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The future oil discovery potential of the Mackenzie/Beaufort Province

Zhuoheng Chen[1], Kirk G. Osadetz[1], James Dixon[1], Giles Morrell[2], and James R. Dietrich[1]
[1] Geological Survey of Canada, 3303 – 33rd street, NW, Calgary, Alberta, Canada, T2L 2A7
[2] Oil and Gas Management Directorate, Northern Oil and Gas Branch, India and Northern Affairs Canada

Introduction

The Mackenzie/Beaufort province (Fig. 1), in northwest Canada, hosts large quantities of proven and potential petroleum resources that are of strategic importance for future North American energy supply. Petroleum exploration in the province has resulted in 53 distinct accumulations in 48 significant conventional crude oil and gas discoveries (National Energy Board, 1998). The discovered quantities of conventional petroleum resources are estimated to be 1.744 x 10^9 bbls (277.3 x 10^6m^3) recoverable crude oil and 11.74 tcf (332.4 x 10^9m^3) recoverable natural gas (Dixon et al., 1994). Recent studies of unconventional petroleum resources indicate that an immense natural gas hydrate resource may exist in the form of methane hydrate in this province (e.g. Osadetz and Chen, 2005).

The Mackenzie/Beaufort province exhibits a complex basin evolution (Fig. 2A), from an open marine setting throughout most of the Paleozoic, followed by a rift-drift system in Jurassic to Early Cretaceous. The Late Cretaceous-Cenozoic successions represent a post-rift passive-margin basin comprising more than 14 km of deltaic sediments (Dixon et al. 1992), complicated by the Cordilleran Thrust Belt in the southwest. Tectonically, the province can be divided into four structural domains: a stable Craton in the south and southeast, a rifted margin in the southwest, the Cordilleran Fold Belt in the southwest, and the Canada Basin in the north. Figure 2 is a composite diagram, showing regional stratigraphy, major tectonic events, essential petroleum system elements, petroleum plays/play groups and their stratigraphic position and spatial association, and discovered reserve and estimated petroleum oil resources. Although oil discoveries are from almost all stratigraphic levels, from Paleozoic to Cenozoic, more than 95% of discovered oil accumulations are in Tertiary successions.

This study is based on the previous petroleum resource assessment conducted by the Geological Survey of Canada (GSC) (Dixon et al., 1994), with emphasis on the petroliferous rifted basin margin and the southern part of the Canada Basin, extending from south of the Mackenzie Delta, north to about 2500 meter water depth because this is the most accessible region for exploration and development. Areal extent of the assessment and boundaries of the play groups are shown in Fig.1. Several petroleum plays overlap, particularly in the south, because of the nature of the rifted passive margin and the stacked stratigraphy of the delta systems. Recent studies in organic geochemistry, basin hydrodynamics, petroleum systems analysis, and geoscience data integration in cooperation with industry, provide an improved geoscience framework for understanding the petroleum resource potential in this province.

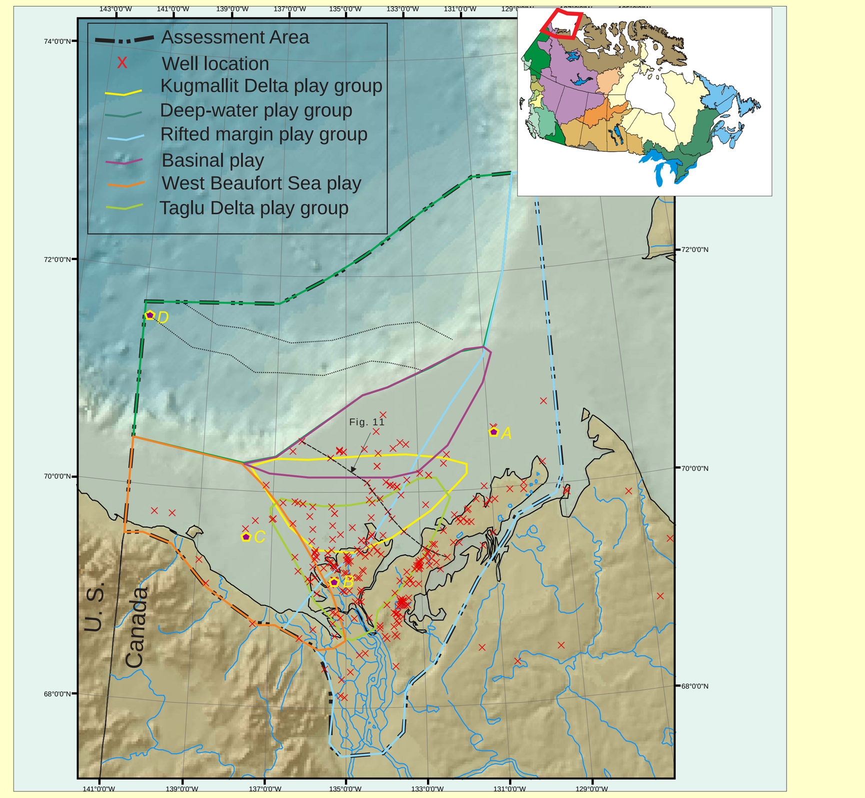

Figure 1. Location map shows the study area of the assessment, play group boundaries and exploratory wells in the province. The red polygon in the inserted map of Canada (upper-right) indicates the location of the Beaufort/Mackenzie area. A, B, C, and D indicate the well locations of 1D modeling of Fig. 6.

