modified from Colpron 2011).*

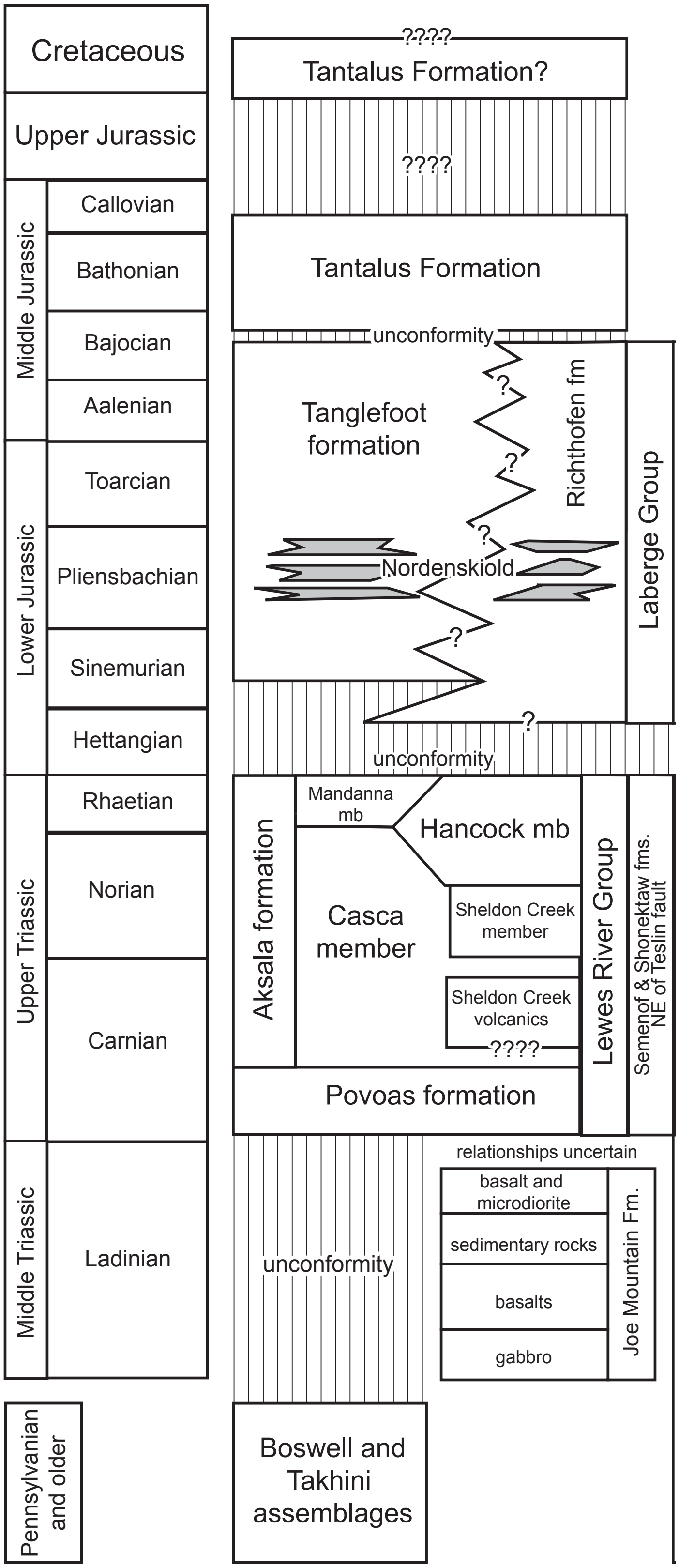


Figure 4. *Stratigraphic column for Whitehorse trough (from Colpron and Friedman, 2008).*

Tantalus Formation strata lie unconformably on the Laberge Group, and consist of fluvial chert-pebble conglomerates with coal-bearing mudstones and sandstones. Deposition took place in small, fault-bounded terrestrial subbasins lying primarily (but not entirely) within Whitehorse trough (Lowey and Hills, 1988; Long, 2005). While Lowey *et al.* (2009) estimated Tantalus strata to range up to 1000 m thick, Colpron (pers. comm., 2012) noted most surface exposures to be highly folded and faulted, and suggested that the Tantalus is no more than about 200 m thick in most areas.

EXPLORATION HISTORY AND HYDROCARBON OCCURRENCES

National Energy Board (2001) and Lowey (2008) provided detailed reviews of surface exploration work in Whitehorse trough up to and including reports of field work by Petro-Canada in 1985 (Gilmore, 1985; Gunther, 1985). Most of this work comprised acquisition of large surface leases, surface geological mapping, and sampling for geochemical/source rock and reservoir analysis. Mapping reports are available through Yukon Geological Survey, while source rock information has been summarized most comprehensively by Hunt and Hart (2004), Lowey and Long (2006), and Lowey *et al.* (2009).

Galeski (1970) reviewed aeromagnetic survey data in the Whitehorse area, and contoured maps which he interpreted as indicative of depth to ‘magnetic basement’. This can be taken as a measurement of the thickness of potentially prospective sedimentary rocks, but this interpretation may not be valid where there are volcanics or intrusive rocks at surface or buried to shallow depths. Locally, these data may assist in defining prospective areas.

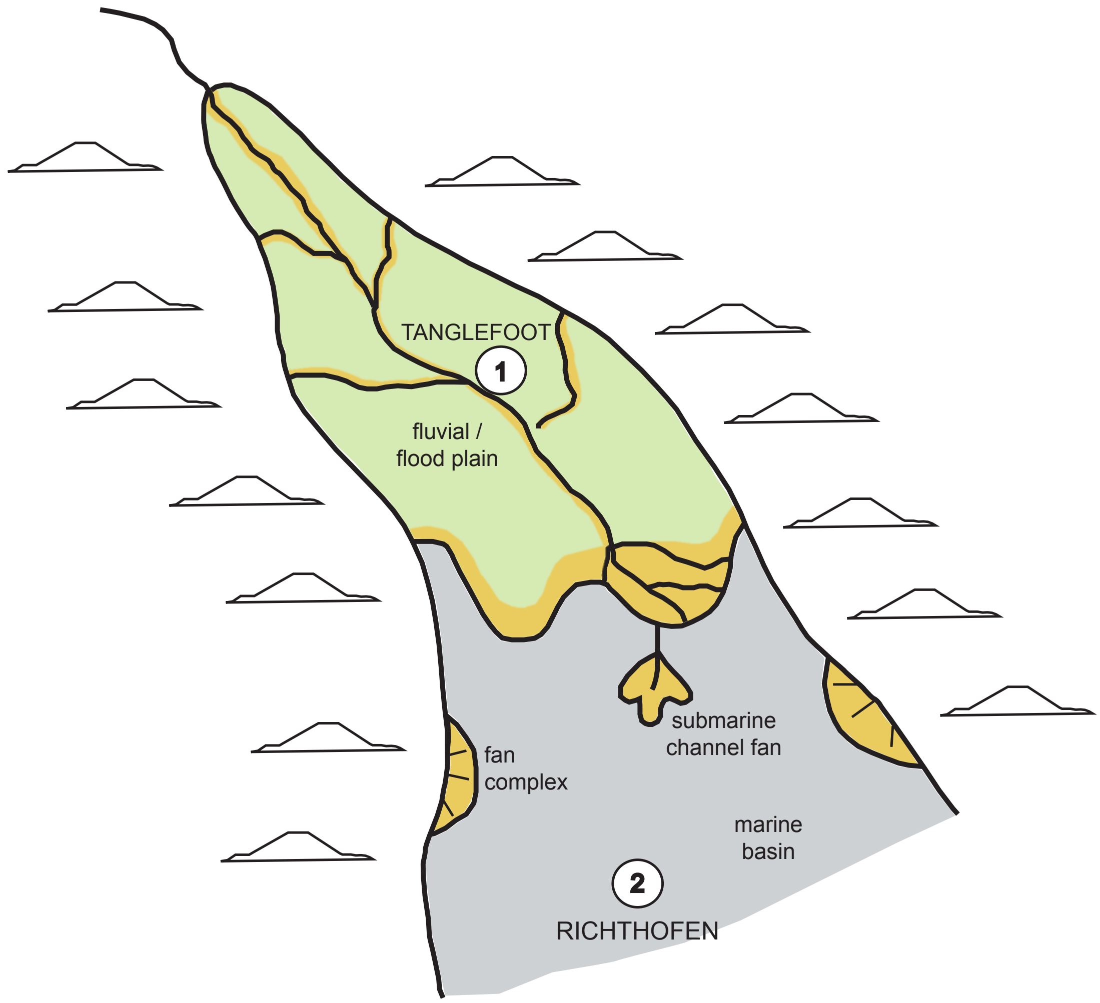


Figure 5. *Schematic paleogeographic map showing Laberge Group (Tanglefoot and Richthofen formations) deposition. Note volcanic input from western flank of basin, preserved as Nordenskiold Formation. Location 1 is a reference for Tanglefoot play schematic diagrams and maps (Figures 10-14); location 2 is a reference for the Richthofen play (Figures 15, 16).*

No petroleum exploration wells have been drilled in the basin. Two regional seismic profiles (170 km total length) were acquired by Yukon Geological Survey and Geological Survey of Canada in 2004, designed to transect the basin and surrounding terranes (Fig. 1). White *et al.* (2006) described their acquisition, and presented a preliminary interpretation, highlighting major structures and stratigraphic subdivisions. No other seismic data have been acquired.

Coal has been mined historically in Whitehorse trough, and coal resources have been assessed locally and regionally (*e.g.*, Allen, 2000; Cameron and Beaton, 2000; Hunt, 1994; Ricketts, 1984). While coal exploration boreholes have been drilled, there has been no exploration systematically directed toward coalbed methane (CBM). Several reports have discussed coals as potential source rocks for conventional hydrocarbon accumulations (*e.g.*, Hunt and Hart, 1994; Lowey *et al.*, 2009).

National Energy Board (2001) listed a number of reports of oil and natural gas seeps in Whitehorse trough, but regarded them as being of questionable value. Osadetz (pers. comm., 2012) has stated the opinion that all shows reported to date probably are biogenic gas occurrences or spills of refined petroleum products.

RESOURCE ASSESSMENT

Petroleum Play Definitions

Conventional Plays

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

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

As there has been no drilling in Whitehorse trough, all plays are currently either conceptual or speculative.

Unconventional Plays

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

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

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

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

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

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

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

‘Hydrocarbon saturated’ means that oil and/or gas occupy a sufficient proportion of reservoir pore volume (generally >75%) to be the fluid that flows preferentially; however, there is almost always some residual water saturation. ‘Abnormal pressures’ indicate that the hydrocarbon phase is not connected to a regional aquifer – pressures may be relatively high or low compared to a normal hydrostatic gradient (and are commonly both in different regions of a given basin). ‘Low permeability’ is a term that has been used in a variety of ways, but the most commonly accepted definition is that ‘tight’ reservoirs have maximum *in situ* permeabilities of <0.1 mD, with the implication that natural or artificial fracture stimulation is required for economic hydrocarbon production. These are generally highly-cemented sandstones, siltstones, or more rarely, carbonates.

Curtis (2002) defined shale reservoirs as:

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

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

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

Hayes (*in press*) discusses unconventional reservoirs in more detail, and surveyed their occurrence throughout the eight hydrocarbon basins of Yukon.

Assessment Methodology

This analysis is patterned after the methodology developed by National Energy Board for basin-scale hydrocarbon assessments, as exemplified by their 2001 assessment of the Whitehorse trough. Key steps in the process include:

- Compilation of regional petroleum geology for the basin, including information on basin evolution and tectonics, sedimentation history, structural history, geochemistry, and hydrocarbon occurrences;
- Definition of potential conventional hydrocarbon plays, based upon identification of potential petroleum systems, including reservoir, source, trap, and seal. As there have been no hydrocarbon discoveries in Whitehorse trough, all plays are conceptual or speculative; none have been proven by drilling and discovery;
- Definition of potential unconventional hydrocarbon plays, based upon the same petroleum systems, but focusing on factors that could charge unconventional reservoirs on a regional basis, as opposed to discrete conventional traps; and

- Systematic statistical analysis of conceptual conventional plays, using a play-based method based on the work of Roadifer (1979) and refined by National Energy Board. Based upon the geological characteristics of each play and analogue information, minimum and maximum values for a variety of reservoir and fluid parameters are input to an Excel spreadsheet. The statistical routine @RISK is employed to sample distributions based on these parameter values, and to create a probabilistic estimate of petroleum resource distribution for each play.

  Numerical data input to the @RISK routine are summarized on a play sheet accompanying each conceptual play (Appendix 1). Play risk factors (source rock, charge, migration, reservoir rock, trap/closure, and seal/containment) are assigned on a play basis. Input parameters are tabulated in Appendix 1.

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

One speculative conventional play is discussed, but is not analyzed statistically, as it lacks sufficient data to assign reservoir parameter values.

Three unconventional plays are discussed, but their regional distribution precludes making a statistical pool or play-based analysis. There is some literature discussing volumetric assessment of unconventional plays; however, such assessments are not undertaken in this study, as there are insufficient data upon which to base the analysis.

Whitehorse Trough Plays

Hydrocarbon prospectivity in Whitehorse trough is assigned to nine plays:

- Cache Creek Assemblage Structural (Speculative);
- Lewes River Structural;
- Hancock Stratigraphic;
- Tanglefoot Structural;
- Tanglefoot Stratigraphic;
- Tanglefoot CBM (Speculative Unconventional);
- Richthofen Stratigraphic/Tight Gas/Shale Gas (Speculative Unconventional);
- Tantalus Structural/Stratigraphic; and
- Tantalus CBM (Speculative Unconventional).

Five plays are conceptual, as sufficient information exists to support estimates of play parameters and potential. The other four are speculative, as we do not have sufficient information to support numerical estimates. All three unconventional plays are speculative, which is to be expected at this early stage of exploration, as specific laboratory-based analytical procedures are required to establish unconventional reservoir parameters.

All nine plays are prospective for gas, and three have oil potential as well. While some basin assessments regard gas and oil prospects in the same reservoir as belonging to separate plays, this distinction has not been made in this report – there is not sufficient information on distribution of oil-prone versus gas-prone source rocks to do so.

NEB (2001) assigned play status to gas prospects in surficial (generally Quaternary) sediments, but this play type has not been considered here for the following reasons:

- Isolated occurrences of small gas pools in surficial sediments have been documented in proven petroleum basins; for example, Bauman (2005) described the sedimentology and reservoir geometry of gas reservoirs in Quaternary sediments at Sousa in northern Alberta. Even in producing basins with good producing infrastructure, however, reservoirs in surficial sediments have very little potential, and are more a drilling hazard than an exploitable resource; and
- There is no systematic mapping of potential reservoirs or other petroleum systems elements in surficial sediments.

Cache Creek Assemblage – Structural Play (Speculative – Gas)

Reservoirs: Prospective reservoirs are carbonate strata within Cache Creek terrane, an oceanic allochthon in southern Whitehorse trough described by Colpron (2011) as massive, finely crystalline, locally crinoidal and fusiline limestone with limestone breccia, recrystallized limestone, and minor dolostone (Fig. 3). Reservoir quality is inferred to arise from fracturing and/or karsting and solution, but has not been quantitatively described.

Traps: Cache Creek rocks were thrust regionally over Whitehorse trough strata during a Middle Jurassic accretionary event (English *et al.*, 2005b). Conceptually, local fold and fault traps were created during numerous episodes of Mesozoic and Cenozoic tectonism, but no subsurface control exists to define such structures.

Seal: Cherts and younger igneous rocks within the Cache Creek Assemblage are potential seals.

Source: Organic-rich laminated carbonates occur interbedded within the Cache Creek succession. Laberge and Lewes River Group strata beneath the Cache Creek allochthon may have generated hydrocarbons that migrated into the Cache Creek section.

Prospective Areas: Cache Creek carbonates crop out south of Crag Lake fault, near the Yukon/British Columbia border (Fig. 3). Prospectivity is inferred to exist only in this area.

Previous Assessments: NEB (2001) recognized a Cache Creek-Nakina carbonate conceptual gas play, but noted only a 3% probability that the play exists, and a mean gas potential of only $44x10^6m^3$ (1.56 BCF). Osadetz (pers. comm., 2012) saw fractured Cache Creek carbonates as a speculative play, lacking definitive geological information.

Discussion: Insufficient information exists to quantify reservoir parameters, making this a speculative play. Particularly high risk levels can be assigned to three parameters:

- Reservoir distribution – current mapping does not distinguish reservoir-quality rocks within Cache Creek carbonates;
- Reservoir quality – substantial occurrence of porous lithologies, such as reefal carbonates or recrystallized dolostones, has not been noted. Fracturing or solution may have generated conventional reservoir quality, but no evidence has been documented. Close association with igneous rocks increases risk of reservoir degradation; and

- Source rocks – Previous assessments interpreted interbedded organic-rich carbonates as primary source rocks for both Cache Creek and younger (Lewes River) carbonate plays (NEB, 2001; Osadetz, pers. comm., 2012). Lowey *et al.* (2009) found younger Lewes River strata to have low organic content and to be post-mature, and thus incapable of generating significant hydrocarbon volumes. Generally deeper burial and a longer post-depositional history thus makes Cache Creek source rock viability highly questionable. Sub-thrust Laberge Group rocks may have generated hydrocarbons, but their distribution and characteristics are unknown.

Summary: The occurrence of gas in Cache Creek carbonates is a speculative possibility, but reservoir quality and presence of a viable source are large risks. There is no subsurface mapping or seismic control to define prospects.

Lewes River Group – Structural Play (Conceptual – Gas)

Reservoirs: The sedimentary rocks in the Aksala Formation of the Triassic Lewes River Group may have reservoir potential (Fig. 4). These include:

- Casca Member: interbedded mudstones, siltstones, sandstones and bioclastic limestones, with pebble and cobble conglomerates and minor volcanic flows;
- Hancock Member: Massive to thick-bedded limestone and minor thin-bedded limestones, massive crystalline dolostone, massive to poorly-bedded conglomerate debris flows and fanglomerates, and calcareous sandstones. Reefal buildups have been described by several workers, including Reid and Tempelman-Kluit (1987); and
- Mandanna Member: interbedded sandstone, conglomerate, mudstone and minor siltstone and limestone, along with minor volcanics. Sandstones of both marginal marine and channelized origin have been documented by Long (2005).

Upper Triassic to Lower Jurassic strata of the Semenof Formation (Quesnellia assemblage), are included in this play because of their similar age and stratigraphic position. These rocks have been described as interbedded volcanics and volcaniclastics; Colpron (pers. comm., 2012) estimated about 40% of the total rock volume as possible clastic reservoir.

Reservoir quality is inferred to occur as intergranular or solution porosity, or to arise from fracturing and/or karsting and solution. Quantitative reservoir studies have not been undertaken.

Traps: Local fold and fault traps were created during Mesozoic and Cenozoic tectonism (Fig. 6). Stratigraphic traps associated with Hancock Member reefal buildups are assessed as a separate play.

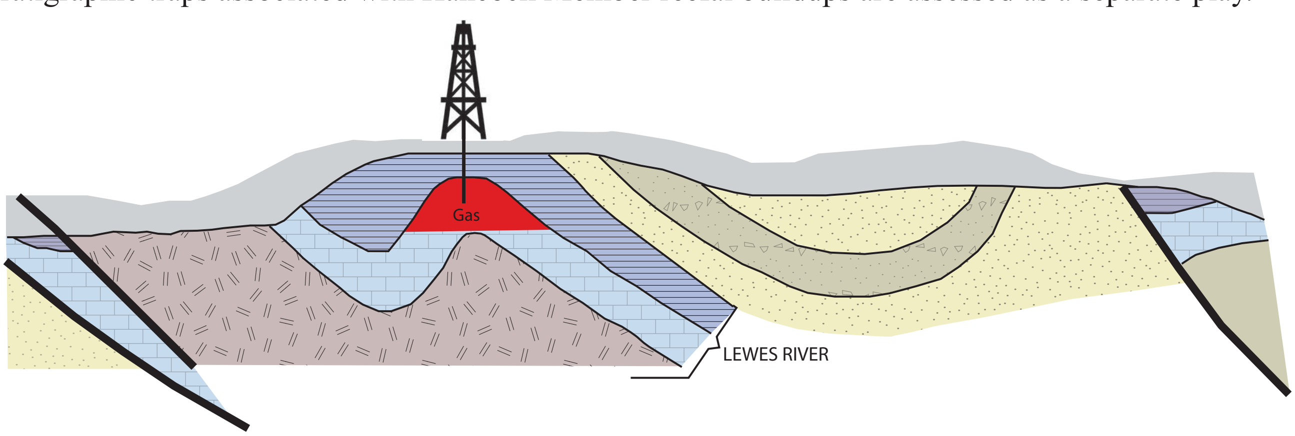


Figure 6. *Schematic cross-section illustrating one possible configuration of Lewes River Structural Play.*

Seal: Fine-grained clastics of the Richthofen Formation should provide an effective top seal to the south. Northward, where the Richthofen passes to equivalent coarse-grained Tanglefoot strata, top seal risk is greater. Locally, interbedded fine-grained rocks and volcanics may seal specific traps.

Source: Organic-rich laminated carbonates occur interbedded within Aksala carbonates.

Prospective Areas: Lewes River strata are assumed to be prospective beneath areas where younger (Laberge Group, Cretaceous and younger volcanics) crop out, excluding intrusive outcrops (Fig. 7).