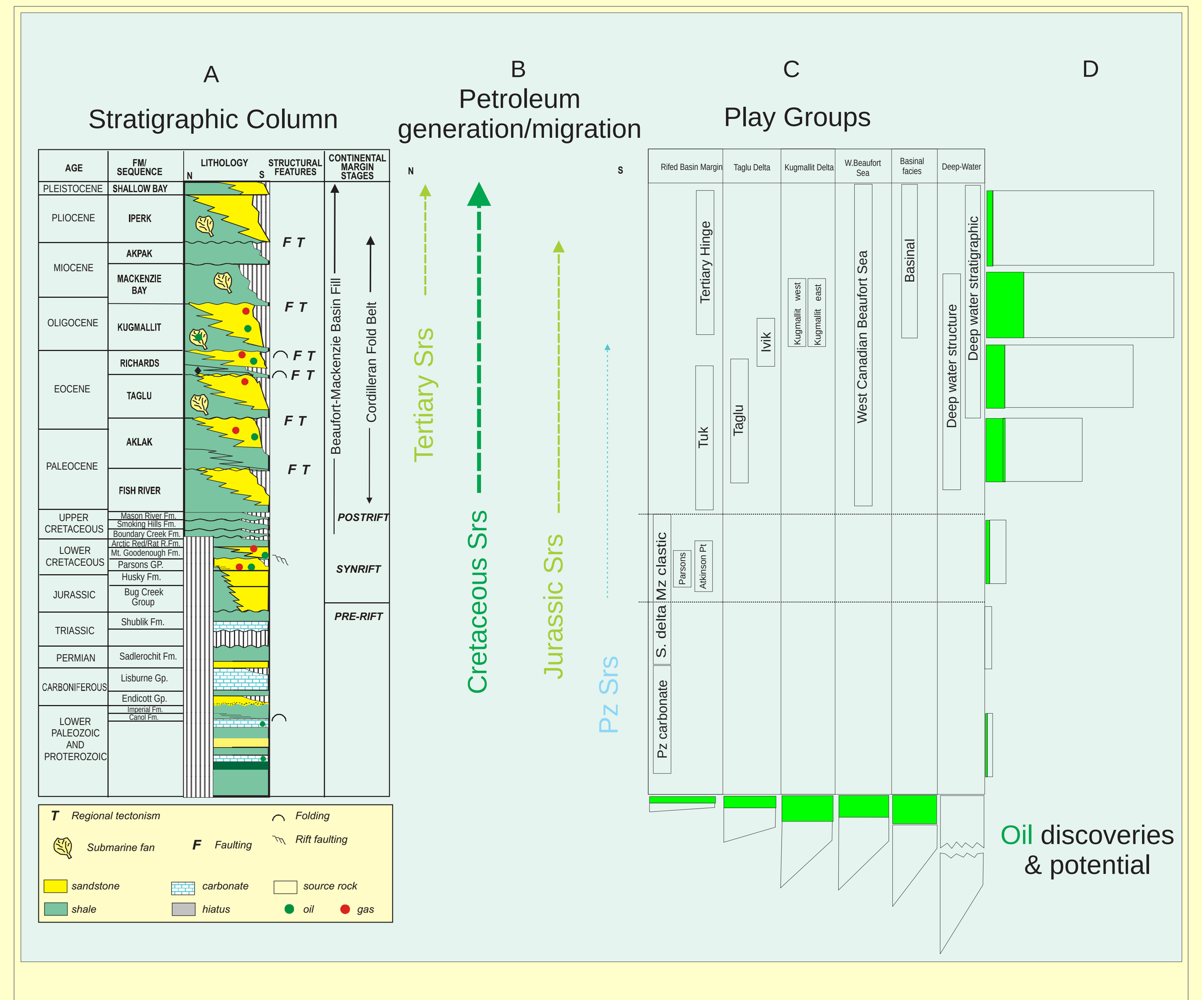

Figure 2. A summary diagram showing regional stratigraphy, major tectonic events, essential petroleum system elements, definition of play and play group and their association with stratigraphic positions and space, and discovered reserve and estimated potential oil resources. The uncertainties of the potential in the play groups are indicated by the difference in length of the potential resource bars. All discoveries and potential resources are relative abundances at different stratigraphic levels and in play groups. See Table 1 for actual estimated potential values.

Source rocks

Three major potential source rock sets may exist in this province: a) the Jurassic-Lower Cretaceous syn-rift shales, b) Upper Cretaceous passive margin marine shales, and c) Tertiary passive margin marine shales. The syn-rift Jurassic-Lower Cretaceous successions may have three potential source beds. Shale in the Husky Formation is found in the southeast basin margin and nearshore areas, and it is also possibly present in some of the deeply buried grabens in the rift area. If the rotational model of Arctic plate tectonics is valid, the syn-rift Jurassic-Lower Cretaceous (J-IK) succession should also be present in the west Beaufort Sea. Oil and source rock correlation indicates that this shale could be a major contributor of natural gas in the Parsons Lake gas field and Unak gas discovery (Langhus, 1980). The Lower Cretaceous Arctic Red Formation, found in the Kugmallit Trough in a slope to basinal environment (Dixon et al., 1994), is presumably present in most of the province and represents sedimentation during the last phase of continental drifting. Recent organic geochemical analyses indicate biomarker signatures from the Arctic Red shale in a number of discoveries (Li, personal communication, 2006). Localized source rock, such as the Lower Cretaceous McGuire shale, is inferred to be responsible for oils found in the Kamik discovery well and adjacent areas (Dixon, personal communication). It may also be present in the offshore area. Source rock maturity studies (Fig. 5) indicate that the J-IK source rocks could be one of the sources for the Rifted Margin, Taglu Delta and Kugmallit Delta play groups, but are over-cooked in most of the offshore area, because of deep burial.

The Upper Cretaceous succession of the Boundary Creek and Smoking Hills formations represents the earliest sedimentary records accumulated in outer shelf and slope environments of this passive margin basin and contain organic-rich and radioactive shales, which are widely distributed in the Arctic region. These shales are recognized to be one of the major contributors to the oils found in the discoveries in the Tuk, Atkinson and Mayogiak wells, in the central and northern Tuktuyaktuk Peninsula (Dixon et al., 1994; Dixon et al., 1985). Biostratigraphic data and new 3D seismic interpretation indicate that the uK mobile substrata cores some of the diapirs in the western part of the Beaufort Sea (Bergquist et al., 2003) in the west Beaufort Sea and part of the uK source rock could still be in the oil generation window in part of the offshore area.