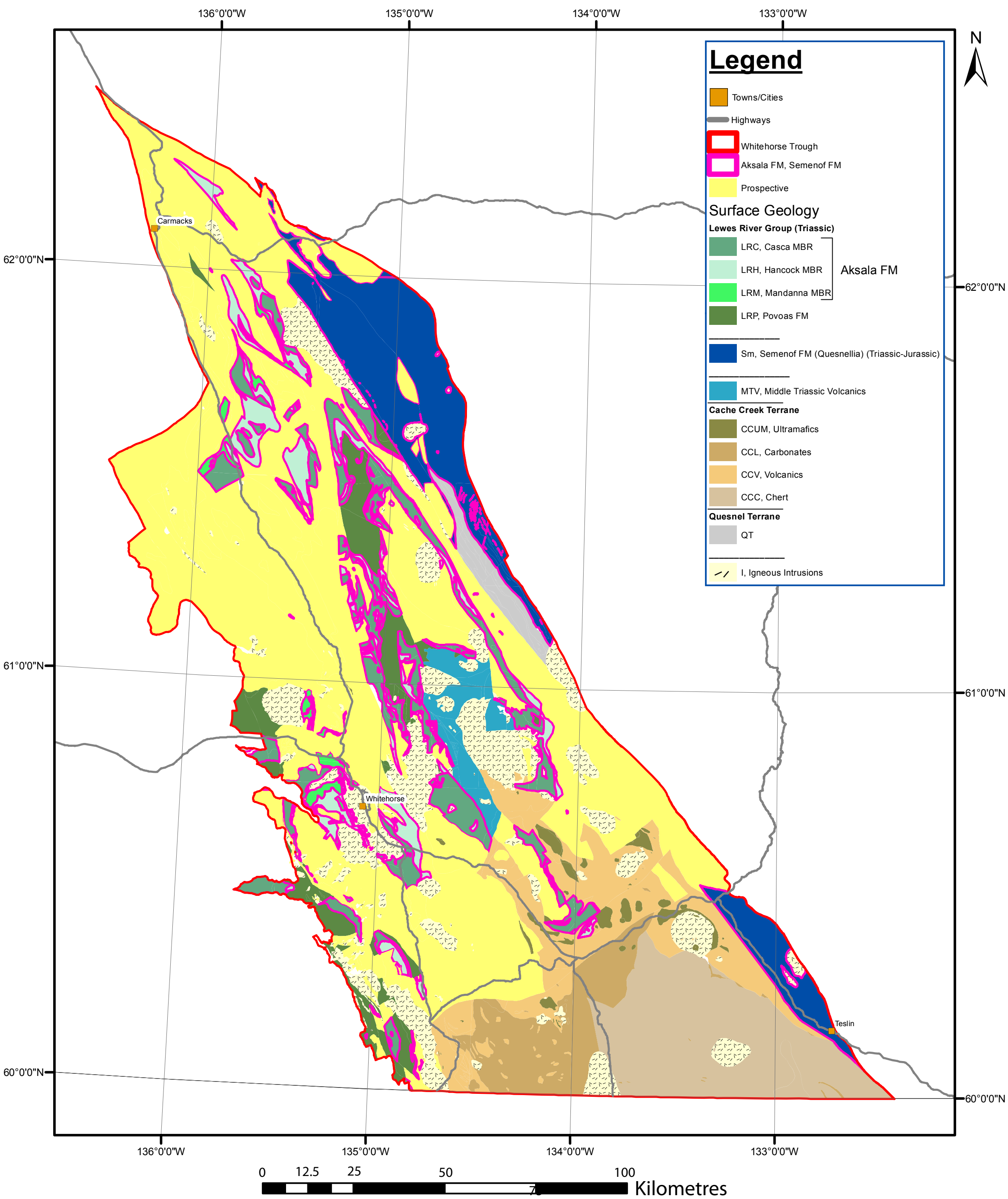


Figure 7. *Map showing prospective areas for Lewes River Structural Play. Outcrop of Lewes River Group is outlined, while prospective areas that may be underlain by Lewes River reservoirs are highlighted yellow (modified from Colpron, 2011).*

Previous Assessments: NEB (2001) recognized potential for structural plays in Lewes River strata as part of the Hancock-Conglomerate structural play. Overall chance of the play existing was judged to be 16%, with mean gas potential of 2.08x10^{9}m^3 (73 BCF) and mean oil potential of 0.45x10^{6}m^3 (2.8 MMBO).

Osadetz (pers. comm., 2012) assessed the Lewes River structural play as having a 50% chance of existing, and a mean play potential of 102x10^{9}m^3 (3.6 TCF), 15% in the B.C. portion of Whitehorse trough.

Discussion: It is likely that significant conventional reservoir quality exists within sedimentary rocks of the Aksala Formation. A variety of structural traps should be present, given the complex tectonics of the region. Seals should generally be effective, particularly in the south.

Source rocks present the most significant risk – Lowey *et al.* (2009) noted very low TOC values (mean 0.12%) in Aksala samples, very low S1/S2 ratios, and very high measures of maturity. They summarized the Aksala as an "organic-lean interval that never had any hydrocarbon potential". As well, black fracture-filling material previously reported as pyrobitumen was found to be black-coloured calcite lacking organic material. However, there are very few samples relative to the size of the basin. Also, English *et al.* (2005a) noted "poor to fair" source potential in equivalent Sinwa carbonates in the B.C. portion of Whitehorse trough.

Summary: Probability of geological success for the Lewes River structural play was calculated to be only 3%, with source rock, charge, and seal/containment judged to be the most significant risks (Appendix 1). However, a large prospective play area and the possible existence of large structural traps give rise to significant potential gas volumes.

Mean unrisked gas in place was calculated to be 19.4x10^{9}m^3 (688 BCF). With the low probability of success on the play, risked gas in place was found to be only 0.59x10^{9}m^3 (21 BCF) (Table 1, 2).

Table 1. Summary of in-place volume calculations for Whitehorse trough conceptual petroleum plays (metric values).

PLAY	PLAY RISK	UNRISKED GAS IN PLACE (x 10^{9}m^3)				RISKED MEAN	UNRISKED LIQUIDS IN PLACE (x 10^{6}m^3)				RISKED MEAN
		P90	P50	P10	MEAN		P90	P50	P10	MEAN	
Lewes River Structural	0.03	1.1	6.9	44.2	19.4	0.59	0.00	0.01	0.12	0.10	0.00
Hancock Stratigraphic	0.05	0.1	0.5	3.4	1.5	0.08	0.00	0.00	0.01	0.00	0.00
Tanglefoot Structural	0.13	2.9	16.6	88.9	39.3	5.10	0.62	4.0	25.0	10.8	1.40
Tanglefoot Stratigraphic	0.23	2.1	10.1	47.5	20.9	4.82	0.44	2.5	13.7	5.8	1.33
Tantalus Struc / Strat	0.08	0.0	0.3	2.8	1.2	0.10	0.01	0.06	0.73	0.40	0.03
TOTALS					**82.3**	**10.68**				**17.10**	**2.76**

Table 2. Summary of in-place volume calculations for Whitehorse trough conceptual petroleum plays (imperial values).

PLAY	PLAY RISK	UNRISKED GAS IN PLACE (BCF)				RISKED MEAN	UNRISKED LIQUIDS IN PLACE (MMBO)				RISKED MEAN
		P90	P50	P10	MEAN		P90	P50	P10	MEAN	
Lewes River Structural	0.03	37	243	1569	688	21	0	0.1	0.8	0.4	0.01
Hancock Stratigraphic	0.05	2.8	18	121	54	2.8	0	0	0.1	0	0
Tanglefoot Structural	0.13	103	588	3156	1393	181	3.9	25	157	68	8.9
Tanglefoot Stratigraphic	0.23	75	360	1685	741	171	2.7	16	86	36	8.4
Tantalus Struc / Strat	0.08	1	10.2	98	44	3.5	0	0.4	4.6	2.2	0.17
TOTALS					**2920**	**379.3**				**106.6**	**17.48**

Hancock Member – Stratigraphic Play (Conceptual – Gas)

Reservoirs: Reefal carbonates in Hancock Member, Aksala Formation have reservoir potential (Fig. 4). A spectrum of reefal facies have been described in outcrop studies (*e.g.*, Reid and Tempelman-Kluit, 1987), but quantitative reservoir studies have not been undertaken.

Traps: Hancock Member reefal buildups, along with flanking calcarenites and other reefal debris are potential stratigraphic traps (Fig. 8). Individual buildups in outcrop range up to 150 m thick and 0.75 km^2 in area, but continuity and density of the buildup population have not been determined. Gilmore (1985) suggested that buildups occur discontinuously along a southeast-northwest trend about 30 km wide on a broader carbonate platform, but this observation is based only upon scattered outcrop observations.

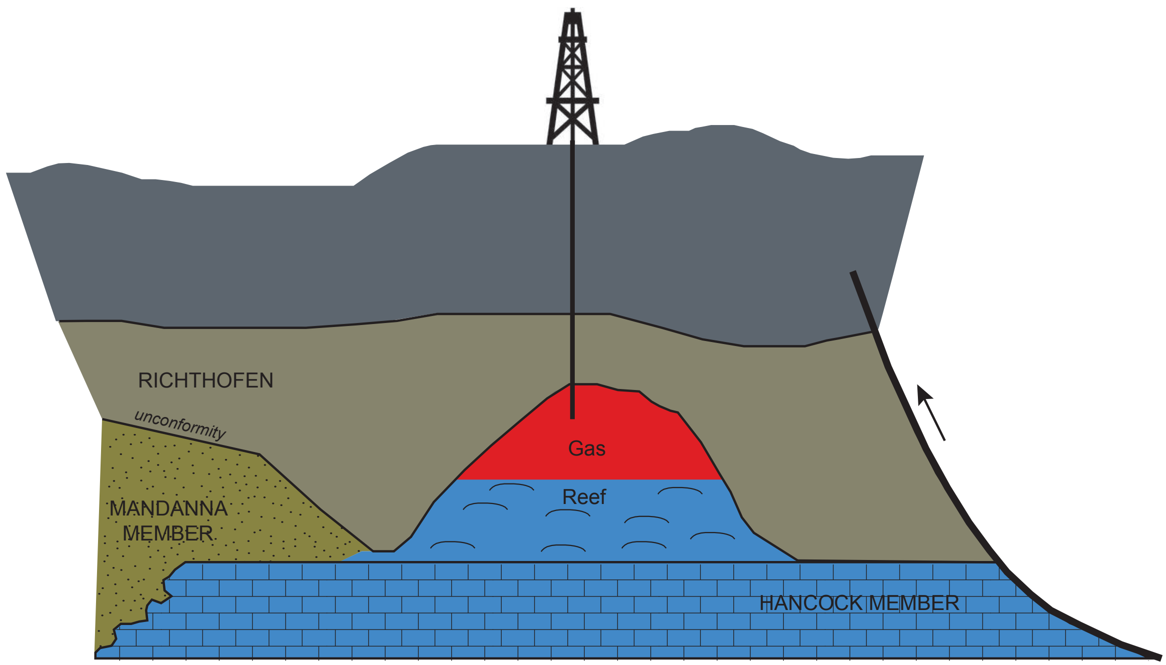


Figure 8. *Schematic cross-section illustrating Hancock Member Stratigraphic Play.*

Structural traps including Hancock Member strata are addressed separately, as part of the Lewes River – Structural play.

Seal: Fine-grained clastics of the Richthofen Formation should provide an effective top seal where present. Risk of ineffective seal is higher where Hancock reefs are overlain by Mandanna Member or coarser Laberge Group strata.

Source: Organic-rich laminated carbonates interbedded within Hancock carbonates are potential source rocks.

Prospective Areas: Hancock strata are assumed to be prospective beneath areas where younger (Mandanna, Laberge Group, Cretaceous and younger volcanics) crop out, excluding intrusive outcrops (Fig. 9). Limited outcrop control and lack of subsurface data preclude determination of depositional trends favourable for reef buildup development and preservation.

Previous Assessments: NEB (2001) recognized potential for the Lewes River (Hancock) stratigraphic play. Overall chance of the play existing was judged to be 11%, with mean gas potential of $2.0x10^9 m^3$ (70 BCF).

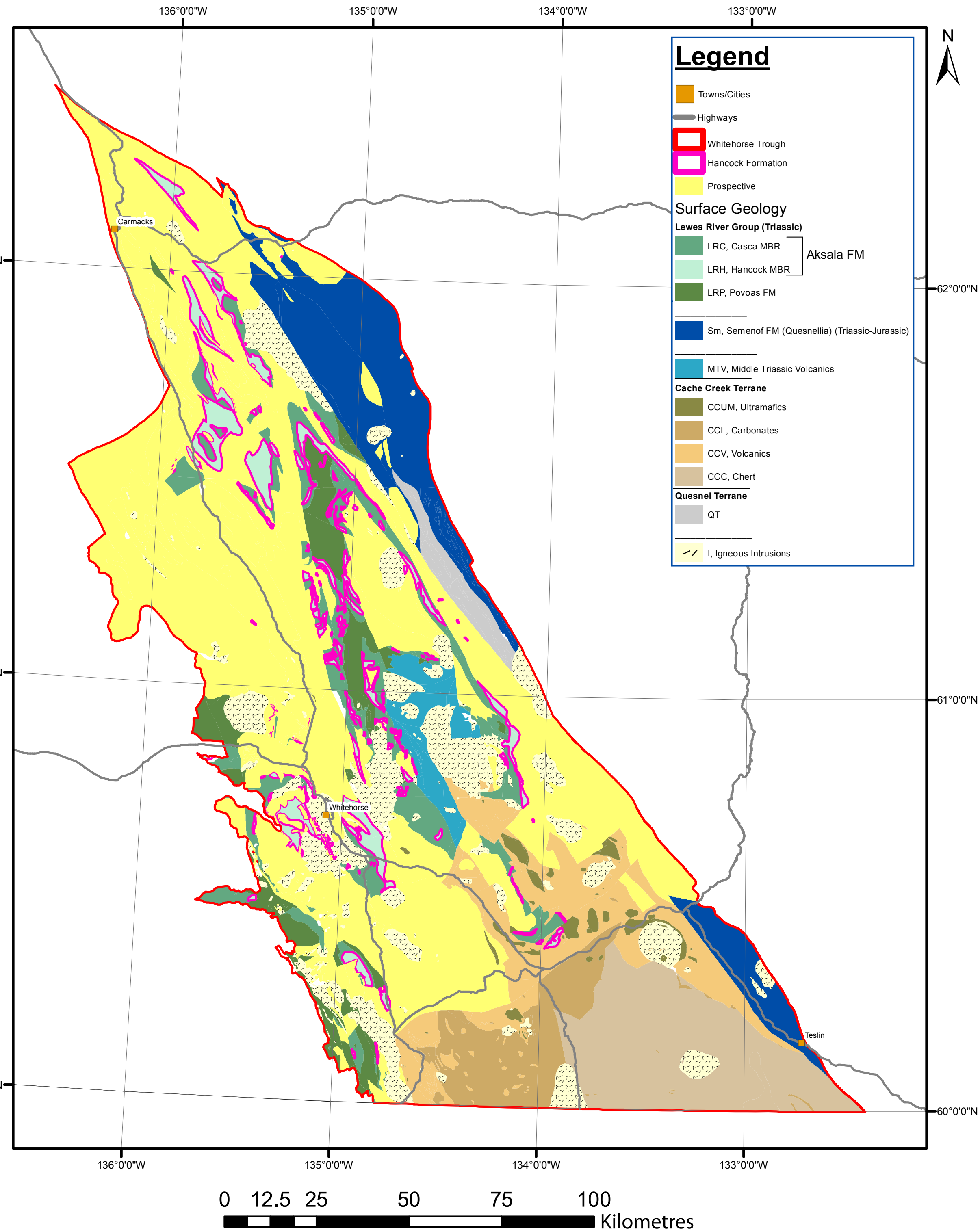


Figure 9. *Map showing prospective areas for Hancock Member Stratigraphic Play. Outcrop of Hancock Member is outlined, while prospective areas that may be underlain by Hancock reservoirs are highlighted yellow (modified from Colpron, 2011).*

Osadetz (pers. comm., 2012) saw Hancock reef buildups as a speculative play, lacking definitive geological information.

Discussion: Reservoir presence and quality are poorly understood for this play. Although well-developed reefal buildups in outcrop provide good pool size parameters, reef distribution is largely unknown. Systematic reservoir quality assessments have not been published; as noted by NEB (2001) fracturing and diagenetic processes have likely had profound effects on reservoir quality and distribution.

Source rocks present the most significant risk – Lowey *et al.* (2009) noted very low TOC values (mean 0.12%) in Aksala (including Hancock) samples, very low S1/S2 ratios, and very high measures of maturity. They summarized the Aksala as an "organic-lean interval that never had any hydrocarbon potential". As well, black fracture-filling material previously reported as pyrobitumen was found to be black-coloured calcite lacking organic material. However, there are very few samples relative to the size of the basin. Also, Reid and Tempelman-Kluit (1987) noted beds in the Hancock containing up to 1.6% TOC, indicating better source potential than documented by Lowey *et al.* (2009).

Summary: Probability of geological success for the Hancock stratigraphic play was calculated to be only 5%, with source rock, charge, and seal/containment judged to be the most significant risks (Appendix 1). Source rock and migration risks are somewhat better than for the Lewes River structural play because of the association noted by some workers of organic-rich laminites with Hancock reefs. However, the prospective play area is much smaller than for the Lewes River structural play, which encompasses potential reservoirs in the Casca and Mandanna members as well.

Mean unrisked gas in place was calculated to be $1.5 \times 10^9 m^3$ (54 BCF). With the low probability of success on the play, risked gas in place was found to be only $0.08 \times 10^9 m^3$ (2.8 BCF) (Table 1, 2).

Tanglefoot Formation – Structural Play (Conceptual – Gas and Oil)

Reservoirs: Interbedded sandstones and siltstones of the Lower to Middle Jurassic Tanglefoot Formation are the primary reservoir rocks (Fig. 4). Associated coals hosting coalbed methane are considered separately as the Tanglefoot – CBM play. Volcaniclastics of the equivalent Nordenskiold Formation are included, although they occur interbedded with pyroclastic deposits, and are expected to have poorer reservoir quality.

Reservoir quality is inferred to occur as intergranular or solution porosity, or to arise from fracturing. Reservoirs should be most continuous and of highest quality where marine and shoreline sandstones dominate the section near the transition to basinal Richthofen facies. Quantitative reservoir studies have not been undertaken.

Traps: A variety of local fold and fault traps were created during Mesozoic and Cenozoic tectonism (Fig. 10).

Seal: Intraformational mudstones are required to provide seals over large areas where the Tanglefoot crops out. Locally, Upper Cretaceous volcanics may provide the top seal. Tantalus Formation overlies the Tanglefoot in small areas, but it is coarse-grained and probably lacks good seal characteristics. Older strata such as Lewes River rocks may provide the seal in traps where they are thrust over Tanglefoot reservoirs.

Source: Interbedded coals and organic-rich mudstones are potential gas and limited oil source rocks.

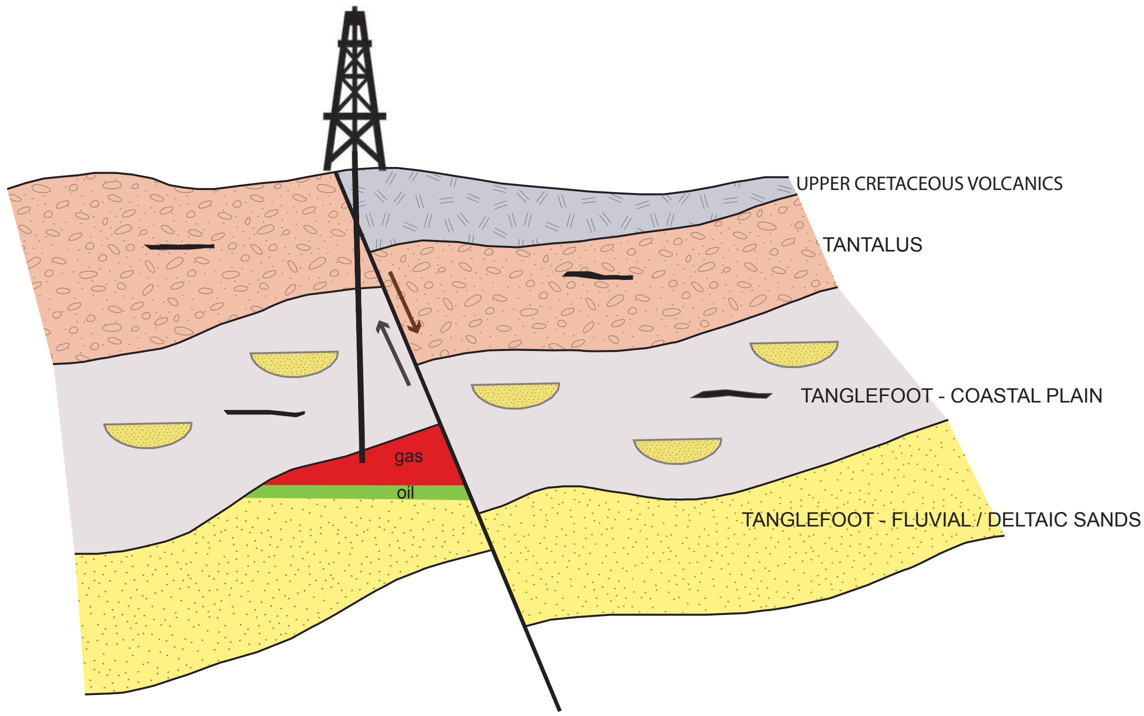


Figure 10. *Schematic cross section illustrating one possible configuration of Tanglefoot Structural Play.*

Prospective Areas: The Tanglefoot is prospective beneath younger rocks, and where it crops out in the northern half of Whitehorse trough (Figs. 5, 11). Although risk for top seal is clearly greater where the formation crops out, the chance for effective intraformational seals is judged to be good where the 3000-metre Tanglefoot section is fully preserved.