The Lower Tertiary succession contains several organic-rich shale intervals in the major sequences, such as Richards, Taglu and Aklak, and are inferred to be responsible for some of the oil and gas accumulations found in this province (Snowdon, 1984; Snowdon et al., 2004; Brooks, 1986). Where it is mature, the Tertiary succession is considered to be one of the major source rocks for the accumulation in the deep ultra deep-water setting. Analyses of the measured vitrinite reflectance from cuttings and cores indicate that the maturity level of the Lower Tertiary succession has reached the oil window just below 3000 meters (Ro>0.6%) in the Richards Island and western Beaufort Sea. The vitrinite reflectance reached 0.6% at top of the Aklak Sequence in Richards Island and offshore areas. The oil correlations indicate a good correspondence between the oils from the Adlartok P-09 well and Tertiary source rocks (Li, personal communication). It is anticipated that the Lower Tertiary shales and coal seams are the major source rocks for the oil and gas accumulation in the west Beaufort Sea play with an important contribution in other part of the shelf area.

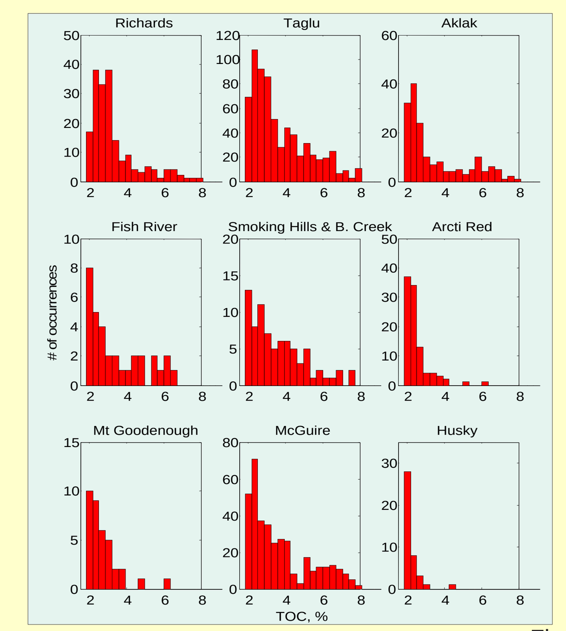

Figure 3. Histograms showing the total organic content (TOC) in weight percent from rock-eval in different sedimentary intervals. Only TOC values between 1.5% - 9% are plotted.

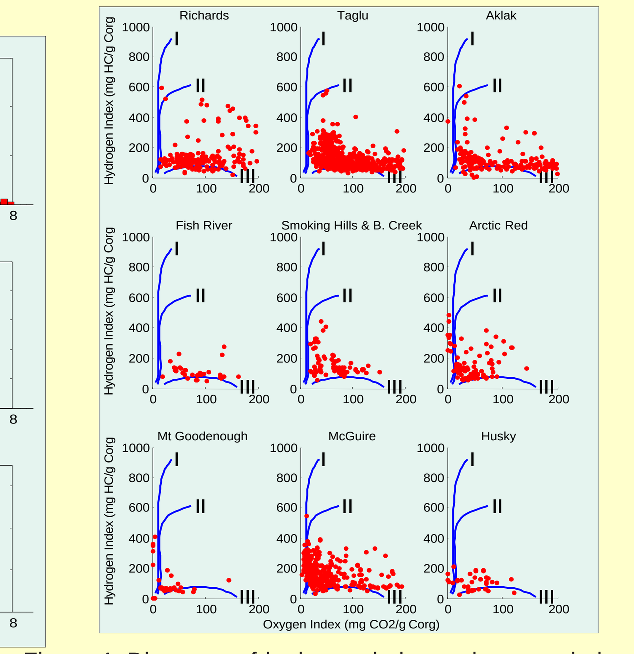

Figure 4. Diagrams of hydrogen index and oxygen index from rock-eval, showing the characteristics of organic matter in various potential source rock beds. Several screening criteria (9<TOC%>1.5, Tmax>390°C and oxygen index <200) were applied to the plots.

Organic geochemical analyses indicate a large range of variation in TOC% measured from cuttings and side wall cores in exploration boreholes at almost all stratigraphic levels. Although most samples have a TOC% <3%, a number of stratigraphic intervals show a fairly high TOC, up to 9%. Fig. 3 displays histograms of TOC% from nine stratigraphic intervals, suggesting the variations. Results from Rock-Eval analysis suggests a diversity of kerogen types in the basin. Figure 4 is a cross-plot set of hydrogen index vs. oxygen index of borehole cuttings from nine stratigraphic intervals, suggesting predominant type II and type III kerogen in this province.

Vitrinite reflectance was measured from cuttings and cores in ninety two wells (green dots, Fig 5). Maturity level increases basin-wards at the top of the Aklak Sequence; whereas it increases northwest-wards for the Mesozoic and older strata. Figures 5a - e show maturity trends at tops of five different stratigraphic levels, indicated by the vitrinite reflectance (Ro) contours. Figure 5f is a Ro contour map at a depth of 3000 meters, showing the spatial variation of the basin thermal heterogeneity.

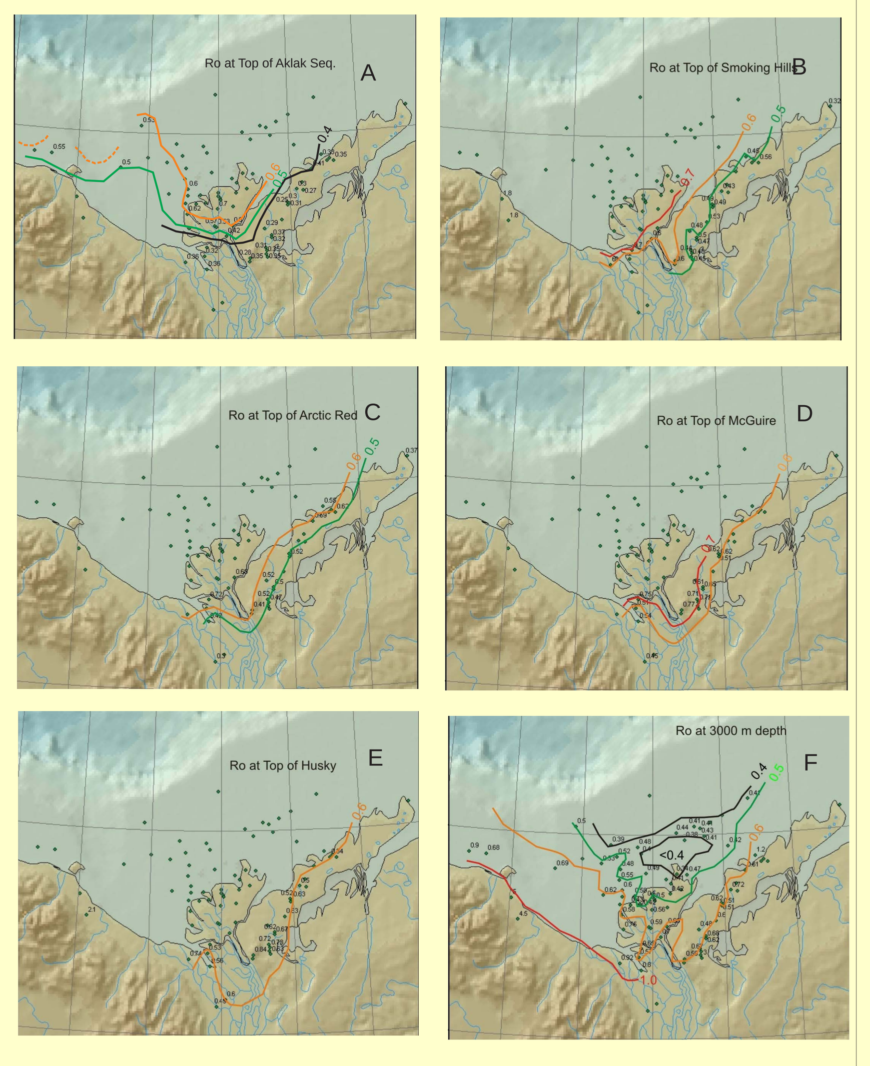

Figure 5. Spatial variation of maturity levels from five inferred source rock intervals in the basin (Fig.5 a - e) as well as the basin thermal regime indicated by contours of the measured vitrinite reflectance at a depth of 3000m below KB (Fig. 5 f). The green dots are well locations with Ro data and the values are the Ro values at the top of the five potential source rock intervals or at a depth of 3000 meters below KB.

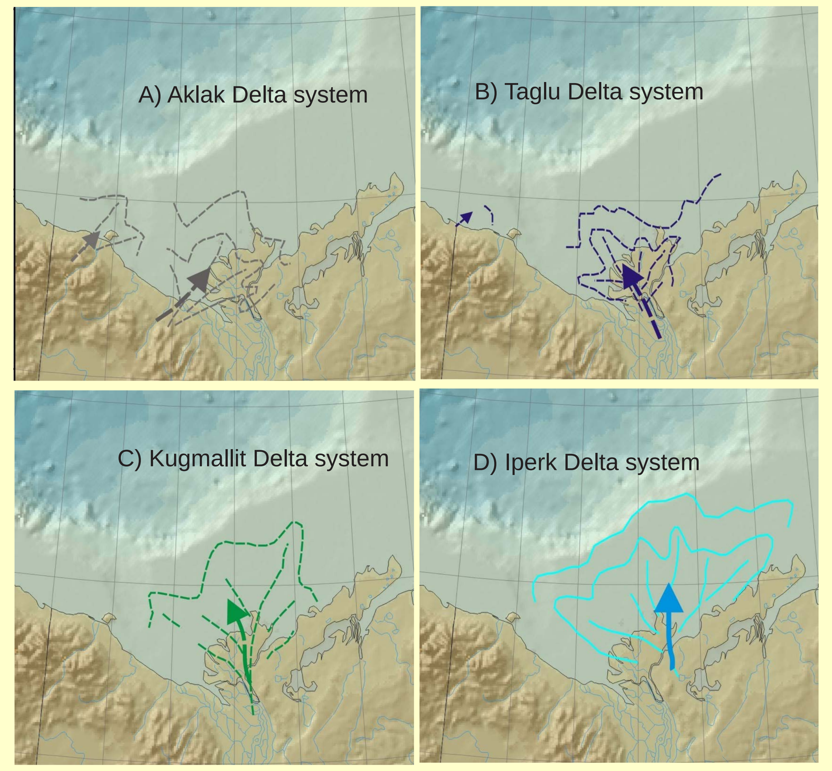

Figure 7. Showing four of the major delta systems developed in the Tertiary based on estimated sand percentage from logs. The Fish River Delta system is inferred to be similar to the Aklak system, but data are insufficient to make a sketch map of the delta. The sedimentary feeds were changing from southwest in the Paleocene to south in the Eocene and later.

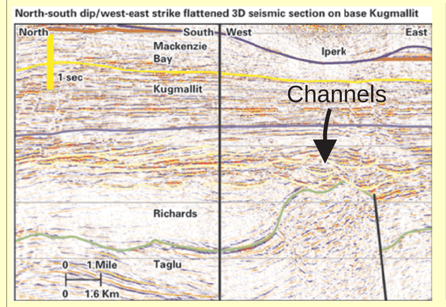

Figure 8a. A 3D seismic section showing interpreted sandstones in channel-fills in Richards Sequence in west Beaufort Sea area (from Bergquist et al. 2003).