Previous Assessments: NEB (2001) recognized potential for structural plays in Tanglefoot strata as part of the Hancock-Conglomerate structural play. Overall chance of the play existing was judged to be 16%, with mean gas potential of $2.08 \times 10^9 m^3$ (73 BCF) and mean oil potential of $0.45 \times 10^6 m^3$ (2.8 MMBO).

Osadetz (pers. comm., 2012) assessed Tanglefoot Structural potential to occur in his Takwahoni Structural play. Laberge Group coarse clastics (Tanglefoot equivalent) were mapped over a larger area than is currently recognized. Osadetz judged the play as certain to exist, with mean in place gas potential of $80.7 \times 10^9 m^3$ (2.85 TCF) and mean oil potential of $13.2 \times 10^6 m^3$ (83 MMBO). Twenty-seven percent of the play area was mapped in the B.C. portion of Whitehorse trough.

Discussion: Clear definition and regional mapping of Laberge Group stratigraphic relationships (Lowey, 2008; Lowey *et al.,* 2009; Colpron, 2011) are major advances in systematic recognition of resource potential. Previous assessments cannot be compared exactly, as the Tanglefoot was not clearly defined at the time they were done.

Abundant trapping configurations, including sub-thrust traps, exist as a product of the complex tectonic history of the basin. However, top seal is a key risk, as unmapped intraformational mudstones are required to seal traps in most areas, except where younger Tantalus and volcanic units are present. This is particularly true in central Whitehorse trough, where more continuous marine and shoreline sands dominate the section.

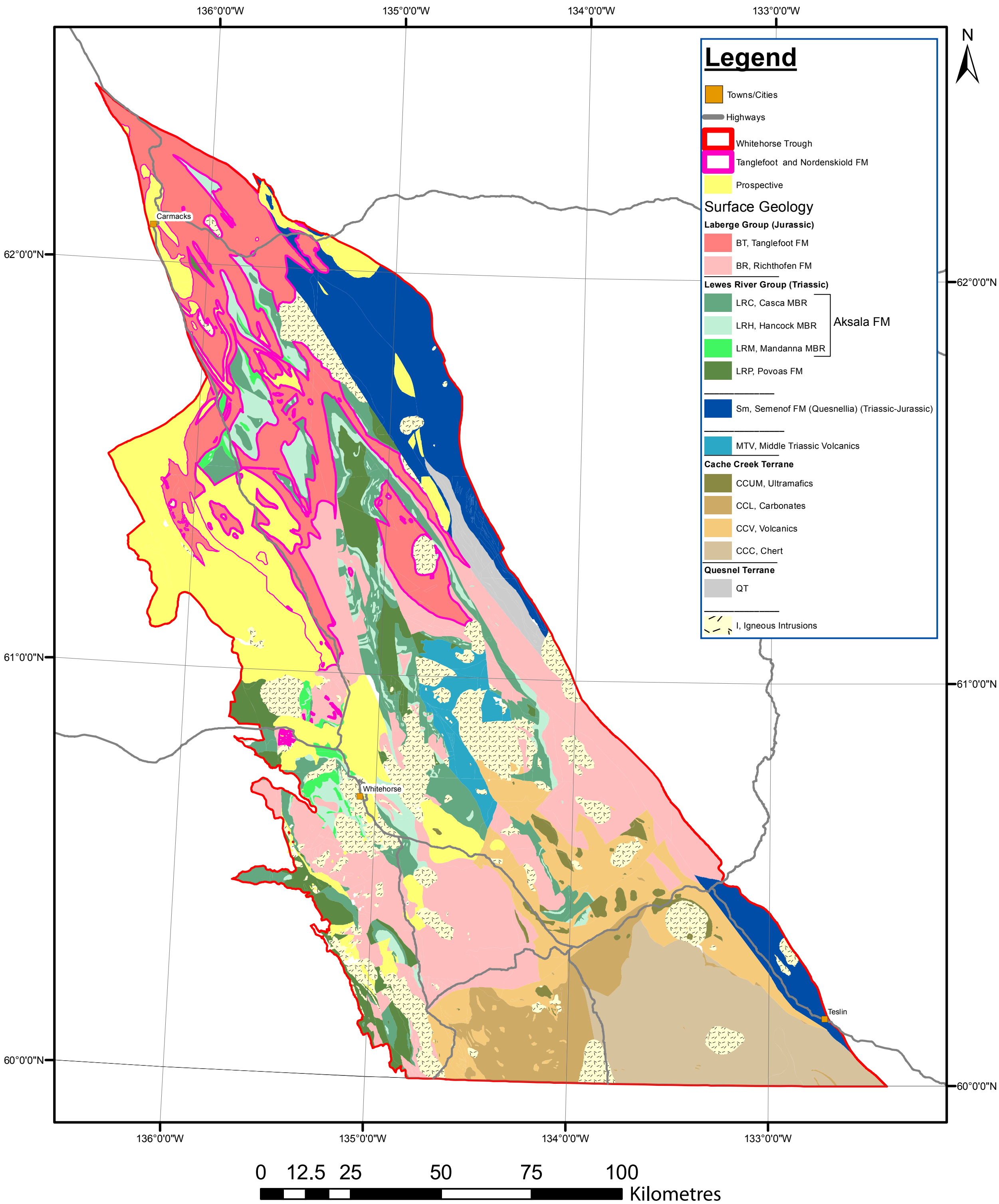


Figure 11. *Map showing prospective areas for Tanglefoot Structural Play. Outcrop of Tanglefoot Formation is outlined, while prospective areas that may be underlain by Tanglefoot reservoirs are highlighted yellow (modified from Colpron, 2011).*

Source rock is a much lower risk than for older units. Tanglefoot mudstones show moderate TOC values, dominantly Type III organics with some Type II (Lowey *et al.*, 2009). T_{max} and vitrinite reflectance values indicate the organics are immature to moderately mature. Coals have a high liptinite content, indicative of oil-generative capacity (Allen, 2000). Liquid petroleum fluid inclusions in fractured grains point to early oil charge and migration. Lowey *et al.* (2009) concluded that the Tanglefoot includes "good source rock, gas-prone, possibly effective".

Summary: Probability of geological success for the Tanglefoot structural play was calculated to be 13%. Source rock, migration and charge are much lower risks than for the Lewes River and Hancock plays, but seal/containment of traps was judged to be a very significant risk (Appendix 1).

Mean unrisked gas in place was calculated to be 39.3x10^{9}m^3 (1393 BCF), and mean unrisked liquids in place are 10.8x10^{6}m^3 (68 MMBO). Risked gas in place was found to be 5.1x10^{9}m^3 (181 BCF), and risked liquids in place 1.4x10^{6}m^3 (8.9 MMBO) (Table 1, 2).

Tanglefoot Formation – Stratigraphic Play (Conceptual – Gas and Oil)

Reservoirs: Interbedded sandstones and siltstones of the Lower to Middle Jurassic Tanglefoot Formation are the primary reservoir rocks (Fig. 4). Associated coals hosting coalbed methane are considered separately as the Tanglefoot – CBM play. Volcaniclastics of the equivalent Nordenskiold Formation are included, although they occur interbedded with pyroclastic deposits, and are expected to have poorer reservoir quality.

Reservoir quality is inferred to occur as intergranular or solution porosity, or to arise from fracturing. Reservoirs should be most continuous and of highest quality where marine and shoreline sandstones dominate the section near the transition to basinal Richthofen facies. Quantitative reservoir studies have not been undertaken.

Traps: Stratigraphic traps within the Tanglefoot should include fluvial channels and associated facies, particularly north of the shoreline to basin transition to the equivalent Richthofen Formation in the south (Fig. 12). Trapping configurations will be less common in sand-dominated shoreline to shallow marine facies near the transition, although more trapping opportunities may exist if the shoreline was dominated by deltaic as opposed to shoreface deposition. Southward, coarse-grained submarine channel and fan facies assigned to the Tanglefoot lithostratigraphically may occur within Richthofen basinal facies.

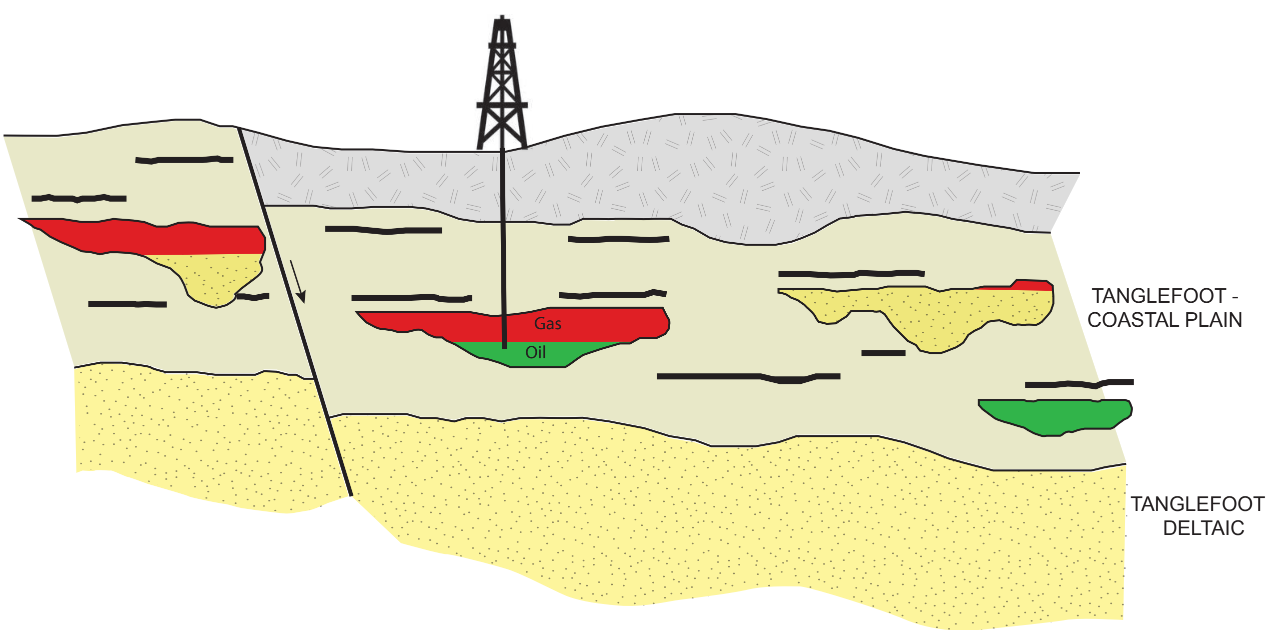


Figure 12. *Schematic cross section illustrating stratigraphic traps in fluvial-dominated section of Tanglefoot Stratigraphic Play. See Figure 5 for location.*

Seal: Intraformational fine-grained clastics – overbank facies, muddy channel fills, and coal swamps – are important seals over large areas in the north where the Tanglefoot crops out (Fig. 13). Locally, Upper Cretaceous volcanics may provide the top seal. Tantalus Formation overlies the Tanglefoot in small areas, but it is coarse-grained and may lack good seal characteristics. Traps in Tanglefoot submarine channels and fans should be much more effectively sealed by equivalent Richthofen basinal mudstones and siltstones.

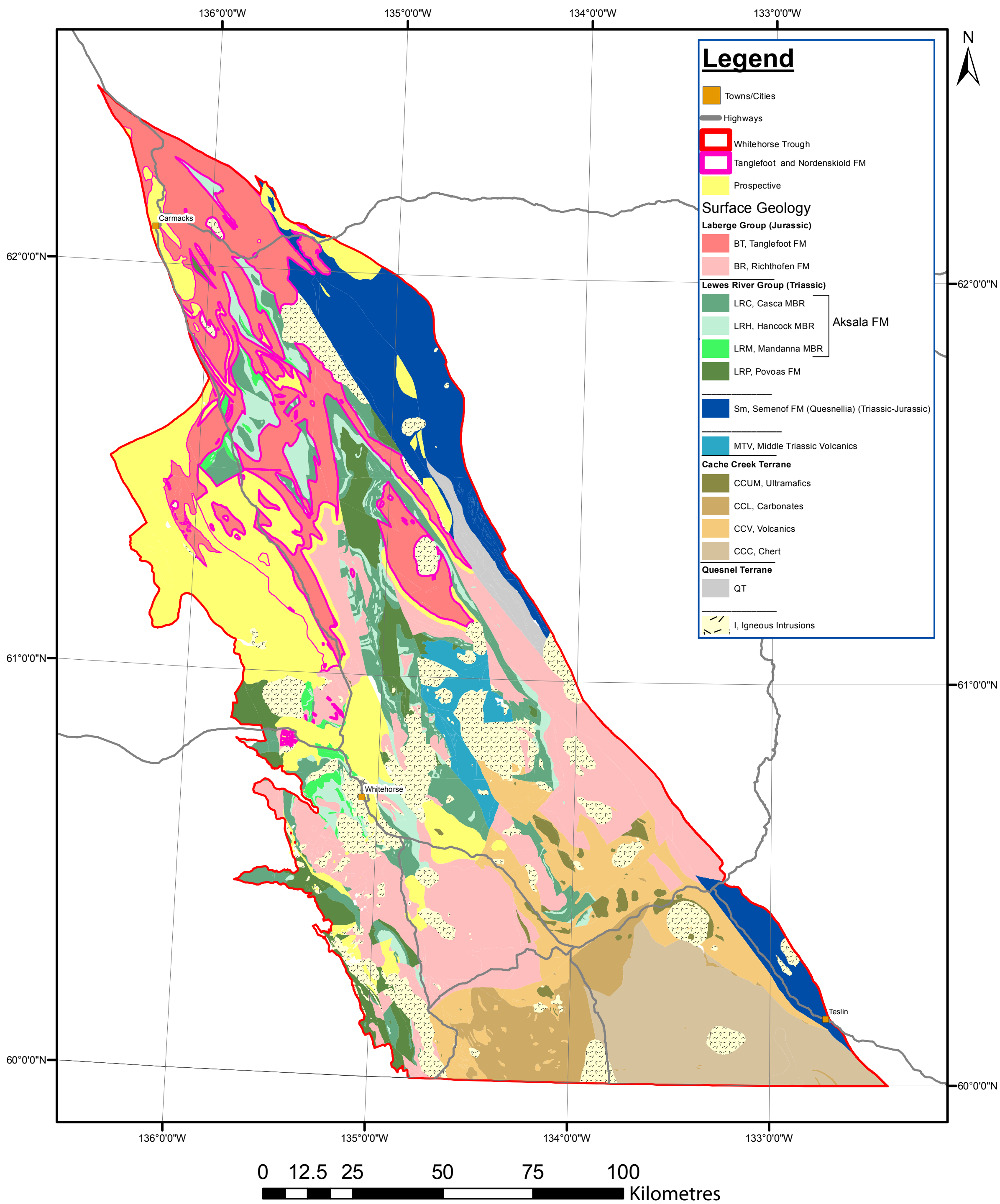


Figure 13. *Map showing prospective areas for Tanglefoot Stratigraphic Play. Outcrop of Tanglefoot Formation is outlined, while prospective areas that may be underlain by Tanglefoot reservoirs are highlighted yellow (modified from Colpron, 2011).*

Source: Interbedded coals and organic-rich mudstones are potential gas and limited oil source rocks.

Prospective Areas: The Tanglefoot is prospective beneath younger rocks, and where it crops out in the northern half of Whitehorse trough (Figs. 5, 13). Although risk for top seal is clearly greater where the formation crops out, the chance for effective intraformational seals is judged to be good where the 3000-metre Tanglefoot section is fully preserved. Tanglefoot submarine channel and fan facies should be prospective immediately basinward of the regional transition from the main body of the Tanglefoot to Richthofen basinal facies (Fig. 5).

Previous Assessments: NEB (2001) recognized potential for stratigraphic plays in Tanglefoot strata in both the Conglomerate-Richthofen Stratigraphic and Conglomerate-Nordenskiold Stratigraphic plays. Overall chance of the plays existing was judged to be 5-10%, with mean gas potential of $0.79 \times 10^9 m^3$ (28 BCF) and mean oil potential of $0.21 \times 10^6 m^3$ (1.3 MMBO).

Osadetz (pers. comm., 2012) classified Tanglefoot Stratigraphic potential in the Takwahoni Stratigraphic play. He judged there to be insufficient geological information to support a quantitative assessment, and play potential to be small.

Discussion: Clear definition and regional mapping of Laberge Group stratigraphic relationships (Lowey, 2008; Lowey *et al.*, 2009; Colpron, 2011) are major advances in systematic recognition of resource potential. Previous assessments cannot be compared exactly, as the Tanglefoot was not clearly defined at the time they were done.

Numerous stratigraphic trapping situations can be envisioned within the coastal plain – deltaic/shoreline setting of the Tanglefoot. However, top seal is a key risk, as unmapped intraformational mudstones are required to seal traps in most areas, except where younger Tantalus and volcanic units are present. This is particularly true in central Whitehorse trough, where more continuous marine and shoreline sands dominate the section. To the south, however, submarine channels and fans associated with Tanglefoot deposition are likely to be effectively sealed by basinal fine-grained clastics of the Richthofen Formation.

Source rock is a much lower risk than for older units. Tanglefoot mudstones show moderate TOC values, dominantly Type III organics with some Type II (Lowey *et al.*, 2009). T_{max} and vitrinite reflectance values indicate the organics are immature to moderately mature. Coals have a high liptinite content, indicative of oil-generative capacity (Allen, 2000). Liquid petroleum fluid inclusions in fractured grains point to early oil charge and migration. Lowey *et al.* (2009) concluded that the Tanglefoot includes “good source rock, gas-prone, possibly effective”.

Summary: Probability of geological success for the Tanglefoot stratigraphic play was calculated to be 23%. Source rock, migration and charge are much lower risks than for the Lewes River and Hancock plays, and seal/containment of traps was judged to be a lesser risk than for the Tanglefoot structural play (Appendix 1). However, total resource volumes for the stratigraphic play are smaller, as pools are expected to be smaller (expressed in the inputs as a lower range of net pay thicknesses).

Mean unrisked gas in place was calculated to be $20.9 \times 10^9 m^3$ (741 BCF), and mean unrisked liquids in place are $5.8 \times 10^6 m^3$ (36 MMBO). Risked gas in place was found to be $4.82 \times 10^9 m^3$ (171 BCF), and risked liquids in place $1.33 \times 10^6 m^3$ (8.4 MMBO) (Table 1, 2).

Tanglefoot Formation – CBM (Speculative – Gas)

Reservoirs: Coal beds within the interbedded sandstone/siltstone/coal/mudstone succession are prospective (Fig. 4). Quantitative CBM reservoir studies have not been undertaken. In areas where the Tanglefoot has been studied in detail for coal mining potential, coals are found predominantly in upper, relatively fine-grained parts of the formation.

Traps: This is an unconventional play – gas may occur relatively continuously throughout coal beds, so no specific trapping configuration is required.

Seal: Intraformational fine-grained clastics – overbank facies, muddy channel fills, and coal swamps – are important to help define the regionally-pervasive coalbed methane petroleum system. Locally, Upper Cretaceous volcanics may provide the top seal over large areas.

Source: Tanglefoot coal beds are self-sourcing; that is, gas occurring within Tanglefoot coals would have been generated by the coals themselves.

Prospective Areas: The Tanglefoot is prospective beneath younger rocks, and where it crops out in the northern half of Whitehorse trough (Figs. 5, 14). Although risk for top seal is clearly greater where the formation crops out, the chance for effective intraformational seals is judged to be good where the 3000-metre Tanglefoot section is fully preserved. Existing regional mapping is not sufficient to define areas where the upper, coal-bearing part of the Tanglefoot has been eroded, although more coal occurrences have been noted in the western part of the basin.

Previous Assessments: Coalbed methane potential has not been assessed prior to this report.

Discussion: Clear definition and regional mapping of Laberge Group stratigraphic relationships (Lowey, 2008; Lowey *et al.*, 2009; Colpron, 2011) is a major advance in systematic recognition of resource potential.

Significant coal resources have been mapped at Division Mountain, where Allen (2000) estimated 52.9 Mt of high-volatile bituminous B/C coals, in more than 30 seams in the top 50 m of the Tanglefoot. Both Allen (2000) and Lowey *et al.* (2009) noted substantial high-volatile bituminous coals in the Tanglefoot at Five Finger Rapids (Fig. 14). Ricketts (1994), Hunt (1994), and Yukon Geological Survey Occurrence records show numerous other coal localities, but most of these appear to be in the Tantalus Formation, or cannot be assigned stratigraphically with certainty. Such descriptions of isolated coal occurrences are not sufficient to assess regional continuity and overall CBM potential.