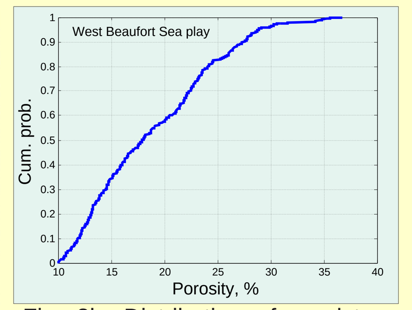

Fig. 8b. Distribution of sandstone porosity of the Taglu and Aklak sequences derived from 471 core measurements in seven wells located in West Beaufort Sea play.

Reservoir

In the Tertiary basin-fill history, five major delta systems developed (Fig. 2A). Figure 7 shows four of the major delta systems, illustrating the extent of each of the systems, and how the delta systems evolved in time and space in response to tectonism, and depositional provenances. The shape and areal extent of each individual delta system is defined from the 20% and 30% sand content derived from borehole logs. The major delta systems cover almost the entire present continental shelf and Richards Island. The deltaic sandstones of delta plain and delta front provide quality reservoirs for hydrocarbon accumulations in the Taglu Delta, Kugmallit Delta and West Beaufort Sea play groups.

Additional types of reservoir rock include channel-fill sandstones and submarine-fan sands in recent as well as paleo-slope and deep-water basins. Interpretation of the newly acquired 3D seismic data indicates the existence of large scale channel-fill sandstones in the Richards Sequence (Bergquist et al., 2003) in the west Beaufort Sea (Fig. 8). The Oligocene and Miocene sequences are shale-dominant in general, and they may also contain channel-fill sandstones or other type of sand bodies. For example, clinoforms (Fig. 41 of Dixon et al., 1985; Fig. 11b and 13 a and b of Hubbard et al., 1985) and channel forms (seismic profile 8E of Dixon et al., 1990) on seismic lines in the Mackenzie Bay Sequence indicate delta front, delta plain and channel sands. Sandstones associated with submarine fan systems in the Iperk, Mackenzie Bay and Kugmallit sequences are the major reservoir type in the Basinal facies play.

In the deep-water play, inferences were made based on analogy to known world deep-water settings (Weimer and Slatt, 2004), as well as the pale-slope and deep-water basins of this province, and limited regional seismic interpretation. Three possible reservoir types may exist in this play: channel fill sands/sandstones, basin floor turbidite sand sheets and overbank levee sand beds. Interpretation of available reflection seismic lines indicates various channel fills and possible basin-floor sheet sands in Tertiary stratigraphic successions. These reservoir rocks are more subtle in older strata on seismic profiles, but possibly also present.

For the Rifted Margin play group, discoveries in the Mesozoic and Lower Paleozoic indicate both porous clastics and carbonates are present and can be reservoir rocks. However, they are restricted to the rifted margin play group in the southeast and shallow burial in the south.

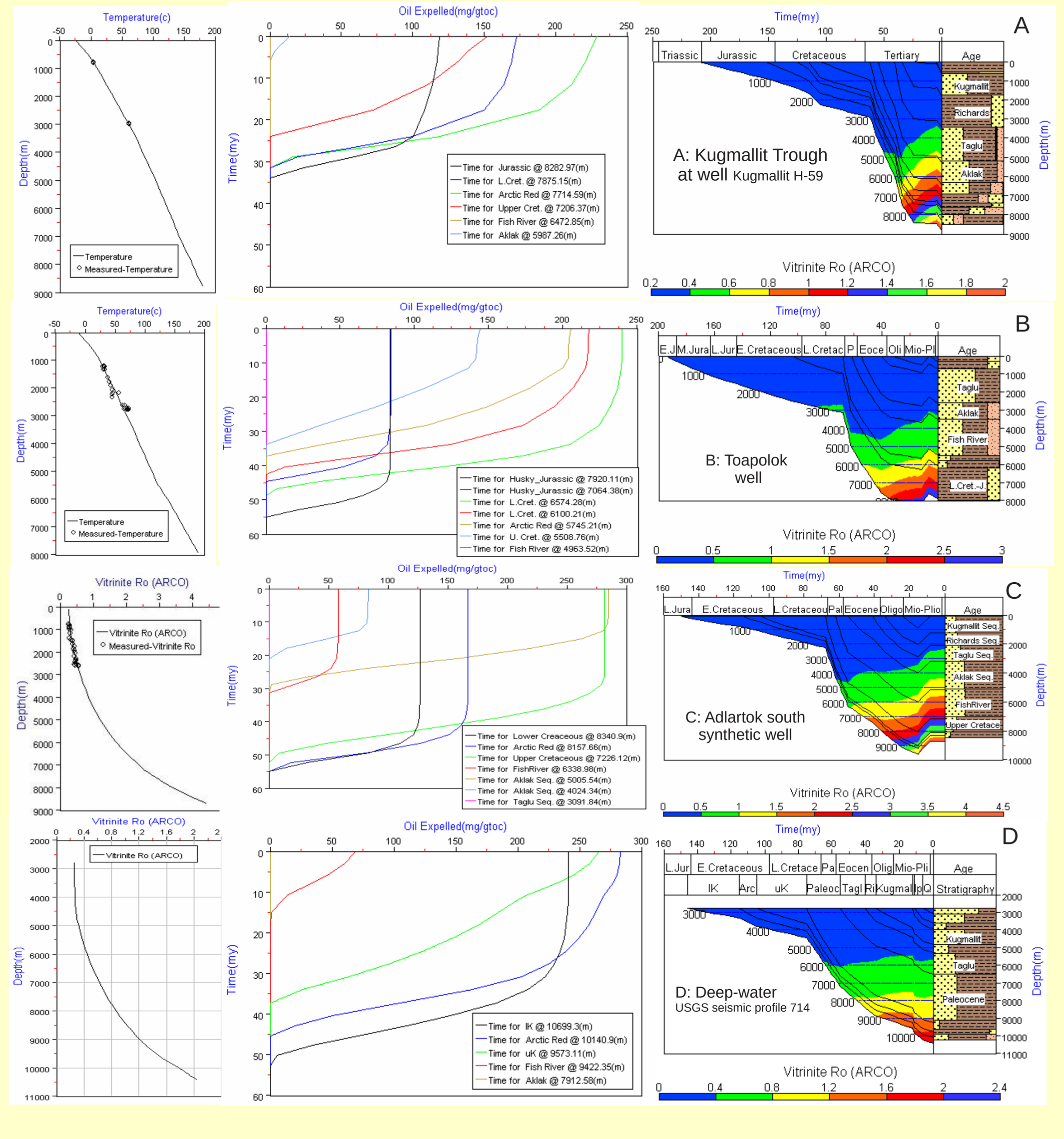

Figure 6 Results from 1D modeling of hydrocarbon generation and migration histories at four synthetic well locations based on well information and seismic interpretation (see Fig. 1 for location). The thermal histories are based on a rifting model and honored by observations from vitrinite reflectance and DST/borehole temperature in wells where data are available. For the synthetic well location at the deep-water location in the northwest, the parameters from the rifting model with well control were used. A) Kugmallit H-59, extended to the Paleozoic unconformity, the depth at which was derived from seismic interpretation; B) Toapolok structure, extended to the base of Mesozoic strata, derived from seismic data; C) south of Adlartok P-09. Vitrinite reflectance is from Adlartok P-09 and depths to sequence boundaries are from interpretation of a seismic line; and D) deep-water location, stratigraphic boundaries are inferred from USGS seismic profile 714.

Generation/migration/timing

Petroleum system modeling suggests multiple phases of petroleum generation and migration from potential source rocks at different burial depths. Significant petroleum generation/migration may have started as early as Late Cretaceous and continued to rather recently, depending upon the thermal history of the source rocks. Figure 6 shows results from 1D modeling at four synthetic well locations, illustrating hydrocarbon generation/expulsion histories in different parts of the basin.

In the west Beaufort Sea, the Tertiary sources appear to be the effective source rocks because of the high thermal maturity level, whereas the Cretaceous and older source rocks have all passed through the oil window and the oils were expelled before the major phase of trap formation in the late Eocene. In contrast, in the southeast part and deep-water portion of the basin, the Cretaceous source rocks seems to be the major contributor because of either a shallow burial depth of the Tertiary source rocks in the rifted margin or a low level of maturity in the Tertiary depocenters.

Faults/fracture zones associated with mobile substrata, listric and thrust fault systems provide adequate vertical migration routes. However, fluid migration and entrapment are dynamic processes throughout the entire basin development history. The episodic nature of overpressure and pressure release may have led to loss/partial loss or redistribution of early accumulated hydrocarbons.

Several episodes of tectonic activity in the Tertiary are recognized in this province (Lane and Dietrich, 1998). The most important ones include tectonic inversion during the Late Eocene, which led to diapirism and trap formation over a wide area. While in the eastern part, the same tectonic episode reactivated the pre-existing faults and generated roll-over structures. Tectonic activity at the end of the Miocene may have triggered large scale submarine sliding and formed turbidites and basin-floor sheet sands over a wide area. Tectonic activity at the end of the Miocene may have accelerated the secondary migration process and caused re-migration of some previously trapped hydrocarbon accumulations.

Trap styles

Several types of traps have been recognized in this region. Structural closures associated with shale-cored anticlines formed during the Eocene tectonic inversion (Bergquist et al. 2003; Dixon, et al., 1994) are typical in the fold belt in the western part of the province (Fig. 9). This type of structural trap is also common in the slope between water depths of 500 m to 2500 m. Beyond the outer continental slope, the magnitude of the structures becomes smaller and then disappears. This type of structures is large (see closure size distribution in Fig. 10 from mapped structure traps) and faults are commonly part of this structural trap. These Tertiary diapiric structures become progressively younger northward, from the uK Smoking Hills/Boundary Creek cored structures (Bergquist et al. 2003) in the west Beaufort Sea to pre-Eocene diapir-cored structures in the slope (Dixon et al., 1990) to the north. Other trap types associated with shale diapirism include the stratigraphic pinch-out against diapirs, fault-sealed structural noses and drape structures over the diapirs. In contrast, the trap styles of a typical passive margin comprise roll-over structures in the east and the delta, and fault blocks in the southeast along the basin margin. These later types of structure are more apparent in older-strata stratigraphic succession. Roll-over anticlines associated with listric faults are most common in the delta area.

Stratigraphic traps are recognized in this province. Unconformity traps are interpreted from seismic data, and pinch-out is an important component for several discoveries made in the basinal facies play (Dixon et al., 1994). Other traps, such as a combination of structural and stratigraphic traps and unconformity associated traps (e.g., erosional truncations), are anticipated in this basin.

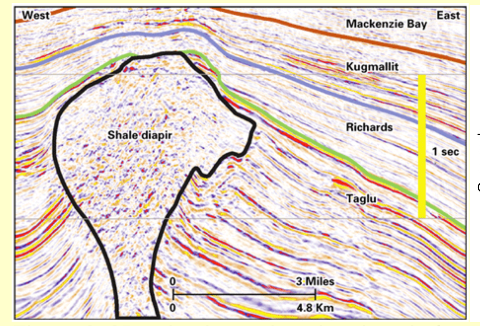

Figure 9. 3D seismic section showing shale-cored structural traps and other associated traps (from Bergquist et al. 2003).