Methane adsorption capacity must be measured in the laboratory in order to quantitatively assess capacity of coals to hold and produce CBM. Matrix porosity, cleat structure and volumes, and reservoir pressures are also important factors to consider, and none of these have been analyzed for Tanglefoot coals. While coal rank and composition of organic matter are commonly used as indicators of CBM potential, Bustin and Clarkson (1998) found these parameters not to be definitive when comparing coals from basin to basin.

Summary: Substantial CBM potential exists in coals of the Tanglefoot Formation in northern Whitehorse trough, but only as a speculative play. Lack of subsurface information, limited outcrop descriptions, and structural complexity of the basin make it impossible to map coals on a regional basis. CBM reservoir parameters, as described by Bustin and Clarkson (1998), have not been measured, and are required to quantify unconventional potential.

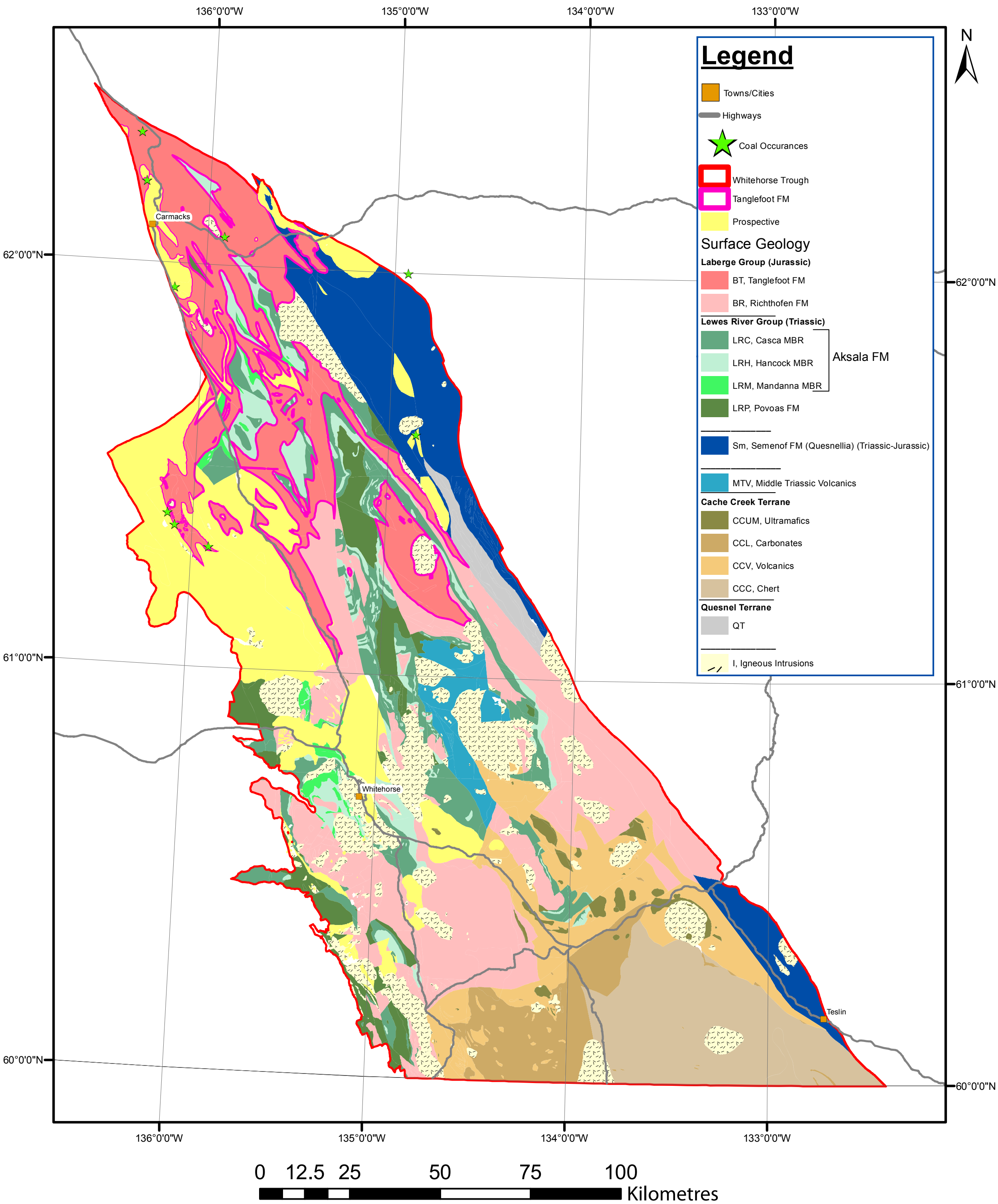


Figure 14. Map showing prospective areas for Tanglefoot CBM Play. Outcrop of Tanglefoot Formation is outlined, while prospective areas that may be underlain by Tanglefoot reservoirs are highlighted yellow. Locations where coals have been described in the Tanglefoot are highlighted with green stars.

Richthofen Stratigraphic/Tight Gas/Shale Gas (Speculative – Unconventional)

Reservoirs: Fine-grained sandstones, siltstones, and shales of the basinal Richthofen Formation are envisioned to be unconventional reservoirs in a basin-centred tight gas/shale gas setting.

Traps: This is an unconventional play – gas would occur relatively continuously throughout low-permeability strata in a basin-centred hydrodynamic regime, so no specific trapping configuration is required (Fig. 15).

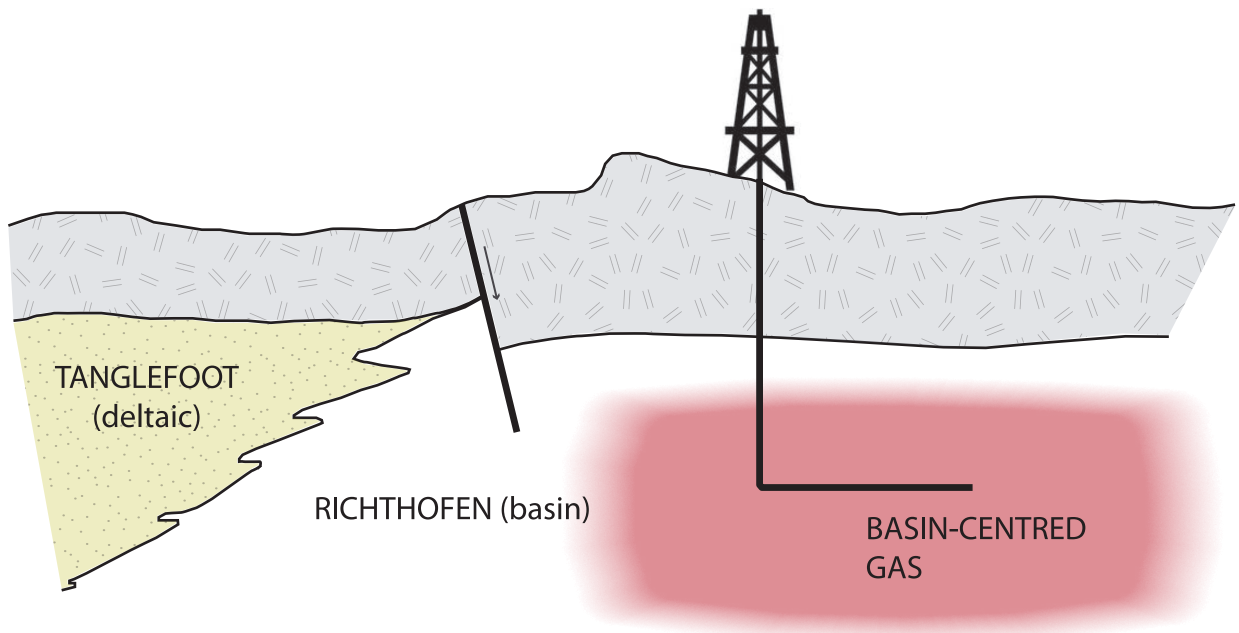


Figure 15. *Schematic cross section illustrating Richthofen Stratigraphic/Tight Gas/Shale Gas Play.*

Seal: Specific, prospect-scale seals are not required, but regional seals must exist to isolate low-permeability reservoir strata from regional aquifers.

Source: Richthofen reservoirs may be self-sourcing; that is, gas occurring within Richthofen tight sands, silts, and shales could have been derived from organic material within the formation.

Prospective Areas: The Richthofen is prospective beneath younger rocks, and where it crops out throughout the south-central part of the basin (Figs. 5, 16). 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.

Previous Assessments: Tight gas/shale gas potential has not been assessed prior to this report.

Discussion: Clear definition and regional mapping of Laberge Group stratigraphic relationships (Lowey, 2008; Lowey *et al.*, 2009; Colpron, 2011) is a major advance in systematic recognition of resource potential.

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.

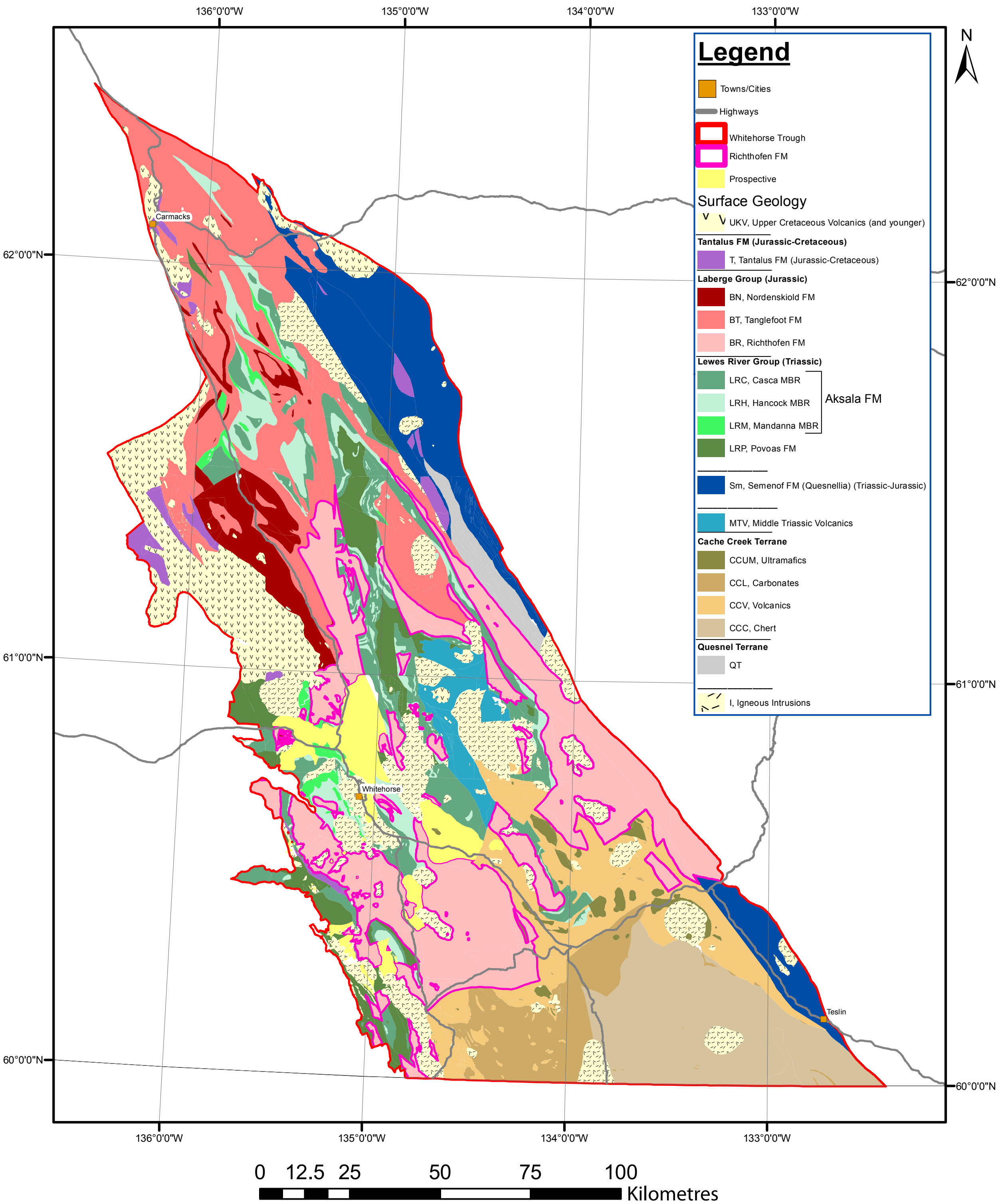


__Figure 16.__ Map showing prospective areas for Richthofen Stratigraphic/Tight Gas/Shale Gas Play. Outcrop of Richthofen Formation is outlined, while prospective areas that may be underlain by Richthofen reservoirs are highlighted yellow (modified from Colpron, 2011).

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 post-mature for oil generation. Very low S_2 values make T_{max} values obtained from Rock-Eval analysis unreliable, but vitrinite reflectance of 1.41% and the presence of black and degraded palynomorphs (thermal alteration index > 4) confirm high thermal maturity.

Productive shale gas and tight gas reservoirs generally require the presence of mature, organic-rich source rocks, often associated with condensed sections deposited in basinal settings. Such strata may possibly exist within the Richthofen, but they have not been identified to date in Whitehorse trough. English *et al.* (2005b) documented more favourable source rocks in the equivalent Inklin Formation in the B.C. portion of the basin, providing encouragement that better source rock remains to be found in Yukon.

Summary: Richthofen strata present an intriguing potential basin-centred tight gas and/or shale gas system in the south-central part of Whitehorse trough. Appropriate source rock richness and maturity are the major risk factors for the play. Exploratory drilling that establishes the presence of hydrocarbons and anomalous subsurface pressure systems is required to move this play from the speculative realm.

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.

Tantalus Formation – Structural/Stratigraphic Play (Conceptual – Gas and Oil)

Reservoirs: Fluvial to deltaic conglomerates and sandstones of the Upper Jurassic to Lower Cretaceous Tantalus Formation are the primary reservoir rocks (Long and Lowey, 2006). Associated coals hosting coalbed methane are considered separately as the Tantalus – CBM play (Fig. 4).

Reservoir quality is inferred to occur primarily as intergranular porosity in coarse-grained clastic rocks, or to arise from fracturing (Long, 2005). Quantitative reservoir studies have not been undertaken.

Traps: No attempt has been made to differentiate stratigraphic and structural traps within the Tantalus. The formation occurs in isolated areas within Whitehorse trough and beyond. Both deposition and preservation were likely strongly influenced by local faulting, and thus there have been no regional stratigraphic/facies relationships defined like those defined for the Tanglefoot/Richthofen succession. Local structure would likely play the dominant role in trap definition, possibly assisted by stratigraphic elements, but specific traps cannot be delineated given our current understanding of the Tantalus (Fig. 17).

Seal: Intraformational fine-grained clastics – overbank facies, muddy channel fills, and coal swamps – occur within the Tantalus, and may form seals locally. The chance for effective intraformational seals is judged to be substantially poorer than for the Tanglefoot, as Tantalus strata are generally only a few hundred metres thick or less (Colpron, pers. comm., 2012). In addition, Long (2005) estimated the Tantalus to contain less than 5% fine-grained clastic material. Upper Cretaceous volcanics may also provide top seal. If traps exist where older rocks are thrust over the Tantalus, top seal may be composed of older strata, and hence may be more effective.

Source: Interbedded coals and organic-rich mudstones are potential gas and limited oil source rocks.

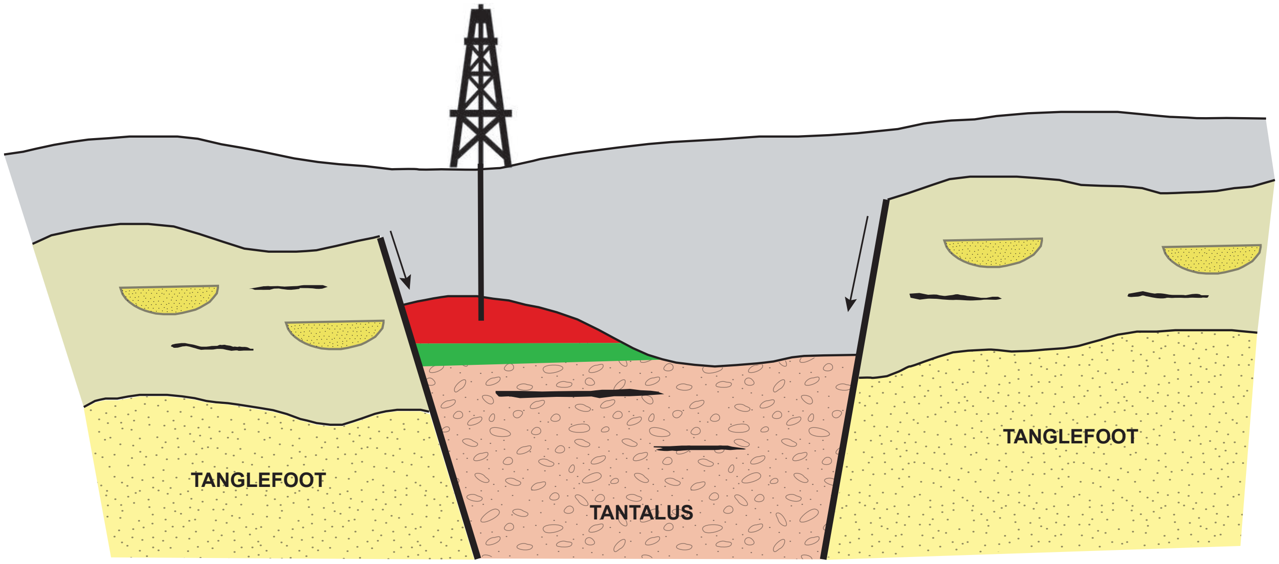


Figure 17. *Schematic cross section illustrating Tantalus Structural/Stratigraphic Play.*

Prospective Areas: The Tantalus is prospective in the small areas where it crops out, and may be prospective beneath Upper Cretaceous volcanics, although its distribution beneath these rocks is highly uncertain (Fig. 18). White *et al.* (2006) noted local occurrence of Tantalus in outcrop beneath Upper Cretaceous volcanics along the Robert Campbell Highway in northern Whitehorse trough.

Previous Assessments: NEB (2001) recognized potential for both stratigraphic and structural plays in Tanglefoot strata, although it is unclear how the two plays were distinguished. Probability for occurrence of the structural play was judged to be 21%, with mean gas potential of $0.45x10^9m^3$ (16 BCF) and mean oil potential of less than 1 MMBO. Probability for occurrence of the stratigraphic play was judged to be 21%, with mean gas potential of $1.56x10^9m^3$ (56 BCF) and mean oil potential of $0.55x10^6m^3$ (3.4 MMBO).

Osadetz (pers. comm., 2012) recognized a Tantalus Structural play, but saw no stratigraphic play potential. He judged that a gas play was almost certain to exist, with mean in place potential of $1.36x10^9m^3$ (48 BCF), and that there would be a 38% chance of an oil play existing in the Carmacks area, with mean in place potential of $1.75x10^6m^3$ (11 MMBO).

Discussion: Reservoir quality is likely relatively good because of the dominance of coarse grain sizes. Structural trapping configurations should be common in the areas where the Tantalus exists, as a product of the complex tectonic history of the area. Facies relationships within the fluvial-dominate succession can be envisioned as relatively minor contributors to trapping. Top seal is the major risk for the Tantalus play, as intraformational seals are likely to be thin and areally restricted, and younger volcanics are present only locally.

Source rock is a relatively low risk. Tantalus mudstones show moderate TOC values, dominantly Type III organics with some Type II (Lowey *et al.*, 2009). T_{max} and vitrinite reflectance values indicate the organics are immature to moderately mature. Coals have a moderate liptinite content, indicative of some limited oil-generative capacity (Lowey *et al.*, 2009). Liquid petroleum fluid inclusions in fractured grains point to early oil charge and migration, but Long (2005) did not find any oil staining in Tantalus rocks. Lowey *et al.* (2009) concluded that the Tantalus includes “good source rock, gas-prone, possibly effective”.