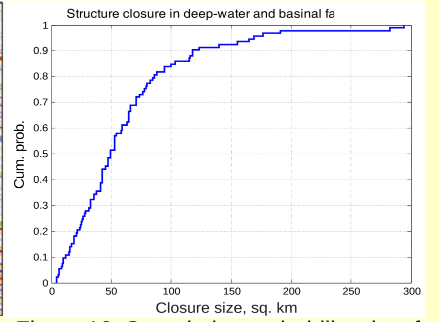

Figure 10. Cumulative probability plot of measured structural closure size of the mapped shale-cored-diapir anticlines in the deep-water and basinal facies plays.

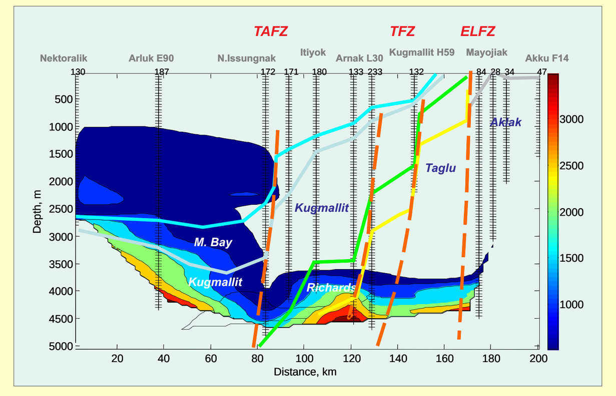

Figure 11. Cross-section view of hydraulic head from DSTs showing hydrodynamic features of the basin (see Fig. 1 for location). Elevated overpressure is common in the west and north where mobile-shale diapirism creates fracture systems on top of shale-cored anticlines. In the center of the Mackenzie Delta, where listric faulting prevails, overpressure usually does not occur above 2500m. Hydrostatic pressure regime is typical in the pre-Tertiary succession to the south basin margin.

Top Seal

The shale-dominant Richards, Mackenzie Bay and Akpak sequences are regional top seals in this area. The shales in this region may contain substantial amount of silts, which may affect the seal capacity.

The seal integrity may be at risk for some of the diapir-cored anticlines because diapirism, overpressure and associated crestal faulting/fracturing may have weakened the top seal. Note the shallow overpressure zone in the basinal facies play, north to the Tarsiut-Amauligak Fault Zone (TAFZ).

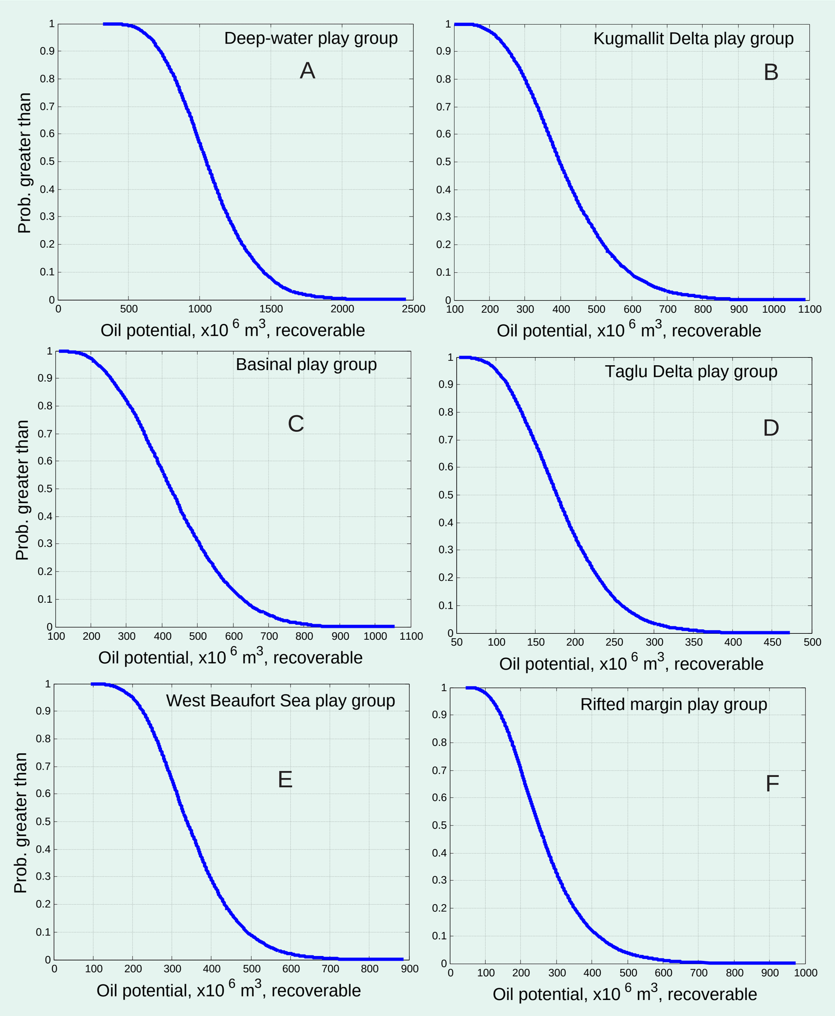

Figure 12. Distributions of estimated oil resources in the six play groups, showing the uncertainty range of estimated resources.

Assessment Results

Eighteen plays were defined based on the trap configurations and reservoir age/types, among which fourteen are identified or inferred to have oil potential. Figure 2C shows the stratigraphic and predominant trap type of the plays/play groups. This assessment employs the GSC's probabilistic approach and uses plays as the unit. For the established plays with sufficient discoveries, statistics from known pools/fields provide good data for estimating the distribution of volumetric parameters, such as pool area, reservoir porosity, net pay and hydrocarbon saturation. For the immature and conceptual plays, the estimation of the volumetric parameters is based on geological similarities with known plays. For the deep water area, where no wells were drilled, analogs were used to derive the volumetric parameters.

These fourteen plays were aggregated into six play groups to represent the stratigraphic and geographic distribution of the oil potential. The six play groups include the Rifted Margin group, the Taglu Delta group, the Kugmallit Delta group, the basinal facies group, the deep water group and Western Beaufort Sea group. Estimated oil potential appears to increase basinward, reflecting the geological control of source-rock quality and source-rock maturity. Other geological factors such as overpressure and top-seal leakage may also affect the geographical distribution of oil resources.

Figure 12a to f are cumulative distributions of the aggregated play group resources for the six play groups, showing the estimated potential and associated ranges of uncertainties. The estimated resource potential in the six play groups as well as the province are summarized in Table 1. The rifted margin play group has an estimated mean of 1.6 billion barrels (268 x10^6m^3), and the Taglu Delta group has 1.2 billion barrels (184 x10^6m^3) recoverable oil resources. The plays in these groups are more gas prone and have the lowest oil potential among the play groups assessed. The Kugmallit Delta has a mean estimate of 2.6 billion barrels (415 x10^6m^3) of recoverable oil. The basinal facies play has potential of 2.4 billion barrels (386 x10^6m^3), and deep water play group has the largest oil resource with a mean estimate of 6.7 billion barrels (1072 x10^6m^3) recoverable oil. The western Beaufort Sea play group has a mean of 2.2 billion barrels (351 x10^6m^3) recoverable oil. The aggregated total mean for the six play groups is 16.8 billion barrels (2.7 x10^9m^3) recoverable oil (Fig. 13).

Table 1. Summary table of the distribution of estimated total recoverable oil resources and discoveries in the six play groups (see Fig. 1 for location of the play groups).

	Play group resource, 10^6m^3				Discovered resource, 10^6m^3		
Play Group	P90	P50	P10	Mean	P90	P50	P10
Deep-water	724	1048	1451	1072	0	0	0
Basinal Facies	228	376	553	386	26	71	117
W. Beaufort Sea	227	338	491	351	20	52	83
Taglu Delta	115	178	260	184	30	59	87
Kugamallit Delta	255	398	596	415	97	129	180
Rifted Margin	143	250	419	268	10	17	24
Basin Total	1691	2588	3770	2675	183	327	491
Basin total in billion bbl	10.6	16.3	23.7	16.8	1.2	2.1	3.1

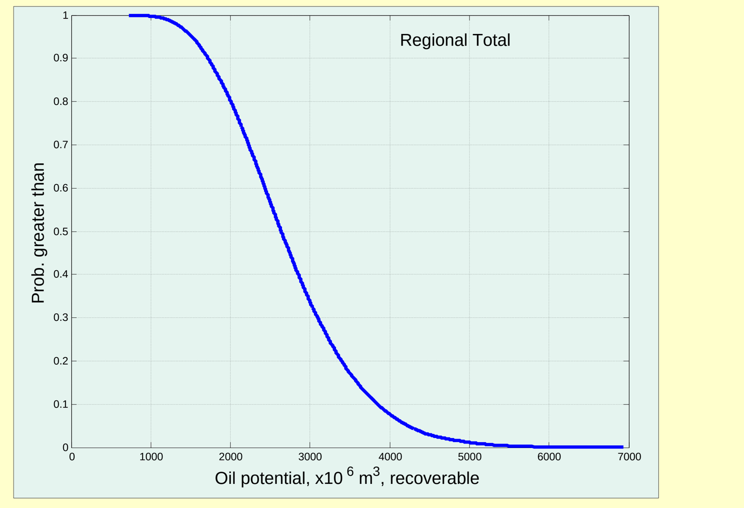

Figure 13. Distribution of aggregated total oil resource in the Canadian Beaufort/Mackenzie province, showing the uncertainty range of the estimate.

Future Discovery Potential

Given the large undiscovered oil resource potential, the future discovery growth in this province is expected to come from: a) drilling the untested/unmapped prospects in the established oil plays, tests of the Tertiary targets where earlier wells focused on deeper Cretaceous targets, such as many wells in the Tuk play (Dixon et al., 1994), or untested targets in deeper intervals where the original targets were at shallower depths; b) new play types in areas where discoveries have been made, such as shale-diapir-related plays (Bergquist et al., 2003); c) untested deep water plays in the north. The deep water region, characterized by mobile substrata fed by large rivers of the Beaufort/Mackenzie province, is the most petroliferous type of deep water basin in Worrel's classification (2001). Geological similarities with the Niger Delta deep water setting, as well as the Gulf of Mexico, suggest that a great oil resource potential may exist. d) Reserve growth has accounted for a large portion of total world oil reserve additions (Klett, 2005); this could also happen in this province, as indicated by untested seismic anomalies around the Amauligak discovery (Enachesu, 1990) and newly estimated reserves of natural gas and NGLs. For example, the recently released industry estimates of gas reserves in the three principal gas fields (Taglu, Parsons Lake and Niginitgak) indicate much higher volumes than the previous NEB's estimates (6.2 tcf vs. 3.7 tcf).

Only a part of the entire Mackenzie/Beaufort province prospective sedimentary succession is the subject to this petroleum resource potential appraisal. Our focus is limited to the region south of continuous pack ice and restricted to the shallow part of the total sedimentary succession (largely in the Tertiary succession). This reflects the current, early exploration history stage of this province. It is expected that there will be both increased data and understanding that will lead to new large discoveries in the more remote areas and deeper parts of the sedimentary succession as the scope of exploration expands both geographically and technologically. The discovery and reserve growth patterns of the Mississippi Delta petroleum province, where very large accumulations continue to be found as exploration expands into the geographically remote, deep water and technologically challenging parts of the Gulf of Mexico, may provide a useful analogy for the future exploration outlook and overall potential of the Mackenzie/Beaufort province.

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