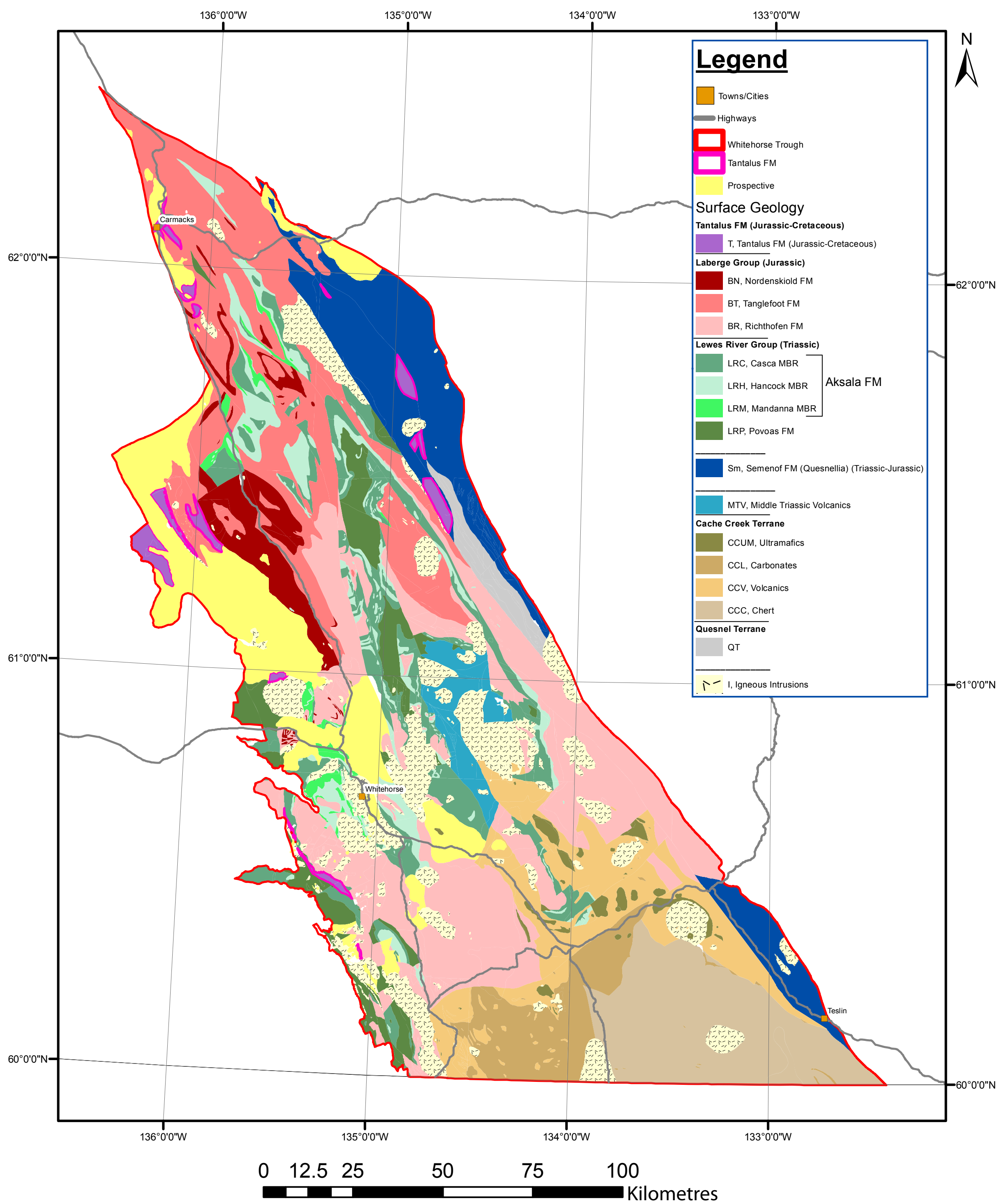


Figure 18. *Map showing prospective areas for Tantalus Structural/Stratigraphic Play. Outcrop of Tantalus Formation is outlined, while prospective areas that may be underlain by Tantalus reservoirs are highlighted yellow (modified from Colpron, 2011).*

Summary: Probability of geological success for the Tantalus structural/stratigraphic play was calculated to be 8%. Source, charge, migration, reservoir, and trap risks are judged to be low, but the chance of effective seals existing is quite low (Appendix 1). Prospective play area is much smaller than for other plays, although in the high case it was assumed that significant play area exists beneath Cretaceous volcanics and Quaternary cover (Appendix 1).

Mean unrisked gas in place was calculated to be $1.2x10^9m^3$ (44 BCF), and mean unrisked liquids in place are $0.40x10^6m^3$ (2.2 MMBO). Risked gas in place was found to be $0.1x10^9m^3$ (3.5 BCF), and risked liquids in place $0.03x10^6m^3$ (0.17 MMBO) (Table 1, 2).

Tantalus Formation – CBM (Speculative – Gas)

Reservoirs: Coal beds within the interbedded conglomerate/sandstone/coal succession are prospective (Fig. 4). Quantitative CBM reservoir studies have not been undertaken. Significant coals have been described at a few specific locations, and have been noted at a number of locations around the basin (Fig. 19).

Traps: This is an unconventional play – gas may occur relatively continuously throughout coal beds, so no specific trapping configuration is required.

Seal: Intraformational fine-grained clastics – overbank facies, muddy channel fills, and coal swamps – are important to help define the regionally-pervasive coalbed methane petroleum system. The chance for effective intraformational seals is judged to be substantially poorer than for the Tanglefoot, as Tantalus strata are generally only a few hundred metres thick or less (Colpron, pers. comm., 2012). Locally, Upper Cretaceous volcanics may provide the top seal over large areas.

Source: Tantalus coal beds are self-sourcing; that is, gas occurring with Tantalus coals would have been generated by the coals themselves.

Prospective Areas: The Tantalus is prospective in the small areas where it crops out, and may be prospective beneath Upper Cretaceous volcanics, although its distribution beneath these rocks is highly uncertain (Fig. 19). White *et al.* (2006) noted local occurrence of Tantalus in outcrop beneath Upper Cretaceous volcanics along the Robert Campbell Highway in northern Whitehorse trough. Although coals have not been mapped systematically on a regional basis, there are more coals observed in the western part of the basin (Fig. 19).

Previous Assessments: Coalbed methane potential has not been assessed prior to this report.

Discussion: Significant Tantalus coal resources have been mapped at Tantalus Butte where Lowey *et al.* (2009) estimated 7.2 Mt of coal in four seams, the thickest up to 4.2 m thick. At Whitehorse, Hunt and Hart (1994) calculated 85 Mt of meta-anthracite in eight seams, interbedded with conglomerate and shale. Proximity to the Coast Plutonic Complex appears to have elevated the coal rank at this locality. Ricketts (1994), Hunt (1994), and Yukon Geological Survey Occurrence records show numerous other coal localities, many in the Tantalus Formation, but such descriptions of isolated coal occurrences are not sufficient to assess regional continuity and overall CBM potential.

Methane adsorption capacity must be measured in the laboratory in order to quantitatively assess capacity of coals to hold and produce CBM. Matrix porosity, cleat structure and volumes, and reservoir pressures are also important factors to consider, and none of these have been analyzed for Tantalus coals. While coal rank and composition of organic matter are commonly used as indicators of CBM potential, Bustin and Clarkson (1998) found these parameters not to be definitive when comparing coals amongst different basins.

Summary: Substantial CBM potential exists in coals of the Tantalus Formation in northern Whitehorse trough, but only as a speculative play. Lack of subsurface information, limited outcrop descriptions, and structural complexity of the basin make it impossible to map coals on a regional basis. CBM reservoir parameters, as described by Bustin and Clarkson (1998), have not been measured, and are required to quantify unconventional potential.

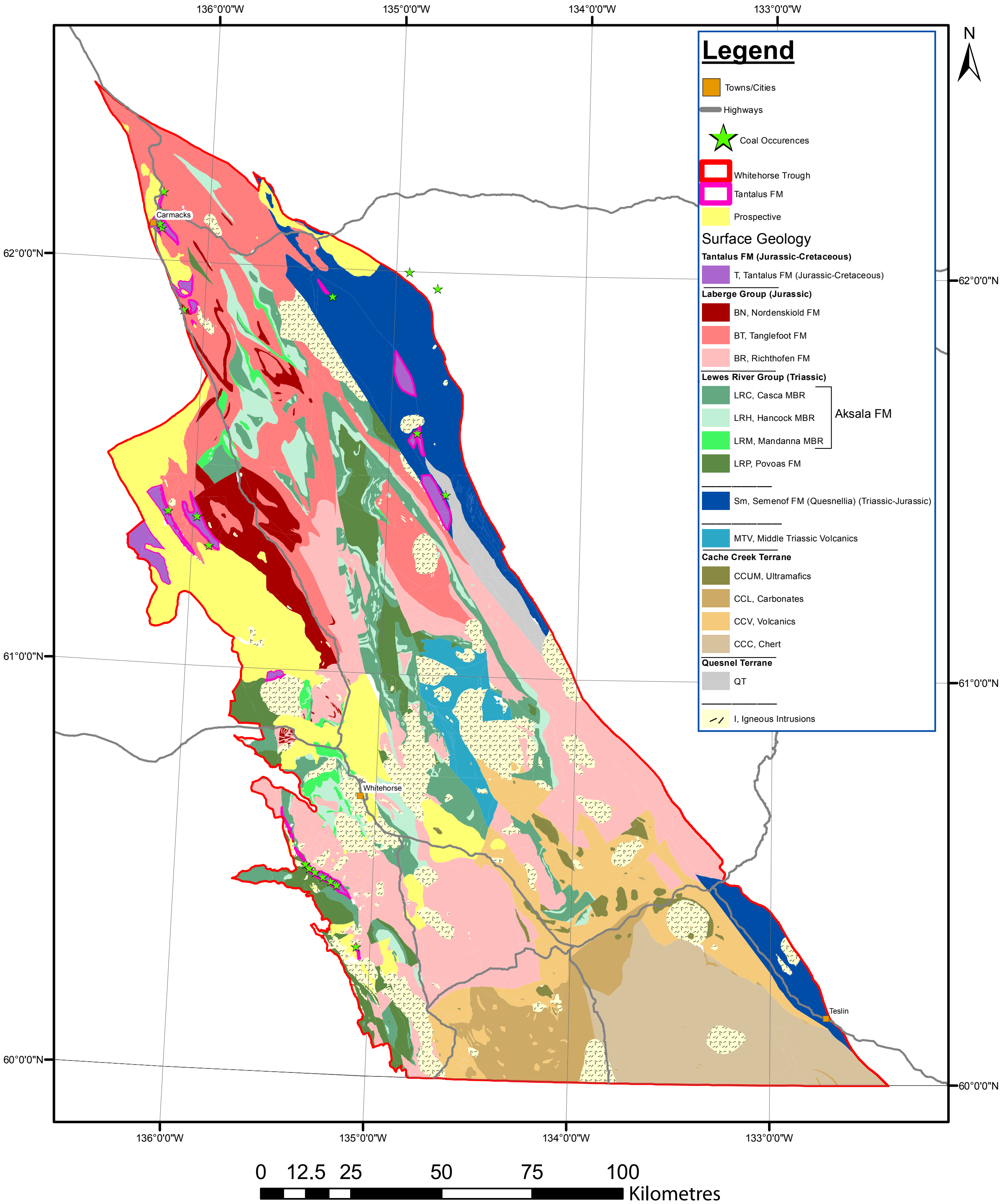


Figure 19. *Map showing prospective areas for Tantalus CBM Play. Outcrop of Tantalus Formation is outlined, while prospective areas that may be underlain by Tantalus reservoirs are highlighted yellow. Locations where coals have been described in the Tantalus are highlighted (modified from Colpron, 2011).*

SUMMARY

Tables 1 (metric units) and 2 (Imperial units) (pg. 14) summarize in place petroleum resource calculations for the five conceptual plays that were analyzed statistically. Unrisked P90, P50, P10 and mean values are shown for gas and for liquids. Mean values after applying play-level risk factors are also shown. Tables 3 and 4 similarly show results for marketable gas and recoverable hydrocarbons, using the assumptions laid out in the assessment methodology (Appendix 1). No pricing or other economic cut-offs have been applied. The full spreadsheets used to calculate these values are included in Appendix 2.

Table 3. Summary of marketable volume calculations for Whitehorse trough conceptual petroleum plays (metric values).

PLAY	PLAY RISK	UNRISKED MARKETABLE GAS ($x 10^9 m^3$)				RISKED MEAN	UNRISKED RECOVERABLE LIQUIDS ($x 10^6 m^3$)				RISKED MEAN
		P90	P50	P10	MEAN		P90	P50	P10	MEAN	
Lewes River Structural	0.03	0.5	3.1	20.2	8.9	0.27	0	0	0.1	0	0
Hancock Stratigraphic	0.05	0	0.2	1.5	0.2	0.04	0	0	0	0	0
Tanglefoot Structural	0.13	1.3	7.6	42.3	18.5	2.4	0.1	0.9	5.9	2.6	0.34
Tanglefoot Stratigraphic	0.23	1	4.7	22.5	9.9	2.3	0.1	0.5	3.2	1.4	0.32
Tantalus Struc / Strat	0.08	0	0.1	1.3	0.6	0.05	0	0	0.2	0.1	0.01
TOTALS					**38.1**	**5.06**				**4.1**	**0.67**

Table 4. Summary of marketable volume calculations for Whitehorse trough conceptual petroleum plays (imperial values).

PLAY	PLAY RISK	UNRISKED MARKETABLE GAS (BCF)				RISKED MEAN	UNRISKED RECOVERABLE LIQUIDS (MMBO)				RISKED MEAN
		P90	P50	P10	MEAN		P90	P50	P10	MEAN	
Lewes River Structural	0.03	18	109	713	314	10	0	0	0.63	0	0
Hancock Stratigraphic	0.05	0	7.1	53	7.1	1.4	0	0	0	0	0
Tanglefoot Structural	0.13	46	268	1494	653	85	0.63	5.66	37.1	16.4	2.14
Tanglefoot Stratigraphic	0.23	35	166	795	350	81	0.63	3.15	20.1	8.81	2.01
Tantalus Struc / Strat	0.08	0	3.5	46	21	1.8	0	0	1.26	0.63	0.06
TOTALS					**1345**	**179**				**25.8**	**4.21**

A number of observations can be made:

- P10/P90 ratios are generally large, and arise from the large uncertainties we have in assignment of most play parameters;
- Total hydrocarbon volumes, particularly on a risked basis, are small for the Lewes River and Hancock plays, despite the fact that these plays are potentially prospective over large areas. This reflects a high level of uncertainty regarding the presence of adequate source rock;
- Relatively large hydrocarbon volumes associated with the Tanglefoot plays, particularly on a risked basis, result from the presence of good potential source rock and good reservoirs;
- Low prospectivity for the Tantalus Formation, despite the presence of good potential source rocks and reservoirs, is primarily the product of the low potential for traps to be effectively sealed; and
- Relatively large liquids volumes in the Tanglefoot and Tantalus plays reflect the potential for their high-liptinite coals to generate liquids.

Extrapolating these observations to the speculative plays (not assessed):

- The Cache Creek play would be heavily downgraded on source rock risk, like the Lewes River and Hancock plays;
- The Richthofen basin-centred gas play would have very large unrisked gas in place values, as it would be regionally-pervasive over large areas, if it exists. However, there would be a large risk factor applied to reflect our very considerable uncertainty regarding the existence of a basin-centred hydrocarbon regime in this basin;
- Prospectivity for the Tanglefoot CBM play may be similar to that for the Tanglefoot stratigraphic play, varying in part by the proportion of potential coal reservoir volumes to sandstone reservoir volumes; and
- Prospectivity for the Tantalus CBM play should be small, as for the Tantalus structural/ stratigraphic play, because of the lack of adequate seals.

A final set of assessment runs was undertaken as a further illustration of the potential variability of results arising from choice of input parameters. Roadifer (1979) noted:

> "Untested area within trap is usually the most difficult of all the parameters to determine, and it has the greatest effect on the results."

Table 5 provides an illustration of the importance of this parameter. The analyses were run for all five plays again, assuming only slightly more conservative value ranges for "fraction of total play within trap". As a result, mean assessed volumes were reduced by about one third. The full spreadsheet with these calculations is included in Appendix 2.

Table 5. Comparison of in-place gas volumes using more conservative values for the "fraction of total play in trap" parameter (metric values).

PLAY	PLAY RISK	UNRISKED GAS IN PLACE (x 10^9m^3)				RISKED MEAN	UNRISKED LIQUIDS IN PLACE (x 10^6m^3)				RISKED MEAN
		P90	P50	P10	MEAN		P90	P50	P10	MEAN	
Lewes River Structural	0.03	0.6	4.3	32.8	14.6	0.44	0.00	0.01	0.09	0.04	0.00
Hancock Stratigraphic	0.05	0.0	0.3	2.6	1.2	0.06	0.00	0.00	0.01	0.00	0.00
Tanglefoot Structural	0.13	1.9	11.1	65.5	28.2	3.67	0.39	2.65	18.15	7.80	1.01
Tanglefoot Stratigraphic	0.23	1.2	5.9	28.7	12.6	2.91	0.25	1.41	8.27	3.50	0.80
Tantalus Struc / Strat	0.08	0.0	0.3	2.8	1.2	0.10	0.01	0.06	0.73	0.40	0.03
TOTALS					**57.8**	**7.17**				**11.74**	**1.84**

Total Hydrocarbon Resources

Summarized arithmetically and on an unrisked basis, the mean in place assessed hydrocarbon resources of the Whitehorse trough include $82.3x10^9m^3$ (2920 BCF) gas and $17.1x10^6m^3$ (107 MMBO) oil. The range of possible values around these means vary tremendously, however, reflecting our limited knowledge about the basin (Table 1, 2). Comparing to the NEB (2001) assessment, total unrisked mean marketable gas is $38.1x10^9m^3$ (1345 BCF) (NEB – $5.52x10^9m^3$ (196 BCF)), and total unrisked mean recoverable oil is $4.1x10^6m^3$ (25.8 MMBO) (NEB - $1.29x10^6m^3$ (8.12 MMBO)).

The evidence for presence of both conventional and unconventional hydrocarbons in Whitehorse trough is compelling, and assessed volumes are sufficiently substantial to support additional exploration and assessment work, as discussed below.

RECOMMENDED FUTURE WORK

Several types of work focused on petroleum systems assessment would be very beneficial in improving our knowledge of conventional and unconventional petroleum prospectivity in Whitehorse trough.

1. Conventional petrographic (thin section) work should be undertaken to characterize reservoir quality in the most prospective conventional reservoirs, with primary focus on the Tanglefoot. It is particularly important to understand geographic and depth-related/diagenetic controls on reservoir quality.
    - More detailed follow-up work utilizing other petrographic methods, such as X-Ray diffraction (XRD) and Scanning Electron Microscope (SEM) techniques, may be suggested by initial results.
    - Systematic sampling and analysis of Richthofen Formation to characterize organic richness and maturity, mineralogy, and lithotypes should be performed – with the aim of characterizing basin-centred tight gas/shale gas prospectivity. Rock-Eval pyrolysis, XRD and SEM work, and conventional petrography should be part of this project. Wide geographic coverage of samples should highlight trends pointing toward the most prospective subsurface areas.
2. Systematic sampling of Tanglefoot and Tantalus coals should be undertaken to assess parameters controlling CBM prospectivity. Methane adsorption work is a key component, but maturity, organic components, and cleat/porosity structure should also be assessed.
3. Detailed regional aeromagnetic and gravity surveys should be acquired and interpreted to better characterize basin structure, and high grade areas for more detailed analysis. This work may be particularly useful in identifying areas where intrusive bodies exist close to the surface, greatly reducing petroleum prospectivity. Suitable data may already exist, as an unpublished figure by Colpron (pers. comm., 2012) illustrates interpretation of aeromagnetic data north of 61˚30'N.
4. Local seismic acquisition and interpretation can assist greatly in better understanding basin structure and in defining traps. As acquisition will be expensive in this remote and rugged terrain, however, considerable work must be done up front to select specific study areas. Interpretation of gravity and aeromagnetic data may be useful in the selection process.
5. Exploratory drilling tied to seismic is ultimately necessary to directly assess reservoir rocks, source rocks and seals in the subsurface, and to enable calibration of remotely-acquired geophysical data to better interpret distribution and characteristics of these petroleum systems elements.

New assessment work should be focused on the Tanglefoot Formation, which is clearly the most prospective of the conventional reservoirs. Geographically, work should therefore be concentrated in the northern part of the Whitehorse trough, north of the facies transition between the Tanglefoot to the north and the Richthofen to the south.

ACKNOWLEDGEMENTS

Tiffani Fraser of Yukon Geological Survey initiated this project and provided able supervision and guidance throughout. Maurice Colpron and Don Murphy, also of YGS, reviewed play definition and mapping at an intermediate stage, and contributed many useful suggestions to better define these elements of the study. Kirk Osadetz of the Geological Survey of Canada contributed information and interpretations from his own work on Whitehorse trough, which was of great assistance in understanding the basin.

Chris Longson of ELcral Ltd. provided advice on play parameters, set up the play sheets, and performed the @RISK analytical runs. Petrel Robertson Consulting Ltd. staff drafted figures and prepared the manuscript for publication.

REFERENCES

Allen, T.L., 2000. An evaluation of coal-bearing strata at Division Mountain (115H/8 east-half, 105E/5 west-half), south-central Yukon. *In:* Yukon Exploration and Geology 1999, D.S. Emond and L.H. Weston (eds.), Exploration and Geological Services Division, Yukon, Indian and Northern Affairs Canada, p. 177-198.

Bauman, P., 2005. Sedimentology and reservoir geometry of Quaternary gas reservoirs, Sousa, Alberta. M.Sc. thesis, University of Calgary, 68 p.

Bustin, R.M. and Clarkson, C.R., 1998. Geological controls on coalbed methane reservoir capacity and gas content. International Journal of Coal Geology, vol. 38, p. 3-26.

Cameron, A.R. and Beaton, A.P., 2000. Coal resources of northern Canada with emphasis on Whitehorse trough, Bonnet Plume Basin and Brackett Basin. International Journal of Coal Geology, vol. 43, p. 187-210.

Colpron, M., 2011 (compiler). Geological compilation of Whitehorse trough – Whitehorse (105D), Lake Laberge (105E), and parts of Carmacks (115I), Glenlyon (105L), Aishihik Lake (115H), Quiet Lake (105F), and Teslin (105C). Yukon Geological Survey, Geoscience Map 2011-1, 1:250 000; 3 maps, legend and appendices.

Colpron, M. and Friedman, R.M., 2008. U-Pb zircon ages for the Nordenskiold formation (Laberge Group) and Cretaceous intrusive rocks, Whitehorse trough, Yukon. *In:* Yukon Exploration and Geology 2007, D.S. Emond, L.R. Blackburn, R.P. Hill and L.H. Weston (eds.), Yukon Geological Survey, p. 139-151.

Curtis, J.B., 2002. Fractured shale-gas systems. American Association of Petroleum Geologists Bulletin, vol. 86, p. 1921-1938.

Dickie, J.R. and Hein, F., 1995. Conglomeratic fan deltas and submarine fans of the Jurassic Laberge Group, Whitehorse trough, Yukon Territory, Canada: fore-arc sedimentation and unroofing of a volcanic island complex. Sedimentary Geology, vol. 98, p. 263-292.

English, J.M., Fowler, M., Johnston, S.T., Mihalynuk, M.G., and Wight, K.L., 2005a. Thermal maturity in the central Whitehorse trough, northwest British Columbia. B.C. Resource Development and Geoscience Branch, Summary of Activities 2004, p. 79-85.

English, J.M., Johannson, G.G., Johnston, S.T., Mihalynuk, M.G., Fowler, M., and Wight, K.L., 2005b. Structure, stratigraphy and petroleum resource potential of the Central Whitehorse trough, northern Canadian Cordillera. Bulletin of Canadian Petroleum Geology, vol. 53, p. 130-153.

Galeski, R.B., 1970. Study of magnetic data, Whitehorse area, Yukon. Unpublished consulting report for Dome Petroleum.

Gilmore, R.G., 1985. Whitehorse field party. Unpublished report, PetroCanada, 16 p.

Gunther, P.R., 1985. Geochemical evaluation of Whitehorse field party samples. Unpublished report, PetroCanada, 19 p.

Hamblin, A.P., 2006. The “Shale Gas” concept in Canada: a preliminary inventory of possibilities. Geological Survey of Canada, Open File 5384, 103 p.

Hayes, B.J.R., in press. Scoping study of unconventional oil and gas potential, Yukon. Yukon Geological Survey, Miscellaneous Report.

Hunt, J.A., 1994. Yukon coal inventory 1994. Consulting report prepared for Energy and Mines Branch, Economic Development, Yukon Territorial Government, 168 p.

Hunt, J.A. and Hart, C.J.R., 1994. Thermal maturation and hydrocarbon source rock potential of the Tantalus Formation coals in the Whitehorse area, Yukon Territory. *In:* Yukon Exploration and Geology, 1993; Exploration and Geological Services Division, Yukon, Indian and Northern Affairs Canada, p. 67-77.

Koch, N.G., 1973. The central Cordilleran region. *In:* Future Petroleum Provinces of Canada, R.G. McCrossan (ed.). Canadian Society of Petroleum Geologists, Memoir 1, p. 37-71.

Law, B.E., 2002. Basin-centered gas systems. American Association of Petroleum Geologists Bulletin, vol. 86, p. 1891-1919.

Law, B.E. and Curtis, J.B., 2002. Introduction to unconventional petroleum systems. American Association of Petroleum Geologists Bulletin, vol. 86, p. 1851-1852.

Long, D.G.F., 2005. Sedimentology and hydrocarbon potential of fluvial strata in the Tantalus and Aksala formations, northern Whitehorse trough, Yukon. *In:* Yukon Exploration and Geology 2004, D.S. Emond, L.L. Lewis and G.D. Bradshaw (eds.), Yukon Geological Survey, p. 167-176.

Long, D.G.F. and Lowey, G.M., 2006. Anatomy of Late Jurassic Gilbert-type delta in basal strata of the Tantalus Formation, Whitehorse trough, Yukon. *In:* Yukon Exploration and Development 2005, D.S. Emond, G.D. Bradshaw, L.L. Lewis, and L.H. Weston (eds.), Yukon Geological Survey, p. 195-205.

Lowey, G.W., 2008. A petroleum events chart for the Whitehorse trough, Yukon. Canadian Society of Petroleum Geologists, Reservoir, vol. 35, p. 32-35.

Lowey, G.W. and Hills, L.V., 1988. Lithofacies, petrography and environments of deposition, Tantalus Formation (Lower Cretaceous) Indian River area, west-central Yukon. Bulletin of Canadian Petroleum Geology, vol. 36, p. 296-310.

Lowey, G.W. and Long, D., 2006. Summary of Rock-Eval data for the Whitehorse trough, Yukon: implications concerning the hydrocarbon potential of a frontier basin. *In:* Yukon Exploration and Geology 2005, D.S. Emond, G.D. Bradshaw, L.L. Lewis and L.H. Weston (eds.), Yukon Geological Survey, p. 207-218.

Lowey, G.W., Long, D.G.F., Fowler, M.G., Sweet, A.R., and Orchard, M.J., 2009. Petroleum source rock potential of Whitehorse trough: a frontier basin in south-central Yukon. Bulletin of Canadian Petroleum Geology, vol. 57, p. 350-386.

McCrossan, R.G. and J.W. Porter, 1973. The geology and petroleum potential of the Canadian sedimentary basins. *In:* Future Petroleum Provinces of Canada, R.G. McCrossan (ed.). Canadian Society of Petroleum Geologists, Memoir 1, p. 589-720.

National Energy Board, 2001. Petroleum resource assessment of the Whitehorse trough, Yukon Territory, Canada, 59 p.

Price, R.A., 1994. Cordilleran tectonics and the evolution of the Western Canada Sedimentary Basin. *In:* Geological Atlas of the Western Canada Sedimentary Basin, G.D. Mossop and I. Shetsen (eds.). Calgary, Canadian Society of Petroleum Geologists/Alberta Research Council.

Reid, R.P. and Tempelman-Kluit, D.J., 1987. Upper Triassic Tethyan-type reefs in Yukon. Bulletin of Canadian Petroleum Geology, vol. 35, p. 316-332.

Ricketts, B.D., 1984. A coal index for Yukon and District of Mackenzie, Northwest Territories. Geological Survey of Canada, Open File 1115, 8 p.

Roadifer, R.E., 1979. A probability approach to estimate volumes of undiscovered oil and gas. *In:* Proceedings of the First IIASA Conference on Energy Resources, Austria, M. Grenon (ed.), Oxford Pergamon Press, p. 268-278.

Wheeler, J.O., 1961. Whitehorse map-area, Yukon Territory (105D). Geological Survey of Canada, Memoir 312.

White, D., Colpron, M., Buffett, G., and Roberts, B., 2006. Structural constraints for oil and gas assessment in the Whitehorse trough: new results from seismic profiling. *In:* Yukon Exploration and Geology 2005, D.S. Emond, G.D. Bradshaw, L.L. Lewis and L.H. Weston (eds.), Yukon Geological Survey, p. 315-323.

APPENDIX 1 Play sheets, Whitehorse trough conceptual petroleum plays.

Area/Region:	Whitehorse Trough; YT		
Play Name:	**Lewes River Structural**		
Avg. Surface Temp. (°C):	5		
Pressure Gradient (kPa/m):	9.70		
Temp. Gradient (°C/100 m.):	3.60		
Raw Gas Gravity:	0.70		
1. Risk Component			
Risk Factors	**Play risk**		
1. Source Rock	0.20		
2. Charge	0.50		
3. Migration	0.70		
4. Reservoir Rock	0.80		
5. Trap/Closure	0.90		
6. Seal/Containment	0.60		
Probability of Geological Success (P_g)	**0.03**		
2. Hydrocarbon Volume Component			
	Low	**Best**	**High**
Gas Reservoir Depth (mRKB)	200	2,500	4,000
Oil Reservoir Depth (mRKB)	200	2,500	4,000
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2
Reservoir Pressure (kPa)	11,298	22,472	32,842
Reservoir Temperature (°C)	46	85	122
H_2S Content	0.01	0.02	0.04
CO_2 Content	0.01	0.05	0.09
Total Play Area (sqkm)	10,000	12,000	13,500
Tested Play Area (sqkm)	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--
Fraction of Total Play in Trap	0.010	0.033	0.080
Fraction of Untested Play Filled	0.050	0.170	0.380
Potential O&G Area (sqkm)	--	--	--
Fraction of PV Oil Bearing	0.000	0.000	0.000
Potential Oil Area (sqkm)	--	--	--
Potential Gas Area (sqkm)	--	--	--
Average Net Pay (m)	5	20	35
Porosity	0.03	0.08	0.14
Hydrocarbon Saturation	0.58	0.65	0.85
Oil Recovery Factor	0.05	0.15	0.25
Gas Recovery Factor	0.40	0.55	0.70
Solution GOR (ksm3/stm3)	0.03	0.09	0.25
Oil Formation Volume Factor	1.20	1.30	1.50
Gas Compressibility "Z"	0.95	0.97	0.98
Gas Formation Expansion Factor	--	--	--
3. Yield Component			
	Low	**Best**	**High**
Yield: Oil-in-Place (stm3/m3)	--	--	--
Yield: Recoverable Oil (stm3/m3)	--	--	--
Yield: Gas-in-Place (sm3/m3)	--	--	--
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--
Yield: Marketable Gas (sm3/m3)	--	--	--
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--
Surface Loss (Fuel gas, etc...)	--	0.10	--
Marketable Gas (Fraction of Raw)	--	--	--

Area/Region:	Whitehorse Trough; YT		
Play Name:	**Hancock Stratigraphic**		
Avg. Surface Temp. (°C):	5		
Pressure Gradient (kPa/m):	9.70		
Temp. Gradient (°C/100 m.):	3.60		
Raw Gas Gravity:	0.70		
1. Risk Component			
Risk Factors	**Play risk**		
1. Source Rock	0.30		
2. Charge	0.50		
3. Migration	0.90		
4. Reservoir Rock	0.80		
5. Trap/Closure	0.80		
6. Seal/Containment	0.60		
Probability of Geological Success (P_g)	**0.05**		
2. Hydrocarbon Volume Component			
	Low	**Best**	**High**
Gas Reservoir Depth (mRKB)	200	2,500	4,000
Oil Reservoir Depth (mRKB)	200	2,500	4,000
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2
Reservoir Pressure (kPa)	11,317	22,472	32,781
Reservoir Temperature (°C)	46	85	122
H_2S Content	0.01	0.02	0.04
CO_2 Content	0.01	0.05	0.09
Total Play Area (sqkm)	1,000	1,800	2,200
Tested Play Area (sqkm)	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--
Fraction of Total Play in Trap	0.004	0.012	0.070
Fraction of Untested Play Filled	0.050	0.170	0.380
Potential O&G Area (sqkm)	--	--	--
Fraction of PV Oil Bearing	0.000	0.000	0.000
Potential Oil Area (sqkm)	--	--	--
Potential Gas Area (sqkm)	--	--	--
Average Net Pay (m)	5	12	25
Porosity	0.03	0.08	0.14
Hydrocarbon Saturation	0.58	0.65	0.85
Oil Recovery Factor	0.05	0.15	0.25
Gas Recovery Factor	0.40	0.55	0.70
Solution GOR (ksm3/stm3)	0.03	0.09	0.25
Oil Formation Volume Factor	1.20	1.30	1.50
Gas Compressibility "Z"	0.95	0.97	0.98
Gas Formation Expansion Factor	--	--	--
3. Yield Component			
	Low	**Best**	**High**
Yield: Oil-in-Place (stm3/m3)	--	--	--
Yield: Recoverable Oil (stm3/m3)	--	--	--
Yield: Gas-in-Place (sm3/m3)	--	--	--
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--
Yield: Marketable Gas (sm3/m3)	--	--	--
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--
Surface Loss (Fuel gas, etc...)	--	0.10	--
Marketable Gas (Fraction of Raw)	--	--	--

Area/Region:	Whitehorse Trough; YT		
Play Name:	**Tanglefoot Structural**		
Avg. Surface Temp. (°C):	5		
Pressure Gradient (kPa/m):	9.70		
Temp. Gradient (°C/100 m.):	3.60		
Raw Gas Gravity:	0.70		
1. Risk Component			
Risk Factors	**Play risk**		
1. Source Rock	0.95		
2. Charge	0.75		
3. Migration	0.90		
4. Reservoir Rock	0.90		
5. Trap/Closure	0.90		
6. Seal/Containment	0.25		
Probability of Geological Success (P_g)	**0.13**		
2. Hydrocarbon Volume Component			
	Low	**Best**	**High**
Gas Reservoir Depth (mRKB)	200	1,500	3,500
Oil Reservoir Depth (mRKB)	200	1,500	3,000
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2
Reservoir Pressure (kPa)	8,529	17,441	27,095
Reservoir Temperature (°C)	36	67	102
H_2S Content	0.01	0.01	0.02
CO_2 Content	0.01	0.03	0.06
Total Play Area (sqkm)	2,422	3,500	5,000
Tested Play Area (sqkm)	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--
Fraction of Total Play in Trap	0.007	0.040	0.100
Fraction of Untested Play Filled	0.500	0.600	0.750
Potential O&G Area (sqkm)	--	--	--
Fraction of PV Oil Bearing	0.010	0.030	0.090
Potential Oil Area (sqkm)	--	--	--
Potential Gas Area (sqkm)	--	--	--
Average Net Pay (m)	5	20	35
Porosity	0.06	0.14	0.19
Hydrocarbon Saturation	0.58	0.65	0.85
Oil Recovery Factor	0.05	0.15	0.25
Gas Recovery Factor	0.40	0.55	0.70
Solution GOR (ksm3/stm3)	0.03	0.09	0.25
Oil Formation Volume Factor	1.20	1.30	1.50
Gas Compressibility "Z"	0.95	0.97	0.98
Gas Formation Expansion Factor	--	--	--
3. Yield Component			
	Low	**Best**	**High**
Yield: Oil-in-Place (stm3/m3)	--	--	--
Yield: Recoverable Oil (stm3/m3)	--	--	--
Yield: Gas-in-Place (sm3/m3)	--	--	--
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--
Yield: Marketable Gas (sm3/m3)	--	--	--
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--
Surface Loss (Fuel gas, etc...)	--	0.10	--
Marketable Gas (Fraction of Raw)	--	--	--

Area/Region:	Whitehorse Trough; YT		
Play Name:	**Tanglefoot Stratigraphic**		
Avg. Surface Temp. (°C):	5		
Pressure Gradient (kPa/m):	9.70		
Temp. Gradient (°C/100 m.):	3.60		
Raw Gas Gravity:	0.70		
1. Risk Component			
Risk Factors	**Play risk**		
1. Source Rock	0.95		
2. Charge	0.75		
3. Migration	0.90		
4. Reservoir Rock	0.90		
5. Trap/Closure	0.80		
6. Seal/Containment	0.50		
Probability of Geological Success (P_g)	**0.23**		
2. Hydrocarbon Volume Component			
	Low	**Best**	**High**
Gas Reservoir Depth (mRKB)	200	1,500	3,500
Oil Reservoir Depth (mRKB)	200	1,500	3,000
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2
Reservoir Pressure (kPa)	8,514	17,441	27,133
Reservoir Temperature (°C)	36	67	102
H_2S Content	0.01	0.01	0.02
CO_2 Content	0.01	0.03	0.06
Total Play Area (sqkm)	2,422	3,500	5,000
Tested Play Area (sqkm)	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--
Fraction of Total Play in Trap	0.006	0.030	0.075
Fraction of Untested Play Filled	0.500	0.600	0.750
Potential O&G Area (sqkm)	--	--	--
Fraction of PV Oil Bearing	0.010	0.030	0.090
Potential Oil Area (sqkm)	--	--	--
Potential Gas Area (sqkm)	--	--	--
Average Net Pay (m)	5	12	19
Porosity	0.06	0.14	0.19
Hydrocarbon Saturation	0.58	0.65	0.85
Oil Recovery Factor	0.05	0.15	0.25
Gas Recovery Factor	0.40	0.55	0.70
Solution GOR (ksm3/stm3)	0.03	0.09	0.25
Oil Formation Volume Factor	1.20	1.30	1.50
Gas Compressibility "Z"	0.95	0.97	0.98
Gas Formation Expansion Factor	--	--	--
3. Yield Component			
	Low	**Best**	**High**
Yield: Oil-in-Place (stm3/m3)	--	--	--
Yield: Recoverable Oil (stm3/m3)	--	--	--
Yield: Gas-in-Place (sm3/m3)	--	--	--
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--
Yield: Marketable Gas (sm3/m3)	--	--	--
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--
Surface Loss (Fuel gas, etc...)	--	0.10	--
Marketable Gas (Fraction of Raw)	--	--	--

Area/Region:	Whitehorse Trough; YT		
Play Name:	**Tantalus Structural/Stratigraphic**		
Avg. Surface Temp. (^oC):	5		
Pressure Gradient (kPa/m):	9.70		
Temp. Gradient (^oC/100 m.):	3.60		
Raw Gas Gravity:	0.70		
1. Risk Component			
Risk Factors	**Play risk**		
1. Source Rock	0.95		
2. Charge	0.75		
3. Migration	0.90		
4. Reservoir Rock	0.90		
5. Trap/Closure	0.90		
6. Seal/Containment	0.15		
Probability of Geological Success (P_g)	**0.08**		
2. Hydrocarbon Volume Component			
	Low	**Best**	**High**
Gas Reservoir Depth (mRKB)	200	1,100	2,000
Oil Reservoir Depth (mRKB)	200	1,100	2,000
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2
Reservoir Pressure (kPa)	6,021	11,068	16,135
Reservoir Temperature (^oC)	27	45	63
H_2S Content	0.01	0.01	0.02
CO_2 Content	0.01	0.03	0.06
Total Play Area (sqkm)	354	825	1,300
Tested Play Area (sqkm)	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--
Fraction of Total Play in Trap	0.001	0.007	0.050
Fraction of Untested Play Filled	0.500	0.600	0.750
Potential O&G Area (sqkm)	--	--	--
Fraction of PV Oil Bearing	0.005	0.019	0.070
Potential Oil Area (sqkm)	--	--	--
Potential Gas Area (sqkm)	--	--	--
Average Net Pay (m)	5	15	30
Porosity	0.05	0.12	0.20
Hydrocarbon Saturation	0.58	0.65	0.85
Oil Recovery Factor	0.05	0.15	0.25
Gas Recovery Factor	0.40	0.55	0.70
Solution GOR (ksm3/stm3)	0.03	0.09	0.25
Oil Formation Volume Factor	1.20	1.30	1.50
Gas Compressibility "Z"	0.95	0.97	0.98
Gas Formation Expansion Factor	--	--	--
3. Yield Component			
	Low	**Best**	**High**
Yield: Oil-in-Place (stm3/m3)	--	--	--
Yield: Recoverable Oil (stm3/m3)	--	--	--
Yield: Gas-in-Place (sm3/m3)	--	--	--
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--
Yield: Marketable Gas (sm3/m3)	--	--	--
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--
Surface Loss (Fuel gas, etc...)	--	0.10	--
Marketable Gas (Fraction of Raw)	--	--	--

APPENDIX 2A @Risk Spreadsheets – Conservative.

Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	Lewes River Structural
Estimator Name:	B. Hayes
Avg. Surface Temp. (°C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (°C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.20
2. Charge	0.50
3. Migration	0.70
4. Reservoir Rock	0.80
5. Trap/Closure	0.90
6. Seal/Containment	0.60
Probability of Geological Success (P_g)	0.03

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	2,500	4,000	2,233	495	1,135	2,290	3,245	3,761
Oil Reservoir Depth (mRKB)	200	2,500	4,000	2,233	496	1,135	2,290	3,245	3,761
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	22,472	4,987	11,359	22,910	32,727	39,096
Reservoir Temperature (°C)	--	--	--	85	23	46	87	122	140
Methane Content	0.80		0.98	0.94	0.84	0.88	0.95	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.02	0.04	0.02	0.00	0.01	0.02	0.04	0.09
CO_2 Content	0.01	0.05	0.09	0.05	0.00	0.01	0.03	0.12	0.30
Total Play Area (sqkm)	10,000	12,000	13,500	11,841	9,249	10,182	11,770	13,604	14,977
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	11,841	9,249	10,182	11,770	13,604	14,977
Fraction of Total Play in Trap	0.005	0.020	0.070	0.030	0.002	0.005	0.019	0.069	0.160
Fraction of Untested Play Filled	0.050	0.170	0.380	0.196	0.029	0.056	0.150	0.399	0.763
Potential O&G Area (sqkm)	--	--	--	69.7	2.1	7.0	33.8	163.8	535.2
Fraction of PV Oil Bearing	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Potential Oil Area (sqkm)	--	--	--	0.0	0.0	0.0	0.0	0.0	0.0
Potential Gas Area (sqkm)	--	--	--	69.7	2.1	7.0	33.8	163.8	535.2
Average Net Pay (m)	5	20	35	20	3	6	16	40	74
Porosity	0.03	0.08	0.14	0.08	0.02	0.03	0.07	0.15	0.24
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	185	50	105	188	246	283

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	10	1	3	8	20	35
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	6	1	2	5	11	21
Yield: Marketable Gas (sm3/m3)	--	--	--	5	1	1	4	9	17
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00	3	0	0	2	7	17
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.83	0.61	0.77	0.85	0.88	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil ($10^6 stm^3$)		0.00		0	0	0	0	0	0
Condensate & NGL ($10^6 stm^3$)		0.00		0	0	0	0	0	1
Total Liquids ($10^6 stm^3$)		0.00		0	0.0	0.0	0.0	0.1	0.5
Total Liquids (MMstb)		*0.01*		*0*	*0.0*	*0.0*	*0.0*	*0.6*	*3.4*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		0.44		15	0	1	4	33	152
Total gas ($10^9 sm^3$)		0.44		15	0	1	4	33	152
Total gas (Bscf)		*15.69*		*519*	*4*	*20*	*153*	*1,166*	*5,379*
MMBOE		*2.62*		*87*	*1*	*3*	*26*	*195*	*900*
Recoverable									
Oil ($10^6 stm^3$)		0.00		0	0	0	0	0	0
Condensate & NGL ($10^6 stm^3$)		0.00		0	0	0	0	0	0
Total Liquids ($10^6 stm^3$)		0.00		0	0.00	0.00	0.00	0.05	0.31
Total Liquids (MMstb)		*0.00*		*0*	*0.0*	*0.0*	*0.0*	*0.3*	*1.9*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		0.24		8	0	0	2	18	85
Total gas ($10^9 sm^3$)		0.24		8	0.1	0.3	2.3	18.0	85.1
Marketable Gas ($10^9 sm^3$)		0.20		7	0.1	0.3	1.9	15.1	70.3
Marketable Gas (Bscf)		*0.04*		*1*	*0*	*0*	*0*	*3*	*14*
MMBOE		*1.20*		*40*	*0*	*2*	*12*	*90*	*417*

Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	Hancock Stratigraphic
Estimator Name:	B. Hayes
Avg. Surface Temp. (°C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (°C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.30
2. Charge	0.50
3. Migration	0.90
4. Reservoir Rock	0.80
5. Trap/Closure	0.80
6. Seal/Containment	0.60
Probability of Geological Success (P_g)	**0.05**

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	2,500	4,000	2,233	495	1,135	2,290	3,245	3,761
Oil Reservoir Depth (mRKB)	200	2,500	4,000	2,233	496	1,135	2,290	3,245	3,761
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	22,472	4,927	11,317	22,894	32,781	38,818
Reservoir Temperature (°C)	--	--	--	85	23	46	87	122	140
Methane Content	0.80		0.98	0.94	0.84	0.88	0.95	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.02	0.04	0.02	0.00	0.01	0.02	0.04	0.09
CO_2 Content	0.01	0.05	0.09	0.05	0.00	0.01	0.03	0.12	0.30
Total Play Area (sqkm)	1,000	1,800	2,200	1,670	851	1,095	1,603	2,345	3,018
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	1,670	851	1,095	1,603	2,345	3,018
Fraction of Total Play in Trap	0.004	0.012	0.070	0.025	0.001	0.004	0.015	0.058	0.146
Fraction of Untested Play Filled	0.050	0.170	0.380	0.196	0.029	0.056	0.150	0.399	0.764
Potential O&G Area (sqkm)	--	--	--	8.1	0.2	0.6	3.5	19.3	69.0
Fraction of PV Oil Bearing	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Potential Oil Area (sqkm)	--	--	--	0.0	0.0	0.0	0.0	0.0	0.0
Potential Gas Area (sqkm)	--	--	--	8.1	0.2	0.6	3.5	19.3	69.0
Average Net Pay (m)	5	12	25	14	3	5	12	25	42
Porosity	0.03	0.08	0.14	0.08	0.02	0.03	0.07	0.15	0.24
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	185	50	105	187	246	281

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	10	1	3	8	20	35
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	6	1	2	5	11	20
Yield: Marketable Gas (sm3/m3)	--	--	--	5	1	1	4	9	17
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00	3	0	0	2	7	17
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.83	0.61	0.77	0.85	0.88	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil (10^6stm^3)		0.00		0	0	0	0	0	0
Condensate & NGL (10^6stm^3)		0.00		0	0	0	0	0	0
Total Liquids (10^6stm^3)		0.00		0	0.0	0.0	0.0	0.0	0.0
Total Liquids (MMstb)		*0.00*		*0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.3*
Solution gas (10^9sm^3)		0.00		0	0	0	0	0	0
Free gas (10^9sm^3)		0.06		1	0	0	0	3	12
Total gas (10^9sm^3)		0.06		1	0	0	0	3	12
Total gas (Bscf)		*2.13*		*41*	*0*	*2*	*12*	*93*	*443*
MMBOE		*0.36*		*7*	*0*	*0*	*2*	*15*	*74*
Recoverable									
Oil (10^6stm^3)		0.00		0	0	0	0	0	0
Condensate & NGL (10^6stm^3)		0.00		0	0	0	0	0	0
Total Liquids (10^6stm^3)		0.00		0	0.00	0.00	0.00	0.00	0.03
Total Liquids (MMstb)		0.00		0	0.0	0.0	0.0	0.0	0.2
Solution gas (10^9sm^3)		0.00		0	0	0	0	0	0
Free gas (10^9sm^3)		0.03		1	0	0	0	1	7
Total gas (10^9sm^3)		0.03		1	0.0	0.0	0.2	1.4	6.8
Marketable Gas (10^9sm^3)		0.03		1	0.0	0.0	0.1	1.2	5.7
Marketable Gas (Bscf)		*0.01*		*0*	*0*	*0*	*0*	*0*	*1*
MMBOE		*0.16*		*3*	*0*	*0*	*1*	*7*	*34*

Petrel Robertson

Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	Tanglefoot Structural
Estimator Name:	B. Hayes
Avg. Surface Temp. (°C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (°C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.95
2. Charge	0.75
3. Migration	0.90
4. Reservoir Rock	0.90
5. Trap/Closure	0.90
6. Seal/Containment	0.25
Probability of Geological Success (P_g)	0.13

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	1,500	3,500	1,733	407	855	1,683	2,687	3,243
Oil Reservoir Depth (mRKB)	200	1,500	3,000	1,567	391	803	1,551	2,352	2,795
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	17,441	4,046	8,573	16,890	27,112	33,428
Reservoir Temperature (°C)	--	--	--	67	20	36	66	102	122
Methane Content	0.85		0.98	0.96	0.89	0.92	0.96	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.01	0.02	0.01	0.00	0.01	0.01	0.02	0.03
CO_2 Content	0.01	0.03	0.06	0.03	0.00	0.01	0.02	0.07	0.16
Total Play Area (sqkm)	2,422	3,500	5,000	3,612	1,949	2,458	3,488	4,949	6,242
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	3,612	1,949	2,458	3,488	4,949	6,242
Fraction of Total Play in Trap	0.007	0.040	0.100	0.049	0.004	0.009	0.031	0.113	0.264
Fraction of Untested Play Filled	0.500	0.600	0.750	0.614	0.439	0.499	0.607	0.739	0.841
Potential O&G Area (sqkm)	--	--	--	109.0	7.1	17.5	66.0	253.4	625.8
Fraction of PV Oil Bearing	0.010	0.030	0.090	0.041	0.005	0.010	0.030	0.087	0.175
Potential Oil Area (sqkm)	--	--	--	4.5	0.1	0.4	2.0	10.7	37.1
Potential Gas Area (sqkm)	--	--	--	104.5	6.8	16.7	63.4	243.0	601.2
Average Net Pay (m)	5	20	35	20	3	6	16	40	74
Porosity	0.06	0.14	0.19	0.13	0.05	0.07	0.12	0.21	0.30
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	151	41	82	147	214	253

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	14	2	5	12	23	38
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	7	1	3	6	13	23
Yield: Marketable Gas (sm3/m3)	--	--	--	6	1	2	5	11	20
Liquids Yield (stm3/e6sm3)	10	40	150	63	4	11	39	145	345
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.86	0.75	0.82	0.87	0.89	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil ($10^6 stm^3$)		0.78		6	0	0	2	14	64
Condensate & NGL ($10^6 stm^3$)		0.23		2	0	0	0	4	22
Total Liquids ($10^6 stm^3$)		1.01		8	0.1	0.4	2.6	18.1	78.8
Total Liquids (MMstb)		*6.36*		*49*	*0.6*	*2.5*	*16.7*	*114.2*	*495.9*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		3.67		28	0	2	11	66	250
Total gas ($10^9 sm^3$)		3.67		28	0	2	11	66	250
Total gas (Bscf)		*130.11*		*1,002*	*16*	*67*	*395*	*2,325*	*8,868*
MMBOE		*28.04*		*216*	*3*	*14*	*83*	*502*	*1,974*
Recoverable									
Oil ($10^6 stm^3$)		0.12		1	0	0	0	2	10
Condensate & NGL ($10^6 stm^3$)		0.13		1	0	0	0	2	12
Total Liquids ($10^6 stm^3$)		0.24		2	0.02	0.08	0.59	4.24	20.05
Total Liquids (MMstb)		*1.53*		*12*	*0.1*	*0.5*	*3.7*	*26.7*	*126.2*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		2.01		15	0	1	6	36	148
Total gas ($10^9 sm^3$)		2.01		15	0.2	1.0	6.0	36.1	148.1
Marketable Gas ($10^9 sm^3$)		1.73		13	0.2	0.8	5.2	31.0	126.7
Marketable Gas (Bscf)		*1.81*		*14*	*0*	*1*	*5*	*32*	*147*
MMBOE		*11.77*		*91*	*1*	*6*	*36*	*209*	*840*

Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	Tanglefoot Stratigraphic
Estimator Name:	B. Hayes
Avg. Surface Temp. (°C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (°C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.95
2. Charge	0.75
3. Migration	0.90
4. Reservoir Rock	0.90
5. Trap/Closure	0.80
6. Seal/Containment	0.50
Probability of Geological Success (P_g)	0.23

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	1,500	3,500	1,733	407	855	1,683	2,688	3,243
Oil Reservoir Depth (mRKB)	200	1,500	3,000	1,567	390	803	1,551	2,352	2,795
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	17,441	4,063	8,576	16,903	27,182	33,352
Reservoir Temperature (°C)	--	--	--	67	20	36	66	102	122
Methane Content	0.85		0.98	0.96	0.89	0.92	0.96	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.01	0.02	0.01	0.00	0.01	0.01	0.02	0.03
CO_2 Content	0.01	0.03	0.06	0.03	0.00	0.01	0.02	0.07	0.16
Total Play Area (sqkm)	2,422	3,500	5,000	3,612	1,949	2,458	3,488	4,949	6,241
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	3,612	1,949	2,458	3,488	4,949	6,241
Fraction of Total Play in Trap	0.006	0.030	0.075	0.037	0.003	0.007	0.024	0.082	0.185
Fraction of Untested Play Filled	0.500	0.600	0.750	0.614	0.439	0.499	0.607	0.739	0.841
Potential O&G Area (sqkm)	--	--	--	81.5	5.9	14.3	51.6	185.8	440.7
Fraction of PV Oil Bearing	0.010	0.030	0.090	0.041	0.005	0.010	0.030	0.087	0.175
Potential Oil Area (sqkm)	--	--	--	3.3	0.1	0.3	1.5	8.1	26.4
Potential Gas Area (sqkm)	--	--	--	78.2	5.5	13.7	49.4	177.5	425.4
Average Net Pay (m)	5	12	19	12	4	6	11	20	31
Porosity	0.06	0.14	0.19	0.13	0.05	0.07	0.12	0.21	0.30
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	151	41	82	147	214	253

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	14	2	5	12	23	38
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	7	1	3	6	13	23
Yield: Marketable Gas (sm3/m3)	--	--	--	6	1	2	5	11	20
Liquids Yield (stm3/e6sm3)	10	40	150	63	4	11	39	145	345
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.86	0.75	0.82	0.87	0.89	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil ($10^6 stm^3$)		0.62		3	0	0	1	7	25
Condensate & NGL ($10^6 stm^3$)		0.18		1	0	0	0	2	8
Total Liquids ($10^6 stm^3$)		0.80		3	0.1	0.3	1.4	8.3	30.2
Total Liquids (MMstb)		*5.04*		*22*	*0.4*	*1.6*	*8.9*	*52.0*	*189.9*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		2.91		13	0	1	6	29	99
Total gas ($10^9 sm^3$)		2.91		13	0	1	6	29	99
Total gas (Bscf)		*103.12*		*447*	*12*	*42*	*209*	*1,018*	*3,497*
MMBOE		*22.22*		*96*	*2*	*9*	*44*	*222*	*773*
Recoverable									
Oil ($10^6 stm^3$)		0.09		0	0	0	0	1	4
Condensate & NGL ($10^6 stm^3$)		0.10		0	0	0	0	1	5
Total Liquids ($10^6 stm^3$)		0.19		1	0.01	0.05	0.31	1.93	7.46
Total Liquids (MMstb)		*1.21*		*5*	*0.1*	*0.3*	*2.0*	*12.2*	*47.0*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		1.59		7	0	1	3	16	57
Total gas ($10^9 sm^3$)		1.59		7	0.2	0.6	3.2	15.8	56.7
Marketable Gas ($10^9 sm^3$)		1.37		6	0.1	0.5	2.7	13.6	48.4
Marketable Gas (Bscf)		*1.44*		*6*	*0*	*0*	*2*	*14*	*55*
MMBOE		*9.33*		*40*	*1*	*4*	*19*	*93*	*319*

Petrel Robertson
Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	Tantalus Structural / Stratigraphic
Estimator Name:	B. Hayes
Avg. Surface Temp. (°C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (°C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.95
2. Charge	0.75
3. Migration	0.90
4. Reservoir Rock	0.90
5. Trap/Closure	0.90
6. Seal/Containment	0.15
Probability of Geological Success (P_g)	0.08

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	1,100	2,000	1,100	327	602	1,100	1,597	1,873
Oil Reservoir Depth (mRKB)	200	1,100	2,000	1,100	327	602	1,100	1,597	1,873
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	11,068	3,281	6,018	11,000	16,158	19,405
Reservoir Temperature (°C)	--	--	--	45	17	27	45	63	72
Methane Content	0.85		0.98	0.96	0.89	0.92	0.96	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.01	0.02	0.01	0.00	0.01	0.01	0.02	0.03
CO_2 Content	0.01	0.03	0.06	0.03	0.00	0.01	0.02	0.07	0.16
Total Play Area (sqkm)	354	825	1,300	820	258	391	734	1,374	2,084
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	820	258	391	734	1,374	2,084
Fraction of Total Play in Trap	0.001	0.007	0.050	0.018	0.000	0.001	0.007	0.047	0.163
Fraction of Untested Play Filled	0.500	0.600	0.750	0.614	0.439	0.499	0.607	0.739	0.841
Potential O&G Area (sqkm)	--	--	--	9.1	0.1	0.4	3.2	22.9	85.3
Fraction of PV Oil Bearing	0.005	0.019	0.070	0.029	0.002	0.005	0.019	0.067	0.157
Potential Oil Area (sqkm)	--	--	--	0.3	0.0	0.0	0.1	0.6	3.2
Potential Gas Area (sqkm)	--	--	--	8.9	0.1	0.4	3.1	22.4	81.9
Average Net Pay (m)	5	15	30	16	3	6	13	32	56
Porosity	0.05	0.12	0.20	0.12	0.04	0.06	0.11	0.21	0.32
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	103	33	59	102	142	167

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	9	2	3	7	15	27
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	5	1	2	4	9	16
Yield: Marketable Gas (sm3/m3)	--	--	--	4	1	1	3	7	14
Liquids Yield (stm3/e6sm3)	10	40	150	63	4	11	39	145	345
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.86	0.75	0.82	0.87	0.89	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil ($10^6 stm^3$)		0.02		0	0	0	0	1	4
Condensate & NGL ($10^6 stm^3$)		0.01		0	0	0	0	0	1
Total Liquids ($10^6 stm^3$)		0.03		0	0.0	0.0	0.1	0.7	4.8
Total Liquids (MMstb)		*0.17*		*2*	*0.0*	*0.0*	*0.4*	*4.6*	*30.3*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		0.10		1	0	0	0	3	15
Total gas ($10^9 sm^3$)		0.10		1	0	0	0	3	15
Total gas (Bscf)		*3.45*		*44*	*0*	*1*	*10*	*100*	*543*
MMBOE		*0.75*		*10*	*0*	*0*	*2*	*21*	*121*
Recoverable									
Oil ($10^6 stm^3$)		0.00		0	0	0	0	0	1
Condensate & NGL ($10^6 stm^3$)		0.00		0	0	0	0	0	1
Total Liquids ($10^6 stm^3$)		0.01		0	0.00	0.00	0.01	0.17	1.16
Total Liquids (MMstb)		*0.04*		*1*	*0.0*	*0.0*	*0.1*	*1.1*	*7.3*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		0.05		1	0	0	0	2	9
Total gas ($10^9 sm^3$)		0.05		1	0.0	0.0	0.2	1.5	8.7
Marketable Gas ($10^9 sm^3$)		0.05		1	0.0	0.0	0.1	1.3	7.5
Marketable Gas (Bscf)		*0.05*		*1*	*0*	*0*	*0*	*1*	*9*
MMBOE		*0.31*		*4*	*0*	*0*	*1*	*9*	*50*

	Play Risk	Risked Liquids volume	OIIP+CIIP given success P90	P50	P10	Risked Gas Volume	GIIP given success P90	P50	P10	Ratio P10:P90
		e6stm3	e6stm3	e6stm3	e6stm3	e9sm3	e9sm3	e9sm3	e9sm3	
Lewes River Structural	0.03	0.00	0.00	0.01	0.09	0.44	0.6	4.3	32.8	57
Hancock Stratigraphic	0.05	0.00	0.00	0.00	0.01	0.06	0.0	0.3	2.6	61
Tanglefoot Structural	0.13	1.01	0.39	2.65	18.15	3.67	1.9	11.1	65.5	35
Tanglefoot Stratigraphic	0.23	0.80	0.25	1.41	8.27	2.91	1.2	5.9	28.7	24
Tantalus Structural / Stratigraphic	0.08	0.03	0.01	0.06	0.73	0.10	0.0	0.3	2.8	101
		1.8	**0.6**	**4.1**	**27.2**	**7.2**	**3.7**	**22.0**	**132.4**	
08-Mar Run										
Lewes River Structural	0.03	0.00	0.00	0.01	0.16	0.86	0.7	6.7	61.2	
Hancock Stratigraphic	0.05	0.00	0.00	0.00	0.01	0.09	0.1	0.4	3.7	
Tanglefoot Structural	0.13	0.02	0.01	0.04	0.32	6.47	5.2	25.0	111.5	
Tanglefoot Stratigraphic	0.23	0.02	0.00	0.02	0.17	6.12	3.2	13.9	60.0	
Tantalus Structural / Stratigraphic	0.08	0.00	0.00	0.00	0.01	0.11	0.0	0.3	3.0	

Petrel Robertson
Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	Lewes River Structural
Estimator Name:	B. Hayes
Avg. Surface Temp. (°C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (°C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.20
2. Charge	0.50
3. Migration	0.70
4. Reservoir Rock	0.80
5. Trap/Closure	0.90
6. Seal/Containment	0.60
Probability of Geological Success (P_g)	0.03

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	2,500	4,000	2,233	495	1,135	2,290	3,245	3,761
Oil Reservoir Depth (mRKB)	200	2,500	4,000	2,233	495	1,135	2,290	3,245	3,761
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	22,472	4,995	11,298	22,949	32,842	39,300
Reservoir Temperature (°C)	--	--	--	85	23	46	87	122	140
Methane Content	0.80		0.98	0.94	0.84	0.88	0.95	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.02	0.04	0.02	0.00	0.01	0.02	0.04	0.09
CO_2 Content	0.01	0.05	0.09	0.05	0.00	0.01	0.03	0.12	0.30
Total Play Area (sqkm)	10,000	12,000	13,500	11,841	9,250	10,182	11,770	13,605	14,975
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	11,841	9,250	10,182	11,770	13,605	14,975
Fraction of Total Play in Trap	0.010	0.033	0.080	0.040	0.006	0.011	0.030	0.082	0.160
Fraction of Untested Play Filled	0.050	0.170	0.380	0.196	0.029	0.056	0.150	0.399	0.763
Potential O&G Area (sqkm)	--	--	--	92.5	4.8	13.4	52.8	213.7	595.4
Fraction of PV Oil Bearing	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Potential Oil Area (sqkm)	--	--	--	0.000	0.0	0.0	0.0	0.0	0.0
Potential Gas Area (sqkm)	--	--	--	92.5	4.8	13.4	52.8	213.7	595.4
Average Net Pay (m)	5	20	35	20	3	6	16	40	74
Porosity	0.03	0.08	0.14	0.08	0.02	0.03	0.07	0.15	0.24
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	185	50	105	188	247	284

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	10	2	3	8	20	35
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	6	1	2	5	11	21
Yield: Marketable Gas (sm3/m3)	--	--	--	5	1	1	4	9	17
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00	3	0	0	2	7	16
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.83	0.61	0.77	0.85	0.88	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil (10^6stm^3)		0.00		0	0	0	0	0	0
Condensate & NGL (10^6stm^3)		0.00		0	0	0	0	0	1
Total Liquids (10^6stm^3)		0.00		0	0.0	0.0	0.0	0.1	0.7
Total Liquids (MMstb)		*0.01*		*0*	*0.0*	*0.0*	*0.1*	*0.8*	*4.6*
Solution gas (10^9sm^3)		0.00		0	0	0	0	0	0
Free gas (10^9sm^3)		0.59		19	0	1	7	44	183
Total gas (10^9sm^3)		0.59		19	0	1	7	44	183
Total gas (Bscf)		*20.81*		*688*	*8*	*37*	*243*	*1,569*	*6,508*
MMBOE		*3.48*		*115*	*1*	*6*	*41*	*262*	*1,089*
Recoverable									
Oil (10^6stm^3)		0.00		0	0	0	0	0	0
Condensate & NGL (10^6stm^3)		0.00		0	0	0	0	0	0
Total Liquids (10^6stm^3)		0.00		0	0.00	0.00	0.01	0.07	0.40
Total Liquids (MMstb)		*0.01*		*0*	*0.0*	*0.0*	*0.0*	*0.4*	*2.5*
Solution gas (10^9sm^3)		0.00		0	0	0	0	0	0
Free gas (10^9sm^3)		0.32		11	0	1	4	24	102
Total gas (10^9sm^3)		0.32		11	0.1	0.6	3.6	24.1	101.5
Marketable Gas (10^9sm^3)		0.27		9	0.1	0.5	3.1	20.2	85.9
Marketable Gas (Bscf)		*0.05*		*2*	*0*	*0*	*1*	*4*	*17*
MMBOE		*1.59*		*53*	*1*	*3*	*18*	*120*	*510*

Petrel Robertson

Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	**Hancock Stratigraphic**
Estimator Name:	B. Hayes
Avg. Surface Temp. (°C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (°C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.30
2. Charge	0.50
3. Migration	0.90
4. Reservoir Rock	0.80
5. Trap/Closure	0.80
6. Seal/Containment	0.60
Probability of Geological Success (P_g)	**0.05**

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	2,500	4,000	2,233	495	1,135	2,290	3,245	3,761
Oil Reservoir Depth (mRKB)	200	2,500	4,000	2,233	495	1,135	2,290	3,245	3,761
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	22,472	4,983	11,347	22,918	32,721	38,992
Reservoir Temperature (°C)	--	--	--	85	23	46	87	122	140
Methane Content	0.80		0.98	0.94	0.84	0.88	0.95	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.02	0.04	0.02	0.00	0.01	0.02	0.04	0.09
CO_2 Content	0.01	0.05	0.09	0.05	0.00	0.01	0.03	0.12	0.30
Total Play Area (sqkm)	1,000	1,800	2,200	1,670	851	1,095	1,603	2,345	3,017
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	1,670	851	1,095	1,603	2,345	3,017
Fraction of Total Play in Trap	0.008	0.020	0.080	0.032	0.004	0.008	0.023	0.070	0.146
Fraction of Untested Play Filled	0.050	0.170	0.380	0.196	0.029	0.056	0.150	0.399	0.763
Potential O&G Area (sqkm)	--	--	--	10.6	0.4	1.3	5.4	24.4	76.8
Fraction of PV Oil Bearing	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Potential Oil Area (sqkm)	--	--	--	0.000	0.0	0.0	0.0	0.0	0.0
Potential Gas Area (sqkm)	--	--	--	10.6	0.4	1.3	5.4	24.4	76.8
Average Net Pay (m)	5	12	25	14	3	5	12	25	42
Porosity	0.03	0.08	0.14	0.08	0.02	0.03	0.07	0.15	0.24
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	185	50	105	188	246	283

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	10	2	3	8	20	35
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	6	1	2	4	11	21
Yield: Marketable Gas (sm3/m3)	--	--	--	5	1	1	4	9	17
Liquids Yield (stm3/e6sm3)	0.50	1.50	8.00	3	0	0	2	7	17
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.83	0.61	0.77	0.85	0.88	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil ($10^6 stm^3$)		0.00		0	0	0	0	0	0
Condensate & NGL ($10^6 stm^3$)		0.00		0	0	0	0	0	0
Total Liquids ($10^6 stm^3$)		0.00		0	0.0	0.0	0.0	0.0	0.1
Total Liquids (MMstb)		*0.00*		*0*	*0.0*	*0.0*	*0.0*	*0.1*	*0.3*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		0.08		2	0	0	1	3	15
Total gas ($10^9 sm^3$)		0.08		2	0	0	1	3	15
Total gas (Bscf)		*2.80*		*54*	*1*	*3*	*18*	*121*	*529*
MMBOE		*0.47*		*9*	*0*	*0*	*3*	*20*	*89*
Recoverable									
Oil ($10^6 stm^3$)		0.00		0	0	0	0	0	0
Condensate & NGL ($10^6 stm^3$)		0.00		0	0	0	0	0	0
Total Liquids ($10^6 stm^3$)		0.00		0	0.00	0.00	0.00	0.01	0.03
Total Liquids (MMstb)		*0.00*		*0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.2*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		0.04		1	0	0	0	2	9
Total gas ($10^9 sm^3$)		0.04		1	0.0	0.0	0.3	1.8	8.5
Marketable Gas ($10^9 sm^3$)		0.04		1	0.0	0.0	0.2	1.5	7.0
Marketable Gas (Bscf)		*0.01*		*0*	*0*	*0*	*0*	*0*	*1*
MMBOE		*0.21*		*4*	*0*	*0*	*1*	*9*	*42*

Petrel Robertson

Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	Tanglefoot Structural
Estimator Name:	B. Hayes

Avg. Surface Temp. (°C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (°C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.95
2. Charge	0.75
3. Migration	0.90
4. Reservoir Rock	0.90
5. Trap/Closure	0.90
6. Seal/Containment	0.25
Probability of Geological Success (P_g)	0.13

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	1,500	3,500	1,733	407	855	1,683	2,688	3,243
Oil Reservoir Depth (mRKB)	200	1,500	3,000	1,567	390	803	1,551	2,352	2,795
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	17,441	4,061	8,537	16,940	27,076	33,378
Reservoir Temperature (°C)	--	--	--	67	20	36	66	102	122
Methane Content	0.85		0.98	0.96	0.89	0.92	0.96	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.01	0.02	0.01	0.00	0.01	0.01	0.02	0.03
CO_2 Content	0.01	0.03	0.06	0.03	0.00	0.01	0.02	0.07	0.16
Total Play Area (sqkm)	2,422	3,500	5,000	3,612	1,949	2,458	3,488	4,949	6,242
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	3,612	1,949	2,458	3,488	4,949	6,242
Fraction of Total Play in Trap	0.010	0.070	0.120	0.068	0.006	0.014	0.046	0.152	0.337
Fraction of Untested Play Filled	0.500	0.600	0.750	0.614	0.439	0.499	0.607	0.739	0.841
Potential O&G Area (sqkm)	--	--	--	151.6	11.7	27.5	96.8	341.3	799.6
Fraction of PV Oil Bearing	0.010	0.030	0.090	0.041	0.005	0.010	0.030	0.087	0.175
Potential Oil Area (sqkm)	--	--	--	6.220	0.2	0.6	2.9	14.7	48.6
Potential Gas Area (sqkm)	--	--	--	145.4	11.2	26.4	92.9	326.6	768.7
Average Net Pay (m)	5	20	35	20	3	6	16	40	74
Porosity	0.06	0.14	0.19	0.13	0.05	0.07	0.12	0.21	0.30
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	151	41	82	147	214	252

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	14	2	5	12	24	39
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	7	1	3	6	13	24
Yield: Marketable Gas (sm3/m3)	--	--	--	6	1	2	5	11	21
Liquids Yield (stm3/e6sm3)	10	40	150	63	4	11	39	145	345
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.86	0.75	0.82	0.87	0.89	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil ($10^6 stm^3$)		1.08		8	0	0	3	19	84
Condensate & NGL ($10^6 stm^3$)		0.32		2	0	0	1	5	28
Total Liquids ($10^6 stm^3$)		1.40		11	0.1	0.6	4.0	25.0	103.2
Total Liquids (MMstb)		*8.84*		*68*	*0.9*	*3.9*	*25.1*	*157.1*	*649.1*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		5.10		39	1	3	17	89	325
Total gas ($10^9 sm^3$)		5.10		39	1	3	17	89	325
Total gas (Bscf)		*180.92*		*1,393*	*26*	*103*	*588*	*3,156*	##########
MMBOE		*38.99*		*300*	*5*	*21*	*123*	*683*	*2,571*
Recoverable									
Oil ($10^6 stm^3$)		0.16		1	0	0	0	3	14
Condensate & NGL ($10^6 stm^3$)		0.18		1	0	0	0	3	15
Total Liquids ($10^6 stm^3$)		0.34		3	0.03	0.13	0.88	5.92	26.37
Total Liquids (MMstb)		*2.12*		*16*	*0.2*	*0.8*	*5.6*	*37.2*	*165.9*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		2.80		22	0	2	9	49	184
Total gas ($10^9 sm^3$)		2.80		22	0.4	1.5	8.9	49.2	183.6
Marketable Gas ($10^9 sm^3$)		2.41		19	0.3	1.3	7.6	42.3	157.3
Marketable Gas (Bscf)		*2.52*		*19*	*0*	*1*	*7*	*44*	*192*
MMBOE		*16.36*		*126*	*2*	*9*	*52*	*286*	*1,056*

Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT								
Play Name:	**Tanglefoot Stratigraphic**								
Estimator Name:	B. Hayes								
Avg. Surface Temp. (°C):	5								
Pressure Gradient (kPa/m):	9.70								
Temp. Gradient (°C/100 m.):	3.60								
Raw Gas Gravity:	0.70								
1. Risk Component									
Risk Factors	**Play risk**								
1. Source Rock	0.95								
2. Charge	0.75								
3. Migration	0.90								
4. Reservoir Rock	0.90								
5. Trap/Closure	0.80								
6. Seal/Containment	0.50								
Probability of Geological Success (P_g)	**0.23**								
2. Hydrocarbon Volume Component									
	Low	**Best**	**High**	**Mean**	**P99**	**P90**	**P50**	**P10**	**P01**
Gas Reservoir Depth (mRKB)	200	1,500	3,500	1,733	407	855	1,683	2,688	3,243
Oil Reservoir Depth (mRKB)	200	1,500	3,000	1,567	390	803	1,551	2,352	2,795
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	17,441	4,044	8,552	16,938	27,174	33,361
Reservoir Temperature (°C)	--	--	--	67	20	36	66	102	122
Methane Content	0.85		0.98	0.96	0.89	0.92	0.96	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.01	0.02	0.01	0.00	0.01	0.01	0.02	0.03
CO_2 Content	0.01	0.03	0.06	0.03	0.00	0.01	0.02	0.07	0.16
Total Play Area (sqkm)	2,422	3,500	5,000	3,612	1,949	2,458	3,488	4,949	6,241
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	3,612	1,949	2,458	3,488	4,949	6,241
Fraction of Total Play in Trap	0.010	0.060	0.110	0.061	0.006	0.013	0.042	0.134	0.288
Fraction of Untested Play Filled	0.500	0.600	0.750	0.614	0.439	0.499	0.607	0.739	0.841
Potential O&G Area (sqkm)	--	--	--	135.2	11.4	26.3	89.3	299.0	680.8
Fraction of PV Oil Bearing	0.010	0.030	0.090	0.041	0.005	0.010	0.030	0.087	0.175
Potential Oil Area (sqkm)	--	--	--	5.548	0.2	0.6	2.7	12.9	41.9
Potential Gas Area (sqkm)	--	--	--	129.6	10.9	25.2	85.6	287.9	656.3
Average Net Pay (m)	5	12	19	12	4	6	11	20	31
Porosity	0.06	0.14	0.19	0.13	0.05	0.07	0.12	0.21	0.30
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	151	41	82	148	214	252
3. Yield Component									
	Low	**Best**	**High**	**Mean**	**P99**	**P90**	**P50**	**P10**	**P01**
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	14	3	5	11	23	39
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	7	1	3	6	13	23
Yield: Marketable Gas (sm3/m3)	--	--	--	6	1	2	5	11	19
Liquids Yield (stm3/e6sm3)	10	40	150	63	4	11	39	145	345
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.86	0.75	0.82	0.87	0.89	0.89
4. Play Totals		Risked Mean volumes		Volumes given Geological Success in Play					
				Mean	**P99**	**P90**	**P50**	**P10**	**P01**
In Place									
Oil ($10^6 stm^3$)		1.02		4	0	0	2	11	41
Condensate & NGL ($10^6 stm^3$)		0.30		1	0	0	0	3	14
Total Liquids ($10^6 stm^3$)		1.33		6	0.1	0.4	2.5	13.7	48.7
Total Liquids (MMstb)		*8.35*		*36*	*0.7*	*2.7*	*15.5*	*86.2*	*306.7*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		4.82		21	1	2	10	47	156
Total gas ($10^9 sm^3$)		4.82		21	1	2	10	47	156
Total gas (Bscf)		*171.03*		*741*	*23*	*75*	*360*	*1,685*	*5,541*
MMBOE		*36.86*		*160*	*5*	*15*	*76*	*367*	*1,230*
Recoverable									
Oil ($10^6 stm^3$)		0.15		1	0	0	0	2	7
Condensate & NGL ($10^6 stm^3$)		0.17		1	0	0	0	2	7
Total Liquids ($10^6 stm^3$)		0.32		1	0.02	0.09	0.54	3.20	12.09
Total Liquids (MMstb)		*2.01*		*9*	*0.1*	*0.6*	*3.4*	*20.1*	*76.1*
Solution gas ($10^9 sm^3$)		0.00		0	0	0	0	0	0
Free gas ($10^9 sm^3$)		2.64		11	0	1	5	26	86
Total gas ($10^9 sm^3$)		2.64		11	0.3	1.1	5.5	26.3	85.8
Marketable Gas ($10^9 sm^3$)		2.28		10	0.3	1.0	4.7	22.5	73.9
Marketable Gas (Bscf)		*2.39*		*10*	*0*	*1*	*4*	*24*	*88*
MMBOE		*15.47*		*67*	*2*	*7*	*32*	*154*	*491*

Petrel Robertson Consulting Ltd.
Global Petroleum Consulting

UNDISCOVERED RESOURCE ESTIMATION TEMPLATE

Area/Region:	Whitehorse Trough; YT
Play Name:	**Tantalus Structural / Stratigraphic**
Estimator Name:	B. Hayes
Avg. Surface Temp. (^{o}C):	5
Pressure Gradient (kPa/m):	9.70
Temp. Gradient (^{o}C/100 m.):	3.60
Raw Gas Gravity:	0.70

1. Risk Component

Risk Factors	Play risk
1. Source Rock	0.95
2. Charge	0.75
3. Migration	0.90
4. Reservoir Rock	0.90
5. Trap/Closure	0.90
6. Seal/Containment	0.15
Probability of Geological Success (P_g)	**0.08**

2. Hydrocarbon Volume Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Gas Reservoir Depth (mRKB)	200	1,100	2,000	1,100	327	602	1,100	1,597	1,873
Oil Reservoir Depth (mRKB)	200	1,100	2,000	1,100	327	602	1,100	1,597	1,873
Reservoir overpressuring (x hydrostatic)	0.9	1.0	1.2	1.03	0.92	0.95	1.02	1.12	1.17
Reservoir Pressure (kPa)	--	--	--	11,068	3,285	6,043	11,015	16,134	19,356
Reservoir Temperature (^{o}C)	--	--	--	45	17	27	45	63	72
Methane Content	0.85		0.98	0.96	0.89	0.92	0.96	0.99	1.00
Ethane Content	0.01	0.02	0.05	0.03	0.01	0.01	0.02	0.05	0.08
Propane Content	0.00	0.01	0.05	0.03	0.00	0.00	0.00	0.08	0.55
H_2S Content	0.01	0.01	0.02	0.01	0.00	0.01	0.01	0.02	0.03
CO_2 Content	0.01	0.03	0.06	0.03	0.00	0.01	0.02	0.07	0.16
Total Play Area (sqkm)	354	825	1,300	820	258	392	734	1,375	2,084
Tested Play Area (sqkm)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Untested Play Area (sqkm)	--	--	--	820	258	392	734	1,375	2,084
Fraction of Total Play in Trap	0.001	0.007	0.050	0.018	0.000	0.001	0.007	0.047	0.163
Fraction of Untested Play Filled	0.500	0.600	0.750	0.614	0.439	0.499	0.607	0.739	0.841
Potential O&G Area (sqkm)	--	--	--	9.1	0.1	0.4	3.1	22.6	90.9
Fraction of PV Oil Bearing	0.005	0.019	0.070	0.029	0.002	0.005	0.019	0.067	0.157
Potential Oil Area (sqkm)	--	--	--	0.269	0.0	0.0	0.1	0.6	3.2
Potential Gas Area (sqkm)	--	--	--	8.9	0.1	0.4	3.0	22.0	88.1
Average Net Pay (m)	5	15	30	16	3	6	13	32	56
Porosity	0.05	0.12	0.20	0.12	0.04	0.06	0.11	0.21	0.32
Hydrocarbon Saturation	0.58	0.65	0.85	0.69	0.50	0.57	0.68	0.82	0.93
Oil Recovery Factor	0.05	0.15	0.25	0.15	0.03	0.06	0.13	0.27	0.46
Gas Recovery Factor	0.40	0.55	0.70	0.55	0.34	0.41	0.54	0.70	0.84
Solution GOR (ksm3/stm3)	0.03	0.09	0.25	0.12	0.02	0.03	0.09	0.24	0.48
Oil Formation Volume Factor	1.20	1.30	1.50	1.33	1.11	1.19	1.32	1.48	1.58
Gas Compressibility "Z"	0.95	0.97	0.98	0.97	0.94	0.95	0.97	0.98	0.99
Gas Formation Expansion Factor	--	--	--	103	34	60	102	142	167

3. Yield Component

	Low	Best	High	Mean	P99	P90	P50	P10	P01
Yield: Oil-in-Place (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Recoverable Oil (stm3/m3)	--	--	--	0	0	0	0	0	0
Yield: Gas-in-Place (sm3/m3)	--	--	--	9	2	3	7	16	28
Yield: Raw Recoverable Gas (sm3/m3)	--	--	--	5	1	2	4	9	16
Yield: Marketable Gas (sm3/m3)	--	--	--	4	1	1	3	8	14
Liquids Yield (stm3/e6sm3)	10	40	150	63	4	11	39	145	345
Gas to BOE Conversion (Mscf/BOE)	--	6.00	--	--					
Surface Loss (Fuel gas, etc...)	--	0.10	--	--					
Marketable Gas (Fraction of Raw)	--	--	--	0.86	0.75	0.82	0.87	0.89	0.89

4. Play Totals

	Risked Mean volumes			Volumes given Geological Success in Play					
				Mean	P99	P90	P50	P10	P01
In Place									
Oil (10^6stm^3)		0.02		0	0	0	0	1	4
Condensate & NGL (10^6stm^3)		0.01		0	0	0	0	0	1
Total Liquids (10^6stm^3)		0.03		0	0.0	0.0	0.1	0.7	4.4
Total Liquids (MMstb)		*0.17*		*2*	*0.0*	*0.0*	*0.4*	*4.6*	*27.7*
Solution gas (10^9sm^3)		0.00		0	0	0	0	0	0
Free gas (10^9sm^3)		0.10		1	0	0	0	3	15
Total gas (10^9sm^3)		0.10		1	0	0	0	3	15
Total gas (Bscf)		*3.45*		*44*	*0*	*1*	*10*	*98*	*531*
MMBOE		*0.75*		*10*	*0*	*0*	*2*	*21*	*116*
Recoverable									
Oil (10^6stm^3)		0.00		0	0	0	0	0	1
Condensate & NGL (10^6stm^3)		0.00		0	0	0	0	0	1
Total Liquids (10^6stm^3)		0.01		0	0.00	0.00	0.01	0.17	1.18
Total Liquids (MMstb)		*0.04*		*1*	*0.0*	*0.0*	*0.1*	*1.1*	*7.4*
Solution gas (10^9sm^3)		0.00		0	0	0	0	0	0
Free gas (10^9sm^3)		0.05		1	0	0	0	1	8
Total gas (10^9sm^3)		0.05		1	0.0	0.0	0.2	1.5	8.3
Marketable Gas (10^9sm^3)		0.05		1	0.0	0.0	0.1	1.3	7.1
Marketable Gas (Bscf)		*0.05*		*1*	*0*	*0*	*0*	*1*	*9*
MMBOE		*0.31*		*4*	*0*	*0*	*1*	*9*	*48*

			OIIP + CIIP given success				GIIP given success			
	Play Risk	Risked Liquids volume	P90	P50	P10	Risked Gas Volume	P90	P50	P10	Ratio P10:P90
		e6stm3	e6stm3	e6stm3	e6stm3	e9sm3	e9sm3	e9sm3	e9sm3	
Lewes River Structural	0.03	0.00	0.00	0.01	0.12	0.59	1.1	6.9	44.2	42
Hancock Stratigraphic	0.05	0.00	0.00	0.00	0.01	0.08	0.1	0.5	3.4	43
Tanglefoot Structural	0.13	1.40	0.62	3.99	24.97	5.10	2.9	16.6	88.9	31
Tanglefoot Stratigraphic	0.23	1.33	0.44	2.47	13.69	4.82	2.1	10.1	47.5	22
Tantalus Structural / Stratigraphic	0.08	0.03	0.01	0.06	0.73	0.10	0.0	0.3	2.8	95
		2.8	**1.1**	**6.5**	**39.5**	**10.7**	**6.2**	**34.4**	**186.8**	
08-Mar Run										
Lewes River Structural	0.03	0.00	0.00	0.01	0.16	0.86	0.7	6.7	61.2	
Hancock Stratigraphic	0.05	0.00	0.00	0.00	0.01	0.09	0.1	0.4	3.7	
Tanglefoot Structural	0.13	0.02	0.01	0.04	0.32	6.47	5.2	25.0	111.5	
Tanglefoot Stratigraphic	0.23	0.02	0.00	0.02	0.17	6.12	3.2	13.9	60.0	
Tantalus Structural / Stratigraphic	0.08	0.00	0.00	0.00	0.01	0.11	0.0	0.3	3.0	